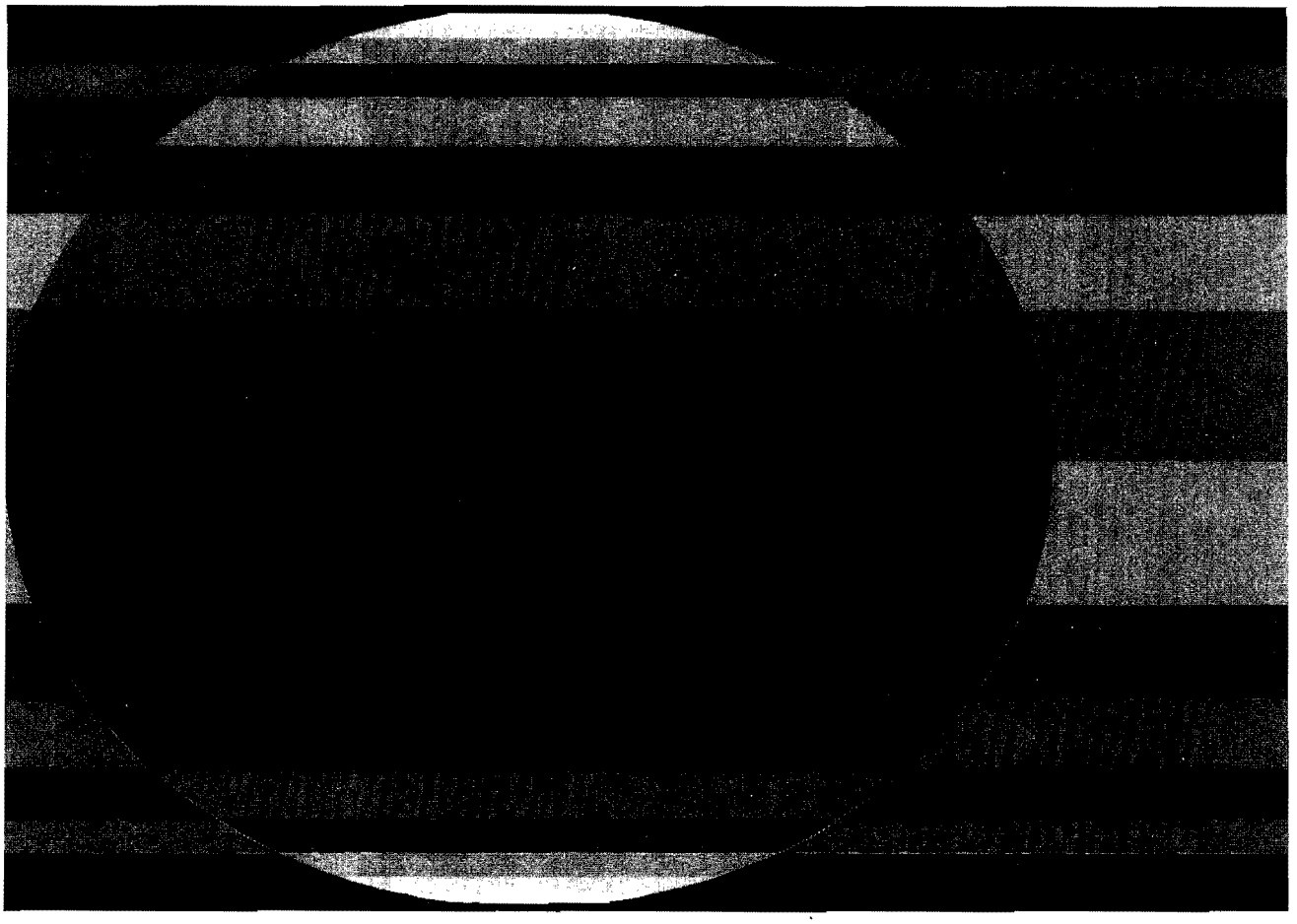
BACKGROUND PAPER

Replacing Oil and Natural Gas with Coal: Prospects in the Manufacturing Industries

August 1978



Congress of the United States
Congressional Budget Office

REPLACING OIL AND NATURAL GAS WITH COAL:

PROSPECTS IN THE MANUFACTURING INDUSTRIES

The Congress of the United States
Congressional Budget Office

For sale by the Superintendent of Documents, U.S. Government Printing Office
Washington, D.C. 20402

PREFACE

Because of the United States' growing dependence on foreign oil and the predictions of an energy "crisis," alternative energy strategies are constantly being evaluated by the Congress. One of the most often discussed alternatives is to increase U.S. reliance on the nation's vast coal reserves. This report addresses one component of this potential strategy. Specifically, it analyzes alternative policies that could be adopted to encourage the manufacturing sector to substitute solid coal for oil and gas consumption. Because of technical or cost restraints in other consuming sectors, the manufacturing industries are the most likely candidates for expanded direct use of solid coal.

This report has been written at the request of the Senate Budget Committee by Craig Roach of the Natural Resources and Commerce Division; Porter Wheeler wrote the appendix on coal transportation. Richard D. Morgenstern and Raymond C. Scheppach supervised the study. Phyllis Nations typed the various drafts of the manuscript. Research assistance was provided by Sarah Beth Lambert. The paper was edited by Robert L. Faherty. In keeping with CBO's mandate to provide objective analysis, this report contains no recommendations.

Alice M. Rivlin
Director

August 1978

CONTENTS

CONTENTS (Continued)

TABLES

APPENDIX TABLES

FIGURES

SUMMARY

When the United States evaluates both short- and long-run policies to reduce its dependence on foreign oil, major consideration is always given to increasing the nation's reliance on coal. Not only are the known U.S. coal reserves immense compared with the domestic reserves of oil and natural gas, but the dramatic increase in the world price of oil in 1973 made coal an economically attractive substitute for some selected uses.

Policies encouraging the substitution of coal for oil and natural gas were an important part of the Administration's National Energy Plan submitted to the Congress in April 1977. By 1985, the Administration planned to reduce oil imports by 4.5 million barrels a day—from 11.5 to 7 million. Of that 4.5 million barrels a day of savings, 2.3 million was to be attained by replacing oil and natural gas with coal in the manufacturing sector; some additional import savings were also credited to coal substitution in existing electric utilities. Although the House and the Senate have, in large part, rewritten the proposed legislation, substituting coal for oil and gas remains a cornerstone. Substitution is to be encouraged primarily by excise taxes on certain uses of oil and natural gas and by tax rebates and tax credits for those buying coal-burning equipment; regulatory programs that simply prohibit the use of oil and gas in specific cases are also proposed.

OPPORTUNITIES FOR COAL SUBSTITUTION

While processing coal into a liquid or gaseous form may prove advantageous in the future, engineering, economic, or institutional barriers appear to hinder widespread adoption in the near term. Hence, current legislative proposals (and this report) focus primarily on the potential substitution of solid coal for oil and gas.

The manufacturing sector is the most likely target for solid coal substitution, since new electric utilities are already turning to coal or nuclear power and there appear to be few opportunities for solid coal substitution in the transportation, residential, and commercial sectors. Within manufacturing, the primary opportunity for shifting to coal lies in fueling boilers, since coal-fired boilers are commercially available. At present, 25 to 30 percent of U.S. oil and natural gas consumption is attributable to the manufacturing sector, and 30 to 40 percent of that (or 8

to 12 percent of total consumption) goes for boiler uses. Since solid coal cannot be burned in existing boilers designed to use oil or gas, coal substitution must depend largely on the choice of coal by firms purchasing new boilers.

Nonboiler uses of oil and natural gas in manufacturing include a large number of heterogeneous processes such as use as a feedstock for the petrochemical industry and as a fuel for cement kilns. Coal-burning equipment is not commercially available for most nonboiler processes; the primary exception is equipment for the production of cement and lime.

BOILER USES

By comparing the total costs of new boilers by fuel type, it is possible to estimate the effects on fuel substitution and on the federal budget of several tax policy incentives designed to decrease the cost of coal-fired boilers relative to that of boiler systems using natural gas and oil. Total costs include equipment, operation, and maintenance costs as well as fuel costs. In addition to relative cost, boiler fuel choice also depends upon noncost factors such as a firm's perceptions of fuel supply availability, equipment reliability, adequacy of land area, and noncost environmental problems. Because of the difficulty in quantifying these noncost factors, all estimates must be viewed with a moderate degree of uncertainty.

Estimates of the effects of five alternative tax policies on the use of solid coal in boilers are presented in the Summary Table. While some of the policy options induce coal use for a large share of new boiler fuel demand, none could reduce oil imports in 1985 by more than 8 percent (assuming 11.5 million barrels a day of imports). The import reduction is modest both because the total boiler fuel market is a relatively small percentage of total U.S. energy demand and because the replacement of existing oil and gas boilers with new coal boilers will occur slowly.

Current Policy

If no specific new federal policies are undertaken to encourage coal use, solid coal is likely to be chosen for only 6 percent of new boiler fuel requirements in the 1981-1985 period. By 1985, total boiler coal use would be about 58 million tons, up from 45 million tons in 1974. This current policy estimate is based on and is sensitive to several key assumptions, including the following:

SUMMARY TABLE. ENERGY AND BUDGETARY EFFECTS OF CURRENT POLICY AND FIVE ALTERNATIVE BOILER TAX POLICIES

	Energy Effects			Budgetary Effects, Fiscal Years 1979-1985 (millions of current dollars) a/	
	1985 total coal use (millions of tons per year)	Percent of 1981-1985 new boiler fuel demand captured by coal b/	1985 oil and gas replacement (barrels per day equivalent)	Cumulative tax revenues	Cumulative tax expenditures
Current Policy	58	6		—	—
A $3.00-a-barrel tax on oil and a tax on gas sufficient to increase its price to that of distillate oil (including the $3.00 tax)	88	36	321,000	3,091	—
A $6.00-a-barrel tax on oil and a tax on gas sufficient to increase its price to that of distillate oil (including the $6.00 tax)	116	63	621,000	3,074	—
40 percent tax credit	95	—	403,000	—	3,361
New boilers	—	38	353,000	—	—
Accelerated retirements	—	—	50,000	—	—
Senate bill incentives	114	61	600,000	1,683	1,950
House bill incentives	140	—	883,000	(13,547) c/	(-1,756) c/
New boilers	—	72	717,000	—	—
Accelerated retirements	—	—	166,000	—	—

SOURCE: Congressional Budget Office

a/ Reflects a 6 percent annual rate of inflation starting in fiscal year 1978.

b/ About 2.2 quadrillion BTUs of fossil fuels will be consumed in all new boilers purchased to meet expansion and replacement demand for the 1981-1985 period; these are the boiler investment decisions affected by federal policies enacted in 1979. The numbers in this column represent the portion of that new fuel demand satisfied by coal.

c/ All of the revenue is rebated. The negative tax expenditure estimate reflects the net impact of the two provisions: the extra 10 percent tax credit and the denial of the existing tax credit for new oil and gas boilers and new coal boilers financed with rebates.

- By 1985, all crude oil will be sold at the world oil price, which is assumed to increase at the rate of U.S. inflation throughout the life of the boiler system.

- A strict interpretation of the 1977 amendments to the Clean Air Act will prevail for both coal and oil starting in 1979.

- Natural gas will be available for new boilers and prices for new gas will be deregulated in 1985.

- Coal prices will increase only because of inflation and depletion of low-cost mines.

- Unlike electric utilities, industries will not be able to sign long-term contracts or use low-rate unit trains for delivery.

Senate Bill

The Senate bill proposes a $6.00-per-barrel oil tax and a tax on natural gas sufficient to raise its price to that of distillate oil including the oil tax. The taxes are on fuel used in new boilers that have a capacity to consume 100 million BTUs of fuel per hour or more and on fuel used in new smaller boilers if they are one of several new units at a single site with aggregate boiler capacity over 250 million BTUs per hour. In addition to the taxes, an extra 15 percent refundable tax credit is offered to firms investing in coal-fired boilers. The increased coal use resulting from this plan is equivalent to 600,000 barrels a day of oil consumption in 1985. The cumulative tax revenue by fiscal year 1985 is $1.7 billion, and the cumulative tax expenditure is $2.0 billion.

House Bill

Oil and gas user taxes in the House version are imposed on oil and gas used in both new and existing boilers and in boilers of all sizes. The oil tax gradually increases to $3.00 per barrel in 1985. The gas tax gradually raises gas prices to the equivalent price of distillate oil not including the oil tax. Both new boilers and existing boilers converted to coal are eligible for tax rebates, and the existing 10 percent investment tax credit is denied to investors choosing oil- and gas-fired systems. By 1985, the resulting increase in coal use is equivalent to 883,000 barrels a day of oil consump-

tion; 19 percent of the replacement involves the early retirement of existing boilers. Cumulative tax revenue would be $13.5 billion, although the total revenue is assumed to be rebated, thus providing a major incentive to use coal. Denying the existing 10 percent investment tax credit to new oil and gas boilers and to new coal boilers financed with the rebate results in a cumulative budget savings of $1.8 billion.

Alternative Tax Options

Coal's market share could be raised to 36 percent by imposing a $3.00-per-barrel tax on oil and a tax on natural gas sufficient to increase its price to that of distillate oil including the oil tax; coal would be substituted for the equivalent of 321,000 barrels of oil a day. By doubling the tax, coal substitution would increase to 621,000 barrels a day. Both sets of taxes are imposed only on oil and gas used in new boilers. An additional 40 percent tax credit for coal boilers would induce coal substitution for the equivalent of 403,000 barrels a day; 12 percent of that substitution is achieved by inducing the early retirement of existing oil and gas units. The first two taxes would generate approximately $3 billion in revenue, while the tax credit would decrease revenue by $3.4 billion.

NONBOILER USES

The original National Energy Plan included taxes on most oil and gas used in the manufacturing industries, but the House and Senate versions of the tax program are primarily boiler fuel taxes. 1/ Most nonboiler uses were exempted because of the lack of proven equipment and processes employing solid coal. The limited engineering analysis available does, in fact, conclude that solid coal-burning technologies are not commercially available for most nonboiler oil and gas uses.

1/ The House version exempts all fuel used as a raw material and other nonboiler ("process") uses in which coal use is not feasible for technical, economic, or environmental reasons. And coal use is not technically feasible for most nonboiler applications. If nonboiler uses do qualify, they are taxed at a lower rate under the House bill. The Senate exempts all raw material and process uses.

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Taxes on nonboiler oil and gas consumption could serve as an incentive for solid coal substitution by inducing businesses to undertake the required research and development of new equipment or processes. Alternatively, the federal government could finance the research and development. Both of these strategies might be misguided, however, since processed coal may be a more likely substitute for nonboiler oil and gas consumption.

ADDITIONAL CONSIDERATIONS

As presented above tax incentives could be adopted to induce manufacturing firms to use solid coal for a substantial portion of their new boiler fuel requirements. The need and exact nature of such legislation could, however, be questioned on several grounds: (1) oil prices may rise faster than projected, leading to more rapid substitution of coal even in the absence of tax incentives; (2) air pollution regulations might restrict or encourage coal use; and (3) in the longer term processed coal could be made a serious competitor to oil and gas for certain selected uses.

Impact of Foreign Oil Prices

The need for coal substitution legislation is uncertain since it depends to a large extent on the future oil-pricing strategy of the Organization of Petroleum Exporting Countries (OPEC). If it is assumed, as the Administration has at times argued, that large oil price increases by OPEC are inevitable starting in the mid-1980s and, further, that coal prices will not increase in tandem, then there is no need for any additional tax legislation promoting a shift to coal. The expectation of high oil prices will drive the private sector to coal for at least the boiler component of total oil and gas use. Specifically, annual oil price increases of 4 percent or more above the U.S. rate of inflation, with no similar price increase for coal, would make solid coal the lowest-cost fuel for most new boilers.

Impact of Air Pollution Regulations

The federal government significantly affects the relative cost of coal, oil, and natural gas boilers through environmental policy as well as through energy tax programs. Most air pollution regulations add to the equipment, operation, or fuel costs of both coal and oil boilers. Consequently, in promulgating air pollution emission standards, it is critical to determine the differential impacts on the total cost of operating boilers of different fuel

types. It is possible to impose air pollution regulations that would be strict, but nonetheless would favor the use of coal; that is, regulations that add more to the cost of using oil than coal and thereby encourage expanded coal use. Therefore, air pollution policy is a critical component of any coal substitution program and can be used in place of, or in addition to, tax incentives.

Solid Coal Versus Processed Coal

If a coal substitution strategy is to be adopted, the nation must ask in what form the coal should be used--in its natural, solid state or processed into a gas or a liquid. Such a focus is essential if the federal government is to guide a transition from oil and gas to coal, and yet it is noticeably lacking in the current energy debate. Each form should be considered since each could meet the needs of a particular energy user or a particular geographic area. Solid coal might, for example, have a relative cost advantage for certain large boilers. Technical constraints, however, preclude its use for many other processes. Furthermore, in certain regions, known and suspected environmental problems might be more manageable if coal is processed into a liquid or gaseous fuel at a small number of large, remotely sited plants rather than being consumed at hundreds of individual factories. Thus, the issue of whether the nation adopts a solid coal, processed coal, or combination strategy is a critical energy policy decision. If processed coal is to play a role, however, the federal government must do more than provide cost incentives. Specifically, regulatory decisions with respect to pricing and environmental policy are needed.

CHAPTER I. INTRODUCTION

The Administration's National Energy Plan, which was submitted to the Congress in April 1977, proposed as a key objective replacing oil and natural gas with coal. It was argued that the nation should use its abundant coal resources instead of depending on unreliable and expensive oil imports or on domestic oil and natural gas reserves that soon could be depleted. Indeed, the majority of the oil import savings credited by the Administration to its plan were to be achieved through coal substitution. Although the National Energy Plan has been largely rewritten by the House and the Senate, replacing oil and gas with coal continues to be a fundamental ingredient. Replacement is to be promoted primarily by offering tax rebates and tax credits to those buying coal-burning equipment and by imposing excise taxes on those consuming oil and gas; also, the use of oil and gas will be prohibited in specific cases through regulatory programs.

This report discusses the likely impact of alternative federal policies aimed at encouraging the replacement of oil and natural gas with solid coal in the manufacturing industries. It focuses on the industrial sector because that is the most likely candidate for increased use of solid coal over the next 10 to 15 years. Few opportunities appear to be available in the residential, commercial, or transportation sectors, and the electric utility industry has already begun the transition to coal and nuclear power. Within the manufacturing sector, oil and gas consumption is most often classified according to boiler or nonboiler use, with the latter including a large number of heterogeneous uses. The present study follows this two-category division. For new boilers--for which solid coal-burning equipment is commercially available--the report analyzes the conditions under which coal would be the cheapest fuel. Firms purchasing new boilers will compare the cost of buying and operating coal, oil, and gas units, and they will choose the lowest-cost fuel if other criteria, such as reliability of fuel supply and availability of space, are satisfied. For nonboiler oil and gas uses, the analysis is more restricted. Some industries (primarily cement and lime producers) already use oil and gas as well as solid coal in their nonboiler equipment and have voluntarily begun coal substitution. For most nonboiler oil and gas uses, however, it appears that technologies for burning solid coal are not readily available; this report identifies specific processes that offer the opportunity for commercial development in the near term.

Coal can be converted into a gas or a liquid and can then be considered as a boiler or nonboiler fuel; this analysis, however, provides information only on the impact of federal policies aimed at increasing the burning of solid coal in the industrial sector. Nevertheless, a review of the costs and timing of a transition to solid coal provides insight into whether or not emphasis should be given to indirect transitions involving gasification and liquefaction or coal converted to electricity.

Chapter II offers an overview of the oil and natural gas consumption in the industrial sector. Particular attention is paid to the type of industrial process and the industry of origin because these characteristics are important in determining the potential for coal substitution. Chapter III analyzes the cost factors that enter into the selection of new boiler equipment and fuel. Since meeting air pollution regulations is a critical cost associated with the consumption of fossil fuel, the assumptions concerning future environmental regulations and cost data for air pollution control equipment are discussed in Chapter IV. The technical feasibility for coal substitution in nonboiler uses is discussed in Chapter V. Chapter VI presents estimates of industrial demand for coal for boilers if current policy were continued and specifies the sensitivity of such estimates to changes in key assumptions. Finally, the effects of alternative coal substitution policies on energy use and on the federal budget are discussed in Chapter VII. The report also contains three appendixes: the first considers the possibility that increased coal demand would be constrained by inadequate rail transportation, the second provides the theory and data for the model of boiler fuel choice used throughout the report, and the third displays impacts on the federal budget by fiscal year.

CHAPTER II. THE POTENTIAL FOR SOLID COAL SUBSTITUTION IN INDUSTRY

The manufacturing sector of the U.S. economy is the most promising target for solid coal substitution. In all other sectors, either major technical barriers to the substitution are present, or the potential for oil and gas savings is slight, or the transition to coal or nuclear fuel is already well-advanced.

Specifically, coal use in the household and transportation sectors--which represent approximately 24 and 16 percent of total U.S. energy consumption--would depend upon solid coal being converted into a liquid or a gas or into electricity. The electric utility industry, which accounts for approximately 16 percent of energy consumption, has already turned from oil and gas to coal or nuclear power because of the relative cost advantage of the latter two fuels. The agriculture, mining, and construction industries combined represent less than 8 percent of total energy consumption; thus, the potential savings from converting these sectors to direct coal use would be minimal. Moreover, there are technical barriers to coal use in these sectors. 1/ Finally, in the commercial sector, which represents 8 percent of total energy use, there is some potential for coal substitution, particularly for steam boiler use. Most of these boilers, however, are small and have relatively low utilization rates; thus, large financial incentives would be needed to stimulate coal substitution.

The major potential to replace oil and gas with solid coal is in the manufacturing sector, which represents about 29 percent of total energy demand. Even within this sector, however, the potential for solid coal use varies significantly, depending upon the specific processes involved and the capability of existing equipment to burn coal. This chapter provides an

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1/ In agriculture, most of the fuel is used to power farm vehicles such as tractors or irrigation pumps. In construction, the greatest use of oil is for asphalt to pave roads, and fuel used to power vehicles accounts for much of the remaining consumption. In mining, the data are limited, but it appears that the greatest use of energy is for extracting oil and natural gas; in this case, solid coal would have to compete with readily available and perhaps unmarketable supplies of oil and gas.

overview of energy consumption in the manufacturing sector, with reference to specific processes and equipment capabilities.

ENERGY USE IN MANUFACTURING

The manufacturing sector consumed 20 quadrillion British Thermal Units (quads) of energy in 1974. Natural gas was by far the most popular fuel, accounting for 36 percent of the total; the market shares for oil (including refinery gas) and coal were 27 percent and 18 percent, respectively. Electricity and other fuels--for example, wood processing waste--represented the remaining 19 percent (see Table 1).

In order to define the potential for substituting solid coal for oil and gas, it is critically important to specify the process in which the fuel is used. In the manufacturing sector, four broad categories of processes can be distinguished according to use:

- Production of steam in industrial boilers;
- Generation of direct heat (rather than indirect heat in the form of steam) for nonboiler equipment such as furnaces, ovens, and kilns;
- Use as a raw material; and
- Use for other purposes such as machine drive.

A recent detailed study of energy use by Energy and Environmental Analysis, Inc., found that, of the 3.6 quads of coal used in 1974 in the manufacturing sector, 65 percent was used to produce coke for the iron and steel industry (that is, as a raw material), 21 percent was used in boilers, 7 percent was used for nonboiler equipment, and the remaining 7 percent could not be traced to specific purposes. About 31 percent of the oil and natural gas consumed by manufacturers in 1974 could be traced to boilers; the remainder was used primarily in nonboiler equipment such as furnaces or as a raw material in the chemical industry (see Table 2). 2/

Tracing fuel use to specific purposes within manufacturing is a difficult task that requires many engineering judgments. Only a few studies

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2/ Energy and Environmental Analysis, Inc., Technical Potential for Coal Use in Industrial Equipment other than Boilers, prepared for the Congressional Budget Office (April 6, 1978).

TABLE 1. NET ENERGY CONSUMPTION IN THE MANUFACTURING SECTOR

Fuel	10^{15} BTUs	Percent
Coal	3.6	18
Oil a/	4.4	22
Natural Gas	7.1	36
Refinery Gas b/	1.0	5
Electricity c/	2.1	10
Other d/	1.8	9
Total	20.0	100

SOURCE: Department of Energy, Energy Consumption Data Base, 1974.

a/ Fuel oil, liquid petroleum gas, and miscellaneous petroleum products.

b/ A by-product gas generated as crude oil is processed in refineries; it is used to generate process heat and steam.

c/ Purchased electricity; these are the BTUs in delivered electricity and exclude conversion losses.

d/ Includes two large items: wood processing wastes burned as fuel in the paper industry (about 800 trillion BTUs) and fuels used at small manufacturing plants, suspected to be primarily natural gas (about 1 quadrillion BTUs).

TABLE 2. OIL AND GAS CONSUMPTION BY INDUSTRY AND TYPE OF PROCESS IN THE MANUFACTURING SECTOR, 1974: IN QUADRILLION BTUs

Industry (SIC Code)	Boiler Equipment a/	Nonboiler Equipment b/	Raw Material	Other c/	Total
Food (SIC 20)	0.40	0.10	--	0.10	0.60
Paper (SIC 26)	0.70	0.15	--	0.13	0.98
Chemicals (SIC 28)	1.10	0.50	2.30	0.30	4.20
Petroleum (SIC 29)	0.63	2.20	--	0.05	2.88
Stone, Clay, Glass (SIC 32)	0.02	0.80	--	--	0.82
Primary Metals (SIC 33)	0.30	1.10	0.10	0.20	1.70
Other Manufacturing	0.70	0.70	--	--	1.40
Total	3.85	5.55	2.40	0.78	12.58

SOURCE: Energy and Environmental Analysis, Inc., Technical Potential for Coal Use in Industrial Equipment Other than Boilers, prepared for the Congressional Budget Office (April 6, 1978).

a/ Includes fuel used for process steam and for on-site production of electricity.

b/ Includes fuel for direct heat.

c/ Includes fuels used for purposes such as machine drive.

on this subject are available, and each has its own approach and set of definitions; nevertheless, the conclusions of other studies are in general agreement with the data in Table 2. In 1975, Dow Chemical Company conducted a survey of large industrial energy consumers and found that 47 percent of the oil and gas used could be traced to boilers; the percentage is higher than that implied in Table 2 because the total excludes oil and gas used as a raw material and the definition of oil and gas appears to exclude refinery gas. 3/ If only boiler and nonboiler equipment was considered in the table, 41 percent of the total would be attributed to boilers. A recent report prepared at Drexel University found that 43 percent of all fossil fuel used in boiler and nonboiler equipment in manufacturing could be traced to boilers; this figure also excludes raw material uses of fuel and includes coal as well as oil and gas. 4/ Battelle Laboratories published a similar estimate, although it is especially difficult to compare this study with the other three. Battelle found that about 33 percent of the fuel used in boiler and nonboiler equipment could be attributed to boilers. 5/

TARGETS FOR SUBSTITUTION

The potential for oil and gas savings through coal substitution depends not only on the purpose of the fuel use but also on the capability of the existing equipment to utilize coal. Unfortunately, coal cannot be used effectively in equipment that was not designed to burn coal. This simple engineering fact implies that policies aimed at replacing oil and gas consumption with coal consumption must necessarily induce firms to replace oil and gas equipment with coal-fired equipment. This replacement of equipment can be achieved in three ways:

- Reconverting existing equipment that was originally designed to burn coal but now uses oil and gas;

3/ Dow Chemical Company, Evaluation of New Energy Sources for Process Heat, prepared for the National Science Foundation (September 1975), p. 115.

4/ Harry Brown and Bernard Hamel, Industrial Application Study, vol. II, prepared for the U.S. Energy Research and Development Administration (December 1976), p. 26.

5/ Battelle Laboratories, Survey of Applications of Solar Thermal Energy Systems to Industrial Process Heat, vol. 2, prepared for the U.S. Energy Research and Development Administration (January 1977), p. 11.

- Accelerating the retirement of oil and gas equipment;
- Purchasing new coal-fired equipment to meet expanded energy needs and replacement demand.

Conversion and Accelerated Retirement of Existing Equipment

A federal regulatory program aimed at replacing oil and gas with coal in the industrial sector already exists. The Energy Supply and Environmental Coordination Act (ESECA) of 1974 authorized the Administration to prohibit existing "major fuel-burning installations" (MFBI) from burning oil or natural gas and to order new equipment to be designed to be capable of burning coal.

The experience of ESECA prohibition orders suggests that the realistic potential for oil and gas replacement in existing units is quite small. Under ESECA, an existing unit could be prohibited from using oil or gas if, among other things, the unit had originally been designed to burn coal. A survey of MFBI conducted by the Federal Energy Administration in 1975 revealed 780 "coal-capable" units, or 12 percent of the 6,200 units covered by the survey. 6/

On May 9, 1977, the Administration took the first legal actions to order the prohibitions: "Notices of Intent to Issue Prohibition Orders" were issued to 24 sites containing 58 units. In June 1977, 28 of the original 58 units were issued actual prohibition orders. The 28 units were expected to use 2.6 million tons of coal each year in lieu of 7 million barrels of oil and 13 billion cubic feet of natural gas; the other 30 units were already using waste fuels.

The Department of Energy is now preparing a second round of orders. They first selected 305 coal-capable units that were installed after 1950 and thus might have sufficient useful life remaining to justify reconversion. 7/Of this total, 100 units located in cities that were not in violation of air pollution standards were targeted for further action. When the firms that

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6/ Federal Energy Administration, Major Fuel Burning Installation Coal Conversion Report (1975).

7/ The MFBI data contain 651 coal-capable boilers that reported oil or gas as a primary fuel; 252 were installed after 1950, and only 75 were installed after 1960.

operated the 100 units were approached, it was found that 35 of the units had already been converted to coal and others were burning coal part of the time.

It thus appears that the potential oil and gas savings from a policy aimed at converting existing coal-capable units are small. First, this category contains few units; second, many of the units will be switched to coal voluntarily in the absence of any federal legislation. The 100 targeted units in the Department of Energy's second round of prohibition orders could potentially consume about 7 million tons of coal a year. Adding this to the 2.6 million tons for units that have already received prohibition orders yields an optimistic estimate of 9.6 million tons of coal that will be consumed by existing units that convert to coal without additional government incentives.

Accelerated retirements of oil and gas units are possible; in view of the high equipment costs for coal, however, they are unlikely without a strong financial incentive. For a firm to decide to scrap an oil or gas unit with remaining useful life, it would have to be cheaper to pay the annualized costs of equipment, fuel, operation, and maintenance for a new coal-fired unit than to pay simply the costs of fuel, operation, and maintenance for the existing oil or gas unit. In addition, an accelerated retirement would be an unscheduled investment and might be precluded by a shortage of investment funds in particular firms. This topic is considered further in Chapter VII.

New Equipment

New boilers are the most promising target for policies promoting coal substitution. Coal boilers are commercially available, and the federal government can, through pricing policies, make coal the economically attractive fuel. But coal is not the only substitute for oil and gas in boilers. Boilers can burn many nonconventional fuels. For example, the most popular boiler fuel in the paper industry is a wood processing waste called "black liquor"; other industries use wood chips, old tires, wastepaper, and the like. Indeed, in the last five years, more large industrial boilers have been designed to burn nonconventional fuels than have been designed to burn coal. Oil and natural gas may be replaced as a boiler fuel, but it is likely that coal and nonconventional fuels will share the task.

Coal is not used widely for nonboiler energy consumption, and coal-fired equipment is not commercially available for many processes; the cement and lime industries are the main exceptions. Coal technologies would have to be demonstrated on a commercial scale before coal could penetrate this market.

SUMMARY

The near-term potential for replacing oil and natural gas with solid coal is restricted largely to the manufacturing sector. Within this sector, the most promising target for coal substitution is oil and gas used in boilers. This target can be set in perspective by noting that, of all U.S. oil and natural gas use, about 25 to 30 percent can be traced to manufacturing, and 30 to 40 percent of that can be traced to boiler uses. Thus, the prime target for coal substitution amounts to 8 to 12 percent of U.S. oil and gas consumption. Finally, since solid coal cannot be burned in existing boilers designed to burn only oil and gas, coal substitution must depend largely on firms purchasing new boilers. The equivalent of 1.1 million barrels a day of fossil fuels is projected to be consumed in all new boilers purchased to meet the demands of expansion and replacement for the 1981-1985 period.

CHAPTER III. THE ECONOMICS OF ALTERNATIVE BOILER FUELS

A firm will usually choose the type of fuel and boiler that produces steam at the lowest total cost to the firm. That total cost must include the annualized costs of equipment, fuel, operations, and maintenance. The least-cost criterion is, however, subject to at least two critical constraints--adequate space and availability of fuel supply. Coal requires far more land area than oil or gas because coal-fired equipment is large and because coal storage piles can cover acres of land. In older industrialized areas, the land needed for coal simply might not be available. At times, firms might not choose the least-cost operation because they believe that an alternative represents less risk of a supply interruption. Users of all major fuels have experienced short-term supply interruptions in the last few years because of coal strikes, oil embargoes, and natural gas curtailments; the possibility of such interruptions, however, varies substantially by region. Many observers believe that firms will be reluctant to use coal, even if it is the lowest-cost fuel, for reasons other than the two critical constraints. For example, coal is more difficult to handle, and it requires more laborers. In short, the use of coal gives rise to a greater number of potential problems than oil or gas. All of this points to the fact that fuel choice is affected by factors other than costs. The Administration's energy plan, however, does not attempt to--and probably cannot--remove many of the noncost factors impeding increased coal use.

This chapter treats only the cost factors that enter into a firm's decisions about which boiler equipment and fuel to choose. First, the economic model that has been used in this analysis to approximate those economic decisions is presented, noting particularly the relative cost information on which the model is based. Then, the critical assumptions that underlie the data used in the model are explained. Appendix B contains a more detailed presentation of the model, and all of the data and methods are documented fully in the cited reports.

THE ECONOMICS OF BOILER FUEL CHOICE

Industrial firms need boiler equipment to produce steam, which is used for a variety of purposes. For example, steam is used in papermills to cook a mixture of wood and a chemical that reduces wood to fiber, producing pulp. Steam drives a turbine to produce electricity in cases where

on-site electricity needs are large. In the chemical industry and in petroleum refining, steam is mixed with intermediate products to cause chemical reactions. Regardless of how the steam is used, however, a firm seeks to produce it at the lowest possible cost. The model used in this study to simulate the economic decisions of a firm is based on this simple concept: a firm will select the least-cost system. In other words, a firm will choose a coal boiler system to produce steam when the total annual cost of coal is less than the total annual cost of oil or gas.

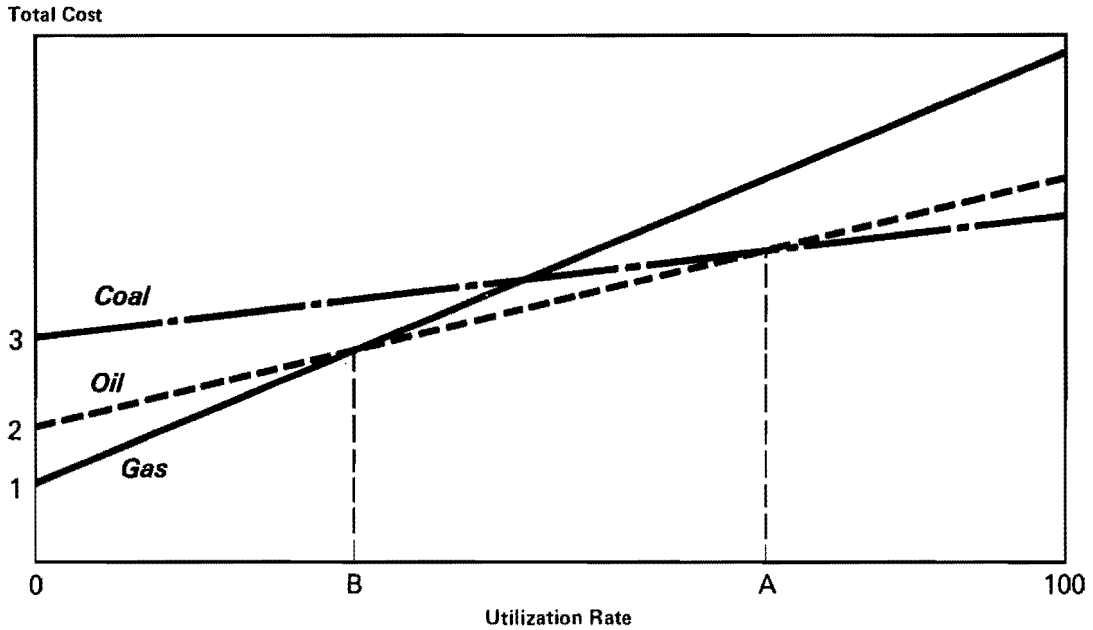
The data collected for this study show that boiler equipment for coal is always more expensive than an oil or gas unit of comparable size. Coal boilers are bigger, coal delivery and handling equipment is more extensive, and coal generally requires more pollution control equipment. Operation and maintenance costs are also higher for coal. In contrast, the fuel prices for coal are lower than those for oil or gas in some regions of the country. A firm will prefer coal if the relative fuel cost advantage of coal overcomes its relative equipment, operation, and maintenance cost disadvantage. The larger the boiler and the higher the utilization rate (the percentage of time the boiler is in operation), the greater are the chances that coal will be chosen over oil or gas.

Before a firm can decide which boiler to purchase, it must know the boiler size required, the delivered cost of alternative fuels, and the expected utilization rate. There is a direct correlation between each of these factors and cost: equipment costs vary significantly by boiler size; the price for fuels varies significantly by region of the country, largely because of transportation costs; and total fuel bills vary with utilization rates. The model developed here performs separate cost comparisons for 5 boiler sizes in 10 regions of the country. The model estimates the utilization rate at which coal starts to be the cheapest fuel for a particular size boiler in a particular region; that is, the utilization rate at which the annual fuel bill advantage of coal starts to outweigh its initial equipment cost disadvantage. Any firm choosing a fuel for that size boiler in that region will choose coal if the expected utilization rate is high enough.

The conceptual framework of the model of boiler fuel choice can be illustrated using Figure 1. Costs of producing steam for a boiler of a certain size are represented on the vertical axis; utilization rates are shown on the horizontal axis. A coal-fired boiler costs more than an oil-fired boiler, which in turn costs more than a boiler designed for natural gas; thus, points 3, 2, and 1 represent different costs at a zero utilization rate. As the utilization rate increases, total cost increases because the costs of fuel, operation, and maintenance are added.

Figure 1.

Boiler Costs By Fuel and Utilization Rate For Region X and Boiler Size Y



In Figure 1, coal becomes cheaper than both oil and gas at utilization rate A; that is, coal will be used in region X for new boilers of size Y that are expected to be used A percent of the time or more. Oil becomes cheaper than gas at utilization rate B; thus, oil will be used for new boilers with expected utilization rates between B and A. Gas will be used in all other new boilers. A computer program was developed to calculate these "breakpoint" utilization rates. 1/

1/ The model compares average annual costs (annuities). The initial investment is annualized by applying a capital charge rate to equipment costs; that rate is similar to a mortgage rate which translates a home loan into required annual payments the homeowner must make. Annual fuel costs are represented as annuities. An 8 percent after-tax, real rate of return is assumed for discounting.

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In order to make the type of cost comparison illustrated by Figure 1, one needs to know the cost of the boiler equipment, the annual cost of operation and maintenance, and the annual cost of fuel. For this analysis, equipment cost data were collected from equipment manufacturers and were then compared with similar data presented in published technical reports (see Table 3). According to these data, coal equipment is generally three times as expensive as equipment for low-sulfur oil and four or five times as expensive as equipment for natural gas. The equipment cost disadvantage of coal relative to low-sulfur oil ranges from $3.2 million to $16.7 million. This disadvantage must be offset by a fuel bill advantage over the life of the boiler if coal is to be chosen.

TABLE 3. BOILER EQUIPMENT COSTS BY FUEL TYPE AND BOILER SIZE: IN THOUSANDS OF 1977 DOLLARS a/

	Boiler Size (MPPH) b/				
Fuel Type	50	100	200	300	400
Coal					
Northern Appalachian	4,855	8,105	14,238	19,508	24,421
Central Appalachian	4,696	7,827	13,796	18,912	23,676
Midwestern	4,862	8,120	14,296	19,592	24,523
Western	4,834	8,073	14,218	19,484	24,400
Oil					
High-sulfur	2,530	4,164	6,966	9,665	12,126
Low-sulfur	1,655	2,668	4,421	6,179	7,780
Natural Gas	1,233	1,882	2,942	4,020	4,964

SOURCE: The data were collected from equipment manufacturers and technical publications and are documented completely in ICF, Inc., Economic Considerations in Industrial Boiler Fuel Choice, submitted to the Congressional Budget Office (June 1978).

a/ Includes costs of equipment, planning and design, and installation for a complete boiler system--from fuel handling through waste disposal.

b/ Thousands of pounds of steam per hour.

The equipment costs presented in Table 3 are for a complete boiler system, from fuel delivery through waste disposal. The detailed costs for a boiler that produces 200,000 pounds of steam per hour (MPPH) using high-sulfur Midwestern coal can serve as an example of the relative importance of the various equipment components (see Table 4). The boiler itself represents 38 percent of the initial direct investment. Air pollution equipment equals 33 percent of the direct costs. Fuel handling facilities, which are required for rail delivery, and coal storage represent 8 percent of direct equipment costs. The expense of constructing the boiler (indirect costs) is also substantial. In this example, total indirect costs are $3.7 million and direct costs are $10.5 million.

The annual operation and maintenance costs employed in this analysis were estimated using standard engineering methods. Those estimates, however, were based on several assumptions that are detailed in the ICF report. 2/ Fuel costs were projected using two models: coal prices from ICF's Coal and Electric Utilities Model, and oil prices from a model developed by Sobotka and Company. 3/

CRITICAL ASSUMPTIONS

A number of assumptions are made throughout this analysis, but the final results are most sensitive to two sets of assumptions: those regarding the relative prices of the three major fuels--oil, natural gas, and coal; and those regarding the requirements for air pollution control equipment. These assumptions are discussed below.

Coal Prices. The most significant and obvious difference between prices for coal and prices for oil or gas is that coal prices are not regulated by the federal government. Coal prices are determined directly by the forces of supply and demand. Also the price of coal to electric utilities can differ significantly from the price to industries. First, coal is generally sold to utilities, which are the largest coal customers, on long-term contracts that specify the price per ton to be paid throughout the contract period. It

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2/ ICF, Inc., Economic Considerations in Industrial Boiler Fuel Choice, submitted to the Congressional Budget Office (June 1978).

3/ Ibid.; and Sobotka and Co., Refinery Gate Product Price Differential Forecasts for 1985, submitted to the Department of Energy (1978).

TABLE 4. DETAILED EQUIPMENT COSTS FOR A COAL BOILER PRODUCING 200 MPPH USING HIGH-SULPHUR MIDWESTERN COAL: IN THOUSANDS OF 1977 DOLLARS

Equipment Components	Steam Plant	Air Pollution Control
Land and Permits	135	8
Yard Work	460	35
Fuel Handling and Storage	825	
Boiler House	695	
Boiler Equipment	4,000	
Ash Handling Equipment	550	
SO_2 Control Equipment		2,755
Particulate Control Equipment		685
Electric Power	395	
Total, Direct Costs	7,060	3,483
Construction Management and Facilities	706	348
Engineering and Design	353	174
Contingency	1,218	401
Working Capital	97	131
Fuel Stockpile	325	
Total, Indirect Costs	2,699	1,054
Total, Capital Costs	9,759	4,537

SOURCE: ICF, Inc., Economic Considerations in Industrial Boiler Fuel Choice.

is not clear whether long-term contracts of this type would be offered to industrial users or would be desired by them. In this analysis it is assumed that industrial users will not enter into long contracts, but will buy coal annually on the "spot market" or on short-term contracts. Spot market prices will generally be higher over the years than prices for coal on long-term contracts. Although long-term contracts would offer a price advantage, they would carry the disadvantage of a long-term financial commitment. Second, utilities often take advantage of the low railroad rates offered for "unit trains"--100-car trains that shuttle between the coal mine and the utility--whereas industries are not expected to require enough coal to use unit trains. Unit train rates are about one-half those for single-car deliveries.

Spot market coal prices are expected to rise over time for two reasons. First, general inflation will drive labor and equipment costs upward. Second, as more coal is used, mining companies will have to open mines in locations where coal is more difficult to extract and therefore more costly to mine. In states such as Colorado and Utah, for example, coal prices for new mines are expected to rise about 1 percent a year (in real terms) because coal will be increasingly more expensive to mine. 4/

Coal prices could, of course, increase at a faster pace than assumed. Wage demands, rising state severance taxes, and higher rail rates are frequently cited as possible reasons for projecting more rapid escalation of coal prices. For example, the 1978 United Mine Workers' settlement could result in a 1 to 2 percent increase in real coal prices at the minesite in each

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4/ Spot prices are assumed to equal the first-year cost of opening a new mine or enlarging an existing mine; that is, spot prices are assumed to equal the marginal cost of producing coal in each region. Spot prices could be higher than contract rates for several reasons. First, the utility signing the contract absorbs the downside risk of opening a mine; that is, the utility will pay for the coal whether it is needed or not. Second, the costs of operating a mine for the spot market can be higher because of variable output; start-up costs are incurred more frequently and problems with cash flow result in a greater number of loans. Third, mine owners might demand a greater rate of return for a spot mine because of the risks involved. Finally, a contract can be viewed as a show of the market strength of the buyer; in a monopsony situation, one buyer can control the market and force producers to accept lower prices (that is, producer surplus can be denied).

of the next three years. It is uncertain whether future wage settlements will be comparable and, more important, whether labor productivity will resume its upward trend and offset any wage pressure on prices. Labor productivity has fallen dramatically since 1969, in part because of federal legislation regarding health and safety in mines and new union work rules. The estimates used in this analysis for current policy implicitly assume that real wage increases are offset by increased productivity; the effect of this assumption is illustrated in Chapter VI.

Oil Prices. The principal petroleum product used in boilers is residual oil, which is made from crude oil at petroleum refineries. Since crude oil accounts for more than 90 percent of the value of residual oil, the price of residual oil is largely determined by the price of crude oil.

The average price of crude oil to U.S. refineries is affected by the relative amounts of imported and domestic crude they use and the prices of each. Imported crude, which currently accounts for about 45 percent of U.S. supply, sells at the going world rate. The price of domestic crude, however, is held below the world price by federal regulation. Those regulations are scheduled to expire by 1981, but it is assumed in this analysis that they would be extended and that the average domestic price will be allowed to rise by 10 percent each year until the world price is reached.

A key assumption underlying the estimates of residual oil prices used in this paper is that the world price of crude oil--the price set by the Organization of Petroleum Exporting Countries (OPEC)--will increase only at the general rate of U.S. inflation. If inflation persists at about 5 or 6 percent, the price for domestic crude under current policy will equal the world price in 1985. 5/ It is assumed that all crude will be sold at the world price from that point on.

There is little analytical basis for projecting the policies of OPEC since the cartel members will face conflicting political and economic pressures when they decide future price policy. The uncertainty is something with which both business and federal policymakers must contend. Chapter VI demonstrates the sensitivity of coal demand to alternative assumptions about oil prices.

5/ The alternative of equaling world prices sooner would not significantly affect investment decisions. This is because the investor views fuel bills over a 30-year period, and slightly lower prices in the first few years is inconsequential.

Natural Gas Prices. Currently, natural gas is sold in two distinct markets: the interstate market, in which prices are controlled by the Federal Energy Regulatory Commission; and the intrastate market, in which prices are not regulated. The price for natural gas used in this report for current policy is based on the assumption that the dual market is allowed to continue.

Under current regulations, distributors of interstate gas pay different prices for gas from different sources. Higher prices are generally allowed for newly discovered gas, gas imports, and synthetic gas. Industrial users face an average of these prices. That average increases over time as more and more gas becomes eligible for higher price levels. In the intrastate market, demand and supply determine how prices will change.

Under current policy, it is assumed that natural gas will be available for new boilers at prices that will be allowed to rise only to the equivalent price of distillate oil, the closest competitor to gas. The point at which gas prices reach the "distillate equivalent" price varies by region, but in general it occurs around 1990. Prices are assumed to be constant in real terms thereafter.

When alternative tax policies for boilers are analyzed in Chapter VII, it will be assumed that prices for new natural gas will be deregulated according to a recent agreement between House and Senate conferees. Under that agreement, prices for new gas are allowed to increase gradually each year until 1985. Under incremental pricing provisions, industries bear the burden of new, high-cost gas if they are served by interstate pipelines. After 1985, gas prices are assumed to rise beyond world oil prices; this "bonus" reflects the lower costs for equipment, operation, and maintenance associated with gas used in both boiler and nonboiler industrial uses, as well as in nonindustrial uses. The bonus is assumed to average $0.50 per million BTUs (MMBTU). 6/

Air Pollution Control Requirements. Many assumptions underlie the estimates of relative equipment costs, and they are discussed thoroughly in this report and its supporting documents. The most important of these assumptions, however, are those regarding air pollution control regulations, which are explained in detail in Chapter IV. The assumed requirements

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6/ That is, the financial average (the annuity) of natural gas is assumed to be $0.50 above that for distillate oil.

reflect a strict interpretation of the 1977 amendments to the Clean Air Act; requirements must be assumed because actual regulations for industry have not yet been promulgated. Of particular importance is the implicit assumption that the standards will be equally strict on coal and oil. As will be demonstrated later, it is the relative strictness that determines the impact of air pollution regulations on fuel choice. 7/

7/ Other important assumptions are as follows: (1) Equipment costs rise at the general rate of inflation throughout the years covered by the analysis. (2) In line with general industry practice, all coal boilers are erected at the factory site, whereas all oil and gas boilers are built and then shipped to the site (so-called "packaged" boilers). Erection at the site increases the cost of coal relative to other fuels because site construction costs are usually high. (3) Most boiler equipment has a 30-year life. Pollution control equipment, however, and all packaged boilers were assumed to have only a 15-year life. This assumption was made after consultation with equipment manufacturers.

CHAPTER IV. ENVIRONMENTAL REGULATIONS AFFECTING INDUSTRIAL ENERGY USE

The production and use of coal cause numerous environmental problems. Strip mining scars acres of land, underground mining poses serious threats to the health and safety of workers, drainage from strip and underground mines pollutes rivers and streams, and burning of coal by utilities and industries emits tons of air pollutants and solid waste. Any attempt to control the environmental effects of coal production and use increases the cost of using coal. For example, the land reclamation that is required for strip mines can add from $0.50 to $5 to the price of a ton of coal, depending on the geographic region. This chapter examines the regulations designed to control the air pollution and solid waste associated with coal burning; it then presents estimates of the investment required to control air pollution and solid waste associated with turning the industrial sector to coal.

The chapter focuses only on the current generation of environmental regulations. New, stricter regulations may be set in future years as scientists learn more about the causes and effects of pollution. For example, additional sulfur controls could be required because some scientists believe that the real problem with the sulfur in fuels is not the sulfur dioxide (SO_2) that it helps to generate, but other forms of sulfur such as sulfates and sulfites. The expectation of more stringent environmental regulations could be a disincentive to increased coal use. Unless a firm knows which regulations will apply, it does not know the true cost of coal use and therefore cannot determine if coal is the economically attractive fuel.

AIR POLLUTION AND ENERGY CONSUMPTION

Under the Clean Air Act of 1970, the Environmental Protection Agency (EPA) established ambient air quality standards for six air pollutants. The combustion of coal, oil, and other fuels is a significant source of three of these emissions--sulfur dioxides (SO_2), nitrogen oxides (NO_x), and particulates (ash, soot, and so forth). The act instructed each state to develop a State Implementation Plan, showing how the standards would be met. Primary standards--those needed to protect human health--were to

be met by 1975 or, if extensions were granted, by 1977. These deadlines were not met in many areas. More stringent secondary standards--those relating to nonhealth effects such as crop losses--were to be met later, but within a "reasonable time."

The primary standards impose limits on the emission of SO_2, NO_x, and particulates from stationary sources such as electric utilities and factories; these limits are in addition to those imposed on mobile sources such as cars and on "fugitive" sources such as unpaved roads. 1/ Annual, daily, or hourly emission limits are set for both new and existing sources. Federal regulations dictate emission limits for all new facilities, so that limits for new pollutors are generally uniform nationwide. In contrast, limits on existing sources are set by states, and they vary by region according to the severity of the air quality problem; the more severe the problem is, the stricter the limits are.

In all cases, the emission limits imply the use of some type of pollution control equipment or some change in the operation of the facility. For SO_2 control, a costly and controversial item called a "scrubber" (a device to remove sulfur from flue gas) can be used. 2/ Alternatively, low-sulfur coal or oil can be burned. Two other methods, which are no longer allowed under the 1977 amendments to the Clean Air Act, are to curtail production on poor air quality days or to use tall stacks to disperse pollutants and thereby reduce their concentration at ground level. For NO_x, the primary control procedure is to regulate combustion temperatures properly and to alter boiler design; further control would require NO_x scrubbers. Particulate control can involve three alternative pieces of

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1/ According to a preliminary EPA estimate, fuel combustion at stationary sources accounted for 37, 80, and 51 percent of particulate, SO_2, and NO_x emissions nationwide in 1975. Industrial processes are the other large source of particulates, accounting for 48 percent (fugitive sources are not included). Transportation accounts for another 44 percent of NO_x emissions. See Federal Energy Administration, Air Pollution Impacts of the Oil and Gas Replacement Program in the Utility and Industrial Sectors (June 20, 1977).

2/ Scrubbers spray a liquid into the exhaust gases that flow up the smoke stack after coal or oil is burned. That liquid reacts with the sulfur in the "flue gas" and prevents their emission into the air. The by-products of this scrubbing process, often a mucky substance called sludge, present a major solid waste disposal problem.

equipment--electrostatic precipitators (ESP), baghouses, or mechanical dust collectors. 3/

All these controls, whether in the form of equipment or procedures, represent an environmental constraint to increased coal consumption only in the sense that they increase the cost of using coal. This "direct" cost effect of environmental regulations is relatively easy to assess. But the costs of using fossil fuels can be increased indirectly through another environmental policy--EPA's emission offset regulations.

The Emissions Offset Policy

Following passage of the 1970 act, a controversy arose over the apparent conflict between the environmental standard of the act and the need for new factories and power plants in "dirty air" areas. Under regulations generated by the act, states could not give their preconstruction review approval to a new or modified air pollution source if that source would "interfere with" the attainment or maintenance of air quality standards. It was dramatically argued by opponents that this policy would limit economic growth in some of the nation's most populated (and most polluted) areas.

In response to these concerns about growth, EPA developed its emissions offset policy, which states that a major new source of air pollution can locate in an area that does not meet the air quality standards (a nonattainment area) only if its emissions will be controlled to the greatest degree possible and, more significantly, only if "more than equivalent offsetting emission reductions (emission offsets) will be obtained from existing sources." Emission offsets must be of the same type; that is, SO_2 can only be traded for SO_2, NO_x for NO_x, particulate for particulate. Furthermore, credit can only be given "for emission reductions from existing sources which would not otherwise be accomplished as a result of the Clean Air Act." In other words, acceptable emission offsets from an existing source are possible only after that source complies with the State Implementation Plan. Trade-off emissions are thus very difficult to find. The Congress has now endorsed this policy with the Clean Air Act Amendments of 1977.

3/ An electrostatic precipitator imparts an electrical charge to particles in the flue gas which allows them to be gathered mechanically. A baghouse traps particulates by filtering flue gas through large fabric bags.

The emissions offset policy also increases the cost of using certain fuels. The costs will be those incurred by the new source as it "buys" emission offsets from existing plants; generally, this will entail the costs of pollution control equipment such as scrubbers for existing sources for which that equipment would not be required. If emissions are scarce, however, their "price" will be bid upward and will therefore include a bonus for the seller.

ASSUMED AIR POLLUTION REGULATIONS

Determining the implications of the array of federal environmental laws for an individual industrial installation is not an easy task. It is important to analyze those implications, however, because the impact of policies promoting the use of coal cannot be determined until the cost of using coal relative to that of using other fuels is known, and that cost must include pollution control equipment.

The pollution control equipment required for new boiler systems will be determined through an analysis of the interaction of three federal environmental policies--New Source Performance Standards (NSPS), regulations to prevent significant deterioration, and nonattainment policies.

Current NSPS set emission limits for "major facilities"--that is, for new boilers that have a capacity to consume at least 250 million BTUs of fuel per hour. The EPA may lower this threshold to whatever level it deems necessary. The Clean Air Act Amendments of 1977 require that new NSPS be set so as to require the "best system of continuous emission reduction." The new NSPS, which have not yet been established for industry, will not only set emission limits but will also require a certain percentage reduction in emissions. This percentage reduction can be accomplished by cleaning fuels before, during, or after combustion; the reduction cannot be accomplished merely by using untreated low-sulfur fuel, although low-sulfur oil, some of which occurs naturally, will probably be allowed.

In areas of the country where ambient air quality standards have been met, the goal of environmental regulations is to "prevent significant deterioration" (PSD) of air quality. In these PSD areas, new major facilities are required to use the "best available control technology," which will be determined on a case-by-case basis. For these areas, major facilities are defined as those with a capacity of more than 250 million BTUs per hour and those with a smaller capacity than this but with the potential to emit 250

tons of a pollutant annually. 4/ As with the NSPS, naturally occurring low-sulfur fuel does not satisfy the control requirements.

In areas that have not attained ambient air quality standards, new major sources are required to achieve the "lowest achievable emission rate" in addition to finding emissions offsets. Major sources in nonattainment areas are those with the potential to emit 100 tons of a pollutant annually.

Until regulations are set and interpreted by the courts, any statements on air pollution control requirements are speculative; in this analysis, strict requirements are assumed. The first important assumption is that all three federal policies will ultimately imply the same emission limits. The following specific emission limits are assumed for major facilities:

- For coal boilers, the standard will allow no more than 1.2 pounds of SO_2 to be emitted per million BTUs burned. For oil boilers, the limit will be 0.8 pounds. These limits are the same as the current NSPS. In addition, an 80 percent reduction in emissions will be required as long as emissions are above 0.4 pounds per million BTUs. That is, no matter what the beginning emissions, they must be reduced by 80 percent until the 0.4 pound floor is reached.

- For both coal and oil, standards will allow no more than 0.03 pounds of particulates to be emitted per million BTUs burned. This standard is less than one-third of the current NSPS of 0.1 pounds.

These standards will imply different pollution control equipment for different fuels in different size boilers. In the preceeding chapter, the costs of "representative" coal, oil, and gas boilers systems were compared. Those costs included the expense of pollution control equipment. The remaining section of this chapter presents the detailed costs to meet the assumed standards described above.

POLLUTION CONTROL EQUIPMENT FOR REPRESENTATIVE BOILER SYSTEMS

Two factors are key to determining what pollution control equipment is required for new boiler systems: the size of the boiler and the sulfur and

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4/ The definition is actually more complex. Twenty-eight specific types of factories emitting only 100 tons are also considered major. For other factories, the standard is 250 tons a year. Many of the new boilers will be in one of the 28 types of factories and could therefore have to abide by the 100-ton threshold.

ash content of fuels. If a boiler is large enough to consume at least 250 million BTUs per hour, it must meet the assumed NSPS. In this analysis it is assumed that for coal boilers a scrubber will be used to meet the SO_2 limit and a baghouse will be used to meet the particulate limit. For oil, there are two alternatives to satisfy the SO_2 standard--using a very high-sulfur oil plus a scrubber or using an oil that is desulfurized at the refinery. The scrubber used with high-sulfur oil is assumed to achieve the moderate particulate removal required for oil, but particulate control equipment is required with low-sulfur oil.

For boilers smaller than 250 million BTUs per hour, the method of estimating equipment requirements is more complex since equipment needs vary by chemical composition of the fuel. Tables 5 and 6 display the sulfur

TABLE 5. UNCONTROLLED SO_2 EMISSION RATES BY FUEL TYPE

Fuel Type	Sulfur Content (percent)	BTU Content	Pounds SO_2 (per million BTUs)
Coal			
Northern Appalachian	2.5	12,000/lb.	4.17
Central Appalachian	0.7	12,000/lb.	1.17
Midwestern	3.3	11,000/lb.	6.00
Western	0.5	8,500/lb.	1.18
Residual Oil			
High-sulfur	3.0	150,560/gal.	3.14
Low-sulfur	0.3	146,430/gal.	0.31
Natural Gas	--	1,027/cu.ft.	0.0006

SOURCE: ICF, Inc., Economic Considerations in Industrial Boiler Fuel Choice, submitted to the Congressional Budget Office (June 1978).

TABLE 6. UNCONTROLLED PARTICULATE (TSP) EMISSION RATES BY FUEL TYPE

Fuel Type	BTU Content	Ash Content (percent)	TSP Emission Rate	Pounds TSP (per million BTUs)
Coal				
Northern Appalachian	12,000/lb.	14.0	13 lb/ton/% ash	7.58
Central Appalachian	12,000/lb.	12.0	13 lb/ton/% ash	6.50
Midwestern	11,000/lb.	11.0	13 lb/ton/% ash	6.50
Western	8,500/lb.	9.0	13 lb/ton/% ash	6.88
Residual Oil				
High-sulfur	150,560/gal.	—	8 lb/10^3 gal.	0.053
Low-sulfur	146,430/gal.	—	8 lb/10^3 gal.	0.055
Natural Gas	1,027/cu.ft.	—	5-15 lb/10^6	0.005-0.015

SOURCE: ICF., Inc., Economic Considerations in Industrial Boiler Fuel Choice.

and ash contents of the seven fuels used in this analysis and an estimate of the amount (pounds) of pollutant that would be emitted by each million BTUs of fuel burned if no control equipment was used. For example, 4.17 pounds of SO_2 would be emitted for each million BTUs of Northern Appalachian coal burned without pollution control equipment. Using such factors, it can be determined whether a particular size boiler, using a particular fuel, would be forced to abide by the PSD policy because it could emit 250 tons of pollutant annually, or would have to abide by nonattainment policies because it could potentially emit 100 tons a year.

It is clear from these tables that, with respect to both SO_2 and particulates, all the representative coal-fired boilers qualify as major facilities under at least one of the federal policies. Even a boiler as small as 50 million BTUs per hour using low-sulfur Western coal could emit more

than 250 tons of both sulfur dioxide and particulates annually. 5/ To meet the emission limits listed above, it is assumed that a scrubber using a water/limestone spray will be used to control SO_2 and that baghouses will be used to control particulate emissions. 6/

It is also clear that systems using high-sulfur oil would be required to use scrubbers, and that systems using low-sulfur oil and natural gas would not. The policy implications are not as clear, however, for particulate control with oil. As specified by the assumed New Source Performance Standards, oil-fired boilers larger than 250 million BTUs per hour will have to meet the assumed limit of 0.03 pounds per million BTUs and would therefore have to use some control equipment. But smaller boilers do not have the potential to emit 250 tons (or even 100 tons) of particulates and therefore would not be considered major facilities. The implication is that no particulate control would be required by federal regulations for oil boilers smaller than 250 million BTUs per hour. This would result in a loophole, however. Small coal-fired boilers would be reducing particulate emissions to 0.03 pounds per million BTUs, while small oil-fired boilers would be allowed to leave their emissions uncontrolled at 0.055 pounds per million BTUs. It is assumed that this loophole would not be allowed to persist and that small oil-fired boilers would be asked to reduce particulate emissions by about 50 percent.

(Because they have the potential to emit over 100 tons of SO_2, all coal-fired boilers and most oil-fired units would, in addition to controlling their own emissions, have to find emission offsets from existing sources if located in a nonattainment area for SO_2. Coal-fired systems would also have to seek particulate offsets. This report, however, does not predict the number of units that will have to abide by the offset policy.)

Examples of the equipment cost of the required pollution control effort for each representative boiler system are presented in Table 7. A complete set of these estimates is used in the analysis of boiler economics in Chapters VI and VII. For the larger boiler shown in Table 7, pollution

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5/ The calculation for SO_2 is as follows: 50 MMBTU/HR x 24 HRS x 365 days x 1.18 lbs. SO_2 per MMBTU = 258 tons of SO_2 per year.

6/ One exception should be noted. Boilers using Central Appalachian or Western coal will only have to reduce their emissions by 60 percent since this will bring them to the floor of 0.4 pounds. For this reason, these boilers can use smaller scrubbers, and the costs of the equipment will therefore be lower.

control equipment costs up to $6.3 million and would increase the cost of that size coal boiler system by up to 48 percent. For the smaller boiler, control equipment costs can reach $2.6 million and would increase coal system costs by up to 46 percent.

TABLE 7. REPRESENTATIVE AIR POLLUTION CONTROL EQUIPMENT COSTS BY FUEL TYPE: IN THOUSANDS OF 1977 DOLLARS a/

	Boiler Size b/	
Fuel Type	100 MPPH	300 MPPH
Coal		
Northern Appalachian	2,568	6,314
Central Appalachian	2,245	5,539
Midwestern	2,575	6,333
Western	2,246	5,541
Residual Oil		
High-sulfur	1,794	4,302
Low-sulfur	238	637
Natural Gas	--	--

a/ Equipment, planning and design, and installation costs are included.

b/ MPPH = thousands of pounds of steam per hour.

For high-sulfur oil, equipment costs can be increased by up to 80 percent and, for low-sulfur oil, by up to 12 percent. But equipment requirements are not the only way low-sulfur oil system costs are increased. Low-sulfur oil costs about $3.00 per barrel more than high-sulfur oil; this premium reflects the additional desulfurization costs at the refinery or the price premium attributed to naturally occurring low-sulfur crude oil.

32-498 O - 78 - 4

Air pollution regulations also increase operation and maintenance costs (see Table 8). For the high-sulfur coal costs, variable operation and maintenance costs can be increased by up to 13 times, and fixed costs can be increased by up to 45 percent. For high-sulfur oil, variable costs are increased up to 13 times, and fixed costs increased by up to 40 percent.

The strict environmental regulations described here are assumed to be imposed on new boilers starting construction in 1979 or thereafter; these boilers will be coming on line beginning in 1981. This timing coincides with the assumed enactment of the oil and gas user taxes detailed in Chapter VII. Before then, existing regulations are assumed to prevail. These regulations are assumed to require the use of low-sulfur coal (Western or Central Appalachian) plus a baghouse in all boilers larger than 250 million BTUs per hour; oil boilers of this size are assumed to use 0.7 percent sulfur oil. No control is assumed for smaller industrial boilers.

In summary, strict regulations are assumed to be imposed as a result of the Clean Air Act Amendments of 1977. The actual requirements for industry have not yet been set, and different legal interpretations could result in the same or in different equipment needs. The most likely point for differences is in regulations for small boilers. Both Chapter VI and Chapter VII discuss the impact of alternative regulations on coal demand.

TABLE 8. REPRESENTATIVE OPERATION AND MAINTENANCE COSTS FOR AIR POLLUTION CONTROL BY FUEL TYPE: IN THOUSANDS OF 1977 DOLLARS

	Boiler Size a/			
	100 MPPH		300 MPPH	
Fuel Type	Fixed	Variable b/	Fixed	Variable b/
Coal				
Northern Appalachian	132	458	303	1,314
Central Appalachian	111	293	247	826
Midwestern	137	522	314	1,500
Western	111	302	248	851
Residual Oil				
High-sulfur	84	255	193	750
Low-sulfur	8	28	18	74
Natural Gas	--	--	--	--

a/ MPPH = Thousands of pounds of steam per hour.

b/ Assumes a 100 percent utilization.

CHAPTER V. THE POTENTIAL FOR NONBOILER SOLID COAL SUBSTITUTION

Large amounts of oil and gas are used in industrial equipment other than boilers and as raw material in the petrochemical industry. Indeed, these uses of oil and gas provide the largest target for coal substitution policies--about eight quads of oil and gas were consumed in nonboiler uses in 1974 as compared with four quads consumed in boilers. Since coal is not widely used in the United States for nonboiler purposes, however, the technical feasibility of using solid coal has not generally been demonstrated. This chapter identifies some industrial nonboiler processes in which solid coal might be used once coal-firing equipment is adequately demonstrated on a commercial scale. Unfortunately, since coal equipment is not marketed for most nonboiler needs, no reasonable cost data are available for cost comparisons.

More than 80 percent of the oil and gas consumed in nonboiler applications in the manufacturing sector can be traced to four industries: chemicals, petroleum refining, primary metals, and stone, clay, and glass. The decision about whether the use of solid coal is technically feasible in a specific industry is a matter of engineering judgment. Few scientists focused on this topic in the 1960s, and thus only a handful of studies are available. In 1974, a select group of industry representatives were urgently called together to formulate the blueprint for Project Independence; they were asked about the potential for substituting coal for oil. 1/ The panel cited the significant potential of using coal in boilers, but they were pessimistic about other potential uses. More importantly, the panel stated: "The obstinate environmental, logistic, lead-time, and economic demands associated with coal as a solid fuel are a strong inducement for a commitment, instead, to a liquid or gaseous derivative." They recommended support of a national coal gasification and liquefaction program.

The Institute of Gas Technology (IGT) recently analyzed industrial candidates for solid coal use in nonboiler equipment. 2/ After screening a

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1/ Science Communication, Inc., Intra Industry Capability to Substitute Coal, prepared for Federal Energy Administration (October 1974).

2/ Institute of Gas Technology, Assessment Application for Direct Coal Combustion, prepared for the National Science Foundation (February 1977).

large number of processes, they identified a few targets for immediate conversion in two industries--stone, clay, and glass and primary metals. 3/ IGT concluded that complete conversion of the existing equipment could save 899 trillion BTUs a year using available equipment and technology. They noted, however, that problems with equipment damage would have to be overcome.

A more complete engineering study recently submitted to the Congressional Budget Office classifies a large number of nonboiler uses according to the risk of failure entailed in developing coal-burning technologies and equipment. The four classes are:

- Proven: Coal is currently used for the industrial process in the United States.
- Low risk: No insurmountable technical obstacles are foreseen, but the coal-burning equipment must be built and demonstrated in the United States before it can be considered commercially available.
- High risk: Coal-burning equipment may be developed, but there is a greater risk of failing to develop reliable and safe systems.
- Not feasible: Without breakthroughs in material or design, coal probably cannot be burned.

The results of this technical feasibility study are summarized in Table 9. The major problems with coal burning are the lack of temperature control, potential equipment damage, and possible product contamination. The temperature and distribution of heat cannot always be controlled because the heat or energy content of the coal being fed to the equipment is not constant. Equipment damage is a problem because of the many chemicals found in most coal; those chemicals can also contaminate the product in situations where the product comes into direct contact with the coal flame. The problem with replacing oil and gas that are used as raw materials is the chemical state of coal.

3/ The processes included: cement and lime calcining where coal is already used; glass melting; iron ore benefication; blast furnace and open hearth operations; soaking pits; copper smelting; and structural clay products.

TABLE 9. TECHNICAL FEASIBILITY OF COAL USE IN NONBOILER APPLICATIONS

Industry	1974 Nonboiler Oil and Gas Consumption (quadrillion BTUs)	Coal Feasibility (percent of 1974 nonboiler oil and gas consumption)				
		Proven	Low risk	High risk	Not feasible	Not studied
Petroleum Refining a/	1.81	--	50	29	9	13
Steel b/	0.64	18	25	6	—	51
Aluminum c/	0.17	--	33	—	47	20
Stone, Clay, Glass d/	0.80	58	—	33	—	9
Ammonia e/	0.59	--	100	—	--	—
Ethylene f/	0.99	--	--	—	100	--
All Others	2.92	—	—	--	--	100
Total	7.92	7	21	10	16	45

SOURCE: EEA, Inc., Technical Potential for Coal Use in Industrial Equipment Other than Boilers, prepared for the Congressional Budget Office (April 6, 1978).

a/ Low-risk processes include atmospheric crude distillation, catalytic reforming, alkylation; high-risk processes include hydrocracking, hydrotreating, vacum distillation, hydrorefining, and hydrogen manufacture.

b/ Proven processes include injection of supplemental fuel into blast furnaces and as a fuel in open hearth steel making (although it should be noted that open hearth processes are being replaced by other steel-making techniques); the reheat furnace is the low-risk process.

c/ Low-risk processes are melting, holding, and casting; processes classed as not feasible, include calcination and fabrication (because of possible product contamination).

d/ Coal use for cement, lime, and brick production processes is proven; glass industry use is high risk (equipment damage and product contamination are the key problems).

e/ Considered low risk because a process that uses coal for both feedstock and fuel is currently used overseas; the process begins with coal gasification. ERDA and W.R. Grace and Company are conducting a joint experiment with the process in the United States.

f/ Process is considered not feasible because precise temperature control is required.

The varying potential for coal use in nonboiler applications is revealed by an examination of three industries: stone, clay, and glass; petroleum refining; and chemicals. Within the stone, clay, and glass industry, coal is already used in the production of cement and lime, and the cement industry is rapidly and voluntarily converting to coal. Industry representatives estimate that 90 percent of the industry will be capable of burning coal as well as oil or gas by 1980; this dual-firing capability will enable them to respond quickly to fluctuations in fuel prices. 4/ The widespread conversion is attributed to two unusual circumstances: little additional equipment is required for coal use; and the production process itself controls the sulfur pollutant by capturing the pollutant in the cement. In glass production, the product comes into direct contact with the coal flame, and there is a chance of product contamination. Recent successful demonstrations, however, make this a likely target for coal use in the future. 5/

Within the petroleum refining industry, oil and gas are used for process heat in tubestill heaters and furnaces. The use of solid coal is judged to be technically low risk for new process equipment, which accounts for 50 percent of oil and gas process uses, including atmospheric crude distillations, catalytic reforming, and alkylation. While new catalytic reforming units may be low risk in terms of technical feasibility, industry sources indicate that the economic cost of any equipment failure by this process is so great that its reliability with coal firing would have to be exhaustively demonstrated before any serious consideration of direct coal firing. Another 30 percent of current process heat uses are considered high risk for new equipment. Retrofit of existing processes is not feasible. Furthermore, much of the gas used in nonboiler equipment is "internally generated refinery off gas"--gases emitted and recaptured as crude oil is processed--and it will be difficult to force refiners to import coal and sell these gases elsewhere.

Within the chemical industry, petrochemical ethylene is a building block for many products, including the packaging material polyethylene and synthetic fibers. Currently, natural gas liquids are the primary raw material

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4/ Portland Cement Association, "U.S. Cement Industry: Fuel Conversion Report," June 1975.

5/ Proceedings of the Fuel Switching Forum, sponsored by the Department of Energy, Pittsburgh, Pennsylvania, June 6-7, 1977.

for ethylene production; the gases emitted during raw material processing are recaptured and used for all the fuel needs. Coal use is termed infeasible and this judgment seems to be shared by the industry since, as curtailments of natural gas increase, billions of dollars are being spent for facilities that use oil as raw material and fuel. 6/ Ammonia produced in the chemical industry is a key ingredient for nitrogen fertilizers. A process now employed in Europe and Asia in the production of ammonia uses coal as both raw material and fuel; the process actually begins with coal gasification. For this reason, the development of a coal-fired process is termed low risk for new equipment.

In sum, processes involving 54 percent of nonboiler uses of oil and gas were reviewed; of that 54 percent, only 7 percent could be considered to have proven technologies for coal. Another 31 percent, however, were judged to have some potential for successful demonstration of coal-based technologies. Penetration into this market appears to be contingent on commercial-scale demonstration of new technologies, and very little information is available on this topic to date.

6/ "Petrochemicals: The Prodigious Costs of Facing the Future," Business Week, July 18, 1977.

32-498 O - 78 - 5

CHAPTER VI. BOILER COAL CONSUMPTION UNDER CURRENT POLICY

The purpose of this chapter is to project the demand for boiler coal in the industrial sector in 1985 if no specific government incentives are adopted--that is, if current policy is maintained; the following chapter will project changes in that demand under alternative federal policies. Since any estimate depends on several key assumptions, this chapter presents the sensitivity of the current policy estimate to four major factors: future OPEC oil prices, future coal prices, natural gas availability for new boilers, and alternative environmental standards.

ESTIMATES OF BOILER COAL CONSUMPTION UNDER CURRENT POLICY

The choice of industrial boiler fuel is plagued with uncertainty. Corporations deciding which equipment to buy must forecast fuel prices and availability for many years into the future. Apart from federal regulations, the most important and unpredictable factors affecting fuel choice are the expected rates of increase in oil and coal prices and the availability of natural gas. The current policy assumptions used here include world oil prices increasing at the U.S. rate of inflation and coal prices increasing slightly faster, primarily because of decreasing mine productivity. Gas is assumed to be available, but at prices that regulators allow to rise only to the level of distillate oil prices by the early 1990s.

With these assumptions, the economic model developed in this analysis is used to forecast boiler fuel choice in future years; that is, the model is used to approximate individual corporate decisions. Unfortunately, historical sales data are of little help in predicting future fuel choice or in gauging the accuracy of the model. Before 1970, puchasers did not have to consider the implications of nationwide air pollution control requirements or predict the impact of comprehensive mine safety legislation on mineworker productivity and thus on coal prices. In addition, before 1973, OPEC had not demonstrated its pricing power and the federal government had not been authorized to order factories to burn coal instead of oil and gas as it was by the Energy Supply and Environmental Coordination Act of 1974.

Even very recent sales data do not reveal a clear trend. Since two to three years are required for construction, most of the new industrial boilers that have or will come on line between 1975 and 1980 were purchased between 1972 and 1977. In the first five years of that period, 10 to 15 percent of the large, industrial, fossil-fuel boiler capacity sold each year was coal-fired. Then, in the first half of 1977, the market share for coal-fired boilers increased to 50 percent, although boiler sales were abnormally low in those months. From 1972 through the first half of 1977, the coal-fired capacity sold to the industrial sector totaled 21,849,000 pounds. This new capacity could account for 8 million tons of coal consumption by the end of 1980. 1/

If current policy is continued, it is projected that coal would represent approximately 13 percent of total new boiler fuel demand over the period from 1975 to 1980. In 1980, this would total 12 million tons of coal consumption. Between 1981 and 1985, when the strict environmental regulations discussed in Chapter IV could be imposed, it is projected that only 6 percent of the new boiler fuel demand would be coal. By 1985, this would represent an additional 6 million tons of coal being consumed as a boiler fuel.

Boiler coal consumption was 45 million tons at the end of 1974. Since about 3 percent of these existing boilers will be retired each year, consumption in old boilers will fall to 30 million tons by 1985. 2/ As explained in Chapter II, 10 million tons is an optimistic estimate of the coal consumed by old oil and gas units that will reconvert to coal; this brings total coal consumption in old boilers to 40 million tons by 1985. Adding the coal consumed by old coal boilers to the coal consumed by the new coal boilers installed in the 1975-1985 period yields an estimate of 58 million

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1/ Based on sales data from the American Boiler Manufacturers Association. SIC codes include 00, 20 through 39, and 73. Total MPPH was multiplied by 1,300 to convert it to million BTUs. Coal boilers were assumed to be operated at 70 percent utilization. Only boilers larger than 80 MPPH were included.

2/ The 45 million tons is taken from the file of major fuel-burning installations (MFBI). A 3 percent retirement rate implies that, over the 1975-1985 period, 30 percent of the existing stock of coal boilers would reach 30 years of age and be retired. In fact, more than 50 percent of the coal boilers listed in the MFBI file were installed before 1950, and another 30 percent were installed between 1951 and 1960.

tons for 1985 boiler coal consumption, assuming that no additional energy legislation is enacted.

THE SENSITIVITY OF BOILER CONVERSION TO ALTERNATIVE ASSUMPTIONS

Although the current policy estimate presented above is based on a set of reasonable assumptions, it is important to stress the fact that a considerable amount of uncertainty surrounds the estimate. This is primarily because the corporate decision about which type of boiler to purchase is extremely sensitive to future oil and coal prices and to environmental standards. To a much lesser extent, the estimate also depends upon the availability of natural gas.

Natural Gas Availability. Coal will be chosen more often as a boiler fuel if natural gas is not available. With no gas available for new boilers, coal would capture 7 percent of the market in the 1981-1985 period instead of 6 percent; 1985 coal consumption would increase to 59 million tons under such an availability assumption.

Future Oil Prices. If, in addition to gas being unavailable, boiler purchasers expect OPEC to increase real crude prices, a much larger share of the boiler market will turn to coal under current policy. For example, if crude oil prices increase fast enough, starting in 1985, to push delivered residual oil prices up each year by 2 percent faster than inflation during the life of the boiler, then 38 percent of the new industrial boiler market will be captured by coal in the 1981-1985 period; 1985 boiler coal consumption would be 90 million tons. Clearly, OPEC price increases or widespread expectation of OPEC price increases can induce significant replacement of oil and gas by coal.

Future Coal Prices. Coal prices in the future are also uncertain because of the difficulties involved in projecting equipment costs, labor costs, and productivity changes. For example, the 1978 labor contract will increase real coal prices at the mine site by a little over 1 percent each year over the next three years, assuming constant labor productivity. It is uncertain whether future contracts will include similar wage and benefit provisions and, more importantly, whether labor productivity will, after the recent dramatic decline, resume its long-term upward trend and offset real wage increases.

A steady increase in coal prices can offset the effect of gas unavailability and an expected OPEC price increase. If coal prices at the

mine site were expected to increase by an additional 2 percent each year starting in 1978, the effect of the 2 percent OPEC price hike would be completely offset; the market share for coal would return to 6 percent.

Environmental Policies. Chapter IV explains the air pollution control requirements assumed in this report. The assumptions reflect a very strict, but plausible, interpretation of the 1977 amendments to the Clean Air Act. Since the control requirements result in higher costs for both coal and oil, they should be expected to encourage the consumption of natural gas; the analysis confirms this point.

When analyzing the effect of alternative assumptions on competition between coal and oil, one obvious, but frequently overlooked, point is made very clear--the impact of air pollution regulations on coal demand depends as much on the requirements for oil as it does on those for coal. A factory's choice between coal and oil depends on relative costs, and air pollution regulations add to the equipment or fuel costs of using both fuels.

To illustrate the point, "pro-coal" air pollution standards were analyzed. First, it was assumed that natural gas is not available for new boilers; as noted, this results in coal being used for 7 percent of new boiler fuel needs in the 1981-1985 period. Second, the oil standards detailed in Chapter IV were changed. Specifically it was assumed that only low-sulfur oil (0.3 percent) can be used, with particulate control equipment; the option of using high-sulfur oil with a scrubber is eliminated. As a result of this tightening of oil standards, the market share for coal increases to 15 percent. Third, it was assumed that boilers under 300 million BTUs per hour are allowed to use low-sulfur coal alone without scrubbers, but particulate control is required. Tight oil requirements are maintained so that for these smaller boilers the SO_2 standard for oil is three times as strict as that for coal--1.2 pounds per million BTUs of fuel consumed as compared with 0.4 pounds. With this standard, coal's market share increases to 27 percent. Finally, if low-sulfur coal is allowed in all sizes of boilers while maintaining the tight oil controls, coal would be used for 39 percent of new boiler fuel needs.

In all the cases considered above, the increase in coal demand must be attributed to tight oil standards together with more lenient standards for coal. For example, consider the case in which low-sulfur coal is allowed in all sizes of boilers, but instead of strict oil standards the current NSPS for oil is imposed--that is, 0.8 pounds of sulfur dioxide per million BTUs of oil burned with no particulate control. Under these regulations, coal captures about 10 to 15 percent of the new boiler market.

CHAPTER VII. POLICY OPTIONS TO REPLACE OIL AND GAS WITH COAL

This chapter analyzes the impact of alternative federal policies aimed at encouraging the replacement of oil and gas with solid coal in the industrial sector. Both boiler and nonboiler uses are considered, although the analysis of the former is based on the detailed economic model and cost information presented above, whereas the analysis of the latter is more subjective. Since the major policy options for boilers are tax incentives, the analysis quantifies the potential budgetary effects as well as the extent of coal substitution.

The first section of the chapter discusses five possible federal tax options to encourage industry to utilize solid coal in boilers. Each option is evaluated in terms of potential oil and gas savings and budgetary effects. The budgetary effects can take three forms: (1) user taxes on oil and gas, which are reflected as increased revenues; (2) rebates of these revenues for those who buy coal equipment; and (3) tax credits on new coal equipment, which are reflected as decreased revenues. Special budgetary implications, administrative issues, and the interaction of the boiler tax incentives with both environmental policy and the coal substitution regulatory program are all treated. The second section discusses the federal policy that might be adopted to encourage coal use for nonboiler purposes in the industrial sector.

REPLACING OIL AND GAS IN BOILERS

The demand for coal as an industrial boiler fuel may increase slowly over the next decade under current policy. The federal government may, however, wish to assure that coal use increases through various tax incentives to reduce the price of coal relative to the price of oil and natural gas. For example, the original National Energy Plan included taxes on most oil and gas used in the industrial sector; that plan also called for rebates of those taxes for firms buying coal equipment. Similarly, the coal conversion programs passed in 1977 by both the House and the Senate included provisions for user taxes on industrial oil and gas and for rebates to firms purchasing coal equipment. The key difference between the Administration's original plan and the Congressional programs is the number of oil and gas uses exempt from the proposed tax. The House and Senate versions

tax boiler fuel uses almost exclusively; nonboiler uses were exempted primarily because of the lack of proven coal-using equipment. 1/

Federal Policy Options

Although the number of policies that the federal government could potentially adopt to accelerate the rate of coal conversion is quite large, only five options are presented in this report. These options should, however, provide policymakers with an overview of the magnitude of replacement to be accomplished by a relatively wide spectrum of policies. Estimates of the potential oil and gas savings and the budgetary effects of policies for new boilers are displayed in Table 10. The estimates are all based on several key assumptions that were discussed elsewhere in detail; chief among these assumptions are the following:

- By 1985, all crude oil will be sold at the world oil price, which is assumed to increase at the rate of U.S. inflation throughout the life of the boiler system.
- Strict environmental regulations will prevail.
- Natural gas prices will be deregulated in 1985, and they will increase to levels that average $0.50 per million BTUs above the price of distillate oil.
- Coal prices will increase only because of inflation and depletion.
- Industries will buy coal on the spot market and use single-car trains for delivery.

Oil and Gas Taxes Without Rebates. A tax on oil of $6.00 a barrel and a tax on gas raising gas prices to oil price levels including the oil tax (hereafter referred to as a gas equalization tax) would increase the percentage of new boiler fuel demand captured by coal to 63 percent

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1/ The House version exempts all fuel used as a raw material and other nonboiler ("process") uses in which coal use is not feasible for technical, economic, or environmental reasons. As discussed in Chapter V, coal use is not technically feasible for most nonboiler applications. If nonboiler uses do qualify, they are taxed at a lower rate under the House bill. The Senate exempts all raw material and process uses.

TABLE 10. ENERGY AND BUDGETARY EFFECTS OF CURRENT POLICY AND FIVE ALTERNATIVE BOILER TAX POLICIES

	Energy Effects			Budgetary Effects, Fiscal Year 1979-1985 (millions of current dollars) a/	
	1985 total coal use (millions of tons per year)	Percent of 1981-1985 new boiler fuel demand captured by coal b/	1985 oil and gas replacement (barrels per day equivalent)	Cumulative tax revenues	Cumulative tax expenditures
Current Policy	58	6		—	—
A $3.00-a-barrel tax on oil and a tax on gas sufficient to increase its price to that of distillate oil (including the $3.00 tax)	88	36	321,000	3,091	—
A $6.00-a-barrel tax on oil and a tax on gas sufficient to increase its price to that of distillate oil (including the $6.00 tax)	116	63	621,000	3,074	—
40 percent tax credit	95	—	403,000	—	3,361
New boilers	—	38	353,000	—	—
Accelerated retirements	—	—	50,000	—	—
Senate bill incentives	114	61	600,000	1,683	1,950
House bill incentives	140	—	883,000	(13,547) c/	(-1,756) c/
New boilers	—	72	717,000	—	—
Accelerated retirements	—	—	166,000	—	—

SOURCE: Congressional Budget Office

a/ Reflects a 6 percent annual rate of inflation starting in fiscal year 1978.

b/ About 2.2 quads of fossil fuels will be consumed in all new boilers purchased to meet expansion and replacement demand for the 1981-1985 period; these are the boiler investment decisions affected by federal policies enacted in 1979. The numbers in this column represent the portion of that new fuel demand satisfied by coal.

c/ All of the revenue is rebated. The negative tax expenditure estimate reflects the net impact of the two provisions: the extra 10 percent tax credit and the denial of the existing tax credit for new oil and gas boilers and new coal boilers financed with rebates.

between 1981 and 1985; total boiler coal consumption would be 116 million tons in 1985. These taxes would increase tax revenues by approximately $3 billion (current dollars) between 1979 and 1985. An oil tax of $3.00 a barrel and the relevant gas equalization tax would increase coal's market share to 36 percent. Both sets of taxes are imposed on oil and gas used in all new boilers.

Investment Tax Credits. Taxes on oil and gas encourage coal consumption by increasing coal's relative price advantage. Investment tax credits encourage coal use by lowering its equipment cost disadvantage. If, for example, an extra 40 percent refundable investment tax credit was allowed for all new coal boilers, the market share for coal would increase to 38 percent of the new boiler fuel market in the 1981-1985 period; this large tax credit would also induce accelerated retirements. Total boiler coal demand would be 95 million tons by 1985 as a result of both the increased share of the new boiler fuel market and the accelerated retirements. The tax expenditures or revenue reductions associated with this credit would be approximately $3.4 billion in current dollars for the period 1979-1985. (Without gas deregulation the tax credit would result in a 29 percent coal share.)

Senate Bill Incentives

The Senate bill proposes a $6.00-a-barrel oil tax and an accompaning gas equalization tax on fuel used in new boilers that have a capacity of 100 million BTUs per hour or more and on fuel used in a new smaller boiler if that unit is one of several new units at a single site with aggregate boiler capacity over 250 million BTUs per hour; new units are not eligible for rebates. Oil and gas burned in an existing coal-capable unit are also taxed, and the taxes can be rebated if the unit is converted to coal. In addition to the taxes, an extra 15 percent refundable tax credit is offered to firms investing in coal-fired boilers.

This policy is estimated to increase the market share for coal to 61 percent in the 1981-1985 period; about 8 percent of that can be attributed to the tax credit in the bill. The increased coal is the equivalent of 600,000 barrels a day of oil consumption. This policy would increase tax revenues by approximately $1.7 billion, while the credit would cause revenue reductions of approximately $2.0 billion. This would net to a $300 million revenue decline in current dollars for the period 1979-1985. Without the provision exempting boilers smaller than 100 million BTUs per hour, coal's market share would be 71 percent.

House Bill Incentives

In the House bill, user taxes are imposed on oil and gas used in both new and existing boilers of all sizes. The oil tax starts at $0.30 a barrel in 1979 and gradually increases to $3.00 a barrel in 1985. The gas tax gradually raises gas prices to the equivalent price of distillate oil not including the oil tax. Both new boilers and existing boilers converted to coal are eligible for rebates, but a firm must choose between a rebate and an extra 10 percent tax credit (added to the existing 10 percent tax credit allowed for all business investments). 2/ Finally, the House bill denies the existing 10 percent tax credit to investors choosing oil- and gas-fired systems.

Estimates of the oil and gas replacement induced by the House incentives depend crucially on what is assumed about deregulated natural gas prices after 1985 and about the effect of the tax rebates. In this report, gas prices to industry are assumed to rise beyond world oil prices and the rebate is assumed to be perfectly effective. 3/ With these assumptions the House incentives enable coal to capture 72 percent of the new boiler market; the bill would also induce enough accelerated retirements to increase coal use by 15 million tons in 1985.

If gas prices after 1985 did not increase as much as assumed, the House incentives would be much less effective. (This is not so for the Senate bill since its user tax already pushes gas prices beyond the world oil price.) For example, if gas prices did not increase beyond the equivalent price of distillate oil, and if gas was still available for new boilers, coal's market share would be 52 percent. The tax portion of the bill would result

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2/ If a rebate is chosen, a firm cannot take the existing credit on the portion of the investment financed with the rebate. The bill also exempts from the taxes the equivalent of the first 50,000 barrels of oil consumed in each firm, and cuts the gas tax by 10 percent for those firms accepting "interruptable" gas contracts; both exemptions lower the pool of funds eligible for rebates and thereby cut the rebate effect.

3/ The entire tax liability for the 1979-1985 period is assumed to be rebated. The user-tax liability (except for 1979 and 1980) cannot be carried forward nor can it be transferred, so it is possible that liability will not be in the right place at the right time.

in only an 18 percent market share; tax rebates would supply much of the incentive for the remaining share. 4/

Total boiler coal consumption would be 140 million tons by 1985 as a result of both the increased share of the new boiler fuel market and the accelerated retirements. The resulting increase in coal use is equivalent to 883,000 barrels a day of oil consumption. The cumulative tax revenues would be $13.5 billion, but the whole amount is assumed to be rebated. Denying the existing 10 percent investment tax credit to oil and gas boilers and to coal boilers financed with the rebate results in a cumulative budget savings of $1.8 billion.

Budgetary Effects

Since the policy incentives for accelerated coal substitution are primarily tax incentives to change the capital or fuel costs of oil and gas relative to coal, these options have budgetary effects. The impacts can be on the revenue side in terms of increased revenues from user taxes for oil and gas or decreased revenues from tax credits on investment in new coal equipment. In addition, the options with tax revenue rebates will be reflected in the budget in terms of direct outlays. The budget estimates in Table 10 are cumulative for fiscal years 1979-1985, and they are given in current dollars with an assumed inflation rate of 6 percent a year; the estimates by fiscal year are displayed in Appendix C.

The estimates of tax expenditures reflect only the investment tax credits on new coal boilers. The Senate bill, for example, actually provides the 15 percent credit for a long list of "Alternate Energy Properties," and the tax expenditure resulting from this broader program would be much higher. Indeed, the most frequently cited disadvantage of the tax credit approach is that it rewards those who would not use oil and gas even in the

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4/ The effect of rebates is equivalent to the effect of an investment tax credit. This can be illustrated by considering a factory paying $10 million in oil user taxes that is faced with a decision of whether to buy a new coal or oil boiler. Since the user tax is a deductible business expense, the tax reduces the firm's after-tax profits by $5 million. If the firm decides to buy a coal boiler for $10 million, all of its user taxes will be rebated and, therefore, it will increase its after-tax profit by $5 million dollars. This effect is identical to that of a 50 percent investment tax credit. With a 50 percent credit, a firm would buy the coal boiler for $10 million, reduce its income tax liability, and thereby increase its after-tax profit by $5 million.

absence of the policy. In view of the widespread use of waste fuels in industries such as paper and steel, the consequent drain on the federal budget could be considerable. With a tax approach, if a factory does not use oil or gas, no tax is levied and thus no tax is collected.

As will be discussed later, the budget estimates are derived from optimistic assumptions about the tax programs. For example, with the House bill a smooth flow of taxes and rebates is required; actually, since tax liability cannot be carried forward, it is possible that millions of tax dollars will remain with the U.S. Treasury. Similarly, coal use could be precluded by physical constraints such as land availability and, if exemptions are not granted, millions of dollars of revenues could accrue to the Treasury.

Interaction of Environmental and Energy Tax Policy

For all of the tax policies considered here, it was assumed that a strict environmental policy would prevail, as detailed in Chapter IV. Alternative environmental policies would affect the impact of any tax program on coal demand. As an illustration of this point, consider the case in which natural gas is simply not available for new boilers and a $3.00-a-barrel oil tax is imposed. With strict controls, coal's market share is 36 percent. With the "extreme pro coal" environmental policy, coal's share of new boiler fuel demand would be 72 percent with this tax. When a "moderate pro coal" policy is coupled with the tax, coal's share is 51 percent. Thus, there is a clear and important interaction between energy taxes and environmental regulations. 5/

Administrative Issues

The estimates of oil and gas replacement in Table 10 should be viewed as optimistic; they do not reflect all the ways taxes can be avoided and, therefore, all the ways the program can be undermined. Since the success of any coal substitution program will depend heavily on how it is administered, it is important to identify possible administrative problems for the recently proposed House and Senate bills.

5/ The extreme pro coal policy allows low-sulfur coal and baghouses for all sizes of coal boilers, but it requires 0.3 percent sulfur oil plus baghouses for all oil boilers. The moderate policy has the same coal standards, but it imposes a standard of 0.8 lbs of SO_2 per million BTUs of oil burned and does not require particulate control on oil boilers.

First, both the House and the Senate bills are primarily boiler fuel taxes. Exemptions of nonboiler fuel uses makes any program harder to administer and may undermine its effectiveness. The program will be difficult to enforce simply because it is hard to trace fuel to specific purposes within a factory. To see how the effectiveness of the program can be undermined by this exemption, it should be remembered that many industries currently use by-product fuels. For example, gases emitted while crude oil is refined are recaptured and used as fuel at refineries; to avoid any boiler fuel tax legally, this by-product fuel could be used exclusively in boilers instead of being used in both boiler and nonboiler applications. If this occurs, the tax is avoided by shuffling types of fuel among boiler and nonboiler uses rather than being avoided by switching to coal. By-product fuels are also available in other industries such as steel and chemicals.

Second, the House bill depends heavily on the rebate effect, and for such policies the number of exemptions and the number of equipment types eligible for rebate are crucial. Exemptions lower the user-tax liability available for rebate and thereby lessen the rebate effect. Recently proposed tax policies exempt firms for which coal burning is precluded by state or federal air pollution regulations. "Preclusion" will have to be defined and, if program administrators are liberal with such exemptions, they will undermine the program by decreasing the number of boilers affected by the tax as well as by lowering the chances for large rebates. Additionally, broad eligibility lowers the portion of the user-tax liability that will actually be available for coal boilers. In recent legislation, rebates are available for equipment using any "alternate substance"; alternate substance means any substance other than oil or natural gas, not just coal. There is the chance that the effectiveness of the rebate plans would be cut because all equipment using substances other than coal, oil, or natural gas would receive rebates. Paper mills, petroleum refineries, and other facilities have always purchased such units.

Third, both tax bills include "environmental exemptions." The House bill exempts only existing units, but the Senate bill makes both new and existing units eligible for exemptions from taxes if the use of coal is precluded by state or federal environmental regulations. Actually, no environmental law specifically precludes coal burning, so the exemptions are a matter for administrative judgment. One popular interpretation of this environmental exemption is that purchase of a new boiler will be considered "precluded" if the purchaser would have to abide by the emission offset policy. Only one study has taken a serious look at the potential for this impact. According to that study, if 296 million tons of coal consumption would be stimulated by the original economic incentives of the National Energy Plan, 29 percent of this economically justified coal use would be

affected. 6/ A number of conceptual problems cloud the study and hence its conclusion. Most notably, since the study was not able to forecast precisely the location of the new fuel use, it is not really possible to estimate how much of it would fall in nonattainment areas; also, it must be remembered that both oil and coal users could be affected by the offset policy. Equally important is the fact that some localities have been assisting industry in obtaining the required offsets. For example, officials of New Stanton, Pennsylvania, recently interceded with state and county officials to get reductions in hydrocarbon emissions from state and county roads, thereby clearing the way for Volkswagon's new assembly plant in the area. Thus, for all practical purposes, Volkswagon did not incur additional expense to locate in a nonattainment area. The effect of the trade-off policy has not been, and perhaps cannot be, estimated confidently, and thus its effect is not reflected in any of the estimates.

Fourth, the Senate bill exempts existing boilers and thus encourages oil and gas users to extend the life of their units so the tax can be avoided.

Fifth, both bills delay inflation adjustments for the oil taxes until after 1980. If inflation is 6 to 7 percent in 1978 and 1979, the oil tax would fall in real terms by more than 14 percent and would thereby cut the effectiveness of both programs; this is not reflected in Table 10. The reason for such a delay is not at all clear once a program is chosen and the appropriate tax level established; the issue does not appear to arise with the natural gas taxes.

Sixth, the tax programs are assumed to be permanent in this analysis. A purchaser buys coal-fired equipment to avoid higher oil or gas prices that are assumed to prevail throughout the life of the boiler. Any indication that the tax could soon be repealed would undermine the program's impact.

Industrial Coal Conversion Regulatory Program

Since 1974, the federal government has had the authority to prohibit the use of petroleum and natural gas in individual factories (major fuel-burning installations). The program typically required a long legal process in which the federal government proved that a new or existing MFBI should be so prohibited. A recent House/Senate Conference agreement makes a broad and basic change in the coal conversion program by establishing a "blanket"

6/ U.S. Environmental Protection Agency, Potential Siting Problem for Increased Coal Use, October 1977.

prohibition: firms are prohibited from using petroleum or natural gas in new boilers unless the federal government grants them a specific exemption. The bill has switched the burden of proof; now, the MFBI must show why it should not be prohibited from using oil or natural gas. Affected by this prohibition are boilers capable of consuming 100 million BTUs of fuel per hour or smaller boilers that are one of a group capable of consuming 250 million BTUs per hour.

As with the old program, existing MFBI must receive specific prohibition orders and the order can only be issued for units originally designed to burn coal. The Secretary of Energy is also given authority to prohibit petroleum and natural gas use in a few vaguely defined and, perhaps, inappropriate nonboiler applications (gas tubines, combined cycle units, or internal combustion engines).

Temporary (5 to 10 years) and permanent exemptions are available upon request. An exemption for a new MFBI can be granted:

- If the cost of using coal "substantially exceeds" the cost of using imported oil;
- If a reliable coal supply is not available;
- If "site limitations" such as inadequate space exist;
- If environmental regulations preclude coal use; and
- If the MFBI plans to use synthetic fuels that are not currently available--in this case a 10-year exemption is available.

The primary targets of the industrial coal conversion program are new boilers larger than 100 million BTUs per hour; these units are projected to consume the equivalent of 0.9 million barrels a day by 1985. Success for the program depends completely on strict and clever enforcement. Projections of the coal substitution induced by the program depends completely on one's guess of how well it will be administered.

The industrial oil and gas user taxes and the regulatory program obviously overlap. Two of the ways in which the programs could interact are:

- The regulatory program prohibits oil and gas use in new boilers as long as coal is not "substantially" more expensive to use than imported oil. Tax programs increase the cost of using oil and, for this reason, it is often argued that the tax program makes the

regulatory program easier to enforce. Another view, however, has been noted. The regulatory program, in effect, guarantees a market for coal as long as the cost of a coal boiler system is within a yet-to-be-prescribed range of oil costs. If a market is guaranteed to coal producers and associated industries, a strong incentive exists to increase the price of coal, coal transportation, and coal-fired equipment, and by adding to oil costs the tax program may invite even more price hikes. Competition among firms will tend to dampen unwarranted price increases, although it is not clear to what extent.

- The Senate tax bill allows exemptions from taxes when a firm is exempt from the regulatory program. The provision complicates program administration by requiring cooperation among the Internal Revenue Service, which will administer the tax program, and the Department of Energy and the Environmental Protection Agency, which have prescribed roles in the regulatory program. This provision also increases the chance for liberal exemptions.

REPLACING OIL AND GAS IN NONBOILER USES

Nonboiler fuel uses are of two general types--oil and gas used in equipment such as ovens, kilns, and furnaces and that used as a raw material in the production of petrochemicals. Coal will be used as a raw material only if it is first processed into a gas or liquid. Solid coal use in nonboiler equipment such as industrial furnaces will generally require Research and Development of new equipment. A federal Research and Development program aimed at developing new, coal-fired industrial equipment and processes could be very expensive, difficult to manage, and have a high risk of failure. The heterogeneity of nonboiler uses necessitates demonstrations at many sites and, therefore, the program would have a high cost and would be difficult to manage. The fact that research on new ways to use energy cannot be divorced from research on new ways to produce products means that such a program might require unprecedented cooperation between government and industry scientists; thus, the risk of failure is high.

Taxes on nonboiler oil and gas users can also be used to encourage coal use. The taxes would first provide an incentive to undertake the required research and development; then, when successful demonstrations are completed, they would provide an incentive to purchase coal-fired equipment. The House bill imposes user taxes on nonboiler uses when such uses are technically, economically, and environmentally feasible. The oil tax reaches $1.00 a barrel in 1982 and is constant in real terms thereafter; the gas tax gradually raises gas prices to a level $0.30 per million BTUs

32-498 O - 78 - 6

below the equivalent price of distillate oil in 1985. The actual eligibility for this tax is a matter of administrative judgment and, for the purposes of this report, it is assumed that most nonboiler uses will be exempt on the grounds that solid coal use is not now technically feasible. Oil and gas consumption in the remaining uses, primarily for cement and lime production, is not estimated, although these energy consumers appear to be turning to coal voluntarily under current policy.

The Administration may have the authority to impose the taxes contained in the House bill on many nonboiler uses because consumption of processed coal may be feasible. It is not likely, however, that these low taxes would induce much demand. But this narrow administrative point raises another broad and complex energy issue: if coal is to be used to replace oil and natural gas, in what form should that coal be employed--in its natural, solid form or processed into gases or liquids.

If the federal government is to guide a transition to processed coal in the near term, it must do more than impose taxes on oil and gas. Many questions must be answered before this new energy industry can flourish. For example, what prices will be allowed for gasified coal? Will those gasification facilities be considered public utilities? How will they be sited, and what environmental regulations will be imposed?

APPENDIXES

APPENDIX A. POSSIBLE TRANSPORTATION CONSTRAINTS TO INCREASED COAL CONSUMPTION

EXISTING PATTERNS OF COAL TRANSPORTATION

Railroads are by far the most important transporter of coal, moving about two-thirds of all produced. The three major competitors to rail for transporting coal are barges, trucks, and mine-mouth generation. Each of these competitors handles just over 10 percent of current U.S. coal production. The railroads' share has dropped slightly over the past 10 years, primarily because of the development of mine-mouth generation plants. Hence, the rail share of coal transported--that is, coal actually moving away from the mine--has remained fairly steady at just under 75 percent.

Current movements of coal are not at all evenly balanced on a geographical basis. Generally, the coal-producing districts in the East have dominated U.S. production, with the Appalachian Region accounting for about two-thirds of total production. A large proportion of coal produced is destined for use in the East-North Central and South-Atlantic Regions; these two census regions account for about two-thirds of coal use. 1/ The general dominance of the East shows up clearly in the maps depicting coal movements by the various modes that accompanied the 1977 Senate report on National Energy Transportation. 2/ The major exceptions are the Great Lakes traffic and the emerging flows of western coal to eastern markets.

Rail Coal Movements

Coal is the largest single commodity carried by railroads. Coal traffic represented 20 percent of total railroad carloadings in 1976. The

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1/ Richard J. Barber Associates, Inc. "The Railroads, Coal, and the National Energy Plan," September 1977, Figure 5.

2/ U.S. Senate, Committee on Energy and Natural Resources and Committee on Commerce, Science, and Transportation, National Energy Transportation, 95 Cong. 1 sess. (May 1977), Volume I, Maps 2-5.

next most important commodity is metallic ores, which account for only about one-third as much of total carloadings as coal.

The slow growth of coal traffic, however, has been a major disappointment for the railroads. Even during the past four years, while the energy crisis has become a prominent issue, railroad coal traffic has grown very slowly (see Table A-1). Coal carloadings had declined fairly sharply in the early 1970s. Since 1973, coal carloadings have increased at a rate of only about 1 percent a year. Over the same period, however, total carloadings moving by rail have, in fact, decreased by 14 percent. Thus, although coal traffic has been relatively flat, it has been stronger than overall traffic.

Focusing on measures of coal traffic other than carloads presents a somewhat different numerical picture of the importance of coal to the railroads, but it does not change the general magnitude discussed above (see Table A-2). Since coal is a relatively dense, heavy commodity, its percentage of traffic by weight (tons originated) is somewhat higher than its percentage of gross revenues or total carloadings--29 percent for all Class I railroads in 1976. On the other hand, coal rates are relatively low per ton compared with the rates for other commodities, and they are thus somewhat lower than the corresponding ratio for carloadings--coal represents 14 percent of total Class I revenues. All three measures--tons, revenues, and carloadings-- show coal to be increasingly important to railroads. The geographic imbalance of coal traffic is also reflected in the traffic carried by the individual railroads. Seven railroad systems currently account for more than 85 percent of total railroad carloadings of coal. These are mostly eastern railroads, especially the Norfolk and Western and the Chessie System, which together earn 39 percent of railroad industry coal revenues. Other eastern rail lines with important coal traffic are the Family Lines System, ConRail, and Southern Railway. Non-eastern railroads with important coal traffic are the Burlington Northern and the Illinois Central Gulf.

SIGNIFICANCE OF INCREASED COAL TRAFFIC

The Administration's National Energy Plan projects a substantial increase in national coal production by 1985, whether or not new energy legislation is passed as recommended. Even without the plan, production is expected to rise by 59 percent over 1976 levels. With implementation of the plan, an 89 percent increase is projected by the Administration. The increased production would be used by electric utilities and by general industry. Although the biggest proportional increases (and the greatest impact of the plan) are projected for general industry use, the largest

TABLE A-1. REVENUE CARLOADINGS OF COAL, 1973 TO 1976: IN THOUSANDS OF CARLOADS

Year	Carloads
1973	4,487
1974	4,544
1975	4,693
1976	4,699

SOURCE: Association of American Railroads, Yearbook of Railroad Facts, various editions.

TABLE A-2. COAL TRAFFIC AS A PERCENTAGE OF TOTAL TRAFFIC FOR CLASS I RAILROADS, 1973 AND 1976

Year	Tons Originated	Gross Revenues	Carloadings
1973	24.3	9.8	16.4
1976	29.0	14.0	19.9

SOURCE: Association of American Railroads, Economics and Finance Department.

absolute increase in tonnage is attributed to electric utilities, representing 56 percent of the projected overall increase.

The implications for the rail industry--indeed, for all transportation modes--depend on the actual increase in coal production, its timing, and the percentage of share going to each mode. For purposes of the present discussion, an arbitrary increase in production of approximately two-thirds (to 1.1 billion tons a year) is assumed. It is further assumed that the railroads continue to move their current share of coal production. Coal traffic by rail would thus increase in the same proportion as production. This would represent an increase in tonnage originated of 288 million tons by 1985, increasing from 437 million tons now hauled to the assumed total of 725 million tons.

If this projected increase were spaced evenly over the eight years from 1978 through 1985, coal tonnage by rail would increase about 35 million tons a year, or about 8 percent annually. The additional coal traffic would increase total rail tonnage of all commodities by only about 3 percent a year. Thus, although coal is the most important single commodity moved by rail, a substantial increase in coal movement taking place over a number of years does not translate into a very striking increase in railroad traffic overall. It remains to be seen, however, whether railroads would be able to transport adequately such an increase in coal traffic.

If the full growth in coal production envisioned in the National Energy Plan is realized, the annual growth in rail tonnage would be about 11 percent, reaching a total of 837 million tons in 1985; again this assumes that rail retains its 66 percent modal share. Other scenarios for coal production and use could imply substantially higher rates of increased coal traffic for the railroads. For example, a study published by the Electric Power Research Institute (EPRI) projected a much larger increase in coal production and consumption by 1985, and further assumed that the railroads might indeed handle 100 percent of all coal production, diverting coal movement from barge, truck, and mine-mouth generation. Under this scenario, rail carloadings of coal were projected to increase by substantial amounts, and the ability of the railroad industry to handle such increases would clearly be more questionable than under the above assumptions.

Key Factors Regarding Rail Capacity

Several key areas can be identified that will determine the ability of the railroads to increase substantially the movement of coal. These factors include the railroads' ability to supply needed equipment and to operate the equipment effectively. These items, in turn, depend on the volume of other

noncoal freight movement and the adequacy of the overall rail plant for other rail shipments. Finally, there is the question of financing needed expansion of either equipment or plant capacity.

Unit Trains. The amount of equipment required and its effective utilization under any scenario regarding coal production will be significantly affected by whether the movement can be made by unit trains. A unit train represents dedicated equipment that is permanently linked and shuttling between fixed production and consumption points on a continuous basis. It has proven to be a cost-efficient method of moving coal to large users. Unit trains provide dramatic improvements in car utilization relative to normal car service: for example, one railroad that converted to unit train service from standard carload service now uses 892 cars in unit train service to deliver the same amount of coal that formerly required 2,400 hopper cars, a dramatic 63 percent reduction in car equipment needed for the service. 3/

While coal tonnage increased only slightly over the past decade, tons moved in unit trains have almost doubled in the same period. Between 1971 and 1976, coal tonnage increased only about 15 percent, but the amount moving by unit trains increased over 60 percent.

Of the growth in coal production, the amount that is likely to move by unit train will depend on the amount going to electric utilities and the intensity of industrial conversion. The National Energy Plan envisions 56 percent of additional coal production going to electric utilities, which are well-suited to unit train service. If industrial conversion is accomplished only for large energy users, and for users that are near each other, then unit train operations could be applicable. It seems likely, however, that much of the projected industrial use will not be of sufficient scale and concentration to warrant unit trains, so that the railroads will need to finance greater expansion of equipment than would otherwise be the case.

Equipment Needs. In order to handle additional coal traffic, railroads will need to add coal-moving equipment, primarily open-top hopper cars and locomotives to pull them. Existing equipment will also have to be replaced in order to maintain current capacity. Based on an assumed two-thirds increase in coal traffic and a constant railroad share, two projections of equipment needs are presented in Table A-3. The influence of unit trains is clear: the number of hopper cars required per year ranges from 9,700 to 13,400, while the number of locomotives required per year ranges from 485 to 670. In both cases, actual coal-carrying capacity rises faster than the

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3/ Association of American Railroads, "Coal and the Railroads--1977."

TABLE A-3. RAIL EQUIPMENT NEEDS FOR COAL TRAFFIC, 1978-1985

Option	Units per Year	Millions of Dollars per Year
High Unit-Train Option		
Hopper cars, new and replace	9,700	291.0
Locomotives	485	242.5
Annual Cost		533.5
Low Unit-Train Option		
Hopper cars, new and replace	13,400	402.0
Locomotives	670	335.0
Annual Cost		737.0

SOURCE: Association of American Railroads, "Coal and the Railroads--1977." Assumes two-thirds increase in coal transported.

rate at which equipment is added, because the new cars are of higher capacity than those being replaced.

These equipment needs compare very well with the current rate of equipment purchases. Three things about the recent experience should be noted:

- The level of open-top hoppers installed in 1976 was 18,160, and over the past three years both orders and cars delivered have been running at an average annual level of about 16,000.

- These high rates of car installations have not resulted in large expansions in fleet available. For example, the total cars in the open-top hopper fleet at the end of 1976 was 365,500, just slightly above the level of 256,600 available at the end of 1974.

- The level of new cars ordered has been declining for the past two years. The level on order as of the end of 1976 was only about 7,000 cars, so that recent levels of new car delivery cannot be maintained unless new orders accelerate.

Thus, the actual rate of new cars installed in recent years has been greater than the rate projected to be necessary to transport expanded coal production. Even the projected need of 13,400 cars under the more likely low unit-train option falls well below the recent three-year installation rate of 16,000. Replacement needs appear to have been higher in recent years, however, than those incorporated in the projections, since the total car fleet has not expanded. Further, the disappointing levels of recent coal traffic have led to reductions in actual car orders, and new orders seem likely to be more closely linked to the level of actual, not projected, coal movements.

Excess Current Capacity. In the fall of 1977, expectations of a coal miners' strike led to increased rail shipments as coal users attempted to build up inventories. If the actual number of carloads moved in the six weeks ending October 22 were extrapolated for an entire year, it would represent an increase of 20 percent over carloads moved in 1976 without any additional equipment. 4/ Thus, excess equipment currently in place could provide capacity for a substantial amount of the projected increase in coal movement.

4/ Remarks by William H. Dempsey, President, Association of American Railroads, before the National Association of Regulatory Utility Commissioners, New Orleans, La., November 15, 1977.

Another dimension of rail capacity is the adequacy of the rail plant to handle coal movements along with other freight. Since World War II, railroads have had difficulty maintaining their share of the intercity freight market; to some extent, they have had difficulty maintaining their absolute level of traffic. While revenue ton-miles in 1976 were slightly higher (7 percent) than in 1966, originated tonnage, freight car miles, and freight train miles were all lower in 1976 than 10 years earlier. Thus, there is a considerable historical potential for moving more freight over the existing rail plant. In more instances, this could be accomplished by reintroducing longer sidings, double track, or centralized traffic control signalling for existing track. The more even geographic distribution of future coal movements seems likely to favor just those railroads with capacity that could be expanded without great difficulty, but a number of specific bottlenecks have been identified in various studies. 5/

The actual, frequent movement of heavy unit trains will not require much new rail line; some existing lines will have to be upgraded within a few years, and the lines will have to be maintained. The grain-hauling railroads of the Midwest and West were constructed with relatively lightweight rail. The Coal Transportation Task Force of the U.S. Department of Transportation concluded: "Although this lighter weight rail will be able to handle coal traffic for the next several years, 130-pound rail is likely to be needed before 1985." 6/

Financing Expanded Capacity. Equipment financing has generally been the least sensitive of all railroad financing to the railroads' problems of low earnings and low rate of return. There are several reasons for this. The equipment itself is portable and can be transferred from one railroad to another in the event of default. Therefore, equipment trusts--that is, loans for the purchase of the equipment--have generally been available to most railroads, even those in financial difficulties. Further, shippers themselves and other third-party groups often purchase cars for lease or dedicated use,

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5/ For example, Manalytics, Inc., "Coal Transportation Capability of the Existing Rail and Barge Network, 1985 and Beyond," prepared for the Electric Power Research Institute, September 1976.

6/ U.S. Department of Transportation, Transporting the Nation's Coal--A Preliminary Assessment (January 1978), pp. 11-22.

reducing the financing needs accruing directly to the railroad in question. Thus, the $4 to $6 billion capital investment for equipment needs that is implied by the estimates in Table A-3 should pose no special problem.

The investment in fixed plant is more difficult to finance externally. Improvements of fixed plant, especially upgrading to heavier rail, and regular maintenance in the face of increased use are the areas of potential financing problems. Increased rates on coal traffic and more certainty about long-term traffic prospects may be necessary to generate adequate private investment. Preliminary estimates in the report of the Coal Transportation Task Force suggest a $4 to $5 billion level for upgrading. Some of this capital might be provided through Title V of the Railroad Revitalization and Regulatory Reform Act of 1976, but the Federal Railroad Administration has not yet released its report on the capital needs anticipated in January 1978. This report is supposed to discuss the overall capital needs of the railroads and the federal role in meeting them.

Conclusions of Other Studies. Several studies of the coal movement and potential rail capacity have been conducted in recent years. On the whole, these studies conclude that projections of coal movement through 1985 are basically manageable by the railroads with selected capacity improvements. Two reports have been less sanguine. First, the Manalytics/Electric Power Research Institute (EPRI) report projected much higher coal traffic for railroads and therefore magnified the potential problems of capacity. Second, various reports put out by the Slurry Pipeline Association generally suggest that the weaker railroads will experience the greatest coal traffic increases and will be unable to handle them; they further suggest that grain and other midwestern traffic may be displaced by the increased coal movement.

KEY LEGISLATIVE ISSUES

There are basically two areas in which legislation can influence the transportation of expanded coal production. The first is legislation providing financial assistance that influences the competitive situation between the various coal-moving modes. The second involves regulatory issues.

Influences on Competition

Transportation legislation influences the competition between modes in several fashions, the simplest of which involves the legislative promotion of specific modes. If the Congress provides promotional assistance for competing modes, such as barge operators on federally financed waterways,

then that mode's privately incurred costs would be lower than they would have been in the absence of such federal assistance, and the mode will be able to compete on more favorable terms. Although coal traffic by truck tends to be mostly intrastate in nature, federal aid for highways in general, and for energy-related roads in particular, could work to the advantage of truck transport of coal. Assistance to these other modes could expand transport capacity in general but undermine the ability of the railroad industry to increase the movement of coal if that assistance results in reduced rail earnings and an inability to build capital either internally or externally.

Not all legislation that affects competition between modes need involve direct financial assistance. For example, the current financial assistance for the railroad industry itself is somewhat indirect and involves a complex mix of loans and loan guarantees. Furthermore, legislation may be nonfinancial in nature, but quite influential nonetheless. For example, the issue of whether to grant eminent domain to proposed coal slurry pipelines involves little direct financial involvement on the part of the government. Nevertheless, Congressional indecision on this issue could have a major impact on railroads' willingness and ability to move additional amounts of coal. Construction of slurry pipelines would provide additional capacity for transporting coal and it reputedly would be less expensive than other forms of transportation. Slurry pipeline competition is potentially destructive, however, since traffic would be diverted on long-term contract, leaving rail unable to compete regardless of the actual cost structure. Pipelines could divert sufficient coal traffic to make railroad expansion unattractive; this might possibly undermine the railroads' viability as a mover of other commodities.

Regulatory Issues

The Congress sets the framework for regulation and often legislates specific regulatory prescriptions. A few selected examples of how legislative policy influences regulatory matters and thereby the potential for expanded coal transportation follow:

- Regulation of railroad rates, and particularly rates for coal movement, will substantially influence the willingness of the railroad industry to expand coal capacity. Rates on coal traffic have increased rather slowly relative to value, and they have often lagged well behind increased costs for factor inputs. If regulatory policy results in unattractive rates for coal movement, railroads will not willingly invest in additional equipment nor be attracted to move coal traffic. The Congress recently changed

the ground rules for rate regulation in the Railroad Rehabilitation and Regulatory Reform Act of 1976, generally moving toward more rate flexibility for the railroads and therefore rendering more likely voluntary expansion of rail capacity. Recent legal decisions, however, have held down unit train rates, and this will have the opposite influence.

- A bill recently introduced by Congressman Harley Staggers of West Virginia (H.R. 9027) proposes a limitation on the length of a freight train. The proposed limit is 4,300 feet, which is the equivalent of roughly 75 cars. Enactment of this bill would substantially influence the economies of unit train operation since most unit trains consist of 100 to 110 cars. Higher transport costs, in turn, might make coal conversion less attractive to industry if the costs were passed on or coal movement less attractive to the railroads if the rates were held down.

- The regulatory process restricts common carriers from entering into long-term contracts in certain ways. The railroads argue that this restriction creates a disadvantage relative to the slurry pipelines, which are likely to offer fixed long-term contracts. At present, railroads publish rates for coal movement, but they cannot build in automatic escalators for future cost increases.

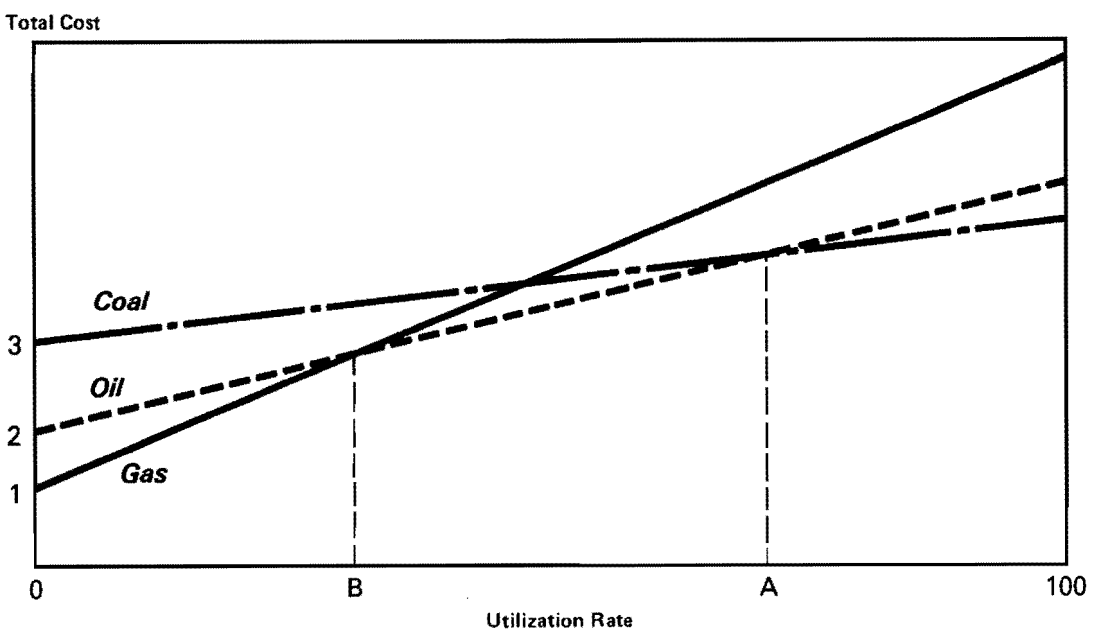
- The Congress controls maximum permissible truck weights, at least on the Interstate System, via provision of various highway acts. The most recent change in these restrictions was introduced in the Federal-Aid Highway Amendments of 1974. This can have pervasive competitive impact between modes, since it directly affects the coal tonnage that a truck can legally carry. The change in certain other clauses regarding state weight limitations in the 1974 legislation may have made trucks much more competitive for coal business. Furthermore, it is often alleged that coal-carrying trucks are typically and substantially overweight relative to both federal and state regulations, thus gaining an illegal competitive advantage.

APPENDIX B. METHODS AND DATA FOR THE ANALYSIS OF INDUSTRIAL BOILER FUEL DEMAND

The concept behind the model of boiler fuel choice developed in this report is best expressed with the aid of Figure B-1. Costs of the steam output for a given size of boiler are represented on the vertical axis, while utilization rates are shown on the horizontal axis. Equipment for a coal boiler costs more than equipment for an oil-fired boiler, which in turn costs more than equipment designed for natural gas; thus, the points 3, 2, and 1 represent costs at a zero utilization rate. As the utilization rate increases, total cost increases because the costs of fuel, operation, and maintenance are added. Coal becomes cheaper than both oil and gas at utilization rate A; that is, coal will be used in region X for new boilers of size Y that are expected to be used A percent of the time or more. Oil becomes cheaper than gas at utilization rate B, so oil will be used for new boilers with

Figure 1-B.

Boiler Costs By Fuel and Utilization Rate For Region X and Boiler Size Y



32-498 O - 78 - 7

expected utilization rates between B and A. Gas will be used in all other new boilers.

A computer program was developed to calculate these "breakpoint" utilization rates with all costs expressed as annuities. The equation used for the calculation is:

(1) $$\text{TOTAL ANNUAL COST} = \text{TAC} = \text{AC} + \text{OF} + (\text{OV} \times \text{CF}) + (\text{F} \times \text{CF})$$

where:

AC = capital cost annuity,
OF = fixed operation and maintenance costs,
CF = utilization rate or capacity factor,
OV = variable operation and maintenance cost (expressed at 100 percent utilization), and
F = fuel cost (expressed at 100 percent utilization).

Coal will be chosen over oil for a particular size of boiler when the total annual cost of coal (TAC_c) is less than the total annual cost of oil (TAC_o); that is:

(2) $$TAC_c < TAC_o$$

The utilization rate at which this begins to be true must be calculated; that is, the following equation must be solved for CF:

(3) $$CF = \frac{AC_c - AC_o + OF_c - OF_o}{OV_o - OV_c + F_o - F_c}$$

Coal would be chosen over oil for all boilers of a given size if their expected utilization rate exceeded CF.

As noted above, the calculation must be performed for eight fuels for five boiler sizes in ten regions. Each term in equation (3) requires a separate set of calculations; these calculations are as follows.

AC. For each boiler system there are two equipment costs--that for equipment which lasts 30 years (CAP 30) and that for equipment which lasts only 15 years (CAP 15). Each of these capital costs must be multiplied by a capital charge rate (CCR) to yield an annuity; to reflect differences in

regional prices, that annuity must then be multiplied by a regional price adjustment factor (RAF). In symbols:

$$(4) \qquad AC = \left[(CAP_{30})(CCR_{30}) + (CAP_{15})(CCR_{15})\right] (RAF)$$

OF. A fixed annual operation and maintenance cost is entered for each boiler system; it is then multiplied by a regional price adjustment factor. In symbols:

$$(5) \qquad OF = OF^* \ (RAF)$$

F. A fuel price per million BTUs (FP) is entered for each boiler. To calculate fuel cost at 100 percent utilization, the fuel price is first multiplied by hourly fuel consumption (HFC); the product of that multiplication is then multiplied by 8,760, the number of hours in a year. In symbols:

$$(6) \qquad F = (FP)(HFC)(8{,}760)$$

OV. Variable operation and maintenance costs at 100 percent utilization are entered and multiplied by a regional price adjustment factor. In symbols:

$$(7) \qquad OV = OV^* \ (RAF)$$

An 8 percent real, after-tax rate of return was used for all discounting. Some capital charge rates used in the analysis are displayed in Table B-1.

Boiler Fuel Demand Projections

Large Boilers. The starting point for the demand projections was 1974 large industrial boiler fuel consumption by region and by SIC code; the data are taken from a federal survey of boilers in that year. 1/ Growth in that boiler fuel demand was then projected to 1980 and to 1985. All increases in fuel consumption were assumed to involve the purchase of a

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1/ The Major Fuel Burning Installation Survey conducted by the Federal Energy Administration in 1975. The data were grouped by the 10 federal regions.

TABLE B-1. CAPITAL CHARGE RATES a/

Investment Tax Credit	Equipment Life	
	30 Years	15 Years b/
10	0.1693	0.1873
25	0.1410	0.1502
40	0.1128	0.1130

SOURCE: Congressional Budget Office

a/ Assuming an 8 percent real after-tax rate of return, straight-line method for book depreciation, sum of the years' digits method for tax depreciation, a 3 percent property tax, 4 percent state income tax, and general and administrative of 1 percent.

b/ Equipment lasting 15 years was assumed to be replaced in the 16th year at the same real equipment price.

new boiler. The increases were calculated by applying estimated industrial growth rates to 1974 BTU consumption. 2/ These growth rates reflect an economy that makes steady progress toward full employment in the early 1980s and has growth sufficient to maintain full employment thereafter; real GNP grows, on average, by 4.5 percent each year between 1976 and 1983 and then by 3.1 percent between 1983 and 1990.

In addition to this "growth demand," a replacement demand for boilers was estimated. It was assumed that 3 percent of the 1974 boilers (representing 3 percent of 1974 boiler fuel consumption) would be retired—and therefore would need replacement—each year. The resulting estimates of new boiler fuel demand are displayed in Table B-2.

The survey cited above was also used to distribute the growth and replacement boiler fuel demand across five boiler sizes and then, for each size group, across seven utilization rates. A change in the size distribution over time was not projected because that distribution, according to survey data, was remarkably stable over the last 30 years. The seven utilization rates are required because fuel choice is very sensitive to small differences in annual usage.

The size and utilization rate distributions are displayed in Tables B-3 and B-4. Given BTU consumption for a particular size of boiler, the portion attributable to a particular utilization rate equals:

$$\frac{U_i N_i}{\Sigma U_i N_i} \tag{8}$$

where

U = utilization rate, and
N = number of boilers with a particular utilization rate.

(The reader should be cautioned that the data in the MFBI file has many obvious errors, and one must be selective about which entries to believe. Unfortunately, the MFBI file is the only source of data on size distribution and utilization rates.)

2/ The industrial growth rates are taken from Data Resources, Inc., U.S. Long Term Review: Fall 1977.

TABLE B-2. FUEL DEMAND FOR NEW, LARGE BOILERS BY FEDERAL REGION: IN TRILLION BTUs

Federal Region	1974 Base	1974-1980	1981-1985
1	103	41	52
2	234	106	124
3	464	186	230
4	600	257	321
5	854	314	392
6	1,185	547	604
7	81	37	37
8	125	46	58
9	143	59	56
10	116	45	55
Total	3,905	1,637	1,928

SOURCE: Congressional Budget Office calculations based on MFBI file provided by the Department of Energy.

TABLE B-3. LARGE BOILER FUEL CONSUMPTION IN 1974, BY BOILER SIZE

Boiler Size (in million BTUs per hour)	Percent of Boiler Fuel Consumption
100 to 199	35
200 to 299	23
300 to 399	15
400 to 499	10
over 500	17

SOURCE: Calculated by Congressional Budget Office with data from the MFBI file provided by the Department of Energy.

TABLE B-4. BOILER UTILIZATION RATE DISTRIBUTION IN 1974 BY SIZE OF BOILER: DISTRIBUTION BY PERCENT OF FUEL CONSUMPTION

Annual Utilization Rates	Boiler Size (in million BTUs per hour)				
	100 to 199	200 to 299	300 to 399	400 to 499	over 500
10 to 29	8	5	2	2	3
30 to 39	12	7	5	3	5
40 to 49	12	6	8	6	10
50 to 59	18	18	13	11	13
60 to 69	14	15	24	17	11
70 to 79	15	20	16	28	32
80 to 100	21	29	32	33	26

SOURCE: Calculated by Congressional Budget Office with data from the MFBI file provided by the Department of Energy.

Small Boilers. No detailed data are available on fuel consumed in small industrial boilers—those with a capacity less than 100 million BTUs per hour. It was assumed that 1974 BTU consumption was a little over 1 quad. The MFBI file traces 3.9 quads of fossil fuels to large boilers in 1974; two other studies estimate total boiler fossil fuel use at about 4.7 quads. 3/

Given this rough estimate, small boiler fuel demand for growth and replacement would be about 500 trillion BTUs between 1974 and 1980, and between 1981 and 1985. This growth was distributed across regions according to the distribution for large boilers displayed in Table B-2. Small boilers were given the same utilization rate distribution as boilers in size group 100-199 million BTUs per hour.

The final form of these large and small boiler projections is "cells" of new boiler fuel demand characterized by region, by boiler size, and by utilization rate.

By applying industrial growth rates to 1974 fuel demand, it was implicitly assumed that boiler energy consumption per unit of output would remain constant through 1985. It is almost certain that coal, oil, and gas use per unit of output will fall over time for three reasons:

- Boilers will be designed to produce steam with less energy per unit of steam generated.
- Production processes will be modified to use less steam.
- Other, nonconventional fuels will replace coal, oil, and gas.

The third point appears to be by far the most important factor. Industrial wastes, for example, are a potentially important alternative fuel for boilers. An assumption of falling energy use per unit of output would reduce the demand for new boilers and, consequently, reduce the opportunity for coal to replace oil or gas as a boiler fuel. Of course, declines in oil and gas use per unit of output--that is, energy conservation--also lessen the need for a replacement policy; conservation and replacement are alternative means to lowering industry's dependence on oil and gas. To reflect conservation, new boiler fuel demand was cut by 10 percent. While 10 percent is not presented

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3/ See the Energy Consumption Data Base; and Harry Brown and Bernard Hamel, Industrial Application Study, vol. II, prepared at Drexel University for the U.S. Energy Research and Development Administration (December 1976).

as a precise estimate, it appears reasonable, but conservative. Energy consumption per unit of manufacturing output fell at an annual rate of 1 percent or more even during the 1960s when real energy prices were constant or falling. 4/ Most industries have set goals of 10 to 15 percent for energy conservation by 1980; the goals were set by industries participating in the federal government's voluntary conservation program. The estimates should be viewed as presenting fossil fuel consumption in boilers at high rates of economic growth and with limited conservation.

Model Solution

In each region, breakpoints are calculated for all relevant fuel comparisons for each of five sizes (100, 200, 300, 400, and 500 million BTUs per hour). These breakpoints are then used to determine which cells of fuel demand will use coal, which will use oil, and which will use gas. For example, if the breakpoint for coal in region X for boilers of 100 million BTUs is 70 percent, two demand cells will be allocated to coal--the cells with boiler size 100 to 199 million BTUs and utilization rates 70 to 80 and 80 to 100 percent.

Fuel Cost Data

The assumptions behind the fuel price estimates used in this report were discussed in Chapter III. The actual estimates for selected years are displayed in Tables B-5 through B-7. All price series were converted to annuities using an 8 percent discount rate.

4/ See Energy Consumption In Manufacturing, a report to the Er Policy Project of the Ford Foundation, 1974.

TABLE B-5. DELIVERED COAL PRICES PER MILLION BTUs:a/ IN 1977 DOLLARS

Federal Region	1980	1985	1990
1	1.57	1.63	1.69
2	1.52	1.58	1.64
3	1.47	1.53	1.59
4	1.35	1.43	1.52
5	1.14	1.22	1.31
6	1.74	1.77	1.80
7	1.27	1.35	1.44
8	0.91	0.94	0.97
9	1.74	1.84	1.95
10	1.82	1.85	1.88

SOURCE: ICF, Inc., Economic Considerations In Industrial Boiler Fuel Choice, submitted to the Congressional Budget Office. These are not the fuel cost annuities presented in the ICF report; they are fuel prices in particular years.

a/ In this analysis, coal can be delivered from five different coal supply regions to any of the 10 federal regions. This table only displays the lowest-price coal for each region. Regions 1, 2, and 3 use Northern Appalachian coal; regions 4, 5, and 7 use Midwestern coal; regions 6, 8, and 10 use Western coal; and region 9 uses Rockies coal. Also in this analysis, boilers smaller than 300 million BTUs per hour use specially prepared and more expensive "stoker" coal; this table shows prices for "pulverized" coal used in large boilers.

TABLE B-6. DELIVERED RESIDUAL OIL PRICES PER MILLION BTUs: a/ IN 1977 DOLLARS

Federal Region	High-Sulfur Oil		Low-Sulfur Oil	
	1980	1985	1980	1985
1	2.07	2.30	2.65	2.91
2	2.02	2.24	2.59	2.85
3	2.09	2.31	2.66	2.92
4	2.10	2.32	2.67	2.93
5	2.22	2.45	2.80	3.06
6	2.07	2.29	2.64	2.90
7	2.10	2.32	2.67	2.93
8	2.00	2.22	2.57	2.83
9	2.04	2.26	2.61	2.87
10	2.04	2.26	2.61	2.87

SOURCE: ICF, Inc., Economic Considerations In Industrial Boiler Fuel Choice and Sobotka and Co., Refinery Gate Product Price Differential Forecasts For 1985, submitted to the Congressional Budget Office. These are not the fuel cost annuities presented in the ICF report; they are fuel prices in particular years.

a/ Prices are constant in real terms after 1985 to reflect the assumption that world oil prices rise no faster than U.S. inflation. High-sulfur oil contains 3 percent sulfur, and low-sulfur oil contains 0.3 percent sulfur.

TABLE B-7. NATURAL GAS PRICES PER MILLION BTUs: a/ IN 1977 DOLLARS

Federal Region	1980	1985	1992
1	2.69	3.02	3.02
2	2.12	2.67	2.96
3	1.76	2.55	3.03
4	1.43	2.19	3.04
5	1.64	2.23	3.17
6	1.30	2.13	3.01
7	1.60	3.04	3.04
8	1.25	2.35	2.94
9	1.69	2.56	2.98
10	1.59	2.20	2.98

SOURCE: ICF, Inc., Economic Considerations In Industrial Boiler Fuel Choice, submitted to the Congressional Budget Office. These are not the fuel cost annuities presented in the ICF report; they are fuel prices in particular years.

a/ Prices are shown for 1992 because by this year gas prices have reached the distillate equivalent price in all regions and remain constant in real terms thereafter.

APPENDIX C. BUDGETARY EFFECTS OF BOILER TAX PROGRAMS

The budgetary impacts of the House and Senate boiler tax programs are displayed in Table C-1. The estimates are in current dollars, assuming a 6 percent annual rate of inflation. Taxes under the Senate bill begin in fiscal year 1982 because only new boilers are taxed and the eligible units will begin to come on line in 1982; the tax expenditure starts in 1980 because "progress payments" will be eligible for the tax credit. The Senate tax revenue is assumed not to be rebated; only existing coal-capable units are eligible and, as discussed in Chapter II, those units not in nonattainment areas are assumed to convert under current policy before 1979. In contrast, all of the revenue collected under the House bill is assumed to be rebated evenly over the years 1980-1985; under the bill, only 1979 and 1980 tax liability can be carried forward.

TABLE C-1. BUDGETARY IMPACTS OF HOUSE AND SENATE BOILER TAX PROGRAMS: BY FISCAL YEAR, IN MILLIONS OF CURRENT DOLLARS a/

Policy Description	1979	1980	1981	1982	1983	1984	1985	Total
Senate Bill								
Taxes				143	330	515	695	1,683
Tax expenditures		218	307	326	345	366	388	1,950
House Bill								
Taxes	485	1,515	1,966	2,200	2,398	2,365	2,618	13,547
Tax expenditures		(227)	(320)	(339)	(289)	(282)	(299)	(1,756)

SOURCE: Congressional Budget Office

a/ Assumes a 6 percent rate of inflation starting in 1978.