REPLACING OIL AND GAS WITH COAL AND OTHER FUELS IN THE INDUSTRIAL AND UTILITY SECTORS

Executive Office of the President
Energy Policy and Planning
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OVERVIEW

REPLACING OIL AND GAS WITH COAL AND OTHER FUELS IN THE INDUSTRIAL AND UTILITY SECTORS

The purpose of this package is to describe the impacts of the program designed to replace oil and gas with coal and other fuels[1/] in the industrial and utility sectors. This overview summarizes the major provisions of the program, identifies the overall energy impacts, and briefly describes the analysis for each sector which is addressed in individual sections.

PROGRAM DESCRIPTION

The program for replacing oil and gas has three principal elements: (1) regulatory program, (2) oil and gas conservation taxes, and (3) financial incentives. These measures differ for the industrial and utility sectors. Table 1 describes the regulatory program for new and existing facilities in both sectors. Table 2 summarizes the taxes and financial incentives for each sector. The different time frame for the effective date of the taxes in the industrial and utility sectors reflects the greater flexibility in the industrial sector to alter current patterns of fuel consumption in the short term.

ENERGY IMPACTS

Table 3 identifies the oil and gas savings which are attributable to the oil and gas replacement program. The oil and gas savings of 3.3 MMB/D of oil equivalent represents a significant percentage of the oil savings from the entire National Energy Plan. Also, as indicated in Table 3, the savings in the industrial sector represent about two-thirds of the total 3.3 MMB/D savings from this program.

DESCRIPTION OF ANALYSIS

Sections I and II of this package present the results of analyses which were conducted to determine:

- energy impacts,
- economic impacts, and
- equipment requirements

of the oil and gas replacement program in the industrial and utility sectors.

1/ Whenever replacement of oil and gas with coal is discussed, it should be assumed that the discussion also includes the use of other non-oil and gas fuels.

TABLE 1

REPLACEMENT OF OIL AND GAS WITH COAL AND OTHER FUELS

REGULATORY MEASURES	
Facilities Covered:	Prohibitions 1/
Utilities	
New	- No use of oil or natural gas as an energy source.
Existing	- No use of natural gas after 1990 2/; plants with capability to burn coal may be ordered to do so.
Major Fuel Burning Installations (MFBI)	
New	- No use of oil or natural gas as an energy source in boilers. Non-boilers subject to case-by-case or categorical prohibitions.
Existing (Coal Capable)	- May be prohibited in categories or individually from using oil or natural gas as an energy source.

1/ Exemptions or exceptions may be granted on the basis of reliability impairment, unavailability of fuel, physical/environmental constraints, or economics.

2/ With provision for up to five year extension.

TABLE 2

REPLACEMENT OF OIL AND GAS WITH COAL AND OTHER FUELS

OIL AND GAS CONSUMPTION TAXES/FINANCIAL INCENTIVES

Measures	Industry	Utility
• Taxes		
Taxable Use	Fuel use over 500 billion Btu/yr.	All Uses
Natural Gas Tax		
Effective:	1979	1983
Level:	Based on a target price keyed to the regional price of distillate	Keyed to the regional cost of distillate
Phasing:	Target price rises to equal the Btu equivalent cost of distillate before tax in 1985	Tax rises until 1988 when the cost of gas equals the Btu equivalent cost of distillate
Oil Tax		
Effective:	1979	1983
Level:1/	$0.90/bbl (initial)	$1.50/bbl
Phasing:	Tax rises to $3.00/bbl in 1985	$1.50/bbl flat rate
• Financial Incentives		
Investment Tax Credit	Industrial users investing in alternative energy property may elect to claim an additional 10% tax credit	Not Applicable
	or	
Rebate	Elect to receive a rebate against current (but not past) consumption taxes, with an indefinite carry-forward on the investment	Utilities elibible for the rebate when making qualified replacement investments

1/ Taxes will go up with inflation.

TABLE 3

ENERGY IMPACTS OF THE OIL AND GAS REPLACEMENT PROGRAM IN THE INDUSTRIAL AND UTILITY SECTORS IN 1985

(oil equivalents, MMB/D)

	Savings		
	Oil	Gas	Total
Industrial	0.9	1.3	2.2
Utility	0.7	0.4 1/	1.1 2/
Total	1.6	1.7	3.3

Energy impacts include an identification of oil and gas savings and increased coal use as well as a characterization of the types of facilities impacted. The economic impacts discussion includes price impacts [product prices and electricity rates], capital requirements, and tax impacts. The equipment availability discussion focuses on boilers and scrubbers. Although environmental impacts were also analyzed, these results will be presented in a separate document.

Section III addresses the level of coal demand and production and the potential for transportation problems. Two appendices are also attached which provide detailed descriptions of the analytical methodology used in the industrial and utility sectors.

The analysis focuses on a 1985 base case, the President's Program, and the oil and gas replacement (or coal conversion) programs. The 1985 base case was generated by the FEA PIES model to reflect a continuation of current practices or the effect of no energy program in 1985. The President's Program includes all measures in the National Energy plan: conservation, fuel pricing, oil and gas replacement, etc. The oil and gas replacement program includes those measures designed to promote replacement of oil and gas with coal and other fuels: specifically, the regulatory and tax/incentive measures described earlier.

1/ Some of this gas displaces oil, resulting in additional oil import reductions.

2/ Oil import reductions due to conservation from higher energy prices are not shown in this table.

June 2, 1977

REPLACING OIL AND GAS WITH COAL IN THE INDUSTRIAL SECTOR

The purpose of this paper is to (1) describe the portion of the National Energy Act which is designed to decrease reliance on oil and gas by increasing the use of coal and other fuels[1/] in the industrial sector, (2) present the estimated oil and gas savings and other impacts of the proposed program, and (3) outline the methodology used to derive these impacts.

I. PROGRAM DESCRIPTION

A. Overview

The purpose of this program is to reduce the consumption of oil and gas in the industrial sector by increasing the use of coal and other fuels. In the absence of an energy plan, the industrial sector is projected to increase its consumption of oil and gas from 7.6 MMB/D of oil equivalent in 1976 to 11.5 MMB/D of oil equivalent in 1985. This expectation is supported by recent trends in boiler sales in which only 10-15 percent of newly ordered units are coal fired.

The oil and gas replacement program will reduce oil and gas consumption in 1985 by 2.2 MMB/D of oil equivalent. This represents a significant percentage of total savings from the National Energy Plan.

The industrial coal conversion program has three mechanisms for replacing oil and gas with coal:

- a regulatory program aimed primarily at new facilities,
- a tax program which sets a national value for the price of oil and gas to industry,
- a rebate which reduces a firm's fuel tax liability by the amount that the firm invests in coal or other non-oil or gas related equipment.

These savings are achieved from three distinct types of facilities:

(1) new facilities which would have burned oil or gas in the absence of the program,

(2) existing facilities which were designed with a capability to burn coal, but which are now burning oil or gas,

(3) existing facilities with no capability to burn coal and which can be replaced with a facility which can use coal or other fuels.

1/ Whenever replacement of oil and gas with coal is discussed, it should be assumed that the discussion also includes the use of other non-oil and gas fuels.

The cost, technical feasibility, and energy savings resulting from the different types of facilities are discussed in the following pages. The paper describes the specific provisions of the program, outlines the analytic approach taken, and presents the impacts of the program. The results of the analysis include:

- energy impacts,
- economic impacts,
- tax and government revenue estimates,
- environmental impacts (to be provided in a separate paper),
- equipment availability

Appendix A provides a more detailed description of the analytic methodology used to derive the results.

II. SPECIFIC PROVISIONS

The rationale for the regulatory and tax/rebate program is described below. The regulatory provisions are designed to:

(1) allow blanket regulation of entire categories or types of facilities where studies have shown coal (and other non-oil and gas fuel) use to be technically feasible and economic,

(2) streamline the current ESECA[1/] regulatory process by placing the burden of proof for the need for an exemption on industry, rather than on the regulatory agency, as ESECA provided.

The tax/rebate provisions are formulated to encourage replacement of oil and gas by:

- changing the economics of a facility's fuel choice to favor coal (and other non-oil and gas fuels) over oil or gas,
- reducing the economic incentive to firms that would apply for exemptions in the absence of the user taxes,
- providing incentives for facilities not covered by the regulatory program to use coal.

A. The Regulatory Program

The regulatory program provides for:

1/ The Energy Supply and Environmental Coordination Act of 1974 (ESECA) is the current coal conversion program.

- a flat prohibiton of use of oil and gas in new industrial boilers above 100,000 Btu/hours (approximately 10 MW),
- authority to prohibit categories of new non-boilers[1/] above 10 MW from burning oil or gas,
- authority to prohibit existing facilities with the capability to burn coal from burning oil or gas on a case-by-case basis, or in categories,
- discretionary authority to prohibit use of gas in existing facilities in categories or on a case-by-case basis,
- exemptions for economic, environmental, fuel availability, and technical infeasibility reasons,
- a mechanism to allow holders of natural gas contracts who convert under this program to sell their gas, subject to certain restrictions.

B. The Incentive Program

The tax/rebate program supplements the regulatory program by providing a tax on oil and gas use above 0.5 trillion Btu's/year (approximately 85,000 barrels/year).

- The oil tax begins at $.15/MMBtu[2/] in 1979 and rises to $.50/MMBtu in 1985.
- The tax on natural gas use is a variable tax equal to the difference between the price the user pays for the gas and a "target price" for gas keyed to the Btu equivalent price of distillate oil. In 1979, the gas "target price" would be $1.05/MMBtu[3/] less than the before tax price of distillate and by 1985, the "target price" of gas would equal the before tax price of distillate.

For example,[4/] in 1985 the tax is expected to have the following effect on oil and gas prices:

1/ Boilers are used to raise steam. Non-boilers are other types of industrial facilities which burn fuel - such as cement kilns, lime kilns, and primary metal smelting furnaces.

2/ In real 1975 dollars. The tax would be increased automatically with inflation. This is equivalent to $.90/bbl in 1979 and $3.00/bbl in 1985 (1975 real $).

3/ Or $1.05/mcf. The tax would automatically increase with inflation.

4/ All prices are in real 1975 $. The tax will be adjusted automatically for inflation.

	Baseline Prices 1/	Tax 2/	After Tax Prices 3/
Natural Gas	2.20	1.10	3.30
Distillate	3.30	.50	3.80
Residual	2.68	.50	3.18

The tax is phased in between 1979 and 1985 to allow industry time to respond to the change in fuel prices, and to allow coal production to phase up at a gradual level.

The tax levels are designed to produce four effects:

(1) change the relative economics of firm's fuel choice,

(2) encourage a substantial amount of oil to coal and gas to coal shifts,

(3) discourage substantial gas to oil shifts,

(4) encourage conservation of oil and gas.

With gas priced near residual oil, users have a limited incentive to shift either from oil to gas or vice versa. Some users of distillate oil will shift to gas. These shifts will not create a gas shortage because large quantities of gas are freed up by the gas to coal shifts, the oil and gas pricing policies, and the conservation measures. Thus, shifts from gas to oil are unnecessary because gas supplies to residential and other uses are adequate under the program, and further reductions in gas use would increase oil imports.

Exemptions are provided to firms using less than 0.5 trillion Btu's (approximately 85,000 barrels of oil equivalent) of oil and gas per year, for transportation and farming uses, and for oil and gas used in the production of ammonia (which is used mostly to manufacture fertilizers).

- Tax liability is phased in between 0.5 trillion Btu's and 1.5 trillion Btu's so that firms with fuel use close to 0.5 trillion Btu's do not close down near the end of the year to avoid the tax.
- Most industrial facilities that consume 0.5 trillion Btu's per year for the purposes of raising steam could probably use coal economically. For example, a 10 MW boiler (100,000 Btu/hr) operating 5,000 hours per year would consume about 0.5 trillion Btu/year. This size boiler could probably economically convert to coal, both because its operating hours are long enough to cover the higher capital cost of using coal (compared to oil or gas) and because its capacity is large enough to adapt to the burning characteristics of coal.

1/ Baseline prices after National Energy Plan oil and gas pricing policy.

2/ While the gas tax is keyed to distillate, the tax shown here is the difference between the baseline natural gas price and the target price for gas.

3/ Reflects price industry pays for fuel.

- Small space heating boilers, small process heaters, and most commercial buildings would probably be excluded from the tax.

- Large chemical, paper and rubber plants and large kilns and furnaces would probably be taxed.

The rebate allows a firm to reduce or offset its tax liability by investing in coal related equipment or other non-oil or gas related equipment. In addition, firms are allowed to carry forward investments that are not offset by their tax liability. For example, a firm which had a tax liability of 10 million dollars in a given year and invested 8 million dollars in that year in non-oil and gas equipment would pay 2 million dollars in taxes. However, a firm which had a tax liability of 10 million dollars, but invested 12 million dollars would pay no tax and could carry forward 2 million dollars in investment to offset tax liabilities in future years.

A firm may elect an additional 10 percent investment tax credit for the same equipment or the rebate. It is expected that most firms will find the rebate preferable to the investment tax credit. The only firms that will elect to use the investment tax credit would be those without substantial tax liabilities.

Once a firm has raised the capital necessary to pay the fuel tax, the firm has, in effect, the option of whether to spend the money on allowed investments in coal or other fuel related equipment, or to pay the money in fuel taxes. If the firm chooses to make a conversion or replacement investment, the tax liability of the firm will decline over time as the firm uses less oil or gas. It should be clear that the rebate does not help the firm raise the capital in the first place--it only enables the firm to use its tax liability in a way which will reduce future oil and gas taxes.

III. DESCRIPTION OF ANALYSIS

This section provides a brief summary of the analytical approach used to estimate the impacts of the fuel taxes and investment incentives. A more complete discussion of the analytical methodology is provided in Appendix A.

A. Determinants of Analytical Approach

The study methodology was guided by the nature of the policy measures which are intended to reduce the costs of using coal relative to oil and natural gas. Investments in coal-fired facilities are currently only marginally economic since equipment and operating costs are much higher compared to oil or natural gas even though coal prices are low compared to oil. In many areas natural gas is still a less expensive fuel than coal even without considering the higher capital costs of using coal. The fuel taxes on oil and gas for industrial users tend to increase the fuel cost differential in favor of coal, and the investment incentives tend to reduce the capital costs of using coal. Consequently, the analytical approach must be able to reflect the impact of the proposed policy measures on the capital and fuel costs of coal relative to the scarce fossil fuels.

The second aspect of the policy measures which guided the analytical approach was the nature of the incentives. The major incentive is a rebate provision which allows industry to reduce its annual fuel tax liability by the amount of eligible, coal-related investment expenditures. Both fuel taxes and rebates are determined at the corporate level. Consequently, the investment incentive in any year depends on the fuel tax liability, the technical potential for coal conversion, and the capital costs of converting the technical potential within the corporation. Thus, the analytical framework had to address this corporate level decision on energy use.

B. Determination of Baseline Energy Use

The first analytical step was to estimate 1985 energy prices and baseline oil and natural gas consumption. Since the potential for coal use differs significantly by type of energy use, the total energy consumption was then categorized by important factors, such as type of facility (boiler vs. non-boiler), age, size, applicable environmental requirements, etc.

C. Estimate Technical Potential for Coal Use

For each of the elements of energy use identified above, the percentage which could technically use coal was estimated. The potential is a function of category of use and industry (e.g., steel manufacture).

D. Estimate Economic Conversions

Once the technical, upper bound potential for coal use was determined, the percentage which would become economic, using normal business decision rules, as a consequence of the NEP proposals was then estimated.

E. Consideration of Other Factors

After the magnitude of economically justifiable oil and gas shifts to coal was estimated, the corporate decision framework was considered to relate tax liability to the magnitude of investments in coal-related equipment eligible for the rebate to determine the time phasing of conversion to coal in relation to the phase in schedule of fuel taxes from 1979 to 1985. Other considerations which would reduce the magnitude of shifts to coal, such as the small business exemption and environmental constraints, were also taken into account in this final analytical step.

F. Non-Energy Impacts

The shifts in fuel consumption provide the basis for determining the economic, environmental, and tax revenue impacts of the program. The equipment availability analysis is based on the implicit demand for new boilers and pollution control equipment contained in the energy calculations.

IV. FINDINGS

A. Energy Impacts

The tax and incentives program serves to reinforce the regulatory program. As seen in Table I-1, the regulatory program alone would produce only .73 MMB/D of oil equivalent savings, or only 33 percent of the 2.2 MMB/D savings[1/] when the regulatory program is combined with the incentive measures. The two measures provide a much greater stimulus to coal use than the regulatory program alone by providing incentives for existing facilities not covered by the regulatory program to convert to coal use. In addition, the incentive program will be much more effective in encouraging coal use in non-boilers (which account for over 50 percent of the potential coal use).

Most of the increased coal use will be in new facilities. When the increased coal use from this program is combined with the increase in coal use in the baseline between 1976 and 1985, the additional demand can be attributed to the following types of facilities:

Type of Facility	% of the Increased Coal Use 1976 - 1985
New Energy Facilities	81%
Existing Facilities Designed to Fire Coal	9%
Accelerated Replacement of Existing Oil or Gas Fired Facilities	10%

These estimates imply that:

- 10% of the oil and gas consumed in existing facilities is converted to coal;
- 37% of all new capacity over the 1976-1985 period will use coal.

B. Economic Impacts

These factors affect the degree of economic impact resulting from this program:

(1) The price paid for fuel before this program relative to the price of fuel under the program.

(2) The degree of energy intensiveness.

(3) The degree to which a firm can offset its fuel tax liability by investing in coal related equipment.

1/ These savings estimates do not include conservation due to higher fuel prices.

TABLE I-1

ENERGY IMPACTS OF INDUSTRIAL COAL PROGRAM[1/]

(by 1985)

	Decrease in Consumption of: Oil	Decrease in Consumption of: Gas	Oil Equivalent	Increased Coal Use
Regulatory Program				
Btu's (quads)	.8	.8	1.6	1.6
Physical Units	.4 MMB/D	.8 TCF	.7 MMB/D	66 Million tons
Regulatory plus Fuel Tax - Incentive Program				
Btu's (quads)	1.9	2.9	4.8	4.8
Physical Units	.9 MMB/D	2.9 TCF	2.2 MMB/D	200 Million tons

1/ Includes effects of regulatory program and fuel tax - tax credit program.

As shown below, six major industries accounted for 67 percent of industrial oil and gas use in 1975.

Industry	Oil and Gas (MMB/D)	% of Total Industrial Oil and Gas Use
Chemicals	2.3	35%
Primary Metals	0.6	9%
Petroleum	0.5	8%
Paper	0.4	6%
Stone, Clay and Glass	0.3	5%
Food	0.3	4%
Six Largest Industries	4.4	67%
Total Industrial Use	6.6	100%

The regions which are most heavily impacted are those areas where natural gas prices are low. Table I-2 shows the percentage increases in energy cost by region.

These regional energy cost increases do not translate directly into equivalent product price increases because:

(1) for the energy intensive industries, the energy costs are between 20-40 percent of the cost of production,

(2) for most industries, energy costs are a small portion (5-10 percent) of the cost of production.

As shown in Table I-3, the average increase for all industries nationally is 1-2 percent for the coal conversion program.

In regions like New England, which have relatively high gas prices before the energy plan is considered and which do not have large concentrations of energy intensive industries, the price increases by industry are quite small (see Table I-4). On the other hand, areas like the Southwest which have, in the past, benefitted from low natural gas prices will experience larger increases in energy and product prices.

C. Tax Revenue Impacts

Table I-5 shows the impact on the tax and rebate provisions on the industrial sector:

- industry will pay 40 billion dollars (in current dollars) in taxes by 1985 as a result of this program,
- industry will invest 38 billion dollars (in current dollars) in coal related equipment as a result of this program.

TABLE I-2

OVERALL ENERGY COST INCREASES TO INDUSTRY RESULTING FROM THE COAL CONVERSION PROGRAM (1985)

Region	Coal Program 1/	Total President's Program 2/
1. New England	5%	11%
2. NY/NJ	6%	13%
3. MID-ATL	9%	11%
4. S-ATL	8%	30%
5. Midwest	7%	9%
6. S-West	43%	78%
7. Central	31%	68%
8. N-Central	31%	50%
9. West	6%	30%
10. N-West	8%	22%
National	17%	20%

1/ These increases represent incremental increases over the energy cost increases due to oil and gas pricing policies.

2/ These increases represent total increases due to both the Coal Program and oil and gas pricing policies.

Federal Energy Administration - REGIONS

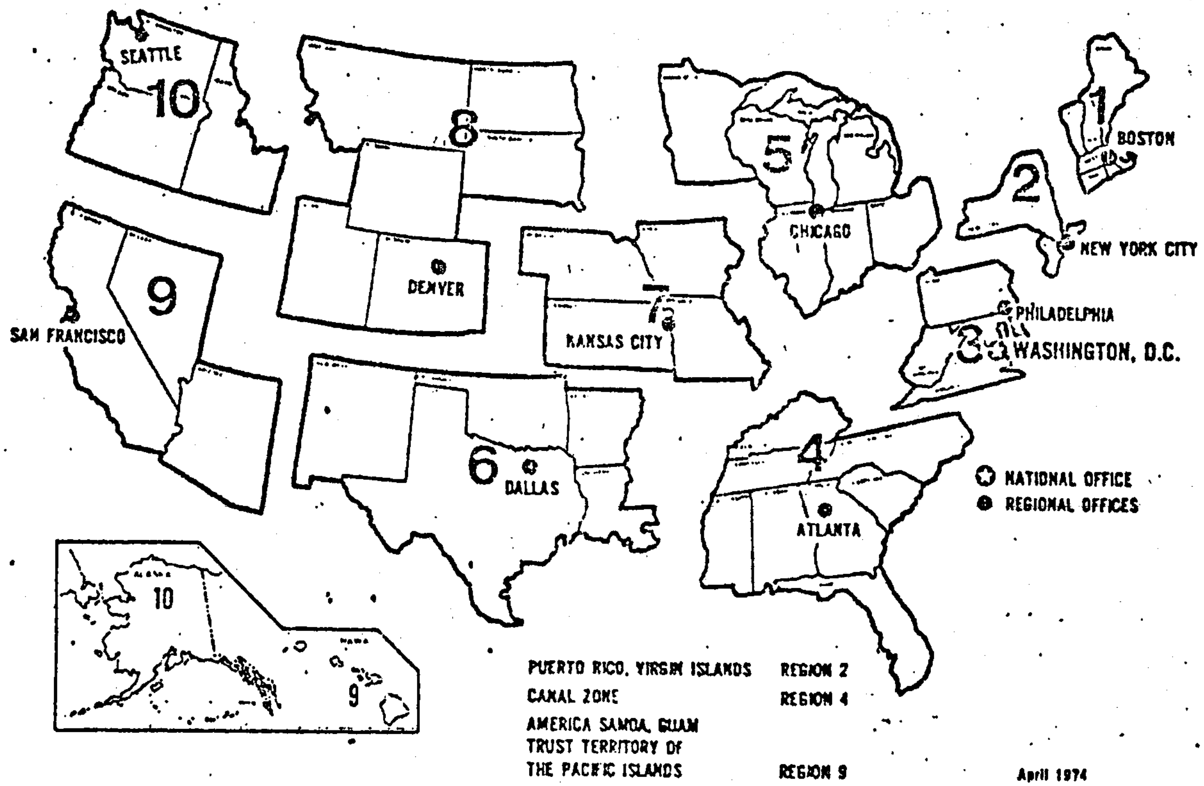


TABLE I-3

INDUSTRIAL PRODUCT PRICE IMPACTS

(1985 percentage increase)

	National
President's Program[1/]	
All industry average	1.4-2.1[2/]
Food	.5-.7
Paper	1.8-2.7
Chemicals	3.8-5.6
Petrochemicals	6.7-9.8
Petroleum	2.6-3.4
Aluminum	5.4-7.7
Steel	1.7-2.6
Coal Program Alone	
All industry average	1.4-2.1
Food	.5-.7
Paper	1.7-2.6
Chemicals	3.6-5.4
Petrochemicals	6.2-9.3
Petroleum	1.7-2.5
Aluminum	4.7-7.0
Steel	1.7-2.6

1/ These increases were determined by considering the effect of the coal program and oil and gas pricing policy.

2/ The range of price impact reflects uncertainty.

TABLE I-4

REGIONAL

INDUSTRIAL PRODUCT PRICE IMPACTS

(1985 percentage increases)

	Northeast	Southwest
President's Program[1/]		
All industry average	1.6-3.2[2/]	3.9-7.9
Food	6.5-0.6	1.5-2.1
Paper	2.3-4.0	6.6-8.9
Chemicals	3.5-4.2	7.0-9.4
Petrochemicals	*	NA
Petroleum	*	5.6-7.6
Aluminum	*	16.5-22.6
Steel	*	8.2-11.6
Coal Program Alone		
All industry average	1.0-2.0	3.6-7.2
Food	0.2-0.3	1.4-2.0
Paper	1.5-2.2	5.5-7.8
Chemicals	1.6-2.3	5.6-8.0
Petrochemicals	*	NA
Petroleum	*	4.7-6.7
Aluminum	*	14.3-20.4
Steel	*	8.0-11.4

*No significant industry.

NA - Data not available on a regional basis.

1/ These increases were determined by considering the effect of the coal program and oil and gas pricing policy.

2/ The range of price impact reflects uncertainty.

TABLE I-5

Industrial Oil and Natural Gas Consumption Taxes 1/

Relationship of Tax without Investment Rebate to Final Tax

($ millions)

	Fiscal Years							1979-
	1979	1980	1981	1982	1983	1984	1985	1985
Tax with rebate for qualified investment	2,745	7,555	10,499	12,467	14,750	16,736	19,519	84,271
Qualified investment rebate	-1,201	-3,675	-5,736	-6,880	-7,343	-7,324	-6,094	-38,253
Reduced industry income tax 2/	-141	-436	-594	-669	-878	-1,134	-1,563	-5,415
Net effect on receipts	1,403	3,444	4,169	4,918	6,529	8,278	11,862	40,603

Office of the Secretary of the Treasury
Office of Tax Analysis

May 27, 1977

1/ Results from less than full pass through of tax to prices.

2/ Expressed in nominal dollars.

The size cutoff (exemption for small business) taxes only the 2,000 most energy intensive firms in the country which consume over 90 percent of industrial oil and gas (see Table I-6). A firm which consumed 0.5 trillion Btu's of oil and gas would have a fuel bill of approximately $1.23 million (1975 prices) and sales of approximately $37 million. Firms which consume 1.5 trillion Btu's and which are taxed for their total fuel consumption would have fuel bills of approximately $3.7 million (in 1975 prices) and sales of 90 to 110 million dollars. Companies of this size ranked 1000th in sales in 1974.

The exemption for ammonia feedstock (used to make fertilizer) amounts to .32 quads or 2 percent of total industrial oil and gas in 1985.

D. Equipment Availability

The tax levels are phased in starting at a relatively low level and increase over time. This has the effect of encouraging industries to spread their investments with their fuel tax liability. This phasing of investments allows time for supply of necessary equipment to respond to demand. The most important equipment needs are boilers and pollution control equipment.

(1) Boilers

The projected industrial demand for new coal-fired boilers without the impact of the coal conversion program is examined in terms of the following factors:

- increased average annual production in terms of capacity (Table I-7),
- increased value of boiler manufacturer output (Table I-8).

Table I-7 shows that under the coal program demand in 1985 is less than 10 percent higher than baseline demand because:

- the incremental demand is a sole function of accelerated replacement of existing units. Replacement capacity represents only 10 percent of anticipated production.

On the basis of dollar sales the coal program is expected to increase production by 70 percent because:

- coal fired units displace production of oil and gas fired units, and
- the cost of coal fired units is at least twice as much as comparably-sized oil/gas fired boilers.

The coal conversion program increases projected boiler demand in 1985 in terms of pounds per hour capacity by less than 10%. The increase in terms of dollar value of production is approximately 65%.

TABLE I-6

ENERGY SUBJECT TO INDUSTRIAL FUEL TAX IN 1985

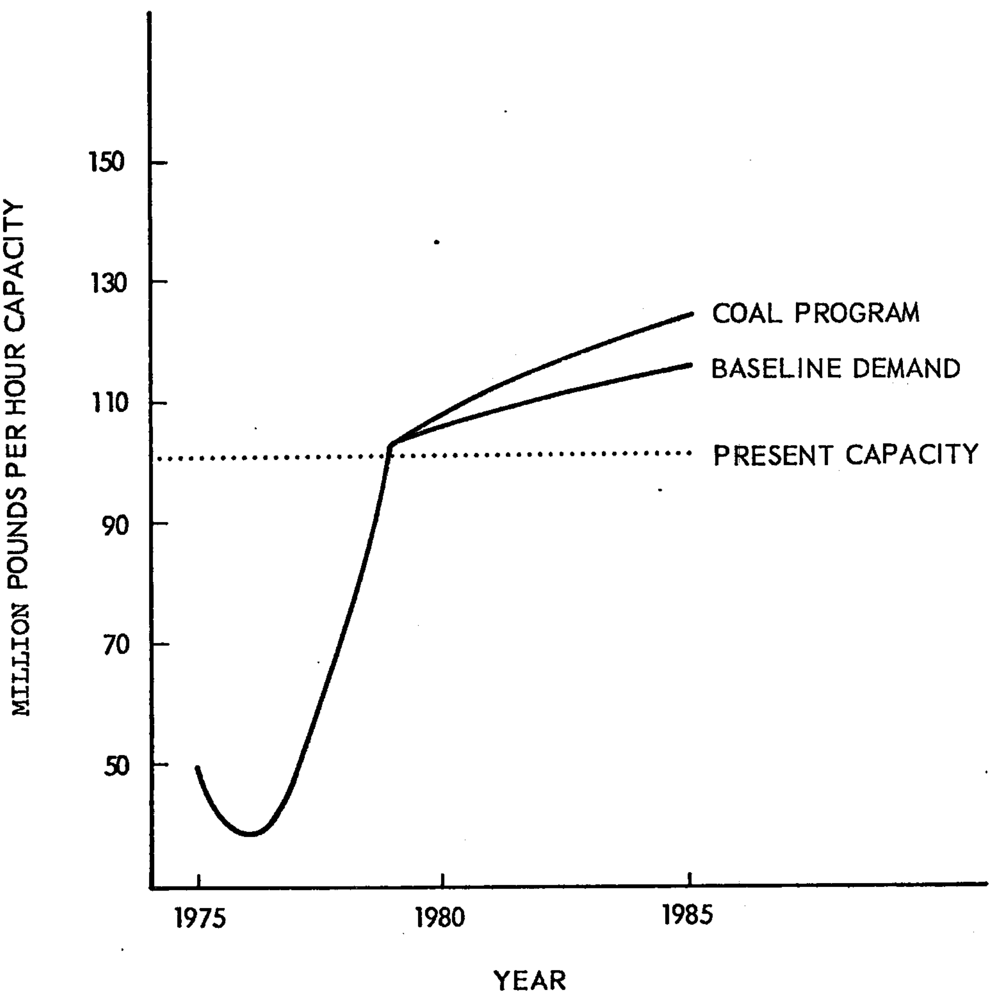
	OIL (QUADS)	GAS (QUADS)	TOTAL (QUADS)
TOTAL ENERGY 1/	9.16	11.54	20.7
LESS EXEMPTION FOR AMMONIA FEEDSTOCKS	----	.317	.317
LESS EXEMPTION FOR SMALL BUSINESS	.82	1.01	1.83
LESS CONVERSIONS	1.9	2.92	4.82
TOTAL ENERGY SUBJECT TO FUEL TAX	6.44	7.29	13.73

1/ INDUSTRIAL FUEL USE IN 1985 AFTER WELLHEAD PRICING POLICY FROM PIES RUN A158569X.

TABLE I-7

PROJECTED BOILER DEMAND

AVERAGE ANNUAL PRODUCTION

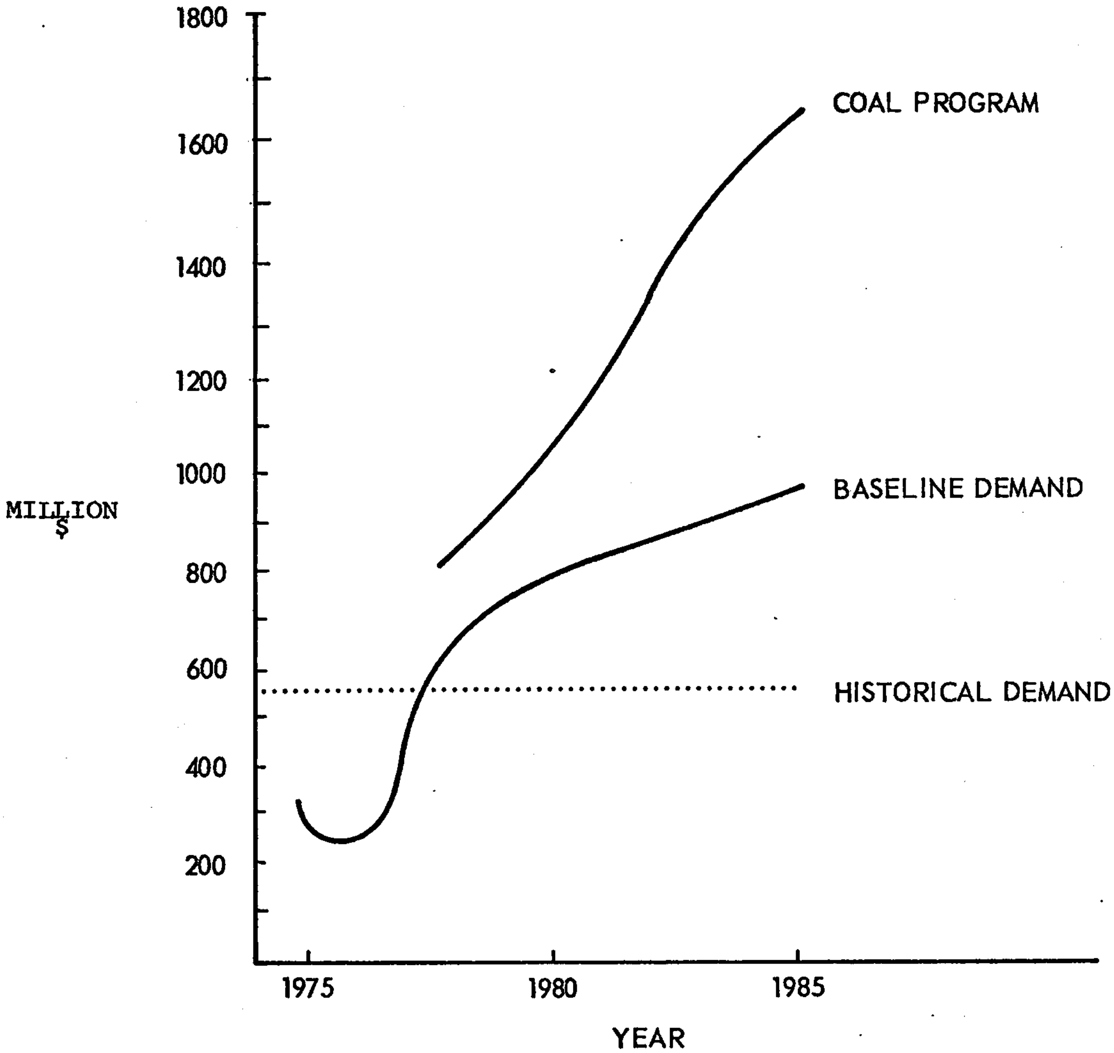


Source: American Boiler Manufactures Association.

TABLE I-8

PROJECTED BOILER DEMAND

DOLLAR VALUE OF PRODUCTION[1/]



1/ *Constant 1976 dollars.* These estimates reflect the combined dollar value of all boilers including oil, gas, coal and other.

The level of demand for coal fired boilers is not expected to be a significant constraint to full implementation of the proposed program. Current production is approximately 50 percent below the capacity of boiler manufacturers. Much of this excess production capacity is the result of companies postponing expansion plans because of depressed economic conditions. With the program, production of coal fired boilers is expected to increase to existing capacity levels by 1980. The boiler industry therefore has three years to expand capacity which should give them sufficient time to prepare for the increase in demand expected during the 1980's. One of the primary reasons for the phased in tax program was to permit manufacturers time to adjust their production schedules.

(2) Pollution Control Equipment

The increase in demand for coal fired combustors in the industrial sector will result in a significant increase in the demand for emission control systems. Table I-9 shows the cumulative impact of the program on the demand for industrial flue gas desulfurization systems. The base case represents the demand in the absence of the coal conversion program. A combined capacity of roughly 8900 megawatts is expected to be constructed in the absence of the coal conversion program. The coal conversion program would increase the demand to 60,600 megawatts.

TABLE I-9

PROJECTED CUMULATIVE SCRUBBER DEMAND

NATIONAL

(1976 - 1985)

Scenario	Existing MW	New Large 1/ MW	New Small 2/ MW	Total MW
Base 3/	0	8900	0	8900
President's Program 4/5/	1000	47600	12000	60600

1/ Average size 40 MW - 50 percent capacity utilization.

2/ Average size 10 MW - 50 percent capacity utilization.

3/ Based on PIES growth projections of coal demand without any of the President's programs, with current environmental regulations. Assumes 60 percent of large units use scrubbers to meet New Source Performance Standards (NSPS).

4/ Based on PIES growth projections of coal demand with coal conversion program, assuming current environmental regulations. Assumes 100 percent of large units use scrubbers to meet NSPS.

5/ Based on PIES growth projections of coal demand with coal conversion program, assuming BACT regulations. Best available control technology (BACT) is assumed to mean scrubbers on all units above 25 MW and a new source performance standard of 1.5#SO_2/MMBTU on units between 10 MW and 25 MW. This is consistent with emission estimates in the environmental analysis of the program.

DRAFT

METHODOLOGY:

Replacing Oil and Gas with

Coal in the Industrial Sector

JUNE 1, 1977

This report was prepared for the White House Energy Policy and Planning Staff and the Energy Research and Development Administration by Energy and Environmental Analysis, Inc., of Rosslyn, Virginia

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I. Scope

A. Elements of the National Energy Plan (NEP) Stimulating Conversion from Oil and Gas to Coal

Three sets of policy measures proposed in the National Energy Plan (NEP) tend to encourage industrial facilities to use coal in place of natural gas or fuel oil:

Oil and Gas Pricing - Wellhead pricing policies for oil and gas, incremental pricing of gas for industrial users, and the domestic crude oil equalization tax tend to make the scarce fuels more expensive relative to coal.

Regulatory Program - The regulatory program requires all new large boilers to use coal and provides discretionary authority to order classes of facilities or specific units to use coal, subject to certain exemptions.

Fuel Taxes and Investment Incentives - Taxes on oil and gas consumption plus tax credits for investments in coal-related equipment further stimulate coal use.

This paper describes the methodology used to analyze the impacts of the last two sets of measures: the regulatory program and the fuel tax/investment incentive measures.[1/] While the fuel taxes on industrial uses of oil and gas tend to stimulate conservation of oil and gas as well as to encourage shifts to coal, the pure conservation effects are not considered in this document.

1/ The impact of wellhead pricing measures, incremental pricing of natural gas, and the excise tax on domestic crude oil were assessed using the Federal Energy Administration's Project Independence Evaluation System (PIES) model.

The objective of this paper is to convey an overview of the methodology used to analyze conversions to coal, to highlight key assumptions and to indicate the factors considered in deriving the quantitative estimates. Detailed documentation of the analysis will be forthcoming at a later date.

B. Impacts Analyzed

This report discusses the methodology used to project impacts of the policy measures discussed above on energy use, industrial product prices, tax revenues, and the environment. The degree to which constraining factors such as coal supply, transportation, and the availability of coal-related equipment were considered is also discussed.

II. Energy Impacts - Fuel Taxes/Investment Incentive Measures

This section describes the analytical approach used to estimate the energy impacts of the fuel taxes and investment incentives. A summary overview of the analytical steps is presented first, followed by a discussion of the factors considered and key assumptions underlying each analytical step.

A. Overview of Methodology

1. Determinants of Analytical Approach

The study methodology was guided by the nature of the policy measures, which are intended to reduce the costs of using coal relative to oil and natural gas. Investments in coal-fired facilities currently are only marginally economic,since equipment and operating costs are much higher compared to oil or natural gas even though coal prices are low compared to oil. In many areas natural gas is still a less expensive fuel than coal, even if the higher capital costs of using coal are not considered. The fuel taxes on oil and gas for industrial users tend to increase gas/oil cost, and the investment incentives tend to reduce the capital costs of using coal. Consequently, the analytical approach must be able to reflect the impact of the proposed policy measures on the capital and fuel costs of coal relative to the scarce fossil fuels.

The second aspect of the policy measures which guided the analytical approach was the nature of the incentives. The major incentive is a rebate provision which allows industry to reduce its annual fuel tax liability by the amount of eligible, coal-related investment expenditures. Both fuel taxes and rebates are determined at the corporate level. Consequently, the investment incentive in any year depends on the fuel tax liability, the technical potential for coal conversion, and the corporation's capital costs of conversion. Thus, the analytical framework must address this corporate level decision on energy use.

2. Determination of Baseline Energy Consumption

The first analytical step was to project 1985 energy prices and baseline oil and natural gas consumption. Since the potential for coal conversion differs significantly by type of energy use, total energy consumption was categorized by use, such as boilers vs non-boilers.

3. Estimation of Technical Potential for Coal Use

For each of the elements of energy use identified above, the percentage which technically could use coal was estimated. The potential is a function of category of use and industry (e.g., steel manufacturing).

4. Estimation of the Share of Technical Potential That Could Convert Economically

Once the technical, upper bound potential for coal use was determined, the percentage which would become economical as a consequence of the NEP proposals was then estimated by applying common business decision procedures.

5. Consideration of Other Factors

After the magnitude of economically justifiable oil and gas shifts to coal was estimated, the corporate decision framework was considered in order to relate tax liability to the magnitude of investments in coal-related equipment eligible for rebates so that the timing of conversion to coal in relation to the phased schedule of fuel taxes from 1979 to 1985 could be estimated. Other considerations which would reduce the number of shifts to coal, such as the small business exception and environmental constraints, were also taken into account in this final analytical step.

B. Determination of Baseline Energy Consumption

1. Oil and Gas Consumption Baseline

Policies for coal conversion in the industrial sector are one of many elements in the NEP. The Federal Energy Administration's (FEA) PIES model was used to integrate the effects of all policy measures to provide a consistent method of aggregating energy impacts. For this reason, this analysis of coal conversion used the results of a PIES model run for 1985 as a baseline. This analysis was integrated into the overall NEP assessment process as follows:

- A base case reflecting a continuation of current policies was first developed (based on PIES);
- An impact case was prepared based on PIES reflecting the impact of all NEP policies (e.g., conservation measures, wellhead pricing, etc.) except the industrial fuel taxes and investment incentives;
- The industrial oil and gas consumption from that PIES scenario served as the baseline to evaluate coal conversion in this study. The shifts from oil and gas to coal were estimated as discussed in the remainder of this paper; and

- These conversion estimates were then input into the PIES model along with the oil and gas price increases due to the industrial fuel taxes (to reflect conservation responses to high fuel prices) to produce a final set of energy estimates for the entire NEP program.

The baseline industrial energy consumption used in this study was 9.2 and 11.5 quadrillion Btu's for oil and natural gas, respectively.

2. Categorizing Energy Use[1/]

Since both the technical potential and the costs of using coal differ significantly among classes of oil and gas uses, the total industrial baseline consumption levels were broken into classes of energy use (Table 1).

Oil and gas consumption first was classified broadly into three energy use categories: boilers, non-boiler uses with coal potential, and other uses of oil and gas where coal probably cannot be used in place of oil and gas in a 1977-1985 timeframe. Boiler uses include process steam uses and fuel used to generate electricity. The third category of non-boiler uses with no coal potential includes primarily oil and gas uses as feedstock for chemical manufacture and minor energy uses (such as mechanical drive and electrolytic processes). Boilers are estimated to account for 31 percent of oil and gas uses, non-boiler uses with coal potential constitute 43 percent and other uses with no coal potential are estimated to comprise the remaining 26 percent of oil and gas use in 1985.

A second broad distinction was made between energy consumption in new versus existing combustors. Existing 1975 oil and gas consumption was adjusted to account for a 3 percent per year rate of decrease in energy consumption; this reflected the shutdown of old facilities and decreases in capacity utilization as older

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1/ The data bases used in this study are described in Attachment B.

TABLE I

INDUSTRIAL OIL AND GAS USE IN 1985[1/]

(Quadrillion Btu's)

CATEGORY OF USE	OIL	GAS
Boilers		
Existing		
Large[5/]	0.50	1.27
(Coal Capable)[2/]	(0.12)	(0.15)
Small	0.06	0.74
Subtotal	0.56	2.01
New		
Large[5/]	1.62	1.44
(Coal Capable)[3/]	(1.19)	(1.05)
Small	0.13	0.67
Subtotal	1.75	2.11
TOTAL BOILERS	2.31	4.12
Non-Boiler Uses with Some Coal Potential		
Existing	0.95	3.01
(Coal Capable)[2/]	(0.02)	(0.03)
New	2.06	2.88
(Coal Capable)[3/]	(1.45)	(2.04)
TOTAL NON-BOILERS	3.01	5.89

TABLE I
(Cont'd)

CATEGORY OF USE	OIL	GAS
Other Uses with No Coal Potential		
Feedstock	3.72	1.35
Other[4/]	0.13	0.18
Subtotal	3.85	1.53
TOTAL OIL AND GAS USE	9.17	11.54

1/ Oil and gas use in industrial sector after inclusion of all policy elements of President's energy program except industrial fuel taxes, coal investment incentives, and the regulatory program.

2/ Fuel consumption in units currently firing oil and gas which were designed to use coal.

3/ Energy use in units coming on line after 1978.

4/ Includes mechanical drive and electric arc furnaces.

5/ Design firing rates exceed 100 million Btu's per hour.

units are phased down or moved to stand-by capacity and new energy consuming units come on line between 1975 and 1985. New energy uses reflect energy consumed in new combustors replacing old units and expansion of industry to meet growth objectives.

Existing energy uses were also broken down to identify oil and gas consumed in combustors originally designed to fire coal. These coal capable units were identified using FEA's Major Fuel Burning Installation Survey.

Consumption in existing and new boiler facilities was divided further into small and large facilities, with the breakpoint established at 100 million Btu's per hour design capacity (roughly 10 MW). Although some combustors below 10 MW currently use coal, for the purposes of this study all units below 10 MW were assumed to be incapable of using coal.

New energy uses were also categorized into uses scheduled to be coming on line between 1975 and 1978 and those which would come on line between 1979 and 1985. Decisions about the early installations have already been made by industry, and it was assumed that such new oil and gas combustors could not use coal.

Based on this initial categorization, estimates of coal using potential were refined and costs of conversion were determined, as described below.

C. Estimation of Technical Potential for Coal Use

The categorization in Table 1 provides an initial basis for screening energy use to determine the maximum technical potential to use coal, ignoring initially whether such conversions would be economical or practicable. The following categories were assumed to have no potential for coal use:

- Small boilers;
- New oil and gas facilities coming on line between 1975 and 1978; and
- Feedstock and other uses.

In addition to the types of exclusions which reduce the technically convertible coal potential for boilers, additional non-boiler uses, which vary by industry and by process within each industry, must be assessed.[1/] Non-boiler uses of oil and gas include kilns and furnaces, indirect heaters for fluids and gases, ovens, stoves, and direct and indirect heat applications. Coal can be used over a range of applications but is limited by problems such as:

- Effects of coal ash and sulfur on product quality in direct heat applications such as pottery kilns.
- Breakdown of some refractories in furnaces and indirect ("process") heaters from chemical attack by coal ash.
- Difficulty of temperature control in some sensitive process heaters.
- Small size of some units such as heat treating ovens.

In estimating the potential use of coal in non-boiler applications, each major energy consuming industry was examined to identify major energy using processes and their technical characteristics. A preliminary evaluation of the feasibility of using coal in these applications was made based on criteria such as:

- Is coal used for this application now?
- Are process requirements similar to known coal uses?
- Is hardware for the application being marketed?
- Have announcements of coal fired facilities been made?

In some cases, a history of coal use can be established and technical feasibility is not much in doubt. Other situations are more speculative, and the potential estimates were discounted appropriately. To illustrate the variation in coal use potential, some specific industries are discussed below.

Petroleum refining is an industry where large amounts of oil and gas are used in process heaters for crude oil heating, reboilers,

1/ For a further discussion of the problems of using coal in process uses of energy, see Attachment A.

cracking, and other uses. With a few exceptions, such as high temperature reformers, temperatures are moderate and temperature control requirements are not extreme. Coal use is unproven, though new coal fired facilities have recently been announced. Technical problems to be solved include selection of appropriate refractories and combustion control. This industry is believed to have a high technical potential for coal use in new units (although costs may be high) and a low to moderate potential for retrofit of existing oil and gas uses.

Food Processing. Most non-boiler energy use is for low temperature (<400^{o}) direct heating such as drying of foods and grains. An alternative already being considered by major food processors is use of high temperature steam from a coal fired boiler to heat air indirectly, using a heat exchanger analogous to a radiator. This industry has a high potential for new plants based on this process alternative, but most existing plants would have to be practically rebuilt to use coal.

Steel. Steel making (including rolling and other forming operations) is a major consumer of oil and gas for non-boiler applications. These include soaking pits for heating pig iron, reheat units in rolling mills, annealing, heat treating, and carburizing furnaces. Because the product (metal) is affected by coal ash and sulfur, this industry will be difficult to convert to coal. Both new and existing plants will have a low potential for coal use.

Overall, the range of potential convertibility of non-boiler oil and gas uses in industry ranged from nearly 60% in industries with high potential to 25% in industries with low potential. In order to achieve these levels of conversion a number of unsolved but probably solvable technical problems must be resolved.

A summary evaluation of the technical potential to use coal excluding small boilers and non-boilers, new units already planned and energy applications which technically cannot use coal resulted in excluding oil and gas applications which account for approximately 60% of the baseline industrial oil and gas consumption in 1985.

D. Estimation of the Share of Technical Potential That Could Convert Economically

1. Approach

In evaluating how much of the technical potential might switch to coal given the stimulus of higher energy prices and the rebate incentive, standard industrial investment evaluation criteria were employed. Industry would view investments in coal-using equipment in terms of the rate of return or net present value of an investment, where the capital cost is the equipment cost of a coal facility less similar costs for oil or gas facilities. The revenue stream from such an investment would be viewed as the reduction in fuel costs (e.g., delivered cost of coal minus the delivered cost of oil) minus the higher operating cost associated with coal use. Industry decisions were assumed to be based on the after tax rate of return.1/ For any prospective project the decision criteria would be that the coal related investment is economically justifiable if the resultant rate of return is 20 percent or greater.2/ The average industry after tax rate of return is currently 13 percent. The cutoff (or breakeven) after tax rate of return of 20 percent used in this analysis was set approximately 50 percent higher than the current industry average to reflect a "hassle" premium associated with:

- The difficulties industry will experience with environmental and facility siting regulatory problems;
- The aversion industry has to using coal due to the difficulties of handling coal at the plant, the extra personnel required, etc.;

1/ Since the evaluation was made on an industrial combustor unit basis and could not consider investments within a corporate entity, rate of return criteria in such circumstances would be equivalent to present value criteria.

2/ This is in nominal terms. The 20 percent essentially includes a 15 percent real rate of return plus a 5 percent allowance for inflation. The rate of return calculations were performed with all values in 1975, real dollars.

- The higher rate of return some firms require on a discretionary investment which neither enhances output not protects production;[1/] and
- The added risks associated with reliability of coal supply to the plant.

2. Factors Affecting Costs

This study utilized combustor-specific data from the Major Fuel Burning Installation Survey to capture the differential costs of using coal in various facilities; these costs vary according to the following factors:

Combustor Size - Size affects costs since coal equipment, including pollution control equipment, is characterized by economies of scale. In addition, size is a determinant of the stringency (and therefore the cost) of pollution control requirements.

Capacity Utilization - This factor obviously affects the attractiveness of coal investments, since it determines the relative importance of capital costs compared to fuel cost savings. The direct use of coal will be more economical for industrial process operations (which operate at 75-90 percent capacity utilization) than heating plants (which operate at 25-40 percent load factors).

Coal Capability - If the unit was designed originally to fire coal, the capital costs of converting will be less than the cost differential between a new gas/oil firing and a new coal firing unit.

1/ Industry regards investments in energy facilities as "essential" rather than "discretionary" when they are designed to insure an adequate, reliable energy supply to maintain production. Investment in oil firing capability to back up or replace natural gas would be considered "production protection." Investments in coal would be more discretionary.

Remaining Useful Life of Facility - The shorter the useful life of an investment, the lower the rate of return will be. This factor is most important for investments in units originally designed to fire coal.

Region - Location affects cost primarily through fuel prices. The most important differences relate to delivered coal costs which, for example, will be higher for a plant in California or New England than for a facility in Ohio.

Environmental Controls - Pollution control equipment is a major expense of using coal, and in some instances such costs are the largest element of capital costs. This analysis considered whether the plant must meet only state regulations which vary in stringency or must comply with the uniformly tight Federal New Source Performance Standards. All new facilities with design firing rates above 250 million Btu's per hour were assumed to incur control costs for sulfur removal equivalent to the cost of flue gas desulfurization devices (roughly $13 per ton of coal used).

New Versus Existing Units - A distinction was made between new facilities and accelerated replacement of existing oil and gas fired units not designed to fire coal. Capital costs for new units were based on the increment above the cost of oil or gas fired facilities, since these costs would have been incurred in the absence of a decision to switch to coal. For the decision to accelerate replacement of existing oil and gas fired units, the full capital costs related to coal were used, since the relevant decision would involve scrapping (or putting on standby) the existing oil or gas fired unit and installing a new coal fired unit.

Fuel Type - The probable price of coal delivered to the plant was compared with that of the principal fuel being burned in the combustor. For example, if an existing facility used 80 percent oil and 20 percent gas in 1974, coal costs were compared against fuel oil costs.

The specific breakdowns used in the analysis for these factors are shown in Table 2. From these factors, 2,880 different cost configurations were created reflecting the variation in the above characteristics in the MFBI survey population. The decision to switch to coal was evaluated on a combustor-specific basis for both new and existing energy uses. Each combustor included in the technical potential was linked to one of the 2,880 cost configurations to determine the after-tax rate of return. If its rate of return exceeded 20 percent with NEP policy measures applied, conversion to coal was assumed to be economically feasible.

3. How NEP Incentives were Analyzed

The NEP policy measures would affect industrial investments in coal-related equipment by raising the costs of oil and gas according to the fuel tax schedules proposed and by reducing the effective capital cost of using coal. While the impact of fuel taxes is straightforward, the effect of the rebate on eligible investment requires explanation.

Table 3 illustrates how the rebate works for a typical corporation. The base case, in the absence of any policy measures, shows corporate revenues, income taxes, and after tax cash flow. The imposition of $100 in fuel taxes is shown on the second line. Since the fuel taxes are an allowable cost for the purposes of determining corporate income taxes, cash flow drops by 52 percent of the fuel taxes. The third case shows the effect of a $100 investment which qualifies for the rebate. In this case, fuel taxes in the year the investment is made are zero because they are fully offset by the rebate. Cash flow is down $48 from case 2 since the fuel tax rebate is partially offset by the increase in corporate income taxes. When fuel taxes are completely offset by the rebate, industry would perceive the $100 investment as costing $48 ($208-160) when compared to the alternative of paying the fuel taxes and not investing in coal facilities. In effect, the rebate amounts to a 52 percent investment tax credit when investments in any year do not exceed the annual fuel

TABLE 2

FACTORS AFFECTING THE COST OF USING COAL

Size of Combustor (3)[1/]

1. Less than 250 million Btu energy through-put (design capacity).
2. 250-400 million Btu.
3. Greater than 400 million Btu.

Capacity Utilization (2)

1. 30 percent (2628 hrs/yr) - average of those <50%.
2. 60 percent (5256 hrs/yr) - average of those >50%.

Environmental Regulation (4)

1. No controls.
2. Baghouse only (particulate control).
3. Baghouse plus low sulfur coal (2-3#SO_2/MMBtu).
4. Flue gas desulfurization required.

Useful Remaining Life (2)

Existing plants:

- 10 years
- 5 years

New plants:

- 15 years

1/ Number of categories.

TABLE 2

(Cont'd)

Location (10)

FEA regions.

Type of Combustor and Coal Capability (3)

1. Existing unit designed to fire coal.

2. Existing unit not designed to fire coal.

3. New unit.

Fuel Type (2)

1. Oil.

2. Gas.

TABLE 3

ILLUSTRATIVE CASH FLOW IMPACT
OF FUEL TAX/REBATE[1/]

Case	Revenue	Fuel Taxes	Income Before Corporate Tax	Corporate Taxes[2/]	Investments Eligible for Rebate	After Tax Cash Flow
Base Case	500	0	500	240	0	260
Fuel Taxes Only	500	100	400	192	0	208
Fuel Taxes and Rebate	500	0	500	240	100	160

1/ This cash flow example does not consider the product pricing policy decisions by industry to pass on to consumers the new cost of fuel taxes and investments in coal equipment. Cash flow shown is first year only.

2/ Assumes 48% tax rate.

tax liability. Since such investments would also be eligible for the current ten percent investment tax credit, the effective tax credit equals 62 percent of allowable investments.

Industry can also make investments in any year in excess of tax liability since investment costs which are not rebated can be carried forward to offset future fuel tax liability. When investments exceed fuel tax liability, the rate of return decreases. Even so some corporations may use the carry forward provision to minimize total fuel taxes over time.

Whether or not industry would utilize the carry forward provision depends on factors specific to each corporation. At this stage of the analysis, energy use potential and costs of conversion cannot be related to corporate entity, since the rates of return are being calculated for each combustor. Consequently, in calculating the magnitude of the investment incentive, we assumed that firms will limit their investments to their annual fuel tax liability. In other words, investments in coal related facilities would only be made when the investment incentive implies an effective 62 percent investment tax credit. This assumption slows the pace of conversions.

4. Cost Elements Considered

a. Capital Costs

Capital equipment costs were determined for a series of typical plant operations utilizing coal, oil and natural gas. Each of the 2880 cost configurations is uniquely associated with certain cost components. The cost for each combustor is determined by selecting and summing the component costs which are applicable to that combustor.

The major components considered include boiler and related facilities, fuel handling systems, particulate control, sulfur oxide control, powerhouse construction, engineering, and contingency costs. Boiler feedwater treatment is not considered, because in all cases such costs are relatively insensitive to fuel type. Land acquisition costs are also not considered. For totally new facilities, the cost of utility hookup is included.

Each of the major components include several types of equipment or several kinds of expenses. Boiler and related facility costs include all of the equipment which is necessary for operation of the boiler. Such equipment includes coal crushers or pulverizers, burners, the furnace, fans, an economizer, air pre-heaters, soot blowers and related equipment. The fuel handling system includes equipment necessary to unload fuel, conveyor belts for on site transport to storage and from storage to the powerhouse, as well as the cost of a fuel stock pile. Particulate control is accomplished either by an electrostatic precipitator, a baghouse, or scrubbers when used. Where scrubbers are not used, the particulate control costs include the precipitator or baghouse, whichever is cheaper (a function of size, the stack configuration) and the facilities for disposal of ash). Sulfur oxide control is accomplished through use of a flue gas desulfurization device and cost elements include the scrubber installation, the scrubber wastewater treatment, and sludge disposal. Powerhouse costs include construction cost for building as well as the building materials. Engineering costs are assumed to be 10% of the capital cost of the facility, and a 20% contingency is allowed to cover miscellaneous and unforeseen expenses.[1/]

1/ Contingency and engineering costs allowances are standard engineering cost estimation practice. Refer to Seymour Calvert, "Air Pollution," A. C. Stern, editor, 3rd edition, Volume 4, pp. 288, 289, Academic Press, NY, NY, 1977.

The cost data has been developed primarily by contacting equipment vendors, and obtaining estimates of the equipment costs for several typical systems. For example, several vendor quotations were obtained for the cost of different sizes and types of boilers, and these quotations were used to estimate costs for 3 standardized boiler packages.[1/] In addition, pollution control equipment costs are based on a recent survey of industrial scrubber installations[2/] as well as equipment vendor quotations.

The equipment costs used in this study are intended to be average costs, and do not reflect plant specific factors which may significantly affect the cost of coal utilization. Capital costs are highly variable, depending upon plant specific factors. Such factors include the number of combustors located at a plant, the processes used at the plant, the availability of land for coal storage, etc.

There are economies of scale both with respect to the size of an individual boiler and with respect to the number of boilers at a plant. Although economies of scale which are related to boiler size are taken into account by this anlaysis thru use of several different boiler configurations, the economies associated with <u>plant</u> configurations are not. For example, the capital cost of using coal considering all components for a 50 MW facility is lower than the capital cost for a 25 MW facility per pound of steam produced, and this economy of scale is captured in this analysis. However, the capital cost of using coal in 4 boilers at the same plant will be lower than the cost of using coal in 4 boilers considered

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1/ Equipment cost data has been developed by Energy and Environmental Analysis, Inc., as part of a contract with FEA investigating industrial coal utilization potential. The report of this study is currently in preparation.

2/ <u>Survey of the Application of Flue Gas Desulfurization Technology in the Industrial Sector</u>, prepared by Energy and Environmental Analysis, Inc., for the Federal Energy Administration, December 1976.

individually. The facility economies of scale are not captured in this analysis. Therefore, the total capital costs used in this analysis are overstated for many facilities.

Some industries, by nature of their processes may be able to utilize coal at a lower total cost than other industries. For example, industries which need to treat plant effluents which result from their processes may be able to utilize the existing wastewater treatment facilities to treat scrubber wastewater, thereby reducing the cost of scrubber installation. Such considerations are not reflected in this analysis therefore the total costs are again probably somewhat overstated.

A major consideration for some plants is land availability. It is assumed that no land acquisition costs will be incurred in conversion to coal. Clearly this is not always the case, however, as pointed out above, those plants where land acquisition is a problem will be probably be located in areas where conversion to coal is not practical due to environmental considerations. The net effect of not considering land acquisition costs is believed to be negligible.

Capital costs therefore are developed by summing costs of coal burning equipment components for several classes of combustors on a combustor-specific level. In order to illustrate how this was done, consider the following example. A typical new boiler of 25 MW, might operate at a capacity utilization rate of 60 percent and may need to comply with strict environmental regulations, necessitating use of a wet scrubber. This information is adequate to determine which capital components will be necessary. The costs of coal and oil boilers, as well as other cost increments, are shown in Table 4. The total capital cost of $5,340,000 will be compared to the annual fuel cost savings after consideration of the NEP policy measures to determine whether this combustor will economically utilize coal.

TABLE 4
EXAMPLE CAPITAL COSTS
25 MW NEW BOILER
($1000)

Cost Component	Coal	Oil	Incremental Cost of Coal
Boiler Related Costs	3,750	1,875	1,875
Fuel Handling	550	100	450
Powerhouse	90	45	45
Environmental Wet Scrubber Cost	1,900	-	1,900
Offsite Utility Hookup	440	200	240
Contingency	960	440	520
Engineering	580	270	310
TOTAL	8,270	2,930	5,340

b. Fuel Costs

The revenue estimate which results from investments in coal related facilities is a function of the cost differential between oil or gas and coal. The FEA-PIES energy model with adjustments was used as a source of fuel price projections for the years through 1990. All prices and fuel cost savings were computed for each FEA region.

The oil price used was a 50:50 weighted average of the PIES projected prices for distillate and residual oils by region, based on the projected mix of these fuels in 1985. The effective price to the industrial users includes the applicable oil or gas consumption tax for each year. The base (no tax) oil prices are projected to vary regionally between $2.93 and $3.15 per MMBtu. Gas prices used are regional average delivered prices incorporating the effect of the proposed gas pricing policy. Gas prices vary widely regionally, between $1.46 and $3.08 per million Btu depending on transportation costs, the prevalence of intrastate sales and other factors. The projected national average price is $2.22/MMBtu in 1985.

Coal prices used reflected delivered prices to industrial consumers, including costs of single car rail shipment, and vary between $1.17 and $1.71 per MMBtu, averaging $1.50 MMBtu or about $35 per ton delivered. These prices are for the least cost delivered coal irrespective of sulfur content, and consequently are based on high sulfur coals delivered to all regions except those west of the Mississippi, which receive low sulfur coal. Since some plants would use low sulfur coal to comply with air quality standards, an extra cost for low sulfur coal was included for plants in the east which must burn it. This cost increase or premium was based on EEA's previous work on analyzing the effect of the sulfur regulations on coal prices.[1/]

1/ See Benefit Cost Analyses of Regulations Affecting Coal, Vol. III, prepared by EEA for Department of Interior, Office of Mineral Policy Development, 1977.

The difference in the FOB mine price of low sulfur (1.5-3.0 lbs of SO_2 per MMBtu) coal and high sulfur coals is estimated to be approximately $5.00. In most cases, low sulfur coal must also be transported further than high sulfur to reach major consuming areas, further raising the costs.

The fuel price differential between coal and the premium fossil fuels was based only on 1985 price differentials. Time limitations did not permit a more elaborate analysis to take account of changing fuel price differentials beyond 1985.

E. Other Factors

The analytical steps discussed above provide estimates of the maximum conversion to coal in 1985 considering technical potential and the costs of conversion. Other factors which must be considered include:

- the time phasing of conversion since the fuel taxes are phased in gradually and timing will depend on the relationship of the capital costs of conversion and annual fuel tax liability of each corporate entity;
- the effect of the corporate size cutoff since companies with total oil and gas use below 500 billion Btu's per year are exempt from the fuel taxes.
- the effect of environmental restrictions (other than cost) which may prevent conversion to coal, for example, in areas where air quality standards are currently being violated.

1. Time Phasing

In order to analyze likely time phasing, it was necessary to develop energy use data by corporate entity. Such data were not available at the time this report was prepared. Consequently, energy consumption levels for corporate profit centers were prepared (see Attachment B for details). Profit centers are sub-elements of a corporation reflecting their sales in each four-digit SIC code. A major corporation may have 10-40 profit centers.

With oil and gas consumption levels estimated for 200,000 profit centers, the next step was to estimate the potential for coal use for each profit center. This was accomplished in the following steps:

- The analytical steps described above resulted in estimates of the share of oil and gas which could be economically converted to coal.
- These estimates were inserted at the 2-digit SIC code to account for differences in the potential by industry.
- All firms in each 2-digit sector were assumed to have the same potential share of oil and gas that would be convertible to coal.1/

These steps, in effect, transferred the estimates of potential coal use in 1985 into a framework where the timing of shifts to coal (or demand for coal) could be evaluated, with the potential being at least roughly proportioned among appropriate industry subsectors. Total oil and gas consumption and coal potential were then interpolated between 1975 and 1985 to provide estimates in each intervening year. The fuel tax schedule was then imposed in each year, providing an estimate of the gross fuel tax liability for each profit center. Since the economic potential had been evaluated assuming industry would invest only up to its tax liability in any year, the same assumption was made in this step. Table 5 shows an illustrative example of how the pace of conversion was determined for one large profit center. This hypothetical firm consumes 100 trillion Btu's of oil in each year and 35% of its oil consumed

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1/ This is an oversimplification, of course, but time limits only permitted identification of differences by industry classes.

TABLE 5

ILLUSTRATIVE CALCULATION OF TIME PHASING OF COAL CONVERSION

Year	Total[1/] Oil Consumption (10^{12} Btu)	Potential to Shift to Coal (10^{12} Btu)	Gross Fuel Taxes Liability ($ million)	Level of Investments in Coal Facilities[2/]	Fuel Switching to Coal (10^{12} Btu)	Fuel Taxes Paid
1979	100	35	15	15	0	0
1980	98.5	32.5	29.6	29.6	2.5	0
1981	93.6	27.6	28.1	28.1	4.9	0
1982	88.9	22.9	31.1	31.1	4.7	0
1983	83.7	17.7	33.5	33.5	5.2	0
1984	78.1	12.1	35.1	35.1	5.6	0
1985	72.2	6.2	36.1	36.1	5.9	0

1/ For exposition purposes, fuel consumption levels are constant each year in this example.

2/ Assumes average capital costs of conversion of $6 per million Btu of energy converted.

could be economically converted to coal if the full investment cost were rebated against the tax. The fuel tax is levied in each year according to the proposed tax schedule ($.15 per million Btu in 1979, etc.). Since its average capital costs of conversion are assumed to be $6 per million Btu of energy, it can invest in conversion facilities for only 2.5 trillion Btu's of oil in 1979. The fuel tax is offset by the rebate and net taxes owed in 1979 are zero and investment outlays are $15 million. This investment is assumed to be realized in 1980 when 2.5 trillion Btu's are converted from oil to coal, reducing both the firm's fuel consumption and potential in 1980. Fuel tax liability and conversion to coal are calculated similarly in other years through 1985. The resultant output provides the basis for estimates of coal conversion, capital costs, and budget impacts.

2. Size Cutoff for Tax Liability

Corporations with oil and gas consumption below .5 trillion Btu's per year are exempt from the fuel taxes. Roughly 9% of oil and gas used is exempted by the size cutoff (see Section IV for derivation of the fuel use excluded). Fuel tax liabilities were reduced proportionately to account for the small business exception. This did not affect the magnitude of coal conversion since a profit center was required to have potential coal related investments above $1.5 million before any fuel could be converted to coal. This minimum conversion cost estimate is keyed to the least expensive coal facility that might be converted. Thus, the size cutoff affected only tax revenue estimates and not the estimates of shifts from oil or gas to coal.

3. Environmental Limitations

Conversion to coal can be constrained by environmental problems. While the analysis thus far considered the impact of the costs of pollution control equipment on the economic payoff of using coal, consideration must also be given to excluding economic conversion potential which may be located in areas with severe air quality problems for sulfur dioxide and particulates, the major air pollutants generated by shifts to coal. Time constraints did not permit an analysis of the location of conversion candidates in relation to existing or anticipated air quality problem areas. In preparing estimates of conversion to coal, we assumed that 25% of potential conversion candidates, regardless of type of facility, would be prevented from converting due to environmental problems. This was a rough estimate based on judgment provided by the technical project officer. Since this adjustment was assumed to apply across the board, the sensitivity of the results to other environmental results can easily be tested.

The total impact of these steps of estimating technical potential, economic conversions, time phasing, and exceptions resulted in estimates of conversion of 23% of total oil and gas use in 1985 to coal.

III. Energy Impacts - Regulatory Program

A. Elements of the Program

The President's program includes amendments to ESECA, the existing mandatory coal conversion legislation which expanded and streamlined the provisions for mandatory use of coal, as follows:

- All new boilers must be non-oil/gas fired with exceptions for environmental or extra-ordinary economic situations;
- Classes of existing coal-capable units may be ordered to burn coal;
- Categories of new non-boiler units such as kilns may be ordered to be non-oil/gas fired.

The proposed coal conversion program does not affect existing oil and gas fired plants which were not designed to fire coal. Implementation of all provisions except those relating to new boilers is discretionary with the Administrator of FEA. Procedurally, plants can be treated under generic (class or category) regulations or individually. Generally the burden of proof in appeal for exemption from the coal use requirements rests with industry.

B. Overview of Methodology

The effect of the program overlaps the coal conversion occurring in the absence of the NEP and under the tax and incentive program, since for example all new large (>10MW) boilers are subject to a prohibition against oil and gas use including those which would use coal in the absence of any program and those which would be induced to use coal by the tax and rebate measures. The approach taken in estimating the effect of the regulatory program is to identify all units which would receive coal use orders and to deduct those using coal in the base case, leaving a measure of the incremental effect of the program.

The group of plants affected is determined by analyzing the scope of the regulation and identifying the population affected, and making appropriate judgments to exclude plants which would be exempted for environmental or economic reasons.

In the case of new and existing coal capable boilers, the population affected includes all units 10MW and larger. Only an allowance for environmental and economic constraints needs to be made. An estimate was made of plants sited in non-attainment areas where new sources of pollution such as coal fired boilers would be unacceptable. Economic exemptions would likely apply to very old existing plants and to new and existing plants in areas remote from coal supplies, such as northern New England. Only a rough qualitative estimate of these factors was possible.

While provision is made for mandatory coal use in new non-boilers such as kilns, furnaces, and indirect process heaters, the scope of the program will be limited to those fuel uses where the technical and economic feasibility of coal can be established. Many of these uses, such as cement and lime kilns, are expected to use coal anyway and are included in the baseline. In the short run (through 1985) the number of new potential coal uses for which practicability can be established by regulatory procedures is believed to be small. Therefore, all estimates based on orders affecting a limited number of specific applications was considered reasonable. Such an estimate is necessarily qualitative, since the coal potential and problem of increasing coal use in non-boilers remains ill-defined. The estimate used is premised on an assumed share of the largest process and direct heat energy uses in major industries.

The oil and gas savings resulting from the proposed regulatory program are summarized in Table 6 below.

TABLE 6

SAVINGS FROM REGULATORY PROGRAM
(1985 Quads of Oil and Gas Converted to Coal)

	Population	Population Affected	Maximum Effect	Likely Effect
Boilers				
Existing Coal Capable	.27	.27	.16	.12
Existing Oil-Gas Only	2.29	- 0 -		
New	3.85	2.24	1.57	1.19
Non-Boilers				
Existing Coal Capable	.05	.05	.03	.03
Existing Oil-Gas Only	3.90	- 0 -		
New	4.94	3.50	1.50	.30
Total	15.30	6.10	3.30	1.64

The population of units in 1985 is defined as all industrial oil and gas use excepting only feedstock and direct drive applications. Only certain segments of this population are affected by the proposed program (for a detailed description of the basis for the estimated population and breakdown see Section II.A.1). Existing oil and gas fired units not designed to use coal are excluded completely. Boilers less than 10 MW are excluded as well as those coming on line before 1978. These exclusions reduce the population affected from 15.5 quads to 6.1 quads, or 40 percent of the total population. The maximum effect of the program is further limited by environmental regulations which will make conversion to coal difficult or impossible in areas where air pollution standards are now exceeded. An across-the-board reduction in the population affected of 25 percent is made to account for the environmental constraints. Only 60 percent of the non-boiler energy use of the remaining population affected is expected to be technically feasible to convert to coal, based on an analysis of energy use in major process heat and direct firing applications of oil and gas.

The likely effect of the program is estimated by excluding 25 percent of existing coal capable boilers and non-boilers, and new boilers which are expected to be uneconomical due to location remote from coal supplies and other factors. The effect of the prohibition for classes of new non-boilers is estimated to be 20 percent of the maximum effect, considering the small number of unconventional (i.e., not included in the base case) uses of coal for which an administrative finding of feasibility could be made in the near term (through 1985).

IV. Methodology for Other Impacts of Coal Conversion Plan

A. Industrial Product Price Impacts

The impact of the Coal Conversion program on production costs depends on:

(1) the distribution of fuel consumption within each industry;

(2) the impact of the program on fuel costs; and

(3) the amount of energy required to produce each dollar of output.

The first step in analyzing product price impacts was to develop an average total energy cost based on fuel prices and distribution for selected industries in 1985. The change in energy price was then calculated by determining the average price under the tax scenario and subtracting the price level in the base case. This energy price change ($/MMBtu) was related to production by an energy per dollar output ratio (MMBtu/$ output) for each industry. The impacts calculated were bounded by a worst case assumption that all increased fuel costs would be passed on in the form of increased product prices.

1. Distribution of Fuel Consumption Within Each Industry

The study focuses on the economic impact of the proposed Coal Conversion Program on six major industries: (1) food, (2) paper, (3) petroleum, (4) chemicals, (5) steel, and (6) aluminum. In addition, the petrochemical segment of the chemicals industry was isolated and analyzed.

Fuel distribution for each industry in 1974 was determined using the Energy Consumption Data Base developed by EEA.[1/] To

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1/ ECDB, described in Attachment B.

encompass major fuel shifts occuring between 1975 and 1985, each fuel was adjusted relative to other fuels based on the PIES total industry fuel consumption shifts. This provided an industry specific fuel distribution that reflected both current industry fuel mix and national or regional fuel shifts.

The impact of the program on total energy cost for each specific industry was calculated by weighting the price increase for each fuel type by the distribution of fuels within the industry. The fuel price increases were taken from the PIES 1985 base case and subsequent runs.[1/]

Two price increases were calculated. Energy price increases due to the oil and gas wellhead pricing policy were first calculated. Then the fuel mix was adjusted to incorporate fuel shifts due to this pricing policy. Using this revised fuel mix as the base, the energy price increase due to the industrial fuel taxes were calculated.

3. Develop Energy Output Coefficients

In order to translate the total energy price increases into product price impacts the energy price increases ($/MMBtu) were multiplied by the energy output coefficients (MMBtu/$ output) for each industry. Energy output coefficients for paper, steel, and aluminum were based on an earlier EEA report.[2/] The other industries and industry total were based on U.S. Department of Commerce 1982 Census of Manufactures value of shipments estimates, inflated to reflect 1974 output. To adjust to 1985, the energy output factors were adjusted for conservation.[3/]

1/ Base Case, PIES run A148542C.
President's total program PIES run A158569C.

2/ FEA, Impact of Proposed Energy Deregulation/Tax Program on Five Energy Intensive Industries, prepared by EEA, March 10, 1975.

3/ Conservation factors from: DOC, Energy Efficiency Improvement Targets, 1976, and CEQ, Energy Conservation in the Manufacturing Sector, 1954-1990, prepared by Energy and Environmental Analysis, Inc., November, 1974.

Two sets of product price increases were calculated. The first set accounted for the share of oil and gas users who converted to coal. The firms that did not convert had energy price increases at the full tax while the firms that converted were assessed at a portion of the full tax. The converting firms paid a tax equivalent to the cost of conversion. The energy price increases were calculated based on these values and the energy output ratios were used to convert price increases into product price increases.

The maximum case product price increases were calculated by assessing all fuel oil and gas uses, including conversions to coal, are priced at the full fuel tax increases. This assumes that industry pricing policy is keyed to the marginal increase in energy costs.

The energy price increases calculated in part 2 ($/MMBtu) were then multiplied by the energy output coefficients from part 3 (MMBtu/$ output) to find the percentage increase in product price. EEA believes these product price impacts to be somewhat overstated since product prices were assumed to grow at the same rate as the GNP deflation from 1975 to 1985 while energy prices grew at a more rapid pace, implying that industry absorbed increases in energy costs at the expense of corporate profits.

B. Revenue from Industrial Fuel Taxes

The primary objective of the industrial fuel taxes is to encourage conversion to coal. However, tax revenue impacts were also developed to assess the budgetary impacts of these policies. The revenue generated by the conversion program will be determined by: the total oil and gas use, the effect of exemptions from the taxes and the magnitude of investments in coal related equipment eligible for the rebate provisions.

Because small corporations have limited conversion potential, the bill provides an exemption for corporations below .5 trillion Btu's of oil and gas.

The mechanism of the tax provides for corporations under .5 trillion Btu's of oil and gas to be excluded from tax liability. Corporations between .5 trillion Btu's and 1.5 trillion Btu's of oil and gas pay a graduated portion of the tax and corporations over 1.5 trillion Btu's were subject to the fuel tax. An average corporation currently consuming 1.5 trillion Btu's of oil and gas is estimated to have sales of approximately $90 to $110 million. This size corporation ranked about 1000th in sales in 1974. This is consistent with the philosophy behind the fuel tax which was designed to apply to only the major fuel consuming corporations.

The primarily analytical step in adjusting revenue generated for small corporations was to relate the data base to the corporate cut off point. The data base used to estimate the share of oil and gas covered by taxes was the 1972 Census of Manufactures.1/

The data was organized into profit centers and each corporation is made up of several profit centers, one from each four digit SIC code. The method of relating corporations to profit centers was sales data.

Total sales of the top 1,000 firms (ranked by sales in Fortune) was determined for the year comparable to the Census Survey.2/ The sales values of the profit centers, starting from the highest energy consumers and proceeding to smaller profit centers were added up until the accumulated value of profit center sales equaled sales of the Fortune 1000. This calculation implied that if the 1000 top profit centers (with sales equal to the Fortune 1000) were owned by the major U.S. Corporations, then 91% of the energy would be subject to fuel taxes. 3/

1/ 1972 Census profit center data base described in Attachment B.

2/ The sales levels were adjusted downward to account for the non-manufacturing activities of these corporations.

3/ Footnote continued next page.

3/ Since other corporations than the Fortune 1000 may own some of the large profit centers, we checked to see whether the ratio of oil and gas use sales by profit center declined sharply between 6-10,000 profit centers. It did not, implying that if the profit centers owned by the top 1000 corporations were among the top 10,000 profit centers, then the estimate of 91% of energy consumed subject to the taxes was reasonable. So long as energy to sales ratios are constant, it does not matter whether the top (in terms of oil and gas use) 6000 profit centers are owned by the Fortune 1000 or profit centers ranked 2000-9000 which have the same sales volume as the top 6000 profit centers.

This rough approximation technique indicated that 9% of the oil and gas usage would be exempt from the fuel taxes. The only other group exempted from the tax was natural gas used for ammonia feedstocks.1/

Table 7 shows the volume of oil and gas consumption in 1985 which is subject to the fuel taxes by excluding exemptions and accounting for oil and gas shifts to coal through 1985.

1/ Agricultural uses were also excluded, but are not covered in the baseline oil and gas use.

TABLE 7

ENERGY SUBJECT TO INDUSTRIAL FUEL TAX IN 1985

	OIL (QUADS)	GAS (QUADS)	TOTAL (QUADS)
TOTAL ENERGY[1/]	9.16	11.54	20.7
LESS EXEMPTION FOR AMMONIA FEEDSTOCKS	----	.317	.317
LESS EXEMPTION FOR SMALL BUSINESS	.82	1.01	1.83
LESS CONVERSIONS	1.9	2.92	4.82
TOTAL ENERGY SUBJECT TO FUEL TAX	6.44	7.29	13.73

1/ INDUSTRIAL FUEL USE IN 1985 AFTER WELLHEAD PRICING POLICY FROM PIES RUN A158569X.

D. Environmental Impacts

1. Air Impacts Methodology

Air impacts of the industrial coal conversion program have been calculated assuming compliance with environmental regulations which limit stack emissions from fossil fuel combustion in steam generating boilers. The regulations utilized are taken from the State Implementation Plans (SIP's), for conversion of existing combustors, and from New Source Performance Standards (NSPS), as promulgated by EPA, for conversion of new combustors. These regulations are applied to the oil and gas burned before conversion to derive existing emissions, and are applied to coal burned after conversion to obtain air emissions as the fuel switch is made. The difference in emissions before and after conversion represents the impact of the industrial conversion program on total national air emissions for each pollutant analyzed.

In some pollutants, such as NOX, emission regulations have not been established for existing fuel combustion sources. Uncontrolled emission factors have been developed in these cases for each fuel to estimate the effects of coal conversion where pollution limits have not been established for fuel combustion.

The SIP regulations are developed from AQCR-specific information found in the Laws and Regulations Affecting Coal, prepared for the U.S. Department of Interior, by Energy and Environmental Analysis, Inc. June, 1976. The uncontrolled emission factors employed where necessary are derived from AP42, Compilation of Air Emission Factors, Second Edition, February, 1976.

EPA's New Source Performance Standards for combustors with capacity of 25 MW or greater are from 40 CFR 60 Standards of Performance, Subpart D, revised 40 FR 46250.

2. Solid Waste Methodology

There are two types of solid waste generated during coal combustion - ash and scrubber sludge if flue gas desulfurization is used. The type and amount of these wastes depends upon the collection technique and coal characteristics.

The typical pulverized coal burner will separate coal ash into 20 percent bottom ash and 80 percent fly ash. The collection efficiency for both fly and bottom ash is assumed to be 100 percent which is consistent with the 99%(+) efficiency of baghouses and electrostatic precipitators. For a ton of 10 percent ash content coal, 200 pounds of ash are collected for disposal.1/

The amount of FGD sludge requiring disposal depends on the type of scrubber and the amount of sulfur dioxide that is removed. For a lime/limestone scrubber, it assumed there will be 2.83 pounds of dry sludge per pound of SO_2 removed.2/ Typically, this disposed sludge consists of 50 percent solids and 59 percent water by weight, producing for disposal 5.66 pounds of scrubber waste per pound of SO_2 removed.

The quantity of ash and sludge produced is determined by the quantity of coal which is burned without and with scrubbing, respectively. For estimation of sludge it is necessary to determine the sulfur content of the coal, because sludge quantity is based

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1/ $$\frac{\text{Pounds of Ash}}{\text{Ton of Coal}} = \left(\begin{matrix}\text{\%Ash Content}\\ \text{Of Coal}\end{matrix}\right)\left(\frac{\text{Pounds}}{\text{Ton}}\right)\left(\begin{matrix}\text{Overall Ash Collection}\\ \text{Efficiency}\end{matrix}\right)$$

where the overall ash collection efficiency is:

$$\left(\begin{matrix}\text{\% ash as}\\ \text{bottom}\\ \text{ash}\end{matrix}\right) \times \left(\begin{matrix}\text{collection efficiency}\\ \text{for bottom ash}\end{matrix}\right) + \left(\begin{matrix}\text{\% ash as}\\ \text{fly ash}\end{matrix}\right) \times \left(\begin{matrix}\text{collection efficienc}\\ \text{for fly ash}\end{matrix}\right)$$

2/ This is based on results reported to EPA from 9 plants using either lime or limestone wet scrubbers, and presented in the Development Document for Proposed Effluent Limitations Guidelines and New Source Performance Standards for the Steam Electric Generating Point Source Category, #440-1-73/029, March, 1974.

on the quantity of SO_2 removed, not on the quantity of coal burned. The sulfur content of the coal is assumed to be the average of the most commonly used local steam coal within each FEA region.[1/]

3. Environmental Impacts from Coal Production

The environmental impacts of increasing the supply of coal depend upon where the coal will be mined, whether it is strip mined or underground mined, and what environmental regulations are applied to strip mining. The production forecast used for estimation of coal production impacts was the PIES model run which included the regulatory and fuel tax-rebate measures. The PIES production forecast projects production by region and mine type (strip or underground).

The environmental impacts resulting from the incremental coal production projected by the PIES model have been calculated from 1974-1975 data available from MESA[2/] and from a recent study.[3/]

The land acid and sediment impacts assumed stringent national strip mine reclamation regulations requiring restoration of the land to approximately the original contour which existed prior to mining. It is important to point out that the impacts could be calculated only for strip mined coal. Underground mining affects land through spoiling of waste and rock and coal, and significant acid drainage problems occur with underground mining, however, these impacts are highly dependent upon local conditions and control technology, and very little work has been done to quantify these impacts.

1/ These averages are as reported by utilities to the FPC in form 423 for the year 1975.

2/ Mining Enforcement and Safety Administration (MESA) District Managers Quarterly Report, July, 1975.

3/ Benefit/Cost Analyses of Laws and Regulations Affecting Coal, prepared for U. S. Department of the Interior by Energy and Environmental Analysis, Inc., April, 1977.

The employment and accident impacts are based on historical (1975) productivity and accident rates. As such, they probably understate the total impacts because productivity per man per hour has been declining since 1969. Accident rates are based on the number of accidents reported to MESA per million man hours, and are calculated separately for each region (using regional accident rates) and mine type.[1/] Additional data on productivity per man per day were obtained from Coal-Bituminous and Lignite, 1975 by the U.S. Bureau of Mines. Projected employment impacts are based primarily on this source.

1/ In the Southwest region national averages are used because the data base was insufficiently large for valid extrapolation.

V. Supply Constraints Considered

A. Coal

The combined tax and regulatory programs for increasing industrial coal use are expected to increase the demand for coal in industry by 200 million tons in 1985 compared to the baseline projected level of 255 million tons of industrial coal demand and 1,045 million tons estimated total U. S. consumption. In order to sustain this increase the production of coal will have to grow at 7 percent per annum between 1976 and 1985 rather than the projected 4.9 percent.

The feasibility of the increase was considered to be a possible constraint on the program and was assessed by comparing projected regional coal production (as predicted by the FEA-PIES national energy model) with current production and with recent estimates of potential production.[1/] In many cases this comparison indicated that a significant number of heretofore unanticipated and unplanned mine openings would be necessary. Since the time required to plan, site, permit and construct new coal mines varies from two to six years, the time phasing of the taxes and rebate was adjusted so the annual incremental demand increases from less than 20 million additional tons in 1979 to a maximum annual increase of about 35 million tons.

B. Transportation of Coal

Coal transportation is not likely to be a significant long run barrier in achieving the projected coal use targets. Coal will be moved to most industrial consumers directly by rail (or in some cases by barge) in shipments of one to a few cars. Most industrial plants which are large enough to use coal have access either to a rail spur or waterway they use for receiving raw materials and

1/ Benefit/Cost Analyses of Regulations Affecting Coal Vol III, prepared for D. O. Interior by EEA, Inc., 1977. Energy and Economic Impacts of HR13950..., prepared for CEQ by ICF, June 1977.

shipping products. The exceptions to this generalization are expected to be plants located in urbanized areas where other constraints such as environmental regulations will make conversion to coal unlikely.

The quality of rail systems (roadbed and rolling stock) is believed to be an issue mainly in the Mid-Atlantic and New England regions served by ConRail. The magnitude of increase in coal traffic in this region is projected to be relatively small. Another area of uncertainty is the Gulf region, because coal has been considered such an unlikely fuel for industry there that it has been ignored. Generally, railroads in this region are in good condition but bottlenecks in moving coal into particular areas might arise. Large scale refurbishment of rights of way is a long term (2-5 year)project if necessary.

C. Coal Fired Boilers and Related Equipment

The additional demand for coal fired boilers and related equipment was assessed by projecting total required industrial boiler capacity (measured in pounds of steam per hour) with and without the effect of the President's program, and by comparing the required manufacturers output measured in dollar terms.

The baseline estimate of coal fired boilers was prepared using the coal use baseline described in Section II-B and assuming an average capacity factor of 50 percent, based on the FEA MFBI survey (this factor is equivalent to 4.38×10^9 Btu per year consumed per 1,000 lb/hr steam capacity). The demand for boiler capacity increases under the coal conversion program due to the accelerated replacement of existing oil and gas fired units. The major effect of the program is to shift the projected boiler production for oil/gas to coal fired units of the same capacity. The increase in the number of coal fired units is estimated based on the projected increase in coal consumption using a distribution of sizes of boilers based on historical trends. The large projected increases in coal fired industrial boilers projected warrant further analyses of vendor capabilities to satisfy such damands.

Another measure of the required increase in boiler manufacturers output is the dollar value of boiler sales. Coal fired industrial size boilers are more complex than oil or gas units and generally cost from two to three times as much as oil or gas fired units of the same size. Hence the dollar value gives a rough way of measuring the increased requirements of materials, labor and capital required to satisfy the projected demand under the program. The increase in the value of boiler production was estimated by multiplying this cost differential by the expected boiler sales.

Boiler sales are now only about 50 percent of peak year (1973) levels. Increases in output resulting from the proposed program would exceed current capacity around 1980, allowing three years for expansions of capacity. The largest annual expansion in output required is roughly 15 percent (increase in dollar value of production).

Because the baseline projections include significant growth in industrial output and energy requirements, which yield a high forecast of boiler demand, this projection may indicate a relatively optimistic (high) estimate of boiler demand. Overall these results indicate a realistic but sustained effort at increasing capacity that could satisfy the projected demand.

D. Environmental Control Equipment

The demand for environmental control equipment was estimated for various air pollution control strategies based on the projected number and size of coal fired units (see C. above) and the applicable environmental regulations.

Little work has been done on the issue of vendor capacity for industrial scale FGD. Based on the results of one recent study,[1/] industrial use of FGD is more widespread than might be expected. Approximately 50 coal-fired boilers ranging in size from 3 to 50 MW have installed some form of an FGD system. Based on somewhat limited operating experience (few units have operated for more than one to two years) the availability of most of these units has been in excess of 90 percent, while SO_2 removal efficiencies have ranged from 30 to 95 percent depending on system type.

The types of FGD systems used in the industrial sector are extremely varied. Due to the generally small sizes of the facilities under consideration, a much greater diversity of systems has been identified. These systems can be classified in four general categories:

- Self-Contained, Solid Waste Producing Systems - these systems are analogous to the systems used on utilities and are typified by the lime, double alkali, and Wellman-Lord type systems.
- Self-Contained, Liquid Waste Stream - these systems generally use a purchased chemical such as sodium hydroxide. Waste from the process is generally disposed of in the plant water treatment plant.
- Self-Contained, Non-Chemical - using water only and no recycling of the liquid, a 30 percent removal of SO_2 can be realized.

1/ "Survey of the Application of Flue Gas Desulfurization Technology in the Industrial Sector," prepared by Energy and Environmental Analysis, Inc., for FEA, October, 1976.

- Waste Stream Systems - certain industrial processes such as pulp and paper, chemical and textile processes can use an alkaline waste stream from the production process as the scrubbing liquid.

The majority of these last three FGD system types were installed on coal-fired boilers predominantly to remove particulate matter with SO_2 control as a desirable by-product.

Estimating the availability of industrial scale FGD systems is very difficult. At the present time, over 100 firms are marketing scrubber systems which potentially could be used as FGD systems depending on the type of system used. At the present time, only a few firms (10) are actively marketing self-contained, solid waste FGD systems. For these firms the present capacity far exceeds demand, although if significant numbers of MFBI's needed FGD systems, the capacity of these vendors would be exceeded. If industrial units are able to utilize process waste stream or a self-contained liquid waste type of FGD system, then the supply of scrubber systems to accommodate these types of systems could be provided by many builders.

The lead times to install FGD systems or industrial units vary by type of system employed. The self-contained, solid waste systems generally require from 18to 24 months for system design and erection. The simpler self-contained, liquid waste and waste stream systems would require from 12 to 18 months for design and construction.

Attachment A

NON-BOILER USES OF COAL

Nearly 80 percent of oil and gas used by the manufacturing industry in non-boiler applications is concentrated in six industries (see Table A-1).

Some examples of non-boiler energy uses in these industries are:

Chemicals

- 'process heaters' where liquids or gases are heated indirectly as they pass through tubes in a furnace; and
- driers, where solid products are heated directly by hot combustion gases.

Primary Metals

- smelting, melting and refining furnaces where ore or metal is heated directly by burning fuel and gases or radiant heat from a flame; and
- reheat furnaces for heating iron charge to a blast furnace, forming operations such as rolling or forging or heat treating.

TABLE A-1

CONSUMPTION OF OIL AND GAS BY MAJOR INDUSTRIES IN NON-BOILER USES IN 1974[1]

Industry	Share of All Manufacturing Uses
Chemicals	12.5%
Primary Metals	23.8%
Petroleum Refining	23.8%
Paper	3.4%
Stone, Clay & Glass	12.9%
Food Processing	2.2%
Six Largest	78.6%
All Manufacturing	100.0%

1/ Excludes oil and gas used to raise steam and for feedstock applications.

SOURCE: ECDB Data Base.

Petroleum

- process heaters such as crude stills, reboilers, crackers and reformers where crude oil or derivatives are heated indirectly.

Stone, Clay and Glass Products

- cement and lime kilns
- glass melting furnaces
- brick or clay products kilns

Difficulties Associated with Coal in Non-Boiler Uses

Technical limitations arise from specific characteristics of coal as a fuel: it is a solid, it has high sulfur and ash content, and it burns less evenly than oil or gas. These characteristics affect coal use since:

- solid fuel is more expensive to handle and more difficult to burn evenly and completely;
- ash can affect product quality in direct firing and creates problems with design and materials used to construct and line boilers, and furnaces;
- sulfur content can hurt product quality; and
- coal is much more variable in quality from shipment to shipment and requires more careful monitoring and control.

Historically, coal used for direct and indirect heat has been limited to industries where the characteristics of coal described above do not affect product quality adversely. Coal is now used in industry mainly for firing boilers, in cement and lime kilns, and less frequently in production of nonferrous metals, and fired clay products such as common brick.

There is significant potential for increased coal use in applications where coal has not been used historically, but where new plants are now being designed to use coal or where coal use requires only the application of readily available technology. One example of new designs is the use of coal in process heaters used in the chemical and refining industries. While these units may prove quite difficult to retrofit, new process heaters are being constructed to use coal. Problems to be overcome involve the selection of tube and refractory materials as well as more precise control of temperature conditions. The variability of coal in its combustion characteristics and its trace element constituents are the chief problems. Iron ore processing (taconite) is an example of a direct fired application where coal fired capability has been successfully pilot tested and is being incorporated into new plant designs.

A large potential for coal exists in the area of medium temperature hot air ($<700^{\circ}F$) uses of energy. Air heated to this temperature is used widely for various drying applications in the textile and paint industries, iron foundries, and food processing applications. In these applications coal would be used to produce a high temperature steam which would heat air by means of a heat exchanger. Heat exchangers are already used in these industries, and this application is being considered by major firms in each of these areas. Substituting indirect coal fired heating for direct heating will result in increased maintenance, but poses few technical problems.

High temperature direct heat applications such as furnaces for refining or melting metals and kilns for ceramic and glass products might be coal fired through adaptations of firing techniques. New refractory materials will also be needed. Product contamination, such as coal ash effects on metals, might be a problem.

In other applications where high temperature air or very precise combustion temperature control is required, coal use will be more difficult. For example, some metal treating processes such as annealing require temperatures of 1300°F. to 1700°F. Many annealing operations are direct fired operations with very precise temperature and trace element requirements. Direct coal use would not provide either the precise temperature control required or the freedom from sulfur and ash contamination needed. Indirect heating, e.g., in muffle furnaces, is also used for annealing operations, but the temperature control needed would be very difficult to obtain with coal firing. To use coal in such applications, refractory materials capable of operating at these temperatures would have to be developed.

Coal use in the iron and steel industry poses similar problems. When using coal to fuel soaking pits, for example, the effect of sulfur on the metal surface and the difficulty in producing high temperature heat through indirect means would present problems.

Some petrochemical and refining operations such as ethylene furnaces pose significant problems is using coal. In this application the principle problem lies in the control of heat transfer required in the process. The temperatures and pressures in the furnaces are such that high quality metal alloys are required. Both the sulfur and ash in coal could react with the tubes, causing corrosion or deposits to form which could interfere with heat transfer.

Attachment B

DATA SOURCES

(1) Energy Consumption Data Base, prepared by Energy and Environmental Analysis, Inc., for the Federal Energy Administration, April 20, 1977.

The data base contains over 7 million bits of energy consumption, and expenditure information covering three years, 1967, 1971, and 1974 for eight economic sectors: agriculture, mining, construction, manufacturing, transportation, commercial, household, and electric utilities. It is further broken down by functional use, fuel type, geographic descriptions, and two digit SIC code. Within the manufacturing sector, for example, the data base lists how much coal was used in the steel industry for coke production in Ohio.

The primary sources of energy data for the manufacturing sector were trade associations, Bureau of Mines, and Census of Manufactures. Where trade association data was available in sufficient regional detail for a specific industry it was used (e.g. paper, steel). If trade association data was not available, Bureau of Mines was used instead (e.g. petroleum). For the industries that rely solely on purchased fuel (e.g. food, textiles) or where trade association data did not provide adequate regional detail (cement), the Census of Manufactures was used.

Functional use breakdowns were based primarily on contractor reports prepared for FEA.

(2) 1972 Census of Manufactures, Profit Center File

In order to relate energy use to the size of the profit center, a methodology was developed for evaluating energy consumption on a profit center-by-profit center basis for all industries included in the Census of Manufacturers. The 1972 Census of Manufacturers lists aggregate energy use for each 2-, 3- and 4-digit SIC code. This information, however, provides no insight into either the relative distribution of energy use among profit centers within each SIC code or between SIC codes. The only available data published by the government that distinguishes relative size of profit centers within each 4-digit SIC code are the concentration ratios. This information, published only irregularly, relates the ratio of total value of shipments to discrete increments of profit centers within each 4-digit SIC code. Table B-1 illustrates this information with a sample SIC code's ratio.

TABLE B-1

SIC CODE	TOTAL # OF PROFIT CENTERS	TOTAL VALUE OF SHIPMENTS $\$10^{6}$	PERCENT VALUE OF SHIPMENTS ACCOUNTED FOR BY 4 LARGEST	8 LARGEST	20 LARGEST	50 LARGEST
2011	2,529	2,220.5	26	38	50	62
...						

From this table it can be seen that for SIC Code 2011, (meatpacking) the 4 largest profit centers accounted for 26 percent of the total value of shipments and the 8 largest profit centers accounted for 38 percent. This information can be put into a different form in order to describe the performance of each increment of profit centers, shown below.

TABLE B-2

SIC CODE	TOTAL # OF PROFIT CENTERS	TOTAL VALUE OF SHIPMENTS $$10^6$	PERCENT ACCOUNTED FOR BY 1st 4 LARGEST	2nd 4 LARGEST	Next 12 LARGEST	Next 30 LARGEST	Next 2479
2011	2,529	2,220.5	26	12	12	12	38

As can be seen from this table, there is now specific information for each incremental group of profit centers listed in the first table as well as for the other 2,479 profit centers. This methodology provides a means for ranking all profit centers within the Census of Manufacturers on the basis of value of shipments.

The Census of Manufacturers publishes energy cost and energy use statistics for each 2-, 3- and 4-digit SIC code. This information is based on reports by manufacturers detailing quantity and cost of coal, coke, distillate fuel oil, residual fuel oil and natural gas as well as the cost for other fuels. This data was transformed into equivalent killowatt hours to provide a basis of comparable units of energy use. For the purposes of this program the equivalent killowatt hours were converted into a BTU equivalent on the basis of 3413 BTU/Kwh. This information completes the data set required to rank energy use within industry.

Total equivalent energy use was distributed among individual firms on the basis of each individual firm's value of shipments. This was accomplished by calculating the number of BTU's per dollar value of shipments for each 4-digit SIC code, or simply dividing total equivalent BTU's by total value of shipment. This figure was then applied to the value of shipments possessed by each profit center within each 4-digit SIC code. This process is illustrated in the table below.

TABLE B-3

SIC CODE	# OF COMPANIES	$\$10^6$ VALUE OF SHIPMENTS	% Distribution 1st 4	2nd 4	Next 12	Next 30	Next 2479	Total Equivalent Kwh's
2011	2,529	18,827.5	26	12	12	12	38	26.8

Total Equivalent BTU's = 26.8 Kwh X 10^9 * 3413 $\frac{\text{BTU's}}{\text{Kwh}}$ = 91.47 X 10^{12} BTU's

$$\frac{\text{BTU's}}{\text{\$ Value of Shipments}} = \frac{91.47 \times 10^{12} \text{ BTU's}}{18.827.5 \times 10^6 \text{ \$}} = .00486 \times 10^6 \text{ BTU/\$}$$

1st 4 profit centers value of shipments = (.26)(18,827.5) = 4895.15

Average value of shipments for each firm in the 4-firm increment. = $\frac{4895.15}{4}$ = 1223,79

Average energy/firm in 1st increment. = 1223.79 X 10^6 * .00486 X 10^6 BTU = 5.948 X 10^{12} BTU

Energy cost per firm was distributed among profit centers by deriving a value of BTU's per dollar energy cost. This value was then applied to the derived BTU's per firm to create an energy cost per firm. Using the same SIC Code for a sample calculation:

SIC CODE	TOTAL EQUIVALENT BTU's (10^{12})	TOTAL ENERGY COST (10^6)
2011	91.47	81.8

$$\frac{\text{BTU's}}{\text{\$ Energy Cost}} = \frac{91.47 \times 10^{12}}{81.8 \times 10^6} = 1.118 \times 10^6$$

Energy Cost Per Profit Center (1st 4) = 5.948 X 10^{12} BTU * $\frac{1}{1.118 \times 10^6 \frac{\text{BTU}}{\$}}$ = \$5.32 X 10^6

This methodology was used to evaluate all 4-digit SIC codes for which compatible information was available. The most recent concentration ratios available for more than just the 8 largest profit centers in each 4-digit SIC code was 1967. This information was applied to the 1971 value of shipments[1/] and 1971 energy cost and energy use data.[2/] The use of 1967 concentration ratios on 1971 data is reasonable because the pattern of industrial concentration shifts very little between sampling periods.

1/ Fuel Consumption Reports, U.S. Department of Commerce, Industrial Analysis, March 1974.

2/ Fuels and Electric Energy Consumed (Supplement), 1972 Census of Manufacturers, Department of Commerce, September 1974.

(3) Major Fuel Burning Installations (MFBI) File

Data on existing industrial plants are available from a FEA questionnaire, entitled "Major Fuel Burning Installation Coal Conversion Report."[1/] It was mailed in the spring of 1975 to industrial companies with MFBI's [2/] that have design firing rates in excess of 100 million Btu's per hour. Its purpose was to provide basic identifying information to be used to determine candidates for coal conversion under the authority of ESECA. Important items of interest on this questionnaire include:

- plant location
- boiler ages and sizes
- 1974 fossil fuel consumption by boiler
- whether the combustor has ever burned coal

A supplemental questionnaire[3/] was mailed in June 1976 to elicit data on company financial status, conversion cost estimates, and coal availability.

MFBI coverage of total U.S. natural gas and fuel oil varies by fuel type and combustor type (boiler or non boiler). Total coverage of both fuels is over 50 percent.

MFBI coverage of boilers is more extensive than the coverage of non boiler combustors. MFBI data covers 90 percent of the total U.S. oil burned in boilers and 70 percent of the natural gas boiler total. This reflects the greater use of natural gas in boilers below the MFBI cutoff point.

1/ Form FEA C-602-S-O, attached

2/ Boilers, burners, or other combustors.

3/ Form FEA C-602-S-1.

FEA C-602-S-0

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

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 10^6 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? 19 ☐☐
   b. How was it Modified?
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.

COMBUSTOR NUMBER ____________________

MFBI NAME ____________________ A-59

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

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 ☐☐ 30

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.

	QUANTITY	
RESIDUAL	☐☐☐☐ 35	10^3 bbls/yr
DISTILLATE	☐☐☐☐ 39	10^3 bbls/yr
GAS	☐☐☐☐ 43 46	10^3 MCF/yr

21. 1974 ANNUAL FUEL USE

	% ASH (by weight)	% SULFUR (by weight)	BTU CONTENT ($\times 10^3$)		QUANTITY	
COAL	____	____	☐☐☐☐ 47	(lb)	☐☐☐☐ 54	10^3 tons/yr
RESIDUAL		____	☐☐☐☐ 55	(gal)	☐☐☐☐ 62	10^3 bbls/yr
DISTILLATE		____	☐☐☐☐ 63	(gal)	☐☐☐☐ 70	10^3 bbls/yr
GAS		____	☐☐☐☐ 71	(MCF)	☐☐☐☐ 78	10^3 MCF/yr

COMBUSTOR NAME ______________________
MFBI NAME ______________________

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

22. 1973 FUEL USE

DO NOT FILL IN [ ][ ] 79 80 [ ][ ][ ][ ][ ] 1 5

	% ASH (by weight)	% SULFUR (by weight)	BTU CONTENT (x10³)	QUANTITY	
COAL	____	____	[ ][ ][ ][ ] (lb) 6	[ ][ ][ ][ ] 13	10³ tons/yr
RESIDUAL		____	[ ][ ][ ][ ] (gal) 14	[ ][ ][ ][ ] 21	10³ bbls/yr
DISTILLATE		____	[ ][ ][ ][ ] (gal) 22	[ ][ ][ ][ ] 29	10³ bbls/yr
GAS		____	[ ][ ][ ][ ] (MCF) 30	[ ][ ][ ][ ] 37	10³ MCF/yr

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

ELECTRIC GENERATION [ ][ ][ ] 38

SPACE HEATING [ ][ ][ ] 41

PROCESS STEAM [ ][ ][ ] 44

OTHER (Specify) [ ][ ][ ] 47

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) [ ] 55

Type (MAG Ox, LIMESTONE, Etc.) ______________________

Date Installed ______________________

Date Last Operated ______________________

Design Efficiency (%) ______________________

Actual Efficiency (%) ______________________

% Availability ______________________