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Electric Utility Steam Generating Units
Background Information for Proposed Particulate Matter Emission Standards

Emission Standards and Engineering Division

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air, Noise, and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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Background Information and
Draft Environmental Impact Statement
for Proposed Particulate Matter Emission Standards for
Electric Utility Steam Generating Units

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Prepared by:

Don R. Goodwin — August 16, 1978 (Date)

Don R. Goodwin
Director, Emission Standards and Engineering Division
Environmental Protection Agency
Research Triangle Park, North Carolina 27711

Approved by:

Walter C. Barber — August 16, 1978 (Date)

Walter C. Barber
Director, Office of Air Quality Planning and Standards
Research Triangle Park, North Carolina 27711

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1. SUMMARY

1.1 PROPOSED STANDARDS

The proposed standards have been developed and are being proposed in accordance with Section 111 of the Clean Air Act as amended. Publication of these proposed standards was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies.

The proposed standards would limit the emissions of particulate matter from electric utility steam generators capable of firing more than 73 megawatts (MW) heat input (250 million Btu hour) of fossil fuel.

The proposed standard would limit particulate matter emissions to 13 ng/J heat input (0.03 lb/million Btu) and would require a 99 percent reduction in uncontrolled emissions from solid fuels and a 70 percent reduction for liquid fuels. No particulate matter control would be necessary for units firing gaseous fuels alone, and thus a percent reduction would not be required.

Because of potential sampling difficulties of sampling particulate matter upstream of a particulate matter control device, the proposed standard would define potential uncontrolled particulate matter emissions as 3,000 ng/J heat input (7.0 lb/million Btu) when firing solid fuel and

75 ng/J heat input (0.17 lb/million Btu) when firing liquid fuel. The percentage reduction for solid and liquid fuels will be satisfied if the facility is in compliance with the 13 nq/s emission limit.

A 20 percent opacity (6-minute average) standard is proposed. Alternately, a source specific opacity standard could be determined during performance testing at the owner's or operator's request. No provisions for short-term exclusions of the opacity standard for tube blowing or preheater cleaning are included.

The proposed emission standards are based on the performance of a well designed and operated baghouse or ESP. Emission test data were collected for baghouse, ESP, and scrubber controlled steam generators. The proposed emission levels can be achieved using baghouses with air to cloth ratios of less than 0.6 actual cubic meters per minute per square meter (2 ACFM/ft^2) of cloth area, or high efficiency ESP systems sized according to coal ash characteristics. No specific collection areas are recommended for ESP's; however, a hot side collection area of 128 square meters per actual cubic meter per second (650 ft^2/1000 ACFM) or a cold side collection area of 197 square meters per actual cubic meter per second (1000 ft^2/1000 ACFM) would be expected to be adequate for even the most difficult cases. EPA considers these air to cloth ratios and specific collection areas reasonable considering cost, energy, and nonair environmental impacts.

Performance testing would be conducted by stack testing using EPA Reference Method 5 (external filter) or Method 17 (in-stack filter). Compliance with the proposed emission limit would be determined by direct comparison of the performance test data with the emission standards.

Compliance with the percentage reduction requirement would be accomplished using the performance test data (ng/J) and the uncontrolled emission levels defined in the proposed standard. The potential uncontrolled emission levels defined for solid and liquid fuels represent estimated emission levels that would be expected from an uncontrolled steam generator firing a typical coal or residual oil respectively. The uncontrolled emission levels are defined because of the potential difficulty of sampling particulate matter upstream of particulate matter control devices and the necessity of accurately knowing the uncontrolled emission level in order to determine the percentage emission reduction achieved. Compliance with the proposed emission limitation will assure compliance with the percentage reduction requirement.

The owner or operator of an affected facility would be required to continuously monitor opacity of the exhaust gases to assure proper maintenance and operation of the air pollution control system. If opacity interference is experienced after a FGD system, the opacity monitor would be located upstream of the FGD system. If opacity interference is experienced both upstream and downstream of the FGD system, operating parameters of the particulate matter control system would be monitored. In cases where the opacity standard is not achieved at the same time the emission limitation is achieved, the general provisions of Part 60 [60.11(e)] of the Code of Federal Regulations allow a source specific opacity standard to be established.

EPA has investigated the possible interaction of flue gas desulfurization (FGD) systems with the proposed particulate matter standard. Three possible mechanisms were investigated: (1) FGD system sulfate carryover from the scrubber slurry, (2) particulate matter removed by the FGD system, and (3) particulate matter generation from condensation of sulfuric acid mist (H_2SO_4). EPA obtained particulate matter data from three FGD system equipped steam generators with low particulate matter emission levels. The data indicate that a properly designed, constructed, and operated FGD system would not result in scrubber slurry carryover and that some particulate matter may in fact be removed by the FGD system. Condensation of sulfuric acid mist (H_2SO_4) from sulfur trioxide (SO_3) in the flue gas has not been a common problem to date because typical stack gas temperatures of 150°C to 200°C (300°F to 400°F) are sufficient to prevent condensation. The sulfuric acid dew point temperature depends on the SO_3 concentration in the flue gas and increases as the sulfur content of the coal fired increases. Flue gas temperatures would be reduced by FGD systems and may result in SO_3 condensation and formation of sulfuric acid mist. Although FGD systems would be expected to remove approximately 50 percent of the acid mist, remaining acid mist may interact with Method 5 or 17 particulate sampling and increase particulate loadings. Data from the three steam generators firing low sulfur coal and equipped with a FGD system were obtained and indicated that acid mist would not be a problem when firing low sulfur coal.

In a case where a FGD is used with high sulfur coal, sufficient data are not available to fully assess if sulfuric acid mist interaction is significant. The proposed emission standard is based on the emission levels demonstrated at the discharge of the particulate matter control device. EPA will continue to investigate this subject and consider its impact on the proposed particulate matter standard as data becomes available.

1.2 ENVIRONMENTAL IMPACT

The beneficial and adverse environmental impacts associated with the proposed standards have been considered prior to proposal. The revised particulate matter performance standard for steam generators would have overall positive effects.

The proposed standard would reduce emissions 70 percent from emission levels currently allowed under 40 CFR, Part 60, Subpart D, which are 43 ng/J heat input (0.1 lb/million Btu). This emission reduction would have a positive air quality impact. The water quality and solid waste impact of the proposed standard would not be significantly changed since less than a 1 percent increase would occur in the quantity of particulate matter collected and disposed of. The energy impact when a baghouse or ESP is used for emission control would not be significant. Particulate matter control through scrubber technology, although not the basis of this proposed standard, would have a larger water and energy impact.

1.3 ECONOMIC IMPACT

The economic impact of the proposed standard is small and varies with the control system used. For a 500 MW plant, the operating cost of an ESP to comply with the current particulate emission standard of 43 ng/J heat input (0.1 lb/million Btu) using an ESP is approximately 2.91 mills/kWhr for Western coal and 1.34 mills/kWhr for Eastern coal. The estimated cost for complying with a 13 ng/J heat input (0.03 lb/million Btu) limit is 1.96 mills/kWhr for Western coal (baghouse) and 1.59 mills/kWhr for Eastern coal (ESP). This use of the more efficient baghouse control technology when firing Western coal would be achieved at no increase in cost above the current standard, just a change in control technology. The use of a higher efficiency ESP when firing Eastern coal would be expected to increase retail electric costs by less than 1 percent above the current standard. The total annualized cost of the particulate matter control system including the cost of complying with the current standard would represent approximately 6 percent of the retail electric cost to consumers.

Table 1-1. MATRIX OF ENVIRONMENTAL AND ECONOMIC IMPACTS OF THE PROPOSED PARTICULATE MATTER PERFORMANCE STANDARD

Administrative Action	Air Impact	Water Impact	Solid Waste Impact	Energy Impact	Noise and Radiation Impact	Economic Impact	Inflationary Impact
State Limits[a]	+2	-1	-1	-1	-1	0	-1
Existing Limits[b]	+3	-1	-2	-1	-1	-1	-1
Proposed Limits[c]	+4	-1	-2	-1	-1	-1	-1

a Prior to December 23, 1971, there were no Federal emission standards.
b These were promulgated on December 23, 1971, under 40 CFR Part 60, Subpart D.
c Proposed under 40 CFR Part 60, Subpart Da in 1978.

KEY:
- 0 No Impact
- 1 Negligible Impact
- 2 Small Impact
- 3 Moderate Impact
- 4 Large Impact

- \+ Beneficial Impact
- \- Adverse Impact

2. INTRODUCTION

Standards of performance are proposed following a detailed investigation of air pollution control methods available to the affected industry and the impact of their costs on the industry. This document summarizes the information obtained from such a study. Its purpose is to explain in detail the background and basis of the proposed standards and to facilitate analysis of the proposed standards by interested persons, including those who may not be familiar with the many technical aspects of the industry. To obtain additional copies of this document or the Federal Register notice of proposed standards, write to EPA Library (MD-35), Research Triangle Park, North Carolina 27711. Specify Electric Utility Steam Generating Units - Background Information for Proposed Particulate Matter Emission Standards, report number EPA-450/2-78-006a, when ordering.

2.1 AUTHORITY FOR THE STANDARDS

Standards of performance for new stationary sources are established under section 111 of the Clean Air Act (42 U.S.C. 7411), as amended, hereafter referred to as the Act. Section 111 directs the Administrator to establish standards of performance for any category of new stationary source of air pollution which ". . . causes or contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare."

The Act requires that standards of performance for stationary sources reflect, ". . . the degree of emission limitation achievable through the application of the best technological system of continuous emission reduction . . . the Administrator determines has been adequately demonstrated." In addition, for stationary sources whose emissions result from fossil fuel combustion, the standard must also include a percentage reduction in emissions. The Act also provides that the cost of achieving the necessary emission reduction, the nonair quality health and environmental impacts and the energy requirements all be taken into account in establishing standards of performance. The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the Federal Register.

The 1977 amendments to the Act altered or added numerous provisions which apply to the process of establishing standards of performance.

1. EPA is required to list the categories of major stationary sources which have not already been listed and regulated under standards of performance. Regulations must be promulgated for these new categories on the following schedule:

25 percent of the listed categories by August 7, 1980

75 percent of the listed categories by August 7, 1981

100 percent of the listed categories by August 7, 1982

A governor of a State may apply to the Administrator to add a category which is not on the list or to revise a standard of performance.

2. EPA is required to review the standards of performance every four years, and if appropriate, revise them.

3. EPA is authorized to promulgate a design, equipment, work practice, or operational standard when an emission standard is not feasible.

4. The term "standards of performance" is redefined and a new term "technological system of continuous emission reduction" is defined. The new definitions clarify that the control system must be continous and may include a low-polluting or non-polluting process or operation.

5. The time between the proposal and promulgation of a standard under section 111 of the Act is extended to six months.

Standards of performance, by themselves, do not guarantee protection of health or welfare because they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect the degree of emission limitation achievable through application of the best adequately demonstrated technological system of continuous emission reduction, taking into consideration the cost of achieving such emission reduction, any nonair quality health and environmental impact and energy requirements.

Congress had several reasons for including these requirements. First, standards with a degree of uniformity are needed to avoid situations where some States may attract industries by relaxing standards relative to other States. Second, stringent standards enhance the potential for long term growth. Third, stringent standards may help achieve long-term cost savings by avoiding the need for more expensive retrofitting when pollution ceilings may be reduced in the future. Fourth, certain types of standards for coal burning sources can adversely affect the coal market by driving up the price of low-sulfur coal or effectively excluding certain coals from the reserve base because their untreated pollution potentials are high. Congress does not intend that new source performance standards contribute to these problems. Fifth, the standard-setting process should create incentives for improved technology.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission limitations for the same sources. States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the national ambient air quality standards (NAAQS) under section 110. Thus, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

A similar situation may arise when a major emitting facility is to be constructed in a geographic area which falls under the prevention of significant deterioration of air quality provisions of Part C of the Act. These provisions require, among other things, that major emitting facilities to be constructed in such areas are to be subject to best available control technology. The term "best available control technology" (BACT), as defined in the Act, means ". . . an emission limitation based on the maximum degree of reduction of each pollutant subject to regulation under this Act emitted from or which results from any major emitting facility, which the permitting authority, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such facility through application of production processes and available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of each such pollutant. In no event shall application of 'best available control technology' result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 or 112 of this Act."

Although standards of performance are normally structured in terms of numerical emission limits where feasible, alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. Section 111(h) provides that the Administrator may promulgate a design or equipment standard in those cases where it is not feasible to prescribe or enforce a standard of performance. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions, high concentrations for short periods during filling, and low concentrations for longer periods during storage, and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

In addition, section 111(h) authorizes the Administrator to grant waivers of compliance to permit a source to use innovative continuous emission control technology. In order to grant the waiver, the Administrator must find: (1) a substantial likelihood that the technology will produce greater emission reductions than the standards require, or an equivalent reduction at lower economic, energy, or environmental cost;

(2) the proposed system has not been adequately demonstrated; (3) the technology will not cause or contribute to an unreasonable risk to public health, welfare or safety; (4) the governor of the State where the source is located consents; and that, (5) the waiver will not prevent the attainment or maintenance of any ambient standard. A waiver may have conditions attached to assure the source will not prevent attainment of any NAAQS. Any such condition will have the force of a performance standard. Finally, waivers have definite end dates and may be terminated earlier if the conditions are not met or if the system fails to perform as expected. In such a case, the source may be given up to three years to meet the standards, with a mandatory progress schedule.

2.2 SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 of the Act directs the Administrator to list categories of stationary sources which have not been listed before. The Administrator, ". . . shall include a category of sources in such list if in his judgment it causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." Proposal and promulgation of standards of performance are to follow while adhering to the schedule referred to earlier.

Since passage of the Clean Air Amendments of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. The approach specifies areas of interest by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants which are emitted by stationary sources. Source categories which emit these pollutants were then evaluated and ranked by a process involving such factors as (1) the level of emission control (if any) already required by State regulations; (2) estimated levels of control that might be required from standards of performance for the source category; (3) projections of growth and replacement of existing facilities for the source category; and (4) the estimated incremental amount of air pollution that could be prevented, in a preselected future year, by standards of performance for the source category. Sources for which new source performance standards were promulgated or are under development during 1977 or earlier, were selected on these criteria.

The Act amendments of August, 1977, establish specific criteria to be used in determining priorities for all source categories not yet listed by EPA. These are

1) the quantity of air pollutant emissions which each such category will emit, or will be designed to emit;

2) the extent to which each such pollutant may reasonably be anticipated to endanger public health or welfare; and

3) the mobility and competitive nature of each such category of sources and the consequent need for nationally applicable new source standards of performance.

In some cases, it may not be feasible to immediately develop a standard for a source category with a high priority. This might happen when a program of research is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. In the developing of standards, differences in the time required to complete the necessary investigation for different source categories must also be considered. For example, substantially more time may be necessary if numerous pollutants must be investigated from a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling. Nevertheless, priority ranking is, and will continue to be, used to establish the order in which projects are initiated and resources assigned.

After the source category has been chosen, determining the types of facilities within the source category to which the standard will apply must be decided. A source category may have several facilities that cause air pollution and emissions from some of these facilities to be insignificant or very expensive to control. Economic studies of the source category and of applicable control technology may show that air pollution control is better served by applying standards to the more severe pollution sources. For this reason, and because there is no adequately demonstrated system for controlling emissions from certain facilities, standards often do not apply to all facilities at a source. For the same reasons, the standards may not apply to all air pollutants emitted. Thus, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

2.3 PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Standards of performance must (1) realistically reflect best demonstrated control practice; (2) adequately consider the cost, and the nonair quality health and environmental impacts and energy requirements of such control; (3) be applicable to existing sources that are modified or reconstructed as well as new installations; and (4) meet these conditions for all variations of operating conditions being considered anywhere in the country.

The objective of a program for development of standards is to identify the best technological system of continuous emission reduction which has been adequately demonstrated. The legislative history of section 111 and various court decisions make clear that the Administrator's judgment of what is adequately demonstrated is not limited to systems that are in actual routine use. The search may include a technical assessment of control systems which have been adequately demonstrated but for which there is limited operational experience. In most cases, determination of the ". . . degree of emission reduction achievable . . ." is based on results of tests of emissions from well controlled existing sources. At times, this has required the investigation and measurement of emissions from control systems found in other industrialized countries that have developed more effective systems of control than those available in the United States.

Since the best demonstrated systems of emission reduction may not be in widespread use, the data base upon which standards are developed may be somewhat limited. Test data on existing well-controlled sources are obvious starting points in developing emission limits for new sources. However, since the control of existing sources generally represents retrofit technology or was originally designed to meet an existing State or local regulation, new sources may be able to meet more stringent emission standards. Accordingly, other information must be considered before a judgment can be made as to the level at which the emission standard should be set.

A process for the development of a standard has evolved which takes into account the following considerations.

1. Emissions from existing well-controlled sources as measured.

2. Data on emissions from such sources are assessed with consideration of such factors as: (a) how representative the tested source is in regard to feedstock, operation, size, age, etc.; (b) age and maintenance of the control equipment tested; (c) design uncertainties of control equipment being considered; and (d) the degree of uncertainty that new sources will be able to achieve similar levels of control.

3. Information from pilot and prototype installations, guarantees by vendors of control equipment, unconstructed but contracted projects, foreign technology, and published literature are also considered during the standard development process. This is especially important for sources where "emerging" technology appears to be a significant alternative.

4. Where possible, standards are developed which permit the use of more than one control technique or licensed process.

5. Where possible, standards are developed to encourage or permit the use of process modifications or new processes as a method of control rather than "add-on" systems of air pollution control.

6. In appropriate cases, standards are developed to permit the use of systems capable of controlling more than one pollutant. As an example, a scrubber can remove both gaseous and particulate emissions, but an electrostatic precipitator is specific to particulate matter.

7. Where appropriate, standards for visible emissions are developed in conjunction with concentration/mass emission standards. The opacity standard is established at a level that will require proper operation and maintenance of the emission control system installed to meet the

concentration/mass standard on a day-to-day basis. In some cases, however, it is not possible to develop concentration/mass standards, such as with fugitive sources of emissions. In these cases, only opacity standards may be developed to limit emissions.

2.4 CONSIDERATION OF COSTS

Section 317 of the Act requires, among other things, an economic impact assessment with respect to any standard of performance established under section 111 of the Act. The assessment is required to contain an analysis of:

(1) the costs of compliance with the regulation and standard including the extent to which the cost of compliance varies depending on the effective date of the standard or regulation and the development of less expensive or more efficient methods of compliance;

(2) the potential inflationary recessionary effects of the standard or regulation;

(3) the effects on competition of the standard or regulation with respect to small business;

(4) the effects of the standard or regulation on consumer cost, and,

(5) the effects of the standard or regulation on energy use.

Section 317 requires that the economic impact assessment be as extensive as practible, taking into account the time and resources available to EPA.

The economic impact of a proposed standard upon an industry is usually addressed both in absolute terms and by comparison with the control costs that would be incurred as a result of compliance with typical existing State control regulations. An incremental approach is taken since both new and existing plants would be required to comply with State regulations in the absence of a Federal standard of performance. This approach requires a detailed analysis of the impact upon the industry resulting from the cost differential that exists between a standard of performance and the typical State standard.

The costs for control of air pollutants are not the only costs considered. Total environmental costs for control of water pollutants as well as air pollutants are analyzed wherever possible.

A thorough study of the profitability and price-setting mechanisms of the industry is essential to the analysis so that an accurate estimate of potential adverse economic impacts can be made. It is also essential to know the capital requirements placed on plants in the absence of Federal standards of performance so that the additional capital requirements necessitated by these standards can be placed in the proper perspective. Finally, it is necessary to recognize any constraints on capital availability within an industry, as this factor also influences the ability of new plants to generate the capital required for installation of additional control equipment needed to meet the standards of performance

2.5 CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(C) of the National Environmental Policy Act (NEPA) of 1969 requires Federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decision-making process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

In a number of legal challenges to standards of performance for various industries, the Federal Courts of Appeals have held that environmental impact statements need not be prepared by the Agency for proposed actions under section 111 of the Clean Air Act. Essentially, the Federal Courts of Appeals have determined that " . . . the best system of emission reduction, . . . require(s) the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry . . ." On this basis, therefore, the Courts ". . . established a narrow exemption from NEPA for EPA determination under section 111."

In addition to these judicial determinations, the Energy Supply and Environmental Coordination Act (ESECA) of 1974 (PL-93-319) specifically exempted proposed actions under the Clean Air Act from NEPA requirements. According to section 7(c)(1), "No action taken under the Clean Air Act shall be deemed a major Federal action significantly affecting the quality of the human environment within the meaning of the National Environmental Policy Act of 1969."

The Agency has concluded, however, that the preparation of environmental impact statements could have beneficial effects on certain regulatory actions. Consequently, while not legally required to do so by section 102(2)(C) of NEPA, environmental impact statements will be prepared for various regulatory actions, including standards of performance developed under section 111 of the Act. This voluntary preparation of environmental impact statements, however, in no way legally subjects the Agency to NEPA requirements.

To implement this policy, a separate section is included in this document which is devoted solely to an analysis of the potential environmental impacts associated with the proposed standards. Both adverse and beneficial impacts in such areas as air and water pollution, increased solid waste disposal, and increased energy consumption are identified and discussed.

2.6 IMPACT ON EXISTING SOURCES

Section 111 of the Act defines a new source as ". . . any stationary source, the construction or modification of which is commenced . . ." after the proposed standards are published. An existing source becomes a new source if the source is modified or is reconstructed. Both modification and reconstruction are defined in amendments to the general provisions of Subpart A of 40 CFR Part 60 which were promulgated in the Federal Register on December 16, 1975 (40 FR 58416). Any physical or operational change to an existing facility which results in an increase in the emission rate of any pollutant for which a standard applies is considered a modification. Reconstruction, on the other hand, means the replacement of components of an existing facility to the extent that the fixed capital cost exceeds 50 percent of the cost of constructing a comparable entirely new source and that it be technically and economically feasible to meet the applicable standards. In such cases, reconstruction is equivalent to new construction.

Promulgation of a standard of performance requires States to establish standards of performance for existing sources in the same industry under section 111(d) of the Act if the standard for new sources limits emissions of a designated pollutant (i.e. a pollutant for which air quality criteria have not been issued under section 108 or which has not been listed as a hazardous pollutant under section 112). If a State does not act, EPA must establish such standards. General provisions outlining procedures for control of existing sources under section 111(d) were promulgated on November 17, 1975, as Subpart B of 40 CFR Part 60 (40 FR 53340).

2.7 REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, section 111 of the Act provides that the Administrator ". . . shall, at least every four years, review and, if appropriate, revise . . ." the standards. Revisions are made to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive but will apply to stationary sources constructed or modified after the proposal of the revised standards.

3. THE FOSSIL FUEL STEAM ELECTRIC UTILITY INDUSTRY

3.1 GENERAL

3.1.1 Description and Uses of Large Steam Generators

A large fossil fuel-fired steam generator is a unit of more than 73 megawatts (250 X 10^6 BTU/Hr) heat input. A 73 megawatt (250 X 10^6 BTU/Hr) steam generator produces enough steam to generate approximately 25 megawatts of electric power.[1,2] The largest fossil fuel-fired steam generators in the United States produce enough steam to generate 1300 megawatts.[3] As shown by Table 3-1, nearly all large fossil fuel-fired steam generators are sold to the electric utility industry for generation of electric power.[4] A few large steam generators are sold to produce steam for industrial use.

3.1.2 Electric Utility Industry Statistics

At the end of 1975, the total capacity of fossil fuel-fired steam generator power units was 347.7 gigawatts.[3] Table 3-2 shows statistics on 1975 fuel consumption.[3] As shown, 60 percent of the thermal energy was supplied by coal and the remainder was about equally split between gas and oil.

TABLE 3-1

COMPARISON OF ANNUAL SALES OF WATERTUBE GENERATORS[4]
TO UTILITIES AND TO ALL USERS
CAPACITIES >31.5 KILOGRAMS OF STEAM PER SECOND (250,000 lb/hr)

Year	Total Steam Capacity Sold Megagrams per Second (10^6 lb/hr) To All Users	Total Steam Capacity Sold Megagrams per Second (10^6 lb/hr) To Utilities
1961	13.02 (103.3)	12.40 (98.4)
1962	10.05 (79.8)	9.69 (76.9)
1963	14.92 (118.4)	13.94 (110.6)
1964	18.85 (149.6)	16.93 (134.4)
1965	24.03 (190.7)	21.37 (169.6)
1966	22.43 (178.0)	20.69 (164.2)
1967	26.11 (207.2)	24.99 (198.3)
1968	25.14 (199.5)	23.89 (189.6)
1969	27.00 (214.3)	24.99 (198.3)
1970	31.08 (246.7)	29.74 (236.0)
1971	18.60 (147.6)	17.83 (141.5)
1972	21.31 (169.1)	19.35 (153.6)
1973	33.30 (264.3)	30.47 (241.8)
1974	37.16 (294.9)	34.41 (273.1)
1975	13.37 (106.1)	11.37 (90.2)
1976	7.17 (56.9)	6.27 (49.8)
TOTAL	343.54 (2726.4)	318.33 (2526.3)

TABLE 3-2

FOSSIL FUEL CONSUMPTION FOR POWER GENERATION 1975[3]

Fossil Fuel	Consumption	Percent of Total Heat Input
Coal	366.1×10^9 Kilograms (403.6×10^6 tons)	60.0
Oil	72.50×10^6 Cubic Metres (456.0×10^6 Bbl)	19.2
Gas	8.38×10^{10} Cubic Metres (2.96×10^{12} Ft^3)	20.8

Table 3-3 shows 1974 United States total electric utility energy generation.[5] Additional electrical energy is generated by industry, remote domestic units, and by automobiles, aircraft, construction equipment, locomotives, and vessels. As shown in Table 3-3, about 79 percent of the 1974 electric utility energy was generated from fossil fuels. About 16 percent was generated by hydropower systems and about 6 percent was generated by nuclear power plants.

TABLE 3-3

1974 UNITED STATES ELECTRIC UTILITY POWER GENERATION[5]

Type	Power Generation Exajoules (10^9 Kw Hr)	Percent
Fuel Burning[(a)]	5.28 (1466)	78.5
Nuclear	.40 (110)	5.9
Hydropower	1.05 (291)	15.6
TOTAL	6.73 (1867)	100.0

(a) Includes oil and gas turbines

Table 3-4 shows use of 1974 electric utility generated energy by consuming sector.[5] As shown, about 58 percent of the total electrical energy was used for domestic or commercial purposes. About 42 percent was used by the industrial sector. Transportation uses very little of the electrical energy generated by power plants because it is more practical to equip mobile units with internal generating systems.

TABLE 3-4

UNITED STATES USE OF ELECTRICAL ENERGY[5]
BY CONSUMING SECTOR 1974

Sector	Exajoules Used (10^{15} Btu)	Percent
Household and Commercial	3.89 (3.69)	57.9
Industrial	2.81 (2.67)	41.8
Transportation[(a)]	0.02 (.016)	0.3
TOTAL	6.72 (6.37)	100.0

(a) Does not include electrical energy generated by transportation equipment, such as automobile generators, etc.

Table 3-5 shows total United States energy consumption by consuming sector and energy source[5]. As shown, United States energy is derived primarily from fossil fuels with small percentages derived from nuclear, hydropower, and geothermal energy sources. About 46 percent is furnished by petroleum, 30 percent by natural gas, and 18 percent by coal. About 27 percent of United States energy is used for electric power generation. About the same proportion is used by the industrial and transportation sectors. Household and commercial sectors use about 19 percent of the total energy. Most of the coal is used for electric power generation with other large use by the industrial sector. The transportation sector uses more than one-half of petroleum derived energy. Household and commercial, industrial, and electrical generation sectors use other large quantities of petroleum derived energy. As shown by Table 3-5, about one-half of the energy used by industry other than electrical energy comes from natural gas. Household and commercial and electrical generation sectors also use large volumes of natural gas. Little natural gas is used by the transportation sector.

3.1.3 New Source Growth Projections

For new source growth projections, see "Review of New Source Standards for SO_2 Emissions From Coal-Fired Utility Boilers, Volume 1, Non Air-Quality Impact Assessment," Teknekron, Inc., Emission Standards and Engineering Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, 1978.

TABLE 3-5 UNITED STATES PRIMARY ENERGY CONSUMPTION BY CONSUMING SECTOR AND ENERGY SOURCE[5] 1974
Exajoules (10^{15} Btu)

Consuming Sector[(a)]	Coal	Petroleum	Natural Gas	Nuclear	Hydropower and Geothermal	Total	Percent
Household and Commercial	0.31 (0.29)	6.75 (6.39)	7.51 (7.116)	--	--	14.57 (13.797)	18.9
Industrial	4.44 (4.208)	6.38 (6.044)	11.75 (11.129)	--	--	22.57 (21.415)	29.3
Transportation	<0.01 (<0.01)	18.59 (17.608)	0.70 (0.664)	--	--	19.29 (18.274)	25.0
Electrical Generation	9.15 (8.668)	3.64 (3.448)	3.51 (3.328)	1.24 (1.173)	3.19 (3.018)	20.73 (19.635)	26.9
Total	13.90 (13.169)	35.36 (33.490)	23.47 (22.237)	1.24 (1.173)	3.19 (3.018)	77.16 (73.121)	100.0
Percent	18.0	45.9	30.4	1.6	4.1	100.0	

(a) Excludes use of electrical energy by household, commercial, industrial and transportation sectors

3.2 FACILITES, FUELS, AND EMISSIONS

3.2.1 Facilities and Fuels

Large fossil fuel-fired steam generators are classified in several different ways as follows:

Fuel

Firing Method

Physical state of ash

Fluid flow

Draft

Manufacture

3.2.1.1 Common Characteristics[6]

Figure 3-1 shows a typical large fossil fuel-fired steam generator system. Although there is a wide difference among pulverized coal-fired steam generators, they have common characteristics. A common design objective is to produce the required quantity and quality of steam at minimum cost. Air preheated to as much as 315°C (600°F) by the combustion gases is introduced into the combustion chamber with the fuel through multiple burners strategically arranged to promote optimum combustion conditions. In the combustion chamber, the combustible matter reacts with the oxygen of the air to release thermal energy at temperatures exceeding 1100°C (2000°F).[6] The walls of the combustion chamber are lined with water-filled tubes which absorb thermal energy and generate steam. The water tubes are filled with liquid or vapor, depending on pressure and temperature conditions. Heat transfer in the combustion chamber cools the combustion gases to about 1100°C (2000°F).

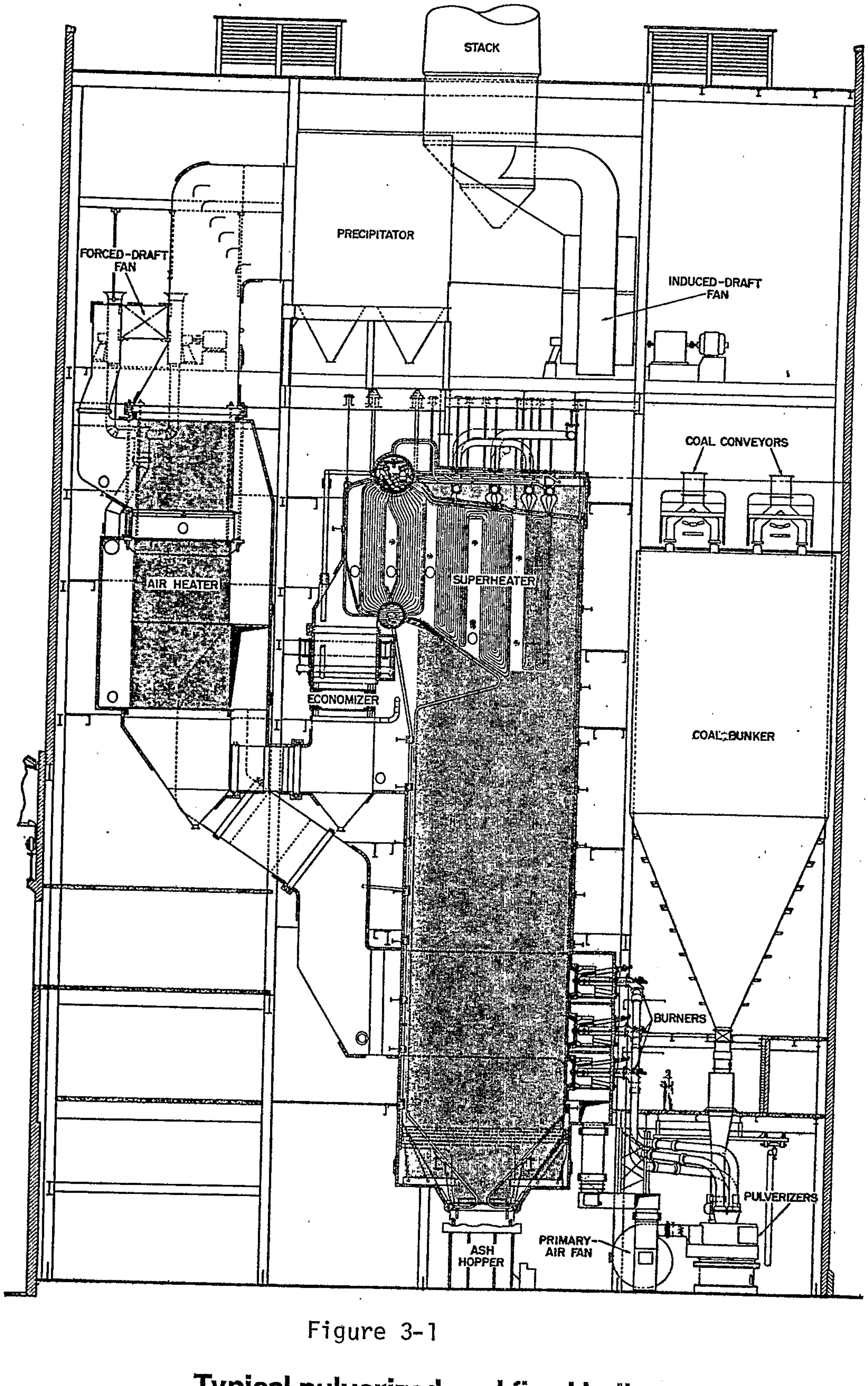

Figure 3-1

Typical pulverized coal fired boiler

The cooler combustion gases flow from the combustion chamber to the superheat and reheat sections of the steam generator where further heat transfer and gas cooling occur. Steam superheat and reheat are necessary for thermodynamic efficiency and also to prevent steam condensation which would damage the blades of the steam turbines which turn the electric power generators. Modern steam electric power generation systems use steam at pressures ranging from 13.8 to 27.6 megapascals (2000-4000 PSI) at a minimum temperature of about 540°C (1000°F). Steam turbines are designed in stages so that steam is sent back to the steam generator for reheat between stages. Most modern systems are designed with a superheat stage followed by a reheat stage. Some systems are designed with more than one reheat stage. The most efficient fossil fuel-fired-steam-electric system generates 3.6 megajoules (one kilowatt hour) of electrical energy from 9.2 megajoules (8714 Btu) of gross thermal energy input.[7] Most modern systems generate 3.6 megajoules (one kilowatt hour) of electrical energy from less than 10.60 megajoules (10,000 Btu) heat input.[7] Because of the thermal energy losses of the steam turbine thermodynamic cycle and the heat losses from the steam generator, less than 40 percent of the thermal energy of the fuel is converted to electrical energy. About 12 to 20 percent of the gross heat input is lost in the steam generation system and the remainder is lost in the steam turbine system, mostly as latent heat in the turbine condenser.

Combustion gases from the superheat and reheat sections flow to the economizer section where heat is transferred to the steam generator feedwater. Combustion gas temperature out of the economizer ranges from 315°C to 480°C (600-900°F). Combustion gases from the economizer flow to the air preheater. When hot-side electrostatic precipitators are used for fly ash collection, the dust collection system is located between the economizer and air preheater. With cold-side electrostatic precipitators, the dust collection system and flue gas desulfurization system, if any, are located after the air preheater and before the induced draft fan and stack. Baghouses and scrubbers are always installed after the air preheater. The air preheater heats the air flowing to the steam generator combustion chamber to as much as 315°C (600°F). Combustion gas temperature out of the air preheater ranges from 120°C to 200°C (250-400°F).

To minimize heat loss, large steam generator air preheaters are designed to reduce stack temperature to the lowest level which does not cause corrosion problems. Corrosion will occur in and after the air preheater if the combustion gas temperature falls below the dew point of sulfuric acid mist. Consequently, air preheaters are designed for higher outlet temperatures when high sulfur fuels are fired than when low sulfur fuels are burned. Heat losses from the steam generation system are also minimized by insulating hot surfaces and by minimizing the quantity of combustion air.

3.2.1.2 Fuels

Large fossil fuel-fired steam generators are designed to fire either coal, oil, or gas or a combination of these fuels. Since no new large oil or gas-fired steam generators are planned for the future, no data are reported for oil or gas fuels.[8,9,10,11] Table 3-6 shows selected

Table 3-6

CHARACTERISTICS OF SEVENTEEN SELECTED UNITED STATES COALS [6]

Coal Description	Proximate Analysis - Percent By Weight, Moisture Basis				Element Analysis - Percent By Weight, Dry, Ash-Free Basis					Heating Value Moist, Mineral Matter Free Megajoules/Kilogram (Btu/lb)
	Moisture	Volatile Matter	Fixed Carbon	Ash	S	C	H_2	O_2	N_2	
Pennsylvania Meta-Anthracite	4.5	1.7	84.1	9.7	0.77	93.9	2.1	2.3	0.3	33.22 (14,280)
Pennsylvania Anthracite	2.5	6.2	79.4	11.9	0.60	93.5	2.6	2.3	0.9	34.61 (14,480)
Virginia Semi Anthracite	2.0	10.6	67.2	20.2	0.62	90.7	4.2	3.3	1.0	35.68 (15,340)
W. Virginia Low Volatile Bituminous	1.0	16.6	77.3	5.1	0.74	90.4	4.8	2.7	1.3	36.29 (15,600)
Pennsylvania Low Volatile Bituminous	1.3	17.5	70.9	10.3	1.68	89.4	4.8	2.4	1.5	36.27 (15,595)
Pennsylvania Medium Volatile Bituminous	1.5	20.8	67.5	10.2	1.68	88.6	4.8	3.1	1.6	36.02 (15,485)
Pennsylvania Medium Volatile Bituminous	1.5	23.4	64.9	10.2	2.20	87.6	5.2	3.3	1.4	36.24 (15,580)
Pennsylvania High Volatile Bituminous	1.5	30.7	56.6	11.2	1.82	85.0	5.4	5.8	1.7	35.42 (15,230)
Kentucky High Volatile A Bituminous	2.5	36.7	57.5	3.3	0.70	85.5	5.5	6.7	1.6	34.98 (15,040)
Ohio High Volatile A Bituminous	3.6	40.0	47.3	9.1	4.00	80.9	5.7	7.4	1.4	33.45 (14,380)
Illinois High Volatile B Bituminous	5.8	36.2	46.3	11.7	2.70	80.5	5.5	9.1	1.6	31.89 (13,710)
Utah High Volatile B Bituminous	5.2	38.2	50.2	6.4	0.90	79.8	5.6	11.8	1.7	31.54 (13,560)
Illinois High Volatile C Bituminous	12.2	38.8	40.0	9.0	3.20	79.2	5.7	9.5	1.5	28.75 (12,360)
Montana Subbituminous A	14.1	32.2	46.7	7.0	0.43	80.9	5.1	12.2	1.3	28.09 (12,075)
Wyoming Subbituminous B	25.0	30.5	40.8	3.7	0.30	75.9	5.1	17.0	1.6	22.67 (9,745)
Wyoming Subbituminous C	31.0	31.4	32.8	4.8	0.55	74.0	5.6	18.6	0.9	20.45 (8,790)
North Dakota Lignite A	37.0	26.6	32.2	4.2	0.40	72.7	4.9	20.8	0.9	17.70 (7,610)

properties of a variety of United States coals.[6] As shown, the Western coals usually have low sulfur content, high moisture content, and low heating value. Eastern coals contain less moisture and have a higher heating value. The sulfur content of Eastern coal ranges from less than 1 percent to more than 4 percent.[3]

3.2.2 Emissions

3.2.2.1 General

Emissions from large fossil fuel-fired steam generators include particulates, sulfur oxides, oxides of nitrogen, carbon monoxide, halogens, trace metals and hydrocarbons, including polycyclic organic matter. The discussion of this section is limited to particulates, primarily particulates from pulverized coal-fired steam generators.

3.2.2.2 Nationwide Particulate Emissions

Table 3-7 gives a summary of 1976 estimated particulate emissions from all sources.[12] As shown, particulate emissions from stationary combustion sources were 4.6 teragrams (5.1×10^6 tons) per year as compared with 13.4 teragrams (14.9×10^6 tons) per year from all sources and were about 34 percent of all particulate emissions.

Table 3-8 shows estimated 1976 particulate emissions from stationary combustion sources.[12] As shown, estimated 1976 particulate emissions from the large fossil fuel-fired generators used by the electric utility industry were 3.24 teragrams (3.57×10^6 tons per year) as compared with 4.34 teragrams (4.78×10^6 tons) per year from all stationary source combustion or about three-quarters of combustion particulate emissions. As shown, nearly all of the particulates from electric utility sources were emitted from coal-fired units.

TABLE 3-7

NATIONWIDE PARTICULATE EMISSION ESTIMATES 1976 [12]

Teragrams Per Year (10^6 tons/yr)

Source Category	
Transportation	1.2 (1.3)
Highway	0.8 (0.9)
Non-Highway	0.4 (0.4)
Stationary Fuel Combustion	4.6 (5.1)
Electric Utilities	3.2 (3.6)
Other	1.4 (1.5)
Industrial Processes	6.3 (7.0)
Chemicals	0.3 (0.3)
Petroleum Refining	0.1 (0.1)
Metals	1.3 (1.5)
Mineral Products	3.2 (3.5)
Other	1.4 (1.6)
Incineration	0.4 (0.5)
Miscellaneous	0.9 (1.0)
Forest Wildfires	0.5 (0.6)
Forest Managed Burning	0.1 (0.1)
Agricultural Burning	0.1 (0.1)
Coal Refuse Burning	0.1 (0.1)
Structural Fires	0.1 (0.1)
Total	13.4 (14.9)

TABLE 3-8

SUMMARY OF 1976 NATIONWIDE PARTICULATE EMISSIONS[12]
FROM STATIONARY FOSSIL FUEL COMBUSTION SOURCES

Particulate Emissions = Teragrams Per Year (10^6 Tons/Yr)

	Coal	Oil	Gas	Total
Electric Utilities	3.10 (3.42)	0.13 (0.14)	0.01 (0.01)	3.24 (3.57)
Industry Except Light Industry	0.71 (0.78)	0.07 (0.08)	0.04 (0.04)	0.82 (0.90)
Residential-Commercial and Light Industry	0.15 (0.16)	0.10 (0.11)	0.04 (0.04)	0.28 (0.31)
Total	3.96 (4.36)	0.30 (0.33)	0.09 (0.09)	4.34 (4.78)

3.2.2.3 Uncontrolled Emissions From Coal

Although the mass emission of particulates cannot be predicted exactly, a conservative value can be estimated by assuming that about 80 percent of the ash of coal is entrained in the combustion gases of pulverized coal-fired steam generators[13]. Consequently, high ash coals generate more particulates than low ash coals.

When the heating value and ash content of coal is known, uncontrolled particulates can be estimated in terms of mass per unit heat input according to the following equation:[2,13]

$$E_m = \frac{8\ A}{Qm}$$

Where:

E_m = Emission rate - micrograms per joule

A = Ash content - percent

Qm = Gross heating value - megajoules per kilogram

or, in English units:

$$E_e = \frac{8000\ A}{Qe}$$

Where:

E_e = Emission rate - lbs/10^6 Btu

A = Ash content - percent

Qe = Gross heating value - Btu/lb

The foregoing equations are useful for estimating control efficiency requirements when particulate regulations are given in terms of mass per unit heat input.

The mass concentration of uncontrolled particulates in the combustion gases of pulverized coal-fired steam generators can be estimated by using the following equations:[2,13,14]

$$C_{I_m} = \frac{24.30A}{Qm}$$

and

$$C_{O_m} = \frac{20.95A}{Qm}$$

Where:

C_{I_m} = Particulate concentration at air preheat inlet - grams per dry standard cubic metre

C_{O_m} = Particulate concentration at air preheat outlet - grams per dry standard cubic metre

Qm = Gross heating value - megajoules per kilogram

A = Ash content - percent

or in English units:

$$C_{I_e} = \frac{4562A}{Qe}$$

and $$C_{O_e} = \frac{3933A}{Qe}$$

Where:

C_{I_e} = Particulate concentration at air preheat inlet - grains per dry standard cubic foot

C_{O_e} = Particulate concentration at air preheat outlet - grains per dry standard cubic foot

A = Ash content - percent

Q_m = Gross heating value - Btu per pound

These equations assume:

1. 263.36 dry standard cubic millimetres per joule (9820 DSCF/10^6 Btu) at 0 percent excess air.[14]
2. 25 percent excess air at the air preheat inlet, and[2]
3. 45 percent excess air at the air preheater outlet.[2]

The foregoing values are also useful for estimating gas flow at the air preheater inlet and outlet. Actual volumes will usually be less than the volumes calculated using these assumptions.

When emission test results are given in terms of mass per unit volume, these values can be converted to units of mass per unit heat input when the percent oxygen at the sampling location is known.[2,14]

Metric Units

$$\text{Nanograms per joule} = 263.36 \left(\begin{array}{l}\text{Particulate concentration} \\ \text{in grams per dry standard} \\ \text{cubic metre}\end{array}\right) \left(\frac{20.9}{20.9 - \%\ O_2}\right)$$

English Units

$$\text{Pounds per million Btu} = 1.4029 \left(\begin{array}{l}\text{Particulate concentration} \\ \text{in grains per dry} \\ \text{standard cubic foot}\end{array}\right) \left(\frac{20.9}{20.9 - \%\ O_2}\right)$$

3.2.2.4 Uncontrolled Emissions From Residual Oil Combustion

Uncontrolled particulate emissions from residual oil combustion are estimated as follows:[13]

Residual Oil Grade	Uncontrolled Particulate Emissions
No. 6	1.25S + 0.38 kilograms per thousand litres (10S + 3 pounds per thousand gallons)
No. 5	1.25 kilograms per thousand litres (10 pounds per thousand gallons)
No. 4	0.88 kilograms per thousand litres (7 pounds per thousand gallons)

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4. PARTICULATE CONTROL TECHNOLOGY FOR COAL-FIRED STEAM GENERATORS

4.1 GENERAL

The device most commonly used for high efficiency removal of particulates from the combustion gases of coal-fired steam generators is the electrostatic precipitator. The use of baghouses for high efficiency particulate control is becoming more widespread, especially for cases where the coal ash is difficult to collect in an electrostatic precipitator.[1] When flue gas desulfurization systems are required, particulate scrubbing is often incorporated into the air pollution control system.

Mechanical collectors such as cyclones and settling chambers are not efficient enough to reduce particulate emissions from pulverized coal-fired steam generators to the levels required by current new source performance standards.

4.2 ELECTROSTATIC PRECIPITATOR (ESP) SYSTEMS

4.2.1 Description

Figure 4-1 shows a cutaway of a typical ESP system applied to pulverized coal-fired steam generators. The ESP system serves the function of particle charging, particle collection, removal of the material from the collection electrodes, and disposal of the collected ash.

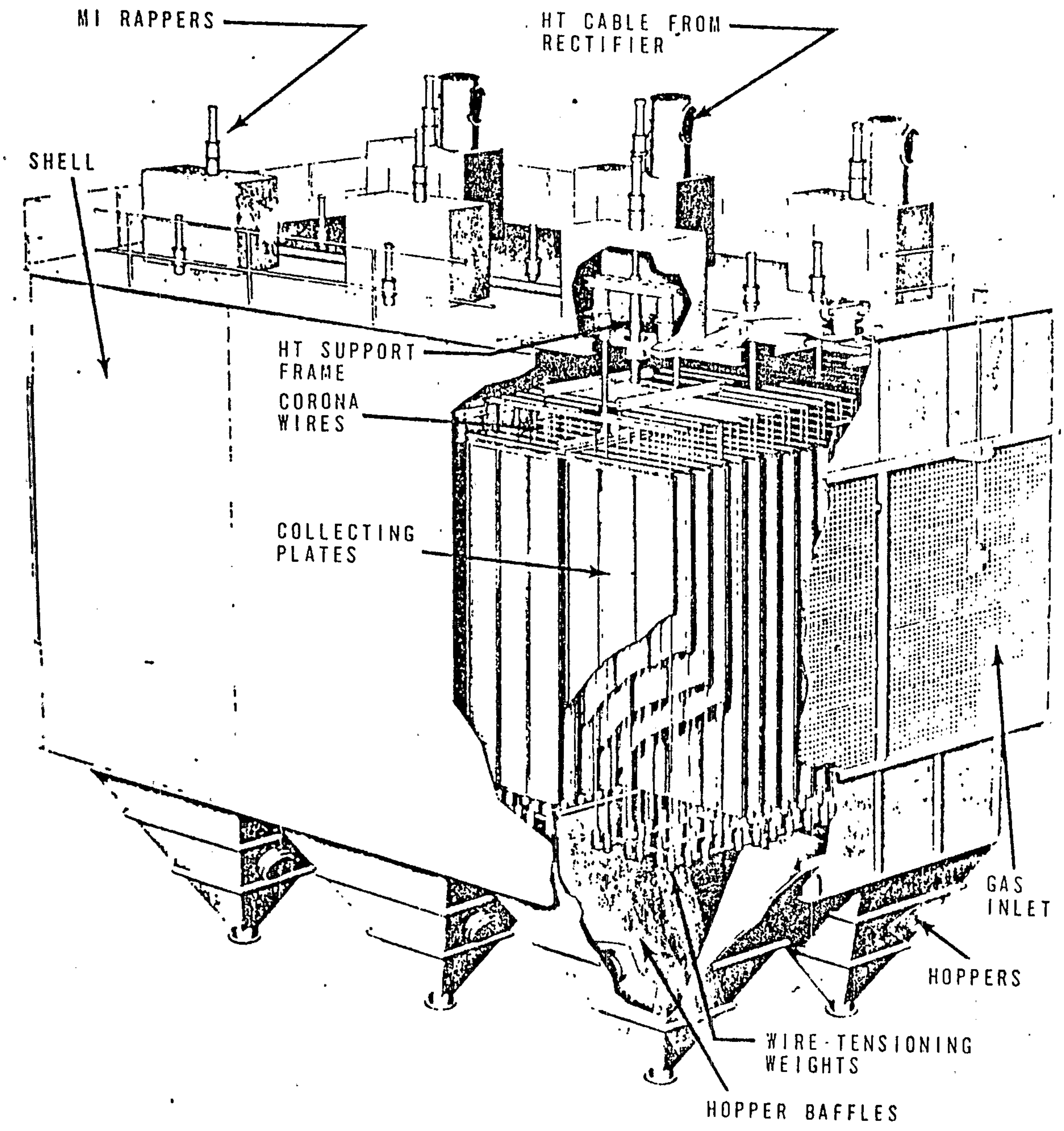


Figure 4-1. Major design features of a common ESP.

Primary electric power is usually 240 or 480 volt alternating current. Transformer-rectifier sets are used to convert the current from alternating to direct and to step up the secondary voltage. High efficiency ESP systems are equipped with power controls which regulate power at the optimum levels for particulate collection. Secondary voltages range from 10,000 to 40,000 volts depending upon particulate and gas characteristics.

Rapping systems are designed to dislodge the collected ash by striking the collecting surface with metal hammers. Rapping systems are equipped with controls which permit adjustment of the frequency and intensity of rapping. This controls the build up of dust on the collection surfaces. High efficiency ESP systems are equipped with multiple hoppers and baffles which minimize the tendency for gases to bypass the electrical field (sneakage).

4.2.2 Performance Factors

ESP performance is affected by several factors such as:[2]

1. Coal ash characteristics
2. ESP size
3. Grounded collection surface spacing
4. Power control design
5. Gas flow distribution
6. Rapping control design
7. Fly ash handling sytem design
8. Thermal expansion design
9. Discharge electrode failure
10. Maintenance practices and
11. Gas conditioning

All of these factors can be related by the following equations:[2]

(1)

$$F_m = \frac{100}{W_m} \ln \frac{100}{100-E}$$

Where F_m = ESP plate area - square metres per actual cubic metre per second

W_m = Particle drift velocity - centimetres per second

E = Particle collection efficiency - percent

or expressed in English Units

(2)

$$F_e = \frac{16.67}{W_e} \ln \frac{100}{100-E}$$

where

F_e = ESP plate area - square feet per 1000 actual cubic feet per minute

W_e = Particle drift velocity - feet per second

E = Particle collection efficiency - percent

Although the foregoing equations might make it appear that predicting the performance of an ESP system is simply a matter of substituting numbers for W and E and then calculating the size required (F), predicting ESP performance is actually very difficult. This is because W and E are a function of numerous factors such as the eleven factors previously named. Even with the most comprehensive data base it is not possible to exactly quantify the effect of these factors on performance. Consequently, the designer usually applies conservative safety factors or provides for the installation of additional collecting surface area should the original installation fail to perform according to design expectations.

Coal ash characteristics vary. Some coal ash is relatively easy to collect and other coals produce an ash which requires much larger ESP systems.[2] When designing new ESP systems, the best data base for predicting size requirements is performance data on a full scale ESP system applied to a coal-fired steam generator firing the same coal that will be fired in the new steam generator. This data is available for plants which are adding another steam generator which will fire the same coal as that fired in existing units or for entirely new plants which will purchase coal supplies from the same mine as another operating plant. When the existing data base is for the same coal and the same efficiency as the design requirements of the new ESP system, ESP size requirements can be predicted more accurately than if these factors are not known.

For situations where there is no experience with the particulate to be handled, coal ash analyses provide valuable data for selecting the size and types of ESP required to achieve the desired efficiency. Ash analyses include measurement of chemical composition and resistivity measurements. Chemical composition of ash includes LiO_2, Na_2O, K_2O, MgO, CaO, Fe_2O_3, Al_2O_3, SiO_2, TiO_2, P_2O_5, SO_3, and loss on ignition.[2] Ash resistivity is measured at temperatures ranging from 70°C to 500°C (150-900°F) and a resistivity versus temperature curve is plotted such as the one simulated in Figure 4-2.[2]

Ash resistivity is a major factor affecting the size of an ESP system.[2] Although low resistivity can make it difficult to collect particulates in an electrostatic precipitator, the resistivity of coal ash is characteristically above the range where low resistivity problems occur. Consequently, coal ash resistivity problems are largely limited to coals which produce a high resistivity ash.

Figure 4-2 shows a typical resistivity-temperature curve for a high resistivity ash. As shown, there is a temperature where resistivity is maximum. For high resistivity ash, collection in an electrostatic precipitator is the most difficult at maximum resistivity. For high resistivity ash coals, the temperature at maximum resistivity usually lies in the same range as the temperature of the gas out of the steam generator air preheater (cold side). The resistivity of the ash entering the air preheater (hot side) is much less at temperatures ranging from 315-480°C (600-900°F). Consequently, high resistivity coal ash is easier to collect on the hot side than on the cold side. However, this does not always mean that a smaller ESP can be applied on the hot side than on the cold side because gas volume is greater on the hot side. The designer decides if a hot side or a cold side ESP is less costly by taking into account the following factors:[2]

1. The temperature-resistivity characteristics of the ash
2. Specific collection area requirements
3. Differences in gas volume caused by temperature differences
4. Differences in gas volume caused by air leakage into the air preheater and
5. Differences in construction requirements caused by temperature differences.

At times even the most expert designers differ on whether a hot side or a cold side ESP is the least costly for a given application.

Although grounded collecting surface area spacing has an important effect on the performance of an ESP system, it is better

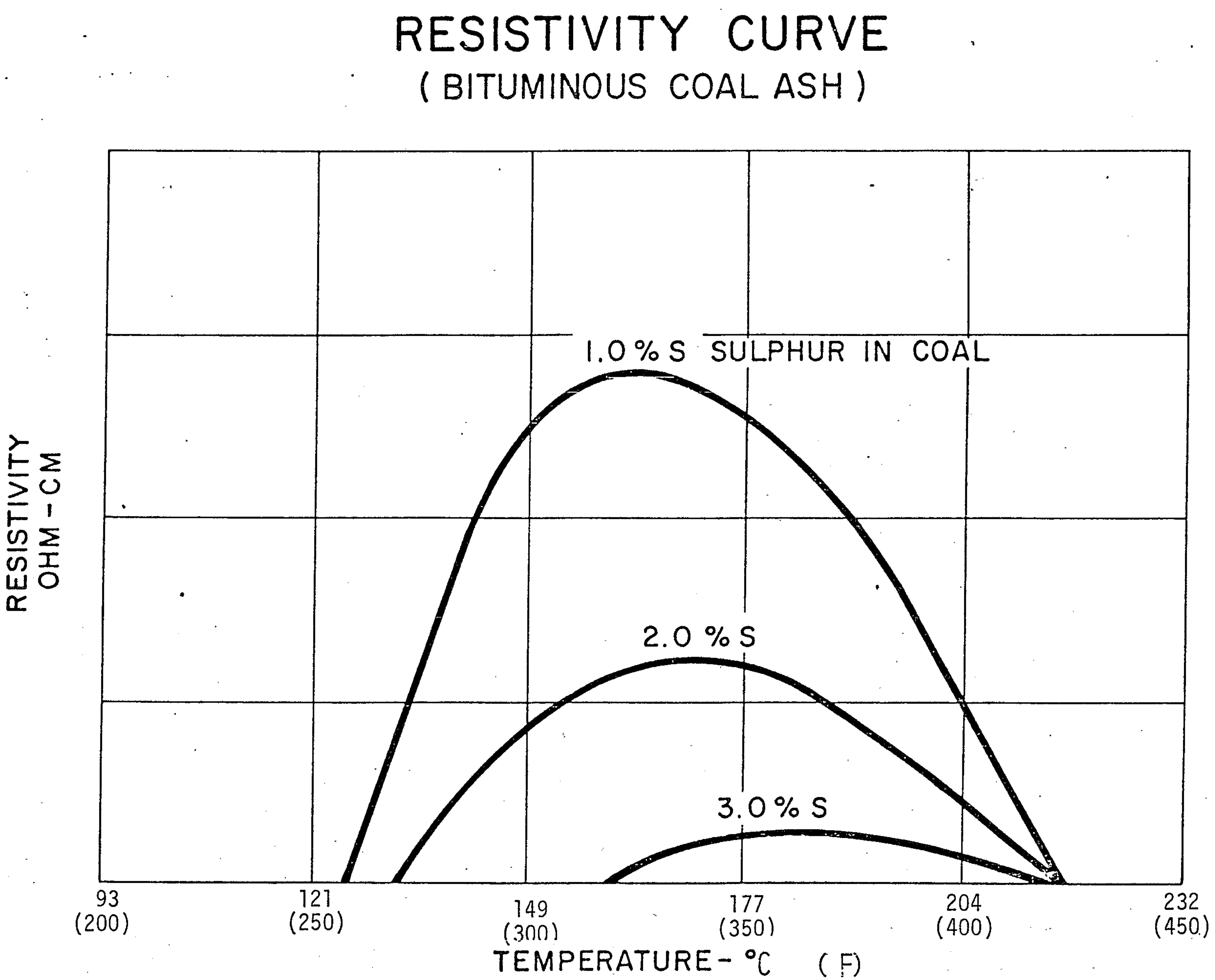

RESISTIVITY CURVE
(BITUMINOUS COAL ASH)
1.0 % S SULPHUR IN COAL
2.0 % S
3.0 % S
RESISTIVITY
OHM - CM
93
(200)
121
(250)
149
(300)
177
(350)
204
(400)
232
(450)
TEMPERATURE - °C (F)

Figure 4-2.

to rely on the judgment of the vendor rather than to set specifications. Most vendors space grounded collecting surface areas 25 centimetres (9 in.) apart. All vendors center the discharge electrodes between the collecting surfaces.[2]

The ESP power control system regulates the power to the discharge electrodes to provide the optimum current and voltage conditions for maximum collection efficiency. The power controls are usually adjusted by the vendor after activation of the unit. Numerous separate power control systems on a single ESP unit provide a safety factor in case of an electrical failure in one part of the ESP system. Separate power controls also improve the efficiency of collection because the separate controls can be adjusted to compensate for different electrical input requirements as the gases flow from the inlet to the outlet of the system. The instrumentation for modern designed ESP systems includes instruments which indicate: (1) primary current, (2) secondary current, (3) primary voltage, (4) secondary voltage, and (5) spark rate for each separate power control system. For large ESP systems there are several hundred separate indicating devices and at times, more than 100 separate control systems.[2]

Poor gas flow distribution can seriously impair the performance of an ESP system. With poor distribution, the gases flow at high velocity through some parts of the system and at low velocity, through other parts. Both mathematical analysis and field performance tests show that poor gas flow distribution reduces collection efficiency.[2] Gas flow distribution is the best when small scale shop models are studied prior to construction and when gas flow distribution adjustments are made under cold conditions in the field. Technology is not developed for measuring gas flow distribution when the electrical system of an ESP is energized.

When the ash is removed from the collecting surface there is reentrainment as the material falls to the hopper below. Reentrainment is less when the deposits fall as a sheet to the hopper. If the deposit becomes too thick, this interferes with collection efficiency because of the increased resistance of the deposit. Control of rapping involves rapping the collecting surfaces with sufficient intensity without damaging the surfaces to remove the maximum proportion of deposit while minimizing reentrainment. These parameters are usually controlled automatically and are adjusted in the field. The use of separately controlled rapping systems is beneficial because the amount and characteristics of the ash deposits vary from the inlet to the outlet. Larger amounts of ash and coarser ash are collected at the inlet.

At times an otherwise well designed ESP system may fail to function properly because of problems with fly ash handling. If the ash is not removed from the hoppers at at least the rate of accumulation, ash will fill the hopper. When this happens, ash will fill the space between the collecting surfaces and will touch the discharge electrodes. This shorts out the affected sections, thereby destroying the effectiveness of the ESP system. Common causes of ash buildup are:

1. Sticky ash or an inadequate system for rapping the sides of the hopper.
2. Undersized outlet openings.
3. Undersized star feeders or other sealing devices.
4. Undersized ash conveying systems.
5. Mechanical and/or electrical failures.

Failure to provide properly for thermal expansion can also cause otherwise well designed ESP systems to function improperly. Unequal expansion can cause buckling of collecting surfaces. This changes the distance between the discharge electrodes and the collecting surfaces and destroys the effectiveness of the affected sections. Unequal expansion can also rupture the ESP housing. When this happens, air leaks into the ESP system. This disturbs flow volumes and patterns and causes ash reentrainment. The increased gas volume caused by leakage also reduces the efficiency of the ESP system.[2]

Discharge electrode failures are not unusual. Failures of the insulators which minimize current leakage to ground are usually caused by dust deposits or cracks in the insulator. Provision for minimizing these types of problems are incorporated in the original design. If the discharge electrode wires become too thin at any point, the wires will break and will ground out on the collecting surfaces. When weights are used for suspension, the weights will fall to the hopper below. This can block fly ash handling systems.[2]

Wire breakage is controlled in a stepwise manner. When breakage occurs, loose ends are trimmed off at the earliest opportunity. This is usually done during a short term shutdown. Because there are many discharge electrodes in each electrical section, cutting off a few wires has little measurable effect on the ESP system performance. Eventually, the wires are replaced when the unit is shut down for long term maintenance, such as where there is a week or more shutdown for maintenance of the entire steam generator system.[2]

Although gas conditioning is not developed to the state where it is certain beneficial results will always ensue, this technique has promise for improving the collection characteristics when high resistivity ash coals are fired.[2,3,4] If ash collection characteristics are improved by gas conditioning, smaller ESP systems can be used to achieve the desired emission control limits. The most common conditioning agents are acidic sulfur compounds such as SO_3 or H_2SO_4 or compounds which release these substances.[3,4] Other compounds such as particulate agglomerating compounds are also used. Although these agents are added in concentrations which do not significantly increase total SO_2 emissions, it is possible that sulfate or sulfuric acid mist emissions could be increased. Data on these latter potential sulfur oxide effects are not conclusive.[2] Ammonia and steam have also been used for gas conditioning.[2]

4.3 BAGHOUSE SYSTEMS

4.3.1 Description

In a baghouse system dust laden gas is passed through a fabric in such a manner that dust particles are retained on the upstream or dirty-gas side of the fabric thereby cleaning the gas. Figure 4-3 shows a cutaway of one type of baghouse system. For this type of system, the dirty gases flow into the housing, upward through the bags, and then out of the clean gas outlet. The gases are moved by a fan installed at the outlet of the baghouse. The system shown in Figure 4-3 is designed for inside-out filtration. Consequently, the pressure differential inflates the bags. Some systems are designed for outside-in filtration.[1] In this case, it is necessary to use stiffening devices to prevent bag collapse during filtration.[1]

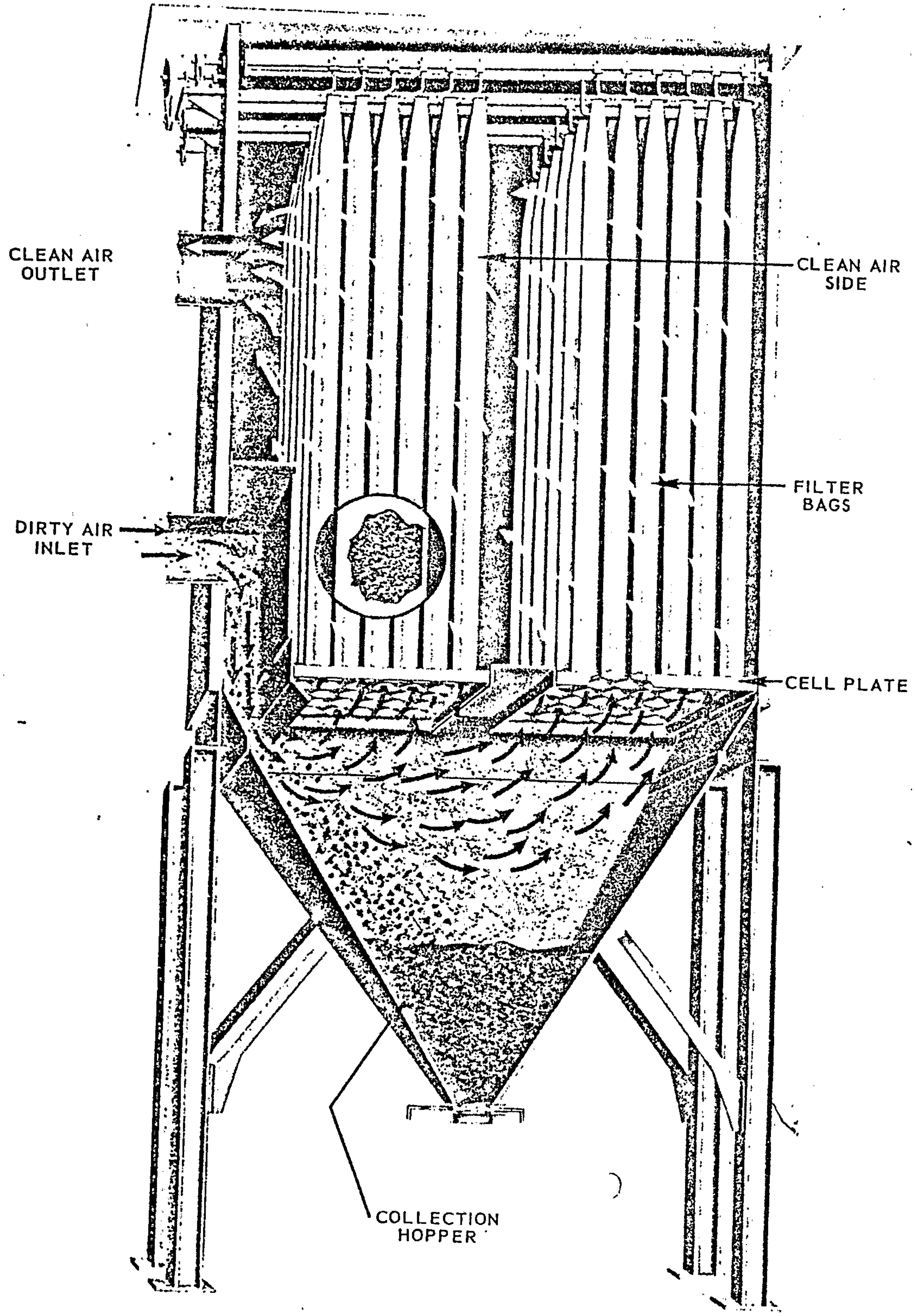
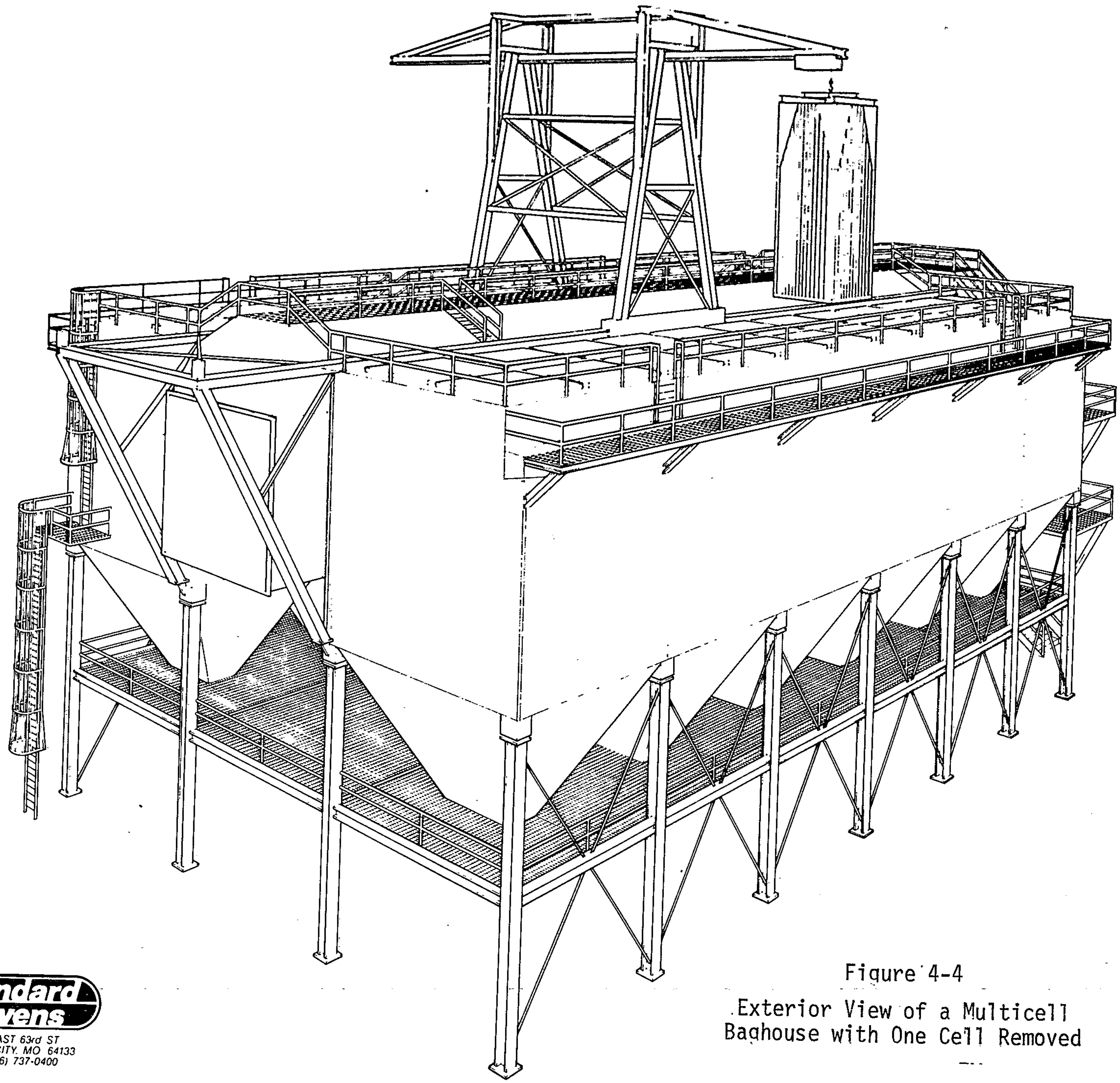


Figure 4-3

A Simple Two Cell Inside Out Baghouse Equipped for Shake Cleaning

Baghouse systems are divided into separate compartments or cells. This allows one compartment to be cleaned while the others are in service. At times, baghouse systems are designed so that bags can be inspected and replaced in one compartment while the other compartments are in service. Figure 4-4 shows a multicell baghouse with one set of bags removed for inspection. The entire system included within a single housing is called a baghouse module. Large baghouse systems can be designed as one module or as several modules. With several modules, one module can be taken out of service for maintenance without affecting the operation of the other modules. If enough modules or isolated compartments are provided, even the largest pulverized coal-fired steam generators can be kept on line at full load while necessary maintenance is performed.[1]

Common methods employed for cleaning the ash from the bags of fabric filter systems of coal-fired steam generators are reverse air and pulse jet cleaning. These techniques may be employed with or without shake assist. Figure 4-5 shows one type of reverse air cleaning cycle. With reverse air cleaning the clean gas outlet of an individual compartment is shut off from the main gas stream. During this period the other compartments handle the dirty gas load. After the outlet is closed, a reverse air fan is used to reverse the flow through the bags. Usually the reverse air fan circulates cleaned combustion gas. When the baghouse is designed for inside-out filtration, the reverse flow will collapse the bag unless stiffening devices are employed. The reverse flow dislodges the ash collected on the bags and causes the ash to fall to the hopper below. The dirty reverse air gas flows into the dirty gas stream and is cleaned by the bags in other compartments of the baghouse. With jet pulse cleaning,



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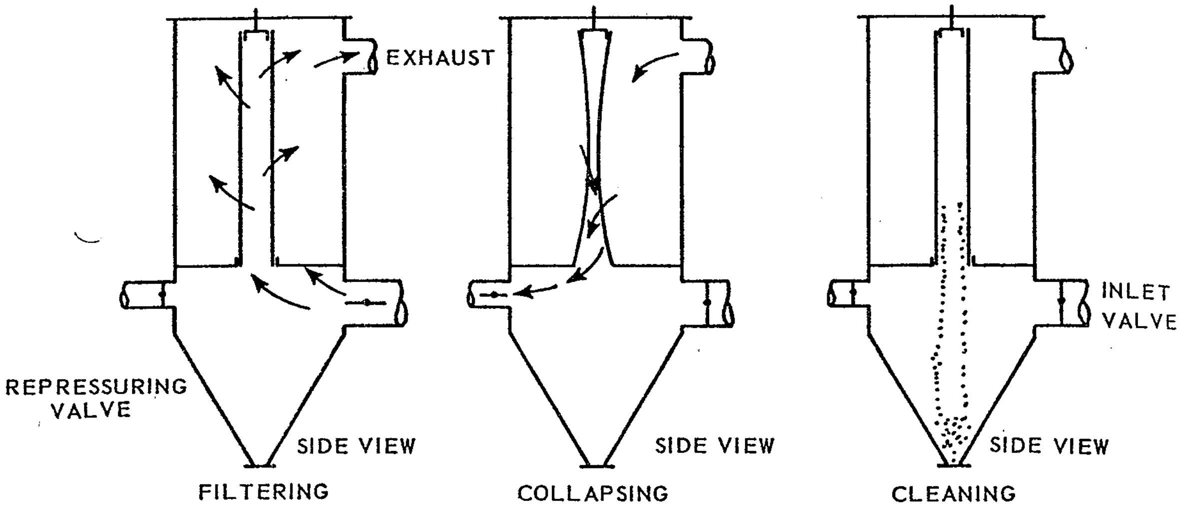
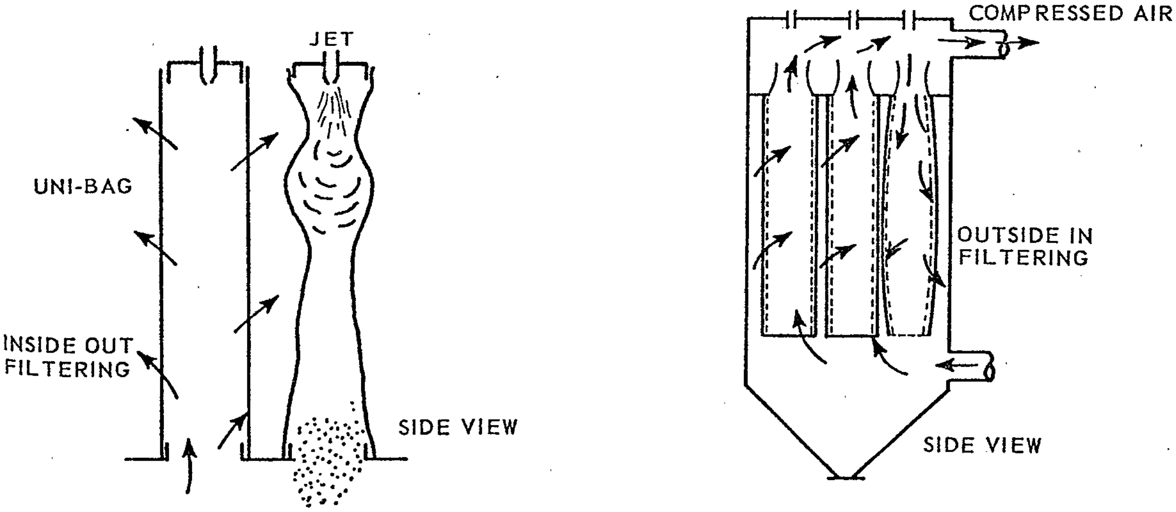
8800 EAST 63rd ST
KANSAS CITY, MO 64133
TEL (816) 737-0400

Figure 4-4
Exterior View of a Multicell Baghouse with One Cell Removed



Operating Cycle for Reverse Air Cleaning
Inside-Out Filtration

Figure 4-5



Operating Cycle for Pulse Jet Cleaning
Inside Out and Outside In Filtration

Figure 4-6

as shown in Figure 4-6, individual bags are exposed to short blasts of clean air. The duration of the blasts is usually less than one second. The blasts cause ripples in the bag fabric which dislodge the ash. Either reverse air or pulse jet cleaning techniques can be combined with mechanical shaking techniques. Mechanical shaking causes ripples in the fabric which dislodge the ash. Some baghouses are designed for either or both reverse air and pulse jet cleaning.

4.3.2 Performance Factors

Baghouse performance is affected by several factors, such as

1. Bag material
2. Bag construction
3. Bag treatment
4. Baghouse size.
5. Baghouse configuration and control
6. Cleaning techniques
7. Tube sheet construction
8. Process characteristics
9. Maintenance practices

Bag material, construction, and treatment are very important factors which affect baghouse performance. The permeability of the fabric must be high enough to minimize pressure drop while at the same time effectively filtering out the fly ash from the gas stream. Frazier permeability is expressed in English units of actual cubic foot of air passing through a square foot of cloth at 0.5 inches of water pressure drop.[5] Frazier permeability can be converted from English units to metric units of cubic metres per minute per square metre by multiplying the English Frazier units by a factor of 0.305. Table 4-1 shows the differences in air permeability for new, used, and used-vacuum cleaned bags.[5] As shown, the air permeability for used bags was much lower than the air permeability of new or used- vacuum cleaned bags.

The bag fabric must be resistant to the effects of chemical attack, abrasion, and temperature. Glass fabrics are used for most modern baghouses installed on coal-fired steam generators. Glass bag finishes such as silicones, resins, graphite, and Teflon(R) are used for improvement of abrasion resistance. Other types of synthetic fabrics are also employed and are specified by fabric filter system vendors.

Unlike electrostatic precipitator systems, where undersizing does not affect the capacity of the steam generator, but does affect the effectiveness of the emission control system, the penalty for undersizing a baghouse is loss of boiler capacity. Full load pressure drops range from 0.75 to 2.5 kilopascals (3-10 in. H_2O). Section 4.5 discusses air to cloth ratios, effectiveness, and pressure drops for operating baghouses.

Baghouse configuration and control have a significant effect on baghouse performance in the field. For baghouses designed for cleaning the bags off line, multi-cell construction is a necessity.[1] Multi-cell construction also has several other advantages. Athough there is no specific criteria for the number of bags per cell, the number of bags is usually small enough to facilitate rapid location of worn or leaky bags or other leakage once a faulty cell is identified.[1] In cases where bags

Table 4-1

AIR PERMEABILITY OF NEW, USED, AND USED-VACUUM CLEANED BAGS[5]

Condition	Frazier Permeability Metres per Minute per Square Metre (CFM/Ft^2)
New Bag	16.6 (54.3)
Used Bag 1	0.335 (1.1)
Used Bag 2	0.488 (1.6)
Used-Vacuum Cleaned Bag 1	9.30 (30.5)
Used-Vacuum Cleaned Bag 2	12.2 (40.0)

are cleaned off line, the number of cells per baghouse are designed to minimize the increase in pressure drop when one cell is off line for cleaning.

Controls often include provision for remote control of the inlet and outlet valves for each cell. With this type of control, faulty cells can be located by shutting off various sections of the baghouse while observing the opacity of the plume. Some baghouses are designed for isolation of faulty cells to permit repairs within a cell while the rest of the baghouse is in service. If there are numerous cells and the baghouse is properly sized, baghouses can be serviced without loss of power generating capacity.[1]

The fabric filter system controls usually provide for automatic cleaning with provisions for adjusting the frequency and duration of cleaning. The baghouse can be equipped so that cleaning can be implemented either by a time cycle or by pressure drop. With timing control, the cells of a baghouse are cleaned at predetermined intervals which keep the pressure drop below 1.25 kilopascals (5 in. of H_2O). With pressure control, a predetermined cleaning cycle is initiated each time the pressure drop across the baghouse exceeds 1.25 kilopascals (5 in. of H_2O). With the foregoing types of controls and multi-cell design, even the largest steam generator can be operated without downtime for repairs or maintenance of the particulate control system.[1] When the boiler is operated at low loads, it is often necessary to shut off part of the baghouse to keep gas temperature high enough to prevent acid attack.

A variety of techniques are used for cleaning filtered particulates from the bags. The prime methods used are: (1) shake, (2) pulse jet, and (3) reverse air cleaning. Sometimes more than one of the foregoing cleaning techniques are used in combination or the baghouse is designed so that the operator can select operation in either a single cleaning mode or in a combination cleaning mode. One baghouse described in Section 4.5 is designed so that the operator can operate the baghouse with (1) pulse jet cleaning, (2) reverse air cleaning, or (3) both pulse jet and reverse air cleaning. Providing for multiple cleaning capabilities provides a safety factor in case particulate characteristics differ from design expectation.

With shake cleaning,the bags are cleaned in a manner similar to shaking a rug. Too violent shaking damages the bags. Too gentle shaking can fail to remove enough particulate causing pressure drop to exceed design specifications. Consequently, controls are needed to permit adjustment of the intensity, frequency, and duration of shaking.

With pulse jet cleaning, each individual bag is subjected to a high intensity blast of air. Pulse jet cleaning air is supplied at about 690 kilopascals (100 PSI) and pulse time is about 0.1 second.[1] Pulse jet units are usually designed so that pulse time, the interval between pulses, the number of pulses, and the frequency of cleaning can be adjusted. Pulse jet cleaning causes ripples in the bags which dislodge the filtered particulate. Pulse jet cleaning can be accomplished either while the bag is filtering combustion gases or with the cell off line.

For combustion sources, most reverse air cleaning systems actually operate with cleaned combustion gas instead of air. Multi-cell baghouse design is a necessity when reverse air cleaning is employed. With reverse air cleaning, the clean gas outlet of a cell or a bank of cells is shut off. Then cleaned combustion gas from a separate reverse air fan is forced from the clean side to the dirty side of the bag in a reverse direction. This dislodges collected particulates. The dirty gas from the cleaning operation flows in a reverse direction through the open dirty side inlet of the cell being cleaned to the dirty side inlets of other cells within the baghouse which are operating in the normal filtration mode. Thus, any particulates entrained by reverse air cleaning are filtered from the gas before the gases flow to the stack.

For a small reverse air type baghouse, normal cleaning involves cleaning one cell at a time. For baghouses with the large numbers of cells, banks of cells are cleaned in common. This leaves the other compartments in the normal filtration mode while the one or one bank of cells being cleaned are off line. For a ten cell system, the available cloth area is reduced by ten percent during cleaning. The cleaning controls are sometimes set so that compartments are continuously cleaned on a cyclic basis, one at a time. Another cleaning option when particulate loadings are low is to initiate a cleaning cycle on a time basis. For example, a baghouse might be operated forty minutes without cleaning at which time a cleaning cycle would be initiated. During cleaning each cell is cleaned separately during a total time period of, perhaps, five minutes. Then forty more minutes of filtration elapses without cleaning. With the latter type of reverse air cleaning, it is possible to shut down the reverse air fan during the forty minute periods between cleaning. Well designed reverse air type baghouses are equipped for adjusting reverse air flow, the frequency of cleaning, and duration of cleaning.

Too much reverse air can impair the efficiency of filtration. Too little reverse air or infrequent cleaning can cause operating pressures to exceed 1.25 kilopascals (5 in. H_2O).[6]

When outside in filtration is employed, each bag must be fitted with a anti-deflation device. Some manufacturers sew metal rings into the bags to prevent collapse during outside in gas flow.[6] Other manufacturers fit the bags over wire cages to prevent collapse.[1] With inside out filtration, no anti-deflation device is needed during filtration since gas pressure inflates the bag. However, manufacturers usually equip inside out bags with anti-deflation devices to prevent collapse if reverse air cleaning is employed.

Baghouses have tube sheets which prevent the leakage of dirty gas to the clean gas side of the bags. The bags are secured to fittings on the tube sheet as shown in Figure 4-7.[1] Because of the change in velocity and direction of gas flow when gases enter the bag in inside out filtration, turbulence is great at the inlet. This turbulence can cause excessive bag wear at the inlet.[1] Consequently, several manufacturers use metal tubular extensions at the point where the gases enter the bag.[1] Other manufacturers design for outside in filtration to minimize wear caused by turbulence.[1]

Maintenance is a key element affecting the performance of baghouses. Since there are usually no visible emissions from baghouses installed on coal-fired steam generators, the opacity of the plume is a good indicator of the need for maintenance. Any visible emissions exceeding five percent opacity are an indicator that maintenance is required. For well designed baghouses equipped for isolation of individual cells, trouble spots can

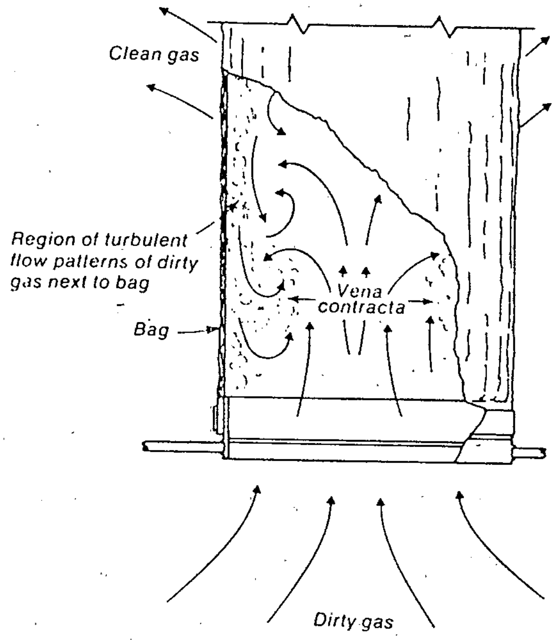


Figure 4-7. Typical Flow at Tube Sheet - Inside Out Filtration

be located by shutting off various sections and observing the stack. Once a faulty cell is identified, visual or fluorescent tracer techniques are used to locate faulty bags or tube sheet leaks.[1] Detailed records of bag replacements and periodic checks on used bag fabric characteristics are helpful for determining the optimum time for replacing an entire set of bags. By staggering replacement schedules on a cell by cell basis, all of the bags can be replaced without shutting down a steam generator.

4.4 SCRUBBERS

Scrubbers are not commonly used for control of particulates from coal-fired steam generators unless the source is equipped for flue gas desulfurization (FGD). The venturi scrubber is the most common type of scrubber applied for scrubbing particulates from coal-fired steam generators. Figure 4-8 shows a venturi scrubber located ahead of a FGD spray tower. As shown, liquor from the hold tank is circulated to both the spray tower and the venturi. Sometimes FGD scrubber systems are designed with separate particulate and sulfur dioxide (SO_2) liquor systems. Figure 4-9 shows a FGD system designed for both SO_2 and particulate removal using a single venturi scrubber system. Figure 4-10 shows a FGD system designed for simultaneous particulate and SO_2 removal in a moving bed absorber. Pressure drops across the foregoing systems range from 2.5 to 5 kilopascals (10-20 in. H_2O).[7] Some FGD systems are equipped with ESP systems ahead of the scrubber systems. The ESP can be designed to achieve full particulate removal or in other cases, partial particulate removal with the remainder being removed in the SO_2 scrubber system.

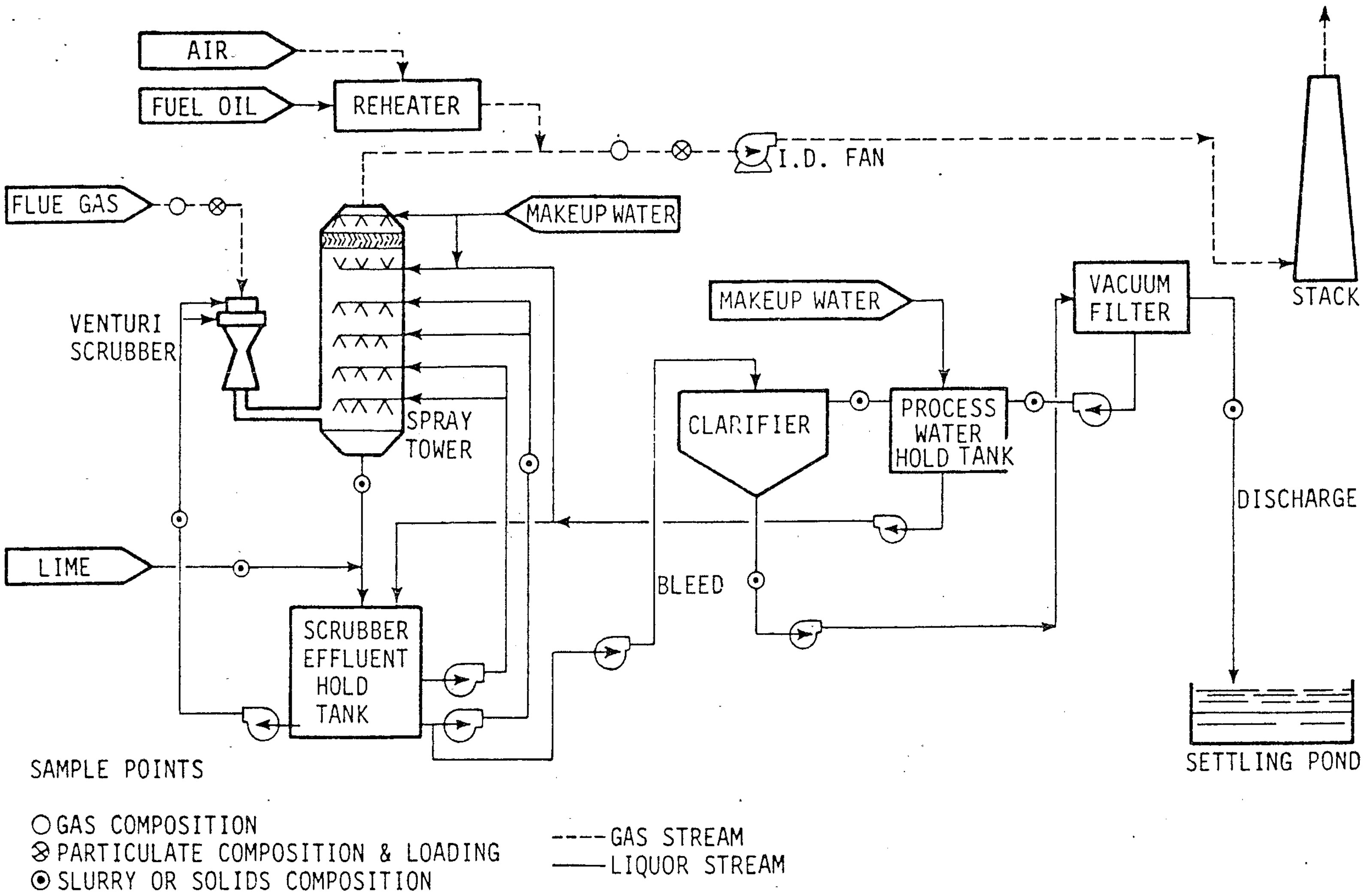


Figure 4-8

Shawnee No. 10 Prototype Test Unit: General Process Diagram.

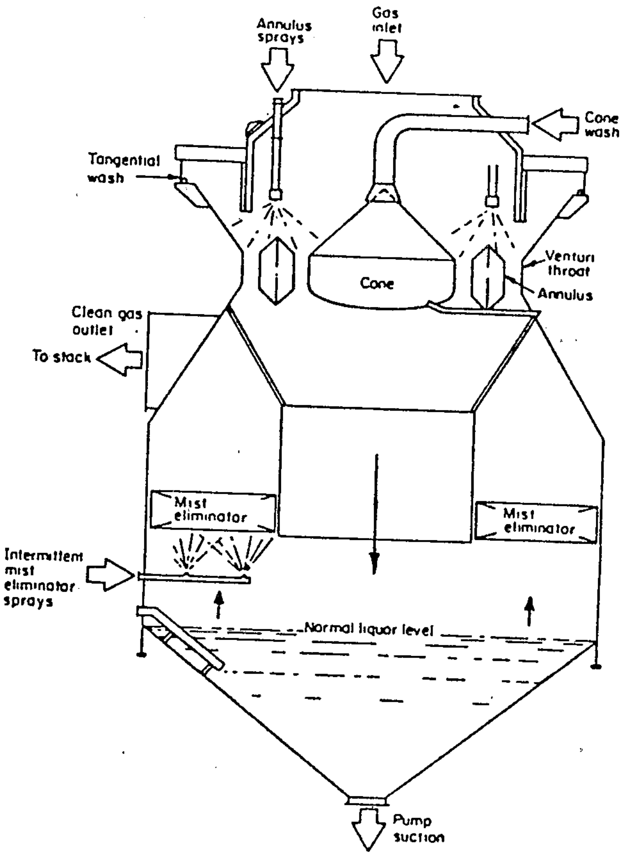


Figure 4-9. Combination Venturi Particulate and SO_2 Scrubber System

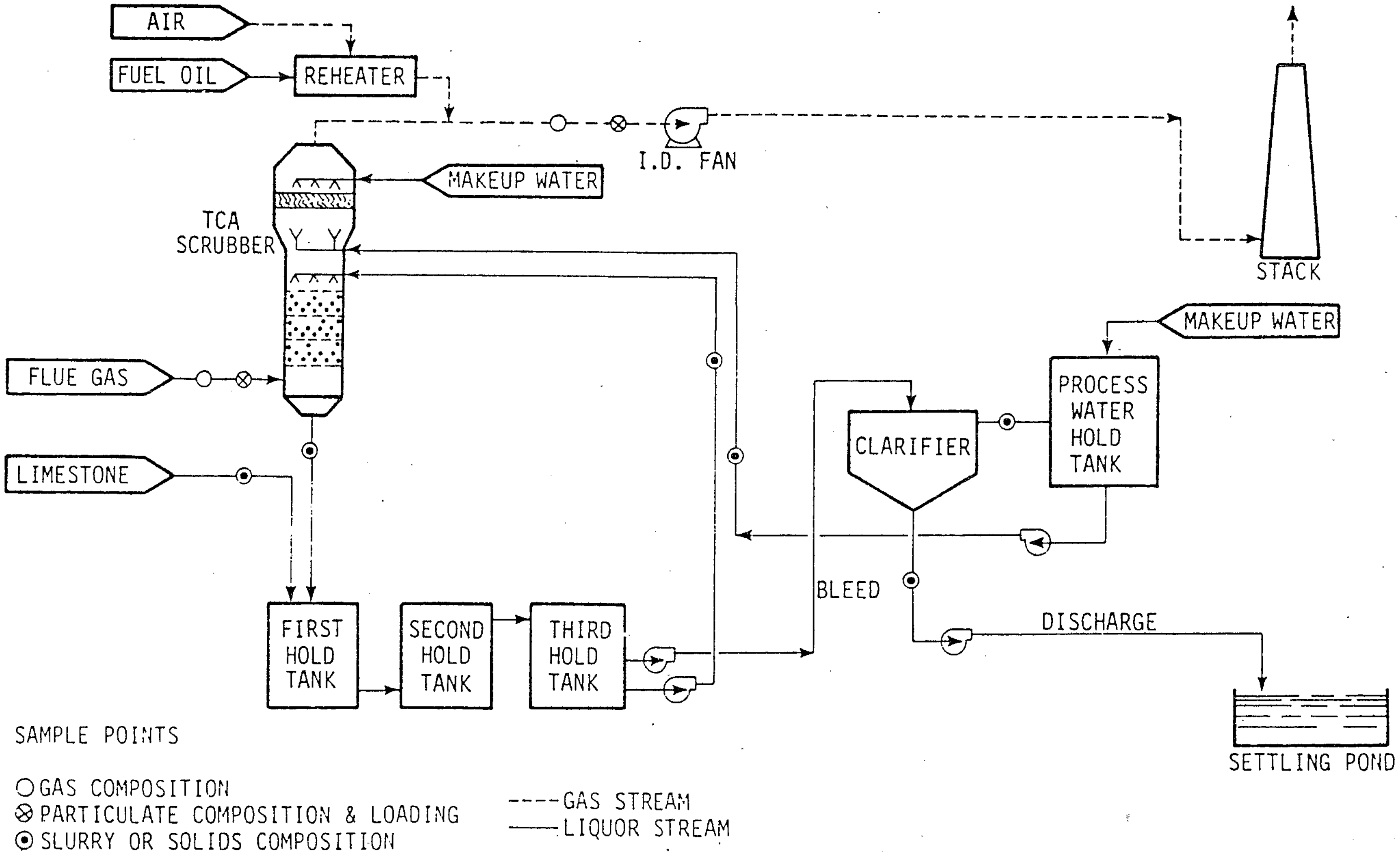


Figure 4-10

Combination Moving Bed Particulate and SO_2 Scrubber System

Even with the most efficient particulate control systems ahead of the SO_2 absorber, the absorber removes additional fly ash from the combustion gases. The absorber also adds some particulates to the combustion gases in the form of entrained liquor which contains dissolved and suspended solids. Consequently, effective particulate control in conjunction with FGD involves not only the application of high efficiency particulate control systems, but the use of effective mist eliminator systems at the outlet of the SO_2 absorber.

A common type of mist eliminator applied to FGD absorbers is the baffle and Chevron type. Figure 4-11 shows two, three, and six pass Chevron configurations. Figure 4-12 shows a radial type mist eliminator which is also applicable to FGD absorbers. The foregoing mist eliminators are designed to remove liquid droplets as they impinge on the surfaces of the device.

Since FGD system liquor is composed of a suspension of solids in a solution of soluble solids, solids from the entrained liquor tend to deposit or precipitate on mist eliminator surfaces. When deposition occurs which cannot be removed, the effectiveness of mist elimination is impaired.

The key design principles for an effective mist eliminator are:[8]

a) the spacing between surfaces should be small enough to permit impingement of droplets on the collecting surfaces before the gases leave the devices,

b) the spacing between surfaces should be wide enough to minimize plugging and to permit cleaning,

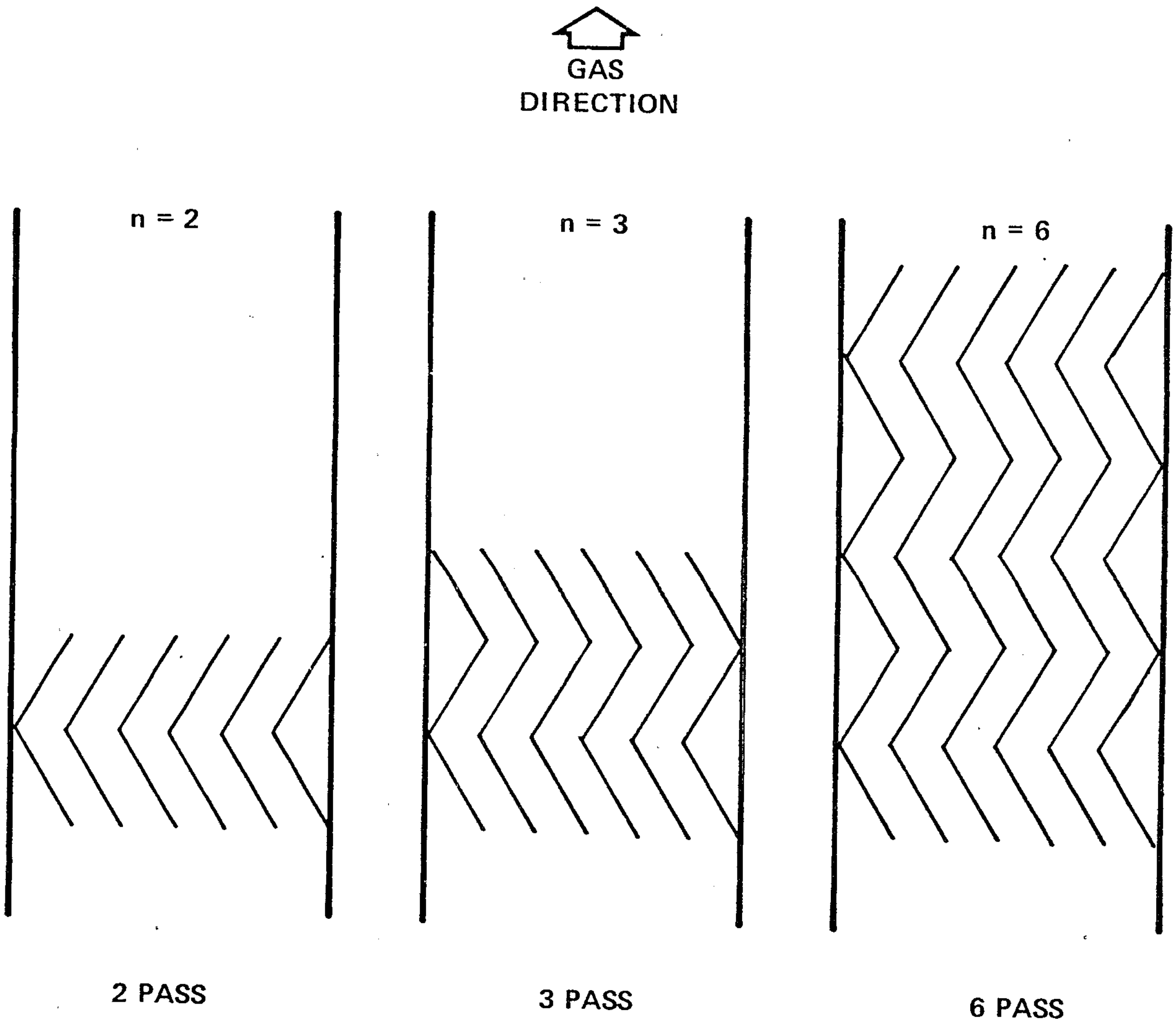


Figure 4-11. SCHEMATIC OF TWO-, THREE-, AND SIX-PASS CHEVRON MIST ELIMINATORS

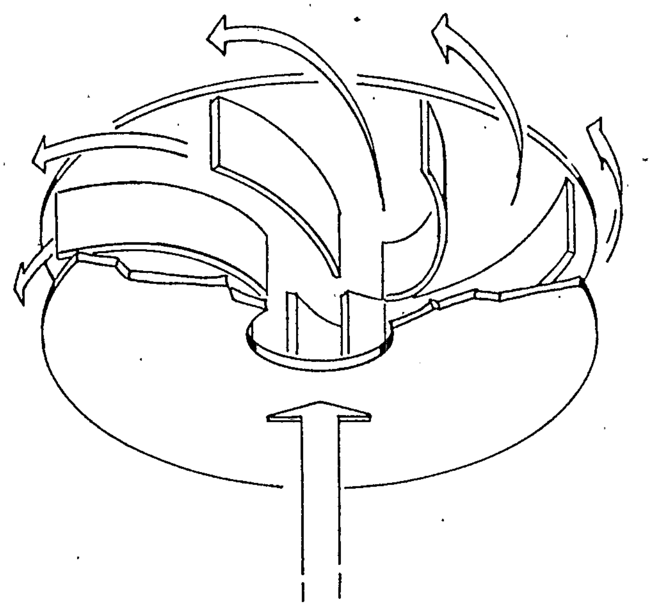


Figure 4-12. RADIAL-VANE MIST ELIMINATOR

c) the angle between the direction of gas flow and the collecting surface and the length of the gas path should promote optimum and effective droplet impingement,

d) linear gas velocity should be high enough to promote droplet impingement while limiting reentrainment,

e) the material of construction and strength should withstand cleaning operations, corrosion, and erosion,

f) effective reliable mist removal should be achieved with minimum pressure drop.

Because of the solubility characteristics of sulfite and sulfates, there is less tendency for solids deposition on mist eliminator surfaces for sodium based liquor than for solids deposition from calcium based liquors. When mist eliminator plugging becomes a problem, corrective measures such as installation of wash sprays upstream and downstream of the mist eliminator are employed. If the problem stems from deposition of soft solids on the mist eliminator surfaces, sprays will usually correct the problem. Often the deposition problem is a combination of soft solids deposition accompanied by the formation of hard scale from precipitation of solids from a supersaturated liquor. Techniques employed to correct this combined problem in addition to spray washing involve pH control and the use of unsaturated mist eliminator wash liquor. At times wash trays, such as the one shown in Figure 4-13, are employed to permit recycling and control of the special liquor used for washing mist eliminator surfaces.

4.5 CONTROL TECHNIQUE DATA FOR COAL-FIRED SOURCES

Sections 4.2, 4.3, and 4.4 discuss electrostatic precipitator,

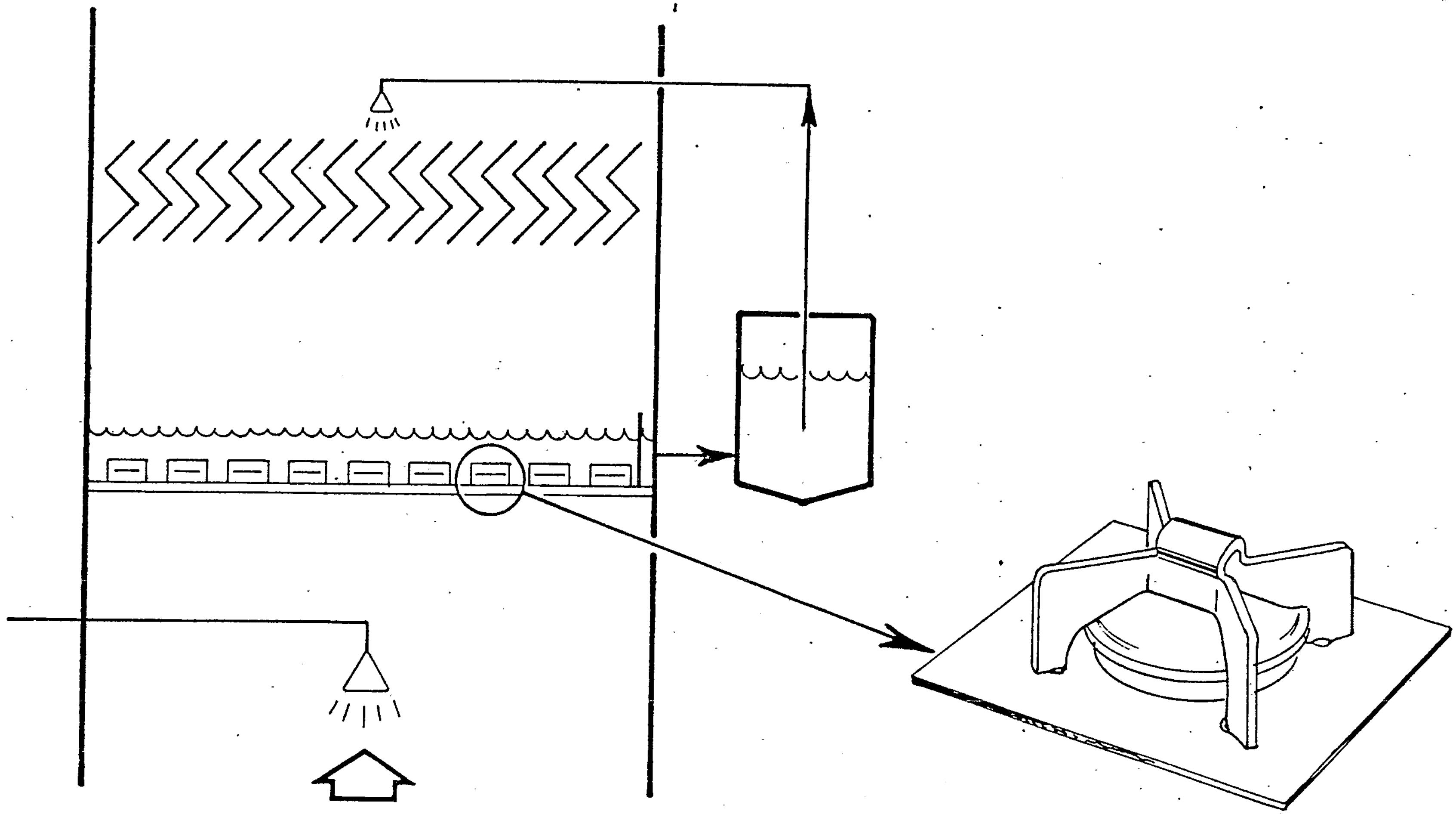


Figure 4-13. KOCH FLEXITRAY WASH TRAY

baghouse, and scrubber particulate control systems. Section 4.5 summarizes and discusses emission and operating data on the foregoing types of systems.

4.5.1 Electrostatic Precipitators

Table 4-2 summarizes particulate emission test data for coal-fired steam generators equipped with high efficiency electrostatic precipitator (ESP) systems. As shown, EPA Method 5 was used for 16 of the 21 tests. The measurements for individual test runs ranged from 3 to 21 nanograms per joule (0.007-0.05 lb/10^6 Btu). Little relationship was found between ESP specific collection area and effectiveness for hot side or cold side ESP systems. This lack of correlation is attributable to differences in the characteristics of the fly ash as discussed in Section 4.2. Figure 4-14 shows that for best controlled sources, ESP systems controlled particulates to less than 13 nanograms per joule (0.03 lb/10^6 Btu).

Table 4-3 summarizes particulate emission test data on difficult particulate emission control cases. The sources of Table 4-3 were selected based on: a) the reports of owners and ESP vendors that the low sulfur coals fired at the plant produced a difficult to collect ash and b) data on ESP size which show the ESP systems installed at the plants have large specific collection areas.

EPA used the data of Table 4-3 and applied modeling techniques to predict the size of ESP required to meet various particulate emission control limits as shown in Table 4-4.

Table 4-2

SUMMARY OF DATA ON PULVERIZED COAL-FIRED STEAM GENERATOR

HIGH EFFICIENCY ELECTROSTATIC PRECIPITATOR SYSTEMS

Unit & Reference Identification Number	Unit Size Megawatts	ESP Type (% Sulfur)	Specific Collection Area (SCA) Square Metres Per Actual Cubic Metres per Second (Ft^2/1000 ACFM)	Control Effectiveness Nanograms per Joule (lb/10^6 Btu)
1[9]	500	Cold (0.6)	96.1 (488)	18-20[a] (0.042-0.046)
2[10]	800	Hot (0.5)	60.4 (307)	12-18[a] (0.027-0.043)
3[10]	800	Hot (0.5)	60.4 (307)	14-16[a] (0.033-0.038)
4[11]	570	Cold (1.9)	57.3-59.1 (291-300)	14-17 (0.032-0.040)
5[12]	570	Cold (1.9)	52.8-54.3 (268-276)	10-18 (0.024-0.043)

a EPA Method 5

b EPA Sponsored Test

Table 4-2 (continued)

SUMMARY OF DATA ON PULVERIZED COAL-FIRED STEAM GENERATOR

HIGH EFFICIENCY ELECTROSTATIC PRECIPITATOR SYSTEMS

Unit & Reference Identification Number	Unit Size Megawatts	ESP Type (% Sulfur)	Specific Collection Area (SCA) Square Metres Per Actual Cubic Metres per Second (Ft^2/1000 ACFM)	Control Effectiveness Nanograms per Joule (lb/10^6 Btu)
6[13]	500	Cold (0.5)	174 (884)	3.0-8.6[a] (0.007-0.020)
7[14]	657	NG (1.1)	NG	16-17[a] (0.037-0.039)
8[15]	46	NG (1.4)	NG	9.0-15[a] (0.021-0.034)
9[15]	46	NG (1.4)	NG	6.4-14[a] (0.015-0.033)
10[16]	1300	Cold (0.9)	65.9 (335)	17-20 (0.040-0.046)
11[17]	69	Hot (1.4)	NG	8.2-15[a] (0.019-0.036)

a EPA Method 5

b EPA Sponsored Test

Table 4-2 (continued)

SUMMARY OF DATA ON PULVERIZED COAL-FIRED STEAM GENERATOR

HIGH EFFICIENCY ELECTROSTATIC PRECIPITATOR SYSTEMS

Unit & Reference Identification Number	Unit Size Megawatts	ESP Type (% Sulfur)	Specific Collection Area (SCA) Square Metres Per Actual Cubic Metres per Second (Ft^2/1000 ACFM)	Control Effectiveness Nanograms per Joule (lb/10^6 Btu)
12[18]	250	Cold (0.7)	158 (803)	19-20 (0.044-0.047)
13[18]	250	Cold (0.7)	158 (803)	20-21 (0.046-0.050)
14[19]	190	Hot (1.4)	53.0 (269)	4.3-5.6[a] (.010-.013)
15[20]	350	Hot (0.4)	NG	18.9[a,b] (0.044)
16[21]	700	Hot (1.4)	53.7 (273)	15-17[a,b] (.034-.039)
17[22]	141	NG (0.8)	NG	11-13[a] (.026-.030)
18[22]	187	NG (0.8)	NG	6.0-7.3[a] (0.014-.017)
19[23]	411	NG (1.1)	NG	5.6-10[a] (.013-.024)
20[24]	74	NG (1.4)	NG	10-13[a] (.024-.031)
21[25]	680	Cold (0.5)	151.0 (767)	12-17[a,b] (0.027-0.040)

NG = Data not given

a EPA Method 5

b EPA Sponsored test

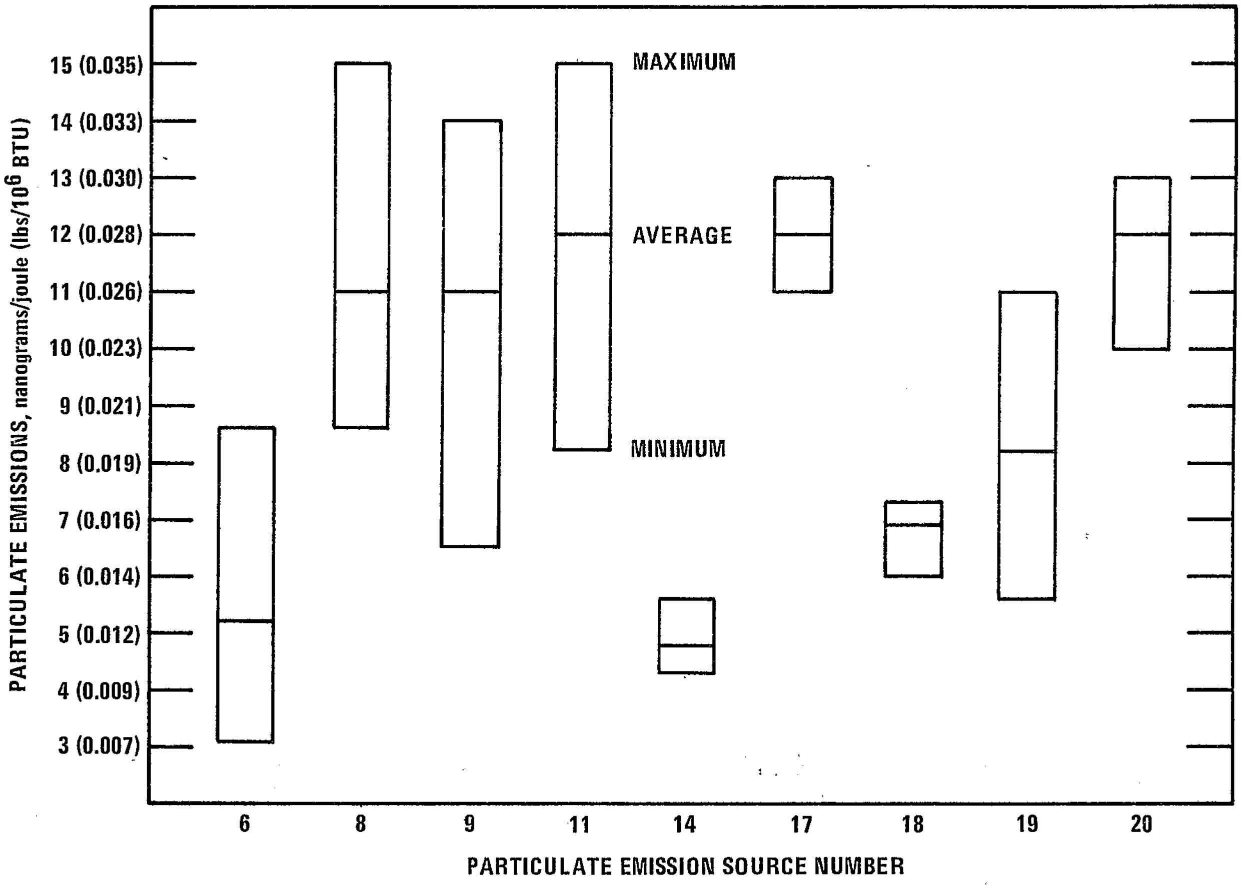


Figure 4-14. Emission test data for electrostatic precipitators at best-controlled coal-fired utility boilers.

Table 4-3

SUMMARY OF DATA ON DIFFICULT ELECTROSTATIC PRECIPITATOR CONTROL CASES

FOR PULVERIZED COAL-FIRED STEAM GENERATORS

Unit & Reference Identification No.	Unit Size Megawatts	ESP Type (% Sulfur)	Specific Collection Area (SCA) Square Metres per Actual Cubic Metre per Second (Ft^2/1000 ACFM)	Average Control Effectiveness Nanograms per Joule (lb/10^6 Btu)
2[10]	800	Hot (0.5)	60.4 (307)	13.7[a] (0.032)
3[10]	800	Hot (0.5)	60.4 (307)	15.5[a] (0.036)
22[26]	330	Hot (0.9)	57.5 (292)	17.2[a] (0.040)
12[18]	250	Cold (0.7)	158 (803)	19.8 (0.046)
13[18]	250	Cold (0.7)	158 (803)	20.6 (0.048)
6[13]	500	Cold (0.5)	174 (884)	4.0[a] (0.0094)
21[25]	680	Cold (0.5)	151 (767)	13.6 (0.032)

[a] = EPA Method 5   [b] = EPA Sponsored Test

Table 4-4

EPA SPECIFIC COLLECTION AREA CRITERIA FOR DIFFICULT ELECTROSTATIC PRECIPITATOR APPLICATIONS FOR PULVERIZED COAL-FIRED STEAM GENERATORS

ESP Type	Control Level Nanograms per Joule ($lb/10^6$ Btu)	Specific Collection Area Required Square Metres per Actual Cubic Metres per Second (Ft^2/1000 ACFM)
Hot	13 (0.03)	128 (650)
Hot	21 (0.05)	108 (550)
Hot	43 (0.10)	79 (400)
Cold	13 (0.03)	197 (1000)
Cold	21 (0.05)	157 (800)
Cold	43 (0.10)	128 (650)

4.5.2 Fabric Filter Systems

Table 4-5 summarizes emission test data on industrial and utility baghouses. As discussed in Section 4.3, effective baghouses are designed on a multicell basis. The prime difference between an industrial and a utility baghouse is the number of cells. Consequently, data on the effectiveness and reliability of industrial boiler baghouses is applicable to utility steam generators. As shown, 5 of the 9 tests were sponsored by EPA and EPA test methods were used. For the other 4 tests, West Virginia test methods were used which are similar to EPA Method 5. As shown by Table 4-5, emissions were less than 13 nanograms per joule (0.03 lb/10^6 Btu) for best controlled sources.

The pressure drop data of Table 4-5 shows that for 4 of the 5 sources for which pressure drop is reported, full load pressure drops were less than 1.25 kilopascals (5 in. H_2O). For the fifth source, full load pressure drop ranged from 2 to 2.5 kilopascals (8-10 in. H_2O). Air to cloth ratios for the 5 tests reported ranged from 0.58 to 0.91 actual cubic metres per minute per square metre (1.9-3.0 ACFM/Ft^2). The foregoing data show that an air to cloth ratio of 0.6 actual cubic metres per minute per square metre (2 ACFM/Ft^2) is a conservative criteria for sizing a baghouse for a coal-fired steam generator which will filter the full load gas volume at a pressure drop less than 1.25 kilopascals (5 in. H_2O).[6]

Since baghouses applied to coal-fired steam generators are relatively new, there is no long term data on bag life. Preliminary reports indicate bag life should be at least two years if pressure drops are less than 1.25 kilopascals (5 in. H_2O).[1,5,29,32]

Table 4-5

SUMMARY OF DATA ON BAGHOUSES APPLIED TO COAL-FIRED STEAM GENERATOR COMBUSTION GASES

Source Identification Number	Coal Sulfur Content and Source Type	Source Size Megawatts	Type Filtration	Type Cleaning Method	Air to Cloth Ratio Actual Cubic Metres Per Minute per Square Metre (ACFM/Ft²)	Pressure Drop Kilopascals (inches H_2O)	Effectiveness Nanograms per Joule (lb/10^6 Btu)
1[27]	S (2.0)	10*	Outside-in	Reverse air	0.61-0.76 (2.0-2.5)	0.52-0.70 (2.1-2.8)	4.7[a,b] (0.011)
1[27]	S (2.0)	10*	Outside-in	Pulse jet	0.76-0.91 (2.5-3.0)	0.55-1.1 (2.2-4.3)	9.9[a,b] (0.023)
2[28]	PC (2.0)	44**	Inside-out	Reverse air	0.58 (1.9)	0.62 (2.5)	1.2-43[a,b] (0.0028-0.0100)
3[29]	S (0.7)	13**	Inside-out	Shaking and reverse air	0.85 (2.8)	1.25 (5.0)	0.60-7.7[a,b] (0.0014-0.0180)
4[30]	S	18*	NG	NG	NG	NG	11.2[c] (0.026)
5[30]	S	12.5*	NG	NG	NG	NG	3.9[c] (0.0.009)
6[30]	S	24*	NG	NG	NG	NG	18[c] (0.042)
7[30]	S	6.4*	NG	NG	NG	NG	6.4[c] (0.015)
8[31]	PC (0.5)	25*	Inside-Out	Reverse air	0.69 (2.26)	2-2.5 (8-10)	15.5[a,b] (0.036)

NG = Data not given
S = Stoker
PC = Pulverized Coal
* = Industrial Boiler

a = EPA Method 5
b = EPA Sponsored Test
c = Non-EPA or No Data
** = Utility Boiler

4.5.3 SCRUBBERS

4.5.3.1 Particulate Removal

Table 4-6 summarizes data on the effectiveness of scrubbers installed on coal-fired power plants. As shown, all of the scrubbers are installed in conjunction with flue gas desulfurization. All of the tests were made using EPA Method 5. EPA witnessed 3 of the 7 tests. Outlet particulate emissions ranged from 8 to 30 nanograms per joule (0.019-0.070 lb/10^6 Btu). Pressure drops ranged from 2.5 to 4.5 kilopascals (10-18 in. H_2O). The emission test data show that scrubbers are capable of controlling particulates to a level less than 21 nanograms per joule (0.05 lb/10^6 Btu).

4.5.3.2 Effect of Scrubber Liquor Entrainment on Particulate Emissions

It is possible that particulates from entrained flue gas desulfurization liquor could make it impossible to achieve low particulate emission levels even though high efficiency particulate control devices are installed ahead of the SO_2 absorber. Table 4-7 and Figure 4-15 show data on the effectiveness of scrubbers equipped with mist eliminators. As shown, in every case outlet particulate emission concentrations were lower than inlet particulate emission concentrations even at inlet loadings as low as 10 milligrams per standard cubic metre (0.0044 grains/SCF).

Other tests have been made to measure entrainment of scrubber liquor. Two separate tests made at Source 2 of Table 4-7 showed scrubber liquor entrainment to be less than 4 nanograms per joule (0.01 lb/10^6 Btu). Additional testing of a venturi spray tower (15 runs) and a turbulent

Table 4-6

DATA ON PARTICULATE SCRUBBING SYSTEMS INSTALLED ON COAL-FIRED STEAM GENERATORS

Source Code & Reference	Boiler Type and Size (% Sulfur)	Particulate Control Before Scrubbing	Separate Particulate Control by Scrubbing	SO_2 or SO_2 and Particulate Control By Scrubbing	Scrubbing P - Kilopascals (Inches H_2O)	Particulates Scrubber Outlet Nanograms/Joule ($lb/10^6$ Btu)	Number of Tests	Test Method
A[33]	125MW-PC (0.5)	Mechanical	None	Venturi Scrubber Carbonate	3.8 (15)	20-24[a,b] (0.046-0.055)	2	EPA 5
B[33]	125MW-PC (0.5)	Mechanical	None	Venturi Scrubber Carbonate	3.8 (15)	22[a,b] (0.051)	2	EPA 5
C[34]	125MW-PC (0.5)	Mechanical	None	Venturi Scrubber Carbonate	3.8 (15)	14-18[a,b] (0.033-0.041)	3	EPA 5
D[35]	350MW-PC (0.7)	None	None	Venturi Scrubber Lime	4.5 (18)	8-10[a] (0.019-0.023)	3	EPA 5
E[36]	116MW-PC (0.5)	Mechanical	Flooded Disc Scrubber	Packed Absorber Limestone	3.0 (12)	16 (0.037-0.038)	2	EPA 5
F[37]	380MW-PC (2.1)	Mechanical and ESP	None	Venturi	2.5 (10)	19-21 (0.045-0.048)	2	EPA 5
G[37]	150MW-PC (2.1)	Mechanical	None	Venturi	2.5 (10)	9-30 (0.022-0.070)	10	EPA 5

PC = Pulverized Coal

a = EPA Method 5

b = EPA Sponsored Test

Table 4-7

SUMMARY OF DATA ON PARTICULATE EMISSIONS FROM FOSSIL FUEL-FIRED STEAM GENERATORS EQUIPPED FOR FLUE GAS DESULFURIZATION (FGD)

Source Identification and Reference Number	Fuel (S Content)	Type FGD System	Type Mist Eliminator	FGD Particulate Emissions Nanograms per joule ($lb/10^6$ Btu)	
				Inlet	Outlet
1[38]	Residual oil (2.0)	Magnesium Oxide	Baffle	85 (0.187)	34[a,b] (0.078)
2[39]	Pulverized coal (2.6)	Double Alkali	Chevron	14 (0.033)	9[a,b] (0.020)
2[39]	Pulverized coal (2.6)	Double Alkali	Chevron	12 (0.028)	7[a,b] (0.017)

[a] = EPA Method 5

[b] = EPA Sponsored Test

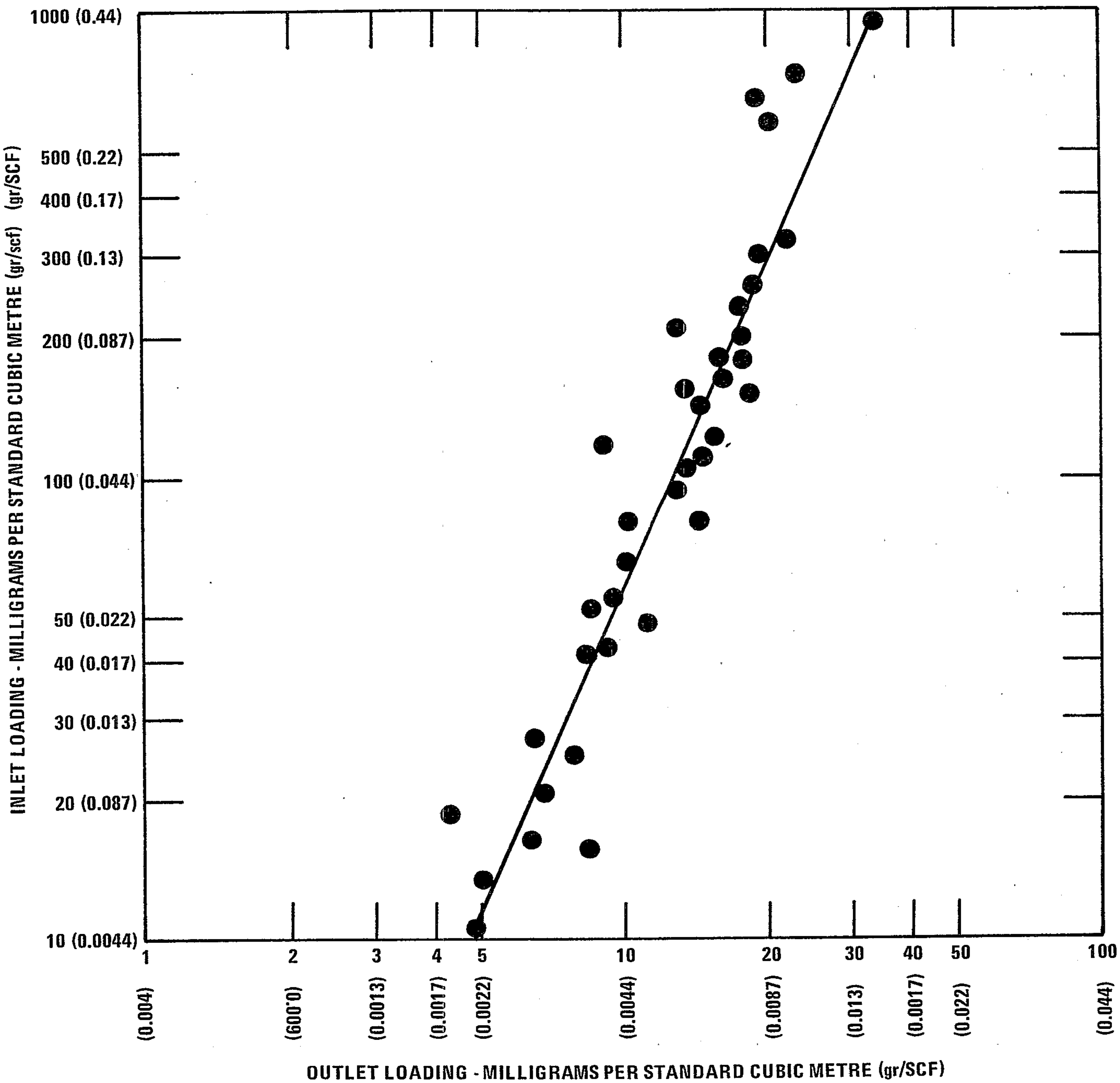


Figure 4-15. Particulate removal effectiveness of a spray type scrubber as a function of inlet loading for a lime scrubbing system. 40

contact absorber (20 runs) system showed entrainment of scrubber liquor was less than 4 nanograms per joule (0.01 lb/10^6 Btu).[41,42,43] The data on entrainment shows that well designed mist eliminator systems, such as well designed Chevron mist eliminator systems, are capable of limiting scrubber liquor particulate entrainment to a level less than 4 nanograms per joule (0.01 lb/10^6 Btu) if mist eliminator surfaces are clean. It is reported that for the FGD systems tested for the data of Table 4-7 and Figure 4-15 and for the forementioned FGD systems tested for entrainment that there were no problems with keeping the mist eliminator surfaces clean during the tests or during extended operations before and after testing.

4.5.3.3 Acid Mist Removal

Table 4-8 shows the effectiveness of two lime scrubbing systems for reducing acid mist emissions.[41,42,43] For the lime venturi spray tower system tests sulfuric acid mist removal ranged from 50.9 to 74.9 percent and averaged 58 percent for a series of 10 runs. The effectiveness measured by the 7 turbulent contact absorber tests ranged from 18.2 to 87.5 percent and averaged 63.9 percent. The effectiveness of the turbulent contact absorber averages 71.5 percent if the atypical 18.2 percent run is excluded. The sulfur content of the coal that was burned during these tests ranged from 3 to 4.5 percent.

4.5.4 Opacity Data

Table 4-9 summarizes data on opacity versus mass particulate emissions from three high efficiency control systems. As shown only one of the sources was equipped with a large diameter stack. Observations were

Table 4-8. EFFECTIVENESS OF LIME SCRUBBING FOR REMOVING ACID MIST[41,42,43]

Scrubber Type	Venturi	Turbulent Contact Absorber
Number of Runs	10	7
Inlet Acid Mist[a] Emissions - Nanograms per Joule ($lb/10^6$ Btu)		
Range	0.6-38.2 (0.0014-0.089)	0-23.6 (0-0.055)
Average	12.1 (0.028)	11.8 (0.027)
Outlet Acid Mist Emissions - Nanograms per Joule ($lb/10^6$ Btu)		
Range	0-21 (0-0.05)	0-13.4 (0-0.031)
Average	5.1 (0.012)	4.3 (0.010)
Percent Removal		
Range	50.9-74.9	18.2-87.5
Average	58.0	63.9 (71.5)[b]

[a] Coal sulfur ranging from 3-4.5 percent

[b] 71.5 percent without atypical 18.2 percent effectiveness

TABLE 4-9

SUMMARY OF EPA METHOD 9 OPACITY DATA FOR HIGH EFFICIENCY

CONTROLLED COAL-FIRED STEAM GENERATORS

Source Identification	A	B(Test 1)	B (Test 2)	C
Source Size MW	680	10	10	25
Coal Sulfur Content Percent	0.5	2.0	2.0	0.5
Source Type	Pulverized Coal	Spreader Stoker	Spreader Stoker	Pulverized Coal
Particulate Control Device	Electrostatic Precipitator	Baghouse (Reverse Air)	Baghouse (Pulse Jet)	Baghouse (Reverse Air)
Stack Diameter Metres (ft)	6.4 (21)	1.4 (4.5)	1.4 (4.5)	2.4 (8.0)
Stack Height Metres (ft)	143 (470)	41 (135)	41 (135)	37 Estimated (120)
Number of Observations	1488	1424	804	2464
Maximum Opacity Reading Percent	10	0	15	10
Minimum Opacity Reading Percent	10	0	0	0
Average Opacity Reading Percent	10	0	0.1	1.0
Average EPA Method 5 Mass Particulate Emission Rate	15	4.7	9.9	15
Nanograms per joule (lb/10^6 Btu)	(0.035)	(0.011)	(0.023)	(0.036)
Range EPA Method 5 Mass Particulate Emission Rate for 3 tests	12-17	3.4-5.2	5.6-16	14-18
Nanograms per joule (lb/10^6 Btu)	(0.027-0.040)	(0.008-0.012)	(0.013-0.038)	(0.032-0.043)
Reference	25	27	27	31

made each 15 seconds during EPA Method 5 mass emission testing. No visible emissions were detected from the spreader stoker-fired source while the baghouse was operating in the reverse air mode. Opacity of the plume from the 680 MW power system was steady at 10 percent throughout mass emission testing. Opacity did not exceed 10 percent for a 6 minute period during any of the observations.

4.6 CONTROL TECHNIQUES DATA FOR OIL-FIRED SOURCES

Table 4-10 summarizes test results for 56 tests of oil-fired utility boilers equipped with electrostatic precipitator (ESP) systems.[44] As shown, controlled particulate emissions ranged from 1.3 to 105 nanograms per joule (0.003-.244 lb/10^6 Btu). Controlled particulates from sources using additives to minimize boiler corrison were greater than particulate emissions from steam generators firing oil without additives. The usefulness of the data of Table 4-10 is limited because the type of ESP is not identified. It is not known how many of the electrostatic precipitators were originally designed for coal and were being used unmodified to control particulates from oil combustion. Such unmodified ESP systems are not as effective as modified ESP systems or ESP systems which are originally designed to control particulates from oil combustion. One test of a modified ESP system installed on a source firing oil with additives shows particulate emissions were as low as 8.6 nanograms per joule (0.02 lb/10^6 Btu).[45] Another EPA study supported by referenced literature and a panel of experts concludes that electrostatic precipitators are capable of

Table 4-10

SUMMARY OF DATA ON CONTROLLED PARTICULATE EMISSIONS[44]

FROM ELECTROSTATIC PRECIPITATORS INSTALLED

ON UTILITY OIL-FIRED STEAM GENERATORS

No. of Sources Tested	Additives	Controlled Emissions Nanograms per joule ($lb/10^6$ Btu) Range	Average
35	Yes	9.0-105 (0.021-.244)	46.4 (1.108)
21	No	1.3-66 (0.003-.154)	15.5 (0.036)
56	--	1.3-105 (0.003-.244)	36.1 (0.084)

controlling particulates from oil-fired utility boilers to a level less than 13 nanograms per joule (0.03 $lb/10^6$ Btu).[45]

Table 4-7 shows test results for a scrubber operating on a residual oil-fired boiler in conjunction with flue gas desulfurization. As shown, the scrubber reduced particulate concentrations from 85 nanograms per joule (0.187 $lb/10^6$ Btu) to 34 nanograms per joule (0.078 $lb/10^6$ Btu).

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5. MODIFICATION AND RECONSTRUCTION

5.1 GENERAL

The terms modification and reconstruction have special meanings when used in new source performance standards. These terms are clarified in Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations. In general terms, a modification is a selected type of change which increases the emission of selected pollutants to the atmosphere. When the alterations are limited, new source performance standards only require that increases in the emission of selected pollutants be prevented. In general terms, reconstruction is a change which is so substantial as to class the source as a new source rather than an altered existing source. In this case, the source becomes subject to all the limits of the new source performance standard.

5.2 MODIFICATION

5.2.1 Scope and Effect of Modifcation Regulations

The term modification has special meaning when used with new source performance standards. According to regulations, a modification means any change in the method of operation of an existing facility which increases the amount of any air pollutant (to which a standard applies) emitted into the atmosphere by that facility or which results in the emission of any air pollutant (to which a standard applies) into the atmosphere not previously emitted.[1] The term modification is further limited by exempting selected types of changes from the applicability of new source performance standards.

Normally, all that is required when an existing source becomes subject to modification regulations is that emissions of a specific pollutant after alteration be no more than they were before alteration. Usually, the source does not have to be equipped to comply with the numerical limits of the standard. Modification regulations apply to the pollutants of the new source standard, and apply on pollutant-by-pollutant basis. In rare cases, emission of one or more pollutants may be less than the limit of a new source performance standard prior to the alteration. In this situation, an emission increase is allowed, up to the limit of the applicable new source performance standard. For example, a source subject to modification regulations because of a switch from gas to coal would not have to be equipped to prevent particulate and SO_2 emission increases. For this situation, emission increases would be allowed up to the levels of the particulate and SO_2 standards for coal.

Adding an affected facility to a plant or replacing an existing facility within a plant would not cause other unchanged existing facilities within the plant to become subject to the no emission increase rule.[1] When a plant has several existing facilities, the no emission increase rule does not apply to an altered existing facility if net plant emissions are not increased.[1] For example, if emissions of pollutant A are increased by a change to facility 1 in a plant, the emission increase is allowed if emission of pollutant A from facility 2 is decreased by an amount equal to or exceeding the amount of increase from facility 1.

Emission increases are allowed if such increases are caused by routine maintenance, repair, and replacement.[1] Emission increases are also allowed if caused by increases in production rate which can be accomplished without major capital expenditure.[1] Increases in emissions caused by longer operating hours are also exempted from the rule on no emission increase.[1] Another exemption is for the use of an alternative fuel or raw material if--prior to the date any standard becomes applicable--the existing facility was designed to accommodate that alternative use.[1] Conversion to coal, required for energy considerations as stipulated in Section 111(a)(8) of the Clean Air Act as amended in 1977, is not considered a modification. Emission increases caused by the addition or use of any system whose primary function is the reduction of air pollutants, are also exempt from the no emission increase rule.[1]

5.2.2 Modified Coal-Fired Steam Generators

For the purposes of determining if modification or reconstruction regulations apply or should apply, the coal-fired steam generator system is defined as including the following major components:

a) Fuel burners (including coal pulverizer, crusher, stoker system)

b) Combustion air system

c) Steam generation system (firebox, tubes, etc.)

d) Draft system (excluding stack)

The major points which define the inlets to the affected facility are:

1. The inlet to the pumps which feed water at steam generator pressure.
2. The inlet to the bins which directly feed the pulverizer or stoker systems unless the bins are sized to store more than enough coal to operate the steam generator 72 hours at full load. When large bins are installed, the inlet to the affected facility is the outlet of the bins feeding the pulverizer or stoker systems.
3. The combustion air intakes.

The major points which define the outlets of the affected facility are:

1. Any steam outlet
2. Any bottom ash outlet
3. The outlet of the last system installed before the stack, such as the outlet of any induced draft fan.

All components of the steam generator installed between these points are part of the affected facility except any air pollution control systems, such as electrostatic precipitators, mechanical collectors, baghouses, or scrubbers.

Replacement of the pulverizer system of an existing coal-fired unit with a similar system or replacement of component parts of the pulverizer system with similar parts would not be considered a modification. However, replacement or redesign of the pulverizer system, which would substantially change the physical characteristics of the pulverized coal and of the particulate emissions, may be a change where modification regulations apply.

Likewise, changes in the design of the combustion air system of an existing unit that change the way combustion air is introduced to the combustion chamber would cause a source to be evaluated to determine if modification regulations should apply. Changing the combustion air damper settings is not a modification as long as no redesign of the combustion air system is involved.

The steam generation system includes the feedwater pumps, combustion chamber, watertubes, economizer, and superheat and reheat sections. Maintenance of these components is not a modification. Major redesign of these parts would cause a source to be evaluated to determine if modification regulations should apply. It is doubtful that redesign of the feedwater system, the economizer, or the superheat or reheat sections would affect particulate emissions.

Redesign of the draft system, such as changing from induced draft conditions to pressurized firing, would cause an existing coal-fired source to be evaluated to determine if modification regulations should apply.

Although a change to a different coal might be considered a modification, these changes are exempted from modification evaluation by current regulations.[1]

5.2.3 Modified Oil or Gas-Fired Steam Generators

The discussion of Section 5.2.3 is limited to modifications which would cause a source to become subject to particulate new source performance standard modification regulations for large coal-fired steam generators.

Alterations which might cause an existing oil or gas-fired steam generator to become subject to particulate modification regulations for coal-fired steam generators are alterations involving a switch from gas or oil to coal. Current regulations provide that if the oil or gas-fired source is already designed to fire coal, a switch to coal does not cause the source to become subject to coal-fired steam generator particulate modification regulations.[1] In addition, Section 111(a)(8) of the Clean Air Act as amended in 1977, exempts from the modification provisions of the Act certain sources switching from oil or gas to coal. The latter category of sources is described in general terms as sources required to switch to coal under Section 2(a) of the Energy Supply and Environmental Coordination Act of 1974. (The reader is cautioned to seek competent legal advice, such as from the Office of Enforcement and General Counsel, U. S. Environmental Protection Agency, Washington, D.C., before assuming that a source switching from oil or gas to coal is exempted from the modification provisions of the Clean Air Act).

Sources switching from oil or gas to coal which are not otherwise excepted by U. S. Environmental Protection Agency regulations or by law would be subject to particulate new source performance standard modification regulations. Because oil and gas-fired steam generators characteristically emit less particulates than coal-fired steam generators, a switch from oil or gas to coal would normally increase particulate emission concentrations. Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations describes the procedure for determining if a particulate emission increase has occurred.

The cost of modifying an oil or gas-fired steam generator to fire coal may be so substantial as to class the source as a reconstructed source (see Section 5.3).

Rulings on whether alternations of fossil fuel fired steam generators constitute a modification can be obtained by contacting a U. S. Environmental Protection Agency Regional Office of Enforcement.

5.3 RECONSTRUCTION

The term reconstruction has special meaning when used in new source performance standards. The purpose of reconstruction regulations is to prevent the perpetuation of existing sources. When modifications or replacements become so extensive as to create an essentially new source, the source becomes a reconstructed source and is subject to the new source performance standards which apply at the time of initiation of reconstruction.

According to the provision of Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations, a facility becomes a reconstructed source irrespective of any change in emission rate when

a) the fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility and,

b) it is technologically and economically feasible to meet applicable standards.

Rulings on whether changes to a fossil fuel-fired steam generator constitute reconstruction can be obtained by contacting a U. S. Environmental Protection Agency Regional Office of Enforcement.

REFERENCES FOR CHAPTER 5

1. Subpart A, Part 60, Title 40, Code of Federal Regulations, as of November, 1977.

6. EMISSION CONTROL SYSTEMS

6.1 GENERAL

Electrostatic precipitator (ESP) systems, baghouses, and scrubbers are potential systems for control of particulates from steam generators of more than 73 megawatts heat input (250 x 10^6 Btu/hr). Since mechanical collectors are not effective enough to meet the current particulate new source performance standard of 43 nanograms per joule (0.1 lb/10^6 Btu), these latter systems are not candidates for control.

Analysis of the data of Chapter 4 shows that the effectiveness of ESP and baghouse systems for control of particulates from steam generators is demonstrated at a level of 13 nanograms per joule (0.03 lb/10^6 Btu). Although it is likely scrubber systems are capable of achieving lower levels as given by the data of Chapter 4, evaluation of the total test data reported in Chapter 4 shows the demonstrated effectiveness of scrubbers is at a particulate control level of 21 nanograms per joule (0.05 lb/10^6 Btu).

6.2 Electrostatic Precipitators

Analysis of the data discussed in Chapter 4 shows that ESP systems can limit particulate emissions from steam generators to levels less than 13 nanograms per joule (0.03 lb/10^6 Btu). The size of the ESP required to meet a given level of control varies with the characteristics of the coal ash and the level of control required. Larger ESP systems are needed for lower levels of control. Table 6-1 shows the specific collection areas (SCA) used in EPA calculations to define worst case size requirements to meet various control limits for coal-fired steam generators.

The ESP systems for control of particulate emissions from large steam generators include the following design features:

1. Either hot side or cold side depending on which type is the least costly for the application.
2. Sufficient sectionalization to ensure that at least 90 percent of the collecting surface area will be available should a breakdown occur in one section.
3. Automatic power controls and instruments showing: a) primary voltage, b) primary current, c) secondary voltage, d) secondary current, and e) spark rate for each individual section.
4. Insulation to minimize temperature drops which would cause acid attack.

No specific collecting area (SCA) values are recommended; EPA uses the conservative values previously discussed to estimate control costs for difficult cases. As discussed in Chapter 4, some designers and owners may prefer to use lower SCA values while allowing space for adding collecting surface area if the original installation fails to perform within the limits of regulations.

Table 6-1

ELECTROSTATIC PRECIPITATOR SPECIFIC COLLECTION AREA CRITERIA

FOR MEETING VARIOUS LEVELS OF CONTROL WHEN FIRING HIGH RESISTIVITY ASH COAL

Control Level Nanograms per Joule ($lb/10^6$ Btu)	ESP Type	Specific Collection Area Square Metres Per Actual Cubic Metre Per Second (Ft^2/1000 ACFM)
13 (0.03)	Hot	128 (650)
21 (0.05)	Hot	108 (550)
43 (0.1)	Hot	79 (400)
13 (0.03)	Cold	197 (1000)
21 (0.05)	Cold	157 (800)
43 (0.10)	Cold	128 (650)

6.3 Fabric Filter Systems

The data of Chapter 4 show that baghouses are capable of controlling particulates from coal combustion to levels less than 13 nanograms per joule (0.03 lb/10^6 Btu) at pressure drops less than 1.25 kilopascals (5 in. H_2O) and with an average bag life of at least two years.

Unlike electrostatic precipitator systems, the effectiveness of fabric filter systems does not depend on baghouse size. However, baghouse size is important because if the fabric filter is undersized, the system will not be able to handle the combustion gas volume at full load. In the EPA calculations, an air to cloth ratio of 0.6 actual cubic metres per minute per square metre (2 ACFM/Ft^2) of cloth area is used for sizing baghouses to handle full load gas volume at pressure drops less than 1.25 kilopascals (5 in. H_2O).

The fabric filter systems selected for control of particulates from coal-fired units include the following features:

1. Reverse air cleaning
2. At least 10 compartments per baghouse to minimize pressure drop when a cell is off line for cleaning and when maintenance is being performed on one other cell.
3. Provision for isolating each cell for cleaning or maintenance while the other cells are on line.
4. Provision for automatic cleaning on a cell by cell basis with controls for adjusting the quantity of reverse air, the frequency of cleaning, and the duration of cleaning.
5. Provision for instruments indicating pressure drop and temperature in and out of the baghouse.

6. Adequate insulation to minimize temperature drops which would cause acid attack on baghouse.

Selection of the foregoing system does not infer that other types of baghouse systems are not as effective or reliable.

Although no air to cloth ratios are recommended, EPA used the conservative values previously discussed to estimate control costs. Some owners and designers may prefer to use somewhat higher air to cloth ratios while providing for adding baghouse cells if the original installation fails to handle the gas volume at full load.

As discussed in Chapter 4, baghouses are capable of removing at least 98 percent of the particulates from the combustion gases of utility oil-fired steam generators.

6.4 Scrubber Systems

As discussed in Chapter 4, there are test results which show scrubbers are capable of controlling particulates to levels less than 13 nanograms per joule (0.03 lb/10^6 Btu). However, as discussed in Chapter 4, the total data on scrubbers are less conclusive than that for baghouses and ESP's. Consequently, EPA makes a more conservative conclusion; namely, that scrubbers are capable of limiting particulate emissions to a level less than 21 nanograms per joule (0.05 lb/10^6 Btu). A scrubber, such as a venturi scrubber, operating at a pressure drop of 4 kilopascals (16 in. H_2O) is capable of reducing particulate emissions to at least a level of 21 nanograms per joule (0.05 lb/10^6 Btu).

The data of Chapter 4 also show that FGD scrubbing systems are demonstrated which operate without significant deposition of solids on mist eliminator collecting surfaces, and that when mist eliminator surfaces are clean and the system is properly designed to handle gas flow, entrainment of FGD liquor does not increase particulate emissions even when FGD absorber inlet particulate loadings are as low as 4 nanograms per joule (0.01 lb/10^6 Btu). A three pass chevron type mist eliminator located after a bubble cap type wash tray is effective for limiting entrainment when used in conjunction with an upstream and downstream low solids content liquor wash spray system.

The fact that the foregoing system is demonstrated does not infer that other types of scrubber mist eliminator systems are not capable of effective particulate control.

7. ENVIRONMENTAL IMPACT

Chapter 7 identifies the productive and counterproductive environmental changes caused by more effective particulate control.

The following impacts are discussed:

1. The air pollution impact of reducing the mass of particulate emission.
2. The air impact of reducing the emission of trace elements and fine particulate.
3. The water pollution impact of the additional particulates.
4. The impact of stricter particulate standards on solid waste disposal.
5. The energy impact of effecting more efficient particulate removal.

7.1 AIR POLLUTION IMPACT

Since lower particulate emission standards do not affect the stack conditions which, together with meteorological and topographical conditions, control the way particulates are dispersed, the prime effect of lower particulate standards on maximum ground level concentrations of particulates is a reduction directly proportional to the reduction of particulate emissions from the stack. For example, if particulate emissions from a stack are reduced to one-half of previous levels without changing stack location, height, diameter, velocity, or temperature, maximum ground level concentrations are one-half of what these concentrations are at the higher emission rate.[1] Consequently, lower emission rates reduce ambient air mass particulate concentrations.

Dispersion calculations show that maximum downwind particulate concentrations caused by a 1000 megawatt steam generator emitting at a level of 43 nanograms per joule (0.1 $lb/10^6$ Btu) and equipped with a 275 metre (900 ft) stack are less than 0.1 microgram per cubic metre on a mean annual basis and are 1.3 micrograms per cubic metre on a maximum 24-hour basis.[1] Appendix F discusses the basis for these estimates and gives other examples. These maximum concentrations are less than the following Federal National Ambient Air Quality Standards.[2]

<u>Primary</u>

75 micrograms per cubic metre - annual geometric mean

<u>Secondary</u>

260 micrograms per cubic metre - maximum 24-hour concentration not to be exceeded more than once per year.

More effective particulate removal also reduces trace element emissions and thereby reduces trace element ambient air concentrations. Table 7-1 shows data on emissions and the effectiveness of a venturi scrubber, a hot side electrostatic precipitator, and a cyclone system for reducing trace element emissions from three different coal-fired power plants.[3] While the data show that particulate emission control systems reduce trace element emissions, the tests do not show which device is the most effective for removing trace metals from coal combustion gases. The tests were conducted at three different power plants firing different

Table 7-1

PERCENTAGES OF ELEMENTS OF THE COAL WHICH WERE DISCHARGED[3]

IN FLUE GAS FOR SAMPLED STATIONS (100 MINUS PERCENT REMOVED)

Element	Station I[(a)]	Station II[(b)]	Station III[(c)]
Aluminum	0.25	0.7	11.2
Antimony	0.61	3.9	77.9
Arsenic	7.5	0.05	20.5
Barium	<0.84	<0.09	1.6
Beryllium	0.65	<2.0	6.5
Boron	5.9	4.7	54.1
Cadmium	7.0	<3.8	41.1
Calcium	0.85	0.8	16.6
Chlorine	75.0	80.2	80.0
Chromium	9.9	12.4	40.3
Cobalt	2.6	1.5	28.5
Copper	0.66	0.8	28.9
Fluorine	2.0	7.6	74.0
Iron	0.63	0.8	17.5
Lead	1.9	7.5	64.6
Magnesium	1.2	0.8	14.8
Manganese	0.38	1.2	12.5
Mercury	86.8	97.9	96.1
Molybdenum	43.2	9.4	63.0
Nickel	4.1	18.2	62.8
Selenium	2.2	27.7	65.4
Silver	4.7	1.3	15.9
Sulfur	62.2	87.8	98.1
Titanium	0.30	0.6	7.9
Uranium	2.0	1.5	27.6
Vanadium	2.5	2.4	24.9
Zinc	2.5	2.6	52.7

(a) Station I - Equipped with 99.7 percent efficient Venturi scrubber

(b) Station II - Equipped with 99.3 percent efficient hot side electrostatic precipitator

(c) Station III - Equipped with 87.1 percent efficient mechanical collector kinds of coal. Consequently, it is not known how much of the differences shown are attributable to differences in the effectiveness of the particulate control systems or how much is caused by differences in the characteristics of the coal fired in the combustion units.

More effective particulate control reduces fine particulate emissions. Figures 7-1 and 7-2 show particle size distributions at the inlet and outlet of an electrostatic precipitator (ESP) installed on a Western coal-fired source.[4] As shown, the ESP reduced total particulate emissions from a level of 22.9 grams per standard cubic metre (10 gr/SCF) to a level of 0.02 grams per standard cubic metre (0.009 gr/SCF). Analysis of Figures 7-1 and 7-2 shows the following effectiveness for various particle sizes.

Table 7-2

Particle Sizes Less Than Given Diameter Micrometres	Percent Removal
1	96
0.5	90
.2	86

7.2 SOLID WASTE IMPACT

Stricter particulate emission standards would have very little effect on the quantity of solid wastes generated from particulate emission control. The particulate solid waste generated from a 1000 megawatt coal-fired power plant for various levels of control are shown in Table 7-3. As shown, reducing emissions to 50 percent of the level of current new source performance standard limits would increase fly ash generation about 0.76 percent. The foregoing increase would not significantly affect fly ash disposal problems.

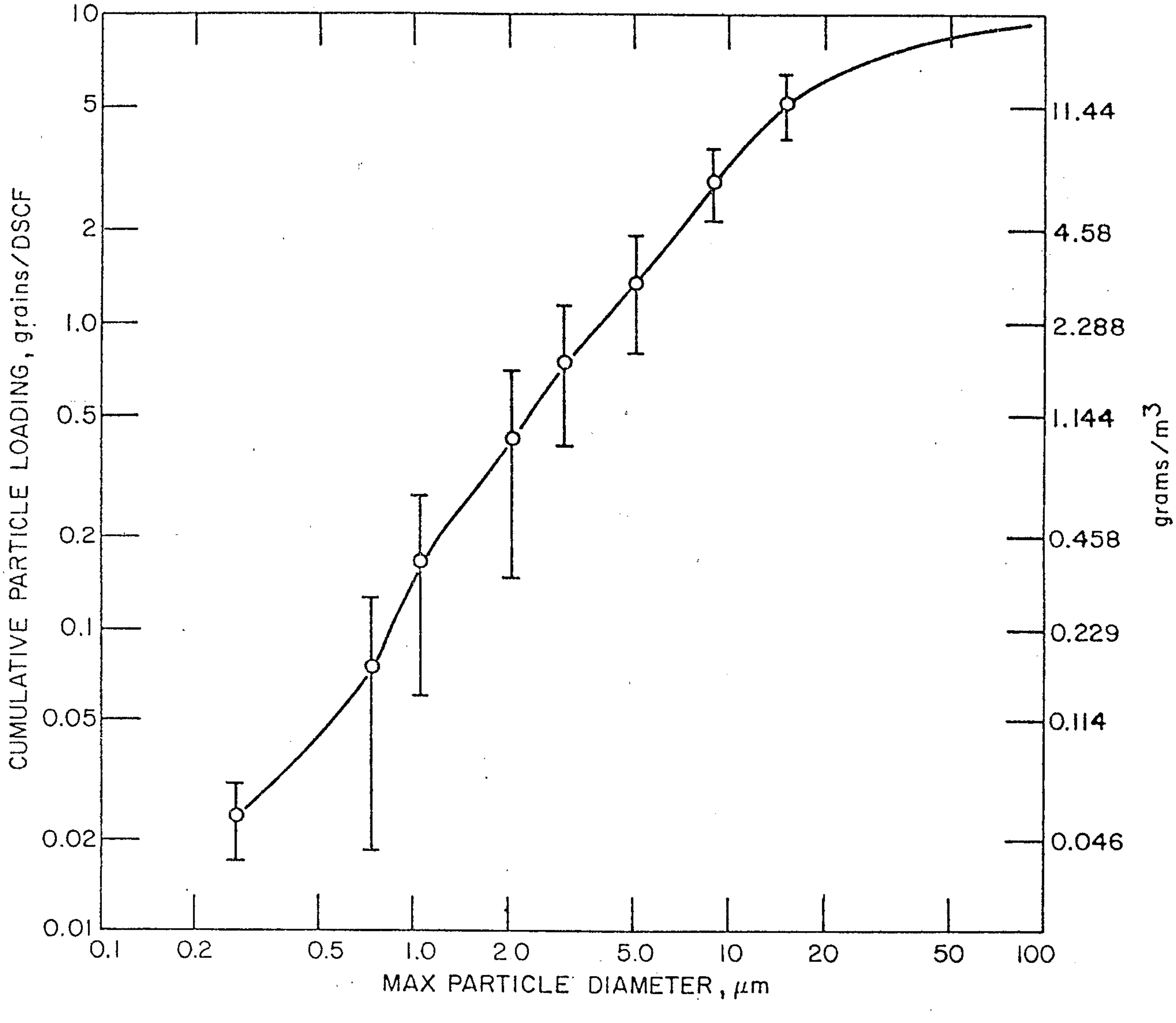

Figure 7-1. Cumulative Particle Size Distribution at the Inlet of a Hot Side Electrostatic Precipitator[4]

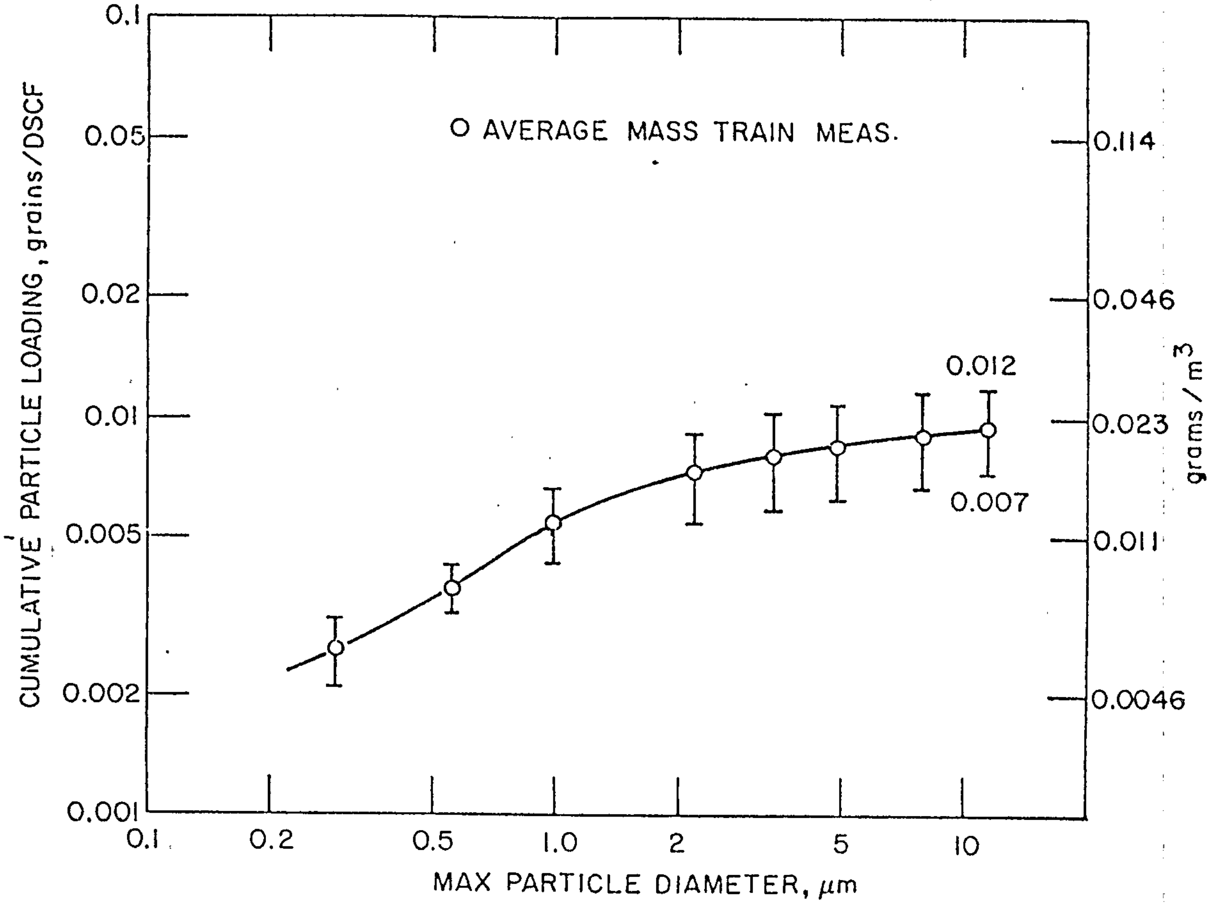

Figure 7-2. Cumulative Particle Size Distribution at the Outlet of a Hot Side Electrostatic Precipitator[4]

Table 7-3

PARTICULATE SOLIDS GENERATION FROM A 1000 MEGAWATT

COAL-FIRED POWER PLANT AT VARIOUS LEVELS OF CONTROL[a]

Control Level Nanograms per Joule (lb/10^6 Btu)	Fly Ash Generation[(c)] Gigagrams per Year (tons/yr)	Percent Increase Over 43 Nanograms/Joule
43 (0.1)[b]	169.72 (186,953)	0
21 (0.05)	171.02 (188,376)	0.76
13 (0.03)	171.53 (188,946)	1.07

(a) Based on:
1. Heat value of 27.93 megajoules per kilogram (12,000 Btu/lb)
2. 10 percent ash
3. 80 percent of ash emitted as fly ash
4. 0.3410 joules output per joule input (10,000 Btu/KwHr)
5. Plant operation of 5694 hours per year at full load

(b) Current new source performance standard

(c) Dry basis. Mass of wet ash would be two to three times as much as the mass of dry ash.[5]

7.3 WATER POLLUTION IMPACT

Potential water pollution from removal of particulates from combustion gases includes the following:

1. Pollution from sluicing fly ash from dry type collection systems.
2. Pollution from disposal of liquor from scrubber systems, and
3. Pollution from leaching of fly ash wastes.

As shown by Figures 7-1 and 7-2, the additional particulate removed in the range less than 43 nanograms per joule (0.1 lb/10^6 Btu) would be less than 10 micrometers in diameter. Collection of small diameter particles tends to increase the water pollution potential of fly ash because smaller particles leach more readily and because it is more difficult to separate the smaller particles from sluicing water. Any water pollution which might be caused by collection of smaller particulates can be prevented by operating fly ash sluicing systems in total recycle and by lining settling ponds and disposal sites to prevent contamination of streams or ground waters.

7.4 ENERGY IMPACT

Table 7-4 shows the energy consumption of various particulate emission control systems at various levels of control. As shown, the baghouse is the most energy efficient particulate control system. The particulates generated in producing the electrical energy to run the various particulate emission control systems ranges from 20.7 megagrams (22.8 tons) per year for a scrubber to 3.1 megagrams (3.4 tons) per year for a baghouse. The particulate produced in generating energy for particulate control is insignificant compared with the some 170,000

TABLE 7-4

ESTIMATED POWER CONSUMPTION AND POLLUTION FROM PARTICULATE CONTROL AT A 1000 MEGAWATT POWER PLANT

	Control Level		
	13 Nanograms per Joule (0.03 lb/10^6 Btu)	22 Nanograms per Joule (0.05 lb/10^6 Btu)	43 Nanograms per Joule (0.1 lb/10^6 Btu)
A. Power Consumption - Megawatts			
Scrubber Total[9]	--	12[c]	8[d]
Scrubber Incremental[a]	--	8	4
Electrostatic Precipitator - Total[6,7]	9	8	6
Electrostatic Precipitator - Incremental[a]	5	4	2
Baghouse Total[8,9]	4[e]	--	--
Baghouse Incremental[a]	0	--	--
B. Particulate Air Emissions From[b] Air Pollution Control Energy Production - Megagrams per Year (Tons/Yr)			
Scrubber Total Particulate	--	15.5 (17.1)	20.7 (22.8)
Scrubber Incremental - Particulate[a]	--	12.4 (13.7)	17.6 (19.4)
Electrostatic Precipitator Total Particulate	7.0 (7.7)	10.3 (11.4)	15.5 (17.1)
Electrostatic Precipitator Incremental Particulate[a]	3.6 (4.0)	7.3 (8.0)	12.4 (13.7)
Baghouse Total Particulate	3.1 (3.4)	--	--
Baghouse Incremental Particulate[a]	0	--	--

[a] As compared with baghouse

[b] Assumes 0.34 joules heat input per joule electrical output (10,000 Btu/kw hr) and 5694 operating hours per year

[c] 3.75 kilopascals (15 in. H_2O) pressure drop

[d] 2.5 kilopascals (10 in. H_2O) pressure drop

[e] 1.25 kilopascals (5 in. H_2O) pressure drop

megagrams (187,000 tons) removed from the atmosphere by the pollution control systems as shown in Table 7-3.

Table 7-4 shows the energy consumption of ESP systems as a function of control level.[6] Most of the energy consumed by an ESP system is used to produce the electrical field.[7] Most of the energy consumed by baghouses and scrubbers is used to overcome pressure drop.[8,9] A high efficiency baghouse operating at 1.25 kilopascals (5.0 in. H_2O) pressure drop uses about 0.4 percent of the power generating capacity of the coal-fired unit. A high efficiency scrubber operating at 3.75 kilopascals (15 in. H_2O) pressure drop uses about three times as much power as a baghouse.

7.5 OTHER ENVIRONMENTAL IMPACT

More efficient particulate control has no effect on noise pollution.

REFERENCES FOR CHAPTER 7

1. Unpublished data, Source Receptor Analysis Branch, Monitoring and Data Analysis Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, N.C., June, 1975.
2. Part 50, Title 40, Code of Federal Regulations, November, 1977.
3. Coal-Fired Power Plant Trace Element Study, U. S. Environmental Protection Agency, Rocky Mountain-Prairie Region, Region VIII, Denver, Colorado, September, 1975.
4. Particulate Collection Efficiency Measurements on Three Electrostatic Precipitators, EPA 600/2-75-056, U. S. Environmental Protection Agency, Research Triangle Park, N. C., October, 1975.
5. Final Report - Sulfur Oxide Throwaway Sludge Evaluation Panel, U. S. Environmental Protection Agency, Research Triangle Park, N.C., September, 1974.
6. Electrostatic Precipitator Costs for Large Coal-Fired Steam Generators, U. S. Environmental Protection Agency, Research Triangle Park, N.C., February, 1977.
7. A Manual of Electrostatic precipitator Technology, PB 196381, U.S. Environmental Protection Agency, Research Triangle Park, N.C., August, 1970.
8. Handbook of Fabric Filter Technology, Fabric Filter Systems Study, PB 200648, U. S. Environmental Protection Agency, Research Triangle Park, N.C., December, 1970.

9. Unapproved Draft, The Energy Requirements for Controlling SO_2 Emissions from Coal-Fired Steam/Electric Generators, U. S. Environmental Protection Agency, Research Triangle Park, N.C., November, 1977.

8 COST ANALYSIS OF ALTERNATIVE CONTROL SYSTEMS

8.1 INTRODUCTION

This section will discuss the control systems, the model plant sizes and the types of coal considered in the analysis. These variables were selected to provide a realistic spread of conditions that might occur within the industry. In all, 38 cases were studied. Two types of coal were considered, a coal containing 0.8 percent sulfur, 8.0 percent ash, and a heat value of 23.3 (MJ/Kg (10,000 Btu/lb); and a coal containing 3.5 percent sulfur, 14 percent ash, and a heat value of 27.9 MJ/Kg (12,000 Btu/lb).

8.2 CONTROL SYSTEMS

Three control systems were considered. Fabric filters are designated as Type 1 and will provide very high efficiencies at a 2:1 air-to-cloth ratio. Electrostatic precipitator systems, designated Type 2a, 2b, and 2c, can be provided to meet varying levels of efficiency depending upon the size of the precipitator. Control Type 3 represents venturi scrubbers with a 0.2 meters (8") water gauge pressure drop and a liquid-to-gas ratio of 54 cubic meters of liquid per thousand actual cubic meters of gas (40 gallons per 1000 acf).

8.3 PLANT SIZES

In order to cover the range of plant sizes likely to be erected in the future four sizes were selected for the electrostatic precipitator and venturi scrubber, 25, 100, 500, and 1000 MW. Data was available from another source for fabric filters in the plant sizes 200, 500, and 1000 MW.

8.4 DEVELOPMENT OF COST ESTIMATES

8.4.1 Capital Costs

Fabric filter costs were generated from vendor sources which provided installed costs of equipment. These costs were escalated from 1977 to August 1980 using a 7.5% annual inflation rate. Indirect costs covering interest during construction, field overhead, engineering, freight, offsites, taxes, spares, and start-up were calculated to be 33.75% of installed cost. Finally, a contingency allowance of 20 percent of the total was added to reach the final turnkey investment. Since fabric filter costs depend more upon the pollutant being removed than upon the required efficiency, only one type of filter was considered, a high temperature unit with an air-to-cloth ratio of 2 to 1. Table 8-1 presents fabric filter costs.

Electrostatic precipitator turnkey costs were calculated the same way as the fabric filters with the indirect costs amounting to 33.75 percent of the installed equipment cost plus a 20% contingency factor. The removal efficiency of the electrostatic precipitator is a function of the plate area and the cost is also a function of the plate area. Therefore, three sizes of precipitators, designated Control Type 2a, 2b, and 2c, were costed. The sizes varied from 78 to 128 square meters of plate per actual cubic meters per second of gas (400 to 650 square feet per 1000 acfm)for hot side precipitators for low sulfur coal.

Table 8-1. TYPE 1 CONTROLS: FABRIC FILTER INVESTMENT AND ANNUALIZED COSTS (1980 Dollars)

Sulfur Content	Ash Content	Boiler Size (MW)	Investment[1] ($/Kw)	Annualized Cost (mills/kWh)[2]
0.8%	8.0%	200	69.47	2.30
		500	58.45	1.96
		1000	53.56	1.81
3.5%	14.0%	200	59.89	1.97
		500	51.83	1.72
		1000	46.73	1.58

[1] Air-to-cloth ratio 0.01 $m^2/(am^3/s)$, or 2 acfm/sq. ft.

[2] Annualized cost is calculated at a load factor of 65% and includes cost of power @ 25 mills/kWh to operate control equipment.

For high sulfur coal the sizes varied from 47 to 71 square meters per actual cubic meters per second of gas (240 to 360 square feet per 1000 acfm) for cold side units. Table 8-2 presents the costs for the electrostatic precipitator cases.

The costs for the venturi scrubbers were calculated using the PEDCo Environmental FGD computer cost program. Since all of the FGD units in the program had venturi units upstream of the sulfur oxide scrubbers, the venturi costs were obtained by subtraction. The units, which are designated Control Type 3, utilize an 0.2 meter (8") water gauge pressure drop and a 54 cubic meters of liquid to one thousand actual cubic meter of gas (40 gallons per 1000 acfm). Costs for the venturi appear in Table 8-3.

For the types of control systems studied and the parameters chosen it would appear that fabric filters are the more economical choice for low sulfur coals and electrostatic precipitators for high sulfur coals. Figures 8-1 and 8-2 depict these relationships.

8.4.2 Annualized Costs

The total annualized costs consist of two categories: direct operating costs and annualized capital charges. Direct operating costs include fixed and variable annual costs such as:

° Labor and materials needed to operate control equipment;

° Maintenance labor and materials;

° Utilities which include electric power, fuel, cooling and process water, and steam;

° Treatment and disposal of liquid and solid wastes.

Table 8-2. TYPE 2 CONTROLS: ELECTROSTATIC PRECIPITATOR INVESTMENT AND ANNUALIZED COSTS (1980 Dollars)

Type	Sulfur Content	Ash Content	Boiler Size (MW)	ESP Location	Specific Collection Area $m^2/(1000\ m^3/s)$	Specific Collection Area $ft^2/1000$ acfm	Investment ($/kw)	Annualized Cost[1] (mills/kWh)
2a	0.8%	8.0%	25	Hot Side	79	400	134.60	6.51
			100				76.06	3.59
			500				52.53	2.46
			1000				50.15	2.34
	3.5%	14.0%	25	Cold Side	47	240	91.80	4.56
			100				51.11	2.40
			500				26.85	1.25
			1000				23.61	1.10
2b	0.8%	8.0%	25	Hot Side	108	550	171.40	8.19
			100				90.67	4.29
			500				68.45	3.21
			1000				65.13	3.04
	3.5%	14.0%	25	Cold Side	59	300	89.80	4.49
			100				53.16	2.50
			500				28.21	1.31
			1000				24.76	1.15
2c	0.8%	8.0%	25	Hot Side	128	650	182.20	8.71
			100				98.22	4.65
			500				80.71	3.77
			1000				73.37	3.43
	3.5%	14.0%	25	Cold Side	71	360	91.00	4.56
			100				57.32	2.69
			500				31.82	1.49
			1000				28.96	1.35

[1] Annualized cost based on 65% load factor and includes the cost of power at 25 mills/kWh to operate the control equipment.

Table 8-3. TYPE 3:CONTROLS VENTURI SCRUBBER INVESTMENT AND ANNUALIZED COSTS (1980 Dollars)

Sulfur Content	Ash Content	Boiler Size (MW)	Investment[1] ($/kW)	Annualized Cost[2] (Mills/kWh)
0.8%	8%	25	111.04	5.78
		100	101.04	5.23
		500	58.93	3.17
		1000	46.07	2.34
3.5%	14.0%	25	112.52	5.93
		100	99.97	5.28
		500	58.67	3.22
		1000	57.21	3.14

[1]Based on 0.2 metre (8") water gauge pressure differential and a liquid to gas ratio of 54 $m^3/(1000\ am^3)$ or 40 gallons per 1000 acfm.

[2]Annualized costs are based on a 65% load factor and include the power at 25 mills/kWh to run the control system.

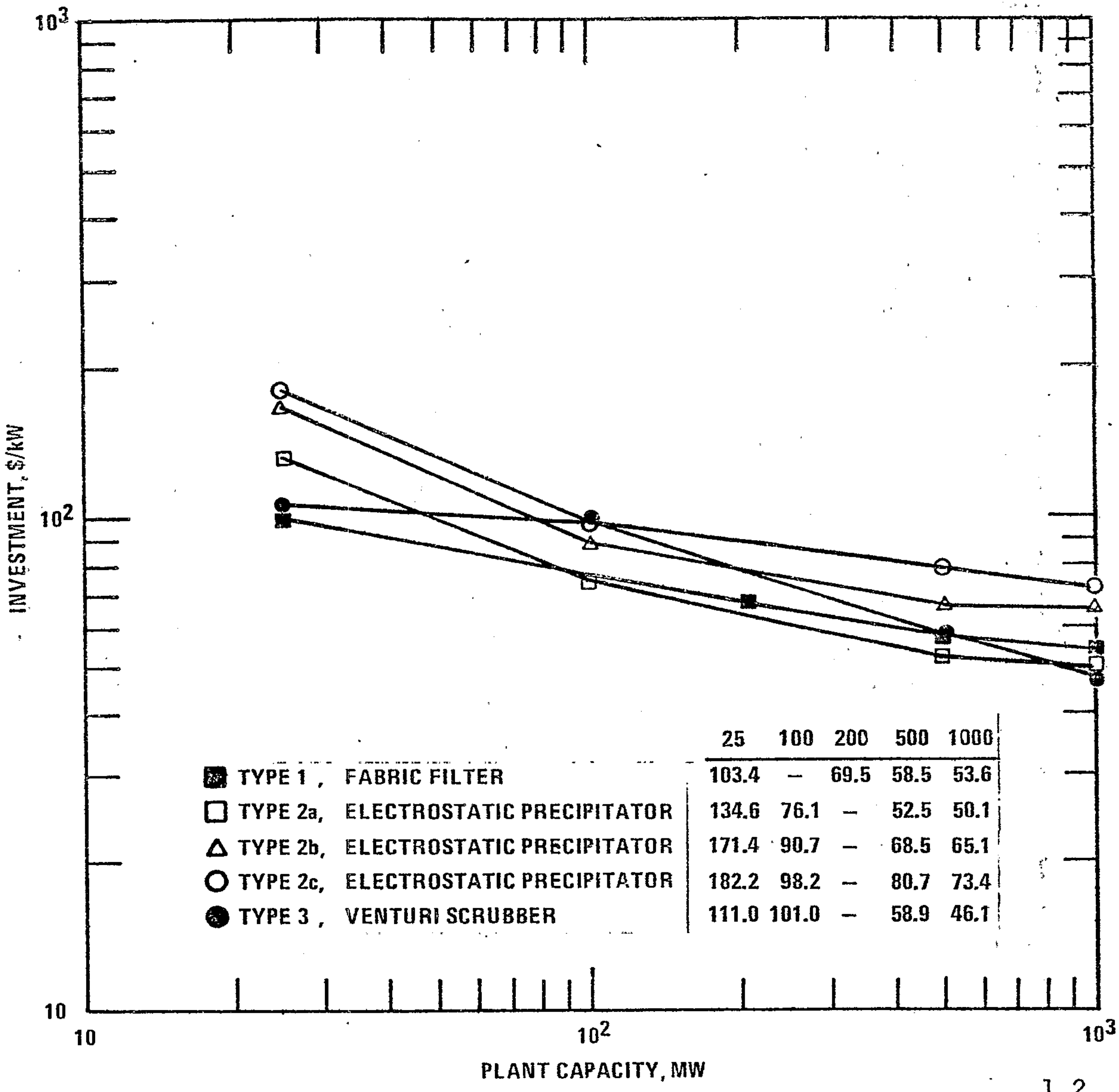

Figure 8-1. Cost of controlling low sulfur coal investments in 1980 dollars.[1,2]

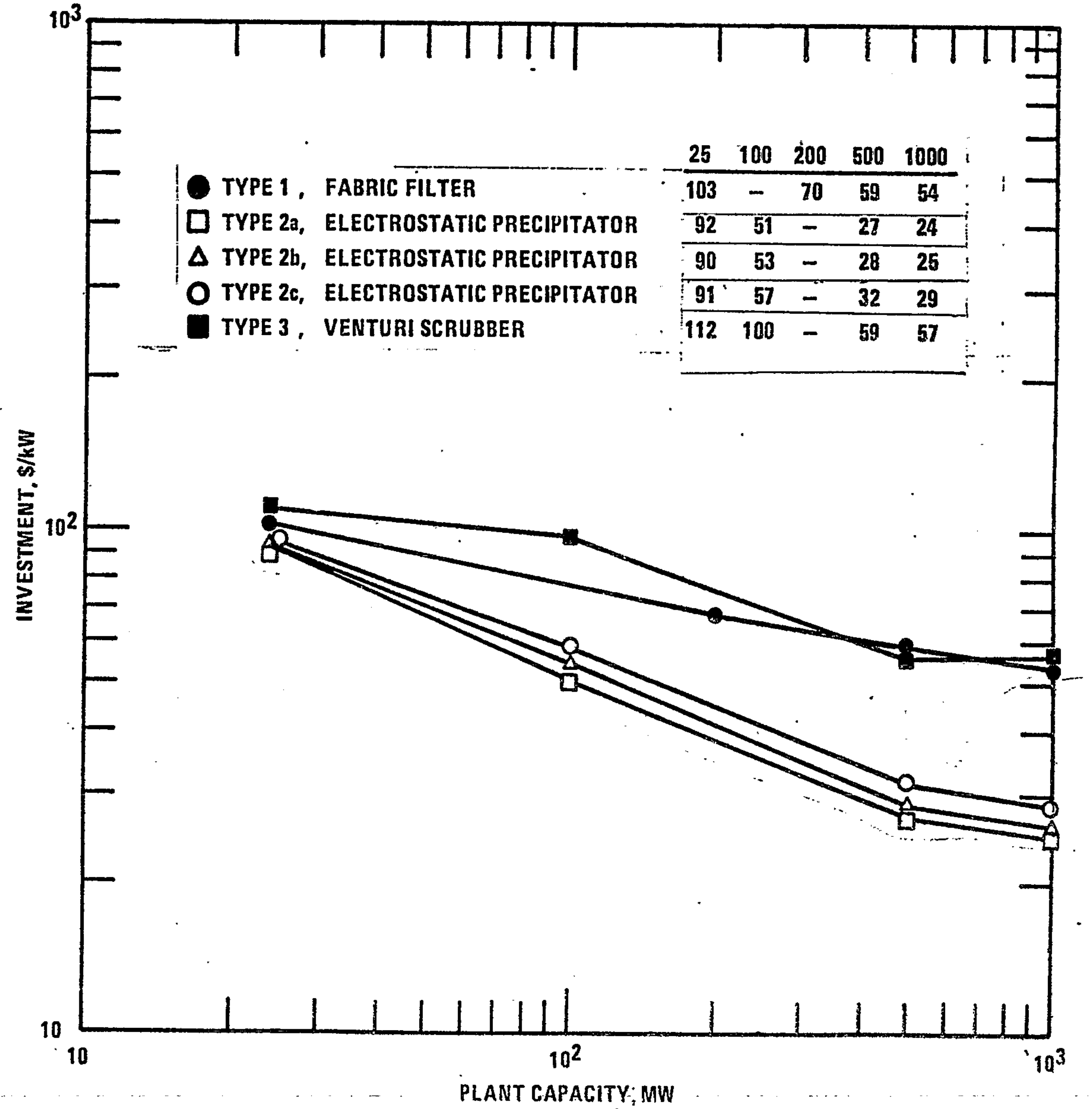

Figure 8-2. Cost of controlling high sulfur coal investments in 1980 dollars.[1,2]

8-8

Annualized capital charges include capital recovery factors representing 10% interest over a 20 year life for ESP's and fabric filters and over a 10 year life for venturi scrubbers. An additional 4 percent of total investment was also added to cover general administration, property taxes, and insurance. The mills per kilowatt-hour were computed using a 65 percent operating factor.

8.5 MONITORING COSTS

In the case of a new electrical generating station where the stack is already equipped with access ports and platforms to enable the initial performance tests to be done, the additional investment for continuous monitoring equipment is approximately $40,000. Annualized costs run $7,000 to $8,000. For a 500 MW station, this amounts to 0.003 mills per kilowatt hour. For the purpose of the analysis, this cost was neglected.

8.6 COST COMPARISONS

Figure 8-3 compares PEDCo Environmental investment costs for fabric filters with the cost of filters installed on utility units at Sunbury and Nucla. The upper set of PEDCo costs represent the low sulfur (0.8%) units and the lower set, the high sulfur (3.5%) units. The Sunbury and Nucla stations fire 1.8% and 0.7% sulfur coal, respectively.

Figure 8-4 gives electrostatic precipitator investment costs for hot side units for several individual stations as well as costs for hot side units calculated by the Southern Research Institute in <u>A Review of Technology for Control of Fly Ash Emissions From Coal in Electric Power Plants</u>, July 1, 1977, pages 13 and 62.

Figure 8-5 shows the comparison of venturi scrubber investment costs between PEDCo and several specific units cited on page 121 of the above mentioned SRI report.

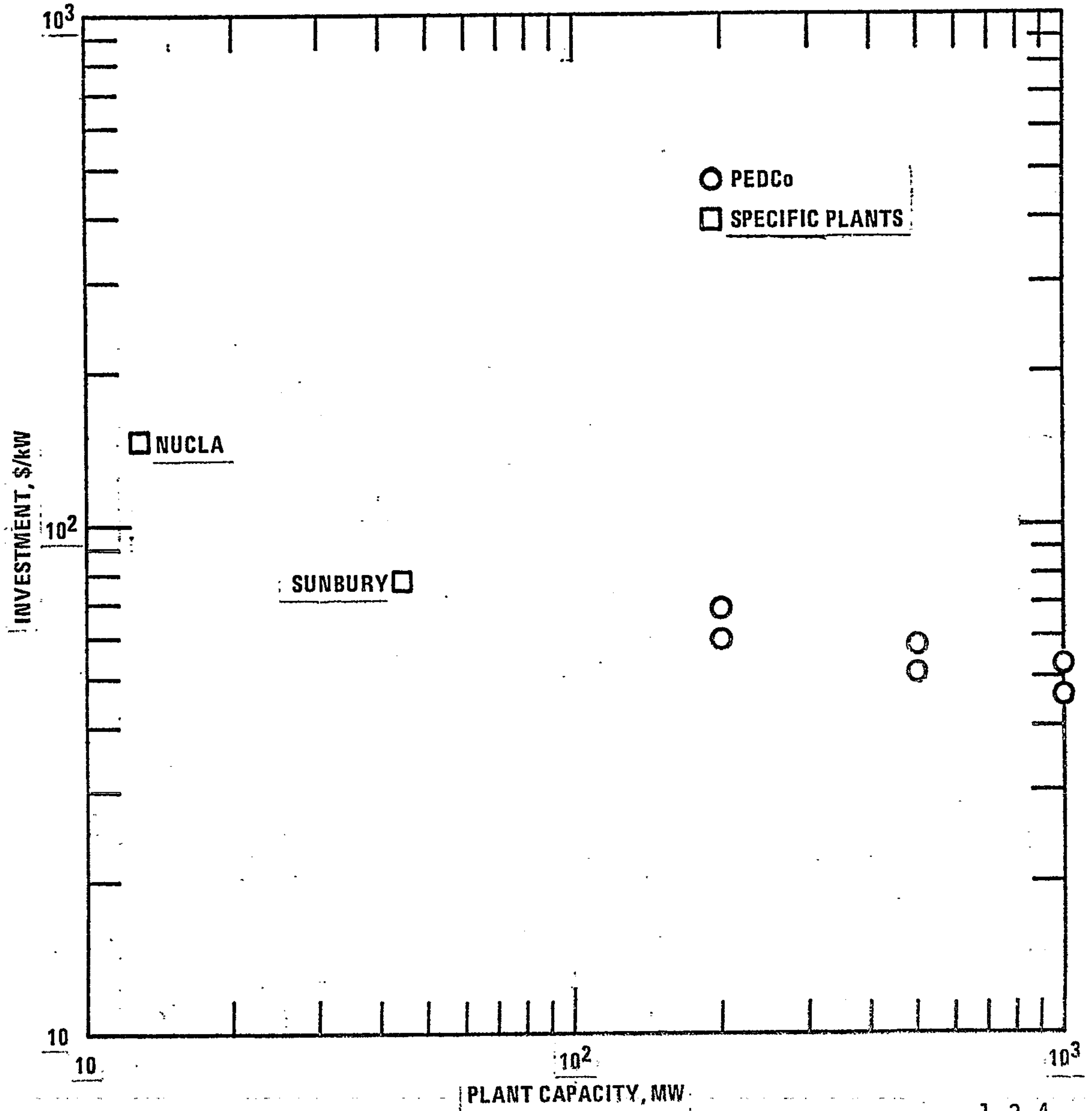

Figure 8-3. Investment cost comparison, fabric filters, (1980 dollars).[1,3,4]

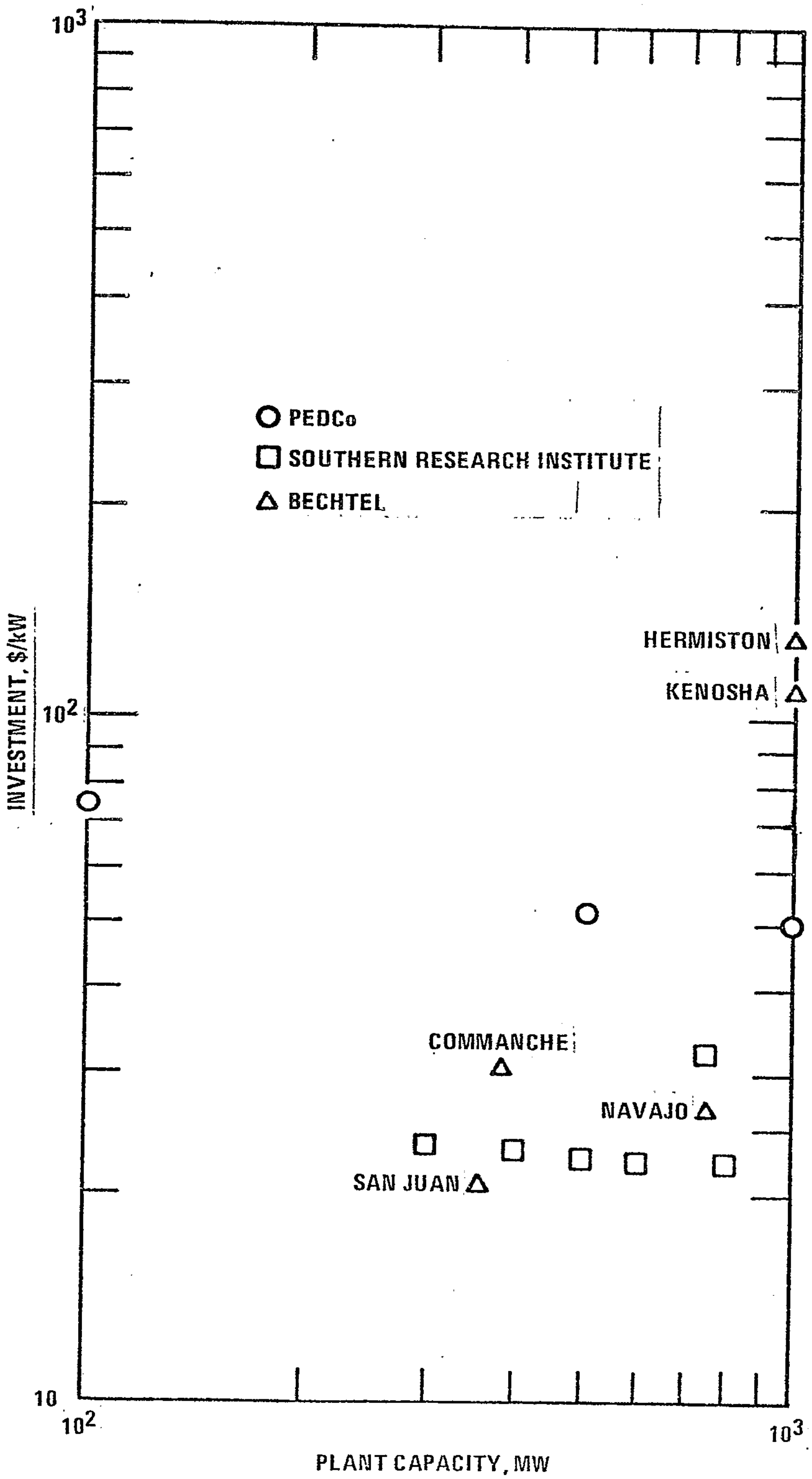

Figure 8-4. Investment cost comparison, electrostatic precipitators, low sulfur coal, (1980 dollars).[1,5,6]

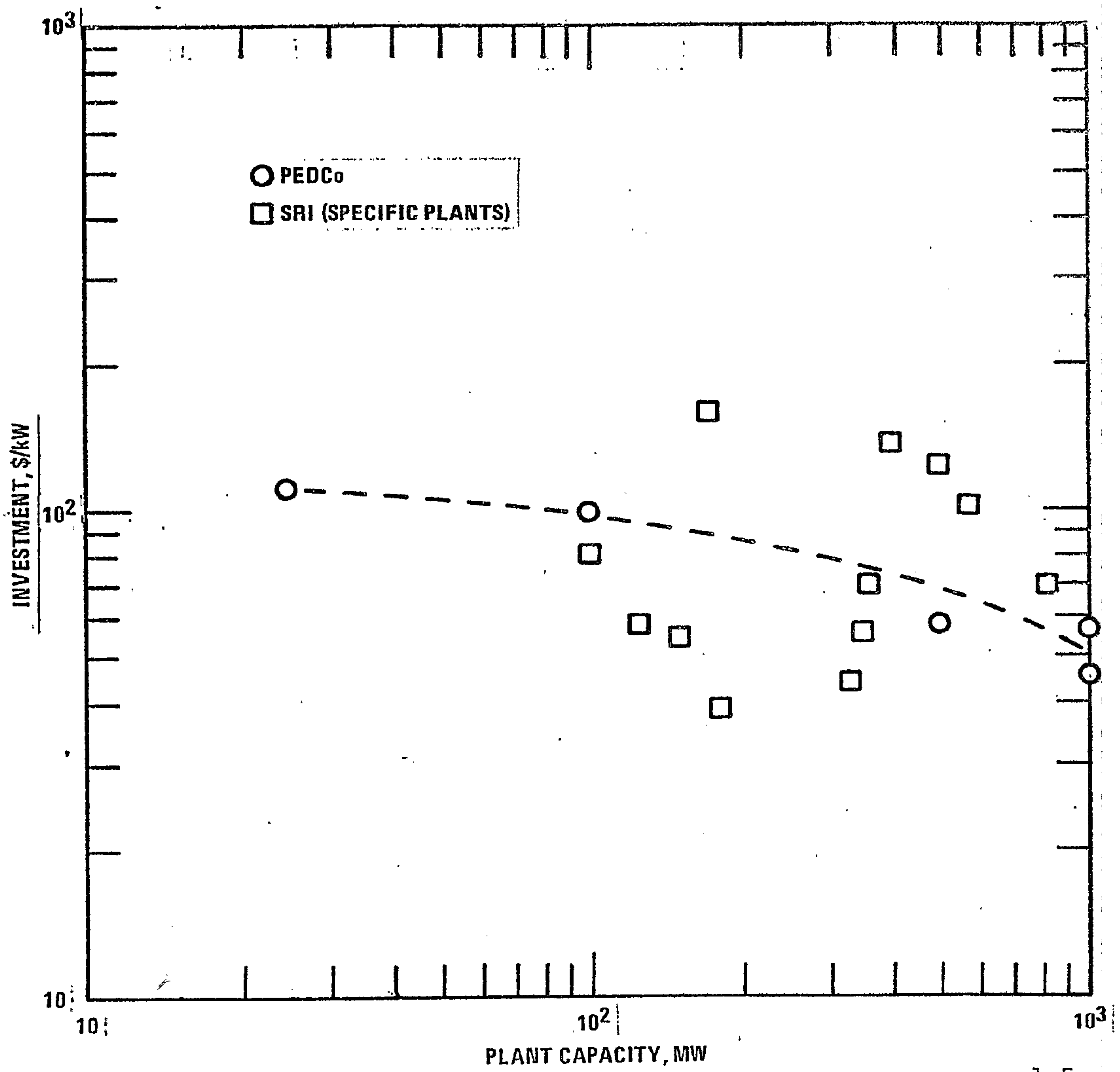

Figure 8-5. Investment cost comparison, venturi scrubbers, (1980 dollars).[1,5]

8.7 MODIFICATION AND RECONSTRUCTION

As discussed in Chapter 5, there is little possibility that any existing power boilers will be subject to the modification and reconstruction provisions of the Act. For this reason, no retrofit costs are included.

REFERENCES FOR CHAPTER 8

1. Particulate and Sulfur Dioxide Emission Control Costs for Large, Coal-Fired Boilers, EPA Contract No. 68-02-2535, Task 2, PEDCo Environmental, Cincinnati, Ohio, 1977.

2. Particulate Control Costs for Intermediate Sized Boilers, EPA Contract No. 68-02-1473, Industrial Gas Cleaning Institute, Stamford, Connecticut, February, 1977.

3. Fractional Efficiency of a Utility Boiler Baghouse, Sunbury Steam Electric Station, EPA 600/2-76-077a, Industrial Environmental Laboratory, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, March, 1976.

4. Fractional Efficiency of a Utility Boiler Baghouse - Nucla Generating Plant, EPA 600/2-75-013a, Industrial Environmental Research Laboratory, U. S. Environmental Protection Agency, Research Triangle Park, North Carolina, August, 1975.

5. Preview of Technology for the Control of Fly Ash Emissions From Coal in Electric Power Generation, Southern Research Institute, Birmingham, Alabama, July, 1977.

6. Coal-Fired Power Plant Capital Cost Estimates, Bechtel Power Corporation, San Francisco, California, January, 1977.

9. TECHNICAL STUDIES TO DEFINE PERFORMANCE OF THE BEST SYSTEM OF EMISSION REDUCTION

9.1 SELECTION OF SOURCE FOR CONTROL

Fossil-fuel-fired steam generators of 73 megawatts (MW) heat input (250 million/Btu hour) or more are considered large steam generators and would produce enough steam to generate 25 megawatts or more electric power. The largest fossil-fuel-fired steam generator constructed in the United States produces enough steam to generate 1300 MW of electricity. A typical size unit would produce enough steam to generate 500MW of electric power. Approximately 90 percent of all large fossil-fuel-fired steam generators constructed are for use as electric utility steam generation units.

At the end of 1975, the total capacity of utility fossil-fuel-fired steam generator power units was approximately 350 gigawatts. Sixty percent of this steam generating capcity was fired by coal and the remainder was about equally split between gas and oil.

About 27 percent of the fuel consumed in the United States is used to generate electric power. A significant and continual increase in electrical generation capacity is projected to occur. Fossil fuel fired steam electric generation capacity is expected to increase from 350 gigawatts in 1975 to more than 700 gigawatts in 1995 (approximately a 5 percent increase per year).

9.2 SELECTION OF POLLUTANTS AND AFFECTED FACILITIES

Particulate emissions from stationary combustion sources are 5.1 teragrams/yr (5.6 million tons/yr) as compared with 15.6 teragrams/yr (17.0 million tons/yr) from all sources. Particulate matter emissions from large utility fossil-fuel-fired generators are 3.1 teragrams/yr (3.5 million tons/yr) or a little more than one-half of the particulate emissions from all stationary combustion sources. Nearly all of the particulate matter emitted from electric utility sources is from coal-fired steam generators.

9.3 SELECTION OF THE BEST SYSTEM OF CONTINUOUS EMISSION REDUCTION

The device that has been most commonly used for high efficiency removal of particulates from the combustion gases of coal-fired and oil-fired steam generators is the electrostatic precipitator (ESP). The use of baghouses for high efficiency particulate control is becoming more common, especially for Western coals where the coal ash is difficult to collect with an ESP.

Mechanical collectors such as cyclones and settling chambers are not efficient enough to reduce particulate emissions to the levels required by current new source performance standards or the proposed revision.

Based on EPA investigations, EPA considers the best demonstrated system of continuous emission reduction to be baghouse control systems and and high efficiency ESP's. Baghouses and high efficiency ESP's can reduce reduce particulate emissions to a level of 13 ng/J (0.03 lb/million Btu) which is about one-third of the current standard. The annualized cost to comply with the current standard (43 ng/J, 0.1 lb/million Btu) using an ESP would be 2.9 mills/kWhr for Western coal and 1.3 mills/kWhr for Eastern coal. An emission level of 13 ng/J (proposed standard) can be achieved at an annualized cost of 1.96 mills/kWhr for Western coal (baghouse) and 1.59 mills/kWhr for Eastern coal (high efficiency ESP). Achievement of the proposed particulate matter emission standard would result in less than a 1 percent increase in retail electrical cost.

9.4 SELECTION OF THE FORMAT FOR THE PROPOSED EMISSION STANDARD

Guidance in selection of the format of the proposed emission standard was provided by the Clean Air Act Amendments of 1977 which requires that the performance standard for stationary fossil-fuel-fired steam generators include (1) an emission limitation, and (2) a percentage reduction in emission levels that could have resulted from combusting fuel without emission control or fuel pretreatment. The emission limitation is developed in units of emissions per unit heat input, namely, nanograms per joule (ng/J) and lb/million Btu. The percentage reduction requiremepmt is based on actual particulate matter emissions to the atmosphere and estimated uncontrolled emissions. Because of the technical difficulties of sampling particulate in the restrictive flow field that typically exists upstream of a particulate matter control device, an uncontrolled emission rate is defined and is incorporated into the proposed regulation in place of actual sampling upstream of the particulate matter control device. The uncontrolled emission rate is used in conjunction with the emission test data to determine the percentage reduction achieved. Compliance with the emission limitation will result in compliance with the percentage reduction requirement.

9.5 SELECTION OF EMISSION LIMITS

The proposed standard is based on the performance of a well designed and operated baghouse or ESP. EPA has determined that these systems are the best systems for continuous control of particulate matter emissions from electric utility steam generators (considering energy, cost, and environmental impact). EPA collected particulate emission data from 8 baghouse equipped coal-fired steam generators. Emission data from 6 of the 8 steam generators showed emission levels less than 13 ng/J heat input (0.03 lb/million Btu). Baghouses with an air to cloth ratio of 0.6 actual cubic meters per minute per square meter (2 ACFM/ft^2) will achieve the proposed emission limit at pressure drops of less than 1.25 kilopascals (5 in. H_2O). EPA considers these air/cloth ratios and pressure drops reasonable when considering cost, energy, and nonair quality impacts.

EPA collected data from 21 steam generators controlled with ESP's. The results from the tests determined 9 of the 21 had emission levels lower than the proposed standard. Emission levels as low as 4 ng/J heat input (0.01 lb/million Btu) were observed when firing a low sulfur coal. Many factors must be considered in an ESP design. A properly designed ESP would have specific collection areas from 128 to 197 square meters per actual cubic meter per second (650-1,000 ft^2/1000 ACFM) when firing a difficult coal. EPA believes that such specific collection areas are reasonable considering cost, energy, and nonair environmental impacts.

EPA collected emission test data from 7 coal-fired steam generators controlled by wet particulate matter scrubbers. Data from 5 of the 7 resulted in emission levels less than 21 ng/J heat input (0.05 lb/million Btu). Data from only 1 of the 7 were less than 13 ng/J (0.03 lb/million Btu) heat input. The data suggests that particulate matter scrubbers, under certain conditions, can achieve emission levels below the proposed standard; however, EPA believes that wet particulate matter scrubbers are limited in their ability to comply with the proposed standard and under most conditions would have difficulty complying with the proposed standard.

Baghouse operating performance is only nominally affected by the ash properties of the fuel fired, but ESP performance is very sensitive to fly ash properties. ESP's have been traditionally used to control particulate emissions from power plants combusting high sulfur coals. High sulfur coal produces fly ash with a low electrical resistivity which can be more easily collected with an ESP. However, low sulfur coals produce fly ash with high electrical resistivity which is more difficult to collect with a conventional ESP. At times, the problem of fly ash with high electrical resistivity can be reduced by using a hot side ESP (ESP located before combustion air preheater) when firing low sulfur coals. Higher fly ash collection temperatures improve ESP performance by reducing fly ash resistivity for most types of low sulfur coal (for example, increasing the fly ash collection temperature from 177°C (350°F) to 204°C (400°F) can reduce electrical resistivity of fly ash from low sulfur coal by approximately 60 percent).

The Clean Air Act Amendments of 1977 require that EPA specify, in addition to an emission limitation, a percent reduction in uncontrolled emission levels for fossil-fuel-fired stationary sources. The proposed standard would require a 99 percent reduction requirement for solid fuels and a 70 percent reduction requirement for liquid fuels. Because of the difficulty of sampling particulate matter upstream of the control device (due to the complex particulate matter sampling conditions), the proposed standard does not require direct performance testing for the percent particulate matter emission reduction level. Instead, EPA has defined an uncontrolled particulate matter emission rate of 3000 ng/J heat input (7.0 lb/million Btu) for solid fuels and 75 ng/J heat input (0.17 lb/million Btu) for liquid fuels. The percent reduction would not require particulate matter emissions to be less than required by the emission limitation (13 ng/J). The emission limitation would determine the emission level at which a unit must operate, and would assure that the percent reduction requirement is achieved. (The uncontrolled particulate emission rates defined by EPA in these regulations are based on average emission factors. Actual uncontrolled emission rates may vary for specific cases). A percentage reduction requirement would not apply for gaseous fuels since a particulate matter control device would not be required.

EPA has investigated the performance of flue gas desulfurization (FGD) control systems to determine whether they affect particulate matter emissions. Three possible mechanisms were investigated: (1) FGD system sulfate carryover from the scrubber slurry, (2) particulate matter removal by the FGD system, and (3) particulate matter generation by FGD system through condensation of sulfuric acid mist (H_2SO_4).

To address the first problem, EPA obtained data from three steam generators that were equipped with a FGD system and that had low particulate matter emission levels. The data from all three tests indicated that particulate emissions did not increase through the FGD system. Proper mist eliminator design is important in preventing scrubber liquid entrainment. Although no data were found to support the following, it may be possible that reentrainment of sulfates from improperly designed mist eliminator systems or reentrainment from FGD systems which are operated with partially plugged mist eliminators could cause the outlet particulate loading to exceed inlet particulate loading.

In relation to the second interaction mechanism, FGD system removal of particulate matter, the data from the three FGD systems available to EPA indicated that particulate matter emissions were reduced by the FGD systems in all 3 cases. That is the particulate matter discharge concentration from the FGD system was less than the inlet concentration. This property has been particularly noted at steam generators equipped with ESP's upstream of FGD systems.

The third interaction mechanism investigated was the potential condensation of sulfuric acid mist (H_2SO_4) from sulfur trioxide (SO_3) in the flue gas. At a typical steam generator most fuel sulfur is converted to SO_2 and a small portion (1-3 percent) is discharged as SO_3. The higher the sulfur content of the fuel being fired, the higher the SO_2 and SO_3 concentrations in the flue gas. Typical stack gas temperatures at a coal-fired steam generator without a FGD system would be between 150°C and 200°C (300°F - 400°F). At such temperatures, the sulfuric acid (mist) remains in its gaseous form (SO_3). However, if flue gas temperatures are reduced sufficiently, the SO_3 would become saturated and condense as sulfuric acid mist (particularly when firing high sulfur coal and producing higher SO_2 concentrations). Gases treated by a FGD system may exit at temperatures as low as 50°C (125°F). If a stack gas reheating system would be used, it would typically reheat flue gases to approximately 80°C (175°F). For sulfuric acid, the dew point temperature would be expected to range between 120°C (250°F) and 175°C (350°F). The lower temperature would correspond to low sulfur coal and higher temperatures would correspond to high sulfur coal.

Available test data indicate that a FGD system would remove about 50 percent of the SO_3 in the flue gas and thus reduce the potential for sulfuric acid mist formulation. However, if sulfuric acid mist is formed in the flue gases, there is a potential for its interaction with the particulate matter performance test. Under Method 5, a sample is extracted at 160°C (320°F) probe temperature. Under current conditions (most power plants do not have FGD systems), this would assure that SO_3 did not condense in the sampling train and would allow it to pass through the filter. However, there is a potential for sulfuric acid mist to form at the low flue gas temperatures typical of power plants with FGD systems (particularly when combusting high sulfur coal), and to interact within the sampling train to form sulfate compounds that are not "driven off" at 160°C (320°F). Also, sulfuric acid mist may be deposited within the test probe. In both cases, the sulfuric acid mist interaction may ultimately be measured as particulate matter.

The proposed particulate matter standard is based on emission levels achieved at the discharge of particulate matter control devices.

EPA obtained data from three FGD equipped power plants firing low sulfur coal. The data indicated that SO_2 condensation to sulfuric acid mist was not a problem. EPA believes this data supports the conclusion that FGD units on low sulfur coal-fired power plants do not increase particulate emissions through sulfuric acid formation and interaction. Thus, EPA believes compliance with the proposed particulate matter standard is demonstrated to be achievable when firing low sulfur coal.

In a case where a FGD is used with higher sulfur coal, sufficient data have not become available to fully assess sulfuric acid mist interaction. The proposed standard is based on emission test data at the particulate matter control device discharge. EPA will continue to investigate this subject and will consider its impact on the particulate matter standard as data becomes available.

9.6 VISIBLE EMISSION STANDARDS

The opacity standard of 20 percent (6-minute average) is based on the current opacity standard. In cases when the proposed opacity standard is not achieved during a performance test, but the particulate emission standard is being achieved, the general provision of Part 60 [60.11(e)] allows an owner or operator of the affected facility to request that a source specific opacity standard be established.

9.7 MODIFICATION/RECONSTRUCTION CONSIDERATIONS

It is doubtful that many existing utility steam generating units will be modified or reconstructed. Additionally, any utility steam generators that switch to coal as a fuel under the Energy Supply and

Environmental Coordination Act of 1974 (or any amendment), or because of gas curtailment plans, are not considered to be modifications under Section 111(a)(8) of the Clean Air Act Amendments of 1977. Typically, utility steam generating units are operated 30-40 years and are gradually transferred from base load units to standby units. At the end of this life period they are retired and entirely new units are built to compensate for the lost capacity. Because of the small capacity of the utility industry prior to 1940 and the rapid growth that has taken place in the utility industry since the 1940's, only a small portion of the accumulative utility capacity constructed to date has become obsolete and retired.

9.8 SELECTION OF MONITORING REQUIREMENTS

Continuous opacity monitoring is useful for determining if the particulate emission control system is properly maintained and operated (It is not used for performance testing). Continuous opacity monitoring is required unless it can be shown that there is no suitable location available which would yield meaningful opacity readings. It is not necessary to install a continuous opacity monitoring system downstream of a FGD system if it can be shown that interferences from entrainment of scrubber liquor and/or condensation of water vapor would prevent the gathering of meaningful opacity data. However, meaningful opacity readings can be obtained when there is a slight interference from entrainment or condensation of water vapor. A slight interference is defined as one where the instrument measured opacity in the stack is less than 20 percent greater than the opacity measured according to EPA Method 9 at the point of discharge to the atmosphere.

In cases where it is not possible to monitor the opacity in the stack because of interferences, the opacity is monitored ahead of the FGD system if an ESP, fabric filter, or other high efficiency dry control system is installed ahead of the FGD system. Opacity monitoring is not required ahead of a FGD system if opacity interference will result from the use of a wet particulate matter control device or if only gaseous fuel is fired.

9.9 SELECTION OF PERFORMANCE TEST METHODS

Performance testing is conducted using EPA Reference Method 9 and 5 or 17. Compliance with the emission limitation will asssure compliance with the percentage reduction requirements.

APPENDIX A

EVOLUTION OF PROPOSED STANDARDS

A.1 GENERAL

New source performance standards for particulate emissions from steam generators of more than 73 megawatts (250 x 16^6 Btu/hr) heat input were proposed on August 17, 1971, and were promulgated December 23, 1971, under authority of the Clean Air Act of 1970. The foregoing Act provided that the Administrator should, from time to time, revise these standards. During late 1975 it was decided that there were enough new developments in control of particulate emissions from large steam generators to warrant considering revising these standards. The new developments were that although no new techniques other than those known in 1971 were being used, that the effectiveness of the 1971 techniques was much better than that reflected by the limits of the 1971 standard. Consequently, the investigation was directed toward determining if particulate emission limits lower than the 1971 limits should be recommended.

Work on the study was initiated in early 1976 by making a comprehensive search of the thousands of references of the EPA Air Pollution Technical Information Center. The EPA research and development activity, Industrial Environmental Research Laboratory (IERL), was also contacted. This data, the IERL advice, and information gathered in conjunction with previous technical assistance activities, indicated that there were electrostatic precipitator (ESP) systems installed at coal-fired power plants which were controlling particulates to levels substantially below the 1971 standard of 43 nanograms per joule (0.1 lb/10^6 Btu). Some IERL test data were on hand to substantiate low emission levels, but more was needed.

The early part of the project was directed toward locating sources which generated fly ash which was difficult to collect and which were equipped with ESP systems with large collecting surface area to gas volume ratios. With the assistance of IERL and the Industrial Gas Cleaning Institute, several sources meeting these criteria were located. After screening, six were selected for study. All six of these sources were surveyed by plant visits. It was found that for three of the sources, adequate emission test data were available. Two other sources were tested by EPA. The sixth source was tested by the company with an EPA observer present.

Further emission test data were gathered from IERL and various State agencies to form a data base of tests of 21 different ESP systems. As discussed in Chapter 4, the data base shows that ESP systems are capable of achieving a limit of 13 nanograms per joule (0.03 lb/10^6 Btu) even when the most difficult to control fly ash is generated.

In January, 1977, further data indicated that baghouse technology was well enough developed to warrant consideration of application of baghouse technology to even the largest power plants. Based on this information, a telephone survey was made of 16 baghouse installations. The survey indicated baghouses were operating with few, if any, problems, and that the effectiveness of baghouses was equal, if not superior, to ESP systems. Although the baghouses surveyed were small in comparison to baghouses for large power stations, it was found that all were composed of numerous individual cells and that even the largest steam generator could be equipped by increasing the number of cells as needed to handle gas flow. Two plants equipped with baghouses were surveyed by plant visits and were subsequently tested by EPA in the spring and summer of 1977. This data base was supplemented by test results provided by IERL and by test data from the State of West Virginia to form a data base of tests of 8 different baghouse systems. As discussed in Chapter 4, the data showed baghouse systems are capable of achieving a limit of 13 nanograms per joule (0.03 lb/10^6 Btu).

Data on particulate emissions from scrubber systems equipped for flue gas desulfurization were gathered under the authority of Section 114 of the Clean Air Act of 1970 during the summer and fall of 1977. This provided data on six scrubber systems. Data on one more system was obtained from the State of Montana. The data from three IERL test projects and one company test project provided a total data base for eleven different scrubber systems. The data showed scrubbers are capable of achieving a particulate limit of 21 nanograms per joule (0.05 lb/10^6 Btu).

The results of cost studies commissioned in late 1976 were received in February, 1977. These studies and the results of additional cost and economic impact studies made in late 1977 were used to determine the cost feasibility of a lower particulate limit.

A recommended revised particulate limit of 13 nanograms per joule (0.03 lb/10^6 Btu) was reviewed before a Working Group composed of interested EPA activities and before the National Air Pollution Control Techniques Advisory Committee in December, 1977.

APPENDIX B

INDEX TO ENVIRONMENTAL IMPACT CONSIDERATIONS

This appendix consists of a reference system which is cross-indexed with the October 21, 1974, Federal Register (39 FR 37419) containing EPA guidelines for the preparation of Environmental Impact Statements. This index can be used to identify sections of the document which contain data and information germane to any portion of the Federal Register guidelines.

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
1. Background and description of the proposed action.	
- Describe the recommended or proposed action and its purpose.	The proposed regulations are summarized in Chapter 1 (section 1.1) and Chapter 9 (section 9.4). The statutory basis for the proposed regulations (section 111 of the Clean Air Act, as amended) is discussed in Chapter 2. The purpose of the proposed regulations is discussed in Chapter 9 (sections 9.1, 9.2, and 9.4).
- The relationship to other actions and proposals significantly affected by the proposed action shall be discussed, including not only other Agency activities, but also those of other governmental and private organizations.	The relationship of the proposed regulations to other actions and proposals is discussed in Chapter 1 (sections 1.1 and 1.2), Chapter 7 (section 7.3), and Chapter 9 (sections 9.2 and 9.6).
2. Alternatives to the proposed action.	
- Describe and objectively weigh reasonable alternatives to the proposed action, to the extent such alternatives are permitted by the law . . . For use as a reference point to which other actions can be compared, the analysis of alternatives should include the alternative of taking no action, or of postponing action. In	The Clean Air Act amendments of 1977 require EPA to revise existing regulations under section 111 of the Act for fossil-fuel-fired stationary sources by August, 1978. Alternative control systems are discussed in Chapter 4 (section 4.2). The environmental impact of different levels of control are discussed in Chapter 7 (section 7.2). The

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
addition, the analysis should include alternatives having different environmental impacts, including proposing standards, criteria, procedures, or actions of varying degrees of stringency. When appropriate, actions with similar environmental impacts but based on different technical approaches should be discussed. This analysis shall evaluate alternatives in such a manner that reviewers can judge their relative desirability.	economic impact of alternative control levels and systems are discussed in Chapter 8. Alternative formats for the proposed regulations are discussed in Chapter 9 (section 9.4).
- The analysis should be sufficiently detailed to reveal the Agency's comparative evaluation of the beneficial and adverse environmental, health, social, and economic effects of the proposed action and each reasonable alternative.	The environmental and energy impacts of the proposed regulations are discussed in Chapter 1 (section 1.2), Chapter 7, Chapter 8 (section 8.5), and Chapter 9 (section 9.1). Economic impacts are discussed in Chapter 1 (section 1.2) and Chapter 8. The inflationary impact is discussed in Chapter 1 (section 1.3) and Chapter 8 (section 8.5). The socioeconomic impact is discussed in Chapter 8 (section 8.5). Section 111 of the Clean Air Act does not require EPA to directly consider health effects in establishing the level of new source performance standards. However, the health effects associated with fossil-fuel-fired steam generators were considered in 1971 (36 FR 5931)

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT
ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
	when these units were listed as sources which may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare.
- Where the authorizing legislation limits the Agency from taking certain factors into account in its decision making, the comparative evaluation should discuss all relevant factors, but clearly identify those factors which the authorizing legislation requires to be the basis of the decision making.	The legislative history of new source performance standards is presented in Chapter 2. The proposed regulations are required by the Clean Air Act amendments of 1977, as discussed in Chapter 9 (sections 9.1 and 9.4).
- In addition, the reasons why the proposed action is believed by the Agency to be the best course of action shall be explained.	The rationale for the proposed regulations is presented in Chapter 9 (in particular, sections 9.3 and 9.5).
3. Environmental impact of the proposed action.	
A. Primary impact	
- Primary impacts are those that can be attributed directly to the action, such as reduced levels of specific pollutants brought about by a new standard and the physical changes that occur in the various media with this reduction.	The primary environmental impacts on mass emissions and ambient air quality are discussed in Chapter 1 (section 1.2), Chapter 7 (section 7.2), and Chapter 9 (section 9.1).

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
B. Secondary impact	
- Secondary impacts are indirect or induced impacts. For example, mandatory reduction of specific pollutants brought about by a new standard could result in the adoption of control technology that exacerbates another pollution problem and would be a secondary impact.	Secondary impacts on air and water quality, solid waste disposal, noise, and energy conservation are discussed in Chapter 1 (section 1.2), Chapter 7 (section 7.3), and Chapter 8 (section 8.5).
4. Other considerations.	
A. Adverse impacts which cannot be avoided should the proposal be implemented. Describe the kinds and magnitudes of adverse impacts which cannot be reduced in severity to an acceptable level or which can be reduced to an acceptable level but not eliminated. These may include air or water pollution, damage to ecological systems, reduction in economic activities, threats to health, or undesirable land use patterns. Remedial, protective, and mitigative measures which will be taken as part of the proposed action shall be identified.	No potential adverse side effects are expected. A more detailed discussion is presented in Chapter 6 and Chapter 9 (sections 9.3 and 9.5). Potential adverse economic impacts are discussed in chapter 8.

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT
ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
B. Relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity. Describe the extent to which the proposed action involves trade-offs between short-term environmental gains at the expense of long-term losses or vice versa and the extent to which the proposed action forecloses future options. Special attention shall be given to effects which pose long-term risks to health or safety. In addition, the timing of the proposed action shall be explained and justified.	No trade-offs are expected. This subject is discussed in more detail in Chapter 6 and Chapter 9 (sections 9.3 and 9.5). The proposed regulations are timed to become effective as quickly as possible.
C. Irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented. Describe the extent to which the proposed action curtails the diversity and range of beneficial uses of the environment. For example, irreversible damage can result if a standard is not sufficiently stringent.	There would be no irreversible and irretrievable commitments of resources as a result of the proposed regulations. See Chapter 7.

CROSS INDEXED REFERENCE SYSTEM TO HIGHLIGHT
ENVIRONMENTAL IMPACT PORTIONS OF THE DOCUMENT (continued)

Agency Guideline for Preparing Regulatory Action Environmental Impact Statements (39 FR 37419)	Location Within the Standards Support and Environmental Impact Statement
D. A discussion of problems and objections raised by other Federal, State, and local agencies and by other persons in this review process. Final statements (and draft statements if appropriate) shall summarize the significant comments and suggestions made by reviewing organizations and individuals and shall describe the disposition of issues surfaced (i.e., revisions to the proposed action to mitigate anticipated impacts of objections). In particular, they shall address in detail the major issues raised when the Agency position is at variance with recommendations and objections (e.g., reasons why specific comments and suggestions could not be adopted, and factors of overriding importance prohibiting the incorporation of suggestions). Reviewer's statements should be set forth in a "comment" and discussed in a "response." In addition, the source of all comments should be clearly identified and copies of the comments (or summaries where response has been exceptionally voluminous) should be attached to the final statement.	All comments received during the public comment period which follows proposal of the regulations will be responded to in a separate document.

APPENDIX D

EMISSION MEASUREMENT AND CONTINUOUS MONITORING

APPENDIX D

EMISSION MEASUREMENT AND CONTINUOUS MONITORING

D.1 EMISSION MEASUREMENT METHODS

Beginning in 1971 in the tests to obtain data for the existing particulate standard, and recently in the tests to obtain a data base for the proposed revision, EPA has relied primarily upon the sampling technique described in Method 5 (40 CFR Part 60 - Appendix A). This method provides detailed procedures and equipment criteria, and includes concepts considered by EPA to be necessary elements required to obtain accurate and representative results. As applied to steam generators, Method 5 initially employed a filter system located out-of-stack and operated at a temperature of 120°C. In October, 1975, the performance test requirements for steam generators were revised to allow operation of the filter system at temperatures up to 160°C. The purpose of this revision was to prevent collection of condensible gaseous compounds which would not be controllable by dry control devices operating at stack temperatures found at modern boilers. More recently, in August, 1977, revisions to Method 5 were promulgated which include clarification, and provide more detailed calibration and operating instructions.

In addition to the Method 5 tests, particulate emission data were also obtained at three plants using proposed Method 17. Two of the plants were controlled with baghouses--the third with an ESP. Method 17, which was proposed in the Federal Register on September 24, 1976 (41 FR 42020), is identical to

Method 5 except that the filter is located in the stack. Particulate samples are, therefore, collected at stack temperature which, for these three plants, ranged from 150°C to 175°C.

Method 17 allows a flexible connection between the probe and sample box and thereby has the advantage of eliminating traversing with the sample box. The method also eliminates the possible imprecision which can occur in recovering sample from long stainless steel probes which are needed for sampling the very large diameter stacks which are typical at modern steam generators. However, Method 17 is not applicable for stack gases containing saturated water vapor and, thus, is not applicable to stacks following wet scrubber systems unless demisting and reheat treatment is sufficient to raise the stack gas above its dewpoint. In order to evaluate the application of particulate methods downstream of a scrubber system, EPA has scheduled a test for early December, 1977. In this test, particulate data will be obtained using Method 17, and Method 5 operated at a filter temperature of about 160°C.

D.2 MONITORING SYSTEMS AND DEVICES

Commercially available opacity monitoring systems are suitable for use on steam generator emission stacks when stack gases do not contain liquid water droplets or mist. The performance specifications for these systems are given in Appendix B, 40 CFR Part 60. When liquid water is present in the stack gas, opacity monitors are not applicable and an alternative monitoring of particulate control may be recommended. For example, if control equipment lend themselves to the measurement of an operational parameter that is indicative of their particulate removal efficiency (e.g., the pressure drop across a venturi scrubber), then continuous monitoring of this parameter may be appropriate.

The equipment and installation costs for a single opacity monitor are estimated to be \$20,000-\$22,000. Annual operating costs, including data recording and reduction are estimated to be between \$9,000 and \$10,000.

D.3 PERFORMANCE TEST METHODS

Consistent with the data base upon which the new source standards have been established, EPA is proposing two reference methods for the measurement of particulate from steam generators--Method 5 (40 CFR Part 60 - Appendix A) and Method 17 (proposed in the Federal Register, September 24, 1976 - 41 FR 42020). Use of either method is considered to produce comparable results indicative of particulate concentrations existing at stack conditions. In most cases, Method 17 will be the preferred method due to its relative ease of use on large diameter stacks. However, as stated in the applicability section of Method 17 (paragraph 1.2), this method is not applicable for sampling wet streams. Therefore, where moisture is present, Method 5 with the filter system operated up to 160°C must be used to prevent filter plugging and to prevent possible reactions from occurring on the wet filter.

EPA Method 3 is recommended for O_2 or CO_2 and molecular weight determinations, and since O_2 and CO_2 are used to convert particulate concentration emission data into the units of the standard (lbs/10^6 Btu heat input), Method 3 samples shall be collected by traversing the stack cross section simultaneously with the particulate sampling. EPA Method 9 is recommended for the determination of opacity. No modifications to Methods 3 or 9 are required for application to testing steam generators.

The sampling cost for a test consisting of three particulate runs and three O_2 or CO_2 runs is estimated to be about \$8,000 to \$12,000 depending on the particulate method used, sampling site preparation required, and site accessability. This estimate is based on testing being conducted by independent contractors. Conducting the test with facility or plant personnel will reduce the performance test cost.

APPENDIX E

ENFORCEMENT ASPECTS

E.1 GENERAL

The candidate affected facilities discussed in this document are limited to electric utility (other than lignite) fired steam generators of more than 73 megawatts (250×10^6 Btu) gross heat input.

As discussed in Chapter 5, some changes in steam generators can cause existing sources to become subject to new source performance standards for modified or reconstructed sources.

The rules and regulations for determining if a source will be subject to new source performance standards by reason that the source is new, modified, or reconstructed, are given in Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations. In view of the multi-million dollar capital costs of large steam generators, it is suggested that interpretation of the foregoing rules and regulations be reviewed through the U. S. Environmental Protection Agency Regional Office Enforcement Division for the region where a source will be located.

The locations and addresses of these regional offices are as follows:

Region I - Connecticut, Maine, Massachusetts, New Hampshire
Rhode Island, Vermont

John F. Kennedy Federal Building
Boston, MA 02203
Telephone: 617-223-5186

Region II - New Jersey, New York, Puerto Rico, Virgin Islands

26 Federal Plaza
New York, NY 10007
Telephone: 212-264-4581

Region III - Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia

Curtis Building
6th and Walnut Streets
Philadelphia, PA 19106
Telephone: 215-597-9814

Region IV - Alabama, Florida, Georgia, Mississippi, Kentucky, North Carolina, South Carolina, West Virginia

345 Courtland, N.E.
Atlanta, GA 30308
Telephone: 404-881-4727

Region V - Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin

230 South Dearborn
Chicago, IL 60604
Telephone: 312-353-5250

Region VI - Arkansas, Louisiana, New Mexico, Oklahoma, Texas

First International Building
1201 Elm Street
Dallas, Texas 75270
Telephone: 214-749-1962

Region VII - Iowa, Kansas, Missouri, Nebraska

1735 Baltimore Street
Kansas City, MO 64108
Telephone: 816-374-5493

Region VIII - Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming

1860 Lincoln Street
Denver, CO 80295
Telephone: 303-837-3895

Region IX - Arizona, California, Hawaii, Nevada, Guam, American Samoa

215 Fremont
San Francisco, CA 94111
Telephone: 415-556-2320

Region X - Washington, Oregon, Idaho, Alaska

1200 Sixth Avenue
Seattle, WA 98101
Telephone: 206-442-1220

E.3 COMPLIANCE

Procedures for compliance testing and emission monitoring are specified in Subpart A, Part 60, Subchapter C, Chapter 1, Title 40, Code of Federal Regulations. In summary, these regulations require that new sources be tested for compliance after shakedown and that sources be equipped for continuous opacity monitoring. These emission monitoring systems must be field tested for accuracy.

APPENDIX F

BASIS FOR DISPERSION ESTIMATES

F.1 GENERAL

An analysis was made to assess the ambient concentrations of pollutants which would result from particulate emissions from pulverized coal combustion. For the purpose of the study, it was assumed particulate pollutants behave as non-reactive gases.

F.2 PLANT CHARACTERISTICS

Table F-1 gives information on the plants studied.[1] All plants were pulverized coal-fired steam generators controlled to meet a particulate limit of 43 nanograms per joule (0.1 lb/10^6 Btu).

Heat rate was assumed to be 10.56 megajoules (10,000 Btu) per kilowatt hour generated from combustion. Plants equipped with 75, 175, 275 metre (246, 574, and 902 ft) stacks were studied. Estimated heights of tall structures near the stacks are given in Table F.1.

It was assumed that plants would operate at all times during a year at full load capacity.

F.3 MODEL TECHNIQUES

A summary description of the models is given in Sections F.5 and F.6.

The model was programmed to derive a set of dispersion conditions for the basic meteorological data for each hour of the given year. The calculations simulated the interaction between the plant characteristics and these dispersion conditions to produce a dispersion pattern for each hour. These computations were performed for each point in an array of 180 receptors encircling the plant and extending downwind from the site. Values were calculated at each of the receptors for each hour and were integrated and averaged to calculate a mean annual average.

TABLE F-1[1]

EMISSION SOURCE CHARACTERISTICS OF THE PROTOTYPE PULVERIZED COAL COMBUSTION PLANTS

Production Rates	Case No.	No. of Stacks	Particulate Emission Rates (gm/sec)	Stack Height (metres)	Stack Temp. (°K)	Stack Velocity (m/sec)	Stack Diam. (metres)	Control Building Height (metres)
25 MW	1	1	3.15	75	400	20	1.68	15
	2	1	3.15	175	400	20	1.68	15
	3	1	3.15	275	400	20	1.68	15
300 MW	4	1	37.8	75	400	20	5.82	30
	5	1	37.8	175	400	20	5.82	30
	6	1	37.8	275	400	20	5.82	30
1,000 MW	7	1	126	75	400	20	10.62	60
	8	1	126	175	400	20	10.62	60
	9	1	126	275	400	20	10.62	60

The aerodynamic effects of surrounding structures were analyzed according to the procedures summarized in Section F.6.

It was assumed the plant would be located in flat or gently rolling terrain with a meteorological regime unfavorable to the dispersion of effluents.

Preliminary analysis indicated that for the plants a combination of unstable atmospheric conditions and relatively low wind speeds would produce the highest short-term concentrations. If such conditions occurred frequently at a given location, especially if they were combined with a high directional bias in the wind, then longer term impacts (e.g., 24 hours and annual) would tend to be high.

For Cases 1-3, preliminary analysis showed that Burbank, California, satisfied the conditions of relatively low wind speeds with moderate persistence and unstable atmospheric conditions. Upper air sounding data from Santa Monica, California, were combined with the surface station data.

For Cases 4-9, the preliminary analysis suggested slightly higher wind speeds and unstable atmospheric conditions. Oklahoma City, Oklahoma, satisfied these conditions. Although on an annual-average basis the wind speed at Oklahoma City is quite high, two features tend to offset this fact: a high annual wind-direction-frequency (22 percent from SSE) and the fact that when the wind is from this sector, atmospheric conditions tend toward the unstable. Upper air observations from Oklahoma City, Oklahoma were combined with the surface data.

Related to the choice of plant location is the selection of source-receptor distances. Preliminary analysis indicated that the model plants exert maximum impact relatively close-in. In light of the preliminary analysis, distances selected are shown in Table F-2.

F.4 RESULTS AND DISCUSSION

The maximum pollutant concentrations for the specified averaging periods for all nine cases considered are listed in Table F-3. These concentrations have been pro-rated according to their respective emission rates. The five receptor distances chosen are listed in Table F-2.

Retardation, although it occurs frequently during the year in all cases, is <u>not</u> the controlling factor in producing maximum concentrations. In Case No. 7, downwash occurs most of the time and does produce the maxima concentrations. The 3- and 24-hour maxima values are not representative of unique meteorological situations with the exception of Case No. 7. Numerous values in the individual maxima ranges were noted on different days at widely separated grid points at source-receptor distances similar to those reported for each case in Table F-3. This is to say then, that with the exception of Case No. 7 (downwash), concentrations similar to those shown in Table F-3 for the individual pollutants are common. It is noticeable generally that as the stack heights increased for a given plant size, the concentration decreased.

The annual-average concentration distributions displayed the expected dependence upon the wind-direction frequency distributions for each meteorological choice. Generally, concentration values similar to those shown in Table F-3 for each of the nine cases (for each individual pollutant) are confined to a sector approximately 90^{o} in width. These concentration values were found at distances similar to those shown in Table F-3 for each individual case.

TABLE F-2[1]

Case No.	Ring 1	Ring 2	Ring 3	Ring 4	Ring 5
	Source Receptor Distances (km.)				
1	0.3	0.9	2.5	7.8	23.0
2	0.3	1.0	3.0	9.2	38.5
3	0.3	0.9	2.3	11.0	42.1
4	1.0	2.1	3.7	6.4	11.2
5	1.3	2.9	6.4	14.8	33.7
6	2.6	5.0	10.2	20.1	42.0
7	0.3	0.6	1.2	2.4	5.1
8	2.6	5.1	10.1	20.5	41.3
9	3.4	6.6	12.3	23.3	40.8

These rings may be viewed as the radii of concentric circles around the plant. Receptors are placed along each 174.5 milliradian (10^{o}) of azimuth, thus accounting for the 180-receptor grid referred to previously.

TABLE F-3[1]

MAXIMUM POLLUTANT CONCENTRATIONS[a] (g/m^3)

Averaging Period	Case	Particulate	Distance (km)
Annual	1	0.1	0.9
	2	<0.1	3.0
	3	<0.1	2.3
	4	0.3	6.4
	5	0.1	14.8
	6	<0.1	20.1
	7	203	0.3[b]
	8	0.2	20.5
	9	<0.1	23.3
24 Hours	1	1.3	0.9
	2	0.5	1.0
	3	0.4	0.9
	4	2.9	3.7
	5	1.3	2.9
	6	1.2	2.6[c]
	7	1,000	0.3[b]
	8	1.8	5.1
	9	1.3	6.6

[a] Concentrations have been prorated according to specific emission rates.

[b] First ring, downwash.

[c] First ring, retardation

F. 5 DESCRIPTION OF THE DISPERSION MODEL

The model used to estimate ambient concentrations in Table F-3 for the pulverized coal-fired plants was one developed by the Meteorology Laboratory, U.S. Environmental Protection Agency, Research Triangle Park, N.C. This model is designed to estimate concentrations due to sources at a single location for averaging times from one hour to one year.

This model is a Gaussian plume model using diffusion coefficients suggested by Turner.[2] Concentrations are calculated for each hour of the year, from observations of wind direction in increments of 17.45 milliradians (10 degrees), wind speed, mixing height, and atmospheric stability. The atmospheric stability is derived by the Pasquill classification method as described by Turner.[1] In the application of this model, all pollutants are considered to be non-reactive and gaseous.

Meteorological data for 1964 are used as input to the model. The reasons for this choice are: (1) data from earlier years did not have sufficient resolution in the wind direction; and (2) data after 1964 are available only for every third hour, where data for 1964 are available on an hourly basis.

Mixing height data are obtained from the twice-a-day upper air observations made at the most representative upper air station. Hourly mixing heights are estimated by the model using an objective interpolation scheme.

making the assessment are wind speed, stack-gas exit velocity, stack height, stack diameter, and building height. If a particular assessment indicates no aerodynamic effect, then for that stack (for that hour) the model behaves just as the unmodified version. If there are aerodynamic effects, the modified version contains equations by which the impact of these effects on ground-level concentrations is estimated.

A feature of this model is the modification of plume behavior to account for aerodynamic effects for plants in which the design is not optimal. Another important aspect of the model is the ability to add concentrations from stacks located closely together. In this feature, no consideration is given to the physical separation between the stacks since all are assumed to be located at the same geographical point.

Calculations are made for 180 receptors (at 36 azimuths and five selectable distances from the source). The model used can consider both diurnal and seasonal variations in the source. Separate

F.7. REFERENCES FOR APPENDIX F.

1. Unpublished Data, Source Receptor Analysis Branch, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, June 1975.

2. Turner, D. B., "Workbook of Atmospheric Dispersion Estimates", U.S. Dept. of H. E. W., PHS Publication No. 999-AP-24 (Revised 1970).

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15. SUPPLEMENTARY NOTES

Revised Standards of Performance for the control of emissions of sulfur dioxide and nitrogen oxides from electric utility steam generating units are also being proposed. These standards are supported in separate Standard Support and Environmental Impact Statements (SSEIS's), EPA-450/2-78-007a for sulfur dioxide and EPA-450/2-78-005a for nitrogen oxides.

16. Abstract

Revised Standards of Performance for the control of emissions of particulate matter from electric utility power plants are being proposed under the authority of section 111 of the Clean Air Act. These standards would apply only to electric utility steam generating units capable of combusting more than 73 megawatts heat input (250 million Btu/hr) of fossil fuel and for which construction or modification began on or after the date of proposal of the regulations. This document contains background information, environmental and economic impact assessments, and the rationale for the standards, as proposed under 40 CFR Part 60, Subpart Da.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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