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APPLICATION OF FLUIDIZED-BED TECHNOLOGY TO INDUSTRIAL BOILERS

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SUMMARY

This study is a small part of the Government's program to develop coal-fired fluidized-bed combustion technology. The study is confined to industrial boilers, and the purposes are to determine the potential for applying coal-fired FBC to industrial boilers with a firing rate of at least 100 million BTU/H and to assess the various impacts associated with deployment of the technology through the year 2000.

A survey of operators of large industrial boiler systems shows that the installation of coal-fired FBC boilers will be considered when:

- The reliability of FBC technology is commercially demonstrated to achieve continuous boiler operation of about one year duration and with effective control of emissions.

- The economics of FBC technology are demonstrated to be competitive with alternative ways of firing solid coal.

The principal alternatives with which FBC must compete are:

- Use of low sulfur "compliance" coal in a conventional boiler, with an electrostatic precipitator (ESP) to control particulate emissions.

- Use of high sulfur coal in a conventional boiler, with a flue gas scrubber to control SO_2 emissions and particulates.

The economics of these alternatives have been developed in 1975 constant dollars, for a Gulf Coast location, on a basis excluding the cost of coal itself, whether it is of compliance quality or high sulfur. As an example, the results for alternative technologies are shown below for the case of adding a single coal-fired 100 KPPH or 400 KPPH industrial boiler system at an existing manufacturing plant that has a petroleum-fired boiler system.

STEAM COST (EX. FUEL) IN
1975 DOLLARS PER THOUSAND POUNDS

	High Sulfur Coal		Low Sulfur "Compliance" Coal	
	FBC	Conventional With Scrubber	FBC	Conventional With ESP
Single Coal-Fired Boiler System Adding to Existing Oil-Fired Plant				
100 KPPH	3.59	3.95	3.15	2.90
400 KPPH	2.49	2.83	2.05	2.01

The estimates (based on current FBC costs) indicate a distinct advantage for FBC technology over conventional coal-firing plus flue gas scrubbing for high sulfur coal. With compliance coal, results are a stand-off in cost at the larger size, with a moderate advantage for conventional firing at the 100 KPPH size. All FBC costs (in constant dollars) are expected to improve significantly as this new technology matures.

FBC technology has potentially important and even decisive, advantages that are not captured by the above estimates. The advantages include flexibility to combust different coals, good control of NOx emissions, flexibility to readily achieve higher sulfur capture if SO_2 emission regulations are tightened, relatively unobjectionable solid wastes for which uses are under development, and ability to be fabricated and shipped in modules for simple field assembly.

However, it is important that commercial development should occur before the growing coal-fired industrial boiler market is pre-empted by other coal-use technologies. Pre-emption is possible if, at the time industrial decision-makers must make commitments to new boilers, other technologies are commercial while FBC technology has not been fully demonstrated. It is believed that the industrial boiler potential of FBC could be impaired if the technology is not demonstrated to be commercially reliable by 1981. Major Governmental funding of FBC development programs suggests that reliability will be demonstrated in time. The estimates of coal-fired FBC potential assume that this will be the case. On this basis, the most probable nationwide potential is estimated to be:

Year	Cumulative Number of Industrial FBC Boilers	10^{15} BTU Per Year	1000 B/D of Oil Equivalent
1980	7	0.01	5
1985	200	0.29	136
1990	685	0.99	462
1995	1170	1.69	793
2000	2050	2.97	1400

Most of the estimated potential is expected to be in the chemicals, petrochemicals, petroleum refining, paper, primary metals, and food industries. Geographically, more than 90% of the potential is expected to be in regions that FEA has designated Appalachian, Southeast, Great Lakes, and Gulf Coast.

The FBC potential can be related to the value of manufacturing that is estimated to be supported by large coal-fired FBC boilers. For the above regions, the FBC-related "Gross Product Originating" is estimated to be:

Region	FBC-Related GPO in Billion 1975 $			
	1985	1990	1995	2000
Appalachian	3.5	12	22	40
Southeast	3.1	11	19	35
Great Lakes	3.1	11	19	36
Gulf Coast	4.2	15	26	48
	13.9	49	86	159

The above estimates are for the "most probable" case considered and apply to existing manufacturing applications. Separate estimates were also made of maximum and minimum potentials and amount, respectively, to slightly less than double and approximately one quarter of the above figures.

Other estimates associated with the most probable potential are that:

- The equivalent of 2000 industrial FBC boilers, with an average capacity of 200 KPPH and a cumulative erected cost of almost $6 billion (1975 constant $), would be installed through the year 2000.

- Coal requirements for the FBC boilers would approximate 140 million tons in the year 2000, and would have an F.O.B. mine value of $2 billion.

- Associated limestone requirements would be about 50 million tons in the year 2000, with an F.O.B. quarry value of $170 million.

- Also, in the year 2000, emissions relating to the coal-fired FBC boilers in compliance with Federal Standards for new point sources, would approximate 48 million tons of solid wastes, 132,000 tons of particulates, 660,000 tons of NO_x, and 1.6 million tons of SO_2.

Despite the seemingly large estimates of emissions, examination of two Air Quality Control Regions (Metropolitan Houston-Galveston and West Central Illinois) suggests that utilization of FBC-technology industrial boilers is likely to have a much smaller impact on ambient air quality than (a) the impact caused by sources other than industrial boilers, and (b) the emissions impact of existing coal-fired equipment in regions that currently use coal to a significant degree. In the latter case and in the long run, a net beneficial effect is possible if FBC installations replace existing coal-fired units.

Low sulfur coals containing appreciable amounts of alkaline ash, when used in conjunction with FBC technology, may alleviate the problem of switching to coal from natural gas and oil. Available technical data are inadequate, and thorough experimental investigation of this important possibility appears desirable. Most Southwestern lignites, which also contain appreciable amounts of alkaline ash, are not compliance coals if combusted conventionally but may become so in fluid-bed units. This possibility is of considerable potential importance to industry located in the Gulf Coast area. Thorough experimental investigation appears desirable.

Compliance with New Source Performance Standards (NSPS) may not be sufficient in some industrial areas of the country which are already at, or beyond, the Federal or state/local limits for ambient air quality. The Metropolitan Houston-Galveston area (AQCR 216) is an example of a highly industrialized area, of critical economic importance to the nation, where current levels of particulates and NO_2 are close to the primary standards for ambient air quality. Directionally, even with excellent control technology, coal use in new installations will make matters worse unless the existing situation is improved.

Where FBC technology is not the technology of choice, industrial boiler fuel demand is expected to be satisfied by a combination of:

- Conventional use of compliance coal
- Application of control technologies such as FGDS ("scrubbers") to non-compliance coal
- Use of solvent refined coal or other forms of cleaned coal
- Use of coal-in-oil slurries
- Continuing use of oil and natural gas

Additionally, it is speculated that some industrial plants will purchase steam from central plants while others may substitute electricity for steam in some industrial processes.

HIGHLIGHTS

The Highlights that follow reflect the contractor's judgment of what are the most important points in each of the detailed sections of the report. The pertinent section numbers are noted in parentheses.

The Highlights section is equivalent to an extended Table of Contents, and its purpose is to help the reader to locate points of interest quickly, and then refer to the section of the report in which the point is discussed in the context of related issues. The reader is especially cautioned not to draw inferences from numerical estimates that are separated from their contexts, assumptions and other qualifications. Such qualifications are deliberately minimized in the Highlights section.

Introduction (1.1)

- The Government is funding an intensive effort to develop coal-fired fluidized-bed combustion technology.
- This study is a small part of this effort.

Objectives (1.2)

- Determine the potential of coal-fired FBC for industrial boilers.
- Assess the impacts of deployment of coal-fired FBC.

Approach (1.3)

- Certain factors, such as plant investments and operating costs can be quantified, while other factors, such as coal-use legislation and the future cost and availability of foreign oil, cannot be quantified. The study attempts to take account of quantifiable and non-quantifiable factors that may affect the commercial potential of coal-fired FBC.

Industrial Boiler Systems (2)

- The manufacturing industries that consume most of the industrial boiler fuel include Chemicals, Petroleum Refining, Paper, Primary Metals, and Food. Large process plants in these industries are usually continuously operated and must have a reliable supply of process steam.

Types of Industrial Boilers (2.1.1)

- Watertube boilers span the size range from less than 10,000 pounds of steam per hour to about 7 million PPH. The very large boilers, of over 1 million PPH, are used almost exclusively by electric utilities. Watertube boilers are designed for a variety of fuels, steam pressures (15 to 4,000 psi) and steam temperatures (250°F to about 1025°F).

- Package boilers are assembled at boiler manufacturers' plants. Railroad shipping constraints limit their dimensions to about 40' long by 13' wide by 16' high. Investment savings for a package unit may be up to 25% of the cost of a field-erected unit of similar capacity.

Present Population of Large Industrial Boilers (2.1.3)

- FEA surveys of large industrial boilers provided the following picture for 1974:

Firing Rate million BTU/H	Steam Rate 1000 PPH	Number of Boilers	Capacity KPPH	Capacity %
100-199	83-153	2404	284	43
200-299	154-214	802	148	22
300-499	215-333	514	141	21
>500	>334	188	91	14
		3908	664	100

FBC as Applied to Industrial Boilers (2.1.4)

- FBC designs have size advantages relative to other boiler designs. In pilot plants operating at atmospheric pressure, FBC units have achieved heat release rates of over 100,000 BTU/H/cubic foot of expanded bed volume. Comparable rates for typical pulverized-coal-fired boilers are 20,000 BTU/H/cubic foot of firebox.

Timetable for FBC Developments (2.1.6)

- - Start-up of Rivesville multicell FBC boiler — Jan. 1977
  - Start-up of industrial development units — 1978
  - Routine designs of industrial units offered by several boiler manufacturers. — 1981-1982

Estimated Investment and Operating Costs (2.3)

- Screening cases have been developed to compare investment and operating costs for:

  - FBC boiler firing high sulfur coal
  - Conventional coal-fired boiler with flue gas scrubber, firing high sulfur coal.
  - FBC boiler firing low sulfur "compliance" coal.
  - Conventional coal-fired boiler firing low sulfur "compliance" coal.
  - Package oil-fired boiler firing low sulfur fuel oil.

- Costs of steam (ex fuel) for 100 KPPH and 400 KPPH add-on and grass-roots boiler projects, in 1975 constant dollars per 1000 pounds of steam and including project contingencies, are estimated to be:

	High Sulfur Coal		Low Sulfur "Compliance" Coal	
	FBC	Conventional With Scrubber	FBC	Conventional With ESP
Single Coal-Fired Boiler Addition to Existing Oil-Fired Plant				
100 KPPH	3.59	3.95	3.15	2.90
400 KPPH	2.49	2.83	2.05	2.01
Grass Roots Coal-Fired Boiler System, With Backup				
100 KPPH	4.81	5.65	4.37	4.07
400 KPPH	3.19	3.91	2.76	2.78

- Comparison of investments, and steam costs (ex fuel), for a single coal-fired boiler added to an existing oil-fired plant:

	High Sulfur Coal			
	FBC		Conventional With Scrubber	
Steam rate, KPPH	100	400	100	400
Investment, million 1975$				
Coal Handling	1.8	2.7	1.8	2.7
Boiler and Stack	3.1	7.6	2.9	8.6
Environmental and Waste Disposal	1.3	3.4	2.6	6.9
Total, M$	6.2	13.7	7.3	18.2
Unit Cost of Steam (ex fuel), 1975$ per 1000 lbs.				
Op. costs excl. BFW	1.42	1.02	1.50	1.08
Boiler Feed Water	0.60	0.60	0.60	0.60
Capital Charges	1.57	0.87	1.85	1.15
Total (ex fuel), ¢/k lbs.	3.59	2.49	3.95	2.83

- Meeting environmental standards, while burning high sulfur fuels, is significantly more costly than burning (compliance) fuels that are low enough in sulfur content to meet SO_2 emission limits directly.

- Based on current FBC costs, there is a distinct advantage for burning high sulfur coal in an FBC boiler compared with conventional burning of the same coal plus flue gas scrubbing. Furthermore, current FBC designs are "first generation", and significant cost reductions can be anticipated in the future.

- Conversion of existing boilers to FBC technology (i.e. "retrofitting FBC") is judged to be economically unattractive.

Market Survey of Large Industrial Boiler Users (2.4)

- Operators of large industrial boiler systems express readiness to consider the installation of coal-fired FBC boilers as soon as:

  - The reliability of FBC technology is commercially demonstrated by continuous boiler operation, with effective control of emissions, for runs approaching a year's duration.
  - The economics of using FBC technology are demonstrated to be competitive with conventional coal-firing.

Standard Industrial Classification (3.1)

- The SIC system of the Bureau of the Census recognizes 21 manufacturing industries in terms of 2-digit codes, which are subdivided into 450 4-digit codes. Approximately 30 of the latter offer a potential to coal-fired FBC, with most of the prospects concentrated within the broader 2-digit groupings of the chemicals, paper, petroleum refining, primary metals and food industries.

1972 Census of Manufactures (3.2)

- The most recent comprehensive data for energy consumption by U.S. manufacturing industries are for 1971, and are published in the 1972 Census of Manufactures.

Fuel Consumption of Large Industrial Boilers in 1974 (3.3)

- In 1975, the FEA conducted a survey of all Major Fuel Burning Installations in the U.S. An MFBI is an installation that has, or is, a fossil-fuel fired boiler, burner, or combustor with a design firing rate of 100 million BTU's per hour or greater.

- FEA's Office of Fuel Utilization has provided survey data for industrial boilers for use in this study. In 1974, there were approximately 4,000 industrial boilers with a design firing rate of 100 million BTU/H or more. These boilers were located at 1,600 industrial plants in the lower 48 states.

- Fuel consumption of the large industrial boilers approximated 4 quads (10^{15} BTU), broken down as follows:

SIC Code	Industry	% of Total Fuel Consumed by Large Industrial Boilers
28	Chemicals	26.2
26	Paper	16.7
29	Petroleum Refining	16.5
33	Primary Metals	12.4
20	Food	5.4
34	Fabricated Metal Products	1.7
35	Machinery, except electrical	1.4
49	Utility Services (excl. electricity generation)	1.3
32	Stone, Clay, Glass, Concrete	0.6
-	Other industries	17.8
		100

Future Demand for Industrial Boiler Fuel (4)

- The future size and structure of the U.S. economy is a principal determinant of industrial energy demand. The first step is to obtain estimates of future manufacturing activity.

Basis of Demand Projections (4.1)

- A joint study by the Office of Business Economics (Dept. of Commerce) and the Economic Research Service (Dept. of Agriculture), known as the "1972 OBERS Projections," provides estimates of U.S. manufacturing a activity through the year 2020 in terms of "Gross Product Originating" (GPO).

- The projections make it possible to calculate the average fuel consumption per unit of product output on an industry-by-industry basis.

Quantitative Projections (4.2)

- Starting with 1974 as a base year for which details of the fuel consumption of large industrial boilers are known (from FEA surveys), it is possible to estimate future boiler fuel consumption using the OBERS projections to derive multipliers for the 1974 data. The multipliers are adjusted for anticipated energy conservation per unit of manufacturing output and for expected changes in the proportion of output supported by the large (MFBI) boilers.

Projections of Coal-Fired FBC Potential; Basis (5.1)

- The coal-fired FBC potential is considered to be a sub-set of coal utilization by all large industrial boilers, and the level of coal utilization by industrial MFBI's is assumed to be driven either by limited availability of petroleum or by legislation (such as the Energy Supply and Environmental Coordination Act of 1974 or the proposed "National Petroleum and Natural Gas Conservation and Coal Substitution Act", i.e. S.1777).

Regional Applicability (5.3)

- Estimates of maximum, most probable, and minimum potentials for coal-fired FBC will be influenced by the regional applicability of the technology. Regional constraints, based on logistics and economics, are conceived to reduce the unconstrained potentials by 8%, 26% and 52% in the minimum, most probable, and maximum cases.

Maximum, Most Probable, and Minimum Potentials (5.4)

- Coal-fired FBC potentials for large industrial boilers are estimated to be:

	10^{15} BTU per year			
Year	Maximum	Most Probable		Minimum
1980	0.02	0.01	(0.2)	Nil
1985	0.62	0.29	(5.5)	0.075
1990	1.97	0.99	(16)	0.29
1995	3.20	1.69	(24)	0.54
2000	5.52	2.97	(36)	1.00

( ) = % of total fossil fuel demand estimated for large industrial boilers.

Boiler Fuel Demand Where FBC is not Utilized (5.6)

- Satisfaction of the fuel demand of the industrial boilers in which coal-fired FBC is not utilized is expected to include (a) conventional use of compliance coal, (b) non-compliance coal with control technologies such as FGDS, (c) solvent refined coal or other forms of cleaned solid coal, (d) coal-in-oil slurries, and the continuing use of oil and gas in some plants. Steam purchased from central plants and/or substitution of electricity for steam in some processes are further possbilities.

Regionalization of FBC Potential (5.7)

- More than 90% of the coal-fired FBC potential of large industrial boilers is expected to be in four regions: Appalachian, Southeast, Great Lakes, and Gulf Coast. (see Table 3-5 for identification of these FEA regions)

Impact on National Energy Consumption (6.1)

- The coal firing of large industrial boilers using FBC technology is not expected to have any marked impact on the aggregate of national energy consumption. The overriding consideration is that industrial boiler fuel demand is set by a given level of manufacturing activity and not by the technology by which the industrial boiler fuel is combusted.

Potential Savings of Oil and Natural Gas ((6.2)

- Savings of petroleum fuels will occur if solid coal is used in (large) industrial boilers, but the level of saving achieved will be essentially independent of the technology by which the coal is combusted.

- Conversion of the most probable estimate of coal-fired FBC potential into 1000 B/D of oil equivalent indicates the following "savings":

Year	1000 B/D of Oil Equivalent
1980	5
1985	136
1990	462
1995	793
2000	1396

Economic Impacts: National (7.1)

- Although the absolute macroeconomic impacts of coal-fired FBC are indeterminate, it is possible to ascribe certain levels of economic activities to certain levels of coal-fired FBC potential.

- In the most probable case, the Gross Product Originating that is relatable to the operation of coal-fired FBC industrial boilers is estimated to be:

Year	FBC-Related GPO in Billion 1975 $
1980	0.5
1985	15
1990	52
1995	93
2000	171

Regional Impacts (7.2)

- Regional impacts, in the four regions of greatest coal-fired FBC potential, in the most probable case, are estimated to be:

Region	FBC-Related GPO in Billion 1975 $			
	1985	1990	1995	2000
Appalachian	3.5	12	22	40
Southeast	3.1	11	19	35
Great Lakes	3.1	11	19	36
Gulf Coast	4.2	15	26	48

Boiler Manufacturing and Related Industries (7.3)

- The economic impact of coal-fired FBC on the manufacture of industrial boilers is estimated in terms of boiler units of 200 KPPH capacity. In the most probable case, the number of units and their erected cost is estimated to be:

	Number of 200 KPPH Units	Erected Cost in Million 1975 $
FBC units added through 1980	7	20
FBC units added through 1981/1985	193	540
FBC units added through 1986/1990	485	1360
FBC units added through 1991/1995	485	1360
FBC units added through 1996/2000	880	2460
	2050	5740

Coal Industry (7.4)

- For the most probable case, the estimates of coal volume and F.O.B. mine value for conventional applications of coal-fired FBC are:

Year	Million Tons	Million 1975 $
1980	0.46	6
1985	13.6	190
1990	47	655
1995	80	1113
2000	140	1960

Limestone Industry (7.5)

- The limestone requirements of coal-fired FBC industrial boilers, in the most probable case, are estimated to be:

Year	Million Tons	F.O.B. Quarry Value, M 1975 $
1980	0.16	0.56
1985	5	16
1990	16	56
1995	27	95
2000	48	167

Environmental Considerations (8.1)

- The environmental aspects of application of coal-fired FBC technology to industrial boilers are considered in relation to national emission standards for new point sources:

Pollutant	Emissions per million BTU's input, not to Exceed:
particulates	0.1 lbs
SO_2	solid fuel: 1.2 lbs liquid fuel: 0.8 lbs
NOx(as NO_2)	solid fuel: 0.7 liquid fuel: 0.3 gaseous fuel: 0.2

Estimates of Emissions (8.4)

- For Illinois No. 6 coal (3.6 wt% sulfur, 10,600 BTU/lb), the emissions from a 100 KPPH industrial FBC boiler operating at nameplate capacity are related to a daily consumption of 144 tons of coal and 54 tons of limestone. The daily emissions are estimated to be:

	Tons/Day
Solid Waste	55
Particulates	0.15
SO_2	1.85
NOx(as NO_2)	0.75

National and Regional Emissions (8.5)

- In the most probable case of FBC application to large industrial boilers, the nationwide emissions are estimated to be:

Year:	1000 Tons/Year 1980	1990	2000
Solid Waste	160	16,000	48,000
Particulates	0.4	44	132
SO_2	5	547	1,640
NOx(as NO_2)	2	220	660

- For the four regions projected to have the greatest potentials for FBC use, the emissions in the most probable case are estimated for the year 2000 to be:

	1000 Tons/Year Appalachian	Southeast	Gt. Lakes	Gulf Coast
Solid Waste	12,400	10,900	11,200	10,100
Particulates	34	30	31	25
SO_2	422	372	383	344
NOx(as NO_2)	170	150	154	139

Estimates of Emissions for Selected AQCR's (8.6)

- Air Quality Control Regions were selected in Texas and Illinois to permit comparisons between regions where, currently, (a) the industrial consumption of coal is minimal (Texas), and (b) there is a significant use of local high sulfur coal in industrial boilers (Illinois). The selected AQCR's were Metropolitan Houston-Galveston (#216) and West Central Illinois (#075).

- For the most probable case of FBC utilization, the projected emissions from coal-fired FBC industrial boilers are not expected to add large increments of criteria pollutants to the ambient air in AQCR 216. Nevertheless, for both particulates and NOx, the impact may be of practical significance because the current level of air quality is marginal. Hence, any incremental pollution would make ambient air quality standards more difficult to achieve and/or maintain.

- For AQCR 075, which has a much lower absolute level of industrialization than AQCR 216, the impact of FBC industrial boilers on ambient air quality is estimated to be minimal.

Disposition of Solid Wastes (8.7)

- Considerable quantities of solid wastes will be generated by coal-fired industrial boilers. By the year 2000, in the most probable case, the annual quantity of waste solids is estimated to approximate 50 million tons. Clearly, the disposal and/or utilization of such a large volume of material will require continued attention and development work.

Environmental Conclusions and Recommendations (8.9)

- Using conventional technology, a change from natural gas or oil to coal-firing would be expected to affect the environment adversely. With FBC technology there is a potential for improvement over conventional coal usage.

- The development of FBC technology will not, of itself, correct existing problems with ambient air quality. Notwithstanding the potentially important contributions that may be made by FBC technology to the coal-firing of industrial boilers in environmentally acceptable ways, such applications are likely to have a smaller impact on ambient air quality than:

  (1) the impact produced by combustion sources other than large industrial boilers, and -

  (2) the impact of emissions from existing coal-fired equipment in regions that currently use coal to a significant extent.

- Available technical data limit the quantitative environmental conclusions that may be drawn about coal-fired FBC per se and in relation to other coal use technologies. Further definition of the following is suggested:

  (1) the quantity of sulfur retained in the ash from FBC and spreader-stoker boilers . . . for representative Western coals (bituminous, sub-bituminous, lignites) and Southwestern lignites.

  (2) NOx emissions . . . for the same types of equipment and coals listed in (1).

  (3) particulate emissions from (atmospheric) coal-fired FBC boilers . . . as for (1) but also including high sulfur coals.

  (4) fate of trace elements . . . as for (1), but also including high sulfur coals and FGDS systems.

1. INTRODUCTION, OBJECTIVES AND APPROACH

1.1 Introduction

The Government is funding an intensive effort to develop fluidized-bed combustion (FBC) technology for coal firing. The purpose is to permit coal to be utilized efficiently and with environmental acceptability. The purposes of this study are to assess the applicability of fluidized-bed combustion of coal in industrial boilers, and to estimate the various consequences of utilizing coal in this way. Work under FEA Contract CO-04-50168-00 began on 6/27/75.

1.2 Objectives

The principal contractual objectives of the study are to:

(1) assess the potential for conservation of scarce petroleum energy resources through the use of clean, efficient, coal-fired FBC technology in industrial boilers.*

(2) determine the extent to which national and regional consumption of oil and gas may be reduced by future commercial use of coal-fired industrial FBC boiler technology, both for new units and as a retrofit technology for existing industrial boilers.

(3) assess the economic impact of widespread industrial application of the pertinent FBC technology to segments of the economy affected by it.

(4) determine and define the demand for the pertinent technology in relation to cost, availability of fuel, and other relevant factors.

(5) determine and define the specific technical requirements for representative applications of the pertinent FBC technology.

(6) assess the potential environmental impacts of the above.

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*The assessment excludes electric utility boilers and industrial process heaters. It is restricted to industrial boilers with a design firing-rate of at least 100 million BTU per hour.

1.3 Approach

The analytical approach used in the study is predicated by the concept that individual manufacturing companies who own and operate industrial boilers regard such operations as essential, but subordinate, to their principal interest which is to produce goods of various kinds efficiently and competitively. The corollary is that industrial decision-makers will regard coal-fired FBC as one of several approaches to satisfactory maintenance and continuation of their manufacturing operations. Hence, their decisions to use, or not use, FBC technology will depend on the status of FBC technology at the time that their individual decisions must be made. A decision to use FBC technology will depend on its having been demonstrated to be (a) reliable, and (b) economically competitive with whatever alternatives are available.

Throughout the study, which is concerned with assessment of the potential for, and related impacts of, coal-fired FBC, we have tried to identify factors believed to be important to the decision-making process. Certain factors, such as plant investments and operating costs, can be quantified. Other factors, such as coal-use legislation and the future cost and availability of foreign oil, cannot be quantified but may prove to be more important than those that can. Therefore, the study attempts to make a balanced assessment of what can affect the commercialization of coal-fired FBC, and does not reach conclusions solely on the basis of what can be quantified.

1.4 Structure of Report

The report is organized to permit sequential discussion of the principal elements or topics that were studied.

Section 2 is concerned with "hardware", i.e. with industrial boilers, their physical and other characteristics, investment and operating costs, technical specifications, and also with a survey of users of industrial boilers to learn their attitudes towards the use of coal and FBC technology.

Section 3 covers the users of industrial boilers from a classificational and statistical standpoint. The statistics relate to the hardware and to the quantities and types of fuel consumed. This part of the report also considers the future options open to the users of industrial boilers in relation to their anticipations of the future availability of different fuels and also coal-use legislation that has been proposed in the expectation that there will be future limitations on the availability of oil and natural gas.

Section 4 provides projections of the future demand for industrial boiler fuels. The estimates are based on published projections of future manufacturing output through the year 2000.

Section 5 derives estimates of the future potential for coal-fired FBC, as applied to industrial boilers, by applying various criteria of applicability to the estimates of industrial boiler demand developed in Section 4. Estimates of potential consider three cases: maximum, "most probable", and minimum.

Section 6 utilizes the estimates of coal-fired FBC potential to derive corresponding estimates of the impact on national energy consumption and the potential savings of oil and natural gas that would accrue from the commercial deployment of the pertinent coal-use technology.

Section 7 discusses a variety of economic impacts to be expected from the commercialization of coal-fired FBC for industrial boilers. Both national and regional economic impacts are considered. Additionally, specific consideration is given to the boiler manufacturing, coal, and limestone industries.

Section 8 addresses the environmental aspects of application of industrial FBC boiler technology. This is done in terms of emissions from point sources and the regional and national aggregates of such emissions. The disposition of solid waste and sludge by-products is also discussed.

The principal conclusions of the study are given in Section 9.

Section 10 is a compilation of the references and additional bibliography for each of the individual sections of the report. There are also four Appendices that include details of cost estimating and large amounts of statistical data that, for the convenience of readers, are separated from the text of the report. Tables, Figures, and references are numbered separately for each section of the report.

2. INDUSTRIAL BOILER SYSTEMS

Industrial boilers range upward in size from 10 thousand pounds steam per hour (10 KPPH) to the largest sizes used in manufacturing industries (not electric utility power stations), in the neighborhood of one million pounds steam per hour. This study is focussed on the larger industrial boilers (>100 KPPH), of which there are about 4,000 in the United States at present.

The manufacturing industries which consume most of the industrial boiler fuel burned in the U.S. include Chemicals, Primary Metals, Petroleum Refining, Paper, and Food. Large process plants in these industries generally are continuously operated and must have a reliable supply of process steam. Thus the boiler systems in these plants normally contain several boilers, with sufficient capacity so that a single boiler can be idled for maintenance or inspection without interrupting the process operations of the plant. Most of these boiler systems are capable of firing fuel oil and/or natural gas, plus any byproduct fuels which may be produced at the plant. Presently, about a quarter of the larger systems can fire coal as one of the fuels.

Fluidized bed combustion appears attractive as a future coal-use technology for new industrial boilers, particularly for additions to existing boiler systems. The principal advantages of FBC compared with conventional coal firing of large industrial boilers include the following:

- effective direct capture of sulfur dioxide from the combustion of high (and low) sulfur coal;
- significantly lower NOx emissions than conventional combustion, because fluidized bed combustors in FBC boilers can be readily designed to be operated at much lower temperatures than are possible in stokers and pulverized-coal-fired units, thus minimizing the formation of thermal NOx;
- reduced problems of slagging and fouling from sodium salts when lower rank coals which contain alkaline ash are burned, because of the lower combustion temperature;
- production of dry, granular, easily-handled solid wastes rather than the wet, unstable sludges characteristic of most flue gas scrubbers (throwaway type).

Operators of large industrial boiler systems have expressed their readiness to consider the installation of FBC-fired boilers to meet their requirements for new coal-fired boilers as soon as:

- the reliability of FBC technology is commercially demonstrated by continuous boiler operation with effective emissions controls for boiler runs approaching a year's duration;

<u>and</u>
- the economics for using FBC technology are shown to be competitive with those for using conventional coal firing.*

*It is understood that the economic comparisons must be made among systems that comply with all applicable environmental regulations during the working life of the boilers.

The first criterion is being addressed in major FBC pilot plant and demonstration programs carried out by ERDA and EPA in conjunction with private industry. As shown in this report, satisfaction of the second criterion is anticipated where high sulfur coal is the fuel of choice, and is probable when low sulfur coals are used.

2.1 Characteristics of Industrial Boilers

Several definitions of industrial boilers are in use. The principal distinctions are between (a) the physical nature of the equipment (boiler size and type) and (b) the function that the equipment is intended to perform (e.g. the disposition of the steam produced and the classification of the user's business). The present study is focussed mainly on the assessment of the application of fluidized bed combustion (FBC) technology to large industrial boilers (over 100 KPPH) in the manufacturing industries -- especially Chemicals, Primary Metals, Petroleum Refining, Paper, and Foods.

Industrial boilers were originally defined for this study to be in the size range of 10 to 500 KPPH. At the lower end of this size range (10-100 KPPH), we concluded very early that plants currently firing oil (or gas) in this smaller size of industrial boilers are very unlikely to be shifted from oil or gas fuels to coal -- these plants themselves are smaller, often located in congested areas where space for coal handling is not available, and in many cases working on a discontinuous schedule of operations (e.g. only one or two shifts per day, or shut down over weekends, etc.). For these plants, it is extremely unlikely that the relatively large investment associated with coal receiving, storing, handling, and firing would be attractive. Moreover, the few exceptions to this generalization would have no material impact on the quantitative potential for coal-fired FBC.

At the upper end of the size range, we found that there are in the U.S. about 200 industrial boilers (as distinguished from electrical utility boilers) with firing capacities considerably greater than 500 M BTU/hr. This is about 5% of the total number of large industrial boilers (over 100 M BTU/hr.) and is considered significant in terms of projecting future fuel requirements in the industrial sector. Since these largest industrial boilers overlap the size range of electric utility boilers, we modified the definition for our study so as to include very large boilers whose purpose is clearly "industrial", while excluding all boilers operated by electric utility companies.

2.1.1 Types of Industrial Boilers

Functionally, industrial boilers are classified into two types, firetube and watertube. In firetube boilers, the hot products of combustion pass through tubes which are submerged in a pool of boiling water. In watertube boilers, water flows by natural or forced circulation through tubes which are exposed to heat transfer by both radiation from the boiler flame and convection from the hot flue gas.

Generally, firetube boilers are used for industrial steam rates up to about 30 KPPH of saturated steam, at pressures up to about 150 pounds per square inch gauge (psig). In the U.S., they are generally fired with gas or oil. Because of the relatively small size of firetube boilers, and the expectation that there is little likelihood of widespread coal firing for this type of boiler in the United States, we conclude that the impact of FBC on plants using firetube boilers will be small*. Hence, we have not studied them as prospective candidates for application of FBC.

Watertube boilers span the size range from less than 10,000 pounds steam per hour to about 7 million pounds per hour. The very large boilers (over 1 million PPH) are almost exclusively for electric utility generation. Watertube boilers are designed for a large variety of fuels (gaseous, liquid, and solid), and cover a wide range of steam pressures and temperatures (pressures from 15 to 4,500 psig, temperatures from 250°F to about 1025°F).

Another very important method of classifying boilers is by type of boiler construction procedure, as either package or field-erected units. A package boiler is assembled at a manufacturer's plant, and then delivered to the operating site where it has only to be set on a foundation and piped up to appropriate connections to be ready for operation (6). In general, railroad shipping constraints limit the dimensions of package boilers to about 40' long by 13' wide by 16' high. A field-erected boiler is shipped in pieces or partial assemblies, and must be built in the field from the ground up. The distinction between package and field-erected boilers is very significant from a cost standpoint. Savings for a package unit compared with the same capacity field-erected boiler may be as much as 25-30%. For this reason, practically all oil and/or gas-fired watertube boilers up to about 250-300 KPPH are package boilers.

Most firetube boilers are package units, regardless of fuel fired. For conventional watertube boilers, the approximate breakpoint between package and field-erected depends on both the steam capacity and the fuel to be used, as indicated in the following table:

Approximate Maximum Size of Watertube Package Boilers, KPPH

Fuel Fired	Natural Gas	Fuel Oils	Solid Fuels
Approximate maximum capacity of package unit, KPPH	350	350	50-60 (7)

Gas or oil-fired package units have been built and shipped in two modules which were joined together in the field, at capacities up to 500 KPPH or greater.

Coal-fired watertube package boilers are relatively rare and relatively small. Most coal-fired watertube boilers are field-erected. One of the incentives for development of coal-fired fluidized bed combustion technology is that larger capacity units can meet the shipping dimension criteria and hence can be shop assembled as package units. For example, a preliminary design has been prepared for a 250 KPPH FBC package unit in two modules (8). The design takes advantage of the intense heat release per cubic foot of fluidized bed volume, and the high rate of heat transfer to boiler tubes submerged within the bed.

*in terms of the estimated savings of gas and oil achieved by use of coal-fired FBC. We are not suggesting that firetube boilers will be unimportant per se.

2.1.2 Boilers Firing Solid Fuels

Confining attention to solid-fuel-fired watertube boilers, there are many methods for firing the coal, lignite, or other solid fuel, and each method requires specific details of boiler design. Solid-fuel-firing methods listed by the American Boiler Manufacturers Association (ABMA) includes the following (3), (4):

Method	1974/1975 Industrial Boiler Sales No. Sold	1974/1975 Industrial Boiler Sales Average Steam Capacity, KPPH
Underfeed Stoker	8	<40
Overfeed Stoker	39	62
Spreader Stoker	82	149
Pulverized Coal Firing (PCF)	11	336
Other Solid Firing (including non-coal)	28	93
Total Non-Solid Firing	1219	97
	1387	101

As illustrated by the above table, the particular "conventional" coal-firing methods of interest for this study of large industrial boilers are (a) spreader stokers, which are typically used for boiler capacities in the range of about 100 to 250 KPPH, and (b) pulverized coal firing, which is almost universally used for larger coal-fired boilers (both industrial and utility).

2.1.3 Present Population of Large Industrial Boilers

In early 1976, a close approximation of a true census of large industrial boilers became available. This tabulation resulted from the Major Fuel Burning Installation Coal Conversion Report survey conducted by the FEA Office of Fuel Utilization. The survey was carried out pursuant to FEA's responsibilities under the Energy Supply and Environmental Coordination Act of 1974, and a reply was required to be submitted by every Major Fuel Burning Installation (MFBI). For this survey project, an MFBI was defined as an installation, other than an electric power plant, at a single site which has combined fossil-fuel-firing capability of 100,000,000 BTU/hr. or more in one or more boilers, burners, or combustors (excluding gas turbine and combined cycle or internal combustion engines) (13). For each individual combustor with a design firing capacity of 99 million BTU/hr or higher, a large amount of information was requested including age, combustor capacity, fuel firing capability, actual fuel consumed in 1974, and plans for conversion to coal firing.

The following table summarizes the population of large boilers with reported firing capacities above 99 M BTU/hr., as developed by the FEA Survey:

1974 Large Boiler Population Reported to FEA

Firing Rate, M BTU/hr	Approximate Steam Rate, KPPH (*)	No. of Boilers	%	Est'd. Total Capacity, KPPH	%
100 - 199	83 - 153	2404	62	284	43
200 - 299	154 - 214	802	20	148	22
300 - 499	215 - 333	514	13	141	21
over 500	over 334	188	5	91	14
Total		3908	100	664	100

* estimated using 1200-1500 BTU fired in the boiler per pound gross steam production.

2.1.4 Description of Fluidized Bed Combustion as Applied to Industrial Boilers

In a fluidized bed combustion (FBC) boiler, crushed high sulfur coal can readily be burned under conditions such that no further controls are necessary to meet emission limits of SO_2 and NOx in the flue gas. Very little experimental information is available on the combustion of low sulfur Western coals using FBC. For the purpose of this report, it is assumed that satisfactory operation can be obtained with this type of fuel using inert material in the fluidized bed. After commercial experience has been gained with this newly-developing technology, the size, initial cost, and operating cost for an FBC system are expected to be lower than for an equivalent conventional boiler system fired with the same fuel and meeting all environmental regulations.

For effective combustion of solid fuels, a furnace designer can manipulate three major inter-related variables by which adequate contact is achieved between solid fuel and oxygen, as follows:

(1) provide large solid fuel surface area;

(2) provide long contact time between gas and solid particles;

(3) provide high relative speed between gas and solid particles, so that fuel is not shielded from oxygen by a thick layer of stagnant burned gases.

Combustion in a spreader stoker emphasizes the second and third of these variables, while pulverized coal firing depends chiefly on the first two. Combustion in a fluidized bed can take advantage of all three of these variables, thus achieving an unusually high intensity of heat release in a small combustion volume.

Figure 2-1 is a schematic diagram of an atmospheric pressure fluidized bed boiler. The bed consists of a mixture of crushed limestone, dolomite, or inert material, and large ash particles, which is "fluidized" by the stream of air and combustion gases rising from the supporting grid beneath the bed. Original particle size of the bed material is about 1/8". The gas velocity is set so that the bed particles are suspended and move about in random motion, but do not blow away. Under these conditions, a gas/solid mixture behaves much like a boiling liquid (e.g. seeks its own level, can be readily moved through channels). The boiler tubes submerged in the bed remove heat at a high rate (extremely effective heat transfer) so that typical bed temperatures are in the range of 1400 to 1600°F.

Crushed coal (1/4" to 1/2" particles) and the required bed makeup material are continuously added at fuel injection points. Within the bed, the coal burns very quickly, and the bed generally contains less than 2 to 4% carbon. Most of the ash resulting from combustion of the coal is in relatively small, light particles which are swept out of the bed by the flue gas. If high sulfur coal is being burned, sulfated bed material is continuously withdrawn to maintain bed volume and activity for sulfur capture. If low sulfur fuel is being burned, it is assumed that the bed can be composed of inert material, such as alumina or sand, and that bed makeup and withdrawal rates will be very low or negligible.

Fluidized bed combustion (FBC) is an effective method for controlling emissions from high-sulfur fuels. For this purpose, the sorbent bed is limestone, dolomite, or lime. Assuming a limestone feed, the first reaction at bed temperatures is calcination.

$$CaCO_3 \longrightarrow CaO + CO_2$$

The sulfur in the fuel burns to sulfur dioxide, SO_2, and bed conditions are maintained to favor sulfation of the lime to gypsum.

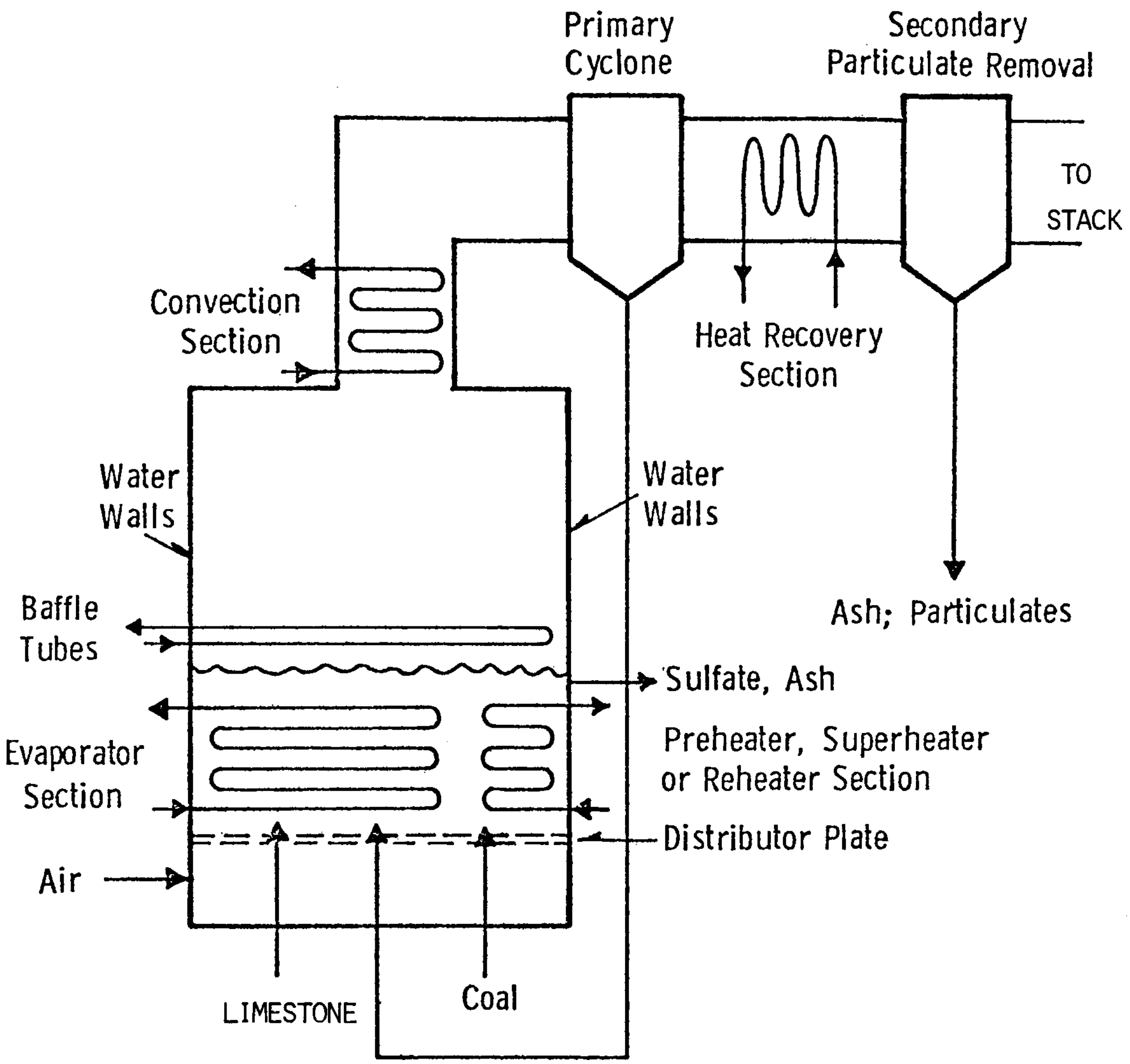
$$CaO + SO_2 + 1/2\ O_2 \longrightarrow CaSO_4$$

The limestone sorbent feed rate is set in accordance with the sulfur content of the fuel, and sufficient cleanup of SO_2 is achieved so that no further treatment is required for compliance with sulfur emission regulations. By contrast, a stoker or pulverized-coal boiler emits most of the sulfur in the fuel as SO_2, and high sulfur fuels cannot be burned in these boilers without desulfurization of the flue gas using some sort of scrubber.

With respect to nitrogen oxide (NOx) emissions, FBC operations on high sulfur coals exhibit inherent advantages over conventional boilers using stokers or pulverized coal firing. This is because the bed temperature is maintained at 1400 to 1600°F, well below the 2500°F + which is characteristic of conventional boilers. The lower FBC temperatures give correspondingly lower formation of thermal NOx, so that most FBC operations produce NOx emissions well below the EPA limits for NOx from new steam generators, without the necessity of any special combustion modifications or design features.

FIGURE 2-1

SCHEMATIC DIAGRAM OF ATMOSPHERIC PRESSURE FLUIDIZED BED COMBUSTION BOILER (8)



Combustion Pressure	-	close to atmospheric (usually balanced draft)
Bed Temperature	-	1400 to 1600°F
Gas Velocity	-	2 to 12 ft/sec
Bed Material	-	limestone or dolomite, or inert material for low sulfur fuels not requiring sulfur capture
Fuel	-	coal, fuel oil, bark and wood wastes, coke, char, etc.

Another valuable characteristic of FBC technology is its very wide tolerance to type and quality of solid fuels. Caking and non-caking coals, refractory cokes and chars, and solid wastes such as bark and wood wastes can all be burned efficiently in a fluidized bed. It is anticipated that FBC boilers will be effective burners for direct combustion of anthracite culm and low-BTU oil shale. The principal detail requiring careful design is to provide the capability of reasonably uniform fuel introduction at multiple points within the bed. Generally one fuel feed point should be specified for about 10 square feet of bed area. Not only is the average bed temperature relatively low, but temperatures throughout the bed are quite uniform if good fluidization is maintained. The absence of hot spots means that fuels having low-softening-point ash can be effectively burned without serious ash fusion or clinker formation.

A final advantage for FBC is that of size. Heat release rates have been achieved in atmospheric FBC pilot plants over 100,000 BTU/(hr)/(cubic foot of expanded bed volume), or perhaps 50,000 - 60,000 BTU/(hr)/(cubic foot of firebox). This can be compared with about 20,000 BTU/(hr)/(cubic foot of firebox) for a typical pulverized-coal-fired boiler. The high intensity of heat release plus the excellent heat transfer rates to boiler tubes submerged in the bed make it possible that FBC boilers up to about 250,000 pounds steam per hour can be designed for "package" shipment by rail (compared to the maximum coal-fired package size of about 50,000 lbs/hr currently available with conventional firing). This package feature should help to make the future erection cost of large sized FBC boilers significantly lower than for corresponding field-erected stoker-fired or pulverized-coal-fired units.

2.1.5 Different Versions of Fluidized Bed Combustion

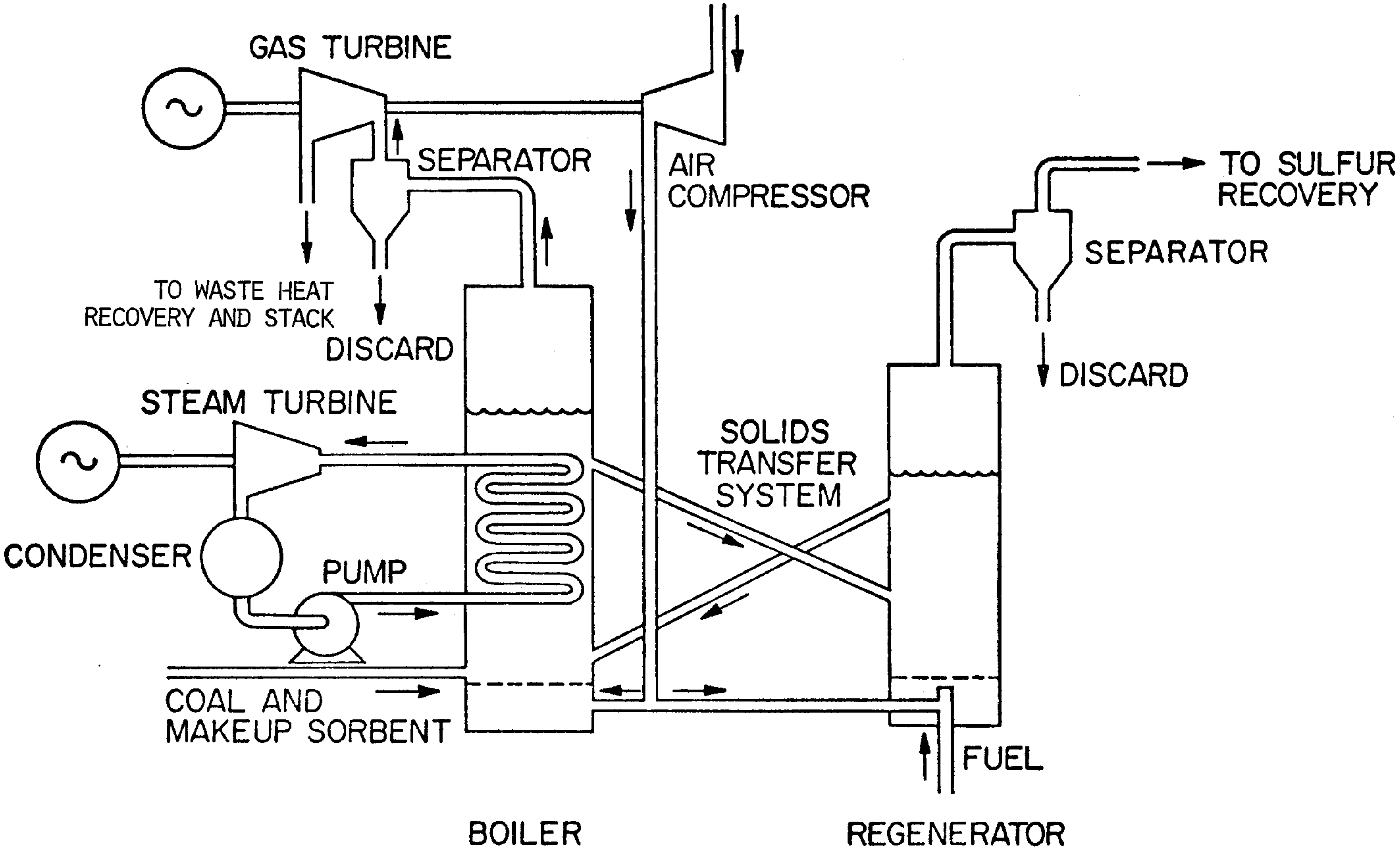
FBC operating schemes have been proposed with once-through or regenerative sorbent usage, and with combustion at atmospheric or elevated pressure. The atmospheric pressure FBC scheme with once-through sorbent flow, as described in the previous section, is the simplest version of this process. Proposed initial commercial FBC designs are all for atmospheric pressure operation with once-through sorbent.

Considerable work is underway to develop sorbent regeneration. The incentive for this is to reduce the requirements for fresh limestone or dolomite, and for high disposal rates of spent stone. In the sorbent regeneration process, the sulfur originally captured by the stone is expected to be released as a more concentrated stream of SO_2, and subsequent disposition of this strem presumably will be by conversion to sulfur (Claus), or to sulfuric acid.

Much work also is underway to develop pressurized fluid bed combustion. A schematic diagram of a pressurized FBC boiler (with sorbent regeneration) is given in Figure 2-2. The objective of higher pressure operation is to achieve higher thermodynamic efficiency for electric power generation than is possible with an atmospheric pressure unit. This is accomplished by use of a combined cycle, generating power both from a steam driven turbo-generator and a gas turbine. The combustor typically operates at a pressure on the order of 10 atmospheres (approx. 135 psig). Air is compressed into the combustor, and coal and limestone are injected through lock hoppers. Because of the higher pressure, even higher combustion intensities are feasible than with atmospheric

FIGURE 2-2

SCHEMATIC DIAGRAM OF PRESSURIZED FBC BOILER WITH SORBENT REGENERATION



FBC, and deeper fluidized beds can be used. Hot effluent flue gas from the boiler is cleaned to reduce particulate loading to a very low level, and then expanded through the gas turbine to generate supplemental electricity. Pressurized FBC when burning high sulfur coal gives significantly lower NOx emissions than the atmospheric version. From an overall standpoint, pressurized FBC is of interest to utilities, and possibly to operators of large industrial boilers who generate a significant portion of their own electric power needs. It is not of interest to those who generate steam directly at the relatively low pressure levels required for process uses.

The above discussion shows that there are four possible configurations of FBC which a future large industrial boiler purchaser might consider, as follows:

	Fluidized Bed Combustion Pressure	
Sorbent Cycle	Atmospheric	Pressurized
Once-through Sorbent	X	X
Sorbent Regeneration	X	X

The technical and economic assessments of FBC in industrial boilers presented later in this report are entirely based on atmospheric FBC with once-through sorbent. This is not because we believe there will be no industrial interest in the other combinations. It is rather because we conclude that the availability (or lack of availability) of sorbent regeneration and pressurized FBC technologies will not have a major effect on the overall penetration of FBC into the industrial boiler business. In other words, we believe it is unlikely (between now and year 2000) that the incremental return for pressurized FBC or for sorbent regeneration over atmospheric FBC with once-through sorbent will ever be so high as to increase significantly the overall industrial use of FBC. In addition, there is the very practical problem that usable cost estimates for pressurized FBC and sorbent regeneration facilities in the industrial size range are nowhere available at this time.

2.1.6 Timetable for FBC Developments

Table 2-1 shows our estimates of the probable timing for the availability of FBC-fired industrial boilers. We expect that atmospheric pressure, once-through sorbent designs will be regularly available from the boiler-making industry by 1981 or 1982. It should be noted that Fluidized Bed Combustion Company of Livingston, N.J. already has completed preliminary designs and would consider commercial sales of FBC-fired industrial boilers now. Other boiler manufacturers are gearing up to do so. Pressurized FBC and sorbent regeneration are several years behind the atmospheric once-through version and are not expected to be commercialized before 1985.

The first large-scale U.S. application of fluidized bed combustion is in a multicell FBC boiler at the Monongahela Power Company's plant in Rivesville, West Virginia, which is scheduled to start up in late 1976. It is designed to generate 300,000 pounds steam per hour, at 1270 psig and 925°F. Although directed towards electric utility operations, the unit is in the size range of greatest

TABLE 2-1

PROBABLE TIMING FOR FBC-FIRED INDUSTRIAL BOILER AVAILABILITY

• Startup of Rivesville Atmospheric Pressure Multicell FBC Boiler	late 1976
• Development Projects for Atmospheric Pressure Industrial Boilers	
- ERDA Contracts Awarded	1976 (1)
- Startup	late 1978
• Atmospheric Pressure Industrial FBC Boilers Offered by Boiler Manufacturers	
- Initial Commercial Unit Award	1979 (2)
- Routine Designs by Several Boiler Manufacturers	1981-82 (2)
• Pressurized FBC Utility Boiler Pilot Plant	
- ERDA Contract Awarded (3)	Jan. 1976
- Startup	1980
• Pressurized FBC Industrial Boiler Projects	
- Pioneer Commercial Unit Award	1983
- Routine Designs	1986-87
• Lime Regeneration Commercialized	1985 or later

Notes: (1) Eight contracts for the development of commercial-sized projects involving all uses of FBC (boilers, direct and indirect process heaters) are being negotiated by ERDA. Of these, five involve atmospheric pressure industrial boilers, the earliest of which is scheduled to start operating in late 1978.

(2) These dates might be somewhat earlier if a sales contract is awarded shortly after initial successful operation of the Rivesville demonstration unit.

(3) Curtiss-Wright Company Contract.

industrial interest. Rivesville is an atmospheric pressure FBC unit which will operate initially with once-through limestone. Regeneration of sulfated stone will be investigated later. Successful extended operation at Rivesville, plus additional demonstrations via the ERDA Development Program, could lead to commercial status for atmospheric FBC as early as 1981-82.

Time is of the essence to FBC developments. The needs to utilize coal in large industrial boilers, and to do this with environmental acceptability, are apparent now. The "time window" for responding to these needs is narrow. If the atmospheric pressure, industrial version of coal-fired FBC technology is adequately demonstrated for general commercial use by 1981/82, then the market potential for this technology seems assured. But the schedule in Table 2-1 is tight. Any slippage would reduce FBC's market potential because it is probable that other technology would have to be deployed instead.

2.2 Boiler System Options

This section describes the framework within which basic decisions are make when a new or modified industrial boiler system is being specified. These decisions include the following:

- how many boilers, and what size
- what fuels will be burned
- at what pressures will steam be generated and used
- will steam use include "byproduct" electric power generation or steam turbine drivers for compressors and large pumps.

2.2.1 Energy Needs of a Process Plant

Manufacturing industries which account for major percentages of energy consumption include:

Chemicals and Allied Products

Primary Metals

Petroleum Refining

Paper and Paper Products

Food and Kindred Products

Large process plants in these industries use energy continuously in at least three forms:

- direct fired heat, as to a high temperature reactor
- process steam, as to a steam stripper, autoclave, or steam-heated drier
- electric power, or steam or gas turbines, to drive pumps, compressors, and other machinery.

Direct fired heat is generally supplied to the process via furnace, kiln, drier, etc., located right at the process unit. Process steam, generally distributed at varying pressure levels from about 450 psig down to 5-10 psig, is usually generated in a central boiler plant consisting of two or more boilers, and distributed through one or more grids at appropriate pressure levels to the individual sites of use. The number and size of the individual boilers are generally selected so that the continuous process needs for steam can be met without interruption even though one boiler is off the line for inspection or maintenance. For energy efficiency, sensible heat from hot streams leaving a process unit is often recovered by unfired steam generators, thus reducing the firing load at the central boiler plant.

The amount of electric power purchased from the local utility and the amount generated within the plant vary widely. A few plants are completely self-sufficient, generating their own power in electric-utility-type power plants. Others generate no power at all. A large number produce what may be termed "by-product" power, by operating steam boilers at a significantly higher pressure than required by the process steam level, and expanding this high pressure steam through topping turbines down to the pressure levels of use. This power increment is generally less than total electric requirements, and the balance is purchased. By-product power produced in this way is always costed out at considerably lower levels than purchased power, because the incremental fuel to generate steam at the higher pressure is of the order of 4,000 to 6,000 BTU/kwh, while a modern, highly efficient utility power station operating a normal condensing steam cycle requires about 9,000 BTU/kwh (9), (10).

2.2.2 Fuels Basis

Most large industrial boilers are located in plants in which by-product fuels are produced in variable quantities. Typical by-product fuels would include refinery and coke oven gases, low BTU gas such as derived from blast furnaces, bark and wood waste, bagasse, process tars and sludges, etc. It is fundamental to the fuel balance of these plants that the available and varying quantities of by-product fuels should always be burned first, preferentially, since these are the lowest-value BTUs which are available. This task often is borne wholly or partially by the boiler plant. Then, as required by overall boiler output requirements, additional fuels are burned. The overall fuel mix is controlled to meet several constraints simultaneously:

- provide the required energy release
- meet all environmental restrictions (e.g. by appropriate mixture of high and low sulfur fuels)
- incur lowest overall cost

Purchased fuels may be selected from the following types:

- natural gas
- fuel oils, either residual or distillate
- solid fuels, such as bituminous coal or lignite; and in the future,
- "synthetic fuels", such as high or low BTU gas, coal liquefaction products, and chars

The above discussion implies that industrial boilers are usually designed to burn two or more fuels. To illustrate this conclusion it is noted that of 1387 industrial watertube boilers solid in 1974 and 1975 by members of the American Boiler Manufacturers Association, 852 or 61% were designed to burn more than one fuel (3), (4). Many of these were designed to fire purchased oil and gas, but the larger ones in the process industries, such as those in the MFBI size range, are likely to have alternate capability for byproduct fuels.

2.2.3 Boiler Basis

There are two general situations in which a company installs one or more new boilers. One is at a grass-roots location, where a new process plant is built from scratch, and a complete boiler system must be included to supply the corresponding steam requirements. The other is at an existing location, when expansion of steam requirements and/or retirement of worn-out boiler(s) necessitate the addition of new steam generation capacity to the existing system.

Selection of particular boiler type and fuel basis for the above boiler projects will be the result of many overall economic, technical, environmental and logistic studies. It should be emphasized that the overall boiler system should be studied for all appropriate alternatives.

A third situation in which a company might consider installation of new boilers would be for a change from gas or oil to coal fuel. Gas/oil package boilers conceivably could be converted to conventional coal firing (e.g. stoker or pulverized coal) with significant revamping, plus major downrating of capacity - downrating by as much as 40 to 80 percent (11). Such conversion in general is considered impractical. Under these circumstances, if a company perceives an incentive or need to switch from gas or oil to coal, it is extremely likely that installation of new coal-fired boilers would be selected rather than revamping of the existing ones. This will be discussed in more detail in a later section of this report.

2.3 Estimated Investments and Operating Costs

Consistent screening cases have been developed to compare investments and operating costs for the following boiler/fuel combinations:

- FBC boiler firing high sulfur coal;
- Conventional coal-fired boiler and flue gas scrubber, firing high sulfur coal;
- Conventional coal-fired boiler firing low sulfur "compliance" coal (low enough sulfur so that no further SO_2 control is required);
- FBC boiler firing low sulfur "compliance" coal;
- Package oil-fired boiler firing low sulfur fuel oil.

The cases cover both complete grass roots boiler systems and addition of single boilers to existing plants.

Investments are presented in terms of 1975 dollars -- no estimate of future inflation has been included. Operating costs include all cost components except fuel. Future f.o.b. and transportation costs for various sources of coal, as well as for industrial fuel oils are so uncertain that it was decided to exclude fuels from the general comparisons of this study. When making a cost comparison for a particular boiler project, an analyst will know which fuels are available and at what prices, so that a direct comparison can be developed.

Results of our economic comparisons for industrial boilers indicate that the level of environmental control required for SO_2 and/or NOx, and the relative prices for high and low sulfur fuels are fully as significant as the investments and other direct operating costs for each case. When working to current EPA New Source Performance Standards For Steam Generating Units, we conclude that:

- When firing high sulfur coals, steam can be produced in industrial boilers by fluidized bed combustion at a cost (ex fuel) of about 85% of that for conventional coal firing followed by flue gas scrubbing.
- If low sulfur "compliance" coal is used, fluidized bed combustion and conventional firing are basically break-even for large boiler sizes.
- As FBC technology matures, FBC boiler investments (in constant 1975 dollars) are expected to decrease, making future cost comparisons relatively more favorable for fluidized bed boilers versus conventional coal firing which is considered to be already "mature".
- If low sulfur fuel oil (LSFO) is available, its use in package boilers may be an attractive alternative. The possible advantage for LSFO (depending or relative fuel prices) decreases as boiler capacity is increased.

The following table illustrates these conclusions:

Cost of Steam (ex Fuel Cost) From 100 KPPH and 400 KPPH Single Boiler Addition and Grass-Roots Boiler Systems

Fuel	High Sulfur Coal		Low Sulfur "Compliance" Coal		Low Sulfur Fuel Oil
Boiler Type	FBC	Conventional With Scrubber	FBC	Conventional With ESP	Package
Cost of Steam (ex Fuel Cost), ¢/k lb.*					
Single Boiler Addition to Oil-Fired Boiler Plant					
100 KPPH	359	395	315	290	147
400 KPPH	249	283	205	201	116
Grass-Roots Boiler System					
100 KPPH	481	565	437	407	218
400 KPPH	319	391	276	278	153

*FBC costs based on current fluidized bed combustion technology.

2.3.1 Basis for Comparing Alternative Technologies

This section describes the screening designs for boiler systems which were developed to evaluate the comparative investments and operating costs associated with both grass roots and boiler addition projects as described in the previous section (2.2.3). The following table summarizes the combination of fuel, boiler type, and environmental provisions which are considered for steam generation rates between 50 and 400 KPPH.

Fuel	Boiler Description	Provision for Environmental Controls SO_2	Provision for Environmental Controls Particulates
High Sulfur Coal	Fluidized Bed Combustion using Package Modules	FBC	Electrostatic Precipitator (ESP)
High Sulfur Coal	Spreader Stoker*, Field Erected	---Limestone Scrubber---	
Low Sulfur Coal	Fluidized Bed Combustion Using Package Modules	**	ESP
Low Sulfur Coal	Spreader Stoker*, Field Erected	-	ESP
Low Sulfur Oil	Package, Watertube	-	-

* For boilers of 200 KPPH or greater, conventional coal cases are assumed to use pulverized coal firing.

** No SO_2 control is needed for low sulfur "compliance" coal; however, the alkaline ash of low sulfur Western coal is expected to give appreciable sulfur capture when the coal is burned in an FBC unit.

In all cases, it is assumed that the NOx level in the flue gas will meet EPA New Source Standards for Steam Generating Equipment of 0.7 lbs. NO_2/M BTU fired for solid fuels and 0.3 lbs. NO_2/M BTU fired for liquid fuels, without provision of major additional facilities specifically for NOx control. FBC systems using high sulfur coals give significantly lower NOx levels in the flue gas than conventional coal firing. For conventional firing, design provision for staged firing or similar combustion modifications, at relatively low cost, may be necessary; even then, emissions may be only marginally within the EPA NOx emission standards. For low sulfur coals and lignites, it is assumed in this report that FBC systems will at least meet the EPA standards. Extensive experimental work on fluidized bed combustion of these fuels has not been carried out.

A. Grass Roots Comparisons

Design of a large coal-firing FBC industrial boiler system involves much more than the boiler itself. Facilities must be provided for coal and limestone receiving, storing and handling; coal preparation for burning; fly ash collection; bed ash and spent stone withdrawal; and waste solids disposal. In the general grass roots case, these ancillary facilities may cost several times as much as the boiler itself. Compared with this complex system, the requirements for oil and gas firing are much simpler, less costly, and more convenient. On the other hand, a conventional coal-fired boiler using high sulfur coal will be even more complex because of the necessity for providing flue gas scrubbing for control of SO_2 emissions. For example, the overall screening investment for a grass roots project to build a conventional high-sulfur-coal-fired industrial boiler system might be put together as follows:

Component	M$	% of Total Investment
Two stoker-fired boilers	4.2	35.5
Coal receiving, storing, handling	1.5	13
Flue gas scrubbers, solid waste collection/storage, stack, etc.	4.2	35.5
Sub-total	9.9	84
Project Contingency	1.9	16
Total system cost	11.8	100

Figures 2-3, 2-4, and 2-5 show schematically the grass roots systems for the above cases, including fuel receipt, transfer, and storage; boilers and all associated facilities; environmental controls; and waste collection, storage, and disposal. These plants are sized to supply a continuous overall steam rate of 100 KPPH. Economic comparison of FBC , conventional coal, and low sulfur oil cases for this size will demonstrate the ease or difficulty with which coal can penetrate the market in which oil and/or gas are currently predominant, and the possible advantage which developing FBC technology may have over conventional coal firing. Below the capacity of about 100 KPPH, we expect the investment cost, space requirements, and general inconvenience of coal-fired systems relative to oil firing will be sufficiently higher that coal is not likely to be widely used. Hence we consider 100 KPPH as the approximate minimum size boiler plant in which FBC could have a significant impact on the choice of coal vs. scarce fuels.

Appendix 1 presents the complete detailed investment and operating cost bases for economic comparison of these grass roots boiler systems.

The manufacturing plants of interest in this study are all energy intensive. Almost universally, large plants in the chemicals, petroleum, paper and other energy intensive industries have multiple boilers with adequate backup capacity such that one of the boilers in the system can be shut down, for annual inspection, scheduled, or unscheduled maintenance, without limiting the plant's throughput. For our comparison of grass roots systems, we have included 2 x 100 KPPH boilers in order to insure an output of 100 KPPH steam even if one boiler is off the line. Alternatively, we could have included 3 x 50 KPPH boilers and still met this backup criterion. Three 50 KPPH boilers would cost a few percent less than 2 x 100 KPPH units, but directionally would require more space, more operating labor, and more maintenance. We decided arbitrarily to base the grass roots comparisons on a two-boiler system, and all of the cases have been handled in the same manner.

FIGURE 2-3
FLUIDIZED BED BOILER SYSTEM
FIRED WITH HIGH SULFUR COAL

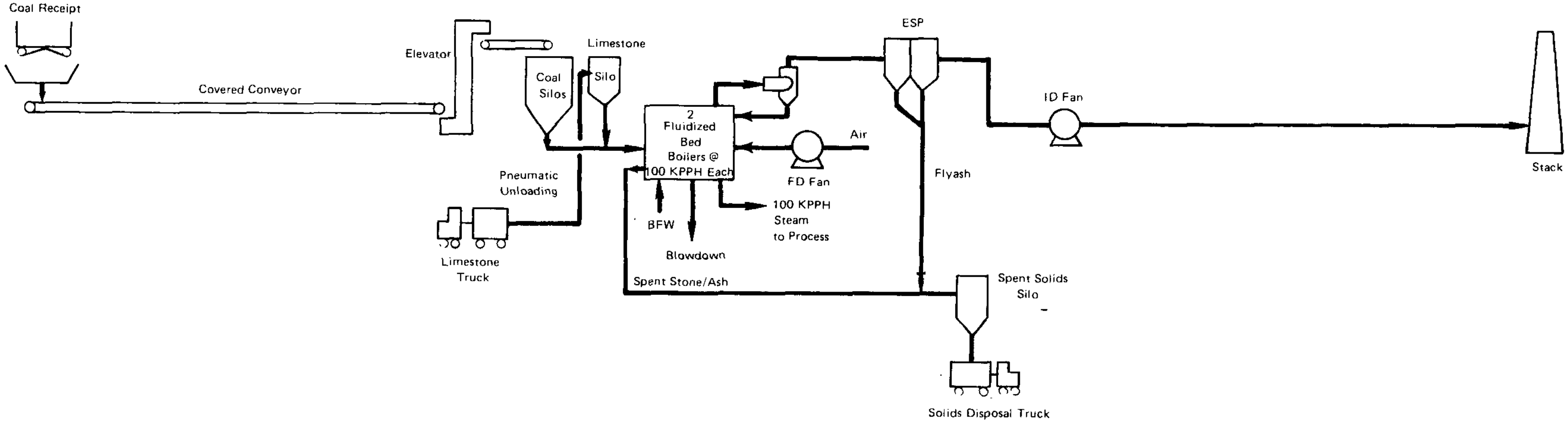
BOILER SIZE	100 k lb./H rating, 125 psig, saturated steam
BOILER TYPE	Fluidized bed, watertube, atmospheric pressure, shop fabricated and assembled
FUEL	High sulfur (3.6 wt. %) Illinois coal, ¼" nominal size
FUEL PREP'N	No further prep'n required

ENVIRONMENTAL PROVISIONS:

SO_2	Fluidized bed system meets sulfur dioxide emission criteria
NO_x	Fluidized bed system meets nitrogen oxides emission criteria
Particulates	Electrostatic precipitator (ESP)

OVERALL RATES

Coal 12,000 lb/H ≡ 144 T/D
Limestone 4,500 lb/H ≡ 54 T/D
Total Dry Solids to Disposal
(Ash & Spent Stone) 2.28 T/H ≡ 55 T/D



Note: Limestone may not be required when low sulfur "compliance" coal is burned in a fluidized bed. In this case, provision is made for receipt, storage, and handling of small quantities of inert makeup material (e.g. crushed cinder, alumina) for the bed.

FIGURE 2-4

CONVENTIONAL BOILER SYSTEM FIRED WITH HIGH SULFUR COAL

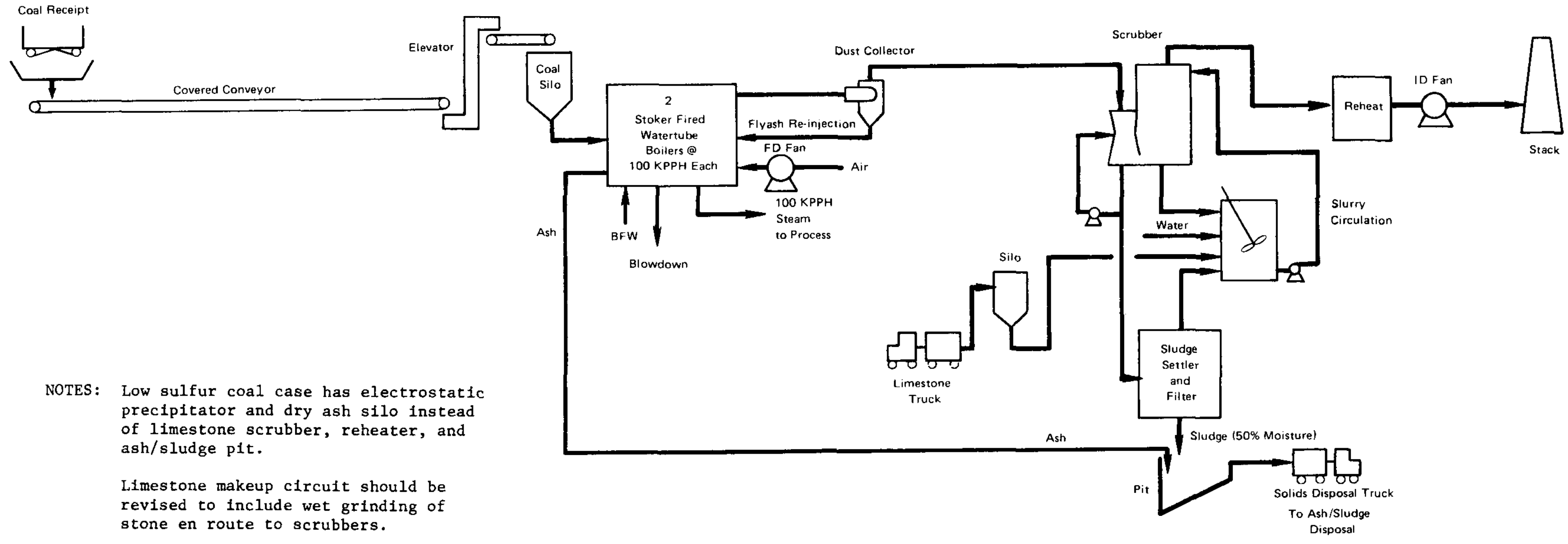
BOILER SIZE	100 k lb./H rating, 125 psig, saturated steam
BOILER TYPE	Watertube, spreader stoker fired, field assembled
FUEL	High sulfur (3.6 wt. %) Illinois coal, 1¼" nominal size for stoker firing
FUEL PREP'N	No further prep'n required

OVERALL RATES

Coal 12,000 lb/H ≡ 144 T/D
Limestone 1,800 lb/H ≡ 22 T/D
Boiler Ash 0.24 T/H ≡ 6 T/D
Scrubber Sludge 2.5 T/H ≡ 60 T/D
Total Solid Waste 66T/D

ENVIRONMENTAL PROVISIONS:

SO_2	Limestone throwaway – wet scrubber
NO_x	Hopefully, spreader stoker will just about meet 0.7 lb. NO_2/M Btu (which is emission limit for > 250 M Btu/H)
Particulates	Multiclone dust collector for bulk fly ash; scrubber for final cleanup



NOTES: Low sulfur coal case has electrostatic precipitator and dry ash silo instead of limestone scrubber, reheater, and ash/sludge pit.

Limestone makeup circuit should be revised to include wet grinding of stone en route to scrubbers.

FIGURE 2-5
CONVENTIONAL PACKAGE BOILER SYSTEM FIRED WITH LOW SULFUR FUEL OIL

BOILER SIZE	100 k lb./h rating, 125 psig, saturated steam
BOILER TYPE	Watertube, package (shop fabricated and assembled)
FUEL	No. 6 Oil (~15^{o} API), low sulfur (0.7 wt %)
FUEL PREP'N	Preheated, no further prep'n required

ENVIRONMENTAL PROVISIONS:

SO_2	Not required
NO_x	Combustion modifications – include small investment allowance in cost of grass roots package boiler
Particulates	Not required

OVERALL RATES

Fuel Oil 485 B/SD ≡ 6820 lb/H ≡ 82 T/D

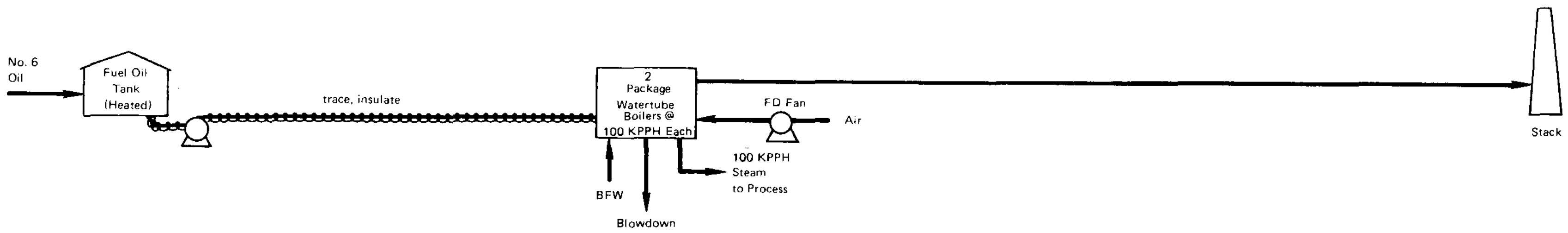


Table 2-2 presents the overall input and output streams for each of the comparable cases, corresponding to a gross steam demand of 100 KPPH.

Using the bases of Appendix 1, consistent screening investment estimates were developed for each case. For facilities for which Exxon has direct cost experience, such as oil-fired package boilers, oil tanks, pumps, piping, ducting, stack, etc., our normal investment estimating procedure was followed. For flue gas scrubbers, vendor quotes were obtained and checked, and indirect costs were added as applicable for Field Labor Overheads, Contractor Engineering, Freight, etc. Care was taken to define clearly the vendor's basis for each quotation, so as to obtain meaningful and consistent estimates for each hypothetical project. ERDA provided cost estimates for fluidized bed boilers and coal-fired stoker boilers, based on project costs reported in proposals submitted to ERDA as part of the FBC technology development program.

In the case of the coal receiving and storage facilities, Appendix 1 includes provision of equipment for direct receipt of coal by rail in shipments of 10 cars at a time, and storage capacity for about 16 days coal supply. The facilities actually provided for a real project at any given location can vary over a very wide range, from almost continuous receipt by truck and minimum onsite storage to large bulk receipt by rail or barge, possible coal processing facilities, and much longer coal storage capability. Hence we did not carry out a complete screening estimate for these specific facilities, but instead used an order-of-magnitude allowance of 1 1/2 million dollars (which was agreed by ERDA and MITRE to be within a reasonable cost range for the receiving and storage system described in Appendix 1). It should be noted that as the receiving/storing system increases in complexity and cost, some offsetting reductions in delivered coal price are likely so that the overall cost of steam production may not be markedly changed in the general case.

Following development of cost estimates for these 100 KPPH systems, we extended the estimates to cover the range of 50 to 400 KPPH by exponential "prorating" in order to evaluate the "economy of size" effects as applied to boiler plants. It is well known that a general relation between investment and capacity for process facilities can be expressed over reasonable ranges of size as:

$$I = KC^n$$

where I is investment, C is capacity in any convenient units of throughput, and K and n are constants characteristic of the particular process under study.

This general relationship has been used to estimate investments for plants of 50, 200, and 400 KPPH capacity relative to the basic 100 KPPH investments. A table included in Appendix 1 presents the exponents which were used for this purpose for each increment of size.

Costs of steam (ex fuel) from the grass-roots boiler systems were built up by estimating direct operating costs and capital charges for each case. Bases for evaluation of these items are contained in Appendix 1.

TABLE 2-2

COMPARATIVE INDUSTRIAL GRASS-ROOTS BOILER SYSTEMS
AND OVERALL INPUT/OUTPUT RATES

Bases: Steam Demand - 100 KPPH, 125 psig, saturated
Boiler Capacity Provided - 2 x 100 KPPH watertube boilers

Fuel	High Sulfur Coal		Low Sulfur Coal*	Low Sulfur Oil*
Fuel Rate, T/D	144	144	187	82 (485 B/D)
Boiler Type	FBC Package Modules	Conventional Spreader Stoker Field Assembled	Conventional Spreader Stoker Field Assembled, or FBC Package Modules	Package
SO_2 Control	FBC	Once-through Limestone Scrubber	Not Needed	Not Needed
Ca/S Ratio	3.0	1.2	--	--
Limestone Rate, T/D	54	22	--	--
Particulate Control	Cyclones and ESP	Cyclones and Scrubber	Cyclones and ESP	Not Needed
Solid Waste	Dry Sulfated Stone/Ash Mix.	Scrubber Sludge/ Ash Mixture	Ash	None
Waste Solid Rate, T/D	55	66	11	--
Approximate Space Required for Grass-Roots Boiler Plant, Acres	5	6	5	1 1/2

* Fuel sulfur content low enough that stack SO_2 emissions comply with Federal EPA New Source Performance Standards for SO_2 from Steam Generators (>250 M Btu/hr) without additional SO_2 controls.

Note that NO_x emissions from FBC-fired boilers are below Federal EPA New Source Performance Standards for NO_x from Steam Generators (>250 M Btu/hr). In all other cases, inclusions of design features for combustion modifications may be necessary in order to meet these standards.

B. Comparisons of Single Boiler Addition Projects

When a single boiler is to be added to an existing boiler system, all of the facilities shown in Figures 2-3 to 2-5 may not be required. In general, the backup capability discussed in the previous section already exists in the system, so that additional backup is usually not required provided the new boiler is fairly close in size to the existing ones. Usually the same fuel is used for the new and existing boilers. It is likely that the increased fuel receipts will be taken care of by increased use of the existing unloading facilities and somewhat shorter average days fuel storage, thus making maximum use of the existing facilities with minor outlays for tie-ins to service the new boiler.

Table 2-3 summarizes the assumptions made in each investment area in deriving cost estimates for single boiler addition projects from the basic estimates for complete grass-roots systems. Parallel procedures were used to estimate unit operating costs of steam generation in "add-on" boilers consistent with those used for the complete grass-roots cases.

2.3.2 Overall Results for Single Boiler Addition Cases

Based on experience, we believe that most sales of large new boilers are for addition of single boilers to existing plants. Therefore, in this report, we will first present comparisons for the different cases of boiler add-on projects, and then proceed to comparisons of grass-roots boiler plants at new plant sites (although this is the reverse of the sequence in which the results were developed).

The simplest case of addition of a coal-fired boiler (either FBC or conventional) is to a boiler plant which already uses coal. In this case, most of the facilities for coal receiving and handling are already in place. However, because of the difference in coal particle size for FBC and conventional firing, we have arbitrarily assumed that precrushed FBC coal is received segregated from the fuel for the rest of the plant, and stored in a new silo. Alternatively, the FBC case could include onsite facilities for coal preparation, with corresponding increases in manning, maintenance, and utilities costs, but no need to segregate coal storage. Table 2-4 summarizes the comparisons for additions of 100 and 400 KPPH boilers. More details are presented in Appendix 3, Tables 12-20. In analyzing these cases, we have assumed that the newly-added boilers will be base-loaded, with an overall availability of 90%.

When burning high sulfur coal, the investment required for an added FBC boiler with electrostatic precipitator is less than for a conventional boiler plus flue gas desulfurization. This advantage increases as boiler capacity goes up. Direct operating costs are estimated to be closely comparable. Capital charges directly reflect the investments, and so the combined operating costs show a small advantage for FBC at the 100 KPPH size, increasing as boiler size goes up (20 to 30 ¢/k lbs.). The cost of steam is quite sensitive to changes in investment -- at the 100 KPPH size an overall change of 0.5 M$ in investment (roughly 10%) results in a change in unit steam cost of 13 ¢/k pounds.

TABLE 2-3

FACILITIES BASIS FOR SINGLE BOILER ADDITION PROJECTS

<table>
<tr><th>Fuel for New Boiler</th><th colspan="2">High Sulfur Coal</th><th colspan="2">Low Sulfur "Compliance" Coal</th><th>Low Sulfur Fuel Oil</th></tr>
<tr><th>New Boiler Type</th><th>FBC</th><th>Conventional</th><th>FBC</th><th>Conventional</th><th>Package</th></tr>
<tr><td colspan="6">A. When Existing System Is Oil-Fired,
Provision in Addition Project For:</td></tr>
<tr><td>Fuel Receiving, Storing, Feeding</td><td>Complete</td><td>Complete</td><td>Complete</td><td>Complete</td><td>Incremental Tie-Ins</td></tr>
<tr><td>Limestone Receiving, Storing, Feeding</td><td>Complete</td><td>Complete</td><td>None*</td><td>None</td><td>None</td></tr>
<tr><td>Boiler</td><td>Single, Complete</td><td>Single, Complete</td><td>Single, Complete</td><td>Single, Complete</td><td>Single, Complete</td></tr>
<tr><td>Stack</td><td colspan="5">Single New Stack, No Tie-Ins</td></tr>
<tr><td>ESP</td><td>Single</td><td>None</td><td>Single</td><td>Single</td><td>None</td></tr>
<tr><td>Flue Gas Scrubber System</td><td>None</td><td>Single</td><td>None</td><td>None</td><td>None</td></tr>
<tr><td>Solid Waste Collection, Storage, Disposal</td><td>Complete</td><td>Complete</td><td>Complete</td><td>Complete</td><td>None</td></tr>
<tr><td colspan="6">B. When Existing System is Coal-Fired,
Provision in Addition Project For:</td></tr>
<tr><td>Fuel Receiving</td><td>Tie-Ins</td><td>Tie-Ins</td><td>Tie-Ins</td><td>Tie-Ins</td><td rowspan="8">THIS CASE NOT CONSIDERED</td></tr>
<tr><td>Fuel Storing, Feeding</td><td>New Silo and Conveyors</td><td>Tie-Ins</td><td>New Silo and Conveyors</td><td>Tie-Ins</td></tr>
<tr><td>Limestone Receiving, Storing, Feeding</td><td>Tie-Ins</td><td>Tie-Ins</td><td>None*</td><td>None</td></tr>
<tr><td>Boiler</td><td>Single, Complete</td><td>Single, Complete</td><td>Single, Complete</td><td>Single, Complete</td></tr>
<tr><td>Stack</td><td colspan="4">Single New Stack, No Tie-Ins</td></tr>
<tr><td>ESP</td><td>Single</td><td>None</td><td>Single</td><td>Single</td></tr>
<tr><td>Flue Gas Scrubber System</td><td>None</td><td>Single</td><td>None</td><td>None</td></tr>
<tr><td>Solid Waste Collection, Storage, Disposal</td><td>Complete</td><td>Tie-Ins</td><td>Tie-Ins</td><td>Tie-Ins</td></tr>
</table>

* However, FBC firing compliance coal does require facilities to receive, store, and feed whatever small quantity of bed makeup material is needed.

TABLE 2-4

COMPARISON OF INVESTMENTS, AND COST OF STEAM (EX FUEL), FOR SINGLE BOILER ADDED TO COAL-FIRED PLANT

Fuel (1)	High Sulfur Coal				Low Sulfur Coal (2)			
Boiler Type	Fluidized Bed Combustion		Conventional With Scrubber		Fluidized Bed Combustion		Conventional With ESP	
Steam Rate, KPPH	100	400	100	400	100	400	100	400
Investment, M$ (3)								
Fuel Handling Additions	0.6	0.9	0.2	0.3	0.6	0.9	0.2	0.3
Boiler and Stack	3.1	7.6	2.9	8.6	3.1	7.6	2.9	8.6
Envtl. and Waste Disp.	1.1	2.9	2.3	6.1	0.9	2.4	0.7	1.8
Total, M$	4.8	11.4	5.4	15.0	4.6	10.9	3.8	10.7
Unit Cost of Steam (ex Fuel), ¢/k lb. (3)								
Direct Op. Costs (ex Fuel and BFW)	125	95	131	100	83	53	64	45
Boiler Feed Water	60	60	60	60	60	60	60	60
Capital Charges	122	72	137	95	117	69	96	68
Total, ¢/k lb. (ex fuel)	307	227	328	255	260	182	220	173

(1) The same type fuel is assumed to be fired in the existing boilers as in the new boiler, i.e., no cases are considered in which low sulfur coal and high sulfur coal are fired simultaneously to different boilers of the same plant.

(2) Low sulfur coal by definition for these cases is assumed to be sufficiently low in sulfur so that no SO_2 controls are needed to meet whatever environmental limits are applicable.

(3) Details of investments and operating costs are presented in Appendix 3, Tables 12-20.

Comparing cases using low sulfur compliance coal, the conventional arrangement of stoker (or PCF unit) plus ESP is indicated to have a slight investment advantage over the FBC system. This investment difference conceivably could be turned around in the future as FBC technology matures, especially for the larger sized boilers. As regards operating costs, the pressure drop across the FBC system is significantly higher than for the conventional system, and the fan power costs reflect this factor. Overall the conventional case shows a moderate advantage over FBC at the 100 KPPH size, shrinking to breakeven at 400 KPPH. We conclude from these estimates that if low sulfur coal is available at a competitive price, boiler operators already firing low sulfur coal in conventional units will not be likely to change to FBC in the early years of FBC application. However, the future relationship between price and availability of high and low sulfur coals is extremely uncertain - it would be expected that low sulfur coal in the future might command a significant premium over high sulfur coal if SO_2 environmental limits are held at the levels used for this study.

In the situation where an existing boiler plant is oil-fired, the cost of introducing the first coal-fired boiler into such a plant will be considerably higher than the cases considered above. The investments for the boiler itself and for its environmental controls will be basically the same, but to this will be added a significant increment for new coal receiving, storing, and handling facilities. Table 2-5 presents the overall results of our comparisons for the addition of 100 and 400 KPPH coal-fired boilers, as well as a comparative case for addition of another 100 or 400 KPPH low sulfur oil-fired unit. Details of these cases are tabulated in Appendix 3, Tables 21-31.

Again for this situation, when high sulfur coal is the fuel of choice FBC has a nominal investment advantage over conventional combustion plus flue gas scrubbing at the 100 KPPH size. This advantage increases as the boiler size goes up to 400 KPPH. Direct operating costs are very similar for the two cases. Overall, FBC is estimated to have about a 35 ¢/k lbs. steam advantage over the conventional system. At the 100 KPPH rate, addition of the complete coal receiving and handling system to the existing oil-fired plant has increased the cost of steam by 50-60 ¢/k lb. over the earlier cases where an existing coal-fired plant was the basis. This increase shrinks to 20-30 ¢/k lbs. at the 400 KPPH level because the cost of the coal handling facilities scales up very slowly compared with the remaining parts of the system.

When cases based on low sulfur compliance coal are compared, the investment estimates for FBC and conventional technology are very close together, with the conventional case having a slight advantage at 100 KPPH and FBC slightly lower at 400 KPPH. As FBC technology matures, it is likely that its costs will decrease relative to conventional combustion. It is important that these improvements be achieved as soon as possible. Many industrial boiler operators now burning fuel oil (or natural gas) expect to switch to new units firing low sulfur coal when oil is no longer available. If the first added unit is a conventional stoker (or PFC boiler), it is likely that subsequent additions will also be conventional ones if FBC and conventional alternatives are close together economically. Thus, significant FBC use for low sulfur coal by these operators is not likely unless the first coal-firing boiler which they add is an FBC unit.

TABLE 2-5

COMPARISON OF INVESTMENTS, AND COST OF STEAM (EX FUEL), FOR SINGLE BOILER ADDED TO OIL-FIRED PLANT

Fuel	High Sulfur Coal				Low Sulfur Coal (1)				Low Sulfur Fuel Oil(1)	
Boiler Type	Fluidized Bed Combustion		Conventional With Scrubber		Fluidized Bed Combustion		Conventional With ESP		Package	
Steam Rate, KPPH	100	400	100	400	100	400	100	400	100	400
Investments, M$ (3)										
Fuel Handling Allowance(2)	1.8	2.7	1.8	2.7	1.9	2.9	1.9	2.9	0.1	0.2
Boiler and Stack	3.1	7.6	2.9	8.6	3.1	7.6	2.9	8.6	1.5	3.7
Envtl and Waste Disp.	1.3	3.4	2.6	6.9	1.1	2.9	1.0	2.6	--	--
Total, M$	6.2	13.7	7.3	18.2	6.1	13.4	5.8	14.1	1.6	3.9
Unit Cost of Steam (ex Fuel), ¢/k lb.(3)										
Direct Op. Costs (ex Fuel and BFW)	142	102	150	108	100	60	83	52	46	31
Boiler Feed Water	60	60	60	60	60	60	60	60	60	60
Capital Charges	157	87	185	115	155	85	147	89	41	25
Total, ¢/k lb. (ex Fuel)	359	249	395	283	315	205	290	201	147	116

(1) Low sulfur coal and fuel oil by definition are sufficiently low in sulfur that no SO_2 controls are needed to meet whatever environmental limits are applicable.

(2) In some cases where coal is reliably available by truck delivery, the capital costs for fuel receipt and storage could be significantly reduced. In such cases, however, the delivered price of coal would rise more-or-less correspondingly so that the overall cost of steam would not be changed markedly.

(3) Details of investments and operating costs are presented in Appendix 3, Tables 21-31.

It should be noted that an FBC boiler has inherent flexibility to handle a tightened SO_2 emission regulation if such a requirement is imposed after the boiler is built. This could be done simply by initiating or increasing the limestone rate charged to the bed and the withdrawal rate of spent bed material. In contrast, reduction of SO_2 emissions from a conventional boiler might require retrofit addition of a flue gas scrubber system.

A case is included in Table 2-5 for addition of a low-sulfur-oil-fired package boiler to an existing oil-fired plant. As would be expected, the investment and operating costs for this case are much below those for coal firing. If fuel oil is permitted for use in new MFBI units, a large boiler operator would be willing to pay a substantial premium -- up to the neighborhood of $1.10/M BTU -- for low sulfur fuel oil over high sulfur coal.

2.3.3 Overall Results for Grass-Roots Boiler Plants

Investments and operating costs for grass-roots boiler systems supplying 100 and 400 KPPH steam are summarized in Table 2-6. More complete details for these cases are given in Appendix 3, Tables 1-11. These results cover the complete grass-roots systems, with 100% boiler and scrubber backup, as described in Figures 2-3 to 2-5 and text of Section 2.3.2. Since they include complete fuels receiving, storing, and handling facilities, plus two boilers such as might be installed in a new, grass-roots location, the investments and operating costs are higher than for the previous cases. The same relative results are obtained, however. Fluidized bed combustion of high sulfur coal shows an advantage of about 70-80 ¢/k lb. steam over conventional combustion of the same coal plus flue gas scrubbing. Note that these results are for current FBC technology; further improvements are anticipated for second-generation and subsequent units, as discussed in a later section (2.3.5).

Low sulfur compliance coal fired using conventional technology enjoys capital and direct operating cost advantages corresponding to the lack of a flue gas scrubber. However, burning of the same low sulfur coal in an FBC system is not far behind at 100 KPPH ($\sim$ 30 ¢/k lbs. steam), and is breakeven at 400 KPPH. As FBC technology matures, its potential application to use of compliance coal will increase.

As in the previous comparison, the investment and direct operating costs for grass-roots low sulfur oil-fired boiler systems are significantly lower than for coal firing.

The following general conclusions are drawn from the cases discussed in Sections 2.3.2 and 2.3.3:

(1) A significant portion of the higher overall cost of burning coal versus oil is attributed to the fuel handling facilities required for coal.

(2) Meeting environmental standards while burning high sulfur fuels is significantly more costly than burning fuels which are low enough in sulfur content to meet SO_2 emission limits directly. In fact if a flue gas scrubber is used with high sulfur fuel, the costs of pollution controls and waste disposal are of the same magnitude as the costs associated with the boiler itself.

TABLE 2-6

COMPARISON OF INVESTMENTS, AND COST OF STEAM (EX FUEL), FOR GRASS ROOTS BOILER PLANTS WITH BACKUP

Fuel	High Sulfur Coal				Low Sulfur Coal(1)				Low Sulfur Fuel Oil(1)	
Boiler Type	Fluidized Bed Combustion		Conventional With Scrubber		Fluidized Bed Combustion		Conventional With ESP		Package	
Steam Rate, KPPH	100	400	100	400	100	400	100	400	100	400
Investment, M$(3)										
Fuel Handling Allowance(2)	1.8	2.7	1.8	2.7	1.9	2.9	1.9	2.9	0.6	1.4
2 Boilers and Stack	5.8	14.3	5.4	16.0	5.8	14.3	5.4	16.0	2.6	6.4
Envtl. and Waste Disp.	1.9	5.0	4.6	12.2	1.7	4.5	1.6	4.2	--	--
Total, M$	9.5	22.0	11.8	30.9	9.4	21.7	8.9	23.1	3.2	7.8
Unit Cost of Steam (ex Fuel), ¢/k lb.(3)										
Direct Op. Costs (ex Fuel and BFW)	180	119	206	135	139	79	121	71	77	44
Boiler Feed Water	60	60	60	60	60	60	60	60	60	60
Capital Charges	241	140	299	196	238	137	226	147	81	49
Total, ¢/k lb. (ex Fuel)	481	319	565	391	437	276	407	278	218	153

(1) Low sulfur coal and fuel oil by definition are sufficiently low in sulfur that no SO_2 controls are needed to meet whatever environmental limits are applicable.

(2) In some cases where coal is reliably available by truck delivery, the capital costs for fuel receipt and storage could be significantly reduced. In such cases, however, the delivered price of coal would rise more-or-less correspondingly so that the overall cost of steam would not be changed markedly.

(3) Details of investments and operating costs are presented in Appendix 3, Tables 1-11.

(3) Generation of steam in industrial boilers using fluidized bed combustion of high sulfur coal is predicted to be economically attractive (by about 35-75 ¢/k lbs. steam) compared with conventional burning of the same coal in conjunction with flue gas scrubbing. This comparison is based on current FBC designs ("first generation"). Cost reduction in FBC designs is anticipated in the future, as FBC technology matures. In a subsequent section (2.3.5), we have discussed the overall order-of-magnitude improvement which is likely.

(4) FBC appears to be fairly close to breakeven with conventional coal-firing for burning low sulfur compliance coal (low enough sulfur content to meet emission criteria without SO_2 removal). In this connection, FBC may well be the only practical technology for burning many slagging coals and high ash lignites which are difficult to use in conventional boilers.

(5) In all cases, capital charges comprise from 43 to 67% of the total controllable operating costs (ex fuel and boiler feed water).

2.3.4 Areas of Technical Uncertainty

Several areas of FBC technology have been identified in which there are real or apparent problems. Resolution of these uncertainties will be needed before widespread application of coal-fired FBC can be expected. The principal uncertainties concern:

(1) availability of suitable limestone (without excessive transportation costs from distant locations)

(2) disposal of waste solids

(3) maintenance of desired particle size distribution in the fluidized bed.

A. Availability of Suitable Limestone

The limestone characteristics which are desired for effective use in once-through FBC systems are high reactivity with SO_2 at bed conditions; particle strength and attrition resistance at bed conditions so that stable fluidized bed behavior can be achieved; resistance to thermal degradation (spalling, fragmentation) as boilers are started up and shut down.

Although limestone deposits are widely distributed, there is no certainty that all stones are suitable for FBC use. Performance data are available for only a few of the many limestone sources, and widely differing behavior is observed from one limestone to another. Unfortunately, there are no simple analytical laboratory methods by which to determine the limestone properties. Each stone has to be tested in an FBC laboratory unit.

In the 30 MWe FBC demonstration utility boiler being installed in Rivesville, West Virginia, local Greer limestone will be used. This stone was initially tested by Pope, Evans and Robbins using conditions under which the Grove limestone used most widely in FBC development work had performed well. The Greer stone could not be retained in the bed during initial calcination under these conditions and appeared unsuitable for use. However, experiments with modified operating conditions successfully identified a suitable working range in which satisfactory initial calcination of the Greer stone could be achieved, and this stone has met the other requirements of reactivity, attrition resistance, and thermal stability (15).

The above discussion pertains to FBC operations in which sorbents (mostly limestones) are used "once-through" with discard of the spent stone. If effective regeneration technology is developed, the regeneration characteristics of the limestones are also significant.

B. Disposal of Waste Solids

The problem of disposing of sulfated, dry granular limestone is quite different from that of wet limestone sludges from once-through flue gas scrubbers, although both are products of control operations to meet environmental criteria for sulfur emissions. Another related problem, if a large increase in coal consumption is to occur, is the disposal of the correspondingly large quantities of ash.

Much work is underway at various locations to characterize more definitively the waste products resulting from different methods of use of a wide variety of coals (e.g. conventional and FBC fly ash, bottom ash, scrubber sludges, FBC bed material, etc.) as regards physical form, particle size, bulk and trace chemical composition, leachability, etc. Work is also underway to identify general and specific possible uses for these materials rather than simply throwing them away. In the future, the decisions in connection with installation of one or more coal-fired industrial boilers at a specific location may be influenced by results from much of this work. Our aim here has been to make reasonable assumptions as a working basis for these generalized screening comparisons.

(1) Ash. Only a small percentage of the fly ash and bottom ash resulting from current coal burning operations is used to manufacture some other product (e.g. cinder block). The largest portion of the ash is directly (or indirectly after storage in ash retention ponds) disposed of in landfill operations. Unless major byproduct outlets for ash are developed, eventual expanded disposition may be in the direction of sending it back to exhausted mines after the coal has been removed. Work by DOT (Department of Transportation) and others is directed toward large scale utilization of fly ash in road construction.

Fly ash from fluidized bed combustion has been exposed to maximum bed temperatures of the magnitude of 1600-1700°F. Hence, it is quite different in physical form from fly ash from conventional combustion, which has been heated to incipient or complete fusion. In this report, we have assumed that capture by ESP and handling of FBC fly ash will not be significantly more costly than in conventional boiler operations.

(2) Wet Sludge. Disposal of scrubber sludge is one of the most perplexing problems and obstacles to widespread adoption of limestone (or lime) throwaway flue gas scrubbing to meet sulfur emission limits. Ponding and eventual landfill disposition is almost the only disposal outlet. Even after long-time settling, a sludge composed predominantly of calcium sulfite is not very compact and does not have high load-bearing capability. One expanding sub-option is to condition or treat the sludge to improve its load-bearing strength. This can be accomplished by oxidizing sulfite to sulfate, and/or by mixing the sludge with ash and additives. If the high calcium ash from some western coals is added to a slurry scrubber, this also has been observed to promote sulfate formation (16).

Large industrial plants may have adequate acreage for building sludge ponds to hold several years' sludge production. Most industrial plants do not have this capability. In our economic studies, the preliminary assumption is that the filtered sludge (mixed with ash in the case of conventional coal firing) is disposed of by truck, at a cost of \$8 per ton. Each \$2/ton variation from this cost changes the cost of steam by 5.5 ¢/k lb.

(3) Dry Waste from FB Combustion of High Sulfur Coal. In the limestone fluidized bed, the $CaCO_3$ of the fresh stone is first calcined

$$CaCO_3 \rightleftarrows CaO + CO_2$$

At bed conditions, the lime reacts with SO_2 (from the sulfur in the coal) and excess O_2 to form calcium sulfate

$$CaO + SO_2 + 1/2\ O_2 \rightleftarrows CaSO_4$$

To achieve adequate sulfur removal, excess limestone is fed to the bed -- feed Ca/S ratios up to 6 have been used in FBC development work. The 30 MW Rivesville demonstration unit is designed for a Ca/S ratio of 2. In our industrial boiler calculations, we have assumed a Ca/S ratio of 3 for high sulfur coal. In the range of Ca/S ratios of 2 to 3, spent waste from an impure limestone has a composition something like the following:

	wt%
$CaSO_4$	30 - 45
CaO (excess)	25 - 35
Other (MgO, SiO_2, Al_2O_3, iron oxide, ash, etc.)	30 - 35

Considerable preliminary work has been done on possible uses for spent stone co-mingled with ash. These uses include production of building materials such as gypsum or aggregate, agricultural use as lime/fertilizer, and neutralization of acid mine drainage. The high free CaO content may make this material unsuitable for direct landfill except in lined cavities. However, the dry granular nature of the waste mixture makes it easily handled and stored.

In our economic calculations, our preliminary assumption is that the dry stone/ash mixture will be carted away be truck, at a selected range of \$/ton cost, without designating the eventual disposition of the material.

For initial evaluation, we have used the same disposal cost of \$8 per ton as was used for the sludge/ash mixture in the stoker case. Any reduction in cost because of the easier handling characteristics of the granular FBC material will represent a corresponding additional advantage for the FBC case. A change of $\pm$ \$2 per ton in disposal cost results in a change in steam cost of $\pm$ 4.6 ¢/k lbs.

Our general basis has been to mix in a single dry waste silo the fine particulate material collected by the electrostatic precipitator with the much coarser spent bed material withdrawn from the FBC combustor. There is some indication that the material collected in the ESP is mostly fly ash from the coal. As such the concentrations of trace components which originated in the coal would be much higher in this ESP stream than in the bed material. If there is an economic incentive to segregate these two streams for separate dispositions, this can readily be done by providing an additional separate storage facility for the small particulate stream collected by the ESP.

(4) Bed Material and Ash from FB Combustion of Low Sulfur Western Coals.

Very little information is available on this version of fluidized bed combustion. Unlike Eastern coals, Montana/Wyoming sub-bituminous coals typically have alkaline ash which contains relatively high percentages of sodium and calcium. For this study, we have assumed that the bed material for FB combustion of these coals would be a relatively hard inert granular material (e.g. crushed cinder, alumina). Very low makeup rates of bed material are assumed necessary to replace depletion of the bed by attrition. Most of the ash from the coal is assumed to leave the bed as fly ash, eventually recovered by the ESP. If the feed coal contains very much inert matter itself (slate, etc.), some purging of the bed may be necessary. Much experimental information is required before this case is clearly defined.

C. Maintenance of Optimum Particle Size Distribution in Fluidized Bed

For effective operation of a fluidized bed, it is essential that neither very fine nor very coarse particles accumulate within the bed. In fluidized bed combustors, careful design of the air-distributing grid and maintenance of adequate gas velocity through the bed are sufficient to sweep out the fine particles, so that accumulation of fines does not appear to be a problem. Considering the other end of the particle size range, FBC investigators on occasion have observed the accumulation of oversized particles in the bed. The cause or causes of this build-up are not yet completely understood. Because such accumulations could lead to ever poorer fluidization, early designs of proposed commercial units made provision for removal of large particles from the bed. This feature is included in the design of the Rivesville unit where bed material withdrawn from the cells of the boiler will undergo continuous hot screening. A large number of those actively engaged in development of FBC technology expect that the need for hot screening might be avoided by choice of coal, cleaning of coal, or specification of a certain maximum size of coal. A higher limestone makeup rate and bed withdrawal rate to purge large particles might also reduce or eliminate the need for hot bed screening.

Recent FBC designs, such as those included in proposals being negotiated with ERDA as FBC development projects, do not include provision for continuous hot screening capability. Hence, the cost estimates used for the preceding economic analyses do not include this provision. However, as explained in detail in Appendix 2, we have included a "process development allowance" of 0.3 M$ per boiler (100 KPPH size) in the cost estimate. This was evaluated as about 20% of that part of the boiler investment which is considered part of the new FBC technology. We believe this allowance is adequate to cover the cost of hot screening if demonstration proves that this is necessary.

2.3.5 Significant Cost Reductions Possible for Future FBC Designs

As stated earlier, fluidized bed combustion of coal in boilers is a newly-developing technology. No commercial-sized boilers have yet been built in the U.S., either for industrial or utility service. The basic cost estimates for the boiler sections of the FBC systems we have studied represent a current FBC process design similar to those being developed by the Fluidized Bed Combustion Company, Livingston, N.J., in response to commercial inquiries. We have communicated closely with engineers of this company during preparation and analysis of these estimates for FBC boilers.

Our estimates include the provision, associated with current FBC designs, of a "process development allowance" as the FBC process is commercialized (as discussed in Appendix 2). Despite the historic need for investment additions during early process development and commercialization, the history of technical processes also clearly demonstrates that major cost improvements are normally achieved as a process matures. Hirschmann (18) presents a general analysis of this "learning curve" experience, which is very similar to what Exxon has found through past studies. Stated simply, after we have built the first commercial plant, and if there is developmental effort to learn from the first plant's actual performance, then subsequent plants cost less. Experiences with many processes could be cited as examples of this learning curve, e.g. fluid catalytic cracking and ethylene manufacture.

In the case of FBC, we expect that reductions of 15-20% are likely in the boiler portion of total project costs for "mature" fluidized bed boilers, based on typical application of the learning curve. Expressed in terms of steam costs, the above investment reduction corresponds to about 20-30 ¢/k lbs. steam for a 100 KPPH grass roots FBC boiler plant.

Note that the conventional technology cases are also subject to the same learning curve effects, but because stokers, pulverized coal units, and oil-fired package boilers are already mature, the likelihood is far smaller for significant cost reductions in these technologies. On the same basis as used for FBC costs, we expect that some improvements will be made for the flue gas scrubbers of the conventional high sulfur coal cases. However, these scrubbers are smaller investment pieces than the FBC boilers, and they are essentially already commercialized, compared to the much earlier demonstration stage for FBC technology. We estimate that the reduction of steam costs resulting from scrubber improvements will be in the magnitude of 5-10 ¢/k lbs. for 100 KPPH grass roots plants.

2.3.6 Revamping of Existing Boilers for FBC Service Not Likely

We have analyzed the likelihood of "retrofitting" fluidized bed combustors to existing industrial boilers, as well as to study the installation of completely new fluidized bed industrial boilers. The term "retrofitting" is subject to a rather wide range of interpretations. Our initial concept of retrofitting was that of fitting a new components (e.g. a flue gas scrubber) into or onto an existing piece of equipment. Using this narrow definition, we conclude that retrofitting of an FBC system to an existing boiler is infeasible. However, we have become aware that a much broader interpretation of retrofitting may be used by others, to cover what we would think of variously as conversion, substitution, rebuilding (revamping), modernization, etc. With this broader usage in mind, we judge that retrofitting is likely to be economically unattractive. In making this judgment, we have taken into account the boiler size range of interest in this study, and apply the following reasoning: Heat release rates in a fluidized bed (BTU/hr/cubic foot) are several times as intense as in a conventional boiler. Furthermore, much of the heat transfer surface in an FBC unit is submerged within the bed, whereas in a conventional boiler the tubes surround the firebox but are located with care so as to avoid flame impingement. A likely way in which an existing oil- or gas-fired package boiler could be "converted" to FBC service would be to remove the burner(s), cut out some or all of the existing tubes and drums and install the fluidized bed with its submerged heat transfer surface within the old boiler shell. Addition of the required solids handling facilities to inject fuel and limestone, recycle bed material, and withdraw ash and sulfated stone, while conforming with the dimensions of the old unit would involve additional constraints. To accomplish the above work, the boiler would be out of service for a very considerable period of time. The likelihood that such a complicated revamp procedure could be economically attractive is remote.

2.4 Market Survey of Large Industrial Boiler Users

The Market Survey part of this study was planned to obtain responses from leading, knowledgable companies in energy-intensive manufacturing industries, in order to

- reinforce (or contradict) the conclusions of our technical and engineering assessments of FBC boilers, and

- collect reactions of potential FBC users to the application of this new technology in their own specific circumstances.

Thirty-two companies were contacted, and their responses covered a wide span of opinions. Most of these companies already burn coal at some locations. They recognize that natural gas will rapidly become unavailable for their use as fuel for steam generation. In general, they expressed a desire to continue to burn fuel oil in boilers as long as possible because of its convenience, lower capital requirements, and lower environmental problems; a few feel that the price differential between oil and low sulfur coal already makes coal a competative fuel for very large boilers. They expect to broaden their use of coal long range, and would prefer to use "compliance" low sulfur coal wherever it is available. All expressed an interest in FBC, and those who expect problems with SO_2 and/or NOx emissions will be ready (over a fairly wide range of enthusiasm from cool to warm) to consider the use of FBC in their own operations when it is demonstrated to be "commercially reliable and economically attractive".

2.4.1 Survey Procedure

The survey was limited to large manufacturers in industries which use large quantities of boiler fuels for continuous steam generation. We contacted:

14	Chemical Companies
6	Paper Companies
2	Petroleum Refiners
3	Food and Kindred Products
3	Primary Metals
4	Other
32	

In each of these companies, we located a staff official, usually in corporate headquarters, with the function of "Energy Coordinator/Long-Range Planner". All contacts were made by telephone. In each case, we assured the company representative that his responses would be kept anonymous, and that neither he nor his company would be identified in our survey reports.

In practically all cases we first outlined the objectives of the telephone discussions and then sent the company a brief summary of the current state of development of FBC. The final phone discussion, about 2 weeks after the initial contact, usually took 30 minutes to an hour. The following outline summarizes the content of the final conversation.

Outline of Discussion With Corporate Energy Coordinator
FBC Market Survey

- Description of typical boiler plant of subject company.

- Technical characteristics of future boilers (FBC or conventional) anticipated by company.

- Expectations for supplying company's future boiler fuel requirements -

  (a) short range
  (b) long range

  Plans for moving from present situation to short range future to long range future.

- Specific problems cited by company which restrict or slow down company's use of coal.

- Company's perception of advantages, disadvantages, and overall outlook for its use of Fluidized Bed Combustion in boilers.

- At what point of FBC's technical development will company be ready to consider installation of FBC boiler?

- Company's suggestions for effective Government actions to promote increased use of coal, and rapid adoption of FBC if demonstrations are successful.

2.4.2 Results and Interpretation

The intent of the "market survey" was to collect reactions and plans of potential users of FBC to their use of coal as industrial boiler fuel and to their possible application of this new technology in their own particular situations. There was no intent to make a statistical analysis of the information collected in this survey, since the companies were not selected to be a representative sample of their industries. Most of the questions asked were not really subject to quantitative interpretation. The following summary gives the broad general positions taken by most of the responders, along with comments pertinent to some of the individual industries.

General Feedback From FBC Market Survey

- Typical large boiler plant may have 4 or 5 good-sized boilers (>150 KPPH). Generates steam at "high" pressure (e.g. 600 psig), expands steam through turbine(s), down to lower pressure level set by process requirements. This configuration produces an increment of low cost "byproduct" power, as well as added reliability or flexibility (motor plus turbine) for driving large pumps, compressors, etc.

- Future boilers will probably be going up in pressure to generate a larger increment of in-plant power. In many cases, respondents expect future individual boiler capacity to remain pretty much at current levels, although a few companies expect significant increases in boiler sizes.

- Few plants burn coal, most burn gas or oil.

- A number of plants burned coal formerly, but have converted more-or-less irreversibly to gas/oil.

- Some companies have already started activities to re-introduce coal at locations where it was previously burned, and to consider coal at new large locations. Many other companies recognize that boilers will be coal-fired long range, but have not yet started to consider how that situation will be reached, starting with present package oil/gas-fired boilers. Coal may be impractical at even relatively large plants if adequate space is not available.

- "Low sulfur" coal -- meaning in the context of the conversation that such coal would meet applicable SO_2 emission limits -- was noted repeatedly as the preferred fuel when coal is introduced at a new location. We found reluctant acceptance, but no enthusiasm for the use of flue gas desulfurization as a sulfur emissions control technology from industrial boilers.

- Converting (or revamping) package gas/oil-fired boilers to coal service is almost certainly impractical, because of:

  + serious downrating
  + high cost
  + long outage time

  Conversion to FBC might result in a lower degree of downrating than conversion to a stoker or pulverized coal unit, but neither conversion alternative is likely to be used to any significant degree.

- Principal government action to stimulate coal use is clear, consistent energy policy, firm guidelines; avoid frequent changes. Stimulate coal production, and make sure adequate transportation capability is developed. Provide tax incentives or $ subsidy, although these actions mentioned less often. Several companies recommended relaxation of environmental standards.

- Fluidized bed combustion looks attractive if it is demonstrated to be

  + reliable
  + economical

- FBC features of significant interest:

  + effective SO_2/NOx control
  + fuel flexibility
  + less severe solid waste disposal problems

Particular concerns with FBC were noted by representatives of industries which burn large quantities of internally-generated by-product fuels. For instance, paper companies expect that FBC in power boilers will have flexibility to burn waste wood, bark, and "hogged" fuel. They are certain that black liquor will continue to be fired in recovery boilers, which are designed specifically to recover and purify sodium chemicals. This service would not be suitable either for conventional or FBC coal firing because of contamination of the recovered sodium salts with ash or sorbent. Steel companies state that their heat balances are subject to wide fluctuations -- boiler fuel may vary from almost all purchased fuel to almost all low BTU blast furnace gas, so it is desirable long range for FBC boilers to have this flexibility. Petroleum refineries burn high viscosity residua, cracked tars and hydrocarbon sludge from high sulfur crudes, as well as refinery gas containing low molecular weight hydrocarbons (containing one to four carbon atoms - methane through butane and butenes). Flexibility to burn these fuels is desirable for FBC boilers in refineries, and somewhat similarly in certain chemicals plants.

Boiler operators expect that FBC boilers will be somewhat more complicated to control than conventional coal-fired units. This is not expected to interfere with initial FBC boiler designs, however, since most of them will be single boiler additions to existing boiler plants. Under these conditions, the new FBC boiler likely will be base loaded, so as to have relatively little need for dynamic response to continual load shifts.

As would be expected, we found wide variations in the level of enthusiasm for FBC. The following excerpts of comments from respondents illustrate the level of expectant support which FBC already has, as well as the lack of interest shown by others.

"We have a 25-year supply of low sulfur coal lined up, and do not foresee any interest in FBC."

"We are opposed to flue gas scrubbers as a matter of company policy. If FBC is proved to be an effective and economically competitive method of sulfur control, we will be glad to use it."

"Do not expect to be in a position to use FBC. Looking at municipal and county solid wastes as our next source of BTU."

"Our company is very conservative as regards technology. We will not be ready to look at FBC seriously until it is thoroughly proven as regards reliability - to level of one emergency outage per year."

"Company has extensive high sulfur coal reserves, and is very interested in FBC. Ready to take reasonable risks in pioneer project, jointly with reputable boiler manufacturer."

Overall, we found the companies which we contacted to be aware and concerned regarding their own energy outlook, generally supportive of a national policy to shift away from scarce fuels to coal, but very concerned about the capital requirements and the environmental constraints which confront such a shift. We conclude that they will welcome the successful technical demonstrations of fluidized bed combustion as applied to industrial boilers, and will be ready to use FBC when it is shown to be economically attractive.

2.5 Specific Technical Requirements for Representative Industrial Fluidized Bed Boilers

Desired performance requirements for industrial fluidized bed boilers do not differ significantly from those for conventional coal-fired boilers. The ideal industrial boiler (regardless of fuel fired) is safe to operate over its entire range of performance, gives high thermal efficiency, requires minimum maintenance and has a high percent availability, can be easily and smoothly shifted from base fuel to alternate fuel or to simultaneous burning of two fuels (or more), has adequate turndown capability, responds quickly to changes in load, and meets all environmental requirements. The final design of a real boiler requires compromises to balance the degree to which each of the above features is achieved against cost. The owner must provide the designer with economic values (e.g. identity and expected value of marginal fuel, incentive for avoiding emergency outages, etc.) so that decisions on these compromises can be reached wisely.

No attempt has been made in this generalized screening study to carry out such economic optimization. It is assumed that the "standard" conventional and FBC boilers provided by boiler manufacturers are designed to be reasonably in agreement with such economic criteria. Optimization is normally carried out during the definitive planning and design stages of a specific project, when the purchase specifications for one or more boilers are being developed.

Practically all participants in our market survey indicated very little or no interest in paying a premium for unusually high turndown or unusually rapid response to changing loads.

Table 2-7 summarizes typical performance requirements for a 250 KPPH industrial fluidized bed boiler in petroleum refinery service. Performance requirements for FBC boilers in chemical plant service would be similar to those in petroleum refining except that in many cases no gaseous fuel would be available as an alternate energy source. In steel plants, alternate fuel could well be low BTU gas (e.g. excess blast furnace gas, providing 90-100 BTU/cubic foot). In paper plants, boiler size could be somewhat larger, possibly limited by the maximum module capacity which can be shop assembled and shipped as a package. Alternate fuels in paper and pulp plants may include bark, wood chips, sawdust, and other waste fuels, but will not include black liquor since recovery of the sodium values would be impractical in admixture with the FBC sorbent. In food processing plants, typical boiler capacity is likely to be smaller than 250 KPPH, and steam pressure will be significantly lower in locations where the owner does not require byproduct power generation.

TABLE 2-7

TYPICAL DUTY SPECIFICATION FOR INDUSTRIAL FLUIDIZED BED BOILER FOR USE IN PETROLEUM REFINERY BOILER SERVICE

Boiler shall be designed in accordance with ASME Boiler and Pressure Vessel Code, Section 1, and with additional local and state requirements as applicable.

Continuous steam generation rate, lbs/hr (Maximum Continuous Rating, MCR)	250,000
Peak steam generation rate, lbs/hr (110% of MCR, peak capacity for 1 hour in 24)	275,000
Steam pressure at superheater outlet, psig	650[1]
Steam Temperature at Superheater Outlet, °F (at continuous steam generation rate)	750[1]
Feedwater temperature from water treating unit, °F	240
Continuous blowdown rate, percent of feedwater rate	To be reported, based on Boiler Feed Water composition.
Maximum solids carryover in steam, wppm (at drum outlet with 2000 ppm Total Dissolved Solids in drum)	1
Turndown ratio Boiler shall be capable of smooth, safe operation with reasonable efficiency at 25% of MCR, and at any higher rate up to 110% of MCR (peak capacity)	4:1

TABLE 2-7 (continued)

Desired speed of response[2]	
Boiler and control system shall be capable of moving smoothly and under continuous control from 30% of MCR to 100% of MCR in a period of 20 minutes (maximum).	
Thermal efficiency (based on HHV of fuel, at MCR)	82% (minimum)
Base fuel fired	Illinois No. 6 Coal
Sorbent	Grove Limestone
Alternate fuel fired	Refinery Gas[3]
Design range for ratio of coal to refinery gas, % of heat release	100/0 to 0/100
Startup fuel	Refinery Gas or No. 2 Fuel Oil
Design availability	92% (minimum)
Boiler shall be designed for continuous runs of one year duration.	
Scheduled annual outage for inspection and maintenance	3% (maximum)
Unscheduled outage	5% (maximum)
Maximum emission of contaminants in flue gas at boiler exit, lbs/M Btu fired	
Sulfur Dioxide	1.2
Nitrogen Oxides (as NO_2)	0.7
Maximum effective noise level	per OSHA limits

TABLE 2-7 (continued)

Safety	Safety valves shall be provided in accordance with ASME Boiler and and Pressure Vessel Code, Section 1. Emergency response controls shall be included for loss of steam pressure, loss of drum level, loss of feed water, loss of fluidization air, loss of ID fan, and high bed temperature. Provision shall also be made to prevent injection of coal feed on startup until bed is preheated to safe ignition temperature.

Notes: (1) 650 psig and 750°F are typical design conditions for current industrial boilers. Future conditions are likely to be more severe (e.g. 900 psig, 900°F, or even higher).

(2) Initial single FBC boilers added to an existing system will probably be base loaded, so this desired response will not become critical until entire boiler systems are comprised of FBC boilers.

(3) Alternate liquid fuels (e.g. No. 2, No. 4, and No. 6 fuel oils and/or high viscosity residual stocks) may also be specified. Typical refinery gas composition is:

Hydrogen	62 vol.%	C4's	2
Methane	14	Water	1
Ethane and Ethylene	12	Nitrogen	4
Propane and Propylene	4	CO_2	1
		Total	100 vol.%

3. MANUFACTURING INDUSTRIES

This section begins defining what is meant by "manufacturing industries" for the purposes of the study. Some industries use a great deal of fuel while others do not. Four industry groups (Chemicals, Primary Metals, Petroleum Refining, Paper) account for about two thirds of the purchased, commercial fuels used by manufacturing industry. In general, the industries that have the highest total fuel consumption also use the largest amounts of boiler fuel, but there are exceptions. These points are discussed, first, in relation to fuel data collected for the 1972 Census of Manufactures (1) and, then, in more detail, by reference to survey data obtained by the Federal Energy Administration in 1975. These statistics are used as background for consideration of how boiler fuel demand may develop in the future.

3.1 Standard Industrial Classification

The Standard Industrial Classification system of the Bureau of the Census (U.S. Department of Commerce) recognizes twenty-one manufacturing industries in terms of 2-digit SIC codes (19 through 39). There is further subdivision to take account of different operations within a given industry. The subdivisions comprise 450 4-digit SIC codes. The current level of fuel consumption and the nature of the pertinent manufacturing operation indicates that about 30 of the 450 4-digit categories may offer a potential to coal-fired FBC. Most of these prospects are concentrated in the broader (2-digit) groupings of the chemicals, paper, petroleum refining, primary metals and food industries.

3.2 1972 Census of Manufactures

The most recent comprehensive data for energy consumption by the manufacturing industries are for 1971, and are published in the 1972 Census of Manufactures (1), (2). These data have the advantage of providing a detailed breakdown by SIC code of fuel purchased by each industry. However, the data have several disadvantages:

(1) by now, they are somewhat out of date.

(2) they deal with purchased fuels, but not with the by-product fuels that are utilized to a significant degree by some industries.

(3) they do not distinguish between fuels consumed in boilers and in a variety of other equipment such as process heaters and kilns.

In spite of these shortcomings, the Census data in Table 3-1 show that a small number of industries is responsible for most of the consumption of purchased fuels. Primary Metals (SIC 33), Petroleum Refining (SIC 29) and the Paper Industires (SIC 26) account for most of the by-product fuels that are used captively but are not included in the Census data. Inclusion of by-product fuels would further increase the fraction of total fuel consumption attributable to the most energy-consuming industries.

TABLE 3-1

PURCHASES OF FUEL BY INDUSTRY GROUP IN 1971

Rank	SIC Code	Description of Industry Group	Billion BTU's	% of Total Purchased Fuel	Cumulative %
1	28	Chemicals and Allied Products	2421	21.5	21.5
2	33	Primary Metal Industries	2018	17.9	39.4
3	29	Petroleum Refining and Related Industries	1500	13.3	52.7
4	26	Paper and Allied Products	1188	10.6	63.3
5	32	Stone, Clay, Glass and Concrete Products	1186	10.5	73.8
6	20	Food and Kindred Products	905	8.0	81.8
7	37	Transportation Equipment	294	2.6	84.4
8	35	Machinery, except Electrical	289	2.6	87.0
9	34	Fabricated Metal Products	281	2.5	89.5
10	22	Textile Mill Products	276	2.5	92.0
11	24	Lumber and Wood Products, except Furniture	195	1.7	93.7
12	36	Electrical Machinery, Equipment, and Supplies	192	1.7	95.4
13	30	Rubber and Miscellaneous Plastic Products	174	1.6	97.0
14	19/39	Ordnance and Accessories/Miscellaneous Manufactures	83	0.7	97.7
15	27	Printing, Publishing and Allied Industries	71	0.6	98.3
16	38	Instruments and Related Products	55	0.5	98.8
17	25	Furniture and Fixtures	48	0.4	99.2
18	23	Apparel and Other Finished Products	47	0.4	99.6
19	31	Leather and Leather Products	28	0.3	99.9
20	21	Tobacco Manufactures	16	0.1	100.
		All Manufacturing Industries	11270	100.	

3.3 Fuel Consumption of Large Industrial Boilers in 1974

In 1975, the Federal Energy Administration conducted a survey of all Major Fuel Burning Installations in the U.S. An MFBI is an installation that has, or is, a fossil-fuel fired boiler, burner or combustor with a design firing rate of 100 million BTU's per hour or greater. The precise definition of MFBI and other pertinent information, such as the purpose of the survey, are given in Chart 1. FEA's Office of Fuel Utilization has provided data from this survey and from a related Natural Gas Task Force (NGTF) survey for use in this study. All of the data apply to industrial boilers having a designed heat input capability of 100 million BTU/H or more. In 1974, there were approximately 4,000 of such boilers at 1,600 industrial installations in the lower 48 states.

From Table 3-2, it will be seen that the population of large industrial boilers had the following breakdown by size and fuel consumption:

Size Range 10^6 BTU/H	% of Number of Large Boilers	% of 1974 Fuel Consumption of Large Boilers
> 500	5.0	16.8
> 350	13.2	32.9
> 250	26.5	51.6
> 200	38.6	64.0

The average consumption of commercial fuels (coal, oil, natural gas) of the entire population of large industrial boilers was 1.0 trillion BTU per boiler in 1974. Total fuel consumption was somewhat higher because "other" fuels, such as black liquor, coke oven gas, and bagasse are excluded from the computation. The reported total consumption of commercial fuels (coal, oil, natural gas) was 4 quads* or 166 million tons of coal equivalent. In fact, 76% of the fuel consumption was in the form of oil (mostly residual fuel) and natural gas.

Similar data are available with a further breakdown by SIC Code, as follows:

SIC Code	Industry	10^{12} BTU in 1974	Average per Boiler 10^{12} BTU in 1974
20	Food	193	0.62
26	Paper	593	1.07
28	Chemicals	926	1.14
29	Petroleum Refining	587	1.61
32	Stone, Clay, Glass, Concrete	19	0.51
33	Primary Metals	443	1.16
34	Fabricated Metal Products	61	0.60
35	Machinery, except Electrical	50	0.49
49	Utility Services**	99 (45)	0.93
-	Other Industries	681 (633)	0.80
-	SIC Code not specified	362	1.23
		4014 (3912)	1.00

*one quad = 10^{15} BTU

**except electricity generation

FEDERAL ENERGY ADMINISTRATION
WASHINGTON, D.C. 20461

APPROVED BY GAO
B-181254 (S75022)
EXPIRES 6-30-75

THIS REPORT IS MANDATORY UNDER P.L. 93-275

MAJOR FUEL BURNING INSTALLATION COAL CONVERSION REPORT

FEA C-602-S-0

INSTRUCTIONS

I. PURPOSE

Form FEA C-602-S-0 is a request for information from "major fuel burning installations" to aid FEA in carrying out its responsibilities under the Energy Supply and Environmental Coordination Act of 1974 (P.L. 93-319). (A major fuel burning installation will be referred to in this form as "MFBI".) The survey is designed to obtain data required by FEA to examine the feasibility and effect of issuing orders to specified major fuel burning installations prohibiting them from burning oil or natural gas as their primary energy source.

II. WHO SHOULD SUBMIT

Form FEA C-602-S-0 must be submitted by every MFBI. MFBI is defined on page 3 of this form. The form may be filled out by a responsible official at either the installation or, if applicable, the parent organization.

III. TO WHOM

Two copies of the Form FEA C-602-S-0 must be filed with:

Federal Energy Administration
ATTN: OFU/CRB Room 6117
Washington, D.C. 20461

IV. WHEN

Form FEA C-602-S-0 must be submitted on or before May 21, 1975.

V. GENERAL INSTRUCTIONS

This report is mandatory, and is being required pursuant to the authorities granted to FEA by the Federal Energy Administration Act of 1974 (P.L. 93-275).

A single Section I shall be filed for each facility, even if it is comprised of more than one combustor of fuel. Sections II and III shall be filed for each separate combustor with an individual capacity of 100 million Btu's/hr or greater.

Fill in the combustor number and installation name at the top of each applicable page in order to facilitate handling should the pages be inadvertently separated in mailing.

For all questions which can be answered by a "Yes" or "No", "1" (for "Yes") or "0" (for "No") shall be entered in the appropriate block unless otherwise stated.

A blank page has been provided at the end of this questionnaire to permit comments to be continued where inadequate space is provided on the form.

VI. SPECIFIC INSTRUCTIONS

Section I

Item No.

- 1 Limit responses to the number of blocks provided, using standard abbreviations where appropriate.
- 1 *Air Quality Control Region:* As designated by the Environmental Protection Agency. Do not fill in the line if the AQCR is unknown.
- 4, 5 Includes all boilers and other combustors regardless of design firing rate. If there are more than 99 in either of these categories insert the number 99.
- 8 Place the 4-digit primary Standard Industrial Classification Code (SIC) in the first column and the percent of total shipments or services (by value) in the second. Three entries are available for multi-commodity installations. If it is possible to enter more than three SIC entries, list the three with the highest percentage of total shipments. If the SIC is unknown, describe the products or services on the line provided.

Section II

Item No.

- 1 Assign each combustor a two-digit identification number if it does not already have one.
- 7a Fill in the blank with 1, 2, or 3.
- 19b The term "rank" of coal refers to anthracite, bituminous, sub-bituminous, or lignite.
- 19g The term "other unique characteristics" refers to % moisture, hardness, fusion, temperature, and all other applicable coal parameters which must be maintained to insure proper operation of the combustor.
- 21, 22 Fill in the estimated "average" Btu content.

Section III

Item No.

- 1 Assign each stack a one-digit identification number.
- 3b The "% Availability" refers to the percentage of time the FGD equipment is available for operation (regardless whether or not it is actually operated).
- 4c, d & 5c, d If it would be necessary to *either* install FGD or obtain conforming coal, please complete both item (c), assuming FGD is used, and item (d), assuming conforming coal is used.

VII. DEFINITIONS

1. "Major Fuel Burning Installation". An installation or unit other than a powerplant that has or is a fossil-fuel fired boiler, burner, or other combustor of fuel, or any combination thereof at a single site, that has individually or in combination, a design firing rate of 100 million BTU's per hour or greater, and includes any person who owns, leases, operates, controls or supervises any such installation or unit. Gas turbines and combined cycle or internal combustion engines are excluded from this classification.
2. "Powerplant". A fossil-fuel fired steam electric generating unit that produces electric power for purposes of sale or exchange, and includes any person who owns, leases, operates, controls or supervises any such unit.
3. "Total Designed Firing Rate". The sum total of all design firing rates of all combusting devices located at the facility, expressed as $[(A) \times 10^6$ Btu/hr$]$.
4. "Combustor". An individual fossil-fuel boiler, burner, or other combustor of fuel.
5. "Combustor Capacity". The design firing rate of a combustor expressed as $[(A) \times 10^6$ Btu/hr$]$.
6. "Topping Turbine". This refers to either steam driven electric generating sets or gas turbine electric generating sets associated with a process steam generating boiler.
7. "Primary Energy Source". That amount of fuel used for all purposes except for the minimum amounts required for start-up, testing, flame stabilization, control uses, and fuel preparation.

TABLE 3-2

1974 CAPACITY AND FUEL CONSUMPTION PROFILES OF LARGE INDUSTRIAL BOILERS

Size Range of Boiler 10^6 BTU/H	Number of Boilers: Units	Number of Boilers: % of Total	Number of Boilers: %	1974 Fuel Consumption*: 10^{12} BTU	1974 Fuel Consumption*: % of Total	1974 Fuel Consumption*: %	Av. Fuel Consumption Per Boiler 10^{12} BTU
1000+	20	0.5	0.5	110	2.8	2.8	5.50
900-999	5	0.1	0.6	14.4	0.4	3.2	2.88
800-899	17	0.4	1.0	64.3	1.6	4.8	3.78
700-799	31	0.8	1.8	105	2.7	7.5	3.38
600-699	47	1.2	3.0	142	3.6	11.1	3.06
500-599	77	2.0	5.0	227	5.7	16.8	2.95
450-499	71	1.8	6.8	160	4.0	20.8	2.25
400-449	98	2.5	9.3	213	5.4	26.2	2.18
350-399	152	3.9	13.2	263	6.7	32.9	1.73
300-349	191	4.9	18.1	310	7.9	40.8	1.62
250-299	327	8.4	26.5	428	10.8	51.6	1.31
200-249	473	12.1	38.6	493	12.4	64.0	1.04
150-199	917	23.4	62.0	651	16.4	80.4	0.71
100-149	1487	38.0	100.	777	19.6	100.	0.52
	3913	100.		3960	100.		1.01

*Coal, oil and natural gas; excludes "other" fuels such as black liquor, bagasse, coke oven gas, etc.

Note: Data for Alaska, Hawaii, Puerto Rico, and Virgin Islands are included.

Source: FEA, MFBI Survey, Report No. 22.

The numbers in parentheses in the above table are our corrections of the raw FEA data to take account of nine very large boilers, believed to be electric utility boilers, that appear to have been included in the industrial boiler statistics. After making this correction, and also prorating the "SIC Code not specified" data to the specified categories, the following breakdown was estimated for 1974:

SIC Code	Industry	% of Total Fuel Consumed by Large Industrial Boilers	Approx. Utilization of Boiler Capacity, %
28	Chemicals	26.2	66
26	Paper	16.7	47
29	Petroleum Refining	16.5	66
33	Primary Metals	12.4	46
20	Food	5.4	40
34	Fabricated Metal Products	1.7	32
35	Machinery, except Electrical	1.4	43
49	Utility Services	1.3	28
32	Stone, Clay, Glass, Concrete	0.6	32
-	Other Industrial	17.8	53
		100.	54

The relatively high boiler capacity utilization reported for the chemicals and petroleum refining industries is in line with prior expectations.

An estimated breakdown of the 17.8% of boiler fuel consumption attributed to "Other Industries" is given in Table 3-3. The estimate is based on disaggregation of purchased fuels data from the 1972 Census of Manufactures.*

Data obtained in FEA's Natural Gas Task Force survey were used to derive the estimates of 1974 fuel consumption by large industrial boilers that are reported in Table 3-4. These estimates give a breakdown both by fuel type and SIC Code. The figures listed in parentheses in the final column are those obtained from the MFBI survey. It will be seen that the differences between the two sets of survey data are not large, and that the largest discrepancy is in the "other SIC's" category. Although the two surveys corroborate each other, it is believed that the MFBI survey data are somewhat more accurate and complete. However, the Natural Gas Task Force survey provides some information that is not available from the MFBI Survey. Pooling of the survey data yielded the maximum information.

The Natural Gas Task Force survey provides a breakdown by the regions listed in Table 3-5. The regional statistics may be disaggregated further by using the number of large industrial boilers reported in the MFBI survey as a multiplier. The number of large boilers in each state may be expressed as a percentage of the regional total. These percentages are shown in column (A) of Table 3-6. In addition, the state boiler totals may be expressed as a percentage of the national total, as shown in column (B). However, for the purpose of disaggregation of other statistics from a regional to a state basis only the percentages in column (A) are needed.

*Since more recent survey data were not made available by FEA's Office of Fuel Utilization.

TABLE 3-3

ESTIMATED BREAKDOWN OF PERCENTAGE OF TOTAL FUEL CONSUMED BY LARGE INDUSTRIAL BOILERS ATTRIBUTABLE TO "OTHER INDUSTRIES"

SIC Code	Industry	% of Total Fuel Consumed by Large Industrial Boilers in 1974
37	Transportation Equipment	3.5
22	Textile Mill Products	3.3
24	Lumber and Wood Products	2.3
36	Electrical Equipment	2.3
30	Rubber and Plastics Products	2.1
19/39	Ordnance/Miscellaneous Manufacturing	1.0
27	Printing and Publishing	0.9
38	Instruments and Related Products	0.7
25	Furniture and Fixtures	0.6
23	Apparel and Other Textiles	0.6
31	Leather and Leather Products	0.3
21	Tobacco Manufactures	0.2
		17.8

TABLE 3-4

1974 FUEL CONSUMPTION BY TYPE AND BY SIC CODE

SIC Code	1974 Fuel Consumption By Large Boilers, 10^{12} BTU						% of Total	
	Coal	Resid	Distillate	Nat. Gas	Other	Total		
20	46	27	8	106	1	188	4.8	(5.4)
26	136	221	6	206	89	658	16.9	(16.7)
28	234	111	12	596	27	980	25.2	(26.2)
29	13.5	75	nil	493	20	602	15.5	(16.5)
32	1.4	11	negl.	7	1.4	21	0.6	(0.6)
331/332	236	8	2	50	100	396	10.2	(12.4)
333/339	1.0	9	nil	74	14	98	2.5	
Other SICs	298	287	39	286	35	945	24.3	(22.2)
Total	966	749	67	1818	288	3888	100	

Notes: (1) Fuel consumption in Alaska, Hawaii, Puerto Rico and Virgin Islands is excluded

(2) Fuel consumption of large boilers for which no SIC Code was reported has been prorated to other SIC Codes.

(3) Figures in parentheses are estimated based on MFBI survey data.

Source: Natural Gas Task Force Survey

TABLE 3-5

REGIONAL BASIS OF NATURAL GAS TASK FORCE DATA

Region No.	Description	States and Territories Included in Region
1	New England	Conn., Me., Mass., N.H., R.I., Vt.
2	Appalachian	Del., D.C., Ky., Md., N.J., N.Y., Ohio, Penna., Va., W. Va.
3	Southeast	Ala., Fla., Ga., N.C., S.C., Tenn.
4	Great Lakes	Ill., Ind., Mich., Wis.
5	Northern Plains	Iowa, Minn., Neb., N.D., S.D.
6	Midcontinent	Kan., Mo., Okla.
7	Gulf Coast	Ark., La., Miss., Tex.
8	Rocky Mountain	Col., Mont., Utah, Wyo.
9	Pacific S.W.	Ariz., Ca., Nev., N.M.
10	Pacific N.W.	Ida., Ore., Wash.
11	Pacific	Alaska, Hawaii
12	Territories	Puerto Rico, Virgin Islands
National Totals		Regions 1 - 12
Lower 48		Regions 1 - 10, i.e. National Totals Minus (Regions 11 & 12)

TABLE 3-6

NUMBER OF LARGE INDUSTRIAL BOILERS BY STATE AND FRACTION OF REGIONAL AND LOWER 48 TOTALS

New England	No.	(A)	(B)
Conn.	54	25.4	0.82
Me.	39	29.1	0.95
Mass.	45	33.6	1.09
N.H.	13	9.7	0.32
R.I.	3	2.2	0.07
Vt.	nil	nil	nil
	134	100.	3.25

Appalachian	No.	(A)	(B)
Del.	14	1.2	0.34
D.C.	19	1.7	0.46
Ky.	61	5.3	1.48
Md.	55	4.8	1.33
N.J.	135	11.7	3.28
N.Y.	160	13.9	3.88
Ohio	270	23.4	6.55
Pa.	231	20.1	5.60
Va.	124	10.8	3.01
W. Va.	82	7.1	1.99
	1151	100.	27.92

Southeast	No.	(A)	(B)
Ala.	89	14.9	2.16
Fla.	89	14.9	2.16
Ga.	81	13.5	1.97
N.C.	122	20.4	2.96
S.C.	93	15.6	2.26
Tenn.	124	20.7	3.01
	598	100.	14.51

Great Lakes	No.	(A)	(B)
Ill.	201	29.4	4.88
Ind.	166	24.3	4.03
Mich.	227	33.3	5.51
Wis.	89	13.0	2.16
	683	100.	16.57

Northern Plains	No.	(A)	(B)
Iowa	42	39.3	1.02
Minn.	44	41.2	1.07
Neb.	10	9.3	0.24
N.D.	4	3.7	0.10
S.D.	7	6.5	0.17
	107	100.	2.60

Midcontinent	No.	(A)	(B)
Kan.	32	27.6	0.78
Mo.	42	36.2	1.02
Okla.	42	36.2	1.02
	116	100.	2.82

Gulf Coast	No.	(A)	(B)
Ark.	48	5.5	1.16
La.	267	30.6	6.48
Miss.	44	5.0	1.07
Tex.	513	58.9	12.45
	872	100.	21.15

Rocky Mountains	No.	(A)	(B)
Col.	63	51.2	1.53
Mont.	15	12.2	0.36
Utah	16	13.0	0.39
Wyo.	29	23.6	0.70
	123	100.	2.98

Pacific S.W.	No.	(A)	(B)
Ariz.	6	3.3	0.15
Ca.	161	89.0	3.91
Nev.	6	3.3	0.15
N.M.	8	4.4	0.19
	181	100.	4.39

Notes: No. = Number of Large Industrial Boilers
(A) = % of Regional Total
(B) = % of Lower 48 States Total

Source: FEA MFBI Survey

TABLE 3-6 (continued)

Pacific N.W.	No.	(A)	(B)
Ida.	17	10.8	0.41
Ore.	31	19.8	0.75
Wash.	109	57.4	2.64
	157	100.	3.81

Pacific	
Alaska	46
Hawaii	12
	58

Territories	
Puerto Rico	13
Virgin Is.	3
	16

Extra Continental	No.	(A)	(B)
Pacific	58		
Territories	16		
	74		

National Total	4196
Extra Continental	74
Lower 48	4122

REGIONAL SUMMARY

Region	No. of Large Boilers	% of Lower 48 Total
New England	134	3.25
Appalachian	1151	27.92
Southeast	598	14.51
Great Lakes	683	16.57
Northern Plains	107	2.60
Midcontinent	116	2.82
Gulf Coast	872	21.15
Rocky Mountain	123	2.98
Pacific S.W.	181	4.39
Pacific N.W.	157	3.81

Notes: No. = Number of Large Industrial Boilers
(A) = % of Regional Total
(B) = % of Lower 48 States Total

Source: FEA MFBI Survey

Fuel consumption, by SIC Code, was obtained on a regional basis in the NGTF survey. Similar statistics for boiler capacity were also obtained. The overall results are reported in Tables 3-7, 3-8, and 3-9 on a percentage basis. Estimates of the absolute levels of fuel consumption by large industrial boilers, state by state, could be calculated from the regional totals using the percentages in column (A) of Table 3-6 as a multiplier.*

FEA's survey data for 1974, which are presented in detail in Appendix 4, form the basis from which projections of future industrial boiler fuel consumption were made. The methods of projection and the quantitative estimates are discussed in Section 4.

3.4 Discussion of Future Options

In 1974, the large industrial boilers, as a group, used approximately 2.9 quads of oil and gas, with gas accounting for two thirds of this quantity. If coal were to be used wherever petroleum was used in 1974, the theoretical annual saving of oil and gas would be the above 2.9 quads. However, the operators of the boilers reported to the FEA that only about 0.65 quads could have been saved by converting to coal. The explanation is that many companies responding to the MFBI survey took the position that most of their oil or gas fired boilers cannot be converted to coal-firing. The implication is that the only way by which the petroleum consumption associated with these boilers could be saved would be by installation of new coal-fired boilers. The reported potential savings of 0.65 quads relates primarily to reconversion (from oil or gas to coal) of boilers that were originally designed for coal-firing.

A boiler originally designed for coal has the physical dimensions for reconversion to coal-firing, without downrating of steam generating capacity, even if the boiler is now firing oil or gas. In contrast, a substantial majority of boilers originally designed to fire oil or gas would undergo severe downrating if revamped for coal-firing.** We have been advised that the expected downrating would be in the range of 40% to 70%. In a literal sense, conversion to coal would be possible but, in practice, such a loss of steam-generating capability would be economically intolerable.

---

*FEA's Office of Fuel Utilization has these data on a plant-by-plant basis since the information was obtained in the 1975 MFBI survey. However, this and other information is considered to be proprietary by FEA and, therefore, not releasable. It is not essential to have this level of detail for the present study.

**In testimony to the Senate Public Works Committee, Mr. William B. Marx, executive director of the American Boiler Manufacturers Association, stated: "Factory assembled package units have been installed by the thousands during the past 20 years and have been almost exclusively engineered for non-coal firing. In fact, well under ten percent of these units have the capability for coal-firing." Reference 3, page 1719.

TABLE 3-7

REGIONAL FUEL CONSUMPTION IN 1974: PERCENTAGE BASIS

Region	Coal	Resid	Distillate	Nat. Gas	Other
New England	-	90.9	-	3.2	5.9
Appalachian	43.6	32.3	0.8	16.1	7.2
Southeast	34.3	28.7	0.7	20.4	15.9
Great Lakes	42.5	10.5	8.2	29.0	9.8
Northern Plains	35.3	4.3	2.7	54.6	3.1
Midcontinent	8.9	negl.	2.2	86.9	2.0
Gulf Coast	2.8	6.3	0.1	86.7	4.1
Rocky Mountain	29.5	21.2	1.2	47.8	0.3
Pacific S.W.	2.0	8.4	0.7	80.7	8.2
Pacific N.W.	8.7	12.3	0.1	73.1	5.8
Lower 48 States	24.8	19.2	1.8	46.8	7.4

TABLE 3-8

LARGE BOILER CAPACITY: REGIONAL % BASIS

Region	Coal	Resid	Distillate	Nat. Gas	Other
New England	-	86.2	-	3.8	10.0
Appalachian	34.7	30.8	2.0	17.8	14.7
Southeast	24.1	24.5	1.5	19.4	30.5
Great Lakes	35.9	12.9	4.3	30.2	16.7
Northern Plains	30.6	6.0	6.0	55.2	2.2
Midcontinent	10.4	1.5	2.0	72.2	13.9
Gulf Coast	1.9	6.0	0.1	80.2	11.8
Rocky Mountain	31.0	9.9	2.5	52.9	3.7
Pacific S.W.	4.5	6.2	1.1	75.0	13.2
Pacific N.W.	12.4	11.1	0.3	50.0	26.2
	21.3	19.0	1.8	41.4	16.5

Note: The fuels noted above are the primary fuels reported in FEA's Natural Gas Task Force survey.

TABLE 3-9

COMPARISON OF REGIONAL PERCENTAGES OF LARGE INDUSTRIAL BOILERS BY NUMBER, 1974 FUEL CONSUMPTION AND BOILER CAPACITY

Region	% of Lower 48 States Total By: No.	1974 Fuel	Capacity
New England	3.25	2.67	2.85
Appalachian	27.92	24.32	26.17
Southeast	14.51	14.27	16.03
Great Lakes	16.57	15.01	15.98
Northern Plains	2.60	2.00	1.99
Midcontinent	2.82	1.79	2.19
Gulf Coast	21.15	31.10	24.98
Rocky Mountain	2.98	3.21	2.63
Pacific N.W.	4.39	3.16	3.86
Pacific S.W.	3.81	2.47	3.32

Note: Above percentages are derived from statistics reported in FEA's Natural Gas Task Force Survey.

The MFBI survey revealed that 40% of the large boilers that were originally designed to fire coal have been converted to oil- or gas-firing. Analysis of fuel consumption data suggests that conversions of smaller boilers has been even more extensive but, as will be apparent from subsequent discussion, reconversion of the smaller boilers to coal-firing is unlikely.

Four general inferences may be drawn:

(1) Boilers that once fired coal may be reconvertible to coal-firing without loss of steam-generating capacity.

(2) Only the large boilers (>100 million BTU/H) in (1) are likely candidates for reconversion.*

(3) The majority of oil/gas-fired package boilers do not appear to be practical candidates for conversion to conventional coal-firing.

(4) Economic considerations, inclusive of the general need to maintain boiler availability, suggest that the majority of additional coal-fired boilers will be new (grass-roots) units, even though many would be installed at existing manufacturing plants.

The above inferences apply to conventional coal-fired boilers, including those with scrubbers or other emission control equipment. The question arises whether conversions, or reconversions, to coal-firing might be relatively more advantageous if FBC technology were to be utilized. This possibility arises primarily because the greater intensity of heat release in the fluid-bed might make it possible to convert a package oil-fired boiler to coal-fired FBC without downrating of the boiler steam generation capacity. Investigation of this question reveals that the actual dimensions of the package boiler and the configuration of its internals are not well suited to substitution of a fluid-bed design. Nevertheless, rough estimates have been made using the assumption that no downrating would be experienced, i.e. that conversion would be practicable from an operational point of view. The rough estimates indicate that the direct cost of conversion would be only slightly less than the cost of a new coal-fired FBC unit. Part of the explanation for the smallness of the estimated cost differential lies in the fact that the design and configuration of the FB boiler could be optimized in a new unit. Moreover, this comparison does not take into account the economic penalty that might have to be assessed against the conversion approach to cover potential loss of manufacturing capacity while the conversion was in progress. Nor does it take account of the likelihood that an existing package boiler might have to be raised in order to make room beneath it for withdrawal of ash, etc.

The conversion to FBC of a boiler that had once fired coal, or still fires coal, would seem somewhat easier. However, the saving in direct costs relative to a new FBC unit also appears small. Moreover, there is evidence that such industrial boilers are beginning to be equipped with scrubbers. Hence, by the time that coal-fired FBC is thoroughly

*Even within this category, reconversion may not be practicable for a variety of reasons, e.g. coal and ash handling facilities may have been dismantled and space may no longer be available for reinstallation of such facilities.

demonstrated for industrial use, some of what may now appear as an FBC potential may have already selected scrubbing as the control technology. If this inference is correct, a corollary is that the time by which FBC is fully demonstrated for industrial use will be an important determinant of the market potential of the technology. Electric utilities were the first to confront SO_2 control in commercial coal-burning equipment in the U.S. Manufacturing industry, in general, has found an answer to the problem by using natural gas, low sulfur fuel oil and, in some cases, low sulfur coal. To be sure, high sulfur coal has been used too, and it is precisely the need for bringing such operations into environmental compliance that, currently, is generating interest in:

- Scrubbers
- Low Sulfur Coal

The market survey, discussed in Section 2.4, revealed that FBC could be of at least comparable interest once this technology is demonstrated as being commercially reliable.

In June, 1974, Congress passed the Energy Supply and Coordination Act of 1974 (ESECA) (4). The Act authorized FEA to prohibit certain power plants and major fuel burning installations from burning oil or gas as a primary fuel, and to order certain power plants, then in the planning stage, to be built with coal-burning capability. ESECA was passed as an emergency measure (shortly after the Arab oil boycott, and undoubtedly influenced by it), and conferred only limited powers of short duration on FEA. Subsequently, however, proposed legislation was introduced in the Senate Public Works Committee. The bill, S.1777, in its 1975 revised version, was tentatively called the "Natural Gas and Petroleum and Coal Utilization Act of 1975" (5). If passed, it would have extended the coal-use provisions of ESECA. In fact, certain provisions of ESECA have already been extended by the Energy Policy and Conservation Act of 1975 (EPCA) (6).

S.1777, as revised, provides for a phased conversion to coal of all existing gas and oil-fired boilers of 100 million BTU/H firing rate or larger. In the first phase, all new or existing gas-fired boilers unable to burn coal would be required to convert to <u>oil</u> by 1/1/79 (except those scheduled to be retired by 1/1/85).

In the second phase, all new or existing oil-fired boilers (except those scheduled for retirement by 1/1/90) would be required to acquire the capability to use coal, and be using it by 1985.

The revised bill provides FEA with authority to extend deadlines for oil and coal use under certain conditions:

- The required fuel is not available.
- Conversion to coal is not practicable.

Several conditions could create non-practicability:

(1) Low capacity factor (less than 3000 hours of operation per year)

(2) Physical and legal factors (site specific limitations)

(3) Capital requirements relative to net current investment

(4) Reliability of electric service (in the case of electric utilities)

(5) Impact on employment and economic activity, both regionally and nationally

(6) Impact on profitability of the fuel user due to diversion of gas or oil to others.

Civil penalties (fines) are proposed for illegal use of oil beyond the deadlines prescribed for conversion.

Extensive testimony was received by the Senate Public Works Committee prior to its revision in July 1975 (3). A substantial majority of the testimoney was aimed at improving the practicability of the proposed legislation by increasing the minimum boiler size to which the legislation would apply (from 50 million BTU/H to 100 million BTU/H) and by specifying criteria for non-practicability (see above). However, some witnesses were opposed to coal-use legislation per se. For example, Donald G. Allen, Vice President of New England Electric System remarked:

> ". . . we suggest that, in general, it is better policy to encourage rather than to force conversion to coal, particularly at a time when market forces are already bringing about the preferential use of coal as boiler fuel."

Naturally, we cannot predict if S.1777 will be enacted and, if so, when. Nor can we predict whether and what further revisions may be made before the Senate, as a whole, takes action on the bill. However, we believe that the passage of the Energy Policy and Conservation Act in December 1975 signifies that further Congressional action is likely, and that legislation similar to, if not identical with, S.1777 will be passed. Our judgment is that such legislation is more likely than it is unlikely. Therefore, two of the key assumptions made in connection with estimation of the most probable potential for coal-fired FBC are that S.1777 type legislation will be enacted, and that this will occur somewhat before the reliability of the coal-fired FBC technology has been fully demonstrated for industrial use. As discussed later, estimation of the minimum potential may also be related to S.1777-type legislation via assumptions that practicability criteria and deadlines for coal substitution will permit a greater usage of petroleum fuel for a longer time than in the "most likely" case.

One of S.1777's provisions, that was retained in the revised version, states:

> ". . . by 1/1/79, any electric powerplant and any major industrial installation which utilizes natural gas or petroleum as its primary energy source and has the capability to utilize coal as its primary energy source (and is not scheduled for retirement prior to 1/1/85) shall, to the extent practicable, utilize coal as its primary energy source, in conformance with applicable environmental requirements."

This provision may apply to boilers reconverted to coal during the next few years. Because of the 1/1/79 deadline, such equipment is likely to meet environmental requirements with either low sulfur coal or scrubbers.

We believe that the stepwise impacts of legislation similar to S.1777 would be reflected in a stepwise or incremental approach to the installation of coal-fired boilers at industrial plants. One of the most probable first steps involves reconversion to coal-firing as discussed above. A parallel step might involve the addition of new coal-fired boilers at existing plants and, in a few cases, as the complete boiler system of a grass-roots plant. Before 1979, such additions are not likely to incorporate FBC technology except as demonstration units. Instead, the major commercial alternatives will be low sulfur coal with an electrostatic precipitator or high sulfur coal with a scrubber. However, by 1979/80, we will assume that FBC technology has been commercially demonstrated to be reliable, and that individual boilers incorporating this technology will start to be added at existing plants in the early 1980's.

There would be advantages for adding a new coal-fired FBC boiler to an existing plant which already has several oil-fired boilers. Initially, the oil-fired boilers could serve as a complete backup system in the event that teething problems were experienced with operation of the new coal-fired boiler. Subsequently, the existence of an oil-fired back-up system would mean that a large inventory of coal would not be needed to protect against possible disruptions in coal supply.* Avoidance of a large inventory of coal would be a considerable advantage to plants that do not have adequate space for the addition of manufacturing units.

If a coal-fired FBC boiler is added at a major plant in one of the process industries, it is probable that the plant will already have a number of oil-fired boilers of varying age and size.** Thus, normal expansion and

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*Eventually, we see the need for a more comprehensive coal delivery system than exists at present. The present system may be adequate in areas where coal is used extensively, but is not adequate in areas such as the Gulf Coast where oil and natural gas are still the predominant industrial boiler fuels.

**Most of the largest petroleum refineries and chemical plants are the result of many years of growth at the same location. The boiler system at these plants will have grown along with expansion of the manufacturing activities.

retirements might be expected to provide the basis for progressive addition of coal-fired boilers. Such addition might continue until the entire installation would be in compliance with S.1777 by 1990 or, possibly, a little later if practicability should require it. In such plants, once confidence is gained with the new FBC technology, it might be expected that the new coal-fired units would be of at least the same steam-generating capacity as the package oil-fired boilers that, otherwise, would be installed. Hence, industrial coal-fired FBC units in the range of 100-400 KPPH should be expected. Even larger units might be installed through use of the modular assembly principle that is being developed for FBC.

The size of the target for industrial use of coal, whether by legislation or if left to market forces, may be inferred from Tables 3-10 and 3-11. Purchased electricity and coking coal are excluded from the estimates of industrial fuel consumption in 1974. It will be seen that:

(1) the split between fuel consumption by boilers and by other industrial combustors was about 54:46.

(2) within the boiler category, those with a capacity of 100 million BTU/H or more accounted for two fifths of the boiler fuel consumed or one fifth of total industrial fuel consumption.

(3) oil and gas were responsible for two thirds of the fuel used by large industrial boilers, however this quantity (2.7 quads in 1974) was only one seventh of total industrial fuel consumption.

Thus, the potential for coal-fired FBC in industrial boilers should be considered, primarily, as a sub-set of coal use within a population of large boilers that will be built after 1980. Significant as this potential may be, it can only be a fraction of the total demand for industrial fuels.

TABLE 3-10

ESTIMATES OF INDUSTRIAL FUEL CONSUMPTION IN 1974

Coal	10^{12} BTU in 1974	% of Subtotal	% of Total Ind. Fuel
Large Boilers (> 100 MBTU/H)	978	63.1	5.2
Smaller Boilers (< 100 MBTU/H)	75	4.8	0.4
Other Large Combustors	462	29.8	2.4
Other Smaller Combustors	35	2.3	0.2
	1550	100	8.2
Oil			
Large Boilers	838	22.6	4.4
Smaller Boilers	1462	39.5	7.7
Other Large Combustors	510	13.8	2.7
Other Smaller Combustors	890	24.1	4.7
	3700	100	19.5
Gas			
Large Boilers	1830	14.5	9.7
Smaller Boilers	4360	34.6	23.1
Other Large Combustors	1900	15.1	10.1
Other Smaller Combustors	4510	35.8	23.9
	12600	100	66.7
Other Fuels			
Large Boilers	311	29.6	1.6
Smaller Boilers	400	38.1	2.1
Other Large Combustors	149	14.2	0.8
Other Smaller Combustors	190	18.1	1.0
	1050	100	5.6
All Fuels			
Large Boilers	3957	20.9	20.9
Smaller Boilers	6297	33.3	33.3
Other Large Combustors	3021	16.0	16.0
Other Smaller Combustors	5625	29.8	29.8
	18900	100	100

Notes: (1) Above estimates exclude purchased electricity and coking coal.
(2) Estimates for Alaska, Hawaii, Puerto Rico and Virgin Islands are included.

Source: ERE estimates based on FEA, BOM and other data.

TABLE 3-11

ESTIMATES OF 1974 INDUSTRIAL FUEL CONSUMPTION BY FUEL TYPE, COMBUSTOR TYPE, AND COMBUSTOR SIZE

Industrial Boilers		Large (>100 MBTU/H)	Smaller (<100 MBTU/H)	All Indust. Boilers
Fuel:	Coal	978	75	1053
	Oil	838	1462	2300
	Gas	1830	4360	6190
	Other	311	400	711
		3957	6297	10254
	% of Subtotal	38.6	61.4	100

Other Industrial Combustors		Large	Smaller	All
Fuel:	Coal	462	35	497
	Oil	510	890	1400
	Gas	1900	4510	6410
	Other	149	190	339
		3021	5625	8646
	% of Subtotal	34.9	65.1	100

Industrial Boilers and Other Combustors		Large	Smaller	All
Fuel:	Coal	1440	110	1550
	Oil	1348	2352	3700
	Gas	3730	8870	12600
	Other	460	590	1050
		6978	11922	18900
	% of Total	36.9	63.1	100

Notes: (1) Above estimates exclude purchased electricity and coking coal.
(2) Industrial fuel consumption in Alaska, Hawaii, Puerto Rico, and Virgin Islands is included.

Source: ERE estimates based on FEA, BOM, and other data.

4. FUTURE DEMAND FOR INDUSTRIAL BOILER FUEL

The future size and structure of the U.S. economy will be a principal determinant of industrial energy demand. As discussed in Section 3, it is necessary to distinguish between boiler fuel demand and fuel used for other purposes (e.g. in process furnaces, cement kilns, etc.). Projection of the future demand for industrial boiler fuel is a prerequisite to estimation of the fraction of this demand that may utilize coal-fired FBC. The first step in the series of necessary projections is to obtain estimates of future manufacturing activity.

4.1 Basis of Demand Projections

A joint study by the Office of Business Economics (OBE) of the Department of Commerce and the Economic Research Service (ERS) of the Department of Agriculture was made for the Water Resources Council (WRC)* and was published in seven volumes in April 1974 (1). The OBERS projections, which extend to the year 2020, involve the concept of Gross Product Originating.** Knowledge of the GPO for each industry in a particular year, and also the fuel consumption for each industry in the same year, makes it possible to calculate the average fuel consumption per unit of product output on an industry by industry basis.

*The United States Water Resources Council, an independent Executive Agency of the U.S. Government, is composed of the Secretaries of Interior; Agriculture; Army; Health, Education, and Welfare; Transportation; Chairman, Federal Power Commission; with participation by the Secretaries of Commerce; Housing and Urban Development; Administrator, Environmental Protection Agency; Attorney General; Director, Office of Management and Budget; Chairman, Council on Environmental Quality; and the Chairmen, River Basin Commissions. Council activities encourage the conservation, development and utilization of water and related land resources on a comprehensive and coordinated basis by Federal, State, local government and private enterprise.

**GPO is defined as follows:

> "Constant dollar GPO is a measure of the volume of real output in each industry. Because of industry variations in the quantity and the price of imports used, each industry has its unique implicit deflator for GPO. In contrast, earnings of persons represent factor returns to labor, and the translation of earnings into constant dollars is conceptually different from the expression of GPO in real terms. The price change that is removed from the current dollar earnings series in the deflation process is the change that has occurred in the purchasing power of the dollar rather than the price change per unit of physical output. The purchasing power of the dollar earned in each industry is assumed to have changed by the same amount. Consequently, the relationship between constant and current dollar earnings is the same in each industry."

4.2 Quantitative Projections

The starting point for the industrial boiler fuel projections was the estimated fuel consumption in 1974. The breakdown by SIC Code (i.e. by industry) is given in Table 4-1. These estimates apply to the population of large industrial boilers (>100 M BTU/H) and are derived from a pooling of data collected in FEA's MFBI and NGTF surveys.

Next, using the OBERS projections, ratios of future industrial fuel consumption by each industry (SIC Code) were calculated relative to the fuel consumption of the industry in 1974 (i.e. 1974 = 1.000 for each industry). The results are shown in Tables 4-2 and 4-3. The latter takes account of energy conservation per unit of manufacturing output anticipated in the future. Multiplication of the fuel consumption in the 1974 base year (Table 4-1) by the conservation corrected ratios for future years (Table 4-3) yields the estimates recorded in Table 4-4. These estimates, however, do not make provision for the probability that, progressively, the larger boilers will account for an increasing fraction of total industrial boiler fuel demand. The reported statistics indicate that the large boilers were responsible for 38.6% of total industrial boiler fuel consumption in 1974. By the year 2000, it is assumed that the percentage will be 50%. This assumption is equivalent to the following increments to the projected fuel demand of the large industrial boiler population:

Year	% Increase over Table 4-4 Estimate
1980	7.0
1985	12.7
1990	18.4
1995	23.8
2000	29.5

The result of incroporating these percentage increases is shown in Table 4-5. As noted, these projections include consumption of by-product fuels, i.e. fuels other than coal, oil, and natural gas. With insignificant exceptions, by-product fuels are consumed within the plant where they are produced and, therefore, do not represent any potential for substitution by coal.

Using FEA survey data for by-product* ("other") fuel consumption by large boilers in 1974, and assuming that the ratio of by-product to commercial fuel will not change in the future, it is possible to convert the projections in Table 4-5 to estimates of coal, oil, and natural gas that will be consumed. The consequence of "backing out" the by-product fuels is shown in Table 4-6. The same estimates are presented in a different format in Table 4-7 for the

*FEA data for the Paper industry (SIC 26) are appreciably at variance with by-product fuel statistics supplied by the American Paper Institute (see Appendix 4, Table 38). The basis of the difference appears to be that statistics for the industry's "recovery boilers" (which recover sodium values from black liquor) are substantially excluded from the FEA surveys. While this is important to an overall understanding of industrial energy consumption, it does not affect the projections discussed above since they are made on an internally consistent basis.

TABLE 4-1

1974 FUEL CONSUMPTION OF LARGE INDUSTRIAL BOILERS BY SIC CODE

SIC Code	Industry	% of 1974 Total	10^{12} BTU's in 1974
28	Chemicals and Allied Products	26.2	1025
26	Paper and Allied Products	16.7	653
29	Petroleum Refining and Related Ind.	16.5	645
33	Primary Metals Industries	12.4	485
20	Food and Kindred Products	5.4	211
34	Fabricated Metal Products	1.7	67
35	Machinery, except Electrical	1.4	55
49	Utility Services*	1.3	51
32	Stone, Clay, Glass and Concrete Products	0.6	23
37	Transportation Equipment	3.5	137
22	Textile Mill Products	3.3	130
24	Lumber and Wood Products	2.3	91
36	Electrical Equipment	2.3	90
30	Rubber and Plastics Products	2.1	82
19/39	Ordnance/Miscellaneous Manufacturing	1.0	39
27	Printing and Publishing	0.9	35
38	Instruments and Related Products	0.7	27
25	Furniture and Fixtures	0.6	23
23	Apparel and Other Textiles	0.6	23
31	Leather and Leather Products	0.3	12
21	Tobacco Manufactures	0.2	8
		100	3912

*except electricity generation.

Notes: (1) Above estimates are based on a pooling of data from MFBI and NGTF surveys.

(2) Data for Alaska, Hawaii, Puerto Rico, and Virgin Islands are excluded.

(3) Numbers in lower half of Table are estimated by disaggregation of purchased fuel statistics for each SIC Code.

TABLE 4-2

INDUSTRIAL FUEL CONSUMPTION RATIOS, RELATIVE TO 1974=1.000, BASED ON OBERS PROJECTIONS

SIC Code	Industry	Fuel Consumption Ratios 1980	1985	1990	2000
28	Chemicals	1.286	1.575	1.923	2.815
26	Paper	1.266	1.463	1.690	2.259
29	Petroleum Refining	1.164	1.343	1.540	2.018
33	Primary Metals	1.127	1.180	1.225	1.331
20	Food	1.114	1.220	1.337	1.621
34	Fabricated Metals	1.324	1.534	1.774	2.375
35	Machinery, except Electrical	1.252	1.422	1.618	2.100
49	Utility Services	1.290	1.523	1.797	2.490
32	Stone, Clay, Glass, Concrete	1.290	1.523	1.797	2.490
37	Transportation Equipment	1.249	1.450	1.681	2.269
22	Textile Mill Products	1.152	1.303	1.463	1.857
24	Lumber and Wood	1.224	1.396	1.592	2.078
36	Electrical Equipment	1.363	1.686	2.088	3.120
30	Rubber and Plastics	1.286	1.575	1.923	2.815
19/39	Ordnance/Miscellaneous	1.324	1.534	1.774	2.375
27	Printing and Publishing	1.244	1.461	1.703	1.810
38	Instruments	1.290	1.523	1.797	2.490
25	Furniture and Fixtures	1.224	1.396	1.592	2.078
23	Apparel	1.221	1.395	1.591	2.082
31	Leather and Leather Products	1.290	1.523	1.797	2.490
21	Tobacco Manufactures	1.290	1.523	1.797	2.490

Note: Above projections do not take account of anticipated energy conservation per unit of manufacturing output.

TABLE 4-3

PROJECTED INDUSTRIAL FUEL CONSUMPTION RATIOS, RELATIVE TO 1974=1.000, MAKING ALLOWANCE FOR ENERGY CONSERVATION

SIC Code	Industry	Conservation Corrected Ratios 1980	1985	1990	2000
28	Chemicals	1.162	1.340	1.542	2.004
26	Paper	1.198	1.357	1.523	1.973
29	Petroleum Refining	1.080	1.202	1.322	1.588
33	Primary Metals	1.054	1.072	1.079	1.105
20	Food	1.035	1.094	1.159	1.310
34	Fabricated Metals	1.246	1.407	1.588	2.021
35	Machinery, except Electrical	1.178	1.305	1.449	1.787
49	Utility Services	1.166	1.397	1.609	2.119
32	Stone, Clay, Glass, Concrete	1.166	1.397	1.609	2.119
37	Transportation Equipment	1.175	1.330	1.505	1.931
22	Textile Mill Products	1.084	1.195	1.310	1.580
24	Lumber and Wood	1.151	1.281	1.425	1.769
36	Electrical Equipment	1.282	1.547	1.869	2.655
30	Rubber and Plastics	1.162	1.340	1.542	2.004
19/39	Ordnance/Miscellaneous	1.246	1.407	1.588	2.021
27	Printing and Publishing	1.170	1.340	1.525	1.540
38	Instruments	1.166	1.397	1.609	2.119
25	Furniture and Fixtures	1.151	1.281	1.425	1.769
23	Apparel	1.149	1.280	1.424	1.772
31	Leather and Leather Products	1.166	1.397	1.609	2.119
21	Tobacco Manufactures	1.166	1.397	1.609	2.119

TABLE 4-4

PROJECTED FUEL CONSUMPTION OF LARGE INDUSTRIAL BOILERS
UNCORRECTED FOR CHANGES IN SIZE DISTRIBUTION

SIC Code	Industry	Boiler Fuel Consumption, 10^{12} BTU's 1980	1985	1990	2000
28	Chemicals	1191	1374	1581	2054
26	Paper	782	886	995	1288
29	Petroleum Refining	697	775	853	1024
33	Primary Metals	511	520	523	536
20	Food	218	231	245	276
34	Fabricated Metals	83	94	106	135
35	Machinery, except Electrical	65	72	80	98
49	Utility Services	59	71	82	108
32	Stone, Clay, Glass, Concrete	27	32	37	49
37	Transportation Equipment	161	182	206	265
22	Textile Mill Products	141	155	170	205
24	Lumber and Wood	105	116	130	161
36	Electrical Equipment	115	139	168	239
30	Rubber and Plastics	95	110	126	164
19/39	Ordnance/Miscellaneous	49	55	62	78
27	Printing and Publishing	41	47	53	57
38	Instruments	31	38	43	57
25	Furniture and Fixtures	26	29	33	40
23	Apparel	26	29	33	41
31	Leather and Leather Products	14	17	19	25
21	Tobacco Manufactures	9	11	13	17
		4446	4983	5558	6914

TABLE 4-5

PROJECTED FUEL CONSUMPTION OF LARGE INDUSTRIAL BOILERS ASSUMING THAT THERE WILL BE A PROGRESSIVE INCREASE IN THE FRACTION OF TOTAL INDUSTRIAL BOILER FUEL CONSUMED BY LARGE BOILERS (>100 M BTU/H)

SIC Code	Industry	Boiler Fuel Consumption, 10^{12} BTU's 1980	1985	1990	2000
28	Chemicals	1274	1548	1872	2660
26	Paper	837	999	1178	1668
29	Petroleum Refining	746	873	1010	1326
33	Primary Metals	547	586	619	694
20	Food	233	260	290	357
34	Fabricated Metals	89	106	125	175
35	Machinery, except Electrical	69	81	95	127
49	Utility Services	63	80	97	140
32	Stone, Clay, Glass, Concrete	29	36	44	63
37	Transportation Equipment	172	205	244	343
22	Textile Mill Products	151	175	201	265
24	Lumber and Wood	112	130	154	208
36	Electrical Equipment	123	157	199	309
30	Rubber and Plastics	102	124	149	212
19/39	Ordnance/Miscellaneous	52	62	73	101
27	Printing and Publishing	44	53	63	70
38	Instruments	33	43	51	74
25	Furniture and Fixtures	28	33	39	51
23	Apparel	28	33	37	53
31	Leather and Leather Products	15	19	22	32
21	Tobacco Manufactures	9	12	15	22
		4756	5615	6579	8950

Note: Above projections include consumption of by-product (i.e. "Other") fuels.

TABLE 4-6

PROJECTIONS OF COAL, OIL, AND NATURAL GAS CONSUMPTION OF LARGE INDUSTRIAL BOILERS

SIC Code	Industry	Fuel Consumption, 10^{12} BTU 1980	1985	1990	2000
28	Chemicals	1236	1501	1816	2580
26	Paper	720	859	1013	1434
29	Petroleum Refining	716	838	970	1273
33	Primary Metals	421	451	477	534
20	Food	227	257	287	353
34	Fabricated Metals	85	102	120	168
35	Machinery, except Electrical	68	79	95	124
49	Utility Services	62	78	95	137
32	Stone, Clay, Glass, Concrete	28	35	43	62
37	Transportation Equipment	169	201	239	336
22	Textile Mill Products	149	173	199	262
24	Lumber and Wood	96	112	132	179
36	Electrical Equipment	120	167	195	303
30	Rubber and Plastics	99	120	145	206
19/39	Ordnance/Miscellaneous	51	61	71	99
27	Printing and Publishing	42	51	60	67
38	Instruments	33	42	50	73
25	Furniture and Fixtures	27	32	37	49
23	Apparel	27	32	38	51
31	Leather and Leather Products	15	19	22	31
21	Tobacco Manufactures	9	12	14	21
		4400	5222	6118	8342

TABLE 4-7

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's					% of 2000 Total
			1980	1985	1990	1995	2000	
28	Process	Chemicals	1236	1501	1816	2165	2580	30.9
30	Process	Rubber and Plastics	99	120	145	173	206	2.4
29	Process	Petroleum Refining	716	838	970	1111	1273	15.3
26	Process	Paper	720	859	1013	1205	1434	17.2
33	Process	Primary Metals	421	451	477	505	534	6.4
20	Process	Food	227	257	287	318	353	4.2
32	Process	Stone, Clay, Glass, Concrete	28	35	43	52	62	0.7
		Subtotal	3447	4061	4751	5529	6442	77.2
37	Gen. Mfg.	Transportation Equipment	169	201	239	283	336	4.0
36	Gen. Mfg.	Electrical Equipment	120	167	195	243	303	3.6
22	Gen. Mfg.	Textile Mill Products	149	173	199	228	262	3.1
23	Gen. Mfg.	Apparel	27	32	38	44	51	0.6
34	Gen. Mfg.	Fabricated Metals	85	102	120	142	168	2.0
35	Gen. Mfg.	Machinery, except Electrical	68	79	95	109	124	1.5
38	Gen. Mfg.	Instruments	33	42	50	60	73	0.9
		Subtotal	651	796	936	1109	1317	15.8
49	Miscellaneous	Utility Services	62	78	95	114	137	1.6
19/39	Miscellaneous	Ordnance/Miscellaneous	51	61	71	84	99	1.2
24	Miscellaneous	Lumber and Wood	96	112	132	154	179	2.2
25	Miscellaneous	Furniture	27	32	37	43	49	0.6
27	Miscellaneous	Printing and Publishing	42	51	60	63	67	0.8
31	Miscellaneous	Leather	15	19	22	26	31	0.4
21	Miscellaneous	Tobacco Manufactures	9	12	14	17	21	0.2
		Subtotal	302	365	431	501	583	7.0

purpose of illustrating that the consumption of boiler fuel by large industrial boilers is concentrated in the process industries, as distinguished from general manufacturing (of equipment, etc.) and a variety of other industrial activities that are labeled "Miscellaneous" in Table 4-7.

The estimates in Table 4-7 are shown in Table 4-8 as increments over boiler fuel consumption in 1974. The final column of this Table expresses the increments for each industry as percentages of the total 1974/2000 increment estimated for the large industrial boilers. These figures indicate the projected degree of concentration of incremental demand for coal, oil and natural gas in the leading process industries:

Industry	% of Total 1974/2000 Increment
Chemicals and Allied Products	33.6
Rubber and Plastics Products	2.7
Subtotal	36.3
Petroleum Refining and Related Ind.	13.9
Paper and Allied Products	18.5
Total	68.7

The projected increment for Primary Metals (SIC 33) is only 3.4%, which appears low. However, it is derived on the same basis as the other projections, and can be rationalized in terms of factors such as:

- relatively slow growth in primary metals production
- some shifts in product mix, e.g. a higher ratio of aluminum to steel
- anticipated savings in energy consumption per unit of output
- greater use of (purchased) electricity in the production of primary metals.

Our judgment is that the additional boiler fuel potential in Primary Metals is significant on an absolute basis but is far less than in the industries cited above. On the other hand, we believe that there may be a major potential for non-boiler applications* of FBC within the Primary Metals industries.

The increments estimated in Table 4-8 understate the potential for new boiler capacity associated with future levels of boiler fuel demand. This is because many of the large boilers that are now in operation will be retired by the year 2000. If oil and natural gas were to remain available a retirement rate of about 3% per year could be expected. However, a significant switching

*e.g. soaking pits, melting, reheating, etc. All such applications are outside the scope of the present study.

TABLE 4-8

PROJECTED INCREMENTS IN CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Increment in Coal, Oil, and Nat. Gas Over 1974, 10^{12} BTU's 1980	1985	1990	1995	2000	% of 2000 Total
28	Process	Chemicals	242	507	822	1171	1586	33.6
30	Process	Rubber and Plastics	19	40	65	93	126	2.7
29	Process	Petroleum Refining	97	219	351	492	654	13.9
26	Process	Paper	158	297	451	643	872	18.5
33	Process	Primary Metals	48	78	104	132	161	3.4
20	Process	Food	18	48	78	109	144	3.0
32	Process	Stone, Clay, Glass, Concrete	5	12	20	29	39	0.8
		Subtotal	587	1201	1891	2669	3582	75.9
37	Gen. Mfg.	Transportation Equipment	35	67	105	149	202	4.3
36	Gen. Mfg.	Electrical Equipment	32	79	107	155	215	4.6
22	Gen. Mfg.	Textile Mill Products	20	44	70	99	133	2.8
23	Gen. Mfg.	Apparel	5	10	16	22	29	0.6
34	Gen. Mfg.	Fabricated Metals	21	38	56	78	104	2.2
35	Gen. Mfg.	Machinery, except Electrical	14	25	41	55	70	1.5
38	Gen. Mfg.	Instruments	6	15	23	33	46	1.0
		Subtotal	133	278	418	591	799	16.9
49	Miscellaneous	Utility Services	12	28	45	64	87	1.8
19/39	Miscellaneous	Ordnance/Miscellaneous	13	23	33	46	61	1.3
24	Miscellaneous	Lumber and Wood	18	34	54	76	101	2.1
25	Miscellaneous	Furniture	5	10	15	21	27	0.6
27	Miscellaneous	Printing and Publishing	8	17	26	29	33	0.7
31	Miscellaneous	Leather	3	7	10	14	19	0.4
21	Miscellaneous	Tobacco Manufactures	1	4	6	9	13	0.3
		Subtotal	60	123	189	259	341	7.2
		TOTAL	780	1602	2498	3519	4722	100
		Increment over 1980 Total	-	822	1718	2739	3942	-

to coal by the large boilers is expected to accelerate the rate at which existing oil/gas-fired capacity is retired, particularly in the period after 1980 when some form of coal-use legislation may be in effect. This expectation was examined at (accelerated) retirement rates of 4% per year and 5% per year, using 1980 as a base year. By definition, 100% of the large boiler capacity operating in 1980 will be in place in that year. In subsequent years, the boilers operating in 1980 will represent a declining percentage of the total capacity of large boilers:

Assumed Retirement Rate	Boilers Operating in 1980 as % of Total Boiler Capacity in Subsequent Years			
	1988	1990	1995	2000
4% per year	67	43	25	11
5% per year	63	36	15	--

The 5% per year retirement schedule would be reasonably consistent with the present provisions of proposed coal-use legislation (i.e. S.1777 in its revised form), making the assumption that the "practicability" criteria of the legislation will permit some large oil/gas-fired boilers to remain in operation beyond 1995. In addition, a relatively small number of existing (large) coal-fired boilers could also be in operation beyond 1995. For practical purposes, the 5% per year retirement schedule would permit almost all large industrial boilers still operating on oil or gas in 1980 to be retired by the year 2000. This possibility provides a scenario in which the market penetration rate of coal-fired FBC may be considered.

5. PROJECTIONS OF COAL-FIRED FBC POTENTIAL

5.1 Basis of Projections

Projections of the potential for coal-fired FBC industrial boilers are made from a base year of 1974, after dividing the industrial boiler population into:

- industrial boilers with a design firing-rate of more than 99 million BTU/H, i.e. MFBI's or "large boilers".
- smaller industrial boilers, i.e. those with a design firing rate of less than 99 million BTU/H.

The 1974 fuel consumption of the large boilers has been discussed in Section 4. For subsequent years, the principal options open to these boilers may be classified in relation to the fuel that they used in 1974 and taking account of the boilers that were originally designed for coal.

Fuel Used in 1974	Principal Future Options
(a) "Other"	Continue use of by-product fuels
(b) Natural Gas	(1) Near term: continue use of gas if available, or substitute oil-firing (2) Longer term: consider replacement of gas-fired boiler with a new coal-fired boiler
(c) Oil	(1) Near term: continue use of oil (2) Longer term: consider replacement of oil-fired boiler with a new coal-fired boiler
(d) Gas or oil-fired, but converted from coal	Consider re-conversion to coal-firing. Also consider "compliance coal"* versus flue gas desulfurization (FGDS), i.e. the retrofitting of a flue gas scrubber system.
(e) Coal	(1) Near term: consider compliance coal versus FGDS (2) Longer term: consider compliance coal versus other control technologies, and also the combination of compliance coal and FBC.

*i.e. coal that has a sufficiently low sulfur content to meet Federal emission standards for new point sources without additional control technology for sulfur oxides.

By 1980, the situation for the large boilers is expected to change as follows:

(1) Fuel demand relative to 1974 will change:

- in proportion to projected increases in industrial output, but corrected for energy conservation per unit of output.

- in relation to projected changes in the fractions of total output supported by large and smaller boilers.

(2) The steam generating capacity of coal-fired boilers will be equal to that in 1974 minus retirements, and plus:

- additions of capacity at plants using coal in 1974.
- reconversions from oil/gas to coal.
- additions of coal-fired capacity at plants using oil/gas in 1974.
- capacity of coal-fired boilers at grass-roots plants that did not exist in 1974.

All of the large industrial boilers that fired oil and/or gas in 1974 are considered to be part of the coal potential, except in areas where coal logistics are unfavorable. Where coal is used, the compliance choices by 1980 will be:

- compliance coal (used in conjunction with an electrostatic precipitator)
- FGDS
- nominal use of FBC, e.g. in demonstration units.

Clearly, the coal-fired FBC potential is a sub-set of coal utilization by all large industrial boilers. The level of coal utilization by industrial MFBI's is assumed to be driven by S.1777-type legislation.* Different assumptions are used to derive maximum, most probable, and minimum estimates of coal-fired FBC potential. The principal assumptions relate to:

(1) the split between (a) compliance coal, and (b) non-compliance coal used with control technology.

(2) the rate of market penetration of FBC technology after being demonstrated to be commercially reliable.

(3) local deviations from Federal emission standards, particularly the standards for new point sources.

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*S.1777 refers to the proposed "National Petroleum and Natural Gas Conservation and Coal Substitution Act", see Reference (5), Section 3.

The consumption of fuel by industrial boilers in the year 2000 is conceptualized in the following diagrams (not to scale):

TOTAL FUEL CONSUMPTION OF INDUSTRIAL BOILERS

Smaller Boilers	Large Boilers

FUEL CONSUMPTION OF LARGE INDUSTRIAL BOILERS

"Other" Fuels	Oil or Gas	Coal	
		Non-FBC Technology	FBC Technology

A B C D E

The AB segment in the lower diagram represents the consumption of by-product fuels such as bagasse and bark. Utilization of such fuels will continue, and they will not be displaced by coal-fired FBC even though their combustion in fluidized beds is a possibility.

The BC segment represents the anticipation that coal use will be impractical in some large industrial boilers for logistical or other reasons. The CD segment represents coal use by any technology other than FBC. In the main, the non-FBC "technology" is expected to be compliance coal although, not necessarily, untreated low sulfur coal. While outside the scope of the present study, it seems likely that coal cleaning technology will develop significantly during the next two decades so as to augment the availability of compliance coal. For the purposes of the present study, it does not make any difference whether synthetic fuels* are considered to be within the BC or CD elements. The critical boundary is fixed by the position of D. In this study, D has three locations within the segment CE which correspond to the estimates of maximum, most probable, and minimum potentials for coal-fired FBC. If the three locations of D are denoted D max., D prob. and D min., then:

- the segment D max. E represents the maximum potential
- the (alternative) segment D prob. E represents the most probable potential
- the (alternative) segment D min. E represents the minimum potential for coal-fired FBC.

*that may be derived from coal and/or oil shale, and may be liquids or gases.

5.2 Modification of Basis

Some important new information was provided by ERDA early in September 1976. This subsection summarizes the nature and original source of the information, and also its implications.

The contract became effective on 6/27/75, and most of the basic cost estimates were made in September 1975. These estimates related to the "state of the art" of atmospheric FBC technology as we appraised it in August/September 1975. During the past year (i.e. September 1975/1976), industrial FBC boiler technology has been developing. One way in which this has become apparent is through the proposals received by ERDA from a number of contractors in response to ERDA's Program Opportunity Notice program for FBC developments. These proposals have contained cost estimates for industrial FBC boilers which are confidential and, hence, not available to us. We were informed that the estimates were numerically lower than those we had made in September 1975, but we could not utilize the information because we did not know either the details of the estimates or the bases upon which they were made. However, in September 1976, ERDA was able to provide us with sufficient detail and quantification to make possible the recalculation of various coal-fired boiler comparisons. The immediate results of these recalculations were that:

(1) for high sulfur coal, a boiler system using FBC technology was indicated to be lower in cost than a system incorporating flue gas desulfurization (i.e. scrubbers).

(2) for low sulfur (compliance) coal, a boiler system using FBC technology was indicated to be a standoff in cost with a conventional spreader-stoker system (not incorporating flue gas desulfurization because of the sulfur compliance quality of the coal).

The first of these results did not affect previously made estimates of FBC potential because we had already judged FBC to be a more attractive technology than scrubbing, even though the previous cost estimates were a stand-off. This judgment was based on a number of potential advantages of FBC that were not "captured" in the cost estimates.

The second result, however, introduces significantly new and different considerations. Because of the potential advantages of FBC, a cost standoff with a conventional spreader-stoker suggests that FBC could be the preferred technology for burning compliance coals (as well as high sulfur coals). Thus, a possible implication is that FBC may be the preferred industrial boiler technology for <u>all</u> coals. Essentially, this implication, in the form of an assumption, was used to generate estimates of the <u>maximum</u> potential for coal-fired, industrial FBC boilers. However, estimates of the <u>most probable</u> potential were less optimistic with respect to domination of the large industrial boiler market by FBC technology where compliance coal is the fuel of choice. Therefore, consequent upon the cost estimates provided by ERDA in September 1976, it has been necessary to make a significant upward revision of the estimates of most probable potential. In making this change, we have retained the previously made assumption of a somewhat slower rate of market penetration in the most probable case that for the maximum case. Also, as detailed later, we did not assume that all compliance coal used in industrial boilers would eventually be burned using FBC technology.

5.3 Regional Applicability

The regional applicability of coal-fired FBC is estimated in Table 5-1. For the estimate of maximum potential, the New England region is excluded on the basis of logistics and because electric utilities in this area are projecting a percentage decrease in their future use of coal (1). Exclusion of New England reduces the potential for coal-fired FBC in the Lower 48 states by 2.76%. Additionally, it is assumed that half of the potential in four other regions (Northern Plains, Rocky Mountain, Pacific Northwest, and Pacific Southwest) will not be secured by coal-fired FBC because these regions will either have access to compliance coal* produced in the West or, in the case of certain areas (e.g. Los Angeles county) will avoid the use of coal for environmental reasons. The combined effect of the assumptions used to exclude part or all of the potential in the above five regions is to reduce the overall potential for coal-fired FBC by 8.4%.

For the most probable case, additional regional exclusions are assumed as indicated in the center portion of Table 5-1. The single most significant increment over the exclusions assumed for the maximum case concerns the potential of the Gulf Coast region. The assumption is based on:

(1) anticipated availability of local lignites many of which will not be "compliance coals".

(2) anticipated need to begin a shift to coal-firing before FBC technology is fully demonstrated.

In total, the regional assumptions in the most probable case reduce the overall potential by about 26%.

Similar but more severe regional limitations are assumed in order to estimate the minimum potential for coal-fired FBC. Details are shown in the bottom section of Table 5-1, and it is estimated that regional constraints would reduce the national potential by 52% in the minimum case.

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*see Table 3-5 for identification of FEA regions.

**taking the discussion in Section 5.2 into consideration.

TABLE 5-1

ESTIMATES OF REGIONAL APPLICABILITY OF COAL-FIRED FBC

• Maximum Potential

Regions Partially or Wholly Excluded from Potential	Fraction Excluded	Exclusion as % of Total Potential in Lower 48 States*
New England	1.0	2.76
Northern Plains	0.5	1.00
Rocky Mountain	0.5	1.46
Pacific Northwest	0.5	1.76
Pacific Southwest	0.5	1.45
		8.43

• Most Probable Potential

New England	1.0	2.76
D.C., Md., N.J., N.Y.	1.0	8.09
Northern Plains	0.7	1.40
Rocky Mountain	0.7	2.04
Pacific Northwest	0.7	2.45
Pacific Southwest	0.7	2.03
Gulf Coast	0.25	7.01
		25.78

• Minimum Potential

New England	1.0	2.76
D.C., Md., N.J., N.Y.	1.0	8.09
Pennsylvania	0.25	1.27
Northern Plains	1.0	2.00
Oklahoma	1.0	0.72
Rocky Mountain	1.0	2.92
Pacific Northwest	1.0	3.51
Pacific Southwest	1.0	2.89
Gulf Coast	1.0	28.04
		52.20

* Based on 1974 fuel consumption and capacity percentages reported in Table 3-9. See Table 3-5 for identification of FEA regions.

5.4 Maximum, Most Probable, and Minimum Potentials

The above regional factors are combined with factors estimated for market penetration and functional applicability in order to derive the combined factors shown in Table 5-2. Multiplication of the total fossil fuel demand estimated for large industrial boilers by the pertinent combined factor yields the estimate of the coal-fired FBC potential (in 10^{15} BTU's per year) for a given year and for each of the cases. The results are summarized below:

Year	Coal-Fired FBC Potential, 10^{15} BTU — Maximum	Most Likely	Minimum
1980	0.02	0.01	nil
1985	0.62	0.29	0.075
1990	1.97	0.99	0.29
1995	3.20	1.69	0.54
2000	5.52	2.97	1.00

5.5 Additional Applications of Coal-Fired FBC

The above estimates do not include possible increments to the overall potential for coal-fired FBC at industrial MFBI's due to:

(1) a reversal of the long term decline trend in the captive generation of electricity.

(2) applications of coal-fired FBC to new industries.

Currently, the captive generation of electricity at manufacturing plants is equivalent to slightly less than 9% of the energy purchased by the plants. The corresponding figure for 1950 was 18%. The reasons for the steady decline in captive generation of electricity are that, in general, it has been cheaper for manufacturing plants to purchase electricity from electric utilities and also that manufacturing industry has preferred to invest its capital in production facilities rather than in supporting services. While the latter condition still applies, the constant dollar cost of electricity has reversed its long-term downtrend. Moreover, rate structures are being revised in ways that are less favorable to the purchase of large blocs of power by industrial customers. Finally, captive generation of electricity is energy-efficient at plants which have a large requirement for process steam and, hence, are able to generate "by-product" electricity through the simple expedient of generating steam at a higher pressure than required for process applications. Letting down the steam pressure through a turbo-generator enables "by-product" electricity to be generated with only a small increment in fuel consumption over what would be required if no electricity were generated. By the same token, the incremental coal-fired FBC potential is relatively small when estimated in terms of fuel consumption. As a sensitivity, it is assumed that a reversal to the downtrend in captive generation of electricity will occur in 1977 and, thereafter, there will be a cumulative increase of 1% per year in the percentage of electricity generated captively relatively to the energy purchased by manufacturing plants. The assumption of 1% per year applies to the maximum case. The corresponding

TABLE 5-2

ESTIMATES OF NATIONAL POTENTIAL FOR COAL-FIRED FBC

Year	Total Fossil Fuel for Large Boilers, 10^{15} BTU*	Regional Factor**	Applicability Factor	Penetration Factor	Combined Factor ϕ	Coal-Fired FBC Potential, 10^{15} BTU ϕϕ	% of Max. Potential
• Maximum Potential							
1980	4.40	0.92	0.50	0.01	0.0046	0.02	
1985	5.22	0.92	0.65	0.2	0.1196	0.62	
1990	6.12	0.92	0.70	0.5	0.322	1.97	
1995	7.14	0.92	0.75	0.65	0.449	3.20	
2000	8.34	0.92	0.80	0.9	0.662	5.52	
• Most Probable Potential							
1980	4.40	0.74	0.30	0.01	0.0022	0.01	-
1985	5.22	0.74	0.50	0.15	0.0556	0.29	47
1990	6.12	0.74	0.55	0.4	0.162	0.99	50
1995	7.14	0.74	0.58	0.55	0.236	1.69	53
2000	8.34	0.74	0.60	0.8	0.356	2.97	54
• Minimum Potential							
1980	4.40	0.48	nil	nil	nil	nil	nil
1985	5.22	0.48	0.3	0.1	0.0144	0.075	12
1990	6.12	0.48	0.4	0.25	0.048	0.294	15
1995	7.14	0.48	0.45	0.35	0.076	0.543	17
2000	8.34	0.48	0.5	0.5	0.120	1.00	18

*From Table 4-6
**From Table 5-1

ϕ Regional Factor x Applicability Factor x Penetration Factor
ϕϕ Total Fossil Fuel for Large Boilers x Combined Factor

assumptions for the most likely and minimum cases are 0.5% per year and 0.2% per year respectively. Estimates based on these assumptions are shown in Table 5-3. Also included are estimates derived from the assumption that coal-fired FBC technology may be applicable to:

(1) the generation of process steam at synthetic fuels plants.

(2) the utilization of by-product coal fractions, e.g. fines, from coal beneficiation plants.

It is further assumed that only nominal applications will be in operation in 1985, but that growth may be quite rapid post-1990.

The final columns of Table 5-3 combine the estimates of coal-fired FBC potential in existing manufacturing applications with the additional potentials estimated as "sensitivities" in relation to higher levels of captive generation of electricity and novel applications of coal-fired FBC.

The estimates discussed above are presented in a different form in Table 5-4. In each case, the maximum, most probable, and minimum coal-fired FBC potentials are presented as percentages of the estimated total fossil fuel demand of large industrial boilers. This is done excluding, and also including, the "sensitivities" relating to higher levels of captive generation of electricity and novel applications of coal-fired FBC. The following percentages are estimated for the most probable case:

	% of Total Fossil Fuel Demand of Large Industrial Boilers	
Year	Excluding Sensitivities	Including Sensitivities
1980	0.2	0.2
1985	5.5	6
1990	16	20
1995	24	30
2000	36	42

5.6 Boiler Fuel Demand Where FBC is Not Applicable

If the above estimates are of the right order of magnitude, two important questions arise:

(1) What fuels will be used in industrial boilers with a design firing-rate of <u>less</u> than 99 million BTU/H?

(2) What fuels will be used in the large industrial boilers that do not employ coal-fired FBC technology?

The first of these questions is outside the scope of the present study. Nevertheless, it may be inferred that (a) there will be a contingency demand for oil and gas as industrial fuels, whether these fuels are petroleum-derived or "synthetic", and (b) that some manufacturing operations may stop

TABLE 5-3

ESTIMATES OF POSSIBLE ADDITIONS TO NATIONAL POTENTIAL FOR COAL-FIRED FBC ATTRIBUTABLE TO HIGHER LEVEL OF CAPTIVE GENERATION OF ELECTRICITY AND NEW APPLICATIONS

Year	Higher Level of Captive Elect., 10^{15} BTU	New Applications, 10^{15} BTU	Subtotal 10^{15} BTU	Table 5-2 Potential 10^{15} BTU	Combined Potential 10^{15} BTU	Comb. Pot. in 10^6 B/D O.E.*
• **Maximum Potential**						
1980	nominal	nil	nominal	0.02	0.02	0.009 (9,000 B/D)
1985	0.06	nominal	0.06	0.62	0.68	0.32
1990	0.24	0.42	0.66	1.97	2.63	1.24
1995	0.84	1.02	1.86	3.20	5.06	2.38
2000	1.80	1.92	3.72	5.52	9.24	4.3
• **Most Likely Potential**						
1980	nominal	nil	nominal	0.01	0.01	0.005 (4,500 B/D)
1985	0.03	nominal	0.03	0.29	0.32	0.15
1990	0.12	0.28	0.40	0.99	1.39	0.65
1995	0.42	0.68	1.10	1.69	2.79	1.31
2000	0.90	1.30	2.20	2.97	5.17	2.4
• **Minimum Potential**						
1980	nil	nil	nil	nil	nil	nil
1985	0.012	nominal	0.012	0.075	0.087	0.04 (40,000 B/D)
1990	0.048	0.084	0.132	0.294	0.43	0.20
1995	0.168	0.204	0.372	0.543	0.91	0.43
2000	0.360	0.384	0.744	1.00	1.74	0.82

*10^{15} BTU per year = 0.47 x 10^6 barrels of oil equivalent per day.

TABLE 5-4

ESTIMATES OF COAL-FIRED FBC POTENTIAL AS PERCENTAGE OF TOTAL FOSSIL FUEL CONSUMPTION OF LARGE INDUSTRIAL BOILERS

• Excluding Higher Level of Captive Generation of Electricity and Novel Applications

Year	Total Fossil Fuel for Large Boilers, 10^{15} BTU*	Maximum FBC Potential ø		Most Prob. Potential ø		Minimum FBC Potential ø	
		10^{15} BTU	% of Total	10^{15} BTU	% of Total	10^{15} BTU	% of Total
1980	4.40	0.02	0.5	0.01	0.2	nil	nil
1985	5.22	0.62	12	0.29	5.5	0.075	1.4
1990	6.12	1.97	32	0.99	16	0.294	5
1995	7.14	3.20	45	1.69	24	0.543	8
2000	8.34	5.52	66	2.97	36	1.000	12

• Including Higher Level of Captive Generation of Electricity and Novel Applications

Year	Total Fossil Fuel for Large Boilers, 10^{15} BTU**	Maximum FBC Potential		Most Prob. FBC Potential		Minimum FBC Potential	
		10^{15} BTU	% of Total	10^{15} BTU	% of Total	10^{15} BTU	% of Total
1980	4.40	0.02	0.5	0.01	0.2	nil	nil
1985	5.29	0.68	13	0.32	6	0.087	1.6
1990	6.84	2.63	38	1.39	20	0.43	6
1995	9.16	5.06	55	2.79	30	0.91	10
2000	12.38	9.24	75	5.17	42	1.74	14

*from Table 4-6 or 5-2
**including increment due to electricity generation etc.
øfrom Table 5-2

generating their own steam and, instead, may purchase steam from electric utilities or central steam-generating plants or may substitute purchased electricity in processes that now use steam.

The second question is at the boundary of the present study. Various answers seem possible. Indeed, the most likely outcome is a combination of conventional use of compliance coal, coal-in-oil slurries, non-compliance coal with control technologies such as FGDS, solvent refined coal or other forms of cleaned solid coal, and also the continuing use of oil and gas in some plants. Moreover, as in the case of smaller manufacturing plants, some MFBI's may be able to purchase steam from central plants and/or substitute electricity for steam in some processes.

The suggestions of (a) higher levels of captive generation of electricity, and (b) substitution of electricity for steam may appear mutually incompatible. However, it is believed that each can occur, although in different types of manufacturing operation. The former is believed best suited to an activity that requires large quantities of process steam and relatively smaller amounts of electricity, as in petroleum refining (or synfuels manufacture) and segments of the chemicals industry. The latter seems compatible with manufacturing operations that require a relatively high ratio of electricity to steam.

5.7 Regionalization of Coal-fired FBC Potential

The future consumption of fossil fuels by large industrial boilers is projected on a regional basis in Tables 5-5 through 5-14. The regionalization is based on the data presented in Section 3 and the quantification accords with the national aggregates of boiler fuel consumption projected in Section 4.

The estimates of coal-fired FBC potential discussed in Section 5.4 are disaggregated to a regional basis using the estimates of regional participation in Table 5-1 and the estimates of nationwide potential given in Table 5-2. The results are shown in Table 5-15. Sensitivities that consider a higher level of captive generation of electricity and novel applications of coal-fired FBC are not included in Table 5-15**. No regionalized estimates of potential are made for 1980 since the national aggregates are expected to be minimal at that time. It should be noted that the estimates in Table 5-15 are in trillions of BTU's not quads (10^{15} BTU), and also that the boiler system in a "small" MFBI might consume slightly less than one trillion BTU's per year. Hence, some of the smaller figures in Table 5-15 represent operations of a practical size. Nevertheless, it must be pointed out that the precision of the individual estimates is very low. The estimates are intended only as semi-quantitative indications of where the potential for coal-fired FBC may develop on a regional basis. These estimates, used in conjunction with those for the total fossil fuel demand of large industrial boilers in Tables 5-6 through 5-14, provide a basis for conceptualizing which industries within each region offer the best prospects for coal-fired FBC.

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*See Table 3-5 for identification of FEA regions.

**If these sensitivities are desired on a regional basis, approximate estimates may be made by proration using the estimates in Table 5-4.

TABLE 5-5

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN NEW ENGLAND REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's 1980	1985	1990	1995	2000
28	Process	Chemicals	17	21	25	30	36
30	"	Rubber & Plastics	5	6	7	9	10
29	"	Petroleum Refining	-	-	-	-	-
26	"	Paper	32	38	45	53	63
33	"	Primary Metals	5	6	6	7	7
20	"	Food	4	4	5	5	6
32	"	Stone, Clay, Glass, Concrete	5	6	6	7	7
			65	77	81	107	126
37	General	Transportation Equipment	9	11	12	14	15
36	Manufacturing	Electrical Equipment	6	9	10	13	15
22	"	Textile Mill Prods.	8	9	11	12	14
23	"	Apparel	2	2	2	2	3
34	"	Fabricated Metals	5	6	6	8	9
35	"	Machinery, ex. Elect.	4	4	5	6	7
38	"	Instruments	2	2	3	3	4
49	Miscellaneous	Utility Services	3	4	5	6	7
19/39	"	Ordnance/Miscellaneous	3	3	4	5	5
24	"	Lumber & Wood	5	6	7	8	9
25	"	Furniture	1	2	2	2	3
27	"	Printing & Publishing	2	3	3	3	4
31	"	Leather	1	1	1	1	1
21	"	Tobacco Manufactures	1	1	1	1	1
			52	62	72	84	107
		Total	117	139	163	191	223

TABLE 5-6

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN APPALACHIAN REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's 1980	1985	1990	1995	2000
28	Process	Chemicals	308	374	452	539	642
30	"	Rubber & Plastics	25	30	36	43	51
29	"	Petroleum Refining	97	113	131	150	172
26	"	Paper	139	166	195	233	277
33	"	Primary Metals	190	204	216	228	250
20	"	Food	34	38	43	47	53
32	"	Stone, Clay, Glass, Concrete	21	26	32	38	45
			814	951	1105	1278	1490
37	General Manufacturing	Transportation Equipment	46	55	67	81	95
36		Electrical Equipment	32	46	55	70	86
22	"	Textile Mill Prods.	40	47	55	65	74
23	"	Apparel	7	9	10	12	14
34	"	Fabricated Metals	23	28	34	40	48
35	"	Machinery, ex. Elect.	18	22	27	31	35
38	"	Instruments	9	12	14	17	21
49	Miscellaneous	Utility Services	17	21	27	32	39
19/39	"	Ordnance/Miscellaneous	14	17	20	24	28
24	"	Lumber & Wood	26	31	37	44	51
25	"	Furniture	7	9	10	12	14
27	"	Printing & Publishing	11	14	17	18	19
31	"	Leather	4	5	6	7	9
21	"	Tobacco Manufactures	2	3	4	5	6
			256	319	383	458	539
		Total	1070	1270	1488	1736	2029

TABLE 5-7

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN SOUTHEAST REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's 1980	1985	1990	1995	2000
28	Process	Chemicals	218	264	320	381	454
30	"	Rubber & Plastics	17	21	26	30	36
29	"	Petroleum Refining	-	-	-	-	-
26	"	Paper	258	308	363	431	513
33	"	Primary Metals	8	9	9	10	10
20	"	Food	12	13	15	17	18
32	"	Stone, Clay, Glass, Concrete	-	-	-	-	-
			513	615	733	869	1031
37	General	Transportation Equipment	20	23	25	26	28
36	Manufacturing	Electrical Equipment	15	18	20	23	25
22	"	Textile Mill Prods.	18	19	20	21	22
23	"	Apparel	3	4	4	4	4
34	"	Fabricated Metals	10	11	12	13	14
35	"	Machinery, ex. Elect.	8	9	10	10	10
38	"	Instruments	4	5	5	6	6
49	Miscellaneous	Utility Services	8	9	10	11	12
19/39	"	Ordnance/Miscellaneous	6	7	7	8	8
24	"	Lumber & Wood	12	13	14	14	15
25	"	Furniture	3	3	4	4	4
27	"	Printing & Publishing	5	6	6	6	6
31	"	Leather	2	2	2	2	3
21	"	Tobacco Manufactures	1	1	1	2	2
			115	130	140	150	159
		Total	628	745	873	1019	1190

TABLE 5-8

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN GREAT LAKES REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's 1980	1985	1990	1995	2000
28	Process	Chemicals	57	69	84	100	120
30	"	Rubber & Plastics	5	6	7	8	9
29	"	Petroleum Refining	100	116	135	154	177
26	"	Paper	60	72	85	101	120
33	"	Primary Metals	152	163	172	182	194
20	"	Food	43	49	54	60	67
32	"	Stone, Clay, Glass, Concrete	5	6	7	9	10
			422	481	544	614	697
37	General	Transportation Equipment	43	53	66	81	98
36	Manufacturing	Electrical Equipment	30	44	54	70	89
22	"	Textile Mill Prods.	37	45	54	65	77
23	"	Apparel	7	8	10	12	15
34	"	Fabricated Metals	21	27	33	40	49
35	"	Machinery, ex. Elect.	17	21	26	31	36
38	"	Instruments	8	11	14	17	21
49	Miscellaneous	Utility Services	15	20	26	32	40
19/39	"	Ordnance/Miscellaneous	13	16	19	24	29
24	"	Lumber & Wood	24	29	36	44	52
25	"	Furniture	7	8	10	12	14
27	"	Printing & Publishing	10	13	16	18	20
31	"	Leather	4	5	6	7	9
21	"	Tobacco Manufactures	2	3	4	5	6
			238	303	374	458	555
		Total	660	784	918	1072	1252

TABLE 5-9

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN NORTHERN PLAINS REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's				
			1980	1985	1990	1995	2000
28	Process	Chemicals	2	3	4	4	5
30	"	Rubber & Plastics	-	-	-	-	-
29	"	Petroleum Refining	4	5	6	7	8
26	"	Paper	19	22	26	31	37
33	"	Primary Metals	-	-	-	-	-
20	"	Food	30	34	39	43	47
32	"	Stone, Clay, Glass, Concrete	-	-	-	-	-
			55	64	75	85	97
37	General	Transportation Equipment	6	7	8	10	12
36	Manufacturing	Electrical Equipment	4	6	7	8	11
22	"	Textile Mill Prods.	5	6	7	8	10
23	"	Apparel	1	1	1	2	2
34	"	Fabricated Metals	3	3	4	5	6
35	"	Machinery, ex. Elect.	2	3	3	4	4
38	"	Instruments	1	1	2	2	3
49	Miscellaneous	Utility Services	2	3	3	4	5
19/39	"	Ordnance/Miscellaneous	2	2	3	3	4
24	"	Lumber & Wood	3	4	5	6	7
25	"	Furniture	1	1	1	2	2
27	"	Printing & Publishing	2	2	2	2	2
31	"	Leather	1	1	1	1	1
21	"	Tobacco Manufactures	negl	negl	negl	1	1
			33	40	47	58	70
		Total	88	104	122	143	167

TABLE 5-10

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN MIDCONTINENT REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's 1980	1985	1990	1995	2000
28	Process	Chemicals	16	20	25	30	35
30	"	Rubber & Plastics	1	1	2	2	3
29	"	Petroleum Refining	33	38	43	50	55
26	"	Paper	11	12	13	14	16
33	"	Primary Metals	1	1	1	1	1
20	"	Food	8	10	12	13	16
32	"	Stone, Clay, Glass, Concrete	-	-	-	-	-
			70	82	96	110	126
37	General	Transportation Equipment	2	2	2	3	4
36	Manufacturing	Electrical Equipment	1	2	2	3	4
22	"	Textile Mill Prods.	1	2	2	2	3
23	"	Apparel	negl	negl	negl	negl	1
34	"	Fabricated Metals	1	1	1	2	2
35	"	Machinery, ex. Elect.	1	1	1	1	1
38	"	Instruments	negl	negl	1	1	1
49	Miscellaneous	Utility Services	1	1	1	1	2
19/39	"	Ordnance/Miscellaneous	1	1	1	1	1
24	"	Lumber & Wood	1	1	1	2	2
25	"	Furniture	negl	negl	negl	negl	1
27	"	Printing & Publishing	negl	1	1	1	1
31	"	Leather	negl	negl	negl	negl	negl
21	"	Tobacco Manufactures	negl	negl	negl	negl	negl
			9	11	14	18	23
		Total	79	93	110	128	149

TABLE 5-11

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN GULF COAST REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's 1980	1985	1990	1995	2000
28	Process	Chemicals	577	702	848	1010	1205
30	"	Rubber & Plastics	46	56	68	70	96
29	"	Petroleum Refining	395	463	535	613	703
26	"	Paper	130	155	182	217	258
33	"	Primary Metals	23	24	26	27	29
20	"	Food	24	27	30	34	38
32	"	Stone, Clay, Glass, Concrete	-	-	-	-	-
			1195	1427	1689	1980	2329
37	General	Transportation Equipment	31	34	37	42	47
36	Manufacturing	Electrical Equipment	22	29	31	36	42
22	"	Textile Mill Prods.	27	30	31	34	37
23	"	Apparel	5	5	6	7	7
34	"	Fabricated Metals	15	17	19	21	24
35	"	Machinery, ex. Elect.	12	14	15	16	17
38	"	Instruments	6	7	8	9	10
49	Miscellaneous	Utility Services	11	13	15	17	19
19/39	"	Ordnance/Miscellaneous	9	10	11	13	14
24	"	Lumber & Wood	17	19	21	23	25
25	"	Furniture	5	5	6	6	7
27	"	Printing & Publishing	8	9	9	9	9
31	"	Leather	3	3	3	4	4
21	"	Tobacco Manufactures	2	2	2	3	3
			173	197	214	240	265
		Total	1368	1624	1903	2220	2594

TABLE 5-12

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN ROCKY MOUNTAIN REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's 1980	1985	1990	1995	2000
28	Process	Chemicals	25	31	38	46	56
30	"	Rubber & Plastics	2	2	3	3	4
29	"	Petroleum Refining	5	6	8	10	14
26	"	Paper	2	3	3	4	4
33	"	Primary Metals	26	28	31	34	37
20	"	Food	20	23	26	29	32
32	"	Stone, Clay, Glass, Concrete	-	-	-	-	-
			80	93	109	126	147
37	General	Transportation Equipment	11	13	16	18	22
36	Manufacturing	Electrical Equipment	8	11	12	16	19
22	"	Textile Mill Prods.	9	11	13	14	17
23	"	Apparel	2	2	2	3	3
34	"	Fabricated Metals	5	7	8	9	11
35	"	Machinery, ex. Elect.	4	5	6	7	8
38	"	Instruments	2	3	3	4	5
49	Miscellaneous	Utility Services	4	5	6	7	9
19/39	"	Ordnance/Miscellaneous	3	4	5	5	6
24	"	Lumber & Wood	6	7	8	10	11
25	"	Furniture	2	2	2	3	3
27	"	Printing & Publishing	3	3	4	4	4
31	"	Leather	1	1	1	2	2
21	"	Tobacco Manufactures	1	1	1	1	1
			61	75	87	103	121
		Total	141	168	196	229	268

TABLE 5-13

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN PACIFIC NORTHWEST REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's 1980	1985	1990	1995	2000
28	Process	Chemicals	1	2	2	2	3
30	"	Rubber & Plastics	negl	negl	negl	negl	negl
29	"	Petroleum Refining	8	9	11	13	14
26	"	Paper	55	65	77	92	109
33	"	Primary Metals	-	-	-	-	-
20	"	Food	18	20	23	25	28
32	"	Stone, Clay, Glass, Concrete	-	-	-	-	-
			82	96	113	132	154
37	General	Transportation Equipment	5	5	7	8	9
36	Manufacturing	Electrical Equipment	3	5	5	7	8
22	"	Textile Mill Prods.	4	5	5	6	7
23	"	Apparel	1	1	1	1	1
34	"	Fabricated Metals	2	3	3	4	4
35	"	Machinery, ex. Elect.	2	2	3	3	3
38	"	Instruments	1	1	1	2	2
49	Miscellaneous	Utility Services	2	2	3	3	4
19/39	"	Ordnance/Miscellaneous	1	2	2	2	3
24	"	Lumber & Wood	3	3	4	4	5
25	"	Furniture	1	1	1	1	1
27	"	Printing & Publishing	1	1	2	2	2
31	"	Leather	negl	1	1	1	1
21	"	Tobacco Manufactures	negl	negl	negl	negl	1
			26	32	38	44	51
		Total	108	128	151	176	205

TABLE 5-14

PROJECTED CONSUMPTION OF COAL, OIL, AND NATURAL GAS BY LARGE INDUSTRIAL BOILERS IN PACIFIC SOUTHWEST REGION, BY SIC CODE AND INDUSTRY TYPE

SIC Code	Type of Industry	Industry	Coal, Oil, Natural Gas, 10^{12} BTU's				
			1980	1985	1990	1995	2000
28	Process	Chemicals	12	15	20	24	28
30	"	Rubber & Plastics	1	1	1	2	2
29	"	Petroleum Refining	54	64	76	90	107
26	"	Paper	11	13	15	18	20
33	"	Primary Metals	15	16	17	18	20
20	"	Food	23	26	29	32	35
32	"	Stone, Clay, Glass, Concrete	1	1	2	2	2
			117	136	160	186	216
37	General	Transportation Equipment	4	5	6	7	8
36	Manufacturing	Electrical Equipment	3	4	5	6	8
22	"	Textile Mill Prods.	3	4	5	6	7
23	"	Apparel	1	1	1	1	1
34	"	Fabricated Metals	2	3	3	3	4
35	"	Machinery, ex. Elect.	2	2	2	3	3
38	"	Instruments	1	1	1	1	2
49	Miscellaneous	Utility Services	1	2	2	3	4
19/39	"	Ordnance/Miscellaneous	1	2	2	2	2
24	"	Lumber & Wood	2	3	3	4	4
25	"	Furniture	1	1	1	1	1
27	"	Printing & Publishing	1	1	2	2	2
31	"	Leather	negl	negl	negl	1	1
21	"	Tobacco Manufactures	negl	negl	negl	negl	1
			22	29	33	40	48
		Total	139	165	193	226	264

TABLE 5-15

REGIONALIZED ESTIMATES OF COAL-FIRED FBC POTENTIAL

• Maximum Potential	10^{12} BTU of Coal			
	1985	1990	1995	2000
New England	-	-	-	-
Appalachian	171	543	882	1522
Southeast	103	326	529	913
Great Lakes	105	334	542	934
Northern Plains	7	21	35	60
Mid-Continent	13	43	69	120
Gulf Coast	189	603	981	1691
Rocky Mountain	10	31	51	88
Pacific Northwest	12	38	61	105
Pacific Southwest	10	31	50	87
	620	1970	3200	5520
• Most Probable Potential				
Appalachian	68	229	390	686
Southeast	59	202	345	606
Great Lakes	61	207	353	621
Northern Plains	2	8	14	24
Mid-Continent	8	27	46	80
Gulf Coast	82	280	478	840
Rocky Mountain	3	12	20	36
Pacific Northwest	4	13	24	41
Pacific Southwest	3	12	20	36
	290	990	1690	2970
• Minimum Potential				
Appalachian	25	98	181	332
Southeast	24	93	172	317
Great Lakes	24	96	176	324
Mid-Continent	2	8	14	27
	75	294	543	1000

See Table 3-5 for identification of regions listed above.

Note: A "small" MFBI, having two coal-fired FBC boilers of 100 M BTU/H capacity, operated at an average annual loading of 50%, would consume $2 \times 100 \times 10^6 \times 8760 \times 0.5 = 876 \times 10^9$ BTU's per year, i.e. slightly less than one trillion BTU's per year.

6. ENERGY IMPACTS

6.1 Impact on National Energy Consumption

A consistent application of the assumptions made elsewhere in this study leads to the conclusion that coal-firing of large industrial boilers using FBC technology will have an insignificant impact on national energy consumption in aggregate. The simplistic explanation is that the aggregate will not be affected greatly by:

(1) the technology by which solid coal is fired in boilers

(2) whether coal or oil is used as boiler fuel, as long as the pertinent fuel is available.

These points will be discussed separately. The first is relatively straightforward, while the second involves exceedingly complex issues. The first point may be explained by considering a hypothetical base case in which all large industrial boilers are fired with solid coal without the use of any control technology. An alternative to the base case would be to have some, or all, of the boilers equipped with flue gas scrubbers. This would increase coal consumption marginally for the same level of steam output because the scrubbing operation consumes some energy. This is an important practical consideration for electric utility boilers, particularly in the case of retrofitting, because some loss of generating capacity occurs when a scrubber is installed. For industrial boilers, however, the long term effect would be small because the capacity loss could be offset by new capacity added during plant expansions. Nominally, energy consumption would be higher, but even this is not a certainty since the boiler efficiency loss might be offset by savings of transportation energy in cases where locally available high sulfur coal was substituted (hypothetically) for compliance coal obtained from a distant location. Additionally, new boilers could be designed to give slightly higher thermal efficiency than the average of the existing boiler population.

If atmospheric FBC technology were to be used instead of FGDS, the net effect on coal consumption would be almost zero. There is a possibility of marginally higher combustion efficiency with FBC but this would be offset by the differential in transportation energy associated with a larger quantity of sorbent required for FBC versus FGDS. The overriding consideration is that industrial boiler fuel demand is set by a given level of manufacturing activity not by the technology by which the industrial boiler fuel is combusted.

For point (2), the overriding considerations are (a) the future availabilities of coal and oil, and (b) the nature of the oil: whether it domestically refined from domestic crude oil, domestically refined from imported crude oil, or imported fuel oil. On a relative basis, national energy consumption is lower if imported fuel oil is used because the energy consumption associated with production and refining takes place outside the U.S. Long range, however, the availability and cost of imported oil is a far more important consideration than energy consumption differentials attributable to petroleum extraction and refining processes. Ronald Kutscher, Assistant Commissioner for Economic Growth, Bureau of Labor Statistics, has remarked(1), (2):

> "With regard to energy, the key question is: will scarcities and much higher prices cause a slower rate of growth in the economy? Related issues are possible disruptions of supply, investment requirements for energy-conserving machinery or plant, search for new energy sources or larger supplies from existing sources, alternative means of transportation, and more efficient energy usage in houses and apartment buildings. Each of these issues could have important effects on the future rate and pattern of growth in the economy."
>
> "Several factors underlie the lowering, at least through 1980, of the expected rate of growth of productivity. . . there is the expected cost of meeting pollution control and industrial safety requirements, a long period of less than full utilization of resources, and higher energy prices, all of which are expected to slow productivity advances in the near term. Investment in energy-saving equipment could also dampen the growth of productivity."
>
> "The new projections, unlike the 1973 set, do not assume the availability of relatively cheap, nearly unlimited energy supplies. The effects of the changed energy outlook on labor productivity, capital requirements, and prices, as well as the relationship of these changes to economic growth are complex issues. Although a great deal of effort was devoted to these questions, BLS has not developed a satisfactory method of dealing with them in the industry and employment projections. Research by others is also just beginning to address the effect of changes in energy supplies and costs on the economy. Clearly, further research and analysis are needed."

The purpose of these citations is to suggest that there are important variables, exogenous to the present study, that can drown out the <u>differential</u> effects of applying coal-fired FBC, versus another, technology to industrial boilers. Directionally, such technology might be expected to permit a net increase in national energy consumption relative to an uncertain alternative of relying on imported oil, primarily because of a higher level of domestic economic activity attributable to a secure, domestic energy supply. However, essentially the same outcome would be expected for any effective technology for using solid coal as an industrial boiler fuel.

6.2 <u>Potential Savings of Oil and Natural Gas</u>

It seems more reasonable to consider the impact of coal-fired FBC in terms of oil alone, rather than in terms of oil and natural gas. This is because the availability of natural gas is declining, and it is not possible to save what is not available. However, it is questionable whether any oil will be saved by coal-fired FBC per se. A saving will occur if solid coal is used instead of oil in large industrial boilers, but the level of saving achieved will be essentially independent of the technology by which the coal is combusted for the reasons given in Section 6.1. Nevertheless, the estimates of coal-fired FBC potential in Tables 5-2, 5-3 and 5-15 may be converted from BTU's to barrels of oil equivalent. The results of these conversions are shown in Table 6-1, and suggest that if coal-fired, atmospheric pressure, FBC technology is demonstrated as reliable for large industrial boilers by 1981 or 1982, then there could be significant "savings" of oil equivalent by 1990. Considering conventional and additional applications, "savings" of 1 million B/D O.E. appear possible shortly thereafter. By the year 2000, the combined "savings" may be in the range of two to four million B/D O.E. These "savings" are not incremental to analogous "savings" achievable with other technologies for utilizing solid coal; the various coal-use technologies are potential alternatives.

TABLE 6-1

ESTIMATES OF COAL-FIRED FBC POTENTIAL EXPRESSED AS BARRELS OF OIL EQUIVALENT

	1000 B/D of Oil Equivalent				
	1980	1985	1990	1995	2000
• Maximum Potential					
Lower 48 states, conventional uses	9	291	926	1504	2594
Lower 48 states, additional uses	-	28	310	874	1748
	9	319	1236	2378	4342
• Most Likely Potential					
Lower 48 states, conventional uses	5	136	462	793	1396
Lower 48 states, additional uses	-	14	188	517	1034
	5	150	650	1310	2430
• Minimum Potential					
Lower 48 states, conventional uses	nil	35	138	255	470
Lower 48 states, additional uses	nil	6	62	175	350
	nil	41	200	430	820
• Most Likely Potential (Regional basis, conventional uses)					
Appalachian	1	32	107	183	321
Southeast	1	28	95	162	284
Great Lakes	1	29	96	166	292
Northern Plains	* -	1	4	6	11
Mid-Continent	* -	4	13	23	38
Gulf Coast	1	38	131	224	394
Rocky Mountain	* -	1	5	9	17
Pacific Northwest	* -	2	6	11	22
Pacific Southwest	* -	1	5	7	17
	5	136	462	793	1396

* = <1

7. ECONOMIC IMPACTS

7.1 National Impacts

For the reasons given in Section 6.1, the absolute economic impacts of coal-fired FBC are indeterminate. The fundamental reason for this indeterminateness is that there are controlling exogenous variables that cannot be precisely forecast because of their political and other complexities.* However, it is possible to ascribe certain levels of economic activities to certain levels of coal-fired FBC potential. The approach described below does not remove the possibility that a similar level of economic activity could apply to other technologies of using solid coal in industrial boilers.

The 1972 OBERS Projections discussed in Section 4.1 include estimates of the value of goods produced by manufacturing industries in terms of Gross Product Originating.** The original projections were made in 1967 constant dollars. For consistency with other estimates in this study, the GPO projections in Table 7-1 have been converted to 1975 constant dollars.*** The total GPO for all manufacturing industries is summarized below:

Year	Manufacturing GPO, billion 1975 $
1980	564.6
1985	656.3
1990	761.4
1995	886.2
2000	1031.6

*The complexities are orders of magnitude beyond the scope of the present study. Nevertheless, Professor Jay Forrester and the System Dynamics group at M.I.T. have already spent three years on the development of a computer simulation model that may, eventually, be able to provide answers of the kind that would be needed for aboslute assessments of economic impact. Professor Forrester's model may be completed during the next three years. Professor Roger Naill, of the Thayer School of Engineering at Dartmouth College, has constructed a simpler SD model that may be developed further to permit economic assessments of energy technologies. At present, neither of the SD models can provide the required answers. (1), (2), (3)

**See Section 4.1 for definition of GPO.

***using a multiplier of 1.573 derived from Bureau of Economic Analysis data.

TABLE 7-1

PROJECTIONS OF GROSS PRODUCT ORIGINATING (GPO)

BEA Industry Classification	SIC Equivalent	GPO in Billions of 1975 Constant Dollars ø 1980	1985	1990	1995	2000
Food and Kindred Products	20	45.1	49.4	54.1	59.5	65.6
Textile Mill Products	22	17.4	19.7	22.2	25.0	28.1
Apparel and Other Fab. Prods.	23	17.6	20.1	22.9	26.2	30.0
Lumber and Furniture	24,25	19.8	22.6	25.8	29.4	33.6
Paper and Allied Products	26	21.5	24.8	28.6	33.1	38.3
Printing and Publishing	27	26.2	30.8	34.5	41.2	49.2
Chemicals and Allied Products	28	60.5	74.1	90.5	110.1	132.4
Petroleum Refining	29	13.2	15.2	17.4	19.9	22.8
Primary Metlas	33	29.5	30.9	32.0	33.4	34.8
Fabricated Metals/Ordnance	34,19	40.1	46.5	53.8	62.2	72.0
Machinery excl. Electrical	35	52.9	60.1	68.4	77.9	88.0
Electrical Equipment	36	73.0	90.4	111.7	136.6	167.0
Motor Vehicles and Equipment	371	51.5	59.8	69.4	80.6	93.6
Transportation Equipment excl. M.V.	37*	22.0	24.2	26.5	29.1	31.9
Other Manufacturing	**	74.3	87.7	103.6	122.0	143.5
All Manufacturing		564.6	656.3	761.4	886.2	1031.6

ø converted from 1967 constant dollars in source document
* excluding SIC 371
** sum of SIC 21, 30, 31, 32, 38 and 39

Source: 1972 OBERS Projections, Vol. 1, Table 5 of Part 3 and Table 1 of Part 4. (See Section 4.1 for discussion of the OBERS projections, and Reference 1.)

As a first approximation, it is assumed that a unit of GPO is proportional to the quantity of industrial boiler fuel consumed but is independent of boiler size per se. This assumption makes it possible to estimate the GPO that is relatable to the operation of large industrial boilers:

Year	Large Boiler GPO, billion 1975 $
1980	233.2
1985	285.5
1990	348.0
1995	423.6
2000	515.8

Next, the estimated most probable potential for coal-fired FBC (Table 5-2) is related to the estimated total fuel consumption of large industrial boilers (Table 4-5):

Year	(A) Most Probable FBC Potential, 10^{12} BTU	(B) Fuel Demand of Large Industrial Boilers, 10^{12} BTU	(A) as % of (B)
1980	10	4756	0.2
1985	290	5615	5.2
1990	990	6579	15.0
1995	1690	7674	22.0
2000	2970	8950	33.2

The percentages in the last column of the above table can then be applied to the estimates of manufacturing GPO associated with the operation of the large industrial boilers.

Year	Manufacturing GPO in Billions of 1975 $ associated with Most Probable FBC Potential
1980	0.5
1985	15
1990	52
1995	93
2000	171

The above estimates, in billions of constant 1975 dollars, are not a direct and unique measure of the economic value of coal-fired FBC, rather they are estimates of the economic value of the manufacturing activity imputed to the operation of large coal-fired FBC industrial boilers. As discussed above, it is possible that the same levels of economic activity could be achieved with other coal use technologies.

Comparable estimates of imputed GPO are given below for the maximum and minimum coal-fired FBC cases:

Year	Manufacturing GPO in Billions of 1975 $ Maximum Potential	Minimum Potential
1980	1	nil
1985	31	4
1990	104	16
1995	177	30
2000	318	57

In addition to estimating, or imputing, economic levels of manufacturing activity to coal-fired FBC, it is also possible to estimate the economic value of the oil that may be "saved" via the use of this technology. The estimates are based on Table 6-1, which projects coal-fired FBC potential in terms of daily barrels of oil equivalent. The conversions are made using a factor of $12 per barrel of low sulfur fuel oil (in constant 1975 dollars) or $4.38 million per year per 1000 B/D of oil equivalent. The results of these calculations are shown in Table 7-2.

7.2 Regional Impacts

As with national economic impacts, regional impacts may also be considered in terms of:

(1) the economic value of the manufacturing activity imputed to the operation of large coal-fired FBC industrial boilers within the region.

(2) "savings" of oil equivalent associated with FBC coal-use technology.

In 1980, for the most probable case, it is estimated that each of four regions may have imputed manufacturing activity in the range of $100-125 million (1975 constant dollars). The four regions are Appalachian, Southeast, Great Lakes, and Gulf Coast. Similar estimates for subsequent years are reported in Table 7-3. Comparable estimates of "savings" of oil equivalent on a regional basis are reported in Table 7-4.

7.3 Boiler Manufacturing and Related Industries

The economic impact of industrial boiler use of coal-fired FBC technology may be estimated in terms of the number of FBC boiler units of some average size that is projected to be installed during a given time period. For this purpose, it was assumed that the size of the average large boiler unit would be 200 KPPH. It was assumed, further, that the manufacturer of the FBC steam generator (i.e. "boiler") would be responsible for manufacture or procurement of other equipment that is directly a part of the boiler "system". Coal and limestone receiving and storage facilities are not included in this system. Additionally, it was assumed that the 200 KPPH boiler would operate with an average annual capacity utilization of 65%, which is typical for large boilers used by the petroleum refining, petrochemical, and chemical industries. These assumptions, and the estimates of coal-fired FBC potential in Table 5-2, yield the results recorded in Table 7-5. It is a common practice for the boiler

TABLE 7-2

ESTIMATED VALUE OF OIL EQUIVALENT "SAVED" BY COAL-FIRED FBC

	Billions of 1975 Constant Dollars				
	1980	1985	1990	1995	2000
• **Maximum Potential**					
Lower 48 states, conventional uses	0.04	1.27	4.06	6.59	11.36
Lower 48 states, additional uses	-	0.12	1.36	3.83	7.66
	0.04	1.4	5.4	10.4	19.0
• **Most Probable Potential**					
Lower 48 states, conventional uses	0.02	0.60	2.02	3.47	6.11
Lower 48 states, additional uses	-	0.06	0.82	2.26	4.53
	0.02	0.66	2.8	5.7	10.6
• **Minimum Potential**					
Lower 48 states, conventional uses	nil	0.15	0.60	1.12	2.06
Lower 48 states, additional uses	nil	0.03	0.27	0.77	1.53
	nil	0.2	0.9	1.9	3.6

TABLE 7-3

ESTIMATED REGIONAL VALUES OF MANUFACTURING ACTIVITY IMPUTED TO USE OF COAL-FIRED FBC TECHNOLOGY IN INDUSTRIAL BOILERS

Region	Billions of 1975 Constant Dollars in Most Probable Case			
	1985	1990	1995	2000
Appalachian	3.5	12.0	21.5	39.5
Southeast	3.1	10.6	19.0	34.9
Great Lakes	3.1	10.9	19.4	35.7
Northern Plains	0.1	0.4	0.7	1.4
Mid-Continent	0.4	1.4	2.5	4.6
Gulf Coast	4.2	14.7	26.3	48.4
Rocky Mountain	0.2	0.6	1.1	2.0
Pacific Northwest	0.2	0.7	1.3	2.4
Pacific Southwest	0.2	0.6	1.1	2.0

Possible additional uses, such as a higher level of captive generation of electricity at manufacturing plants, are excluded from above estimates.

TABLE 7-4

ESTIMATED REGIONAL VALUES OF OIL EQUIVALENT "SAVED" BY COAL-FIRED FBC IN MOST PROBABLE CASE*

	Billions of 1975 Constant Dollars				
	1980	1985	1990	1995	2000
Appalachian	0.14	0.47	0.80	1.39	1.41
Southeast	0.12	0.41	0.71	1.23	1.25
Great Lakes	0.13	0.42	0.73	1.25	1.28
Northern Plains	0.005	0.02	0.03	0.04	0.05
Mid-Continent	0.02	0.05	0.09	0.17	0.17
Gulf Coast	0.17	0.57	0.98	1.13	1.73
Rocky Mountain	0.007	0.02	0.04	0.06	0.07
Pacific Northwest	0.008	0.03	0.05	0.07	0.09
Pacific Southwest	0.007	0.02	0.04	0.06	0.07

*excluding possible additional uses such as a higher level of captive generation of electricity at manufacturing plants.

TABLE 7-5

ESTIMATES OF NUMBER OF INDUSTRIAL FBC BOILERS AND RELATED ERECTED VALUES OF THE BOILER SYSTEMS

	Number of Units*	Erected Equipment Cost in Millions of 1975 $ **
• Maximum Potential, Conventional Uses		
FBC units added through 1980	14	39 ϕ
FBC units added 1981/1985	413	1156
FBC units added 1986/1990	890	2490
FBC units added 1991/1995	890	2490
FBC units added 1996/2000	1600	4480
	3807	10,655
• Most Probable Potential, Conventional Uses		
FBC units added through 1980	7	20 ϕ
FBC units added 1981/1985	193	540
FBC units added 1986/1990	485	1360
FBC units added 1991/1995	485	1360
FBC units added 1996/2000	880	2460
	2050	5,740
• Minimum Potential, Conventional Uses		
FBC units added through 1980	nil	-
FBC units added 1981/1985	51	145
FBC units added 1986/1990	152	425
FBC units added 1991/1995	172	480
FBC units added 1996/2000	315	880
	690	1,930

*based on an average steam generating capability of 200 KPPH.

**boiler system includes coal/limestone metering and fuel injection, fans and drivers, steam generator, waste solids handling equipment, control instruments, flues and ducts; excludes all contingencies and costs of work not normally performed by a boiler manufacturer/erector.

ϕ estimates are probably unrealistically low for "pioneer" units.

manufacturer to be responsible for the on site erection of large industrial boilers. However, a rough estimate of the equipment cost, F.O.B. the manufacturer's plant, is 55% of the corresponding erected cost.

Table 7-5 depicts a situation where, in the most probable case, the equivalent of seven 200 KPPH industrial boilers are estimated to be in operation by the end of 1980. In practice, it is expected that the average size of the initial commercial units will be less than 200 KPPH. For this reason and because the initial boilers will be "pioneer" and demonstration units, the unit erected costs are probably understated. Subsequent to 1980, however, the estimates of equipment costs are believed to be in reasonable correspondence with the fuel potentials estimated in Table 5-2 and the numbers of large FBC industrial boiler units listed in the first column of Table 7-5. The latter figures may be compared with those from FEA's MFBI survey which reported approximately 4,000 large industrial boilers to be in operation in 1974. As reported in Table 20 of Appendix 4, the average steam generating capacity of the MFBI boiler population was 223 million BTU/H or approximately 190 KPPH. Hence, the assumption of an average size of 200 KPPH for large coal-fired FBC boilers appears reasonable.

7.4 Coal Industry

Estimates of the volumes of coal associated with different levels of FBC potential are reported in Table 7-6. Numerically, the estimates are based on Illinois No. 6 coal, with a heating value of 10,600 BTU/lb. However, this does not imply that coal-fired FBC will be limited to a single type of coal.

Estimates of the F.O.B. mine value of the coal shipped for FBC industrial boiler use are also given in Table 7-6. In the most probable case, assuming a combination of conventional and additional uses of FBC, the quantity and F.O.B. value of the coal in the year 2000 are estimated to be 244 million tons and $3.4 billion (constant 1975 dollars) respectively. Considering conventional uses only, the corresponding estimates are 140 million tons and approximately $2 billion dollars.

7.5 Limestone Industry

The limestone requirements associated with coal-fired FBC also assume the use of Illinois No. 6 coal which has an average sulfur content of 3.6 wt%. Clearly, the use of non-compliance coals of lower sulfur content would require lesser quantities of limestone than are estimated in Table 7-7. On the other hand, no provision has been made for some use of limestone when compliance coals are used with FBC technology, thereby offsetting the overestimates of limestone usage with non-compliance coals.

The average, or representative, cost of limestone F.O.B. quarry is assumed to be $3.50 per ton (in 1975 dollars). This price includes whatever crushing or other treatments at the quarry are needed to prepare the limestone for use in coal-fired FBC boilers.

In the most probable case, the year 2000 requirements of limestone are estimated to be 87 million tons, with a corresponding F.O.B. value of $300 million.

TABLE 7-6

ESTIMATES OF COAL VOLUMES REQUIRED FOR APPLICATION OF FBC TO INDUSTRIAL BOILERS

	Conventional Uses		Additional Uses**		Combined Potential **	
	10^6 Tons	F.O.B. Mine Million 1975 $*	10^6 Tons	F.O.B. Mine Million 1975 $*	10^6 Tons	F.O.B. Mine Million 1975 $*
• **Maximum Potential**						
1980	0.94	13	-	-	0.94	13
1985	29.2	409	2.8	39	22	308
1990	90.6	1268	31.1	435	122	1700
1995	150.9	2110	87.7	1228	239	3300
2000	260.4	3640	175.5	2460	436	6100
• **Most Probable Potential**						
1980	0.46	6	-	-	0.46	6
1985	13.6	190	1.4	20	15	210
1990	46.8	655	18.9	265	66	920
1995	79.7	1113	51.9	727	132	1840
2000	140.1	1960	103.8	1450	244	3410
• **Minimum Potential**						
1980	nil	nil	-	-	nil	nil
1985	3.5	49	0.6	8	4.1	57
1990	13.9	195	6.2	87	20	280
1995	25.6	358	17.5	245	43	600
2000	47.2	660	35.1	491	82	1150

Note: Coal volumes are estimated in terms of millions of short tons of Illinois No. 6 coal.

*long run price for high sulfur coal estimated by Sobotka, and considering other information presented in "A Study of Coal Prices", Council on Wage and Price Stability, Executive Office of the President, March 1976. (4)

**see Table 5-3.

TABLE 7-7

ESTIMATES OF LIMESTONE VOLUMES REQUIRED FOR APPLICATION OF FBC TO INDUSTRIAL BOILERS

	Conventional Uses		Additional Uses*		Combined Potential*	
	Limestone 10^6 Tons	F.O.B. Quarry Million 1975 $	Limestone 10^6 Tons	F.O.B. Quarry Million 1975 $	Limestone 10^6 Tons	F.O.B. Quarry Million 1975 $
• Maximum Potential						
1980	0.35	1.2	-	-	0.35	1.2
1985	11.0	39	1.05	3.7	11	43
1990	34.0	119	11.7	41	46	160
1995	56.6	198	32.9	115	89	310
2000	97.7	342	65.8	230	163	570
• Most Probable Potential						
1980	0.16	0.56	-	-	0.16	0.56
1985	4.6	16	0.53	1.9	5	18
1990	15.9	56	7.1	25	23	80
1995	27.1	95	19.5	68	47	140
2000	47.6	167	38.9	136	87	300
• Minimum Potential						
1980	nil	nil	-	-	nil	nil
1985	1.3	4.6	0.23	0.8	1.5	6
1990	5.2	18	2.3	8	7.5	26
1995	9.6	34	6.6	23	16	57
2000	17.7	62	13.2	46	31	108

*see Table 5-3.

8. ENVIRONMENTAL CONSIDERATIONS

8.1 Introduction

The application of any new technology should be considered from the viewpoint of its possible benefits/debits to the environment, especially when alternatives exist for meeting the same needs in other ways. The possible application of fluidized bed coal combustion technology (FBC) to industrial steam generation raises the question of what implications this would have from an environmental standpoint. This section discusses and, where possible, quantifies these implications.

The environmental component of the present study is a small part of a much larger program of FBC environmental assessment and development of control technology sponsored by the Environmental Protection Agency.

For convenience, when words such as "meeting (not meeting) EPA regulations" are used, it should be understood that this means New Source Performance Standards (NSPS) applicable only to (large) installations of 250 x 10^6 BTU/hr. or greater input. These standards are shown in Table 8-1. At present, there are no comparable regulations for the 100 to 250 x 10^6 BTU/hr. units considered in this study, although it is possible that NSPS will be promulgated for the smaller units. Also, as discussed later, it is possible that National Ambient Air Quality Standards (NAAQS) will override NSPS in some Air Quality Control Regions. Pertinent air quality standards are listed in Table 8-2.

8.2 Fuels and Boilers Considered

The industrial boiler systems and fuels considered are those discussed in Section 2 and Appendices 1-3. Comparisons were made of FBC and a spreader stoker boiler because the latter represents a likely option for industrial application. A high sulfur coal was chosen for comparison in the two systems since such coals are abundant in the highly industrialized areas of the east and midwestern sections of the country where effluents would be a major concern. A low sulfur western coal not meeting EPA standards for sulfur emissions was compared in the two systems since large quantities of such coals exist and their price might be attractive compared to lower sulfur western coals. Furthermore, it was felt that undesirable effluents could be significantly different for such coals than for high sulfur coals. A low sulfur western coal meeting EPA regulations for sulfur emissions was included in the study for the spreader stoker boiler to give a base point for a fuel in ample supply offering desirable environmental qualities. Finally, a boiler utilizing a low-sulfur fuel oil was included because this type fuel could be replaced by boilers using coal. Thus the low sulfur fuel oil represents a base case for environmental comparisons. Natural gas was assumed not to be available at new installations.

TABLE 8-1

SELECTED NEW SOURCE PERFORMANCE
STANDARDS (NSPS) FOR AIR POLLUTION SOURCES (Ref. 1)

Source	Pollutant	Emissions Not to Exceed
STEAM GENERATORS		
Fossil-fuel fired $\geq 250 \times 10^6$ Btu/hr input	Particulate Matter	0.1 $lb/10^6$ Btu input 20% opacity
	Sulfur Dioxide	1.2 $lb/10^6$ Btu (Solid Fuel)
		0.8 $lb/10^6$ Btu (Liquid Fuel)
	Nitrogen Oxides (as NO_2)	0.7 $lb/10^6$ Btu (Solid Fuel)
		0.3 $lb/10^6$ Btu (Liquid Fuel)
		0.2 $lb/10^6$ Btu (gaseous fuel)

TABLE 8-2

SUMMARY OF NATIONAL AMBIENT AIR QUALITY STANDARDS[a]

Pollutant	Averaging time	Primary standards	Secondary standards	Comments
Particulate matter	Annual (Geometric mean)	75 $\mu g/m^3$	60 $\mu g/m^3$	The secondary annual standard (60 $\mu g/m^3$) is a guide for assessing SIP's to achieve the 24-hour secondary standard.
	24-hour[b]	260 $\mu g/m^3$	150 $\mu g/m^3$	
Sulfur oxides	Annual (Arithmetic mean)	80 $\mu g/m^3$ (0.03 ppm)	-	
	24-hour[b]	365 $\mu g/m^3$ (0.14 ppm)	-	
	3-hour[b]	-	1300 $\mu g/m^3$ (0.5 ppm)	
Nitrogen dioxide	Annual (Arithmetic mean)	100 $\mu g/m^3$ (0.05 ppm)	(Same as primary)	The continuous Saltzman; Sodium Arsenite (Christie), TGS, and Chemiluminescence have been proposed as replacements for the J-H method. New FRM* will be forthcoming in the near future.

[a]The air quality standards and a description of the Federal Reference Methods *(FRM) were published on April 30, 1971 in 42 CFR 410, recodified to 40 CFR 50 on November 25, 1972.

[b]Not to be exceeded more than once per year.

8.2.1 Emissions Considered

The principal emissions considered were particulate matter, sulfur dioxide and nitrogen dioxide, in relation to the standards listed in Tables 8-1 and 8-2. Some consideration was also given to solid or sludge wastes and to the trace metals present in different coals.

Waste heat emitted to the environment was not considered since the major heat losses resulted from thermal inefficiencies in steam generation and these were assumed equal for all units. Coal preparation and drying can vary considerably from coal to coal and generate considerable thermal losses vis-a-vis direct use of fuel oil. These losses were not considered because (1) it was assumed in the economic study that coal arrived at the plant ground and dried, (2) the specific coals chosen for study represent only a few of a multitude of coals and estimation of heat losses associated with preparation and drying these particular coals would have little general usefulness, and (3) when comparing coal preparation with the direct use of fuel oil it must be remembered that there are heat losses associated with the refinery where the oil was refined.

Water consumption and aqueous effluents (other than sludge), which in many cases are of major environmental concern, were not considered. Water consumption would consist of evaporation, drift loss, and blowdown from cooling towers and boilers, and scrubber consumption while aqueous effluents would consist of blowdown and drift losses. Since steam production is the same in all cases considered, water consumption and major water effluents would be the same except for that water used in the flue gas scrubber systems. The water consumption in these systems was not estimated.

8.2.2 General Approach to the Environmental Analysis

The designs and fuels used in the economic analysis of steam production were also used for the environmental assessment. The environmental emission factors to be considered were then determined as reported in 8.4. Available information was collected concerning emissions from the various units studied. "Best" estimates were then made of the quantity of each pollutant emitted on a lb/MBTU basis and on total pounds per day.

Use was then made of the comparative quantity of each pollutant emitted to determine the relative differential impacts of the various technologies and fuels in two Air Quality Control Regions (AQCR's) based on the "most probable" degree of FBC applications. The differential impact approach was selected as being more meaningful than an absolute basis due to the large masking effects of mobile sources and power plant emissions.

Possible environmental consequences of regeneration and the environmental aspects of solids waste utilization were then addressed and other environmental aspects of FBC were discussed. Finally, conclusions and recommendations were given.

8.3 Bases and Assumptions

In this section, the bases used in the evaluation are discussed in more detail, the assumptions that had to be made are pointed out and discussed, and qualifications of the results are given.

8.3.1 Description of Operating Units

As indicated previously, the environmental analysis was carried out assuming the same operating units and fuels used in the economic studies. Also, the same steam producing capacity, 100 KPPH, was assumed. The design of the FBC boiler is, of course, conceptual (atmospheric pressure operation) and the data used to estimate emissions was obtained from various sources which may or may not be exactly compatible with the present design. This is unavoidable since all required information was not available from a single source. It is felt, however, that the pertinent data are sufficiently insensitive to operating parameters that the conclusions would not be significantly changed with a different design. In a couple of cases this may not be true and these will be pointed out.

8.3.2 Descriptions of Fuels Considered

As previously indicated, the fuels assumed for use were the same in the economic and environmental studies. The rationale for choosing the particular types of fuels was given in Section 8.2. The choice of the actual fuel with each type was made on the basis of ready availability of data on the fuel or availability of data on the use of the fuel in a particular operating unit. The fuels selected are described below.

High Sulfur Coal

The high sulfur coal chosen was a commercially available Illinois No. 6 coal. Its analyses and properties as well as those for the ash are given in Table 8-3.

Low Sulfur Western Coals

The low sulfur western coal chosen that meets current EPA regulations was a typical low sulfur, Wyoming coal. Its properties as well as those of its ash are given in Table 8-4.

The lower sulfur western coal chosen was San Juan sub-bituminous coal, used previously by Argonne National Laboratory (ANL) in an FBC experiment (2). The sulfur content of this San Juan coal was lower than that required to meet EPA regulations for SOx emissions. The analysis, as reported by ANL, is reproduced in Table 8-5.

Low Sulfur Fuel Oil

The low sulfur fuel oil was assumed to be a typical residual fuel of about 20° API gravity with an HHV of 18,600 BTU/lb. No nitrogen or sulfur content was specified since in the environmental studies it was assumed that sufficient furnace modifications could be effected to allow the NOx emissions to meet current EPA standards, and that the sulfur content would be sufficiently low to meet existing standards without further treatment.

8.4 Results for Individual Installations

The base levels of emissions assumed for this study were those that would just meet present EPA regulations for new point sources (NSPS), as listed

TABLE 8-3

ANALYSIS OF HIGH SULFUR COAL

Coal Type	Illinois No. 6
Total Coal Comp., Wt.%	
Carbon	57.8
Hydrogen	4.2
Oxygen	7.8
Nitrogen	1.5
Chlorine	0.2
Sulfur	3.6
Ash	8.0
Moisture	16.9
Total	100.0
HHV (Btu/#)	10600

Ash Properties

Ash Fusion Temperatures, °F

	Reducing	Oxidizing
Initial Deformation	2016	2292
Softening (H=W)	2200	2445
Softening (H=1/2W)	2227	2469
Fluid Temp.	2352	2588

Ash Composition, Wt.%

P_2O_5	0.11
SiO_2	43.82
Fe_2O_3	24.69
Al_2O_3	17.19
TiO_2	0.88
CaO	4.96
MgO	1.02
SO_3	4.02
K_2O	1.61
Na_2O	1.21
Undetermined	0.22
	100.00

TABLE 8-4

ANALYSIS OF LOW SULFUR
COAL MEETING EPA REGULATIONS

Coal Type		Wyoming
Total Coal Composition, Wt.%		
Carbon		47.7
Hydrogen		3.3
Oxygen		12.1
Nitrogen		0.7
Chlorine		-
Sulfur		0.4
Ash		5.8
Moisture		30.0
Total		100.0
HHV (Btu/#)		8150
Ash Properties		
Ash Fusion Temperatures, °F		
	Reducing	Oxidizing
Initial Deformation	2100	2175
Softening (H=W)	2110	2180
Softening (H=1/2W)	2120	2185
Fluid Temp.	2130	2190
Ash Composition, Wt.%		
P_2O_5		0.60
SiO_2		34.63
Fe_2O_3		5.99
Al_2O_3		14.90
TiO_2		1.01
CaO		19.96
MgO		4.49
SO_3		16.92
K_2O		0.18
Na_2O		1.04
Undetermined		0.28
		100.00

TABLE 8-5

ANALYSIS OF LOW SULFUR WESTERN COAL WITH SULFUR CONTENT EXCEEDING EPA REGULATIONS (FROM REF. 4)

Coal Type	San Juan Sub-bituminous	
	Proximate Analysis, wt%	
	As Received	Dry Basis
Moisture	9.28	--
Ash	16.96	18.70
Volatile Matter	33.28	36.68
Fixed Carbon	40.48	44.62
	100.00	100.00
Sulfur, wt%	0.78	0.86
Heating Value, Btu/lb	9,621	10,605

	Ultimate Analysis, wt%	
	As Received	Dry Basis
Moisture	9.28	--
Carbon	55.82	61.53
Hydrogen	3.96	4.36
Nitrogen	1.14	1.26
Chlorine	0.10	0.11
Sulfur	0.78	0.86
Ash	16.96	18.70
Oxygen, by diff.	11.96	13.18
	100.00	100.00

in Table 8-6. The assumption is that all systems will be operated with emissions up to the levels permitted by the NSPS (except in cases where emissions would be inherently lower due to coal composition). However, such compliance would result in differences in emissions relative to operation with low sulfur fuel oil. These points are illustrated on an absolute and on a relative basis in Tables 8-7 and 8-8 respectively.

8.4.1 Estimates of Particulate Emissions

It was assumed in this study that appropriate means (e.g. enclosed storage, proper wetting of solids, bag houses where necessary, etc.) would be taken to prevent fugitive emissions of particulates. Therefore the values given in Tables 8-7 and 8-8 represent stack emissions. The value for the spreader stoker/Illinois No. 6 case was estimated from data contained in reference 3. Since this data is from a commercial size plant, the value calculated is assumed to be fairly accurate. No data was available for the spreader stoker/San Juan case so it was assumed that this value would be the same as for the Illinois No. 6 case. It is recognized that this assumption is questionable, because it is the scrubber that is controlling both SOx and particulate emissions in the Illinois No. 6 case whereas the low sulfur San Juan coal might be burned without the need for a scrubber. In this case particulate control would probably be provided by an electrostatic precipitator, and emissions would be the maximum permitted by EPA's New Source Performance Standards (NSPS).

For the Illinois No. 6, Wyoming, and San Juan sub-bituminous coals, fired in the FBC, the particulate level was controlled by an electrostatic precipitator and was set by economic considerations, i.e. at the maximum permissible emission level provided by NSPS.

8.4.2 Estimates of SO_2 Emissions

The values of SO_2 emissions were calculated as previously indicated. The SO_2 from the Wyoming coal represents that from the sulfur in the coal. No attempt was made to correct the value for ash retention since the value is significantly below 1.2 lb SO_2/M BTU and there is no scrubber effluent that is affected.

For Illinois No. 6 coal, fired in the FBC, the level of SO_2 emissions is determined by the Ca/S atomic ratio fed to the bed and was set at the maximum level permitted by NSPS in order to minimize costs. For the spreader-stoker, the SO_2 level was also set at the maximum value to minimize costs. As discussed in Section 2.3.1 and reported in Table 2-2, the Ca/S ratios assumed were 3 for FBC and 1.2 for the spreader-stoker/scrubber case.

8.4.3 Estimates of NOx Emissions

For the FBC/Illinois No. 6 case the NOx emissions were estimated from the Pope, Evans and Robbins data in Figure 7 of reference 4. The other values of NOx emissions were assumed as discussed below.

For the spreader stoker, the level of NOx is determined by furnace design and was set at the maximum allowable; this is a reasonable goal as determined by recent studies of such furnaces for steam generation using coals similar to Illinois No. 6 (5), (6).

TABLE 8-6

QUANTITIES OF EMISSIONS ARBITRARILY SET (100 KPPH steam)

Fuel	Illinois No. 6 Coal		San Juan Sub-bituminous Coal		Wyoming Coal	Low S Fuel Oil
Boiler Type	FBC	Spreader Stoker	FBC	Spreader Stoker	Spreader Stoker	Package
NOx, lb/M Btu	<0.7	0.7	<0.7	0.7	0.7	0.3
SO_2, lb/M Btu	1.2	1.2	Low	Low	-	0.8
Particulates, lb/M Btu	0.1	0.1*	0.1	0.1**	0.1	nil

*actual emission likely to be lower due to ability of scrubber system to reduce particulates (see Footnote to Table 8-7).

**would be lower than 0.1 lbs/M BTU if a scrubber is used, as assumed in Table 8-7. Otherwise, with an electrostatic precipitator, the 0.1 lbs/M BTU figure would apply since the design objective would be to meet EPA's New Source Performance Standards at minimum cost.

TABLE 8-7

ESTIMATED EMISSIONS FOR INDIVIDUAL INSTALLATIONS AND FUELS
(Basis: 100,000 lb/hr, 125 psig saturated steam)

Fuel	Illinois No. 6 Coal		San Juan Sub-bitúminous Coal		Wyoming Coal	Low S Fuel Oil
Fuel Rate (t/d)	144	144	156	156	187	82
Boiler Type	FBC	Spreader Stoker	FBC	Spreader Stoker	Spreader Stoker	Package
SO_2 Control	FBC	Limestone Scrubber	FBC	Limestone Scrubber	Not Needed	
Particulate Control	cyclones/ESP	cyclones/scrubber	cyclones/ESP	cyclones/scrubber	cyclones/ESP	Not Needed
Solid Waste Type	sulfated stone/ash	sludge/ash	sulfated stone/ash	sludge/ash	ash	None
Solid Waste, t/d	55	66	30	44	11	nil
Stack Emissions						
Particulates						
Emission Standard, lb/MBTU	------	------	0.1	------	------	0.1
Actual Level, lb/MBTU	0.1	0.05*	0.1	0.05*	0.1	nil
Actual Level, lb/day	300	150	300	150	300	nil
NOx (as NO_2)						
Emission Standard, lb/MBTU	------	------	0.7	------	------	0.3
Actual Level, lb/MBTU	0.5	0.7	<0.5**	0.7	0.7	0.3
Actual Level, lb/day	1500	2100	<1500	2100	2100	900
SO_2						
Emission Standard, lb/MBTU	------	------	1.2	------	------	0.8
Actual Level, lb/MBTU	1.2	1.2	0.8***	1.0***	0.65***	0.8
Actual Level, lb/day	3700	3700	2400	3000	2000	2400

*Below NSPS due to inherent ability of limestone scrubber to reduce particulate level.

**Below NSPS due to inherent ability of FBC system to minimize NOx emissions.

***Below NSPS due to low sulfur content of coal.

TABLE 8-8

INCREASED EMISSIONS CAUSED BY SHIFTING FROM LOW-SULFUR FUEL OIL
(Basis: 100,000 lb/hr saturated steam)

Fuel	Illinois No. 6 Coal		San Juan Sub-bituminous Coal		Wyoming Coal
Boiler Type	FBC	Spreader Stoker	FBC	Spreader Stoker	Spreader Stoker
Increase in Emissions					
Solid Waste, t/d	55	66	30	44	11
NOx, lb/d (as NO_2)	600	1,200	<600	1,200	1,200
SO_2, lb/d	1,300	1,300	0	600	(400)*
Particulates, lb/d	300	150	300	150	300

*Numbers in parenthesis indicate a reduction in emissions relative to emissions with LSFO. (The base-case, low-sulfur fuel oil was assumed to contain levels of sulfur and nitrogen that would meet present EPA standards. The quantities of particulates are negligible.)

For the low sulfur coals, the NOx level for the spreader stoker was assumed at 0.7, as in the case of the Illinois No. 6 coal, although no data is now available on NOx levels when sub-bituminous coals are used in boilers of the size considered here.

8.4.4 Estimates of Solid Wastes

For the high-sulfur Illinois No. 6 coal, considerable information is available from numerous sources as to the Ca/S ratio required to hold the SO_2 exit concentration to 1.2 lb/M Btu. (See, for example, references 2 and 7.) Thus, it is believed that the estimate of the quantity of solid waste is fairly accurate. Similarly, considerable commercial operating experience allowed an accurate estimate of the solid waste from the spreader stoker.

For the cases where San Juan sub-bituminous coal was used as fuel, the quantities of solid waste are less certain. For the FBC, one experiment on this coal has been reported (2), showing that the addition of a Ca/S ratio of 1.1 gave a sulfur retention of 72%. For this particular coal, assuming the percent retention is proportioned to the Ca/S ratio, only a ratio of 0.4 is necessary to meet the 1.2 lb SO_2/M BTU. It was felt, however, that the FBC would not be operable with this low ratio, but that the bed could be maintained at a Ca/S ratio of about 0.8. This would, again assuming the proportionality of percent retention and Ca/S ratio, give a retention of about 50%. This results in the emissions of about 0.8 lb SO_2/MM BTU which is lower than present standards, and is comparable to the use of low sulfur fuel oil.

Similarly, little information exists as to the operation of a spreader stoker of the size assumed in this study with a limestone scrubber. It is generally recognized that burning high calcium western coals in larger boilers at higher temperatures can result in the retention of part of the sulfur in the ash. A nominal value of 5% is accepted by some people. No such information is available for smaller spreader stoker boilers. It would be expected that the lower temperatures in these units would result in a greater sulfur retention. For this study the figure of 5% was used for lack of a better number. For scrubbing the stack gas it was assumed that, for proper operation of the scrubber, a 20% excess of $CaCO_3$ over the stoichiometric requirement would be used and that the emission of SO_2 would be reduced to 1.0 lb/MM Btu. This resulted in the quantity of ash/sludge given in Table 8-7.

For the case of the Wyoming coal, the solids effluent consists only of the ash in the coal since no scrubber is necessary. The solids from the low sulfur fuel oil reference case are negligible.

8.5 National and Regional Emissions

Estimates of the emissions associated with the use of coal-fired FBC technology in industrial boilers are based on:

(1) the unit emissions for point sources (see Table 8-7)

(2) the market potential estimated for coal-fired FBC (see Table 5-2).

Calculation of unit emissions is based on the assumed use of high sulfur coal, with Illinois No. 6 taken as a representative coal. The emissions are also estimated on an incremental basis relative to low sulfur fuel oil (LSFO), where the sulfur content just meets the Federal standard for new point sources. When LSFO is used, the solid waste and particulate emissions are neglible. Hence, the incremental and absolute estimates of solid waste and particulate emissions are the same.

Estimates of nationwide emissions are presented in Table 8-9 for maximum, most probable, and minimum cases. Corresponding estimates of emissions on a regional basis, for the most probable case, are presented in Table 8-10. These estimates pertain only to the use of high sulfur coal in industrial FBC boilers. They do not include estimates of emissions associated with the use of compliance coal in FBC boilers, since insufficient technical data are available for such estimates.

8.6 Estimates of Emissions for Selected Air Quality Control Regions

8.6.1 Current Situation: Mass Emissions

Air Quality Control Regions (AQCR's) were selected in Texas and Illinois in order to obtain comparisons between regions where currently:

(1) the industrial consumption of coal is minimum (Texas)

(2) there is a significant use of high sulfur (local) coal in industrial boilers (Illinois).

Current data for the state of Texas and the Metropolitan Houston-Galveston area (AQCR 216) are presented in Tables 8-11 and 8-12. The data are from EPA's National Emissions Data System.* It will be seen that industrial boilers were minor contributors to the total emissions of the state of Texas relative to similar emissions from other sources such as industrial processes and land vehicles. On a relative basis, the percentage levels were slightly higher for the Houston-Galveston AQCR, particularly with respect to NOx. In general, however, it is apparent that industrial boilers are not the principal source of emissions that affect ambient air quality.

Initially, it was not known which of the AQCR's in Illinois would yield the most meaningful information. Accordingly, NEDS data were obtained for three of the intrastate regions:

- West Central Illinois (AQCR 075; selected for further study)
- Southeast Illinois (AQCR 074)
- North Central Illinois (AQCR 071)

*The pertinent state emissions and AQCR emissions reports were computer-generated by EPA on 3/1/76 specifically for use in the present study. It appears that estimates for individual sources of emissions in the NEDS data bank date back as far as 1970.

TABLE 8-9

ESTIMATES OF EMISSIONS ASSOCIATED WITH USE OF COAL-FIRED FBC IN INDUSTRIAL BOILERS

	Emissions in Million Tons per Year				Incremental Emissions Versus LSFO*			
• Maximum Potential	Sol. Waste	Partic.	NOx	SO_2	Sol. Waste	Partic.	NOx	SO_2
1980	0.36	0.001	0.005	0.012	0.36	0.001	0.002	0.004
1985	11.1	0.030	0.152	0.377	11.1	0.030	0.061	0.132
1990	34.4	0.094	0.471	1.17	34.4	0.094	0.189	0.41
1995	57.3	0.157	0.784	1.95	57.3	0.157	0.315	0.68
2000	99.0	0.271	1.35	3.36	99.0	0.271	0.544	1.18
• Most Probable Potential								
1980	0.16	0.0004	0.002	0.005	0.16	0.0004	0.0009	0.002
1985	4.7	0.013	0.064	0.157	4.7	0.013	0.026	0.056
1990	16.1	0.044	0.220	0.547	16.1	0.044	0.089	0.192
1995	27.4	0.075	0.375	0.931	27.4	0.075	0.151	0.326
2000	48.2	0.132	0.660	1.64	48.2	0.132	0.265	0.574
• Minimum Potential								
1980	nil	nil	nil	nil	nil	nil	nil	nil
1985	1.3	0.004	0.018	0.045	1.3	0.004	0.007	0.016
1990	5.3	0.014	0.072	0.179	5.3	0.014	0.029	0.063
1995	9.7	0.027	0.133	0.330	9.7	0.027	0.053	0.116
2000	17.9	0.052	0.245	0.609	17.9	0.052	0.099	0.213

*Low Sulfur Fuel Oil. The increment in "environmental insult" vs. LSFO may be overstated since some FBC units would probably replace conventional coal-fired boilers.

Possible additional uses, such as a higher level of captive generation of electricity at manufacturing plants, are excluded from the above estimates.

Also excluded are estimates of emissions associated with the use of compliance coal in industrial FBC boilers, since insufficient technical data are available. As a rough approximation, the estimates for the most probable case may be increased by 10% to account for such use.

TABLE 8-10

ESTIMATES OF EMISSIONS ASSOCIATED WITH USE OF COAL-FIRED FBC IN INDUSTRIAL BOILERS ON REGIONAL BASIS (MOST PROBABLE CASE, CONVENTIONAL USES)

• 1990, Most Probable Case, 1000 T/yr of Emissions

Region	Sol. Waste	Partic.	NOx	SO_2	Increment over LSFO NOx	Increment over LSFO SO_2
Appalachian	4150	11.3	56.8	141	23.0	49
Southeast	3650	10.0	49.9	124	20.2	43
Great Lakes	3740	10.2	51.0	127	20.6	45
Northern Plains	110	0.3	1.5	4	0.6	1
Mid-Continent	500	1.4	6.8	17	2.8	6
Gulf Coast	3430	9.4	46.9	116	19.0	41
Rocky Mountain	150	0.4	2.0	5	0.8	2
Pacific Northwest	220	0.6	3.1	8	1.2	3
Pacific Southwest	150	0.4	2.0	5	0.8	2

• 1995, Most Probable Case, 1000 T/yr of Emissions

Region	Sol. Waste	Partic.	NOx	SO_2	Increment over LSFO NOx	Increment over LSFO SO_2
Appalachian	7040	19.3	46	239	39	84
Southeast	6250	17.1	85	212	34	74
Great Lakes	6360	17.4	87	216	35	76
Northern Plains	190	0.5	3	7	1	2
Mid-Continent	850	2.3	12	29	5	10
Gulf Coast	5750	15.8	79	196	31	68
Rocky Mountain	300	0.8	4	10	2	4
Pacific Northwest	360	1.0	5	12	2	4
Pacific Southwest	300	0.8	4	10	2	4

• 2000, Most Probable Case, 1000 T/yr of Emissions

Region	Sol. Waste	Partic.	NOx	SO_2	Increment over LSFO NOx	Increment over LSFO SO_2
Appalachian	12400	33.9	170	422	68	148
Southeast	10900	30.0	150	372	60	130
Great Lakes	11200	30.7	154	383	62	134
Northern Plains	300	0.9	5	11	2	4
Mid-Continent	1500	4.1	20	51	8	18
Gulf Coast	10100	27.7	139	344	56	121
Rocky Mountain	600	1.5	7	18	3	6
Pacific Northwest	600	1.7	8	21	3	7
Pacific Southwest	600	1.5	7	18	3	6

Notes: (1) The estimates of solid waste and particulate emissions apply to both absolute levels of emissions and to the increment relative to low sulfur fuel oil.

(2) The estimates do not include the use of compliance coal in industrial FBC boilers, because insufficient technical data are available. As a rough approximation, the national estimates may be increased by 10% to account for this use. Much of this use could occur in the Gulf Coast region.

TABLE 8-11

ANNUAL EMISSIONS ESTIMATED FOR STATE OF TEXAS

Source of Emission	1000 Tons Per Year SOx	1000 Tons Per Year NOx	1000 Tons Per Year Particulates	% of Total SOx	% of Total NOx	% of Total Particulates
Residential	0.3	11.6	1.5	negl.	0.7	0.2
Commercial/Institutional	11.1	20.1	4.1	1.4	1.3	0.7
Land Vehicles	35.3	624.1	61.3	4.4	39.3	10.1
Other Transportation	18.0	56.9	63.9	2.2	3.6	10.5
Solid Waste Disposal	14.3	4.9	17.1	1.8	0.3	2.8
Electric Utilities	53.8	372.4	20.0	6.7	23.5	3.3
Miscellaneous	7.3	167.3	14.1	0.9	10.5	2.3
Industrial Processes	620.3	130.0	406.8	77.6	8.2	66.9
Industrial Boilers	40.3	200.5	19.5	5.0	12.6	3.2
Total	800.6	1587.9	608.3	100	100	100

Source: National Emissions Data System, State Emissions Report, Emissions as of 3/1/76.

TABLE 8-12

ANNUAL EMISSIONS ESTIMATED FOR METROPOLITAN HOUSTON-GALVESTON AREA (AQCR 216)

Source of Emission	1000 Tons Per Year SOx	NOx	Particulates	% of Total SOx	NOx	Particulates
Residential	0.03	1.2	0.2	negl.	0.3	0.2
Commercial/Institutional	2.0	4.0	0.6	1.1	1.0	0.6
Land Vehicles	5.7	104.7	10.6	3.0	27.0	9.8
Other Transportation	3.3	12.7	2.3	1.7	3.3	2.1
Solid Waste Disposal	3.5	1.1	3.5	1.8	0.3	3.2
Electric Utilities	8.2	113.5	2.3	4.3	29.2	2.1
Miscellaneous	0.1	3.1	3.2	0.1	0.8	3.0
Industrial Processes	148.0	63.4	81.3	78.2	16.3	75.5
Industrial Boilers	18.5	84.4	3.8	9.8	21.8	3.5
Total	189.4	388.1	107.7	100	100	100
AQCR as % of Texas						
All Sources	24	24	18			
Land Vehicles	16	17	17			
Industrial Boilers	46	42	20			

Source: National Emissions Data System, AQCR Emissions Report, Emissions as of 3/1/76.

Of these three AQCR's, West Central Illinois appeared the best choice for the present study because of its mix of industrial plants and other emission sources.* NEDS data for the state of Illinois and for AQCR 075 are presented in Tables 8-13 and 8-14. As in the cases of the state of Texas and the Houston-Galveston AQCR, it will be seen that industrial boilers are a relatively minor factor in ambient air quality in Illinois. Particulate emissions are somewhat higher than expected in the West Central Illinois AQCR (#075). The explanation is not known, but it is possible that the current situation reflects an insufficient use of electrostatic precipitators, i.e. there may be a number of existing industrial boiler installations that do not meet Federal standards for new point sources. This may also be the case for NOx and SO_2 emissions, although no supporting data are available. If this is so, it seems possible that application of coal-fired FBC to industrial boilers could reduce the total emissions of particulates, NOx and SO_2 as facilities complying with Federal standards gradually replace installations that are not in compliance now.

The counties included in the selected AQCR's are listed in Table 8-15, while their geographical location is shown in Figures 8-1 and 8-2.

8.6.2 Current Situation: Ambient Air Quality

In accordance with requirements of the Clean Air Act and EPA Regulations for State Implementation Plans (SIP's), (13), ambient air quality data resulting from air monitoring operations of State, local, and Federal networks must be reported each calendar quarter to the Environmental Protection Agency. The EPA Storage and Retrieval of Aerometric Data (SAROAD) format, (14), is the established medium for transmittal of air data to EPA Regional Offices within 45 days after each reporting period. EPA Regional Offices must, within an additional 30 days, forward data they have received to the EPA National Aerometric Data Bank (NADB), of which the SAROAD system is an operational part. The NADB is managed by the National Air Data Branch, Monitoring and Data Analysis Division of the OAQPS. In a continuing effort to provide these data to participating agencies as well as to the public, EPA periodically publishes a summary of all data submitted, e.g. references (15) and (16). Statistics drawn from these references were used as an indication of current ambient air quality in AQCR 216 and AQCR 075. In fact, the analytical measurements were made in 1973 and 1974. The data relate to sampling and analysis performed at two locations. Three laboratories are housed at the Houston location.

- AQCR 216 810 Bagby Street, Houston, Texas
  - EPA Regional Office (001 P01)
  - EPA Atmospheric Surveillance Office (001 A01)
  - Houston Health Department (001 H01)
- AQCR 075 224 West Adams Street, Springfield, Illinois
  - State of Illinois EPA (003 F01)

*However, substantially the same conclusions would have been reached if either of the other two Illinois AQCR's had been selected.

TABLE 8-13

ANNUAL EMISSIONS ESTIMATED FOR STATE OF ILLINOIS

Source of Emission	1000 Tons Per Year			% of Total		
	SOx	NOx	Particulates	SOx	NOx	Particulates
Residential	68.1	25.5	16.2	2.6	1.9	1.7
Commercial/Institutional	44.7	35.5	19.9	1.7	2.7	2.1
Land Vehicles	23.8	436.2	44.7	0.9	33.3	4.8
Other Transportation	2.3	11.5	2.4	0.1	0.8	0.2
Solid Waste Disposal	6.3	12.7	53.7	0.2	1.0	5.8
Electric Utilities	1998.2	631.1	232.5	76.3	48.2	25.0
Industrial Processes	91.4	29.1	409.4	3.5	2.2	44.0
Industrial Boilers	383.6	129.9	152.3	14.7	9.9	16.4
Total	2618.5	1311.6	931.1	100	100	100

Source: National Emissions Data System, State Emissions Report, Emissions as of 3/1/76.

TABLE 8-14

ANNUAL EMISSIONS ESTIMATED FOR WEST CENTRAL ILLINOIS (AQCR 075)

Source of Emission	1000 Tons Per Year SOx	NOx	Particulates	% of Total SOx	NOx	Particulates
Residential	4.2	1.2	1.0	1.0	0.6	1.1
Commercial/Institutional	4.9	1.9	2.6	1.1	1.0	2.8
Land Vehicles	1.6	32.5	3.4	0.4	17.6	3.7
Other Transportation	0.2	1.0	0.2	negl.	0.5	0.2
Solid Waste Disposal	0.3	0.9	3.5	0.1	0.5	3.8
Electric Utilities	399.1	139.4	22.8	89.8	75.5	24.9
Miscellaneous	-	-	-	-	-	-
Industrial Processes	negl.	negl.	32.1	negl.	negl.	35.0
Industrial Boilers	33.6	8.0	26.1	7.6	4.3	28.5
Total	444.0	184.9	91.7	100	100	100
ACQR as % of Illinois						
All Sources	17	14	10			
Land Vehicles	7	7	8			
Industrial Boilers	9	6	17			

Source: National Emissions Data System, AQCR Emissions Report, Emissions as of 3/1/76.

TABLE 8-15

COUNTIES INCLUDED IN SELECTED AQCR's

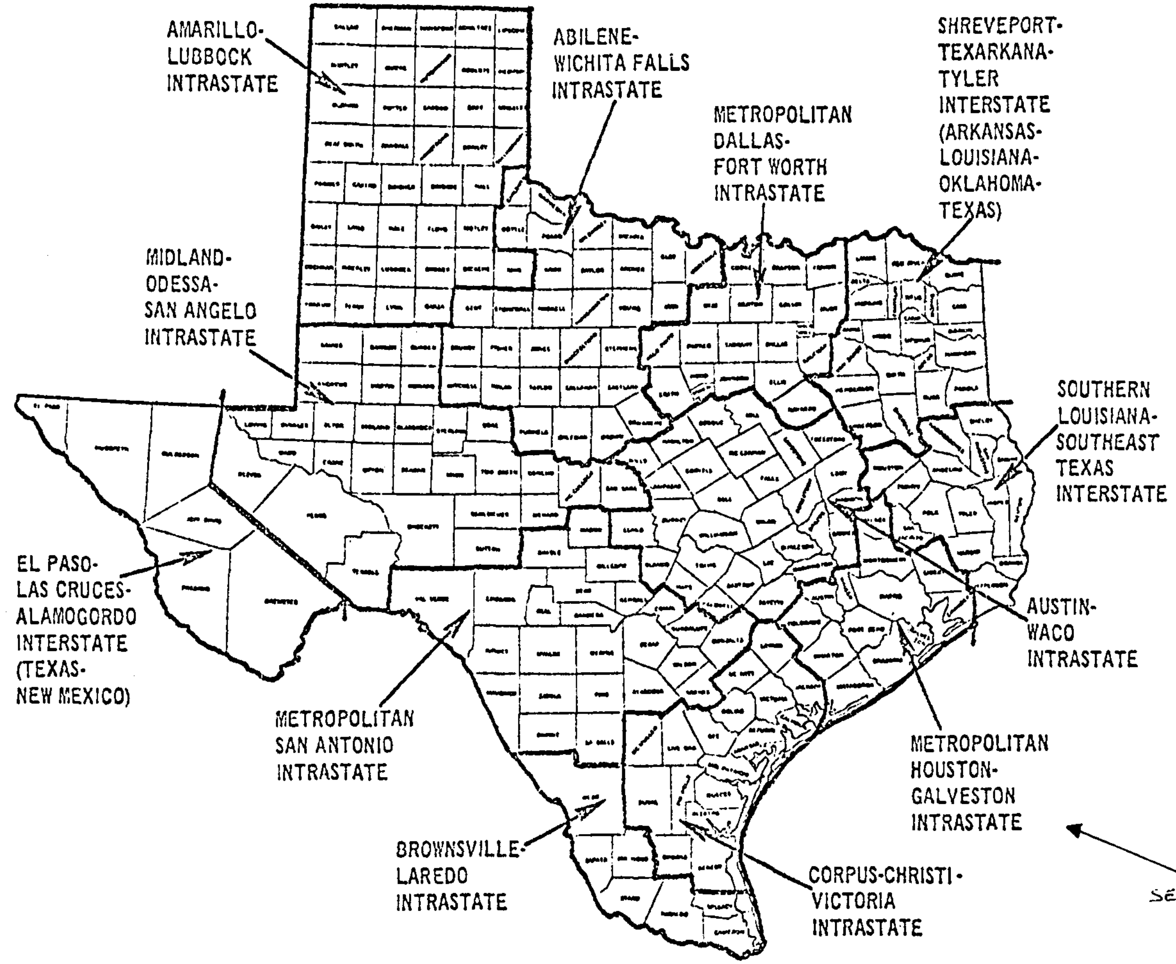
West Central Illinois Intrastate (AQCR 075)

Counties:	Adams	Jersey	Morgan
	Brown	Logan	Pike
	Calhoun	Macon	Sangamon
	Cass	Macoupin	Schuyler
	Christian	Menara	Scott
	Greene	Montgomery	

Metropolitan Houston-Galveston Intrastate (AQCR 216)

Counties:	Austin	Galveston	Walker
	Brazonia	Harris	Waller
	Chambers	Liberty	Wharton
	Colorado	Matagorda	
	Fort Bend	Montgomery	

FIGURE 8-1



SELECTED

Air Quality Control Regions in Texas.

FIGURE 8-2

Air Quality Control Regions in Illinois.

Pertinent measurements of ambient air quality were:

Micrograms per Cubic Meter, μg/cu.m., Annual Basis

	Particulates (Geometric Mean)	SO_2 (Arithmetic Mean)	NO_2 (Arithmetic Mean)
AQCR 216	81*	4**	75***
AQCR 075	65*	25**	21***
NAAQS Primary Std.	75	80	100

Detailed discussion of the reported ambient air quality measurements is beyond the scope of this study. However, it should be pointed out that the nationwide reports exhibit variability among test methods, evidence of statistical or analytical errors, and problems associated with computer generated reports. While effort was made to extract statistics representative of the air quality conditions in AQCR's 216 and 075, the numbers reported should be taken as illustrative rather than as precise. For example, the reported particulate level of 81 μg/cu.m. for AQCR 216 exceeds the primary standard of 75 μg/cu.m. Other sample points within the AQCR report both higher and lower values. Hence, the geometric mean of 81 μg/cu.m. should probably be taken as an indication that the Houston-Galveston area has a potential problem with particulates rather than as categorical evidence that the area is not in compliance with an NAAQS primary standard. Analogously, even though the arithmetic mean of 75 μg/cu.m. NO_2 is below the primary standard of 100 μg/cu.m. the relatively high observed level may be taken as an indication of an incipient problem. On the other hand, reported sulfur dioxide levels in AQCR 216's ambient air are at the very low level of 4 μg/cu.m. which is appreciably below the primary standard of 80 μg/cu.m. Undoubtedly, the low level reflects the extensive use of natural gas in the Houston area. Corresponding measurements for AQCR 075 indicate a borderline situation for particulates and comfortable margins below the primary standards for both SO_2 and NO_2.

8.6.3 Future Situation: Mass Emissions

Estimates of emissions, related to coal-fired FBC industrial boiler technology, for Metropolitan Houston-Galveston (AQCR 216) and West Central Illinois (AQCR 075) may be derived from:

(1) Table 3-6 which indicates that the states of Texas and Illinois account, respectively, for 58.9% and 29.4% of the pertinent industrial boiler capacity in the Gulf Coast and Great Lakes regions.

(2) Tables 8-12 and 8-14 which indicate that AQCR 216 and AQCR 075 account, respectively, for about 45% and 8% of the pertinent state totals of industrial boiler emissions.****

(3) Table 8-10 which provides regional estimates of emissions associated with the most probable coal-fired FBC potential.

*Test Method: Hi-Vol Gravimetric, 24 hours.
**Test Method: Gas Bubbler para-rosaniline sulfamic acid, 24 hours.
***Test Method: Gas Bubbler sodium arsenite, frit, 24 hours.
****based on SO_2 and NO_2 emissions.

Applying the appropriate percentages for (1) and (2) as multiplying factors to the pertinent numbers in Table 8-10 yields estimates of emissions associated with the potential future use of coal-fired FBC in AQCR 216* and AQCR 075. These estimates are recorded in Table 8-16. Present levels of emissions, based on the National Emissions Data System are repeated at the bottom of Table 8-16.

Unfortunately, no estimates of future mass emissions from all** sources are available for AQCR's 216 and 075. Hence, it is necessary to relate the estimates of incremental emissions from coal-fired FBC boilers with the current levels of particulate, SO_2 and NO_2 emissions in the selected AQCR's:

	Estimated Increment to Mass Emissions Attributable to Coal-Fired FBC Industrial Boilers as a % of Current Emissions from All Sources		
AQCR 216	Particulates	SO_2	NO_2
1980	negligible	negligible	negligible
1990	2	2	3
2000	7	5	10
AQCR 075			
1980	negligible	negligible	negligible
1990	0.3	0.7	0.7
2000	0.8	2	2

The above estimates suggest that coal-fired FBC industrial boilers will not be <u>major</u> contributors to air emissions in either of the selected AQCR's. On the other hand, <u>any</u> increment to emissions would be expected to exacerbate the situation in a region such as Houston-Galveston where current emission levels are approaching the NAAQS primary standards (for particulates and NO_2). This is discussed further below.

8.6.4 Future Situation: Ambient Air Quality

The previously discussed mass emissions projected for coal-fired FBC industrial boilers were converted by proration to absolute increments to pollutants in the ambient air in the selected AQCR's. The simple proration procedure has the effect of assuming that all of the incremental mass emissions stay within the AQCR in which they are generated. Because some dispersion will occur, the assumption leads to what may be considered as a "worst increment" to degradation of ambient air quality.

*excluding the emissions associated with the use of compliance coal in AQCR 216, since insufficient technical data are available to make such estimates.

**i.e. for all sources other than large industrial boilers.

TABLE 8-16

ESTIMATES OF EMISSIONS IN AQCR 216 AND AQCR 075 ASSOCIATED WITH POTENTIAL USE OF COAL-FIRED FBC IN INDUSTRIAL BOILERS

- Metropolitan Houston-Galveston (AQCR 216), Most Probable Case ϕ

	1000 Tons Per Year of Emissions from FBC Industrial Boilers			
	Solid Waste	Particulates	SO_2	NO_2
1980	9	0.02	0.28	0.11
1985	262	0.72	9	3.6
1990	909	2.5	31	12
1995	1520	4.2	52	21
2000	2680	7.3	91	37

- West Central Illinois (AQCR 075), Most Probable Case

	1000 Tons Per Year of Emissions from FBC Industrial Boilers			
	Solid Waste	Particulates	SO_2	NO_2
1980	0.9	0.002	0.03	0.01
1985	26	0.07	0.87	0.35
1990	88	0.24	3.0	1.2
1995	149	0.41	5	2.0
2000	260	0.72	9	3.6

- Present Emission Levels* (see Tables 8-11 and 8-13)

  - From Industrial Boilers

	1000 Tons Per Year of Emissions			
	Solid Waste	Particulates	SO_2	NO_2
AQCR 216	not applic.**	3.8	18.5	84.4
AQCR 075	not applic.**	26.1	33.6	8.0

  - From All Sources Within AQCR

AQCR 216	not applic.**	107.7	189.4	388.1
AQCR 075	not applic.**	91.7	444.0	184.9

*NEDS estimates

**solid waste disposal in current NEDS system does not apply to FBC solid wastes since FBC technology is not in use.

ϕ excluding use of compliance coal.

TABLE 8-17

ESTIMATED INCREMENTS TO AMBIENT AIR POLLUTION ASSOCIATED WITH COAL-FIRED FBC INDUSTRIAL BOILERS

• Metropolitan Houston-Galveston (AQCR 216)

	Estimated FBC Increment, μg/cu.m.		
	Particulates	SO_2	NO_2
1985	0.6	0.2	0.7
1990	1.8	0.6	2.3
1995	3.2	1.1	4.1
2000	5.5	1.9	7.1
Current Level in AQCR	81	4	75
Primary Standard	75	80	100

• West Central Illinois (AQCR 075)

	Particulates	SO_2	NO_2
1985	0.1	0.1	negligible
1990	0.2	0.2	0.1
1995	0.3	0.3	0.2
2000	0.5	0.5	0.4
Current Level in AQCR	65	25	21
Primary Standard	75	80	100

For the Houston-Galveston region, the projected emissions from coal-fired FBC industrial boilers are not expected to add large increments of particulates, SO_2 or NO_2 to the ambient air. Nevertheless, in the case of both particulates and NO_2, the impact may be of practical significance because the current level of air quality is marginal and, hence, any incremental pollution will make NAAQS more difficult to achieve and/or maintain. However, the increments associated with FBC industrial boilers assume further industrialization of AQCR 216. If this industrialization occurs, there will be problems in meeting current NAAQS regardless of the technology applied to industrial boilers. The difficulty lies in the current emission levels not with FBC as a control technology. In fact, other technologies for combusting coal in industrial boilers might well produce larger detrimental increments to ambient air pollution levels than those estimated for FBC. This is probable for NOx emissions, but not necessarily the case for particulates. A possible inference is that to derive maximum environmental advantage from FBC, it may be necessary to develop extremely effective particulate removal technology.

West Central Illinois has a moderate industrial base but, industrially, cannot be compared with Houston-Galveston which is the nation's leading petroleum refining/petrochemical region. The difference in degree of industrialization is the principal reason why the ambient air quality impacts associated with FBC industrial boilers are projected to be minimal in AQCR 075. The increments projected in Table 8-17 are all within the current accuracy of the test methods for the pollutants in question.

8.7 Disposition of Solids and Sludge

The greatest incremental volumes of emissions on conversion from natural gas or low sulfur fuel oil to coal will be the solid and/or sludge streams. From an environmental viewpoint, however, these streams may be of less concern than other increased emissions such as NOx and SO_2.

A number of studies have been carried out for EPA covering the environmental problems connected with solids disposal; among these are references 8, 9, 10 and 11. Reports in reference 11 were more concerned with disposal of ash chars and sludges from coal gasification and liquefaction plants, although in many cases coal fired boilers were assumed. Reference 8 devotes 19 pages to limestone regeneration as a method of reducing solids disposal and to a discussion of the environmental problems, and also five pages to solids disposal and possible environmental problems. Reference 9 contains 6 pages and twelve further references devoted to these subjects. Reference 10 contains 35 pertinent pages, eighteen additional references, and includes original experimental work related to the environment. Although, as discussed below, conclusions from these references are applicable to the present study, they do not accurately reflect the on-going efforts on disposal of solid and sludge wastes. Such efforts include laboratory leaching/lysimeter tests, low temperature fixation of wastes, and assessment of ocean disposal.

8.7.1 Solid/Sludge Byproducts

Table 8-18 shows the calculated compositions of the solid waste streams produced when Illinois No. 6 coal is burned under the conditions assumed in 8.3 and 8.4.

TABLE 8-18

COMPOSITION OF SOLIDS/SLUDGE FROM BURNING ILLINOIS NO. 6 COAL

• Basis: 100 KPPH industrial boiler

	% in Solids/Sludge	
	FBC	Spreader Stoker
$CaSO_4$	33	*
CaO	36	--
$CaSO_3$	--	24
$CaCO_3$	--	9
Inert from limestone	10	3
Ash	21	18
H_2O	--	46
Form of waste stream	Dry, granular stone/ash mixture	Mixture of wet scrubber sludge with boiler ash
Quantity of waste stream, T/D	55	66

*Sludge will contain small amount of $CaSO_4$ oxidized from $CaSO_3$, but oxidation rate at scrubber/settler/filter conditions is low.

The quantity of sludge from the spreader stoker/scrubber is somewhat greater than the solids from the FBC (66 t/d vs. 55 t/d) but the difference in quantity is not significant from an environmental standpoint. The difference in form (solid vs. sludge) and composition may be significant depending on ultimate disposition.

8.7.2 Solids Disposal

The environmental problems of solids disposal from burning coal for industrial heat generation can be quite different from those connected with large coal conversion plants (11) or large power generation plants utilizing coal (12). In the latter two cases, disposal of solids is of such importance in the original plant design that it may be a factor in determining the location of the plant. Frequently the solids from such plants can be returned to the coal mine. Usually the locations of such plants would be in areas with sufficient available land to allow impoundment of sludges. On the other hand, the locations of industries that may utilize coal for heating purposes would probably be determined by other factors. Oil refineries, for example, are placed in locations where crude oil is easily accessible and markets are close. Frequently these industries are in areas where land availability is limited. Solids disposal can then only be effected by carting the materials away. Thus the immediate environmental problem is solved. The question then arises as to ultimate disposal of the solids/sludges. Assuming that dusting problems can be adequately handled the main environmental problems connected with storing the materials in some remote area is that of leaching of harmful materials and use of land. These problems have been discussed in a number of references (8-11). Leaching does occur as reported in reference 11. However, the problem may be no worse than leaching of gypsum itself. By proper site selection and mechanical design, both sludges and solids may be storable indefinitely in landfill sites without representing a hazard to water supplies. Availability of nearby landfill sites may be a problem in some locations, and would surely become a general problem if total U.S. consumption of solid coal increases two to three-fold. Hence, utilization, rather than disposal, of the "wastes" would appear to be a desirable and necessary long term goal.

Ocean dumping is another possible solution, although one that would require very careful control.

8.7.3 Utilization of Solid Wastes

The use of the solids for road fill material has been suggested but the problem of leaching would have to be examined on a larger scale than has been done to date to determine the consequences of sulfate and calcium contamination of water supplies.

About 13 percent of the ash produced in 1971 found use in various applications (9) and some possibilities for the use of FBC solids have been suggested (9) (10). However, looked at differently, 87% of the ash produced in 1971 was not utilized -- in spite of many years of effort made by the National Ash Association to find commercial outlets for ash. It appears that there are institutional as well as technological barriers to ash utilization and, hence, that utilization efforts will have to be sustained for a long time.

8.7.4 Regeneration of Treater Materials

Regeneration of the calcium sulfate (sulfites) has been considered as a method of reducing the quantities of solids to be disposed of and research work is in progress (8). Insufficient information is available to determine that regeneration is economically viable. The environmental problems connected with regeneration will have to be examined to determine if regeneration affects the environment to a greater extent than impoundment of the total solid wastes.

8.8 Modification of Basis

As discussed in Section 5.2, new information provided by ERDA in September 1976 has required re-estimation of the most probable potential for application of coal-fired FBC technology to industrial boilers. The re-estimation introduces quantitative uncertainties in the area of "environmental impacts" and with respect to the combustion of compliance coal in industrial FBC boilers. The major problem, with respect to this study, is that insufficient technical data are available for quantification of the emissions associated with the use of a variety of low sulfur bituminous, sub-bituminous, and lignite coals in FB boilers.

Qualitatively, we visualize considerable practical advantages in being able to apply FBC technology to low sulfur coals, as discussed below. However, with existing technical information, it is not possible to quantify these advantages. From economic and practical standpoints, FBC technology may permit:

(1) coals with significant content of alkaline ash to become compliance coals (whereas they would not be compliance coals if combusted by conventional technology).

(2) lower emissions of sulfur oxides and, possibly, nitrogen oxides than would be achievable at comparable cost using conventional technology.

The first of the above possibilities requires at least four factors to be taken into account in determination of whether a particular coal is "compliant":

- the sulfur content of the coal
- the ash content of the coal
- the composition of the ash
- the technology by which the coal will be combusted.

The second possibility introduces a fifth factor, namely that the definition of "compliance" may vary with location and with time. Put differently, compliance with New Source Performance Standards (NSPS) may not be sufficient in some industrial areas of country which are already at, or beyond, ambient air quality standards (NAAQS). Thus, "compliance" may become a variable that depends on the interaction of other factors. Current information about these factors is inadequate. Moreover, the ways in which NAAQS are being attained (or not attained) are being affected by legislative and regulatory changes, i.e. by non-technological and essentially unpredictable factors.

Available data on sulfur content, ash content, ash composition, and source of coal are summarized in Figure 8-3 and Tables 8-19 and 8-20. The stoichiometric ratios of alkali metals to sulfur appear to be most important because the alkali metals present in the coal can capture sulfur during combustion -- particularly if the coal is combusted in a fluid bed. The point is made in terms of Ca/S ratio in the last horizontal row of Table 8-20.

8.9 Environmental Conclusions and Recommendations

Using conventional technology, a change from natural gas or oil to coal-firing would be expected to affect the environment adversely. With FBC technology, there is a potential for improvement over conventional coal use technology. Industrial FBC boilers should be able to meet and improve upon New Source Performance Standards. However, it is improbable that coal-fired FBC will ever achieve the degree of control possible with natural gas or low sulfur fuel oil. This is not to the detriment of FBC because it is expected that natural gas and LSFO will become supply limited before synthetic fuels are available.

The development of FBC technology will not, of itself, correct existing problems with ambient air quality. Notwithstanding the potentially important contributions that may be made by FBC technology to the coal-firing of industrial boilers in environmentally acceptable ways, such applications are likely to have a smaller impact on ambient air quality than:

(a) the impact produced by combustion sources other than large industrial boilers, and -

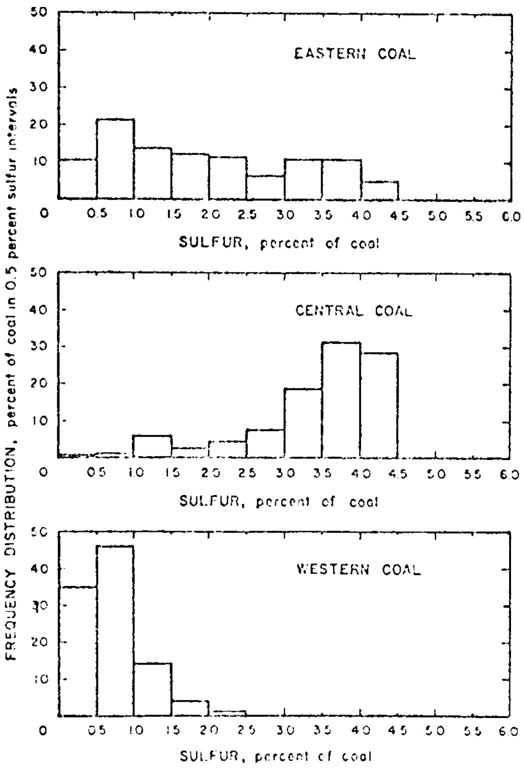
(b) the impact of emissions from existing coal-fired equipment in regions that currently use coal to a significant extent.

The Metropolitan Houston-Galveston Air Quality Control Region contains the most important industrial area in the nation.* By the year 2000, projected use of FBC technology in large industrial boilers in AQCR 216 could raise levels of ambient air pollution from particulates and NOx by an increment equal to about 7% of the Primary Ambient Air Quality Standard for each of these criteria pollutants. The practical significance of this increment will depend on the general level of ambient air quality that exists in the year 2000 in AQCR 216. Currently, ambient air quality is marginal. Hence, any increment could be significant unless the aggregate of existing sources of air emissions is brought under better control.

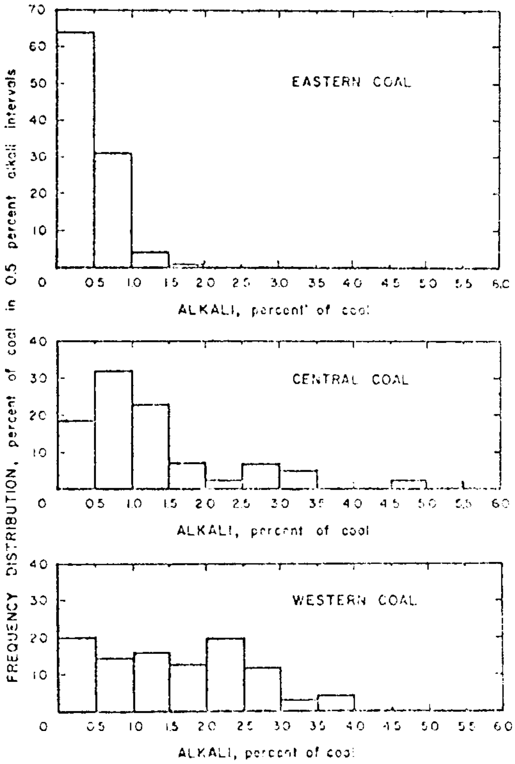
*important in the sense that the area contains the greatest industrial concentration in the U.S. Moreover, chemicals and petrochemicals plants are responsible for a large element of this concentration. Demand for petrochemical products is growing about twice as fast as demand for industrial products in general. Hence, constraint of industrial expansion in AQCR 216 might be expected to have significant national repercussions.

FIGURE 8-3

DISTRIBUTION OF SULFUR AND ALKALI CONSTITUENTS OF COAL BY REGION



Frequency distribution of coal reserves by sulfur content and region.



Frequency distribution of coal reserves by ash alkali content and region.

Source: Reference (17)

TABLE 8-19

ALKALI ELEMENTS IN COAL ASH BY REGION

Region	Alkali Oxides, % of Ash			
	CaO	MgO	Na_2O	K_2O
East	3.15	0.86	0.91	1.48
Central	9.38	1.07	0.74	1.45
West	13.74	3.71	3.44	0.86

- Stoichiometric ratio of alkali metals to sulfur

	Percent of Coal		Stoichiometric Ratio
	av. alkali	av. sulfur	Alkali/Sulfur
East	0.43	1.95	0.12
Central	1.27	3.43	0.21
West	1.54	0.70	1.31

Source: E. A. Sondreal and P. H. Tufte, "Comparison of Flue Gas Desulfurization for Eastern vs. Western U.S. Coals", U.S. Bureau of Mines, Grand Forks, North Dakota, September 1974 (17). (Source refers to U.S. Bureau of Mines Bulletin 567 and unpublished data.)

TABLE 8-20

SELECTED ANALYSES OF ASH IN WESTERN COALS

	Lignite	Sub-bituminous				Bituminous	
State	N.D.	Mont.	Wyo.	Ariz.	N.M.	N.M.	Col.
Mine	-	-	Big Horn	Black Mesa	Navajo	McKinley	Hawks Nest
No. of Samples	212	125	12	1	2	1	3
Ash, wt.%	6.2	9.3	4.8	7.5	20.2	8.0	5.4
Oxide constituents of ash, %							
SiO_2	19.7	35.5	27.4	42.0	55.6	54.7	44.8
Al_2O_3	11.1	18.7	12.7	18.1	26.2	21.6	28.3
	30.8	54.2	40.1	60.1	81.8	76.3	73.1
Fe_2O_3	9.1	7.8	13.9	5.7	6.1	7.0	11.5
TiO_2	0.4	0.7	0.6	0.8	0.6	1.0	0.8
	9.5	8.5	14.5	6.5	6.7	8.0	12.3
SO_3	19.5	13.4	17.0	8.2	3.2	5.8	4.0
CaO	24.6	15.6	16.6	17.8	3.9	6.5	5.6
MgO	6.9	4.4	5.5	2.4	0.8	1.2	1.9
	31.5	20.0	22.1	20.2	4.7	7.7	7.5
Na_2O	6.5	1.7	2.2	1.4	1.5	1.6	0.6
K_2O	0.4	0.4	0.5	0.3	0.6	0.8	0.5
	6.9	2.1	2.7	1.7	2.1	2.4	1.1
P_2O_5	0.3	0.3	0.5	0.6	0.5	nil	0.7
Ca/S ratio	2.2	2.1	1.7	3.8	2.2	2.0	2.5

Source: ERDA Open File Report: "Survey of Coal and Ash Composition and Characteristics of Western Coals and Lignite", Grand Forks, North Dakota, 1975 (18).

At present, available technical data limit the quantitative environmental conclusions that may be drawn about coal-fired FBC, per se, and in relation to other coal use technologies. Further definition of the following is suggested:

(1) the quantity of sulfur retained in the ash from FBC and spreader-stoker boilers . . . for representative Western coals (bituminous, sub-bituminous, lignites) and Southwestern lignites.

(2) NOx emissions . . . for the same types of equipment* and coals listed in (1).

(3) particulate emissions from (atmospheric) coal-fired FBC boilers . . . as for (1) but also including high sulfur coals.

(4) fate of trace elements . . . as for (1), but also including high sulfur coals and FGDS systems.

*there is some evidence, not sufficiently reliable to cite here, that different designs of atmospheric fluidized bed combustors have different NOx control potentialities. This possibility warrants further investigation.

9. CONCLUSIONS

The conclusions of any forecasting study are conditioned by the assumptions used and by the judgment of the investigator. The conclusions below are accompanied by the letters (a), (b) and (c) which signify:

(a) high probability: the evidence and logic appear so persuasive that the conclusion may be taken as objectively valid.

(b) dependent on assumptions used: the conclusion is valid only if the assumptions are valid, e.g. that limited availability or very high cost of imported oil will force the use of greatly increased quantities of coal as industrial boiler fuel within the timeframe of interest.

(c) dependent on contractor's judgment: many factors affecting long range projections are not forecastable in a rigorous way and must be dealt with by judgment.

— — — — — — — — — — — — —

(1) Parity price calculations indicate that fuel price alone is not likely to provide a sufficient incentive for conversion of industrial boilers from oil/gas-firing to coal-firing during the next decade. (a)

(2) Aside from mandated switching, a decision to use coal is apt to be induced by the perception that, during the life of a particular plant, the supply of oil may become unreliable (e.g. interrupted, rationed, or unavailable). (c)

(3) Capital-intensive manufacturing operations cannot tolerate unreliability or unavailability of energy supply. (a)

(4) A survey of operators of large industrial boiler systems revealed that almost all are considering the use of coal and are expecting that, eventually, such use will be unavoidable. Once a decision to use coal is made, consideration will be given to whatever coal-use technologies have been demonstrated to be commercially reliable at the time the decision is made. Installation of coal-fired FBC boilers will be considered if commercial reliability has been demonstrated to be competitive with environmentally acceptable alternatives. (a)

(5) An increasing shortage of natural gas, a growing compliance with environmental regulations (to achieve "clean air"), and recovery from economic recession are expected to result in decisions by many companies to install new industrial boilers during the next few years. Therefore, it appears important for coal-fired FBC technology to be fully demonstrated for industrial use as soon as possible. (b) (c)

(6) Erosion of the potentials estimated in this study may be expected if the demonstration of commercial reliability of FBC technology occurs after 1981, or 1982 at the latest. (c)

(7) The use of compliance coal is widely perceived to be a more economic choice than the use of high sulfur coal plus flue gas desulfurization (i.e. "scrubbers"). (a) (c)

(8) The cost of using compliance coal with FBC technology is estimated to be a stand-off with using the same compliance coal in conventional coal-fired industrial boilers. (b)

(9) The major resources of compliance coal are in the Western states, hence transportation costs to many industrial plants will be high. (a)

(10) The combined demand for compliance coal by electric utilities and manufacturing plants may constrain its availability in the 1980's and, eventually, will do so. (c)

(11) Southwestern lignites, which contain appreciable amounts of alkaline ash, are not compliance coals if combusted conventionally but may become so in fluid-bed units. This possibility is of considerable potential importance to industry located in the Gulf Coast area. (c)

(12) In general, Western coals of all ranks contain alkaline ash that can effect sulfur capture when the coals are combusted. A much higher level of sulfur capture is likely via FBC than with conventional combustion. (a) (c)

(13) The foregoing points, taken together, give qualitative backing to this study's estimates of coal-fired FBC potential provided that timely demonstration of commercial reliability is achieved. (c)

(14) FBC technology has important advantages that, currently, cannot be quantified. The advantages include flexibility to combust different types of coal, good control of NOx emissions, relatively unobjectionable solid wastes for which uses are under development, and ability to be fabricated and shipped in modules for simple field assembly. Hence, a decisive advantage in new boilers is possible for FBC over scrubber technology provided that commercial reliability of FBC technology is demonstrated in time. (c)

(15) Conversion of existing boilers to FBC technology (i.e. "retrofitting FBC") is judged to be economically unattractive. (a) (c)

(16) The potential for coal-fired FBC is concentrated in the chemicals, petrochemicals, petroleum refining, paper, primary metals, and food industries. (a) (c)

(17) The coal-fired FBC potential is considered to be a sub-set of coal utilization by all large industrial boilers, and the level of coal utilization by industrial MFBI's may be influenced strongly by the existence, or absence, of coal-use legislation such is now under Congressional consideration. (b) (c)

(18) Over 90% of the coal-fired FBC potential is in four regions: Appalachian, Southeast, Great Lakes, and Gulf Coast. (c)

(19) The coal firing of large industrial boilers, employing FBC technology, is not expected to have much impact on the aggregate of national energy consumption. (c)

(20) Estimated potentials for coal-fired FBC may be converted to "savings" of oil equivalent ranging from 150,000 B/D in 1985 to 2.4 million B/D in the year 2000. (b) (c)

(21) Realization of the estimated coal-fired FBC potentials would have significant economic impacts in the boiler manufacturing, coal, and limestone industries. However, essentially the same impacts would be expected if the same level of coal utilization is achieved with alternative coal-use technologies. (c)

(22) This study assumes (with much supporting evidence) that coal-fired FBC will be an environmentally acceptable technology. On this basis, the deployment of the technology is likely to have a net beneficial impact on ambient air quality as it replaces existing coal-fired equipment in regions that currently use coal to a significant extent. (c)

(23) The environmental impact of coal-fired FBC industrial boilers will be small by comparison with the impact caused by sources other than industrial boilers. (a)

(24) Compliance with New Source Performance Standards (NSPS) may not be sufficient in some industrial areas of the country which are already at or beyond ambient air quality standards (NAAQS). The Houston-Galvestor area (AQCR 216), which is the leading petroleum refining/petrochemical area in the U.S., has particulate and NO_2 levels in ambient air that are close to the primary standards. (a) (c)

(25) Directionally, even with excellent control technology, coal use in new installations would worsen the quality of the ambient air unless the existing situation is improved. (c)

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CONVERSION FACTORS - ENGLISH TO SI UNITS

	English System	SI Equivalent
Length	in	2.54 cm
	ft	0.305 m
Area	in^2	6.45 cm^2
	ft^2	0.0930 m^2
Volume	in^3	16.39 cm^3
	ft^3	28.32 dm^3
	B or bbl (barrel)	159 dm^3
Mass	oz	28.35 gm
	lb	453.6 gm
	ton	907.2 kg
Pressure	lb/in^2	6.89 kPa
	in H_2O	0.249 kPa
Temperature	°F	1.8 (°C) + 32
	°R	1.8 °K
Energy	BTU	1.06 kJ
	10^{15} BTU or "quad"	33450 MW_t
Power	BTU/hr or BTU/H	0.293 W

Abbreviations/Acronyms

ABMA	American Boiler Manufacturers Association
AQCR	Air Quality Control Region
¢/K lbs	cents per thousand pounds (of steam)
FB	fluid-bed or fluidized bed
GPO	Gross Product Originating
HHV	higher heating value
KPPH	thousand pounds (of steam) per hour
LSFO	low sulfur fuel oil
M$	million dollars
MFBI	Major Fuel Burning Installation
MWe	megawatts electric
MW_t	megawatts thermal
NAAQS	National Ambient Air Quality Standards
NGTF	Natural Gas Task Force (FEA)
NSPS	New Source Performance Standards
OE	oil equivalent (B.O.E. = barrels of oil equivalent)
OSHA	Occupational Safety and Health Act (or Administration)
PCF	pulverized coal fired (boiler)
SIC	Standard Industrial Classification

APPENDIX 1

BASES FOR ECONOMIC EVALUATIONS OF GRASS ROOTS INDUSTRIAL BOILER COMPARISONS

1. INVESTMENT BASES

   A. GENERAL PROJECT OUTLINE

   Location - U.S. Gulf Coast

   Time - 1st quarter 1975

   Final cost is a "Total Erected Cost" for the entire boiler system (exclusions as noted).

   Design and erection of boiler project by contractor under a reimbursable cost contract.

   Investment estimates are of initial screening quality, considered suitable for general comparison of alternatives but not developed to a definitive level suitable as a basis for allocation of funds.

   Fluidized bed combustion has not been demonstrated commercially. As such the FBC portion of the FBC package boiler estimate is increased by a process development allowance of 20%. A small process development allowance is also applied to industrial-sized flue gas scrubbers.

   Investment estimates exclude the purchase of any land. It is assumed that adequate space for the required facilities is already available, and that extensive site clearance (e.g. blasting or draining and filling) is not required.

   All cases are planned to meet appropriate environmental requirements.

   Investment estimates include 20% project contingency. This is considered necessary at the screening stage of <u>any project</u>, because of the incomplete project definition which is characteristic of this stage of project development. For ease of use, this contingency is broken out so that the estimates can be readily worked with on a non-contingency basis if desired.

   The "Total Erected Cost" for each screening case of this study is built up including the following components:

   Direct Materials Cost, delivered to project location (including freight, delivery charges, sales taxes, etc.)

   Direct Labor Cost at Location

   Field Labor Overheads
   - Construction Supervision
   - Construction Tools
   - Temporary Construction Facilities and Consumables

Contractor's Field Payroll Burden
Insurance, Union Welfare Funds, Indirect Labor Costs, and any other contractor overheads

Contractor Engineering

Contractor Fees for Engineering and Erection

Process Development Allowance for New Technology Components

Sub-Contracts for Civil and Tankage Items

Escalation to later project time (if desired)

Contingency - @ 20% of all above components except Process Development Allowance

B. FUEL AND LIMESTONE RECEIVING AND STORING FACILITIES

- Fuel Oil Receiving and Storing

No. 6 Fuel Oil (high or low sulfur) received in 5,000-barrel parcels, delivered by barge.

Oil storage: two steam-heated cone roof tanks with combined capacity sized for 10 days requirement plus parcel size (i.e. 10,000 barrels combined storage. Facilities include:

8" fuel receiving line, steam-traced and insulated from existing barge dock to storage tanks (approx. 1000 feet)

Two 5,000 barrel cone-roof tanks, approximately 30' x 40'. Tanks are heated with low-pressure steam coils ($\sim$125 psig), and insulated with foam sprayed insulation

Two fuel oil pumps, pumping approx. 20 gpm @ 150 psig

Transfer line (2", traced and insulated), from tanks to boiler area and return.

- Coal Receiving and Storing

Coal received in 10-car lots (100 tons/car); bottom-hopper cars

Coal as received is fully prepared for FBC charging (screened to approx. 1/4-inch top size) or for use in stoker (1 1/4" nominal size), and sprayed with oil to minimize dust and facilitate unloading in freezing weather

Coal storage: two silos with combined capacity sized for 10 days requirement plus parcel size (i.e. 2400 tons combined storage)

Facilities include:

Railroad track extension (approx. 1400 feet)

Covered car-unloading dump hopper and pit

Car puller

Feeders and covered conveyor from pit to elevator

Elevator to top level of silos

Transfer conveyor from elevator to silo charging hopper

Two 30' x 80' silos with mass flow hoppers

Vibrating pan feeders and covered conveyors from silos to fuel distribution facilities of boilers

- Limestone Receiving and Storing

Screened granular limestone, fully prepared for FBC charging (approximately 1/8" particle size), is received by truck and pneumatically unleaded to silo

Limestone storage: single silo with 10-days storage capacity

Facilities include:

Pneumatic unloading system

Single silo - 500 tons capacity with twin cone bottom
Silo is provided with conventional dust-prevention system for pneumatic receipt of solids.

Vibrating pan feeders and covered conveyors from silo to fuel distribution facilities of boilers.

Limestone for slurry flue gas scrubbing use is received and stored as crushed stone (2 1/2" maximum size), and wet-milled to 325 mesh en route to the scrubber system.

C. BOILERS AND STACK

Steam demand is assumed at 100 k lbs/onstream hour to industrial process, with year-round 90% load factor. Steam conditions 125 psig, saturated.

Condensate collection/feed water treating system supplies deaerated feed water at 200°F.

To assure continuity of steam supply, two 100 KPPH boilers are installed (alternatively could provide 3 x 50 KPPH units, at somewhat lower investment cost but with higher space requirements, piping, manning and maintenance costs).

Efficiency of all boilers is assumed to be 82%. Flue gas temperature from economizer outlet is assumed at 350°F. No air preheaters.

- Oil-Fired Boilers
  Two 100 KPPH complete package watertube boilers
- Conventional Coal-Fired Boilers
  Two 100 KPPH complete spreader stoker field-erected watertube boilers, with fly ash reinjection
- Coal-Fired Fluidized Bed Boilers

  Two 100 KPPH FBC shop-assembled watertube boilers, with complete facilities as follows:

  Coal and limestone metering and feeding systems to multiple fuel injection points of boilers

  FD/ID fans and drivers

  Steam generators (with main combustor cells, carbon burnup cell (CBC), water wall and submerged steam tubing, economizer sections, plenum and air distribution grid, cyclone-type dust collectors on flue gas streams from main combustor cells and carbon burnup cell, oil-fired ignition system, bed drain system).

  Controls, flues, ducts
- Stack

  Common stack, ground-supported, carbon steel, 8' diameter x 75' high with self-supporting liner of regular firebrick

As noted, the investment comparisons are based on boiler outlet conditions of 125 psig, saturated. Many industrial boilers generate steam at significantly higher pressures and temperatures. We estimate that the boiler portion of project investments should be multiplied by the following factors to reflect the increased capital requirement for generating steam at higher pressures:

Steam Conditions	125 psig Saturated	600 psig 750°F	1300 psig 900°F
Oil-Fired Package Boilers	1.0	1.15	1.33
Coal-Fired Conventional Boilers	1.0	1.12	1.27
Coal-Fired FBC Boilers	1.0	1.07	1.16

D. ENVIRONMENTAL CONTROLS

Firing rate in all cases is lower than 250 M Btu/hr., so no Federal emission standards are currently applicable. Nevertheless, each case is designed to meet EPA New Source Standards For Steam Generating

Equipment of 250 M Btu/hr. or greater, as follows:

	Oil Fuel	Solid Fuel
Particulates		
Opacity	- - - No. 1 Ringelmann (20% opacity)- - -	
Emissions, lb/M Btu	0.1	0.1
SO_2, lb/M Btu	0.8	1.2
NOx, lb/M Btu (as NO_2)	0.3	0.7

Low sulfur fuel oil requires no controls.
If high sulfur fuel oil is used, it requires flue gas desulfurization (FGDS). For this study, we would assume use of once-through limestone slurry scrubbing, producing scrubber sludge dewatered to 50% solids.

Low sulfur coal fired in a spreader stoker requires an electrostatic precipitator (ESP) to meet particulate standards.

High sulfur coal fired in a spreader stoker requires flue gas desulfurization. For this study, we assume once-through limestone slurry scrubbing, producing scrubber sludge dewatered to 50% solids. The scrubber effluent exhibits better than standard particulate loading (estimated at .05 lbs/M Btu vs. standard of 0.1 lbs/M Btu).

For all the above conventional boilers, NOx emissions will be close to the limiting standard. To insure meeting the standard, boiler design modifications may be required so as to carry out combustion in a mode which minimizes NOx formation.

High sulfur coal fired in an FBC boiler only requires adjustment of the limestone/coal ratio to meet the SO_2 emission standard. Effluent from the FBC boiler is comfortably better than standard with respect to NOx. An electrostatic precipitator (ESP) is provided to meet the particulate emission standard.

In each grass roots case, required environmental control facilities are provided with each of the two 100 KPPH boilers, so that each "train" of equipment can be operated independently.

E. SOLID WASTE COLLECTION, STORAGE, DISPOSAL

Sludge from scrubbers, dewatered to 50% solids via rotary vacuum filter, is dumped via conveyor to covered sludge pit (assuming that plant does not have land for long-term ponding of sludge and ash). Sludge is hauled away by truck.

In high sulfur coal case with stoker, ash is also sent via conveyor to sludge pit and mixed with sludge.

In FBC and low sulfur coal cases, where no sludge is produced, dry wastes (fly ash from ESP's, and pit ash from stoker or ash/sulfated stone mixture from FBC) are pneumatically transferred to dry waste silo and hauled away by truck. Silo has seven days storage capacity, and is elevated,with "Hydromix" loader for loading to disposal trucks.

In all cases, solids handling systems are designed to minimize discharge of contaminants (dust, sump drains, etc.).

F. EXCLUSIONS

Land

Unusual site preparation (clear, level site assumed)

Boiler feed water (BFW) treating facilities

BFW pumps

Blowdown system

Steam distribution system

These facilities are common to all cases, and are not included in any of the investment estimates.

Allowances for Boiler Feed Water costs have been included in the operating cost calculations, and these allowances include a typical capital charge for a boiler feed water system.

2. OPERATING COST BASES

Manpower cost (salaries/wages and benefits) is 20 k$/yr/man

Electric power cost is 4¢/KWH

Limestone cost, delivered, is $12 per ton for FBC use. It is assumed that the total cost of coarse crushed stone plus wet grinding for use in the flue gas scrubber cases is also approximately $12 per ton.

Waste solids disposal cost (sludge, ash, sulfated limestone from FBC) is $8/ton

Annual repair materials cost is 1 1/2% of investment

Annual cost for supplies, local taxes, administrative expense, general expense is 3% of investment

Annual capital charges, covering cost of capital invested in these facilities (including interest, effect of depreciation on income taxes, and other investment-related charges) is taken at 20% of investment.*

Treated and deaerated boiler feed water cost (at 200°F), including 50% purchased makeup water and 50% condensate return from process operations, is assumed at $0.60 per k lbs. steam (includes effect of about 10% blowdown).

When a new boiler is added to an existing boiler system, it is assumed that the new boiler is base-loaded and operates at capacity with an overall availability of 90%.

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* Pope Evans & Robbins in their 1970 comparison of conventional and FBC economics used a 20% capital charge; Westinghouse in 1971 and Battelle in 1974 used 16.7%.

3. CHARACTERISTICS OF ASSUMED FUELS

Fuel	Fuel Characteristics
Low Sulfur Fuel Oil	15° API (0.966 spec. gr.) 18,600 Btu/lb. HHV Sulfur content just meets 0.8 lb SO_2/M Btu ($\sim$ 0.7 wt%S)
High Sulfur Coal	Illinois No. 6 3.6 wt%S 8.0 wt% ash 16.9 wt% moisture 10,600 Btu/lb HHV
Low Sulfur Coal	Wyoming 0.4 wt%S 5.8 wt% ash 30.0 wt% moisture 8,150 Btu/lb HHV

4. EXPONENTS USED TO ESTIMATE INDUSTRIAL BOILER PLANT INVESTMENTS BASED ON 100 KPPH BASE CASES

$$I = KC^n$$

Type of Facility	Capacity Range, KPPH Steam	Exponent "n"
Oil-Fired Fuel Receiving/ Storing/Feeding	50-100	0.6
	100-400	0.6
Coal-Fired Fuel Receiving/ Storing/Feeding	50-100	0.3
	100-400	0.3
Packaged Oil-Fired Boilers	50-100	0.65
	100-400	0.65
Coal-Fired Spreader Stoker Boilers	50-100	0.75
	100-200	0.75
Pulverized-Coal-Fired Boilers	200-400	0.75
FBC Boilers	50-100	0.65
	100-400	0.65
Solids Waste Collection/Disposal including Electrostatic Precipitators	50-100	0.7
	100-400	0.7
Limestone Slurry Flue Gas Scrubbers	50-100	0.65
	100-400	0.7

APPENDIX 2

DESCRIPTION OF SCREENING QUALITY INVESTMENT ESTIMATES

The investments we have developed for use in the economic comparison of alternative boiler systems are of "screening quality." In putting together these screening numbers, our aim is to develop the cost level for a system which will meet the overall process objectives, making reasonable general engineering assumptions as we go along. The usual purposes of such screening estimates are:

- to analyze alternatives on a consistent basis, and
- to quickly eliminate those which are clearly unattractive;
- to lay the groundwork for more definitive comparison of the remaining alternatives;
- to establish a reasonable order-of-magnitude for the absolute cost of a real project; and
- to identify major areas of concern (technical or economic) which should be studied in depth in subsequent R&D and/or project planning.

Screening estimates for new technologies or processes are widely used for guidance of Research and Development activities, although they are not of adequate quality to be used as a basis for making final investment decisions for specific projects.

The main objective of this part of the work is to compare the economics of fluidized bed combustion with alternative industrial boiler cases. Since fluidized bed combustion is as yet uncommercialized, we could only obtain this type of screening estimate by working with boiler manufacturers who are engaged in exploratory FBC studies themselves. The same approach was used for estimates involving conventional boiler technology.

Appendix 1 shows the components which were included in building up these estimates. We believe all are self explanatory except for brief discussions regarding contingency level, and inclusion of a process development allowance for new technology.

For screening estimates at this very early stage of project definition, we recommend, and have used, a contingency level of 20%. As project activities continue and the basis for a cost estimate becomes more detailed and defined, the contingency level is correspondingly reduced, eventually to the level of 8-10% (just prior to construction of a real project).

Fluidized bed combustion is a developing, as yet non-commercialized technology. A process development allowance, based on prior general experience with such new process applications, represents additional hardware/equipment/materials of construction which may become necessary as problems are identified during detailed design, construction, and startup of a project utilizing the newly-developing technology. Experience has taught that costs are usually underestimated at this early stage in the development of new technologies. Generally the pattern has been that estimates of costs increase as the estimates become progressively more detailed prior to construction of the first, full-scale commercial plant that incorporates the new technology. In an attempt to take this pattern into account for the fluidized bed boiler, we have included in our screening estimates a process development allowance of 20% of the portion of the FBC system which is considered to be susceptible to these developmental problems. In similar fashion, in the case of conventional combustion of high sulfur fuels, a smaller allowance of 10% is included for appropriate sections of the industrial-sized flue gas scrubber systems which are just now becoming commercialized. As a real project proceeds from initial screening to a definitive cost estimate and then to detailed design, the process development allowance becomes progressively smaller while identified costs increase.

In Appendix 3, which presents the screening estimates for the cases we have developed, the amounts ascribed to "contingency" and "process development allowance" are specifically broken out and identified for the convenience of the user.

The question of the possible range (optimistic or pessimistic) around such screening estimates has been raised. Very little actual statistical experience can be brought to bear on this question, because of the many basis changes which occur in practically all real project histories. However, we have tried to estimate the span of optimism/pessimism we would expect could be applied to Exxon's typical screening estimates, and conclude that the optimistic level is not likely to be more than 10% below the quoted level; conversely, the pessimistic range is likely to be as much as 20-25% above the quoted figure.

APPENDIX 3

DETAILED TABULATION OF INVESTMENT AND OPERATING COST ESTIMATES

APPENDIX 3

TABLE 1

BREAKDOWN AND COMPARISON OF INVESTMENTS FOR
GRASS-ROOTS INDUSTRIAL BOILER SYSTEMS (STEAM DEMAND = 100 KPPH)

Fuel	High Sulfur Coal				Low Sulfur "Compliance" Coal				Low Sulfur Fuel Oil	
Fired in	Fluidized Bed Boiler		Conventional Stoker		Fluidized Bed Boiler		Conventional Stoker		Package Boiler	
External SO_2 Control	Not Needed		Limestone Scrubber		Not Needed		Not Needed		Not Needed	
Particulate Control	Electrostatic Precip.		Scrubber		Electrostatic Precip.		Electrostatic Precip.		Not Needed	
INVESTMENTS, M$ (1)										
Fuel Receiving, Storing, Feeding Allowance		1.5		1.5		1.6		1.6		0.5
Limestone Receiving, Storing, Feeding		0.3		0.3		0.1 (3)		-		-
Boilers (2 @ 100 k lb/hr) (2)	2 @ 2.0	4.0	2 @ 2.1	4.2	2 @ 2.0	4.0	2 @ 2.1	4.2	2 @ 0.95	1.9
Stack		0.3		0.3		0.3		0.3		0.3
Electrostatic Precipitators	2 @ 0.45	0.9		-	2 @ 0.45	0.9	2 @ 0.45	0.9		-
Flue Gas Scrubber Systems		-	2 @ 1.6	3.2		-		-		-
Solid Waste Collection, Storage, Disposal	Silo	0.4	Pit	0.2	Silo	0.4	Silo	0.4		-
Sub-Total (Before Contingency)		7.4		9.7		7.3		7.4		2.7
Contingency @ 20%		1.5		1.9		1.5		1.5		0.5
Process Development Allowance										
For Scrubbers		-		0.2		-		-		-
For FBC Boilers		0.6		-		0.6		-		-
TOTAL INVESTMENT, M$		9.5		11.8		9.4		8.9		3.2

(1) Investments expressed in 1st Q 1975 Dollars for project located at U.S. Gulf Coast.

(2) Boiler pressure is 125 psig, saturated steam. See Appendix 1 for approximate variation of boiler cost with steam generation pressure.

(3) Limestone may not be used in an FBC boiler firing low sulfur compliance coal, but some facilities will be required to receive, store, and feed the bed makeup material.

APPENDIX 3

TABLE 2

SCREENING INVESTMENTS FOR GRASS ROOTS
FLUIDIZED BED HIGH-SULFUR-COAL-FIRED BOILER SYSTEMS (1)

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Investments, M$ (2)				
Fuel Receiving, Storing, Feeding Allowance	1.8	1.5	2.2	2.7
2 FBC Boilers, Common Stack (3)	5.8	3.7	9.1	14.3
Precipitators, Ash/ Sulfated Stone Collection, Storage, Loading	1.9	1.2	3.1	5.0
Total	9.5	6.4	14.4	22.0

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) FBC Boiler investments represent current state of technology; investments also include 20% "process development" allowance (2 x 0.3 M $ for base case) on commercially-undemonstrated sections.

APPENDIX 3

TABLE 3

SCREENING INVESTMENTS FOR GRASS-ROOTS
CONVENTIONAL HIGH-SULFUR-COAL-FIRED BOILER SYSTEMS WITH FLUE GAS DESULFURIZATION (1)

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Investments, M$ (2)				
Fuel Receiving, Storing, Feeding Allowance	1.8	1.5	2.2	2.7
2 Boilers, Common Stack	5.4	3.2	9.5 (4)	16.0 (4)
2 Flue Gas Scrubbers (3), Sludge and Ash Storage/ Loading	4.6	2.9	7.5	12.2
Total	11.8	7.6	19.2	30.9

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) Scrubber investments include 10% "process-development" allowance (2 x 0.1 M $ for base case) on critical sections.
(4) Boilers for 200 KPPH and higher are assumed to be Pulverized Coal Fired (PCF) units. At 200 KPPH size, PCF boiler investment is assumed 5% higher than for corresponding stoker boiler.

APPENDIX 3

TABLE 4

SCREENING INVESTMENTS FOR GRASS ROOTS
FLUIDIZED BED LOW-SULFUR-COAL-FIRED BOILER SYSTEMS (1)

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Investments, M$ (2)				
Fuel Receiving, Storing, Feeding Allowance	1.9	1.5	2.3	2.9
2 FBC Boilers, Common Stack (3)	5.8	3.7	9.1	14.3
Precipitators, Ash Collection, Storage, Loading (4)	1.7	1.0	2.8	4.5
Total	9.4	6.2	14.2	21.7

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) FBC Boiler investments represent current state of technology; investments also include 20% "process development" allowance (2 x 0.3 M $ for base case) on commercially undemonstrated sections.
(4) Includes small allowance for facilities to store and handle inert bed material.

APPENDIX 3

TABLE 5

SCREENING INVESTMENTS FOR GRASS-ROOTS
CONVENTIONAL LOW-SULFUR-COAL-FIRED BOILER SYSTEMS (1) (2)

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Investments, M$ (3)				
Fuel Receiving, Storing, Feeding Allowance	1.9	1.5	2.3	2.9
2 Boilers, Common Stack	5.4	3.2	9.5 (4)	16.0 (4)
Precipitators, Ash Collection, Storage, Loading	1.6	1.0	2.6	4.2
Total	8.9	5.7	14.4	23.1

(1) 1975 level, U.S. Gulf Coast location.
(2) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.
(3) Investments include 20% contingency.
(4) Boilers for 200 KPPH and higher are assumed to be Pulverized Coal Fired (PCF) units. At 200 KPPH size, PCF boiler investment is assumed to be 5% higher than for corresponding stoker boiler.

APPENDIX 3

TABLE 6

SCREENING INVESTMENTS FOR GRASS-ROOTS
LOW-SULFUR-OIL-FIRED PACKAGE BOILER SYSTEMS (1)

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Investments, M$ (2)				
Fuel Receiving, Storing, Feeding	0.6	0.4	0.9	1.4
2 Boilers, Common Stack	2.6	1.7	4.1	6.4
Total	3.2	2.1	5.0	7.8

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.

APPENDIX 3

TABLE 7

UNIT OPERATING COSTS (EX FUEL) FOR GRASS ROOTS FLUIDIZED BED HIGH-SULFUR-COAL-FIRED BOILER SYSTEMS

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Costs, ¢/k lbs. steam (ex fuel)				
Wages, Salaries, Benefits	56	103	31	18
Repair Materials	18	24	14	10
Utilities	25	25	25	25
Limestone	27	27	27	27
Supplies, Local Taxes, Admin. Exp., etc.	36	49	27	21
Ash/Sulfated Stone Disposal	18	18	18	18
Sub-total Direct Op. costs	180	246	142	119
Capital Charges	241	325	183	140
BFW	60	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	481	631	385	319

APPENDIX 3

TABLE 8

UNIT OPERATING COSTS (EX FUEL) FOR GRASS ROOTS
CONVENTIONAL HIGH-SULFUR-COAL-FIRED BOILER SYSTEMS WITH FLUE GAS DESULFURIZATION

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Costs, ¢/k lbs. steam (ex fuel)				
Wages, Salaries, Benefits	76	141	42	24
Repair Materials	22	29	18	15
Utilities	30	30	34	34
Limestone	11	11	11	11
Supplies, Local Taxes Admin. Exp., etc.	45	58	36	29
Ash/Sludge Disposal	22	22	22	22
Sub-total Direct Op. costs	206	291	163	135
Capital Charges	299	385	243	196
BFW	60	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	565	736	466	391

APPENDIX 3

TABLE 9

UNIT OPERATING COSTS (EX FUEL) FOR GRASS ROOTS FLUIDIZED BED LOW-SULFUR-COAL-FIRED BOILER SYSTEMS (1)

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Costs, ¢/k lbs. steam (ex fuel)				
Wages, Salaries, Benefits	56	101	31	19
Repair Materials	18	24	13	10
Utilities	25	25	25	25
Limestone	-	-	-	-
Bed Makeup Material	- - - - - - - - - negligible - - - - - -			
Supplies, Local Taxes, Admin. Exp., etc.	36	47	27	21
Ash Disposal	4	4	4	4
Sub-total Direct Op. Costs	139	201	100	79
Capital Charges	238	314	180	137
BFW	60	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	437	575	340	276

(1) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.

APPENDIX 3

TABLE 10

UNIT OPERATING COSTS (EX FUEL) FOR GRASS ROOTS
CONVENTIONAL LOW-SULFUR-COAL-FIRED BOILER SYSTEMS (1)

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Costs, ¢/k lbs. steam (ex fuel)				
Wages, Salaries, Benefits	53	98	30	17
Repair Materials	17	22	14	11
Utilities	13	13	17	17
Supplies, Local Taxes, Admin. Exp., etc.	34	43	27	22
Ash Disposal	4	4	4	4
Sub-total Direct Op. costs	121	180	92	71
Capital Charges	226	289	183	147
BFW	60	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	407	529	335	278

(1) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.

APPENDIX 3

TABLE 11

UNIT OPERATING COSTS (EX FUEL) FOR GRASS ROOTS LOW-SULFUR-OIL-FIRED PACKAGE BOILER SYSTEMS

	Base Case	Derivative Cases		
Steam Requirement, k lbs/hr.	100	50	200	400
Costs, ¢/k lbs. steam (ex fuel)				
Wages, Salaries, Benefits	38	71	21	12
Repair Materials	6	8	5	4
Utilities	21	21	21	21
Supplies, Local Taxes, Admin. Exp., etc.	12	16	9	7
Sub-total Direct Op. costs	77	116	56	44
Capital Charges	81	106	63	49
BFW	60	60	60	60
Total cost, ¢/k lbs. (ex fuel)	218	282	179	153

APPENDIX 3

TABLE 12

BREAKDOWN AND COMPARISON OF INVESTMENTS FOR
ADDING A SINGLE 100 KPPH BOILER TO EXISTING COAL-FIRED BOILER PLANT

Fuel	High Sulfur Coal (2)		Low Sulfur "Compliance" Coal (3)		Low Sulfur Fuel Oil
Fired in	Fluidized Bed Boiler	Conventional Stoker	Fluidized Bed Boiler	Conventional Stoker	Package Boiler
External SO_2 Control	Not Needed	Limestone Scrubber	Not Needed	Not Needed	Not Needed
Particulate Control	Electrostatic Precip.	Scrubber	Electrostatic Precip.	Electrostatic Precip.	Not Needed
INVESTMENTS, M$ (1)					
Fuel Receiving, Storing, Feeding Additions	0.5	0.2	0.5	0.2	
Limestone Receiving, Storing, Feeding Additions	0.1	0.1	0.1 (4)	-	THIS CASE NOT CONSIDERED APPLICABLE
Boiler	2.0	2.1	2.0	2.1	
Stack	0.3	0.3	0.3	0.3	
Electrostatic Precipitator	0.45	-	0.45	0.45	
Flue Gas Scrubber System	-	1.6	-	-	
Solid Waste Collection, Storage, Disposal	Silo 0.4	0.1	0.2	0.1	
Sub-Total (Before Contingency)	3.75	4.4	3.55	3.15	
Contingency @ 20%	0.75	0.9	0.75	0.65	
Process Development Allowance					
For Scrubber	-	0.1	-	-	
For FBC Boiler	0.3	-	0.3	-	
TOTAL INVESTMENT, M$	4.8	5.4	4.6	3.8	

(1) Investments expressed in 1st Q 1975 Dollars for project located at U.S. Gulf Coast.
(2) These cases are based on the assumption that high sulfur coal is being fired in the existing boilers.
(3) These cases are based on the assumption that low sulfur compliance coal is being fired in the existing boilers.
(4) Limestone may not be used in an FBC boiler firing low sulfur compliance coal, but some facilities will be required to receive, store, and feed the bed makeup material.

APPENDIX 3

TABLE 13

SCREENING INVESTMENTS FOR ADDING A SINGLE
FLUIDIZED BED HIGH-SULFUR-COAL-FIRED BOILER TO EXISTING COAL-FIRED BOILER PLANT (1) (4)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (2)			
Fuel Receiving, Storing, Feeding Additions	0.6	0.7	0.9
FBC Boiler, Stack (3)	3.1	4.9	7.6
Precipitator, Ash/ Sulfated Stone Collection, Storage, Loading	1.1	1.8	2.9
Total	4.8	7.4	11.4

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) FBC Boiler investment represents current state of technology; investment also includes 20% "process development" allowance (0.3 M $ for base case) on commercially-undemonstrated sections.
(4) Large-size high sulfur coal assumed to be fired in existing boilers.

APPENDIX 3

TABLE 14

SCREENING INVESTMENTS FOR ADDING A SINGLE CONVENTIONAL HIGH-SULFUR-COAL-FIRED BOILER WITH FLUE GAS DESULFURIZATION TO EXISTING COAL-FIRED BOILER PLANT (1) (5)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (2)			
Fuel Receiving, Storing, Feeding Additions	0.2	0.2	0.3
Boiler, Stack	2.9	5.1 (4)	8.6 (4)
Flue Gas Scrubber (3), Sludge and Ash Storage/ Loading	2.3	3.7	6.1
Total	5.4	9.0	15.0

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) Scrubber investment includes 10% "process development" allowance (0.1 M $ for base case) on critical sections.
(4) Boilers for 200 KPPH and higher are assumed to be Pulverized Coal Fired (PCF) units. At 200 KPPH size, PCF boiler investment is assumed 5% higher than for corresponding stoker boiler.
(5) High sulfur coal assumed to be fired in existing boilers.

APPENDIX 3

TABLE 15

SCREENING INVESTMENTS FOR ADDING A SINGLE FLUIDIZED BED LOW-SULFUR-COAL-FIRED BOILER TO EXISTING CONVENTIONAL LOW-SULFUR-COAL-FIRED BOILER PLANT (1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (2)			
Fuel Receiving, Storing, Feeding Additions	0.6	0.7	0.9
FBC Boiler, Stack (3)	3.1	4.9	7.6
Precipitator, Ash/Inert Bed Material Handling and Storage	0.9	1.5	2.4
Total	4.6	7.1	10.9

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) FBC Boiler investment represents current state of technology; investment also includes 20% "process development" allowance (0.3 M $ for base case) on commercially-undemonstrated sections.
(4) Large-size low sulfur compliance coal assumed to be fired in existing boilers.

APPENDIX 3

TABLE 16

SCREENING INVESTMENTS FOR ADDING A SINGLE CONVENTIONAL LOW-SULFUR-COAL-FIRED BOILER TO EXISTING COAL-FIRED BOILER PLANT (1) (2) (5)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (3)			
Fuel Receiving, Storing, Feeding Additions	0.2	0.2	0.3
Boiler, Stack	2.9	5.1 (4)	8.6 (4)
Precipitator, Ash Collection, Storage, Loading	0.7	1.1	1.8
Total	3.8	6.4	10.7

(1) 1975 level, U.S. Gulf Coast location.
(2) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.
(3) Investments include 20% contingency.
(4) Boilers for 200 KPPH and higher are assumed to be Pulverized Coal Fired (PCF) units. At 200 KPPH size, PCF boiler investment is assumed to be 5% higher than for corresponding stoker boiler.
(5) Low sulfur coal assumed to be fired in existing boilers.

APPENDIX 3

TABLE 17

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE FLUIDIZED BED HIGH-SULFUR-COAL-FIRED BOILER TO EXISTING COAL-FIRED BOILER PLANT

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	28	15	9
Repair Materials	9	7	5
Utilities	25	25	25
Limestone	27	27	27
Supplies, Local Taxes, Admin. Exp., etc.	18	14	11
Ash/Sulfated Stone Disposal	18	18	18
Sub-Total Direct Op. Costs	125	106	95
Capital Charges	122	94	72
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	307	260	227

APPENDIX 3

TABLE 18

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE
CONVENTIONAL HIGH-SULFUR-COAL-FIRED BOILER WITH FLUE GAS DESULFURIZATION
TO EXISTING COAL-FIRED BOILER PLANT

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	38	21	12
Repair Materials	10	9	7
Utilities	30	34	34
Limestone	11	11	11
Supplies, Local Taxes, Admin. Exp., etc.	20	17	14
Ash/Sludge Disposal	22	22	22
Sub-Total Direct Op. Costs	131	114	100
Capital Charges	137	114	95
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	328	288	255

APPENDIX 3

TABLE 19

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE FLUIDIZED BED LOW-SULFUR-COAL-FIRED BOILER TO EXISTING CONVENTIONAL LOW-SULFUR-COAL-FIRED BOILER PLANT (1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	28	15	9
Repair Materials	9	7	5
Utilities	25	25	25
Limestone	-	-	-
Bed Makeup Material	- - - - - - - negligible - - - - -		
Supplies, Local Taxes, Admin. Exp., etc.	17	14	10
Ash Disposal	4	4	4
Sub-Total Direct Op. Costs	83	65	53
Capital Charges	117	90	69
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	260	215	182

(1) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.

APPENDIX 3

TABLE 20

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE CONVENTIONAL LOW-SULFUR-COAL-FIRED BOILER TO EXISTING COAL-FIRED BOILER PLANT(1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	25	14	9
Repair Materials	7	6	5
Utilities	13	17	17
Supplies, Local Taxes, Admin. Exp., etc.	15	12	10
Ash Disposal	4	4	4
Sub-Total Direct Op. Costs	64	53	45
Capital Charges	96	81	68
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	220	194	173

(1) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.

APPENDIX 3

TABLE 21

BREAKDOWN AND COMPARISON OF INVESTMENTS FOR
ADDING A SINGLE 100 KPPH BOILER TO EXISTING OIL-FIRED BOILER PLANT

Fuel	High Sulfur Coal		Low Sulfur "Compliance" Coal		Low Sulfur Fuel Oil
Fired in	Fluidized Bed Boiler	Conventional Stoker	Fluidized Bed Boiler	Conventional Stoker	Package Boiler
External SO_2 Control	Not Needed	Limestone Scrubber	Not Needed	Not Needed	Not Needed
Particulate Control	Electrostatic Precip.	Scrubber	Electrostatic Precip.	Electrostatic Precip.	Not Needed
INVESTMENTS, M $ (1)					
Fuel Receiving, Storing, Feeding Additions	1.5	1.5	1.6	1.6	0.1
Limestone Receiving, Storing, Feeding Additions	0.3	0.3	0.1 (2)	-	-
Boiler	2.0	2.1	2.0	2.1	0.95
Stack	0.3	0.3	0.3	0.3	0.3
Electrostatic Precipitator	0.45	-	0.45	0.45	-
Flue Gas Scrubber System	-	1.6	-	-	-
Solid Waste Collection, Storage, Disposal	0.4	0.2	0.4	0.4	-
Sub-Total (Before Contingency)	4.95	6.0	4.85	4.85	1.35
Contingency @ 20%	0.95	1.2	0.95	0.95	0.25
Process Development Allowance					
For Scrubber	-	0.1	-	-	-
For FBC Boiler	0.3	-	0.3	-	-
TOTAL INVESTMENT, M $	6.2	7.3	6.1	5.8	1.6

(1) Investments expressed in 1st Q 1975 Dollars for project located at U.S. Gulf Coast.
(2) Limestone may not be used in an FBC boiler firing low sulfur compliance coal, but some facilities will be required to receive, store, and feed the bed makeup material.

APPENDIX 3

TABLE 22

SCREENING INVESTMENTS FOR ADDING A SINGLE
FLUIDIZED BED HIGH-SULFUR-COAL-FIRED BOILER TO EXISTING OIL-FIRED BOILER PLANT (1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (2)			
Fuel Receiving, Storing, Feeding Allowance	1.8	2.2	2.7
FBC Boiler, Stack (3)	3.1	4.9	7.6
Precipitator, Ash/ Sulfated Stone Collection, Storage, Loading	1.3	2.1	3.4
Total	6.2	9.2	13.7

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) FBC Boiler investment represents current state of technology; investment also includes 20% "process development" allowance (0.3 M $ for base case) on commercially-undemonstrated sections.

APPENDIX 3

TABLE 23

SCREENING INVESTMENTS FOR ADDING A SINGLE
CONVENTIONAL HIGH-SULFUR-COAL-FIRED BOILER WITH FLUE GAS DESULFURIZATION
TO EXISTING OIL-FIRED BOILER PLANT (1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (2)			
Fuel Receiving, Storing, Feeding Allowance	1.8	2.2	2.7
Boiler, Stack	2.9	5.1 (4)	8.6 (4)
Flue Gas Scrubber (3), Sludge and Ash Storage/ Loading	2.6	4.2	6.9
Total	7.3	11.5	18.2

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) Scrubber investment includes 10% "process development" allowance (0.1 M $ for base case) on critical sections.
(4) Boilers for 200 KPPH and higher are assumed to be Pulverized Coal Fired (PCF) units. At 200 KPPH size, PCF boiler investment is assumed 5% higher than for corresponding stoker boiler.

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TABLE 24

SCREENING INVESTMENTS FOR ADDING A SINGLE FLUIDIZED BED LOW-SULFUR-COAL-FIRED BOILER TO EXISTING OIL-FIRED BOILER PLANT (1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (2)			
Fuel Receiving, Storing, Feeding Allowance	1.9	2.3	2.9
FBC Boiler, Stack (3)	3.1	4.9	7.6
Precipitator, Ash/Inert Bed Material Handling and Storage	1.1	1.8	2.9
Total	6.1	9.0	13.4

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.
(3) FBC Boiler investment represents current state of technology; investment also includes 20% "process development" allowance (0.3 M $ for base case) on commercially-undemonstrated sections.

APPENDIX 3

TABLE 25

SCREENING INVESTMENTS FOR ADDING A SINGLE
CONVENTIONAL LOW-SULFUR-COAL-FIRED BOILER
TO EXISTING OIL-FIRED BOILER PLANT (1) (2)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (3)			
Fuel Receiving, Storing, Feeding Allowance	1.9	2.3	2.9
Boiler, Stack	2.9	5.1 (4)	8.6 (4)
Precipitator, Ash Collection, Storage, Loading	1.0	1.6	2.6
Total	5.8	9.0	14.1

(1) 1975 level, U.S. Gulf Coast location.
(2) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.
(3) Investments include 20% contingency.
(4) Boilers for 200 KPPH and higher are assumed to be Pulverized Coal Fired (PCF) units. At 200 KPPH size, PCF boiler investment is assumed to be 5% higher than for corresponding stoker boiler.

APPENDIX 3

TABLE 26

SCREENING INVESTMENTS FOR ADDING A SINGLE LOW-SULFUR-OIL-FIRED PACKAGE BOILER TO EXISTING OIL-FIRED BOILER PLANT (1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Investments, M$ (2)			
Fuel Receiving, Storing, Feeding Additions	0.1	0.1	0.2
Boiler, Stack	1.5	2.4	3.7
Total	1.6	2.5	3.9

(1) 1975 level, U.S. Gulf Coast location.
(2) Investments include 20% contingency.

APPENDIX 3

TABLE 27

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE FLUIDIZED BED HIGH-SULFUR-COAL-FIRED BOILER TO EXISTING OIL-FIRED BOILER PLANT

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	36	21	12
Repair Materials	12	9	7
Utilities	25	25	25
Limestone	27	27	27
Supplies, Local Taxes, Admin. Exp., etc.	24	17	13
Ash/Sulfated Stone Disposal	18	18	18
Sub-Total Direct Op. Costs	142	117	102
Capital Charges	157	116	87
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	359	293	249

APPENDIX 3

TABLE 28

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE
CONVENTIONAL HIGH-SULFUR-COAL-FIRED BOILER WITH FLUE GAS DESULFURIZATION
TO EXISTING OIL-FIRED BOILER PLANT

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	45	25	15
Repair Materials	14	11	9
Utilities	30	34	34
Limestone	11	11	11
Supplies, Local Taxes Admin. Exp., etc.	28	22	17
Ash/Sludge Dispsoal	22	22	22
Sub-Total Direct Op. Costs	150	125	108
Capital Charges	185	146	115
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	395	331	283

APPENDIX 3

TABLE 29

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE FLUIDIZED BED LOW-SULFUR-COAL-FIRED BOILER TO EXISTING OIL-FIRED BOILER PLANT (1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	36	21	12
Repair Materials	12	9	6
Utilities	25	25	25
Limestone	-	-	-
Bed Makeup Material	- - - - - - - - - neglible - - - - - -		
Supplies, Local Taxes, Admin. Exp., etc.	23	17	13
Ash Disposal	4	4	4
Sub-Total Direct Op. Costs	100	76	60
Capital Charges	155	114	85
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	315	250	205

(1) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.

APPENDIX 3

TABLE 30

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE CONVENTIONAL LOW-SULFUR-COAL-FIRED BOILER TO EXISTING OIL-FIRED BOILER PLANT(1)

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	33	19	11
Repair Materials	11	9	7
Utilities	13	17	17
Supplies, Local Taxes, Admin. Exp., etc.	22	17	13
Ash Disposal	4	4	4
Sub-Total Direct Op. Costs	83	66	52
Capital Charges	147	114	89
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	290	240	201

(1) Sulfur content of coal assumed sufficiently low that flue gas desulfurization is not required.

APPENDIX 3

TABLE 31

UNIT OPERATING COSTS (EX FUEL) FOR ADDING A SINGLE
LOW-SULFUR-OIL-FIRED PACKAGE BOILER TO EXISTING OIL-FIRED BOILER PLANT

	Base Case	Derivative Cases	
Steam Requirement, k lbs/hr.	100	200	400
Costs, ¢/k lbs. steam (ex fuel)			
Wages, Salaries, Benefits	18	10	6
Repair Materials	3	2	2
Utilities	19	19	19
Supplies, Local Taxes, Admin. Exp., etc.	6	5	4
Sub-Total Direct Op. Costs	46	36	31
Capital Charges	41	32	25
BFW	60	60	60
Total Cost, ¢/k lbs. (ex fuel)	147	128	116

APPENDIX 4

TABULATED DATA DERIVED FROM FEA'S NATURAL GAS TASK FORCE AND MFBI SURVEYS

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*based on data from Natural Gas Task Force survey.

*based on data from Natural Gas Task Force survey.

APPENDIX 4

TABLE 1

CAPACITY AND FUEL CONSUMPTION PROFILES OF LARGE INDUSTRIAL BOILERS

Size Range Million BTU/H	Number of Boilers: Units	Number of Boilers: % of Total	Number of Boilers: Σ%	Fuel Consumption* in 1974: 10^{14} BTU	Fuel Consumption* in 1974: % of Total	Fuel Consumption* in 1974: Σ%	Per Boiler 10^{12} BTU
1000 +	20	0.5	0.5	1.10	2.8	2.8	5.50
900 - 999	5	0.1	0.6	0.144	0.4	3.2	2.88
800 - 899	17	0.4	1.0	0.643	1.6	4.8	3.78
700 - 799	31	0.8	1.8	1.05	2.7	7.5	3.38
600 - 699	47	1.2	3.0	1.42	3.6	11.1	3.06
500 - 599	77	2.0	5.0	2.27	5.7	16.8	2.95
450 - 499	71	1.8	6.8	1.60	4.0	20.8	2.25
400 - 449	98	2.5	9.3	2.13	5.4	26.2	2.18
350 - 399	152	3.9	13.2	2.63	6.7	32.9	1.73
300 - 349	191	4.9	18.1	3.10	7.9	40.8	1.62
250 - 299	327	8.4	26.5	4.28	10.8	51.6	1.31
200 - 249	473	12.1	38.6	4.93	12.4	64.0	1.04
150 - 199	917	23.4	62.0	6.51	16.4	80.4	0.71
100 - 149	1487	38.0	100.	7.77	19.6	100.	0.52
Total	3913	100.		39.6	100.		1.01

Summary

Slightly more than half of the capacity is in the 200+ million BTU/H size range.
Approximately one third of the capacity is in the 350+ million BTU/H size range.
Approximately 17% of the capacity is in the 500+ million BTU/H size range.

*Coal, oil, and natural gas; does not include "other" fuels such as black liquor.

Source: FEA MFBI Survey, Report No. 22

APPENDIX 4

TABLE 2

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY FOOD INDUSTRY (SIC 20)

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974: Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	1	-	-	1.95	2.0	1.0	1.0
900 - 999	-	-	-	-	-	-	1.0
800 - 899	-	-	-	-	-	-	1.0
700 - 799	-	-	-	-	-	-	1.0
600 - 699	-	-	-	-	-	-	1.0
500 - 599	-	-	-	-	-	-	1.0
450 - 499	-	-	-	-	-	-	1.0
400 - 449	-	-	-	-	-	-	1.0
350 - 399	5	107	55	7.1	10.0	5.2	6.2
300 - 349	11	478	275	4.1	16.7	8.6	14.8
250 - 299	14	209	3208	9.2	34.2	17.7	32.5
200 - 249	29	344	307	6.2	15.9	8.2	40.7
150 - 199	75	343	1251	26.0	42.0	21.7	62.4
100 - 149	175	407	4137	37.1	72.7	37.6	100.
Total	310	1888	9233	91.6	193.	100.	

*Coal, oil and natural gas; does not include "other" fuels such as bagasse.

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 3

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY PAPER INDUSTRY (SIC 26)

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974 Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	3	134	54	0.08	3.4	0.6	0.6
900 - 999	-	-	-	-	-	-	0.6
800 - 899	6	-	1424	2.3	11.3	1.9	2.5
700 - 799	10	284	2234	10.5	31.2	5.3	7.8
600 - 699	15	180	3198	5.7	30.0	5.0	12.8
500 - 599	21	438	2685	16.0	43.0	7.3	20.1
450 - 499	11	198	2151	5.4	23.5	4.0	24.1
400 - 449	22	658	1183	15.3	37.8	6.4	30.5
350 - 399	19	535	2526	5.2	33.2	5.6	36.1
300 - 349	37	467	2142	26.7	51.2	8.6	44.7
250 - 299	43	541	4598	15.7	56.6	9.6	54.3
200 - 249	67	160	6128	36.7	79.5	13.4	67.7
150 - 199	115	1116	5918	25.5	88.3	14.9	82.6
100 - 149	184	811	8315	33.0	103.0	17.4	100.
Total	553	5522	42556	198.1	593.	100.	

*Coal, oil and natural gas; does not include "other" fuel such as black liquor and bark.

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 4

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY CHEMICALS INDUSTRY (SIC 28)

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974 Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	3	-	40	10.5	10.9	1.2	1.2
900 - 999	1	-	150	-	0.9	0.1	1.3
800 - 899	3	268	-	12.2	18.5	2.0	3.3
700 - 799	1	230	-	-	5.2	0.6	3.4
600 - 699	1	-	-	4.4	4.5	0.5	4.4
500 - 599	17	1048	1237	23.7	55.4	6.0	10.4
450 - 499	10	269	7	23.9	30.5	3.2	13.6
400 - 449	19	197	273	35.5	42.3	4.6	18.2
350 - 399	31	455	2228	35.2	60.2	6.5	24.7
300 - 349	46	908	1421	43.7	73.9	8.0	32.7
250 - 299	97	1248	2286	84.5	128.0	13.8	46.5
200 - 249	143	1876	3285	113.8	179.0	19.4	65.9
150 - 199	187	1470	6401	88.4	163.0	17.6	83.5
100 - 149	255	863	5863	95.4	153.0	16.5	100.
Total	814	8832	23191	571.4	926.	100.	

*Coal, oil and natural gas; does not include "other" fuels (such as black liquor in paper industry).

Source: FEA MFBI Survey, Report No. 24 A

APPENDIX 4

TABLE 5

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY PETROLEUM REFINING AND COAL PRODUCTS INDUSTRY (SIC 29)

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974 Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	-	-	-	-	-	-	-
900 - 999	-	-	-	-	-	-	-
800 - 899	2	-	-	10.4	10.6	1.8	1.8
700 - 799	3	-	309	8.8	10.9	1.9	3.7
600 - 699	22	-	2810	74.3	93.3	15.9	19.6
500 - 599	11	-	273	44.3	46.9	8.0	27.6
450 - 499	17	-	541	36.7	40.7	6.9	34.5
400 - 449	14	-	1187	23.7	31.6	5.4	39.9
350 - 399	31	-	95	70.1	72.0	12.3	52.2
300 - 349	25	-	867	44.1	50.3	8.6	60.8
250 - 299	43	528	1552	39.9	62.3	10.6	71.4
200 - 249	61	-	2537	47.6	64.5	11.0	82.4
150 - 199	59	228	1747	36.4	53.2	9.0	91.4
100 - 149	76	28	1940	37.1	50.3	8.6	100.
Total	364	784	13858	473.4	587.	100.	

*Coal, oil and natural gas; does not include "other fuels" (such as black liquor in the paper industry).

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 6

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY STONE, CLAY, GLASS, AND CONCRETE PRODUCTS INDUSTRY (SIC 32)

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974: Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	-	-	-	-	-	-	-
900 - 999	-	-	-	-	-	-	-
800 - 899	-	-	-	-	-	-	-
700 - 799	-	-	-	-	-	-	-
600 - 699	-	-	-	-	-	-	-
500 - 599	-	-	-	-	-	-	-
450 - 499	-	-	-	-	-	-	-
400 - 449	-	-	-	-	-	-	-
350 - 399	-	-	-	-	-	-	-
300 - 349	1	-	53	0.34	0.07	3.5	3.5
250 - 299	2	-	40	1.16	1.43	7.4	10.9
200 - 249	4	-	109	1.44	2.15	11.1	22.0
150 - 199	12	49	750	1.60	7.45	38.6	60.6
100 - 149	19	2	872	2.05	7.60	39.4	100.
Total	38	51	1824	6.6	19.3	100.	

*Coal, oil and natural gas; does not include "other" fuels (e.g. black liquor in paper industry).

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 7

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY PRIMARY METALS INDUSTRY (SIC 33)

		Fuel Consumption* in 1974					
Size Range Million BTU/H	Number of Boilers	Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	4	269	65	5.15	11.7	2.6	2.6
900 - 999	3	145	272	6.74	11.8	2.7	5.3
800 - 899	6	832	-	5.63	24.5	5.5	10.8
700 - 799	8	527	246	7.61	21.1	4.8	15.6
600 - 699	5	189	19	7.62	12.2	2.8	18.4
500 - 599	10	324	214	1.90	10.6	2.4	20.8
450 - 499	17	1179	42	8.44	35.5	8.0	28.8
400 - 449	20	1511	679	5.70	44.2	10.0	38.8
350 - 399	23	270	875	7.59	19.3	4.3	43.1
300 - 349	33	414	247	49.03	60.9	13.7	56.8
250 - 299	21	68	502	12.68	17.6	4.0	60.8
200 - 249	58	638	840	39.64	60.0	13.5	74.3
150 - 199	74	640	1053	34.87	56.5	12.8	87.1
100 - 149	99	1247	1741	17.93	57.4	12.9	100.
Total	381	8253	6795	210.5	443.	100.	

*Coal, oil and natural gas; does not include "other" fuels (such as black liquor in paper industry).

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 8

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS
USED BY FABRICATED METAL PRODUCTS INDUSTRY (SIC 34)

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974: Coal 1000 Tons	Oil 100 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	-	-	-	-	-	-	-
900 - 999	1	-	150	-	0.94	1.6	1.6
800 - 899	-	-	-	-	-	-	1.6
700 - 799	1	-	208	0.05	1.36	2.3	3.9
600 - 699	1	12	-	-	0.27	0.4	4.3
500 - 599	4	448	68	-	10.5	17.4	21.7
450 - 499	-	-	-	-	-	-	-
400 - 449	-	-	-	-	-	-	-
350 - 399	-	-	-	-	-	-	-
300 - 349	4	-	24	0.4	0.56	0.9	22.6
250 - 299	18	300	144	2.8	10.5	17.4	40.0
200 - 249	3	23	-	-	0.52	0.9	40.9
150 - 199	14	192	418	2.6	9.6	15.9	56.8
100 - 149	55	297	2117	6.2	26.1	43.2	100.
Total	101	1272	3129	12.1	60.5	100.	

*Coal, oil and natural gas; does not include "other" fuels (such as blast furnace gas in steel industry).

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 9

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY MACHINERY (NON-ELECTRICAL) INDUSTRY (SIC 35)

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974					
		Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	-	-	-	-	-	-	-
900 - 999	-	-	-	-	-	-	-
800 - 899	-	-	-	-	-	-	-
700 - 799	-	-	-	-	-	-	-
600 - 699	-	-	-	-	-	-	-
500 - 599	-	-	-	-	-	-	-
450 - 499	-	-	-	-	-	-	-
400 - 449	3	-	-	8.4	8.6	17.3	17.3
350 - 399	-	-	-	-	-	-	17.3
300 - 349	1	-	58	-	0.3	0.7	18.0
250 - 299	6	34	-	9.0	9.9	20.0	38.0
200 - 249	6	106	328	1.5	5.9	12.0	50.0
150 - 199	22	82	164	5.8	8.8	17.6	67.0
100 - 149	63	92	842	8.7	16.1	32.4	100.
Total	101	314	1392	33.4	49.7	100.	

*Coal, oil and natural gas; does not include "other" fuels (such as blast furnace gas in steel industry).

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 10

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY ELECTRICITY, GAS, AND SANITARY SERVICES INDUSTRY (SIC 49)

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974 Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	5**	2343	238	-	54.4	54.9	54.9
900 - 999	-	-	-	-	-	-	54.9
800 - 899	-	-	-	-	-	-	54.9
700 - 799	-	-	-	-	-	-	54.9
600 - 699	-	-	-	-	-	-	54.9
500 - 599	1	-	159	-	1.0	1.0	55.9
450 - 499	1	-	-	0.04	0.04	negl.	55.9
400 - 449	3	-	357	-	2.2	2.3	58.2
350 - 399	4	-	664	-	4.2	4.2	62.4
300 - 349	2	31	-	3.23	4.0	4.0	66.4
250 - 299	-	-	-	-	-	-	66.4
200 - 249	10	14	152	5.34	4.7	4.7	71.1
150 - 199	41	49	2037	3.88	17.6	17.8	88.9
100 - 149	39	76	830	4.02	11.0	11.1	100.
Total	106	2513	4437	14.6	99.1	100.	

*Coal, oil and natural gas; does not include "other" fuels (such as carbon monoxide in petroleum refining industry).

**it is possible that these 5 boilers are electric utility, not industrial, boilers. Note that 93% of the coal consumption by SIC 49 is attributable to these 5 boilers.

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 11

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS USED BY MANUFACTURING INDUSTRIES OTHER THAN SIC 20, 26, 28, 29, 32, 33, 34, 35 and 49

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974 Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	4**	2100	57	0.07	47.8	7.0	7.0
900 - 999	-	-	-	-	-	-	7.0
800 - 899	-	-	-	-	-	-	7.0
700 - 799	3	-	1397	0.65	9.4	1.4	8.4
600 - 699	3	110	765	0.41	7.7	1.1	9.5
500 - 599	7	286	1065	5.37	18.6	2.7	12.2
450 - 499	8	377	371	7.68	18.6	2.7	14.9
400 - 449	8	475	1757	4.10	25.9	3.8	18.7
350 - 399	26	903	3576	6.55	49.5	7.3	26.0
300 - 349	21	386	1491	11.46	29.7	4.4	30.4
250 - 299	46	657	3786	11.30	50.1	7.4	37.8
200 - 249	63	402	3640	25.64	57.4	8.5	46.3
150 - 199	254	2230	7201	50.56	146.0	21.5	67.8
100 - 149	412	1548	12665	102.30	218.0	32.2	100.
Total	855	9474	37771	226.1	681.	100.	

*Coal, oil and natural gas; does not include "other" fuels (such as acid sludge in chemicals industry).

**it is questionable whether these 4 boilers are actually industrial boilers. The 1974 fuel consumption data indicate that these 4 boilers have an average steam generation capacity equivalent to a heat input of at least 1.3 billion BTU/H, which would be more typical of electric utility boilers.

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 12

NUMBER AND FUEL CONSUMPTION OF LARGE BOILERS FOR WHICH NO SIC CODE WAS SPECIFIED IN FEA'S MFBI SURVEY

Size Range Million BTU/H	Number of Boilers	Fuel Consumption* in 1974: Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	-	-	-	-	-	-	-
900 - 999	-	-	-	-	-	-	-
800 - 899	-	-	-	-	-	-	-
700 - 799	5	-	3223	3.8	24.0	6.6	6.6
600 - 699	-	-	-	-	-	-	-
500 - 599	6**	-	5156	7.8	37.8	10.5	17.1
450 - 499	7	-	457	8.0	11.0	3.0	20.1
400 - 449	9	-	925	11.3	17.3	4.8	24.9
350 - 399	13	145	266	11.5	16.6	4.6	29.5
300 - 349	12	376	708	13.7	26.9	7.4	36.9
250 - 299	37	491	2651	42.2	70.7	19.5	56.4
200 - 249	31	542	890	18.7	36.7	10.1	66.5
150 - 199	64	763	2771	22.1	57.2	15.9	82.4
100 - 149	110	1002	2792	22.9	63.5	17.6	100.
Total	294	3319	19839	162.1	362.	100.	

*Coal, oil and natural gas; does not include "other fuels" (such as waste heat derived from combustion of catalyst coke in petroleum refining).

**the fuel consumption data imply that these 6 boilers were operated at 120% capacity throughout 1974 -- or else that the fuel consumption data are in error.

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 13

NUMBER AND FUEL CONSUMPTION OF ALL* LARGE INDUSTRIAL BOILERS INCLUDED IN FEA'S MFBI SURVEY

		Fuel Consumption** in 1974					
Size Range Million BTU/H	Number of Boilers	Coal 1000 Tons	Oil 1000 BBLS	Gas Billion CF	Total Trillion BTU	% of Total	Σ%
1000 +	11	403	159	17.6	28.0	0.7	0.7
900 - 999	5	145	572	6.7	13.7	0.4	1.1
800 - 899	17	1100	1417	30.6	64.5	1.7	2.8
700 - 799	31	1041	7617	31.5	103.3	2.6	5.4
600 - 699	47	491	6792	92.5	148.0	3.8	9.2
500 - 599	77	2544	10857	99.1	224.0	5.7	14.9
450 - 499	71	2023	3569	90.2	160.0	4.1	19.0
400 - 449	98	2841	6361	104.2	210.0	5.4	24.4
350 - 399	152	2415	10285	143.3	265.0	6.8	31.2
300 - 349	193	3060	7286	196.7	315.0	8.1	39.3
250 - 299	327	4076	18767	228.5	442.0	11.3	50.6
200 - 249	475	4105	18216	294.7	506.0	12.9	63.5
150 - 199	917	7162	29711	297.7	651.0	16.6	80.1
100 - 149	1487	6378	42114	366.7	780.0	19.9	100.
Total	3908	37779	163730	2000.	3908.	100.	

*except for 5 boilers in SIC 49 and 4 boilers in "other SIC's" that appear to be wrongly coded electric utility boilers.

**coal, oil and natural gas; does not include "other" fuels (such as black liquor in the paper industry).

Source: FEA MFBI Survey, Report No. 24A

APPENDIX 4

TABLE 14

APPARENT UTILIZATION OF LARGE BOILERS IN 1974

Size Range M BTU/H	Food SIC 20	Paper SIC 26	Chemicals SIC 28	Pet. Ref. SIC 29	Ceramics SIC 32	P. Metals SIC 33	F. Metals SIC 34	Equip. SIC 35	U. Services SIC 49	Other SIC's	Not Specif.	Total
	% of Theoretical Boiler Utilization in 1974 Based on Consumption of Coal, Oil & Natural Gas*											
1000 +	22	12	40	-	-	32	-	-	119ϕ	130ϕ	-	28ϕϕ
900-999	-	-	11	-	-	47	11	-	-	-	-	33
800-899	-	25	83	71	-	55	-	-	-	-	-	51
700-799	-	48	79	55	-	40	21	-	-	48	73	51
600-699	-	35	79	75	-	43	48	-	-	45	-	55
500-599	-	43	68	91	-	22	55	-	21	55	131ϕ	61
450-499	-	52	73	58	-	50	-	-	1	56	38	54
400-449	-	46	60	61	-	60	-	77	20	87	52	58
350-399	61	52	59	71	-	26	-	-	32	58	39	53
300-349	53	49	57	71	24	65	5	12	71	50	79	58
250-299	60	55	55	61	30	35	24	69	-	46	80	56
200-249	28	61	64	54	28	53	9	51	24	47	61	55
150-199	37	51	57	59	41	50	45	26	28	38	59	47
100-149	39	52	56	62	37	54	45	24	26	50	54	49
Arithmetic average utilization of all boilers in 100-899 Million BTU/H size range												
	46	47	66	66	32	46	32	43	28	53	54**	54
Fuel Consumption (coal, oil and natural gas; does not include "other" fuels)												
10^{12} BTU's	193	593	926	587	19	443	61	50	45	633	362	3912
% of Total	4.9	15.2	23.7	15.0	0.5	11.3	1.5	1.3	1.2	16.2	9.2	100.

*does not include the consumption of "other" fuels (by-product fuels) such as black liquor, bagasse, catalyst coke, etc.
ϕdata appear questionable
ϕϕexcluding questionable data in SIC 49 and "other SIC's"
**correcting for questionable data in "SIC not specified"

APPENDIX 4

TABLE 15

1974 FUEL CONSUMPTION OF LARGE INDUSTRIAL BOILERS BY SIZE RANGE AND SIC CODE

	Aggregate 1974 Fuel Consumption, 10^{12} BTU						
Size Range 10^6 BTU/H	100/149	150/199	200/299	300/399	400/499	500+	Total
SIC 20	70.2	41.4	49.2	26.4	NIL	2.1	189
SIC 26	105.0	91.5	137.0	86.1	62.9	120.0	604
SIC 28	152.0	166.0	299.0	140.0	59.9	93.0	912
SIC 29	47.9	46.5	118.0	112.0	82.2	156.0	563
SIC 32	7.3	7.4	3.6	0.6	NIL	NIL	19
SIC 331/2	44.3	49.5	67.4	34.1	72.9	96.1	364
SIC 333/9	8.2	5.7	10.6	49.2	10.3	6.5	91
Other SIC's	280.0	181.0	134.0	83.7	57.0	127.0	864
Not Spec.	62.3	57.2	104.0	41.0	28.3	63	356
Total	778	647	926	573	373	664	3962

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 16

TOTAL CAPACITY OF LARGE INDUSTRIAL
BOILERS BY SIZE RANGE AND SIC CODE

Size Range, 10^6 BTU/H SIC Code/Industry		Aggregate Boiler Capacity, 10^9 BTU/H						
		100/149	150/199	200/299	300/399	400/499	500+	Total
20	Food	21.7	12.8	11.0	5.4	--	3.1	53.9
26	Paper	23.4	20.4	31.6	21.0	16.7	49.8	162.8
28	Chemicals	33.7	33.8	59.7	30.1	10.9	19.5	187.8
29	Petroleum Refining	9.8	9.5	26.1	20.0	15.4	24.8	105.7
32	Stone, Clay, Glass, Concrete	2.3	2.3	1.5	0.3	--	--	6.4
331/332	Blast Furnaces/I & S Foundries	9.7	12.6	17.5	14.0	13.0	26.9	93.7
333/339	Other Primary Metals	2.0	1.4	2.6	6.3	1.8	0.7	14.7
Other SIC's		73.0	60.0	40.2	20.9	11.9	31.5	237.5
No SIC Code Specified		14.9	12.4	19.6	9.5	7.9	7.8	72.0
		190.6	165.2	209.5	127.5	77.7	164.1	934.7
Subtotal as % of Total		20.4	17.7	22.4	18.6	8.3	17.6	100

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 17

NUMBER OF LARGE INDUSTRIAL
BOILERS BY SIZE RANGE AND SIC CODE

Size Range, 10^6 BTU/H		100/149	150/199	200/299	300/399	400/499	500+	Subtotal	% of Grand Total
SIC 20	Number	184	76	47	16	--	3	326	7.8
	% of Subtotal	56.5	23.3	14.4	4.9	--	0.9	100	
SIC 26	Number	194	119	132	62	38	68	613	14.6
	% of Subtotal	31.7	19.4	21.5	10.1	6.2	11.1	100	
SIC 28	Number	272	197	247	89	25	28	858	20.4
	% of Subtotal	31.6	23.0	28.8	10.4	2.9	3.3	100	
SIC 29	Number	81	55	108	58	35	39	376	9.0
	% of Subtotal	21.5	14.6	28.8	15.4	9.3	10.4	100	
SIC 32	Number	19	13	6	1	--	--	39	0.9
	% of Subtotal	48.7	33.3	15.4	2.6	--	--	100	
SIC 331/332	Number	79	73	76	40	30	38	336	8.0
	% of Subtotal	23.6	21.7	22.6	11.9	8.9	11.3	100	
SIC 333/339	Number	17	8	10	19	4	1	59	1.4
	% of Subtotal	28.8	13.6	16.9	32.2	6.8	1.7	100	
Other SIC's	Number	611	352	168	60	27	35	1253	29.9
	% of Subtotal	48.8	28.1	13.4	4.8	2.1	2.8	100	
Not Spec.	Number	126	73	79	28	18	12	336	8.0
	% of Subtotal	37.5	21.7	23.5	8.3	5.4	3.6	100	
Totals	Number	1583	966	873	373	177	224	4196	100
	% of Subtotal	37.8	23.0	20.8	8.9	4.2	5.3	100	--

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 18

1974 FUEL CONSUMPTION OF LARGE INDUSTRIAL BOILERS BY REGION AND TYPE OF FUEL USED

Region	1974 Fuel Consumption, 10^{12} BTU						% of
	Coal	Resid	Dist.	Gas	Other	Total	Lower 48
New England	NIL	95.1	NIL	3.4	6.2	104	2.67
Appalachian	412	305	8.0	152	67.7	946	24.32
Southeast	190	159	4.1	113	88.4	555	14.27
Great Lakes	248	61.4	48.1	169	57.3	584	15.01
Northern Plains	27.6	3.4	2.1	42.7	2.4	78.1	2.00
Midcontinent	6.2	0.03	1.5	60.5	1.4	69.6	1.79
Gulf Coast	34.1	76.2	1.2	1050	49.5	1210	31.10
Rocky Mountains	36.9	26.5	1.5	59.6	0.4	125	3.21
Pacific S.W.	2.5	10.3	0.9	99.5	10.1	123	3.16
Pacific N.W.	8.3	11.8	0.1	70.0	5.6	95.9	2.47
	966	747	68	1820	289	3890	100

Percent Breakdown of Fuel Consumption Within Regions

New England	NIL	90.9	NIL	3.2	5.9
Appalachian	43.6	32.3	0.8	16.1	7.2
Southeast	34.3	28.7	0.7	20.4	15.9
Great Lakes	42.5	10.5	8.2	29.0	9.8
Northern Plains	35.3	4.3	2.7	54.6	3.1
Midcontinent	8.9	negl	2.2	86.9	2.0
Gulf Coast	2.8	6.3	0.1	86.7	4.1
Rocky Mountains	29.5	21.2	1.2	47.8	0.3
Pacific S.W.	2.0	8.4	0.7	80.7	8.2
Pacific N.W.	8.7	12.3	0.1	73.1	5.8
Lower 48 States	24.8	19.2	1.8	46.8	7.4

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 19

AGGREGATE CAPACITY OF LARGE INDUSTRIAL BOILERS BY REGION AND BY PRIMARY FUEL FIRED

Region	Aggregate Boiler Capacity, 10^9 BTU/H: Coal	Resid	Dist.	Gas	Other	Total	% Of Lower 48
New England	NIL	22.6	NIL	1.0	2.6	26.2	2.85
Appalachian	83.3	74.3	4.9	43.0	35.5	241.0	26.17
Southeast	35.6	36.1	2.2	28.5	45.1	147.6	16.03
Great Lakes	52.7	19.0	6.4	44.5	24.6	147.2	15.98
Northern Plains	5.6	1.1	1.1	10.1	0.4	18.3	1.99
Midcontinent	2.1	0.3	0.4	14.6	2.8	20.2	2.19
Gulf Coast	4.3	13.7	0.2	184.7	27.1	230.0	24.98
Rocky Mountain	7.5	2.4	0.6	12.8	0.9	24.2	2.63
Pacific S.W.	1.6	2.2	0.4	26.7	4.7	35.6	3.86
Pacific N.W.	3.8	3.4	0.1	15.3	8.0	30.6	3.32
	196.5	175.1	16.3	381.3	151.7	920.9	100

Percentage Distribution of Capacity Within Regions by Primary Fuel Used in 1974

Region	Coal	Resid	Dist.	Gas	Other
New England	NIL	86.2	NIL	3.8	10.0
Appalachian	34.7	30.8	2.0	17.8	14.7
Southeast	24.1	24.5	1.5	19.4	30.5
Great Lakes	35.9	12.9	4.3	30.2	16.7
Northern Plains	30.6	6.0	6.0	55.2	2.2
Midcontinent	10.4	1.5	2.0	72.2	13.9
Gulf Coast	1.9	6.0	0.1	80.2	11.8
Rocky Mountain	31.0	9.9	2.5	52.9	3.7
Pacific S.W.	4.5	6.2	1.0	75.0	13.2
Pacific N.W.	12.4	11.1	0.3	50.0	26.2
Lower 48 States	21.3	19.0	1.8	41.4	16.4

Source: Natural Gas Task Force Summary

APPENDIX 4

TABLE 20

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN LOWER 48 STATES BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC	Coal		Resid		Dist.		Nat. Gas		Other		Total		Aver.
Code	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap	No.	Cap.	Size
20	69	12.6	46	6.3	11	1.5	190	31.4	6	1.3	322	53.1	165
26	93	21.2	169	42.4	8	1.3	174	37.5	167	60.2	611	162.5	266
28	182	41.7	140	25.4	11	1.8	472	105.3	42	10.3	847	184.5	218
29	7	1.7	62	16.4	--	--	273	78.5	22	7.2	364	103.7	285
32	4	0.6	13	2.1	1	0.1	17	2.9	4	0.6	39	6.4	164
331/2	127	38.2	15	2.4	3	0.5	38	10.8	153	41.8	336	93.7	279
333/9	6	1.1	15	2.8	--	--	32	9.2	6	1.6	59	14.7	249
Other	306	66.4	331	61.6	43	7.3	458	76.4	76	19.5	1214	231.3	191
N.S.	78	13.2	71	15.8	13	3.8	130	29.3	38	9.0	330	72.2	219
Total	872	196.7	862	175.1	90	16.3	1784	381.4	514	151.5	4122	921.1	223

NOTES: "No." refers to the number of large industrial boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^9 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers, expressed in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.
Data for Alaska, Hawaii, Puerto Rico and Virgin Islands are tabulated separately and are not included above.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 21

INSTALLED CAPACITY OF LARGE INDUSTRIAL
BOILERS IN NEW ENGLAND BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC Code	Coal		Resid		Dist.		Nat. Gas		Other		Total		Aver. Size
	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	
20	--	--	6	830	--	--	1	105	--	--	7	935	134
26	--	--	27	6178	--	--	1	101	4	951	32	7230	226
28	--	--	14	2556	--	--	--	--	--	--	14	2556	183
29	--	--	--	--	--	--	--	--	--	--	--	--	--
32	--	--	2	398	--	--	--	--	--	--	2	398	199
331/2	--	--	3	375	--	--	--	--	--	--	3	375	128
333/9	--	--	4	722	--	--	2	390	--	--	2	1112	185
Other	--	--	52	10471	--	--	3	398	5	1032	60	11901	198
N.S.	--	--	7	1107	--	--	--	--	3	600	10	1707	171
Total	--	--	115	22637	--	--	7	12	12	2583	134	26214	196

NOTES: "No." refers to the number of large industrial boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 22

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN
APPALACHIAN REGION BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC	Coal		Resid		Dist.		Nat. Gas		Other		Total		Aver.
Code	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	Size
20	5	539	23	3553	3	436	28	3496	--	--	59	8024	136
26	41	10336	51	10219	8	1251	16	2717	20	780	136	31603	232
28	99	21736	80	14468	2	255	51	9628	3	368	235	46455	198
29	2	211	23	4569	-	--	21	7393	7	2027	53	14200	218
32	4	633	9	1399	1	121	12	1918	4	648	30	4719	157
331/2	72	21993	4	650	-	--	13	2025	87	23068	176	47736	271
333/9	2	370	9	1433	-	--	3	300	--	--	14	2103	150
Other	109	21462	163	30855	17	2484	61	12842	9	2344	359	69987	195
N.S.	36	6061	38	7195	2	310	13	2701	--	--	89	16267	183
Total	370	83341	400	74341	33	4857	218	43020	130	35535	1151	241094	209

NOTES: "No." refers to the number of large industrial boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 23

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS SOUTHEAST BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC Code	Coal		Resid		Dist.		Nat. Gas		Other		Total		Aver. Size
	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	
20	--	--	8	866	--	--	6	869	5	1052	19	2787	147
26	23	5985	56	17639	--	--	27	7193	73	27932	179	58749	328
28	60	14376	31	5170	2	560	45	8803	13	4063	151	32972	218
29	--	--	--	--	--	--	--	--	--	--	--	--	--
32	--	--	--	--	--	--	--	--	--	--	--	--	--
331/2	8	1672	--	--	--	--	--	--	3	469	11	2141	195
333/9	--	--	--	--	--	--	--	--	--	--	--	--	--
Other	58	12991	60	10140	8	1619	49	7750	26	8995	201	41495	206
N.S.	4	898	9	2328	--	--	15	3936	9	2590	37	9452	255
Total	153	35622	164	36143	10	2179	142	28551	129	45101	598	147596	247

NOTES: "No." refers to the number of large industrial boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 24

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN GREAT LAKES REGION BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC	Coal		Resid		Dist.		Nat. Gas		Other		Total		Aver.
Code	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	Size
20	18	3807	7	818	2	210	32	4981	--	--	59	9816	166
26	24	4153	7	979	--	--	34	5946	9	2092	74	13170	178
28	11	1724	6	1083	1	142	29	4475	3	854	50	8278	166
29	5	1480	30	8500	--	--	4	1237	9	2791	48	14008	292
32	--	--	2	280	--	--	3	768	--	--	5	1048	210
331/2	31	11122	8	1330	3	530	23	8551	54	15338	119	36871	310
333/9	1	108	--	--	--	--	--	--	6	1577	7	1685	241
Other	118	25517	25	4118	14	2591	96	14850	3	490	256	47566	186
N.S.	25	4767	8	1848	8	2974	19	3734	5	1433	65	14736	227
Total	233	52658	93	18956	28	6447	240	44542	89	24575	683	147178	215

NOTES: "No." refers to the number of large individual boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 25

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN NORTHERN PLAINS REGION BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC Code	Coal No.	Coal Cap.	Resid No.	Resid Cap.	Dist. No.	Dist. Cap.	Nat. Gas No.	Nat. Gas Cap.	Other No.	Other Cap.	Total No.	Total Cap.	Aver. Size
20	20	3504	-	--	5	748	19	2983	-	--	44	7235	164
26	5	694	2	388	-	--	17	3362	-	--	24	4444	185
28	--	--	-	--	-	--	3	330	-	--	3	330	110
29	--	--	3	625	-	--	-	--	-	--	3	625	208
32	--	--	-	--	-	--	-	--	-	--	--	--	--
331/2	--	--	-	--	-	--	-	--	-	--	--	--	--
333/9	--	--	-	--	-	--	-	--	-	--	--	--	--
Other	9	1446	1	115	1	150	18	3050	1	360	30	5121	171
N.S.	--	--	-	--	1	173	2	394	-	--	3	567	189
Total	34	5644	6	1128	7	1071	59	10119	1	360	107	18322	171

NOTES: "No." refers to the number of large individual boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 26

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN MIDCONTINENT REGION BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC Code	Coal		Resid		Dist.		Nat. Gas		Other		Total		Aver. Size
	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	
20	4	600	1	107	1	144	9	1687	-	--	15	2538	169
26	-	--	-	--	-	--	2	246	3	2249	5	2495	499
28	5	921	1	235	2	275	9	1367	-	--	17	2798	165
29	-	--	-	--	-	--	27	4851	1	364	28	5215	186
32	-	--	-	--	-	--	-	--	-	--	--	--	--
331/2	-	--	-	--	-	--	2	212	-	--	2	212	106
333/9	-	--	-	--	-	--	-	--	-	--	--	--	--
Other	4	614	-	--	-	--	39	5609	1	138	44	6361	145
N.S.	-	--	-	--	-	--	5	650	-	--	5	650	130
Total	13	2135	2	342	3	419	98	14622	5	2751	116	20269	175

NOTES: "No." refers to the number of large individual boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 27

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN GULF COAST REGION BY SIC CODE AND BY PRIMARY FUEL USED IN 1974

SIC	Coal		Resid		Dist.		Nat. Gas		Other		Total		Av.
Code	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	Size
20	-	-	-	-	-	-	21	5404	1	215	22	5619	255
26	-	-	20	5834	-	-	33	8136	41	15069	94	29039	309
28	-	-	6	1461	-	-	325	79164	23	5035	354	85660	242
29	-	-	6	2708	-	-	169	53736	2	619	177	57063	322
32	-	-	-	-	-	-	-	-	-	-	-	-	-
331/2	-	-	-	-	-	-	-	-	2	450	2	450	225
333/9	-	-	-	-	-	-	18	5430	-	-	18	5430	302
Other	4	3644	8	1524	-	-	110	19894	16	2946	138	28008	203
N. S.	3	636	3	2124	1	243	42	12921	11	2734	67	18658	278
Total	7	4280	43	13651	1	243	725	184685	96	27068	872	229927	264

NOTES: "No." refers to the number of large individual boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Av. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 28

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN ROCKY MOUNTAIN REGION BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC	Coal		Resid		Dist.		Nat. Gas		Other		Total		Aver.
Code	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	Size
20	7	1178	1	100	-	--	16	3022	-	--	24	4300	179
26	--	--	--	--	-	--	1	280	1	190	2	470	235
28	4	1916	--	--	1	152	7	1186	-	--	12	3254	271
29	--	--	--	--	-	--	3	615	-	--	3	615	205
32	--	--	--	--	-	--	--	--	-	--	--	--	--
331/2	16	3453	--	--	-	--	--	--	-	--	16	3453	216
333/9	--	--	--	--	-	--	7	2649	-	--	7	2649	378
Other	4	757	9	1351	2	319	23	2947	1	100	39	5474	140
N.S.	1	240	4	905	1	102	11	2112	3	565	20	3920	196
Total	32	7544	14	2356	4	573	68	12811	5	855	123	24139	196

NOTES: "No." refers to the number of large individual boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 29

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN PACIFIC SOUTHWEST REGION BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC	Coal		Resid		Dist.		Nat. Gas		Other		Total		Av.
Code	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	Size
20	-	-	-	-	-	-	48	7684	-	-	48	7684	160
26	-	-	-	-	-	-	12	2212	2	396	14	2608	186
28	3	1024	2	472	3	416	1	160	-	-	9	2070	230
29	-	-	-	-	-	-	45	9599	2	1260	47	10839	231
32	-	-	-	-	-	-	2	236	-	-	2	236	118
331/2	-	-	-	-	-	-	-	-	7	2500	7	2500	357
333/9	3	619	2	651	-	-	2	438	-	-	7	1708	244
Other	-	-	3	888	-	-	33	4802	1	304	37	5994	162
N. S.	-	-	1	180	-	-	8	1549	1	300	10	2029	203
Total	6	1643	8	2191	3	416	151	266680	13	4740	181	35668	197

NOTES: "No." refers to the number of large individual boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Av. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Survey

APPENDIX 4

TABLE 30

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN PACIFIC NORTHWEST REGION BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC	Coal		Resid		Dist.		Nat. Gas		Other		Total		Aver.
Code	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	Size
20	15	2932	--	--	-	--	10	1181	--	--	25	4113	165
26	--	--	6	1195	-	--	31	7259	14	4211	51	12665	248
28	--	--	--	--	-	--	2	216	--	--	2	216	108
29	--	--	--	--	-	--	4	1020	1	112	5	1132	226
32	--	--	--	--	-	--	--	--	--	--	--	--	--
331/2	--	--	--	--	-	--	--	--	--	--	--	--	--
333/9	--	--	--	--	-	--	--	--	--	--	--	--	--
Other	--	--	10	2104	1	112	26	4307	13	2837	50	9360	187
N.S.	9	900	1	100	-	--	8	1352	6	820	24	3172	132
Total	24	3832	17	3399	1	112	81	15335	34	7980	157	30658	195

NOTES: "No." refers to the number of large individual boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Aver. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Force Survey

APPENDIX 4

TABLE 31

INSTALLED CAPACITY OF LARGE INDUSTRIAL BOILERS IN ALASKA, HAWAII, PUERTO RICO, AND VIRGIN ISLANDS BY SIC CODE AND PRIMARY FUEL USED IN 1974

SIC Code	Coal		Resid		Dist.		Nat. Gas		Other		Total		Av. Size
	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	No.	Cap.	
20	-	-	1	220	-	-	-	-	3	671	4	891	223
26	-	-	-	-	-	-	-	-	2	340	2	340	170
28	-	-	8	2783	-	-	3	433	-	-	11	3216	292
29	-	-	4	685	4	525	4	815	-	-	12	2025	169
32	-	-	-	-	-	-	-	-	-	-	-	-	-
331/2	-	-	-	-	-	-	-	-	-	-	-	-	-
333/9	-	-	-	-	-	-	-	-	-	-	-	-	-
Other	27	3960	-	-	-	-	8	1180	4	1125	39	6265	161
N. S.	-	-	2	266	-	-	4	621	-	-	6	887	148
Total	27	3960	15	3954	4	525	19	3049	9	2136	74	13624	184

NOTES: "No." refers to the number of large individual boilers in each category.
"Cap." refers to the aggregate capacity of the pertinent group of boilers in 10^6 BTU/H.
"Av. Size" refers to the aggregate capacity divided by the number of boilers in 10^6 BTU/H.
"N.S." denotes SIC Code not specified.

Source: Natural Gas Task Survey

APPENDIX 4

TABLE 32

REGIONAL VARIATIONS IN AVERAGE SIZE OF LARGE INDUSTRIAL BOILERS BY SIC CODE

Region	Average Boiler Size, 10^6 BTU/H									Number of Large Boilers
	20	26	28	29	32	331/2	333/9	Other	All	
New England	134	226	183	---	199	128	185	198	196	134
Appalachian	136	232	198	268	157	271	150	195	209	1151
Southeast	147	328	218	---	---	195	---	206	247	598
Great Lakes	166	178	166	292	210	310	241	186	215	683
Northern Plains	164	185	110	208	---	---	---	171	171	107
Midcontinent	169	499	165	186	---	106	---	145	175	116
Gulf Coast	255	309	242	322	---	225	302	203	264	872
Rocky Mountain	179	235	271	205	---	216	378	140	196	123
Pacific Southwest	160	186	230	231	118	357	244	162	197	181
Pacific Northwest	165	248	108	226	---	---	---	187	195	157
Lower 48 States	165	266	218	285	164	279	249	191	223	4122

Source: Calculated from data reported in Natural Gas Task Force Survey

APPENDIX 4

TABLE 33

NUMBER OF LARGE INDUSTRIAL BOILERS BY SIZE RANGE AND 1974 FUEL CONSUMPTION FOR ELEMENTS OF THE FOOD INDUSTRIES

SIC 201 Meat Products

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTU
100-149	8	3.4
150-199	4	2.8
	12	6.2

SIC 202 Dairy Products

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTU
100-149	1	0.5

SIC 203 Canned, Cured, and Frozen Foods

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTU
100-149	39	12
150-199	8	1.5
200-249	2	0.4
	49	14

SIC 204 Grain Mill Products

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTU
100-149	23	9
150-199	21	20
200-249	6	6
250-299	2	3
300-349	7	12
350-399	2	5
	61	54

SIC 205 Bakery Products

No large boilers

Note: Comparable statistics for SIC 206 (Sugar), SIC 207 (Confectionery and Related Products), SIC 208 (Beverages), and SIC 209 (Miscellaneous, including vegetable oils) were not reported. In fact, SIC 206, 208, and 209 each account for significant consumption of boiler fuels. In aggregate, these three 3-digit SIC Codes used more boiler fuel in 1974 than the food industry elements listed above.

Source: FEA's MFBI survey, Report No. 25

APPENDIX 4

TABLE 34

NUMBER OF LARGE INDUSTRIAL BOILERS BY SIZE RANGE AND 1974 FUEL CONSUMPTION FOR SEGMENTS OF THE CHEMICALS INDUSTRY

SIC 281 Industrial Chemicals

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs	% of Fuel Consumed
100-149	83	58	16.1
150-199	58	52	14.2
200-249	58	85	23.5
250-299	32	43	11.8
300-349	13	28	7.7
350-399	9	20	5.6
400-449	5	14	3.9
450-499	4	12	3.2
500-599	4	15	4.2
600-699	1	4	1.2
700-799	1	5	1.4
800-899	3	19	5.1
900-999	-	-	-
1000+	2	7	1.9
	273	361	100

SIC 282 Plastics Materials and Synthetics

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs	% of Fuel Consumed
100-149	57	29	12.9
150-199	52	45	20.3
200-249	54	59	26.3
250-299	32	40	17.7
300-349	15	21	9.6
350-399	9	18	8.1
400-449	3	5	2.3
500-599	2	5	2.4
900-999	1	1	0.4
	225	224	100

Source: FEA's MFBI Survey, Report No. 25

APPENDIX 4

TABLE 35

NUMBER OF LARGE INDUSTRIAL BOILERS BY SIZE RANGE AND 1974 FUEL CONSUMPTION FOR STONE, CLAY, GLASS, AND CONCRETE PRODUCTS INDUSTRIES (SIC 32)

SIC 321/2 Glass

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs
100-149	5	1.2
150-199	1	0.6
200-249	3	1.2
250-299	2	1.4
300-349	1	0.7
	12	5.1

SIC 324 Cement

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs
150-199	2	1.0

SIC 325 Clay Products

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs
	No large boilers	

SIC 327 Concrete

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs
100-149	2	2.5

Source: FEA's MFBI Survey, Report No. 25

APPENDIX 4

TABLE 36

NUMBER OF LARGE INDUSTRIAL BOILERS BY SIZE RANGE AND 1974 FUEL CONSUMPTION FOR SIC 331 (BLAST FURNACES, BLAST STEEL PRODUCTS)

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs	% of Fuel Consumed
100-149	73	41	12.2
150-199	64	50	15.1
200-249	48	50	15.1
250-299	18	15	4.4
300-349	16	13	3.8
350=399	22	18	5.5
400-449	19	43	12.8
450-499	11	25	7.4
500-599	8	9	2.8
600-699	5	12	3.6
700-799	7	15	4.4
800-899	6	25	7.3
900-999	1	4	1.3
1000+	4	14	4.3
	302	334	100

SIMILAR DATA FOR SIC 332 (IRON AND STEEL FOUNDRIES)

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs
100-149	4	0.9
150-199	2	0.5
200-249	1	1.5
350-399	1	1.2
500-599	1	0.2
	9	4.4

Source: FEA's MFBI Survey, Report No. 25

APPENDIX 4

TABLE 37

NUMBER OF LARGE INDUSTRIAL BOILERS BY SIZE RANGE AND 1974 FUEL CONSUMPTION FOR SIC 333/5 (PRIMARY NON-FERROUS METALS)

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs	% of Fuel Consumed
100-149	16	5.6	7.7
150-199	5	1.8	2.6
200-249	5	2.4	3.3
250-299	3	2.9	4.0
300-349	15	42.8	59.4
400-449	1	1.2	1.7
450-499	3	9.0	12.4
700-799	1	6.4	8.9
	49	72.0	100

SIMILAR DATA FOR SIC 339 (MISCELLANEOUS PRIMARY METALS PRODUCTS)

Size Range 10^6 BTU/H	Number of Boilers	Fuel Consumed 10^{12} BTUs
100-149	1	2.7
200-249	2	5.5
300-349	2	5.5
	11	13.7

Source: FEA's MFBI Survey, Report No. 25

APPENDIX 4

TABLE 38

FUEL CONSUMPTION OF PULP, PAPER AND PAPERBOARD INDUSTRY

Purchased Fuels	% of Total Fuel 1972	1975	Fuel Consumption in 1975 10^{12} BTU*
Electricity	3.5	4.6	86.1
Steam	0.8	0.8	14.2
Residual fuel	22.4	23.8	463.0
Distillate fuel	1.2	0.8	14.9
LPG	0.1	0.1	1.2
Natural Gas	19.3	18.3	340.0
Coal	10.9	9.1	169.6
	58.2	57.5	1068.9
By-Product/Captive Fuels			
Hogged fuel (50% moisture)	1.7	2.6	48.0
Bark (50% moisture)	4.9	4.2	79.2
Spent liquor	34.6	34.8	646.6
Self-generated hydro.	0.4	0.5	9.2
Other	0.2	0.4	7.6
	41.8	42.5	790.6
TOTAL	100	100	1859.5** or 1.86 quads

* based on data for first six months, annualized

** in addition to the above consumption, the industry sold 16 x 10^{12} BTUs (0.9% of total)

Source: American Paper Institute, based on 78% coverage of industry

APPENDIX 4

TABLE 39

FUEL CONSUMPTION OF LARGE INDUSTRIAL BOILERS BY FUEL TYPE AND BY SIC CODE IN 1974

SIC 20 Food and Kindred Products

	10^{12} BTU	%
Coal	42.4	25.1
Resid.	24.4	14.5
Dist.	3.4	2.0
Nat. Gas	97.6	57.8
Other	1.0	0.6
Total	168.8	100

SIC 29 Petroleum Refining

	10^{12} BTU	%
Coal	12.4	2.2
Resid.	67.8	12.2
Dist.	nil	nil
Nat. Gas	456.2	82.3
Other	18.2	3.3
Total	554.6	100

SIC 333/9 Non-Ferrous Metals/Misc.

	10^{12} BTU	%
Coal	0.9	1.0
Resid.	8.1	9.0
Dist.	nil	nil
Nat. Gas	68.1	75.2
Other	13.4	14.8
Total	90.5	100

SIC 26 Paper and Allied Products

	10^{12} BTU	%
Coal	125.0	20.8
Resid.	201.0	33.4
Dist.	2.3	0.4
Nat. Gas	190.0	31.6
Other	83.1	13.8
Total	601.4	100

SIC 32 Stone, Clay, Glass, Concrete

	10^{12} BTU	%
Coal	1.3	7.0
Resid.	10.1	53.2
Dist.	negl.	0.1
Nat. Gas	6.2	32.7
Other	1.3	7.0
Total	19.0	100

Other SIC Codes

	10^{12} BTU	%
Coal	274.0	32.3
Resid.	261.0	30.7
Dist.	16.1	1.9
Nat. Gas	264.5	31.2
Other	32.9	3.9
Total	848.5	100

SIC 28 Chemicals and Allied Products

	10^{12} BTU	%
Coal	215.0	24.0
Resid.	101.0	11.3
Dist.	4.8	0.5
Nat. Gas	550.6	61.4
Other	25.3	2.8
Total	896.7	100

SIC 331/2 Primary Ferrous Metals

	10^{12} BTU	%
Coal	217.0	59.5
Resid.	7.2	2.0
Dist.	0.8	0.2
Nat. Gas	46.2	12.7
Other	93.2	25.6
Total	364.6	100

All Manufacturing SIC Codes

	10^{12} BTU	%
Coal	96.7	24.8
Resid.	749	19.3
Dist.	67	1.7
Nat. Gas	1822	46.8
Other	288	7.4
Total	3893	100

Source: based on data reported by Natural Gas Task Force Survey

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TABLE 40

REGIONAL FUEL CONSUMPTION OF LARGE INDUSTRIAL COMBUSTORS* BY COMMERCIAL FUEL TYPE IN 1974

	% of	1974 Fuel Consumption			
New England	Region	10^{12} BTU	10^{6} T Coal	10^{6} Bbl Oil	10^{9} CF Gas
Maine	48.5	54.3	0.028	8.5	nil
Massachusetts	21.5	24.1	0.008	3.1	3.8
Connecticut	19.9	22.3	0.002	3.2	2.1
New Hampshire	8.2	9.2	nil	1.3	0.7
Rhode Island	1.6	1.8	nil	0.3	nil
Vermont	0.3	0.3	nil	negl.	<0.1
	100	112.0	0.038	16.4	6.7
Appalachian					
Pennsylvania	28.2	465.0	9.998	16.1	125.4
Ohio	28.1	463.0	9.022	9.8	180.4
New York	8.8	145.0	1.895	14.8	9.0
Maryland	8.7	143.0	3.340	5.4	32.6
New Jersey	7.6	125.0	0.004	14.8	29.8
West Virginia	7.0	116.0	3.602	2.0	20.3
Virginia	6.9	114.0	2.018	9.1	10.8
Kentucky	2.1	34.9	0.957	0.3	12.5
Delaware	1.0	31.6	nil	2.8	13.1
D. C.	0.7	10.9	0.294	0.7	nil
	100	1648.4	31.030	75.8	433.9
Southeast					
Alabama	25.8	180.0	2.627	7.2	68.6
Tennessee	19.8	138.0	3.386	1.7	47.4
S. Carolina	13.8	96.2	1.628	5.1	25.1
N. Carolina	13.7	95.7	1.074	9.4	11.6
Florida	13.7	95.7	nil	10.8	25.6
Georgia	13.2	92.4	0.456	7.5	32.2
	100	698.0	9.171	41.7	210.5
Great Lakes					
Indiana	36.5	372.0	9.728	8.8	88.5
Michigan	29.5	301.0	4.215	9.6	135.6
Illinois	27.4	279.0	2.792	10.1	138.8
Wisconsin	6.6	66.8	1.097	1.7	28.6
	100	1018.8	17.832	30.2	391.5

* boilers and other combustors, such as process furnaces, with a rated heat input of 100 M BTU/H or more

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TABLE 40 (con't.)

Northern Plains	% of Region	1974 Fuel Consumption 10^{12} BTU	10^{6} T Coal	10^{6} Bbl Oil	10^{9} CF Gas
Iowa	44.4	58.5	0.955	0.6	30.2
Minnesota	33.6	46.3	0.337	0.8	28.9
Nebraska	12.4	16.3	0.152	0.1	11.1
S. Dakota	5.5	7.2	0.281	negl.	0.6
N. Dakota	4.2	5.5	0.108	0.3	0.9
	100	131.8	1.833	1.8	71.7
Midcontinent					
Oklahoma	41.1	72.5	nil	3.3	46.8
Missouri	32.5	57.3	1.399	0.7	19.5
Kansas	26.4	46.5	0.071	0.6	37.3
	100	176.3	1.470	4.6	103.6
Gulf Coast					
Texas	63.7	1270.0	2.320	6.0	1078.8
Louisiana	27.6	551.0	0.010	3.7	478.6
Mississippi	5.7	114.0	0.107	5.2	72.0
Arkansas	3.0	59.3	nil	2.6	39.2
	100	1994.3	2.437	17.5	1668.6
Rocky Mountain					
Colorado	35.7	80.2	1.216	2.5	33.8
Utah	28.8	64.6	1.191	0.9	29.0
Wyoming	27.1	60.7	0.624	2.5	28.3
Montana	8.4	18.8	nil	0.4	15.0
	100	224.3	3.031	6.3	106.1
Pacific Southwest					
California	84.6	295.0	0.110	5.6	234.6
Arizona	10.7	37.4	0.021	1.3	26.3
New Mexico	3.1	10.7	nil	0.3	7.8
Nevada	1.6	5.4	0.081	0.2	2.1
	100	348.5	0.212	7.4	270.8

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TABLE 40 (con't.)

Pacific Northwest	% of Region	1974 Fuel Consumption 10^{12} BTU	10^6 T Coal	10^6 Bbl Oil	10^9 CF Gas
Washington	70.5	105.0	0.145	4.3	68.6
Oregon	18.5	27.5	0.115	1.4	14.7
Idaho	11.0	16.4	0.271	negl.	9.2
	100	148	0.531	5.7	92.5
Lower 48 States	--	6512	67.6	207.6	3356
Alaska/ Hawaii/ P. R./ V. I.	--	107.6	0.588*	9.1	34.7

* = entirely in Alaska

Notes

(1) By-product and "Other" fuels are excluded

(2) FEA appears to have used a BTU conversion factor of 1100 BTU/CF for "Gas," possibly to take account of LPG etc. Thus, the following BTU balance applies to the Lower 48 States total:

67.6 million tons of coal at 22.6 million BTU/ton	= 1528 x 10^{12} BTU
207.6 million barrels of oil at 6.22 million BTU/bbl	= 1291 x 10^{12} BTU
3356 billion CF of gas at 1100 BTU/CF	= 3692 x 10^{12} BTU
	6511

(3) The consumption of 67.6 million tons of coal, reported by FEA, by the large industrial combustors appears high in relation to the total of 64.0 million tons of coal consumption, for all general industrial uses, reported by the Bureau of Mines. Furthermore, the average heat content of the industrial coal assumed by FEA, appears low (22.6 x 10^6 BTU per ton) and to be more applicable to electric utility coal then to industrial coal (excluding metallurgical coal). While the basis on which the statistics were collected may be slightly different, it is obvious that the coal consumption of the large coal-fired combustors can not have exceeded the total consumption by all sizes of coal-fired industrial combustors. It is believed that part of the discrepancy is due to inclusion of the coal consumption (4.4 million tons) of nine large coal-fired electric utility boilers in FEA's survey of industrial MFBI boilers. Making this correction would reduce the above figure of 67.6 million tons to 63.2 million tons. If the heat content of this coal were to have averaged 24 x 10^6 BTU per ton, instead of the 22.6 x 10^6 BTU per ton assumed by FEA, the corrected total tonnage would be about 59.4 million tons (including 40.2 million for large industrial boilers and 19.2 million for other large industrial combustors). Thus, the implied coal consumption of the smaller industrial combustors (less than 100 million BTU/H) would be 64.0 - 59.4 = 4.6 million tons, of which about 3.1 million tons may have been used by the smaller boilers. This rationalization of the reported coal consumption statistics for 1974 suggests that coal use by industrial boilers approximated:

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TABLE 40 (con't.)

Notes (con't.)

	Million Tons	% of Total
100 million BTU/H or larger	40.2	93
Smaller than 100 million BTU/H	3.1	7
	43.3	100

Although the estimate for the smaller coal-fired boilers is approximate, it is the best available. It tends to confirm that the potential for coal-firing in new industrial boilers is likely to be almost entirely in units with a designed heat rate of 100 million BTU/H or more.

Source: based on pooling of statistics from FEA's Natural Gas Task Force and MFBI surveys, with additional information from Bureau of Mines reports

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TABLE 41

COAL CONSUMPTION BY REGION OF ALL LARGE INDUSTRIAL COMBUSTORS (INCLUDING BOILERS) IN 1974

New England	10^3 Tons
Maine	28
Massachusetts	8
Connecticut	--
New Hampshire	--
Rhode Island	--
Vermont	--

Appalachian	
Pennsylvania	9998
Ohio	9002
West Virginia	3602
Maryland	3340
Virginia	2018
New York	1895
Kentucky	857
D. C.	294
New Jersey	4
Delaware	--

Southeast	
Tennessee	3386
Alabama	2627
S. Carolina	1628
N. Carolina	1074
Georgia	456
Florida	--

Great Lakes	
Indiana	9728
Michigan	4215
Illinois	2792
Wisconsin	1097

Northern Plains	10^3 Tons
Iowa	955
Minnesota	337
South Dakota	281
Nebraska	152
North Dakota	108

Midcontinent	
Missouri	1399
Kansas	71
Oklahoma	--

Gulf Coast	
Texas	2320
Mississippi	107
Louisiana	10
Arkansas	--

Rocky Mountain	
Colorado	1216
Utah	1191
Wyoming	624
Montana	--

Pacific Southwest	
California	110
Nevada	81
Arizona	21
New Mexico	--

Pacific Northwest	
Idaho	271
Washington	145
Oregon	115

Source: Natural Gas Task Force survey