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Cost Analysis of Lime-based Flue Gas Desulfurization Systems for New 500-MW Utility Boilers

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Cost Analysis of Lime-based Flue Gas Desulfurization Systems for New 500-MW Utility Boilers

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ACKNOWLEDGMENT

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SECTION 1

INTRODUCTION

This report studies the effect of sulfur dioxide (SO_2) removal levels on the cost of lime-based flue gas desulfurization (FGD) systems for total and partial scrubbing. The analysis is performed for a 500-MW utility boiler firing three major types of coal. The results are presented as graphs for six cost components.

The three types of coal considered are bituminous, subbituminous, and lignite. Because these coals differ from each other in firing characteristics, boilers using different fuels have different FGD costs for the same SO_2 removal levels.

The results of this analysis are to be used in studying the effects of limitation levels and averaging times on SO_2 control costs. The U.S. Environmental Protection Agency (EPA) has contracted with PEDCo Environmental, Inc., to perform this analysis in support of a program to review New Source Performance Standards for SO_2 emissions from coal-fired utility boilers.

Section 2 discusses the system variables for each kind of coal, and Section 3 describes the cost components studied. The results and applications of the analysis are presented in Section 4, which includes costs for model plants defined by the EPA.

SECTION 2

SYSTEM VARIABLES

This report is intended for use with various combinations of input parameters. To present a broad spectrum of cases, the report follows these guidelines:

1. Cost components are evaluated for three types of coal that are representative of the coals mined in the United States.

2. To study the effect of partial scrubbing, the analysis includes FGD cost curves for flue gas flows from 20 through 100 percent of the total boiler exhaust.

3. The analysis is applicable to SO_2 removal levels up to 3867 ng/J (9.0 lb/10^6 Btu).

The ranges of variables and FGD system assumptions are discussed in this section.

2.1 FGD SYSTEM CONFIGURATION

The process diagram for a typical lime FGD system is shown in Figure 2-1. The system does not include equipment for particulate removal. It is assumed that the particulate concentration of flue gas entering the absorber complies with the applicable particulate emission regulations.

The FGD system has three major process areas: (1) slurry preparation, (2) SO_2 scrubbing, and (3) sludge disposal. The items of equipment included for each process area are as follows:

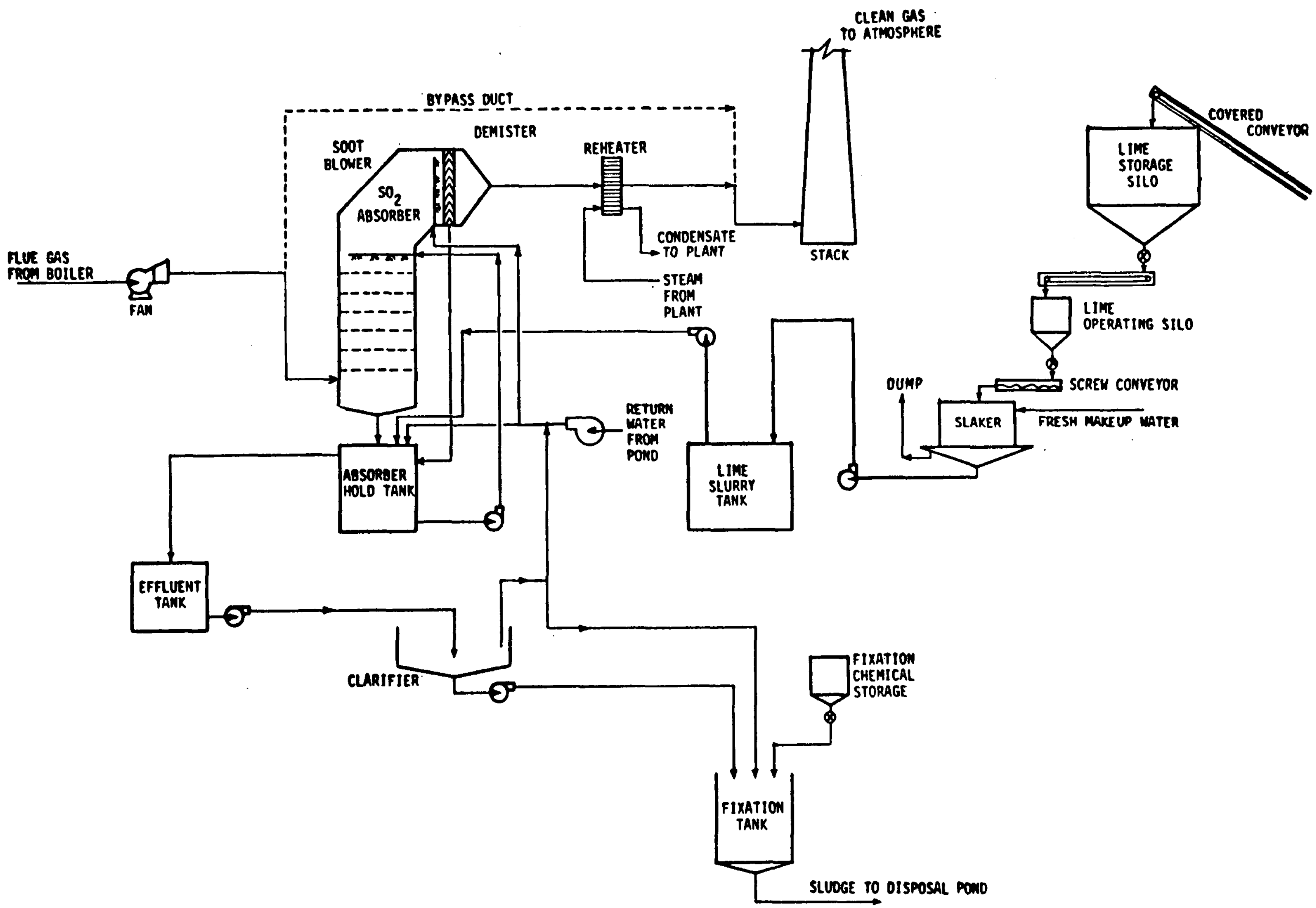

Figure 2-1. Lime FGD system.

(1) Slurry preparation:
- Conveyors
- Slakers
- Storage silos
- Storage tanks
- Pumps and motors

(2) SO_2 scrubbing:
- Absorbers
- Fans and motors
- Heat exchangers (reheaters)
- Duct work and dampers
- Slurry hold tanks
- Recycle pumps

(3) Sludge disposal:
- Clarifiers
- Chemical storage equipment
- Mobile equipment
- Hold tanks
- Sludge pumps

The stack at the plant is not considered a part of the FGD system. The sludge generated by the FGD is disposed of in an onsite sludge pond. Sludge is assumed to be pumped 1.6 km (1 mile). Costs are for new applications only; retrofit applications are out of the scope of this report.

2.2 PLANT VARIABLES

FGD costs are estimated for single boiler plants, each with a total electrical capacity of 500 MW. Use of an FGD system, however, causes plant generating capacity to be derated by the amount of electricity needed to operate the system.

Costs are presented for plants firing three types of coal: bituminous, subbituminous, and lignite. These coals have different firing characteristics; those affecting the design of FGD systems are listed in Table 2-1. Heating value and heat rate determine the quantity of coal fired per hour, and the SO_2 in boiler outlet gases is proportional to this quantity. Thus, FGD costs vary for coals with different heat rates and heating values.

TABLE 2-1. ASSUMED COAL CHARACTERISTICS

Coal type	Heating value kJ/kg (Btu/lb)	Flue gas rate,[a] m^3/s (acfm)	Heat rate, kJ/kWh (Btu/kWh)
Bituminous	27,920 (12,000)	713 (1,510,000)	9500 (9000)
Subbituminous	24,330 (10,500)	727 (1,540,000)	9560 (9050)
Lignite	18,380 (7,900)	763 (1,616,000)	9720 (9200)

[a] For 500-MW plant.

The size of handling equipment depends on total gas flow through an FGD system. The amount of air required for complete combustion varies for different coals and produces different exhaust gas flow rates.

2.3 ANALYSIS APPROACH

To cover a broad range of cases, the report considers four levels of SO_2 removal: 859 ng/J (2.0 lb/10^6 Btu), 1718 ng/J (4.0 lb/10^6 Btu), 2578 ng/J (6.0 lb/10^6 Btu), and 3437 ng/J (8.0 lb/10^6 Btu). Values of each cost component are calculated for these levels and are plotted as points on graphs. Curves are drawn through the points, and costs for intermediate SO_2 removal levels can be interpolated from the curves.

Separate curves are drawn for nine gas flow rates, ranging from 20 to 100 percent of the exhaust gases at increments of 10 percent.

Figure 2-2 shows the plant variables and total number of plant combinations necessary for the analysis.

2.3.1 Module Selection

Items of gas handling equipment in an FGD system are generally referred to as scrubbing modules. Limitations on the physical size of absorbers and ancillary devices force manufacturers of FGD equipment to limit maximum module size. The number of modules selected depends on the reliability requirements and volume of gas to be treated. The cost of an FGD system varies according to the number of modules it contains. The availability of an FGD system is a direct function of number of scrubbing modules. The more scrubbing modules there are, the greater the availability of the system. A system with four scrubbing modules, for example, loses 25 percent of capacity if one module is down; but a system with only two scrubbing modules loses 50 percent capacity if one module is down. Availability is thus enhanced by a maximum number of functioning modules, as well as by some spare scrubbing capacity.

Module selection for this analysis is based on reducing system cost while providing for redundancy. The largest scrubber size assumed is 218 m^3/s (462,000 acfm) of flue gas at 155°C (310°F). This size is equivalent to 150 MW of electrical capacity for subbituminous coal. Based on this size limitation, the total costs for different numbers of modules are compared for

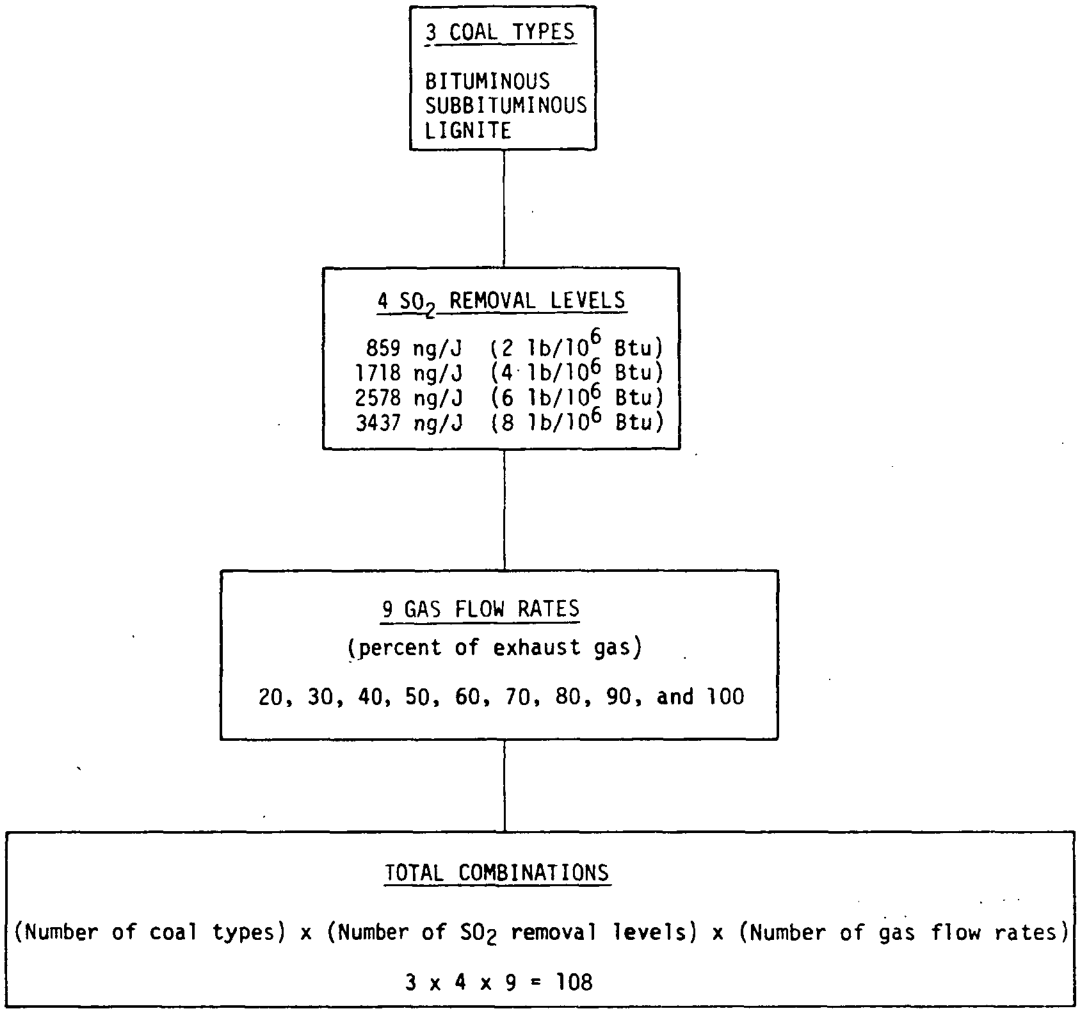

Figure 2-2. Plant combinations for FGD cost analysis.

each scrubbing case. Table 2-2 shows the number of modules selected for the cases analyzed. Each case includes one spare scrubbing module.

The cost bases and rate data used for the analysis are presented in Table 2-3.

TABLE 2-2. SELECTED NUMBER OF SCRUBBER MODULES AND SPARE CAPACITY

Gas flow through FGD system, % of total exhaust	Bituminous coal			Subbituminous coal			Lignite		
	Total number of scrubber modules	Spare modules	Spare scrubbing capacity, %	Total number of scrubber modules	Spare modules	Spare scrubbing capacity, %	Total number of scrubber modules	Spare modules	Spare scrubbing capacity, %
100	5	1	25	5	1	25	5	1	25
90	4	1	33	4	1	33	5	1	25
80	4	1	33	4	1	33	4	1	33
70	4	1	33	4	1	33	4	1	33
60	3	1	50	3	1	50	4	1	33
50	3	1	50	3	1	50	3	1	50
40	3	1	50	3	1	50	3	1	50
30	3	1	50	3	1	50	3	1	50
20	3	1	50	3	1	50	3	1	50

TABLE 2-3. COST BASES AND RATES

Escalation factor for capital cost[a]	1.156
Electricity rate, mills/kWh	25.00
Reheat/steam rate, \$/GJ (\$/10^6Btu)	1.18 (1.25)
Labor rate, \$/man-hour	10.00
Capital recovery factor for annualizing capital investment, % of capital cost	11.70
Insurance, taxes, and general administrative expenses, % of capital cost	4.30
Land rate, \$/m^2 (\$/acre)	0.49 (2000)
Lime rate, \$/Mg (\$/ton)	38.60 (35.00)
Fixation chemicals, \$/Mg (\$/ton)	22.00 (20.00)

[a] The base year for computer model costs is 1976; the escalation factor is used to update the costs to 1978.

SECTION 3

COST COMPONENTS

The cost of an FGD system is estimated as capital cost and annualized cost. The capital cost represents the initial investment necessary to install and commission the system. The annualized cost represents the cost of operating and maintaining the system and the charges needed to recover the capital investment, which are referred to as fixed costs or fixed charges.

3.1 CAPITAL COSTS

Capital costs consist of direct and indirect costs incurred up to the successful commissioning date of the facility. Direct costs include the costs of various items of equipment and the labor and material required for installing these items and interconnecting the system. Indirect costs are expenditures for the overall facility that cannot be attributed to specific equipment; they include such items as freight and spares.

3.1.1 Direct Costs

The "bought-out" cost of the equipment and the cost of installing it are considered direct costs. A bought-out cost of an equipment item is the purchase price paid to the equipment supplier on a free-on-board (f.o.b.) basis; this does not include the freight charges. Installation costs cover the interconnection of the system, which involves piping, electrical, and the other work needed to commission it. Also attributed to installation are the costs of foundations, supporting structures, enclosures, ducting, control panels, instrumentation, insulation, painting, and similar items. Costs for interconnecting various items of FGD equipment include site development, construction of access roads and walkways, and the establishment of rail, barge, or truck facilities. Finally, the cost of administrative facilities is considered a direct cost.

Various procedures are available for estimating direct costs. The PEDCo computer model uses the installation factor technique to estimate total direct costs. The bought-out cost of each item of equipment is multiplied by an individual installation factor to obtain the installed cost. This installed cost includes a proportional cost for interconnecting the equipment into the system. The installation factors are based on the complexity of the equipment and the cost of the material and labor required. The installed costs of all the equipment are added together to obtain the total direct cost of the facility.

3.1.2 Indirect Costs

The indirect costs of an FGD system include the following:

Interest: covers interest accrued on borrowed capital during construction.

Engineering costs: include administrative, process, project, and general costs; design and related functions for specifications; bid analysis; special studies; cost analysis; accounting; reports; purchasing; procurement; travel expenses; living expenses; expediting; inspection; safety;

communications; modeling; pilot plant studies; royalty payments during construction; training of plant personnel; field engineering; safety engineering; and consultant services.

Field overhead: includes the cost of securing permits and right-of-way sections, and the cost of insurance for the equipment and personnel on site.

Freight: includes delivery costs on FGD process and related equipment shipped f.o.b. point of origin.

Offsite expenditures: include expenditures for powerhouse modifications, interruption to power generation, and service facilities added to the existing plant facilities.

Taxes: include sales, franchise, property, and excise taxes.

Spare parts: represent costs of items stocked to permit 100 percent process availability; such items include pumps, valves, controls, special piping and fittings, instruments, spray nozzles, and similar equipment.

Shakedown: includes costs associated with system startup.

Contractor's fee and expenses: include costs for field labor payroll, supervision field office, administrative personnel, construction offices, temporary roadways, railroad trackage, maintenance and welding shops, parking lot, communications, temporary piping, electrical, sanitary facilities, rental equipment, unloading and storage of materials, travel expenses, permits, licenses, taxes, insurance, overhead, legal liabilities, field testing of equipment, and labor relations.

Contingency costs: include costs resulting from malfunctions, equipment design alterations, and similar unforeseen sources.

Land cost: includes only the cost of the land required for sludge disposal. The cost of land for installing FGD equipment is accounted for in the installation factors.

All indirect cost components, except land cost, are obtained by multiplying the direct costs by an indirect cost factor. The land cost is based on land rate and the disposal area required.

3.2 ANNUALIZED COSTS

The annualized operating costs of an FGD system consist of the following:

Raw materials: include costs of lime for the FGD system and fixation chemicals.

Utilities: include costs of water for slurries, cooling, and cleaning; electricity for pumps, fans, valves, lighting controls, conveyors, and mixers; fuel for reheating flue gases; and steam for processing.

Operating labor: includes costs of supervision and skilled and unskilled labor to operate, monitor, and control the FGD process.

Maintenance and repairs: include costs of manpower and materials to keep the unit operating efficiently. The function of maintenance is both preventive and corrective, to keep outages to a minimum.

Overhead: represents business expenses that are not charged directly to a particular part of a process, but are allocated to it. Overhead costs include administrative, safety, engineering, legal, and medical services; payroll; employee benefits; recreation; and public relations.

The capital investment in an FGD system is generally translated into annual fixed charges. These charges, along with the annual operating cost, represent the total revenue requirement or annualized cost of a system. The annual fixed charges are calculated under four cost components: depreciation, taxes, insurance, and capital costs. The values for these components are obtained as follows:

Depreciation: calculated by using a sinking-fund method over the life period of the FGD system.

Taxes: calculated by multiplying the total capital cost by the input tax rate. The tax rate varies for different plants.

Insurance: calculated by multiplying the total capital cost by the insurance rate.

Capital charges: calculated by multiplying the total capital cost by the input interest rate. Capital charges represent the interest paid per year for the use of capital, and they vary according to interest rates.

The total annual fixed charges are obtained by adding the values of the above four components. The annualized cost or total annual revenue required is the sum of the annual operating costs and the total annual fixed charges. Table 2-3, presented at the end of Section 2, shows the cost bases and rates used in this analysis.

3.3 COMPUTER MODEL FOR COSTS

The costs for lime FGD systems were calculated using the computer model developed by PEDCo. This model is structured to provide capital and annualized costs for different FGD variables. The input for the model consists of the rate data, coal data, gas flow rates, rates of allowable SO_2, and other related data. The base year for the model is 1976; a provision exists for adjusting the capital costs by an escalation factor to the year of FGD startup.

SECTION 4

RESULTS AND APPLICATIONS

4.1 RESULTS

4.1.1 Cost Components

The coal fired in a utility boiler varies in sulfur content. An FGD system designed for a long-term average sulfur content in the coal would allow excessive emissions of SO_2 during short-term peaks of sulfur content. To meet SO_2 control regulations consistently, an FGD system must be designed for these peaks and thus be larger than would be required for a long averaging time.

To analyze the effect of averaging time, this report subdivides the FGD costs generated by the computer model into six components. Of the six cost components, three are dependent on averaging time: (1) capital cost of system equipment, (2) fixed charges of total capital investment, and (3) capacity penalty. The components independent of averaging time are: (1) capital investment for sludge pond and land and (2) energy penalty. The operation and maintenance costs are made up of components dependent on averaging time and components independent of averaging time. Costs of raw materials used by the FGD system are independent of the averaging time, whereas maintenance costs, which are a function of capital investment, are dependent on it. The importance of these components in cost analysis is explained below.

4.1.1.1 Capital Cost of System Equipment--

The FGD system must be large enough to accommodate sulfur content peaks in the coal. Such a system operates at a slightly reduced load when sulfur content is lower than the peaks, and brings a higher capital investment than a system designed for long-term average sulfur content.

4.1.1.2 Fixed Charges--

The high capital investment for systems designed for short averaging times also brings high annual capital charges, because these charges are proportional to the capital investment.

4.1.1.3 Capacity Penalty--

The capacity penalty represents an instantaneous derating in boiler capacity by the amount required to operate the FGD system. The derating depends upon the maximum power to be reserved for the system during sulfur peaks. This study treats the capacity penalty as a percentage of total generating capacity.

4.1.1.4 Capital Investment for Sludge Pond and Land--

The total sludge generated by the FGD system depends on the long-term sulfur content of coal and is independent of short-term sulfur peaks. The capital investment for sludge pond and land therefore always varies according to the long-term sulfur content of the coal.

4.1.1.5 Operation and Maintenance Costs--

The cost components for operation and maintenance include costs of lime, fixation chemicals, and labor. Reheat and electricity are not included. The operating costs are independent of the averaging time, and maintenance costs are dependent on it.

4.1.1.6 Energy Penalty--

The energy penalty is represented as the percentage of total generating capacity. The energy used by the FGD system does not depend on averaging time.

4.1.2 Graphs for Cost Components

Graphs are presented for six cost components of lime FGD systems at plants firing each of the three types of coal. Figures 4-1 through 4-6 are for bituminous-coal-fired units; Figures 4-7 through 4-12, for subbituminous-coal-fired ones; and Figures 4-13 through 4-18, for lignite-fired ones. The six cost components are:

(1) Capital investment excluding sludge pond and land.

(2) Capital cost of sludge pond and land.

(3) Operation and maintenance costs excluding electricity and reheat.

(4) Fixed charges.

(5) Capacity penalty.

(6) Energy penalty.

The graphs for components 1 through 4 have x-axes showing the amount of SO_2 removed. The graphs for components 5 and 6 have

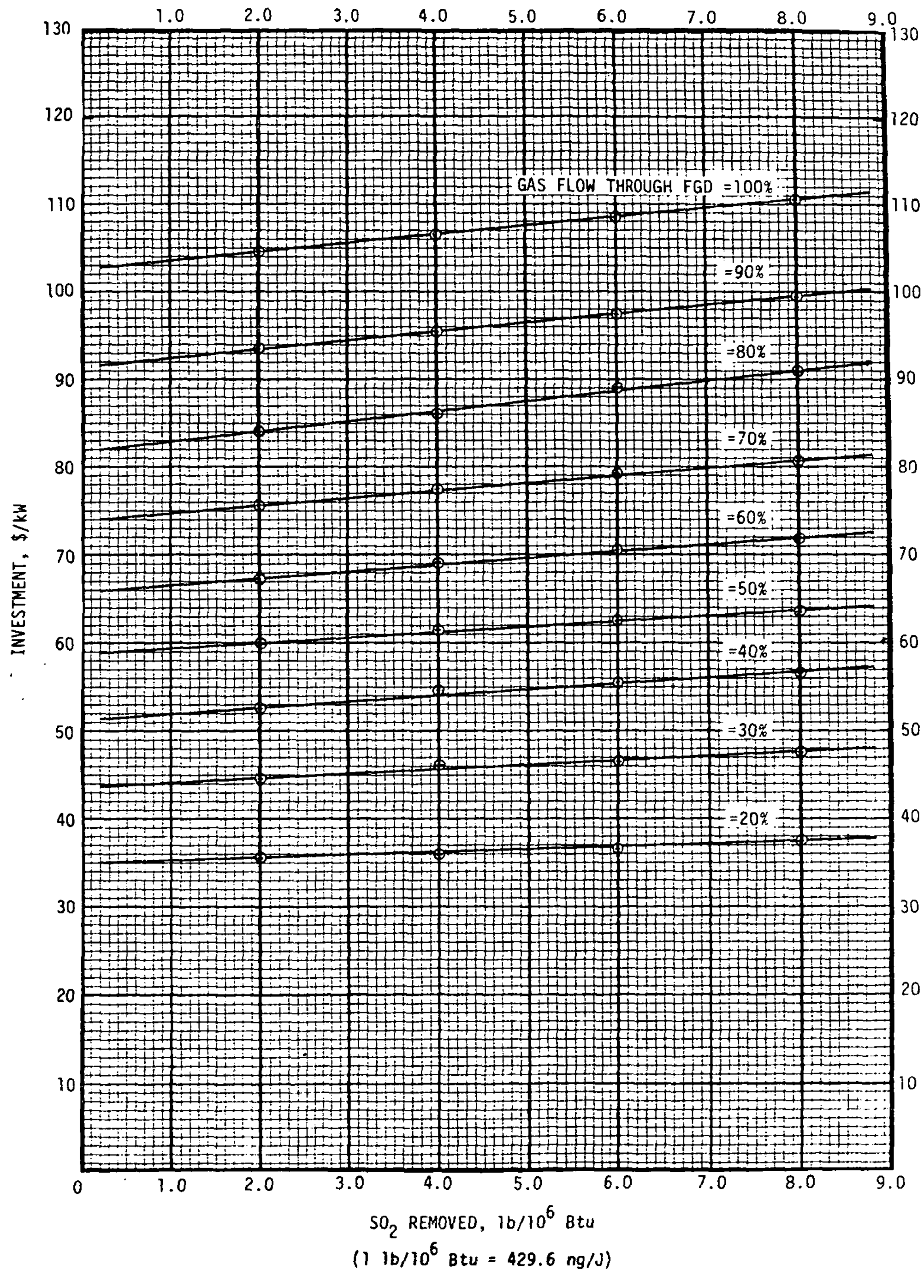

Figure 4-1. Capital investment excluding cost of sludge pond and land for a lime FGD system at a bituminous-coal-fired 500-MW plant.

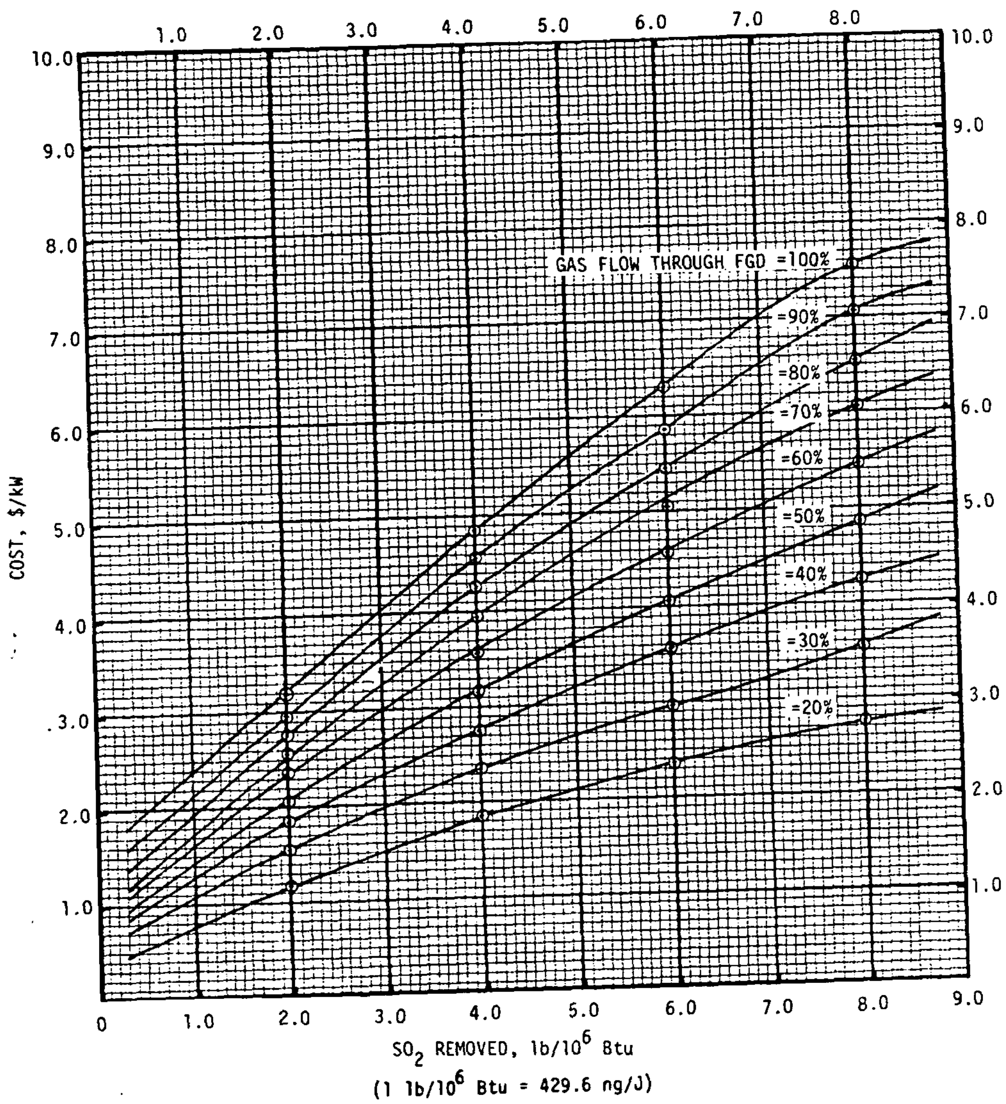

Figure 4-2. Capital cost of sludge pond and land for a lime FGD system at a bituminous-coal-fired 500-MW plant.

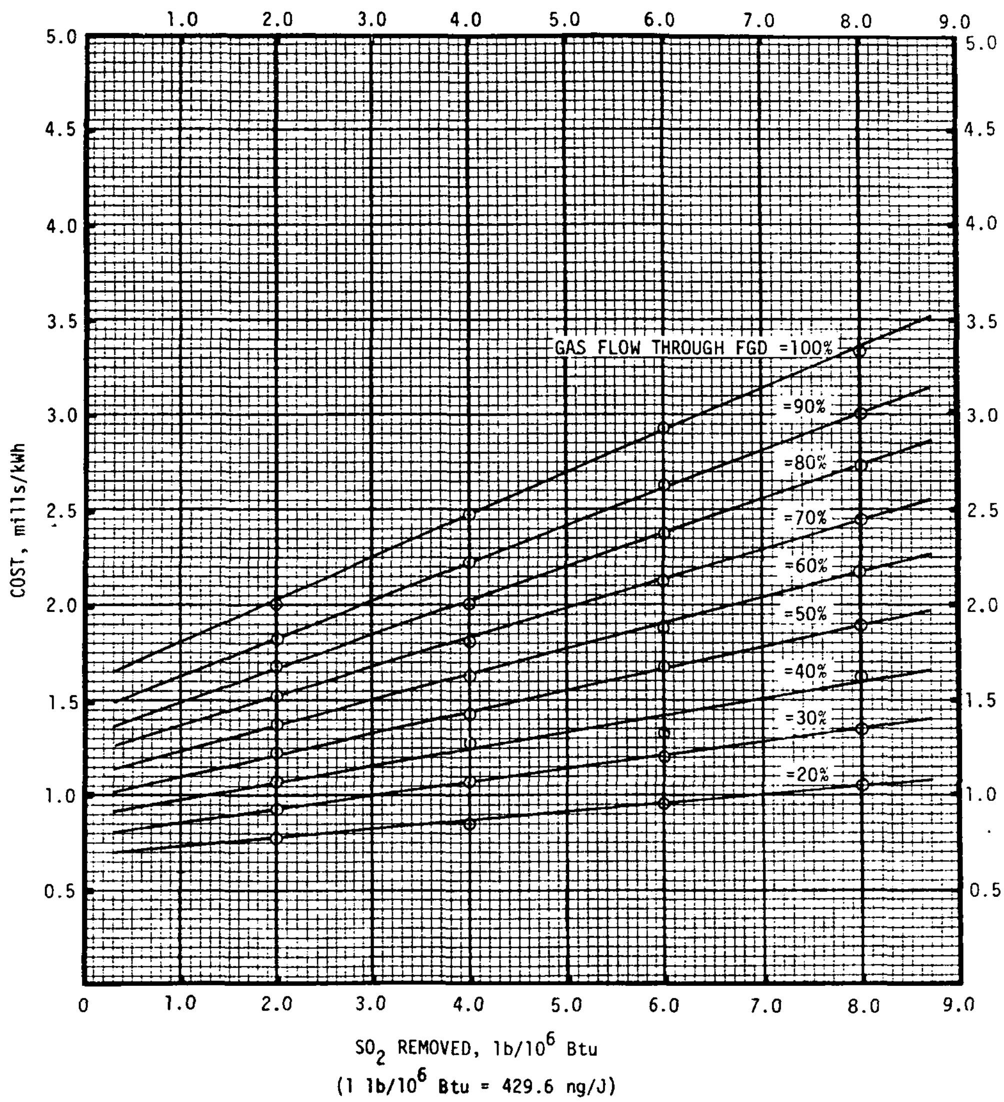

Figure 4-3. Operation and maintenance cost excluding electricity and reheat for a lime FGD system at a bituminous-coal-fired 500-MW plant.

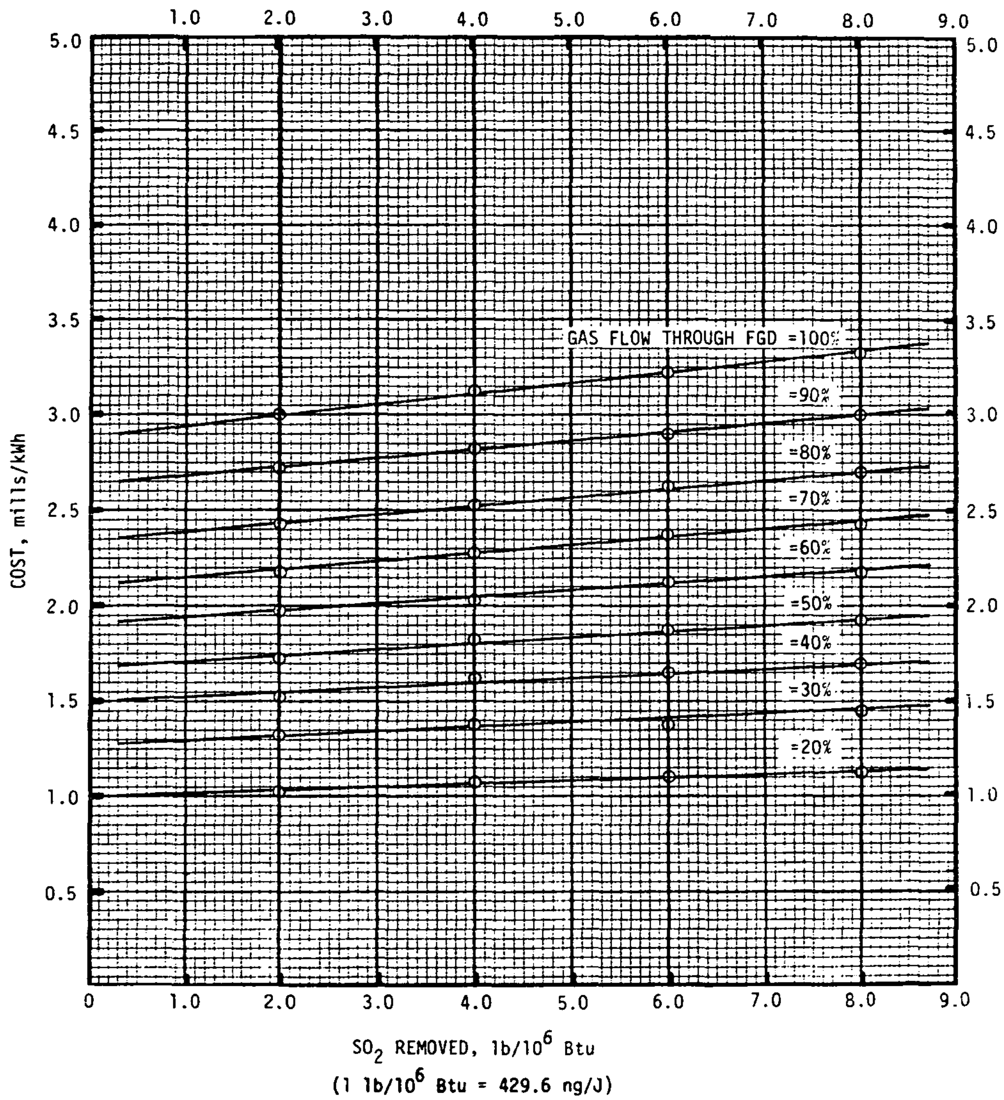

Figure 4-4. Fixed charges for a lime FGD system at a bituminous-coal-fired 500-MW plant.

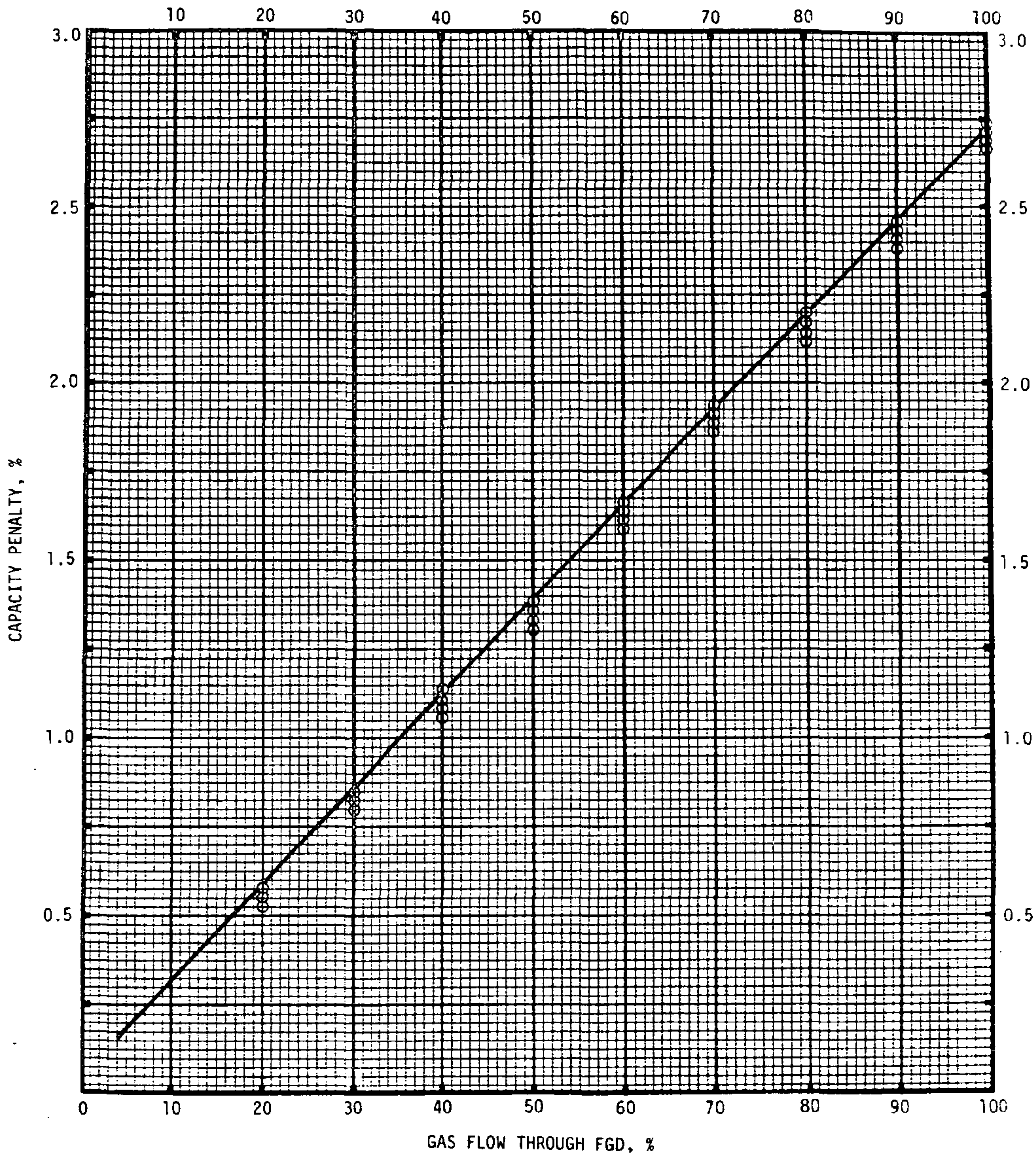

Figure 4-5. Capacity penalty for a lime FGD system at a bituminous-coal-fired 500-MW plant.

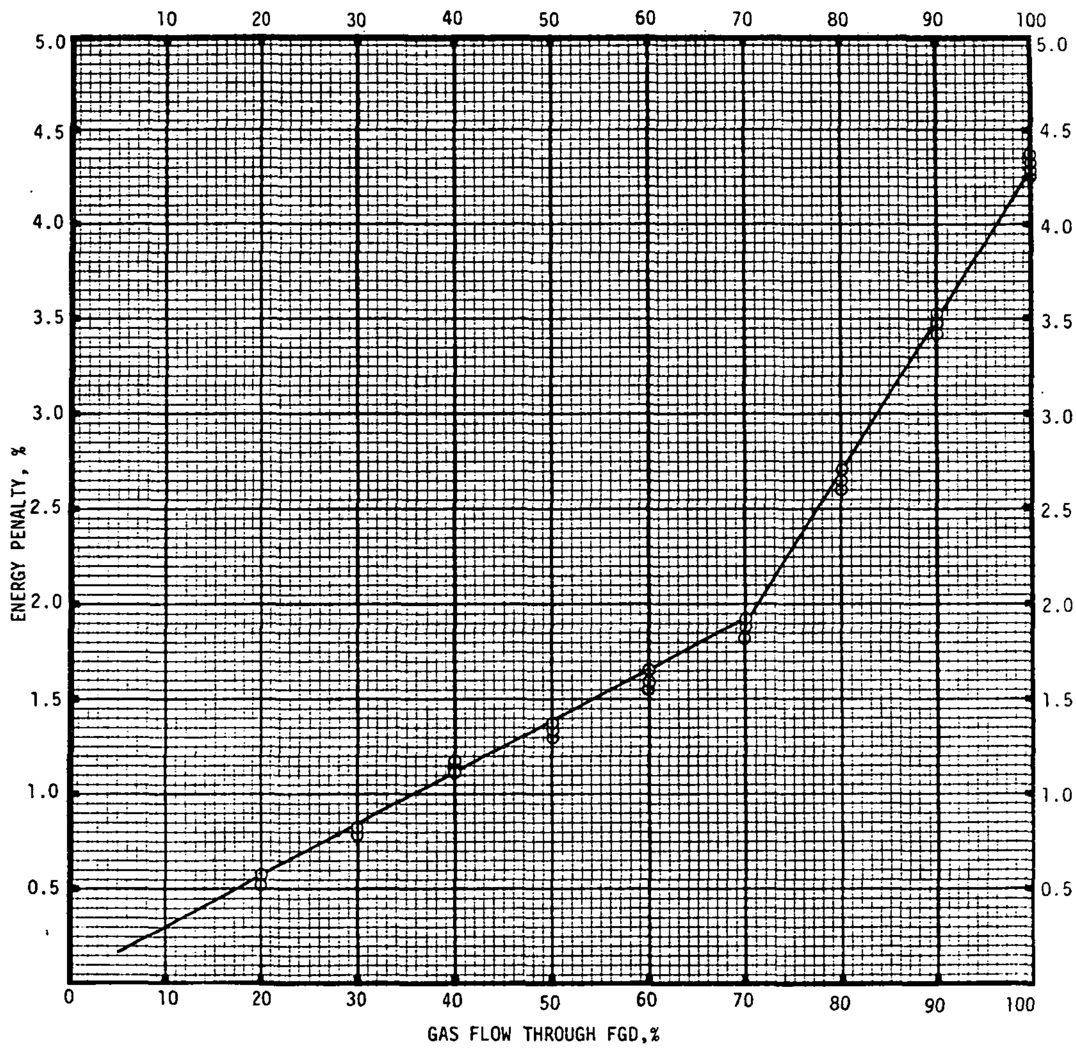

Figure 4-6. Energy penalty for a lime FGD system at a bituminous-coal-fired 500-MW plant.

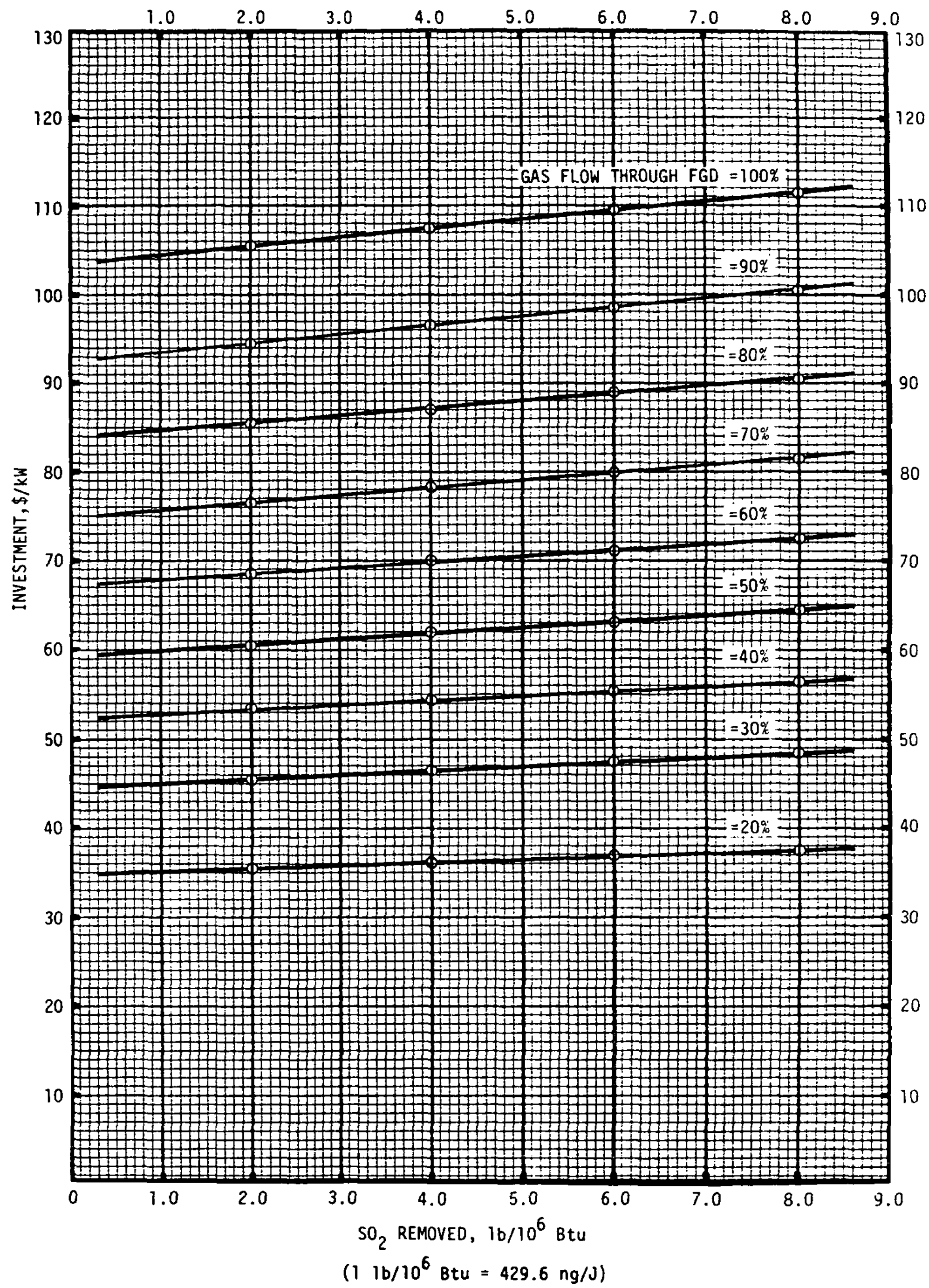

Figure 4-7. Capital investment excluding cost of sludge pond and land for a lime FGD system at a subbituminous-coal-fired 500-MW plant.

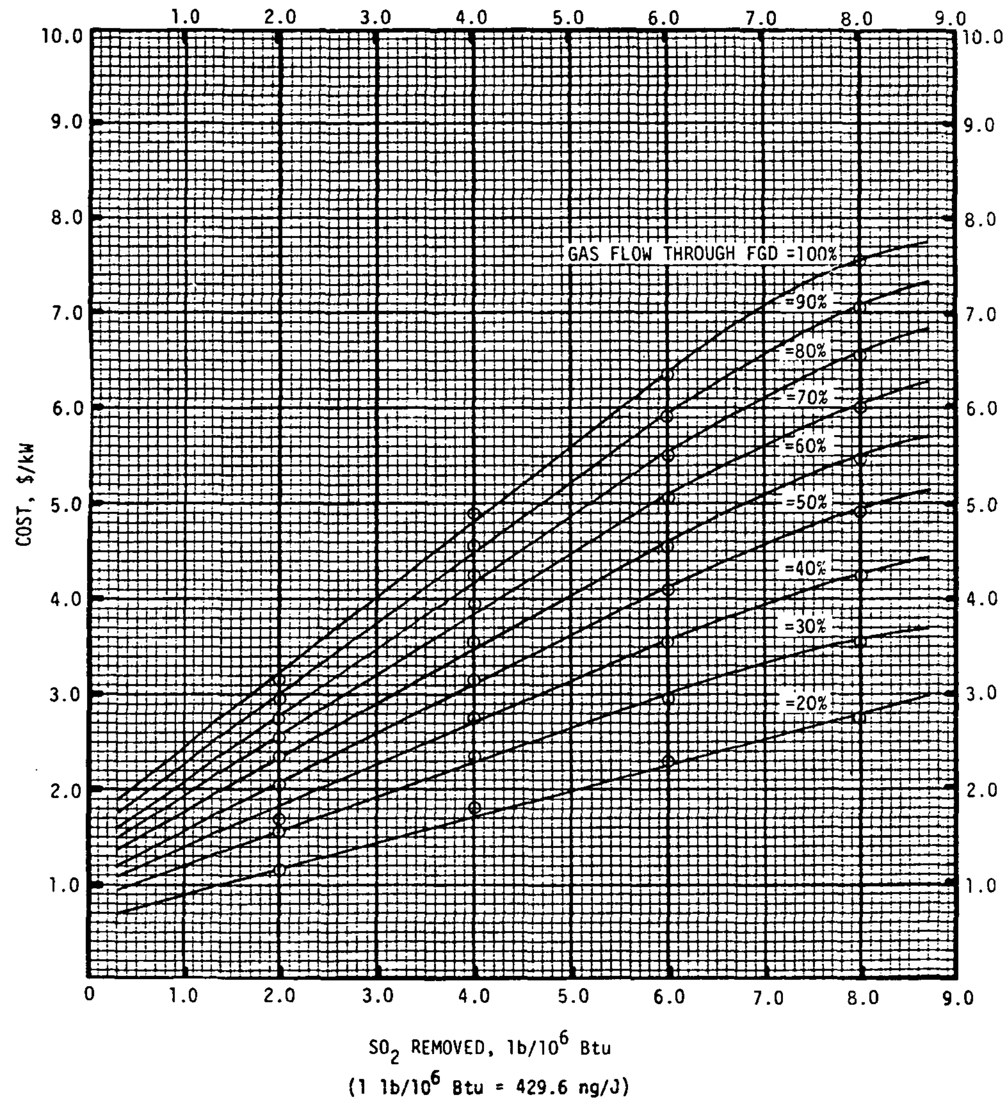

Figure 4-8. Capital cost of sludge pond and land for a lime FGD system at a subbituminous-coal-fired 500-MW plant.

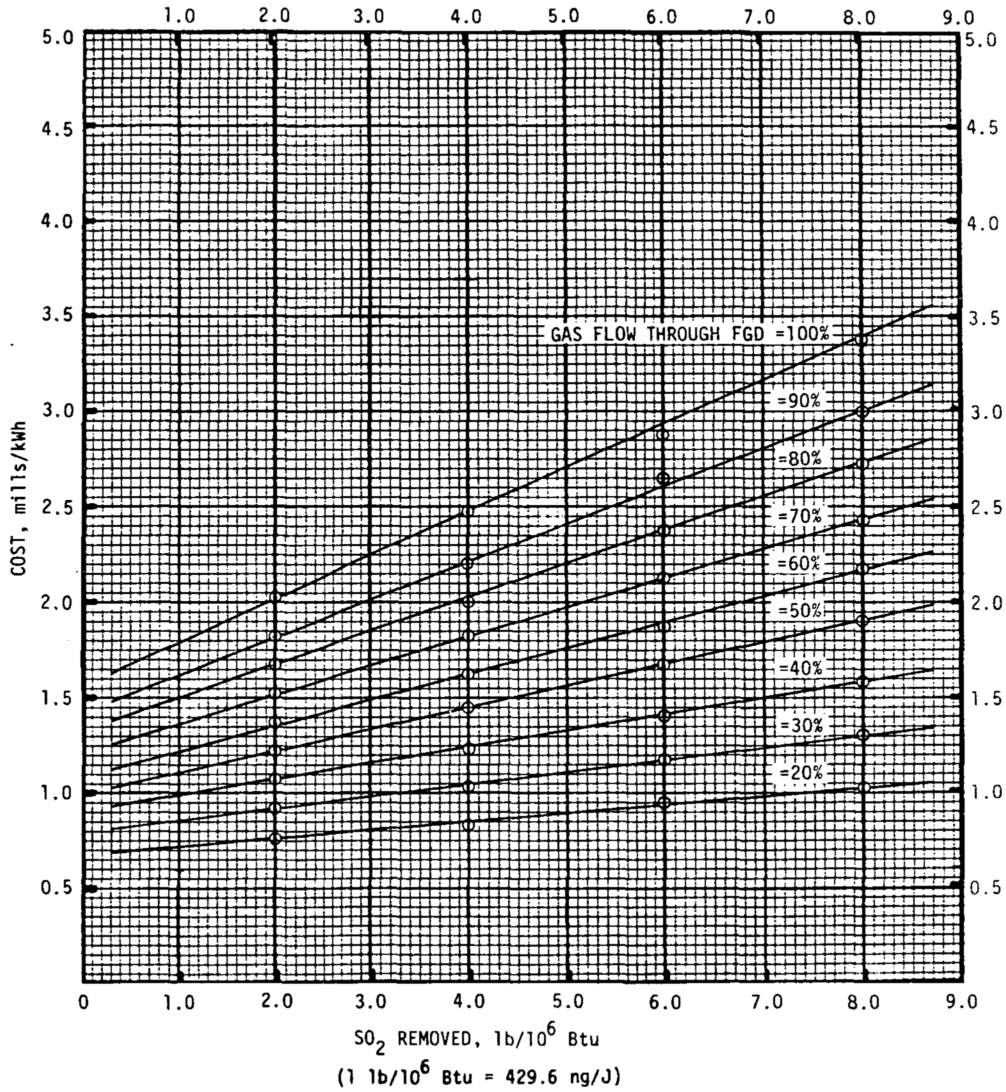

Figure 4-9. Operation and maintenance cost excluding electricity and reheat for a lime FGD system at a subbituminous-coal-fired 500-MW plant.

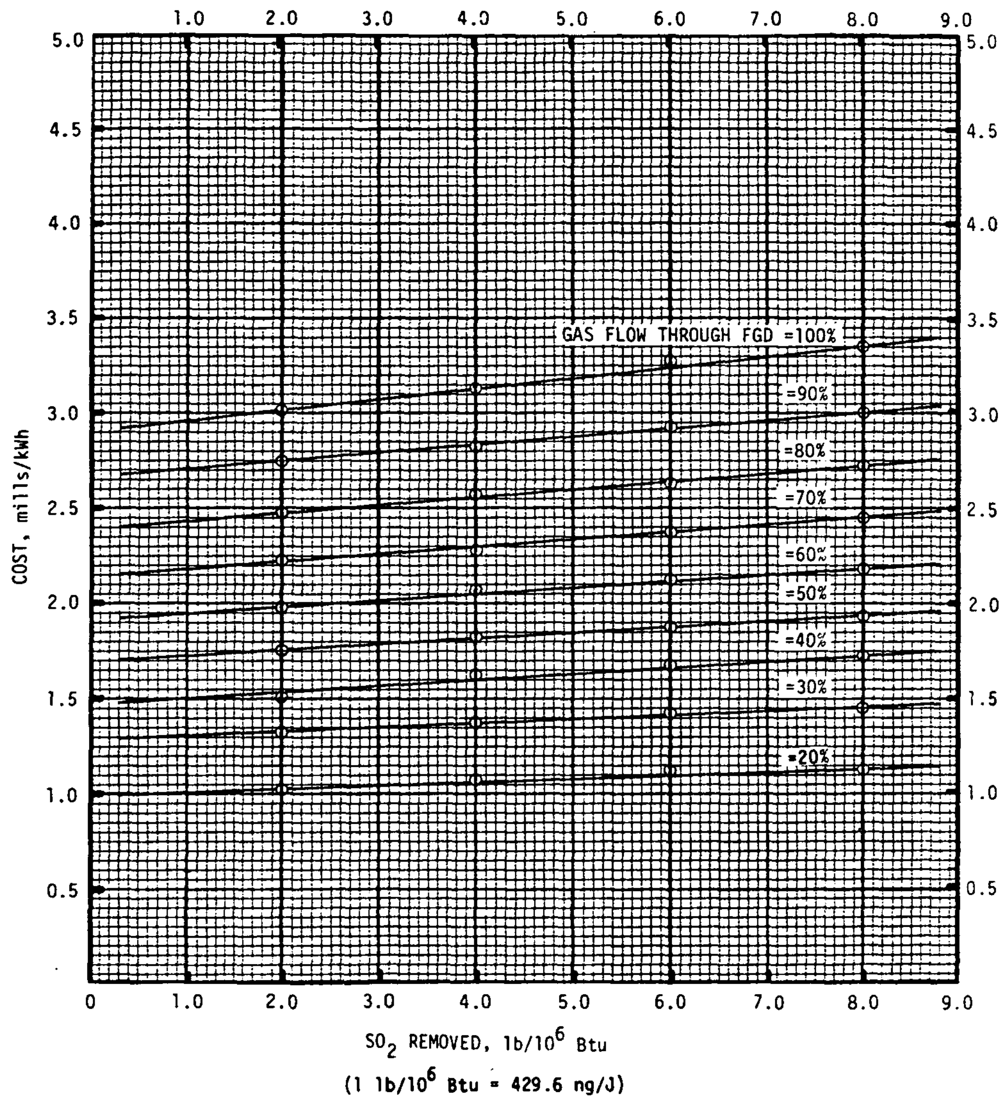

Figure 4-10. Fixed charges for a lime FGD system at a subbituminous-coal-fired 500-MW plant.

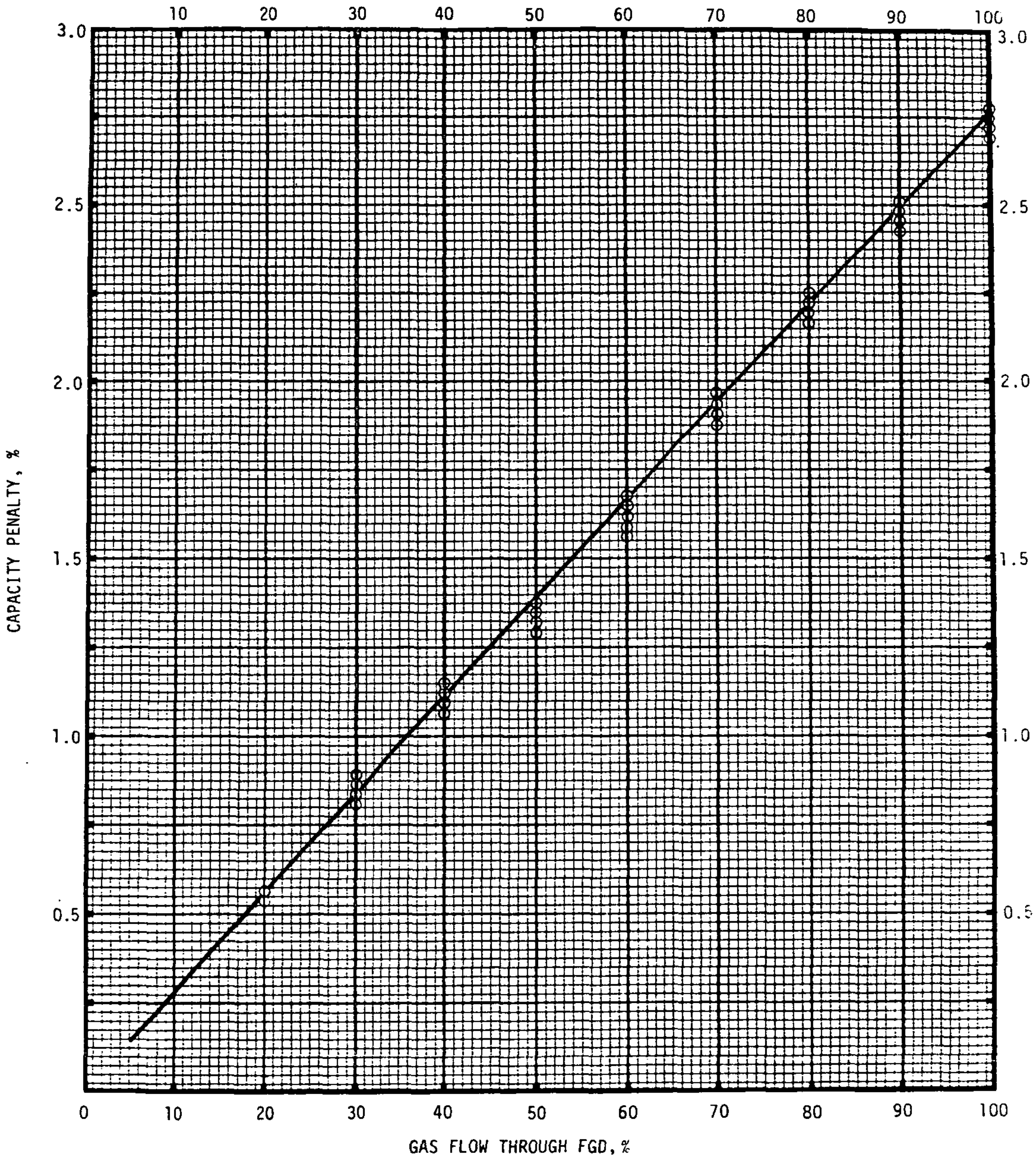

Figure 4-11. Capacity penalty for a lime FGD system at a subbituminous-coal-fired 500-MW plant.

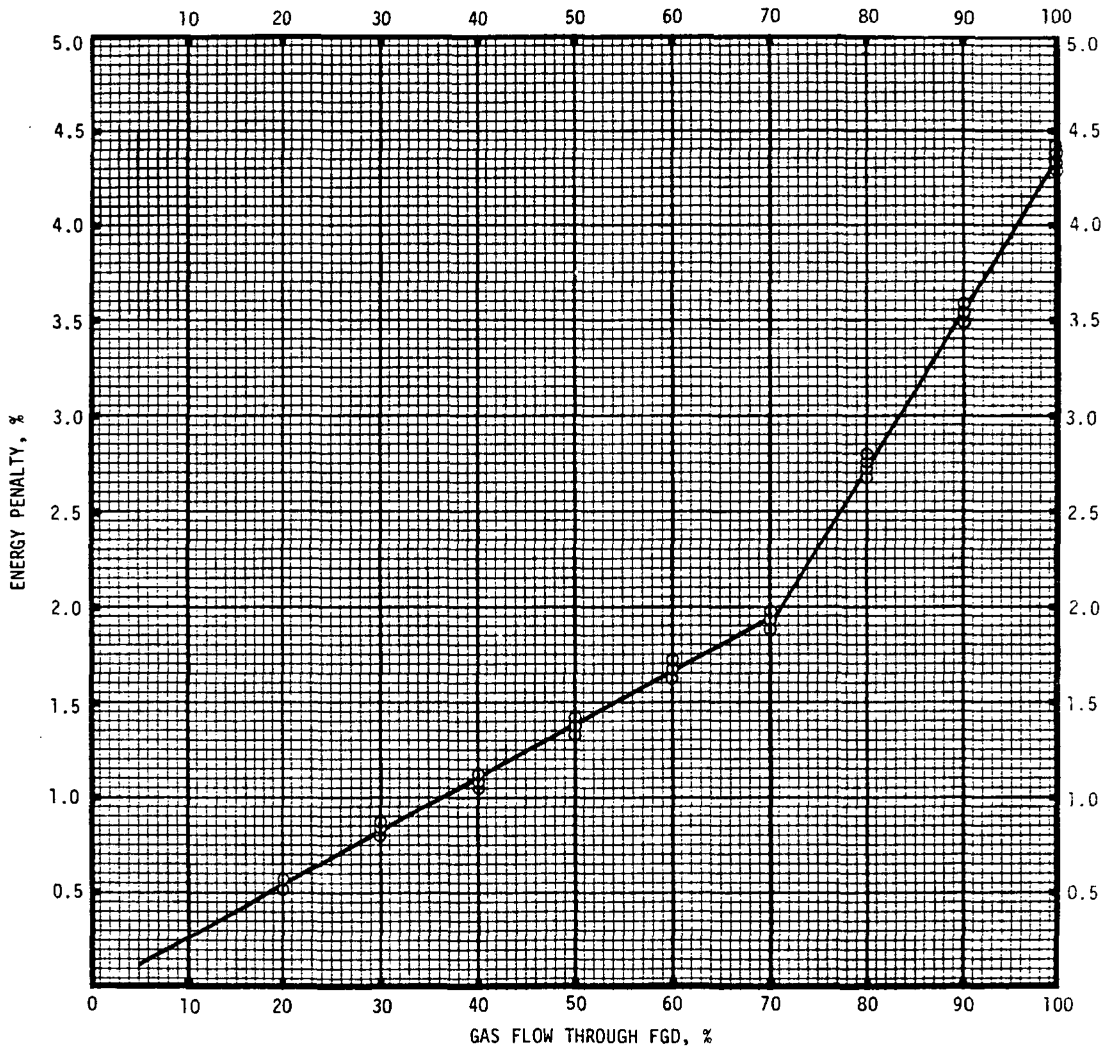

Figure 4-12. Energy penalty for a lime FGD system at a subbituminous-coal-fired 500-MW plant.

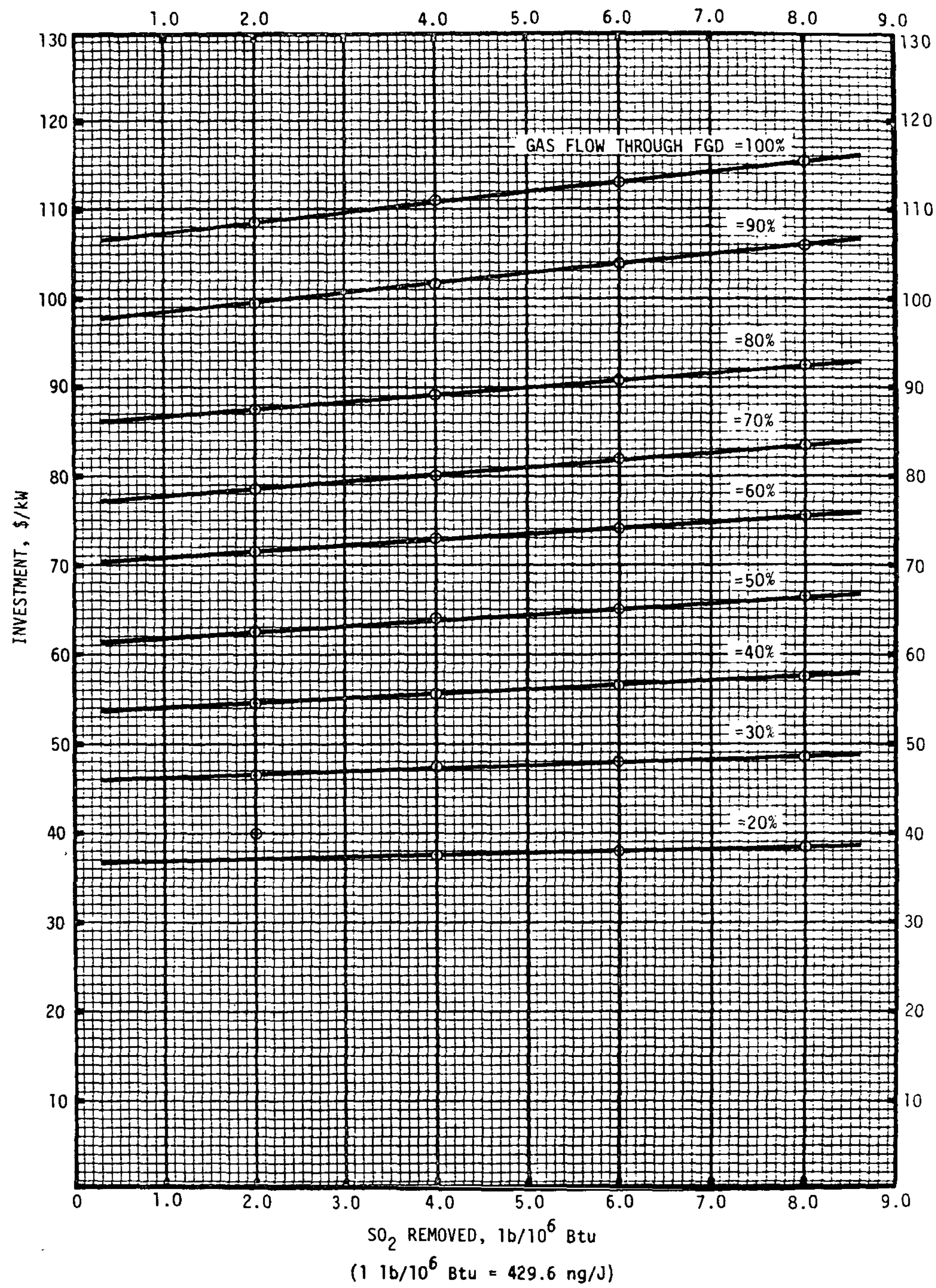

Figure 4-13. Capital investment excluding cost of sludge pond and land for a lime FGD system at a lignite-fired 500-MW plant.

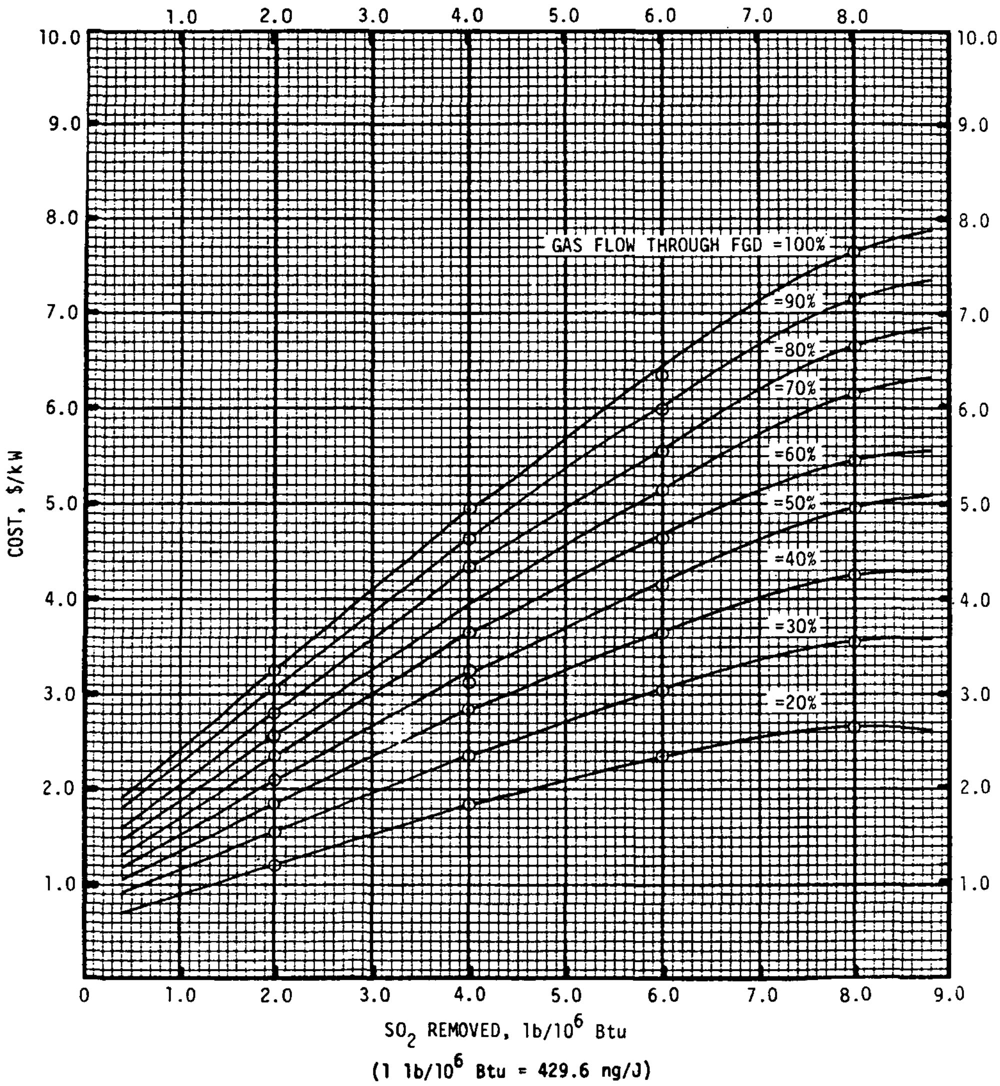

Figure 4-14. Capital cost of sludge pond and land for a lime FGD system at a lignite-fired 500-MW plant.

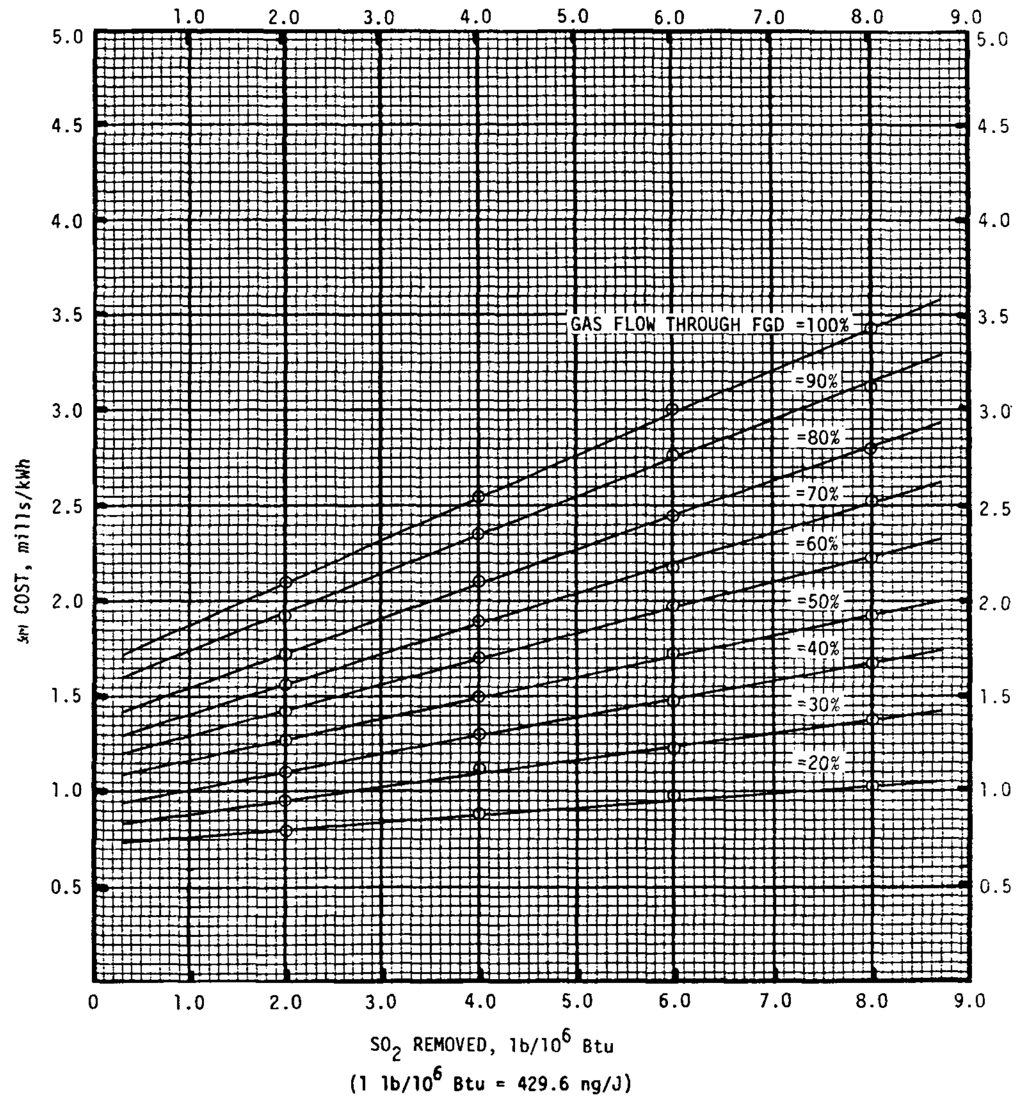

Figure 4-15. Operation and maintenance cost excluding electricity and reheat for a lime FGD system at a lignite-fired 500-MW plant.

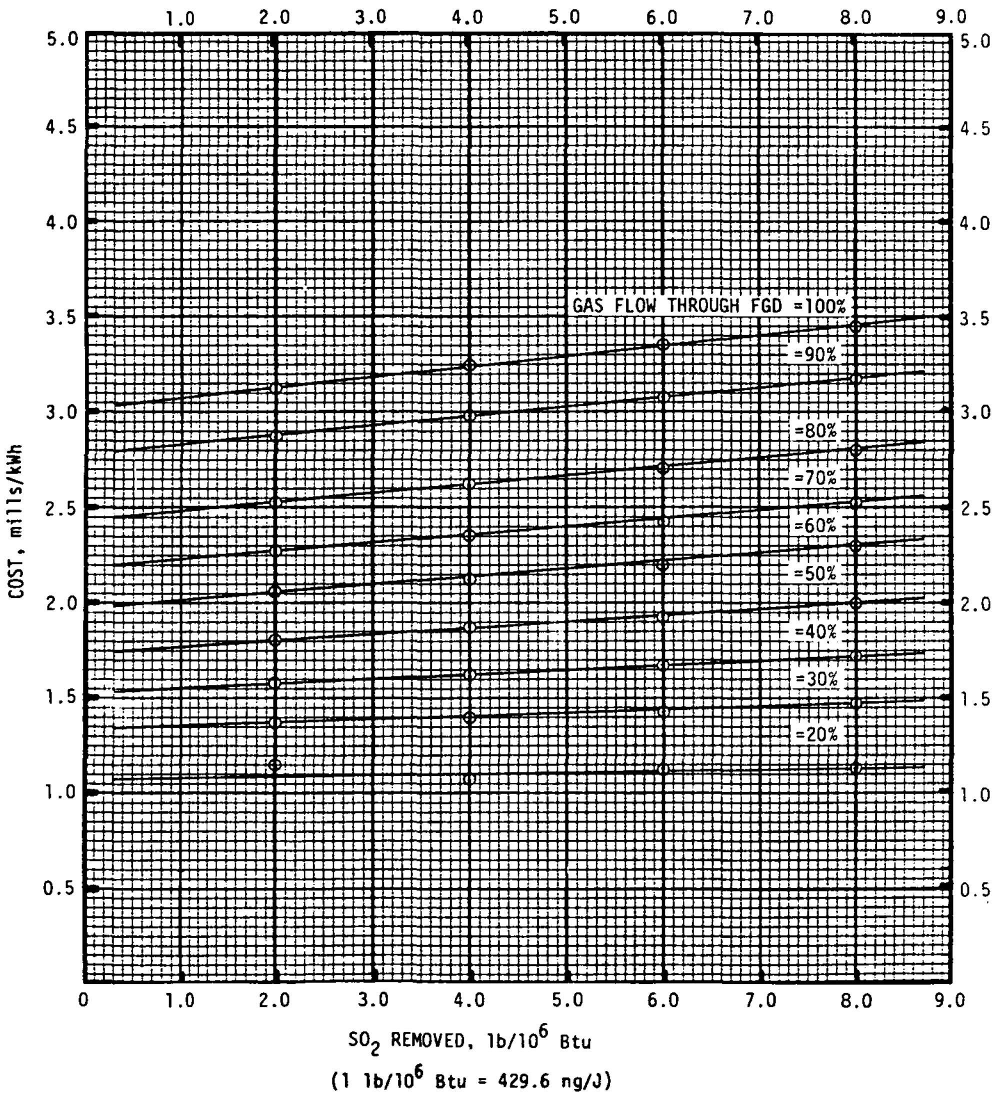

Figure 4-16. Fixed charges for a lime FGD system at a lignite-fired 500-MW plant.

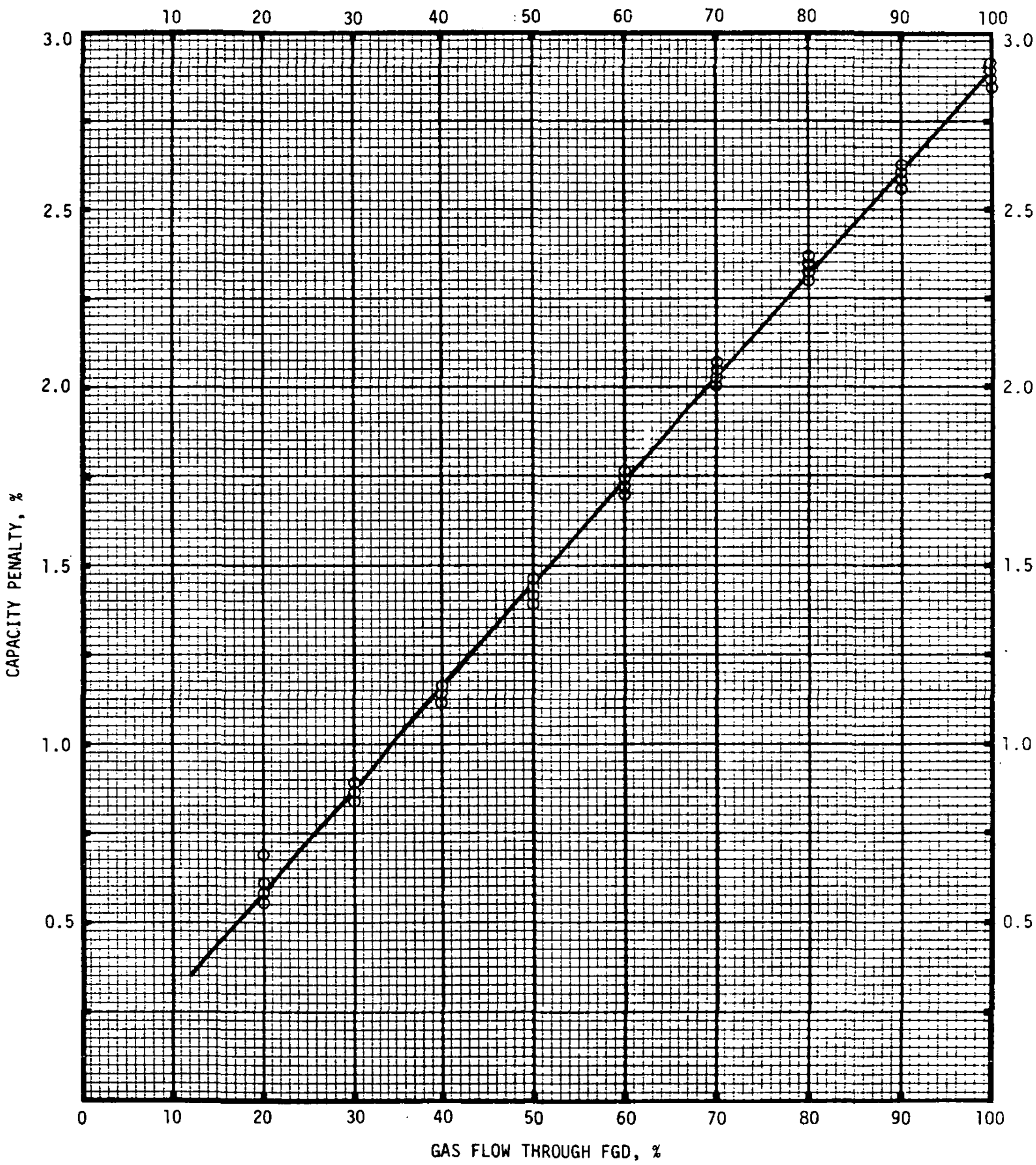

Figure 4-17. Capacity penalty for a lime FGD system at a lignite-fired 500-MW plant.

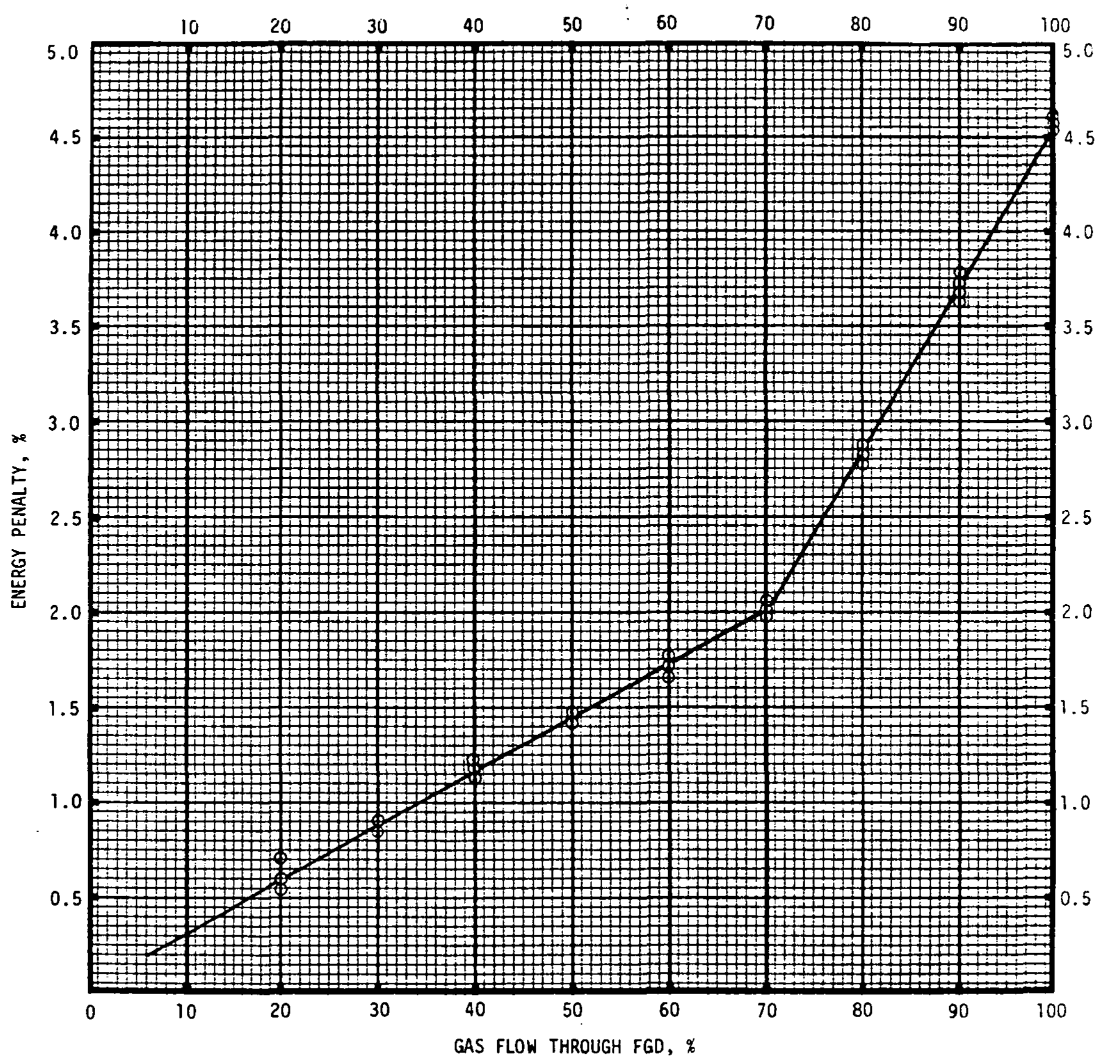

Figure 4-18. Energy penalty for a lime FGD system at a lignite-fired 500-MW plant.

x-axes showing the percentage of gas flow through the FGD system because the capacity and energy penalties are insensitive to SO_2 removal levels.

4.2 APPLICATIONS

Figures 4-1 through 4-18 were used to calculate the costs of various model plant scenarios. In evaluating the effects of averaging time on the scenarios, it was assumed that an averaging time could be treated as a relative standard deviation (RSD) of the long-term sulfur content of coal and that each RSD amounted to an average increase in sulfur content of 15 percent. Model plant costs are presented for three RSD values: 0.0, 1.3, and 3.0. The values for SO_2 removal factor, percentage of gas flow through the FGD system, and amount of SO_2 removed are obtained with the following equations:

(1) $$SO_2 \text{ removal factor} = \frac{U_R - U^*}{U_R}$$

$$U_R = [\text{long-term sulfur content of coal} \times 2 \times (1 + n \times RSD)]^{\dagger}$$

U = Allowable SO_2 emissions

(2) Percentage of gas flow through the FGD system

$$= \frac{SO_2 \text{ removal factor}}{0.85} \times 100$$

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* In these equations, U and U_R should have the same units (either ng/J or lb/10^6 Btu).

† n = number of RSD's (i.e., 0.0, 1.3, or 3.0); and RSD = 0.15 (15 percent).

(3) Amount of SO_2 removed by FGD system = $U_R - U$

The model plant scenarios are presented in Tables 4-1 through 4-9.

TABLE 4-1. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING BITUMINOUS COAL WITH 0.0 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level	
	344 ng/J ($0.8\ lb/10^6$ Btu)	50% control
Capital cost of FGD system, $/kW	110.75	69.76
Increment of capital cost above cost of base plant, %[b]	14.55	9.17
Annualized cost of FGD system, mills/kWh	6.44	3.76
Increment of annualized cost above the operating cost of the base plant, %[c]	25.75	15.05
Annual SO_2 emissions, Mg/yr (tons/yr)	9,300 (10,250)	29,060 (32,030)
SO_2 removal efficiency, %	84.00	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	375.39 (340.55)	368.68 (334.47)

[a] Sulfur content of bituminous coal = 1074 ng/J ($2.5\ lb/10^6$ Btu).

[b] Base plant capital cost = $761/kW.

[c] Base plant annualized operating cost = 25.0 mills/kWh.

TABLE 4-2. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING BITUMINOUS COAL WITH 1.3 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level of 50%
Capital cost of FGD system, $/kW	70.10
Increment of capital cost above cost of base plant, %[b]	9.21
Annualized cost of FGD system, mills/KWh	3.77
Increment of annual cost above the operating cost of the base plant, %[c]	15.09
Annual SO_2 emissions, Mg/yr (tons/yr)	29,060 (32,030)
SO_2 removal efficiency, %	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	369.61 (335.31)

[a] Sulfur content of bituminous coal = 1074 ng/J (2.5 lb/10^6 Btu).

[b] Base plant capital cost = $761/kW.

[c] Base plant annualized operating cost = 25.0 mills/kWh.

TABLE 4-3. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING BITUMINOUS COAL WITH 3.0 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level of 50%
Capital cost of FGD system, $/kW	70.56
Increment of capital cost above cost of base plant, %[b]	9.27
Annualized cost of FGD system, mills/KWh	3.79
Increment of annual cost above the operating cost of the base plant, %[c]	15.14
Annual SO_2 emissions, Mg/yr (tons/yr)	29,060 (32,030)
SO_2 removal efficiency, %	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	370.88 (336.46)

[a] Sulfur content of bituminous coal = 1074 ng/J (2.5 lb/10^6 Btu).

[b] Base plant capital cost = $761/kW.

[c] Base plant annualized operating cost = 25.0 mills/kWh.

TABLE 4-4. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING SUBBITUMINOUS COAL WITH 0.0 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level		
	215 ng/J (0.5 lb/10^6 Btu)	344 ng/J (0.8 lb/10^6 Btu)	50% control
Capital cost of FGD system, $/kW	88.34	69.79	68.29
Increment of capital cost above cost of base plant, %[b]	10.79	8.52	8.34
Annualized cost of FGD system, mills/kWh	4.68	3.61	3.49
Increment of annualized cost above the operating cost of the base plant, %[c]	18.71	14.44	13.98
Annual SO_2 emissions, Mg/yr (tons/yr)	5840 (6440)	9350 (10,310)	9700 (10,690)
SO_2 removal efficiency, %	69.88	51.81	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	982.30 (891.14)	1022.86 (927.94)	1025.44 (930.29)

[a] Sulfur content of subbituminous coal = 356 ng/J (0.83 lb/10^6 Btu).

[b] Base plant capital cost = $819/kW.

[c] Base plant annualized operating cost = 25.0 mills/kWh.

TABLE 4-5. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING SUBBITUMINOUS COAL WITH 1.3 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level		
	215 ng/J (0.5 lb/10^6 Btu)	344 ng/J (0.8 lb/10^6 Btu)	50% control
Capital cost of FGD system, $/kW	94.95	76.67	68.37
Increment of capital cost above cost of base plant, %[b]	11.59	9.36	8.35
Annualized cost of FGD system, mills/kWh	4.88	3.76	3.50
Increment of annualized cost above the operating cost of the base plant, %[c]	19.51	15.06	13.98
Annual SO_2 emissions, Mg/yr (tons/yr)	5840 (6440)	9350 (10,310)	9700 (10,690)
SO_2 removal efficiency, %	69.88	51.81	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	1024.45 (929.38)	1066.29 (967.34)	1026.11 (930.89)

[a] Sulfur content of subbituminous coal = 356 ng/J (0.83 lb/10^6 Btu).

[b] Base plant capital cost = $819/kW.

[c] Base plant annualized operating cost = 25.0 mills/kWh.

TABLE 4-6. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING SUBBITUMINOUS COAL WITH 3.0 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level	
	344 ng/J (0.8 lb/10^6 Btu)	50% control
Capital cost of FGD system, $/kW	85.67	68.47
Increment of capital cost above cost of base plant, %[b]	10.46	8.36
Annualized cost of FGD system, mills/kWh	4.12	3.50
Increment of annualized cost above the operating cost of the base plant, %[c]	16.48	14.00
Annual SO_2 emissions, Mg/yr (tons/yr)	9350 (10,310)	9700 (10,690)
SO_2 removal efficiency, %	51.81	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	1166.70 (1058.43)	1026.94 (931.64)

[a] Sulfur content of subbituminous coal = 356 ng/J (0.83 lb/10^6 Btu).

[b] Base plant capital cost = $819/kW.

[c] Base plant annualized operation cost = 25.0 mills/kWh.

TABLE 4-7. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING LIGNITE WITH 0.0 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level			
	86 ng/J (0.2 lb/10^6 Btu)	215 ng/J (0.5 lb/10^6 Btu)	344 ng/J (0.8 lb/10^6 Btu)	50% control
Capital cost of FGD system, $/kW	108.63	78.50	53.70	69.72
Increment of capital cost above cost of base plant, %[b]	13.26	9.58	6.56	8.51
Annualized cost of FGD system, mills/kWh	5.77	4.03	2.73	3.57
Increment of annualized cost above the operating cost of the base plant, %[c]	23.09	16.12	10.92	14.29
Annual SO_2 emissions, Mg/yr (tons/yr)	2380 (2620)	5940 (6550)	9500 (10,480)	7130 (7860)
SO_2 removal efficiency, %	83.33	58.33	33.33	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	1383.23 (1254.87)	1379.43 (1251.42)	1634.84 (1483.13)	1426.43 (1294.06)

[a] Sulfur content of lignite = 258 ng/J (0.6 lb/10^6 Btu).

[b] Base plant capital cost = $819/kW.

[c] Base plant annualized operating cost = 25.0 mills/kWh.

TABLE 4-8. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING LIGNITE WITH 1.3 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level		
	215 ng/J (0.5 lb/10^6 Btu)	344 ng/J (0.8 lb/10^6 Btu)	50% control
Capital cost of FGD system, $/kW	85.60	68.89	70.01
Increment of capital cost above cost of base plant, %[b]	10.45	8.41	8.55
Annualized cost of FGD system, mills/kWh	4.29	3.36	3.58
Increment of annualized cost above the operating cost of the base plant, %[c]	17.17	13.42	14.32
Annual SO_2 emissions, Mg/yr (tons/yr)	5940 (6550)	9500 (10,480)	7130 (7860)
SO_2 removal efficiency, %	58.33	33.33	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	1469.55 (1333.18)	2010.36 (1823.80)	1429.70 (1297.02)

[a] Sulfur content of lignite = 258 ng/J (0.6 lb/10^6 Btu).

[b] Base plant capital cost = $819/kW.

[c] Base plant annualized operating cost = 25.0 mills/kWh.

TABLE 4-9. COST-EFFECTIVENESS OF A LIME FGD SYSTEM FOR A 500-MW PLANT FIRING LIGNITE WITH 3.0 RSD IN LONG-TERM SULFUR CONTENT[a]

	Controlled SO_2 emission level	
	344 ng/J (0.8 lb/10^6 Btu)	50% control
Capital cost of FGD system, $/kW	73.09	70.21
Increment of capital cost above cost of base plant, %[b]	8.92	8.57
Annualized cost of FGD system, mills/kWh	3.53	3.59
Increment of annualized cost above the operating cost of the base plant, %[c]	14.14	14.34
Annual SO_2 emissions, Mg/yr (tons/yr)	9500 (10,480)	7130 (7860)
SO_2 removal efficiency, %	33.33	50.00
Annualized cost of SO_2 removal, $/Mg ($/ton)	2117.00 (1920.55)	1431.93 (1299.05)

[a] Sulfur content of lignite = 258 ng/J (0.6 lb/10^6 Btu).

[b] Base plant capital cost = $819/kW.

[c] Base plant annualized operating cost = 25.0 mills/kWh.

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16. ABSTRACT

Cost curves for the calculation of capital investment, operating and maintenance cost, capacity, and energy penalties are presented. These curves apply only to 500-MW coal-fired utility boilers controlled by lime based flue gas desulfurization systems. Costs can be determined for bituminous, sub-bituminous, and lignite coals with sulfur contents ranging up to about 4.5%. The cost of FGD treatment of 20 - 100 percent of the gas flow in 10 percent increments and in a broad range of sulfur removal efficiencies can also be calculated.

17. KEY WORDS AND DOCUMENT ANALYSIS

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