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RETROFIT COSTS FOR SO_2 AND NO_x CONTROL OPTIONS AT 200 COAL-FIRED PLANTS

VOLUME IV - SITE SPECIFIC STUDIES FOR
Missouri, Mississippi, North Carolina, New Hampshire,
New Jersey, New York, Ohio

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ABSTRACT

This report documents the results of a study conducted under the National Acid Precipitation Assessment Program by the U.S. Environmental Protection Agency's Air and Energy Engineering Research Laboratory. The objective of this research program was to significantly improve engineering cost estimates currently being used to evaluate the economic effects of applying sulfur dioxide and nitrogen oxides controls at 200 large sulfur dioxide emitting coal-fired utility plants. To accomplish the objective, procedures were developed and used that account for site-specific retrofit factors. The site-specific information was obtained from aerial photographs, generally available data bases, and input from utility companies. Cost estimates are presented for the following control technologies: lime/limestone flue gas desulfurization, lime spray drying, coal switching and cleaning, furnace and duct sorbent injection, low NO_x combustion or natural gas reburn, and selective catalytic reduction. Although the cost estimates provide useful site-specific cost information on retrofitting acid gas controls, the costs are estimated for a specific time period and do not reflect future changes in boiler and coal characteristics (e.g., capacity factors and fuel prices) or significant changes in control technology cost and performance.

NOTICE

This document has been reviewed in accordance with U.S. Environmental Protection Agency policy and approved for publication. Mention of trade names or commercial products does not constitute endorsement or recommendation for use.

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ABBREVIATIONS AND SYMBOLS

ABBREVIATIONS

acfm -- actual cubic feet per minute

AEERL -- Air and Energy Engineering Research Laboratory

AEP -- Associated Electric Cooperative

AFDC -- allowance for funds during construction

AUSM -- advanced utility simulation model

-C -- constant dollars in cost tables

CG -- coal gasfication

CG&E -- Cincinnati Gas and Electric

CS -- coal switching

CS/B -- coal switching and blending

DOE -- Department of Energy

DSD -- duct spray drying

EIA-767 -- Energy Information Administration Form 767

EPA -- Environmental Protection Agency

EPRI -- Electric Power Research Institute

ESP -- electrostatic precipitator

FBC -- fluidized bed combustion

FF -- fabric filter

FGD -- flue gas desulfurization

FPD -- fuel price differential

FSI -- furnace sorbent injection

ft -- feet

FWF -- front, wall-fired

IAPCS -- Integrated Air Pollution Control System

ABBREVIATIONS AND SYMBOLS (Continued)

IRS	-- Internal Revenue Service
KU	-- Kentucky Utilities
kW	-- kilowatt
kWh	-- killowatt hour
LC	-- low cost
LIMB	-- limestone injection multistage burner
L/LS	-- lime/limestone
LNB	-- low-NO_x burner
LNC	-- low-NO_x combustion
LSD	-- lime spray drying
m	-- meter
MM	-- millions
MW	-- megawatt
NAPAP	-- National Acid Precipitation Assessment Program
NGR	-- natural gas reburning
NRDC	-- Natural Resources Defense Council
NSPS	-- new source performance standard
NTIS	-- National Technical Information Service
OEUI	-- Ohio Electric Utilities
OFA	-- overfire air
OWF	-- opposed, wall-fired
O&M	-- operating and maintenance
PCC	-- physical coal cleaning
PM	-- particulate matter
psia	-- pounds per square inch absolute

SCA -- specific collection area (ft^2/1000 acfm)

SCR -- selective catalytic reduction

SCR-CS -- selective catalytic reduction - cold side

SCR-HS -- selective catalytic reduction - hot side

sec -- second

SI -- sorbent injection

sq ft -- square feet

TAG -- Technical Assessment Guideline

TVA -- Tennessee Valley Authority

UARG -- Utility Air Regulatory Group

USGS -- U.S. Geological Survey

$/kW -- dollars per kilowatt

SYMBOLS

MgO -- magnesium oxide

NH_3 -- ammonia

NO_x -- nitrogen oxides

SO_2 -- sulfur dioxide

SO_3 -- sulfur trioxide

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METRIC EQUIVALENTS

Readers more familiar with the metric system may use the following factors to convert to that system.

Non-metric	Times	Yields Metric
acfm	0.028317	acms
acre	4046.9	m^2
Btu/lb	0.5556	kg-calories/kg
°F	5/9 (°F-32)	°C
ft	0.3048	m
ft^2	0.0929	m^2
ft^3	0.028317	m^3
gal.	3.78533	L
lb/MMBtu	1.8	kg/kg-calorie
psia	0.0703	g/cm^2
ton	0.9072	ton

SECTION 14.0 MISSOURI

14.1 ASSOCIATED ELECTRIC COOPERATIVE SYSTEM

14.1.1 New Madrid Steam Plant

The New Madrid steam plant is located within New Madrid County, Missouri,as part of the Associated Electric Cooperative system. The plant contains two coal-fired boilers with a total gross generating capacity of 1,200 MW. Figure 14.1.1-1 presents the plant plot plan showing the general layout and location of the boilers and major associated auxiliary equipment.

Table 14.1.1-1 presents operational data for the existing equipment at the New Madrid steam plant. All boilers burn high sulfur coal (3.2 to 4.1 percent sulfur). Coal shipments are received by freight barge and conveyed to a coal storage and handling area located northwest of the plant.

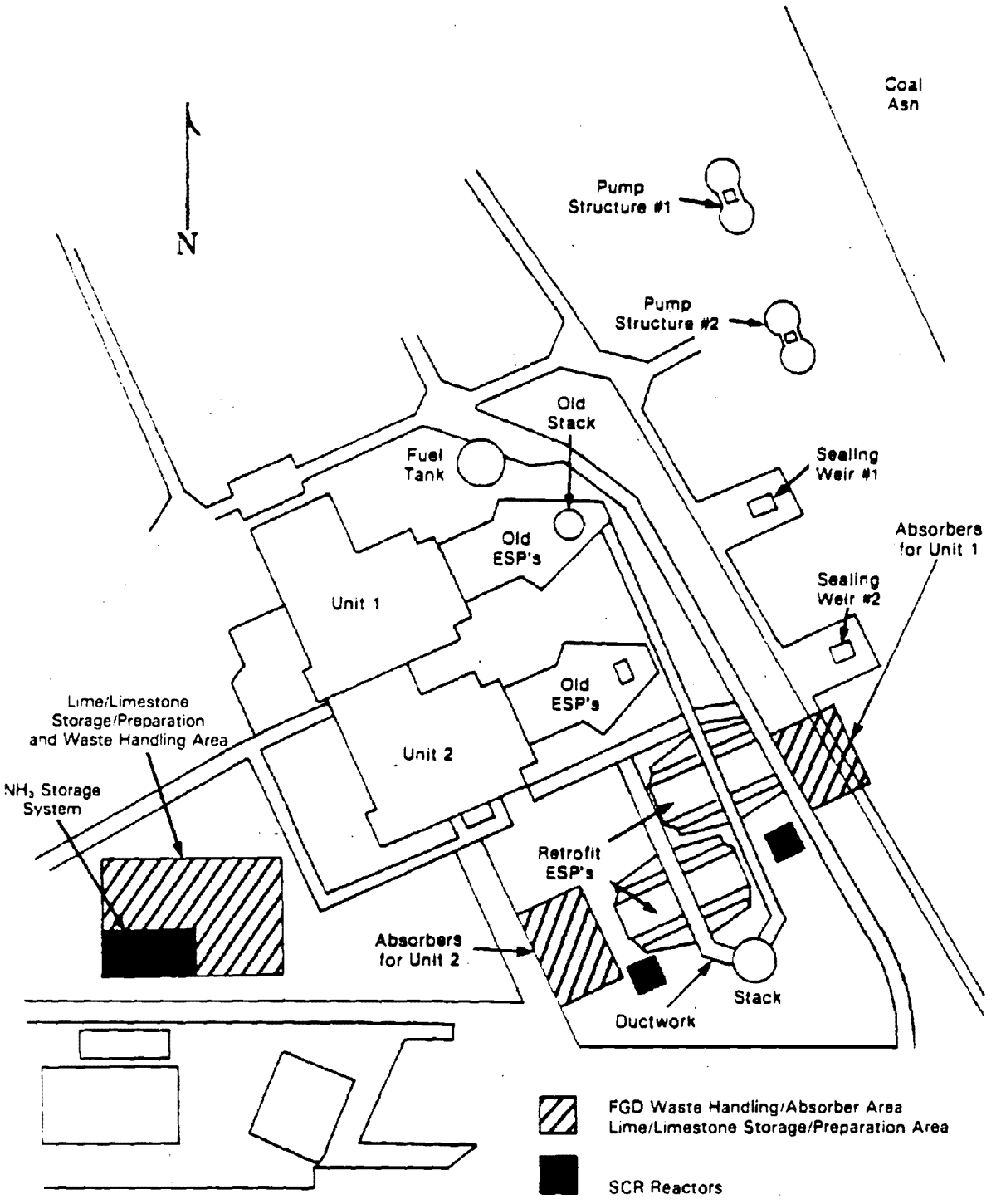
Particulate matter emissions for both boilers are controlled with retrofit ESPs located south of Unit 2. Ash from all units is wet sluiced to ponds located southeast of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.1.1-1 shows the general layout and location of the FGD control system. Absorbers for both units and both FGD technologies were located in a relatively open area south of unit 2 on either side of the retrofit ESPs, adjacent to the chimney. The lime and limestone preparation/storage area was placed west of the absorbers with the waste handling area being located south of the preparation/storage area. No major demolition/relocation would be required to locate the absorbers. Therefore, a low general facility factor (5 percent) was assigned to all units and technologies.

Retrofit Difficulty and Scope Adder Costs--

The FGD equipment for both units would be located in a relatively low site access/congestion area on either side of the retrofit ESPs. No major obstacles/obstructions exist in the surrounding area where the absorbers and



Not to scale

Figure 14.1.1-1. New Madrid plant plot plan

TABLE 14.1.1-1. NEW MADRID STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	600
CAPACITY FACTOR (PERCENT)	49, 45
FIRING TYPE	CYC
INSTALLATION DATE	1972-77
COAL SULFUR CONTENT (PERCENT)	3.2
COAL HEATING VALUE (BTU/LB)	10500
COAL ASH CONTENT (PERCENT)	10.5
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1-2
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1982
EMISSION (LB/MM BTU)	0.06-0.05
REMOVAL EFFICIENCY	98.0
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	4.7
SURFACE AREA (1000 SQ FT)	572
GAS EXIT RATE (1000 ACFM)	2200
SCA (SQ FT/1000 ACFM)	260
OUTLET TEMPERATURE (°F)	310

tie-in ductwork would be located. As a result, a low site access/congestion factor was assigned to the FGD absorbers and flue gas handling system for all units and all FGD technologies. A short duct run was required to route the flue gas to absorbers.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Table 14.1.1-2. The largest scope adder for the New Madrid plant would be the conversion of units 1 and 2 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD and LSD-FGD cases. It was assumed that dry fly ash would be necessary to stabilize conventional L/LS-FGD scrubber sludge waste and to prevent plugging of sluice lines in LSD-FGD system (for the ESP-reuse case). This conversion is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases were low (1.24 to 1.31).

The LSD with reused ESP was the only LSD-FGD technology considered because the existing ESPs have moderate size SCAs (260). The retrofit factor determined for the LSD technologies was low (1.27) and did not include particulate control upgrading costs. A separate retrofit factor was developed for upgrading the ESPs (1.16) and used in the IAPCS model to estimate the particulate control costs of additional ESP plate area. The low factor is a result of the space availability around the existing ESPs.

Table 14.1.1-3 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1 and 2.

The low cost control case reduces capital and annual operating costs. The significant reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber module, and optimization of scrubber size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined. This is particularly true for cyclone boilers. Therefore, coal switching was not evaluated for the New Madrid Plant.

TABLE 14.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR NEW MADRID UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4673	NA	4673
NEW CHIMNEY*	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.31	1.24	
ESP REUSE CASE			1.27
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

* The existing chimney is relined.

Table 14.1.1-3. Summary of FGD Control Costs for the New Madrid Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.31	600	49	3.2	132.6	221.0	64.9	25.2	90.0	69750	930.9
L/S FGD	2	1.31	600	45	3.2	132.6	221.0	63.2	26.7	90.0	64056	986.9
L/S FGD-C	1	1.31	600	49	3.2	132.6	221.0	37.8	14.7	90.0	69750	541.8
L/S FGD-C	2	1.31	600	45	3.2	132.6	221.0	36.8	15.6	90.0	64056	574.7
LC FGD	1-2	1.31	1200	47	3.2	199.7	166.4	103.9	21.0	90.0	133806	776.5
LC FGD-C	1-2	1.31	1200	47	3.2	199.7	166.4	60.4	12.2	90.0	133806	451.6
LSD+ESP	1	1.27	600	49	3.2	79.6	132.7	39.2	15.2	75.0	57908	677.6
LSD+ESP	2	1.27	600	45	3.2	79.6	132.7	38.1	16.1	75.0	53181	716.6
LSD+ESP-C	1	1.27	600	49	3.2	79.6	132.7	22.8	8.9	75.0	57908	394.4
LSD+ESP-C	2	1.27	600	45	3.2	79.6	132.7	22.2	9.4	75.0	53181	417.3

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at New Madrid. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at New Madrid were: NGR and SCR.

Low NO_x Combustion--

Units 1 and 2 are wet bottom, cyclone boilers, each rated at 600 MW. The combustion modification technique that was applicable was NGR. The NO_x reduction performance estimated for the units was 60 percent. Table 14.1.1-4 presents the NGR NO_x reduction performance result for the boilers. Table 14.1.1-5 presents the costs of retrofitting NGR at the New Madrid boilers.

Selective Catalytic Reduction--

Table 14.1.1-4 presents the SCR retrofit results for each unit. Results include a process area retrofit factor and scope adder cost. The scope adders include costs estimated for ductwork demolition, flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

Each SCR reactor was located behind (south) the respective ESPs and to either side of the chimney in areas of low congestion with easy access. Therefore, both reactors were assigned a low access/congestion factor. The reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was located southwest of the powerhouse in a relatively open area. Table 14.1.1-5 presents the costs estimated to retrofit SCR at the New Madrid plant.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

TABLE 14.1.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR NEW MADRID

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	CY	CY
TYPE OF NOx CONTROL	NGR	NGR
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	60
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	104	104
New Duct Length (Feet)	170	150
New Duct Costs (1000$)	2,403	2,191
New Heat Exchanger (1000$)	5,461	5,461
TOTAL SCOPE ADDER COSTS (1000$)	7,968	7,756
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 14.1.1-5. NOx Control Cost Results for the New Madrid Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	600	49	3.2	8.5	14.2	14.3	5.6	60.0	12668	1129.9
NGR	2	1.00	600	45	3.2	8.5	14.2	13.2	5.6	60.0	11634	1137.5
NGR-C	1	1.00	600	49	3.2	8.5	14.2	8.2	3.2	60.0	12668	650.4
NGR-C	2	1.00	600	45	3.2	8.5	14.2	7.6	3.2	60.0	11634	655.0
SCR-3	1	1.16	600	49	3.2	71.5	119.1	27.9	10.8	80.0	16891	1650.1
SCR-3	2	1.16	600	45	3.2	71.2	118.7	27.6	11.7	80.0	15512	1780.0
SCR-3-C	1	1.16	600	49	3.2	71.5	119.1	16.3	6.3	80.0	16891	964.4
SCR-3-C	2	1.16	600	45	3.2	71.2	118.7	16.1	6.8	80.0	15512	1040.4
SCR-7	1	1.16	600	49	3.2	71.5	119.1	22.8	8.9	80.0	16891	1352.4
SCR-7	2	1.16	600	45	3.2	71.2	118.7	22.6	9.5	80.0	15512	1455.9
SCR-7-C	1	1.16	600	49	3.2	71.5	119.1	13.4	5.2	80.0	16891	793.8
SCR-7-C	2	1.16	600	45	3.2	71.2	118.7	13.3	5.6	80.0	15512	854.7

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for both units were located east of the plant in a relatively open area in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the New Madrid steam plant would be very easy. There is sufficient flue gas ducting residence time between the boilers and the retrofit ESPs and the ESPs are moderate in size (SCAs >250). However, if additional ESP plate area was required, the ESP access/congestion factor would be low (1.13) because of the space availability around the ESPs with easy access. The conversion of wet to dry fly ash handling system would be needed for reusing the ESPs. Table 14.1.1-6 presents a summary of the site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the New Madrid steam plant. Table 14.1.1-7 presents the costs estimated to retrofit DSD and FSI at the New Madrid plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the New Madrid plant. The boilers at New Madrid would not be considered good candidates for AFBC retrofit and AFBC or CG/combined cycle repowering because of the large boiler sizes (600 MW).

14.1.2 Thomas Hill Steam Plant

The Thomas Hill steam plant is located within Randolph County, Missouri, as part of Associated Electric Cooperative system. The plant contains three coal-fired boilers with a total gross generating capacity of 1,140 MW. Figure 14.1.2-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 14.1.2-1 presents operational data for the existing equipment at the Thomas Hill plant. The boilers burn high sulfur coal (4.1 percent sulfur). Coal shipments are received by conveyors from a nearby coal mine and transferred to two coal storage and handling areas located east of the plant.

TABLE 14.1.1-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR NEW MADRID UNITS 1-2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	4673
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	115
TOTAL COST (1000$)	
ESP UPGRADE CASE	4788
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 14.1.1-7. Summary of DSD/FSI Control Costs for the New Madrid Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	600	49	3.2	39.6	66.0	26.2	10.2	48.0	37092	706.4
DSD+ESP	2	1.00	600	45	3.2	39.6	66.0	25.1	10.6	48.0	34064	738.0
DSD+ESP-C	1	1.00	600	49	3.2	39.6	66.0	15.2	5.9	48.0	37092	409.5
DSD+ESP-C	2	1.00	600	45	3.2	39.6	66.0	14.6	6.2	48.0	34064	428.0
FSI+ESP-50	1	1.00	600	49	3.2	32.9	54.8	32.6	12.7	50.0	38750	841.0
FSI+ESP-50	2	1.00	600	45	3.2	32.9	54.8	30.7	13.0	50.0	35587	861.6
FSI+ESP-50-C	1	1.00	600	49	3.2	32.9	54.8	18.8	7.3	50.0	38750	485.6
FSI+ESP-50-C	2	1.00	600	45	3.2	32.9	54.8	17.7	7.5	50.0	35587	497.8
FSI+ESP-70	1	1.00	600	49	3.2	32.6	54.4	33.1	12.8	70.0	54250	609.6
FSI+ESP-70	2	1.00	600	45	3.2	32.6	54.4	31.1	13.1	70.0	49821	624.3
FSI+ESP-70-C	1	1.00	600	49	3.2	32.6	54.4	19.1	7.4	70.0	54250	352.0
FSI+ESP-70-C	2	1.00	600	45	3.2	32.6	54.4	18.0	7.6	70.0	49821	360.6

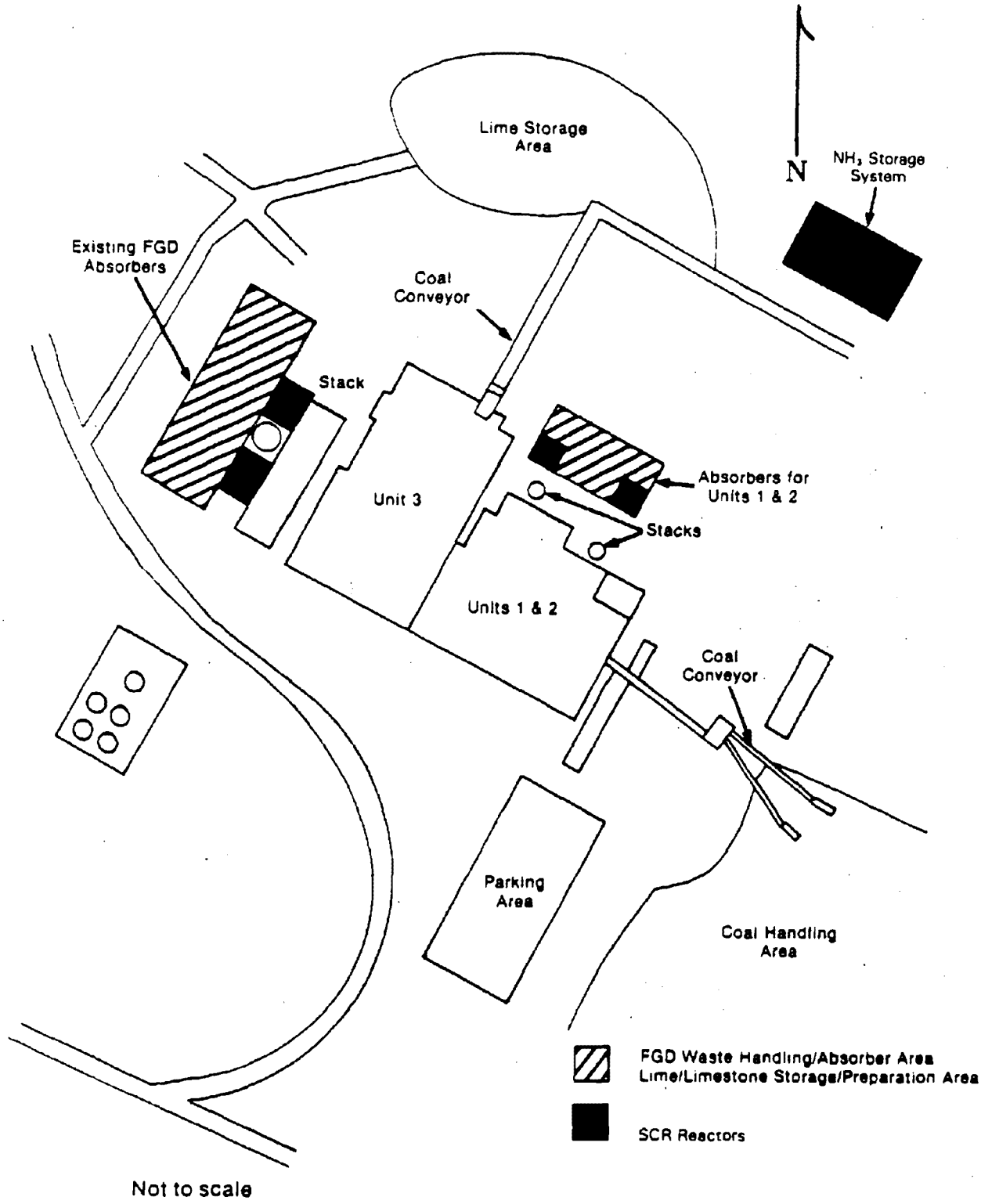


Figure 14.1.2-1. Thomas Hill plant plot plan

TABLE 14.1.2-1. THOMAS HILL STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3
GENERATING CAPACITY (MW)	180	290	670
CAPACITY FACTOR (PERCENT)	59	57	57
INSTALLATION DATE	1966	1969	1982
FIRING TYPE	CYC	CYC	OWF
COAL SULFUR CONTENT (PERCENT)	4.1	4.1	4.1
COAL HEATING VALUE (BTU/LB)	10400	10406	10123
COAL ASH CONTENT (PERCENT)	11.3	10.5	11.7
FLY ASH SYSTEM	DRY HANDLING		
ASH DISPOSAL METHOD	OFF SITE/MINE FILL		
STACK NUMBER	1	2	3
COAL DELIVERY METHODS	CONVEYORS/NEARBY COAL MINE		
FGD SYSTEM	NO	NO	YES
INSTALLATION DATE	-	-	1982
FGD TYPE	-	-	LIMESTONE WET SCRUBBER
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1983	1969,79	1982
EMMISION (LB/MM BTU)	0.17	0.13	0.02
REMOVAL EFFICIENCY	99.5	99.0	99.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	4.0	4.0	4.8
SURFACE AREA (1000 SQ FT)	330.6	112,256	858
GAS EXIT RATE (1000 ACFM)	675	498,702	2900
SCA (SQ FT/1000 ACFM)	490	225,365	296
OUTLET TEMPERATURE (°F)	310	310	310

Particulate matter emissions for the boilers are controlled with retrofit ESPs located behind each unit. The plant has a dry fly ash handling system.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.1.2-1 shows the general layout and location of the FGD control system. The three boilers are located beside each other close to the Middle Fork Cliften River and adjacent to the Thomas Hill Reservoir. Each unit has its own chimney. Unit 3 currently has a wet FGD system located behind the chimney and its respective limestone storage/preparation area is located north of the boiler. The absorbers for L/LS-FGD and LSD-FGD for units 1 and 2 would be located behind each respective chimney and the storage, preparation and handling area for unit 3 would be expanded and used for all three boilers. No major demolition/relocation would be required; therefore, a factor of 5 percent was assigned to general facilities.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for units 1 and 2 would be located north of the chimneys in an area bounded by the conveyors. A medium site access/congestion factor was assigned to units 1 and 2 absorber locations due to the access difficulty to this area as well as underground obstruction. For flue gas handling, short duct runs for both units would be required for L/LS-FGD cases.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 14.1.2-2 and 14.1.2-3. The major scope adder cost would be installation of a new chimney. Plant personnel indicated that the chimneys for units 1 and 2 would need to be replaced for FGD systems. The overall retrofit factors determined for the L/LS-FGD cases were moderate.

The absorbers for LSD-FGD would be located in a similar location as in L/LS-FGD cases. LSD-FGD with reused ESP was the only LSD-FGD technology considered for the units because of the moderate size of the ESPs (SCAs >365). For flue gas handling for LSD cases, short to moderate duct runs would be required. A high site access/congestion factor was assigned to the flue gas handling system because of the difficulty to tie into the upstream of the ESPs in order to divert flue gas from the boilers to the absorbers

TABLE 14.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR THOMAS HILL UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	1260	1260	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.40	1.42	
ESP REUSE CASE			1.49
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 14.1.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR THOMAS HILL UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	2030	2030	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.40	1.42	
ESP REUSE CASE			1.49
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

and back to the ESPs. The retrofit factor determined for the LSD technology case was moderate (1.49) and did not include particulate control upgrading costs. Separate retrofit factors were developed for upgrading ESPs for each unit. A moderate retrofit factor (1.36) was assigned for upgrading ESPs for unit 1 due to the available space on one side of the ESPs and the close proximity to unit 2 on the other side; for unit 2, a high retrofit factor was assigned (1.58) because of the close proximity of the ESPs, powerhouse, and chimney. These factors were used in the IAPCS model to estimate particulate control upgrading costs.

Table 14.1.2-4 presents cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 1 and 2. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

Coal Switching and Physical Coal Cleaning Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined. This is particularly true for cyclone boilers; therefore, coal switching was not evaluated.

Table 14.1.2-5 presents the IAPCS results for physical coal cleaning at Thomas Hill plant. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Thomas Hill steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were:

Table 14.1.2-4. Summary of FGD Control Costs for the Thomas Hill Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.40	180	59	4.1	65.3	362.8	31.9	34.3	90.0	32638	977.9
L/S FGD	2	1.40	290	57	4.1	88.0	303.3	43.8	30.2	90.0	50767	862.0
L/S FGD-C	1	1.40	180	59	4.1	65.3	362.8	18.6	20.0	90.0	32638	569.2
L/S FGD-C	2	1.40	290	57	4.1	88.0	303.3	25.5	17.6	90.0	50767	501.6
LC FGD	1-2	1.40	470	58	4.1	14.1	30.0	8.5	3.6	90.0	1247	6839.4
LC FGD-C	1-2	1.40	470	58	4.1	101.5	215.9	32.7	13.7	90.0	83722	390.6
LSD+ESP	1	1.49	180	59	4.1	31.9	177.5	17.1	18.4	66.0	23915	714.2
LSD+ESP	2	1.49	290	57	4.1	49.4	170.3	25.3	17.4	67.0	38003	664.6
LSD+ESP-C	1	1.49	180	59	4.1	31.9	177.5	9.9	10.7	66.0	23915	415.2
LSD+ESP-C	2	1.49	290	57	4.1	49.4	170.3	14.7	10.1	67.0	38003	386.6

Table 14.1.2-5. Summary of Coal Switching/Cleaning Costs for the Thomas Hill Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
PCC	1	1.00	180	59	4.1	2.5	14.0	3.0	3.2	38.0	13674	217.4
PCC	2	1.00	290	57	4.1	4.0	13.8	4.4	3.0	38.0	21246	207.8
PCC	3	1.00	670	57	4.1	8.9	13.3	8.7	2.6	15.0	19850	438.6
PCC-C	1	1.00	180	59	4.1	2.5	14.0	1.7	1.8	38.0	13674	125.4
PCC-C	2	1.00	290	57	4.1	4.0	13.8	2.5	1.8	38.0	21246	119.9
PCC-C	3	1.00	670	57	4.1	8.9	13.3	5.0	1.5	15.0	19850	253.3

NGR - units 1 and 2; LNB - unit 3; and SCR - all units. Even though Unit 3 already should have achieved 1979 NSPS for NO_x emissions, it was included for consideration in this study.

Low NO_x Combustion--

Units 1 and 2 are wet bottom, cyclone-fired boilers rated at 180 and 290 MW, respectively. The combustion modification technique applied to both boilers was NGR. Unit 3 is dry bottom, opposed wall-fired boiler, rated at 670 MW. The combustion modification technique applied for this unit was LNB. As Table 14.1.2-6 shows, the LNB NO_x reduction performance for each unit was estimated to be 50 percent. This reduction performance level was assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. However, this boiler probably already is equipped with LNBs in which case additional NO_x reductions achievable with LNC technique would likely be less than 20 percent. As such, no cost estimates were developed for unit 3. Table 14.1.2-7 presents the cost of retrofitting NGR at the Thomas Hill plant.

Selective Catalytic Reduction--

Table 14.1.2-6 presents the SCR retrofit results for units 1 to 3. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 and 2 would be located immediately behind their respective chimneys; whereas, the SCR reactor for unit 3 would be located south of both the existing FGD unit and chimney for unit 3. All three reactors are located in low congestion and open areas. No major relocation or demolition would be required for any of the units. Therefore, the reactors for units 1 to 3 were assigned low access/congestion factors. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/ congestion factor.

TABLE 14.1.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR THOMAS HILL

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	CY	CY	OWF
TYPE OF NOx CONTROL	NGR	NGR	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA	10.7
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA	120.6
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	3.79
ESTIMATED NOx REDUCTION (PERCENT)	60	60	50
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	42	71	113
New Duct Length (Feet)	100	100	350
New Duct Costs (1000$)	699	1,227	5,277
New Heat Exchanger (1000$)	2,652	4,642	5,835
TOTAL SCOPE ADDER COSTS (1000$)	3,393	5,940	11,225
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	13

Table 14.1.2-7. NOx Control Cost Results for the Thomas Hill Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	180	59	4.1	3.4	19.0	5.3	5.7	60.0	4627	1143.3
NGR	2	1.00	290	57	4.1	4.9	16.8	8.1	5.6	60.0	7197	1130.5
NGR-C	1	1.00	180	59	4.1	3.4	19.0	3.0	3.3	60.0	4627	658.3
NGR-C	2	1.00	290	57	4.1	4.9	16.8	4.7	3.2	60.0	7197	650.8
SCR-3	1	1.16	180	59	4.1	27.5	152.6	10.1	10.8	80.0	6169	1634.6
SCR-3	2	1.16	290	57	4.1	41.3	142.4	15.3	10.5	80.0	9595	1590.7
SCR-3	3	1.16	670	57	4.1	81.6	121.8	31.0	9.3	80.0	14133	2196.5
SCR-3-C	1	1.16	180	59	4.1	27.5	152.6	5.9	6.3	80.0	6169	956.5
SCR-3-C	2	1.16	290	57	4.1	41.3	142.4	8.9	6.2	80.0	9595	930.6
SCR-3-C	3	1.16	670	57	4.1	81.6	121.8	18.2	5.4	80.0	14133	1284.3
SCR-7	1	1.16	180	59	4.1	27.5	152.6	8.6	9.2	80.0	6169	1389.8
SCR-7	2	1.16	290	57	4.1	41.3	142.4	12.8	8.9	80.0	9595	1337.0
SCR-7	3	1.16	670	57	4.1	81.6	121.8	25.4	7.6	80.0	14133	1797.0
SCR-7-C	1	1.16	180	59	4.1	27.5	152.6	5.0	5.4	80.0	6169	816.2
SCR-7-C	2	1.16	290	57	4.1	41.3	142.4	7.5	5.2	80.0	9595	785.3
SCR-7-C	3	1.16	670	57	4.1	81.6	121.8	14.9	4.5	80.0	14133	1055.5

As discussed in Section 2, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. If both SO_2 and NO_x emissions were needed to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers. For unit 3, the SCR reactor is already located downstream of the absorber; therefore, the results listed above for retrofitting SCR to this boiler would apply in this case. For units 1 and 2, the SCR reactors would be located downstream of the absorber (i.e., west of the absorbers) in a relatively open area having easy access. Therefore, low access/congestion factors would again be assigned to SCR reactors for units 1 and 2. Table 14.1.2-7 presents the estimated cost of retrofitting SCR at the Thomas Hill boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located north of the plant in a similar fashion as LSD-FGD. The retrofit of FSI and DSD technologies at the Thomas Hill steam plant for both units would be relatively easy due to the large ESP size (SCAs >300) of the ESPs. However, there appears to be short duct residence time between the boilers and ESPs, making the application of DSD more difficult. Because the ESPs are large, the E-SO_x technology may be applicable at these units. A medium to high site access/congestion factor was assigned for upgrading the ESPs for the same reasons as mentioned in the previous section. Tables 14.1.2-8 and 14.1.2-9 present a summary of the site access/congestion factors for DSD and FSI technologies at the Thomas Hill steam plant. Table 14.1.2-10 presents the costs estimated to retrofit DSD and FSI at the Thomas Hill plant.

TABLE 14.1.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR THOMAS HILL UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	46
TOTAL COST (1000$)	
ESP UPGRADE CASE	46
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.34
NEW BAGHOUSE	NA

TABLE 14.1.2-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR THOMAS HILL UNIT 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	66
TOTAL COST (1000$)	
ESP UPGRADE CASE	66
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

Table 14.1.2-10. Summary of DSD/FSI Control Costs for the Thomas Hill Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	180	59	4.1	13.3	73.9	11.3	12.2	43.0	15765	717.9
DSD+ESP	2	1.00	290	57	4.1	20.2	69.5	16.2	11.2	44.0	24925	651.6
DSD+ESP-C	1	1.00	180	59	4.1	13.3	73.9	6.5	7.0	43.0	15765	415.1
DSD+ESP-C	2	1.00	290	57	4.1	20.2	69.5	9.4	6.5	44.0	24925	377.0
FSI+ESP-50	1	1.00	180	59	4.1	12.9	71.8	15.4	16.6	50.0	18132	850.3
FSI+ESP-50	2	1.00	290	57	4.1	18.5	63.8	22.9	15.8	50.0	28204	810.6
FSI+ESP-50-C	1	1.00	180	59	4.1	12.9	71.8	8.9	9.6	50.0	18132	490.3
FSI+ESP-50-C	2	1.00	290	57	4.1	18.5	63.8	13.2	9.1	50.0	28204	467.4
FSI+ESP-70	1	1.00	180	59	4.1	13.2	73.1	15.7	16.9	70.0	25385	620.4
FSI+ESP-70	2	1.00	290	57	4.1	18.9	65.0	23.4	16.1	70.0	39486	591.9
FSI+ESP-70-C	1	1.00	180	59	4.1	13.2	73.1	9.1	9.8	70.0	25385	357.8
FSI+ESP-70-C	2	1.00	290	57	4.1	18.9	65.0	13.5	9.3	70.0	39486	341.2

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Thomas Hill plant. Units 1 and 2 would be considered good candidates for AFBC retrofit because of their small boiler size. However, their high capacity factors make them less likely to be good candidates due to replacement power costs and mixed potential improvement in unit heat rate.

14.2 EMPIRE DISTRICT ELECTRIC COMPANY

14.2.1 Asbury Steam Plant

The Asbury steam plant is located within Jasper County, Missouri, as part of the Empire District Electric Company system. The plant contains one coal-fired boiler with a total net generating capacity of 213 MW. Figure 14.2.1-1 presents the plant plot plan showing the location of the boiler and major associated auxiliary equipment.

Table 14.2.1-1 presents operational data for the existing equipment at the Asbury steam plant. The boiler burns high sulfur coal (5.5 percent sulfur). Coal shipments are received by conveyor from a nearby mine and conveyed to a coal storage and handling area located northeast of the plant. Plant personnel indicated that Asbury plant is in the process of converting to low sulphur fuel bringing the plant emission within 1.2 lb SO_2/million Btu. The construction for this conversion is underway with completion scheduled for mid 1990.

Particulate matter emissions for the boiler are controlled with ESPs located behind the chimney. Ash from the unit is wet sluiced to ponds located east of the plant. On-site waste disposal appears to be available and no additional land purchases are anticipated for future FGD waste disposal.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.2.1-1 shows the general layout and location of the FGD control system. The absorbers would be located southeast of the unit directly behind the chimney for L/LS-FGD and on either side of the ESPs for the LSD-FGD. The absorber area would be bounded by the construction building (southwest) and the cooling towers (northeast). The lime and limestone preparation/storage area and waste handling area were placed south and southwest of the absorber, respectively. No major demolition/relocation would be required to locate the absorbers. Therefore, a factor of 5 percent was assigned to general facilities.

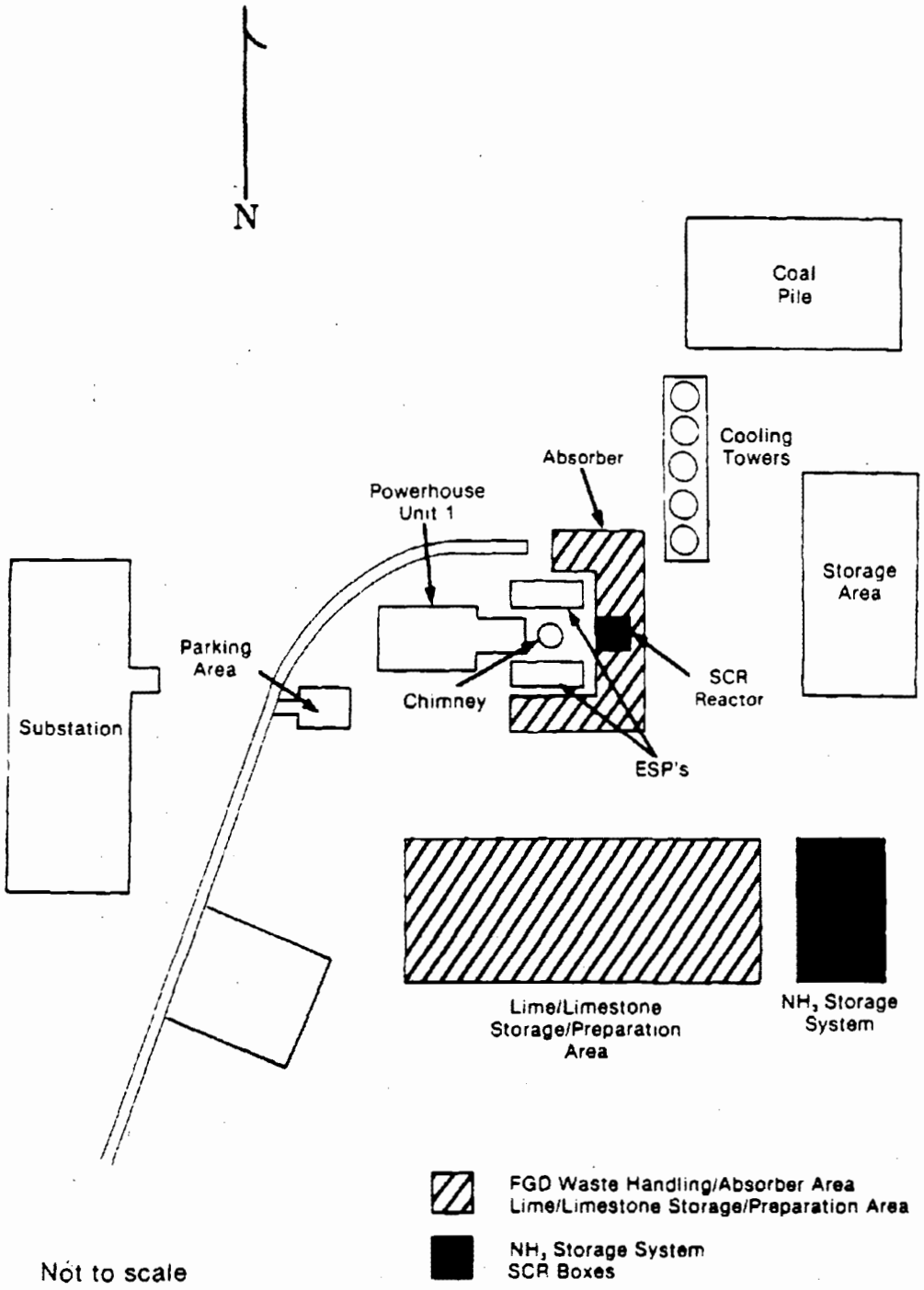


Figure 14.2.1-1. Asbury plant plot plan

TABLE 14.2.1-1 ASBURY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1
GENERATING CAPACITY (MW)	213
CAPACITY FACTOR (PERCENT)	68
FIRING TYPE	CYC
INSTALLATION DATE	1970
COAL SULFUR CONTENT (PERCENT)*	5.5
COAL HEATING VALUE (BTU/LB)	10700
COAL ASH CONTENT (PERCENT)	23
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	CONVEYOR
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1970
EMISSION (LB/MM BTU)	0.134
REMOVAL EFFICIENCY	96.4
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	6.0
SURFACE AREA (1000 SQ FT)	86.4/147.6
GAS EXIT RATE (1000 ACFM)	613.7
SCA (SQ FT/1000 ACFM)	381
OUTLET TEMPERATURE (°F)	310

* Asbury is in the process of converting to low sulfur coal.

Retrofit Difficulty and Scope Adder Costs--

The FGD equipment was located southeast of the unit 1 for L/LS-FGD and on either side of the ESPs for LSD-FGD. No major obstacles/obstructions exist in the surrounding area where the absorbers and tie-in ductwork would be located and a short to medium duct run would be required. As a result, a low site access/congestion factor was assigned to the absorber location and flue gas handling for all FGD technologies.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Table 14.2.1-2. The largest scope adder for Asbury would be the conversion of unit 1 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD and LSD-FGD cases. It was assumed that dry fly ash would be necessary to stabilize L/LS-FGD scrubber sludge waste and to prevent plugging of sluice lines in the LSD-FGD system for the ESP-reuse case). However, this conversion would not be necessary for forced oxidation. The overall retrofit factors determined for the L/LS-FGD cases were low to moderate (1.24 to 1.31).

The LSD with reuse ESP was the only LSD-FGD case evaluated because the ESP presently has a moderate SCA size (>300) and the existing ESPs are located in a low site access/congestion area. The retrofit factor determined for the LSD technology was low to moderate (1.34) and did not include particulate control upgrading costs. A separate retrofit factor was developed for upgrading ESPs (1.16) and used in the IAPCS model to estimate the particulate control costs. The low factor is a result of the space availability around the existing ESPs.

Table 14.2.1-3 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boiler 1. The low cost control case reduces capital and annual operating costs due to the benefits of elimination of spare scrubber module and optimization of scrubber module size.

Coal Switching and Physical Coal Cleaning Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be

TABLE 14.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR ASBURY UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	2001	NA	2001
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.31	1.24	
ESP REUSE CASE			1.34
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

Table 14.2.1-3. Summary of FGD Control Costs for the Asbury Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.31	213	68	5.5	64.7	303.7	35.7	28.1	90.0	57795	617.2
L/S FGD-C	1	1.31	213	68	5.5	64.7	303.7	20.7	16.3	90.0	57795	358.6
LC FGD	1	1.31	213	68	5.5	46.4	217.7	29.7	23.4	90.0	57795	513.2
LC FGD-C	1	1.31	213	68	5.5	46.4	217.7	17.2	13.6	90.0	57795	297.6
LSD+ESP	1	1.34	213	68	5.5	34.8	163.3	19.5	15.4	49.0	31609	618.2
LSD+ESP-C	1	1.34	213	68	5.5	34.8	163.3	11.4	8.9	49.0	31609	359.1

determined. This is particularly true for cyclone boilers; as such, coal switching was not evaluated.

Table 14.2.1-4 presents the IAPCS results for physical coal cleaning at Asbury plant. These costs do not include reduced pulverizer operating costs or system modifications that may be necessary to handle deep cleaned coal.

NO_x Control Technology Cost--

This section presents the performance and costs estimated for NO_x controls at the Asbury steam plant. These controls include NGR and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2.

Low NO_x Combustion--

The boiler at the Asbury plant is a wet bottom, cyclone boiler rated at 213 MW. The combustion modification technique that was applicable was NGR. The NO_x reduction performance estimated for the unit was 60 percent. Table 14.2.1-5 presents the NGR NO_x reduction performance result for the boiler. Table 14.2.1-6 presents the costs of retrofitting NGR at the Asbury boiler.

Selective Catalytic Reduction--

Table 14.2.1-5 presents the SCR retrofit results for unit 1. The results include a process area retrofit factor and scope adder cost. The scope adders include costs estimated for ductwork demolition, flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The reactor was located southeast of the powerhouse and the chimney and the ammonia storage system was also located southeast of the chimney. The SCR reactor was given a low access/congestion factor. Also, the ammonia storage system was placed in an area with low access/congestion. The reactor was assumed to be in an area with significant underground obstructions while the ammonia system was not. Table 14.2.1-6 presents the estimated cost of retrofitting SCR at the Asbury boiler.

Table 14.2.1-4. Summary of Coal Switching/Cleaning Costs for the Asbury Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
PCC	1	1.00	213	68	5.5	2.7	12.7	2.7	2.2	97.0	62419	44.0
PCC-C	1	1.00	213	68	5.5	2.7	12.7	1.6	1.2	97.0	62419	25.4

TABLE 14.2.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR ASBURY

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1
FIRING TYPE	CY
TYPE OF NOx CONTROL	NGR
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA
FURNACE RESIDENCE TIME (SECONDS)	NA
ESTIMATED NOx REDUCTION (PERCENT)	60
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	48
New Duct Length (Feet)	115
New Duct Costs (1000$)	887
New Heat Exchanger (1000$)	2934
TOTAL SCOPE ADDER COSTS (1000$)	3868
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

Table 14.2.1-6. NOx Control Cost Results for the Asbury Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	213	68	5.5	3.8	18.0	6.9	5.4	60.0	6107	1128.4
NGR-C	1	1.00	213	68	5.5	3.8	18.0	4.0	3.1	60.0	6107	649.3
SCR-3	1	1.16	213	68	5.5	31.1	146.2	11.7	9.2	80.0	8143	1437.4
SCR-3-C	1	1.16	213	68	5.5	31.1	146.2	6.8	5.4	80.0	8143	840.7
SCR-7	1	1.16	213	68	5.5	31.1	146.2	9.9	7.8	80.0	8143	1218.8
SCR-7-C	1	1.16	213	68	5.5	31.1	146.2	5.8	4.6	80.0	8143	715.5

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for unit 1 was located southeast of the plant in a relatively open area. The retrofit of DSD and FSI technologies at Asbury steam plant would be relatively easy. There is sufficient flue gas ducting residence time between the boiler and the retrofit ESPs which have moderate size SCAs (>380) and a large amount of space available for plate area upgrade. A low retrofit factor was estimated for upgrading the ESPs (1.13). Table 14.2.1-7 presents a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the Asbury steam plant. Table 14.2.1-8 presents the cost estimate to retrofit DSD and FSI at the Asbury unit 1.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technology at the Asbury plant. The boiler at Asbury would be considered a good candidate for AFBC retrofit and AFBC or CG/combined cycle repowering because of small boiler size (213 MW). However, the high capacity factor indicates a good unit heat rate and a potentially high replacement power cost which makes retrofit/repowering of AFBC or CG less attractive economically.

TABLE 14.2.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ASBURY UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2001
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	56
TOTAL COST (1000$)	
ESP UPGRADE CASE	2057
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 14.2.1-8. Summary of DSD/FSI Control Costs for the Asbury Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	213	68	5.5	16.8	78.9	13.5	10.6	35.0	22547	597.3
DSD+ESP-C	1	1.00	213	68	5.5	16.8	78.9	7.8	6.1	35.0	22547	345.6
FSI+ESP-50	1	1.00	213	68	5.5	17.8	83.5	24.8	19.5	50.0	32108	772.3
FSI+ESP-50-C	1	1.00	213	68	5.5	17.8	83.5	14.3	11.3	50.0	32108	445.0
FSI+ESP-70	1	1.00	213	68	5.5	18.1	84.8	25.3	20.0	70.0	44951	563.8
FSI+ESP-70-C	1	1.00	213	68	5.5	18.1	84.8	14.6	11.5	70.0	44951	324.8

14.3 KANSAS CITY POWER AND LIGHT

14.3.1 Hawthorn Steam Plant

The Hawthorn steam plant is located within Jackson County, Missouri, as part of the Kansas City Power and Light Company system. The plant contains five coal-fired boilers; units 1-4 are presently inactive. Unit 5 has a total gross generating capacity of 515 MW. Figure 14.3.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 14.3.1-1 presents operational data for the existing equipment at the Hawthorn plant. The boiler burns low sulfur coal (1.1 percent sulfur). Coal shipments are received by railroad and to a conveyed coal storage and handling area located south of the powerhouse.

Particulate matter emissions for the boilers are controlled with retrofit ESPs located northeast of the boilers. Fly ash is wet sluiced to ponds located west of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.3.1-1 shows the general layout and location of the FGD control system. The five boilers sit beside each other, adjacent to the levee, close to the Missouri River. Although they are inactive, units 3 and 4 currently have a wet FGD system. The absorbers for L/LS-FGD and LSD-FGD for unit 5 would be located northwest of the boiler adjacent to the ESPs and close to the levee in an open area. No major demolition/relocation would be required; therefore, a factor of 5 percent was assigned to general facilities. The lime and limestone storage/preparation area and waste handling area would be located adjacent to the absorbers.

Retrofit Difficulty and Scope Adder Costs--

A low site access/congestion factor was assigned to the unit 5 absorber location due to no major obstacles or obstructions in the surrounding area. For flue gas handling, moderate duct runs for unit 5 would be required for L/LS-FGD cases. A medium site access/congestion factor was assigned to the

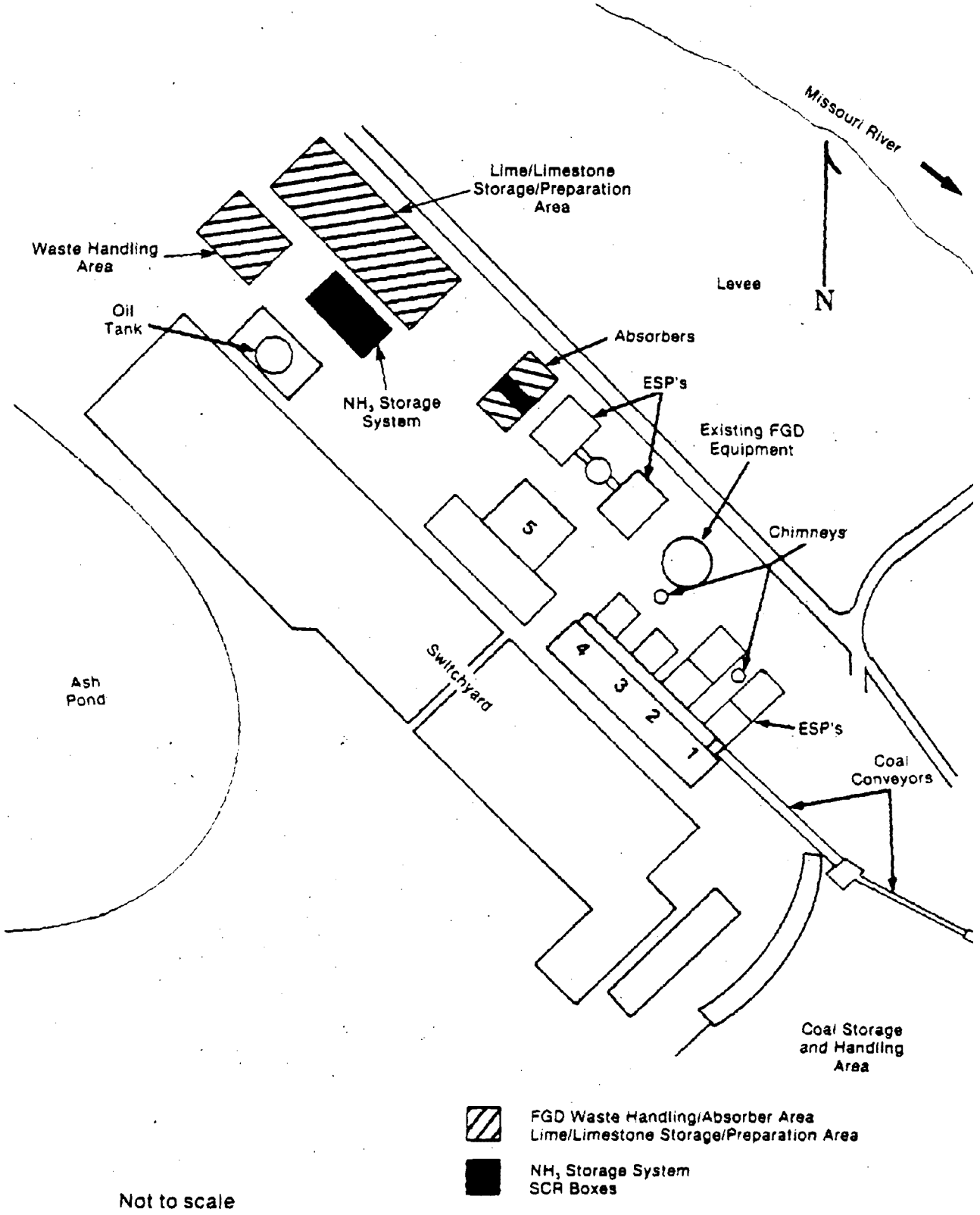


Figure 14.3.1-1. Hawthorn plant plot plan

TABLE 14.3.1-1. HAWTHORN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3,4	5
GENERATING CAPACITY (MW-each)	69	112,142	514
CAPACITY FACTOR (PERCENT)	--	--	46
INSTALLATION DATE	1951	1953-55	1969
FIRING TYPE	-	-	TANG
COAL SULFUR CONTENT (PERCENT)	-	-	1.1
COAL HEATING VALUE (BTU/LB)	-	-	9447
COAL ASH CONTENT (PERCENT)	-	-	7.3
FLY ASH SYSTEM		WET SLUICE	
ASH DISPOSAL METHOD		POND/ON-SITE	
STACK NUMBER	1	2	3
COAL DELIVERY METHODS		RAILROAD	
FGD SYSTEM	NO	YES	NO
INSTALLATION DATE	-	NA	-
FGD TYPE	-	-	-
PARTICULATE CONTROL			
TYPE	ESP	WET SCRUBBER	ESP
INSTALLATION DATE	1977	1972	1978
EMMISION (LB/MM BTU)	0.02	0.17	0.04
REMOVAL EFFICIENCY	99.4	98.5	99.4
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	0.6	6.4	0.2
SURFACE AREA (1000 SQ FT)	240	-	1357
GAS EXIT RATE (1000 ACFM)	324	346	2100
SCA (SQ FT/1000 ACFM)	740	-	646
OUTLET TEMPERATURE (°F)	300	185	310

Units 1-4 are no longer in service.

flue gas handling system because the chimney is located between the two ESPs boxes.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 14.3.1-2. The largest scope adder cost for the Hawthorn plant would be the conversion of unit 5 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD and LSD-FGD cases. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste in the L/LS-FGD system and to prevent plugging of sluice lines in the LSD-FGD system for the ESP-reuse case. This conversion is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors determined for the L/LS-FGD cases were moderate (1.35 to 1.42).

The absorbers for LSD-FGD would be located in a similar location close to the boiler as in L/LS-FGD cases. LSD-FGD with reused ESP was the only LSD-FGD technology considered for the unit because its ESPs are large (SCA =646). For flue gas handling for LSD cases, moderate duct runs would be required and a medium site access/congestion factor was assigned to the flue gas handling system for the same reasons as stated above in L/LS-FGD cases. The retrofit factor determined for the LSD technology case was moderate (1.38) and did not include particulate control upgrading costs. A separate retrofit factor was developed for upgrading ESPs. A low retrofit factor (1.16) was assigned to the upgraded ESP location due to the available space if additional plate area is required. This factor was used in the IAPCS model to estimate particulate control upgrading costs.

Table 14.3.1-3 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boiler 5.

The low cost control case reduces capital and annual operating costs due to the benefits of elimination of a spare scrubber module, optimization of scrubber module size, and use of organic acid additives.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for

TABLE 14.3.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR HAWTHORN UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4073	NA	4073
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	1.35	
ESP REUSE CASE			1.38
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

Table 14.3.1-3. Summary of FGD Control Costs for the Hawthorn Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	5	1.42	514	46	1.1	128.0	249.0	56.5	27.3	90.0	21770	2594.8
L/S FGD-C	5	1.42	514	46	1.1	128.0	249.0	32.9	15.9	90.0	21770	1513.0
LC FGD	5	1.42	514	46	1.1	102.1	198.7	48.0	23.2	90.0	21770	2206.3
LC FGD-C	5	1.42	514	46	1.1	102.1	198.7	28.0	13.5	90.0	21770	1285.1
LSD+ESP	5	1.38	514	46	1.1	58.4	113.6	25.0	12.0	76.0	18456	1352.1
LSD+ESP-C	5	1.38	514	46	1.1	58.4	113.6	14.6	7.0	76.0	18456	788.8

the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Hawthorn steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR.

Low NO_x Combustion--

Unit 5 is a dry bottom, tangential-fired boiler rated at 515 MW. The combustion modification technique applied for this evaluation was OFA. As Table 14.3.1-4 shows, the OFA NO_x reduction performance for this unit was estimated at 20 percent. This reduction performance level was assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. Table 14.3.1-5 presents the cost of retrofitting OFA at the Hawthorn boiler.

Selective Catalytic Reduction--

Table 14.3.1-4 presents the SCR retrofit results for unit 5. The results include a process area retrofit factor and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactor for unit 5 would be located northwest of the boiler, adjacent to the ESPs and close to the levee, in an open area with no major obstacles. Therefore, the reactor was assigned a low access/congestion factor. No major relocation and demolition of existing equipment and buildings would be required and a low factor of 13 percent was assigned to

TABLE 14.3.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR HAWTHORN

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	5
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	13.4
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	154.7
FURNACE RESIDENCE TIME (SECONDS)	2.93
ESTIMATED NOx REDUCTION (PERCENT)	20
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	92
New Duct Length (Feet)	500
New Duct Costs (1000$)	6,463
New Heat Exchanger (1000$)	4,983
TOTAL SCOPE ADDER COSTS (1000$)	11,538
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

Table 14.3.1-5. NOx Control Cost Results for the Hawthorn Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	5	1.00	514	46	1.1	1.2	2.3	0.3	0.1	20.0	1692	153.9
LNC-OFA-C	5	1.00	514	46	1.1	1.2	2.3	0.2	0.1	20.0	1692	91.3
SCR-3	5	1.16	514	46	1.1	66.9	130.1	24.2	11.7	80.0	6766	3577.3
SCR-3-C	5	1.16	514	46	1.1	66.9	130.1	14.2	6.8	80.0	6766	2093.9
SCR-7	5	1.16	514	46	1.1	66.9	130.1	19.8	9.6	80.0	6766	2930.7
SCR-7-C	5	1.16	514	46	1.1	66.9	130.1	11.7	5.6	80.0	6766	1723.4

general facilities. The reactor was assumed to be in an area with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.

As discussed in Chapter 2, all NO_x control techniques were evaluated independently from those evaluated for SO_2 control. As a result for this plant, the FGD absorber was located in the same area as the SCR reactor. If both SO_2 and NO_x emissions have to be reduced at this plant, the SCR reactor would have to be located downstream of the FGD absorber (i.e., west of the absorber) in a relatively open area having easy access. A low access/congestion factor again would be assigned to this SCR reactor. Table 14.3.1-5 presents the estimated cost of retrofitting SCR at the Hawthorn boiler.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Hawthorn steam plant of unit 5 would be very easy. This is due to the long duct residence time between the boiler and the ESPs and the large SCA (640). The major scope adder cost for DSD and FSI would be the conversion of the fly ash from wet to dry. Table 14.3.1-6 presents a summary of the site access/congestion factors for DSD and FSI technologies at the Hawthorn steam plant. Table 14.3.1-7 presents the costs estimated to retrofit DSD and FSI at the Hawthorn plant.

TABLE 14.3.1-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR HAWTHORN UNIT 5

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	4073
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	102
TOTAL COST (1000$)	
ESP UPGRADE CASE	4175
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 14.3.1-7. Summary of DSD/FSI Control Costs for the Hawthorn Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	5	1.00	514	46	1.1	21.1	41.1	13.0	6.3	49.0	11768	1106.2
DSD+ESP-C	5	1.00	514	46	1.1	21.1	41.1	7.6	3.6	49.0	11768	641.8
FSI+ESP-50	5	1.00	514	46	1.1	20.7	40.3	13.8	6.6	50.0	12094	1138.3
FSI+ESP-50-C	5	1.00	514	46	1.1	20.7	40.3	8.0	3.9	50.0	12094	659.8
FSI+ESP-70	5	1.00	514	46	1.1	20.9	40.7	14.0	6.8	70.0	16932	826.7
FSI+ESP-70-C	5	1.00	514	46	1.1	20.9	40.7	8.1	3.9	70.0	16932	479.2

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Hawthorn plant. The boiler would not be considered a good candidate for AFBC retrofit due to its large boiler size (515 MW) and new age (1969).

14.3.2 Iatan Steam Plant

L/S-FGD and LSD-FGD retrofit factors for unit 1 at the Iatan plant were developed; however, costs are not presented since the boiler fires a low sulfur coal which would yuield low capital/operating costs and high cost per ton of SO_2 removed. CS was not evaluated because the plant currently burns a low sulfur coal. The unit is equipped with LNBs; however, for additional NO_x control, SCR was evaluated.

TABLE 14.3.2-1. IATAN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1
GENERATING CAPACITY (MW-each)	674
CAPACITY FACTOR (PERCENT)	67
INSTALLATION DATE	1980
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	YES
COAL SULFUR CONTENT (PERCENT)	0.4
COAL HEATING VALUE (BTU/LB)	8840
COAL ASH CONTENT (PERCENT)	5
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	POND/ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1980
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	99.4
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.3
SURFACE AREA (1000 SQ FT)	1728
GAS EXIT RATE (1000 ACFM)	2643
SCA (SQ FT/1000 ACFM)	654
OUTLET TEMPERATURE (°F)	302

TABLE 14.3.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR IATAN UNIT 1 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	5186	NA	5186
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			1.43
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

* L/LS-FGD absorbers for unit 1 would be located southeast of the unit 1 chimney. LSD-FGD absorbers for unit 1 would be located southeast of the unit 1 ESPs.

TABLE 14.3.2-3. SUMMARY OF NOx RETROFIT RESULTS FOR IATAN

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1
FIRING TYPE	NA
TYPE OF NOx CONTROL	NA
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	NA
SLAGGING PROBLEM	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA
SCR RETROFIT RESULTS *	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	113
New Duct Length (Feet)	200
New Duct Costs (1000$)	3026
New Heat Exchanger (1000$)	5856
TOTAL SCOPE ADDER COSTS (1000$)	8995
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

* Cold side SCR reactors for unit 1 would be located southeast of the unit 1 chimney.

Table 14.3.2-4. NOx Control Cost Results for the Iatan Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3	1	1.16	674	67	0.4	81.8	121.3	32.3	8.2	80.0	19526	1655.9
SCR-3-C	1	1.16	674	67	0.4	81.8	121.3	18.9	4.8	80.0	19526	967.5
SCR-7	1	1.16	674	67	0.4	81.8	121.3	26.5	6.7	80.0	19526	1359.2
SCR-7-C	1	1.16	674	67	0.4	81.8	121.3	15.6	3.9	80.0	19526	797.5

TABLE 14.3.2-5. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR IATAN UNIT 1

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	5186
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	125
TOTAL COST (1000$)	
ESP UPGRADE CASE	5311
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Sufficient duct residence time exist between unit 1 and the unit 1 ESPs. A low factor was assigned to ESP upgrade since the ESPs are large in size and space is available around the ESPs.

Table 14.3.2-6. Summary of DSD/FSI Control Costs for the Iatan Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	674	67	0.4	17.8	26.4	11.7	3.0	49.0	8821	1323.6
DSD+ESP-C	1	1.00	674	67	0.4	17.8	26.4	6.8	1.7	49.0	8821	767.4
FSI+ESP-50	1	1.00	674	67	0.4	21.6	32.1	12.5	3.2	50.0	9065	1380.2
FSI+ESP-50-C	1	1.00	674	67	0.4	21.6	32.1	7.3	1.8	50.0	9065	801.4
FSI+ESP-70	1	1.00	674	67	0.4	21.8	32.3	12.7	3.2	70.0	12692	999.1
FSI+ESP-70-C	1	1.00	674	67	0.4	21.8	32.3	7.4	1.9	70.0	12692	580.1

14.3.3 La Cygne Steam Plant

The La Cygne steam plant is located within Linn County, Missouri, as part of the Kansas City Power and Light Company system. The plant is located adjacent to a lake and contains two coal-fired boilers with a total gross generating capacity of 1,558 MW.

Table 14.3.3-1 presents operational data for the existing equipment at the La Cygne plant. Boiler 1, which is equipped with a new FGD unit, is burning high sulfur coal while boiler 2 is burning low sulfur coal. Coal shipments are received by railroad and transferred to two coal piles east of the plant. One pile is for the low sulfur coal and the other one is for high sulfur coal.

PM emissions for boiler 1 are controlled with wet scrubbers and boiler 2 by ESPs which are located behind each unit. Fly ash is disposed on-site in several ash ponds north of the plant. Each unit has its own chimney.

Lime/Limestone and Lime Spray Drying FGD Costs--

Both boilers are located southeast of the lake. Because unit 1 has a new FGD system, it was not considered in this study. Unit 2 is burning a very low sulfur coal. Retrofit factors were developed for unit 2, although costs were not developed. FGD costs generated based on the current coal burned would result in low capital and operating cost estimates relative to burning a high sulfur coal. As is the case for unit 1, it is likely that unit 2 would be switched to burn a high sulfur coal if an FGD unit was needed due to acid rain legislation or due to the increased cost differential between low and high sulfur coal.

The absorbers for unit 2 would be located behind its chimney, adjacent to a storage building. The existing unit 1 limestone preparation, storage, and handling area located northeast of the coal pile would be expanded for unit 2. No major demolition/relocation would be required and a factor of 5 percent was assigned to general facilities.

A low site access/congestion factor was assigned to the unit 2 FGD absorber location because of the space available behind the chimney. Because the absorbers would be placed behind the chimney, a relatively short

TABLE 14.3.3-1. LA CYGNE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW-each)	873	685
CAPACITY FACTOR (PERCENT)	26	42
INSTALLATION DATE	1973	1977
FIRING TYPE	CYCLONE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	529	NA
LOW NOx COMBUSTION	NO	YES
COAL SULFUR CONTENT (PERCENT)	4.7	0.39
COAL HEATING VALUE (BTU/LB)	9100	8500
COAL ASH CONTENT (PERCENT)	25.0	5.4
FLY ASH SYSTEM	DRY HANDLING	
ASH DISPOSAL METHOD	ON-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
FGD SYSTEM	YES	NO
FGD TYPE	VENTURI LIMESTONE	--
FGD INSTALLATION DATE	1973	--
PARTICULATE CONTROL		
TYPE	WET SCRUBBERS	ESP
INSTALLATION DATE	1973	1977
EMISSION (LB/MM BTU)	0.21	0.01
REMOVAL EFFICIENCY	98.0	99.4
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	5.4	0.3
SURFACE AREA (1000 SQ FT)	NA	1728
GAS EXIT RATE (1000 ACFM)	2500	2926
SCA (SQ FT/1000 ACFM)	NA	590
OUTLET TEMPERATURE (°F)	151	302

duct length would be required. A low site access/congestion factor was also assigned to the flue gas handling system because of the easy accessibility to the existing chimney.

LSD with reuse of the existing ESPs was considered for unit 2 because the ESPs are large (SCA =590) and would not require major upgrading and plate area additions to handle the increased PMs generated from the LSD application. The absorbers would be located behind the chimney; hence, a low site access/congestion factor was assigned to the absorber location. A high site access/congestion factor was assigned to the flue gas handling system because duct work has to go around the ESPs and access to the upstream of the existing ESPs is difficult. Duct length of over 1,000 feet would be required.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 14.3.3-2. Costs were not developed for unit 2 because the unit is burning a very low sulfur coal which would result in very high unit costs.

Coal Switching and Physical Coal Cleaning Costs--

La Cygne unit 2 is already burning a low sulfur coal and would not be considered for CS/blending/cleaning.

Low NO_x Combustion--

Unit 2 is equipped with LNBs and, as such, was not considered a candidate for LNC. Unit 1 is a cyclone boiler and the combustion modification techniques applied to this boiler is NGR. Plant personnel indicated that the La Cygne plant does not presently use natural gas, therefore, the plant does not have a natural gas line. The projected cost for installation of a natural gas pipeline is approximately ten million dollars. Tables 14.3.3-3 and 14.3.3-4 present performance and cost results for retrofitting NGR at the La Cygne plant.

Selective Catalytic Reduction--

Cold side SCR reactors for both units would be located immediately behind the unit 2 chimney. The SCR reactors for unit 1 were not placed behind its respective chimney because of the obstructions created by the

TABLE 14.3.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR LA CYGNE UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			1000 +
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.20	NA	
ESP REUSE CASE			1.64
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 14.3.3-3. SUMMARY OF NOx RETROFIT RESULTS FOR LA CYGNE

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	CYC	OWF
TYPE OF NOx CONTROL	NGR	NA
FURNACE VOLUME (1000 CU FT)	529	NA
BOILER INSTALLATION DATE	1973	1977
SLAGGING PROBLEM	NA	NO
ESTIMATED NOx REDUCTION (PERCENT)	60	NA
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	137	114
New Duct Length (Feet)	600	200
New Duct Costs (1000$)	10561	3055
New Heat Exchanger (1000$)	6839	5913
TOTAL SCOPE ADDER COSTS (1000$)	17537	9082
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 14.3.3-4. NOx Control Cost Results for the La Cygne Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	873	26	4.7	21.5	24.6	13.1	6.6	60.0	11527	1135.4
NGR-C	1	1.00	873	26	4.7	21.5	24.6	7.6	3.8	60.0	11527	658.9
SCR-3	1	1.16	873	26	4.7	105.9	121.3	39.1	19.7	80.0	15369	2546.5
SCR-3	2	1.16	685	42	0.4	81.5	118.9	31.2	12.4	80.0	13013	2398.1
SCR-3-C	1	1.16	873	26	4.7	105.9	121.3	22.9	11.5	80.0	15369	1489.9
SCR-3-C	2	1.16	685	42	0.4	81.5	118.9	18.2	7.2	80.0	13013	1402.0
SCR-7	1	1.16	873	26	4.7	105.9	121.3	31.7	15.9	80.0	15369	2060.3
SCR-7	2	1.16	685	42	0.4	81.5	118.9	25.3	10.0	80.0	13013	1942.9
SCR-7-C	1	1.16	873	26	4.7	105.9	121.3	18.6	9.4	80.0	15369	1211.3
SCR-7-C	2	1.16	685	42	0.4	81.5	118.9	14.9	5.9	80.0	13013	1141.2

coal conveyors. The SCR reactors were assigned a low site access/congestion factor for the same reasons as were outlined in the FGD section. Flue gas duct length of 600 feet would be required for unit 1 and 200 feet would be required for unit 2. The ammonia storage system was placed west of the reactors. No major demolition/relocation would be necessary; therefore, a base factor of 13 percent was assigned to general facilities.

Table 14.3.3-3 presents the SCR retrofit results for both units. Table 14.3.3-4 presents the estimated cost of retrofitting SCR at the La Cygne boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the La Cygne steam plant for unit 2 would be difficult. This is caused by inadequate duct residence time between the boilers and the ESPs for either humidification (FSI application) or sorbent droplet evaporation (DSD application). However, the ESPs are sufficiently large that the first ESP section can be used for humidification or sorbent injection. A high site access/congestion factor was assigned to the ESP locations if additional plate area or upgrading of the existing ESPs is required. This factor reflects the access difficulty to the existing ESPs as well as congestion created by the close proximity of the ESPs, chimneys, and interferences created by the coal conveyor. Because unit 2 is burning a very low sulfur coal, cost estimates for DSD/FSI are not reported.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the La Cygne plant. Neither of these units would be considered good candidates for repowering or retrofit because of their large boiler size and short service life.

14.3.4 Montrose Steam Plant

The Montrose steam plant is located within Henry County, Missouri, as part of the Kansas City Power and Light Company system. Located to the north of Montrose Lake, the plant contains three coal-fired boilers and has a total gross generating capacity of 564 MW.

Table 14.3.4-1 presents operational data for the existing equipment at the Montrose plant. In the EIA-767 form, it is reported that the boilers burn high sulfur coal (4.5 percent sulfur). However, plant personnel indicated that the plant switched to a western low sulfur coal (0.5 percent sulfur) in 1987. Coal shipments were originally made by truck. After switching to western coal, railroad transportation was used. Coal is transferred to a coal storage and handling area east of the plant and adjacent to the lake.

PM emissions for the boilers are controlled with retrofit ESPs located behind each unit. Even though the ESPs are large (SCA >500), some difficulty has been observed in removing PM since the plant switched to low sulfur coal. Plant personnel indicated that upgrading the ESP voltage controls or gas conditioning is being considered to improve the ESP performance. The plant has the capability of disposing the fly ash either dry or wet. Fly ash is disposed of on-site west of the plant. Originally, there was one chimney serving each unit. Now, however, units 2-3 are served by one chimney and unit 1 is served by a separate chimney. The middle chimney behind unit 2 is out of service.

Lime/Limestone and Lime Spray Drying FGD Costs--

The three boilers are located beside each other and are parallel to the lake. Water intake and discharge structures are located behind unit 3. For retrofit FGD systems, the unit 1 through 3 absorbers would be located behind the chimneys between the units and the lake. The limestone preparation, storage, and handling area would be located west of the plant adjacent to the existing ash pond site. The ash sluice lines, a road, and some storage buildings would be relocated and, as such, a factor of 10 percent was assigned to general facilities.

A medium site access/congestion factor was assigned to the FGD absorber locations due to some congestion difficulties created by the water intake,

TABLE 14.3.4-1. MONTROSE STEAM PLANT OPERATIONAL DATA *

BOILER NUMBER	1-3
GENERATING CAPACITY (MW-each)	188
CAPACITY FACTOR (PERCENT)	28,28,47
INSTALLATION DATE	1958,60,64
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	102
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	0.5
COAL HEATING VALUE (BTU/LB)	8800
COAL ASH CONTENT (PERCENT)	5
FLY ASH SYSTEM	WET/DRY HANDLING
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1-2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1972
EMISSION (LB/MM BTU)	0.11
REMOVAL EFFICIENCY	99.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	5.0
SURFACE AREA (1000 SQ FT)	300
GAS EXIT RATE (1000 ACFM)	581.6
SCA (SQ FT/1000 ACFM)	516
OUTLET TEMPERATURE (°F)	290

* This table was revised after talking to the plant personnel.

discharge channel, and storage area. In addition, the absorbers would be located in an area with high underground obstructions created by the circulating water coming from the intake channel. For flue gas handling, because the absorbers were placed immediately behind the chimneys, short duct runs would be required for L/LS-FGD cases (about 250 feet). A low site access/congestion factor was assigned to the flue gas handling system due to easy access to the existing chimneys.

LSD with reuse of the existing ESPs was considered for the Montrose plant because the units have relatively large ESPs. The absorbers would be located behind the chimneys as in the L/LS-FGD cases and a medium site access/congestion factor was assigned to the absorber location. For the flue gas handling system, a high site access/congestion factor was assigned because of the difficulties in gaining access upstream of the existing ESPs.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 14.3.4-2. No large scope adder cost is required for the Montrose plant.

Costs were not developed for FGD technologies based on the currently fired coal because the plant has already switched to a low sulfur coal. Cost estimates based on the current coal would result in lower capital and operating costs than for a high sulfur coal. This plant would not scrub unless the fuel price differential between high and low sulfur coal made FGD economical.

Coal Switching and Physical Coal Cleaning Costs--

Montrose plant has already switched to a low sulfur coal; therefore, costs were not developed for coal switching and cleaning.

Low NO_x Combustion--

Units 1 through 3 are dry bottom, tangential-fired boilers rated at 188 MW each. The combustion modification technique applied to all boilers was OFA. As Table 14.3.4-3 shows, the OFA NO_x reduction performance for each unit is 25 percent. Table 14.3.4-4 presents the cost of retrofitting OFA at the Montrose plant.

TABLE 14.3.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR MONTROSE UNITS 1,2,3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.30	NA	
ESP REUSE CASE			1.49
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

TABLE 14.3.4-3. SUMMARY OF NOx RETROFIT RESULTS FOR MONTROSE

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2,3	1-3
FIRING TYPE	TANG	NA
TYPE OF NOx CONTROL	OFA	NA
FURNACE VOLUME (1000 CU FT)	102	NA
BOILER INSTALLATION DATE	1958	NA
SLAGGING PROBLEM	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	NA
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	43	99
New Duct Length (Feet)	250	250
New Duct Costs (1000$)	1792	3408
New Heat Exchanger (1000$)	2722	5262
TOTAL SCOPE ADDER COSTS (1000$)	4558	8769
RETROFIT FACTOR FOR SCR	1.34	1.34
GENERAL FACILITIES (PERCENT)	20	20

Table 14.3.4-4. NOx Control Cost Results for the Montrose Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1, 2	1.00	188	28	0.5	0.8	4.2	0.2	0.4	25.0	511	341.1
LNC-OFA	3	1.00	188	47	0.5	0.8	4.2	0.2	0.2	25.0	857	203.2
LNC-OFA-C	1, 2	1.00	188	28	0.5	0.8	4.2	0.1	0.2	25.0	511	202.5
LNC-OFA-C	3	1.00	188	47	0.5	0.8	4.2	0.1	0.1	25.0	857	120.6
SCR-3	1, 2	1.34	188	28	0.5	32.6	173.6	10.8	23.5	80.0	1634	6619.7
SCR-3	3	1.34	188	47	0.5	32.6	173.7	11.0	14.3	80.0	2743	4023.1
SCR-3	1-3	1.34	564	34	0.5	76.5	135.7	27.4	16.3	80.0	5953	4598.8
SCR-3-C	1, 2	1.34	188	28	0.5	32.6	173.6	6.3	13.8	80.0	1634	3882.2
SCR-3-C	3	1.34	188	47	0.5	32.6	173.7	6.5	8.4	80.0	2743	2358.3
SCR-3-C	1-3	1.34	564	34	0.5	76.5	135.7	16.0	9.5	80.0	5953	2692.4
SCR-7	1, 2	1.34	188	28	0.5	32.6	173.6	9.2	20.0	80.0	1634	5630.0
SCR-7	3	1.34	188	47	0.5	32.6	173.7	9.4	12.2	80.0	2743	3433.5
SCR-7	1-3	1.34	564	34	0.5	76.5	135.6	22.5	13.4	80.0	5953	3783.8
SCR-7-C	1, 2	1.34	188	28	0.5	32.6	173.6	5.4	11.7	80.0	1634	3315.2
SCR-7-C	3	1.34	188	47	0.5	32.6	173.7	5.5	7.2	80.0	2743	2020.5
SCR-7-C	1-3	1.34	564	34	0.5	76.5	135.6	13.2	7.9	80.0	5953	2225.5

Selective Catalytic Reduction--

Cold side SCR reactors for all units would be located immediately behind the chimneys. All three reactors are located in areas with medium site access/congestion and high underground obstructions as outlined in the FGD section. Because the SCR reactors are located close to the chimneys, a short duct length of 250 feet was required for the flue gas handling systems. The ammonia storage system was placed close to the reactors and east of the plant. A plant road, ash silos, and sluice lines have to be relocated to open up sufficient space for the SCR reactors. Therefore, a factor of 20 percent was assigned to general facilities.

Table 14.3.4-3 presents the SCR retrofit results of all units. Table 14.3.4-4 presents the estimated cost of retrofitting SCR at the Montrose boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the Montrose steam plant would be difficult since inadequate duct residence time exists between the boilers and the retrofit ESPs for either humidification (FSI application) or sorbent droplet evaporation (DSD application). However, the ESPs are large and the first ESP section could be modified for humidification or sorbent injection. A high site access/congestion factor was assigned to the ESP locations for modifying and upgrading the existing ESPs. This factor reflects the access difficulty for the existing ESPs due to congestion created by the close proximity of the ESPs, chimneys, and ash silos. The sorbent receiving/storage/preparation areas were located west of the plant close to unit 3.

Table 14.3.4-5 presents the estimated retrofit factors and scope adder costs for FSI and DSD technologies at the Montrose plant. Table 14.3.4-6 presents the costs for sorbent injection technologies. The estimated unit costs are high because of the low coal sulfur content.

TABLE 14.3.4-5. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MONTROSE UNITS 1,2,3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	48
TOTAL COST (1000$)	
ESP UPGRADE CASE	48
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 14.3.4-6. Summary of DSD/FSI Control Costs for the Montrose Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1, 2	1.00	188	28	0.5	7.1	38.0	5.2	11.2	49.0	1292	3987.1
DSD+ESP	3	1.00	188	47	0.5	7.1	38.0	5.6	7.2	49.0	2169	2571.2
DSD+ESP-C	1, 2	1.00	188	28	0.5	7.1	38.0	3.0	6.5	49.0	1292	2309.1
DSD+ESP-C	3	1.00	188	47	0.5	7.1	38.0	3.2	4.2	49.0	2169	1487.9
FSI+ESP-50	1, 2	1.00	188	28	0.5	8.0	42.7	4.2	9.2	50.0	1328	3178.0
FSI+ESP-50	3	1.00	188	47	0.5	8.0	42.7	4.8	6.2	50.0	2229	2155.6
FSI+ESP-50-C	1, 2	1.00	188	28	0.5	8.0	42.7	2.5	5.3	50.0	1328	1847.9
FSI+ESP-50-C	3	1.00	188	47	0.5	8.0	42.7	2.8	3.6	50.0	2229	1251.2
FSI+ESP-70	1, 2	1.00	188	28	0.5	8.1	43.3	4.3	9.3	70.0	1859	2295.5
FSI+ESP-70	3	1.00	188	47	0.5	8.1	43.3	4.9	6.3	70.0	3120	1559.3
FSI+ESP-70-C	1, 2	1.00	188	28	0.5	8.1	43.3	2.5	5.4	70.0	1859	1334.8
FSI+ESP-70-C	3	1.00	188	47	0.5	8.1	43.3	2.8	3.6	70.0	3120	905.1

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Montrose plant. All units would be considered good candidates for repowering and retrofit because of their small boiler sizes and low capacity factors.

14.4 MISSOURI PUBLIC SERVICE

14.4.1 Sibley Steam Plant

The Sibley steam plant is located within Jackson County, Missouri, as part of the Missouri Public Service system. The plant contains three coal-fired boilers with a total gross generating capacity of 508 MW. Figure 14.4.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 14.4.1-1 presents operational data for the existing equipment at the Sibley plant. All boilers burn high sulfur coal (3.2 percent sulfur). Coal shipments are received by railroad and conveyed to a coal storage and handling area located west of the plant.

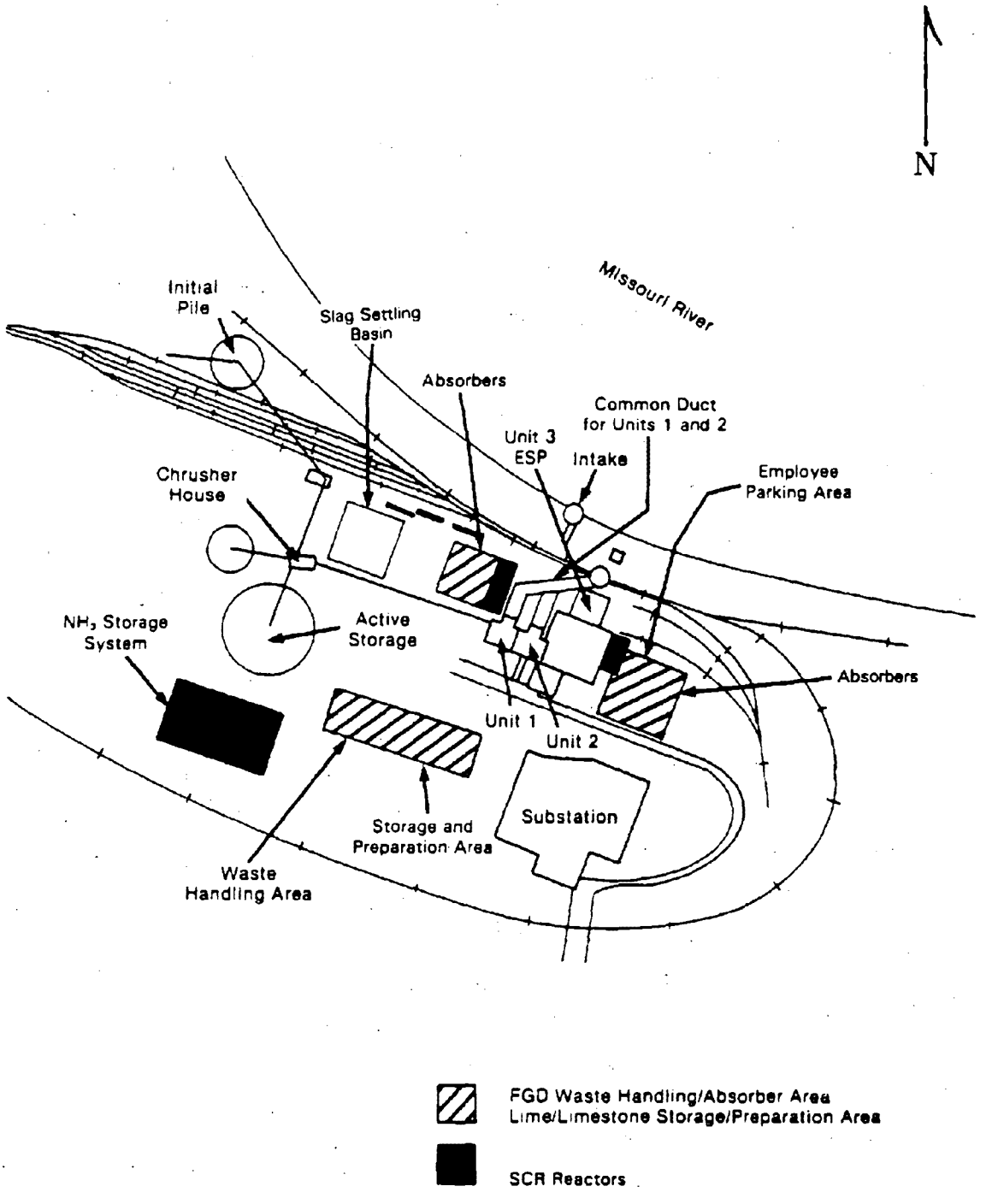
Particulate matter emissions for all boilers are controlled with ESPs located behind each unit. Ash from all units is wet sluiced to ponds located southeast of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.4.1-1 shows the general layout and location of the FGD control system. The absorbers for L/LS-FGD and LSD-FGD for units 1 and 2 would be located between the ESPs and the railroad, adjacent to the propane tanks (east). The unit 3 absorber would be located east of the unit 3 boiler, between the railroad and the switch yard on the existing employee parking area. The slag settling basin close to unit 1 and the process waste pond east of unit 3, as well as the parking area beside unit 3 would have to be relocated; therefore, a factor of 15 percent was assigned to general facilities. Lime was used as the sorbent choice because of the limited space available. The lime storage (silos)/preparation area and temporary waste handling area would be located southwest of unit 1 between the coal pile and the switch yard.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for units 1 and 2 were located north of the ESPs, between the railroad (south) and the propane tanks (east). The unit 3 absorbers were located beside unit 3 (east), between the railroad (south) and the switch yard (north).



Not to scale

Figure 14.4.1-1. Sibley plant plot plan

TABLE 14.4.1-1. SIBLEY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3
GENERATING CAPACITY (MW-each)	53, 55	400
CAPACITY FACTOR (PERCENT)	20, 36	26
FIRING TYPE	CYC	CYC
INSTALLATION DATE	1960,62	1969
COAL SULFUR CONTENT (PERCENT)	3.2	3.2
COAL HEATING VALUE (BTU/LB)	10800	10800
COAL ASH CONTENT (PERCENT)	11.2	11.2
FLY ASH SYSTEM	WET SLUICE	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1973,72	1969
EMISSION (LB/MM BTU)		
REMOVAL EFFICIENCY	95.2,97.2	96.5
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	3.2	3.2
SURFACE AREA (1000 SQ FT)	48.6	161.3
GAS EXIT RATE (1000 ACFM)	188	1033
SCA (SQ FT/1000 ACFM)	259	156
OUTLET TEMPERATURE (°F)	310	310

The absorber locations for units 1 and 2 were assigned a high site access/congestion factor, while for unit 3, a medium factor was assigned. For units 1 and 2, this was due to the area being surrounded by units 1 and 2 boilers (north), the railroad (south), and the propane tanks (east). For unit 3, the medium site access/congestion factor was due to the office building, roads and other minor obstacles.

Flue gas from all three boilers is currently converged into duct runs going into a common chimney which is located over the railroad (the railroad runs directly underneath the chimney). For flue gas handling, medium duct runs for all units would be required for L/LS-FGD cases.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 14.4.1-2 and 14.4.1-3. The largest scope adder for the Sibley plant would be the conversion of units 1 to 3 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD cases. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste. This conversion is not necessary for forced oxidation L/LS-FGD.

The LSD-FGD with reused ESP was the only LSD-FGD technology considered for units 1 and 2 because the boilers presently have large SCAs (>250). The LSD-FGD with a new baghouse was the only LSD case considered for unit 3 because the ESPs are small (SCA <160). For flue gas handling for LSD cases, moderate duct runs would be required for units 1-3. A high site access/congestion factor was assigned for units 1 and 2 because of the difficulty of routing the flue gas from the boilers to the absorbers and back to the ESPs. A low site access/congestion factor was assigned for unit 3 flue gas handling because the new baghouse would be installed close to the absorbers. The retrofit factors determined for the LSD technology case were moderate and did not include particulate control costs. Separate retrofit factors were developed for upgrading ESPs for units 1 and 2 and for a new baghouse for unit 3. These factors were used in the IAPCS model to estimate particulate control costs. The access/congestion factor associated with upgrading the ESPs would be moderate due to congestion created by the close proximity of the ESPs. The access/congestion factor for the new baghouse would be low due to the space availability to the east of unit 3.

TABLE 14.4.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR SIBLEY UNITS 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	531,549	NA	531,549
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.64	1.60	
ESP REUSE CASE			1.69
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	15	15

TABLE 14.4.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR SIBLEY UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	3249	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	1.43	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.40
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	15	15	15

FGD Retrofit Costs--

Table 14.4.1-4 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1 and 2 and installing a new baghouse to handle the additional particulate loading for boiler 3. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size. For the low cost case, all absorbers were located next to unit 3.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined. This is particularly true for cyclone boilers; as such, coal switching was not evaluated.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Sibley steam plant. These controls include NGR and SCR. NGR was the LNC modification control for the three Sibley units because LNB and OFA are not applicable to cyclone-fired boilers. SCR was considered to be applicable to all coal-fired boiler types.

Low NO_x Combustion--

Table 14.4.1-5 presents the NO_x reduction performance and costs of NGR for each unit at the Sibley plant. The NGR NO_x reduction performance for all units was estimated to be 60 percent. Table 14.4.1-6 presents the costs of retrofitting NGR at the Sibley boilers. Natural gas is not currently supplied to the plant and the closest source is about 30 miles away. The plant estimated $9.75 million would be the cost of the pipeline, which was added to the NGR capital cost.

Table 14.4.1-4. Summary of FGD Control Costs for the Sibley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.64	53	20	3.2	38.2	720.9	15.0	161.6	90.0	2435	6162.7
L/S FGD	2	1.64	55	36	3.2	39.1	710.2	16.3	94.2	90.0	4548	3593.2
L/S FGD	3	1.48	400	26	3.2	108.6	271.6	45.3	49.8	90.0	23888	1897.7
L/S FGD-C	1	1.64	53	20	3.2	38.2	720.9	8.8	94.4	90.0	2435	3601.2
L/S FGD-C	2	1.64	55	36	3.2	39.1	710.2	9.5	55.0	90.0	4548	2097.2
L/S FGD-C	3	1.48	400	26	3.2	108.6	271.6	26.5	29.0	90.0	23888	1107.6
LC FGD	1-3	1.51	518	27	3.2	107.8	208.0	47.8	39.0	90.0	32125	1488.4
LC FGD-C	1-3	1.51	518	27	3.2	107.8	208.0	27.9	22.8	90.0	32125	867.8
LSD+ESP	1	1.69	53	20	3.2	15.4	290.8	7.4	79.7	76.0	2064	3587.1
LSD+ESP	2	1.69	55	36	3.2	15.8	287.0	7.9	45.6	76.0	3856	2049.6
LSD+ESP-C	1	1.69	53	20	3.2	15.4	290.8	4.3	46.4	76.0	2064	2088.7
LSD+ESP-C	2	1.69	55	36	3.2	15.8	287.0	4.6	26.5	76.0	3856	1192.6
LSD+FF	3	1.40	400	26	3.2	88.9	222.1	31.7	34.8	87.0	22959	1381.0
LSD+FF-C	3	1.40	400	26	3.2	88.9	222.1	18.6	20.4	87.0	22959	808.5

TABLE 14.4.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR SIBLEY

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	CY	CY	CY
TYPE OF NOx CONTROL	NGR	NGR	NGR
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	60	60
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	17	17	76
New Duct Length (Feet)	300	400	400
New Duct Costs (1000$)	1,025	1,397	4,460
New Heat Exchanger (1000$)	1,273	1,302	4,282
TOTAL SCOPE ADDER COSTS (1000$)	2,316	2,716	8,818
RETROFIT FACTOR FOR SCR	1.36	1.36	1.36
GENERAL FACILITIES (PERCENT)	13	13	13

Table 14.4.1-6. NOx Control Cost Results for the Sibley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	53	20	3.2	2.4	45.0	0.9	9.6	60.0	481	1843.2
NGR	2	1.00	55	36	3.2	2.5	45.9	1.3	7.6	60.0	899	1471.4
NGR	3	1.00	400	26	3.2	14.1	35.3	6.9	7.6	60.0	4722	1459.4
NGR-C	1	1.00	53	20	3.2	2.4	45.0	0.5	5.6	60.0	481	1078.3
NGR-C	2	1.00	55	36	3.2	2.5	45.9	0.8	4.4	60.0	899	855.6
NGR-C	3	1.00	400	26	3.2	14.1	35.3	4.0	4.4	60.0	4722	849.6
SCR-3	1	1.36	53	20	3.2	14.6	276.4	4.5	48.4	80.0	642	7008.3
SCR-3	2	1.36	55	36	3.2	15.3	277.3	4.7	27.3	80.0	1199	3943.9
SCR-3	3	1.36	400	26	3.2	57.9	144.8	20.1	22.0	80.0	6295	3188.1
SCR-3-C	1	1.36	53	20	3.2	14.6	276.4	2.6	28.5	80.0	642	4117.6
SCR-3-C	2	1.36	55	36	3.2	15.3	277.3	2.8	16.0	80.0	1199	2316.7
SCR-3-C	3	1.36	400	26	3.2	57.9	144.8	11.8	12.9	80.0	6295	1867.8
SCR-7	1	1.36	53	20	3.2	14.6	276.4	4.1	43.7	80.0	642	6319.0
SCR-7	2	1.36	55	36	3.2	15.3	277.3	4.3	24.6	80.0	1199	3561.1
SCR-7	3	1.36	400	26	3.2	57.9	144.8	16.7	18.4	80.0	6295	2657.8
SCR-7-C	1	1.36	53	20	3.2	14.6	276.4	2.4	25.7	80.0	642	3722.7
SCR-7-C	2	1.36	55	36	3.2	15.3	277.3	2.5	14.5	80.0	1199	2097.3
SCR-7-C	3	1.36	400	26	3.2	57.9	144.8	9.8	10.8	80.0	6295	1564.0

Selective Catalytic Reduction--

Table 14.4.1-5 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 and 2 were located directly behind (north) their respective ESPs between the railroad and the propane tanks. The SCR reactor for unit 3 was located beside unit 3 between the railroad and the switch yard.

The SCR reactors for all units were assigned medium access/congestion factors because of access difficulty and interference of existing equipment near the reactors. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in an area of low access and congestion. Table 14.4.1-6 presents the estimated cost of retrofitting SCR at the Sibley boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located south of the plant in a similar fashion as LSD-FGD. There is sufficient duct residence time (~2 seconds) between boilers 1-2 and the respective ESPs to evaluate FSI and DSD with ESP reuse. The retrofit of DSD and FSI for unit 3 would be difficult because of the short duct residence time (~1 second) and small ESPs (SCA <160). Sufficient duct residence time could be made available for DSD if a new baghouse is installed. For ESP upgrades and addition of a new fabric filter, a medium access/congestion factor of 1.36 was assumed. Additionally, the conversion of the wet fly ash handling system

to dry handling would be required when reusing the ESPs. Tables 14.4.1-7 and Table 14.4.1-8 present a summary of the site access/congestion factors for DSD and FSI technologies at the Sibley steam plant. Table 14.4.1-9 presents the costs estimated to retrofit DSD and FSI at the Sibley plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Sibley plant. Boilers 1 and 2 would be considered good candidates for AFBC retrofit and AFBC or CG/combined cycle repowering because of their small boiler sizes (53-55 MW) and low capacity factors. Although the unit 3 boiler would not be a good candidate due to its large boiler size (>300 MW), its low capacity factor indicates that purchased power cost for unit downtime may not be significant and preclude application of AFBC or CG.

TABLE 14.4.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR SIBLEY UNITS 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	531, 549
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	19
TOTAL COST (1000$)	
ESP UPGRADE CASE	550, 568
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

TABLE 14.4.1-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR SIBLEY UNIT 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE (FSI)	MEDIUM
NEW BAGHOUSE (DSD)	MEDIUM
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	3249
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	400
ESTIMATED COST (1000$)	4135
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	85
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	3334
A NEW BAGHOUSE CASE (DSD)	4220
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE (FSI)	1.36
NEW BAGHOUSE (DSD)	1.36

Table 14.4.1-9. Summary of DSD/FSI Control Costs for the Sibley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	53	20	3.2	6.2	116.9	4.6	49.6	49.0	1316	3498.5
DSD+ESP	2	1.00	55	36	3.2	6.3	115.0	5.0	28.9	49.0	2458	2040.5
DSD+ESP-C	1	1.00	53	20	3.2	6.2	116.9	2.7	28.7	49.0	1316	2025.5
DSD+ESP-C	2	1.00	55	36	3.2	6.3	115.0	2.9	16.7	49.0	2458	1180.6
DSD+FF	3	1.00	400	26	3.2	58.3	145.8	22.0	24.1	71.0	18779	1170.7
DSD+FF-C	3	1.00	400	26	3.2	58.3	145.8	12.9	14.1	71.0	18779	684.7
FSI+ESP-50	1	1.00	53	20	3.2	7.0	132.2	3.8	41.3	50.0	1353	2833.8
FSI+ESP-50	2	1.00	55	36	3.2	7.1	129.9	4.6	26.4	50.0	2527	1814.1
FSI+ESP-50	3	1.00	400	26	3.2	30.5	76.2	16.8	18.5	50.0	13271	1267.3
FSI+ESP-50-C	1	1.00	53	20	3.2	7.0	132.2	2.2	24.0	50.0	1353	1646.8
FSI+ESP-50-C	2	1.00	55	36	3.2	7.1	129.9	2.7	15.3	50.0	2527	1052.0
FSI+ESP-50-C	3	1.00	400	26	3.2	30.5	76.2	9.8	10.7	50.0	13271	736.4
FSI+ESP-70	1	1.00	53	20	3.2	7.1	133.8	3.9	41.7	70.0	1894	2045.9
FSI+ESP-70	2	1.00	55	36	3.2	7.2	131.5	4.6	26.8	70.0	3537	1312.3
FSI+ESP-70	3	1.00	400	26	3.2	30.6	76.6	17.0	18.7	70.0	18580	917.4
FSI+ESP-70-C	1	1.00	53	20	3.2	7.1	133.8	2.3	24.2	70.0	1894	1188.9
FSI+ESP-70-C	2	1.00	55	36	3.2	7.2	131.5	2.7	15.5	70.0	3537	761.0
FSI+ESP-70-C	3	1.00	400	26	3.2	30.6	76.6	9.9	10.9	70.0	18580	533.0

14.5 CITY UTILITIES OF SPRINGFIELD

14.5.1 James River Steam Plant

The James River Power Station is located within Greene County, Missouri, as part of the City Utilities of Springfield. The plant is located adjacent to the James River and Lake Springfield and contains five coal-fired boilers with a total gross generating capacity of 249 MW.

Table 14.5.1-1 presents operational data for the existing equipment at the James River plant. The boilers burn high sulfur coal which is received by railroad and transferred to a coal storage and handling area south of the plant away from the lake. The coal handling system was upgraded in 1987 and the coal pile was moved to the west portion of the coal storage and handling area. The coal conveyors were also moved to the west.

Units 1-4 have retrofit ESPs and unit 5 has its original ESPs. Fly ash and bottom ash are wet sluiced and disposed of in two ash ponds west of the coal pile. Every 2 years ash is removed from these ponds and transferred to another site on the other side of the James River. Units 1 and 2 are served by a common chimney while the other units have separate chimneys.

Lime/Limestone and Lime Spray Drying FGD Costs--

The absorbers for units 1-3 would be located east of unit 1 toward the lake and south of the employee parking area between the gas peaking turbines and the coal pile. The absorbers for units 4-5 would be located west of unit 5 adjacent to the coal conveyor and north of the coal pile and fly ash sluice lines. The limestone preparation, storage, and handling area would be located east of the ash ponds and northwest of the coal pile. No major demolition/relocation would be required for units 1-3 locations and a factor of 5 percent was assigned to general facilities. By contrast, a storage building adjacent to the unit 5 chimney has to be relocated for the unit 4, 5 location and a factor of 8 percent was assigned to general facilities.

Low site access/congestion factors were assigned to the FGD absorber locations due to the space availability and easy accessibility to these locations. For flue gas handling, the unit 1-2 chimney is boxed in by the ESPs making access to it rather difficult. For unit 3, the chimney is placed

TABLE 14.5.1-1. JAMES RIVER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2	3	4	5
GENERATING CAPACITY (MW-each)	23	45	62	96
CAPACITY FACTOR (PERCENT)	12	28	40	45
INSTALLATION DATE	1957	1960	1964	1970
FIRING TYPE	TANGENTIAL		FRONT WALL	
FURNACE VOLUME (1000 CU FT)	NA	NA	39.3	55.6
LOW NOx COMBUSTION	NO	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)	4.2	4.2	4.2	4.2
COAL HEATING VALUE (BTU/LB)	12500	12500	12500	12500
COAL ASH CONTENT (PERCENT)	12.0	12.0	12.0	12.0
FLY ASH SYSTEM		WET SLUICE		
ASH DISPOSAL METHOD	ON-SITE/REMOVED EVERY 2 YEARS			
STACK NUMBER	1	2	3	4
COAL DELIVERY METHODS		RAILROAD		
PARTICULATE CONTROL				
TYPE	ESP	ESP	ESP	ESP
INSTALLATION DATE	1980-81	1979	1976	1970
EMISSION (LB/MM BTU)	0.06	0.07	0.05	0.07
REMOVAL EFFICIENCY	99.6	99.5	99.2	99.2
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	3.9	3.9	3.9	3.9
SURFACE AREA (1000 SQ FT)	36.72	69.3	77.76	54.0
GAS EXIT RATE (1000 ACFM)	111.9	210	249.9	344
SCA (SQ FT/1000 ACFM)	328	330	311	157
OUTLET TEMPERATURE (°F)	320	317	320	320

in an open area behind the retrofit ESPs which can be accessed easily. The unit 4 chimney is located behind the retrofit ESPs but access to it is limited because of the unit 5 and coal conveyor interferences. Access to the unit 5 chimney is also limited because of the coal conveyor. Duct lengths of 200 to 500 feet would be required for these units.

LSD with reuse of the existing ESPs was considered for units 1-4 because the retrofit ESPs have adequate sizes (SCA >350) and would not require major upgrading and plate area additions to handle the increased PM generated from the LSD application. By contrast, unit 5 has very small ESPs which possibly would not be able to handle the increased load. LSD with a new baghouse was also not considered for unit 5 because the boilers are burning high sulfur coal making wet FGD more practical. A medium site access/congestion factor was assigned to the unit 1-4 ESP locations due to space limitations behind the ESPs created by the coal pile. This factor was used by the IAPCS model for particulate control cost estimates. Medium to high site access/congestion factors were assigned to the flue gas handling system for units 3 and 4. This reflects the access difficulty to the upstream of the ESPs caused mainly by other units. Ductwork has to go around the existing units (1-2 and 5) before accessing units 3-4 ESPs. The low cost FGD option has 7 percent added to the retrofit factors to account for the cost of a new chimney.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 14.5.1-2 through 14.5.1-5. Table 14.5.1-6 presents the process area retrofit factors and capital/operating costs for commercial FGD technologies.

Coal Switching and Physical Coal Cleaning Costs--

Table 14.5.1-7 presents the IAPCS results for CS at the James River plant. These costs do not include boiler and pulverizer operating cost changes or any system modifications that may be necessary to the coal handling system for blending. PCC was not evaluated because this is not a mine mouth plant.

TABLE 14.5.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR JAMES RIVER UNITS 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	251	NA	251
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.35	NA	
ESP REUSE CASE			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 14.5.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR JAMES RIVER UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	458	NA	458
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.38	NA	
ESP REUSE CASE			1.54
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 14.5.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR JAMES RIVER UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	611	NA	611
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	NA	
ESP REUSE CASE			1.45
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

TABLE 14.5.1-5. SUMMARY OF RETROFIT FACTOR DATA FOR JAMES RIVER UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	NA
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NA
ESTIMATED COST (1000$)	904	NA	NA
NEW CHIMNEY	NO	NA	NA
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.35	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	0

Table 14.5.1-6. Summary of FGD Control Costs for the James River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1-2	1.35	46	12	4.2	29.5	641.7	11.4	236.4	90.0	1407	8122.8
L/S FGD	3	1.38	45	28	4.2	29.9	664.1	12.4	112.2	90.0	3212	3854.9
L/S FGD	4	1.42	62	40	4.2	36.6	590.8	15.6	72.0	90.0	6322	2474.1
L/S FGD	5	1.35	96	45	4.2	42.7	444.4	18.9	49.9	90.0	11012	1715.0
L/S FGD-C	1-2	1.35	46	12	4.2	29.5	641.7	6.7	138.2	90.0	1407	4747.9
L/S FGD-C	3	1.38	45	28	4.2	29.9	664.1	7.2	65.5	90.0	3212	2250.3
L/S FGD-C	4	1.42	62	40	4.2	36.6	590.8	9.1	42.0	90.0	6322	1443.5
L/S FGD-C	5	1.35	96	45	4.2	42.7	444.4	11.0	29.1	90.0	11012	1000.0
LC FGD	1-3	1.44	91	20	4.2	30.9	340.0	12.9	81.1	90.0	4639	2787.5
LC FGD	4-5	1.45	158	43	4.2	40.2	254.6	19.6	32.9	90.0	17319	1131.9
LC FGD-C	1-3	1.44	91	20	4.2	30.9	340.0	7.5	47.3	90.0	4639	1626.9
LC FGD-C	4-5	1.45	158	43	4.2	40.2	254.6	11.4	19.2	90.0	17319	658.9
LSD+ESP	1, 2	1.31	23	12	4.2	7.3	319.5	4.7	195.6	69.0	542	8726.4
LSD+ESP	3	1.54	45	28	4.2	12.4	276.0	6.7	60.4	68.0	2444	2726.2
LSD+ESP	4	1.45	62	40	4.2	14.7	237.4	7.9	36.4	69.0	4870	1623.2
LSD+ESP-C	1, 2	1.31	23	12	4.2	7.3	319.5	2.7	113.4	69.0	542	5060.4
LSD+ESP-C	3	1.54	45	28	4.2	12.4	276.0	3.9	35.1	68.0	2444	1584.7
LSD+ESP-C	4	1.45	62	40	4.2	14.7	237.4	4.6	21.2	69.0	4870	943.5

Table 14.5.1-7: Summary of Coal Switching/Cleaning Costs for the James River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1, 2	1.00	23	12	4.2	1.5	64.9	0.8	32.2	78.0	607	1282.1
CS/B+$15	3	1.00	45	28	4.2	2.3	50.2	2.1	19.4	78.0	2772	772.6
CS/B+$15	4	1.00	62	40	4.2	2.8	45.4	3.7	17.0	78.0	5456	677.3
CS/B+$15	5	1.00	96	45	4.2	4.4	46.3	6.2	16.3	78.0	9503	649.8
CS/B+$15-C	1, 2	1.00	23	12	4.2	1.5	64.9	0.5	18.7	78.0	607	745.6
CS/B+$15-C	3	1.00	45	28	4.2	2.3	50.2	1.2	11.2	78.0	2772	446.3
CS/B+$15-C	4	1.00	62	40	4.2	2.8	45.4	2.1	9.8	78.0	5456	390.4
CS/B+$15-C	5	1.00	96	45	4.2	4.4	46.3	3.6	9.4	78.0	9503	374.4
CS/B+$5	1, 2	1.00	23	12	4.2	1.3	54.6	0.5	22.2	78.0	607	884.5
CS/B+$5	3	1.00	45	28	4.2	1.8	39.8	1.1	10.4	78.0	2772	414.2
CS/B+$5	4	1.00	62	40	4.2	2.2	35.0	1.8	8.2	78.0	5456	327.8
CS/B+$5	5	1.00	96	45	4.2	3.5	36.0	2.9	7.6	78.0	9503	302.6
CS/B+$5-C	1, 2	1.00	23	12	4.2	1.3	54.6	0.3	13.0	78.0	607	516.0
CS/B+$5-C	3	1.00	45	28	4.2	1.8	39.8	0.7	6.0	78.0	2772	240.2
CS/B+$5-C	4	1.00	62	40	4.2	2.2	35.0	1.0	4.8	78.0	5456	189.6
CS/B+$5-C	5	1.00	96	45	4.2	3.5	36.0	1.7	4.4	78.0	9503	175.0

Low NO_x Combustion--

Units 1-2 are tangential and units 3-5 are front wall-fired boilers. The combustion modification techniques applied to these boilers was OFA for boilers 1-2 and LNB for boilers 3-5.

Table 14.5.1-8 presents the performance results and Table 14.5.1-9 presents the cost results of retrofitting OFA and LNB at the James River plant. Although units 3-5 volumetric heat release rates indicate low to moderate NO_x reductions are possible, the small size of units 3 and 4 may preclude successful application of LNB.

Selective Catalytic Reduction--

Cold side SCR reactors for all units would be located in a similar layout to the FGD absorbers in low site congestion areas. For flue gas handling, the duct lengths of 200, 250, 450, 500, and 200 feet were estimated for units 1-5, respectively. The ammonia storage system was placed north of the coal pile close to the ash ponds. No major relocation would be required for unit 1-3 reactors and a base factor of 13 percent was assigned to general facilities. A storage building has to be relocated for units 4-5 reactor locations and, as such, a factor of 20 percent was assigned to unit 4-5 general facilities.

Table 14.5.1-8 present the SCR retrofit results for all units. Table 14.5.1-9 presents the estimated cost of retrofitting SCR at the James River boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of FSI and DSD technologies at the James River steam plant would be relatively easy for units 1-4 because ESPs are large and probably would be able to handle the increased PM and would not require major ESP upgrading and plate area additions. Units 3 and 4 have short duct residence time but it was assumed that the first part of the retrofit ESPs could be modified for humidification (FSI application) or sorbent evaporation (DSD application). A medium site access/congestion factor was assigned to the ESP locations for upgrading the ESPs because of the close proximity to the coal pile. Unit 5 was not considered for sorbent injection technologies because of inadequate ESP sizes. The sorbent receiving/storage/preparation areas were located west of the plant in a similar fashion as L/LS-FGD.

TABLE 14.5.1-8. SUMMARY OF NOx RETROFIT RESULTS FOR JAMES RIVER

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1-2	3	4	5
FIRING TYPE	TANG	FWF	FWF	FWF
TYPE OF NOx CONTROL	OFA	LNB	LNB	LNB
FURNACE VOLUME (1000 CU FT)	NA	NA	39.3	55.6
BOILER INSTALLATION DATE	1957	1960	1964	1970
SLAGGING PROBLEM	NO	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	40	44	40
SCR RETROFIT RESULTS				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	15	15	19	26
New Duct Length (Feet)	250	450	500	200
New Duct Costs (1000$)	786	1398	1873	968
New Heat Exchanger (1000$)	1170	1154	1399	1819
TOTAL SCOPE ADDER COSTS (1000$)	1971	2567	3291	2813
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13	20	20

Table 14.5.1-9. NOx Control Cost Results for the James River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	3	1.00	45	28	4.2	1.9	41.2	0.4	3.7	40.0	183	2215.7
LNC-LNB	4	1.00	62	40	4.2	2.1	34.0	0.5	2.1	44.0	396	1164.0
LNC-LNB	5	1.00	96	45	4.2	2.5	26.2	0.5	1.5	40.0	628	875.3
LNC-LNB-C	3	1.00	45	28	4.2	1.9	41.2	0.2	2.2	40.0	183	1315.2
LNC-LNB-C	4	1.00	62	40	4.2	2.1	34.0	0.3	1.3	44.0	396	690.8
LNC-LNB-C	5	1.00	96	45	4.2	2.5	26.2	0.3	0.9	40.0	628	519.4
LNC-OFA	1, 2	1.00	23	12	4.2	0.3	15.0	0.1	3.1	25.0	18	4196.3
LNC-OFA-C	1, 2	1.00	23	12	4.2	0.3	15.0	0.0	1.8	25.0	18	2492.1
SCR-3	1-2	1.16	46	12	4.2	12.0	261.5	3.7	76.4	80.0	115	32273.1
SCR-3	3	1.16	45	28	4.2	12.5	277.2	3.8	34.4	80.0	366	10365.4
SCR-3	4	1.16	62	40	4.2	15.4	248.1	4.7	21.8	80.0	720	6587.6
SCR-3	5	1.16	96	45	4.2	18.4	191.5	6.1	16.0	80.0	1255	4826.4
SCR-3-C	1-2	1.16	46	12	4.2	12.0	261.5	2.2	44.9	80.0	115	18961.4
SCR-3-C	3	1.16	45	28	4.2	12.5	277.2	2.2	20.2	80.0	366	6091.4
SCR-3-C	4	1.16	62	40	4.2	15.4	248.1	2.8	12.8	80.0	720	3870.1
SCR-3-C	5	1.16	96	45	4.2	18.4	191.5	3.6	9.4	80.0	1255	2830.9
SCR-7	1-2	1.16	46	12	4.2	12.0	261.5	3.3	68.7	80.0	115	28995.6
SCR-7	3	1.16	45	28	4.2	12.5	277.2	3.4	31.0	80.0	366	9361.4
SCR-7	4	1.16	62	40	4.2	15.4	248.1	4.2	19.5	80.0	720	5884.8
SCR-7	5	1.16	96	45	4.2	18.4	191.5	5.3	13.9	80.0	1255	4201.6
SCR-7-C	1-2	1.16	46	12	4.2	12.0	261.5	2.0	40.5	80.0	115	17083.4
SCR-7-C	3	1.16	45	28	4.2	12.5	277.2	2.0	18.3	80.0	366	5516.3
SCR-7-C	4	1.16	62	40	4.2	15.4	248.1	2.5	11.5	80.0	720	3467.4
SCR-7-C	5	1.16	96	45	4.2	18.4	191.5	3.1	8.2	80.0	1255	2472.9

Tables 14.5.1-10 through 12 present a summary of the site access/ congestion factors for FSI and DSD technologies at the James River steam plant. Table 14.5.1-13 presents the costs estimated to retrofit FSI and DSD at the James River boilers.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the James River plant. All units would be considered good candidates for repowering and retrofit because of their small boiler sizes and low capacity factors.

TABLE 14.5.1-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR JAMES RIVER UNITS 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	251
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	10
TOTAL COST (1000$)	
ESP UPGRADE CASE	261
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

TABLE 14.5.1-11. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR JAMES RIVER UNIT 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	458
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	16
TOTAL COST (1000$)	
ESP UPGRADE CASE	474
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

TABLE 14.5.1-12. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR JAMES RIVER UNIT 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	611
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	21
TOTAL COST (1000$)	
ESP UPGRADE CASE	632
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Table 14.5.1-13. Summary of DSD/FSI Control Costs for the James River Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1, 2	1.00	23	12	4.2	4.2	183.9	3.8	156.0	45.0	353	10680.9
DSD+ESP	3	1.00	45	28	4.2	5.9	132.0	4.7	42.2	45.0	1597	2917.5
DSD+ESP	4	1.00	62	40	4.2	7.1	114.2	5.5	25.4	45.0	3173	1736.0
DSD+ESP-C	1, 2	1.00	23	12	4.2	4.2	183.9	2.2	90.1	45.0	353	6173.3
DSD+ESP-C	3	1.00	45	28	4.2	5.9	132.0	2.7	24.4	45.0	1597	1688.2
DSD+ESP-C	4	1.00	62	40	4.2	7.1	114.2	3.2	14.7	45.0	3173	1004.6
FSI+ESP-50	1,2	1.00	23	12	4.2	4.7	206.1	2.7	111.2	50.0	391	6880.4
FSI+ESP-50	3	1.00	45	28	4.2	6.2	137.3	3.9	35.2	50.0	1784	2174.5
FSI+ESP-50	4	1.00	62	40	4.2	7.4	118.7	5.2	24.0	50.0	3512	1484.8
FSI+ESP-50-C	1,2	1.00	23	12	4.2	4.7	206.1	1.6	64.6	50.0	391	3996.3
FSI+ESP-50-C	3	1.00	45	28	4.2	6.2	137.3	2.3	20.4	50.0	1784	1261.3
FSI+ESP-50-C	4	1.00	62	40	4.2	7.4	118.7	3.0	13.9	50.0	3512	860.1
FSI+ESP-70	1, 2	1.00	23	12	4.2	4.8	209.4	2.7	112.3	70.0	547	4959.9
FSI+ESP-70	3	1.00	45	28	4.2	6.3	139.5	3.9	35.6	70.0	2498	1573.9
FSI+ESP-70	4	1.00	62	40	4.2	7.5	120.5	5.3	24.4	70.0	4917	1076.6
FSI+ESP-70-C	1, 2	1.00	23	12	4.2	4.8	209.4	1.6	65.2	70.0	547	2881.2
FSI+ESP-70-C	3	1.00	45	28	4.2	6.3	139.5	2.3	20.7	70.0	2498	913.0
FSI+ESP-70-C	4	1.00	62	40	4.2	7.5	120.5	3.1	14.1	70.0	4917	623.6

14.6 UNION ELECTRIC COMPANY

14.6.1 Labadie Steam Plant

The Labadie steam plant is located within Franklin County, Missouri, as part of Union Electric Company system. The plant contains four coal-fired boilers with a total gross generating capacity of 2,482 MW. Figure 14.6.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 14.6.1-1 presents operational data for the existing equipment at the Labadie steam plant. All boilers burn medium sulfur coal (2.5 percent sulfur), a blend of high-sulfur and low-sulfur Illinois coals. Coal shipments are received by railroad and conveyed to a coal storage and handling area located west of the plant.

Particulate matter emissions are controlled with ESPs located behind each boiler unit. Retrofit ESPs are added to the existing ESPs behind the chimneys. The ESPs operate in parallel and 60 percent of the flue gases for each unit go to the old ESPs while 40 percent go to the retrofit ESPs. Fly ash from all units is sluiced to ponds located south and west of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.6.1-1 shows the general layout and location of the FGD control system. The absorbers for L/LS-FGD for all units would be located southwest of unit 4 between the railroads and east of the coal storage handling area. For LSD-FGD cases, the absorbers for units 1 and 2 would be located beside the water treatment area adjacent to unit 1 (northwest). The LSD absorbers for units 3 and 4 would be located southwest of the plant in the same site location as described above for L/LS-FGD. Some storage buildings would be demolished to make space available for FGD equipment; therefore, a factor of 10 percent was assigned to general facilities. The lime and limestone storage/preparation area and waste handling area would be located southeast of the powerhouse adjacent to the absorbers.

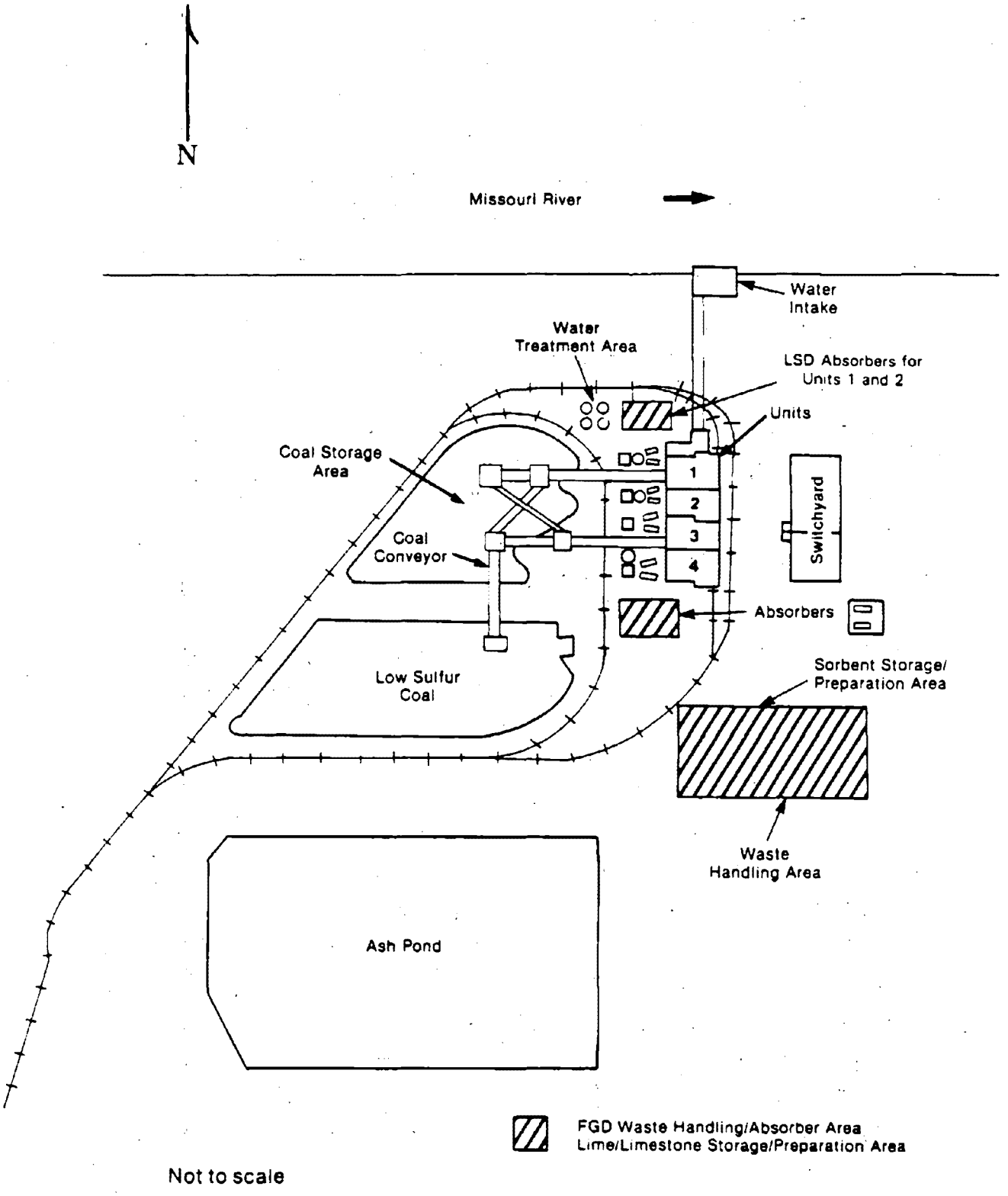


Figure 14.6.1-1. Labadie plant plot plan

TABLE 14.6.1-1. LABADIE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-4
GENERATING CAPACITY (MW-each)	620.5
CAPACITY FACTOR (PERCENT)	59,52,58,59
FIRING TYPE	TANGENTIAL
INSTALLATION DATE	1970-73
COAL SULFUR CONTENT (PERCENT)	2.5
COAL HEATING VALUE (BTU/LB)	11300
COAL ASH CONTENT (PERCENT)	9.0
FLY ASH SYSTEM	WET
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1-3
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1983
EMISSION (LB/MM BTU)	0.009-0.033
REMOVAL EFFICIENCY	99.4-99.8
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	2.3
SURFACE AREA (1000 SQ FT)	701.3
GAS EXIT RATE (1000 ACFM)	2,200
SCA (SQ FT/1000 ACFM)	319
OUTLET TEMPERATURE (°F)	310

Retrofit Difficulty and Scope Adder Costs--

After demolition and relocation of the storage and shop buildings south of unit 2, a relatively open area with no major obstacle/obstruction is available for the placement of the FGD units. As such, a low site access/congestion and underground obstruction factor is assigned to the L/LS-FGD absorber location for all units. On the other hand, the lack of space around the existing chimney due to the retrofit ESPs and the coal handling area resulted in a high site access/congestion and underground obstruction factor being assigned to the flue gas handling systems. Since units 1 and 2 are in excess of 600 feet from the absorber area (south of unit 4) with high site access/congestion, the cost of a new chimney for units 1 and 2 is included. Interferences with the coal handling/blending operation are also reduced by installing a new chimney. For flue gas handling, duct lengths range from 650 feet for unit 4 to 900 feet for unit 1.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Tables 14.6.1-2 through 14.6.1-5. The largest scope adder cost is for the conversion of the fly ash handling system from wet to dry. The overall retrofit factors determined for the L/LS-FGD cases were moderate (1.45 to 1.62).

To be able to reuse the unit 1 and 2 ESPs, the LSD absorbers for units 1 and 2 could be located beside the water treatment area adjacent to unit 1 (northwest) without major demolition. The LSD absorbers for units 3 and 4 could be located southwest of the plant in the same manner as L/LS-FGD.

In LSD-FGD cases, units 1 and 2 absorber locations were assigned a high site access/congestion factor due to the congestion created by the water treatment area (north), railroad (west), ESPs (south), and unit 1 and an office building (east). The absorber locations for units 3 and 4 (located south of unit 4) were assigned a low access/congestion factor for the same reason as in L/LS-FGD cases.

For units 1 and 4, a medium site access/congestion factor has been assigned to the flue gas handling system for the following reason. Although it is difficult to reach the upstream of the old ESP boxes (60 percent of flue gas), it is relatively easy to access the inlet of the retrofit ESP box. As such, an average (medium) congestion factor has been assigned. Access to the unit 2 and 3 ESPs, on the other hand, is extremely difficult and a high

TABLE 14.6.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR LABADIE UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	HIGH
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4,714	NA	4,714
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	4,890	4,344	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.64	1.57	
ESP REUSE CASE			1.67
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.59
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 14.6.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR LABADIE UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	HIGH
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
ESP REUSE			600-1,000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4,714	NA	4,714
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	4,890	4,890	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.57	1.50	
ESP REUSE CASE			1.82
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.59
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 14.6.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR LABADIE UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1,000	600-1,000	
ESP REUSE			600-1,000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4,714	NA	4,714
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.59	1.52	
ESP REUSE CASE			1.55
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.59
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 14.6.1-5. SUMMARY OF RETROFIT FACTOR DATA FOR LABADIE UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1,000	600-1,000	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4,714	NA	4,714
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.54	1.47	
ESP REUSE CASE			1.39
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.38
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

site access/congestion factor has been assigned to these two units for the flue gas handling systems. In addition, a high underground obstruction factor has been assigned to all units for flue gas handling. Duct lengths range from 400 feet for unit 1 to 840 feet for unit 3 for the flue gas handling system. Major scope adjustments are presented in Tables 14.6.1-2 through 14.6.1-5. The retrofit factors for LSD-FGD cases range from 1.39 for unit 4 to 1.82 for unit 2.

Table 14.6.1-6 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 1-4. The low cost control case reduces capital and annual operating costs by due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 14.6.1-7.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Labadie steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR, as shown in Tables 14.6.1-8 and 14.6.1-9.

Table 14.6.1-6. Summary of FGD Control Costs for the Labadie Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.64	621	59	2.5	158.7	255.8	75.0	23.4	90.0	62370	1201.8
L/S FGD	2	1.57	621	52	2.5	152.7	246.1	70.3	24.9	90.0	54970	1279.6
L/S FGD	3	1.59	621	58	2.5	154.4	248.9	73.1	23.2	90.0	61313	1193.0
L/S FGD	4	1.54	621	59	2.5	150.2	242.0	72.1	22.5	90.0	62370	1155.7
L/S FGD-C	1	1.64	621	59	2.5	158.7	255.8	43.7	13.6	90.0	62370	700.0
L/S FGD-C	2	1.57	621	52	2.5	152.7	246.1	41.0	14.5	90.0	54970	745.6
L/S FGD-C	3	1.59	621	58	2.5	154.4	248.9	42.6	13.5	90.0	61313	694.8
L/S FGD-C	4	1.54	621	59	2.5	150.2	242.0	42.0	13.1	90.0	62370	673.0
LC FGD	1-4	1.59	2482	58	2.5	427.2	172.1	219.7	17.5	90.0	244828	897.5
LC FGD-C	1-4	1.59	2482	58	2.5	427.2	172.1	127.8	10.2	90.0	244828	522.0
LSD+ESP	1	1.67	621	59	2.5	96.5	155.5	44.0	13.7	76.0	52876	831.5
LSD+ESP	2	1.82	621	52	2.5	104.2	167.9	44.7	15.8	76.0	46602	958.4
LSD+ESP	3	1.55	621	58	2.5	90.3	145.5	41.9	13.3	76.0	51979	806.1
LSD+ESP	4	1.39	621	59	2.5	81.6	131.4	39.6	12.3	76.0	52876	748.0
LSD+ESP-C	1	1.67	621	59	2.5	96.5	155.5	25.6	8.0	76.0	52876	484.6
LSD+ESP-C	2	1.82	621	52	2.5	104.2	167.9	26.1	9.2	76.0	46602	559.1
LSD+ESP-C	3	1.55	621	58	2.5	90.3	145.5	24.4	7.7	76.0	51979	469.7
LSD+ESP-C	4	1.39	621	59	2.5	81.6	131.4	23.0	7.2	76.0	52876	435.5

Table 14.6.1-7. Summary of Coal Switching/Cleaning Costs for the Labadie Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	621	59	2.5	19.3	31.1	45.8	14.3	67.0	46143	993.4
CS/B+$15	2	1.00	621	52	2.5	19.3	31.1	40.9	14.5	67.0	40668	1005.6
CS/B+$15	3	1.00	621	58	2.5	19.3	31.1	45.1	14.3	67.0	45361	994.9
CS/B+$15	4	1.00	621	59	2.5	19.3	31.1	45.8	14.3	67.0	46143	993.4
CS/B+$15-C	1	1.00	621	59	2.5	19.3	31.1	26.3	8.2	67.0	46143	571.0
CS/B+$15-C	2	1.00	621	52	2.5	19.3	31.1	23.5	8.3	67.0	40668	578.3
CS/B+$15-C	3	1.00	621	58	2.5	19.3	31.1	25.9	8.2	67.0	45361	571.9
CS/B+$15-C	4	1.00	621	59	2.5	19.3	31.1	26.3	8.2	67.0	46143	571.0
CS/B+$5	1	1.00	621	59	2.5	12.9	20.8	18.2	5.7	67.0	46143	394.9
CS/B+$5	2	1.00	621	52	2.5	12.9	20.8	16.4	5.8	67.0	40668	403.8
CS/B+$5	3	1.00	621	58	2.5	12.9	20.8	18.0	5.7	67.0	45361	396.0
CS/B+$5	4	1.00	621	59	2.5	12.9	20.8	18.2	5.7	67.0	46143	394.9
CS/B+$5-C	1	1.00	621	59	2.5	12.9	20.8	10.5	3.3	67.0	46143	227.5
CS/B+$5-C	2	1.00	621	52	2.5	12.9	20.8	9.5	3.3	67.0	40668	232.8
CS/B+$5-C	3	1.00	621	58	2.5	12.9	20.8	10.4	3.3	67.0	45361	228.2
CS/B+$5-C	4	1.00	621	59	2.5	12.9	20.8	10.5	3.3	67.0	46143	227.5

TABLE 14.6.1-8. SUMMARY OF NOx RETROFIT RESULTS FOR LABADIE UNITS 1-3

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	13.2	13.2	13.2
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	98.4	98.4	98.4
FURNACE RESIDENCE TIME (SECONDS)	3.52	3.52	3.52
ESTIMATED NOX REDUCTION (PERCENT)	25	25	25
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	106	106	106
New Duct Length (Feet)	400	700	800
New Duct Costs (1000$)	7,900	13,825	15,800
New Heat Exchanger (1000$)	5,575	5,575	5,575
TOTAL SCOPE ADDER COSTS (1000$)	13,581	19,506	21,481
RETROFIT FACTOR FOR SCR	1.52	1.52	1.16
GENERAL FACILITIES (PERCENT)	25	25	25

TABLE 14.6.1-9. SUMMARY OF NOx RETROFIT RESULTS FOR LABADIE UNIT 4

	BOILER NUMBER
	4
COMBUSTION MODIFICATION RESULTS	
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	13.2
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	98.4
FURNACE RESIDENCE TIME (SECONDS)	3.52
ESTIMATED NOX REDUCTION (PERCENT)	25
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	106
New Duct Length (Feet)	620
New Duct Costs (1000$)	12,245
New Heat Exchanger (1000$)	5,575
TOTAL SCOPE ADDER COSTS (1000$)	17,926
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	25

Low NO_x Combustion--

Units 1 to 4 are dry bottom, tangential-fired boilers rated at 621 MW each. The combustion modification technique applied for this evaluation was OFA. The OFA NO_x reduction performance for units 1 to 4 was estimated to be 25 percent for all units. This reduction performance level was assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. Table 14.6.1-10 presents the cost of retrofitting OFA at the Labadie boilers.

Selective Catalytic Reduction--

Tables 14.6.1-8 and 14.6.1-9 present the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 and 2 were located north of the ESPs for unit 1 and west of the office building in a high congestion area. The SCR reactors for units 3 and 4 were located south of the ESPs for unit 4 and east of the track hopper in a low congestion area. The arrangement of all units is similar to the LSD-FGD layout; therefore, similar retrofit factors are also assigned to the SCR reactor. The ammonia storage system was placed to the south of unit 4 in a remote area having a low access/congestion factor. Table 14.6.1-10 presents the estimated cost of retrofitting SCR at the Labadie boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbert receiving/storage/preparation areas for both units were located south of unit 4 in a relatively open area. Forty percent of the flue

Table 14.6.1-10. NOx Control Cost Results for the Labadie Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	621	59	2.5	1.3	2.1	0.3	0.1	25.0	2665	105.4
LNC-OFA	2	1.00	621	52	2.5	1.3	2.1	0.3	0.1	25.0	2349	119.5
LNC-OFA	3	1.00	621	58	2.5	1.3	2.1	0.3	0.1	25.0	2620	107.2
LNC-OFA	4	1.00	621	59	2.5	1.3	2.1	0.3	0.1	25.0	2665	105.4
LNC-OFA-C	1	1.00	621	59	2.5	1.3	2.1	0.2	0.1	25.0	2665	62.5
LNC-OFA-C	2	1.00	621	52	2.5	1.3	2.1	0.2	0.1	25.0	2349	71.0
LNC-OFA-C	3	1.00	621	58	2.5	1.3	2.1	0.2	0.1	25.0	2620	63.6
LNC-OFA-C	4	1.00	621	59	2.5	1.3	2.1	0.2	0.1	25.0	2665	62.5
SCR-3	1	1.52	621	59	2.5	94.8	152.7	32.8	10.2	80.0	8529	3846.1
SCR-3	2	1.52	621	52	2.5	100.8	162.4	33.6	11.9	80.0	7517	4472.5
SCR-3	3	1.16	621	58	2.5	89.2	143.7	30.7	9.7	80.0	8385	3664.3
SCR-3	4	1.16	621	59	2.5	85.5	137.9	30.1	9.4	80.0	8529	3531.8
SCR-3-C	1	1.52	621	59	2.5	94.8	152.7	19.2	6.0	80.0	8529	2253.4
SCR-3-C	2	1.52	621	52	2.5	100.8	162.4	19.7	7.0	80.0	7517	2622.5
SCR-3-C	3	1.16	621	58	2.5	89.2	143.7	18.0	5.7	80.0	8385	2147.1
SCR-3-C	4	1.16	621	59	2.5	85.5	137.9	17.6	5.5	80.0	8529	2068.5
SCR-7	1	1.52	621	59	2.5	94.8	152.7	27.7	8.6	80.0	8529	3243.0
SCR-7	2	1.52	621	52	2.5	100.8	162.4	28.5	10.1	80.0	7517	3788.2
SCR-7	3	1.16	621	58	2.5	89.2	143.7	25.6	8.1	80.0	8385	3050.9
SCR-7	4	1.16	621	59	2.5	85.5	137.9	25.0	7.8	80.0	8529	2928.7
SCR-7-C	1	1.52	621	59	2.5	94.8	152.7	16.3	5.1	80.0	8529	1907.8
SCR-7-C	2	1.52	621	52	2.5	100.8	162.4	16.8	5.9	80.0	7517	2230.5
SCR-7-C	3	1.16	621	58	2.5	89.2	143.7	15.1	4.8	80.0	8385	1795.6
SCR-7-C	4	1.16	621	59	2.5	85.5	137.9	14.7	4.6	80.0	8529	1722.9

gas for each unit passes through a separate duct to a retrofit ESP located behind the chimney. This duct has a sufficient residence time (~4 seconds) and can be used for DSD application with relatively easy retrofit. However, the other 60 percent of the flue gas has a short residence time (1.5 seconds) before the old ESPs. Therefore, application of DSD would be more difficult. Since the old ESP boxes are adequate in size for the 60 percent flow (SCA > 270), E-SO_x technology can be applied to remove SO_2 and particulate. If upgrading of the ESPs is needed, a medium to high access/congestion factor was applied. Table 14.6.1-11 presents a summary of the site access/congestion factors for DSD and FSI technologies at the Labadie steam plant. Table 14.6.1-12 presents the costs estimated to retrofit DSD and FSI at the Labadie plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Labadie plant. The boilers at the Labadie plant would not be considered good candidates for AFBC retrofit because of their large size (620 MW) and high capacity factors (>50 percent).

14.6.2 Meramec Steam Plant

The Meramec steam plant is located within St. Louis County, Missouri, as part of Union Electric Company system. The plant contains four coal-fired boilers with a total net generating capacity of 923 MW. Figure 14.6.2-1 presents the plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 14.6.2-1 presents operational data for the existing equipment at the Meramec steam plant. All boilers burn low sulfur coal (1.1 percent sulfur). Coal shipments are received by barge and conveyed to a coal storage and handling area located south of the plant.

Particulate matter emissions are controlled with ESPs located behind each boiler unit. Retrofit ESPs are added behind the chimneys/existing ESPs. Fly ash from all units is wet sluiced to several large on-site ponds located

TABLE 14.6.1-11. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR LABADIE UNITS 1-4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (UNITS 1-3)	HIGH
ESP UPGRADE (UNIT 4)	MEDIUM
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	4714
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	118
TOTAL COST (1000$)	
ESP UPGRADE CASE	4832
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (UNITS 1-3)	1.59
ESP UPGRADE (UNIT 4)	1.38

Table 14.6.1-12. Summary of DSD/FSI Control Costs for the Labadie Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	621	59	2.5	34.0	54.7	24.1	7.5	49.0	33714	714.4
DSD+ESP	2	1.00	621	52	2.5	34.0	54.7	22.6	8.0	49.0	29714	760.5
DSD+ESP	3	1.00	621	58	2.5	34.0	54.7	23.9	7.6	49.0	33143	720.3
DSD+ESP	4	1.00	621	59	2.5	33.3	53.6	23.9	7.5	49.0	33714	709.2
DSD+ESP-C	1	1.00	621	59	2.5	34.0	54.7	14.0	4.4	49.0	33714	413.8
DSD+ESP-C	2	1.00	621	52	2.5	34.0	54.7	13.1	4.6	49.0	29714	440.9
DSD+ESP-C	3	1.00	621	58	2.5	34.0	54.7	13.8	4.4	49.0	33143	417.3
DSD+ESP-C	4	1.00	621	59	2.5	33.3	53.6	13.8	4.3	49.0	33714	410.8
FSI+ESP-50	1	1.00	621	59	2.5	29.4	47.4	29.4	9.2	50.0	34650	848.5
FSI+ESP-50	2	1.00	621	52	2.5	29.4	47.4	26.9	9.5	50.0	30539	880.4
FSI+ESP-50	3	1.00	621	58	2.5	29.4	47.4	29.0	9.2	50.0	34062	852.6
FSI+ESP-50	4	1.00	621	59	2.5	28.5	46.0	29.2	9.1	50.0	34650	842.0
FSI+ESP-50-C	1	1.00	621	59	2.5	29.4	47.4	17.0	5.3	50.0	34650	490.0
FSI+ESP-50-C	2	1.00	621	52	2.5	29.4	47.4	15.5	5.5	50.0	30539	508.7
FSI+ESP-50-C	3	1.00	621	58	2.5	29.4	47.4	16.8	5.3	50.0	34062	492.4
FSI+ESP-50-C	4	1.00	621	59	2.5	28.5	46.0	16.8	5.3	50.0	34650	486.1
FSI+ESP-70	1	1.00	621	59	2.5	29.1	46.9	29.8	9.3	70.0	48510	614.9
FSI+ESP-70	2	1.00	621	52	2.5	29.1	46.9	27.3	9.6	70.0	42754	637.5
FSI+ESP-70	3	1.00	621	58	2.5	29.1	46.9	29.5	9.3	70.0	47687	617.8
FSI+ESP-70	4	1.00	621	59	2.5	28.3	45.6	29.6	9.2	70.0	48510	610.5
FSI+ESP-70-C	1	1.00	621	59	2.5	29.1	46.9	17.2	5.4	70.0	48510	355.0
FSI+ESP-70-C	2	1.00	621	52	2.5	29.1	46.9	15.7	5.6	70.0	42754	368.3
FSI+ESP-70-C	3	1.00	621	58	2.5	29.1	46.9	17.0	5.4	70.0	47687	356.7
FSI+ESP-70-C	4	1.00	621	59	2.5	28.3	45.6	17.1	5.3	70.0	48510	352.4

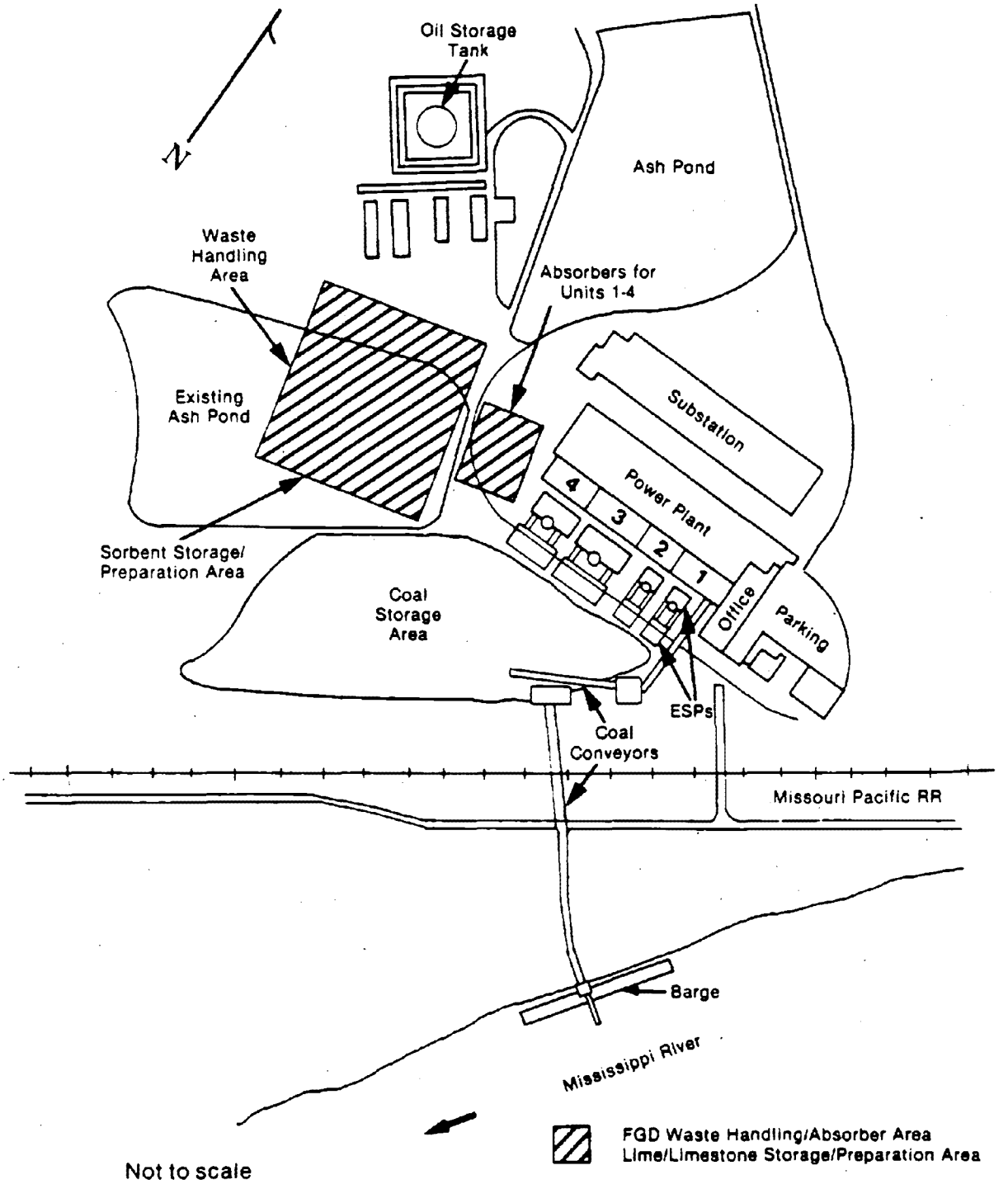


Figure 14.6.2-1. Meramec plant plot plan

TABLE 14.6.2-1. MERAMEC STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4
GENERATING CAPACITY (MW-each)	137.5	289	350
CAPACITY FACTOR (PERCENT)	10, 13	11	12
FIRING TYPE	TANG	FWF	FWF
INSTALLATION DATE	1953-54	1959	1961
COAL SULFUR CONTENT (PERCENT)	1.3	1.3	1.3
COAL HEATING VALUE (BTU/LB)	12000	12000	12000
COAL ASH CONTENT (PERCENT)	6.6	6.6	6.6
FLY ASH SYSTEM		WET HANDLING	
ASH DISPOSAL METHOD		ON-SITE/PONDS	
STACK NUMBER	1-2	3	4
COAL DELIVERY METHODS		BARGE	
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1981	1982	1981
EMISSION (LB/MM BTU)	0.001	0.004	0.006
REMOVAL EFFICIENCY	99.6	99.5	99.8
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	0.9	0.9	0.9
SURFACE AREA (1000 SQ FT)	295.6	608.4	790.5
GAS EXIT RATE (1000 ACFM)	600	1,165	1,450
SCA (SQ FT/1000 ACFM)	492	522	545
OUTLET TEMPERATURE (°F)	330	360	365

above the coal storage area to the north of the plant. Each unit is served by its own chimney located between the ESPs.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.6.2-1 shows the general layout and location of the FGD control system. The retrofit ESPs are located between the chimneys and coal storage and handling area. To the east of unit 1, the area is congested with office buildings, coal conveyors, and other buildings. The only available space for absorber placement is to the west of unit 4. This area is presently one of several ash pond sites.

For absorber placement, relocation is necessary for a plant road and ash sluice pipe lines. Consequently, a factor of 8 percent is assigned to general facilities. The lime and limestone storage/preparation and waste handling areas are located to the west of the absorbers.

Retrofit Difficulty and Scope Adder Costs--

The site to the west of unit 4 is an open area with no major obstacle/obstruction. Consequently, a low site access/congestion factor is assigned to the absorber location for all units. On the other hand, due to space constraints around the existing chimney from ESP placements and the coal handling area, a high site access/congestion and underground obstruction factor is assigned to all flue gas handling systems. Since unit 1 through 3 absorbers are placed at a distance from the open area (west of unit 4) with extremely difficult access, the cost of a new chimney for units 1-3 is included resulting in a shorter duct length for the L/LS-FGD case. Building a new chimney is cost effective, since construction of outlet ductwork with high congestion factors would be eliminated, and interference would also be reduced with other equipment. For flue gas handling, duct lengths range from 400 feet for unit 3 to 650 feet for unit 1.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Tables 14.6.2-2 through 14.6.2-5. The largest scope adder cost are construction of a new chimney and conversion of the fly ash handling system from wet to dry. The overall retrofit factors determined for the L/LS-FGD cases were medium (1.32 to 1.59).

TABLE 14.6.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR MERAMEC UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1,000	600-1,000	
ESP REUSE			1,000+
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	1,225	NA	1,225
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	1,898	1,898	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.59	1.54	
ESP REUSE CASE			1.72
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.59
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

TABLE 14.6.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR MERAMEC UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			1,000+
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	1,225	NA	1,225
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	1,898	1,898	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.53	1.48	
ESP REUSE CASE			1.63
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.59
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

TABLE 14.6.2-4. SUMMARY OF RETROFIT FACTOR DATA FOR MERAMEC UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			600-1,000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	2,377	NA	2,399
NEW CHIMNEY	YES	YES	NO
ESTIMATED COST (1000$)	2,975	2,975	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	1.41	
ESP REUSE CASE			1.52
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.59
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

TABLE 14.6.2-5. SUMMARY OF RETROFIT FACTOR DATA FOR MERAMEC UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	2,887	NA	2,887
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.38	1.32	
ESP REUSE CASE			1.36
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.38
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

The LSD with reused ESP is the only LSD-FGD technology which is considered for Meramec plant since all units presently have large SCAs (>490). For the LSD-FGD case, absorbers are located west of unit 4 in the same manner as L/LS-FGD. A low site access/congestion factor is also assigned to the absorber locations. For units 1 through 3, it is extremely difficult to reach the upstream of the ESPs due to the close proximity of the ESPs to each other, the chimneys, and the boiler house. As a result, high site access/congestion and underground obstructions are assigned to the unit 1-3 flue gas handling area. For unit 4, a medium site access/congestion factor is assigned to the flue gas handling system. Duct lengths range from 500 feet for unit 4 to 1,300 feet for unit 1. The retrofit factors determined for LSD-FGD cases range from 1.36 to 1.72.

Table 14.6.2-6 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 1-4.

The low cost control case reduces capital and annual operating costs by more than 50 percent. The significant reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 14.6.2-7.

Table 14.6.2-6. Summary of FGD Control Costs for the Meramec Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.59	138	10	1.3	55.8	406.0	20.3	168.6	90.0	1137	17865.3
L/S FGD	2	1.53	138	13	1.3	53.9	392.0	19.9	127.4	90.0	1478	13496.2
L/S FGD	3	1.48	289	11	1.3	80.5	278.7	29.1	104.4	90.0	2629	11059.7
L/S FGD	4	1.38	350	12	1.3	84.3	240.9	30.7	83.3	90.0	3473	8829.7
L/S FGD-C	1	1.59	138	10	1.3	55.8	406.0	11.9	98.7	90.0	1137	10455.8
L/S FGD-C	2	1.53	138	13	1.3	53.9	392.0	11.7	74.5	90.0	1478	7895.9
L/S FGD-C	3	1.48	289	11	1.3	80.5	278.7	17.0	61.1	90.0	2629	6473.9
L/S FGD-C	4	1.38	350	12	1.3	84.3	240.9	17.9	48.8	90.0	3473	5167.6
LC FGD	1-4	1.46	914	12	1.3	141.9	155.2	51.9	54.1	90.0	9069	5726.6
LC FGD-C	1-4	1.46	914	12	1.3	141.9	155.2	30.4	31.6	90.0	9069	3351.1
LSD+ESP	1	1.72	138	10	1.3	24.3	177.1	9.9	81.9	76.0	964	10234.8
LSD+ESP	2	1.63	138	13	1.3	23.3	169.2	9.6	61.5	76.0	1253	7679.9
LSD+ESP	3	1.52	289	11	1.3	40.4	139.9	14.9	53.5	76.0	2228	6688.7
LSD+ESP	4	1.36	350	12	1.3	43.9	125.5	16.2	44.0	76.0	2944	5492.3
LSD+ESP-C	1	1.72	138	10	1.3	24.3	177.1	5.8	47.8	76.0	964	5977.2
LSD+ESP-C	2	1.63	138	13	1.3	23.3	169.2	5.6	35.9	76.0	1253	4483.3
LSD+ESP-C	3	1.52	289	11	1.3	40.4	139.9	8.7	31.3	76.0	2228	3913.5
LSD+ESP-C	4	1.36	350	12	1.3	43.9	125.5	9.5	25.7	76.0	2944	3213.6

Table 14.6.2-7. Summary of Coal Switching/Cleaning Costs for the Meramec Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	138	10	1.3	5.5	40.1	2.9	24.3	31.0	394	7437.1
CS/B+$15	2	1.00	138	13	1.3	5.5	40.1	3.4	21.8	31.0	512	6678.3
CS/B+$15	3	1.00	289	11	1.3	10.1	35.0	6.0	21.5	31.0	910	6579.0
CS/B+$15	4	1.00	350	12	1.3	11.9	34.1	7.5	20.5	31.0	1202	6279.5
CS/B+$15-C	1	1.00	138	10	1.3	5.5	40.1	1.7	14.1	31.0	394	4323.9
CS/B+$15-C	2	1.00	138	13	1.3	5.5	40.1	2.0	12.7	31.0	512	3874.6
CS/B+$15-C	3	1.00	289	11	1.3	10.1	35.0	3.5	12.5	31.0	910	3819.3
CS/B+$15-C	4	1.00	350	12	1.3	11.9	34.1	4.4	11.9	31.0	1202	3642.2
CS/B+$5	1	1.00	138	10	1.3	4.1	29.7	1.7	14.0	31.0	394	4273.8
CS/B+$5	2	1.00	138	13	1.3	4.1	29.7	1.9	12.0	31.0	512	3661.7
CS/B+$5	3	1.00	289	11	1.3	7.1	24.7	3.2	11.3	31.0	910	3473.7
CS/B+$5	4	1.00	350	12	1.3	8.3	23.7	3.9	10.5	31.0	1202	3222.2
CS/B+$5-C	1	1.00	138	10	1.3	4.1	29.7	1.0	8.2	31.0	394	2495.2
CS/B+$5-C	2	1.00	138	13	1.3	4.1	29.7	1.1	7.0	31.0	512	2133.8
CS/B+$5-C	3	1.00	289	11	1.3	7.1	24.7	1.8	6.6	31.0	910	2025.3
CS/B+$5-C	4	1.00	350	12	1.3	8.3	23.7	2.3	6.1	31.0	1202	1877.1

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Meramec steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR for units 1 and 2 and LNB and SCR for units 3 and 4.

Low NO_x Combustion--

Units 1 and 2 are dry bottom, tangential-fired boilers, rated at 138 MW each; whereas, units 3 and 4 are dry bottom, front wall-fired boilers, rated at 289 and 359 MW, respectively. The combustion modification technique applied for this evaluation was OFA for units 1 and 2 and LNB for units 3 and 4. As Table 14.6.2-8 and 14.6.2-9 shows, the OFA NO_x reduction performance for units 1 and 2 was estimated to be 30 percent and the LNB NO_x reduction performance for units 3 and 4 was estimated to be 40 percent. Both reduction performance levels were assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. Table 14.6.2-10 presents the cost of retrofitting OFA and LNB at the Meramec boilers.

Selective Catalytic Reduction--

Tables 14.6.2-8 and 16.6.2-9 present the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors were placed west of unit 4. As such, low site access/ congestion factors and underground obstruction factors were assigned to the SCR reactor locations. For scope adders, cost for a new chimney was added to unit 1-3 SCR reactors to reduce duct work interferences with other equipment. Table 14.6.2-10 presents the estimated cost of retrofitting SCR at the Meramec boilers.

TABLE 14.6.2-8. SUMMARY OF NOx RETROFIT RESULTS FOR MERAMEC UNITS 1-2

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	12.8	12.8
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	27.6	27.6
FURNACE RESIDENCE TIME (SECONDS)	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	30	30
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
New Chimney (1000$)	1898	1898
Ductwork Demolition (1000$)	34	34
New Duct Length (Feet)	650	520
New Duct Costs (1000$)	5317	4253
New Heat Exchanger (1000$)	2261	2261
TOTAL SCOPE ADDER COSTS (1000$)	9510	8446
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

TABLE 14.6.2-9. SUMMARY OF NOx RETROFIT RESULTS FOR MERAMEC UNITS 3-4

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	3	4
FIRING TYPE	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	17.1	15.4
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	68.2	71.4
FURNACE RESIDENCE TIME (SECONDS)	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	40	40
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
New Chimney (1000$)	2975	0
Ductwork Demolition (1000$)	60	71
New Duct Length (Feet)	400	440
New Duct Costs (1000$)	5052	5468
New Heat Exchanger (1000$)	3523	4013
TOTAL SCOPE ADDER COSTS (1000$)	11,160	9552
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 14.6.2-10. NOx Control Cost Results for the Meramec Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	3	1.00	289	11	1.3	3.9	13.5	0.9	3.1	40.0	484	1763.4
LNC-LNB	4	1.00	350	12	1.3	4.2	12.0	0.9	2.5	40.0	639	1441.3
LNC-LNB-C	3	1.00	289	11	1.3	3.9	13.5	0.5	1.8	40.0	484	1046.5
LNC-LNB-C	4	1.00	350	12	1.3	4.2	12.0	0.5	1.5	40.0	639	855.3
LNC-OFA	1	1.00	138	10	1.3	0.7	5.1	0.2	1.3	30.0	112	1371.7
LNC-OFA	2	1.00	138	13	1.3	0.7	5.1	0.2	1.0	30.0	146	1055.2
LNC-OFA-C	1	1.00	138	10	1.3	0.7	5.1	0.1	0.8	30.0	112	813.4
LNC-OFA-C	2	1.00	138	13	1.3	0.7	5.1	0.1	0.6	30.0	146	625.7
SCR-3	1	1.16	138	10	1.3	29.1	211.9	8.6	71.2	80.0	299	28696.2
SCR-3	2	1.16	138	13	1.3	28.0	204.0	8.4	53.7	80.0	389	21630.0
SCR-3	3	1.16	289	11	1.3	46.4	160.6	14.8	53.0	80.0	968	15259.8
SCR-3	4	1.16	350	12	1.3	49.0	139.9	16.4	44.5	80.0	1279	12810.4
SCR-3-C	1	1.16	138	10	1.3	29.1	211.9	5.0	41.9	80.0	299	16877.8
SCR-3-C	2	1.16	138	13	1.3	28.0	204.0	4.9	31.6	80.0	389	12716.1
SCR-3-C	3	1.16	289	11	1.3	46.4	160.6	8.7	31.1	80.0	968	8957.8
SCR-3-C	4	1.16	350	12	1.3	49.0	139.9	9.6	26.1	80.0	1279	7511.3
SCR-7	1	1.16	138	10	1.3	29.1	211.9	7.5	61.9	80.0	299	24917.8
SCR-7	2	1.16	138	13	1.3	28.0	204.0	7.3	46.5	80.0	389	18723.8
SCR-7	3	1.16	289	11	1.3	46.4	160.4	12.4	44.4	80.0	691	17873.0
SCR-7	4	1.16	350	12	1.3	49.0	139.9	13.5	36.7	80.0	1279	10561.1
SCR-7-C	1	1.16	138	10	1.3	29.1	211.9	4.4	36.5	80.0	299	14713.2
SCR-7-C	2	1.16	138	13	1.3	28.0	204.0	4.3	27.4	80.0	389	11051.0
SCR-7-C	3	1.16	289	11	1.3	46.4	160.4	7.3	26.2	80.0	691	10540.8
SCR-7-C	4	1.16	350	12	1.3	49.0	139.9	8.0	21.6	80.0	1279	6222.5

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

For units 1 and 2, the flue gas ducting travels from the outlet of the old boxes around the chimney and over the new boxes. As such, there is plenty of droplet drying time for DSD and humidification time for FSI. For units 3 and 4, the flue gas ductwork leaves the outlet of the old boxes, goes around the chimney and directly into the new boxes. These duct runs are short and have a number of turns, thus making these units poor candidates for DSD and humidification injection. However, the old boxes would be good candidates for sorbent injection for the E-SO_x technology in conjunction with retrofit advance particulate control technology. Tables 14.6.2-11 through 14.6.2-13 present a summary of the site access/congestion factors for DSD and FSI technologies at the Meramec steam plant. Table 14.6.2-14 presents the costs estimated to retrofit DSD and FSI at the Meramec plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Meramec plant. The unit 1, 2, and 3 boilers at the Meramec plant would be considered good candidates for AFBC retrofit because of the small boiler sizes (<300 MW). Although unit 4 may not be a good candidate because of its large boiler size (>300 MW), its low capacity factor would indicate it may be a good candidate because there would be low replacement power costs for downtime and heat rate improvement benefits may be significant.

TABLE 14.6.2-11. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MERAMEC UNITS 1-2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1225
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	34
TOTAL COST (1000$)	
ESP UPGRADE CASE	1259
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.59
NEW BAGHOUSE	NA

TABLE 14.6.2-12. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MERAMEC UNIT 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2399
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	60
TOTAL COST (1000$)	
ESP UPGRADE CASE	2459
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.59
NEW BAGHOUSE	NA

TABLE 14.6.2-13. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MERAMEC UNIT 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2887
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	70
TOTAL COST (1000$)	
ESP UPGRADE CASE	2957
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.38
NEW BAGHOUSE	NA

Table 14.6.2-14. Summary of DSD/FSI Control Costs for the Meramec Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	138	10	1.3	8.1	59.1	4.9	40.7	49.0	615	7974.1
DSD+ESP	2	1.00	138	13	1.3	8.1	59.1	5.0	31.8	49.0	799	6226.6
DSD+ESP	3	1.00	289	11	1.3	13.3	46.1	6.6	23.6	49.0	1421	4628.3
DSD+ESP	4	1.00	350	12	1.3	14.7	41.9	7.1	19.4	49.0	1877	3796.5
DSD+ESP-C	1	1.00	138	10	1.3	8.1	59.1	2.8	23.6	49.0	615	4628.0
DSD+ESP-C	2	1.00	138	13	1.3	8.1	59.1	2.9	18.4	49.0	799	3613.1
DSD+ESP-C	3	1.00	289	11	1.3	13.3	46.1	3.8	13.7	49.0	1421	2693.8
DSD+ESP-C	4	1.00	350	12	1.3	14.7	41.9	4.1	11.3	49.0	1877	2210.2
FSI+ESP-50	1	1.00	138	10	1.3	8.8	63.9	3.8	31.8	50.0	632	6062.1
FSI+ESP-50	2	1.00	138	13	1.3	8.8	63.9	3.9	25.2	50.0	821	4806.3
FSI+ESP-50	3	1.00	289	11	1.3	14.3	49.6	5.7	20.4	50.0	1460	3889.6
FSI+ESP-50	4	1.00	350	12	1.3	15.7	44.8	6.3	17.1	50.0	1929	3260.6
FSI+ESP-50-C	1	1.00	138	10	1.3	8.8	63.9	2.2	18.5	50.0	632	3535.5
FSI+ESP-50-C	2	1.00	138	13	1.3	8.8	63.9	2.3	14.7	50.0	821	2801.7
FSI+ESP-50-C	3	1.00	289	11	1.3	14.3	49.6	3.3	11.9	50.0	1460	2272.5
FSI+ESP-50-C	4	1.00	350	12	1.3	15.7	44.8	3.7	10.0	50.0	1929	1904.6
FSI+ESP-70	1	1.00	138	10	1.3	8.9	64.8	3.9	32.1	70.0	884	4375.8
FSI+ESP-70	2	1.00	138	13	1.3	8.9	64.8	4.0	25.5	70.0	1150	3471.1
FSI+ESP-70	3	1.00	289	11	1.3	14.5	50.2	5.7	20.6	70.0	2044	2810.2
FSI+ESP-70	4	1.00	350	12	1.3	15.9	45.3	6.4	17.3	70.0	2701	2355.2
FSI+ESP-70-C	1	1.00	138	10	1.3	8.9	64.8	2.3	18.7	70.0	884	2552.3
FSI+ESP-70-C	2	1.00	138	13	1.3	8.9	64.8	2.3	14.9	70.0	1150	2023.5
FSI+ESP-70-C	3	1.00	289	11	1.3	14.5	50.2	3.4	12.1	70.0	2044	1641.9
FSI+ESP-70-C	4	1.00	350	12	1.3	15.9	45.3	3.7	10.1	70.0	2701	1375.7

14.6.3 Rush Island Steam Plant

The Rush Island steam plant is located within Jefferson County, Missouri, and is part of the Union Electric Company system. The plant contains two coal-fired boilers with a net generating capacity of 1,241 MW. The plant is bounded by the Mississippi River to the east and by rolling hills to the west. Figure 14.6.3-1 presents the plant plot plan showing the location of both boilers and major associated auxiliary equipment.

Table 14.6.3-1 presents the operational data for the existing equipment at the Rush Island plant. Both boilers burn low sulfur coal (1.2 percent sulfur). Coal shipments are received by freight barge or railroad. The coal is conveyed to a coal storage area south of the boilers.

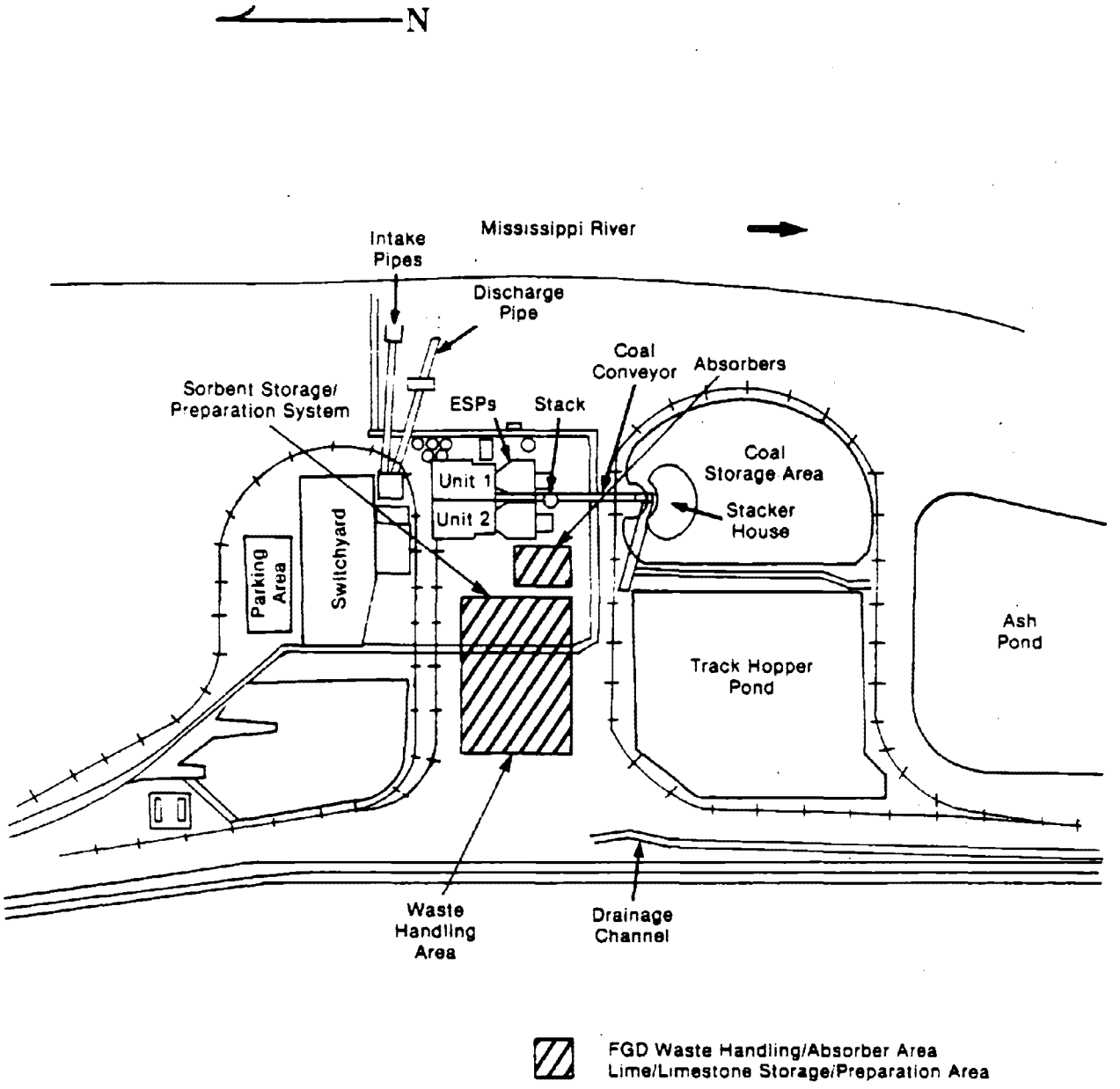
Particulate matter emissions for both boilers are controlled with ESPs located behind each unit. Ash from the units is wet sluiced to ponds located southwest of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.6.3-1 shows the general layout and location of the FGD control system. The absorbers for both units are located west of the unit 2 ESPs and north of the coal storage handling areas. No demolition/relocation of existing equipment/buildings would be required for the placement of the absorbers; therefore, a factor of 5 percent was assigned to general facilities.

Retrofit Difficulty and Scope Adder Costs--

The FGD equipment was located in a low site access/congestion area. Two site locations are possible for the placement of the unit 1 and 2 absorbers. One location is between the coal pile and units 1 and 2, on either side of the coal conveyor, close to the common chimney. The second location is to the west of unit 2 and to the north of the coal storage and handling area. The first location initially was considered for absorber placement since it was thought that possible future units would be constructed to the west of unit 2. However, plant personnel indicated that no additional units would be added to the plant. As such, the second location to the west of the plant was used for absorber placement in this study due to the large available



Not to scale

Figure 14.6.3-1. Rush Island plant plot plan

TABLE 14.6.3-1. RUSH ISLAND STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	620.5
CAPACITY FACTOR (PERCENT)	42, 59
INSTALLATION DATE	1976-77
FIRING TYPE	TANGENTIAL
COAL SULFUR CONTENT (PERCENT)	1.2
COAL HEATING VALUE (BTU/LB)	10,600
COAL ASH CONTENT (PERCENT)	8.2
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1976-77
EMISSION (LB/MM BTU)	0.006
REMOVAL EFFICIENCY	99.4
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.0
SURFACE AREA (1000 SQ FT)	933.1
GAS EXIT RATE (1000 ACFM)	3340
SCA (SQ FT/1000 ACFM)	279
OUTLET TEMPERATURE (°F)	270

space. Space between the units and the coal handling area is limited, which would result in a medium site access/congestion factor. By contrast, to the west of unit 2 is an open area with no obstructions. Low site access/ congestion factors have been assigned to this location. For the flue gas handling system a low site access/ congestion factor was assigned to both units since space is available behind the chimney for the duct runs.

The major scope adjustment costs and estimated retrofit factors for the FGD technologies are presented in Tables 14.6.3-2 and 14.6.3-3. The largest scope adder for Rush Island was the conversion of the fly ash conveying system from wet to dry for both boilers (conventional L/LS-FGD and LSD technologies). It was assumed that the fly ash would be necessary to stabilize the scrubber sludge waste resulting from conventional L/LS-FGD application and to prevent plugging of the sluice lines in the LSD-FGD system (for the ESP-Reuse case). The conversion of wet to dry ash handling is not necessary for forced oxidation L/LS-FGD. The overall retrofit factors estimated for the L/LS-FGD cases were moderate (1.25 to 1.39).

The LSD with reused ESP is the only LSD-FGD technology considered for both units since both boilers have moderate size ESPs (SCA >270). The LSD absorbers are placed in a similar location, as in the case of L/LS-FGD, with the same site access/congestion and underground obstruction factors being assigned. For the unit 1 flue gas handling, medium site access/congestion and underground obstruction factors are assigned. These factors represent access difficulty to the upstream of the unit 1 ESPs and congestion created by the unit 1 ESPs. To access the unit 1 ESPs, duct runs pass over the unit 2 ESPs, creating congestion and access difficulties. For unit 2, medium site access/congestion and underground factors are assigned to flue gas handling. Flue gas from the boiler is divided into two duct runs prior to the ESPs. It is relatively easy to access the outer duct run upstream of the unit 2 ESPs. By contrast, access to the inner duct run is difficult. Therefore, a median of the two access difficulties is used in this study, and a medium site access/congestion factor is assigned to the unit 2 flue gas handling system for LSD-FGD. Duct runs of 900 and 560 feet are required for units 1 and 2, respectively.

Table 14.6.3-4 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for

TABLE 14.6.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR RUSH ISLAND UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	MEDIUM
FLUE GAS HANDLING	LOW	HIGH	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1,000	600-1,000	
ESP REUSE			600-1,000
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4,823	0	4,823
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.39	1.34	
ESP REUSE CASE			1.53
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.38
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 14.6.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR RUSH ISLAND UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4,823	0	4,823
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.31	1.25	
ESP REUSE CASE			1.36
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.38
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

Table 14.6.3-4. Summary of FGD Control Costs for the Rush Island Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.39	621	42	1.2	129.8	209.1	56.9	24.9	90.0	22935	2483.1
L/S FGD	2	1.31	621	59	1.2	123.4	198.9	60.3	18.8	90.0	32218	1873.0
L/S FGD-C	1	1.39	621	42	1.2	129.8	209.1	33.2	14.5	90.0	22935	1448.0
L/S FGD-C	2	1.31	621	59	1.2	123.4	198.9	35.1	11.0	90.0	32218	1090.3
LC FGD	1-2	1.35	1241	50	1.2	191.0	153.9	93.9	17.3	90.0	54607	1718.8
LC FGD-C	1-2	1.35	1241	50	1.2	191.0	153.9	54.6	10.1	90.0	54607	1000.5
LSD+ESP	1	1.53	621	42	1.2	74.6	120.2	30.0	13.1	76.0	19443	1542.0
LSD+ESP	2	1.36	621	59	1.2	67.2	108.3	30.1	9.4	76.0	27313	1103.0
LSD+ESP-C	1	1.53	621	42	1.2	74.6	120.2	17.5	7.7	76.0	19443	900.7
LSD+ESP-C	2	1.36	621	59	1.2	67.2	108.3	17.6	5.5	76.0	27313	643.0

boilers 1 and 2. The low cost control case reduces capital and annual operating costs due to the benefits elimination of spare scrubber modules, optimization of scrubber module size, and use of organic acid additives.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 14.6.3-5.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Rush Island steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR.

Low NO_x Combustion--

Units 1 and 2 are dry bottom, tangential-fired boilers, rated at 621 MW each. The combustion modification technique applied for this evaluation was OFA. As Table 14.6.3-6 shows, the OFA NO_x reduction performance for units 1 and 2 was estimated to be 23 percent. This reduction performance level was assessed by examining the effects of volumetric heat release rate and furnace residence time through the use of the simplified NO_x procedures. No information was available in Power to calculate the boiler/waterwall surface area heat release rate for determining the effect of this parameter on NO_x

Table 14.6.3-5. Summary of Coal Switching/Cleaning Costs for the Rush Island Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	621	42	1.2	19.4	31.2	33.9	14.8	35.0	8999	3763.5
CS/B+$15	2	1.00	621	59	1.2	19.3	31.2	45.9	14.3	35.0	12641	3629.4
CS/B+$15-C	1	1.00	621	42	1.2	19.4	31.2	19.5	8.5	35.0	8999	2165.9
CS/B+$15-C	2	1.00	621	59	1.2	19.3	31.2	26.4	8.2	35.0	12641	2086.3
CS/B+$5	1	1.00	621	42	1.2	12.9	20.8	13.9	6.1	35.0	8999	1542.8
CS/B+$5	2	1.00	621	59	1.2	12.9	20.8	18.3	5.7	35.0	12641	1444.8
CS/B+$5-C	1	1.00	621	42	1.2	12.9	20.8	8.0	3.5	35.0	8999	890.4
CS/B+$5-C	2	1.00	621	59	1.2	12.9	20.8	10.5	3.3	35.0	12641	832.4

TABLE 14.6.3-6. SUMMARY OF NOx RETROFIT RESULTS FOR RUSH ISLAND

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	9.1	9.1
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	2.63	2.63
ESTIMATED NOx REDUCTION (PERCENT)	23	23
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	106	106
New Duct Length (Feet)	160	160
New Duct Costs (1000$)	2,317	2,317
New Heat Exchanger (1000$)	5,581	5,581
TOTAL SCOPE ADDER COSTS (1000$)	8,004	8,004
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

reduction. Table 14.6.3-7 presents the costs of retrofitting OFA at the Rush Island boilers.

Selective Catalytic Reduction--

Table 14.6.3-6 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new flue gas duct runs from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 and 2 were located directly behind (south) their respective ESPs, to the north of the coal pile in a low congestion area with easy access. Both reactors are assumed to be in areas with high underground obstructions. The ammonia storage system is placed to the west of unit 2 in a remote area having a low access/congestion factor. Both SCR reactors were assigned low access/congestion factors, since they were in an area surrounded on one side by the ESPs. Both reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.
Table 14.6.3-7 presents the estimated cost of retrofitting SCR at the Rush Island boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for both units were located south of the boilers in a similar layout to that of LSD-FGD. There is not sufficient flue gas ducting residence time (~1 second) between the boilers and ESPs. However, all ESPs should be good candidates for the E-SO_x technology because of the overall good particulate removal performance currently being achieved. The major scope adder for DSD and FSI would be

Table 14.6.3-7. NOx Control Cost Results for the Rush Island Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	621	42	1.2	1.3	2.1	0.3	0.1	23.0	1879	149.5
LNC-OFA	2	1.00	621	59	1.2	1.3	2.1	0.3	0.1	23.0	2639	106.4
LNC-OFA-C	1	1.00	621	42	1.2	1.3	2.1	0.2	0.1	23.0	1879	88.7
LNC-OFA-C	2	1.00	621	59	1.2	1.3	2.1	0.2	0.1	23.0	2639	63.2
SCR-3	1	1.16	621	42	1.2	72.7	117.1	27.2	11.9	80.0	6534	4162.5
SCR-3	2	1.16	621	59	1.2	72.7	117.2	27.8	8.7	80.0	9179	3028.5
SCR-3-C	1	1.16	621	42	1.2	72.7	117.1	15.9	7.0	80.0	6534	2434.7
SCR-3-C	2	1.16	621	59	1.2	72.7	117.2	16.3	5.1	80.0	9179	1770.6
SCR-7	1	1.16	621	42	1.2	72.7	117.1	22.0	9.6	80.0	6534	3367.7
SCR-7	2	1.16	621	59	1.2	72.7	117.2	22.6	7.0	80.0	9179	2462.7
SCR-7-C	1	1.16	621	42	1.2	72.7	117.1	12.9	5.7	80.0	6534	1979.4
SCR-7-C	2	1.16	621	59	1.2	72.7	117.2	13.3	4.1	80.0	9179	1446.5

the conversion of the fly ash from wet to dry for reusing the ESPs. Table 14.6.3-8 presents a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the Rush Island plant. The scope adder costs presented are on a dollar per boiler basis. Table 14.6.3-9 presents the costs estimated to retrofit DSD and FSI at the Rush Island plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Rush Island plant. None of the boilers at Rush Island would be considered good candidates for AFBC retrofit and AFBC or coal gasification/combined cycle repowering because of their large boiler sizes (621 MW).

14.6.4 Sioux Steam Plant

The Sioux steam plant is located along the Mississippi River within St. Charles County, Missouri, as part of Union Electric Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 1100 MW. Figure 14.6.4-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 14.6.4-1 presents operational data for the existing equipment at the Sioux steam plant. All boilers burn medium sulfur coal (2.5 percent sulfur), which is blend of two types, Illinois high-sulfur and western low-sulfur. Coal shipments are received by railroad and conveyed to a coal storage and handling area located east of the plant.

Particulate matter emissions for the boilers are controlled with ESPs located behind each unit. Fly ash from all units is wet sluiced to ponds located south of the plant. A very large on-site waste disposal area is available.

TABLE 14.6.3-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR RUSH ISLAND UNITS 1-2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	4823
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	118
TOTAL COST (1000$)	
ESP UPGRADE CASE	4941
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.38
NEW BAGHOUSE	NA

Table 14.6.3-9. Summary of DSD/FSI Control Costs for the Rush Island Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	621	42	1.2	25.1	40.4	14.3	6.3	49.0	12397	1153.6
DSD+ESP	2	1.00	621	59	1.2	25.1	40.4	16.4	5.1	49.0	17415	942.5
DSD+ESP-C	1	1.00	621	42	1.2	25.1	40.4	8.3	3.6	49.0	12397	670.0
DSD+ESP-C	2	1.00	621	59	1.2	25.1	40.4	9.5	3.0	49.0	17415	546.5
FSI+ESP-50	1	1.00	621	42	1.2	28.5	46.0	16.2	7.1	50.0	12741	1272.2
FSI+ESP-50	2	1.00	621	59	1.2	28.5	46.0	19.4	6.1	50.0	17899	1086.3
FSI+ESP-50-C	1	1.00	621	42	1.2	28.5	46.0	9.4	4.1	50.0	12741	738.9
FSI+ESP-50-C	2	1.00	621	59	1.2	28.5	46.0	11.3	3.5	50.0	17899	629.5
FSI+ESP-70	1	1.00	621	42	1.2	28.7	46.2	16.4	7.2	70.0	17838	921.8
FSI+ESP-70	2	1.00	621	59	1.2	28.7	46.3	19.8	6.2	70.0	25058	788.3
FSI+ESP-70-C	1	1.00	621	42	1.2	28.7	46.2	9.5	4.2	70.0	17838	535.3
FSI+ESP-70-C	2	1.00	621	59	1.2	28.7	46.3	11.4	3.6	70.0	25058	456.8

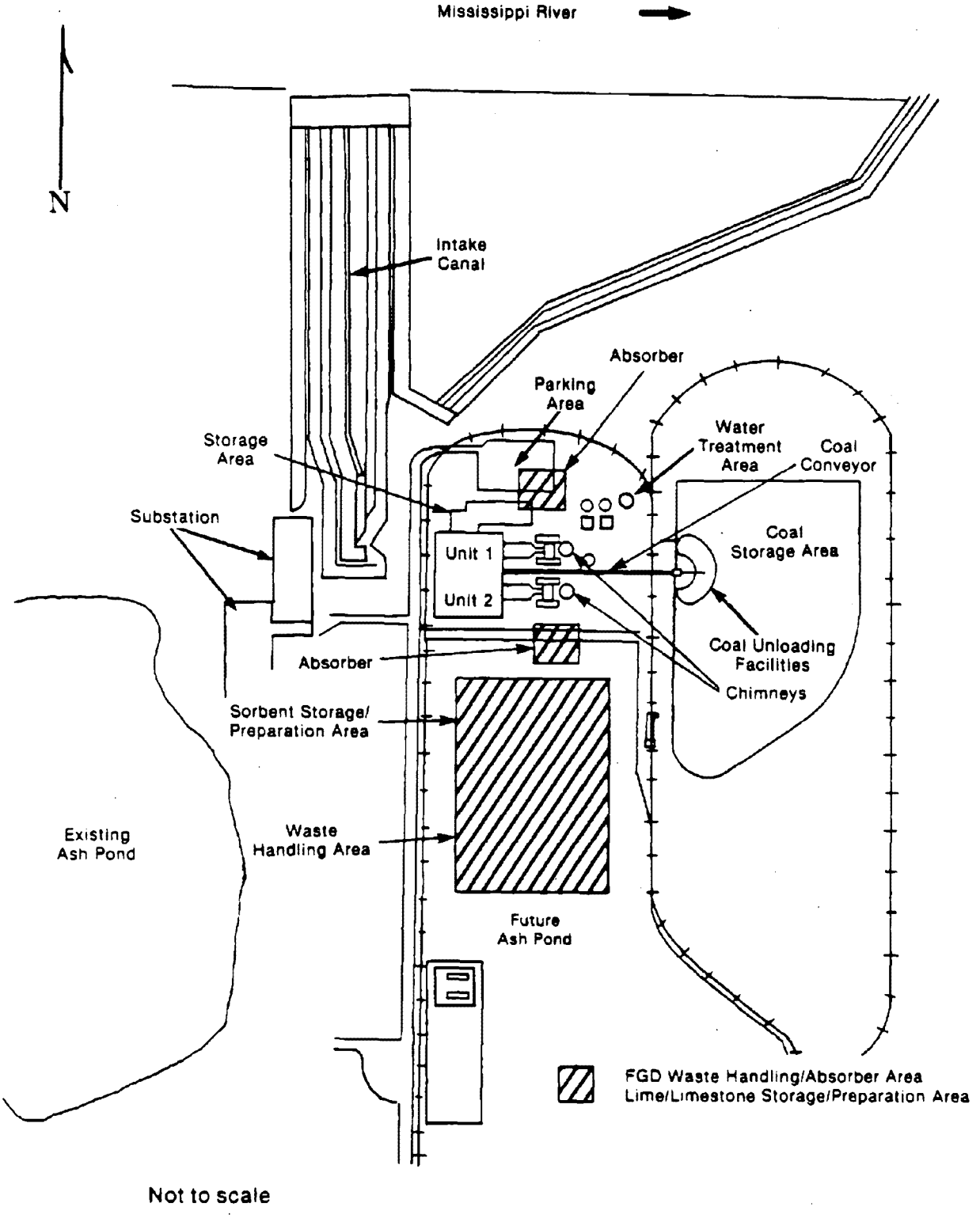


Figure 14.6.4-1. Sioux plant plot plan

TABLE 14.6.4-1. SIOUX STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	550
CAPACITY FACTOR (PERCENT)	43, 33
FIRING TYPE	CYCLONE
INSTALLATION DATE	1967 & 1968
COAL SULFUR CONTENT (PERCENT)	1.7
COAL HEATING VALUE (BTU/LB)	11,245
COAL ASH CONTENT (PERCENT)	7.1
FLY ASH SYSTEM	WET
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1-2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1973
EMISSION (LB/MM BTU)	0.08
REMOVAL EFFICIENCY	98.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	3.5
SURFACE AREA (1000 SQ FT)	536.4
GAS EXIT RATE (1000 ACFM)	2000
SCA (SQ FT/1000 ACFM)	268
OUTLET TEMPERATURE (°F)	310

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 14.6.4-1 shows the general layout and location of the FGD control system. The absorbers for L/LS-FGD and LSD-FGD for unit 1 would be located north of the water treatment area beside the employee parking area, northeast of unit 1. The absorbers for unit 2 would be located southeast of unit 2 beside the railroad and south of the ESPs, which is presently a part of the future ash pond site. In the placing of the unit 1 absorbers, relocation is necessary for part of the parking lot and storage area. As a result, a factor of 8 percent was assigned to general facilities. No major relocation or demolition would be required for unit 2; therefore, a factor of 5 percent was assigned to general facilities. The lime and limestone storage/preparation area and waste handling area would be located south of unit 2 (below the unit 2 absorbers), which is presently the future ash pond site.

Retrofit Difficulty and Scope Adder Costs--

Even though space is available for the unit 1 absorbers between the coal storage area (west) and unit 1 adjacent to the chimney (east), major relocation and demolition would be required for the water treatment area and water storage tank. Therefore, the site north of the water treatment area beside the parking lot (east) and northeast of unit 1 was designated for the unit 1 absorbers. This site is between the railroad, parking area, and water treatment area.

There are two possible site locations for the unit 2 absorber. For the first location, space is available between the coal pile and unit 2, east of the unit 2 ESPs and south of the coal conveyor. The second possible location is in an open area south of unit 2 and what is presently the future ash pond site. For this study, the latter location has been designated for the unit 2 absorbers due to its spacious area. However, it is possible that a future unit 3 may be placed at this site and, if so, the absorber would then need to be placed at the first location as described above.

The absorber locations for both units were assigned a low site access/congestion factor because they were located in relatively open areas with no major obstacles/interferences and no major underground obstruction.

For flue gas handling, short to moderate duct runs would be required for both units for L/LS-FGD cases. A low site access/congestion factor was

assigned to the flue gas handling system due to easy access to the chimneys with no major obstructions.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Tables 14.6.4-2 and 14.6.2-3. The largest scope adder cost is the conversion of the fly ash handling system from wet to dry. The overall retrofit factors determined for the L/LS-FGD cases ranged from low to moderate (1.23 to 1.36).

The LSD with reused ESP was the only LSD-FGD technology considered for both units because of boilers presently having large SCAs (>260). For flue gas handling for LSD cases, moderate duct runs would be required and a medium site access/congestion factor was assigned. This was due to the site access/congestion created by the ESPs to route flue gas from the boilers to the absorbers and back to the ESPs. The retrofit factors determined for the LSD technology case ranged from 1.35 to 1.39.

Table 14.6.4-4 presents the cost estimates for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 1 and 2.

The low cost control case reduces capital and annual operating costs by 25 to 55 percent. The reduction in costs is primarily due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined. This is particularly true for cyclone boilers; as such, CS was not evaluated.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Sioux steam plant. These controls include NGR and SCR. NGR was the LNC modification control for the two Sioux units because LNB and OFA are not applicable to cyclone-fired boilers. SCR was considered to be applicable to all coal-fired boiler types.

TABLE 14.6.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR SIOUX UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4,232	NA	4,232
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.36	1.29	
ESP REUSE CASE			1.39
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.59
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	8	8

TABLE 14.6.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR SIOUX UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	4,232	NA	4,232
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.30	1.23	
ESP REUSE CASE			1.35
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.34
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

Table 14.6.4-4. Summary of FGD Control Costs for the Sioux Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.36	550	43	1.7	117.1	212.9	51.9	25.0	90.0	27680	1876.5
L/S FGD	2	1.30	550	33	1.7	110.7	201.3	46.7	29.6	90.0	21016	2223.8
L/S FGD-C	1	1.36	550	43	1.7	117.1	212.9	30.3	14.6	90.0	27680	1094.*
L/S FGD-C	2	1.30	550	33	1.7	110.7	201.3	27.3	17.3	90.0	21016	1297.7
LC FGD	1-2	1.33	1100	38	1.7	165.7	150.7	75.9	20.7	90.0	48696	1558.5
LC FGD-C	1-2	1.33	1100	38	1.7	165.7	150.7	44.2	12.1	90.0	48696	908.2
LSD+ESP	1	1.39	550	43	1.7	63.6	115.6	26.2	12.6	76.0	23467	1117.6
LSD+ESP	2	1.35	550	33	1.7	60.3	109.6	24.0	15.2	76.0	17817	1346.9
LSD+ESP-C	1	1.39	550	43	1.7	63.6	115.6	15.3	7.4	76.0	23467	652.4
LSD+ESP-C	2	1.35	550	33	1.7	60.3	109.6	14.0	8.9	76.0	17817	786.8

Low NO_x Combustion--

Table 14.6.4-5 presents the NO_x reduction performance and costs of NGR for each unit. It also shows that the NGR NO_x reduction performance for both units was estimated to be 60 percent. Table 14.6.4-6 presents the costs of retrofitting NGR at the Sioux boilers.

Selective Catalytic Reduction--

Table 14.6.4-5 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactor for unit 1 was located north of the ESPs for unit 1 and east of the parking lot in a low congestion area with easy access. The SCR reactor for unit 2 was located south of the ESPs for unit 2 in a low congestion area with easy access. Therefore, both reactors were assigned a low site access/congestion factor. Table 14.6.4-6 presents the estimated costs of retrofitting SCR at the Sioux boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbert receiving/storage/preparation areas for both units were located south of unit 2 in a relatively open area in a similar fashion as LSD-FGD (south of the unit 2 absorbers). There is sufficient flue gas ducting residence time (2 seconds) between the boilers and the retrofit ESPs. Additionally, developments in particulate control technology may be used to modify the existing ESP by combining advanced ESP technology and spray dryer technology to remove SO_2 and particulate (E-SO_x technology). Since both units have adequate ESP sizes (SCA >260), it was assumed that DSD and FSI

TABLE 14.6.4-5. SUMMARY OF NOx RETROFIT RESULTS FOR SIOUX

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	CY	CY
TYPE OF NOx CONTROL	NGR	NGR
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	60
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	97	97
New Duct Length (Feet)	560	440
New Duct Costs (1000$)	7558	5939
New Heat Exchanger (1000$)	5184	5184
TOTAL SCOPE ADDER COSTS (1000$)	12,839	11,220
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 14.6.4-6. NOx Control Cost Results for the Sioux Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	550	43	1.7	8.0	14.5	11.7	5.6	60.0	10298	1138.5
NGR	2	1.00	550	33	1.7	8.0	14.5	9.1	5.8	60.0	7819	1170.1
NGR-C	1	1.00	550	43	1.7	8.0	14.5	6.8	3.2	60.0	10298	655.7
NGR-C	2	1.00	550	33	1.7	8.0	14.5	5.3	3.3	60.0	7819	674.9
SCR-3	1	1.16	550	43	1.7	71.5	130.0	26.3	12.6	80.0	13731	1915.6
SCR-3	2	1.16	550	33	1.7	69.8	127.0	25.5	16.1	80.0	10425	2445.9
SCR-3-C	1	1.16	550	43	1.7	71.5	130.0	15.4	7.4	80.0	13731	1120.9
SCR-3-C	2	1.16	550	33	1.7	69.8	127.0	14.9	9.4	80.0	10425	1431.4
SCR-7	1	1.16	550	43	1.7	71.5	130.0	21.7	10.4	80.0	13731	1583.3
SCR-7	2	1.16	550	33	1.7	69.8	127.0	20.9	13.2	80.0	10425	2008.2
SCR-7-C	1	1.16	550	43	1.7	71.5	130.0	12.8	6.1	80.0	13731	930.5
SCR-7-C	2	1.16	550	33	1.7	69.8	127.0	12.3	7.8	80.0	10425	1180.6

with ESP reuse is applicable. Table 14.6.4-7 presents a summary of the site access/congestion factors for DSD and FSI technologies at the Sioux steam plant. For upgrading the ESPs, a high access/congestion factor was assigned to unit 1 and a medium factor was assigned to unit 2. Table 14.6.4-8 presents the costs estimated to retrofit DSD and FSI at the Sioux plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Sioux plant. The boilers at the Sioux plant would not be considered good candidates for AFBC retrofit because of the large sizes (550 MW).

TABLE 14.6.4-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR SIOUX UNITS 1-2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH/MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	4,267
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	107
TOTAL COST (1000$)	
ESP UPGRADE CASE	4,374
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.59, 1.34
NEW BAGHOUSE	NA

Table 14.6.4-8. Summary of DSD/FSI Control Costs for the Sioux Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	550	43	1.7	23.8	43.2	13.8	6.6	49.0	14963	919.6
DSD+ESP	2	1.00	550	33	1.7	22.9	41.7	12.3	7.8	49.0	11361	1084.8
DSD+ESP-C	1	1.00	550	43	1.7	23.8	43.2	8.0	3.8	49.0	14963	534.0
DSD+ESP-C	2	1.00	550	33	1.7	22.9	41.7	7.2	4.5	49.0	11361	630.5
FSI+ESP-50	1	1.00	550	43	1.7	30.6	55.6	18.3	8.8	50.0	15378	1192.4
FSI+ESP-50	2	1.00	550	33	1.7	28.9	52.6	15.6	9.9	50.0	11676	1336.4
FSI+ESP-50-C	1	1.00	550	43	1.7	30.6	55.6	10.6	5.1	50.0	15378	692.1
FSI+ESP-50-C	2	1.00	550	33	1.7	28.9	52.6	9.1	5.7	50.0	11676	776.8
FSI+ESP-70	1	1.00	550	43	1.7	30.5	55.4	18.5	8.9	70.0	21529	860.3
FSI+ESP-70	2	1.00	550	33	1.7	28.9	52.5	15.7	10.0	70.0	16346	963.1
FSI+ESP-70-C	1	1.00	550	43	1.7	30.5	55.4	10.7	5.2	70.0	21529	499.3
FSI+ESP-70-C	2	1.00	550	33	1.7	28.9	52.5	9.1	5.8	70.0	16346	559.7

SECTION 15.0 MISSISSIPPI

15.1 MISSISSIPPI POWER COMPANY

15.1.1 V.J. Daniel Jr. Steam Plant

Both units at this plant fire a low sulfur coal with an emission rate less than 1.2 lb SO_2/MBtu (1971 NSPS unit). Although retrofit factors for FGD were developed, costs were not because it is unlikely that these units would be scrubbed. Likewise, retrofit factors and costs were not estimated for sorbent injection because of the low sulfur coal and small ESPs. Since both units have OFA systems, the only NO_x control technology considered was SCR.

TABLE 15.1.1-1. V. J. DANIEL STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	500
CAPACITY FACTOR (PERCENT)	49,37
INSTALLATION DATE	1977,1981
FIRING TYPE	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	NA
OVER FIRE AIR	YES
COAL SULFUR CONTENT (PERCENT)	0.5
COAL HEATING VALUE (BTU/LB)	11800
COAL ASH CONTENT (PERCENT)	7.8
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	PONDS/ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1977, 1981
EMISSION (LB/MM BTU)	0.04
REMOVAL EFFICIENCY	99.3
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.6
SURFACE AREA (1000 SQ FT)	201.6
GAS EXIT RATE (1000 ACFM)	2390
SCA (SQ FT/1000 ACFM)	84
OUTLET TEMPERATURE (°F)	622

TABLE 15.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR V. J. DANIEL UNIT 1 OR 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	3968	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.31
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	0	8

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for units 1 and 2 would be located south of the common chimney, beyond the coal conveyor.

TABLE 15.1.1-3. SUMMARY OF NOx RETROFIT RESULTS FOR V. J. DANIEL

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	NA
TYPE OF NOx CONTROL	NA
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	NA
SLAGGING PROBLEM	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA
SCR RETROFIT RESULTS *	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	90
New Duct Length (Feet)	200
New Duct Costs (1000$)	2541
New Heat Exchanger (1000$)	0
TOTAL SCOPE ADDER COSTS (1000$)	
INDIVIDUAL CASE	2632
COMBINED CASE	3963
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

* Hot side SCR reactors for units 1 and 2 would be located behind the common chimney for units 1 and 2.

Table 15.1.1-4. NOx Control Cost Results for the V. J. Daniel Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3	1	1.16	500	49	0.5	58.5	117.0	21.7	10.1	80.0	5431	3987.2
SCR-3	2	1.16	500	37	0.5	58.5	117.0	21.3	13.2	80.0	4101	5205.2
SCR-3	1-2	1.16	1000	43	0.5	110.1	110.1	41.2	10.9	80.0	9532	4324.5
SCR-3-C	1	1.16	500	49	0.5	58.5	117.0	12.7	5.9	80.0	5431	2332.7
SCR-3-C	2	1.16	500	37	0.5	58.5	117.0	12.5	7.7	80.0	4101	3046.2
SCR-3-C	1-2	1.16	1000	43	0.5	110.1	110.1	24.1	6.4	80.0	9532	2529.4
SCR-7	1	1.16	500	49	0.5	58.5	117.0	17.5	8.2	80.0	5431	3228.8
SCR-7	2	1.16	500	37	0.5	58.5	117.0	17.2	10.6	80.0	4101	4201.0
SCR-7	1-2	1.16	1000	43	0.5	110.1	110.1	33.0	8.8	80.0	9532	3460.3
SCR-7-C	1	1.16	500	49	0.5	58.5	117.0	10.3	4.8	80.0	5431	1898.2
SCR-7-C	2	1.16	500	37	0.5	58.5	117.0	10.1	6.3	80.0	4101	2470.8
SCR-7-C	1-2	1.16	1000	43	0.5	110.1	110.1	19.4	5.1	80.0	9532	2034.3

15.1.2 Jack Watson Steam Plant

The Jack Watson Steam Plant is located in Harrison County, Mississippi, as part of the Mississippi Power Company system. The plant contains two coal-fired boilers with a total gross generating capacity of 750 MW. Tables 15.1.2-1 through 15.1.2-10 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 15.1.2-1. JACK WATSON STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4	5
GENERATING CAPACITY (MW-each)	75	112	250	500
CAPACITY FACTOR (PERCENT)			53	70
INSTALLATION DATE	1957,60	1962	1968	1973
FIRING TYPE	TANGENTIAL		OPPOSED WALL	
FURNACE VOLUME (1000 CU FT)	PETROLEUM		NA	272
LOW NOx COMBUSTION	BURNING		NO	NO
COAL SULFUR CONTENT (PERCENT)			2.4	
COAL HEATING VALUE (BTU/LB)			12300	
COAL ASH CONTENT (PERCENT)			8.5	
FLY ASH SYSTEM			WET DISPOSAL	
ASH DISPOSAL METHOD			PONDS/ON-SITE	
STACK NUMBER			4	5
COAL DELIVERY METHODS			BARGE	
PARTICULATE CONTROL				
TYPE			ESP	ESP
INSTALLATION DATE			1968	1973
EMISSION (LB/MM BTU)			0.07	0.06
REMOVAL EFFICIENCY			98	99
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)			3.7	3.7
SURFACE AREA (1000 SQ FT)			NA	NA
GAS EXIT RATE (1000 ACFM)			NA	NA
SCA (SQ FT/1000 ACFM)			305	305
OUTLET TEMPERATURE (°F)			270	327

TABLE 15.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR WATSON UNIT 4 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	2132	NA	2132
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.57	NA	
ESP REUSE CASE			1.56
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

* L/S-FGD and LSD-FGD absorbers for unit 4 would be located southwest of the unit 4 chimney, beyond the coal conveyor.

TABLE 15.1.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR WATSON UNIT 5 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	3968	NA	3968
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			1.51
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

* L/S-FGD and LSD-FGD absorbers for unit 5 would be located north of the unit 5 chimney.

Table 15.1.2-4. Summary of FGD Control Costs for the Watson Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	4	1.57	250	53	2.4	81.6	326.3	33.6	29.0	90.0	19661	1709.9
L/S FGD	5	1.48	500	70	2.4	112.9	225.8	54.0	17.6	90.0	51934	1039.9
L/S FGD-C	4	1.57	250	53	2.4	81.6	326.3	19.6	16.9	90.0	19661	998.3
L/S FGD-C	5	1.48	500	70	2.4	112.9	225.8	31.4	10.3	90.0	51934	605.5
LC FGD	4-5	1.51	750	64	2.4	126.9	169.1	64.7	15.4	90.0	71225	908.2
LC FGD-C	4-5	1.51	750	64	2.4	126.9	169.1	37.6	8.9	90.0	71225	528.3
LSD+ESP	4	1.56	250	53	2.4	40.7	162.8	17.2	14.8	73.0	16035	1072.3
LSD+ESP	5	1.51	500	70	2.4	67.0	134.0	31.6	10.3	76.0	44029	716.7
LSD+ESP-C	4	1.56	250	53	2.4	40.7	162.8	10.0	8.6	73.0	16035	625.8
LSD+ESP-C	5	1.51	500	70	2.4	67.0	134.0	18.4	6.0	76.0	44029	417.4

Table 15.1.2-5. Summary of Coal Switching/Cleaning Costs for the Watson Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	4	1.00	250	53	2.4	8.8	35.1	17.3	14.9	62.0	13464	1282.4
CS/B+$15	5	1.00	500	70	2.4	16.1	32.2	43.6	14.2	62.0	35566	1225.7
CS/B+$15-C	4	1.00	250	53	2.4	8.8	35.1	9.9	8.6	62.0	13464	737.6
CS/B+$15-C	5	1.00	500	70	2.4	16.1	32.2	25.0	8.2	62.0	35566	704.3
CS/B+$5	4	1.00	250	53	2.4	6.2	24.8	7.2	6.2	62.0	13464	536.6
CS/B+$5	5	1.00	500	70	2.4	10.9	21.8	17.4	5.7	62.0	35566	488.2
CS/B+$5-C	4	1.00	250	53	2.4	6.2	24.8	4.2	3.6	62.0	13464	309.5
CS/B+$5-C	5	1.00	500	70	2.4	10.9	21.8	10.0	3.3	62.0	35566	281.1

TABLE 15.1.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR WATSON

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	4	5
FIRING TYPE	OWF	OWF
TYPE OF NOx CONTROL	LNB	LNB
FURNACE VOLUME (1000 CU FT)	NA	272
BOILER INSTALLATION DATE	1968	1973
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	37
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	54	90
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	1694	2541
New Heat Exchanger (1000$)	3230	4895
TOTAL SCOPE ADDER COSTS (1000$)	4977	7527
RETROFIT FACTOR FOR SCR	1.34	1.16
GENERAL FACILITIES (PERCENT)	20	20

* Cold side SCR reactors for units 4 and 5 would be located behind their respective chimneys.

Table 15.1.2-7. NOx Control Cost Results for the Watson Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	4	1.00	250	53	2.4	3.7	14.7	0.8	0.7	40.0	1961	397.8
LNC-LNB	5	1.00	500	70	2.4	4.9	9.7	1.0	0.3	37.0	4790	214.7
LNC-LNB-C	4	1.00	250	53	2.4	3.7	14.7	0.5	0.4	40.0	1961	236.3
LNC-LNB-C	5	1.00	500	70	2.4	4.9	9.7	0.6	0.2	37.0	4790	127.6
SCR-3	4	1.34	250	53	2.4	39.4	157.5	13.2	11.4	80.0	3921	3366.3
SCR-3	5	1.16	500	70	2.4	62.2	124.4	23.1	7.5	80.0	10357	2228.8
SCR-3-C	4	1.34	250	53	2.4	39.4	157.5	7.7	6.7	80.0	3921	1973.7
SCR-3-C	5	1.16	500	70	2.4	62.2	124.4	13.5	4.4	80.0	10357	1303.9
SCR-7	4	1.34	250	53	2.4	39.4	157.5	11.2	9.6	80.0	3921	2844.3
SCR-7	5	1.16	500	70	2.4	62.2	124.4	19.0	6.2	80.0	10357	1833.6
SCR-7-C	4	1.34	250	53	2.4	39.4	157.5	6.6	5.7	80.0	3921	1674.6
SCR-7-C	5	1.16	500	70	2.4	62.2	124.4	11.2	3.6	80.0	10357	1077.4

TABLE 15.1.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR WATSON UNIT 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2132
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	59
TOTAL COST (1000$)	
ESP UPGRADE CASE	2191
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

A medium duct residence time exists between unit 4 and the unit 4 ESPs. A high factor was assigned to ESP upgrade due to the conjestion around the unit 4 ESPs.

TABLE 15.1.2-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR WATSON UNIT 5

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	3968
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	100
TOTAL COST (1000$)	
ESP UPGRADE CASE	4068
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

A medium duct residence time exists between unit 5 and the unit 5 ESPs. A medium factor was assigned to ESP upgrade since the ESPs are somewhat conjested.

Table 15.1.2-10. Summary of DSD/FSI Control Costs for the Watson Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	4	1.00	250	53	2.4	15.1	60.3	9.6	8.3	47.0	10311	934.9
DSD+ESP	5	1.00	500	70	2.4	25.5	50.9	19.0	6.2	49.0	28073	675.7
DSD+ESP-C	4	1.00	250	53	2.4	15.1	60.3	5.6	4.8	47.0	10311	542.2
DSD+ESP-C	5	1.00	500	70	2.4	25.5	50.9	11.0	3.6	49.0	28073	391.2
FSI+ESP-50	4	1.00	250	53	2.4	16.0	63.9	11.5	9.9	50.0	10923	1049.7
FSI+ESP-50	5	1.00	500	70	2.4	25.2	50.4	24.6	8.0	50.0	28852	852.7
FSI+ESP-50-C	4	1.00	250	53	2.4	16.0	63.9	6.6	5.7	50.0	10923	608.0
FSI+ESP-50-C	5	1.00	500	70	2.4	25.2	50.4	14.2	4.6	50.0	28852	492.4
FSI+ESP-70	4	1.00	250	53	2.4	16.2	64.6	11.7	10.1	70.0	15292	763.2
FSI+ESP-70	5	1.00	500	70	2.4	24.9	49.8	24.9	8.1	70.0	40393	617.6
FSI+ESP-70-C	4	1.00	250	53	2.4	16.2	64.6	6.8	5.8	70.0	15292	442.0
FSI+ESP-70-C	5	1.00	500	70	2.4	24.9	49.8	14.4	4.7	70.0	40393	356.6

SECTION 16.0 NORTH CAROLINA

16.1 CAROLINA POWER AND LIGHT COMPANY

16.1.1 Mayo Steam Plant

The Mayo steam plant is located on Mayo Lake in Person County, North Carolina, and is operated by the Carolina Power and Light Company. The Mayo plant contains one coal-fired boiler with a gross generating capacity of 736 MW.

Table 16.1.1-1 presents operational data for the existing equipment at the Mayo plant. Coal shipments are received by railroad and transferred to a coal storage and handling area west of the plant. PM emissions from the boilers are controlled by ESPs installed at the time of construction. The ESPs are located behind the units. Flue gas from the boiler is directed to a chimney located behind the ESPs. Fly ash is disposed of in a pond north of the plant or sold.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers would be located behind the chimney. Because no major demolition or relocation would be required, a low (5 percent) general facilities factor was assigned to the location. A low site access/congestion factor was also assigned to the location. Between 100 and 300 feet of ductwork would be required for installation of the wet FGD system. A low site access/congestion factor was assigned to flue gas handling.

LSD-FGD with reuse of the existing ESPs was not considered because the unit is equipped with hot side ESPs. LSD with a new FF was considered. The LSD-FGD absorber and FF would be located west of the chimney. The site access/congestion factor was low for this location. About 100 to 300 feet of ductwork would be required for installation of the LSD absorbers. A low site access/congestion factor was assigned to flue gas handling.

Table 16.1.1-2 presents the retrofit factor inputs to the IAPCS model. Costs are not presented since the boiler at the Mayo plant is burning a low sulfur coal in compliance with the 1971 NSPS.

TABLE 16.1.1-1. MAYO STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1
GENERATING CAPACITY (MW)	736
CAPACITY FACTOR (PERCENT)	77
INSTALLATION DATE	1983
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	YES (OFA)
COAL SULFUR CONTENT (PERCENT)	0.6
COAL HEATING VALUE (BTU/LB)	12300
COAL ASH CONTENT (PERCENT)	10.0
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	PONDS/SOLD
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1983
EMISSION (LB/MM BTU)	0.01
REMOVAL EFFICIENCY	99.6
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	0.6
SURFACE AREA (1000 SQ FT)	237.6
GAS EXIT RATE (1000 ACFM)	958
SCA (SQ FT/1000 ACFM)	248
OUTLET TEMPERATURE (°F)	715

TABLE 16.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR MAYO UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	3015	NA	0
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.16
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for the Mayo plant because the plant is already burning low sulfur coal.

NO_x Control Technologies--

OFA is already in use at the Mayo plant; therefore, no additional combustion modification technologies were considered.

Selective Catalytic Reduction--

Hot side SCR reactors for the boiler at the Mayo plant would be located similarly to the wet FGD absorbers, behind the chimney. A low general facilities value (13 percent) and site access/congestion factor were assigned to the location. About 200 feet of ductwork would be required for installation of the SCR reactors and a low site access/congestion factor was assigned to flue gas handling. Tables 16.1.1-3 and 16.1.1-4 present the retrofit factor inputs to the IAPCS model and the estimated cost for installation of SCR at the Mayo plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies were not considered at the Mayo plant because the unit is equipped with hot side ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The 736 MW boiler at the Mayo plant is too large and has too long of a remaining useful life to be considered a good candidate for AFBC/CG repowering technologies.

16.1.2 Roxboro Steam Plant

The Roxboro steam plant is located on Lake Hyco in Person County, North Carolina, and is operated by the Carolina Power and Light Company. The Roxboro plant contains four coal-fired boilers with a gross generating capacity of 2,558 MW.

Table 16.1.2-1 presents operational data for the existing equipment at the Roxboro plant. Coal shipments are received by railroad and transferred

TABLE 16.1.1-3. SUMMARY OF NOx RETROFIT RESULTS FOR MAYO

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1
FIRING TYPE	NA
TYPE OF NOx CONTROL	NA
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	NA
SLAGGING PROBLEM	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	121
New Duct Length (Feet)	200
New Duct Costs (1000$)	3186
New Heat Exchanger (1000$)	0
TOTAL SCOPE ADDER COSTS (1000$)	3306
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

Table 16.1.1-4. NOx Control Cost Results for the Mayo Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
SCR-3	1	1.16	736	77	0.6	83.9	114.0	32.5	6.5	80.0	16771	1935.6
SCR-3-C	1	1.16	736	77	0.6	83.9	114.0	19.0	3.8	80.0	16771	1131.4
SCR-7	1	1.16	736	77	0.6	83.9	114.0	26.4	5.3	80.0	16771	1576.3
SCR-7-C	1	1.16	736	77	0.6	83.9	114.0	15.5	3.1	80.0	16771	925.5

TABLE 16.1.2-1. ROXBORO STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3	4
GENERATING CAPACITY (MW-each)	411	657	745	745
CAPACITY FACTOR (PERCENT)	65	68	46	64
INSTALLATION DATE	1966	1968	1973	1980
FIRING TYPE	OPPOSED WALL	TANG	FRONT WALL	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	194	330	203	200
LOW NOx COMBUSTION	NO	NO	NO	YES
COAL SULFUR CONTENT (PERCENT)	0.9	0.9	0.9	0.7
COAL HEATING VALUE (BTU/LB)	12500	12500	12500	12200
COAL ASH CONTENT (PERCENT)	9.5	9.5	9.5	10
FLY ASH SYSTEM		WET DISPOSAL		
ASH DISPOSAL METHOD		POND/ON-SITE		
STACK NUMBER	1	2	3	4
COAL DELIVERY METHODS		RAILROAD		
PARTICULATE CONTROL				
TYPE	ESP	ESP	ESP	ESP
INSTALLATION DATE	1974	1974	1979	1980
EMISSION (LB/MM BTU)	0.05	0.03	0.1	0.09
REMOVAL EFFICIENCY	99.2	98.9	99.6	99.7
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	0.7	0.7	0.7	0.7
SURFACE AREA (1000 SQ FT)	430.3	670	518	831
GAS EXIT RATE (1000 ACFM)	1215	2200	2760	2158
SCA (SQ FT/1000 ACFM)	354	305	375	385
OUTLET TEMPERATURE (°F)	290	290	305	770

to a coal storage and handling area north of the plant. PM emissions from units 1-3 are controlled by retrofit ESPs and emissions from unit 4 are controlled by ESPs which were installed at the time of construction. All of the ESPs are located behind the boilers. Flue gases from each boiler are directed to a chimney located behind each unit. Fly ash from the units is disposed of in a pond south of the plant. Unit 4 complies with the 1971 NSPS.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1 and 2 would be located near the unit 1 chimney, absorbers for unit 3 would be located on the west side of the unit 3 ESPs, and absorbers for unit 4 would be located beside the unit 4 chimney. The general facilities factor is high (15 percent) for all of these locations because the railroad spur for coal delivery would have to be relocated. The site access/congestion factor is medium for the unit 1-3 locations because of the proximity of the coal pile, coal conveyor, and railroad. The site access/congestion factor for the unit 4 location is low. About 200 feet of ductwork would be required for units 1 and 4 and about 600 feet would be required for units 2 and 3. A low site access/congestion factor was assigned to flue gas handling for units 1 and 4. A high site access/congestion factor was assigned to flue gas handling for units 2 and 3.

LSD with reuse of the existing ESPs was considered for units 1 and 2. LSD-FGD absorbers for unit 1 would be located beside the unit 1 ESPs and absorbers for unit 2 would be located near the unit 1 chimney. High general facilities factors were assigned to both locations because several storage buildings would have to be relocated. A medium site access/congestion factor was assigned to the unit 1 and 2 locations because of the congestion caused by the coal conveyor, coal pile, and railroad. About 200 feet of ductwork would be required for unit 1 and over 600 feet of ductwork would be required for unit 2. High site access/congestion factors were assigned to flue gas handling for units 1 and 2 because of the difficulty in accessing the upstream side of the ESPs. The unit 3 ESPs are too small to be reused for LSD-FGD and the unit 4 ESPs cannot be reused because they are hot side. Therefore, LSD-FGD with new FF was considered for units 3 and 4. The

LSD-FGD absorbers and baghouse for unit 3 would be located similarly to the L/LS-FGD absorbers for this unit, west of the unit 3 ESPs. A medium site access/congestion factor and a high general facilities value (15 percent) were assigned to the location. LSD-FGD absorbers and baghouse for unit 4 would be located near the unit 4 chimney. A high general facilities value (15 percent) was assigned to this location because a large storage building would have to be relocated. A low site access/congestion factor was assigned to the location. Between 400 and 600 feet of ductwork would be required for installation of LSD-FGD for unit 3 and about 200 feet would be required for unit 4. A high site access/congestion factor was assigned to flue gas handling for unit 3 because of the congestion around the unit 3 chimney. A low site access/congestion factor was assigned to flue gas handling for unit 4.

Tables 16.1.2-2 through 16.1.2-5 present retrofit factor results for installation of conventional FGD technologies at the Roxboro plant. Costs are not presented because the plant is burning low sulfur coal.

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for the Roxboro plant because the plant is already burning low sulfur coal.

NO_x Control Technologies--

LNB was considered for control of NO_x emissions from units 1 and 3 which are wall-fired. OFA was considered for unit 2 which is tangential-fired. No combustion control technologies were considered for unit 4 because LNB is already in place for this unit. Tables 16.1.2-6 and 16.1.2-7 present retrofit factors and costs, respectively, for installation of NO_x control technologies at the Roxboro plant.

Selective Catalytic Reduction--

Cold side SCR reactors for units 1, 2, and 3 and hot side SCR reactors for unit 4 would be located similarly to the LSD-FGD absorbers. Reactors for unit 1 would be located beside the unit 1 ESPs, reactors for unit 2 would be located near the unit 1 chimney, reactors for unit 3 would be located west of the unit 3 ESPs, and reactors for unit 4 would be located

TABLE 16.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR ROXBORO UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	3329	NA	3329
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	YES		YES
RETROFIT FACTORS			
FGD SYSTEM	1.47	NA	
ESP REUSE CASE			1.58
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 16.1.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR ROXBORO UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	5069	NA	5069
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	YES		YES
RETROFIT FACTORS			
FGD SYSTEM	1.67	NA	
ESP REUSE CASE			1.79
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 16.1.2-4. SUMMARY OF RETROFIT FACTOR DATA FOR ROXBORO UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	5674	NA	0
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.57	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.49
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 16.1.2-5. SUMMARY OF RETROFIT FACTOR DATA FOR ROXBORO UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	5674	NA	0
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.16
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 16.1.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR ROXBORO

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1	2	3	4
FIRING TYPE	OWF	TANG	FWF	NA
TYPE OF NOx CONTROL	LNB	OFA	LNB	NA
FURNACE VOLUME (1000 CU FT)	194	330	203	NA
BOILER INSTALLATION DATE	1966	1968	1973	NA
SLAGGING PROBLEM	YES	YES	YES	NA
ESTIMATED NOx REDUCTION (PERCENT)	27	20	14	NA
SCR RETROFIT RESULTS				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	MEDIUM	MEDIUM	LOW
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	78	111	122	122
New Duct Length (Feet)	200	500	400	200
New Duct Costs (1000$)	2266	7452	6417	3208
New Heat Exchanger (1000$)	4352	5767	6219	0
TOTAL SCOPE ADDER COSTS (1000$)	6696	13330	12757	3330
RETROFIT FACTOR FOR SCR	1.16	1.34	1.34	1.16
GENERAL FACILITIES (PERCENT)	38	38	38	38

Table 16.1.2-7. NOx Control Cost Results for the Roxboro Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1	1.00	411	65	0.9	4.5	10.9	0.9	0.4	27.0	2619	358.6
LNC-LNB	3	1.00	745	46	0.9	5.7	7.7	1.2	0.4	14.0	1742	683.9
LNC-LNB-C	1	1.00	411	65	0.9	4.5	10.9	0.6	0.2	27.0	2619	213.1
LNC-LNB-C	3	1.00	745	46	0.9	5.7	7.7	0.7	0.2	14.0	1742	406.5
LNC-OFA	2	1.00	657	68	0.9	1.3	2.0	0.3	0.1	20.0	2318	118.6
LNC-OFA-C	2	1.00	657	68	0.9	1.3	2.0	0.2	0.0	20.0	2318	70.5
SCR-3	1	1.16	411	65	0.9	54.9	133.7	19.5	8.3	80.0	7761	2506.6
SCR-3	2	1.34	657	68	0.9	94.3	143.5	32.2	8.2	80.0	9270	3472.0
SCR-3	3	1.34	745	46	0.9	103.7	139.2	35.3	11.8	80.0	9955	3545.4
SCR-3	4	1.16	745	64	0.7	91.6	122.9	33.8	8.1	80.0	14242	2376.0
SCR-3-C	1	1.16	411	65	0.9	54.9	133.7	11.4	4.9	80.0	7761	1467.9
SCR-3-C	2	1.34	657	68	0.9	94.3	143.5	18.9	4.8	80.0	9270	2034.8
SCR-3-C	3	1.34	745	46	0.9	103.7	139.2	20.7	6.9	80.0	9955	2078.0
SCR-3-C	4	1.16	745	64	0.7	91.6	122.9	19.8	4.7	80.0	14242	1390.1
SCR-7	1	1.16	411	65	0.9	54.9	133.7	16.1	6.9	80.0	7761	2074.1
SCR-7	2	1.34	657	68	0.9	94.3	143.5	26.8	6.9	80.0	9270	2893.2
SCR-7	3	1.34	745	46	0.9	103.7	139.2	29.2	9.7	80.0	9955	2934.2
SCR-7	4	1.16	745	64	0.7	91.6	122.9	27.7	6.6	80.0	14242	1947.2
SCR-7-C	1	1.16	411	65	0.9	54.9	133.7	9.5	4.0	80.0	7761	1220.1
SCR-7-C	2	1.34	657	68	0.9	94.3	143.5	15.8	4.0	80.0	9270	1703.2
SCR-7-C	3	1.34	745	46	0.9	103.7	139.2	17.2	5.7	80.0	9955	1727.8
SCR-7-C	4	1.16	745	64	0.7	91.6	122.9	16.3	3.9	80.0	14242	1144.5

beside the unit 4 chimney. Low site access/congestion factors were assigned to the unit 1 and 4 locations and medium site access/congestion factors were assigned to the unit 2 and 3 locations. High general facilities values (38 percent) were assigned to all of the reactor locations. About 200 feet of ductwork would be required for units 1 and 4, 500 feet for unit 2, and 400 feet for unit 3. Tables 16.1.2-6 and 16.1.2-7 present the retrofit factors and costs for installation of SCR at the Roxboro plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for units 3 or 4 because the existing ESPs for these units cannot be reused. The unit 3 ESPs are too small and the unit 4 ESPs are hot side. FSI and DSD were considered for units 1 and 2. There is a short duct residence time between the boilers and ESPs; however, the ESPs are large enough to handle the additional particulate load and the first section of the ESPs can be modified for slurry evaporation and humidification. Tables 16.1.2-8 and 16.1.2-9 present retrofit data and costs for installation of FSI and DSD technologies at the Roxboro plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

All of the boilers at the Roxboro plant are too large and have too long of a remaining service live to be considered good candidates for AFBC/CG technologies.

TABLE 16.1.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ROXBORO UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
WET TO DRY FLY ASH HANDLING	YES
ESTIMATED COST (1000$) (1,2)	3329,5069
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$) (1,2)	86,123

TOTAL COST (1000$)	
ESP UPGRADE CASE (1,2)	3415,5192
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 16.1.2-9. Summary of DSD/FSI Control Costs for the Roxboro Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	411	65	0.9	15.9	38.6	9.6	4.1	49.0	7888	1214.7
DSD+ESP	2	1.00	657	68	0.9	23.0	35.1	13.9	3.5	49.0	13192	1051.7
DSD+ESP-C	1	1.00	411	65	0.9	15.9	38.6	5.6	2.4	49.0	7888	705.0
DSD+ESP-C	2	1.00	657	68	0.9	23.0	35.1	8.1	2.1	49.0	13192	610.4
FSI+ESP-50	1	1.00	411	65	0.9	16.1	39.2	9.8	4.2	50.0	8107	1210.2
FSI+ESP-50	2	1.00	657	68	0.9	26.6	40.5	15.8	4.0	50.0	13558	1164.9
FSI+ESP-50-C	1	1.00	411	65	0.9	16.1	39.2	5.7	2.4	50.0	8107	702.3
FSI+ESP-50-C	2	1.00	657	68	0.9	26.6	40.5	9.2	2.3	50.0	13558	676.2
FSI+ESP-70	1	1.00	411	65	0.9	16.3	39.6	10.0	4.3	70.0	11350	878.5
FSI+ESP-70	2	1.00	657	68	0.9	26.8	40.8	16.0	4.1	70.0	18981	845.3
FSI+ESP-70-C	1	1.00	411	65	0.9	16.3	39.6	5.8	2.5	70.0	11350	509.8
FSI+ESP-70-C	2	1.00	657	68	0.9	26.8	40.8	9.3	2.4	70.0	18981	490.6

16.2 DUKE POWER COMPANY

16.2.1 Allen Steam Plant

Units 1 and 2 were not evaluated because these units are not in service. Retrofit factors were developed for units 3, 4, and 5 at the Allen plant; however, costs are not shown since the boilers fire a low sulfur coal. Since the boilers fire a low sulfur coal, CS was not evaluated. Sorbent injection technologies (FSI and DSD) were not considered because of the short duct residence time between the boilers and their respective ESPs, and the lack of ESP information such as SCA size.

TABLE 16.2.1-1. ALLEN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3	4	5
GENERATING CAPACITY (MW)	165	165	275	275	275
CAPACITY FACTOR (PERCENT)	OUT OF SERVICE		38	26	32
INSTALLATION DATE	1957	1957	1959	1960	1961
FIRING TYPE	TANGENTIAL				
FURNACE VOLUME (1000 CU FT)	112	112	165	165	165
LOW NOx COMBUSTION	NO	NO	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.0				
COAL HEATING VALUE (BTU/LB)	12500				
COAL ASH CONTENT (PERCENT)	11.3				
FLY ASH SYSTEM	WET DISPOSAL				
ASH DISPOSAL METHOD	PONDS/ON SITE				
STACK NUMBER	1	2	3	4	5
COAL DELIVERY METHODS	RAILROAD				
PARTICULATE CONTROL					
TYPE			ESP	ESP	ESP
INSTALLATION DATE					
EMISSION (LB/MM BTU)			0.06	0.05	0.07
REMOVAL EFFICIENCY			97	97.3	96.9
DESIGN SPECIFICATION					
SULFUR SPECIFICATION (PERCENT)			NA	NA	NA
SURFACE AREA (1000 SQ FT)			NA	NA	NA
EXIT GAS FLOW RATE (1000 ACFM)			NA	NA	NA
SCA (SQ FT/1000 ACFM)			NA	NA	NA
OUTLET TEMPERATURE (°F)			NA	NA	NA

TABLE 16.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR ALLEN UNIT 3 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	2322	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	1925	0	1925
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.46	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.41
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for unit 3 would be located north of unit 5.

TABLE 16.2.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR ALLEN UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	2322	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	1925	0	1925
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.40	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.34
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for unit 4 would be located north of unit 5.

TABLE 16.2.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR ALLEN UNIT 5 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	2322	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	1925	0	1925
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.29	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.23
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for unit 5 would be located north of unit 5.

TABLE 16.2.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR ALLEN

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	3	4	5
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
FURNACE VOLUME (1000 CU FT)	165	165	165
BOILER INSTALLATION DATE	1959	1960	1961
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25	25
SCR RETROFIT RESULTS *			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	58	58	58
New Duct Length (Feet)	200	200	200
New Duct Costs (1000$)	1791	1791	1791
New Heat Exchanger (1000$)	3420	3420	3420
TOTAL SCOPE ADDER COSTS (1000$)	5269	5269	5269
RETROFIT FACTOR FOR SCR	1.34	1.34	1.16
GENERAL FACILITIES (PERCENT)	20	20	20

* Cold side SCR reactors for all boilers would be located behind their respective chimney.

Table 16.2.1-6. NOx Control Cost Results for the Allen Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	3	1.00	275	38	1.0	0.9	3.4	0.2	0.2	25.0	678	286.2
LNC-OFA	4	1.00	275	26	1.0	0.9	3.4	0.2	0.3	25.0	464	418.2
LNC-OFA	5	1.00	275	32	1.0	0.9	3.4	0.2	0.3	25.0	571	339.8
LNC-OFA-C	3	1.00	275	38	1.0	0.9	3.4	0.1	0.1	25.0	678	170.2
LNC-OFA-C	4	1.00	275	26	1.0	0.9	3.4	0.1	0.2	25.0	464	248.7
LNC-OFA-C	5	1.00	275	32	1.0	0.9	3.4	0.1	0.1	25.0	571	202.1
SCR-3	3	1.34	275	38	1.0	42.6	154.8	13.8	15.1	80.0	2168	6372.5
SCR-3	4	1.34	275	26	1.0	42.6	154.7	13.7	21.8	80.0	1484	9209.8
SCR-3	5	1.16	275	32	1.0	39.2	142.4	12.9	16.8	80.0	1826	7084.3
SCR-3-C	3	1.34	275	38	1.0	42.6	154.8	8.1	8.9	80.0	2168	3739.0
SCR-3-C	4	1.34	275	26	1.0	42.6	154.7	8.0	12.8	80.0	1484	5405.2
SCR-3-C	5	1.16	275	32	1.0	39.2	142.4	7.6	9.8	80.0	1826	4155.0
SCR-7	3	1.34	275	38	1.0	42.6	154.8	11.6	12.6	80.0	2168	5336.7
SCR-7	4	1.34	275	26	1.0	42.6	154.7	11.4	18.2	80.0	1484	7695.9
SCR-7	5	1.16	275	32	1.0	39.2	142.4	10.7	13.9	80.0	1826	5854.3
SCR-7-C	3	1.34	275	38	1.0	42.6	154.8	6.8	7.5	80.0	2168	3145.6
SCR-7-C	4	1.34	275	26	1.0	42.6	154.7	6.7	10.7	80.0	1484	4537.8
SCR-7-C	5	1.16	275	32	1.0	39.2	142.4	6.3	8.2	80.0	1826	3450.3

16.2.2 Belews Creek Steam Plant

The Belews Creek steam plant is located on Belews Lake in Stokes County, North Carolina, and is operated by Duke Power Company. The Belews Creek plant contains two coal-fired boilers with a gross generating capacity of 2,000 MW.

Table 16.2.2-1 presents operational data for the existing equipment at the Belews Creek plant. Coal shipments are received by railroad and transferred to a coal storage and handling area northwest of the plant. PM emissions from the boilers are controlled by retrofit ESPs. The ESPs are located behind the boilers. Flue gases from each boiler are directed to a chimney behind the ESPs. Dry fly ash is landfilled by the utility.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers would be located behind the chimney for each unit. Medium (8 percent) general facility factors were assigned to the FGD absorber locations because a plant road would have to be relocated. Low site access/congestion factors were assigned to the absorber locations. About 200 feet of ductwork would be required to install the L/LS-FGD absorbers and a low site access/congestion factor was assigned to flue gas handling.

LSD with reuse of the existing ESPs was considered for both units because the retrofit ESPs are large enough to handle the increased particulate load of the LSD system. LSD absorbers would be located on either side of the ESPs for easy access to the upstream of the ESPs. Low site access/congestion factors were assigned to the LSD absorber locations. About 400 feet of duct length with a high flue gas handling site access/ congestion factor would be required for each unit.

Tables 16.2.2-2 and 16.2.2-3 present the retrofit factors and cost estimates for commercial FGD technologies.

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for the Belews Creek plant because the plant is already burning low sulfur coal.

TABLE 16.2.2-1. BELEWS CREEK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	1000
CAPACITY FACTOR (PERCENT)	83,80
INSTALLATION DATE	1974,75
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	776
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	1.0
COAL HEATING VALUE (BTU/LB)	12600
COAL ASH CONTENT (PERCENT)	10.0
FLY ASH SYSTEM	DRY DISPOSAL
ASH DISPOSAL METHOD	LANDFILL
STACK NUMBER	1,2
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1986
EMISSION (LB/MM BTU)	0.12,0.06
REMOVAL EFFICIENCY	98.7,99.5
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	NA
SURFACE AREA (1000 SQ FT)	NA
GAS EXIT RATE (1000 ACFM)	NA
SCA (SQ FT/1000 ACFM)	305
OUTLET TEMPERATURE (°F)	300

TABLE 16.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR BELEWS UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.20	NA	
ESP REUSE CASE			1.36
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

Table 16.2.2-3. Summary of FGD Control Costs for the Belews Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.20	1000	83	1.0	152.0	152.0	77.5	10.7	90.0	49917	1552.9
L/S FGD	2	1.20	1000	80	1.0	152.0	152.0	76.3	10.9	90.0	48113	1586.5
L/S FGD-C	1	1.20	1000	83	1.0	152.0	152.0	45.1	6.2	90.0	49917	903.4
L/S FGD-C	2	1.20	1000	80	1.0	152.0	152.0	44.4	6.3	90.0	48113	923.1
LC FGD	1-2	1.20	2000	82	1.0	225.1	112.5	127.9	8.9	90.0	98631	1296.6
LC FGD-C	1-2	1.20	2000	82	1.0	225.1	112.5	74.3	5.2	90.0	98631	753.1
LSD+ESP	1	1.36	1000	83	1.0	99.9	99.9	42.9	5.9	76.0	42318	1014.9
LSD+ESP	2	1.36	1000	80	1.0	99.9	99.9	42.4	6.1	76.0	40789	1040.0
LSD+ESP-C	1	1.36	1000	83	1.0	99.9	99.9	25.1	3.4	76.0	42318	592.1
LSD+ESP-C	2	1.36	1000	80	1.0	99.9	99.9	24.8	3.5	76.0	40789	606.8

NO_x Control Technologies--

Both units are dry bottom, opposed wall-fired boilers rated 1,000 MW each. LNB was considered as the combustion modification technique to remove NO_x. Tables 16.2.2-4 and 16.2.2-5 present performance and cost estimates for LNB at units 1 and 2.

Selective Catalytic Reduction--

Hot side SCR reactors for the Belews Creek plant would be located on either side of the ESPs similar to the LSD absorbers. As in the LSD case, a medium general facilities value (20 percent) and a low site access/ congestion factor were assigned to the locations. Approximately 400 feet of ductwork would be required to span the distance between the SCR reactors and the air preheaters. Tables 16.2.2-4 and 16.2.2-5 present the retrofit factors and cost estimates for installation of SCR at the Belews Creek plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

It was assumed that the existing ESPs at the Belews Creek plant are large enough to accommodate sorbent injection technologies (FSI and DSD). Tables 16.2.2-6 and 16.2.2-7 present the retrofit factors and cost estimates for FSI and DSD technologies at the Belews Creek plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The 1,000 MW boilers at the Belews Creek plant are too large and have too long of a remaining useful life to be considered for AFBC/CG repowering.

16.2.3 Cliffside Steam Plant

The Cliffside steam plant is located on the Broad River in Cleveland and Rutherford Counties in North Carolina and is operated by the Duke Power Company. The Cliffside plant contains five coal-fired boilers with a gross generating capacity of 781 MW. Units 1-4 were not considered in this study because they are out of service.

Table 16.2.3-1 presents operational data for unit 5 at the Cliffside plant. Coal shipments are received by railroad and transferred to a coal

TABLE 16.2.2-4. SUMMARY OF NOx RETROFIT RESULTS FOR BELEWS

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	OWF
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	776
BOILER INSTALLATION DATE	1974, 1975
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	53
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	152
New Duct Length (Feet)	400
New Duct Costs (1000$)	7623
New Heat Exchanger (1000$)	0
TOTAL SCOPE ADDER COSTS (1000$)	7775
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

Table 16.2.2-5. NOx Control Cost Results for the Belews Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1	1.00	1000	83	1.0	6.4	6.4	1.3	0.2	53.0	15828	84.7
LNC-LNB	2	1.00	1000	80	1.0	6.4	6.4	1.3	0.2	53.0	15256	87.9
LNC-LNB-C	1	1.00	1000	83	1.0	6.4	6.4	0.8	0.1	53.0	15828	50.3
LNC-LNB-C	2	1.00	1000	80	1.0	6.4	6.4	0.8	0.1	53.0	15256	52.2
SCR-3	1	1.16	1000	83	1.0	110.5	110.5	43.5	6.0	80.0	23892	1819.8
SCR-3	2	1.16	1000	80	1.0	110.5	110.5	43.3	6.2	80.0	23028	1879.0
SCR-3-C	1	1.16	1000	83	1.0	110.5	110.5	25.4	3.5	80.0	23892	1063.3
SCR-3-C	2	1.16	1000	80	1.0	110.5	110.5	25.3	3.6	80.0	23028	1098.1
SCR-7	1	1.16	1000	83	1.0	110.5	110.5	35.3	4.9	80.0	23892	1478.3
SCR-7	2	1.16	1000	80	1.0	110.5	110.5	35.1	5.0	80.0	23028	1524.8
SCR-7-C	1	1.16	1000	83	1.0	110.5	110.5	20.7	2.9	80.0	23892	867.7
SCR-7-C	2	1.16	1000	80	1.0	110.5	110.5	20.6	2.9	80.0	23028	895.1

TABLE 16.2.2-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BELEWS UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	168
TOTAL COST (1000$)	
ESP UPGRADE CASE	168
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Table 16.2.2-7. Summary of DSD/FSI Control Costs for the Belews Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	1000	83	1.0	24.7	24.7	21.2	2.9	49.0	26983	786.5
DSD+ESP	2	1.00	1000	80	1.0	24.7	24.7	20.8	3.0	49.0	26007	798.1
DSD+ESP-C	1	1.00	1000	83	1.0	24.7	24.7	12.3	1.7	49.0	26983	454.7
DSD+ESP-C	2	1.00	1000	80	1.0	24.7	24.7	12.0	1.7	49.0	26007	461.5
FSI+ESP-50	1	1.00	1000	83	1.0	29.7	29.7	25.9	3.6	50.0	27731	935.0
FSI+ESP-50	2	1.00	1000	80	1.0	29.7	29.7	25.3	3.6	50.0	26729	945.7
FSI+ESP-50-C	1	1.00	1000	83	1.0	29.7	29.7	15.0	2.1	50.0	27731	540.5
FSI+ESP-50-C	2	1.00	1000	80	1.0	29.7	29.7	14.6	2.1	50.0	26729	546.8
FSI+ESP-70	1	1.00	1000	83	1.0	29.7	29.7	26.3	3.6	70.0	38824	678.6
FSI+ESP-70	2	1.00	1000	80	1.0	29.7	29.7	25.7	3.7	70.0	37421	686.3
FSI+ESP-70-C	1	1.00	1000	83	1.0	29.7	29.7	15.2	2.1	70.0	38824	392.2
FSI+ESP-70-C	2	1.00	1000	80	1.0	29.7	29.7	14.8	2.1	70.0	37421	396.8

TABLE 16.2.3-1. CLIFFSIDE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2,3,4	5
GENERATING CAPACITY (MW-each)	40,40,65,65	571
CAPACITY FACTOR (PERCENT)	OUT OF	47
INSTALLATION DATE	SERVICE	1972
FIRING TYPE		TANGENTIAL
FURNACE VOLUME (1000 CU FT)		428.7
LOW NOx COMBUSTION		NO
COAL SULFUR CONTENT (PERCENT)		1.0
COAL HEATING VALUE (BTU/LB)		12500
COAL ASH CONTENT (PERCENT)		9.5
FLY ASH SYSTEM		WET DISPOSAL
ASH DISPOSAL METHOD		PONDS/SOLD
STACK NUMBER		1
COAL DELIVERY METHODS		RAILROAD
PARTICULATE CONTROL		
TYPE		ESP
INSTALLATION DATE		1972
EMISSION (LB/MM BTU)		0.01
REMOVAL EFFICIENCY		97.9
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)		NA
SURFACE AREA (1000 SQ FT)		211
GAS EXIT RATE (1000 ACFM)		1780
SCA (SQ FT/1000 ACFM)		118
OUTLET TEMPERATURE (°F)		300

storage and handling area between units 1-4 and unit 5. PM emissions from unit 5 are controlled by ESPs which were installed at the time of construction. The ESPs are located behind the boiler. Flue gases are directed to a chimney located behind the unit. Fly ash from the unit is disposed of in ponds east of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for unit 5 would be located on the south side of the boiler. A medium general facilities value (8 percent) was assigned to the location because a plant road would have to be relocated. The site access/congestion factor would be medium for this location because there is some underground piping beneath the site. About 200 feet of ductwork would be required to install the wet FGD system and a low site access/congestion factor was assigned to flue gas handling.

LSD with reuse of the existing ESPs was not considered because of the small sizes of the ESPs. However, a new baghouse could be installed to accommodate the LSD system. The LSD absorbers and FF would be placed similarly to the wet FGD absorbers south of the boiler. As in the wet FGD case, a medium (8 percent) general facilities value and site access/congestion factor were assigned to the location. About 200 feet of ductwork would be required and a low site access/congestion factor was assigned to flue gas handling.

Tables 16.2.3-2 and and 16.2.3-3 present retrofit factor inputs to the IAPCS model and the estimated cost for installation of conventional FGD technologies at the Cliffside plant.

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for unit 5 because low sulfur coal is already being burned at the Cliffside plant.

NO_x Control Technologies--

OFA was considered for control of NO_x emissions from unit 5 because it is tangential-fired. The estimated NO_x reduction and costs developed for the 571 MW boiler are presented in Tables 16.2.3-4 and 16.2.3-5.

TABLE 16.2.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR CLIFFSIDE UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	4470	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.37	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.29
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	0	8

Table 16.2.3-3. Summary of FGD Control Costs for the Cliffside Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	5	1.37	571	47	1.0	107.8	188.8	43.5	18.5	90.0	16288	2670.0
L/S FGD-C	5	1.37	571	47	1.0	107.8	188.8	25.4	10.8	90.0	16288	1559.4
LC FGD	5	1.37	571	47	1.0	85.8	150.3	37.0	15.8	90.0	16288	2273.6
LC FGD-C	5	1.37	571	47	1.0	85.8	150.3	21.6	9.2	90.0	16288	1326.2
LSD+FF	5	1.29	571	47	1.0	100.0	175.2	33.0	14.0	87.0	15655	2107.1
LSD+FF-C	5	1.29	571	47	1.0	100.0	175.2	19.3	8.2	87.0	15655	1235.9

TABLE 16.2.3-4. SUMMARY OF NOx RETROFIT RESULTS FOR CLIFFSIDE

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	5
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
FURNACE VOLUME (1000 CU FT)	428.7
BOILER INSTALLATION DATE	1972
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	25
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	100
New Duct Length (Feet)	200
New Duct Costs (1000$)	2746
New Heat Exchanger (1000$)	5301
TOTAL SCOPE ADDER COSTS (1000$)	8147
RETROFIT FACTOR FOR SCR	1.34
GENERAL FACILITIES (PERCENT)	20

Table 16.2.3-5. NOx Control Cost Results for the Cliffside Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	5	1.00	571	47	1.0	1.2	2.2	0.3	0.1	25.0	1740	149.3
LNC-OFA-C	5	1.00	571	47	1.0	1.2	2.2	0.2	0.1	25.0	1740	88.7
SCR-3	5	1.34	571	47	1.0	75.6	132.3	26.1	11.1	80.0	5569	4679.8
SCR-3-C	5	1.34	571	47	1.0	75.6	132.3	15.3	6.5	80.0	5569	2742.0
SCR-7	5	1.34	571	47	1.0	75.6	132.3	21.4	9.1	80.0	5569	3842.3
SCR-7-C	5	1.34	571	47	1.0	75.6	132.3	12.6	5.4	80.0	5569	2262.2

Selective Catalytic Reduction--

Cold side SCR reactors for unit 5 at the Cliffside plant would be located similarly to the wet FGD absorbers south of the boiler. A medium general facilities value (20 percent) and site access/congestion factor were assigned to the reactor location. Approximately 200 feet of ductwork would be required to span the distance between the SCR reactors and the chimney. A low site access/congestion factor was assigned to flue gas handling. Tables 16.2.3-4 and 16.2.3-5 present the retrofit factor inputs to the IAPCS model and cost for installation of SCR at the Cliffside plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for unit 5 at the Cliffside plant because of the small sizes of the existing ESPs and the short duct residence time between the boiler and the ESPs.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Unit 5 is large and has a long remaining service life; therefore, is not considered a good candidate for repowering technologies.

16.2.4 Marshall Steam Plant

The Marshall steam plant is located on Lake Norman in Catawba County, North Carolina, and is operated by Duke Power Company. The Marshall plant contains four coal-fired boilers with a gross generating capacity of 1,996 MW.

Table 16.2.4-1 presents operational data for the existing equipment at the Marshall plant. Coal shipments are received by railroad and transferred to a coal storage and handling area north of the plant. PM emissions from the units are controlled by retrofit ESPs located behind the boilers. Flue gases from the boilers are directed to four chimneys, one for each unit. The Marshall plant has a dry fly ash handling system.

TABLE 16.2.4-1. MARSHALL STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3,4
GENERATING CAPACITY (MW-each)	350	648
CAPACITY FACTOR (PERCENT)	56,49	61,50
INSTALLATION DATE	1965,66	1969,70
FIRING TYPE	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	NA	366
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	0.9	0.9
COAL HEATING VALUE (BTU/LB)	12500	12500
COAL ASH CONTENT (PERCENT)	10.7	10.7
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	ON-SITE/PAID	
STACK NUMBER	1,2	3,4
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1986	1986
EMISSION (LB/MM BTU)	0.03,.02	0.09,0.11
REMOVAL EFFICIENCY	98.1	96.8,98.1
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	NA	NA
SURFACE AREA (1000 SQ FT)	NA	NA
GAS EXIT RATE (1000 ACFM)	NA	NA
SCA (SQ FT/1000 ACFM)	200	357
OUTLET TEMPERATURE (°F)	NA	NA

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1 and 2 would be located at the north end of the plant and the absorbers for units 3 and 4 would be located at the south end of the plant. The general facilities factor would be low (5 percent) for the L/LS-FGD absorber locations. The site access/congestion factor would be low for the unit 3 and 4 locations but medium for the unit 1 and 2 locations because of the proximity of the coal conveyor and a storage building. Over 200 feet of ductwork would be required for installation of the wet FGD system for unit 1, 400 feet for unit 2, greater than 600 feet for unit 3, and greater than 300 feet for unit 4. A low site access/congestion factor was assigned to flue gas handling for all of the units.

LSD with reuse of the existing ESPs was considered because the ESPs are large enough to accommodate the additional load imposed by an LSD system. LSD absorbers would be located similarly to the L/LS-FGD absorbers with similar site access/congestion and general facilities factors. Approximately 300, 500, 700, and 300 feet of ductwork would be required for installation of the LSD systems for units 1-4, respectively. A medium site access/congestion factor was assigned to flue gas handling for units 1 and 4, while a high factor was assigned to units 2 and 3 because of the access difficulties to the upstream of the ESPs. A high site access/congestion factor was assigned for upgrading of the existing ESPs, if required.

Tables 16.2.4-2 through 16.2.4-5 present the retrofit factors for installation of FGD systems at the Marshall plant. Costs were not developed because it is unlikely that the current low sulfur coal would be used if scrubbing were required. FGD cost estimates based on the current coal would result in low estimates of capital/operating costs and high cost effectiveness values.

Coal Switching and Physical Coal Cleaning Costs--

CS and PCC were not considered for the Marshall plant because this plant is already burning low sulfur coal.

NO_x Control Technologies--

All four units are dry bottom, tangential-fired boilers; therefore, OFA was considered for control of NO_x emissions for the Marshall plant. Table

TABLE 16.2.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR MARSHALL UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.30	NA	
ESP REUSE CASE			1.44
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 16.2.4-3. SUMMARY OF RETROFIT FACTOR DATA FOR MARSHALL UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.41	NA	
ESP REUSE CASE			1.49
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 16.2.4-4. SUMMARY OF RETROFIT FACTOR DATA FOR MARSHALL UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.37	NA	
ESP REUSE CASE			1.47
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 16.2.4-5. SUMMARY OF RETROFIT FACTOR DATA FOR MARSHALL UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.31	NA	
ESP REUSE CASE			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

Tables 16.2.4-6 and 16.2.4-7 present NO_x performance and cost results for application of OFA at the Marshall plant.

Selective Catalytic Reduction--

Cold side SCR reactors for units 1-4 would be located behind the respective unit, adjacent to the chimneys. A low site access/congestion factor was assigned to units 1 and 4 reactor locations. A medium factor was assigned to unit 2 because of the close proximity to the water channel and the chimney. A high factor was assigned to unit 3 because of the underground obstruction created by the water intake channels. The duct length requirement for units 1-4 would be 200 feet. A low general facilities factor (13 percent) was assigned to the reactor locations. Tables 16.2.4-6 and 16.2.4-7 present the retrofit factors and cost estimates for installation of SCR at the Marshall plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were considered for units 3 and 4. It was assumed that the existing ESPs would be large enough to accommodate the additional particulate load imposed by the sorbent injection technologies and there is sufficient duct residence time between the boilers and the ESPs. However, units 1 and 2 ESPs are not large and there is not sufficient duct residence time between the boilers and the ESPs. Therefore, FSI and DSD were not considered for units 1 and 2. Tables 16.2.4-8 and 16.2.4-9 summarize the retrofit factors and cost estimates for FSI and DSD technologies.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

None of the boilers would be considered good candidates for AFBC/CG repowering because of the large boiler sizes, moderate capacity factors, and moderate remaining base load life.

TABLE 16.2.4-6. SUMMARY OF NOx RETROFIT RESULTS FOR MARSHALL

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1	2	3	4
FIRING TYPE	TANG	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA	OFA
FURNACE VOLUME (1000 CU FT)	NA	NA	366	366
BOILER INSTALLATION DATE	1965	1966	1969	1970
SLAGGING PROBLEM	NO	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25	25	25
SCR RETROFIT RESULTS				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	MEDIUM	HIGH	LOW
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	69	69	110	110
New Duct Length (Feet)	200	200	200	200
New Duct Costs (1000$)	2062	2062	2957	2957
New Heat Exchanger (1000$)	3952	3952	5719	5719
TOTAL SCOPE ADDER COSTS (1000$)	6084	6084	8786	8786
RETROFIT FACTOR FOR SCR	1.16	1.34	1.52	1.16
GENERAL FACILITIES (PERCENT)	13	13	13	13

Table 16.2.4-7. NOx Control Cost Results for the Marshall Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	350	56	0.9	1.0	2.9	0.2	0.1	25.0	1271	168.0
LNC-OFA	2	1.00	350	49	0.9	1.0	2.9	0.2	0.1	25.0	1112	192.0
LNC-OFA	3	1.00	648	61	0.9	1.3	2.0	0.3	0.1	25.0	2563	106.6
LNC-OFA	4	1.00	648	50	0.9	1.3	2.0	0.3	0.1	25.0	2101	130.0
LNC-OFA-C	1	1.00	350	56	0.9	1.0	2.9	0.1	0.1	25.0	1271	99.8
LNC-OFA-C	2	1.00	350	49	0.9	1.0	2.9	0.1	0.1	25.0	1112	114.1
LNC-OFA-C	3	1.00	648	61	0.9	1.3	2.0	0.2	0.0	25.0	2563	63.4
LNC-OFA-C	4	1.00	648	50	0.9	1.3	2.0	0.2	0.1	25.0	2101	77.3
SCR-3	1	1.16	350	56	0.9	45.0	128.6	15.8	9.2	80.0	4067	3873.3
SCR-3	2	1.34	350	49	0.9	49.0	140.0	16.6	11.0	80.0	3559	4654.0
SCR-3	3	1.52	648	61	0.9	89.3	137.8	30.9	8.9	80.0	8202	3761.6
SCR-3	4	1.16	648	50	0.9	75.9	117.1	27.3	9.6	80.0	6723	4064.1
SCR-3-C	1	1.16	350	56	0.9	45.0	128.6	9.2	5.4	80.0	4067	2268.7
SCR-3-C	2	1.34	350	49	0.9	49.0	140.0	9.7	6.5	80.0	3559	2728.2
SCR-3-C	3	1.52	648	61	0.9	89.3	137.8	18.1	5.2	80.0	8202	2203.9
SCR-3-C	4	1.16	648	50	0.9	75.9	117.1	16.0	5.6	80.0	6723	2379.1
SCR-7	1	1.16	350	56	0.9	45.0	128.6	12.9	7.5	80.0	4067	3170.4
SCR-7	2	1.34	350	49	0.9	49.0	140.0	13.7	9.1	80.0	3559	3850.7
SCR-7	3	1.52	648	61	0.9	89.3	137.8	25.6	7.4	80.0	8202	3116.3
SCR-7	4	1.16	648	50	0.9	75.9	117.1	22.0	7.8	80.0	6723	3276.9
SCR-7-C	1	1.16	350	56	0.9	45.0	128.6	7.6	4.4	80.0	4067	1866.1
SCR-7-C	2	1.34	350	49	0.9	49.0	140.0	8.1	5.4	80.0	3559	2267.9
SCR-7-C	3	1.52	648	61	0.9	89.3	137.8	15.0	4.3	80.0	8202	1834.2
SCR-7-C	4	1.16	648	50	0.9	75.9	117.1	13.0	4.6	80.0	6723	1928.0

TABLE 16.2.4-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MARSHALL UNIT 3 OR 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	121
TOTAL COST (1000$)	
ESP UPGRADE CASE	121
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 16.2.4-9. Summary of DSD/FSI Control Costs for the Marshall Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	3	1.00	648	61	0.9	18.2	28.0	12.5	3.6	49.0	11671	1074.2
DSD+ESP	4	1.00	648	50	0.9	18.2	28.0	11.5	4.0	49.0	9567	1200.1
DSD+ESP-C	3	1.00	648	61	0.9	18.2	28.0	7.3	2.1	49.0	11671	622.4
DSD+ESP-C	4	1.00	648	50	0.9	18.2	28.0	6.7	2.3	49.0	9567	696.1
FSI+ESP-50	3	1.00	648	61	0.9	17.6	27.2	12.9	3.7	50.0	11995	1073.9
FSI+ESP-50	4	1.00	648	50	0.9	17.6	27.2	11.5	4.1	50.0	9832	1169.4
FSI+ESP-50-C	3	1.00	648	61	0.9	17.6	27.2	7.5	2.2	50.0	11995	621.9
FSI+ESP-50-C	4	1.00	648	50	0.9	17.6	27.2	6.7	2.3	50.0	9832	678.0
FSI+ESP-70	3	1.00	648	61	0.9	17.8	27.5	13.1	3.8	70.0	16793	780.6
FSI+ESP-70	4	1.00	648	50	0.9	17.8	27.5	11.7	4.1	70.0	13765	849.4
FSI+ESP-70-C	3	1.00	648	61	0.9	17.8	27.5	7.6	2.2	70.0	16793	452.0
FSI+ESP-70-C	4	1.00	648	50	0.9	17.8	27.5	6.8	2.4	70.0	13765	492.5

SECTION 17.0 NEW HAMPSHIRE

17.1 PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

17.1.1 Merrimack Steam Plant

The Merrimack steam plant is located on the Merrimack River in Merrimack County, New Hampshire, and is operated by the Public Service Company of New Hampshire. The Merrimack plant contains two coal-fired boilers with a gross generating capacity of 459 MW.

Table 17.1.1-1 presents operational data for the existing equipment at the Merrimack plant. Coal shipments are received by railroad and transferred to a coal storage and handling area west of the plant. PM emissions from the boilers are controlled by the ESPs which were built at the same time as the boilers. The ESPs are located behind the boilers and flue gases are directed to chimneys behind the ESPs. Dry fly ash from the units is either landfilled by the utility or sold.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers would be located at the west and east ends of the units beside the units 1 and 2 ESPs. Low (5 percent) general facilities and site access/congestion factors were selected for the FGD absorber locations. Approximately 100 to 300 feet of ductwork would be required to span the distance from the chimney to the absorbers back to the chimney for each unit. Low site access/congestion factors were assigned to flue gas handling.

LSD was not considered for the Merrimack plant. The existing ESPs cannot be reused because of their small sizes and poor performance. The medium to high sulfur content of the coal being burned at the plant would not likely favor use of LSD with new FFs.

Tables 17.1.1-2 and 17.1.1-3 present the retrofit factor input to the IAPCS model and the estimated cost for installation of L/LS-FGD at the Merrimack plant. The combined and low cost FGD cases show the benefits of economy of scale. The low cost case also shows the benefits of no spare absorber modules and large absorbers.

TABLE 17.1.1-1. MERRIMACK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	114	345
CAPACITY FACTOR (PERCENT)	73	45
INSTALLATION DATE	1960	1968
FIRING TYPE	CYCLONE	
FURNACE VOLUME (1000 CU FT)	37.1	NA
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	2.3	2.3
COAL HEATING VALUE (BTU/LB)	13400	13400
COAL ASH CONTENT (PERCENT)	7.1	7.1
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL/SOLD	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1960	1968
EMISSION (LB/MM BTU)	0.24	0.19
REMOVAL EFFICIENCY	88.9	97.7
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	3.5	3.0
SURFACE AREA (1000 SQ FT)	40.3	111.4
GAS EXIT RATE (1000 ACFM)	329	885
SCA (SQ FT/1000 ACFM)	122	126
OUTLET TEMPERATURE (°F)	245	300

TABLE 17.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR MERRIMACK UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	NA
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NA
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.20	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	0

Table 17.1.1-3. Summary of FGD Control Costs for the Merrimack Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.20	114	73	2.3	36.9	323.5	17.6	24.2	90.0	10727	1641.5
L/S FGD	2	1.20	345	45	2.3	70.0	202.9	30.5	22.5	90.0	20010	1526.3
L/S FGD-C	1	1.20	114	73	2.3	36.9	323.5	10.3	14.1	90.0	10727	955.9
L/S FGD-C	2	1.20	345	45	2.3	70.0	202.9	17.8	13.1	90.0	20010	890.1
LC FGD	1-2	1.20	459	52	2.3	62.9	137.0	32.3	15.4	90.0	30764	1048.6
LC FGD-C	1-2	1.20	459	52	2.3	62.9	137.0	18.8	9.0	90.0	30764	610.0

Coal Switching and Physical Coal Cleaning Costs--

CS was not considered for the Merrimack plant because these are wet bottom (slagging) boilers requiring coals with low ash fusion temperatures. Low sulfur, low ash fusion temperature bituminous coals required for cyclone boilers are not readily available in the eastern United States and use of western subbituminous coal would result in a significant unit derate. PCC was not considered for the Merrimack plant because it is not a mine mouth plant.

NO_x Control Technologies--

NGR was considered for NO_x emissions control for the two cyclone-fired boilers at the Merrimack plant. Tables 17.1.1-4 and 17.1.1-5 present the NO_x reduction performance and the costs developed for installation of this technology at the plant.

Selective Catalytic Reduction--

Cold side SCR reactors for the boilers at the Merrimack plant would be located next to the ESPs, similar to the wet FGD absorbers. As in the FGD case, low general facilities values (13 percent) and site access/congestion factors were assigned to the locations. About 200 feet of ductwork would be required. Tables 17.1.1-4 and 17.1.1-5 present the retrofit factor inputs to the IAPCS cost model and the costs for installation of SCR at the Merrimack plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were not considered for the Merrimack plant because the existing ESPs are too small to handle the additional load imposed by these technologies. In addition, the duct residence time between the boilers and ESPs is insufficient for slurry drying or humidification.

TABLE 17.1.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR MERRIMACK

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	CYCLONE	CYCLONE
TYPE OF NOx CONTROL	NGR	NGR
FURNACE VOLUME (1000 CU FT)	37.1	NA
BOILER INSTALLATION DATE	1960	1968
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	60	60
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	30	68
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	1070	2045
New Heat Exchanger (1000$)	2016	3918
TOTAL SCOPE ADDER COSTS (1000$)	3116	6032
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 17.1.1-5. NOx Control Cost Results for the Merrimack Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	114	73	2.3	2.4	21.4	4.1	5.6	60.0	2950	1379.4
NGR	2	1.00	345	45	2.3	5.5	16.0	7.6	5.6	60.0	5503	1389.5
NGR-C	1	1.00	114	73	2.3	2.4	21.4	2.3	3.2	60.0	2950	794.0
NGR-C	2	1.00	345	45	2.3	5.5	16.0	4.4	3.2	60.0	5503	800.6
SCR-3	1	1.16	114	73	2.3	20.0	175.1	6.9	9.4	80.0	3933	1751.3
SCR-3	2	1.16	345	45	2.3	46.3	134.2	16.4	12.1	80.0	7337	2238.6
SCR-3-C	1	1.16	114	73	2.3	20.0	175.1	4.0	5.5	80.0	3933	1026.1
SCR-3-C	2	1.16	345	45	2.3	46.3	134.2	9.6	7.1	80.0	7337	1310.8
SCR-7	1	1.16	114	73	2.3	20.0	175.1	6.0	8.2	80.0	3933	1517.0
SCR-7	2	1.16	345	45	2.3	46.3	134.2	13.6	10.0	80.0	7337	1858.4
SCR-7-C	1	1.16	114	73	2.3	20.0	175.1	3.5	4.8	80.0	3933	891.9
SCR-7-C	2	1.16	345	45	2.3	46.3	134.2	8.0	5.9	80.0	7337	1093.0

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The 345 MW boiler (unit 2) at the Merrimack plant is probably too large and too new to be considered for AFBC/CG repowering at this time. Unit 1 is a better candidate for AFBC/CG because of its small size and the available space next to the unit. However, because of the high capacity factor for unit 1, a long boiler downtime would cause the cost of power replacement to be high.

SECTION 18.0 NEW JERSEY

18.1 ATLANTIC CITY ELECTRIC COMPANY

18.1.1 B. L. England Steam Plant

The B. L. England steam plant is located on the Great Egg Harbor Bay in Cape May County, New Jersey, and is operated by the Atlantic City Electric Company. The B. L. England plant contains two coal-fired boilers and one petroleum-burning boiler with a gross generating capacity of 475 MW.

Table 18.1.1-1 presents operational data for the existing equipment at the B. L. England plant. Coal shipments are received by railroad and transferred to a coal storage and handling area south of the plant. PM emissions from the boilers are controlled by retrofit ESPs. The ESPs are located on the north side of the boilers. Flue gases from the boilers are directed to a common chimney located east of the unit 1 ESPs. Dry fly ash is reinjected into the boilers.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for unit 1 and unit 2 would be located east of unit 1. The general facilities factor would be medium (10 percent) for the FGD absorber location because several storage buildings would have to be relocated. Plant personnel indicated that this area is a coastal area which puts constraints on siting and process options, therefore a high site access/congestion factor was assigned to the site. Approximately 200 feet of ductwork would be required to span the distance from the chimney to the absorbers and back to the chimney. A low site access/congestion factor was assigned to flue gas handling. Plant personnel indicated that sufficient disposal site is not available on site or in surrounding counties. Therefore, waste has to be hauled off site, possibly out of state. The cost of disposal was reported to be $30-$70/ton; in this study $30/ton was used.

LSD with reuse of the existing ESPs was considered for unit 2 because its ESP size is adequate for LSD. Plant personnel indicated that virtually no space exists between the unit 1 airheater and the ESP in which to tie in

TABLE 18.1.1-1. B. L. ENGLAND STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3
GENERATING CAPACITY (MW-each)	136	163	176
CAPACITY FACTOR (PERCENT)	55	59	35
INSTALLATION DATE	1962	1964	1974
FIRING TYPE	CYCLONE		PETROLEUM
FURNACE VOLUME (1000 CU FT)	46.6	62.4	BURNING
LOW NOx COMBUSTION	NO	NO	
COAL SULFUR CONTENT (PERCENT)	2.6	2.6	
COAL HEATING VALUE (BTU/LB)	13000	13000	
COAL ASH CONTENT (PERCENT)	9.9	9.9	
FLY ASH SYSTEM	DRY DISPOSAL		
ASH DISPOSAL METHOD	REINJECTED INTO BOILERS/ON-SITE		
STACK NUMBER	1	2	
COAL DELIVERY METHODS	RAILROAD		
PARTICULATE CONTROL			
TYPE	ESP	ESP	
INSTALLATION DATE	1981	1982	
EMISSION (LB/MM BTU)	0.03	0.02	
REMOVAL EFFICIENCY	99.0	99.5	
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	3.0	3.0	
SURFACE AREA (1000 SQ FT)	209.5	265.4	
GAS EXIT RATE (1000 ACFM)	593	760	
SCA (SQ FT/1000 ACFM)	353	349	
OUTLET TEMPERATURE (°F)	290	290	

the FGD system. As such, LSD was not considered for unit 1. The LSD absorbers for unit 2 would have a similar location to the wet FGD absorbers; therefore, similar site access/congestion and general facility factors were assigned to the LSD absorber location. Over 400 feet of ductwork would be required to access upstream of the ESPs for unit 2. The site access/congestion factor for flue gas handling would be high due to the close proximity of the ESPs and the boilers.

Tables 18.1.1-2 and 18.1.1-3 present retrofit factors and cost estimates for installation of FGD control technologies at the B. L. England plant.

Coal Switching and Physical Coal Cleaning Costs--

CS was not considered for the B. L. England plant because low sulfur bituminous coals having low ash fusion temperatures required for cyclone-fired boilers are not readily available in the east. PCC was not considered because the B. L. England plant is not a mine mouth plant. Plant personnel indicated that Atlantic Electric is exploring coal switching options. Conversion to oil is also considered as a potential alternative.

NO_x Control Technologies--

NGR was considered for the wet bottom, cyclone boilers at the B. L. England plant. Plant personnel indicated that there is no gas supply to the station and as such NGR application might not be feasible. Tables 18.1.1-4 and 18.1.1-5 presents the performance results and cost estimates for installation of NGR at the B. L. England plant.

Selective Catalytic Reduction--

Cold side SCR reactors for the boilers at the B. L. England plant would be located east of unit 1. As in the FGD case, a medium general facilities value of 20 percent and a high site access/congestion factor would be assigned to the location. Approximately 200 feet of ductwork would be required to span the distance between the SCR reactors and the chimney. Tables 18.1.1-4 and 18.1.1-5 present the retrofit factors and cost estimates for installation of SCR at the B. L. England plant.

TABLE 18.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR ENGLAND UNITS 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
			Unit 2 only
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.40	NA	
ESP REUSE CASE			1.62
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	10

Table 18.1.1-3. Summary of FGD Control Costs for the England Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.40	136	55	2.6	49.9	367.2	24.4	37.2	90.0	11284	2162.8
L/S FGD	2	1.40	163	59	2.6	54.5	334.5	27.5	32.6	90.0	14508	1895.1
L/S FGD	1-2	1.40	299	57	2.6	77.8	260.3	40.4	27.0	90.0	25711	1570.0
L/S FGD-C	1	1.40	136	55	2.6	49.9	367.2	14.2	21.7	90.0	11284	1259.0
L/S FGD-C	2	1.40	163	59	2.6	54.5	334.5	16.0	19.0	90.0	14508	1102.6
L/S FGD-C	1-2	1.40	299	57	2.6	77.8	260.3	23.5	15.7	90.0	25711	913.1
LC FGD	1-2	1.40	299	57	2.6	59.3	198.5	34.2	22.9	90.0	25711	1328.8
LC FGD-C	1-2	1.40	299	57	2.6	59.3	198.5	19.8	13.3	90.0	25711	771.7
LSD+ESP	2	1.62	163	59	2.6	27.2	166.9	14.5	17.2	76.0	12300	1175.9
LSD+ESP-C	2	1.62	163	59	2.6	27.2	166.9	8.4	10.0	76.0	12300	683.6

TABLE 18.1.1-4. SUMMARY OF NOx RETROFIT RESULTS FOR ENGLAND

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	CYCLONE	
TYPE OF NOx CONTROL	NGR	NGR
FURNACE VOLUME (1000 CU FT)	46.6	62.4
BOILER INSTALLATION DATE	1962	1964
SLAGGING PROBLEM	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	60
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	34	39
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	1186	1319
New Heat Exchanger (1000$)	2241	2499
TOTAL SCOPE ADDER COSTS (1000$)	3462	3857
COMBINED CASE	5538	
RETROFIT FACTOR FOR SCR	1.52	1.52
GENERAL FACILITIES (PERCENT)	20	20

Table 18.1.1-5. NOx Control Cost Results for the England Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	136	55	2.6	2.7	20.1	3.6	5.4	60.0	2745	1296.1
NGR	2	1.00	163	59	2.6	3.1	19.1	4.5	5.3	60.0	3529	1275.5
NGR-C	1	1.00	136	55	2.6	2.7	20.1	2.1	3.1	60.0	2745	747.0
NGR-C	2	1.00	163	59	2.6	3.1	19.1	2.6	3.1	60.0	3529	734.8
SCR-3	1	1.52	136	55	2.6	27.3	200.5	9.2	14.0	80.0	3660	2500.6
SCR-3	2	1.52	163	59	2.6	31.0	190.3	10.6	12.6	80.0	4706	2247.3
SCR-3	1-2	1.52	299	57	2.6	49.3	164.8	17.3	11.6	80.0	8339	2075.9
SCR-3-C	1	1.52	136	55	2.6	27.3	200.5	5.4	8.2	80.0	3660	1466.1
SCR-3-C	2	1.52	163	59	2.6	31.0	190.3	6.2	7.4	80.0	4706	1317.1
SCR-3-C	1-2	1.52	299	57	2.6	49.3	164.8	10.1	6.8	80.0	8339	1215.9
SCR-7	1	1.52	136	55	2.6	27.3	200.5	8.0	12.3	80.0	3660	2198.6
SCR-7	2	1.52	163	59	2.6	31.0	190.3	9.2	11.0	80.0	4706	1965.7
SCR-7	1-2	1.52	299	57	2.6	49.3	164.8	14.9	10.0	80.0	8339	1784.4
SCR-7-C	1	1.52	136	55	2.6	27.3	200.5	4.7	7.2	80.0	3660	1293.0
SCR-7-C	2	1.52	163	59	2.6	31.0	190.3	5.4	6.5	80.0	4706	1155.8
SCR-7-C	1-2	1.52	299	57	2.6	49.3	164.8	8.7	5.9	80.0	8339	1048.8

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

FSI was considered for unit 2 at the B. L. England plant because its ESP is of an adequate size. However, space is not available for injecting sorbent or adding spray humidification and as a result FSI and DSD were not considered for unit 1. The first section of the unit 2 ESP would have to be modified in order to provide sufficient duct residence time for slurry droplet evaporation or humidification. Tables 18.1.1-6 and 18.1.1-7 present the retrofit factors and cost estimates for installation of FSI and DSD at the B. L. England plant. Currently, units 1 and 2 have a recycle flyash system, producing 100 percent bottom ash which is reusable and marketable. FSI application would create a combined flyash/spent sorbent stream which cannot be recycled. This would eventually increase the disposal cost because of the loss of bottom ash sales.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Units 1 and 2 at the B. L. England plant would be good candidates for AFBC/CG repowering because of their small boiler size (<300 MW).

TABLE 18.1.1-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR ENGLAND UNIT 2

ITEM	FSI Only
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	NA
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	43
TOTAL COST (1000$)	
ESP UPGRADE CASE	43
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	NA
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Table 18.1.1-7. Summary of DSD/FSI Control Costs for the England Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
FSI+ESP-50	2	1.00	163	59	2.6	9.9	60.7	10.7	12.7	50.0	8060	1331.0
FSI+ESP-50-C	2	1.00	163	59	2.6	9.9	60.7	6.2	7.3	50.0	8060	768.1
FSI+ESP-70	2	1.00	163	59	2.6	10.1	62.0	11.2	13.3	70.0	11284	994.7
FSI+ESP-70-C	2	1.00	163	59	2.6	10.1	62.0	6.5	7.7	70.0	11284	573.9

18.2 PUBLIC SERVICE ELECTRIC & GAS COMPANY

18.2.1 Hudson Steam Plant

Costs were not generated due to the use of low sulfur coal. CS was not evaluated since the boilers currently fire a low sulfur coal. The ESPs were assumed to be inadequate for an additional load, hence sorbent injection technologies were not considered, and LSD with a new baghouse was considered.

TABLE 18.2.1-1. HUDSON STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW)	383	600
CAPACITY FACTOR (PERCENT)	21	50
INSTALLATION DATE	1964	1968
FIRING TYPE	CYCLONE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	PETROLEUM	354.6
LOW NOx COMBUSTION	BURNING	NO
COAL SULFUR CONTENT (PERCENT)		0.9
COAL HEATING VALUE (BTU/LB)		13200
COAL ASH CONTENT (PERCENT)		8.6
FLY ASH SYSTEM		DRY
ASH DISPOSAL METHOD		SOLD/OFF-SITE
STACK NUMBER		2
COAL DELIVERY METHODS		BARGE
PARTICULATE CONTROL		
TYPE		ESP
INSTALLATION DATE		1984
EMISSION (LB/MM BTU)		0.10
REMOVAL EFFICIENCY		99
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)		1.0
SURFACE AREA (1000 SQ FT)		377.2
EXIT GAS FLOW RATE (1000 ACFM)		2500
SCA (SQ FT/1000 ACFM)		164
OUTLET TEMPERATURE (°F)		275-325

TABLE 18.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR HUDSON UNIT 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.38	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.37
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	10	0	10

* L/S-FGD and LSD-FGD absorbers would be located behind the unit 2 chimney.

TABLE 18.2.1-3. SUMMARY OF NOx RETROFIT RESULTS FOR HUDSON

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	2
FIRING TYPE	OWF
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	354.6
BOILER INSTALLATION DATE	1968
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	41
SCR RETROFIT RESULTS *	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	104
New Duct Length (Feet)	200
New Duct Costs (1000$)	2827
New Heat Exchanger (1000$)	5461
TOTAL SCOPE ADDER COSTS (1000$)	8392
RETROFIT FACTOR FOR SCR	1.34
GENERAL FACILITIES (PERCENT)	20

* Cold side SCR reactors would be located behind the unit 2 chimney.

Table 18.2.1-4. NOx Control Cost Results for the Hudson Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	2	1.00	600	50	0.9	5.2	8.7	1.2	0.4	41.0	4196	274.8
LNC-LNB-C	2	1.00	600	50	0.9	5.2	8.7	0.7	0.3	41.0	4196	163.0
SCR-3	2	1.34	600	50	0.9	78.7	131.1	28.7	10.9	80.0	8187	3503.3
SCR-3-C	2	1.34	600	50	0.9	78.7	131.1	16.8	6.4	80.0	8187	2050.2
SCR-7	2	1.34	600	50	0.9	78.7	131.1	23.8	9.1	80.0	8187	2909.5
SCR-7-C	2	1.34	600	50	0.9	78.7	131.1	14.0	5.3	80.0	8187	1710.0

18.2.2 Mercer Steam Plant

The Mercer steam plant is located on the Delaware River in Mercer County, New Jersey, and is operated by the Public Service Electric and Gas Company. The Mercer plant contains two coal-fired boilers with a gross generating capacity of 600 MW.

Table 18.2.2-1 presents operational data for the existing equipment at the Mercer plant. Coal shipments are received by barge and transferred to a coal storage and handling area southeast of the plant. PM emissions are controlled by original ESPs located behind the respective chimney. Wet fly ash from the units is disposed of in ash ponds north of the plant or sold.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1 and 2 would be located on either side of the units. The site access/congestion factor for either location would be low. For both locations, a plant road and storage buildings would have to be relocated; therefore, the general facilities factor would be medium (8 percent). Over 300 feet of ductwork would be required for both absorber locations. A medium site access/congestion factor was assigned to flue gas handling since the chimneys are surrounded by ESPs and original duct.

LSD with reuse of the existing ESPs was considered for the Mercer plant. For both units, the LSD absorbers would have a similar location as the wet FGD absorbers; thus, similar site access/congestion and general facilities factors were assigned for these locations. Over 300 feet of ductwork would be required. The site access/congestion factor for flue gas handling would be medium just as in the wet FGD case.

Table 18.2.2-2 presents the retrofit factors for installation of FGD control technologies at the Mercer plant. Since the boilers fire a low sulfur coal, coal costs are not presented.

Coal Switching and Physical Coal Cleaning Costs

The boilers at the Mercer plant currently fire a low sulfur coal, therefore, CS and PCC were no evaluated.

TABLE 18.2.2-1. MERCER STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2
GENERATING CAPACITY (MW-each)	300
CAPACITY FACTOR (PERCENT)	55,69
INSTALLATION DATE	1960,61
FIRING TYPE	FRONT WALL
FURNACE VOLUME (1000 CU FT)	193
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)*	0.89
COAL HEATING VALUE (BTU/LB)	13270
COAL ASH CONTENT (PERCENT)	6.9
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	ASH PONDS/SOLD
STACK NUMBER	1,2
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1960,61
EMISSION (LB/MM BTU)	0.1
REMOVAL EFFICIENCY	99.0
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.0-0.0
SURFACE AREA (1000 SQ FT)	NA
GAS EXIT RATE (1000 ACFM)	900
SCA (SQ FT/1000 ACFM)	NA
OUTLET TEMPERATURE (°F)	269

* 1988 value.

TABLE 18.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR MERCER UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	2510	NA	2510
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	NA	
ESP REUSE CASE			1.38
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

NO_x Control Technologies--

Both units are slagging, wall-fired, Foster Wheeler boilers rated at 300 MW each; as such, NGR was considered for both units at the Mercer plant. Performance results and costs developed for the two units are presented in Tables 18.2.2-3 and 18.2.2-4.

Selective Catalytic Reduction--

Hot side SCR reactors for units 1 and 2 would be located on either side of the units. Low site access/congestion factors were assigned to these locations. The general facilities factor was medium (20 percent) due to the relocation of plant roads and storage buildings. About 300 feet of ductwork would be required for either reactor location. Tables 18.2.2-3 and 18.2.2-4 present the retrofit factors and cost estimates for installation of SCR at the Mercer plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Both units at the Mercer plant would be good candidates for sorbent injection technologies because of the sufficient duct residence time between the boilers and the ESPs. Approximately 200 feet of duct exist between the boilers and the ESPs allowing for slurry droplet evaporation or humidification. Tables 18.2.2-5 and 18.2.2-6 present retrofit factors and cost estimates for installation of FSI and DSD at the Mercer plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

Both boilers at the Mercer plant currently are marginal candidates for AFBC/CG repowering due to their large boiler size.

TABLE 18.2.2-3. SUMMARY OF NOx RETROFIT RESULTS FOR MERCER

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	FWF
TYPE OF NOx CONTROL	NGR
FURNACE VOLUME (1000 CU FT)	193
BOILER INSTALLATION DATE	1960,1961
SLAGGING PROBLEM	NA
ESTIMATED NOx REDUCTION (PERCENT)	60
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	62
New Duct Length (Feet)	300
New Duct Costs (1000$)	2827
New Heat Exchanger (1000$)	0
TOTAL SCOPE ADDER COSTS (1000$)	2889
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	20

Table 18.2.2-4. NOx Control Cost Results for the Mercer Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	300	55	0.9	5.0	16.6	8.0	5.5	60.0	5435	1470.6
NGR	2	1.00	300	69	0.9	5.0	16.6	9.9	5.4	60.0	6818	1444.8
NGR-C	1	1.00	300	55	0.9	5.0	16.6	4.6	3.2	60.0	5435	846.7
NGR-C	2	1.00	300	69	0.9	5.0	16.6	5.7	3.1	60.0	6818	831.0
SCR-3	1	1.16	300	55	0.9	39.2	130.6	14.8	10.2	80.0	7246	2043.1
SCR-3	2	1.16	300	69	0.9	39.2	130.6	15.1	8.4	80.0	9090	1665.8
SCR-3-C	1	1.16	300	55	0.9	39.2	130.6	8.7	6.0	80.0	7246	1194.8
SCR-3-C	2	1.16	300	69	0.9	39.2	130.6	8.9	4.9	80.0	9090	973.7
SCR-7	1	1.16	300	55	0.9	39.2	130.6	12.4	8.6	80.0	7246	1707.9
SCR-7	2	1.16	300	69	0.9	39.2	130.6	12.7	7.0	80.0	9090	1398.6
SCR-7-C	1	1.16	300	55	0.9	39.2	130.6	7.3	5.0	80.0	7246	1002.8
SCR-7-C	2	1.16	300	69	0.9	39.2	130.6	7.5	4.1	80.0	9090	820.6

TABLE 18.2.2-5. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MERCER UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	2510
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	68
TOTAL COST (1000$)	
ESP UPGRADE CASE	2578
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 18.2.2-6. Summary of DSD/FSI Control Costs for the Mercer Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	300	55	0.9	14.9	49.7	8.5	5.9	49.0	4549	1868.6
DSD+ESP	2	1.00	300	69	0.9	14.9	49.7	9.0	5.0	49.0	5707	1578.5
DSD+ESP-C	1	1.00	300	55	0.9	14.9	49.7	4.9	3.4	49.0	4549	1085.3
DSD+ESP-C	2	1.00	300	69	0.9	14.9	49.7	5.2	2.9	49.0	5707	916.1
FSI+ESP-50	1	1.00	300	55	0.9	18.6	62.1	9.1	6.3	50.0	4675	1950.1
FSI+ESP-50	2	1.00	300	69	0.9	18.6	62.1	9.9	5.5	50.0	5865	1689.7
FSI+ESP-50-C	1	1.00	300	55	0.9	18.6	62.1	5.3	3.7	50.0	4675	1135.1
FSI+ESP-50-C	2	1.00	300	69	0.9	18.6	62.1	5.8	3.2	50.0	5865	982.3
FSI+ESP-70	1	1.00	300	55	0.9	18.7	62.5	9.2	6.4	70.0	6545	1407.6
FSI+ESP-70	2	1.00	300	69	0.9	18.8	62.5	10.0	5.5	70.0	8211	1220.7
FSI+ESP-70-C	1	1.00	300	55	0.9	18.7	62.5	5.4	3.7	70.0	6545	819.3
FSI+ESP-70-C	2	1.00	300	69	0.9	18.8	62.5	5.8	3.2	70.0	8211	709.6

SECTION 19.0 NEW YORK

19.1 NEW YORK STATE ELECTRIC AND GAS CORPORATION

19.1.1 Goudey Steam Plant

The Goudey steam plant is located on the Susquehanna River in Broome County, New York, and is operated by New York State Electric and Gas Corporation. The Goudey plant contains three coal-fired boilers with a gross generating capacity of 127 MW.

Table 19.1.1-1 presents operational data for the existing equipment at the Goudey plant. Coal shipments are received by railroad and transferred to a coal storage and handling area east of the plant. PM emissions from the units are controlled by retrofit ESPs located behind the boilers. The flue gas from all three boilers is directed to a common chimney located behind unit 3. The plant has paid off-site disposal for its dry fly ash.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for all units would be located east of unit 1. The site access/congestion factor would be low. No equipment relocation or demolition would be required; hence, a low percentage was assigned to general facilities. Each unit would need 300 to 600 feet of ductwork. The site access/congestion factor assigned to flue gas handling was medium for all units due to the close proximity of the coal pile/railroad and the chimney.

LSD with reuse of the existing ESPs was considered for all units at the Goudey plant. The LSD absorbers for all three units would have the same location as the wet FGD absorbers; therefore, similar site access/congestion and general facility factors were assigned. The site access/congestion factor for flue gas handling was high for all units due to the close proximity of the ESPs to the boilers.

Tables 19.1.1-2 and 19.1.1-3 present retrofit factors and cost for installation of conventional FGD technologies at the Goudey plant.

TABLE 19.1.1-1. GOUDEY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3
GENERATING CAPACITY (MW)	44(COMBINED)	83
CAPACITY FACTOR (PERCENT)	63	41
INSTALLATION DATE	1943	1951
FIRING TYPE	OPPOSED WALL	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	NA	44.6
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.9	
COAL HEATING VALUE (BTU/LB)	12200	
COAL ASH CONTENT (PERCENT)	13.4	
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	PAID	
STACK NUMBER	1	1
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1973	1973
EMISSION (LB/MM BTU)	0.05	0.05
REMOVAL EFFICIENCY	99.2,96.8	99.6
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.0	1.0
SURFACE AREA (1000 SQ FT)	67	201.6
GAS EXIT RATE (1000 ACFM)	110	335
SCA (SQ FT/1000 ACFM)	609	602
OUTLET TEMPERATURE (°F)	325	275

TABLE 19.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR GOUDEY UNITS 1-3 (EACH)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.35	NA	
ESP REUSE CASE			1.36
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

Table 19.1.1-3. Summary of FGD Control Costs for the Goudey Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1-3	1.35	127	49	1.9	44.3	349.1	19.7	36.1	90.0	7379	2669.6
L/S FGD-C	1-3	1.35	127	49	1.9	44.3	349.1	11.5	21.1	90.0	7379	1556.4
LC FGD	1-3	1.35	127	49	1.9	31.0	244.0	15.3	28.0	90.0	7379	2071.8
LC FGD-C	1-3	1.35	127	49	1.9	31.0	244.0	8.9	16.3	90.0	7379	1205.8
LSD+ESP	1,2	1.36	22	63	1.9	6.5	297.4	4.8	39.8	76.0	1393	3472.1
LSD+ESP	3	1.36	83	41	1.9	13.9	168.0	7.4	25.0	65.0	2920	2549.7
LSD+ESP-C	1,2	1.36	22	63	1.9	6.5	297.4	2.8	23.1	76.0	1393	2010.3
LSD+ESP-C	3	1.36	83	41	1.9	13.9	168.0	4.3	14.5	65.0	2920	1482.2

Coal Switching and Physical Coal Cleaning Costs--

Table 19.1.1-4 presents the IAPCS cost results for CS at the Goudey plant. These costs do not include boiler and pulverizer operating cost changes or any coal handling system modifications that may be necessary. PCC was not considered because the Goudey plant is not a mine mouth plant.

NO_x Control Technologies--

LNBs were considered for NO_x emissions control for the two opposed wall-fired boilers and OFA was considered for the tangential-fired boiler. Tables 19.1.1-5 and 19.1.1-6 present the NO_x performance and cost estimates for LNC technologies at the Goudey plant.

Selective Catalytic Reduction--

Cold side SCR reactors for all three units would be located east of unit 1, similar to the wet FGD absorber location. Low site access/ congestion and general facility factors (13 percent) were assigned to the SCR reactor locations. The duct length needed to span the distance between the SCR reactors and the chimney would be 400 feet for all units. Tables 19.1.1-5 and 19.1.1-6 present the retrofit factors and estimated cost for installation of SCR at the Goudey plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were considered for all boilers at the Goudey plant. Although there is not sufficient duct residence time between the boilers and the ESPs, the ESPs are large enough to handle the additional load generated by DSD or FSI. Tables 19.1.1-7 and 19.1.1-8 summarize the retrofit factors and cost for installation of sorbent injection technologies at the Goudey plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The three boilers at the Goudey plant would be good candidates for AFBC/CG repowering because of their small boiler size and likely short remaining service life.

Table 19.1.1-4. Summary of Coal Switching/Cleaning Costs for the Goudey Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1,2	1.00	22	63	1.9	1.4	62.3	2.3	18.7	52.0	949	2387.0
CS/B+$15	3	1.00	83	41	1.9	3.3	40.2	4.8	16.1	52.0	2331	2062.2
CS/B+$15-C	1,2	1.00	22	63	1.9	1.4	62.3	1.3	10.7	52.0	949	1374.0
CS/B+$15-C	3	1.00	83	41	1.9	3.3	40.2	2.8	9.3	52.0	2331	1187.9
CS/B+$5	1,2	1.00	22	63	1.9	1.1	52.0	1.2	10.1	52.0	949	1288.7
CS/B+$5	3	1.00	83	41	1.9	2.5	29.8	2.2	7.4	52.0	2331	941.2
CS/B+$5-C	1,2	1.00	22	63	1.9	1.1	52.0	0.7	5.8	52.0	949	743.7
CS/B+$5-C	3	1.00	83	41	1.9	2.5	29.8	1.3	4.3	52.0	2331	544.0

TABLE 19.1.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR GOUDEY

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2	3
FIRING TYPE	OWF	TANG
TYPE OF NOx CONTROL	LNB	OFA
FURNACE VOLUME (1000 CU FT)	NA	44.6
BOILER INSTALLATION DATE	1943	1951
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	9	24
New Duct Length (Feet)	400	400
New Duct Costs (1000$)	817	1777
New Heat Exchanger (1000$)	751	1667
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	1577	3468
COMBINED CASE (1-3)	4463	
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Table 19.1.1-6. NOx Control Cost Results for the Goudey Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1,2	1.00	22	63	1.9	1.4	63.3	0.3	2.5	40.0	207	1473.9
LNC-LNB-C	1,2	1.00	22	63	1.9	1.4	63.3	0.2	1.5	40.0	207	874.9
LNC-OFA	3	1.00	83	41	1.9	2.4	28.6	0.5	1.7	25.0	318	1633.5
LNC-OFA-C	3	1.00	83	41	1.9	2.4	28.6	0.3	1.0	25.0	318	969.3
SCR-3	1,2	1.16	22	63	1.9	9.1	414.2	2.8	22.8	80.0	414	6685.4
SCR-3	3	1.16	83	41	1.9	17.2	207.4	5.5	18.5	80.0	1017	5425.8
SCR-3	1-3	1.16	127	49	1.9	22.7	179.0	7.5	13.8	80.0	1859	4049.7
SCR-3-C	1,2	1.16	22	63	1.9	9.1	414.2	1.6	13.4	80.0	414	3928.9
SCR-3-C	3	1.16	83	41	1.9	17.2	207.4	3.2	10.9	80.0	1017	3184.5
SCR-3-C	1-3	1.16	127	49	1.9	22.7	179.0	4.4	8.1	80.0	1859	2375.0
SCR-7	1,2	1.16	22	63	1.9	9.1	414.2	2.6	21.3	80.0	414	6249.6
SCR-7	3	1.16	83	41	1.9	17.2	207.4	4.8	16.2	80.0	1017	4756.2
SCR-7	1-3	1.16	127	49	1.9	22.7	179.0	6.5	11.9	80.0	1859	3489.7
SCR-7-C	1,2	1.16	22	63	1.9	9.1	414.2	1.5	12.5	80.0	414	3679.4
SCR-7-C	3	1.16	83	41	1.9	17.2	207.4	2.8	9.6	80.0	1017	2800.9
SCR-7-C	1-3	1.16	127	49	1.9	22.7	179.0	3.8	7.0	80.0	1859	2054.2

TABLE 19.1.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR GOUDEY UNIT 1, 2, OR 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	10,10,26
TOTAL COST (1000$)	
ESP UPGRADE CASE	10,10,26
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 19.1.1-8. Summary of DSD/FSI Control Costs for the Goudey Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1,2	1.00	22	63	1.9	3.1	141.0	3.8	31.1	49.0	888	4253.9
DSD+ESP	3	1.00	83	41	1.9	5.4	65.4	4.8	16.2	43.0	1931	2505.9
DSD+ESP-C	1,2	1.00	22	63	1.9	3.1	141.0	2.2	17.9	49.0	888	2452.9
DSD+ESP-C	3	1.00	83	41	1.9	5.4	65.4	2.8	9.4	43.0	1931	1448.3
FSI+ESP-50	1,2	1.00	22	63	1.9	3.5	158.8	3.1	25.3	50.0	913	3366.8
FSI+ESP-50	3	1.00	83	41	1.9	5.7	69.0	4.3	14.5	50.0	2242	1924.6
FSI+ESP-50-C	1,2	1.00	22	63	1.9	3.5	158.8	1.8	14.6	50.0	913	1946.1
FSI+ESP-50-C	3	1.00	83	41	1.9	5.7	69.0	2.5	8.4	50.0	2242	1114.2
FSI+ESP-70	1,2	1.00	22	63	1.9	3.5	161.0	3.1	25.5	70.0	1278	2425.2
FSI+ESP-70	3	1.00	83	41	1.9	5.8	70.0	4.4	14.7	70.0	3138	1392.2
FSI+ESP-70-C	1,2	1.00	22	63	1.9	3.5	161.0	1.8	14.8	70.0	1278	1401.9
FSI+ESP-70-C	3	1.00	83	41	1.9	5.8	70.0	2.5	8.5	70.0	3138	805.9

19.1.2 Greenidge Steam Plant

Sorbent injection technologies (FSI and DSD) were not considered for any of the boilers at the Greenidge plant due to the marginal ESP size and performance.

TABLE 19.1.2-1. GREENIDGE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	4+5	6
GENERATING CAPACITY (MW-each)	59	104
CAPACITY FACTOR (PERCENT)	46	48
INSTALLATION DATE	1950	1953
FIRING TYPE	FRONT WALL	TANGENTIAL
FURNACE VOLUME (1000 CU FT)	NA	57.6
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.9	
COAL HEATING VALUE (BTU/LB)	11900	
COAL ASH CONTENT (PERCENT)	13.7	
FLY ASH SYSTEM	WET DISPOSAL	
ASH DISPOSAL METHOD	PONDS/ON-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	MECH. COLLECTOR AND ESP	ESP
INSTALLATION DATE	1971	1970
EMISSION (LB/MM BTU)	0.13	0.10
REMOVAL EFFICIENCY	96.2	99.7
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.0	
SURFACE AREA (1000 SQ FT)	20.8	89.3
GAS EXIT RATE (1000 ACFM)	210	412
SCA (SQ FT/1000 ACFM)	99	217
OUTLET TEMPERATURE (°F)	300	300

TABLE 19.1.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR GREENIDGE UNIT 4+5, OR 6 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	NO
ESTIMATED COST (1000$)	584-971	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	413-728	0	413-728
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.48	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.43
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	8	0	8

* Absorbers for boilers 4+5 and 6 would be located west of boiler 6.

Table 19.1.2-3. Summary of FGD Control Costs for the Greenidge Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	4+5	1.48	59	46	1.9	34.0	576.8	14.6	61.5	90.0	3312	4416.0
L/S FGD	6	1.48	104	48	1.9	44.6	428.8	19.3	44.1	90.0	6091	3164.6
L/S FGD-C	4+5	1.48	59	46	1.9	34.0	576.8	8.5	35.9	90.0	3312	2576.1
L/S FGD-C	6	1.48	104	48	1.9	44.6	428.8	11.2	25.7	90.0	6091	1846.0
LC FGD	4-6	1.48	163	47	1.9	39.3	241.3	18.8	28.0	90.0	9348	2009.3
LC FGD-C	4-6	1.48	163	47	1.9	39.3	241.3	10.9	16.3	90.0	9348	1170.1
LSD+FF	4+5	1.43	59	46	1.9	19.2	324.8	8.8	36.8	84.0	3090	2833.0
LSD+FF	6	1.43	104	48	1.9	28.6	275.3	12.1	27.7	84.0	5684	2132.9
LSD+FF-C	4+5	1.43	59	46	1.9	19.2	324.8	5.1	21.5	84.0	3090	1651.0
LSD+FF-C	6	1.43	104	48	1.9	28.6	275.3	7.1	16.2	84.0	5684	1244.6

Table 19.1.2-4. Summary of Coal Switching/Cleaning Costs for the Greenidge Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	4,5	1.00	30	46	1.9	1.9	63.3	2.3	19.0	53.0	998	2298.0
CS/B+$15	6	1.00	104	48	1.9	3.9	37.5	6.7	15.3	53.0	3610	1857.6
CS/B+$15-C	4,5	1.00	30	46	1.9	1.9	63.3	1.3	10.9	53.0	998	1325.2
CS/B+$15-C	6	1.00	104	48	1.9	3.9	37.5	3.9	8.8	53.0	3610	1069.1
CS/B+$5	4,5	1.00	30	46	1.9	1.6	52.9	1.2	10.3	53.0	998	1242.8
CS/B+$5	6	1.00	104	48	1.9	2.8	27.1	2.9	6.6	53.0	3610	804.8
CS/B+$5-C	4,5	1.00	30	46	1.9	1.6	52.9	0.7	5.9	53.0	998	719.2
CS/B+$5-C	6	1.00	104	48	1.9	2.8	27.1	1.7	3.8	53.0	3610	464.6

TABLE 19.1.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR GREENIDGE

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	4,5	6
FIRING TYPE	FWF	TANG
TYPE OF NOx CONTROL	LNB	OFA
FURNACE VOLUME (1000 CU FT)	NA	57.6
BOILER INSTALLATION DATE	1950	1953
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	40	25
SCR RETROFIT RESULTS *		
BOILER NUMBER	4+5	6
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	18	28
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	728	1014
New Heat Exchanger (1000$)	1358	1908
TOTAL SCOPE ADDER COSTS (1000$)	2104	2950
RETROFIT FACTOR FOR SCR	1.52	1.52
GENERAL FACILITIES (PERCENT)	20	20

* Cold side SCR reactors for boilers 4+5 and 6 would be located behind their respective chimney.

Table 19.1.2-6. NOx Control Cost Results for the Greenidge Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	4,5	1.00	30	48	1.9	1.6	52.6	0.3	2.7	40.0	221	1561.2
LNC-LNB-C	4,5	1.00	30	48	1.9	1.6	52.6	0.2	1.6	40.0	221	926.3
LNC-OFA	6	1.00	104	48	1.9	0.6	6.0	0.1	0.3	25.0	343	402.1
LNC-OFA-C	6	1.00	104	48	1.9	0.6	6.0	0.1	0.2	25.0	343	238.5
SCR-3	4+5	1.52	59	46	1.9	16.6	280.9	5.1	21.6	80.0	834	6164.8
SCR-3	6	1.52	104	48	1.9	23.0	220.7	7.3	16.7	80.0	1096	6679.7
SCR-3-C	4+5	1.52	59	46	1.9	16.6	280.9	3.0	12.7	80.0	834	3621.1
SCR-3-C	6	1.52	104	48	1.9	23.0	220.7	4.3	9.8	80.0	1096	3920.9
SCR-7	4+5	1.52	59	46	1.9	16.6	280.9	4.7	19.6	80.0	834	5582.9
SCR-7	6	1.52	104	48	1.9	23.0	220.7	6.5	14.8	80.0	1096	5899.0
SCR-7-C	4+5	1.52	59	46	1.9	16.6	280.9	2.7	11.5	80.0	834	3287.8
SCR-7-C	6	1.52	104	48	1.9	23.0	220.7	3.8	8.7	80.0	1096	3473.6

19.1.3 Milliken Steam Plant

The Milliken Steam Plant is located in Tompkins County, New York, as part of the New York State Electric and Gas Corporation system. The plant contains two coal-fired boilers with a total gross generating capacity of 316 MW. Tables 19.1.3-1 through 19.1.3-9 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 19.1.3-1. MILLIKEN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2
GENERATING CAPACITY (MW-each)	157	159
CAPACITY FACTOR (PERCENT)	27	73
INSTALLATION DATE	1955	1958
FIRING TYPE	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	93	
LOW NOx COMBUSTION	NO	
COAL SULFUR CONTENT (PERCENT)	1.9	
COAL HEATING VALUE (BTU/LB)	11800	
COAL ASH CONTENT (PERCENT)	14	
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	LANDFILL/SOLD/OFF-SITE	
STACK NUMBER	1	2
COAL DELIVERY METHODS	RAILROAD	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1972	1972
EMISSION (LB/MM BTU)	0.03	0.05
REMOVAL EFFICIENCY	99.5	99.6
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1	1
SURFACE AREA (1000 SQ FT)	188.6	188.6
GAS EXIT RATE (1000 ACFM)	650	650
SCA (SQ FT/1000 ACFM)	290	290
OUTLET TEMPERATURE (°F)	300	300

TABLE 19.1.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR MILLIKEN UNIT 1 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	1099	0	1099
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.41	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.43
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for unit 1 would be located north of unit 2.

TABLE 19.1.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR MILLIKEN UNIT 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	1113	0	1113
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.34	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.35
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for unit 2 would be located north of unit 2.

Table 19.1.3-4. Summary of FGD Control Costs for the Milliken Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.41	157	27	1.9	52.8	336.6	21.2	57.2	90.0	5223	4064.3
L/S FGD	2	1.34	159	73	1.9	50.8	319.7	24.9	24.5	90.0	14300	1738.7
L/S FGD	1-2	1.38	316	50	1.9	76.8	242.9	34.9	25.2	90.0	19466	1793.2
L/S FGD-C	1	1.41	157	27	1.9	52.8	336.6	12.4	33.4	90.0	5223	2373.9
L/S FGD-C	2	1.34	159	73	1.9	50.8	319.7	14.5	14.2	90.0	14300	1012.1
L/S FGD-C	1-2	1.38	316	50	1.9	76.8	242.9	20.3	14.7	90.0	19466	1045.1
LC FGD	1-2	1.38	316	50	1.9	58.0	183.5	28.7	20.7	90.0	19466	1475.1
LC FGD-C	1-2	1.38	316	50	1.9	58.0	183.5	16.7	12.1	90.0	19466	858.5
LSD+FF	1	1.43	157	27	1.9	38.2	243.4	14.5	39.0	83.0	4834	2991.9
LSD+FF	2	1.35	159	73	1.9	37.6	236.3	16.9	16.6	83.0	13237	1273.8
LSD+FF	1-2	1.39	316	50	1.9	68.2	215.8	26.7	19.3	83.0	18019	1479.0
LSD+FF-C	1	1.43	157	27	1.9	38.2	243.4	8.5	22.8	83.0	4834	1749.6
LSD+FF-C	2	1.35	159	73	1.9	37.6	236.3	9.8	9.7	83.0	13237	742.5
LSD+FF-C	1-2	1.39	316	50	1.9	68.2	215.8	15.6	11.3	83.0	18019	864.4

Table 19.1.3-5. Summary of Coal Switching/Cleaning Costs for the Milliken Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	157	27	1.9	5.4	34.3	6.1	16.3	54.0	3121	1941.6
CS/B+$15	2	1.00	159	73	1.9	5.4	34.2	14.4	14.2	54.0	8547	1689.8
CS/B+$15-C	1	1.00	157	27	1.9	5.4	34.3	3.5	9.4	54.0	3121	1120.2
CS/B+$15-C	2	1.00	159	73	1.9	5.4	34.2	8.3	8.2	54.0	8547	971.0
CS/B+$5	1	1.00	157	27	1.9	3.8	24.0	2.7	7.3	54.0	3121	867.6
CS/B+$5	2	1.00	159	73	1.9	3.8	23.9	5.8	5.7	54.0	8547	673.4
CS/B+$5-C	1	1.00	157	27	1.9	3.8	24.0	1.6	4.2	54.0	3121	502.5
CS/B+$5-C	2	1.00	159	73	1.9	3.8	23.9	3.3	3.3	54.0	8547	387.8

TABLE 19.1.3-6. SUMMARY OF NOx RETROFIT RESULTS FOR MILLIKEN

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1	2
FIRING TYPE	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA
FURNACE VOLUME (1000 CU FT)	93	93
BOILER INSTALLATION DATE	1955	1958
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	38	38
New Duct Length (Feet)	200	200
New Duct Costs (1000$)	1290	1300
New Heat Exchanger (1000$)	2443	2462
TOTAL SCOPE ADDER COSTS (1000$)	3771	3800
RETROFIT FACTOR FOR SCR	1.34	1.16
GENERAL FACILITIES (PERCENT)	20	13

* Cold side SCR reactors for unit 1 would be located south of the unit 1 chimney, and cold side SCR reactors for unit 2 would be located north of the unit 2 chimney.

Table 19.1.3-7. NOx Control Cost Results for the Milliken Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	157	27	1.9	0.7	4.7	0.2	0.4	25.0	294	553.0
LNC-OFA	2	1.00	159	73	1.9	0.7	4.7	0.2	0.2	25.0	804	203.1
LNC-OFA-C	1	1.00	157	27	1.9	0.7	4.7	0.1	0.3	25.0	294	327.9
LNC-OFA-C	2	1.00	159	73	1.9	0.7	4.7	0.1	0.1	25.0	804	120.5
SCR-3	1	1.34	157	27	1.9	28.0	178.3	9.1	24.6	80.0	940	9724.5
SCR-3	2	1.16	159	73	1.9	25.4	159.8	8.9	8.7	80.0	2573	3456.0
SCR-3-C	1	1.34	157	27	1.9	28.0	178.3	5.4	14.4	80.0	940	5705.0
SCR-3-C	2	1.16	159	73	1.9	25.4	159.8	5.2	5.1	80.0	2573	2024.3
SCR-7	1	1.34	157	27	1.9	28.0	178.3	7.8	21.1	80.0	940	8348.2
SCR-7	2	1.16	159	73	1.9	25.4	159.8	7.6	7.5	80.0	2573	2946.9
SCR-7-C	1	1.34	157	27	1.9	28.0	178.3	4.6	12.4	80.0	940	4916.5
SCR-7-C	2	1.16	159	73	1.9	25.4	159.8	4.5	4.4	80.0	2573	1732.7

TABLE 19.1.3-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MILLIKEN UNITS 1 AND 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	42
TOTAL COST (1000$)	
ESP UPGRADE CASE	42
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Long duct residence time exists between the boilers and the retrofit ESPs. A high factor was assigned to ESP upgrade since little space is available around the ESPs.

Table 19.1.3-9. Summary of DSD/FSI Control Costs for the Milliken Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	157	27	1.9	9.4	59.6	6.3	16.9	46.0	2661	2356.3
DSD+ESP	2	1.00	159	73	1.9	9.4	59.3	8.2	8.1	46.0	7285	1127.5
DSD+ESP-C	1	1.00	157	27	1.9	9.4	59.6	3.6	9.8	46.0	2661	1365.8
DSD+ESP-C	2	1.00	159	73	1.9	9.4	59.3	4.7	4.7	46.0	7285	651.8
FSI+ESP-50	1	1.00	157	27	1.9	10.0	63.8	5.7	15.2	50.0	2901	1947.4
FSI+ESP-50	2	1.00	159	73	1.9	10.1	63.5	8.8	8.7	50.0	7944	1107.5
FSI+ESP-50-C	1	1.00	157	27	1.9	10.0	63.8	3.3	8.8	50.0	2901	1131.2
FSI+ESP-50-C	2	1.00	159	73	1.9	10.1	63.5	5.1	5.0	50.0	7944	640.2
FSI+ESP-70	1	1.00	157	27	1.9	10.1	64.6	5.7	15.4	70.0	4062	1409.7
FSI+ESP-70	2	1.00	159	73	1.9	10.2	64.3	8.9	8.8	70.0	11122	804.6
FSI+ESP-70-C	1	1.00	157	27	1.9	10.1	64.6	3.3	9.0	70.0	4062	818.8
FSI+ESP-70-C	2	1.00	159	73	1.9	10.2	64.3	5.2	5.1	70.0	11122	465.1

19.2 NIAGARA MOHAWK POWER CORPORATION

19.2.1 Dunkirk Steam Plant

The Dunkirk steam plant is located on Lake Erie in Chautauqua County, New York, and is operated by Niagara Mohawk Power Corporation. The Dunkirk plant contains four coal-fired boilers with a total name plate generating capacity of 583 MW.

Table 19.2.1-1 presents operational data for the existing equipment at the Dunkirk plant. Coal shipments are received by railroad and transferred to a coal storage and handling area east of the plant. PM emissions are controlled by retrofit ESPs located behind the boilers. Units 1 and 2 have separate roof-mounted chimneys and units 3 and 4 share a common chimney located between the unit 3 and 4 ESPs. The plant operates its own off-site disposal area for dry fly ash.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for all boilers would be located west of the unit 4 ESPs. A low site access/congestion factor was assigned to this location because of the space availabile beside unit 4. In addition, the general facilities factor was low (5 percent). The duct length requirements for units 1 and 2 would be greater than 700 feet. A duct length of 400 feet would be required for both units 3 and 4. Since units 1 and 2 have roof-mounted chimneys, access to them would be difficult. Therefore, a new chimney would be built beside the absorbers. Access to units 1 and 2 is difficult because of the congestion created by the unit 3 and 4 ESPs and the lake; therefore, a high site access/congestion factor was assigned to units 1 and 2 flue gas handling. The access to the chimney for units 3 and 4 is somewhat difficult; hence, these units were assigned a medium site access/congestion factor for flue gas handling.

LSD with reuse of the existing ESPs was not considered here because the boilers are equipped with hot side ESPs which cannot be reused for LSD application. Therefore, LSD with a new baghouse was considered for units 1 through 4. LSD absorbers would be placed in a location similar to the L/LS-FGD case with similar general facility factors, site access/congestion

TABLE 19.2.1-1. DUNKIRK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3,4
GENERATING CAPACITY (MW-each)	90	195,185
CAPACITY FACTOR (PERCENT)*	88,86	83,90
INSTALLATION DATE	1950	1959,60
FIRING TYPE	TANGENTIAL	
FURNACE VOLUME (1000 CU FT)	NA	104
LOW NOx COMBUSTION	NO	NO
COAL SULFUR CONTENT (PERCENT)	2.1	
COAL HEATING VALUE (BTU/LB)	12800	
COAL ASH CONTENT (PERCENT)	9.0	
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	OFF SITE LANDFILL	
STACK NUMBER	1,2	3
COAL DELIVERY METHODS	RAILROAD/TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1973,72	1972
EMISSION (LB/MM BTU)	0.03,0.08	0.14,0.03
REMOVAL EFFICIENCY	99.4,98.7	97.6,99.4
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.2	2.2
SURFACE AREA (1000 SQ FT)	223.4	446.9
GAS EXIT RATE (1000 ACFM)	715	1350
SCA (SQ FT/1000 ACFM)	304	322
OUTLET TEMPERATURE (°F)	600	600

* 1989 Projected.

factors and duct length. Baghouses would be located behind the absorbers with a low site access/congestion factor assigned to them.

Tables 19.2.1-2 through 19.2.1-4 present the retrofit factor inputs to the IAPCS model and the estimated cost for the installation of L/LS-FGD and LSD at the Dunkirk plant.

Coal Switching and Physical Coal Cleaning Costs--

Table 19.2.1-5 presents the IAPCS cost results for CS at the Dunkirk plant. These costs do not include pulverizer and boiler operating cost changes or any system modifications that may be necessary to the coal handling system. Since the Dunkirk plant is not a mine mouth plant, PCC was not considered.

NO_x Control Technologies--

OFA was considered for NO_x emissions control for the four tangential-fired, dry bottom boilers at the Dunkirk plant. Tables 19.2.1-6 and 19.2.1-7 summarize the NO_x performance estimates and costs for installing OFA at the Dunkirk plant.

Selective Catalytic Reduction--

Hot side SCR reactors for units 1-4 would be located adjacent to their respective ESPs. The site access/congestion factor for all locations would be low. Ductwork requirements for all units would be 300 feet. Medium to low general facility factors were assigned to all units. Tables 19.2.1-6 and 19.2.1-7 present the retrofit factors and costs for installation of SCR at the Dunkirk plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies were not considered for any of the units at the Dunkirk plant because ESPs are hot side and cannot be reused for sorbent injection technologies.

TABLE 19.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR DUNKIRK UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			NA
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	630	0	630
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.53	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.54
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 19.2.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR DUNKIRK UNIT 3 OR 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.35	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.31
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

Table 19.2.1-4. Summary of FGD Control Costs for the Dunkirk Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.53	90	88	2.1	44.4	493.7	20.9	30.2	90.0	9822	2130.9
L/S FGD	2	1.53	90	86	2.1	44.4	493.7	20.8	30.7	90.0	9599	2169.4
L/S FGD	3	1.35	195	83	2.1	57.5	295.1	28.8	20.3	90.0	20072	1432.6
L/S FGD	4	1.35	185	90	2.1	56.2	303.7	28.6	19.6	90.0	20649	1386.3
L/S FGD	1-2	1.53	180	87	2.1	62.0	344.6	30.1	22.0	90.0	19421	1551.6
L/S FGD	3-4	1.35	380	86	2.1	85.9	225.9	45.1	15.8	90.0	40529	1113.4
L/S FGD-C	1	1.53	90	88	2.1	44.4	493.7	12.2	17.6	90.0	9822	1241.1
L/S FGD-C	2	1.53	90	86	2.1	44.4	493.7	12.1	17.9	90.0	9599	1263.7
L/S FGD-C	3	1.35	195	83	2.1	57.5	295.1	16.7	11.8	90.0	20072	833.7
L/S FGD-C	4	1.35	185	90	2.1	56.2	303.7	16.7	11.4	90.0	20649	806.5
L/S FGD-C	1-2	1.53	180	87	2.1	62.0	344.6	17.5	12.8	90.0	19421	903.3
L/S FGD-C	3-4	1.35	380	86	2.1	85.9	225.9	26.2	9.2	90.0	40529	647.4
LC FGD	1-4	1.41	560	73	2.1	93.2	166.3	50.7	14.2	90.0	50699	1000.7
LC FGD-C	1-4	1.41	560	73	2.1	93.2	166.3	29.5	8.2	90.0	50699	581.6
LSD+FF	1	1.54	90	88	2.1	32.0	355.2	14.2	20.4	87.0	9441	1500.5
LSD+FF	2	1.54	90	86	2.1	32.0	355.2	14.1	20.8	87.0	9227	1527.8
LSD+FF	3	1.31	195	83	2.1	55.7	285.7	23.5	16.6	87.0	19294	1217.0
LSD+FF	4	1.31	185	90	2.1	53.4	288.9	23.1	15.8	87.0	19848	1162.3
LSD+FF-C	1	1.54	90	88	2.1	32.0	355.2	8.3	11.9	87.0	9441	874.9
LSD+FF-C	2	1.54	90	86	2.1	32.0	355.2	8.2	12.1	87.0	9227	890.9
LSD+FF-C	3	1.31	195	83	2.1	55.7	285.7	13.7	9.7	87.0	19294	710.2
LSD+FF-C	4	1.31	185	90	2.1	53.4	288.9	13.5	9.2	87.0	19848	678.0

Table 19.2.1-5. Summary of Coal Switching/Cleaning Costs for the Dunkirk Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	90	88	2.1	3.9	43.3	10.5	15.1	54.0	5905	1769.9
CS/B+$15	2	1.00	90	86	2.1	3.9	43.3	10.2	15.1	54.0	5771	1773.7
CS/B+$15	3	1.00	195	83	2.1	7.1	36.6	20.5	14.5	54.0	12068	1700.1
CS/B+$15	4	1.00	185	90	2.1	6.8	36.9	21.0	14.4	54.0	12415	1693.1
CS/B+$15-C	1	1.00	90	88	2.1	3.9	43.3	6.0	8.7	54.0	5905	1017.0
CS/B+$15-C	2	1.00	90	86	2.1	3.9	43.3	5.9	8.7	54.0	5771	1019.2
CS/B+$15-C	3	1.00	195	83	2.1	7.1	36.6	11.8	8.3	54.0	12068	976.7
CS/B+$15-C	4	1.00	185	90	2.1	6.8	36.9	12.1	8.3	54.0	12415	972.5
CS/B+$5	1	1.00	90	88	2.1	3.0	33.0	4.6	6.6	54.0	5905	771.9
CS/B+$5	2	1.00	90	86	2.1	3.0	33.0	4.5	6.6	54.0	5771	775.0
CS/B+$5	3	1.00	195	83	2.1	5.1	26.2	8.5	6.0	54.0	12068	700.4
CS/B+$5	4	1.00	185	90	2.1	4.9	26.6	8.6	5.9	54.0	12415	695.7
CS/B+$5-C	1	1.00	90	88	2.1	3.0	33.0	2.6	3.8	54.0	5905	444.5
CS/B+$5-C	2	1.00	90	86	2.1	3.0	33.0	2.6	3.8	54.0	5771	446.3
CS/B+$5-C	3	1.00	195	83	2.1	5.1	26.2	4.9	3.4	54.0	12068	403.2
CS/B+$5-C	4	1.00	185	90	2.1	4.9	26.6	5.0	3.4	54.0	12415	400.4

TABLE 19.2.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR DUNKIRK

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1,2	3	4	3-4
FIRING TYPE	TANG	TANG	TANG	NA
TYPE OF NOx CONTROL	OFA	OFA	OFA	NA
FURNACE VOLUME (1000 CU FT)	NA	104	104	NA
BOILER INSTALLATION DATE	1950	1959	1960	NA
SLAGGING PROBLEM	NO	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	25	25	NA
SCR RETROFIT RESULTS				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	LOW	LOW
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	0	0	0	0
Ductwork Demolition (1000$)	25	45	43	74
New Duct Length (Feet)	300	300	300	300
New Duct Costs (1000$)	1398	2197	2130	3246
New Heat Exchanger (1000$)	0	0	0	0
TOTAL SCOPE ADDER COSTS (1000$)	1422	2242	2173	3320
RETROFIT FACTOR FOR SCR	1.16	1.16	1.16	1.16
GENERAL FACILITIES (PERCENT)	20	13	13	13

Table 19.2.1-7. NOx Control Cost Results for the Dunkirk Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	90	88	2.1	0.6	6.6	0.1	0.2	25.0	500	259.9
LNC-OFA	2	1.00	90	86	2.1	0.6	6.6	0.1	0.2	25.0	488	266.0
LNC-OFA	3	1.00	195	83	2.1	0.8	4.1	0.2	0.1	25.0	1021	173.5
LNC-OFA	4	1.00	185	90	2.1	0.8	4.3	0.2	0.1	25.0	1051	165.1
LNC-OFA-C	1	1.00	90	88	2.1	0.6	6.6	0.1	0.1	25.0	500	154.3
LNC-OFA-C	2	1.00	90	86	2.1	0.6	6.6	0.1	0.1	25.0	488	157.9
LNC-OFA-C	3	1.00	195	83	2.1	0.8	4.1	0.1	0.1	25.0	1021	102.9
LNC-OFA-C	4	1.00	185	90	2.1	0.8	4.3	0.1	0.1	25.0	1051	97.9
SCR-3	1	1.16	90	88	2.1	16.9	188.1	5.9	8.5	80.0	1599	3677.5
SCR-3	2	1.16	90	86	2.1	16.9	188.1	5.9	8.7	80.0	1563	3755.9
SCR-3	3	1.16	195	83	2.1	28.8	147.8	10.5	7.4	80.0	3268	3204.6
SCR-3	4	1.16	185	90	2.1	27.6	149.3	10.1	6.9	80.0	3362	3002.3
SCR-3	3-4	1.16	380	86	2.1	46.8	123.1	18.0	6.3	80.0	6599	2730.3
SCR-3-C	1	1.16	90	88	2.1	16.9	188.1	3.4	5.0	80.0	1599	2154.4
SCR-3-C	2	1.16	90	86	2.1	16.9	188.1	3.4	5.1	80.0	1563	2200.4
SCR-3-C	3	1.16	195	83	2.1	28.8	147.8	6.1	4.3	80.0	3268	1875.5
SCR-3-C	4	1.16	185	90	2.1	27.6	149.3	5.9	4.1	80.0	3362	1757.0
SCR-3-C	3-4	1.16	380	86	2.1	46.8	123.1	10.5	3.7	80.0	6599	1596.1
SCR-7	1	1.16	90	88	2.1	16.9	188.1	5.1	7.4	80.0	1599	3219.3
SCR-7	2	1.16	90	86	2.1	16.9	188.1	5.1	7.6	80.0	1563	3287.1
SCR-7	3	1.16	195	83	2.1	28.8	147.8	8.9	6.3	80.0	3268	2719.0
SCR-7	4	1.16	185	90	2.1	27.6	149.3	8.6	5.9	80.0	3362	2554.5
SCR-7	3-4	1.16	380	86	2.1	46.8	123.1	14.9	5.2	80.0	6599	2261.6
SCR-7-C	1	1.16	90	88	2.1	16.9	188.1	3.0	4.4	80.0	1599	1891.9
SCR-7-C	2	1.16	90	86	2.1	16.9	188.1	3.0	4.5	80.0	1563	1931.8
SCR-7-C	3	1.16	195	83	2.1	28.8	147.8	5.2	3.7	80.0	3268	1597.3
SCR-7-C	4	1.16	185	90	2.1	27.6	149.3	5.0	3.5	80.0	3362	1500.4
SCR-7-C	3-4	1.16	380	86	2.1	46.8	123.1	8.8	3.1	80.0	6599	1327.5

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

All four boilers at the Dunkirk plant would be considered good candidates for retrofit or repowering technologies because of their small boiler size and possibly short remaining useful life.

19.2.2 C. R. Huntley Steam Plant

The C. R. Huntley steam plant is located within Erie County, northwest of Buffalo, New York, and is part of the Niagara Mohawk Power Company. The plant has six coal-fired boilers with a total nameplate generating capacity of 715 MW. The plant is located east of the East Niagara River which marks the boundary between the United States and Canada.

Table 19.2.2-1 presents the operational data for the Huntley plant. All six boilers burn medium sulfur coal. Coal shipments are received by railroad and conveyed to a coal storage and handling area beside the East Niagara River. The coal is crushed and conveyed to the first boilerhouse, containing units 67 and 68, along the southeast side of unit 68; and then to the second boilerhouse, containing units 63-66, along the southeast side of unit 63.

PM emissions for all six boilers are controlled with retrofit ESPs. The ESPs are located behind each boiler away from the river. (the boilerhouses are situated between the ESPs and the river). Units 67-68 are served by a common chimney centered behind the units. Units 63-66 are served by another chimney located to the north and on the side of the boilerhouse away from the ESPs.

The plant has a dry ash handling system. Waste ash is disposed of in an off-site landfill because of limited space surrounding the plant. Also, a small portion of the dry fly ash is sold.

Lime/Limestone and Lime Spray Drying FGD Costs--

The absorbers for units 67-68 would be placed directly behind their respective ESPs and close to the common chimney. The absorbers for units 63-66 would be placed behind their respective ESPs and adjacent to the common chimney located to the side of unit 66. The lime/limestone preparation, storage, and waste handling area was assumed to be located

TABLE 19.2.2-1. HUNTLEY STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2,3,4 (63-66)		5,6 (67-68)
GENERATING CAPACITY (MW-each)	85		185,190
CAPACITY FACTOR (PERCENT)*	67,68,75,79		80,81
INSTALLATION DATE	1942,48,53,54		1957,58
FIRING TYPE	ARCH		TANGENTIAL
FURNACE VOLUME (1000 CU FT)	NA		104,104
LOW NOx COMBUSTION	NO		NO
COAL SULFUR CONTENT (PERCENT)	1.8		1.8
COAL HEATING VALUE (BTU/LB)	12,800		12,800
COAL ASH CONTENT (PERCENT)	8.0		8.0
FLY ASH SYSTEM		DRY DISPOSAL/SELL	
ASH DISPOSAL METHOD		OFF-SITE LANDFILL	
STACK NUMBER	1		2
COAL DELIVERY METHODS		RAILROAD	
PARTICULATE CONTROL			
TYPE	ESP		ESP
INSTALLATION DATE	1973		1973
EMISSION (LB/MM BTU)	0.02,0.02,0.07,0.13		0.15,0.09
REMOVAL EFFICIENCY	99.5,99.2,98.4,96.2		98.2,98.6
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	1.7		1.7
SURFACE AREA (1000 SQ FT)	NA		NA
GAS EXIT RATE (1000 ACFM)	500		1352
SCA (SQ FT/1000 ACFM)	246		312
OUTLET TEMPERATURE (°F)	310		650

* Average forecasted capacity factors over next 15 years (1990-2004).

close to the coal unloading facility south of the plant. Because there is limited space available for FGD waste, it would be dewatered and sent off-site. For units 67-68, a paved road and storage building would need to be relocated, therefore, a factor of 10 percent was assigned for general facilities. For units 63-66, however, no major demolition/relocation of existing equipment/buildings would be required and a base factor of 5 percent was assumed.

The FGD system absorber for units 67-68 would be located in a low site access/congestion area after the demolition/relocation of the storage building and road. For units 63-66, a low access/congestion factor was also assigned to the absorbers.

Flue gas handling for units 67-68 would require about 300 feet of ducting. A high access/congestion factor was applied to units 67-68 because the common chimney is surrounded by the retrofit ESPs and it is difficult to access on either side. Flue gas handling for units 63-66 would require approximately 500 feet of ducting, since the absorbers would be located behind the ESPs and the ducting must reach from the common chimney to the absorbers and then back again. Because the common chimney for units 63-66 is located beside the boilerhouse and the main access road to the switchyard, a medium site access/congestion factor was assigned to flue gas handling.

For LSD, reuse of the ESPs was not considered for units 67-68 because the units are equipped with hot side ESPs. Therefore, a new baghouse was considered. LSD absorbers and new FFs would be located in a similar location to L/LS-FGD absorbers. For flue gas handling, units 67-68 would require 300-500 feet of ducting with high site access/congestion. Reuse of ESPs was not considered for units 63-66 because the building that houses the ESPs would require major demolition in order to access the ESPs. For this reason, new FFs were chosen for these units. The FFs would be positioned close to their respective absorbers and have low site access/congestion factors. A medium factor was assigned to flue gas handling.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 19.2.2-2 and 19.2.2-3. Table 19.2.2-4 presents the process area retrofit factors and capital and operating costs for commercial FGD technologies. These costs do not include

TABLE 19.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR C.R. HUNTLEY UNITS 1-4 (63-66, EACH)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			MEDIUM
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.35	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.36
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	5	0	5

TABLE 19.2.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR C.R. HUNTLEY UNITS 5 OR 6 (67-68)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.39	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.36
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

Table 19.2.2-4. Summary of FGD Control Costs for the Huntley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.35	85	67	1.8	37.3	439.4	17.3	34.8	90.0	6055	2865.6
L/S FGD	2	1.35	85	68	1.8	37.3	439.4	17.4	34.4	90.0	6145	2832.1
L/S FGD	3	1.35	85	75	1.8	37.4	439.5	17.8	31.8	90.0	6778	2622.0
L/S FGD	4	1.35	85	79	1.8	37.4	439.5	18.0	30.6	90.0	7139	2518.5
L/S FGD	5	1.39	185	80	1.8	59.5	321.5	28.4	21.9	90.0	15732	1804.4
L/S FGD	6	1.39	190	81	1.8	60.2	317.0	28.9	21.4	90.0	16359	1766.4
L/S FGD	1-4	1.35	340	72	1.8	77.1	226.7	38.8	18.1	90.0	26026	1490.2
L/S FGD	5-6	1.39	375	81	1.8	89.7	239.2	44.5	16.7	90.0	32288	1379.6
L/S FGD-C	1	1.35	85	67	1.8	37.3	439.4	10.1	20.3	90.0	6055	1669.4
L/S FGD-C	2	1.35	85	68	1.8	37.3	439.4	10.1	20.0	90.0	6145	1649.9
L/S FGD-C	3	1.35	85	75	1.8	37.4	439.5	10.3	18.5	90.0	6778	1527.0
L/S FGD-C	4	1.35	85	79	1.8	37.4	439.5	10.5	17.8	90.0	7139	1466.4
L/S FGD-C	5	1.39	185	80	1.8	59.5	321.5	16.5	12.8	90.0	15732	1050.7
L/S FGD-C	6	1.39	190	81	1.8	60.2	317.0	16.8	12.5	90.0	16359	1028.6
L/S FGD-C	1-4	1.35	340	72	1.8	77.1	226.7	22.6	10.5	90.0	26026	867.1
L/S FGD-C	5-6	1.39	375	81	1.8	89.7	239.2	25.9	9.7	90.0	32288	802.9
LC FGD	1-6	1.37	715	76	1.8	105.5	147.6	59.6	12.5	90.0	57010	1044.7
LC FGD-C	1-6	1.37	715	76	1.8	105.5	147.6	34.6	7.3	90.0	57010	606.8
LSD+FF	1	1.36	85	67	1.8	23.0	271.1	10.5	21.0	87.0	5819	1804.3
LSD+FF	2	1.36	85	68	1.8	23.0	271.1	10.5	20.8	87.0	5906	1782.2
LSD+FF	3	1.36	85	75	1.8	23.0	271.1	10.7	19.2	87.0	6514	1643.7
LSD+FF	4	1.36	85	79	1.8	23.0	271.1	10.8	18.4	87.0	6861	1575.8
LSD+FF	5	1.36	185	80	1.8	56.5	305.3	22.7	17.5	87.0	15123	1502.6
LSD+FF	6	1.36	190	81	1.8	57.7	303.9	23.3	17.3	87.0	15726	1479.1
LSD+FF-C	1	1.36	85	67	1.8	23.0	271.1	6.1	12.3	87.0	5819	1051.5
LSD+FF-C	2	1.36	85	68	1.8	23.0	271.1	6.1	12.1	87.0	5906	1038.6
LSD+FF-C	3	1.36	85	75	1.8	23.0	271.1	6.2	11.2	87.0	6514	957.6
LSD+FF-C	4	1.36	85	79	1.8	23.0	271.1	6.3	10.7	87.0	6861	917.9
LSD+FF-C	5	1.36	185	80	1.8	56.5	305.3	13.3	10.2	87.0	15123	877.6
LSD+FF-C	6	1.36	190	81	1.8	57.7	303.9	13.6	10.1	87.0	15726	863.9

downtime needs in the case of LSD-FGD. The low cost FGD option shows the effect of no spare absorber modules and economy of scale when combining FGD systems and increased absorber size.

Coal Switching and Physical Coal Cleaning Costs--

Table 19.2.2-5 presents the IAPCS cost results for CS at the Huntley plant. These costs do not include boiler and pulverizer operating cost changes or any system modifications that may be necessary to blend coal. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Units 63-66 are wet bottom, arch-fired boilers rated at 85 MW each and units 67-68 are dry bottom, tangential-fired boilers. The combustion modification technique applied to units 67-68 was OFA. LNC was not considered for units 63-66. Table 19.2.2-6 shows the estimated OFA NO_x reduction performances based on the volumetric heat release rate. Table 19.2.2-7 presents the cost of retrofitting OFA at the Huntley plant.

Selective Catalytic Reduction--

SCR reactors for all units would be located in a similar layout as the FGD absorbers with all six reactors located in low site access/ congestion areas. Units 67-68 are hot-side SCR and units 63-66 are cold side SCR. The ammonia storage system was placed in the same manner as the lime/limestone preparation, storage, and handling areas. Duct lengths of 300 and 500 feet were estimated for units 67-68 and 63-66, respectively. A paved road and a storage building behind units 67-68 would have to be relocated and a factor of 20 percent was assigned to the general facilities. For units 63-66, a base factor of 13 percent was assigned to general facilities because no major relocation is required. Table 19.2.2-7 presents the estimated cost of retrofitting SCR at the Huntley plant.

Duct Spray Drying and Furnace Sorbent Injection--

FSI and DSD technologies were not considered for units 67-68 because of their hot-side ESPs. The sorbent injection technologies were not considered

Table 19.2.2-5. Summary of Coal Switching/Cleaning Costs for the Huntley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	85	67	1.8	3.8	44.6	7.8	15.6	46.0	3125	2496.1
CS/B+$15	2	1.00	85	68	1.8	3.8	44.6	7.9	15.6	46.0	3172	2491.9
CS/B+$15	3	1.00	85	75	1.8	3.8	44.6	8.6	15.4	46.0	3498	2464.7
CS/B+$15	4	1.00	85	79	1.8	3.8	44.6	9.0	15.4	46.0	3685	2451.4
CS/B+$15	5	1.00	185	80	1.8	6.9	37.4	19.0	14.6	46.0	8121	2335.5
CS/B+$15	6	1.00	190	81	1.8	7.1	37.2	19.7	14.6	46.0	8445	2330.2
CS/B+$15-C	1	1.00	85	67	1.8	3.8	44.6	4.5	9.0	46.0	3125	1435.5
CS/B+$15-C	2	1.00	85	68	1.8	3.8	44.6	4.5	9.0	46.0	3172	1433.1
CS/B+$15-C	3	1.00	85	75	1.8	3.8	44.6	5.0	8.9	46.0	3498	1417.0
CS/B+$15-C	4	1.00	85	79	1.8	3.8	44.6	5.2	8.8	46.0	3685	1409.1
CS/B+$15-C	5	1.00	185	80	1.8	6.9	37.4	10.9	8.4	46.0	8121	1341.9
CS/B+$15-C	6	1.00	190	81	1.8	7.1	37.2	11.3	8.4	46.0	8445	1338.8
CS/B+$5	1	1.00	85	67	1.8	2.9	34.3	3.5	7.1	46.0	3125	1128.2
CS/B+$5	2	1.00	85	68	1.8	2.9	34.3	3.6	7.0	46.0	3172	1124.7
CS/B+$5	3	1.00	85	75	1.8	2.9	34.3	3.9	6.9	46.0	3498	1102.1
CS/B+$5	4	1.00	85	79	1.8	2.9	34.3	4.0	6.8	46.0	3685	1091.0
CS/B+$5	5	1.00	185	80	1.8	5.0	27.0	7.9	6.1	46.0	8121	975.6
CS/B+$5	6	1.00	190	81	1.8	5.1	26.8	8.2	6.1	46.0	8445	970.8
CS/B+$5-C	1	1.00	85	67	1.8	2.9	34.3	2.0	4.1	46.0	3125	650.6
CS/B+$5-C	2	1.00	85	68	1.8	2.9	34.3	2.1	4.1	46.0	3172	648.5
CS/B+$5-C	3	1.00	85	75	1.8	2.9	34.3	2.2	4.0	46.0	3498	635.1
CS/B+$5-C	4	1.00	85	79	1.8	2.9	34.3	2.3	3.9	46.0	3685	628.6
CS/B+$5-C	5	1.00	185	80	1.8	5.0	27.0	4.6	3.5	46.0	8121	561.7
CS/B+$5-C	6	1.00	190	81	1.8	5.1	26.8	4.7	3.5	46.0	8445	558.9

TABLE 19.2.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR C.R. HUNTLEY

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2,3,4(63-66)	5,6,(67-68)
FIRING TYPE	ARCH	TANG
TYPE OF NOx CONTROL	NA	OFA
FURNACE VOLUME (1000 CU FT)	40.3	104
BOILER INSTALLATION DATE	1942-54	1957,58
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	NA	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	24	44
New Duct Length (Feet)	500	300
New Duct Costs (1000$)	2253	2164
New Heat Exchanger (1000$)	1691	0
TOTAL SCOPE ADDER COSTS (1000$)		
COMBINED	9021	3294
INDIVIDUAL	3967	2208
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	20

Table 19.2.2-7. NOx Control Cost Results for the Huntley Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	5	1.00	185	80	1.8	0.8	4.3	0.2	0.1	25.0	934	185.8
LNC-OFA	6	1.00	190	81	1.8	0.8	4.2	0.2	0.1	25.0	971	180.3
LNC-OFA-C	5	1.00	185	80	1.8	0.8	4.3	0.1	0.1	25.0	934	110.2
LNC-OFA-C	6	1.00	190	81	1.8	0.8	4.2	0.1	0.1	25.0	971	107.0
SCR-3	1	1.16	85	67	1.8	18.0	212.1	5.8	11.7	80.0	1610	3621.6
SCR-3	2	1.16	85	68	1.8	18.0	212.1	5.8	11.5	80.0	1634	3572.0
SCR-3	3	1.16	85	75	1.8	18.0	212.1	5.9	10.5	80.0	1802	3260.4
SCR-3	4	1.16	85	79	1.8	18.0	212.1	5.9	10.0	80.0	1898	3107.4
SCR-3	5	1.16	185	80	1.8	28.5	154.1	10.2	7.9	80.0	2989	3415.4
SCR-3	6	1.16	190	81	1.8	28.9	152.3	10.4	7.7	80.0	3108	3348.6
SCR-3	1-4	1.16	340	72	1.8	48.9	143.9	17.4	8.1	80.0	6920	2513.4
SCR-3	5-6	1.16	375	81	1.8	47.6	126.9	18.0	6.8	80.0	6134	2940.1
SCR-3-C	1	1.16	85	67	1.8	18.0	212.1	3.4	6.9	80.0	1610	2125.2
SCR-3-C	2	1.16	85	68	1.8	18.0	212.1	3.4	6.8	80.0	1634	2096.0
SCR-3-C	3	1.16	85	75	1.8	18.0	212.1	3.4	6.2	80.0	1802	1912.8
SCR-3-C	4	1.16	85	79	1.8	18.0	212.1	3.5	5.9	80.0	1898	1822.9
SCR-3-C	5	1.16	185	80	1.8	28.5	154.1	6.0	4.6	80.0	2989	1999.6
SCR-3-C	6	1.16	190	81	1.8	28.9	152.3	6.1	4.5	80.0	3108	1960.2
SCR-3-C	1-4	1.16	340	72	1.8	48.9	143.9	10.2	4.7	80.0	6920	1471.7
SCR-3-C	5-6	1.16	375	81	1.8	47.6	126.9	10.5	4.0	80.0	6134	1719.3
SCR-7	1	1.16	85	67	1.8	18.0	212.1	5.1	10.3	80.0	1610	3191.9
SCR-7	2	1.16	85	68	1.8	18.0	212.1	5.1	10.2	80.0	1634	3148.6
SCR-7	3	1.16	85	75	1.8	18.0	212.1	5.2	9.3	80.0	1802	2876.4
SCR-7	4	1.16	85	79	1.8	18.0	212.1	5.2	8.9	80.0	1898	2743.0
SCR-7	5	1.16	185	80	1.8	28.5	154.1	8.7	6.7	80.0	2989	2911.6
SCR-7	6	1.16	190	81	1.8	28.9	152.3	8.9	6.6	80.0	3108	2850.9
SCR-7	1-4	1.16	340	72	1.8	48.9	143.8	14.4	6.7	80.0	4943	2912.4
SCR-7	5-6	1.16	375	81	1.8	47.6	126.9	15.0	5.6	80.0	6134	2442.5
SCR-7-C	1	1.16	85	67	1.8	18.0	212.1	3.0	6.1	80.0	1610	1878.9
SCR-7-C	2	1.16	85	68	1.8	18.0	212.1	3.0	6.0	80.0	1634	1853.4
SCR-7-C	3	1.16	85	75	1.8	18.0	212.1	3.1	5.5	80.0	1802	1692.9
SCR-7-C	4	1.16	85	79	1.8	18.0	212.1	3.1	5.2	80.0	1898	1614.1
SCR-7-C	5	1.16	185	80	1.8	28.5	154.1	5.1	3.9	80.0	2989	1710.9
SCR-7-C	6	1.16	190	81	1.8	28.9	152.3	5.2	3.9	80.0	3108	1675.1
SCR-7-C	1-4	1.16	340	72	1.8	48.9	143.8	8.5	3.9	80.0	4943	1713.0
SCR-7-C	5-6	1.16	375	81	1.8	47.6	126.9	8.8	3.3	80.0	6134	1434.2

for units 63-66 because of the short duct residence time and the enclosed ESPs which made access to them very difficult.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Huntley plant. All units would be considered good candidates for repowering and retrofit because of their small boiler sizes.

19.3 ROCHESTER GAS & ELECTRIC

19.3.1 Rochester 7 Russell

LSD with reuse of the existing ESPs was not considered for the Rochester 7 Russell plant due to the inadequate size of the ESPs. LSD with a new baghouse was also not considered since the boilers fire a high sulfur coal. Sorbent injection technologies were not evaluated since the ESPs cannot be reused.

TABLE 19.3.1-1. ROCHESTER 7 RUSSELL STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1	2	3	4
GENERATING CAPACITY (MW-each)	46	63	63	82
CAPACITY FACTOR (PERCENT)	21	45	41	53
INSTALLATION DATE	1948	1950	1953	1957
FIRING TYPE		TANGENTIAL		
FURNACE VOLUME (1000 CU FT)	NA	NA	30.4	54.1
LOW NOx COMBUSTION		NO		
COAL SULFUR CONTENT (PERCENT)		2.3		
COAL HEATING VALUE (BTU/LB)		13100		
COAL ASH CONTENT (PERCENT)		8.0		
FLY ASH SYSTEM		DRY DISPOSAL		
ASH DISPOSAL METHOD		SELL/OFF-SITE		
STACK NUMBER	1	1	2	2
COAL DELIVERY METHODS		RAILROAD		
PARTICULATE CONTROL				
TYPE	ESP	ESP	ESP	ESP
INSTALLATION DATE	1948	1950	1953	1957
EMISSION (LB/MM BTU)	0.12	NA	0.23	NA
REMOVAL EFFICIENCY	98.2	NA	96.5	97.6
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	2.4	2.4	2.4	2.4
SURFACE AREA (1000 SQ FT)	27.7	29.8	29.8	34
GAS EXIT RATE (1000 ACFM)	200	230	230	251
SCA (SQ FT/1000 ACFM)	139	130	130	136
OUTLET TEMPERATURE (°F)	300	298	298	280

TABLE 19.3.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR ROCHESTER 7 RUSSELL UNIT 1 OR 2 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	322,441	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.55	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	0

* The L/LS-FGD absorbers for units 1 and 2 would be located east of the unit 1 and 2 chimney, behind the fuel storage area.

TABLE 19.3.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR ROCHESTER 7 RUSSELL UNIT 3 OR 4 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	NA
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NA
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	NA
ESTIMATED COST (1000$)	441,574	0	0
OTHER	NO		
RETROFIT FACTORS			
FGD SYSTEM	1.55	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	0	0

* The L/LS-FGD absorbers for units 3 and 4 would be located east of the unit 3 and 4 chimney, behind the fuel storage area.

Table 19.3.1-4. Summary of FGD Control Costs for the Rochester 7 Russell Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.55	46	21	2.3	31.6	686.7	12.5	148.1	90.0	1278	9806.0
L/S FGD	2	1.55	63	45	2.3	36.6	580.8	15.5	62.6	90.0	3750	4146.3
L/S FGD	3	1.55	63	41	2.3	36.6	580.8	15.4	67.9	90.0	3417	4496.3
L/S FGD	4	1.55	82	53	2.3	43.1	525.5	18.6	48.9	90.0	5749	3235.6
L/S FGD	1-2	1.55	109	35	2.3	47.6	436.4	19.5	58.4	90.0	5047	3866.0
L/S FGD	3-4	1.55	145	48	2.3	55.9	385.4	24.0	39.4	90.0	9207	2608.6
L/S FGD-C	1	1.55	46	21	2.3	31.6	686.7	7.3	86.5	90.0	1278	5729.0
L/S FGD-C	2	1.55	63	45	2.3	36.6	580.8	9.1	36.5	90.0	3750	2419.3
L/S FGD-C	3	1.55	63	41	2.3	36.6	580.8	9.0	39.6	90.0	3417	2624.1
L/S FGD-C	4	1.55	82	53	2.3	43.1	525.5	10.9	28.5	90.0	5749	1887.4
L/S FGD-C	1-2	1.55	109	35	2.3	47.6	436.4	11.4	34.1	90.0	5047	2257.2
L/S FGD-C	3-4	1.55	145	48	2.3	55.9	385.4	14.0	23.0	90.0	9207	1521.8
LC FGD	1-2	1.55	109	35	2.3	34.0	311.9	15.0	44.9	90.0	5047	2976.1
LC FGD	3-4	1.55	145	48	2.3	38.9	268.5	18.4	30.2	90.0	9207	1997.9
LC FGD-C	1-2	1.55	109	35	2.3	34.0	311.9	8.8	26.2	90.0	5047	1735.3
LC FGD-C	3-4	1.55	145	48	2.3	38.9	268.5	10.7	17.6	90.0	9207	1163.6

Table 19.3.1-5. Summary of Coal Switching/Cleaning Costs for the Rochester 7 Russell Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	46	21	2.3	2.8	60.6	1.9	22.9	57.0	809	2395.1
CS/B+$15	2	1.00	63	45	2.3	3.5	55.9	4.4	17.7	57.0	2374	1847.8
CS/B+$15	3	1.00	63	41	2.3	3.5	55.9	4.1	18.0	57.0	2163	1884.0
CS/B+$15	4	1.00	82	53	2.3	4.2	51.7	6.3	16.6	57.0	3639	1738.0
CS/B+$15-C	1	1.00	46	21	2.3	2.8	60.6	1.1	13.3	57.0	809	1387.6
CS/B+$15-C	2	1.00	63	45	2.3	3.5	55.9	2.5	10.2	57.0	2374	1065.3
CS/B+$15-C	3	1.00	63	41	2.3	3.5	55.9	2.4	10.4	57.0	2163	1086.7
CS/B+$15-C	4	1.00	82	53	2.3	4.2	51.7	3.6	9.6	57.0	3639	1001.0
CS/B+$5	1	1.00	46	21	2.3	2.3	50.2	1.2	13.6	57.0	809	1427.4
CS/B+$5	2	1.00	63	45	2.3	2.9	45.5	2.2	8.9	57.0	2374	935.5
CS/B+$5	3	1.00	63	41	2.3	2.9	45.5	2.1	9.2	57.0	2163	966.9
CS/B+$5	4	1.00	82	53	2.3	3.4	41.3	3.0	8.0	57.0	3639	833.0
CS/B+$5-C	1	1.00	46	21	2.3	2.3	50.2	0.7	7.9	57.0	809	830.6
CS/B+$5-C	2	1.00	63	45	2.3	2.9	45.5	1.3	5.2	57.0	2374	541.4
CS/B+$5-C	3	1.00	63	41	2.3	2.9	45.5	1.2	5.4	57.0	2163	559.9
CS/B+$5-C	4	1.00	82	53	2.3	3.4	41.3	1.8	4.6	57.0	3639	481.4

TABLE 19.3.1-6. SUMMARY OF NOx RETROFIT RESULTS FOR ROCHESTER 7 RUSSELL

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
FURNACE VOLUME (1000 CU FT)	NA	NA	30.4
BOILER INSTALLATION DATE	1948	1950	1953
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25	25
SCR RETROFIT RESULTS *			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	15	19	19
New Duct Length (Feet)	400	400	400
New Duct Costs (1000$)	1259	1512	1513
New Heat Exchanger (1000$)	1170	1413	1413
TOTAL SCOPE ADDER COSTS (1000$)	2444	2944	2944
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52
GENERAL FACILITIES (PERCENT)	20	20	20

* Cold side SCR reactors for units 1, 2, and 3 would be located east of the chimneys, behind the feuel storage area.

TABLE 19.3.1-7. SUMMARY OF NOx RETROFIT RESULTS FOR ROCHESTER 7 RUSSELL

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	4	1-2	3-4
FIRING TYPE	TANG	NA	NA
TYPE OF NOx CONTROL	OFA	NA	NA
FURNACE VOLUME (1000 CU FT)	54.1	NA	NA
BOILER INSTALLATION DATE	1957	NA	NA
SLAGGING PROBLEM	NO	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	25	NA	NA
SCR RETROFIT RESULTS *			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	23	29	36
New Duct Length (Feet)	400	400	400
New Duct Costs (1000$)	1765	2084	2463
New Heat Exchanger (1000$)	1655	1963	2329
TOTAL SCOPE ADDER COSTS (1000$)	3443	4076	4828
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52
GENERAL FACILITIES (PERCENT)	20	20	20

* Cold side SCR reactors for unit 4 and the combined cases would be located east of the chimneys, behind the fuel storage area.

Table 19.3.1-8. NOx Control Cost Results for the Rochester 7 Russell Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-OFA	1	1.00	46	21	2.3	0.5	9.9	0.1	1.2	25.0	59	1672.9
LNC-OFA	2	1.00	63	45	2.3	0.5	8.2	0.1	0.5	25.0	174	647.0
LNC-OFA	3	1.00	63	41	2.3	0.5	8.2	0.1	0.5	25.0	159	710.1
LNC-OFA	4	1.00	82	53	2.3	0.6	7.0	0.1	0.3	25.0	267	469.2
LNC-OFA-C	1	1.00	46	21	2.3	0.5	9.9	0.1	0.7	25.0	59	994.0
LNC-OFA-C	2	1.00	63	45	2.3	0.5	8.2	0.1	0.3	25.0	174	384.0
LNC-OFA-C	3	1.00	63	41	2.3	0.5	8.2	0.1	0.3	25.0	159	421.5
LNC-OFA-C	4	1.00	82	53	2.3	0.6	7.0	0.1	0.2	25.0	267	278.2
SCR-3	1	1.52	46	21	2.3	15.2	329.8	4.5	53.0	80.0	190	23594.3
SCR-3	2	1.52	63	45	2.3	17.9	283.9	5.4	21.8	80.0	557	9717.6
SCR-3	3	1.52	63	41	2.3	17.9	283.9	5.4	23.9	80.0	508	10641.0
SCR-3	4	1.52	82	53	2.3	20.6	251.1	6.4	16.7	80.0	855	7445.9
SCR-3	1-2	1.52	109	35	2.3	24.6	225.4	7.6	22.8	80.0	750	10151.1
SCR-3	3-4	1.52	145	48	2.3	29.8	205.3	9.4	15.5	80.0	1369	6903.4
SCR-3-C	1	1.52	46	21	2.3	15.2	329.8	2.6	31.1	80.0	190	13875.7
SCR-3-C	2	1.52	63	45	2.3	17.9	283.9	3.2	12.8	80.0	557	5711.4
SCR-3-C	3	1.52	63	41	2.3	17.9	283.9	3.2	14.0	80.0	508	6254.5
SCR-3-C	4	1.52	82	53	2.3	20.6	251.1	3.7	9.8	80.0	855	4374.1
SCR-3-C	1-2	1.52	109	35	2.3	24.6	225.4	4.5	13.4	80.0	750	5962.7
SCR-3-C	3-4	1.52	145	48	2.3	29.8	205.3	5.5	9.1	80.0	1369	4052.7
SCR-7	1	1.52	46	21	2.3	15.2	329.8	4.1	48.6	80.0	190	21630.6
SCR-7	2	1.52	63	45	2.3	17.9	283.9	4.9	19.8	80.0	557	8800.9
SCR-7	3	1.52	63	41	2.3	17.9	283.9	4.9	21.6	80.0	508	9634.9
SCR-7	4	1.52	82	53	2.3	20.6	251.1	5.7	15.0	80.0	855	6667.6
SCR-7	1-2	1.52	109	35	2.3	24.6	225.4	6.7	20.1	80.0	750	8972.6
SCR-7	3-4	1.52	145	48	2.3	29.8	205.3	8.3	13.6	80.0	1369	6043.9
SCR-7-C	1	1.52	46	21	2.3	15.2	329.8	2.4	28.6	80.0	190	12750.6
SCR-7-C	2	1.52	63	45	2.3	17.9	283.9	2.9	11.6	80.0	557	5186.2
SCR-7-C	3	1.52	63	41	2.3	17.9	283.9	2.9	12.7	80.0	508	5678.0
SCR-7-C	4	1.52	82	53	2.3	20.6	251.1	3.4	8.8	80.0	855	3928.1
SCR-7-C	1-2	1.52	109	35	2.3	24.6	225.4	4.0	11.9	80.0	750	5287.5
SCR-7-C	3-4	1.52	145	48	2.3	29.8	205.3	4.9	8.0	80.0	1369	3560.3

SECTION 20.0 OHIO

20.1 CARDINAL OPERATING COMPANY

20.1.1 Cardinal Steam Plant

The Cardinal steam plant is located within Jefferson County, Ohio, as part of the Cardinal Operating Company system. The plant is located on a long narrow site, bounded by the Ohio River on one side and a railroad and major highway on the other. The plant contains three coal-fired boilers with a total gross generating capacity of 1,880 MW. Figure 20.1.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 20.1.1-1 presents operational data for the existing equipment at the Cardinal plant. The boilers burn low (unit 3) to high (units 1 and 2) sulfur coal (0.7-3.2 percent sulfur). Coal shipments are received by barge and conveyed to a coal storage and handling area located beside the Ohio River.

Particulate matter emissions for the boilers are controlled with ESPs located behind each unit. The plant has a dry fly ash handling system and is disposed to a landfill on-site or sold.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 20.1.1-1 shows the general layout and location of the FGD control system. Units 1 and 2 are located northeast of the coal pile, sitting beside each other parallel to the Ohio River. They are each served by their own chimney. The powerhouse is close to the river and the ESPs/chimneys (Units 1 and 2) are located away from the river on the north side of the powerhouse. Unit 3 is located south of the coal pile and is served by its own chimney. The unit 3 chimney and ESPs are close to the river and powerhouse near the railroad track. There are natural draft cooling towers located south of unit 3. Unit 3 was considered in this study even though it is a 1971 NSPS boiler burning low sulfur coal (1.2 lb per million Btu) and may not require scrubbing. If scrubbing is required, it is more cost effective to switch to

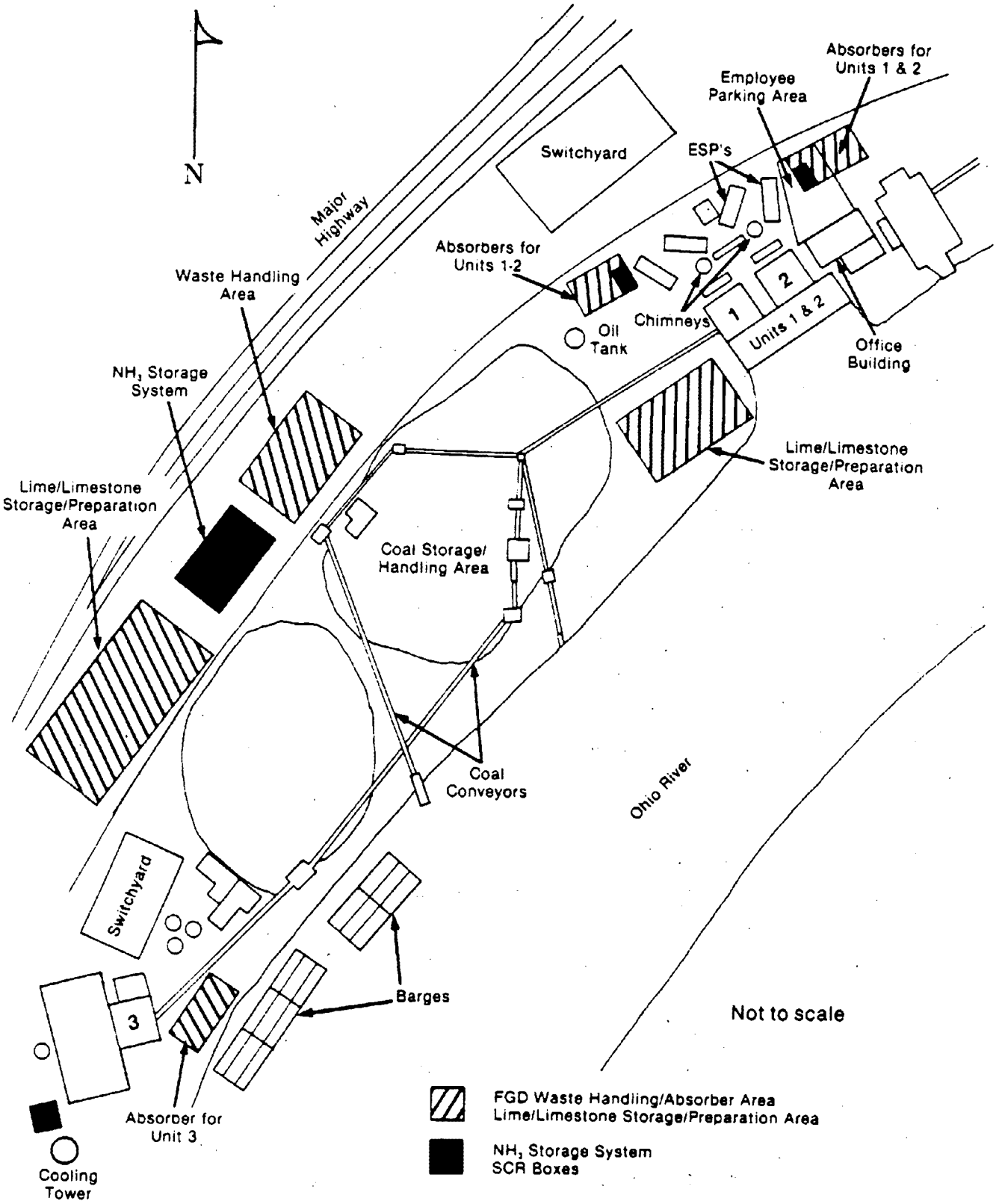


Figure 20.1.1-1. Cardinal plant plot plan

TABLE 20.1.1-1. CARDINAL STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3
GENERATING CAPACITY (MW-each)	615	650
CAPACITY FACTOR (PERCENT)	51, 55	53
INSTALLATION DATE	1966-67	1977
FIRING TYPE	FWF	OWF
COAL SULFUR CONTENT (PERCENT)	3.2, 3.1	0.7
COAL HEATING VALUE (BTU/LB)	11652-775	11235
COAL ASH CONTENT (PERCENT)	12	17.2
FLY ASH SYSTEM	DRY DISPOSAL	
ASH DISPOSAL METHOD	ON-SITE/SALE	
STACK NUMBER	1-2	3
COAL DELIVERY METHODS	BARGE	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1980	1977
EMISSION (LB/MM BTU)	0.04	0.03
REMOVAL EFFICIENCY	99.4	99.8
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	2.0	0.7
SURFACE AREA (1000 SQ FT)	891	1918.1
EXIT GAS FLOW RATE (1000 ACFM)	2100	3900
SCA (SQ FT/1000 ACFM)	424	492
OUTLET TEMPERATURE (°F)	350, 310	310

a higher coal sulfur content, taking into account the fuel cost differential while estimating cost effectiveness. Costs presented in this section for unit 3 are dependent on acid rain legislation and plant Figure 20.1.1-1 decisions regarding the type of coal fired. For units 1 and 2, space is available for the absorbers on either side of the ESP units. The absorbers for L/LS-FGD and LSD-FGD for unit 1 would be located close to the ESPs northeast of the unit in the present employee parking area. The unit 2 absorber would be located southwest of the respective ESPs in an open area between the chimney and coal pile. For unit 3, the absorbers would be located between the river and powerhouse close to the coal conveyor. Part of the plant roads and employee parking area would need to be demolished/ relocated for the unit 2 absorbers; therefore, a factor of 10 percent was assigned to general facilities. A 5 percent general facilities factor was assigned to the unit 1 absorber location since no major relocation would be required. For unit 3, part of the railroad and plant roads would need to be demolished and relocated to make space for the storage/handling area; a 10 percent factor was assigned to general facilities for this location. The lime storage/handling area for units 1 and 2 would be located southeast of unit 1 in an open area between the coal pile and river. The storage/handling area for unit 3 would be a separate location northwest of the unit away from the absorbers and close to the railroad track. The waste handling area for all three units would be located close to the coal pile between the highway and railroad.

Retrofit Difficulty and Scope Adder Costs--

A low site access/congestion factor was assigned to the absorber locations for units 1 and 2 due to the absorbers being located in a relatively open area. The unit 3 location was assigned a high site access/ congestion factor because of its location east of the powerhouse between the coal pile, powerhouse, and Ohio River with very high access difficulty.

For flue gas handling, short duct runs for units 1 and 2 would be required for L/LS-FGD cases since the absorbers would be located adjacent to the ESPs and close to the chimneys. Unit 3 would require moderate duct runs for flue gas handling due to the absorbers being located away from the chimney. A low site access/congestion factor was assigned to the flue gas

handling system for units 1 and 2. A high factor was assigned to unit 3 due to the access difficulty and congestion created by the ESPs and coal conveyor.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 20.1.1-2 through 20.1.1-4. No large scope adder cost is required for the Cardinal plant. The overall retrofit factors determined for the L/LS-FGD cases were low to medium (1.24 for units 1 and 2; 1.61 for unit 3).

The absorbers for LSD-FGD would be located in a similar location as in L/LS-FGD cases. Reused ESPs was the only LSD-FGD technology considered for the units because of the large SCAs (>420). For LSD-FGD flue gas handling cases, short duct runs and a low site access/congestion factor was assigned for units 1 and 2. Unit 3 would require a moderate duct run with a high site access/congestion factor due to the access difficulty to the upstream of the ESPs (because of their location adjacent to the powerhouse). The retrofit factors determined for the LSD technology case for the units were low (1.20-1.62) and did not include particulate control upgrading costs. Separate retrofit factors were developed for upgrading ESPs for the units. A low retrofit factor (1.16) was assigned to the upgraded ESP location for units 1 and 2 due to the available space around the ESPs. The unit 3 location was assigned a medium retrofit factor (1.36) because the ESPs are bounded by the powerhouse, chimney, and river. These factors were used in the IAPCS model to estimate particulate control upgrading costs.

Table 20.1.1-5 presents the cost estimates for L/LS-FGD and LSD-FGD cases for units 1 and 2. Costs are not presented for unit 3, because this unit is burning a low sulfur coal resulting in a very high unit cost. The LSD-FGD costs include upgrading the ESPs for boilers 1-2. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer

TABLE 20.1.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR CARDINAL UNIT 1

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.24	1.24	
ESP REUSE CASE			1.20
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 20.1.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR CARDINAL UNIT 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.24	1.24	
ESP REUSE CASE			1.20
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 20.1.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR CARDINAL UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.61	1.64	
ESP REUSE CASE			1.62
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

Table 20.1.1-5. Summary of FGD Control Costs for the Cardinal Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kWh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1-2	1.24	1230	53	3.2	167.0	135.8	101.0	17.7	90.0	137239	735.9
LC FGD-C	1-2	1.24	1230	53	3.2	167.0	135.8	58.6	10.3	90.0	137239	427.1
LFGD	1	1.24	615	51	3.2	113.6	184.7	60.4	22.0	90.0	66029	914.4
LFGD	2	1.24	615	55	3.1	115.0	187.1	62.2	21.0	90.0	68158	913.1
LFGD-C	1	1.24	615	51	3.2	113.6	184.7	35.1	12.8	90.0	66029	531.6
LFGD-C	2	1.24	615	55	3.1	115.0	187.1	36.2	12.2	90.0	68158	530.7
LSD+ESP	1	1.20	615	51	3.2	76.1	123.8	38.0	13.8	76.0	55979	678.8
LSD+ESP	2	1.20	615	55	3.1	72.4	117.7	36.2	12.2	70.0	53292	679.3
LSD+ESP-C	1	1.20	615	51	3.2	76.1	123.8	22.1	8.0	76.0	55979	395.0
LSD+ESP-C	2	1.20	615	55	3.1	72.4	117.7	21.1	7.1	70.0	53292	395.3

capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 20.1.1-6.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Cardinal steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: LNB and SCR.

Low NO_x Combustion--

Units 1 and 2 are dry bottom, front wall-fired boilers each rated at 615 MW. Unit 3 is a dry bottom, opposed wall-fired boiler rated at 650 MW. The combustion modification technique applied for these boilers was LNB. As Table 20.1.1-7 shows, the LNB NO_x reduction performances for these units could not be estimated using the simplified procedures. No boiler information could be found for units 1 to 3 to assess their NO_x reduction performances. Since these boilers are relatively new, it is estimated that a NO_x reduction of 35 percent can be achieved by units 1 and 2 retrofitted with LNB, and a NO_x reduction of 45 percent can be achieved by unit 3 retrofitted with LNB. Units 1 and 2 were installed between 1966 and 1967 while unit 3 was installed in 1977.

Table 20.1.1-8 presents the cost of retrofitting LNB at the Cardinal boilers, assuming an NO_x reduction performance of 35 percent for units 1 and 2 and 45 percent for unit 3.

Table 20.1.1-6. Summary of Coal Switching/Cleaning Costs for the Cardinal Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	615	51	3.2	18.6	30.3	39.1	14.2	73.0	53528	731.3
CS/B+$15	2	1.00	615	55	3.1	18.7	30.3	41.9	14.1	72.0	54335	771.6
CS/B+$15-C	1	1.00	615	51	3.2	18.6	30.3	22.5	8.2	73.0	53528	420.5
CS/B+$15-C	2	1.00	615	55	3.1	18.7	30.3	24.1	8.1	72.0	54335	443.6
CS/B+$5	1	1.00	615	51	3.2	12.2	19.9	15.3	5.6	73.0	53528	286.4
CS/B+$5	2	1.00	615	55	3.1	12.3	20.0	16.3	5.5	72.0	54335	300.7
CS/B+$5-C	1	1.00	615	51	3.2	12.2	19.9	8.8	3.2	73.0	53528	165.1
CS/B+$5-C	2	1.00	615	55	3.1	12.3	20.0	9.4	3.2	72.0	54335	173.3

TABLE 20.1.1-7. SUMMARY OF NOx RETROFIT RESULTS FOR CARDINAL

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	FWF	FWF	OWF
TYPE OF NOx CONTROL	LNB	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	35	35	45
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW	MEDIUM
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	106	106	110
New Duct Length (Feet)	350	350	500
New Duct Costs (1000$)	5019	5019	7406
New Heat Exchanger (1000$)	5543	5543	5730
TOTAL SCOPE ADDER COSTS (1000$)	10667	10667	13246
RETROFIT FACTOR FOR SCR	1.16	1.16	1.34
GENERAL FACILITIES (PERCENT)	13	25	13

Table 20.1.1-8. NOx Control Cost Results for the Cardinal Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1	1.00	615	51	3.2	5.3	8.6	1.1	0.4	35.0	4321	263.8
LNC-LNB	2	1.00	615	55	3.1	5.3	8.6	1.1	0.4	35.0	4604	247.6
LNC-LNB	3	1.00	650	53	0.7	5.4	8.3	1.2	0.4	45.0	6363	183.2
LNC-LNB-C	1	1.00	615	51	3.2	5.3	8.6	0.7	0.2	35.0	4321	156.6
LNC-LNB-C	2	1.00	615	55	3.1	5.3	8.6	0.7	0.2	35.0	4604	147.0
LNC-LNB-C	3	1.00	650	53	0.7	5.4	8.3	0.7	0.2	45.0	6363	108.8
SCR-3	1	1.16	615	51	3.2	75.5	122.8	27.8	10.1	80.0	9876	2812.0
SCR-3	2	1.16	615	55	3.1	77.6	126.3	28.4	9.6	80.0	10523	2703.5
SCR-3	3	1.34	650	53	0.7	88.0	135.4	31.4	10.4	80.0	11311	2776.1
SCR-3-C	1	1.16	615	51	3.2	75.5	122.8	16.3	5.9	80.0	9876	1645.4
SCR-3-C	2	1.16	615	55	3.1	77.6	126.3	16.6	5.6	80.0	10523	1582.0
SCR-3-C	3	1.34	650	53	0.7	88.0	135.4	18.4	6.1	80.0	11311	1625.4
SCR-7	1	1.16	615	51	3.2	75.5	122.8	22.7	8.3	80.0	9876	2298.1
SCR-7	2	1.16	615	55	3.1	77.6	126.3	23.4	7.9	80.0	10523	2221.9
SCR-7	3	1.34	650	53	0.7	88.0	135.4	26.0	8.6	80.0	11311	2299.2
SCR-7-C	1	1.16	615	51	3.2	75.5	122.8	13.3	4.9	80.0	9876	1350.9
SCR-7-C	2	1.16	615	55	3.1	77.6	126.3	13.7	4.6	80.0	10523	1306.1
SCR-7-C	3	1.34	650	53	0.7	88.0	135.4	15.3	5.1	80.0	11311	1352.2

Selective Catalytic Reduction--

Table 20.1.1-7 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESP to the reactor and from the reactor to the chimney.

The SCR reactor for unit 1 would be located southwest of the respective ESPs in an open area between the chimney and coal pile. Since both reactors were located in open area having easy access with no major obstacles, the reactors for units 1 and 2 were assigned low access/congestion factors. The SCR reactor for unit 2 would be located immediately north of the ESP for unit 2 in the employee parking lot. A 25 percent general facility factor was assigned to the reactor for unit 2 because part of the parking lot would have to be demolished and relocated. For unit 3, the SCR reactor would be located in a relatively high congested area, west of the respective ESP and north of the cooling towers. Because access to this area is relatively easy, a medium access/congestion factor was assigned to the reactor for unit 3. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor.

As discussed in Section 2, all NO_x control techniques were evaluated independently from those techniques evaluated for SO_2 control. If both SO_2 and NO_x emissions needed to be reduced at this plant, the SCR reactors would have to be located downstream of the FGD absorbers in highly congested areas. The SCR reactors for units 1 and 2 would be located immediately north and south of the absorbers for units 1 and 2, respectively. The SCR reactors for unit 3 would be located east of the ESP and south of the absorber for unit 3, near the banks of the river. In all three cases, high access/congestion factors would be assigned to the three SCR reactors. Table 20.1.1-8 presents the estimated cost of retrofitting SCR at the Cardinal boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately

from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Cardinal steam plant for units 1 and 2 would be relatively easy. There is sufficient duct residence time between the boilers and the ESPs and, in addition, the ESPs have large SCAs (>400). There is not sufficient duct residence time for unit 3; however, ESPs are large and can be modified for sorbent injection technologies. A low retrofit factor for units 1-2 was assigned to DSD and FSI for the same reasons as mentioned in the previous section. Tables 20.1.1-9 and 20.1.1-10 present a summary of the site access/congestion factors for DSD and FSI technologies at the Cardinal steam plant. Table 20.1.1-11 presents the costs estimated to retrofit DSD and FSI at the Cardinal plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Cardinal plant. None of the boilers would be considered good candidates for AFBC retrofit because of their large boiler sizes (>600 MW), high capacity factors, and relatively new ages (built after 1960).

TABLE 20.1.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR CARDINAL UNITS 1-2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	117
TOTAL COST (1000$)	
ESP UPGRADE CASE	117
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

TABLE 20.1.1-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR CARDINAL UNIT 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	122
TOTAL COST (1000$)	
ESP UPGRADE CASE	122
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

Table 20.1.1-11. Summary of DSD/FSI Control Costs for the Cardinal Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	615	51	3.2	33.3	54.1	24.9	9.0	49.0	35693	696.5
DSD+ESP	2	1.00	615	55	3.1	29.2	47.4	22.9	7.7	46.0	34598	662.7
DSD+ESP	3	1.00	650	53	0.7	62.7	96.5	27.2	9.0	72.0	13251	2055.0
DSD+ESP-C	1	1.00	615	51	3.2	33.3	54.1	14.4	5.2	49.0	35693	403.2
DSD+ESP-C	2	1.00	615	55	3.1	29.2	47.4	13.3	4.5	46.0	34598	383.4
DSD+ESP-C	3	1.00	650	53	0.7	62.7	96.5	15.9	5.3	72.0	13251	1198.6
FSI+ESP-50	1	1.00	615	51	3.2	23.2	37.7	29.1	10.6	50.0	36684	792.0
FSI+ESP-50	2	1.00	615	55	3.1	22.4	36.4	29.6	10.0	50.0	37865	780.6
FSI+ESP-50	3	1.00	650	53	0.7	17.0	26.1	11.5	3.8	50.0	9190	1246.6
FSI+ESP-50-C	1	1.00	615	51	3.2	23.2	37.7	16.7	6.1	50.0	36684	456.6
FSI+ESP-50-C	2	1.00	615	55	3.1	22.4	36.4	17.0	5.7	50.0	37865	449.9
FSI+ESP-50-C	3	1.00	650	53	0.7	17.0	26.1	6.6	2.2	50.0	9190	722.5
FSI+ESP-70	1	1.00	615	51	3.2	23.5	38.3	29.7	10.8	70.0	51357	578.0
FSI+ESP-70	2	1.00	615	55	3.1	22.7	36.9	30.2	10.2	70.0	53011	569.8
FSI+ESP-70	3	1.00	650	53	0.7	17.1	26.4	11.6	3.9	70.0	12866	904.3
FSI+ESP-70-C	1	1.00	615	51	3.2	23.5	38.3	17.1	6.2	70.0	51357	333.2
FSI+ESP-70-C	2	1.00	615	55	3.1	22.7	36.9	17.4	5.9	70.0	53011	328.4
FSI+ESP-70-C	3	1.00	650	53	0.7	17.1	26.4	6.7	2.2	70.0	12866	524.0

20.2 CINCINNATI GAS AND ELECTRIC COMPANY

20.2.1 Walter C. Beckjord Steam Plant

The Beckjord steam plant is located within Clermont County, Ohio, as part of Cincinnati Gas and Electric Company system. The plant has six coal-fired boilers with a total gross generating capacity of 1,201 MW. Figure 20.2.1-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 20.2.1-1 presents operational data for the existing equipment at the Beckjord steam plant. Boilers 1-4 burn low sulfur coal (1.0 percent sulfur) while boilers 5-6 burn medium sulfur coal (2.5 percent). Coal shipments are received by barge and conveyed to a coal storage and handling area located north of the plant.

Particulate matter emissions for the boilers are controlled with retrofit ESPs; the ESPs for boilers 1-5 are located behind each unit, while the ESPs for unit 6 are located on the boiler building roof and at ground level. Units 1-4 have a dry fly ash handling system and fly ash is disposed off-site or sluiced to ponds located north of the plant. Fly ash from units 5 and 6 are wet sluiced to ponds located south of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 20.2.1-1 shows the general layout and location of the FGD control system. The absorbers for all units would be located between the unit 6 ESPs and the ash pond. No major demolition/relocation would be required for placing the absorbers; therefore, a base factor of 5 percent was assigned to general facilities. The lime storage/preparation area and waste handling area would be located south of the plant between the power house and the ash pond site, adjacent to the turbines.

Retrofit Difficulty and Scope Adder Costs--

Absorbers for all units would be located south of the plant, parallel to the river, and adjacent to the unit 6 ESPs.

Unit 1-6 absorber locations were assigned a medium site access/congestion factor due to the closeness to the river (poor load bearing capacity of soil).

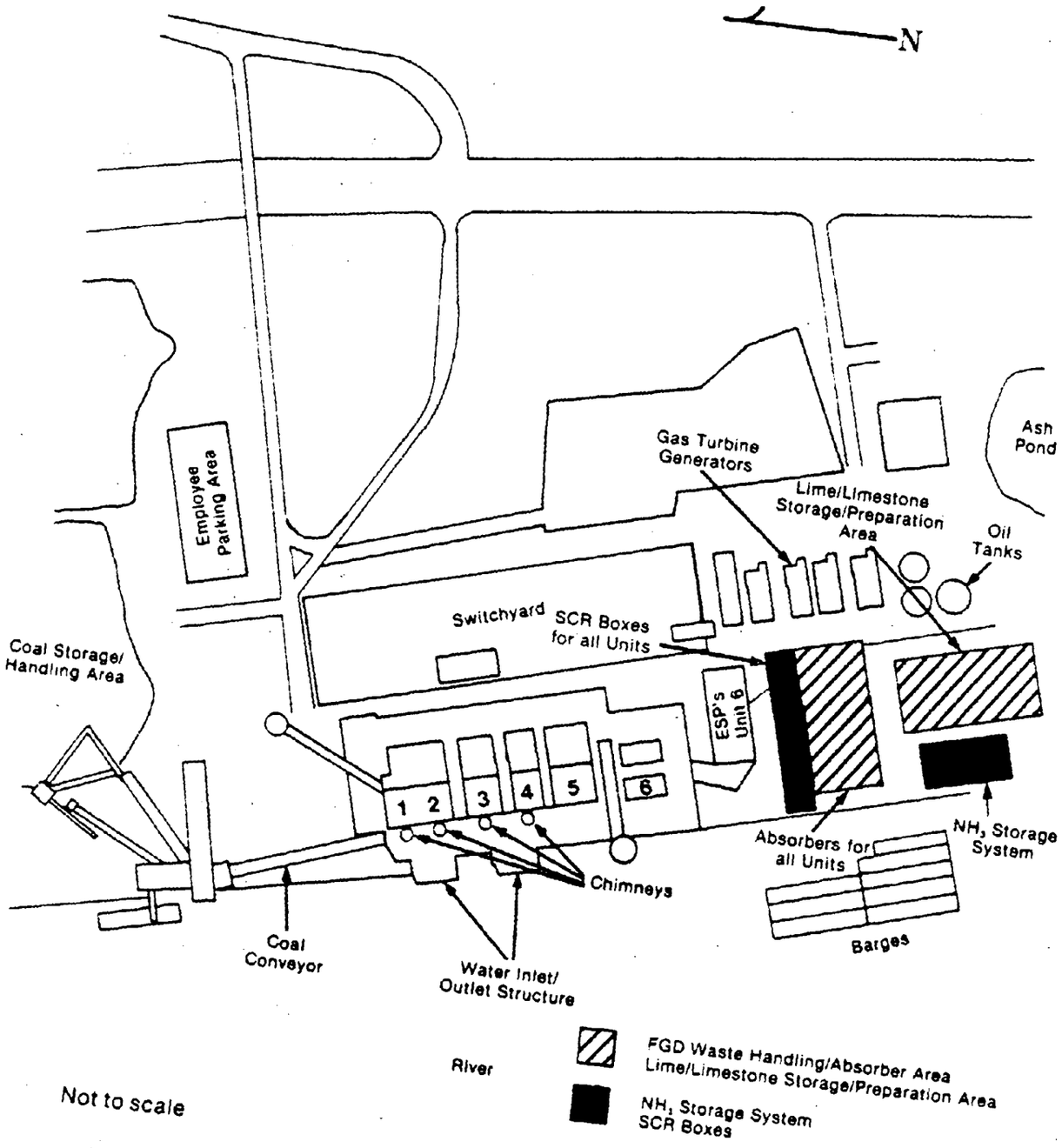


Figure 20.2.1-1. Beckjord plant plot plan

TABLE 20.2.1-1. BECKJORD STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4	5	6
GENERATING CAPACITY (MW-each)	100	135	162	255	449
CAPACITY FACTOR (PERCENT)	6,8	10	22	29	57
INSTALLATION DATE	1952	1954	1958	1962	1969
FIRING TYPE	TANG	FWF	TANG	TANG	TANG
COAL SULFUR CONTENT (PERCENT)	1.0	1.0	0.9	2.5	2.5
COAL HEATING VALUE (BTU/LB)	11000	11000	11000	11000	11000
COAL ASH CONTENT (PERCENT)	14.4	14.2	14.2	16.4	16.0
FLY ASH SYSTEM	DRY HANDLING			WET SLUICE	
ASH DISPOSAL METHOD	OFF-SITE			ON-SITE	
STACK NUMBER	1-2	3	4	5	5
COAL DELIVERY METHODS			BARGE		
PARTICULATE CONTROL					
TYPE	ESP	ESP	ESP	ESP	ESP
INSTALLATION DATE	1974	1973	1975	1976	1969/79
EMISSION (LB/MM BTU)	0.05	0.05	0.05	0.05	0.05
REMOVAL EFFICIENCY	99.5	99.5	99.5	99.5	99.5
DESIGN SPECIFICATION					
SULFUR SPECIFICATION (PERCENT)	1.0	1.0	1.0	1.0	2.5
SURFACE AREA (1000 SQ FT)	82.6	123.1	119.9	216	203/832
GAS EXIT RATE (1000 ACFM)	350	505	585	875	1600
SCA (SQ FT/1000 ACFM)	236	244	205	247	646
OUTLET TEMPERATURE (°F)	250	250	250	250	250

For flue gas handling for L/LS-FGD cases, various length duct runs would be required for each unit. Units 1-4 would require extreme length duct runs, unit 5 long and unit 6 short. Separate site access/congestion factors for both technologies were assigned to each unit for the flue gas handling system as follows. For units 1-4, a high access/congestion factor was assigned because of the location of the chimney and obstructions caused by other units ESPs/chimneys. Unit 5 had a high access factor due to congestion created by unit 5 ESPs and obstructions caused by the unit 6 ESPs to access unit 5. For unit 6, a low access/congestions factor was designated because the ESPs are located beside unit 6 and access to the existing duct work on both the upstream and downstream of the ESPs would be easy.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Tables 20.2.1-2 through 20.2.1-4. The largest scope adder for the Beckjord plant would be the conversion of unit 5 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD cases. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste. However, this conversion would not be necessary for units 1-4 because the existing fly ash handling system is dry. An additional scope adder would be the construction of a new chimney for units 1-5 to decrease the extreme duct runs. The retrofit factors determined for the L/LS-FGD cases ranged from moderate to high (1.31-1.84).

LSD with reused ESP was the only LSD-FGD technology considered for unit 6 because it has a large SCA (=646). LSD with a new baghouse was the only case considered for units 3-5 because of the extreme difficulty to reuse the ESPs for these units and the considerable amount of ESP upgrading required. Also, the locations of the ESPs are in very congested areas and there would be extreme difficulty to access and extend the duct runs required. A new baghouse was located south of the plant close to the absorbers. For flue gas handling for LSD cases, the duct runs and site access/congestion factors would be the same as in L/LS-FGD cases as stated earlier. The retrofit factors determined for the LSD technology case ranged from moderate to high (1.31 to 1.87) and did not include particulate control costs. A separate retrofit factor was developed for upgrading ESPs for unit 6. This factor for unit 6 was low (1.16) due to the available space around the ESPs. A separate retrofit factor developed for the new baghouse

TABLE 20.2.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR BECKJORD UNITS 1-4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	1000 +	1000 +	
ESP REUSE			NA
BAGHOUSE			1000 +
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	YES	YES
ESTIMATED COST (1000$)	1134	1134	1134
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.84	1.84	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.87
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 20.2.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR BECKJORD UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
ESP REUSE			NA
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	MEDIUM
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	2170	NA	NA
NEW CHIMNEY	YES	YES	YES
ESTIMATED COST (1000$)	1785	1785	1785
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.61	1.66	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.69
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.36
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 20.2.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR BECKJORD UNIT 6

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			LOW
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	0-100	0-100	
ESP REUSE			0-100
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	YES
ESTIMATED COST (1000$)	NA	NA	3603
NEW CHIMNEY	NO	YES	NO
ESTIMATED COST (1000$)	0	1997	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.31	1.27	
ESP REUSE CASE			1.31
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

for units 1-5 was medium (1.36) and reflects the site access difficulty created by the location of the area being close to the turbines and river. These factors were used by the IAPCS model to estimate the particulate control costs for all units.

Table 20.2.1-5 presents the costs estimated for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boiler 6 and installing new baghouses to handle the additional particulate loading for boilers 1-5. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 20.2.1-6. CS was not evaluated for units 1-4 since these units currently fire a low sulfur coal.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Beckjord steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR for all units except unit 3 and LNB and SCR for unit 3.

Table 20.2.1-5. Summary of FGD Control Costs for the Beckjord Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1-2	1.84	200	7	1.0	46.2	230.9	16.5	134.5	90.0	984	16760.4
LC FGD	3-6	1.54	1001	39	1.8	153.6	153.5	72.6	21.2	90.0	49390	1469.3
LC FGD-C	1-2	1.84	200	7	1.0	46.2	230.9	9.7	78.7	90.0	984	9813.1
LC FGD-C	3-6	1.54	1001	39	1.8	153.6	153.5	42.3	12.4	90.0	49390	855.8
LFGD	1	1.84	100	6	1.0	48.4	484.4	16.9	321.0	90.0	422	40010.7
LFGD	2	1.84	100	8	1.0	48.4	484.5	17.0	243.3	90.0	562	30322.1
LFGD	3	1.84	135	10	1.0	57.0	422.0	20.1	170.1	90.0	949	21196.5
LFGD	4	1.84	162	22	0.9	62.9	388.2	23.3	74.7	90.0	2255	10344.0
LFGD	5	1.61	255	29	2.5	78.5	307.8	31.6	48.9	90.0	12994	2435.4
LFGD	6	1.31	449	57	2.5	92.6	206.2	48.7	21.7	90.0	44971	1082.0
LFGD-C	1	1.84	100	6	1.0	48.4	484.4	9.9	188.1	90.0	422	23438.6
LFGD-C	2	1.84	100	8	1.0	48.4	484.5	10.0	142.5	90.0	562	17758.7
LFGD-C	3	1.84	135	10	1.0	57.0	422.0	11.8	99.6	90.0	949	12413.4
LFGD-C	4	1.84	162	22	0.9	62.9	388.2	13.6	43.7	90.0	2255	6051.5
LFGD-C	5	1.61	255	29	2.5	78.5	307.8	18.5	28.5	90.0	12994	1422.4
LFGD-C	6	1.31	449	57	2.5	92.6	206.2	28.3	12.6	90.0	44971	629.1
LSD+ESP	6	1.31	449	57	2.5	50.0	111.4	23.1	10.3	47.0	23505	984.0
LSD+ESP-C	6	1.31	449	57	2.5	50.0	111.4	13.5	6.0	47.0	23505	573.3
LSD+FF	1	1.87	100	6	1.0	31.4	314.1	11.0	208.8	75.0	351	31294.4
LSD+FF	2	1.87	100	8	1.0	31.4	314.2	11.0	157.2	75.0	468	23568.1
LSD+FF	3	1.87	135	10	1.0	38.6	285.6	13.1	110.5	75.0	791	16507.9
LSD+FF	4	1.87	162	29	0.9	43.6	269.3	15.2	36.8	75.0	2490	6090.8
LSD+FF	5	1.69	255	29	2.5	64.4	252.4	22.0	33.9	70.0	10046	2189.0
LSD+FF-C	1	1.87	100	6	1.0	31.4	314.1	6.4	122.3	75.0	351	18331.1
LSD+FF-C	2	1.87	100	8	1.0	31.4	314.2	6.5	92.1	75.0	468	13804.1
LSD+FF-C	3	1.87	135	10	1.0	38.6	285.6	7.7	64.8	75.0	791	9676.4
LSD+FF-C	4	1.87	162	29	0.9	43.6	269.3	8.9	21.6	75.0	2490	3568.2
LSD+FF-C	5	1.69	255	29	2.5	64.4	252.4	12.9	19.9	70.0	10046	1282.9

Table 20.2.1-6. Summary of Coal Switching/Cleaning Costs for the Beckjord Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	5	1.00	255	29	2.5	6.8	26.8	9.7	14.9	68.0	9760	988.7
CS/B+$15	6	1.00	449	57	2.5	12.0	26.6	30.6	13.7	68.0	33777	906.2
CS/B+$15-C	5	1.00	255	29	2.5	6.8	26.8	5.6	8.6	68.0	9760	569.6
CS/B+$15-C	6	1.00	449	57	2.5	12.0	26.6	17.6	7.8	68.0	33777	520.8
CS/B+$5	5	1.00	255	29	2.5	4.2	16.4	3.8	5.9	68.0	9760	393.1
CS/B+$5	6	1.00	449	57	2.5	7.3	16.3	11.3	5.0	68.0	33777	333.8
CS/B+$5-C	5	1.00	255	29	2.5	4.2	16.4	2.2	3.4	68.0	9760	227.1
CS/B+$5-C	6	1.00	449	57	2.5	7.3	16.3	6.5	2.9	68.0	33777	192.2

Low NO_x Combustion--

Units 1, 2, and 4 to 6 are dry bottom, tangential-fired boilers; units 1 and 2 are rated at 100 MW each while units 4, 5, and 6 are rated at 162, 255, and 449 MW, respectively. Unit 3 is a dry bottom, front wall-fired boiler rated at 135 MW. The combustion modification technique applied for this evaluation to all units except unit 3 was OFA and that applied to unit 3 was LNB. As Tables 20.2.1-7 and 20.2.1-8 show, the OFA NO_x reduction performance for units 1, 2, 4, 6 was estimated to be 20 percent while the OFA NO_x reduction performance for unit 5 was estimated to be 15 percent. The LNB NO_x reduction performance for unit 3 was estimated to be 43 percent. These reduction performance levels were assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. Table 20.2.1-9 presents the cost of retrofitting OFA and LNB at the Beckjord boilers.

Selective Catalytic Reduction--

Tables 20.2.1-7 and 20.2.1-8 present the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 to 6 were located south of unit 6 between the ESPs for unit 6 and the ash pond. The SCR reactors for all units were assigned medium access/congestion factors because of the foundation difficulty caused by poor load bearing soil (close to the river). However, the poor soil quality is offset by the reactors being located in a low congestion area with easy access. All six reactors were assumed to be in areas with high underground obstructions. Since access to the unit 3-4 chimneys are difficult, a new chimney was built for both units. The ammonia storage system was placed in a remote area having a low access/congestion factor. Table 20.2.1-9 presents the estimated cost of retrofitting SCR at the Beckjord boilers.

TABLE 20.2.1-7. SUMMARY OF NOx RETROFIT RESULTS FOR BECKJORD UNITS 1-3

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	TANG	TANG	FWF
TYPE OF NOx CONTROL	OFA	OFA	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	14.7	14.7	15
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	26.2	26.2	69.4
FURNACE RESIDENCE TIME (SECONDS)	3.04	3.04	2.46
ESTIMATED NOx REDUCTION (PERCENT)	20	20	43
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--			
New Chimney (1000$)	0	0	1134
Ductwork Demolition (1000$)	27	27	34
New Duct Length (Feet)	1000+	1000+	1000+
New Duct Costs (1000$)	4500	4500	6000
New Heat Exchanger (1000$)	1864	1864	2232
TOTAL SCOPE ADDER COSTS (1000$)	6391	6391	9400
RETROFIT FACTOR FOR SCR	1.34	1.34	1.34
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 20.2.1-8. SUMMARY OF NOx RETROFIT RESULTS FOR BECKJORD UNITS 4-6

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	4	5	6
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	13	15.8	13.9
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	69.6	73.3	147.6
FURNACE RESIDENCE TIME (SECONDS)	2.97	2.45	2.83
ESTIMATED NOx REDUCTION (PERCENT)	20	15	20
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--			
New Chimney (1000$)	1134	0	0
Ductwork Demolition (1000$)	39	55	83
New Duct Length (Feet)	1000+	750	150
New Duct Costs (1000$)	9000	6426	1789
New Heat Exchanger (1000$)	2490	3268	4589
TOTAL SCOPE ADDER COSTS (1000$)	12662	9749	6462
RETROFIT FACTOR FOR SCR	1.34	1.34	1.34
GENERAL FACILITIES (PERCENT)	13	13	13

Table 20.2.1-9. NOx Control Cost Results for the Beckjord Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	3	1.00	135	10	1.0	2.9	21.3	0.6	5.3	43.0	244	2546.9
LNC-LNB-C	3	1.00	135	10	1.0	2.9	21.3	0.4	3.1	43.0	244	1512.1
LNC-OFA	1	1.00	100	6	1.0	0.6	6.2	0.1	2.5	20.0	36	3706.7
LNC-OFA	2	1.00	100	8	1.0	0.6	6.2	0.1	1.9	20.0	48	2780.0
LNC-OFA	4	1.00	162	22	0.9	0.8	4.6	0.2	0.5	20.0	214	757.1
LNC-OFA	5	1.00	255	29	2.5	0.9	3.5	0.2	0.3	15.0	333	583.5
LNC-OFA	6	1.00	449	57	2.5	1.1	2.5	0.2	0.1	20.0	1537	158.6
LNC-OFA-C	1	1.00	100	6	1.0	0.6	6.2	0.1	1.5	20.0	36	2200.2
LNC-OFA-C	2	1.00	100	8	1.0	0.6	6.2	0.1	1.1	20.0	48	1650.1
LNC-OFA-C	4	1.00	162	22	0.9	0.8	4.6	0.1	0.3	20.0	214	449.3
LNC-OFA-C	5	1.00	255	29	2.5	0.9	3.5	0.1	0.2	15.0	333	346.4
LNC-OFA-C	6	1.00	449	57	2.5	1.1	2.5	0.1	0.1	20.0	1537	94.2
SCR-3	1	1.34	100	6	1.0	23.7	237.2	6.9	131.3	80.0	144	47883.5
SCR-3	2	1.34	100	8	1.0	23.7	237.2	6.9	98.6	80.0	192	35960.5
SCR-3	3	1.34	135	10	1.0	30.5	225.8	8.8	74.8	80.0	454	19478.2
SCR-3	4	1.34	162	22	0.9	36.8	227.3	10.6	34.0	80.0	856	12383.1
SCR-3	5	1.34	255	29	2.5	44.1	173.1	14.0	21.6	80.0	1777	7865.5
SCR-3	6	1.34	449	57	2.5	59.5	132.6	21.4	9.6	80.0	6150	3486.1
SCR-3-C	1	1.34	100	6	1.0	23.7	237.2	4.1	77.3	80.0	144	28171.5
SCR-3-C	2	1.34	100	8	1.0	23.7	237.2	4.1	58.0	80.0	192	21156.2
SCR-3-C	3	1.34	135	10	1.0	30.5	225.8	5.2	44.0	80.0	454	11460.6
SCR-3-C	4	1.34	162	22	0.9	36.8	227.3	6.2	20.0	80.0	856	7287.6
SCR-3-C	5	1.34	255	29	2.5	44.1	173.1	8.2	12.7	80.0	1777	4617.8
SCR-3-C	6	1.34	449	57	2.5	59.5	132.6	12.5	5.6	80.0	6150	2040.7
SCR-7	1	1.34	100	6	1.0	23.7	237.1	6.1	115.5	80.0	144	42109.1
SCR-7	2	1.34	100	8	1.0	23.7	237.2	6.1	86.8	80.0	192	31629.7
SCR-7	3	1.34	135	10	1.0	30.5	225.8	7.7	65.3	80.0	454	17004.1
SCR-7	4	1.34	162	22	0.9	36.8	227.3	9.3	29.6	80.0	856	10808.7
SCR-7	5	1.34	255	29	2.5	44.1	173.1	11.9	18.3	80.0	1777	6671.0
SCR-7	6	1.34	449	57	2.5	59.5	132.6	17.7	7.9	80.0	6150	2878.4
SCR-7-C	1	1.34	100	6	1.0	23.7	237.1	3.6	68.2	80.0	144	24862.9
SCR-7-C	2	1.34	100	8	1.0	23.7	237.2	3.6	51.2	80.0	192	18674.7
SCR-7-C	3	1.34	135	10	1.0	30.5	225.8	4.6	38.6	80.0	454	10043.0
SCR-7-C	4	1.34	162	22	0.9	36.8	227.3	5.5	17.5	80.0	856	6385.4
SCR-7-C	5	1.34	255	29	2.5	44.1	173.1	7.0	10.8	80.0	1777	3933.4
SCR-7-C	6	1.34	449	57	2.5	59.5	132.6	10.4	4.6	80.0	6150	1692.5

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

Units 1-5 were not considered for DSD or FSI application because of the poor performance of the ESPs and no space is available between the units and ESPS. Sorbent injection for DSD and humidification for FSI applications are not possible because of very short duct residence time and poor ESP performance. DSD or FSI as applied to unit 6 would be very easy due to the long duct residence time, very large ESPs (SCA >600) and a great deal of space is available if additional plate area is required. Table 20.2.1-10 presents a summary of the site access/congestion factors for DSD and FSI technologies at the Beckjord steam plant. Table 20.2.1-11 presents the costs estimated to retrofit DSD and FSI at the Beckjord plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Beckjord plant. Boilers 1-5 at the Beckjord plant would be considered good candidates for AFBC or coal gasification/combined cycle repowering because of the small boiler sizes (<300 MW) and low capacity factors. Boiler 6 would not make a good candidate due to its large boiler size (>400 MW).

20.2.2 Miami Fort Steam Plant

The Miami Fort steam plant is located within Hamilton County, Ohio, as part of Cincinnati Gas and Electric Company system. The plant contains four coal-fired boilers with a total gross generating capacity of 1,308 MW. Boiler 8 is located beside the Ohio River south of the plant, boiler 7 is

TABLE 20.2.1-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BECKJORD UNIT 6

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	3603
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	92
TOTAL COST (1000$)	
ESP UPGRADE CASE	3695
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 20.2.1-11. Summary of DSD/FSI Control Costs for the Beckjord Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	6	1.00	449	57	2.5	21.0	46.7	13.6	6.1	34.0	16999	800.9
DSD+ESP-C	6	1.00	449	57	2.5	21.0	46.7	7.9	3.5	34.0	16999	464.4
FSI+ESP-50	6	1.00	449	57	2.5	21.3	47.5	21.3	9.5	50.0	24983	854.3
FSI+ESP-50-C	6	1.00	449	57	2.5	21.3	47.5	12.3	5.5	50.0	24983	493.3
FSI+ESP-70	6	1.00	449	57	2.5	21.6	48.1	21.8	9.7	70.0	34976	622.7
FSI+ESP-70-C	6	1.00	449	57	2.5	21.6	48.1	12.6	5.6	70.0	34976	359.5

located north of the plant away from the river, and boilers 5 and 6 are in-between. Figure 20.2.2-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 20.2.2-1 presents operational data for the existing equipment at the Miami Fort steam plant. Boilers 5, 6, and 7 burn medium sulfur coal (1.9 to 2.3 percent sulfur) while boiler 8 burns a low sulfur "compliance coal" (0.7). Coal shipments are received by barge and conveyed to a coal storage and handling area located east of the plant.

Particulate matter emissions for the boilers are controlled with ESPs (units 5 and 6 are roof-mounted and units 7 and 8 are located behind each respective boiler). Fly ash from units 5 and 6 are wet sluiced to ponds located west of the plant. Units 7 and 8 have a dry fly ash handling system and is disposed off-site (2 miles).

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 20.2.2-1 shows the general layout and location of the FGD control system. Units 5-7 absorbers would be located in an open area to the northwest of unit 7. The unit 8 absorbers would be located in a small available space behind and to the east of its chimney between the coal conveyors. Plant personnel indicated that unit 5 is an old unit with a very low capacity factor and, if scrubbing is required, the unit would be put out of service because it will be uneconomical to operate. In addition, unit 8 is a 1971 NSPS boiler burning low sulfur coal (1.1 lb per million Btu) and might not require scrubbing. Therefore, retrofit factors and costs were not developed for these two units because they are not potential candidates for scrubbing. Units 6 and 7 would require the demolition/relocation of part of the warehouse building and one paved road; therefore, a factor of 10 percent was assigned to general facilities. The lime storage/preparation area would be located to the north of unit 7 in a relatively open area between the chimney/storage building, parallel to a major highway, and close to the cooling towers (other side of the highway). The waste handling area would be located to the northwest of the powerhouse, adjacent to the absorbers.

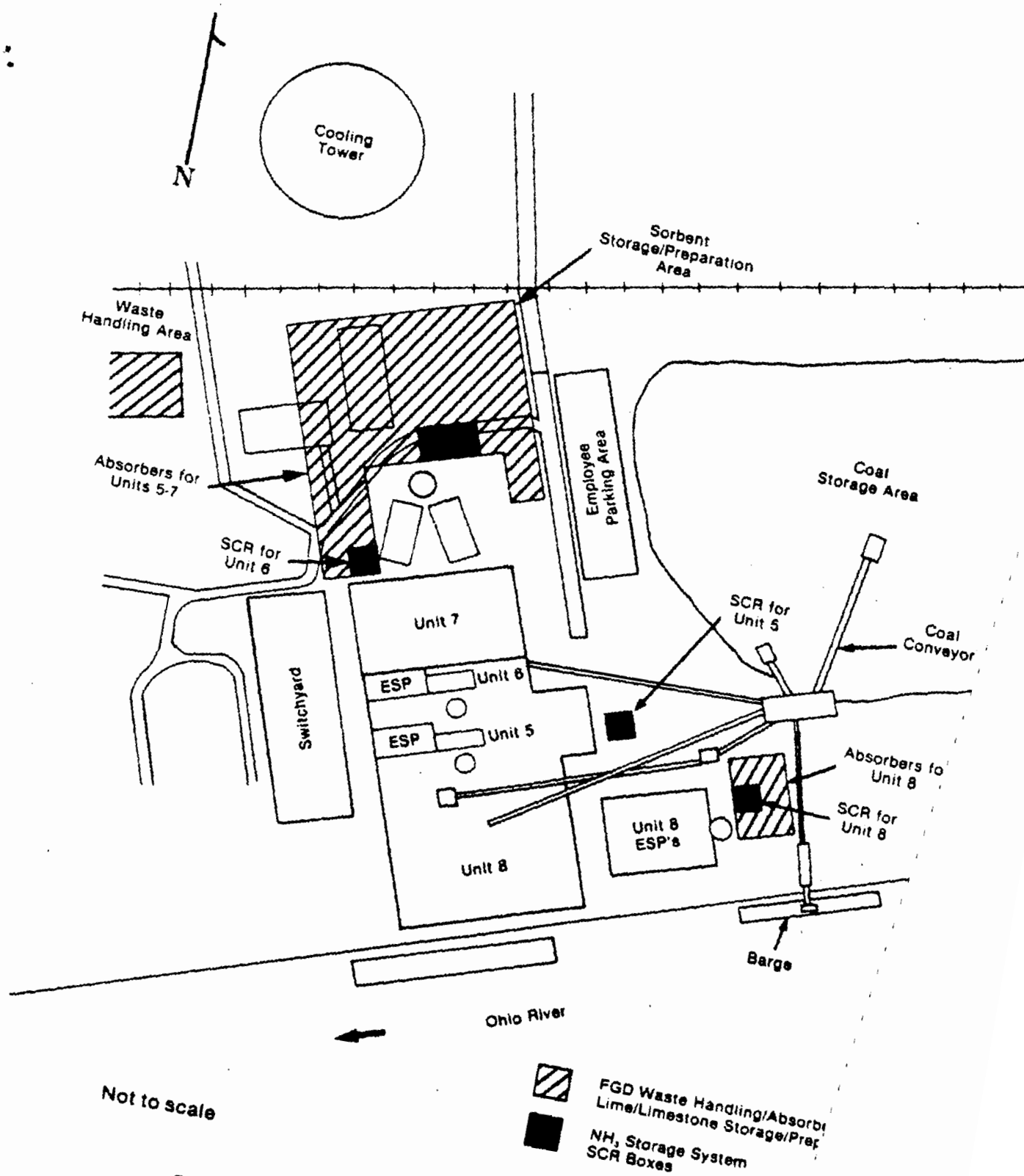


Figure 20.2.2-1. Miami Fort plant plot plan

TABLE 20.2.2-1. MIAMI FORT STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	5	6	7	8
GENERATING CAPACITY (MW)	85	175	524	524
CAPACITY FACTOR (PERCENT)	40	71	67	56
INSTALLATION DATE	1949	1960	1975	1978
FIRING TYPE	FWF	TANG	OWF	OWF
COAL SULFUR CONTENT (PERCENT)	1.9	2.1	2.3	0.7
COAL HEATING VALUE (BTU/LB)	11000	11000	11000	12300
COAL ASH CONTENT (PERCENT)	15.2	14.8	15.1	11.0
FLY ASH SYSTEM	WET	WET	DRY	DRY
ASH DISPOSAL METHOD	ON-SITE		OFF-SITE	
STACK NUMBER	1	2	3	4
COAL DELIVERY METHODS	BARGE			
PARTICULATE CONTROL				
TYPE	ESP	ESP	ESP	ESP
INSTALLATION DATE	1977	1976	1975	1978
EMISSION (LB/MM BTU)	0.05	0.05	0.05	0.05
REMOVAL EFFICIENCY	99.7	99.4	99.4	99.7
DESIGN SPECIFICATION				
SULFUR SPECIFICATION (PERCENT)	1.0	1.0	3.0	0.7
SURFACE AREA (1000 SQ FT)	185.3	119.9	557.3	663.5
GAS EXIT RATE (1000 ACFM)	524	585	2020	2020
SCA (SQ FT/1000 ACFM)	354	205	275	328
OUTLET TEMPERATURE (°F)	310	310	310	310

Retrofit Difficulty and Scope Adder Costs--

Units 6 and 7 were assigned a low site access/congestion factor due to the relatively open space available with no major obstacles/obstructions and very good accessibility.

For flue gas handling for L/LS-FGD cases, short to moderate duct runs would be required for units 6 and 7. Separate site access/congestion factors were assigned to each unit for the flue gas handling system as follows. Unit 6 was assigned a medium access/congestion factor which reflects the access difficulty associated with routing flue gas from the ESPs to the absorbers. A low site access/congestion factor was assigned to unit 7 due to the absorbers being located close to the chimney with no major obstacles/ obstructions surrounding the chimney.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Tables 20.2.2-2 and 20.2.2-3. The largest scope adder for the Miami Fort plant would be the conversion of unit 6 fly ash conveying/disposal system from wet to dry for conventional L/LS-FGD case. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste. However, this conversion would not be necessary for unit 7 because the existing fly ash handling system is dry. The overall retrofit factors determined for the L/LS-FGD cases ranged from low to medium (1.24 to 1.44).

Unit 7 is the only candidate for LSD with reuse ESP technology. Unit 6 was not considered because of its marginal size SCA in addition to roof-mounted ESPs which makes it difficult to add plate area. By contrast, unit 7 has adequate size SCA with good removal efficiency. Moderate duct length is required and medium access/congestion factors is assigned to the flue gas handling system due to access difficulty created by the limited space availability upstream of the ESPs. The retrofit factors determined for the LSD technology case was low (1.24) and did not include particulate control upgrading costs. A separate retrofit factor was developed for upgrading ESPs. Upgrading the two ESPs for unit 7 would be easy (with a low retrofit factor of 1.16) because the ESPs are located in a relatively open area with space availability around the two ESPs. This factor was used by the IAPCS model to estimate the particulate control upgrading costs.

TABLE 20.2.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR MIAMI FORT UNIT 6

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	NA
FLUE GAS HANDLING	MEDIUM	MEDIUM	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	300-600	
ESP REUSE			NA
BAGHOUSE			NA
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NA
ESTIMATED COST (1000$)	1548	NA	NA
NEW CHIMNEY	YES	YES	NA
ESTIMATED COST (1000$)	1225	1225	NA
OTHER	NO	NO	NA
RETROFIT FACTORS			
FGD SYSTEM	1.44	1.37	
ESP REUSE CASE			NA
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	NA

TABLE 20.2.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR MIAMI FORT UNIT 7

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.24	1.24	
ESP REUSE CASE			1.24
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

Table 20.2.2-4 presents the costs estimated for L/LS and LSD-FGD cases. As mentioned in the previous section, boiler 8 is currently meeting 1971 NSPS SO_2 emission standards. It is unlikely that this unit would need scrubbing. If, however, scrubbing is required for this unit, it would be more cost effective to switch to a coal with a higher sulfur content, taking into consideration the fuel cost differential. Therefore, the costs cannot be presented realistically for unit 8 because they would possibly change depending on acid rain legislation and plant decisions regarding the type of coal used for unit 8. The LSD-FGD costs include upgrading the ESPs only for boiler 7. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Unit 8 has already switched to low sulfur coal. Therefore, this unit was not considered for coal switching and physical coal cleaning.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 20.2.2-5.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Miami Fort steam plant. These controls include LNC modification and SCR. Sum of the retrofit factor data for Miami Fort unit 8

Table 20.2.2-4. Summary of FGD Control Costs for the Miami Fort Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	6-7	1.29	699	68	1.8	86.1	123.2	50.8	12.2	90.0	46356	1095.7
LC FGD-C	6-7	1.29	699	68	1.8	86.1	123.2	29.5	7.1	90.0	46356	636.1
LFGD	6	1.44	175	71	2.1	50.7	289.7	24.6	22.6	90.0	14137	1739.9
LFGD	7	1.24	524	67	1.6	86.1	164.3	44.6	14.5	90.0	30435	1464.9
LFGD-C	6	1.44	175	71	2.1	50.7	289.7	14.3	13.2	90.0	14137	1012.9
LFGD-C	7	1.24	524	67	1.6	86.1	164.3	25.9	8.4	90.0	30435	852.0
LSD+ESP	7	1.24	524	67	1.6	55.2	105.3	26.4	8.6	76.0	25802	1023.0
LSD+ESP-C	7	1.24	524	67	1.6	55.2	105.3	15.4	5.0	76.0	25802	595.7

Table 20.2.2-5. Summary of Coal Switching/Cleaning Costs for the Miami Fort Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	5	1.00	85	40	2.1	3.4	40.2	4.8	16.1	50.0	2148	2237.1
CS/B+$15	6	1.00	175	71	2.1	6.2	35.7	15.6	14.3	50.0	7849	1990.0
CS/B+$15	7	1.00	524	67	1.6	16.0	30.5	42.7	13.9	34.0	11609	3681.3
CS/B+$15-C	5	1.00	85	40	2.1	3.4	40.2	2.8	9.3	50.0	2148	1288.8
CS/B+$15-C	6	1.00	175	71	2.1	6.2	35.7	9.0	8.2	50.0	7849	1143.7
CS/B+$15-C	7	1.00	524	67	1.6	16.0	30.5	24.6	8.0	34.0	11609	2115.3
CS/B+$5	5	1.00	85	40	2.1	2.5	29.8	2.2	7.4	50.0	2148	1019.7
CS/B+$5	6	1.00	175	71	2.1	4.4	25.3	6.3	5.8	50.0	7849	804.1
CS/B+$5	7	1.00	524	67	1.6	10.6	20.1	16.4	5.3	34.0	11609	1411.3
CS/B+$5-C	5	1.00	85	40	2.1	2.5	29.8	1.3	4.3	50.0	2148	589.6
CS/B+$5-C	6	1.00	175	71	2.1	4.4	25.3	3.6	3.3	50.0	7849	463.2
CS/B+$5-C	7	1.00	524	67	1.6	10.6	20.1	9.4	3.1	34.0	11609	812.6

application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: LNB and SCR for units 5, 7, and 8; and OFA and SCR for unit 6.

Low NO_x Combustion--

Unit 5 is a dry bottom, front wall-fired boiler rated at 85 MW. Units 7 and 8 are dry bottom, opposed wall-fired boilers, each rated at 524 MW. The combustion modification technique applied for these boilers was LNB. Unit 6 is a dry bottom, tangential-fired boiler rated at 175 MW. The combustion modification technique applied for this boiler was OFA. As Tables 20.2.2-6 and 20.2.2-7 show, the LNB NO_x reduction performance for units 7 and 8 was estimated at 50 percent, and the OFA NO_x reduction performance for unit 6 was estimated at 20 percent. These reduction performance levels were assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. No boiler information was available on unit 5 to assess the NO_x reduction performance for this unit. However, based on NO_x performance results from similar boilers of the same age and size, LNB NO_x reductions are expected to be between 20 and 30 percent. Table 20.2.2-8 presents the cost of retrofitting LNB and OFA at the Miami Fort boilers.

Selective Catalytic Reduction--

Tables 20.2.2-6 and 20.2.2-7 present the SCR retrofit results for units 5 to 8. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactor for unit 5 would be located behind the respective unit between the coal pile and the powerhouse. The SCR reactor for unit 6 would be located in front of unit 6 in an open area east of the switch yard and immediately west of unit 7. The SCR reactor for unit 7 would be located immediately north of the respective chimney in an open area having easy access. For unit 8, the SCR reactor would be located behind the respective chimney between the coal pile and the powerhouse.

TABLE 20.2.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR MIAMI FORT UNITS 5-7

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	5	6	7
FIRING TYPE	FWF	TANG	OWF
TYPE OF NOx CONTROL	LNB	OFA	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	13	14
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	69.6	71
FURNACE RESIDENCE TIME (SECONDS)	NA	2.97	2.95
ESTIMATED NOx REDUCTION (PERCENT)	25	20	50
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	LOW	LOW
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	24	41	94
New Duct Length (Feet)	400	700	200
New Duct Costs (1000$)	1802	4812	2611
New Heat Exchanger (1000$)	1691	2608	5035
TOTAL SCOPE ADDER COSTS (1000$)	3517	7461	7740
RETROFIT FACTOR FOR SCR	1.52	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	17	13

TABLE 20.2.2-7. SUMMARY OF NOx RETROFIT RESULTS FOR MIAMI FORT UNIT 8

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	8
FIRING TYPE	OWF
TYPE OF NOx CONTROL	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	11.8
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	38.3
FURNACE RESIDENCE TIME (SECONDS)	3.48
ESTIMATED NOx REDUCTION (PERCENT)	50
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	94
New Duct Length (Feet)	100
New Duct Costs (1000$)	1306
New Heat Exchanger (1000$)	5035
TOTAL SCOPE ADDER COSTS (1000$)	6435
RETROFIT FACTOR FOR SCR	1.52
GENERAL FACILITIES (PERCENT)	13

Table 20.2.2-8. NOx Control Cost Results for the Miami Fort Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	5	1.00	85	40	2.1	2.4	28.1	0.5	1.7	25.0	276	1875.7
LNC-LNB	7	1.00	524	67	1.6	5.0	9.5	1.1	0.3	50.0	5690	187.9
LNC-LNB	8	1.00	524	50	0.7	5.0	9.5	1.1	0.5	50.0	4246	251.8
LNC-LNB-C	5	1.00	85	40	2.1	2.4	28.1	0.3	1.0	25.0	276	1113.5
LNC-LNB-C	7	1.00	524	67	1.6	5.0	9.5	0.6	0.2	50.0	5690	111.6
LNC-LNB-C	8	1.00	524	50	0.7	5.0	9.5	0.6	0.3	50.0	4246	149.5
LNC-OFA	6	1.00	175	71	2.1	0.8	4.4	0.2	0.2	20.0	575	290.2
LNC-OFA-C	6	1.00	175	71	2.1	0.8	4.4	0.1	0.1	20.0	575	172.4
SCR-3	5	1.52	85	40	2.1	20.7	243.0	6.3	21.1	80.0	882	7117.5
SCR-3	6	1.16	175	71	2.1	30.8	176.1	10.0	9.2	80.0	2302	4338.6
SCR-3	7	1.16	524	67	1.6	63.0	120.2	23.6	7.7	80.0	9104	2595.6
SCR-3	8	1.52	524	50	0.7	72.7	138.8	25.6	11.2	80.0	6794	3772.4
SCR-3-C	5	1.52	85	40	2.1	20.7	243.0	3.7	12.4	80.0	882	4183.0
SCR-3-C	6	1.16	175	71	2.1	30.8	176.1	5.9	5.4	80.0	2302	2545.7
SCR-3-C	7	1.16	524	67	1.6	63.0	120.2	13.8	4.5	80.0	9104	1518.1
SCR-3-C	8	1.52	524	50	0.7	72.7	138.8	15.0	6.5	80.0	6794	2209.3
SCR-7	5	1.52	85	40	2.1	20.7	243.0	5.6	18.8	80.0	882	6341.5
SCR-7	6	1.16	175	71	2.1	30.8	176.1	8.6	7.9	80.0	2302	3726.5
SCR-7	7	1.16	524	67	1.6	63.0	120.2	19.4	6.3	80.0	9104	2132.3
SCR-7	8	1.52	524	50	0.7	72.7	138.8	21.4	9.3	80.0	6794	3151.6
SCR-7-C	5	1.52	85	40	2.1	20.7	243.0	3.3	11.1	80.0	882	3738.4
SCR-7-C	6	1.16	175	71	2.1	30.8	176.1	5.1	4.6	80.0	2302	2195.1
SCR-7-C	7	1.16	524	67	1.6	63.0	120.2	11.4	3.7	80.0	9104	1252.7
SCR-7-C	8	1.52	524	50	0.7	72.7	138.8	12.6	5.5	80.0	6794	1853.6

Since the reactors for units 6 and 7 would be located in an open area with easy access and no major obstacles, the reactors were assigned low access and congestion factors. The reactor for unit 6 would require the relocation of one paved road; therefore, a general facility factor of 17 percent was assigned to this unit. A low general facility factor of 13 percent was assigned to all the other reactor locations because no major demolition or relocation would be required. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor. Table 20.2.2-8 presents the estimated cost of retrofitting SCR at the Miami Fort boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for all units were located north of the plant along side the highway. The retrofit of DSD technology at units 5 and 7 would be relatively difficult due to the short duct residence time and the upgrading of the ESPs for unit 5 would be difficult because they are roof-mounted. However, developments in particulate control technology may be used to modify unit 7 ESPs by combining advanced ESP technology and spray dryer technology to remove SO_2 and particulate (E-SO_x technology). Since unit 7 has adequate ESPs, it was assumed that DSD with ESP reuse is an alternative low cost method to the new baghouse option. Table 20.2.2-9 presents a summary of the site access/congestion factors for DSD and FSI technologies at the Miami Fort steam plant. Table 20.2.2-10 presents the costs estimated to retrofit DSD and FSI at the Miami Fort plant.

TABLE 20.2.2-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR MIAMI FORT UNIT 7

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	104
TOTAL COST (1000$)	
ESP UPGRADE CASE	104
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 20.2.2-10. Summary of DSD/FSI Control Costs for the Miami Fort Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	7	1.00	524	67	1.6	18.3	34.9	15.0	4.9	49.0	16452	909.7
DSD+ESP-C	7	1.00	524	67	1.6	18.3	34.9	8.7	2.8	49.0	16452	526.2
FSI+ESP-50	7	1.00	524	67	1.6	19.8	37.8	16.8	5.5	50.0	16908	996.1
FSI+ESP-50-C	7	1.00	524	67	1.6	19.8	37.8	9.7	3.2	50.0	16908	575.9
FSI+ESP-70	7	1.00	524	67	1.6	20.0	38.1	17.1	5.6	70.0	23671	724.3
FSI+ESP-70-C	7	1.00	524	67	1.6	20.0	38.1	9.9	3.2	70.0	23671	418.7

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Miami Fort plant. Boilers 5 and 6 at the Miami Fort plant would be considered good candidates for AFBC retrofit because of the small boiler sizes (<300 MW). Boilers 7 and 8 would not make good candidates due to the large boiler sizes (524 MW) and high capacity factors. The high capacity factor indicates that purchased power cost for unit downtime may be significant for repowering.

20.3 CLEVELAND ELECTRIC ILLUMINATING COMPANY

20.3.1 Ashtabula Steam Plant

The boilers at the Ashtabula plant are at two locations. The aerial photograph for units 1-7 was not available. Units 1-6 are petroleum burning and are not applicable to this study. For unit 7, average retrofit factors of 1.5 and 1.36 were assumed for L/LS-FGD and SCR, respectively. The aerial photograph was available for units 8-11. Sorbent injection technologies (FSI and DSD) were not evaluated for units 8-11 due to the short duct residence time.

TABLE 20.3.1-1. ASHTABULA STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-6	7	8,9,10,11
GENERATING CAPACITY (MW-each)	PETROLEUM	244	44
CAPACITY FACTOR (PERCENT)	BURNING	73	70,72,60,75
INSTALLATION DATE		1958	1949,49,53,53
FIRING TYPE		TANGENTIAL	FRONT WALL
FURNACE VOLUME (1000 CU FT)	RETIRED OR	NA	NA
LOW NOx COMBUSTION	ON STANDBY	NO	NO
COAL SULFUR CONTENT (PERCENT)		4.0	2.6
COAL HEATING VALUE (BTU/LB)		12300	13000
COAL ASH CONTENT (PERCENT)		10.6	6.7
FLY ASH SYSTEM		DRY DISPOSAL	
ASH DISPOSAL METHOD		PAID/OFF-SITE	
STACK NUMBER		1	2
COAL DELIVERY METHOD		RAILROAD	
PARTICULATE CONTROL			
TYPE		ESP	ESP
INSTALLATION DATE		1980	1979
EMISSION (LB/MM BTU)		0.04	0.04
REMOVAL EFFICIENCY		99.6	99.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)		2.0-5.0	
SURFACE AREA (1000 SQ FT)		609	101
GAS EXIT RATE (1000 ACFM)		995	265
SCA (SQ FT/1000 ACFM)		607	380
OUTLET TEMPERATURE (°F)		280	310

* SCA size assumed to be larger than 300 since the ESPs are 1985 retrofit ESPs.

TABLE 20.3.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR ASHTABULA UNITS 8-11 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	HIGH	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	NA	YES
ESTIMATED COST (1000$)	1288	0	1288
OTHER	YES		YES
RETROFIT FACTORS			
FGD SYSTEM	1.83	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.89
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	15	0	15

* L/S-FGD absorbers, LSD-FGD absorbers and new FFs for units 8-11 would be located north of the boilers. Plant personnel indicated that sufficient space near the boilers is not available for the absorbers.

Table 20.3.1-3. Summary of FGD Control Costs for the Ashtabula Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	8-11	1.83	176	69	2.6	47.9	272.3	25.0	23.5	90.0	18320	1364.4
LC FGD-C	8-11	1.83	176	69	2.6	47.9	272.3	14.5	13.7	90.0	18320	793.4
LFGD	7	1.50	244	73	4.0	73.3	300.2	40.0	25.6	90.0	44051	907.1
LFGD	8	1.83	44	70	2.6	35.5	807.5	15.5	57.3	90.0	4646	3329.5
LFGD	9	1.83	44	72	2.6	35.5	807.5	15.5	56.0	90.0	4779	3253.1
LFGD	10	1.83	44	60	2.6	35.5	807.3	15.1	65.2	90.0	3983	3786.6
LFGD	11	1.83	44	75	2.6	35.5	807.6	15.7	54.2	90.0	4978	3146.1
LFGD	8-11	1.83	176	69	2.6	71.6	406.6	32.6	30.6	90.0	18320	1778.9
LFGD-C	7	1.50	244	73	4.0	73.3	300.2	23.2	14.9	90.0	44051	527.2
LFGD-C	8	1.83	44	70	2.6	35.5	807.5	9.0	33.4	90.0	4646	1941.9
LFGD-C	9	1.83	44	72	2.6	35.5	807.5	9.1	32.7	90.0	4779	1897.2
LFGD-C	10	1.83	44	60	2.6	35.5	807.3	8.8	38.0	90.0	3983	2209.4
LFGD-C	11	1.83	44	75	2.6	35.5	807.6	9.1	31.6	90.0	4978	1834.5
LFGD-C	8-11	1.83	176	69	2.6	71.6	406.6	19.0	17.9	90.0	18320	1036.7
LSD+FF	8	1.89	44	70	2.6	21.7	492.3	9.3	34.5	87.0	4466	2082.8
LSD+FF	9	1.89	44	72	2.6	21.7	492.3	9.3	33.6	87.0	4593	2032.1
LSD+FF	10	1.89	44	60	2.6	21.7	492.3	9.1	39.5	87.0	3828	2387.1
LSD+FF	11	1.89	44	75	2.6	21.7	492.3	9.4	32.5	87.0	4785	1961.3
LSD+FF	8-11	1.89	176	69	2.6	55.9	317.7	21.7	20.4	87.0	17608	1231.6
LSD+FF-C	8	1.89	44	70	2.6	21.7	492.3	5.4	20.1	87.0	4466	1215.1
LSD+FF-C	9	1.89	44	72	2.6	21.7	492.3	5.4	19.6	87.0	4593	1185.4
LSD+FF-C	10	1.89	44	60	2.6	21.7	492.3	5.3	23.1	87.0	3828	1393.0
LSD+FF-C	11	1.89	44	75	2.6	21.7	492.3	5.5	18.9	87.0	4785	1144.0
LSD+FF-C	8-11	1.89	176	69	2.6	55.9	317.7	12.7	11.9	87.0	17608	719.9

Table 20.3.1-4. Summary of Coal Switching/Cleaning Costs for the Ashtabula Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	7	1.00	244	73	4.0	8.4	34.4	22.3	14.3	77.0	37678	591.9
CS/B+$15	8	1.00	44	70	2.6	2.5	56.2	4.6	16.9	62.0	3215	1417.0
CS/B+$15	9	1.00	44	72	2.6	2.5	56.2	4.7	16.8	62.0	3306	1411.6
CS/B+$15	10	1.00	44	60	2.6	2.5	56.2	4.0	17.3	62.0	2755	1449.0
CS/B+$15	11	1.00	44	75	2.6	2.5	56.2	4.8	16.7	62.0	3444	1404.2
CS/B+$15-C	7	1.00	244	73	4.0	8.4	34.4	12.8	8.2	77.0	37678	340.1
CS/B+$15-C	8	1.00	44	70	2.6	2.5	56.2	2.6	9.7	62.0	3215	815.3
CS/B+$15-C	9	1.00	44	72	2.6	2.5	56.2	2.7	9.7	62.0	3306	812.1
CS/B+$15-C	10	1.00	44	60	2.6	2.5	56.2	2.3	9.9	62.0	2755	834.2
CS/B+$15-C	11	1.00	44	75	2.6	2.5	56.2	2.8	9.6	62.0	3444	807.7
CS/B+$5	7	1.00	244	73	4.0	5.9	24.0	9.0	5.8	77.0	37678	238.1
CS/B+$5	8	1.00	44	70	2.6	2.0	45.8	2.2	8.3	62.0	3215	698.8
CS/B+$5	9	1.00	44	72	2.6	2.0	45.8	2.3	8.3	62.0	3306	694.2
CS/B+$5	10	1.00	44	60	2.6	2.0	45.8	2.0	8.7	62.0	2755	726.7
CS/B+$5	11	1.00	44	75	2.6	2.0	45.8	2.4	8.2	62.0	3444	687.7
CS/B+$5-C	7	1.00	244	73	4.0	5.9	24.0	5.2	3.3	77.0	37678	137.1
CS/B+$5-C	8	1.00	44	70	2.6	2.0	45.8	1.3	4.8	62.0	3215	403.2
CS/B+$5-C	9	1.00	44	72	2.6	2.0	45.8	1.3	4.8	62.0	3306	400.4
CS/B+$5-C	10	1.00	44	60	2.6	2.0	45.8	1.2	5.0	62.0	2755	419.7
CS/B+$5-C	11	1.00	44	75	2.6	2.0	45.8	1.4	4.7	62.0	3444	396.6

TABLE 20.3.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR ASHTABULA

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	7	8,9,10,11
FIRING TYPE	TANG	FWF
TYPE OF NOx CONTROL	OFA	LNB
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1958	1949,49,53,53
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	40
SCR RETROFIT RESULTS *		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	HIGH
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	53	41
New Duct Length (Feet)	200	500
New Duct Costs (1000$)	1670	3449
New Heat Exchanger (1000$)	3183	2616
TOTAL SCOPE ADDER COSTS (1000$)		
INDIVIDUAL CASE	4906	NA
COMBINED CASE	NA	6106
RETROFIT FACTOR FOR SCR	1.36	1.52
GENERAL FACILITIES (PERCENT)	20	38

* Cold side SCR reactors for units 8-11 would be located south of the boilers behind the ESPs. Due to the lack of an aerial photo, no SCR reactor location is reported for unit 7.

Table 20.3.1-6. NOx Control Cost Results for the Ashtabula Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	8	1.00	44	70	2.6	1.8	41.8	0.4	1.5	40.0	428	928.7
LNC-LNB	9	1.00	44	72	2.6	1.8	41.8	0.4	1.4	40.0	440	902.9
LNC-LNB	10	1.00	44	60	2.6	1.8	41.8	0.4	1.7	40.0	367	1083.5
LNC-LNB	11	1.00	44	75	2.6	1.8	41.8	0.4	1.4	40.0	458	866.8
LNC-LNB-C	8	1.00	44	70	2.6	1.8	41.8	0.2	0.9	40.0	428	551.4
LNC-LNB-C	9	1.00	44	72	2.6	1.8	41.8	0.2	0.8	40.0	440	536.0
LNC-LNB-C	10	1.00	44	60	2.6	1.8	41.8	0.2	1.0	40.0	367	643.2
LNC-LNB-C	11	1.00	44	75	2.6	1.8	41.8	0.2	0.8	40.0	458	514.6
LNC-OFA	7	1.00	244	73	4.0	0.9	3.6	0.2	0.1	25.0	1177	162.3
LNC-OFA-C	7	1.00	244	73	4.0	0.9	3.6	0.1	0.1	25.0	1177	96.3
SCR-3	7	1.36	244	73	4.0	39.1	160.1	13.4	8.6	80.0	3765	3562.8
SCR-3	8-11	1.52	176	69	2.6	36.7	208.5	11.7	11.0	80.0	3373	3470.0
SCR-3-C	7	1.36	244	73	4.0	39.1	160.1	7.9	5.0	80.0	3765	2087.8
SCR-3-C	8-11	1.52	176	69	2.6	36.7	208.5	6.9	6.5	80.0	3373	2036.9
SCR-7	7	1.36	244	73	4.0	39.1	160.1	11.4	7.3	80.0	3765	3032.2
SCR-7	8-11	1.52	176	69	2.6	36.7	208.5	10.3	9.7	80.0	3373	3046.2
SCR-7-C	7	1.36	244	73	4.0	39.1	160.1	6.7	4.3	80.0	3765	1783.8
SCR-7-C	8-11	1.52	176	69	2.6	36.7	208.5	6.1	5.7	80.0	3373	1794.0

20.3.2 Avon Lake Steam Plant

The Avon Lake steam plant is located within Lorain County, Ohio, and is part of the Cleveland Electric Illuminating Company system. The plant contains 8 oil-fired boilers and 4 coal-fired boilers. Boiler 12 is the only unit being considered for FGD retrofit in this evaluation with a gross generating capacity of 680 MW. Figure 20.3.2-1 presents the plant plot plan showing the location of the boilers and major associated auxiliary equipment.

Table 20.3.2-1 presents operational data for unit 12 at Avon Lake. This unit burns medium sulfur coal (2.5 percent sulfur). Coal is received by rail and transferred to the coal handling/storage area located a block away on the other side of the highway.

Particulate matter emissions for unit 12 are controlled with retrofit ESPs located behind the boiler/chimney. Dry ash from all units is disposed off-site.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 20.3.2-1 shows the general layout and location of the FGD control system. Two cases were considered for the placement of the FGD absorbers. First, the absorbers for FGD technologies could be located northwest of unit 12 between the retrofit ESPs and the highway. Second, the plant could purchase the land adjacent to the unit 12 ESPs and place the absorbers in the open, unobstructed area adjacent to the lake. For the first case, the lime preparation/storage area and the waste handling area would be located northwest of the plant (on the other side of the highway) on what is presently a parking area and, for the second case, they would be located on the purchased land (plant personnel indicated that this is a city park). Demolition and relocation of miscellaneous buildings, a road, and a parking area would be required to locate the absorbers adjacent to unit 12 (first case) and a factor 10 percent was assigned to general facilities. No demolition/relocation would be required for the second case; therefore, 5 percent was assigned to general facilities.

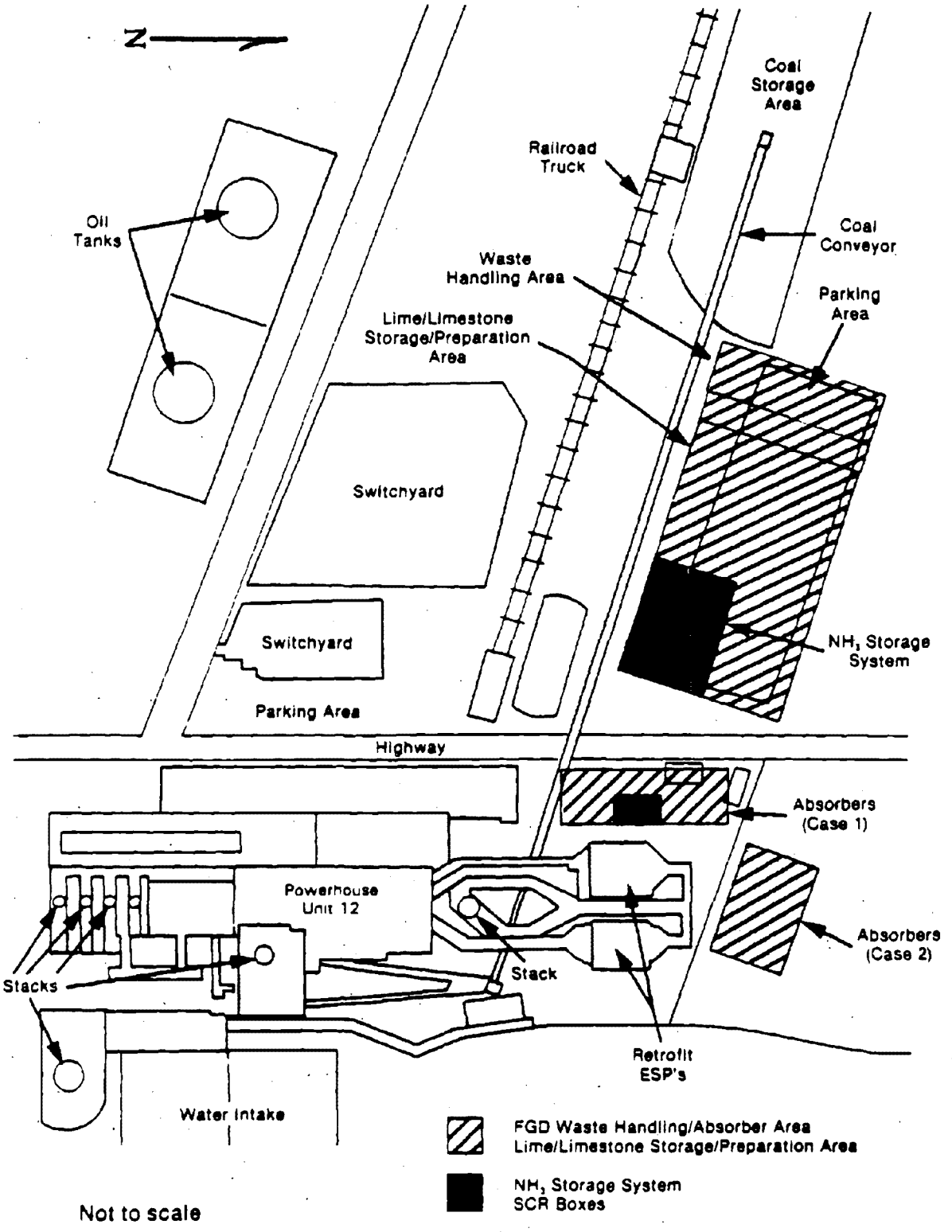


Figure 20.3.2-1. Avon Lake plant plot plan

TABLE 20.3.2-1. AVON LAKE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	12
GENERATING CAPACITY (MW)	680
CAPACITY FACTOR (PERCENT)	50
INSTALLATION DATE	1970
FIRING TYPE	OPPOSED WALL
COAL SULFUR CONTENT (PERCENT)	2.5
COAL HEATING VALUE (BTU/LB)	12300
COAL ASH CONTENT (PERCENT)	10
FLY ASH SYSTEM	PAID DISPOSAL/DRY
ASH DISPOSAL METHOD	OFF-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1978
EMISSION (LB/MM BTU)	0.03
REMOVAL EFFICIENCY	99.7
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	5.0
SURFACE AREA (1000 SQ FT)	1687
GAS FLOW RATE (1000 ACFM)	2600
SCA (SQ FT/1000 ACFM)	646
OUTLET TEMPERATURE (°F)	295

Retrofit Difficulty and Scope Adder Costs--

As mentioned above, unit 12 is the only unit being considered for FGD retrofit at the Avon Lake plant. As shown in Figure 20.3.2-1, the boiler is located directly in front of the chimney and the retrofit ESPs are located directly behind the chimney. The plant is bounded on one side by Lake Erie. In the first case, the FGD absorbers were located on the side of unit 12 where they would be bounded by the conveyor and a bridge, the retrofit ESPs, and a major highway. The second case would involve locating the FGD absorbers in an open area behind the ESPs relatively close to the lake. The site access/congestion factors assumed for the FGD cases reflect the congestion associated with the absorber locations mentioned above: a high site access/congestion factor for the first case and a low site access/congestion factor for the second case.

High site access/congestion factors were assigned to the flue gas handling system because significant congestion exists around the ESPs due to the existing ductwork and the coal conveyor. On the other hand, for the second case, the flue gas handling site access/congestion factors assigned were low for L/LS-FGD technologies because there are no obstructions between the absorber location and the ESPs. Short to moderate duct runs would be required for either of the above cases for all technologies.

The major scope adjustment costs and estimated retrofit factors for the FGD technologies are presented in Tables 20.3.2-2 and 20.3.2-3. There are no significant scope adjustments and related costs required for the retrofit of FGD control technologies at Avon lake. As shown in the table, there are no significant scope adjustments and costs associated with the retrofit of FGD control technologies at Avon Lake. The overall retrofit factors determined for the L/LS-FGD cases were medium for the first scenario and low for the second case.

LSD with reused ESP was the only LSD-FGD technology considered for unit 12 because the available SCA is large (>400). The retrofit factor determined for the LSD technology was medium to high (1.62) for the first case and medium (1.43) for the second case. A separate retrofit factor was developed for the upgrade of the ESPs for unit 12 and was used in the IAPCS model to estimate the particulate control upgrading costs if additional plate area was required. These factors, estimated for both scenarios discussed

TABLE 20.3.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR AVON LAKE UNIT 12 (CASE 1)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.53	1.56	
ESP REUSE CASE			1.62
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 20.3.2-3. SUMMARY OF RETROFIT FACTOR DATA FOR AVON LAKE UNIT 12 (CASE 2)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	0-100	0-100	
ESP REUSE			600-1,000
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.19	1.19	
ESP REUSE CASE			1.43
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

above, were high (1.58) for the first case and low (1.16) for the second case. The low retrofit factor reflects the space availability in front of the ESPs while the high factor reflects the limited space availability on either side of the ESPs for the first case.

Table 20.3.2-4 presents the cost estimates for L/LS and LSD-FGD case 1. The LSD-FGD costs include upgrading the ESPs for boiler 12. The low cost control case reduces capital and annual operating costs due to the elimination of spare scrubber modules, optimization of scrubber module size, and use of organic acid additives. Costs for case 2 were not presented because of the unlikelihood of purchasing the land where the city park is located.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent. Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 20.3.2-5.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at Avon Lake boiler 12. These controls include LNC modifications and SCR. The NO_x technologies applied at the Avon Lake boiler 12 were: LNB and SCR.

Low NO_x Combustion--

Unit 12 is a dry bottom, opposed wall fired boiler rated at 680 MW. Thus, the NO_x combustion control considered for this unit was LNB.

Table 20.3.2-4. Summary of FGD Control Costs for the Avon Lake Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD (1)	12	1.53	680	50	2.5	117.6	172.9	59.6	20.0	90.0	52554	1134.7
LC FGD (1)-C	12	1.53	680	50	2.5	117.6	172.9	34.7	11.6	90.0	52554	660.1
LFGD (1)	12	1.53	680	50	2.5	138.5	203.6	66.3	22.3	90.0	52554	1261.5
LFGD (1)-C	12	1.53	680	50	2.5	138.5	203.6	38.6	13.0	90.0	52554	734.6
LSD+ESP (1)	12	1.62	680	50	2.5	94.9	139.5	39.8	13.4	65.0	37783	1054.7
LSD+ESP (1)-C	12	1.62	680	50	2.5	94.9	139.5	23.3	7.8	65.0	37783	615.5

Table 20.3.2-5. Summary of Coal Switching/Cleaning Costs for the Avon Lake Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	12	1.00	680	50	2.5	19.8	29.2	41.8	14.0	63.0	36886	1133.9
CS/B+$15-C	12	1.00	680	50	2.5	19.8	29.2	24.1	8.1	63.0	36886	652.1
CS/B+$5	12	1.00	680	50	2.5	12.8	18.8	16.0	5.4	63.0	36886	433.5
CS/B+$5-C	12	1.00	680	50	2.5	12.8	18.8	9.2	3.1	63.0	36886	249.9

Table 20.3.2-6 presents the NO_x reduction performance results for this unit. The NO_x reduction performance was determined by examining the effects of heat release rates and furnace residence time on NO_x reduction through the use of the simplified procedures. Table 20.3.2-7 presents the estimated cost of retrofitting LNB on the coal-fired boiler at Avon Lake.

Selective Catalytic Reduction--

Table 20.3.2-6 presents the SCR retrofit results for unit 12. The results include process area retrofit factor and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESP to the reactor and from the reactor to the chimney.

The SCR reactor for unit 12 was located west of the retrofitted ESPs. The reactor was assigned a medium access/congestion factor because it was located in a highly congested area surrounded by the ESPs and two buildings; however, access to this area is relatively low. The reactor was assumed to be in an area with high underground obstructions. Table 20.3.2-7 presents the estimated cost of retrofitting SCR at the Avon Lake boiler.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for unit 12 were located west of the ESPs in the same manner as LSD-FGD technology. The retrofit of DSD and FSI technologies at the Avon Lake steam plant would be relatively easy. This is due to the long flue gas ducting residence time between the boilers and the large retrofit ESPs and because of the large ESP SCA. Table 20.3.2-8 presents a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies. Table 20.3.2-9 presents the costs estimated for FSI and DSD retrofit at Avon Lake.

TABLE 20.3.2-6. SUMMARY OF NOx RETROFIT RESULTS FOR AVON LAKE

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	12
FIRING TYPE	OPPOSED WALL
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	1970
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	40
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	114
New Duct Length (Feet)	300
New Duct Costs (1000$)	4562
New Heat Exchanger (1000$)	5887
TOTAL SCOPE ADDER COSTS (1000$)	10563
RETROFIT FACTOR FOR SCR	1.34
GENERAL FACILITIES (PERCENT)	13

Table 20.3.2-7. NOx Control Cost Results for the Avon Lake Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	12	1.00	680	50	2.5	5.5	8.1	1.2	0.4	40.0	5031	235.9
LNC-LNB-C	12	1.00	680	50	2.5	5.5	8.1	0.7	0.2	40.0	5031	140.1
SCR-3	12	1.34	680	50	2.5	87.8	129.1	31.6	10.6	80.0	10061	3144.7
SCR-3-C	12	1.34	680	50	2.5	87.8	129.1	18.5	6.2	80.0	10061	1840.8
SCR-7	12	1.34	680	50	2.5	87.8	129.1	26.1	8.8	80.0	10061	2591.4
SCR-7-C	12	1.34	680	50	2.5	87.8	129.1	15.3	5.1	80.0	10061	1523.8

TABLE 20.3.2-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR AVON LAKE UNIT 12

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	126
TOTAL COST (1000$)	
ESP UPGRADE CASE	126
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

Table 20.3.2-9. Summary of DSD/FSI Control Costs for the Avon Lake Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	12	1.00	680	50	2.5	27.9	41.1	19.7	6.6	43.0	25023	785.9
DSD+ESP-C	12	1.00	680	50	2.5	27.9	41.1	11.4	3.8	43.0	25023	455.3
FSI+ESP-50	12	1.00	680	50	2.5	23.0	33.8	24.6	8.3	50.0	29196	843.2
FSI+ESP-50-C	12	1.00	680	50	2.5	23.0	33.8	14.2	4.8	50.0	29196	486.6
FSI+ESP-70	12	1.00	680	50	2.5	23.4	34.4	25.1	8.4	70.0	40874	615.2
FSI+ESP-70-C	12	1.00	680	50	2.5	23.4	34.4	14.5	4.9	70.0	40874	355.0

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering criteria presented in Section 2 were used to determine the applicability of these technologies at the Avon Lake plant. Boiler 12 at Avon Lake would not be considered a good candidate for AFBC retrofit and AFBC or coal gasification/combined cycle repowering because of its large size (680 MW).

20.3.3 Eastlake Steam Plant

The Eastlake steam plant is located within Lake County, Ohio, as part of Cleveland Electric Illuminating Company system. The plant contains five coal-fired boilers with a total gross generating capacity of 1,372 MW. Figure 20.3.3-1 presents the plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 20.3.3-1 presents operational data for the existing equipment at the Eastlake steam plant. All boilers burn high sulfur coal (3.0 percent sulfur). Coal shipments are received by railroad and conveyed to a single coal pile located behind the existing ESPs.

Particulate matter emissions for boilers 1-4 are controlled with retrofit ESPs located behind the old ESPs/chimney of each unit. Particulate emissions for boiler 5 are controlled with ESPs located immediately behind the unit. Boilers 1-4 utilize four ducts each going into a common stack; unit 5 has its own chimney. Fly ash from all units is dry and disposed off-site as there is no space available on-site.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 20.3.3-1 shows the general layout and location of the FGD control system. The absorbers for L/LS-FGD and LSD-FGD for all units would be located west of the chimney between the coal pile and the lake. There is just enough space available and only minor relocation and demolition would be required

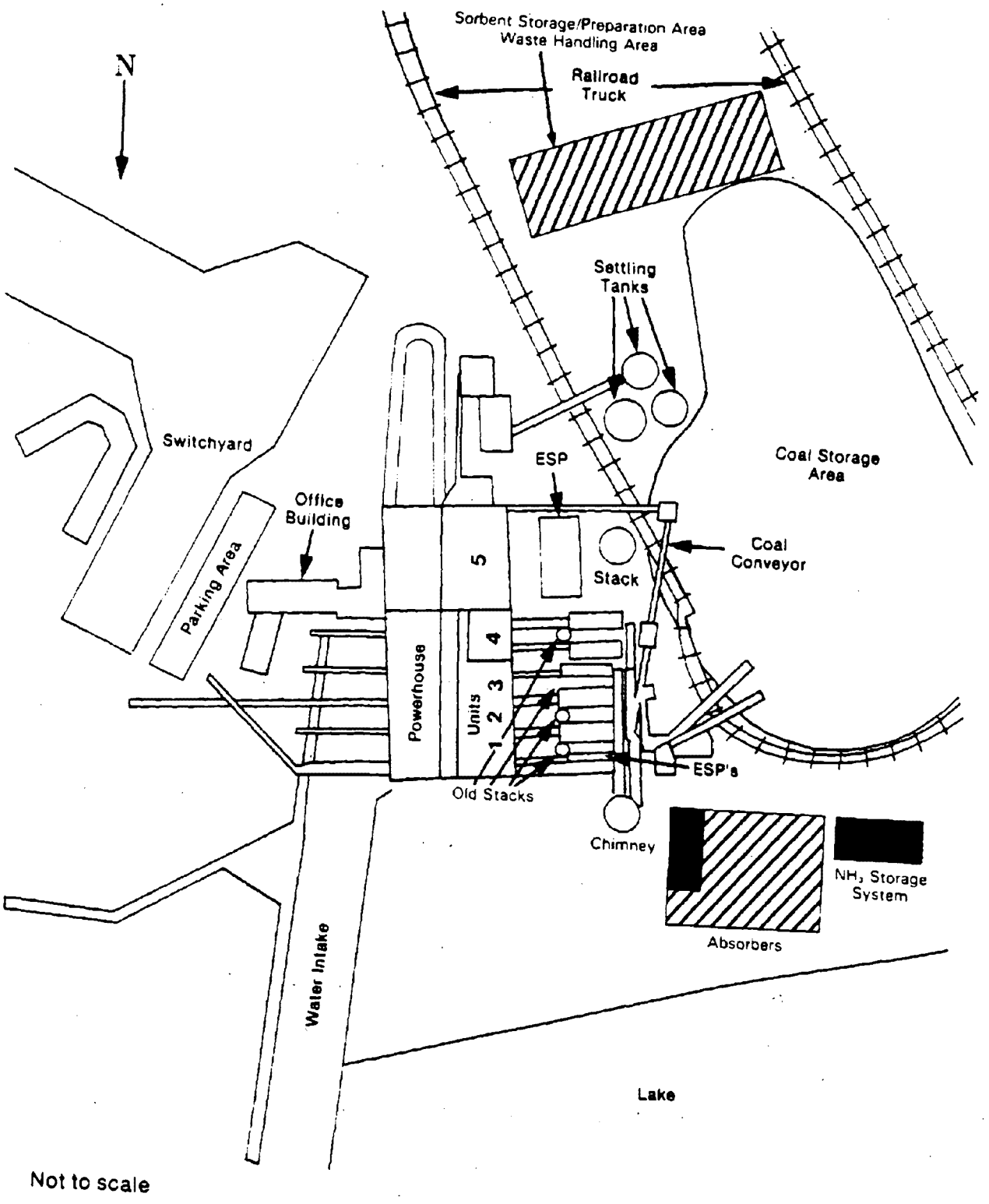


Figure 20.3.3-1. Eastlake plant plot plan

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TABLE 20.3.3-1. EASTLAKE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1-3	4	5
GENERATING CAPACITY (MW-each)	144	260	680
CAPACITY FACTOR (PERCENT)	62,65,74	56	60
INSTALLATION DATE	1953	1954	1972
FIRING TYPE	TANG	TANG	OWF
COAL SULFUR CONTENT (PERCENT)	2.9	2.9	3.0
COAL HEATING VALUE (BTU/LB)	12100	12100	12100
COAL ASH CONTENT (PERCENT)	10.7	10.7	10.7
FLY ASH SYSTEM	DRY HANDLING		
ASH DISPOSAL METHOD	OFF-SITE		
STACK NUMBER	1	1	2
COAL DELIVERY METHODS	RAILROAD		
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1979-80	1981	1972
EMISSION (LB/MM BTU)	0.03	0.02	0.09
REMOVAL EFFICIENCY	99.6	99.6	99.4
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	5.0	5.0	5.0
SURFACE AREA (1000 SQ FT)	379	553	449
GAS FLOW RATE (1000 ACFM)	620	995	1950
SCA (SQ FT/1000 ACFM)	611	556	230
OUTLET TEMPERATURE (°F)	300	280	285

entailing moving the general facility equipment buildings. Therefore, a 5 percent general facilities factor was assigned. The lime storage/ preparation area and waste handling area would be located south of the coal pile.

Retrofit Difficulty and Scope Adder Costs--

The absorbers for all units would be located on the lakeside beside unit 1. A high site access/congestion factor was assigned to the absorber locations due to the following reasons: access difficulty from the lake, powerhouse, and coal pile and poor quality of the soil (low bearing soil) for building because it is so close to the lake.

The flue gas from units 1-4 are going into a common chimney. For flue gas handling, short to medium breaching duct runs would be required to divert flue gas to the absorbers and back to the existing chimney. A low site access/congestion factor was assigned to the flue gas handling system for units 1-4 because of no significant obstacles around the existing chimney.

By contrast, flue gas handling for unit 5 would require long duct runs for L/LS-FGD cases for diverting flue gas from the absorbers back to the chimney. A high site access/congestion factor was assigned to the flue gas handling system because of limited space below the unit 1-4 ESPs, the coal conveyor, and other auxiliary equipment. For reusing the existing chimney, more than 1,000 feet of duct run would be required in a high site access/ congestion area. Therefore, to decrease the duct run needed for L/LS-FGD case at unit 5, a new chimney was constructed adjacent to the absorbers on the side of the lake.

The major scope adjustment costs and retrofit factors estimated for the FGD control technologies are presented in Tables 20.3.3-2 through 20.3.2-4. No large scope adder cost is required for the Eastlake plant. The overall retrofit factors determined for the L/LS-FGD cases ranged from moderate to high (1.64 to 1.91).

LSD with reused ESP was the only LSD-FGD technology considered for units 1-4 because of boilers presently having large SCA (>380). For flue gas handling for LSD cases, medium duct runs would be required for units 1 and 2 and long duct runs for units 3 and 4. A high site access/congestion factor was assigned for units 1-4 flue gas handling system. This was due to the

TABLE 20.3.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR EASTLAKE UNITS 1-2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	YES	NO	YES
RETROFIT FACTORS			
FGD SYSTEM	1.64	1.48	
ESP REUSE CASE			1.82
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 20.3.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR EASTLAKE UNITS 3-4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	YES	NO	YES
RETROFIT FACTORS			
FGD SYSTEM	1.64	1.48	
ESP REUSE CASE			1.91
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	5	5

TABLE 20.3.3-4. SUMMARY OF RETROFIT FACTOR DATA FOR EASTLAKE UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	HIGH	HIGH
FLUE GAS HANDLING	HIGH	HIGH	
ESP REUSE CASE			NA
BAGHOUSE CASE			HIGH
DUCT WORK DISTANCE (FEET)	600-1000	600-1000	
ESP REUSE			NA
BAGHOUSE			600-1000
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	HIGH
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NO	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	YES	YES	YES
ESTIMATED COST (1000$)	4760	4760	4760
OTHER	YES	NO	YES
RETROFIT FACTORS			
FGD SYSTEM	1.91	1.75	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.98
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.58
GENERAL FACILITIES (PERCENT)	5	5	5

site access congestion created to route flue gas from the boilers to the absorbers and back to the ESPs. This factor reflects the access difficulty created by the old chimneys, old ESPs, and duct runs. For unit 5, extremely long duct runs would be required for LSD cases. Because the ESPs are small (SCA = 230) and access congestion for ducting would be very high, a new baghouse was considered for unit 5. The retrofit factors determined for the LSD technology case for units 1-4 were high (1.82 to 1.91) and did not include costs for upgrading existing particulate controls. A separate retrofit factor was developed for upgrading units 1-4 ESPs (1.58) and was used in the IAPCS model to estimate particulate control upgrading costs. The access/congestion factor associated with the upgrading of the ESPs would be high due to the close proximity of the ESPs, duct runs, and coal conveyor. The retrofit factor determined for LSD technology for unit 5 was high (1.98) and did not include new baghouse costs. A separate retrofit factor was estimated for a new particulate control (1.58) and a high site access/congestion factor was assigned to the new baghouse because of access difficulty from the lake, powerhouse, and coal pile, in addition to poor quality of the soil.

Table 20.3.3-5 presents the costs estimated for L/LS and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 1-4 and installing a new baghouse to handle the additional particulate loading for boiler 5. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, optimization of scrubber size, and use of organic acid additives.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing

Table 20.3.3-5. Summary of FGD Control Costs for the Eastlake Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1-4	1.64	692	63	2.9	121.1	174.9	69.7	18.3	90.0	79652	875.6
LC FGD	5	1.91	680	60	3.0	136.9	201.4	73.6	20.6	90.0	77114	954.1
LC FGD-C	1-4	1.64	692	63	2.9	121.1	174.9	40.5	10.6	90.0	79652	508.5
LC FGD-C	5	1.91	680	60	3.0	136.9	201.4	42.8	12.0	90.0	77114	554.6
LFGD	1	1.64	144	62	2.9	56.2	390.5	26.2	33.5	90.0	16312	1608.0
LFGD	2	1.64	144	65	2.9	56.2	390.5	26.6	32.4	90.0	17101	1553.5
LFGD	3	1.64	144	74	2.9	56.2	390.5	27.6	29.5	90.0	19469	1416.3
LFGD	4	1.64	260	56	2.9	79.8	307.0	37.4	29.3	90.0	26602	1407.1
LFGD	5	1.91	680	60	3.0	170.1	250.2	84.2	23.6	90.0	77114	1091.7
LFGD-C	1	1.64	144	62	2.9	56.2	390.5	15.3	19.5	90.0	16312	936.7
LFGD-C	2	1.64	144	65	2.9	56.2	390.5	15.5	18.9	90.0	17101	904.8
LFGD-C	3	1.64	144	74	2.9	56.2	390.5	16.1	17.2	90.0	19469	824.4
LFGD-C	4	1.64	260	56	2.9	79.8	307.0	21.8	17.1	90.0	26602	819.7
LFGD-C	5	1.91	680	60	3.0	170.1	250.2	49.0	13.7	90.0	77114	635.4
LSD+ESP	1	1.82	144	62	2.9	29.1	202.4	13.9	17.8	73.0	13263	1050.4
LSD+ESP	2	1.82	144	65	2.9	29.1	202.4	14.1	17.2	73.0	13905	1013.6
LSD+ESP	3	1.91	144	74	2.9	30.4	210.8	14.9	16.0	73.0	15830	943.6
LSD+ESP	4	1.91	260	56	2.9	48.4	186.0	20.9	16.4	66.0	19574	1068.5
LSD+ESP-C	1	1.82	144	62	2.9	29.1	202.4	8.1	10.4	73.0	13263	611.7
LSD+ESP-C	2	1.82	144	65	2.9	29.1	202.4	8.2	10.0	73.0	13905	590.1
LSD+ESP-C	3	1.91	144	74	2.9	30.4	210.8	8.7	9.3	73.0	15830	549.2
LSD+ESP-C	4	1.91	260	56	2.9	48.4	186.0	12.2	9.6	66.0	19574	623.2
LSD+FF	5	1.98	680	60	3.0	180.1	264.9	67.3	18.8	81.0	69708	965.2
LSD+FF-C	5	1.98	680	60	3.0	180.1	264.9	39.4	11.0	81.0	69708	564.6

area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent. Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 20.3.3-6.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the East Lake steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: OFA and SCR for units 1 to 4 and LNB and SCR for unit 5.

Low NO_x Combustion--

Units 1 to 4 are dry bottom, tangential-fired boilers; units 1 to 3 are rated at 123 MW each while unit 4 is rated at 208 MW. Unit 5 is a dry bottom, opposed wall-fired boiler rated at 680 MW. The combustion modification technique applied for this evaluation to units 1 to 4 was OFA and that applied to unit 5 was LNB. As Tables 20.3.3-7 and 20.3.3-8 show, the OFA NO_x reduction performance for units 1 to 4 was estimated to be 20 percent and the LNB NO_x reduction performance for unit 5 was estimated to be 40 percent. These reduction performance levels were assessed by examining the effects of heat release rates and furnace residence time through the use of the simplified NO_x procedures. Table 20.3.3-9 presents the cost of retrofitting OFA and LNB at the Eastlake boilers.

Selective Catalytic Reduction--

Tables 20.3.3-7 and 20.3.3-8 present the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 1 to 4 were located close to the lakeside beside the chimeny. On the other hand, the SCR reactor for unit 5 was

Table 20.3.3-6. Summary of Coal Switching/Cleaning Costs for the Eastlake Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	144	62	2.9	5.4	37.5	11.6	14.8	69.0	12477	930.7
CS/B+$15	2	1.00	144	65	2.9	5.4	37.5	12.1	14.8	69.0	13081	926.1
CS/B+$15	3	1.00	144	74	2.9	5.4	37.5	13.6	14.6	69.0	14892	914.6
CS/B+$15	4	1.00	260	56	2.9	8.8	34.0	18.6	14.6	69.0	20348	914.8
CS/B+$15	5	1.00	680	60	3.0	20.8	30.6	50.6	14.2	70.0	59874	844.8
CS/B+$15-C	1	1.00	144	62	2.9	5.4	37.5	6.7	8.5	69.0	12477	535.2
CS/B+$15-C	2	1.00	144	65	2.9	5.4	37.5	7.0	8.5	69.0	13081	532.4
CS/B+$15-C	3	1.00	144	74	2.9	5.4	37.5	7.8	8.4	69.0	14892	525.6
CS/B+$15-C	4	1.00	260	56	2.9	8.8	34.0	10.7	8.4	69.0	20348	526.1
CS/B+$15-C	5	1.00	680	60	3.0	20.8	30.6	29.1	8.1	70.0	59874	485.6
CS/B+$5	1	1.00	144	62	2.9	3.9	27.2	4.9	6.3	69.0	12477	392.0
CS/B+$5	2	1.00	144	65	2.9	3.9	27.2	5.1	6.2	69.0	13081	388.4
CS/B+$5	3	1.00	144	74	2.9	3.9	27.2	5.6	6.1	69.0	14892	379.3
CS/B+$5	4	1.00	260	56	2.9	6.1	23.6	7.6	6.0	69.0	20348	373.9
CS/B+$5	5	1.00	680	60	3.0	13.8	20.2	19.8	5.5	70.0	59874	331.1
CS/B+$5-C	1	1.00	144	62	2.9	3.9	27.2	2.8	3.6	69.0	12477	226.0
CS/B+$5-C	2	1.00	144	65	2.9	3.9	27.2	2.9	3.6	69.0	13081	223.8
CS/B+$5-C	3	1.00	144	74	2.9	3.9	27.2	3.3	3.5	69.0	14892	218.5
CS/B+$5-C	4	1.00	260	56	2.9	6.1	23.6	4.4	3.4	69.0	20348	215.6
CS/B+$5-C	5	1.00	680	60	3.0	13.8	20.2	11.4	3.2	70.0	59874	190.7

TABLE 20.3.3-7. SUMMARY OF NOx RETROFIT RESULTS FOR EASTLAKE UNITS 1-3

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	TANG	TANG	TANG
TYPE OF NOx CONTROL	OFA	OFA	OFA
FURNACE VOLUME (1000 CU FT)	NA	NA	NA
BOILER INSTALLATION DATE	1953	1953	1953
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	25	25
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	HIGH
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	NA	NA
Ductwork Demolition (1000$)	36	36	36
New Duct Length (Feet)	200	150	150
New Duct Costs (1000$)	1227	920	920
New Heat Exchanger (1000$)	2320	2320	2320
TOTAL SCOPE ADDER COSTS (1000$)	3582	3275	3275
RETROFIT FACTOR FOR SCR	1.52	1.52	1.52
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 20.3.3-8. SUMMARY OF NOx RETROFIT RESULTS FOR EASTLAKE UNITS 4-5

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	4	5
FIRING TYPE	TANG	OWF
TYPE OF NOx CONTROL	OFA	LNB
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1954	1972
SLAGGING PROBLEM	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	25	40
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	NA
Ductwork Demolition (1000$)	55	114
New Duct Length (Feet)	200	950
New Duct Costs (1000$)	1733	14447
New Heat Exchanger (1000$)	3307	5887
TOTAL SCOPE ADDER COSTS (1000$)	5095	20448
RETROFIT FACTOR FOR SCR	1.52	1.16
GENERAL FACILITIES (PERCENT)	13	25

Table 20.3.3-9. NOx Control Cost Results for the Eastlake Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	5	1.00	680	60	3.0	5.5	8.1	1.2	0.3	40.0	6151	192.9
LNC-LNB-C	5	1.00	680	60	3.0	5.5	8.1	0.7	0.2	40.0	6151	114.5
LNC-OFA	1	1.00	144	62	2.9	0.7	5.0	0.2	0.2	25.0	601	257.3
LNC-OFA	2	1.00	144	65	2.9	0.7	5.0	0.2	0.2	25.0	630	245.4
LNC-OFA	3	1.00	144	74	2.9	0.7	5.0	0.2	0.2	25.0	717	215.5
LNC-OFA	4	1.00	260	56	2.9	0.9	3.5	0.2	0.2	25.0	980	199.8
LNC-OFA-C	1	1.00	144	62	2.9	0.7	5.0	0.1	0.1	25.0	601	152.8
LNC-OFA-C	2	1.00	144	65	2.9	0.7	5.0	0.1	0.1	25.0	630	145.7
LNC-OFA-C	3	1.00	144	74	2.9	0.7	5.0	0.1	0.1	25.0	717	128.0
LNC-OFA-C	4	1.00	260	56	2.9	0.9	3.5	0.1	0.1	25.0	980	118.6
SCR-3	1	1.52	144	62	2.9	27.8	193.2	9.1	11.6	80.0	1923	4707.2
SCR-3	2	1.52	144	65	2.9	27.5	191.0	9.0	11.0	80.0	2016	4474.9
SCR-3	3	1.52	144	74	2.9	27.5	191.0	9.1	9.7	80.0	2295	3963.5
SCR-3	4	1.52	260	56	2.9	43.1	165.7	14.4	11.3	80.0	3136	4594.8
SCR-3	5	1.16	680	60	3.0	93.6	137.6	32.8	9.2	80.0	12303	2669.6
SCR-3-C	1	1.52	144	62	2.9	27.8	193.2	5.3	6.8	80.0	1923	2761.8
SCR-3-C	2	1.52	144	65	2.9	27.5	191.0	5.3	6.5	80.0	2016	2625.0
SCR-3-C	3	1.52	144	74	2.9	27.5	191.0	5.3	5.7	80.0	2295	2324.6
SCR-3-C	4	1.52	260	56	2.9	43.1	165.7	8.4	6.6	80.0	3136	2694.1
SCR-3-C	5	1.16	680	60	3.0	93.6	137.6	19.2	5.4	80.0	12303	1563.6
SCR-7	1	1.52	144	62	2.9	27.8	193.2	7.9	10.1	80.0	1923	4092.6
SCR-7	2	1.52	144	65	2.9	27.5	191.0	7.8	9.6	80.0	2016	3888.7
SCR-7	3	1.52	144	74	2.9	27.5	191.0	7.9	8.5	80.0	2295	3448.6
SCR-7	4	1.52	260	56	2.9	43.1	165.7	12.3	9.6	80.0	3136	3914.5
SCR-7	5	1.16	680	60	3.0	93.6	137.6	27.3	7.6	80.0	12303	2216.0
SCR-7-C	1	1.52	144	62	2.9	27.8	193.2	4.6	5.9	80.0	1923	2409.7
SCR-7-C	2	1.52	144	65	2.9	27.5	191.0	4.6	5.6	80.0	2016	2289.1
SCR-7-C	3	1.52	144	74	2.9	27.5	191.0	4.7	5.0	80.0	2295	2029.5
SCR-7-C	4	1.52	260	56	2.9	43.1	165.7	7.2	5.7	80.0	3136	2304.3
SCR-7-C	5	1.16	680	60	3.0	93.6	137.6	16.0	4.5	80.0	12303	1303.7

located in a parking lot area diagonally opposite those reactors for units 1 to 4 on the other side of the powerhouse.

High access/congestion factors were assigned to the SCR reactors for units 1 to 4 due to access difficulty from the lake, powerhouse, and coal pile and poor soil quality for building near the lake. The SCR reactor for unit 5 was assigned a low access/congestion factor due to the relatively easy access to this area and open space for construction. Because the parking lot will have to be relocated, a 25 percent general facility factor was assigned for the SCR reactor for unit 5. All five reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor. Table 20.3.3-9 presents the estimated cost of retrofitting SCR at the EastLake boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbert receiving/storage/preparation areas for all units were located west of the existing chimney along the lakeside. For units 1-4, the retrofit of DSD and FSI technologies at the Eastlake steam plant would be relatively easy. There is sufficient flue gas ducting residence time between the boilers and the retrofit ESPs and large SCAs (>380). The retrofit of FSI and DSD unit 5 would be difficult because of the marginal ESP size. Additionally, the unit 5 ESPs are located in a high site access/congestion area making the addition of plate area more costly. Therefore, it was assumed that for DSD new particulate controls would be needed resulting in 700 feet of duct run required to divert the flue gas from the boiler to the baghouse. For FSI, it was assumed that the ESPs for all units could be upgraded and reused. Tables 20.3.3-10 through 20.3.3-12 present a summary of the site access/congestion factors for DSD and FSI technologies at the

TABLE 20.3.3-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR EASTLAKE UNITS 1, 2 OR 3

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	HIGH
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	39
TOTAL COST (1000$)	
ESP UPGRADE CASE	39
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.37
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

TABLE 20.3.3-11. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR EASTLAKE UNIT 4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	HIGH
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	61
TOTAL COST (1000$)	
ESP UPGRADE CASE	61
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.37
ESP UPGRADE	1.55
NEW BAGHOUSE	NA

TABLE 20.3.3-12. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR EASTLAKE UNIT 5

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE (FSI)	HIGH
NEW BAGHOUSE (DSD)	HIGH
SCOPE ADDERS	
NEW CHIMNEY (DSD)	YES
ESTIMATED COST (1000$)	4,760
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	700
ESTIMATED COST (1000$)	9869
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	126
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	126
A NEW BAGHOUSE CASE (DSD)	14755
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE (FSI)	1.55
NEW BAGHOUSE (DSD)	1.55

Eastlake steam plant. Table 20.3.3-13 presents the costs estimated to retrofit DSD and FSI at the Eastlake plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Eastlake plant. Boilers 1-4 at the Eastlake plant would be considered good candidates for AFBC retrofit because of the small boiler sizes (<300 MW). However, the high unit capacity factors make these units poor candidates because of replacement power costs during downtime and marginal heat rate improvements. Unit 5 would not be a good candidate due to its large boiler size (680 MW) and because it is relatively new (built in 1972).

Table 20.3.3-13. Summary of DSD/FSI Control Costs for the Eastlake Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	144	62	2.9	9.7	67.6	8.1	10.4	47.0	8535	952.3
DSD+ESP	2	1.00	144	65	2.9	9.7	67.6	8.3	10.1	47.0	8948	925.3
DSD+ESP	3	1.00	144	74	2.9	9.7	67.6	8.7	9.4	47.0	10187	857.3
DSD+ESP	4	1.00	260	56	2.9	13.9	53.5	10.7	8.4	44.0	12890	827.5
DSD+ESP-C	1	1.00	144	62	2.9	9.7	67.6	4.7	6.0	47.0	8535	550.7
DSD+ESP-C	2	1.00	144	65	2.9	9.7	67.6	4.8	5.8	47.0	8948	535.0
DSD+ESP-C	3	1.00	144	74	2.9	9.7	67.6	5.0	5.4	47.0	10187	495.5
DSD+ESP-C	4	1.00	260	56	2.9	13.9	53.5	6.2	4.8	44.0	12890	478.9
DSD+FF	5	1.00	680	60	3.0	109.0	160.3	44.3	12.4	68.0	58416	759.1
DSD+FF-C	5	1.00	680	60	3.0	109.0	160.3	25.9	7.2	68.0	58416	443.3
FSI+ESP-50	1	1.00	144	62	2.9	9.3	64.8	9.0	11.5	50.0	9062	995.3
FSI+ESP-50	2	1.00	144	65	2.9	9.3	64.8	9.3	11.3	50.0	9501	977.5
FSI+ESP-50	3	1.00	144	74	2.9	9.3	64.8	10.1	10.8	50.0	10816	932.9
FSI+ESP-50	4	1.00	260	56	2.9	13.7	52.6	13.5	10.6	50.0	14779	916.5
FSI+ESP-50	5	1.00	680	60	3.0	35.1	51.6	36.1	10.1	50.0	42840	842.0
FSI+ESP-50-C	1	1.00	144	62	2.9	9.3	64.8	5.2	6.7	50.0	9062	574.9
FSI+ESP-50-C	2	1.00	144	65	2.9	9.3	64.8	5.4	6.5	50.0	9501	564.5
FSI+ESP-50-C	3	1.00	144	74	2.9	9.3	64.8	5.8	6.2	50.0	10816	538.4
FSI+ESP-50-C	4	1.00	260	56	2.9	13.7	52.6	7.8	6.1	50.0	14779	529.2
FSI+ESP-50-C	5	1.00	680	60	3.0	35.1	51.6	20.8	5.8	50.0	42840	486.1
FSI+ESP-70	1	1.00	144	62	2.9	9.5	66.0	9.2	11.8	70.0	12687	724.9
FSI+ESP-70	2	1.00	144	65	2.9	9.5	66.0	9.5	11.6	70.0	13301	712.0
FSI+ESP-70	3	1.00	144	74	2.9	9.5	66.0	10.3	11.0	70.0	15142	679.8
FSI+ESP-70	4	1.00	260	56	2.9	13.9	53.6	13.8	10.8	70.0	20690	668.3
FSI+ESP-70	5	1.00	680	60	3.0	35.5	52.2	36.8	10.3	70.0	59977	613.4
FSI+ESP-70-C	1	1.00	144	62	2.9	9.5	66.0	5.3	6.8	70.0	12687	418.7
FSI+ESP-70-C	2	1.00	144	65	2.9	9.5	66.0	5.5	6.7	70.0	13301	411.2
FSI+ESP-70-C	3	1.00	144	74	2.9	9.5	66.0	5.9	6.4	70.0	15142	392.3
FSI+ESP-70-C	4	1.00	260	56	2.9	13.9	53.6	8.0	6.3	70.0	20690	385.9
FSI+ESP-70-C	5	1.00	680	60	3.0	35.5	52.2	21.2	5.9	70.0	59977	354.1

20.4 COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY

20.4.1 Conesville Steam Plant

Information for Conesville steam plant appears in U.S. EPA report number EPA-600/7-88/014, entitled "Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Retrofit Study" (NTIS PB88-244447/AS).

20.4.2 Picway Steam Plant

The Picway steam plant is located in Coshocton County, Ohio as part of the Columbus and Southern Ohio Electric Company system. The plant contains one coal-fired boiler with a total gross generating capacity of 106 MW. Tables 20.4.2-1 through 20.4.2-8 summarize the plant operational data and present the SO_2 and NO_x control cost and performance estimates.

TABLE 20.4.2-1. PICWAY STEAM PLANT OPERATIONAL DATA *

BOILER NUMBER	9
GENERATING CAPACITY (MW)	106
CAPACITY FACTOR (PERCENT)	42
INSTALLATION DATE	1955
FIRING TYPE	FRONT WALL
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	2.5
COAL HEATING VALUE (BTU/LB)	11400
COAL ASH CONTENT (PERCENT)	10.4
FLY ASH SYSTEM	WET DISPOSAL
ASH DISPOSAL METHOD	PONDS/ON-SITE
STACK NUMBER	9
COAL DELIVERY METHODS	TRUCK
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1976
EMISSION (LB/MM BTU)	0.05
REMOVAL EFFICIENCY	99.7
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	3.0-9.0
SURFACE AREA (1000 SQ FT)	134.6
EXIT GAS FLOW RATE (1000 ACFM)	442
SCA (SQ FT/1000 ACFM)	305
OUTLET TEMPERATURE (°F)	310

* Some information was obtained from plant personnel.

TABLE 20.4.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR PICWAY UNIT 9 *

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	988	NA	988
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.42	NA	
ESP REUSE CASE			1.43
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

* L/S-FGD and LSD-FGD absorbers for unit 9 would be located south of unit 9.

Table 20.4.2-3. Summary of FGD Control Costs for the Picway Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	9	1.42	106	42	2.5	29.6	279.3	14.3	36.6	90.0	7508	1901.4
LC FGD-C	9	1.42	106	42	2.5	29.6	279.3	8.3	21.3	90.0	7508	1107.1
LFGD	9	1.42	106	42	2.5	43.3	408.4	18.7	47.8	90.0	7508	2485.3
LFGD-C	9	1.42	106	42	2.5	43.3	408.4	10.9	27.9	90.0	7508	1449.7
LSD+ESP	9	1.43	106	42	2.5	19.4	182.6	9.5	24.2	76.0	6365	1485.3
LSD+ESP-C	9	1.43	106	42	2.5	19.4	182.6	5.5	14.1	76.0	6365	864.6

Table 20.4.2-4. Summary of Coal Switching/Cleaning Costs for the Picway Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	9	1.00	106	42	2.5	4.2	39.8	6.2	15.9	66.0	5527	1123.9
CS/B+$15-C	9	1.00	106	42	2.5	4.2	39.8	3.6	9.2	66.0	5527	647.3
CS/B+$5	9	1.00	106	42	2.5	3.1	29.4	2.8	7.2	66.0	5527	506.2
CS/B+$5-C	9	1.00	106	42	2.5	3.1	29.4	1.6	4.1	66.0	5527	292.6

TABLE 20.4.2-5. SUMMARY OF NOx RETROFIT RESULTS FOR PICWAY

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	9
FIRING TYPE	FWF
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	NA
BOILER INSTALLATION DATE	1955
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	40
SCR RETROFIT RESULTS *	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	28
New Duct Length (Feet)	300
New Duct Costs (1000$)	1538
New Heat Exchanger (1000$)	1930
TOTAL SCOPE ADDER COSTS (1000$)	3496
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

* Cold side SCR reactors for unit 9 would be located south of unit 9.

Table 20.4.2-6. NOx Control Cost Results for the Picway Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	9	1.00	106	42	2.5	2.6	24.7	0.6	1.4	40.0	719	785.1
LNC-LNB-C	9	1.00	106	42	2.5	2.6	24.7	0.3	0.9	40.0	719	466.1
SCR-3	9	1.16	106	42	2.5	19.7	186.1	6.4	16.5	80.0	1438	4468.3
SCR-3-C	9	1.16	106	42	2.5	19.7	186.1	3.8	9.7	80.0	1438	2621.5
SCR-7	9	1.16	106	42	2.5	19.7	186.1	5.5	14.2	80.0	1438	3857.8
SCR-7-C	9	1.16	106	42	2.5	19.7	186.1	3.3	8.4	80.0	1438	2271.7

TABLE 20.4.2-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR PICWAY UNIT 9

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	988
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	31
TOTAL COST (1000$)	
ESP UPGRADE CASE	1019
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.36
NEW BAGHOUSE	NA

The duct residence time between unit 9 and the unit 9 ESPs is short; however, the ESPs are large enough for FSI and DSD.

Table 20.4.2-8. Summary of DSD/FSI Control Costs for the Picway Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	9	1.00	106	42	2.5	8.9	84.0	6.2	16.0	49.0	4059	1533.8
DSD+ESP-C	9	1.00	106	42	2.5	8.9	84.0	3.6	9.2	49.0	4059	888.6
FSI+ESP-50	9	1.00	106	42	2.5	8.9	84.4	5.9	15.1	50.0	4171	1414.6
FSI+ESP-50-C	9	1.00	106	42	2.5	8.9	84.4	3.4	8.8	50.0	4171	820.1
FSI+ESP-70	9	1.00	106	42	2.5	9.0	84.7	6.0	15.3	70.0	5840	1022.0
FSI+ESP-70-C	9	1.00	106	42	2.5	9.0	84.7	3.5	8.9	70.0	5840	592.5

20.4.3 Poston Steam Plant

The Poston steam plant is located within Athen County, Ohio, as part of the Columbus and Southern Ohio Electric Company system. The plant contains four coal-fired boilers with a gross generating capacity of 232 MW. Figure 20.4.3-1 shows the plant and major associated auxiliary equipment at the Poston plant.

Table 20.4.3-1 presents the operational data for the existing equipment at the Poston plant. The boilers burn medium to high sulfur coal (3.0 percent sulfur). The coal for the plant is received by truck and conveyed to a coal storage/handling area located beside (east) unit 1.

Particulate matter emissions for all units are controlled with ESPs located behind each unit. The ash from the units is wet sluiced to an ash pond south of the switch yard.

Lime/Limestone and Lime Spray Drying FGD Costs--

The L/LS-FGD absorbers were located behind the chimney where several small buildings and miscellaneous tanks would be relocated in order to make space available. The LSD absorbers were located to the east of the powerhouse in an area between the ESPs and the cooling towers. The lime preparation/storage area was located adjacent to the absorbers to the northeast, between the powerhouse and the cooling tower. Finally, the temporary waste handling area was located to the west between the ash pond and the switch yard. The 10 percent general facilities adjustment is required for the demolition and replacement of several small buildings and miscellaneous tanks for the placement of the absorbers as close as possible to the chimney.

Retrofit Difficulty and Scope Adder Costs--

The equipment at the Poston plant includes four boilers, two abandoned chimneys and one common chimney, old ESPs, and retrofit ESPs. The boilers sit side by side in ascending order. The old ESPs are still in place and are located immediately behind the boilers while the retrofit ESPs are located directly behind these old ESPs. Although there are three chimneys at the plant, only one is used and it is located behind (north) the units 2

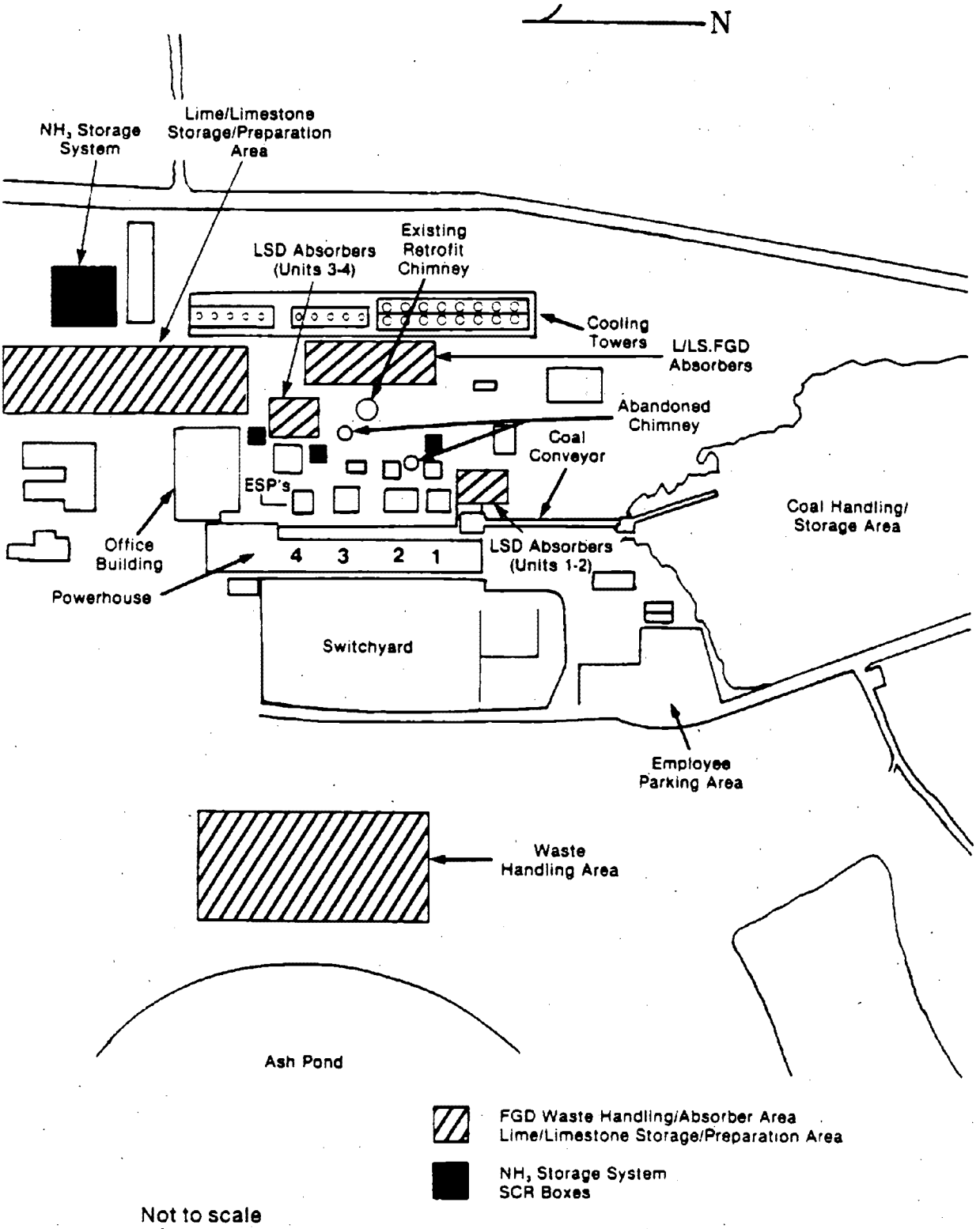

Figure 20.4.3-1. Poston plant plot plan

TABLE 20.4.3-1. POSTON STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3,4
GENERATING CAPACITY (MW-each)	44	69, 75
CAPACITY FACTOR (PERCENT)	34, 31	34, 50
INSTALLATION DATE	1949-50	1952-54
FIRING TYPE	FWF	FWF-TANG
COAL SULFUR CONTENT (PERCENT)	3.0	3.0
COAL HEATING VALUE (BTU/LB)	11500	11500
COAL ASH CONTENT (PERCENT)	9.5	9.5
FLY ASH SYSTEM	WET SLUICE	
ASH DISPOSAL METHOD	POND/ON-SITE	
STACK NUMBER	3	3
COAL DELIVERY METHODS	TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE	1976	1977
EMISSION (LB/MM BTU)	0.09-0.05	0.09-0.08
REMOVAL EFFICIENCY	99.7	99.7
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	3.0	3.0
SURFACE AREA (1000 SQ FT)	63.6	83.2
GAS FLOW RATE (1000 ACFM)	198	267
SCA (SQ FT/1000 ACFM)	321	312
OUTLET TEMPERATURE (°F)	277-305	316, 309

and 3 retrofit ESPs. The cooling towers sit to the north of the equipment discussed above. The flue gases from units 1-2 and 3-4 are routed from two separate ducts to a single, common duct which feeds into the chimney. No operational data was available for unit 4 during 1986.

The L/LS-FGD absorbers for all units were located north of the powerhouse and ESPs. This location is bounded by the chimney, the cooling towers, and an open area. A medium site access/congestion factor was assigned to the L/LS-FGD absorber locations to account for this congestion.

The flue gas handling factor assigned to the L/LS-FGD cases were low because of the short duct run required and the minimal congestion associated with the placement of the L/LS-FGD absorbers.

The major scope adjustment costs and estimated retrofit factors for the FGD control technologies are presented in Tables 20.4.3-2 and 20.4.3-3. The largest scope adder at the Poston plant would be the conversion from wet to dry ash handling/disposal for both conventional L/LS-FGD and LSD-FGD technologies. It was assumed that dry fly ash would be necessary to stabilize scrubber sludge waste and to prevent plugging of sluice lines in LSD-FGD system for the ESP reuse case. This conversion is not required for forced oxidation FGD application. The overall retrofit factors determined for the L/LS-FGD cases were medium (1.31 to 1.36).

The LSD technology evaluated at Poston was LSD with ESP reuse. This technology was selected because of the moderate SCA (>310). For the LSD-FGD cases, two absorber sites were designated. The absorbers for units 1 and 2 were placed adjacent and to the south of unit 1 in an open area with no significant obstructions. The absorbers for units 3 and 4 were placed to the east of the ESPs for units 3 and 4. This area is congested by the chimney, ductwork and ESPs and, as such, a medium site access/congestion factor was assigned to these absorber locations. A medium to high flue gas handling factor was assigned to the LSD-FGD cases because of the limited space available for the flue gas ducting from the boiler air heater outlet to the absorbers and back. The retrofit factors for LSD-FGD were medium (1.44 to 1.48) because of the space constraints created between the old chimney and the duct. Separate factors were estimated for particulate control upgrading at the plant. These factors were low to medium (1.16 to 1.36) and reflect the access/congestion around the existing ESPs. This

TABLE 20.4.3-2. SUMMARY OF RETROFIT FACTOR DATA FOR POSTON UNITS 1-2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	0-100	0-100	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	MEDIUM
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	449	NA	449
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.36	1.31	
ESP REUSE CASE			1.48
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.36
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

TABLE 20.4.3-3. SUMMARY OF RETROFIT FACTOR DATA FOR POSTON UNITS 3-4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	MEDIUM	MEDIUM
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			MEDIUM
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	0-100	0-100	
ESP REUSE			100-300
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	YES
ESTIMATED COST (1000$)	549	NA	549
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.36	1.31	
ESP REUSE CASE			1.44
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	10	10	10

factor was used by the IAPCS model to estimate costs of plate area addition, if required.

Table 20.4.3-4 presents the cost estimates for L/LS-FGD and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs and ash handling systems for boilers 1-4. The low cost control case reduces capital and annual operating costs due to the benefits of economies-of-scale when combining process areas, elimination of spare scrubber modules, and optimization of scrubber module size.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent. Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 20.4.3-5.

NO_x Control Technology Costs--

This section presents the performance and various related costs estimated for NO_x controls at Poston. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The low NO_x combustion modification controls evaluated were LNB for units 1 to 3 and OFA for unit 4. SCR was also evaluated for all four boilers.

Low NO_x Combustion--

Units 1 and 3 are dry bottom, front wall-fired boilers; units 1 and 2 are rated at 44 MW each and unit 3 is rated at 69 MW. Unit 4 is a dry bottom, tangential-fired boiler rated at 75 MW. Thus, the combustion modification

Table 20.4.3-4. Summary of FGD Control Costs for the Poston Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1-4	1.36	232	39	3.0	45.2	194.6	22.7	28.7	90.0	18129	1254.2
LC FGD-C	1-4	1.36	232	39	3.0	45.2	194.6	13.2	16.7	90.0	18129	729.7
LFGD	1	1.36	44	34	3.0	27.5	623.9	11.6	88.2	90.0	2998	3856.8
LFGD	2	1.36	44	31	3.0	27.5	625.2	11.4	95.6	90.0	2733	4180.3
LFGD	3	1.36	69	34	3.0	34.6	501.9	14.5	70.5	90.0	4701	3080.7
LFGD	4	1.36	75	50	3.0	36.2	482.4	16.3	49.5	90.0	7514	2164.8
LFGD-C	1	1.36	44	34	3.0	27.5	623.9	6.7	51.5	90.0	2998	2250.8
LFGD-C	2	1.36	44	31	3.0	27.5	625.2	6.7	55.8	90.0	2733	2440.2
LFGD-C	3	1.36	69	34	3.0	34.6	501.9	8.5	41.1	90.0	4701	1798.1
LFGD-C	4	1.36	75	50	3.0	36.2	482.4	9.5	28.9	90.0	7514	1261.9
LSD+ESP	1	1.48	44	34	3.0	11.3	255.7	6.0	46.1	65.0	2172	2781.1
LSD+ESP	2	1.48	44	31	3.0	11.8	268.9	6.2	52.2	75.0	2277	2741.1
LSD+ESP	3	1.44	69	34	3.0	15.2	220.3	7.6	37.1	76.0	3985	1912.6
LSD+ESP	4	1.44	75	50	3.0	16.0	213.0	8.4	25.7	76.0	6370	1323.7
LSD+ESP-C	1	1.48	44	34	3.0	11.3	255.7	3.5	26.8	65.0	2172	1616.7
LSD+ESP-C	2	1.48	44	31	3.0	11.8	268.9	3.6	30.4	75.0	2277	1593.8
LSD+ESP-C	3	1.44	69	34	3.0	15.2	220.3	4.4	21.6	76.0	3985	1112.9
LSD+ESP-C	4	1.44	75	50	3.0	16.0	213.0	4.9	14.9	76.0	6370	769.6

Table 20.4.3-5. Summary of Coal Switching/Cleaning Costs for the Poston Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	44	34	3.0	2.3	52.3	2.5	18.7	72.0	2384	1028.8
CS/B+$15	2	1.00	44	31	3.0	2.3	52.3	2.3	19.1	72.0	2174	1052.4
CS/B+$15	3	1.00	69	34	3.0	3.1	45.4	3.6	17.5	72.0	3739	960.5
CS/B+$15	4	1.00	75	50	3.0	3.3	44.3	5.3	16.1	72.0	5976	887.6
CS/B+$15-C	1	1.00	44	34	3.0	2.3	52.3	1.4	10.8	72.0	2384	593.7
CS/B+$15-C	2	1.00	44	31	3.0	2.3	52.3	1.3	11.1	72.0	2174	607.7
CS/B+$15-C	3	1.00	69	34	3.0	3.1	45.4	2.1	10.1	72.0	3739	554.0
CS/B+$15-C	4	1.00	75	50	3.0	3.3	44.3	3.1	9.3	72.0	5976	511.0
CS/B+$5	1	1.00	44	34	3.0	1.8	42.0	1.3	9.8	72.0	2384	541.3
CS/B+$5	2	1.00	44	31	3.0	1.8	42.0	1.2	10.2	72.0	2174	561.7
CS/B+$5	3	1.00	69	34	3.0	2.4	35.0	1.8	8.6	72.0	3739	473.0
CS/B+$5	4	1.00	75	50	3.0	2.5	33.9	2.5	7.5	72.0	5976	410.8
CS/B+$5-C	1	1.00	44	34	3.0	1.8	42.0	0.7	5.7	72.0	2384	313.6
CS/B+$5-C	2	1.00	44	31	3.0	1.8	42.0	0.7	5.9	72.0	2174	325.6
CS/B+$5-C	3	1.00	69	34	3.0	2.4	35.0	1.0	5.0	72.0	3739	273.9
CS/B+$5-C	4	1.00	75	50	3.0	2.5	33.9	1.4	4.3	72.0	5976	237.3

control considered for units 1 to 3 was LNB and that considered for unit 4 was OFA. Tables 20.4.3-6 and 20.4.3-7 present the NO_x reduction performance results for the four units. The NO_x reduction performance could not be estimated for units 1 and 2 due to lack of information from POWER. Although LNBs are applicable for these units, LNB may not be feasible from a cost standpoint since both units are small and old. The NO_x reduction performance estimated for unit 3, equipped with LNBs, would be 50 percent while the NO_x reduction performance for unit 4, equipped with OFA, would be 20 percent. The NO_x reduction performances were determined by examining the effects of heat release rates and furnace residence time on NO_x reduction through the use of the simplified procedures.

Table 20.4.3-8 presents the cost of retrofitting LNB and OFA at the Poston plant. The unit cost of LNC was estimated to be 440 to 804 $/ton of NO_x removed. Application of LNC to all the boilers reduces NO_x by 700 tons per year.

Selective Catalytic Reduction--

Tables 20.4.3-6 and 20.4.3-7 present the SCR retrofit results for each unit. The results include process area retrofit difficulty factors and scope adder costs. For scope adders, costs are estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney. The reactors for units 1 and 2 were located behind their respective ESPs north of the powerhouse; the reactors for units 3 and 4 were located northwest of their respective ESPs and west of the common chimney.

Reactors for units 1-4 were assigned a medium access/congestion factor since the reactors were located on a highly congested area surrounding the common chimney with easy assess. All reactors were assumed to be on areas with high underground obstructions. Table 20.4.3-8 presents the estimated cost of retrofitting SCR at the Poston boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately

TABLE 20.4.3-6. SUMMARY OF NOx RETROFIT RESULTS FOR POSTON UNITS 1-3

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1	2	3
FIRING TYPE	FWF	FWF	FWF
TYPE OF NOx CONTROL	LNB	LNB	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA	14
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA	46.3
FURNACE RESIDENCE TIME (SECONDS)	NA	NA	3.87
ESTIMATED NOx REDUCTION (PERCENT)	NA	NA	50
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM	MEDIUM	MEDIUM
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	15	15	17
New Duct Length (Feet)	100	100	100
New Duct Costs (1000$)	307	307	349
New Heat Exchanger (1000$)	1139	1139	1466
TOTAL SCOPE ADDER COSTS (1000$)	1460	1460	1833
RETROFIT FACTOR FOR SCR	1.34	1.34	1.34
GENERAL FACILITIES (PERCENT)	13	13	13

TABLE 20.4.3-7. SUMMARY OF NOx RETROFIT RESULTS FOR POSTON UNIT 4

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	4
FIRING TYPE	TANG
TYPE OF NOx CONTROL	OFA
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	17.5
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	29.6
FURNACE RESIDENCE TIME (SECONDS)	3.04
ESTIMATED NOx REDUCTION (PERCENT)	20
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	MEDIUM
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	20
New Duct Length (Feet)	150
New Duct Costs (1000$)	588
New Heat Exchanger (1000$)	1466
TOTAL SCOPE ADDER COSTS (1000$)	2074
RETROFIT FACTOR FOR SCR	1.34
GENERAL FACILITIES (PERCENT)	13

Table 20.4.3-8. NOx Control Cost Results for the Poston Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	3	1.00	69	34	3.0	2.2	31.9	0.5	2.3	50.0	469	1014.3
LNC-LNB-C	3	1.00	69	34	3.0	2.2	31.9	0.3	1.4	50.0	469	602.1
LNC-OFA	4	1.00	75	50	3.0	0.6	7.4	0.1	0.4	20.0	214	557.3
LNC-OFA-C	4	1.00	75	50	3.0	0.6	7.4	0.1	0.2	20.0	214	330.7
SCR-3	1	1.34	44	34	3.0	12.4	281.7	3.8	29.1	80.0	478	7978.4
SCR-3	2	1.34	44	31	3.0	12.4	282.6	3.8	31.9	80.0	436	8752.3
SCR-3	3	1.34	69	34	3.0	15.7	228.1	5.0	24.2	80.0	750	6629.9
SCR-3	4	1.34	75	50	3.0	16.6	221.4	5.3	16.1	80.0	856	6180.5
SCR-3-C	1	1.34	44	34	3.0	12.4	281.7	2.2	17.1	80.0	478	4687.2
SCR-3-C	2	1.34	44	31	3.0	12.4	282.6	2.2	18.8	80.0	436	5142.4
SCR-3-C	3	1.34	69	34	3.0	15.7	228.1	2.9	14.2	80.0	750	3892.6
SCR-3-C	4	1.34	75	50	3.0	16.6	221.4	3.1	9.5	80.0	856	3627.9
SCR-7	1	1.34	44	34	3.0	12.4	281.7	3.5	26.3	80.0	478	7218.2
SCR-7	2	1.34	44	31	3.0	12.4	282.6	3.5	28.9	80.0	436	7918.4
SCR-7	3	1.34	69	34	3.0	15.7	228.1	4.4	21.4	80.0	750	5869.3
SCR-7	4	1.34	75	50	3.0	16.6	221.4	4.7	14.2	80.0	856	5456.4
SCR-7-C	1	1.34	44	34	3.0	12.4	281.7	2.0	15.5	80.0	478	4251.6
SCR-7-C	2	1.34	44	31	3.0	12.4	282.6	2.0	17.0	80.0	436	4664.7
SCR-7-C	3	1.34	69	34	3.0	15.7	228.1	2.6	12.6	80.0	750	3456.8
SCR-7-C	4	1.34	75	50	3.0	16.6	221.4	2.8	8.4	80.0	856	3213.1

from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas for the plant were located to the northeast of the units in a layout similar to that for LSD-FGD. The retrofit of DSD and FSI would be relatively easy given the large SCA of the units (>310) and sufficient duct residence. An access/congestion factor of low to medium was assumed for any ESP upgrades. The major scope adder cost for DSD and FSI would be the conversion of the fly ash from wet to dry for reusing the ESPs. Tables 20.4.3-9 and 20.4.3-10 present a summary of site access/congestion factors, scope adders, and retrofit factors for DSD and FSI technologies at the Poston plant. Table 20.4.3-11 presents the cost estimated to retrofit DSD and FSI at the Poston plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Poston plant. All boilers at Poston would be considered good candidates for AFBC retrofit and AFBC or coal gasification/combined cycle repowering due to their small boiler sizes (<70 MW), age, and low capacity factors.

TABLE 20.4.3-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR POSTON UNITS 1-2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	MEDIUM
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	449
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	16
TOTAL COST (1000$)	
ESP UPGRADE CASE	465
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.34
NEW BAGHOUSE	NA

TABLE 20.4.3-10. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR POSTON UNITS 3-4

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	655
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	22
TOTAL COST (1000$)	
ESP UPGRADE CASE	677
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.13
NEW BAGHOUSE	NA

Table 20.4.3-11. Summary of DSD/FSI Control Costs for the Poston Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	44	34	3.0	5.2	118.5	4.2	32.2	43.0	1436	2936.1
DSD+ESP	2	1.00	44	31	3.0	5.6	126.2	4.3	36.4	48.0	1457	2983.8
DSD+ESP	3	1.00	69	34	3.0	6.8	98.2	5.1	24.7	49.0	2541	1994.7
DSD+ESP	4	1.00	75	50	3.0	7.1	94.0	5.7	17.3	49.0	4062	1403.0
DSD+ESP-C	1	1.00	44	34	3.0	5.2	118.5	2.4	18.6	43.0	1436	1698.5
DSD+ESP-C	2	1.00	44	31	3.0	5.6	126.2	2.5	21.1	48.0	1457	1726.7
DSD+ESP-C	3	1.00	69	34	3.0	6.8	98.2	2.9	14.3	49.0	2541	1154.8
DSD+ESP-C	4	1.00	75	50	3.0	7.1	94.0	3.3	10.0	49.0	4062	811.6
FSI+ESP-50	1	1.00	44	34	3.0	5.8	131.2	3.6	27.6	50.0	1665	2169.7
FSI+ESP-50	2	1.00	44	31	3.0	5.8	131.6	3.5	29.5	50.0	1518	2324.3
FSI+ESP-50	3	1.00	69	34	3.0	6.8	99.1	4.4	21.6	50.0	2611	1698.3
FSI+ESP-50	4	1.00	75	50	3.0	7.1	95.1	5.5	16.6	50.0	4174	1308.8
FSI+ESP-50-C	1	1.00	44	34	3.0	5.8	131.2	2.1	16.0	50.0	1665	1258.6
FSI+ESP-50-C	2	1.00	44	31	3.0	5.8	131.6	2.0	17.1	50.0	1518	1348.8
FSI+ESP-50-C	3	1.00	69	34	3.0	6.8	99.1	2.6	12.5	50.0	2611	984.8
FSI+ESP-50-C	4	1.00	75	50	3.0	7.1	95.1	3.2	9.6	50.0	4174	757.5
FSI+ESP-70	1	1.00	44	34	3.0	5.9	133.3	3.7	27.9	70.0	2331	1570.0
FSI+ESP-70	2	1.00	44	31	3.0	5.9	133.2	3.6	29.9	70.0	2126	1678.7
FSI+ESP-70	3	1.00	69	34	3.0	6.9	99.7	4.5	21.8	70.0	3656	1225.9
FSI+ESP-70	4	1.00	75	50	3.0	7.2	95.8	5.5	16.8	70.0	5844	947.1
FSI+ESP-70-C	1	1.00	44	34	3.0	5.9	133.3	2.1	16.2	70.0	2331	910.8
FSI+ESP-70-C	2	1.00	44	31	3.0	5.9	133.2	2.1	17.3	70.0	2126	974.1
FSI+ESP-70-C	3	1.00	69	34	3.0	6.9	99.7	2.6	12.6	70.0	3656	710.8
FSI+ESP-70-C	4	1.00	75	50	3.0	7.2	95.8	3.2	9.8	70.0	5844	548.1

20.5 DAYTON POWER AND LIGHT COMPANY

20.5.1 James M. Stuart Steam Plant

Information on James M. Stuart Steam Plant appears in U.S. EPA report number EPA-600/7-88/014, entitled "Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Retrofit Study" (NTIS PB88-244447/AS).

20.6 OHIO EDISON COMPANY

20.6.1 R. E. Burger Steam Plant

Information on R. E. Burger Steam Plant appears in U.S. EPA report number EPA-600/7-88/014, entitled "Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Retrofit Study" (NTIS PB88-244447/AS).

20.6.2 Niles Plant

The Niles plant is located within Trumbull County, Ohio, as part of the Ohio Edison Company system. The plant is located beside the Mahoning River northeast of the Meander reservoir and contains two coal-fired boilers with a total gross generating capacity of 230 MW.

Table 20.6.2-1 presents operational data for the existing equipment at the Niles plant. The boilers burn high sulfur coal which is received by truck and transferred to a coal storage and handling area east of the plant and adjacent to the river.

PM emissions for both boilers are controlled with retrofit ESPs located north of units 1-2. The fly ash is wet sluiced and disposed to an ash pond located west of the plant. A common chimney was constructed in the early 1980's on the south side of the plant.

Lime/Limestone and Lime Spray Drying FGD Costs--

The FGD absorbers would be located in a relatively open space beside the chimney south of the coal conveyor. Because there are no major obstacles or obstructions around the absorber locations, a low site access/ congestion factor was assigned. Short duct runs would be required for

TABLE 20.6.2-1. NILES STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2
GENERATING CAPACITY (MW-each)	115
CAPACITY FACTOR (PERCENT)*	69,67
INSTALLATION DATE	1954
FURNACE VOLUME (1000 CU FT)	NA
LOW NOX COMBUSTION	NO
FIRING TYPE	CYCLONE
COAL SULFUR CONTENT (PERCENT)	3.2
COAL HEATING VALUE (BTU/LB)	11700
COAL ASH CONTENT (PERCENT)	12
FLY ASH SYSTEM	ON-SITE
ASH DISPOSAL METHOD	WET SLUICE
STACK NUMBER	1
COAL DELIVERY METHODS	TRUCK
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1981
EMISSION (LB/MM BTU)	0.02
REMOVAL EFFICIENCY	99.0
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	4.0
SURFACE AREA (1000 SQ FT)	278
GAS EXIT RATE (1000 ACFM)	535
SCA (SQ FT/1000 ACFM)	520
OUTLET TEMPERATURE (°F)	270

*1988 data.

L/LS-FGD cases (about 200 feet) because the absorbers would be placed immediately behind the chimneys. Plant personnel indicated that this area will be used as a site for the Clean Coal II project (35MW, WSA-SNOX) in mid-1990. Therefore, retrofit factors developed here might not be appropriate in the future.

LSD with reuse of the existing ESPs was considered for this plant because the retrofit ESPs are large (SCA =520) and would not require major upgrading and plate area additions to handle the increased PM generated from the LSD application. The LSD absorbers would be located beside the common chimney with a low site access/congestion factor. To access the upstream of the ESPs which are faced toward the river, duct runs would have to go under the coal conveyor and around the ESPs. Therefore, a high site access/ congestion factor was assigned to the flue gas handling system. A separate retrofit factor was developed for ESP upgrade, if needed. The assigned factor was high because of the congestion around the ESPs. This congestion is created by the river to the north, coal conveyor to the east, and close proximity of the ESPs to each other and to the boilerhouse.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 20.6.2-2. Table 20.6.2-3 presents the process area retrofit factors and capital/operating costs for commercial FGD technologies. The low cost FGD option shows the cost reduction due to eliminating spare absorber modules.

Coal Switching and Physical Coal Cleaning Costs

Both units at the Niles plant have wet bottom boilers and CS was not considered because low sulfur bituminous coals having low ash fussion temperatures are not readily available in the east. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Both units are cyclone boilers rated at 115 MW each and the combustion modification technique applied to both boilers was NGR. As Table 20.6.2-4 shows, the NGR NO_x reduction performance for each unit was assumed to be 60 percent. Table 20.6.2-5 presents the cost of retrofitting NGR at the Niles plant.

TABLE 20.6.2-2. SUMMARY OF RETROFIT FACTOR DATA FOR NILES UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION*			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	1063	NA	1063
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			1.43
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	5	0	5

* This area will be used for Clean Coal II demonstration sites in mid-1990, and retrofit factors developed here need to be revised in the future.

Table 20.6.2-3. Summary of FGD Control Costs for the Niles Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
L/S FGD	1	1.27	115	69	3.2	42.7	371.5	20.7	29.8	90.0	16627	1246.5
L/S FGD	2	1.27	115	67	3.2	42.7	371.4	20.6	30.5	90.0	16145	1273.3
L/S FGD	1-2	1.27	230	68	3.2	61.6	267.7	31.3	22.8	90.0	32772	954.7
L/S FGD-C	1	1.27	115	69	3.2	42.7	371.5	12.1	17.4	90.0	16627	725.7
L/S FGD-C	2	1.27	115	67	3.2	42.7	371.4	12.0	17.7	90.0	16145	741.4
L/S FGD-C	1-2	1.27	230	68	3.2	61.6	267.7	18.2	13.3	90.0	32772	555.4
LC FGD	1-2	1.27	230	68	3.2	43.0	187.2	25.4	18.5	90.0	32772	775.0
LC FGD-C	1-2	1.27	230	68	3.2	43.0	187.2	14.7	10.8	90.0	32772	449.9
LSD+ESP	1	1.43	115	69	3.2	20.2	175.9	11.1	15.9	76.0	14095	786.5
LSD+ESP	2	1.43	115	67	3.2	20.2	175.9	11.0	16.3	76.0	13687	803.4
LSD+ESP-C	1	1.43	115	69	3.2	20.2	175.9	6.4	9.3	76.0	14095	457.0
LSD+ESP-C	2	1.43	115	67	3.2	20.2	175.9	6.4	9.5	76.0	13687	466.9

TABLE 20.6.2-4. SUMMARY OF NOx RETROFIT RESULTS FOR NILES

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	1,2	1-2
FIRING TYPE	CYC	NA
TYPE OF NOx CONTROL	NGR	NA
FURNACE VOLUME (1000 CU FT)	NA	NA
BOILER INSTALLATION DATE	1954	NA
SLAGGING PROBLEM	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	NA
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION* FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	30	50
New Duct Length (Feet)	250	250
New Duct Costs (1000$)	1344	2016
New Heat Exchanger (1000$)	2027	3072
TOTAL SCOPE ADDER COSTS (1000$)	3401	5139
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

* This area will be used for Clean Coal II demonstration sites in mid-1990, and retrofit factors developed here need to be revised in the future.

Table 20.6.2-5. NOx Control Cost Results for the Niles Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	115	69	3.2	2.5	21.4	3.9	5.6	60.0	3286	1191.3
NGR	2	1.00	115	67	3.2	2.5	21.4	3.8	5.6	60.0	3191	1194.9
NGR-C	1	1.00	115	69	3.2	2.5	21.4	2.3	3.2	60.0	3286	685.9
NGR-C	2	1.00	115	67	3.2	2.5	21.4	2.2	3.3	60.0	3191	688.0
SCR-3	1	1.16	115	69	3.2	20.6	178.8	7.2	10.3	80.0	4382	1636.9
SCR-3	2	1.16	115	67	3.2	20.6	178.8	7.2	10.6	80.0	4255	1680.6
SCR-3	1-2	1.16	230	68	3.2	33.9	147.5	12.4	9.1	80.0	8636	1440.7
SCR-3-C	1	1.16	115	69	3.2	20.6	178.8	4.2	6.0	80.0	4382	958.9
SCR-3-C	2	1.16	115	67	3.2	20.6	178.8	4.2	6.2	80.0	4255	984.5
SCR-3-C	1-2	1.16	230	68	3.2	33.9	147.5	7.3	5.3	80.0	8636	843.0
SCR-7	1	1.16	115	69	3.2	20.6	178.8	6.2	9.0	80.0	4382	1420.4
SCR-7	2	1.16	115	67	3.2	20.6	178.8	6.2	9.2	80.0	4255	1457.7
SCR-7	1-2	1.16	230	68	3.2	33.9	147.5	10.5	7.7	80.0	8636	1221.1
SCR-7-C	1	1.16	115	69	3.2	20.6	178.8	3.7	5.3	80.0	4382	834.9
SCR-7-C	2	1.16	115	67	3.2	20.6	178.8	3.6	5.4	80.0	4255	856.8
SCR-7-C	1-2	1.16	230	68	3.2	33.9	147.5	6.2	4.5	80.0	8636	717.2

Selective Catalytic Reduction--

Cold side SCR reactors for both units would be located beside the common chimney in a low site access/congestion areas with short flue gas duct runs. No major demolition/relocation would be required for SCR reactor locations. Therefore, a factor of 13 percent was assigned to general facilities. Again, due to the Clean Coal II project, site access/congestion and duct length would possibly be different.

Table 20.6.2-4 presents the SCR process area retrofit factors and scope adder costs. Table 20.6.2-5 presents the estimated cost of retrofitting SCR at the Niles boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of DSD and FSI technologies at the Niles steam plant for both units would be possible for two major reasons: 1) ESPs have large SCAs (>500) and would probably be able to handle the increased particulate matter; and 2) sufficient duct residence time between the boilers and ESPs would possibly provide sufficient time for humidification (FSI application) or sorbent evaporation (DSD application). Table 20.6.2-6 presents a summary of the site access/congestion factors for FSI and DSD technologies at the Niles steam plant. Plant personnel indicated that installation of a bypass duct is likely for sorbent injection technologies. Table 20.6.2-7 presents the costs estimated to retrofit FSI and DSD at the Niles boilers.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Niles plant. Both units would be considered good candidates for repowering or retrofit because of their small boiler size and long service life. However, because of the small volumetric heat release area, it would be difficult to convert the existing boilers to FBC units. The relatively high capacity factors could result in high replacement power costs for extended downtime.

TABLE 20.6.2-6. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR NILES UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1063
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	35
TOTAL COST (1000$)	
ESP UPGRADE CASE	1098
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 20.6.2-7. Summary of DSD/FSI Control Costs for the Niles Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	115	69	3.2	9.5	82.7	7.8	11.2	49.0	8987	864.8
DSD+ESP	2	1.00	115	67	3.2	9.5	82.7	7.7	11.4	49.0	8727	880.8
DSD+ESP-C	1	1.00	115	69	3.2	9.5	82.7	4.5	6.5	49.0	8987	500.2
DSD+ESP-C	2	1.00	115	67	3.2	9.5	82.7	4.4	6.6	49.0	8727	509.5
FSI+ESP-50	1	1.00	115	69	3.2	9.8	85.1	9.1	13.1	50.0	9237	989.2
FSI+ESP-50	2	1.00	115	67	3.2	9.8	85.1	9.0	13.3	50.0	8969	1000.6
FSI+ESP-50-C	1	1.00	115	69	3.2	9.8	85.1	5.3	7.6	50.0	9237	571.5
FSI+ESP-50-C	2	1.00	115	67	3.2	9.8	85.1	5.2	7.7	50.0	8969	578.2
FSI+ESP-70	1	1.00	115	69	3.2	10.0	86.7	9.3	13.4	70.0	12932	720.8
FSI+ESP-70	2	1.00	115	67	3.2	10.0	86.7	9.2	13.6	70.0	12557	729.0
FSI+ESP-70-C	1	1.00	115	69	3.2	10.0	86.7	5.4	7.7	70.0	12932	416.4
FSI+ESP-70-C	2	1.00	115	67	3.2	10.0	86.7	5.3	7.8	70.0	12557	421.2

20.6.3 W. H. Sammis Steam Plant

Information on W. H. Sammis Steam Plant appears in U.S. EPA report number EPA-600/7-88/014, entitled "Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Retrofit Study" (NTIS PB88-244447/AS).

20.6.4 Toronto Plant

The Toronto plant is located within Jefferson County, Ohio, as part of the Ohio Edison Company system. The plant is bounded by the Ohio River and a major highway. The plant contains 11 coal-fired boilers but units 1-8 are retired. Only units 9-11 were considered for this study and they have a total gross generating capacity of 181 MW. Figure 20.6.4-1 presents the plant plot plan showing the location of all boilers and major associated auxiliary equipment.

Table 20.6.4-1 presents operational data for the existing equipment at the Toronto plant. Coal shipments are received by truck and conveyed to a coal storage and handling area located southwest of the main plant building.

Particulate matter emissions for the boilers are controlled with retrofit ESPs. The plant has a wet sluiced fly ash handling system and is disposed to two ash ponds north of the plant (bottom ash ponds are located southwest of the plant). The fly ash ponds are periodically taken out of service on a rotational basis, dewatered, and the ash loaded into trucks and taken to a landfill for disposal.

Lime/Limestone and Lime Spray Drying FGD Costs--

Figure 20.6.4-1 shows the general layout and location of the FGD control system. All 11 boilers sit side by side, parallel to the Ohio River. Flue gas for units 9-11 is converged into a common duct to a common chimney, located behind the powerhouse beside the switch yard. The absorbers for L/LS-FGD and LSD-FGD for the units would be located close to the chimney beside the powerhouse west of the river in a relatively open area. No major demolition/relocation would be required. The lime storage/handling area would be located north of the absorbers in what is presently an ash pond with the waste handling area located adjacent to it. Plant personnel indicated that additional real estate has to be acquired to accommodate the FGD

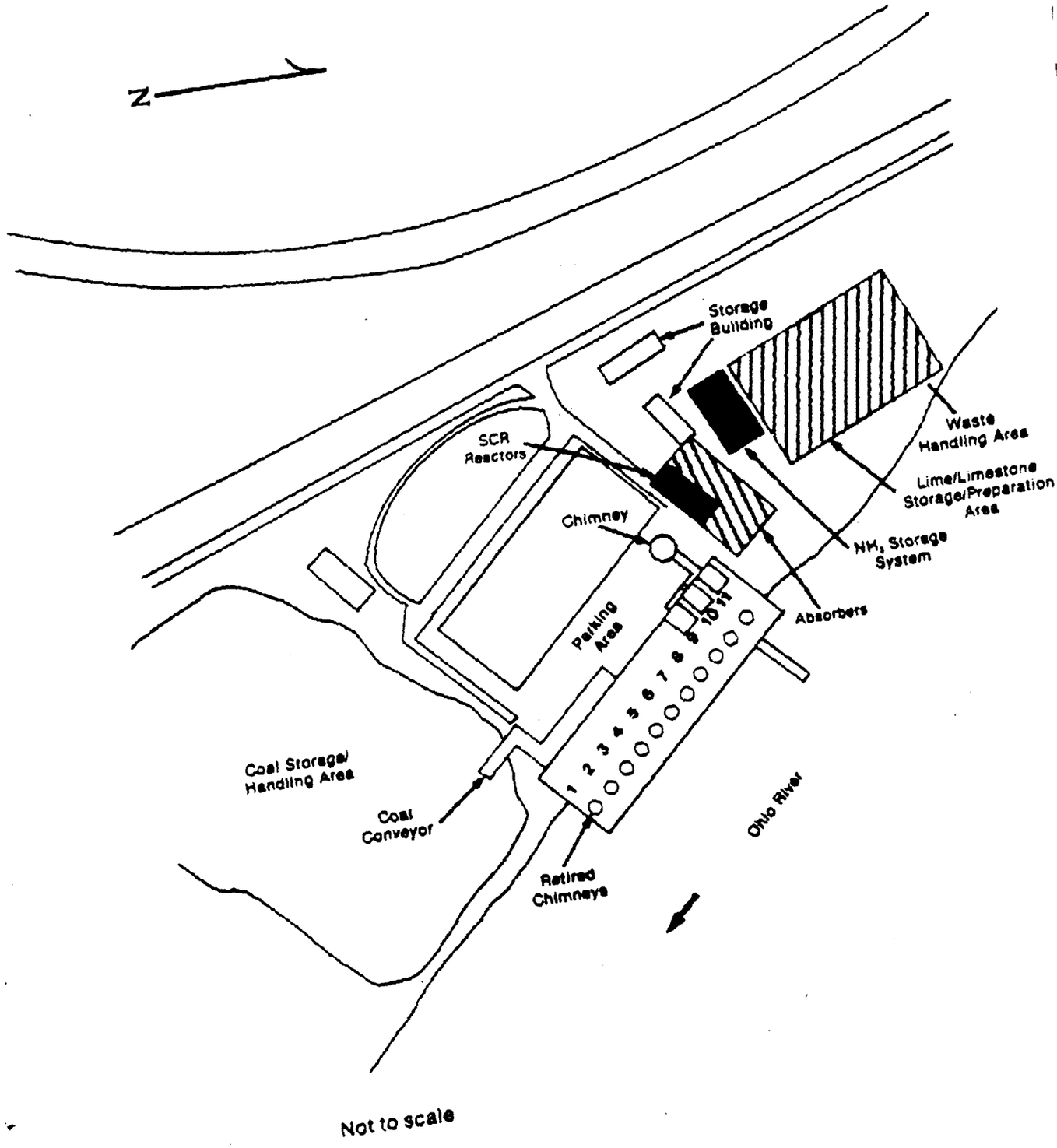

Figure 20.6.4-1. Toronto plant plot plan

TABLE 20.6.4-1. TORONTO STEAM PLANT OPERATIONAL DATA+

BOILER NUMBER	9	10,11
GENERATING CAPACITY (MW-each)	45	68
CAPACITY FACTOR (PERCENT)	34	41,45
INSTALLATION DATE	1940	1949
FIRING TYPE	FWF	FWF
COAL SULFUR CONTENT (PERCENT)	3.4	3.4
COAL HEATING VALUE (BTU/LB)	11300	11300
COAL ASH CONTENT (PERCENT)	14.7	14.7
FLY ASH SYSTEM	WET-SLUICED	
ASH DISPOSAL METHOD	PONDS/ON-SITE	
STACK NUMBER	1	
COAL DELIVERY METHODS	TRUCK	
PARTICULATE CONTROL		
TYPE	ESP	ESP
INSTALLATION DATE*	1970	1970
EMISSION (LB/MM BTU)	0.03	0.07-9
REMOVAL EFFICIENCY	99.0	99.0
DESIGN SPECIFICATION		
SULFUR SPECIFICATION (PERCENT)	1.5	1.5
SURFACE AREA (1000 SQ FT)	44.3	72
EXIT GAS FLOW RATE (1000 ACFM)	186	303
SCA (SQ FT/1000 ACFM)	238	237
OUTLET TEMPERATURE (°F)	350	350

+ 1988 data.
* Upgraded in 1980.

equipment. This cost was added to the FGD costs (5 percent increase in general facilities).

Retrofit Difficulty and Scope Adder Costs--

A low site access/congestion factor was assigned to the absorber locations due to the absorbers being located beside the chimney with no major obstacles/obstructions.

For flue gas handling, short to medium duct runs for the units would be required for L/LS-FGD cases since the absorbers would be close to the common duct run/chimney with easy accessibility. A low site access/congestion factor was assigned to the flue gas handling system.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 20.6.4-2. No large scope adder cost is required for the Toronto plant. The overall retrofit factor determined for the L/LS-FGD cases was low (1.24).

The absorbers for LSD-FGD would be located in a similar location as in the L/LS-FGD cases. LSD with a new baghouse was the only case considered for the Toronto plant. Since the ESPs are roof-mounted and their sizes are marginal with difficult to access, a baghouse was considered for placement close to the absorbers. For flue gas handling for LSD cases, moderate duct runs would be required to divert the flue gas from the boilers to the absorbers and back to the ESPs. A low site access/congestion factor was assigned to the flue gas handling system. The retrofit factors determined for the LSD technology case were low (1.27) and did not include new particulate control costs. A separate retrofit factor was developed for the units. A low retrofit factor (1.13) was developed for a new baghouse. A low site access/congestion factor was assigned since no major demolition or relocation would be required. This factor was used in the IAPCS model to estimate new particulate control costs.

Table 20.6.4-3 presents the costs estimated for L/LS-FGD and LSD-FGD cases. The LSD-FGD costs include upgrading the ESPs for boilers 9-11.

Since flue gas from units 9-11 are converged into a common chimney, a combined case for L/LS-FGD was also considered in this study. The low cost control case reduces capital and annual operating costs even further than a

TABLE 20.6.4-2. SUMMARY OF RETROFIT FACTOR DATA FOR TORONTO UNITS 9-11

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	LOW	LOW
FLUE GAS HANDLING	LOW	LOW	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	100-300	
ESP REUSE			NA
BAGHOUSE			300-600
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NO	NO
ESTIMATED COST (1000$)	458-663	NA	NA
NEW CHIMNEY	NO	NO	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO	NO	NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	1.24	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.27
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.13
GENERAL FACILITIES (PERCENT)	10	10	10

Table 20.6.4-3. Summary of FGD Control Costs for the Toronto Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	9-11	1.27	181	41	3.4	37.2	205.7	19.4	29.9	90.0	17194	1129.4
LC FGD-C	9-11	1.27	181	41	3.4	37.2	205.7	11.3	17.4	90.0	17194	656.8
LFGD	9	1.27	45	34	3.4	26.2	582.8	11.2	83.9	90.0	3545	3170.7
LFGD	10	1.27	68	41	3.4	32.8	483.0	14.5	59.2	90.0	6460	2239.5
LFGD	11	1.27	68	45	3.4	32.8	483.1	14.7	55.0	90.0	7090	2079.1
LFGD	9-11	1.27	181	41	3.4	54.8	302.5	25.0	38.5	90.0	17194	1454.0
LFGD-C	9	1.27	45	34	3.4	26.2	582.8	6.6	48.9	90.0	3545	1849.8
LFGD-C	10	1.27	68	41	3.4	32.8	483.0	8.4	34.5	90.0	6460	1305.9
LFGD-C	11	1.27	68	45	3.4	32.8	483.1	8.6	32.1	90.0	7090	1212.0
LFGD-C	9-11	1.27	181	41	3.4	54.8	302.5	14.6	22.4	90.0	17194	847.3
LSD+FF	9	1.27	45	34	3.4	16.7	372.1	7.7	57.2	87.0	3407	2250.5
LSD+FF	10	1.27	68	41	3.4	22.3	327.5	9.8	40.2	84.0	6021	1629.3
LSD+FF	11	1.27	68	45	3.4	22.3	327.5	10.0	37.1	84.0	6608	1506.9
LSD+FF-C	9	1.27	45	34	3.4	16.7	372.1	4.5	33.3	87.0	3407	1311.4
LSD+FF-C	10	1.27	68	41	3.4	22.3	327.5	5.7	23.4	84.0	6021	950.1
LSD+FF-C	11	1.27	68	45	3.4	22.3	327.5	5.8	21.7	84.0	6608	878.5

combined case alone due to the elimination of spare scrubber modules, and optimization of scrubber module size, and use of organic acid additives.

Coal Switching Costs--

Coal switching can impact boiler performance in several ways. Key parameters of concern include boiler capacity, furnace slagging, pulverizer capacity, tube erosion, and coal rate. However, without an ash analysis for the existing and switch coals, boiler derate or capacity increase cannot be determined.

The ESP performance impacts were evaluated using the IAPCS model to estimate the needed plate area. This plate area was compared to the existing area to determine whether SO_3 conditioning or additional plate area was needed. SO_3 conditioning was assumed to reduce the needed plate area up to 25 percent.

Costs were generated to show the impact of two different coal fuel cost differentials. The costs associated with each boiler for the range of fuel cost differential are shown in Table 20.6.4-4.

NO_x Control Technology Costs--

This section presents the performance and costs estimated for NO_x controls at the Toronto steam plant. These controls include LNC modification and SCR. The application of NO_x control technologies is determined by several site-specific factors which are discussed in Section 2. The NO_x technologies evaluated at the steam plant were: LNB and SCR.

Low NO_x Combustion--

Unit 9 is wet and units 10-11 are dry bottom, front wall-fired boilers rated at 44, 66, and 66 MW, respectively. The combustion modification technique applied for these boilers was NGR for unit 9 and LNB for units 10-11. As Table 20.6.4-5 shows, the LNB NO_x reduction performances for these units could not be estimated using the simplified procedures. No boiler information could be found for units 10 and 11 to assess their NO_x reduction performances. Based on NO_x performance results from similar boilers of the same age and size, it is estimated that a NO_x reduction of 20 to 30 percent can be achieved by these boilers retrofitted with LNB.

Table 20.6.4-4. Summary of Coal Switching/Cleaning Costs for the Toronto Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	9	1.00	45	34	3.4	2.0	43.8	2.4	17.6	75.0	2971	793.3
CS/B+$15	10	1.00	68	41	3.4	2.8	40.6	3.9	16.2	75.0	5414	729.2
CS/B+$15	11	1.00	68	45	3.4	2.8	40.6	4.3	15.9	75.0	5942	718.3
CS/B+$15-C	9	1.00	45	34	3.4	2.0	43.8	1.4	10.1	75.0	2971	457.5
CS/B+$15-C	10	1.00	68	41	3.4	2.8	40.6	2.3	9.3	75.0	5414	420.1
CS/B+$15-C	11	1.00	68	45	3.4	2.8	40.6	2.5	9.2	75.0	5942	413.6
CS/B+$5	9	1.00	45	34	3.4	1.5	33.5	1.2	8.7	75.0	2971	393.2
CS/B+$5	10	1.00	68	41	3.4	2.1	30.2	1.8	7.4	75.0	5414	333.8
CS/B+$5	11	1.00	68	45	3.4	2.1	30.2	1.9	7.2	75.0	5942	324.9
CS/B+$5-C	9	1.00	45	34	3.4	1.5	33.5	0.7	5.0	75.0	2971	227.6
CS/B+$5-C	10	1.00	68	41	3.4	2.1	30.2	1.0	4.3	75.0	5414	192.9
CS/B+$5-C	11	1.00	68	45	3.4	2.1	30.2	1.1	4.2	75.0	5942	187.7

TABLE 20.6.4-5. SUMMARY OF NOx RETROFIT RESULTS FOR TORONTO

	BOILER NUMBER	
COMBUSTION MODIFICATION RESULTS		
	9	10,11
FIRING TYPE	FWF	FWF
TYPE OF NOx CONTROL	NGR	LNB
VOLUMETRIC HEAT RELEASE RATE (1000 BTU/CU FT-HR)	NA	NA
BOILER/WATERWALL SURFACE AREA HEAT RELEASE RATE (1000 BTU/SQ FT-HR)	NA	NA
FURNACE RESIDENCE TIME (SECONDS)	NA	NA
ESTIMATED NOx REDUCTION (PERCENT)	60	25
SCR RETROFIT RESULTS		
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW	LOW
SCOPE ADDER PARAMETERS--		
Building Demolition (1000$)	0	0
Ductwork Demolition (1000$)	15	20
New Duct Length (Feet)	150	200
New Duct Costs (1000$)	466	791
New Heat Exchanger (1000$)	1154	1479
TOTAL SCOPE ADDER COSTS (1000$)	1635	2290
RETROFIT FACTOR FOR SCR	1.16	1.16
GENERAL FACILITIES (PERCENT)	13	13

Units 9 to 11 were installed between 1940 and 1949. Table 20.6.4-6 presents the cost of retrofitting LNB at the Toronto boilers, assuming an NO_x reduction performance of 25 percent.

Selective Catalytic Reduction--

Table 20.6.4-5 presents the SCR retrofit results for each unit. The results include process area retrofit factors and scope adder costs. The scope adders include costs estimated for ductwork demolition, new flue gas heat exchanger, and new duct runs to divert the flue gas from the ESPs to the reactor and from the reactor to the chimney.

The SCR reactors for units 9 to 11 would be located side by side in a relatively open area close to the chimney, north of the powerhouse and west of the river. Since the reactors were located in open area having easy access with no major obstacles, the reactors for units 9 to 11 were assigned low access/congestion factors. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed in a remote area having a low access/congestion factor. Table 20.6.4-6 presents the estimated cost of retrofitting SCR at the Toronto boilers.

Sorbent Injection and Repowering--

This section presents the cost/performance estimates for SO_2 control technologies that are under development but have not been demonstrated on commercial utility boilers. These technologies are presented separately from the commercialized technologies because the cost/performance estimates have a high degree of uncertainty due to the lack of commercial scale data.

Duct Spray Drying and Furnace Sorbent Injection--

The sorbent receiving/storage/preparation areas were located north of the plant in a similar fashion as LSD-FGD. The retrofit of DSD and FSI technologies at the Toronto steam plant for the units would be very difficult. This is due to the short duct residence time between the boilers and the ESPs, as well as the ESP roof-mounted location in a high site access/congestion area. Therefore, a new baghouse was considered for DSD which would be located north of the plant, close to the chimney. Duct runs of 300-400 feet would be required to divert flue gas from all three boilers to

Table 20.6.4-6. NOx Control Cost Results for the Toronto Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	10	1.00	68	41	3.4	2.2	32.2	0.5	1.9	25.0	284	1663.1
LNC-LNB	11	1.00	68	45	3.4	2.2	32.2	0.5	1.8	25.0	312	1515.2
LNC-LNB-C	10	1.00	68	41	3.4	2.2	32.2	0.3	1.1	25.0	284	987.4
LNC-LNB-C	11	1.00	68	45	3.4	2.2	32.2	0.3	1.0	25.0	312	899.7
NGR	9	1.00	45	34	3.4	1.3	28.2	0.9	6.7	60.0	606	1482.7
NGR-C	9	1.00	45	34	3.4	1.3	28.2	0.5	3.9	60.0	606	859.0
SCR-3	9	1.16	45	34	3.4	11.7	260.3	3.7	27.5	80.0	808	4555.4
SCR-3	10	1.16	68	41	3.4	14.8	217.2	4.7	19.3	80.0	909	5185.2
SCR-3	11	1.16	68	45	3.4	14.8	217.2	4.7	17.7	80.0	998	4741.9
SCR-3-C	9	1.16	45	34	3.4	11.7	260.3	2.2	16.1	80.0	808	2675.0
SCR-3-C	10	1.16	68	41	3.4	14.8	217.2	2.8	11.3	80.0	909	3043.6
SCR-3-C	11	1.16	68	45	3.4	14.8	217.2	2.8	10.4	80.0	998	2783.2
SCR-7	9	1.16	45	34	3.4	11.7	260.3	3.3	24.7	80.0	808	4093.8
SCR-7	10	1.16	68	41	3.4	14.8	217.2	4.2	17.0	80.0	909	4565.2
SCR-7	11	1.16	68	45	3.4	14.8	217.2	4.2	15.6	80.0	998	4177.1
SCR-7-C	9	1.16	45	34	3.4	11.7	260.3	1.9	14.5	80.0	808	2410.5
SCR-7-C	10	1.16	68	41	3.4	14.8	217.2	2.4	10.0	80.0	909	2688.4
SCR-7-C	11	1.16	68	45	3.4	14.8	217.2	2.5	9.2	80.0	998	2459.5

the baghouses and then to the chimney. A low retrofit factor (1.13) was assigned to the new baghouse location because of a low site access/ congestion. Tables 20.6.4-7 through 20.6.4-9 present a summary of the site access/congestion factors for DSD technology at the Toronto steam plant. Table 20.6.4-10 presents the costs estimated to retrofit DSD at the Toronto plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Toronto plant. All three boilers would be considered good candidates for AFBC retrofit because of their small boiler sizes (<70 MW) and ages (built before 1950).

TABLE 20.6.4-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR TORONTO UNIT 9

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	400
ESTIMATED COST (1000$)	1152
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	16
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	NA
A NEW BAGHOUSE CASE (DSD)	1168
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	1.13

TABLE 20.6.4-8. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR TORONTO UNIT 10

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	350
ESTIMATED COST (1000$)	1283
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	22
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	NA
A NEW BAGHOUSE CASE (DSD)	1305
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	1.13

TABLE 20.6.4-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR TORONTO UNIT 11

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	LOW
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	300
ESTIMATED COST (1000$)	1100
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	22
TOTAL COST (1000$)	
ESP UPGRADE CASE (FSI)	NA
A NEW BAGHOUSE CASE (DSD)	1122
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE (FSI)	NA
NEW BAGHOUSE (DSD)	1.13

Table 20.6.4-10. Summary of DSD/FSI Control Costs for the Toronto Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+FF	9	1.00	45	34	3.4	11.9	264.5	6.1	45.7	71.0	2787	2196.7
DSD+FF	10	1.00	68	41	3.4	15.4	226.7	7.6	31.3	69.0	4984	1532.0
DSD+FF	11	1.00	68	45	3.4	15.2	223.9	7.7	28.9	69.0	5470	1415.0
DSD+FF-C	9	1.00	45	34	3.4	11.9	264.5	3.6	26.6	71.0	2787	1277.7
DSD+FF-C	10	1.00	68	41	3.4	15.4	226.7	4.4	18.2	69.0	4984	891.6
DSD+FF-C	11	1.00	68	45	3.4	15.2	223.9	4.5	16.8	69.0	5470	823.2

20.7 OHIO POWER COMPANY

20.7.1 General James M. Gavin Steam Plant

The Gavin steam plant is located within Gallia County, Ohio, as part of the Ohio Power Company system. The plant is located west of the Ohio River and contains two coal-fired boilers with a total gross generating capacity of 2,600 MW.

Table 20.7.1-1 presents operational data for the existing equipment at the Gavin plant. The boilers burn high sulfur coal. Coal shipments are received by barge and transferred to a coal storage and handling area west of the plant and away from the river.

PM emissions for the boilers are controlled with ESPs located behind each unit. Fly ash is wet sluiced and disposed of in an ash pond south of the plant adjacent to the river. Both units are served by a common chimney centered behind the two units toward the river.

Lime/Limestone and Lime Spray Drying FGD Costs--

The Gavin plant is located immediately north of the Kyger Creek plant. Both boilers are located beside each other parallel to the river. Two recirculating forced draft cooling towers are located on either side of the units. The absorbers for both units would be located behind the chimneys to the east of the units toward the river. The limestone preparation, storage, and handling area would be located south of the coal pile and close to the railroad tracks. It is assumed that the railroad tracks can be upgraded for sorbent delivery. A warehouse building behind the chimney has to be relocated to make space available for the FGD absorbers. Therefore, a factor of 8 percent was assigned to general facilities.

A low site access/congestion factor was assigned to the FGD absorber locations due to the space availability after relocating the storage building. Because absorbers are placed immediately behind the chimneys, short duct runs would be required for L/LS-FGD cases (about 200 feet). The common chimney is very easy to access and, as such, a low site access/congestion factor was assigned to the flue gas handling system.

TABLE 20.7.1-1. GAVIN STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2
GENERATING CAPACITY (MW-each)	1300
CAPACITY FACTOR (PERCENT)	60,58
INSTALLATION DATE	1974,75
FIRING TYPE	OPPOSED WALL
FURNACE VOLUME (1000 CU FT)	990
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	3.4
COAL HEATING VALUE (BTU/LB)	11200
COAL ASH CONTENT (PERCENT)	12
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	BARGE/RAILROAD
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1974-75
EMISSION (LB/MM BTU)	0.03
REMOVAL EFFICIENCY	99.8
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	1.0
SURFACE AREA (1000 SQ FT)	240.4
GAS EXIT RATE (1000 ACFM)	4400
SCA (SQ FT/1000 ACFM)	546
OUTLET TEMPERATURE (°F)	300

LSD with reuse of the existing ESPs was considered for this plant because the ESPs are large (SCA=546) and would not require major upgrading or plate area additions to handle the increased particulate load generated from the LSD application. The LSD absorbers would be located behind the ESPs with low site access/congestion factors. However, access to the existing ESPs would be difficult because of the limited space between the ESPs and the boilerhouse. Therefore, a high site access/congestion factor was assigned to the flue gas handling system. Over 600 feet of duct length would be required to divert the flue gas from upstream of the ESPs to the absorbers and back to the ESPs. Because space is available behind the ESPs, a low site access/congestion factor was assigned to the ESP upgrades.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Table 20.7.1-2. Table 20.7.1-3 presents the process area retrofit factors and capital/operating costs for commercial FGD technologies. The low cost FGD option reduces costs due to eliminating spare absorber modules and maximizing absorber module size.

Coal Switching and Physical Coal Cleaning Costs--

Table 20.7.1-4 presents the IAPCS cost results for CS at the Gavin plant. These costs do not include boiler and pulverizer operating cost changes or any system modifications that may be necessary to blend coal. PCC was not evaluated because Gavin is not a mine mouth plant.

Low NO_x Combustion--

Units 1 and 2 are opposed wall-fired dry bottom boilers rated at 1,300 MW each. The combustion modification technique applied to both boilers was LNB. Tables 20.7.1-5 and 20.7.1-6 present the performance and cost results of retrofitting LNB at the Gavin plant. A high NO_x reduction performance was estimated based on the low volumetric heat release rate.

Selective Catalytic Reduction--

Cold side SCR reactors for both units would be located immediately behind the chimney in a similar layout as FGD absorbers. Both reactors are located in low site/congestion areas for the same reasons as were outlined in the FGD section. Access to the common chimney is easy and about 250 feet

TABLE 20.7.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR GAVIN UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	LOW	NA	LOW
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	LOW
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	9346	NA	9346
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.27	NA	
ESP REUSE CASE			1.54
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.16
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	8	0	8

Table 20.7.1-3. Summary of FGD Control Costs for the James M. Gavin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kWh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1	1.27	1300	60	3.4	192.1	147.8	123.3	18.0	90.0	182577	675.3
LC FGD	2	1.27	1300	58	3.4	192.1	147.8	121.2	18.3	90.0	176491	686.6
LC FGD-C	1	1.27	1300	60	3.4	192.1	147.8	71.5	10.5	90.0	182577	391.6
LC FGD-C	2	1.27	1300	58	3.4	192.1	147.8	70.3	10.6	90.0	176491	398.3
LFGD	1	1.27	1300	60	3.4	222.1	170.9	132.8	19.4	90.0	182577	727.4
LFGD	2	1.27	1300	58	3.4	222.1	170.9	130.7	19.8	90.0	176491	740.6
LFGD-C	1	1.27	1300	60	3.4	222.1	170.9	77.1	11.3	90.0	182577	422.2
LFGD-C	2	1.27	1300	58	3.4	222.1	170.9	75.9	11.5	90.0	176491	429.9
LSD+ESP	1	1.54	1300	60	3.4	182.2	140.2	85.3	12.5	63.0	128612	663.1
LSD+ESP	2	1.54	1300	58	3.4	182.2	140.2	84.2	12.8	63.0	124325	677.5
LSD+ESP-C	1	1.54	1300	60	3.4	182.2	140.2	49.7	7.3	63.0	128612	386.2
LSD+ESP-C	2	1.54	1300	58	3.4	182.2	140.2	49.1	7.4	63.0	124325	394.7

Table 20.7.1-4. Summary of Coal Switching/Cleaning Costs for the James M. Gavin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	1300	60	3.4	37.4	28.8	94.6	13.8	76.0	153525	616.3
CS/B+$15	2	1.00	1300	58	3.4	37.4	28.8	91.7	13.9	76.0	148407	618.1
CS/B+$15-C	1	1.00	1300	60	3.4	37.4	28.8	54.4	8.0	76.0	153525	354.2
CS/B+$15-C	2	1.00	1300	58	3.4	37.4	28.8	52.7	8.0	76.0	148407	355.3
CS/B+$5	1	1.00	1300	60	3.4	23.9	18.4	35.8	5.2	76.0	153525	233.4
CS/B+$5	2	1.00	1300	58	3.4	23.9	18.4	34.8	5.3	76.0	148407	234.6
CS/B+$5-C	1	1.00	1300	60	3.4	23.9	18.4	20.6	3.0	76.0	153525	134.4
CS/B+$5-C	2	1.00	1300	58	3.4	23.9	18.4	20.1	3.0	76.0	148407	135.1

TABLE 20.7.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR GAVIN

	BOILER NUMBER
COMBUSTION MODIFICATION RESULTS	
	1,2
FIRING TYPE	OWF
TYPE OF NOx CONTROL	LNB
FURNACE VOLUME (1000 CU FT)	990
BOILER INSTALLATION DATE	1974, 1975
SLAGGING PROBLEM	NO
ESTIMATED NOx REDUCTION (PERCENT)	52
SCR RETROFIT RESULTS	
SITE ACCESS AND CONGESTION FOR SCR REACTOR	LOW
SCOPE ADDER PARAMETERS--	
Building Demolition (1000$)	0
Ductwork Demolition (1000$)	185
New Duct Length (Feet)	250
New Duct Costs (1000$)	5554
New Heat Exchanger (1000$)	8685
TOTAL SCOPE ADDER COSTS (1000$)	14425
RETROFIT FACTOR FOR SCR	1.16
GENERAL FACILITIES (PERCENT)	13

Table 20.7.1-6. NOx Control Cost Results for the James M. Gavin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	1	1.00	1300	60	3.4	7.1	5.5	1.5	0.2	52.0	16706	92.1
LNC-LNB	2	1.00	1300	58	3.4	7.1	5.5	1.5	0.2	52.0	16149	95.2
LNC-LNB-C	1	1.00	1300	60	3.4	7.1	5.5	0.9	0.1	52.0	16706	54.7
LNC-LNB-C	2	1.00	1300	58	3.4	7.1	5.5	0.9	0.1	52.0	16149	56.5
SCR-3	1	1.16	1300	60	3.4	144.3	111.0	56.2	8.2	80.0	25702	2187.8
SCR-3	2	1.16	1300	58	3.4	144.3	111.0	56.1	8.5	80.0	24845	2256.2
SCR-3-C	1	1.16	1300	60	3.4	144.3	111.0	32.9	4.8	80.0	25702	1278.6
SCR-3-C	2	1.16	1300	58	3.4	144.3	111.0	32.8	5.0	80.0	24845	1318.7
SCR-7	1	1.16	1300	60	3.4	144.3	111.0	45.4	6.7	80.0	25702	1768.0
SCR-7	2	1.16	1300	58	3.4	144.3	111.0	45.3	6.9	80.0	24845	1821.8
SCR-7-C	1	1.16	1300	60	3.4	144.3	111.0	26.7	3.9	80.0	25702	1038.1
SCR-7-C	2	1.16	1300	58	3.4	144.3	111.0	26.6	4.0	80.0	24845	1069.8

of duct length would be required to divert the flue gas from the downstream of the ESPs to the reactors and back to the chimney. The ammonia storage system would be placed immediately south of the reactors. No major demolition/relocation would be needed for the placement of the SCR reactors. Therefore, a base factor of 13 percent was assigned to general facilities.

Table 20.7.1-5 presents the SCR retrofit results for both units. Table 20.7.1-6 presents the estimated cost of retrofitting SCR at the Gavin boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The retrofit of conventional FSI and DSD technologies at the Gavin steam plant for both units would be difficult due to the short duct residence time between the boilers and ESPs. The duct residence time would not be sufficient for humidification (FSI application) or sorbent evaporation (DSD application). However, FSI and DSD technologies were considered for this plant assuming the first ESPs section could be modified for humidification or sorbent injection and additional plate area would not be needed downstream of the remaining ESPs section due to their large size. A low site access/congestion factor was assigned for modifying the ESPs because of the space availability behind the ESPs. The sorbent receiving/storage/preparation areas were located beside the coal pile in a similar fashion as L/LS-FGD.

Table 20.7.1-7 presents a summary of the site access/congestion factors for FSI and DSD technologies at the Gavin steam plant. Table 20.7.1-8 presents the costs estimated to retrofit FSI and DSD at the Gavin steam plant.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Gavin plant. Neither of these units would be considered good candidates for repowering/retrofit because of their large size, high capacity factor, and short service life.

TABLE 20.7.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR GAVIN UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	LOW
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	9346
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	205
TOTAL COST (1000$)	
ESP UPGRADE CASE	9551
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.16
NEW BAGHOUSE	NA

Table 20.7.1-8. Summary of DSD/FSI Control Costs for the James M. Gavin Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	1300	60	3.4	72.9	56.1	50.6	7.4	42.0	85606	591.4
DSD+ESP	2	1.00	1300	58	3.4	72.9	56.1	49.7	7.5	42.0	82753	600.2
DSD+ESP-C	1	1.00	1300	60	3.4	72.9	56.1	29.3	4.3	42.0	85606	342.7
DSD+ESP-C	2	1.00	1300	58	3.4	72.9	56.1	28.8	4.4	42.0	82753	347.8
FSI+ESP-50	1	1.00	1300	60	3.4	57.1	43.9	75.6	11.1	50.0	101431	745.2
FSI+ESP-50	2	1.00	1300	58	3.4	57.1	43.9	73.5	11.1	50.0	98050	750.0
FSI+ESP-50-C	1	1.00	1300	60	3.4	57.1	43.9	43.6	6.4	50.0	101431	429.5
FSI+ESP-50-C	2	1.00	1300	58	3.4	57.1	43.9	42.4	6.4	50.0	98050	432.3
FSI+ESP-70	1	1.00	1300	60	3.4	57.8	44.5	77.2	11.3	70.0	142003	544.0
FSI+ESP-70	2	1.00	1300	58	3.4	57.8	44.5	75.1	11.4	70.0	137270	547.4
FSI+ESP-70-C	1	1.00	1300	60	3.4	57.8	44.5	44.5	6.5	70.0	142003	313.5
FSI+ESP-70-C	2	1.00	1300	58	3.4	57.8	44.5	43.3	6.6	70.0	137270	315.5

20.7.2 Muskingum River Steam Plant

Information on Muskingum River steam plant appears in U.S. EPA report number EPA-600/7-88/014, entitled "Ohio/Kentucky/TVA Coal-Fired Utility SO_2 and NO_x Retrofit Study" (NTIS PB88-244447/AS).

20.8 OHIO VALLEY ELECTRIC CORPORATION

20.8.1 Kyger Creek Steam Plant

The Kyger Creek steam plant is located within Gallia County, Ohio, as part of the Ohio Valley Electric Corporation system. The plant is located west of the Ohio River and directly south of the Gavin plant. It contains five coal-fired boilers with a total design gross generating capacity of 1,085 MW.

Table 20.8.1-1 presents operational data for the existing equipment at the Kyger Creek plant. The boilers burn high sulfur coal. Coal shipments are received only by barge and transferred to a coal storage and handling area north of the plant and adjacent to the river.

PM emissions for the boilers are controlled with retrofit ESPs located behind and away from each unit. A three-story service building is located between the ESPs and the units. This building contains offices, lab, machinery, and a cafeteria. In addition, underground tanks and equipment are located in the vicinity of the building. The plant has a wet fly ash handling system. Fly ash is disposed of in a large ash pond west of the plant. Units 1 through 5 are served by a common retrofit chimney.

Lime/Limestone and Lime Spray Drying FGD Costs--

The absorbers for units 1-5 would be located west of the plant between unit 5 and the ash pond on the existing employee parking area. The limestone preparation, storage, and handling area would be located south of the ash pond site. Some of the plant roads and two employee parking areas have to be relocated to open up space for the FGD absorbers. Therefore, a factor of 15 percent was assigned to general facilities.

A high site access/congestion factor was assigned to the FGD absorber locations due to the space limitation between the unit 5 ESPs and a major road beside the ash pond site. Absorbers for unit 5 would be located close to the unit 5 ESPs and short duct runs of about 300 feet would be required. For units 1-4, duct lengths of 400 to 800 feet would be required to divert the flue gas from the chimney to the absorbers and back to the chimney. It is relatively easy to Table 20.8.1-1 access unit 5 flue gas downstream of the

TABLE 20.8.1-1. KYGER CREEK STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1, 2, 3, 4, 5
GENERATING CAPACITY (MW-each)	217
CAPACITY FACTOR (PERCENT)	89, 89, 86, 80, 89
INSTALLATION DATE	1955
FIRING TYPE	FRONT WALL
FURNACE VOLUME (1000 CU FT)	NA
LOW NOx COMBUSTION	NO
COAL SULFUR CONTENT (PERCENT)	3.72
COAL HEATING VALUE (BTU/LB)	12008
COAL ASH CONTENT (PERCENT)	10.1
FLY ASH SYSTEM	WET SLUICE
ASH DISPOSAL METHOD	ON-SITE
STACK NUMBER	1
COAL DELIVERY METHODS	BARGE
PARTICULATE CONTROL	
TYPE	ESP
INSTALLATION DATE	1980
EMISSION (LB/MM BTU)	0.01-0.02
REMOVAL EFFICIENCY	99.8-99.9
DESIGN SPECIFICATION	
SULFUR SPECIFICATION (PERCENT)	3.0-5.0
SURFACE AREA (1000 SQ FT)	310.4
GAS EXIT RATE (1000 ACFM)	925
SCA (SQ FT/1000 ACFM)	335
OUTLET TEMPERATURE (°F)	350

ESPs and, as such, a low site access/congestion factor was assigned to the unit 5 flue gas handling system. On the other hand, a medium site access/congestion factor was assigned to the unit 1-4 flue gas handling systems because the flue gas duct runs for units 1-4 have to go around the unit 5 ESPs. Plant personnel indicated that the existing chimney cannot be reused for the FGD system because the design velocity of the existing stack is too great for a saturated plume.

LSD with reuse of the existing ESPs was considered for this plant because ESPs are adequate in size (SCA =335) and have good particulate removal efficiencies. The retrofit ESPs would probably not require major upgrading or plate area additions to handle the increased PMs generated from the LSD application. The LSD absorbers would be located in the same location as the L/LS-FGD absorbers. Once again, a high site access/congestion factor was assigned to the absorber locations. Duct lengths between 450 to over 1,000 feet would be required to divert the flue gas from upstream of the ESPs to the absorbers and back to the retrofit ESPs. Because of the space constraints in front of the retrofit ESPs created by the service building and truncated old chimneys and underground obstructions created by the underground tanks and equipment, high site access/congestion factors were assigned to the flue gas handling systems for units 1-5.

The major scope adjustment costs and retrofit factors estimated for the FGD technologies are presented in Tables 20.8.1-2 through 20.8.1-5. Table 20.8.1-6 presents the process area retrofit factors and capital/operating costs for commercial FGD technologies. Plant personnel indicated that retrofitting each individual boiler with a separate FGD system is the only viable option; further consolidation of the control equipment for the units might penalize future plant generating availability. In addition, O & M calculations do not include the unavailability of the units due to FGD systems maintenance (estimated by the plant to be 3% of total power generated).

Coal Switching and Physical Coal Cleaning Costs--

All units are wet bottom boilers. Coal switching was not considered for the Kyger Creek plant because low sulfur bituminous coal having low ash

TABLE 20.8.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR KYGER CREEK UNIT 1 OR 2

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			1000 +
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	1878	NA	1878
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	1519	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.74	NA	
ESP REUSE CASE			2.03
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 20.8.1-3. SUMMARY OF RETROFIT FACTOR DATA FOR KYGER CREEK UNIT 3

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	600-1000	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	1878	NA	1878
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	1519	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.74	NA	
ESP REUSE CASE			1.83
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 20.8.1-4. SUMMARY OF RETROFIT FACTOR DATA FOR KYGER CREEK UNIT 4

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	MEDIUM	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			600-1000
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	1878	NA	1878
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	1519	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.66	NA	
ESP REUSE CASE			1.83
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

TABLE 20.8.1-5. SUMMARY OF RETROFIT FACTOR DATA FOR KYGER CREEK UNIT 5

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	HIGH	NA	HIGH
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			HIGH
BAGHOUSE CASE			NA
DUCT WORK DISTANCE (FEET)	300-600	NA	
ESP REUSE			300-600
BAGHOUSE			NA
ESP REUSE	NA	NA	HIGH
NEW BAGHOUSE	NA	NA	NA
SCOPE ADJUSTMENTS			
WET TO DRY	YES	NA	YES
ESTIMATED COST (1000$)	1878	NA	1878
NEW CHIMNEY	YES	NA	NO
ESTIMATED COST (1000$)	1519	0	0
OTHER	NO		NO
RETROFIT FACTORS			
FGD SYSTEM	1.61	NA	
ESP REUSE CASE			1.69
BAGHOUSE CASE			NA
ESP UPGRADE	NA	NA	1.58
NEW BAGHOUSE	NA	NA	NA
GENERAL FACILITIES (PERCENT)	15	0	15

Table 20.8.1-6. Summary of FGD Control Costs for the Kyger Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1-5	1.70	1085	87	3.7	211.0	194.5	142.1	17.2	90.0	221969	640.1
LC FGD-C	1-5	1.70	1085	87	3.7	211.0	194.5	82.4	10.0	90.0	221969	371.0
LFGD	1-5	1.70	1085	87	3.7	254.9	234.9	156.2	18.9	90.0	221969	703.5
LFGD	1	1.74	217	89	3.7	82.4	379.6	44.0	26.0	90.0	45414	968.3
LFGD	2	1.74	217	89	3.7	82.4	379.6	44.0	26.0	90.0	45414	968.3
LFGD	3	1.74	217	86	3.7	82.4	379.6	43.4	26.6	90.0	43884	989.4
LFGD	4	1.66	217	80	3.7	79.0	363.8	41.2	27.1	90.0	40822	1009.2
LFGD	5	1.61	217	89	3.7	76.8	354.1	42.2	24.9	90.0	45414	928.3
LFGD-C	1-5	1.70	1085	87	3.7	254.9	234.9	90.6	11.0	90.0	221969	408.2
LFGD-C	1	1.74	217	89	3.7	82.4	379.6	25.6	15.1	90.0	45414	562.9
LFGD-C	2	1.74	217	89	3.7	82.4	379.6	25.6	15.1	90.0	45414	562.9
LFGD-C	3	1.74	217	86	3.7	82.4	379.6	25.2	15.4	90.0	43884	575.3
LFGD-C	4	1.66	217	80	3.7	79.0	363.8	24.0	15.8	90.0	40822	586.9
LFGD-C	5	1.61	217	89	3.7	76.8	354.1	24.5	14.5	90.0	45414	539.5
LSD+ESP	1	2.03	217	89	3.7	53.6	246.8	26.6	15.7	76.0	38502	690.9
LSD+ESP	2	2.03	217	89	3.7	53.6	246.8	26.6	15.7	76.0	38502	690.9
LSD+ESP	3	1.83	217	86	3.7	48.9	225.4	24.9	15.3	76.0	37204	670.6
LSD+ESP	4	1.83	217	80	3.7	48.9	225.4	24.3	16.0	76.0	34608	703.1
LSD+ESP	5	1.69	217	89	3.7	45.7	210.5	24.3	14.4	76.0	38502	631.6
LSD+ESP-C	1	2.03	217	89	3.7	53.6	246.8	15.5	9.1	76.0	38502	402.1
LSD+ESP-C	2	2.03	217	89	3.7	53.6	246.8	15.5	9.1	76.0	38502	402.1
LSD+ESP-C	3	1.83	217	86	3.7	48.9	225.4	14.5	8.9	76.0	37204	390.1
LSD+ESP-C	4	1.83	217	80	3.7	48.9	225.4	14.2	9.3	76.0	34608	409.2
LSD+ESP-C	5	1.69	217	89	3.7	45.7	210.5	14.1	8.4	76.0	38502	367.2

fusion temperatures are not readily available in the east. PCC was not evaluated because this is not a mine mouth plant.

Low NO_x Combustion--

Units 1-5 are front wall, wet bottom boilers rated at 217 MW each. The combustion modification technique applied to all boilers was NGR. Table 20.8.1-7 shows the NGR NO_x reduction performance and Table 20.8.1-8 presents the cost of retrofitting NGR at the Kyger Creek plant.

Selective Catalytic Reduction--

Cold side SCR reactors for all units would be located immediately behind the retrofit ESPs and adjacent to the coal pile. Reactors for units 1-3 are located in a very congested area bounded by the ESPs, chimney, and the coal pile. As such, a high retrofit factor was assigned to the SCR reactor locations for units 1-3. For units 4-5, limited space is available behind the ESPs close to the common chimney and the coal pile and, as such, a medium site access/congestion factor was assigned to this location. Because reactors were located close to the common chimney, short duct runs of 200-300 feet would be required for all units. No major demolition/ relocation would be required for the SCR reactor locations and, as such, a base factor of 13 percent was assigned to general facilities. All reactors were assumed to be in areas with high underground obstructions. The ammonia storage system was placed close to the reactors west of the plant and close to the ash pond.

Table 20.8.1-7 presents the SCR retrofit results for all units. Table 20.8.1-8 presents the estimated cost of retrofitting SCR at the Kyger Creek boilers.

Duct Spray Drying and Furnace Sorbent Injection--

The Kyger Creek plant boilers are ideal for furnace sorbent injection (FSI) or duct spray drying (DSD) technologies for two major reasons: 1) ESPs have adequate SCAs (=335) and probably would be able to handle the increased PM not requiring major ESP upgrading or plate area additions, and 2) long straight duct residence time (>2 seconds) between the boilers and ESPs would be sufficient for humidification (FSI application) or sorbent

TABLE 20.8.1-7. SUMMARY OF NOx RETROFIT RESULTS FOR KYGER CREEK

	BOILER NUMBER		
COMBUSTION MODIFICATION RESULTS			
	1, 2	3	4, 5
FIRING TYPE	FWF	FWF	FWF
TYPE OF NOx CONTROL	NGR	NGR	NGR
FURNACE VOLUME (1000 CU FT)	NA	NA	NA
BOILER INSTALLATION DATE	1959	1959	1959
SLAGGING PROBLEM	NO	NO	NO
ESTIMATED NOx REDUCTION (PERCENT)	60	60	60
SCR RETROFIT RESULTS			
SITE ACCESS AND CONGESTION FOR SCR REACTOR	HIGH	HIGH	MEDIUM
SCOPE ADDER PARAMETERS--			
Building Demolition (1000$)	0	0	0
Ductwork Demolition (1000$)	81	48	81
New Duct Length (Feet)	300	300	200
New Duct Costs (1000$)	3508	2339	2339
New Heat Exchanger (1000$)	4497	2967	4497
TOTAL SCOPE ADDER COSTS (1000$)			
COMBINED	8086	NA	6917
INDIVIDUAL	5354	5354	4574
RETROFIT FACTOR FOR SCR	1.52	1.52	1.34
GENERAL FACILITIES (PERCENT)	13	13	13

Table 20.8.1-8. NOx Control Cost Results for the Kyger Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
NGR	1	1.00	217	89	3.7	3.9	18.0	9.2	5.4	60.0	7134	1285.0
NGR	2	1.00	217	89	3.7	3.9	18.0	9.2	5.4	60.0	7134	1285.0
NGR	3	1.00	217	86	3.7	3.9	18.0	8.9	5.4	60.0	6893	1287.8
NGR	4	1.00	217	80	3.7	3.9	18.0	8.3	5.5	60.0	6412	1294.1
NGR	5	1.00	217	89	3.7	3.9	18.0	9.2	5.4	60.0	7134	1285.0
NGR-C	1	1.00	217	89	3.7	3.9	18.0	5.3	3.1	60.0	7134	738.7
NGR-C	2	1.00	217	89	3.7	3.9	18.0	5.3	3.1	60.0	7134	738.7
NGR-C	3	1.00	217	86	3.7	3.9	18.0	5.1	3.1	60.0	6893	740.4
NGR-C	4	1.00	217	80	3.7	3.9	18.0	4.8	3.1	60.0	6412	744.2
NGR-C	5	1.00	217	89	3.7	3.9	18.0	5.3	3.1	60.0	7134	738.7
SCR-3	1-2	1.52	434	89	3.7	65.1	150.0	24.3	7.2	80.0	19024	1277.8
SCR-3	4-5	1.34	434	85	3.7	59.2	136.3	22.8	7.0	80.0	18169	1252.8
SCR-3	1	1.52	217	89	3.7	38.8	178.9	13.7	8.1	80.0	9512	1440.6
SCR-3	2	1.52	217	89	3.7	38.8	178.9	13.7	8.1	80.0	9512	1440.6
SCR-3	3	1.52	217	86	3.7	38.8	178.9	13.6	8.3	80.0	9191	1484.2
SCR-3	4	1.34	217	80	3.7	35.3	162.5	12.7	8.3	80.0	8550	1484.9
SCR-3	5	1.34	217	89	3.7	35.3	162.5	12.9	7.6	80.0	9512	1353.9
SCR-3-C	1-2	1.52	434	89	3.7	65.1	150.0	14.2	4.2	80.0	19024	747.5
SCR-3-C	4-5	1.34	434	85	3.7	59.2	136.3	13.3	4.1	80.0	18169	732.4
SCR-3-C	1	1.52	217	89	3.7	38.8	178.9	8.0	4.7	80.0	9512	843.7
SCR-3-C	2	1.52	217	89	3.7	38.8	178.9	8.0	4.7	80.0	9512	843.7
SCR-3-C	3	1.52	217	86	3.7	38.8	178.9	8.0	4.9	80.0	9191	869.3
SCR-3-C	4	1.34	217	80	3.7	35.3	162.5	7.4	4.9	80.0	8550	869.3
SCR-3-C	5	1.34	217	89	3.7	35.3	162.5	7.5	4.5	80.0	9512	792.3
SCR-7	1-2	1.52	434	89	3.7	65.1	150.0	20.7	6.1	80.0	19024	1090.4
SCR-7	4-5	1.34	434	85	3.7	59.2	136.3	19.2	5.9	80.0	18169	1056.5
SCR-7	1	1.52	217	89	3.7	38.8	178.9	11.9	7.0	80.0	9512	1253.2
SCR-7	2	1.52	217	89	3.7	38.8	178.9	11.9	7.0	80.0	9512	1253.2
SCR-7	3	1.52	217	86	3.7	38.8	178.9	11.9	7.3	80.0	9191	1290.2
SCR-7	4	1.34	217	80	3.7	35.3	162.5	10.9	7.2	80.0	8550	1276.4
SCR-7	5	1.34	217	89	3.7	35.3	162.5	11.1	6.6	80.0	9512	1166.4
SCR-7-C	1-2	1.52	434	89	3.7	65.1	150.0	12.2	3.6	80.0	19024	640.1
SCR-7-C	4-5	1.34	434	85	3.7	59.2	136.3	11.3	3.5	80.0	18169	619.9
SCR-7-C	1	1.52	217	89	3.7	38.8	178.9	7.0	4.1	80.0	9512	736.3
SCR-7-C	2	1.52	217	89	3.7	38.8	178.9	7.0	4.1	80.0	9512	736.3
SCR-7-C	3	1.52	217	86	3.7	38.8	178.9	7.0	4.3	80.0	9191	758.1
SCR-7-C	4	1.34	217	80	3.7	35.3	162.5	6.4	4.2	80.0	8550	749.8
SCR-7-C	5	1.34	217	89	3.7	35.3	162.5	6.5	3.9	80.0	9512	684.9

sorbent receiving/storage/preparation areas were located west of the plant in a similar fashion as L/LS-FGD.

Table 20.8.1-9 presents a summary of the site access/congestion factors for sorbent injection technologies at the Kyger Creek steam plant. Table 20.8.1-10 presents the costs estimated to retrofit FSI and DSD at the Kyger Creek.

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

The AFBC retrofit and AFBC/CG repowering applicability criteria presented in Section 2 were used to determine the applicability of these technologies at the Kyger Creek plant. All units would be considered good candidates for repowering or retrofit because of their small boiler sizes.

TABLE 20.8.1-9. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR KYGER CREEK UNIT 1, 2, 3, 4 OR 5

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	MEDIUM
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	YES
ESTIMATED COST (1000$)	1878
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	53
TOTAL COST (1000$)	
ESP UPGRADE CASE	1931
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.25
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 20.8.1-10. Summary of DSD/FSI Control Costs for the Kyger Creek Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	217	89	3.7	16.9	77.9	15.4	9.1	49.0	24549	625.8
DSD+ESP	2	1.00	217	89	3.7	16.9	77.9	15.4	9.1	49.0	24549	625.8
DSD+ESP	3	1.00	217	86	3.7	16.9	77.9	15.1	9.2	49.0	23722	635.4
DSD+ESP	4	1.00	217	80	3.7	16.9	77.9	14.5	9.5	49.0	22067	656.7
DSD+ESP	5	1.00	217	89	3.7	16.9	77.9	15.4	9.1	49.0	24549	625.8
DSD+ESP-C	1	1.00	217	89	3.7	16.9	77.9	8.9	5.2	49.0	24549	361.6
DSD+ESP-C	2	1.00	217	89	3.7	16.9	77.9	8.9	5.2	49.0	24549	361.6
DSD+ESP-C	3	1.00	217	86	3.7	16.9	77.9	8.7	5.3	49.0	23722	367.2
DSD+ESP-C	4	1.00	217	80	3.7	16.9	77.9	8.4	5.5	49.0	22067	379.7
DSD+ESP-C	5	1.00	217	89	3.7	16.9	77.9	8.9	5.2	49.0	24549	361.6
FSI+ESP-50	1	1.00	217	89	3.7	15.8	72.6	20.3	12.0	50.0	25231	802.7
FSI+ESP-50	2	1.00	217	89	3.7	15.8	72.6	20.3	12.0	50.0	25231	802.7
FSI+ESP-50	3	1.00	217	86	3.7	15.8	72.6	19.7	12.1	50.0	24380	809.4
FSI+ESP-50	4	1.00	217	80	3.7	15.8	72.6	18.7	12.3	50.0	22679	824.4
FSI+ESP-50	5	1.00	217	89	3.7	15.8	72.6	20.3	12.0	50.0	25231	802.7
FSI+ESP-50-C	1	1.00	217	89	3.7	15.8	72.6	11.7	6.9	50.0	25231	462.7
FSI+ESP-50-C	2	1.00	217	89	3.7	15.8	72.6	11.7	6.9	50.0	25231	462.7
FSI+ESP-50-C	3	1.00	217	86	3.7	15.8	72.6	11.4	7.0	50.0	24380	466.6
FSI+ESP-50-C	4	1.00	217	80	3.7	15.8	72.6	10.8	7.1	50.0	22679	475.4
FSI+ESP-50-C	5	1.00	217	89	3.7	15.8	72.6	11.7	6.9	50.0	25231	462.7
FSI+ESP-70	1	1.00	217	89	3.7	16.0	73.8	20.7	12.2	70.0	35323	586.0
FSI+ESP-70	2	1.00	217	89	3.7	16.0	73.8	20.7	12.2	70.0	35323	586.0
FSI+ESP-70	3	1.00	217	86	3.7	16.0	73.8	20.2	12.3	70.0	34132	590.8
FSI+ESP-70	4	1.00	217	80	3.7	16.0	73.8	19.1	12.6	70.0	31751	601.7
FSI+ESP-70	5	1.00	217	89	3.7	16.0	73.8	20.7	12.2	70.0	35323	586.0
FSI+ESP-70-C	1	1.00	217	89	3.7	16.0	73.8	11.9	7.1	70.0	35323	337.8
FSI+ESP-70-C	2	1.00	217	89	3.7	16.0	73.8	11.9	7.1	70.0	35323	337.8
FSI+ESP-70-C	3	1.00	217	86	3.7	16.0	73.8	11.6	7.1	70.0	34132	340.6
FSI+ESP-70-C	4	1.00	217	80	3.7	16.0	73.8	11.0	7.2	70.0	31751	347.0
FSI+ESP-70-C	5	1.00	217	89	3.7	16.0	73.8	11.9	7.1	70.0	35323	337.8

20.9 TOLEDO EDISON COMPANY

20.9.1 Bay Shore Steam Plant

The Bay Shore steam plant is located on the Maumee Bay in Lucas County, Ohio, and is operated by the Toledo Edison Company. The Bay Shore plant contains four coal-fired boilers with a gross generating capacity of 658 MW.

Table 20.9.1-1 presents operational data for the existing equipment at the Bay Shore plant. Coal shipments are received by railroad and transferred to a coal storage and handling are south of the plant. PM emissions from units 1 and 2 are controlled by retrofit ESPs and emissions from units 3 and 4 are controlled by ESPs installed at the time of construction. All of the ESPs are located behind their respective boiler. Flue gases from all units are directed into a common chimney east of unit 4. Dry fly ash from the units is disposed of in landfills north of the plant or sold.

Lime/Limestone and Lime Spray Drying FGD Costs--

L/LS-FGD absorbers for units 1-4 would be located beside the common chimney. The site access/congestion factor for this location would be medium. Plant personnel indicated that the preparation and waste handling areas would have to be located away from the plant. Barge unloading facilities would possibly be required for unloading sorbent. Some auxiliary equipment and storage building would need to be relocated; hence, 10 percent was assigned to the general facilities factor. Approximately 200 feet of ductwork would be required for installation of the L/LS-FGD system. A low site access/congestion factor was assigned to flue gas handling.

LSD with reuse of the existing ESPs was not considered for the Bay Shore plant. Even though the unit 1 and 2 ESPs could handle the additional load of the LSD system, access to the ESPs would be difficult because of the congestion created by the existing ESPs, old chimneys, and the water intake structure. LSD with a new baghouse was considered for units 1-4 combined. The LSD absorbers and new baghouse would have a similar location as the wet FGD absorbers; thus, similar site access/congestion and general facilities factors were assigned. A duct length of 200 feet would be required. The site access/congestion factor for flue gas handling is low.

TABLE 20.9.1-1. BAY SHORE STEAM PLANT OPERATIONAL DATA

BOILER NUMBER	1,2	3	4
GENERATING CAPACITY (MW-each)	141,143	150	224
CAPACITY FACTOR (PERCENT)	84,47	83	65
INSTALLATION DATE	1955,59	1963	1968
FIRING TYPE	TOP FIRED FRONT WALL		
FURNACE VOLUME (1000 CU FT)	98.4	54	103.54
LOW NOx COMBUSTION	NO	NO	NO
COAL SULFUR CONTENT (PERCENT)	1.2	1.2	1.2
COAL HEATING VALUE (BTU/LB)	13200	13200	13200
COAL ASH CONTENT (PERCENT)	7.0	7.0	7.0
FLY ASH SYSTEM	DRY DISPOSAL		
ASH DISPOSAL METHOD	LANDFILL/SOLD		
STACK NUMBER	1	1	1
COAL DELIVERY METHODS	RAILROAD		
PARTICULATE CONTROL			
TYPE	ESP	ESP	ESP
INSTALLATION DATE	1980	1963	1968
EMISSION (LB/MM BTU)	0.02	0.08	0.05
REMOVAL EFFICIENCY	99.8	99.5	99.5
DESIGN SPECIFICATION			
SULFUR SPECIFICATION (PERCENT)	0.3-0.8	NA	NA
SURFACE AREA (1000 SQ FT)	247.3	76	112.3
GAS EXIT RATE (1000 ACFM)	463	398	620
SCA (SQ FT/1000 ACFM)	534	191	181
OUTLET TEMPERATURE (°F)	320	259	259

Tables 20.9.1-2 and 20.9.1-3 present the retrofit factors and cost estimates for installation of FGD control technologies at the Bay Shore plant.

Coal Switching and Physical Coal Cleaning Costs--

Table 20.9.1-4 presents the IAPCS cost results for CS at the Bay Shore plant. These costs do not include boiler and pulverizer operating cost changes or any system modifications that may be necessary for coal blending. PCC was not considered at the Bay Shore plant because it is not a mine mouth plant.

NO_x Control Technologies--

LNBs were considered for the two front wall-fired, dry bottom boilers at the Bay Shore plant. Performance results and costs developed for the four units are presented in Tables 20.9.1-5 and 20.9.1-6.

Selective Catalytic Reduction--

Cold side SCR reactors for units 1-4 combined would be located beside the common chimney. A medium general facilities factor (20 percent) and a low site access/congestion factor were assigned to the reactor location. Approximately 200 feet of ductwork would be required. Tables 20.9.1-5 and 20.9.1-6 present the retrofit factors and cost estimates for installation of SCR at the Bay Shore plant.

Furnace Sorbent Injection and Duct Spray Drying FGD Costs--

Sorbent injection technologies (FSI and DSD) were considered for units 1 and 2 at the Bay Shore plant because of the sufficient duct residence time between the old and retrofit ESPs, allowing for humidification or slurry droplet evaporation. Units 1 and 2 also have adequate ESPs to handle the increased load. For units 3 and 4, the duct residence time between the boilers and the ESPs is not sufficient and the ESPs are small; therefore, FSI and DSD were not considered for these units. Tables 20.9.1-7 and 20.9.1-8 present retrofit factors and cost estimates for installation of FSI and DSD at the Bay Shore plant.

TABLE 20.9.1-2. SUMMARY OF RETROFIT FACTOR DATA FOR BAY SHORE UNITS 1-4 (COMBINED)

	FGD TECHNOLOGY		
	L/LS FGD	FORCED OXIDATION	LIME SPRAY DRYING
SITE ACCESS/CONGESTION			
SO2 REMOVAL	MEDIUM	NA	MEDIUM
FLUE GAS HANDLING	LOW	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			LOW
DUCT WORK DISTANCE (FEET)	100-300	NA	
ESP REUSE			
BAGHOUSE			100-300
ESP REUSE	NA	NA	NA
NEW BAGHOUSE	NA	NA	LOW
SCOPE ADJUSTMENTS			
WET TO DRY	NO	NA	NO
ESTIMATED COST (1000$)	NA	NA	NA
NEW CHIMNEY	NO	NA	NO
ESTIMATED COST (1000$)	0	0	0
OTHER	YES		YES
RETROFIT FACTORS			
FGD SYSTEM	1.50	NA	
ESP REUSE CASE			NA
BAGHOUSE CASE			1.48
ESP UPGRADE	NA	NA	NA
NEW BAGHOUSE	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	10	0	10

Table 20.9.1-3. Summary of FGD Control Costs for the Bay Shore Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
LC FGD	1-4	1.50	658	69	1.2	98.9	150.4	53.2	13.4	90.0	31063	1714.0
LC FGD-C	1-4	1.50	658	69	1.2	98.9	150.4	30.9	7.8	90.0	31063	996.3
LFGD	1-4	1.50	658	69	1.2	124.6	189.3	61.4	15.4	90.0	31063	1977.4
LFGD-C	1-4	1.50	658	69	1.2	124.6	189.3	35.8	9.0	90.0	31063	1150.9
LSD+FF	1-4	1.48	658	69	1.2	122.0	185.5	44.8	11.3	87.0	29855	1499.8
LSD+FF-C	1-4	1.48	658	69	1.2	122.0	185.5	26.2	6.6	87.0	29855	877.6

Table 20.9.1-4. Summary of Coal Switching/Cleaning Costs for the Bay Shore Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
CS/B+$15	1	1.00	141	84	1.2	5.6	40.0	15.4	14.8	17.0	1512	10168.0
CS/B+$15	2	1.00	143	47	1.2	5.7	39.9	9.3	15.8	17.0	858	10834.5
CS/B+$15	3	1.00	150	83	1.2	6.2	41.2	16.2	14.9	17.0	1590	10192.6
CS/B+$15	4	1.00	224	65	1.2	8.8	39.1	19.1	15.0	17.0	1859	10267.6
CS/B+$15-C	1	1.00	141	84	1.2	5.6	40.0	8.8	8.5	17.0	1512	5842.4
CS/B+$15-C	2	1.00	143	47	1.2	5.7	39.9	5.4	9.1	17.0	858	6237.3
CS/B+$15-C	3	1.00	150	83	1.2	6.2	41.2	9.3	8.5	17.0	1590	5857.2
CS/B+$15-C	4	1.00	224	65	1.2	8.8	39.1	11.0	8.6	17.0	1859	5903.8
CS/B+$5	1	1.00	141	84	1.2	4.2	29.6	6.5	6.3	17.0	1512	4331.4
CS/B+$5	2	1.00	143	47	1.2	4.2	29.5	4.2	7.1	17.0	858	4864.4
CS/B+$5	3	1.00	150	83	1.2	4.6	30.9	6.9	6.3	17.0	1590	4353.9
CS/B+$5	4	1.00	224	65	1.2	6.4	28.8	8.1	6.4	17.0	1859	4381.5
CS/B+$5-C	1	1.00	141	84	1.2	4.2	29.6	3.8	3.6	17.0	1512	2494.1
CS/B+$5-C	2	1.00	143	47	1.2	4.2	29.5	2.4	4.1	17.0	858	2809.1
CS/B+$5-C	3	1.00	150	83	1.2	4.6	30.9	4.0	3.7	17.0	1590	2507.6
CS/B+$5-C	4	1.00	224	65	1.2	6.4	28.8	4.7	3.7	17.0	1859	2525.9

TABLE 20.9.1-5. SUMMARY OF NOx RETROFIT RESULTS FOR BAY SHORE

	BOILER NUMBER			
COMBUSTION MODIFICATION RESULTS				
	1,2	3	4	1-4
FIRING TYPE	TOP FIRED	FWF	FWF	NA
TYPE OF NOx CONTROL	NA	LNB	LNB	NA
FURNACE VOLUME (1000 CU FT)	98.4	54	103.54	NA
BOILER INSTALLATION DATE	1955,59	1963	1968	NA
SLAGGING PROBLEM	NO	NO	NO	NA
ESTIMATED NOx REDUCTION (PERCENT)	NA	26	33	NA
SCR RETROFIT RESULTS				
SITE ACCESS AND CONGESTION FOR SCR REACTOR	NA	NA	NA	LOW
SCOPE ADDER PARAMETERS--				
Building Demolition (1000$)	NA	NA	NA	0
Ductwork Demolition (1000$)	NA	NA	NA	111
New Duct Length (Feet)	NA	NA	NA	200
New Duct Costs (1000$)	NA	NA	NA	2984
New Heat Exchanger (1000$)	NA	NA	NA	5772
TOTAL SCOPE ADDER COSTS (1000$)	NA	NA	NA	8867
RETROFIT FACTOR FOR SCR	NA	NA	NA	1.16
GENERAL FACILITIES (PERCENT)	NA	NA	NA	20

Table 20.9.1-6. NOx Control Cost Results for the Bay Shore Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	NOx Removed (%)	NOx Removed (tons/yr)	NOx Cost Effect. ($/ton)
LNC-LNB	3	1.00	150	83	1.2	3.0	20.0	0.6	0.6	26.0	1104	587.2
LNC-LNB	4	1.00	224	65	1.2	3.5	15.7	0.8	0.6	33.0	1639	464.5
LNC-LNB-C	3	1.00	150	83	1.2	3.0	20.0	0.4	0.4	26.0	1104	348.7
LNC-LNB-C	4	1.00	224	65	1.2	3.5	15.7	0.5	0.4	33.0	1639	275.8
SCR-3	1-4	1.16	658	69	1.2	78.3	119.0	29.7	7.5	80.0	12390	2395.3
SCR-3-C	1-4	1.16	658	69	1.2	78.3	119.0	17.4	4.4	80.0	12390	1400.7
SCR-7	1-4	1.16	658	69	1.2	78.3	119.0	24.3	6.1	80.0	12390	1965.0
SCR-7-C	1-4	1.16	658	69	1.2	78.3	119.0	14.3	3.6	80.0	12390	1154.1

TABLE 20.9.1-7. DUCT SPRAY DRYING AND FURNACE SORBENT INJECTION TECHNOLOGIES FOR BAY SHORE UNIT 1 OR 2

ITEM	
SITE ACCESS/CONGESTION	
REAGENT PREPARATION	LOW
ESP UPGRADE	HIGH
NEW BAGHOUSE	NA
SCOPE ADDERS	
CHANGE ESP ASH DISCHARGE SYSTEM TO DRY HANDLING	NO
ESTIMATED COST (1000$)	NA
ADDITIONAL DUCT WORK (FT)	
NEW BAGHOUSE CASE	NA
ESTIMATED COST (1000$)	NA
ESP REUSE CASE	NA
ESTIMATED COST (1000$)	NA
DUCT DEMOLITION LENGTH (FT)	50
DEMOLITION COST (1000$)	39
TOTAL COST (1000$)	
ESP UPGRADE CASE	39
A NEW BAGHOUSE CASE	NA
RETROFIT FACTORS	
CONTROL SYSTEM (DSD SYSTEM ONLY)	1.13
ESP UPGRADE	1.58
NEW BAGHOUSE	NA

Table 20.9.1-8. Summary of DSD/FSI Control Costs for the Bay Shore Plant (June 1988 Dollars)

Technology	Boiler Number	Main Retrofit Difficulty Factor	Boiler Size (MW)	Capacity Factor (%)	Coal Sulfur Content (%)	Capital Cost ($MM)	Capital Cost ($/kW)	Annual Cost ($MM)	Annual Cost (mills/kwh)	SO2 Removed (%)	SO2 Removed (tons/yr)	SO2 Cost Effect. ($/ton)
DSD+ESP	1	1.00	141	84	1.2	6.5	45.8	6.0	5.7	49.0	4380	1361.8
DSD+ESP	2	1.00	143	47	1.2	6.5	45.5	5.2	8.8	49.0	2486	2082.5
DSD+ESP-C	1	1.00	141	84	1.2	6.5	45.8	3.4	3.3	49.0	4380	786.8
DSD+ESP-C	2	1.00	143	47	1.2	6.5	45.5	3.0	5.1	49.0	2486	1204.9
FSI+ESP-50	1	1.00	141	84	1.2	7.3	51.7	5.9	5.7	50.0	4502	1310.4
FSI+ESP-50	2	1.00	143	47	1.2	7.3	51.4	4.7	7.9	50.0	2555	1826.7
FSI+ESP-50-C	1	1.00	141	84	1.2	7.3	51.7	3.4	3.3	50.0	4502	758.0
FSI+ESP-50-C	2	1.00	143	47	1.2	7.3	51.4	2.7	4.6	50.0	2555	1059.4
FSI+ESP-70	1	1.00	141	84	1.2	7.4	52.5	6.0	5.8	70.0	6303	951.2
FSI+ESP-70	2	1.00	143	47	1.2	7.5	52.2	4.7	8.0	70.0	3577	1323.5
FSI+ESP-70-C	1	1.00	141	84	1.2	7.4	52.5	3.5	3.3	70.0	6303	550.2
FSI+ESP-70-C	2	1.00	143	47	1.2	7.5	52.2	2.7	4.7	70.0	3577	767.6

Atmospheric Fluidized Bed Combustion and Coal Gasification Applicability--

All units would be potential candidates for AFBC/CG repowering because of their small boiler size (<300 MW). However, the high capacity factors could result in high replacement power costs for extended boiler downtime.