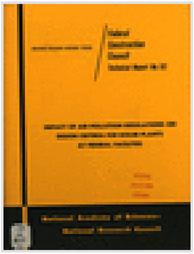

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IMPACT OF AIR-POLLUTION REGULATIONS ON DESIGN CRITERIA FOR BOILER PLANTS AT FEDERAL FACILITIES

Technical Report No. 63

Prepared by Task Group T-65
of the
Federal Construction Council
Building Research Advisory Board
Division of Engineering
National Research Council

NATIONAL ACADEMY OF SCIENCES
Washington, D.C.
1972

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The members of the study committee were selected for their individual competence and judgment with due consideration for the balance and breadth of disciplines. Responsibility for all aspects of this report rests with the study committee, to whom sincere appreciation is expressed.

Although the reports of our study committees are not submitted for approval to the Academy membership or to the Council, each report is reviewed by a second group of appropriately qualified individuals according to procedures established and monitored by the Academy's Report Review Committee. Such reviews are intended to determine, *inter alia*, whether the major questions and relevant points of view have been addressed and whether the reported findings, conclusions, and recommendations arose from the available data and information. Distribution of the report is approved, by the President, only after satisfactory completion of this review process.

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FEDERAL CONSTRUCTION COUNCIL
TASK GROUP T-65
IMPACT OF AIR-POLLUTION REGULATIONS ON DESIGN CRITERIA FOR BOILER PLANTS AT FEDERAL FACILITIES

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At the request of the Council, the following persons were designated by the various agencies to organize and direct this study:

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FOREWORD

Regulations limiting the emission of air pollutants from industrial and commercial combustion processes are becoming increasingly stringent. Federal agencies, under the mandate of various executive orders, are required to provide for the compliance of federal facilities with the national ambient-air-quality standards as well as with the often more stringent state and local regulations concerning the emission of air pollutants.

In view of this trend and the fact that federal boilers are designed for use under normal operating conditions for a minimum of 20 years, air-pollution regulations anticipated for the future, as well as those already in existence, must be considered when designing and selecting new boilers and related equipment and when extensively modifying existing facilities.

Thus, the Federal Construction Council (FCC) requested Task Group T-65 to develop criteria for federal boiler plants that take into consideration both existing and anticipated air-pollution regulations. This report presents the criteria developed by the task group for boiler performance requirements in relation to the control of various emissions including smoke and other particulates, sulfur oxides, and nitrogen oxides. Information concerning the control of dust from fuel- and ash-handling operations and other related information is also included.

This report has been reviewed and approved by the Federal Construction Council, and, on recommendation of the Council, the Building Research Advisory Board (BRAB) has approved the report for publication.

The Board gratefully acknowledges the work of Task Group T-65 and sincerely appreciates the contribution of others to this effort.

JOSEPH H. NEWMAN, *Chairman*
Building Research Advisory Board

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INTRODUCTION

A. OBJECTIVES OF THE STUDY

The objectives of this study were (1) to determine the extent to which current and anticipated air-pollution regulations will affect design criteria of boilers for central heating and steam power plants owned and operated by federal agencies and (2) to recommend procedures to be used by agencies in determining design specifications for new plants or for existing plants being modified which take into account such restrictions.

B. SCOPE OF THE STUDY

The study was concerned with federally owned and operated boilers having a heat-input capacity of from 5 million to 250 million British Thermal Units per hour (Btu/hr). Regulations concerning the emission of smoke and other particulates, sulfur oxides, and nitrogen oxides were evaluated to determine their impact on coal-, oil-, and gas-fired boiler plants. Related fuel- and ash-handling operations also were considered in the study.

C. CONDUCT OF THE STUDY

Information presented in this report is based on data obtained from federal, state, and local air-pollution control agencies, published technical literature, and meetings with researchers, manufacturers, and users of pollution-control equipment as well as on the experience of the Task Group members.

D. ORGANIZATION OF THE REPORT

This report is divided into two major sections in addition to this introduction: Recommendations and Discussion. In the Recommendations section, the specific recommendations of the Task Group are set forth, without elaboration. These, made in light of current and anticipated air-pollution regulations, are on design criteria and specifications for boilers owned and operated by federal agencies. The data on which these recommendations are based is presented in the Discussion section. A bibliography is appended to provide additional background and support for the discussion; numbers in parentheses appearing in the report refer to items in the bibliography.

II
RECOMMENDATIONS

A. GENERAL

1. As required by recent legislation and executive orders, federal agencies should design and specify new boiler plants to comply with the most stringent federal, state, or local air-pollution-control requirements applicable. Specifications should include performance requirements for smoke and other particulates, sulfur oxides, and nitrogen oxides.

2. In designing and specifying new boiler plants, federal agencies should consider not only existing air-pollution-control standards but also the more stringent standards, especially those of state and local agencies, that can be anticipated for the near future. The appropriate state agency* should be contacted for information regarding applicable standards.

3. Federal agency boiler specifications should stipulate that boiler manufacturers must provide test data on the levels of smoke and other particulates and of nitrogen oxides generated by distillate-oil- and gas-fired boilers smaller than 50 million Btu/hr heat input.

4. Federal agency boiler specifications should stipulate that all new residual-oil- and coal-fired boilers and those distillate-oil- and gas-fired boilers of 50 million Btu/hr heat input or larger must be tested as discussed in Sections B-2, C-2, D-2, and E-2 of these recommendations to determine their compliance with air-pollution-control requirements. Such testing should:

    a. Be conducted either at start-up of the boiler, if the boiler can be operated at maximum-design steam-generating rates, or as part of the acceptance test of the boiler system.

    b. Be conducted when the boiler is operating at 33 percent, 67 percent, and 100 percent of its design capacity.

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*State agencies are listed in the Directory of Governmental Air Pollution Agencies, published annually by the Air Pollution Control Association, 4400 Fifth Avenue, Pittsburgh, Pennsylvania 15213.

c. Be conducted on a clean boiler, operating in a manner typical and representative of its designed operation and using the same fuel, air rates, and other combustion variables that affect air-contaminant-emission rates.

d. Be conducted either by the government agency involved or by an independent testing organization, qualified by broad experience in the conduct of such tests and approved by the agency.

5. To determine whether the various performance requirements are being met, federal agencies should include in their economic analyses costs for necessary air-pollution-control equipment as well as costs for stack testing.

6. Federal agencies should consider using a two-stage contracting mechanism when modifying existing boilers to comply with air-pollution-control requirements.

B. SMOKE AND OTHER PARTICULATES

1. Performance Requirements

Unless, in some instances, state or local requirements necessitate more stringent control, agency specifications for new boilers and boilers being extensively modified should require that:

a. The opacity of any visible emission should be less than No. 1 on the Ringelmann chart* or its equivalent except during start-up, cleaning, or soot-blowing.

b. The emission rate of solid particulates should not exceed 0.1 lb/million Btu** for all units of 50 million Btu/hr or greater heat input or 0.2 lb/million Btu for all units of less than 50 million Btu/hr heat input.

c. The emission of particles larger than 60 microns in diameter normally should not occur during routine operations.

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*A No. 9 on the Shell, Dwyer, and Bacharach scales is considered approximately equivalent to a No. 1 on the Ringelmann. Therefore, allowing for some margin of safety, a No. 5 on the Shell, Dwyer, or Bacharach smoke scale should ensure that the No. 1 Ringelmann requirement is being met (32).

**The emission rate of 0.1 lb/million Btu is roughly equivalent to 0.04 grains per standard cubic foot (scf) or 0.08 lb/1,000 lb of gases (adjusted to 50 percent excess air).

2. Testing Requirements

a. For all residual-oil- or coal-fired boilers and for distillate-oil- and gas-fired boilers larger than 50 million Btu/hr heat input, stack observations should be made for smoke density using the Ringelmann Chart procedure published by the U.S. Bureau of Mines (30).

   When the opacity of the stack effluent cannot be judged accurately by visual means, a Shell, Dwyer, or Bacharach smoke scale should be accepted as a secondary testing procedure.

b. For residual-oil- and coal-fired boilers, stack tests for particulate emissions should be made in accordance with American Society of Mechanical Engineers Power Test Code No. 27 (3).

c. For all residual-oil- or coal-fired boilers or for distillate-oil- or gas-fired boilers larger than 50 million Btu/hr heat input, stack tests for the emission of particles larger than 60 microns in diameter should be made using the adhesive-paper procedure (18).

3. Control Equipment

For distillate-oil- or gas-fired boilers and for residual-oil-fired boilers under 50 million Btu/hr heat input, particulate-control equipment should not be specified to meet the smoke and other particulate-matter emission requirements. For all other boilers, however, certain basic control equipment should be specified. The following minimum efficiencies may be required in certain applications to meet the control requirements.

a. For residual-oil-fired boilers of greater than 50 million Btu/hr heat input, mechanical collectors always should be installed and utilized during normal operations. Collectors should have an overall efficiency of at least 80 percent and a pressure drop of at least 3 in. of water. In rare cases where particulate loading from the mechanical collectors is expected to exceed limits, electrostatic precipitators, specially designed for oil-firing to minimize the fire hazard and corrosion, should be considered for use on an experimental basis.

b. For coal-fired boilers employing stokers other than those of the spreader type, in which fly ash is not reinjected, mechanical collectors with an overall collection efficiency of at least 80 percent and a pressure drop of at least 3 in. of water should be specified. In cases where particulate loading from the mechanical collectors is expected to exceed limits, electrostatic precipitators should be specified.

c. For coal-fired boilers employing spreader stokers, for boilers with other types of stoker in which fly ash is reinjected, and for all pulverized-coal-fired boilers, electrostatic precipitators should be used either alone or in-series with mechanical collectors to meet emission-control requirements. Overall collection efficiency should be at least 99 percent.

d. All particulate-control equipment, either in-series or by itself, must have an efficiency of 100 percent for particles greater than 60 microns in diameter.

4. Other Requirements

a. A smoke detector and indicator should be installed on residual-oil- and coal-fired boiler units having heat inputs between 10 and 50 million Btu/hr. In addition, recorders should be provided on residual-oil- or coal-fired units having heat inputs greater than 50 million Btu/hr.

b. When reinjection of fly ash is planned for coal-fired boilers, all collected material should be segregated by size and only particles larger than 44 microns in diameter should be reinjected.

c. Commercial oil additives should be considered as a means for reducing particulate emissions only on existing boilers and then only when control equipment, burner modification, fuel substitution, or other procedures are not sufficient to meet emission-control requirements.

C. SULFUR OXIDES

1. Performance Requirements

Unless, in some instances, state or local requirements necessitate more stringent control, the emission rate of sulfur oxides should not exceed the limits recommended in BRAB/FCC Technical Report No. 57, Impact of Air Pollution Regulations on Fuel Selection for Federal Facilities (15).

2. Testing Requirements

For coal-, oil-, or gas-fired boilers, the sulfur oxides emission rate should be calculated from sulfur-in-fuel analyses and fuel-consumption rates as described in BRAB/FCC Technical Teport No. 57 (15).

3. Control Equipment

Stack-gas cleaning equipment for removing sulfur oxides from flue gases is being researched and developed for large power-generating sources and, until commercially accepted, should be specified for boiler plants at federal facilities only on an experimental basis.

4. Other Requirements

Federal agency specifications should require the use of fuels having a sulfur content sufficiently low so that emission limits will not be exceeded. For the immediate future, the recommendations in BRAB/FCC Technical Report No. 57 (15) should be followed by the agencies in selecting fuels and preparing specifications.

D. NITROGEN OXIDES

1. Performance Requirements

Unless, in some instances, state or local requirements necessitate more stringent control, new federal boilers should be designed to limit nitrogen oxides (NO_2) emissions to: 0.3 $lb/10^6$ Btu when gaseous fuel is burned; 0.5 $lb/10^6$ Btu when liquid fuel is burned; and 0.8 $lb/10^6$ Btu when solid fuel is burned.

2. Testing Requirements

For all residual-oil- or coal-fired boilers and for distillate-oil- and gas-fired boilers larger than 50 million Btu/hr heat input, the nitrogen oxides emission rate should be determined in accordance with "Standards of Performance for New Stationary Sources" as promulgated by the Environmental Protection Agency (40).

3. Control Equipment

Stack-gas cleaning equipment for removing nitrogen oxides from flue gases is only now being researched and developed for noncombustion sources such as nitric acid plants with high NO_x concentrations and a high NO_2/NO ratio; such equipment should not be specified for boiler plants at federal facilities.

4. Other Requirements

Federal agencies should require that new boilers and existing boilers being extensively renovated operate with the lowest excess-air rate that is feasible with commercially available equipment and consistent with safe and economical operation under all conditions.*

With regard to other matters relating to combustion equipment, agencies should, in preparing specifications, continue to follow the criteria recommended in BRAB/FCC Technical Report No. 51, Combustion Equipment and Related Facilities for Non-Residential Heating Boiler (14); however, when low excess-air rates are specified, consideration should be given to requiring (a) that a safety cut-off be installed in the combustion control system to shut down the burner when the fuel-air ratio varies too far from the preset value and (b) that the combustion control system be the type in which the airflow rate is increased before the fuel-flow rate with an increasing load, and the fuel-flow rate is decreased first with a decreasing load.

E. DUST FROM FUEL- AND ASH-HANDLING OPERATIONS

1. Performance Requirements

Unless, in some instances, state or local requirements necessitate more stringent control, solid fuels and ash should be stored and handled so that dustfall concentrations, measured at the agency's property line, do not exceed background levels by more than 15 tons per square mile per month.

2. Testing Requirements

Dustfall concentrations should be measured around new coal-fired boiler plants when the boiler plant is operating at or near capacity. The test should be conducted using ASTM D 1739-62, Collection and Analysis of Dustfall (6).

3. Control Equipment

a. Coal transfer points should be enclosed; conveyer belts should be covered; and bunkers should be enclosed, sealed, and equipped with a vacuum dust-collecting system.

b. Ash-handling and -disposal facilities should be enclosed; conveyor belts should be covered; and wind barriers should be provided for ash-storage piles.

*There are some indications that NO_x emissions also can be reduced through reduction in heat-release rates and in the nitrogen content in fuel. If future studies determine that this is feasible, consideration should be given to incorporating such requirements in agency specifications.

4. Other Requirements

Coal-storage piles should be compacted and, if inactive, should be capped with asphalt. Wind barriers or shields (fences, trees, or walls) should be provided along the perimeter of coal-storage piles.

III
DISCUSSION

A. GENERAL

The following discussion provides the reasons, including an evaluation of the effect of current and anticipated air-polluting-emissions regulations on boiler design criteria, for the Task Group's recommendations presented in the preceding section of this report. Air contaminants of primary interest and concern to federal planners of boiler plants of the size considered in this report are smoke and other particulates, sulfur oxides, and nitrogen oxides.

1. Design Concept

In the federal establishment, boiler plants represent the largest single class of stationary air-pollution sources; therefore, it is essential that federal agencies devote particular attention to boiler design and operation in order to minimize the generation of air contaminants and to demonstrate exemplary performance in the environmental control area. Federal regulations, promulgated as a result of various executive orders, require federal facilities to meet certain emission limits and to conform to air-pollution-control requirements prescribed by the state or community in which they are located if such regulations are more stringent than the federal standards. Under the expanded Clean Air Act of 1970, the federal government promulgated national ambient-air-quality standards for several air contaminants (including particulates, sulfur oxides, and nitrogen oxides). State air-pollution-control agencies then developed implementation plans to achieve the air-quality goals. Of particular interest to designers and specification writers in the federal establishment are the emission standards for smoke and other particulates, sulfur oxides, and nitrogen oxides that have been suggested by the Environmental Protection Agency (EPA) to the state and local agencies (39). In addition, EPA has promulgated national standards of performance for new stationary sources including fossil-fuel-fired steam generators of more than 250 million Btu/hr heat input (40). While the scope of this report is limited to boilers smaller than 250 million Btu/hr heat input, the national standards should serve as harbingers of potential future standards that may be applicable to the smaller federal boilers.

Carbon monoxide and hydrocarbon emissions have not been covered in this report for two reasons. First, there are no regulations concerning the emission of these pollutants from the types of boiler plant considered in this report. Second, with good combustion, the emission of these contaminants from boilers is minimal; therefore, no regulations are anticipated for their control.

2. Present and Future Standards

The trend in air-pollution-control regulations has been to place more stringent controls on the emission of pollutants from industrial or commercial combustion processes and to require the addition of more and more sophisticated stack-gas cleaning equipment to ensure compliance with the various emission requirements. Boilers are designed and used by the government for a minimum of 20 years when normal operation, maintenance, and water treatment are provided; therefore, air-pollution regulations anticipated for the future, as well as those already existing, must be considered in the design and selection of new boilers and related equipment.

Smoke-control ordinances, the oldest air-pollution-control laws on the statute books, date back 200 to 300 years. They have followed a pattern of increasing stringency from No. 3 Ringlemann to No. 2 Ringlemann (the current federal standard for existing boilers) to No. 1 Ringlemann (the current federal standard for new large boilers) to No. 0 Ringlemann, a clear stack (the newest limit in Maryland and the one proposed in other states). Fly ash and other particulate emissions, especially from coal-fired boilers, have been limited by regulations for the past 30 years; maximum emission limits have dropped from 1.0 lb/10^6 Btu heat input in the 1940s to as low as 0.20 lb/10^6 Btu in recent years for very large boilers. Proposed limits in some states are so stringent that particulate-control equipment on residual-oil-fired boilers will be required.

Sulfur oxides emission restrictions also date back many years but only for industrial processes such as smelters and acid plants. Sulfur-in-fuel limitations or emission limitations specifically applicable to boiler plants have been in force only for about 10 years. The earliest rules, adopted in Los Angeles County, make use of natural gas mandatory whenever it is available and allow the use of fuel oil having a sulfur content in excess of 0.5 percent only when neither natural gas nor low-sulfur fuel is available and then only after formal approval. Within the past three years, several state and local agencies have limited sulfur content of fuels to 2 percent, 1 percent, and as low as 0.2 percent.

Nitrogen oxides emissions have only been regulated since 1969, but new limitations can be anticipated in the future because of the importance of nitrogen oxides in the formation of photochemical smog. Primary emphasis for controlling these emissions will be on motor vehicles and steam-electric generating plants. However, boilers of the size used at federal installations will certainly face restrictions on NO_x emissions within the next few years, and design criteria for new boilers should include such considerations.

3. Distillate-Oil- and Gas-Fired Boilers

The Task Group feels that boiler manufacturers should develop and make available data on the emission of smoke and other particulates and nitrogen oxides for small distillate-oil- and gas-fired units, i.e., units with a heat input of up to 50 million Btu/hr (approximately the amount of heat obtained from burning 45,000 cf/hr of natural gas or 2,500 lb/hr of fuel oil). Large numbers of these small units are utilized by the government, and they are ordinarily sold as factory-assembled units, complete with uncomplicated burners and controls. The design of these units is standardized by the manufacturer and used for a considerable period of time; therefore, it is believed safe to assume that emissions from a given model will not vary greatly from unit to unit. Data from prototype tests would be sufficiently reliable for use in making decisions about the unit relative to air pollution, particularly when gas and light oil are used since these fuels seldom cause emissions in excess of standards. The cost of these small packaged-boilers is relatively low; therefore, from a cost-benefit viewpoint, testing on site for each installation would be difficult to justify for clean-burning fuels.

4. Testing Procedures for Large Boilers

The operating specifications provided by boiler manufacturers and air-pollution-control equipment manufacturers usually represent the best condition instead of the normal operating condition. Large emissions sources have combustion variables, such as excess-air and fuel-feed rates and reinjection of ash, which may affect air-contaminant emission rates. To provide a reliable and accurate inventory of emissions, individual-unit testing must be performed on each boiler/control equipment configuration.

a. When To Test

The boiler should be operated until consistent, reliable performance can be assured at maximum-design steam-generating rates and various turn-down ratios before air-pollution testing commences. This procedure should eliminate irregular emissions caused by start-up problems and, at the same time, allow boiler operators to gain experience with their new equipment. If initial testing were postponed for too long a period, normal wear on the boiler or control equipment might result in inconsistant emission rates. Furthermore, the contractor and boiler manufacturer will be anxious to have the installation tested and accepted so that final payment can be received. Whenever possible, air-pollution tests should be conducted simultaneously with acceptance tests for the boiler system.

b. What Steam Loads To Test

Tests for air-contaminant emissions and boiler efficiency are commonly conducted at one operating load--100 percent of design capacity. In practice, however, most boilers operate at about 67 to 75 percent of design capacity and, as steam-load demand increases, another boiler is added to the line. Also, during summer months, many federal boilers operate at 33 percent or less of capacity. Emissions of air contaminants may increase or decrease as the boiler operates at lower loads. For example, smoke emissions may increase but oxides of nitrogen may be expected to decrease at low load. Because of the uncertainty of this relationship, some control-equipment manufacturers will provide, on request, an adjustment curve of their performance guarantee for operating at steam loads other than 100 percent of design capacity. However, by testing at 33, 67, and 100 percent of design capacity, a realistic picture of emissions will be obtained that will provide the basis for interpolations of emissions for any capacity level. The test data taken at the different levels should include information on all parameters, such as fuel quality, fuel-feed, and excess-air rates, all of which may affect emission rates.

c. Boiler Condition for Test

For emission-test results to be valid, all testing must be conducted on a clean boiler and the boiler must be operated in a manner typical and representative of its designed operation, using the same fuel, air rates, and other combustion variables that could affect air-contaminant-emission rates.

d. Who Should Test

Stack testing is quite complex and requires special equipment, specially trained personnel, and laboratory support. Agencies may choose to employ a private testing firm or a separate governmental agency to perform required testing. In addition, the objectivity of test results secured from an unbiased third party may minimize disputes between the construction contractor and the purchasing agency.

5. Air-Pollution-Control Costs

Air-pollution-control problems can generally be solved in several ways: A different type of fuel may be employed; a boiler may be redesigned; or flue-gas cleaning equipment may be used. Although, in most cases, the easiest solution would be to switch fuels (e.g., merely switching to a low-sulfur, low-ash, low-nitrogen content fuel oil may solve all boiler-emission problems), this is frequently not the most economical solution. Clean fuels are significantly more expensive than fuels containing impurities, and the cost associated with clean-fuel use can frequently exceed the total capital and operating costs associated with redesigning a boiler and/or providing flue-gas cleaning equipment to permit the use of a cheaper fuel. In some cases, of course, the converse may be true. It is therefore important that decisions on the method to be used to solve air-pollution-control problems be made only after a thorough engineering and economic analysis has been performed. Among the important factors to be considered are:

Capital Investment Costs

- Engineering studies
- Land
- Control hardware
- Auxiliary equipment
- Operating supply inventory
- Installation
- Start-up and testing
- Structure modification
- Interest

Maintenance and Operation Costs

- Utilities
- Labor
- Supplies and materials (including fuel)
- Treatment and disposal of collected material

One of the major considerations, of course, is the cost of flue-gas cleaning equipment. No attempt will be made here to show the prices of such equipment since they are affected by a great number of variables.

Another important cost item, and one that is sometimes overlooked in economic analyses, is the cost of onsite stack testing. As indicated previously, such testing is believed to be essential for all large plants regardless of fuel used and for all smaller plants burning residual fuel oil and coal. The approximate cost of air-pollution stack testing is shown in Table 1.

6. Modifying Existing Boilers

The United States Air Force has had good experience with the two-step procurement approach in contracting for modification of existing boilers (e.g., converting from coal-firing to gas- or oil-firing), and it is believed that other agencies also might want to consider using this approach. Two-stage contracting works in the following manner: The agency indicates the end performance required in a Request for Technical Proposal (RFTP). The RFTP is advertised (step 1) requesting potential contractors to submit designs. The agency reviews the proposals for compliance with the criteria. Bidders whose submittals meet the criteria are asked to bid (step 2) on their proposals. The low bidder is awarded the contract.

TABLE 1 Approximate Costs for Determining Compliance with Air-Pollution Standards

Fuel	Required Emission Tests	Cost Range[a]
Gas[b]	Smoke, 60-micron particles, sulfur dioxide, nitrogen dioxide	\$500-1,000
Distillate oil[b]	Smoke, 60-micron particles, sulfur dioxide, nitrogen dioxide	\$500-1,000
Residual oil	Smoke, 60-micron particles, sulfur dioxide, nitrogen dioxide, and total particulate emissions	\$2,000-4,000
Coal	Smoke, 60-micron particles, sulfur dioxide, nitrogen dioxide, total particulate emissions, and dustfall	\$3,000-5,000

[a]The estimate includes field, laboratory, and report costs assuming three tests on each installation. It does not include travel, per diem, scaffolding, stack preparation, or other preparation costs.

[b]Only those distillate-oil- or gas-fired units greater than 50 million Btu/hr heat input should be tested in the field.

B. SMOKE AND OTHER PARTICULATES

Smoke and other particulates are air contaminants of major interest to air-pollution-control authorities. Smoke as well as fine particles of calcium, sodium, silica, iron, and oxides or salts of these and other elements are discharged to the atmosphere primarily from combustion of coal and to a lesser degree from combustion of residual oil. Federal boilers constitute a relatively small percentage of the industrial-size boilers and, therefore, an even smaller percentage of the nation's sources of particulate emissions. Still, in view of the executive mandate for federal leadership, smoke and other particulate controls should be as effective as control technology will allow (44,45).

1. Performance Requirements

a. Smoke from Existing Boilers

Concern as to the effect of all air contaminants on public health and welfare was first evinced in ordinances and regulations governing visible pollutants. Local regulatory efforts to restrict the blackness or density of smoke were followed by ordinances limiting emissions of particulates. Common types of particulates generated by fuel combustion are soot, fly ash, and dust.

Smoke and other particulates resulting from fuel combustion were the target of the first federal regulations, promulgated in 1966 pursuant to Executive Order 11282, to control air pollution from federal facilities. These regulations also require federal facilities to conform to the air-pollution standards of the jurisdiction in which they are located if the state or local regulations are more stringent than the federal standards (44).

In the past, most limits for visible emissions have been based on either No. 2 Ringlemann or its equivalent opacity; such is the case with the Department of Health, Education, and Welfare (HEW) regulations published June 2, 1966. No. 2 Ringlemann is still the most common smoke limitation of the state and local air-pollution-control agencies. Recently, however, under the Clean Air Act of 1970, the EPA published primary and secondary ambient-air-quality standards for suspended particulates (38). The EPA then published guidelines and suggested emission standards to the states for use in preparing their implementation plans to achieve the published standards (39). Plans with which the Task Group is familiar call for a tightening of the visible smoke regulations to below No. 2 Ringlemann.

b. Smoke from New Boilers

The Governing Board of Directors of the Air Pollution Control Association adopted a resolution on October 16, 1970, that endorsed the idea of eliminating all visible emissions to the atmosphere from all pollution sources (1). An emission standard prohibiting all visible emissions (No. 0 Ringlemann) has already been promulgated by the State of Maryland and has been proposed for New Jersey and other states. The EPA suggested to the states that visible emissions from boilers be less than No. 1 Ringlemann, except for three minutes during each hour for soot-blowing (39). For distillate-oil- and gas-fired boilers, improved equipment designs have made it possible to eliminate all visible discharges. For coal- and residual-oil-fired boilers, the use of combustion controls and particulate-emission-control equipment can reduce visible emissions to barely detectable levels. In view of the trend in visible emissions regulations and the long life of federal boiler plants, new federal facilities should be designed to keep visible emissions to a minimum and boiler specifications should prohibit emissions from equaling or exceeding No. 1 Ringlemann.

c. Particulates from Existing Boilers

States and communities in the past have utilized a number of different units of measurement to express particulate-emission limitations for fuel combustion sources. Regulations are variously based on weight of particulates emitted per 1,000 pounds of flue gas, grains per standard cubic foot of exhaust gas, pounds of fly ash emitted per hour, and pounds of particulate matter emitted per million Btu hourly heat input.* The latter is becoming the most common for fuel-burning equipment and is employed in the federal regulations for particulate emissions (41). Also, in recent years, a sliding-scale standard has gradually replaced the old concentration scale. The sliding scale has the following desirable features: (a) it indirectly limits mass-emission rate; (b) it varies control according to plant size; (c) it eliminates the need to standardize flue-gas volumes, and (d) it varies control according to modern technology.

Prior to 1955, no community had a limit more restrictive than 1 lb/million Btu, which was the approximate equivalent limit recommended by the 1949 American Society of Mechanical Engineers (ASME), Example Sections for a Smoke Regulation Ordinance (2). This level was expressed in the suggested ordinance as 0.85 lb of particulate/1,000 lb of flue gases, adjusted to 50 percent excess air.

Since 1955, more than half of the new ordinances adopted by various agencies have been more restrictive than 1.0 lb/million Btu. By 1965, the ASME had lowered its recommendation to a maximum of 0.8 lb of dust/million Btu heat input and noted that some areas would need a lower maximum, depending on such factors as topography and meteorology, number and variety of dust sources, height and manner of discharge, existing concentration of dust at ground level, and the desires of the community (4).

Presently, federal regulations limit the emission of fly ash and other particulate matter from units of less than 10 million Btu/hr heat input to 0.6 lb/million Btu heat input (41). For units between

*A means of converting from one set of limitations to another is available in Appendix C of the ASME Standard Guide for Control of Dust Emission (4).

10 million and 1 billion Btu heat input, the maximum permissible emission rate ranges downward to 0.28 lb/million Btu heat input. Figure 1 illustrates the present federal curve, which has been adopted by many state and local agencies.

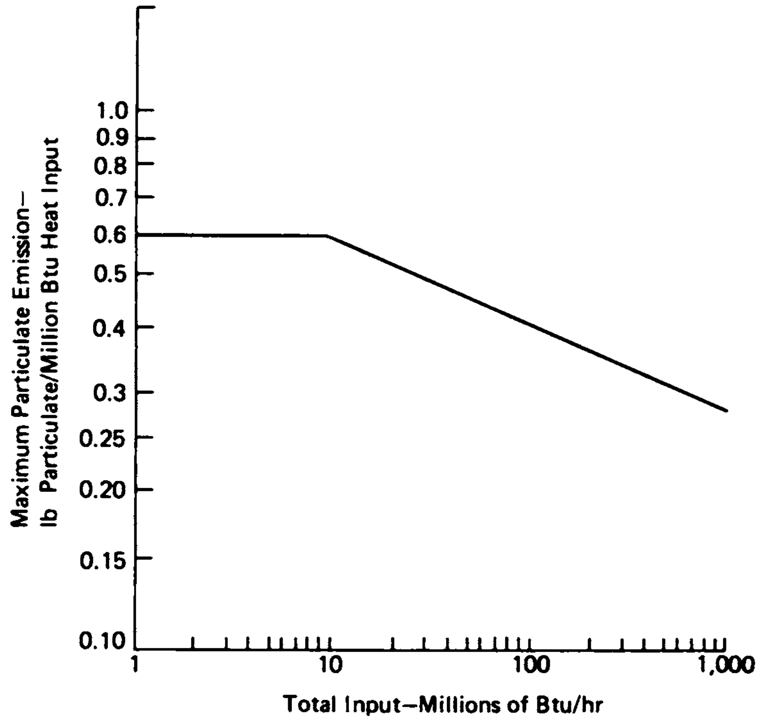

FIGURE 1 Maximum emission of particulate matter from fuel-burning installations (41).

d. Particulates from New Boilers

State and local regulations in some areas already are more stringent than the federal limitations (Table 2), and this will become increasingly the case in the near future in accordance with the timetable of the Clean Air Act of 1970 (28,31,39,41,47). Maryland and Montana particulate-emission limitations, for instance, are consistent with the 1966 federal standard for existing units but range downward to 0.20 lb/million Btu for new units of 1 billion Btu/hr, as compared to 0.28 lb in the federal regulations. Maryland regulations for new units of about 250 million Btu/hr heat input (the maximum size considered in this report) limit emissions to a maximum of 0.27 lb/10^6 Btu or 68 lb/hr; West Virginia's limit for the same size boiler is 0.25 lb/10^6 Btu or 63 lb/hr.

New York City's newest regulations (Figure 2) limit particulate emissions to 0.6 lb/10^6 Btu for boilers with a heat input of 10 million Btu/hr or less; for larger boilers, the limit is gradually lowered. For a 250 million Btu/hr boiler, New York City limits

TABLE 2 Particulate Emission Limitations of Standard Codes (lb/hr emission rate)

Heat Input (million Btu/hr)	Federal Existing (41)	Maryland (31)	New York City (28)	West Virginia (47)	EPA Suggested Guidelines (39)
1	0.6	0.6	0.6	0.55	0.3
10	6	6	6	5.5	3
50	23	21	13	19	15
100	40	35	18	32	30
200	71	60	25	54	60
250	88	68	28	63	75

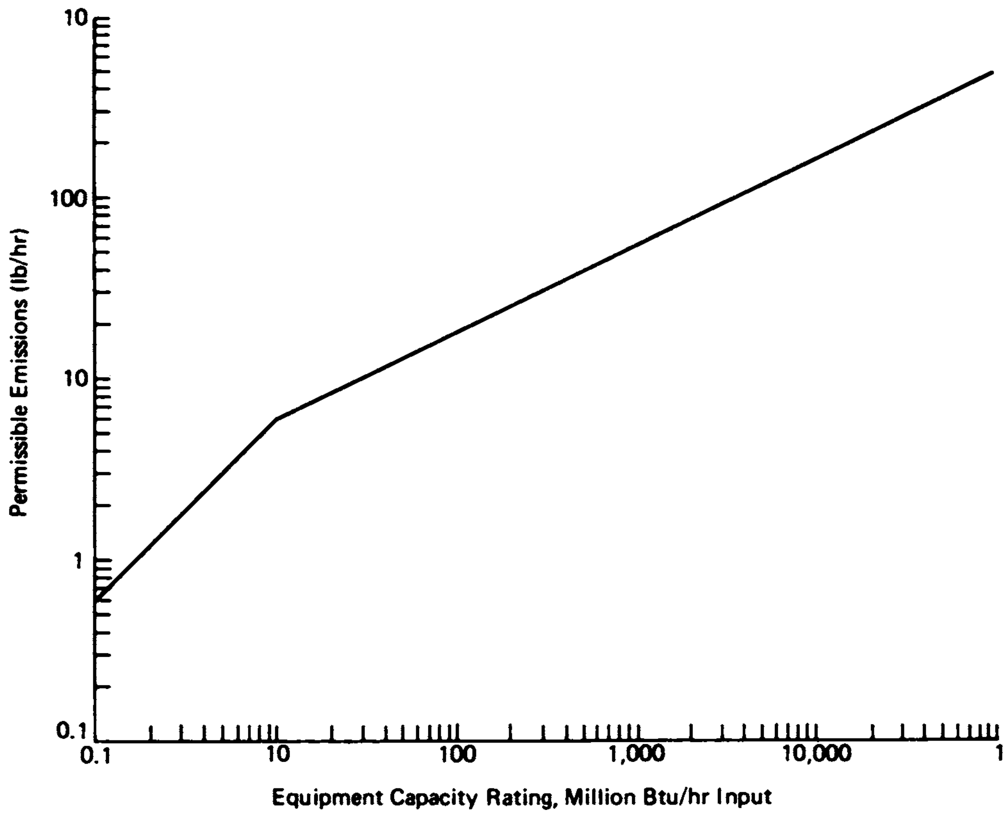

FIGURE 2 New York City's permissible emissions of particulate matter from fuel-burning equipment (28).

particulate emissions to 28 lb/hr or about 0.1 lb/10^6 Btu (28). Maryland has promulgated regulations, effective October 1, 1972, that limit particulate emissions from both coal- and oil-fired boilers to 0.03 grains or less per standard cubic foot of exhaust gas (about 0.066 lb/10^6 Btu).

The EPA suggested to the states that particulate emissions from existing coal-fired boilers can be limited to 0.3 lb/10^6 Btu. The EPA standard of performance for new fossil-fuel-fired steam generators of more than 250 million Btu/hr heat input has been established at 0.1 lb/million Btu.

It should be noted, however, that the testing procedure is equally as important as the emission limit. The EPA standards for new power plants are based on a testing procedure that may catch a higher percentage of the particulate matter present in the flue gas than is caught using the ASME procedure, the one required for determinimg compliance with the 1966 regulations for federal boilers. A further discussion of these procedures appears under Section 2, "Testing Requirements."

In view of EPA's suggestions to states and the trend for particulate-emission regulations, in general, it would seem prudent for federal agencies to set particulate-emission limits for themselves which are somewhat more stringent than those now in existence; this should avoid installation of boilers that will be quickly outmoded by new tighter regulations. The fact that designers normally apply a small factor of safety in selecting equipment should not be considered insurance for meeting tighter restrictions in the future; such factors of safety are normally provided only to allow for operational variation and degradation of equipment.

e. Particles Larger than 60 Microns

The federal regulations contain a provision that reads as follows: "During routine operation, the emission of particles larger than 60 microns shall not normally occur." It is the intent of this provision to prevent dustfall on homes, vegetation, cars, or other property in the vicinity of a boiler plant due to the settling of large particles. This provision is not found in many, if any, state or local air-pollution-control regulations. Certain state and local codes accomplish the same objective, however, by limiting total neighborhood dustfall concentrations and almost all codes contain a general clause that prohibits creation of a neighborhood nuisance condition.

Figure 3 relates the 60-micron particles to other units of expression or to other parameters used in this report. One micron (micrometer) is equal to 1/1,000 mm or 1/25,400 in. Particles larger than 60 microns will normally be cinders or soot particles (agglomerated smoke), which are easily visible with the naked eye.

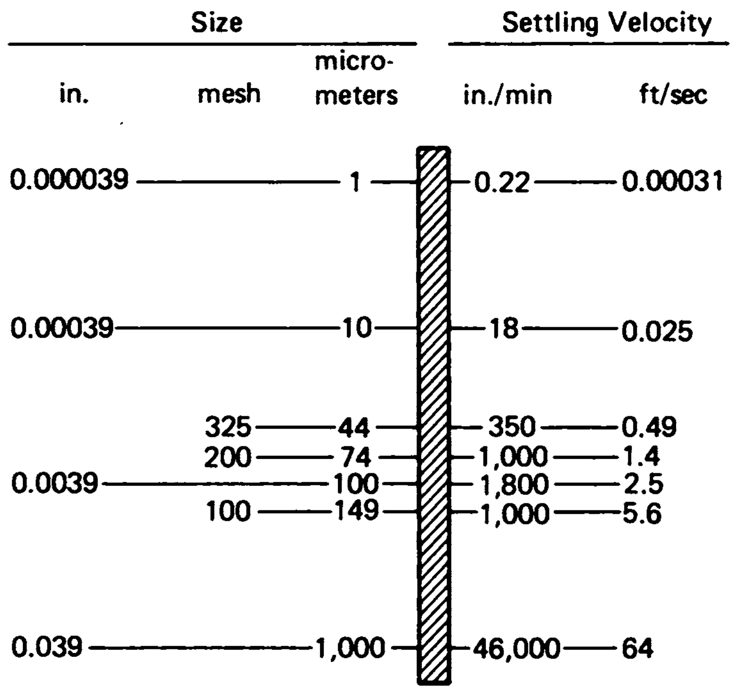

FIGURE 3 Size-settling velocity relationships for spherical fly-ash particles (sp. gr. 2.5) (19). Reproduced with permission of the National Coal Association.

2. Testing Requirements

a. Smoke-Density Testing

The recommended procedure for determining smoke density is to use the Ringlemann Smoke Chart. This chart was used by the Bureau of Mines in their studies of smokeless combustion that began at St. Louis in 1904 (30). It was first recognized officially in this country in a smoke ordinance for Boston, which was passed by the Massachusetts Legislature. Because of the universal acceptance of the Ringlemann Smoke Chart, it continues to be the accepted procedure by which air-pollution-control officials determine smoke density.

The Task Group's experience suggests that the Ringlemann procedure is an imprecise method for determining smoke density in that the darkness of smoke plume cannot always be determined accurately. The color of the sky cover, the direction of the sun's rays, the elevation of the plume, and the height of surrounding buildings are some of the factors that make the determination of smoke darkness difficult. Moreover, the effect of these factors is more pronounced with light colored smoke--the color commonly seen today. In other words, with a Ringlemann Chart, it is more difficult to accurately differentiate between No. 0 and No. 1 than between No. 2, 3, 4, or 5 smoke density.

On the assumption that a smoke-spot method, using either the Dwyer, Shell, or Bacharach scale would answer this need, the Environmental Health Service of the U.S. Air Force reportedly has undertaken an investigation to relate smoke-spot readings to Ringlemann observations. Results of this investigation were not available to the Task Group for inclusion in this report; however, previous investigators had reported that a No. 1 Ringlemann opacity was equivalent to a No. 9 Dwyer, Shell, or Bacharach smoke-spot density. Assuming that this is true, then a smoke-spot reading lower than 9 should ensure that the performance standard of No. 1 Ringlemann is being met. Allowing for variations in particle size and color, which undoubtedly influence this relationship, the Task Group has suggested that a No. 5 smoke-spot reading be accepted as evidence of compliance with the No. 1 Ringlemann.

b. Particulate-Loading Testing

The amount of particulate matter generated by various boilers depends primarily on the ash content of the fuel and the type of firing procedure. Since natural gas contains no ash and distillate oil contains very minute quantities, no testing is required to ensure that a distillate-oil- or gas-fired boiler facility will comply with particulate-emission standards. In the case of coal, however, ash content typically averages 10 percent of the fuel weight--an amount sufficient to cause many coal-fired boilers to exceed permissible particulate-emission standards, even many of the old standards. Coal-fired boilers, therefore, have normally been tested for compliance with particulate codes. Residual oil contains only a fraction of the ash commonly found in coal; until recently, emission limits were sufficiently liberal that residual-oil-fired boilers easily satisfied such standards and testing of such boilers was unusual. Now, however, with more stringent regulations, it will be necessary to test such boilers.

There are several particulate-emission testing procedures that have received recognition for use in various applications. For boiler plants, the most common and widely used procedure has been Power Test Code No. 27, Determining Dust Concentrations in a Gas Stream, which was developed and published by the American Society of Mechanical Engineers (3). This procedure does not specifically include submicron particles or condensable hydrocarbons; however, a certain amount of such material undoubtedly is collected in the sampling train.

A particulate-emission testing procedure that has received wide acceptance in recent years is Specifications for Incinerator Testing at Federal Facilities (42). This procedure for particulate loading utilizes an impinger train in-series after the filter to entrap submicron particles and condensable hydrocarbons. As evident from the title, it was developed specifically for incinerators, which do generate variable quantities of condensable hydrocarbons; however, it is now being specified in some cases for testing on boilers.

There has been an active debate over these particulate-emission testing procedures in recent years, primarily over the definition of "particulate matter." In essence, the debate centers on whether particulates should include condensable matter. The incinerator testing procedure specifically includes, as total particulate, material that is in the gaseous phase at stack temperatures but exists as particulate matter at 70°F, whereas the ASME procedure excludes this fraction. Both of the sampling trains include a filter element in the hot-gas stream to collect stack-conditioning particulate matter, but the basic ASME sampling train does not specifically collect particulate matter condensed between stack temperatures and 70°F. Undoubtedly, some condensables are absorbed or otherwise collected on the filter.

Federal standards of performance for new fossil-fuel-fired steam generators were promulgated in accordance with requirements of the Clean Air Act of 1970 and published December 23, 1971 (40). Compliance with the particulate standard is determined by the EPA sampling procedure, which utilizes the sampling train required for incinerator testing but excludes the material trapped in the impinger train.

Very few test data are available on the amount of condensable particulates generated by boilers so it would be difficult, if not impossible, to predict, before a boiler is built, whether it is likely to meet standards regulating the emission of such particulates. If a boiler, after it is built, is found to produce excessive amounts of condensable particulates, it will be difficult to correct the problem since dry-type collectors normally used on boilers will not collect condensable particulate matter.

c. Sixty-Micron Particle Testing

In 1962, a procedure was developed for estimating particulate emissions from incinerators (12, 18). The procedure consists simply of holding an adhesive paper in the stack-gas stream for a short period of time and observing the collected particles with a microscope. If particles larger than 60 microns are observed, the boiler is in violation of the performance standard. Even though the procedure is quite unsophisticated, it is believed to be completely adequate for the intended purpose.

3. Control Equipment

Boiler particulate emissions have been gradually reduced over the years by improvements in the combustion process. With this reduction in emission loading, however, the control problem has been made more difficult because the remaining particles are much smaller and more difficult to remove.

Most particulate-control equipment is tailored to meet a specific set of conditions in a new or existing plant; very little equipment is bought off-the-shelf as packaged equipment, which makes cost estimating difficult. Furthermore, fitting air-pollution-control equipment into an existing plant usually requires extensive plant changes and renovation costs.

During the hearing on May 18, 1967, before the U.S. Senate Committee on Public Works, Subcommittee on Air and Water Pollution, Earl Wilson, president of the Industrial Gas Cleaning Institute, presented some rule-of-thumb costs (Table 3) for typical collectors of standard mild-steel construction (37). As can be seen, the cost range is quite wide. To pinpoint cost estimates, plans and specifications have to be worked out before costs can be compared.

TABLE 3 Cost Data on Typical Particulate Collectors of Standard Mild-Steel Construction (37)

Type of Collector	Equipment Cost ($/cfm)	Erection Cost ($/cfm)	Maintenance and Repair Cost ($/cfm/year)
Mechanical collector	0.07-0.25	0.03-0.12	0.005-0.020
Electrostatic precipitator	0.25-1.00	0.12-0.50	0.010-0.025
Fabric filter	0.35-1.25	0.25-0.50	0.020-0.080
Wet scrubber	0.10-0.40	0.04-0.16	0.020-0.050

a. Distillate-Oil and Gas-Fired Boilers

Gas-fired boilers are relatively free of particulate emissions and, if the effluent gas includes particulate matter, it is usually a sign of improper combustion. Similarly, distillate-oil-burning units do not have a particulate-emission problem (22). The emission loading is very light, but oil does have an ash residue that appears in the stack discharge. These fine particles may cause the stack discharge to be visible because the particle size approaches the wavelength of visible light, 0.3 microns. Although the quantity of particulate matter emitted is well within the dust-loading requirements of air-pollution ordinances, the visibility of the plume is a potential source of difficulty. In most cases, however, a visible plume is caused by incomplete or improper combustion, which can be corrected by appropriate adjustments.

b. Residual Oil-Fired Boilers

Until World War II, nearly all industrial and power plant boilers were fired with coal. Since then, and particularly in the past decade, residual oil has largely replaced coal in new boilers in the higher capacity ranges as the fuel most commonly used at federal facilities. Oil is easier to handle and store than coal and has the added advantage of a considerably lower ash content. Coal contains an average of 10-percent incombustible ash, while No. 6 oil contains only about 0.1 percent incombustible ash. Oils, however, differ considerably in composition and ash content according to their source. Venezuelan residual, for example, is noted for its high vanadium content; it also is generally high in sulfur and sodium compounds.

The boiler ash that is most common is still that from coal; it is a dry, granular material with a specific gravity of about 2.5 and a relatively high melting point. Ash from oil-fired boilers is lighter, with a specific gravity of about 1.0. It is a granular, hygroscopic material; generally, the greater the sulfur content of the ash, the more hygroscopic it is. Since there is a significant amount of water in the flue gases, the ash can form a sticky acidic material that adheres to any surface--including the ash-collection equipment--and dries to a hard slag which is difficult to remove. Typical particle-size-distribution analyses show that from 50 to 60 percent of the particles (by weight) are less than 10 microns in diameter.

The characteristics of oil ash change when certain additives are used (see Section B.4.c, "Commercial Oil Additives"). The ash tends to be somewhat less hygroscopic because less vanadium is present in a form to catalyze the sulfur compounds into acidic gases; however, the ash still attracts enough water to cause a problem. Slag and wet-ash buildup is more friable and easier to remove and, of greatest importance to the designer of collection equipment, a smaller proportion of the total particulate is in the less-than-10-microns size range--approximately 40 percent compared to the normal 50 to 60 percent (Table 4) (11).

TABLE 4 Typical Size Distribution for Oil Ash Where Additives Have Been Used (11)

Size Range (microns)	Average Size (microns)	Weight of Particulates in Stream (percent)
>60	60	8.5
40 - 60	50	7.0
30 - 40	35	7.5
20 - 30	25	12.0
15 - 20	17.5	10.0
10 - 15	12.5	15.0
7.5 - 10	8.75	9.5
<7.5	3.75	30.5
		100.0

The total particulate loading of oil-fired stack gases depends primarily upon the efficiency of combustion and the rate of buildup of boiler deposits. The data do not follow any trend when the percent ash in the oil is plotted against stack loadings.

The degree of atomization has an important effect on particulate emissions. Low-pressure atomization produces larger fly-ash particles and a higher total particulate loading. High-pressure atomization (400 psig or greater) produces smaller particles, fewer censospheres, and lower particulate loadings.

Oil viscosity, in turn, has a major effect on atomization. Oil viscosity is a function of temperature for a given oil. In two experiments on a 186-MW electric plant, seven tests showed that increasing the oil temperature (which was normally between 230 and 240°F) by approximately 35°F, halved the fly-ash emissions and reduced the combustible portion by 15 to 17 percent (32).

Particulate-loading ranges cited in the literature are represented in Figure 4. This figure shows an extremely wide range between 0.005 and 0.205 gr/sfc; however, the common range is between 0.02 and 0.06 gr/scf (32).

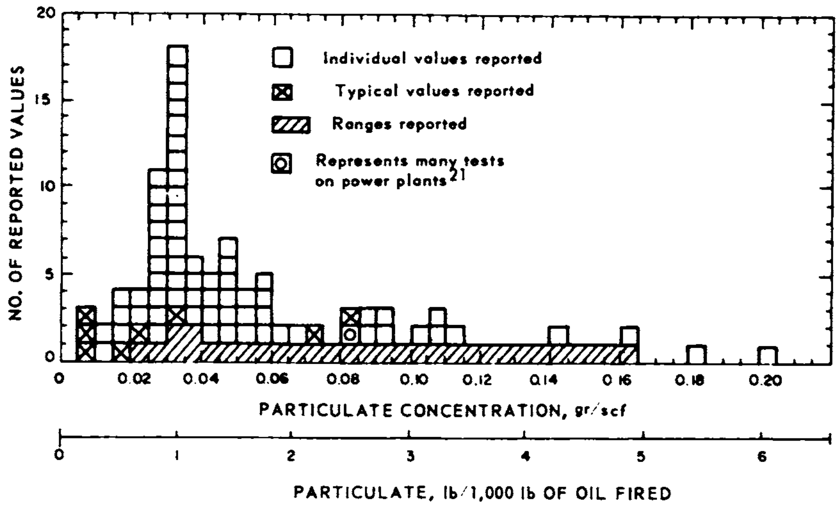

FIGURE 4 Particulate loading in stacks of large units (32).

A performance standard of 0.1 $lb/10^6$ Btu--the value that the Task Group believes agencies should use in the absence of more stringent requirements--would appear to be easily achievable by the average residual-oil-fired boiler during normal operation without mechanical control equipment. During soot blowing, however, such equipment would be required on most residual-oil-fired boilers to achieve an emission rate of 0.1 $lb/10^6$ Btu (0.04 gr/scf). For the extremely heavy loading of 0.5 $lb/10^6$ Btu, which may occur in rare instances, a collection efficiency of 80 percent would be required to achieve 0.1 $lb/10^6$ Btu.

For a new oil-fired boiler to comply with the recommended performance standard of visible smoke density less than No. 1 on the Ringlemann Chart, the total particulate loading would have to be reduced to about 0.1 $lb/10^6$ Btu, thus requiring overall collector efficiency of about 80 percent for the boiler with the extremely heavy loading of 0.2 gr/scf.

For a new oil-fired boiler to comply with the recommended performance standard of no particles greater than 60 microns in diameter in the stack gases, a fractional efficiency of 100 percent would be required on particles larger than 60 microns. Collectors having an overall particle-collection efficiency of 80 percent by weight are almost always close to 100-percent efficient in collecting large particles.

As discussed earlier, the ash particles are highly acidic in character and can cause significant damage to painted surfaces such as automobile finishes. Because their specific gravity is low, they can be carried by the wind for considerable distances. Thus, even when the above performance standards are not applicable, a high degree of cleanup may be required to prevent localized nuisances. During soot-blowing, emission rates could be expected to increase significantly, so control equipment is definitely required during this period.

In the past, most residual-oil-fired boilers were not designed or equipped with particulate control equipment; therefore, very little actual in-use experience reports were available for review by the Task Group. There are four types of collection equipment that could be used for controlling particulate emissions from residual-oil-fired boilers--electrical precipitators, bag filters, wet scrubbers, and centrifugal collectors. Precipitators have not generally been used in the past because of the possible danger of the sparking in the precipitator setting the ash on fire. The acidic character of the ash tended to discourage use of bag filters or scrubbers. Centrifugal collectors, therefore, have generally been the preferred control equipment.

Use of the electrostatic precipitator, discussed later in this report (see Section B.4.c, "Coal-Fired-Boilers"), with the coal-fired boiler has achieved wide acceptance since it offers the advantages of low pressure drop and low energy requirements. For large utility boilers, at least one manufacturer plans to install three new precipitators on oil-fired units. For the small- to medium-size boilers at federal installations, no precipitators have been installed or are anticipated.

If a particular boiler situation requires the efficiency and warrants the cost of a precipitator for an oil-fired unit, then specifications should require: (a) an added 1/16 in. of shell thickness; (b) all specialty-steel construction; (c) water sprays to remove collected oil-ash particles; (d) continuous wet-bottom hopper discharge; and (e) heated clean air under positive pressure around the electrical bushings. Such units should be considered experimental until more experience is gained with such applications.

The fabric filter has been available for years, but only recently has it been seriously considered for power boilers. Tests from 1966 to 1969 at Southern California Edison Company proved the ability of glass-fiber bags to remove particulate matter from oil-firing boilers (7). The company utilized an additive feed to remove sulfur trioxide. The cost of both the initial filterhouse and bag replacements so far has been prohibitive. Newer materials guaranteeing long filter life at higher temperatures may, in the future, open the way to a whole new field of application in the boiler industry. For new federal boiler applications, use of the bag filter currently would be considered in the experimental stage.

Although scrubbers probably have the widest range of application of the various types of dust and mist collectors, they have not received acceptance in the boiler industry. Their history is dotted with instances of failure and disappointments as well as noteworthy successes (16). Experience has shown that scrubbers can very effectively remove dust from gas streams. The pressure requirements are about 5 to 12 in. of water for an acceptable job on fly ash. In the past this pressure drop, along with problems of corrosion and contaminated-water disposal, have militated against their use in the boiler industry.

Use of scrubbers for boiler plant exhausts is being explored extensively. Scrubbers recently installed in small power-generating facilities are currently being tested to determine their efficiency in removing sulfur oxides and other gases along with the particulates. Operating problems are also being investigated; the problem of disposing of contaminated liquid wastes from these units is expected to be only slightly greater than the problem of disposing of water created by the water-wash system on a precipitator or mechanical collector. Still, federal designers and planners should consider such applications experimental.

Mechanical collectors, as a class of collection equipment, have a long history in boiler service, both for oil-fired and coal-fired units. The principal representatives of this class are the familiar cyclones and multicyclones. Since mechanical collectors achieve particulate removal by means of centrifugal, inertial, and gravitational forces, collection efficiencies vary with particle size and density, gas temperature, and pressure drop (Figures 5 and 6) (19,27). Efficiencies are normally very high on particulate matter larger than 20 microns in diameter, but drop off rapidly as particles smaller than 10 microns are encountered.

An oil-fired federal facility in Bethesda, Maryland, was tested to determine the efficiency of the control equipment. Test No. 1 showed a 0.009 gr/scf inlet loading and 0.004 gr/scf outlet loading for an efficiency of 56 percent. Test No. 2 showed an inlet loading of 0.027 gr/scf and an outlet loading of 0.005 gr/scf for an efficiency of 82 percent. Gas temperature was 600°F; pressure drop through the system, although not reported, is estimated at 3 in. of water.

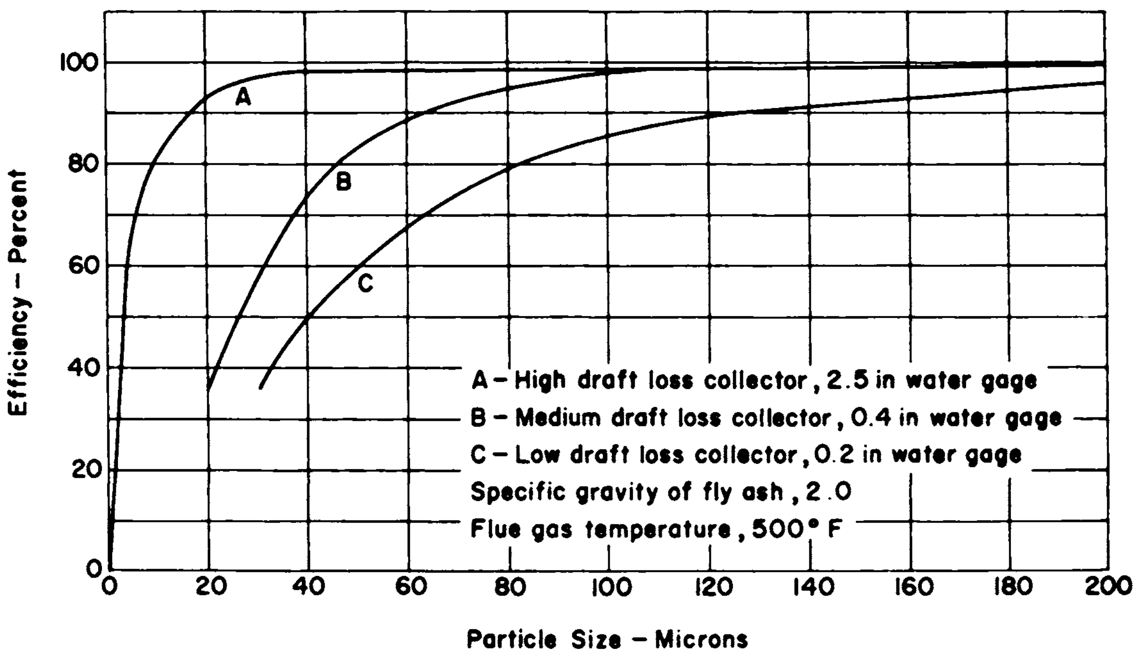

FIGURE 5 Fractional efficiency curves for three types of inertial collectors (27). Reproduced by permission of the National Coal Association.

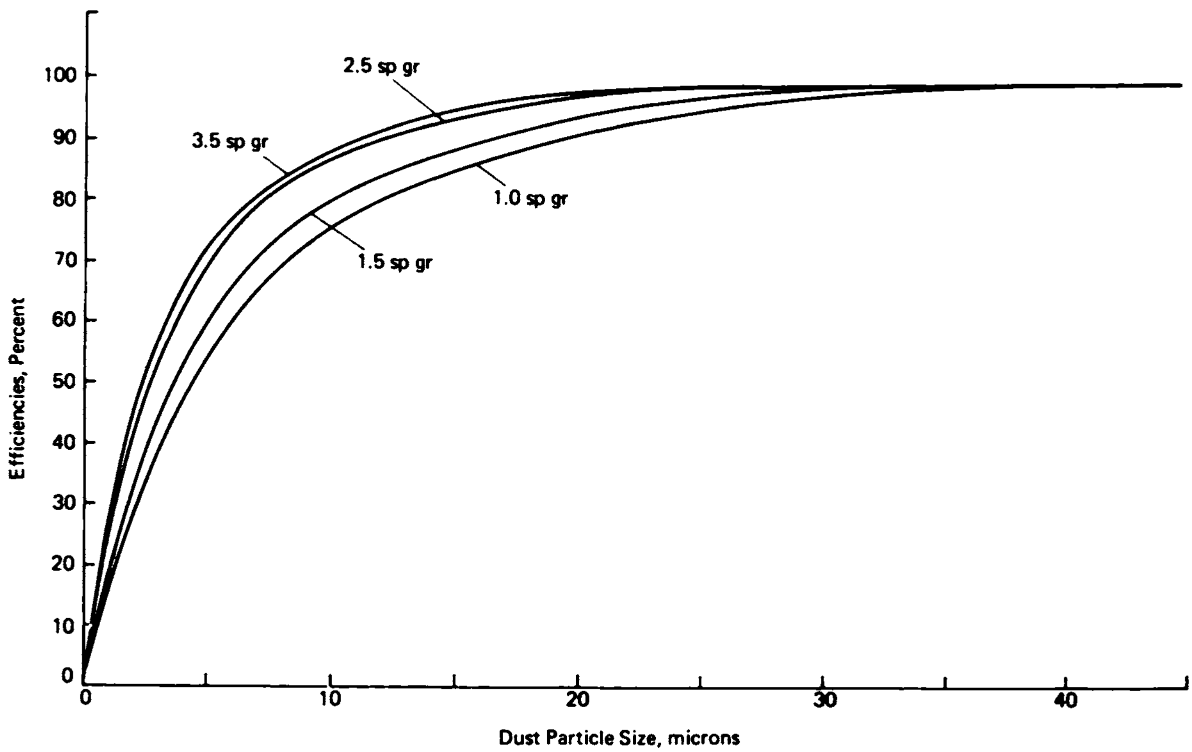

FIGURE 6 Typical fractional efficiency curve for multicyclone dust collector.

Pressure requirements for mechanical collectors in normal boiler operation are from 0.5 to 3 in. of water. For a selected pressure drop and with accurate particle-size data, the manufacturer's fractional-efficiency curve (Figure 7) can be used to predict overall collection efficiencies for a given collector (27). This value of efficiency can then be guaranteed, since sizing standards have been accepted and are being used by the industry. Because of the

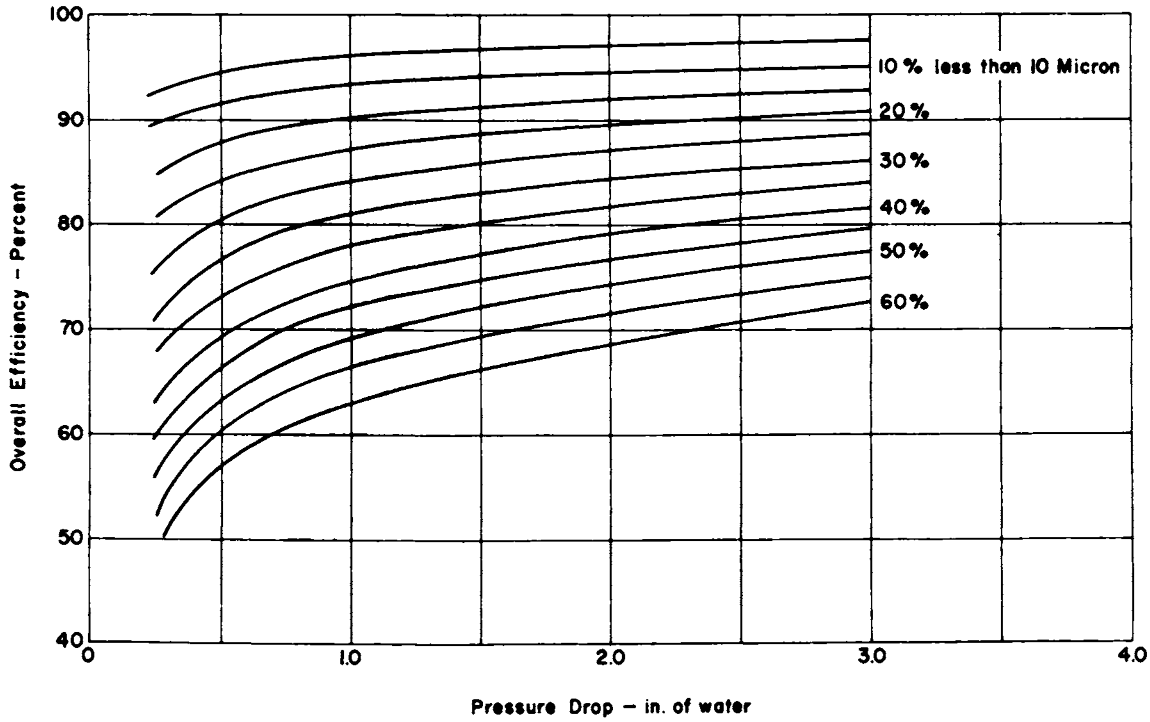

FIGURE 7 Performance of typical mechanical cyclone dust collector (27). Reproduced with permission of the National Coal Association.

difficulties and costs of stack testing and particle-size analyses, federal equipment specifications should require that guaranteed micron efficiency curves be provided on each job. For residual-oil-fired boilers, mechanical collector specifications should require overall collection efficiencies of 80 percent, a pressure drop through the collector of at least 3 in. of water, and 100 percent collection of particles larger than 60 microns in diameter.

As previously stated, oil ash is hygroscopic. If collected ash is not removed from the hoppers frequently, it tends to solidify into a slag and plug the hoppers or other parts of the collection system. Continuous ash-removal systems therefore are advisable whereever possible.

Slag formation in the collector is largely a function of gas temperature. Generally, if flue-gas temperatures are kept above 400°F, wet-ash buildup will be minimized. Where this is not possible, a water-wash system as an integral part of the collector is recommended. Water will dissolve some part, primarily the sodium compounds, of the wet ash; the remainder, particularly in systems where additives have been used, is friable and is carried out of the collector in slurry form. The washing equipment can also be used to coat the inside of the collector with a caustic solution to reduce acidic corrosion. If a water-wash system is to be used, a manometer installed across the collector (inlet to outlet) will help determine desirable washing frequency.

c. Coal-Fired Boilers

The following variables are felt to be the most important in relation to particulate emissions from coal-fired boilers (33):

1. Amount of ash in the coal;
2. Heat content or heating value of the coal;
3. Method of burning the coal; and
4. Rate at which the coal is burned.

Ideally, the only particulate emission would be the material ash contained in the coal; however, 0.5 to 5 percent of the combustible content of the coal can also be emitted as particulate matter. Thus, more particulate matter can be emitted than there is ash in the coal because of the combustible fraction in the emissions. If reinjection of fly ash is practiced, there can be an accumulation in the furnace of suspended solids representing more than 100 percent of the ash in the fuel. Solids leaving the furnace (before the fly-ash collector) can thus be greater than the total ash entering in the fuel.

The method of burning coal also influences particulate-emission rates. When coal is thrown or blown into a furnace, combustion takes place in suspension. As pieces of coal burn, they get smaller, and their chance of being exhausted with stack gases is increased. When coal is pushed or pulled into a furnace to form a bed, coal or ash has less chance of being entrained by flue gases because of impingement onto larger particles. When coal is introduced tangentially into a cylinder, such as in the cyclone furnace, the burner acts as a cyclone separator and therefore reduces the emission of larger particles.

As the velocity of gases passing through the furnace increases, larger particles of coal and ash are carried out of the furnace. Velocity of the gases is directly proportional to the burning rate of a given furnace (Figure 8); therefore, the size of the particle and the rate of emission (Figure 9) should be a function of burning

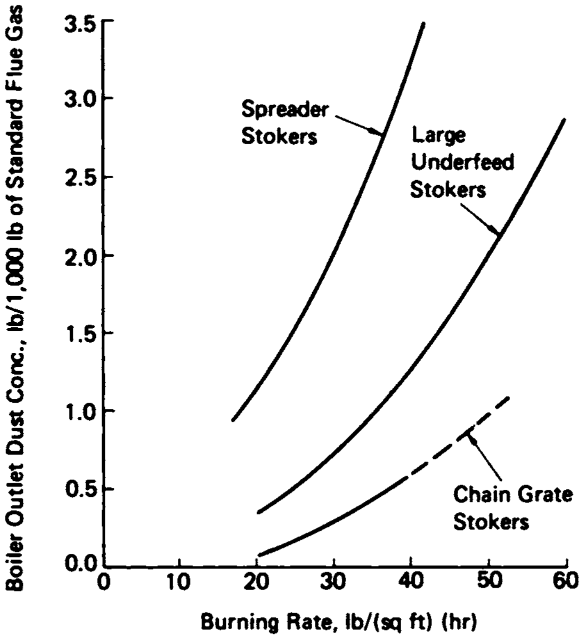

FIGURE 8 Trends of dust emissions for stokers (27). Reproduced with permission of the National Coal Association.

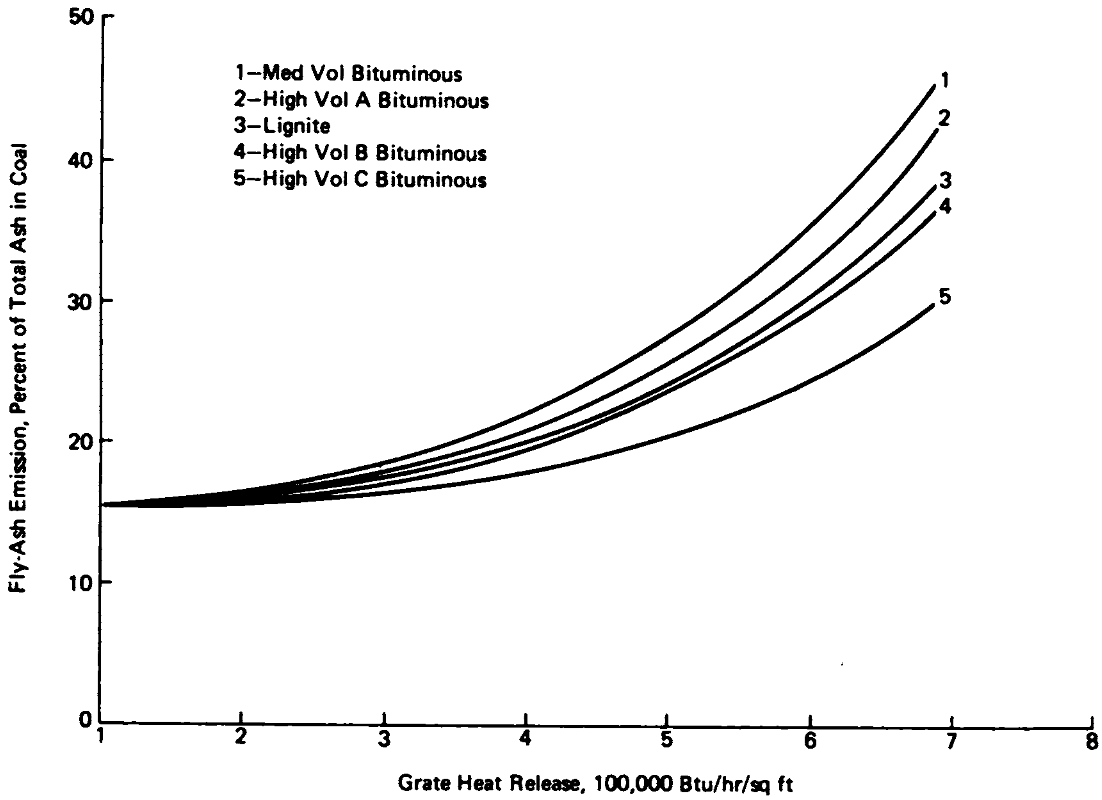

FIGURE 9 Fly-ash emission from spreader-stoker-fired furnace, with continuous ash discharge (19). Reproduced with permission of the National Coal Association.

rate (19,27). In a similar manner, excess air, pressure, and temperature are related to particulate emissions in that they control gas velocity.

Particle-size distribution of the emitted fly ash is extremely important. It can dictate the use of certain collection equipment and affect the design of the selected equipment, as will be noted later. The variation in particle-size distribution in flue gases with different methods of firing is shown in Figure 10 (16). In this figure the left-hand curves represent particle-size distribution in flue gases from stoker-fired boilers. As might be expected, pulverized-coal fly ash is further to the right than that from the spreader stoker, with about 45 percent of the dust from pulverized coal less than 10 microns in diameter. On the extreme right, the

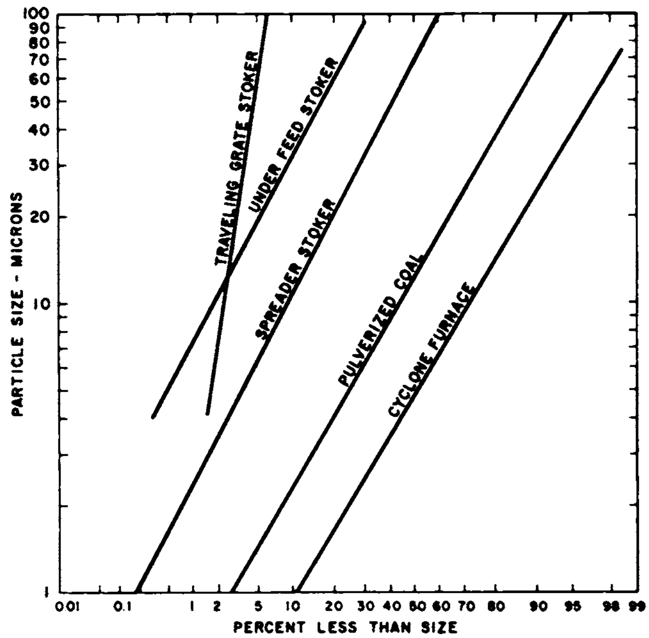

FIGURE 10 Particle-size distribution for different methods of firing (16).

size distribution of dust from a cyclone furnace is presented. This figure is, at best, an approximation. It is very difficult to arrive at average size distributions for the different methods of firing coal, since much depends on fuel preparation and sizing, excess air used, firing rate, and furnace design, as well as on the method of firing itself.

i. Stoker-Fired Boilers

Probably the most definitive information on particulate emissions from stoker-fired boilers was compiled by a joint technical committee of the American Boiler Manufacturers Association and the Industrial Gas Cleaning Institute (ABMA-IGCI) (20). In the study, the only variables considered by the committee were firing method, particulate emissions, particle-size distribution, and ash content of coal burned. These variables were considered to be the major ones necessary for an initial orientation to air-pollution-control equipment requirements. Significant results of this study are presented below.

A total of 54 measurements of particulate emissions from 14 stoker-fired boiler installations were evaluated. The mean value of all the particulate concentration measurements was 2.26 gr/scf. The distribution of measurements indicated two distinct populations of data. Of the total of 54 measurements, 17 fell between 2.16 and 5.2 gr/scf and 17 fell between 0 and 1.0 gr/scf. The mean value for the higher mode, which apparently was representative of boiler operation with ash reinjection, was 3.71 gr/scf; the mean value for the lower mode, possibly reflecting combustion practice without reinjection, was 0.364 gr/scf.

There was no significant correlation between the ash content of the coal fired and the particulate-emission level. This suggested the existence of more critical variables involved in the emission of particulates from stoker-fired boilers, such as the above-mentioned practice with regard to ash reinjection and flow of combustion air through the grate.

A total of nine particle-size distributions obtained by the ASME PTC-28 method was also evaluated. The data did not submit to detailed analysis other than to calculation of the overall arithmetic averages for the various types of spreader stokers for which samples were analyzed. For spreader stokers, which are very commonly used at federal heating plants, the specific gravity of the particles averaged 2.5 and about 20 percent of the particulate, by weight, was smaller than 10 microns (Figure 11).

For an average stoker-fired unit without reinjection, the average emission rate of 0.364 gr/scf can be reduced 80 percent to 0.08 gr/scf (0.2 lb/10^6 Btu) by using a mechanical collector. Therefore, specifications should require an overall efficiency of 80 percent and a pressure drop of at least 3 in. of water. Specifications also should require 100-percent collection efficiency on particles larger than 60 microns.

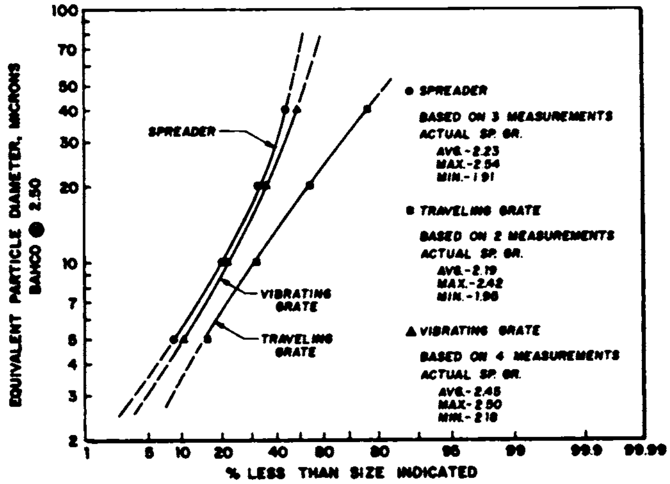

FIGURE 11 Stoker-fired boiler -- particle-size distribution (20). Reproduced with permission of the American Boiler Manufacturers Association.

With regard to stack opacity, attempts have been made to correlate mass emissions with optical properties of the stack; however, the problem is extremely complex because the opacity of a stack plume is related not only to the mass of particulates but also to their color and specific surface and to the presence of condensed vapors. Based on ABMA-IGCI experience with many measurements and observations of stoker ash, 0.02 to 0.04 gr/scf should give a clear stack on a stoker-fired boiler. To achieve this degree of cleanliness (as calculated earlier) will require a collection efficiency of over 90 percent by weight; specifications should limit emissions to 0.04 gr/scf where No. 0 Ringlemann is required. For new stoker-fired units with reinjection, collection efficiencies will have to exceed 99 percent to reduce emissions from 3.71 to 0.04 gr/scf (0.1 lb/10^6 Btu).

ii. Pulverized-Coal-Fired Boilers

The correlation between particulate emissions and ash content of coal burned is shown in Figure 12 for dry-bottom, pulverized-coal-fired boilers. The mean value of the 78 measurements of particulate emissions utilized in this correlation is 3.3 gr/scf with a standard deviation of 1.44. A linear correlation exists between percent ash in the coal and particulate emissions with a high degree of confidence (greater than 99.9 percent).

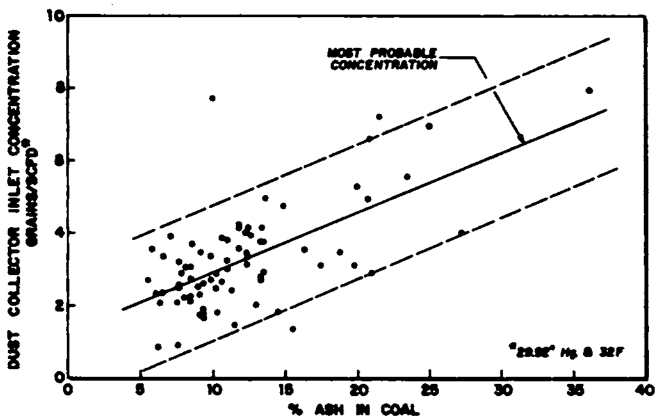

FIGURE 12 Pulverized coal-fired boilers -- 78 measurements on 44 installations (20). Reproduced with permission of the American Boiler Manufacturers Association.

The equation for the linear regression line (i.e., the most probable value of particulate emissions for a given ash content in the coal) is

$$C = 16.2A + 1.32,$$

where C = particulate emissions concentration (gr/scf) and A = fractional percent ash in coal.

The equation for maximum particulate emissions for a given ash content for 90 percent chance of being correct in the prediction under all operating conditions is

$$C = 16.2A + 3.25.$$

Using these two equations for prediction of particulate emissions should provide a reasonable basis for specification of most probable and maximum concentration to dust collectors for ash contents ranging from 5 to 40 percent.

A total of 69 individual particle-size distribution analyses, performed according to the ASME PTC-28 method, was submitted for dry-bottom, pulverized-coal-fired boilers. Analysis of the weight percentages of particulate emissions in the various size fractions (0 - 5 microns, 0 - 10 microns, 0 - 20 microns, and 0 - 40 microns) indicated they were normally distributed; thus, confidence intervals for the total size distribution could be established. Results are shown in Figure 13; an average or most probable distribution indicates 44 percent (by weight) of the particles are smaller than 10 microns in diameter with a specific gravity of 2.34.

Specific gravity determinations, on a total sample basis, were not normally distributed. Based upon 69 measurements, a mean of 2.34, a minimum of 1.90, and a maximum of 2.92 were indicated. Fifty percent of the measurements were between 2.10 and 2.40.

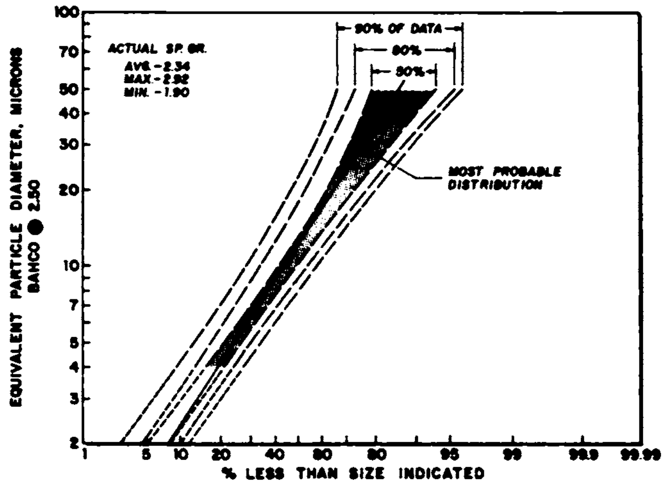

FIGURE 13 Particle-size distribution -- pulverized coal-fired boilers based on 69 measurements (20). Reproduced with permission of the American Boilers Manufacturers Association.

iii. Cyclone-Fired Boilers

A total of 77 measurements of particulate emissions on approximately 20 installations was submitted. Fifty-seven of the measurements reported had associated ash content of the coal included. The data were log-normally distributed with a mean value of 0.85 gr/scf and a standard geometric deviation of 2.23. Thus 90 percent of the measurements fell between limits of 0.23 and 3.2 gr/scf.

Correlation of particulate emissions with ash content of the coal is shown in Figure 14. A linear correlation exists between percent ash in the coal and particulate emissions with a high degree of confidence. Dotted lines indicate the interval that embraces 90 percent of the measurements. The linear regression line is expressed

$$C = 14.4A - 0.42.$$

The extreme scatter of the data submitted on the cyclone boiler reflects a much greater variation in firing practice with cyclone boilers than is evident with pulverized-coal-

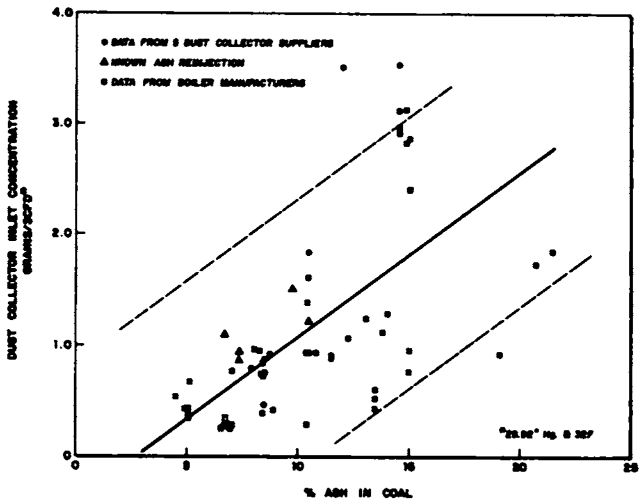

FIGURE 14 Cyclone-fired boilers -- dust-collector inlet concentration (20). Reproduced with permission of the American Boiler Manufacturers Association.

fired boilers. This variation is probably a result of ash reinjection practiced in many cyclone boiler installations. Since no information was available for separating the data on installations practicing from those not practicing ash reinjection, the correlation shown is of questionable value in predicting particulate emissions from cyclone boilers without rather large safety factors. In the absence of further data and analysis, it would appear that the only recourse in establishing efficiency specifications for dust collectors on cyclone boilers is to utilize the upper limit of particulate emissions indicated in this analysis. A value of particulate emissions, as determined from

$$C = 14.4A + 0.88,$$

would represent the maximum particulate emissions to be expected, with a 90-percent chance of being correct, for ash contents of coal ranging from 4 to 22 percent.

A total of only six particle-size distributions, based on ASME PTC-28 methods, was submitted for cyclone-fired boilers. These data did not submit to analysis other than to the calculation of the arithmetic average distribution. The individual distributions, specific gravities, and the arithmetic average distribution are shown in Figure 15. The broad variation in particle-size distribution also reflects the apparently broad variation in firing practice on cyclone boilers.

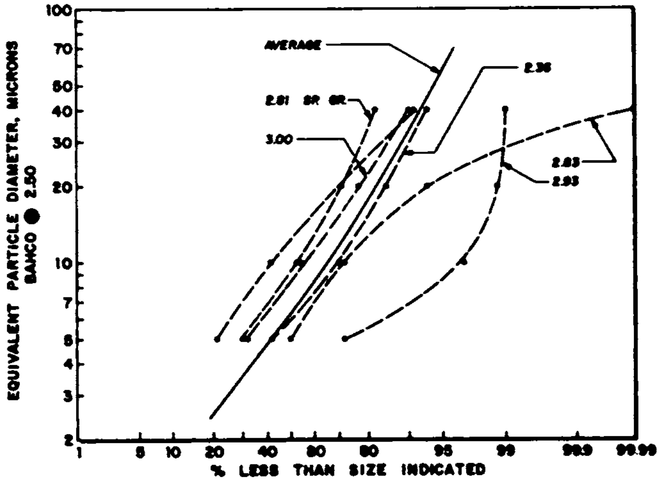

FIGURE 15 Particle-size distribution and specific gravity -- cyclone-fired boilers (20). Reproduced with permission of the American Boiler Manufacturers Association.

iv. Electrostatic Precipitators

Pulverized-coal-, cyclone-, and stoker-fired units with reinjection would generate on the order of 0.85 to 3.7 gr/scf of exhaust gas. To achieve an emission limit of 0.1 lb/10^6 Btu (about 0.04 gr/scf) at the stack discharge therefore would require efficiencies up to about 99 percent. Even to meet existing requirements (0.35 gr/scf or 0.6 lb/10^6 Btu), federal facilities with rated capacities under 10 million Btu/hr would require efficiencies greater than 90 percent. The efficiency requirements to have stacks optically clear of dry particulates (0.02 gr/scf based on the criteria discussed earlier) would be 99.4 percent (3.68/3.70) (46). Obviously, the only equipment that can provide the desired efficiency on this fine-ash and -dust particulate is an electrostatic precipitator. A high-efficiency venturi scrubber or bag house also may be able to provide the necessary efficiency but judgment should be exercised in specifying such equipment, except on an experimental basis, in applications such as those where contaminant gases also are being removed.

The electrostatic precipitator has been used on power boilers for about 40 years and has built an enviable reputation. In general, it is conceded that the electrostatic precipitator is the most efficient collecting device in general boiler use today. Simply stated, the process consists of the electrostatic charging of dust particles with a corona discharge and passing them through an electrical field where they are attracted to a collecting surface. For high collection efficiency, velocity must be low, as shown in Figure 16 (19). Theoretically, particle size is directly related to precipitator collection efficiency; in actual practice, however, this has not been proven true. Collection efficiency is only slightly dependent on particle size. Gas viscosity increases with temperature, which indicates that collection efficiency improves at lower temperatures, but this effect is more than cancelled by other factors.

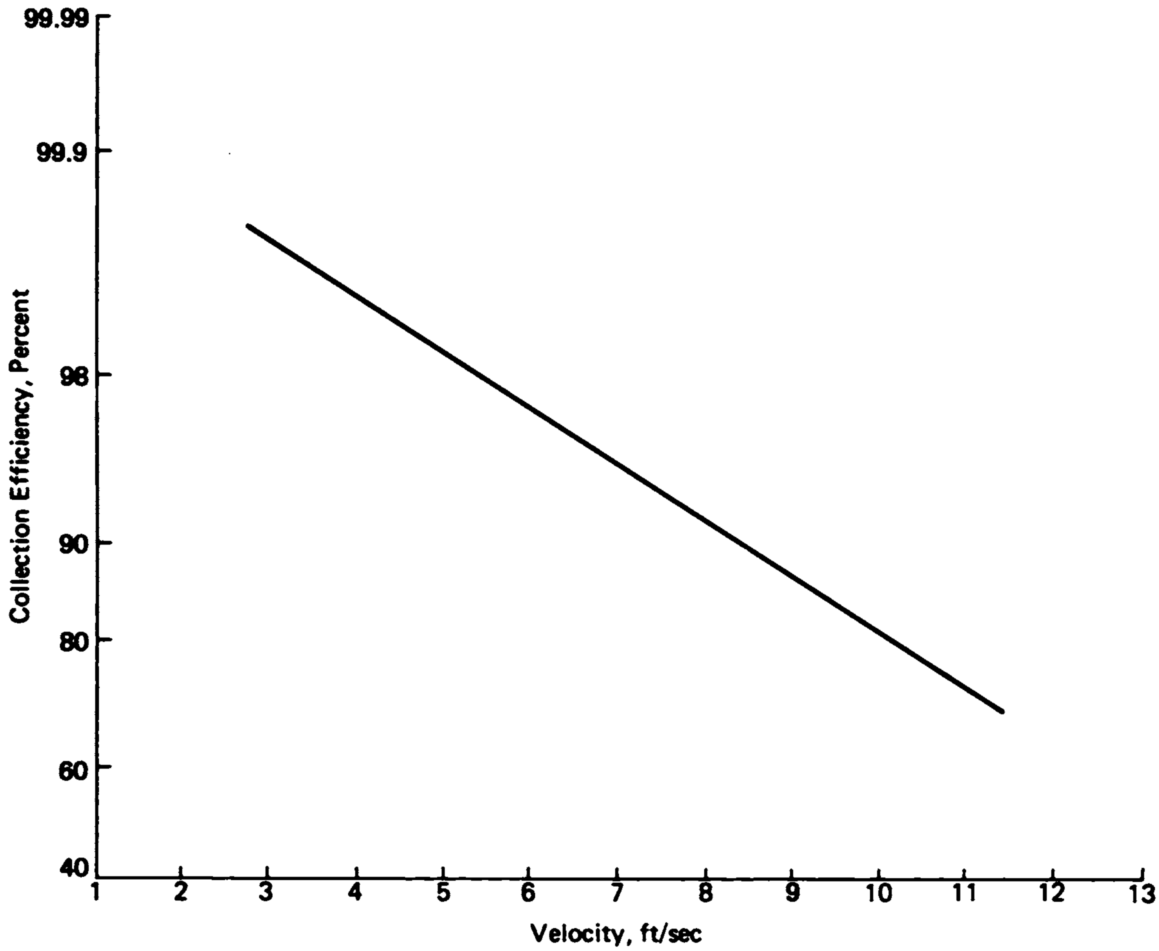

FIGURE 16 Theoretical efficiency curve -- electrical precipitator (19). Reproduced with permission of the National Coal Association.

The strength of the electrical fields is of the utmost importance, and factors that influence these fields affect collection efficiency. The most obvious factor is the charging voltage, but others, including dust resistivity, have strong effects on precipitator performance (34). Of significant interest among the other factors affecting performance are sulfur content of the coal, gas temperature, boiler load, flow distribution, and carbon content of the fly ash (Figures 17 and 18).

One of the major reasons for the acceptance of electrostatic precipitators is the fact that they are not limited by particulate size. In the size range from 1 micron to 0.01 micron, electrostatic precipitators are very effective, and the electrical charge on the particulate becomes the dominant force affecting collection. The precipitators can be designed for any efficiency required, can operate over a broad spectrum of concentration, and require a very nominal draft loss of about 0.5 - 1 in. of water pressure. Although the coarser particles collect more easily, they also may be more readily lost to the gas stream through re-entrainment resulting from vibration of the collection plate or gas eddy currents. For many years, this problem was solved by combining the electrostatic precipitator with a mechanical collector to remove the coarser particles; however, recent developments have made it possible for a number of plants in the United States to go into service with only an electrostatic precipitator.

Information of value to preparers of specifications for electrostatic precipitators can be found in two publications of the Industrial Gas Cleaning Institute*: Terminology for Electrostatic Precipitators and Information Required for the Preparation of Bidding Specifications for Electrostatic Pre cipitators.

4. Other Requirements

a. Smoke Detection

Federal regulations issued pursuant to Executive Order 11282 provide, in part, that a "Photoelectric eye or other type smoke detector, recorder, or alarm shall be installed on units larger than 10 million Btu/hr input, except where gas or light oil (No. 2 or lighter) is burned" (41).

*Box 448, Rye, New York 10580.

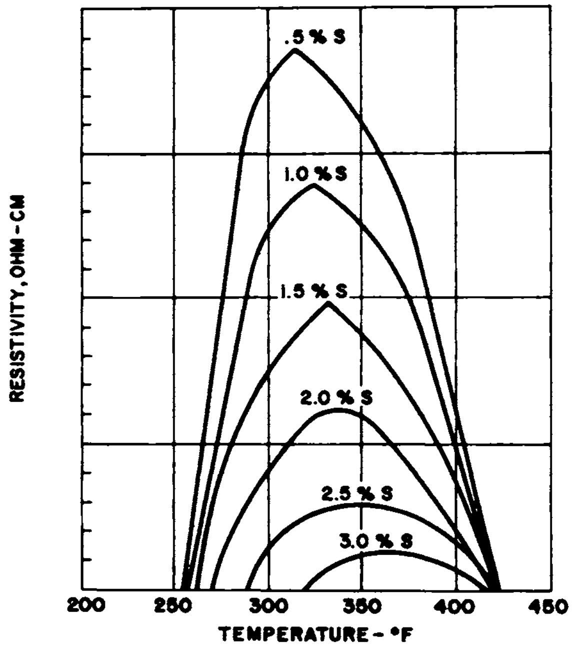

FIGURE 17 Temperature/sulfur/fly-ash resistivity relationships for bituminous coal.

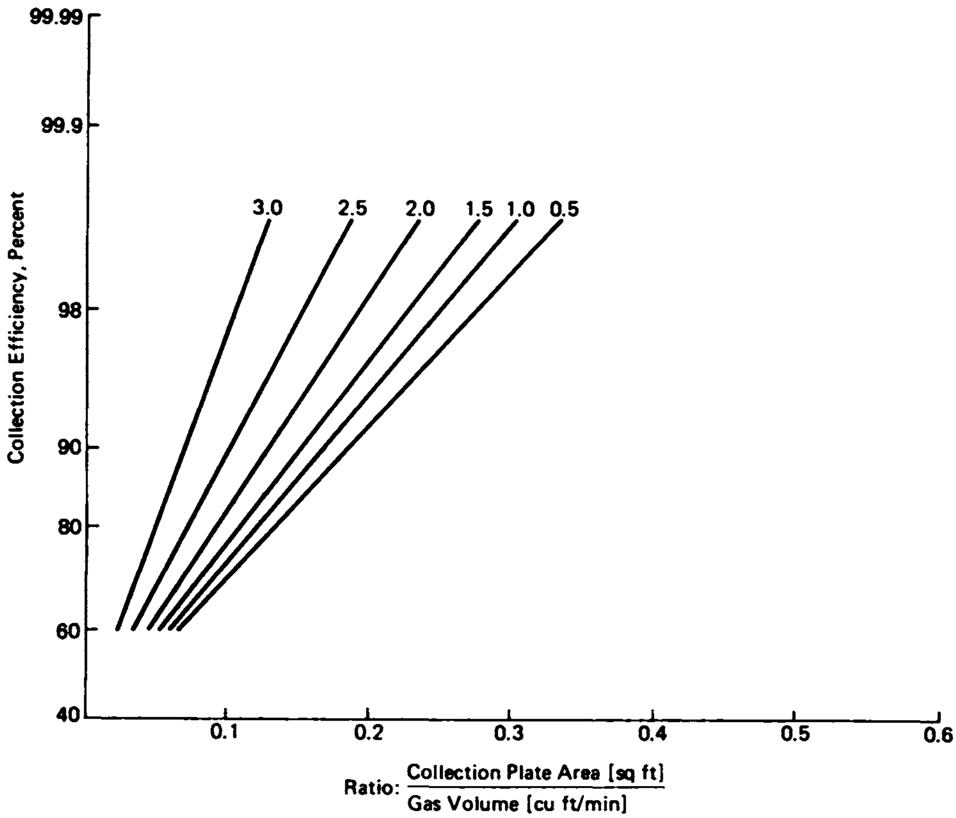

FIGURE 18 Effect of coal sulfur content on fly-ash collection by electric precipitation at 300°F (19).

Economic and practical considerations dictate the use of smoke detectors with an indicator in the boiler room for residual-oil- and coal-fired units with rated capacities between 10 and 50 million Btu/hr input. For residual-oil- and coal-fired units larger than 50 million Btu/hr, smoke-density readings should be kept by a recorder in the boiler room along with other combustion-control instrumentation.

b. Fly-Ash Reinjection

Fly ash from coal-fired boilers is often reinjected into the furnace to improve the overall combustion efficiency of the unit; some boiler manufacturers claim an additional 0.5-percent increase in boiler efficiency because of reinjection. Another reason for reinjection is bulk reduction of the total fly ash. In spreader-stoker boilers, particulates average 50 percent combustible content, which makes these units uniquely adaptable to recycling. The major factor affecting combustible content of the particulates is firing rate; higher firing rates yield a high combustible content of the fly ash. Total reinjection increases the dust loading to the collector by a factor of 10 over no reinjection (described earlier) since all particulates are sent back to the furnace. These excess solids can overload the collector and greatly reduce overall collector efficiency. Total reinjection, therefore, should not be practiced unless designed collector capacity and operating efficiency are both sufficient to handle the additional dust carryover caused by the recycling. Furthermore, most boiler operators do not use 100-percent reinjection of the collected ash because of the additional wear and tear on the combustion chamber. From the air-pollution-control viewpoint, fly-ash reinjection, if operated incorrectly, will lead to very deficient fly-ash collection for the total boiler system. Therefore, air-pollution-control requirements can be maintained only if the smaller particles are removed and only the larger particles (over 44 microns) are reinjected.

This compromise between total reinjection and no reinjection is the so-called partial reinjection in which a mechanical collector is used to ventilate the main-collector hopper. The main collector then becomes, in effect, a dust classifier that allows only reinjection of the coarse content of the fly ash back into the boiler. The fly-ash particles are drawn off into the auxiliary collector where they are captured and removed from the system. Partial reinjection does, in fact, lead to reduction of boiler particulate emissions by about a factor of five, compared to total reinjection. The overall result also includes increased fuel efficiency (46).

Approximately 30 percent of the particulates from the first pass of spreader-stoker-fired units are greater than 44 microns in diameter (No. 10 mesh). The finer portions of the fly ash are sometimes removed from the system by secondary collectors, while coarser particulates (greater than 44 microns) are collected in a primary collector, segregated, and the larger dust particles sent back into the furnace.

Another method for separating the particles for partial reinjection is the use of screens (9). Several tests on larger stoker-fired units, with screens to separate the coarse particles, have shown good results. The selection of screen size is made with consideration given to furnace-grate loading, heat release, and reinjection rate.

c. Commercial Oil Additives

Commercial oil additives frequently are used with certain types of residual fuel oil to minimize corrosion and slag buildup problems associated with such fuel (see Section B.3.c). Commonly used additives are magnesium, calcium oxides, sulfates, and dolomite lime. Such materials alleviate the corrosion problem by converting some of the vanadium compounds to other compounds having higher melting points (24).

Other additives are used selectively to improve oil viscosity, luminometer number, flash point, and distillation number, all of which tend to accelerate firing and increase overall combustion efficiency. A magnesium additive reportedly has advantages that include inhibiting corrosion, raising melting points, preventing reaction from taking place (SO_3 + water vapor = H_2SO_4), preventing hard-type slag from forming on the boiler tubes, and causing particulate matter to agglomerate and therefore to be more easily collected (29).

Some additives may be of value in mitigating air pollution (17); however, the matter is still under investigation. The EPA's Office of Air Programs is currently conducting a study to determine the relationship of fuel-oil-additive technology and fuel composition to air-polluting emissions. According to an interim status report, a majority of the proprietary additives tested have no beneficial effects on controlling air-polluting emissions in the test system (24).

The experimental phase of the evaluation included obtaining samples of additive compounds, charterizing their chemical composition, and measuring their effects on emissions of air pollutants in an experimental test system. Flue-gas data from the test system were analyzed for particulates, smoke, carbon monoxide, carbon dioxide, oxygen, total gaseous hydrocarbons, oxides of nitrogen, and oxides of sulfur. Test conditions were simulated using various compounds, and the emissions during base-line operation were compared. Two hundred and six commercial additives, including combinations of 10 metallic compounds and 19 pure nonmetallic compounds, were analyzed.

Conclusions drawn from the tests include the following (24):

- Certain metal compounds and proprietary additives reduced carbon particulate emissions. The metals in order of decreasing effect are cobalt, iron, nickel, manganese, and barium.

- The tests showed no evidence that a combination of metals offers any advantage over single-metal additives.

- Although some metallic compounds apparently reduced particulate emissions, the concentrations required were generally large.

- No additives reduced emissions of SO_2 or SO_3 at the concentrations produced by the 0.1-percent sulfur fuel used for the tests.

- No additives reduced emissions of unburned hydrocarbons or carbon monoxide at the low test levels.

- In the test system, many additives produced no beneficial effect from the standpoint of air-pollution control, and many produced detrimental effects.

- Initial testing of water-oil emulsions did not show promise for use in light oils. Although they reduced emissions of nitrogen oxides significantly, they also caused large increases in particulate emissions.

- Nitrogen content of fuel significantly affected formation of oxides of nitrogen. Nitrogen-containing fuel additives, such as diesel ignition improvers, are used at concentrations that can add significantly to nitrogen levels in fuel.

Fuel additives were never intended to be used as a means of reducing particulate emissions when improper burner adjustments, poor fuel quality, or inadequate control equipment create excessive discharges to the atmosphere, but the investigation indicates that marginal air-pollution benefit may be achieved through decreased soot formation. Other contaminants, however, may be increased.

Oil additives are regulated by the Office of Air Programs, EPA, under the Clean Air Act Amendments of 1970. Therefore, additional information on fuel-oil additives should become available in the future.

C. SULFUR OXIDES

Sulfur oxides (SO_x) are important as air contaminants due to their corrosive and irritating properties. On a national basis, the principal source of SO_x is the combustion of coal; however, residual-fuel-oil combustion and industrial processes such as smelting and acid manufacture contribute significant quantities. Sulfur present in fossil fuels is oxidized during combustion to form sulfur dioxide and lesser amounts of other oxides of sulfur, most of which are discharged with other combustion gases into the atmosphere. Sulfur oxides from fuel combustion are little affected by type, size, or other design features of the combustion equipment or by the way in which the fuel is burned. Thus, concentrations of sulfur oxides are essentially determined by the amount of sulfur in the fuel.

1. Performance Requirements

Emission limitations for sulfur oxides have been promulgated by federal, state, and local agencies in several parts of the country in recent years. Utilizing published information on the regulations that already have been adopted, the sulfur oxide pollution levels of communities in different parts of the country, and possible content of legislation needed to achieve local air-quality goals, Task Group T-65 prepared and published FCC Technical Report No. 57 (15).

Report No. 57 had two objectives: (a) to determine the extent to which current and anticipated air-pollution regulations would restrict the types of fuel which federal agencies will be allowed to burn in steam-power and central heating plants and (b) to recommend procedures to be used by agencies in taking account of such restrictions in economic analyses to determine the type of fuel to burn in new plants or existing plants being modified. The report concluded that sulfur oxide restrictions would affect the type of fuel that could be burned at federal facilities. It also provided SO_x emission requirements for various parts of the country that should be utilized by federal planners unless specific state or local regulations are more stringent.

2. Testing Requirements

Some methods have been specifically developed to test for sulfur oxides emissions in stack gases while others have been adapted from procedures used to measure atmospheric levels of sulfur dioxide. The recommended method for testing stack gases is a gravimetric analysis. The analytical procedure is somewhat long and tedious but for years it has been considered a standard method in water analysis. It is the American Petroleum Institute's method for sampling and analysis of refinery wastes (API Method 774-754) and it is the standard test procedure for sulfur oxides in the Los Angeles County Air Pollution Control District

(23). To determine compliance with the EPA standards of performance for SO_2 emissions from new stationary sources, the barium-thorin titration method is specified (40).

As an alternative to stack testing for sulfur oxides, sulfur-in-fuel analyses may be made using ASTM Code 396 (5). Stack emissions are calculated from fuel-combustion rates, excess air rates, and other combustion variables as described in BRAB/FCC Technical Report No. 57.

3. Control Equipment

A special ad hoc panel of the National Academy of Engineering conducted a study on abatement of sulfur oxide emissions from stationary combustion sources. In its report, the panel concluded (13): Contrary to widely held belief, commercially proven technology for control of sulfur oxides from combustion processes does not exist.... Efforts to force the broad-scale installation of unproven processes would be unwise; the operating risks are too great to justify such action, and there is a real danger that such efforts would, in the end, delay effective SO_2 emission control.

The panel recommended a five-year, federally supported research plan for developing the following control approaches:

a. "Throw-away" processes for removal of SO_2 from stack gases, such as limestone injection, which produce a presently nonmarketable product.

b. New combustion concepts, such as fluidized-bed combustion (FBC), which fixes the sulfur as a sulfate during combustion and prevents its release as SO_2 to the stack.

c. Chemical-recovery processes, which produce salable SO_2 sulfuric acid, elemental sulfur, or fertilizers.

d. Coal-gasification processes, which produce sulfur-free fuels.

e. New concepts in engineering and chemical approaches to desulfurizing coal.

The National Air Pollution Control Administration had earlier advised one federal agency that current research on developing control techniques for removing sulfur oxides from stack gases is not directed to heating plants of the small size common to federal installations (15).

Based on such information, Task Group T-65, in BRAB/FCC Technical Report No. 57 (15) recommended, in part, that: Use of equipment to remove sulfur oxides from flue gas is not to be considered (unless there is no other alternative); instead, only those types of fuel are to be considered that have a sufficiently low sulfur content to meet both present and anticipated sulfur oxide emission restrictions applicable to the plant in question and that are available or are expected to be available in the region of the plant. (Possibly future developments in equipment for the removal of sulfur from flue gases may call for later modification of this recommendation.)

The Task Group concludes that no change in its earlier recommendations is warranted at this time.

4. Other Requirements

As noted above, the only feasible method of controlling sulfur oxides emissions at plants of the sizes covered by this report is to burn only those fuels having sufficiently low sulfur content that emission limits will not be exceeded. While the projected performance requirements (presented in BRAB/FCC Technical Report No. 57) are attainable with existing technology, more stringent standards in the future may require the development of new technology.

D. NITROGEN OXIDES

When fossil fuels (gas, fuel oil, and coal) are burned with air, some of the oxygen and nitrogen gas present combine to form a class of pollutants referred to as NO_x--a general term that includes such oxides of nitrogen as NO, NO_2, N_2O_4, and N_2O_5. NO is the primary compound formed but it oxidizes slowly in the atmosphere to produce nitrogen dioxide (NO_2). In the presence of sunlight, nitrogen dioxide reacts with hydrocarbons to produce a highly reactive class of compounds known as photochemical oxidants. These oxidants cause plant damage and eye irritation, reduce visibility, and have other unpleasant side effects. The two principal sources of the 20.6 million tons of nitrogen oxides discharged into the atmosphere annually are motor vehicles (50 percent) and power plants (25 percent). The next largest source is natural-gas-driven compressors for oil and gas pipelines and gas plants.

The main factors in NO_x formation are the flame temperature, the length of time the combustion gases are maintained at that temperature, and the amount of excess air present in the flame (Figure 19). Small combustion units operating under relatively low temperature conditions produce an exhaust gas containing only small amounts of NO_x. The vent gas from a typical domestic gas-fired water heater, for example, contains only 10 ppm NO_x. The concentration rises rapidly with combustion intensity and may reach 500 to 1,000 ppm or more in a power plant steam boiler (Figure 20). Table 5 shows some average emission factors for different fuels (43). The

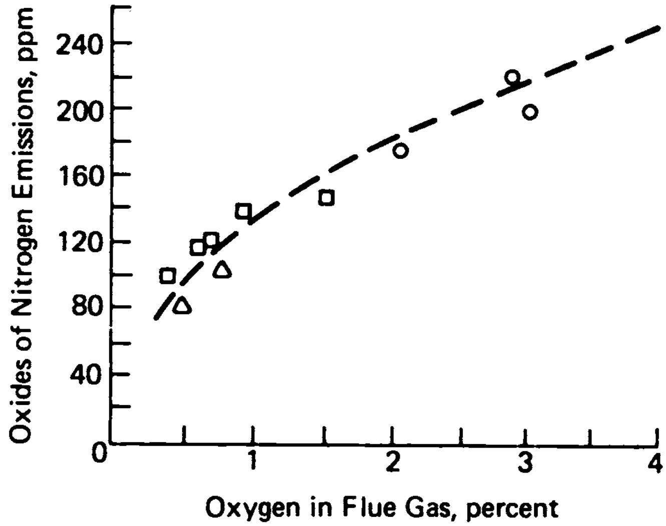

FIGURE 19 Oxides of nitrogen emissions from oil-fired boilers at low excess air (43).

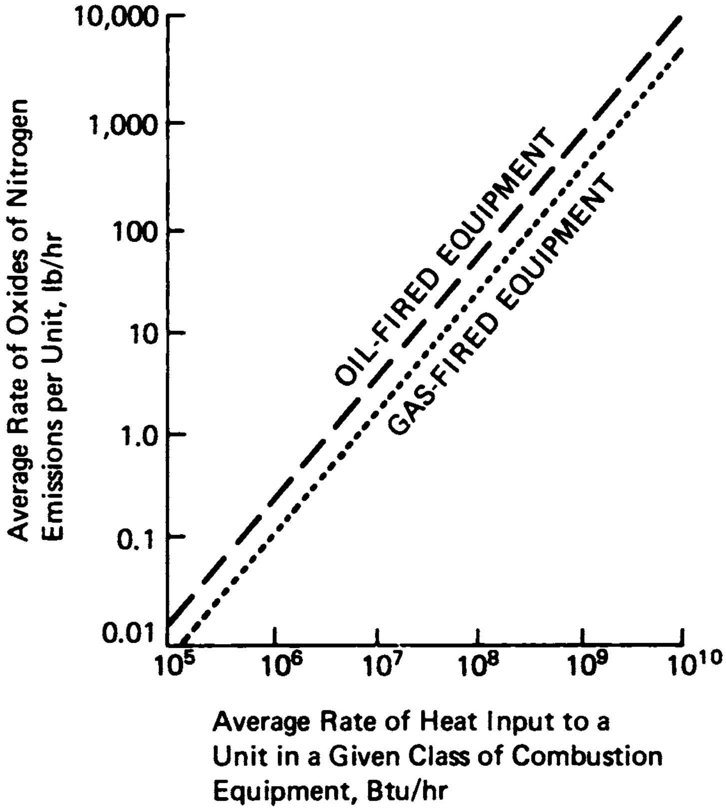

FIGURE 20 Estimation of average unit oxides of nitrogen emissions from similar combustion equipment (43).

heat input includes gross heat in the fuel plus heat contained in the preheated combustion air. Wide variations from these curves are to be expected for individual units, depending on fuel type, operating conditions, and equipment design; therefore, emission factors should be used only when stack-test results are unavailable.

TABLE 5 Emission Factors for Nitrogen Oxides during Combustion of Fuels (43)

Fuel and Source	Average NO_x Emissions Factor	
	lb/unit of fuel	lb/10^6 Btu
Coal		
Household and commercial	8 lb/ton	0.337
Industry	20 lb/ton	0.842
Utility	20 lb/ton	0.842
Fuel oil		
Household and commercial	12-72 lb/10^3 gal	0.080-0.480
Industry	72 lb/10^3 gal	0.480
Utility	104 lb/10^3 gal	0.680
Natural gas		
Household and commercial	116 lb/10^6 cf	0.111
Industry	214 lb/10^6 cf	0.205
Utility	390 lb/10^6 cf	0.373

For boilers of the size range found at federal installations, the average emission rate depends primarily on the type of fuel being burned. Comparative emission rates, in pounds per million Btu, for industrial-size boilers have been calculated for the three fossil fuels and are shown in Table 6.

1. Performance Requirements

Only three known NO_x emission regulations have been adopted by local agencies for existing stationary fuel combustion sources. Los Angeles County limits emissions from new power plants, regardless of size, to 140 lb/hr (calculated as nitrogen dioxide); Monterey-Santa Cruz Counties district (California) limits emissions from all stationary sources to 550 ppm by volume at the point of discharge; and New York City has established a 50-ppm limit on oxides of nitrogen from furnaces used to generate off-site electrical power with a capacity of 50 MW or more.

TABLE 6 Comparison of Calculated NO_x Emission Rates for a 250 Million Btu/hr Boiler with Selected Emission Standards for Large Utility Boilers

	Emission Rates[a]			Emission Standards[b]			
Fuel	$lb/10^6$ Btu	lb/hr	ppm	EPA (40)	Los Angeles	Monterey	New York City
Coal	0.84	210	950	0.7 $lb/10^6$ Btu	140 lb/hr	550 ppm	50 ppm
Oil	0.48	120	585	0.3 $lb/10^6$ Btu	140 lb/hr	550 ppm	50 ppm
Gas	0.21	53	265	0.2 $lb/10^6$ Btu	140 lb/hr	550 ppm	50 ppm

[a]Average stack-gas concentrations were calculated using 10 percent excess air and the following fuel values: coal, 12,000 Btu/lb; oil, 18,300 Btu/lb; and gas, 1,020 Btu/cf.

[b]These emission standards are presented for illustration only; they do not apply to units of the size covered in this report.

The EPA has adopted the following federal standards of performance for new fossil-fuel-fired steam generating plants over 250 million Btu/hr heat input. Oxides of nitrogen, expressed as NO_2, shall not exceed: 0.2 $lb/10^6$ Btu when gaseous fuel is fired; 0.3 $lb/10^6$ Btu when liquid fuel is fired; or 0.7 $lb/10^6$ Btu when solid fuel is fired.

None of the above regulations have much impact on federal facilities at present inasmuch as the regulations either apply to boilers larger than those commonly used at federal facilities (and not covered in this report) or are easily met by boilers of the size used by federal agencies (Table 6). However, future state and local regulations governing nitrogen oxides emissions from steam and steam-electric plants may apply to and be stringent enough to be a consideration with some or all federal boilers.

In anticipation of such regulations, the Task Group believes that federal agencies should set limits on NO_x emissions from new boilers purchased for use at federal installations. By anticipating restrictions on NO_x, agencies will minimize the risk that boilers purchased now will be in violation of NO_x restrictions imposed in the future. The recommended maximum emission rates are as follows: 0.3 $lb/10^6$ Btu when gaseous fuel is burned; 0.5 $lb/10^6$ Btu when liquid fuel is burned; and 0.8 $lb/10^6$ Btu when solid fuel is burned.

It will be noted that these emission rates are approximately the same as the average emission rates estimated in Table 6 for 250 million Btu/hr boilers, and agencies should encounter little difficulty in obtaining boilers that satisfy the limitations; this would be especially true for boilers of significantly less than 250 million Btu/hr capacity.

2. Testing Requirements

Considering the absence of widespread NO_x emission limitations and the dearth of actual test information available on NO_x emission rates versus design or operating variables, the routine reporting of NO and NO_2 emission rates from newly installed federal boilers is desirable for the purposes of: (a) establishing base-line emission levels of NO_x and providing the basis for sound federal research and development programs for NO_x control; (b) alerting boiler manufacturers to the federal government's interest in reducing NO_x emissions; and (c) allowing NO_x emission rules and regulations to be based on scientific evidence.

The recommended procedure for analysis of total oxides of nitrogen is a colorimetric determination on a 2-liter grab sample known as the phenoldi-sulfonic acid method. The procedure is applicable to the determination of total oxides of nitrogen in stack gases at the concentrations expected (40).

3. Control Equipment

Research and development on controlling NO_x emissions by both stack-gas cleaning and combustion modifications is currently being carried out. The only pilot-scale stack-gas cleaning method for NO_x that has been reported on so far uses limestone as the reactive agent and removes only about 20 percent or less of the NO_x found in the flue gas. Other potential stack-gas cleaning techniques for controlling NO_x from stationary combustion sources include the Reinluft char process, which uses an activated charcoal bed, and the Tyco lead chamber process, which uses the sulfuric acid plant's lead chamber (10). Other methods for stack-gas cleaning include catalytic reduction of NO_x to N_2 and the decomposition of NO_x in the absence of a reducing agent. Both of these processes, however, require catalysts that are inefficient in the presence of other pollutants such as SO_2.

Flue-gas cleaning methods for NO_x face major research and development problems since a large percentage (i.e., about 90 percent) of the NO_x in combustion gases is in the form of nitric oxide (NO), which is relatively unreactive. Other more reactive gases, such as H_2O, CO_2, and SO_2, are present in higher concentrations and thus inhibit the removal of nitric oxide. In addition, the need to process very large volumes of stack gases for NO_x control creates additional engineering problems. Scrubbing the stack gases with solutions in undesirable because such scrubbing cools the gases and creates a visible plum with poor buoyancy. At present, NO_x control equipment does not exist commercially and probably will not be economical or practical for boilers of the size used by federal agencies when and if it is developed.

4. Other Requirements

For economic and operational reasons, combustion modification appears to be the more promising approach to NO_x control for boilers of the size used by federal facilities; the most cost-effective combustion modification appears to be low excess-air firing. Under favorable conditions, this technique gives both reduction in NO_x levels and improved combustion efficiency. NO_x reductions up to 60 percent have been demonstrated for oil- and gas-fired units with low excess-air firing (10). Figure 21 shows the relationship between NO_x emmissions and excess air for various loads in a large utility boiler.

In view of the double benefit that could accrue to federal agencies from low excess-air firing, consideration should be given to lowering the maximum permissible excess-air rate in federal specifications for boilers as a means of ensuring lower NO_x emissions. However, to prevent federal agencies from becoming the testing ground for unproven equipment, the excess-air limitation in specifications should not be beyond the capabilities of at least some commercially available equipment. Also, since the chances of an explosion are increased with reduced excess-air rates, added safety precautions should be required when especially low rates are specified.

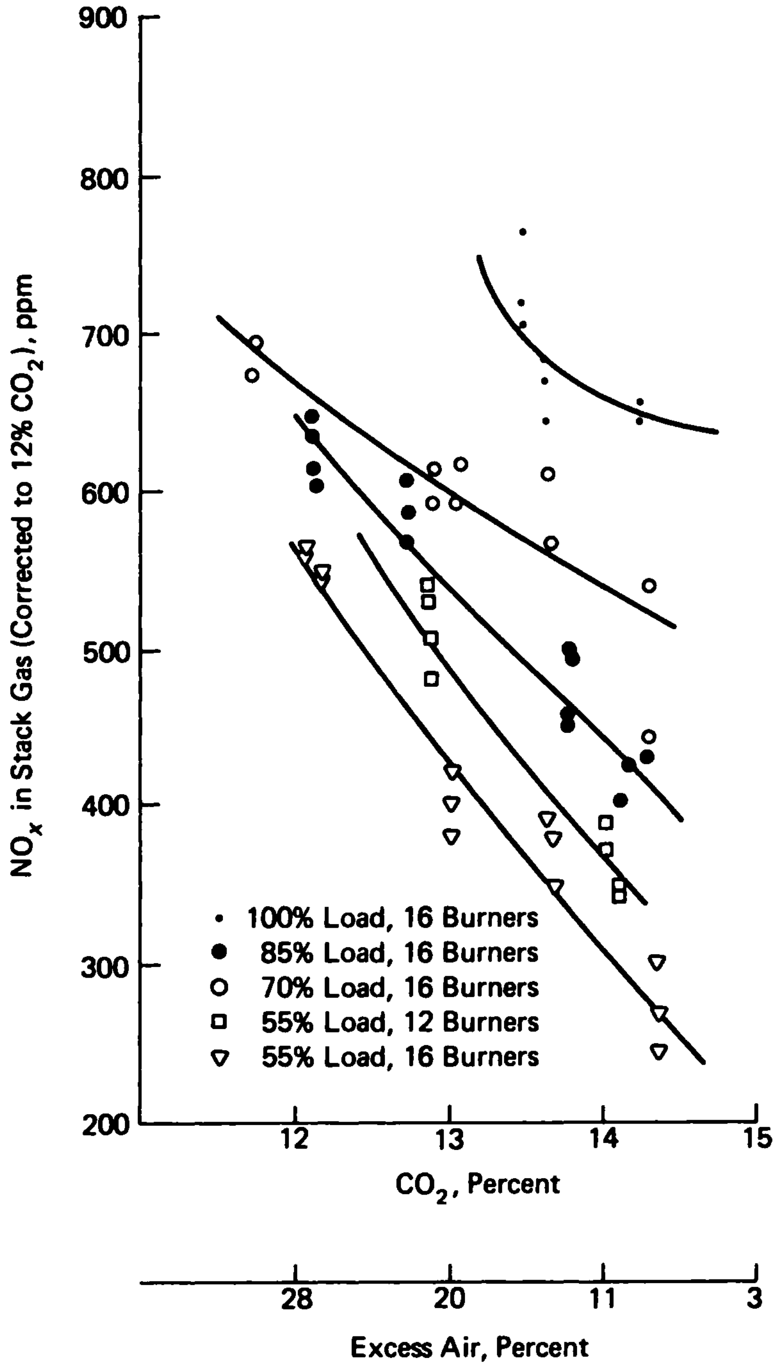

FIGURE 21 Effect of excess air on emissions of nitrogen oxides from a large unit (10).

Other modifications of the combustion process that appear to hold promise for reducing NO_x emissions are flue-gas recirculation, two-stage combustion, and selection/arrangement of burning apparatus. With flue-gas recirculation, a portion of the products of combustion (10 - 20 percent of feed to the furnace) is recirculated into the combustion zone to lower the flame temperature and, as a result, reduce NO_x formation. The value of flue-gas recirculation in reducing NO_x has been demonstrated in the laboratory, but boiler tests are inconclusive (8,26).

In two-stage combustion, the intensity of the flame is reduced by purposely slowing down the combustion process. This is accomplished by dividing the process into two phases: in the initial phase, combustion is partially completed under substoichiometric conditions; in the second phase, burnout is completed downstream with air injected through overfire airports. This method is particularly useful in reducing NO_x emissions due to fuel nitrogen that may be as high as 1 percent resulting in about 1,500 ppm in the stack gases. However, for federal boilers, the combustion zone in most cases may be too small to allow for use of two-stage combustion.

Variations in NO_x emission levels have been observed with different types of burners. For example, the highly turbulent operating features of cyclone burners result in high-level NO_x emissions in coal-fired power plants. Spacing the burners to promote low heat-release rates and high heat-transfer rates results in reduced NO formation through lower peak temperatures and shorter residence times. Tangential firing as opposed to front-wall or opposed-wall firing has been found to produce 30 to 40 percent less NO_x in a gas-fired power boiler. The fluid-bed concept offers potential with very high heat-transfer rates, hence, low average combustion-bed temperatures with most of the NO_x originating from nitrogen in the fuel. Further research is required for optimizing each of these approaches and applying them to boilers of the size considered in this report.

Reduction of combustion-air preheat has been shown to reduce NO_x concentrations regardless of fuel type. Reduction of fuel constituent nitrogen appears to be of some importance to reducing emissions of NO_x, especially on small boilers. As far as is known, no fuel additive is available to inhibit the formation on NO_x during combustion.

E. DUST FROM FUEL- AND ASH-HANDLING OPERATIONS

1. Performance Requirements

The typical dustfall rate for rural areas of the United States is from 5 to 15 tons per square mile per month. Typical values for urban areas range from 10 to 100 tons per square mile per month; New York City is near 50 and heavily polluted areas approach 100. The concentration around major dust sources may be even higher.

While the federal regulations do not specify any dustfall limitations, many state and local agencies do. It is therefore advisable in the judgment of the Task Group, to minimize blowing coal dust and ashes to less than 15 tons per square mile per month.

2. Testing Requirements

Dustfall measurements (6) will determine if there is an air-pollution problem. Specifically, this test will determine whether fuel- and ash-handling procedures as well as control equipment are adequate. The 30-day sampling period will provide an average concentration. Three stations should be located around the plant at 120° intervals near the property boundary, and background levels should be obtained from the local or state air-pollution-control officials. If such data are unavailable, a background station should be located approximately 1 mile from the boiler plant in an area with similar land-use zoning to obtain a background level.

3. Control Equipment

Pollution problems result from coal and ash handling when fine particles of the material are picked up by the wind and carried aloft. Various techniques used successfully to minimize such problems include the following:

a. Enclosing conveyor belts, chutes, and hoppers used in transporting and storing coal and ash (a vacuum dust-collecting system is frequently employed with enclosed materials-handling systems to remove suspended particles from interior airways to minimize the possibility of dust explosions);

b. Spraying the coal and ash with water (wetting agents are sometimes added to the water to increase its effectiveness);

c. Placing tarpaulins over trucks used to transport coal and ash;

d. Erecting wind barriers (large fences or lines of trees) around storage and dumping areas;

e. Compacting and/or covering storage piles with some protective material (No. 6 fuel oil or asphalt in the case of coal and ash or earth in the case of ash); and

f. Halting handling operations during windy periods.

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