The Use Of Coal In The Industrial, Commercial, Residential, And Transportation Sectors

THE NATIONAL COAL COUNCIL

DECEMBER 1988

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U.S. DEPARTMENT OF ENERGY

John S. Herrington, Secretary

The National Coal Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Coal Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to coal or the coal industry.

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December 1, 1988

The Honorable John S. Herrington
Secretary of Energy
U. S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Secretary:

On behalf of the National Coal Council, I am pleased to submit the attached report, "The Use of Coal in the Industrial, Commercial, Residential, and Transportation Sectors," prepared in response to your letter of November 6, 1987.

This report identifies opportunities for the increased use of coal/coal-derived fuels in the nonutility sectors and recommends both government and industry actions that can be taken to increase coal use. The report reviews the consumption of primary energy as well as the total national energy input, defines opportunities for coal/coal-derived fuels to replace existing fuels, discusses clean coal technologies that can be more broadly utilized, and identifies challenges facing coal use in each of the four nonutility sectors. It also explores three policy issue areas which impact increased coal utilization, specifically, national security issues, environmental and regulatory concerns, and public opinion. Further, the report outlines factors relating to material handling and waste disposal and cites examples of the use of coal in nonutility sector applications in foreign countries.

In studying this subject, it was found that, while coal is our nation's most certain and predictable fossil fuel resource, it is the least used in the nonutility sectors. Significant findings include the following:

- The most feasible method of penetrating the nonutility sectors, and avoid equipment and infrastructure changes, is to convert coal to liquids and gas. Commercial processes have been demonstrated and currently are in use to make oil-based liquids and gas.

- The transportation sector consumes more oil each year than the U. S. produces - 27 percent of the total U.S. energy input and nearly two-thirds of all oil used in this country. Currently, only liquids or perceived liquids can play a role in the short-term replacement of gasoline and distillate. Methanol is the primary alternative presently being considered; its use would require infrastructure changes. Coal can produce synthetic hydrocarbon liquids, requiring no infrastructure changes.

- The industrial sector offers unique opportunities for coal in the supply of chemical feedstocks and cogeneration.

- Coal can penetrate the commercial sector through the increased use of district heating and cooling and the cogeneration of electricity.

- Electricity generated by coal can be used in the electrification of railroads, regional transportation systems, and as an energy source for new, improved batteries which will be available in future mobile equipment.

Based upon these and other major findings, the National Coal Council offers for your consideration several recommendations to help increase the use of coal/coal-derived fuels to the nonutility sectors. Specifically, the Council recommends the following:

- Priority be accorded to the improvement of methods to produce alternative transportation fuels from coal.

  Transportation is totally dependent on petroleum-based liquid fuels, leaving that sector vulnerable to supply disruptions which could wreak havoc with the functioning of commerce and society.

- The image of coal be rebuilt in order to cast a positive light which will enable the public at large as well as legislative groups to better understand the benefits of coal use and clean coal technologies.

  Coal is our nation's most abundant and lowest cost fossil fuel. It has been demonstrated that coal is being used in an environmentally acceptable manner, as evidenced by the fact that sulfur dioxide emissions decreased by 27 percent over the period of 1973 to 1985 despite an increase of 35 percent in coal consumption. The public needs to be made aware of the positive aspects of coal in our energy mix.

The study group and the Council have strived to present an objective and balanced report. We hope it will be useful to the Department of Energy in its formulation of energy policies involving the use of coal in the industrial, commercial, residential, and transportation sectors.

Sincerely,

James G. Randolph
Chairman

JGR:ph
Attachment

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Introduction

At the request of the Secretary of Energy, a study was initiated by the National Coal Council in January 1988. The Secretary's request is excerpted below.

"Coal utilization in the light industrial, commercial, residential and transportation sectors – What are the opportunities for innovative technologies? A study is needed of the impediments to and actions that can be taken to accelerate the penetration of coal or coal–derived fuels into the nonutility sectors. In addition, quantification of the potential impact on energy security resulting from application of coal–based fuels in these sectors would be very useful. The study breadth should span mine mouth to end user fuel delivery and waste removal, and indicate technical and economic impacts of codes and regulations on fuel transport, waste removal and coal or coal–derived fuels utilization."

The Work Group was composed of representatives to the National Coal Council and industry representatives at large. The Work Group met in a plenary session, then divided into three subgroups, namely: Technical, Applications, and Policy. These subgroups met several times to prepare the substance of this report. An Editorial Subgroup was formed, consisting of members from each of the previously named subgroups. The Editorial Subgroup consolidated the report into its present form. An interim progress report was made to the Coal Policy Committee of the National Coal Council on June 8, 1988, in Washington, D.C. This study was reviewed by the Coal Policy Committee of the National Coal Council on October 4, 1988, in San Francisco, California, and by the entire Council on November 15 and 16, 1988, in Washington, D.C.

This report is divided into eight chapters. The first chapter, ENERGY OVERVIEW, reviews the consumption of primary energy in the United States during 1987. Total national energy input, which includes domestic production as well as total imports and exports, also is presented. Nonutility energy consumption is traced by sector (industrial, commercial, residential, and transportation) and by fuel type. Projections pertaining to U.S. consumption of major energy products for the years 1987 and 2000 are shown using Department of Energy, Data Resources, Inc., and Gas Research Institute forecasts. Other projections reflecting high and low oil price scenarios as well as natural gas prices also are discussed.

The next chapter introduces the first of four sector discussions. The INDUSTRIAL SECTOR is defined and an energy overview of this sector is presented. Opportunities for coal/coal–derived fuels to replace existing fuels used in this sector are outlined. Specifically, coal–derived medium and low Btu gas replacing natural gas and coal–derived liquids replacing petroleum liquids and liquified petroleum gas are conveyed. Because of its breadth of potential applications, a discussion of coal gasification is also included. The technologies for coal/coal–derived fuels that can be utilized in penetrating this sector are listed and explained. Importantly, challenges facing coal use in the industrial sector are defined: the protection of the current market share of coal–fired process steam boilers and the potential to expand market penetration by replacing existing oil and gas boilers.

Chapter three, the COMMERCIAL SECTOR, includes the definition of the components of the sector as well as an explanation of the principal sources of energy currently utilized. Natural gas is the current fuel of choice; cogeneration and district heating emerge as having the greatest potential in this sector. The applications of district heating plants are addressed with priorities for potential market penetration accorded to universities and colleges, hospitals, and U.S. military installations.

The RESIDENTIAL SECTOR, chapter four, defines the energy consumption and current fuels of choice for private households, multi-family dwellings, and apartment and condominium complexes. Constraints for re-introducing coal/coal-derived fuels into this sector are detailed and discussed. They include high conversion cost, public perception of coal as a dirty fuel, current unavailability of the proper size of coal-fired boiler, and the inconvenience associated with handling and storing coal and removing ash. An overview of transportation and distribution systems also is presented.

Chapter five, the TRANSPORTATION SECTOR, includes a definition of the vehicles that move people and commodities as well as an energy overview that dramatically reflects this sector's dependence on imported oil. The transportation sector is described as the only major sector of the economy that has achieved little fuel flexibility and fuel diversification, with automobiles, trucks, and planes consuming 80 percent of the fuel utilized, namely gasoline and distillate. Consequently, only liquids or perceived liquids can act as replacement fuels. Methanol is discussed as an alternate fuel type and cost projections using gasification of coal as a feedstock are offered. Coal liquefaction technologies are described as a long-term effort to replace petroleum-derived fuels.

Chapter six, POLICY, covers three critical areas of importance in utilizing coal in the nonutility sectors: national energy security issues, environmental and regulatory considerations, and public opinion. Major fuels of choice are recapped to highlight the country's increasing dependence on imported oil in the national energy security discussion. Environmental and regulatory constraints which effect all forms of energy production are addressed, with particular attention focused on the increased use of coal in the nonutility sectors. Specific issues impacting energy production are delineated and discussed. They include air quality, water quality, waste disposal, and the socioeconomic concerns pertaining to siting (land use), permitting, aesthetics, and public opinion. Public opinion on coal use in the nonutility sectors is presented in a review of trend sample survey data.

MATERIAL HANDLING AND WASTE DISPOSAL, chapter seven, outlines factors which describe delivery systems as inbound material handling and waste disposal systems as outbound material handling. A discussion of the utilization and marketing of fly ash also is presented.

The final chapter, INTERNATIONAL PROGRAMS, cites examples of the use of coal in nonutility sector applications in foreign countries as well as various government and industry partnerships which have resulted in the increased utilization of coal/coal-derived fuels. Funding for research, development, and demonstration in the European Economic Community is provided, along with a brief description of several current overseas joint government- and industry-funded development and demonstration programs.

The Executive Summary contains conclusions and recommendations which are presented to the Secretary for consideration. Appendices to support the contents of the study are provided. Appendix B is a coal technology summary for use by the reader who may wish to review some of the technical terms as well as to brush up on coal technology in general.

All data presented in the study are in U.S. dollars and short tons unless specifically noted. The term "nonutility," as used throughout the report, refers specifically to the Industrial, Commercial, Residential, and Transportation Sectors collectively.

Executive Summary

The electric utility sector has made significant strides in reducing its consumption of petroleum products and increasing its consumption of coal to generate electricity; other energy consuming sectors have not. These nonutility sectors, namely the industrial, commercial, residential, and transportation sectors, are an integral part of our society. As such, any disruptions in the supply of energy sources which fuel these sectors would send serious reverberations throughout the economy. This report examines these nonelectric utility sectors and identifies opportunities for coal/coal-derived fuels to replace other fossil fuels.

Petroleum products represent the single largest fuel source used in this country. The transportation sector alone consumes nearly two-thirds of the oil used. Increasing reliance on imported oil to meet the demand for petroleum products places the nation at risk and susceptible to a foreign supply disruption. Coal/coal-derived fuels can afford an energy alternative which will lessen the nation's dependence on imported oil. This study does not propose that all the imported oil consumed can be replaced by coal, but does outline the steps necessary to develop coal-based energy alternatives which will allow progressive replacement to occur.

Natural gas also is an important fuel source in these nonutility sectors. Currently, the threat of a supply disruption of natural gas is not present. The potential for shortages does exist for several reasons. These include the uncertainty of reserve estimations; the sudden increase in demand for natural gas as a swing fuel due to a potential petroleum supply disruption; the probable increase in the fuel cost as reserves are depleted; and the possibility of import restrictions by the country of origin in order to meet their own demand.

Coal/coal-derived fuels can play an increasingly important role in the overall energy policy of the United States. Coal is not an immediate cure for an energy crisis but its use as a diversification fuel can function to mitigate the impact of an interruption or restriction of any one fuel source. The production of coal is both a capital intensive and labor intensive effort; therefore, it cannot be turned on or off at will. Identification of long-term demand and planning to meet that demand will allow coal, America's most abundant fossil fuel resource, to provide alternatives to decrease our dependence on imported energy. Conclusions and Recommendations follow.

Conclusions

Coal is our nation's most certain and predictable fossil fuel resource, yet the least used in the industrial, commercial, residential, and transportation sectors. Natural gas and electricity are the most significant forms of energy used in the industrial, commercial, and residential sectors; in the transportation sector, liquid fuel from petroleum is the predominant form of energy. Based upon these facts, the following conclusions, related to the nonutility sectors, are presented.

- Currently, the most feasible method of penetrating the nonutility sectors is to convert coal to liquids and gas to avoid equipment and infrastructure changes. Commercial processes have been demonstrated and are in use to make coal-based liquids and gas. In the long term, new, emerging coal technologies which require infrastructure changes may have potential for use in the nonutility sectors.

- The United States uses more oil for transportation alone each year than it produces. At the present time, only liquids or perceived liquids can play a role in the short-term replacement of gasoline and distillate. Methanol is the primary alternate liquid currently being considered for transportation. Fuel-flexible vehicles which can run on methanol, gasoline, or a mixture of the two fuels have been built and are being demonstrated in the State of California. Methanol fuel would require infrastructure changes; however, coal can be used to produce synthetic hydrocarbon liquids, which are compatible with petroleum-derived fuels and which require no infrastructure changes.

- The industrial sector offers unique opportunities for coal in the supply of chemical feedstocks and cogeneration. There are many opportunities for coal in process heat production and steam raising. Concerns have been expressed regarding the regulatory issues being inhibiting, particularly the 10 micron particulate emissions and the SO_2 and NOx control requirements.

- Coal can penetrate the commercial sector principally in two ways: district heating and cooling and cogeneration of electricity. Universities and colleges, hospitals, penitentiaries, airports, industrial/office parks, and sports and recreational complexes are some of the major commercial sector candidates for consideration.

- The application of coal in the residential sector, more than in any other sector, will be influenced by public perception. Aesthetics, convenience, and cost will be principal considerations.

- Electricity is a significant energy input into the nonutility sectors. Its use in these sectors can be thought of as an indirect use of coal because more than half of the energy supply for electricity production comes from coal. For example, in the transportation sector, electricity can be used in the electrification of railroads, regional transportation systems, and as an energy source for new, improved batteries which will be available in future mobile equipment.

- All forms of energy have environmental constraints as well as advantages. Increased penetration of coal in the nonutility sectors must be both environmentally and economically acceptable. Currently, a reasonable increase in the use of coal in the industrial and commercial sectors can be accommodated while still meeting ambient air standards. Widespread use of coal in the residential sector may pose problems in many areas. When it comes to meeting ambient air standards, all sectors need to be considered jointly to maintain compliance within a given attainment area.

- Underlying all issues in the nonutility sectors is the public perception of coal. The Work Group believes that public information is negatively presented by the media and a more balanced view is required, particularly with respect to "Acid Rain" and the "Greenhouse Effect." The importance of coal as a reliable fuel with price stability has to be emphasized as well as the fact that technologies are available to use coal in an environmentally acceptable manner. Energy education in the primary and secondary schools is needed in order to create awareness in future generations of the strategic implications of coal in the nation's energy mix.

- Paramount to all of these issues are concerns of national security and economic survival. Petroleum is currently supplying 39.6 percent of all energy used in the United States. More than 25 percent of the balance of payment deficit is currently caused by imported oil. By 1990, the country could depend on imported oil for more than 50 percent of its petroleum needs. Where will it all end?

Recommendations

To increase the use of coal in the industrial, commercial, residential, and transportation sectors, the National Coal Council recommends that the Secretary of Energy consider taking the following steps.

1. **THE TRANSPORTATION SECTOR CONSUMES 27 PERCENT OF THE TOTAL**

UNITED STATES ENERGY INPUT AND NEARLY TWO–THIRDS OF THE OIL USED IN THE COUNTRY. IT IS ALSO THE ONLY SECTOR OF THE ECONOMY ALMOST ENTIRELY DEPENDENT UPON LIQUIDS WITH LITTLE FUEL FLEXIBILITY OR DIVERSIFICATION. *THE NATIONAL COAL COUNCIL RECOMMENDS THAT THE SECRETARY COMMISSION A STUDY OF THE METHODS OF PRODUCING ALTERNATIVE TRANSPORTATION FUELS FROM COAL.* THE PURPOSE OF THE STUDY WOULD BE:

- determine which alternative fuels and direct use technologies hold the most promise, both in the short and long term, for economically converting coal into energy forms usable in the transportation sector;
- support Federal demonstration projects, in cooperation with other Federal Agencies, implementing the use of coal–derived fuels in mobile equipment; and
- define a program of demonstration projects, in cooperation with other Federal and State Agencies, for the production and use of coal–derived liquids in mobile equipment, with opportunities for industry participation and cost–sharing where appropriate.

2. ***CONTINUE TO SUPPORT PROGRAMS PROMOTING RESEARCH AND DEVELOPMENT TO CONVERT SYNGAS TO LIQUID, COAL TO GAS, AND COAL TO LIQUID IN ORDER TO LESSEN U.S. DEPENDENCE ON IMPORTED OIL.* DEMONSTRATION PROGRAMS ARE NEEDED FOR SEVERAL REASONS:**

- to maintain a viable research and development capability as well as interest;
- to provide the basis for expansion of coal use to avoid a national energy emergency; and
- to provide benchmarks to measure performance and incremental costs.

3. **THE IMAGE OF COAL MUST BE REBUILT BASED UPON ITS PRESENTLY KNOWN ENVIRONMENTAL BENEFITS AND ITS POTENTIAL FOR FUTURE BENEFITS RESULTING FROM CLEAN COAL TECHNOLOGIES. TO THIS END, *THE DEPARTMENT OF ENERGY SHOULD CONVENE A WORK GROUP OF APPROPRIATE EXECUTIVE BRANCH AGENCIES/DEPARTMENTS; STATE AND LOCAL GOVERNMENT REPRESENTATIVES* (NATIONAL GOVERNORS ASSOCIATION, NATIONAL CONFERENCE OF STATE LEGISLATORS, NATIONAL LEAGUE OF CITIES); *AND INDUSTRY OFFICIALS TO DEVELOP A SUBSTANTIAL PUBLIC OUTREACH PROGRAM TO IMPROVE PERCEPTIONS AND ATTITUDES RELATED TO COAL.***

Further, the Secretary should encourage industry to become substantially more aggressive in educating and informing the public in a positive manner.

- Mount a coordinated effort under the leadership of the Department of Energy which will bring together other Federal Agencies and the energy industry to provide business and civic leaders with a more balanced view of the "Greenhouse Effect" and "Acid Rain" issues. One mechanism that could be used to accomplish this would be through the existing Interagency Task Force on the Greenhouse Effect.
- Embark upon a comprehensive program in conjunction with the Secretary of Education to expand energy awareness programs in primary and secondary schools. By creating a series of programs appropriate for each grade level, kindergarten through twelfth grade, and making these programs available nationwide and at no cost to the local school system, future generations will come to realize the essential role that energy plays in our daily lives. These programs should stress coal as the nation's most abundant fossil fuel resource.

If public information programs are not actively pursued, Congress could face pressures to enact legislation which would inhibit the future use of fossil fuels. Information currently reaching the public on these issues has been one-sided.

4. ***ENCOURAGE FEDERAL AGENCIES SUCH AS THE GENERAL SERVICES ADMINISTRATION, THE VETERANS' ADMINISTRATION, THE POSTAL SERVICE, THE DEPARTMENT OF DEFENSE, AS WELL AS THE DEPARTMENT OF ENERGY, TO INCREASE THE USE OF COAL IN PUBLIC FACILITIES.***

This action will serve as a role model or proving ground for similar applications in state and local government facilities and in commercial establishments. Since these facilities are based geographically throughout the nation, a broad-based infrastructure would be created to deliver coal/coal-derived fuel, dispose of ash and other waste, and service the equipment.

5. ***UNDERTAKE A REVIEW OF THE PERMITTING PROCESS AND THE REGULATIONS WHICH AFFECT COAL USE WITH APPROPRIATE FEDERAL AND STATE AGENCIES WITH THE OBJECTIVE OF REDUCING INCONSISTENCIES AND OVERLAPS.***

The Department of Energy should evaluate the recommendations by the Vice President's Task Force on Regulatory Relief. These recommendations provide guidance on how regulatory uncertainties can be reduced and deployment of clean coal technologies can be encouraged. Cooperative reviews of the implementation procedures of environmental regulations by Federal and state agencies could lead to accommodation of new opportunities for coal use in the industrial and commercial sectors in many attainment areas of the country.

6. ***INVESTIGATE THE USE OF ECONOMIC INCENTIVES THAT WOULD HAVE THE LARGEST IMPACT ON INCREASING THE USE OF COAL IN THE INDUSTRIAL, COMMERCIAL, RESIDENTIAL, AND TRANSPORTATION SECTORS AND SPONSOR LEGISLATION AS DEEMED APPROPRIATE.***

Incentives should be applied when appropriate for promoting the economical use of coal in an environmentally acceptable manner. Incentives also are desirable to lessen commercial risk when projects are marginally feasible.

7. ***STIMULATE INTEREST WITHIN THE COMMERCIAL SECTOR TO DEVELOP NEW COAL-FUELED DISTRICT HEATING AND COOLING SYSTEMS.***

The Department of Energy, in cooperation with the Department of Housing and Urban Development, should expand existing programs to develop model projects and to evaluate system technologies and candidates for the establishment of new coal-based energy systems on conversion to coal of existing community energy systems. The heating and cooling industry, developers, and state and local governments should be encouraged to move rapidly toward more widespread application of such systems.

8. ***REVIEW AND EVALUATE IN GREATER DETAIL THE PROGRAMS OF FOREIGN COUNTRIES WHICH HAVE SUCCESSFULLY IMPLEMENTED COAL USE IN THE INDUSTRIAL, COMMERCIAL, RESIDENTIAL, AND TRANSPORTATION SECTORS.***

The lessons learned can be applied in the appropriate sectors, taking advantage of the fact that these applications have been successful elsewhere. The study of foreign programs which use coal in the nonutility sectors should be a joint government/industry effort involving, not only the coal industry, but representatives from other affected industries.

Chapter I

Energy Overview

The United States consumed approximately 76.2 quads[1] of primary energy in 1987. Of this amount, petroleum products accounted for an estimated 32.6 quads, natural gas for 17.4 quads, coal for 18.0 quads, nuclear for 4.9 quads, and hydroelectric and other fuels for 3.3 quads. In this same year, the total national energy input, which includes domestic production and total imports and exports, was 79.6 quads. Imports accounted for approximately 15.3 quads, or about 19.2 percent of total energy inputs. Exports of energy from the U.S. to other nations were an estimated 3.6 quads; coal was over 50 percent of this amount. Figure 1 shows U.S. energy inputs and exports for 1987 based on Department of Energy, Energy Information Administration (DOE/EIA) data. The difference between energy inputs and exports and consumption represents stockpile drawdown.[2]

As shown on Figure 1, fossil energy forms -- petroleum, coal, and natural gas -- accounted for over 89 percent of U.S. total energy inputs in 1987. Petroleum was the largest single energy source, providing 39.6 percent[3] of all energy supplied to our nation. Natural gas and coal provided 24.7 percent and 25.2 percent, respectively. Since about 90 percent of coal is consumed by utilities, used in steelmaking, or is exported, the energy forms of current choice in the nonutility market are petroleum, natural gas, and electricity.

Current Energy Choices

The 1987 nonutility energy consumption by sector and fuel type is shown on Figure 2. The largest single use was petroleum in the transportation sector, which accounted for 64.9 percent of all petroleum products consumed. Other significant uses included natural gas in the industrial, residential, and commercial sectors.

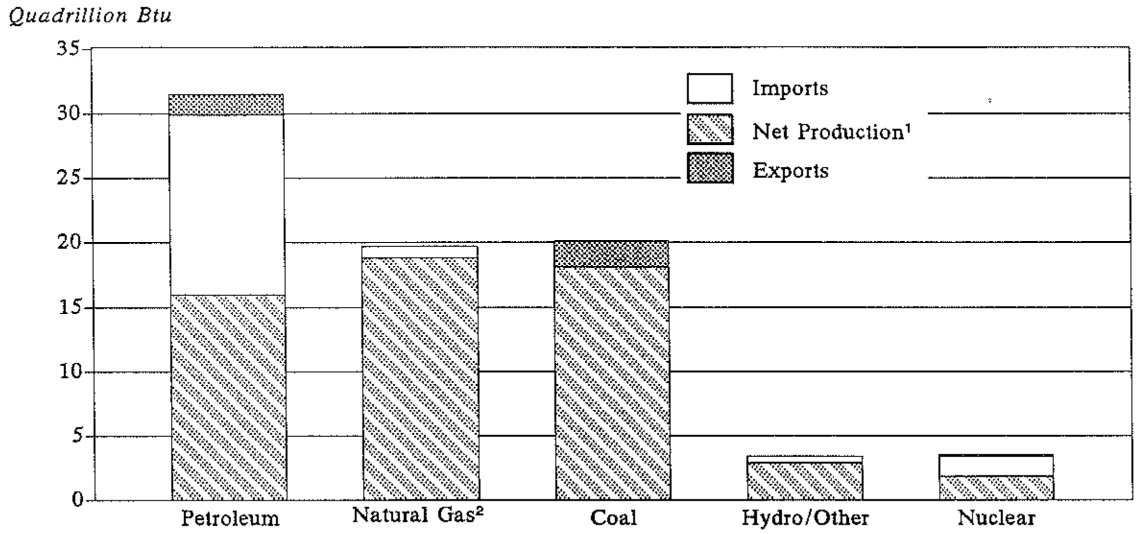
Many factors must be considered in estimating the quantity of coal which might replace other energy forms. Two of the most important considerations are the size of the market which coal can penetrate and the user cost differential between coal and other energy sources. Projecting accurate energy prices and consumption between coal and petroleum is difficult at best, as evidenced by comparing the petroleum and utility industries' forecasts of the last 10 years with the actual outcome. From an historical perspective, the volatility in oil pricing makes any long-range oil price projection suspect. As illustrated on Figure 3, coal pricing has remained steady during the same period. This adds another positive dimension to coal, our nation's most certain and predictable fossil fuel resource.

1 One quadrillion Btu (quad) equals 10^{15} Btu. One quad is approximately equivalent to 46 million tons of coal, 172 million barrels of crude oil, or 980 TCF of natural gas.

2 U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987), Tables A1 and A2, pp. 33 and 34.

3 Percentages used here reflect total fuel energy input over total U.S. energy input.

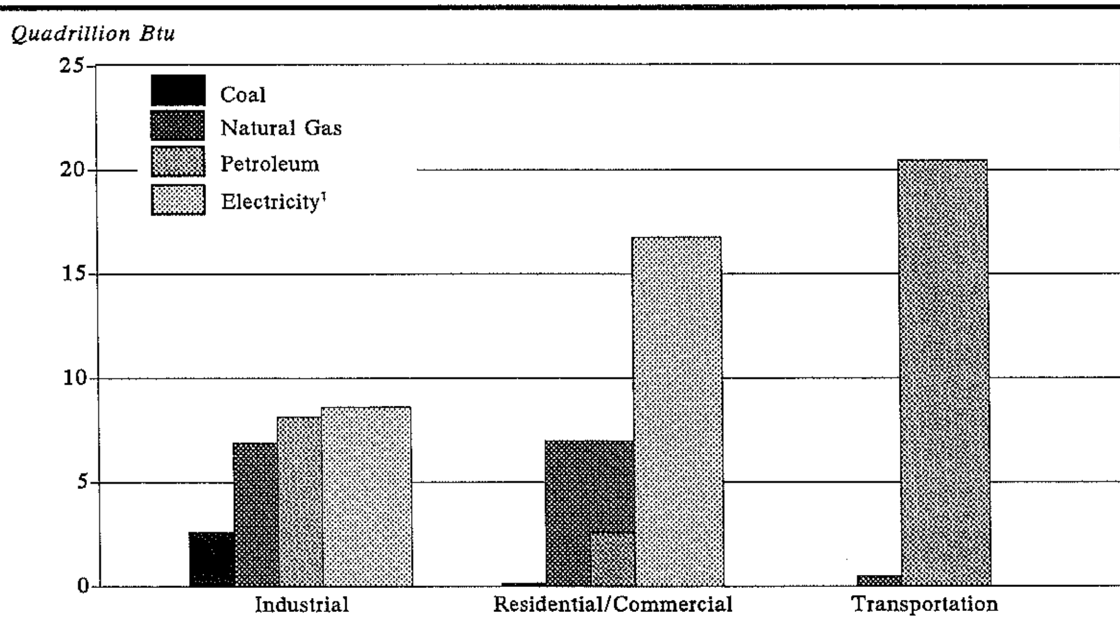
FIGURE 1 1987 U.S. Energy Inputs and Exports



SOURCES: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).
U.S. Department of Energy, Energy Information Administration, *Domestic Uranium Mining and Military Industry, 1986 Viability Assessment* (DOE/EIA-0477, 1986), pp. 9, 108, and 109.

NOTES:
1. Total production less exports is net production.
2. Includes natural gas plant liquids.

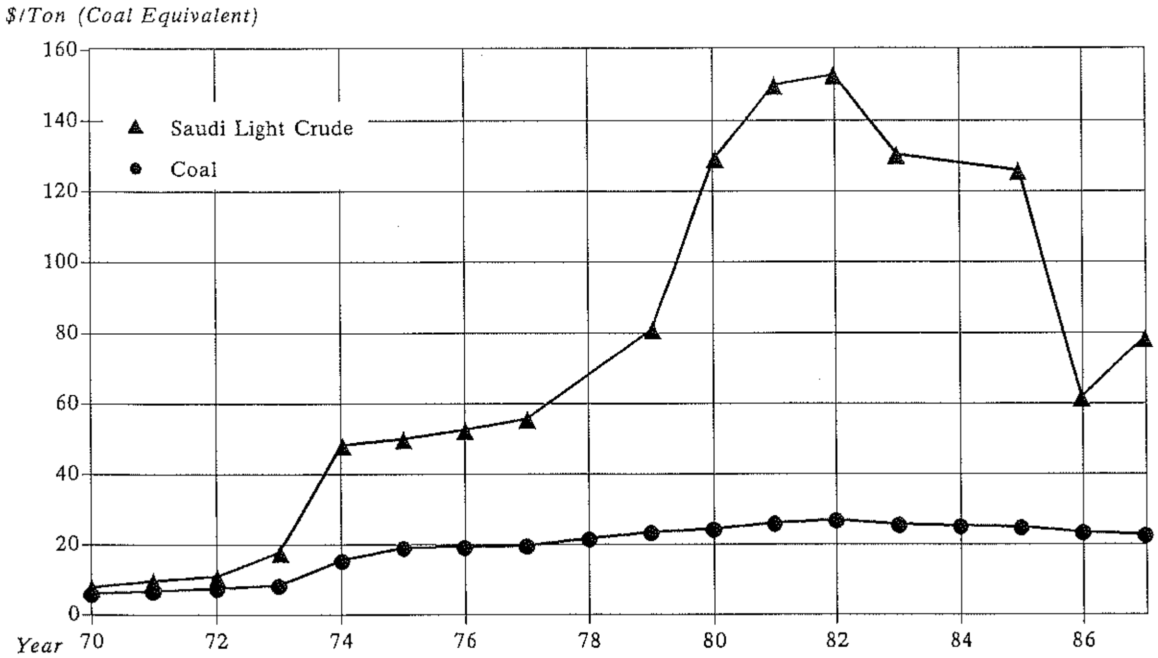
FIGURE 2 Energy Use by Energy Source



SOURCE: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).

NOTE:
1. Includes electrical system energy losses of 67%. (Electrical system energy losses are the amount of energy lost during generation, transmission, and distribution of electricity, including plant use and unaccounted for electrical energy.)

FIGURE 3 Historic Oil and Coal Pricing



SOURCES: U.S. Department of Energy, Energy Information Administration, *Coal Data: A Reference* (DOE/EIA-0064, 1985).

American Petroleum Institute, *Basic Petroleum Data Book*, September 1988.

NOTES:
Coal prices: FOB ($/short ton); current dollars.
Oil prices: $/ton (coal equivalent) = $/bbl current dollars x 4.5.

Considering potential market size first, natural gas provides the largest amount of energy used in the residential, commercial, and industrial sectors. The Department of Energy forecasts natural gas use will grow slightly more than 0.5 percent per year. Figure 4 shows 1987 use in each sector, along with DOE projections of the year 2000 consumption. A forecast by Data Resources, Inc. (DRI) is given for comparison. In the commercial area, both forecasts expect consumption in the year 2000 of about 2.7 quads.

In the residential sector, DOE expects consumption to decrease 0.1 percent per year, between 1987 and 2000, to 4.5 quads. DRI, on the other hand, predicts a decrease of about 1 percent per year to 4.0 quads.

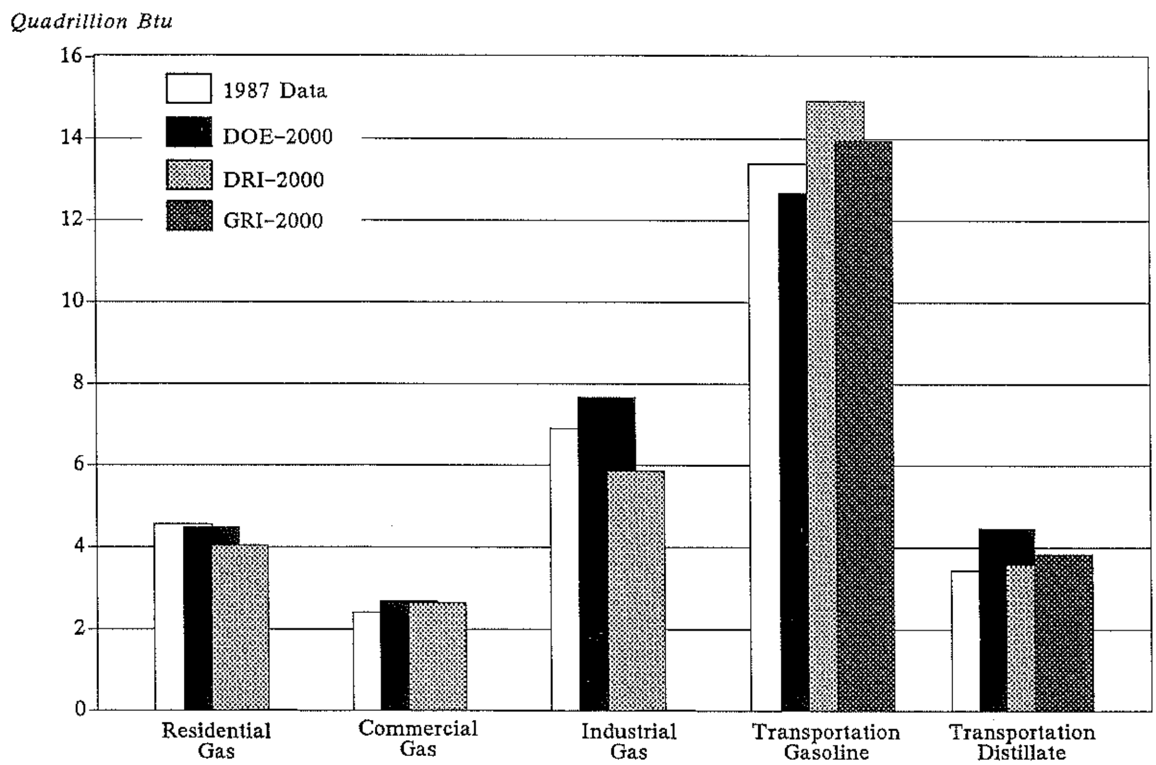
Figure 4 also shows the projected use of transportation fuels, the largest nonutility energy consumer. The DRI forecasts for diesel and gasoline differ considerably from the DOE Base Case. While the Gas Research Institute (GRI) and DOE expect distillate consumption in the year 2000 to increase to 3.8 quads and 4.5 quads, respectively, DRI predicts that diesel fuel use will remain constant at about 3.4 quads. In contrast, the DOE gasoline forecast shows a drop in use to 12.7 quads, while GRI and DRI expect gasoline use to increase to 14.0 quads and 14.7 quads, respectively. Regardless of which forecast proves to be more accurate, distillate and gasoline are significant transportation sector markets in which coal or coal-derived liquids could be used.

The Department of Energy has attempted to address some of the uncertainty in consumption forecasts by providing a range of estimates around the Base Case used on Figure 4. These estimates consider two scenarios: high world oil prices and a low economic growth rate, and low world oil prices with an accompanying high economic growth rate. A detailed description of these cases has been provided in Appendix A. Selected nonutility sector energy consumption estimates for the year 2000, based upon these three DOE cases, are shown on Figure 5. DRI and GRI projections have been included for comparison. These forecasts of natural gas use in the residential and commercial sectors and diesel fuel required for the transportation area are less than DOE's "High Price - Low Use" case. Conversely, DRI and GRI predict gasoline use higher than DOE's "Low Price - High Use" case. Again, this is another indication of the underlying uncertainty in predicting energy markets.

Energy prices for 1987, and DRI, GRI, and DOE Base Case price projections for the years 2000 and 2010, all in constant 1987 dollars, are shown on Figure 6. Natural gas prices in the residential, commercial, and industrial sectors are projected to increase in the year 2000 to $7.50, $6.00–$6.60, and $4.00–$4.50/MM Btu, respectively. DRI predictions are higher than those of DOE for commercial gas use, but lower for the industrial sector. The DRI forecast for the year 2010 shows further price increases to $10.20, and $8.60/MM Btu in the three areas.

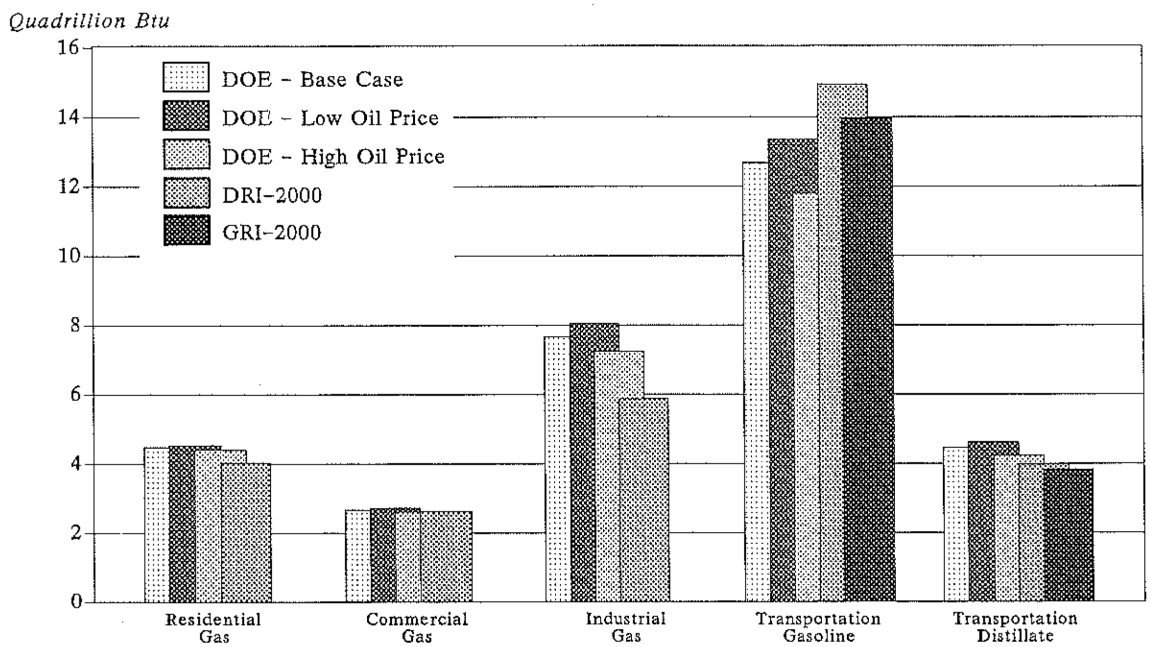
Forecasted gasoline prices in the year 2000 range from $10.10 to $11.10/MM Btu. Both DRI and GRI predict lower gasoline prices than in the DOE Base Case. For the year 2010, DRI and GRI projections are essentially the same, about $13.25/MM Btu of gasoline. The DOE Base Case forecast for the price of distillate is $8.60/MM Btu. Neither the DRI or GRI forecasts for this commodity are on a basis consistent with DOE data.

FIGURE 4 U.S. Consumption of Major Energy Products 1987 and 2000



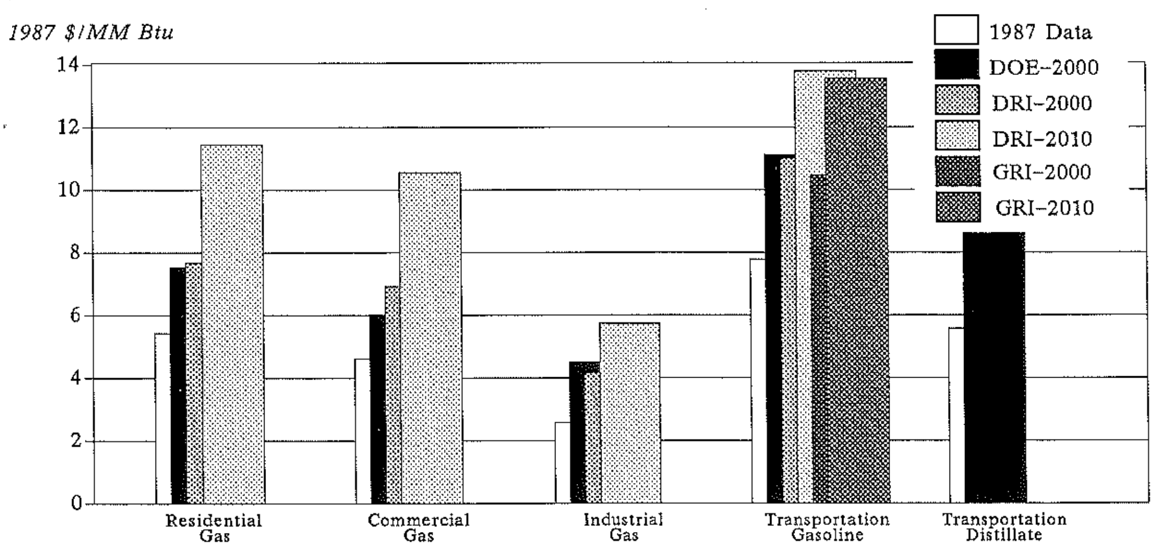
SOURCES: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).
Data Resources, Inc., *DRI Energy Review*, Winter 1987–88, Vol. 2, No.4.
Gas Research Institute, *1987 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, December 1987.

FIGURE 5 Energy Consumption Forecasts for 2000



SOURCES: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).
Data Resources, Inc., *DRI Energy Review,* Winter 1987-88, Vol. 2, No.4.
Gas Research Institute, *1987 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010,* December 1987.

FIGURE 6 Price Projections for Major Energy Products 1987, 2000, and 2010



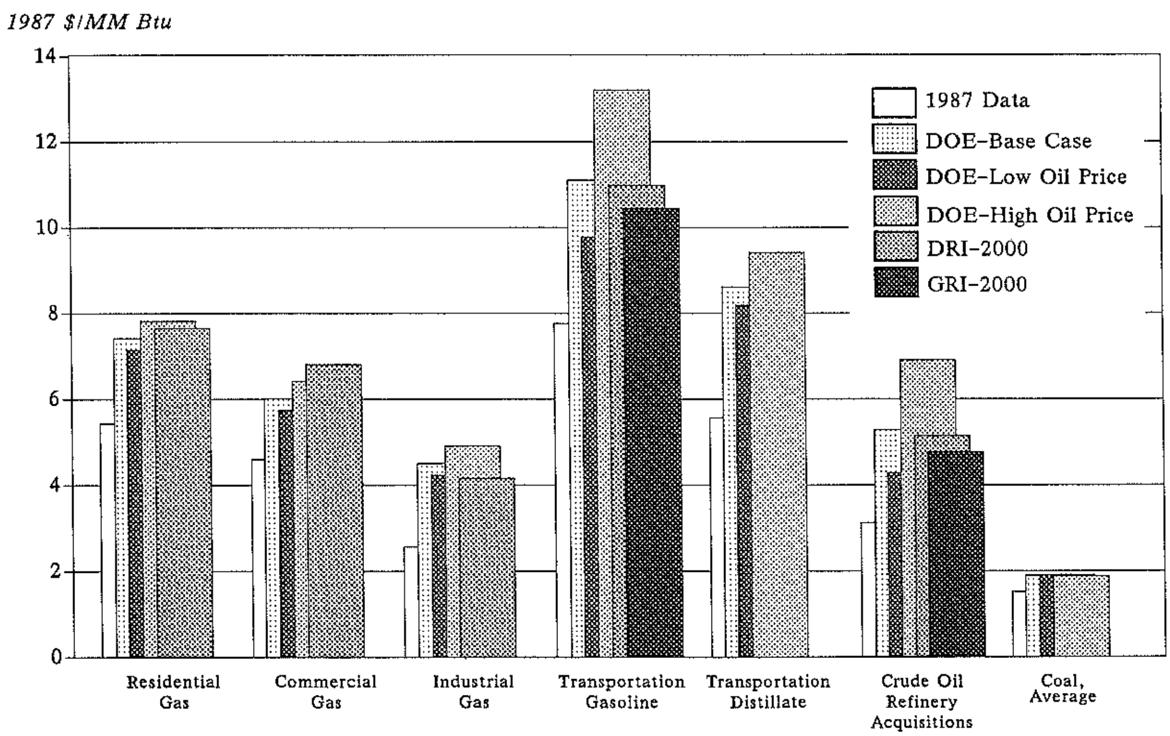
SOURCES: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).
Data Resources, Inc., *DRI Energy Review,* Winter 1987-88, Vol. 2, No.4.
Gas Research Institute, *1987 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010,* December 1987.

NOTE:
$/bbl oil equivalent = $/MMBtu x 5.79.

Department of Energy price forecasts for the Low Oil Price, Base, and High Oil Price cases in the year 2000 are shown on Figure 7. Where applicable, DRI and GRI data have been included for comparison. With one exception, all private sector price forecasts fall within the boundaries defined by DOE's High Oil and Low Oil Price cases. The exception is commercial sector natural gas, for which DRI predicts a slightly lower price than that of the DOE Low Oil Price Case.

As a measure of energy prices expected in the future, Figure 7 includes DOE (three cases), DRI, and GRI crude oil price projections for the year 2000 as well as DOE's predictions for coal prices in that year. For reference, 1987 costs also have been included. Between the years 1987 and 2000, crude oil prices are predicted to increase by at least 40 percent to $4.30/MM Btu or $24.90/bbl. The average of the private and DOE Base Case suggests crude oil prices of about $4.90/MM Btu, or slightly over $28/bbl. In DOE's High Oil Price Case, crude oil could cost as much as $40/bbl, or $5.30/MM Btu, an increase of 125 percent. During the same period, coal prices are expected to go up by about 25 percent from $1.53/MM Btu in 1987 to a high of $1.92/MM Btu. If coal, natural gas, and liquid fuels prices rise as predicted, a variety of coal-based technologies could provide economically viable liquid, solid, and gaseous substitutes for conventional energy sources. These projections provide the target price range at which coal-derived fuels must compete. With expected improvements in these technologies, many coal-derived fuels should be competitive by the turn of the century.

FIGURE 7 Energy Price Forecasts for 2000



SOURCES: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).
Data Resources, Inc., *DRI Energy Review*, Winter 1987-88, Vol. 2, No.4.
Gas Research Institute, *1987 GRI Baseline Projection of U.S. Energy Supply and Demand to 2010*, December 1987.

NOTE:
$/bbl oil equivalent = $/MMBtu x 5.79.

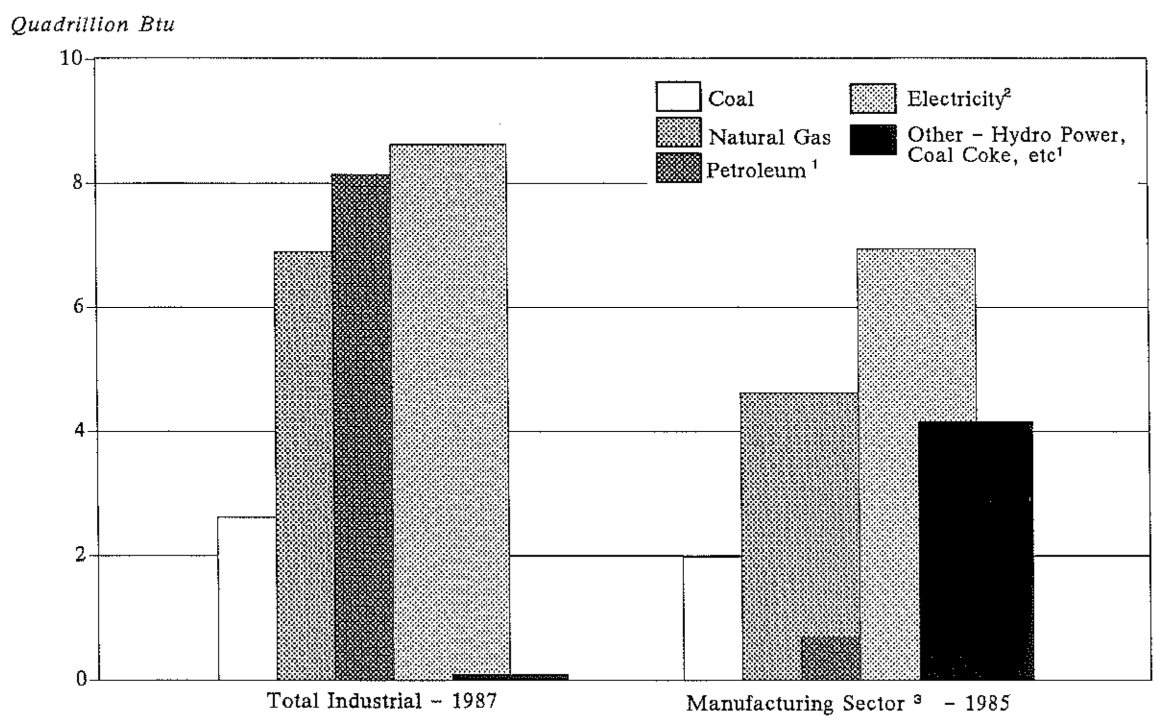
Chapter II

Industrial Sector

The industrial sector is defined as manufacturing, construction, mining, agriculture, fishing, and forestry establishments. A breakdown of energy sources utilized in the industrial sector is provided on Figure 8. The manufacturing component of the industrial sector[4] represents 67 percent of the energy use for this sector; therefore, it is also provided in Figure 8.

[4] U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review January 1987* (DOE/EIA-0035, January 1987), Table FE1.

FIGURE 8 Industrial Sector Energy Sources



SOURCE: U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review January 1987* (DOE/EIA-0035, January 1987).

U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).

NOTES:

1. Petroleum and Other are not reported on the same basis. Other for the manufacturing sector includes the following estimated petroleum-based fuels: Still Gas 1.2 quads, Petrochemical Feedstocks .82 quads, Petroleum Coke .47 quads, and LPG 0.1 quads.
2. Includes electrical system energy losses of 67%.
3. Manufacturing sector is 67% of total industrial sector.

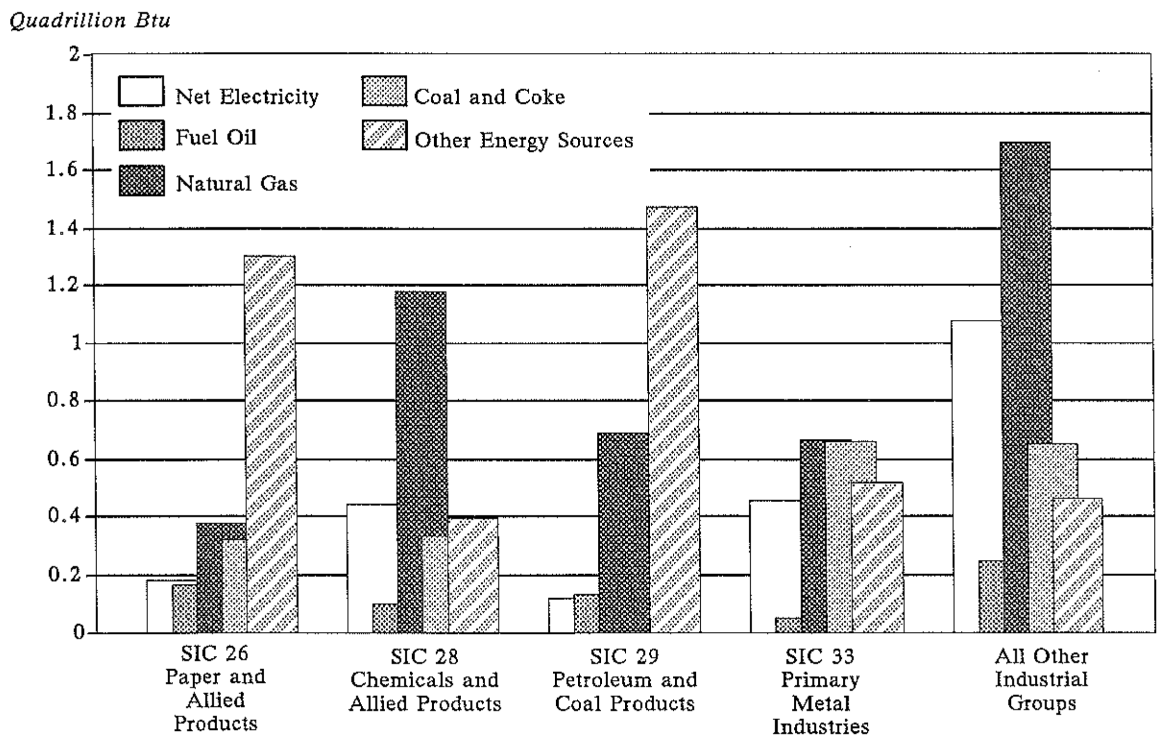
Overview

Energy consumption by major manufacturing business areas in 1985 is shown on Figure 9, representing the most current available data.[5] The consumption patterns in 1986 and 1987 are expected to be similar. Natural gas is the current fuel of choice in the manufacturing component of this sector, which is diverse in both needs and uses of energy. In general, the manufacturing industry is knowledgeable and able to influence the prices of energy sources (the amount of impact is based on the size of the user).

[5] U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review January 1987* (DOE/EIA-0035, January 1987), Table FE1.

Energy sources in the industrial sector are provided by well established distribution systems, such as truck, rail, pipeline, and wire delivery. This sector represents a more diverse number of energy sources than in the residential, commercial, and transportation sectors. Suppliers to industrial users include private and public power and natural gas distribution companies as well as petroleum- and coal-producing companies. The users of mobile industrial equipment depend on the transportation sector for delivery of liquid or compressed gaseous fuels; however, the use of large, centrally located, onsite or offsite storage facilities allows for bulk deliveries by the most economical means. The industrial sector typically does not involve as many levels of distribution as in the residential/commercial sectors.

FIGURE 9 Manufacturing Sector Energy Consumption by Industry Group 1985 Provisional Estimates



SOURCE: U.S. Department of Energy, Energy Information Administration, Office of Energy Markets and End Use, Energy End Use Division. Form EIA-846(F), *1985 Manufacturing Energy Consumption Survey.*

NOTE:
The consumption of energy for nonfuel purposes is not included.

The net energy (total energy use excluding electrical system energy losses) used in 1987 in the industrial sector was 20.6 quads, of which 2.63 quads were obtained from coal. These quantities are expected to increase to 24.2 and 2.83 quads, respectively, by the year 2000.[6] In this sector, coal is utilized for three purposes: as a feedstock for coke, for process heat and steam raising, and as a feedstock for chemicals.

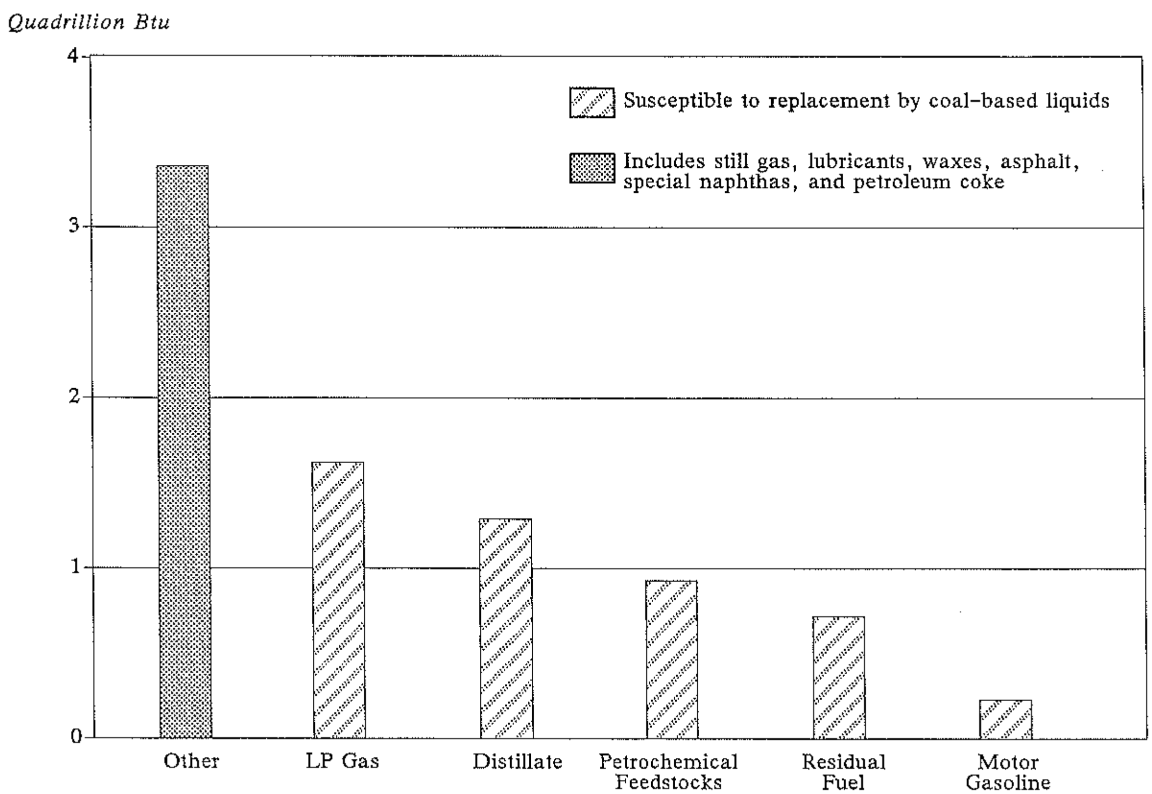
Energy consumption in the industrial sector is expected to increase by 3.58[6] quads from 1987 to the year 2000. Significant penetration of coal into the industrial sector can be achieved by replacing existing fuel, particularly natural gas and petroleum.

Natural gas consumption in the industrial sector was 6.9 quads in 1987. Coal-derived medium and low Btu gas could replace most of this energy. Industrial sector petroleum consumption in 1987 was 8.15 quads.[6] The breakdown of petroleum products consumption is shown on Figure 10. Coal-derived liquids could replace about 3.86 quads of petroleum liquids and liquified petroleum gas (LPG). Other uses of petroleum include lubricants, petroleum coke, waxes, and still gas, which do not appear to be susceptible to replacement.

The largest industrial sector energy input in 1987 was purchased electricity at 8.63 quads, 5.78 quads of which was lost in the electrical system itself. Electrical system energy losses are the amount of energy lost during generation, transmission, and distribution of electricity, including plant use and unaccounted for electrical energy. More than half the electrical energy in the U.S. is generated with coal. Cogeneration has had a significant impact on the electric utilities industry. Total cogeneration at the end of 1986 was 20,000 MW.

[6] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987), Table A2.

FIGURE 10 1987 Consumption of Petroleum Products – Industrial Sector



SOURCE: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outook* 1987: *With Projections to 2000* (DOE-0383, 1987).

This is forecasted to increase to 46,475 MW by the year 2005. The Public Utility Regulatory Policies Act of 1978 requires utilities to purchase cogenerated power at the utilities "avoided cost." The coal use in new industrial cogeneration facilities (i.e., 21,650 MW 1987 to 2005) could amount to 1.95 quads/year.[7]

Of the technologies available to increase the use of coal, coal gasification has a wide variety of potential applications. The products from gasification can be used as raw material for producing organic and inorganic chemicals, power generation, alternate methods of destroying organic wastes, and to generate process steam. Coal gasification processes yield a carbon monoxide and hydrogen gas mixture. Sulfur compounds in the coal can be converted to hydrogen sulfide and then into elemental sulfur which is suitable for sale. Particulates are removed from the gas to yield a clean fuel or chemical feed stream. Slag coming from high temperature gasifiers is classified as a nonhazardous material suitable for use as an aggregate, in road building, or for other similar applications.

Technologies and Applications

The following technologies, listed in alphabetical order, will allow coal to penetrate the industrial sector:

- coal gasification
- coal liquid mixtures
- coal preparation and cleaning
- direct fired heat engines (i.e., gas turbines, diesels)
- direct liquefaction
- fluidized bed and other combustion techniques
- hot gas clean up
- indirect liquefaction (i.e., Fischer–Tropsch, methanol)
- micronized/pulverized coal
- pyrolysis

Commercially proved technologies are available for the manufacture of coal liquids and gases; these are summarized in Appendix B. Opportunities are now available for these technologies, and widespread use may occur when the price of oil rises to $30/barrel in 1988 dollars. Of the technologies listed above, those in commercial use today are coal gasification, micronized/pulverized coal, fluidized bed combustion, and coal cleaning.

The industrial use of coal can be expanded by the application of technologies capable of providing either steam or a combination of steam, power, and/or raw materials for chemical manufacture and other uses. Consideration should be given to the choice of technology depending upon the end use and requirements for products in the industrial sector. For example, a fluidized bed boiler may be more desirable if the end product is steam and/or power only. On the other hand, coal gasification may be a desirable way to produce co–products such as steam, power, and raw materials for manufacturing chemicals, e.g., ammonia methanol or oxo–chemicals. The potential for increased coal use in the industrial sector, as shown in Table 1, is approximately 134 million tons per year. Potentially, during the next 10 years, half of this amount could be put into place as aging boilers are retired, oil and natural gas prices rise, and chemical manufacturing raw materials change.

Research and Development

Advanced industrial applications using coal in an environmentally acceptable manner are being investigated in the U.S. through government and private funds. The Department of Energy provides leadership and some financial resources in these research and development activities, and also encourages and promotes industry and academic institutions to team up on advanced research and development. This cooperation is essential to maintaining a balance in project orientation toward a viable product.

[7] Cogen Additions of 46,475 MW by 2005 Projected in New Study. *Cogeneration*, Pequot Publishing, November–December 1987, p. 26.

TABLE 1
SELECTED INDUSTRIAL COAL USES
(million tons/yr)

Use	1987	Minimum Potential
Fuel	9.1	91
Methanol	0.3	45
Oxo-Alcohols	–	4
Ammonia	–	27
Sugar Refinery	–	3–4
Cement Kilns	–	2–3
	9–10	131–134

SOURCES:

Letter dated September 9, 1988, from W. R. Siegart, Texaco Inc., White Plains, NY, to J. J. M. Plante, Stone & Webster Engineering Corporation, Boston, MA.

Data Resources, Inc., *DRI Energy Review,* Winter 1987-88, Vol. 2, No. 4, Table A-1.

U.S. Industrial Energy Market Outlook, Vol. II. Petroleum Industry Research Associates, Inc. and Dun & Bradstreet Technical Economic Services, 1986.

1987 Directory of Chemical Producers, SRI International.

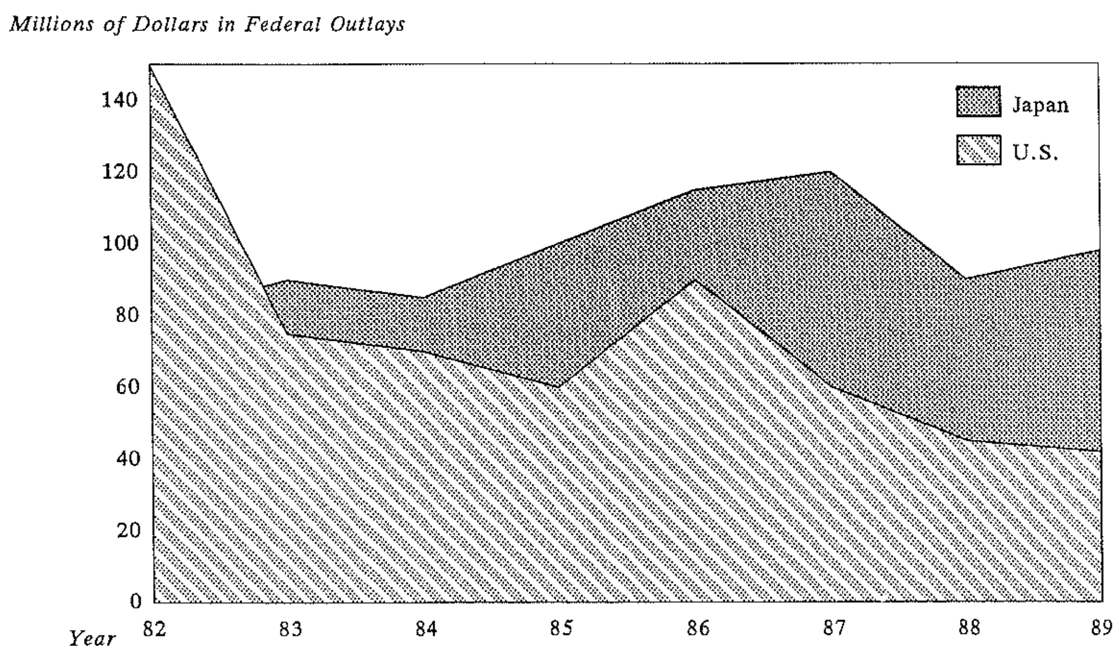
Chemical Economics Handbook, SRI International.

Compared with Japan and West Germany, research and development efforts in the U.S. are modest. Japan surpassed the U.S. in research and development for coal liquefaction and gasification in 1983 as shown on Figure 11. In fiscal 1987, Japan spent twice as much on coal gasification/liquefaction research and development as the U.S., despite the fact that the Federal budget of the U.S. Government was three times that of the Japanese Government. The Federal Republic of Germany reported planned 1987 expenditures for coal research and development of $167 million[8] compared to the Office of Coal Technology's 1987 budget of $253 million.[9] To summarize, Japan spent about $1.00 per person on coal liquefaction and gasification research and development while the U.S. spent 25 cents per person; West Germany spent $2.75 per person on coal research and development while the U.S. spent $1.00 per person.

[8] *Research and Development Progress in the German Hard Coal Mining Industry.* Paper presented at the 13th Meeting of the International Committee for Coal Research, September 1987.

[9] U.S. Department of Energy, Office of Coal Technology. *Fiscal Year 1988, Program Plan March 1988* (DOE/FE-0102, March 1988), p. 3.

FIGURE 11 U.S. Lagging in Coal Gasification/Liquefaction R&D



SOURCE: Council on Alternate Fuels, Washington, D.C.

Challenges and Opportunities

In 1987, major users of coal in the industrial area were chemicals and allied products; stone, clay, and glass products; paper and allied products; primary metal industries; petroleum and coal products; and food and kindred products.[10]

Presently, the most important use of coal in the industrial sector is coke production. In 1987, 37 million tons of coal was carbonized to produce 28 million tons of coke. This was an increase of 9.8 percent over 1986 tonnage (25.5 million tons of coke).[11] Aging coke facilities are not being replaced due to environmental and economic reasons.

There are two challenges facing coal use in the industrial sector. The first is to protect the current coal market represented by over 8,000 large industrial steam boilers in service today.[12] The second is to capitalize on the potential of coal to replace oil and gas boilers, both current and future, by making coal substitution economically and environmentally attractive.

Another important consideration is the average age of existing coal-fired boilers in this sector. Approximately 50 percent have been in use for over 20 years[13], and owners are faced with increasing maintenance costs, lower availability, and environmental concerns. Currently, a boiler owner's alternatives are to replace coal in the boilers with oil or gas or to replace the boiler with new oil or gas units. A solution to the aging boiler problem is the application of clean coal technology alternatives. These alternatives, as well as other research and development activities of DOE, could be competitive with either natural gas or oil. To preserve existing segments and to penetrate new areas, the stategy must be competitive on a product-cost basis (steam, power, chemical, etc).

With industry using more coal in an environmentally acceptable manner, the U.S. economy can only benefit. To add a degree of certainty to decisions concerning investment in large industrial coal plants, some improvements in the regulatory process are needed. There must be a system that provides for rapid and clearly defined permitting. Inconsistencies or overlaps between state and Federal regulations must be resolved whenever they occur. In order to encourage investment in industrial coal use, regulatory systems must be streamlined to allow for objective, environmentally sound decisions. To encourage increased industrial coal use, the Federal and State Governments also should consider special investment tax credits and rapid depreciation schedules to encourage change to, or initial use of, coal in industry. The technology is available today to use coal cleanly and economically as a fuel for industry and as a raw material for chemicals.

[10] U.S. Department of Energy, Energy Information Administration, *Quarterly Coal Report October-December 1987* (DOE/EIA-0121, Fourth Quarter, 1987) Table 30.

[11] Ibid., Appendix A.

[12] Letter dated September 15, 1988, from E.T. Robinson, Standard Oil, Advanced Fuel Technology Company, Bridgeport, NJ, to J.J.M. Plante, Stone & Webster Engineering Corporation, Boston, MA.

[13] Verbal Communication: W.B. Marx, President, Council of Industrial Boiler Owners, Burke, VA, and J.J.M. Plante, Stone & Webster Engineering Corporation, Boston, MA.

Chapter III

Commercial Sector

The commercial sector encompasses nonmanufacturing business establishments, including hotels, motels, restaurants, wholesale businesses, retail stores, laundries, and other service enterprises; health, social, and educational institutions; and Federal, state, and local governments. Street lights, pumps, bridges, and public services also are included.

Overview

Energy consumption in this sector was 6.10 quads in 1987, and it is expected to grow to 7.30 quads by the year 2000. The principal sources of energy for the commercial sector in 1987 were natural gas (2.40 quads) and net electricity (2.58 quads). Together these accounted for 81.6 percent of the energy consumed in the commercial sector. The total 1987 energy input to the commercial sector, including electrical system losses, was 11.34 quads.[14]

Natural gas is the principal fuel in the commercial sector; however, cogeneration and district heating have the greatest potential for coal to impact in this sector. It is estimated that cogeneration in this sector will grow to 4825 MW by the year 2005. The annual energy input for 4825 MW is 0.43 quads, including electrical system losses.[15]

Equipment designed for coal firing, in a suitable range of capacities and a manufacturing service infrastructure, is necessary to promote the use of coal in this sector. Usually air conditioning as well as heating systems are necessary.

In cogeneration and heating use, many of the developing clean coal technologies would be suitable. Several coal technologies in appropriate capacity must be made available commercially to cover all facets of this sector's energy demands (i.e., absorption chillers).

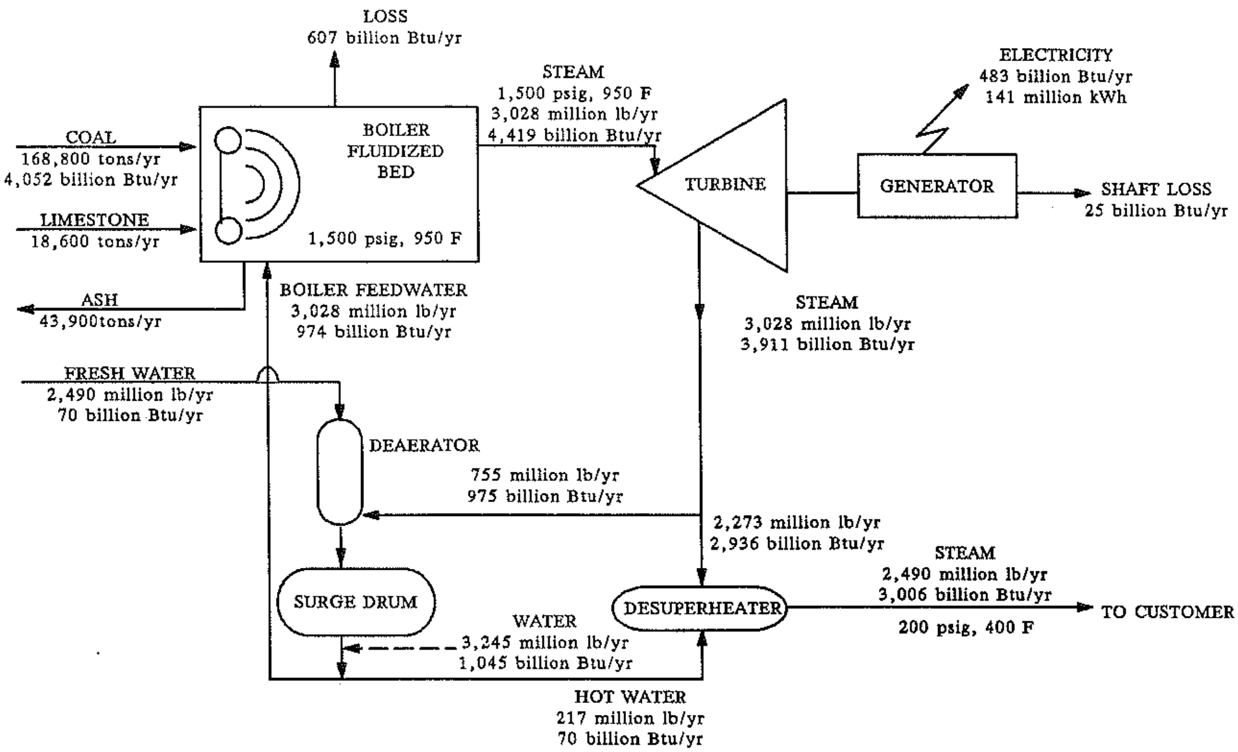
District Heating

A survey of this industry indicated that 29 existing systems, representing 120 trillion Btu of annual energy input, could convert from other hydrocarbon fuels to coal. At 24 million Btu per ton of coal, district heating represents a conversion potential of 5 million tons of coal annually. The economics of a district heating system are illustrated on Figure 12 and in Table 2. Table 2 demonstrates that coal-based district heating currently is economically attractive. Increased use of coal beyond existing systems should be explored in depth.

[14] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: with Projections to 2000* (DOE/EIA-0383, 1987), Tables A1 and A2, pp. 33 and 34.

[15] Cogen Additions of 46,475 MW by 2005 Projected in New Study. *Cogeneration*, Pequot Publishing, November-December 1987, p.26.

FIGURE 12 Example: District Steam Plant Configuration



SOURCE: Catalyst Thermal Energy Corporation, Engineering Department, Nashville, TN. May 1988.

TABLE 2 Example: Economics of a District Steam System Operation

				$000/year
Pay for coal, delivered	168,800 tons/yr	@ $35.00/ton		5,908
Pay for limestone, delivered	18,600 tons/yr	@ $12.50/ton		233
Pay for ash removal	43,900 tons/yr	@ $23.50/ton		1,032
Pay for water, chemicals, electricity:	2,490 mlb/yr	@ $0.25/mlb		623
Pay for 18 jobs @ $40,000/yr (average including burden and benefits)				720
Pay for maintenance, taxes, insurance, and all other overhead				500
	Subtotal			**9,016**
Pay Capital Charge: $36,000,000 for 20 yr @ 10% VOM[1]				4,228
	Cost of steam and electricity			**13,244**
	Electricity sales priced at		$.03/kWh	$.05/kWh
Receive Credit for Sale of 141 x 10[6] kWh/yr			*4,230*	*7,050*
Cost of steam after electricity credit			$9,014	$6,194
Cost of steam $/MMBtu at steam plant			$3.00	$2.06
Cost of steam $/MMBtu delivered to customer (15% loss)			$3.53	$2.42

SOURCE: Baltimore Thermal Energy Corporation, Baltimore, MD.

NOTE:

1. Assumes 500,000 lb/hr plant @ $56/hourly lb will cost $28,000,000; 10,000 ft of main trunk line @ $600/ft or $6,000,000; and 5,000 ft of distribution network lines at $400/ft or $2,000,000. Total cost of system is $36,000,000.
2. Figure 12 illustrates a fluidized bed boiler in a district steam plant application. Other configurations such as coal gasification combined cycle and conventional coal boilers also are feasible.

Universities and Colleges

There are approximately 2500 universities and colleges in the U.S. Based upon data from a survey of 500 institutions (125 responded), the following extrapolations, using 2500 institutions as the basis, have been made to derive the hydrocarbon to coal conversion potential for this energy consuming group.[16]

- There are 200 institutions which are supplied steam for heating and air conditioning from local district heating and cooling systems.
- There are 500 institutions which fuel their own "district" heating and cooling systems with coal.
- There are 1800 institutions which fuel their own "district" steam systems with hydrocarbons. The average energy consumption of each institution in this group is 300 billion Btu per year.

The 1800 institutions which fuel their own district steam systems consume 540 trillion Btu of hydrocarbon fuels annually and represent a conversion potential of 22 million tons of coal annually.

Hospitals

There are nearly 7000 hospitals in the U.S. Based upon survey responses from 37 VA hospitals and information from the International District Heating and Cooling Association, the following extrapolations, using 7000 hospitals as the basis, have been made to derive the conversion potential of this group.[16]

- There are 2800 (40 percent) U.S. hospitals currently being supplied steam from local district heating companies or are currently using coal. This hospital subgroup represents the larger hospitals which exist in the larger metropolitan areas of the U.S.
- The 2100 (30 percent) U.S. hospitals in the "sun belt" are not susceptible to coal conversion, except under strong economic or legal pressures.
- The remaining 2100 hospitals each consume an average of 65 billion Btu of hydrocarbon energy annually and are susceptible to conversion.

These 2100 hospitals consume 130 trillion Btu annually and represent a conversion potential of 5 million tons of coal annually.

Federal Government Facilities

Throughout the country, the Federal Government maintains facilities to accommodate the operations of various Federal Agencies and Departments. These facilities represent a potential market for increased utilization of coal/coal-derived fuels.

A recent chart published by USA TODAY, August 30, 1988, using Energy Information Administration data, showed energy use by various Federal Government Agencies as follows:

Department	Energy Use in Trillion Btu
Defense	1,497.8
Energy	93.2
Postal Service	53.4
Veterans' Administration	42.0
General Services Administration	32.4
Transportation	28.3

Increased use of coal/coal-derived fuels in Federal facilities could serve as a role model or proving ground for similar applications in both state and local government facilities, especially in the coal-producing states. Because Federal facilities are widely dispersed on a geographic basis, a broad-based infrastructure would be created for the delivery of coal-based fuels, for the removal of ash and other waste products, and for the servicing of attendant equipment. Targets of opportunity for increased coal use include, but are not limited to, the Departments of Energy, Defense, Justice, Interior, Labor, and Agriculture; the General Services Administration, the U. S. Postal Service, and the Veterans' Administration.

U.S. Military Installations

U.S. military installations are included as a part of government entities. Because of national security

[16] Letter dated September 7, 1988, from M.O. Hill, Baltimore Thermal Energy Corporation, Baltimore, MD, to J.J.M. Plante, Stone & Webster Engineering Corporation, Boston, MA.

implications, definitive and comprehensive data reflecting the total energy consumption of the U.S military establishment are unavailable. Data are available and made public by the Department of Defense in conjunction with the Department of Energy concerning the use of petroleum products in U.S. military installations as well as the procurement of those products.

During peacetime, the U.S. military establishment uses the equivalent of approximately 3 percent of the petroleum products consumed by this country. For fiscal year 1986, Department of Defense data reflected total petroleum consumption of 180.1 million barrels.[17] A breakdown by fuel type showed over two-thirds of this total, or 72.4 percent, for jet fuel; 17.4 percent for distillate/diesel; 7.2 percent for fuel oil; 2.4 percent for gasoline; 0.5 percent for the Navy (special purpose); and 0.1 percent for other. Of the total amount of petroleum required by the military, 70 percent was satisfied by procurement in the continental United States and Canada.[18]

The amount of military fuel purchased directly from Persian Gulf countries (Bahrain, Iran, Iraq, Kuwait, Qatar, Saudi Arabia, and the United Arab Emirates) has been decreasing in recent years: 7 percent was recorded in 1985, 6 percent in 1986, and 5 percent in 1987.[18] Indirect purchases of military fuel from Persian Gulf countries, i.e., petroleum products purchased outside the Gulf but refined from Persian Gulf crude oil, are not included. While purchases from various sources of supply fluctuate from year to year, purchases in the continental United States and Canada have been increasing from 331,000 barrels per day in 1985 to 350,000 barrels per day in 1987.

[17] U.S. Department of Defense and U.S. Department of Energy, *National Defense Authorization Act for Fiscal Years 1988 and 1989 (Public Law 100-180), A Report to the Congress: Contingency Plans to Deal with Disruption in Persian Gulf Crude Oil Supply.* (March 1988), p. 12.

[18] Ibid, p. 11.

Challenges and Opportunities

To implement a significant conversion from hydrocarbons to coal in the commercial sector of the United States marketplace and to solve the problems of insufficient land and shortage of capital, the following general strategies are suggested.

1. Create new district steam systems with coal fuel plants capable of cogenerating electricity; locate such systems in semi-rural or industrial areas to facilitate siting and permitting; deliver the steam to the consuming points by a long main trunk pipeline (2 miles or so) and hook up to a cluster of consumers, say within 1 mile of a secondary distribution network.

2. To stimulate such a strategy, the siting and permitting process must be streamlined, but most important would be to make available long-term, low-interest borrowings to the entities who would develop such district heating and cogeneration systems.

3. In the commercial sector, promote the use of electricity which could be furnished from coal-fueled power plants.

4. Increase coal's penetration in universities and colleges, military installations penitentiaries, airports, industrial/office parks, and sports complexes through government/industry interaction.

Chapter IV

Residential Sector

The residential sector consists of private household establishments that consume energy primarily for space heating, water heating, air conditioning, lighting, refrigeration, cooking, and clothes drying. The sector also includes multi-family dwellings and apartment and condominium complexes.

Overview

In 1940, 19,056,000 housing units[19] were heated with coal or coke. This comprised about 55 percent of the housing unit total of 34,855,000. According to a 1984 Department of Energy Residential Energy Consumption Survey, approximately 700,000 households burn coal as their primary heating fuel, less than 1 percent of the total housing units. Of that total, roughly 400,000 are located in the south and 300,000 are in the northeast. In the midwest, less than 100,000 households burn coal as their primary fuel source for heating. In addition to space heating requirements, coal-fired boilers account for hot water requirements in about 200,000 residences. The 1984 distribution of some of the residential appliances that consume energy is shown in Table 3.[20]

[19] U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1975* (Washington, D.C., 1975), Table 1234, p. 722.

[20] U.S. Department of Energy, Energy Information Administration, *Housing Characteristics 1984: Residential Energy Consumption Survey* (DOE/EIA-0314, 1984), p. 1.

Table 3
1984 Residential Energy Equipment Use[1]
(in millions of housing units)

Primary Heating Fuel		*Air Conditioners*	
Natural Gas	47.9	Room	26.8
Fuel Oil,		Central	24.6
Kerosene	12.2		
Electricity	14.5	*Water Heaters*	
LPG	3.9	Electric	27.9
Wood	6.5	Natural Gas	41.3
Coal[2]	0.7	Other	2.8
Ranges			
Electric	46.5		
Natural Gas	39.0		
Total Occupied Housing Units	86.3 million		

SOURCES:

[1] U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1987* (Washington, D.C., 1987), Table 1288, p. 713; Table 1289, p. 714.

[2] U.S. Department of Energy, Energy Information Administration, *Housing Characteristics 1984: Residential Energy Consumption Survey* (DOE/EIA-0314, 1984), p. 1.

Energy consumption in the residential sector in 1987 was 9.09 quads, and this is expected to grow to 9.67 quads by the year 2000.[21] Patterns of energy consumption are shown on Figure 13.

[21] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987* (DOE/EIA-0383, 1987), Table A2, p. 34.

As shown on Figure 13, natural gas and electricity are the most significant energy sources in this sector. Other types of fuel are petroleum-based distillate and liquified petroleum gas. These fuels can be replaced by coal in three ways: as gaseous or liquid fuels if no appliance or equipment changes are contemplated; as coal liquid mixtures and improved solid fuels from coal with equipment changes; or indirectly by increased electricity use generated from coal. Electricity can be considered an indirect use of coal because more than 50 percent of the energy supplied for electricity comes from coal.

Technologies and Applications

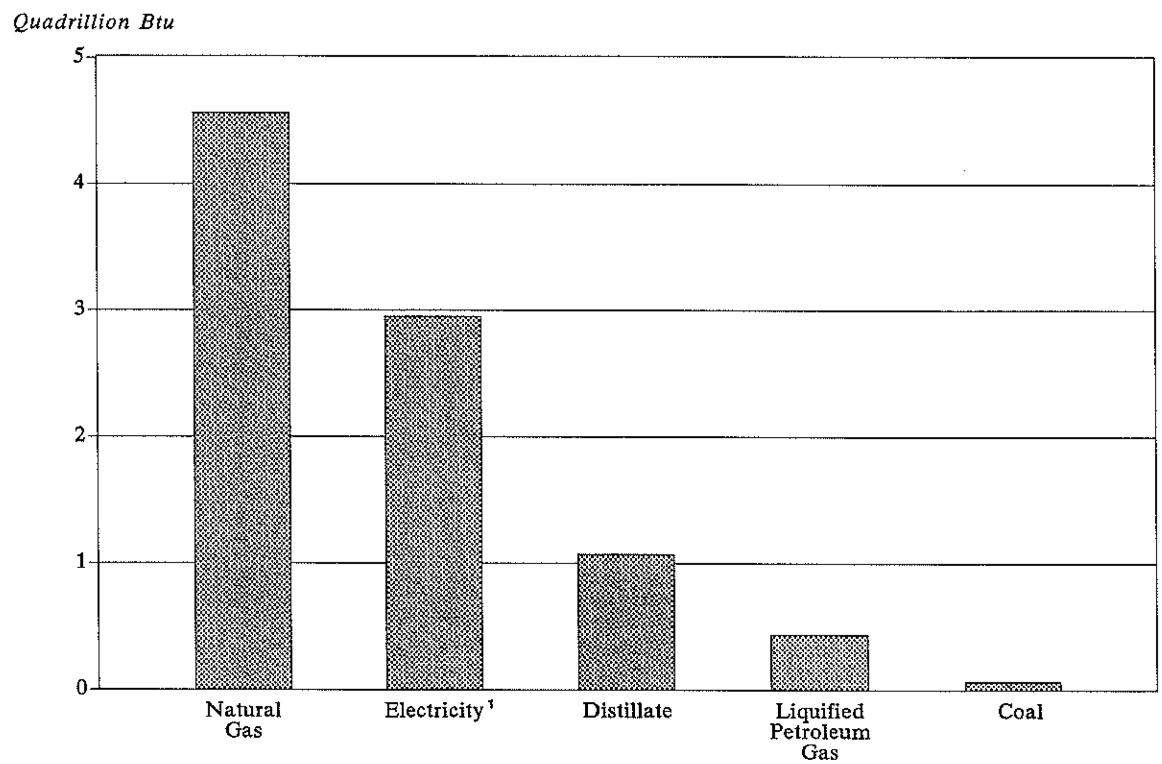
This section addresses residential applications in two technological areas: coal-based fuels and direct-coal firing. The application of coal in the residential sector, more than in any other sector, will be influenced primarily by public perception. Secondary but important considerations include convenience and cost. Before these technologies can capture any significant share of the residential market, the equipment developed will have to be convenient to use, aesthetically pleasing, and environmentally acceptable.

Two coal-based fuels that may satisfy this need are clean coal liquid mixtures and clean dry pulverized coal fuels. Development efforts on both fuels are quite advanced with dry fine-coal technology already implemented in the Federal Republic of Germany and Japan.

Direct-coal firing technologies have been developed. To broaden the application of these technologies to meet the specific needs of the residential sector, additional work in specific areas is needed.

- Develop smaller combustors which are more compatible with the average energy consumption in new homes being built.

FIGURE 13 1987 Residential Energy Consumption Pattern



SOURCE: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).

NOTE:
1. Does not include electrical system energy loss estimated at 6.76 quads.

- Design suitable coal and ash handling systems which will not significantly increase the capital cost of coal-fired systems, and which do not require constant customer involvement.
- Offer the residential user a commercially available package of equipment and service which is competitive with existing fuel sources.

The British Coal Corporation's Coal Research Establishment is developing a self de-ashing, underfeed stoker with retort sizes from 60,000 Btu/hr to 500,000 Btu/hr in both boiler and hot air versions. They also are developing a downdraft burning open fire room heater and boiler, and a system with automatic coal feed from an overhead hopper. These products would have to be tested with American coals prior to introduction into the U.S. market. Similarly, the United Kingdom has developed a range of residential coal-fired appliances for use in smoke control areas which would have to be tested in the U.S. Particulate emissions from these appliances conform to current United Kingdom regulations.

Transportation and Distribution

Bulk transportation of coal in the U.S. should not be a problem. Coal-fired power stations (1283 units) exist throughout all states except Maine, Idaho, California, and Hawaii.[22] Coal is produced in over 4000 mines in 26 states.[23] Because transportation systems are in place to service coal-fired power stations and mines, the ability to get coal in the vicinity of most areas in the U.S. already exists. Two scenarios are suggested for developing a residential coal solid fuel product.

- Mine-mouth coal beneficiation and blending plants (including SO_2 reduction reagents) to permit distribution in car-lot loads directly to a local distributor who would then deliver the shipments to the individual residential users.
- Local beneficiation and blending plants near the coal power plant delivery points operated by the local bulk distributor.

[22] U.S. Department of Energy, Energy Information Administratin, *Inventory of Power Plants in the United States 1985* (DOE/EIA-0095), Figure 1, p. 3.

[23] U.S. Department of Energy, Energy Information Administration, *Quarterly Coal Report* (DOE/EIA-0121 (8742) Table 3, p. 16; Table B5, p. 87.

The coal-based solid fuel would meet environmental requirements by proper blending with reagents and could be in various forms -- solid sized compliance coal or processed fuels such as pellets, dry powders, or briquettes specially formulated for residential use.

In a manner similar to gas and electric companies in the past, local distributors could enhance the service provided by including appliance sales and service, coal delivery, and ash removal for the residential users. Such a distribution and service infrastructure would have to be developed.

Challenges and Opportunities

In general, major impediments to increasing the residential market for coal are as follows.

1. The initial capital cost for installation of coal burning equipment is higher than for other fuels, even though the cost of coal is lower than that of other fuels.

2. Coal is perceived by the public as a dirty fuel.

3. Most coal-fired boilers and hot air furnaces manufactured in the U.S. are limited in size, most of which are larger than required for the average residence. With better insulated houses and with the typical house having about 2000 to 2500 square feet, the average boiler size is around 65,000 to 80,000 Btu. The smaller coal-fired American central heating systems are usually 100,000 Btu. It should be noted that others, most notably the British, have smaller sizes in commercial production.

4. Coal is inconvenient to handle and store. Ash removal is inconvenient, and coal delivery is difficult in many urban settings. Systems now in use in other countries should be studied for possible use in the United States. Retail delivery of coal, as set forth in the preceding discussion, presents its own set of challenges and opportunities.

5. There is a lack of public awareness regarding the use of coal in residences. Proactive public education programs should be initiated so the public can become more knowledgeable.

Chapter V

Transportation Sector

The transportation sector includes private and public vehicles that move people and commodities; i.e., automobiles, trucks, buses, motorcycles, railroads, air craft, ships, barges, and natural gas pipelines. This sector does not include mobil equipment in the industrial sector that utilizes central refueling stations onsite. Transportation energy consumption sources are provided on Figure 14, and energy use by mode of transportation is presented on Figure 15.

Overview

The United States uses more oil for transportation alone each year than it produces domestically.[24] Coal-derived liquids can be used to replace substantial quantities of this oil. The transportation sector consumes 27 percent (21.2 quads) of the total U.S. energy input, but it consumes nearly two-thirds of the oil used in this country. This heavy dependence on petroleum-derived energy requires large imports of foreign oil, which currently accounts for 25 percent of the current U.S. trade deficit.[25] Even if the recent low level of oil prices persists, the country could grow to depend on foreign imports for more than 50 percent of its oil supplies by 1990. The transportation sector is expected to increase to 22.3 quads by the year 2000. Specifically, the transportation sector currently uses approximately 10.5 million barrels of oil per day,[26] but when mobile equipment in other energy sectors is included, this consumption increases to 11.0 million barrels per day.[27] Highway transportation is entirely dependent upon petroleum fuels, while non-highway transportation utilizes small amounts of natural gas and electricity in addition to petroleum fuels.

The past use of coal in steamships and steam locomotives is a matter of historical record. As late as 1950, more than half the locomotives in the U.S. were steam driven, using 55,452,000 short tons of coal as fuel. Correspondingly, steamships used 20,000,000 short tons of coal in 1950.[28] These facts demonstrate that even in 1950, when coal use was waning in the transportation sector, coal quantities in this sector were significant. Today, approximately 12,000 steam locomotives are in common use throughout the world (this figure does not include the USSR).[29] It may be presumed that many of these locomotives are coal-fired.

Transportation sector fuel economics are particularly sensitive to the energy content per unit of volume of the fuels involved. Coal-derived liquids, coal liquid mixtures, and electricity may be more suitable for use in the transportation sector.

[24] U.S. Department of Energy, *Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector: Progress Report One*, January 1988.

[25] U.S. Department of Commerce, *Survey of Current Business* (Vol. 68, No. 4) April 1988, pp. 5-16 and 5-17.

[26] U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987*, Figure 7, p. 8.

[27] Oak Ridge National Laboratory, Transporation Research. *1988 Automated Transportation Energy Data Bank* (Draft), May 31, 1988.

[28] U.S. Department of Commerce, Bureau of the Census, *Statistical Abstract of the United States 1975*, Tables 979 and 980, p. 583, and Table 1161, p. 684.

[29] Jane's Publishing, Inc., *Jane's World Railways, 1987-1988*.

It should be noted that the transportation of coal, this country's largest solid bulk commodity, is accomplished primarily by means of using liquid fuels. If economically viable, coal transportation should be tied in with the industry it serves by using coal-based fuels in the appropriate mobile equipment (railroads, trucks, barges, and ships).

Automobiles, trucks, and planes dominate the transportation sector, as shown on Figure 14. Users primarily obtain liquid fuels from individual distribution sites (i.e., gasoline service stations, truck stops, and fuel terminals). Any alternative energy sources for major users in the short term must be a liquid fuel or have the characteristics of a liquid fuel.

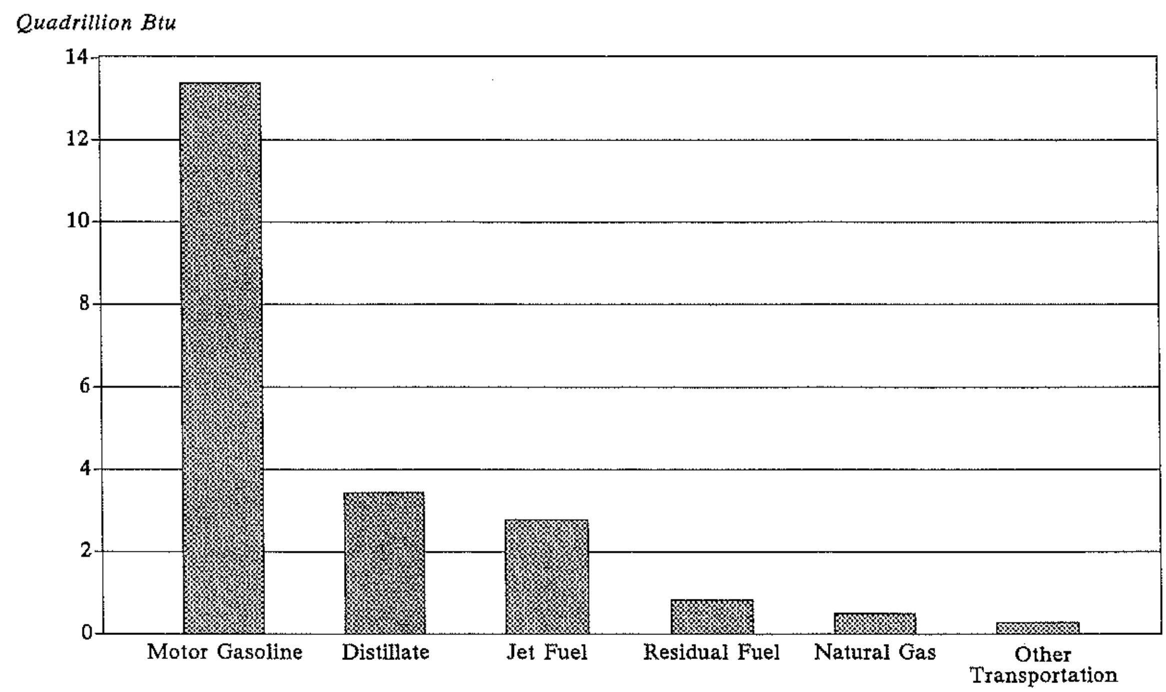
As previously stated, the three top consumers of energy in this sector are automobiles, trucks and planes; together they consume 80 percent of the fuel in the sector. The fuels used are gasoline and distillate, and only liquids or perceived liquids (such as coal–liquid mixtures) can currently play a major role in the short–term replacement of gasoline and distillate.

Technologies and Applications

The primary alternate liquid to gasoline currently being considered is methanol. The current feedstock for methanol is natural gas. Methanol can be produced from coal in a grass roots plant or as a co–product of an integrated gasification combined cycle plant (yet to be demonstrated). Other technically feasible sources of coal–based fuels are coal–based liquids from pyrolysis, direct and indirect liquefaction, coal liquid mixtures, and micronized coal. Micronized coal can be readily produced, offering application in locomotives, ships, and other marine transport.

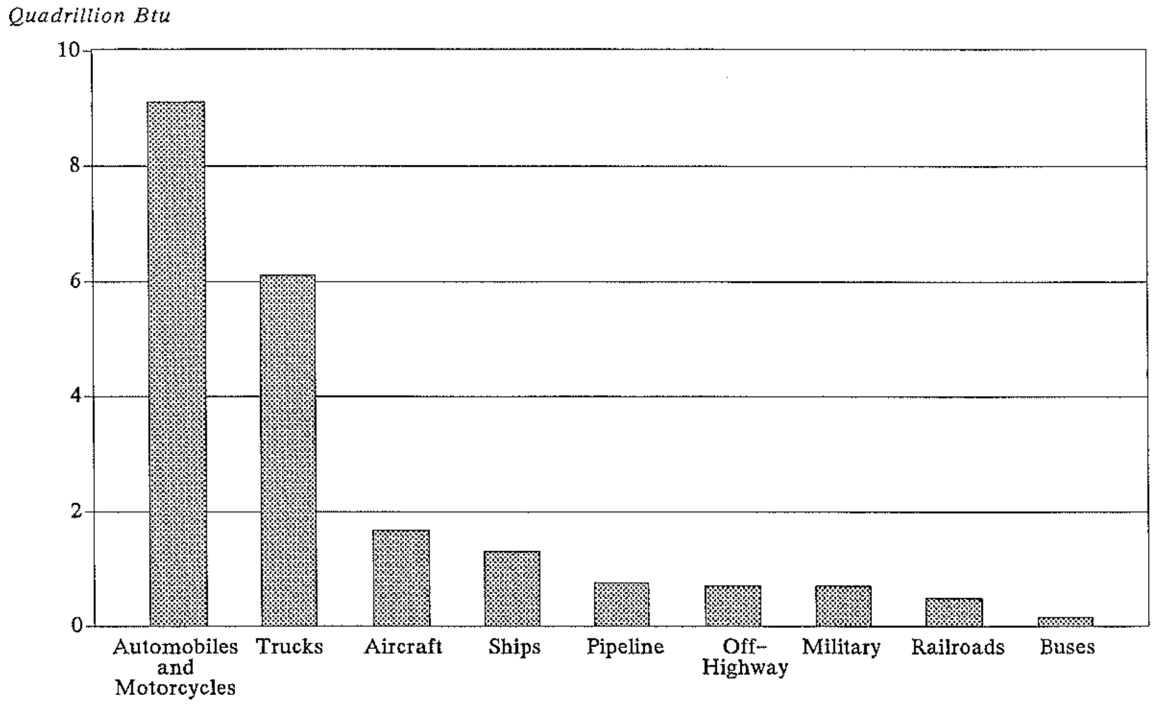
Most of the engines used in the transportation sector are of a relatively small size, less than 1000 horsepower. Fuels used must be specifically tailored for these engines. Conversely, engines and vehicles must be customized to the fuel sources developed. Liquid fuels compatible with today's

FIGURE 14 1987 Transportation Energy Consumption Sources



SOURCE: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).

FIGURE 15 Energy Use by Transportation Mode



SOURCE: Oak Ridge National Laboratory, Transportation Research. *1988 Automated Transportation Energy Data Book* (Draft), May 31, 1988 (1985 Data).

gasoline– and diesel–powered engines can be produced from coal by direct and indirect liquefaction and pyrolysis. Fuels produced by these technologies can be treated in conventional petroleum refining processes to be indistinguishable from materials made from crude oil. Thus, they can be distributed, stored, and marketed using the existing petroleum infrastructure and also should not require any vehicle modification. On the other hand, establishing a widespread fuel distribution and service station network is one of the key barriers which fuels such as methanol or coal–water mixtures must overcome before they can have a major impact in the transportation sector.

The potential for replacement of oil by alternative fuels, including coal–based fuels, is significant. This is the only major sector of the economy that has achieved little fuel flexibility and fuel diversification. The most promising technologies to replace oil used in highway transportation in the near–term future include alcohol fuels, compressed natural gas, and electricity stored in chemical batteries. Of these options, domestic coal could play a part in the production of alcohol fuels and stored electricity. Although coal–related technologies are fairly advanced, there are still significant obstacles to implementation, including lack of economic incentive, lack of commercial market development, insufficient competitive production capacity, inadequate distribution systems, and vehicle unavailability.

In the long term, advances in coal liquefaction technologies and reduction in production costs could obviate many of the problems facing the introduction of alcohol fuels and stored electricity in the transportation sector. Liquid fuels made by these processes do not require new infrastructure or vehicle development/modification work; market acceptance programs would not be needed to introduce them to the consumer.

Today, indirect liquefaction supplies a large share of the motor fuel market in South Africa, albeit at more expense than if petroleum–based materials were being used. Pyrolysis liquids and mild gasification products also could make a contribution to the liquid fuel supply if produced by a facility which had a market for the large quantities of char generated by the processes. Technologies are available for managing the by-products produced by these processes.

Direct liquefaction technologies are another possible way of producing gasoline and distillate from coal. Work by the Department of Energy in a large-scale pilot plant at Wilsonville, Alabama suggests that direct coal liquids will be competitive with products made from petroleum when crude oil prices reach $35/bbl, in 1988 dollars. The Department of Energy projects that this cost can be reduced, through technology development, to the $28-$30/bbl range, making direct coal liquids economically competitive with conventional petroleum products around the turn of the century. This promising process needs to be demonstrated to confirm the economics.

The gasification of coal holds potential for producing low-cost methanol in the future. This technique currently is price competitive on a selective basis. Although methanol and ethanol are used extensively in the chemical industry, a significant increase in production capacity would be required to provide even a small percentage of the U.S. transportation sector demand. The most significant cost for grass roots coal-to-methanol conversion is the capital component. Depending upon the source used, capital charges represent 60 to 68 percent of total production cost, which is between 2.3 and 3.0 times more than for converting natural gas to methanol.[30] [31] After adjusting for the differences in energy content, methanol is currently more expensive in the U.S. than premium gasoline and would require a larger fuel tank to achieve equivalent driving range due to methanol's lower energy density.

Driven by the need to improve air quality and to reduce dependence upon imported oil, the State of California enacted legislation in 1986 which provided the California Energy Commission (CEC) with $5 million to demonstrate and study methanol fuel in various transportation applications. As a result, appropriations for three programs were developed:

- $700,000 in funding to demonstrate the feasibility of and potential environmental impacts from using methanol fuel in heavy-duty diesel engines under 500 horsepower;
- $1.8 million in funding to assist both public and private transit operators in purchasing and operating new and retrofitted methanol-powered buses; and
- $2.5 million in funding to assist state and local government fleet operators as well as private rideshare programs in underwriting the differential costs of purchasing fuel-flexible fuel vehicles and establishing the necessary fueling facilities.

The existence of these demonstration programs in California reflect the unique partnership established between state, private industry, and local government. The California Methanol Bus Program, for example, is a combined effort of the CEC along with General Motors Corporation and M.A.N. Truck & Bus Corporation which supply the methanol buses operated by Golden Gate Transit. Celanese Corporation supplies the methanol for the buses. As bus engines are overhauled at 100,000 miles, they can easily be retrofitted with an engine that will accept methanol-based fuel.

Domestic auto manufacturers, specifically Ford and General Motors, have built fuel flexible vehicles that can run on methanol, gasoline, or any mixture of the two fuels with a single fuel tank. Fuel methanol (M-85) is a mixture of 85 percent methanol and 15 percent unleaded gasoline. Its octane rating of 102 versus 87 for regular unleaded gasoline makes it a high performance fuel. The fuel flexible vehicle concept permits manufacturers to introduce a new vehicle which operates on an alternative fuel without having to overcome consumer fears about limited availability of fuel methanol at retail outlets. It overcomes the "chicken or egg" dilemma of introducing methanol vehicles before a widespread methanol fuel distribution system is in place. The Atlantic Richfield Company and Chevron U.S.A. have entered into agreements with the CEC to each install

[30] R.L. Dickenson and S. Vejtasa, Alternate Fuel Technologies: Prospects and Options (SFA Pacific, April 1988).

[31] T.O. Wagner and D.F. Tatterson, Comparative Economics of Methanol and Gasoline (SAE Technical Paper Series 872061, November 1987).

methanol fuel at 25 retail gasoline outlets in the state.

Cost projections for utilizing methanol fuel as forecast by the CEC are shown in Table 4. These methanol cost projections are based upon natural gas sources. While forecasts suggest that the economics of methanol may be favorable in the middle of the next decade, Department of Energy price projections differ significantly enough from those of the CEC to cast doubt on these favorable economics. This is particularly true if coal is used to produce the alcohol.

In Southwestern Virginia, the United Companies, with the support of the Department of Energy, has successfully produced test quantities of locomotive diesel fuel as well as high octane gasoline using additives produced from coal-derived liquids. This process uses a mild gasification process.

A coal-burning locomotive study has been conducted with Burlington Northern and Norfolk Southern sponsorship and additional funding from DOE. The study has been detailed in a paper entitled, Economic Assessment of Coal Burning Locomotives by M. J. Hapeman and S. D. Savkar of the General Electric Company. The objectives of the study were to test the feasibility of a coal-burning locomotive design and coal as fuel. Based upon the cost analysis in the study, the coal slurry-fired diesel and the coal slurry-fired simple cycle gas turbine look attractive to the manufacturer, based upon projected rates of return. To expand coal use in this area, continued large-scale development is needed.

No other sector is more vulnerable to energy supply disruptions because no other sector is more dependent upon a single source of energy. The challenge, therefore, is to convert the fuel sources for the transportation sector from petroleum-based to coal-based. Interest in coal-based liquid transportation fuels can be created by demonstrating that it is possible to replace petroleum-based fuels with coal-based liquids.

Table 4
METHANOL COSTS
PRICE PROJECTIONS
(1987 dollars per gallon)

Year	Landed Cost in Los Angeles	M-85 Retail (gasoline equivalent)	Premium Unleaded Retail
1991	0.35	1.24	1.40
1992	0.36	1.26	1.41
1993	0.37	1.28	1.42
1994	0.39	1.31	1.44
1995	0.41	1.34	1.46
1996	0.42	1.36	1.47

SOURCE:
Koyama, K.; Smith, K.D.; Ghaffari, L., California Energy Commission; Carl Moyer, Acurex Corporation, *Methanol Supply and Demand Issues from a California Perspective*, presented at the 1987 World Methanol Conference, December 1-3, 1987.

Electricity in the Transportation Sector

More than 50 percent of the U.S. energy sources for the production of electricity comes form coal. Therefore, coal may still contribute to transportation when electricity is used as a replacement for gasoline or diesel powered vehicles. Also, this substitution has the potential for reducing the emissions of CO and NOx from the transportation sector which is a problem in many urban areas of the country.

It is estimated that today there are 165,000 kilometers of electrified railways worldwide. In Switzerland, Sweden, and Italy, more than half of the rail lines are electrified. In the U.S., electrified rail lines have declined to 2800 kilometers; this is the only country worldwide where a decline has occurred.[32] The potential for rail electrification continues to be evaluated by government and industry but has yet to be considered economically attractive enough to create an upward trend in the U.S.

Several major cities (i.e., Houston, Denver, Los Angeles, Philadelphia) are considering new mass transit systems which may be electrically based as a means of reducing traffic congestion and the corresponding release of emissions to the

[32] Ross, B.A., "Railroad Electrification: An Opportunity and a Challenge." *Rail International*, August-September 1987.

environment. An analysis (1986) of the Pittsburg–Allegheny County area shows that 28 million revenue bus miles were used and 9.7 million gallons of diesel fuel were consumed. The conversion from light rail car to bus mile is generally one to one. A light rail car uses approximately 6.5 kWh/car mile. Therefore, if 25 percent or 7 million car miles were electrified, 45.5 million kWh would be used which is equivalent to 22,750 tons of coal.[33]

Electric-powered vehicles have significant limitations which may prevent them from coming into wide use in the foreseeable future, but they are appropriate in certain niche applications. Due to the limited range of vehicles powered by electric storage batteries, they would be most useful in operations such as city transit facilities or local government or commercial fleet operations.

In Los Angeles, a pilot test program is being developed to demonstrate the feasibility of electric-powered vehicles. The funding of this program demonstrates the partnership between the State of California and the private sector. All the examples previously cited offer hope that electricity in the transportation sector is emerging and can play an increasing role.

[33] Letter dated October 7, 1988, from B.A. Ross, American Electric Power Service Corporation, Columbus, OH, to J.J.M. Plante, Stone & Webster Engineering Corporation, Boston, MA.

Chapter VI

Policy

Opportunities to increase the use of coal in the industrial, commercial, residential, and transportation sectors are limited by certain policy-related issues. These issues have been mentioned, to some extent, in the context of previous sector discussions, but the importance and overall impact of these issues warrant a more detailed presentation. This chapter specifically reviews national energy security issues, environmental and regulatory considerations, and public opinion.

NATIONAL ENERGY SECURITY

The most prominent energy source of current choice in the industrial, commercial, residential, and transportation sectors is petroleum which is susceptible to supply disruption. Since coal reserves represent our most abundant fossil fuel resource, it is vital to the energy security of the nation in order to mitigate a national energy emergency. As such, the promotion of the use of coal/coal-derived fuels in this nonutility sector over the long term will help to ease a national energy emergency when it next occurs.

As previously discussed, 1987 data compiled by DOE, show that natural gas comprised the major fuel of choice in the residential and commercial sectors, and approximately one-third in the industrial sector. In the transportation sector motor gasoline comprised 63 percent of the total sector demand, and distillate fuel accounted for 16 percent.

Increasing the utilization of coal in these sectors would contribute to a decrease of foreign supply sources and make the U.S. less vulnerable to foreign supply interruptions. The ability for those sectors primarily relying on natural gas or petroleum-based forms of energy to "switch" to an alternative source of coal cannot be accomplished overnight. The time required to develop and demonstrate certain coal technologies must be considered in an overall preparedness plan. The commercial availability of these technologies also is a factor. Most critical, depending on the time and source of the disruption, will be economics, which is predicated on the cost comparison of available energy supplies to alternatives at the time.

Under funding administered by the Department of Energy's Office of Clean Coal Technology, programs are currently under way in cooperation with industry which will demonstrate technology options using coal as an energy source. One of the objectives of these programs is to demonstrate that clean coal technologies can produce a near-term reduction of emitted sulfur dioxide and nitrogen oxides in an economically viable manner. These technologies involve new or retrofit nonutility as well as utility commercial applications which should be deployable by the mid-1990s.

The United States participates in the development of the policy plans and programs of the International Energy Agency for emergency response. In the event of an oil supply disruption, the cornerstone of current U.S. energy emergency response policy is to rely on the free market, supported by the Strategic Petroleum Reserve. Currently, the Strategic Petroleum Reserve is being expanded to a 750-million barrel capacity. In view of the almost overwhelming impact of energy in our daily lives, the Work Group encourages the Secretary to remain proactive in matters relating to national energy security and emergency preparedness.

ENVIRONMENTAL AND REGULATORY CONSIDERATIONS

Every form of energy has environmental constraints as well as advantages. The cost of environmental compliance is a significant consideration in the choice of any energy system. Increased coal use in the nonutility sectors would require development of newer systems for coal use as well as substitution of coal for oil and/or natural gas in existing systems. This increased coal use must be both environmentally and economically acceptable.

While the nonutility sectors differ in many respects from the utility sector, the well-developed regulatory framework applicable to coal use in the utility sector provides detailed guidance on the likely environmental and economic issues and challenges facing increased coal use in the nonutility sectors. Because of the sheer size of the utility industry and the magnitude of emissions from coal use, reasonable patterns for environmental standards and regulations have been established. These patterns also apply to acceptable technologies for coal use, particularly in the industrial sector. Regulated utilities also provide a meaningful pattern for methods to influence the economics of energy choices for the nonutility sectors. A policy to promote increased domestic coal use can be implemented by offering proper incentives to improve the economics of coal use for either the regulated utility industry or the competitive nonutility sectors. Such incentives could include tax exemptions and/or credits or regulatory incentives designed to reduce the cost of environmental compliance (e.g., modified emission limits, emission trade-offs, or bubbling techniques for averaging emissions from multiple sources).

Increased coal use for the transportation sector shares some regulatory considerations with the other sectors, but presents unique challenges. The transportation sector is a critical user of liquid fuels. Coal use in this sector could be accomplished indirectly, by shifting to coal-generated electricity, or directly, by producing liquid fuels from coal. Presently, there is considerable debate regarding whether current emission limits for the transportation sector are adequate to meet clean air goals. This strongly suggests that future environmental requirements for the transportation sector will become more stringent which will increase the challenges in promoting coal use in this sector.

Air Quality Regulations

Over a number of years, regulations to improve air quality have evolved from basic nuisance prevention measures to control smoke to the current complex regulatory framework for comprehensive air quality management designed to broadly protect the health and welfare of the public.

The key regulatory parameters of the current system are the National Ambient Air Quality Standards (NAAQS) and the New Source Performance Standards (NSPS). The NAAQS define the concentrations of particulate matter (PM), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), carbon monoxide (CO), ozone (O_3), and lead necessary in the ambient environment to protect human health and welfare. The NSPS define the emission limitations which are to be achieved by specifically defined new sources (both stationary and mobile or transportation sources) using the best technology currently available.

The regulatory system provides that the air quality goals (NAAQS) and technology standards (NSPS) are set at the Federal level by the Environmental Protection Agency. Implementation is accomplished by the separate states through State Implementation Plans under Environmental Protection Agency oversight to ensure a minimum national consistency.

States have the latitude to enact more stringent standards and requirements and, importantly, to design State Implementation Plans with different emphasis on different source categories. For areas meeting the ambient standards (attainment areas), industrial and energy development activities can proceed with reasonable regulatory flexibility. However, for areas not meeting any of the ambient standards (non-attainment areas), more stringent emission controls (e.g., lowest achievable emission rate) may be required for existing and new sources and/or further development in the area may be curtailed by cessation of issuance of permits. Sanctions on Federal grants also may be imposed on non-attainment areas to enforce further control action as is currently under debate for O_3 and CO for a number of urban areas in the nation.

There are several important implications and potential impediments posed by this air quality management system to the increased coal use in the nonutility sectors. Most areas of the country are currently meeting the ambient standards (i.e., attainment areas) except for O_3 and CO which primarily result from transportation sources. This attainment status, however, reflects the current mix of energy sources in a given area. Most attainment areas would probably accommodate a reasonable increase of coal use in the industrial sector under the applicable State Implementation Plan without violation of ambient air quality standards. Limited conversion of commercial sector installations would probably not compromise attainment. Widescale conversion to coal in the residential sector, in many cases, could cause violation of the ambient air standards which would require a revision of the State Implementation Plan to bring the area into compliance. An example of a NAAQS problem for the residential sector is wood burning fireplaces and stoves. Widespread wood burning in some ski resorts in recent years has sufficiently degraded local air quality that local ordinances have restricted the practice of wood burning and/or the allowable types of wood burning equipment. Currently, Denver, under its State Implementation Plan, restricts wood burning on high pollution potential days. This suggests that widespread coal use for many small sources would likely be limited by ambient air quality considerations in an area since there is only a finite available air resource to accept emissions. An obvious alternative to increased reliance upon coal for the residential and other sectors without violating ambient standards would be to increase the reliance upon electricity produced at large, well-controlled, coal-fired electric utility generating plants. This indirect reliance on coal could supplement direct uses in the nonutility sectors.

Transportation sources also contribute emissions which affect the attainment of the ambient air quality standards of an area. Transportation sources are largely responsible for the current non-attainment of a number of urban areas with the O_3 and CO ambient standards. Near-term control measures for transportation sources as components of a State Implementation Plan may include restrictions on vehicle use and improved inspection programs for vehicle emission control systems. Long-term measures could include additional vehicle emission control systems with reduced allowable emissions. Emission controls would be in the form of more stringent NSPS to be discussed subsequently.

Coal-based fuels for the transportation sector would have to yield emissions which do not conflict with efforts to reach the attainment goals. Electrification of mass transportation systems also has been considered by many urban areas as part of their strategy to comply with ambient standards. This may represent one potential avenue to indirectly increase coal use for the transportation sector. An important consideration relative to the transportation sector is that if an area becomes non-attainment for O_3 and/or CO primarily because of transportation sources, this State Implementation Plan will have to be revised to impose corrective measures. This could result in the requirement of additional controls, for example on industrial coal burning sources which emit CO and nitrogen oxides (NOx) (which along with hydrocarbons are precursors of O_3). Simply stated, an urban area with ambient air quality problems primarily due to transportation sources would pose greater permitting problems for nonutility (e.g., industrial) sources which might wish to convert from oil or gas to coal.

For example, California, Texas, and New Jersey have problems with O_3 attainment and have enacted more stringent controls on emissions of NOx (and hydrocarbons) from stationary (e.g., industrial) sources. These regulations have increased the NOx control cost by two to three times; the cost per pound of NOx removed is almost ten times higher for industrial sources than for utilities.[34]

The foregoing discussion describes the implications of the NAAQS to increased coal use in the nonutility sector. There are two additional important NAAQS considerations: new PM10 stan-

[34] Vaught, J. M. and Bach, C. S. "NOx Reduction Experience in Model 501-KB and KB5 Gas Turbines." Presented at the 1987 APCA Annual Conference, Paper No. 87-6.3.

dards for particulate and potential NAAQS revisions being considered for O_3 and SO_2.

In July 1987, the NAAQS for particulate matter were revised to delete the previous total suspended particulate regulations and impose regulations on particulates with a size less than or equal to 10 microns. These small particulates are considered to be inhalable by humans and are judged to better regulate the health impacts of particulates. It appears that a number of urban areas, which were previously attainment for particulates, may be non–attainment for PM10 particulates. This may then require more stringent particulate emission limitations on all sources in the area. Moreover, industrial and commercial sources are likely to have a relatively higher fraction of PM10 in their emissions than a utility source. Hence, the new PM10 standard will likely require a greater degree of particulate control on industrial sources than would have previously been the case.

The NAAQS for O_3 and for SO_2 (e.g., a 1–hour SO_2 standard, in addition to the 3–hour and annual average standards) are currently under review. Changes in the O_3 standard could mandate tighter emission limits for NOx and unburned hydrocarbons from stationary sources, including those in the industrial sector. Changes in the SO_2 NAAQS could result in more stringent SO_2 emission limits on all sources. Notably, a 1–hour SO_2 standard which is not actually needed for public health would require a national SO_2 emission reduction nearly as great as proposed Acid Rain reductions which will be discussed subsequently.

New Source Performance Standards are emission limitations imposed by regulation on new or significantly modified sources. These limits are imposed as permit conditions under a State Implementation Plan designed to maintain the NAAQS. For attainment areas, emission limits may be more stringent than the NSPS.

New Source Performance Standards for larger industrial boilers and gas turbines require stringent control for particulate, NOx, and SO_2 emissions. New large industrial coal burning installations as well as existing installations which would require major modification to convert to coal would be subject to these stringent control requirements. Table 5 summarizes the applicable Federal NSPS for coal–fired industrial and utility boilers.

TABLE 5
FEDERAL EMISSION NEW SOURCE PERFORMANCE STANDARDS
FOR COAL–FIRED STEAM GENERATING UNITS
100% Coal–Fired
(lbs/MMBtu)

Emission	Industrial–Commercial–Institutional[1] >100 MMBtu/Hour		Utility[2] >250 MMBtu/Hour	
SO_2	$\leq$1.20 lbs 90% reduction FBC w/coal refuse: $\leq$1.2 lbs/ 80% reduction Emerging technologies: 0.60 lb/ 50% reduction		$\leq$1.20 lbs/90% reduction or $\leq$0.60 lbs/70% reduction	
NO_X	By steam generating unit type:		By fuel type:	
	Mass–feed stoker	0.50	Lignite	0.60/.80
	FBC, spreader stoker	0.60	Sub–bituminous	0.50
	Pulverized Coal	0.70	Bituminous	0.60
	Lignite	0.60	Anthracite	0.60
Particulate Matter		0.05		0.03
Opacity		$\leq$20%		$\leq$20%

SOURCES:
[1] U.S. Environmental Protection Agency, Standards of Performance for New Stationary Sources, 40CFR60, Subpart Db.
[2] Ibid., Subpart Da.

New SO_2 NSPS were promulgated by EPA in December 1987 for small-sized boilers such as would be used in the industrial and commercial sectors. These standards require the same stringent controls for these small boilers as for large utility boilers, notably including a 90 percent SO_2 reduction requirement. The universal application of this technology-forcing percentage reduction requirement (e.g., requirement of scrubbers) has proved to be technology-inhibiting relative to developing alternatives to scrubbers.

The 1986 National Coal Council report on Industrial Boiler Performance Standards[35] noted that these standards would significantly increase the cost of new coal-fired industrial boilers with little or no environmental benefits. The practical result would be a shift away from coal to natural gas in this sector. These standards pose a clear conflict between environmental policy and the increased use of domestic coal. Alternative standards could have met both environmental and energy goals. Moreover, this increased impediment to coal use in the industrial sector, as well as the commercial sector, conflicts with the need to promote the demonstration of clean coal technologies. Specifically, demonstration of clean coal technologies on reasonable sized industrial boilers is vitally needed to ensure effective development of these technologies before wide scale deployment in the utility industry. The industrial boiler NSPS need to be reconsidered and modified to support continued and timely progress on clean coal technology developments.

[35] Blackmore, G. and Marx, William S. "Report on Industrial Boiler New Source Performance Standards." The National Coal Council, June 1986.

In the transportation sector, NSPS impose stringent emission limits on CO, NOx, hydrocarbons (HC or volatile organic compounds), and particulates (for diesels only). Lead and sulfur emissions are controlled through fuel specification regulations. Table 6 summarizes the applicable transportation emission regulations.

Emission limits have been phased in and have become more stringent over a number of vehicle model years. Total emissions in a given year reflect the age mix of the national vehicle fleet which is generally considered to be replaced over a 10-year period. Emission controls involve improving combustion efficiency through engine modifications, use of catalytic converters, and reducing fuel volatility. Use of oxygenated fuels has also been employed in some regions. Existing control limits have posed a challenge to current control technologies. More stringent NSPS limits are likely within the next few years to assist reaching attainment goals in urban areas.

TABLE 6
ENVIRONMENTAL STANDARDS FOR AUTOS AND TRUCKS[1 2]

	PASSENGER CARS (Grams/Mile)			TRUCKS (Grams/Brake Horsepower-Hour)			
	Current		Proposed	Current		Proposed	
	Federal	Calif.[3]		Gas	Diesel	Gas	Diesel
HC	0.4	0.39	-	1.9	1.3	1.1	-
CO	3.4	3.4	0.4	37.1 (25)	15.5	14.4	-
NOx	1.0	0.7	0.4	4.5	5.1	-	-
Part (Diesel)	0.2	0.2	0.08	-	0.6	-	0.1

SOURCES:

1 U.S. Environmental Protection Agency, Standards of Performance for New Stationary Sources, 40CFR60, Subpart G. May 1985.

2 U.S. Environmental Protection Agency, Control of Air Pollution from New Motor Vehicles and New Motor Vehicle Engines, 40CFR86. July 1986.

3 California Motor Vehicle Emissions Regulations. California Administrative Code, Title 13, Motor Vehicles, as amended April 25, 1987.

Coal–derived fuels for the transportation sector would be faced with similar emission control challenges as the current petroleum based liquid fuels. However, methanol, which could be produced from coal, has shown promise for meeting emission limitations for automobiles, buses, and trucks. Properly modified cars and buses using methanol are currently being demonstrated in the State of California.

For areas with transportation–related air quality problems, a simple compliance strategy would be to impose more stringent, but costly, additional controls possibly coupled with restrictions of vehicle use. A more cost–effective strategy might be to maintain present vehicle control requirements but provide incentives for use of methanol powered vehicles and convert mass transit systems to electrified systems. This strategy could increase reliance upon domestic coal directly for methanol production and indirectly for production of electricity at well controlled central generating stations (possibly of industrial scale). Hence, flexible combination transportation strategies are potentially more cost–effective and may meet multiple national policy goals more than uniform emission control strategies.

Potential Air Quality Issues

Regardless of the demonstrated success of the Clean Air Act, some groups, including some members of both houses of Congress, have raised concerns and promoted legislation to address two additional air quality issues – "Acid Rain" and the "Greenhouse Effect."

The "Acid Rain" theory suggests that SO_2 and NOx emissions from coal fired power plants, primarily located in the midwestern United States, are transported over long distances to the northeast and Canada. These emissions presumably form sulfuric and nitric acid which is deposited as dry acid particulate or as acid rain. This is further suggested to damage crops, waters, forests and the environment of the receiving areas. The controls suggested by proposed legislation would reduce national SO_2 emissions by 50 percent, primarily by imposing scrubbers on older existing utility plants. The acid rain issue has escalated to a diplomatic debate between the United States and Canada, and has become highly political in the United States.

The United States embarked on a coordinated national research program to define the problem before adopting the proposed costly and restrictive legislation. The preliminary results of this research were described in a 1987 report by the National Acid Precipitation Assessment Program (NAPAP).[36] The results indicate that the problem was overstated and misunderstood – particularly implying that the suggested control program would not provide the claimed environmental benefits. Moreover, the NAPAP report documented the improvements in national air quality resulting from the existing Clear Air Act. These improvements over the period 1973–1985 included a decreased national SO_2 emission of 27 percent[36] in spite of an increase of 34.9 percent[37] in coal consumption over the period.

Although the scientific basis for "Acid Rain" requires further study, it is recognized by industry that NOx and SOx reduction technologies should continue to be developed in the interim. Premature legislation poses a threat to the increase of domestic coal consumption. This threat is that great capital resources would be directed to retrofit older plants with scrubber technology. This would delay or prevent significant further advances on converting the national coal burning utility boiler inventory to clean coal technologies which have the prospect to burn coal even more cleanly and potentially more cost–effectively. Since industrial SO_2 emissions are about 14 percent of the national emissions, acid rain legislation could pose a similar threat to industrial coal burning.[38] However, it is most likely that additional stringent controls on industrial/commercial coal burning would simply shift these units to natural gas thus preventing possible increased domestic coal use in these sectors.

Concern over the "Greenhouse Effect" represents an even greater challenge to the continued

[36] Kulp, Dr. J. L. Annual Report, 1986. National Acid Precipitations Assessment Program. Washington, D.C., 1987.

[37] U.S. Department of Energy, Energy Information Administration, *Monthly Energy Review March 1988* (DOE/EIA–0035, March 1988), Table 1.4.

[38] USEPA National Air Pollutant Emission Estimates, 1940–1985. EPA–450–4/86–018, January 1987.

reliance upon all fossil fuels. This is because proponents of this theory, including some members of Congress, are proposing major reductions of CO_2 emissions in the United States. Such reductions would be accomplished by reducing the burning of fossil fuels (e.g., increased reliance upon nuclear power) or by conversion to natural gas which has relatively more hydrogen and relatively less carbon than coal or oil (i.e., less CO_2 per unit of heat produced). Presumably, some would suggest that CO_2 be scrubbed like SO_2. However, SO_2 is only a trace contaminant of emissions whereas CO_2 and water are the primary combustion products. Thus, CO_2 scrubbing is not feasible unless there is a commercial use for the end product.

There exists a natural beneficial climate control system which maintains the earth's climate within a normal range of variations. Natural sunlight is short–wave radiation which passes through the relatively transparent atmosphere and is absorbed as heat by the earth. This heat is re–radiated back to the atmosphere as long–wave radiation which is absorbed by a variety of gases in the atmosphere including CO_2, water vapor, and others. This heat can then be transported and distributed about the earth by the atmosphere before it is re–radiated back to space. This complex dynamic system has many positive and negative feedback controls involving the land, the ocean, the forests and other vegetation, and the atmosphere and clouds. Without this natural climate control, the earth's surface would be subject to wide temperature variations.

The recent press coverage and legislative attention to the "Greenhouse Effect" is largely prompted by the drought of 1988 which has been cited by some as evidence that man's activities (specifically burning of fossil fuels and deforestation of the Amazon) causes global warming. This concern maintains that CO_2 levels are increasing in the atmosphere because of man's increased fossil fuel use and removal of trees which absorb CO_2. This increased level of CO_2, as well as other atmospheric gases such as methane and N_2O, is presumed to absorb more of the long–wave radiation and to cause global warming which will increase melting of the ice caps causing rising sea levels and flooding coastal areas. Moreover, it is claimed that major shifts of climate will disrupt world agriculture leading to famine and will disrupt world economies leading to war.

The "Greenhouse Effect" is a hypothesis unsubstantiated by persuasive comprehensive evidence. Notably, the computer models of some scientists predict a warming trend in the northern latitudes whereas the measured data of these same scientists actually show a cooling trend in these latitudes over the last several decades. In addition, the models used do not include variations of solar intensity, the effect of the oceans which cover three–quarters of the earth's surface, the effect of clouds and atmospheric particulates, or the increased CO_2 absorption rate of vegetation when the atmospheric CO_2 level is increased.There is insufficient scientific basis for modifying the national energy policy so as to reduce CO_2 emissions from fossil fuel combustion. In fact, there are simpler and more realistic suggested explanations for the 1988 drought as being within the normal range of variations resulting from shifts of the jet stream possibly relating to reduced atmospheric particulate levels. Such simpler explanations have not received significant press coverage or consideration in legislative hearings. A massive "Greenhouse Effect" research program is needed to properly define the scientific facts on this subject. Such a program would include government and industry participants as needed to address this concern in a constructive way and to encourage international cooperation in the study of global warming.

In conclusion, premature legislative and/or regulatory actions without strong scientific support relative to "Acid Rain" and "Greenhouse Effect" concerns represent major impediments to enacting a national energy policy to increase reliance upon domestic coal. The use of coal and other fossil fuels would be more expensive and less prevalent if legislation on either subject were forthcoming. On the other hand, the concern about "Acid Rain" led to major research which improved the understanding of how to improve the management of air quality. Most importantly, "Acid Rain" concerns prompted significant advances in clean coal technology which offers the prospect for using coal more cleanly and more cost–effectively than the current systems. These technology advances could, in fact, provide the opportunity to actually increase the national reliance on domestic coal resources in both the utility and nonutility sectors. Possibly, the research which might occur to address the concerns of the "Greenhouse Effect" could yield some unexpected national benefits in terms of improved climate and weather forecasting which could assist energy policy development in the area of load forecasting and energy efficiency.

Water Quality and Waste Disposal

Both utility and nonutility coal-fired systems must store their coal supply (usually open storage) and manage their waste ash after combustion (often in open storage ponds). In addition, boilers must be periodically chemically cleaned producing a liquid waste which is usually acidic and contains high metal concentrations. These facilities are subject to requirements of the Clean Water Act for liquid discharges and possibly to the Safe Drinking Water Act and to some extent the Resource Recovery and Conservation Act specifically for protection of ground water at the facility.

For conventional facilities, these issues have proved to be relatively manageable without creating an environmental problem. In fact, ash can often be used as a beneficial by-product. Conventional facilities with scrubbers would face considerable additional cost for managing the larger volume of sludge; however, this can be accomplished in an environmentally acceptable manner.

Clean coal technologies will face some challenges for managing their liquid and solid wastes to comply with the applicable regulations. From the viewpoint of increasing coal use in the industrial/commercial and residential sectors, smaller sized facilities may lose some economy of scale for water and solid waste management. While this would not likely be a critical factor, there would be opportunities for joint management of such wastes by a number of facilities to gain cost reductions. Coal-based fuel production for the transportation sector would be expected to occur at facilities similar to conventional oil refineries which currently provide satisfactory water and solid waste management.

It is important to note that clean coal technologies have the potential to reduce present solid waste problems. As an example, high temperature gasifier slag is classified as nonhazardous. In addition, fluidized bed combustors and gasifiers have the capability of using coal cleaning plant waste, thereby reducing the volume of an existing waste material by 50 percent or more. Finally, the higher efficiencies possible through clean coal technologies will reduce all emissions, solid, liquid, and gaseous, including SO_2, NOx, and CO_2.

Socioeconomic Considerations

The public's perception of coal is not favorable. This has been aggravated by information being presented in a negative manner, particularly in the areas of Acid Rain and the perceived Greenhouse Effect. Public education is needed in order to build support for a national program to increase reliance upon domestic coal.

Technically, well-controlled conventional coal combustion and clean coal technologies can be employed which meet stringent environmental requirements and which can be aesthetically acceptable to the public. If a national energy program were adopted to expand reliance upon domestic coal, it should be portrayed as a decision in the national interest which will protect the environment and be competitive with other fuel sources. This approach, coupled with demonstrations of clean coal technologies to public opinion leaders, politicians, citizen groups, and regulatory agencies, should simplify resolution of potential siting problems and regulatory (permitting) delays for new facilities. Some legislative provision may be needed to assist in reducing these delays.

Other Regulatory Considerations

In planning for new power production facilities, the utility sector must consider the foregoing existing and pending environmental regulations. In addition, these utilities are subject to Federal regulations under the Federal Energy Regulatory Commission and state regulations under a state public utility commission. These regulations control the financing aspects of a new facility - specifically how much of the cost can be charged to the rate payer or customer and over what time period (e.g., rate of return on the project). In many cases, these financing issues have not been resolved until after facilities were built and costs incurred. This uncertainty of rate-of-return and even incomplete cost reimbursement has posed great impediments to decisions to construct new capital intensive facilities, particularly clean coal technology systems which have not been commercially proven over many years. Potential cogeneration projects promoted by the Public Utility Regulatory Policies Act of 1978 have added additional uncertainties to utilities relative to their needed capacity and their financing situation. On balance, these numerous uncertainties facing utilities have greatly slowed progress on deployment of clean coal technologies. Methods to reduce these uncertainties are being evaluated and the Vice President's Task Force on Regulatory Relief has recommended to the Department of Energy that tax and regulatory incentives (to reduce uncertainty) be provided to regulated utilities to encourage deployment of clean coal technologies.

This same incentive approach could be used to promote increased coal use with clean coal technologies in the nonutility sectors. In fact, states such as Illinois, Ohio, Indiana, and Kentucky have provided such incentives to the competitive industrial sector for deployment of clean coal technology. Comparable Federal Tax incentives could be offered to the nonutility sector styled not as subsidies but as national investments in energy security, improved employment, and national competitiveness.

Within the continuing review of the Public Utility Regulatory Policies Act, consideration is being given in Congress and in the Department of Energy to promoting clean coal technology deployment in the nonutility sectors (Public Law 100-202). This would be accomplished through federal assistance and cost-sharing provisions focused primarily on industrial cogeneration applications.

These current and pending legislative and regulatory proposals highlight the need for coordination of national environmental and energy policy goals to reduce uncertainty and produce an environmentally acceptable and cost effective national energy supply. Domestic coal with clean coal technology should occupy a prominent role in the evolving system.

PUBLIC OPINION

The following summary of public opinion on coal use in the nonutility sectors is based upon trend sample survey data from 1987 and previous years collected by Cambridge Research and published in their quarterly Cambridge Report.[39]

Monthly national probability sample surveys of over 1,000 adult Americans were conducted. The survey results can be projected to the U.S. population within a margin of error of plus or minus 5 percent. The surveys are based upon random groupings of individuals with diverse backgrounds.

Since the 1973 energy crisis, greater public attention has been directed at our plentiful coal resources in meeting the country's energy needs and lessening our dependence on foreign oil. In 1982, 77 percent of Americans held the opinion that the use of coal should be increased. In 1987, that preference, although still a majority, had dwindled to a 55 percent support for increase in the country's use of coal. Public opinion broadly affects all sectors evenly; therefore, data will not be presented by sector.

Support for increased use of alternative energy sources other than foreign oil correlates with the public's perception of the severity of an energy crisis and the country's dependence on foreign oil. Survey results from 1980 show that given a choice between increasing construction of nuclear power plants and increasing our dependence on foreign oil, 66 percent preferred increasing nuclear versus 13 percent who preferred an increase in foreign oil. Today, with less fear of an energy crisis and with a growing public sentiment against nuclear energy, those preferences have shifted dramatically. Increasing nuclear power capabilities was preferred by 41 percent, and 43 percent preferred increasing imports of foreign oil.

The energy crisis of the 1970s focused the nation's attention and resources toward the development of new technologies to capitalize on our na-

[39] *Cambridge Reports*. Quarterly Public Opinion Surveys, 1987.

tional abundance of coal and oil shale. Simultaneously, the concern for improved environmental quality was growing and today remains a top priority. Americans will not compromise on the quality of their environment.

Given a choice between protection of the environment or reducing our dependence on foreign oil, the majority of Americans clearly opposed any increased energy development that would impair environmental quality. Concern for the environment and environmental protection has significantly increased since 1982. The public opinion survey trends illustrate that environmental protection is now as much a part, if not more so, of the American values systems as is economic growth.

The most pressing environmental problem seen by the public is the quality of the air we breathe. In fact, a recent Cambridge Reports public opinion survey showed that the air quality was identified as the most serious concern associated with using more coal.

A review of public opinion surveys indicates that the general public has had limited exposure to coal. Because the public has little firsthand experience with coal, and because it is not widely advertised and sold to the general public, what image there is comes from the media. For example, the burning of coal has been identified as having negative effects on air quality, and coal mining is associated with higher occupational hazards.

Although professionals in the energy resource community are generally becoming more familiar with new coal technologies, public opinion surveys indicate the general public knows only that our country's coal resources are abundant and hold promise for meeting our future energy needs.

Research shows that the public must associate improved environmental quality with new coal technology or coal–derived fuels before there is wide acceptance of coal. Transportation fuel, such as methanol, that appears to be clean burning (low particulates, NOx, SO_2 and CO) and central district heating systems with modern sophisticated pollution control systems are the types of coal applications that could have broad public acceptance.

The image of coal must be rebuilt based upon the positive benefits of clean coal technology. The opportunity to gain public acceptance and support for these technologies is dependent upon the ability of coal and its associated industries to publicize and promote the benefits of clean coal technology. Environmental problems caused by traditional coal use and other fuel sources can be mitigated, and investment in these new technologies will, over time, minimize our country's dependence on imported oil. These are the critical messages that must be conveyed in an industry public information program.

Education in primary and secondary schools is an important way to improve the public understanding of the importance of our coal resources and emerging coal technologies, but more public education is needed if Americans are to realize the value of our coal resources and understand the benefits clean coal technology can contribute to the improved environmental quality in our country.

Two national foundations are currently involved in the development of primary and secondary school curricula. The American Coal Foundation's primary purpose is to support educators with training and teaching curriculum on coal resources. The Mineral Information Institute is broader based in its mission and has developed primary and secondary school curricula on the mining, milling, and use of mined fossil fuels as well as hard rock minerals.

We recommend to the Secretary that any program to promote research and development and pilot applications of clean coal technologies be coupled with comprehensive public information programs. These communications programs should stress coal use and its importance as a national fuel resource, explain the environmental and other benefits achieved through this new technology, and reinforce the message that new coal technology will, over time, lessen our country's dependency on foreign oil imports.

Chapter VII

Material Handling and Waste Disposal

This chapter examines material handling and waste disposal of coal/coal-derived fuels. Delivery systems are addressed as inbound material handling. A discussion of the utilization and marketing of fly ash also is presented.

Overview

From a transportation perspective, most of the factors which influence the design of a coal/coal-derived fuels delivery system also influence the design of a waste removal system. These systems are designed around the physical properties and chemical characteristics of the materials as well as the codes and regulations governing their movement and storage. Factors that could constrain these systems include economics (both capital and operating costs), space (land availability), public perception, technology, and demographics.

Transportation is regulated at the Federal level by the Federal Highway Administration, U.S. Department of Transportation, and Interstate Commerce Commission. Transportation of coal and nonhazardous coal waste materials are affected more by local and state ordinances than by Federal regulation.

Disposal of coal waste is regulated through the Federal Resource Conservation and Recovery Act under Environmental Protection Agency-defined guidelines for solid wastes. Water-related coal combustion effects also are impacted by the Clean Water Act and the Safe Drinking Water Act. Although the Federal Resource Conservation and Recovery Act assigns control of coal ash and other high-volume utility wastes to the states as a nonhazardous substance, the agency controls coal waste directly through coal pile runoff limitations. State regulators are under its direction. Many states have elected to adopt the solid waste criteria established by the Environmental Protection Agency (40CFR257, September 13, 1979), which require that disposal facilities be located, designed, and operated with minimal undesirable discharges.[40]

In March 1988, the Environmental Protection Agency tentatively concluded that ash and flue gas desulfurization sludge wastes from coal-fired power plants can continue being disposed in landfills or reused without stringent new controls. The Environmental Protection Agency has left open its ruling on classifying wastes from emerging clean coal technologies. The slag from the high temperature gasifiers at Tennessee Eastman and Coolwater, located in Dagget, California, have been declared nonhazardous by the Environmental Protection Agency as well as the respective state agencies in Tennessee and California. Should other wastes be classified as hazardous, the attendant costs of handling and disposal could render the actual deployment of these new technologies as economically unattainable.

Coal/coal-derived fuels delivery and waste material disposal are discussed separately to address the disposal and possible utilization of coal waste materials more fully; however, transportation systems designed to share both capital and operating expenses for both products and waste are highly desirable. In certain geographic areas, a fully integrated material handling system involving the transportation of coal from mine-mouth to end user, and the return of coal waste material for dis-

[40] Strauss, Sheldon D. "Managing Powerplant Combustion Wastes." *Power*, January 1987, p. 17.

posal at the mine site may be the best alternative both economically and environmentally.

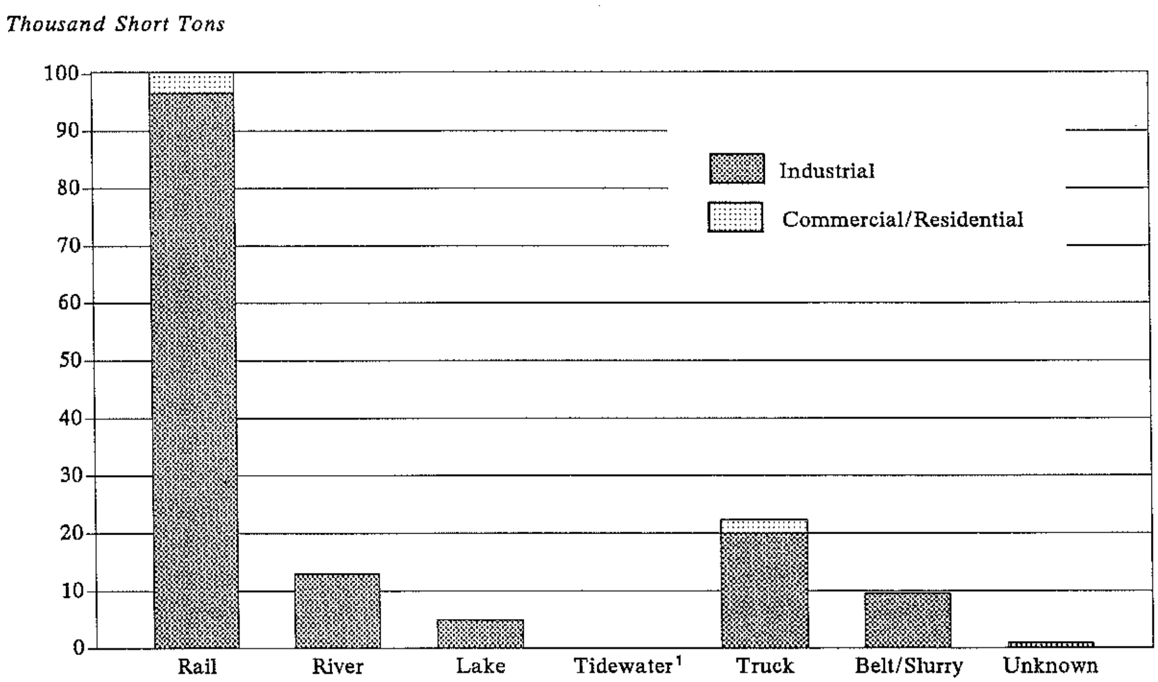
Inbound Material Handling: Delivery Systems

The design of a coal/coal-derived fuel delivery system is largely a function of the physical and chemical properties of the material. The state of the fuel (gaseous, liquid, or solid) is the primary determinant in the transportation technology selected. The fuel properties with respect to combustibility, volatility, corrosiveness, etc, will affect the capital cost and design of any of the technologies. Various technologies are available to transport coal-derived fuels, each with advantages and disadvantages depending on the application. These technologies, presented on Figure 16, include barges, conveyor belts, pipelines, rail, trucks, and tube-express transport.

Given the forecast for natural gas and oil prices through the year 2010, it may be necessary to use existing transportation infrastructures unless a specific application can justify large capital outlays to fund any major transportation construction. From the standpoint of the transportation industry, the greatest challenge to increased use of coal-derived fuels is the logistics of tailoring the existing transportation infrastructure to a particular application.

As a percentage of delivered cost, transportation is a significant determinant to increased use of coal-derived fuels. While transportation cost is largely a function of distance and time, the cost of coal transportation will be greatly influenced by the distance of the mine and end user to navigable rivers, rail lines, highways, pipelines, etc. Customer costs also are influenced by the existence of competing transportation systems, the demographics of the towns and cities to be traversed, and local ordinances and perceptions of coal handling and storage.

FIGURE 16 Domestic Distribution of U. S. Coal by Method of Transportation to Nonutilitiy Sectors



SOURCES: U.S. Department of Energy, Energy Information Administration, *Coal Distribution, January-December 1986* (DOE/EIA-0215-86-3Q).

NOTE:
1. Too small to be shown.

Permitting a dock or coal transfer facility may be met with strong resistance, in many instances due to the public's perception of coal as a dirty, inconvenient, and noisy alternative rather than the environmental impacts of coal handling.

Within the four sectors discussed in this report -- industrial, commercial, residential, and transportation -- coal handling would have higher delivered costs per unit in the following order: residential, commercial, transportation, and industrial (refer to Table 7). This is based upon the impact within each sector to such factors as land availability (space), convenience, noise, fugitive dust, demographics, aesthetics, and capital costs. Regional differences also could be an important factor.

TABLE 7
PRICE OF ENERGY–COAL VERSUS ALL OTHER BY END-USE SECTOR
(1987 Dollars Per Million Btu)

Sector	Steam Coal	All Energy[1]
Residential	2.72	11.41
Commercial	2.56	11.76
Industrial	1.58	4.89
Transportation	N/A	6.95

SOURCE: U.S. Department of Energy, Energy Information Administration, *Annual Energy Outlook 1987: With Projections to 2000* (DOE/EIA-0383, 1987).

NOTE
1. Weighted average price of all energy consumed on delivered basis (including electricity).

The residential consumer is sensitive to all of the factors listed above. Coal-derived fuels would have to be delivered to the end user either by existing pipelines or by trucks (containers). The system would probably have to be enclosed to minimize handling by the homeowner. Such systems are already in widespread use in the United Kingdom.

The commercial consumer is less sensitive than the residential consumer because of the plant size and the higher volume of fuel used. Delivery may be possible by rail or barge to larger commercial consumers, but delivery to smaller commercial consumers would follow the same route as to residential consumers.

The transportation consumer is sensitive to the existing distribution network and possible capital modifications for coal-derived fuels. In general, cars, trucks, planes, tugboats, and locomotives are refueled at decentralized locations -- filling stations, central garages, airports, docks, and yard shops. These refueling facilities currently store and dispense petroleum-based fuels. If the form of a coal-derived fuel is significantly incompatible with the existing distribution network of petroleum-based fuels, the amount of capital dollars required to construct a new distribution network could preclude the introduction of the fuel.

In the State of California, for example, the California Energy Commission has entered into agreements with the Atlantic Richfield Company and Chevron U.S.A. to install fuel methanol at retail gasoline outlets throughout the state in conjunction with the California Energy Commission methanol fuel demonstration program. Atlantic Richfield will have these pumps at 25 stations in southern California by the end of 1988, and Chevron's 25 pumps will be installed primarily in northern California and other parts of the state. In this demonstration program, coal/coal-derived fuels are not used to produce the fuel methanol; natural gas is used as the feedstock. The distribution network to be used, however, is compatible with that already existing for petroleum-based fuels. Coal could be used as a feedstock for methanol in the future.

The industrial consumer is the most flexible and versatile in fuel choices. Since each industrial site may have its own opportunities/limitations, the best delivery system will be the one most economically suited to the specific location and volume of fuel. It should be noted that current rail and barge systems have excess capacity; therefore, these systems could easily respond to increased demand.

Across all consuming sectors, transportation costs are evaluated on the cost of Btu delivered; therefore, the higher heating quality of the fuel will produce a lower net transportation cost on a delivered basis. Coal transportation charges are based on weight; the cost per MMBtu of a delivered fuel is inversely proportional to the heating value.

The coal-derived fuels discussed here fall into four major categories: gaseous, liquid mixtures, liquid-derived, and solid. Each of these categories will dictate the mode of transportation used. Gaseous fuel will be transported the same way as natural gas. Both medium Btu gas and low Btu gas will be influenced more by transportation costs than natural gas on a delivered basis because of their lower Btu value. Synthetic natural gas is interchangeable with natural gas.

Liquid mixtures can be transported by a variety of methods, including pipeline, rail tank car, and truck. Liquid-derived fuels are discussed in Appendix B.

Solid fuels fall into four general classes: pulverized, micronized, sized (stoker, char, pellets, briquettes), and run-of-mine. Both run-of-mine and sized coals are transported in significant quantities today. Sized coals require more careful handling to avoid breakage. Consequently, the transportation of a sized product is more expensive than run-of-mine. Pulverized coal is transported currently in Japan, Denmark, Sweden, and the Federal Republic of Germany but not to any great extent in the U.S. The transportation of micronized coal requires further study to ensure safe, economical systems are developed.

Coal fuels could be pulverized at a location that minimizes the cost of transporting inbound raw coal, outbound waste materials, and delivered pulverized product. In some instances, a centralized pulverizing plant designed to receive raw coal via conventional barge, rail or, truck delivery and distribute pulverized coal via pipeline or container to an end consumer may prove the most economical approach. Further research and observation of international experience in handling pulverized and micronized coals in pipelines, containers, and conventional modes is needed.

Outbound Material Handling: Waste Disposal

The issue of waste disposal is an important factor in considering the use of coal in nonutility sectors. Approximately 80 percent[41] of wastes from coal-fired power plants are currently buried in landfills; however, landfill space is becoming scarce, particularly in urban areas and densely populated regions of the northeastern United States. The increased use of disposal areas by both the public and private sectors coupled with public resistance and municipal ordinances which prohibit the siting of additional disposal areas near populated areas have compounded the problem.

The American Coal Ash Association reported that in 1986 approximately 67 million tons of ash and flue gas desulfurization scrubber sludge were produced by electric utilities in the U.S. burning some 682 million tons of coal. As coal utilization increases, so does the amount of waste which must be properly handled. According to the National Coal Association projections, total domestic coal consumption in 1990 is expected to reach 859 million tons and by 1995, 963 million tons.[42] Taking into account the average quality of coal delivered to electric utilities in 1986, the ash content by weight was 9.98 percent.[43] Based upon this percentage, approximately 86 million tons of ash would be produced from projected coal consumption in 1990, and 96 million tons of ash would be produced in 1995. Solid waste generated in the nonutility sector is essentially the same as seen in the utility sector and should be covered by the same regulations and fit under the same criteria.

As mentioned earlier, the Environmental Protection Agency has left open its ruling on classifying solid wastes from emerging clean coal technologies except as previously noted. The Agency needs to resolve the open issue on classifying solid wastes from emerging clean coal technologies in order to remove as many unknowns and obstacles as possible in developing new, evolving technologies. If more research and data are needed, the EPA should specify the requirements and help obtain the data. Waste products from liquid and

[41] "EPA Says Control Needn't Be Tightened on Power Plant Ash." *The Wall Street Journal*, March 11, 1988.

[42] The National Coal Association. *Coal 2000*. March 1986, p.6.

[43] Energy Information Administration. *Cost and Quality of Fuels for Electric Utility Plants 1986*. (DOE/EIA-0191 (86), July 1987), p. 19.

gaseous fuels developed from coal feedstocks should not have different problems from the liquid and gaseous fuels they replace.

Since coal-fired power plants have extensive experience in waste management, it may be useful to review their lessons learned. Principal waste materials have traditionally been boiler bottom ash plus fly ash collected from the flue gas stream. Typically, ash accounts for approximately 10 percent of the total mass of coal burned. Flue gas desulfurization systems installed to comply with sulfur dioxide air pollution regulations usually produce a calcium-based sludge that may be as much as two to three times higher than the amount of ash material generated at a particular plant.[44] For plants with flue gas desulfurization systems, the current waste disposal practice usually involves mixing the sludge and fly ash (possibly with the addition of a fixing agent) and co-disposal in a pond or dry landfill. Landfill operations are generally the preferred disposal alternative for new power plants, although the choice of disposal method is often highly site-specific. Depending upon state and local regulations, solid waste disposal ponds may be required to have synthetic liners to prevent the leaching of materials into the ground.

Ash Utilization

Although ash is considered a waste, its use shows promise as an attractive alternative to disposal. Potential applications of conventional power plant waste include use for structural fill, lightweight aggregate, cement manufacturing, soil stabilization, concrete products, and liming agents. Flue gas desulfurization processes can also be designed to produce by-product sulfur, sulfuric acid or commercial grade gypsum. Coal waste piles are a potential source of low-grade fuel (e.g., for fluidized bed boilers).[45] Waste from existing coal cleaning plants is a source of medium Btu fuel. Any utilization must take into account potential transportation problems with fly ash in a dry form.

[44] U.S. Department of Energy, Research Advisory Board. *Clean Coal Use Technologies*, June 1985, Vol. II, p. 106. Rubin, E.

[45] *Ibid*, p. 107.

Fly ash can be used to manufacture cement when mixed with water. Its mineral constituents and proportions are similar to those of Portland cement. Properly designed fly ash-cement combinations have lower water requirements, heat of hydration and autoclave expansion. The resulting concrete has improved marketability and equal or greater strength compared to cement concrete.[46] Fly ash also contains metals as both major and minor constituents and it could be an inexpensive ore. Recovery of minerals from fly ash requires methods that will attack the refractory glass matrix of ash particles. Research on the recovery of metals has been reported in various scientific journals.[46]

Fly ash is used in large structures such as dams, power stations, and silos, as well as in other construction applications, such as concrete block, brick, pipe, paving, lightweight aggregate, structural fill, and grouting.[46] Approximately 14 percent of the fly ash collected in the U.S. is utilized, primarily in these construction-related applications. Other industrialized countries, however, have a much higher utilization rate: the Federal Republic of Germany uses roughly 80 percent, France uses 65 percent, and the United Kingdom uses 55 percent.[46] Conversion of fly ash to lightweight synthetic aggregate is widely practiced and highly developed in the United Kingdom. A small number of U.S. power plants use regenerative flue gas desulfurization systems producing salable by-products; however, such systems have not gained widespread use in this country because of generally unfavorable economics. This helps to explain why U.S. plants typically dispose of the low-grade gypsum produced by conventional lime/limestone flue gas desulfurization systems rather than produce higher quality gypsum potentially suitable for wallboard and other applications, as commonly practiced in the Federal Republic of Germany and Japan.[47]

As illustrated in Appendix C, Southwestern Public Service in Amarillo, Texas, has effectively

[46] Burnett, George. "Newer Technologies for Resource Recovery from Coal Combustion Solid Wastes." Ames Laboratory, U.S. Department of Energy and Department of Chemical Engineering, Iowa State University, Ames, Iowa, 1986, p. 1369-1370.

[47] U.S. Department of Energy, Research Advisory Board. *Clean Coal Use Technologies*, June 1985, Vol. II, p. 106. Rubin, E.

marketed ash. Florida Power Corporation is currently constructing a \$3.0 million plant in St. Petersburg to process fly ash into light-weight aggregate for producing light-weight concrete at the Crystal River energy complex. The amount of unsalable fly ash from the company's generating plant will be significantly reduced by this conversion. At the present time, much of Florida Power's coal fly ash is sold for direct use in concrete as cement; however, more ash is produced than can be used in this application. The plant will have no impact on the availability of fly ash to the concrete ready-mix market.[48]

[48] "How Not to Pollute with Coal Fly Ash." *Electric Light and Power*. September 1987, p. 14.

Research continues on the effects of utilizing ash in various highway and road pavement base applications. A project is now underway, funded by the Department of Energy, the Commonwealth of Kentucky, and the Tennessee Valley Authority to evaluate the performance of highway pavement sections using materials consisting of fly ash, bottom ash, and atmospheric fluidized bed combustion residue. This study was undertaken specifically to demonstrate the use of waste to conserve resources and reduce waste disposal problems.

Chapter VIII

International Programs

Coal/coal derived fuels have been used in the nonutility sectors in several foreign countries for some time. This chapter briefly reviews examples of the use of coal in nonutility sector applications as well as various government/industry partnerships and describes what type of technologies were deployed. These examples demonstrate the success which other countries have achieved in utilizing coal in nonutility sectors, and provide a glimpse of the lessons learned in already demonstrated applications. Included are examples of the use of coal/coal–derived fuels in Sweden for the commercial sector, in the United Kingdom for the residential sector, in France for the application of district heating, and in Japan and the Federal Republic of Germany for the production of organic and inorganic chemicals. A review of funding levels for research, development, and demonstration in the European Economic Community also is presented, along with a brief description of several current overseas joint government/industry funded development and demonstration programs.

The nonutility use of coal/coal–derived fuels is also common in the centrally planned economies of countries such as the U.S.S.R. and the Peoples Republic of China. South Africa leads the world in the production of liquid transportation fuels and other materials from indigenous brown coal resources. Coal utilization in these countries will not be discussed because the decisions and funding to carry out these technology development programs come directly from the government with no private sector involvement, a method incompatible with U.S. political and economic systems.

Sweden

In 1978, the government of Sweden put the issue of nuclear energy use to a referendum vote. The result led to the establishment of a National Energy Policy in 1981. The policy determined that energy development would be geared toward renewable and indigenous sources of energy, moving away from dependence on oil. This policy also called for the phase–out of nuclear power by 2010. Specific goals were established: 10 percent of oil usage was to be replaced by coal and another 10 percent replaced by peat and wood by 1990. Several coal–related efforts evolved from this new energy policy; many were backed by some of Sweden's largest corporations. As Sweden has little indigenous coal, the development work emphasized compatibility with existing oil–fired boilers as well as the environmental acceptability of the oil replacement. This development work led to combined industry/government efforts in coal water fuel and in fluidized bed combustion. Coal water fuel represented a direct replacement for residual oil. If already clean coals were cleaned further, then the stringent Swedish air pollution criteria would be attainable. From this, three coal water fuel firms evolved: NYCOL, Carbogel and Fluidcarbon. They were backed by some of Sweden's largest firms including Electrolux, Euroc, Axel Johnson, Boliden, Berol, and Allis Chalmers.

The key element of the NYCOL process, for example, utilized a proprietary technology (developed by Standard Oil Advanced Fuels Technology Company) for coal beneficiation and for the preparation of liquid pumpable coal fuels. Due to the fact that the coal was subjected to a cleaning process, a more homogeneous fuel could be obtained from a wide range of different types of coal. This, in turn, resulted in a wide range of coals that could be used, lowering the risk of becoming dependent on only a few exporting countries. By controlling the cleaning process, the refined coal fuels could, within certain limitations, be given predetermined low concentrations of minerals and sulphur. Consequently, the heating value or Btu per pound of the fuel was increased and the moisture content could be tailored to meet consumer requirements.

Utilizing low interest government loans, two demonstration plants were built in Stora Vika and Malmo to produce coal water fuel. Boilers were converted to fire coal water fuel with funds provided by the Swedish government under the guidance of the coal water fuel producers, the boiler manufacturers and the end steam/power users. By way of this comprehensive government program, Sweden became the first country in the world to have commercial-sized plants. Through these efforts, a large body of knowledge in the combustion and manufacturing of the fuel has been gathered.

Simultaneously, government-sponsored research was underway in coal gasification and fluidized bed combustion. Several pilot projects were initiated at various locations in Sweden as government and industry (i.e., ASEA and Allis Chalmers) cooperated in the effort. These projects were stimulated by the support of liberal government loans and grants, the repayment of which was tied, on a performance basis, to the success of the project.

During 1986–1987, Swedish Energy Policy underwent a rapid revision which removed the incentives for coal and limited the use of coal in favor of gas. On January 1, 1987, the Swedish Parliament decided to increase the tax on coal.[49] The nuclear power phase-out policy also was reconsidered. Although this government redirection essentially cut off new efforts in coal, the 1981 Energy Policy existed for a sufficiently long period to actually create new coal-based businesses in Sweden. For pressurized fluidized bed combustion, ASEA has developed a technology that is being installed in commercial-sized utility boilers in Sweden as well as the U.S. and, of the coal water fuel firms, NYCOL simultaneously developed a coal water fuel and clean coal pulverized coal plant at Stora Vika. Using an idle cement plant as a commercial production base, NYCOL began marketing coal water fuel and pulverized coals concurrently. Clean coal pulverization is currently competitive in Sweden with residual oil both economically and environmentally. Without the government backing of the CWF effort, the clean coal pulverization effort would not have been developed.

A 1983 report of the Swedish State Power Board concluded:

> *"...that coal can be utilized as a replacement for oil for district heating and combined heat and power production, and within industry, in a manner acceptable from the aspects of health and environment if the coal is used in well-maintained installations of such a size that an effective environmental technology can be used."*[50]

United Kingdom

In the United Kingdom (U.K.), the British Coal Corporation is responsible for the mining and distribution of coal. During 1985–1986, the saleable output of coal was 104.5 million metric tons. Of this total, approximately 85 percent was utilized for power generation, 8 percent was utilized in the industrial sector and 7 percent was utilized in residential heating.[51]

To support and promote the use of coal, British Coal Corporation has conducted various research and development programs aimed at making coal more attractive to the residential, commercial and industrial energy user in terms of its convenience, efficiency, flexibility and environmental acceptability. These research and development programs have been carried out in collaboration with U.K.

[49] International Energy Agency, *Clean Coal Technology*. (Paris, France, 1987).

[50] The Swedish State Power Board, *The Health and Environmental Effects of Coal.* The Swedish Coal-Health-Environment Project Final Report. (Stockholm, Sweden, April 1983).

[51] Payne, R. C., "Living with Coal in Smoke Control Areas." British Coal Corporation. (Stoke Orchard, England, October 1987).

combustion equipment manufacturers in jointly funded projects. As a result of this collaboration, several developments have taken place which have led to manufactured smokeless fuels and improved bituminous coal-burning appliances. These appliances meet modern requirements for smoke control, efficiency, automatic operation and reliability.

Manufactured smokeless fuels or "authorized" smokeless fuels are defined as those fuels that, when burned in a conventional dry back open fill at an average radiant output level of 2 kW, give a total particulate emission (including coal ash) of less than 5 g/h, measured from the top of a standard brick test chimney using the electro-static precipitator method. Such smokeless fuels may be burned on conventional grates in specially designated smoke control areas which currently include about one-half of all U.K. homes, primarily in urban areas. By comparison, bituminous coal burned under similar methods gives off emissions of approximately 25 g/h. The development of a special class of appliances called "smoke-eaters," however, provides the capability of burning specified bituminous house coal grades directly and can meet stringent environmental requirements. They are approved for use in smoke control areas.[52]

Because intense competition exists between the natural gas, oil, electricity and coal industries in the residential heating market, a primary objective in the development work for this sector was to enable coal firing to provide a clean, efficient, convenient and attractive means of home heating at an acceptable cost. From a fuel distribution standpoint, unique advantages are enjoyed by the U.K. coal industry. The existence of a well-established coal distribution network through a merchant service is one advantage, coupled with the fact that the majority of the 21 million U.K. dwellings have been built with suitable chimneys. This market size is approximately 60 million metric tons coal equivalent; coal currently maintains a 15-percent share of this total.[52] A wide range of type and size of mineral solid fuel is available for the residential heating market. These solid fuels can be classified into three major categories: natural smokeless fuels such as anthracites and dry steam coal; manufactured smokeless fuels such as cokes and briquetted fuel; and washed high volatile bituminous coal.

The 1956 U.K. Clean Air Act made it illegal to burn high volatile bituminous coal on conventional grates in designated smoke control areas. Market pressures have, therefore, called for the design of a range of special types of appliances to burn high volatile bituminous house coal directly in a clean, convenient and efficient manner in order to comply with the U.K. Clean Air requirements. These types of appliances can be sold into smoke control areas, and heating costs can be competitive over alternative fuels such as oil or gas. The appliance designs employ batch fed downdraught or mechanically fed, underfeed stoker combustion principles. Fully automatic bituminous coal-burning appliances, based on this underfeed stoker design principle, have been developed for the commercial, small premises market. Units have been installed and are currently operating to heat large dwellings, schools, hotels and local government premises.

The British Coal Corporation also supports development and demonstration of technologies for converting coal into liquid and gaseous fuels which can be used by the nonutility sectors in that country. Some of this work is with the European Economic Community (EEC) and both domestic and foreign companies. Current work underway with partial EEC funding includes a small coal liquid solvent extraction pilot plant (the British Department of Energy and Ruhrkohle are participants) which is expected to economically liquefy most coals and lignites and can also handle high ash feed stocks.[53]

The British Gas Board has developed a high pressure slagging fixed bed gasifier at a scale of 550 tons of coal feed per day. Plans are to test this equipment in 1988 to determine gasifier operability, gas purification, and methanation of syngas to produce substitute natural gas. Both the

[52] Payne, R. C., "Living with Coal in Smoke Control Areas." British Coal Corporation. (Stoke Orchard, England, October 1987).

[53] Pace Synfuels Report. Vol. 25, No. 1. March 1988, p 4.

Electric Power Research Institute and the Gas Research Institute are planning to participate in several tests at the facility.[54]

The British Coal Corporation/European Economic Community also is developing a program for a low Btu spouting fluidized bed gasifier. One goal of this project is to develop equipment which can be used for onsite generation of gas for industrial use.[55] The current facility can gasify 12 tons of coal per day. Results of the program are expected to be released in 1989, at the completion of the project.

France

In France, the Charbonnages de France, a government agency, is responsible for all coal production and coal–related research and development. This agency has exerted strong influence, both financially and technically, in support of programs through which progress has been made in increasing the use of coal in the industrial, commercial, and residential sectors. The Government of France, with the support of the private sector, promoted the use of district heating plants in its overall energy policy. Charbonnages de France has encouraged the shift to utilize coal in these types of applications. An example of such an application is seen in the district heating operations in Paris, which uses coal and garbage. Another example is a suburb outside of Paris where the heating of all units in the area, including single family homes, is provided principally from a coal–fired central facility.[56] This suburb is similar in its makeup to Reston, Virginia or Columbia, Maryland.

In addition, France has made progress in the conversion to coal of commercial plants such as sugar beet factories, hay dryers, and hospitals. The French government, through Charbonnages de France and other agencies has provided incentive programs for conversion to coal. In one such program, to help defray the capital costs involved in converting to coal, the government provided the converter a small allowance for every barrel of oil saved.

Japan

In Ube, Japan, Ube Industries, Ltd (Ube) is operating the first coal fed world–scale ammonia facility, using Texaco's gasification process.[57] Ube installed a gasifier as an alternative "front end" to a conventional steam reforming process to provide additional feedstock flexibility and as protection against oil and natural gas supply interruptions and price increases. Built totally with private funds, the facility has successfully operated for four years at a designed capacity of 1,000 tons of ammonia per day using Canadian, Australian, South African, and Chinese coals. Ube claims that the overall cost of ammonia has been reduced by over 20 percent by using coal gasification. The coal gasification plant is expected to be even more economical when the price differential between crude oil and coal increases.

In 1980, Japan passed a law which established the New Energy Development Organization (NEDO) to accelerate developing new energy technologies which would commercialize energy production from alternative sources, not including nuclear and oil. In fulfilling this charter, NEDO has been active in many areas of coal research, development and demonstration, usually in consort with the Japanese private sector, and at times with foreign governments or companies.

One area NEDO is emphasizing is coal gasification technologies based on the fluidized bed concept.[58] Currently, priority has been given to a multipurpose gasifier for manufacturing hydrogen, the product the Japanese consider to be the most valuable material which can be made by this process. The project is currently in the design stage with a 20 ton per day, oxygen blown, dry coal feed pilot plant scheduled to start up in 1990. Work is being carried out by the Research Association for Hydrogen from Coal Process Development, a joint venture involving nine private sector companies and organized by NEDO. Several other

[54] Pace Synfuels Report. Vol. 25, No. 1. March 1988, p 4–74.

[55] Ibid., p 4–56.

[56] James F. McAvoy, personal correspondence, June 9, 1988.

[57] Pace Synfuels Report. Vol. 24, No. 2. June 1987, p 4–70.

[58] Ibid., p 4–65.

private companies are doing additional research for the project.

The New Energy Development Organization also assumed the responsibility for developing and commercializing coal liquefaction technologies, and has two large pilot plants, either in operation or in the planning stage.[59] These programs demonstrate the degree of involvement between the Japanese government and private industry in increasing the pace of commercialization. Cooperation with foreign governments is also a key part of this work, as evidenced by the pilot plant already in operation located in Australia.

This operating plant, which feeds 50 tons per day of Australian brown coal, was completed in 1986. The project is being run as an intergovernmental cooperative project, involving NEDO (which provides full funding), the Federal Government of Australia and the State Government of Victoria. Brown Coal Liquefaction (Victoria) Pty. Ltd. is operating the facility. Brown Coal Liquefaction is a subsidiary of the Japanese-owned Nippon Brown Coal Liquefaction Company, a consortium involving Kobe Steel, Mitsubishi Chemical Industries, Nissho Iwai, Idemitsu Kosan, and Asia Oil. Nippon Brown Coal Liquefaction is responsible for implementing the entire program. The Victorian Government is providing the plant site, the coal, and some personnel.[60]

A 250-ton per day direct liquefaction pilot facility is being built in Japan, using a process based on the information gathered at the facility in Australia. This unit is designed to hydrogenate all high boiling materials in the reactor to products such as gasoline and diesel fuel. Startup is scheduled for 1991.

Federal Republic of Germany

Coal gasification is being used by Synthesegasanlage Ruhr (SAR) at Oberhausen-Holten in the Federal Republic of Germany (FRG) where approximately 250,000 tons per year are gasified, using Texaco's gasification process, to generate 400 million cubic meters per year of the synthesis gas and hydrogen which are then used to manufacture oxo-chemicals.[61] This facility is subsidized by the Federal Minister of Economics of the FRG. The Minister of Economics, Small Business and Technology of the state of North-Rhine Westphalia, also participates by partially subsidizing the cost of the coal fed to the facility.

Experience in the FRG again shows a high level of industry/government cooperation in developing and demonstrating emerging technologies for converting coal into energy forms usable in the non-utility sector. One of several examples is the Bottrop Direct Coal Liquefaction Pilot Plant project, jointly funded by Ruhrkohle AG, Veba Oel AG, the Ministry of Economics, Small Business and Technology of the state of North-Rhine Westphalia, and the Federal Ministry of the FRG.[62] This facility, debottlenecked to 220 tons of coal feed per day, produces high grade refined synthetic oil products instead of lower grade materials similar to crude oil. The facility also has been modified so it can co-process coal and petroleum residuum.

Rheinbraun and Uhde are developing a high temperature Winkler fluidized bed coal gasifier process with the FRG Ministry for Research and Technology. A 720 ton per day demonstration facility has operated successfully since early 1986 which is designed to produce 29 million scfd of syngas.[63] Rheinbraun and Uhde plan further work on a 160 ton per day gasifier which will operate at about 350 psi and optimize the conditions established in the 720 ton per day unit.

European Economic Community: Funding of Research, Development, and Demonstrations

As many foreign countries develop and refine an overall energy policy to move toward energy security and a lessening dependence on imported oil, funds are often appropriated for various research and development programs. It is useful to review the commitment to technical research, develop-

[59] Pace Synfuels Report. Vol. 24, No. 2. June 1987, p 4-65.

[60] Ibid., p 4-77.

[61] Ibid., p 4-38.

[62] Ibid., p 4-56.

[63] Ibid., p 4-72.

ment and demonstration in the solid fuel sector by the European Economic Community (EEC) as a benchmark for the future use of coal in their countries.

Until the early 1970s, EEC research, development and demonstration relating to solid fuel was conducted by the European Coal and Steel Community (ECSC) coal research program. The main thrust of that program, begun in 1958, was directed toward the production and utilization of coals indigenous to the Communities. After the oil crisis of 1973/1979, the aspect of a safe supply became predominant and stimulated interest in the conversion of coal and lignite into more convenient energy carriers. A subprogram for financial assistance of pilot and demonstration projects on the liquefaction and gasification of solid fuels was implemented in 1978 to create a medium- to long-term option for the diversification of the Community's energy sources. A second subprogram for demonstration projects on the substitution of hydrocarbons by solid fuels was launched in 1983 to make possible a more rapid transfer of the results of previous research and development activities to practical, industrial use, especially with regard to the use of solid fuels in medium and large combustion installations. In 1985, a third subprogram was initiated as the nonnuclear energy research program to cover the period through 1988 and reflect the growing interest in lignite and peat.

Table 8 presents an overview of the financial commitments to the four programs for the period from 1973 (the year the U.K., as the largest coal producer, joined the Community) until 1986. This table shows that the EEC has intensified its commitment to solid fuels research, development and demonstration by a factor of 10; i.e., from 6.1 million European Currency Unit (ECU) in 1973 to 62 million ECU in 1986. It should be noted that this table represents funds expended by the EEC only. Some member countries additionally allocate funds for their own research.

TABLE 8
FINANCIAL SUPPORT FOR RESEARCH, DEVELOPMENT, AND DEMONSTRATION PROJECTS IN THE FIELD OF SOLID FUELS: 1973 to 1986
(in million ECUs)

Year	ECSC Coal Research	Nonnuclear Energy R&D (Solid Fuels)	Demonstration Projects: Liquefaction and Gasification	Demonstration Projects: Solid Fuel Use	Total
1973	6.1	-	-	-	6.1
1974	7.1	-	-	-	7.1
1975	18.4	-	-	-	18.4
1976	14.7	-	-	-	14.7
1977	16.2	-	-	-	16.2
1978	16.0	-	11.5	-	27.5
1979	17.0	-	-	-	17.0
1980	16.0	-	40.1	-	56.1
1981	16.0	-	19.0	-	35.0
1982	17.0	-	-	-	17.0
1983	19.5	-	27.7	19.6	66.8
1984	19.0	-	20.3	12.9	52.2
1985	19.0	11.4	21.9	16.2	68.5
1986	22.4	6.1	18.4	15.2	62.1
Total	224.4	17.5	158.9	63.9	464.7

*The European Currency Unit (ECU) is a composite monetary unit in which the relative value of each currency is determined by the gross national product and the volume of trade of each country. The composition of the ECU is: Belgium Franc, Danish Krone, French Franc, Deutsche Mark, Greek Drachmae, Irish Pound, Italian Lire, Luxembourg Franc, Netherland Guilder, and Pound Sterling. The value of the ECU in national currencies is calculated and published daily. At September 30, 1986, its value was U.S. $1.02959.[64] At May 3, 1988, its value was U.S. $1.23665.[65]

SOURCE:

Kindermann, F. W.; Wilkinson, J. K.; Furfari, S. "Technical Research, Development and Demonstration in the Solid Fuels Sector" (Brussels, Belgium: Commission of the European Communities, 1987), p. 15.

[64] *The Europa Year Book 1987*. Europa Publications Limited, 1987, p 151.

[65] *The Wall Street Journal*. May 3, 1988.

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Appendix A

Department of Energy Alternate Energy Forecasts

The Department of Energy Base Case forecast used throughout this report was obtained from the Energy Information Administration's Annual Energy Outlook 1987. The forecast assumes a crude oil price of $30.80/bbl in the year 2000 (expressed in 1987 dollars) and a real domestic GNP growth rate averaging 2.2 percent per year between 1987 and 2000. These assumptions led to projected oil demand increasing from 16.5MM barrels per calendar day (bcd) in 1987 to 19.5MM bcd in the year 2000, and domestic production dropping to 8.4MM bcd from last year's 10.6MM bcd. To maintain the supply/demand balance in the year 2000, oil imports would have to increase to 10.0MM bcd, up from 5.8MM bcd in 1987.

In addition to the Base Case forecast, the Department of Energy developed two alternate scenarios. To some degree these scenarios address the uncertainty of projecting energy prices and consumption and "bracket" the Base Case by using different combinations of oil prices and economic growth rates.

In the Low Oil Price-High Growth Case, crude oil prices are assumed to be $24.90/bbl in the year 2000 and GNP growth rate is accelerated compared to the Base Case, at 2.5 percent per year between 1987 and 2000. The low oil price discourages domestic oil exploration and production while at the same time, spurring consumption. As a result, projected U.S. production falls to 7.9MM bcd while demand rises to 19.5MM bcd. Imports increase to 11.7MM bcd to satisfy demand.

In the High Oil Price-Low Growth Case, oil prices are assumed to be $40.20/bbl in the year 2000 while GNP growth rate falls to 1.9 percent per year between 1987 and 2000. Higher oil prices compared to the Base Case depress petroleum consumption to 16.7MM bcd in the year 2000. However, the higher oil prices also provide more incentive for petroleum exploration and production and domestic supply increases to 9.1MM bcd. The combination of lower demand and increased supply results in imports of 7.6MM bcd in the year 2000.

The two alternate scenarios, along with the Base Case, lead to a broad spread in the projected need for imported oil in the year 2000; from a low of 7.6MM bcd to a high of 11.7MM bcd.

Appendix B

Coal Technology

Jim Walter resources, inc.
MINING DIVISION • BROOKWOOD, ALABAMA

William Carr
President

September 1, 1988

Mr. J. J. M. Plante
Vice President and Senior Manager of Projects
STONE & WEBSTER ENGINEERING CORPORATION
245 Sumner Street
Boston, Massachusetts 02107

Dear Joe:

On behalf of the Technology Subgroup for the study of the "Use of Coal in the Non-Utility Sectors," I am pleased to submit our final report, attached hereto. The report includes discussions on solid forms of coal, coal liquid mixtures, coal derived liquid hydrocarbons, and coal combustion. Historic, technical and economic information is provided for each technology discussed. It is our understanding that this write-up will be incorporated into the Appendix of the final report as background information.

For myself and the other members of the Technology Subgroup, it has been most rewarding to participate in the study of the "Use of Coal in the Non-Utility Sectors" under your chairmanship.

Sincerely,

WCarr.

William Carr
Chairman, Technology Subgroup

WC/bl
Attachment

cc: Mr. B. Brodfeld
Stone & Webster Engineering Corp.

Mr. J. B. Cottingham
Pyropower Corporation

Mr. Hugh F. Grabosky
Amoco Corporation

Mr. K. J. Heritage
Riley Stoker Corporation

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SOLID COAL FUELS

History of Coal and Coal Processing

Evidence of coal use has been suggested as early as 1000–1100 B.C. in China and Wales. While Aristotle refers to coal use in northern Greece and Italy by 350 B.C., it was not until the middle ages in England that coal came into widespread use for forges, lime production, and breweries, as a replacement for wood and charcoal.

Coal use in the United States originated as early as 1100 A.D., as evidence indicates coal use by the Navaho and Hopi for firing pottery. The first commercial coal mine was located in the James River Coal Field near Richmond, Virginia, in 1750. U.S. dependence on coal grew rapidly, from 108,000 short tons in 1880, to 200,000,000 short tons by 1900. In 1985, the U. S. consumed over 800,000,000 short tons of coal.

The size and purity of coal has a large impact on its utilization. Screening of coal was practiced as early as 1740. Cleaning processes to reduce ash appeared in Europe by the mid–1800s and in the U.S. by the early 1900s. Presently, virtually all coal produced in the U.S. receives some size or quality preparation in order to meet market specifications.

The production of coke from bituminous coal represents a more drastic alteration of the original coal characteristics than does sizing or cleaning. Coke is made when bituminous coal is heated to a temperature of up to 2000°F under reducing conditions. The solid char, which remains after carbonization, is approximately 75 percent of the original weight charged into the coke oven. In the United Kingdom, the use of coke to smelt iron dates to the early 1700s.

Today, processed, ungraded coal (i.e., coal containing all sizes as–mined) is the dominant form of coal. Char from coke–making also accounts for tens of millions of tons annually in the U.S. Coarse, graded sizes of coal (stoker coal), once the dominant form, is still required for stoker applications in the industrial, residential, and commercial markets. In the future, solid forms of coal may be expanded to include processed low–sulfur coals, micronized coals, briquetted or pelletized coal fines from cleaning processes, and intermediate ash (middling) coals suitable for fluidized–bed combustors.

Processed Coals

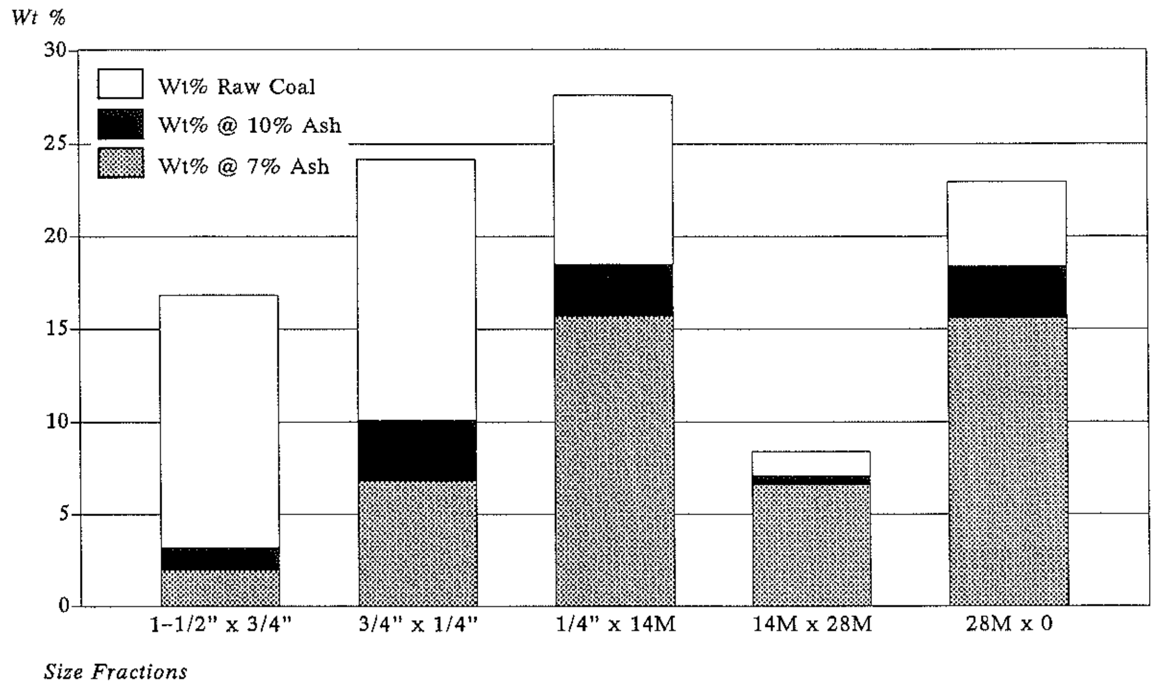
As–mined coal generally must be modified in order to be sold. The modifications to coal to meet customer requirements can be as simple as crushing or as extreme as coking. The process of improving the inherent characteristics of as–mined coal is termed beneficiation. A subset of beneficiation is coal preparation, which includes coal cleaning.

To understand beneficiation processes, it must be recognized that coal is not a homogeneous material, but instead, like crude oil it is a mixture of components which can be separated. On a basic level, coal consists of particles of various sizes, as shown on Figure 1. Each size fraction consists of particles containing varying amounts of ash. The highlighted areas within the histogram depict the relative proportions of each size fraction which could be recovered as products at 7 percent ash or at 10 percent ash.

The higher the ash in the product, the higher the recovery; recovery varies with particle size and has a significant impact on coal production costs. For example, using the data on Figure 1, the net recovery at 7 percent ash was 46.3 percent, and the recovery at 10 percent ash was 57.3 percent. Assuming a mining and processing cost of $12.50 per raw ton at 7 percent ash, the product cost would be $27.00; while at 10 percent ash, the product cost would be $21.82 per ton of marketable coal produced. The effective cost reduction afforded by producing a higher ash product would be nearly 20 percent.

Coal from a single mine can be processed to make products of varying ash content. This is due to the fact that the ash content of a particle is directly proportional to its density. Figure 2 shows the distribution of material by density fraction for the 1/4" x 14 mesh(M) size fraction of the data set used above. Note that the ash content of material having a density of less than 1.3 grams/cc is 4.5 percent and the material with a density of greater than 2.0 grams/cc has an ash of 88 per-

FIGURE 1 Distribution of Raw Coal by Size



cent. Density fractions from 1.3 to 2.0 have progressively higher ashes. A coal preparation plant separates raw coal into various size and density fractions. Next it recombines clean fractions into specified products and discards low quality material.

For example, using Figure 2, if all the 1.3 fraction is combined with half the 1.3 x 1.4 fraction, the result is 41.8 percent recovery of a 5.9 percent ash product. By combining the remainder of the 1.3 x 1.4 fraction with the material between 1.4 and 2.0, the result is 29.4 percent recovery of a 21.6 percent ash product. This intermediate ash product is termed "middling."

In this manner, by density separation, coal may be "cleaned" to produce multiple fuels consisting of both low and medium ash coals for metallurgical and thermal coal applications and high ash coals for blending or direct use in thermal applications.

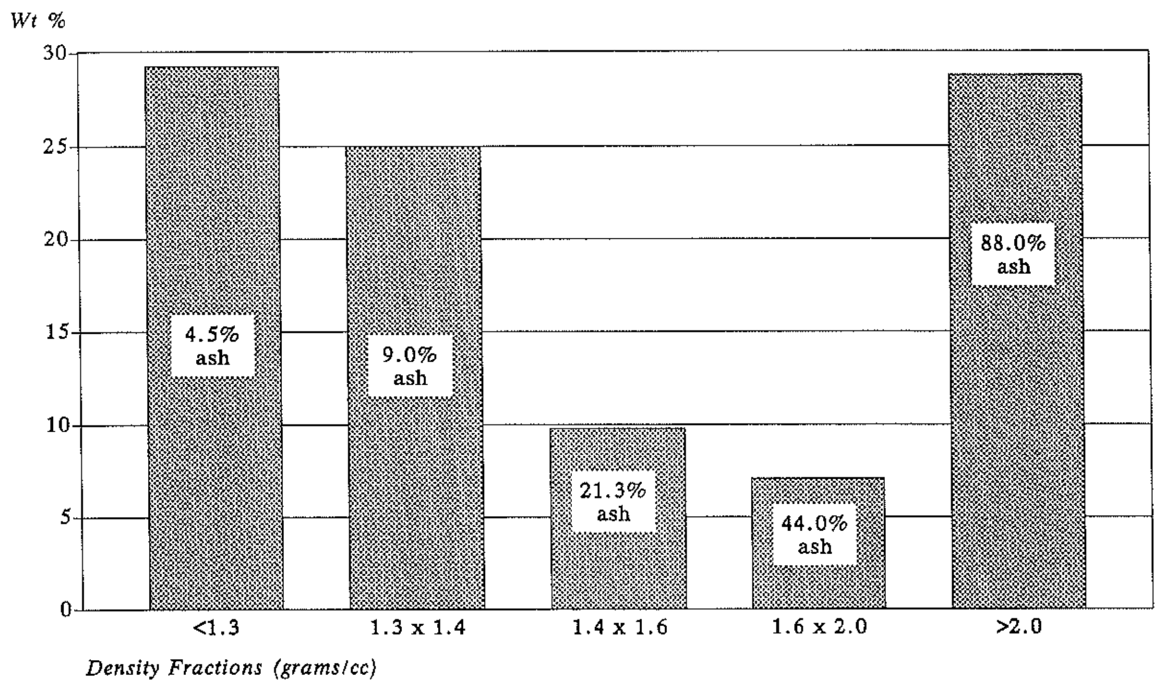
While in the U.S., an ash content of 20–30 percent is considered high, in many nations of the world, fuels at this ash level and higher are routinely utilized for steam raising. In South Africa, mine-mouth power stations are supplied with 20–27 percent ash coals, the domestic steel industry is supplied with 10–14 percent ash coal, and low ash coal, 7–7.5 percent, is reserved for the export market. It is interesting that coal utilized in the Sasol process is specified at +30 percent ash.

Because the ability to recover and market higher ash fuels is an important factor in minimizing production costs, fluidized bed combustion (FBC) technology is an important and synergistic development. The presence of FBC units will provide an outlet for middling coal and the availability of low-cost middling coal should provide a stimulus for FBC projects.

Fine Coal Preparation

The process of mining, handling, and cleaning coal involves particle breakage and ultimately results in the generation of fine particles, defined here as particles smaller than 28 mesh (0.6MM), or approximately the size of a grain of salt. In the future, much coal may be intentionally reduced to this size in order to liberate sulfur-containing minerals (pyrite) normally attached to coal particles.

FIGURE 2 Distribution of Coal by Density



Fine coal, however, has a number of inherent disadvantages compared to coarser-size coal:

it is likely to contain a higher percentage of moisture;

it is difficult to handle, store, and transport; and

it may cause environmental and safety problems.

Many of the fine coal cleaning processes under development are water based and can be expected to result in high residual moisture levels. As shown on Figure 3, the moisture content of coal increases exponentially as particle size decreases, due to the increased surface area of fine size particles. For many water based cleaning processes, using -200 mesh coal would result in product moistures in excess of 40 percent after mechanical drying. Thermal drying of 40 percent moisture fines to a 5 percent moisture level could be expected to cost over $8 per ton, based upon evaporation of water from coarser size material using state-of-the-art technology. The dried fine product would be difficult to handle, store, or transport by conventional methods.

Briquetting and Pelletization of Coal Fines

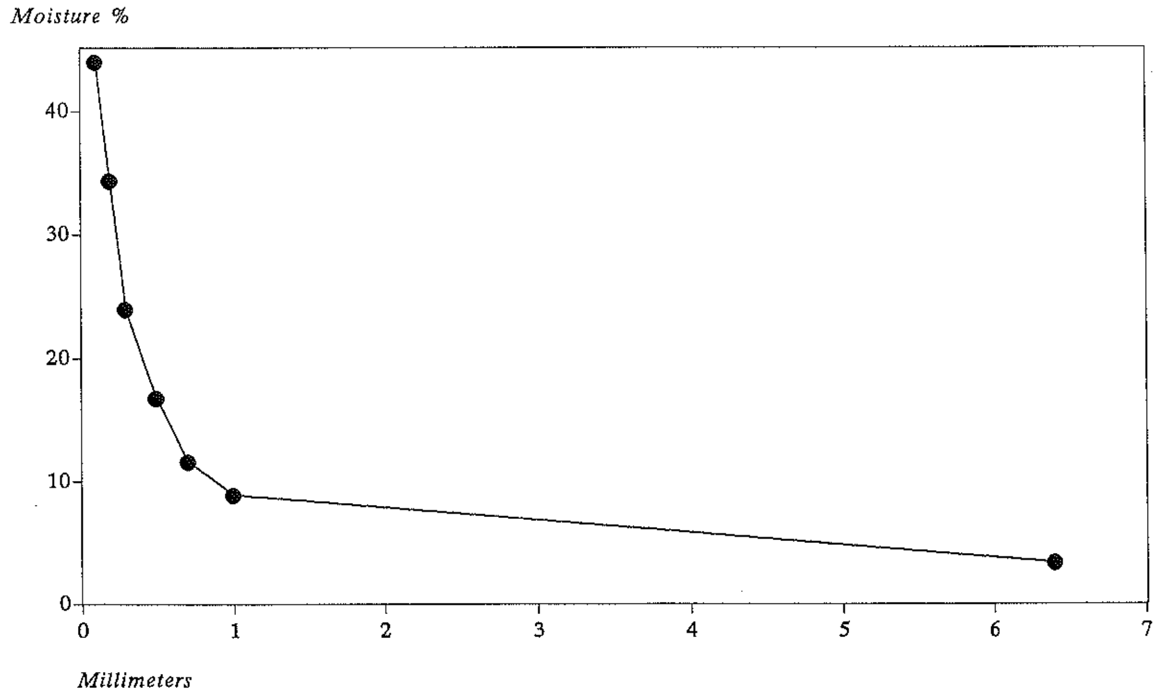
Coarser sizes of coal are desirable for most applications from the standpoint of handling and utilization. Briquetting and pelletizing are two technologies capable of drying and consolidating fine-wet coal into useful, manageable products.

Briquetting may be achieved by either extrusion methods or by mechanical pressure. Chemical binders or heat may be used to maintain the formed briquette and to improve its resistance to degradation brought on by weathering or handling.

Coal pellets are formed by the balling action of a rotating disc pelletizer. Chemical binders are required to agglomerate the coal particles.

Coal briquetting was developed over 100 years ago and was prevalent from approximately 1900 to World War I. It is anticipated that pelletizing and briquetting may play an integral role in the recovery of fugitive coal from coal cleaning operations. It has been estimated that up to 30 million tons per year of recoverable coal are lost to cleaning plant waste. Given that this material presently

FIGURE 3 Moisture Percent vs Particle Size



represents a negative cost to the mine operator, pelletizing and briquetting (combined with waste recovery processes) could provide an important new source of stoker grade fuels for residential, commercial, and industrial markets.

Micronized Coal

Micronized coal, pulverized to finer than 325 mesh, has been proposed as an alternative fuel for boilers designed to fire oil or gas. The greater surface area of micronized coal, versus conventional pulverized coal, speeds up combustion and thereby alleviates derating of gas or oil units while firing coal.

In 1985, a Florida company began commercial deliveries of micronized coal to a local chemical company. However, low oil prices have impeded the enterprise.

Char Fuels

Coal char, in the form of metallurgical coke, has long been used as a combination fuel and reducing agent for iron making. Recently, interest has developed in producing char fuels from western coal and in char as a by-product of mild gasification.

Char fuels derived from western coal are intended to reduce the high moistures of western subbituminous coals and lignites and increase the heating value. Test data published by Western Energy Company indicate that feeds containing from 13 to 48 percent moisture can be reduced to the 0.5 percent range. Coal heating value is similarly improved. In addition, the Western Energy process also reduces sulfur. The resulting bituminous-rank char is more suitable for transport to distant markets than typical high moisture subbituminous coals and lignite.

Another potential char fuel may be a by-product of a mild gasification, low-temperature, carbonization synfuels process. In this process, residual char accounts for 72–75 percent of the products, with the remainder being coal-liquids and gases. Uses for the char could include blending stock for steam coal or a feedstock for graphite application.

Barriers to Solid Coal Fuels

A significant barrier to the introduction of new solid coal forms is the perception within the industry of coal as a monolithic commodity when, in fact, a typical run-of-the-mine coal is a combination of products of widely varying moistures, purity, and handling characteristics. Many of the clean coal technologies presently under development could best be applied to existing fine coal process streams, rather than coal fines resulting from intentional grinding. Because cost is such an important factor in coal utilization decisions, recovery of fugitive coal from past and existing operations should receive more attention.

COAL LIQUID MIXTURES

History

Coal liquid mixture (CLM) is a term applied to a family of fuels which includes coal-oil mixture (COM), coal-oil-water mixture (COWM), coal-water mixture (CWM), and coal-methanol mixture (CMM). CLMs are generally comprised of a carrier liquid, at least 50 percent (by weight) of pulverized coal, and frequently, less than 1 percent of chemicals to enhance the stability and viscosity of the mixture.

As with coal-derived liquid hydrocarbons, CLMs have a long and inconsistent history of development. The first U.S. patent for a COM was issued in 1879. A successful COM combustion test was conducted in a naval vessel watertube boiler during World War I. COM research again was performed briefly during World War II in response to oil shortages.

Work on combustible CWMs occurred in the early 1960s in Germany, the U.S., and the USSR. The coal content of the coal water fuels (CWFs) used in early tests ranged from about 50 percent in the Soviet program to about 70 percent in the U.S. demonstration at Jersey Central Power and Light Company's Werner Plant in South Amboy, New Jersey.

The rapid increases in the price of oil, which occurred in the 1970s, stimulated new CLM studies and demonstrations. COM demonstrations, some funded by the U.S. government and others by private industry, commenced in the mid-1970s. Although much of the COM activity took place in the U.S., many other nations implemented programs, including Canada, the United Kingdom, Sweden, Japan, Colombia, China, Spain, and Israel. Since the early 1970s, COM development activities have been replaced, to a large extent, by CWM programs. However, in November 1987, a U.S. firm announced plans to convert a 44 MW boiler in Puerto Rico to a 60-20-20 COWM.

Coal-water mixture programs, spawned by COM development work, began to appear in the late 1970s and early 1980s. The rationale behind CWM is that water is a cheaper medium than oil; therefore, significant reductions in fuel price for CWM, compared to COM, were expected. Major industrial and utility demonstrations of CWF were conducted in the mid 1980s in the U.S., Canada, Japan, Italy, Sweden, China, and the U.K. Significant industrial and utility CWM projects continue in Japan, Italy, Korea, China, and the USSR. Although activities involving CWM for boiler applications in the U.S. have nearly ceased, some research and development work continues in the area of ultra-clean CWMs for combustion turbines, diesel engines, and slurry-fed gasifiers.

Coal liquid mixture activity continues worldwide, although due to the 1985-1986 collapse in oil prices, programs in many countries, including the U.S., have been deemphasized.

General Fuel Characteristics

The general composition of various CLMs is as follows:

Fuel Form	% Coal	% Oil	% Water	Particle Size
COM	20-53	47-80	0	70% -200M to 100% -325M
COWM	40-60	20-50	10-20	50%-75% -200M
CWM	60-75	0	25-40	99% -48M to 99% -325M
CMM	60-65	30-40*	0-10	90% -200M

* percent Methanol

Both COM and CWM may contain about 1 percent additives to reduce viscosity and inhibit settling of the coal from suspension. Ash content of the CLMs is dependent upon the quantity of ash in the parent coal used as feedstock. However, because fine-sized coal is utilized in the mixtures and fine-sized coal also is required for deep-cleaning processes, beneficiated parent coals containing less than 1 percent ash have been utilized in CLMs.

Applications

Ash content plays a major role in the application of CLMs to specific markets. Generally, ash-tolerant units such as cement kilns, aggregate dryers, or coal designed boilers could be expected to handle CLMs made from feedstocks containing 6 percent ash or higher. Boilers designed to fire oil or gas require CLMs made from lower ash coals, in order to avoid derating. Coals destined as feedstock in CWMs for combustion turbines or diesel engines should contain less than 1/2 percent ash in order to avoid damage to these types of units. CWMs for slurry-fed gasifiers appear to have similar ash requirements to CWMs intended for coal designed boilers.

Recently, increasing attention has been given to CWF combustion units suitable for residential and commercial applications. Both a small fluidized bed combustor and residential warm air heating system have been under development.

Characteristics

Although there are many similarities among the various types of CLMs, there are some important differences which impact economics, applications, and the types of coal suitable for feedstock.

Coal-Oil Mixtures

Coal-oil mixtures have appeared in at least two forms: conventional utility grind (about 80 percent -200M) and ultrafine grind (100 percent -325M). Utility grind COMs required chemical additives to inhibit settling while ultrafine grind COMs are inherently stable and require no additives. The viscosity of COMs is very sensitive to coal content; therefore, coal is normally limited to 50 percent of the mixture, by weight.

Combustion characteristics of COMs are significantly impacted by the volatile content of both the oil and coal used. Low volatile oil in combination with medium to high volatile coal is preferred. High volatile oils, such as No. 2, and low volatile coals have been shown to degrade the combustion performance of COMs.

STATUS OF TECHNOLOGY

In the U.S., COM technology benefited from demonstrations at a utility and at industrial sites in Florida. The utility, Florida Power Corporation, burned COM at its Bartow Unit No. 1 from 1982–1986, but due to relatively high delivered coal costs ($55/ton) and low oil prices, the unit discontinued COM firing. A fuel oil price greater than $20 per barrel was considered necessary for COM reintroduction at Bartow.

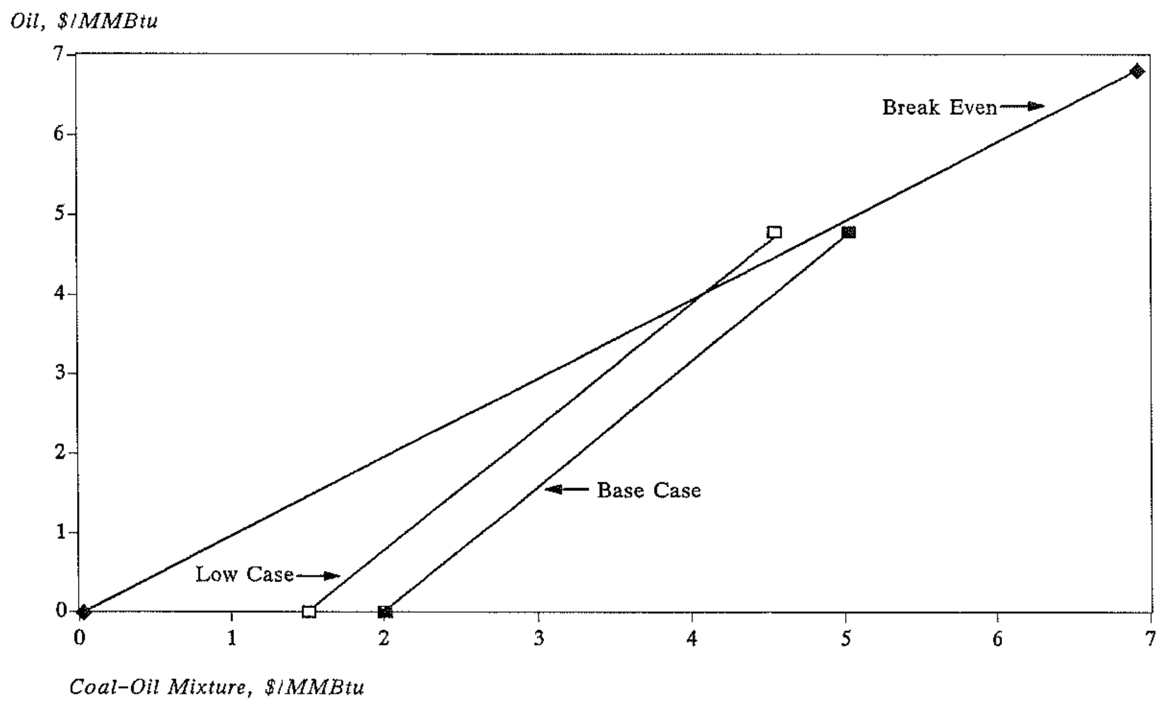
COMMERCIAL STATUS

The technology to produce, transport, and burn COM appears to be adequate; however, COM costs are not competitive with present fuel oil prices. Utilizing published graphical information, COM economics appear very sensitive to fuel oil prices and to delivered coal price and processing cost. Figure 4 illustrates the possible relationship between oil price and COM cost. The graph indicates that with a coal cost of $2.20/MMBtu and a processing cost of $0.70/MMBtu, the threshold price of fuel oil necessary for COM introduction would be around $5/MMBtu, or $31/Barrel. Reducing delivered coal cost to $1.50 and processing cost to $0.50 results in a threshold fuel oil price of about $4/MMBtu, or $25/Barrel.

Coal-Oil-Water Mixture

Coal-oil-water mixtures reportedly have contained from 10–20 percent water and appear to use standard p.c. grinding (80 percent -200M). Although COWMs have been reported which contain up to 65 or 70 percent coal, recent reports indicate a blend of 60 percent coal, 20 percent oil, and 20 percent water. Coal is stabilized in the oil/water mixture by emulsion techniques, both conventional (by shear) and ultrasonic. The stability of ultrasonically treated COWMs is adversely affected by temperature changes and, consequently, the COWM is stored at temperatures between 110° and 160°F.

FIGURE 4 Coal–Oil Mixture Costs



Compared to COMs, COWMs can contain higher proportions of coal and lower proportions of oil due to the fact that the inclusion of water in a COM reduces viscosity. COWMs also have shown better combustion properties than COMs, a finding which is also attributed to the water content. Rapid evaporation of water is said to cause micro-explosions which inhibit formation of fuel agglomerates and thereby improve carbon burnout.

STATUS OF TECHNOLOGY

Production and utilization technology for COWMs as with COMs, appears to be adequate. The announcement in late 1987 of the retrofit of a 44 MW utility boiler in Puerto Rico to COWM reinforces this impression.

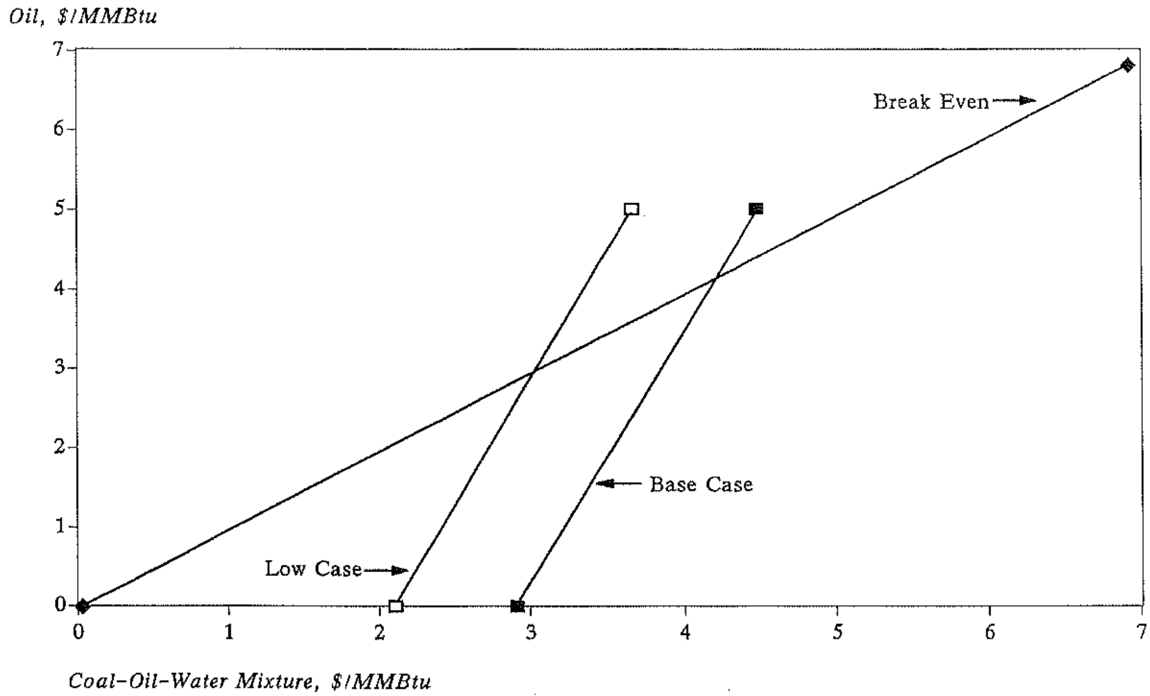
COMMERCIAL STATUS

It is estimated that COWMs can be processed, transported, and used for roughly the same cost as COM. However, because COWM contains less than half the oil of COM, product cost sensitivity to oil price is much less. Figure 5 presents base case and low cost scenarios analogous to those presented for COM. In the base case, it was assumed that user cost would be somewhat higher because of higher ash than COM, processing costs would increase because of greater complexity, and transportation costs would increase because of lower fuel Btu. Even so, the threshold price of oil ($4/MMBtu) for COWM viability was about $1/MMBtu lower than for COM. In the low cost case (coal = $1.50/MMBtu, processing = $0.50/MMBtu), the threshold oil price was estimated at $3/MMBtu, or about $18–$19 per barrel.

Coal-Water Mixture

Combustible coal-water mixtures may range in coal content from around 60 percent to over 80 percent, based upon use of bituminous coals. Commercial quality CWMs have been produced in the range of 65–70 percent coal, resulting in stable, moderate viscosity fuels. Particle size of CWMs, while nominally 75 percent -200M, is generally broader and finer than a typical p.c. grind in order to improve particle packing and thereby lower viscosity and increase solids loading. A subset of CWMs, micronized CWMs are made from coal ground to minus 325 mesh and

FIGURE 5 Coal–Oil–Water Mixture Costs



are generally lower in coal content (50–60 percent), higher in viscosity at comparable solids loadings, and more stable than conventional, more coarsely ground CWFs.

For most CWFs developed, a variety of chemicals have been required to reduce viscosity (dispersants), enhance stability, and inhibit bacterial attack and degradation of the surfactant chemicals. The presence of submicron particles, either from finely ground coal or in the form of an additive like atapulgite clay, also enhance CWF stability.

A number of comprehensive studies on CWF and micronized CWF have been performed. CWF combustion characteristics reflect those of the parent coal, and combustion of CWFs may be as good as, or considerably worse than, their parent coals and fuels they are intended to replace, namely gas and fuel oil. CWF combustion performance will depend upon the coal and CWF process utilized, application, burner design, and preheating of CWF and/or combustion air. CWF combustion performance can be (and in many demonstrations has been) improved by co-firing with natural gas. Published results on micronized CWM combustion indicate that benefits may be derived from microning that are attributable to fine-size ash than with conventional CWMs. Techniques for good fuel atomization are important to realizing the benefits of micronized CWF.

STATUS OF TECHNOLOGY

Major areas of CWM technology are still in development, although considerable progress has been made since the early 1980s. The technology appears adequate to commence with initial large-scale, long-term, commercial demonstrations.

While the U.S. was arguably the overall leader in CLM technology during the late 1970s and early 1980s, recently technology leadership has shifted to foreign nations with active CWM programs. CWM technology continues to develop in Japan, Italy, Korea, and the USSR, where Italy is assisting the Soviets in the construction of a 3-million ton per year CWM mine-mouth-to-power station project.

COMMERCIAL STATUS

Unlike COM or COWM, CWM cost is not sensitive to the price of oil; therefore, the threshold oil price and CWM cost, including user cost, are identical. Figure 6 displays information for CWM similar to that presented for COM and COWM. In the base case, it was assumed that user cost was $0.40/MMBtu, processing cost was $1.00/MMBtu, and transportation cost was $0.25/million Btu. The low cost CWM case was analogous to those of COM and COWM. CWM cost is most sensitive to delivered coal cost, and at a coal price of $2.20/MMBtu, the threshold oil price ranges from $3.85/MMBtu in the base case to $4.10/MMBtu in the high cost case. Reducing coal prices to $1.50/MMBtu and processing costs to $0.50/MMBtu would result in a threshold price of $2.65/MMBtu, a value competitive with recent oil prices.

In order to achieve commercial viability, CWM technology must progress to technical maturity and a means must be found to reduce coal and processing costs.

Coal-Methanol Mixtures

Coal-methanol mixtures have played a minor role in the development of CLM technology. Aside from DOE studies, there appears to be a limited number of CMM studies. Although CMM's hold the promise of clean burning fuels which eliminate the need for combustion air preheat, the availability and high cost of methanol has discouraged the development of CMM technology. Using a current price for methanol of $0.35/gallon ($4.76/MMBtu), the threshold price of oil for CMM viability is $4.62/MMBtu, or approximately $28/bbl. Figure 7 illustrates the relationship between methanol price and CMM/threshold oil price. Until the time that the relationship between fuel oil prices and methanol prices reverses itself, it appears that CMM technology will remain dormant.

Barriers to Commercialization

TECHNICAL

The foundation of CLM technology is strong. However, refinement is required to improve production, transportation, and use of CLMs prior to widespread commercial implementation.

REGULATORY

A major regulatory constraint which impacts CLM commercialization is the concern users have for air emissions standards. The concern is that unit

FIGURE 6 Coal-Water Mixture Costs

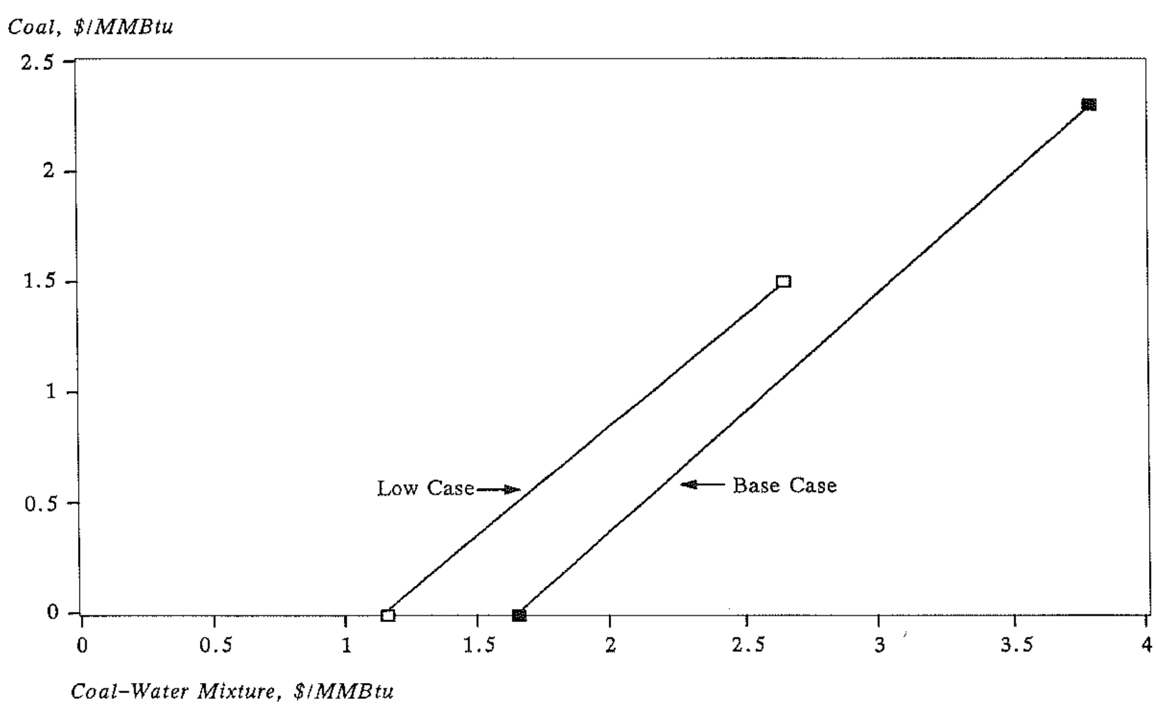
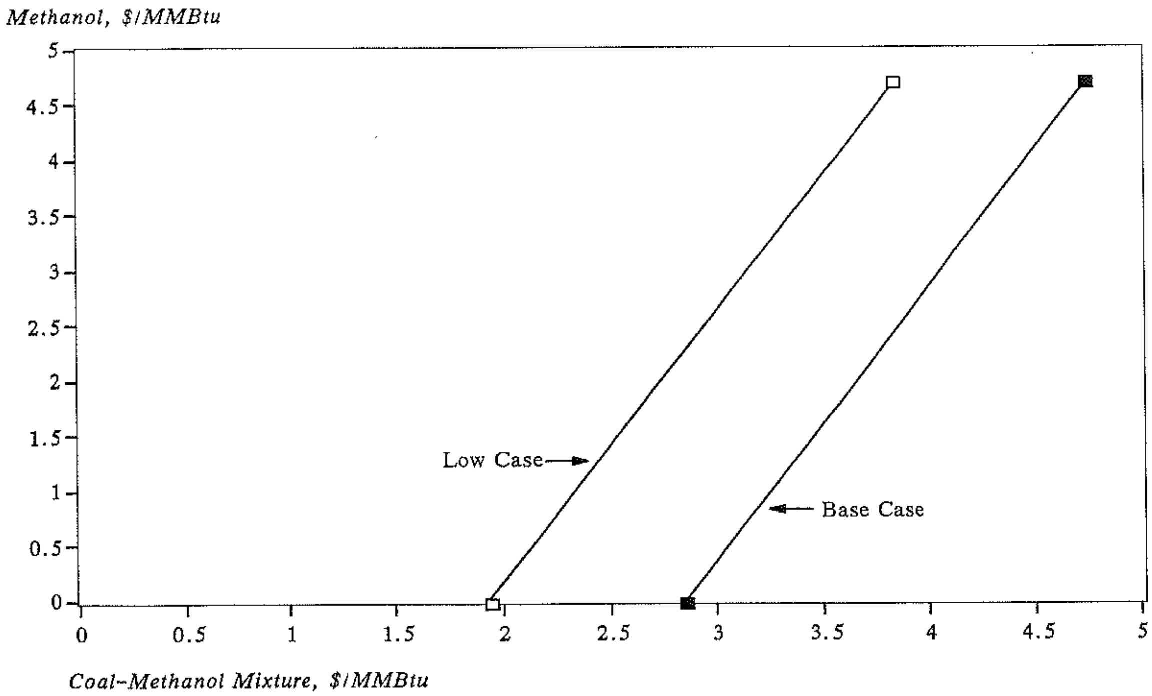


FIGURE 7 Coal–Methanol Mixture Costs



retrofit changes required for CLM utilization may expose the unit to lower emission standards than before the change–over, thereby increasing costs.

ECONOMIC

To become commercial, CLM prices must be reduced or oil prices must go up. From a national perspective, the former alternative is preferable. Costs of producing and using CLMs are presently too high to compete with oil and gas alternatives. Figure 8 displays relative CLM, oil, and gas prices, assuming current technology; and 1995 DOE estimates for coal, oil, and gas prices.

CLMs would appear to have some economic advantage; however, cost reduction would be beneficial. An integrated coal slurry pipeline/CWM system, utilizing the ultrafine fraction for CWM feedstock, is one example of a method of reducing CLM cost; but it is one which is constrained by the lack of slurry pipelines.

Recommendations

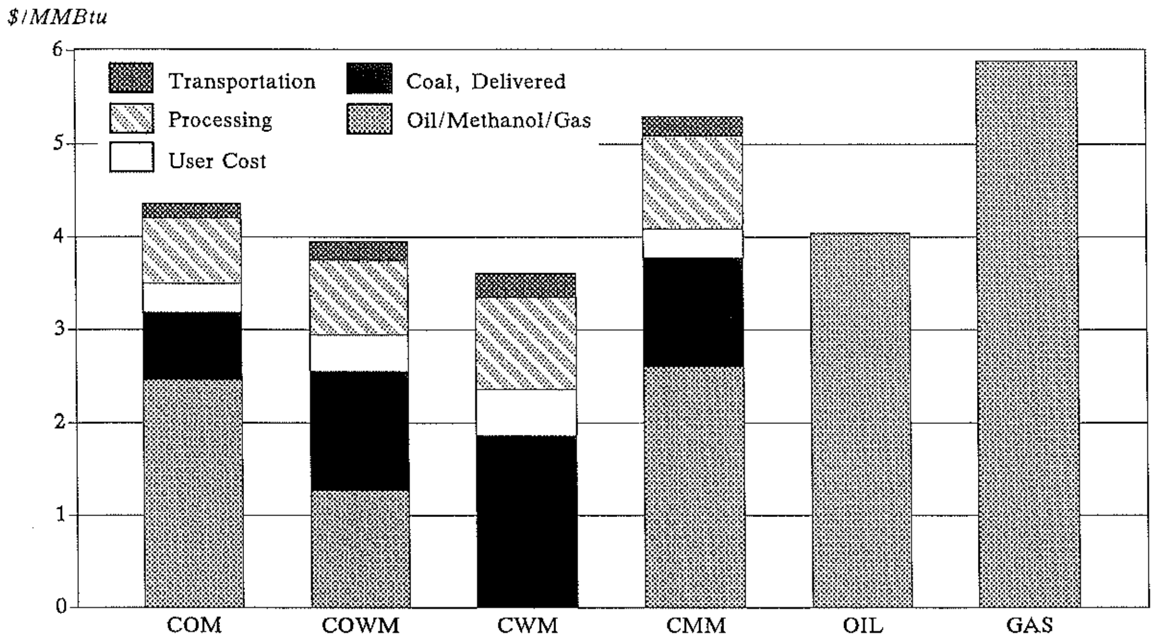
If CLM technology is to once again develop in the U.S., as it is in Japan, Italy, Korea, China, and the Soviet Union, then the U.S. Government must provide financial assistance and regulatory relief as governments in active CLM nations do. The U.S. Government should work with American industry in efforts designed to reduce the cost of producing, transporting, and using CLMs. Emission waivers for initial commercial demonstration projects also would facilitate user participation.

COAL GASIFICATION AND INDIRECT LIQUEFACTION

Introduction

Coal gasification technologies are capable of producing gases suitable for direct fuel use or as building blocks for the synthesis of chemicals and transportation fuels in a process referred to as Indirect Liquefaction. Depending upon the technology employed, the gas produced ranges from less than 150 Btu per standard cubic foot to about 1000 Btu per standard cubic foot, which is functionally equivalent to natural gas. Liquefaction processes can convert gasifier products to chemicals such as ammonia, acetic anhydride, and methanol or motor fuels, including diesel and gasoline. Methanol also can be used directly as a

FIGURE 8 Comparative Coal Liquid Mixture Prices



transportation fuel or as an intermediate in the producing of gasoline or chemicals. Commercial-scale gasifiers are presently operating in the U.S. The commercial-scale gasifiers based on the Texaco process are operating at Tennessee Eastman in Kingsport, Tennessee, and at Coolwater in Daggit, California. These produce fuel gases for power generation and synthesis gas for chemical production.

History

Technology for converting coal into a gaseous fuel has been applied commercially for over 150 years. The basic process consists of heating coal and reacting it with steam and oxygen to form carbon monoxide and hydrogen. The use of coal gasifiers peaked in the United States in the 1920s when about 11,000 were operating, making either town gas/manufactured gas for distribution or producer gas for onsite industrial consumption. With the advent of cheap natural gas in the 1940s and 1950s, nearly all the gasifiers in the United States were shut down. The technology has continued to be practiced in several foreign countries primarily for chemical synthesis using two coal gasification processes developed in Germany after World War II – the Koppers–Totzek gasifier and the Lurgi gasifier.

The energy crisis of 1973 renewed interest in coal gasification. Several companies began developing more efficient, large capacity gasifiers intended for utility, large (heavy) industrial, or centralized gas distribution applications. Other companies concentrated on developing small capacity gasifiers for small (light) industrial and commercial use.

When natural gas and fuel oil prices dropped in the early 1980s and concerns about availability of these fuels disappeared, the incentive for coal gasification was again eliminated.

Alternatives

If nearly pure oxygen is fed to a coal gasifier, the product gas has a fuel heating value of about 300 Btu per standard cubic foot. When intended for use as fuel, this product gas is called medium Btu gas (MBG). Natural gas, which is essentially methane, has a heating value of about 1,000 Btu per standard cubic foot. MBG also can be used to make methane (called substitute or synthetic natural gas), ammonia, methanol, and many other chemicals. When used to make substitute natural gas (SNG) or chemicals, MBG is called synthesis gas.

Alternatively, if air is fed to a coal gasifier, the product gas is diluted with the nitrogen in the air and the heating value is reduced to about 150 Btu per standard cubic foot. This gas, called low Btu gas (LBG), can only be used as a fuel.

There are three basic types of coal gasifiers – fixed bed (also known as moving bed), fluidized bed, and entrained flow. In a fixed bed gasifier, coal primarily in the 1/4 to 2 inch size range is fed to the top of the coal bed in the gasifier; oxygen or air and steam are fed into the bottom of the bed; the coal-derived gas exits from the top of the gasifier at a temperature in the range of 800 – 1,000°F; and the coal ash is removed from the bottom. Because of its low operating temperature, a fixed bed gasifier produces high molecular weight tar and oil compounds in addition to carbon monoxide and hydrogen. These tars and oils will condense as the gas is cooled.

Fluidized bed gasifiers operate at higher gas velocities, which are necessary to fluidize the coal bed. The coal feed is usually 1/4 inch or less. Coal fines blown out of the bed and entrained in the gas stream are captured with cyclones and recycled to the bed. The raw gas leaves the gasifier at temperatures ranging from 1,600 – 1,800°F. Ash gradually agglomerates forming heavy enough particles to drop out of the bed for removal.

The entrained flow gasifier is essentially a burner in a small reaction chamber where pulverized coal, air or oxygen, and steam are reacted in a reducing atmosphere. To achieve high carbon conversion in an extremely short residence time, the operating temperatures must be high. The raw gas leaves the gasifier at temperatures in the 2,300 to 2,800°F range. The ash in the coal melts and flows out the bottom of the high temperature gasifier as slag. Slag coming from the high temperature gasifiers is classified as nonhazardous and is in a reduced form.

The focus of gasifier technology in the 1970s was on the design of "second generation," large capacity, pressurized, oxygen blown gasifiers capable of converting caking and swelling eastern U.S. bituminous coal to MBG or synthesis gas and the development of small scale, atmospheric, air blown gasifiers to make LBG.

Applications

Large coal gasifiers can be used onsite to produce fuel gas for a correspondingly large industrial plant or synthesis gas for use as feedstock for a chemicals plant. The Great Plains Project in North Dakota uses Lurgi gasifiers to make SNG which is fed into the existing natural gas pipeline system. If sufficient customers are located in a 100-mile area, large coal gasifiers could be employed in a centrally located gasification plant distributing MBG/ synthesis gas via a new, dedicated pipeline system.

Small coal gasifiers could be employed onsite by either a single industrial plant, a light manufacturing industrial park, a large commercial development, or even a large residential development.

Because of its low heating value per unit volume, building a pipeline to distribute LBG more than a mile generally cannot be justified economically.

During the 1970s, projects were studied to use gasifiers to fuel a variety of kilns, dryers, furnaces, boilers, diesels, and gas turbines. LBG gasifiers were installed at an industrial park, a brick plant, and a tractor manufacturing plant. As part of a large capacity LBG gasifier demonstration, LBG was burned in a utility boiler. MBG demonstration projects included ammonia production, SNG production, gas turbine firing, and retrofit boiler firing. Tennessee Eastman Company installed a commercial MBG entrained flow gasifier for acetic anhydride and methanol synthesis. Coolwater is a Texaco entrained bed gasifier, generating electric power through combined cycle; also, it is used as the fuel gas to retrofit-fire an existing boiler at the plant site.

LBG and MBG can be used for nearly any combustion service. For retrofit applications with MBG, the only modifications necessary may be the installation of new burners. With LBG, the retrofit modifications are more extensive, and even then, a derating of the unit may be necessary if it was designed specifically for natural gas firing.

This again is partly because of the low volumetric heating value of LBG in comparison to natural gas. In addition, the adiabatic flame temperature of LBG is about 400°F cooler than for natural gas; and for a given heat input, the flue gas volume generated from LBG combustion is about 18 percent more than from natural gas.

CHEMICALS FROM INDIRECT LIQUEFACTION

About 7 percent of U.S. chemical production is currently based on coal as a feedstock. These chemicals are derived from the downstream processing of synthesis gas (or syngas). Of the 30 highest volume chemicals (by weight) manufactured in the U.S. in 1985, all but 7 are (or can be) produced from syngas.

While coal derived syngas can be burned to produce electricity, it is also a potential source of both chemicals and liquid fuels. As an example, while Sasol produces over 58M barrels per calendar day (bcd) of transportation fuels, it also makes more than 650,000 tons/yr of ethylene, ammonia, and other materials as by-products.

Syngas, whether produced from natural gas or coal, can be used to make chemicals by three different methods:

(1) direct conversion to chemicals or fuels;

(2) indirect conversion to chemicals or fuels via methanol as an intermediate; and/or

(3) reacting syngas, methanol, or carbon monoxide with another chemical.

Some of the materials which can be made by the first method include ammonia, methanol, hydrogen, methane, isobutane, ethylene, CI–C5 alcohols, ethylene glycol and C2–C4 olefins. Currently, UBE Industries in Japan is producing 1,000 tons per day (tpd) of ammonia from Australian and South African coal using a Texaco gasifier to generate syngas. AECI also makes 1,000 tpd of ammonia and 100 tpd of methanol in South Africa.

Chemicals, which can be produced indirectly using methanol as an intermediate, include acetic acid and acetic anhydride, formaldehyde, methyl formate, acetaldehyde, ethylene, propylene, CI–C5 alcohols, benzene, toluene, xylenes, and ethyl acetate. Tennessee Eastman is producing 150MM lb/yr of acetic acid and 500MM lb/yr of acetic anhydride from coal in its Kingsport facility using 900 tpd of high sulfur Virginia and Kentucky coal. This plant also has enough excess methanol capacity to satisfy all of Eastman Chemical's internal needs.

The third route to producing useful chemicals from coal could result in an extremely long list. A few of the possibilities are:

- Methanol + isobutene to make MTBE, an oxygenate used in gasoline;
- Olefins + syngas to make aldehydes and alcohols; and
- Methanol + ammonia to make methylamines.

All of these processes are in commercial use, but none are based on coal–derived syngas.

Transportation Fuel from Indirect Liquefaction

Indirect liquefaction, or the production of coal liquids by synthesis from carbon monoxide/hydrogen mixtures, has been a commercial technology since the mid–1930s, based on the Fischer–Tropsch (F–T) process. Sasol in South Africa is using the F–T process to fulfill most of that nation's liquid fuel needs. Other processes, which produce methanol directly from syngas, are commercially available. Mobil also has developed a process to convert methanol to gasoline, and Shell has announced plans to commercialize a technology that converts syngas directly into middle distillate fuel oils (SMDS process).

Sasol's commercial process is based on Lurgi gasification equipment. After leaving the gasifiers, the syngas is cleaned and fed to both circulating fluidized bed catalytic Synthol reactors and fixed bed catalytic reactors. The fixed bed produces heavier paraffinic hydrocarbons which are best suited for diesel fuels, while the fluidized bed reactors make hydrocarbons mostly in the motor fuel range. Following synthesis, the product is processed into products ranging from LPG through the heavier fuels. Various chemicals, mostly alcohols, also are made as by-products. Methane made in the process is separated as a fuel gas or reformed into carbon monoxide and hydrogen which is recycled to the reactors to increase liquid yield. Considering the overall thermal efficiency of the facility, using the methane as a fuel gas is the preferred method.

The overall efficiency of indirect liquefaction is low compared to other liquefaction technologies because of the thermal losses inherent in the production of synthesis gas. The process also makes a broad spectrum of products unrelated to the desired liquid fuels. As a result, the cost of liquid fuels from a F–T facility is relatively expensive. South Africa's decision to commercialize this process despite poor economics was driven by the following two factors:

- the need for a secure domestic supply of liquid fuels is dictated by political considerations, and
- the lack of coal deposits amenable to direct liquefaction technologies.

For many years, Lurgi and ICI have offered commercial methods of converting synthesis gas into methanol. Unlike the F–T process, which makes a wide variety of products, methanol synthesis is over 95 wt percent selective. Mobil has developed the MTG process, which makes gasoline from methanol. The key element is a shape selective zeolite catalyst which produces hydrocarbons in the gasoline and distillate range from methanol; the reaction terminating when a molecule containing about ten carbon atoms are formed. This process has both a fixed and fluid bed configuration. New Zealand and Mobil are operating a 12,000 barrel per day facility based on this technology. Synthesis gas feed is produced from natural gas instead of coal, but there is no reason a coal-based syngas facility could not be built to feed the MTG process.

Technical/Economic Status

Demonstration projects which have occurred to date indicate that coal gasification is technically ready for application. Regarding large capacity gasifiers, the Great Plains Project has proved that lignite can be converted to SNG with no difficulty. The TVA and Tennessee Eastman projects have demonstrated that ammonia, acetic anhydride, and methanol can be reliably made from eastern bituminous coals. The Cool Water Project confirmed that gas turbines can be fired with MBG made from bituminous coal. Other large scale gasification demonstration projects are currently in progress and several others are expected to be operating in a few years.

The Caterpillar Tractor and Can Do Projects showed that smaller gasifiers can be used with no major problems. Unfortunately, activities involving small gasifiers appear to have ceased.

The economics of coal gasification are highly site- and project-specific. Studies of small scale LBG industrial projects indicate that LBG can be made at a cost of $3.50 to $4.50 per million Btu. Studies of large scale central MBG gasification plants have estimated MBG costs in the range of $4.50 to $6.50 per million Btu. Interestingly, the cost of SNG from the Great Plains Plant is no higher than the predicted costs of MBG.

Investigations involving coal gasification for ammonia production indicate that the cost of the MBG or synthesis gas must be less than 50 percent higher than the cost of natural gas for coal gasification to be competitive with natural gas steam-reforming. For this to happen, the price of coal must be approximately $3.75 per million/Btu lower than the cost of natural gas.

For MBG, the cost of the coal gasification equipment contributes about 25 percent of the cost of the entire coal gasification plant. This implies that 75 percent of the plant capital cost is associated with widely employed ancillary systems for which capital costs are well documented. One study showed that a 20 percent reduction in the cost of the gasifier components only translated into a 1.5 percent reduction in the cost of the MBG.

For LBG coal gasification plants, the gasifier accounts for a much larger share of the total gasification facility cost, so a reduction in the cost of the gasifier would have a greater impact. However, the reduction would have to be large in order to significantly affect the LBG cost.

A review of published economics for both actual and proposed projects raises the following points.

- LBG appears to be closest to being economically competitive with conventional fuels.
- The additional capital cost of processing equipment to produce SNG that can be carried in existing natural gas pipelines appears to be more cost effective than building new pipelines for distribution of MBG.
- For cost reductions to be large enough to have a significant impact on reducing the cost of coal gas, they must not be confined to only the gasifier components.
- Annual plant operating hours have a major effect on coal gas cost and consequently they must be high because of the large capital investment.

Barriers to Implementation

TECHNICAL

There are no technical barriers to commercializing gasification or indirect coal liquefaction. Sasol has proved this technology on a large scale. Conversion of coal to methanol and gasoline also is a proved technology. Commercial scale gasification processes developed by Lurgi, Texaco, Dow, Winkler, Koppers–Totzek, and Shell are all in operation. Mobil's process for converting syngas to methanol and then motor gasoline is being used in New Zealand.

In theory, there are no technical barriers to producing chemicals from coal. Several coal gasification technologies have been, or are being proved on a large scale. Commercially ready processes include Texaco, Lurgi, Winkler, and Koppers–Totzek. Processes now being demonstrated on a large scale include Dow, KRW, and Shell in the U.S., and the British Gas/Lurgi Slagging Gasifier. However, at the current state of development, these technologies are not economically competitive with the production of synthesis gas from natural gas. Reasons for the economic disadvantage of coal versus natural gas are described in this section under Economics.

As discussed, there are commercial processes for converting syngas directly to ammonia and methanol. Also, the conversion of methanol to motor fuels, acetic acid, and acetic anhydride is commercial. Proved processes also exist for converting methanol into formaldehyde, methyl formate, formic acid, methyl acetate, chlorinated methanes, dimethyl acetate, vinyl acetate, ethylene glycol, styrene, and dimethyl terephthalate.

The single most important barrier to widespread use of coal gasification is cost. Natural gas is presently available to industrial consumers at a price ranging from $2.50 to $3.10 per million Btu. Commercial users are currently paying around $4.80 per million Btu, and the cost to residential customers is about $5.45 per million Btu.

Given these natural gas prices, there is no incentive for the private sector to produce SNG or MBG from coal. There would appear to be a small incentive for commercial enterprise or a large residential development to consider installing a LBG plant. However, these developers are unlikely to bear the additional capital burden of a coal gasification plant. In any case, the market potential of commercial and residential application would not be significant. Most of these drawbacks can be accommodated by industrial applications, but are unlikely to be acceptable for commercial or residential usage.

Natural gas is used to produce almost all of the syngas made in the U.S., although it could be made from coal, municipal wastes, and biomass. Natural gas requires little preparation before it can be used as a feedstock to a syngas process, but the first step with coal (and the other materials) would be sorting, screening, pulverizing, and removal of tramp materials. Converting natural gas to synthesis gas can be done using either a catalytic partial oxidation process or by a catalytic steam reforming process. Coal cannot be catalytically converted to syngas. It must be done thermally and requires high purity oxygen, and with more steam and higher temperatures than methane. This results in a more costly process with lower thermal efficiencies.

The sulfur in coal must also be removed from synthesis gas to prevent damage to catalysts in the downstream chemical production units.

Coal is deficient in hydrogen compared to natural gas and it is usually necessary to adjust the ratios of carbon monoxide, hydrogen, and carbon dioxide before feeding it to downstream processes. Because each chemical requires a different ratio of hydrogen to carbon monoxide, the gasifier that produces the exact stoichiometric hydrogen/CO ratio would have an economic advantage. This makes the choice of the gasification process to produce any given chemical critical. The syngas exit temperature from the gasifier directly affects the ratio of hydrogen to CO, with lower temperatures favoring hydrogen. This can be seen from data on the hydrogen to carbon monoxide ratios of the syngas produced by Lurgi fixed bed reactor (gas outlet temperature of 1078°F), a KRW fluid bed gasifier (1800°F), and a Texaco entrained bed reactor (2360°F) at 2.8/1, 0.5/1, and 0.7/1, respectively.

The stoichiometric ratio of hydrogen to carbon monoxide for several important chemicals is:

Chemical	Hydrogen/CO
Carbonization	(Pure CO)
Acetic Acid	1.0
Ethylene Glycol	1.5
Ethylene	2.0
Methanol	2.0
Ethanol	2.0
Ammonia	(Pure Hydrogen)

The syngas hydrogen/CO ratio from a coal gasifier can be adjusted in a water gas shift reaction external to the gasifier, resulting in additional equipment and added operating costs.

There is a commercial plant in the United States manufacturing methanol from coal and, under the circumstances of a "complete plant" starting from coal to the final product, acetic anhydride. The economics are attractive and, in fact, the plant is used as a base plant for the manufacture of the chemical. Therefore, under these specific circumstances a new coal plant is indeed desirable to make methanol. The environmental suitability of such a process from coal and the fact that the process is based on coal may make it attractive in various locations in the country.

The effect of the differences between using coal and natural gas on the economics of producing chemicals is illustrated in Table 1. This table provides the cost breakdown for a grass roots Gulf Coast methanol plant with an assumed capacity of 20M bcd. While this case is coal to methanol, the disadvantages of coal compared to natural gas as a synthesis gas feedstock would apply to any coal-based chemical facility.

TABLE 1
COST OF MANUFACTURING METHANOL, CENTS/GALLON
Plant Size–20M bcd

	Natural Gas	Coal
Feedstock:		
Natural Gas @ $2.00/MM Btu	16	NA
Coal @ $1.25/MM Btu ($30/ton)	NA	15
Other Variable Costs	3	2
Fixed Plant Charges	5	7–23
Capital Charges @ 10% ROI above 5% Inflation	19	40–72
Total Cost/Gallon	43	61–112
Plant Investment $MM	250	461–900

SOURCES:

1. Letter dated October 13, 1988, from W.R. Siegart, Texaco, Inc., White Plains, NY, to J.J.M. Plante, Stone & Webster Engineering Corporation, Boston, MA.
2. Letter dated October 10, 1988, from H.F. Grabosky, Amoco Corporation, Chicago, IL, to J.J.M. Plante, Stone & Webster Engineering Corporation, Boston, MA.
3. Assessment of Costs and Benefits of Flexible and Alternative Fuel Use in the U.S. Transportation Sector, DOE/PE-800-January 1988.

The plant using natural gas as a feedstock can be built for about $250MM, while the coal-based facility requires an investment of $461MM. The extra cost is for the facilities needed to handle and prepare the coal feedstock, gasify the coal and clean up the syngas, and finally, the cost of equipment required to adjust the composition of the syngas to get the proper ratios of hydrogen, carbon monoxide, and carbon dioxide required by the methanol reaction.

The cost of methanol from coal is more than 40 percent higher than natural gas-based methanol. In fact, the cost of capital recovery for the coal-based plant ($0.37/gal) is more than 85 percent of the total cost of methanol from the natural gas facility. Also, with methane as the feedstock, the methanol contains about 70 percent of the energy in the gas consumed. With coal, the energy efficiency is only about 50 percent.

All of these manufacturing and construction cost estimates were based upon demonstrated technologies. If improved technologies could be developed, the cost of methanol from coal might be lower. One possibility would be to make syngas by gasifying coal underground; this would eliminate mining and coal preparation along with handling costs. The underground coal gasification technology is still under development. Underground environmental and subsidence problems may deter commercialization of this process.

COAL DERIVED LIQUID HYDROCARBONS

Regardless of what end use is considered, coal derived liquid hydrocarbons could be used as a replacement for their petroleum counterparts because they can be processed to meet typical petroleum specifications. They can directly substitute petroleum in the transportation sector and in industrial, commercial, and residential uses.

There are three ways of producing liquid fuels from coal.

(1) Pyrolysis, or the thermal decomposition of coal in an oxygen free atmosphere.

(2) Indirect liquefaction, or the synthesis of liquid fuels from carbon monoxide/hydrogen mixtures (called synthesis gas or syngas). Coal is gasified to produce the carbon monoxide/hydrogen mixture. This step is followed by catalytic synthesis of liquid fuels, which could include methanol. Methanol can also be converted to gasoline by Mobil MTG process.

(3) Direct liquefaction (or hydrogenation) uses high pressure and temperature to dissolve coal and to add hydrogen to the coal structure. Hydrogen can be either gaseous or come from a donor solvent.

The current status of indirect liquefaction, methanol production from coal, and direct liquefaction of coal to liquid fuels is described below. Where information is available, data will be provided on the threshold crude price level at which these processes can compete economically with petroleum-based products.

Pyrolysis

High temperature pyrolysis has been used for years to produce metallurgical-grade coke for the steel industry. At one time, by-products from coke ovens were the principal source of many materials used by the chemical industry. Typical by-product yields from this high temperature pyrolysis process include approximately 3 gallons of light oil (primarily benzene, toluene, and xylenes) per ton of coal, 8 gallons per ton of coal tar (from which naphthalene, creosote, phenols, cresols, pyridene, and quinoline are recovered as well as various grades of pitch) plus 120 lb/ton of ammonium sulfate in the coke oven quenching liquor. A significant quantity of hydrogen, carbon monoxide, and hydrocarbon gases also are released while devolatilizing the coal, but these are generally burned to provide the heat required in the pyrolysis process.

During the 1950s, natural gas and petroleum replaced coal as a source of many of these by-products. The retrenchment in the steel industry has led to a further decrease in the importance of the chemicals produced with by-products from the production of metallurgical grade coke.

Low temperature pyrolysis processes have been developed since the nineteenth century as a method of upgrading inexpensive coal to make char, tar, and gas products. In a 1983 book, Lowry uses 76 pages to describe over 41 low temperature pyrolysis processes. A 1983 update by Elliott has 62 pages devoted to 10 additional processes. Coal pyrolysis has been commercially successful in certain applications. Many variations of pyrolysis have also been tried with little technical or economic success. The attraction of these processes has been their low cost and relative lack of complexity when compared to direct and indirect liquefaction technologies.

Pyrolysis occurs in essentially all coal conversion processes and is a demonstrated method of liquefying coal. However, approximately half the coal is converted to a solid char. Coal-fired boilers could be an incremental source of liquid fuels if coal is pyrolyzed to recover hydrogen-rich volatiles and the carbon-rich char is then used to produce power in industrial applications. As an example of how much char would be produced from a modest sized pyrolysis facility, Ford, Bacon & Davis, Inc., estimate that a plant feeding 2,500 tons of coal per day would make enough char to feed a 250MW power plant. Liquid fuel production at this coal feed rate would be slightly more than 4.4M bcd.

Pyrolysis involves a thermal decomposition step which releases volatiles in the coal. Secondary cracking and polymerization reactions occur until the volatiles are cooled or quenched. The composition and yield of the primary products depend on the coal type and heating rate, with higher rank coals and fast heating rates favoring higher liquid yields. Prolonged pyrolysis reduces the liquid yield and increases char and gas formation because of the secondary reactions. Stabilization of liquid precursors may occur by internal hydrogen transfer and by direct hydrogenation (hydropyrolysis), which requires high hydrogen pressures and catalysts.

In rapid pyrolysis, small coal particles are heated quickly to increase liquid yield because rapid breakup of the coal structure and fast vaporization minimize char formation. Short vapor residence times and rapid quenching retard secondary cracking and polymerization reactions and maximize net liquid production.

Conversely, hydropyrolysis, uses a hydrogen pressure of 500–2000 psi to cap free radicals in the coal vapors and improve yield and product quality.

Rapid pyrolysis and hydropyrolysis give roughly the same liquid yield, or a maximum of about 38 percent on moisture and ash-free (MAF) coal. About 50 percent more liquids can be made from bituminous coal than from subbituminous coal. Char formation is typically greater than 50 percent.

Pyrolysis products need further hydrogenation, but hydrogen can be made by reforming the pyrolysis gases. Char sulfur content is about the same as the coal feed, so using it as a fuel requires desulfurization and gasification, followed by post-combustion control. Although hydropyrolysis liquids are of better quality than pyrolysis liquids, further hydrotreating is still required to make them acceptable as liquid fuels.

A commercial pyrolysis technology proved in a 1,600 tpd plant is the Lurgi–Ruhrgas process which produces both synthetic crude oil and a char from brown coal. Heat for pyrolysis comes from introducing circulating, fine-grained, heat carriers into the reactor, preferably the pyrolysis char.

This process is called rapid or flash pyrolysis because carbonization takes place in seconds instead of the several hours required to carbonize coal in conventional steel mill coke ovens. The short heating time (20 sec) and low reactor temperatures (1110°F) used in this process maximizes the yield of liquids at about 24 percent (MAF) on brown coal.

Another pyrolysis process called TOSCOAL uses ceramic balls to supply the heat for carbonization. At a retort temperature of 900°F, U.S. subbituminous coals yield about 50 percent char, 8 percent light gases, 7 percent oil, and 35 percent water on an as-mined basis.

COED is a pyrolysis process tested in a 26 tpd pilot plant by FMC. It produces synthetic crude in a fluidized bed pyrolyzer followed by separate oil hydrotreating. Retort temperatures varied between 575 and 1600°F with residence times of 1 to 4 hours depending on the type of coal being processed. Yields from this process were 35 percent (MAF) on high volatile bituminous coal and 12 percent on subbituminous coal.

Barriers to Commercialization

TECHNICAL

The Lurgi–Ruhrgas pyrolysis process has been proved commercially. For certain applications, this or other pyrolysis technologies might be of use in producing supplemental supplies of liquid fuels. Because of the low liquid yield and high char make, these special gases might arise when a supply of inexpensive, high volatile coal is available near a facility requiring large quantities of solid fuel. This facility could use the char to generate steam and the by–product tars and oils could be sent elsewhere for further upgrading. It may be possible to use pyrolysis to dry very moist coal while recovering the volatiles, but fluidized bed combustors now under development would probably be more economical.

ECONOMIC

Pyrolysis may become economically viable around the turn of the century. A study by Ford, Bacon & Davis, Inc., for the Eyring Research Institute suggests that crude oil prices would have to increase to approximately $35/bbl before a plant could be built. Again, sales of the large quantities of char produced by the facility is a prerequisite for developing this technology.

Direct Coal Liquefaction

Because coal has a hydrogen–to–carbon ratio substantially lower than petroleum, converting it into liquid hydrocarbons requires the addition of hydrogen. Direct coal liquefaction processes hydrogenate coal in a solvent slurry at temperatures of 700 to 900°F and pressures of 1500 to 4000 psig. The high temperature is needed for the thermal dissolution of the coal to produce reactive fragments. The solvent, either hydrogen donor or non–hydrogen donor, dissolves the coal and transfers reactive hydrogen to stabilize the coal reactive fragments. As a result, gases and liquids of relatively low molecular weight are produced.

This direct liquefaction concept was pioneered in Germany, with improvements by I.G. Farben, in the 1930s, making commercial scale direct coal liquefaction plants possible. By 1938, Germany was producing about 32M bcd of motor fuels by this process. By the end of World War II, this had increased to 86M bcd.

After World War II, the German technology was tested by the U.S. Bureau of Mines in a 200–300 bcd pilot plant and by the British at Billingham. This work was ended because direct liquefaction could not compete with inexpensive Mid–East crude oil.

Interest in direct liquefaction was spurred by the 1973 Arab oil embargo and a variety of processes were tested in small pilot facilities. Three of these processes were scrutinized in the late 1970s and early 1980s: SRC–II (Solvent Refined Coal) at 30 tpd, EDS (Exxon Donor Solvent) at 250 tpd, and H–Coal also at 250 tpd. This work demonstrated the new technologies and set the scene for future developments. However, they were unable to make direct coal liquefaction cost competitive with crude oil.

The results from the SRC–II and EDS pilot plants suggested that these processes were not likely candidates for further development. Both technologies depended on donor solvents as a source of hydrogen during liquefaction and used only the minerals in the coal as catalysts. The EDS process did use a catalyst to replenish the hydrogen used from the donor solvent, but none was used in the liquefaction reactor. Liquid yields also were relatively low and the economics unattractive.

The H–Coal process was developed by Hydrocarbon Research, Inc., (HRI) and is based on an ebullient catalyst bed reactor; a liquid phase version of the gas fluidized bed processes widely used in the petroleum industry. Coal slurried in product liquid is contacted with hydrogen in a reactor at 800–850°F and 3000 psig where it is dissolved and upgraded in a single step. The ebullient bed uses a conventional solid hydrotreating catalyst with the coal slurry ash and undissolved coal removed from the product oil which is then distilled. Some of the oil is recycled as process solvent. Products are distillate or distillate and resid (for boiler fuel, depending on the coal feed rate).

While the H–Coal process was a technical success, it also was not economically attractive. However, the following two developments suggested that the economics of the technology could be improved:

- a new catalyst that improved liquid yields, particularly from low rank inexpensive coals; and
- HRI experiments indicated that the consumption of expensive hydrogen in the liquefaction could be reduced if two reactors were used in series.

These concepts are currently being tested in a 6-tpd fully integrated pilot plant located at Wilsonville, Alabama, with funds provided by DOE, EPRI, and other private sources.

Table 2 shows the evolution of direct coal liquefaction technology from I.G. Farben's early work to recent Wilsonville runs.

With a trend to milder operating conditions, the consumption of expensive hydrogen has been reduced by cutting the amount of by-product gas made. Liquid yield and quality have been increased by recycling resid to extinction. This results in higher yields of more valuable gasoline and distillate products. The Department of Energy projects that a commercial project based on the Wilsonville technology would be economically viable at crude oil prices of $35/bbl (1987 dollars). It is believed that additional improvements could reduce the required oil price to the $26–$27/bbl range.

Barriers to Commercialization

Direct coal liquefaction technologies are the least proved of the three methods of producing liquid fuels from coal. Exxon's successful demonstration of the EDS process at 250 tpd has made this technology available for licensing. The Department of Energy also has a highly detailed commercial design and cost estimate prepared for a project based on the H-Coal technology, suggesting that this method of direct liquefaction is technically ready for the first-of-a-kind, large-scale installation.

The most promising direct coal liquefaction technology is the two-stage pilot plant process in Wilsonville, Alabama. Continued pilot effort is needed to improve this process and determine its technical and economic merit. Before commercialization, the optimized process must be demonstrated at a scale similar to the EDS and H-Coal processes, or approximately 250 tpd.

TABLE 2
EVOLUTION OF DIRECT COAL LIQUEFACTION TECHNOLOGY

Plant Characteristics	I.G. Farben 1935	Billingham 1945	H-Coal 1980	Wilsonville 1986
Pressure (psi)	10,000	3,000	3,000	2,750
Maximum Temperature (deg F)	895	870	850	825
Coal Conversion (%)*	–	94	94	94
Hydrogen Consumption (%)*	14	8	6	6.5
Yields (%)*				
H.C. Gases	30	25	11	7
Distillable Liquids	54	54	51	65

*As weight percent on moisture, ash-free bituminous coal

ECONOMIC

No technology which produces liquid fuels from coal is competitive with crude oil today. (The spot market price of crude oil was $15.75/bbl on March 2, 1988). Although there is a great deal of information about the projected cost of coal liquefaction in the literature, a comparison of studies is difficult because of the different assumptions used in preparing these estimates. Herbert and Loeffler presented estimates for the cost of various indirect coal liquids in $/GJ of product versus feed cost in $/GJ. Assuming $30/ton coal with a heat content of 22.41MM Btu/ton, the values of the products were calculated on a $/bbl basis using the heating value of each material. The cost of production, according to Herbert and Loeffler, included fixed and variable production costs, based on a–15 year plant life, and "realistic" costs for capital recovery, labor, overhead, repair, maintenance, and insurance. The results of these calculations are shown in 1980 dollars.

Process	$/bbl
F–T Synthesis (diesel, mogas)	65
Mobil MTG	54
Methanol	42
F–T Synthesis (gasoline, diesel, and pipeline gas)	35
Methanol + Pipeline gas	32

It must be noted that the cost of methanol shown must be multiplied by 1.7 to correct for its lower energy content if comparing it to the cost of gasoline. Thus, on a Btu equivalency basis, the cost of methanol from coal is $54 to $92/bbl.

Other estimates for the cost of producing methanol from coal range from $40/bbl ($69/bbl on a Btu equivalency to gasoline) and $52/bbl ($89/bbl).

Another source of the cost for producing liquid fuels from coal is J.M. Holmes, et al. These data are shown below in 1981 dollars and assume a 10 percent DCF, no taxes, coal at $24/ton, and SNG at $4.75/MM Btu.

Process		$/bbl
F–T with Lurgi/Synthol	– SNG Produced	55–66
	– Methane Reform.	56–69
Gasoline via MTG/Lurgi	– SNG Produced	52–68
	– Methane Reform.	58–68
Direct – EDS, H–Coal		54–56
Advanced Direct – Chevron, HRI, et al		43

Information on the economics of specific direct coal liquefaction processes is given below.

Based on Department of Energy studies of the Breckenridge project and an update by Amoco, the H–Coal technology would require oil prices to increase to about $90/bbl before a commercial installation could be justified. This estimate assumes 100 percent equity financing, constant 1987 dollars, and a 10 percent real rate of return on capital investment.

Data from Wilsonville suggest that this two–stage direct liquefaction process would require an oil price of $35/bbl before a commercial project could be economically competitive, with a possibility that this could be reduced to the $28–30/bbl range if the pilot work continues and is successful. Based on current oil price forecasts, it appears that two–stage liquefaction may be economically viable at or before the year 2000.

Barriers to Commercialization

TECHNICAL

In theory, there are no technical barriers to producing chemicals from coal. Several coal gasification technologies have been proved on a large scale. Commercially ready processes include Texaco, Lurgi, Winkler, and Koppers–Totzek. Processes now being demonstrated on a large scale include Dow, KRW, and Shell in the U.S., and the British Gas/Lurgi Slagging Gasifier. However, at the current state of development, these technologies are not economically competitive with the production of synthesis gas from natural gas. Reasons for the economic disadvantage of coal versus natural gas are described in the Economic Section.

As discussed, there are commercial processes for converting syngas directly to ammonia and methanol. Also, the conversion of methanol to motor fuels, acetic acid, and acetic anhydride is commercial. Proved processes also exist for converting methanol into formaldehyde, methyl formate, formic acid, methyl acetate, chlorinated methanes, dimethyl acetate, vinyl acetate, ethylene glycol, styrene, and dimethyl terephthalate.

ECONOMIC

To make the chemicals from coal process economically viable, technological improvements are required in the gasification and synthesis gas clean up processes. One area for reducing the cost of gasification may be the development of suitable pregasification catalysts. By adding a suitable catalyst to the coal feed, it may be possible to reduce gasification temperatures, pressures, and residence times thus minimizing the size and cost of the facility. Catalysts also might improve gasifier quality and yield. Work by Exxon and others suggests that the carbonate and hydroxide salts of alkali metals may accelerate the gasification of coal. Exxon terminated this work in 1983.

Gas cleaning and cooling equipment total between 35–40 percent of the total investment in a synthesis gas production facility. The most probable method of reducing the capital investment required for gas cleaning equipment is the simplification or elimination of one or more to the process units in the system. This will require additional research and development.

COMBUSTION OF COAL FUELS

Pulverized Coal Firing

HISTORY

Pulverized coal was used by Rudolf Diesel in the 1890s for the first experiments on his internal combustion engine. During this same time period, pulverized coal firing achieved its first commercial success in the cement industry. The major growth in the use of pulverized coal, however, began following World War I with its introduction into the utility power industry. Today the vast majority of coal–fired utility boilers are designed for pulverized coal–firing. At present, the largest single utility coal–fired unit produces approximately 1300MW of electricity. In the last 20 years, considerable research has occurred on pulverized coal systems in an effort to control emissions such as nitrogen oxides (NOx). This has led to the development of low–NOx burners and staged combustion systems. Advanced ultrafine grinding techniques also are under development; these may make pulverized coal applicable to a wider range of industrial and commercial applications.

TECHNOLOGY

Pulverized coal combustion is generally less sensitive to fuel properties than other firing techniques. The firing of finely ground coal in suspension falls into the following two major categories.

(1) Pulverized coal, coal residues, solvent refined coal (SRC), or partly dewatered slurries blown into suspension with transport air.

(2) Pulverized coal that has been slurried into water, oil, methanol, or some other liquid medium and blown into suspension in the form of a finely divided spray.

Pulverized coal is fired in a wide variety of furnace designs. These designs can be broadly classified into categories: dry ash furnaces or "dry bottom" furnaces and molten ash furnaces or "wet bottom" furnaces. Furnace configurations include wall–fired, tangentially fired, turbo–fired, and vertical down–fired designs. In order to achieve burnout within a reasonable furnace volume at reasonable entrainment velocities, current commercial practice is to grind coal to a fineness of 70 percent or more through a 200–mesh (74 micron) sieve. However, new pulverizer systems are under development capable of grinding coal into the ultrafine micron size range.

Today pulverized coal is used in boilers, dryers, roasters, kilns, and in asphalt plants. Ultrafine beneficiated fuels (either dry or as a coal slurry), containing less than 1 percent sulfur and ash, are currently being considered for many gas– and oil–fired applications, including heat engines. This new form of coal may introduce innovative, pulverized coal combustion concepts in the light industrial, commercial, and residential sectors.

TECHNICAL STATUS

Pulverized coal combustion is a mature technology. Although pulverized coal is occasionally employed in some institutional settings, economics currently favor large systems. It is well established for utility and large industrial boiler applications. Pulverized coal also is used extensively to fire cement kilns and rotary dryers.

BARRIERS TO IMPLEMENTATION

One of the major barriers to the light industrial/ commercial application of pulverized coal is the large plan area required for fuel preparation and back-end, clean-up equipment (particulate and sulfur dioxides). Pulverized coal systems are susceptible to fires and explosions unless adequate safety and control systems are provided. Also, entrained suspensions systems have essentially no thermal storage capacity and do not respond easily to interrupted flow conditions.

Consequently, pulverized coal systems are difficult to apply in commercial situations requiring cyclic, on/off, or switching operations. Also, the transportation and distribution of pulverized coal in small systems is difficult.

Erosion is a major concern in using pulverized coal directly in heat engine applications. Corrosion is an additional concern in high temperature applications.

Stoker Firing

HISTORY

The stoker firing of coal is perhaps the oldest form of direct coal combustion. References to hand-fired domestic stokers can be traced back to 13th century England. Stoker derives its name from the individual assigned to poke and stir the fire as well as supply it with fuel. The first known patent for a mechanical stoker was issued to James Watt in 1785. Watt's device combined a coal hopper, a grate for fuel burning, and a provision for ash disposal. Mechanical stokers were prevalent by the mid 1800s. In this century, in the U.S., stokers became popular in the light industrial, commercial, and residential sectors. As equipment has become larger, the use of stokers declined due to heat release limitations. Pulverized coal soon replaced stoker firing in the utility boiler industry.

Although the use of stokers has all but disappeared at central electric generating stations, they have remained in commercial use in industrial and institutional power plant settings. This technology is still employed in co-firing a wide variety of waste and by-product fuels. Automatic domestic single stokers are currently in use in Europe.

TECHNOLOGY

The most important types of stokers can be classified according to patterns of feeding fuel and air. These patterns are underfeed, cross feed, and overfeed. In the underfeed pattern, the flow of coal air is co-current. Underfeed stokers are built in single and multiple rotary designs. In the cross-feed stoker, the fuel and air enter at right angles. The traveling-grate stoker is the most common cross-feed type. In the overfeed pattern, the flow of coal and air is counter current. The principle type is the spreader stoker. In spreader stoker systems, a portion of the fuel burns in suspension while the remainder burns on the grate. Spreader traveling-grate stoker systems have been supplied on boiler systems up to 650,000 lb/hr of steam capacity. Underfeed stokers are used principally for heating and small industrial and residential boilers of less than 30,000 lb/hr of steam capacity. In addition to heating and steam generation, stokers are used for coal drying, carbonization, and ore beneficiation.

PRESENT STATUS

Stoker firing is an old and mature technology. It represents the lowest initial capital investment of any direct combustion method. Historically, it has demonstrated relatively low operating and maintenance costs. However, options for controlling NOx and SO_2 emissions from stoker-firing systems are limited.

BARRIERS TO IMPLEMENTATION

Fuel size segregation and ash melting characteristics are important considerations in selecting a stoker-firing system. This can limit the fuel flexibility of stoker systems. Also, the efficiency of stoker firing is somewhat less than other firing methods.

The public's perception of coal as a dirty fuel is perhaps most closely linked to memories of old domestic stoker-fired heaters. Emissions and environmental concerns provide the strongest barriers to the more widespread use of stokers in coal-fired applications. Recent, more stringent, emission regulations for NOx, SO_2, and particulates may lead smaller size industries to shift to cleaner burning fuels. A clean coal burning technology is required to meet the needs of this market sector.

Advanced Combustors

History

In 1982, the Department of Energy began a program to develop advanced combustors. This development was focused on large-scale systems. Research on advanced slagging combustors had evolved from previous development work on MHD power generation. In 1986, the emphasis of this program shifted to smaller industrial, commercial, and residential systems in an effort to displace petroleum-based fuels in this market. Because of the diverse nature of this market, advanced combustion systems cover a wide range of technologies which include slagging and non-slagging systems, as well as fluidized bed technology. Advanced non-fluidized bed systems are being developed for use on coal-water fuels and standard grind coals.

Technology

Advanced combustors include technologies such as advanced slagging combustors, pulsed combustors, duct burners, and vortex combustors. The objective of these technologies is to reduce both capital and operating costs associated with coal based systems. Automation and simplified fuel feeding systems should result in reduced labor costs. NOx and $S0_2$ emission control strategies such as lime/limestone injection and staged combustion are designed to eliminate the need for costly and bulky back-end cleanup equipment. In addition to boiler systems, these new systems are being evaluated for a variety of cogeneration, heating, ventilating, and air conditioning applications.

Present Technical/Economic Status

Advanced slagging combustors are the most developed in this group. Two slagging combustor designs (Coal-Tech and TRW) will be demonstrated under Round One of the Department of Energy's Clean Coal Technology program. Highly efficient, coal-based, pulse combustors are perhaps the farthest from commercial application. Compact pulse jet systems, such as the L-Star concept, are still in the proof-of-concept stage.

Barriers to Implementation

One of the major barriers to implementation is the ability to scale coal combustors down to small sizes. Slagging combustors are particularly susceptible to this barrier. Small systems with large surface areas are subject to excessive heat losses making it difficult to maintain slagging and slag removal conditions. The commercial and residential market will demand a greater degree of automation, simplification, and reliability than has been achieved historically with coal-based combustion systems.

INDIRECT AND DIRECT COAL-FIRED TURBINES

Industrial gas turbines can be modified to operate on coal. On a near-term basis, the likely configurations consist mainly of indirect systems, i.e., coal gasification and fluidized bed combustion. These configurations primarily depend upon the capability of on-line, hot, gas cleanup devices. Current particulate controls are temperature limited. These limitations are imposed in order to prevent the alkali from vaporizing in the gas stream and to allow the gas filtration devices to withstand high turbine inlet temperatures.

To commercialize industrial gas turbines, development of on-line gas filtration systems at turbine inlet temperatures should be given a high priority.

Advanced coal gasification and pressurized fluidized bed combustion configurations should be considered as alternative technologies for coal burning industrial facilities. Their inherently high thermal efficiencies, and their ability to utilize "as received" coal, could make these technologies economically attractive.

Among the best candidates, direct coal-fired combustion turbines offer a lucrative opportunity over the long term. The ability to burn coal directly in the combustors makes these configurations highly efficient.

Another technological challenge facing the direct, coal-fired turbines is the ability to clean the coal economically prior to injection in the combustors.

Economic coal cleaning and processing of coal to make the fuel compatible with turbine inlet conditions is a major challenge facing this particular technology.

The cost of fuel processed, to meet not only the turbine conditions but also to enable environmental compliance, must be competitive with other fuels. The technology of utilizing coal in combustion turbines deserves a high national priority.

Current Research and Development

Industrial gas turbines and diesel engine applications, using coal as the primary fuel, are being investigated with both private and government funding. The technology research activity in these areas is being funded by the Morgantown Energy Technology Center (METC) of the U. S. Department of Energy. Companies such as General Electric and General Motors have committed their own sizeable resources for this research and development activity.

METC has awarded four research and development contracts to heat engine suppliers to develop coal utilization capability. The contractors, their locations and the type of projects are:

Westinghouse	Pittsburgh, PA	Utility turbines
General Electric	Evandale, OH	Locomotive turbines
Solar	San Diego, CA	Industrial turbines
GM-Allison	Indianapolis, IN	Industrial and locomotive turbines

Also, METC has been funding research and development on industrial applications of coal-fueled diesel engines. Several companies -- A.D. Little of Boston, Massachusetts; General Electric, Erie, Pennsylvania; and GM Allison, Indianapolis, Indiana -- are currently co-funded to develop diesel engines with coal burning capability.

In addition to these industrial contracts, METC is funding advanced research and technology activities at various universities and institutes. The common objective here is to enhance the technology of burning coal in turbines and diesel engines. Some institutions are conducting similar research in cooperation with the industry. These institutions are:

Massachusetts Institute of Technology
Purdue University
Carnegie-Mellon
University of Pittsburgh
Ohio State University
University of Illinois
University of Wisconsin
Southern Illinois University
West Virginia University
Institute of Gas Technology
Battelle
EPRI
New York University

ATMOSPHERIC FLUIDIZED BED COMBUSTION TECHNOLOGY

History

Atmospheric Fluidized Bed Combustion (AFBC) is now a commercially viable technology that may be used as an alternative to conventional boiler systems for the generation of industrial process steam or power. Over the past 10 years, this technology has demonstrated the ability to burn a wide variety of fuels efficiently and in an environmentally acceptable manner.

The technology is not new, having been developed as early as 1920 in Europe. It was not until the mid-1960s that the potential application to industrial steam generation was initiated with the following technological developments.

1960-1970
Fluidized bed combustion of coal with limestone. Developments in England by BCURA and NCB and in the United States by NAPCA (Pope, Evans and Robbins).

1970–1980
Installation and startup of first bubbling fluidized bed (BFB) units at Rivesville (30MWe) and Georgetown University (10MWe). Development of circulating fluidized bed (CFB) technology in Europe.

1980 to Present
Increased commercialization and acceptance of BFB and CFB technology. Startup of largest industrial CFB boiler of 650,000 lb/hr capacity in the United States. Startup of other utility demonstration units 100MWe and larger in the United States.

Technology

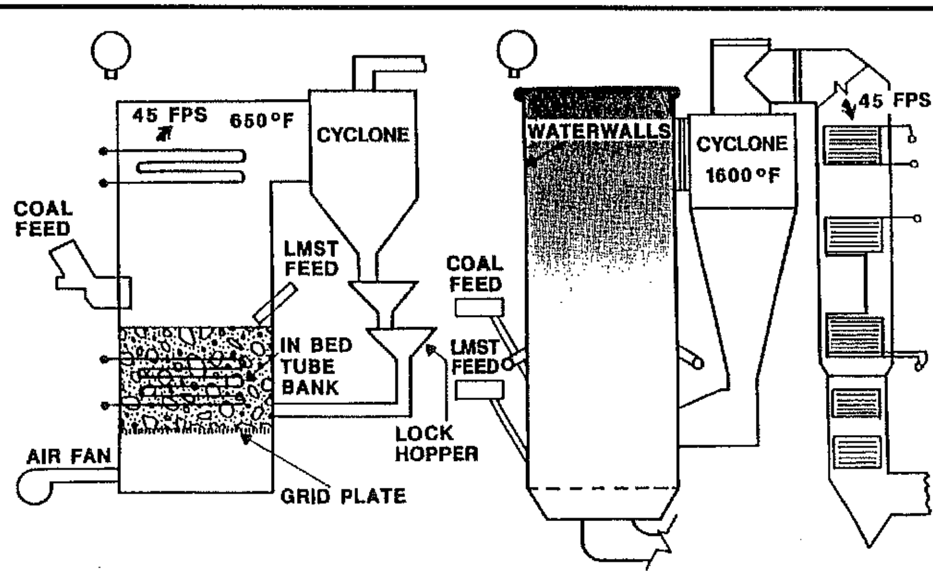
The AFBC process has a bed of particles suspended by an upward flow of fluidizing gas, i.e., combustion air. This results in a turbulent mixture of bed particles which assumes the free flowing properties of a liquid and provide an environment for stable combustion. This allows combustion to occur at lower temperatures than conventional combustion processes. A sorbent material, usually limestone, is fed with the fuel for effective sulfur removal around temperatures of 1500 – 1600°F.

The advantages of the process as compared to a conventional coal-fired boiler using a wet scrubber are:

- boiler design is much less affected by coal ash properties and softening characteristics because of the lower temperatures;
- provides the optimum conditions for sulfur capture through calcined limestone without the complications of wet scrubbing;
- generates solid wastes that are easier to handle and to dispose of;
- total NOx emissions are reduced with less than 5 percent thermal NOx formation; and
- ability to burn fuels in various physical forms simultaneously.

The two most commonly used processes are the BFB process and the CFB process. These are shown schematically on Figure 9.

FIGURE 9 Bubbling Bed and Circulating Bed Schematics



BUBBLING FLUIDIZED BED BOILER

- Fluidizing Velocities 4–12 ft/sec
- Bed Depth 4-8 ft
- In Bed Heat Transfer Surface
- Simple Compact Design
- Multiple Feed Points

CIRCULATING FLUIDIZED BED BOILER

- Fluidizing Velocities 12–36 ft/sec
- High Turbulent Continuous Bed
- No Heat Transfer Surface in Bed
- Solid Separation Device Required
- Smaller Number of Feed Points

Applications

The AFBC technology has penetrated many marketplaces. Some of the more significant are:

Industrial	Institutional
Food Processing	Hospitals
Pulp and Paper	Universities
Petrochemical	Army Bases
Automobile	Naval Bases
Cement	District Heating
Manufacturing	

This technology has been a popular choice for third party cogeneration projects where low grade fuels are to be burned or where very stringent emission requirements are to be met, e.g., California.

From a series of special reports on AFBC technology developed by POWER Magazine in 1982, 1985, and 1987, a total of 279 fluidized bed boiler projects in various parts of the world were listed. The 1987 report also identified a total of 55 suppliers of fluidized bed combustion systems.

Figure 10A indicates the disposition of AFBC projects in the United States, Europe, and other countries. However, not evident from this depiction is that unit sizes were steadily increasing. The 1982 survey had only 10 percent of projects with unit sizes greater than 100,000 lb/hr of steam. In 1987, about 75 percent of the projects had a unit size greater than 100,000 lb/hr of steam. The marked increase in interest in CFBs with decreasing interest in BFBs is also evident from Figure 10B.

FIGURE 10A Disposition of AFBC Projects by Country

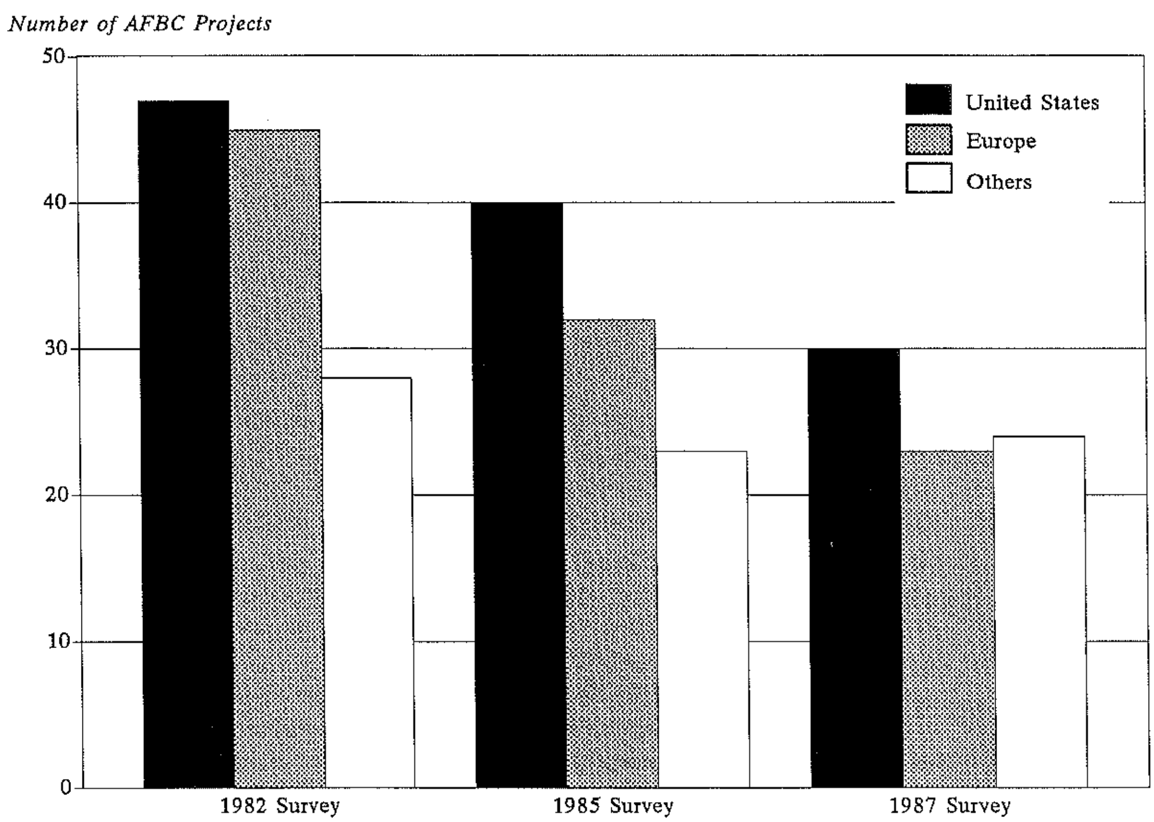
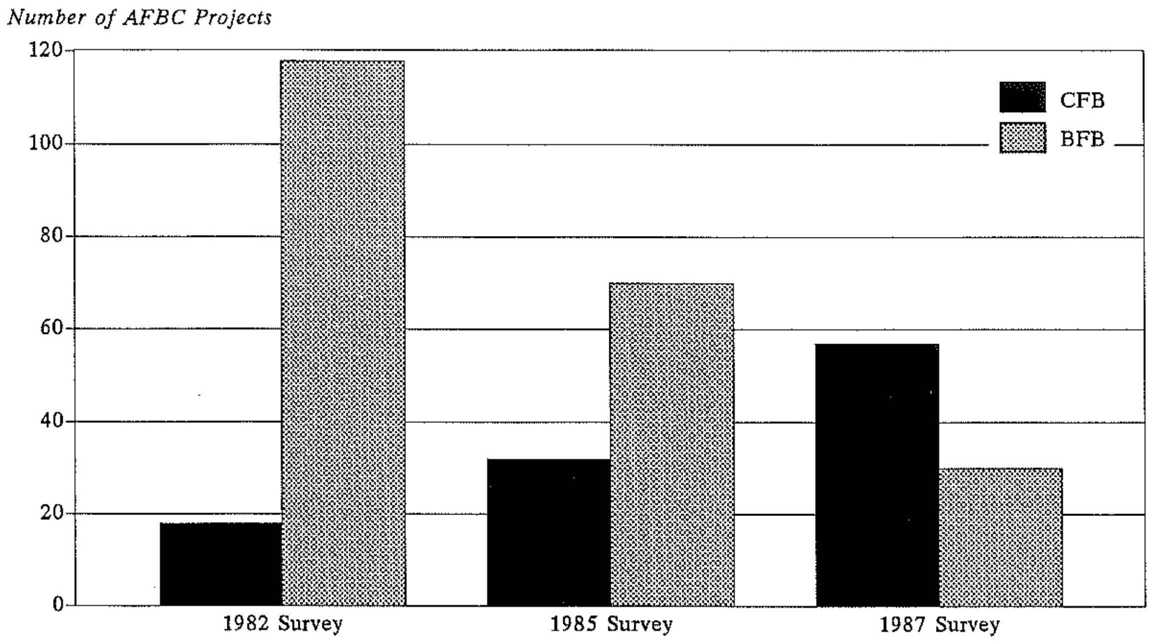


FIGURE 10B Disposition of AFBC Projects by Technology



The number of projects burning coal, including lignite and coal wastes, is shown on Figure 11. The results are interesting in that despite the widely publicized claims concerning low grade fuels, an increasing proportion of bituminous coal is being burned. From 1982, the proportion increased from about 40 percent of projects burning coal to about 75 percent in 1987. To date, lignites and subbituminous coals have not proved to be popular fuels. Coal washery wastes also have been slow to develop. However, anthracite culm projects are beginning to appear, particularly in Pennsylvania.

Technical Status

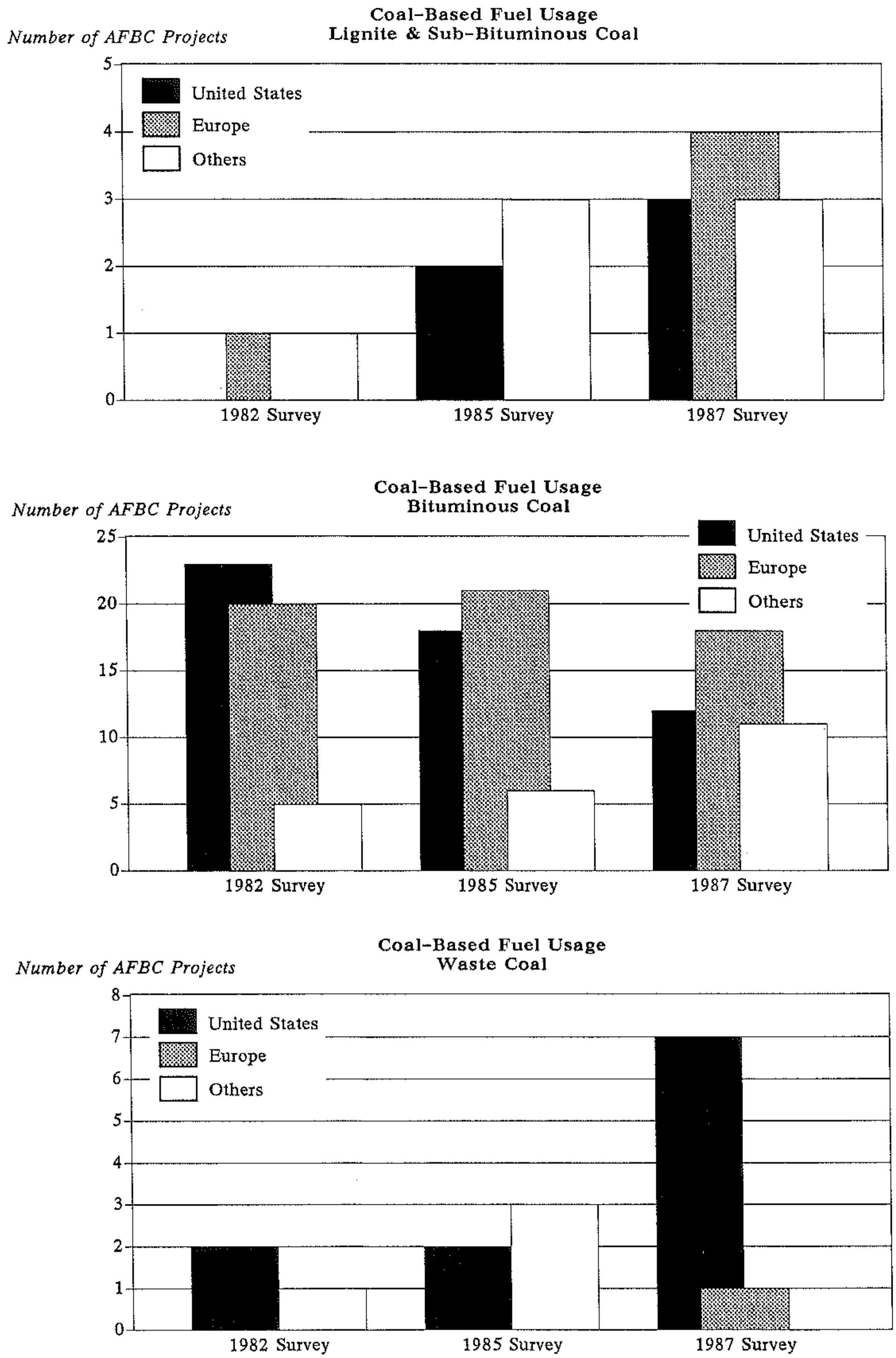
BFB and CFB technologies have generally lived up to their performance goals, despite the relatively short development phase prior to the commercialization of each technology. The BFB units tend to have a more extensive data base but the experience is with smaller unit capacities, i.e., less than 100,000 lb/hr of steam. Larger capacity units favor CBF technology where operating experience is now becoming available. Major difficulties have occurred in the following areas:

- problems with preparation, handling and feeding of high moisture, high fines fuel;
- poor combustion efficiency through insufficient residence time and/or elutriation of fines;
- increased limestone consumption through inefficient sulfur capture mechanisms;
- bed ash agglomeration or clinkering through poor fluidization or use of low ash fusion temperature fuel; and
- erosion of metal and refractory surfaces, especially in BFB units with heat transfer surfaces in the lower combustor.

Such difficulties have been greatly minimized over the past years as a better understanding of fuel, limestone, and ash characteristics, as related to the combustion process, is obtained.

Concerning emissions, most AFBC installations are able to meet current New Source Performance Standards. It is generally state and local government environmental requirements which present permitting problems.

FIGURE 11


Coal-Based Fuel Usage
Lignite & Sub-Bituminous Coal
Number of AFBC Projects
United States
Europe
Others
0
1
2
3
4
5
1982 Survey
1985 Survey
1987 Survey
Coal-Based Fuel Usage
Bituminous Coal
Number of AFBC Projects
United States
Europe
Others
0
5
10
15
20
25
1982 Survey
1985 Survey
1987 Survey
Coal-Based Fuel Usage
Waste Coal
Number of AFBC Projects
United States
Europe
Others
0
1
2
3
4
5
6
7
8
1982 Survey
1985 Survey
1987 Survey

Economic Status

Because of the highly competitive and proprietary aspects of the technology, most companies which sell or purchase AFBC boilers are reluctant to provide capital and operating cost information. Also, care must be exercised in the site specific nature of the costs since large cost variations may exist for similar steam outputs.

Despite this lack of information, the following observations pertain to the competitive aspects of this technology:

- AFBC technology allows combustion of a wide range of fuels;
- waste materials may be burned which results in avoided disposal costs with some decrease in main fuel consumption;
- dual fuel operation is possible on gas or oil;
- when SO_2 removal is required, both BFB and CFB systems indicate a cost advantage over stoker or pulverized coal units; and
- when both SO_2 and NOx reduction requirements are stringent, recent developments in AFBC technology (e.g., ammonia injection) make it competitive.

A recent study performed by Stearns Catalytic Corporation for the Department of Energy indicated plant capital costs as shown on Figure 12 for a range of capacities from 10,000 lb/hr to 200,000 lb/hr when utilizing AFBC technology. Levelized steam costs by technology (BFB or CFB), boiler size, and fuel type are shown on Table 3.

Barriers to Implementation

There are few, if any, barriers to the implementation of AFBC technology. It is now commercially accepted (even for utility applications) and meets current New Source Performance Standards. The performance of units located in Southern California highlights the capability of the technology to comply with stringent emission requirements.

FIGURE 12 Plant Capital Costs

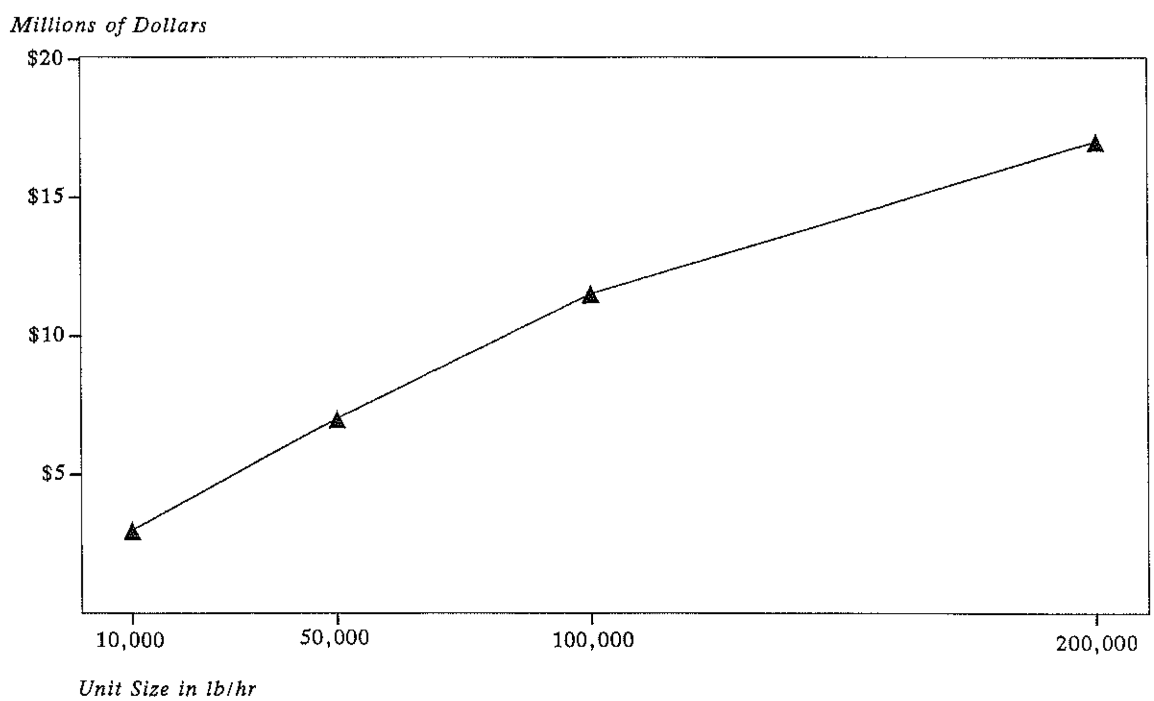


TABLE 3 Levelized Steam Costs by Technology, Boiler Size, and Fuel Type

Boiler Size (PPH)	Coal Type	Levelized Steam Costs ($/1,000 Lb/Yr, 4/30/89)		
		CFB	BFB	% Difference
10,000	Ohio		16.08	
	Illinois		16.13	
	Pennsylvania		15.74	
	West Virginia		15.57	
50,000	Ohio	8.61	9.07	5.3
	Illinois	8.75	9.12	4.2
	Pennsylvania	8.45	8.68	2.8
	West Virginia	8.39	8.50	1.3
100,000	Ohio	7.17	7.62	6.2
	Illinois	7.32	7.67	4.8
	Pennsylvania	7.05	7.26	3.0
	West Virginia	6.95	7.06	1.6
200,000	Ohio	6.08	6.53	7.3
	Illinois	6.22	6.57	5.6
	Pennsylvania	5.94	6.16	3.6
	West Virginia	5.88	5.99	1.8

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"Work on Slurry-Fired Diesel Engine Progresses," Coal Fuels Letter, August 1987.

Appendix C

Ash Production and Utilization at Southwestern Public Service Company

SOUTHWESTERN PUBLIC SERVICE COMPANY
P. O. BOX 1261 • AMARILLO, TEXAS 79170 • 806/378-2121

MAY 1988

May 2, 1988

Ms. Maryann Aimone
Manager, Business Development
KERR-MC GEE COAL CORPORATION
P. O. Box 25861
Oklahoma City, OK 73125

Dear Ms. Aimone:

Please find attached a paper describing the utilization of coal ash at Southwestern Public Service Company. Please call me at (806) 378-2194 if you have any questions.

Sincerely,

SOUTHWESTERN PUBLIC SERVICE COMPANY

Olon Plunk

Olon Plunk
Manager, Licensing and
Environmental Affairs

OP/cc

Enclosure

cc: Kenneth Ladd

Southwestern Public Service Company (SPS) is an investor owned electric utility with headquarters in Amarillo, Texas. SPS supplies electricity to approximately 350,000 customers in 96 communities, covering 52,000 square miles, including the Panhandle and South Plains of Texas, southeastern New Mexico, the Panhandle of Oklahoma and southwestern Kansas. The Company has eight (8) steam electrical generating plants with a total generating capacity of 4,154,000 KW. Currently, over 80 percent of SPS's electrical production is produced by burning low sulfur, sub-bituminous Western coal.

SPS made the decision to switch from natural gas to coal as the primary fuel supply due to curtailments of natural gas the Company experienced in the early 1970's. SPS brought on new coal fueled power units in 1976, 1978, 1980, 1982, and 1985, with a total capacity of 2267 MW. When SPS committed to coal as a fuel, it also committed to burn it in an environmentally acceptable manner. SPS chose low sulfur coal for compliance with sulfur dioxide standards. SPS was the first utility to apply fabric filtration at a new coal fueled-installation. Because of the large quantites of ash that would be produced, SPS began investigating methods of using the ash before the first unit was actually started up. Since 1976, SPS has produced about 2.3 million tons of ash. SPS has marketed or utilized 86% of this ash. The remainder of ash is in storage for future reclamation and utilization. SPS has adopted a philosophy that these materials are marketable resources.

Fly Ash. Of the ash products produced at Harrington Station, 80 percent is fly ash. After collection from the flue gas, the fly ash is conveyed in dry form to storage. The ash handling system is designed for quick and easy removal to market or long term storage. The silo storage system allows direct delivery into transport trucks which are driven to the user without further handling.

In 1976, SPS determined that the best market for its fly ash was in dry form for an additive used in cementing oil wells. The fly ash meets ASTM 618 standard for Pozzolan admixture. Through a cooperative effort with two area oil well cementing firms the use of a 50–50 mixture of fly ash with cement for oil and gas well use was developed. This application of cement and fly ash is not the same as that for concrete and required special qualities; the consistency of the quality of the ash product is critical for oil well use. SPS has implemented a continuous quality control program to ensure delivery of high quality ash material. Harrington Station fly ash has consistently proven acceptable for this application and in 1984 the oil field service sale of fly ash represented about 50 percent of SPS's fly ash sales. Presently, the oil field activity is down and stabilization has taken the place of oil well cementing.

Fly ash which is not marketed immediately, and is in excess of the storage system, must be placed in a temporary storage area where it is stabilized and solidified with water. The rock-like substance that accumulates in the landfill has the appearance of "home-made rock". Testing of the "home-made rock" proved it to be an excellent road base material which meets the Texas highway specifications for highway construction. Heavy equipment is used to rip the "home-made rock" out of the storage area where it is crushed and classified for marketing. This "home-made rock" has excellent water abrasion resistance and has been used by SPS to dress the water side face of a earthen dam.

Recent developments in soil stabilization has resulted in the specification of SPS ASTM C-618 high calcium (25%) fly ash for soil stabilization of federal and state highways, FAA airports, and large private industrial jobs.

Bottom Ash. About 20 percent of the solids produced at Harrington Station are bottom ash. This ash is collected in the bottom of the boiler furnace in a water-filled hopper. The bottom ash handling system is designed to recover the ash with heavy equipment. The material is a porous slag to a coarse sand in appearance. Chemically, bottom ash, like aggregate, is stable and inert. Testing has shown that its chemical and mineralogical properties are similar to those found in local soils.

Bottom ash is removed from the plants and stockpiled for crushing and classification for marketing. The classified aggregate has been marketed for Texas Highway Grade 4 topping rock, drain field aggregate and asphalt fill material. The sandy material resulting from the crushing and classification is marketed for structure support backfill material. Presently, the bottom ash market is utilizing the amount produced at Harrington Station.

Reuse of valuable resources is not new to SPS. SPS began reusing treated municipal sewage effluent as a cooling water supply in 1961. Presently, SPS has eight (8) steam–electric generating units (totaling 2128 MW) using treated municipal sewage effluent as a cooling water supply. By reusing wastewater, SPS is conserving groundwater for other uses.

Appendix D

Comments on the Report

Numerous comments were received from the members of the National Coal Council, and these have been incorporated into the report. In this Appendix, comments which were not incorporated are stated and the Work Group's response is provided.

COMMENT	RESPONSE
New England Energy Incorporated 25 Research Drive Westborough, Massachusetts 01582	New England Energy, Inc. 25 Research Drive Westborough, Massachusetts 01582
Glenn R. Schleede, President	Attn: G. R. Schleede, President
October 4, 1988 To: James McAvoy From: Glenn Schleede	NATIONAL COAL COUNCIL REPORT (NCC) USE OF COAL IN THE INDUSTRIAL, RESIDENTIAL, COMMERCIAL, AND TRANSPORTATION SECTORS OCTOBER 1988 DRAFT
Subject: Comments on Draft Report	October 20, 1988 Dear Sir: This letter responds to your comments dated October 4, 1988, addressed to J. F. McAvoy, Executive Director, National Coal Council, relating to the above-captioned report.

GENERAL OVERVIEW

COMMENT	RESPONSE
• In my opinion, the draft report does not satisfy the original scope of work. The discussions of issues and recommendations are too general to vividly describe coal's outlook in these sectors.	• The Coal Policy Committee of the NCC reviewed the report on October 4, 1988, and concurred with the conclusions and recommendations stated.
• The report lacks detail because it sidesteps an analysis of the current market. There is no analysis of coal's position in a less than $20/bbl oil price environment. Presumably, the authors consider the current energy market an aberration which will soon correct itself allowing oil to stabilize at $30/bbl levels. The report's Historic Oil and Coal Pricing Chart (pg. 7, Figure 3) does not describe energy prices past 1985.	• An analysis of the current energy market was not included intentionally. The environment with oil at less than $20 per bbl is our current situation; this has been extensively analyzed in current literature. Figure 3 is being updated as suggested.
• Because the analysis anticipates + $30/bbl prices, the technologies it considers most promising are coal gasification and liquefaction.	• On Page 10, the report states that an oil price of slightly over $28 per bbl is expected in the year 2000 based upon the several forecasts provided in Figure 7. The reason for recommending coal gasification and liquefaction is to minimize equipment changes and new infrastructure buildup.

COMMENT	RESPONSE
• Because + $30/bbl oil is expected, the report appears to assume that coal will be the dominant fuel for generating the electricity consumed by non-utility sectors. Recent experiences in New England and other regions show that such assumptions are questionable.	• The report does not state that cogeneration is a captive market to coal – rather the cogeneration information is provided to indicate an important market potential for coal
• If oil prices of + $30/bbl do not materialize, the actions the report recommends (support synthetic fuels research, creates a positive image for coal, etc.) will probably have very little benefit.	• Most of the energy forecasts in use predict an oil price increase some time in the future. What is difficult to state with certainty is "How Much?" and "When?". If the lead time necessary to implement developing technologies is taken into account, the recommendations in the report are appropriate now.

EXECUTIVE SUMMARY

• The report makes eight recommendations, as summarized below:

• The recommendations of the report were reviewed at the October 4, 1988, meeting of the Coal Policy Committee and accepted without dissent.

Recommendations	NCC Draft	Comments
1	Study alternative means of producing transportation fuel	Only practical in + 30/bbl oil environment
2	Continue to support synthetic fuels	Only practical in + 30/bbl oil environment
3	Improve coal's public image through education, media	Would this really be effective?
4	Encourage federal agencies to use coal	This is old hat
5	Review regulatory constraints to coal	This is old hat
6	Investigate the economic incentives needed to encourage coal use	Good starting point for an objective analysis, if done with recognition of possibility that low oil prices may be persistent
7	Stimulate commercial interest in coal fired commercial heating	If it's a good idea, is "stimulation" necessary? (It wasn't for petroleum coke)
8	Review coal programs of foreign countries	Coal use encouragement programs that I am aware of are extremely expensive. Is this worthwhile?

SECTION 1 - ENERGY OVERVIEW

• Update discussion to cover post-1985 energy market	• 1987 pricing information was included in Figure 6 and will be added to Figures 3 and 7.
• Update Figure 3	• Figure 3 will be updated as suggested.
• Describe track record and uncertainties of oil price forecasting	• On page 5, the report states "From an historical perspective, the volatility in oil pricing makes any long-range oil price projection suspect." On Page 8, the report states "Again, this is another indica-

COMMENT	RESPONSE
	tion of the underlying uncertainty in energy predicting markets." These statements are adequate to warn the reader about the concerns of oil price forecasting.
• For all graphs, provide $/barrel oil price equivalents	• Oil price equivalents are given in the notes for Figure 3. A similar note will be added to Figures 6 and 7.
• On Figure 7, provide 1987 natural gas prices	• Gas prices to residential, commercial, and industrial users have been provided. This coverage of gas prices is believed to be sufficient.
• Describe how natural gas and coal compete in historical and current markets	• Coal currently has very little impact in the light industrial, commercial, residential, and transportation markets. Historically, ever since oil and gas have been available at competitive prices, coal use has declined to less than 1 percent today. To describe this level as competition is not germain. More importantly, the report looks into where coal may be able to compete in the future.
• Figure 7 projects large increase in natural gas prices by 2000. This is a very critical assumption and should be discussed in greater detail.	• Sources for the data in Figure 7 have been provided. The reader desiring more information can consult these sources.

SECTION II - INDUSTRIAL SECTOR

COMMENT	RESPONSE
• Coal's share of electricity purchases should be discussed in more detail (page 13)	• The Work Group believes that coal's share of the electricity market has been adequately discussed.
• Coal's share of cogeneration is not as large as projected (page 13, 14)	• The report does not imply that cogeneration is a captive coal market.
• Table One - Industrial coal use projections appear very casual and are probably misleading	• Table 1 has had a title change and additional sources identified to render the presentation more specific.
• R&D spending level discussion - apparently, authors assume that no greater coal use is possible except as synthetic fuels.	• Many technologies are listed on Page 15 in the R&D section. The discussions on spending levels makes a specific point vis-a-vis Japan based on available data; however, all aspects of coal R&D are included in the discussions vis-a-vis Germany.

SECTION III - COMMERCIAL SECTOR

COMMENT	RESPONSE
• District heating pro-forma - example appears to have limited application (low delivered coal and limestone prices)	• The average price of coal delivered to industrials for 1987 was approximately $35.42 per ton based upon Annual Energy Outlook - Table A10, Page 41.
• Federal government already uses coal where economics are marginal (i.e., U.S. Army bases in Germany).	• The Work Group believes that the Federal Government has an opportunity to demonstrate many of the concepts recommended in the report.
• If coal-fired district heating is attractive, why does it need government support?	• The report recommends stimulating the use of district heating - not subsidies and continuing support. Refer to Report, Page 20 - Item 2.

SECTION IV - RESIDENTIAL SECTOR

COMMENT	RESPONSE
• Residential coal use appears to be the least promising application. Why not say so?	• The report does point out the many impediments to residential coal use.

COMMENT	RESPONSE
• Report's statement that "Bulk transportation in the U.S. should not be a problem" is dead wrong.	• The railroad and barge systems of this country can deliver coal to most areas of the country in "bulk," i.e., rail car or barge lots. It is the retail delivery of coal that poses major problems. A statement has been added to Page 23 as follows: "Retail delivery of coal as set forth in the preceding discussion presents its own set of challenges and opportunities."

SECTION V - TRANSPORTATION

COMMENT	RESPONSE
• The transportation sector is not likely to use conventional-technology coal, why not clearly state this.	• The report's conclusions and statements on Page 26 clearly state that only liquids or perceived liquids can currently play a major role in the short-term replacement of gasoline and distillate.
• As in other sectors, coal's role in electricity generation is not assured.	• Noted.

SECTION VI - POLICY

COMMENT	RESPONSE
• This report should describe how the costs of environmental regulations change the costs of using coal <u>relative to natural gas alternatives</u>.	• The report repeatedly makes the point that coal can play a role only if it can be used in an economically and environmentally acceptable manner. The issue is not to position coal so that it enjoys some unique advantage over other fuels.
• The report should describe the environmental constraints to coke-making operations and investments.	• A statement was added on Page 16 regarding aging coke facilities.

SECTION VII - MATERIAL HANDLING

COMMENT	RESPONSE
• Coal transportation costs, specifically rail costs, are a major constraint to industrial use and should be given more attention.	• It was so noted on Page 42 of the report.
• Ash disposal costs are significant constraints in many areas and should be given greater emphasis.	• The work group believes the information on Pages 44 and 45 is quite sufficient to make this point.

The above comments essentially respond to yours point for point. Thank you for reviewing the report in such detail. I hope that these responses clarify your concerns.

Yours very truly,

J. J. M. Plante
Work Group Chairman

Appendix E

Letters from the Secretary of Energy and the Response of The National Coal Council

THE NATIONAL COAL COUNCIL, INC.

Post Office Box 17370, Arlington, Virginia 22216

(703) 527-1191

November 19, 1987

The Honorable John S. Herrington
The Secretary of Energy
Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

Dear Mr. Secretary:

On November 12, the National Coal Council unanimously accepted your request for two additional studies to assist the Department in its formulation of national energy policy.

Dr. Kurt Yeager, Electric Power Research Institute, will chair the work group on clean coal technology. Mr. Joseph Plante, Stone and Webster, will direct the study on coal utilization in the light industrial, commercial, residential, and transportation sectors. The Coal Policy Committee, chaired by Dr. Irving Leibson, Bechtel Corporation, will provide overall study oversight and coordination to insure proper consideration of all relevant information and data.

The Council will strive to provide comprehensive, yet concise, reports that are objective and balanced in their treatment of information considered in preparation of the reports.

On behalf of the entire Council, I wish to express our appreciation for this opportunity to contribute through these studies our collective experience and insight about pertinent and relevant energy issues.

Sincerely,

James G. Randolph
Chairman

JGR:ph

An Advisory Committee to the Secretary of Energy

THE SECRETARY OF ENERGY
WASHINGTON, D.C.

November 6, 1987

Mr. James G. Randolph
Chairman
National Coal Council
P.O. Box 17370
Arlington, Virginia 22216-7370

Dear Mr. Randolph:

The two reports the National Coal Council (NCC) submitted in June were extremely valuable. Now that they have been completed, this is an appropriate time to request new studies for the NCC to undertake. Particularly, there are two studies I am requesting and which are described in the following items:

1. Clean Coal Technology -- Many reports have been generated recently on the potential impacts of deploying innovative clean coal technologies. Areas addressed in these reports include economic and environmental benefits as well as opportunities to link export of innovative clean coal technologies to U.S. coal export sales. A compilation of these reports is needed. In addition, recognizing the substance of these reports, advice is needed on what actions the Federal Government can take to commercially deploy the technologies once demonstrated so that the Administration's coal-related energy, environmental and competitiveness goals can be achieved.

2. Coal utilization in the light industrial, commercial, residential and transportation sectors -- What are the opportunities for innovative technologies? A study is needed of the impediments to and actions that can be taken to accelerate the penetration of coal or coal-derived fuels into the nonutility sectors. In addition, quantification of the potential impact on energy security resulting from application of coal-based fuels in these sectors would be very useful. The study should span mine mouth to end user and indicate technical and economic impacts of codes and regulations on fuel transport, waste removal and coal or coal-derived fuels utilization.

I believe these studies to be extensions of or complementary to the first six reports: "Coal Conversion," "Interstate Transmission of Electricity," "Clean Coal Technology," "Industrial New Source Performance Standards," "Reserve Data Base," and "Improving International Competitiveness of U.S. Coal and Coal Technologies." I appreciate the Council's efforts in preparing these reports and

2

recognize the quality of analyses and poignancy of recommendations found in the reports. I look forward to receiving resulting reports from the two new studies mentioned above.

Yours truly,

John S. Herrington

John S. Herrington

Appendix F

Description of The National Coal Council

Recognizing the valuable contribution of the industry advice provided over the years to the Executive Branch by the National Petroleum Council and the extremely critical importance of the role of coal to America and the world's energy mix for the future, the idea of a similar advisory group for the coal industry was put forward in 1984 by the White House Conference on Coal. The opportunity for the coal industry to have an objective window into the Executive Branch drew overwhelming support.

In the fall of 1984, The National Coal Council was chartered and in April of 1985, Secretary of Energy John Herrington, made the Council fully operational. Secretary Herrington's action was based on his conviction that such an industry advisory council could make a vital contribution to America's energy security by providing him with information that could help shape policies leading to the increased production and use of coal and, in turn, decreased dependence on other, less abundant, more costly and less secure sources of energy.

The Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of The National Coal Council is solely to advise, inform and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry that he may request.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The Council does not represent any one segment of the coal or coal related industry nor the views of any one particular part of the country. It is instead to be a broad, objective advisory group whose approach is national in scope. Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the Coal Policy Committee which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

The first major studies undertaken by the National Coal Council at the request of the Secretary of Energy were presented to the Secretary of Energy in the summer of 1986, barely one year after the start up of the Council. These reports covered: Coal Conversion, Clean Coal Technologies and Interstate Transmission of Electricity.

In 1987, at the request of the Secretary, the Council completed two additional reports which were then presented to him. The studies examined the Coal Reserve Data Base and International Competitiveness of U.S. Coal and Coal Technologies.

The Council also can determine topics which it believes significant for study and then seek the approval of the Secretary to proceed, as in the case of the study of New Source Performance Standards for Industrial Boilers, also completed in 1986.

Members of The National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and geographical disbursement. The National Coal Council is headed by a Chairman and a Vice-Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

Appendix G

The National Coal Council Membership Roster – 1988

CHAIRMAN

MR. JAMES G. RANDOLPH
President
Kerr–McGee Coal Corporation

VICE CHAIRMAN

MR. WILLIAM CARR
President
Mining Division
Jim Walter Resources, Inc.

MEMBERS

MR. JOHN W. ARLIDGE *(New Member April 1988)*
Vice President
Resource Planning and Power Dispatch
Nevada Power Company

MR. BERT BALLENGEE
Chairman/Chief Executive Officer
Southwest Public Service Company

MR. JOHN P. BAUGUES, SR.
President
James Spur Coal Company, Inc.

MR. DANIEL BEAM
Commercial Fuels, Inc.

MR. DONALD P. BELLUM
Executive Vice President
Cyprus Minerals Company

MR. THOMAS J. BELVILLE
President
Belville Mining Company, Inc.

MR. WILLIAM W. BERRY
Chief Executive Officer
Dominion Resources

MR. GEORGE M. BIGG
President
Simms Fork Associates, Inc.

MR. GERALD BLACKMORE
G. Blackmore, Inc.

MS. SANDRA BLACKSTONE
Professor – College of Law
University of Denver

MR. BRENT W. BLAUCH *(New Member April 1988)*
Vice President
Environmental Power Corporation

MRS. JOAN T. BOK
Chairman
New England Electric System

MR. PHIL A. BOWMAN *(New Member April 1988)*
President
R. A. Eberts Company, Inc.

MR. THOMAS H. BRAND, JR. *(New Member April 1988)*
President
York Services Corporation

MR. J. ROBERT BRAY
Executive Director
Virginia Port Authority

MR. WILLIAM T. BRIGHT
Chairman of the Board
Land Use Corporation

DR. ROBERT W. BROCKSEN
Executive Director
Living Lakes, Inc.

MR. BOBBY R. BROWN
Chairman/Chief Executive Officer
Consolidation Coal Company

MR. THOMAS BROWN *(New Member April 1988)*
Representative
Eastern Conference Teamsters

MR. OMER BUNN
President
Southwestern Virginia Coal Corporation

DR. DONALD CARLTON
President
Radian Corporation

THE HONORABLE GARREY CARRUTHERS
Governor of New Mexico

MR. WILLIAM CAVANAUGH, III
President/Chief Executive Officer
System Energy Resources, Inc.

MR. FRED CLAYTON
President
Shand Mining, Inc.

MR. ROBERT P. COOPER *(New Member April 1988)*
Vice President
Land Acquisition & Environmental Affairs
Farrell-Cooper Mining Company

MR. JOSEPT W. CRAFT, III *(New Member April 1988)*
President
MAPCO Coal, Inc.

MR. A. W. DAHLBERG *(New Member April 1988)*
President
Georgia Power Company

THE HONORABLE EDDY DALTON *(New Member April 1988)*
Virginia State Senator

MS. BARBARA DEVERICK
Administrative Manager
Blueridge Electric Membership Corporation

MR. GARRY DRUMMOND
Chairman of the Board
Drummond Coal Company

MR. JOHN DWYER
President
North Dakota Lignite Council

THE HONORABLE GEORGE EVANS *(New Member April 1988)*
Secretary
Kentucky Energy Cabinet

MR. JACK R. FAIRCHILD
Chairman/Chief Executive Officer
Fairchild International

MR. JOSEPH FARRELL
Chairman–Coal Group
The Pittston Company

MR. JERRY FARRINGTON *(New Member April 1988)*
Chairman & Chief Executive Officer
Texas Utilities Company, Inc.

MR. MASON FOERTSCH
President
Foertsch Construction Company

MR. LAWRENCE E. FORGY, JR.
Attorney at Law
Stohl, Keenan, and Park

MR. JOSEPH A. FRANK *(New Member November 1988)*
President
Centralia Coal Sales Company

MR. GEORGE FUMICH, JR.
George Fumich Associates, Inc.

MR. JOHN D. GEARY *(Resigned July 1988)*
President
Midland Enterprises, Inc.

MR. LARRY W. GEORGE
Attorney–Consultant

MR. HUGH F. GRABOSKY
Director, Program Planning & Development,
Synthetic Fuels Development, AMOCO

DR. ALEX E. S. GREEN
Graduate Research Professor
University of Florida

MR. W. CARTER GRINSTEAD, JR.
General Manager
U.S. Coal Operations
EXXON Coal & Minerals Company

DR. BILL HARRISON
Birmingham, AL

MS. PAT HARRISON
President
National Women's Economic Alliance

MR. RICHARD M. HOLSTEN
Chairman & President
The Pittsburgh & Midway Coal Mining Company

MR. H. RICHARD HORNER *(New Member April 1988)*
General Manager
Alternate Energy & Resources Department
Texaco, Inc.

THE HONORABLE GUY HUNT
Governor of Alabama

MR. TREVOR J. JONES
President
Jeffrey Mining Machinery

MR. W. O. KEGEL
President/Chief Executive Officer
Rochester & Pittsburgh Coal Company

MR. WILLIAM M. KELCE
President
Alabama Coal Association

MR. DWIGHT W. KNOTT
The Sun Oil Company

MR. WILLIAM M. LAUB, SR.
President/Chief Executive Officer
Southwest Gas Corporation

MR. JOSEPH W. R. LAWSON, II
President/Chief Executive Officer
SESCO Management Consultants

DR. IRVING LEIBSON
Executive Consultant
Marketing and Technology
Bechtel Group, Inc.

MR. WILLIAM W. LYONS
Vice President
NERCO, Inc.

MR. PETER MacDONALD
Chairman
The Navajo Nation

MR. ROGER A. MARKLE
President
Quaker State Oil Refining Corporation

MR. WILLIAM B. MARX
President
Council of Industrial Boiler Owners

MR. WALTER J. McCARTHY, JR.
Chairman of the Board
Detroit Edison Company

MR. ROBERT G. McGINN
President
Mobil Coal Producing, Inc.

MR. JAMES McGLOTHLIN
President/Chief Executive Officer
The United Companies

MR. PAUL McINTYRE
Jacobs Ranch Mine

MR. JAMES H. McJUNKIN
International Trade and Marketing Advisor
The Port of Long Beach

MR. ARNOLD B. McKINNON
Chairman
Norfolk Southern Corporation

MR. WILLIAM H. MELLOR, III *(New Member April 1988)*
President/Chief Executive Officer
Pacific Research Institute for Public Policy

MR. LLOYD MEYERS
President
Washington Irrigation & Development Company

MR. RICHARD MILLER, JR.
President/Chief Executive Officer
Elgin National Industries
Roberts & Schaefer Company

MR. JAMES MOCKLER
Executive Director
Montana Coal Council

THE HONORABLE ARCH A. MOORE, JR.
Governor of West Virginia

MR. NICHOLAS P. MOROS *(New Member April 1988)*
Vice President
Coal and Taconite Marketing

Burlington Northern Railroad

MR. GEORGE NICOLOZAKES
President
Marietta Coal Company

MR. JAMES J. O'CONNOR
Chairman & President
Commonwealth Edison Company

MR. S. O. OGDEN
Chairman/Chief Executive Officer
Island Creek Coal Company

MS. MARY EILEEN O'KEEFE
President/Chief Executive Officer
Lake Shore International, Ltd.

MR. EDDIE P. S. PEN
President/Chief Executive Officer
Pen Holdings, Inc.

MR. R. E. PERKINSON, SR.
President
South Atlantic Coal & PERMAC, Inc.

MR. DAVID PETERSON
Director of Fuel Resources
Northern State Power Company

MR. ABE PHILLIPS
President
Coors Energy Company

MR. JOSEPH J. M. PLANTE
Vice President & Senior Manager of Projects
Project Management Department
Stone & Webster Engineering Corporation

MR. JOSEPH WILLIAM POST
President
The Lady H Coal Company

MR. ROBERT H. QUENON
President/Chief Executive Officer
Peabody Holding Company

MR. J. F. RATCHYE
Executive Vice President
Wyoming Mining Association

MR. JUSTIN T. ROGERS, JR. *(New Member April 1988)*
President
Ohio Edison Company

MR. JIM ROSE
President
Interstate Coal Company, Inc.

MR. MASON RUDD
President
Rudd Equipment Company

MR. RODNEY DON RUSSELL
President
Russell Coal, Inc.

MR. PETER F. SCHABARUM *(New Member November 1988)*
Los Angeles County Supervisor

MS. DEBBIE SCHUMACHER
Women In Mining

MR. KENNETH SMITH
President
Utility Fuels, Inc.

MR. JOHN W. SNOW *(New Member October 1988)*
President/Chief Executive Officer
CSX Corporation

MR. ROBERT SPENCER
Secretary-Treasurer/Chief Executive Officer
Hepburnia Coal Company

MR. JOE J. STEWART *(New Member April 1988)*
Vice President & Group Executive
Power Generation Group
Babcock & Wilcox

THE HONORABLE JAMES R. THOMPSON
Governor of Illinois

MR. NEAL S. TOSTENSON
President
Ohio Mining & Reclamation Association

MR. RICHARD TRUMKA
President
United Mine Workers of America

MR. ERNST UPMEYER
Vice President
Electric Fuels Corporation

MR. JOE USIBELLI
Chairman
Usibelli Coal Mine, Inc.

MR. JAMES L. VAN LANEN
(Resigned October 1988)
President
ANR Coal

MR. TED VENNERS
Managing Partner
K-Fuel Partnership

MR. WILLIAM R. WAHL
President/Chief Executive Officer
AMAX Coal Company

MR. GERALD D. WALTZ *(New Member April 1988)*
Senior Vice President
Engineering and Operations
Indianapolis Power & Light Company

MR. BILL W. WAYCASTER *(New Member November 1988)*
Vice President/General Manager
Hydrocarbons Department
DOW Chemical USA

MR. HAYS WATKINS *(Resigned September 1988)*
Chairman/Chief Executive Officer
CSX Corporation

MR. W. S. WHITE, JR.
Chairman
American Electric Power Service Corp.

MR. GEORGE WILTSEE
Assistant to the Vice President
Electric Power Research Institute

MS. SUSAN WINGFIELD
President
Mississippi Valley Coal Exporters Council

MR. KURT YEAGER
Senior Vice President
Electric Power Research Institute

Appendix H

The National Coal Council Coal Policy Committee – 1988 and the Use of Coal in the Nonutility Sectors Work Group

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