DOE/EIA/2832-2

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INDUSTRIAL FUEL CHOICE ANALYSIS MODEL

Volume II

APPENDICES TO MODEL DOCUMENTATION

F I R S T D R A F T

Prepared for:

DEPARTMENT OF ENERGY
OFFICE OF POLICY AND EVALUATION
Washington, D.C.

Prepared by:
ENERGY AND ENVIRONMENTAL ANALYSIS, INC.
1111 North 19th Street
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January 8, 1979

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APPENDIX A. ENERGY CONSUMPTION DATA BASE

A.1 BRIEF DESCRIPTION OF ECDB

This data base, developed for FEA by EEA, describes and documents, in great detail, energy consumption in the United States during the years 1967, 1971, and 1974. This information has a wide variety of application in both energy and environmental areas.

The data base handles several million pieces of energy consumption (in Btu's or traditional units) and expenditure information on the agricultural, mining, construction, manufacturing, transportation, commercial, household, and electric utilities sectors on a state-by-state basis. The number of data cells in each sector varies from 16,000 in the electric utilities sector to 2,800,000 in the manufacturing sector. The elements are fully cross-stratified so that, for example, the data base contains a record of the amount of coal used in the steel industry in Ohio during 1971 coke production. Although all combinations of data elements already are aggregated to the Census region and national levels, any other combination of state data such as EPA regions or PAD districts could be produced easily.

The data have been produced primarily by three different techniques: (1) direct input from a primary source (Census, BOM, FPC, etc.) with case-by-case refinements where superior data from isolated sources exist; (2) disaggregating micro data by taking shares of control totals based on output or other indicators; and (3) aggregating micro data, such as the amounts of fuel required by various machines to complete various types of construction projects, to develop data in a more useful summary form.

A list outlining the 12 fuel types, 11 functional uses, and 26 industry subgroups is presented in Table A.1.

TABLE A.1 LEVEL OF DETAIL AVAILABLE IN ECDB

Fuel Type

Coal
 Coke and breeze
 Distillate oil (including diesel)
 Residual oil
 Asphalt
 Miscellaneous petroleum products
 Liquefied petroleum gases
 Natural gas
 Other gas, NSK/NEC
 Hydro
 Electricity
 Other energy, NSK/NEC
 Total - all energy

Functional Use

Space heating
 Space cooling
 Space conditioning, NSK/NEC
 Lighting
 Total direct heat
 Direct heat - below 600°F
 Direct heat - 600-1000°F
 Direct heat - 1000-1500°F
 Direct heat - above 1500°F
 Direct heat, NSK
 Raw material
 Process steam
 Electricity generation
 Coke production
 Machine drive
 Electrolytic processes
 Other uses, NSK/NEC
 Total - all functional uses

Industry

Food and kindred products
 Tobacco manufacturers

Textile mill products
Apparel
Lumber
Furniture
Paper (total)
Pulp, paper, paperboard, building paper, and board mills
Other paper products, NSK/NEC
Printing, publishing
Chemicals
Petroleum refining
Rubber and miscellaneous plastics
Leather
Stone, clay, glass, concrete (total)
Cement
Other stone, clay, etc., NSK/NEC
Primary metals (total)
Blast furnace and steel mills
Aluminum
Other primary metals, NSK/NEC
Fabricated metal products
Machinery (except electrical)
Electrical and electronic machinery
Transportation equipment
Measuring, etc. equipment
Miscellaneous manufacturing industries
Other industries, NSK/NEC
Total - all industry

A.2 COMPARISON OF ECDB AND BUREAU OF MINES CONTROL TOTALS

ECDB was used in tandem with the MEFS industrial energy consumption information. Because MEFS is based primarily on BOM data it is useful to compare BOM and ECDB even if only on a cross-sectional (all segments of the economy) basis. By looking at the cross-sectional energy use, differences in definition of the economic segments (e.g., commercial versus large residential apartments or small utilities versus industry) will be eliminated.

It appears that, in most cases, the sum of individual sectors' fuel use in ECDB was close to control totals published by the BOM or other primary data collectors. Some major discrepancies are apparent, however, which cannot be attributed strictly to definitional differences. A preliminary list of discrepancies is presented in Table A.2.

TABLE A.2 COMPARISON OF 1974 BOM AND ECDB CROSS-SECTIONAL DATA

<u>Fuel</u>	<u>ECDB (10⁹ MMBtu)</u>	<u>BOM (10⁹ MMBtu)</u>	<u>Difference (%)</u>
Coal	12.4	13.1	(5.3)
Petroleum	32.0	33.4	(4.2)
Natural gas	<u>20.4</u>	<u>22.0</u>	<u>(7.3)</u>
Total fossil fuel	64.8	68.5	(5.4)

A summary of some of the factors contributing to the differences shown in the above table are as follows:

- Some of ECDB's fossil fuel is categorized as "other energy, NSK/NEC," mainly due to establishments too small to report individual fuels to the Census Bureau in the manufacturing sector.
- Petroleum usage in the ECDB omits about 0.2 quads of asphalt not used in the construction sector, but unable to be classified according to industry in the manufacturing sector.
- Natural gas use in the mining sector of the ECDB was derived from Census Bureau data which were about 0.5 quads less than comparable BOM data for oil and gas extraction.

In addition, electricity production (6.4 quads) does not equal electricity consumption (6.2 quads) when all sector uses are added together. Since 6.2 quads represents only end use consumption and transmission losses may be eight to 10 percent of net generation, the consumption estimate could be overstated or the generation estimate understated by as much as 0.3 to 0.4 quads.

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APPENDIX B. MAJOR FUEL BURNING INSTALLATION SURVEY

B.1 DESCRIPTION

The Major Fuel Burning Installation (MFBI) report was a survey of industrial plants which was performed in May 1975 by the Office of Fuel Utilization, FEA (now DOE). A follow-up survey was sent to a subset of the total survey, but the MFBI is not a periodic survey. All firms consuming more than 99 MMBtu/hr at specific plant sites were required to complete and forward requested information to FEA.

The primary purpose of this survey was to identify large combustors capable of firing coal which at the present time are relying heavily on either oil or gas. Under ESECA, FEA had the authority to force these plants to convert to coal. Total coverage is about 6300 combustors at 3400 plants.

The data from MFBI deal with specific plants (and government installations) and with specific combustors within particular plants. The plants are identified according to company name, street address, zip code, and state. For the plant as a whole, the total number of boilers and the number of "other combustors" are specified. The total designed firing rate for all combustors is given. For individual combustors with a designed firing rate greater than 99 MMBtu/hr, the following information was collected:

- Kind of combustor (boiler, burner, other).
- Combustor capacity.
- Date installed.
- Primary and alternate energy sources (coal, residual, distillate, gas, other).
- Information about current and historical coal burning capability.
- 1974 and 1973 fuel use (Btu content and physical quantity consumed of coal, residual, distillate, and gas).

- Percent of combustor output devoted to electric generation, space heating, process steam, other.
- Information about type of air pollution control equipment and removal efficiencies.

B.2 COVERAGE

The MFBI survey does not provide complete coverage of the industrial sector's energy usage. It is focused on the large boilers, burners, and other combustors, and detailed fuel usage information is not available for any combustor which uses less than 100 MMBtu/hr. Even for a given plant with several large combustors, the data in the MFBI survey do not give information about all of that plant's energy demands since much of the fuel conceivably could have been burned in smaller units or used for non-fuel purposes (i.e., chemical feedstocks). Total 1974 energy use by the approximately 6300 large combustors covered in the survey was about 6.6 quadrillion Btu's, of which about 3.5 quads were gas, 1.3 quads were oil, and about 1.8 quads were coal.

MFBI coverage of total U.S. natural gas and fuel oil varies by fuel type and combustor type (boiler or nonboiler). Total coverage of both fuels, excluding feedstocks, is over 50 percent. MFBI coverage of boilers is more extensive than the coverage of nonboiler combustors. Comparisons with ECDB control totals indicate that MFBI data cover approximately 90 percent of the total U.S. oil burned in boilers and 70 percent of the natural gas boiler total. This either reflects the greater use of natural gas in boilers below the MFBI cutoff point or a lower reporting frequency of natural gas users.

The MFBI data have not been published by DOE and are considered to be confidential due to the information provided on individual companies. Aggregated summaries by SIC code and state were prepared by EEA for use by FEA's 1975 Natural Gas Task Force and DOE's analysis of the proposed NEP. The MFBI probably represents the only source of actual survey data on the energy use characteristics of large combustors in specific plants.

B.3 SAMPLE

The following seven pages represent the actual survey forms sent to individual companies.

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 Classi-

fication 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 & 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 $[(A) \times 10^6 \text{ Btu/hr}]$.

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 $[(A) \times 10^6 \text{ Btu/hr}]$.

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.

DO NOT FILL IN

Diagram showing base ten blocks: one unit block (labeled 1), one ten block (labeled 10), and one unit block (labeled 10).

FEDERAL ENERGY ADMINISTRATION
MAJOR FUEL BURNING INSTALLATION COAL CONVERSION REPORT
FEA C-602-S-0

This report is mandatory under Public Law 93-275

SECTION I GENERAL PLANT INFORMATION

1. MFBI NAME AND LOCATION:

NAME

A horizontal number line with arrows at both ends. It is divided into 16 equal segments by 17 vertical tick marks. The first tick mark on the left is labeled '11' and the last tick mark on the right is labeled '26'.

STREET

A horizontal number line starting at 27 and ending at 42. There are 16 empty boxes between the numbers, representing the numbers 28 through 43. The boxes are arranged in a single row, with the first box at 28 and the last box at 43.

CITY

A horizontal number line with 10 empty boxes. Below the first box is the number 43, and below the last box is the number 53.

STATE _____ ZIP _____

54 58

AIR QUALITY CONTROL REGION (if known) _____

2. PARENT COMPANY NAME AND GENERAL OFFICE LOCATION:

NAME

59													73

STREET _____

CITY _____

STATE _____ ZIP _____

--	--	--	--	--

74
78

DO NOT FILL IN

79 · 80

3. PERSON TO CONTACT IN FUTURE CORRESPONDENCE

NAME

A horizontal number line with arrows at both ends. It is divided into 16 equal segments by 17 vertical tick marks. The first tick mark on the left is labeled '6' and the last tick mark on the right is labeled '22'.

TITLE

A horizontal number line starting at 23 and ending at 35. There are 12 empty boxes between the numbers, representing the numbers 24 through 35.

STREET _____

CITY/STATE _____

ZIP

A horizontal number line with five empty boxes. Below the first box is the number 36, and below the last box is the number 40.

TELEPHONE (with Area Code)

$$\left(\begin{array}{|c|} \hline \\ \hline \end{array} \right) - \begin{array}{|c|} \hline \\ \hline \end{array}$$

4. TOTAL NUMBER OF BOILERS AT THIS INSTALLATION

52

5. TOTAL NUMBER OF OTHER COMBUSTORS AT THIS INSTALLATION

53	

6. TOTAL DESIGNED FIRING RATE (X 10⁶ Btu's/hr) (of #4 and #5)

55		59	

7. IDENTIFY PAIRINGS (ETC) OF COMBUSTORS (Example: Boilers 04, 05, and 06 Share a Common Manifold and are Vented through a Common Stack)

8. PRINCIPAL PRODUCTS PRODUCED AT, OR SERVICES PROVIDED BY THIS INSTALLATION (If SIC Codes are Unknown, Provide Written Description in Space Provided).

Standard
Industrial
Classification
(4 Digit)

80			
67			
73			

Percent of
Total Shipments
or Services
by Value

66	
72	
78	

9. IDENTIFY THE MAJOR TECHNICAL, REGULATORY, ECONOMIC, AND ENVIRONMENTAL IMPEDIMENTS, IF ANY, TO YOUR UTILIZING COAL TO A GREATER EXTENT AT THIS INSTALLATION)

DO NOT FILL IN

79 80	

10. WHAT ACTIONS BY THE FEDERAL GOVERNMENT WOULD ENCOURAGE YOU TO UTILIZE COAL TO A GREATER EXTENT?

11. CERTIFICATION:

CERTIFYING OFFICER. I certify to the best of my knowledge that the information in this report is correct.

NAME _____ SIGNATURE _____ DATE _____

TITLE _____

Title 18 USC 1001, makes it a crime for any person knowingly and willingly to make to any agency or department of The United States any false, fictitious or fraudulent statements as to any matter within its jurisdiction.

FEA C-602-S-0

FEDERAL ENERGY ADMINISTRATION
Washington, D.C. 20461APPROVED 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

DO NOT FILL IN

1				5

FILL IN THIS PAGE FOR EACH COMBUSTOR OVER 99 MILLION BTUs/HR

MFBI NAME _____

SECTOR II - COMBUSTOR DATA

1. COMBUSTOR NUMBER

6	

2. WHAT KIND OF COMBUSTOR IS THIS?

1 = boiler 2 = burner 3 = other combustor of fuel

☐
3. COMBUSTOR CAPACITY (x 10⁶ BTU/HR)

--	--	--	--

4. MANUFACTURER _____

5. DATE INSTALLED (YEAR)

19

--	--

6. a. If Combustor has been Modified to be Capable of Burning Coal, What Year was it Modified?
b. How was it Modified?

19

--	--

7. DO YOU INTEND TO INSTALL A TOPPING TURBINE ON THIS COMBUSTOR?

☐

a. If Yes, Will You Need to:

☐

(1) Replace Your Combustor.

(2) Modify Your Combustor.

(3) Make No Combustor Modification.

b. If the Answer to 7(a) was "1" or "2", Do You Intend to Modify/Replace Your Combustor so that You Can Burn Coal?

☐

8. PRIMARY ENERGY SOURCE FOR EXISTING COMBUSTOR

1 = coal 2 = residual 3 = distillate 4 = gas 5 = other (specify) _____

☐

9. ALTERNATE ENERGY SOURCE FOR EXISTING COMBUSTOR

1 = coal 2 = residual 3 = distillate 4 = gas 5 = other (specify) 6 = no alternate.

☐

List secondary alternate energy sources, if any: _____

10. IF COAL IS THE PRIMARY ENERGY SOURCE, DO YOU INTEND TO CONTINUE ITS USE?
☐

11. IF COAL IS NOT THE PRIMARY ENERGY SOURCE, DO YOU INTEND TO CONVERT TO COAL IN THE NEAR FUTURE?

☐

12. WAS THIS COMBUSTOR ORIGINALLY DESIGNED TO BE CAPABLE OF BURNING COAL?

☐

13. WAS COAL EVER BURNED IN IT?

☐

14. CAN COAL NOW BE BURNED IN THIS COMBUSTOR?

☐

15. IS LAND AVAILABLE FOR COAL STORAGE?

☐

16. IF THE ANSWER TO NO. 12 OR 13 IS "YES", IS ANY OR ALL OF THE COAL BURNING SUPPORT EQUIPMENT STILL IN PLACE?

☐

17. IF THE ANSWER TO NO. 12 OR 13 IS "YES", IS ANY OR ALL OF THIS EQUIPMENT STILL OPERATIONAL?

☐

29

18. IF THE ANSWER TO NO. 16 OR 17 WAS "NO", PLEASE IDENTIFY ANY ANTICIPATED ACQUISITION OR REFURBISHING OF COAL HANDLING AND FIRING EQUIPMENT.

19. IF COAL WAS EVER USED AS THE PRIMARY FUEL SOURCE PRIOR TO 1973 GIVE (for the last year coal was used):

a. Year

19

3	0

b. Rank of Coal _____

c. Percent Ash by Weight (to the nearest percent) _____

d. Percent Sulfur by Weight (to the tenth of a percent) _____

--	--

e. BTU/lb _____

f. Quantity _____ Tons/Year

g. Other Unique Characteristics

_____h. Method of Delivery: (Train, Truck, Barge, etc.)
_____i. If Coal is not Presently Being Used, Do You Anticipate that it Could be Obtained if you Were to Convert? ☐j. If Not, Why Not?

20. ESTIMATE YOUR ANNUAL NON-COAL FUEL SAVINGS IF YOU WERE TO CONVERT TO COAL

RESIDUAL

QUANTITY

--	--	--	--

10³ bbls/yr

35

DISTILLATE

--	--	--	--

10³ bbls/yr

30

GAS

--	--	--	--

10³ MCF/yr

43

46

21. 1974 ANNUAL FUEL USE

% ASH
(by weight)% SULFUR
(by weight)BTU CONTENT (x10³)

QUANTITY

COAL

--	--	--	--

(lb)

--	--	--	--

10³ tons/yr

47

(gal)

--	--	--	--

10³ bbls/yr

RESIDUAL

--	--	--	--

55

(gal)

--	--	--	--

10³ bbls/yr

DISTILLATE

--	--	--	--

63

(MCF)

--	--	--	--

10³ MCF/yr

GAS

--	--	--	--

71

--	--	--	--

78

22. 1973 FUEL USE

79	80	1						DO NOT FILL IN

	% ASH (by weight)	% SULFUR (by weight)	BTU CONTENT (x10 ³)	QUANTITY	
COAL	_____	_____	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">6</div> (lb)	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">13</div>	10 ³ tons/yr
RESIDUAL	_____	_____	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">14</div> (gal)	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">21</div>	10 ³ bbls/yr
DISTILLATE	_____	_____	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">22</div> (gal)	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">29</div>	10 ³ bbls/yr
GAS	_____	_____	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">30</div> (MCF)	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">37</div>	10 ³ MCF/yr

23. INDICATE (to the nearest percent) THE PERCENT OF COMBUSTOR OUTPUT THAT IS DEVOTED TO:

ELECTRIC GENERATION	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">38</div>
SPACE HEATING	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">41</div>
PROCESS STEAM	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">44</div>
OTHER (Specify) _____	<div style="border: 1px solid black; display: inline-block; width: 40px; height: 15px; text-align: center;">47</div>

SECTION III AIR QUALITY

1. STACK NUMBER

2. STACK HEIGHT (Feet Above Ground)

3. CURRENTLY INSTALLED POLLUTION CONTROL EQUIPMENT AS PERTAINS TO THE COMBUSTOR (Answer Yes or No with a "1" or "0" respectively).

a. Precipitator (Also referred to as Dust Collector)

Type (Centrifugal, Electrostatic, Etc.) _____

Date Installed _____

Date Last Operated _____

Design Efficiency (%) _____

Actual Efficiency (%) _____

b. FLUE GAS DESULFURIZATION (FGD) EQUIPMENT (Also referred to as Scrubber or Sulfur Dioxide Absorber)

Type (MAG Ox, LIMESTONE, Etc.) _____

Date Installed _____

Date Last Operated _____

Design Efficiency (%) _____

Actual Efficiency (%) _____

% Availability _____

4. TO BURN COAL AND MEET THE SIP EMISSION LIMITATIONS RELATING TO ATTAINMENT OF THE FEDERAL PRIMARY AMBIENT AIR QUALITY STANDARDS, THIS INSTALLATION MUST:
(Answer with Yes (1) or No (0) in the blocks provided)

a. Upgrade Precipitators

☐
56

If yes, give approximate cost \$ _____ time _____ (weeks)

b. Install Precipitators

☐

If yes, give approximate cost \$ _____ time _____ (weeks)

c. Install FGD

☐

If yes, give approximate cost \$ _____ time _____ (weeks)

d. Obtain Conforming Coal

☐

This coal must be _____ % Sulfur by weight, _____ % Ash by weight.

Do you anticipate that you will be able to obtain conforming coal?

☐

5. TO BURN COAL AND MEET OTHER APPLICABLE SIP REQUIREMENTS, (THIS INSTALLATION MUST: (Answer with a Yes (1) or No (0) in the blocks provided)

a. Upgrade Precipitators

☐

If yes, give approximate cost \$ _____ time _____ (weeks)

b. Install Precipitators

☐

If yes, give approximate cost \$ _____ time _____ (weeks)

c. Install FGD

☐

If yes, give approximate cost \$ _____ time _____ (weeks)

d. Obtain Conforming Coal

☐

This coal must be _____ % Sulfur by weight, _____ % Ash by weight.

Do you anticipate that you will be able to obtain conforming coal?

☐
65

DO NOT FILL IN

☐
79 80

APPENDIX C. AMERICAN BOILER MANUFACTURERS ASSOCIATION DATA FILE

C.1 FILE DESCRIPTION

The American Boiler Manufacturers Association (ABMA) provides data on boiler sales from 1965 to 1977. These data give information on an annual basis about sales of different types of boilers in eight size ranges.

IFCAM used ABMA data on stationary watertube boiler sales to create a size distribution for the new units in the model. The data are in the form of computer cards for each boiler sale, coded with detailed information on the boiler. The key specifications for a boiler are:

- Capacity in thousands of pounds per hour.
- Primary fuel (bituminous coal; oil; natural gas; wood or bark; bagasse; black liquor; other fuels; waste heat; waste heat, auxiliary firing; lignite; raw municipal waste, unsorted, non-combustible removed, or sorted and sized; other industrial wastes).
- Auxiliary or alternative fuels (same breakdown as for primary fuels).
- Firing method.
- Package or field-erected.
- SIC.
- Domestic or export (export not used in IFCAM).
- Geographic region.

ABMA data represent the best available source of information on recent industrial investment patterns for boilers. There were some problems with duplicate records in the data base which were sorted out by computational method where possible.

TABLE C.1 BOILER CAPACITY SOLD, 1965-1977

SIC Code	Thousands of Pounds of Steam per Hour								Total
	<u>0-9</u>	<u>10-24</u>	<u>25-49</u>	<u>50-99</u>	<u>100-149</u>	<u>150-249</u>	<u>250-399</u>	<u>400+</u>	
20	0	2,679	14,688	30,966	22,957	18,845	5,608	900	96,623
21	0	54	595	355	300	175	0	0	1,479
22	0	2,318	10,636	14,971	5,431	3,584	300	0	37,240
23	0	0	0	66	0	0	0	0	66
24	0	1,119	5,387	8,606	7,022	4,669	1,891	2,279	30,973
25	0	20	50	0	0	0	0	0	70
26	0	980	3,529	12,495	11,251	25,342	30,679	56,729	141,005
27	0	0	0	0	0	0	0	0	0
28	18	2,860	12,877	28,768	28,317	51,378	17,865	31,910	173,993
29	0	552	5,910	10,586	10,804	30,185	16,057	23,600	97,694
30	0	863	2,692	8,338	4,065	1,175	0	0	17,133
31	0	0	90	0	120	0	0	0	210
32	0	0	0	0	0	0	0	0	0
33	16	710	2,880	7,795	5,237	9,770	7,890	12,275	46,573
34	0	0	40	0	200	0	0	0	240
35	0	24	0	435	110	0	0	0	569
36	0	0	0	0	0	0	0	0	0
37	18	305	2,963	12,357	13,201	16,158	5,504	800	51,306
38	0	0	0	0	0	0	0	0	0
39	0	2,510	10,755	24,712	18,576	15,068	3,948	4,675	80,236
20-39	52	14,944	73,072	160,450	127,591	176,341	89,742	133,168	775,410

C.2 DERIVATION OF SIZE DISTRIBUTIONS

The ABMA boiler data were sorted into size classes based on total capacity sold as shown in Table C.1. Percent shares in three size classes (25-100 MMBtu/hr, 100-250 MMBtu/hr, and above 250 MMBtu/hr; assuming 10^3 lb steam equals 10^6 Btu) for the first five model industry groups as shown in Table C.2. These shares are not adjusted for capacity utilization; they represent total capacity sold.

SCG had poor coverage in the ABMA data, so the MFBI data for this industry (which is also limited) and in-house EEA data were used to make as good an estimate as possible. Total new boiler growth in this industry is quite small, so any inaccuracies in the size share estimates would have a minimal impact on the total model accuracy.

Steel and aluminum were not separated in the ABMA data, so a combination of MFBI and NEDS data was used to determine the size distributions for these industries. The "other industry" size distribution was taken from ABMA, but reweighted toward more small boiler capacity to reflect the industrial uses covered in IFCAM that were not included in the preliminary ABMA data.

Finally, capacity utilization shares of each size class were estimated from MFBI data to adjust the size shares from total capacity shares to fuel actually consumed in each size class. Table C.3 shows the sample results of this adjustment in the petroleum industry.

TABLE C.2 ABMA SIZE DISTRIBUTION FOR FIVE MAJOR INDUSTRIES^{a/}

<u>SIC</u>	<u>25-100 MMBtu/hr</u>	<u>100-250 MMBtu/hr</u>	<u>>250 MMBtu/hr</u>
Food	0.47	0.43	0.07
Textiles	0.66	0.23	0.01
Paper	0.11	0.26	0.62
Chemicals	0.24	0.46	0.29
Petroleum	0.17	0.42	0.41

^{a/} These distributions are directly from ABMA capacity sold figures.

TABLE C.3 PETROLEUM INDUSTRY SIZE DISTRIBUTION, ADJUSTED
FOR CAPACITY UTILIZATION
(percent)

<u>Size (MMBtu/hr)</u>	<u>Preliminary Size Distribution^{a/}</u>	<u>Average Capacity Utilization^{b/}</u>	<u>Size Distribution after Adjustment for Capacity Utilization^{c/}</u>
25-100	17	55	13
100-250	42	75	44
250+	41	75	43

^{a/} Based on straight ABMA capacity sold figures.
Percent of total capacity in each size class.

^{b/} Estimated from MFBI data (see Appendix F).

^{c/} Represents percent of total Btu's consumed in each size class.

TABLE C.4 NEW BOILER SIZE DISTRIBUTION USED IN IFCAM
(Percent of Total Fuel in Each Industry)

<u>INDUSTRY</u>	<u>SIZE (MMBtu/hr)</u>			
	<u>0-25</u>	<u>25-100</u>	<u>100-250</u>	<u>250 & Above</u>
Food	.13	.33	.44	.10
Textiles	.06	.69	.23	.02
Paper	.02	.09	.24	.65
Chemicals	.01	.23	.46	.30
Petroleum	0	.13	.44	.43
Stone, Clay, and Glass	.20	.60	.20	0
Steel	.12	.22	.60	.06
Aluminum	0	.11	.60	.29
Other	.08	.34	.49	.09

APPENDIX D. MIDRANGE ENERGY FORECASTING SYSTEM

The Midrange Energy Forecasting System* (MEFS) is a model of the technologies, lead times, costs, and geographic locations which affect energy commodities. MEFS traces energy use from the point of discovery through production, transportation, conversion to more useful forms, and ultimately consumption by all sectors of the economy. The system consists of a demand model, several supply models, and an integrating model which combines the outputs of the other models to estimate market clearing prices, demands, and supplies. The forecasts generated are functions of varying economic and policy assumptions structured into scenarios. A downward sloping demand and upward sloping supply curve are assumed. Also assumed is that prices will clear the market in all regions. All prices and quantities of energy goods produced, consumed, or converted are estimated on a regional basis.

The demand model consists of sectoral models which project final demand for the covered fuels on a regional basis for a given set of prices in a given year. The sectors are residential, commercial, industrial, utility, and transportation. The sector of primary interest to IFCAM is the industrial sector.

The fuels covered in the industrial sector are primary fossil fuels (distillate and residual fuel oils, natural gas, and steam coal), fuels used mainly as feedstock (LPG, metallurgical coal, and naphtha), and electricity.

Total energy demand is determined for each of the sectors outlined above. A series of indices is used in determining the energy demand by region and fuel type. The total energy demand index is specified depending on:

- The level of a total energy price index in a given region.

*Formerly referred to as the Project Independence Evaluation System (PIES).

- The activity level in a region, measured by value added in manufacturing.
- The logged value of the total quantity index.

Next, the ratio of each specific fuel demand to the total quantity index is determined depending on:

- The relative price of the fuel in the region (the ratio of the regional fuel price to the regional total energy price index).
- The logged value of the ratio of the specific fuel demand to the total quantity index.

Finally, the total price and quantity indices are regionally value weighted averages of regional prices or quantities. All these relationships are specified to be linear in the logarithms of the variables.

The supply side of the model develops supply quantities for coal, petroleum, and natural gas. Coal is handled in a fairly straightforward manner, while the oil and gas figures required a series of submodels to account for more complicated set of variables involved.

The three categories of supply activity are production, energy conversion, and transportation. Each activity is described by possible combinations of outputs, inputs, and costs. Existing activities include only variable costs while new activities also include amortized capital costs.

Coal supply data came from the Bureau of Mines. The following steps summarize the coal supply curve methodology used in MEFS.

- Obtain BOM-demonstrated reserve base estimates of coal tonnage and quality characteristics by seam and county and assign reserves to coal supply regions. Assign reserves within each region to product classes by Btu and sulfur content, eliminating negligible reserves that are too costly because of coal quality or amount.
- Estimate production capacity from existing mines for each forecast year and reserves committed to existing mines, including an estimate of the effects of mine closings.

- Allocate uncommitted strippable reserves to overburden ratio categories (the overburden ratio of a coal seam is the cubic yards of overburden per ton of coal). Allocate uncommitted deep reserves to seam thickness and seam depth categories. Allocate uncommitted reserves to mine size categories so that production may be maintained for 20 years.
- Assign production estimates to mine types. Estimate minimum acceptable selling price for each mine type and size using a discounted cash flow analysis.
- Arrange mine types with associated production levels in order of minimum acceptable selling prices.

Oil and gas supplies were estimated using a series of mathematical models and engineering estimates. Central to oil and gas supply figures is the rate of discovery of new reserves projected by the model.

The first model is used to forecast oil and the coproducts of crude oil (mainly associated and dissolved natural gas). The second model forecasts non-associated natural gas and coproducts such as butane and natural gas liquids. A different approach is used for estimating supplies from speculative, immature areas such as the Alaskan North Slope. Engineering estimates are made in a fashion that is compatible with the MEFS models, but represents expanded geographical detail and recognition of the character of these new sources.

The models first are used to estimate a set of possible additions to reserves of oil and natural gas. The models determine the total exploratory and developmental drilling opportunities which are profitable for each combination of product and coproduct prices examined. These drilling opportunities then are allocated over time for each region to give each a set of drilling opportunities. Developed reserves are produced over time using a fixed decline curve. Once the set of supply opportunities is estimated for each region, the total cost of each possibility is calculated. This calculation gives the cost coefficient associated with the supply trajectory of products and coproducts to be used in the integrating model.

Representations of the above demand and supply components are used in the integrating model in solving a linear program to produce interim market clearing prices. The prices are used to refine the demand component, after which the linear program is resolved. This process continues until the equilibrium supply, demand quantities, and market clearing prices are determined.^{1/}

FOOTNOTES

1. Federal Energy Administration, 1976 National Energy Outlook, Chapter I and Appendices A, C, and D.

APPENDIX E. PROJECTION METHOD

E.1. INTRODUCTION

This appendix describes the methodology used to estimate 1985 industrial fuel use by major industry and region. In order to be consistent with MEFS 1985 regional total fossil fuel demand and to incorporate energy growth parameters at the level of detail required in this analysis, energy use was projected in three steps:

- Developed a detailed regional baseline of historical energy use.
- Projected growth and redistribution of energy by region and industry based on various inputs.
- Reconciled the detailed energy projection with MEFS regional total fossil fuel demand.

An energy data base was developed from existing data sources, primarily ECDB, which include industry and regional detail. This baseline energy demand was projected to 1985 based on an independent conservation adjustment and industrial growth projections consistent with MEFS input parameters. The resultant energy projection was not consistent with the actual MEFS forecast of 1985 regional industrial energy use. To reconcile these data differences, the industry ranking within each region was assumed to be the same for both data sources and the regional totals in ECDB were adjusted to equal those in MEFS. These steps are illustrated in Figure E.1 and described in more detail below.

Industrial detail was required for the 1975 historical energy use as well as for 1985 projected industrial energy use. The projection methodology explained in this appendix was abbreviated to industrialize the 1975 MEFS regional fuel totals. The industry-specific fuel demands from 1974 were fitted to the 1975 totals as described in Section E.4 below.

FIGURE E.1 INDUSTRIALIZATION, 1975-1985

E.2 PROJECTION OF 1985 TOTAL ENERGY DEMAND

E.2.1 1974 Total Energy Demand

The first step in determining 1985 total energy demand was to determine 1974 energy demand by nine industry subgroups (Box 2 in Figure E.1). The nine subgroups are food, textiles, paper, chemicals, petroleum refining, SCG, steel, aluminum, and other industries. The "other" category includes manufacturing not covered in the first eight subgroups, plus mining, construction, and agriculture. Gasoline and diesel use in the latter three industries in "other" are classified in the transportation sector and, thus, are not considered here.

The baseline energy demand was provided by the 1974 ECDB. After removing feedstocks and classifying the industries into nine distinct groups,^{1/} the 1974 total energy was used as a proxy for energy demand by industry and region. The raw 1974 data from the ECDB have fuel type, regional, and two-digit SIC detail. The fuels covered are steam coal, distillate fuel oil, residual fuel oil, natural gas, LPG, and miscellaneous petroleum products. Together these fuels account for over 85 percent of the fuel consumed in the manufacturing sector; the remaining portion consists of fuels such as waste fuels and other gases.

E.2.2 1974-1985 Conservation Adjusted Growth Factors

The second data step (Boxes 3, 4, 5, and 6 in Figure E.1) was to develop 1974-1985 conservation adjusted growth factors. This step was divided into two parts, calculating output growth factors and calculating energy conservation factors.

The macroeconomic forecasts used in MEFS were developed by DRI. To be consistent, DRI Trend Long projections of industrial output demand by region, industry, and year were used to calculate the growth factors in IFCAM. DRI projections assume a steady growth, base simulation extending

from the fourth quarter of 1977 through 1995. The exogenous policy and price variables are manipulated to provide a stable background for growth throughout the 1980's.^{2/} Basic economic assumptions under the DRI Trend Long scenario include the following:

- GNP rises at 4.2 percent per year from 1975 to 1985.
- Unemployment moves from 8.7 percent in 1975 to 4.7 percent in 1985.
- Real personal income grows at three percent per year.
- Net industrial production index increases 3.4 percent per year.

The regional DRI data were presented as a series of nine values for each year from 1973 to 1995. These values represent food, paper, chemicals, petroleum, SCG, primary metals, machinery, total less petroleum, and total. Table E.1 shows the national growth rates in value added data (increases in constant 1975 dollars).

TABLE E.1 ANNUAL INDUSTRY GROWTH^{a/}
(percent)

<u>Industry</u>	<u>1974-85</u>	<u>1974-90</u>	<u>1974-95</u>
Food	3.63	3.23	2.97
Paper	2.18	2.67	2.90
Chemicals	4.96	5.26	5.32
Petroleum	2.53	2.42	2.66
SCG	3.20	3.24	3.06
Primary metals	0.36	1.41	1.93
Other manufacturing ^{b/}	3.66	3.75	3.80
Total manufacturing	3.57	3.83	3.94

^{a/} Increases in value added data. Consistent with Trend Long Low .8 scenario.

^{b/} Excluding machinery and transportation equipment.

Growth rates in industries modeled by EEA for which DRI did not provide explicit growth rates were developed from the aggregate growth rates DRI provided. Growth rates for textiles and "other" were assumed to resemble the average growth rate for total manufacturing. Steel and aluminum growth rates were estimated based on the primary metals' values.

A certain portion of industrial growth is expected to be offset by energy conservation measures. The effect of these measures must be included in industrial growth factors. Although conservation measures vary from industry to industry, MEFS does not identify conservation measures by industry. Consequently, MEFS was not used to estimate conservation impacts in IFCAM.

The IFCAM conservation factors, i.e., the technical potential for conservation in each industry subgroup, were derived from an EEA study completed in 1974.^{3/} These factors are given in Table E.2 and represent projections for three periods, 1974-1985, 1974-1990, and 1974-1995. The primary metal factor was used for both steel and aluminum, and the factor for all industries was used for the "other industry" and textiles subgroups in the model. To highlight the assumptions underlying various conservation estimates, Table E.3 breaks down the conservation estimate in petroleum refining by component for a 1972-1980 time frame.

E.2.3 1985 Projected Energy

The 1985 projected energy is produced by multiplying the 1974 total energy demand for each industry by its corresponding DRI 1974-1985 industrial production growth factor and conservation factor in each region (Box 6 in Figure E.1). Table E.4 illustrates this for Region 3. The resulting 1985 energy demand projection contains total energy demand for each industry within a region, but no fuel type detail within an industry.

TABLE E.2 PROJECTED INDUSTRIAL ENERGY CONSERVATION FACTORS^{a/}

<u>Industry</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>
Food	0.949	0.959	0.959
Paper	0.871	0.788	0.788
Chemicals	0.842	0.765	0.765
Petroleum	0.924	0.914	0.914
SCG	0.827	0.789	0.789
Primary metals	0.825	0.758	0.758
Textiles	0.844	0.759	0.759
Other industry	0.844	0.759	0.759

^{a/}Energy consumption per unit of output: 1974=1.0

SOURCE: Derived from Energy Conservation in the Manufacturing Sector, 1954-1990, prepared for Council on Environmental Quality by Energy and Environmental Analysis, Inc., November, 1974.

TABLE E.3 CONTRIBUTION OF SPECIFIC CONSERVATION MEASURES
IN PETROLEUM REFINING
(SIC 2911)

<u>Conservation Measure</u>	<u>Energy Savings (percent)</u>
Air preheater installation (process heaters)	1.0
Convection sections in process heaters	0.5
Sootblowers on process heaters	0.3
Combustion control instrumentation for process heaters	0.4
Improved insulation for process heaters	0.1
Replacement of old heaters with new equipment	0.7
Convection sections for boilers	0.1
Boiler blowdown heat recovery	0.1
Replacement of old boilers with new equipment	0.1
Combustion control instrumentation for boilers	-
Sootblowers for boilers	-
Improved insulation for boilers	-
Power recovery turbines (FCC systems)	-
Optimization of steam balances	0.4
Condensate recovery (and replacement of steam traps)	0.5
Additional heat exchangers, hot oil systems, interchange of heat between different process units	2.3
Optimization of heat exchanger cleaning cycles	0.5
Insulation of storage tanks	1.0
Instrumentation and computer control of complex units (including fractionating tower controls)	0.3
Direct hot rundown/hot feed systems	1.1
CO boilers for FCC units, high temperature regeneration on FCC units	1.3
Refinery loss control	1.0
Housekeeping	7.1
Other small items not included as separate contributions	0.2
Capacity expansions	1.5
TOTAL	19.0

- indicates less than 0.05 percent.

SOURCE: An Energy Conservation Target for SIC 29; technical potential for conservation in 1972-1980 period in petroleum refining, expressed as percent of total 1972 energy use.

TABLE E.4 PROJECTED ENERGY GROWTH IN REGION 3, 1974-1985

<u>Industry</u>	Total Energy 1974 (1012 Btu) ^{a/} x	DRI Growth Factor ^{b/} x	Conservation Factors ^{c/}	= 1985 Projected Energy (1012 Btu)
Food	76.5	1.48	0.949	107.4
Textiles	32.0	1.49	0.844	40.2
Paper	199.4	1.27	0.871	220.6
Chemicals	168.4	1.70	0.842	241.0
Petroleum	222.6	1.32	0.924	271.5
SCG	188.0	1.42	0.827	220.8
Steel	1160.6	1.04	0.825	995.8
Aluminum	26.6	1.04	0.825	22.8
Other	633.0	1.49	0.844	796.0

a/ Includes steam coal, distillate and residual fuel oil, natural gas, and refinery (still) gas.

b/ DRI growth factors are based on output indicators that vary by region, industry, and year. DRI Trend Long Low .8 scenario.

c/ Conservation factors are industry-specific, but do not vary by region. (For sources, see Table E.2)

E.3 RECONCILING INDEPENDENT PROJECTIONS WITH MEFS

Total projected fuel use, as projected in Section E.2, is aggregated by region and reconciled with fuel control totals provided by MEFS. The preliminary regional projected numbers are normalized to those of MEFS under the assumption that fuel use by industry within a region will not change on a relative basis. For example, if the projection indicates 1.5 quads of fuel use in the Midwest region in 1985 while MEFS only predicts one quad of fuel use in that region, each industry's fuel demand within the region is reduced by one-third ($1.5 \text{ quads} - 1 \text{ quad} / 1.5 \text{ quads} = 1/3$).

This same procedure takes place for 1990 and 1995. Note that MEFS also provides specific fuel use detail on the refinery sector, thus, normalization of fuel use in this industry is completed separately.

E.4 RESULTS AND CONCLUSIONS

Several problems exist with the method used to project 1985 fossil fuel demand. Differences in data bases, assumptions, and logic contribute to the significant differences between preliminary industry projections and MEFS regional totals. The program used to reconcile these results is fairly reasonable only if the projected industry results are close to MEFS.

Table E.5 compares preliminary industry projections to a set of 1985 MEFS regional totals. The preliminary or first approximation overstates regional fuel consumption in most regions. MEFS, however, projects considerably more fuel consumption in region 6 (Southwest)* than was anticipated using the simple projection method. The first approximation shows energy consumption increasing at 2.1 percent annually in region 6, whereas the MEFS growth rate is 5.9 percent (see Table 3.5). Due to this large difference, the regional results should be interpreted carefully.

* Arkansas, Louisiana, New Mexico, Oklahoma, and Texas.

TABLE E.5 COMPARISON OF THE FIRST APPROXIMATION AND
MEFS REGIONAL TOTAL FOSSIL FUEL DEMAND^{a/}
(10¹² Btu)

<u>Region</u>	<u>First Approximation</u>	<u>MEFS Projection</u> ^{b/}
1	344.0	283.9
2	742.9	531.6
3	1,440.9	1,185.3
4	2,185.4	1,569.5
5	2,720.2	2,656.0
6	4,673.4	6,966.5
7	1,310.1	534.4
8	948.3	598.9
9	1,197.6	1,440.6
10	524.1	465.2
Total	16,086.9	16,231.9

a/ Includes steam coal, distillate oil, residual oil, natural gas, and refinery (still) gas.

b/ Sample run regional control totals used in Section 8.

Table E.6 displays the variations in growth rates by industry after preliminary numbers have been normalized to the MEPS regional control totals. The major implication of these data is that most fossil fuel growth by 1985 is expected from the chemicals industry.

TABLE E.6 TOTAL FOSSIL FUEL DEMAND^{a/}

<u>Industry</u>	<u>1974 Total Fossil Fuel^{b/} (10¹² Btu's)</u>	<u>1985 Total Fossil Fuel^{c/} (10¹² Btu's)</u>	<u>Compound Annual Increase (percent/year)</u>
Food	682.3	880.3	2.3
Textiles	189.1	177.2	-0.6
Paper	1,183.0	1,236.0	0.4
Chemicals	2,210.4	4,126.1	5.8
Petroleum	2,491.6	3,294.5	2.6
SCG	1,025.4	1,230.6	1.7
Steel	1,231.4	984.4	-2.0
Aluminum	508.3	616.9	1.8
Other	2,700.2	3,685.9	2.9
Total	12,221.7	16,231.9	2.6

a/ Steam coal, distillate oil, residual oil, natural gas, and refinery (still) gas.

b/ Source: Energy Consumption Data Base, prepared by EEA for FEA, June, 1977. Includes steam coal, distillate and residual fuel oil, natural gas, and refinery (still) gas.

c/ Sample run population (see Section 8). Includes steam coal, distillate oil, residual oil, natural gas, and refinery (still) gas.

FOOTNOTES

1. See Section 3.1.
2. DRI U.S. Long Term Review, Winter 1977: Model Notes on Trend Long 1276.
3. Energy and Environmental Analysis, Inc., Energy Conservation in the Manufacturing Sector, 1954-1990, prepared for Council on Environmental Quality, November, 1974.

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APPENDIX F. BOILER CAPACITY UTILIZATION RATES

F.1 INTRODUCTION

This appendix presents the methodology used to derive data on boiler capacity utilization rates currently contained in IFCAM. The derivation of the "original" data files on capacity utilization suffered from two serious problems: use of an unedited, preliminary version of DOE's MFBI survey and the judgmental criteria used to select values from the MFBI and other data sources. As a consequence of these problems with the "original" capacity utilization data, a "revised" file of capacity utilization rates also is derived in this appendix based on improved data and systematic statistical criteria.

Finally, this section presents preliminary results of statistical analysis of factors related to variations in boiler capacity utilization rates to provide guidance for further refinements of these data files. Refining the capacity utilization rates used in IFCAM is an ongoing effort. This appendix essentially constitutes a status report on that effort.

F.2 DERIVATION OF THE ORIGINAL BOILER CAPACITY UTILIZATION RATES

F.2.1 Limitations Imposed by IFCAM Model Structure

The model projects boiler fuel use by nine industrial sectors and three boiler size categories for new units. Consequently, the original capacity utilization files could differentiate capacity utilization by industrial sector and size. Computational limitations were imposed so that no more than two capacity utilization rates could be used for any industrial/size boiler cell. Thus, the model structure and computer programming specifications limited capacity utilization data to a maximum of 54 capacity utilization rates (nine industries x three boiler sizes x two capacity utiliza-

tion rates). In effect, for each industry/size cell, high and low capacity utilization rates could be derived.

F.2.2 Preliminary Data Sources

The three principal data sources used to develop capacity utilization distribution were DOE's MFBI survey, EPA's National Emissions Data System (NEDS), and the Bureau of Census' Survey of Plant Capacity (SPC). The MFBI file has been described in Appendix B. NEDS and SPC data are described below.

F.2.2.1 NEDS

The NEDS data base covers all plants with a potential of emitting more than 100 tons/year of any of five major pollutants. Total coverage is more than 94,000 emission sources at nearly 34,000 facilities. The operating rate of each combustor is included. Like MFBI, many records could not be considered because of obvious inconsistencies.

F.2.2.2 SPC

The SPC data for 1974 include tables on the number of shifts at actual production levels for all two-digit SIC manufacturing industries. Assuming that hours of plant operation correlate well with hours of boiler operation, these data can serve as a general guide to industry boiler capacity utilization.

F.2.3 Methodology Used to Generate Original Capacity Utilization Distributions

Distributions of boiler capacity utilizations were determined separately for new and existing installations. MFBI was used as the basis for the distribution among existing boilers. Distribution of capacity utilization among new boilers also was based on MFBI data, but included adjustments when there were significant conflicts with SPC data and when engineering judgments based on steam applications for each industry indicated significantly different distributions.

F.2.3.1 Existing Boilers

All existing boilers were classified into two categories, units operating at over 50 percent capacity utilization and units operating below that utilization rate. Fifty percent capacity utilization was judged as the natural breakpoint because steam uses above this ratio primarily consist of high capacity process uses and steam uses below this ratio were generated primarily by space heating boilers. This simplification was made because it decreased the practical operating time of the model. The original objective of the model was to estimate coal use, and the use of only two capacity utilization rates for existing boilers did not affect substantially the results, since relatively few existing boilers converted to coal under the fuel price scenario being used.

An average capacity utilization rate was estimated for the two capacity utilization classes. The ratio for boilers above 50 percent, estimated from the average historical capacity utilization rates of those units, is 63 percent. The utilization ratio of boilers below 50 percent capacity utilization was 30 percent. Thus, for each industry and boiler size class for existing boilers, boiler fuel use was assigned one of the two capacity utilization rates, depending on whether the actual capacity utilization rate of the boiler, according to MFBI data, was above or below 50 percent.

F.2.3.2 New Boilers

Since variations in capacity utilization rates for new boilers were judged more critical to the economics of fuel choice, especially for coal, a more complicated method was used to derive capacity utilization rates. A unique distribution was developed for each size class within each industry. Three steps were involved in the development of each distribution. First, preliminary MFBI data from the MFBI file were examined by industry and size category to develop first-cut distributions. Second, these distributions were compared with SPC data on the number of shifts employed by each industry. When there were significant discrepancies between the SPC and MFBI

data, the MFBI data were altered in the direction of the SPC data. Such adjustments were usually minor when required.

Third, adjustments were made based on the actual steam applications in various industries. Some industries, for example, use a significant portion of their total steam production for space heating. Because space heating is only required a few months of the year in many parts of the country, the capacity utilization assumed for such needs was 25 percent. Other industries, which use steam for power generation, are known to operate around the clock, year round. MFBI distributions of capacity utilization for each industry and size class were examined to insure that they were consistent with these practical considerations.

The resulting distributions are summarized in Table F.1. For example, five percent of new boiler fuel use in the food industry would be in units in the 100-250 MMBtu/hr range operating at a capacity utilization rate of 25 percent. Since the MFBI file has data only for boilers above 100 MMBtu/hr firing rates, capacity utilization rates for the class of smaller boilers usually were assumed to be the same as for the 100-250 MMBtu size. For a few sectors which appeared to experience very high capacity utilization rates for all the larger boiler sizes (paper, chemicals, and aluminum), somewhat lower rates were set for the less than 100 MMBtu/hr size to capture space heating applications in some of the smaller plants which conducted less energy-intensive final processing steps.

F.2.3.3 Problems with the Original Data Files

The original capacity utilization files contained several weaknesses. Some of these relate to conceptual issues on how historical data were applied. For example, use of Table F.1 for all new boilers regardless of the fuel selected requires the incentive for new boilers users to operate the same boiler at a higher capacity utilization rate when considering coal, since its capital costs are so high. In other words, a shift toward coal in the

TABLE F.1 CAPACITY UTILIZATION FOR NEW BOILERS BY SIZE, BY INDUSTRY

<u>Industry</u>	<u>Size (MMBtu/hr)</u>	<u>Capacity Utilization (percent)</u>	<u>Percent of Total Energy</u>
Food	<25	*	13
	25-100	25	1
		45	32
	100-250	25	5
		45	39
	>250	45	6
		65	4
Textiles	<25	*	6
	25-100	25	10
		65	59
	100-250	25	1
		55	22
	>250	65	2
Paper	<25	*	2
	25-100	45	4
		55	5
	100-250	55	11
		65	13
	>250	65	30
		75	35
Chemicals	<25	*	1
	25-100	45	9
		65	14
	100-250	55	12
		65	34
	>250	65	30
Petroleum	<25	*	0
	25-100	45	5
		65	8
	100-250	75	44
	>250	75	43
SCG	<25	*	20
	25-100	25	60
	100-250	25	20
	>250	-	-
Steel	<25	*	2
	25-100	25	12
		65	20
	100-250	25	6
		55	54
	>250	55	2
		65	4
Aluminum	<25	*	0
	25-100	25	4
		55	7
	100-250	55	24
		75	36
	>250	55	7
		75	22
Other	<25	*	8
	25-100	25	11
		55	23
	100-250	25	8
		55	41
	>250	45	4
		65	5

* Not included in the model.

future probably will mean a trend toward larger boilers with higher operating rates than in the past. By strictly applying historical size and capacity utilization rates, the model will tend to understate the economics of coal use. Similarly, for existing boilers, a greater differential between coal and scarce fuel prices in the future will tend to raise capacity utilization rates in scarce fuel-fired boilers to the extent that plant operating conditions will allow.^{1/} These and similar issues are discussed further in the last section of this appendix which addresses the determinants of capacity utilization rates.

Another problem relates to the use of only two capacity utilization rates for existing boilers. This was reasonable for the original model version which focused only on the selection of coal. However, since the model was expanded to make the fuel choice decision between gas, distillate oil, and residual oil as well as coal, the lack of more realistic differences in capacity utilization rates will tend to produce more "bing-bang" fuel choice decisions between the scarce fuels. Thus, the programming capacity of IFCAM which allows for 54 different capacity utilization rates for existing units also should be utilized.

Finally, the rates for new boilers shown in Table F.1 were derived based on unedited MFBI data files which included bad records, such as capacity utilization rates exceeding 100 percent, and miscoded data. In addition to data problems, the method used to select capacity utilization rate levels (the first column of numbers in Table F.1) and the percentage of fuel use in each size cell (the last column in Table F.1), while reasonable, were done very quickly based on judgmental criteria. No optimization criteria were used to select break points which are statistically supported. The extent of errors introduced by this judgmental process was inherently unknown.

F.2.4 Development of Revised Capacity Utilization Distributions for IFCAM

The first steps in the improvement of the capacity utilization data in IFCAM were to edit the MFBI file and regenerate Table F.1 based on a readily reproducible, statistically based methodology.

F.2.4.1 Definition of Capacity Utilization

Capacity utilization was derived from the MFBI file by dividing the Btu's consumed in a boiler by its capacity. In order to convert fuel consumption to Btu's, the following conversion ratios were used (physical units times MMBtu's).

- Coal consumption x 26.0.
- Residual oil consumption x 6.287.
- Distillate oil consumption x 5.83.
- Gas consumption x 1.024.

Using these ratios, capacity utilization was derived as follows:

$$\text{Capacity Utilization} = \frac{\text{Btu's consumed}}{\text{Firing rate} \times 8760}$$

where 8760 equals the number of hours in a year. Since the MFBI file only lists detailed information for boilers with a capacity of 100 MMBtu/hr or greater, the only capacity utilizations which were analyzed were those in the larger size classes used in IFCAM.

F.2.4.2 Improvements in the Original MFBI File

EEA's initial copy of the MFBI file contained many data inaccuracies. Many estimates of capacity utilization yielded results that were greater than 100 percent. Although some of these estimates were caused by EEA's use of standardized Btu conversion ratios, most of the error was due to unverified keypunching. Some other records had functional use shares (process steam vs. space heating) summing to greater than 100 percent. These incorrect records either were revised or eliminated. Other file corrections made included changing the SIC code from two- and three-digit to four-digit whenever possible and checking the year the boiler was built.

After these file changes were made, EEA felt reasonably confident to use the revised MFBI file as a check upon some of the characteristics in the original capacity utilization data files described above. Table F.2 illustrates base data elements of the revised MFBI file. It shows the mean capacity utilization for all boilers in each industrial sector as well as the confidence interval around the mean and the number of observations for each size category within each industrial sector.

F.2.4.3 Statistical Methodology for Calculating Capacity Utilization Distributions from the Revised MFBI File

As mentioned previously, a bimodal distribution of capacity utilization by boiler size and industry was developed in order to conform to the practical dimensional limitations within the model. The original estimates of capacity utilization currently used in IFCAM were developed within these dimension limitations based on preliminary MFBI data and additional subjective judgment. A statistical test was developed that would eliminate the subjective element in the original capacity utilization distribution but still conform to a bimodal split of capacity utilization rates within each industry and size cell. The following two sections describe this statistical test and the resultant distributions with respect to the preliminary estimates.

The two capacity utilization rates and the two fuel distributions for each industry/boiler size cell are determined by ranking the capacity utilization rate of the boilers in the cell and selecting a break point in the ranking list. For example, selecting 45 percent as the break point and taking the mean capacity utilization rate for the boilers below that break point and calculating the share of all fuel use below the break point gives values for two of the four distribution values. Similarly, calculating the mean capacity utilization rate for boilers above the break point and taking (1-share of fuel use) above the break point provides the remaining two numbers in the distribution. It was determined that the best criterion for selecting the break point in the ranking was to select the point so that

TABLE F.2 CAPACITY UTILIZATION: REVISED MFBI DATA
(percent)

<u>Industry</u>	<u>100-250^{a/} MMBtu/hr</u>	<u>Number of Observations (100-250 MMBtu/hr)</u>	<u>>250^{a/} MMBtu/hr</u>	<u>Number of Observations (>250 MMBtu/hr)</u>	<u>Mean Capacity Utilization</u>
Food	28-37	273	29-59	31	34
Textiles	28-44	66	55-100	9	42
Paper	42-49	374	32-45	208	43
Chemicals	49-55	580	49-61	189	53
Petroleum	48-58	200	55-67	152	56
SCG	22-42	34	13-41	3	32
Steel	29-42	188	26-39	110	35
Aluminum	75 ^{b/}	6	75 ^{b/}	15	75
Other	33-38	1158	35-46	254	37

a/ Numbers represent confidence intervals around the mean at 99.7 percent.

b/ The mean capacity utilization was substituted for the actual distribution for aluminum due to the small number of observations existing in this category.

the resulting bimodal distribution maximized the explained variance around the mean capacity utilization rate for the specific industry/boiler size cell.

In order to derive a statistically valid capacity utilization distribution according to this criterion, the variance was calculated for each industry and size cell. Maintaining the bimodal distribution within each size and industry, the historical MFBI data were split into two parts -- units above a certain capacity utilization and units below that capacity utilization rate. This data splitting was done for 20 different capacity utilization breakpoints within each size and industry category. By minimizing the pooled variance of the two data sets (above and below each breakpoint), the best (lowest pooled variance) bimodal distribution was found for each category, and the mean, as well as the percent of fuel consumed, within each data set was established.^{2/}

Two sets of distributions -- mean capacity utilizations and percent of fuel consumed in each cell -- were generated by the above statistical procedure. By comparing these mean capacity utilization rates and the percentage of fuel consumed in each cell with the original data file, one can evaluate the accuracy of the estimation techniques used in the initial analysis.

F.2.4.4 Comparison of Revised with Original Capacity Utilization Estimates

A similar statistical analysis was performed for the single bimodal distribution for all existing boilers to compare with the original estimates. Even though the full distribution of capacity utilization for existing units with 54 rates should be used, it is useful to see how different the simple two element capacity utilization rates would be for existing boilers.

For existing units, the statistical analysis was done on the total industry data. All boilers were classified as high or low capacity utilization and tested to determine reasonable groupings. Based on the above statistical

analysis, the average high/low capacity utilization rates should have been 67 percent/15 percent for large units (over 250 MMBtu/hr) and 68 percent/24 percent for smaller units (100-250 MMBtu/hr) compared to the 63 and 30 percent originally used for both sizes. Boiler size distribution does not seem critical in existing units and, although the results seem to indicate that average capacity utilization for low-utilization boilers is somewhat overestimated, in general the estimates are comparable to the original distributions, based on a 50 percent capacity utilization breakpoint.

Table F.3, which displays the resulting mean capacity utilization rates by nine industry groups and two sizes, as well as the percentage of fuel use by each category, is useful in comparing the revised data to the original unit distributions used for new boilers in IFCAM. As explained above, this table lists the mean capacity utilizations associated with the smallest unexplained variance for each group. The table shows that, although the capacity utilization rates are quite similar for many industries, the percentage of fuel use in cells differs significantly between the original estimates and the revised MFBI file in many cases.

Four industries - paper, chemicals, steel, and "other" -- show large disparities in capacity utilization rates. The chemical industry's revised MFBI distributions as well as those for steel and "other industry" show a greater range in high to low capacity than the original estimates. For example, revised data on 100-250 MMBtu/hr boilers in the chemical industry suggest that the capacity utilizations should be grouped at 66 percent (high capacity) and 20 percent (low capacity). The current file in IFCAM decreases this range by assigning 65 percent to high capacity boilers and 55 percent to low capacity boilers. The indication from this analysis is that the file should be modified to incorporate wider high/low capacity variations than are currently in the model for these three as well as other industries.

TABLE F.3 COMPARISON OF CAPACITY UTILIZATION FILE USED IN IFCAM
WITH REVISED MFBI FILE

Industry	Size (MMBtu/hr)	Capacity Utilizations		% of Fuel Use in Cells	
		Revised ^{a/} MFBI File	Original File	Revised ^{a/} MFBI File	Original File
Food	100-250	16	25	17	9
		52	45	56	72
	>250	19	45	4	11
		61	65	23	8
Textiles	100-250	34	25	44	4
		73	55	15	88
	>250	17	65 ^{b/}	1	8
		94	-	40	-
Paper	100-250	20	55	6	12
		66	65	39	15
	>250	8	65	3	34
		63	75	52	39
Chemicals	100-250	24	55	7	16
		67	65	51	45
	>250	18	65	2	39
		67	-	40	-
Petroleum	100-250	7	75	1	51
		61	-	31	-
	>250	29	75	6	49
		73	-	62	-
SCG	100-250	21	25	36	100
		56	-	51	-
	>250	28	-	13	-
Steel	100-250	18	25	11	9
		72	55	26	82
	>250	14	55	14	3
		66	65	49	6
Aluminum	100-250	-	55	-	27
		-	75	-	40
	>250	-	55	-	8
		-	75	-	25
Other	100-250	30	25	37	14
		83	55	21	71
	>250	17	45	7	7
		67	65	35	8

a/ Bimodal capacity utilizations with smallest unexplained variance.

b/ Too few observations for analysis.

The last two columns in Table F.3 compare the share of fuel in the high/low capacity utilization rates for each industry/size class. While there is no consistent trend, the revised fuel shares by high/low differ substantially from the original estimates.

Table F.4 illustrates the aggregated data for all industries based on the MFBI file industry mix. Within each of the two large boiler size classes, the revised data clearly show a much greater share of fuel use in both the highest and lowest capacity utilization classes. For example, the revised data for the 100-250 MMBtu/hr class show over 30 percent of fuel use with capacity utilization rates below 50 percent, compared to only 12 percent in the original files. For the largest boiler size, the revised data show both more low capacity utilization units and have 53 percent of fuel use above 70 percent operating rates compared with only 23 percent of fuel use in the original file.^{3/}

It is clear that insertion of the revised data into IFCAM, which has not taken place yet, could alter substantially the economics of fuel choice for many of the model cells, although the overall effect cannot be predicted readily. Until we have time to perform a similar statistical analysis for boilers below 100 MMBtu/hr using the NEDS data file, we will have to continue to assume that the capacity utilization rates and distributions are similar to those in the 100-250 MMBtu/hr class, even though these boilers are likely to have even lower capacity utilization rates.

F.3 VARIABLES THAT IMPACT CAPACITY UTILIZATION RATES

If no other factors were present, combustor capacity utilization would be set to maximize fuel use efficiency in each combustor. Other factors, however, do affect capacity utilization. For example, varying plant steam load characteristics (daily and seasonal fluctuations) affect capacity utilization rates. Boilers firing more expensive fuels will tend to be utilized less than low cost alternatives. Boilers generating process steam are run

TABLE F.4 AGGREGATED CAPACITY UTILIZATION DISTRIBUTION

(percent of total)

ORIGINAL CAPACITY UTILIZATION DATA

Capacity Utilization ^{a/} Rates (%)	Boiler Size (MMBtu/hr)		
	<u>100-250</u>	<u>>250</u>	<u>Total</u>
5-29	7	-	4
30-49	5	7	6
50-59	42	0.3	21
60-69	37	70	53
70-100	9	23	16

REVISED CAPACITY UTILIZATION DATA

Capacity Utilization Rates (%)	Boiler Size (MMBtu/hr)		
	<u>100-250</u>	<u>≥250</u>	<u>Total</u>
5-29	12	6	9
30-49	19	14	17
50-59	16	14	15
60-69	16	13	14
70-100	37	53	45

^{a/} Before base case conversions.

at higher load factors than space heat boilers. The following is a partial list of the factors that might affect capacity utilization rates for each combustor.

- Functional use (process steam, space heat, etc.).
- Industry group.
- New/existing distinction.
- Age.
- Size.
- Fuel type/price.
- Plant boiler capacity in relation to annual steam demand.

In IFCAM, capacity utilization is allowed to vary by industry and size only. The analysis discussed below incorporates most of the variables listed above except for fuel price distinctions. It should be recognized at the outset that generic factors such as those listed above probably can be expected to explain only a relatively small share of the variance in boiler generating rates. This is because capacity utilization rates depend heavily on plant-specific contexts. Each plant will have its own steam load characteristics composed of peak demand, seasonal fluctuations, etc. Given steam load characteristics, the plant will have a specified mix of boilers with varying sizes and operating characteristics. For example, a plant with large and constant process steam demands would have primarily base-loaded boilers. Some plants may use more smaller boilers to meet such a steam load because they are more concerned about vulnerability to forced boiler outages. This reliability concern will vary depending on the plant engineers' judgment (and biases) as well as the nature of the production processes. Other plants with more variable swings in steam loads will tend to have lower capacity utilization rates and will select boilers with high turndown rates and quick start-up capability. These factors affect fuel choice as well since, for example, some coal-fired boilers have less operating flexibility in load swings than oil- or gas-fired units.

Thus, unless we can capture the variability among plants in plant steam load requirements and the configuration of existing boilers to meet such loads, much of the impact of these factors on boiler capacity utilization rates cannot be captured, except to the extent it is reflected in the historical distributions discussed in previous sections of this appendix.

However, this does not mean that we should not attempt to determine the influence of generic factors we can quantify on capacity utilization rates and incorporate these into IFCAM if they appear to be important.

F.3.1 Relevance of Independent Variables

This section discusses the potential impact of each of the generic variables and proposes hypotheses in the nature of the impacts to be tested in the statistical analysis.

F.3.1.1 Functional Use

Boilers' functional use, one of the factors which might affect capacity utilization, is separated into four categories in the MFBI survey (see Appendix B): electricity generation, space heating, process steam, and other. Boilers of different functional uses should have different capacity utilization rates. For example, a space heater generally is used during the winter months; consequently, it would tend to have a lower capacity utilization rate (25-30 percent). A boiler used to generate process steam would tend to have a relatively high capacity utilization. While some process operations (e.g., canning of food products) are influenced by seasonal factors, a boiler devoted primarily to process demands should exhibit a higher capacity utilization rate than one which satisfies space heat requirements.

It is not clear whether a boiler which is used primarily to generate electricity would tend to have high or low operating rates. The MFBI survey provides no additional insights which might help, such as whether the unit is part of a cogeneration complex, whether it generates power to meet peak

plant electricity demand or is used to generate baseload power for plant operations. A boiler used for baseload power generation should have a relatively high load factor similar to process steam loads. A cogenerating unit probably would operate at high operating rates as well. Assuming that industrial boilers whose steam primarily is used for power generation are generally baseload, one might hypothesize a high load factor relative to space heating uses.

The "other" category is difficult, if not impossible, to interpret. It could contain special requirements or merely reflect a misunderstanding of terms by the reporting entity.

F.3.1.2 Industry

Use of SIC code of the industrial sector in which the boiler is being used may capture variations in capacity utilization rates. This variable is a rough proxy for capturing plant-specific steam load demands and boiler configurations to the extent that these differ systematically between industries. If general boiler operating practices tend to differ between major production processes, SIC codes also may reflect the status of the business cycle for a specific sector, such as whether the chemical industry was operating at the peak of plant capacity while petroleum refineries were operating at a lower rate in 1974 due to lack of demand following sharp world oil price increases.

F.3.1.3 Boiler Size

There is some reason to expect larger boilers to operate at higher capacity utilization rates. First, when the fuel user is considering purchase of the boiler, there are economies of scale in capital cost, i.e., cost per MMBtu of capacity declines as unit size increases. Other factors being equal, the choice of a larger boiler is more likely for a steam demand characterized by high operating requirements. Selecting a large boiler to meet a steam load with low capacity utilization will tend to result in a high capital cost per

pound of steam generated. Conversely, capital costs per pound of steam generated for a requirement of 200 MMBtu/hr capacity at a 70 percent load factor will be less for a 200 MMBtu/hr boiler than for two 100 MMBtu/hr boilers.

Boiler operating costs also exhibit economies of scale, e.g., it takes almost the same labor per boiler to operate a boiler of a certain type, regardless of boiler size. Thus, given a particular set of boilers in a plant, large boilers will tend to be used more intensively in order to minimize non-fuel operating costs per pound of steam generated.

F.3.1.4 Fuel Type

There are several reasons to expect capacity utilization rates to differ by fuel type. In general, boilers fueled by oil and gas can respond more rapidly to load swings than those fired by coal. Among the coal-fired boilers, the pulverized coal direct-fired systems can respond to load fluctuation most quickly. However, their use in boiler systems smaller than 100 MPPH is uneconomic as compared to the stoker coal-fired systems.

Not only are coal-fired boilers' responses to load swings more sluggish, but also the turndown ratio available to coal-firing burners is smaller with respect to oil and gas burners. Circular type burners for gas and return-flow type burners for oil can achieve a 10:1 turndown ratio; a well designed coal-fired burner will operate, on the other hand, over a range of two or three to one. For these reasons, one would expect proportionately more coal boilers to be used for baseload demand while oil and gas would be used for peaking or more cyclical steam demands. This distinction would directly affect the capacity utilization rates associated with different fuels.

Fuel costs also determine the capacity utilization rate of a boiler. Coal and gas probably would have higher capacity utilization rates than oil, due to their relatively lower prices in 1974. Time limitations did not permit us to include regional fuel prices as an independent variable to capture

this effect. To the extent that coal and gas tended to be cheaper in the 1974 period, their capacity utilization rates should be higher than for oil-fired boilers.

Finally, coal-fired boilers of all sizes have both higher capital and fixed operating costs. Consequently, even if fuel prices were equal, coal-fired boilers should operate at higher capacity utilization rates.

All of these fuel-specific factors should tend to encourage users to operate a coal-fired boiler at higher operating rates than oil-fired units. Operating flexibility factors will tend to encourage gas use at low load factors while the low cost of gas also favors its use for baseload steam demands. Consequently, the load factor for gas is difficult to predict relative to oil or coal.

F.3.1.5 Age

It is not clear whether capacity utilization rates will be correlated with age in the industrial sector. Figure F.1a illustrates typical practices in the electrical utility industry. New boilers typically operate at low operating rates during start-up as debugging problems are resolved. Then, the unit will operate at a high capacity utilization rate. Since the utility industry can generate power from many plants, it will tend to reduce the capacity utilization rate of a boiler over time as new boilers come on line. As the boiler ages, operating costs will tend to increase and new boilers may be more efficient in terms of fuel required per pound of steam generated.

Industrial boilers may go through a similar cycle. However, we would anticipate its age profile to look more like the curve in Figure F.1b. This is because boiler operating requirements are constrained far more by conditions specific to the plant. While a new utility boiler at plant A can replace power previously generated from an existing boiler at plant B, this is not the case in an industrial plant. This reduced flexibility in industrial

FIGURE F.1

a. Capacity Utilization vs. Boiler Age for a Utility

b. Capacity Utilization vs. Boiler Age for an Industry

facilities is more likely to lead to a lack of correlation between age and capacity utilization rates. Thus, an industrial boiler is more likely to be operated at its planned capacity utilization rate for a long period than retired to a stand-by status.

F.3.1.6 Boiler/Plant Consumption Ratio

Capacity utilization rates for a boiler in any plant may depend on its importance in relation to overall boiler capacity. A boiler which comprises only five percent of total plant boiler capacity is much more likely to be operated at a lower capacity utilization rate than a boiler comprising 80 percent of plant capacity. Essentially, the plant manager has more flexibility to take account of operation cost/MMBtu differences for a boiler which comprises only a small segment of steam capacity, or this situation may reflect a past decision to place the boiler in a stand-by capacity since a new boiler recently was installed at the plant.

F.3.2 Statistical Analyses of Capacity Utilization

In order to determine which variables affect capacity utilization, regression analysis was applied to the revised MFBI data base. Capacity utilization was regressed against the six independent variables discussed above. The determinants of capacity utilization rates were analyzed separately for each industrial sector. This approach was used since industrial SIC code is the primary proxy for operating practices and thus we expected that different variables might be important in different industries.^{4/}

Six sets of sensitivity regressions were made for each industry. In the first five, capacity utilization was regressed against one of the five independent variables listed above. The last regression looked at capacity utilization as a function of all the significant independent variables from the single variable regressions. For example, industrial sector, boiler size, and functional use all will be correlated. The food industry tends to have low capacity utilization rates, small boilers, and largely space heating

functional uses. In analyzing each single variable, they all may be significant. When all three variables are evaluated jointly, one or two of the variables may drop out.

The independent variables were specified in the form of dummy or "class" variables. Table F.5 lists the categories used. For example, functional use had five variables. Three reflect predominant functional uses for space heat, process heat, and electricity generation. Along with the "other" class reported on the MFBI, the fifth variable reflects cases when no one functional use dominated.

For each independent variable $n-1$ regressions were run where n equals the number of classes for that variable. Each regression had $(n-1)$ classes. The "nth" class was omitted to ensure a non-orthogonal relationship between capacity utilization and the independent variable. A similar procedure was followed for the set of multiple regressions, except that only the classes which proved to be significant in the individual regressions were included. Using a student's t -score to determine whether a particular variable, and an f -score to determine whether the overall regression, significantly affected capacity utilization, the regressions were tested to see if the assumptions cited in F.3.1 were reflected by the data.

F.3.3 Results of Statistical Analysis of Capacity Utilization

Tables F.6 through F.10 list the significant class breakout by industry for each independent variable, as well as the mean capacity utilization associated with that class. As the tables point out, the revised MFBI data yield different class breakouts for different industries. A discussion of each variable's effect upon capacity utilization is presented below.

F.3.3.1 Single Variable Analyses

The results on fuel type do confirm the hypothesis (in all industries where coal is a significant fuel) that coal-fired boilers have a significantly

TABLE F.5 CLASS BREAKDOWN OF DUMMY VARIABLES USED IN REGRESSION ANALYSIS
ON CAPACITY UTILIZATION

Functional Use

- Class 1: Percent of electricity generation ≥ 60
- Class 2: Percent of space heating ≥ 60
- Class 3: Percent of process steam ≥ 60
- Class 4: Percent of other use ≥ 60
- Class 5: Percent of any use < 60

Size

- Class 1: Capacity between 100-129 MMBtu
- Class 2: Capacity between 130-169 MMBtu
- Class 3: Capacity between 170-199 MMBtu
- Class 4: Capacity between 200-249 MMBtu
- Class 5: Capacity between 250-299 MMBtu
- Class 6: Capacity between 300-349 MMBtu
- Class 7: Capacity between 350-399 MMBtu
- Class 8: Capacity between 400-499 MMBtu
- Class 9: Capacity ≥ 500 MMBtu

Age

- Class 1: Boilers built prior to 1940
- Class 2: Boilers built between 1940-1949
- Class 3: Boilers built between 1950-1959
- Class 4: Boilers built between 1960-1964
- Class 5: Boilers built between 1965-1969
- Class 6: Boilers built in and after 1970

Fuel Type

- Class 1: Coal ≥ 60 percent of boiler fuel consumption.
- Class 2: Residual ≥ 60 percent of boiler fuel consumption.
- Class 3: Distillate ≥ 60 percent of boiler fuel consumption.
- Class 4: Gas ≥ 60 percent of boiler fuel consumption
- Class 5: Any fuel < 60 percent of boiler fuel consumption.

TABLE F.5 (continued)

Boiler/Plant Consumption Ratio^{a/}

- Class 1: Ratio between 0-9 percent.
- Class 2: Ratio between 10-39 percent.
- Class 3: Ratio between 40-69 percent.
- Class 4: Ratio between 70-100 percent.

^{a/} Ratio of single boiler capacity to the sum of the capacity of all boilers in the plant.

TABLE F.6 SIGNIFICANT FUELS AND THEIR MEAN CAPACITY UTILIZATIONS
BY IFCAM INDUSTRY GROUP^{a/}

<u>Industry</u>		<u>Coal</u>	<u>Residual</u>	<u>Distillate</u>	<u>Gas</u>
Food	Class	x		x	x
	Mean capacity utilization	43		17	33
Textiles	Class		x		x
	Mean capacity utilization		57		38
Paper	Class	x	x	x	
	Mean capacity utilization	60	44	28	
Chemicals	Class	x	x	x	
	Mean capacity utilization	61	49	23	
Petroleum	Class		x		
	Mean capacity utilization		40		
Steel	Class	x			
	Mean capacity Utilization	54			
Other	Class		x	x	x
	Mean capacity utilization		37	27	42
Total	Class	x	x	x	x
	Mean capacity utilization	49	40	27	48

^{a/} Significance was determined at 95 percent. A blank space indicates a non-significant t-score. Aluminum and SCG were omitted because of too few observations.

TABLE F.7 SIGNIFICANT FUNCTIONAL USES AND THEIR MEAN CAPACITY
UTILIZATIONS BY IFCAM INDUSTRY GROUP^{a/}

<u>Industry</u>		<u>Electricity Generation</u>	<u>Space Heating</u>	<u>Process Steam</u>	<u>Other</u>
Food	Class				
	Mean capacity utilization	not significant			
Textiles	Class	x		x	
	Mean capacity utilization	79		38	
Paper	Class				
	Mean capacity utilization	not significant			
Chemicals	Class			x	x
	Mean capacity utilization			55	61
Petroleum	Class			x	x
	Mean capacity utilization			60	47
Steel	Class			x	x
	Mean capacity Utilization			35	44
Other	Class	x			
	Mean capacity utilization	60			
Total	Class	x	x	x	
	Mean capacity utilization	57	38	46	

^{a/} Significance was determined at 95 percent. A blank space indicates a non-significant t-score. Aluminum and SCG were omitted because of too few observations.

TABLE F.8 SIGNIFICANT SIZES AND THEIR MEAN CAPACITY UTILIZATIONS
BY IFCAM INDUSTRY GROUP^{a/}

<u>Industry</u>		<u>Size 2</u>	<u>Size 3</u>	<u>Size 4</u>	<u>Size 5^{b/}</u>
Food	Class	100-169	170-299	300-349	350+
	Mean capacity utilization	33	40	59	36
Textiles	Class	100-249	250+		
	Mean capacity utilization	39	85		
Paper	Class	100-199	200-499	500+	
	Mean capacity utilization	47	52	37	
Chemicals	Class	100-169	170+		
	Mean capacity utilization	52	59		
Petroleum	Class	100-199	200-299	300-399	400+
	Mean capacity utilization	58	54	69	63
Steel	Class	100-249	250-399	400+	
	Mean capacity Utilization	39	25	46	
Other	Class	100-299	300+		
	Mean capacity utilization	39	48		
Total	Class	100-169	170-299	300+	
	Mean capacity utilization	42	48	53	

a/ Significance was determined at 95 percent. A blank space indicates a non-significant t-score. Aluminum and SCG were omitted because of too few observations.

b/ Size "1" (25-99 MMBtu) of IFCAM model cannot be analyzed by MFBI data.

TABLE F.9 SIGNIFICANT YEARS BOILER BUILT AND THEIR MEAN CAPACITY
UTILIZATIONS BY IFCAM INDUSTRY GROUP^{a/}

<u>Industry</u>		<u>Age 1</u>	<u>Age 2</u>	<u>Age 3</u>
Food	Class	pre-1940	1940-1959	1960+
	Mean capacity utilization	28	44	33
Textiles	Class	pre-1940	1940-1959	1960+
	Mean capacity utilization	38	72	33
Paper	Class	pre-1960	1960-1969	1970+
	Mean capacity utilization	52	46	31
Chemicals	Class	pre-1940	1940-1969	1970+
	Mean capacity utilization	49	58	44
Petroleum	Class	pre-1970	1970+	
	Mean capacity utilization	60	50	
Steel	Class	pre-1940	1940-1964	1965+
	Mean capacity Utilization	46	36	26
Other	Class	pre-1940	1940+	
	Mean capacity utilization	47	39	
Total	Class	pre-1965	1965-1969	1970+
	Mean capacity utilization	48	44	37

^{a/} Significance was determined at 95 percent. A blank space indicates a non-significant t-score. Aluminum and SCG were omitted because of too few observations.

TABLE F.10 SIGNIFICANT BOILER/PLANT CONSUMPTION RATIOS AND THEIR
MEAN CAPACITY UTILIZATIONS BY IFCAM INDUSTRY GROUP^{a/}

<u>Industry</u>		<u>Boiler Plant 1</u>	<u>Boiler Plant 2</u>	<u>Boiler Plant 3</u>
Food	Class	0-9%	10-100%	
	Mean capacity utilization	18	37	
Textiles	Class	0-39%	40-100%	
	Mean capacity utilization	55	37	
Paper	Class	0-9%	10-100%	
	Mean capacity utilization	15	58	
Chemicals	Class	0-9%	10-39%	40-100%
	Mean capacity utilization	43	60	54
Petroleum	Class			
	Mean capacity utilization		not significant	
Steel	Class			
	Mean capacity Utilization		not significant	
Other	Class	0-9%	10-69%	70-100%
	Mean capacity utilization	25	43	38
Total	Class	0-9%	10-69%	70-100%
	Mean capacity utilization	35	49	44

^{a/} Significance was determined at 95 percent. A blank space indicates a non-significant t-score. Aluminum and SCG were omitted because of too few observations.

higher capacity utilization rate than scarce fuel-fired boilers. The results for gas-fired boilers were mixed, as expected, since gas-fired boilers could have both lower operating rates due to flexibility and higher rates in regions where gas prices are below fuel oil costs.

The results for functional use within each industry show no significant differences among the three major uses (electricity generation, process steam, and space heat) except in textiles. The results for "other uses" in chemicals, petroleum, and steel are difficult to interpret, since the other uses are not well defined.^{5/} Only the "all industry" regression (last one in Table F.7) shows significant results in the expected direction. This suggests that industry SIC, as a proxy for how boilers are used in the production process, is a more important variable than functional uses within any industry. In the last equation, the functional uses probably are capturing just the fact that the high percentage process steam industries (chemicals, paper, etc.) tend to operate at high operating rates, while the sectors with high shares of space heating (such as food and "other") generally have lower capacity utilization rates.

The analyses of boiler size in Table F.8 show that size is significant for all industries, although the cutoff points differ among the sectors. The results show which classes differ significantly from the others. For example, in the paper industry, the three small sizes below 200 MMBtu/hr experience significantly lower capacity utilization rates than the 200-499 class. In general, there is a slight (five to 10 percent) difference in operating rates, which is correlated positively with size. In some cases where very large boilers (paper and food) showed low capacity utilization rates, only a few boilers were in the large boiler size classes.

In effect, this regression is a check on the boiler size classes used in IFCAM for the industry/size data files. The results suggest that the data files might be revised to use different size classes for each industry.

While date of boiler installation is correlated significantly with capacity utilization rates, there is no clear trend or logic to the results. The newest boilers surprisingly tend to have the lowest capacity utilization rates. The relationship between age and operating rate is bell-shaped (highest rate, for food, if installed in 1940-59). For the remaining sectors, the newer the boiler, the lower its operating rate. The newest boilers (post-1970) may be low because of break-in problems. It is not clear why the oldest boilers often tend to operate at higher capacity utilization rates.

Table F.10 shows that boilers which comprise less than 10 percent of the plant steam generating capacity have consistently lower operating rates. These units are probably stand-by or used for peaking purposes.

F.3.3.2 Multiple Variable Regressions

Table F.11 lists the results of the multiple regression analyses and their coefficients by industry. For each industry, a multiple regression was run in which the significant classes from the simple regressions were included. Classes included in each run were noted by a "✓" or by the class groups. Significance was determined at a 95 percent level. Following the logic explained for the simple regressions about non-orthogonality, each variable had one of the n classes suppressed. An asterisk indicates which class was eliminated. If, as in the case of fuel for petroleum, there was only one class listed, the suppressed class was the miscellaneous class. A blank coefficient indicates the variable was not significant.

The capacity utilization for many types of boilers can be estimated using the regressions listed in Table F.11. For example, in the food industry the intercept represents a gas-fired boiler with a 300-349 MMBtu/hr capacity, built after 1960, with a boiler/plant consumption ratio of greater than or equal to 10 percent (indicated by the asterisks). If we want to see how a coal-fired boiler of the same size, age, and boiler/plant ratio compares

TABLE P.11 SIGNIFICANT MULTIPLE REGRESSION CLASSES AND THEIR COEFFICIENTS, BY INDUSTRY GROUP^{a/}

Industry	Intercept	Fuel Type ^{b/}				Size Category ^{b/}				Year Built Category			Boiler/Plant Consumption Ratio (percent)			Functional Use				R ²
		Coal	Resid.	Dist.	Gas	2	3	4	5	1	2	3	1	2	3	Electricity Generation	Space Heating	Process Steam	Other	
Food																				
Classes in run	✓	✓		✓	✓	100-159	170-299	300-349	350+	pre-1940	1940-1959	1960+	0-9	10-100						
Coefficient	49.13	8.75			*	-19.25		*			6.94	*	-18.84	*		-----Not Significant-----				0.16
Textiles																				
Classes in run	✓		✓		✓	100-199	250+			pre-1940	1940-1959	1960+	0-39	40-100		✓		✓		
Coefficient	32.05				*	*	14.23				26.87	*		*				*		0.65
Paper																				
Classes in run	✓	✓	✓	✓		100-199	100-499	500+		pre-1960	1960-1969	1970+	0-9	10-100						
Coefficient	59.92			*		-4.43	*	-10.41		12.22		*	-43.25	*		-----Not Significant-----				0.50
Chemicals																				
Classes in run	✓	✓	✓	✓		100-169	170+			pre-1940	1940-1969	1970+	0-9	10-39	40-100			✓	✓	
Coefficient	14.92	15.33	22.79	*		*	4.6				10-23	*	-12.77		*			*	5.51	0.19
Petroleum																				
Classes in run	✓		✓			100-199	200-299	300-399	400+	pre-1970	1970+							✓	✓	
Coefficient	52.78		19.86			-9.8	-8.82	*		11.09	*		-----Not Significant-----						*	0.20
Steel																				
Classes in run	✓	✓				100-149	250-399	400+		pre-1940	1940-1964	1965+						✓	✓	
Coefficient	17.24	24.93				13.25	*	17.10				*	-----Not Significant-----						*	0.28
Other																				
Classes in run	✓	✓	✓	✓	✓	100-199	300+			pre-1940	1940+		0-9	10-69	70-100	✓				
Coefficient	54.26		-5.72	-14.58	*	*					*		-17.68		*	*				0.17
Total																				
Classes in run	✓	✓	✓	✓	✓	100-169	170-299	300+		pre-1965	1965-1969	1970+	0-9	10-69	70-100	✓	✓	✓		
Coefficient	50.19		-8.51	-16.52	*	-6.6	*	4.40		6.24	*	-4.82	-14.80	*		9.42	-6.31	*		0.12

^{a/} Significance was determined at 95 percent. Aluminum and SCG were omitted because of too few observations. Classes run for each industry's dummy variables were the same as those used in each industry's individual regressions. An asterisk indicates the class is included in the intercept.

^{b/} Size "1" (25-99 MMBtu) of CUNIS cannot be analyzed by MBI data.

to the gas-fired boiler, we add the 8.75 coefficient to the 49.13. Using this method, capacity utilizations of various boiler types can be calculated.

Coal-fired boilers consistently have higher capacity utilization rates, as expected. Further work should be done on fuel type by including fuel prices explicitly so that the separate impacts of boiler operating characteristics and cost by fuel type can be distinguished.

Larger units tend to have higher operating rates, due presumably to economies of scale, in most cases.

Boiler age is insignificant in many cases, suggesting that the single variable results were capturing the effects of other variables (such as the older boilers being coal-fired).

The boiler/plant capacity ratio continues to show that boilers comprising a small share of plant capacity are on a stand-by or peaking status, often with much lower average operating rates.

Except for textiles and paper, the variance explained by the regression (R^2) is quite low (10 to 20 percent), suggesting that plant-specific factors tend to dominate operating practices. For the paper industry, fuel type, size, whether the boiler was installed after 1970, and boiler/plant capacity capture half of the variation in capacity utilization rate.

F.4 SUMMARY

The above analysis indicates that capacity utilization is affected by variables included in IFCAM (size and industry) as well as other variables not included in the model, such as boiler/plant consumption ratio, fuel type, and age. The effects of these variables, and of the distinct classes within them, differ by industry.

Further improvements to IFCAM should incorporate the results presented above. Capacity utilization for existing boilers should be changed to be "by industry." The size categories should depend on the industry rather than a uniform 25-99 MMBtu, 100-249 MMBtu, 250+ MMBtu, breakout. As was mentioned above, the results indicate that the variables which best explain capacity utilization differ among industries. Below is a list of the functions which appear to have the most effect upon capacity utilization.

- $CU(\text{food}) = f(\text{fuel}, \text{size}, \text{year built}, \text{boiler/plant consumption})$.
- $CU(\text{textiles}) = f(\text{size}, \text{year built}, \text{boiler/plant consumption})$.
- $CU(\text{paper}) = f(\text{size}, \text{year built}, \text{boiler/plant consumption})$.
- $CU(\text{chemicals}) = f(\text{fuel}, \text{size}, \text{year built}, \text{boiler/plant}, \text{functional use})$.
- $CU(\text{petroleum}) = f(\text{fuel}, \text{size}, \text{year built})$.
- $CU(\text{steel}) = f(\text{fuel}, \text{size}, \text{year built})$.
- $CU(\text{other}) = f(\text{fuel}, \text{size boiler/plant consumption})$.
- $CU(\text{total}) = f(\text{fuel}, \text{size}, \text{year built}, \text{boiler/plant}, \text{functional use})$.

Future analysis should account explicitly for the impact of fuel prices on capacity utilization rates. Since MFBI data do not cover boilers below 100 MMBtu/hr, NEDS should be used to supplement the MFBI information.

FOOTNOTES

1. The model simulates this effect (arbitrarily) by applying a more rapid retirement rate for scarce fuel-fired boilers than for existing coal-fired boilers.
2. For further discussion on pooled variances, see T. Wonnacott and R. Wonnacott, Introductory Statistics for Business and Economics (New York: John Wiley and Sons, Inc.), 1972, Chapter 10.
3. The reader should keep in mind that the aggregate mix for new boilers in IFCAM constantly changes depending on the economic growth scenario which alters the share between industries. For example, there are more big boilers with higher capacity utilization rates when the growth scenario has high industrial growth rates (e.g., chemicals, paper, and petroleum).
4. In a statistical sense, we expected the effect of the independent variables to interact with the industrial code, i.e., a non-additive relationship.
5. It should be noted, however, that although the food industry did not have any significant t-scores, it did have a significant F-test. The significant F-test, coupled with nonsignificant t-scores, reveals that although the individual variables are not significant (i.e., we cannot reject the hypothesis that the individual coefficients $b_i=0$), the four variables' joint contribution is indeed significant (i.e., we must reject the hypothesis that $b_1=b_2=b_3=b_4=0$). See Jan Kmenta, Elements of Econometrics (New York: MacMillan Publishing Co.), 1971, Section 10.2.

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APPENDIX G. NONBOILER CHARACTERISTICS

G.1 INTRODUCTION

The effect of significant nonboiler characteristics such as firing rate, useful life, technical conversion capability, pollution control devices, and lead time factors on 1) the market penetration of a newly developed coal-burning application; 2) the selection of environmental control strategies; and 3) the estimation of process-specific capital and non-fuel O&M expenses by fuel type has been discussed throughout the documentation report. This appendix provides process-specific data for each of these significant nonboiler characteristics.

Table G.1 lists estimated data of nonboiler characteristics used in IFCAM for the major energy-intensive process applications. Data estimates also are listed for miscellaneous processes, characterized by the following factors:

- Relative contributions to total fuel consumption are unknown, but are expected to be quite small.
- No technical potential for coal use is expected.
- Equipment types are too numerous and varied to gather relative cost data by fuel type.

Note that because these processes are considered as a group, estimates are incorrect to the extent that they do not adequately represent individual miscellaneous processes. It also is important to emphasize that all data are estimates. This is because there is a lack of data describing the non-boiler population; for example, data on size distributions, sales, load factors, and current ages of existing units are unavailable. The estimates used reflect average, not extreme, projections.

TABLE G.1 DATA ESTIMATES OF NONBOILER CHARACTERISTICS

Industry	Description	Firing Rate (MMBtu/hr)	C.U. ^{a/}	Useful Life (yr)		Lead Time Factor						Conversion ^{b/} from Gas to			Pollution Control	
						Existing Units			New Units			Resid.	Dist.	Coal	Coal	Type ^{c/}
				Ex.	New	1985	1990	1995	1985	1990	1995					
Food	Miscellaneous	10	0.75	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	I	I	I	-	-
Textiles	Miscellaneous	10	0.75	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.1000	I	I	I	-	-
Paper	Miscellaneous	10	0.75	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
Chemicals	Primary reformer	340	0.94	15	25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	N	R	I	-	-
	Primary reformer	60	0.96	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	N	R	I	-	-
	Miscellaneous	60	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	N	R	I	-	-
Petroleum	Tubestill heater	99	0.90	15	25	0.0000	0.0000	0.0000	0.1070	0.3300	0.4500	R	R	N	FGD	H
	Tubestill heater	215	0.90	15	25	0.0000	0.0000	0.0000	0.1070	0.3300	0.4500	R	R	N	FGD	H
	Tubestill heater	364	0.90	15	25	0.0000	0.0000	0.0000	0.1070	0.3300	0.4500	R	R	N	FGD	H
	Tubestill heater, H ₂ S ^{d/}	99	0.90	15	25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	N	R	I	-	-
	Tubestill heater, H ₂ S ^{d/}	215	0.90	15	25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	N	R	I	-	-
	Tubestill heater, H ₂ S ^{d/}	364	0.90	15	25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	N	R	I	-	-
	Tubestill furnace	97	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
	Miscellaneous	10	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	N	R	I	-	-
	Miscellaneous	10	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	N	R	I	-	-
SCG	Melt melter glass	50	0.90	5	5	0.0050	0.1050	0.2000	0.0050	0.1050	0.2000	R	R	R	FGD	H
	Melt melter glass	125	0.90	5	5	0.0050	0.1050	0.2000	0.0050	0.1050	0.2000	R	R	R	FGD	H
	Regenerative melter	50	0.90	5	5	0.0050	0.1050	0.2000	0.0050	0.1050	0.2000	R	R	R	FGD	H
	Regenerative melter	200	0.90	5	5	0.0050	0.1050	0.2000	0.0050	0.1050	0.2000	R	R	R	FGD	H
	Annealinglehr	5	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	I	I	I	-	-
	Rotary kiln (cement)	333	0.90	15	25	0.7000	0.7000	1.000	0.6500	0.6500	1.0000	R	R	R	Cyclone	H
	Brick tunnel kiln	11	0.90	15	25	0.1900	0.3000	0.5000	0.1900	0.3000	0.5000	R	R	R	Cyclone	H
	Brick tunnel kiln	42	0.90	15	25	0.1900	0.3000	0.5000	0.1900	0.3000	0.5000	R	R	R	Cyclone	H
	Refractory br. tun. kiln	11	0.90	15	25	0.1500	0.3000	0.5000	0.1500	0.3000	0.5000	R	R	R	Cyclone	H
	Refractory br. tun. kiln	42	0.90	15	25	0.1500	0.3000	0.5000	0.1500	0.3000	0.5000	R	R	R	Cyclone	H
	Rotary kiln (lime)	96	0.90	15	25	0.7000	0.9000	0.9000	0.6500	1.0000	1.0000	R	R	R	Cyclone	H
	Miscellaneous	10	0.90	15	25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
	Miscellaneous	10	0.90	15	25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
	Miscellaneous	10	0.90	15	25	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
Steel	Vert. shaft furnace	15	0.55	25	30	0.0900	0.2000	0.5000	0.0900	0.2000	0.5000	R	R	R	Cyclone	H
	Trav. grate furnace	200	0.55	25	30	0.5000	0.7500	1.0000	0.5000	0.7500	1.0000	R	R	R	FGD	H
	Sintering furnace	1	0.55	25	30	0.5000	0.7500	1.0000	0.5000	0.7500	1.0000	R	R	R	FGD	H
	Calc oven battery	740	0.65	25	50	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
	Blast fur. hydrop. inj.	400	0.65	25	50	0.2500	0.5000	1.0000	0.2500	0.5000	1.0000	R	R	R	Cyclone	H
	Blast fur. stove	5	0.65	25	50	0.0000	0.0000	0.0000	0.0100	0.1000	0.5000	N	R	N	FGD	H
	Pelletiz. grate kiln	250	0.55	25	30	0.5000	1.0000	1.0000	0.5000	1.0000	1.0000	R	R	R	Cyclone	H
	Open hearth furnace	135	0.65	25	50	0.9000	0.9000	1.0000	0.9000	0.9000	1.0000	R	R	R	ESP	H
	Soaking pits	40	0.65	25	50	0.0200	0.1500	0.5000	0.0200	0.2500	0.5000	R	R	R	ESP	L
	Reheat furnace	200	0.55	15	30	0.0750	0.1500	0.5000	0.0750	0.2500	0.5000	R	R	R	ESP	L
	Heat treat. furnace	10	0.55	15	30	0.0750	0.1500	0.5000	0.0750	0.2500	0.5000	R	R	R	Cyclone	L
	Miscellaneous	10	0.55	15	30	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
	Miscellaneous	10	0.55	15	30	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
	Miscellaneous	10	0.55	15	30	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
Aluminum	Rotary kiln	50	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	I	R	I	-	-
	Lime calciner	96	0.90	15	25	0.7000	0.7000	1.0000	0.6500	0.6500	1.0000	R	R	R	ESP	L
	Anode prebake oven	10	0.90	20	35	0.0160	0.0800	0.2000	0.0500	0.2500	0.5000	R	R	R	ESP	L
	Anode prebake oven	20	0.90	20	35	0.0160	0.0800	0.2000	0.0500	0.2500	0.5000	R	R	R	ESP	L
	Reverberatory furnace	10	0.90	10	15	0.0280	0.0800	0.2000	0.0875	0.2500	0.5000	R	R	R	ESP	L
	Reverberatory furnace	40	0.90	10	15	0.0280	0.0800	0.2000	0.0875	0.2500	0.5000	R	R	R	ESP	L
	Heat treat. furnace	5	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	I	R	I	-	-
	Heat treat. furnace	20	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	I	R	I	-	-
	Miscellaneous	10	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
	Miscellaneous	10	0.90	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-
Other	All other industry	10	0.75	10	20	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	R	R	I	-	-

a/ Capacity utilization.
b/ Three possibilities are considered in conversion:
R = retrofit of unit possible
N = new unit required
I = use of fuel is technically infeasible
c/ H = high sulfur assumed required
L = low sulfur assumed required
- = no type required because use of fuel is technically infeasible
d/ High risk.

The following briefly discusses significant nonboiler parameters. Because most of these parameters are detailed elsewhere in the documentation, only lead time factors are discussed in depth.

G.2 SIGNIFICANT PARAMETERS

Average sizes and load factors, significant nonboiler characteristics, were estimated in terms of fuel input (MMBtu/hr) and the ratio of actual annual fuel consumption to the firing rate times 8760 hrs/yr. Useful lives are process-specific and are important because they are used in the economic analysis to estimate the total project life in the fuel choice decision.

The technical evaluations of fuel substitution also are process-specific. Oil is technically feasible for most processes; however, retrofitting to residual fuel oil is not technically feasible for several units and replacement by new units is required. Coal use often is technically infeasible, and gas is technically feasible for all processes. Issues related to these technical evaluations are discussed in Section 5. More details on process descriptions and specific technical risk assessments are discussed in recent EEA reports.^{1/}

The pollution control strategy for coal also is process-specific. Location-specific environmental regulations for specific nonboiler processes are unavailable, as are the locations of individual nonboilers. Therefore, reasonable uniform control strategies were selected after considering possible product contamination and process emissions not related to fuel type but currently being controlled by pollution abatement equipment. For residual fuel oil, low sulfur oil without pollution control equipment was selected as the optimal control strategy for all process heat applications. To the extent that local regulations do not require the degree of pollution control implied by these assumptions, the total cost of burning coal (and perhaps residual fuel oil) may be overstated. Pollution control issues are discussed in greater detail in Section 6. Lead time factors are discussed in detail below.

G.3 LEAD TIME FACTORS

Lead time factors refer to the time required for commercially unproven technologies to impact the energy marketplace. Oil and gas uses are proven technically and economically for most nonboiler processes and delays associated with research, development, and commercialization are not anticipated. This is not the case for coal, however, even with government incentives. Although coal technology is not necessarily complex, it is new to the industrial manager and engineer. The uncertainty associated with this novelty must be dispelled before coal will gain a large percentage of the nonboiler market. The uncertainty due to operational reliability also must be resolved. After the technology is demonstrated to be commercially viable, it still is not used 100 percent. Some potential users are not aware of the new technology; other potential users require a process to be proven in their competitors' facilities and at one of their own installations before adopting the technology company-wide.

In a setting without government incentives, industry would try to develop those coal use technologies that give the greatest reward for the lowest effort and risk. After these technologies were developed, the more difficult, less rewarding attempts at conversion would be considered. The more difficult conversions would draw on the experience of previous non-boiler coal uses. Industry, if unregulated, would try one conversion at a time rather than a wholesale conversion.

Because coal use in nonboilers could damage major pieces of production equipment, thus the entire manufacturing process, thorough development and demonstration of the technology is needed before a firm will consider coal substitution. The use of coal in nonboilers requires more than basic research; it must be matched with the intricacies of each potential process use. This match-up, called development design, must be formulated by design engineers from furnace vendors, coal burner vendors, and users. After the design is finalized, a prototype unit must be built based on the design. The prototype unit would be operated in a commercial-like manner

to prove the design and confirm its reliability. The prototype operation, called demonstration, would be followed by construction of the first commercial facilities. Only after design, demonstration construction, demonstration, and commercial construction periods have elapsed would coal use start to impact the fuel market.

Once the technology is proven, it is affected by market penetration factors. These factors indicate that much less than 100 percent of the potential users immediately will adopt the technology. In addition, the innovativeness of different industries affects the absolute size of market penetration factors. For each impacted industry, market penetrations were projected in terms of percentage of new installations over a given time frame adopting the direct coal use technology.

The composite of demonstration periods and penetration factors projects the future market share of coal in nonboilers, assuming a favorable economic climate.

G.3.1 Lead Time Factor Estimation

It was assumed that each industry will act in an expeditious but business-like manner to move toward coal use in nonboilers. Demonstrations were assumed to start in all areas simultaneously rather than starting with the relatively easy conversions first and the more difficult and expensive conversions later. No resource constraints were considered. It also was presumed that there would be a sufficient number of demonstrations in each industry. No delays were assumed between the various steps in the commercial testing of nonboiler coal technologies. The demonstration design periods estimated by industry representatives were based on design periods for similarly novel applications. Construction time of the prototype unit parallels the building of similar projects. The demonstration time required was derived from various estimates of reasonableness by industry experts. The commercial construction time again was based on recent historical experience for projects of similar magnitude. The market penetra-

tion rates were based on product and process innovations within each industry. Penetration rates were based on rates for the float process for glass and the basic oxygen process for steel, two very famous, often cited examples of innovation. Penetration rates, however, depend on other variables in addition to the industry into which the technology is being introduced. Other market penetration variables which will interact with other NEP model inputs are profitability, demand growth, rate of old capital retirement, and risk aversion.

C.3.2 Example of Effect of Lead Time Factors

An example of how lead time factors affect the potential for nonboiler coal use will make this limiting mechanism clear. Consider, for example, atmospheric distillation in petroleum refining. In the model, the start date is assumed to be January 1, 1979. The prototype design and construction period was estimated to be two years in duration. Eight months were allocated to the design and 16 months to the construction: January 1, 1979 + two years = January 1, 1981.

Providing for a one-year demonstration of the coal burning: January 1, 1981 + one year = January 1, 1982.

After demonstration, there is a two-year commercial construction phase: January 1, 1982 + two years = January 1, 1984.

A market penetration rate of 20 percent of total market in two years, 50 percent in five years, and 75 percent in 10 years has been estimated based on industry history of introducing a new technology.

Year end 1985: 9% x amount capacity installed in 1984
 +20% x amount capacity installed in 1985
 = total potential coal capacity for new units installed by
 1985

Year end 1990: 30% x amount capacity installed in 1986
+40% x amount capacity installed in 1987
+50% x amount capacity installed in 1988
+55% x amount capacity installed in 1989
+60% x amount capacity installed in 1990

= total potential coal capacity in new units installed between 1985 and 1990

The start date greatly affects total capacity, especially in the near-term time frame.

The data in Table G.1 do show lead time factors increasing over time (from 1985 to 1995) for each process technically capable of burning coal. Zero lead time factors correspond to processes evaluated as technically incapable of burning coal. Processes with relatively low lead time factors in 1995 are nonhomogeneous categories with several unique equipment types and configurations, not all of which are likely to be capable of burning coal due to technical or business risk assessments.

FOOTNOTES

1. Energy and Environmental Analysis, Inc., "The Technical Feasibility of Coal Use in Industrial Process Heat Applications," draft report prepared for Department of Energy, May 22, 1978; and "The Substitution Potential of Alternative Fuels for Natural Gas in Selected Industries," prepared for Department of Commerce, June 8, 1978.

APPENDIX H. BOILER CAPITAL AND O&M COST DATA

H.1 INTRODUCTION

This appendix presents the capital costs and annual O&M expenses used in this analysis for boilers and auxiliary equipment. The firing rates of the four boilers being considered are 15, 50, 175, and 325 MMBtu/hr. The fuels that can be burned in these boilers are natural gas, distillate fuel oil, residual fuel oil, and coal. The 15 MMBtu/hr boiler was assumed to be a firetube boiler,^{1/} and the three larger size boilers were assumed to be watertube. Generic equipment cost data have been developed for each of the following systems:

- Boiler.
- Fuel handling and storage.
- Ash handling.
- Environmental control.

For the boiler system, new and retrofit capital costs are presented for the sizes and fuels being considered. The non-fuel O&M costs are presented as a function of the firing rate and capacity utilization. The sources and methodologies used to obtain these numbers also are discussed. The fuel handling and storage system for coal, distillate fuel oil, and residual fuel oil are discussed in Section H.2.2. The key parameters, system designs, and capital and O&M costs also are presented. The capital and O&M costs of ash handling systems are presented in Section H.2.3. The types of ash handling systems available and their use with different types and sizes of boilers are discussed. The environmental control systems, which include particulate control systems and FGD, are discussed in Section H.2.4.2. The capital and O&M costs of an ESP and a self-contained solid waste FGD system also are provided.

In addition, other general costs (including powerhouse construction, engineering, offsite utility hookup, and other contingencies) have been estimated. All cost data are expressed in 1975 dollars.

H.2 DETERMINATION OF CAPITAL AND ANNUAL O&M EXPENSES

Generic cost data have been developed for each boiler size and fuel type. Capital costs have been estimated for both new and retrofit units. For retrofit units, capital costs are the costs incurred to prepare the boiler to burn an alternate fuel; these cost estimates were provided by equipment vendors. The annual O&M costs were derived from industry contacts and literature.

H.2.1 Boiler and Related Equipment

H.2.1.1 Boiler Types

There are many different types and sizes of boilers, and boiler design (and cost) is influenced principally by the following parameters:

- Type of fuel used.
- Method of firing.
- Rated firing capacity.
- Method of construction.

Boilers and related equipment include all the equipment necessary to receive the fuel from working storage, prepare the fuel for combustion, burn the fuel, and circulate water through heat exchangers to create steam. A partial inventory of this equipment is included below.

coal crushers	induced draft fan
coal pulverizers	forced draft fan
coal feeders	sootblowers
coal classifiers-distributors	combustion control instruments
burners/stokers	economizers
furnaces and watertubes	superheaters and reheaters
air heaters	

H.2.1.2 Capital Cost Data

Data on the cost of installing new boilers were obtained primarily by contacting boiler manufacturers. The costs of retrofitting an existing boiler to an alternate fuel type were developed from three sources: 1) industrial users who had retrofitted their boilers; 2) equipment vendor quotations for the cost of installing each piece of equipment necessary to complete conversion; and 3) data contained in previous studies.^{2/}

H.2.1.2.1 New Boiler Costs

Boiler manufacturers provided estimates of the installed costs of the four boilers and fuels considered, for a given steam pressure/temperature requirement. Firetube boiler manufacturers were contacted to provide costs for the 15 MMBtu/hr firetube boilers with steam specifications of 150 psig/saturated temperature. Estimates of the installed cost for oil/gas-fired boilers were approximately \$5/lb of steam/hr capacity. The difference in the cost between a gas-fired and an oil-fired boiler was insignificant. The cost of a chain grate stoker coal-fired boiler was estimated by vendors at \$14/lb of steam/hr capacity.

The 50 MMBtu/hr watertube boiler is assumed to produce 250 psig/saturated temperature steam. The two larger watertube boilers had steam specifications of 700 psig/700°F. The 50 and 175 MMBtu/hr boilers were packaged units (except for coal) and the installed cost for firing these units with gas/distillate oil was \$6/lb of steam/hr capacity. Residual oil-fired boilers typically were 10-15 percent more expensive because of additional equipment, such as sootblowers, and more expensive components, such as high quality refractory and heat exchanger tubes. The coal-fired boilers using chain grate stokers were estimated to cost \$15/lb of steam/hr capacity.

The 325 MMBtu/hr boiler was a field-erected unit and thus had higher installation costs. The installed cost of oil/gas boilers was quoted as \$7.50/lb of steam/hr capacity. The coal-fired boiler burning pulverized coal was

estimated at \$15/lb of steam/hr capacity. No economies of scale were observed for coal-fired boilers. The higher installation costs of field erection and change to pulverized burners offset any economies that may have been associated with the coal boiler. The estimation of these costs is conservative in that it reflects estimates for high pressure and temperature steam. Boiler capital costs are lower for lower pressure/temperature steam. Detailed costs of the new units are shown at the end of this appendix.

H.2.1.2.2 Boiler Retrofit Capital Costs

Retrofitting boilers implies shifting from an existing fuel to an alternate fuel. Since we are considering four fuel types, each boiler has three retrofit options; however, there are some restrictions on these options. We assume that no coal boiler will retrofit away from coal because of economic and legal considerations. We further assume that no residual oil boiler is likely to retrofit to distillate oil since the fuel price differential between distillate and residual oil should equal or exceed operating cost differentials.

When considering a retrofit to coal, two cases are possible depending on whether or not the boiler originally was designed to burn coal. The retrofit costs associated with each case can vary significantly. The two cases are described below.

- Coal-Capable Boilers. Coal-capable boilers are those originally designed to burn coal. The cost of converting coal-capable boilers back to coal^{3/} depends on the operational status of equipment needed to burn coal. On one extreme, when the boiler already is using coal, conversion can be as simple as not burning any more oil or gas, and conversion costs are negligible. On the other hand, if auxiliary coal-burning equipment has not been installed, conversion can entail purchase of new equipment.

Estimating the cost of such a conversion can be accomplished only by determining the cost of components which may need to be purchased or replaced and the cost of boiler modifications. Modification costs have been derived from costs reported by industrial users, equipment vendors, and consulting engineering studies. The

cost of new equipment which may be necessary is estimated from basic equipment costs provided by vendors.

- Non-Coal Capable Boilers. Non-coal capable boilers are units originally not designed to burn coal. Since attempts to retrofit to coal would involve major redesign of the furnace and possibly an efficiency loss, the cost of retrofitting a non-coal capable boiler to burn coal is considered to be the cost of a new coal boiler (less the feedwater treatment capital cost).

For each retrofitting option, EEA examined the effect of retrofitting on the important components of the boiler: burner/stoker, heat exchanger tubes, refractories, sootblowers, economizers, air blowers, and the fuel control system (valves, metering devices, return flow equipment). The extent of change required for each of the possible retrofit cases was estimated. The installed cost of the new component considered necessary was estimated from costs provided by vendors. Estimates of retrofit costs were made using this information. This procedure was repeated for the four boiler sizes being studied.

Every retrofit requires burners to be replaced or stokers to be installed. Heat exchanging tubes need to be replaced if the boiler is retrofitted to burn residual oil or coal. These tubes prevent ash accumulation on the ribbed tubes and increase the surface area exposed to combustion products. The amount of refractory brick replaced depends on the type of fuel the boiler is retrofitted for. The change is nominal when the boiler is retrofitted to burn gas, distillate oil, or residual oil. However, retrofitting to coal requires extensive refractory change to prevent eutectic formations and significant deterioration of the refractory. A change to residual oil and coal requires installation of high-quality refractory.

Accumulated ash can reduce significantly heat transfer through tubes; ash deposition can be severe when burning residual oil and coal. Therefore, sootblowers, devices that use steam/air to dislodge ash accumulation, are installed when boilers are retrofitted to these two fuels. Typically, residual oil and coal require greater percentages of excess air for com-

plete combustion. Therefore, additional air blower capacities also are installed for these fuels.

When considering the above retrofits, no site-specific data on retrofit requirements were examined. We could, therefore, be under- or overestimating retrofit costs. This variance may be especially pronounced when retrofitting to coal in a coal-capable boiler. We also assume that boiler efficiency remains unaffected by retrofitting. For some boilers, this probably will not be the case. When retrofitting to residual oil from gas, there is a fundamental change in heat transfer mechanisms. The combustion of residual oil produces luminous flames which increase the radiation heat transfer in the radiation section of the boiler. The flue gases passing through the convection section and the superheating section of the boiler are, therefore, at a lower temperature. This lower flue gas temperature may pose a problem in some boilers, where the steam is superheated to high temperatures and pressures in the convection zone. A rearrangement, by installing superheating tubes in the radiation section, may be necessary.

Table H.1 details the eight retrofit options for a 175 MMBtu/hr boiler. The cost algorithms used for each component are shown in Appendix I, Section I.3.2. For a particular retrofit, the blanks in the boiler-related direct costs suggest that no change was considered necessary. The retrofit costs for other boiler sizes are shown in Table H.12 at the end of the appendix.

H.2.1.3 Annual Non-Fuel O&M Costs

Boiler O&M costs are assumed to be a function of size (firing rate), current boiler load factor, and fuel type. These O&M costs do not include O&M costs of fuel handling, ash handling, and pollution control systems.

Boiler O&M costs are higher for large boilers than for small units and increase with the amount of time the boiler is operated. O&M costs have been classified into four categories: labor, supplies, maintenance materials, and general and administrative (G&A).

TABLE H.1

RETROFIT COSTS OF A 175 MMBtu/HR BOILER (1975 \$)

<u>Direct Costs</u> <u>(boiler related)</u>	<u>Conversions^{a/}</u>							
	G → D	G → R	G → C	D → R	D → C	R → C	D → G	R → G
Burners/Stokers	28,230	30,787	423,320	30,787	423,320	423,320	25,674	25,674
Heat exchanger tubes	-	181,800	181,800	181,800	181,800	-	-	-
Refractory	806	1,320	68,320	1,320	68,320	68,320	806	806
Sootblowers	-	49,145	49,145	49,145	49,145	-	-	-
Air blowers	-	15,077	15,077	15,077	15,077	-	-	-

a/ Conversion Key

G = Natural Gas

D = Distillate Fuel Oil

R = Residual Fuel Oil

C = Coal

Conversions from residual to distillate oil are not considered since distillate oil is always more expensive.

Labor costs include all employee costs related to an operation, including any part-time work and supervision. Supplies cover those costs related to items used in daily unit operations, such as water, chemicals, electricity, lubricants, and other supplies. Maintenance materials are items needed for replacing worn parts in a system during both planned and unexpected shutdowns. G&A expenses include direct costs such as management and overhead attributable to a system.

Labor costs vary directly with the size of the boiler and the number of shifts it is operated (independent of the firing rate during a shift). Determining typical labor requirements of a boiler is difficult because of many plant-specific factors. The mix of boiler sizes and fuel types at a steam plant makes assigning labor to a particular boiler difficult. Also, separating labor requirements for a boiler from those for fuel handling and pollution control systems is difficult. Labor requirements for a coal-fired boiler are greater than those for a gas/oil-fired boiler because of more complex combustion mechanisms, larger furnace volumes, and flame stabilization problems. The total labor cost includes the salaries and benefits (30 percent of salary) of the operators, maintenance team, and supervisors.

The cost of supplies is variable, and includes the cost of water, feedwater treatment, power, and atomization steam (for residual oil only). This cost is directly proportional to the size of the boiler and its load factor. The amount of make-up water added depends on the quantity and quality of the condensate returns and the blowdown losses. In this analysis, 90 percent of the water entering the boiler is from uncontaminated condensate returns and 10 percent is make-up water. The feedwater treatment costs are primarily the costs of chemicals and electricity. These costs vary directly with the quantity of water that flows through the softening system and inversely with the initial hardness of the water. To burn residual oil efficiently, steam atomization is required. Typically, two pounds of steam (250 psig/400°F) are used to atomize one gallon of residual oil; in practice,

the amount and pressure/temperature of the steam can vary significantly. The power requirements are greater for coal than for gas or oil. A significant portion of the power is expended in preparing the solid fuel for combustion in equipment such as pulverizers, FD fans, and stokers. Sootblowers are used when the fuel fired is coal or residual oil.

The cost of maintenance materials is a function of fuel type because this cost varies according to the degree of corrosion/erosion produced by a fuel. The fuel types, in decreasing order of corrosiveness, are coal, residual oil, distillate oil, and gas. The fly ash produced when burning coal can adhere to the heat exchanging tubes and reduce heat transfer. This reduces the efficiency of the boiler and can cause localized overheating which may lead to tube rupture. Non-fouling, non-slugging coals, therefore, are preferred to help reduce maintenance costs of coal use. Ash problems also exist with residual fuel oil, but are much smaller in magnitude. In addition to varying with fuel type, the cost of maintenance materials also will vary directly with the boiler's size and load factor.

As stated previously, G&A expenses are direct costs such as management and overhead costs. G&A costs are considered to be a fixed percentage of the sum of O&M costs of labor, supplies, and maintenance materials.

Literature review and consultations with boiler users and vendors yielded estimates of O&M costs. Table H.2 lists these O&M costs for each fuel type as a function of size and capacity utilization, with both a fixed and a variable component.

H.2.2 Fuel Handling and Storage

Fuel handling and storage costs were estimated for coal, distillate oil, and residual oil systems. Gas normally is not stored on-site by industrial plants and its handling costs are insignificant.^{4/} Handling and storage estimates are used for both new and retrofit units.

TABLE H.2 BOILER O&M COSTS
(1975 \$10³)

	<u>Fixed</u>	<u>Variable</u>
Gas-fired	$= 1.805 (FR)^{0.4418}$	$+ 0.752 (FR)^{0.9692} \times CU$
Distillate oil-fired	$= 1.805 (FR)^{0.4418}$	$+ 0.853 (FR)^{0.9799} \times CU$
Residual oil-fired	$= 1.805 (FR)^{0.4418}$	$+ 1.255 (FR)^{0.9488} \times CU$
Coal-fired	$= 6.637 (FR)^{0.4406}$	$+ 1.338 (FR)^{0.9491} \times CU$

LEGEND:

FR = firing rate (MMBtu/hr)

CU = capacity utilization (fraction)

H.2.2.1 Coal Handling System

The cost of handling coal at a plant has been cited as one disincentive to industrial coal use. On-site handling of coal requires significantly more space and equipment and therefore greater capital expenditure than on-site handling of either oil or gas. Because coal handling is viewed as a major cost element for industrial plants but one for which detailed cost data are relatively unavailable, significant effort was placed in developing coal handling system costs.

H.2.2.1.1 Key Parameters

The design of a coal handling system is sensitive to several key parameters:

- Total annual volume of coal consumed.
- Mode of delivery.
- Outdoor and/or indoor storage.
- Land availability/physical plant layout.

A coal handling system will be designed to transport the total quantity of coal used at the plant, regardless of the number of coal-fired boilers.

Coal will be delivered by rail, truck, or barge and will require:

- Unloading.
- Storing.
- Reclaiming.

Storage may be outdoors in a coal pile or under cover in a bin, silo, or bunker. The design of all components will depend on land availability for storage, topography of the area, and physical plant constraints.

The quantity (or volume) of coal consumed at the plant directly affects the size of the handling system components. Conveyor belts, hoppers, feeders, bins, etc., vary according to the maximum quantity of coal they must handle. Another factor controlled by the volume of coal consumed is the amount of coal which must be stored due to possible delays in delivery.

The mode by which coal is delivered to the plant determines the type of unloading system needed. Both rail cars and trucks can dump coal into a hopper which feeds directly to the system conveying the coal to storage. Barges, on the other hand, require a clamshell crane or bucket wheel excavator to life the coal out of the barge, a significantly greater investment. In addition, barge shipment requires docking capability for the barges, which can be quite costly. Since the total coal handling capital costs for barge delivery are at least twice as expensive as those for rail or truck delivery,^{5/} further discussion and cost estimates assume rail or truck delivery.

Special requirements dictated by the location and layout of the plant can increase or decrease the cost of the coal handling system. Climate, a function of plant location, is a factor wherever extended periods of freezing conditions exist because coal is more difficult to handle when it is frozen. Plants in such climates may require rail car thawing equipment, and special provisions may be necessary in the stacking and reclaiming equipment. The layout of the plant may result in either a favorable or unfavorable location for coal storage (a favorable location will minimize the length and size of conveyor belts). Topography may be beneficial or detrimental by decreasing or increasing the distance coal must be lifted by conveyor belts. Lack of available space may increase coal handling costs by requiring remote storage (increasing haulage costs) or by favoring more costly storage systems such as silos, which use less land area.

In addition to those factors listed above, there are several other factors which can influence the type and cost of a coal handling system installed at a plant. For example, silo storage may be desirable, not only on the basis of land availability, but because silos (or other forms of enclosed storage) mitigate fugitive dust, water pollution, and visual impacts which may be significant, particularly for urban plants, and also reduce physical degradation of the coal. Another possible storage system which may be cost effective for plants consuming only small amounts of coal is to lease or

purchase rail hopper cars (or pay demurrage) in which coal is stored until needed. Perhaps the most important factor influencing the type of coal handling system chosen is the way in which corporate management views a tradeoff between capital costs and operating costs. For any industrial plant there may be several possible ways of handling coal, ranging from systems with small capital investment to ones which cost well in excess of a million dollars. The advantages of more expensive systems generally include lower operating costs as well as fewer environmental problems and greater efficiency.

H.2.2.1.2 Design of Coal Handling Systems

In this analysis, the coal handling system is defined to include the equipment necessary to unload the rail car or truck, convey the coal to a coal pile, reclaim it, crush it (if necessary), and transport it to the coal bunkers inside the powerhouse. The basic approach for determining the capital costs of a coal handling system was to design several "typical" systems for plants receiving different volumes of coal.

The first step was to determine the range of annual coal requirements expected at industrial plants. The MFBI survey data indicated a wide annual volume range, from under 50,000 tons to 400,000 tons. Coal handling systems were designed for the following three annual volume classes:

- Class 1: 25,000-75,000 tons/year.
- Class 2: 75,000-150,000 tons/year.
- Class 3: greater than 150,000 tons/year.

Coal handling costs for boilers burning less than 25,000 tons annually were estimated separately.

The second step was to consider the influence of the delivery mode. This factor affects the unloading system; for example, the equipment employed to unload coal from rail cars operating under a single-car rate is different from components used to unload coal from unit trains. Delivery model does not affect storage or reclaim components.

Coal handling systems to unload barges or unit trains are not included in this analysis because they generally do not apply to the industrial sector. Railroads will not write a unit train rate for a customer using a small amount of coal because such rates are based on the level of efficiency experienced with frequent, large shipments and rapid loading and unloading. Plants not using 10,000 tons of coal approximately every week or two would not be considered unit train size. Similarly, although it is possible for small plants to receive coal by barge, it is uncommon.

The final step prior to obtaining cost data was designing system layouts. This step included determining the necessary equipment and calculating the size of the components. For example, engineering estimates were made of the length and width of conveyor belts, the horsepower requirements of belt drive motors, the number of belt trips, hopper sizes, and coal pile dimensions. The system layouts were based upon information found in Steam,^{6/} the McNally Pittsburgh Coal Preparation Manual, and EEA's engineering experience. Important assumptions regarding system layouts are listed below.

- Coal is unloaded and transferred to a conveyor belt which carries it to the coal pile. In a separate operation, coal is reclaimed from the pile, crushed, and conveyed by belt to the bins within the powerhouse.
- A coal pile contains ten days of live (temporary) storage and 30 days of dead (permanent) storage.
- Coal piles use limestone (nine inches thick) spread under the pile as a coal pile drainage control technique.
- All systems include only the equipment necessary to deliver coal to the hopper in the powerhouse. Equipment such as pulverizers, burners, etc., are included in the boiler section.
- Plants are assumed to have adequate land available, not to have beneficial or detrimental topography, and not to be subject to extraordinary environmental or zoning regulations.

The goal in designing these prototypical coal handling systems has been to portray typical industry practice at the level of sophistication found in new installations of coal handling equipment.^{8/} Cost extremes on either

end of the spectrum have been avoided, although certain plant factors tend to favor systems more or less expensive than those used. It was assumed that new coal handling systems would be required for both new coal boilers and for retrofitting existing coal-capable boilers.

The components in each system designed are listed in Tables H.3 through H.5 and characterized in Figures H.1 and H.2 with side and overhead views. System #1 was designed for a plant using about 50,000 tons of coal annually transported by rail (single-car or special rate) or truck. System #2 applies to the same type of plant consuming about 100,000 tons of coal annually, and System #3 characterizes this type of plant requiring about 200,000 tons of coal annually.

Most of the components listed in the inventory equipment tables have been identified (by number) on the charts. Note, however, that Systems #2 and #3 are identical except for some of the reclaim equipment. Specifically, in Figure H.2 the five belt feeders (component #15) apply to System #3. System #2 has only four feeders.

H.2.2.1.3 Costs

Capital cost data were obtained primarily by sending preliminary handling system layouts and equipment inventories to vendors for cost estimates and comments. Cost estimates were provided for the majority of components and for installation and annual maintenance and supply costs. Some component costs were estimated by EEA staff based upon materials costs as reported in recent editions of Engineering News Record,^{9/} equipment costs shown in the Cost Reference Guide,^{10/} and previous experience with related equipment.

Annual O&M costs have been based on the need for personnel, the costs of parts and supplies, and equipment maintenance. Equipment vendors have indicated that parts and supplies represent an annual cost of two percent of the basic equipment capital costs. Maintenance costs have been based

TABLE H.3 COAL HANDLING SYSTEMS: UNLOADING EQUIPMENT INVENTORY

<u>No. a/</u>	<u>Equipment</u>	<u>Systems</u>		
		<u>#1</u>	<u>#2</u>	<u>#3</u>
*	Car shaker	1	1	1
1	Hopper ^{b/}	1@10t	1@10t	1@10t
2	Vibratory feeder	1@150tph	1@150tph	1@150tph
3	Belt feeder	1@150tph	1@150tph	1@150tph
*	Dust collector	1	1	1

Legend

t = tons

tph = tons per hour

* = not depicted in coal handling system diagrams

a/ "Number" refers to components identified in Figures H.1 and H.2.

b/ Open hopper for truck deliveries; undertrack hopper for rail deliveries.

TABLE H.4 . COAL HANDLING SYSTEMS: STORAGE EQUIPMENT INVENTORY

No. ^{a/}	Equipment	Systems		
		#1	#2	#3
7	Belt	1		
	- dimensions	24"x300'	35"x300'	36"x300'
	- drive motor	10hp	25hp	25hp
	- length in tunnel	55'	55'	55'
8	Belt			
	- dimensions	24"x140'	36"x140'	36"x140'
	- drive motor	10hp	20hp	20hp
9	Tower	1	1	1
	- dump height	48'	48'	48'
10	Supporting tower		2	2
11	Belt		1	1
	- dimensions		36"x120'	36"x120'
	- drive motor		5hp	5hp
12	Storage tripper		1	1
14	Coal pile ^{b/}	1	1	1
	- dimensions ^{c/}	140'x180' x45'	140'x260' x45'	140'x300' x45'

Legend: " = inches

' = feet

hp = horsepower

a/ "Number" refers to components identified in Figures H.1 and H.2.

b/ Underlined with nine inches of limestone.

c/ Approximate - varies depending upon schedule of deliveries and consumption.

TABLE H.5 COAL HANDLING SYSTEMS: RECLAIM EQUIPMENT INVENTORY

No. ^{a/}	Equipment	Systems		
		#1	#2	#3
*	Vibratory electromagnetic feeders	2@20tph	4@30tph	5@75tph
15	Belt feeders	2@20tph	4@30tph	5@75tph
16	Belt	1	1	1
	- dimensions	18"x100'	18"x175'	18"x225'
	- drive motor	2hp	2hp	4hp
17	Belt	1	1	1
	- dimensions	18"x200'	18"x200'	18"x200'
	- drive motor	5hp	5hp	5hp
*	Crusher	1	1	1
*	Tramp iron magnet	1	1	1

Legend: " = inches

' = feet

tph = tons per hour

hp = horsepower

* = not depicted in coal handling system diagrams

^{a/} "Number" refers to components identified in Figures H.1 and H.2.

FIGURE H.1
COAL HANDLING SYSTEM #1

FIGURE H.2
COAL HANDLING SYSTEMS #2 AND #3

a/ COAL HANDLING SYSTEM #2 HAS ONLY FOUR FEEDERS.

upon standard cost estimation references.^{11/} Personnel costs have been calculated based on the staff necessary for unloading, storing, and reclaiming the coal. These annual O&M expenses are estimated to be:

- System #1: \$ 73,000
- System #2: 111,000
- System #3: 151,000

Capital costs for a new coal handling system include the cost of purchasing and installing the equipment shown in the system inventories and the cost of acquiring the coal stockpile or dead storage, properly considered working capital. Table H.6 shows the installed equipment costs for the three prototypical systems, broken down by major subsystems. These costs are for totally new systems and do not include engineering expenses or contingency costs.

The capital costs for boilers burning less than 250,00 tons of coal annually were estimated separately. The design of this coal handling system was similar to System #1. Smaller capacity components were designed and costed, and the need for expensive high annual volume equipment was eliminated. This system was costed at \$139, 033. Annual O&M costs, estimated on the same basis as for larger coal handling systems, were estimated at \$40,000 per year.

The cost of acquiring a one-month supply of coal for the coal pile is calculated for each plant based upon the plant's projected coal consumption. Unfortunately, it was not possible to use the actual regional delivered coal cost due to computer programming complications; a value of \$40/ton is assumed.*

H.2.2.2 Oil Handling System

Standard configurations of fuel handling systems for distillate and residual oil were chosen. For distillate oil, the design included storage

* This coal price is a representative mid-1980's estimate in 1975 dollars.

TABLE H.6 CAPITAL COSTS FOR PROTOTYPICAL COAL
HANDLING SYSTEMS^{a/}
(1975 \$10³)

<u>System</u>	<u>Unloading</u>	<u>Storage</u>	<u>Reclaim</u>	<u>Total</u>
#1	61	168	127	356
#2	61	405	142	608
#3	61	414	157	632

a/ Does not include the coal stockpile.

tanks, fuel pumps, delivery lines, and return flow lines. The high viscosity of residual oil required additional equipment such as fuel oil heaters, steam tracing lines, and tank and line insulation. In addition, an oil heater and a pump were added to increase the temperature and pressure of residual oil just prior to atomization. It was assumed that the tank size would hold three weeks' supply, based on the expected capacity utilization rate.

The capital cost estimates of these fuel handling systems were derived from vendors and literature. There are significant economies of scale associated with these facilities, and this is reflected in the cost algorithms. The annual O&M costs were estimated under the following categories: operating labor, maintenance and repairs, operating supplies, and utilities. The utility cost included the cost of steam for residual oil. These costs are detailed below.

TABLE H.7 OIL HANDLING SYSTEM CAPITAL AND O&M COSTS
(\$10³)

Capital Costs

$$\text{Distillate oil} = 1.464 (\text{FR})^{0.58}$$

$$\text{Residual oil} = 11.849 (\text{FR})^{0.32}$$

O&M Costs

$$\text{Distillate oil} = 13.24 (\text{FR})^{0.07}$$

$$\text{Residual oil} = 14.38 (\text{FR})^{0.05}$$

where FR stands for firing rate, in MMBtu/hr.

H.2.3 Ash Handling System

H.2.3.1 Purpose

Ash refers to a variety of non-combustible solid materials which are by-products of combustion of solid fuels. Ash consists primarily of inorganic compounds (mostly silicon, aluminum, iron, and calcium with smaller amounts of magnesium, titanium, sodium, and potassium) that entered the coal seam during or after coal formation or were included from adjacent rock strata during mining. Five to 20 percent of the weight of most bituminous coal is non-combustible residue which must be disposed of after combustion.

Ash removal from the boiler is critical because ash may form deposits of slag on furnace walls and act as insulation (inhibiting heat transfer in tubes) or foul tubes in flue gas passes. Erosion of boiler tubes and equipment is a potential problem when ash particles are concentrated in a local region.^{12/} It also is important not to permit ash emissions carried by the flue gases to enter the atmosphere. Therefore, the purpose of the ash handling system is to remove ash from the bottom of the boiler and from particulate control equipment (designed to remove fly ash from the stack gases) and convey it to a sanitary disposal site.

H.2.3.2 Key Parameters

There are several different types of ash handling systems. The key parameters affecting costs and design are:

- Size of boiler.
- Type of boiler.
- Type of ash handling system.
- Number of boilers burning solid fuels.

H.2.3.2.1 Boiler Size

Boiler size directly affects the quantity of ash produced because larger boilers burn more coal and therefore produce more ash. The size of the

components in the ash handling system (i.e., conveying lines, hoppers, silos, etc.) is selected based upon the quantity of ash which must be handled.

H.2.3.2.2 Boiler Type

Boiler type is a significant parameter because the amount of ash originally in the coal deposited at the bottom of the furnace and the amount of ash entrained in the flue gas vary by boiler type. When pulverized coal is burned in a dry ash furnace, all of the ash particles are formed in suspension and most remain in suspension. In this case, approximately 80 percent of the ash is fly ash and 20 percent is bottom ash.^{13/}

However, in a stoker-fired boiler, only about 10-30 percent (depending on the type of stoker) of the ash is fly ash and the remainder is bottom ash because most combustion occurs in the fuel bed. This difference affects the size of the hoppers and conveying lines used in the different components of the ash handling system.

H.2.3.2.3 Type of Ash Handling System

There are two common methods for handling ash: hydraulic and pneumatic.^{14/} Hydraulic systems (more commonly used for large utility rather than smaller industrial boilers) use water to convey ash from the collection hopper to the disposal point. Pneumatic systems use compressed air (or other gases) for this purpose. An ash handling system also can be a combination of these two basic types; for example, bottom ash could be transported hydraulically and fly ash could be conveyed pneumatically.

Pneumatic systems generally are recommended by vendors for industrial plants because water treatment problems are minimized. Hydraulic systems must be designed so that ash-laden waters are not allowed to pollute nearby waterways. This is commonly accomplished by installing a closed recirculating system where water is drained from dewatering bins and recycled or by ponding the ash-laden water on-site if land is available.

H.2.3.3 Capital Costs

The capital costs used in this analysis are based on the installed cost estimates provided by vendors, actual equipment expenses from recent sales, and a recent report on coal conversion costs.^{15/} These costs include the following equipment when appropriate:

exhauster	ash receiver and separator
hoppers (ash pit and dust collector)	water supply piping
conveying lines	ash pond
ash storage or dewatering bin	settling tank
bag filter	control instrumentation
air washer	blowers or pumps

The items listed above are associated with collecting and transporting the ash to a storage or dewatering bin. The cost of disposing of this residue is included in the annual O&M expenses.

Installed cost estimates were collected for 16 ash handling systems of different sizes for coal-fired boilers. These systems include hydraulic and pneumatic types. The following equations were derived to approximate ash handling capital expenses:

$$\begin{aligned} \text{Capital cost } (\$ 10^3) &= 75 \times [(BC)^{.301}], & BC < 300 \\ &= 16.9 \times [(BC)^{.5623}], & BC \geq 300 \end{aligned}$$

where BC equals boiler capacity (thousands of pounds of steam per hour).

A plot of dollars/unit capacity versus capacity is presented in Figure H.3. This graph indicates that ash handling capital expenses range from \$1-3/lb of steam capacity per hour for industrial coal-fired boilers, depending on the boiler size. These two equations intersect at 300 lbs of steam capacity per hour, near the size cutoff for stoker-fired vs. pulverized coal boilers and pneumatic vs. hydraulic ash handling systems.

FIGURE H.3
ASH HANDLING SYSTEM CAPITAL COSTS

If a boiler is employing an FGD system to control sulfur emissions, then it also will collect and dispose of the fly ash.* It has been assumed that a new ash handling facility is required for both new coal boilers and the retrofit of existing coal-capable boilers.

H.2.3.4 Annual Operating and Maintenance Costs

There are two components of annual O&M costs for an ash handling system. First, there are the expenses for personnel, parts, and supplies; second, there is the cost of ash disposal.

The first component includes monitoring the control panel, cleaning, painting, inspections, etc. These activities are not expected to involve any unusual manpower or equipment requirements. Therefore, these expenses have been estimated as a percentage of capital costs. Five percent has been selected as typical of industrial practice.

Ash disposal costs can be significant. Truck or rail haulage is common for plants without space for on-site disposal. The ash may be taken to a land-fill area if there is no danger of contaminating surface or underground water supplies or it may be used commercially as an additive for road-based or roofing material, concrete, asphalt mix, cinders, insulation, or grit for sandblasting.^{16/}

A figure of \$1.50-2.00 per ton of ash has been cited by vendors and in various reports^{17/} as the cost for truck haulage. Two dollars per ton of ash is assumed in this analysis. The quantity of ash to be disposed of is a function of the amount of coal burned and its ash content. Assuming (conservatively) that coal has a heating value of 20 MMBtu/ton and 10 percent ash content, then:

* At a typical efficiency of 94-99 percent of the fly ash.

$$\begin{aligned}
 \text{Annual ash disposal cost (\$)} &= \frac{\text{annual coal consumption (MMBtu)}}{20 \text{ MMBtu/ton}} \times 10\% \text{ ash} \\
 &\quad \text{content} \times \$2/\text{ton ash} \\
 &= \text{annual coal consumption (MMBtu)} \times 0.1 \times 2/20 \\
 &= \text{annual coal consumption (MMBtu)} \times 1\$/\text{MMBtu}
 \end{aligned}$$

H.2.4 Environmental Control Equipment

Environmental control equipment includes either an ESP for control of particulate emissions or an FGD for control of both particulate and SO₂ emissions. The type of environmental control equipment installed at any plant depends upon the regulation applicable at that plant and the quality (sulfur content) of the coal.

H.2.4.1 Electrostatic Precipitators

Particulate emission control is necessary when burning any kind of coal, regardless of the sulfur content. Generally speaking, particulate control can be achieved with ESP's, fabric filters, cyclones, and wet or dry scrubbers. These types of control equipment vary in their effectiveness and cost and consequently the type of equipment used depends upon the type of installation and the stringency of the emission limits. ESP's are assumed to be the type of control equipment used because: 1) stringent limits for particulate emissions are assumed, and 2) cyclones are not capable of the level of control currently required in many areas.

Capital cost of ESP's is a function of boiler capacity; operating cost is a function of capacity and the number of hours per year the precipitator is used. Costs have been developed through contacts with equipment vendors, previous work by EEA, and published reports.^{18/} The following equations give the total installed cost of the ESP, including construction and engineering costs:

$$\text{Annual operating cost } (\$10^3) = 1.896 (FR^{0.56}) \times \left(\frac{CUF}{0.4}\right)$$

$$\text{Capital cost } (\$10^3) = 91.84 (FR^{0.38})$$

where FR = firing rate (MMBtu/hr) and CUF = capacity utilization factor.

H.2.4.2 Flue Gas Desulfurization

H.2.4.2.1 Key Parameters

High sulfur coal can be burned in compliance with SO₂ emission regulations by using FGD. In this system, flue gases pass through an alkaline solution in a wet scrubber. The SO₂ chemically reacts with and is absorbed in the alkaline solution in the scrubber. At the same time, a high level of particulate control can be achieved.* Therefore, additional particulate control (an ESP) may not be required when coal is scrubbed, depending on the stringency of the particulate control requirement.^{19/}

There are several different types of scrubbers. Major differences between FGD systems involve the type of chemicals used, whether the scrubbing fluid can be regenerated, whether the waste is solid or liquid, and whether or not plant process water can be used as the scrubbing reagent.

This analysis assumed that the FGD system is a self-contained, solid waste system using sodium or lime as the scrubbing agent. This system is appropriate for any type of industrial application and it is possible to achieve a high degree of SO₂ removal (up to 90-95 percent).

FGD systems using self-contained liquid waste or industrial process waste streams are significantly less expensive than self-contained solid waste systems. However, most industries do not have the appropriate waste stream characteristics to utilize a waste stream system. The liquid waste FGDs

* Typically, 94-99 percent fly ash removal.

systems have much higher chemical and water requirements than solid waste systems and, therefore, are more economical than solid waste systems only for low operating hours.

H.2.4.2.2 Cost Data

Information on scrubber types and costs has been taken from a recent report prepared by EEA for the FEA.^{20/} This report is based on a survey of current FGD systems at industrial installations. Generic capital and operating costs for three boiler sizes (10 MWe, 25 MWe, and 40 MWe) are included in the report. These estimates include all direct and indirect (site preparation, offsite utilities, engineering, and contingency expenses) costs.

The principal components of the self-contained, solid waste FGD system are the mechanical collectors, scrubber and separator, tanks, clarifier, thickener, filters, ducting and piping, pumps, chemical storage bins, conveyors, motors, fans, starter, damper, and stack. Sludge removal costs are considered an operating expense.

These cost data for a self-contained, solid waste FGD system assume:

- SO₂ removal efficiency is 90 percent.
- Particulate removal efficiency is 95 percent.
- The coal type is bituminous with three percent sulfur content, 11.5 percent ash content, and a received heating value of 12,000 Btu/lb.

The cost data in the Guidebook to the Applicability of Flue Gas Desulfurization for Industrial Coal-Fired Boilers have been supplemented by an unpublished analysis by EEA for EPA on the economic impact of new emissions standards for industrial boilers. This report contains cost data for FGD systems for four boiler sizes (50, 100, 250, and 600 MMBtu/hr). The generic cost data in these two reports have been approximated by the following equations in order to estimate costs for all industrial boiler sizes:

$$\begin{aligned}\text{Capital cost } (\$10^3) &= 45.03 (\text{FR}^{0.748}), \text{ if FR} < 250 \\ &= 187.14 (\text{FR}^{0.49}), \text{ if FR} \geq 250\end{aligned}$$

where FR = boiler firing rate (MMBtu/hr).

The annual operating costs have a fixed and a variable component. Maintenance costs have been estimated as three percent of the total installed cost of the FGD system. Operating costs are a function of the number of hours the system is used and include requirements for electricity, chemicals, water, manpower, and solid waste disposal. These costs have been approximated from data reported in the report cited above as:

$$\begin{aligned}\text{Annual operating cost } (\$10^3) &= 0.9 (\text{FR}^{0.817}) + 0.963 (\text{FR}^{-0.24}) \text{FR}(\text{AH}/1000), \\ &\quad \text{if FR} < 250 \\ &= 0.9 (\text{FR}^{0.817}) + 0.271 (\text{FR}^{-0.011}) \text{FR}(\text{AH}/1000), \\ &\quad \text{if FR} \geq 250\end{aligned}$$

where FR = boiler firing rate (MMBtu/hr) and AH = number of annual operating hours.

H.2.5 Other Costs

Other costs for which generic data have been developed include:

- Boiler feedwater treatment.
- Powerhouse construction.
- Engineering.
- Offsite utility hookup (electrical).
- Provision for other indirect costs and contingency.

Powerhouse construction and offsite utility hookup are only relevant for new plants or early replacement of existing boilers. Contingency and engineering costs are applicable to all conversions.

H.2.5.1 Boiler Feedwater Treatment

Boiler feedwater treatment is not affected by the type of fuel used in the boiler. The design and, therefore, costs of treatment systems depend on many site-specific factors such as the quality of local water, contaminants in the condensate returns, and percentage of make-up water used. An estimate of the cost of this system is \$2.50 to \$3.00 per pound of steam per hour capacity. This estimate does not include engineering and contingency, but otherwise represents an installed cost.

H.2.5.2 Powerhouse Construction

The cost of building a powerhouse for a coal-fired boiler is greater than for an oil- or gas-fired boiler because the coal boiler is larger. When a new boiler is being installed or when early replacement of existing boilers is being considered, the increased cost of the powerhouse for coal-fired boilers must be considered. Conversion of existing coal-capable boilers does not generally require significant modification of the powerhouse.

Powerhouse costs were developed by determining the size of the structure and contacting construction companies for cost estimates. Cost estimates are based on a building constructed of structural steel supports, a corrugated metal-type skin on a concrete foundation. All catwalks, ladders, lighting, ventilation, etc., are installed as well as coal bins adequate for three days of storage. Installed building costs (less engineering) are estimated to be \$4/lb of steam/hr capacity for coal boilers and \$2/lb of steam/hr capacity for oil/gas boilers.

H.2.5.3 Engineering

Engineering costs are estimated as a percentage of capital cost. Generally, engineering fees are approximately 10 percent of the capital costs;^{21/} this percentage has been added to all costs except for the environmental control equipment costs that already include engineering.

H.2.5.4 Offsite Utility Hookup

This cost applies only to grassroots plants and includes costs of constructing an electrical substation and extending rail lines and water to the site. This cost also is calculated as 10 percent of the total capital cost (before engineering).^{22/} Coal-fired plants require more extensive utility installation, because power and water must be available for coal and ash handling equipment. Calculating these costs as a percentage of the capital cost for new grassroots plants captures the increased costs for coal burning. Existing plants already have utilities, and although conversion may entail costs for transporting electricity and water to the coal and ash handling equipment, these costs are too highly variable to estimate.

H.2.5.5 Provision for Other Indirect Costs and Contingency

Contingency and other indirect costs also are estimated as a percentage of capital costs. In this analysis, a "conservative" 20 percent of the capital costs have been added to cover insurance and overhead.^{23/} In addition, a working capital component has been added to the capital costs. This is represented as equivalent to two months of O&M expenses. This category consists of a cash reserve for parts, supplies, and utility expenses.

H.3 COST DATA COMPARISONS

Key parameters, major system design assumptions, and cost equations have been presented in Section H.2. This subsection summarizes the cost data by:

- Type of cost component (capital and O&M).
- Type of equipment (boiler, pollution control, etc.).
- Fuel type.
- Size.
- Capacity utilization.

H.3.1 New Boiler Capital Costs

Tables H.8 through H.11 summarize total capital costs for new boiler systems by size, fuel type, and major equipment component. Coal boilers are significantly more expensive than gas or oil boilers and require more auxiliary equipment.

For illustrative purposes, pollution control costs have been added for some sizes and fuel types. Pollution control requirements vary widely in the model, from no control (Table H.8) to stringent controls (Tables H.10 and H.11). However, not all small new boilers are free from environmental control expenses. The pollution control requirements in Table H.8 and H.9 are indicative of some SIP regulations. The pollution control requirements in Tables H.10 and H.11 do conform to the interpretation of the revised NSPS for new boilers used in the sample run for boilers installed after 1981.

H.3.2 Retrofit Capital Costs

Retrofit capital costs are summarized in Table H.12 by boiler size. Conversion costs are dependent on the current and new fuel types. These costs represent average installed costs. Actual installations may be more or less expensive to retrofit depending upon site-specific factors and the condition of existing equipment.

H.3.3 Annual Non-Fuel O&M Expenses

Table H.13 presents annual non-fuel O&M expenses by fuel type and boiler size. Pollution control costs selected have been included in order to conform to the control strategies assumed in Tables H.8 through H.11. These cost estimates include a component which does not vary with the capacity utilization.

H.3.4 Annualized Cost Comparisons

Table H.14 compares new boiler annualized costs by fuel type and boiler size for two capacity utilizations, 25 and 75 percent, which represent the extreme

TABLE H.8 CAPITAL COST OF NEW 15 MMBTU/HR BOILER,
150 PSIG/SAT STEAM SPECIFICATION
(1975 \$10³)

	<u>Gas</u>	<u>Distillate</u>	<u>Residual</u>	<u>Coal</u>
<u>Direct Costs</u>				
Boiler	60	60	60	168
Feedwater	32	32	32	32
Powerhouse	20	20	20	20
Fuel Handling	0	7	28	188
Ash handling	-	-	-	121
Pollution control				
ESP	-	-	-	-
FGD	-	-	-	-
Total Direct Costs	<u>112</u>	<u>119</u>	<u>140</u>	<u>549</u>
<u>Indirect Costs</u>				
Offsite utilities (10%)	11.2	11.9	14.0	54.9
Engineering (10%)	12.3	13.0	15.4	60.4
Contingency (20%)	27.1	28.8	35.9	132.9
Working capital	2.7	5.6	6.2	13.4
Fuel stockpile	0.0	14.6	12.3	12.5
Total Indirect Costs	<u>53.3</u>	<u>73.9</u>	<u>83.8</u>	<u>274.1</u>
Total Capital Costs	165.3	193.0	221.8	823.1

TABLE H.9 CAPITAL COST OF NEW 50 MMBTU/HR BOILER,
250 PSIG/SAT STEAM SPECIFICATION
(1975 \$10³)

			<u>Residual</u>		<u>Coal</u>	
	<u>Gas</u>	<u>Distillate</u>	<u>L.S.</u>	<u>H.S.</u>	<u>L.S.</u>	<u>H.S.</u>
<u>Direct Costs</u>						
Boiler	178.2	178	210	210	565	565
Feedwater	107.1	107	107	107	107	107
Powerhouse	71.4	71	71	71	123	123
Fuel handling		12	17	17	292	292
Ash handling	-	-	-	-	174	174
Pollution control						
ESP	-	-	-	-	369	-
FGD	-	-	-	762	-	762
Total Direct Costs	<u>356.7</u>	<u>368</u>	<u>405</u>	<u>1167</u>	<u>1630</u>	<u>2023</u>
<u>Indirect Costs</u>						
Offsite utilities (10%)	35.6	36.8	40.5	116.2	163.0	202.0
Engineering (10%)	39.1	40.5	44.5	128.0	179.0	222.0
Contingency (20%)	86.1	89.0	98.0	282.0	395.0	490.0
Working capital	7.0	10.7	12.1	39.6	36.0	58.0
Fuel stockpile	0.0	49.0	46.0	41.0	49.0	42.0
Total Indirect Costs	<u>167.8</u>	<u>226.0</u>	<u>241.1</u>	<u>606.8</u>	<u>822.0</u>	<u>1014.0</u>
Total Capital Costs	524.5	594.0	646.1	1775.0	2452.0	3034.0

TABLE H-10

CAPITAL COST OF NEW 175 MMBtu/HR BOILER,
 700 PSIG/700°F SPECIFICATION
 (1975 \$10³)

			<u>Residual</u>		<u>Coal</u>	
	<u>Gas</u>	<u>Distillate</u>	<u>L.S.</u>	<u>H.S.</u>	<u>L.S.</u>	<u>H.S.</u>
<u>Direct Costs</u>						
Boiler	777	777	843	843	2083	2083
Feedwater	375	375	375	375	481	481
Powerhouse	250	250	250	250	500	500
Fuel handling	0	24	52	52	355	355
Ash handling	-	-	-	-	254	254
Pollution control						
ESP	-	-	633	633	633	633
FGD	-	-	-	1949	1949	1949
Total Direct Costs	<u>1402</u>	<u>1426</u>	<u>2153</u>	<u>4102</u>	<u>6255</u>	<u>6255</u>
<u>Indirect Costs</u>						
Offsite utilities (10%)	140	142	215	410	626	626
Engineering (10%)	154	157	237	451	688	688
Contingency (20%)	339	234	521	993	1514	1514
Working capital	22	28	49	130	162	162
Fuel stockpile	0	198	163	144	145	145
Total Indirect Costs	<u>655</u>	<u>870</u>	<u>1185</u>	<u>2128</u>	<u>3135</u>	<u>3135</u>
Total Capital Costs	2057	2296	3338	6230	9390	9390

TABLE H.11 CAPITAL COST OF NEW 325 MMBTU/HR BOILER,
700 PSIG/700°F SPECIFICATION
(1975 \$10³)

			<u>Residual</u>		<u>Coal</u>	
	<u>Gas</u>	<u>Distillate</u>	<u>L.S.</u>	<u>H.S.</u>	<u>L.S.</u>	<u>H.S.</u>
<u>Direct Costs</u>						
Boiler	1805	1805	1870	1870	3288	3288
Feedwater	697	697	697	697	722	722
Powerhouse	464	464	464	464	962	962
Fuel handling	0	35	63	63	583	583
Ash handling	-	-	-	-	323	323
Pollution control						
ESP	-	-	751	751	751	751
FGD	-	-	-	2891	2891	2891
Total Direct Costs	<u>2966</u>	<u>3001</u>	<u>3895</u>	<u>6736</u>	<u>9520</u>	<u>9520</u>
<u>Indirect Costs</u>						
Offsite utilities (10%)	297	300	385	674	952	952
Engineering (10%)	326	330	423	741	1047	1047
Contingency (20%)	718	726	930	1630	2304	2304
Working capital	40	48	79	207	204	204
Fuel stockpile	0	317	267	302	270	270
Total Indirect Costs	<u>1381</u>	<u>1721</u>	<u>2084</u>	<u>3554</u>	<u>4777</u>	<u>4777</u>
Total Capital Costs	4347	4722	5979	10290	14297	14297

TABLE H. 12 RETROFIT CAPITAL COSTS^{a/}
(\$ 1975)

Retrofit from:	Retrofit to:			
	<u>Gas</u>	<u>Dist.</u>	<u>Resid.</u>	<u>Coal</u> ^{b/}
1. 325 MMBtu/hr., steam - 700 psig/700°F.				
Gas	-	52627	497708	1203456
Distillate	48181	-	497708	1203456
Residual	48181	-	-	763913
2. 175 MMBtu/hr., steam - 700 psig/700°F.				
Gas	-	29036	278129	737662
Distillate	26480	-	278129	737662
Residual	26480	-	-	491640
3. 50 MMBtu/hr., steam - 250 psig/sat. temp.				
Gas	-	14979	107006	305719
Distillate	13653	-	107006	305719
Residual	13653	-	-	215489

a/ These costs include the installed costs of the equipment that was changed during the retrofit. They do not include indirect costs associated with the retrofit nor do they include costs associated with fuel handling, ash handling and pollution control systems.

b/ A boiler originally designed to burn coal.

TABLE H. 13 OPERATION AND MAINTENANCE COSTS^{a/}
(1975 \$10³)

	Natural Gas	Distillate	Residual		Coal	
			LS	HS	LS	HS
<u>15 MMBtu/hr</u>						
Boiler related	12.7	13.9	16.6	16.6	33.2	33.2
Fuel handling		16.0	16.5	16.5	24.5	24.5
Ash handling					6.9	6.9
Pol. Cont. - ESP						
Pol. Cont. - FGD						
Property tax	3.2	3.5	4.1	4.1	15.9	15.9
TOTAL	15.9	33.4	37.2	37.2	80.5	80.5
<u>50 MMBtu/hr</u>						
Boiler related	31.8	35.8	43.5	43.5	72.8	72.8
Fuel handling		17.4	17.5	17.5	41.5	41.5
Ash handling					11.5	11.5
Pol. Cont. - ESP					42.4	
Pol. Cont. - FGD				164.9		164.9
Property tax	10.5	10.7	11.8	33.9	47.3	58.7
TOTAL	42.3	63.9	72.8	259.8	215.5	349.4
<u>175 MMBtu/hr</u>						
Boiler related	90.6	105.2	127.3	127.3	181.6	181.6
Fuel handling		19.0	18.6	18.6	71.8	71.8
Ash handling					22.6	22.6
Pol. Cont. - ESP			85.5	85.5	85.5	85.5
Pol. Cont. - FGD				427.4	427.4	427.4
Property tax	40.7	41.4	62.5	119.1	181.6	181.6
TOTAL	131.3	165.6	293.9	777.9	970.6	970.6
<u>325 MMBtu/hr</u>						
Boiler related	155.8	183.7	220.4	220.4	295.6	295.6
Fuel handling		19.8	19.2	19.2	94.0	94.0
Ash handling					33.8	33.8
Pol. Cont. - ESP			120.9	120.9	120.9	120.9
Pol. Cont. - FGD				684.2	684.2	684.2
Property tax	86.1	87.1	111.7	195.6	276.5	276.5
TOTAL	241.9	290.6	472.2	1240.3	1505.1	1505.1

a/ These costs do not include the cost of the fuel burned. The capacity utilization is assumed to be 65%.

TABLE H. 14 NEW BOILER ANNUALIZED COSTS^{a/}
(1975 \$/MMBtu)

Size (MMBtu/hr)	C.U. ^{b/} :	Gas		Residual Oil		Distillate Oil		Gas	
		25%	75%	25%	75%	25%	75%	25%	75%
15	capital cost	.54	.18	.73	.24	.63	.21	2.70	.90
	O & M cost	.33	.16	.85	.42	.79	.32	2.08	.77
	Total cost	.87	.34	1.58	.66	1.42	.53	4.78	1.67
50	capital cost	.52	.17	.64	.21	.59	.20	1.89	.63
	O & M cost	.24	.13	.44	.22	.40	.19	1.26	.50
	Total cost	.76	.30	1.08	.43	.99	.39	3.15	1.13
175	capital cost	.58	.19	.68	.23	.65	.22	1.59	.53
	O & M cost	.21	.11	.34	.18	.27	.14	.92	.38
	Total cost	.79	.30	1.02	.41	.92	.36	2.51	.91
325	capital cost	.66	.22	.74	.25	.72	.24	1.37	.46
	O & M cost	.21	.11	.30	.16	.25	.13	.73	.31
	Total cost	.87	.33	1.04	.41	.97	.37	2.10	.77

a/ Values shown are pre-tax figures without fuel expenses. Represents boiler and auxiliary equipment costs without pollution control equipment expenses. Assumes the discount rate is 7 percent and sum-of-year digit depreciation over 28 years.

b/ Capacity utilization.

points of the range of capacity utilizations for new boilers used in IFCAM. This table clearly shows the economies of scale associated with higher capacity utilizations.

Note that coal is considerably more expensive than gas (especially for small capacity utilization boilers) and these data do not include pollution control expenses. As a result, the price of coal must be significantly less expensive than the price of gas for coal to be the least cost fuel choice.

Tables H.15 and H.16 compare pre-tax annualized new boiler costs including representative pollution control expenses. The pollution control strategies in Table H.15 are representative of SIP requirements. Pollution control costs are significant. For example, if an FGD system is required to burn residual oil, the total annualized (non-fuel) costs increase by 200 percent for the 50 MMBtu/hr boiler. The difference between coal and gas also increases substantially. These cost differences are larger for smaller capacity utilizations because of economies of scale factors.

Table H.16 compares pre-tax annualized costs for large new boilers. An interpretation* of the revised new boiler NSPS requires both FGD and ESP when burning residual oil or coal. SIP regulations, on the other hand, may require no pollution control equipment, an ESP only, or only an FGD system.

* Used in the sample run.

TABLE H. 15 NEW BOILER ANNUALIZED COSTS^{a/}
(1975 \$/MMBtu)

Size (MMBtu/hr)	Gas	Residual Oil		Distillate Oil	Coal	
		w/ESP	w/FGD		w/ESP	w/FGD
15 Capital cost:						
Boiler	.21	.28	.28	.24	1.04	1.04
PC ^{b/}	-	.32	.43	-	.32	.43
Operating cost:						
Boiler	.17	.40	.40	.36	.86	.86
PC ^{b/}	-	.23	.71	-	.23	.71
Total	.38	1.23	1.82	.60	2.45	3.04
50 Capital cost:						
Boiler	.20	.24	.24	.22	.73	.73
PC ^{b/}	-	.20	.42	-	.20	.42
Operating cost:						
Boiler	.14	.23	.23	.21	.56	.56
PC ^{b/}	-	.14	.53	-	.14	.53
Total	.34	.81	1.42	.43	1.63	2.24

a/ Values shown are pre-tax figures without fuel expenses. Boiler costs include all boiler and applicable auxiliary equipment expenses. Assumes the discount rate is 7 percent, sum-of-years digit depreciation over 28 years, and a 65 percent capacity utilization.

b/ Pollution control.

TABLE H. 16 NEW BOILER ANNUALIZED COSTS^{a/}
(1975 \$/MMBtu)

Size (MMBtu/hr)	Gas	Residual Oil			Distillate Oil	Coal		
		w/ESP	w/FGD	w/Both		w/ESP	w/FGD	w/Both
175 Capital cost:								
Boiler	.22	.26	.26	.26	.25	.61	.61	.61
PC ^{b/}	-	.10	.31	.41	-	.10	.31	.41
Operating cost:								
Boiler	.12	.19	.19	.19	.15	.42	.42	.42
PC ^{b/}	-	.08	.39	.47	-	.08	.39	.47
Total:	.34	.63	1.15	1.33	.40	1.21	1.73	1.91
325 Capital cost:								
Boiler	.25	.29	.29	.29	.28	.53	.53	.53
PC ^{b/}	-	.06	.24	.30	-	.06	.24	.30
Operating cost:								
Boiler	.12	.17	.17	.17	.14	.35	.35	.35
PC ^{b/}	-	.06	.34	.40	-	.06	.34	.40
Total:	.37	.58	1.04	1.16	.42	1.00	1.46	1.58

a/ Values shown are pre-tax figures without fuel expenses. Boiler costs include all boiler and applicable auxiliary equipment expenses. Assumes the discount rate is 7 percent, sum-of-years digit depreciation over 28 years, and a 65 percent capacity utilization.

b/ Pollution control.

FOOTNOTES

1. Considering the economics and efficiency, the assumption is a good one. See "Measuring and Improving the Efficiency of a Boiler," Auburn University, Alabama Engineering Extension Service, pp. 3.2-3.6.
2. Particularly a study performed by Gilbert Associates, Inc., "Major Fuel Burning Installation (MFBI) Analysis of Cost for Coal Conversion," prepared for the Federal Energy Administration, October, 1976.
3. For a further discussion of the technical problems associated with converting boilers to coal firing, refer to the following:
 Bell, A.W., and Breen, B.P., "Converting Gas Boilers to Oil and Coal," Chemical Engineering, April 26, 1976.
 Bogot, A., and Sherrill, R.C., "Principal Aspects of Converting Steam Generators Back to Coal Firing," presentation at the NCA/BCR Coal Conference and Expo II, Louisville, Kentucky, October 21-23, 1975.
 Heil, T.J., and Leatham, C.H., "Principal Aspects of Converting Back to Coal Firing," Gilbert/Commonwealth presentation at the Industrial Coal Conference, April 20, 1977.
 Schweiger, R.G., "Should You Convert to Coal?," Power, July 20, 1976.
 Seibold, P.F., and Bessette, R.D., "Latest Equipment and Design for New Coal Fired Plants and the Conversion of Existing Plants to Coal Firing," presentation at the Industrial Fuel Conference, Purdue U., October 67, 1976.
4. This cost is incurred in a separate category for new units. See estimates for offsite utility hookup.
5. Energy and Environmental Analysis, Inc., "Coal Utilization in the Paper Industry," prepared for Department of Energy, September 1, 1978, Section A.3.2.2, "Technical, Economic, and Regulatory Aspects of Fuel Transportation."
6. Steam: Its Generation and Use, Babcock and Wilcox Co., 1975.
7. 30 days is a typical industrial coal stockpile as reported by the Bureau of Mines in Coal, Bituminous and Lignite, 1975. Utilities typically have 90 days of dead storage. It is thought that industries have smaller stockpiles because of greater capability to switch to oil or gas in the event of supply interruption.
8. For more details on design characteristics of coal handling systems, see "Power from Coal, Part I, A Special Report, Handling Equipment,

Flexible System Design Should Be Your Primary Goal," Power, February, 1974, pp. S.11-S.24.

9. McGraw Hill's Construction Weekly, New York, New York.
10. National Research and Appraisal Company, "Cost Reference Guide for Construction Equipment," Equipment Guide Book Company, Palo Alto, California, 1976.
11. Aries, R.S., and Newton, R.D., Chemical Engineering Cost Estimation McGraw Hill Book Company, New York, New York, 1955, p. 164.
12. For further information, see Babcock and Wilcox, Steam, Chapter 15, Fuel Ash Effects on Boiler Design and Operation.
13. Ibid, p. 15-7.
14. For a further explanation, see Reference 8, pp. X.44-X.48.
15. See Reference 2.
16. See Reference 6, p. 18-2.
17. Coffin, B.D., "Estimate the Cost of Your Next Coal-Fired Industrial Boiler Plant," Power, October 17, p. 29.
18. Industrial Gas Cleaning Institute, "Particulate Control Costs for Intermediate Sized Boilers," Stamford, Connecticut, February, 1977.
19. Assuming current regulations.
20. Energy and Environmental Analysis, Inc., Guidebook to the Applicability of Flue Gas Desulfurization for Industrial Coal-Fired Boilers, prepared for Federal Energy Administration, November 3, 1977.
21. Guthrie, K.M., "Capital Cost Estimating," Chemical Engineering, March 24, 1969; Peters, M.S., and Timmerhaus, K.D., Plant Design and Economics for Chemical Engineers, McGraw Hill Book Company, New York, New York, 1968, p. 140; and Bauman, H.C., "Engineering Costs," Cost Engineer Notebook, American Association of Cost Engineers.
22. Peters, M.S., and Timmerhaus, K.D., op. cit.
23. Guthrie, K.M., Process Plant Estimating Evaluation and Control, Craftsman Book Company of America, Solana Beach, California, 1974.

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APPENDIX I. NONBOILER CAPITAL AND O&M COST DATA

I.1 INTRODUCTION

Energy use in the industrial sector has been divided into two categories: boiler and nonboiler. The nonboiler category is split into 48 major energy-consuming processes representing eight industries and a ninth category of industries entitled "other." Table I.1 lists, for each major process, the firing rates and capacity utilization that reflect the sizes of nonboilers currently being used or built. Because the firing rates and capacity utilizations vary for nonboiler units, more than one rate sometimes is shown for each process. Firing rates and capacity utilizations for that portion of nonboiler energy use not included in the major processes are listed in a miscellaneous category.

This appendix describes how nonboiler costs were calculated and presents some of the costs used in the model. The costs were divided into four categories for this appendix:

- New capital costs.
- Retrofit capital costs.
- O&M costs.
- Other costs (includes fuel handling, fuel pile, ash handling, pollution control, working capital, engineering, offsite utilities, and contingency costs).

Because costs were determined by analyzing a single nonboiler and all necessary auxiliary equipment standing alone, total costs may be slightly overstated. In most plants, combustors share auxiliary equipment, so that the costs are split between several units.

TABLE I.1 FIRING RATES AND CAPACITY UTILIZATIONS
FOR NONBOILER PROCESSES

<u>Industry</u>	<u>Process</u>	<u>Firing Rate (MMBtu/hr)</u>	<u>C.U.</u>
Food	Miscellaneous	10	0.75
Textiles	Miscellaneous	10	0.75
Paper	Miscellaneous	10	0.75
Chemicals	Primary reformer	340	0.94
	Primary reformer	60	0.96
	Miscellaneous	60	0.90
Petroleum	Tubestill heater	99	0.90
	Tubestill heater	215	0.90
	Tubestill heater	364	0.90
	Tubestill heater (high risk)	99	0.90
	Tubestill heater (high risk)	215	0.90
	Tubestill heater (high risk)	364	0.90
	Tubestill furnace	97	0.90
	Miscellaneous	10	0.90
SCG	Unit melter glass	50	0.90
	Unit melter glass	125	0.90
	Regenerative melter	50	0.90
	Regenerative melter	200	0.90
	Annealing lehrs	5	0.90
	Rotary kiln (cement)	333	0.90
	Face brick tunnel kiln	11	0.90
	Face brick tunnel kiln	42	0.90
	Refractory brick tunnel kiln	11	0.90
	Refractory brick tunnel kiln	42	0.90
	Rotary kiln (lime)	96	0.90
	Miscellaneous	10	0.90
Steel	Vertical shaft furnace	15	0.55
	Traveling grate furnace	200	0.55
	Sintering furnace	1	0.55
	Coke oven	740	0.65
	Blast furnace hydrocarbon injection	400	0.65
	Blast furnace stove	5	0.65
	Pelletizing grate kiln	250	0.55
	Open hearth furnace	135	0.65
	Soaking pits	40	0.65
	Reheat furnace	200	0.55

TABLE I.1 (continued)

<u>Industry</u>	<u>Process</u>	<u>Firing Rate (MMBtu/hr)</u>	<u>C.U.</u>
Steel	Heat treating furnace	10	0.55
	Miscellaneous	10	0.55
Aluminum	Rotary kiln (alumina)	50	0.90
	Anode prebake oven	10	0.90
	Anode prebake oven	20	0.90
	Reverberatory furnace	10	0.90
	Reverberatory furnace	40	0.90
	Heat treating furnace	5	0.90
	Heat treating furnace	20	0.90
	Miscellaneous	10	0.90
Other	All other industrial	10	0.75

I.2 NEW NONBOILER CAPITAL COSTS

This section includes costs only for those components directly associated with a nonboiler process. Fuel handling, ash handling, and pollution control capital costs are considered in Appendix H.

I.2.1 Methodology and Sources for Calculating Costs

Because most industrial furnaces have been designed for specific conditions, are replaced very slowly (see Table 4.15), and have burned only one or two fuels, there are no readily available equipment costs for most processes. For a few processes which are becoming obsolete (for example, open hearth and vertical shaft furnaces), no new capital costs were estimated. When possible, new capital costs were obtained from furnace equipment vendors and users. For example, direct vendor quotations were used for 50 and 200 MMBtu/hr regenerative glass melters, rotary cement kilns, and several direct-fired iron and steel industry furnaces. In the iron and steel industry, some furnace users were visited and others were contacted by phone to determine equipment costs. A petroleum industry consultant also was referred to in establishing petroleum industry costs. In a few cases when costs seemed unavailable, published data from cost estimating manuals were used to determine base costs.

For industrial process furnaces that have never burned certain fuels (usually coal or residual oil), cost estimates had to be made without referring to outside sources. These processes were assigned costs similar to processes which have burned these fuels and which have similar major cost components. For example, the costs for tubestill heaters that produce hydrogen in the petroleum industry were used to estimate the costs of primary reformers used in the chemicals industry.

In many cases, estimates were made by taking the base cost of a natural gas-fired furnace and adding the costs of all the specific changes required to burn an alternate fuel. In an oversimplified case, the cost of a gas

burner would be subtracted from the total cost of a furnace or kiln and the cost of a compatible coal burner would be added. The general example below shows how an original gas furnace cost would be adjusted to arrive at the coal cost.

Base cost = gas furnace cost - burners - refractories

Coal cost = base cost + burners + refractories + sootblowers +
combustion air blowers + pulverizers

I.2.2 Primary Cost Determinants

The most important determinant of process equipment costs is the design of the furnace as required by its function and intended use. Steel reheat furnaces, for example, can be side- or roof-fired, and soaking pits are built in one of several designs. Independently of the fuel fired, the design and firing rate are the two key parameters which affect costs. A large portion of capital costs, however, are determined by the fuel fired in the furnace. In general, fuel-related costs increase as the fuel fired changes from natural gas to distillate oil to residual oil to coal.

Because gas burns very quickly and cleanly, capital costs are lowest for gas-fired furnaces. Distillate oil, while containing small amounts of sulfur preventing its use in a few processes, also burns cleanly, resulting in capital costs very close to, but slightly higher than, those in gas-fired furnaces. Because distillate oil is liquid, mechanical atomization is required before burning, and it cannot be used for pilot lights or in radiant tube furnaces.

Although residual oil burns with higher luminosity than gas or distillate oil, burning residual oil may result in some product degradation, heat distribution problems, furnace corrosion, and plugging of heat recovery devices. If residual oil can be burned, these factors influence furnace design and increase the capital cost above the costs of gas- and distillate-fired furnaces. The extra equipment required to burn residual oil includes atomizers, combustion air blowers, and sootblowers. Capital costs of re-

sidual-fired furnaces vary, but generally are 10-50 percent higher than those of gas-fired furnaces.

Coal-fired furnaces must contend with similar, but more severe, problems than those encountered in residual oil-fired furnaces. In addition to equipment necessary to control these problems, pulverizers or stokers are needed. The design of coal furnaces and the extra fuel handling, ash handling, and pollution control equipment required can cause coal-fired furnaces to cost three times as much as gas-fired furnaces. Column 2 of Table I.2 shows how installed capital costs vary by fuel type for a 333 MMBtu/hr capacity rotary cement kiln.

The problems associated with burning fuels other than gas prohibit their use in several processes. Annealing lehrs in the glass industry can burn only gas, for example, and coke ovens and rotary alumina kilns cannot burn coal. The infeasible fuels were not considered in the fuel choice decision for these processes.

I.2.3 Miscellaneous Processes

An attempt has been made to model the portion of nonboiler energy use not included in the major processes by using a "miscellaneous" process in each industry. These extra processes generally have been assigned a smaller firing rate than most of the major processes and a capacity utilization typical of that industry. Because these are smaller processes, it was assumed that burning coal would be infeasible. There is also an "all other industry" process to simulate energy use in the other manufacturing industries and in non-manufacturing industries whose processes have not been characterized yet.

TABLE I.2 NEW NONBOILER COST COMPARISON
 FOR A 333 MMBTU/HR ROTARY CEMENT KILN^{a/}
 (10³ 1975 \$)

<u>Fuel Burned</u>	<u>Capital Cost^{b/}</u>	<u>Incremental O&M Cost^{b/}</u>	<u>Total Annualized Cost^{c/}</u>	<u>Annualized \$/MMBtu</u>
Gas	7252	0	365	.14
Distillate	7902	76	432	.17
Residual	8226	142	478	.18
Coal	8865	365	611	.23

a/ Capacity utilization of 90 percent.

b/ Includes fuel handling and ash handling systems, but excludes pollution control costs.

c/ Includes only incremental, or fuel related O&M costs. Assumes 25 years physical life, 15 year depreciable life, sum of years digits depreciation method, 7 percent discount rate, 50 percent tax rate, and 10 percent ITC.

I.3 RETROFIT CAPITAL COSTS

I.3.1 Methodology and Sources for Cost Calculations

Like new capital costs, retrofit capital costs strongly depend on the specific nonboiler conditions existing before retrofitting and on the fuel to be fired. Estimating retrofit costs is difficult because, in many cases, the process being considered never has been fired by other fuels, especially coal. It is not known, for example, whether firing residual oil in a regenerative glass melter will significantly reduce the length of its campaign. Although there is one coal-fired steel reheat furnace in England, it is unique, and there is no simple, reliable way to estimate the cost of retrofitting other reheat furnaces.

The first step in estimating nonboiler retrofit costs was to determine which fuels could not be burned in certain furnaces. A technical review of each process determined that retrofitting to a specific fuel was infeasible if burning that fuel would result in unacceptable heat distribution, furnace deterioration, or product quality degradation. If a process was considered infeasible with a certain fuel, that fuel is not considered in the fuel choice decision for that process.

For most processes, retrofitting is more a question of cost than technical feasibility. The cost of retrofitting nonboilers was estimated by determining, on the average, what changes must be made, and what their costs would be. The cost of retrofitting any specific process was calculated by summing the costs of replacing and adding specific equipment.

Retrofits can be divided into relatively low and relatively high cost cases. The relatively low cost retrofits require only routine changes of standard equipment independent of combustor type. The capital cost estimates include, where necessary, modifications of burners and combustion controls, pulverizers, refractories, sootblowers, and combustion air blowers. Retrofitting from gas to oil firing, for example, generally requires the same

number and kind of equipment changes for any process. In these low cost cases, the annualized cost of retrofitting per MMBtu burned varies only over a small range (\$0.01-0.05) which generally is insignificant when compared with purchased fuel and O&M costs per MMBtu burned.

When design complications or space limitations are important, retrofit costs may be relatively high. For example, retrofitting roof-fired reheat furnaces away from gas requires structural changes that make costs higher than those for standard retrofits. The model makes no adjustment for these high cost retrofit cases because results under current price projections have indicated that all low cost retrofits will not be made. Therefore, there is little incentive to undertake relatively high cost retrofits.

Although the percent of retrofit possibilities that have relatively high costs is not known, industry contacts characterize the large majority of retrofits as standard low cost cases. Efforts have begun to visit major industries to determine how much energy is consumed in processes with high retrofit costs and to determine what those costs are.

I.3.2 Component Cost Calculations

Component costs were determined primarily by contacting equipment vendors and nonboiler users who had retrofitted or were planning to retrofit their units. Refractories and sootblowers are costed per unit. Burner, pulverizer, and combustion air blower costs are defined by exponential relationships, based on data for a variety of sizes. All costs are for installed equipment in 1975 dollars. The references for these formulae are shown at the end of this appendix.

- Burners: firing rate (FR) in MMBtu/hr
 - Natural gas burner cost = $\$803 \times FR^{0.55}$
 - Distillate oil burner cost = $\$883 \times FR^{0.55}$
 - Residual oil burner cost = $\$963 \times FR^{0.55}$
 - Coal burner cost = $\$13,337 \times FR^{0.55}$

- Pulverizers: Assumes 24 MMBtu/ton coal; FR in MMBtu/hr
 - FR < 175: Cost = \$2500 x FR
 - 175 < FR < 375: Cost = \$1143 x FR
 - 375 < FR: Cost = \$815 x FR
- Refractories: SF = number of square feet to be replaced
 - Gas, distillate oil,
residual oil cost = SF x \$20.2
 - Coal cost = SF x \$33
- Sootblowers: SB = number of sootblowers required
 - 15 ft blower cost = SB x \$17,238
 - 25 ft blower cost = SB x \$24,573
- Combustion air blowers:
 - Total cost = \$26.2 x (cu ft/min)^{0.68}

Table I.3 shows a detailed cost breakdown for retrofitting rotary cement kilns, independent of the fuel fired before retrofitting. Because firing coal requires much more equipment than firing oil or gas, retrofit costs to coal are largely independent of the fuel previously fired. For retrofits from distillate oil to residual oil, the model may slightly overstate costs because it assumes that the same additional equipment is needed in a retrofit from natural gas as is needed in a retrofit from distillate oil. This will be the case if the distillate oil is still burned in other places, but, if not, a distillate oil-fired furnace probably already would have most of the required fuel handling equipment and its burners may be able to fire residual oil.

The retrofit costs used in the model may overstate the total cost of retrofitting because the model makes no allowance for existing processes which are dual-fired. Where combustors are capable of firing two fuels, there are no capital costs associated with changing to the secondary fuel. Current work includes efforts to determine what percent of combustors are dual-fired.

TABLE I.3 DETAILED COST BREAKDOWN FOR RETROFITTING A
333 MMBTU/HR ROTARY CEMENT KILN^{a/}

<u>Cost Component</u>	<u>Retrofit to</u>			
	<u>Natural Gas</u>	<u>Distillate Fuel Oil</u>	<u>Residual Fuel Oil</u>	<u>Coal</u>
Burners	19,591	21,543	23,495	325,389
Pulverizers				394,667
Refractories				
Sootblowers				
Combustion air blowers			19,460	19,460
Fuel handling		35,431	63,341	471,763
Ash handling				39,141
Fuel pile		425,310	378,054	380,679
Engineering	1,959	5,679	10,630	153,042
Contingency	4,310	12,534	23,385	336,692
Total	25,860	500,515	518,365	2,400,833

^{a/} Installed costs for a kiln with 90 percent capacity utilization.

Changing fuels may require an increase or decrease in the fuel input to maintain the same heating conditions that existed before retrofitting. Because each fuel burns with different flame characteristics, retrofitting could result in derating a combustor (reducing the maximum firing rate) or changing the firing rate to maintain the same amount of heat transfer. Derating results from flame impingement or incomplete combustion and sometimes can be prevented by installing special burners. When a new fuel is burned, the rate of radiative heat transfer will change due to the difference in flame luminosity. In some processes, the firing rate may have to be slightly adjusted after retrofitting to maintain the same heat transfer conditions. Discussions with industry contacts indicate that derating will not occur in a significant number of retrofits, and firing rates will not change substantially. The model, therefore, makes no adjustments to the firing rate of a furnace retrofitted to burn a different fuel.

I.3.3 Retrofit Cost Example

To demonstrate how retrofit capital costs have been calculated, the following simple example shows how costs are estimated for a retrofit from a gas-fired rotary cement kiln to coal-firing. The first step is to determine whether coal firing is feasible. Since many rotary cement kilns currently are burning coal, coal firing certainly is feasible. In cement kilns, it even is considered beneficial because coal flame characteristics result in improved radiative heat transfer and coal ash enhances product quality and suppresses alkali-aggregate reactions. The lime in a cement kiln also removes SO_2 from emitted gas so that coal with less than 3.5 percent sulfur can be burned without scrubbers.

The second step establishes what components of a rotary cement kiln must be changed to fire coal. Because kiln design is not a function of the fuel burned, no design changes are required to retrofit to coal. However, the gas burner must be replaced with a coal burner and coal pulverizers also must be installed to prepare the coal for burning. Higher quality refractories are not needed since a layer of clinker protects the refractories

from increased wear. Sootblowers are unnecessary because ash does not contaminate the product. Combustion air blowers are needed because coal requires more excess air to burn thoroughly.

A coal handling and storage system will have to be installed, but, because ash will be absorbed as a raw material, no ash handling system will be needed. A coal stockpile of four weeks will be purchased to guard against delays in coal delivery. The total retrofit capital cost equals the sum of the costs of the above changes plus 10 percent of the sum for engineering, plus 20 percent of the above costs (including engineering) for contingencies.

Column 5 of Table I.3 shows EEA's estimates of these costs and the total cost. The cost for each component was calculated from the formulas presented in Section I.3.2. The fuel handling and stockpile costs are based on the formulae presented in Appendix H.

I.4 O&M COSTS

O&M costs include labor, supplies, maintenance materials, and G&A expenses. These costs can be divided into costs associated with operating a process and costs of burning a particular fuel. Process-related O&M costs include manpower for moving raw materials and other activities independent of what fuel fires the furnace. Because the model bases fuel choice decisions on the cost differences between alternatives, and because process-related O&M costs are constant for all fuels, the model disregards process-related O&M costs and focuses on the differences in fuel-related O&M costs.

The model assumes that for a given firing rate and capacity utilization, the differences in O&M costs between alternative fuels are the same for boilers and nonboilers. This results from the fact that a nonboiler firing coal or oil generally will have the same additional equipment that a boiler firing the same fuel would have. For example, both a boiler and a nonboiler

fired with coal would have the same burners, combustion air blowers, and fuel handling equipment. Therefore, if they had the same firing rate and capacity utilization, their fuel-related O&M costs, which include the fuel handling, ash handling, and pollution control systems, would be the same.

See Appendix H for a detailed explanation of O&M costs and Table I.2 for an example that shows how O&M costs vary by fuel type. Column 3 shows the incremental O&M costs above the costs of operating a natural gas-fired kiln.

Using boiler O&M costs for nonboilers may overstate slightly nonboiler O&M costs because the extra operators needed to run an oil- or coal-fired boiler may not be required to operate an oil- or coal-fired nonboiler with the same firing rate. Nonboilers typically have operators doing process-related activities who can contribute to fuel-related work. Boiler operators, however, are devoted only to steam raising because there are no additional process-related tasks to perform.

I.5 OTHER COSTS

Fuel handling system costs, ash handling system costs, fuel stockpile costs, and pollution control costs are all discussed in Appendix H. These costs generally are assumed to be identical for boilers and nonboilers because they are largely independent of the process or boiler itself and instead are linked to the rate at which fuel is burned. Similarly, working capital, engineering, offsite utilities, and contingencies are all calculated the same way for nonboilers as they are for boilers.

I.6 EXPLANATION OF TABLES

Table I.4 shows total installed capital costs and O&M costs for all non-boiler processes by fuel type. These capital cost figures include costs for the nonboiler, fuel handling system, fuel stockpile, ash handling system if coal-fired, engineering, offsite utilities, and contingencies. The O&M costs include expenses related to fuel and ash handling in addition

TABLE I.4 NEW NONBOILER INSTALLED COSTS AND INCREMENTAL O&M COSTS^{a/}
(1975 \$10³)

Industry	Process	Natural Gas	Residual Fuel Oil		Distillate Fuel Oil		Coal	
		Capital	Capital	Incremental O&M ^{b/}	Capital	Incremental O&M	Capital	Incremental O&M
Food	Miscellaneous	252	-1 ^{c/}	-1	-1	-1	-1	-1
Textiles	Miscellaneous	252	-1	-1	-1	-1	-1	-1
Paper	Miscellaneous	252	348	21	270	17	-1	-1
Chemicals	Primary reformer	2,496	3,798	146	3,618	78	-1	-1
	Primary reformer	531	696	46	652	29	-1	-1
	Miscellaneous	498	651	42	611	26	-1	-1
Petroleum	Tubestill heater	1,242	1,571	59	1,475	35	1,915	171
	Tubestill heater	2,104	2,684	100	2,511	54	3,550	280
	Tubestill heater	3,039	3,498	149	3,728	80	5,446	396
	Tubestill heater (high risk)	1,304	1,603	58	1,507	34	-1	-1
	Tubestill heater (high risk)	2,156	2,895	102	2,846	58	-1	-1
	Tubestill heater (high risk)	3,115	4,053	152	3,804	80	-1	-1
	Tubestill furnace	1,211	1,538	58	1,445	34	-1	-1
	Miscellaneous	132	184	21	152	17	-1	-1
	Miscellaneous	132	184	21	152	17	-1	-1
SCG	Unit melter glass	1,149	1,359	40	1,247	26	1,993	121
	Unit melter glass	2,118	2,548	69	2,356	38	3,673	207
	Regenerative melter	1,512	1,837	41	1,607	25	2,180	119
	Regenerative melter	4,841	5,948	102	5,216	51	7,181	279
	Annealing lehrs	60	-1	-1	-1	-1	-1	-1
	Rotary kiln (cement)	7,252	8,226	142	7,902	76	8,865	365
	Face brick tunnel kiln	333	457	23	356	17	929	58
	Face brick tunnel kiln	864	1,160	38	948	24	2,274	119
	Refractory brick tunnel kiln	333	495	23	357	17	929	58
	Refractory brick tunnel kiln	1,169	1,519	39	1,256	24	3,170	127
	Rotary kiln (lime)	2,297	2,615	58	2,478	33	2,850	165
	Miscellaneous	230	275	21	249	17	-1	-1
	Miscellaneous	230	275	21	249	17	-1	-1
	Miscellaneous	230	275	21	249	17	-1	-1
Steel	Vertical shaft furnace	-1	-1	-1	-1	-1	-1	-1
	Traveling grate furnace	268	509	64	496	39	679	215
	Sintering furnace	674	643	14	1,081	19	709	17
	Coke oven	6,985	8,348	202	8,043	114	-1	-1
	Blast furnace hydro. inj.	13,486	14,073	121	14,048	68	16,320	374
	Blast furnace stove	236	249	4	243	3	262	12
	Pelletizing grate kiln	54,450	54,992	78	54,750	46	55,367	251
	Open hearth furnace	-1	-1	-1	-1	-1	-1	-1
	Soaking pits	4,046	4,136	30	4,103	22	4,321	95
	Reheat furnace	8,091	8,451	66	8,329	40	9,699	232
	Heat treating furnace	1,281	1,335	20	1,294	16	1,668	51
	Miscellaneous	80	101	19	92	16	-1	-1
	Miscellaneous	80	101	19	92	16	-1	-1
	Miscellaneous	80	101	19	92	16	-1	-1
Aluminum	Rotary kiln (alumina)	1,626	-1	-1	1,592	24	-1	-1
	Lime calciner	2,297	2,615	58	2,478	33	2,935	166
	Anode prebake oven	4,840	4,882	21	4,863	17	5,048	51
	Anode prebake oven	6,655	6,722	26	6,735	20	6,893	71
	Reverberatory furnace	411	457	21	432	17	482	49
	Reverberatory furnace	1,447	1,532	34	1,524	24	1,774	102
	Heat treating furnace	130	-1	-1	141	16	-1	-1
	Heat treating furnace	363	-1	-1	404	20	-1	-1
	Miscellaneous	260	319	21	282	17	-1	-1
Other	All other industrial	252	348	21	270	17	-1	-1

a/ Excludes pollution control costs.

b/ Fuel-related O&M costs above those required for natural gas.

c/ "-1" indicates that this fuel is considered infeasible to fire this process.

to nonboiler expenses. Pollution control costs are excluded from both capital and O&M figures.

Table I.5 shows annualized costs, including O&M, per MMBtu of firing capacity. When these figures are added to annualized pollution control costs, one can easily determine the approximate fuel price difference per MMBtu that must exist before a fuel change will occur.

Table I.6 shows total retrofit capital costs similar to the new capital costs shown in Table I.4.

TABLE I.5 NEW NONBOILER ANNUALIZED COST COMPARISON^{a/}
(1975 \$/MMBtu)

Industry	Process	Natural Gas	Residual Fuel Oil	Distillate Fuel Oil	Coal
Food	Miscellaneous	0.215	999.000 ^{b/}	999.000	999.000
Textiles	Miscellaneous	0.197	999.000	999.000	999.000
Paper	Miscellaneous	0.215	0.441	0.345	999.000
Chemicals	Primary reformer	0.052	0.090	0.076	999.000
	Primary reformer	0.056	0.114	0.095	999.000
	Miscellaneous	0.056	0.113	0.094	999.000
Petroleum	Tubestill heater	0.078	0.134	0.113	0.221
	Tubestill heater	0.061	0.105	0.087	0.178
	Tubestill heater	0.052	0.091	0.077	0.156
	Tubestill heater (high risk)	0.082	0.135	0.115	999.000
	Tubestill heater (high risk)	0.063	0.111	0.098	999.000
	Tubestill heater (high risk)	0.053	0.094	0.078	999.000
	Tubestill furnace	0.084	0.141	0.121	999.000
	Miscellaneous	0.089	0.246	0.200	999.000
SCG	Unit melter glass	0.287	0.375	0.334	0.608
	Unit melter glass	0.211	0.279	0.249	0.442
	Regenerative melter	0.377	0.495	0.424	0.653
	Regenerative melter	0.302	0.394	0.337	0.512
	Annealing lehrs	0.084	999.000	999.000	999.000
	Rotary kiln (cement)	0.139	0.182	0.164	0.233
	Face brick tunnel kiln	0.193	0.384	0.297	0.846
	Face brick tunnel kiln	0.131	0.228	0.177	0.510
	Refractory brick tunnel kiln	0.193	0.409	0.298	0.846
	Refractory brick tunnel kiln	0.177	0.284	0.224	0.658
	Rotary kiln (lime)	0.153	0.208	0.185	0.289
	Miscellaneous	0.147	0.298	0.257	999.000
Steel	Vertical shaft furnace	999.000	999.000	999.000	999.000
	Traveling grate furnace	0.014	0.056	0.044	0.137
	Sintering furnace	6.864	7.904	12.807	8.849
	Coke oven	0.074	0.111	0.098	999.000
	Blast furnace hydro. inj.	0.265	0.301	0.290	0.398
	Blast furnace stove	0.371	0.452	0.426	0.604
	Pelletizing grate kiln	2.217	2.269	2.247	2.357
	Open hearth furnace	999.000	999.000	999.000	999.000
	Soaking pits	0.795	0.874	0.850	1.046
	Reheat furnace	0.412	0.462	0.443	0.606
	Heat treating furnace	1.304	1.546	1.474	2.187
	Miscellaneous	0.081	0.286	0.250	999.000
Aluminum	Rotary kiln (alumina)	0.222	999.000	0.245	999.000
	Lime calciner	0.151	0.206	0.183	0.293
	Anode prebake oven	2.790	2.938	2.903	3.217
	Anode prebake oven	1.918	2.014	2.000	3.200
	Reverberatory furnace	0.319	0.472	0.428	0.645
	Reverberatory furnace	0.280	0.344	0.328	0.486
	Heat treating furnace	0.178	999.000	0.369	999.000
	Heat treating furnace	0.124	999.000	0.193	999.000
	Miscellaneous	0.178	0.340	0.290	999.000
Other	All other industrial	0.197	0.416	0.326	999.000

a/ Excludes fuel costs and pollution control costs.

b/ "999.000" indicates this fuel is considered infeasible to fire this process.

TABLE I.6 NONBOILER RETROFIT CAPITAL COSTS^{a/}
(1975 \$10³)

Industry	Process	Retrofit from	Retrofit to:			
			Natural Gas	Residual Fuel Oil	Distillate Fuel Oil	Coal
Food	Miscellaneous	Gas	0	-1	-1	-1
		Resid.	20	-1	-1	-1
		Dist.	20	-1	-1	-1
Textiles	Miscellaneous	Gas	0	-1	-1	-1
		Resid.	20	-1	-1	-1
		Dist.	20	-1	-1	-1
Paper	Miscellaneous	Gas	0	99	39	-1
		Resid.	20	0	-1	-1
		Dist.	20	99	0	-1
Chemicals	Primary reformer	Gas	0	3453	641	-1
		Resid.	296	0	-1	-1
		Dist.	128	3453	0	-1
	Primary reformer	Gas	0	632	158	-1
		Resid.	84	0	-1	-1
		Dist.	53	632	0	-1
	Miscellaneous	Gas	0	592	145	-1
		Resid.	76	0	-1	-1
		Dist.	47	592	0	-1
Petroleum	Tubestill heater	Gas	0	318	206	1741
		Resid.	101	0	-1	1741
		Dist.	51	318	0	1741
	Tubestill heater	Gas	0	591	397	3228
		Resid.	185	0	-1	3228
		Dist.	79	591	0	3228
	Tubestill heater	Gas	0	893	666	4949
		Resid.	319	0	-1	4949
		Dist.	137	893	0	4949
	Tubestill heater (HR ^{c/})	Gas	0	1457	206	-1
		Resid.	101	0	-1	-1
		Dist.	51	1457	0	-1
	Tubestill heater (HR)	Gas	0	2631	397	-1
		Resid.	185	0	-1	-1
		Dist.	79	2631	0	-1
	Tubestill heater (HR)	Gas	0	3683	666	-1
		Resid.	319	0	-1	-1
		Dist.	137	3683	0	-1
	Tubestill furnace	Gas	0	314	202	1552
		Resid.	99	0	-1	1475
		Dist.	50	314	0	1552
	Miscellaneous	Gas	0	137	35	-1
		Resid.	26	0	-1	-1
		Dist.	14	137	0	-1
SCG	Unit melter glass	Gas	0	176	120	1423
		Resid.	37	0	-1	1392
		Dist.	37	176	0	1423
	Unit melter glass	Gas	0	289	253	2313
		Resid.	60	0	-1	2298
		Dist.	60	289	0	2313
	Regenerative melter	Gas	0	124	93	975
		Resid.	12	0	-1	968
		Dist.	12	124	0	975
	Regenerative melter	Gas	0	359	331	2018
		Resid.	37	0	-1	1999
		Dist.	17	342	0	1999
	Annealing lehrs	Gas	0	-1	-1	-1
		Resid.	55	-1	-1	-1
		Dist.	55	-1	-1	-1
	Rotary kiln (cement)	Gas	0	519	502	2401
		Resid.	26	0	-1	2374
		Dist.	26	519	0	2401

TABLE I.6 (continued)

Industry	Process	Retrofit from	Retrofit to:			
			Natural Gas	Residual Fuel Oil	Distillate Fuel Oil	Coal
SCG	Face brick tunnel kiln	Gas	0	91	43	736
		Resid.	21	0	-1	711
		Dist.	21	91	0	736
	Face brick tunnel kiln	Gas	0	182	125	1615
		Resid.	52	0	-1	1586
		Dist.	52	182	0	1615
	Refractory brick tun. kiln	Gas	0	104	55	736
		Resid.	32	0	-1	711
		Dist.	32	104	0	736
	Refractory brick tun. kiln	Gas	0	214	155	2058
		Resid.	79	0	-1	2029
		Dist.	79	214	0	2058
	Rotary kiln (lime)	Gas	0	191	159	1315
		Resid.	13	0	-1	1304
		Dist.	13	191	0	1315
	Miscellaneous	Gas	0	82	35	-1
		Resid.	15	0	-1	-1
		Dist.	15	82	0	-1
Steel	Vertical shaft furnace	Gas	0	59	33	584
		Resid.	11	0	-1	581
		Dist.	11	59	0	584
	Traveling grate furnace	Gas	0	463	315	617
		Resid.	103	0	-1	617
		Dist.	103	463	0	617
	Sintering furnace	Gas	0	40	4	324
		Resid.	1	0	-1	299
		Dist.	1	40	0	324
	Coke oven	Gas	0	1578	1456	-1
		Resid.	552	0	-1	-1
		Dist.	552	1578	0	-1
	Blast furnace hydro. inj.	Gas	0	549	542	3624
		Resid.	111	0	-1	3624
		Dist.	111	549	0	3624
	Blast furnace stove	Gas	0	11	8	238
		Resid.	1	0	-1	238
		Dist.	1	11	0	238
	Pelletizing grate kiln	Gas	0	297	260	1780
		Resid.	2	0	-1	1759
		Dist.	23	297	0	1780
	Open hearth furnace	Gas	0	256	185	1929
		Resid.	29	0	-1	1882
		Dist.	29	256	0	1929
	Soaking pits	Gas	0	128	63	921
		Resid.	11	0	-1	883
		Dist.	11	128	0	921
	Reheat furnace	Gas	0	367	289	2828
		Resid.	84	0	-1	2738
		Dist.	84	367	0	2828
	Heat treating furnace	Gas	0	69	23	559
		Resid.	7	0	-1	534
		Dist.	7	69	0	559
	Miscellaneous	Gas	0	48	25	-1
		Resid.	8	0	-1	-1
		Dist.	8	48	0	-1
Aluminum	Rotary kiln (alumina)	Gas	0	-1	89	-1
		Resid.	1478	-1	-1	-1
		Dist.	9	-1	0	-1
	Lime calciner	Gas	0	191	159	1315
		Resid.	13	0	-1	1304
		Dist.	13	191	0	1315
	Anode prebake oven	Gas	0	73	28	558
		Resid.	7	0	-1	511
		Dist.	7	73	0	558
	Anode prebake oven	Gas	0	97	47	752
		Resid.	10	0	-1	682
		Dist.	10	97	0	752
	Reverberatory furnace	Gas	0	70	25	426
		Resid.	5	0	-1	401
		Dist.	5	70	0	426

TABLE I.6 (continued)

<u>Industry</u>	<u>Process</u>	<u>Retrofit from</u>	<u>Retrofit to:</u>			
			<u>Natural Gas</u>	<u>Residual Fuel Oil</u>	<u>Distillate Fuel Oil</u>	<u>Coal</u>
Aluminum	Reverberatory furnace	Gas	0	130	77	940
		Resid.	11	0	-1	912
		Dist.	11	130	0	940
	Heat treating furnace	Gas	0	71	29	535
		Resid.	11	0	-1	511
		Dist.	11	66	0	535
	Heat treating furnace	Gas	0	99	71	967
		Resid.	25	0	-1	954
		Dist.	25	99	0	967
	Miscellaneous	Gas	0	90	43	-1
		Resid.	16	0	-1	-1
		Dist.	16	83	0	-1
Other	All other industrial	Gas	0	96	49	01
		Resid.	20	0	-1	-1
		Dist.	20	96	0	-1

a/ Excludes fuel costs and pollution control cost.

b/ "-1" indicates that this fuel is considered infeasible to fire this process.

c/ HR = high risk.

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Sootblower Costs

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APPENDIX J. APPROACH TO ESTIMATING ENERGY IMPACTS OF THE COAL CONVERSION REGULATORY PROGRAM

J.1 INTRODUCTION

This appendix describes the method used in IFCAM to assess the energy impacts of the proposed regulatory program established by PIFUA. The appendix details the methodology used to simulate the regulatory program and forecast the level of industrial oil and gas use expected to convert to coal as a direct result of the program. This appendix also highlights major areas of uncertainty which affect the program's energy impacts. This appendix does not consider any secondary effects of the regulatory program, such as higher fuel prices or possible equipment and supply shortages. For a detailed projection of 1985 energy impacts resulting from the regulatory program, see Section 8.

J.2 ENERGY IMPACT ASSESSMENT METHODOLOGY

To simulate the regulatory program, all oil- or gas-fired industrial combustors were considered converted to coal by regulatory authority except for: 1) combustors that voluntarily converted to coal (baseline conversions); or 2) combustors specifically exempted by the program. Baseline conversions were removed from the combustor population prior to regulatory program assessment. Five categories of exemptions were modeled explicitly. These include:

- Nonboiler combustors.
- Boilers with capacities less than 100 MMBtu/hr.
- Existing boilers not originally designed to use coal.
- Boilers located in nonattainment areas.
- Boilers for which the costs of using coal are substantially higher than the costs of using imported oil.

These exemptions and the way they were simulated are described below in more detail. No other exemptions are accounted for by the model. For instance, the model cannot determine which small boilers (less than 100 MMBtu/hr) are sited within a plant in which total plant capacity is greater than 250 MMBtu/hr and, thus, are subject to conversion.

J.2.1 Nonboiler Combustors

Nonboiler combustors generally were not considered subject to the conversion authority of the regulatory program. Although some specific nonboiler MFBI's are identified by the program (gas turbines, combined cycle units, indirect fired units, or internal combustion engines), a variety of physical barriers prevent most of these combustors from being converted to coal. Only by changing the nature of the nonboiler process itself (e.g., replacing a gas turbine with a steam turbine) can coal be substituted for most of these processes. Consequently, only boilers were considered in the regulatory analysis.

J.2.2 Small Boiler Exemption

The regulatory program targets all oil- and gas-fired boilers that have a capacity greater than 100 MMBtu/hr or are located in a facility with a total capacity greater than 250 MMBtu/hr. Because IFCAM assigns capacity detail to projected combustor populations, modeling the capacity exemption for individual boilers was straightforward. The impact of the aggregated plant capacity provision, however, was not modeled because reliable data were not available. Consequently, conversions resulting from the program may be somewhat understated.

J.2.3 Existing Boilers Not Originally Designed to Burn Coal

This exemption incorporates two important distinctions made in IFCAM: 1) the difference between new and existing units; and 2) the distinction between coal-capable units and those units never designed to burn coal. In IFCAM, each industrial combustor is designated either as "new" (combustors coming

on line in 1980 or later)^{1/} or "existing" (combustors operating today or scheduled to come on line prior to 1980). This distinction was made for both analytical and legislative reasons. Analytically, a firm's investment approach for new units is different from that for existing units. If a unit already is in operation, boiler capital cost has been committed. The principal costs involved in continuing boiler operation are those for O&M. Thus, if an alternative fuel is to be considered for an existing combustor, both the capital costs of modifying the existing combustor plus the operating costs of the alternative fuel are compared to the O&M costs of the original fuel. If an alternative fuel is being considered for new investments, however, capital and O&M costs of both the original (or "opportunity") fuel and the alternative fuel are compared. This is because in a new investment, there is no sunk capital.

From a legislative standpoint, the regulatory program distinguishes between new and existing units. While many existing units are covered by the regulatory program, only those receiving orders to convert will be required to convert. New units, however, covered by the program must burn coal unless the owners can prove to the government that they are eligible for an exemption. In other words, for existing units, the burden of proof is on the government while for new units, the burden of proof is on the owners.

The second important distinction made in this exemption concerns "coal capability." Most existing oil- and gas-fired boilers that are legislated to convert to coal originally were designed to burn coal as their primary fuel. These units were identified in IFCAM based on distributions from MFBI data. The MFBI survey includes questions directly relating to previous coal burning capability.^{2/}

J.2.4 Boilers Located in Nonattainment Areas

A boiler was assumed to be exempt from the regulatory program if located in what is designated as an air quality "nonattainment" area, i.e., an area

where air quality exceeds federally mandated standards for certain pollutants. The impact of this exemption was estimated for each AQCR. The projected combustor population was allocated among AQCR's based on historical patterns of location of industrial energy use. Any oil- or gas-fired boiler located in an AQCR designated as nonattainment was considered exempt from the program and was blocked from converting to coal. For some AQCR's, only portions of the total land area are nonattainment. In such instances, a fraction of the total oil and gas conversions to coal were blocked, based on the fraction of total AQCR land area designated as nonattainment.

J.2.5 Boilers for Which the Costs of Using Coal are Substantially Higher than the Costs of Using Imported Oil

The regulatory program targets those boilers in which the cost of using coal does not "substantially exceed" the cost of using imported oil. In IFCAM, "substantially exceeds" can take the form either of an absolute cost differential or a ratio of the total cost of a coal system to imported oil. The cost of the boiler system does not vary whether imported or domestic oil is used, but the price of fuel must be adjusted. The program has the capability of adding a premium to the domestic oil price to approximate imported oil prices. Depending on the assumptions for a given run, i.e., if domestic crude is assumed to increase up to the imported price, this option can be used.

J.2.6 Mixed Fuel and Synthetic Fuel Firing

The authority to legislate existing combustors to fire mixed and synthetic fuels potentially could result in substantial savings of oil and gas. This option was not modeled, however, for the following reasons. Little is known about the cost and reliability of mixed fuel and synthetic fuel firing. These two types of firing never have been demonstrated on a commercial scale. In recent years, only two prototype demonstrations of mixed fuel firing have been attempted and they were subject to intermittent shutdowns. To date, industry has manifested a skeptical attitude towards

mixed fuel firing. Until more is known, proving its applicability at any particular plant will not be possible.

This assumption should not seriously bias the accuracy of estimating the energy impacts of the regulatory program. Although not modeled specifically, the effectiveness of the regulatory program on existing units will be limited by administrative resources. Since any conversions of existing units must be ordered by DOE, the amount of existing units ordered to convert will be limited by the amount of personnel and resources committed to this task. According to EEA and DOE estimates, the amount of potential conversions of existing coal-capable boilers will more than exhaust the resources likely to be committed to this task. Therefore, no resources will be available for ordering units to use fuel mixtures or synthetic fuels.

J.2.7 Other Exemptions

Other exemptions from the program due to site-specific constraints to coal conversion include inaccessibility to coal supplies or equipment associated with coal use, and lack of storage area for a coal pile. Because of the obvious difficulties associated with estimating the impact of such site-specific constraints, they were not taken into account in this analysis. As a result, the conversion due to the regulatory program may be overstated.

J.3 MAJOR AREAS OF UNCERTAINTY

As with any attempt to simulate a complex real-world situation, this analysis oversimplified various assumptions. Two key sets of assumptions necessarily subject to a great deal of uncertainty include those regarding the projected prices of alternative fuels and treatment of environmental exemptions. These two assumptions are discussed below. Also note that in simulating the regulatory program, it was assumed that the program would be administered effectively. If administration difficulties are encountered, conversion due to the program will be less than estimated by IFCAM.

J.3.1 Prices of Alternative Fuels

Fuel prices are critical to this analysis because they help determine base-line conversion to coal and identify those boilers subject to the legislation. Baseline prices, through the MEFS model framework, determine the "base case" levels of industrial consumption of oil, gas, and coal which, in turn, directly influence the amount of remaining boiler oil and gas use subject to regulatory legislation. The higher the baseline oil and gas prices, the greater the amount of coal that would be used in the absence of a regulatory program and the less the fossil fuel demand subject to conversion authority.

J.3.2 Environmental Exemptions

A major constraint to coal use in the future will be enforced attainment of air quality standards. In this analysis, all combustors technically and economically capable of burning coal which were located in AQCR's considered violating air quality standards ("nonattainment") were considered automatically exempt from the program and prohibited to burn coal.

Each unit in the projected combustor population is assigned to an AQCR solely to incorporate the impact of nonattainment designations. New combustor location is based on historical patterns of industrial energy use. Future locational patterns of industrial energy use may be substantially different, partially due to nonattainment designations. Because of the enormous complexity of anticipating such shifts and the uncertain influence nonattainment designations will have, no attempt was made in this analysis to project these shifts. To the extent that actual new unit siting patterns deviate from historical trends, the oil and gas use exempted on environmental grounds probably will tend to be overstated.

It should be emphasized that a new coal-fired boiler may be permitted to site in nonattainment areas, although more stringent environmental controls and other higher costs may have to be incurred. Since this analysis assumes

P that no coal-fired units could be sited in nonattainment areas, it will tend to overstate the magnitude of oil and gas use exempted on environmental grounds to an unknown extent.

FOOTNOTES

1. A two-year construction period was assumed for boilers. Any boiler beginning construction on January 1, 1978 would not be operating until January 1, 1980.
2. See questions 12, 13, and 14 on the original MFBI survey questionnaire.

APPENDIX K. INDEX OF ACRONYMS

<u>Section</u>	<u>Acronym</u>	<u>Unabbreviated Form</u>
1	AQCR	Air Quality Control Region
	DOE	Department of Energy
	IFCAM	Industrial Fuel Choice Analysis Model
	MEFS	Midrange Energy Forecasting System
	NEP	National Energy Plan
2	DRI	Data Resources, Inc.
	ECDB	Energy Consumption Data Base
	ESP	Electrostatic Precipitator
	FGD	Flue Gas Desulfurization
	ITC	Investment Tax Credit
	NO _x	Nitrous Oxides
	NPV	Net Present Value
	NSPS	New Source Performance Standards
	O&M	Operation and Maintenance
	PIFUA	Powerplant and Industrial Fuel Use Act of 1978
	SO ₂	Sulfur Oxide
	TSP	Total Suspended Particulates
3	BOM	Bureau of Mines
	LPG	Liquid Petroleum Gas
	SCG	Stone, Clay and Glass
4	ABMA	American Boiler Manufacturers Association
	MFBI	Major Fuel Burning Installation
5	NEA	National Energy Act
6	BACT	Best Available Control Technology
	NAAQS	National Air Quality Control Standard
	PSD	Prevention of Significant Deterioration
	SIP	State Implementation Plan