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# Industrial Boiler $SO_2$ Cost Report

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# 1.0 INTRODUCTION

This report presents a cost analysis of alternative sulfur dioxide ($SO_2$) controls on coal- and residual oil-fired industrial boilers in EPA Regions V (Midwest) and VIII (North Central). Alternative $SO_2$ controls examined included the use of various low-sulfur fuels and flue gas desulfurization (FGD) techniques. For each alternative control method, the capital costs, operating and maintenance costs, and annualized costs are presented.

Chapter 2 discusses the methodologies and cost bases for estimating boiler and control costs. Chapter 3 presents the capital and annualized costs for coal-fired model boilers, and Chapter 4 presents costs for residual oil-fired model boilers.

Two appendices are also included for reference. Appendix A is a listing of the cost algorithms used to estimate the boiler, PM control, $SO_2$ control, and $NO_x$ control costs. These algorithms are all based on mid-1978 dollars. The cost basis used in this report corresponds to January 1983 dollars. The factors used to convert algorithm costs to this later basis are presented in Appendix B. Appendix B also provides factors for adjusting report costs to other bases selected by the reader.

# 2.0 COSTING METHODOLOGY

This chapter presents the methodologies and bases used to calculate the costs of model boilers and $SO_2$ controls presented in Chapters 3 and 4 of this report. Section 2.1 discusses the basic costing approach used in calculating capital, operating and maintenance, and annualized costs for boilers and control devices. The specific equipment specifications used to calculate the model boiler and control device costs are presented in Section 2.2. Lastly, Section 2.3 discusses other cost considerations such as continuous emission measurement costs, FGD malfunction costs, and regional cost differences.

## 2.1 COSTING APPROACH

In this report, the cost impacts of applying $SO_2$ controls to various types and sizes of industrial boilers are assessed through an analysis of "model boilers". These model boilers are selected to represent the population of new industrial boilers expected to be built in the future, and thus cover a range of boiler sizes, fuel types, and $SO_2$ control methods. The costs of each model boiler can be broken down into three major cost categories:

- Capital Costs (total capital investment required to construct and make operational a boiler and control systems),
- Operation and Maintenance (O&M) costs (total annual cost necessary to operate and maintain a boiler and control systems), and
- Annualized Costs (total O&M costs plus annualized capital-related charges).

Each of these cost categories can be further subdivided into individual cost components. Sections 2.1.1, 2.1.2, and 2.1.3 present the individual cost components and the methods used to develop the capital, O&M, and annualized costs, respectively, for each of the model boilers.

### 2.1.1 Capital Costs

Table 2-1 presents the individual components of capital cost and the general methodology used for calculating total capital costs. Direct capital costs consist of the basic and auxiliary equipment costs in addition to the labor and material required to install the equipment. Equipment and installation costs for boilers and control systems are calculated using the algorithms presented in Appendix A. Section 2.2 of this report discusses the bases for each of these algorithms.

Other capital cost components are calculated using the factors shown in Table 2-1. Indirect costs are those costs not attributable to specific equipment items. Contingencies are included in capital costs to compensate for unpredicted events and other unforeseen expenses. However, in some cases, factors for indirect costs and contingencies different from those shown in Table 2-1 may be used. For example, in the cases of dual alkali and dry scrubbing FGD systems for boilers with heat inputs of 58 MW (200 million Btu/hr) or less, engineering costs are calculated as 10 percent of the total direct costs for an FGD system applied to a 58 MW (200 million Btu/hr) boiler. And for sodium scrubbing FGD systems, turnkey capital costs are calculated directly, based on vendor and plant cost data.

The interest cost incurred during the period of construction of the boiler and associated control equipment is also included in the boiler total capital costs as a function of the turnkey capital cost. It is assumed that payment terms for boilers and control equipment typically consist of a down payment of approximately 20 percent of the turnkey capital cost with the balance paid in equal progress payments over the period of construction and startup. The interest cost is a function of turnkey cost, interest rate, period of construction and total number of equal progress payments. The equations used to calculate interest cost are shown in Table 2-2. Table 2-3 lists the construction period and the interest during construction factors as a function of turnkey capital cost.[3]

TABLE 2-1. CAPITAL COST COMPONENTS[a]

(1) Direct Costs

Equipment
\+ Installation
= Total Direct Costs

(2) Indirect Costs

Engineering (10 % of total direct costs)[b]
\+ Construction and Field Expenses (10% of total direct costs)[b]
\+ Construction Fees (10% of total direct costs)[b]
\+ Start Up Costs (2% of total direct costs)[b]
\+ Performance Costs (1% of total direct costs)[c]
= Total Indirect Costs

(3) Contingencies[b] = 20% of (Total Indirect + Total Direct Costs)

(4) Total Turnkey Cost = Total Indirect Cost + Total Direct Cost + Contingencies

(5) Interest During Construction[d]

(6) Working Capital[e]

(7) Land[f]

(8) Total Capital Cost = Total Turnkey + Interest During Construction + Working Capital + Land

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[a]Boiler and each control system costed separately; factors apply to cost of boiler or control system considered; i.e., the engineering cost for the PM control system is 10% of the direct cost of the PM control system.

[b]Reference 1.

[c]Reference 2.

[d]See Tables 2-2 and 2-3.

[e]See Table 2-4.

[f]Land costs for boiler and control system are included in capital cost of boiler.

TABLE 2-2. CALCULATION OF INTEREST COSTS DURING CONSTRUCTION[a]

Assume: interest (i) = 10 percent effective annual rate

terms = 20 percent of total turnkey capital cost paid at contract award and balance paid in equal monthly installments over the period of construction.

Future value of the 20 percent down payment is found by using the compound interest law or,

$$S = P\,(1 + i)^n, \text{ where } S = \text{Future Value}$$

P = Present Worth

n = Number of years

Future value of the equal monthly installments is calculated by the following equation:

$$S = \frac{R(1 + i/m)^{mn} - 1}{(1 + i/m)^{m/p} - 1}$$

R = Equal payment = P/np

m = No. of times compounded per year = 1

n = No. of years (see Table 2-3)

p = No. of payments per year = 12

Combining the two equations yields,

$$S = 0.2\,P\,(1 + i)^n + 0.80\,\frac{P}{np}\left(\frac{(1 + i/m)^{mn} - 1}{(1 + i/m)^{m/p} - 1}\right)$$

[a]Reference 3 and 4.

TABLE 2-3. CONSTRUCTION PERIODS AND INTEREST-DURING-CONSTRUCTION FACTORS

| Boiler or Control Equipment | Approximate Construction Period (Months)[a] | Interest During Construction Factor[b] |
|---|---|---|
| Boilers and $NO_x$ Control: | | |
| For Packaged Oil and Gas-fired Boilers | 12 | IDC = 0.056 * TK[c,d] |
| For Field-erected Oil and Gas Boilers | 18 | IDC = 0.087 * TK |
| For Coal-fired Boilers $\leq$ 150 MM Btu/hr | 20 | IDC = 0.095 * TK |
| For Coal-fired Boilers > 150 MM Btu/hr | 24 | IDC = 0.120 * TK |
| For PM Control: | | |
| For Q $\leq$ 150 MM Btu/hr | 8 | IDC = 0.036 * TK |
| For Q > 150 MM Btu/hr | 11 | IDC = 0.051 * TK |
| For $SO_2$ Control: | | |
| Sodium Scrubbing: all sizes | 6.75 | IDC = 0.030 * TK |
| Dry Scrubbing: all sizes | 27 | IDC = 0.137 * TK |
| Dual Alkali: all sizes | 27 | IDC = 0.137 * TK |

[a] Reference 3.

[b] All factors are based on 10% effective annual interest rate.

[c] IDC = interest costs during construction.

[d] TK = turnkey capital cost.

Costs of land for the boiler and control system are all included in boiler capital costs. All model boilers except pulverized coal boilers are assumed to require one acre of land and have land costs of $2,800. Pulverized coal boilers are assumed to require two acres of land and have land costs of $5,700.[1]

The computation of working capital requirements for fuel and non-fuel items differs slightly as shown in Table 2-4. These equations are based on three months of direct annual non-fuel operating costs and one month of fuel costs.

### 2.1.2 Operation and Maintenance (O&M) Costs

Table 2-5 lists the individual cost components and the general methodologies used in calculating total O&M costs. Direct O&M costs include operating, supervisory, and maintenance labor, fuel, utilities, replacement parts, supplies, waste disposal and chemicals. Direct O&M costs for model boilers and control systems are calculated using the algorithms presented in Appendix A. Indirect operating costs include payroll and plant overhead and are calculated based on a percentage of some key O&M cost components (e.g. operating labor, supervisory labor, maintenance labor, and replacement parts).

Table 2-6 presents the unit costs for utilities, raw materials, waste disposal, and labor used in calculating non-fuel O&M costs for the boilers and control equipment. The largest O&M cost for boilers is fuel. Fuel costs and specifications such as heating value, sulfur content, and ash content for coals and residual oils used in this analysis are presented in Chapters 3 and 4, respectively.

Operating and maintenance costs incurred are dependent upon the boiler capacity utilization, defined as the actual annual fuel consumption as a percentage of the potential annual fuel consumption at maximum firing rate. Fuel costs, raw material costs, utility costs, and waste disposal costs decrease in direct proportion to the capacity utilization factor. However, labor costs do not decrease in direct proportion due to shift manpower requirements. In order to account for reduced labor costs for boilers

TABLE 2-4. WORKING CAPITAL CALCULATIONS FOR BOILERS AND CONTROL DEVICES

Working Capital (WC)

Boilers - Assume three months of direct annual non-fuel operating costs and one month of fuel costs

$WC^a$ = 0.25 (Direct annual non-fuel operating costs) + 0.083 (Fuel costs)

Control Equipment - Assume three months of direct annual operating costs

$WC^b$ = 0.25 (Direct annual operating costs)

[a]Reference 5.

[b]Reference 1.

TABLE 2-5. OPERATING AND MAINTENANCE COST COMPONENTS[a]

(1) Direct Operating Costs

Operating Labor
\+ Supervision
\+ Maintenance Labor, Replacement Parts and Supplies
\+ Electricity
\+ Water
\+ Steam
\+ Waste Disposal
  Solids (Fly ash and bottom ash)
  Sludge
  Liquid
\+ Chemicals

Total Non-Fuel O&M
\+ Fuel

= Total Direct Operating Costs

(2) Indirect Operating Costs (Overhead)[b]

Payroll (30% Operating Labor)
\+ Plant (26% of Operating Labor + Supervision + Maintenance Costs + Replacement Parts)

(3) Total Annual Operating and Maintenance Costs = Total Direct + Total Indirect Costs

[a]Boilers and control systems are costed separately; factors apply to boiler or control system being considered, (i.e., payroll overhead for FGD system is 30% of the labor requirement for the FGD system).

[b]Factors recommended in Reference 6.

TABLE 2-6 UNIT COSTS USED IN CALCULATIONS[a,b]

| | |
|---|---|
| Utilities | |
| Electricity | \$0.0390/Kwh |
| Water | \$0.06/$m^3$ (\$0.23/$10^3$ gal) |
| Steam | \$4.55/GJ (\$5.3/$10^3$ lb) |
| Raw Materials | |
| $Na_2CO_3$ | \$0.150/kg (\$136/ton) |
| Lime | \$0.059/kg (\$53/ton) |
| Limestone | \$0.014/kg (\$12/ton) |
| Labor | |
| Direct Labor | \$18.15/man-hour |
| Supervision | \$23.60/man-hour |
| Maintenance Labor | \$22.09/man-hour |
| Waste Disposal | |
| Solids (Ash, Spray Dried Solids) | \$0.0251/kg (\$23/ton) |
| Sludge | \$0.0251/kg (\$23/ton) |
| Liquid | \$0.88/$m^3$ (\$0.60/$10^3$ gal) |

[a]All costs in January 1983 \$. Updated from 1978 using a multiplier of 1.51 (see Appendix B).

[b]Reference 7.

operating at reduced capacity utilization, the algorithms also incorporate labor factors. Table 2-7 presents the capacity utilization factors and corresponding labor factors assumed for various model boilers.

### 2.1.3 Annualized Costs

Total annualized costs are the sum of the annual O&M costs and the annualized capital charges. The annualized capital charges include the payoff of the capital investment (capital recovery), interest on working capital, general and administrative costs, taxes (real estate and local taxes but not corporate taxes), and insurance.

Table 2-8 presents the methods used in this report to calculate the individual annualized capital charge components. The capital recovery cost is determined by multiplying the capital recovery factor, which is based on the real interest rate and the equipment life, by the total turnkey costs (see Table 2-8). For this analysis a 10 percent real interest rate and a 15 year equipment life are assumed for the boilers and control equipment. This translates into a capital recovery factor of 13.15 percent. The real interest rate of 10 percent was selected as a typical constant dollar rate of return on investment to provide a basis for calculation of capital recovery charges. This interest rate is the "real" interest rate above and beyond inflation.

Table 2-8 also presents the methods used to calculate other components of the annualized capital charges. Interest on working capital is based on a 10 percent interest rate. The remaining components (general and administrative costs, taxes, and insurance) are estimated as 4 percent of total turnkey costs.

## 2.2 BOILER AND CONTROL DEVICE SPECIFICATIONS

Direct capital and direct O&M costs for model boilers and PM, $NO_x$, and $SO_2$ control techniques are estimated in this report by the use of cost "algorithms". Each algorithm is an algebraic function which projects capital and O&M costs for a particular system based on key process

TABLE 2-7. CAPACITY UTILIZATION AND LABOR FACTORS USED FOR MODEL BOILER COST CALCULATIONS[a]

| Boiler Type | Capacity Utilization Factor (CF) | Labor Factor (LF) |
|---|---|---|
| Coal-fired (Spreader stoker, pulverized coal) | 0.60 | 0.75 |
| Residual oil-fired | 0.55 | 0.62 |

Labor Factor Equations

| CF | LF |
|---|---|
| >0.7 | 1 |
| 0.5 - 0.7 | 0.5 + 2.5 (CF - 0.5) |
| <0.5 | 0.5 |

[a]References 5 and 8.

TABLE 2-8. ANNUALIZED COST COMPONENTS

(1) Total Annualized Cost = Annual O&M Costs + Capital Charges

(2) Capital Charges = Capital recovery + interest on working capital + miscellaneous (G&A, taxes and insurance)

(3) Calculation of Capital Charges Components

A. Capital Recovery = Capital Recovery Factor (CRF) x Total Turnkey Cost

$$CRF = \frac{i\,(1 + i)^n}{(1 + i)^n - 1}$$

i = interest rate

n = number of years of useful life of boiler or control system

| Item | n | i | CRF |
|---|---|---|---|
| Boiler, control systems | 15 | 10 | 0.1315 |

B. Interest on Working Capital = 10% of working capital[a]

C. G&A, taxes and insurance = 4% of total turnkey cost[a]

[a]Reference 1.

parameters (e.g., heat input to boiler, $SO_2$ removal efficiency, capacity utilization factor, flue gas flow rate). The boiler and emission control costing algorithms used in this report are provided in Appendix A. It should be noted that the algorithms in Appendix A are given in 1978 dollars. The cost factors used to update the 1978 estimates to January 1983 dollars are presented in Appendix B. It should also be noted that all algorithms are based on a Midwest (i.e., Region V) boiler location. However, these algorithms can be used to predict costs in any other region of the U.S. (see Section 2.3.3 for discussion of regional cost differences).

The battery limits of the boiler extend from the fuel-receiving equipment to the ash disposal operation. Excluded are steam and condensate piping beyond the boiler building. Costs of ducting and the stack are also included in the battery limits of the boiler. Battery limits of the PM, $NO_x$, and $SO_2$ emission control systems include the control devices themselves, auxiliaries, raw material handling, waste disposal, and any additional ducting required. The specific equipment lists and assumptions used to develop the various algorithms are discussed in the following sections.

### 2.2.1 Uncontrolled Boiler Costs

This section presents the specific cost assumptions and methodologies that were used to calculate the industrial boiler costs presented in Chapters 3 and 4. References 8 and 9 detail the specific equipment lists and assumptions used to develop the boiler algorithms presented in Appendix A (Tables A-4 through A-7).

All of the coal-fired model boilers in this analysis are field-erected units. In addition, all coal-fired boilers have the same heat transfer configuration in that they are watertube units, although the firing mechanism varies according to size. Model boilers with heat inputs of less than 73 MW (250 million Btu/hr) are assumed to be spreader stokers and larger model boilers are assumed to fire pulverized coal. All of the residual oil-fired model boilers in this analysis are package watertube units designed with the capability of firing residual oil or natural gas.

All boiler costs are based on a new boiler constructed at a new plant in the Midwest. It is assumed that new plants will operate multiple boilers rather than one boiler where economically justified. Annual O&M costs such as labor, utilities, chemicals, spare parts and ash disposal will be reduced per boiler because of the economies of scale. To account for the O&M cost reductions associated with multiple boiler installations, multipliers for the annual O&M costs are incorporated into the algorithms presented in Appendix A. These multipliers are presented in Table 2-9. These multipliers are not included in the PM, $NO_x$, or $SO_2$ control algorithms, however. It is assumed that a single PM and/or $SO_2$ control system will be used at each facility regardless of the number of boilers used. And, the major component of $NO_x$ control O&M costs is fuel cost (or savings), which does not exhibit economies of scale.

The boiler specifications presented in Tables 2-10 and 2-11 have been used to calculate the boiler capital costs presented in this report. It is assumed that all boilers operate under low excess air firing conditions. The flue gas flow rates for various model boilers are calculated using the algorithms presented in Appendix A (Table A-15).

### 2.2.2 Particulate Matter (PM) Control Costs

The algorithm used to calculate capital and operating costs for PM control on coal-fired boilers is presented in Appendix A (Table A-8). The cost algorithm for reverse-air fabric filters for coal-fired boilers was developed by PEDCo, Inc.[10] Table 2-12 lists the general specifications for a reverse-air fabric filter. It is assumed that no separate PM control is required for residual oil-fired boilers; it is assumed that the small amount of PM generally emitted by oil-fired boilers can be controlled through the use of FGD systems for $SO_2$ control or through the use of low sulfur/low ash oils.

### 2.2.3 $NO_x$ Control Costs

The algorithms used to calculate capital and operating costs for $NO_x$ control devices are presented in Appendix A (Tables A-12 through A-14). The

TABLE 2-9. DIRECT O&M MULTIPLIERS TO ACCOUNT FOR ECONOMIES ASSOCIATED WITH MULTIPLE BOILER INSTALLATIONS[a]

| | |
|---|---|
| Coal-Fired Boilers: | |
| | Multiplier |
| Utilities, chemicals, and ash disposal | 0.848 |
| All labor, replacement parts, and overhead | 0.767 |
| Residual Oil-Fired Boilers: | |
| Utilities and chemicals | 0.845 |
| All labor, replacement parts, and overhead | 0.799 |

[a]Reference 5.

TABLE 2-10. SPECIFICATIONS FOR COAL-FIRED MODEL BOILERS

| | | | | |
|---|---|---|---|---|
| Thermal input, MW ($10^6$ Btu/hr) | 29.0 (100) | 44.0 (150) | 73.0 (250) | 117.2 (400) |
| Fuel firing method | Spreader stoker | Spreader stoker | Pulverized coal | Pulverized coal |
| Excess air, % | 35 | 35 | 35 | 35 |
| Flue gas flow rate,[a] $m^3/s$ (acfm) | - | - | - | - |
| Load factor, % | 60 | 60 | 60 | 60 |
| Efficiency (%) | 80.0 | 80.9 | 82.0 | 83.1 |
| Steam quality | | | | |
| Pressure, kPa (psig) | 3100 (450) | 3100 (450) | 5170 (750) | 5170 (750) |
| Temperature, °k (°F) | 590 (600) | 590 (600) | 670 (750) | 670 (750) |

[a]Dependent upon coal heating value. See Table A-15 to calculate flue gas flow rate for various coal types.

TABLE 2-11. SPECIFICATIONS FOR RESIDUAL OIL-FIRED MODEL BOILERS

| | | | | |
|---|---|---|---|---|
| Thermal input, MW ($10^6$ Btu/hr) | 29.0 (100) | 44.0 (150) | 73.0 (250) | 117 (400) |
| Excess air, % | 9.1 | 9.1 | 9.1 | 9.1 |
| Flue gas flow rate, $m^3/s$ (acfm)[a] | 14.1 (30,000) | 21.2 (45,000) | 35.4 (75,100) | 56.6 (120,000) |
| Load factor, % | 55 | 55 | 55 | 55 |
| Efficiency (%) | 85.0 | 85.0 | 85.0 | 85.0 |
| Steam quality | | | | |
| Pressure, kPa (psig) | 5170 (750) | 5170 (750) | 5170 (750) | 5170 (750) |
| Temperature, °K (°F) | 670 (750) | 670 (750) | 670 (750) | 670 (750) |

[a]Based on a heating value of 43,000 kJ/kg (18,500 Btu/lb).

TABLE 2-12. GENERAL DESIGN SPECIFICATIONS FOR PM CONTROL SYSTEMS

| Control Device | Item | Specification |
|---|---|---|
| Fabric Filter (FF) for coal-fired boilers | Material of Construction | Carbon steel (insulated) |
| | Cleaning method | Reverse-air (multi-compartment) |
| | Air to cloth ratio | 2 ft/min |
| | Bag material | Teflon-coated fiberglass |
| | Bag life | 2 years |
| | Pressure drop[a] | 6 in. $H_2O$ gauge |

[a]Pressure drop refers to gas-side pressure drop across entire control system.

cost algorithms for low excess air (LEA) operation, and staged combustion (SCA) were developed by Radian based on costs presented in the Individual Technology Assessment Report (ITAR) for $NO_x$ Combustion Modification.[11] Table 2-13 presents the general specifications for LEA and SCA.

### 2.2.4 $SO_2$ Control Costs

The cost algorithms used to calculate capital and annual operating costs for flue gas desulfurization units are also presented in Appendix A (Tables A-9 through A-11). The cost algorithms are based on information presented in the FGD ITAR and Reference 12, but are not exact representations of these costs. The ITAR costs were modified to reflect revised installation factors for double alkali FGD systems and revised fabric filter costs for spray drying FGD systems.[13,14] A revised cost algorithm for sodium scrubbing FGD systems was developed based on information received from vendors and plants;[15] this algorithm also includes wastewater treatment costs.[16,17]

The cost algorithms used to estimate FGD capital costs are based on shop-fabricated, or packaged, FGD units.[13] These algorithms were developed using techniques consistent with typical "budget-cost" estimates provided by vendors to clients in the preliminary stages of project evaluation. These estimates are considered accurate to within ±30 percent of the actual installed costs of FGD systems.

Table 2-14 presents the general specifications for the FGD systems analyzed in this report. These specifications are typical for FGD systems currently in use.

## 2.3 OTHER COST CONSIDERATIONS

This section addresses additional cost considerations that may be incurred by boiler operators and/or regulatory agencies that have not been addressed in Section 2.2. Section 2.3.1 presents costs associated with continuous emission measurement, Section 2.3.2 presents the costs of

TABLE 2-13. $NO_x$ COMBUSTION MODIFICATION EQUIPMENT REQUIREMENTS OR MODIFICATIONS

| Control Device | Specification |
|---|---|
| Low Excess Air (LEA) | Oxygen trim system - $O_2$ analyzer, air flow regulators |
| | Wind box modifications (may be required for multi-burner boilers) |
| Staged Combustion Air (SCA) | |
| Pulverized coal-fired boilers: | Oxygen trim system - $O_2$ analyzer, air flow regulators |
| | Air ports |
| | Wind box modifications |
| | Larger forced draft fan power |
| Residual oil-fired boilers: | Oxygen trim system - $O_2$ analyzer, air flow regulators |
| | Up to 30 percent larger boiler to accommodate longer flame |

TABLE 2-14. GENERAL DESIGN SPECIFICATIONS FOR FGD SYSTEM FOR $SO_2$ CONTROL

| Control Device | Item | Specification |
|---|---|---|
| Double Alkali FGD ($SO_2$ removal only) (DA) | Scrubber type | Tray tower |
| | Pressure drop[a] | 8 in. $H_2O$ |
| | L/G | 10 gal/$10^3$ acf |
| | Scrubber sludge | 60% solids |
| | Sludge disposal | Trucked to off-site landfill |
| Sodium Scrubbing FGD ($SO_2$ removal only) (SOD) | Scrubber type | Spray baffle |
| | Pressure drop[a] | 8 in. $H_2O$ |
| | L/G | 40 gal/$10^3$ acf |
| | Disposal method | Oxidation and sewerage |
| Dry Scrubbing (spray drying, $SO_2$ and PM removal) (DS) | Material of construction | Carbon steel spray dryer and fabric filter (insulated) |
| | Reagent | Lime; with solids recycle at 2 kg recycle solids/kg fresh lime feed |
| | Fabric filter | Pulse jet; air-to-cloth ratio of 4 acfm/$ft^2$ |
| | Pressure drop[a] | 6 in. $H_2O$ |
| | L/G | 0.3 gal/acf |
| | Solids disposal | Trucked to off-site landfill |

[a]All pressure drops refer to gas side pressure drop across entire control system.

requiring $SO_2$ control during periods of FGD malfunction, and Section 2.3.3 discusses the impacts of regional cost differences.

### 2.3.1 Continuous Emission Measurement Costs

Table 2-15 presents estimates for continuous emission measurement costs for opacity, $NO_x$, and $SO_2$.[18] Costs are shown in January 1983 dollars. For the purposes of this analysis, it is assumed that continuous $NO_x$ monitors are required on all coal- and residual oil-fired boilers with a heat input capacity greater than 29 MW (100 million Btu/hour). Opacity monitors are required for all boilers except those equipped with wet FGD systems. Units with FGD are assumed to require continuous monitors for inlet and outlet $SO_2$ and a diluent ($CO_2$ or $O_2$) monitor. Units without FGD are assumed to require a single $SO_2$ monitor and a single diluent monitor at the outlet. An automatic data reduction system is included as part of monitoring costs for all model boilers. Continuous emission measurement costs shown in Table 2-15 are included in the total costs presented in subsequent chapters.

### 2.3.2 FGD Malfunction Costs[19]

In order to maintain compliance with applicable emission requirements during periods of FGD malfunction, several alternative methods of $SO_2$ control may be used. One alternative is to install a spare scrubbing unit for operation during FGD malfunction. However, sparing is a capital intensive alternative. Another alternative would be to fire low sulfur fuels such as natural gas, low sulfur oil, or low sulfur coal during FGD downtime. Nearly all new boilers will be designed for multi-fuel firing or will be installed at facilities where spare natural gas or low sulfur oil-fired boiler capacity is available. Therefore, there are essentially no additional capital costs associated with the firing of natural gas or low sulfur oil during malfunction.

Malfunction costs can vary as a function of boiler size, capacity factor, type of FGD system, FGD system reliability and differential cost between fuels fired during normal operation and during FGD malfunction. In general, however, malfunction costs represent less than 3 percent of the

TABLE 2-15. CONTINUOUS EMISSION MEASUREMENT COSTS (January 1983 $)[a,b]

| System | Capital Cost ($1000) | O & M Cost ($1000/yr) | Annualized Cost ($1000/yr) |
|---|---|---|---|
| Opacity | 57 | 8 | 15 |
| $NO_x$ | 57 | 36 | 44 |
| $SO_2$ (outlet only) | 44 | 36 | 42 |
| $SO_2$ (inlet and outlet) | 64 | 72 | 81 |
| $O_2/CO_2$ (outlet only) | 9 | 8 | 9 |
| $O_2/CO_2$ (inlet and outlet) | 18 | 15 | 18 |

[a]Reference 18.

[b]See Section 2.3.1 for discussion of continuous emission measurement costs assumed for each model boiler.

total boiler annualized costs. In order to maintain consistency throughout this report, it is assumed that FGD operators fire natural gas during periods of malfunction. The FGD system reliability is assumed to be 95 percent.[20] Malfunction costs are included in the total annualized costs in subsequent chapters.

### 2.3.3 Regional Cost Considerations

Model boiler costs can vary on a regional basis due to differences in fuel price, labor rates, utility rates, raw material costs, and waste disposal costs. However, since fuel costs generally represent 50 to 75 percent of the total O&M costs for coal-fired boilers and 80 to 90 percent for residual oil-fired boilers, regional differences in fuel price have a much greater impact on regional model boiler costs than do non-fuel O&M components such as labor rates, etc.[21] Table 2-16 shows how fuel prices vary by Region and, for reference, Figure 2-1 depicts each region geographically.

This report presents costs for coal-fired model boiler in Regions V and VIII. As shown in Table 2-16, a large number of bituminous and subbituminous coals are readily available in Region V. Generally, only low- and medium-sulfur content bituminous and subbituminous coals are delivered to Region VIII. Table 2-16 also shows that coal prices in Region V do not differ significantly from prices in Regions I through VII. Coal prices in Regions VIII, IX, and X are typically lower than in the other regions, with Region VIII having the lowest prices anywhere in the U.S. Therefore, Regions V and VIII were selected for analysis in this report - Region V because it is representative of many other regions, and Region VIII because it has significantly lower coal prices than any other region in the U.S. Table 2-16 shows that regional variations in residual oil prices are not as important as variations in coal prices. In addition, the premium price for a low sulfur oil compared to high sulfur oil is essentially constant for all regions. Therefore, this report presents costs for residual oil-fired model boilers in Region V only. These costs should be representative of costs in all regions.

TABLE 2-16. REGIONAL FUEL PRICES IN $\$/10^6$ BTU (JANUARY 1983 $)[a,b,c]

| Fuel Type | Sulfur Content (lb $SO_2/10^6$ Btu)[d] | REGION I | II | III | IV | V | VI | VII | VIII | IX | X |
|---|---|---|---|---|---|---|---|---|---|---|---|
| COAL | | | | | | | | | | | |
| Bituminous | | | | | | | | | | | |
| B | 0.80 - 1.08 | 3.76 | 3.52 | 3.14 | 3.19 | 3.32 | 3.34 | 3.14 | 1.99 | 2.80 | 3.18 |
| D | 1.08 - 1.67 | 3.71 | 3.45 | 2.94 | 2.98 | 3.18 | 3.21 | 3.08 | 1.86 | 2.82 | 2.97 |
| E | 1.67 - 2.50 | 3.65 | 3.30 | 2.85 | 2.96 | 3.08 | 3.20 | 3.04 | 1.87 | 2.77 | 2.84 |
| F | 2.50 - 3.33 | 3.46 | 3.13 | 2.75 | 2.88 | 2.93 | 3.19 | 2.92 | - | - | - |
| G | 3.33 - 5.0 | 3.16 | 2.82 | 2.42 | 2.80 | 2.67 | 3.09 | 2.62 | - | - | - |
| H | >5.00 | 3.26 | 2.85 | 2.39 | 2.62 | 2.50 | 2.96 | 2.47 | - | - | - |
| Subbituminous | | | | | | | | | | | |
| B | 0.80 - 1.08 | - | - | - | - | 3.38 | 3.49 | 2.74 | 1.40 | 2.84 | 2.66 |
| D | 1.08 - 1.67 | - | - | - | - | 3.34 | 3.39 | 2.69 | 1.39 | 2.74 | 2.60 |
| E | 1.67 - 2.50 | - | - | - | - | 3.30 | 3.32 | 2.72 | 1.28 | 2.65 | 2.09 |
| RESIDUAL OIL 0.8 lb $SO_2/10^6$[e] | 0.80 | 5.50 | 5.49 | 5.49 | 5.46 | 5.63 | 5.49 | 5.60 | 5.29 | 5.11 | 5.07 |
| NATURAL GAS | - | 5.83 | 5.79 | 5.73 | 6.02 | 5.88 | 5.41 | 5.45 | 4.91 | 5.44 | 5.57 |

[a] Reference 22.

[b] 1990 levelized fuel prices in January 1983 dollars.

[c] To convert $\$/10^6$ Btu to $/kJ, multiply by 0.947.

[d] To convert $lb/10^6$ Btu to ng/J, multiply by 430.

[e] Subtract $\$0.70/10^6$ Btu for 3.0 lb $SO_2/10^6$ Btu oil; subtract $\$0.38/10^6$ Btu for 1.6 lb $SO_2/10^6$ Btu oil; add $0.37/10^6$ Btu for 0.3 lb $SO_2/10^6$ Btu oil.

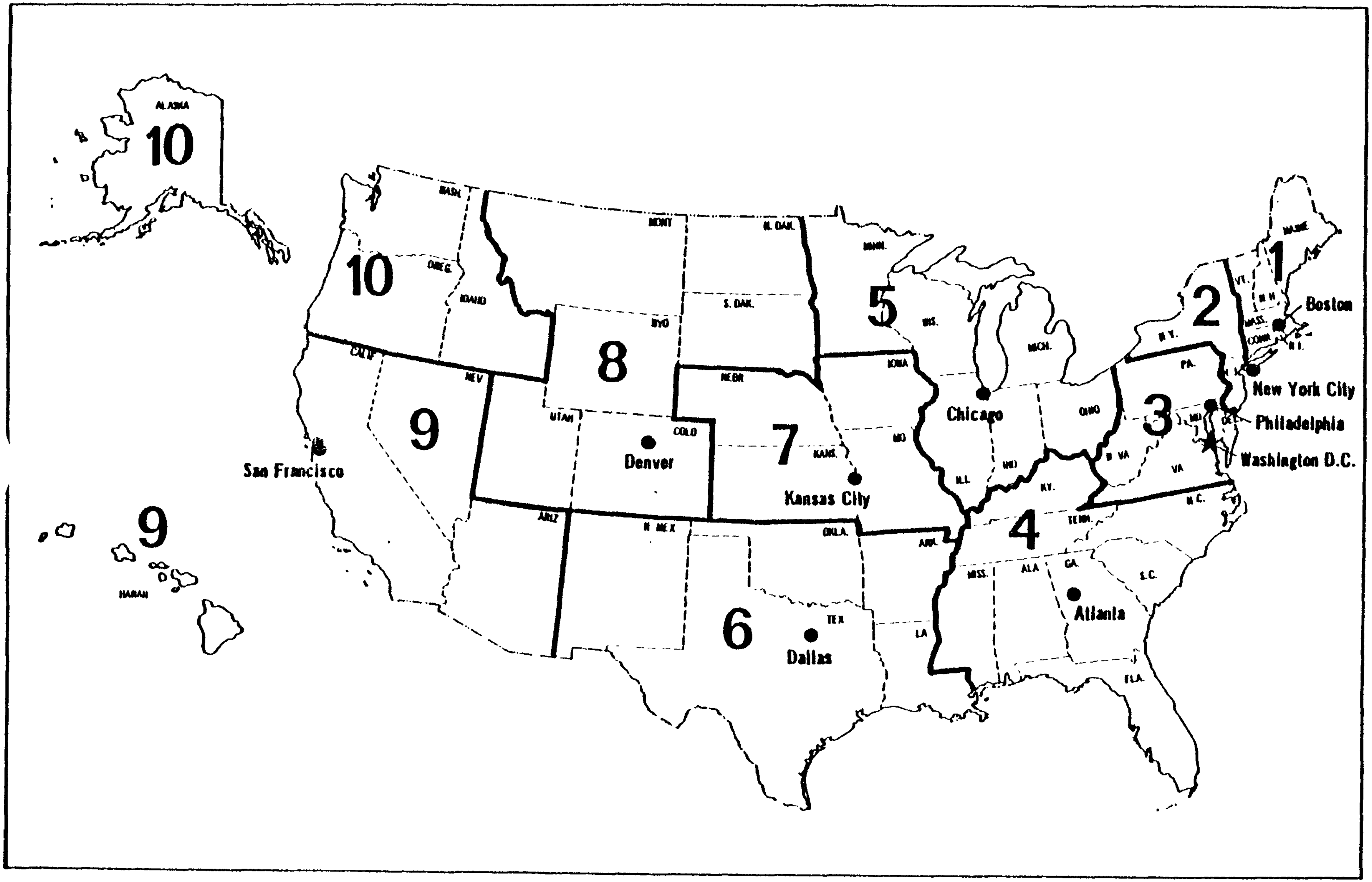


Figure 2-1 Federal Regions of the United States

It was assumed that all costs other than fuel (capital charges, non-fuel O&M costs) remain constant on a regional basis. Regional variations in labor rates, utility rates, raw materials costs and waste disposal costs can result in regional variations in absolute costs for any given alternative. However, the purpose of this analysis is not to compare the absolute costs of $SO_2$ control in various regions but rather to determine the difference in cost between various alternatives within a given region. In other words, the objective of this analysis is to determine the cost difference between a given $SO_2$ control alternative and the baseline alternative, and to determine whether that difference varies significantly from region to region.

The incremental cost of one alternative as compared to another includes differences in fuel prices and/or differences in the capital and operating costs of FGD systems. The variation in FGD capital and operating costs from region to region due to differences in labor rates, utility rates, raw material costs, and waste disposal costs is small in comparison to variations in regional fuel prices, and can therefore be neglected.[21] For this reason, the results presented here include only fuel price variations and assume all other unit costs are equal on a regional basis.

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# 3.0 COST OF $SO_2$ CONTROL ON COAL-FIRED MODEL BOILERS

This chapter presents the results of an analysis of $SO_2$ control costs for coal-fired model boilers in Region V and in Region VIII. Capital and annualized costs are examined for boilers with no $SO_2$ control (baseline) and for boilers equipped with FGD systems achieving 50 percent, 70 percent, and 90 percent $SO_2$ removal. Costs are examined for several boiler sizes and for numerous coal types. The boiler sizes selected for this analysis are 29, 44, 73 and 117 MW (100, 150, 250 and 400 million Btu/hr) heat input.

Specifications and prices of coals delivered to Region V and to Region VIII are presented in Table 3-1. To maintain consistency with the Industrial Fuel Choice Analysis Model (IFCAM), which is used to project the national impacts of alternative $SO_2$ standards, the values in Table 3-1 are projections for 1990 delivered fuel prices expressed in January 1983 dollars.[1] The projections ignore the effects of inflation but assume that fuel prices will escalate in real terms. In addition, the fuel prices have been "levelized" over the life of the boiler (i.e., an equivalent constant price has been calculated after allowing for escalation and the time value of money).

The PM and $NO_x$ controls examined are the same under the baseline and for each of the $SO_2$ control alternatives selected. All model boilers are assumed to require a fabric filter for particulate matter control. Spreader stoker boilers [boilers with heat inputs of less than 73 MW (250 million Btu/hr)] are assumed to require the use of low-excess air (LEA) operation for $NO_x$ control and pulverized coal boilers [boilers with heat inputs of 73 MW (250 million Btu/hr) or greater] are assumed to require staged combustion air (SCA) operation in addition to LEA.

Several types of FGD systems are available for control of $SO_2$ from industrial boilers, including double alkali, sodium scrubbing, and dry scrubbing FGD. Table 3-2 presents the costs for a 44 MW (150 million Btu/hr) boiler in Region V for each of the FGD systems above for two coal types. The same relative relationships as those shown in Table 3-2 would

TABLE 3-1. SPECIFICATIONS FOR COAL DELIVERED TO REGION V AND REGION VIII[a]

| Coal Type | Uncontrolled $SO_2$ Ng/J (lb/$10^6$ Btu) | Fuel Price[b] \$/kJ (\$/$10^6$ Btu) | Heating Value kJ/kg (Btu/lb) | Sulfur Content Wt. % | Ash Content Wt. % |
|---|---|---|---|---|---|
| Region V: | | | | | |
| B-sub | 409 (0.95) | 3.20 (3.38) | 20,524 (8,825) | 0.42 | 6.9 |
| D-sub | 624 (1.45) | 3.16 (3.34) | 20,524 (8,825) | 0.64 | 6.9 |
| E-sub | 903 (2.10) | 3.13 (3.30) | 20,524 (8,825) | 0.93 | 6.9 |
| B-bit | 409 (0.95) | 3.14 (3.32) | 29,000 (12,500) | 0.60 | 11.0 |
| D-bit | 624 (1.45) | 3.01 (3.18) | 29,300 (12,600) | 0.91 | 11.0 |
| E-bit | 903 (2.10) | 2.92 (3.08) | 27,400 (11,800) | 1.24 | 10.5 |
| F-bit | 1,226 (2.85) | 2.77 (2.93) | 26,700 (11,500) | 1.64 | 10.9 |
| G-bit | 1,785 (4.15) | 2.53 (2.67) | 26,700 (11,500) | 2.38 | 12.2 |
| H-bit | 2,382 (5.54) | 2.37 (2.50) | 27,200 (11,700) | 3.23 | 12.0 |
| Region VIII: | | | | | |
| B-sub | 409 (0.95) | 1.33 (1.40) | 20,400 (8,770) | 0.42 | 8.4 |
| D-sub | 624 (1.45) | 1.32 (1.39) | 20,000 (8,620) | 0.63 | 6.9 |
| E-sub | 903 (2.10) | 1.22 (1.28) | 20,000 (8,620) | 0.91 | 6.9 |
| B-bit | 409 (0.95) | 1.88 (1.99) | 25,300 (10,900) | 0.52 | 10.0 |
| D-bit | 624 (1.45) | 1.76 (1.86) | 23,900 (10,300) | 0.75 | 10.0 |
| E-bit | 903 (2.10) | 1.77 (1.87) | 23,900 (10,300) | 1.08 | 10.0 |

[a]Reference 1.

[b]1990 levelized fuel price in 1983 \$.

TABLE 3-2. PM/$SO_2$ CONTROL COSTS FOR A 44 MW (150 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] (JAN 1983 $)

| | Sodium Scrubbing[c] | | | Dry Scrubbing[d] | Double Alkali[c] | | |
|---|---|---|---|---|---|---|---|
| | Fabric Filter | FGD | Total | Total | Fabric Filter | FGD | Total |
| Capital Cost ($1000): | | | | | | | |
| High Sulfur Bituminous Coal[e] | 1,549 | 919 | 2,468 | 3,102 | 1,549 | 2,403 | 3,952 |
| Low Sulfur Subbituminous Coal[f] | 1,607 | 698 | 2,305 | 2,617 | 1,607 | 1,894 | 3,501 |
| Annualized Cost ($1000/yr): | | | | | | | |
| High Sulfur Bituminous Coal[e] | 419 | 919 | 1,338 | 1,504 | 419 | 1,171 | 1,590 |
| Low Sulfur Subbituminous Coal[f] | 440 | 458 | 898 | 1,095 | 440 | 811 | 1,251 |

[a] Includes applicable monitoring costs as shown in Table 2-15.

[b] Includes FGD malfunction costs.

[c] Assumes 95 percent FGD reliability.

[d] Assumes 90 percent FGD reliability.

[e] Heating value = 27,200 kJ/kg (11,700 Btu/lb); Sulfur content = 3.23 wt. %; Ash content 12.0 wt. %. Uncontrolled $SO_2$ = 2380 ng/J (5.54 lb/$10^6$ Btu).

[f] Heating value = 20,500 kJ/kg (8,825 Btu/lb); Sulfur content = 0.42 wt. %; Ash Content 6.9 wt. %; Uncontrolled $SO_2$ = 409 ng/J (0.95 lb/$10^6$ Btu).

exist for other regions and other boiler sizes. Dry scrubbing FGD systems are designed for combined control of $SO_2$ and particulate matter, whereas sodium scrubbing and double alkali FGD systems are designed for $SO_2$ control only. For this reason, Table 3-2 also shows the cost of a fabric filter for particulate matter control for sodium scrubbing and double alkali FGD systems. Table 3-2 shows that the capital and annualized costs of sodium scrubbing are lowest for both high and low sulfur coals. Also the capital and annualized costs of double alkali are highest for both coal types. In general, dry scrubbing costs fall between the costs of sodium scrubbing and dual alkali. In order to maintain consistency throughout this report, all FGD costs are based on sodium scrubbing. Sodium scrubbing is currently the most widely used FGD technology and its costs are considered representative of FGD costs in general.

## 3.1 REGION V COSTS

### 3.1.1 Capital Costs

The capital costs presented in this report are based on the assumption that industrial boilers will be designed specifically to fire either bituminous or subbituminous coal. The FGD system capital costs reflect the current practice of industrial boiler owners to design and install FGD systems capable of achieving 90 percent $SO_2$ removal on the highest sulfur coal available in order to provide maximum fuel firing flexibility.

Table 3-3 presents the capital costs of $SO_2$ control for 29, 44, 73, and 117 MW (100, 150, 250, and 400 million Btu/hr) model boilers firing bituminous and subbituminous coals. Capital costs for boilers at the baseline firing subbituminous coals are higher than for those firing bituminous coals due to the lower heating value of subbituminous coals which, in turn, require larger boilers in order to achieve the same heat input. Total capital costs for boilers equipped with FGD systems are also higher for subbituminous coals than for bituminous coals.

TABLE 3-3. CAPITAL COST OF $SO_2$ CONTROL IN REGION V ($1000) (JAN 1983 $)[a]

| Boiler Size/ Coal Classification | Baseline[b] | With FGD[c] |
|---|---|---|
| 29 MW (100 million Btu/hr) | | |
| Bituminous | 10,106 | 10,787 |
| Subbituminous | 10,998 | 11,561 |
| 44 MW (150 million Btu/hr) | | |
| Bituminous | 14,050 | 14,899 |
| Subbituminous | 15,200 | 16,001 |
| 73 MW (250 million Btu/hr) | | |
| Bituminous | 24,026 | 25,142 |
| Subbituminous | 25,023 | 25,943 |
| 117 MW (400 million Btu/hr) | | |
| Bituminous | 33,154 | 34,616 |
| Subbituminous | 34,379 | 35,578 |

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/$NO_x$ control costs.

[c]Based on sodium scrubbing FGD.

### 3.1.2 Annual O&M Costs

Tables 3-4 through 3-7 present the annual O&M costs of $SO_2$ control for the various boiler sizes examined. These tables show that, at the baseline, fuel costs represents 50 to 60 percent of the total O&M costs for a 29 MW (100 million Btu/hr) boiler and 60 to 70 percent of the total for a 117 MW (400 million Btu/hr). For the 90 percent $SO_2$ removal cases, fuel costs represent about 45 to 55 percent of the total O&M costs for a 29 MW (100 million Btu/hr) boiler and about 55 to 65 percent of the total for a 117 MW (400 million Btu/hr) boiler. As expected, these tables show that the annual O&M costs at the baseline for bituminous coals increase with increasing fuel price for all boiler sizes. The annual O&M costs at the baseline for subbituminous coals are generally comparable to costs for medium sulfur bituminous coals (Types D, E, and F coals). As expected, the annualized cost of $SO_2$ control for boilers equipped with FGD systems increases with increasing coal sulfur content. However, total O&M costs for boilers equipped with FGD control generally track fuel price rather than sulfur content, indicating the importance of fuel price in estimating $SO_2$ control costs.

### 3.1.3 Annualized Costs

As discussed in Section 2.1.3, annualized costs are calculated as the sum of annualized capital-related charges and annual O&M costs. Tables 3-8 through 3-11 present the annualized costs of $SO_2$ control for the various boiler sizes and coal types examined.

These tables show that the difference in annualized costs of $SO_2$ control for 50 percent, 70 percent, and 90 percent FGD for a particular coal type is relatively small when compared to the total annualized costs of the boiler. These tables further show that, as expected, the annualized cost of $SO_2$ control increases with increasing coal sulfur content. However, the total annualized costs generally track fuel price rather than sulfur content, such that the total annualized costs of 90 percent FGD are lowest for a Type H coal for all boiler sizes examined.

TABLE 3-4. O & M COSTS FOR A 29 MW (100 MILLION BTU/HR) MODEL BOILER IN REGION V[a]
($1000/YR) (JAN 1983 $)

| Coal Type | Baseline[b] | | | 50% FGD[c] | | | 70% FGD[c] | | | 90% FGD[c] | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fuel | Other | Total | Fuel | Other | Total | Fuel | Other | Total | Fuel | Other | Total |
| Type B - bit | 1,729 | 1,155 | 2,884 | 1,729 | 1,337 | 3,066 | 1,729 | 1,349 | 3,078 | 1,729 | 1,360 | 3,089 |
| Type D - bit | 1,656 | 1,155 | 2,811 | 1,656 | 1,353 | 3,009 | 1,656 | 1,371 | 3,027 | 1,656 | 1,389 | 3,045 |
| Type E - bit | 1,604 | 1,156 | 2,760 | 1,604 | 1,374 | 2,978 | 1,604 | 1,400 | 3,004 | 1,604 | 1,426 | 3,030 |
| Type F - bit | 1,526 | 1,157 | 2,683 | 1,526 | 1,399 | 2,925 | 1,526 | 1,434 | 2,960 | 1,526 | 1,469 | 2,995 |
| Type G - bit | 1,390 | 1,159 | 2,549 | 1,390 | 1,441 | 2,831 | 1,390 | 1,492 | 2,882 | 1,390 | 1,544 | 2,934 |
| Type H - bit | 1,302 | 1,158 | 2,460 | 1,302 | 1,483 | 2,785 | 1,302 | 1,551 | 2,853 | 1,302 | 1,620 | 2,922 |
| Type B - sub | 1,760 | 1,161 | 2,921 | 1,760 | 1,335 | 3,095 | 1,760 | 1,346 | 3,106 | 1,760 | 1,358 | 3,118 |
| Type D - sub | 1,739 | 1,162 | 2,901 | 1,739 | 1,350 | 3,089 | 1,739 | 1,368 | 3,107 | 1,739 | 1,386 | 3,125 |
| Type E - sub | 1,718 | 1,162 | 2,880 | 1,718 | 1,371 | 3,089 | 1,718 | 1,397 | 3,115 | 1,718 | 1,423 | 3,141 |

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include $PM/NO_x$ control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-5. O & M COSTS FOR A 44 MW (150 MILLION BTU/HR) MODEL BOILER IN REGION V[a]
($1000/YR) (JAN 1983 $)

| Coal Type | Baseline[b] Fuel | Baseline[b] Other | Baseline[b] Total | 50% FGD[c] Fuel | 50% FGD[c] Other | 50% FGD[c] Total | 70% FGD[c] Fuel | 70% FGD[c] Other | 70% FGD[c] Total | 90% FGD[c] Fuel | 90% FGD[c] Other | 90% FGD[c] Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Type B - bit | 2,593 | 1,420 | 4,013 | 2,593 | 1,639 | 4,232 | 2,593 | 1,657 | 4,250 | 2,593 | 1,674 | 4,267 |
| Type D - bit | 2,484 | 1,419 | 3,903 | 2,484 | 1,662 | 4,146 | 2,484 | 1,689 | 4,173 | 2,484 | 1,716 | 4,200 |
| Type E - bit | 2,406 | 1,421 | 3,827 | 2,406 | 1,694 | 4,100 | 2,406 | 1,733 | 4,139 | 2,406 | 1,772 | 4,178 |
| Type F - bit | 2,289 | 1,423 | 3,712 | 2,289 | 1,731 | 4,020 | 2,289 | 1,784 | 4,073 | 2,289 | 1,837 | 4,126 |
| Type G - bit | 2,086 | 1,425 | 3,511 | 2,086 | 1,793 | 3,879 | 2,086 | 1,871 | 3,957 | 2,086 | 1,948 | 4,034 |
| Type H - bit | 1,953 | 1,424 | 3,377 | 1,953 | 1,857 | 3,810 | 1,953 | 2,960 | 3,913 | 1,953 | 2,063 | 4,016 |
| Type B - sub | 2,640 | 1,430 | 4,070 | 2,640 | 1,638 | 4,278 | 2,640 | 1,655 | 4,295 | 2,640 | 1,673 | 4,313 |
| Type D - sub | 2,609 | 1,429 | 4,038 | 2,609 | 1,661 | 4,270 | 2,609 | 1,688 | 4,297 | 2,609 | 1,715 | 4,324 |
| Type E - sub | 2,578 | 1,429 | 4,007 | 2,578 | 1,691 | 4,269 | 2,578 | 1,730 | 4,308 | 2,578 | 1,769 | 4,347 |

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include $PM/NO_x$ control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-6. O & M COSTS FOR A 73 MW (250 MILLION BTU/HR) MODEL BOILER IN REGION V[a]
($1000/YR) (JAN 1983 $)

| | Baseline[b] | | | 50% FGD[c] | | | 70% FGD[c] | | | 90% FGD[c] | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Coal Type | Fuel | Other | Total | Fuel | Other | Total | Fuel | Other | Total | Fuel | Other | Total |
| Type B - bit | 4,373 | 2,411 | 6,784 | 4,373 | 2,696 | 7,069 | 4,373 | 2,725 | 7,098 | 4,373 | 2,754 | 7,127 |
| Type D - bit | 4,189 | 2,410 | 6,599 | 4,189 | 2,734 | 6,923 | 4,189 | 2,779 | 6,968 | 4,189 | 2,824 | 7,013 |
| Type E - bit | 4,057 | 2,412 | 6,469 | 4,057 | 2,787 | 6,844 | 4,057 | 2,852 | 6,909 | 4,057 | 2,917 | 6,974 |
| Type F - bit | 3,860 | 2,417 | 6,277 | 3,860 | 2,850 | 6,710 | 3,860 | 2,938 | 6,798 | 3,860 | 3,027 | 6,887 |
| Type G - bit | 3,517 | 2,428 | 5,945 | 3,517 | 2,961 | 6,478 | 3,517 | 3,090 | 6,607 | 3,517 | 3,218 | 6,735 |
| Type H - bit | 3,293 | 2,424 | 5,717 | 3,293 | 3,065 | 6,358 | 3,293 | 3,237 | 6,530 | 3,293 | 3,409 | 6,702 |
| Type B - sub | 4,452 | 2,408 | 6,860 | 4,452 | 2,679 | 7,131 | 4,452 | 2,708 | 7,160 | 4,452 | 2,738 | 7,190 |
| Type D - sub | 4,400 | 2,407 | 6,807 | 4,400 | 2,717 | 7,117 | 4,400 | 2,762 | 7,162 | 4,400 | 2,807 | 7,207 |
| Type E - sub | 4,347 | 2,408 | 6,755 | 4,347 | 2,768 | 7,115 | 4,347 | 2,833 | 7,180 | 4,347 | 2,899 | 7,246 |

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/$NO_x$ control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-7. O & M COSTS FOR A 117 MW (400 MILLION BTU/HR) MODEL BOILER IN REGION V[a]
($1000/YR) (JAN 1983 $)

| Coal Type | Baseline[b] Fuel | Baseline[b] Other | Baseline[b] Total | 50% FGD[c] Fuel | 50% FGD[c] Other | 50% FGD[c] Total | 70% FGD[c] Fuel | 70% FGD[c] Other | 70% FGD[c] Total | 90% FGD[c] Fuel | 90% FGD[c] Other | 90% FGD[c] Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Type B - bit | 6,997 | 3,236 | 10,233 | 6,997 | 3,614 | 10,611 | 6,997 | 3,661 | 10,658 | 6,997 | 3,708 | 10,705 |
| Type D - bit | 6,702 | 3,236 | 9,938 | 6,702 | 3,677 | 10,379 | 6,702 | 3,749 | 10,451 | 6,702 | 3,820 | 10,522 |
| Type E - bit | 6,492 | 3,237 | 9,729 | 6,492 | 3,759 | 10,251 | 6,492 | 3,864 | 10,356 | 6,492 | 3,968 | 10,460 |
| Type F - bit | 6,175 | 3,247 | 9,422 | 6,175 | 3,862 | 10,037 | 6,175 | 4,004 | 10,179 | 6,175 | 4,145 | 10,320 |
| Type G - bit | 5,627 | 3,263 | 8,890 | 5,627 | 4,039 | 9,666 | 5,627 | 4,245 | 9,872 | 5,627 | 4,451 | 10,078 |
| Type H - bit | 5,269 | 3,258 | 8,527 | 5,269 | 4,206 | 9,475 | 5,269 | 4,481 | 9,750 | 5,269 | 4,755 | 10,024 |
| Type B - sub | 7,124 | 3,230 | 10,354 | 7,124 | 3,592 | 10,716 | 7,124 | 3,639 | 10,763 | 7,124 | 3,687 | 10,811 |
| Type D - sub | 7,040 | 3,230 | 10,270 | 7,040 | 3,654 | 10,694 | 7,040 | 3,726 | 10,766 | 7,040 | 3,798 | 10,838 |
| Type E - sub | 6,955 | 3,231 | 10,186 | 6,955 | 3,736 | 10,691 | 6,955 | 3,840 | 10,795 | 6,955 | 3,945 | 10,900 |

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/$NO_x$ control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-8. ANNUALIZED COSTS OF $SO_2$ CONTROL FOR A 29 MW (100 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] ($1000/YR) (JAN 1983 $)

| Coal Type | Baseline[c] | 50% FGD[d] $SO_2$[e] | 50% FGD[d] Total | 70% FGD[d] $SO_2$[e] | 70% FGD[d] Total | 90% FGD[d] $SO_2$[e] | 90% FGD[d] Total |
|---|---|---|---|---|---|---|---|
| Type B - Bit | 4,557 | 359 | 4,916 | 372 | 4,929 | 384 | 4,941 |
| Type D - Bit | 4,484 | 378 | 4,862 | 398 | 4,882 | 416 | 4,900 |
| Type E - Bit | 4,433 | 401 | 4,834 | 429 | 4,862 | 456 | 4,889 |
| Type F - Bit | 4,355 | 430 | 4,785 | 467 | 4,822 | 503 | 4,858 |
| Type G - Bit | 4,220 | 478 | 4,698 | 532 | 4,752 | 584 | 4,804 |
| Type H - Bit | 4,130 | 526 | 4,656 | 598 | 4,728 | 668 | 4,798 |
| Type B - Sub | 4,743 | 330 | 5,073 | 343 | 5,086 | 355 | 5,098 |
| Type D - Sub | 4,722 | 347 | 5,069 | 366 | 5,088 | 385 | 5,107 |
| Type E - Sub | 4,701 | 369 | 5,070 | 397 | 5,098 | 423 | 5,124 |

[a] All costs include applicable monitoring costs as shown in Table 2-15.

[b] All costs include FGD malfunction costs as discussed in Section 2.3.2.

[c] Baseline costs include PM/$NO_x$ control costs.

[d] Based on the use of sodium scrubbing FGD.

[e] Cost of $SO_2$ control is incremental cost above baseline cost.

TABLE 3-9. ANNUALIZED COSTS OF $SO_2$ CONTROL FOR A 44 MW (150 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] ($1000/YR) (JAN 1983 $)

| Coal Type | Baseline[c] | 50% FGD[d] | | 70% FGD[d] | | 90% FGD[d] | |
|---|---|---|---|---|---|---|---|
| | | $SO_2$[e] | Total | $SO_2$[e] | Total | $SO_2$[e] | Total |
| Type B - Bit | 6,344 | 454 | 6,798 | 472 | 6,816 | 490 | 6,834 |
| Type D - Bit | 6,233 | 485 | 6,718 | 512 | 6,745 | 540 | 6,773 |
| Type E - Bit | 6,156 | 520 | 6,676 | 560 | 6,716 | 600 | 6,756 |
| Type F - Bit | 6,040 | 561 | 6,601 | 616 | 6,656 | 670 | 6,710 |
| Type G - Bit | 5,838 | 633 | 6,471 | 712 | 6,550 | 791 | 6,629 |
| Type H - Bit | 5,703 | 706 | 6,409 | 811 | 6,514 | 917 | 6,620 |
| Type B - Sub | 6,607 | 419 | 7,026 | 438 | 7,045 | 456 | 7,063 |
| Type D - Sub | 6,575 | 445 | 7,020 | 473 | 7,048 | 501 | 7,076 |
| Type E - Sub | 6,544 | 478 | 7,022 | 518 | 7,062 | 558 | 7,102 |

[a] All costs include applicable monitoring costs as shown in Table 2-15.

[b] All costs include FGD malfunction costs as discussed in Section 2.3.2.

[c] Baseline costs include PM/$NO_x$ control costs.

[d] Based on the use of sodium scrubbing FGD.

[e] Cost of $SO_2$ control is incremental cost above baseline cost.

TABLE 3-10. ANNUALIZED COSTS OF $SO_2$ CONTROL FOR A 117 MW (250 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b] ($1000/YR) (JAN 1983 $)

| Coal Type | Baseline[c] | 50% FGD[d] $SO_2$[e] | 50% FGD[d] Total | 70% FGD[d] $SO_2$[e] | 70% FGD[d] Total | 90% FGD[d] $SO_2$[e] | 90% FGD[d] Total |
|---|---|---|---|---|---|---|---|
| Type B - Bit | 10,751 | 629 | 11,380 | 659 | 11,410 | 689 | 11,440 |
| Type D - Bit | 10,565 | 678 | 11,243 | 724 | 11,289 | 770 | 11,335 |
| Type E - Bit | 10,433 | 737 | 11,170 | 804 | 11,237 | 871 | 11,304 |
| Type F - Bit | 10,240 | 806 | 11,046 | 897 | 11,137 | 988 | 11,228 |
| Type G - Bit | 9,905 | 927 | 10,832 | 1,058 | 10,963 | 1,190 | 11,095 |
| Type H - Bit | 9,676 | 1,048 | 10,724 | 1,224 | 10,900 | 1,400 | 11,076 |
| Type B - Sub | 10,987 | 585 | 11,572 | 615 | 11,602 | 645 | 11,632 |
| Type D - Sub | 10,934 | 627 | 11,561 | 673 | 11,607 | 719 | 11,653 |
| Type E - Sub | 10,881 | 682 | 11,563 | 749 | 11,630 | 816 | 11,697 |

[a]All costs include applicable monitoring costs as shown in Table 2-15.

[b]All costs include FGD malfunction costs as discussed in Section 2.3.2.

[c]Baseline costs include PM/$NO_x$ control costs.

[d]Based on the use of sodium scrubbing FGD.

[d]Cost of $SO_2$ control is incremental cost above baseline cost.

TABLE 3-11. ANNUALIZED COSTS OF $SO_2$ CONTROL FOR A 117 MW (400 MILLION BTU/HR) MODEL BOILER IN REGION V[a,b]
($1000/YR) (JAN 1983 $)

| Coal Type | Baseline[c] | 50% FGD[d] $SO_2$[e] | 50% FGD[d] Total | 70% FGD[d] $SO_2$[e] | 70% FGD[d] Total | 90% FGD[d] $SO_2$[e] | 90% FGD[d] Total |
|---|---|---|---|---|---|---|---|
| Type B - Bit | 15,706 | 875 | 16,581 | 923 | 16,629 | 971 | 16,677 |
| Type D - Bit | 15,409 | 954 | 16,363 | 1,027 | 16,436 | 1,101 | 16,510 |
| Type E - Bit | 15,198 | 1,048 | 16,246 | 1,155 | 16,353 | 1,262 | 16,460 |
| Type F - Bit | 14,889 | 1,159 | 16,048 | 1,304 | 16,193 | 1,449 | 16,338 |
| Type G - Bit | 14,353 | 1,351 | 15,704 | 1,562 | 15,915 | 1,773 | 16,126 |
| Type H - Bit | 13,986 | 1,546 | 15,532 | 1,827 | 15,813 | 2,109 | 16,095 |
| Type B - Sub | 16,023 | 818 | 16,841 | 866 | 16,889 | 914 | 16,937 |
| Type D - Sub | 15,938 | 885 | 16,823 | 959 | 16,897 | 1,033 | 16,971 |
| Type E - Sub | 15,853 | 973 | 16,826 | 1,080 | 16,933 | 1,187 | 17,040 |

[a]All costs include applicable monitoring costs as shown in Table 2-15.

[b]All costs include FGD malfunction costs as discussed in Section 2.3.2.

[c]Baseline costs include $PM/NO_x$ control costs.

[d]Based on the use of sodium scrubbing FGD.

[e]Cost of $SO_2$ control is incremental cost above baseline cost.

## 3.2 REGION VIII COSTS

### 3.2.1 Capital Costs

Table 3-12 presents the capital costs of control at the baseline and for the various $SO_2$ control alternatives for 29, 44, 73, and 117 MW (100, 150, 250, and 400 million Btu/hr) model boilers. A comparison of the costs in Table 3-3 with those in Table 3-12 for Region VIII shows that the capital costs for coal-fired boilers are about equal to those in Region V. Any slight differences in capital costs between the two regions are attributable to differences in fuel costs which, in turn, impact working capital requirements.

### 3.2.2 Annual O&M Costs

Table 3-13 presents the annual O&M costs for each of the boiler sizes examined. At the baseline level of control, fuel costs represent 35 to 45 percent of the total O&M costs for a 29 MW (100 million Btu/hr) model boiler and 45 to 55 percent for a 117 MW (400 million Btu/hr) model boiler. For the 90 percent $SO_2$ removal cases, fuel costs account for about 30 to 40 percent of the total O&M costs for a 29 MW (100 million Btu/hr) model boiler and about 40 to 50 percent for a 117 MW (400 million Btu/hr) model boiler. Fuel costs as a percentage of total O&M costs are lower in Region VIII than in Region V (see Section 3.1.2). This is explained by the significantly lower fuel prices in Region VIII as compared to Region V. (Table 3-1 presented the fuel prices and specifications for coals in these regions).

### 3.2.3 Annualized Costs

Table 3-14 presents the annualized costs of control at the baseline and for each $SO_2$ control alternative for the various boiler sizes examined. Annualized costs are calculated as the sum of the annualized capital charges and annual O&M costs.

Table 3-14 shows that the differences in $SO_2$ control costs for 50, 70 and 90 percent FGD for a particular coal type are small relative to the

TABLE 3-12. CAPITAL COST OF $SO_2$ CONTROL IN REGION VIII ($1000) (JAN 1983 $)[a]

| Boiler Size/ Coal Classification | Baseline[b] | With FGD[c] |
|---|---|---|
| 29 MW (100 million Btu/hr) | | |
| Bituminous | 10,062 | 10,728 |
| Subbituminous | 10,913 | 11,476 |
| 44 MW (150 million Btu/hr) | | |
| Bituminous | 13,983 | 14,810 |
| Subbituminous | 15,171 | 15,873 |
| 73 MW (250 million Btu/hr) | | |
| Bituminous | 23,913 | 24,993 |
| Subbituminous | 24,807 | 25,727 |
| 117 MW (400 million Btu/hr) | | |
| Bituminous | 32,973 | 34,376 |
| Subbituminous | 34,033 | 35,233 |

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/$NO_x$ control costs.

[c]Based on sodium scrubbing FGD.

TABLE 3-13. O & M COSTS IN REGION VIII ($1000/YR) (JAN 1983 $)[a]

| Coal Type | Baseline[b] | | | 50% FGD[c] | | | 70% FGD[c] | | | 90% FGD[c] | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fuel | Other | Total | Fuel | Other | Total | Fuel | Other | Total | Fuel | Other | Total |
| 29 MW (100 x $10^6$ Btu/hr) model boiler | | | | | | | | | | | | |
| Type B - Bit | 1,036 | 1,158 | 2,194 | 1,036 | 1,341 | 2,377 | 1,036 | 1,353 | 2,389 | 1,036 | 1,365 | 2,401 |
| Type D - Bit | 969 | 1,159 | 2,128 | 969 | 1,358 | 2,327 | 969 | 1,376 | 2,345 | 969 | 1,394 | 2,363 |
| Type E - Bit | 974 | 1,160 | 2,134 | 974 | 1,378 | 2,352 | 974 | 1,404 | 2,378 | 974 | 1,430 | 2,404 |
| Type B - Sub | 729 | 1,164 | 1,893 | 729 | 1,338 | 2,067 | 729 | 1,349 | 2,078 | 729 | 1,361 | 2,090 |
| Type D - Sub | 724 | 1,162 | 1,886 | 724 | 1,351 | 2,075 | 724 | 1,368 | 2,092 | 724 | 1,386 | 2,110 |
| Type E - Sub | 667 | 1,162 | 1,829 | 667 | 1,371 | 2,038 | 667 | 1,397 | 2,064 | 667 | 1,423 | 2,090 |
| 44 MW (150 x $10^6$ Btu/hr) model boiler | | | | | | | | | | | | |
| Type B - Bit | 1,554 | 1,425 | 2,979 | 1,554 | 1,645 | 3,199 | 1,554 | 1,663 | 3,217 | 1,554 | 1,680 | 3,234 |
| Type D - Bit | 1,453 | 1,427 | 2,880 | 1,453 | 1,670 | 3,123 | 1,453 | 1,697 | 3,150 | 1,453 | 1,724 | 3,177 |
| Type E - Bit | 1,461 | 1,427 | 2,888 | 1,461 | 1,700 | 3,161 | 1,461 | 1,739 | 3,200 | 1,461 | 1,778 | 3,239 |
| Type B - Sub | 1,094 | 1,433 | 2,527 | 1,094 | 1,642 | 2,736 | 1,094 | 1,660 | 2,754 | 1,094 | 1,677 | 2,771 |
| Type D - Sub | 1,086 | 1,431 | 2,517 | 1,086 | 1,662 | 2,748 | 1,086 | 1,689 | 2,775 | 1,086 | 1,715 | 2,801 |
| Type E - Sub | 1,000 | 1,431 | 2,431 | 1,000 | 1,693 | 2,693 | 1,000 | 1,732 | 2,732 | 1,000 | 1,772 | 2,772 |
| 73 MW (250 x $10^6$ Btu/hr) model boiler | | | | | | | | | | | | |
| Type B - Bit | 2,621 | 2,416 | 5,037 | 2,621 | 2,702 | 5,323 | 2,621 | 2,732 | 5,353 | 2,621 | 2,761 | 5,382 |
| Type D - Bit | 2,450 | 2,420 | 4,870 | 2,450 | 2,745 | 5,195 | 2,450 | 2,790 | 5,240 | 2,450 | 2,835 | 5,285 |
| Type E - Bit | 2,463 | 2,421 | 4,884 | 2,463 | 2,796 | 5,259 | 2,463 | 2,861 | 5,324 | 2,463 | 2,926 | 5,389 |
| Type B - Sub | 1,844 | 2,424 | 4,268 | 1,844 | 2,695 | 4,539 | 1,844 | 2,725 | 4,569 | 1,844 | 2,754 | 4,598 |
| Type D - Sub | 1,831 | 2,410 | 4,241 | 1,831 | 2,719 | 4,550 | 1,831 | 2,763 | 4,594 | 1,831 | 2,808 | 4,639 |
| Type E - Sub | 1,686 | 2,410 | 4,096 | 1,686 | 2,771 | 4,457 | 1,686 | 2,837 | 4,523 | 1,686 | 2,902 | 4,588 |
| 117 MW (400 x $10^6$ Btu/hr) model boiler | | | | | | | | | | | | |
| Type B - Bit | 4,194 | 3,244 | 7,438 | 4,194 | 3,624 | 7,818 | 4,194 | 3,672 | 7,866 | 4,194 | 3,719 | 7,913 |
| Type D - Bit | 3,920 | 3,251 | 7,171 | 3,920 | 3,694 | 7,614 | 3,920 | 3,766 | 7,686 | 3,920 | 3,838 | 7,758 |
| Type E - Bit | 3,941 | 3,252 | 7,193 | 3,941 | 3,775 | 7,716 | 3,941 | 3,879 | 7,820 | 3,941 | 3,983 | 7,924 |
| Type B - Sub | 2,951 | 3,256 | 6,207 | 2,951 | 3,618 | 6,569 | 2,951 | 3,666 | 6,617 | 2,951 | 3,713 | 6,664 |
| Type D - Sub | 2,930 | 3,234 | 6,164 | 2,930 | 3,657 | 6,587 | 2,930 | 3,728 | 6,658 | 2,930 | 3,799 | 6,729 |
| Type E - Sub | 2,698 | 3,234 | 5,932 | 2,698 | 3,740 | 6,438 | 2,698 | 3,845 | 6,543 | 2,698 | 3,950 | 6,648 |

[a]Includes applicable monitoring costs as shown in Table 2-15.

[b]Baseline costs include PM/$NO_x$ control costs.

[c]Based on the use of sodium scrubbing FGD.

TABLE 3-14. ANNUALIZED COSTS OF $SO_2$ CONTROL IN REGION VIII ($1000/yr) (JAN 1983 $)[a,b]

| Coal Type | Baseline[c] | 50% FGD[d] | | 70% FGD[d] | | 90% FGD[d] | |
|---|---|---|---|---|---|---|---|
| | | $SO_2$[e] | Total | $SO_2$[e] | Total | $SO_2$[e] | Total |
| 29 MW (100 x $10^6$ Btu/hr) model boiler | | | | | | | |
| Type B - Bit | 3,862 | 369 | 4,231 | 382 | 4,244 | 394 | 4,256 |
| Type D - Bit | 3,796 | 388 | 4,184 | 407 | 4,203 | 426 | 4,222 |
| Type E - Bit | 3,801 | 408 | 4,209 | 436 | 4,237 | 463 | 4,264 |
| Type B - Sub | 3,706 | 357 | 4,063 | 370 | 4,076 | 382 | 4,088 |
| Type D - Sub | 3,699 | 372 | 4,071 | 392 | 4,091 | 410 | 4,109 |
| Type E - Sub | 3,641 | 397 | 4,038 | 425 | 4,066 | 452 | 4,093 |
| 44 MW (150 x $10^6$ Btu/hr) model boiler | | | | | | | |
| Type B - Bit | 5,301 | 470 | 5,771 | 490 | 5,791 | 508 | 5,809 |
| Type D - Bit | 5,201 | 499 | 5,700 | 528 | 5,729 | 556 | 5,757 |
| Type E - Bit | 5,209 | 529 | 5,738 | 571 | 5,780 | 611 | 5,820 |
| Type B - Sub | 5,051 | 460 | 5,511 | 480 | 5,531 | 499 | 5,550 |
| Type D - Sub | 5,041 | 483 | 5,524 | 513 | 5,554 | 540 | 5,581 |
| Type E - Sub | 4,954 | 520 | 5,474 | 562 | 5,516 | 602 | 5,556 |
| 73 MW (250 x $10^6$ Btu/hr) model boiler | | | | | | | |
| Type B - Bit | 8,989 | 655 | 9,644 | 685 | 9,674 | 715 | 9,704 |
| Type D - Bit | 8,821 | 703 | 9,524 | 749 | 9,570 | 795 | 9,616 |
| Type E - Bit | 8,835 | 753 | 9,588 | 820 | 9,655 | 887 | 9,722 |
| Type B - Sub | 8,374 | 651 | 9,025 | 681 | 9,055 | 712 | 9,086 |
| Type D - Sub | 8,347 | 690 | 9,037 | 736 | 9,083 | 781 | 9,128 |
| Type E - Sub | 8,200 | 752 | 8,952 | 819 | 9,019 | 886 | 9,086 |
| 117 MW (400 x $10^6$ Btu/hr) model boiler | | | | | | | |
| Type B - Bit | 12,888 | 915 | 13,803 | 964 | 13,852 | 1,012 | 13,900 |
| Type D - Bit | 12,619 | 993 | 13,612 | 1,066 | 13,685 | 1,140 | 13,759 |
| Type E - Bit | 12,641 | 1,074 | 13,715 | 1,181 | 13,822 | 1,287 | 13,928 |
| Type B - Sub | 11,841 | 925 | 12,766 | 973 | 12,814 | 1,022 | 12,863 |
| Type D - Sub | 11,798 | 987 | 12,785 | 1,060 | 12,858 | 1,133 | 12,931 |
| Type E - Sub | 11,564 | 1,084 | 12,648 | 1,191 | 12,755 | 1,299 | 12,863 |

[a] All costs include applicable monitoring costs as shown in Table 2-15.

[b] All costs include malfunction costs as discussed in Section 2.3.2.

[c] Baseline costs include $PM/NO_x$ control costs.

[d] Based on the use of sodium scrubbing FGD.

[e] Cost of $SO_2$ control is incremental cost above Baseline Cost.

total annualized cost of a boiler. Also, the total annualized cost of control tracks the fuel price rather than the sulfur content. Therefore, the least costly fuel has the lowest total annualized costs for each alternative.

## 3.3 REFERENCES

1. Projected Environmental, Cost and Energy Impacts of Alternative $SO_2$ NSPS for Industrial Fossil Fuel-Fired Boilers. (Prepared for U. S. Environmental Protection Agency). Energy and Environmental Analysis, Arlington, Virginia. July 27, 1984. pp. 9-10.

# 4.0 COST OF $SO_2$ CONTROL ON RESIDUAL OIL-FIRED MODEL BOILERS

This chapter presents the results of an analysis of $SO_2$ control costs for residual oil-fired model boilers. Capital and annualized costs are examined for boilers with no $SO_2$ control (baseline) and for boilers equipped with FGD systems achieving 50 percent, 70 percent, and 90 percent $SO_2$ removal. Costs are examined for several boiler sizes and for several oil sulfur contents. The boiler sizes selected for this analysis are 29, 44, 73 and 117 MW (100, 150, 250 and 400 million Btu/hr) heat input. The 117 MW (400 million Btu/hr) model boiler is actually two 59 MW (200 million Btu/hr) boilers sharing a common stack. This arrangement was selected because two small packaged units are less costly than one large field-erected unit.

Specifications and prices of residual oil delivered to Region V are presented in Table 4-1. To maintain consistency with the Industrial Fuel Choice Analysis Model (IFCAM), which is used to project the national impacts of alternative $SO_2$ standards, the values in Table 4-1 are projections for 1990 delivered fuel prices expressed in January 1983 dollars.[1] The projections ignore the effects of inflation but assume that fuel prices will escalate in real terms. In addition, the fuel prices have been "levelized" over the life of the boiler (i.e., an equivalent constant price has been calculated after allowing for escalation and the time value of money.

In this analysis, it is assumed that all boilers require the use of low excess air operation (LEA) for $NO_x$ control. Costs are also presented for a model boiler using staged combustion air (SCA) operation in addition to LEA when firing a high sulfur content oil since high sulfur oil may also contain high nitrogen levels. It is also assumed that no add-on particulate matter controls are required.

The basis of the FGD costs presented in this report for residual oil-fired boilers is sodium scrubbing FGD. Sodium scrubbing FGD was selected because it is the most widely used in residual oil applications and it is generally the least costly method of control. Double alkali FGD is more costly both on a capital and an annualized basis. And dry scrubbing FGD is not considered applicable to residual oil-fired applications. Also

TABLE 4-1. SPECIFICATIONS FOR RESIDUAL OILS DELIVERED TO REGION V AND REGION VIII[a]

| Sulfur Content lb $SO_2/10^6$ Btu | Fuel Price[b] \$/kJ (\$/$10^6$ Btu) | Heating Value kJ/kg (Btu/lb) | Ash Content Wt. % | Nitrogen Content Wt. % |
|---|---|---|---|---|
| Region V: | | | | |
| 0.3 | 5.69 (6.01) | 43,000 (18,500) | 0.10 | 0.04 |
| 0.8 | 5.33 (5.63) | 43,000 (18,500) | 0.10 | 0.12 |
| 1.6 | 4.97 (5.25) | 43,000 (18,500) | 0.10 | 0.23 |
| 3.0 | 4.68 (4.94) | 43,000 (18,500) | 0.10 | 0.44 |
| Region VIII: | | | | |
| 0.3 | 5.37 (5.67) | 43,000 (18,500) | 0.10 | 0.04 |
| 0.8 | 5.01 (5.29) | 43,000 (18,500) | 0.10 | 0.12 |
| 1.6 | 4.67 (4.93) | 43,000 (18,500) | 0.10 | 0.23 |
| 3.0 | 4.36 (4.60) | 43,000 (18,500) | 0.10 | 0.44 |

[a]Reference 1.

[b]1990 levelized fuel price in 1983 \$.

the FGD costs are based on an industrial boiler located in Region V. Unlike coal all ten EPA regions have the same residual oils available. Thus the only difference in FGD costs in Region V and any other region can be attributed to fuel cost. Therefore, the cost impact of $SO_2$ control compared to the regulatory baseline in Region V is representative of impacts nationwide.

## 4.1 REGION V COSTS

### 4.1.1 Capital Costs

Table 4-2 presents the capital costs of $SO_2$ control for 29, 44, 73, and 117 MW (100, 150, 250 and 400 million Btu/hr) model boilers. The capital costs of FGD for all oil types and percent removal requirements are designed to achieve 90 percent $SO_2$ removal on a 3.0 lb $SO_2/10^6$ Btu oil. In other words, it is assumed that a boiler owner/operator will design an FGD for maximum fuel-firing flexibility.

### 4.1.2 Annual O&M Costs

Table 4-3 presents the annual O&M costs of $SO_2$ control for residual oil-fired model boilers in Region V. Table 4-3 shows that fuel costs represent 80 to 90 percent of the total O&M costs at the baseline and for each FGD alternative. In other words, a scrubbing requirement has little impact on the total system costs since fuel costs represent such a large percentage of the total costs.

### 4.1.3 Annualized Costs

Table 4-4 shows that, at the baseline and for each FGD alternative, total annualized costs decrease with increasing fuel sulfur content. Table 4-4 also shows that it is less costly to scrub a 3.0 lb $SO_2/10^6$ Btu oil than it is to fire a 0.3 lb $SO_2/10^6$ Btu oil uncontrolled for all boiler sizes examined. Furthermore, as boiler size increases, the premium price of a 0.3 lb $SO_2/10^6$ Btu oil becomes even more important and scrubbing a 0.8 lb $SO_2/10^6$ Btu oil becomes less costly than firing a 0.3 lb $SO_2/10^6$ Btu oil uncontrolled.

TABLE 4-2. CAPITAL COSTS OF $SO_2$ CONTROL FOR MODEL BOILERS IN REGION V[a]
($1000) (JAN 1983 $)

| Boiler Size/ Coal Classification | Baseline[b] | With FGD[c] |
|---|---|---|
| 29 MW (100 Million Btu/hr) | 2,545 | 3,104 |
| 44 MW (150 Million Btu/hr) | 3,278 | 3,973 |
| 73 MW (250 Million Btu/hr) | 4,579 | 5,500 |
| 117 MW (400 Million Btu/hr) | 7,732 | 8,998 |

[a] Includes applicable monitoring costs as shown in Table 2-15.

[b] Baseline costs include PM/$NO_x$ control costs.

[c] Based on sodium scrubbing FGD.

TABLE 4-3. OPERATING AND MAINTENANCE COSTS OF $SO_2$ CONTROL FOR MODEL BOILERS IN REGION V[a]

($1000/YR) (JANUARY 1983 $)

| | Baseline[b] | | | 50% FGD[c] | | | 70% FGD[c] | | | 90% FGD[c] | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fuel | Other | Total | Fuel | Other | Total | Fuel | Other | Total | Fuel | Other | Total |
| 29 MW ($100 \times 10^6$ Btu/hr | | | | | | | | | | | | |
| 0.3 lb $SO_2/10^6$ Btu | 2,847 | 521 | 3,368 | 2,847 | 677 | 3,524 | 2,847 | 673 | 3,520 | 2,847 | 677 | 3,524 |
| 0.8 lb $SO_2/10^6$ Btu | 2,667 | 521 | 3,188 | 2,667 | 693 | 3,360 | 2,667 | 694 | 3,361 | 2,667 | 704 | 3,371 |
| 1.6 lb $SO_2/10^6$ Btu | 2,487 | 521 | 3,008 | 2,487 | 717 | 3,204 | 2,487 | 729 | 3,216 | 2,487 | 748 | 3,235 |
| 3.0 lb $SO_2/10^6$ Btu[d] | 2,340 | 521 | 2,861 | 2,340 | 760 | 3,100 | 2,340 | 789 | 3,129 | 2,340 | 826 | 3,166 |
| 3.0 lb $SO_2/10^6$ Btu[e] | 2,386 | 541 | 2,927 | 2,386 | 780 | 3,166 | 2,386 | 809 | 3,195 | 2,386 | 846 | 3,232 |
| 44 MW ($150 \times 10^6$ Btu/hr) | | | | | | | | | | | | |
| 0.3 lb $SO_2/10^6$ Btu | 4,241 | 652 | 4,893 | 4,241 | 801 | 5,072 | 4,241 | 828 | 5,069 | 4,241 | 834 | 5,075 |
| 0.8 lb $SO_2/10^6$ Btu | 4,000 | 623 | 4,623 | 4,000 | 825 | 4,825 | 4,000 | 831 | 4,831 | 4,000 | 846 | 4,846 |
| 1.6 lb $SO_2/10^6$ Btu | 3,730 | 623 | 4,353 | 3,730 | 861 | 4,591 | 3,730 | 883 | 4,613 | 3,730 | 912 | 4,642 |
| 3.0 lb $SO_2/10^6$ Btu[d] | 3,510 | 622 | 4,132 | 3,510 | 926 | 4,436 | 3,510 | 973 | 4,483 | 3,510 | 1,028 | 4,538 |
| 3.0 lb $SO_2/10^6$ Btu[e] | 3,579 | 651 | 4,230 | 3,579 | 954 | 4,533 | 3,579 | 1,001 | 4,580 | 3,579 | 1,056 | 4,635 |
| 73 MW ($250 \times 10^6$ Btu/hr) | | | | | | | | | | | | |
| 0.3 lb $SO_2/10^6$ Btu | 7,118 | 816 | 7,934 | 7,118 | 1,035 | 8,153 | 7,118 | 1,045 | 8,163 | 7,118 | 1,054 | 8,172 |
| 0.8 lb $SO_2/10^6$ Btu | 6,667 | 817 | 7,484 | 6,667 | 1,075 | 7,742 | 6,667 | 1,099 | 7,766 | 6,667 | 1,124 | 7,791 |
| 1.6 lb $SO_2/10^6$ Btu | 6,217 | 817 | 7,034 | 6,217 | 1,136 | 7,353 | 6,217 | 1,185 | 7,402 | 6,217 | 1,234 | 7,451 |
| 3.0 lb $SO_2/10^6$ Btu[d] | 5,850 | 817 | 6,667 | 5,850 | 1,243 | 7,093 | 5,850 | 1,335 | 7,185 | 5,850 | 1,427 | 7,277 |
| 3.0 lb $SO_2/10^6$ Btu[e] | 5,965 | 862 | 6,827 | 5,965 | 1,288 | 7,253 | 5,965 | 1,380 | 7,345 | 5,965 | 1,472 | 7,437 |
| 117 MW ($400 \times 10^6$ Btu/hr) | | | | | | | | | | | | |
| 0.3 lb $SO_2/10^6$ Btu | 11,388 | 1,368 | 12,756 | 11,388 | 1,635 | 13,023 | 11,388 | 1,650 | 13,038 | 11,388 | 1,664 | 13,052 |
| 0.8 lb $SO_2/10^6$ Btu | 10,668 | 1,368 | 12,036 | 10,668 | 1,696 | 12,364 | 10,668 | 1,735 | 12,403 | 10,668 | 1,775 | 12,443 |
| 1.6 lb $SO_2/10^6$ Btu | 9,948 | 1,368 | 11,316 | 9,948 | 1,794 | 11,742 | 9,948 | 1,873 | 11,821 | 9,948 | 1,951 | 11,899 |
| 3.0 lb $SO_2/10^6$ Btu[d] | 9,360 | 1,370 | 10,730 | 9,360 | 1,967 | 11,328 | 9,360 | 2,115 | 11,475 | 9,360 | 2,263 | 11,623 |
| 3.0 lb $SO_2/10^6$ Btu[e] | 9,544 | 1,442 | 10,986 | 9,544 | 2,040 | 11,584 | 9,544 | 2,187 | 11,731 | 9,544 | 2,335 | 11,879 |

[a] Includes applicable monitoring costs as shown in Table 2-15.

[b] Baseline costs include $NO_x$ control costs.

[c] Based on the use of sodium scrubbing FGD.

[d] $NO_x$ control = Low Excess Air

[e] $NO_x$ control = Staged Combustion Air

TABLE 4-4. ANNUALIZED COSTS OF $SO_2$ CONTROL FOR RESIDUAL OIL-FIRED MODEL BOILERS IN REGION V[a,b] ($1000/YR) (JANUARY 1983 $)

| | Baseline[c] | 50% FGD[d] | | 70% FGD[d] | | 90% FGD[d] | |
|---|---|---|---|---|---|---|---|
| | | $SO_2$[e] | Total | $SO_2$[e] | Total | $SO_2$[e] | Total |
| 29 MW ($100 \times 10^6$ Btu/hr) | | | | | | | |
| 0.3 lb $SO_2/10^6$ Btu | 3,767 | 252 | 4,019 | 256 | 4,023 | 260 | 4,027 |
| 0.8 lb $SO_2/10^6$ Btu | 3,585 | 277 | 3,862 | 287 | 3,872 | 297 | 3,882 |
| 1.6 lb $SO_2/10^6$ Btu | 3,404 | 311 | 3,715 | 331 | 3,735 | 351 | 3,755 |
| 3.0 lb $SO_2/10^6$ Btu[f] | 3,256 | 363 | 3,619 | 400 | 3,656 | 438 | 3,694 |
| 3.0 lb $SO_2/10^6$ Btu[g] | 3,354 | 362 | 3,716 | 400 | 3,754 | 438 | 3,792 |
| 44 MW ($150 \times 10^6$ Btu/hr) | | | | | | | |
| 0.3 lb $SO_2/10^6$ Btu | 5,408 | 295 | 5,703 | 301 | 5,709 | 307 | 5,715 |
| 0.8 lb $SO_2/10^6$ Btu | 5,136 | 332 | 5,468 | 347 | 5,483 | 362 | 5,498 |
| 1.6 lb $SO_2/10^6$ Btu | 4,864 | 383 | 5,247 | 414 | 5,278 | 444 | 5,308 |
| 3.0 lb $SO_2/10^6$ Btu[f] | 4,642 | 461 | 5,103 | 517 | 5,159 | 574 | 5,216 |
| 3.0 lb $SO_2/10^6$ Btu[g] | 4,782 | 461 | 5,243 | 518 | 5,300 | 574 | 5,356 |
| 73 MW ($250 \times 10^6$ Btu/hr) | | | | | | | |
| 0.3 lb $SO_2/10^6$ Btu | 8,671 | 351 | 9,022 | 361 | 9,032 | 370 | 9,041 |
| 0.8 lb $SO_2/10^6$ Btu | 8,217 | 414 | 8,631 | 439 | 8,656 | 464 | 8,681 |
| 1.6 lb $SO_2/10^6$ Btu | 7,763 | 500 | 8,263 | 550 | 8,313 | 601 | 8,364 |
| 3.0 lb $SO_2/10^6$ Btu[f] | 7,393 | 628 | 8,021 | 723 | 8,116 | 817 | 8,210 |
| 3.0 lb $SO_2/10^6$ Btu[g] | 7,619 | 628 | 8,247 | 723 | 8,342 | 817 | 8,436 |
| 117 MW ($400 \times 10^6$ Btu/hr) | | | | | | | |
| 0.3 lb $SO_2/10^6$ Btu | 13,994 | 446 | 14,440 | 461 | 14,455 | 477 | 14,471 |
| 0.8 lb $SO_2/10^6$ Btu | 13,268 | 545 | 13,813 | 586 | 13,854 | 626 | 13,894 |
| 1.6 lb $SO_2/10^6$ Btu | 12,542 | 683 | 13,225 | 764 | 13,306 | 844 | 13,386 |
| 3.0 lb $SO_2/10^6$ Btu[f] | 11,950 | 889 | 12,839 | 1,040 | 12,990 | 1,191 | 13,141 |
| 3.0 lb $SO_2/10^6$ Btu[g] | 12,316 | 889 | 13,205 | 1,040 | 13,356 | 1,191 | 13,507 |

[a] Includes monitoring costs as shown in Table 2-15.

[b] Includes FGD malfunction costs as discussed in Section 2.3.2.

[c] Baseline costs include $NO_x$ control costs.

[d] Based on the use of sodium scrubbing FGD.

[e] Cost of $SO_2$ control is incremental over baseline cost.

[f] $NO_x$ Control = Low Excess Air.

[g] $NO_x$ Control = Staged Combustion Air.

## 4.3 REFERENCES


1. Projected Environmental, Cost and Energy Impacts of Alternative $SO_2$ NSPS for Industrial Fossil Fuel-Fired Boilers. (Prepared for U. S. Environmental Protection Agency). Energy and Environmental Analysis, Arlington, Virginia. July 27, 1984. pp. 9-10.

# APPENDIX A

TABLE A-1. SUMMARY OF COSTING ALGORITHMS

| Routine Code[a] | Algorithm Type | Boiler Size Applicability ($10^6$ Btu/hr) | Table |
|---|---|---|---|
| SPRD | Boiler, spreader stoker, watertube, field-erected | 60 - 200 | A-4 |
| PLVR | Boiler, pulverized coal, watertube, field-erected | ≥200 | A-5 |
| RNG1 | Boiler, residual/natural gas, watertube, package | 30 - 200 | A-6 |
| RNG2 | Boiler, residual/natural gas, watertube, field-erected | 200 - 700 | A-7 |
| FF | Fabric filter applied to coal-fired boiler | 30 - 700 | A-8 |
| DA | Dual alkali FGD system without PM removal | All sizes | A-9 |
| SOD | Sodium scrubbing FGD system | All sizes | A-10 |
| DS | Lime spray drying (dry scrubbing) FGD system | All sizes | A-11 |
| LEA | Low excess air applied to all fuel types | All sizes | A-12 |
| SCA | Staged combustion air applied to pulverized coal-fired boiler | >150 | A-13 |
| SCA | Staged combustion air applied to residual oil-fired boiler | 30 - 250 | A-14 |
| FLW | Calculates flue gas flowrates for all fuel types | All sizes | A-15 |

TABLE A-2. NOMENCLATURE USED IN COST ALGORITHMS

1. Capital Costs (1978 dollars)

| | | |
|---|---|---|
| EQUP | = | Equipment |
| INST | = | Installation |
| TD | = | Total Direct |
| IND | = | Indirect (Engineering, Field, Construction, Start-up, and other miscellaneous costs) |
| TDI | = | Total Direct and Indirect |
| CONT | = | Contingencies |
| TK | = | Turnkey |
| LAND | = | Land |
| WC | = | Working Capital |
| TOTL | = | Total Capital |

2. Operation and Maintenance Costs[a] (1978 dollars/year)

| | | |
|---|---|---|
| DL | = | Direct Labor |
| SPRV | = | Supervision Labor |
| MANT | = | Maintenance Labor |
| SP | = | Spare Parts |
| ELEC | = | Electricity |
| UC | = | Utilities and Chemicals |
| WTR | = | Water |
| SW | = | Solid Waste Disposal |
| SLG | = | Sludge Waste Disposal |
| LW | = | Liquid Waste Disposal |
| SC | = | Sodium Carbonate |
| LMS | = | Limestone |
| LIME | = | Lime |
| FUEL | = | Fuel |
| TDOM | = | Total Direct Operation and Maintenance |
| OH | = | Overhead |
| TOTL | = | Total Operation and Maintenance |

3. Annualized Costs (1978 dollars/year)

| | | |
|---|---|---|
| CR | = | Capital Recovery |
| WCC | = | Working Capital Charges |
| MISC | = | Miscellaneous (G & A, Taxes, Insurance) |
| TCC | = | Total Capital Charges |
| TOTL | = | Total Annualized Charges |

TABLE A-2. (Continued)

4. Boiler Specifications

| | | |
|---|---|---|
| Q | = | Thermal Input ($10^6$ Btu/hr) (MW)[b] |
| FLW | = | Flue Gas Flowrate (acfm) ($m^3/s$)[b] |
| CF | = | Capacity Factor (-)[c] |
| BCRF | = | Capital Recovery Factor for Boiler System |

5. Fuel Specifications

| | | |
|---|---|---|
| FC | = | Fuel Cost ($/$10^6$ Btu) ($MJ)[b] |
| H | = | Heating Value (Btu/lb) (KJ/kg)[b] |
| S | = | Sulfur Content (percent by weight) |
| A | = | Ash Content (percent by weight) |
| N | = | Fuel Nitrogen Content (percent by weight) |

6. $SO_2$ Control Specifications

| | | |
|---|---|---|
| UNCSO2 | = | Uncontrolled $SO_2$ Emissions (lb/$10^6$ Btu) (ng/J)[b] |
| CTRSO2 | = | Controlled $SO_2$ Emissions (lb/$10^6$ Btu) (ng/J)[b] |
| EFFSO2 | = | $SO_2$ Removal Efficiency (percent) |
| CRFSO2 | = | Capital Recovery Factor for $SO_2$ Control System |

7. PM Control Specifications

| | | |
|---|---|---|
| UNCPM | = | Uncontrolled PM Emissions (lb/$10^6$ Btu) (ng/J)[b] |
| CTRPM | = | Controlled PM Emissions (lb/$10^6$ Btu) (ng/J)[b] |
| EFFPM | = | PM Removal Efficiency (percent) |
| CRFPM | = | Capital Recovery Factor for PM Control System |

8. Cost Rates

| | | |
|---|---|---|
| ELEC | = | Electricity Rate ($/kw-hr) |
| WTR | = | Water Rate ($/$10^3$ gal) ($/$m^3$)[b] |
| ALIME | = | Lime Rate ($/ton) ($/kg)[b] |
| ALS | = | Limestone Rate ($/ton) ($/kg)[b] |
| SASH | = | Sodium Carbonate Rate ($/ton) ($/kg)[b] |
| SLDG | = | Sludge Disposal Rate ($/ton) ($/kg)[b] |
| SWD | = | Solid Waste Disposal Rate ($/ton) ($/kg)[b] |
| LWD | = | Liquid Waste Disposal Rate ($/$10^3$ gal) ($/$m^3$)[b] |
| DLR | = | Direct Labor Rate ($/man-hr) |
| SLR | = | Supervision Labor Rate ($/man-hr) |
| AMLR | = | Maintenance Labor Rate ($/man-hr) |

TABLE A-2. (Continued)

9. Miscellaneous

| | | |
|---|---|---|
| S1 | = | Heat Specific Sulfur Removal (kg S/1000 MJ) |
| S2 | = | Time Specific Sulfur Removal (kg S/hr) |
| LF | = | Labor Factor (-)[d] |

10. $NO_x$ Control Specifications

| | | |
|---|---|---|
| FFAC | = | F-Factor (dscf/$10^6$ Btu) |
| UNCEA | = | Uncontrolled Excess Air (%) |
| CTREA | = | Controlled Excess Air (%) |
| PRCT | = | Percent Flame Extension Due to Staging |
| DELT | = | Change in the flue gas exit temperature due to the elimination of the air preheater or a reduction in its effectiveness. |
| $CRFNO_x$ | = | Capital Recovery Factor for $NO_x$ Control System |

[a]Cost categories are not mutually exclusive. For example, some costing routines include electricity and waste cost in the utilities category while other calculate these cost separately.

[b]FGD algorithms use metric units.

[c](-) factor presented as fraction not as percent.

TABLE A-3. CALCULATIONS COMMON TO COST ALGORITHMS

1. Capital Costs

EQUP + INST = TD[a]
IND = 0.333 * TD[b]
TDI = TD + IND
CONT = 0.20 * TDI
LAND[c] = $4000 pulverized coal boilers
= $2000 all other boilers
WC = 0.25 * (TDOM - Fuel) + 0.0833 (Fuel)[d]
TOTL = TK + LAND + WC

2. Operation and Maintenance Costs

FUEL = CF * Q * FC * 8760
TDOM = Sum of all O&M Costs other than OH
OH = 0.30 * DL + 0.26 * (DL + SPRV + MANT + SP)
TOTL = TDOM + OH

3. Annualized Costs

CR = CRF * TK
WCC = 0.10 * WC
MISC = 0.04 * TK
TCC = CR + WCC + MISC
TOTL = TCC + TOTL O&M Costs

4. Labor Factors

LF = 1 if CF > 0.7
LF = 0.5 + 2.5 * (CF - 0.5) if $0.5 \leq CF \leq 0.7$
LF = 0.5 if CF < 0.5

---

[a] FGD system cost algorithms compute TD without prior computation of EQUP and INST

[b] Some algorithms compute IND explicitly as a function of boiler and/or control device specifications.

[c] Only boilers have costs assumed for land.

[d] For boilers, assume a 3-month supply of all working capital components except fuel which will have a 1-month supply. For control devices, working capital is 25% of total direct operating and maintenance costs.

TABLE A-4. COST EQUATIONS FOR FIELD-ERECTED, WATERTUBE SPREADER-STOKER BOILERS

($60\text{-}200 \times 10^6$ Btu/hr)[1]

Routine Code: SPRD

Capital Costs:

$$\text{EQUP} = \frac{Q}{7.5963 \times 10^{-8}\, Q + 4.7611 \times 10^{-5}} \left(\frac{H}{11{,}800}\right)^{-.35}$$

$$\text{INST} = \frac{Q}{8.9174 \times 10^{-8}\, Q + 5.5891 \times 10^{-5}} \left(\frac{H}{11{,}800}\right)^{-.35}$$

$$\text{IND} = \frac{Q}{1.2739 \times 10^{-7}\, Q + 7.9845 \times 10^{-5}} \left(\frac{H}{11{,}800}\right)^{-.35}$$

Annual Costs:[a]

$$\text{DL} = \text{LF}\,(202{,}825 + 5.366\, Q^2)\ (0.767)$$

$$\text{SPRV} = \text{LF}\,(136{,}900)\ (0.767)$$

$$\text{MANT} = \text{LF}\,(107{,}003 + 1.873\, Q^2)\ (0.767)$$

$$\text{SP} = (50{,}000 + 1{,}000\, Q)\ (0.767)$$

$$\text{UC} = \text{CF}\,(29{,}303 + 719.8\, Q)\ (0.848)$$

$$\text{SW} = 0.38\, \text{CF}\,\left(547{,}320 + 66{,}038 \ln \frac{A}{H}\right) \left(\frac{Q}{150}\right)^{0.9754} (0.848)$$

[a]The multipliers used, 0.767 and 0.848, are included in determining annual O&M costs. These factors reflect the economies of multiple boilers at a facility (see Chapter 2).

TABLE A-5. COST EQUATION FOR FIELD-ERECTED, WATERTUBE PULVERIZED COAL-FIRED BOILERS

($>200 \times 10^6$ Btu/hr)[1]

Routine Code: PLVR

Capital Costs:

$$EQUP = (4{,}926{,}066 - 0.00337\ H^2)\left(\frac{Q}{200}\right)^{0.712}$$

$$INST = 1{,}547{,}622.7 + 6{,}740.026\ Q - 0.0024133\ H^2$$

$$IND = 1{,}257{,}434.72 + 6{,}271.316\ Q - 0.00185721\ H^2$$

Annual Costs:[a]

$$DL = LF\ (244{,}455 + 1{,}157\ Q)\ (0.767)$$

$$SPRV = LF\left(243{,}985 - \frac{20{,}636{,}709}{Q}\right)(0.767)$$

$$MANT = LF\ (-1{,}162{,}910 + 256{,}604\ \ln Q)\ (0.767)$$

$$SP = (180{,}429 + 405.4\ Q)\ (0.767)$$

$$UC = CF\ (189{,}430 + 1476.7\ Q)\ (0.848)$$

$$SW = 0.38\ CF\left(-641.08 + \frac{70{,}679{,}828\ A}{H}\right)\left(\frac{Q}{200}\right)^{1.001}(0.848)$$

[a]The multipliers used, 0.767 and 0.848, are included in determining annual O&M costs. These factors reflect the economies of multiple boilers at a facility (see Chapter 2).

TABLE A-6. COST EQUATIONS FOR PACKAGE, WATERTUBE DUAL-FIRED BOILERS FIRING RESIDUAL OIL/NATURAL GAS

($30\text{-}200 \times 10^6$ Btu/hr)[1]

---

Routine Code: RNG1

Capital Costs

$$\text{EQUP} = 15{,}925\ Q^{.775}$$

$$\text{INST} = 54{,}833\ Q^{0.364}$$

$$\text{IND} = 16{,}561\ Q^{.613}$$

Annual Costs[a]

$$\text{DL} = \text{LF}\left(\frac{Q^2}{8{,}135 \times 10^{-4}\ Q - 1.585 \times 10^{-2}}\right)\ (0.799)$$

$$\text{SPRV} = \text{LF}\ (68{,}500)\ (0.799)$$

$$\text{MANT} = \text{LF}\left(\frac{-1{,}267{,}000}{Q}\right) + 77{,}190)\ (0.799)$$

$$\text{SP} = 7{,}185\ Q^{0.4241}\ (0.799)$$

$$\text{UC} = \frac{\text{CF}}{.55}\ (202\ Q + 24{,}262)\ (0.845)$$

---

[a]The multipliers used, 0.799 and 0.845, are included in determining annual O&M costs. These factors reflect the economies of multiple boilers at a facility (see Chapter 2).

TABLE A-7. COST EQUATIONS FOR FIELD-ERECTED, WATERTUBE RESIDUAL OIL/GAS-FIRED BOILERS

$(200 - 700 \times 10^6$ Btu/hr)[1]

Routine Code: RNG2

Capital Costs:

EQUP = 1,024,258 + 8,458 Q

INST = 579,895 + 5,636 Q

IND = 515,189 + 4,524 Q

Annual Costs:[a]

DL = LF (173,197 + 734 Q) (0.799)

$$SPRV = LF \left(263{,}250 - \frac{30{,}940{,}000}{Q}\right)(0.799)$$

MANT = LF (32,029 + 320.4 Q)(0.799)

SP = (50,000 + 250 Q) (0.799)

UC = CF (43,671.7 + 479.6 Q) (0.845)

[a]The multipliers used, 0.799 and 0.845 are included in determining annual O&M costs. These factors reflect the economies of multiple boilers at a facility (see Chapter 2).

## TABLE A-8. COST EQUATIONS FOR FABRIC FILTERS APPLIED TO COAL-FIRED BOILERS

$(30 - 700 \times 10^6$ Btu/hr$)^2$

Routine Code: FF

Capital Costs:

| | | | |
|---|---|---|---|
| EQUP | = | $8.340\ (FLW)^{0.966}$ | |
| INST | = | $-1{,}506{,}523 + 168{,}531 \ln (FLW)$ | |
| IND | = | $24.990\ (FLW)^{0.821}$ | |

Annual Costs:

| | | | |
|---|---|---|---|
| DL | = | $LF\ (10{,}150 + 106\ Q)$ | if $30 < Q < 400$ |
| | = | $LF\ (52{,}600)$ | if $400 < Q \leq 700$ |
| SPRV | = | $0$ | if $30 < Q \leq 400$ |
| | = | $LF\ (17{,}000)$ | if $400 < Q \leq 700$ |
| MANT | = | $LF\ (14{,}840 + 0.106\ Q^2)$ | if $30 < Q \leq 400$ |
| | = | $LF\ (32{,}000)$ | if $400 < Q \leq 700$ |
| SP | = | $0.278\ (FLW)^{0.997}$ | |
| ELEC | = | $(\frac{CF}{0.6})\ 0.740\ (FLW)^{0.953}$ | |
| SW | = | $(\frac{CF}{0.6})\ 39.42\ Q\ (UNCPM - CTRPM)$ | |

TABLE A-9. COST EQUATIONS FOR DUAL ALKALI FGD SYSTEMS WITHOUT PM REMOVAL[a]

---

Routine Code: DA

Capital Costs:[b,c]

| | | | |
|---|---|---|---|
| TD | = | $35{,}500\ (FLW)^{0.61} + 83{,}118\ (S2)^{0.39}$ | |
| TK | = | 1.48 TD + 93,600 | if Q $\leq$58.6 |
| | = | 1.48 TD + 130,000 | if Q >58.6 |

Annual Costs:[b,c]

| | | | |
|---|---|---|---|
| DL | = | 8,760 * DLR * LF | |
| SPRV | = | 1,314 * DLR * LF | |
| MANT | = | 0.08 TD * LF | |
| ELEC | = | 8,760 CF * ELEC [2.94 FLW (0.121 S1 + 0.861)] | |
| WTR | = | 8,760 CF * WTR [0.197 FLW + 0.30]* [0.977 + 0.119 ln S1] | |
| SW | = | 8,760 CF * SWD [7.73 S2 - 3.34] | |
| SC | = | 8,760 CF * SASH [1.13 FLW - 2.06]* $[0.41 - 0.70\ (0.24 - S1)^{1.74}]$ | if S1 < 0.24 |
| | = | 8,760 CF * SASH [1.13 FLW - 2.06]* $[0.70\ (S1 - 0.24)^{1.74} + 0.41]$ | if S1 $\geq$ 0.24 |
| LIME | = | 8,760 CF * ALIME [1.61 S2 - 0.85] | |

---

[a]FGD algorithms use metric units as noted in Table A-2.

[b]S1 = S * EFFSO2 * 100/H.

[c]S2 = S1 * Q * 3.6

TABLE A-10. COST EQUATIONS FOR SODIUM SCRUBBING FGD SYSTEMS[a]

Routine Code: SOD[b,c]

Capital Costs:[d]

$TK_s$ = $39,900\ (FLW)^{0.585} + 1,370\ (S2)^{0.727}$

$TK_w$ = $26,500\ S_2^{\ 0.39}$

$TK$ = $TK_s + TK_w$

Annual Costs:

DL = 1,100*DLW

SPRV = 165*SPRV

MANT = 0.08*TK

$ELEC_s$ = 8,760*CF*ELEC [3.61(FLW) - 2.15]

$ELEC_w$ = 8760*CF*ELEC [0.23(S2) + 1.32]

ELEC = $ELEC_s$ + $ELEC_w$

WTR = 8760*CF*WTR [0.600(FLW) - 2.08] [0.527(S1) + 0.364]

SC = 8760*CF*SASH [3.33(S2) + 0.082]

LW = 8760*CF*LWD [0.0616(S2) + 0.298][e]

---

[a]All FGD algorithms are in metric units as noted in Table A-2.

[b]S1 = S*EFFSO$_2$*100/H

[c]S2 = S1*Q*3.6

[d]The subscript "s" denotes scrubber costs and the subscript "w" denotes wastewater costs.

[e]This equation assumes that the wastewater stream has a total dissolved solids concentration (TDS) of 5.7.

TABLE A-11. COST EQUATIONS FOR LIME SPRAY DRYING FGD SYSTEMS WITH PM REMOVAL[a]

Routine Code: DS

Capital Costs:[b,c]

TD = C1 + C2 + C3 + C4

C1 = $55,600\ (FLW)^{0.51}$

C2 = $32,900\ (S2)^{0.40}$

C3 = $18,400 + 8,260\ (FLW) + 6,420\ (FLW)^{0.50}$

C4 = $256,320\ [W1 + W2]^{0.63}$

W1 = Q * S/H * [0.626 EFFS02 - 79.9 ln (1-EFFS02/100) - 10.1]

W2 = $3.96 \times 10^{-6}Q$ (UNCPM - CTRPM)

TK = 1.48 TD + 110,400 if $Q \leq 58.6$

= 1.60 TD if $Q > 58.6$

Annual Costs, $/Year

DL = 8,760 * DLW * LF

SPRV = 1,314 * SPRV * LF

MANT = $[0.08\ [55,600\ (FLW)^{0.51} + 32,900(S2)^{0.40}] + M1 + M2] * LF$

M1 = 834 FLW

M2 = MANT * (4.04 FLW + 1,086)

ELEC = $8,760\ CF * ELEC\ [6.14\ (FLW)^{0.82}]$

WTR = 8,760 CF * WTR [0.144 FLW]

SW = 8,760 CF * SWD [W3 + W4]

W3 = (Q * S/H) * [569 EFFS02 - 72,700 ln (1-EFFS02/100) - 9,230]

W4 = $3.6 \times 10^{-3}Q$ (UNCPM - CTRPM)

LIME = 8,760 CF * ALIME * (-48,500) * Q * S/H * [ln (1-EFFS02/100) + 0.127]

[a]FGD algorithms use metric units as noted in Table A-2.

[b]S1 = S * EFFS02 * 100/H.

[cd]S2 = S1 * Q * 3.6.

TABLE A-12. COST EQUATIONS FOR LOW EXCESS AIR APPLIED TO INDUSTRIAL BOILERS

---

Routine Code: LEA

Capital Costs:

Coal: EQUIP = 46.22(Q) + 6496
INST and IND = 21.50(Q) + 1123

Oil and Gas: EQUIP = 31.38(Q) + 5185
INST and IND = 11.37(Q) + 1161

Annual Costs:

SP[b] = 0.05 (TK)
FUEL = -.00055(FC)(Q)(CF)(FFAC)(UNCEA - CTREA)

---

[a]Algorithm assumes a flue gas temperature of 400°F and the ambient air temperature to be 77°F.

[b]Spare parts costs consist of the costs for spare parts, maintenance labor, and maintenance materials.

TABLE A-13. COST EQUATIONS FOR STAGED COMBUSTION AIR APPLIED TO PULVERIZED COAL-FIRED BOILERS

($>150 \times 10^6$ Btu/hr)

Routine Code: SCA

Capital Costs:

EQUIP = 65 (Q) + 13000
INST and IND = 60 (Q) + 2000

Annual Costs:

SP[a] = 0.05 (TK)
ELEC = 105 (Q)(CF)
FUEL = 21.9 (FC)(Q)(CF)

[a] Spare parts costs consist of the costs for spare parts, maintenance labor, and maintenance materials.

TABLE A-14. COST EQUATIONS FOR STAGED COMBUSTION AIR APPLIED TO RESIDUAL OIL-FIRED BOILERS (fuel N >0.23 wt. percent)

($30 - 250 \times 10^6$ Btu/hr)

---

Routine Code: SCA

Capital Costs:

TK = 1000 [(Q)(PRCT) 0.0536 + 2.56 (PRCT)]

where:

PRCT = 30; when N $\geq$0.6
PRCT = 81.1(N) - 18.7 when 0.23 <N <0.6

Annual Costs:

SP[a] = 0.05 (TK)
ELEC = 102 (Q)(CF)
FUEL = 21.9 (FC)(Q)(CF)

---

[a]Spare parts costs consists of the costs for spare parts, maintenance labor, and maintenance maerials.

TABLE A-15. FLUE GAS FLOWRATE ALGORITHMS[a,b]

---

Natural Gas

$FLW = 8.14 \times 10^6\ Q/H$ (non-LEA)

$FLW = 6.81 \times 10^6\ Q/H$ (LEA)

Distillate and/or Residual

$FLW = 0.189\ Q\ H^{0.77}$ (non-LEA)

$FLW = 0.156\ Q\ H^{0.77}$ (LEA)

Coal (Stoker)

$FLW = EXP\ [8.14 \times 10^{-5} H] * 1.84 \times 10^6\ Q/H$ (non-LEA)

$FLW = EXP\ [8.14 \times 10^{-5} H] * 1.66 \times 10^6\ Q/H$ (LEA)

Coal (Pulverized)

$FLW = 1.62 \times 10^6 * EXP\ [8.03 \times 10^{-5}\ H] * Q/H$ (LEA)

FBC (Pulverized Coal)

$FLW = 297.82Q$

---

[a]LEA and non-LEA conditions are defined as follows:

NG and oil: LEA - 15% excess air
Non-LEA - 40% excess air

Coal: LEA - 35% excess air for stokers and 30% excess air pulverized coal.
Non-LEA - 50% excess air

[b]Flue gas flowrate in acfm.

# APPENDIX B

TABLE B-1. COST ESCALATION FACTORS

Capital Costs

$$\text{Capital Cost Escalation Factor} = \frac{\text{index for update year}}{\text{index for July 1978}}$$

| | CE Plant Index[a] |
|---|---|
| July 1978 | 219.2 |
| Jan. 1979 | 229.8 |
| July 1979 | 239.3 |
| Jan. 1980 | 247.5 |
| July 1980 | 263.6 |
| Jan. 1981 | 276.6 |
| July 1981 | 303.1 |
| Jan. 1982 | 311.8 |
| July 1982 | 314.2 |
| Jan. 1983 | 315.5 |

Operating and Maintenance Costs

$$\text{O \& M Cost Escalation Factor} = \frac{\text{index for update year}}{\text{index for July 1978}}$$

| | Producer Price Index[b] |
|---|---|
| July 1978 | 210.1 |
| Jan. 1979 | 220.0 |
| July 1979 | 237.5 |
| Jan. 1980 | 260.6 |
| July 1980 | 276.2 |
| Jan. 1981 | 291.5 |
| July 1981 | 306.2 |
| Jan. 1982 | 311.8 |
| July 1982 | 312.8 |
| Jan. 1983 | 313.9 |

TABLE B-1 COST ESCALATION FACTORS (Continued)

[a] Economic Indicators. Chemical Engineering. 85 (23): 7, October 23, 1978; 85 (11): 7, May 8, 1978; 86 (24): 7, November 5, 1979; 86 (10): 7, May 7, 1979; 87 (23): 7, November 17, 1980; 87 (9): 7, May 5, 1980; 88 (23): 7, November 16, 1984; 88 (10): 7, May 18, 1981; 89 (23): 7, November 15, 1982; 89 (10): 7, May 17, 1982; 90 (24): 7, November 28, 1983; 90 (11): 7, May 30, 1983.

[b] BLS Producer Price Index. All Industrial Commodities. File 176, Dinlog Information Services, Inc. July 26, 1984 update.

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16. ABSTRACT

This report is a resource document for the development of Federal standards of performance for control of sulfur dioxide emissions for new industrial boilers. It presents capital and annualized costs for $SO_2$ control technologies applied to coal- and residual oil-fired industrial boilers. Control costs are presented for model boilers with heat input capacities of 100, 150, 250, and 400 million Btu per hour firing fuels with various sulfur contents and achieving 50, 70, and 90 percent $SO_2$ reduction using flue gas desulfurization systems. The cost algorithms used to calculate these costs are also presented.

17. KEY WORDS AND DOCUMENT ANALYSIS

| a. DESCRIPTORS | b. IDENTIFIERS/OPEN ENDED TERMS | c. COSATI Field/Group |
|---|---|---|
| $SO_2$ Emissions<br>Coal Air Pollution<br>Industrial Boilers<br>Pollution Control Costs<br>Fuel Standards<br>Emission Standards<br>Flue Gas Desulfurization | Coal<br>Air Pollution Control | |

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