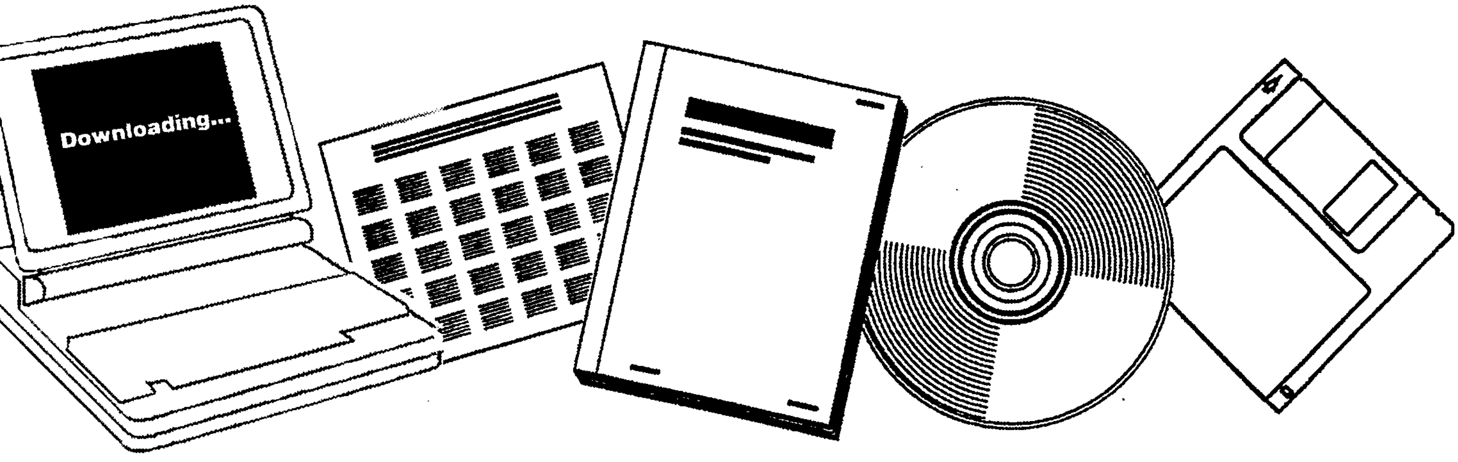
ENERGY FROM COAL: A STATE-OF-THE-ART REVIEW

TETRA TECH, INC.
ARLINGTON, VA

1975



One Source. One Search. One Solution.

NTIS

Providing Permanent, Easy Access to U.S. Government Information

National Technical Information Service is the nation's largest repository and disseminator of government-initiated scientific, technical, engineering, and related business information. The NTIS collection includes almost 3,000,000 information products in a variety of formats: electronic download, online access, CD-ROM, magnetic tape, diskette, multimedia, microfiche and paper.

Search the NTIS Database from 1990 forward

NTIS has upgraded its bibliographic database system and has made all entries since 1990 searchable on **www.ntis.gov.** You now have access to information on more than 600,000 government research information products from this web site.

Link to Full Text Documents at Government Web Sites

Because many Government agencies have their most recent reports available on their own web site, we have added links directly to these reports. When available, you will see a link on the right side of the bibliographic screen.

Download Publications (1997 - Present)

NTIS can now provides the full text of reports as downloadable PDF files. This means that when an agency stops maintaining a report on the web, NTIS will offer a downloadable version. There is a nominal fee for each download for most publications.

For more information visit our website:

www.ntis.gov

U.S. DEPARTMENT OF COMMERCE
Technology Administration
National Technical Information Service
Springfield, VA 22161

ERDA 76-67

ENERGY FROM COAL

MASTER

ENERGY FROM COAL

A STATE-OF-THE-ART REVIEW

Prepared for:

Office of Fossil Energy
United States Energy Research and
Development Administration
Under Contract No. E(49-18)-2225

Prepared by:

Tetra Tech, Inc.
1911 North Fort Myer Drive
Arlington, Virginia 22209

For sale by the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402 - Price $2.05

TABLE OF CONTENTS

BLANK PAGE

TABLE OF CONTENTS (Continued)

Generalized Gasification Processes (Continued)

Appendix A. Coal Gasification

Appendix B. Coal Liquefaction

Appendix C. Primary Sources

LIST OF ILLUSTRATIONS

LIST OF TABLES

I. INTRODUCTION

Executive Summary

The United States has more energy available in the form of coal than in the combined resources of petroleum, natural gas, oil shale, and tar sands. In light of nationwide energy shortages, the increased use of abundant coal reserves is vital to the nation's total supply of clean energy. However, this solid fuel can be currently applied to only a limited portion of the total national energy demand. The primary user of coal is the electric utilities industry, where coal is mechanically cleaned, pulverized, and then burned in solid form in boilers. Statistics in the *Project Independence Report* indicate that the transportation sector depends nearly exclusively on liquid fuels, the household and commercial sectors depend almost entirely on liquid and gaseous fuels, and three-quarters of the energy used by industry is provided by liquid and gaseous fuels. Consequently, converting coal to gaseous and liquid fuels in commercial quantities is fundamental to ensuring the availability of fuel in conventional forms for the major users as the availability of petroleum sources becomes less certain. The ultimate objective of coal conversion research is therefore to provide the technology for rapid commercialization of processes for converting coal to synthetic fuels and for improved direct combustion of coal.

Technical and social problems related to the use of coal as an energy source can be resolved. For instance, steps are being taken to overcome drawbacks related to the mining of coal. Land reclamation techniques are being developed to return mined-out land to usable forms. The Federal Coal Mine Health and Safety Act added impetus to the movement to reduce underground mining hazards.

The development of coal conversion processes by the Energy Research and Development Administration is oriented towards accelerating and stimulating a synthetic fuel industry. Fossil energy research, development and demonstration strategy is to sponsor a wide variety of technical options so that promising processes will eventually be commercialized and will therefore provide a long-term payoff.

Scope of Report

Energy From Coal is an overview of coal as an energy source. The report may serve as an introduction to and/or a comprehensive review of all aspects of coal.

In preparation for the final compilation of information, a survey of current literature was made. Recent technology symposia, government documents, reports and studies prepared by various organizations, and current texts were reviewed. Primary sources identified in the literature survey are listed at the conclusion of each chapter.

The following organizations are referred to throughout the text by their abbreviations.

AEC*	Atomic Energy Commission
AGA	American Gas Association
ASTM	American Society of Testing and Materials
BCR	Bituminous Coal Research, Inc.
CEQ	Council on Environmental Quality
CCU	Division of Coal Conversion and Utilization
DOI	Department of the Interior
DOT	Department of Transportation
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
ERDA	Energy Research and Development Administration
FEA	Federal Energy Administration
GFERC	Grand Forks Energy Research Center
IGT	Institute of Gas Technology
MERC	Morgantown Energy Research Center
NASA	National Aeronautics and Space Administration
NOAA	National Oceanic and Atmospheric Administration
NRC	Nuclear Regulatory Commission
NSF	National Science Foundation
OCR*	Office of Coal Research
PERC	Pittsburgh Energy Research Center

---

*These organizations are no longer operating. Their energy research functions have been redistributed within ERDA.

Origin of Coal

Coal is a complex substance consisting of the metamorphosed remains of ancient vegetation. Because of variation in degree of metamorphic change from the original plant material, coal is not a uniform substance, and no two coals are the same in every respect.

Peat was originally formed as a dark-brown residuum produced by the partial decomposition and disintegration of mosses, sedges, trees and other plants. As peat accumulated, the weight of the top layers of peat compacted the lower layers, primarily by squeezing out large amounts of water. Burial by sediments, physical-chemical effects associated with the changed environment, and loss of water and volatile materials resulted in formation of lignite, the earliest stage in the formation of coal. With increasingly deeper burial, pressure continued to compress the lignite, and the increase in heat associated with the increasing depth of burial further devolatilized the coal-forming materials. The rank of the coal became progressively higher, rising from lignite, subbituminous, bituminous, semianthracite, and anthracite to meta-anthracite.

Early Use and Technology Advances

In 1350, coal first became a commercial commodity. Gas was first recognized as a state of matter in 1620, and coal was first distilled in the laboratory to yield gas in 1660.

The carbonization of coal to produce metallurgical coke was known in the late 1600's but was not practiced on a large scale until 1730. Coke was a by-product of another process developed in 1792 in which coal was distilled in an iron retort to produce illuminating gas. These two processes initially were considered basically different and this concept persisted until the early 1900's.

The first by-product coke ovens were constructed in France in 1856. Since then they have gradually replaced beehive ovens. With the increasing use of by-product coke ovens in the early 1900's, it became apparent that it was more efficient and economical to produce gas in the by-product coke oven than in the more labor-intensive gas retort.

The advent of electric lighting opened up a great potential for coal combustion in the generation of steam for power generation. Thus, the combustion of coal went through the stages of burning in open fireplaces in the early days to burning in the fuel beds of small household furnaces and subsequently large industrial furnaces and finally to burning as pulverized fuel in large central station furnaces. This latter application was first tried in 1876, but was not successful in the United States until the factors affecting proper furnace design were elucidated in 1917.

As the use of coal gas developed, the production of gas for heating purposes was also developing. The first gas producer making low-Btu gas was built in 1832. This principle was not widely used until it was applied by the Siemens brothers in connection with their invention of the open-hearth furnace in 1861. The use of producer gas increased from that time, until at the turn of the century it was an important fuel source for heating furnaces. But after that time its use declined until by 1920 there were only 11,000 producers in use in the United States.

Another development in the field of gas making stemmed from Fontana's discovery in 1780 of the production of blue gas when steam was passed over incandescent carbon. This discovery was dormant until the period between 1823 and 1859 when additional experimental work was done on the steam carbon reaction. This eventually led to the development of processes for producing blue-water gas in the period of 1859 to 1875. The first successful commercial process was developed by Lowe in 1875 when he introduced the carburetted water gas jet. The increased use of this gasification technology continued until natural gas supplanted manufactured gas.

The history of coal hydrogenation begins in 1913 when work on the Bergius concept of direct hydrogenation of coal under hydrogen pressure at an elevated temperature was undertaken in Germany. A 31-ton-per-day pilot plant was built in Germany in 1921. The possibility of producing liquid hydrocarbons from water gas (Fischer-Tropsch synthesis) was also conceived in 1913. The first experimental work on this synthesis, which is sometimes referred to as the indirect hydrogenation of coal, was published in 1923.

During World War II, the Germans produced a major part of their aviation gasoline using liquefaction technology based on hydrogenation of coal. They also produced some liquids by indirect liquefaction using Fischer-Tropsch technology. At about the time the technology had reached a stage where plants could be installed, however, natural gas was discovered in the North Sea and in North Africa. In addition, most of the European nations decided to shift from an economy based on high-cost indigenous coal to one based on what was at the time low-cost imported petroleum. Few coal gasification plants embodying new technology were installed, and interest in further improving the technology lagged.

Future of Coal

Coal's immediate future is closely tied to its consumption by the electric utilities. The use of low ash and low sulfur products from the liquefaction and gasification of coal by the industrial transportation and heating sectors of the economy, as well as use by the electric utilities, should be possible by the 1990's. Advanced methods of generating electricity from coal. using fluidized-bed boilers and combustors. MHD generators. solid electrolyte fuel cells and topping cycles are currently in fundamental research stages. These concepts theoretically offer a means of increasing the efficiency of coal's utilization in the production of energy. However. the long-term expansion of the coal market will depend upon the eventual commercial availability of clean synthetic fuel products and advanced power systems now under development by ERDA.

REFERENCES

Bagge, Carl E. *The Expanding World of Coal.* Washington, D.C.: National Coal Association, 1973.

Energy Fact Book 1975. Tetra Tech, Inc., 1975, p. E-1.

Ode, W. H. "Coal." *Standard Handbook for Mechanical Engineers.* 7th ed. Edited by Theodore Baumeister. New York: McGraw-Hill Book Co., 1958.

O'Hara, J. B. *Coal Conversion: An Overview of Status and Potential.* Pasadena: The Ralph M. Parsons Co., April 3, 1975. Presented at Los Angeles Council of Engineers and Scientists Energy Symposium.

Osborn, Elbert F. "Coal and the Present Energy Situations." *Science* 8 February 1974: 477-81.

Simon, Jack A. and Hopkins, M. E. "Geology of Coal." *Elements of Practical Coal Mining.* Edited by Samuel M. Cassidy. Baltimore: Port City Press, Inc., 1973.

Elliott, Martin A. "Fuels 1924-1940." *Fuels Chemistry—A Mid-Century Perspective.* A Battelle Energy Program Report. Columbus, Ohio: Battelle Memorial Institute, November 1974: 2-4.

II. COAL SUPPLY AND DEMAND

Coal Resources and Reserves

According to data gathered at the 1974 World Energy Conference, the United States contains about 25 to 30 percent of the world's recoverable coal beds, although the percentage could be greatly reduced as more land areas in the Soviet Union and the People's Republic of China are explored.

The coal lands of the United States are held by several broad classes of owners, including the federal and state governments, mining and manufacturing corporations, railroads, Indian tribes, and private individuals. Most of the coal lands in the East and in the Mississippi Valley region are privately owned. In the Appalachian basin, many large tracts of coal land are held by mining, petroleum, manufacturing, or landholding corporations. The majority of the coal lands in the Rocky Mountains and Northern Great Plains regions are owned by the federal government.

A major percentage of bituminous and lignitic coal production is from three states:

		Percentage	
	Surface	Underground	Total
Kentucky	23	23	23
Pennsylvania	12	15	13
West Virginia	6	30	18
	41	68	54

Table II-1, on the following page, lists 1975 production of bituminous and lignitic coal by method of mining.

Figure II-1 compares identified and hypothetical coal resources of the United States. Approximately 44 percent of the total estimated remaining coal resources in the United States have been identified, of which at least 12.5 percent are considered economically recoverable, based on past recovery rates. Increased production by strip mining would

Table II-1

PRODUCTION OF BITUMINOUS AND LIGNITE COAL, BY TYPE OF MINING, 1975

State	Production by Type of Mining (thousand short tons)		
	Underground	Surface	All*
Alabama	7,053	12,771	19,824
Alaska	–	700	700
Arizona	–	6,448	6,448
Arkansas	–	455	455
Colorado	3,260	3,636	6,896
Illinois	31,256	26,960	58,216
Indiana	139	23,587	23,726
Iowa	379	211	590
Kansas	–	718	718
Kentucky:			
East	40,509	44,847	85,356
West	22,988	28,853	51,841
Subtotal	63,497	73,700	137,197
Maryland	90	2,247	2,337
Missouri	–	4,623	4,623
Montana	–	14,106	14,106
New Mexico	529	8,864	9,392
North Dakota	–	7,463	7,463
Ohio	14,365	31,044	45,409
Oklahoma	–	2,356	2,356
Pennsylvania	42,249	38,213	80,462
Tennessee	3,106	4,435	7,541
Texas	–	7,684	7,684
Utah	5,858	–	5,858
Virginia	22,767	11,559	34,326
Washington	15	3,898	3,913
West Virginia	82,220	20,242	102,462
Wyoming	526	20,177	20,703
Total	277,309	326,097	603,406

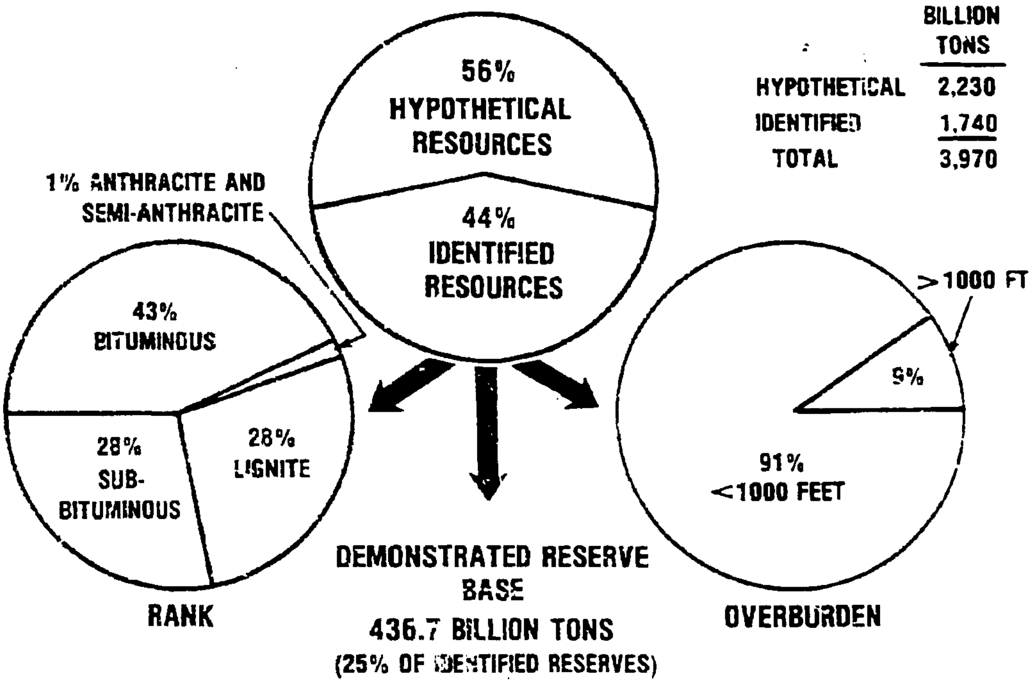
*Data may not add to totals shown because of independent rounding.

Source: *Mineral Industry Survey*, USDOI, Bureau of Mines, Weekly Coal Report, November 21, 1975.

raise this percentage. Of the total identified resources, approximately 43 percent is bituminous coal, 91 percent is 1,000 feet or less below the surface, and 33 percent is in thick beds. Figure II-1 also breaks down identified resources by rank, amount of overburden, and demonstrated reserve base.

Coal resources and reserves are categorized using the following definitions:

Hypothetical Resources – estimates of coal in the ground in unmapped and unexplored parts of known coal bases to an overburden of 6,000 feet. These estimates are determined by extrapolation from nearby areas of identified resources.



Source: U.S. Geological Survey Bulletin No. 1412.

Figure II-1. U.S. COAL RESOURCES AND RESERVES

The term "identified resources" includes all of the remaining categorizations of coal.

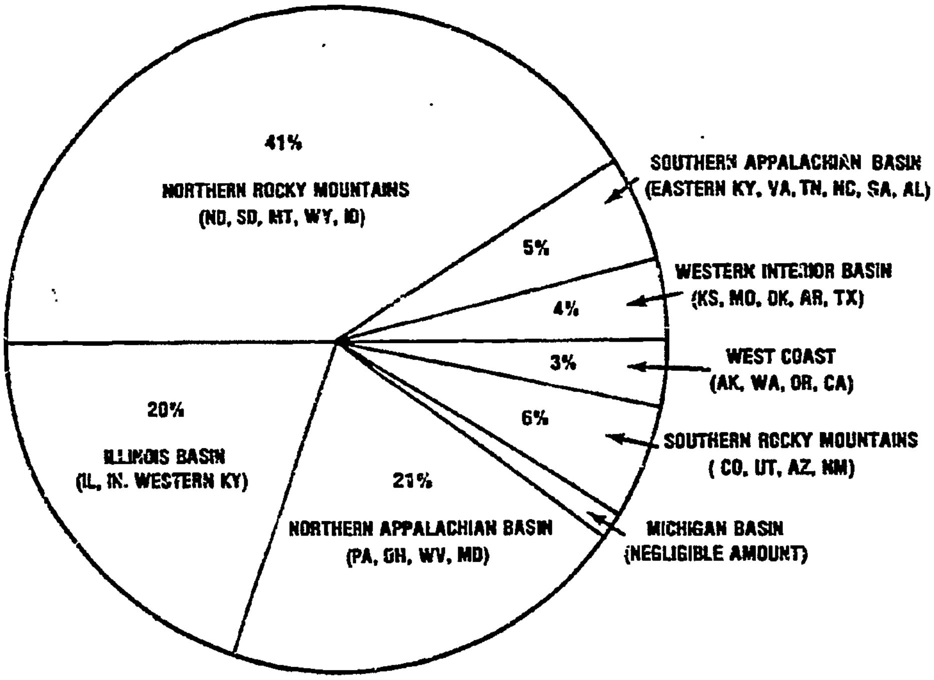
Measured resources – tonnages of coal in the ground based on assured coal-bed correlations and on closely spaced observations, about one-half mile apart. Computed tonnages are judged to be accurate within 20 percent of the tonnage.

Indicated resources – coal in the ground based partly on specific observations (measured resources) and partly on reasonable geologic projection. The points of observation and measurement are about one mile apart for beds of known continuity.

Demonstrated resources – in states where measured resources are comparatively small, the measured and indicated categories are combined into a single category referred to as demonstrated resources.

Inferred resources – tonnages of coal in the ground based on an assumed continuity of coal beds that are down-dip from and adjoining areas containing measured and indicated resources.

Demonstrated coal reserve base – selected portion of the identified resources deemed to be suitable for mining by 1974 methods. The coal in the reserve base is in the measured and indicated (demonstrated) resource category and is restricted



Source: U.S. Geological Survey Bulletin No. 1412.

Figure II-2. DEMONSTRATED COAL RESERVE BASE*

primarily to coal in thick or intermediate beds less than 1000 feet below the surface. Figures II-2 and II-3 depict the demonstrated reserve base by basin or region and by method of mining. Figure II-4 shows the sulfur range of coals in the demonstrated reserve base, divided into surface and underground categories. The locations of coal fields are shown in Figures II-5 and II-6.

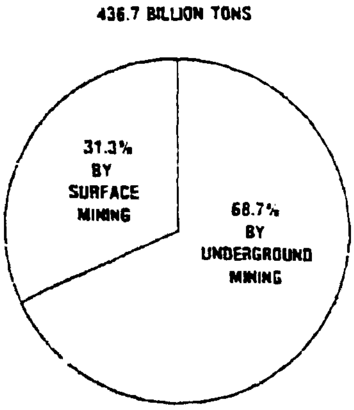
Utilization and Trends

At the beginning of the twentieth century, coal supplied 90 percent of U.S. energy consumption. However, during the first half of this century, coal consumption grew less rapidly than total energy consumption. More convenient than coal and competitively priced, domestic oil and natural gas became available and new uses of oil (e.g., automobiles) expanded rapidly. By 1972, coal dropped to about 23 percent of the energy consumption.

Figure II-7 indicates the domestic production of coal from 1960 to 1974. Coal in its natural form is clearly the least flexible of the fossil fuels. Being solid and containing

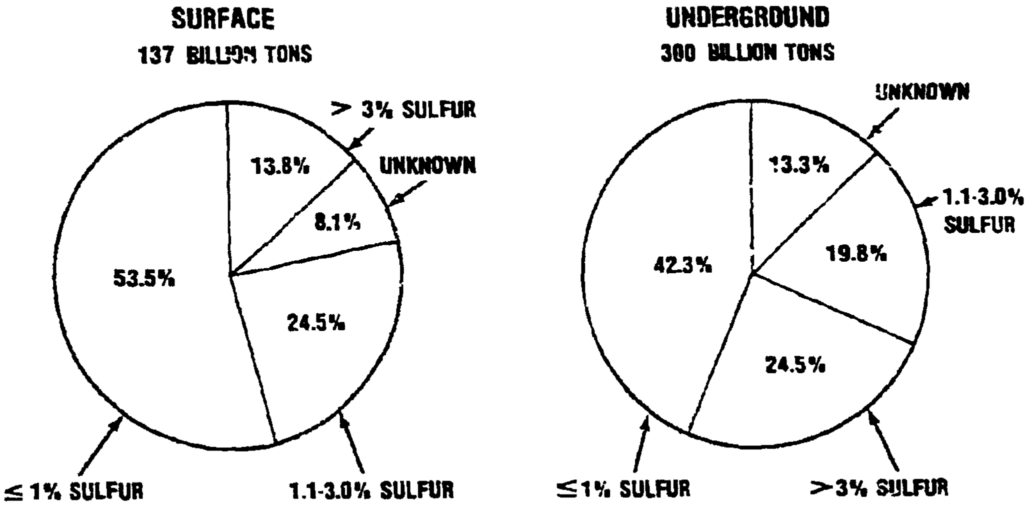
---

*0-1000 feet overburden; total: 437 x 10^9 short tons; at least half of the reserve base is recoverable.



Source: U.S. Geological Survey Bulletin No. 1412.

Figure II-3. DEMONSTRATED COAL RESERVE BASE BY METHOD OF MINING



Source: U.S. Geological Survey Bulletin No. 1412.

Figure II-4. SULFUR RANGE OF COALS IN DEMONSTRATED RESERVE BASE

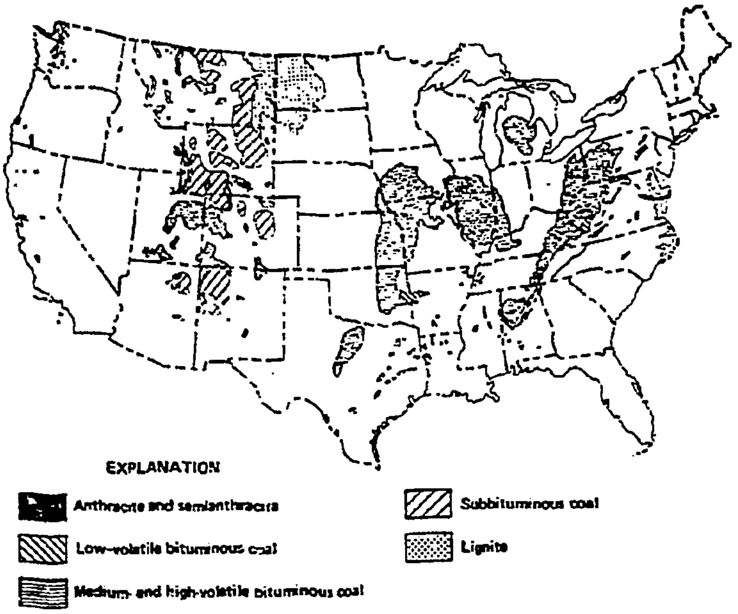


Figure II-5. COAL FIELDS OF THE CONTERMINOUS UNITED STATES

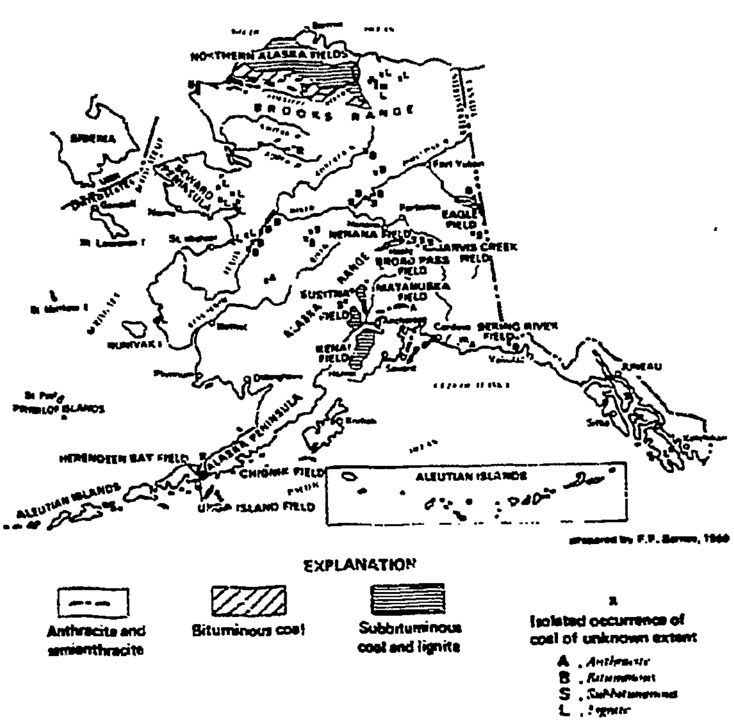
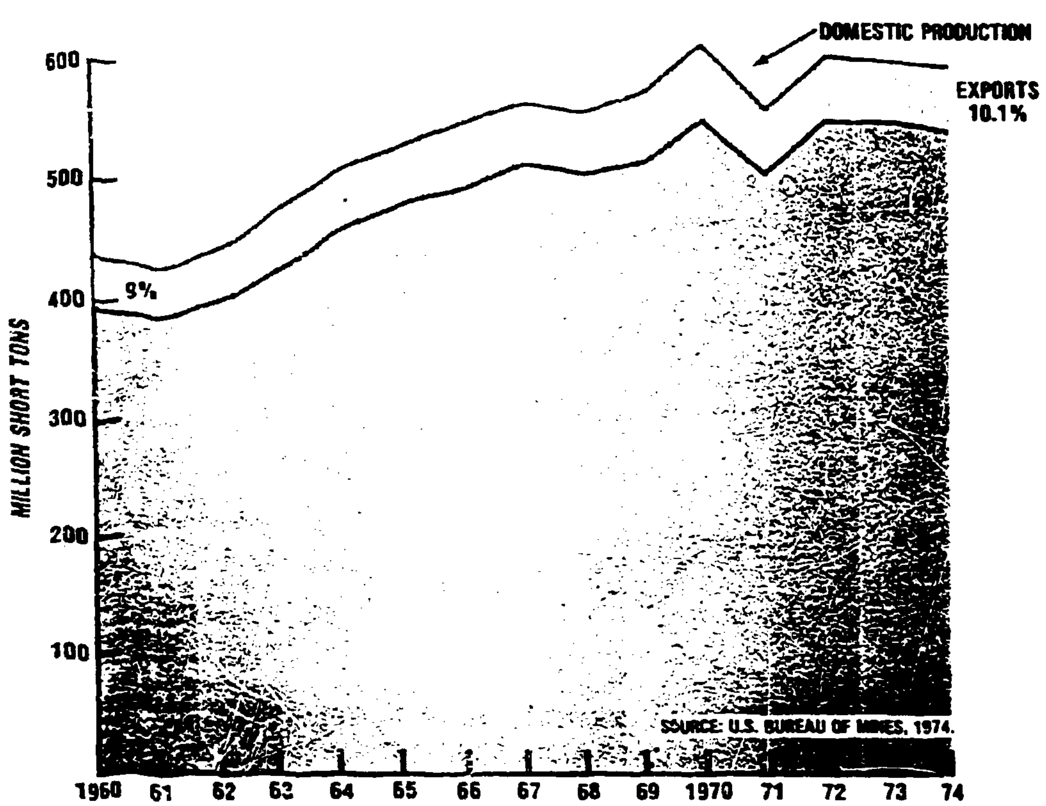


Figure II-6. COAL FIELDS OF ALASKA



SOURCE: U.S. BUREAU OF MINES, 1974.

Figure II-7. U.S. COAL PRODUCTION AND EXPORTS, 1960-1974

impurities, coal creates greater difficulties at every stage of use. Moreover, coal production and use have the misfortune of causing a wide array of environmental damage. As a result, coal becomes economical only when the economies of scale in coal handling enable large users to overcome these disadvantages. In an era of environmental concern and amid growing competition from other energy forms, coal has become a highly specialized fuel, attractive primarily to inland electric utilities and the steel industry.

Only coal's use for its coking properties appears protected from further competition. Coal use by the electric power industry faces major competition from all of the other fossil fuels. (See Figure II-8.) If its long distance pipelining were not so impractical, residual fuel oil could compete for some of coal's inland markets. Natural gas is widely used as a boiler fuel in southwestern areas where it is abundant. Minor competition, primarily in the far west, from geothermals and hydroelectric power contribute further to define coal's market boundaries.

Forecasts of the demand for coal are closely related to the growth of the electric utilities industry as indicated in Figure II-9. While electricity demands have been temporarily depressed due to the 1974-1975 recession, prospects are that demand growth will shortly regain its average annual rate of 6 to 7 percent in spite of rapidly rising electricity

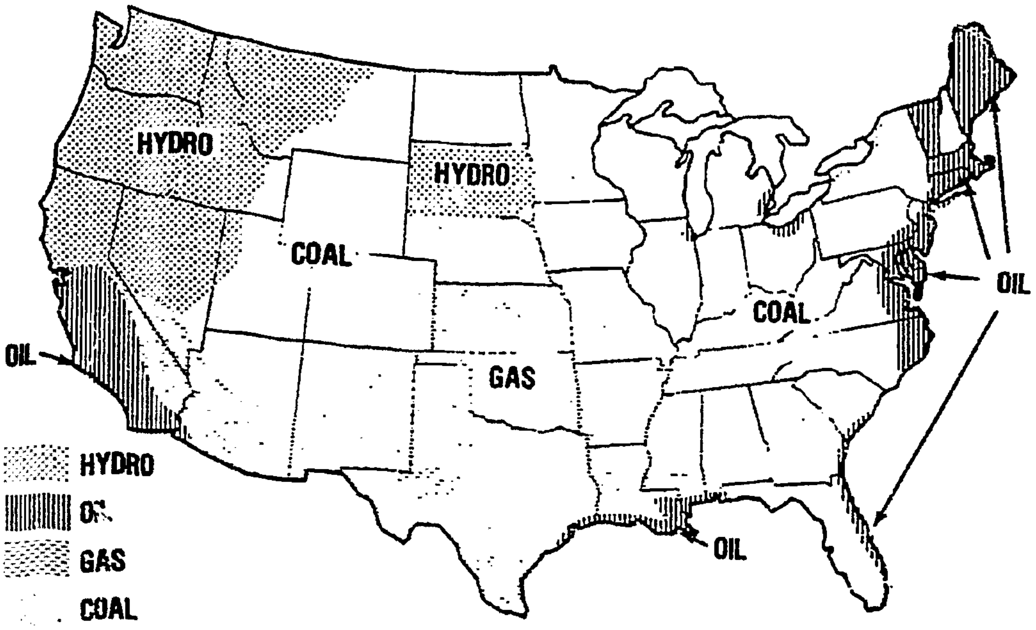


Figure II-8. FUEL COMPETITION IN THE ELECTRIC POWER INDUSTRY, 1973

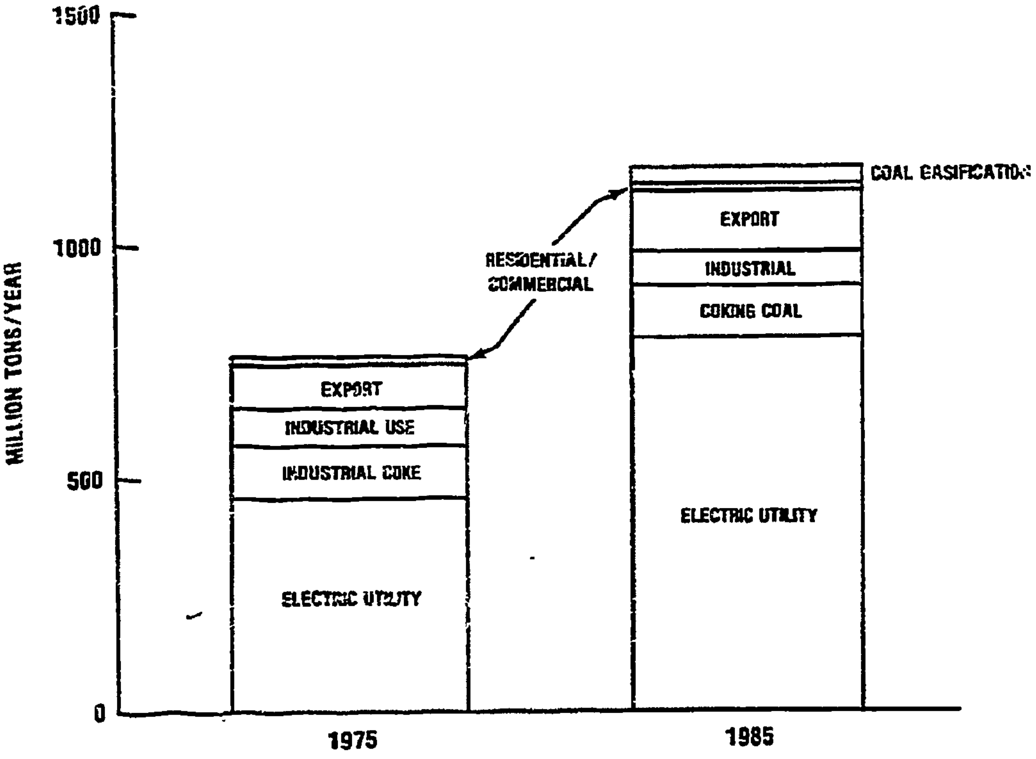


Figure II-9. DEMAND FOR COAL BY USE, 1975 AND 1985 price rates. Most residential and commercial demands for electricity are considered to be relatively price inelastic, i.e., not responsive to price changes in the short run. Although the availability of dependable low-cost electricity is a factor almost always taken into account in the selection of new plant sites, in only a few industries does the cost of electricity account for a substantial part of the cost of manufacturing. Indications are that despite the general turbulence of today's fuel markets, cost trends, fuel availability and environmental factors, electricity will continue its rapid gains.

To determine the impact these implications have on the demand for coal, the nature of the demands placed on the utilities industry and the economic forces surrounding procurement of additional generating capacity must be considered. Municipal power demand is not constant; a typical plant must respond to wide variations in the hourly load and substantial changes in seasonal loads. As a result, an electric power plant must utilize three basic types of generating plants. Base-load plants operate at constant power levels to meet the normal expected minimum daily demand. These plants are engineered to produce electricity as efficiently and cheaply as possible, consistent with high reliability standards. Since these units are operated nearly continuously over a long period of time, low operating cost benefits far outweigh capital cost considerations. Intermediate-load plants provide the normal daytime increase in demand. The daytime load may be twice the base-load; consequently, the intermediate-load plant may have to deliver as much power as the base-load plant on a wide cyclic output schedule. The intermediate-load plant will therefore be a high capital value item which will be lower in efficiency and higher in operating cost than the base-load plant. Peak-load units, using aircraft-type gas-turbine generators that are engineered for quick startup and shutdown, are designed to supply electricity principally during periods of maximum system demand and characteristically operate only a few hours a day. Peak-load units minimize capital investment rather than energy production cost.

While coal-fired units have supplied both base-load and intermediate-load plants, the largest coal-fired units today provide mainly base-load power. The fact that coal is a cheaper fuel than oil, gas, and uranium enhances coal's competitive position. However, this position may be impaired by the large capital investment that may be necessary to reduce emission problems.

Coal's competitive position at present is best described as uncertain. Federal and state government policies toward energy and the environment will play a dominant role in the future of each of the primary energy sources. Industry has been reluctant to commit itself to coal or synthetic fuels because of the large capital costs involved and the high risk associated with conversion to coal. Deregulation of interstate natural gas prices, sulfur restrictions, enforced scrubber utilization, nuclear restraints, strip mining legislation, and decontrol of oil are but a few of the major policy decisions that will impact heavily on the future of the coal industry. Figure II-10 shows use of nuclear power by electric utilities in 1990 if nuclear power growth is accelerated through national policy incentives.

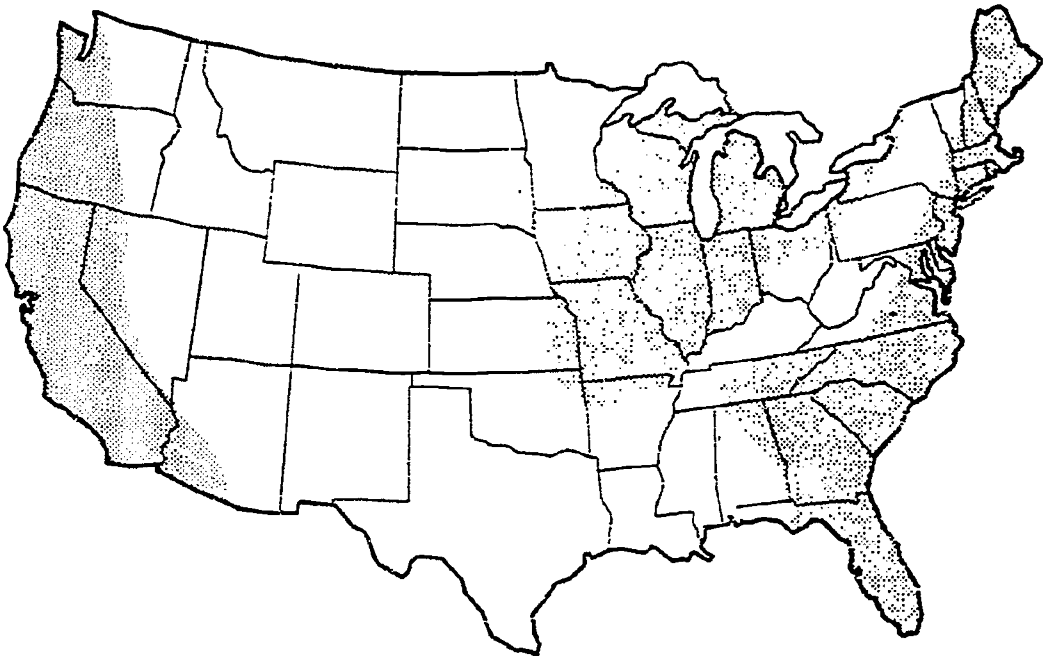
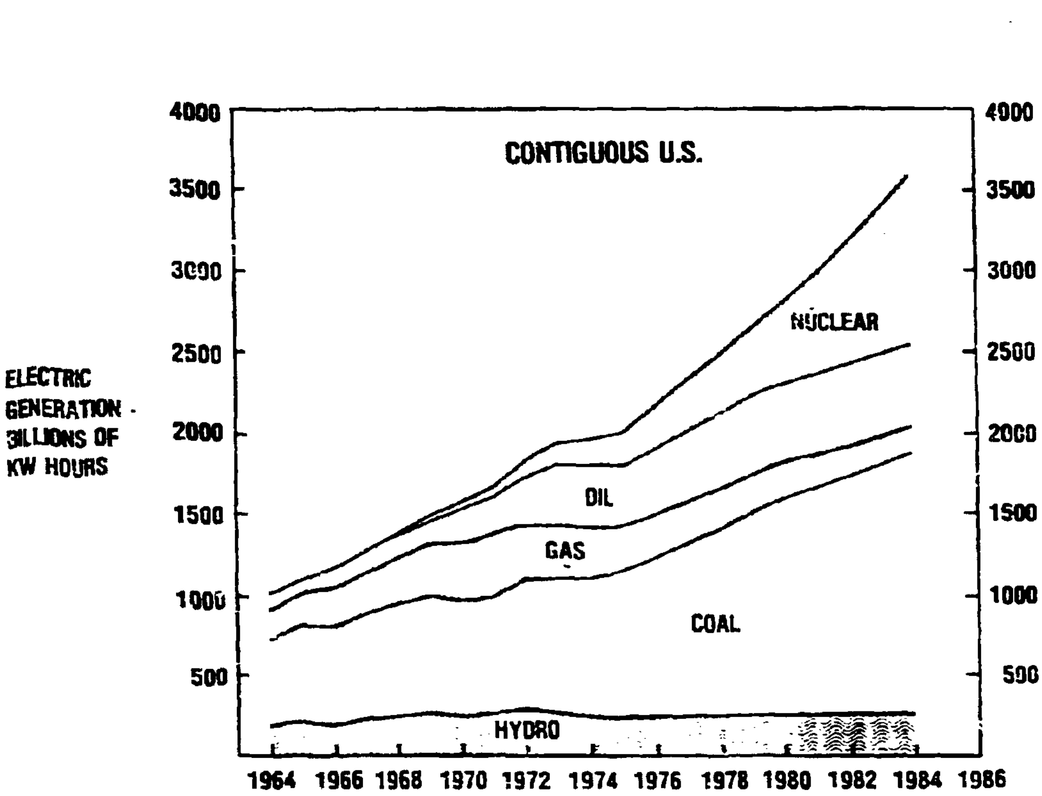


Figure II-10. POTENTIAL NUCLEAR ELECTRIC POWER REGIONS IN 1990

A study by the National Electric Reliability Council in July 1975 has projected an apparent shift away from coal-fired generation and into nuclear power in regions that historically have been large consumers of utility coal. But, as indicated in Figure II-11, shifts away from oil-fired and gas-fired base-load generators in traditional oil- and gas-burning areas toward coal-fired plants and nuclear plants are also expected. The net result through 1984 is an average annual increase in coal usage of 6.1 percent while generation capacity increases by 6.7 percent. This marks a slippage in the percentage of total generation requirements being supplied by coal from 48.4 percent in 1975 to 45.0 percent in 1984. A subsequent analysis by FEA that is less optimistic for total generation growth and coal's growth at least through 1980 forecasts a 5.6 percent annual increase in coal demand.

Coal gasification may provide only a small contribution to total energy demand by 1985. However, a potential market for gasified coal may develop by the end of the century. A number of coal gasification processes are being developed to derive a low-Btu fuel gas from coal. Electric power stations using this clean, desulfurized, low-ash fuel could meet emission standards. Coal can also be converted to a high-Btu substitute natural gas (SNG) to supplement domestic supplies of natural gas.



Source: National Electric Reliability Council. *Review of the Overall Reliability and Adequacy of the North American Bulk Power System*, 1975.

Figure II-11. ELECTRIC ENERGY GENERATION BY PRINCIPAL SOURCES

Conversion of coal to a synthetic crude oil has been commercialized to some extent (the SASOL plant in South Africa) but most technologically proven liquefaction processes have tended to be very expensive. Several liquefaction processes can also yield char, a relatively clean solid fuel for boilers. One synthetic liquid fuel process receiving particular attention is solvent refining. The primary products are clean liquid and solid fuels that are usable in electric power plants. Chemicals and light oils are also produced. The addition of a coking step can increase the oil yield and produce coke. Even without coking, chemical and light oil products can account for 47 percent of the process revenues; consequently, the process is not limited to clean fuel production.

Another source of boiler fuel is the char residual from a process producing high quality synthetics. Solvent refining and low-Btu gas are being stressed for the electric power industry, while high-Btu gas and synthetic crudes are being considered for markets in which premiums for their special properties can be earned.

If economical processes can be developed to produce environmentally clean synthetic fuels from indigenous sources of coal that can compete favorably with natural gas and crude oil, the future of the coal industry will be ensured. To date, however, research has not led to firm commitments for commercialization of any process.

Coal's future as a metallurgical fuel for blast furnaces and foundries is more clearly defined. Pig-iron manufacture is the only process in which coal's chemical and physical properties, as improved by coking, are of a distinct advantage. However, not all types of coal found in the United States are suitable for coking. Coking, or metallurgical, coals are of high quality, distinguished primarily by low sulfur and ash content. The United States has extensive reserves of bituminous coal, including adequate supplies of coking coal. Typical metallurgical coal prices range from 2 to 3 times the price of coal used by the electric utilities.

In the recent past, the blast furnace has been criticized as inefficient and quite difficult to control. However, no other process can produce more than a small fraction of the world's smelting needs. Concerted efforts to improve the operation of the blast furnace have resulted in changes in furnace design and operating techniques. Such improvements have reduced the amount of coke consumed per ton of pig iron by 20 to 25 percent while the average product of pig iron per blast-furnace day has increased approximately 51 percent since 1960.

Domestic steel shipments are expected to increase by 2 to 2.5 percent annually for the remainder of this century. Coking coal requirements, based on the present state-of-the-art of steelmaking, are projected therefor to be 108 million tons by 1985 and 151 million tons by the year 2000. However, based on trends of this industry over the last 10 years, these projections decrease to 82 and 89 million tons respectively. This trend represents a significant decrease from 1975 demand levels.

The only other market area for coal that promises growth is in U.S. exports of coking coal. In 1975, exports of coking coal were anticipated to be about 100 million tons, an amount nearly equal to U.S. coke consumption. Participation by the United States in the world coking coal market has been projected to expand to 20 percent of the world requirements by 1985. The process in the future that may have the greatest impact on this market is formcoke.* This process would enable western Europe and Japan, the principal importers of U.S. coal, to utilize local coals of a much greater qualitative range. Formcoking would eventually eliminate most of the U.S. export coal market.

Constraints to Future Coal Supply

The national energy policy requires doubling the production and consumption of coal by 1985. The magnitude of the projected increase in coal production can be translated into physical facilities to be added. Listed below are the kinds of actions that would be needed to achieve the estimated 1985 production levels:

---

*Formcoke is produced by heating pelletized or briquetted coal fines from a wide variety of noncoking coals.

- Develop 140 new 2-mmtpy (million tons per year) eastern underground mines.
- Develop 30 new 2-mmtpy eastern surface mines.
- Develop 100 new 5-mmtpy western surface mines.
- Recruit and train 80,000 new eastern coal miners.
- Recruit and train 45,000 new western coal miners.
- Manufacture 140 new 100-cubic-yard shovels and draglines.
- Manufacture 2,400 continuous mining machines.

That is, an average of one new deep mine and one new surface mine must be brought into production every month for 10 years. In contrast, only 13 mines of greater than 2-mmtpy production were opened in the 10 years from 1960 to 1969. In 1971, only 25 mines larger than 2-mmtpy were operating and only 3 of these exceeded 5-mmtpy.

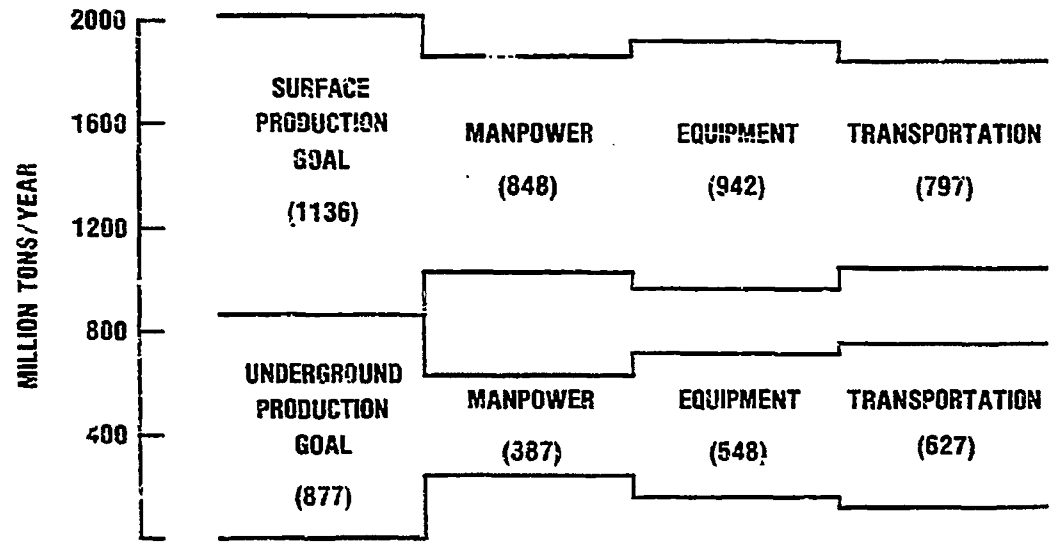
Three key elements determine the attractiveness of a given coal to a particular consumer: mining costs, transportation costs, and the physical properties of the coal. And these factors govern the opening of new mines. The Mitre Corporation has conducted an analysis of the constraints to large increases in coal supply. Summarized below are the highlights of that analysis:

Capital

Estimates are that over $25 billion will be required to finance coal's expansion. In an extremely tight capital market, sufficient capital money will not be forthcoming unless there is an attractive return on investment. Significant uncertainties relating to oil and gas economics and environmental policies cloud prospects for coal market growth and hence stifle investment. Uncertainty in the national energy and environmental policy is the most serious constraint facing coal production.

Manpower

In all probability, adequate manpower exists to fill the needs of strip mining operations although some local shortages of surface miners in mining operations in northern and southern Appalachia will probably occur. The unique working environment in underground mines that jeopardizes miner safety could cause shortages of manpower in southern Appalachia, in Northern Great Plains, and the Pacific Coast regions. Less severe shortages will likely occur in northern Appalachia, Midwestern and Rocky Mountain regions. An alternative to increasing manpower is to improve productivity. The consensus among the coal industry is that productivity increases will be evolutionary rather than revolutionary. Underground productivity rates per man that were reduced by the Federal Coal Mine Health and Safety Act are expected to regain the 1969 level by 1980.



Source: Mitre Corporation PB-240-6B.

Figure II-12. CONSTRAINTS TO 1985 ACCELERATED COAL SUPPLY GOALS

Equipment

The backlog for some orders has become critical, especially for those items where the total time necessary to acquire the equipment exceeds the time required to open the mine. For example, new strip mines require three years to reach initial operating readiness, but walking drag-lines, a critical component, currently require a six-year lead time for delivery. Mining equipment availability will be tight over the short term for draglines, replacement machinery and spare parts. However, equipment need not be a critical constraint to increased coal production over the long term.

Transportation

If the railroad and waterway networks are expanded at rates commensurate with their internal and presently planned capabilities, they will not be able to supply even the lowest level of projected increases in coal production. If on the other hand, they were to operate at maximum theoretical capacities and expand at potentially possible rates, after initial adjustments they could support almost any forseeable increases in coal production.

Environment

Without the development of economically feasible scrubbing devices, approximately 155-300 million tons of coal will be environmentally unacceptable under current legal emission constraints.

The most serious constraint to the expansion of the coal market is lack of sufficient capital. Utlimately, the availability of capital affects the ability to expand manpower, equipment and transportation, and to compensate for emission control requirements. However, even with adequate capital there are limiting physical factors that will constrain large increases in the production of coal. Figure II-12 is a graphical display of these limiting factors adapted from the Mitre study.

SUPPLY AND DEMAND BIBLIOGRAPHY

Averitt, Paul. *Coal Resources of the United States, January 1, 1974.* U.S. Geological Survey Bulletin No. 1412. Washington, D.C.: U.S. Government Printing Office, 1975.

Edison Electric Institute. *Statistical Year Book of the Electric Utility Industry for 1973.* Edison Electric Institute, 1973. (EEI Publication No. 75-39.)

Federal Energy Administration. *Demand for Coal for Electricity Generation 1975-1984.* Federal Energy Administration, August 1975.

Gordon, Richard L. *U.S. Coal & The Electric Power Industry.* Washington, D.C.: Resources for the Future, 1975.

Mitre Corporation. *Analysis of the Constraints on Increased Coal Production.* Mitre Corporation, 1975. (PB-240-6B.)

Mutschler, Paul H. *Impact of Changing Technology on the Demand for Metallurgical Coal and Coke Produced in the U.S. to 1985.* Washington, D.C.: Bureau of Mines, 1975.

National Academy of Engineers. *U.S. Energy Prospects: An Engineering Viewpoint.* National Academy of Engineers, 1973.

National Electric Reliability Council. *Review of the Overall Reliability and Adequacy of the North American Bulk Power Systems.* National Electric Reliability Council, July 1975.

National Petroleum Council. *U.S. Energy Outlook: U.S. Coal Availability.* National Petroleum Council, 1972.

U.S. Department of the Interior. "Demonstrated Coal Reserve Base of the United States, by Sulfur Category, in January 1, 1974." *Mineral Industry Surveys.* Washington, D.C.: U.S. Government Printing Office, May 1975.

III. CLASSIFICATION

Coal may be classified in various ways: by rank, by variety, by size, and sometimes by use. Coals are classified in an effort to provide the data for predicting their probable performance under given operating conditions.

The term *rank* is used to differentiate coals with respect to their degree of metamorphism. Table III-1 is the ASTM classification of coals by rank. The stage of coal in the series peat, lignite, subbituminous coal, bituminous coal, and anthracite is evidenced by progressive changes in the content of fixed carbon.

Peat, while essential to the development of coal, is not classified as a coal itself. Lignite is the lowest classification of coal. Bituminous coal has greater heat value and better weathering characteristics than lower rank coals. It is the most useful and abundant kind of coal. Anthracite ignites with some difficulty and is used primarily for space heating and as a source of carbon.

Proximate analysis, sulfur content, and heating value are the analytical determinations most commonly used for industrial characterization of coal. Proximate analysis based on ASTM standard laboratory procedures separates the products obtained during heating into four groups: (1) moisture, (2) volatile matter, (3) fixed carbon, and (4) ash. Moisture consists of (1) surface or extraneous moisture that may come from external sources and (2) inherent or bed moisture.

Volatile matter does not exist in coal as such but is produced by decomposition of the coal when heated under prescribed conditions. It consists chiefly of the combustible gases hydrogen, carbon monoxide, methane and other hydrocarbons, tar vapors, volatile sulfur compounds, and some noncombustible gases, such as carbon dioxide and water vapor. The heating value is perhaps the most important property as far as combustion is concerned. Heat values and proximate analysis of coal of different ranks are compared in Figure III-1.

The standard method of determining the fixed carbon is to subtract from 100 the sum of the percentages of the moisture, volatile matter, and ash of the proximate analysis. Fixed carbon is the carbonaceous residue less ash remaining in the test crucible

Table III-1

CLASSIFICATION OF COALS BY RANK[1]
(FC = Fixed carbon; VM = Volatile matter; Btu = British thermal units)

Class	Group	Limits of Fixed Carbon or Btu Mineral-Matter-Free Basis	Requisite Physical Properties
I Anthracitic	1. Meta-anthracite	Dry FC, 98% or more Dry VM, 2% or less	
	2. Anthracite	Dry FC, 92-98% Dry VM, 2-8%	
	3. Semianthracite	Dry FC, 86-92% Dry VM, 8-14%	Nonagglomerating[2]
II Bituminous[3]	1. Low-volatile bituminous	Dry FC, 78-86% Dry VM, 14-22%	
	2. Medium-volatile bituminous	Dry FC, 69-78% Dry VM, 22-31%	
	3. High-volatile A bituminous	Dry FC, less than 69% Dry FM, more than 31% Moist[4] Btu, 14,000 or more	
	4. High-volatile B bituminous	Moist[4] Btu, 13,000-14,000[5]	
	5. High-volatile C bituminous	Moist Btu, 11,000-13,000[5]	Either agglomerating or nonweathering[6]
III Subbituminous	1. Subbituminous A	Moist Btu, 11,000-13,000[5]	Both weathering and nonagglomerating
	2. Subbituminous B	Moist Btu, 9,500-11,000[5]	
	3. Subbituminous C	Moist Btu, 8,300-9,500[5]	
IV Lignitic	1. Lignite	Moist Btu, less than 8,300	Consolidated
	2. Brown coal	Moist Btu, less than 8,300	Unconsolidated

[1] ASTM D 388 does not include a few coals of unusual physical and chemical properties which come within the limits of fixed carbon or Btu of the high-volatile bituminous and subbituminous ranks.

[2] If agglomerating, classify in low-volatile group of the bituminous class.

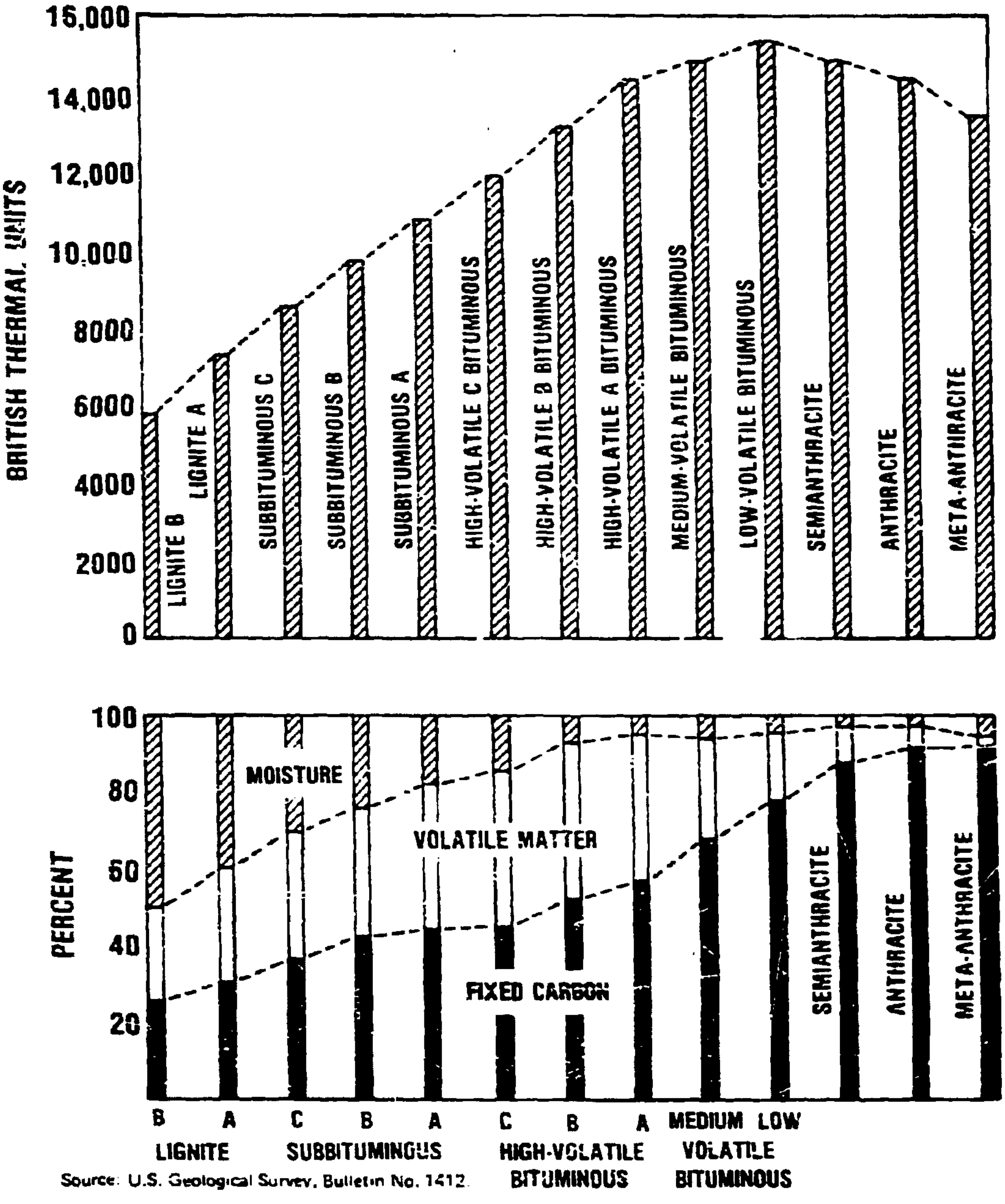
[3] There may be noncaking varieties in each group of the bituminous class.

[4] Moist Btu refers to coal containing only its natural bed moisture.

[5] Coals having 69 per cent or more fixed carbon on the dry, mineral-matter-free basis are classified according to fixed carbon regardless of Btu.

[6] There are three varieties in the high-volatile C bituminous coal group, 1) agglomerating and nonweathering, 2) agglomerating and weathering, and 3) nonagglomerating and nonweathering.

Source: American Society for Testing and Materials.



Source: U.S. Geological Survey, Bulletin No. 1412.

Figure III-1. HEAT VALUES AND PROXIMATE ANALYSES OF COAL ON A MOIST, MINERAL MATTER-FREE BASIS after determination of the volatile matter. Ash is the inorganic residue that remains after burning the coal in a muffle furnace to a final temperature of 1290° to 1380° F.

The ultimate analysis of coal is the determination of carbon and hydrogen as found in the gaseous products of its complete combustion, and the determination of sulfur, nitrogen, and ash in the material as a whole, and the estimation of oxygen by difference. Sulfur occurs in three forms of coal: (1), pyritic sulfur or sulfur combined with iron as pyrite or marcasite, (2) organic sulfur or sulfur combined with coal substance, (3) sulfate sulfur or sulfur combined mainly with iron or calcium together with oxygen as iron sulfate or calcium sulfate. About half of the sulfur in coal is pyritic sulfur and the other half is organic sulfur. Sulfate sulfur is present only in trace amounts. The percentage of carbon in coal, which increases with rank, supplies most of its heating value.

When coal is heated in an atmosphere very deficient in oxygen, volatile matter is driven off, leaving behind a residue of carbon, called coke, which may take the form of small powdery particles or may fuse into lumps of varying size and strength. In commercial coke making, the term *coke* refers to lumps of marketable size and quality. Coke is produced from coking coals in a coke oven. Metallurgical coal is coal with strong or moderately strong coking properties.

Coke formation represents an intermediate stage in any fuel bed. In a boiler furnace, for example, some coals become plastic, soften upon heating and form lumps or masses of coke. Those coals that show little or no fusing action are called free burning.

The caking properties of a coal and the size and strength of the coke masses it forms are valuable indicators of a fuel's performance in the furnace. The free-swelling index gives an indication of the caking characteristics of the coal when burned on fuel beds. The agglomerating index is used in the classification of coals to indicate the dividing line between noncoking coals and those having weak caking properties.

All of these chemical and physical properties of coal are defined by ASTM standards. Other frequently referenced properties of coal are:

- Ash fusibility
- Color and luster
- Friability
- Grindability
- Hardness
- Size
- Specific gravity
- Weathering

International System

The greatly increased volume of trade in coal among various nations following World War II emphasized the need for an international system of coal classification The various coal-producing countries concerned possessed their own national classification systems. developed to fit the characteristics of domestic coals and often the needs of the national coal-using industry. This practice of developing national coal classification systems resulted in the evolution of different terminologies for describing similar or identical coals. which naturally led to confusion in evaluating and comparing coals shipped in international trade.

The international system is similar to the ASTM system in that coals are first separated into classes according to volatile matter and calorific value. However. coals are classified on an ash-free basis rather than on the ASTM mineral-free basis. Where the ASTM provides for classification of all ranks of coal. the international system is based on only two systems: one for hard coals and the other for brown coals and lignite.

The term *hard coal* as used in the international system is based on European usage and is defined as coal with a gross calorific value of more than 10.260 Btu/lb (4700 Kcal/kg) on the moist ash-free basis. Coals classified in the ASTM system as anthracite. bituminous and the higher-rank subbituminous coals are included in the international system for classification of hard coals by type.

The international scheme of classification for brown coals is based on two intrinsic principal characteristics which indicate the value of brown coal as a fuel. and as a raw material for chemical purposes: (1) the total moisture on ash-free basis. and (2) the tar yield on dry ash-free basis. The soft or brown coals of European terminology are ASTM lower-rank subbituminous and lignitic coals.

CLASSIFICATION BIBLIOGRAPHY

Averitt, Paul. *Coal Resources of the United States, January 1, 1974*. U.S. Geological Survey Bulletin No. 1412. Washington, D.C.: U.S. Government Printing Office, 1975.

Babcock and Wilcox Co. "Sources of Chemical Energy." *Steam: Its Generation and Use*. 38th ed. New York: The Babcock and Wilcox Co., 1972.

Bethlehem Steel. *The Story of Coal.*

Curtis, Harry A. "Solid Fuels." *Chemical Engineers Handbook*. Edited by John H. Perry. 3rd ed. New York: McGraw-Hill, 1950.

Hendrickson, Dr. Thomas A., ed. *Synthetic Fuels Data Handbook*. Denver, Colorado: Cameron Engineers, Inc., 1975.

Mitre Corporation. *Coal: The Black Magic*. Mitre Corporation, 1973.

Ode, W. H. "Coal." *Standard Handbook for Mechanical Engineers*. Edited by Theodore Baumeister, 7th ed. New York: McGraw-Hill, 1958.

Ode, W. H., and Frederic, W. H. *U.S. Bureau of Mines. Report of Investigation No. 5435.* Washington, D.C.: U.S. Government Printing Office, 1958.

Parks, Bryan C. "Origin, Petrography, and Classification of Coal." *Chemistry of Coal Utilization*. Supplementary Volume. Edited by H. H. Lowry. New York: John Wiley and Sons, Inc., 1963.

Rose, Harold J. "Classification of Coal." *Chemistry of Coal Utilization*. Volume 1. Edited by H. H. Lowry. New York: John Wiley and Sons, Inc., 1945.

Simon, Jack A., and Hopkins, M. E. "Geology of Coal. *Elements of Practical Coal Mining*. Edited by Samuel M. Cassidy. Baltimore: Port City Press, 1973.

IV. MINING TECHNOLOGY

In 1900 nearly all of the coal produced in the United States was from underground mines. Surface mining appeared around 1915 and produced about 1.5 percent of that year's coal. Advances in mining technology and equipment development have resulted in surface mine production nearing 50 percent of total coal production.

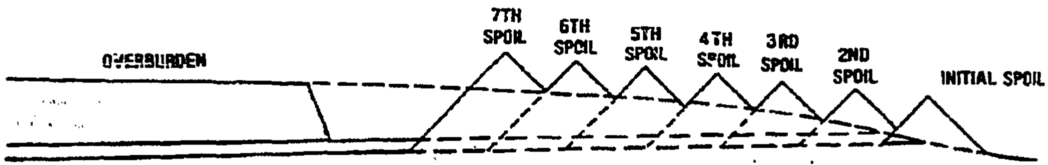
Surface Mining

Surface mining has been increasing for several decades. Improved excavating equipment and exploiting economies of scale have made possible the surface mining of coal at even greater depths and, at the same time, have nearly doubled the output per man-day from coal stripping operations.

As costs of strip-mine produced coal are dependent mainly on the cost of equipment and maintenance and only secondarily on labor costs, it is beneficial that the mine be as large as practical. The cost per ton is greatly reduced by surface mining because of the relative ease of obtaining the coal. Also, the percentage of coal recovered from surface mines is nearly 85 percent as compared to an average of about 50 percent in underground mines.

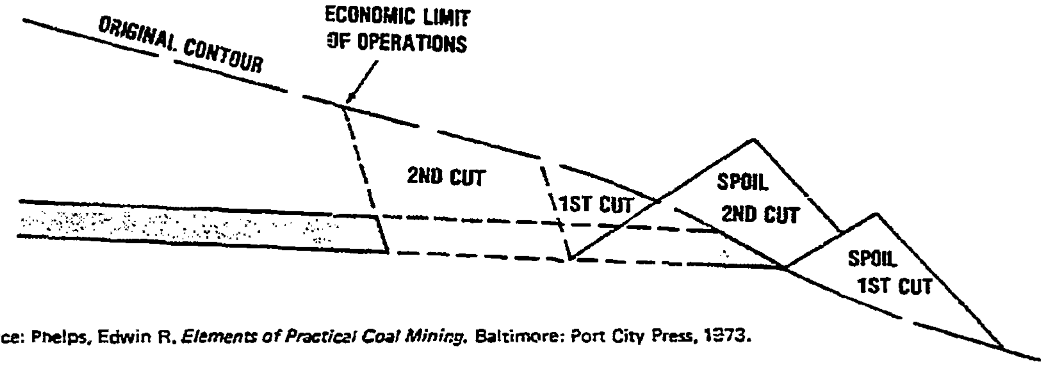
Much surface mining recovers coal that could not be extracted by underground methods because of coal bed thinness, multiple beds close together, split seams, the nature of the roof, and other geologic conditions. During the process of stripping away the overburden to reach thick coal seams, thinner seams are often encountered and profitably extracted.

The overburden-to-coal or stripping ratio (cubic yards of overburden to tons of marketable coal) has a very strong influence on the decision of whether or not to use surface mining methods. Available machinery currently limits surface mining to depths less than 180 feet.



Source: Phelps, Edwin R. *Elements of Practical Coal Mining.* Baltimore: Port City Press, 1973.

Figure IV-1. AREA MINING



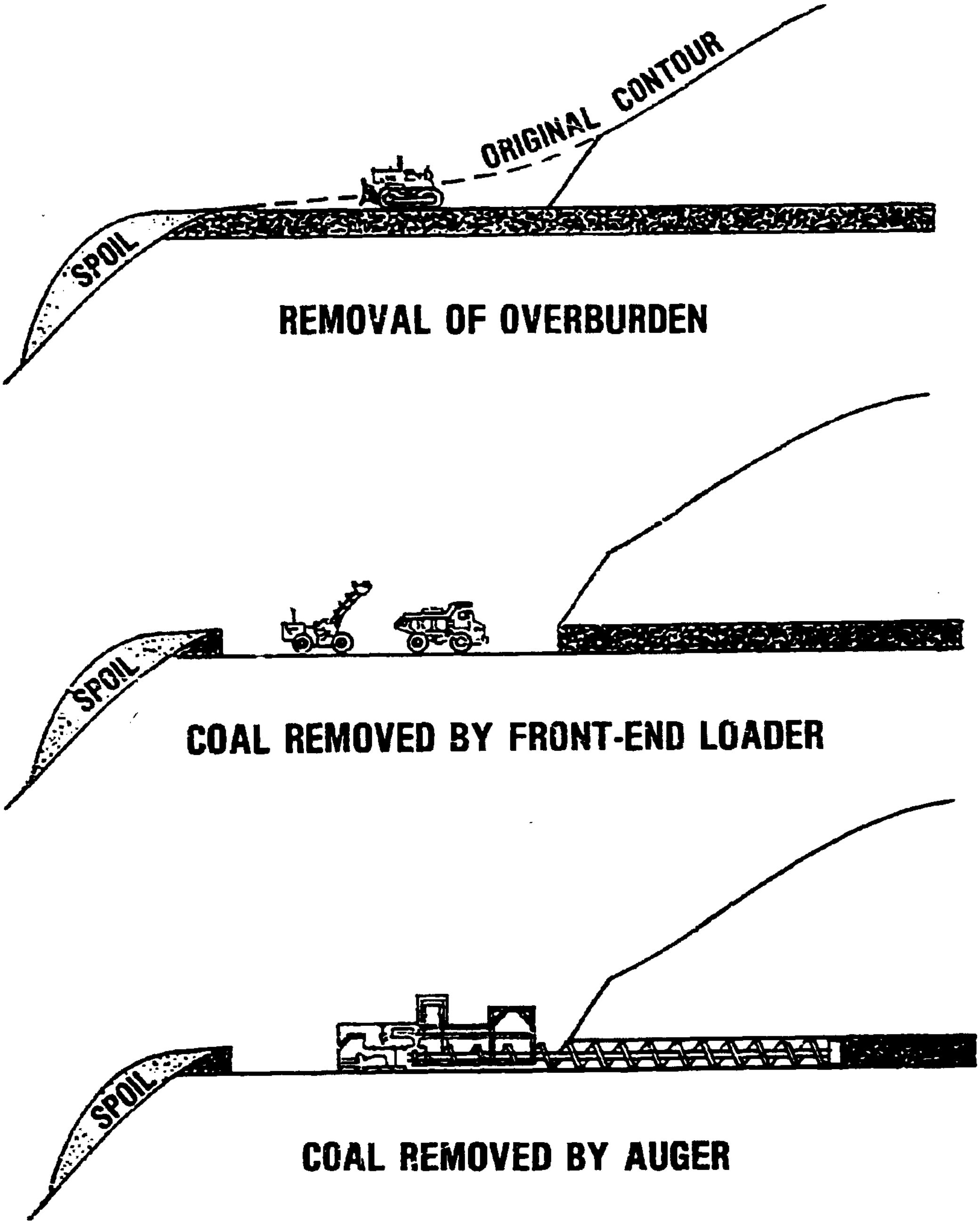
Source: Phelps, Edwin R. *Elements of Practical Coal Mining.* Baltimore: Port City Press, 1973.

Figure IV-2. CONTOUR MINING

The basic functional steps involved in the production of coal by surface mining techniques are:

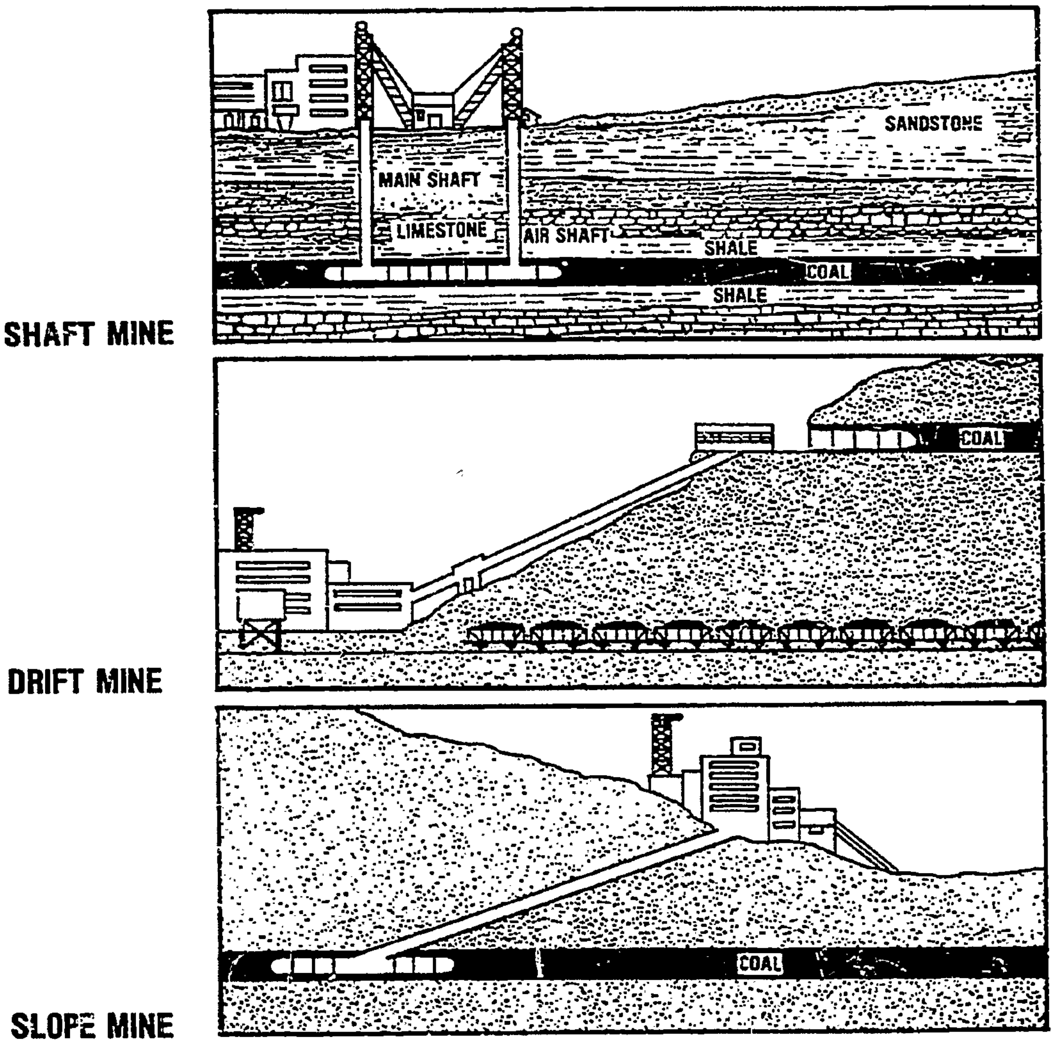
- *Drilling* – precisely positioned holes are bored in overburden.
- *Blasting* – holes are loaded with explosives and detonated to break up consolidated overburden.
- *Excavating* – fragmented overburden is discharged (spoiled at the side of the pit opposite the high wall).
- *Loading* – coal is removed from the seam,
- *Hauling* – the coal is transported out of the pit.
- *Reclamation* – vegetation is restored to the area.

Area mines are developed when coal seams lie in a relatively level plane beneath a level to gently rolling surface terrain as shown in Figure IV-1. Contour mining, depicted in Figure IV-2, prevails in mountainous or hilly terrain. Open pit mining is practiced where the coal beds are extremely thick or sharply pitching. When the economic limit is reached in normal surface mining operations, a portion of the exposed coal seam may be recovered by auguring, depicted in Figure IV-3.



Source: Phelps, Edwin R. *Elements of Practical Coal Mining*. Baltimore: Port City Press, 1973.

Figure IV-3. CONTOUR MINING WITH BULLDOZER AND AUGER



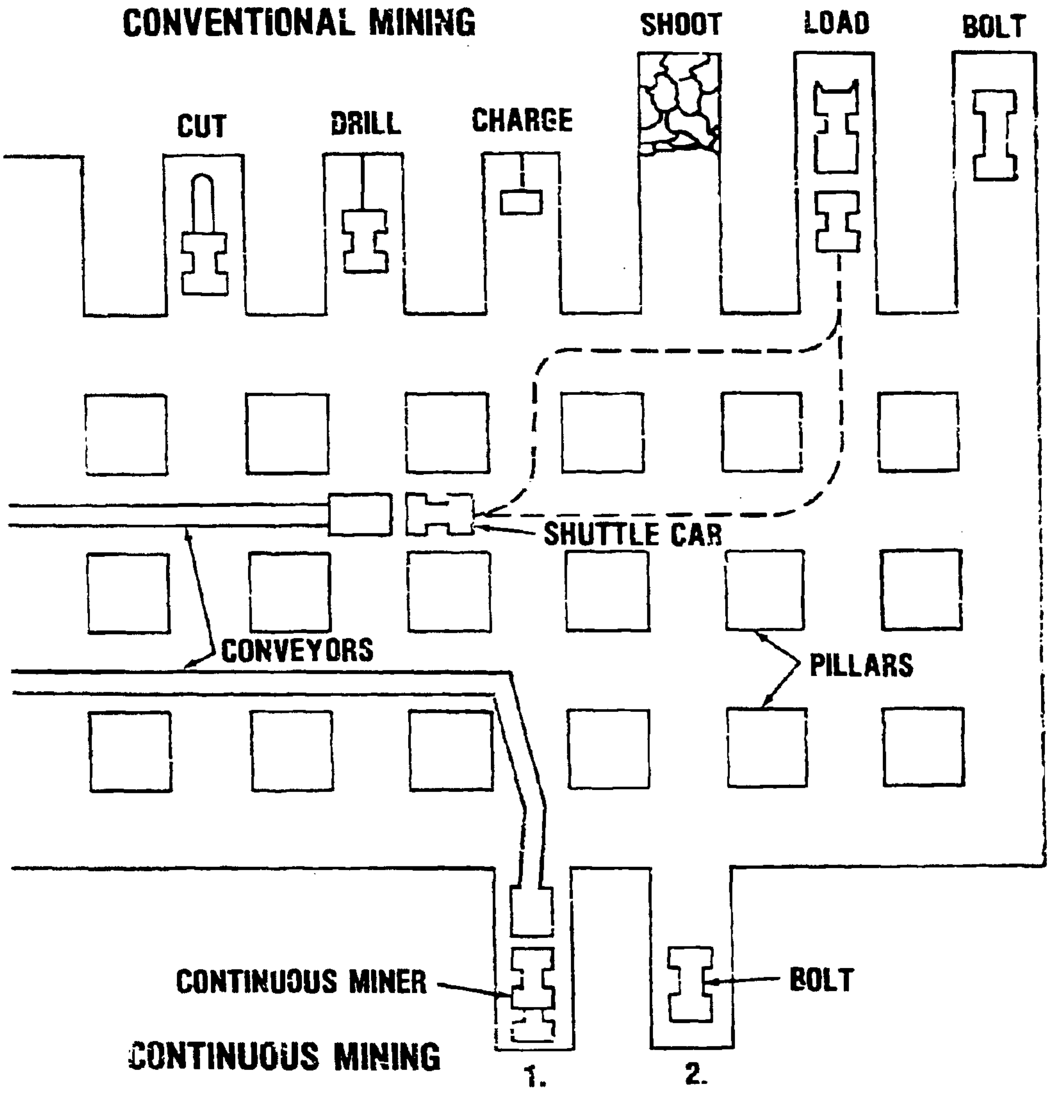
Source: National Coal Association. *Coal Facts 1974-1975.* Washington, D.C. National Coal Association. 1975.

Figure IV-4. UNDERGROUND MINES

Underground Mining

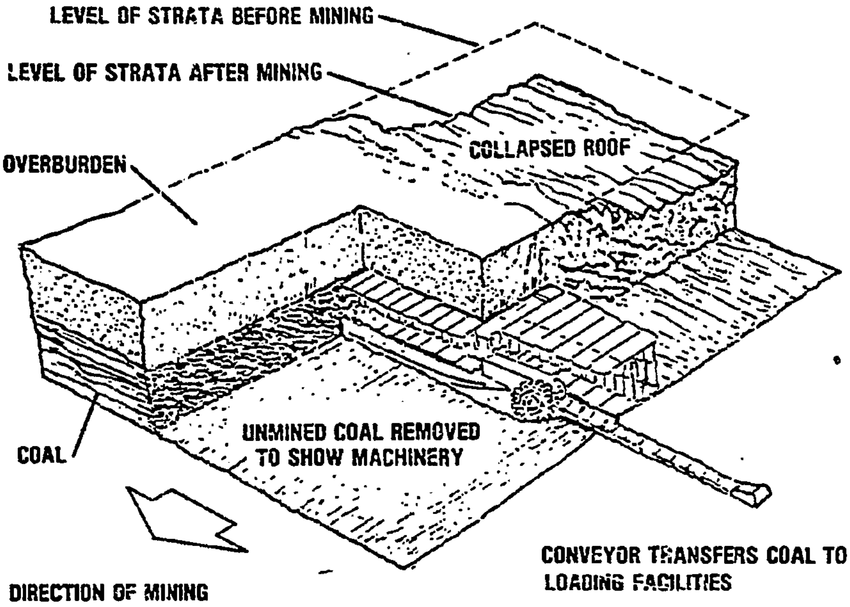
Underground mining is used when the coal is buried too deep in the ground to make surface mining feasible or possible. There are three different types of underground mines. illustrated in Figure IV-4.

Underground mining systems. shown in Figures IV-5 and IV-6. are classified according to the equipment used. e.g.. conventional. continuous. or longwall. The tonnage and percent of total underground coal mined by each method is shown in Figure IV-7.



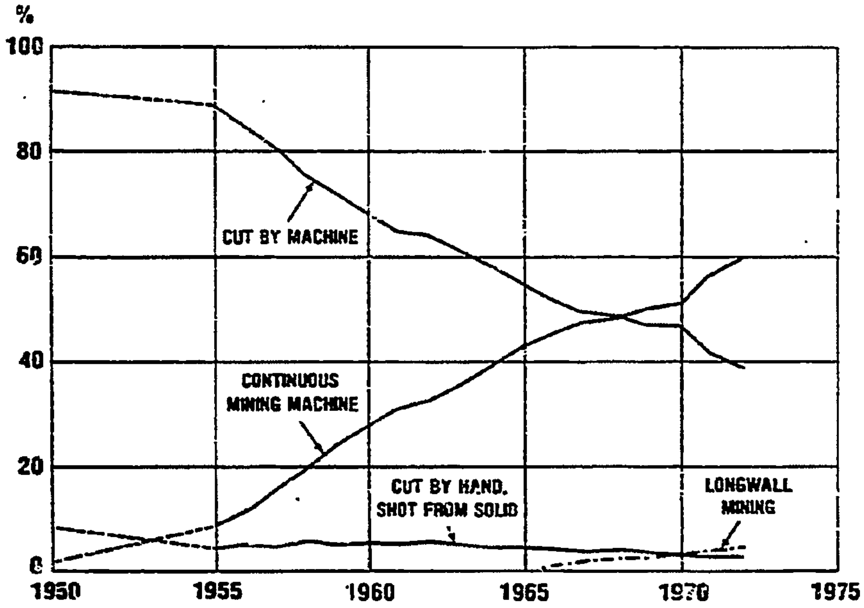
Source: University of Oklahoma, The Science and Public Policy Program. *Energy Alternatives: A Comparative Analysis.* Washington, D.C.: U.S. Government Printing Office, May 1975.

Figure IV-5. ROOM AND PILLAR MINING



Source: Young, Gordon. "Will Coal Be Tomorrow's Black Gold?" *National Geographic Magazine*, August 1975.

Figure IV-6. LONGWALL MINING



Source: National Coal Association. *Bituminous Coal Facts 1974*, Washington, D.C.: National Coal Association, 1975.

Figure IV-7. PERCENT OF TOTAL UNDERGROUND TONNAGE MINED BY EACH METHOD

Both conventional and continuous mining systems follow the room-and-pillar mining plan. About half of the coal is removed from the seam by carving out intersecting tunnels. Between the tunnels, large blocks of coal pillars are left standing to support the mine roof. When pillars are no longer needed, they are sometimes removed to recover additional coal.

Conventional mining has five major production steps:

1. *Cutting* – slots cut in the coal to allow the solid coal to shatter more easily
2. *Drilling* – holes are bored for explosives
3. *Blasting* – spark-proof explosives or cylinders of compressed air are used to shatter the coal
4. *Loading* – coal is conveyed out of the mine
5. *Roof Bolting* – roof support is installed.

Ventilation is then extended and the coal face is ready for the next cycle.

In the continuous mining system, a single machine, called a *continuous miner*, breaks the coal mechanically and loads it for transport. Roof support is installed, ventilation advanced, and the coal face is ready for the next cycle.

In the longwall mining system, large blocks of coal are completely extracted in a single, continuous operation. Hydraulic yielding jacks support the roof at the immediate face as the coal is removed by longwall mining machines able to cut in both directions. As the face advances the strata are allowed to cave behind the support units.

The shortwall mining system is a combination of continuous and longwall mining systems Continuous mining or conventional equipment is used to develop the field. Then a continuous miner, in conjunction with the longwall-type roof supports, is used to extract the remaining coal pillars.

Health and Safety

The Federal Coal Mine Health and Safety Act of 1969 standards specify (1) the amount of respirable dust which may be inhaled, (2) the amount of dust which may be emitted from drilling operations, (3) the level of noise which is permitted, and (4) the frequency with which chest X-rays must be given to each miner at the operator's expense.

Major Bureau of Mines research includes efforts to:

- Eliminate or reduce disasters caused by fires in underground coal mines by improving detection. suppression. and extinguishment technology.
- Identify health and safety problems and develop advanced mining systems and subsystems to eliminate them.
- Provide technology to protect miners from exposure to respirable dust. noise, toxic gases, and radiation hazards.
- Prevent coal bumps and accidental falls of roof. rib. and face by improving artificial support. hazards detection. and mine opening design.
- Develop technology for controlling methane prior to and during the mining of methane-laden coal beds.
- Develop technology to improve the probability of a miner surviving a disaster and improve rescue methods and mine-reopening technology.
- Identify and provide technology to correct hazards in electrical. mechanical. illumination. communication. haulage. and material handling areas.

Reclamation

The uncertainty about future federal and state regulatory legislation has tended to inhibit the industry's initiative in developing new mines and also to stifle introduction of innovative reclamation practices.

In surface mining. the major problem is repairing the surface disruption. This normally involves smoothing out piles of overburden and making some attempt to revegetate the area. Comprehensive reclamation programs include restoring the surface topography. replacing the topsoil. fertilizing. revegetating. and returning the land to productive use. whether agricultural. commercial. residential. or recreational.

Underground mining presents considerable environmental danger through ground subsidence. acid mine drainage and disposal of mine wastes.

Environmental research objectives are to:

- Develop new and improved systems and techniques for correcting environmental and public safety problems resulting from past mining activities.
- Prevent similar problems in current and future mining including subsidence control: vegetative and physical stabilization of waste banks: extinguishment of underground. outcrop. and refuse bankfires: and reclamation of mined land for a variety of public uses.

Union-Management Relations

Cooperation of labor and industry is required if increased coal production is to take place. The coal industry's compliance with any reasonable union demands should not seriously affect coal production nor materially foreclose its markets because of increased costs. Some costs for this compilance have already been passed on by the industry. Additional demands are expected to increase the cost of mined coal by 10 to 15 percent; that is. 5 to 6 cents per million Btu. While this increase seems to be high in percentage terms, it is dwarfed in absolute terms by recent price increases in the oil world.

A major emphasis of the new union leadership has been on health, safety, and training. The 1974 contract provisions bear this out. In addition, United Mine Workers of America (UMWA) staff members have been vociferous advocates of both intra-industry and inter-industry technology transfer.

Implications of the 1974 UMWA-BCOA* Agreement

A new Joint Industry Training Committee has been established which will provide an opportunity for both sides to suggest new approaches to the significant training problems confronting the industry. At the local level, the previously mentioned Mine Communications Committees have been established, the members of which will meet frequently to discuss matters which they consider significant. Such interaction could well lead to a safe, more efficient mining community with increased satisfaction for both management and labor.

With this new contract, the industry has obviously recognized the important part that the UMWA can play in achieving a safe work place, especially at the local level. The individual miner has been given the right to leave his work place when he is in danger. Regular mine and equipment inspections are also a part of the new contract.

Many aspects of the new contract will lead to increased costs – and perhaps in rather subtle ways – for example, the restructuring of wage grades, the increased wage benefits, the cost-of-living allowance, the new health and retirement plan, and the more liberal vacation benefits. In addition, the requirements to employ inexperienced new miners in safe "off-face" jobs for 90 days and to provide helpers on most continuous miners and roof bolters will cause further increases in total wages paid. The extensive training requirements will demand additional training program developers, instructors, facilities, and paid time for trainee's attendence.

---

*Bituminous Coal Operators of America

Certain costs should eventually be reduced. If the new health and safety provisions are effective, they should eventually lead to lower accident costs and lower sickness-health benefit costs. Workmen's Compensation premiums and black lung payments, once assumed, should eventually decrease – in terms of constant dollars.

The new requirements for helpers, the expanded training and maintenance programs, and the new machinery for settlement of disputes could eventually lead to greater production capacities. The immediate result, however, of these innovations and the 90-day indoctrination period is expected to be a drop in labor-productivity levels. The necessary increase in production required to maintain the 1973 production level of approximately 11 tons per man shift will be difficult to achieve while this large increment in labor hours is being added.

MINING TECHNOLOGY BIBLIOGRAPHY

Argonne National Laboratory. *Surface Mined Land in the Midwest: A Regional Perspective for Reclamation Planning*. Springfield, Virginia: NTIS, June 1974.

Breslin, John J. and Anderson, Richard A. *Observations on the Surface Mining of Coal*. Columbus, Ohio: Battelle Memorial Institute, 1974.

Battelle Energy Program Report. *A System Approach to Underground Coal Mining. Phase I-Problem Analysis and Research Recommendations*. Columbus: Battelle Memorial Institute, June 1975.

Bethlehem Steel. *The Story of Coal.*

Mitre Corporation. *An Analysis of Constraints on Increased Coal Production*. Mitre Corporation, January 1975.

National Coal Association. *Bituminous Coal Facts 1974*. Washington, D.C.: National Coal Association, 1975.

National Coal Association. *Coal Facts 1974-1975*. Washington, D.C.: National Coal Association, 1975.

National Petroleum Council. *U.S. Energy Outlook: Coal Availability*. Report by Coal Task Group of Energy Resources Subcommittee of NPC's Committee on U.S., E. H. Reichle, Chairman. Washington, D.C.: National Petroleum Council, 1972.

Nephew, Edmund A. "The Challenge and Promise of Coal." *Technology Review*, December, 1973: 20-29.

Office of Coal Research. *Policy Analysis for Coal Development at a Wartime Urgency Level to Meet the Goals of "Project Independence"*. Croton-on-the-Hudson, New York: Hudson Institute, 4 February 1974.

Phelps, Edwin R. "Modern Mining Methods–Surface." *Elements of Practical Coal Mining*. Edited by Samuel M. Cassidy. Baltimore: Port City Press, 1973.

Schroder, John L., Jr. "Modern Mining Methods-Underground." Elements of Practical Coal Mining. *Edited by Samuel M. Cassidy. Baltimore: Port City Press, 1973.*

University of Oklahoma. The Science and Public Policy Program. *Energy Alternatives: A Comparative Analysis.* Washington, D.C.: U.S. Government Printing Office, May 1975.

Young, Gordon. "Will Coal be Tomorrow's 'Black Gold'?" *National Geographic Magazine* August, 1975: 234-259.

V. TRANSPORTATION AND STORAGE

Transportation

The cost of transportation is a large part of the total cost of delivering clean energy from coal. Raw coal is moved from the mine to either its consumption point or a processing facility by rail, barge, truck, or slurry pipeline. Coal transport expansion will depend heavily upon assurance of continued traffic over the investment period This expansion of transportation capabilities will hinge in large measure upon the ability of coal producers and consumers to secure long-term markets for coal.

An in-mine transportation system, in addition to the movement of coal from the face to the outside of the mine, must also move supply materials to the inside; it must move men in and out of the mine, and it must move rock and other debris out of the mine for disposal. Selection of the transportation system must be based on the seam height, mining methods used to extract the coal, capacity required, ease of coal handling and haulage efficiency. Possible in-mine systems include:

- Rubber-tired units (scoops, articulated haulers, shuttle cars, tractor trailers)
- Conveyor units (chain, shaker, belt)
- Rail shuttle cars.

The river barges, Great Lakes freighters, and intercoastal freighters of the waterway system provide low cost delivery of coal to distant markets which are beyond economical reach by rail or truck. Coal is the largest commodity movement on the inland waterway system, a network of over 25,000 miles of navigable waterways.

Slurry pipelines are used to transport crushed coal suspended in water. The major advantage of slurry pipelines for transporting coal long distances is low operating cost. The major disadvantages are high capital costs and substantial water requirements. However, once constructed, slurry pipelines are relatively inflation resistant, dependable, environmentally acceptable, and able to move large volumes of material with a minimum of disruption.

Three types of trains are used in transporting raw coal: conventional trains, unit trains, and dedicated railroads. When conventional trains are used, cars carrying coal are treated like other cars. Unit trains are made up entirely of cars carrying coal. A dedicated railroad links a mine to a single source user when an existing railroad is not available.

In order to take advantage of reduced transportation rates on train-load shipments of coal offered by unit train movement, operators have found that storage is an economic necessity. In unit train practice, large predetermined quantities must be loaded in relatively short periods of time as opposed to conventional practice where coal is loaded at a speed dependent on the production capacity of the mine and/or the cleaning capacity of the preparation plant.

An alternative to transporting coal is to generate electricity at a site distant from the demand and to transmit electric power. Generally, on a cost-per-energy unit basis, electricity is more expensive to transport than coal, especially over long distances. Also, transmission line losses can be substantial, amounting to as much as 10 percent of the line loading per 100 circuit miles of transmission.

Storage

Coal can be stored at the mine mouth, at a preparation plant, and at the user's plant.

Raw and clean coal storage is generally practiced in order to accomplish one, or a combination, of the following objectives:

- To improve plant efficiency by distributing plant feed over the entire operating time, or to allow a preparation rate different from the production rate.
- To allow mine and plant to function independently with delays in one not affecting the operation of the other.
- To reduce the number of plant shifts worked as compared to mine shifts with resultant lower preparation costs (unless plant size becomes uneconomical).
- To schedule overall production so as to obtain lower cost by working more days with smaller crews (steady employment, not seasonal).
- To store certain sizes whose prices and market demand fluctuate with seasons and to permit shipping in good weather.
- To keep coal on hand for the domestic and truck trades.

- To facilitate blending (on the raw coal side) in order to even out chemical and physical inconsistencies in plant feed so as to utilize cleaning equipment to greatest efficiency and (on the clean coal side) to prepare desired products or to attain maximum product uniformity.
- To promptly and economically load unit trains.

Coal may be stored in open or closed storage facilities. Large quantities of coal may be kept in open storage, but the coal is then subject to weathering and oxidation, which can reduce the heating value up to 5 percent the first year, and may also affect the coking properties of the coal. Further, unless the stockpile has adequate ventilation hot spots can develop leading to spontaneous combustion. Three basic open storage stockpiling configurations are: (1) conical shaped (most common), (2) wedge shaped (large capacity), (3) kidney shaped (large capacity, minimal area requirements, simplified handling).

Closed storage facilities, while limited in capacity compared to open storage, reduce weathering effects and combustion hazards and require less land area for storage. A typical cylindrical steel storage bin may have a capacity of 1000 tons. Steel storage bins allow uniform movement of hopper cars through a loading station. Precast concrete silos are less expensive and can have greater capacity than the steel bins. Multiple silos offer considerable flexibility for blending and loading out.

TRANSPORTATION AND STORAGE BIBLIOGRAPHY

Bechtel Corporation. *Clean Coal Energy: Source to Use Economics Phase I Report.* Washington, D.C.: U.S. Government Printing Office, 1975.

Bucklen, O. B., and Meikle, P. G. "Coal Storage and Loading." *Coal Preparation.* Edited by Joseph W. Leonard and David R. Mitchell. 3rd ed. New York: The American Institute of Mining, Metallurgical, and Petroleum Engineers, Inc., 1968.

Draper, John C. "Transportation." *Elements of Practical Coal Mining.* Edited by Samuel M. Cassidy. Baltimore: Port City Press, 1973.

Hearings. U.S. Congress Committee on Interior and Insular Affairs. Statement by Robert V. Price, Executive Vice President of the National Coal Association. 93rd Cong., 2nd session, June 11, 1974.

National Petroleum Council. *U.S. Energy Outlook: Coal Availability.* E. H. Reichle, Chairman. National Petroleum Council, 1972.

Task Force Report–Coal. Thomas V. Falkie, Chairman. Washington, D.C.: U.S. Government Printing Office, 1974.

University of Oklahoma, Science and Policy Program: *Energy Alternatives: A Comparative Analysis.* Norman, Oklahoma: University of Oklahoma, 1975.

VI. COAL PREPARATION

The electric utilities and most conversion processes are equipped to handle coals with specified physical properties. Coal preparation involves mechanical cleaning and sizing, usually carried out in a water medium. A prepared coal has a lower moisture and ash content and, to some extent, a lower pyritic sulfur content than raw coal. The overall result is a coal product with more nearly uniform physical properties and a higher calorific value.

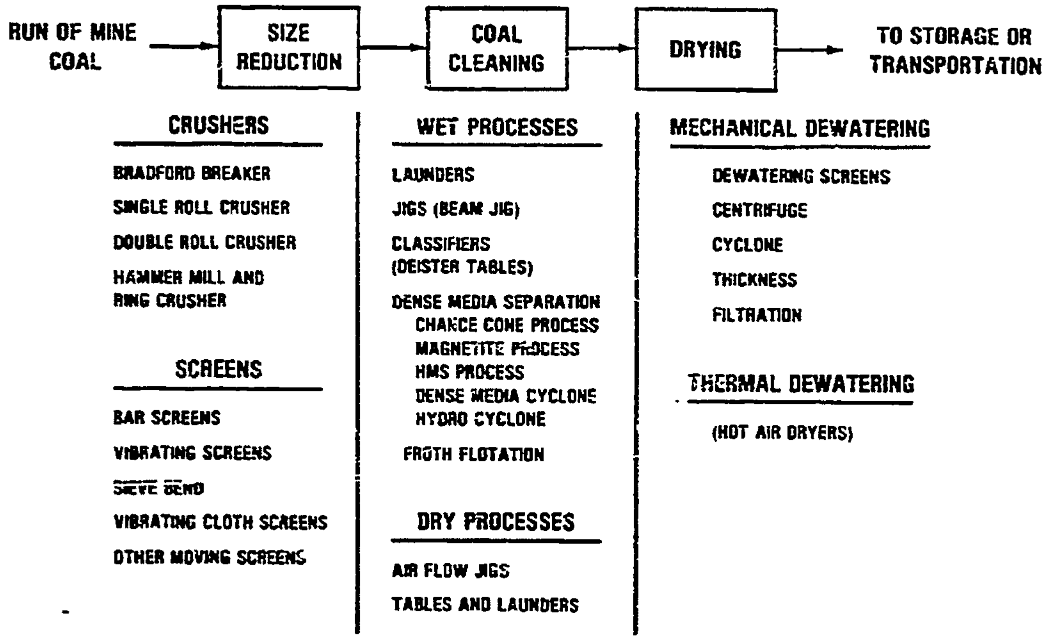
Major unit operations performed in the coal preparation plant are indicated in Figure VI-1. The basic preparation plant operations are:

- Size reduction (breaking and crushing)
- Screening
- Coal cleaning by wet and dry processes
- Drying.

In addition to these major operations, sometimes coal is cleaned at the mine face as well as subjected to in-plant raw coal preparation. Some of the special treatment, such as dedusting, dustproofing, and freeze proofing are also applied for better utilization of coal.

Size Reduction

There are two primary objectives in crushing coal. One is to reduce run-of-mine lump to sizes suitable for cleaning or further reduction; the other is to reduce the coal to market sizes. A primary breaker, such as the Bradford breaker, reduces the raw coal to a top size of from four to eight inches for washing or other preparation purposes. Primary breaking may occur at the mine or at a preparation plant. Secondary crushers reduce the size of products received from the washers or primary breakers to sizes from 1½ inch to 1 3/4 inch and smaller sizes. Crusher types include the single-roll crusher, double-roll



NOTE: ANY ONE OR MORE OF THE ABOVE CRUSHING, SCREENING, CLEANING AND DRYING DEVICES ARE USED IN VARIOUS PARTS OF PREPARATION PLANT DEPENDING ON THE EXTENT OF PREPARATION REQUIRED

Figure VI-1. COAL PREPARATION PROCESS FLOW DIAGRAM

crusher, and hammer mill and ring crushers. Closed circuit crushing is a means of controlling the product top size by screening the product and returning the oversize lumps to the feed end of the machine for further crushing.

Screening

Screening may be performed wet or dry. In dry screening, the ambient fluid in the process is air. In wet screening, water is commonly used, but other liquids may be used occasionally. Screens are used in all phases of coal processing. Their uses include presizing to the crusher (run-of-mine scalper), sizing the coal from the crusher (raw coal screens), pre-wetting the coal for wet cleaning processes and for draining, rinsing, dewatering and classifying functions.

Screens used in preparation of coal may be stationary or moving. Moving screens may shake or vibrate and surfaces may consist of parallel bars, punched steel plates, or woven wire cloth with square or rectangular openings. In fine coal screening, screen blinding occurs which obstructs separation. Blinding may be cleared by heating the screen to 150° F by electric resistance.

Coal Cleaning

Coal cleaning begins at the mine face where, during manual cutting and loading, the miner can distinguish between coal and rock and discards accordingly. Cleaning at the mine face is greatly facilitated by mechanical mining methods. Tramp iron can be removed by magnets. Raw coal blending is generally practiced where a high degree of product quality control is necessary.

Wet Cleaning Processes

The wet processes utilize several well-known types of equipment for coal cleaning. They are further divided according to process characteristics and principles of operations.

- Launders
- Jigs
- Classifiers or concentrating tables
- Dense media separation processes
- Froth flotation

The Rheolaveur process is typical of the launder type. It consists of two parts, a short steeply inclined section at the coal-and-water inlet end and a longer more gradually sloped section beyond. In the gradually sloped section, the velocity decreases and the heavy particles settle to the bottom of the trough where they are removed through two or more Rheo boxes. The difference in velocity between the bottom and top of the stream keeps the impurities below and the coal above the settling velocity; hence, the coal is carried through the launder with the water stream. In the case of pneumatic launders (dry processes), air is used instead of water.

Jigging is a process of particle stratification in which the particle rearrangement results from an alternate expansion and compaction of a bed of particles by a pulsating fluid flow. In the Baum type jig, the water is moved by air pressure. Other well known jigs are the Feldspar jig for fine coal washing and the Tazub jig. In Germany, the Tazub jig is replacing the Baum jig because of its better performance.

In the many forms of classifiers, the principle of free and hindered settling in water is applied to obtain classification. The feed coal is immersed in a flowing current of water (usually upward) with a velocity greater than the settling velocity of the low-gravity fractions–the coal, and less than the settling velocity of the high-gravity fractions–the refuse, which separates the coal from the refuse. Classifies are suitable for a wide variety of coals, but efficient operation usually requires careful sizing of the feed coal.

Deister tables apply differential motion to impart a conveying action to the table. The fundamental effect of this motion is to make the table deck approach its reversing point and recede from it with greater speed at one end of its travel than at the other. The material to be treated is fanned out over the table deck by the differential motion and gravitational flow. The water flows from top to bottom by cross flow. Coal middlings and refuse are separated by gravitation and stratification principles.

Dense medium separation includes those coal preparation processes which clean raw coal by immersing it in a fluid having a density intermediate between clean coal and reject. Categorically, four types of separating media have been used commercially: organic liquids, dissolved salts in water, aerated solids, and suspensions consisting of fine solids suspended in water. Commonly utilized dense media gravity separation processes are Belknap chloride process, Chance Cone process, Magnetite process, heavy media separation process, dense media cyclone, dynawhirlpool vessel, and hydrocyclone.

Froth flotation is a chemical process. Fine coal is mixed with water in a flotation cell containing flotation agents such as frothers, collectors or modifying agents to improve froth flotation. Finely disseminated air bubbles are passed through the slurry. Air adhering coal particles are separated from nonadhering refuse particles. Coal floating on the surface is removed, washed, and dried.

Most froth flotation circuits in domestic coal preparation plants are relatively simple. The slurry generally comes to the froth cells directly from the dewatering screen or sieve bed underflow or from the classifier tank overflow. The flotation cells used in the industry are Wemco cells, Heyle and Patterson Cyclo-cell, and Denver cells.

Dry Cleaning Processes

Pneumatic or dry processes are generally applied to coal one-half inch or less in size. Dry processes do not contribute to stream pollution as may water cleaning techniques. Air particulate emissions are minimized by using cloth filters and no thermal or chemical pollution of air results. The air machines are pneumatic jigs, pneumatic tables and pneumatic launders. In case of pneumatic tables similar to the Deister table, air is admitted through holes in the table and is blown up through the bed of coal. The motion of the table plus the air flow segregates the coal and impurities.

Drying

Coal needs to be dried for one or more of the following reasons: (1) to avoid freezing during transportation, (2) to reduce heat loss in the burning processes, (3) to decrease transportation cost.

Mechanical drying (dewatering) refers to the processes used with wet cleaning of coal. Different types of equipment are used to dewater different sizes of coal. Material greater than one-quarter inch, for example, can be dewatered by shaker screens, high speed vibrating screens (not used below three-eighth to one-quarter inch) and possibly stoker centrifuges for the finer sizes of coal. At the fine size level, centrifuges are used almost exclusively in the 0.5 to 1 mm size range. Solid bowl centrifuges can be used on sizes smaller than 0.5 mm. The disc filter is used mainly for dewatering coal. With the aid of flocculants, fine coal is dewatered very quickly.

Thermal dewatering is used to remove final water content or the moisture of the coal. This method may be used in coal preparation plants or in coal processing plants. All industrial coal dryers now in use are the continuous direct contact type which employ convection as the major principle of heat transfer. Thus, hot gases and wet coal are brought into intimate contact with each other on a continuous gas flow-coal feed basis. The six basic dryer types are (1) fluidized bed, (2) suspension or flash, (3) multi-louvre, (4) vertical tray and cascade, (5) continuous carrier and (6) drum type.

Special Treatment and Miscellaneous Processes

Dedusting, dustproofing, and freezeproofing are examples of special coal treatment. Degradation of coal in screening, handling, and shipment may increase the percentage of dust. Both wet and pneumatic cleaning provides dedusting. Air passes through the coal and entrains a large percentage of fines which can be recovered from the air with cyclone separator and bag filters. Water, and sometimes small amounts of commercial wetting agents, are added to reduce dustiness. Oil and calcium chloride are commonly used for dustproofing coal at the mine. An oil film causes dust to adhere to the large pieces of coal. Calcium chloride absorbs moisture from the air providing a wet surface to which dust adheres. The chemical additives usually used to prevent freezing of wet coal during shipment are calcium chloride and rock salt. Occasionally the car hoppers are heavily sprayed with oil for freezeproofing coal.

COAL PREPARATION BIBLIOGRAPHY

Babcock and Wilcox Co. *Steam: Its Generation and Use.* 37th ed. New York: The Babcock and Wilcox Co., 1963.

Leonard, Joseph W., and Mitchell, David R., eds. *Coal Preparation.* 3rd ed. New York: The American Institute of Mining, Metallurgical and Petroleum Engineers, 1968.

Lovell, Dr. Harold. "Coal Preparation." Prepared for the *C. E. Tyler Desulfurization Seminar*, 12 February 1975.

VII. COAL PROCESS TECHNOLOGY

FUNDAMENTALS OF COAL CONVERSION PROCESSES

Figure VII-1 is a generalized flow chart depicting the various coal conversion possibilities. Essentially, liquid or gaseous fuels are produced by decreasing the carbon to hydrogen ratio of solid coal. The raw products are desulfurized, de-ashed and further processed resulting in a wide range of clean fuels from coal.

Low-Btu gas, with a heating value of 100 or 500 Btu per cubic foot, is suitable for use as a fuel feedstock or for power generation in combined gas-steam turbine power cycles. On an equivalent Btu basis, conversion of coal to low-Btu gas is less complex with lower capital costs than conversion to high-Btu gas. Low-Btu gas can be produced at a competitive cost if the low-Btu gasifier is built on the premises of a power generating station, eliminating long-distance pumping costs.

Medium-Btu gas is usually a feed gas for production of high-Btu gas. High-Btu gas from coal, with a heating value of 950 to 1000 Btu per cubic foot, can be substituted for natural gas, which is a widely used heating fuel and industrial feedstock. Natural gas, composed essentially of methane, is virtually free of sulfur and contains essentially no carbon monoxide or free hydrogen. The conversion of coal to high-Btu gas requires a major chemical and physical transformation of solid coal to produce a pipeline quality substitute for natural gas.

Techniques for converting coal to synthetic liquid fuels, originally developed in the early 1930's, are being improved to increase the supply of nonpolluting liquid fuel and to produce a more easily transportable and usable fuel. Current emphasis is being placed on the development of fuels suitable for firing industrial and electric utility boilers and gas turbines. Modern improvements are providing better catalysts, better reactor designs, and better construction materials, leading to more attractive processing economics and lower capital investment. Coal liquefaction can now be achieved under more moderate processing conditions and more rapidly than was the case in the early 1930's. The advantage of coal liquefaction is that the entire range of liquid products, including fuel

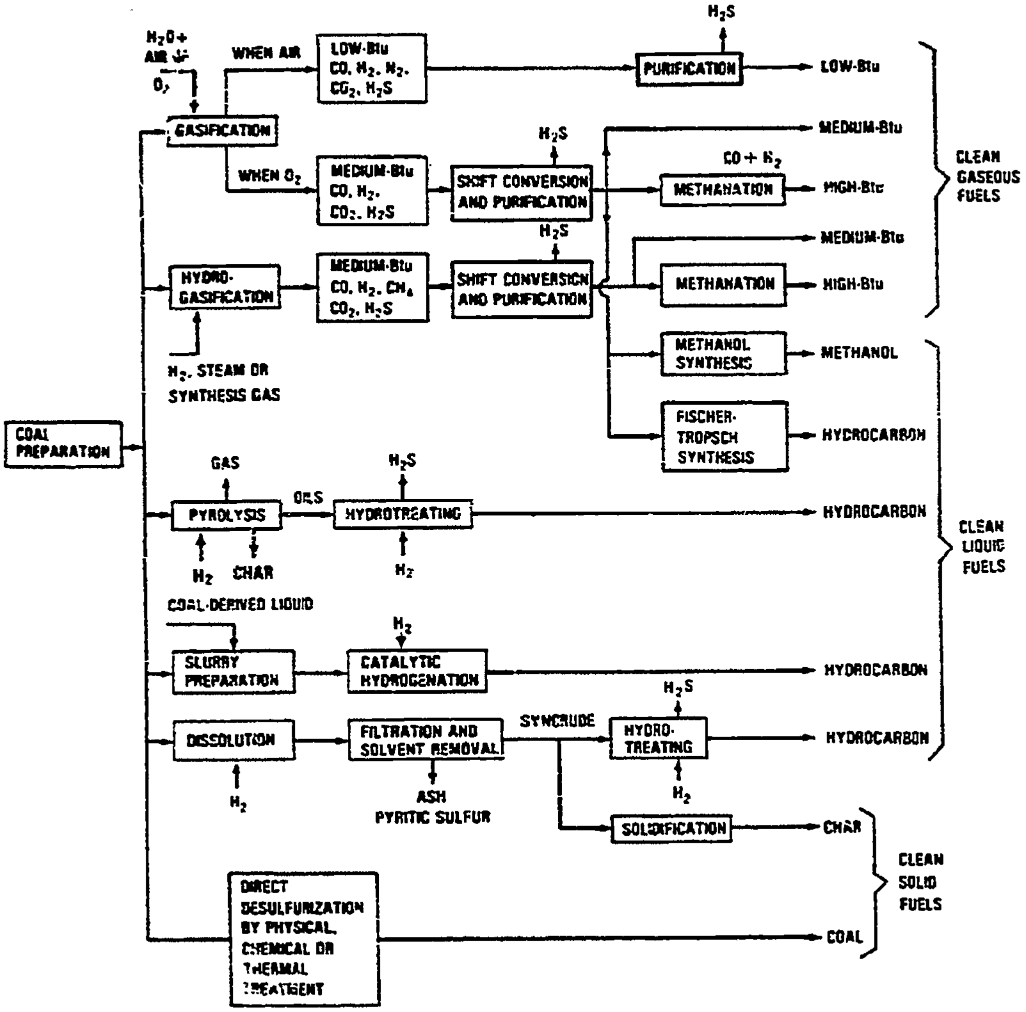


Figure VII-1. CLEAN FUELS FROM COAL

oil, gasoline, jet fuel, and diesel oil, can be produced from coal by varying the type of catalysts and other operating conditions. Conversion processes currently under development may produce clean solid fuels as well as liquid fuels.

The technologies for producing clean gaseous, liquid and solid fuels from coal are described in detail in this section. Chemical reaction equations indicate the predominating reactions and the favored reaction direction.

Coal has a carbon to hydrogen (C/H) weight ratio ranging from 12 for lignite to 20 for bituminous grades. Either by addition of hydrogen or by rejection of carbon, the C/H ratio can be lowered to 10 to produce the heavier, by molecular weight, synthetic crude liquids. Increasing the volume percent of hydrogen yields progressively lighter, by molecular weight, fractions. As the C/H ratio decreases to 3, methane gas can be formed:

$$CH_{0.8} + 0.4\,H_2 \rightarrow CH_{1.6} + 1.2\,H_2 \rightarrow CH_4$$

	Coal	Liquid	Gas
C/H Ratio:	15	10 to 6.5	3

Hydrogen to support these reactions is typically produced by reacting steam with char:

$$C + 2H_2O \rightarrow 2H_2 + CO_2$$

Gasification

As indicated in the upper half of Figure VII-1, the initial step in conversion to gas may be either simple gasification or hydrogasification. The former involves primarily the direct reaction of steam with coal. Heat to support this reaction is generally furnished by combustion of char by-product with air or oxygen.

The reaction of carbon with steam producing carbon monoxide and hydrogen is endothermic:

$$C + H_2O \rightarrow CO + H_2 \qquad \text{(steam-carbon reaction)}$$

The above reaction does not occur unless the required heat is supplied by burning some of the coal or char, which produces the following reactions.

$$C + O_2 \rightarrow CO_2 \qquad \text{(combustion reactions)}$$

$$CO_2 + C \rightarrow 2CO$$

$$CO + 1/2\,O_2 \rightarrow CO_2$$

If air instead of oxygen is used, N_2 will appear in the raw gas limiting its heating value. The product gas will also contain sulfur oxides and other pollutants which must be removed. The resulting low-Btu gas can then be burned in a power plant. Alternatively, for production of high-Btu gas, oxygen rather than air supports combustion and the H_2/CO ratio is adjusted as required by a water gas shift reaction:

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \text{(water-gas shift reaction)}$$

Following the water gas shift reaction both sulfur (in the form of H_2S) and CO_2 are removed by acid gas cleaning. The gas containing CO and H_2 is subjected to methanation or hydrocarbon synthesis. One mole of carbon monoxide reacts with three moles of hydrogen and produces methane and steam.

$$3\,H_2 + CO \rightarrow CH_4 + H_2O \qquad \text{(methanation reaction)}$$

Steam is condensed to water and removed resulting in a high-Btu, methane-rich product.

In hydrogasification, conversion is effected by bringing hydrogen produced elsewhere into contact with coal. More methane is produced directly with hydrogasification than by steam-oxygen gasification. The fundamental hydrogasification reaction is:

$$2CH_{0.8} + 1.2\,H_2 \rightarrow CH_4 + \underset{\text{(char)}}{C}$$

Therefore, for production of high-Btu gas, less additional methanation is required. The required hydrogen can be produced in a steam-oxygen gasifier (as in the HYGAS process) by gasifying the char products:

$$2C + H_2O + O_2 \rightarrow CO + H_2 + CO_2$$

$$CO + H_2O \rightarrow CO_2 + H_2$$

Modern coal gasification processes utilize hydrogasification directly in the primary gasifier. The heat released by methane formation is used in steam carbon reactions to produce hydrogen. Consequently, less O_2 is required to produce heat than for the steam-carbon reactions and less heat is lost in the low temperature methanation step. These factors lead to higher overall conversion efficiencies of 65 to 70 percent in contrast to 50 to 55 percent by synthesis gas plus methanation.

By eliminating the shift conversion and methanation steps, the gas produced by hydrogasification is a medium-Btu gas. This gas can be used as a fuel for power or for steam generation on site. The product gas could also be used to produce methanol and hydrocarbon liquids. Therefore, a combiantion of processes for utilizing the medium-Btu for high-Btu gas production while producing liquids has been proposed.

Liquefaction

As indicated in the lower half of Figure VII-1, production of clean liquid fuels from coal is carried out by four principal processes.

- Hydroliquefaction (direct catalytic hydrogenation)
- Solvent extraction (noncatalytic liquid phase-dissolution)
- Pyrolysis
- Liquid hydrocarbon catalytic synthesis (Fischer-Tropsch)

In the first process, diagrammed in Figure VII-2, pulverized coal is slurried with coal-derived recycle oil, mixed with hydrogen and fed to a reactor operated at moderate temperatures (850° F) and high pressures (2000 to 4000 psia). One of the best catalysts is cobalt molybdate. Other catalysts, such as tungsten and molybdenum sulfide and an impure iron oxide (Bayermasse) also are useful but require higher pressures. In recent years processes using entrained, fluid bed or fixed bed catalysts have been proposed.

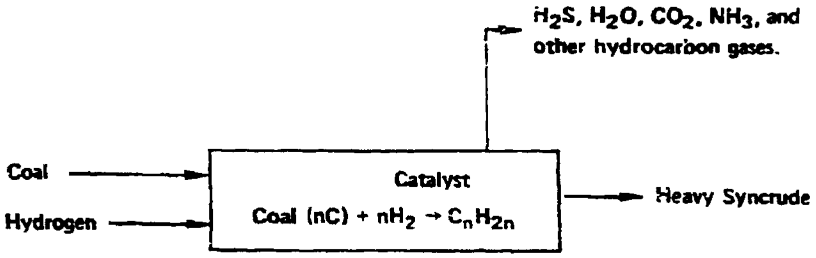


Figure VII-2. CATALYTIC HYDROGENATION

In this catalytic hydrogenation process, the sulfur in the coal is converted to H_2S, the oxygen to H_2O or CO_2, and the nitrogen to NH_3. These compounds leave with the gas stream. The coal is converted to liquids ranging from heavy to light oils and gases: however, the main product is liquid.

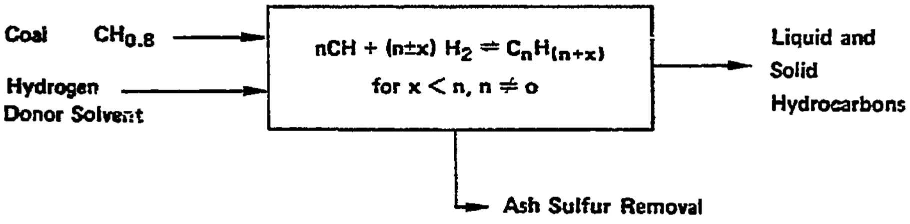


Figure VII-3. SOLVENT EXTRACTION

The second method, diagrammed in Figure VII-3, is the solvent extraction of coal. In this process, coal is partially dissolved in a hydrogen-rich solvent and the undissolved solid is filtered out. The solvent is recovered from the high boiling product and recycled to the dissolver. The carbonaceous solids are reacted with steam to produce hydrogen. Ash, containing pyritic sulfur, is also removed at this stage. Hydrogenation of the excess solvent produces liquid fuels.

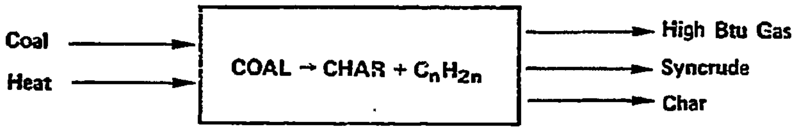


Figure VII-4. PYROLYSIS

The third method to produce clean liquid fuels, diagrammed in Figure VII-4, uses pyrolysis of coal to recover products by the application of heat without direct addition of hydrogen. In this process, most of the carbon is rejected as a solid. Liquids and gases containing a lower C/H ratio than the original coal are recovered. Pyrolysis processes produce significant quantitites of by-product gas and char which must be disposed of economically. The liquid product is further hydrogenated for desulfurization and quality improvement.

The quantities of gas, liquid and resulting char are dependent on the type of coal, the rate of heating, the nature of the gas atmosphere surrounding the coal and the ultimate temperature achieved. Yields of liquid are maximized by minimizing the time during which the product is exposed to elevated temperatures, thus avoiding further decomposition of the gas.

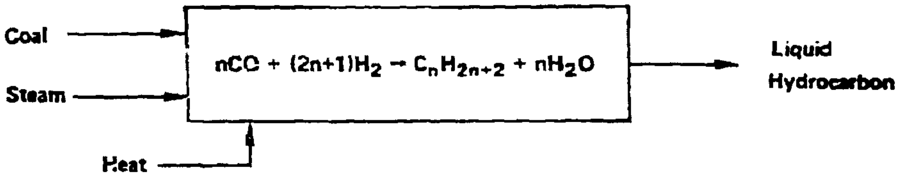


Figure VII-5. LIQUID HYDROCARBON SYNTHESIS

In the fourth method. diagrammed in Figure VII-5. a hydrogencarbon monoxide mixture (medium Btu synthesis gas) is produced from coal. Carbon monoxide and hydrogen react in the presence of the Fischer-Tropsch catalyst to produce a wide variety of liquid products. The yield of products, such as gas. LPG gasoline, kerosene, diesel fuel. fuel oil. wax oil, methanol and acetone is dependent upon the catalyst and operating conditions. The types of catalyst typically used are Fe, Co, Ni. Ru. ZnO and ThO_2. The behavior of these catalysts depends on the presence of chemical and structural promotors. on the procedure of catalyst manufacture, on catalyst surface conditions and on other factors.

The Fischer-Tropsch hydrocarbon synthesis process can also be used to produce methanol by employing special catalysts of the copper-zinc-chrominum and zinc-chromium-oxide types. The generalized reaction for methanol is:

$$CO + 2H_2 \overset{cat}{\rightarrow} CH_3OH$$

The rate of these reactions is higher at higher pressures. Operating conditions for methanol synthesis vary from 750 to 6000 psig and from 500° to 800° F depending on the catalyst and desired yield per pass. Higher temperatures and presures increase the side reactions and produce other materials such as ethers and heavier alcohols in the crude methanol stream. Crude methanol can be further distilled to produce chemical grade methanol.

Clean solid fuels can be produced by dissolution and limited hydrogenation. The solid fuel is produced when the syncrude is allowed to cool before the hydrotreating step. Direct desulfurization of coal by physical, chemical or thermal treatment will also produce a liquid fuel.

Byproducts

In the production of clean gaseous. liquid or solid fuels from coal. various byproducts are produced depending on the processing method. operating conditions and composition of the coal. Some of the byproducts produced are light aromatics, oils and tars, ammonia, hydrogen sulfide, sulfur dioxide, phenols and cresols, nitrogen oxides, traces of hydrogen cyanide, char, and ash. Plant designs will provide for recovery of the byproducts where economical or for environmentally satisfactory methods of disposal.

GENERALIZED GASIFICATION PROCESSES

As illustrated in the process flow diagrams of Figure VII-1, the methods for producing high-Btu and low-Btu gases are similar. The essential differences are that air is used instead of oxygen to produce low-Btu gas and that no shift conversion or methanation steps are required. A brief explanation of each process flow step follows.

Coal Preparation and Pretreatment

For most processes, the coal will be ground to a relatively fine size. Some processes require lump coal and will not accept coal fines (less than 1/8 of an inch); briquetting of the fines may be necessary.

If the coal used as feed material is of a rank or grade which would cake or agglomerate in the gasifier, a pretreatment step is usually necessary. Pretreatment of coal means a partial devoliatilization and oxidation of the coal particle surface with steam and oxygen, a reaction which results in a loss of a significant amount of potentially valuable volatile matter in the coal. Lignite, which does not agglomerate, requires no pretreatment before the gasification step. Certain gasifier reactor designs, such as the entrained reactor and the free-fall reactor, also eliminate the requirement to pretreat bituminous coal.

There are essentially three types of pretreaters: fixed bed, free fall, and fluidized bed. In the fixed bed pretreater, the temperature is about 800° F and the pressure is approximately 325 psig. The units are pressurized by the steam-oxygen mixture. In the free-fall pretreater, the temperature is 1100° F and the pressure is 300 psig. Coal is dropped through a countercurrent flow of steam containing 5 to 12 percent oxygen by volume. The oxygen to coal ratio varies about 2.4 scf per pound of coal. The residence time is approximately 2 seconds. If the oxygen is insufficient or the reaction temperature is too low, the coal will agglomerate and plug the treater. In the fluidized bed pretreater, used to treat caking coal, oxygen mixes with steam or inert gases such as nitrogen and carbon dioxide. The temperature range is approximately 700° to 775° F.

Since pretreatment is an oxidation reaction, the amount of oxidation is proportional to the length of pretreatment. Minimum pretreatment which allows production of a noncaking coal retains about 26 percent volatile matter in the pretreated char.

Coal Feeding

In most gasification processes, the reactions are carried out at high pressures, which, for continuous processing, means that the coal feedstock must be introduced under pressure. This can be accomplished in several ways, including pressurized lock hoppers, mechanical (auger) feeding, or wet feeding. In wet feeding, coal is slurried and pumped under pressure and then dried immediately prior to the gasification process. The gasification pressures range from about 100 psig to over 1000 psig.

Gasification

If the feed coal is not devolatilized in pretreatment, it is usually devolatilized as it is fed into the low temperature zone of the gasifier (near the top of the gasifier vessel). The coal begins to form char as it is heated and then is mixed with steam to form carbon monoxide and hydrogen, which are essential to forming either low-Btu or medium-Btu product gases. The steam-carbon reaction is favored at temperatures above 1700° F. The exothermic water-gas shift reaction will also occur in the gasifier to some extent. To a lesser degree, hydrogasification will occur producing small quantities of methane ($C + 2H_2 \rightarrow CH_4$). In some processes, the char which results from these three gasification steps eventually falls to a combustion zone where it reacts with oxygen. The combustion heat supports the endothermic steam-carbon reaction. Although direct heating is more thermally efficient than are indirect heating methods, the removal of CO_2 in the effluent requires more extensive purification systems.

If air rather than oxygen supports combustion in the gasifier, small quantities of nitrogen-oxides (NO_x) are formed and large quantities of nitrogen accumulates in the product gas. Unless combustion heat is transported to the gasifier indirectly, the nitrogen from combustion will be in the raw product gases which will limit the heating value of the final product gas. Consequently, air is used where only low-Btu gases are to be produced; however, oxygen is usually required for producing high-Btu gases. Because oxygen is an expensive feed material, some high-Btu gasification processes are attempting to develop indirect heating techniques.

Indirect heating techniques involve sensible heat carriers such as pebbles, or molten slag. Dolomite (limestone) solids or molten salt may transfer latent heat to the gasification process.

Gas Cleaning

In general, most gasification processes have a particulate and tar removal step. This step usually involves direct water quenching or scrubbing the raw gas, followed by the use of cyclones, sand filters, or electrostatic precipitators. The bulk removal of oils and water is accomplished by quenching or cooling, during which heavy oils are completely removed with a large fraction of the light oils. The remaining light oil fraction in the gases is absorbed by solid absorbents. Also, some of the ammonia produced in the gasification step can be recovered in the condensed water phase.

Shift Conversion

Medium-Btu gases from the gasifier are cooled to approximately 800° F and sent to a shift converter. Iron-chromium oxide compounds are used as catalysts for shift conversion. The 3:1 H_2/CO composition of the gases from the shift converter may then be purified and methanated for high-Btu gas production.

The fundamental shift conversion process may also be used to produce hydrogen rich gases for hydrogasification or to produce methanol. The H_2/CO ratio is adjusted to 2:1 if methanol is to be produced.

Gas Purification

The purification of the gas coming from the shift converters is essential, not only from the pollution point of view, but because it enhances the high caloric value required for pipeline quality gas. Carbon dioxide adds nothing to the heating value of the final gas and should be removed before methanation. The methanation catalysts, usually containing nickel compounds, are extremely sensitive to any contaminating sulfur.

Gas purification processes generally fall into one of three categories: absorption into a liquid chemical, conversion to another compound, and absorption on solids. In order to economically remove CO_2 and H_2S from the gas stream, a combination of the three methods is normally used. Gas coming from the shift converter is passed through a hot potassium carbonate process, or through a monoethanolamine (MEA) process and finally, an activated carbon tower. Because of its lower heat requirement and better operating flexibility, the hot potassium carbonate process is more economical than the MEA process and is therefore usually preferred.

Heat and energy recovery units, such as turbines, aid in increasing the operating efficiency of this system. The CO_2 and H_2S removed by the first two purification processes are sent to sulfur-recovery plants where, depending on the concentration of H_2S, sulfur in the elemental form is recovered either by the Claus Process followed by a Stretford Process or by a Stretford Process alone. The process effluent gas contains less than 1.5 percent of CO_2 by volume, and less than 0.1 grain of H_2S per 1000 scf.

Methanation

The methanation step is of considerable importance to coal gasification because it accomplishes two things. First, it converts a mixture of gases of relatively low heating value into methane, which is compatible in physical properties and heating value with natural gas, and second, the methanation step reduces the carbon monoxide content to a nontoxic level.

A 3:1 volume ratio of hydrogen to carbon monoxide is methanated in the presence of a nickel based catalyst at approximately 600° F. This reaction is highly exothermic by nearly 53 kcal/gm mole of converted CO leading to approximately a 140° F temperature increase for each one percent CO converted. An efficient heat-removal system is required to maintain characteristic methanation temperatures since higher temperatures would spoil the catalyst. Typical dry compositions of a raw gasifier product, methanator feed (medium-Btu gas), and methanator product are shown below for the Synthane process.

	Gasifier Product	Methanator Feed	Methanator Product
H_2	23.62	45.05	1.79
CO	15.23	14.68	0.10
CO_2	34.93	0.97	1.74
CH_4	23.09	35.44	91.90
C_2H_6	0.74	1.14	–
N_2	1.67	2.58	4.47
H_2S	0.74	–	–

The compositions in other coal gasification processes are similar. Ru, Co, Mo, and Fe are other important commercial methanation catalysts.

Reactor Types Used in Gasfication Processes

A coal gasifier reactor must be designed to carry out a chemical reaction under controlled operating conditions. This necessitates intimate mixing between the chemical reactants, the removal of product gases and by-product ashes, and the regulation of temperatures during these processes. Gasifiers can be placed into three general categories: fixed bed, fluidized bed, and entrained flow.

The difference in the design of individual gasifier reactors can be best characterized by the magnitude and direction of movement of the coal particles. In a fixed-bed reactor the gas velocity is relatively low and the solid particles remain stationary. If the gas velocity is increased, the drag forces on the particles will equal the gravitational forces on the particles. At this point, the bed expands and the distance between the particles becomes significantly greater. The particles also acquire a rapid random velocity throughout the reactor which makes the reactor appear like a container of rapidly boiling liquid and for this reason is referred to as being *fluidized*. Because the particles are in such violent motion and mix in all directions, such a reactor is frequently referred to as a stirred reactor. If the gas velocity into the reactor is increased to even higher values, then the interface between the bed and the gas above it disappears. The distance between the particles increases significantly and the particles experience practically no interaction. This condition is referred to as entrained flow because the particles are merely swept along by the high velocity gas stream.

Fixed Bed Reactor

A fixed bed reactor is generally a cylindrical structure with a metallic grid or grate at the bottom to support the bed of coal. The grate is generally mounted a short distance above the bottom of the reactor and serves two purposes: (1) it promotes an even distribution of reacting gases across the radial distance of the reactor, and (2) it provides a means of drawing ash off the bottom of the bed. The coal particle size is generally larger, ranging up to six inches, depending on the design of the reactor.

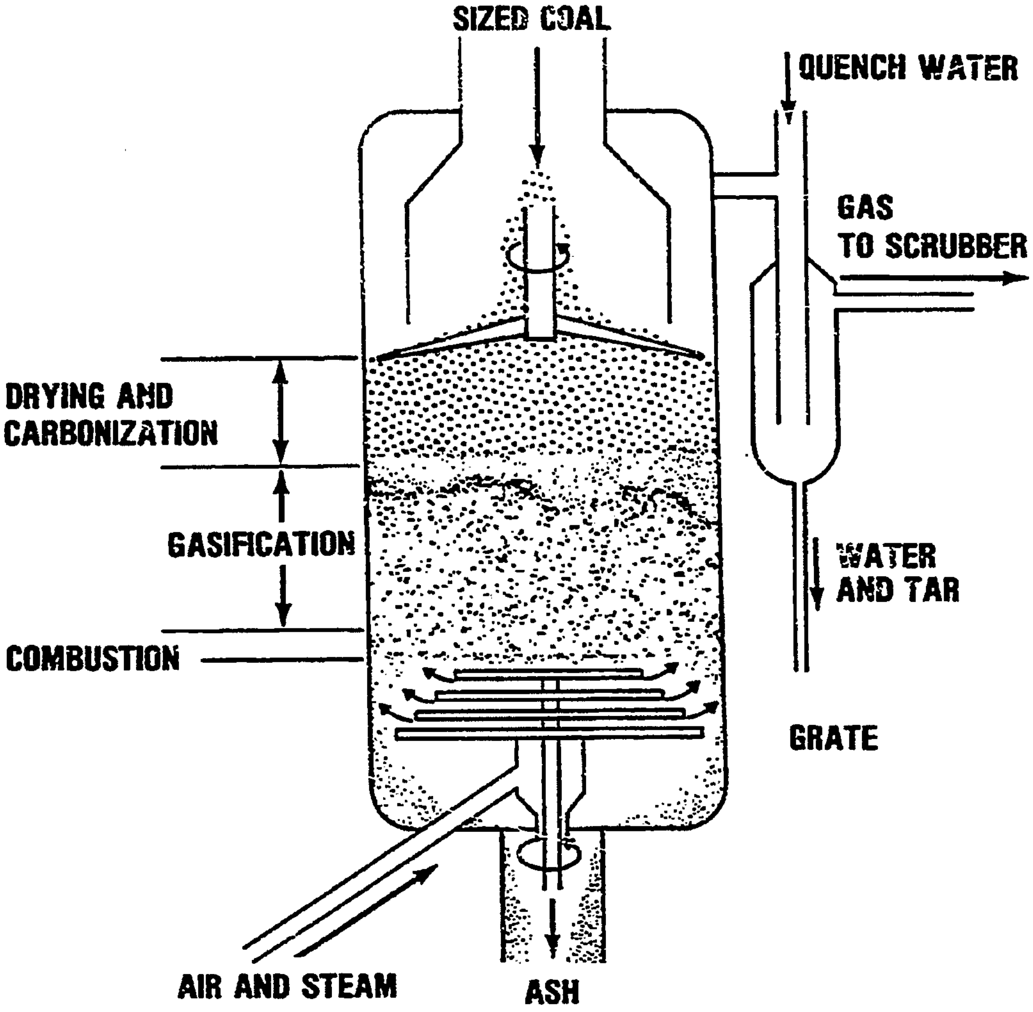
Early gasifier reactors did not operate continuously, but instead, operated in cycles. The first cycle, referred to as a blast, consisted of blowing air through the coal (or coke) bed in order to burn the fuel and heat the unburned fuel to reaction temperature. The second cycle referred to as the run, consisted of passing steam through the bed to react with the high temperature coal. When the endothermic reaction between steam and coal caused the bed temperature to fall below the necessary for the reaction, the steam flow was terminated and air was again blown through the bed.

From a operational point of view, continuous reactors are preferred. Consequently, over the years a wide variety of continuous reactors have been developed which permit continuous flow of coal input, reacting gases, and ash discharge. A typical continuous flow fixed bed reactor is illustrated in Figure VII-6. Here the raw coal is introduced at the top of the reactor and is spread uniformly by a rotating mechanical device. At this point in the reactor the temperature is relatively low and the feed coal is dried and devolatilized. Rotating grates at the base of the reactor allow continuous withdrawal of ash and consequently the gradual settling of the entire bed. Thus, the devolatilized particles settle toward the higher temperature zone in the base of the reactor where gasification occurs. The smaller particles are rapidly gasified and disappear, while the larger particles continue to settle deeper in the bed. At the bottom of the bed, air or oxygen and steam are blown up through the grate and the oxygen preferentially racts with the relatively large ungasified pieces of coal. The exothermic heat of this process produces the high temperatures needed in the gasification process which occurs immediately above this zone in the reactor.

Another variable in the design of fixed-bed reactors is the method of ash removal. Ash may be removed in either the solid form in a dry ash gasifier or the liquid form in a slagging gasifier. Dry ash gasifiers generally operate at temperatures of approximately 1800° F while slagging gasifiers must operate with the ash zone at approximately 3000° F to melt the slag. Molten ash is withdrawn continuously from the bottom of the unit. Slagging permits the gasification of lump coal at higher temperatures and offers better steam decomposition and higher throughput than nonslagging. Its disadvantages are those associated with higher temperatures and refractory erosion caused by the molten slag. Several slagging bed gasifiers have been built and operated abroad on a commercial scale, these include the Thyssen-Galoczy and Leuna-Wurth units. The fuel for these reactors has generally been coke or char. Further development will be required if this type of gasification is to be adapted to coal, particularly caking coal. The major fixed-bed reactor processes identified in Figure VII-6 are further described in Appendix A.

Fluidized-Bed Reactor

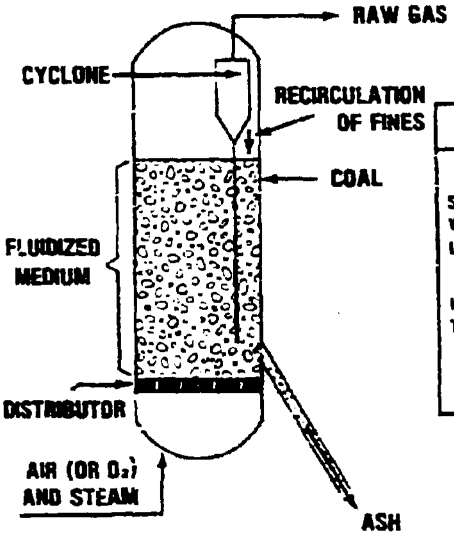
A fluidized-bed reactor is shown schematically in Figure VII-7. Prior to operation, the relatively fine grid distributor plate supports the pulverized solid material (coal or pretreated coal). Air or oxygen and steam enter at the base of the reactor and are forced up through the distributor under pressure. Above the distributor plate, the gaseous medium passes between bed particles forcing them apart and opening larger pathways through which to flow. The downward gravitational force of the particles becomes balanced by the upward drag force on the particles by the gaseous stream. In order for this balance to occur at reasonable gas velocities, small particles, 8 to 100 mesh, are used. At these sizes the weight of the individual particles is reduced and gas stream pathways are reduced which increases



MAJOR FIXED BED REACTORS
LURGI
GEGAS
STIRRED, FIXED-BED (BuMINES)
WELLMAN-GALUSHA

Source: Jaeger, Leigh, and Pegg, *1975 Pitt. Symp.*

Figure VII-6. TYPICAL FIXED-BED GASIFIER



MAJOR FLUIDIZED BED REACTORS

SINGLE STAGE	TWO-STAGE
SYNTHANE : DRY ASH	SELF AGGLOMERATING (BATTELLE)
WINKLER	CO_2 ACCEPTOR
U-GAS (ASH AGGLOMERATING)	COGAS
	ADVANCED SYSTEM (WESTINGHOUSE)
HYDROCARBONIZATION PROCESS*	COMBINED CYCLE (FOSTER WHEELER)
TOSCOAL PROCESS*	HYGAS
	HYDRANE (LOWER STAGE)

* FLUID BED PRE-HEATER IS USED AS A PRELIMINARY STEP TO LIQUEFACTION

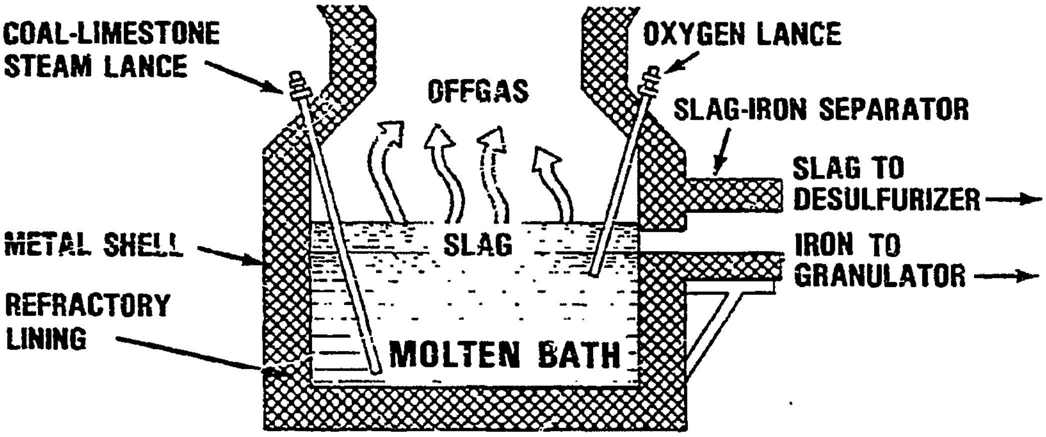
Figure VII-7. FLUIDIZED BED REACTOR

the drag force. Above the fluidized bed is a zone relatively free of particles. Here fine particles ejected from the bed have a chance to decelerate and return. An internal cyclone is usually used to remove any entrained particles and return them to the bed.

Because fluidization causes random motion of uniform particles, the temperature and composition of the bed are fairly uniform throughout. Reaction zones operating at different temperatures, analogous to those in the fixed bed reactor, may be established by using a series of fluidized reactors.

To prevent agglomerization, caking coal is pretreated in a fluidized bed where it is reacted with air at about 700° F to mildly oxidize its surface. The combustion and gasification of the coal may be carried out in a single stage fluidized bed reactor, or sequentially in a two stage arrangement. The specifics of the processes listed on Figure VII-7 are outlined in Appendices A and B. The locations at which steam, oxygen, and coal are added and the reaction conditions vary from process to process with temperatures ranging from 1200 to 1900° F and pressures from one to 100 atmospheres. Most processes are designed to separate the combustion and gasification reactions.

Some processes improve the efficiency of ash removal by carefully adjusting the bed to a temperature at which the ash just begins to melt. The ash particles then agglomerate as they interact with one another. The resulting increase in the ratio of the weight of the larger ash agglomerates to the drag force exerted on them causes the agglomerates to migrate to the bottom of the reactor for removal. This ash, which still contains some combustible material, is characterized as char and may be burned to produce heat for steam production or other process needs.



MAJOR MOLTEN BATH REACTORS

MOLTEN CARBONATE (M. W. KELLOGG CO.)
MOLTEN IRON (ATGAS)
MOLTEN SALT (ATOMICS INTERNATIONAL)
$ZnCl_2$ CATALYSIS (LIQUEFACTION)

Source: LaRosa and McGarvey, *1973 IGT Symp.*

Figure VII-8. MOLTEN-BATH REACTOR

Sulfur removal can be accomplished to a large extent by including limestone particles in the fluidized bed. The limestone reacts with sulfur from the coal, substantially reducing the suflur in the product gas.

The molten bath reactor, illustrated in Figure VII-8, is really a special case of a fluidized bed. The molten bath provides a well mixed medium in which combustion and gasification occur simultaneously. The molten medium, which can be a salt such as sodium carbonate, provides a means to transfer and store heat as well as to disperse the reactants. The medium may be reactive, catalytic, or passive. The reaction takes place above the melting temperature of the medium and above the slagging temperature of the ash. As a result, an ash free product stream is generated. Limestone added to the melt will react with sulfur in the coal and remain in the slag. The product fuel then will be low in sulfur. Gasification processes employing the molten-bath reactor, listed on Figure VII-8, are described in Appendix A and Appendix B.

Entrained-Flow Reactor

The entrained-flow reactor is characterized by very high gas phase velocities and very small particle sizes of about 200 mesh. The drag force on the particles exceeds the gravity force, carrying the particles along with the gases. The reactants pass through the reaction zone for only a short time, but the very small size of the coal particles and high temperatures ensure a rapid reaction. Because all the reactants travel through the reaction zone at essentially the same velocity, the entrained flow reactor is not mixed like a fluidized bed, but behaves chemically more nearly like a fixed-bed reactor in that the events naturally occur sequentially. The differentiation between one and two stage processes is simply one of physical location of the oxidant and steam injection point. Where they are injected together, as in a Koppers-Totzek reactor, a single stage process results. Where the oxidant is injected upstream of the steam injection point, two reaction stages result: combustion and gasification. Figure VII-9 illustrates a two-stage entrained gasifier designed to inject the coal with the steam in the gasification stage, using char and oxidant to generate heat in the combustion stage. Other entrained-flow processes identified in Figure VII-9 are described in Appendix A.

By adjusting the fuel-oxidant ratio, temperatures above the slagging temperature can be obtained in the combustion zone. This is the most common mode of operation. The short contact time in the reaction zone requires a high temperature to increase the reaction rates. Temperatures as high as 3500° F in the combustion zone and 2700° F in the gasification zone are possible. The excess heat in the product gas at these high temperatures is usually used to generate process steam.

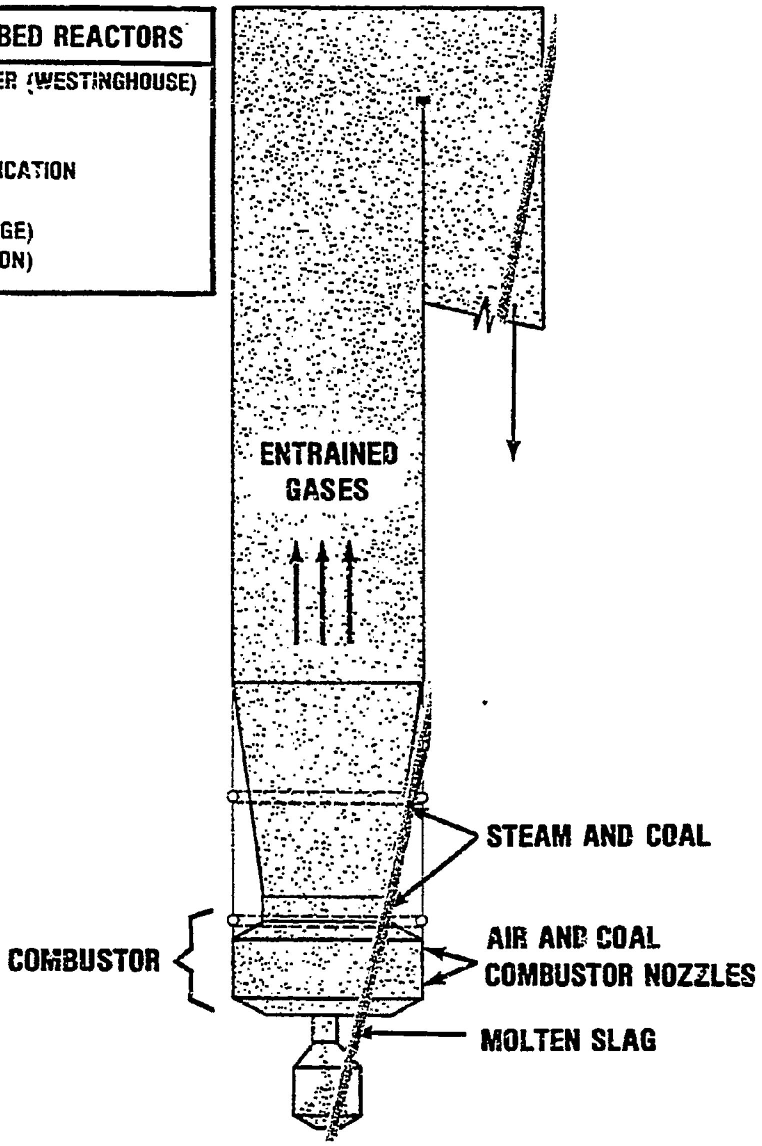
GENERALIZED LIQUEFACTION PROCESSES

Of the various approaches to convert coal into improved nonpolluting energy sources, liquefaction appears best in terms of economics, confidence in reliable commercial operability, and the shortest lead time to achieve commercial implementation. Economic advantages derive from the fact that fewer chemical changes are required to convert solid coal into a liquid than into gas, and the energy conversion efficiency to liquids is higher. Commercial liquefaction processes could use, to a certain extent, components in use in the petroleum refining industry.

A typical direct catalytic hydrogenation process is shown in Figure VII-10. Coal is mixed with a vehicle, usually coal-derived oil from the process itself, and the slurry is mixed with hydrogen and then passed through a reactor at a high temperature and high pressure. Coal reacts with hydrogen in the presence of a catalyst, producing additional oil. All

MAJOR ENTRAINED BED REACTORS

- ATMOSPHERIC GASIFIER (WESTINGHOUSE)
- KOPPERS-TOTZEK
- TEXACO
- NUCLEAR COAL GASIFICATION
- BIGAS (TWO-STAGE)
- HYDRANE (UPPER STAGE)
- GARRETT (LIQUEFACTION)



Source: R. C. Patterson, *et al., OCR Report No. 83*, September 1973.

Figure VII-9. ENTRAINED BED GASIFIER

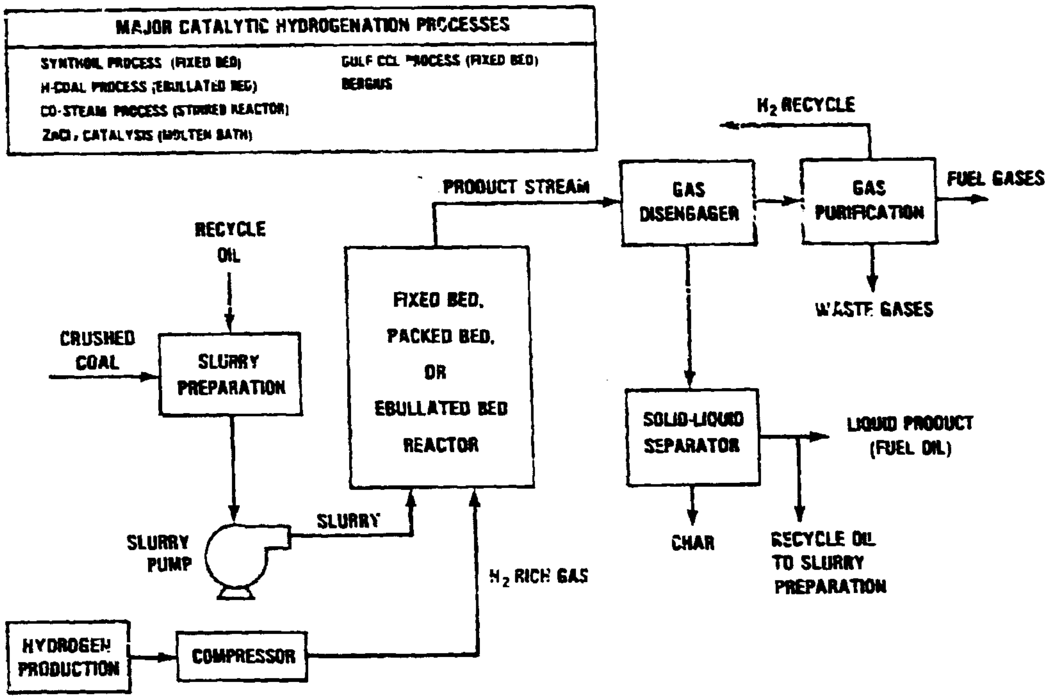


Figure VII-10. CATALYTIC HYDROGENATION PROCESS DIAGRAM

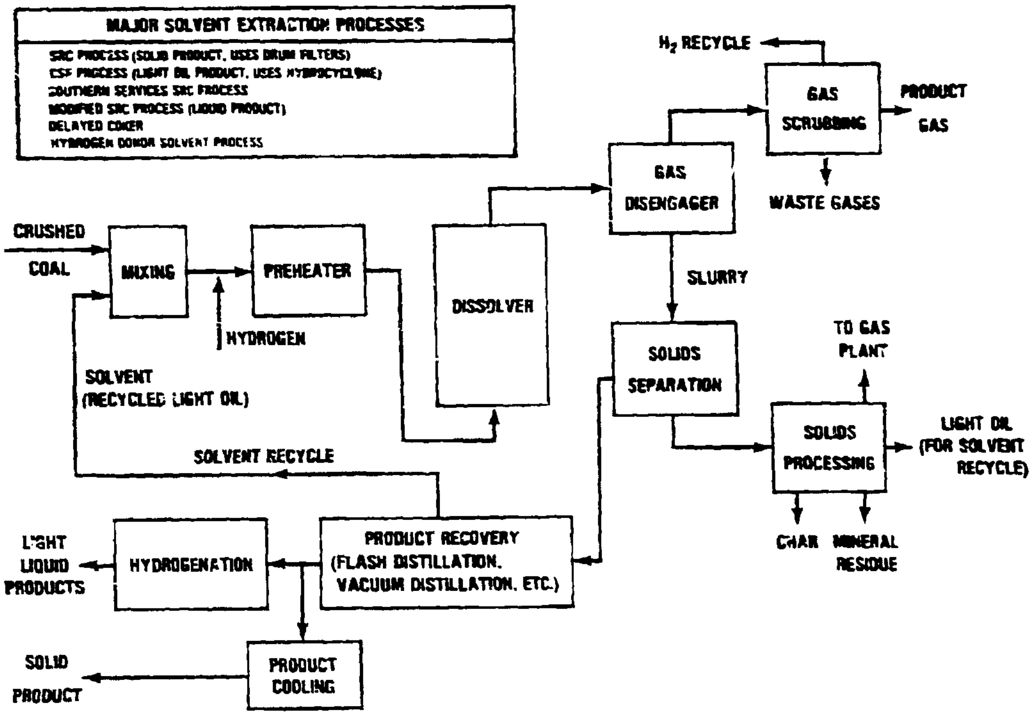
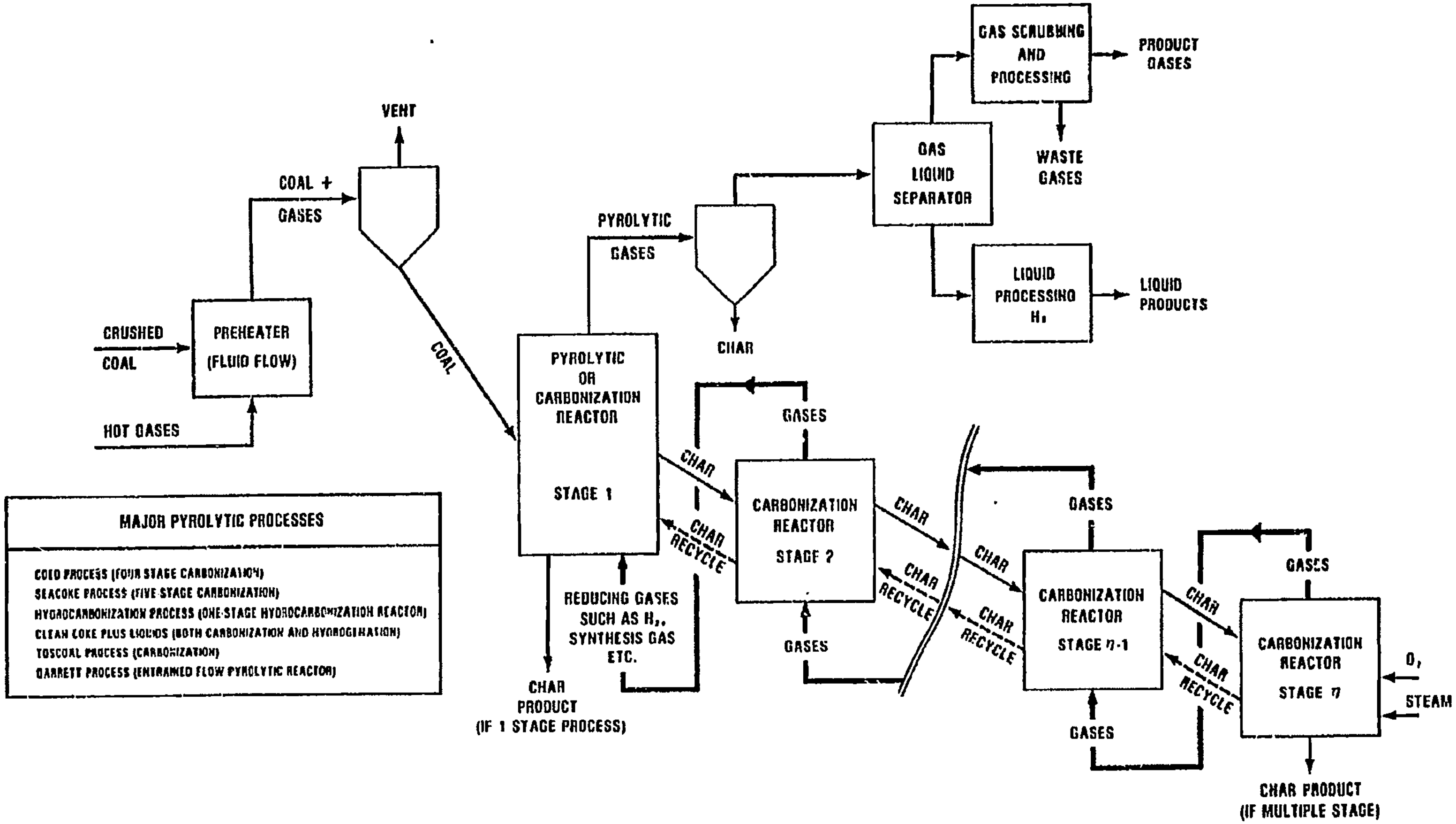


Figure VII-11. SOLVENT EXTRACTION PROCESS DIAGRAM



MAJOR PYROLYTIC PROCESSES

COED PROCESS (FOUR STAGE CARBONIZATION)
SEACOKE PROCESS (FIVE-STAGE CARBONIZATION)
HYDROCARBONIZATION PROCESS (ONE-STAGE HYDROCARBONIZATION REACTOR)
CLEAN COKE PLUS LIQUIDS (BOTH CARBONIZATION AND HYDROGENATION)
TOSCOAL PROCESS (CARBONIZATION)
GARRETT PROCESS (ENTRAINED FLOW PYROLYTIC REACTOR)

Figure VII-12. MULTI-STAGE PYROLYTIC PROCESS DIAGRAM

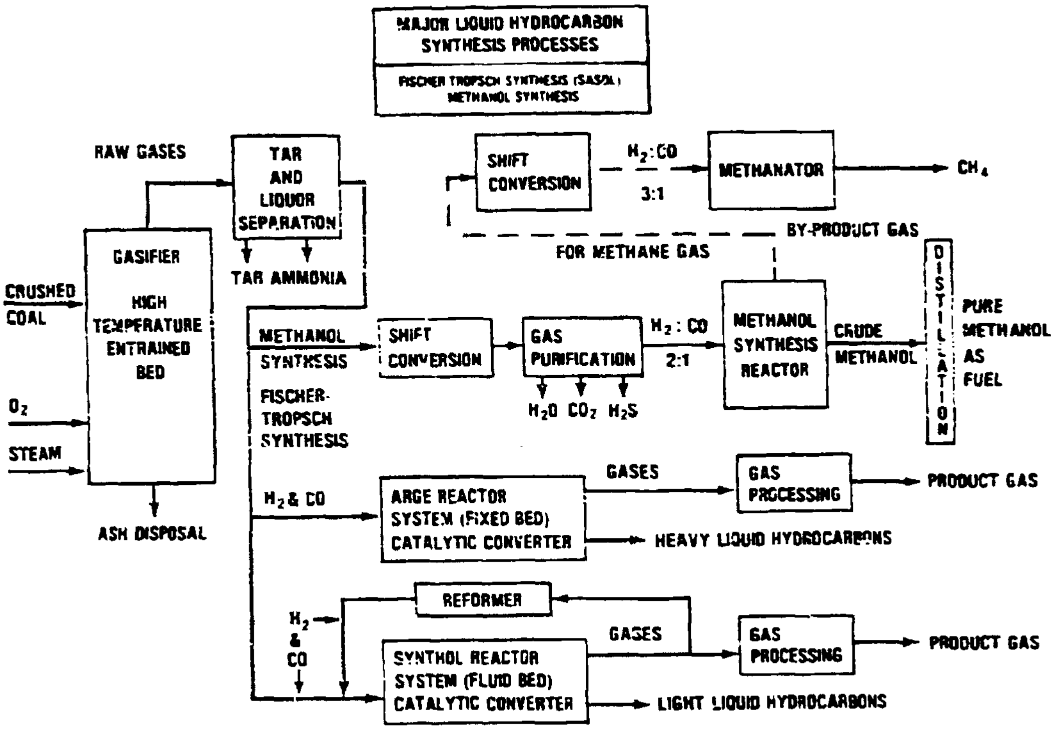
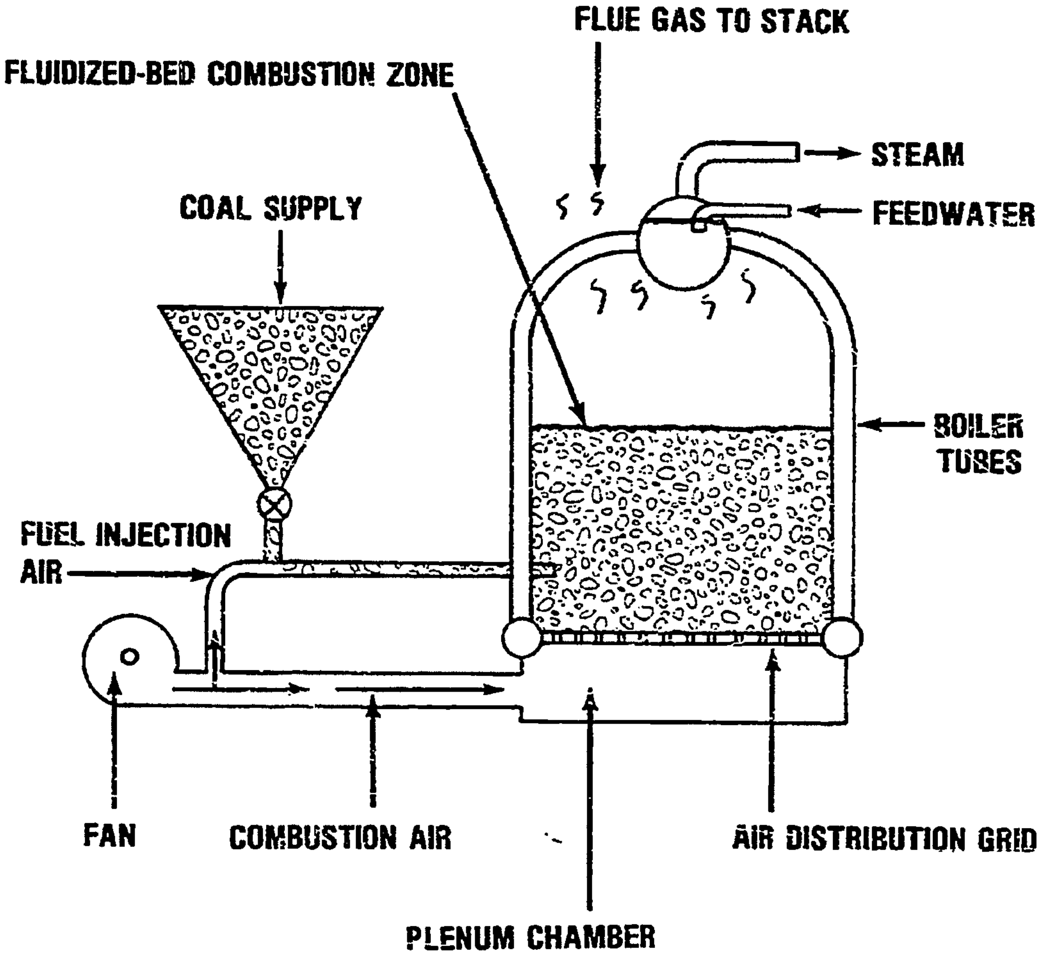


Figure VII-13. LIQUID HYDROCARBON SYNTHESIS DIAGRAM

resulting oil is then separated from solids by filtration or centrifuging. Part of the oil product is then recycled to generate slurry.

The solvent extraction process illustrated in Figure VII-11 uses a solvent to extract or dissolve the coal, and the ash, which includes pyritic sulfur, is filtered out. In some cases the solvent acts as the agent that transfers hydrogen to the coal to in order to liquify it. After removing the solvent, the remaining heavy oil is treated with hydrogen to remove organic sulfur and sometimes to improve its quality.

Pyrolysis or carbonization is destructive distillation of coal. Coal is heated in absence of oxygen until it decomposes producing liquid hydrocarbons, gases, and char. As illustrated in Figure VII-12, four or five pyrolyzing stages may be required in an efficient pyrolysis process. The char is primarily carbon withdrawn from the coal to allow the remaining carbon to hydrogen ratio to reach the liquefaction level. Primary processes utilizing the pyrolysis principle to produce liquid products are the hydrocarbonization process, Char-Oil-Energy-Development (COED), the Toscoal Process, and the Garrett Process.



Source: R. D. Glenn. *Fluidized Bed Combustion and Coal-Fired Packaged Boilers.* 1975.

Figure VII-14. FLUIDIZED BED BOILER

In liquid hydrocarbon synthesis, coal is gasified with oxygen and steam as indicated in Figure VII-13 to produce gas containing a high concentration of CO and H_2. This gas is purified to remove sulfur compounds and CO_2. Carbon monoxide and hydrogen are converted to liquid hydrocarbons through a Fischer-Tropsch catalyst. Liquid hydrocarbon synthesis is divided into Fischer-Tropsch synthesis (at SASOL) and methanol synthesis.

In Appendix B, abstracts of 23 significant liquefaction processes are described briefly and their distinguishing characteristics are pointed out.

DIRECT COMBUSTION AND ADVANCED POWER SYSTEMS

Several long-range advanced combustion and power concepts are under development by ERDA, the Department of Defense, the Maritime Administration of the U.S. Department of Commerce, other federal agencies, and by private industry. ERDA is concentrating on two major areas in order to use coal as a fuel source in advanced systems: direct combustion of coal and advanced power systems which could be coal fueled.

For direct combustion system research, ERDA's emphasis currently has been placed on (1) development of atmospheric and pressurized systems capable of burning high-sulfur coals of all degrees of rank and quality in fluidized-bed combustors, (2) development of the ability to burn coal-oil slurries in oil-fired combustors, and (3) improvement in the reliability of present boilers. Compared with conventional coal-fired systems, fluidized-bed combustion systems result in higher power efficiencies and cleaner exhaust gases, even when burning high-sulfur coals. If the fluidized-bed system is pressurized, additional economies in capital costs accrue through decreased construction expenses and operating costs are lower because of increased efficiencies. The benefits from high-pressure combustion are (1) a reduction of furnace size because of decreased gas volume and (2) an increase of sulfur removal ability.

In a fluidized bed boiler, shown in Figure VII-14, small particles of limestone are held in dense suspension by a stream of air passing upward through the dense bed. This fluidized bed is heated to about 1600° F. Finely crushed coal injected into the fluid bed combustion zone burns very rapidly in the bed so that at any given moment the amount of combustible material in the bed is very low, probably less than one percent. A suitable amount of powered limestone is added continuously to the bed where it reacts with the sulfur dioxide released by the burning of the coal to product calcium sulfate, an inert substance which is discharged with the ash.

The primary advantage of the fluidized-bed boiler is that sulfur and much of the ash may be removed during the direct combustion of the coal. In bench-scale tests, the technique has removed over 90 percent of the sulfur dioxide pollutants resulting from the burning of coal. To avoid creating a solid waste problem from the discharged limestone, a method for regenerating and recycling the spent limestone is being developed. The sulfur would then be separated in pure form for sale or storage. Many of the uncertainties in the fluidized-bed concept are associated with scale-up to commercial sizes.

A small scale, 0.5 MW atmospheric pressure fluidized-bed boiler has been under development by Pope, Evans and Robbins, Inc. (PER). The success of this ERDA-sponsored project has led to the current effort to develop a multicell 30 MW fluidized-bed boiler. This system is also being developed under ERDA sponsorship by PER with Foster Wheeler

Energy Corporation and Champion Construction and Engineering Company, Inc. at Rivesville, West Virginia. The multicell fluidized-bed boiler is to be operated under practical electric utility conditions and will be used as the basis for scaling up to a 200 MW system. Operational tests are scheduled to be started by the end of 1976.

ERDA is sponsoring several other projects which employ fluidized-bed combustion for the eventual production of electric power. The CPU-400 is an experimental power plant originally developed by EPA for converting the heat energy of solid waste to electrical energy. The Combustion Power Company, Inc., of Menlo Park, California, has modified the CPU-400 to burn coal in its fluidized-bed combustor. The product gases are cleaned and then expanded in a gas turbine which drives a 1 MW generator. The process development unit is being modified to test improved gas clean-up devices and to test the effect of coal combustion gases on the turbine and other materials in the hot gas system.

Other more fundamental fluidized-bed combustion testing is being conducted by Argonne National Laboratory in Argonne, Illinois, and by the National Research and Development Corporation of London, England. Additionally ERDA is sponsoring advanced studies related to the future application of fluidized-bed combustion. In particular, Oak Ridge National Laboratory (ORNL) Oak Ridge, Tennessee, is studying the feasibility and practicality of a modular integrated utility system (MIUS). Preliminary analyses indicate that a localized total energy system could be powered by a closed cycle gas turbine fueled by coal in a fluidized bed combustor. The waste heat from a relatively small 5 MW MIUS could be used to heat buildings, process potable water, and drive absorption cycle air conditioning systems. This localized total energy approach would employ a more complete utilization of the available heat energy in a given quality of coal. One or more MIUS demonstration units are to be developed in a future phase of the ORNL program.

The advanced power systems program in ERDA is directed toward developing electric power generation systems that operate on coal or coal-derived fuels. Fundamental research is underway on developing magnetohydrodynamic (MHD) generators, closed cycle gas turbine systems, liquid metal topping cycles, and fuel cells.

An MHD generator produces direct current electrical energy from the expansion of ionized, high temperature combustion gases called plasmas through a magnetic field. The motion of a conducting gas through the magnetic field induces an electromotive force in transverse electrodes according to Faraday's laws. The essential difference between an MHD generator and a conventional turbine generator is that in the MHD system, the ionized gas both moves physically and acts as a conductor.

Coal is fired at relatively high pressure and resulting gases are channeled through an MHD duct at very high velocities. The exhaust gases leaving the MHD generator are hot enough so that the waste heat in these gases can be recovered in a boiler to drive a conventional steam plant. The generation of electric power by means of an open cycle MHD energy conversion system integrated as a topping cycle to a closed conventional steam generating plant can significantly increase total plant thermal efficiencies.

MHD generators have been tested for short periods with both clean and dirty gas streams. This experience and supporting analytical work provide a base for effective first-phase electrode and channel design and engineering development. Experimental results indicate that both the desired output and continuous operating times required to justify commercial development have been achieved, but not simultaneously. Commercial applications will require 15-20 percent recovery of the thermal energy input to the generator as electric power output. the best performance to date has been on the order of 8 percent thermal efficiency. High temperature, corrosion/erosion-resistant components are needed in combustors, channels, boilers, and regenerators. The components are exposed to chemical and erosive attack by molten slag, fly ash and alkali salts at very high temperatures. Component designs and materials to meet these requirements must be developed.

MHD research is being developed through several joint government/industry programs. ERDA is sponsoring major hardware test programs at the AVCO Everett Research Laboratory, FERC, and the Arnold Engineering Development Center.

ERDA has been coordinating the cooperative program in MHD power generation being undertaken with the Union of Soviet Socialist Republics under the Science and Technology agreement reached in May 1972. Recently the Soviets achieved 12.4 MWe performance in their MHD facility and supplied power to the Moscow electric power grid for 30 minutes. In a previous operation, the U-25 has supplied electric power for 100 hours at the 1-4 MWe power level. Agreement was also reached on the joint study of technical and economic problems involved in the introduction of MHD power plants into commercial service.

The current MHD development work is being expedited and specifically directed to support the national objective of achieving a commercial MHD power demonstration in the late 1980s. ERDA's initial goals are to demonstrate the feasibility of the MHD generator and to build and demonstrate the 20 MWe Engineering Test Facility to be located in Montana.

Closed cycle gas turbines and liquid metal topping cycles would operate at cycle temperatures higher than are currently possible in conventional electric power systems. As maximum cycle temperatures increase, theoretical thermal efficiencies (work out/heat in) can increase. These high temperature heat engine devices can realize a net efficiency increase only if associated mechanical and thermal losses do not also increase proportionately. Also, materials must be designed to withstand the erosive effects of the high operating temperatures. Research therefore includes developing special high temperature materials and consideration of total system performance.

Closed Brayton cycle gas turbine systems could use low-Btu gas or liquid fuels derived from coal as a fuel source. High temperature heat from combustion would pass to the closed cycle through a special high temperature heat exchanger. An inert gas such as helium would absorb the heat, expand through a turbine which drives a compressor to support the cycle and produce sufficient net work to drive a generator. The closed cycle turbine uses an inert gas working fluid to reduce oxidation of materials at high operating temperatures. Waste heat from this cycle could then be used to drive a conventional plant. A closed Brayton power cycle should have advantages in size and weight and therefore in first cost over conventional electric power units.

In an alkali metal topping cycle, liquid metal is boiled in a high temperature heat exchanger. Vaporized metal then expands through a turbine, is condensed and finally recycled to the boiler. The liquid metal boils at a high temperature compared to conventional steam plant boiling temperatures. As the liquid metal is condensed, it gives up heat to a waste heat boiler which drives a conventional steam power plant. The two plants together allow greater extraction of the available fuel energy, resulting in a greater combined efficiency than that attainable by a conventional steam plant alone

The Office of Fossil Energy at ERDA is also studying fuel cells. The fuel cell is a device for converting the energy released in a chemical reaction directly into electrical energy. Fuel gas and air (or oxygen) are continuously and separately supplied to the anode and cathode. Electrical energy is produced and carbon dioxide and water vapor products are released. Engineering studies of a complete fuel cell system indicate that efficiencies of 60 percent may be attainable.

The molten carbonate/fuel cell has been constructed by Westinghouse Electric Corporation. The electrolyte is a 20-micron film of oxide ceramic (zirconia) stabilized in the cubic fluorite crystal structure. At the operating temperature of 1870° F, oxygen ions flow through the electrolyte by activated diffusion. The anode is cobalt or nickel made porous by the inclusion of a ceramic skeleton, and the cathode is electronically conductive oxide fabricated in a porous structure readly permeated by oxygen from air. Fuel gas flowing over the anode reacts with the oxygen ions diffusing through the electrolyte to form H_2O and CO_2 with the liberation of electrons and thus useful current. The rate-limiting process at the anode is the countercurrent diffusion of fuel and reaction products. Oxygen accepts electrons at the cathode where the rate-limiting step is diffusion of oxygen through the electrode structure. Gas from eitherside does not penetrate the electrolyte layer, and the reaction can only occur when current is drawn. Additional research is required to develop suitable support for multiple thin film cells and to develop low cost techniques for consturction of cells and cell interconnections.

The outstanding problems involved iusing fuel cells for central-station power production do not appear to be close to solution. More small-scale, fundamental research will be required before large-scale development is pursued.

SULFUR REMOVAL PROCESSES

A considerable portion of the pyritic sulfur in coal can be removed by conventional cleaning processes. Sulfur oxides may be removed from flue gases after coal combustion; sulfur can be removed chemically during coal liquefaction and coal gasification processes.

Washing coal before burning can remove up to 90 percent of the pyritic sulfur but essentially none of the organic sulfur, which constitutes about half of the sulfur in coal. Since most coal contains more than 2 percent sulfur, deep washing alone cannot produce a coal that can be burned freely without atmospheric pollution. However, coal washing in conjunction with flue gas cleaning appears to create more acceptable sulfur discharge rates.

Of the more than 50 processes proposed for the desulfurization of flue gas, no one process has achieved such completely satisfactory results so that it has attained worldwide acceptance. Limestone injection into the combustion chamber of the boiler along with the coal to be burned has proven so unsatisfactory that the process is no longer available on a commercial basis. Sulfur recovery was poor, and system plugging by deposits reduced boiler availability.

At the present time only the wet limestone scrubbing system has proved itself in a 100 MW large scale boiler operation over a one year period on coal-fired boilers. The process has not been without serious corrosion and plugging problems, and the disposal of large quantities of waste sludge remains a serious drawback. Several other processes, however, look quite promising but they are only in the pilot plant or early developmental stages, or have been used only on oil-fired boilers. The difference between emissions from coal-fired and oil-fired boilers is sufficiently great that a process that works well on oil-fired boilers always needs considerable modification to work on coal-fired boilers. Such modification is often extremely difficult, and much effort is being expended to solve this problem.

Current processes that operate successfully and achieve desulfurization have large waste disposal problems, while the ones that produce a salable byproduct such as elemental sulfur or sulfuric acid have not reached large scale operation on coal-fired boilers, and have not produced enough operating data.

Sulfur removal during liquefaction and gasification of coal is relatively straightforward. Hydrogen sulfide (H_2S) is removed by absorption in a solution or absorption on the surface of a solid. H_2S is then burned in an oxygen atmosphere which produces sulfur oxides that can be converted to elemental sulfur and removed. The Claus, Stretford, Selexol, Rectisol hot carbonate and amine processes are successful commercial methods.

CHEMICALS FROM COAL

In the process of the distillation of coal, other substances besides coke are produced. In the early days of the industry, these byproducts were considered of value only for their tar content. The first recorded attempt to refine these products by the distillation of coal tar was at Glasgow, Scotland, in 1822. Coke-oven byproduct gases contain such chemicals as ammonia, sulfur compounds, volatile hydrocarbons and suspended tar. The hydrocarbons boiling below 338° F are generally referred to as light oils. Prior to World War II practically the entire nation's supply of benezene, toluene and xylene were produced from this light oil. At that time, the tar was often burned as a fuel, but larger plants distilled it and manufactured additional byproducts. Some of the products produced by distillation of a high temperature coal tar are phenol, cresols, pyridine, benzene, toluene, xylenes, naphthalene, creosote, anthracene, and pitch. These are the typical products from one ton of coking coal from a high temperature coking operation: coke yield 60-70 percent, tar 8-12 gallons, light oil 2.5-3.0 gallons, ammonium sulfate 20-25 pounds. During World War II, coal could not meet the demand for many of these products and processes were developed for their production from petroleum. Today only a minor part of the world's organic chemicals are made from coal, derived either from coke making, or by deliberate synthesis, while about 10 percent of total crude oil, natural gas, and gas liquid production now goes to satisfy petrochemical industry feedstock and energy demand.

Utilizing synthesis gas as a feedstock, even with today's technology, coal-based ammonia and methanol will be competitive in the United States with the products derived from gas and residual oils by 1980. Since 1970, Monsanto has been producing acetic acid using a methanol/carbon monoxide feed. Union Carbide is well into the pilot plant stage with a process that reacts carbon monoxide and hydrogen at extremely high pressure to produce ethylene glycol. Coal-based methanol can be converted to ethanol and then dehydrated to produce ethylene. This product could compete in cost with the same product produced by conventional processes.

Currently, coal liquids are being considered for making such products as benzene, toluene, xylene, phenol, cresylic acid, and naphthalene. Utilizing their Clean Coke process, the U.S. Steel Corporation predicts yields from a 5.8×10^6 ton/year coal facility to be as follows:

725 million lb/yr ethylene,

800 million gal/yr benzene,

230 million lb/yr naphthalene,

130 million lb/yr each of propylene, phenol, cresol and xylenols and lesser quantitites of ammonia, sulfur, pyridine, etc.

Utilizing magnetohydrodynamics, the AVCO Corporation is developing a process to convert coal directly into acetylene.

SUPPORT REQUIREMENTS

Hydrogen and Oxygen

The main problem in the conversion of coal to liquids is the transformation of a low-hydrogen content solid into a liquid containing a substantially higher amount of hydrogen. To convert the organic material in coal to a petroleum-like liquid theoretically requires about 5000 standard cubic feet of hydrogen per barrel. This amount of hydrogen would be enough to remove the sulfur, oxygen and nitrogen compounds and produce a liquid containing about 13 percent hydrogen, without making any substantial amounts of light hydrocarbon gases. In practice, the hydrogen consumption is much higher, ranging from 6,000 to 10,000 standard cubic feet per barrel due primarily to a substantial production of light hydrocarbon gases and to loss of hydrogen in the unliquified solid residue. As a result, the production of hydrogen represents a major factor in coal liquefaction and the processing of coal liquids.

The steam-oxygen process, the steam-iron process, and electrothermal gasification are generally considered to be the most promising for the production of hydrogen. In the steam-oxygen process, steam and carbon are reacted at temperatures of approximately 1900° F to produce hydrogen and carbon monoxide. Since the chemical process is highly endothermic, some process heat must be used to maintain the desired reaction temperature. This is accomplished by the addition of oxygen to the reactor to burn some of the carbon to produce carbon dioxide and liberate the desired heat.

The steam-iron process is one of the oldest methods for making hydrogen. Steam is reacted with metallic iron at an elevated temperature to produce hydrogen and iron oxide. The iron oxide is then reacted in another reactor with a mixture of carbon monoxide and hydrogen to regenerate the metallic iron. The carbon monoxide and hydrogen used in this regenerator are generally produced from the reaction of coal or char with steam. In electrothermal gasification the reaction is sustained by electrical heat rather than chemcial heat.

The primary use of oxygen in coal processing is to produce an enriched fuel gas. By using oxygen rather than air, the product gas contains less nitrogen and consequently will have a higher heating value. The quantities of oxygen required per unit of energy produced for two gasification processes are shown below.

Process	Tons Oxygen Required per Btu
BCR two-stage	2.17×10^{-7}
Texaco steam-oxygen	1.67×10^{-8}

The cost of oxygen enrichment of gasified coal products can range from 20 to 27 cents/million Btu.

Water

As no modern-design coal-gasification plants of commercial scale exist in the United States, estimates of water demand must be based on research operations, foreign experience, and design data of projected plants. Water consumption in coal gasification plants producing pipeline gas of 250 million standard cubic feet per day (7 million m^3 per day) capacity can be expected to range from about 10,000 acre-ft (12 million m^3) per year where water is at a premium to 45,000 acre-ft (55 million m^3) per year where abundant but poor quality water is used for cooling.

As the methane synthesis does not play a major role in water consumption, this alternative mode of gas production would have little bearing on consumptive demand for comparable Btu outputs.

Unit water consumption estimates range from as little as 0.2 acre-ft (247 m^3) annually per barrel per day of synthetic-oil output to as much as 1.3 acre-ft (1,600 m^3) per year per barrel per day capacity.

COAL PROCESS TECHNOLOGY BIBLIOGRAPHY

*FUNDAMENTALS**

Boddle, W. W., Talwalker, A. T., and Vyas, K.C. "Clean Fuels from Coal—Technical–Historical Background and Principles of Modern Technology" *Clean Fuels from Coal Symposium II Papers.* Chicago: Institute of Gas Technology. 1975: 53-84.

National Academy of Engineering for OCR. *Evaluation of Coal-Gasification Technology: Part II–Low and Intermediate Btu Fuel Gases.* Washington, D.C.: Government Printing Office.

University of Oklahoma Science and Public Policy Program. *Energy Alternatives: A Comparative Analysis.* Norman, Oklahoma: University of Oklahoma. May 1975. Section 1.9.

*GASIFICATION**

Forney, A. J., Haynes, W. P., and Starkey, J. P. *Methanation in Coal Gasification Processes.* ERDA Report No. PERC/IC-75/1. September 1975.

1975 Cameron, p. 177.

U.S. Federal Power Commission, *Current Status of Technology, Section IV, National Gas Survey Vol. II,* pp. 450-452.

Howell, Richard D. "Mechanical Design Considerations In Commercial Scale Coal Gasification Plants." *Sixth AGA Pipeline Gas Symposium,* October, 1974.

Jaeger, H. L., Leigh, D. C., and Foster Pegg, R. W. "Electric Power from Low-Btu Gas in Combined Power Plants." *Pittsburgh Symposium.* 1975.

LaRosa, P. and McGarvey, R. J. "Fuel Gas From Molten Iron Coal Gasification." *1973 IGT Symposium.*

---

*Refer to Appendix C for identification of abbreviated primary sources.

Mills, G. Alex. "OCR Coal Utilization R&D Program," *Energy Technology I Symposium Papers.* Washington, D.C.: Government Institute Inc.

National Academy of Engineering for OCR. *Evaluation of Coal-Gasification Technology: Part II–Low and Intermediate Btu Fuel Gases.* Washington, D.C.: Government Printing Office, 1974.

Patterson, R. C. *et al. Low Btu Gasification of Coal for Electric Power Generation.* OCR Report No. 83, September 1973.

Wen, C. Y. *Optimization of Coal Gasification Processes Vol. I.* OCR R&D Report No. 66, Interim Report No. 1. Washington, D.C.: Government Printing Office.

*LIQUEFACTION**

1974 O & GJ.

Yavorsky, P.M "Overview of R&D on Coal Liquefaction." *Pittsburgh Symposium 1975.*

ADVANCED POWER SYSTEMS

Glenn, Roland D. *Fluidized-Bed Combustion and Coal-Fired Packaged Boilers.* New York: Combustion Processes, Inc., 1975

Hearings U.S. Congress, Subcommittees of the Committee on Appropriations. 93rd Congress, 2nd Section, Pt. 1, February, 1974, pp. 597, 667.

Jackson, Dr. William D. "MHD Power Generation, Technical Status and Development Plan." *Clean Fuels from Coal Symposium II Papers.* Chicago: Institute of Gas Technology, 1975.

Jonke, A. "Fluidized-Bed Combustion: A Status Report," *Coal Processing Technology, Vol. II.* New York: American Institute of Chemical Engineers, 1975.

National Petroleum Council. *U.S. Energy Outlook: An Interim Report.* Olaf A. Larson, Chairman. National Petroleum Council, 1972.

New Energy Technology. pp. 290-293.

Sheindlin, A. E., and Jackson, W. D., "MHD Electrical Power Generation–An International Status Report." *WEC-CME IX.* Detroit: WEC-CME IX, 1974.

---

*Refer also to Coal Process Technology, Chapter VII.

Sverdrup, E. V., Warde, C. J. and Galsser, A. D. "A Fuel-Cell Power System for Central Station Power Generation Using Coal As A Fuel." *From Electrocatalysis to Fuel Cells.*

Westinghouse Electric Company. *Final Report: Project Fuel Cell.*

SULFUR REMOVAL PROCESSES

Coal Technology from Tyler. Proceedings of Conferences in Pittsburgh, Charleston, St. Louis, and Denver. Cleveland, Ohio: W. S. Tyler, Inc., 1975.

"Hydrocarbon Processing." *NG/LNG/SNG Handbook.* April, 1973: 88-116. Osborn, E. G. "Coal and The Present Energy Situation."
Osborn, E. G. "Coal and The Present Energy Situation." *Science.* February 8, 1973: 473.

Pfeitfer, J. B. (ed). *Sulfur Removal and Recovery from Industrial Processes.* Advances in Chemical Series, No. 139. Washington, D.C.: American Chemical Society, 1975.

Rosenberg, H. S., and others. "The Status of SO_2 Control Systems," *CEP.* 1975: 66.

"SO_2 Processing." *Chemical Engineering Progress.* May 1975: 55-79

U.S. Congress. Senate. Committee on Public Works. *Air Quality and Stationary Source Emission Control.* 94th Congress., 1st Session. March 1975. pp. 385-390.

Wen, C. Y. *Optimization of Coal Gasification Processes Vol. I.* OCR R&D Report No. 66 Interim Report No. 1. Washington, D.C.: Government Printing Office.

CHEMICALS FROM COAL

Bureau of Mines, U.S. Department of Interior. *Coke and Coal Chemicals Annual for 1974.* Mineral Industry Surveys. Washington, D.C.: Government Printing Office.

Griswold, John. *Fuels, Combustion and Furnaces.* New York: McGraw-Hill, 1946.

SUPPORT REQUIREMENTS

Federal Energy Administration. *Project Independent Report.* Federal Energy Administration, November 1974: 304.

VIII. ECONOMIC CONSIDERATIONS

Coal prices during the 1970s have been subject to a variety of market forces. Popular concerns over miner safety and air pollution have led to regulations that have significantly increased the production and utilization costs of coal. Other factors, such as strip mining regulation and reclamation, threaten to push the price of coal even higher. The 1973 oil embargo and the subsequent quadrupling in the price of oil imports caused a sharp, though temporary, rise in the demand for coal. As a result, market prices for short-term supplies of coal (spot market) reached $50 per ton, nearly five times the value justified by production and capital costs.

These coal price increases have created loud protests inferring collusion. Most investigations of this charge have concluded that while the coal industry is composed of fewer and larger firms, the industry lacks the significant degree of concentration necessary to impose monopoly pricing. These conclusions support the view that the sharp increase in coal prices in the spot market following the oil embargo were a short-term aberration where the sudden increase in demand far exceeded the industry's capacity to increase supply. Recent price quotations confirm these views. During the last year, the market price for coal has declined significantly. This trend is expected to continue until the market price nears a price based on production costs.

Coal market prices, as quoted in dollars per ton, vary considerably from region to region. Most of these variations are attributable to varying production costs of the different mining methods. Other variations are related to the chemical properties of the coal. Low sulfur and high Btu coals extract premiums for the advantages they offer the user. As a result, market prices are often accompanied by measures of the Btu and sulfur content of the coal as indicated in Table VIII-1.

Mining Costs

Prices required* to support the production of coal depend upon many economic and

---

*Required prices cover mining costs and yield a specified discounted cash flow (DCF) rate of return on investment.

Table VIII-1.
SPOT MARKET PRICES FOR STEAM COAL, DECEMBER 1975

	Btu/lb	% SULPHUR	PRICE ($/NET TON)	PRICE (¢/MMBtu)
CENTRAL PENNSYLVANIA	11980	2.00	$18.00	15
WEST PENNSYLVANIA	11540	2.39	17.50	15
NORTH WEST VIRGINIA	12040	2.67	18.25	15
OHIO	10720	3.23	18.25	17
SOUTHEAST WEST VIRGINIA AND VIRGINIA	11760	0.85	15.00	13
SOUTHWEST VIRGINIA, EAST KENTUCKY, NORTH TENNESSEE	11630	1.25	14.50	12
WEST KENTUCKY	10940	3.43	13.25	12
ILLINOIS	10680	3.41	15.50	15
INDIANA	10650	3.10	13.00	12
IOWA	9480	3.67	10.75	11
ALABAMA AND CENTRAL TENNESSEE	12050	2.05	18.75	16
KANSAS/MISSOURI/OKLAHOMA	11520	3.78	16.25	14
WYOMING/MONTANA	9370	0.61	6.50	7

physical factors. Economic factors include unit costs of labor, capital, and intermediate inputs (operating and maintenance supplies, power, and services). Other indirect economic variables are the effective tax rate, depreciation, depletion, reclamation requirements, and proposed environmental regulations. A wide range of physical factors affect the cost of producing coal. The average seam thickness, size of the mine, and depth of overburden are major factors. Other physical conditions which affect the cost of mining coal follow:

- The type of overburden affects the cost of drilling, shooting, and removing the overburden at surface mines.
- The amount of methane gas present in underground mines affects ventilation costs.
- Average roof conditions affect the cost of roof bolting and other support.
- The average topography affects the selection of capital equipment and method of reclamation.

Underground Mining

The type of underground mine, drift or shaft/slope, and the method of mining, either continuous or conventional room and pillar, significantly affect the production and capital costs required. One assessment of the variations in required selling prices due to these physical factors was conducted by FEA in 1974. They estimated prices, based on costs, that ranged from $9.37 to $16.34 per ton (1974 dollars, 15 percent DCF and 100 percent equity) depending upon the combination of the physical factors characteristic of a particular mine.

Recently published data for 1975 from the Bureau of Mines suggests that over the last year, underground prices, based on cost, have increased significantly. Calculations for a drift mine with a four foot seam show a price ranging from $13.26-$14.83 per ton. This increase is primarily due to two cost components, land and labor. Land costs, previously on the order of $350 per acre, have now skyrocketed to $2500 per acre. Labor costs contributed to the upswing with a nearly 12 percent increase in the average wage. Estimates of new required prices for shaft/slope mined coal can be expected to be about $1-2 higher per ton than coal from drift mines, depending upon the annual production rate of the mine. Mines with six foot seams would be approximately $1 per ton cheaper than mines with four foot seams.

Surface Mining

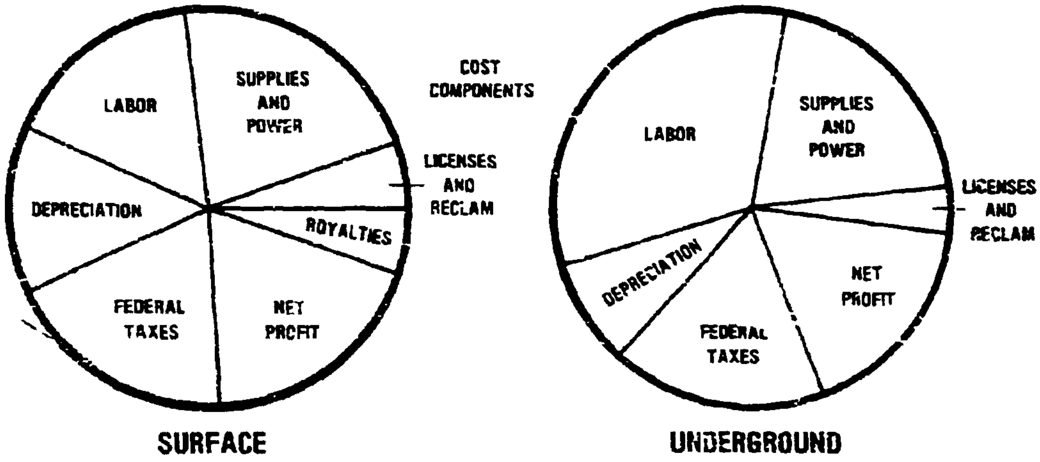
Until the mid 1960s, surface mining of coal was not considered feasible unless the stripping ratio was 10:1 or less. Since 1965, this ratio has been steadily increasing. Today most coal within 180 feet of the surface is considered economically recoverable, even when the stripping ratio nears 30:1.

Estimates of the required selling prices for coal from surface mines, made by FEA in 1974, ranged from $3.78–$10.19 per ton depending upon the stripping ratio and the yearly output of the mine. The $3.78 per ton price corresponds to a 5 million ton per year (mmtpy) mine with a 5:1 stripping ratio. A similarly-sized mine with a larger stripping ratio of 15:1 was priced at $7.42 per ton, nearly a 100 percent increase. Mine size is also a significant factor in production cost. A 5 mmpty mine with a 15:1 stripping ratio would require a price of $9.31 per ton, a 25 percent increase, if its annual output were reduced to only 1 mmtpy.

The typical cost components of surface and underground mines are compared in Figure VIII-1. Production costs, including depreciation, typically constitute 60-65 percent of the required selling price of coal. Comparison of the components indicates that underground mining is significantly more labor intensive. That is, labor costs are a higher fraction of total costs than capital related costs. Conversely, surface mines tend to be more capital intensive, culminating in higher net profit and, consequently, higher taxes.

Comparison of required prices on a Btu basis, also in Figure VIII-1, indicate that surface coal is typically much cheaper than underground coal even with the large

	SURFACE 5:1 OVERBURDEN 5 MMTPY	UNDERGROUND 48 INCH SEAM 3 MMTPY
REQUIRED SELLING PRICE		
$/TON	3.78	13.26
¢/MMBtu	18	50
CAPITAL INVESTMENT ($/ANNUAL TON)	10.39	30.10
OPERATING COST ($/ANNUAL TON)	2.33	8.61



1974 $: 15% DCF; 100% EQUITY

$MM=10^6$

Figure VIII-1. COAL PRODUCTION COSTS

variations in Btu content. For this reason, the regained economic advantage of coal due to the change in oil economics will most likely result in the accelerated development of western surface mined coal.

Reclamation

While stringent reclamation requirements would affect the price of surface mined coal, cost increases are not expected to significantly deteriorate coal's competitive position. Assuming the worst of conditions where reclamation costs for a low-Btu lignite mine are nearly $9000 per acre, the price increase of coal is only about 4 cents per million Btu.

Coal Preparation

Capital investment costs for a coal preparation plant range from 10 to 23 percent of the total mining investment. Typically, preparation operating costs increase coal costs by $1.25-$1.75 per ton. Coal preparation generally increases the selling price by about $2 per ton.

Transportation

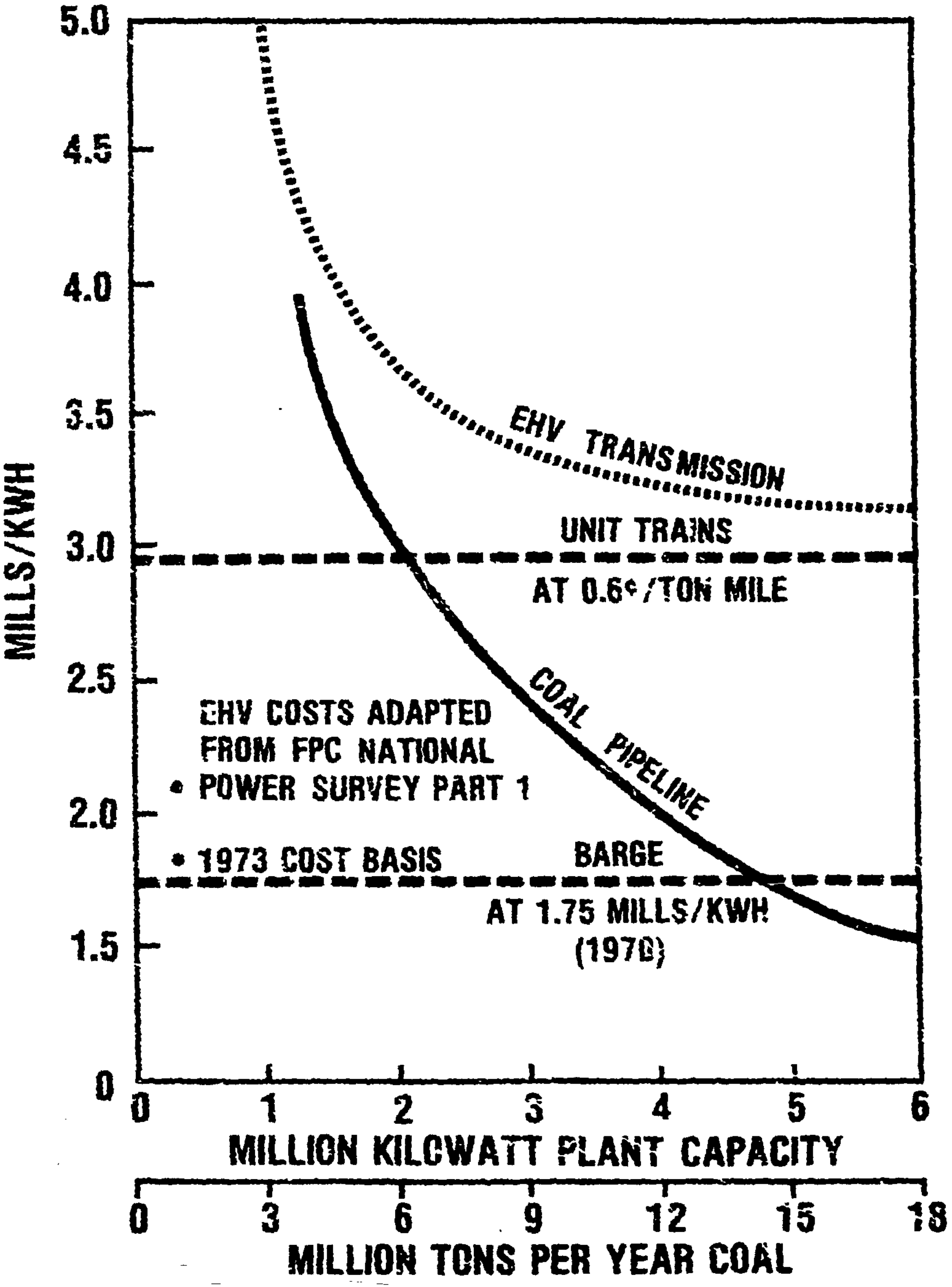
Transportation costs are a significant factor in the ultimate price of coal, and therefore play a central role in determining coal's competitive position in many energy markets. Figure VIII-2 indicates the relative costs of each of the forms of coal transportation.

Railroads are burdened with a large excess of fixed capacity. Coal traffic can alleviate some of railroad's excess track capacity. The railroad industry also is highly labor-intensive. As a result, the unit train has evolved and it offers 25 to 40 percent rate advantage over conventional train rates. The next step in reducing costs is the construction of integral trains specifically designed for shuttle use. Although the reliability of the projected costs is probably not high, estimates indicate that the integral train should be competitive with coal slurry pipelines and even gas pipelines.

Barge transport of coal is relatively inexpensive and remains in demand where trans-shipments are not required, or where a significant portion of the distance can be covered by water. In some instances, the availability of return freight helps keep these rates low. Significant drawbacks of the expansion of waterborne coal movements include inadequate lock capacities and bottlenecks in the waterway systems. These drawbacks tend to reduce the competitiveness of this mode of transportation.

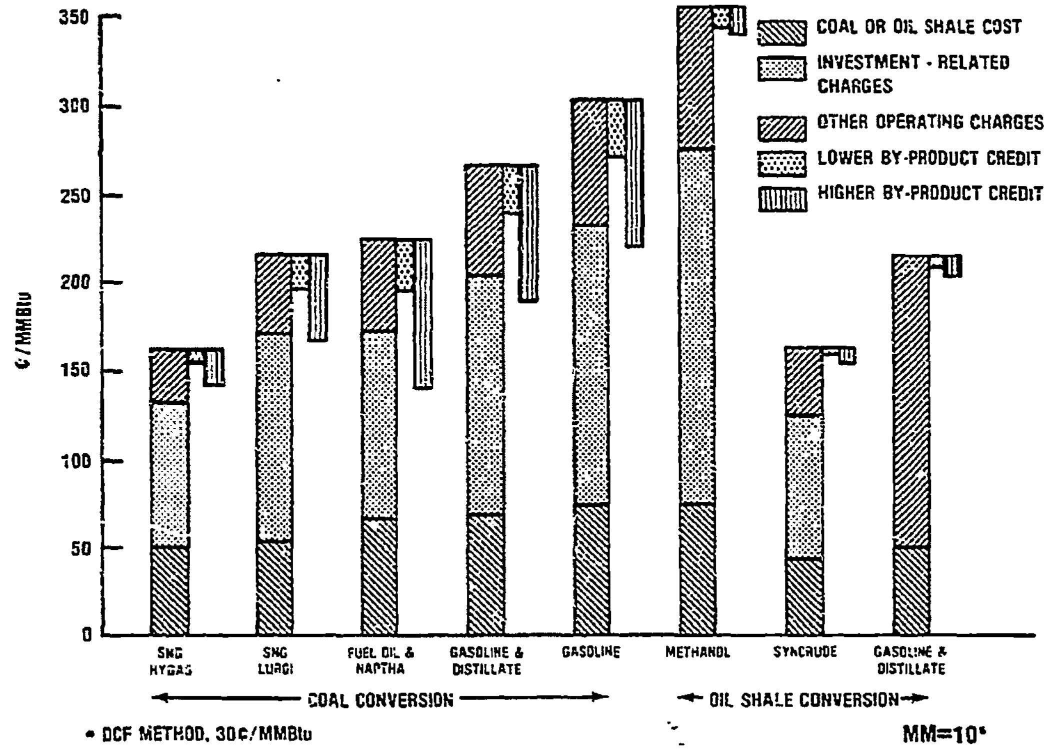
Slurry pipelines are characterized by economies of scale that promise large cost savings for coal delivered over long distances. Pipelines demand relatively high capital investment, typically 70 percent of total costs of building and operating the system. Due to inflation, operating costs are equally divided between electricity, labor and supplies. Once established, however, pipeline rates are sheltered to a degree from cost increases.

Innovations in transmission technology involving use of extra high voltages (EHV) have significantly lowered transmission costs and make plant locations near coal mines more attractive. In addition, the tendency to build long-distance transmission lines to permit pooling of power also makes such remote siting less costly, since the transmission lines can often be routed near fuel supplies. Some doubt exists, however, about whether



Source: National Petroleum Council, Federal Power Commission, and Energy Transportation Systems, Inc.

Figure VIII-2. COMPARISON OF ALTERNATIVE MODES OF COAL ENERGY TRANSMISSION (FOR 1000 MILE TRANSPORT DISTANCE)



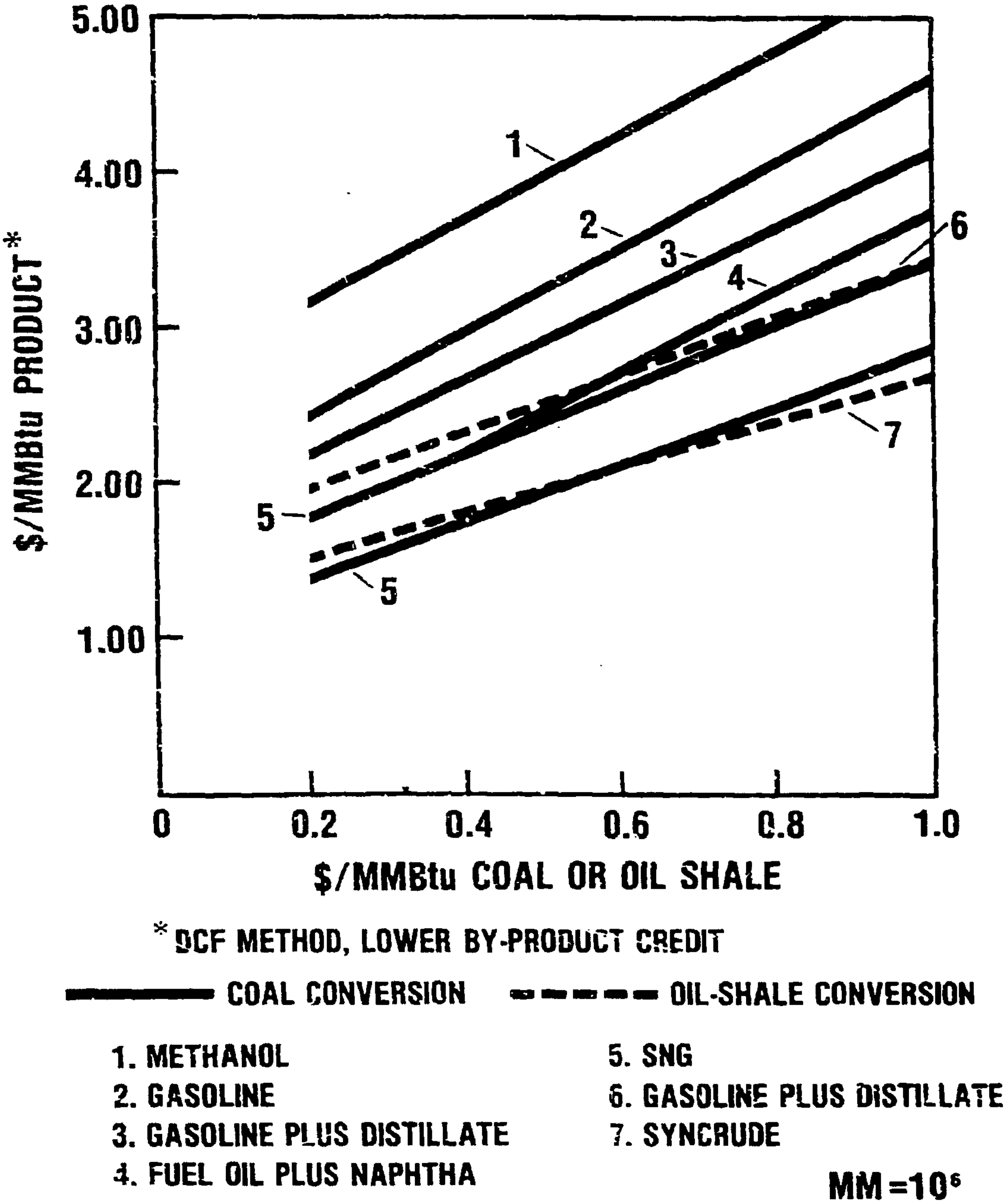
Source: *Oil and Gas Journal,* 24 March 1975.

Figure VIII-3. COST COMPONENTS OF VARIOUS SYNTHETIC FUEL PROCESSES

this mine mouth concept will make a great contribution beyond that already planned. Low levels of pollution produced by mine-mouth plants were expected to be tolerable in remote regions. Unfortunately, these plants have become so large that even with fairly good particulate emission controls, the emissions remain substantial and spread their effects over a wide area.

Synthetic Fuel Costs

Numerous synthetic fuel processes are currently being designed and evaluated. Figure VIII-3 shows the projected required selling prices (1973 dollars) and the cost components of a few of the processes being given serious consideration. In addition, these coal fed processes are compared to similar processes using oil shale as the primary feed. All of the processes are seen to be capital intensive and highly dependent upon byproducts to make them competitive with existing sources of energy. The byproducts from conversion plants are expected ultimately to saturate byproduct markets, decreasing their value. Consequently, the selling price that must be sought for the synthetic fuel must increase to bring an adequate return to the investor.



Source: *Oil and Gas Journal*, 24 March 1975.

Figure VIII-4. EFFECT OF PRICE OF ENERGY FEED ON PRODUCT SELLING PRICE

The cost of the fuel feed is a significant factor in the ultimate production cost of the converted product. Figure VIII-4 indicates for each process the relative effect of changes in coal price on the price for the synthetic fuel.

ECONOMIC CONSIDERATIONS BIBLIOGRAPHY

Basic Estimates Capital Investment and Operating Costs for Underground Bituminous Coal Mines; Mines with Annual Production of 1.03 to 3.09 Million Tons From a 48-inch Coalbed. *Bureau of Mines Information Circular. No. 8689. (Revision of Information Circular No. 8641). Washington, D.C.: U.S. Government Printing Office. 1975.*

Duchesneau, Thomas D. *Competition in The U.S. Energy Industry.* Cambridge, Massachusetts: Ballinger. 1975.

Federal Energy Administration. *Project Independence Report.* Washington, D.C.: U.S. Government Printing Office, November 1974.

Gordon, Richard L. *U.S. Coal & The Electric Power Industry.* Washington, D.C.: Resources for the Future, 1975.

Hottel, H. C. and J. B. Howard. *New Energy Technology–Some Facts and Assessments.* Cambridge, Mass.: The MIT Press, 1971.

National Petroleum Council, *U.S. Energy Outlook: Coal Availability.* Olaf A. Larson, Chairman. National Petroleum Council, 1972.

Slurry Pipeline, Innovation in Energy Transportation. Energy Transportation System, Inc., March 1975.

University of Oklahoma. The Science and Public Policy Program. *Energy Alternatives: A Comparative Analysis.* Norman, Oklahoma: University of Oklahoma, May 1975.

IX. LEGISLATIVE POLICY

In addition to the technological, economic and geological influences, the present and future development of coal is, to a significant extent, determined by federal energy policy as it is formulated through legislation and administered by various agencies. This chapter addresses the development of policies relating to coal and identifies government agencies responsible for implementing programs and regulations to achieve these policy goals.

Historically, any semblance of a national energy policy has been the byproduct of programs relating to the economy, national security, scientific research, water, land and mineral development, the environment or health safety. A dramatic shift took place, however, when in 1973 the oil embargo, the balance of payments deficit, and the increasing cost of crude oil brought the United States to the realization that the country needed a comprehensive energy program to curb dependence on foreign petroleum products, to develop energy resources and to research, develop, and test alternative energy sources.

In response to the emerging energy crisis an examination of the national situation was made, and a report submitted to the President by then Chairman of the Atomic Energy Commission, Dixie Lee Ray. In that report, a five-year, $10 billion program of energy research and development was recommended to develop potential domestic energy resources. As a follow up to the Ray Report, the Federal Energy Administration was instructed in early 1974 to evaluate the nation's energy problems and to develop a framework for a national energy policy. Their report, known as Project Independence, was shaped by three underlying considerations: the importance of making explicit the dependence of supply, demand and policy alternatives on prices; the need to consider domestic supply, demand and constraints on a regional rather than a national basis; and the desirability of structuring the overall energy system in one cohesive, analytical framework.

Influenced by the recommendations of the reports and a growing concern over the energy crisis, the President submitted proposals to create a coordinated energy program. As a result of these proposals, the Congress enacted legislation to reorganize the federal government for the handling of energy issues. This effort included the creation of a new independent energy research and development agency as well as the assignment of primary and secondary energy responsibilities to existing agencies. The following laws serve as the mandate for federal energy organization:

The Federal Energy Administration of 1974 (P.L. 93-275) which was signed on May 7, 1974 established FEA.

The Special Energy Research and Development Appropriation Act (P.L. 93-322) was signed June 30, 1974. This act:

- Appropriated money to AEC, DOI, NSF, EPA, FEA, NASA, DOT and NOAA for expansion of energy R&D;
- Funded projects such as coal liquefaction, Hydrane high-Btu gasification, MHD, fuel allocation, and oil and gas programs.

The Energy Reorganization Act of 1974 (P.L. 93-438) was signed October 11, 1974. This act:

- Abolished AEC;
- Established ERDA as a major federal energy R&D agency;
- Established the Energy Resources Council to coordinate energy policy and advise the President and Congress on government energy management;
- Created NRC to carry on AEC's regulatory function.

The Federal Nonnuclear Energy Research and Development Act of 1974 (P.L. 93-577) was signed December 31, 1974. This act:

- Gives ERDA policy guidance for conducting nonnuclear R&D;
- Includes implementation of special nonnuclear technologies previously enacted into law;
- Accelerates commercial demonstration of technologies for: (a) producing substitutes for natural gas; (b) geothermal energy; (c) electrical energy generation, storage and transmission; (d) production of syncrude from oil shale and coal;
- Includes authorization for CEQ to analyze the effects of nonnuclear energy technologies on the environment.

Federal Agency Functions

The reorganization of the federal government to provide for a coordinated national energy program resulted in changes in the administration of existing coal-related activities as well as the creation of new projects. The following is a brief summary of the coal-related responsibilities of the major energy agencies in federal government.

The *Federal Energy Administration* has as one of its responsibilities the administration of the Energy Conservation and Oil Policy Act of 1975. This Act has a significant impact on coal in that it gives FEA the authority to prohibit power plants and other major fuel burning installations from burning natural gas or petroleum products and to require them to substitute coal as their primary energy source. It also provides that FEA may guarantee loans for the development of new underground coal mines.

Other FEA responsibilities relating to gas and oil allocation programs and long term national planning also influence the demand for coal.

The *Energy Research and Development Administration's* coal R&D program is designed to accelerate the development of the technology for converting coal to environmentally acceptable liquid and gaseous fuels. to stimulate improved methods for the direct combustion of coal, and to develop advanced power conversion systems to improve electric power plant efficiency. Specific coal conversion programs include:

- Liquefaction R&D to advance the technology needed to convert coal to low-sulfur, low-ash fuel oil for power generation and for upgrading to transportation fuels. Four methods are being tested: catalytic hydrogenation, solvent extraction, pyrolysis, and indirect synthesis variations.
- High-Btu and low-Btu gasification R&D is being sponsored to produce a suitable utility fuel and a pipeline quality gas. In-situ processes are included in this R&D effort.
- Fluidized-bed boiler systems are being developed to remove sulfur directly during the combustion of coal.
- Advanced power conversion systems such as fuel cells. MHD generators, and liquid metal topping cycles are being sponsored.
- Advanced research and supporting technology in liquefaction, gasification. direct combustion, and advanced power system programs are being expanded in 1976.
- Pilot plant development, including conceptual and engineering design phases, for the clean boiler fuel demonstration plant is being sponsored with construction scheduled for early 1978.

The *Department of Interior's* coal-related activities are centered in the Bureau of Mines, the Bureau of Land Management and the Mining Enforcement and Safety Administration. The Bureau of Mines monitors the entire range of activities involved in the utilization of coal. These include extraction, reclamation, and actual use as an energy source. The Bureau of Land Management regulates the leasing of federal land. The Mining Enforcement and Safety Administration acts as the administrator of programs established by the Federal Coal Mine Health and Safety Act.

Since its establishment in 1970, the *Environmental Protection Agency* has carried out the enforcement of regulations and has participated in research activities to prevent and control air and water pollution. These programs for the most part have been mandated by the Federal Water Pollution Control Act and The Clean Air Acts. EPA has conducted coal-related research to develop improved low-cost techniques to remove air pollutants before and after combustion of coal: to improve the efficiency of fuel combustion: to dispose of the undesirable products of combustion; and to produce synthetic or new fuels which create less air pollution.

The *National Science Foundation's* coal-related research is funded through the Research Applied to National Needs (RANN) program. Research is directed toward developing new or improved technology which can be transferred to and carried out by other federal agencies or industry involved in coal research at a more advanced stage.

Congress, over the years, has created a complex network of laws which influence the present and future development of coal. The laws which, at present, have the most significant effects on coal are listed below. They fall into four categories: environment, conversion, health and safety standards, and leasing policy. Currently Congress has before it legislation which would provide new policy initiatives governing the development of synthetic fuels from coal; the transport of coal via slurry pipelines; the establishment of federal surface mining regulations, and revision of existing Department of Interior leasing programs. These and other proposals may become the latest additions to the network of federal coal policy.

ENVIRONMENT

Regulations dealing with environmental problems include overall policy as well as specific legislation addressing air and water.

National Environmental Policy Act of 1969

This act provides both a conceptual basis and a legal sanction for establishing environmental management as a national priority. The act has three major purposes: (1) to declare protection of environmental quality to be a national policy and provide a mandate to all federal agencies to carry out that policy; (2) to create CEQ to ensure that the mandate is carried out; and (3) to establish a set of action-forcing procedures requiring an environmental impact statement for any proposed major federal action which could significantly affect the quality of the environment.

Clean Air Act of 1963

This act provides for grants to states and local agencies to assist in controlling air pollution and provides limited authority for federal action to abate interstate pollution problems.

Air Quality of 1967 and Clean Air Amendments of 1970

These acts both amend the Clean Air Act of 1963 and initiated the organization and preparation necessary for a nationwide program for air quality. The Air Quality Act of 1967 set in motion the development of regulations by state and local governments. Under the 1970 amendments to the act, states are charged to develop implementation plans to control and reduce air polluting emissions so that the ambient-air-quality standards could be met. Primary ambient-air-quality standards define levels of air quality judged to allow an adequate margin of safety to protect the public health. Secondary standards define levels judged to protect public welfare.

Water Resource Planning Act of 1965

The act established the Water Resources Planning Council which has been given the responsibility for coordinating the planning for water and related land resources.

Federal Water Pollution Control Act Amendments of 1972

These amendments established controls over the disposal of pollutants from any man-made or man-induced source or cause, including those from federal installations. To administer the act, the Administrator of EPA is given broad powers to establish and enforce standards.

CONVERSION

To reduce dependence on fuels in low or restricted supply, legislation has been enacted to encourage conversion of oil and gas-fired plants to coal-fired plants.

Defense Production Act of 1950 (As amended)

This act authorizes the President to establish priorities in the performance of contracts or orders needed to promote the national defense: to require the acceptance and performance of such contracts or orders for assisting in establishing priorities: and to allocate materials and facilities to promote national defense.

Energy Policy and Conservation Act of 1975

Title I of this act amends the Energy Supply and Environmental Coordination Act of 1974 and extends its authority until January 1, 1985. Under the new law the FEA is authorized to prohibit any power plant or major fuel burning installation from burning natural gas or petroleum products as its primary energy source. This action may only be taken upon determination by FEA that the facility meets defined criteria for capability and plant equipment to burn coal. FEA is also authorized to require that facilities in the early stages of planning be designed and built to be able to use coal as their primary fuel (FEA cannot order these power plants to burn coal, however) and to allocate coal to power plants and major fuel burning installations that have been prohibited from burning oil and natural gas.

A provision providing for loan guarantees to eligible persons to increase coal production through the development of underground mines is also included as an amendment.

HEALTH AND SAFETY STANDARDS

Regulations requiring that mining operations maintain certain health and safety standards are significant in that they have an impact on production levels and the cost of mining.

Federal Metal and Nonmetallic Mine Safety Act of 1966

This act gives the responsibility to the Secretary of Interior for the development of mine health and safety standards, the regular inspection of mines, and implementation of a safety training program.

Federal Coal Mine Health and Safety Act of 1969

This act provides authority to promulgate and enforce health and safety regulations. Major areas covered are dust concentration, gas hazards, roof support, ventilation, electrical equipment and fire protection. Title IV of this act established the Black Lung Benefit Program which provides compensation to miners (and their dependents) in the event that they contract black lung.

LEASING POLICY

The leasing policy of the federal government regulates the level of mineral production from federal land. This policy is of great importance since a large portion of the western coal resources are on public land. Presently, a moratorium is in effect on all leasing. However, the following acts regulate leasing under normal conditions.

Mineral Leasing Act of 1920

This act allows the prospecting and mining of minerals (coal) on public land on a lease basis.

The Mineral Leasing Act for Acquired Lands of 1947

This act extends the provisions of the Mineral Leasing Act of 1920 to include acquired lands.

The Mining and Minerals Policy Act of 1970

This act establishes a federal policy to govern the development of mineral resources. to include the encouragement of private enterprise in the development. mining and study of minerals.

STATE LAWS AND REGULATIONS

In addition to federal influences. individual states also have laws and regulations which play a significant role in the development of coal. Surface mining and land reclamation is one aspect of coal recovery where the states alone have jurisdiction. The establishment of a federal policy for surface mining and reclamation was provided for in the Surface Mining Control and Reclamation Act of 1975, but was never implemented as the result of a presidential veto of the bill.

The existing state laws range from strict. including stiff license. bonding and reclamation requirements to provisions which contain only moderate standards with small penalties. State laws pertaining to tranportation, such as weight load limitation, must also be recognized as a factor in the delivery of coal.

Other areas in which states provide input include the development of state implementation plans called for by the Clean Air Act. While minimum standards have been established by the EPA, individual states are free to require more rigid controls.

State water laws providing for control over water use and pollution are also important to any development of coal. Along the same line are the state land use and mineral rights statutes which may restrict the utilization of some resource areas.

ABSTRACTED GASIFICATION PROCESSES

1. Advanced Gasification System

Two pressurized, fluidized-bed vessels are used. Air, steam, and char react in the gasifier. Resulting hot gases provide heat for the devolatilizer/desulfurizer where dolomite is added to remove sulfur. Low-Btu product gases may be used as a fuel gas or in a combined power system. Process conditions in the reactors are 10 to 20 atm with temperatures at 1900° F in the gasifier and 1600° F in the devolatilizer.

A 1200 lb/hr process development unit (PDU) has been constructed at Waltz Mill, Pa. Westinghouse Corporation, five private industry participants, and CCU are cosponsoring the project.

2. BIGAS

The gasifier is a two-stage entrained-flow reactor. Coal fed into the top stage of the reactor is entrained and devolatilized by hot synthesis gas rising from the lower stage. Unreacted char from the top stage is gasified in the lower stage with oxygen and steam under slagging conditions. The partially methanated product gases in the top stage are cleaned and further methanated into pipeline quality gas. Process conditions are 50-100 atm with temperatures of 2700-2800° F in the lower stage and 1400-1700° F in the top stage.

A 120 tpd BCR pilot plant is under construction at Homer City, Pa. CCU and AGA are cosponsoring the pilot plant program.

3. CO_2 Acceptor

Two fluidized-bed reactors are used to convert highly reactive coals, such as lignite and subbituminous coal, into a medium-Btu gas which can be upgraded to pipeline quality gas. Coal fed into the gasifier is devolatilized and then gasified with steam. Heated calcium oxide provides reaction heat and combines with (acceptor) CO_2 from reaction products. Char and calcium carbonate products from the gasifier are fed to the regenerator where char supported combustion reverses the acceptor reaction, thereby recycling calcium oxide acceptor to the gasifier. The process operates at a pressure of 150 psi with a gasifier temperature of 1500° F and a regenerator temperature of 1870° F.

Through CCU and AGA sponsorship, a 40 tdp pilot plant has been built in Rapid City, South Dakota, by Conoco Coal Development Company.

BLANK PAGE

4. COGAS

A fluidized bed char gasifier produces a medium-Btu gas which can be cleaned up and upgraded to pipeline quality gas. A portion of the feed char is burned in a combustor with air. Char fines or inert pellets are thereby heated and then fed to the gasifier to provide endothermic heat for a steam-carbon reaction which produces the medium-Btu gas. A coal pyrolysis process, such as COED, would produce liquid fuels and char for the production of high-Btu gas without the use of an oxygen plant. Reaction pressures are 0-30 psig and reaction temperatures are 1600 to 1700° F.

A 2½ tpd (char) pilot plant is in operation in Princeton, N.J., under private funding by the COGAS Development Company (a partnership of six companies). Also, a 50 tpd (char) pilot plant is in operation in England by British Coal Utilization Research Association.

5. Gasification – Combined Cycle

An air-blown, two-stage entrained flow gasifier is used to produce low-Btu gas. Coal is fed into the top stage of the reactor where it is entrained and partially gasified by hot gases from the lower stage. Char is separated from the raw product gases by cyclones and fed to the lower stage where complete gasification occurs with air and steam. Product gases are cooled and cleaned and can then be used to fuel a gas turbine. Waste gases are then cooled in a waste heat boiler producing steam for a steam turbine resulting in a combined power system. The process operates at a pressure of 500 psig and temperatures of 1800° F in the top stage and 2800° F in the lower stage.

A 500 tpd pilot plant is being designed and developed by Foster Wheeler Energy Corporation with the cosponsorship of ERDA.

6. GEGAS

A stirred, fixed-bed reactor is used to produce a low-Btu gas from a wide variety of coals. Reactor pressure may be on the order of 350 psi. Coal is fed to the gasifier with a unique extruder (auger) feed which could facilitate the flow of coal from lock hoppers to a pressurized gasifier.

A 2000 lb/hour pilot plant is under construction through joint funding by General Electric Company and EPRI.

7. HYDRANE

A two-stage fluidized-bed reactor produces high-Btu gas from caking coals without pretreatment. Coal is fed into the top stage where it reacts with hydrogen in a free-fall zone (dilute-phase hydrogenation). Resultant char reacts further with hydrogen in the fluidized bed of the lower stage, producing methane. Hydrogen is produced in a separate reactor by steam-oxygen gasification of excess char from the gasifier. Gasifier pressures may exceed 1000 psig and hydrogasification temperatures are generally 1600° F.

A 10 lb/hour laboratory unit is in operation and a 24 tpd pilot plant is being planned by PERC.

8. *HYGAS*

A two-stage, fluidized-bed gasifier is used to produce a raw gas that can be upgraded to pipeline gas. Caking coals are pretreated in a fluidized bed to produce a nonagglomerating coal which is slurried in light oil and fed to a low temperature fluidized drying bed. Coal from the drying bed then passes into the first stage of the gasifier where it is devolatilized and partially methanated. Char then falls to the lower stage where it is gasified at high temperatures in the presence of hydrogen and steam. Hydrogen for the process can be generated by any one of three fluidized bed gasification methods currently under investigation. Process pressure is 1000 to 1500 psig in the drying bed and in the gasifier. Gasifier temperatures are 1300-1500° F in the top stage and 1700-1800° F in the lower stage. The hydrogen producing gasifiers will also operate at high pressure and temperatures.

A 75 tpd IGT pilot plant has been in operation since 1973 through IGT, CCU and AGA cosponsorship. The "Steam Oxygen" and "Steam-Iron" hydrogen producing gasifiers are being researched. These two and the "Electro-Thermal" gasifier are being studied for commercial application.

9. *Koppers-Totzek (K-T)*

An entrained flow reactor can produce a medium-Btu gas from coal. The feed coal is partially oxidized in suspension with oxygen and steam. Product gases can be upgraded to pipeline gas. Reactor temperatures may be 3500° F with pressures up to 150 psig.

Thirteen plants employing 39 gasifiers have been installed in Europe, Africa, and Asia. Koppers Company, Inc. in the U.S. and Koppers (of West Germany) market the K-T systems.

10. *Liquid Phase Methanation*

Fluidized nickel catalyst is used to convert carbon monoxide and hydrogen feed gas (medium-Btu) to high-Btu gas. The solid catalyst is suspended in a circulating inert paraffinic oil. Feed gas enters at the bottom of the low temperature reactor and is converted to methane as it passes upward through the fluidized catalyst. The three-phase flow reactor operates at a pressure of 1000 psig and a temperature of 570° F.

Chem Systems, Inc. is developing the process under contract with CCU and AGA. A pilot plant capable of producing 250 mmscf per day has been built and operation is pending.

11. *Low-Btu/Fixed-Bed Gasifier*

Three fixed-bed gasifier configurations are to be tested to develop a clean low-Btu gas process for combined power plant systems. The gasifiers will be developed to utilize a highly agglomerating run of mine coal. High temperature and low temperature sulfur removal methods will be used. The stirred. fixed-bed reactor under development by MERC is serving as a design basis for this gasifier development program.

One 25 ton per hour reactor will operate over a pressure range of 100 to 300 psi. The other two atmospheric pressure reactors will have a capacity of 10 tons per hour each. The Tennessee Valley Authority (TVA) is managing the program in an interagency agreement with ERDA.

12. *Low-Btu Fuel Gas*

Three fluidized-bed reactors are used to produce low-Btu gas from caking and noncaking coals. Coal is devolatilized in the first stage reactor. Devolatilized coal is burned in the second stage reactor forming char which is burned in the third stage reactor. Off-gas from the first and third stages support the primary production of fuel gas from the second stage reactor. The third stage reactor operates at a temperature of 2100° F. The second and first stages operate at lower temperatures of 2000° F and 1200° F respectively. (Process pressures are apparently low).

A 100 lb per hour PDU is in operation in Monroeville, Pa. BCR is developing the process under ERDA sponsorship.

13. *Low-Btu Gasification for Electricity Generation*

An atmospheric pressure, entrained flow reactor is being designed to produce low-Btu gas from coal and recycled char. Coal. char, and air (or O_2) are fed into the combustor section in the lower part of the reactor. Additional coal and steam are injected into the reducer section above the combustor. In this entrainment process. coal is devolatilized and reacts with hot combustion gases to result in low-Btu gases being produced in the upper gasifier section of the reactor. Product gas temperatures may be 1600° F.

A 5 ton per hour pilot plant is being developed by Combustion Engineering. Inc. and EPRI through cosponsorship with ERDA. The pilot plant is in design and is scheduled to be constructed and operating in 1977.

14. *Lurgi*

A fixed-bed reactor is used to convert primarily noncaking coals to a medium-Btu gas that can be upgraded to pipeline gas. Coal is fed into the top of the reactor where it is devolatilized and distributed. Coal is gasified in an intermediate zone as it falls to the oxygen-rich combustion zone. Steam is also fed to the combustion zone where temperatures reach 2500° F. Reactors are typically designed for pressures of up to 450 psi.

Nearly 60 commercial units have been installed worldwide by Lurgi Gasellschaft fur Warme and Chemietechnik. M.b.H. (of West Germany). Thirteen Lurgi gasifiers are installed in Sasolburg. South Africa. to produce raw synthesis gas for oil synthesis.

15. Molten Carbonate Process

Coal and steam are fed into a molten bath of sodium carbonate which serves as a heat source and as a catalyst. The product gas can be upgraded to methane. Sulfur entering with the coal accumulates in the bath as sodium sulfide. Circulating melt carries char to a combustor where char is burned in oxygen or air which reheats the melt for the gasifier. A stream of melt is continuously withdrawn to purge the melt of ash and sulfur (in the form of hydrogen sulfide). Most of the sulfur in the coal is removed in this way. This two-vessel process is now being developed into one vessel to perform both gasification and combustion functions. The process gasifies coal at 1830° F and burns char at 1900° F at a pressure of 420 psia.

Bench scale tests have been conducted in-house by the M. W. Kellogg Company of Houston, Texas. The design, development, construction, and operation of a pilot plant is being proposed.

16. Molten Iron

Using steam as a carrier, a mixture of coal and limestone is injected into a molten bath of iron. By injecting either air or oxygen into the molten bath, the carbon from the coal is oxidized to CO. Injected steam dissociates to produce hydrogen and additional CO. A low, medium or high-Btu gas can be formed through this basic process. The limestone in the mixture absorbs sulfur and forms slag near the surface of the molten bath. The slag is removed through a slag port, is desulfurized, and the limestone is then recycled to the gasifier. Process conditions are 50 psig and 2500° F.

Bench-scale tests have been conducted by Applied Technology Corp. through EPA sponsorship (ATGAS, PATGAS, and two-stage processes produce high, medium, and low-Btu gases respectively).

17. Molten Salt

Air carries coal and sodium carbonate into a molten bath of sodium carbonate. Coal volatiles crack, producing a low-Btu off-gas. A stream of melt is continuously removed to purge the melt of sulfur and ash. With some modifications, a high-Btu gas could be produced via this basic reactor concept. Process conditions are 5 to 10 atmospheres and 600° F to 700° F.

A 120 tpd pilot plant is being built by Atomics International. The project is being cosponsored by ERDA and Northeast Utilities Service Company.

18. Nuclear Gasification

Coal is slurried and dissolved in the presence of hydrogen. Liquid coal is further hydrogenated in subsequent steps, resulting in a desulfurized high-Btu gas. A portion of the product gas is cycled to a steam-methane reformer, a heat exchanger in the primary coolant loop of a high temperature gas-cooled reactor (HTGR). Endothermic steam-methane reforming produces hydrogen-rich gas and CO_2. The hydrogen is then separated and cycled back to the coal hydrogenation part of the process. Liquid fuel products can also be formed by this fundamental process. Reformer pressures can be in excess of 700 psi and temperatures can be 1200-1600° F.

A demonstration plant is being planned and the process is being developed by Stone and Webster Engineering Corp. and General Atomic Co.

19. Self-Agglomerating

Two fluidized bed reactors are used to produce a raw synthesis gas that could be upgraded to pipeline gas from coal. Coal is burned in a fluidized bed burner at a temperature approaching the ash fusion point of the feed coal. Off-gases from this burner should be sufficiently clean of fly-ash to be expanded in an open cycle gas turbine. Ash agglomerates are transferred from the burner to the gasifier via a steam lift. Additional coal is fed to the gasifier. Superheated steam fluidizes the coal/ash mixture. The hot, inert ash supplies heat of reaction for endothermic coal gasification reactions which can be the basis for producing methane.

A 25 tpd PDU is under construction in West Jefferson, Ohio and the process is being developed by Battelle Memorial Institute Columbus Laboratories. The project is being sponsored by CCU.

20. STEAG-Combined Plant

A Lurgi gasifier is used to produce high pressure, low-Btu gas which is scrubbed, expanded in an expansion turbine, burned in a pressurized boiler and finally expanded again in a gas turbine. The pressurized boiler drives a steam turbine which, in combination with gas turbine power extraction, extracts a maximum of heat energy from the combustion and gasification of coal. The combined plant currently operating in Lunen, Germany, is too small to actually maximize the heat energy recovery from coal that a commercial size plant may be able to achieve.

The 170 Mw combined plant currently in operation is the design basis of an 800 Mw plant in planning. STEAG Atiengesellshaft of West Germany is developing the concept.

21. Stirred Fixed-Bed Gasifier

A pressurized, air-blown fixed-bed gasifier is being developed to produce a low-Btu gas from a wide variety of coals. A variable height stirrer facilitates the breaking-up and gasifying of caking coals. The gasifier is very similar to the Lurgi gasifier in operating principle. Process conditions are 2300° F in the combustion zone and the pressure is 300 psig.

A 2000 lbs per hour gasifier is being tested and developed by MERC in Morgantown, West Virginia.

22. Synthane

A fluidized bed gasifier is used to produce a medium-Btu gas which can be upgraded to a high-Btu gas. A pretreated or noncaking coal is fed into the top of the gasifier.

The coal is devolatilized and gasified as it falls freely to the fluidized bed level. The bed is fluidized by a rising mixture of oxygen and steam fed into the bottom of the gasifier. Flue gas from the burned char would then have to be scrubbed to remove sulfur compounds. Unreacted char settles to the bottom of the reactor where it is removed. Gasifier conditions are 1000 psig and 1800° F.

A 75 tpd pilot plant has been constructed and is in operation. PERC is developing the process.

23. *Texaco Heavy Oil Gasification*

Petroleum based heavy residual fuels are converted to hydrogen or gaseous fuels of several different heating values in this commercially proven process. This partial oxidation process could also be used to gasify coal tars. The reactor is apparently an entrained flow type.

A large scale pilot unit is now under development by the Texas Oil Company.

24. *U-Gas*

A fluidized bed gasifier produces a low-Btu gas from a wide variety of coals. Pretreated coal or noncaking coal is fed into the gasifier where it is gasified directly with steam and air or oxygen. By carefully selecting the steam to air (or oxygen) ratio, ash will agglomerate and can be separated by weight from the fluidized bed. Process conditions are 300-350 psig and 1900° F in the gasifier.

IGT has developed the U-Gas process for the last 30 years. Tests have been conducted on a reactor four feet in diameter.

25. *Wellman-Galusha*

A fixed bed gasifier produces low-Btu gas primarily from mildly caking or noncaking coal. It operates much like the Lurgi gasifier. The stirred fixed-bed gasifier being developed by MERC is based on the Wellman-Galusha gasifier design. The Wellman Galusha operates at near atmospheric pressures.

The gasifier has been operated commercially and a few plants are still operational.

26. *Winkler*

A fluidized bed gasifier produces a low-Btu gas or a medium-Btu gas from a wide variety of coals. Coal is auger fed into the gasifier where it is gasified directly with steam and oxygen. Reactor conditions are atmospheric pressure and 1500 to 1800° F.

Commercial installations are in worldwide use. Bamag Verfahrenstechnik GmBH of (West) Germany and Davy Powergas market the gasifier.

Early Gasification Processes

During World War II, Germany developed a coal-based synthetic fuel industry primarily to produce transportation fuels. Both a Fischer-Tropsch catalytic process and a catalytic coal hydrogenation process were used to obtain a liquid fuel. Most of the German processes and reactors were designed to gasify generally available brown coal (lignite) resources. Consequently, these early gasification processes are not directly applicable to all coal types (Ref. 27).

Several of the early German processes have been refined for commercial applications. Widely employed are the Lurgi gasifier, the Winkler Gasifier and the Koppers-Totzek gasifier, all three of which evolved from early German models. Other early German processes and reactor designs are being adapted and developed for a wider variety of feed coals.

BCR conducted a survey of coal gasification processes (commercial, pilot scale, and conceptual) available in 1965. The survey included only those processes which held promise for potential development as economical systems for the production of fuel gas and/or synthesis gas capable of conversion by water-gas shift and methanation into high-Btu gas. The survey described 65 processes in detail. (Ref. 28 and 29).

In-Situ (Underground) Gasification

Early Russian underground gasification work reached the stage where the extracted gas was used for large-scale generation of electricity and to supply local industries. Outside Russia, most of the experimental activity occurred in the post World Wra II period from 1945 to 1960. Today, no significant activity seems to be underway anywhere in the world, mainly for lack of economic incentives but also because of serious technical problems, such as the lack of process control and the resultant inability to produce gases of a predictable quailty and quantity. In the U.S., ERDA has recently revived experimental work on underground gasification at a site near the town of Hanna, Carbon County, Wyoming, and in Morgantown, W. Va. The decision to revive this work resulted from interest in clean fuels from coal, the changing domestic energy situation and more specifically, the recommendations of a committee in favor of new work to determine the technologic, economic, and environmental feasibility of gasifying eastern and western coals.

Sources for Gasification Abstracts by Abstract Number

1. "Coal Gasification for Clean Power Production" by D. H. Archer, E. J. Vidt, and D. L. Keaims from 1975 IGT Symp.

2. "BIGAS Pilot Plant" by V. L. Brant, from 1974 Ohio Wkshp.
3. "The CO_2 Acceptor Process" by Carl E. Fink from 1973 IGT Symp. "CO_2 Acceptor Pilot Plant-1974" by Carl E. Fink, George Curran and John Sudbury from 1975 IGT Symp.

4. "The Status of the COGAS Project" by R. Bloom, Jr., and R. T. Eddinger from Sixth AGA Synthetic Pipeline Gas Symposium, AGA, Oct. 28, 1974, AGA, CCU, IGA.

5. "Phase I Study of Coal Gasification Combined Cycle Pilot Plant" by Pittsburg and Midway Coal Mining Co., Foster Wheeler Corp., and Northern States Power, Co., March 1, 1974, OCR.

6. "The GEGAS Process" by Paul H. Kydd from 1975 IGT Symp.

7. "The Hydrane Process" by Paul M. Yavorsky from 1973 IGT Symp. "The Hydrane Process" by H. F. Feldman and P. M. Yavorsky from Fifth Synthetic Pipeline Gas Symposium, October 28-31 1973, sponsored by AGA, OCR (CCU) and IGT.

8. "The HYGAS Process" by A. E. Cover, W. C. Schreiner and G. T. Skaperdas from Coal Processing Technology edited by *Chemical Engineering Process* and published by AIChE.

9. "The Koppers-Totzek (K-T) Process and Its Application to Industrial Needs", J. F. Famsworth and D. M. Mitsak from 1975 IGT Symp.

10. "The Liquid Phase Methanation Process" from ERDA-111 75/1.

11. "Low-Btu Fired Bed Coal Gasification and Desulfurization Program" from "Shaping Coal's Future through Technology," (annual report) 1974-1975 by OCR (now CCU).

12. "Gas Generator Research and Development, Clean Fuel Gas Annual Report" from period June 1974–June 1975 by Bituminous Coal Research (BCR), BCR report No. L-705 of 8 August 1975 and ERDA Report No. FE-1527-1. "Low Btu Gas Generator Research and Development" from (ERDA-111-75/1).

13. "Low Btu Gasification of Coal for Electricity Generation" from ERDA 111 75/1.

14. "Evaluation of Coal Gasification Technology, Part I Pipeline Quality Gas." Nat'l Academy of Engineering (GPO), 1974, OCR. pp. 25 and 26. *Project Independence. Synthetic Fuels from Coal.* DOI, Nov. 1974, FEA pp. 112 to 123.

15. "Kellogg's Coal Gasification Process" A. E. Cover, W. C. Schreinder and G. T. Skaperdas from "Coal Processing Technology" editors *Chemical Engineering Progress* (CEP) publishers-AIChE, 1974.

16. "Fuel Gas from Molten Iron Coal Gasification" Paul LaRose and R. J. McGarvey, 1973 IGT Symp.

17. "Molten Salt Process for the Gasification of Coal" by C. A. Trilling from 1974 Ohio Wkshp.

18. "Nuclear Energy for Coal Gasification" R. N. Quade and A. T. McMain from 1973 IGT Symp.

19. "Union Carbide/Battelle Coal Gasification Process" by W. C. Corder, H. R. Batchelder, and W. N. Goldleiger from 1974 Ohio Wkshp.

20. "Combined Gas and Steam-Turbine Process with Lurgi Coal Pressure Gasification" by K. H. Krieb from 1975 IGT Symp.

21. "Bituminous Coal Gasified in a Stirred Bed Producer," by P. S. Lewis, et al. (Report MERC/RI-75 No. 1) MERC June 1975.

22. "The Synthane Process" by W. P. Haynes and A. J. Forney from 1975 IGT Symp.

23. "Texaco Heavy Oil Gasification" by E. T. Child from University of Pittsburg School of Engineering Symposium, Texaco Development Corp. August 6-8, 1974 for OCR (CCU).

24. "IGT U-GAS Process" by J. G. Patel from 1975 IGT Symp.

25. "Advanced Anthracite Technology and Research" by U. H. Burt, and J. R. Kalafut. Published by University of Scranton, Jan. 6 and 7, 1975. ERDA Report No. FE 1774-T1, pp. 60 to 62.

26. "The Winkler Process for the Production of Low Btu Gas from Coal" by I. N. Banchik from 1975 IGT Symp.

27. *Report on the Petroleum and Synthetic Oil Industry of Germany*. by A. Mission from The Ministry of Fuel and Power (London. England). 1947. pp. 3 to 46.

28. *Gas Generator Research and Development Survey and Evaluation. Phase I. Vol. 1 and 2* by Bituminous Coal Research. No. L-156 to The Office of Coal Research. 1965.

29. *Synthetic Fuels Data Handbook* compiled by Dr. T. A. Hendrickson. Cameron Engineers. Inc. 1975. pp. 175. 176 and Appendix. Part I.

30. "Underground Gasification of Coal" by R. M. Nadkarni. C. Bliss. and W. I. Wilson from *1973 IGT Symp.*

APPENDIX B

COAL LIQUEFACTION

ABSTRACTED LIQUEFACTION PROCESSES

Direct Catalytic Hydrogenation

1. H-Coal

Pulverized coal is slurried with coal derived recycled oil mixed with hydrogen and fed into an ebullated bed with cobalt-molydbate catalyst. Liquids and gases are produced. Hydrogen consumption requirements are from 12,200 to 18,600 scf/ton where, respectively, low sulfur fuel oil or syncrude are to be produced. Synthetic crude yield may be 4.06 to 4.38 bbl ton depending upon the type of coal used. Product oil contains less than 0.1 percent sulfur (by weight). Reactor operating conditions are 850° F and 3000 psig.

A 3 tpd PDU is in operation and the process is being developed by Hydrocarbon Research Inc. A 600 tpd pilot plant is being designed and constructed under the cosponsorship of ERDA, EPRI and four oil companies.

2. Synthoil

Coal in a recycled oil slurry is mixed with hydrogen and fed into a fixed bed (packed bed) catalytic reactor. The catalyst is composed of pellets of cobalt molybdate on silica promoted alumina. In this hydrodesulfurization process, coal is liquefied and sulfur removed as H_2S. Liquid product is fuel oil. Hydrogen consumption is from 3400 to 4375 scf/bbl of product. Fuel oil yield is 3.2 to 3.4 bbl/ton of coal and has a heating value of 17,000 btu/lb. Sulfur content is 0.4 to 0.2 percent by weight. Reactor operating conditions are 850° F and 4000 psig.

PERC has been operating a 1/2 tpd experimental unit. A 10 tpd PDU is being designed by Foster Wheeler Energy Corp. through ERDA sponsorship.

3. Co-Steam

Pulverized lignite in some of the product oil is pumped with process gas (CO and steam) into a stirred reactor. The process utilizes natural alkalinity of lignite to catalyze the CO + water reaction to produce hydrogen, which liquefies lignite. The product goes to a receiver where oil, gas ($CO + H_2$) and unreacted solids are separated. Low sulfur fuel oil yield is 69.4 to 77 percent by weight. Product gases provide the hydrogen for the hydrogenation process. Reactor operating conditions are 800° F and 4000 psig.

A 1/2 tpd unit has been in operation. A 10 tpd PDU is to be built and developed by Grand Forks Energy Research Center GFERC (ERDA).

4. *Gulf CCL*

Coal is slurried in recycle oil, mixed with hydrogen and fed to the fixed-bed reactor. Coal molecules are deploymerized in the presence of hydrogen and a catalyst. Gas, liquid and solid products are then separated. A heavy fuel oil (similar to #6) with a heating value of 17,900 Btu/lb and a light fuel oil (similar to #2) with a heating value of 18,800 Btu/lb are produced. The yield of heavy fuel oil is 2.3 bbl/ton and 0.9 bbl/ton for the light fuel oil. Products contain approximately 0.04 percent sulfur.

A 120 lb/day bench scale unit is being operated and developed by Gulf Research and Development Co.

5. *Bergius Process Hydrogenation*

Coal is pulverized and made into paste with heavy oil derived from the process. Powdered catalyst and hydrogen are mixed with the paste and the liquid phase hydrogenation is carried out in a series of converters. Gasoline and middle oil are eventually distilled from liquid products. The catalyst is composed of $FeSO_4$-H_2O and sodium sulfide. Reactor process conditions are 800 to 900° F and 250 to 700 atm. The yield range is 50 to 67 percent of coal fed by weight.

Peak production capacity was 64,200 bbl/day during WW II in Germany.

6. *Zinc Chloride Catalysts*

Coal is pulverized and slurried in the recycle oil. The slurry is fed to the reactor where hydrogen and molten zinc chloride are added at high reactor temperature and pressure. One-step hydrocracking takes place in the molten salt reactor. The distillate product is separated from gases. The spent catalyst is regenerated in the fluidized bed combustor and recycled. Fuel oil and low-Btu gas are produced. Reactor operating conditions are 700 to 825° F and 1500 to 3500 psia.

A 2.5 lb/hr bench-scale unit is in operation. A 1.2 tpd PDU is currently in design and development by CONOCO Coal Development Co. and Shell Development Co. with cosponsorship from ERDA.

7. *Disposable Catalyst Hydrogenation (Advanced version of Bergius Process)*

A low cost disposable catalyst is being tested in a Synthoil style fixed bed reactor and in a stirred reactor. Low sulfur fuel oil is the primary product. Reactor operating conditions (850° F and 250 to 700 atm.) are significantly less than those of the Bergius process.

A 50 lb/hr PDU is being designed at PERC and a 5 to 10 tpd unit may follow.

Solvent Extraction Processes

8. CSF (Cresap)

Crushed coal is mixed with a recycled solvent, then heated and fed to the extractor. Coal is dissolved in solvent and the product from the extractor is separated. Solid product is carbonized to char which may be used to produce H_2 for the process. Liquid is subjected to hydrogenation and fractionation to produce low sulfur fuel oil and solvent for recycle. No catalyst is required for solvent extraction. Reactor operating conditions are 765° F and 150 psig.

The 20 tpd CSF pilot plant in Cresap, West Virginia has been operated. Fluor Engineers and Constructors, Inc. is reactivating the plant under contract with ERDA.

9. PAMCO SRC Process

Pulverized coal is mixed with a recycled coal derived solvent, pumped through a preheater where hydrogen is mixed in and then sent to a dissolver. The coal is dissolved in solvent. The liquid product from the dissolver is degassed, hydrogen is recirculated and passed through a distillation unit to recover solvent and heavy product which is cooled and solidified to result in solvent refined coal. SRC has a heating value of 16,000 Btu/lb and a sulfur content of 0.5 to 0.9 percent by weight. Process operating conditions are 800 to 900° F and 1000 to 2000 psi.

A 50 tpd pilot plant is currently in operation. The process is being developed by Pittsburg and Midway Coal Mining Co. (PAMCO) and Rust Engineering Co., under ERDA sponsorship.

10. Southern Services SRC Process

This process is similar to the PAMCO SRC process except for the filtration and product solidification system.

A 6 tpd pilot plant has been in operation. Project sponsors are Southern Services, Inc. and EPRI.

11. Modified SRC Process

Similar to PAMCO SRC process, the difference is that the unfiltered dissolver product is recycled as feed slurry medium. The dissolver product is further hydrotreated to produce a low sulfur liquid product.

Preliminary design of a 10,000 tpd plant has been completed.

12. Solvent Refined Lignite

Solvent extraction of lignite is produced from synthesis gas (CO & H_2) under 1500 to 3000 psig by vacuum flashing, producing solvent refined lignite and light oils.

A 5 tpd PDU is being tested by the University of North Dakota under ERDA sponsorship.

13. Delayed Coking

Deep hydrogenation followed by thermal cracking produces distillate fuels.

Laboratory batch tests are being conducted by A. D. Little, Co. and Foster Wheeler Energy Corp. under ERDA sponsorship.

14. Hydrogen Donor Solvent Process

A process under development by the Exxon Co. uses a separately hydrogenated solvent which exchanges hydrogen with coal. The hydrogen donor solvent process uses coal heated in the presence of hydroaromatic material at 700-850° F and 200-1000 psi. Liquid products can be upgraded by catalytic hydrogenation.

Exxon has operated 1/2 tpd pilot plant at its research center in Baytown, Texas.

15. Hydrocarbonization Process

Coal is crushed, dried and preheated to 750° F in a stream of hot flue gas. A hydrogen stream produced from char carries the coal into the fluidized bed hydrocarbonization reactor where coal is converted to gas, liquid and char. Hydrocarbonization consists of a combination of coal devolatilization and hydrogenation of various constitutents of volatile matter. The product, after char removal, is sent to a fractionator. Heavy and light oils are separated. Gas, after passing through purification, is methanated to produce pipeline gas. Process conditions are 470 to 560° F and 300 to 1000 psig. H_2 is produced by a Koppers-Totzek gasifier.

A 500 tpd pilot plant was operated by Union Carbide Co. in the mid-1950's. Construction and operation of the Clean Boiler Fuels Demonstration Plants by Coalcon Development Co., is being sponsored by ERDA.

16. COED Process

Pulverized coal is heated using successively higher temperatures in a series of four fluidized bed pyrolytic reactors (carbonizers). In the first stage, coal is heated by hot fluidizing gases. Devolatilized char from the first reactor flows toward hotter reactors while steam and oxygen introduced in the last reactor flows countercurrent to the main stream. Vapors from the second stage are separated into a liquid product and a gas product in a product recovery section. Process pressures are from 5 to 10 psig. Process temperatures range from 500° F in the first stage to 1600° F in the fourth stage.

A 36 tpd COED pilot plant at Princeton, N.J., has been successfully operated and is being dismantled. COGAS pilot plant is now being constructed by the FMC Corporation under ERDA sponsorship to desulfurize char and produce clean gas.

17. Seacoke

Similar to the COED process, five fluidized bed pyrolyzers produce a syncrude (1.3

bbl/ton), char and fuel gas. The operating pressure is 1 atm. Process temperatures range from 600° to 1600° F from the first to fifth stage.

The related COED process is being developed in lieu of the Seacoke process.

18. Clean Coke Plus Liquids

Crushed coal is split into two fractions. One fraction is processed in a carbonization unit where it is devolatilized and partially desulfurized to produce char which is further processed to metallurgical coke. The second portion is slurried with recycled oil and processed in a hydrogenation unit which produces liquid and gas products. Liquid products from both the carbonization and the hydrogenation unit are treated in a liquid processing unit to get liquid fuels and chemical feedstocks. Operating conditions are 1200-1400° F and 9-100 psi in the carbonizer. Operating conditions are 900° F and 3000 to 4000 psi in the hydrogenation unit.

A 1/2 tpd PDU is in operation. A 500 tpd pilot plant is being designed by U.S. Steel Co. under ERDA sponsorship.

19. Garrett Coal Pyrolysis

Pulverized coal is transported to the entrained-flow pyrolysis reactor where it is mixed with the stream of hot char coming from the char heater. Hot char provides heat for the flash pyrolysis process. Effluent from the reactor is passed through a cyclone to separate char, part of it goes to the char heater and the remainder goes out as product. Effluent gases are cooled. Tar is separated and hydrotreated to produce syncrude and medium-Btu gases which are purified to get product gas. The process temperature is 1100° F.

A 3.6 tpd pilot plant is in operation under the Garrett development program. Island Creek Coal Co. (a subsidiary of Occidental Petroleum Co.) is cosponsoring the project.

20. TOSCOAL

Crushed coal is preheated by the dilute phase fluid bed technique and fed to a pyrolysis drum where it is heated with hot circulated ceramic balls. The char product is passed through a revolving screen to separate ceramic balls, unreacted coal or char and vapors. Pyrolytic vapors are condensed and fractionated. Ceramic balls are heated and recirculated. Solid char and fuel oil are produced. Operating temperatures are 800 to 1000° F.

Wyoming subbituminous coal was tested in a 25 tpd pilot plant originally built to process oil shale by the Oil Shale Corporation in cooperation with other private companies.

21. Petrocoal

Crushed coal with recycle oil and hydrogen is fed to a hydropyrolytic reactor where coal is converted to asphaltenes. The liquid product, after the removal of solids, is subjected to catalytic hydrogenation at 800-850° F and 1500 psig and product oil suitable for refining is obtained.

A 120 lbs coal/day lab unit has been operated. The process is being developed by MERC.

Liquid Hydrocarbon Synthesis

22. Fischer-Tropsch Synthesis at SASOL

Synthesis gas (CO & H_2) from Lurgi gasifiers is converted to liquid hydrocarbons via an iron catalyst in two basic reactor types. The two reactor types are the Arge Reactor System (fixed bed synthesis) and Synthoil reactor system. Operating conditions are 300 to 360 psig and 430 to 660° F depending on the reactor used.

A commercial scale plant at SASOL, South Africa uses 8000 tpd. The plant is operated by the South African Coal, Oil and Gas Corp. (SASOL) of the Republic of South Africa.

23. Methanol Synthesis

Synthesis gas from a high temperature (2400° F) entrained bed gasifier is passed through a shift converter where the H_2:CO ratio is adjusted to 2:1, purified, and sent to a methanol converter. Crude methanol is distilled to remove water, higher alcohols and other chemicals to get chemical-grade methanol (1000° Btu/lb.) A Cu-Zn-Cr catalyst is used. Catalyst operating conditions are 500° F and 800 psi. Low temperature fluid bed gasification is used for methane-methanol coproducts.

Methanol is presently produced from natural gas.

Sources for Liquefaction Abstracts by Abstract Number

1. "The H-Coal Process" by R. H. Wolk from 1974 Ohio Wkshp.: "The H-Coal Process" from 1975 Cameron Synthetic Fuels Data Handbook; "H-Coal: How Near to Commercialization" by D. A. Johnson and B. Y. Livingston from 1974 Pitt. Symp.

2. "The Synthoil Process by S. Friedman, P. M. Yavorsky and S. Akhtar from 1975 – IGT Symp.; "Synthoil Process" from ERDA-114 75/1.

3. "Oil by Liquefaction of Lignite" by E. DelBel, S. Friedman, P. M. Yavorsky and I. Wender from CPT Vol. 2 by AIChE; "Clean Energy from Coal-New Developments" by I. Wender PERC (BOM now ERDA) report April 1974.

4. "The Gulf Catalytic Coal Liquid Process" by H. G. McIlvried. S. W. Chun. D. C., Cronauer. Report #6214 RDO15 May 25. 1973. Gulf R&D Co. Pittsburgh. Pa.

5. "Report on the Petroleum and Synthetic Oil Industry of Germany by A Mission from the Ministry of Fuel and Power." published by His Majesty's Stationary Office. London 1947.

6. "Coal Liquefaction Research and Development. Program Plan. Dec. 31. 1974." Prepared for Office of Coal Research. Department of Interior by TRW Inc. McLean. Va.

7. "An Overview of R&D on Coal Liquefaction" by P. M. Yavorsky from 1975 Pitt. Symp.

8. "Cresap Test Facility" from ERDA. 114-75/1: "Clean Fuels via CSF Process" by J. A. Phinney from 1973 IGT Symp.: "Coal Liquefaction at Pilot Plant Level" by J. A. Phinney. Chemical Engineering Progress. April 1975 pp. 65-67.

9. "Progress Report of Pilot Plant Work on the SRC Process" by G. E. Chemoweth from 1975 Pitt. Symp.: "The Solvent Refined Coal Process" by B. K. Smidt from 1974 Pitt. Symp.: "The Solvent Refined Coal Process" by R. M. Baldwin. J. O. Golden. J. H. Gary. R. L. Bain. R. J. Long. Chemical Engineering Progress. April 1975: "Recycling Solvent Techniques for the SRC Process" by R. P. Anderson. Chemical Engineering Progress. April 1975.

10. "Status of the SRC Project: by B. K. Smidt. Chemical Engineering Progress. April 1975 pp. 75-78.

11. "Coal Conversion. An Overview of Status and Potential" by J. B. O'Hara. paper presented at Los Angeles Council of Engineers and Scientists Energy Symposium. Los Angeles. Ca. April 3. 1975.

12. "Overview of R&D on Coal Liquefaction" by P. M. Yavorsky from 1975 Pitt. Symp.

13. "OCR Coal Utilization R&D Program" by G. Alex Mills from First Energy Technology Conference. Government Institute Inc.. Washington. D.C.. 1974.

14. "1975 Energy Fact Book." Tetra Tech. Inc.. Arlington. Virginia.

15. "Clean Boiler Fuel Demonstration Plant" from ERDA 112-75-/1: "Union Carbide's Coalcon Process" by J. R. Martin from 1975 IGT Symp.

16. “COED Process” from New Energy Tech. pp. 178-182; “The COED Process” from 1975 Cameron Synthetic Fuels Data Handbook.

17. “Project Seacoke” from New Energy Tech. pp 175-178.

18. “The Clean Coke Process for Metallurgical Coke” by K. A. Schowalter and N. S. Boodman from CPT. Vol I by AIChE. 1974.

19. “Synthetic Fuels from Coal – The Garrett Process” by N. W. Green from 1975 IGT Symp.; “Garrett's Coal Pyrolysis” from CFFC Oil and Gas Journal August 1975.

20. “The Toscol Process – Coal Liquefaction and Char Production” by F. B. Carlson, L. Y. Yadumian and M. T. Atwood from 1973 IGT Symp.; “The Toscoal Process from Low Temperature Coal Pyrolysis” by F. B. Carlson, L. Y. Yardumian and M. T. Atwood from CPT Vol. I by AIChE 1974.

21. “What MERC's Doing In Coal Liquefaction” published by Morgantown Energy Research Center, ERDA, Morgantown, W.Va.

PRIMARY SOURCES*

Identification	Source
1973 IGT Symp.	*Clean Fuels from Coal (CFFC) Symposium*. September 10-14, 1973, sponsored by Institute of Gas Technology (IGT).
1975 IGT Symp.	*CFFC-II*. June 23-27. 1975, sponsored by IGT.
1974 Pitt. Symp.	*Coal Gasification, Liquefaction Symposium*. held at University of Pittsburgh, Pittsburgh, Pa., August 1974.
1975 Pitt. Symp.	*Second Annual Symposium Coal Gasification, Liquefaction, and Utilization: Best Prospects for Commercialization*. University of Pittsburgh, Pittsburgh, Pa., August 5-7, 1975.
1974 Ohio Wkshp.	*Materials, Problems, and Research Opportunities in Coal Conversion*. April 16-18, 1974 Workshop documented by Department of Metallurgical Engineering, Ohio State University, Columbus, Ohio.
ERDA-111, 75/1	*Coal Gasification Quarterly Report*. January-March 1975. Office of Fossil Energy, ERDA-111 75/1.
ERDA-112, 75/1	*Coal Demonstration Plants Quarterly Report*. January-March 1975. Office of Fossil Energy, ERDA-112 75/1.
ERDA-113, 75/1	*Power and Combustion Quarterly Report*. January-March 1975. Office of Fossil Energy, ERDA-113, 75/1.
ERDA-114, 75/1	*Coal Liquefaction Quarterly Report*. January-March 1975. Office of Fossil Energy, ERDA-114 75/1.
CPT Vol. 1	*Coal Processing Technology*. New York: The American Institute of Chemical Engineers, 1974.
CPT Vol. 2	*Coal Processing Technology, Vol. 2*. New York: The American Institute of Chemical Engineers, 1975.
1974 O&GJ	Beddle, W. W. and Vyas, K. C. "Clean Fuels from Coal," *The Oil and Gas Journal*, August 26, 1974, pp. 73-88.
1975 Cameron	Hendricksen, Thomas A. (ed). *Synthetic Fuels Data Handbook*. Denver, Colorado: Cameron Engineers, Inc., 1975.
New Energy Tech.	Hottel, H. C. and Howard, J. B. *New Energy Technology–Some Facts and Assessments*. Cambridge, Massachusetts: The Massachusetts Institute of Technology Press, 1971.

---

*Refer also to Coal Process Technology, Chapter VII.

Reproduced by NTIS

National Technical Information Service
Springfield, VA 22161

This report was printed specifically for your order from nearly 3 million titles available in our collection.

For economy and efficiency, NTIS does not maintain stock of its vast collection of technical reports. Rather, most documents are custom reproduced for each order. Documents that are not in electronic format are reproduced from master archival copies and are the best possible reproductions available.

Occasionally, older master materials may reproduce portions of documents that are not fully legible. If you have questions concerning this document or any order you have placed with NTIS, please call our Customer Service Department at (703) 605-6050.

About NTIS

NTIS collects scientific, technical, engineering, and related business information – then organizes, maintains, and disseminates that information in a variety of formats – including electronic download, online access, CD-ROM, magnetic tape, diskette, multimedia, microfiche and paper.

The NTIS collection of nearly 3 million titles includes reports describing research conducted or sponsored by federal agencies and their contractors; statistical and business information; U.S. military publications; multimedia training products; computer software and electronic databases developed by federal agencies; and technical reports prepared by research organizations worldwide.

For more information about NTIS, visit our Web site at http://www.ntis.gov.

NTIS

Ensuring Permanent, Easy Access to U.S. Government Information Assets

SATISFACTION GUARANTEED

NTIS strives to provide quality products, reliable service, and fast delivery. Please contact us for a replacement within 30 days if the item you receive is defective or if we have made an error in filling your order.

▶ E-mail: info@ntis.gov
▶ Phone: 1-888-584-8332 or (703)605-6050

U.S. DEPARTMENT OF COMMERCE
Technology Administration
National Technical Information Service
Springfield, VA 22161 (703) 605-6000