LIGNITE COMBUSTION
AP-42 Section 1.7
Reference Number
3

4/93

EPA-450/2-76-030a

December 1976

STANDARDS SUPPORT AND ENVIRONMENTAL IMPACT STATEMENT VOLUME 1: PROPOSED STANDARDS OF PERFORMANCE FOR LIGNITE-FIRED STEAM GENERATORS

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

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Publication No. EPA-450/2-76-030a

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DRAFT

Standards Support and
Environmental Impact Statement
Lignite-Fired Steam Generators

Type of Action: Administrative

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Draft Statement Submitted to Council
on Environmental Quality

in

January 1977
(Date)

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STANDARDS SUPPORT

AND

ENVIRONMENTAL IMPACT STATEMENT, VOLUME 1:

PROPOSED STANDARD OF PERFORMANCE FOR

LIGNITE-FIRED STEAM GENERATORS

Emission Standards and Engineering Division

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October 1976

PREFACE

Standards of performance under section 111 of the Clean Air Act are proposed following a detailed investigation of air pollution control methods available to the affected industry and the impact of their costs on the industry. This document summarizes the information obtained from such a study of lignite-fired steam generators. Its purpose is to explain in detail the background and basis of the proposed standards and to facilitate analysis of the proposed standards by interested persons, including those who may not be familiar with the many technical aspects of the industry. To obtain additional copies of the FEDERAL REGISTER notice of proposed standards, write to Mr. Don R. Goodwin, Director, Emission Standards and Engineering Division (MD-13), United States Environmental Protection Agency, Research Triangle Park, North Carolina 27711. To obtain additional copies of this document write to the Environmental Protection Agency, Public Information Center (PM-215), Washington, D.C. 20460.

AUTHORITY FOR THE STANDARDS

Standards of performance for new stationary sources are developed under section 111 of the Clean Air Act (42 U.S.C. 1857c-6), as amended in 1970. Section 111 requires the establishment of standards of performance for new stationary sources of air pollution which ". . . may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare." The Act requires that standards of performance for such sources reflect " . . . the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) the Administrator determines has been adequately demonstrated." The standards apply only to stationary sources, the construction or modification of which commences after regulations are proposed by publication in the FEDERAL REGISTER.

Section 111 prescribes three steps to follow in establishing standards of performance.

1. The Administrator must identify those categories of stationary sources for which standards of performance will ultimately be promulgated by listing them in the FEDERAL REGISTER.

2. The regulations applicable to a category so listed must be proposed by publication in the FEDERAL REGISTER within 120 days of its listing. This proposal provides interested persons an opportunity for comment.

3. Within 90 days after the proposal, the Administrator must promulgate standards with any alterations he deems appropriate.

Standards of performance, by themselves, do not guarantee protection of health or welfare; that is, they are not designed to achieve any specific air quality levels. Rather, they are designed to reflect best demonstrated technology (taking into account costs) for the affected sources. The overriding purpose of the collective body of standards is to maintain existing air quality and to prevent new pollution problems from developing.

Previous legal challenges to standards of performance have resulted in several court decisions[1,2] of importance in developing future standards. In those cases, the principal issues were whether EPA: (1) made reasoned decisions and fully explained the basis of the standards, (2) made available to interested parties the information on which the standards were based, and (3) adequately considered significant comments from interested parties.

Among other things, the court decisions established: (1) that preparation of environmental impact statements is not necessary for standards developed under section 111 of the Clean Air Act because, under that section, EPA must consider any counter-productive environmental effects of a standard in determining what system of control is "best;" (2) in considering costs it is not necessary to provide a cost-benefit analysis; (3) EPA is not required to justify standards that require different levels of control in different industries unless such different standards may be unfairly discriminatory; and (4) it is sufficient for EPA to show that a standard can be achieved rather than that it has been achieved by existing sources.

Promulgation of standards of performance does not prevent State or local agencies from adopting more stringent emission standards for the same sources. On the contrary, section 116 of the Act (42 U.S.C. 1857d-1) makes clear that States and other political subdivisions may enact more restrictive standards. Furthermore, for heavily polluted areas, more stringent standards may be required under section 110 of the Act (42 U.S.C. 1857c-5) in order to attain or maintain national ambient air quality standards prescribed under section 109 (42 U.S.C. 1857c-4). Finally, section 116 makes clear that a State may not adopt or enforce less stringent new source standards than those adopted by EPA under section 111.

Although standards of performance are normally structured in terms of numerical emission limits where feasible,* alternative approaches are sometimes necessary. In some cases physical measurement of emissions from a new source may be impractical or exorbitantly expensive. For example, emissions of hydrocarbons from storage vessels for petroleum liquids are greatest during tank filling. The nature of the emissions (high concentrations for short periods during filling and low concentrations for longer periods during storage) and the configuration of storage tanks make direct emission measurement impractical. Therefore, a more practical approach to standards of performance for storage vessels has been equipment specification.

SELECTION OF CATEGORIES OF STATIONARY SOURCES

Section 111 directs the Administrator to publish and from time to time revise a list of categories of sources for which standards of performance are to be proposed. A category is to be selected " . . . if [the Administrator] determines it may contribute significantly to air pollution which causes or contributes to the endangerment of public health or welfare."

Since passage of the Clean Air Amendments of 1970, considerable attention has been given to the development of a system for assigning priorities to various source categories. In brief, the approach that has evolved is as follows. Specific areas of interest are identified by considering the broad strategy of the Agency for implementing the Clean Air Act. Often, these "areas" are actually pollutants which are primarily emitted by stationary sources. Source categories which emit these pollutants are then evaluated

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*/ "'Standards of performance,' . . . refers to the degree of emission control which can be achieved through process changes, operation changes, direct emission control, or other methods. The Secretary [Administrator] should not make a technical judgment as to how the standard should be implemented. He should determine the achievable limits and let the owner or operator determine the most economical technique to apply." Senate Report 91-1196.

and ranked by a process involving such factors as (1) the level of emission control (if any) already required by State regulations; (2) estimated levels of control that might result from standards of performance for the source category; (3) projections of growth and replacement of existing facilities for the source category; and (4) the estimated incremental amount of air pollution that could be prevented, in a preselected future year, by standards of performance for the source category. An estimate is then made of the time required to develop a standard. In some cases, it may not be feasible to develop a standard immediately for a source category with a high priority. This might occur because a program of research and development is needed to develop control techniques or because techniques for sampling and measuring emissions may require refinement. The schedule of activities must also consider differences in the time required to complete the necessary investigation for different source categories. Substantially more time may be necessary, for example, if a number of pollutants must be investigated in a single source category. Further, even late in the development process the schedule for completion of a standard may change. For example, inability to obtain emission data from well-controlled sources in time to pursue the development process in a systematic fashion may force a change in scheduling.

Selection of the source category leads to another major decision: determination of the types of facilities within the source category to which the standard will apply. A source category often has several facilities that cause air pollution. Emissions from some of these facilities may be insignificant or very expensive to control. An investigation of economics may show that, within the costs that an owner could reasonably afford, air pollution control is better served by applying standards to the more severe pollution problems. For this reason (or perhaps because there may be no adequately demonstrated system for controlling emissions from certain facilities), standards often do not apply to all sources within a category. For similar reasons, the standards may not apply to all air pollutants emitted by such sources. Consequently, although a source category may be selected to be covered by a standard of performance, not all pollutants or facilities within that source category may be covered by the standards.

PROCEDURE FOR DEVELOPMENT OF STANDARDS OF PERFORMANCE

Congress mandated that sources regulated under section 111 of the Clean Air Act be required to utilize the best system of air pollution control (considering costs) that has been adequately demonstrated at the time of their design and construction. In so doing, Congress sought to:

1. Maintain existing high-quality air,
2. Prevent new air pollution problems, and
3. Ensure uniform national standards for new facilities.

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

The objective of a program for development of standards is to identify the best system of emission reduction which "has been adequately demonstrated (considering cost)." The legislative history of section 111 and the court decisions referred to earlier make clear that the Administrator's judgment of what is adequately demonstrated is not limited to systems that are in actual routine use. Consequently, the search may include a technical assessment of control systems which have been adequately demonstrated but for which there is limited operational experience. In most cases, determination of the "degree of emission limitation achievable" is based on results of tests of emissions from existing sources. This has required worldwide investigation and measurement of emissions from control systems. Other countries with heavily populated, industrialized areas have sometimes developed more effective systems of control than those used in the United States.

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

Since passage of the Clean Air Act Amendments of 1970, a process for the development of a standard has evolved. In general, it follows the guidelines below.

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

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

3. During development of the standards, information from pilot and prototype installations, guarantees by vendors of control equipment, contracted (but not yet constructed) projects, foreign technology, and published literature are considered, especially for sources where "emerging" technology appears significant.

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

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

6. Where possible, standards are developed to permit use of systems capable of controlling more than one pollutant (for example, a scrubber can remove both gaseous and particulate matter emissions, whereas an electrostatic precipitator is specific to particulate matter).

7. Where appropriate, standards for visible emissions are developed in conjunction with concentration/mass emission standards. The opacity standard is established at a level which will require proper operation and maintenance of the emission control system installed to meet the concentration/mass standard on a day-to-day basis, but not require the installation of a control system more efficient or expensive than that required by the concentration/mass standard. In some cases, however, it is not possible to develop concentration/mass standards, such as with fugitive sources of emissions. In these cases, only opacity standards may be developed to limit emissions.

CONSIDERATION OF COSTS

Section 111 of the Clean Air Act requires that cost be considered in developing standards of performance. This requires an assessment of the possible economic effects of implementing various levels of control technology in new plants within a given industry. The first step in this analysis requires the generation of estimates of installed capital costs and annual operating costs for various demonstrated control systems, each control system alternative having a different overall control capability. The final step in the analysis is to determine the economic impact of the various control alternatives upon a new plant in the industry. The fundamental question to be addressed is whether or not a new plant would be constructed if a certain level of control costs would be incurred. Other issues that are analyzed are the effects of control costs upon product prices and product supplies, and producer profitability.

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

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

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

CONSIDERATION OF ENVIRONMENTAL IMPACTS

Section 102(2)(c) of the National Environmental Policy Act (NEPA) of 1969 (PL-91-190) requires Federal agencies to prepare detailed environmental impact statements on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment. The objective of NEPA is to build into the decision-making process of Federal agencies a careful consideration of all environmental aspects of proposed actions.

As mentioned earlier, in a number of legal challenges to standards of performance for various industries, the Federal Courts of Appeals have held that environmental impact statements need not be prepared by the Agency for proposed actions under section 111 of the Clean Air Act. Essentially, the Federal Courts of Appeals have determined that " . . . the best system of emission reduction," " . . . require(s) the Administrator to take into account counter-productive environmental effects of a proposed standard, as well as economic costs to the industry . . ." On this basis, therefore, the Courts " . . . established a narrow exemption from NEPA for EPA determinations under section 111."[1,2]

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

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

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

IMPACT ON EXISTING SOURCES

Standards of performance may affect an existing source in either of two ways. Section 111 of the Act defines a new source as "any stationary source, the construction or modification of which is commenced after the regulations are proposed." Consequently, if an existing source is modified after proposal of the standards, with a subsequent increase in air pollution, it is subject to standards of performance. [Amendments to the general provisions of Subpart A of 40 CFR Part 60 to clarify the meaning of the term modification were promulgated in the FEDERAL REGISTER on December 16, 1975 (40 FR 58416).]

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

REVISION OF STANDARDS OF PERFORMANCE

Congress was aware that the level of air pollution control achievable by any industry may improve with technological advances. Accordingly, section 111 of the Act provides that the Administrator may revise such standards from time to time. Although standards proposed and promulgated by EPA under section 111 are designed to require installation of the " . . . best system of emission reduction . . . (taking into account the cost) . . ." the standards will be reviewed periodically. Revisions will be proposed and promulgated as necessary to assure that the standards continue to reflect the best systems that become available in the future. Such revisions will not be retroactive but will apply to stationary sources constructed or modified after proposal of the revised standards.

REFERENCES

1. Portland Cement Association vs. Ruckelshaus, 486 F. 2nd 375 (D.C. Cir. 1973).

2. Essex Chemical Corp. vs. Ruckelshaus, 486 F. 2nd 427 (D.C. Cir. 1973).

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I. SUMMARY AND INTRODUCTION

A. SUMMARY OF PROPOSED AMENDMENT

Large fossil fuel-fired steam generators were originally selected for standards of performance because this category is the largest stationary source of sulfur dioxide, particulate matter, and nitrogen oxides. When standards of performance were promulgated for large steam generators under Subpart D of 40 CFR Part 60 in December 1971 (36 FR 24877), lignite-fired units were exempted from the nitrogen oxides standard (the sulfur dioxide and particulate matter standards are applicable to lignite firing) because of a lack of data on attainable levels of emission from such units. Data gathered since 1971 are sufficient to propose amendments to Subpart D to limit atmospheric emissions of nitrogen oxides to 260 nanograms per joule heat input (0.6 lb per million Btu) from lignite-fired steam generators with a heat input of 73 MW thermal* (250 million Btu per hour) - equivalent to about 25 MW electrical. The proposed standard reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction) has been adequately demonstrated. The best system is considered to be a combination of staged combustion and low excess air.

This document provides the background information, environmental impact statement, and the rationale for the derivation of the proposed amendment. Standards of performance are proposed and promulgated under the authority of section 111 of the Clean Air Act.

*Unless specified otherwise in this report all values of megawatts or kilowatts are output or electrical values.

B. ECONOMIC AND ENVIRONMENTAL IMPACTS

The cost to the lignite-fired utilities of complying with the proposed standard for nitrogen oxides has been analyzed and is negligible in comparison to capital investment costs. Conservative estimates show that the nitrogen oxides standard could, for some boiler designs, require an increase of 0.5 percent in capital investment costs for the lignite-fired boiler and its auxillary equipment. This percentage increase represents an increase in cost of $2 per kW relative to a capital investment cost of about $400 per kW for a new bituminous coal-fired boiler island. There would be no increase in the cost of power to the consumer.

Control of nitrogen oxides emissions to 260 ng/J (0.6 lb/10^6 Btu input) would reduce emissions from lignite-fired steam generators operating in 1980 by 29 percent. For the 10,000 MW installed lignite steam generating capacity expected in 1980, this emission level would reduce NO_x emissions by 83,000 Mg/yr (92,000 tons/yr), if the standard were applicable to these units. Since lignite is an important energy resource in certain geographic areas and lignite is presently underutilized, extrapolation of historical growth rates indicates a generating capacity of 16,000 MW subject to the NO_x standard by 1985. The emission reduction from the proposed standard for this estimated increase would be 128,000 Mg/yr (141,000 tons/yr).

The environmental impact of the proposed standard is beneficial since the increase in emissions due to growth of lignite-fired steam generators would be minimized. The proposed standard would be beneficial in reducing the atmospheric burden of nitrogen oxides and help prevent increased ambient oxidant concentrations in areas where lignite-fired steam generators will be located (primarily North Dakota and Texas). There are no adverse environmental impacts associated with the proposed standard. Control techniques required to comply with the proposed standard do not cause boiler efficiency losses, and thus there are no incremental energy demands associated with the proposed standard.

II. LIGNITE-FIRED STEAM GENERATION AND CURRENT EMISSIONS

A. CHARACTERISTICS OF LIGNITE

1. Chemical Analysis

The differences between lignite and bituminous coal are petrographic differences derived from their geological history. Lignite has more moisture, an ash of lower fusion point, and a lower carbon-hydrogen ratio. An illustration of the difference in chemical analysis and the ASTM standard rank classification are given in Table II-1. The significant difference lies in the equilibrium moisture content, 1.5-12.5 percent in the case of bituminous coal and 35-45 percent in the case of lignite.

2. Grindability

The grindability of lignite varies over a wide range, just as with other coals. Lignite is not necessarily more difficult to grind or pulverize than bituminous coal. However, larger particle-sizes are used in pulverized lignite firing, compared to bituminous coal, because lignite is so readily burnable.

3. Combustion and Ash Fouling Characteristics

Since lignite has a higher moisture content and a lower carbon-hydrogen ratio than coal, the adiabatic flame temperature for lignite combustion is expected to be lower than for bituminous coal. Lignite requires more air preheat for drying; it also requires a larger furnace volume per unit heat input to limit furnace outlet

TABLE II-1 CHEMICAL ANALYSIS OF COAL BY RANK

Class	Bituminous	Subbituminous	Lignite
ASTM Standard D 388-66:			
1) Fixed Carbon %	<69	-	-
2) Volatile Matter %	<31	-	-
3) Heating Value, Btu/lb moist mineral Matter free	14,000-11,500	11,500-8,300	8,300-6,300
Group	High-volatile A	C	A
Heating value, Btu/lb ash-free	13,325	8,320	7,255
Equilibrium moisture, %	1.5	31.0	37.0
Volatile matter, %	30.7	31.4	26.6
Fixed carbon, %	56.6	32.8	32.2
Ash, %	11.2	4.8	4.2
Sulfur, %	1.82	0.55	0.40
Nitrogen, %	1.4	0.9	0.7

Source: References 1, 22.

temperatures and to keep unit heat absorptions low thus avoiding slagging and excessive ash buildup on tube surfaces.

Lignite ash may contain from 0.1-28 percent Na_2O and is often high in other alkali earths.[43] The U. S. Bureau of Mines[2] has shown that this contributes greatly to ash fouling of boiler superheaters. Almost all of the larger North Dakota area plants have experienced severe operational difficulties as a result of ash fouling. Lignitic ash with from 3-6 weight percent Na_2O is considered to have a high fouling potential, and a Na_2O ash content of greater than 6 weight percent implies a severe fouling potential. Boiler manufacturers agree that the problem can be minimized by using more soot blowers in the convective gas passes than normal, by utilizing greater transverse spacing of convection heating surface, by increasing the size of the furnace to reduce the heat release rate, and at the same time by controlling the furnace temperature profile to limit the temperature of the gas entering the superheater.

4. <u>Nitric-Oxide Production</u>

The nitrogen oxides (NO_x) derived from chemically bound nitrogen in the fuel is anticipated to be lower or comparable to that of bituminous coal, since the nitrogen content of lignite is about 0.6% by weight on an as-received basis (bituminous coal has a nitrogen content ranging from 0.7 to 2.0% by weight). In pulverized firing, as much as 80-90% of total NO_x emissions can result from oxidation of fuel-nitrogen.[47] The NO_x from thermal fixation is expected to be somewhat lower for lignite than that of bituminous coal due to lignite's lower flame temperatures and "lazy" firing characteristics (cyclone burners excepted).

5. Geographic Distribution

According to the most recent U. S. Bureau of Mines Report[3], the U. S. lignite reserve base is estimated to be 28 billion tons, 27 of which lie west of the Mississippi River. The large reserves are concentrated in the Central Northwestern and Western Gulf Coast Regions. The development of the lignite-fired electric-power generating industry of the U. S. has been centered around those few areas. This localized use relates to two specific characteristics of the fuel:

- High moisture content, making storage and transportation less feasible.
- Lower heating value than other coals, making it uneconomical to transport long distances (about 300 miles).

The 15 large lignite-burning plants presently in operation domestically are located in Montana, Minnesota, North Dakota, and Texas.

6. Cost

When available, the price of lignite in the marketplace is still comparatively cheap per Btu, in keeping with its characteristic disadvantage of low heat value per unit weight and high moisture content. A comparison of alternative fuels based on early 1975 prices paid by steam-electric plants show:

	$\$/10^6$ Btu	Comment
Lignite	0.14-.43	Based on 3 plants
Coal	0.8	Nationwide average
Natural Gas	0.66	"
Oil	2.05	"

Virtually all plants now operating are located at the mine-mouth and have captive reserves of lignite or long-term contracts for fuel supply.

B. INDUSTRY CHARACTERIZATION

In this section, the population of steam-generators fired by lignite is described, the utilities and industrial firms which utilize the steam-generators are identified, and the past and future growth of lignite-consumption is outlined. Further background and support information, including profiles of the major utilities which use lignite, may be found in Appendix A.

1. Installed Capacity

Steam-electric generating units fired by lignite are found in both the electric utility and private industrial sectors. Of those large lignite units subject to regulation under the standards of performance for new sources (rated capacity above 250 x 10^6 Btu/hour, equivalent to about 25 MW electrical) about 87% of all capacity is controlled by electric utilities. Current practice among utilities employing lignite-fired steam-electric generating plants is to use these plants as the base load for the utility networks. This is due to the quality of the fuel (discussed previously) and its cost. For instance, Texas Utilities, Inc., has stations firing both lignite and natural gas. The lignite-fired plants are used for the base load and natural gas stations are used for peak loading. The North Dakota utilities use lignite as the base load and add Bureau of Reclamation hydroelectric power during peak periods. Because of this practice, lignite-fired steam generating plants are generally utilized at 70 to 90 percent of their designed capacity.

Tables II-2 and II-3 present a list of utility and industrial steam generators located in the United States which fire lignite. Based on Table II-2, the installed generating capacity of utility-owned lignite-fired units was 2,269 MW as of 1972, and represented a net power generation of 9,227 million kWh. Eleven of the 26 units in the tables have less than 250 10^6 Btu/hr input (most of these are stokers) and accounted for less than 5% of the total steam generated by lignite firing in 1972. For each plant, the tables show the year service was initiated, heating value of the fuel, installed generating capacity and net generation in 1973. In addition, boiler manufacturers, firing mechanisms, and bottom types are noted.

Comparing lignite capacity to the installed generating capacity from all fuels in 1972, Table II-4 shows that lignite capacity accounted for slightly less than one percent of U. S. total utility power generation. Since lignite reserves make up about 27% of the total U. S. coal resource, lignite appears to be underutilized.

As expected, the size of the lignite-fired power "industry" is, by any criteria, an extremely small fraction of the total U. S. power generating industry. However, lignite fired capacity is a significant percentage of installed power plant capacity within certain areas, particularly North Dakota and Texas.

2. Historic Growth

Regarding the growth of the lignite-fired generating capacity, Table II-5 summarizes the installed generating capacity, net power generation, and lignite consumption by state. Summary totals and resultant average annual growth rates for lignite-fired capacity are also shown.

TABLE II-2

UTILITY-OWNED LIGNITE-FIRED STEAM GENERATORS IN THE U.S., 1972

State-City	Company	Plant[1]	Date of Service	Fuel Heating Value Btu/lb	Installed Generating Capacity (MW)	Net Gen. (10^6 KWH)	Boiler Manufacturer	Type[2] of Firing	Type of Bottom	Remarks
Montana										
Sidney	Montana-Dakota Utilities Co.	*Lewis & Clark	1958	6,500	50.0	340.8	CE	Tang.	Dry	
Minnesota										
Crookston	Otter Tail Power Company	Crookston	Old	7,150	10.0	30.9	Riley	Stoker	-	
Fergus Falls	Otter Tail Power Company	*Hoot Lake	1959/ 1964	7,104	59/66	831.6	CE/B&W	Tang./ Front	Dry	2 units
Ortonville	Otter Tail Power Company	Ortonville	Old	6,200	15.0	88.5	Riley	Stoker	-	Standby
Moorhead	Moorhead Public Service Dept.	*Moorhead	1969	7,000	25	1.3	Riley	Stoker	-	
			SUBTOTAL		175.0	952.3				
North Dakota										
Beulah	Montana-Dakota Utilities Co.	Beulah	1949	6,970	13.5	64.0	Riley	Stoker	-	To be closed
Mandan	Montana-Dakota Utilities Co.	*Heskett	1963	6,970	100.0	612.9	Riley	Stoker	-	Largest stoker in U.S.(65 m
Devils Lake	Otter Tail Power Company	Devils Lake	Old	6,678	12.5	47.7	Riley	Stoker	-	To be closed
Jamestown	Otter Tail Power Company	Jamestown	Old	6,678	7.5	42.7	Riley	Stoker	-	To be closed
Wahpeton	Otter Tail Power Company	Kidder	Old	6,678	20.5	23.4	Riley	Stoker	-	To be closed
Valley City	Valley City Municipal Utilities	Valley City	Old	6,900	5.0	3.5	5 Units	Stoker	-	All too small
Stanton	Basin Electric Power Coop.	*Leland Olds	1966	6,663	215.7	1575.4	B&W	H.O.	Dry	
Velva	Basin Electric Power Coop.	W. J. Neal	1953	6,600	38.5	186.9	CE	Front	Dry	2 units
Grand Forks	Minnkota Power Coop., Inc.	F. P. Wood	1950	6,391	21.5	3.0	Riley	Stoker	-	
Center	Minnkota Power Coop., Inc.	*Young-Center	1970	6,391	234.6	1841.8	B&W	Cyclone	Wet	
Stanton	United Power Association	*Stanton	1966	7,026	172.0	1041.9	FW	Front	Dry	
			SUBTOTAL		841.3	5443.2				
South Dakota										
Mobridge	Montana-Dakota Utilities Co.	Mobridge	1950	7,900	8.5	1.7	B&W	Stoker	-	
Texas										
Fairfield	Dallas Power & Light Company	*Big Brown	Late 60's	7,000	1186	2460.6	CE	Tang.	Dry	2 units
Wyoming										
Sheridan	Montana-Dakota Utilities Co.	Acme	Old	7,000	8.0	28.4	B&W	Stoker	-	To be closed
			U.S. TOTAL		2269	9227				

[1] Plants with asterisks have units of rated capacity above 250×10^6 Btu/hr input; these account for 95% of lignite consumption.

[2] Tang. = tangential; front = front wall; H.O. = horizontally opposed.

SOURCE: Steam-Electric Plant Factors, 1973 Edition: National Coal Association; various industry contacts; boiler manufacturers. American Boilers Manufacturing Association, unpublished data.

TABLE II-3

INDUSTRIALLY-OWNED LIGNITE-FIRED STEAM GENERATORS IN THE U. S., 1973

Location	Company	Plant	Date of Service	Fuel Heating Value Btu/lb	Inst. Gen. Cap. (MW)	Net Gen. (10^6 kWh)	Boiler Manufacturer	Type of Firing	Bottom	Remarks
Rockdale, Texas	Alcoa	*Sandow	1953	6,600	3 x 100	2,500	CE	Tangential	Wet	3 units
Drayton, North Dakota	American Crystal Sugar Co.	* -	1963	N.A.	30	70**	B & W	Stoker	-	4 Mo/Year
TOTAL					330	2,570				

*Plants with asterisks have units of rated capacity above 250 x 10^6 Btu/hour input; these account for 95% of lignite consumption.

**Estimate based on 90% utilization for 4 months during 1973.

SOURCE: Steam-Electric Plant Factors, 1973 Edition: National Coal Association; various industry contacts; boiler manufacturers. American Boilers Manufacturing Association, unpublished data.

TABLE II-4

COMPARISON OF LIGNITE-FIRED AND TOTAL U.S. STEAM-ELECTRIC GENERATING CAPACITY, 1972

	Number of Companies	Number of Plants	Installed Generating Capacity (MW)	Net Power Generation (10^6 kWh)
Lignite-Fired Plants	8	19	2269	9227
U.S. Electric-Generating Plants, All Fuels	395	966	297,564.9	1,358,785.4
Lignite Share	-	-	0.8%	0.7%

SOURCE: Federal Power Commission, Steam-Electric Plant Construction Cost and Annual Production Expenses, 1972; various utilities.

TABLE II-5

GROWTH OF LIGNITE-FIRED

ELECTRIC GENERATING INDUSTRY

1960 - 1972

STATE	Generating Capacity (MW)				Net Power Gen. 10^6 kWh				Lignite Consumption 10^3 ton/year			
	1960	1970	1972	%/Year	1960	1970	1972	%/Year	1960	1970	1972	%/Year
Minnesota	98	173	204	6.2	364	976	952	8.4	335	869	836	7.9
N. Dakota	179	653	841	13.8	559	3686	5443	21.0	850	3429	4856	15.7
Montana	50	50	50	0	182	337	341	11.1	187	321	320	10.6
S. Dakota	9	9	9	0	14	16	2	-	30	34	13	-
Texas	-	-	1187	-	-	-	2461	-	-	-	1790	-
Wyoming	12	12	8	-	16	29	28	-	18	30	30	-
Total U.S.	348	897	2299	17.6	1084	5044	9227	19.8	1420	4683	7845	15.6
All fuels,U.S.	-	-	-	7.0	-	-	-	7.2	-	-	-	6.1*

* Coal only

Source: Steam-Electric Plant Construction Cost and Annual Production Expenses, Federal Power Commission, 1972 data. For Complete breakdown see Appendix A.

According to Table II-5, growth in lignite-fired industry capacity over the period 1960-72 averaged 17.6% per year, which is more than twice the growth rate of 7.0% per year experienced by U. S. electric generating capacity as a whole. Similar effects are shown for comparative growths in net power generation.

Table II-5 also shows that the growth in lignite consumption exceeds twice the growth rate experienced by coal consumption for power generation.

3. Announced Expansion

Inasmuch as the design/ordering/erection schedule for steam-electric power plants is typically a three to five-year undertaking, a reasonably accurate projection of future industry growth is possible under the reasonable assumption that plants already ordered are not affected by the adoption of pollution control regulations. Table II-6 summarizes information on new generating stations currently being planned for construction within the next five years. Thirteen new installations are being built, and at least one other is currently being planned. All of these units will be owned by utility companies.

Summing the capacities shown in Table II-6, it is shown that 7,930 MW will be added by 1980, representing an average annual growth rate of 20.7% per year over the period 1972-80. This is comparable to the industry's present growth rate. In essence, it is anticipated that the capacity of the industry will increase by a factor of 4.5 by 1980.

There are two principal restraints on future development of lignite-fired steam generators:

TABLE II-6

UTILITY-OWNED LIGNITE-FIRED STEAM GENERATING PLANTS UNDER CONSTRUCTION OR BEING PLANNED

YEAR	COMPANY	LOCATION	INSTALLED CAPACITY (MW)	BOILER MANUFACTURER	TYPE OF FIRING*	REMARKS
1975	Otter Tail Power Co.	Big Stone, Minn.	440	B&W	Cyclone	Small Units to Close
1975	Basin Electric Power Coop.	Leland Olds, N.D. (#2)	440	B&W	Cyclone	
1975	Texas Utilities, Co.	Monticello, Tex.	575	CE	Tang.	
1976	Texas Utilities, Co.	Monticello, Tex. (#2)	575	CE	Tang.	
1976	Minnkota Power Coop., Inc.	M. P. Young, N.D.	400	B&W	Cyclone	
1977	Texas Utilities, Co.	Martin Lake, Tex.	750	CE	Tang.	
1977	Texas Utilities, Co.	Monticello, Tex. (#3)	750	B&W	H.O.	
1978	Texas Utilities, Co.	Martin Lake, Tex. (#2)	750	CE	Tang.	
1978	United Power Assoc.	Underwood, N.D.	500	CE	Tang.	
1979	United Power Assoc.	Underwood, N.D. (#2)	500	CE	Tang.	
1979	Texas Utilities, Co.	Martin Lake, Tex. (#3)	750	CE	Tang.	
1979	Texas Power & Light Co.	Forest Grove, Tex.	750	B&W	H.O.	
1980	Texas Utilities	Martin Lake, Tex. (#4)	750	CE	Tang.	
		TOTAL	7,930			
Currently in Planning						
1981	Otter Tail Power Co. Montana-Dakota Utilities Co.	Beulah, N.D.	450	-	-	

*Tang. = tangential; H.O. = horizontally opposed.

SOURCE: American Boiler Manufacturers Association, Industry Contacts.

- Lignite-fired steam generators and any other fossil fuel-fired steam generators require a constant source of water in order to operate; and water is scarce in most areas where there are known lignite reserves.
- The high moisture content and low energy content of lignite combine to make it uneconomical to transport long distances.

4. Financial Resources

The financial resources, borrowing power, and ability to sustain capital expansion of a utility company are dependent both upon the individual company and the type of utility. The lignite-fired electric generating "industry" can be characterized by six of the eight utilities previously listed in Table II-2. For the purposes of discussion, we have divided the utilities into two distinct classes from which financial data and future construction plans have been assembled through a review of their annual reports and discussions with their corporate management and various state regulatory authorities.*

Class I: Investor Owned

The designation, Class I, refers to investor-owned utilities, which use long-term public and private debt placement and/or equity to finance their capital expenditure programs for capacity expansion. Three such utilities (Companies A, B, and C) have major building programs for

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* Two very small, municipally-owned utilities that use lignite fuel were excluded. The electric revenues of the two utilities combined were less than $4 million, their net plant was less than $10 million, and they have no announced plans for capacity expansion.

lignite-fired generating capacity. One of these (Company C) controls nearly half the lignite-firing capacity of the United States. Nearly 70% of present lignite-generated capacity is held by Class I utilities.

Class II: Rural Cooperatives

Class II utilities differ from Class I utilities in that they may either borrow directly from the REA (at significantly lower rates than investor-owned utilities) to finance construction or may ask for REA guarantees on loans from other sources. Class II utilities are typically smaller in terms of their generating capacity and invested capital. Three such cooperatives (Companies D, E, and F) herein discussed, have lignite-fired generating stations and are adding additional lignite-fired capacity.

Both the investor-owned and rural electric cooperative utilities are making a significant investment to expand lignite-fueled capacity. Companies A, B, and C whose total installed capacity is over 12,300 megawatts, of which 1,511.3 megawatts (12%) are accounted for by lignite-fired plants, will add 6490 megawatts of lignite fired capacity by 1981, or about 4.3 times their current lignite capacity. Note that Class I's total installed capacity will increase only 1.5 times by 1981; thus it appears that the Class I companies are depending heavily on lignite-based expansion rather than other alternatives.

The three rural electric cooperatives (D, E, and F) account for almost one-third of all lignite-fired generating capacity and will add 1,895 megawatts of lignite-fired generating capacity between 1975 and 1981, to increase lignite-fired capacity 3.8 times.

Basic financial data has been collected in Appendix A for the three investor-owned electric utilities (Table A-2) and for three electric power cooperatives (Table A-3) from Moody's Public Utilities Manual and annual reports.* Briefly, the fixed interest charges of Class I companies are covered by earnings to a greater degree than those of Class II companies. Thus Class I companies have significantly more capitalization and are readily able to obtain rate structure adjustments to cover increased costs.

C. EMISSIONS REQUIRING CONTROL

Large fossil fuel-fired steam generators are the largest stationary source of sulfur oxides, nitrogen oxides, and particulate matter. When standards of performance were promulgated for fossil fuel-fired steam generators under Subpart D of 40 CFR Part 60 in December 1971 (36 FR 24877), lignite-fired units were exempted from the nitrogen oxides standard because of lack of data on levels of emission reduction achievable on such units. The degree of urgency in controlling NO_x emissions from lignite firing has been questioned since neither North Dakota nor East Texas have high ambient levels of NO_x and neither has a heavy concentration of automobiles, the primary source for NO_x. These two regions of heavy lignite utilization have a potential for growth either as population centers or more likely as energy producers. The fact that the North Dakota area is becoming an exporter of energy and the fact that lignite

* A financial brief for each of the six utilities, including planned pollution control expenditures, is found in Appendix A. We suggest that the reader consult the prospectuses for bond issues, bond counsel, or others, if more detailed information is needed.

is becoming an attractive fuel alternative in both the North Dakota area and in Texas suggest the possibility of a potential high concentration of NO_x if control action is not forthcoming.

Other pollutants from lignite firing include:

- Carbon monoxide, unburned hydrocarbons, soot
- Particulates
- Sulfur Oxides (SO_x)

These pollutants are common to all fossil fuel stationary combustion sources and particulate and SO_x standards of performance are already applicable to lignite firing. The expected levels of these emissions for lignite firing are not significantly different from those expected from bituminous coal firing.

D. STEAM GENERATION PROCESSES

All but one of the large (250 x 10^6 Btu's per hour input) lignite-fired steam generating units in the United States are associated with the production of electricity. In a steam-electric plant the fuel is burned in a steam boiler to generate steam, which is in turn passed through a steam turbine to generate electricity. Such plants are designed for high reliability, operating 350 days per year or more. Comparing generated power to generating capacity in Tables II-2 and II-3, the nationwide utilization factor for lignite firing was 52% in 1972.

A sketch of a typical steam boiler is shown in Figure II-1. The radiant section of the boiler is lined with boiler tubes on the walls, floor and roof of the furnace enclosure. The boiler feed water is converted to saturated steam within these tubes through the radiant transfer of heat from the hot combustion gases within the furnace. Additional heat transfer tubes required to superheat the saturated steam (i.e., the primary, secondary and reheat superheaters) are usually included directly following the radiant section of the boiler. Finally, most boilers have an air preheater to transfer heat from the boiler exhaust to incoming combustion air.

The three areas where steam-generating equipment differ in design are in fuel preparation, firing mechanism, and ash removal. These variables are summarized in Table II-7.

The boilers have been classified according to the three commonly used methods of fuel firing:

- Pulverized fuel firing
- Cyclone firing
- Stoker firing

These three categories are discussed further below.

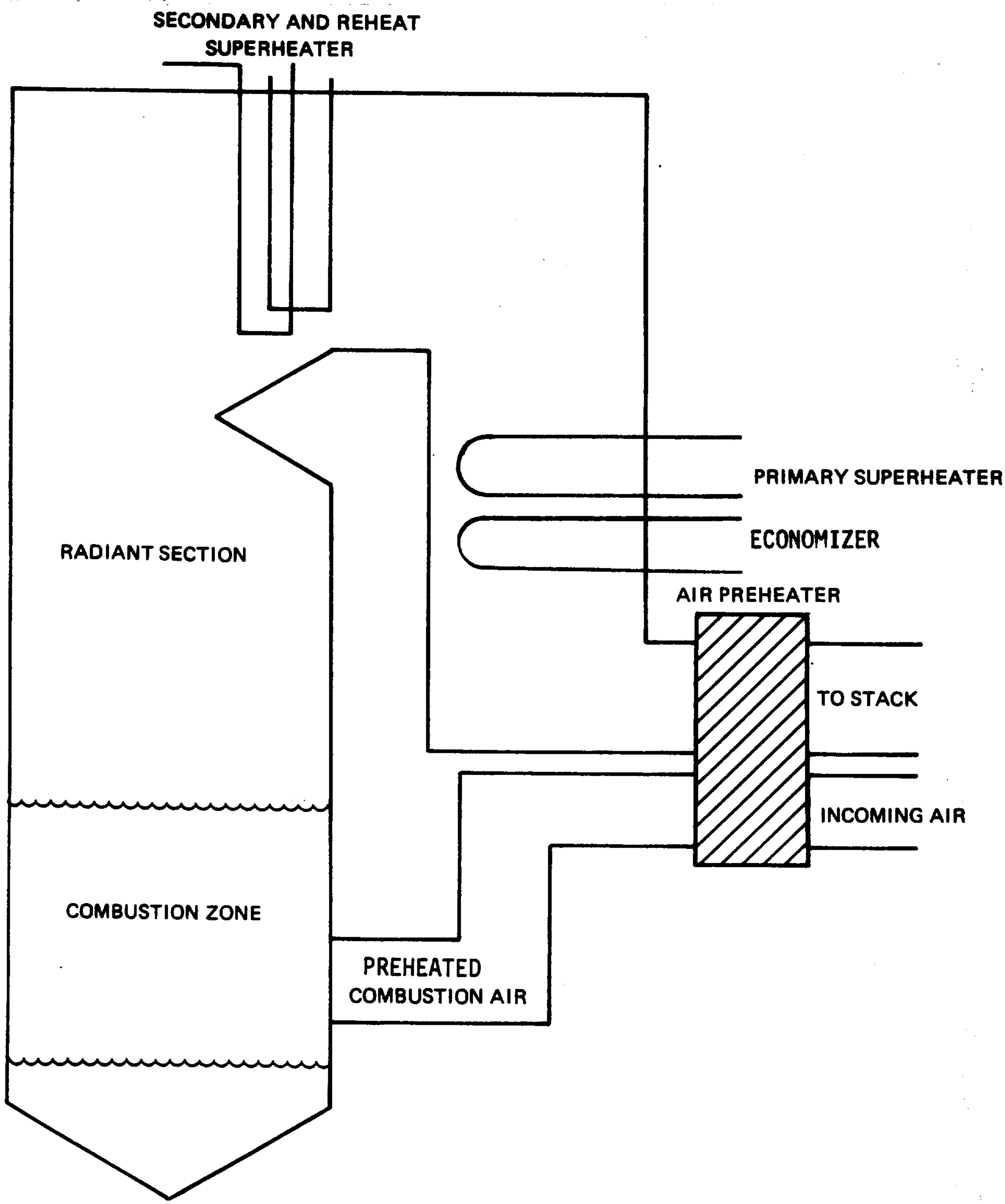


Figure II-1. SCHEMATIC DIAGRAM OF UTILITY STEAM GENERATOR.

TABLE II-7. SUMMARY OF UTILITY BOILER DESIGN FEATURES

Firing mechanism	Fuel preparation size	Fuel preparation drying	Ash removal
Pulverized fuel	200 mesh	Partial	Dry (typically)
Cyclone	1/4 in.	Partial	Wet
Stoker	2 in.	No	Dry

1. Pulverized Firing

In a pulverized fuel steam generator, the fuel is fed from the stock pile into bunkers adjacent to the steam boiler. From the bunkers, the fuel is metered into several pulverizers which grind it to approximately 200 mesh particle size. A stream of hot air from the air preheater partially dries the fuel and conveys it pneumatically to the burner nozzle where it is injected into the burner zone of the boiler.

Three burner arrangements are used for firing pulverized lignite in existing steam generators:

- Tangential firing
- Horizontally-opposed burners
- Front wall burners

These arrangements are shown schematically in Figure II-2.

The tangential method of firing pulverized coal into the burner zone has been developed by Combustion Engineering, Inc., (CE) of Windsor, Conn. In this firing method the pulverized coal is introduced from the corners of the boiler in vertical rows of burner nozzles. Such a firing mechanism produces a vortexing flame pattern which CE describes as "using the entire furnace enclosure as a burner."

Other manufacturers, such as Babcock and Wilcox and Foster Wheeler, have developed both front-wall firing and horizontally-opposed firing. In these firing mechanisms, the pulverized coal is introduced into the burner zone through a horizontal row of burners. For furnaces less than about 200 MW the burners are usually located on only one wall. For larger boilers, the burners have been located on the front and back walls firing directly opposed to each other. This type of firing mechanism produces a more intense combustion pattern than the tangential firing and has a slightly higher heat release rate in the burner zone itself.

In all of these methods for firing pulverized fuel, the ash is removed from the furnace both as fly ash and bottom ash. The bottom of the furnace is often characterized as either wet or dry, depending upon whether the ash is removed as a liquid slag or as a solid. Pulverized coal units have been designed for both wet and dry bottoms, but the current practice is to design only dry bottom furnaces. The wet bottom furnace requires higher temperatures(usually <2600°F) in order to melt the ash before it is removed from the furnace. This is important to NO_x control since higher temperatures result in higher NO_x emissions from thermal fixation.

2. Cyclone Firing

The cyclone burner, manufactured by Babcock and Wilcox, is a slag-lined high-temperature vortex burner. The coal is fed from the storage area to a crusher that crushes the coal (or lignite) into particles of approximately 1/4 in. or less. Crushed lignite is partially dryed in the crusher and is then fired in a tangential or vortex pattern into the cyclone burner. The burner itself is shown schematically in Figure II-3. The temperature within the burner is hot enough to melt the ash to form a slag. Centrifugal force from the vortex flow forces the melted slag to the outside of the burner where it coats the burner walls with a thin layer of slag. As the solid coal particles are fed into the burner, they are forced to the outside of the burner and are imbedded in the slag layer. The solid coal particles are trapped there until complete burnout is attained.

The ash from the burner is continuously removed through a slag tap flush with the furnace floor. Such a system insures that the burner has a sufficient thickness of slag coating on the burner walls at all times.

One of the disadvantages of cyclone firing is that in order to maintain the ash in a slagging (liquid) state, the burner temperature must be maintained at a relatively high level. The higher temperature promotes NO_x fixation. Unfortunately, this cannot be

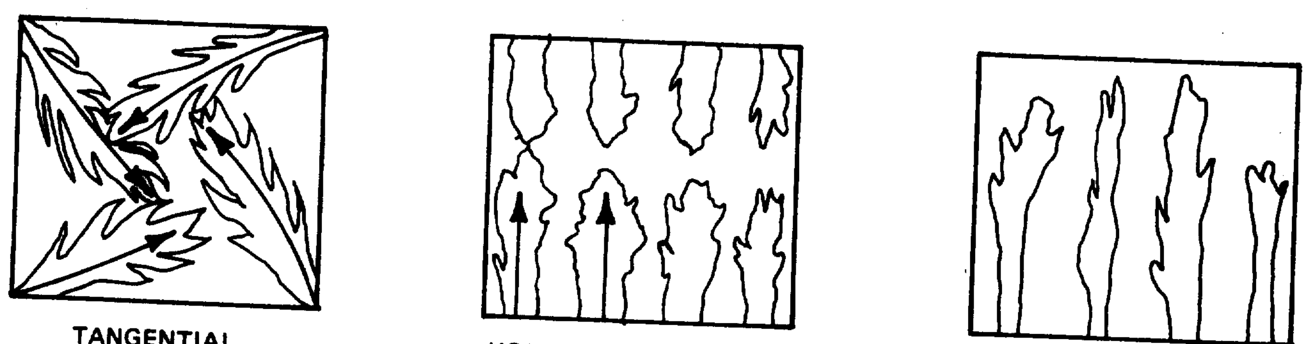


FIGURE II-2. BURNER ARRANGEMENTS FOR PULVERIZED-FUEL FIRING IN A UTILITY BOILER offset via the reduction of available oxygen without employing an auxiliary fuel to maintain stability. Tests on cyclone burners firing lignite alone have shown that the burner cannot be satisfactorily operated at a sub-stoichiometric air condition because of flame stability problems, i.e., the fire goes out at air addition rates less than the theoretical requirement.

3. Stoker Firing

In a stoker-firing furnace, shown schematically in Figure II-4, the coal is spread across a grate to form a bed which burns until the coal is completely burned out. In such a mechanism the coal is broken up into approximately 2-in. size and is fed into the furnace by one of several feed mechanisms -- underfeed, overfeed, or spreading. The type of feed mechanism used has very little effect on NO_x emissions.

The physical size of stoker-fired boilers is limited because of the structural requirements and extreme difficulties in obtaining uniform fuel and air distribution to the grate. Most manufacturers of stoker-fired equipment limit their design to 30 MW. The largest stoker in the United States, Heskett Station in Mandan, North Dakota, is a 65 MW twin stoker and is fired with lignite. It is unlikely that plants any larger than this would ever be built in the United States.

In most stoker units the grate on which the coal is burned gradually moves from one end of the furnace to the other. The coal is spread on the grate in such a fashion that at the end of the grate only ash remains, i.e., all of the coal has been burned to the final ash product. When the ash reaches the end of the grate it

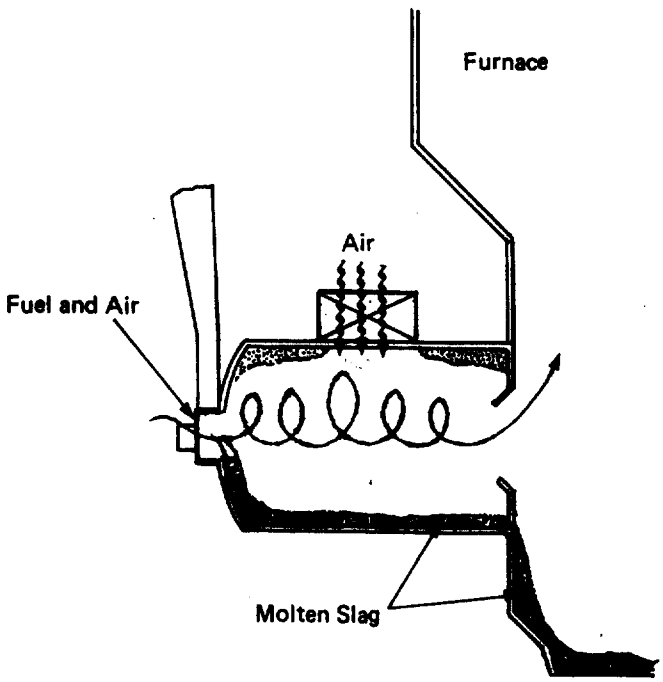


FIGURE II-3 **SCHEMATIC OF CYCLONE FIRING OF LIGNITE IN A UTILITY BOILER**

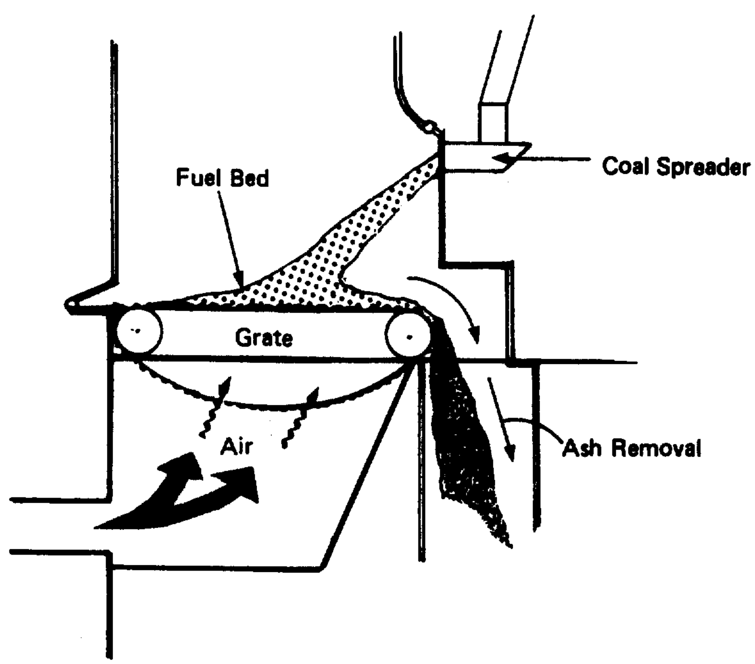


FIGURE II-4. **SCHEMATIC OF STOKER FIRING IN A BOILER** falls off into an ash collection hopper and is removed from the furnace.

Stoker-fired furnaces are dry-bottom furnaces and, as such, generally have lower heat release rates and lower temperature profiles than the corresponding pulverized coal or cyclone-fired units. Hence stoker-fired units typically have lower NO_x emission rates than other coal-burning equipment used for generating steam.

E. NO_x EMISSIONS FROM LIGNITE FIRING

Several emission factors have been published comparing the different types of stationary combustion steam-generating equipment currently in use. These are shown in Table II-8. Preliminary emission factors were published in 1956 by the Public Health Service.[6] These numbers have been recently revised through an extensive field testing program carried out by Exxon Research and Engineering for EPA.[7,8] The emission factors for lignite firing were determined from data reported in Chapter V of this report.

The variables which affect NO_x emissions can be segregated into two classes: fuel variables and burner design parameters. The significant parameters in each of these two classes are listed below along with a brief discussion of the reasons for their importance.

a. Fuel Variables --

- Fuel moisture content - the flame temperature in the combustion zone is inversely proportional to the moisture content of the fuel being fired. A high moisture-containing fuel, such as lignite, burns at a relatively lower flame

TABLE II-8 NOx EMISSION FACTORS FOR STEAM GENERATORS
($lb/10^6$ Btu input)

Fuel	Coal (4)	Coal (5,6)			Lignite (See Chap. IV)	
Control conditions	Uncontrolled	Uncontrolled	Combustion controls	Reduced load	Uncontrolled	Combustion controls
Pulverized fuel						
Tangential	0.59	0.59	0.46	0.31	0.52	0.45
Horizontal opposed	0.71	0.98	0.59	0.47	0.92	0.60
Front wall	0.95	0.87	0.50	0.50	--	--
Cyclone	2.20	1.60	1.23	1.23	0.81	0.66
Stoker	0.76	--	--	--	--	--

Numbers in parentheses indicate references listed at the end of this document.

temperature than that corresponding to the firing of bituminous coal. The lower temperature results in lower NO_x emissions.

- Volatility content - the rate of devolatilization of fuel particles alters the local combustion conditions surrounding each individual particle. Experimental data suggest that high volatile fuels burn at a lower heat release rate than less volatile fuels. Hence, the anticipated temperature profile within a boiler is expected to be lower for a high volatile fuel than it is for a low volatile fuel, resulting in a correspondingly lower NO_x emission.
- Fuel-nitrogen - although the mechanism by which NO_x originates from the fuel-nitrogen is not clearly defined, it has been demonstrated that fuel nitrogen oxidation can account for as much as 80-90 percent of the total NO_x emissions in pulverized firing.[47] Lignite has a fuel nitrogen content larger than gas or oil and comparable (on a Btu basis) with that of bituminous coal.
- Sodium content of the ash - although the sodium content of the lignitic ash does not affect NO_x emissions, it has an indirect effect on the emissions level in that lignite boilers are designed with low heat release rates to avoid ash fouling problems accompanying the high sodium ash. The lower heat release rate results in lower NO_x emissions.

b. Burner Design Parameters --

- Firing mechanism - the method of firing fuel into the boiler affects the local heat release rate and temperature within the burner zone, and thus the thermal NO_x. Of the three boiler designs discussed above, the cyclone burner has the highest local heat release rate. Pulverized coal firing has a heat release rate in the burner zone, lower than that of cyclone firing but higher than stoker firing. The lowest heat release rate of all is obtained by stoker-fired units. However, stoker units are limited in physical size and will not be of significant importance in future lignite-fired steam-generating equipment.
- Temperature profile - the temperature profile throughout the boiler is directly related to local levels of available oxygen, heat transfer and heat release rates. Although the designer has little control over the burning rate of the coal particle (i.e., heat release rate), they can predict what these rates will be for a given furnace and fuel combination. The local temperatures can then be controlled through the addition of excess air or provision for greater heat transfer surface. Above the burner zone, the temperature profile for pulverized coal firing and cyclone firing are similar. The temperature of gas entering the superheating section is limited to about 1850°F in both types of furnaces, so as to minimize the effects of ash fouling. This design

philosophy has a favorable impact on the level of NO_x emissions.

- Ash handling - ash can be removed from the boiler either as a molten slag (wet bottom) or as a dry-bottom ash (dry bottom). The wet-bottom furnaces require much higher temperatures in the burner zone in order to maintain the ash in the molten state. This high temperature results in a higher NO_x emission rate. The cyclone is the only wet-bottom design being proposed for lignite firing.

F. CONTROL OF PARTICULATE MATTER EMISSIONS

All of the large lignite-fired steam generators in the country either (1) have high efficiency precipitators, or wet scrubbers, or (2) are in the process of purchasing this equipment. Since lignite is relatively low in sulfur, the ash resistivity is lower than needed for standard precipitators. Hence, some companies have selected the "hot side" precipitator design. The combustion of lignite does not affect the possible level of control attainable using these high efficiency air pollution control devices nor does the firing of lignite alter any of the general design features of this equipment. All of the large existing sources currently meet the State implementation plan regulations for particulate matter. New lignite-fired steam generators using properly designed control systems can easily comply with new source performance standards for particulate matter.

G. CONTROL OF SULFUR OXIDES EMISSIONS

Lignite is a relatively low sulfur fuel, typically containing less than 0.4 percent sulfur. Sulfur oxide emissions from combustion of lignite are a function of the alkalinity (especially sodium content) of the ash. Unlike bituminous coal combustion, in which over 90 percent of the fuel sulfur content is emitted as SO_2, a significant fraction of the sulfur in the lignite is retained in the boiler ash deposits and flyash. Thus, most lignite-fired units may not require application of SO_2 control systems and flyash. The Energy Research and Development Agency in Grand Forks, North Dakota, is experimenting with removal of SO_2 by lignitic flyash. Pilot scale demonstrations of this technology have been developed using Montana subbituminous C coal at the Montana Power Company's Corette Station in Billings, Montana. A full-scale scrubbing system (360 MW) is scheduled for start-up at MPC's Colstrip Station in March 1975. A second system will be installed on Colstrip #2, scheduled for start-up in March 1976.

H. MODIFICATIONS

Under section 111(a)(4) of the Clean Air Act, a source may become subject to standards of performance if equipment or operations are altered in a manner which increases emissions. To clarify the meaning of the term "modification" appearing in the Act and to clarify when standards of performance are applicable, EPA established interpretative amendments to Part 60 of Chapter 1 of Title 40 of the Code of Federal Regulations. These provisions were adopted in the Federal Register on December 16, 1975 (40 FR 58416).

The provisions of 40 CFR 60.14 provide that a modification is considered to have occurred if a physical or operational change to an existing facility results in an increase in the emission rate to the atmosphere of any pollutant for which a standard of performance is applicable. Section 60.14 also provides that the following changes applicable to lignite-fired steam generators do not of themselves classify a facility as modified:

1. Routine maintenance, repair, and replacement of equipment,
2. An increase in production rate if the increase can be accomplished without a capital expenditure,
3. An increase in the hours of operation,
4. Use of an alternative fuel or raw material if the facility was designed to accommodate use of that fuel. Conversion of facilities to coal firing required for energy considerations as specified in section 119(d)(5) of the Act is not considered a modification.

For lignite-fired steam generators a modification is considered to have occurred if an increase in emission rate of sulfur oxides, nitrogen oxides, or particulate matter occurs after a change in the physical facility or its operation. Examples of changes which would be considered a modification of an existing lignite-fired steam generator are:

- <u>Installation of burners of a different type than initially installed (e.g., cyclone burners in a pulverized fuel furnace or a pulverized fuel burner instead of a stoker)</u>. The changes indicated above would result in higher NO_x emissions due to firing design changes which inherently produce higher NO_x emissions.
- <u>Relocation of burners in an existing furnace with or without a change in the number of burners</u>. A change in burner arrangement or number which created a more intense flame pattern would result in higher NO_x emissions.

For effective implementation of the provisions of sections 111 of the Clean Air Act, knowledge of sources which may be subject to the standards is important. For this reason, provisions were established in 40 CFR 60.7 which require written notification to EPA of any physical or operational change to an existing facility which may make it an affected facility. This notification shall be postmarked within 60 days or as soon as practicable prior to commencement of the change. The notification shall include the precise nature of the change, present and proposed emission control systems, productive capacity of the facility before and after the change, and the expected completion date of the change.

III. PROCEDURES FOR DEFINING BEST CONTROL TECHNOLOGY

A. DEVELOPMENT OF DATA BASE

The following steps were taken to develop adequate information to support emission limitations for NO_x control for lignite-fired steam generation.

1. The population of lignite-fired steam generators currently being operated by utility and industrial concerns was identified and sorted by state, furnace type, and size.
2. Nationwide emissions of NO_x were estimated from the population of lignite-fired steam generators.
3. Steam generators with "best systems" of NO_x emission reduction were identified.
4. The available methods for sample collection and analysis of NO_x emissions from lignite-fired steam generators were documented.
5. Presurvey inspections were conducted on 8 plants to select candidates for source testing by EPA and its contractors.
6. Source tests were conducted to gather information on the emissions, the processes, and the emission control systems.
7. Alternative emission limitations for new lignite-fired steam generators were formulated.

B. SOURCES OF PLANT DATA

To obtain basic data on plant location, capacity and generation for utility boilers (presented in Table II-2 of this report), a literature survey was conducted and the following source was identified as containing the most complete and up-to-date information:

Steam-Electric Plant Factors/1973 Edition. National Coal Association, Washington, D. C., 1974. (Reference 10)

Similar information on industrial-type steam generators was obtained from records kept by the American Boiler Manufacturers Association (ABMA) from January 1970 to April 1974. These documents indicated that no industrial installations were supplied with new lignite-fired steam boilers during this time period. The ABMA records previous to January 1970 do not separate lignite-fired generators from the general classification of coal-fired generators. Conversations with the four major boiler manufacturers confirmed our assumption that the number of industrial facilities burning lignite would be very small. Two of these manufacturers have significantly contributed to lignite-fired steam generation. These are Combustion Engineering and Babcock and Wilcox. Riley Stoker, Inc., supplied many of the older stoker-type boilers; Foster-Wheeler Corporation supplied two installations. Information on two industrial units of sufficient size to be studied was also obtained.

Individual utility and industrial companies were then canvassed. Information on boiler configurations was gathered from them directly.

C. SELECTION OF PLANTS FOR EMISSION TESTING

As a result of our literature review, conversations with industrial and utility lignite users and eight site visits for pre-survey inspection, four lignite-fired steam generators were recommended for emission testing.

D. SAMPLING AND ANALYTICAL TECHNIQUES RECOMMENDED

The sampling and analytical techniques used for this work are the same as those used in developing the standard for other fossil fuel steam generators. A detailed discussion of these is given in Chapter IX of this report.

The primary technique for analysis of NO_x is the phenol-disulfonic acid (PDS) method, EPA Method 7. Instrumental methods were also used to provide a check for the PDS method and also to provide data while the tests were in progress. A comparison of the PDS method data and the instrumental data is given in Appendix B. Use of a continous monitoring device which meets the criteria of Performance Specification 2 of Appendix A to 40 CFR Part 60 is required for NO_x emission monitoring.

E. EMISSION MEASUREMENT PROGRAM

In order to obtain the data required to investigate alternative NO_x emission limitations, four boilers (three stations) were tested. The summary of the text matrix for each of the boilers and the data obtained as a result of that testing program are presented in Chapter V of this report.

F. UNITS OF THE EMISSION LIMIT

All units used in this document are consistent with the units of measure used for developing the standard for the combustion of other fossil fuels. EPA has promulgated in the Federal Register (40 FR 46250) a procedure, the F factor method, for calculating NO_x emissions in lbs/million Btu's heat input. The method determines the ratio of NO_x to heat input based upon an Orsat analysis of the stack gas, instead of using data obtained from EPA Methods 1 and 2 (i.e., flow rate and moisture content of flue gas). The calculation of NO_x emissions in terms of lbs/million Btu's heat input has been made according to the

F factor procedure (see Appendix B). For all coals including lignite, heat input is based upon the higher heating value of the fuel when calculating emission factors. We have also included the NO_x emissions calculated using the methods 1 and 2 data whenever the data have been available.

IV. NO_x CONTROL TECHNOLOGY FOR LIGNITE-FIRED BOILERS

A. PRINCIPLES UNDERLYING NO_x CONTROL METHODS FOR FOSSIL FUELS

Nitric oxide is known to form via two distinct mechanisms, one in which nitrogen is taken from the air and the other in which nitrogen is taken from the fuel.

Some fuels such as natural gas and distillate (#2) oil contain negligible organic nitrogen; control methods for combustion of these fuels are based solely on preventing nitrogen from being taken from the air. "Fixation" of N_2 can be prevented by reducing the level of thermal excitation in the flame, thereby minimizing the Zel'dovich reactions[4]:

$$O_2 + M \rightarrow O + O + M$$

$$O + N_2 \rightarrow NO + N$$

$$N + O_2 \rightarrow NO + O$$

Thermal excitation or peak flame temperature can be reduced by means of (a) flue gas recirculation, (b) staged combustion, (c) water injection, (d) reduced air preheat, or (e) combinations of these techniques.

Other fuels such as residual (#6) oil, coal and lignite contain 0.2 to 1.5 percent organic nitrogen; control methods for these fuels are based not only on reducing thermal fixation but also on preventing fuel nitrogen from forming NO upon volatilization. Oxidation of fuel-nitrogen may be responsible for as much as 80 - 90 percent of the total NO_x emissions from pulverized coal firing.[47] Thus, control of fuel-nitrogen oxidation may be the limiting factor in controlling NO_x emissions from pulverized lignite-fired boilers. Fuel nitrogen conversion can be controlled by removing oxygen from the volatilization zone by means of (a) low excess air, (b) staged combustion, (c) fuel/air mixing pattern adjustment (burner design).

An approximately constant fuel-nitrogen content for the various U.S. lignites rules out the possibility of changing to a lower fuel-nitrogen lignite for NO_x control (see Appendix D).

In Table IV-1, these NO_x control methods are summarized. In Sections C, D, E, and F of this chapter, the most effective control methods are described in detail.

B. CONTROL METHODS APPLICABLE TO LIGNITE-FIRED BOILERS

Because of intolerable efficiency losses, water injection and reduced preheat are not competitive NO_x control methods for large steam generators Flue gas recirculation is not competitive for lignite because the substantial fuel NO_x contribution would go uncontrolled. Therefore, the viable control methods in Tables IV-1 to be considered in further detail for lignite are as follows:

- Low Excess Air (LEA)
- Staged Combustion (SC)
- Low-Emission Burners
- Combined Low Excess Air and Staged Combustion

Certain peculiarities of lignite impose constraints on the application of these NO_x control techniques. For example, higher primary air

Table IV-1. NO_x CONTROL METHODS FOR FOSSIL FUELS[1]

[Methods for coal are expected to be applicable for lignite]

Category	Method	NO_x Reduction: Gas	NO_x Reduction: Oil	NO_x Reduction: Coal	Constraints
Prevention of Thermal NO_x	Flue gas recirculation	60% (7,25,26,28, 32, 36)	20% (7,27,28,32, 35)	Not effective (7,8)	Costly ducts, fans
	Reduced preheat	50% (32,36)	40% (27,28,36)	Not effective (7,8)	Efficiency loss
	Water injection	60% (26)	40% (29;32)	Not effective (7,8)	Efficiency loss, costly pumps
Prevention of Thermal NO_x and Fuel NO_x	Staged combustion	55% (7,28,32,34, 36)	40% (7,27,28,32, 36)	40% (7,8,32,36)	Requires either some burners idled or inlets for over-firing
	Low excess air	20% (7,34,36)	20% (7,34,35)	20% (7,8,32,35,36)	Tube corrison, ash fouling, heat transfer in superheater
	Combined staging and low excess air	50% (7)	35% (7)	40% (7,30)	Same as above, combined
	Burner Modifications	20% (28)	20% (28)	30% (24,35,21)	Newly developed. Little service history.

[1] References in parentheses are given at the conclusion of this document.

temperatures are employed, larger furnace volumes per unit heat input are customary, the number of soot blowers is increased and pulverizers are larger. Among planned units or units under construction cyclone burner lignite furnaces are more prevalent for high-fouling North Dakota lignite; whereas, pulverized firing is used with little difficulty for the low-fouling Texas lignite. Due to the variability of the ash fusion temperature of Texas lignites, pulverized firing is preferred to cyclone firing. Cyclone burners are believed by some in the industry to be better able to handle the slagging problems of high sodium lignite than pulverized fired units. The reliability of cyclone-firing of lignite in the U. S. is good; however, experience with firing of high sodium lignite is limited for either cyclone or pulverized fired units.

The impact of the ash-depositing tendency of lignite on NO_x emission controls is as follows:

- If operational dependability is obtained by using cyclone burners, then NO_x controls such as SC or LEA are quite limited. Cyclones must have 110 percent of the total stoichiometric air directed into the burner and cannot be staged when firing lignite alone without compromising the high heat release per unit volume required for slag control. Initial testing indicates that cyclone combustion air can be staged if an auxiliary oil gun is employed to provide sufficient heat for slag control.
- If pulverized firing is adopted, utilization of 100-110 percent of the total stoichiometric air in the fuel admitting zone can be achieved with 18-25 percent overall excess air. Thus, staged combustion with pulverized firing is not unduly restricted by fouling considerations.

C. STAGED COMBUSTION

A typical utility boiler operates with an array of burners, each of which produces a flame "basket" of overall excess air equal to the total excess air of the entire boiler. Staged combustion is accomplished by redistributing the air flow such that a secondary combustion zone is encountered by the hot combustion gases after they leave the flame basket. This two-stage combustion has two effects on NO_x:

- Fuel NO_x is reduced because less oxygen is available during volatilization.
- Thermal NO_x is reduced because the temperature does not reach as high a peak as when all the heat release occurs in one stage (heat loss occurs between the two stages).

Two methods of air redistribution are shown schematically in Figure IV-1. Starting from the normal air/fuel ratio at the burners, staging can be accomplished either by maldistributing air (overfire air port), or by maldistributing fuel (burner out of service). The extent of staged air can be conveniently indexed by the fraction of stoichiometrically-required air remaining at the burner flame baskets. For example, suppose a boiler operating with 15 percent excess air has five operating burner levels with air supplied to six levels. Then one-sixth of the air supply is staged, leaving the burners with (115 x 5/6) or 95 percent of stoichiometric air at the burners.

Staged combustion has shown reductions of about 30 percent when applied to lignite fired utility boilers, as shown in Figure IV-2.

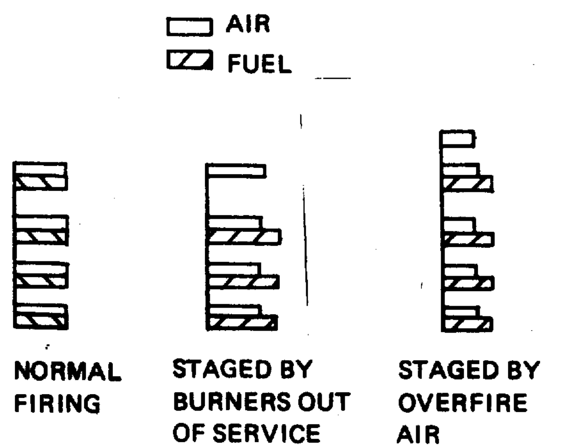
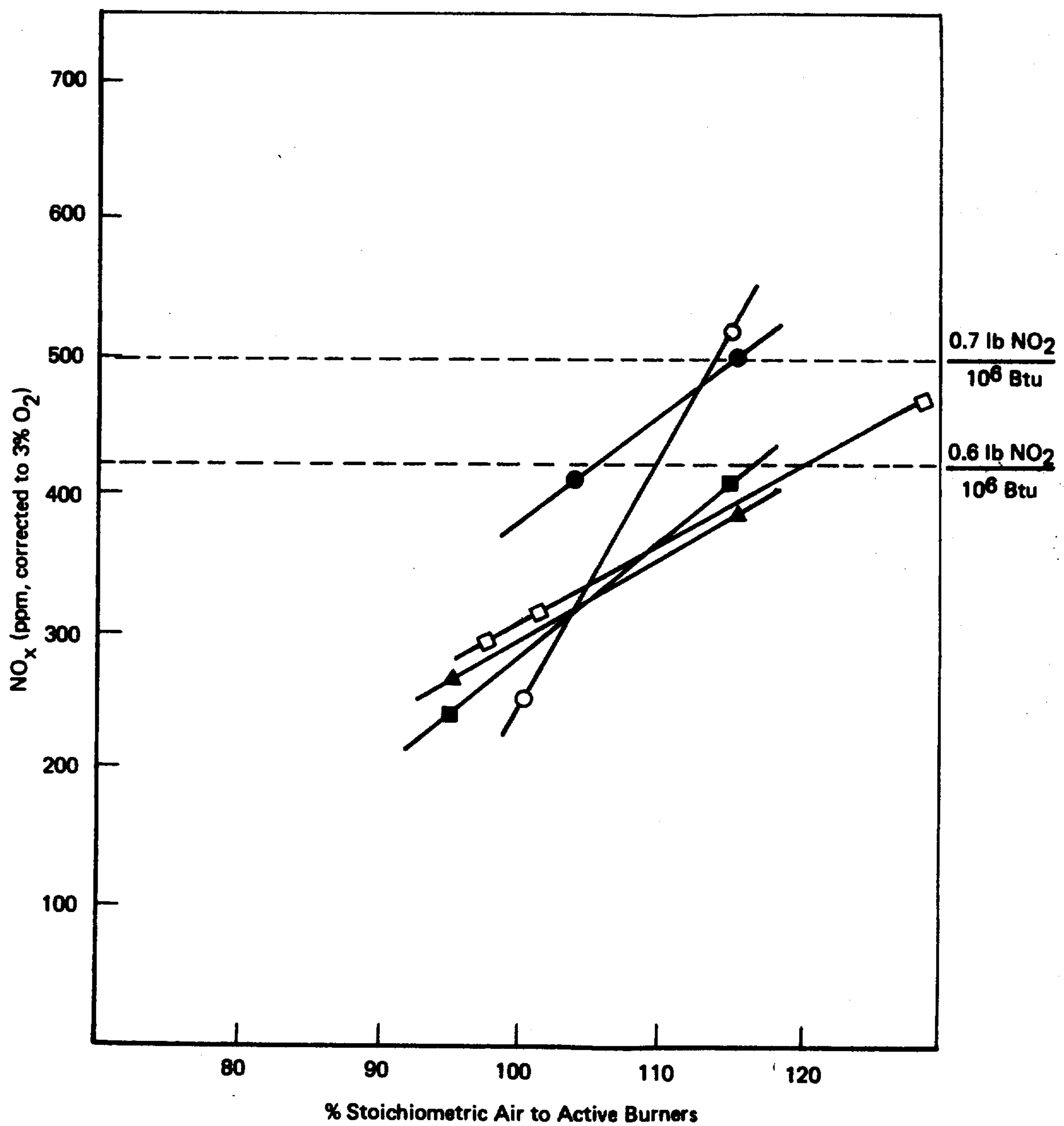


Figure IV-1. TWO METHODS OF STAGED COMBUSTION AS APPLIED TO A VERTICAL COLUMN OF BURNERS IN A UTILITY BOILER.

■ 570MW, Tangentially Fired, Habelt (1974) - Ref. 18
▲ 155MW, Tangentially Fired, Habelt (1974) - Ref. 18
○ 102MW, Front Wall Fired, Crawford (1974)* - Ref. 8
□ 328MW, Tangentially Fired, Habelt (1974) - Ref. 18
● 218MW, Front Wall Fired, Crawford (1974) - Ref. 8



*This unit was fired by a fuel which, although classified subbituminous, had a heating value of 6800 to 7800 Btu/lb., 7 to 16% ash, and 28% moisture. Since these values are similar to lignite, this data is useful for assessing NO_x control effectiveness for lignite firing.

Figure IV-2. EFFECT OF STAGED COMBUSTION ON NO_x FROM LIGNITE-FIRED BOILERS.

D. LOW EXCESS AIR

In addition to the air needed to complete combustion, about 10 to 20 percent overall excess air is added to utility boilers to insure an oxidizing atmosphere throughout the burning process, to cover normal ± 3 percent fluctuations in excess air, to aid carbon burnout, and to increase the convective heat transfer rate. Subject to these operating constraints, if excess air can be minimized then NO_x is reduced for two reasons:

- Fuel NO_x is reduced because less oxygen is available during volatilization.
- Thermal NO_x is reduced because the controlling Zel'dovich reaction, $O + N_2 \rightarrow NO + N$, is retarded by low oxygen radical concentrations.

It should be noted that well mixed, adiabatic combustion systems respond adversely to lower excess air, giving higher NO because of higher adiabatic flame temperature. But real utility boiler systems usually show NO_x reduction with low excess air. Low excess air has been tested on lignite fired boilers, as shown in Figure IV-3. About 20 percent reduction in NO_x can be expected when excess air is reduced from 20 to 10 percent (excess oxygen from 4 to 2 percent).

● 218MW, Horizontally Opposed Fired, Crawford (1974) - Ref. 8

○ 102MW, Front Wall Fired, Crawford (1974) - Ref. 8

▲ 155MW, Tangentially Fired, Habelt (1974) - Ref. 18

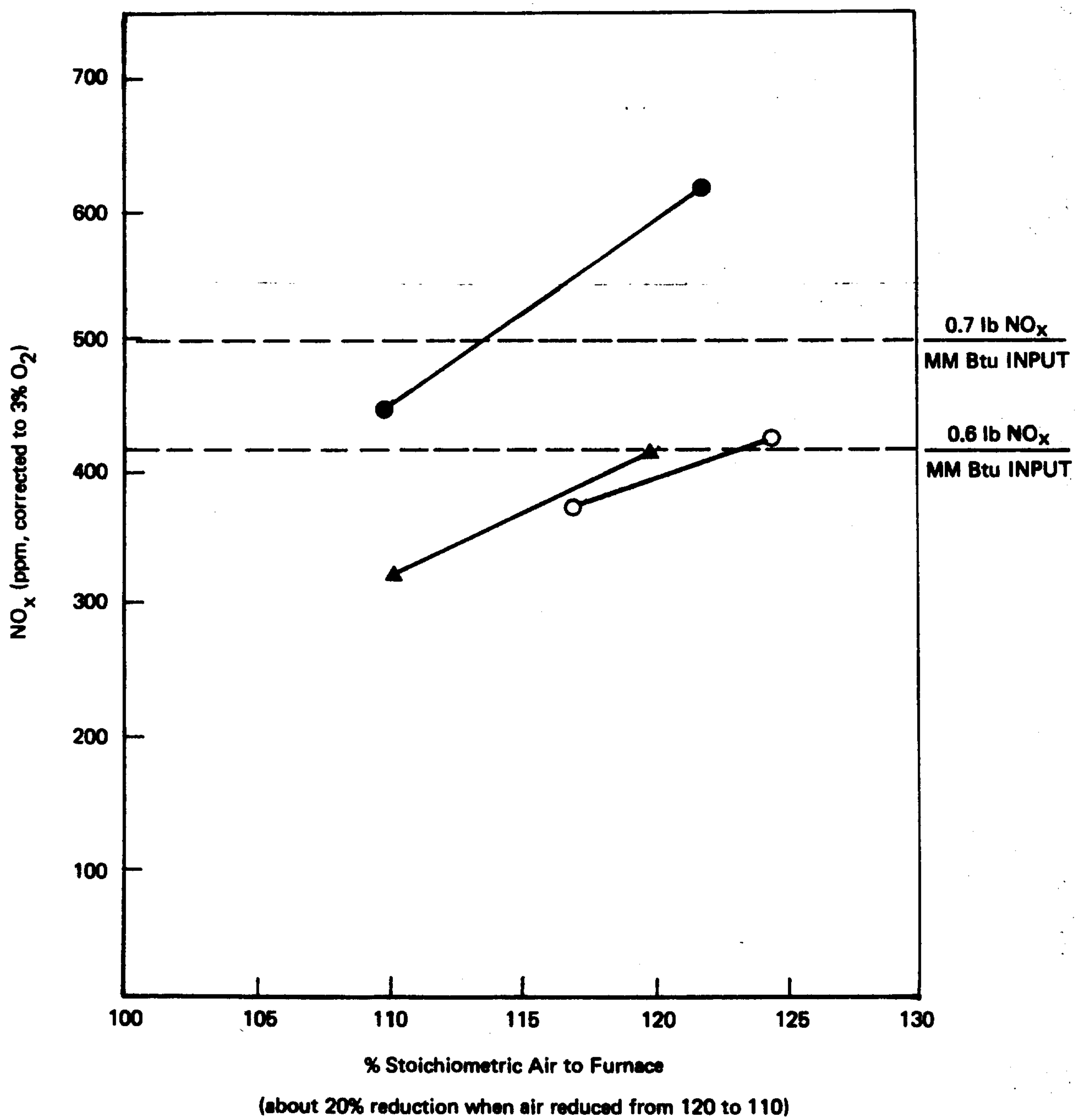


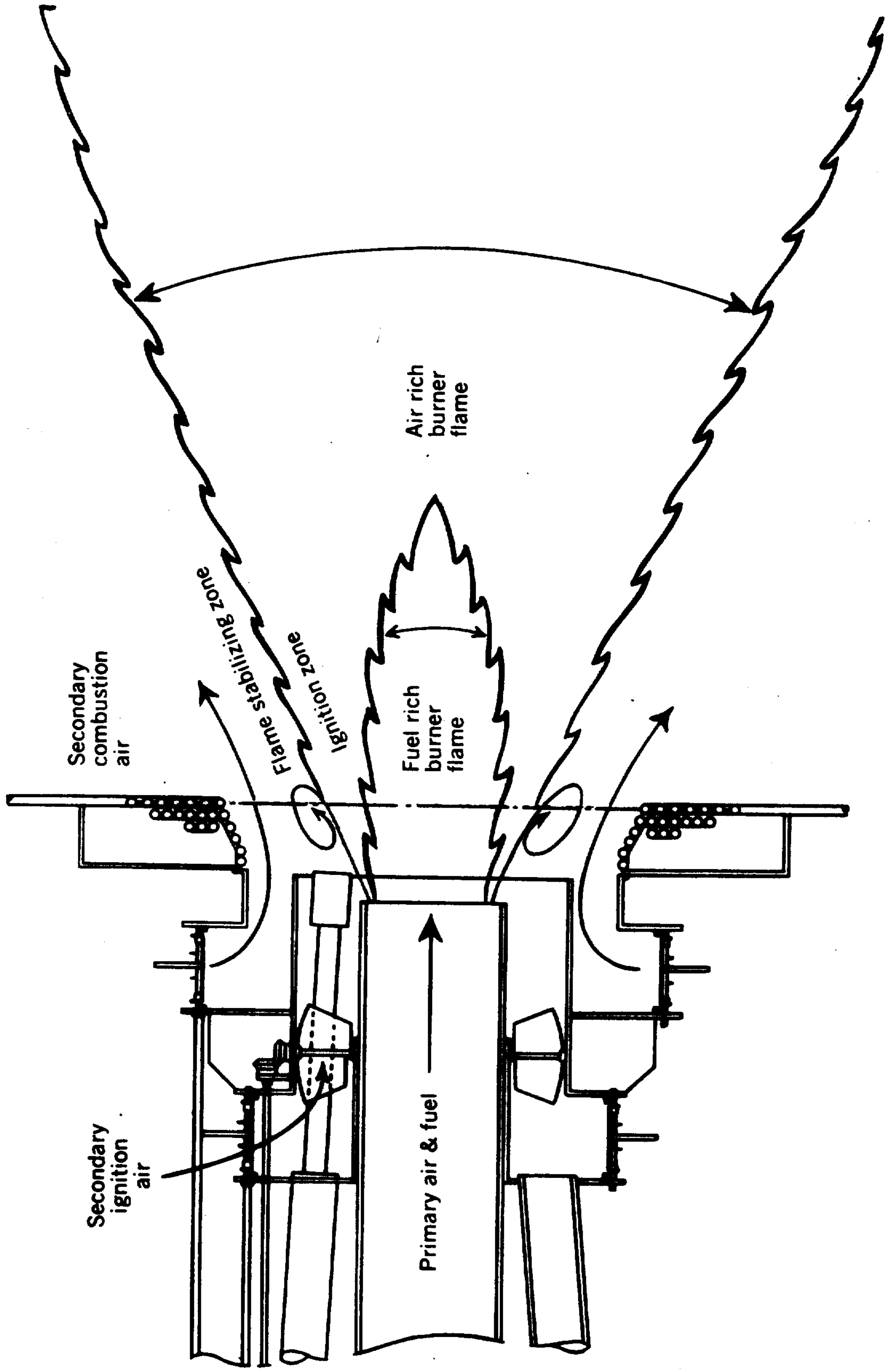
Figure IV-3. EFFECT OF EXCESS AIR ON NO_x FROM LIGNITE-FIRED BOILERS.

E. DUAL REGISTER-LOW NO_x EMISSION-PULVERIZED COAL BURNER[9]

Near the end of 1974, one of the two major suppliers of lignite-fired boilers made a corporate decision to include low NO_x emission burners as standard equipment on all pulverized coal fired boilers. Although EPA emission testing on only one retrofitted furnace is complete,[9] these results indicate that this burner yields NO_x reductions close to those obtained by tangential firing. For this reason, the following description of the low NO_x emission burner is given even though it is not presently a well-demonstrated NO_x control technology for lignite-fired steam generators.

Figures IV-4 through IV-6 illustrate the principles on which the low NO_x emission burner is based. Due to slagging and fouling problems, combining lower peak flame temperatures with controlled fuel-air distribution is the optimum design tool for NO_x control in coal-fired furnaces. Burners have been spaced to increase the water-cooled surface area around the burners, thereby lowering the burner zone heat release rate, and the burners and windbox have been designed to provide for optimum air distribution to the burners and within the burners. This arrangement permits the burners to operate with minimum total air for NO_x control, while providing sufficient air for combustion and slagging control.

During the last two months of 1974, the EPA performed NO_x emissions tests on a 270 MW, 18-burner, horizontally opposed, bituminous coal fired utility boiler equipped with dual register low NO_x emission burners. These tests were run on a boiler firing bituminous coal, not lignite.



Burner principles for low NO_x emissions

Figure IV-4

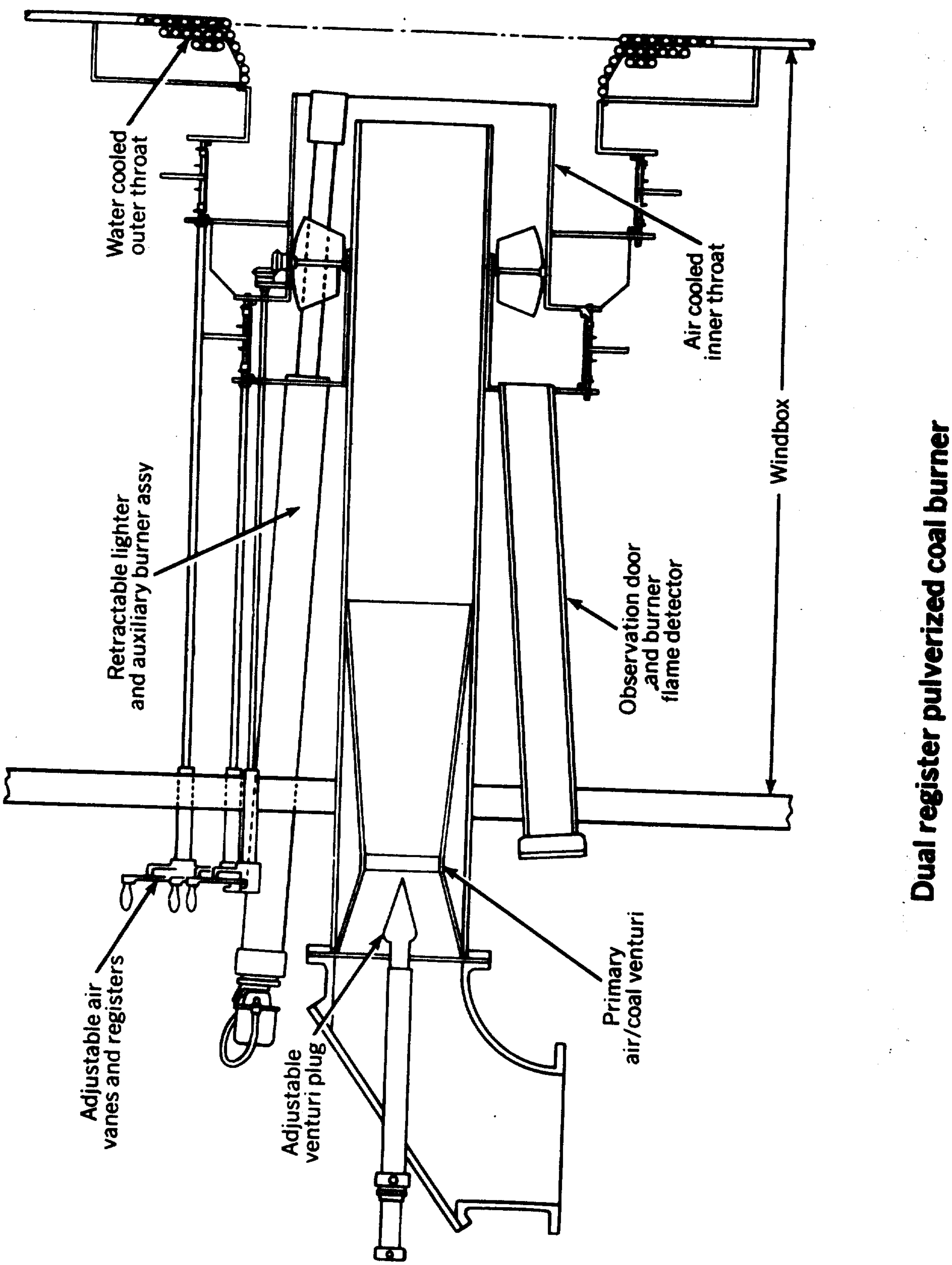

Water cooled
outer throat
Air cooled
inner throat
Retractable lighter
and auxiliary burner assy
Windbox
Observation door
and burner
flame detector
Adjustable air
vanes and registers
Adjustable
venturi plug
Primary
air/coal venturi
Dual register pulverized coal burner

Figure IV-5

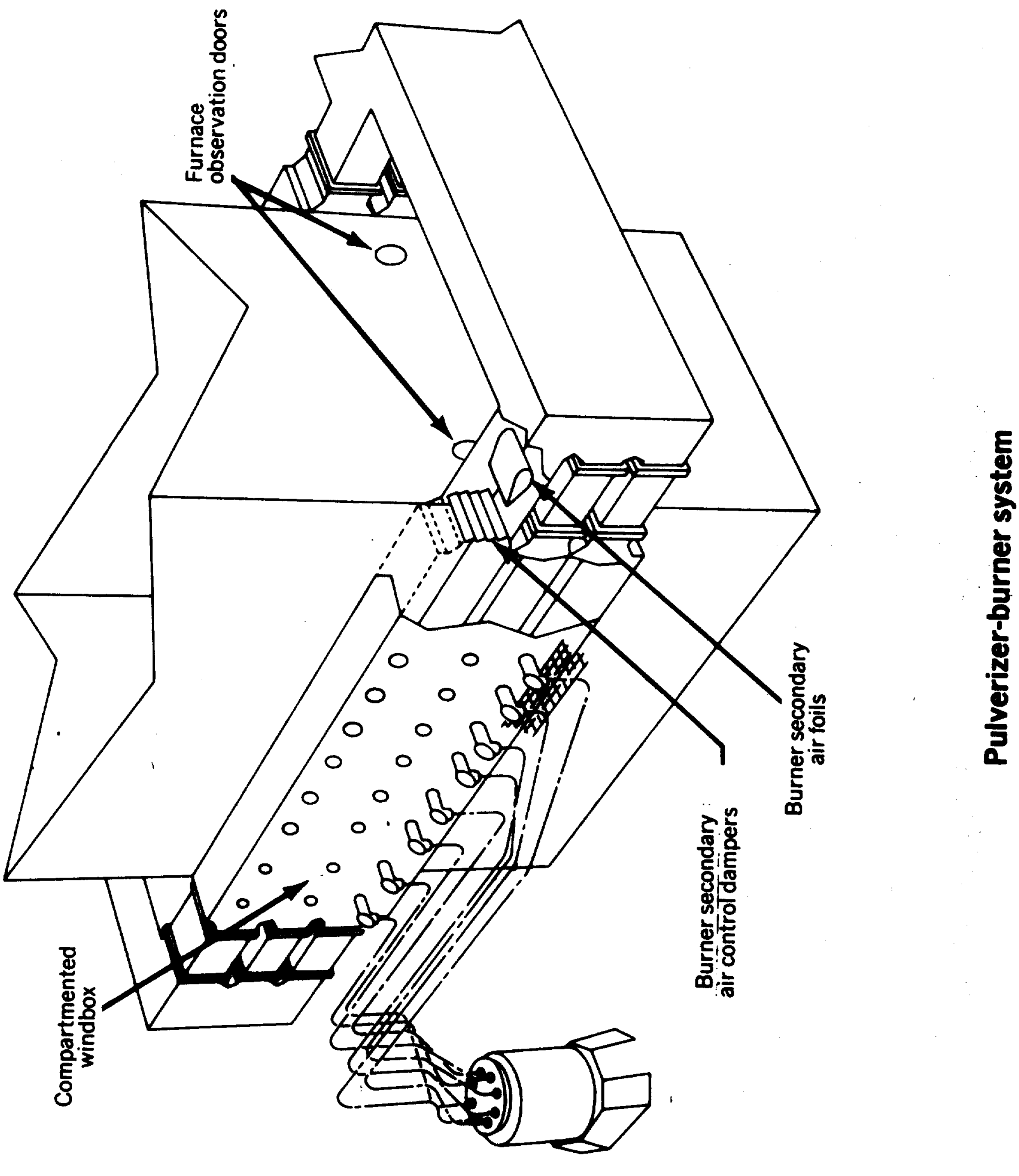

Furnace
observation doors
Compartmented
windbox
Burner secondary
air control dampers
Burner secondary
air foils
Pulverizer-burner system

Figure IV-6

Operating at baseline conditions, this boiler had an emission factor of approximately 0.53 lb $NO_x/10^6$ Btu while a sister unit identical in design, but not equipped with the low NO_x emission burners had an emission factor of approximately 0.82 lb $NO_x/10^6$ Btu when run under identical baseline conditions. When the boiler equipped with the low NO_x dual register burners was operated with low excess air, NO_x emissions were further reduced to approximately 0.38 lb $NO_x/10^6$ Btu.[9] Although these figures are only data from tests on one retrofitted boiler, it is clear that the low NO_x emission burner should prove to be a viable and effective NO_x control technology for coal-fired and possibly lignite-fired steam generators.

F. BEST AVAILABLE CONTROL SYSTEM: COMBINED LOW EXCESS AIR AND STAGED COMBUSTION

By reducing excess air from 20 to 10 percent and simultaneously diverting about 15 percent of this reduced air supply to a second stage combustion zone, NO_x reductions of about 40 percent are expected, based on test results reported by Crawford et al[8] on lignite-fired units. This figure is conservative since reductions of 55 to 64 percent were reported for other coal-fired units. The applicability of this control system to any given unit and any particular lignite will depend on slagging and efficiency constraints as affected by burner, furnace, and soot blower arrangements. Successful prolonged application of the technique also requires closer control over air flow distribution and better control over excess O_2 drift than is currently available at most utility steam generators.

V. EMISSION DATA TO SUBSTANTIATE STANDARDS

A. SUMMARY OF NO_x DATA FOR LIGNITE FIRING

A field test program covering four lignite-fired utility boilers was conducted to determine NO_x emissions under normal operating conditions, low excess air and staged air.

The results of this test program are summarized in Table V-8 and Figure V-4. Details of the test methodology are contained in Sections B, C and D, and a complete listing of individual data points may be found in Section E directly preceding the results summary.

B. DESCRIPTION OF BOILERS TESTED

1. Basis of Selection

There are currently only five lignite-fired utility boilers of greater than 70 MW generating capacity in the United States; four of these were included in the field test program, as shown in Table V-1. Note that of the 13 units planned to go on line between 1975-1980, eight are tangential, three are cyclone, and two are horizontally-opposed fired. All three types were tested. Additional reasons for selecting these units are as follows: (a) to include both Texas and North Dakota lignites, (b) to compare emissions from nominally identical units (Plants I & II), (c) to compare emissions taken in successive years (plant IV had previously been tested by EPA[8]).

Table V-1 UTILITY BOILERS EMPLOYED FOR NO_x EMISSION TESTS

Name	Capacity (MW)	Manuf.	Type	Date of Boiler Start up	Emission tests performed	Number of units of this type to be built (1975-1980)
Plant IV	215	B&W	Horiz.opposed	1966	Yes	2
Plant III	235	B&W	Cyclone	1970	Yes	3
Plant V	172	FW	Front-fired	1966	No	-
Plants I & II	575	CE	Tangential	1968, 1970	Yes	8

2. Process Description of Plant IV

Plant IV is a 215 MW steam-electric plant. The boiler, designed by Babcock and Wilcox, burns pulverized lignite which is fired through horizontally-opposed burners, as shown in Figure V-1. The lignite is pulverized in one of ten pulverizers, each pulverizer feeding two burners. The burners are arranged in three rows of four burners each on the front wall, and two rows of four burners each on the rear wall. The plant was first put into operation in 1966.

3. Process Description of Plant III

Plant III is a 235 MW steam-electric plant which burns crushed lignite (1/4 in. size) in a boiler designed by Babcock and Wilcox, using cyclone burners. The boiler is depicted in Figure V-2. There are a total of seven burners located in two rows on the front wall of the furnace. Crushed lignite is fired tangentially into each burner at a high velocity, creating a vortex effect. The burner temperature is maintained at a sufficiently high temperature to melt the fly ash and thereby create a molten layer of ash on the inside surface of the burner. The ash is continuously tapped from the burner and is drained out through the bottom of the furnace. In order to maintain high temperatures within the cyclone, relatively low excess air is used. Additional air is added to the hot gases after they leave the burners, creating a form of staged combustion. This plant was put into operation in 1970 and, as of 1974, is the only operating cyclone design firing lignite.

4. Process Description of Plants I & II

Each of the units is a CE twin furnace, tangentially fired boiler of 575 MW rated load, as shown in Figure V-3a and b. Approximately

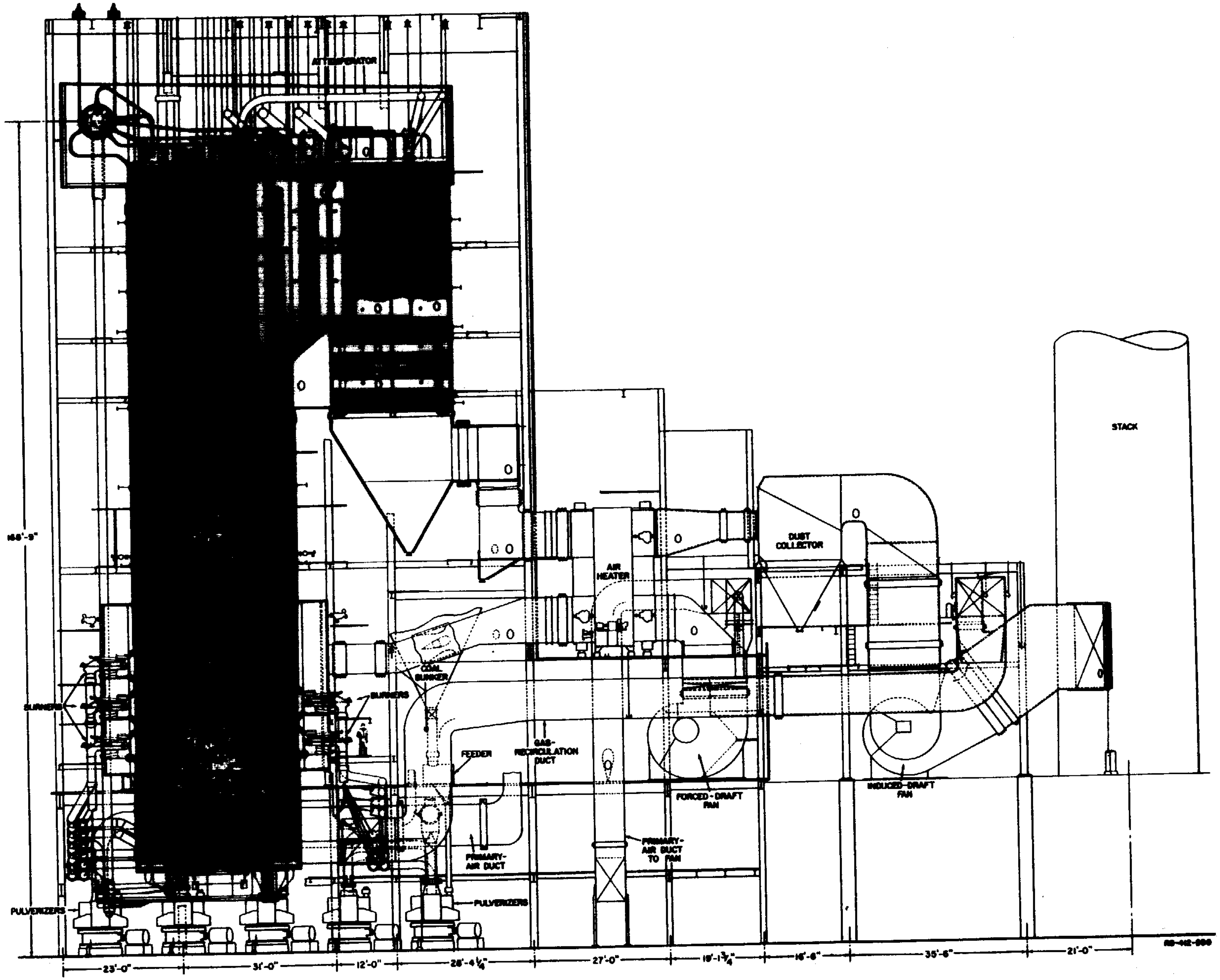


Figure V-1. PLANT IV

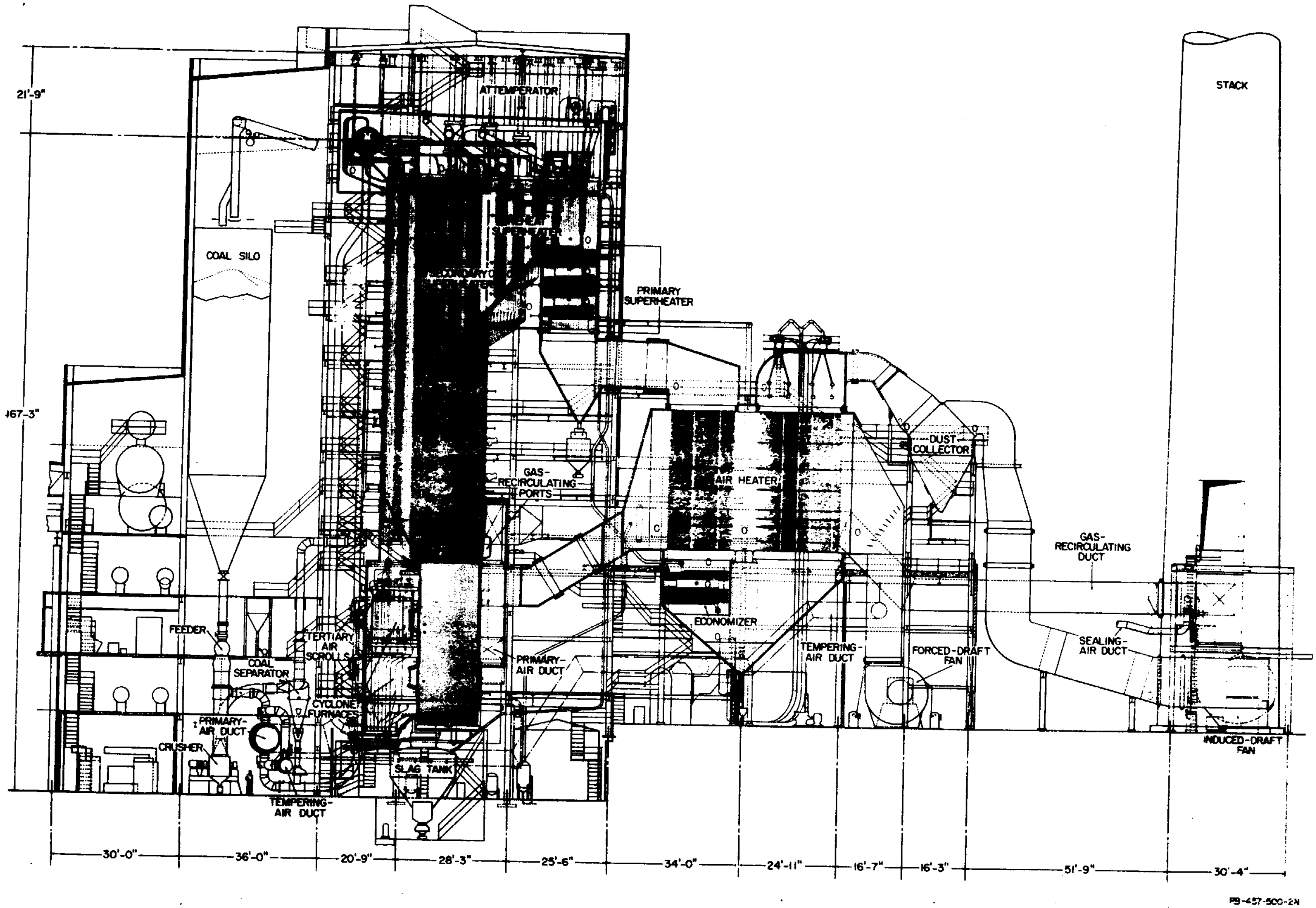


Figure V-2. PLANT III

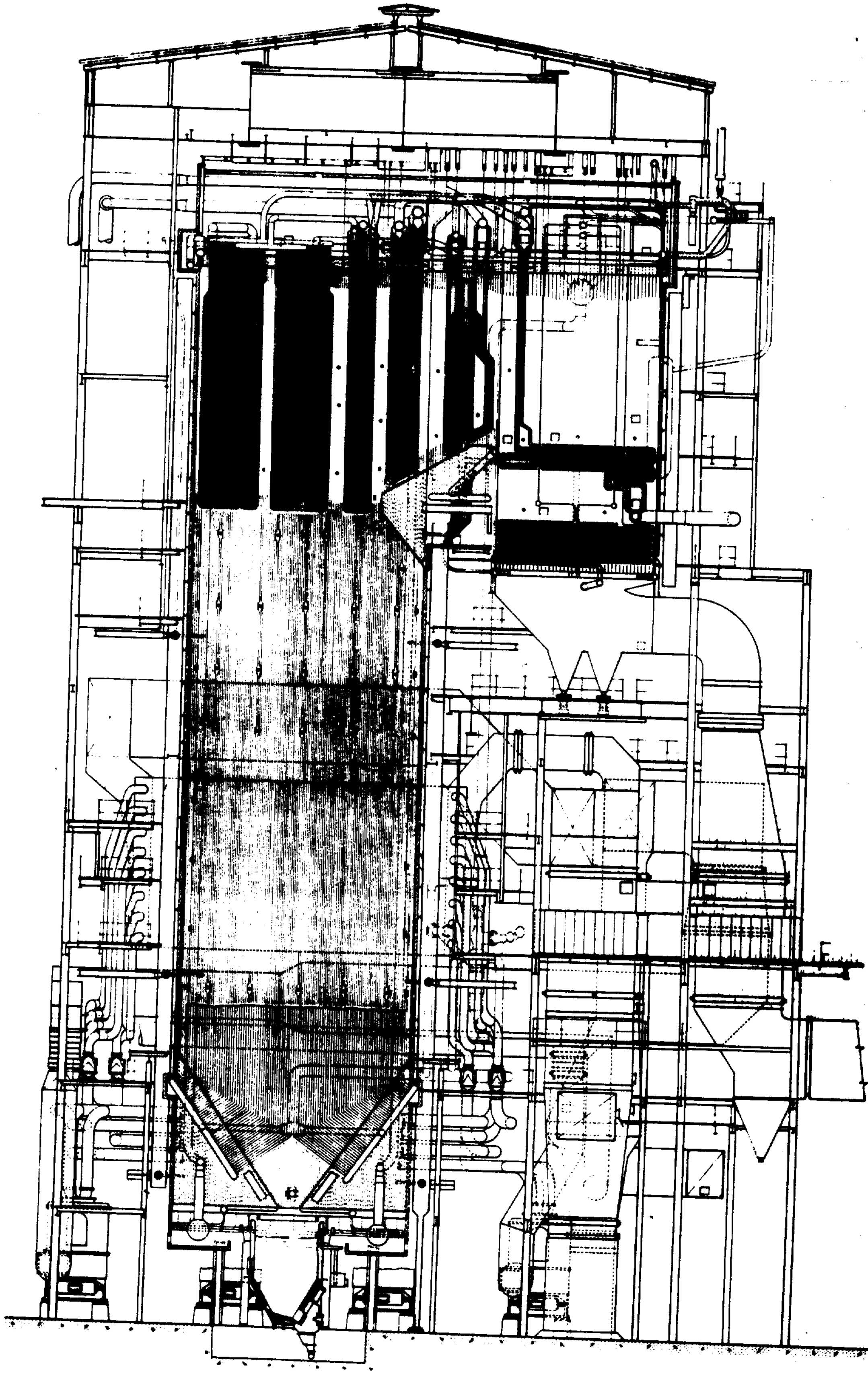


Figure V-3(a). TYPICAL TANGENTIALLY-FIRED BOILER.

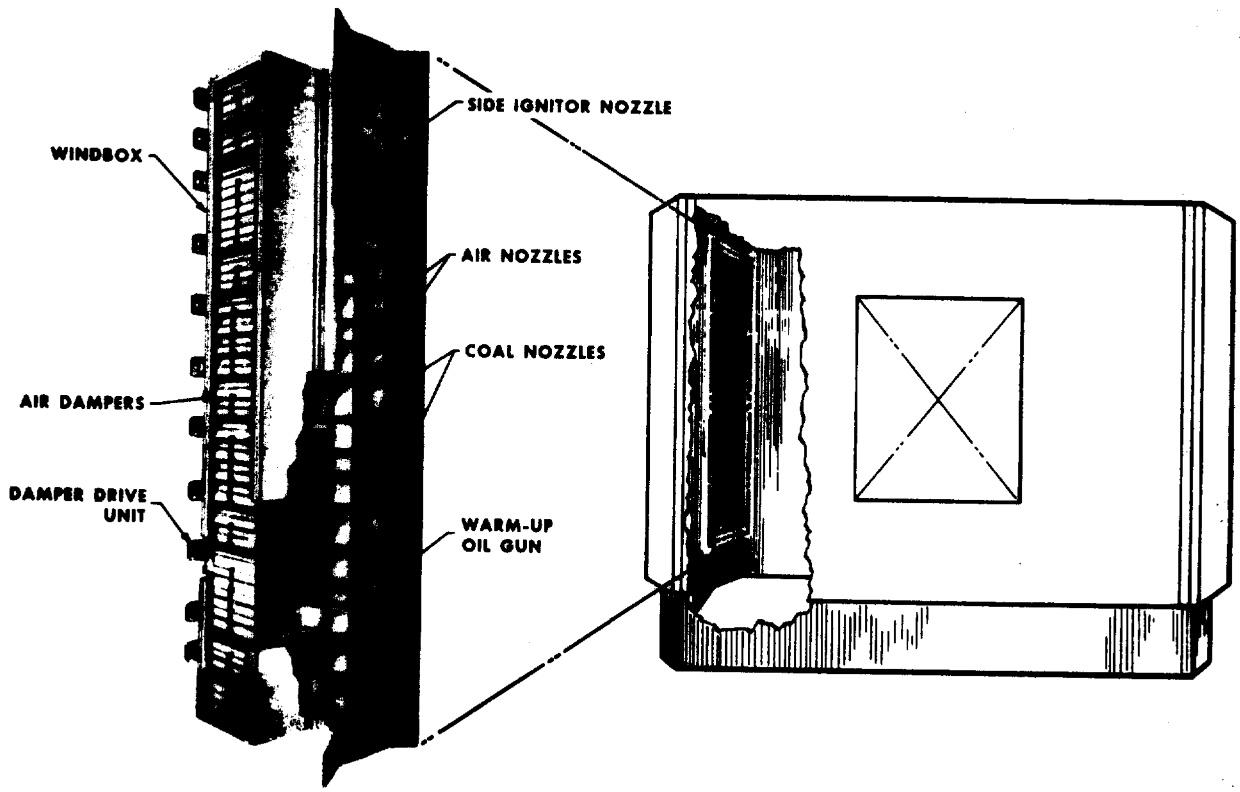


Figure V-3(b). TANGENTIAL FIRING SYSTEM

4.2×10^6 lb/hr steam flow is generated at 1000°F, 3650 psig. Texas lignite of 7000±500 Btu/lb heating value is carried through eight burner levels by preheated primary air. Secondary air is preheated to 760°F to assist in lignite volatilization and combustion. The primary secondary air flow ratio is normally 35/65, and the overall excess oxygen is normally 3.2±0.4 percent. Less than 1 percent of the total airflow is supplied by the soot blowers, which number over 100. It is interesting to note that normal operating practice at these units calls for the top burner level to be out of service, which means that one-eighth of the secondary air (about 8 to 10 percent of the total air) is staged. The remaining seven burner levels operate at about 105 percent stoichiometric air.

C. DESCRIPTION OF OPERATING CONDITIONS MEASURED

Three basic parameters characterize boiler operation: the chemical energy feed rate, the overall air flow and the air distribution to active burners. Although gross load (MW) and excess O_2 are "output" variables, they were used as convenient and reliable indices for "input" chemical energy and overall air flow. This interchangeability is justified because (1) combustion is essentially complete and (2) boiler efficiency is nearly constant.

The air flow to active burners (as percent of stoichiometric) was controlled and estimated differently for each boiler:

a. For Plants I & II, burner air flow was varied by withholding fuel (but not air) from the top burner level. Three conditions could be set up: no overfire with all burners operating, moderate overfire with secondary air to the top idled burner level, or maximum overfire with primary and secondary air to the top idled burner level. For each case, the air flow was measured by calibrated pitot tubes.

b. For Plant IV, no overfire was attempted and total air was assumed equally distributed over the burners.

c. For Plant III, about 15 percent of the total air flow bypasses the cyclone combustion chambers and is injected above the chamber outlets. This air comes from the coal handling and preheat system. The amount of overfire air as a fraction of total air is fixed for all tests.

Additional variables also known to affect NO_x were also measured: windbox temperature and pressure, ambient humidity, and fuel nitrogen content. Sufficient steam cycle measurements were recorded to construct an energy balance and verify normal operation of each boiler. The methods of measuring these operating conditions are given in Table V-2 for Plants I & II; nearly identical methods were used for Plants III & IV.

Emissions data corresponding to discrete, identifiable, reproducible operating conditions is impossible to obtain because of continuous drift in operating conditions during each two- or three- hour test interval. It was not unusual for excess oxygen to fluctuate between 2.7 and 3.3 percent within one-half hour when set at 3.0 percent. The reason for this drift is as follows: electrical output and steam flow typically are maintained constant with about ± 0.5 percent by continually adjusting excess air or burner tilt to compensate for transient slag buildup, coal heating value, or air flow variations. This drift contributes to the scatter in successive NO_x measurements taken at one-half hour intervals. Therefore the averaged NO_x data corresponds to an average condition representative of the range over which the boiler conditions drifted.

TABLE V-2 PROCESS MEASUREMENT METHODS

TYPICAL OF THOSE USED*

ITEM	METHOD OF DETERMINATION
Electrical load	Gross load before subtracting auxiliary
Flue excess O_2	Measured before preheater. For Plants I & II, values given are average of two furnaces (A&B) which typically differed by 0.3% O_2. Stack O_2 values expected to be larger because of preheater leaks.
Air to active burners (% stoichiometric)	For Plants I & II, air to active burners can be estimated by noting number and level of coal pulverizers out of service (see text). For Plant IV, burner air was taken equal to total air (no staging). For Plant III, burner air was taken at 85% of total air.
Coal rate	Sum of rates measured for each operating pulverizer using the RPM of conveyor belts. A scraper adjusts to maintain 100 lb on each belt. Estimated accuracy ± 2%.
Total air flow	Secondary air to each burner is measured with venturis. Total air determined from sum of primary and secondary air.
Pressure drop across burner and primary air flow	Pitot-tubes in windbox and furnace.
Air temperature	Thermocouples in windbox (secondary), and at pulverizer outlet (primary).
Relative Humidity	Continuous dew-point monitor. Changes due to temperature not water content.
Steam cycle	Flow nozzle at inlet to economizer measures feedwater flow (503°F, 4200 psig). Pressure drop across HP turbine measures throttle flow (1000°F, 3650 psig). Approximately proportional to load.

* These methods were used for Plants I & II.

D. TEST METHODS

A complete description of the field test methods may be found in the Contractors' reports to the Emission Measurement Branch of the EPA.

The analytical methods employed for the field tests are summarized in Table V-3. The primary analysis technique for NOx was the phenoldisulfonic acid (PDS) method (Method 7 as specified in the Federal Register, Vol. 36, No. 247, 23 December 1971)[11]. A continuous NOx monitor was used to obtain on site information about the emission behavior of the boiler, and to provide back-up data in support of the PDS samples. The Orsat analysis of Method 3 was performed to obtain O_2, CO_2, and CO with the methods outlined in the Federal Register.

Lignite samples were taken every half hour and the moisture, volatiles and ash content of the lignite samples were determined by using ASTM Method D 271-70.

Data on NOx concentration (lb/dscf) must be multiplied by the volume of flue gas produced per heating value (dscf/Btu) to obtain emission indices (lb/Btu). The volume of flue gas produced per heating value was determined as follows:

(i) by direct measurement of flue gas flow rate, coal flow rate, and heating value.

(ii) by calculating the volume of combustion products expected, using data on the coal composition, and correcting for dilution using excess O_2 data ("F-factor" method).

Table V-3 ANALYTICAL METHODS USED IN ACQUISITION OF NOx EMISSION DATA

Substance	Reference method #	Analysis techniques	Test series
NO_x	7	PDS	All four
	-	Electrochemical	Plants I & II
	-	Chemiluminescence	Plant III, Plant IV
O_2	3	Orsat	All four
	-	Continuous Analyzers on site	All four
CO_2	3	Orsat	All four
CO	3	Orsat	All four
Lignite	-	Proximate analysis ASTM Method D 271-70	All four

Based on method (ii), which agreed with the value recommended in the Federal Register[14] for sub-bituminous coal, a constant value of F = 98 dscf/10^4 Btu was used for all data reduction. This F-factor must be multiplied by 2090/(20.9 - O_2 percent) in order to estimate actual flue gas volume per 10^6 Btu under air-dilution conditions. Excess O_2 (percent) in the stack was measured by the Orsat method as described above.

Both methods (i) and (ii) were used in calculation of dry gas volumes, but emissions were calculated using gas volumes as determined by the F factor method (method ii). Dry gas volumes as determined by direct measurements were not used to calculate emissions because for all four test series these volumes were 5 to 16 percent greater than expected from the elemental composition of lignite and there was much scatter in the data. Consequently, the emission rates in the lignite tests were calculated using the F factor method. A subsequent study on a lignite fired steam generator showed excellent agreement between dry gas volumes as calculated by the F factor method and as determined by direct measurements. The follow up study also indicated that the discrepancy observed in the four lignite tests was due to errors in the measurements of gas velocity. (See Appendix B for discussion of discrepancy of data reduction procedures.)

E. DATA REDUCTION PROCEDURES

The emission index E (lb/million Btu) was calculated as NO_2 from the following expression:

$$E = 1.215 \times 10^{-7} CFD$$

where C = NO_x concentration (ppm, dry basis), F is the dry flue gas volume (dscf per 10^4 Btu) at zero excess air as discussed above, and D= 2090/(20.9-percent O_2). The F-factor method was used to calculate emissions with F taken to be 98 dscf/10^4 Btu. A simpler F-factor method, which results in comparable values, was published in the Federal Register on October 6, 1975, (40 FR 42650).

Based on an analysis of the uncertainty of emission measurements, we estimate emission uncertainty at ± 9 percent, ± 7 percent, and ± 6 percent for Plants I & II, Plant IV, and Plant III series, respectively. (See Appendix B).

All NOx data taken during a fixed boiler operating condition during any one day was averaged PDS data only, adjusted as noted in Appendix B and supplemented by electrochemical data where appropriate. We denote this average $<NO_x>$.

The O_2 data was also averaged for each test interval and dilution corrections applied to reduce (NO_x) values to common dilution condition (3 percent O_2). The lignite feed rate (ton/hr) and stack gas velocity were also averaged over each test series. From this average data, a representative dscf/Btu value was calculated by both direct method and F-factor method.

In addition, all baseline (NO_x at 3 percent O_2) data for a given boiler were averaged, and standard deviations derived (weighted by the number of samples per test interval). The values of E(or NO_x at 3 percent O_2)from successive test series were usually within the 8 percent estimated scatter.

F. RESULTS

Test results are presented in Tables V-4 through V-7 for the four utility boilers and a summary of results is given in Table V-8 and Figure V-4. Specific values are presented, and calculated averages for the test condition are given in brackets<>. Questionable data which were discarded are given in parentheses. Data listed for a given time of day was taken usually within ten minutes and always during the half hour following that time of day. Nitrogen oxides emissions are calculated as NO_2 and are given three ways: g/10^6 joules, lb/10^6 Btu, and ppm (dry) @ 3 percent O_2.

TABLE V-4. DATA FROM PLANT I

Day Hour[a]	Load (mw)	Feed rate (kg/sec)	Heating value (joules/g, rec'd)	Condition	Burner air (% Stoich)	NO_x (ppm) Method 7 *	NO_x (ppm) Analyzer	O_2 (%) Method 3 *	O_2 (%) Analyzer	dscm/10^6 cal F-factor[b] Method 2	dscm/10^6 cal F-factor[b] Method *	NO_x Emission[c] (using*) g/10^6 joules	NO_x Emission[c] (using*) lb/10^6 Btu	ppm @ 3% O_2
9/30 1200	607	108				254	-	-	3.2					
30	-	-				262	-	-	-					
1300	608	108				299	-	-	2.8					
30	-	-				279	-	-	-					
1400	596	104				309	-	-	3.7					
30	-	-				338	(110)	(6.3)	-					
1500	596	104				314	(110)	-	3.1					
30	-	-				310	(100)	-	-					
Mean	<601>	<106>	14,900	Baseline	105	<295>	-	<5.3>	-	.0155	.0148	0.20	.47	332
1600	483	84	14,900	Low load	105	<333>	(90)	<5.3>	3.2	.0157	.0148	0.23	.53	375
10/1 1000	597	101				280	-	4.6	3.6	.0161				
30	-	-				338	410	5.2	-	-				
Mean	<597>	<101>	14,020	Baseline	104	<309>	-	<4.9>	-	.0161	.0145	0.21	.49	348
1100	599	102				345	370	5.2	2.8					
30	-	-				336	-	(7.6)	-					
1200	597	102				317	-	4.1	2.6					
30	-	-				328	390	5.3	-					
1300	596	101				-	380	(11.0)	2.8					
30	-	-				346	385	(8.1)	-					
1400	600	102				280	(368)	(10.0)	2.7					
Mean	<598>	<102>	14,020	Low air	103	<333>	-	<4.6>	-	.0160	.0143	.22	.51	380
30	-	-				(75)	385	5.4	-					
1500	598	103				367	372	4.4	3.2					
30	-	-				(413)	386	(6.5)	-					
1600	600	105				339	380	-	3.2					
Mean	<599>	<104>	14,020	Baseline	105	<341>	-	<5.0>	-	.0157	.0146	.23	.54	378
10/2 0900	593	101	14,990	High air	111	268	-	6.0	4.2	.0156	.0156	.19	.46	314
30	-	-				(96)	(286)	5.3	-					
1000	592	103				334	250	4.7	3.6					
30	-	-				307	380	4.5	-					
1100	594	103				-	370	4.3	2.8					
30	-	-				364	310	-	-					
1200	560	97				(870)	315	-	3.0					
30	-	-				(2987)	315	-	-					
1300	594	102				346	290	-	3.1					
Mean	<596>	<101>	14,990	No overfire	116	<335>	-	<4.6>	-	.0155	.0143	.22	.52	382
30	-	-				(5906)	(280)	-	-					
1400	595	102				304	320	4.8	3.0					
30	-	-				309	320	4.4	-					
1500	595	102				(701)	335	6.4	3.2					
-	-	-				-	-	-	-					
Mean	<595>	<102>	14,990	Baseline	104	<306>	-	<5.0>	-	.0152	.0146	.21	.48	340
10/3 0700	602	104				306	-	5.0	3.7					
30	-	-				-	-	-	-					
800	601	105				300	-	5.2	3.9					
30	-	-				(202)	-	5.0	-					
900	599	105				308	-	5.8	3.7					
30	-	-				-	-	5.7	-					
Mean	<601>	<105>	14,400	High air	109	<305>	-	<5.4>	-	.0177	.0149	.21	.49	340
1000	602	104				(559)	370	5.4	3.4					
30	-	-				(3057)	435	(7.0)	-					
1100	602	104				(267)	-	5.8	3.5					
Mean	<602>	<104>	14,400	Baseline	106	-	-	-	-	.0160	.0152	-	-	-
30	-	-				295	-	5.1	-					
1200	601	106				209	-	5.6	3.2					
30	-	-				(470)	200	5.2	-					
1300	601	106				(2942)	200	5.8	3.1					
Mean	<601>	<106>	14,400	Max overfire	101	<252>	-	<5.3>	-	.0155	.0145	.17	.40	280
30	-	-				393	220	4.8	-					
1400	600	105	14,400	Baseline	104	(1089)	250	<4.9>	3.1	.0162	.0145	-	-	-
10/4 0900	595	106				(565)	-	6.0	3.9					
30	-	-	13,480	High air	107	(475)	(375)	6.2	3.1	.0175	.0156	-	-	-
1000	594	107				(385)	(500)	4.9	3.0					
30	-	-				358	-	4.9	2.5					
1100	593	107				288	-	(6.3)	2.3					
30	-	-				311	310	4.5	2.7					
1200	594	107				(477)	275	4.6	2.5					
30	-	-				(2687)	(85)	5.0	2.5					
Mean	<594>	<107>	13,480	No overfire	114	<310>	-	<4.7>	-	.0171	.0144	.21	.48	340
1300	592	106				275	(55)	5.9	2.8					
30	-	-	13,480	Baseline	104	271	-	-	-	.0173	.0746	-	-	-

[a]Listed time includes 1/2 hour interval which followed.
<-Values representative of test series.
()Data in parentheses were discarded according to screening criteria discussed in the text.
[b]See Section IV-D, Appendix B and Reference 14.
[c]Weight units are calculated as NO_2.

TABLE V-5. DATA FROM PLANT II

Day	Hour[a]	Load (mw)	Feed rate (kg/sec)	Heating value (joules/g, rec'd)	Condition	Burner air (% Stoich)	NO_x (ppm) Method 7 *	NO_x (ppm) Analyzer	O_2 (%) Method 3 *	O_2 (%) Analyzer	dscm/10^4 cal F-factor[b] Method 2	dscm/10^4 cal F-factor[b] Method *	NO_x Emission[c] (using*) g/10^6 joules	NO_x Emission[c] (using*) lb/10^6 btu	ppm @ 3% O_2
10/10	1230	-	-				-	370	-	-					
	1300	580	104				-	380	-	3.4					
	30	-	-				342	375	5.3	-					
	1400	580	105				318	375	5.3	3.3					
	30	-	-				(197)++	365	6.3	-					
	1500	580	106				(180)	390	4.7	3.3					
	30	-	-				(178)	380	4.6	-					
	1600	558	102				337	400	4.8	3.3					
	30	-	-				357	405	4.8	-					
	1700	578	105				314	395	5.7	3.4					
	30	-	-				305	405	4.7	-					
	1800	579	105				378	405	5.4	3.2					
	Mean	<577>	<105>	15,090	Special level (B off)	105	<330>	-	<5.1>	-	.0179	.0146	.22	.52	370
10/11	0900	598	110				274	285	4.8	3.5					
	30	-	-				288	285	6.1	-					
	1000	594	108				301	300	4.5	3.4					
	30	-	-				317	285	5.2	-					
	Mean	<596>	<109>	14,480	Max overfire	101	<290>	-	<5.1>	-	.0154	.0146	.20	.46	320
	1100	595	108				349	370	4.6	3.4					
	30	-	-				368	375	5.4	-					
	1200	594	108				361	370	4.7	3.2					
	30	-	-				327	365	4.7	-					
	1300	595	108				295	370	5.4	3.1					
	30	-	-				321	360	(6.6)	-					
	Mean	<595>	<108>	14,480	No overfire	117	<337>	-	<5.0>	-	.0161	.0145	.23	.53	380
	1400	596	107				(400)	310	4.5	3.1					
	30	-	-				335	320	6.1	-					
	1500	596	107				292	320	4.6	3.1					
	Mean	<596>	<107>	14,480	Baseline	104	<310>		<5.0>	-	.0172	.0145	.21	.49	350
10/12	0900	599	110				290	330	5.9	3.9					
	30	-	-				294	315	6.2	-					
	1000	598	110				294	328	7.2	4.0					
	30	-	-				308	330	6.6	-					
	1100	597	109				(255)	334	5.3	3.7					
	30	-	-				321	323	5.3	-					
	1200	598	110				309	335	5.3	3.6					
	30	-	-				313	325	5.6	-					
	1300	597	109				(245)	345	5.6	3.6					
	30	-	-				329	350	5.4	-					
	1400	597	109				333	350	5.9	3.8					
	Mean	<598>	<110>	14,780	Baseline	108	<300>	-	<5.5>	-	.0181	.0150	.21	.49	360
	1430	-	-				316	330	5.8	-					
	1500	596	110				(191)	320	5.8	4.0					
	30	-	-				298	305	6.0	-					
	1600	598	110				-	313	5.5	3.5					
	Mean	597	110	14,780	High air and Max overfire	104	< 300>	-	5.7	-	.0182	.0153	.22	.50	360

[a]Listed time includes 1/2 hour interval which followed.
()Data in parentheses were discarded according to screening criteria discussed in text.
<>Values representative of test series.
[b]See Section IV-D, Appendix B and Reference 14.

TABLE V-6. DATA FROM PLANT III

Day	Hour	Load (mw)	Feed rate (kg/sec)	Heating value (joules/g, rec'd)	Condition	Burner air (% Stoich)	NO_x (ppm)[a] Method 7 *	NO_x (ppm)[a] Analyzer[c]	O_2 (%) Method 3 *	O_2 (%) Analyzer[b]	dscm/10^4 cal[d] F-factor Method 2	dscm/10^4 cal[d] F-factor Method	NO_x Emission (using*) g/10^6 joules	NO_x Emission (using*) lb/10^6 btu	NO_x Emission (using*) ppm @ 3% O_2
10/7	0830	-					489	480	4.2	-					
	0900	251					500	480	-	4.3					
	30	-					412	365	4.2	-					
	1000	251					385	-	-	3.8					
	30	-					421	-	3.4	-					
	1100	250					546	-	-	3.7					
	30	-					479	-	3.6	-					
	1200	251					594	700	-	3.7					
	30	-					625	700	3.7	-					
	1300	252					578	-	-	3.7					
	30	-					628	680	3.9	-					
	1400	252					666	665	-	3.8					
	30	-					587	-	3.0	-					
	Mean	<251>	51.5	15,400	Baseline	106	<532>	<581>	<3.7>	<3.8>	.0152	.0135	.34	.79	[illegible]
10/8	0800	251					564	-	4.0	3.7					
	30	-					566	600	-	-					
	0900	252					542	600	4.1	4.1					
	30	-					530	-	-	-					
	1000	252					577	545	-	4.0					
	Mean	<252>	51.8	14,690	Baseline	107	<560>	<581>	<4.1>	<3.9>	.0167	.0138	.36	.84	[illegible]
	1030	-					447	460	3.5	-					
	1100	251					408	430	-	3.2					
	30	-					484	480	3.5	-					
	1200	251					482	480	-	3.1					
	30	-					483	500	-	-					
	Mean	<251>	51.5	14,690	Low air	102	<461>	<470>	<3.5>	<3.2>	.0162	.0133	.28	.66	470
	1300	251					524	540	3.9	4.0					
	30	-					588	560	-	-					
	1400	250					542	565	3.1	3.7					
	30	-					560	560	-	-					
	1500	251					571	570	-	3.8					
	Mean	< 251 >	51.5	14,690	Baseline	107	< 551 >	< 559 >	< 3.5 >	< 3.8 >	.0160	.0133	.34	.79	[illegible]
10/9	0800						473	-	3.8	3.8					
	30						503	520	-	-					
	0900						503	520	3.6	3.8					
	30						472	520	-	-					
	1000						506	550	-	3.9					
	Mean	252	51.8	15,110	Baseline	107	< 491 >	< 528 >	< 3.7 >	< 3.8 >	.0156	.0135	.31	.72	[illegible]
	1030						581	605	3.9	-					
	1100						586	600	-	3.8					
	30						656	620	4.2	-					
	1200						598	620	-	4.1					
	30						624	640	-	-					
	Mean	254	52.3	15,110	High air	109	< 609 >	< 617 >	< 4.1 >	< 4.0 >	.0164	.0138	.39	.91	[illegible]
	1300						621	620	3.8	3.7					
	30						615	610	-	-					
	1400						631	630	3.7	3.7					
	30						684	640	-	-					
	1500						626	610	-	3.6					
	Mean	256	52.5	15,110	Baseline	106	< 635 >	< 622 >	< 3.8 >	< 3.7 >	.0159	.0136	.40	[illegible]	670
10/10	0800						518	540	3.8	3.8					
	30						517	520	-	-					
	0900						560	540	3.4	4.0					
	30						560	560	-	-					
	1000						524	520	-	3.8					
	Mean	252	51.9	15,200	Baseline	106	< 534 >	< 536 >	< 3.6 >	< 3.9 >	.0156	.0134	.33	.77	[illegible]
	1030						503	530	3.6	-					
	1100						518	540	-	4.1					
	30						464	540	4.1	-					
	1200						[illegible]	540	-	4.0					
	30						573	560	-	-					
	Mean	251	51.6	15,200	"High air"	106	< 519 >	< 542 >	< 3.9 >	< 4.1 >	.0163	.0136	.33	.76	[illegible]

[a]Duct 1 measurements only (see text).

[b]Teledyne O_2.

[c]TECO Chemiluminescent.

[d]See Section IV-D, Appendix B and Reference 14.

TABLE V-7. DATA FROM PLANT IV

Day	Hour	Load (mw)	Feed rate (kg/sec)	Heating value (joules/g, rec'd)	Condition	Burner air (% Stoich)	NO_x (ppm) Method 7 *	NO_x (ppm) Analyzer	O_2 (%) Method 3 * (Stack)	O_2 (%) Analyzer (Preheater)	dscm/10^4 cal[a] F-factor Method 2	dscm/10^4 cal[a] F-factor Method *	NO_x Emission (using*) $\frac{g}{10^6 \text{ joules}}$	NO_x Emission (using*) $\frac{lb}{10^6 \text{ btu}}$	NO_x Emission (using*) ppm @ 3% O_2
10/1	1030						529	**	4.9	5.1					
	1100						544		-	5.2					
	30						516		5.0	5.0					
	1200						518		-	5.0					
	30						541		4.7	4.9					
	1300						568		-	4.9					
	30						585		4.8	4.9					
	1400						606		-	4.8					
	30						620		4.9	5.0					
	1500						594		-	5.1					
	30						625		5.0	4.9					
	1600						557		-	4.8					
	30						576		5.0	4.7					
	Mean	205	40.7	16,200	Burner "J" off	127	<568>		<4.9>	<4.9>	.0162	.0145	.38	.84	640
10/2	0830						529	**	4.5	5.0					
	0900						506		-	5.0					
	30						475		4.3	4.7					
	1000						516		-	4.6					
	Mean	203	40.3	15,030	Baseline	126	<507>		<4.4>	<4.8>	.0171	.0141	.33	.77	550
	1400						425	**	3.2	3.2					
	30						396		-	2.6					
	1500						444		3.2	3.3					
	30						383		-	3.5					
	1600						377		3.2	3.2					
	30						378		-	3.1					
	1700						391		2.8	2.8					
	30						411		-	2.8					
	1800						426		3.1	3.0					
	Mean	200	39.4	15,030	Low air	115	<403>		<3.1>	<3.1>	.0156	.0131	.25	.57	410
10/3	0830						531	-	4.7	4.4					
	0900						505	-	-	4.5					
	30						535	-	5.0	4.6					
	1000						617	-	-	4.6					
	30						590	540	5.3	4.5					
	Mean	198	39.2	16,070	Baseline	125	<556>	<540>	<5.0>	<4.5>	.0165	.0146	.38	.88	630
	1230						453	510	3.3	3.0					
	1300						420	420	-	2.6					
	30						425	440	4.0	3.0					
	1400						457	505	-	3.0					
	30						381	520	3.4	3.0					
	Mean	198	39.2	16,070	Low air	113	<427>	<479>	<3.6>	<2.9>	.0151	.0134	.24	.62	440
	1500						620	630	5.0	4.2					
	30						623	660	-	4.6					
	1600						636	660	5.3	4.5					
	30						623	700	-	4.4					
	1700						592	680	4.9	4.5					
	30						626	680	-	4.0					
	1800						670	680	4.8	4.2					
	30						657	680	-	4.2					
	1900						634	680	4.8	4.4					
	Mean	200	39.7	16,070	Baseline	122	<631>	<672>	<5.0>	<4.3>	.0166	.0146	.43	1.00	710

**No readings due to plugged capillary.

[a]See Section IV-D, Appendix B and Reference 14.

TABLE V-8 SUMMARY OF MEASURED NOx EMISSIONS FROM LIGNITE-FIRED STEAM GENERATORS

Unit	Manuf.	Type	Load (MW)	Condition	Burner Air (% stoich)	No. of Runs	Scatter	NO_x* ($lb/10^6 Btu$)	NO_x (ppm @ 3% O_2)
Plant I	CE	Tang.	600	Baseline	105	16	± 9%	.48	340
				Low air	103	5	(± 35 ppm)	.51	360
				High air	109	4		.48	340
				Max. overfire	101	2		.40	280
				No overfire	115	6		.50	350
Plant II	CE	Tang.	600	Baseline	107	12	± 9%	.49	350
				Max. overfire	102	6	(± 35 ppm)	.47	330
				No overfire	117	6		.53	380
Plant III	B&W	Cyclone	250	Baseline	106	28	± 6%	.81	580
				Low air & overfire	102	5	(± 35 ppm)	.66	470
				High air	109	5		.92	660
				High air & overfire	106	5		.76	540
Plant IV	B&W	Opposed	200	Baseline	126	31	± 7%	.92	650
				Low air	114	14	(± 35 ppm)	.60	430

*Calculated as NO_2.

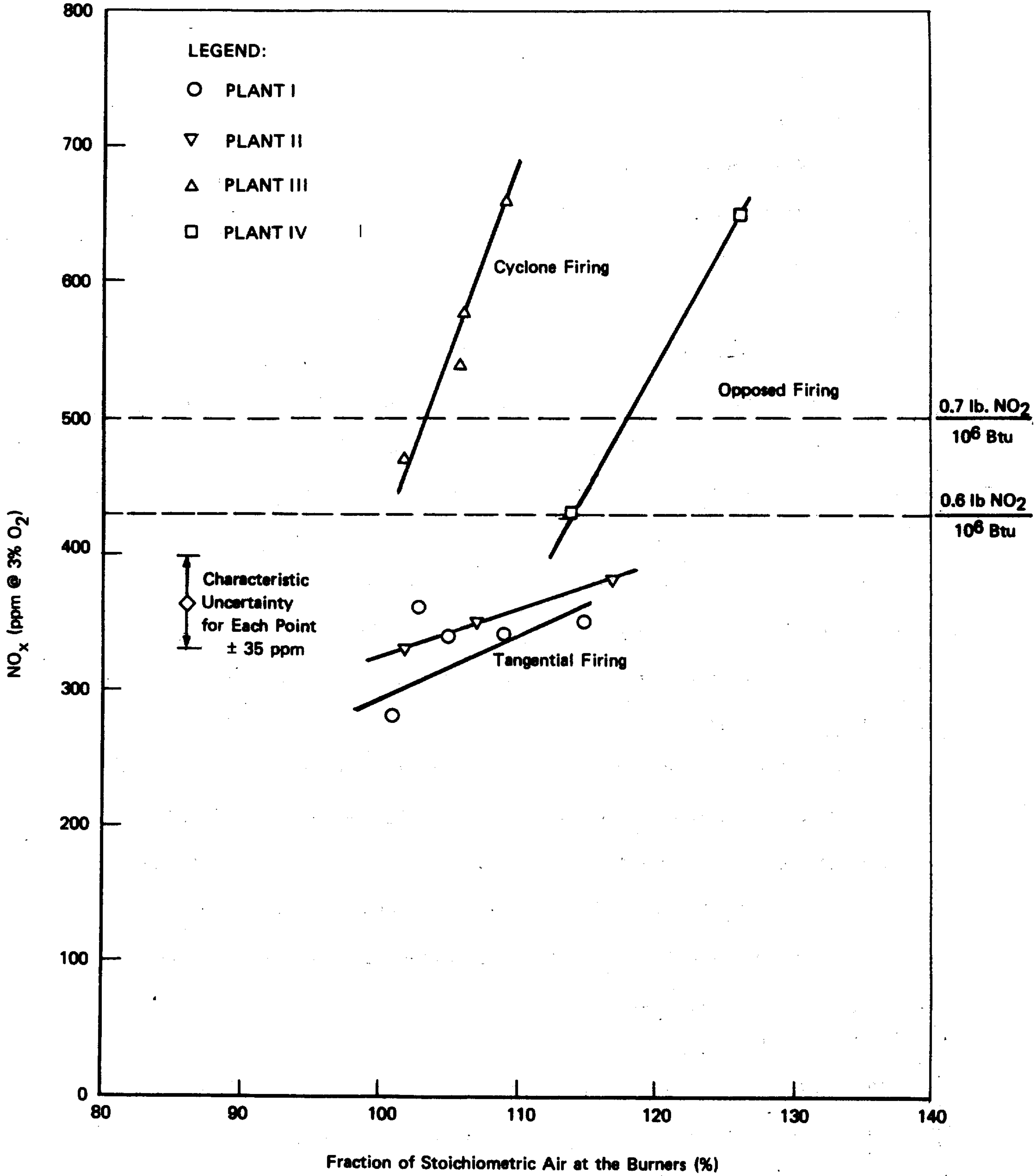


Figure V-4. NO_x EMISSIONS FROM LIGNITE-FIRED BOILERS.

G. DISCUSSION

1. Comparison with Prior Data

Table V-9 compares the results of this program with previous data. NO_x measurements on all four boilers agree fairly well with previously published data when the estimated uncertainty of 35 ppm is taken into account.

2. Effect of Low Excess Air and Staging

Reducing excess air flow to the active burners can yield about a 20-35 percent reduction in NO_x emissions, as shown in Table V-8, V-9 and Figure V-4. For tangential units, the overall air flow cannot be lowered more than 5 percent. The only viable way to lower burner air is by increasing the overfire air. For the horizontally opposed fired pulverized unit, reduction in total air gives a 34 percent NO_x reduction. The cyclone-fired boiler proved responsive to either LEA or staging.

3. Effect of Boiler Type

Horizontally opposed fired and cyclone boilers appear to give nearly comparable uncontrolled NO_x emissions (650 versus 580 ppm), a level which is about 70-90 percent higher than the tangential units (340-350 ppm). However, the horizontally opposed fired and cyclone boilers appear more responsive to NO_x control techniques percentage-wise, as is indicated in Figure V-4.

4. Effect of Fuel Type

The test program did not permit firing two substantially distinct lignites in the same boiler in order to discern fuel effects. There are two expected effects, however:

a. Moisture - The high moisture content of lignite relative to bituminous coal might be expected to control both thermal NO_x and fuel NO_x to the extent that water evaporation occurs in the volatilization

Table V-9 NO_x DATA COMPARED TO EARLIER PUBLISHED RESULTS FOR LIGNITE-FIRED UTILITY BOILERS

Unit	Condition	NO_x (ppm @ 3% O_2) This work	Prior data	Ref
Plants I & II	Normal	350	390	Habelt and Selker[18]
	Staged	280-330	290	"
Plant III	Normal	580	620-750	Gronhovd et al[19]
		-	540	Duzy and Hillier[20]
	LEA/Staged	470	440	Duzy and Hillier[20]
Plant IV	Normal	650	560-580	Gronhovd et al[19]
			570	Crawford et al[8]
	LEA	430	450	"
	Staged	-	380	"

zone of the flame. Indeed, restricting our attention to the tangential furnace, the mean uncontrolled NO_x emission level of 16 coal-fired units was about 15 percent higher than the mean uncontrolled NO_x emissions from 11 lignite- and subbituminous-fired units.[19] The current emissions results for lignite-fired cyclone furnaces are well below the results of early studies on NO_x emissions from coal-fired cyclones.

b. Fuel Nitrogen - Evidence is mounting that as much as 90 percent of the observed NO_x emitted from pulvertzed coal is derived from organically bound nitrogen.[47] The NO_x levels observed in this program may have resulted from a 15-25 percent conversion to NO_x of the organically-bound nitrogen in the fuel. The lignites tested contained 0.9 - 1.0 percent chemically bound nitrogen, on a dry fuel basis.

VI. SUMMARY OF ECONOMIC INFORMATION

A. PURPOSE AND APPROACH

The purpose of this chapter is to develop an economic impact analysis for application of the control systems identified in Chapter IV. The approach to the economic impact analysis was as follows:

1. Derive baseline capital investment and annual production costs for three selected model lignite-fired steam-electric generating plants (Section B);
2. Derive capital investment and annual cost of control for each of several alternative NO_x abatement schemes (Section C);
3. Compare the cost of control for the alternative NO_x limitations, and develop a cost-effectiveness curve (Section D);
4. Evaluate the direct impacts of the various NO_x limitations upon the cost of power, the lignite-fired utility industry and the major boiler manufacturers. Also evaluate the possible indirect effects on related industries such as the lignite mining industry and the conventional bituminous-fired utility industry (Section E).

B. BASELINE INVESTMENT AND ANNUAL PRODUCTION COSTS

The reduction of NO_x emissions from lignite-fired steam-electric generators is accompanied by an incremental cost differential which is expressed both as an increase in capital investment (or installation) costs and annual production costs. The logical first step in investigating such additional costs is to develop a baseline cost to which these incremental costs may be added. The model plant sizes* thought to be most indicative of future lignite-fired units, and selected for analysis here, were as follows:

250 megawatts

450 megawatts

750 megawatts

Based on discussions with various utilities and the selective use of plant financial data as reported by the Federal Power Commission,+ it was determined that actual baseline investment and operating costs for field-erected central station steam boiler units are largely a function of the plant size and fuel characteristics, and are independent of burner configuration. Thus, the investment and operating costs estimated for this study were assumed applicable to all three major burner configurations--cyclone fired, horizontally opposed, and tangentially fired.

Of the 24 utility-owned units identified within the U. S. (see Table II-2), detailed cost information was collected on 21 units and is summarized in Appendix C. From this list, which represents 98% of the installed generating capacity and 97% of the annual production accounted for in Table II-2, we derived the following:

- Unit investment cost ($/kW) as a function of total plant size, and

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* Actually, the weighted average unit size for planned lignite-fired plants is about 600 MW.

+ Federal Power Commission; <u>Statistics of Publicly-Owned Electric Utilities in the United States</u>, 1972; <u>Statistics of Privately-Owned Electric Utilities in the United States</u>, 1972.

- Unit production costs (mills/kWh) as a function of annual net generation.

In general, it appears that no significant differences in unit costs exist between large (> 200 MW) lignite-fired and coal-fired plants. It was felt justified to estimate capital investment and annual production costs for lignite-fired units based upon those costs typically used for coal-burning units. The expected installed cost of a new uncontrolled * coal-fired central station steam-electric power plant in the U.S., is on the order of \$350-400/kW + in constant 1975 dollars.++

Based on several recent studies[37, 38, 39] concerned with estimates of the cost of new coal-burning plants for base-load utility service, we have estimated the following total capital costs ** for new uncontrolled lignite-fired electric generating plants:

Model Plant Size (MW)	Installed Capital Cost (\$/kW)
250	420
450	395
750	365

* An uncontrolled plant is defined to be one without either particulate, SO_2, or NO_x air pollution control equipment.

+ Includes \$15/kW for thermal pollution control cost.

++ Design engineering estimates of the cost breakdown of complete new lignite-fired generating plants (each of which typically represents a quarter of a billion dollars) are beyond the scope of this study.

** Figures are in 1975 dollars and include interest during construction.

Using these capital costs, annual production costs were estimated for the 250, 450, and 750 megawatt model plant sizes. These costs are summarized in Table VI-1, and were derived under the following assumptions:

- Capital charges reflect a level fixed-charge rate to cover interest, return on equity, depreciation, taxes, and property insurance.
- The annual fixed-charge rate was assumed to be 15% as representative of the investor-owned facilities, and 10% as representative of the rural electric cooperatives. Regarding investor-owned utilities, an assumption of 15% is consistent with traditional Federal Power Commission and Atomic Energy Commission cost estimation guidelines, conventional utility financing, accounting, and taxation based upon 60-65% debt funding, approximately 8-1/2% long-term bond interest rate, and a 30-year depreciation. The 10% used for rural electric cooperatives reflects their reliance on lower cost REA financing (5%/year), and different tax status.
- A load factor of 80% was assumed, resulting in 7,000 annual operating hours. (Some of the older lignite plants have historically shown lower load factors.) This estimate is supported by the intended use of large lignite-fired plants as base-load plants, many of which are cooperative projects which will be producing large demand wholesale electricity.

TABLE VI-1

BASELINE CAPITAL INVESTMENT AND ANNUAL PRODUCTION COSTS,[a] LIGNITE-FIRED GENERATING UNITS, 1975

Model Plant Size	Capital Investment Without Air Pollution Control ($/kW)[b]	Annual Production Costs (Mills/kWh For Investor-Owned Utilities				Annual Production Costs (Mills/kWh For REA Utilities			
		Capital Charges[c]	Fuel[d]	O&M	Total	Capital Charges[c]	Fuel[d]	O&M	Total
250 MW	420	9.0	1.8	1.5	12.3	6.0	1.8	1.5	9.3
450 MW	395	8.5	1.8	1.5	11.8	5.6	1.8	1.5	8.9
750 MW	365	7.8	1.8	1.5	11.1	5.2	1.8	1.5	8.5

(a) Assumed approximately similar to costs associated with bituminous-fired steam-electric plants.
(b) Includes thermal pollution abatement cost of $15/kW.
(c) Assumes fixed charge rates of 15% for investor-owned utilities, and 10% for REA utilities; 7,000 operating hours per year.
(d) Assumes lignite cost of $2.40/ton; heating value 7,000 Btu/lb; heat rate ≈ 10,000 Btu/kWh.

SOURCE: Arthur D. Little, Inc., estimates.

- Lignite costs are based on 1975 prices, and were assumed to be \$2.40 per ton delivered. This is consistent with unit price estimates made elsewhere in this Chapter.
- The plant heat rate was assumed to be 10,000 Btu/kWh and the heating value of lignite to be 7,000 Btu/lb.
- Plant operating and maintenance (O&M) costs were assumed to average 1.5 mills/kWh for all plant sizes based on averaged data from the Federal Power Commission (reproduced in Appendix C).

C. ESTIMATED COST OF NO_x EMISSION CONTROL

The NO_x control technologies summarized in Chapter IV are based on combustion modifications to the furnace and/or auxiliary equipment, which in turn implies a differential cost of manufacturing. In view of this, our basis for costing NO_x control schemes is based upon direct communications with the two major boiler manufacturers. Based on discussions with these manufacturers, the following observations are made:

- Significant reduction in NO_x emissions can be achieved most readily using low excess air in the fuel admitting zone and/or "overfire air," otherwise known as "staged combustion." This is consistent with the findings of Chapter IV
- The incremental cost of adding overfire air ports to any boiler configuration is relatively minimal, and in the case of both manufacturers, will require no major modifications of the windbox.

- Other alternative combustion control schemes such as low emission burners are being tested, although insufficient data exist which would confirm that such schemes could greatly reduce NO_x emissions below those levels achievable through the use of staged combustion and low excess air.
- While manufacturers have widely differing opinions as to the effectiveness of schemes other than staged combustion, they agree that the approximate range of NO_x emission levels achievable using staged combustion would be consistently equal to, or somewhat better than, the present 0.7 $lb/10^6$ Btu standard for coal-fired boilers.

Based on input from manufacturers, Table VI-2 summarizes the cost impacts attributable to the most promising alternative control schemes: staged combustion, low excess air, combined staging and low excess air, and low emission burners. These costs are not applicable to cyclones.

The incremental investment shown is expressed as a percentage of "boiler island" cost, not as a percentage of total cost. The "boiler island" consists of equipment relating to fuel preparation and handling, steam generation, fans, soot blowers, and auxiliary boiler attendants, among others. Based on discussions with manufacturers, we assumed the boiler island costs to be 12% to 15% of the total plant costs excluding air pollution control equipment, or \$55, \$50, and \$45 per kW for the 250, 450, and 750 megawatt model plants, respectively.

In regard to low emission burners, it should be noted that one manufacturer was constrained in the level of NO_x emissions which could be achieved as recently as 1970. Based on verbal discussions with this

Table VI-2

ALTERNATIVE CONTROL COSTS FOR NOx EMISSIONS
FROM LIGNITE-FIRED STEAM-ELECTRIC GENERATORS

Control Method	Impacts	Estimated Incremental Cost (%) Installation Cost (a)	Prod. Cost (b)
Dual Register Burners	• Negligible, if any, loss in efficiency. • No additional operating costs.	0-3	0
Staged Combustion	• Negligible, if any, loss in efficiency. • No additional operating costs.	0-3	0
Low Excess Air	• Negligible, if any, loss in efficiency.	0	0
Combined Staging and Low Excess Air	• Minimal loss in efficiency.	0-3	0

(a) Percentage of boiler island cost, assumed to range between $45-55 per kW. Assumes boiler rating remains constant.

(b) Percentage of conventional production costs (excluding capital charges) assumed to be 3.3 mills/kWh (Table VI-1).

SOURCE: Arthur D. Little, Inc., estimates, based on discussions with boiler manufacturers.

manufacturer, it was reported that major design changes dealing with the installation of compartmented windboxes and dual register burners resulted in a reduction in NO_x emissions level from 0.9 to 0.6 lbs/10^6 Btu. * The incremental investment associated with these changes has been estimated to cost $1.50 per kW.

Given the data in Table VI-2, investment and annual control costs by model plant size can be estimated, and are shown in Table VI-3. Again, the upper range of the estimates are believed to be conservative so as to allow for potential error and to permit an analysis of maximum economic impact.

Finally, Table VI-4 summarizes the control costs assumed for several alternative levels of NO_x emissions attainable with the most promising control systems based upon the costs shown in Table VI-3 for each model plant size. The mean cost estimates of Table VI-3 were used and rounded upward to the nearest dollar or nearest hundredth of a mill.

D. COST EFFECTIVENESS OF NO_x CONTROL

Figure VI-1 graphically relates the level of obtainable NO_x emissions as a function of the incremental capital investment and annual cost for a 600 MW plant, or that size which best represents the size of new lignite-fired units. These costs are applicable only for pulverized-fired units and exclude cyclones.

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* This manufacturer plans to furnish the dual register burner on new units, and would offer staged combustion very seldomly and only for well defined fuels.

TABLE VI-3

COST OF NO_x CONTROL FOR LIGNITE-FIRED STEAM-ELECTRIC GENERATORS (EXCLUDING CYCLONES)

Control Scheme	Model Unit Size (MW)	Cost of Boiler Island ($/kW)	Lb $NO_x/10^6$ Btu NO_x Level(c)	Investment Cost ($kW) Range	Investment Cost ($kW) Mean	Annual Cost(a) (mills/kWh) Range	Annual Cost(a) (mills/kWh) Mean
Dual Register Burners(b)	250	55	0.5 - 0.6	1.5	1.5	0.03	0.03
	450	50		1.5	1.5	0.03	0.03
	750	45		1.5	1.5	0.03	0.03
Staged Combustion	250	55	0.5 - 0.6	0-1.5	0.75	0-.03	0.015
	450	50		0-1.5	0.75	0-.03	0.015
	750	45		0-1.5	0.75	0-.03	0.015
Low Excess Air	250	55	0.6 - 0.7	0	0	0	0
	450	50		0	0	0	0
	750	45		0	0	0	0
Combined Staging and Low Excess Air	250	55	0.5 - 0.6	0-1.5	0.75	0-.03	0.015
	450	50		0-1.5	0.75	0-.03	0.015
	750	45		0-1.5	0.75	0-.03	0.015

(a) Production cost plus capital charges @ 15%/year.

(b) Tests currently underway

(c) Calculated as NO_2

SOURCE: Arthur D. Little, Inc., estimates, based upon discussions with boiler manufacturers.

TABLE VI-4

CONTROL COSTS FOR ALTERNATIVE NO_x EMISSIONS LEVELS (EXCLUDING CYCLONE BURNERS)

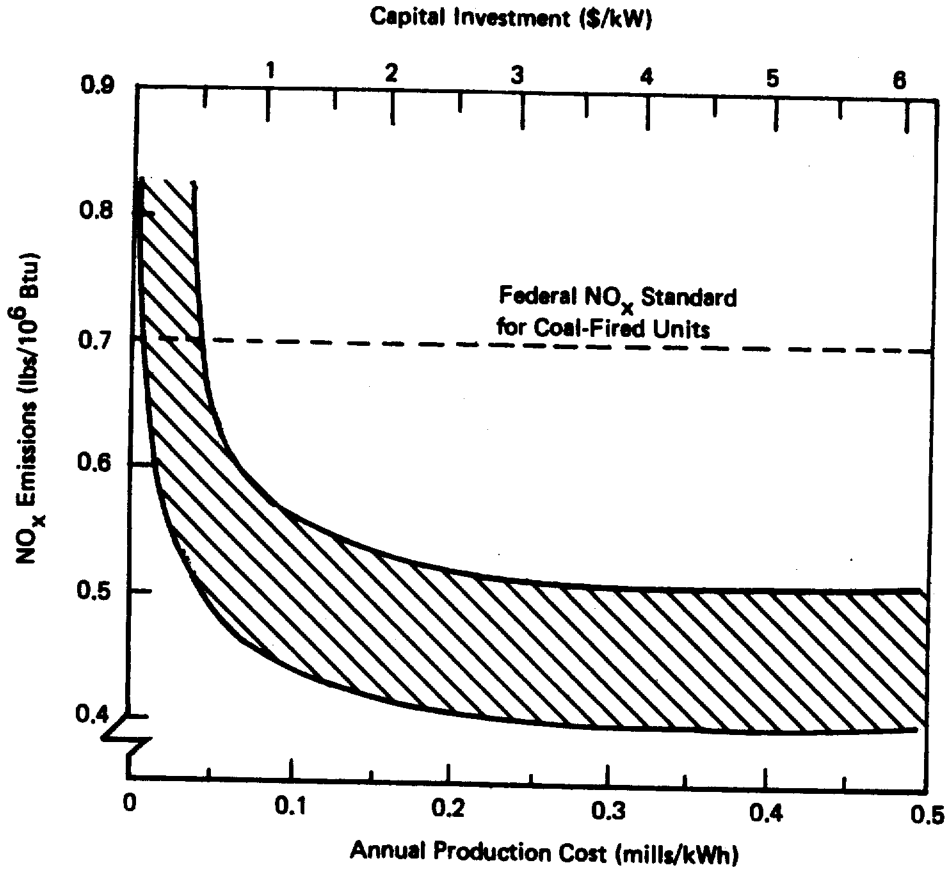
Emission Level (c)	Control Technology Assumed	MODEL PLANT SIZE 250 MW	450 MW	750 MW
		Investment Cost ($/kW)		
0.8 (lbs./10^6 Btu)	Uncontrolled or partial low excess air	420	395	365
0.7	Combined staging and low excess air or dual register burners	421-422	396-397	366-367
0.6	Combined staging and low excess air or dual register burners	421-422	396-397	366-367
0.5	Combined staging and low excess air and dual register burners (a)	421-422	396-397	366-367
Emission Level		**Annual Cost (Mills/kWh)(b)**		
0.8 (lbs./10^6 Btu)	(same as above)	9.30	8.90	8.50
0.7		9.32-9.33	8.92-8.93	8.52-8.53
0.6		9.32-9.33	8.92-8.93	8.52-8.53
0.5		9.32-9.33	8.92-8.93	8.52-8.53

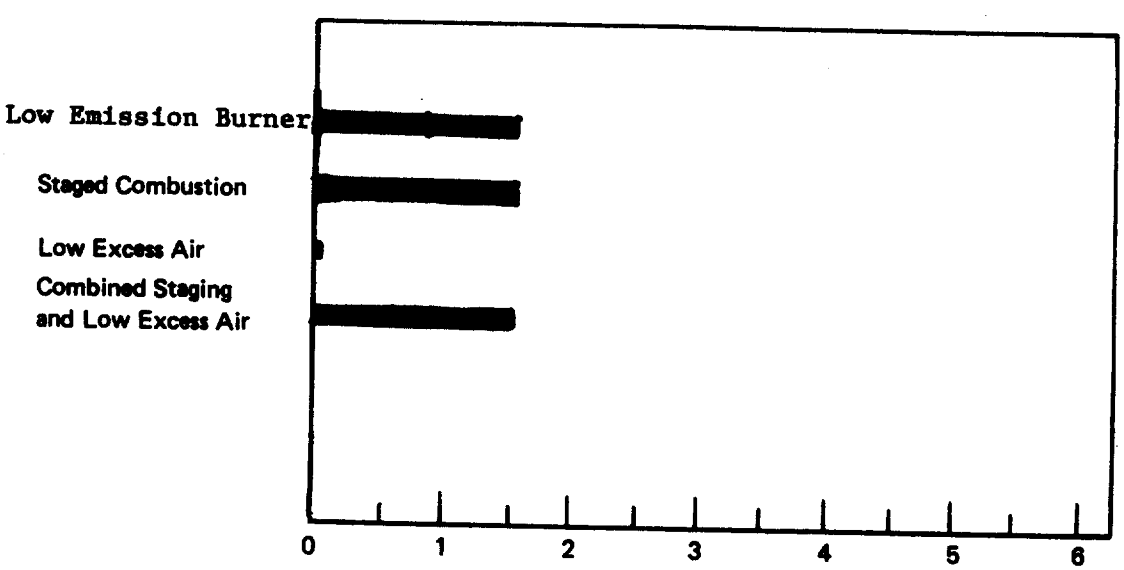
(a) Technology not yet well demonstrated.

(b) Calculated based on REA financing of investment.

(c) Calculated as NO_2.

SOURCE: Arthur D. Little, Inc., estimates.





Capital Investment, ($/kW)

Comparative Investment for NO$_x$ Control Alternatives

*Applicable to pulverized units only, excludes cyclone-type burners.

Source: Arthur D. Little, Inc., estimates.

Figure VI-1. COST EFFECTIVENESS OF NO$_x$ EMISSIONS CONTROL OF 600 MW LIGNITE-FIRED STEAM-ELECTRIC GENERATOR*

The relatively broad band of costs reflects the range of emissions performance associated with distinct boiler/burner designs. Although the exact limit is debatable, manufacturers are in agreement that to guarantee NO_x emissions levels somewhere below about 0.4 lbs/10^6 Btu would be technically infeasible regardless of cost.

Those tangentially-fired and horizontally-opposed units presently sold can generally meet the NO_x standard of performance for coal-fired units (0.7 lbs/10^6 Btu) with only minor investment. Tangential units will be able to achieve a level of 0.6 lbs/10^6 Btu without additional costs. Horizontally-opposed units will also be able to meet a level of 0.6 lbs/10^6 Btu. The applicability of control technique for horizontally-opposed units at 0.5 lbs./10^6 Btu has not yet been well demonstrated.

E. ECONOMIC IMPACT ANALYSIS

The lignite-fired steam-electric generating "industry," as it applies to this analysis, is unique in two respects. First, it is more appropriately considered a sub-industry of the steam-electric utility industry, and second, the behavior and general economic health of the utility industry is strongly determined by regulatory authority pressures rather than by the more conventional market-oriented pressures of other nonregulated industries. These differences suggest that the economic impacts brought about by the setting of NO_x emission limits be presented in a slightly different fashion than in previous industry impact studies. In general, there are three distinct areas which will be directly affected by the incremental cost increases associated with NO_x control of lignite-fired steam-electric power plants:

- The cost of electrical power production,
- The lignite-fired utility industry, and
- The boiler manufacturers.

Each will be discussed separately, in addition to a brief discussion of secondary impacts on related industries.

1. Effect Upon Cost of Power Production

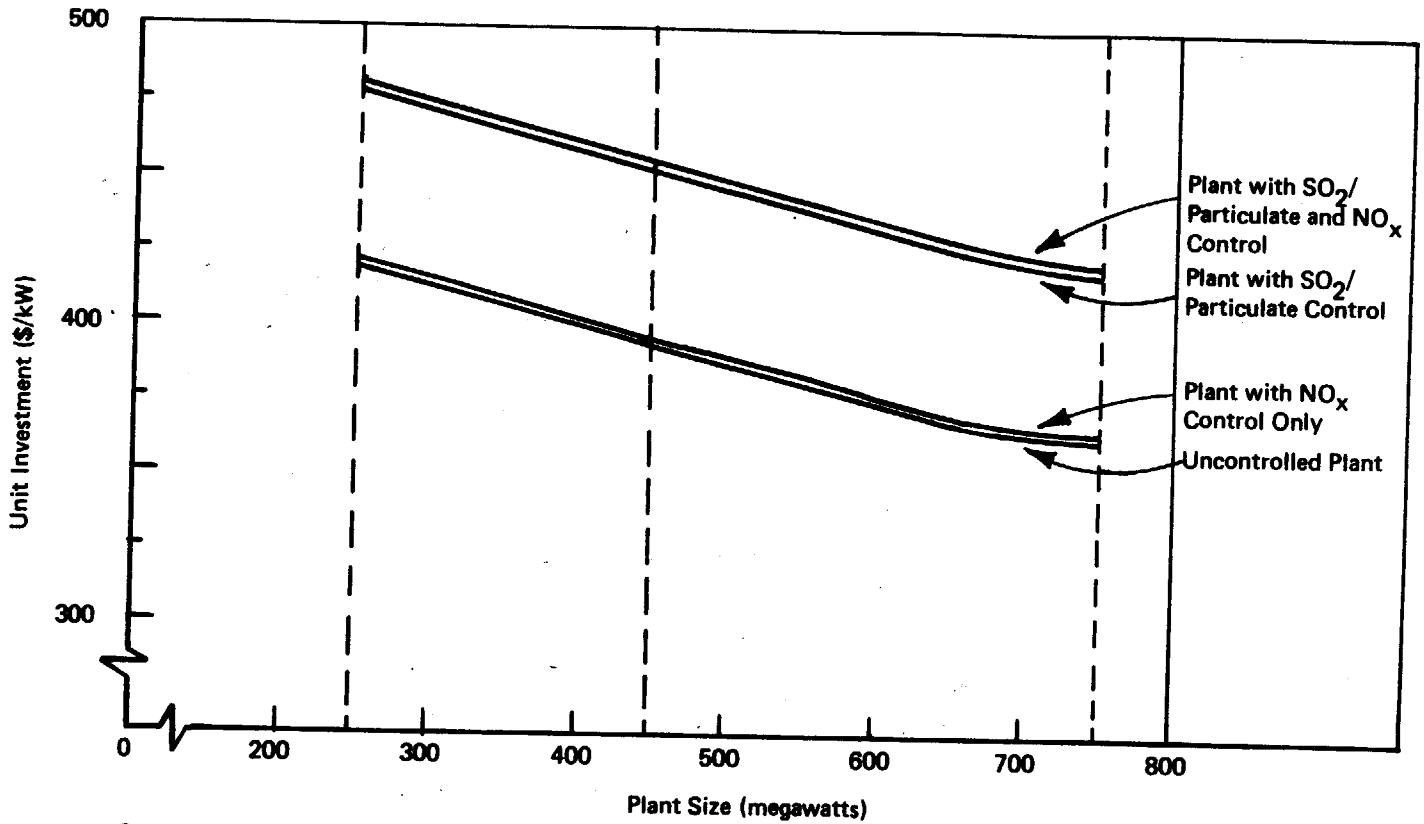
It appears that the impact of NO_x control on the cost of new generating capacity within any particular utility is relatively negligible even under the most stringent NO_x standard under consideration.

Figures VI-2 and VI-3 summarize the comparative capital investment and annual costs of NO_x control on investor-owned or rural electric cooperative utilities with and without SO_2 control. Based on these estimates, the following may be concluded as the effect of NO_x control on the cost of power:

- Incremental capital investment costs for NO_x control range as follows, depending on plant size:

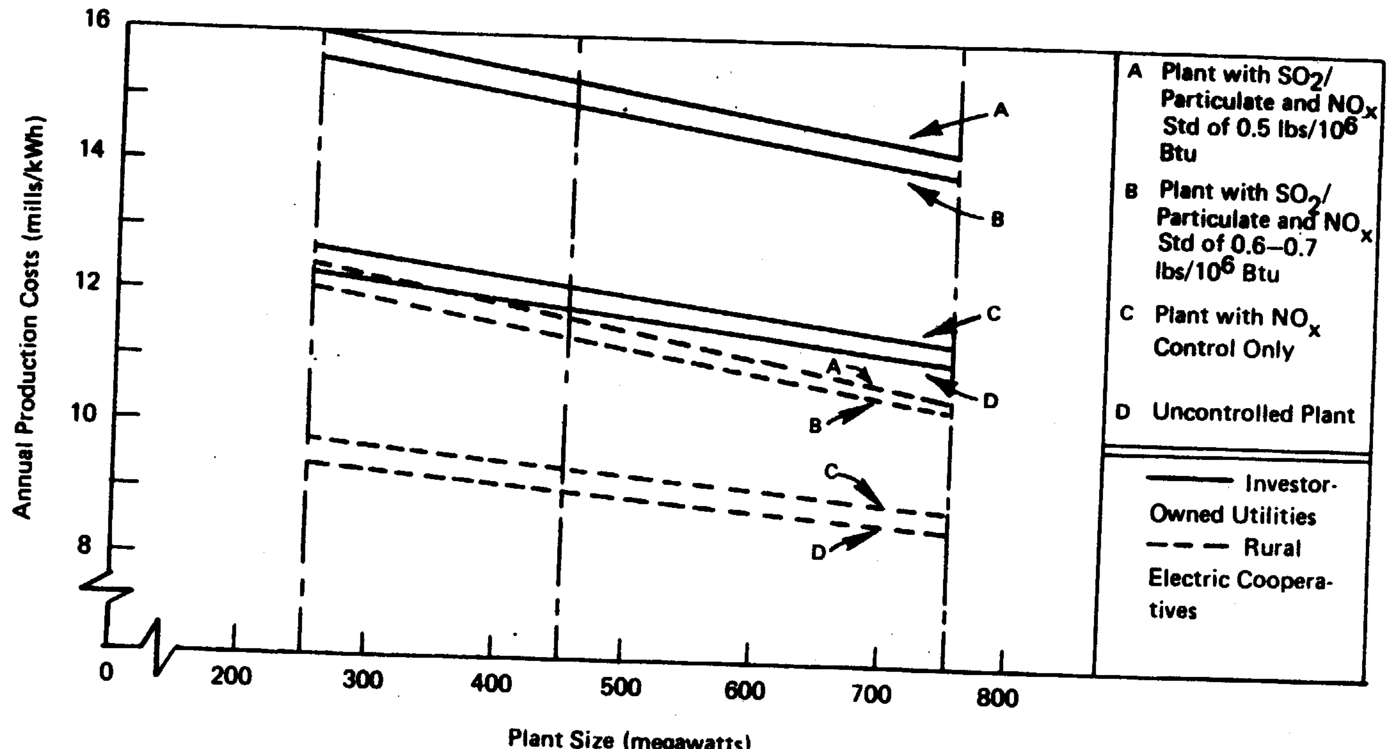
Emission Factor Lbs. $NO_x/10^6$ Btu	$/kW	Percent Increase in Power Plant Investment Cost
0.8	0	0
0.7	1-2	0.3 - 0.5
0.6	1-2	0.3 - 0.5
0.5	1-2	0.3 - 0.5

From this, it appears that the difference between a control level of 0.8 lbs. $NO_x/10^6$ Btu and 0.5 lbs. $NO_x/10^6$ Btu poses no significant economic barrier, and that the effect on capital investment of the most stringent alternative levels would result in only a 0.5% increase in capital investment requirements.



Source: Arthur D. Little, Inc., estimates.

Figure VI-2 **COMPARATIVE CAPITAL INVESTMENT COSTS, NEW LIGNITE-FIRED STEAM GENERATORS (1975 Dollars)**



Source: Arthur D. Little, Inc., estimates.

Figure VI-3 **COMPARATIVE ANNUAL PRODUCTION COSTS, NEW LIGNITE-FIRED STEAM GENERATORS (1975 Dollars)**

- Concerning annualized production costs including fixed capital charges, the incremental cost impact of the most stringent NO_x limit is small as indicated in Table VI-4.

Reflecting upon the way in which costs are passed on to consumers, the cost of power is generally a weighted average of the cost of production for the utility as a whole. Thus, if it is assumed that existing capacity retains its present level of control, incremental increases in power costs for the utility's customers would be less than cited above.

2. Effect Upon Lignite-Fired Utility Industry

Implications based on the previous sections are that the incremental cost of NO_x control on capital requirements and annual production costs are relatively minimal, and could readily be handled by the affected utilities.

3. Effect Upon Boiler Manufacturers

The market for large steam-electric furnaces within the U. S. is dominated by four suppliers, two of which have an estimated 70% of the market between them:

Company AA	35%
Company BB	35%
Company CC	20%
Company DD	10%

Of these, Companies AA and BB have supplied furnaces for all lignite-fired installations greater than 200 MW, and will be responsible for virtually all announced capacity increases within the industry through 1980.* In both cases, lignite units have accounted for a minor percentage of their annual revenues.

* It is extremely doubtful that foreign manufacturers will enter the U. S. market for lignite furnaces.

We believe the market for lignite units will continue to be dominated by AA and BB following 1980, providing the NO_x emission limit which is adopted does not result in a restraint of trade situation by effectively constraining one (or both) of the companies for technical reasons.

Both companies have a positive attitude towards being able to meet a limit of 0.7 or 0.8 lbs $NO_x/10^6$ Btu heat input based upon the adoption of staged combustion (overfire air) or dual register burners to furnace configurations other than the cyclone. Likewise, both companies are willing to guarantee to their customers the ability of their furnaces to meet such a limit. Thus, there are no foreseeable marketing disadvantages which might affect the balance between Company AA and BB and thus act as a restraint of competition.

The adoption of an NO_x emission limit of 0.6 lbs $NO_x/10^6$ Btu, could have a slight effect on the competitive position of Company BB relative to Company AA. In this instance, cyclone-type burners probably would not be guaranteed * by BB, and would result in its removal from the list of alternative burner systems available to utility pruchasers. However, this would not necessarily impair Company BB's position, since cyclone units represent a small proportion of coal-fired utility boiler sales due to their lack of fuel versatility or cost advantage.

Finally, the adoption of a limit of 0.5 lbs $NO_x/10^6$ Btu would probably result in the destruction of a competitive balance between the two major manufacturers, even after assuming Company BB has foregone

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* A boiler supplier generally guarantees a certain emission level when experience has shown its equipment is capable of bettering the allowable standard by at least 0.1 lbs $NO_x/10^6$ Btu.

the cyclone burner. At this level of emissions, the burner configuration (horizontally-opposed) by which Company BB will base its future lignite fired business may not consistently achieve 0.5 $lb/10^6$ Btu. Consequently Company BB may not offer performance guarantees to purchasing utilities; leaving only one major established supplier. We do not believe it is in the best interests of purchasing utilities to remove their option to obtain competitive bids for industry expansion. Further, at an emission limit of 0.5 lb $NO_x/10^6$ Btu, Company AA may not offer compliance guarantees either.

4. Indirect Effects

In addition to the above three sectors, there is a possibility of some indirect effects due to NO_x emissions abatement on lignite-fired plants. In general, most such secondary effects will be comparatively minor; however, those dealing with the following should be noted anyway:

- Lignite's position as an energy resource,
- Lignite mining industry, and
- Cost of lignite.

The effect on lignite in relation to bituminous-coal due to the inclusion of NO_x emission abatement on new sources appears to be negligible. Moreover, the relative cost of NO_x versus SO_2/particulate control dictates that no substantial economics of production can be obtained by those facilities without NO_x control assuming all facilities are equipped to handle SO_2 and particulate emissions. It appears logical that any change in the percentage of installed capacities firing lignite instead of other fossil fuels will occur for reasons other than NO_x control.

Regarding lignite mining, the unit consumption of lignite per kWh is not expected to be affected by NO_x emission limitations.

Finally, concerning the cost of lignite, we note that the relative isolation of large lignite reserves plus the fact that most utilities operate captive mines or have established long-term contracts will probably constrain the f.o.b. mine price. Of those utilities of concern to us, all have long-term purchasing agreements or own and operate captive mines. Their activity in 1974 was as follows:

Utility	Fuel Supply
A	Buys lignite under contract at \$2.32 to \$2.73/ton f.o.b. mines.
B	Owns and operates lignite mines, and is developing a new coal mine at an estimated cost of \$8.5 million. Their full costs were about \$3.30/ton delivered.
C	Owns and operates lignite mines through a subsidiary company; 1973 price at about \$3.00/ton.
D	Buys lignite at \$2.15 to \$3.00/ton.
E	Recently participated in expansion of leased lignite reserves at plant's mine-mouth (\$1.52/ton in 1973).
F	Buys lignite at \$2.24/ton.

We are of the opinion that lignite prices peaked in 1974, and that prices may be leveling off, with a slight downward trend expected.

Lignite prices paid in 1974 were, according to the Office of Coal Research, about $1.50 to $1.75 more per ton than 1973 prices.

We do not believe that NO_x control costs will directly affect lignite prices, nor is the attractiveness of lignite so great versus bituminous fuels that its price can be expected to increase substantially.

VII. RATIONALE FOR THE PROPOSED STANDARD OF PERFORMANCE

Based on the technical information presented in Chapters IV and V, it can be concluded that low excess air, staged combustion, low emission burners and combined staged firing and low excess air are the best systems of emission reduction. In addition, the method of firing and boiler design parameters can affect the quantity of nitrogen oxides emitted and the degree to which control techniques are effective. Consequently, in order to consider these factors, alternative emission standards ranging from 0.5 to 0.8 pounds NO_x per million Btu heat input were considered for proposal. The low end of the range represents a level of control which would push the limits of existing control technology, while the upper end of the range represents a level of control which all furnace types can meet with little or no control.

On the basis of the test data, it appears that the cyclone furnace cannot meet a nitrogen oxides standard more stringent than 0.8 lb per million Btu. The test data also indicate that horizontally opposed-fired units would have difficulty consistently achieving a nitrogen oxides standard of 0.6 lb per million Btu over a long time period. However, development of low emission burners for pulverized-fired units appears promising for application to horizontally opposed-fired units, and with application these units should be able to attain a standard of 0.6 lb per million Btu. Tangentially-fired units should have no difficulty meeting a standard of 0.6 lb per million Btu and may be able to consistently achieve a level of 0.5 lb per million Btu.

In selecting the level of the proposed standard, EPA considered whether the cyclone furnace was necessary for burning lignite. As mentioned in Chapters II and IV, the high temperature necessary to maintain the ash in a slagging state in a cyclone burner promotes NO_x fixations. The methods of NO_x control, low excess air and staged combustion, have limited applicability to cyclone-fired units because of operating problems of flame instability. Thus in development of a proposed NO_x standard for lignite-fired steam generators, consideration had to be given to the necessity of setting a standard achievable by cyclone units (i.e. a standard not less than 0.8 lb/10^6 Btu).

EPA discussed the need for cyclone furnaces to fire high-sodium lignite with the lignite electric utilities and with manufacturers of utility steam boilers. Some of the lignite electric utilities maintained that cyclone furnaces are better able to handle the slagging problem of high-sodium lignite than are pulverized-fired units. These utilities believe that the cyclone burner retains a large proportion of the ash in the burner, thus reducing fouling of the boiler tubes. However, due to the higher temperatures more volatilization of the sodium in the ash will occur in a cyclone burner than in a pulverized coal-fired boiler. Depending on the gas temperature profile in the furnace, these sodium compounds can condense on the boiler tubes or the air heater and cause fouling.

The relative advantages and disadvantages of the two firing systems cannot be thoroughly evaluated due to the limited amount of information available. Presently, the experience of the utility industry in firing high-sodium lignite is very limited for either pulverized or cyclone-fired units. The Minnkota Power Cooperative's Young-Center station, which started up in 1970, was the first large cyclone-fired steam generator unit designed to fire North Dakota lignite. The cyclone-fired 235 MW B & W boiler was selected on the basis of a cooperative study to develop a better method for firing high-sodium lignite. The Young-Center station has a good record of operating availability. However, as of 1976 the unit has not used the high-sodium lignite for which it was designed.(55) In addition, the operating reliability may be attributed to other boiler design features such as increased number of soot blowers, increased furnace surface area, and increased spacing between boiler tubes. These design features help minimize the ash fouling problems associated with firing high-sodium lignite. Since startup of the Young-Center station, three additional cyclone-fired units have been purchased by power cooperatives and companies in the area. Two of these three units were started up in 1975 and have been operating for less than one year. One of the units has been firing lignite with sodium content of about four percent; while the other unit has fired lignites of about six percent sodium for short periods. Since numerous operating problems typically occur in the first year of operation of a boiler, the performance of these units on high-sodium lignite cannot be accurately evaluated at this time.

Of the units presently planned or under construction, not all of the boilers designed to use North Dakota lignite will be cyclone-fired units (see Table II-5). In 1972, the United Power Association (UPA) solicited bids for two 500 MW boilers to burn lignite with a maximum sodium content of five percent. Bids were received for both cyclone and pulverized-fired units. UPA purchased two CE tangentially pulverized-fired units guaranteed to reliably fire lignite with a maximum sodium content of 4.8 percent. This selection of a pulverized-fired unit to burn North Dakota lignite with high fouling potential indicates that pulverized-fired units are economically competitive with cyclone units and that at least one utility believes that cyclone burners are not required for use of high-sodium lignite. Startup of these two units at Underwood, North Dakota, is scheduled for 1978 and 1979 and thus evaluation of the operating reliability of a modern designed pulverized-fired unit will not be possible until 1979. Presently, experience with pulverized firing of lignite is limited to two units: a frontwall-fired 192 MW unit and a horizontally-opposed fired 215 MW unit at Stanton, North Dakota. The horizontally-opposed fired 215 MW boiler at Leland-Olds station of Basin Electric Power is a good example of early experience with pulverized firing of lignite. When this unit was designed in the early 1960's, there was little experience with lignite firing and effects of various amounts of sodium in the fuel on boiler operation. The horizontally-opposed fired unit at Leland-Olds is susceptible to extensive slagging and ash fouling problems when firing high-sodium lignite. Short term derating of the unit has been prevented by selective mining of the lignite to maintain the sodium content below five percent. For the 192 MW frontwall-fired unit at Stanton, North Dakota, the ash fouling problem has been managed by increasing the spacing between the tubes and installation of additional soot blowers as well as by derating of the unit. For the past year, this boiler has been firing 8 percent sodium lignite at about 86 percent boiler capacity and has not been shutdown to deslag the unit. Based on this experience, new lignite pulverized-fired units would be designed with greater surface area, increased superheater tube spacing, and increased number of sootblowers, than is conventional for bituminous-fired units. Thus, B & W believes that a properly designed pulverized-fired unit should be able to burn high-sodium lignite without derating due to slagging problems. In addition, EPA discussed this issue with boiler manufacturers and determined that manufacturers of pulverized-fired units (including B & W, the manufacturer of cyclone burner units) believe that the pulverized-fuel design can be as effective as cyclones for burning lignites, including the high-sodium ones. Combustion Engineering, which is installing the units for UPA, is confident that pulverized-fired units can be properly designed to handle the slagging and ash fouling problems of high-sodium lignite.

In addition to the experience of boilers operating on high-sodium lignite, ERDA has conducted a short term study on the relative ash fouling rates on pulverized fuel and cyclone-fired boilers. The test was conducted while the two units were firing lignite with 3.5 to 4.5 percent sodium in the ash. The preliminary results of the study show that coupons located in the pulverized-fired boiler had deposition rates approximately twice those of the coupons in the cyclone-fired boiler. Because the study was conducted over a two-day period and the fuel supply was relatively inflexible, study of the relative deposition rates at higher sodium contents could not be investigated. Possible interpretations of these results are (1) that cyclone-fired units can operate more reliably and possibly at a lower cost on high sodium lignite than pulverized-fired units or (2) that cyclone-fired units do not require as conservatively designed convection section as do pulverized-fired units. Until verified by further testing possible differences in design and operation of pulverized or cyclone-fired units for high-sodium lignite are speculation only. At this time, design of pulverized-fired units for high-sodium lignite is proven and a retrofitted unit has been operating reliably on eight percent sodium lignite for the past year. Therefore, the standard was not established at a level which would allow use of cyclone-fired boilers. EPA recognizes that this decision is based on limited information on the slagging and ash fouling problems of firing of high-sodium lignite and is requesting all interested persons to submit factual information on this issue during the public comment period of the proposed standard.

EPA also considered proposing the same standard for lignite-fired steam generators as the present standard for coal-fired steam generators, 300 nanograms per joule heat input (0.70 lb per million Btu heat input). Application of staged combustion and low excess air firing techniques to lignite boilers was observed in this study to result in emission levels sufficiently lower than 300 nanograms per joule (0.7 lb/10^6 Btu). The measured levels of 0.4 to 0.5 lb/10^6 Btu indicated that a 300 nanograms per joule standard would not require best demonstrated control technology considering costs. Also, recent studies on combustion modifications to utility boilers have reported control of nitrogen oxides emissions from coal-fired units to levels of approximately 0.4 to 0.5 lb per 10^6 Btu.[8,9] The standard of 300 nanograms per joule heat input (0.7 lb per million Btu heat input) for coal-fired units was based on limited data on combustion modification techniques in 1970-1971. Since 1971, research into this area has been conducted and considerable improvements have been made in boiler design, the flexibility for staged firing, and low excess air operation. Consequently, EPA recognizes that assessment of recent information and data for nitrogen oxides control techniques on coal-fired units could indicate a need for revision of the standard for coal-fired units.

Since tangentially-fired boilers have been demonstrated to achieve emission levels of less than 0.5 lb/10^6 Btu, alternative standards of less than 0.6 lb/10^6 Btu were considered. On the basis of available data it appears that the other pulverized-fired boiler designs, horizontally opposed or frontwall, probably cannot consistently achieve an emission level of less than 0.6 lb NO_x per million Btu input. Thus, a standard of less than 0.6 lb NO_x per million Btu could destroy the competitive balance between the two major boiler manufacturers. Consequently, only one major established supplier would be available. EPA has concluded that it is not in the best interest of purchasing utilities to remove their option to obtain a competitive bid for expansions.

On the basis of the test data and the above considerations, EPA is proposing a standard of 260 nanograms per joule (0.6 lb per million Btu) for lignite-fired steam generators. The proposed standard, while numerically more stringent than the present coal-fired standard, will require the same types of combustion modifications (i.e. low excess air and staged combustion) as the coal-fired performance standard.

TABLE VII-1

COMPARISON OF ALTERNATE EMISSION LEVELS FOR LIGNITE-FIRED STEAM GENERATORS

		Alternative NO_x Emission Levels ($lb\ NO_x/10^6$ Btu input)			
		0.5	0.6	0.7	0.8
Description		Target Level (Not Consistently Achievable)	Best Available Technology	Current SPNSS for Solid Fuel Fired Steam Generators	Above Current SPNSS
Control Technology Required		Tangential Firing with Staged Combustion or Horizontally Opposed Firing with Low-Emission Burner	Tangential Firing with Staged Combustion or Horizontally Opposed Firing with Low-Emission Burner	Low Excess Air (LEA) or Staged Combustion (SC)	None
COST 450 MW Plant	Investment ($/KW)	0-2.0	2.0	2.0	0
	% increase in investment	0-0.5	0-0.5	0-0.5	0
	Annualized (mills/kwh)	3	3	3	0
	% increase in annualized	0-0.3	0.3	0.3	0
Emissions Reduction Over Uncontrolled Lignite-Fired Boiler Population		35%	29%	27%	25%
Competitive Effects		Might eliminate compliance guarantees (indirect prohibition of lignite-fired steam generators)	C.E. can guarantee; B&W will probably guarantee	B&W can guarantee but may not be able to offer cyclone-firing	Status quo
Effect on Lignite Utilization		Might Jeopardize	Negligible	Negligible	Might Enhance

Using these best adequately demonstrated systems of control, all the major boiler manufacturers should be able to design equipment to achieve an emission level below 0.6 lb per million Btu. The alternative standards considered are summarized in Table VII-1.

Since there is essentially no difference in investment or annualized costs to achieve an emission level of 0.5 to 0.8 lbs per million Btu (see Chapter VI-Table VI-4), cost was not a determining factor in selecting the proposed standard. The cost to the utilities as a result of compliance with the proposed standard has been analyzed and appears to be negligible in comparison to capital costs. Conservative estimates show that nitrogen oxides control costs will increase capital investment cost 0.5 percent for a new lignite-fired utility boiler and ancillary equipment. The incremental costs for NO_x control, thus, represent approximately $2 per kW installed capacity relative to the estimated capital investment costs of approximately $400 per kW installed capacity for a new boiler and associated equipment. Since power costs are a weighted average of production costs for the entire utility, the costs for NO_x control will result in only a negligible increase in costs to the consumer.

In the discussions with the lignite steam generating industry, the comment was made that the economic analysis should consider the costs associated with derating of the boiler when firing high-sodium lignite. EPA discussed this issue with the four major boiler manufacturers and found that derating does not result from NO_x control techniques. Derating of a boiler occurs due to inadequate design of the furnace gas temperature profile and inadequate soot blowing for the fuel being fired. For high fouling fuels, proper design of the boiler requires a larger furnace and more liberal tube spacing. These design practices for high-fouling lignites have been developed from experience with units designed in the late 1960's. To maintain equivalent slagging and fouling conditions when firing a high-sodium fuel, a cyclone-fired boiler should be the same size as a pulverized coal-fired boiler.[55] So, there are no cost advantages associated with cyclone-fired units. The increased costs referred to by the industry result from firing of high slagging and fouling fuel and not from NO_x control procedures. The economic analysis does not reflect the costs of construction of the larger lignite boiler, or derating of the model units. This omission does not affect the analysis of costs for NO_x control and somewhat decreases the percentage control costs relative to baseline plant costs.

EPA also considered whether or not the fuel-nitrogen content of lignite varies enough between geographical areas to warrant separate standards of performance. A comprehensive literature search revealed that Texas lignite contains a slightly higher fuel-nitrogen content than North Dakota lignite, 1.4 versus 1.1 percent N_2 on an ash and moisture free basis. However, this apparent difference in fuel-nitrogen content may only be the result of a larger data base for North Dakota lignite. A statistical analysis of lignites from the 10 major North Dakota mines showed that there is no significant difference in the average fuel-nitrogen contents of the various North Dakota lignites. A detailed discussion of this question along with pertinent data are contained in Appendix D.

While the best adequately demonstrated system of emission reduction has been defined as low excess air and staged combustion, EPA has considered whether or not the low NO_x emission burner discussed in Chapter IV can achieve equivalent emission reductions. Initial EPA tests of a horizontally opposed-fired boiler employing bituminous coal indicated that the low NO_x emission burner operated with low excess air through the burner was equivalent to tangential firing with over-fire air. However, NO_x emission tests of lignite-fired boilers equipped with low NO_x emission burners have not yet been performed.

VIII. ENVIRONMENTAL EFFECTS

A. ENVIRONMENTAL IMPACT OF THE BEST SYSTEMS OF EMISSION REDUCTION

1. Air Impacts

Lignite-fired steam generators are not uniformly distributed throughout the country but are concentrated in the North Dakota and Texas areas. Both of these areas currently enjoy relatively low ambient air concentrations of NO_2. It is expected that one primary beneficial impact of an NO_x emission limit for lignite-fired boilers would be reduction of the atmospheric burden of nitrogen oxides. A second potential environmental benefit would be prevention of increased ambient oxidant concentrations. The potential for high ambient concentrations of oxidant exists if appropriate concentrations of precursors are present. The required precursors (primarily reactive hydrocarbons, and NO_x) may come from natural or anthropogenic sources. Reactive hydrocarbons may be present in rural air as a result of emissions from natural sources such as vegetation or natural gas deposits and from transport of urban pollution into rural areas. Transport of urban pollution has been documented for distances as great as 80 km (50 miles)[48], and has been strongly indicated by pollution characteristics for distances of 700 km (435 miles)[49,50]. Investigations of rural oxidant levels relative to urban hydrocarbon emissions have found that rural emissions combine with transported urban pollutants to generate appreciable quantities of oxidant over wide areas[48]. In addition, irradiation of bag samples of rural air, without urban pollution, has shown enhanced oxidant production with addition of NO_x to bag samples having very low initial NO_x concentrations[52]. This finding is consistent with theoretical curves derived from smog chamber data[53] which show increased oxidant formation with addition of NO_x to mixtures containing large hydrocarbon to NO_x ratios. Since a number of investigators[48,52] have reported measuring high non-methane hydrocarbon to NO_x ratios in rural air samples, control of NO_x emissions in rural areas may be expected to help prevent an increase in rural oxidant levels.

The primary impact of an NO_x emission limitation on air quality can be assessed in two ways: the reduction in total mass emissions of NO_x to the atmosphere and the reduction in the maximum predicted ambient NO_2 concentration in the vicinity of a source.

a. Mass Emissions

The reduction in mass emission levels was calculated assuming an emission limitation of 0.6 lb/10^6 Btu and using the known increase in lignite-fired steam generator capacity to 1980. The standards of performance for nitrogen oxides would not affect any of the existing or planned lignite-fired steam generators scheduled to come on-line before 1980. The lignite-fired utility boilers planned and under construction will increase the 1972 capacity by a factor of 4.5 in 1980. Although it is safe to say that growth of the lignite-fired utility boiler industry will continue after 1980, it is impossible to accurately predict the number or distribution of boiler types which will be installed. For this reason, an example of the mass emission reduction that would result from adoption of a 0.6 lb/10^6

Btu emission standard has been calculated by assuming that future capacity increases will have similar distribution of boiler types to that present with existing power plants (see Table VIII-1).

TABLE VIII-1. NO_x EMISSION REDUCTIONS FROM LIGNITE-FIRED STEAM GENERATORS LOCATED IN TEXAS AND NORTH DAKOTA--ESTIMATED FOR THE YEAR 1980 BASED ON 0.6 LB/10^6 BTU EMISSION STANDARD (BY BOILER CATEGORY AND REGION)

Boiler Category	Lignite Consumed[b] (10^6 tons/yr)	Emissions[a] 10^3 tons NO_x/yr		Region
		Uncontrolled	0.6 lb NO_x/10^6 Btu input	
Tangential	35.5	161	124	---
Horizontal - Opposed	12.3	81	54	---
Cyclone	9.8	68	41[c]	---
Other	.6	4.0	3	---
----	19.5	119	78	North Dakota
---	38.7	195	144	Texas
Total	58.2	314	222	----
% Emission Reduction	-----	-----	29	----

[a] Mass emissions of NO_x are calculated as NO_2.

[b] Estimated from net generation using the conversion factor 1000 MWh = 900 ton lignite. Net generation for 1980 taken from Table II-5 using the conversion factor 1 MW capacity = 7 x 10^3 MWh/yr.

[c] Emission level not achievable by specified boiler category.

Table VIII-1 indicates than an emission standard of 0.6 lb $NO_x/10^6$ Btu input would reduce NO_x emissions by 29 percent. Although a standard of performance for nitrogen oxides would not apply to the boilers used in these calculations, the emission reduction percentage should be valid for boilers built after 1980 which would come under the standard. By 1985 it is estimated that installed lignite generating capcity will have increased by an additional 16,000 MW if the recent 20.7 percent growth rate continues. Control of NO_x emissions from these boilers to 0.6 lb/10^6 Btu will reduce emissions of nitrogen oxides by 141,000 tons per year. The standard of performance limiting NO_x emissions from bituminous-fired steam generators requires a comparable degree of control.

b. Ambient NO_2 Levels

Another method of evaluating the impact of emissions is to calculate the maximum ambient concentrations of NO_2 at ground level from model facilities. These estimates are made using atmospheric dispersion modeling assuming that all nitrogen oxides were emitted from the source as nitrogen dioxide (NO_2). For the dispersion analysis, ground level concentrations of NO_2 were estimated for a 450 MW lignite-fired steam generator. Because emissions vary with the furnace design, the dispersion analysis considered emission rates for cyclone, tangential, and horizontally opposed fired boilers. The plant and exhaust gas parameters used in the model are shown in Table VIII-2. Ground level concentrations of NO_2 associated with building downwash were not estimated in this analysis because it is expected that stacks will be designed to avoid downwash problems.

The atmospheric dispersion model used in the analysis was EPA's "24-Hour Single Point Source" model modified for aerodynamic effects. This model assumes that:

1) there are no significant seasonal or hourly variations in emission rates,

Table VIII-2. Model Lignite-Fired Steam Generator Emission Parameters

Furnace Design	Max. Building Height	Stack Height	Gas Discharge Temp., (k)	Stack* Velocity (m/sec)	Actual Gas Flow Rate SCM/min	Conc. NO_x ppm	NO_x Emission Rate (g/sec)
Cyclone	64 m	122 m	464	30	33,800	700	807
Opposed	64 m	122 m	464	30	33,800	500	577
Tangential	64 m	122 m	464	30	33,800	300	346

* Stack ID = 6.38 m

2) the plants are located in gently rolling terrain, and

3) meteorological conditions are unfavorable to dispersion.

The model integrates the plant parameters with hour-by-hour actual meteorological conditions recorded over a one-year period. "Worst case" climatology consists of a high frequency of strong winds of persistent direction under conditions of neutral stability. Omaha, Nebraska fits this description fairly well, and data for this location were readily available in a form appropriate for input into the model. The above estimate is valid, then, for the Omaha area. Winds in North Dakota are generally less persistent in direction than are the Omaha winds; thus the estimate is conservative for North Dakota.

The results of the dispersion analysis indicate that emissions from the model lignite-fired steam generators would have a nominal impact on ambient NO_2 levels on an annual average basis. Specifically, the resulting maximum ground level annual average concentrations would be about 1-2 $\mu g/m^3$ for the cyclone furnace emission rate and proportionally less for the other two furnace designs with lower emission factors. The maxima would occur at distances of 10-15 km from the plant. All the annual average concentrations of NO_2 calculated by the dispersion model were lower than the national primary and secondary ambient air quality standard for nitrogen dioxide, 100 $\mu g/m^3$ (annual average).

2. <u>Water Pollution Impact</u>

The NO_x control techniques required to meet the alternative emission limitations would not create any aqueous wastes or additional thermal pollution. Staged combustion, tangential firing, low excess air, and burner modifications are NO_x control techniques which have no adverse or beneficial water pollution impact.

3. Solid Waste Disposal Impact

The alternative NO_x emission limitations would have no effect on the amount of solid waste produced, but would have an effect on the form of the solid waste. The solid waste generated by lignite-fired steam generators depends upon the type of equipment being used. If the furnace is a dry bottom furnace (pulverized-fuel or stoker) then the solid waste is in the form of fly ash and bottom ash which can be landfilled, used as a road filler, or because of lignitic ash's pozzolanic characteristics can also be used as raw material in the manufacture of construction blocks or other cementious materials. Many of the utilities market fly ash with reasonable success. However, when markets are not available for fly ash, the material can be landfilled or placed in the lignite mine with no serious environmental effects.

For wet bottom furnaces (cyclones) the bottom ash is in a slag form; slag tap ash can be utilized in road construction. Any alternative which would essentially prohibit the use of cyclone furnaces would thus change the form but not the amount of solid waste produced.

4. Energy Impact

The NO_x control measures presented in Chapter IV do not cause boiler efficiency losses, and therefore, no serious impacts are expected with respect to energy. If other control techniques such as the addition of unpreheated air or the use of flue gas recirculation were considered, impacts on boiler efficiency as large as 6 percent could be expected, lowering boiler efficiencies from 80 percent to approximately 74 percent. However, NO_x control techniques which cause boiler efficiency losses are not needed to meet a limitation of 0.6 lb $NO_x/10^6$ Btu input. For this reason, there is no incremental energy demand associated with the proposed limitation.

5. Other Environmental Concerns

There are no anticipated adverse environmental concerns associated with the NO_x control technologies required to meet the alternative emission limitations. These NO_x control technologies are all based upon modification of combustion conditions within the furnace. Although combustion conditions are altered, the primary chemical reaction which occurs in the furnace is still oxidation of lignite, and effective operation of a boiler requires complete combustion of the fuel. The combustion modifications do not alter the nature or quantity of the particulate matter emitted and do not affect the quantity of sulfur oxides emitted. Thus, NO_x control techniques do not adversely affect the ability of a lignite-fired steam generator to comply with the standards of performance for particulate matter or sulfur dioxide.

B. ENVIRONMENTAL IMPACT UNDER ALTERNATIVE EMISSION CONTROL SYSTEMS

1. No Standard

Lignite-fired steam generators are only a small portion (about 1/2 percent) of the total number of fossil fuel-fired steam generators. Although units firing lignite were exempted from the current fossil fuel-fired steam generator NO_x standards, pulverized lignite firing units have benefited from furnace design changes implemented by boiler manufacturers to meet the NO_x standard for boilers firing bituminous coal. Over-fire air controls will be included as standard equipment for all tangentially-fired pulverized coal boilers supplied by one of two major manufacturers of lignite units. As a result of this manufacturer's stated corporate policy, tangentially-fired furnaces utilizing lignite will emit NO_x at a rate of approximately 0.5 $\pm$ 0.1 lb $NO_x/10^6$ Btu input regardless of the proposed NO_x limitation for lignite-fired steam generators. The other major manufacturer of lignite-fired boilers will provide new low NO_x emission burners as standard equipment for its horizontally opposed fired boilers. Although EPA tests of this burner are not complete, horizontally opposed fired boilers can achieve an emission rate of approximately 0.6 lb $NO_x/10^6$ Btu input without using the burner (See Figure VIII-1).

From the previous statements, it appears that a proposed limitation of 0.6 lb $NO_x/10^6$ Btu would have little effect on emissions from lignite-fired steam generators; however, this is not the case. Cyclone boilers which can only achieve an emission rate of approximately 0.7 lb $NO_x/10^6$ Btu input would be indirectly prohibited. Also, the proposed NO_x emission limitation would guarantee that horizontally opposed firing boilers are equipped with low emission burners. A general rule of thumb is that a boiler must produce an emission rate 0.1 lb $NO_x/10^6$ Btu input below the emission standard in order to be guaranteed by the boiler manufacturer. Thus, horizontally opposed firing boilers would be encouraged to achieve an emission factor of 0.5 lb $NO_x/10^6$ Btu input.

Continuing to exempt lignite-fired steam generators from an NO_x standard would not yield any beneficial secondary environmental impacts. As stated in Section A, the proposed NO_x limitation does not have any water pollution, solid waste disposal, or energy impact.

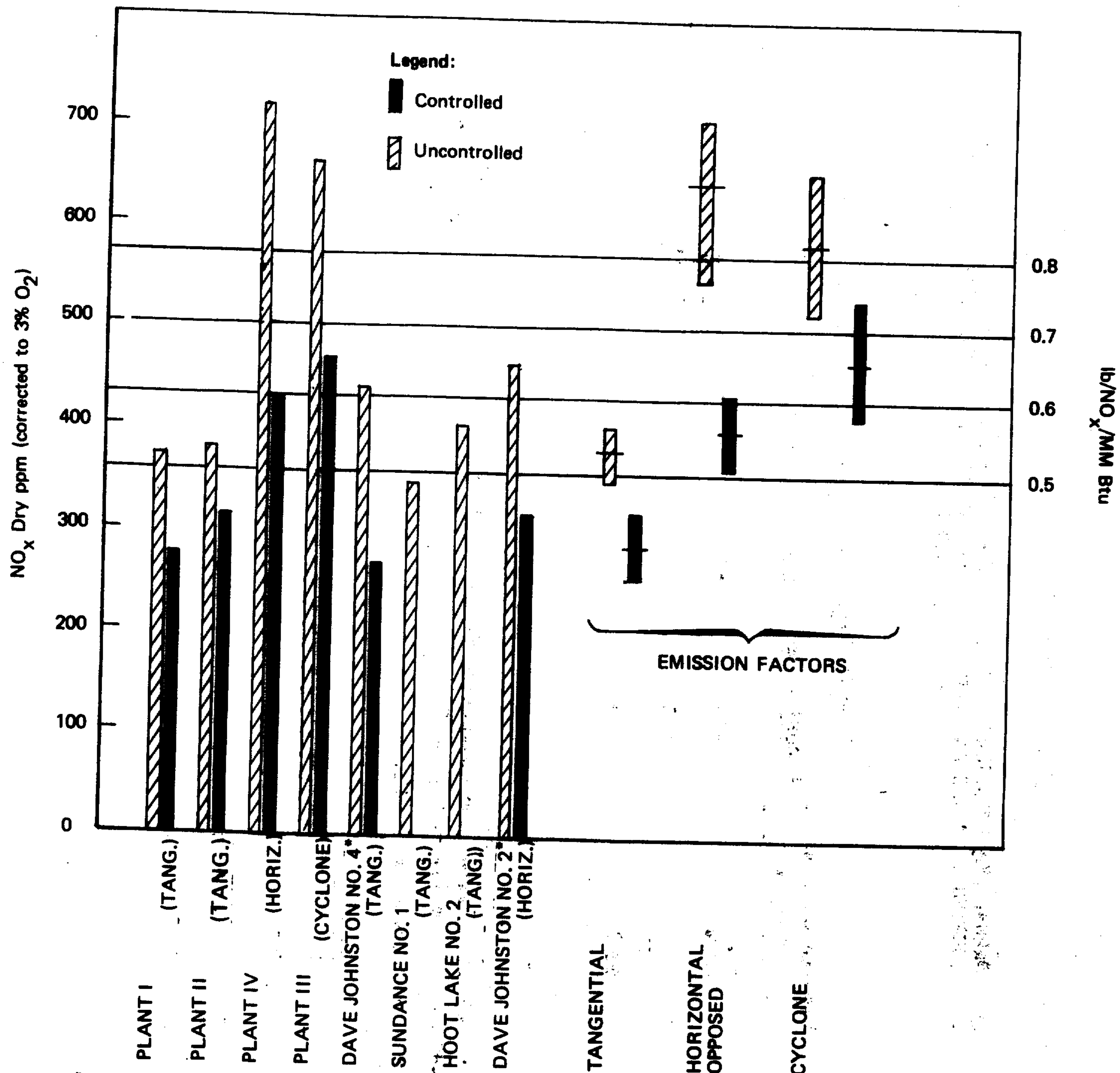
2. <u>Delayed Standard</u>

None of the currently existing or planned boilers firing lignite would be affected by the proposed SPNSS for NO_x. Therefore, it is impossible to state quantitatively the effect of delaying the proposed emission limitation. As of February 1976 it is believed that tangentially fired-units can consistently achieve the proposed NO_x standard. The other major suppliers' horizontally opposed fired boilers have a controlled emission factor nearly equal to the proposed emission limitation, and that manufacturer has recently decided to include low emission burners for these units. Although testing of these low emission burners is not now complete, they will probably further reduce the NO_x emission factor for horizontal opposed boilers. For these reasons, delay of the proposed NO_x emission limitation is not thought to be desirable or necessary.

3. More Effective Emission Control System

Figure VIII-1 shows NO_x emission factors for the three major furnace configurations used in lignite-fired steam generators. This figure compares emission factors for both controlled and uncontrolled sources. The NO_x controls used in generating these factors include over-fire air, low excess air, and combinations of the two. Tables VIII-3 and 4 list Texas and North Dakota NO_x emissions from lignite-fired steam generators in 1980 by boiler category and region for the proposed and three alternative emission limitations. Identical assumptions to those made in Section A.1 of this chapter were used to construct these tables.

As indicated in Figure VIII-1, tangential firing with over-fire and low excess air is currently the best demonstrated NO_x control technology for lignite-fired steam generators. This type of boiler will be provided by one of the boiler manufacturers who supply lignite-fired units. The other major supplier, although not yet equal in NO_x control technology, would have to employ a low NO_x emission burner to lower NO_x emissions.



*This unit was fired by a fuel which, although classified subbituminous, had a heating value of 6800 to 7800 Btu/lb., 7 to 16% ash, and 28% moisture. Since these values are similar to lignite, this data is useful for assessing NO_x control effectiveness for lignite firing.

SOURCE: REF. 8, 18, 19, 20 AND CURRENT FIELD TEST DATA (SEE CHAPTER IV).

FIGURE VIII-1 NO_x EMISSION FACTORS BY BURNER CONFIGURATION FOR LIGNITE-FIRED STEAM GENERATORS.

TABLE VIII-3 . ANNUAL NO_x EMISSIONS FROM LIGNITE-FIRED STEAM GENERATORS LOCATED IN TEXAS AND NORTH DAKOTA--ESTIMATES FOR THE YEAR 1980 (BY REGION)

State	Lignite Consumption (10^6 tons/year) [a]	Emissions (1000 tons per year) [b] Uncontrolled	Lb NO_x/10^6 Btu input 0.5	0.6	0.7	0.8
North Dakota	19.5	119	69	78	85	92
Texas	38.7	195	135	144	144	144
TOTAL	58.2	314	204	222	229	236

a Estimated from net generation using the conversion factor 1000 MWh = 900 tons lignite. Net generation for 1980 taken from Table II-5 using the conversion factor 1 MW = 7 x 10^3 MWh per year.

b Mass NO_x emissions were calculated as NO_2.

TABLE VIII-4 ANNUAL NO_x EMISSIONS FROM LIGNITE-FIRED STEAM GENERATORS LOCATED IN TEXAS AND NORTH DAKOTA--ESTIMATES FOR THE YEAR 1980 (BY BOILER CATEGORY)

Boiler Category	Lignite Consumption[c] (10^6 tons/year)	Emissions[d] (1000 tons per year)				
		Uncontrolled	Lb $NO_x/10^6$ Btu input			
			0.5	0.6	0.7	0.8
Tangential	35.5	161	124[b]	124	124	124
Horizontal-Opposed	12.3	81	43[a]	54	54	54
Cyclone	9.8	68	35[a]	41[a]	48[a]	55
Other	0.6	4.0	2[a]	3	3	3
TOTAL	58.2	314	204	222	229	236
% Emission Reduction		---	35	29	27	25

[a] Emission level not currently achievable by specified boiler category.

[b] This emission level probably would not be guaranteed by the boiler manufacturer.

[c] Estimated from net generation using the conversion factor 1000 MWh = 900 ton lignite. Net generation for 1980 taken from Table II-5using the conversion factor 1 MW capacity = 7×10^3 MWh per year.

[d] Mass emissions of NO_x are calculated as NO_2.

A more stringent NO_x limitation, 0.5 lb $NO_x/10^6$ Btu input was not proposed because adoption of this standard could adversely affect the competitive balance between the major suppliers of lignite-fired boilers. Horizontally-opposed fired boilers manufactured by one of the major suppliers may not be capable of consistently achieving 0.5 lb $NO_x/10^6$ Btu and the manufacturer probably would not guarantee compliance with this standard. Thus, only one proven supplier of lignite-fired boilers would be available.

4. Less Effective Emission Control System

Figure VIII-1 and Tables VIII-1 and 3 show that cyclones are the least controllable type of boilers. The two major boiler manufacturers agree that cyclone furnaces are not necessary to fire high sodium lignite, and at present cyclone furnaces have not been demonstrated to fire high sodium lignite more reliably than pulverized coal boilers. Also, cyclone furnaces are essentially equivalent in price to pulverized coal units. For these reasons, new cyclone boilers have been indirectly prohibited by the proposed emission limitation. Raising the proposed NO_x limitation to allow use of cyclones would clearly violate the mandate of Section 111 of the Clean Air Act of 1970 which requires use of the best demonstrated technology taking costs into account. (See Chapter

C. SOCIO-ECONOMIC IMPACTS

Compliance with the proposed emission limitation should cause no adverse socio-economic impacts. The NO_x control costs associated with the proposed emission limitation are small and would be lost in the overall cost of power generation. Thus, the cost impact of the proposed emission limitation on electricity bills paid by consumers would be negligible. (See Chapter VI).

The small incremental capital cost associated with the NO_x control cost requirement would not cause any problems to the owners of the affected facilities who would be required to make additional investment to comply with the proposed emission limitation. There would be no plant closures or other such hardships on the electric utilities involved.

The proposed emission limitation should not give any one boiler manufacturer a monopoly on future sales of lignite-fired boilers. The required NO_x control technology is already available to the manufacturers. Also, the additional control cost is a small part of the total capital cost of the boiler. Thus, factors other than control cost would affect the choice of boilers selected by a customer.

D. OTHER CONCERNS OF THE BEST SYSTEMS OF EMISSION REDUCTION

Promulgation of the proposed NO_x emission limitation for lignite-fired steam generators would not result in any irreversible and irretrievable commitment of natural resources, nor would it cause any long-term environmental losses. The proposed emission limitation fulfills its intended purpose of reducing NO_x emissions without generating any adverse secondary environmental impacts. In fact, probably the only secondary environmental impact of the proposed standard would be a change in the form of solid waste produced by lignite-fired steam generators. (Section A.3.).

IX. ENFORCEMENT ASPECTS OF THE PROPOSED STANDARD

The proposed standard limits emissions of nitrogen oxides from lignite-fired steam generators of greater than 73 megawatts thermal (250 million Btu heat input). Nitrogen oxides emissions can be reduced to the level of the standard by the combustion modification techniques of low excess air, staged combustion, low emission burners, and combined low excess air and staged combustion. Based on present information cyclone-fired steam generators firing lignite alone cannot achieve the proposed standard and operate reliably.

Compliance with standards of performance is determined by performance testing of the affected facility while it is operating under representative conditions. In addition continuous monitoring requirements are established where the information will assist enforcement personnel in ensuring continued compliance with the standard or in ensuring proper operation and maintenance of the control system. Consequently, this section will briefly discuss the performance test methods and continuous monitoring requirements and equipment available. Determination of compliance with the nitrogen oxides standard also requires designation of the type fuel being burned. Due to the variability of the heating value of lignite, in some cases there could be a question as to which nitrogen oxides standard is applicable.

A. PERFORMANCE TESTING

The EPA reference method for the analysis of nitrogen oxide emissions from stationary sources (Method 7) calls for the use of the phenoldisulfonic acid (PDS) procedure for the analysis. This involves oxidizing all NO to NO_2, followed by colorimetric measurement using PDS. The mass emission rate for the facility is calculated using either of the following equations:

$$E = CF\left(\frac{20.9}{20.9 - \%O_2}\right)$$

or

$$E = CF_c\left(\frac{100}{\%CO_2}\right)$$

B. CONTINUOUS MONITORING

There are a large number of potential instrumental methods for the measurement of nitric oxide emissions from stationary sources. Perhaps the largest problem encountered in the use of many of these techniques is in providing proper sampling interface and conditioning equipment for the transport of the stack gas to the analyzer. The performance specifications for instrumental methods for the measurement of nitric oxides from stationary sources required to continuously monitor emissions were published in the Federal Register on October 6, 1975 (40 FR 46250).

Due to the sensitive relationship between operating conditions and NO_x emissions, a continuous monitoring device is required for NO_x emission monitoring of lignite-fired steam generators. Any instrument which meets the criteria of Performance Specification 2 of 40 CFR 60, Appendix B is acceptable for this purpose.

C. FUEL ANALYSIS

Lignite has a high moisture content and low heating value. Analyses of lignite show considerable variation in moisture and ash content and the heating value on a moist mineral matter free basis. Lignite is defined by ASTM D 388-66 as any solid fossil fuel with a moist mineral matter free heating value between 8,300 and 6,300 Btu/lb. As a result of this definition, a boiler which fires a fuel of around 8,300 Btu/lb technically may be firing lignite one day and subbituminous coal the next.

In order to resolve this problem, EPA considered alternative definitions for lignite. No generally acceptable definition was found which would avoid this arbitrary differentiation and which would not introduce additional enforcement determination problems. Consequently, in order to reduce the relative effect of fuel analysis and sample handling errors, EPA concluded that the coal rank should be determined on the basis of a relatively large sample population. Determination of the coal rank on the basis of daily samples is not recommended because a facility would not know the applicable NO_x standard at all times. Therefore, in order to simplify enforcement of the applicable NO_x standards, the rank of a coal will be determined on the basis of the mean heating value for a 30 day period prior to the period in question.

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APPENDIX A

BACKGROUND ON LIGNITE-CONSUMING UTILITIES AND INDUSTRIES

1. PAST GROWTH OF LIGNITE-FIRED PLANTS

In Table A-1 we have collected data on the capacity, output, and lignite consumption of all major lignite-fired plants in the United States for three years: 1960, 1970, and 1972. The data differ slightly from Table II-2 in the main body of the text because certain boilers using sub-bituminous coal have been included in Table A-1.

2. EXPANSION PLANS OF SELECTED UTILITIES

Annual reports and data published in Moody's Public Utilities manuals about the six utilities discussed in Chapters I and V show the following commitments to lignite-fired expansion:

- Utility A budgeted over $33 million for construction in 1974. A new, jointly owned 440-megawatt steam generating plant, of which this utility will own 47 and 1/2%, will be on-line in 1975, and is expected to cost about $148 million. The utility's forecasts of its construction budget for 1975 and 1976 are about $19 million and $11 million, respectively, with 1974-78 construction budgets expected to total about $113 million. This utility is also sharing the construction costs of a 450-megawatt plant due to go on-stream in 1981. Utility A has issued pollution control revenue bonds. It also issued first mortgage bonds, pollution control series, in February 1974, for $13.3 million to be used to cover the company's share of air and water pollution control facilities at its plant due for completion in 1975. The budget presently does not include provisions for SO_2 control, but includes provisions for an electrostatic precipitator for particulate control.

TABLE A-1

LIGNITE-FIRED STEAM-ELECTRIC PLANTS, NET GENERATION AND LIGNITE CONSUMPTION

	1960			1970			1972		
	Installed Generating Capacity (Mw)	Net Power Generation (10^6 kwh)	Lignite Consumption (10^3 Tons)	Installed Generating Capacity (Mw)	Net Power Generation (10^6 kwh)	Lignite Consumption (10^3 Tons)	Installed Generating Capacity (Mw)	Net Power Generation (10^6 kwh)	Lignite Consumption (10^3 Tons)
UNITED STATES	536.5	2,223.3	2,335	1,432.3	8,350.8	7,148	3,164.5	13,137.3	10,788
WEST NORTH CENTRAL	335.0	1,084.2	1,351	888.1	4,908.8	4,533	1,107.2	6,608.5	5,882
Minnesota	90.0	364.3	335	173.4	976.4	869	203.9	952.3	836
Otter Tail Power Co. Hoot Lake	61.0	258.4	211	125.0	842.4	705	125.0	831.6	607
Otter Tail Power Co. Crookston	10.0	15.3	19	10.0	38.9	47	10.0	30.9	38
Otter Tail Power Co. Ortonville	15.0	90.1	101	16.5	93.2	111	15.0	88.5	101
Public Service Dept. Moorhead	12.0	0.5	4	10.0	1.9	6	25.0	1.3	3
North Dakota	178.5	558.6	850	652.7	3,686.1	3,429	841.3	5,443.2	4,886
Mont-Dak. Util. Co. Beulah	13.5	47.8	69	13.5	77.1	127	13.5	64.0	108
Mont-Dak. Util. Co. Bismarck	10.0	12.3	37	—	—	—	—	—	—
Mont-Dak. Util. Co. Kincaid	6.0	25.5	68	—	—	—	—	—	—
Mont-Dak. Util. Co. Heskett	25.0	136.8	145	100.0	564.8	520	100.0	612.9	571
No. States Power Co. Fargo	20.0	50.7	113	20.0	38.9	72	—	—	—
No. States Power Co. Grand Forks	18.0	41.5	80	16.0	65.8	101	—	—	—
No. States Power Co. Minot	10.0	30.8	77	10.0	29.7	40	—	—	—
Otter Tail Power Co. Devils Lake	12.5	39.2	57	12.5	40.6	61	12.5	47.7	76
Otter Tail Power Co. Jamestown	8.5	37.3	47	7.5	43.0	58	7.5	42.7	50
Otter Tail Power Co. Washburn	8.0	7.1	14	—	—	—	—	—	—
Otter Tail Power Co. Kidder	20.5	42.3	55	20.5	13.3	18	20.5	23.4	31
Valley City Mun. Util. Valley City	5.0	7.3	24	5.0	8.7	29	5.0	3.5	19
Basin Elec. Power Coop. Leland Olds W.J. Neal	—	—	—	215.7	1,542.4	1,298	215.7	1,575.4	1,326
Minnkota Power Coop. F.P. Wood	21.5	60.0	64	21.5	1.4	2	21.5	3.0	4
Minnkota Power Coop. Young-Center	—	—	—	—	—	—	234.6	1,841.8	1,616
United Power Assn. Stanton	—	—	—	172.0	1,027.3	854	172.0	1,041.9	857
South Dakota	58.5	161.3	166	62.0	246.3	235	62.0	213.0	200
Black Hills Power & Light Ben French*	22.0	9.4	5	22.0	125.4	107	22.0	108.7	85
Black Hills Power & Light Kirk*	28.0	137.5	131	31.5	104.7	94	31.5	102.6	102
Mont-Dak. Util. Co. Mobridge	8.5	14.4	30	8.5	16.2	34	8.5	1.7	13
WEST SOUTH CENTRAL	—	—	—	—	—	—	1,186.8	2,460.6	1,790
Texas	—	—	—	—	—	—	1,186.8	2,460.6	1,790
Dallas Power & Light Co. Big Brown	—	—	—	—	—	—	1,186.8	2,460.6	1,790
MOUNTAIN	201.5	1,139.1	984	544.2	3,442.0	2,615	870.5	4,068.2	3,183
Montana	50.0	182.2	187	50.0	337.3	321	50.0	340.8	320
Mont-Dak. Util. Co. Lewis & Clark	50.0	182.2	187	50.0	337.3	321	50.0	340.8	320
Wyoming	151.5	956.9	797	494.2	3,104.7	2,294	820.5	3,727.4	2,783
Black Hills Power & Light Osage*	34.5	247.1	226	34.5	235.8	220	34.5	231.1	219
Black Hills Power & Light Neil Simpson*	5.0	27.0	45	27.7	177.2	192	27.7	184.1	190
Mont-Dak. Util. Co. Acme	12.0	16.1	18	12.0	28.6	30	8.0	28.4	30
Pacific Power & Light D. Johnston*	100.0	666.7	508	420.0	2,663.1	1,852	750.3	3,283.8	2,336

*Sub-bituminous plants whose fuel input characteristics were thought to be close to lignite.

SOURCE: Steam-Electric Plant Construction Cost and Annual Production Expenses, Federal Power Commission, 1960, 1970, and 1972 data.

Company A also issued pollution control bonds for retrofit expenses to be incurred in 1974 and 1975.

- Utility B is sharing 20% of the costs of the 440-megawatt facility being completed in 1975 with A, and a third utility which is to own the remaining 32.5%. Utility B's share of the new lignite-fired facility will cost about $30 million. It also will share the 450-megawatt facility due in 1981. This company planned to issue an aggregate of $16 million to cover pollution control expenditures already incurred or to be made in 1974 and 1975 at three facilities. The utility's 1974 construction budget was $27.4 million. Construction estimates beyond 1974 are not available.

- Utility C (a holding company for three large utilities) outlined a three-year construction program for the years 1974 through 1976 of $1,457 million, of which $821 million will be used to build production facilities, with most of the latter amount committed to lignite-fired facilities. The company is spending $68 million on developing lignite-fuel facilities (i.e., mines). Besides seven lignite-fired facilities due to begin operation between 1975 and 1980, the company is adding two shared nuclear-powered generating units by 1981.* The estimated construction expenditures for lignite-fueled generating units, nuclear-fueled generating units and for additional items contributing to the protection of the environment will be about $72 million over a three-year period. They are apportioned to the three utilities owned by the parent as shown:

*One of the companies is adding an additional lignite-fired unit that will not be shared by the other two.

	Millions of Dollars			
	1974	1975	1976	Total
C(1)	2.0	5.4	9.1	16.5
C(2)	2.3	5.8	-	8.1
C(3)	5.7	15.6	26.1	47.4
TOTALS	10.0	26.8	35.2	72.0

- Electric Power Cooperative D has a 460-megawatt addition to lignite-fired capacity scheduled for 1975 operation. This facility, scheduled for 1975, required supplemental financing of $30 million from REA to finance "additional cost overruns, facilities modifications,* and additions to Unit 2 facilities." Company D expects to spend $6 million for retrofit pullution control equipment.

- Electric Power Cooperative E is adding 435-megawatts of lignite capacity due to be completed by 1976. They have just spent $4.75 million to install a precipitator on an existing site, and will install a precipitator on the new plant.

- Electric Power Cooperative F is adding significantly to its own lignite-fired capacity and to that of another power cooperative which did not have any lignite burning plants in 1974. As project manager, it is overseeing the addition of 1,000 megawatts more lignite capacity in 1979. In December of 1973, it borrowed $4.6 million to finance pollution control equipment for existing lignite-fired facilities. They (F and partner cooperative) borrowed $85 million to finance 1,000 megawatts

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*An additional stack and electrostatic precipitator were added to an existing unit.

of new facilities from REA at 5%. The balance of the $454 million needed to complete the project is guaranteed by REA, but will be borrowed from private sources.

These expansion plans contribute to the expected fourfold increase in lignite capacity illustrated in Figure A-1.

3. FINANCIAL RESOURCES

The financial resources, borrowing power, and ability to sustain capital expansion of a utility company are dependent both upon the individual company and the type of utility. The lignite-fired electric generating "industry" has been analyzed by examining six of the eight utilities previously listed in Table I-2. For the purposes of discussion, we have divided the utilities into two distinct classes from which financial data and future construction plans have been assembled through a review of their annual reports and discussions with their corporate management and various state regulatory authorities.*

The designation, Class I, refers to investor-owned utilities, which use long-term public and private debt placement and/or equity to finance their capital expenditure programs for capacity expansion. Three such utilities (Companies A, B, and C) have major buildings programs for lignite-fired generating capacity. The designation, Class II, refers to rural electric cooperatives. Three such cooperatives (Companies, D, E, and F), herein discussed, have lignite-fired capacity.

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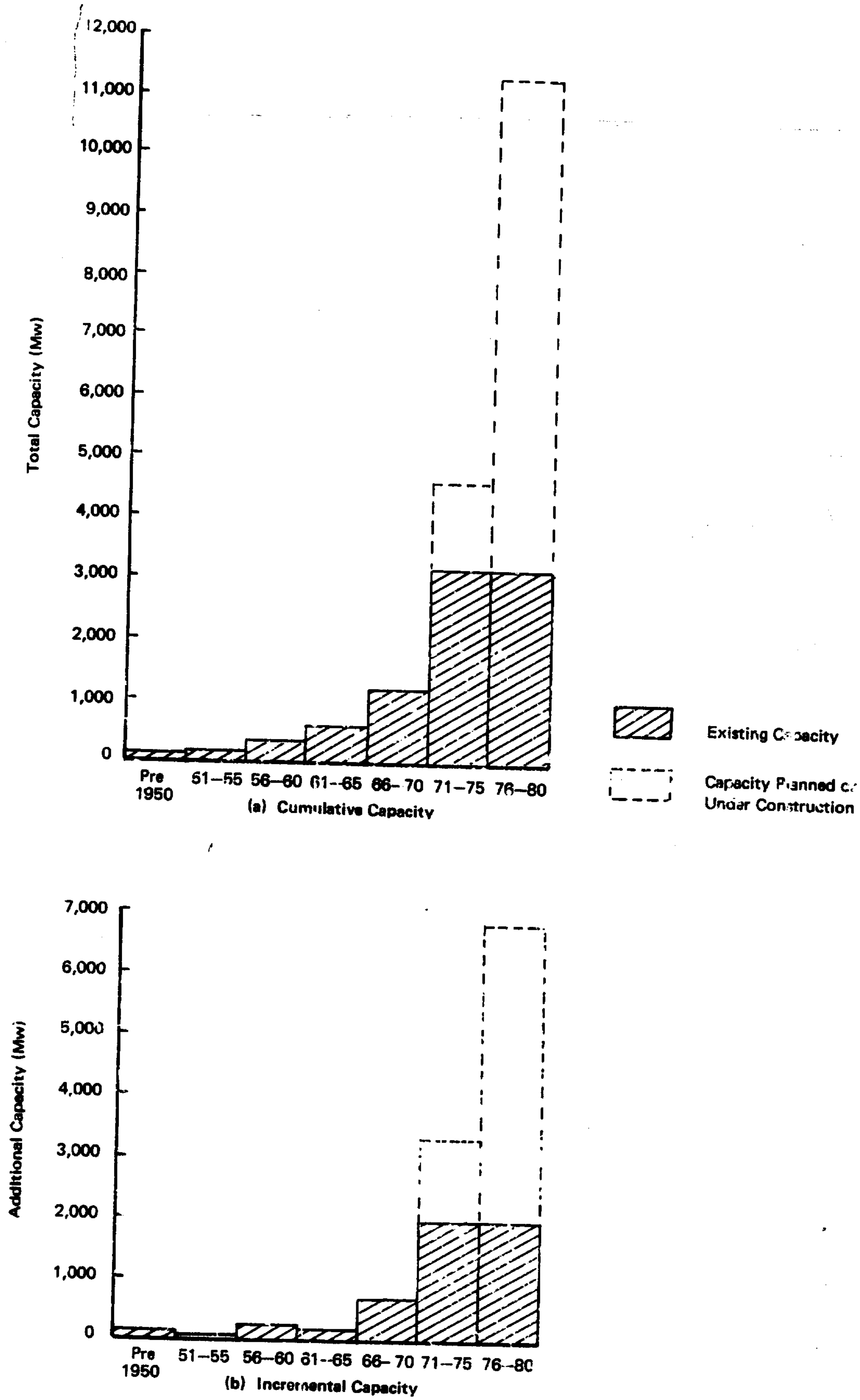
*A third class, comprised of two very small, municipally-owned utilities that use lignite fuel, was reviewed and excluded. The electric revenues of the two utilities combined were less than $4 million, their net plant was less than $10 million, and they have no announced plans for capacity expansion.



Source: Federal Power Commission, Industry Contacts.

FIGURE A-1 **INSTALLED CAPACITY, UTILITY-OWNED LIGNITE-FIRED STEAM ELECTRIC GENERATORS, 1950–1980**

Class II utilities differ from Class I utilities in that they may either borrow directly from the REA (at significantly lower rates that investor-owned utilities) to finance construction or may ask for REA guarantees on loans from other sources. Class II utilities are typically smaller in terms of their generating capacity and invested capital.

The basic financial data for the three investor-owned electric utilities and the three electric power cooperatives were taken from Moody's Public Utilities Manual and annual reports, and are shown in Tables A-2 and A-3 respectively. One of the independently-owned utilities, Company C, dwarfs the others, and it should be noted that the financial data shown in Table A-2 for this utility are for the parent company which owns three large subsidiary utilities.

The capitalization of Class I utilities is fairly evenly divided between debt and equity financing.* Future capital expansion plans show that A plans to spend $103 million from 1974-78, B plans to spend $27.4 million in 1974 alone and C plans to spend $1,457 million from 1974-76.

Each of the three Class I utilities has been able to adjust its rates to cover increase in costs of construction, purchased power, labor, materials, and borrowed money. When contacted, each of them also indicated that further increases will be necessary to assure coverage of the interest charges for the new financing planned principally to support their construction programs.

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*Debt is that amount of outstanding capitalization which is held by other institutions (including REA) and upon which interest is paid. Equity consists of common stock and earned surplus.

TABLE A-2

INVESTOR-OWNED UTILITIES (CLASS I), BASIC FINANCIAL DATA, 1973

(Millions of Dollars)

COMPANY:	A	B Elec.	B Gas	C
Revenues: 1970	$ 34.5	$24.3	$31.1	$ 453.0
1971	38.1	25.2	32.9	483.4
1972	41.7	27.0	36.1	563.3
1973	44.5	28.7	37.1	615.1
Net Plant (1973)	$146.1	$199.4		$2,219.2
Accumulated Depreciation	$ 54.0	95.7		$ 552.5
Capitalization:				
Long-Term Debt	59.4	84.3		993.9
Equity[a]	49.9	73.9		857.2
Preferred	15.5 65.4	19.2 93.1		298.0 1155.2[b]
Total	$124.8	$177.4		$2,149.1
Interest:				
Long-Term Debt	$ 3.52	$5.569		$56.44
Other Debt	.90	.749		.87
		$6.318		
Allowance for Funds Used During Construction	-	-1.054		-
Total	$ 3.42	$5.264		$57.31
Moody's Bond Rating	A	A		Aaa,Aa
Net Operating Earnings After Taxes	$ 7.92	$11.829		$163.5
Times Interest Rate (Coverage Ratio)	2.3	2.25		2.85[c]
Capital Expansion:				
Last five years	66.0	92.7		1,011
Future	113.0 (5 yrs)	27.4 (1974)		1,475 (3 yrs)

[a] Common stocks and earned surplus, etc.

[b] Includes surplus reserves.

[c] 2.51 coverage after transfer of surplus reserves.

Source: Moody's Public Utilities Index, 1974, and annual reports.

TABLE A-3

RURAL ELECTRIC COOPERATIVES (CLASS II), BASIC FINANCIAL DATA, 1973

(Millions of Dollars)

COMPANY:	D	E	F
Revenues: 1970	-	6.81	-
1971	6.75	10.9	-
1972	8.65	13.5	16.8
1973	10.0	14.2	18.1
1974 (est.)	14.1	-	-
Net Plant (1973)	102.5	72.3	64.0
Accumulated Depreciation	1.02	19.4	22.0
Capitalization:			
Long-term Debt (REA)	107.6	72.6	68.1[a]
Other Long-term Members' Equity	1.59	5.1	5.7
Total	109.2	77.7	98.8
Net Operating Earnings After Taxes	.493	2.00	2.24
Interest on Debt	.64	1.46	1.36
Times Interest Rate (Coverage Ratio)	.77	1.37	1.65
Rates to Members, Wholesale (mills/kWh)	6.52	7.87	-
Capital Expense Program:			
Last five years	-	27.3	-

[a] Current maturities were subtracted from long-term debt to REA.

Source: Moody's Public Utilities Index, 1974, and annual reports.

Interest coverage ("net operating earnings" divided by interest charges) is a key test in meeting the provisions of financial agreements, e.g., indenture restrictions, which may affect the timing and amount of new financing which can be completed. It is sometimes defined to include the interest on proposed new debt. However, the figures shown herein only represent a snapshot in time, and are susceptible to change due to rate increases and accounting charges. A coverage of 2.00 is typically the minimum required of investor-owned utilities by the conventional bond market indenture provisions. This coverage is exceeded by all of the Class I utilities.

In comparison, interest coverage by the three rural electric cooperatives, shown in Table A-3 appears to be lower than for investor-owned utilities. Indeed, Utility D apparently had a slight deficit in 1973, after interest deductions. Wherever rate increase approvals are delayed by regulatory commissions, earnings can be appreciably affected, as was the case with Company D. However, we hasten to add that there are significant differences between the financial structures and regulatory frameworks operative between the various investor-owned systems and the rural electric cooperatives. Thus, an interest coverage of REA utilities which is less than 2.00 should not reflect negatively upon the financial structure of the companies.

4. TWO METHODS OF RAISING CAPITAL FOR CONSTRUCTION

A review of the financial profiles of those utilities of concern here shows little if any difference between utilities which have no lignite-fired capacity. In terms of total capitalization, debt structure, and coverage ratios, both Class I (investor-owned) and Class II (REA) companies are typical of the utility industry in general.

The six utilities comprising the lignite-fired "industry" are but a small part of the most capital intensive industry in the United States. The construction programs required to support new lignite-fired facilities, are only a minor part of the anticipated construction of new generating facilities (oil, gas, nuclear, coal, sub-bituminous coal facilities having been excluded). If there is one key issue facing the industry at the present time, it is related to the problem of raising capital for construction.

The debate now centers on whether to continue to increase rates or whether to assure the flow of lower cost debt to the industry through government credit assistance in the form of insurance and guarantee of debt securities of investor-owned utilities. This is similar to the way in which the government now assists the rural electric cooperatives that benefit from REA financing and guarantees. The latter implies reduced interest costs to the company and utility rates to the customer.

The second, and more obvious approach is to increase electric rates, which is an unpopular solution to the consumer but without which the utilities shall find it hard to cover interest charges in times of increased costs for capital. Unfortunately, these financial problems arise at a time when it is important to reduce the nation's dependence on oil and to begin to rely more heavily on domestic fuels such as lignite.

The six utilities discussed in this report all commented in their annual reports on the importance of rate increases to a financially viable operation. The salient issues regarding their rate situations may be summarized as follows:

Company A:

Average residential rate -- 3¢/kWh; sought permission to raise its electric rates by mid-1974. Based on their 1973 Annual Report, they paid 7.65% interest on a new bond issue, 5.92% for interest on pollution revenue bonds, and issued more common stock, and complain that it is becoming more difficult for them to cover increased costs, including costs of lignite fuel.

Company B:

Average residential rate = 2.7¢/kWh. Issued debt, asked for increases in rates to cover higher costs.

Company C:

Their average rates appear comparable to Companies A and B. Raised its rates in 1972 and filed for rate increases of 9% to 11% with cities and towns in its service area to cover increased operating costs.

Companies D and E:

Both sell power wholesale for 0.652¢/kWh and 0.787¢/kWh, respectively. They each have REA financed lignite capacity under construction. D was to effect a 21% rate increase to its wholesale customers effective with their January, 1975 billing, while E's member's charge rural residential customers 2.01 to 2.53¢/kWh.

Company F:

Recently received a loan of $36.47 million from REA at an interest rate of 5% and payable over 35 years for construction financing. F's management does not foresee a reversal of economic conditions to the relatively stable ones it has known before.

In summary, it appears that the financial viability of both Class I and Class II utilities is being undermined by high operating costs, high finance costs, a possible shrinking availability of debt and, for investor-owned utilities, the weakness of the present equity market as well as the need for near-term pollution control equipment financing. Forces quite outside the utilities' control are requiring at the same time that these utilities plan for continued growth in service at reasonable rates.

In general, the Class I utilities appear to have the resources to service the debt required if the rate making process (or the equivalent mechanism by which the public interest is served and the financial integrity of the utility is maintained) can respond to assure the utilities' ability to carry out a contemplated construction program. The Class II companies appear to be in a slightly more flexible position.* In neither case is the cost of NOx control overburdening.

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*A more complete treatment of the financing requirements of the principal utilities associated with lignite involves the host of considerations affecting the U. S. electric utilities in general at this juncture. Such a treatment is well beyond the scope of the present study.

APPENDIX B

DATA REDUCTION PROCEDURES

1. Emission Index

The emission index E (lb/million Btu) was calculated from the following expression[14]:

$$E = 1.215x10^{-7}CFD \qquad (1)$$

where C = NO_x concentration (ppm, dry basis), F is the dry flue gas volume (dscf per 10^4 Btu) at zero excess air as discussed above, and D = 2090/(20.9-percent O_2). The F-factor method was used with F taken to be 98 dscf/10^4 Btu. Direct measurements of FD using velocity traverses and moisture data were not used in expression (1) because the values were 5 to 16 percent greater than expected from lignite C-H-O composition for all four test series. These direct measurements of FD also exhibited much more scatter. This is illustrated in Table B-1. Possible explanations are as follows:

(i) Measured lignite heating value is lower than actual.

(ii) Measured mean stack velocity is higher than actual, due to swirl component.

(iii) Measured lignite feed rate is lower than actual.

(iv) Stack cross sectional area is lower than assumed.

(v) Stagnant zones existed and were not traversed.

Accordingly the emission index values were calculated using the F-factor method. The use of the F-factor method was later verified in follow-up tests. One of the lignite-fired steam generators was retested to determine the probable cause of the discrepancy between the measured gas volume and gas volume as calculated by the F-factor method. This investigation determined that the gas velocity measurements were in error due to interference between the thermocouple and the pitot tube of the contractor's

Table B-1 SYSTEMATIC ERROR IN FLUE GAS VOLUME PER BTU

Unit	Difference (percent)	Volume per Btu using stack velocity (dscf/10^4 Btu)	Volume per Btu using F-factor (dscf/10^4 Btu)
Plant I	+5	138	132
	+10	143	129
	+11	142	127
	+7	140	130
	+9	138	127
	+4	135	130
	+16	157	133
	+5	138	132
	+11	144	129
	+12	156	139
Average systematic error	9.5%		

equipment. The gas volumes calculated from the measured values were, consequently, in error. Preliminary analysis of the data from the retest showed excellent agreement between the dry gas volume calculated by the F-factor method and the measured values. A simpler F-factor method which gives comparable results was promulgated in the Federal Register on October 6, 1975 (40 FR 46250).

2. Uncertainty Analysis

Let us examine the uncertainty in emission index, $\Delta E/E$, in terms of the component uncertainties $\Delta O_2/O_2$, $\Delta F/F$, and $\Delta C/C$. Taking the partial differentials of expression (1) we can derive the uncertainty:

$$(\Delta E/E)^2 = \left(\frac{\Delta C}{C}\right)^2 + \left(\frac{\Delta F}{F}\right)^2 + \left[\left(\frac{O_2}{20.9 - O_2}\right) \frac{\Delta O_2}{O_2}\right]^2 \qquad (2)$$

Since O_2 was typically 5 percent at the point where NO_x measurements were made, expression (2) reduces to

$$(\Delta E/E)^2 = (\Delta C/C)^2 + (\Delta F/F)^2 + (0.3\ \Delta O_2/O_2)^2 \qquad (3)$$

We estimate the uncertainty in reported O_2 data of approximately 10 percent of reading (typical value 5.0 ±.5 percent):

$$\frac{\Delta O_2}{O_2} = 10 \text{ percent}$$

This is based on (a) observation of O_2 drift in the control room, (b) scatter in the Orsat O_2/CO_2 correlation (See Figure B-1), (c) scatter in the difference between O_2 measured before and after the preheater (See Figure B-2), (d) readability and precision of O_2 instrumentation.

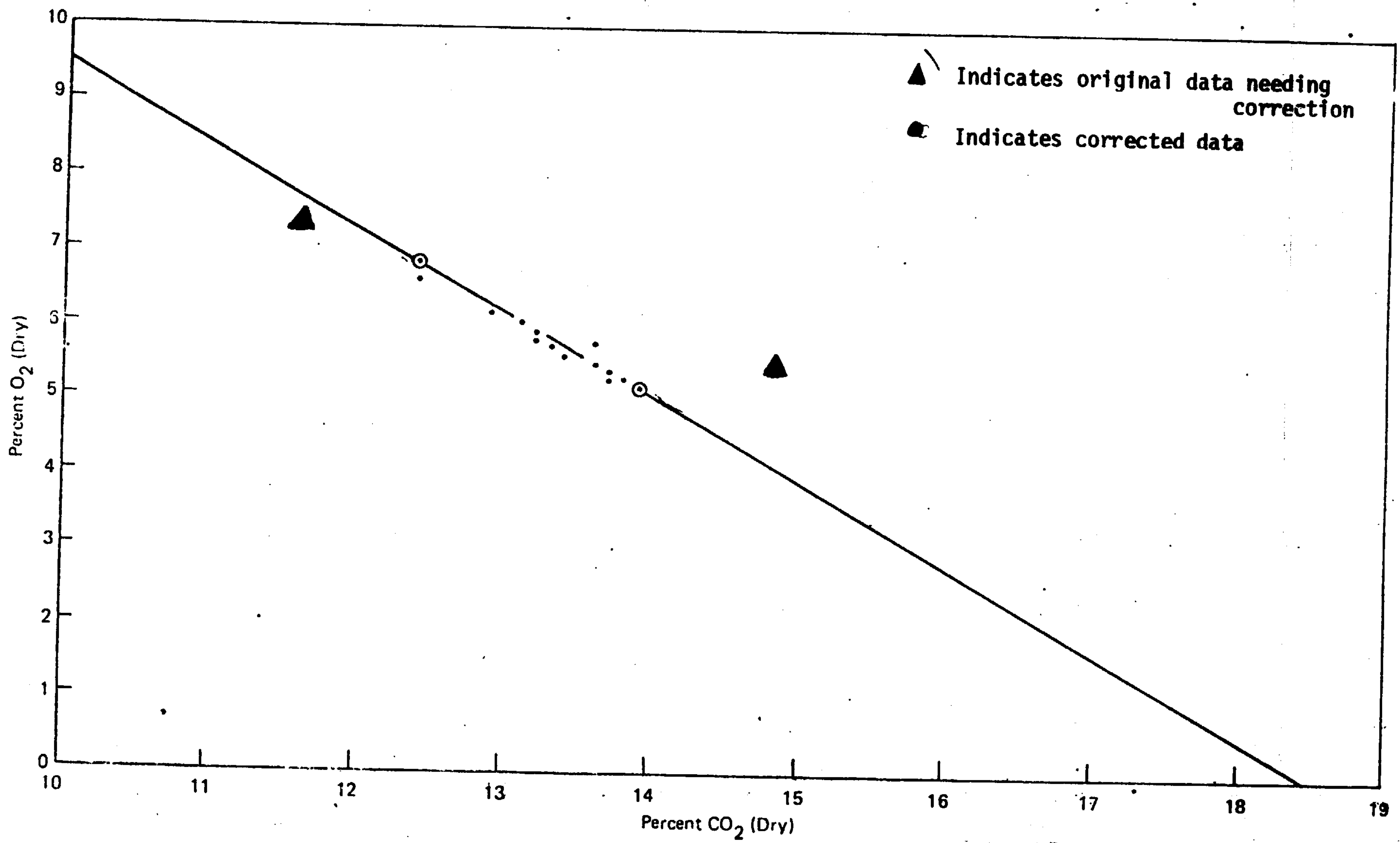

Figure B-1. SCATTER IN THE ORSAT O_2/CO_2 CORRELATION.

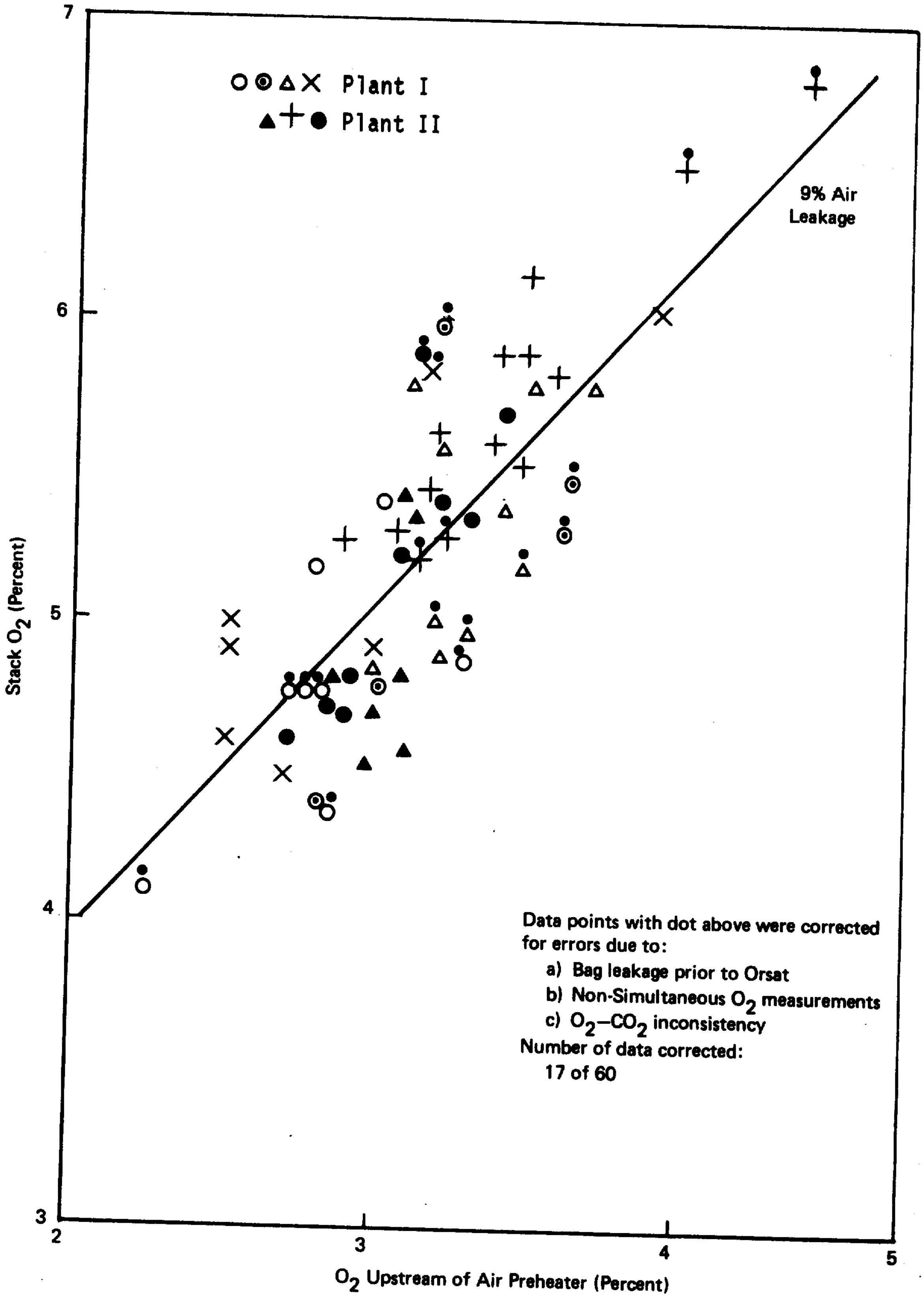

Figure B-2 ESTIMATION OF PREHEATER LEAKAGE.

Based on variations in lignite analyses, we place the uncertainty in F-factor at 3 percent of reading (typical value 98 ± 3 dscf/10^4Btu). This agrees with previous experience of EPA personnel with F-factors.

$$\frac{\Delta F}{F} = 3 \text{ percent}$$

The uncertainty in NO_x (ppm) dominates the emission factor uncertainty and critically affects the standard setting process in that (a) some margin is required for NO_x guarantees of boilers, and (b) the standard must be based on upper limit emission behavior rather than on the mean emissions. We estimate the uncertainty in the NO_x concentration measurements conducted in support of this standard at ± 8 percent for the Plants I & II test series, at ± 5 percent for the Plant IV series, and ± 4 percent for the Plant III test data.

$$\frac{\Delta C}{C} = \begin{cases} 8 \text{ percent for Plants I \& II} \\ 5 \text{ percent for Plant IV} \\ 4 \text{ percent for Plant III} \end{cases}$$

This corresponds to about ± 30 ppm for all test series.

Three pieces of evidence support this contention:

<u>Reproducibility</u>: Observed scatter in the current NO_x data (PDS) taken on a given boiler (for a given operating condition) resulted in a standard deviation of 3 to 9 percent, as shown in Table B-2. It was necessary to discard 29 out of 95 data points in the Plants I & II Series because contamination of PDS samples and leakage caused anomalous results.

PDS Accuracy: A recent study[12] reports that the accuracy of the PDS method on coal-fired boiler ranges from 3 percent at 1000 ppm to 10 percent at 100 ppm. At 400 ppm the accuracy is about ± 5 percent. Fisher[18] reports 4 percent reproducibility of the PDS method on repeat tests of the same sample, and 5 percent random difference from the NDIR results.

Table B-2 REPRODUCIBILITY OF NO_x MEASUREMENTS
(Lignite-Fired Utility Boilers, PDS Method)

Unit	No. samples at test condition	Standard deviation as percent of mean
Plant II	7	7.3%
	6	6.8%
	10	8.6%
Plant I	7	7.8%
Plant III	13	(16.2%)*
	5	3.0%
	5	6.0%
	5	3.2%
	5	3.6%
Plant IV	13	(6.3%)*
	9	5.7%
	9	3.5%

* First day; systematic drift gave large "apparent" scatter.

Electrochemical Analyzer Accuracy: Although it proved useful to reveal on-site trends, the continuous monitor as used was of limited value as a rigorous data source, because of inadequate protection against thermal drift, ± 5 percent readibility (low range was 500 ppm), observed calibration adjustment of about ± 5 percent, and limitations of the SO_2 scrubbing solution (if 50 ppm of SO_2 gets through the scrubber, it is detected as NOx).

Based on substitution of these values into expression (3), we estimate emission uncertainty at ± 9 percent, ± 7 percent, and ± 6 percent for the Plants I & II, Plant IV, and Plant III series, respectively,

$\Delta E/E$ = 9 percent, Plants I & II
7 percent, Plant IV
6 percent, Plant III

3. Screening and Adjustment of O_2 and NO_x Data

The O_2 data were critically examined using three tests: First, Orsat O_2 was compared to analyzer O_2, expecting a fairly uniform degree of leakage for Plants I and II to cause a standard 2 percent O_2 difference (See Figure B-2). Second, abnormally high O_2 readings, say in excess of 7 percent, were discarded and attributed to Orsat bag leakage. Third, (O_2, CO_2) pairs were plotted to reveal pairs falling unusually far from the straight line expected for lignite (based on 18.5 percent CO_2 at 0 percent O_2). An example of this third screening technique is illustrated in Figure B-1.

Of 60 O_2 data points in the Plants I & II series, 17 were adjusted to provide internal consistency and satisfy the three criteria above within 0.5 percent O_2 (denoted with dots on Figure B-2).

The NO_x data were reviewed according to the following criteria:

(i) Data taken during a boiler transition (approximately 15 min duration) were discarded.

(ii) Method 7 PDS data were discarded when deviating more than two standard deviations (approximately 70 ppm) from the mean for a given condition. Flask leakage and hood contamination gave some quite obvious stray data for the Plants I & II tests. These stray data were discarded.

(iii) Dynasciences NO_x data were used only when PDS data was insufficient for a given boiler condition, and then only provided the Dynasciences results had shown good correlation with PDS samples of the same day.

Figure B-3 compares the PDS and electrochemical data on NO_x; this Figure was useful in identifying stray points. The best fit gave PDS results 15-50 ppm lower, conceivably due to flask leakage before PDS analysis. Corrections were applied to the electrochemical data to compensate for this systematic error, as shown in Table B-3.

4. Averaging Procedures

All NO_x data taken during a fixed boiler operating condition, during any one day, were averaged-PDS data only, adjusted as noted above, and supplemented by electrochemical data where appropriate.

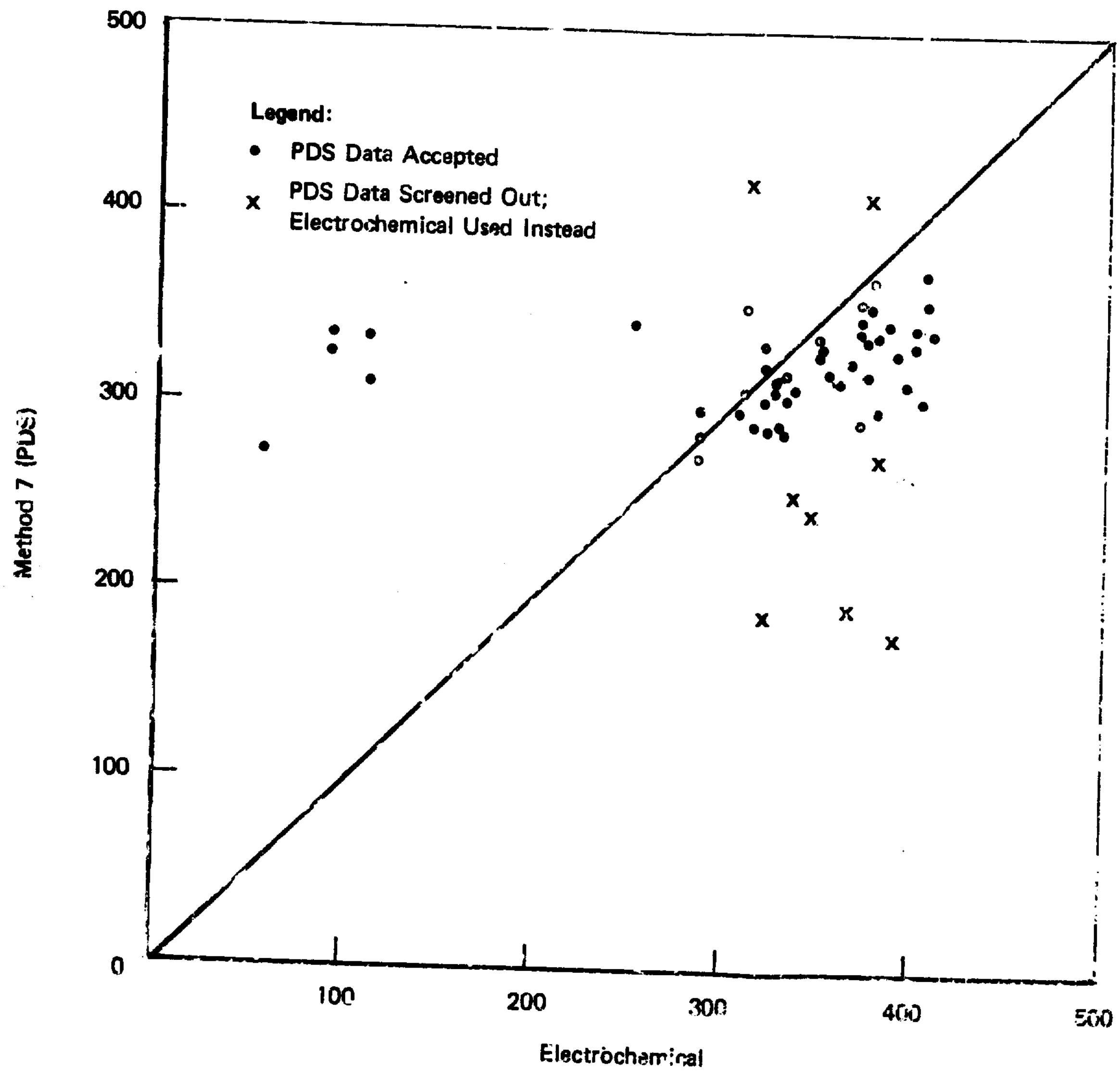

Figure B-3. NO_x (ppm, dry) MEASURED BY METHOD 7 AND BY ELECTROCHEMICAL ANALYZER

Table B-3 ADJUSTMENTS APPLIED TO ELECTROCHEMICAL NO_x DATA IN ORDER TO COMPENSATE FOR SYSTEMATIC DIFFERENCE BETWEEN PDS AND ELECTROCHEMICAL

Unit	Measured electrochemical NO_x (ppm)	Systematic difference between electrochemical and PDS on that day (ppm)	Adjusted electrochemical NO_x (ppm)
Plant I	385	-45	340
Plant II	310	-15	295
	390	-50	340
	365	-50	315
	380	-50	330
	320	-20	300
	345	-20	325
	335	-20	315

We denote this average <NO_x>. The O_2 data were also averaged for each test interval and dilution corrections were applied to reduce (NO_x) values to a common dilution condition (3 percent O_2). The O_2 and NO_x samples were not always simultaneous; thus individual emission index calculations at a given day and hour were not possible. The lignite feed rate (ton/hr) and stack gas velocity were also averaged over each test series. From this average data, a representative dscf/Btu value was calculated by both the direct and F-factor method.

In addition, all baseline (NO_x at 3 percent O_2) data for a given boiler were averaged, and standard deviations derived (weighted by the number of samples per test interval). The values of E (< NO_x at 3 percent O_2) from successive test series were well within the 8 percent estimated scatter.

APPENDIX C

COSTS FOR LIGNITE AND COAL FIRED PLANTS

Of the 26 utility owned units[1] idenified within the U.S., detailed cost information was collected on 21 units and is summarized in Table C-1. From this list, which represents 98% of the installed generating capacity and 97% of the annual production accounted for in Chapter II, we derived the following:

- Unit investment cost ($/kW) as a function of total plant size, and
- Unit production costs (mills/kWh) as a function of annual net generation.

Figures C-1 and C-2 show the installed costs and production costs respectively of those units for which data was available; these figures are expressed in 1972 dollars. For comparison, investment and annual operating costs were assembled for 15 bituminous-fired steam-electric units between 200 to 1,000 megawatts in size. These data are shown in Table C-2.

TABLE C-7

[illegible] COSTS AND ANNUAL [illegible] FOR [illegible] LIGNITE-FIRED [illegible][1] BY STATE

([illegible] dollars)

Utility:	[illegible]	MINNESOTA			NORTH DAKOTA						
	Mont. Dak. Util. Co.	Otter Tail Power Co.	Otter Tail Power Co.	Otter Tail Power Co.	Mont. Dak. Util. Co.	Mont. Dak. Util. Co.	Otter Tail Power Co.	Otter Tail Power Co.	Otter Tail Power Co.	Valley City Mun. Opt.	Basin Elec. Power Corp.
Plant:	Lewis & Clark	Crookston	Hoot Lake	Ortonville	Beulah	Heskett	Devils Lake	Jamestown	Kidder	Valley City	Leland Olds
Installed Generating Capacity (megawatts)	50.0	10.0	136.9	15.0	13.3	100.0	12.5	7.5	20.5	5.0	210.0
Net Generation (10^6 kWh)	340.2	39.9	831.6	90.5	66.0	312.9	47.7	42.7	23.4	3.7	1,575.6
Peak Demand on Plant (megawatts)	52.3	12.6	95.7	18.6	15.0	95.7	13.8	7.3	22.7	10.2	232.0
First Year of Operation:	1958	1948	1951	1930	1919	1953	1947	1925	1927	1957	1966
COST OF PLANT:											
Land	47	-	17	-	-	17	-	-	-	54	187
Structures	1,813	-	4,560	-	-	2,336	-	-	-	[illegible]	5,982
Equipment	9,142	-	20,736	-	-	12,800	-	-	-	1,776	22,353
Total Cost	11,004	3,448	25,337	3,687	2,750	15,153	3,[illegible]8	2,397	2,331	2,072	28,522
Unit Installed Cost ($/kW):											
Total Cost	220	344	185	245	207	152	267	320	133	415	119
Equipment Only	183	-	152	-	-	130	-	-	-	355	99
PRODUCTION EXPENSES[2]:											
Operation Supervision	15	211	36	236	132	37	223	212	183	14	33
Steam Expenses	110	-	175	-	-	146	-	-	-	101	236
Electric Expenses	69	-	122	-	-	85	-	-	-	9	104
Misc. Power Expenses	24	-	43	-	-	22	-	-	-	-	136
Maintenance		45		146	94		72	60	49	-	
Supervision	14	-	90	-	-	32	-	-	-	0	31
Structures	1	-	20	-	-	8	-	-	-	2	41
Boiler Plant	95	-	234	-	-	131	-	-	-	22	330
Electrical Plant	30	-	69	-	-	15	-	-	-	5	132
Structure	16	-	11	-	-	7	-	-	-	-	6
Subtotal	365	256	372	376	256	543	495	200	232	140	1,049
Fuel	1,131	252	3,[illegible]18	627	239	1,561	388	327	195	96	2,707
Total Expenses	1,496	508	4,750	1,003	495	2,504	683	607	427	236	3,756
Fuel Percentage of Total:	75.6	49.6	61.9	62.5	48.3	78.3	56.8	53.9	45.7	40.7	71.9
Unit Operating Cost (Mills/kWh):	4.39	16.4	5.76	11.0	7.73	4.09	14.3	16.2	18.2	67.4	2.38
FUEL CONSUMPTION											
Coal (10^3 Tons)	129.2	35	496.8	101	102	571.3	76	59	31	19	1,316.2
(cost/ton)	[illegible]	NA	5.57	NA	[illegible]	3.43	NA	NA	NA	500	2.06
(Btu/lb)	6,[illegible]0	[illegible]50	7,194	6,200	6,970	6,970	6,678	6,678	6,678	6,900	6,663
Oil (Bbls)											
(cost/bbl)											
(Btu/gal)											
Gas (Mcf)	141.3										
(cost/10^3 Mcf)	34.6										
(Btu/cub. ft.)	1,020										
Avg. Btu/kWh Net Generation:	12,642	16,197	11,910	14,131	21,217	12,994	22,704	20,354	17,693	74,914	10,699
Average Annual Plant Efficiency:	.270	.211	.286	.242	.155	.262	.150	.185	.193	.046	.300

[1] Includes some sub-bituminous plants whose quality of fuel is so low as to approach lignite.

[2] Does not include annual fixed charges on [illegible] in coal mining and transportation.

SOURCE: Federal Power Commission, [illegible]

TABLE C-1

CONSTRUCTION COSTS AND ANNUAL PRODUCTION EXPENSES FOR SELECTED LIGNITE-FIRED STEAM-ELECTRIC PLANTS[1] BY STATE [illegible]

(thousands of 1972 dollars)

	NORTH DAKOTA				SOUTH DAKOTA		TEXAS	WYOMING			AVERAGE
Utility:	Basin Elec.	Minnkota Power Corp. Inc.	Minnkota Power Corp. Inc.	United Power Assoc.	Black Hills Power & Light Co.	Mont. Dak. Util. Co.	Dallas Power & Light Co.	Black Hills Pow.& Lt.Co.	Mont.Dak.	Pac.Power & Lt.Co.	
Plant:	W. J. Neal*	F.P. Wood	Young-Center	Stanton	Ben French	Mobridge	Big Brown	Osage	Acme	D.Johnston	
Installed Generating Capacity (megawatts)	34.5	21.5	234.6	172.0	22.0	8.0	1,186.3	34.3	8.0	750.3	166.8
Net Generation (10^6 kWh)	130.9	3.0	1,841.8	1,041.9	108.7	20.4	2,440.6	231.1	20.4	3,283.8	680.2
Peak Demand on Plant (megawatts)	38.5		236.0	166.0	23.2	8	574.0	32.0	8	736.0	
Plant Year of Operation:	1951	1950	1970	1967	1960	1928	1971	1948	1910	1959	
COST OF PLANT:											
Land	17		310	173	59	-	NR	7	-	1,059	
Structures	1,822		7,227	5,642	1,146	-	NR	604	-	13,356	
Equipment	5,439		29,261	19,415	4,485	-	NR	2,862	-	112,726	
Total Cost	7,278	4,338	36,798	25,230	5,690	2,190	NR	3,353	2,147	127,141	15,796
Unit Installed Cost ($/kWh):											
Total Cost	211	202	157	147	259	258	-	152	268	169	215
Equipment Only	158		125	113	204	-		122	-	150	-
PRODUCTION EXPENSES:											
Operation Supervision	6	98	52	80	10	70	504	11	161	157	
Steam Expenses	49	-	172	217	72	-	656	114	-	936	
Electric Expenses	35	-	157	70	79	-	80	79	-	208	
Misc. Power Expenses	40	-	259	142	21	-	72	18	-	196	
Maintenance	-	4	-	-	-	26	-	-	60	-	
Supervision	3	-	43	16	10	-	46	11	-	136	
Structures	1	-	30	21	15	-	237	6	-	62	
Boiler Plant	17	-	546	647	63	-	712	30	-	1,003	
Electrical Plant	4	-	-	107	49	-	190	46	-	100	
Structure	1	-	80	33	16	-	92	15	-	127	
Subtotal	156	102	1,399	1,293	334	96	2,677	342	221	2,923	675
Fuel	462	23	2,307	2,076	479	87	5,640	684	135	3,725[2]	1,387
Total Expenses	618	125	3,866	3,369	813	183	8,317	1,026	356	6,648	1,998
Fuel Percentage of Total:	74.8	18.4	64.8	61.6	58.9	47.5	67.8	66.7	37.9	56.0	66.1
Unit. Operating Cost (Mills):	4.72	41.6	2.10	3.24	7.48	6.44	3.38	4.44	12.5	2.02	3.3
FUEL CONSUMPTION											
Coal (10^3 Tons)	222.6	4	1,615.6	857.0	85.3	13	1,790.0	219.4	30	2,335.6	10,500
(cost/ton)	3.00	NA	1.49	2.37	3.35	NA	2.94	3.12	NA	1.33	-
(Btu/lb)	6,644	6,391	6,391	7,026	7,947	7,900	7,000	7,947	7,000	7,420	6,900
Oil (bbls)			18.8	9.0							
(cost)			NA	4.90							
(Btu/gal)			140,000	137,550							
Gas (Mcf)							960.6				
(cost)							30.90				
(Btu/cub. ft.)							1,070				
Avg. Btu/kwh Net Generation:	22,942	17,043	11,212	11,559	12,673	120,824	10,600	15,000	14,700	10,597	11,404
Average Annual Plan Efficiency:	.149	.200	.304	.295	.269	.028	.321	.226	.232	.322	.300

[1] Includes some sub-bituminous plants whose quality of fuel is so low as to approach lignite.

[2] Does not include annual fixed charges on $8 million investment in coal mining and transportation.

SOURCE: Federal Power Commission, Steam-Electric Plant Construction Cost and Annual Production Expenses, 1970; various utilities.

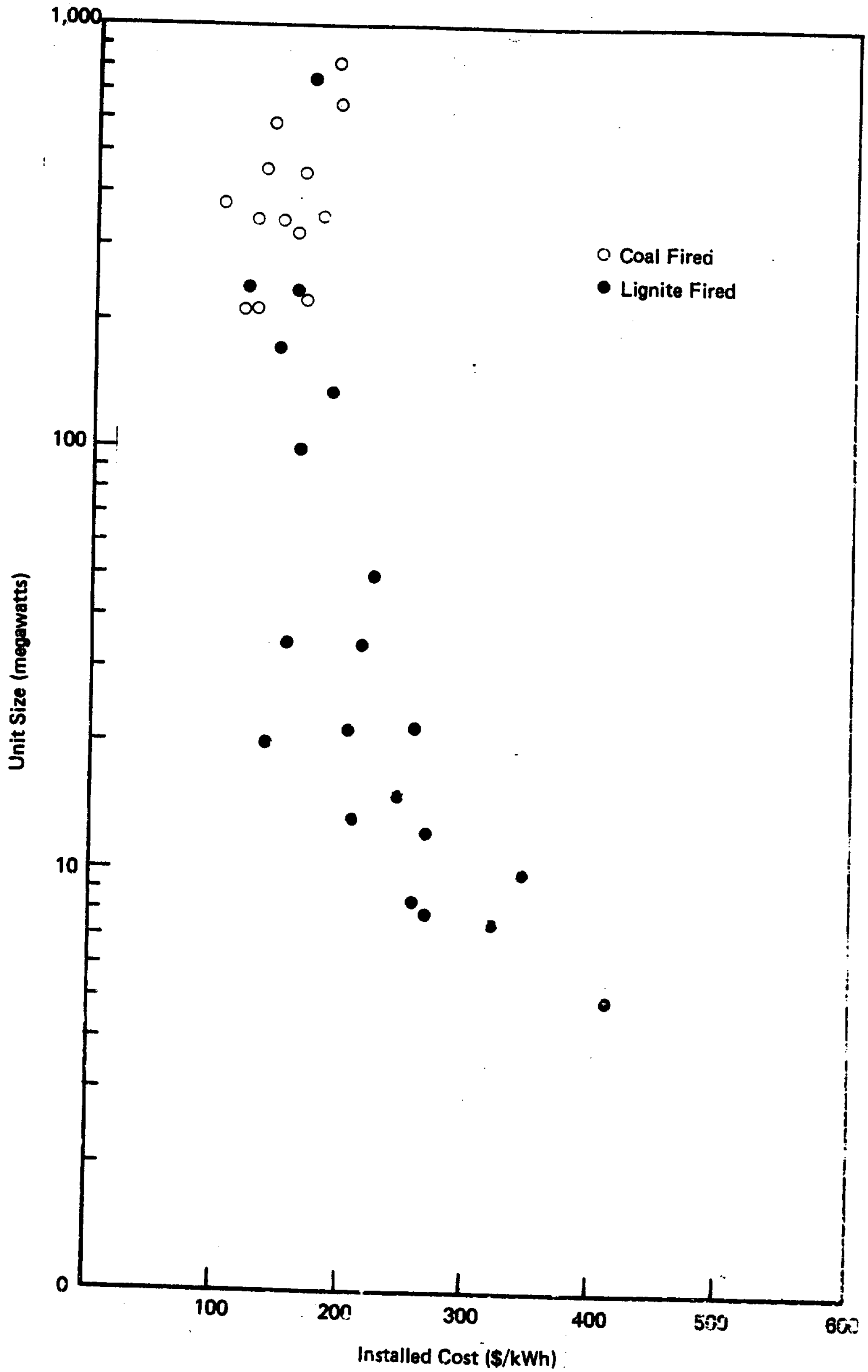

FIGURE C-1 INSTALLED COST VS PLANT SIZE FOR REPRESENTATIVE COAL-FIRED AND LIGNITE-FIRED PLANTS

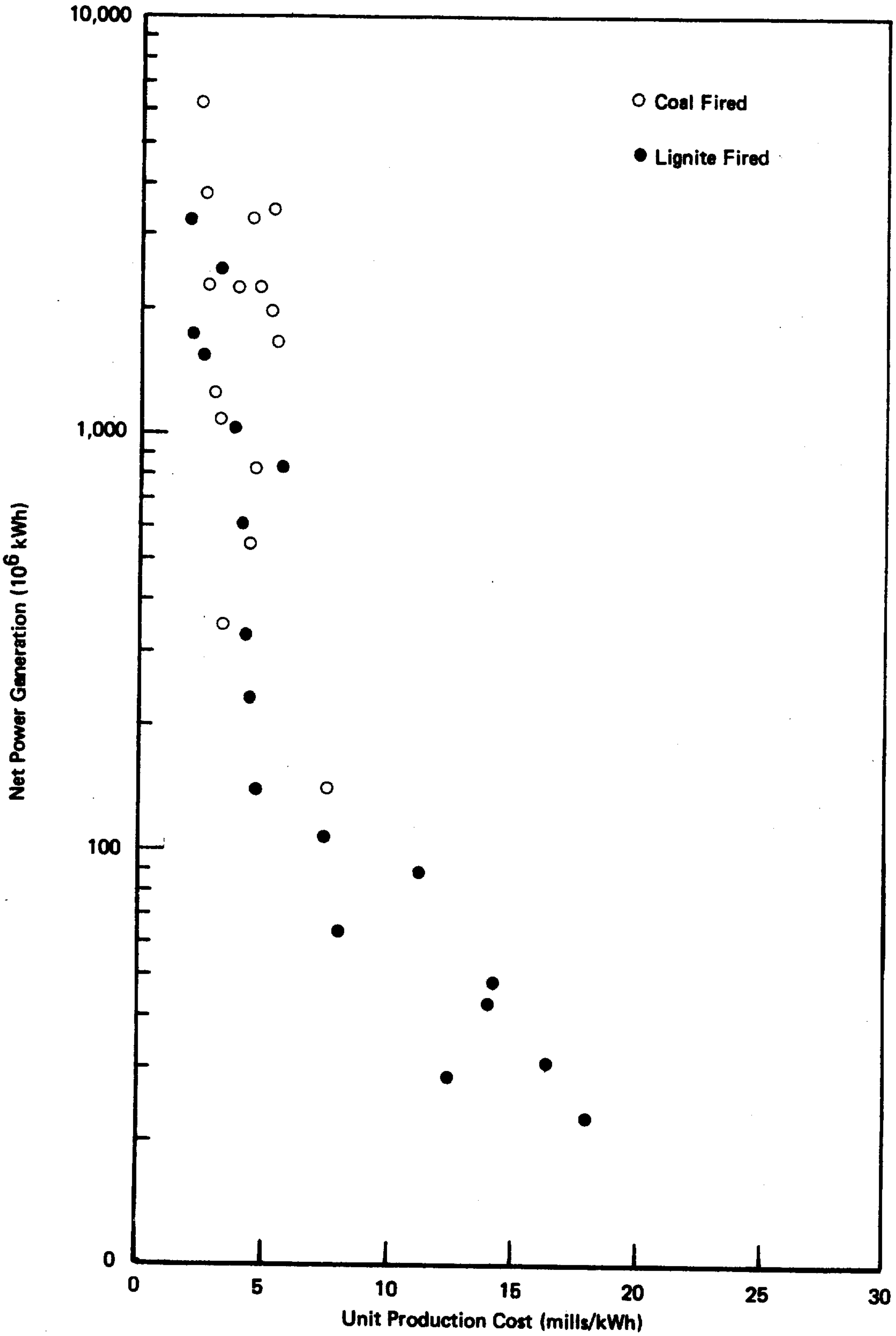

FIGURE C-2 PRODUCTION COST VS NET GENERATION FOR REPRESENTATIVE COAL-FIRED AND LIGNITE-FIRED PLANTS

TABLE C-2

CONSTRUCTION COSTS AND ANNUAL PRODUCTION EXPENSES FOR SELECTED COAL-FIRED STEAM-ELECTRIC PLANTS, BY STATE

(thousands of 1972 dollars)

	PENNSYLVANIA	WEST VIRGINIA	OHIO	KENTUCKY		INDIANA		ILLINOIS	IOWA	WISCONSIN	
Utility:	Penn. Pow. & Lt. Co.	Monongahela Power Co.	Cincinnati Gas & Elec. Co.	Louisville Gas & Elec.	Tennessee Valley Auth.	Alcoa Gen. Corp.	Ind. Statewide Rival Elec. Corp.	Ill. Power Co.	Iowa Southern Utilities Co.	Dairyland Power Corp.	Wisc. Power and Light
Plant:	Montour	Harrison	Beckjord 6	Millcreek	Paradise 3	Warricky	Frank E. Ratts	Baldwin	Burlington	New Genoa	Edgewater 4
Installed Generating Capacity (megawatts)	822.7	684.0	460.8	355.5	1,150.2	300.0	293.2	623.1	212.0	345.6	351.0
Net Generation (10^6 kWh)	3,463.8	141.2	2,247.2	545.9	6,313.7	2,273.2	1,357.1	3,796.5	1,099.6	1,672.3	2,236.2
Peak Demand on Plant (megawatts)	716.0	536.0	430.0	334.0	1,090.0	319.0	NR	617.0	213.0	346.0	328.0
First Year of Operation:	1972	1972	1969	1972	1970	1970	1969	1970	1968	1969	1960
COST OF PLANT:											
Land	2,594	4,637	27	842	298	-	82	2,661	81	376	268
Structures	19,883	25,733	8,877	15,855	23,334	1,938	6,785	30,812	4,443	7,607	7,136
Equipment	122,485	136,189	51,868	45,469	133,598	34,916	30,900	83,737	20,637	41,293	36,870
Total Cost	144,962	166,559	60,772	62,166	157,230	36,854	37,767	117,210	25,161	49,276	44,276
Unit Installed Cost ($/kW):											
Total Cost	176	244	132	175	137	97	162	188	119	143	126
Equipment Only	149	199	113	128	116	92	133	134	97	119	105
PRODUCTION EXPENSES:											
Operation Supervision	117	8	82	21	178	43	30	258	37	191	106
Steam Expenses	383	50	161	116	496	103	180	313	119	262	217
Electric Expenses	472	8	127	102	215	24	101	199	33	210	105
Misc. Power Expenses	90	498	79	43	494	143	44	253	37	135	92
Maintenance	-	-	-	-	-	-	-	-	-	-	-
Supervision	50	4	38	31	116	9	-	144	36	107	41
Structures	175	-	42	23	146	8	127	63	13	91	57
Boiler Plant	777	63	401	188	2,930	367	178	633	107	702	220
Electrical Plant	165	55	51	88	293	175	50	198	46	146	57
Structure	174	3	3	27	206	9	116	39	23	28	7
Subtotal	2,586	689	984	650	5,074	949	836	2,100	441	1,872	987
Fuel	15,927	384	8,024	1,832	10,479	5,416	[illegible]	7,796	3,235	7,313	9,804
Total Expenses	18,513	1,073	9,008	2,482	15,553	6,365	4,577	9,896	3,676	9,185	10,791
Fuel Percentage of Total:	86.0	35.8	89.1	73.8	67.4	85.1	86.3	78.8	88.0	79.6	90.9
Unit Operating Cost (Mills):	5.35	7.60	4.01	4.55	2.46	2.80	3.37	2.61	3.34	5.49	6.82
FUEL CONSUMPTION											
Coal (10^3 Tons)	929.0	38.4	1,026.7	233.4	2,870.8	1,003.3	641.5	1,842.1	544.5	731.2	996.5
(cost/ton)	8.95	10.01	7.79	7.85	3.59	5.36	6.16	4.23	5.93	9.74	9.82
(Btu/lb)	11,255	12,550	10,580	11,113	10,190	10,749	10,594	9,960	10,138	9,712	10,913
Oil (bbls)			4.8								
(cost/bbl)			5.06								
(Btu/gal)			138,000								
Gas (Mcf)						3.1					
(cost/10^3 Mcf)						74.85					
(Btu/cub. ft.)						1,013					
Avg. Btu/kwh Net Generation:	10,581	11,560	9,681	9,501	9,300	9,876	10,019	9,669	10,040	8,771	9,730
Average Annual Plant [illegible]	[illegible]		[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	.351

SOURCE: Federal Power Commission, Steam-Electric Plant Construction Cost and Annual Production Expenses, 1972.

TABLE C-2 (Continued)

CONSTRUCTION COSTS AND ANNUAL PRODUCTION EXPENSES FOR SELECTED COAL-FIRED STEAM-ELECTRIC PLANTS, BY STATE

(thousands of 1972 dollars)

	MINNESOTA	MISSOURI	FLORIDA	WYOMING	AVERAGE
Utility:	No. States Paper Co.	Empire District Elec. Co.	Tampa Electric Co.	Utah Power and Light	
Plant:	Allen S. King	Asbury	Big Bend	Naughton III	
Installed Generating Capacity (megawatts)	598.4	212.8	445.5	326.4	480.1
Net Generation (10^6 kwh)	3,310.1	1,288.7	1,976.5	828.8	2,170.1
Peak Demand on Plant (megawatts)	NR	192.0	382.0	327.0	448.5
First Year of Operation:	1968	1970	1970	1971	1970
COST OF PLANT:					
Land	566	125	3,931	-	1,099.2
Structures	15,151	778	14,372	5,930	12,581.6
Equipment	66,215	25,004	53,999	45,350	61,896
Total Cost	81,932	25,907	72,302	51,280	75,576.8
Unit Installed Cost ($/kw):					
Total Cost	137	122	162	157	152
Equipment Only	111	118	121	139	125
PRODUCTION EXPENSES:					
Operation Supervision	124	111	127	33	98
Steam Expenses	530	108	261	54	224
Electric Expenses	214	116	191	58	145
Misc. Power Expenses	317	40	239	48	170
Maintenance	-	-	-	-	-
Supervision	76	27	56	35	51
Structures	61	12	28	11	51
Boiler Plant	864	170	593	113	554
Electrical Plant	52	32	151	66	108
Structure	78	4	85	36	49
Subtotal	2,316	620	1,734	454	1,472
Fuel	12,811	3,296	8,314	2,111	6,713
Total Expenses	15,127	3,916	10,048	2,565	8,185
Fuel Percentage of Total:	84.7	84.2	82.7	82.3	79.6
Unit Operating Cost Mills:	4.57	3.04	5.08	3.10	4.15
FUEL CONSUMPTION					
Coal (10^3 Tons)	1,476.4	654.5	929.0	450.3	987.8
(cost/ton)	8.68	5.02	8.95	4.65	7.30
(Btu/lb)	10,770	10,434	11,255	9,458	10,738
Oil (bbls)					
(cost/bbl)					
(Btu/gal)					
Gas (Mcf)				37.1	
(cost/10^3 Mcf)				39.84	
(Btu/cub. ft.)				828	
Avg. Btu/kwh Net Generation:	9,608	10,609	10,581	10,318	9,944
Average Annual Plant Efficiency:	.355	.382	.323	.332	.349

SOURCE: Federal Power Commission, Steam-Electric Plant Construction Cost and Annual Production Expenses, 1972.

APPENDIX D

FUEL-NITROGEN CONTENTS OF LIGNITES

Table D-1 lists literature values for the average fuel-nitrogen content of Texas and North Dakota lignites. All values have been recalculated as necessary to express percent nitrogen on a common, moisture and ash free basis. Specific references have also been listed with each entry in Table D-1 to allow quick verification of sources.

Table D-1. FUEL-NITROGEN CONTENT OF NORTH DAKOTA AND TEXAS LIGNITE

Percent Fuel-Nitrogen on a Moisture and Ash Free Basis		Reference
Texas	North Dakota	
1.4	1.3	44
1.4	1	45
-	1.1	43

Table D-1 shows that North Dakota lignite does not contain substantially more fuel-nitrogen than Texas lignite as some utilities claim. However, it should not be concluded that Texas lignite has significantly more fuel-nitrogen either. Reference (43) which is specific for North Dakota lignite is an exhaustive study in which over 500 separate analyses were performed. Consequently, the apparent difference between the fuel-nitrogen content of Texas versus North Dakota lignite may only be the result of possessing a smaller amount of data for Texas lignite.

Table D-2 gives the average fuel-nitrogen content for the ten major North Dakota lignite mines. Variation of the average fuel-nitrogen content among these ten mines is slight. In order to test the hypothesis that there is no appreciable difference between fuel-nitrogen contents of various North Dakota lignites, the Chi Square Test has been applied to the data in Table D-2. The Chi Square Test indicates the probability that deviation from an average value (0.6% N_2 as received in this case) was caused by some factor other than chance or sampling error. Letting "f" equal the average percent fuel-nitrogen per mine on an as received basis, the Chi Square for the data in Table D-2 is:

$$\chi^2 = \Sigma\ [(0.6 - f)^2/f] = 0.0829.$$

Comparing the calculated Chi Square to a standard table of Chi Squares, there is less than a 1 percent chance that the observed deviations occurred due to some factor other than chance or sampling error.[46] Thus, statistically, there is no reason to assume that the average fuel-nitrogen content of North Dakota lignite varies significantly between mines.

Table D-2. FUEL-NITROGEN CONTENT OF VARIOUS NORTH DAKOTA LIGNITES[43]

Mine	Average % Fuel-Nitrogen	
	As Received	Water and Ash Free
South Beulah	0.7	1.2
North Beulah	0.6	1.05
Indianhead	0.6	1.05
Glenharold	0.6	1.06
Dakota Star	0.5	0.9
Velva	0.7	1.25
Baukol-Noonan	0.7	1.2
Kincaid	0.6	1.1
Gascoyne	0.5	1.0
Savage	0.6	1.1

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

1. REPORT NO. EPA-450/2-76-030a	2.	3. RECIPIENT'S ACCESSION NO.
4. TITLE AND SUBTITLE Standards Support and Environmental Impact Statement, Volume 1: Proposed Standard of Performance for Lignite-Fired Steam Generators		5. REPORT DATE December 1976
		6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)		8. PERFORMING ORGANIZATION REPORT NO.
9. PERFORMING ORGANIZATION NAME AND ADDRESS U. S. Environmental Protection Agency Office of Air Quality Planning and Standards Research Triangle Park, North Carolina 27711		10. PROGRAM ELEMENT NO.
		11. CONTRACT/GRANT NO.
12. SPONSORING AGENCY NAME AND ADDRESS		13. TYPE OF REPORT AND PERIOD COVERED
		14. SPONSORING AGENCY CODE

15. SUPPLEMENTARY NOTES Volume 1 discusses the proposed standards and the resulting environmental and economic effects. Volume 2, to be published when the standards are promulgated, will contain public comments on the proposed standards, EPA responses,

16. ABSTRACT

and a discussion of differences between the proposed and promulgated standards.

A standard of performance for the control of emissions of nitrogen oxides from new and modified lignite-fired steam generators is being proposed under the authority of section 111 of the Clean Air Act. When standards of performance for large steam generators were promulgated under Subpart D of Part 60, lignite-fired units were exempted from the nitrogen oxides standard (the sulfur dioxide and particulate matter standards are applicable to lignite-firing) because of a lack of data on attainable levels of emission from such units. Since then, sufficient data has been obtained to propose a standard. This document contains the background information, environmental impact assessment, and the rationale for the derivation of the proposed standard.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air pollution Pollution control Standards of performance Fossil-fuel fired steam generators Nitrogen oxides	Air pollution control	

18. DISTRIBUTION STATEMENT Unlimited	19. SECURITY CLASS (This Report) Unclassified	21. NO. OF PAGES 190
	20. SECURITY CLASS (This page) Unclassified	22. PRICE

EPA Form 2220-1 (9-73)