1/13-83 (3)

Dr.1568-7

DOE/NASA/0292-1
NASA CR-168093
JACKFAU-82-299

I-10211

Energy and Precious Fuels Requirements of Fuel Alcohol Production

Volume IV—Appendices G and H: Methanol from Coal

Herbert Weinblatt and Geoffrey Back
Jack Faucett Associates

and

T. S. Reddy
Battelle Columbus Laboratories

December 1982

Prepared for
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Lewis Research Center
Under Contract DEN 3-292

for
U.S. DEPARTMENT OF ENERGY
Conservation and Renewable Energy
Office of Vehicle and Engine R&D

Printed in the United States of America

Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

NTIS price codes[1]
Printed copy: A04
Microfiche copy: A01

[1]Codes are used for pricing all publications. The code is determined by the number of pages in the publication. Information pertaining to the pricing codes can be found in the current issues of the following publications, which are generally available in most libraries: *Energy Research Abstracts (ERA); Government Reports Announcements* and Index (*GRA* and I); *Scientific and Technical Abstract Reports (STAR);* and publication, NTIS-PR-360 available from NTIS at the above address.

DOE/NASA/0292-1
NASA CR-168093
JACKAU-82-299

Energy and Precious Fuels Requirements of Fuel Alcohol Production.

Volume IV—Appendices G and H: Methanol from Coal

DOE/NASA/0292--1-Vol.4

DE83 013329

Herbert Weinblatt and Geoffrey Back
Jack Faucett Associates
Chevy Chase, Maryland 20815

and

T. S. Reddy
Battelle Columbus Laboratories
Columbus, Ohio 43201

December 1982

Prepared for
National Aeronautics and Space Administration
Lewis Research Center
Cleveland, Ohio 44135
Under Contract DEN 3-292

for
U.S. DEPARTMENT OF ENERGY
Conservation and Renewable Energy
Office of Vehicle and Engine R&D
Washington, D.C. 20585
Under Interagency Agreement DE-AI01-81CS50006

FOREWORD

The study presented in this report was funded by the U.S. Department of Energy (DOE) and performed under Contract No. DE-AC01-80CS50005 with DOE and Contract No. DEN3-292 with the National Aeronautics and Space Administration (NASA) under Interagency Agreement DE-AC01-81CS50006. The work was performed by Jack Faucett Associates, with subcontractual assistance from Battelle-Columbus Laboratories and from the Center for Agricultural and Rural Development of Iowa State University. DOE responsibilities were carried out by E. Eugene Ecklund of DOE's Office of Vehicle and Engine R&D, and Dr. Daniel P. Maxfield of the same office assisted him. NASA responsibilities were carried out by George M. Prok of the Aerothermodynamic and Fuels Division at NASA-Lewis Research Center, Cleveland, Ohio.

ACKNOWLEDGMENTS

This report is the product of a team of persons from Jack Faucett Associates (JFA), Battelle-Columbus Laboratories (BCL), and the Center for Agricultural and Rural Development (CARD) of Iowa State University (ISU). Dr. Herbert Weinblatt and Michael F. Lawrence of JFA had overall responsibility for performing the study. Dr. Weinblatt had primary responsibility for final editing and for preparing Volume I and Appendices A and G of the report. Rena K. Margulis of JFA was responsible for Appendix E. Geoffrey Back of JFA was responsible for Appendix D and contributed to Appendix G.

David M. Jenkins had overall responsibility for BCL's contributions to the report. T.S. Reddy of BCL drafted Appendices B, F and H. Karen St. John of BCL drafted Appendix C, and Dr. Thomas McClure of BCL contributed to Appendix A.

Dr. Anthony J. Turhollow, Jr., of CARD performed all runs of the ISU Model reported in Appendices A and E and contributed to the drafting of Appendix A.

Thomas J. Timbario of the Transportation/Fuel Systems Department of Mueller Associates, Inc., Baltimore, Md., along with members of his staff, provided consultation and critiqued all draft reports.

The manuscript was typed by Pamela C. Brockington with assistance from other members of the JFA secretarial staff.

TABLE OF CONTENTS

VOLUME IV

ABBREVIATIONS

B	billion
Btu	British thermal unit
bbl	barrel
bu	bushel
C	Centigrade
cu ft	cubic foot
cwt	hundred weight (100 lb)
d	distance
DDG	distillers' dark grains
DTE	dry ton equivalent
F	Fahrenheit
gal	gallon
ha	hectare
HHV	higher heating value
hp	high pressure
hr	hour
K	Potassium
kw	kilowatt
kwhr	kilowatthour
lb	pound
lp	low pressure
LPG	liquefied petroleum gas
M	thousand
MLRA	major land resource area
MM	million
N	Nitrogen
P	Phosphorus
psia	pounds per square inch absolute
psig	pounds per square inch gauge
T	trillion
wt	weight
yr	year

BTU CONVERSION FACTORS

Fuel	Units	HHV
Coal	Btu/ton	22,500,000[a]
Distillate	Btu/gal	140,000
Electricity Consumption	Btu/kwhr	3,413
Ethanol	Btu/gal	84,200
LPG	Btu/gal	95,000
Lubricating Oil	Btu/gal	145,000
Methanol	Btu/gal	64,350
Motor Gasoline	Btu/gal	125,000
Natural Gas	Btu/cu ft	1,020
Residual Fuel Oil	Btu/gal	150,000

ELECTRICITY CONVERSION FACTOR

Fuel	Btu's consumed/Btu electricity produced
Coal	3.05

[a] *When no specific coal characteristics were known, the energy content of a "standard ton" of coal (22,500,000 Btu) was used. Other values were used when more appropriate and are indicated in footnotes.*

SI CONVERSION FACTORS

1 acre	=	4046.8564 square meters
1 bbl	=	158.98284 liters
1 Btu	=	1054.35 joules
1 cu ft	=	0.028316847 cubic meters
1 gal	=	3.7854118 liters
1 lb	=	453.592 grams
1 mile	=	1609.344 meters
1 psi	=	0.0680460 atmospheres
1 ton	=	907184.74 grams
273.15 + 5/9(F-32)	=	degrees Kelvin
273.15 + C	=	degrees Kelvin

OTHER CONVERSION FACTORS

1 acre	=	0.40468564 ha
1 bbl	=	42 gal
1 Btu	=	252 calories
1 bu barley	=	48 lb
1 bu corn	=	56 lb
1 bu grain sorghum	=	56 lb
1 bu oats	=	32 lb
1 bu soybeans	=	60 lb
1 bu wheat	=	60 lb
1 psi	=	6895 pascals
1 square mile	=	640 acres
1 ton	=	2000 lb

APPENDIX G

COAL

Since the turn of the century, coal has been losing its energy market share to oil and natural gas. By 1949, coal was still the primary energy resource in the U.S., supplying nearly 41 percent of the nation's energy needs, but this was down from 90 percent in 1900. Coal's steady decline in energy market share continued until the last decade when it reached a low of 18 percent.

The decline in domestic production of oil and gas and the increasing cost of these premium fuels, dramatized by the two oil embargoes, ended and then reversed this decline in coal's market share. In each of the years 1973-1978, coal accounted for about 18 percent of U.S. energy consumption, with this share rising to 19.1 percent in 1979 and 20.6 percent in 1980 (U.S. Department of Energy (DOE), 1981c)[1]. A comparison of coal's share of the energy market with those of the other energy sources is provided in the following table.

U.S. CONSUMPTION OF ENERGY BY SOURCE - 1980

Source	10^{15} Btus	Percent of Total
Coal	15.674	20.6
Natural Gas	20.437	26.8
Petroleum	34.249	44.9
Hydroelectric	3.126	4.1
Nuclear	2.704	3.5
Other	0.114	0.1
Total	76.267	100.0

Source: U.S. Department of Energy, 1981c.

The increase in coal's market share is likely to continue as the rising price of oil makes substitution of coal more attractive.

The primary coal user will continue to be the electric utility industry. In 1980, electric utilities consumed 569.2 million tons of coal or 81 percent of the total coal consumed (DOE, 1981c). The conversion of on-line, oil-fired electric generating capacity to coal

[1] *Parenthetical references to authors and dates identify bibliographic references. Full citations are contained in the bibliography at the end of this volume.*

and Congressional legislation[1] forbidding the building of oil-fired electrical generating capacity will further increase the use of coal by electric utilities.

The following table shows that, after utilities, the industrial sector is the second largest consumer of coal, followed by the residential/commercial Sector. The transportation sector presently consumes only negligible amounts of coal. However, as stated in Section 1, there is a potential for the indirect use of coal as a transportation fuel by converting the coal to a liquid fuel suitable for use in the existing market.

U.S. ENERGY USE BY SOURCE

(in percent)

Source	Electric Utilities	Industry	Residential Commercial	Transportation
Coal	77.4	21.4	1.2	—
Natural Gas	18.5	41.1	37.4	3.0
Petroleum	8.8	25.9	12.8	52.5

Source: U.S. Department of Energy, 1981c.

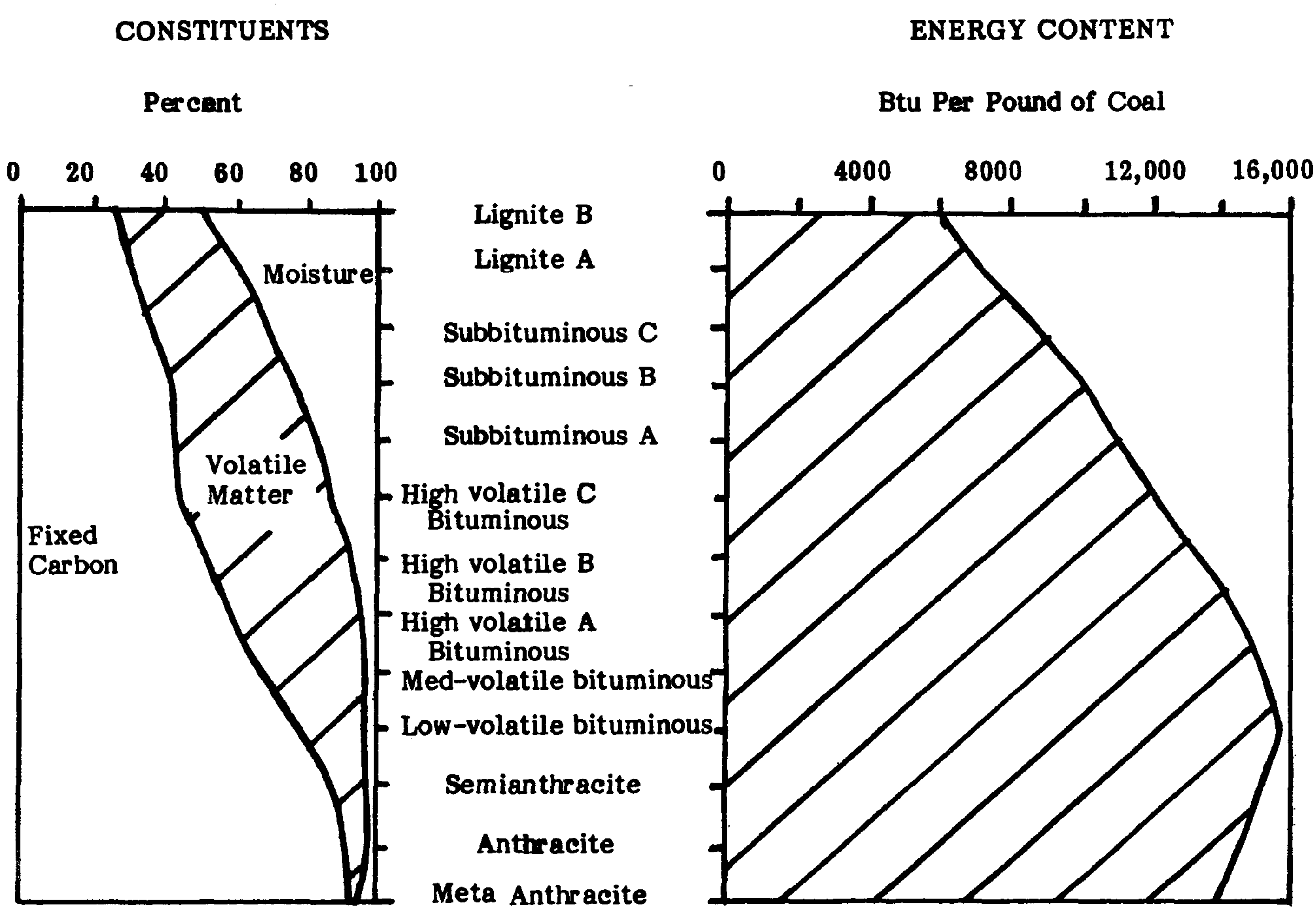
In this section, the energy consumed in mining coal for eventual conversion to methanol is analyzed. Energy consumption estimates are developed for both underground and surface mining methods.

G.1 Mine Location

Coal deposits are generally distinguished by their carbon content as well as moisture content and heating value. The different coal types or ranks, by increasing carbon content, are: lignite, subbituminous, bituminous, and anthracite coals. Heating value or the Btu content per pound peaks at 14,000 Btu with the low volatility bituminous coals (see Exhibit G-1).

[1] *The Powerplant and Industrial Fuel Use Act of 1978 (P.L. 95-620).*

EXHIBIT G-1: CHARACTERISTICS AND ENERGY CONTENTS OF DIFFERENT COAL RANKS



SOURCE: Cuff and Young, 1980.

The distribution of coal reserves in this country is shown, in tabular form, in Exhibit G-2 and in the U.S. Geological Survey (USGS) map reproduced as Exhibit G-3. The first of these exhibits gives the demonstrated reserve base[1] by coal rank, State, and whether the coal is appropriate for mining by surface or underground methods. About 90 percent of these reserves are bituminous or subbituminous coal. Most of the subbituminous coal is located in Montana and Wyoming, identified as the Northern Great Plains Province on the USGS map. Much of the bituminous coal is located in the Eastern Province (i.e., the Appalachian Region) and the eastern part of the Interior Province (i.e., Illinois, Indiana and Western Kentucky).

All types of coal are suitable for gasification (the first step in the production of methanol); however, not all sources of coal are equally likely to be used for producing methanol (or other coal-derived synthetic fuels). In particular, coal used for such purposes is most likely to come from areas containing large volumes of coal which can be mined economically and, preferably, where adequate water supplies can be obtained.

A methanol production facility must be sited in coal resource areas where sufficient quantities of coal for methanol conversion are available over and above near-term coal demands. Any one methanol plant must be large enough to achieve appropriate economies of scale. Current projections place economic plant capacity in the range of 6,000 to 25,000 tons of coal per day. This places a constraint on coal resource size. Assuming a plant life of 20 years and a 300-day per year operating schedule, between 36 million and 150 million tons of coal would be needed to supply the methanol production facility. Exhibit G-4 shows the coal regions which have the greatest potential for supplying the large volumes of coal required for this purpose.

The most economic means of transporting large volumes of methanol is by pipeline. Since pipeline transport of methanol is both less costly and more energy efficient than transport of the coal (by rail or slurry pipeline) required to produce the methanol, location of the methanol plant in the vicinity of the coal source is generally preferred.

Gasification processes, however, require substantial amounts of water for cooling and as a source of hydrogen. The particular gasification process assumed in the present analysis requires 5.3 gallons of water for each gallon of methanol produced, or 82

---

[1] *The demonstated reserve base consists essentially of those coal resources which are deemed economically and legally available for mining.*

EXHIBIT G-2: DEMONSTRATED RESERVE BASE COALS IN THE U.S. ON JANUARY 1, 1976, ACCORDING TO RANK AND POTENTIALLY MINEABLE BY UNDERGROUND AND SURFACE METHODS
(in millions of tons)

	ANTHRACITE		BITUMINOUS		SUBBITUMINOUS		LIGNITE		TOTAL[a]	
STATE	UND.	SURF.	UND.	SURF.	UND.	SURF.	UND.	SURF.	UND.	SURF.
Alabama	—	—	1,724.2	284.4	—	—	—	1,083.0	1,724.2	1,367.4
Alaska	—	—	617.0	80.5	4,805.9	640.7	—	14.0	5,473.0	735.2
Arizona	88.6	—	—	325.5	—	—	—	—	—	325.5
Arkansas	25.5	7.8	163.1	107.0	—	—	—	25.7	251.7	140.5
Colorado	—	—	8,467.9	676.2	3,972.1	149.2	—	2,965.7	12,465.4	3,791.0
Georgia	—	—	0.5	0.4	—	—	—	—	0.5	0.4
Idaho	—	—	4.4	—	—	—	—	—	4.4	—
Illinois	—	—	53,128.1	14,841.2	—	—	—	—	53,128.1	14,841.2
Indiana	—	—	8,939.8	1,774.5	—	—	—	—	8,939.8	1,774.5
Iowa	—	—	1,736.8	465.4	—	—	—	—	1,736.8	465.4
Kansas	—	—	—	998.2	—	—	—	—	—	998.2
Kentucky	—	—	17,582.9	8,418	—	—	—	—	17,582.9	8,414
Louisiana	—	—	—	—	—	—	—	b	—	b
Maryland	—	—	913.8	134.5	—	—	—	—	913.8	134.5
Michigan	—	—	125.2	1.6	—	—	—	—	125.2	1.6
Missouri	—	—	1,418.0	3,596.0	—	—	—	—	1,418.0	3,596.0
Montana	—	—	1,385.4	—	69,573.5	33,843.2	—	15,766.8	70,958.9	44,610.1
New Mexico	2.3	—	1,258.8	601.1	889.0	1,846.8	—	—	2,150.1	2,447.9
North Carolina	—	—	31.3	0.4	—	—	—	—	31.3	0.4
North Dakota	—	—	—	—	—	—	—	10,145.3	—	10,145.3
Ohio	—	—	13,090.5	6,139.8	—	—	—	—	13,090.5	6,139.8
Oklahoma	—	—	1,192.9	425.2	—	—	—	—	1,192.9	425.2
Oregon	—	—	b	—	14.5	2.9	—	—	14.5	2.9
Pennsylvania	6,966.8	142.7	22,335.9	1,391.8	—	—	—	—	29,302.7	1,534.4
South Dakota	—	—	—	—	—	—	—	426.1	—	526.1
Tennessee	—	—	627.2	337.9	—	—	—	—	627.2	337.9
Texas	—	—	—	—	—	—	—	3,181.9	—	3,181.9
Utah	—	—	6,283.8	267.9	1.1	—	—	—	6,284.9	267.9
Virginia	137.5	—	3,277.0	888.5	—	—	—	—	3,414.5	888.5
Washington	—	—	255.3	—	835.3	481.5	—	8.1	1,090.6	489.5
West Virginia	—	—	33,457.4	5,149.1	—	—	—	—	33,457.4	5,149.1
Wyoming	—	—	4,002.5	—	27,644.8	23,724.7	—	—	31,647.2	23,724.7
Total east	7,104.3	142.7	155,233.7	39,362	—	—	—	1,083.0	162,337.9	40,587.7
Total west	116.4	7.8	26,785.9	7,543	107,736.2	60,689.0	—	32,533.6	134,638.4	100,773.3
U.S. TOTAL[a]	7,220.7	150.5	182,019.6	46,905.0	107,736.2	60,689.0	—	33,616.6	296,976.3	141,361.0

[1]Includes measured and indicated resource categories as defined by the U.S. Bureau of Mines and U.S. Geological Survey and represents 100% of the coal in place.
a. Data may not add to totals shown due to rounding.
b. Quantity undetermined.

Source: U.S. Department of Energy, 1980.

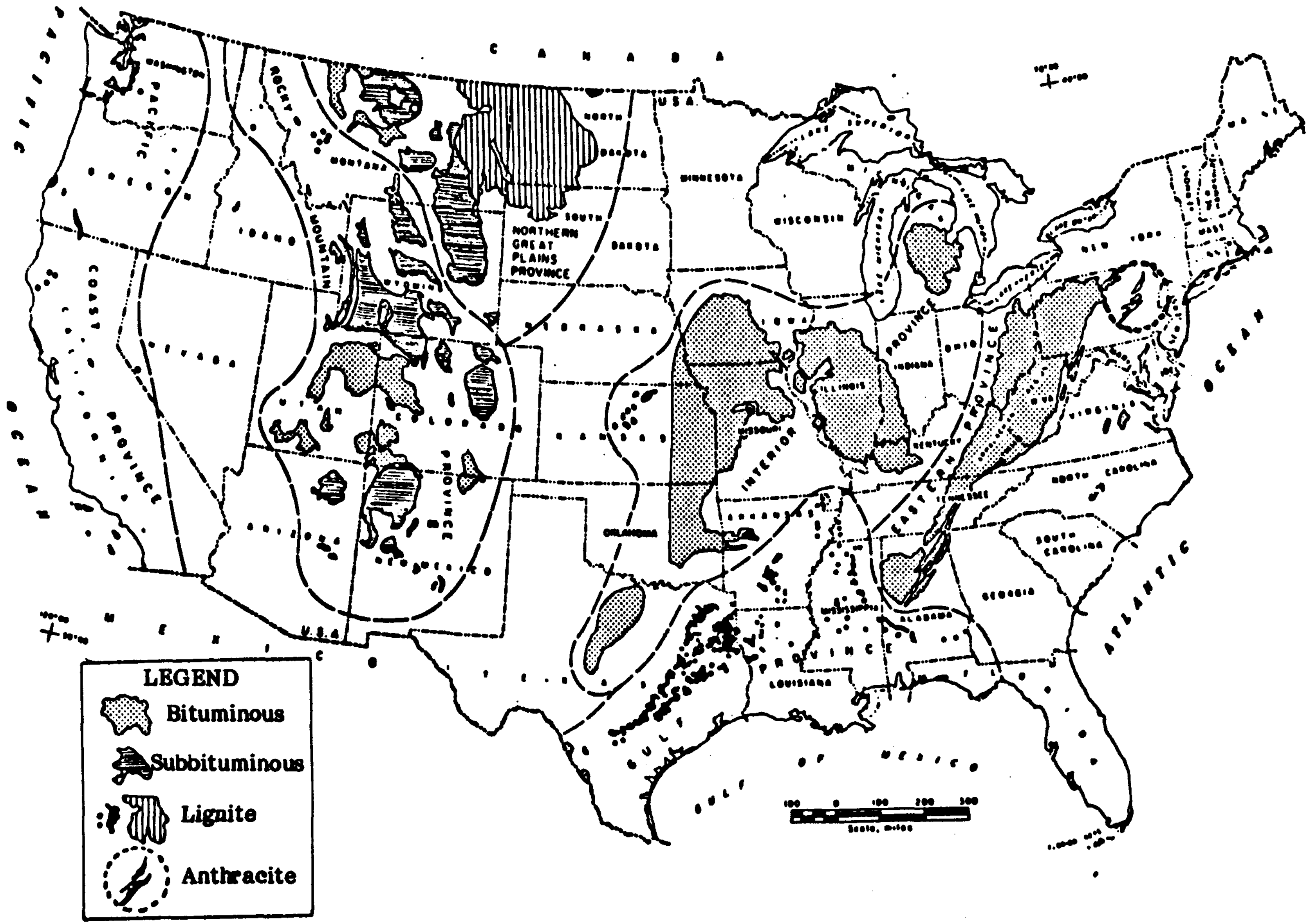


EXHIBIT G-3: **COAL FIELDS OF THE CONTIGUOUS UNITED STATES**

Source: U.S. Department of Energy, 1980. Adapted from U.S.G.S. Coal Map of the United States, 1960.

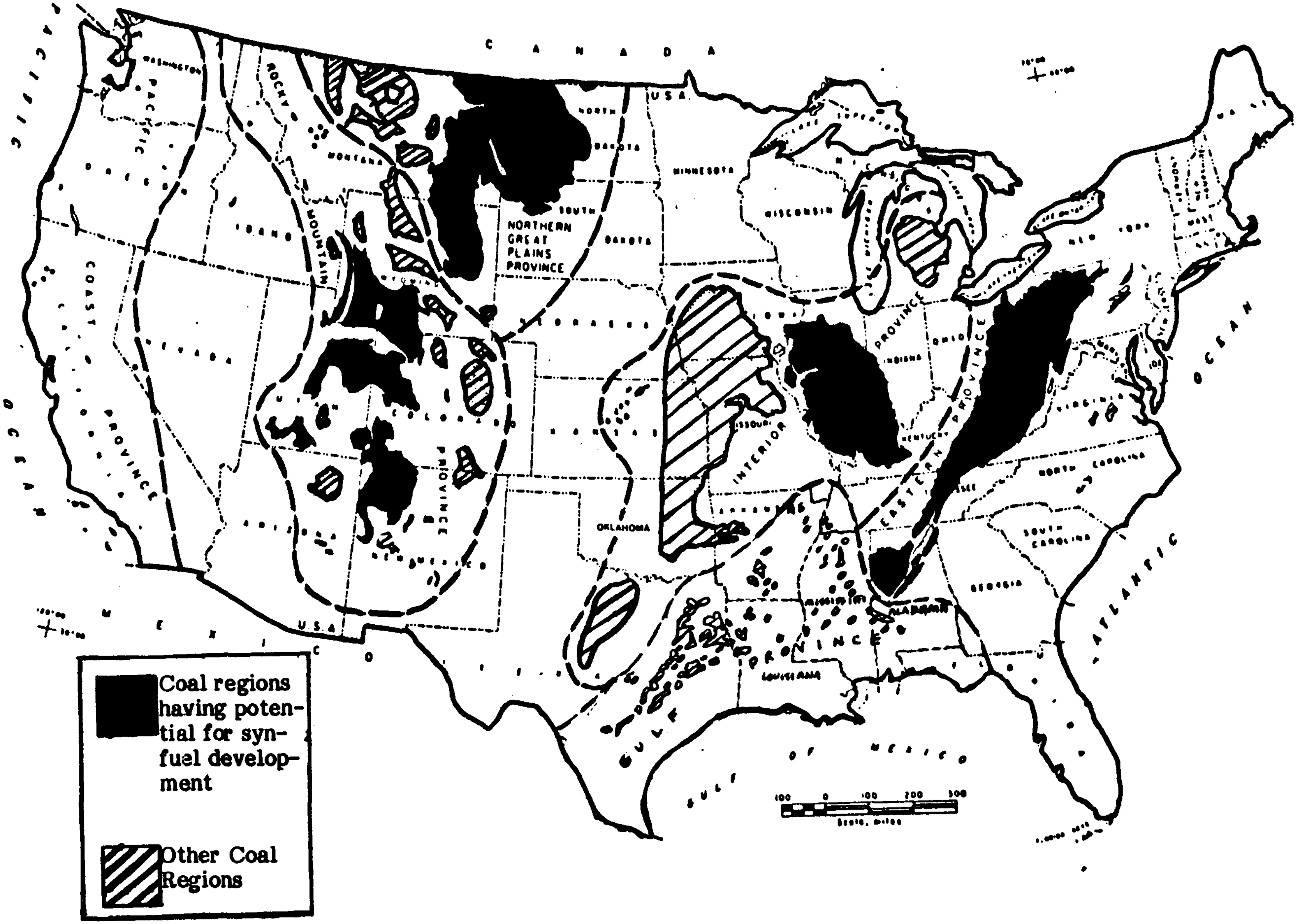


EXHIBIT G-4: **COAL RESOURCES MOST LIKELY TO BE USED FOR SYNFUELS PRODUCTION**

Source: U.S. Department of Energy, 1980. Adapted from U.S.G.S. Coal Map of the United States, 1960.
U.S. Department of Interior, Geological Survey, 1979.

gallons of water per million Btu of methanol (McGeorge, 1976). (Coal mining, by comparison, typically requires between 0.5 and 2.5 gallons per million Btu.) Other synfuel processes may require less water. In particular, direct liquefaction processes do not require the large amounts of process water required for medium and high-Btu gasification, and water consumption of all processes can be reduced (at substantial cost) by recycling of cooling water. Nonetheless, all synfuel processes are considered to be major consumers of water.

As a result, many of the Western regions identified in Exhibit G-4 as having potential for providing coal for synfuel facilities may not contain appropriate sites for the location of these facilities, either because local water is insufficient to supply such facilities or because the water is already fully appropriated to other uses. These areas, as well as those having both sufficient coal resources and sufficient unappropriated water supplies, are depicted in Exhibit G-5.

The analysis presented in this report presumes a minemouth location for the methanol plant. However, it is likely that synfuel plants will be constructed at non-minemouth locations as well as minemouth locations. In addition to lack of water, reasons for selecting non-minemouth locations may include labor costs and availability and related socio-economic factors. The lack of water in a specific area thus does not mean that coal in that area may not be appropriate for supplying synfuel plants located in areas where sufficient water is more readily available.

G.2 Mining Technology

The two most significant methods of underground mining methods are room-and-pillar and longwall mining. Commonly used with either method are continuous miners and loaders which convey the coal away from the cutting face and automatically load the coal onto shuttle cars or conveyors. In the United States, most of the coal mined underground is removed by the room-and-pillar method. Longwall mining involves taking successive slices over the length of a long working face. It is used extensively in Europe but has only recently been introduced in this country. Longwall methods can remove more coal than room-and-pillar methods, though at some increased risk of mine subsidence. For coal seams whose location makes it possible to tolerate some subsidence, and particularly for seams located at relatively greater depths, the use of longwall methods should increase. For coal beds up to 10-feet thick, longwall methods can recover up to 85 percent of the coal, while room-and-pillar methods can recover

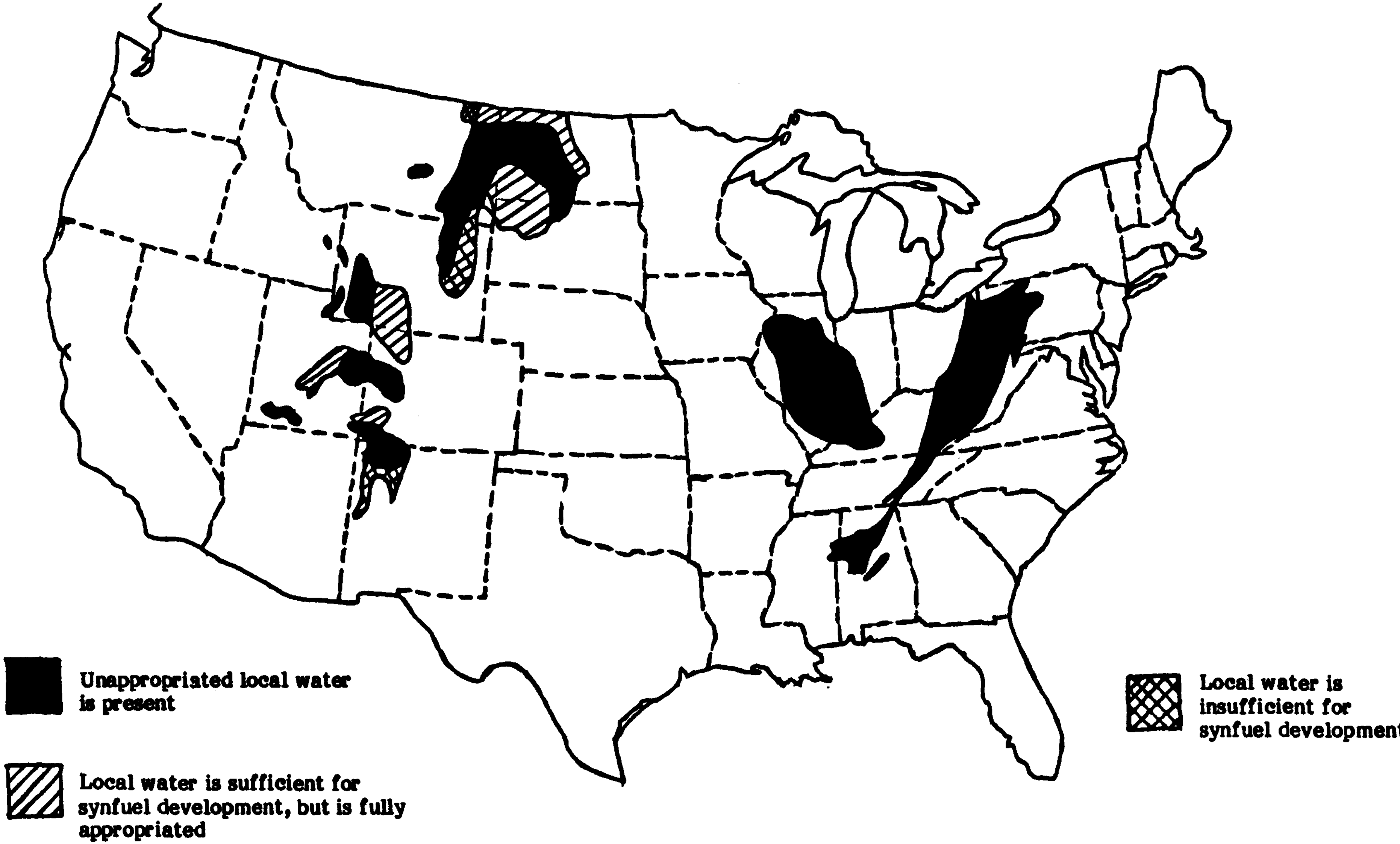


EXHIBIT G-5: WATER RESOURCES AVAILABLE FOR ADDITIONAL USE IN AREAS OF POTENTIAL SYNFUELS DEVELOPMENT

SOURCE: U.S. Department of Interior, 1979.

only 57 percent (Cuff and Young, 1980). The recovery rates for both types of mining drop sharply for thicker seams, but, for any seam thickness, they are always greater for longwall mining.

Most of the equipment used in underground mining is powered by electricity, thus avoiding the problem of venting exhaust gases from diesel-driven equipment. Continuous underground mining machines also use a large amount of lubricating oil, both on moving parts and at the working face. Energy requirements increase with increasing seam depth (because of the deeper shafts which are required) and with decreasing seam thickness (because of the greater area over which a given amount of coal is spread).

Surface mining methods include strip mining and auger mining. Strip mining is further subdivided into area mining, contour mining, and mountaintop removal. Of these methods, area mining is the most common and the only method analyzed in the present study. Coal recovery for strip mining methods averages around 80 to 90 percent.

For surface mines requiring the removal of large amounts of overburden, electricity is the most common form of energy used. Usually, such mines utilize electricity supplied by coal-burning power plants located nearby. Petroleum products are used as fuel for diesel-powered equipment, mixed with ammonium nitrate for use as an explosive, and used for lubrication. Petroleum usage is most significant when coal seams are located near the surface and which thus can be mined by diesel-powered equipment (Berkshire, 1981). As is the case for underground mines, energy requirements increase with increasing seam depth (because of the greater amount of overburden which must be removed) and with decreasing seam thickness (because of the greater area over which a given amount of coal is spread).

G.3 Energy Consumed in Mining

For reasons discussed in Section 4.1 of the Summary Volume, energy consumed in coal mining does not enter into the estimates of overall energy consumption of methanol production. Nonetheless, since coal mining is a significant step in the production of methanol from coal, the energy requirements of this step are of interest. Estimates of average energy consumed per ton for all coal mined are developed in this section as well as estimates for several specific underground and surface mines.

G.3.1 National Average Energy Consumption

Estimates of national average energy consumed in coal mining are presented in Exhibit G-6. These estimates were derived from 1977 Census data on electricity, fuels and explosives consumed by the bituminous coal and lignite mining industry (U.S. Department of Commerce (DOC), 1980b and 1981) and from 1977 DOE data on bituminous coal and lignite mined (DOE, 1979d). Estimates of the energy required to produce explosives are based on data for prilled (i.e., pelletized) ammonium nitrate presented in Exhibit G-7. (Estimates of energy required to produce other explosives could not be obtained because the processes are considered proprietary. These explosives, all of which use ammonium nitrate as a base, may be somewhat more energy intensive than ammonium nitrate; however, they represent less than fifteen percent of all explosives used in coal mining.)

Total energy consumption is about 326,000 Btu per ton of coal mined. If, as assumed, all electricity used is generated from coal, more than half the energy consumed (168,000 Btu) is from coal. Petroleum products (predominantly lubricating oil and diesel fuel) account for about thirty percent of energy consumption. The manufacture of explosives accounts for nearly ten percent of energy consumption and most of the natural gas consumption.

G.3.2 Energy Consumed by Specific Mines

The national data presented in Exhibit G-6 fail to distinguish between underground and surface mines or between large mines and small mines. Accordingly, additional analysis was performed to obtain estimates of energy consumption by moderately large underground and surface mines.

The primary source of data used for these analyses was a series of reports on the capital investment and operating costs of underground and surface coal mines produced by the U.S. Bureau of Mines (BOM) of the U.S. Department of the Interior (1975d; 1976a; 1976c) and DOE (1977; 1978c; 1979a). These reports present estimates of capital and operating costs of typical mines producing various amounts of coal from seams of selected depths and thicknesses in several parts of the country. These included estimates of electric power requirements and direct fuel costs.

EXHIBIT G-6: ENERGY CONSUMPTION PER TON OF MINED COAL

		Petroleum Products						
	Assumptions	Motor Gasoline (gal)	Lubricating Oil and Distillate (gal)	Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
Bituminous coal and lignite mining industry	Total production in 1977: 691.3 MM tons (1)							
	Total energy consumption in 1977:							
	— Electricity (2): 10,145 MM kwhr					0.006730*		151,400
	— Direct Fuels (2 and 3): Gasoline: 61.5 MM gal Distillate: 368.7 MM gal Residual: 52.3 MM gal Natural Gas: 1697 MM cu ft Coal: 474,400 tons	0.089	0.533	0.0757	2.5	0.000686	97,100	146,200 (4)
	— Explosives (3): Ammonium nitrate: 1601 MM lbs Other explosives: 222 MM lbs 1823 MM lbs			0.0005	26.5	0.000070	100	28,700
TOTAL BITUMINOUS COAL AND LIGNITE INDUSTRY		0.089	0.533	0.0762	29.0	0.007486	97,200	326,300

*Based on use of 22,500,000 Btu per ton coal.

Sources:
(1) DOE, 1979d.
(2) DOC, 1981.
(3) DOC, 1980b.
(4) Estimated directly from source data. Includes other purchased fuels and undistributed fuels.

EXHIBIT G-7: ENERGY CONSUMED IN PRODUCING PRILLED AMMONIUM NITRATE

	Energy Consumption per Pound of Ammonium Nitrate		
	Physical Units		Btu
Residual Fuel	0.0002	gal	29
Natural Gas	10.19	cu ft	10,393
Coal	0.000027	tons	685*
			11,107

*Based on use of 22,500,000 Btu per ton coal.

Sources: Tyson, Belzer and Associates, 1980.
Davis and Blouin, 1976.

Note: Energy requirements for all explosives were assumed to be equal to those for ammonium nitrate (see text).

These reports contain data for sixteen mines, twelve of which are designed to produce a minimum of two million tons annually. Each of these mines could thus produce enough coal to supply the 1.8 million tons of coal required annually by the smallest methanol plant considered to be economic. The largest of the mines is designed to produce five million tons annually. Two to four of these twelve mines would be required to supply the 7.5 million tons required annually by the largest plant currently contemplated.

The twelve mines consist of seven underground mines and five surface mines. The major characteristics of each of these mines, including their size, seam depth and seam thickness, are presented in Exhibit G-8. The mining plans assumed by BOM and DOE are summarized in Exhibit G-9, and the power-driven equipment requirements are shown in Exhibit G-10.

The BOM and DOE reports provide estimates of electricity consumption by underground mines and of the daily cost of electricity for surface mines, as well as the daily cost of fuel for all mines. The cost figures were converted into estimates of energy consumption by dividing by appropriate estimates of unit cost. For surface mines, the cost of electricity was based on the cost used by DOE (1978c) for underground mines in 1978 (3 cents/kwhr) and indexed on the basis of data on the average annual cost of electricity to industrial users from DOE's <u>Monthly Energy Review</u> (1981c). For all mines, the cost of distillate and residual fuel were based on the average cost of these fuels to bituminous and lignite coal mines in 1977 (DOC, 1981) (43.45 and 41.8 cents per gallon, respectively) and indexed on the basis of average annual price data from the <u>Monthly Energy Review</u>.

The energy consumption estimates reflect the use of fuels and electrical energy in the following operations:

- Strip mining
  - removal of overburden
  - removal of coal
  - restoration of sites
  - transfer of coal out of the pit

- Underground mining
  - opening of shafts

EXHIBIT G-8: CHARACTERISTICS OF SELECTED COAL MINES

Mining Operation	Mine Number	Mining System	Average Coal Seam Depth (ft)	Average Coal Seam Thickness (inches)	Acres Per Year of Coal Resource Mined	Mine Output (MM tons per year)	Index Year For Cost	Source
• Underground								
— Bituminous								
	(1)	Continuous Room and Pillar	800	72	7,600[a]	2.38	1978	1
	(2)	Continuous Room and Pillar	800	48	10,035[b]	2.06	1975	2
	(3)	Continuous Room and Pillar	800	72	6,639[b]	2.04	1975	3
	(4)	Continuous Room and Pillar	800	48	15,053[b]	3.09	1975	2
	(5)	Continuous Room and Pillar	800	72	10,326[b]	3.18	1975	3
	(6)	Continuous Room and Pillar	800	72	16,228[b]	4.99	1975	3
	(7)	Continuous-Longwall	800	48	10,305[c]	2.60	1976	4
• Surface								
— Bituminous Interior Province	(8)	Area	70	60	415[d]	3.36	1977	5
— Subbituminous Northern Great Plains Province	(9)	Area	65	684	55[d]	5.0	1977	5
	(10)	Area	120	360	84[d]	4.0	1979	6
— Lignite Northern Great Plains Province	(11)	Area	60	240	98[d]	3.0	1979	6
	(12)	Area	50	120	327[d]	5.0	1979	6

(a) Assumes 57 percent recovery; 1,830 tons of coal per acre-foot with a 20 year life.
(b) Assumes 57 percent recovery; 1,800 tons of coal per acre-foot with a 20 year life.
(c) Assumes 70 percent recovery; 1,830 tons of coal per acre-foot with a 20 year life.
(d) Assumes 90 percent recovery.

Sources: (1) DOE, 1978
(2) BOM, 1975d.
(3) BOM. 1976c.
(4) BOM, 1976b.
(5) DOE, 1977.
(6) DOE, 1979a.

EXHIBIT G-9: MINING PLANS FOR SELECTED COAL MINES

Mining Plan Descriptions

(1) 12 continuous miner units operating 3 shifts per day, 5 days per week, 220 days per year, for 20 years assuming each unit averages 300 tons of coal per shift.

(2) 10 continuous miner units operating 3 shifts per day, 5 days per week, 220 days per year, for 20 years assuming each unit averages 312 tons of coal per shift.

(3) 9 continuous miner units operating 3 shifts per day, 5 days per week, 220 days per year, for 20 years assuming each unit averages 344 tons of coal per shift.

(4) 15 continuous miner units operating 3 shifts per day, 5 days per week, 220 days per year, for 20 years assuming each unit averages 312 tons of coal per shift.

(5) 14 continuous miner units operating 3 shifts per day, 5 days per week, 220 days per year, for 20 years assuming each unit averages 344 tons of coal per shift.

(6) 22 continuous miner units operating 3 shifts per day, 5 days per week, 220 days per year, for 20 years assuming each unit averages 344 tons of coal per shift.

(7) 5 continuous miner units develop panels for the 4 longwall units; all units operate 3 shifts per day, 5 days per week, 220 days per year, for 20 years assuming each the continuous miner unit averages 300 tons of coal per shift, and the longwall unit averages 700 tons per shift.

(8) overburden blasted and removed by electric dragline; electric shovel and diesel front-end loader load coal into trucks; diesel bulldozer and scraper remove and replace topsoil; overburden is removed 3 shifts per day, 345 days per year, for 20 years; coal loading operates 2 shifts per day, 220 days per year, for 20 years.

(9) diesel tractor scraper removes topsoil; coal loaded with electric dragline and shovels into trucks; overburden is removed 3 shifts per day, 345 days per year, for 20 years; coal loading operates 2 shifts per day, 220 days per year, for 20 years.

(10, 11, 12) diesel tractor scraper removes topsoil; overburden drills, stripping equipment, loading shovels, pumps, and lighting equipment operated by electric power; overburden removed by electric dragline and diesel bulldozer; coal loaded by electric shovel and diesel front-end loader into trucks; overburden removed 3 shifts per day, 345 days per year, for 20 years; coal load operates 2 shifts per day, 220 days per year, for 20 years.

Sources:
Mine (1): DOE, 1978.
Mines (2) and (4): BOM, 1975d.
Mines (3), (5) and (6): BOM, 1976c.
Mine (7): BOM, 1976b
Mines (8) and (9): DOE, 1977
Mines (10)-(12): DOE, 1979a.

EXHIBIT G-10: EQUIPMENT USED IN SELECTED COAL MINES

	Continuous Miner	Longwall Miner	Loading Machine	Shuttle Car	Roof Bolter	Ratio Feeder	Aux. Fan	Mantrip Jeep	Mechanic Jeep	Personnel Jeep
• Underground										
(1)										
quantity	12		12	24	12	12	12	12	10	6
horsepower	600		160	135	50	125	30	15	15	7.5
hrs. at full load	15		15	15	18	15	18	4	10	10
kw used at full load	5,371		1,432	2,417	448	1,119	269	134	34	34
(2)										
quantity	10		10	20	10	10	10	10	5	6
horsepower	220		160	100	50	125	30	15	15	7.5
hrs. at full load	15		15	15	18	15	18	6	15	15
kw used at full load	1,641		1,194	1,492	373	933	224	112	56	34
(3)										
quantity	9		9	18	9	9	9	9	4	6
horsepower	600		160	135	50	125	30	15	15	7.5
hrs. at full load	15		15	15	18	15	18	6	15	15
kw used at full load	4,028		1,074	1,813	336	839	201	101	45	34
(4)										
quantity	15		15	30	15	15	15	15	6	10
horsepower	220		160	100	50	125	30	15	15	7.5
hrs. at full load	15		15	15	18	15	18	6	15	15
kw used at full load	2,462		1,790	2,238	560	1,399	336	168	67	56
(5)										
quantity	14		14	28	14	14	14	14	6	8
horsepower	600		160	135	50	125	30	15	15	7.5
hrs. at full load	15		15	15	18	15	18	6	15	15
kw used at full load	6,266		1,671	2,820	522	1,305	313	156	67	45
(6)										
quantity	22		22	44	22	22	22	22	10	10
horsepower	600		160	135	50	125	30	15	15	7.5
hrs. at full load	15		15	15	18	15	18	6	15	15
kw used at full load	9,847		2,626	4,431	821	2,052	492	246	112	56
(7)										
quantity	4	4	4	8	4	4	4	8	6	6
horsepower	550	625	160	135	50	125	15	15	15	7.5
hrs. at full load	10	16	10	10	12	10	18	4	15	15
kw used at full load	1,641	1,865	477	806	149	373	45	90	67	45

Sources:

Mine (1): DOE, 1978.
Mines (2) and (4): BOM, 1975d.
Mines (3), (5) and (6): BOM, 1976c.
Mine (7): BOM, 1976b
Mines (8) and (9): DOE, 1977
Mines (10)-(12): DOE, 1979a.

EXHIBIT G-10: EQUIPMENT USED IN SELECTED COAL MINES
(Continued)

	Rock Duster	Supply Motor	42-Inch Conveyor	36-Inch Conveyors		Ventilation Fans	Outside Elec. Equip.	Hoists	Extra for Pumps, etc.	Shops, Lighting, etc.
• Underground										
(1)										
quantity	12	5	4	4	4					
horsepower	30	80	125	100	50					
hrs. at full load	12	12	15	15	15	24	14	15	10	24
kw used at full load	269	298	373	298	149	746	895	1,343	448	463
(2)										
quantity	10	4	3	2	10	1				
horsepower	30	80	125	100	50	500				
hrs. at full load	12	12	15	15	15	24			10	
kw used at full load	224	239	280	149	373	373			373	
(3)										
quantity	9	5	3	2	7	1				
horsepower	30	80	125	100	50					
hrs. at full load	12	12	15	15	15	24			10	
kw used at full load	201	298	280	149	261	373			373	
(4)										
quantity	30	7	3	3	12	1				
horsepower	30	80	200	100	50	500				
hrs. at full load	12	12	15	15	15	24			10	
kw used at full load	671	418		224	448	373			373	
(5)										
quantity	14	6	3	12		1				
horsepower	30	80	200	150		500				
hrs. at full load	12	12	15	15		24			10	
kw used at full load	313	358	448	560		373			373	
(6)										
quantity	22	8	3	20						
horsepower	30	80	300	150						
hrs. at full load	12	12	15	15		24				10
kw used at full load	492	477	671	895		373				522
(7)										
quantity	5	3		12		1				
horsepower	30	80		100		500			400	
hrs. at full load	12	12		16		24			10	24
kw used at full load	112	179		395		373			298	482

• Surface	Bull-dozer (diesel)	Tractor Scraper (diesel)	Front-end Loader (diesel)	Crawler Drill (diesel)	Crawler Drill (electric)	Crawler Shovel (electric)	Walking Dragline (electric)	Haul Trucks (diesel)
(8) quantity	2	1	1	—	1	1	1	7
(9) quantity	2	1	1	—	1	2	1	9
(10) quantity	1	—	1	—	1	1	1	7
(11) quantity	1	—	1	—	1	1	1	5
(12) quantity	1	—	1	—	1	1	1	7

Sources: See first page of this exhibit.

- removal of coal
- transfer of coal out of the mine
- handling of slag, spoil and refuse

The estimates presented for underground mines are based on surveys of Eastern underground mines, particularly in northern West Virginia, but they can be assumed to be reasonably representative of all underground mines of the indicated size (two to five million tons per year) operating on seams of the indicated depth (800 feet) and thickness (48 or 72 inches). An 800-foot seam depth and 48 to 72-inch seam thickness is fairly typical of mines in the Appalachian and eastern Interior coal resource areas; however, coal seam thickness and depth in the Western states is far more variable. Exhibit G-11 summarizes data on seam thickness and depth of major new underground and surface mines which have been planned or proposed. It can be seen that in the West, where only the most economically attractive resources are presently of commercial interest, planned mines are limited to seams which lie at relatively shallow depths and/or are relatively thick.

The BOM and DOE reports do not contain information on explosives required for individual mines. Accordingly, estimates of explosives required were derived from national data on explosives used in coal mining and total coal produced. These are shown in Exhibit G-12. The data in this exhibit divide explosives used in 1977 between underground and surface mines. This division was inferred from the division existing in 1972 (DOC, 1975) and the assumption that the rate of growth of explosives used per ton of coal mined would be the same for both types of mines.

Since a minemouth location has been assumed for the methanol plant, the energy consumed in transporting the coal from the mine entrance to the plant will be minimal and has not been included in the analysis. (However, the energy required to transport the coal within the mine from the seam face to the loading station is included as part of the estimate of mining energy requirements.) Secondary energy inputs, such as energy consumed in the production of the equipment used, have also been excluded from the analysis.

The resulting estimates of energy consumption per ton are presented in Exhibit G-13 for the seven underground mines and in Exhibit G-14 for the five surface mines. A summary of estimated energy consumption for the twelve mines is presented in

EXHIBIT G-11: FUTURE COAL MINES PROJECTED TO EXPAND FUEL SOURCES IN EASTERN AND WESTERN STATES

		No. of New Mines		Coal Seam Thickness (inches)		Overburden Depth (feet)	
Region	State	Underground	Surface	Underground	Surface	Underground	Surface
East	Alabama	13	6	34 - 78	20 - 40	500 - 2500	NR
	Georgia	—	5	—	10 - 22	—	50 - 75
	Illinois	9	6	60 - 100	48	200 - 950	65 - 100
	Indiana	1	4	72	48 - 65	450*	30 - 100
	Kentucky	19	8	50 - 72	60 - 72	300 - 1000	50 - 125
	Maryland	1	—	56 - 100	—	NR	—
	Ohio	10	2	48 - 66	48	70 - 530	60*
	Pennsylvania	28	2	40 - 85	NR	160 - 540	NR
	Tennessee	2	1	36 - 40	36	NR	150*
	Virginia	10	—	NR	NR	60 - 84	NR
	West Virginia	47	15	40 - 101	30 - 50	735*	NR
West	Alaska	—	1	—	240 - 600	—	shallow
	Arkansas	1	—	47 - 72	—	500 - 1000	—
	Colorado	46	31	48 - 324	36 - 480	250 - 2200	2 - 260
	Montana	—	12	—	144 - 720	—	4 - 200
	New Mexico	1	15	NR	48 - 128	NR	150 - 200
	North Dakota	—	10	—	24 - 300	—	0 - 150
	Oklahoma	7	12	36 - 72	16*	600 - 1400	NR
	Texas	—	5	—	24 - 180	—	47 - 70*
	Utah	28	3	60 - 168	132*	1200*	90*
	Wyoming	5	22	48 - 192	36 - 1440	300 - 1800	0 - 710

NR: Not reported   *only one figure reported   (-): zero

Source: BOM, 1978.

EXHIBIT G-12: EXPLOSIVES USED IN BITUMINOUS COAL AND LIGNITE MINING

	Explosives Used (MM lbs)			Coal Produced (MM tons)	Explosives Used (lbs) per Ton of Coal
	Ammonium Nitrate	Other	Total		
1972					
Total Industry (1)	899.6	92.0	991.6	595.4	1.67
1977					
Total Industry (2)	1,601.0	221.5	1,822.5	691.3	2.63
Underground Mines (3)	9.4	75.5	84.9	265.9	0.32
Surface Mines (3)	1,591.6	146.0	1,737.6	425.4	4.1

Sources:

(1) DOC, 1975 and DOI, 1973.
(2) DOC, 1981 and DOE, 1979d.
(3) Coal production from DOE 1979d; explosives used estimated from data in above sources.

EXHIBIT G-13: ENERGY CONSUMPTION ESTIMATES PER TON OF MINED COAL FOR SPECIFIC UNDERGROUND MINING OPERATIONS

Coal Type and Mining Method	Assumptions	Petroleum Products: Motor Gasoline (gal)	Petroleum Products: Lubricating Oil and Distillate (gal)	Petroleum Products: Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
	Mine parameter data presented in order of seam depth in feet (D), seam thickness in inches (T), acres of resource mined per year (A/yr), and mine output in millions of tons per year (MMt/yr) Source is cited in parentheses.							
Mine #1	800' D; 72" T; 7,600 A/yr; 2.38 MMt/yr (1)							
Bituminous Coal	— Electricity, 255,500 kwhr/day (1), 220 days/yr					0.01092*		245,800
Continuous Room and Pillar Mining System	— Direct Fuels $350,000/yr (1978) for lubricating and hydraulic oil (1) at 40.3¢/gal (2)		0.365				52,900	52,900
	— Explosives 0.32 pounds per ton of coal (see Exhibit G-7)			0.00007	3.26	0.00001	**	3,600
TOTAL	MINE #1 (Underground, Bituminous, 2.38 MMt/yr)		0.365	0.00007	3.26	0.01093	52,900	302,300

*Based on use of 22,500,000 Btu per ton coal.

**Less than 50 Btu.

Sources:
(1) DOE, 1978c.
(2) DOC, 1980c; DOE, 1981c.
(3) BOM, 1975d.
(4) DOE, 1978a.
(5) BOM, 1976c.
(6) BOM, 1976b.

EXHIBIT G-13: ENERGY CONSUMPTION ESTIMATES PER TON OF MINED COAL FOR SPECIFIC UNDERGROUND MINING OPERATIONS
(Continued)

Coal Type and Mining Method	Assumptions	Petroleum Products: Motor Gasoline (gal)	Petroleum Products: Lubricating Oil and Distillate (gal)	Petroleum Products: Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
Mine #2	800' D; 48" T; 10,035 A/yr; 2.06 MMt/yr; (3)							
Bituminous Coal	— Electricity, 121,941 kwhr/day (3)					0.00602*		135,500
Continuous Room and Pillar Mining System	— Direct Fuels 514,800/yr (1975) for lubricating and hydraulic oil (3) at 36.8¢/gal (2)		0.679				98,500	98,500
	— Explosives Equivalent to 0.10 pounds of ammonium nitrate per ton of coal (Exhibit G-7)			0.00007	3.26	0.00001	**	3,600
TOTAL	MINE #2 (Underground, Bituminous, 2.06 MMt/yr)		0.679	0.00007	3.26	0.00603	98,500	237,600
Mine #3	800' D; 72" T; 6,639 A/yr; 2.04 MMt/yr; (5)							
Bituminous Coal	— Electricity, 156,787 kwhr/day (5)					0.00782*		176,000
Continuous Room and Pillar Mining System	— Direct Fuels $510,800/yr (1975) for lubricating and hydraulic oil (5) at 36.8¢/gal (2)		0.68				98,600	98,600
	— Explosives Equivalent to 0.10 pounds of ammonium nitrate per ton of coal (Exhibit G-7)			0.00007	3.26	0.00001	**	3,600
TOTAL	MINE #3 (Underground, Bituminous, 2.04 MMt/yr)		0.68	0.00007	3.26	0.00783	98,600	278,200

*Based on use of 22,500,000 Btu per ton coal.

**Less than 50 Btu.

Sources:
(1) DOE, 1978c.
(2) DOC, 1980c; DOE, 1981c.
(3) BOM, 1975d.
(4) DOE, 1978a.
(5) BOM, 1976c.
(6) BOM, 1976b.

EXHIBIT G-13: ENERGY CONSUMPTION ESTIMATES PER TON OF MINED COAL FOR SPECIFIC UNDERGROUND MINING OPERATIONS
(Continued)

		Petroleum Products						
Coal Type and Mining Method	Assumptions	Motor Gasoline (gal)	Lubricating Oil and Distillate (gal)	Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
Mine #4	800' D; 48" T; 15,053 A/yr; 3.09 MMt/yr; (3)							
Bituminous Coal	— Electricity, 179,866 kwhr/day (3)					0.00592*		133,300
Continuous Room and Pillar Mining System	— Direct Fuels 772,200/yr (1975) for lubricating and hydraulic oil (3) at 36.8¢/gal (2)		0.679				98,500	98,500
	— Explosives 0.32 pounds per ton of coal (see Exhibit G-7)			0.00007	3.26	0.00001	**	3,600
TOTAL	MINE #4 (Underground, Bituminous, 3.09 MMt/yr)		0.679	0.00007	3.26	0.000593	98,500	235,400
Mine #5	800' D; 72" T' 10,326 A/yr; 3.18 MMt/yr; (5)							
Bituminous Coal	— Electricity, 234,415 kwhr/day (5)					0.00750*		168,800
Continuous Room and Pillar Mining System	— Direct Fuels $794,700/yr (1975) for lubricating and hydraulic oil (5) at 36.8¢/gal (2)		0.678				98,300	98,300
	— Explosives 0.32 pounds per ton of coal (see Exhibit G-7)			0.00007	3.26	0.00001	**	3,600
TOTAL	MINE #5 (Underground, Bituminous, 3.18 MMt/yr)		0.678	0.00007	3.26	0.00751	98,300	270,700

*Based on use of 22,500,000 Btu per ton coal.

**Less than 50 Btu.

Sources:
(1) DOE, 1978c.
(2) DOC, 1980c; DOE, 1981c.
(3) BOM, 1975d.
(4) DOE, 1978a.
(5) BOM, 1976c.
(6) BOM, 1976b.

EXHIBIT G-13: ENERGY CONSUMPTION ESTIMATES PER TON OF MINED COAL FOR SPECIFIC UNDERGROUND MINING OPERATIONS
(Continued)

Coal Type and Mining Method	Assumptions	Petroleum Products: Motor Gasoline (gal)	Petroleum Products: Lubricating Oil and Distillate (gal)	Petroleum Products: Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
Mine #6	800' D; 72" T; 16,228 A/yr; 4.99 MMt/yr; (5)							
Bituminous Coal	— Electricity, 361,260 kwhr/day (5)					0.00736*		165,700
Continuous Room and Pillar Mining System	— Direct Fuels $1,250,000/yr (1975) for lubricating and hydraulic oil (5) at 36.8¢/gal (2)		0.681				98,700	98,700
	— Explosives 0.32 pounds per ton of coal (see Exhibit G-7)			0.00007	3.26	0.00001	**	3,600
TOTAL	MINE #6 (Underground, Bituminous, 4.99 MMt/yr)		0.681	0.00007	3.26	0.00737	98,700	268,000
Mine #7	800' D; 48" T; 10,305 A/yr; 2.6 MMt/yr; (6)							
Bituminous Coal	— Electricity, 108,760 kwhr/day (6)					0.00426*		95,800
Continuous-Longwall Mining System	— Direct Fuels $407,700/yr (1976) for lubricating and hydraulic oil (6) at 36.3¢/gal (2)		0.432				62,600	62,600
	— Explosives 0.32 pounds per ton of coal (see Exhibit G-7)			0.00007	3.26	0.00001	**	3,600
TOTAL	MINE #7 (Underground, Bituminous, 2.6 MMt/yr)		0.432	0.00007	3.26	0.00427	62,600	162,000

*Based on use of 22,500,000 Btu per ton coal.

**Less than 50 Btu.

Sources:
(1) DOE, 1978c.
(2) DOC, 1980c; DOE, 1981c.
(3) BOM, 1975d.
(4) DOE, 1978a.
(5) BOM, 1976c.
(6) BOM, 1976b.

EXHIBIT G-14: ENERGY CONSUMPTION ESTIMATES PER TON OF MINED COAL
FOR SPECIFIC SURFACE MINING OPERATIONS

Coal Type and Mining Method	Assumptions	Petroleum Products: Motor Gasoline (gal)	Petroleum Products: Lubricating Oil and Distillate (gal)	Petroleum Products: Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
	Mine parameter data presented in order of seam depth in feet (D), seam thickness in inches (T), acres of resource mined per year (A/yr), and mine output in millions of tons per year (MMt/yr) Source is cited in parentheses.							
Mine #8	70' D; 60" T; 415 A/yr; 3.36 MMt/yr; (1)							
Bituminous Coal Interior Province Area Mine	— Electricity $985,600/yr (1977) (1) at 2.69¢/kwhr (2)					0.00501*		113,500
	— Direct Fuels $435,100/yr. (1977) for diesel fuel and lubricating and hydraulic oil (1) at 43.45¢/gal (2)		0.298				41,700	41,700
	— Explosives 4.1 pounds per ton of coal (see Exhibit G-7)			0.0008	26.8	0.00007	100	29,200
TOTAL MINE #8 (Surface, Bituminous, 3.36 MMt/yr)			0.298	0.0008	26.8	0.00508	41,800	184,400

*Based on use of 22,500,000 Btu per ton coal.

Sources: (1) DOE, 1977.
(2) DOC, 1980c; DOE, 1981c.
(3) DOE, 1979a.

EXHIBIT G-14: ENERGY CONSUMPTION ESTIMATES PER TON OF MINED COAL
FOR SPECIFIC SURFACE MINING OPERATIONS
(Continued)

		Petroleum Products						
Coal Type and Mining Method	Assumptions	Motor Gasoline (gal)	Lubricating Oil and Distillate (gal)	Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
Mine #9	65' D; 684" T; 55 A/yr; 5.0 MMt/yr; (1)							
Subbituminous Coal Northern Great Plains Area Mine	— Electricity $302,200/yr (1977) (1) at 2.69¢/kwhr (2)					0.00117*		23,400
	— Direct Fuels $435,100/yr. (1977) for diesel fuel and lubricating and hydraulic oil (1) at 43.45¢/gal (2)		0.20				28,000	28,000
	— Explosives 4.1 pounds per ton of coal (see Exhibit G-7)			0.0008	26.8	0.00007	100	29,200
TOTAL MINE #9 (Surface, Subbituminous, 5.0 MMt/yr)			0.20	0.0008	26.8	0.00124	28,100	80,600
Mine #10	120' D; 360" T; 84 A/yr; 4.0 MMt/yr; (3)							
Subbituminous Coal Northern Great Plains Area Mine	— Electricity $990,000/yr (1979) (3) at 3.32¢/kwhr (2)					0.00388*		77,600
	— Direct Fuels $387,000/yr. (1979) for diesel fuel and lubricating and hydraulic oil (3) at 69¢/gal (2)		0.14				19,600	19,600
	— Explosives 4.1 pounds per ton of coal (see Exhibit G-7)			0.0008	26.8	0.00007	100	29,200
TOTAL MINE #10 (Surface, Subbituminous, 4.0 MMt/yr)			0.14	0.0008	26.8	0.00395	19,700	126,400

*Based on use of 20,000,000 Btu per ton coal.

Sources:
(1) DOE, 1977.
(2) DOC, 1980c; DOE, 1981c.
(3) DOE, 1979a.

EXHIBIT G-14: ENERGY CONSUMPTION ESTIMATES PER TON OF MINED COAL
FOR SPECIFIC SURFACE MINING OPERATIONS
(Continued)

Coal Type and Mining Method	Assumptions	Petroleum Products: Motor Gasoline (gal)	Petroleum Products: Lubricating Oil and Distillate (gal)	Petroleum Products: Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
Mine #11	60' D; 240" T; 98 A/yr; 3.0 MMt/yr; (3)							
Lignite Northern Great Plains	— Electricity $486,000/yr (1979) (3) at 3.32¢/kwhr (2)					0.00363*		50,800
Area Mine	— Direct Fuels $297,000/yr. (1979) for diesel fuel and lubricating and hydraulic oil (3) at 69¢/gal (2)		0.143				20,100	20,100
	— Explosives 4.1 pounds per ton of coal (see Exhibit G-7)			0.0008	26.8	0.00007	100	29,200
TOTAL MINE #11 (Surface, Lignite, 3.0 MMt/yr)			0.143	0.0008	26.8	0.0037	20,200	100,100
Mine #12	50' D; 120" T; 327 A/yr; 5.0 MMt/yr; (3)							
Lignite Northern Great Plains	— Electricity $1,603,000/yr (1979) (3) at 3.32¢/kwhr (2)					0.00740		103,600
Area Mine	— Direct Fuels $699,000/yr. (1979) for diesel fuel and lubricating and hydraulic oil (3) at 69¢/gal (2)		0.203				28,400	28,400
	— Explosives 4.1 pounds per ton of coal (see Exhibit G-7)			0.0008	26.8	0.00007	100	29,200
TOTAL MINE #12 (Surface, Lignite, 5.0 MMt/yr)			0.203	0.0008	26.8	0.00747	28,500	161,200

28

*Based on use of 14,000,000 Btu per ton coal.

Sources:
(1) DOE, 1977.
(2) DOC, 1980c; DOE, 1981c.
(3) DOE, 1979a.

Exhibit G-15. Total energy consumption is between 235,000 and 303,000 Btu per ton for the room-and-pillar mines, 162,000 Btu per ton for the longwall mine, and between 80,000 and 185,000 Btu per ton for the surface mines.

Energy consumption for the room-and-pillar mines is somewhat below the 326,000 Btu per ton figure previously obtained for all coal mines, and energy consumption for the other mines is even lower. The results, however, are not completely comparable. The estimate for all coal mines includes all energy consumed by establishments engaged in mining and preparing coal. This estimate thus includes a small amount of energy consumed in cleaning coal as well as energy (and, in particular, gasoline and residual fuel) consumed in various activities conducted by such establishments but not included in the analysis of the individual mines.

Among the individual mines, Mines 1-8 produce bituminous coals. Since such coals normally contain between twenty and thirty million Btu per ton, for the room-and-pillar mines (Mines 1-6) energy consumed in mining generally represents about one percent of the energy content of the coal, while for Mines 7 and 8 this energy consumption represents less than one percent of the energy content of the coal. Mining the last four surface mines (Mines 9-12) also generally requires somewhat less than one percent of the energy content of the lower-Btu subbituminous and lignite coals being mined.

It can be seen from Exhibit G-13 that almost all primary energy consumed by underground mines is in the form of electricity and lubricating and hydraulic oil. The energy embodied in explosives represents less than two percent of total energy consumption. All electricity is presumed to be coal derived. Allowing for electric-generating losses, the energy content of the coal consumed represents between 55 and 85 percent of total energy consumption of the underground mines studied.

In the case of surface mines (see Exhibit G-14) explosives account for a more significant share of energy consumption, between 15 and 40 percent of the total. Energy embodied in explosives is primarily natural gas, though some coal and a very small amount of residual fuel are also consumed. Also required are petroleum products for operating diesel-powered equipment and for mixing with explosives. The energy content of the coal consumed (primarily for electricity generation) represents between 25 and 65 percent of the energy consumed by the surface mines studied, and that of petroleum products between 15 and 35 percent. The differences in the relative

EXHIBIT G-15: COMPARISON OF ENERGY CONSUMPTION ESTIMATES FOR VARIOUS MINES

Mine Number	Mining System	Source	Seam Depth (ft)	Seam Thickness (in)	Output (MMt/yr)	Btu/ton
Underground						
1.	Room and Pillar	DOE, 1978	800	72	2.38	302,300
2.	Room and Pillar	BOM, 1975d	800	48	2.06	237,600
3.	Room and Pillar	BOM, 1976c	800	72	2.04	278,200
4.	Room and Pillar	BOM, 1975d	800	48	3.09	235,400
5.	Room and Pillar	BOM, 1976c	800	72	3.18	270,700
6.	Room and Pillar	BOM, 1976c	800	72	4.99	268,000
7.	Longwall	BOM, 1976b	800	48	2.60	162,000
Surface						
8.	Area	DOE, 1977	70	60	3.36	184,400
9.	Area	DOE, 1977	65	684	5.0	80,400
10.	Area	DOE, 1979a	120	360	4.0	126,400
11.	Area	DOE, 1979a	60	240	2.0	100,100
12.	Area	DOE, 1979a	50	120	4.0	161,200

importance of electricity and petroleum products are primarily due to differences in the equipment used in these mines.

Energy requirements for coal mining are sensitive to seam depth and thickness and to mining technology and equipment used. Halving the thickness of a coal seam results in doubling the area which must be mined; for a given technological design, this change increases energy requirements by fifty to eighty percent (depending, in part, on equipment characteristics) (Berkshire, 1981). Increasing seam depth similarly results in a somewhat less than proportional increase in energy requirements.

Because of different equipment characteristics and different engineering assumptions, the energy-consumption estimates of the various mines are not directly comparable. The estimates for room-and-pillar mining of a 72-inch seam developed in BOM, 1976c, for example, indicate that more electricity and total energy will be required than those developed in BOM, 1975d, for a 48-inch seam, though one would normally expect the reverse would be the case. The results for the various surface mines, however, are in conformity with the general rule that energy requirements increase with increasing depth and decreasing seam thickness. It is also interesting to note that the results for the three mines for which a consistent set of estimates was developed in BOM, 1976c, (Mines 3, 5 and 6) indicate a small decrease in energy consumption with increasing mine size, and that the same observation holds for the two mines for which a consistent set of estimates was developed in BOM, 1975d, (Mines 2 and 4).

G.4 Coal Transport

The energy consumption estimates presented in the preceding section represent all energy consumed in mining. As such, they include energy consumed in the removal of coal from the mine, a form of local transport which is intrinsic to the mining process. Since a minemouth location has been assumed for the methanol plant, no additional coal transport is required. If, however, the methanol plant were to be located at a greater distance from the mine, additional energy would be consumed in transport.

For several route-specific coal movements, it has been estimated (Rogozen, et.al., 1978) that transport by unit train requires between 350 and 540 Btu of diesel fuel per ton-mile and that (allowing for conversion losses) transport by slurry pipeline requires, per ton-mile, between 410 and 1300 Btu of fuel to generate electricity. Thus, for a

1000-mile unit-train haul of subbituminous coal from a Western mine to a Midwestern methanol plant, between 350,000 and 540,000 Btu of diesel fuel would be required, representing two to three percent of the energy content of the coal being transported. For corresponding transport by slurry pipeline, between 410,000 and 1,300,000 Btu of coal would be needed to generate electricity for slurrying, pumping and dewatering.

G.5 Potential Availability of Coal

DOE projections of total domestic coal production and use of coal for synthetic fuels through the year 2020 are shown in Exhibit G-16. The projections indicate that, in the next forty years, total coal production will more than quadruple. Of the 3.5 billion tons of coal to be produced in 2020, more than one-third will be used to produce synthetic fuels, and over ninety percent of that will be used to produce coal-derived liquids (DOE, 1981a). A total of 25.8 quads (quadrillion Btus) of coal is projected to be used for this purpose.

The methanol process analyzed in this study (see Appendix H) has an overall energy efficiency of 53 percent, but technologies now being developed have indicated overall energy efficiencies of up to 58 percent. Such technologies may be capable of producing about 0.57 Btu of methanol per Btu of coal.[1] If all coal which is projected to be used for production of liquids is converted to methanol at a coal-to-methanol energy efficiency of 57 percent, about 14.7 quads of methanol (230 billion gallons) will be produced.

This volume of methanol represents about 72 percent of the 20.3 quads of liquid transportation fuels consumed annually; about 84 percent of the 17.4 quads of these fuels projected to be consumed in 2020 under the scenario presented in Exhibit G-16; and about 58 percent of the 25.4 quads of liquid fuels projected to be used for all purposes in 2020 under this scenario (DOE, 1981a, Table 4.13). Thus the DOE projections indicate that, within forty years, we will be obtaining a major portion of our liquid fuels from coal-based synthetics. (The actual quantity of such fuels which would be obtained from the projected 25.8 quads of coal to be used for this purpose will, of course, depend on the efficiency of the conversion process. If processes with energy

[1] *The ratio of methanol energy content to coal energy content is slightly lower than the overall energy efficiency of the process because the latter value includes an energy credit for byproduct sulfur produced. (See Section H.4 for further discussion.)*

EXHIBIT G-16: PROJECTIONS OF COAL PRODUCTION AND USAGE OF COAL FOR SYNTHETIC FUELS

	1980	1985	1990	1995	2000	2010	2020
Total Production (millions of tons)	835	1,000	1,400	n.a.	1,900	n.a.	3,500
Used for Synthetic Fuels (millions of std. tons)[a,b]	0	17	111	169	182	609	1,227[b]
Coal-Oil Mixture	0	8	18	3	—	—	—
Coal Gases	0	5	55	68[c]	18[c]	49	80
Coal Liquids	0	4	38	98	164	560	1,147

n.a. — Projections of total coal production in 1995 and 2010 not available from consistent source.

[a] A standard ton contains 22.5 million Btu.

[b] Because of projected decline in average Btu content of mined coal, projections imply that actual tons devoted to synthetic fuels will be higher than indicated in table. Projections indicate coal mined in 2020 will average 21.1 million Btu. On this basis, 1308 million tons of coal will be required to supply the 27.6 quadrillion Btu of coal projected to be used by synfuels in 2020.

[c] Projections of coal used by synfuels in midterm (1985-1995) and longterm (2000-2020) developed separately, thus producing apparent discontinuity in projected production of coal gases between 1995 and 2000.

Sources: DOE, 1981b, Tables S.2, 3.29 and 4.19. Projections are for the middle oil-price scenario.
DOE, 1981c.

efficiencies exceeding 57 percent are developed, the quantity of liquid fuels to be produced will be higher; if processes are used which produce other fuels, such as gasoline or synthetic oils, but at a lower energy efficiency, the energy content of the liquid fuels will be lower.)

In evaluating this information, it is important to consider the ability of our coal resources to sustain the 3.5 billion tons-per-year production rate projected for 2020. Total identified coal resources are 1.9 trillion tons and there are an additional 2.0 trillion tons of hypothetical resources.[1] The portion of these resources which are economically and legally available for mining, however, is only 438 billion tons (DOE, 1980a). This last category of coal is known as the demostrated coal reserve base (DCRB) and its size and distribution by State was previously presented in Exhibit G-1.

It is not possible to recover all coal in the DCRB. BOM estimates of recoverable reserves are usually based on a 50 percent recovery factor for underground mining and an 80 percent recovery factor for surface mining, though some observers use higher rates (Cuff and Young, 1980). Applying the more conservative 50 percent and 80 percent factors to the DCRB data in Exhibit G-1 yields an estimate for recoverable reserves of 262 billion tons. Of these reserves, 43 percent would be mineable by surface methods with the remainder requiring underground methods.

Defining recoverable coal reserves in this way clearly requires some interpretation. Much of the coal in these reserves is less attractive to mine from both economic and net-energy standpoints than coal which has been mined in the past. Much of the most economically mined Eastern coal has already been mined; mining in the East, in the future, will turn increasingly to seams which are thinner, lie at greater depths, or have higher sulfur content than seams mined in the past. As the economically attractive coal seams currently being mined in the West are played out, mining of less attractive seams will be necessary in the West as well. Thus, as our recoverable reserves are depleted, some increase in the energy required for mining (currently about 1.5 percent of coal energy content) and transporting coal will result.

---

[1] *"Hypothetical coal resources" consist of estimated resources in unexplored parts of known coal basins and are limited to a depth of less than 6000 feet.*

On the other hand, recoverable reserves are, to some extent, expandable. Improved coal-recovery techniques (such as longwall mining) will increase the recoverability factors. New coal reserves may be discovered. And the increasing value of coal will eventually make mining of thinner seams or at deeper depths economic (though the increasing energy requirements of such mining will place a limit on the extent to which mining of deep coal and coal in thin seams will ever become economic).

With the foregoing discussion in mind, it may be observed that, at an annual 3.5 billion-ton rate of production, this country's 262 billion tons of recoverable reserves will last about 75 years. Allowing for coal to be consumed between now and 2020, a 3.5 billion-ton annual rate of production achieved in 2020 and maintained in subsequent years would result in exhausting the 262 billion tons of recoverable reserves in about 2070. Our recoverable coal reserves thus appear to be sufficient to support the rate of coal production being projected for 2020 for a reasonably long time, but certainly not forever. DOE's projected rates of coal production for 2020 (3.5 billion tons for all purposes, 1.3 billion tons for synthetic fuels) thus appear to be reasonable, but it would not appear to be prudent to set a target much above this level.

On the basis of this discussion, it may be concluded that it is reasonable to expect to obtain as much as 15 quads of liquid fuels annually from coal. This volume represents nearly 75 percent of present annual consumption of liquid transportation fuels, and about 70 percent of projected annual consumption of liquid fuels for all purposes in the year 2020. Whether or not methanol will be one of these synthetic fuels will depend upon both the relative economics of methanol-fueled and conventionally fueled engines and the relative economics of the competing coal-conversion processes, as well as on energy-efficiency, environmental, safety and health factors and on governmental policy.

APPENDIX H

METHANOL FROM COAL

This appendix describes the estimated energy requirements to convert mined coal to fuel-grade methanol. Investigation of the further conversion of methanol to gasoline (using the Mobil M or similar technology) is beyond the scope of this study. Neither does this study attempt to evaluate all the individual steps within a process required for methanol production in terms of their being altered in order to lower the overall energy balance.

H.1 Selection of Technology

The Texaco-gasification/ICI methanol-synthesis process was selected for evaluation in this study. This process was chosen because it is near commercial readiness and appears economically competitive. As can be seen from Exhibit H-1, the Texaco and Koppers KBW gasifiers[1] are the most popular technologies for the methanol production projects that had applied to the Synthetic Fuels Corporation for subsidies as of April, 1981; and ICI was one of the most frequently used methanol-synthesis technologies.

While coal properties may dictate the selection of the gasification process, published studies indicate that methanol processes using the Texaco gasifier are superior to those using the Koppers-Totzek (K-T), Lurgi, Winkler, and British Gas Council (BGC)-Lurgi Slagger processes in terms of overall energy requirements and applicability to different coals (McGeorge, 1976; Chow et al., 1977). The Texaco gasifier has been considered for many of the coal gasification feasibility studies for plants to be built in the immediate future. In addition, the Texaco system has the ability to gasify both eastern and western U.S. coals.

For the liquefaction step, the ICI low-pressure synthesis was selected because it is an established process, and, as shown in Exhibit H-1, it is commonly used for commercial methanol synthesis. It is a good example of typical technology. Lurgi, Mitsubishi Gas Chemicals (MGC), Haldor-Topsoe and Wentworth also offer commercial methanol

[1] *The KBW gasifier is also a near-commercial gasifier. It is a newer design than the Koppers-Totzek (K-T) system. KBW has a different heat transfer system and increased capacity compared to K-T, but the gas composition and energy efficiency are similar.*

EXHIBIT H-1: PROPOSED METHANOL PROJECTS

Name	Location	Gasifier	Methanol Synthesis	Further Conversion
Beluga Methanol Project	Granite Point, AK	Winkler	ICI	
Chokecherry (Energy Transition Corp)	Moffat County, CO	Koppers KBW	n.a.	
Mapco Synfuels Inc.	White County, IL	Texaco	Lurgi	
Clark Oil & Refining	St. Clair County, IL	n.a.	n.a.	
W.R. Grace	Edmonson County, KY	Texaco	n.a.	
Convent Methanol Project (Texaco)	Convent, LA	Texaco	n.a.	
Whitehorn Gasification Project (Hercules, Norfolk & Western)	Montgomery County, MD	n.a.	n.a.	Mobil
EG&G	Fall River, MA	Texaco	n.a.	
Grants Project (Energy Transition Corp)	Grants, NM	n.a.	n.a.	
Peat-to-Methanol Project (Energy Transition Corp)	Croswell, NC	Koppers KBW	n.a.	
A-C Valley Corp.	Venango County, PA	Koppers	ICI	Mobil
Keystone Project (Westinghouse)	Cambria & Somerset Counties, PA	Westinghouse	n.a.	
Tennessee Synfuels Associates (Koppers + Citgo)	Oak Ridge, TN	Koppers (KBW)	ICI	Mobil/MTG
Energy Synfuels Associates	Emery County, VT	Lurgi dry bottom	n.a.	
Hampshire Energy (Kaneb Service, Koppers Northwestern Mutual Life)	Gillette, WY	Lurgi and Koppers KBW	n.a.	Mobil/MTG

n.a. = not available

SOURCE: Alcohol Week, 2, 3 (April 6, 1981).

technology. Chem Systems is developing a methanol technology, but as it is not commercially proven it has not been considered in this analysis. However, the Chem Systems process is more energy efficient than the ICI process. The Chem Systems process has higher heat recovery from the methanol reactor and lower compression energy, because of lower operating pressure requirements for the gasifier (Chia, et al., 1979).

The ICI methanol synthesis is used in many commercial installations throughout the world. In late 1979, there were 24 commercial methanol plants in operation and five in design or construction using the ICI technology. This compares to seven operating Lurgi methanol plants plants (plus four under construction) and eight MGC plants (plus three in design or construction).

Other process steps, such as the air separation and oxygen compression, shift, acid-gas removal, Claus sulfur plant, tail-gas treatment, and coal preparation, are all standard established processes and may be considered to have comparable energy requirements for the same input/output stream characteristics. Their selection depends more on the coal properties and operating pressure levels in the system as a whole.

Coal gasification technologies are generally classified into three groups: fixed-bed technology, fluidized-bed technology, and entrained-bed technology. Some of the established processes are: Lurgi (fixed bed), Winkler (fluidized bed), Texaco (entrained-bed), and K-T (entrained bed). Although these processes had a significant number of applications in the past, it appears from recent preliminary screenings that, for methanol synthesis, the Texaco process is superior to the other processes in terms of overall thermal efficiency, coal use, oxygen requirements and capital investment (McGeorge, 1976; Chow et al., 1977). The higher operating pressure of the Texaco gasifier compared to the others contributes to the higher overall thermal efficiency in methanol synthesis. Other pressurized gasifiers (for example pressurized Winkler) would be expected to give similar overall process efficiencies. Full-scale Texaco coal-gasification units are now being built in the U.S. for demonstration purposes.

The Texaco process may be applied to a wide variety of caking and non-caking bituminous and subbituminous coals. However, the conventional Lurgi and Winkler gasifiers are limited to non-caking coals. In the United States these coals are found primarily in the West.

Oxygen-blown coal gasification systems (where gasification takes place in the presence of pure oxygen, rather than air) have higher overall thermal efficiencies, lower unit product capital requirements, and increased product yields than the air-blown systems. All the above mentioned processes can be operated as oxygen-blown processes. For methanol synthesis from coal, oxygen-blown gasification would be preferred. An oxygen-blown system would produce medium-Btu gas while an air-blown system would produce low-Btu gas.

H.2 Process Description

Exhibit H-2 presents a simplified flow diagram of the overall process.

Coal of size 8" x 0 is conveyed from the mine to a 15-day storage pile.[1] Coal from this pile is then reduced to 3/4" x 0 size in Ring Mill crushers. A portion of the 3/4" x 0 coal is combined with wet char in a double-shaft paddle mixer. This mix then serves as the boiler fuel.

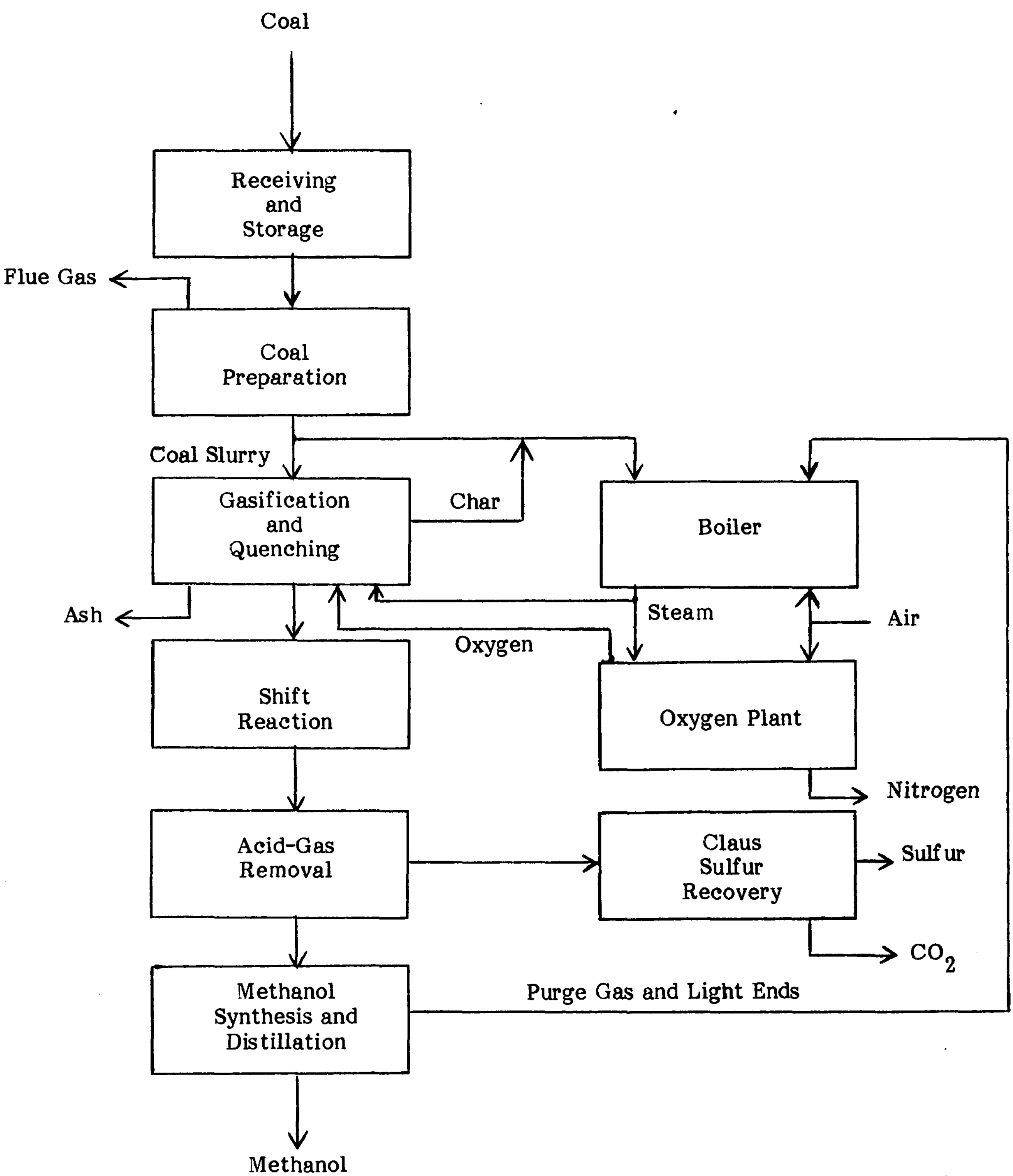
By means of regulating feeders, 3/4" x 0 coal from a surge bin is discharged into rod mills for wet grinding to 14 mesh x 0. The amount of water added to the mill is controlled by a density controller located at the discharge of each mill. A slurry is formed of 50-54 percent solids by weight. The slurry is next pumped to ball mills where the solids are reduced so that 80 percent are sized less than 200 mesh. The slurry is stored in a day-tank to serve the gasification section.

The oxygen plant section consists of an air separation plant and a compressor. An air-separation plant, operating at 92 psig, produces oxygen for the gasifier. The oxygen is then compressed to 935 psig in steam-driven centrifugal compressors. Air cooling is used in the intercoolers; water cooling is used in the turbine exhaust steam-condensers.

---

[1] *8" x 0 refers to the upper and lower size of coal pieces. All the coal will pass through a screen with 8-inch openings. The zero indicates that there is no minimum size and that the coal contains very small particles (fines). 14 mesh x 0 means all coal passes through a screen with 14 holes per inch.*

EXHIBIT H-2: SIMPLIFIED FLOWCHART OF COAL-TO-METHANOL PROCESS



The preheated coal slurry and oxygen are introduced through a special burner into the Texaco gasifiers. At about 800 psig and 2000-3000° F, the coal is partially oxidized to carbon monoxide, hydrogen, and carbon dioxide. Because of the high temperature, no tars, oils, phenols or other by-products are formed in the gasifier. Most of the sulfur present in the coal is converted to hydrogen sulfide (H_2S) and small amounts of carbonyl sulfide (COS), while the organic nitrogen is reduced to free nitrogen with some traces of ammonia (NH_3) and hydrogen cyanide (HCN). Temperature in the gasifiers is maintained above the melting point of the ash in order to yield a free-flowing molten slag through the lockhopper system. About 95 percent of the carbon in the feed is converted to synthesis gas in the slagging entrained downflow Texaco gasifiers; the remaining carbon is recovered as char from the quench scrubber. Sour water from the shift is used for quenching the synthesis gas, thus eliminating the requirement of additional steam for the shift reactor. The quenched gas from the gasifier section is next cooled to about 600° F in a waste-heat boiler generating 1270 psig, 576° F steam. Slag is removed from the gasifiers via lockhoppers. The slag, which contains about 0.5 percent carbon, is separated into fine and coarse fractions in a slag separator. The fines, containing substantially more carbon, may be either recycled to the gasifier or discarded with the coarse slag.

The synthesis gas is then sent to the shift section where the hydrogen-to-carbon-monoxide ratio is adjusted to the stoichiometry required for methanol synthesis. A sulfur tolerant catalyst for the shift reactor was assumed, because this approach would eliminate the requirement of an additional acid-gas removal step ahead of the shift reactor. A waste-heat boiler operating on the reactor effluent gases would generate high and low pressure steam.

The shifted gas is sent to the acid-gas removal section for the removal of sulfur compounds and carbon dioxide. In the particular design selected for analysis, the Selexol unit (a part of the acid-gas removal section) would selectively remove hydrogen sulfide and provide it as a feed gas at about 23 mole percent hydrogen sulfide to the Claus sulfur plant. Steam is generated in the sulfur plant and used in the acid-gas removal unit. Molten sulfur is recovered for sale.

The synthesis gas from the acid-gas removal section next feeds into the make-up compressor of the methanol synthesis section. After compression to 1550 psig, it is conveyed to the methanol synthesis reactor where methanol and some water are formed. The mixture is condensed and then distilled to remove the water. A portion of the heat recovered during condensation is used to preheat the feed and to supply heat for the distillation unit. The remaining heat is used in the acid-gas removal section. Light ends containing dimethyl ether are recovered separately from the distillation column. This stream along with a methane-rich purge-gas steam removed from the methanol synthesis loop is then used as boiler fuel. The make-up compressor is driven by condensing steam turbines.

Some of the high-pressure steam (superheated to 950° F) required for the process is produced in the gasification, shift, Claus sulfur plant, and methanol synthesis sections. The remaining high-pressure steam is generated in the steam plant operating on char from the gasifiers, light ends and purge gas from the synthesis section, and coal. Electric power is generated from the high pressure steam. Air for the boiler is preheated to 220° F by low-pressure steam. Tail gases from the sulfur plant and a large amount of CO_2-rich gas from the Selexol unit are also fed into the boiler.

The remaining sulfide in the tail gas is incinerated in the boiler. The incinerated tail gas and the boiler flue gas are treated in a Wellman-Lord desulfurization unit. The Wellman-Lord unit concentrates the sulfur dioxide in the gas. The sulfur dioxide is then sent to the sulfur plant for conversion to elemental sulfur.

H.3 Process Chemistry

The gasification step combines partial oxidation and steam reforming of the carbon contained in the coal. The oxidation step provides the heat needed for the steam-carbon and pyrolysis reactions. The major reactions in the gasifier are:

$$C + O_2 = CO_2$$

$$C + \tfrac{1}{2} O_2 = CO$$

$$C + CO_2 = 2CO$$

$$C + H_2O = CO + H_2$$

$$CH_x = C + \frac{x}{2} H_2$$

There are additional reactions which form the synthesis gas hydrocarbons as follows:

$$4CH_x = xCH_4 + (4\text{-}x)C$$

$$C + 2H_2 = CH_4$$

Sulfur contained in the coal forms acidic gases, mainly hydrogen sulfide (H_2S):

$$S + H_2 = H_2S$$

In the shift process step, the carbon monoxide (CO) to hydrogen (H_2) ratio is adjusted in the shift reaction:

$$CO + H_2O = CO_2 + H_2$$

The acidic gases, mostly carbon dioxide (CO_2) and hydrogen sulfide, are removed, and the carbon monoxide and hydrogen synthesis gas is sent to the methanol synthesis loop. There, they combine to form methanol (CH_3OH):

$$CO + 2H_2 = CH_3OH$$

There are also side reactions which lead to the formation of water:

$$CO_2 + 3H_2 = CH_3OH + H_2O$$

$$CO + H_2 = C + H_2O$$

$$2CH_3OH = CH_3OCH_3 + H_2O$$

In the sulfur plant, part of the hydrogen sulfide, recovered in the acid-gas removal process step is oxidized to sulfur dioxide (SO_2):

$$H_2S + \frac{3}{2}O_2 = H_2O + SO_2$$

This sulfur dioxide is mixed with the rest of the hydrogen sulfide and with the sulfur dioxide recovered from the flue gas desulfurization system. The gases are then converted to elemental sulfur and water in the Claus sulfur plant according to the reaction:

$$2H_2S + SO_2 = 3S + 2H_2O$$

H.4 Energy and Materials Consumption

The primary energy balance is based on the conversion of eastern bituminous coal to fuel grade methanol. The coal composition used in the following analysis had a higher heating value (as received) of 11,340 Btu per pound, 6.4 percent free moisture, and the following analysis (McGeorge, 1976):

Carbon	66.9%
Hydrogen	4.5
Oxygen	8.4
Nitrogen	1.3
Sulfur	4.5
Ash	14.4
	100.0%

The fuel grade methanol produced contains 99.8 percent methanol, 0.1 percent higher alcohols and less than 0.1 percent water.

The only significant energy input to the process is coal. The electricity used in the process is generated in the plant. The coal is used primarily in the gasifier but some is also used to fuel the boiler. Char from the gasifier and fuel gas generated in the process are also burned in the boiler. Waste heat is recovered wherever feasible. The fuel and energy balance within the plant is given in Exhibit H-3.

There is also a small amount of diesel fuel consumed by bulldozers in the coal storage area. For a plant consuming 10,000 tons of coal per day, four bulldozers operating eight hours each would consume about 280 gallons per day, or about 0.15 gallons of diesel fuel for every 1,000 gallons of methanol produced (Hoffman, 1981).

EXHIBIT H-3: METHANOL FROM COAL ENERGY BALANCE TEXACO/ICI PROCESS[1]

Process Section	Coal tons per 10^6 Btu Methanol	Electricity[4] Btu per Btu Methanol	Char (Dry) Btu per Btu Methanol	By-Product Fuel Btu per Btu Methanol	hp Steam[2] Consumed Btu per Btu Methanol	hp Steam[2] Produced Btu per Btu Methanol	lp Steam[2] Consumed Btu per Btu Methanol	lp Steam[2] Produced Btus per Btus Methanol
Coal Preparation		-0.027						
Gasification	-0.078	-0.007	+0.029			0.283	0.013	0.007
Oxygen Plant					0.330			
Shift		-0.001				0.035		0.124
Acid-Gas Removal		-0.005			0.068		0.034	
Methanol Synthesis		-0.004		+0.113	0.177	0.071	0.103	0.030
Claus Sulfur Plant		-0.001						0.011
Tail-Gas Boiler and Flue-Gas Cleaning		-0.005			0.014		0.036	
Steam Generation	-0.007	-0.002	-0.029	-0.113	0.334	0.645	0.015	
Power Generation		+0.079			0.111			0.029
Miscellaneous[3]		-0.027						
TOTAL	-0.085	0.000	0.000	0.000	0.000		0.00	

(1) balance shown is for the base case described in the text.
(2) hp steam is three levels: 1,175 psig, 925 F; 1,275 psig, saturated; and 550 psig, 750 F.
lp steam is at two levels: 100 psig, saturated; and 20 psig saturated. Steam enthalpy above water at 32 F.
(3) Includes cooling tower, sour water stripper, and others.
(4) Electricity calculated on the basis of 10,400 Btu of coal consumed per kwhr of electricity produced.

A sulfur byproduct is obtained in the process. The energy credit, which is based upon fuel consumption data for sulfur mining in the 1977 Census of Mineral Industries, is 3444 Btu per pound sulfur. The components of this energy credit are shown in Exhibit H-4.[1]

Based on the above assumptions, feedstock characteristics, and the energy balance shown in Exhibit H-3, the energy input to the methanol manufacturing process is calculated to be 5.5 tons of 11,340 Btu/lb bituminous coal per thousand gallons of methanol produced, or 1.94 Btu of total energy input per Btu of methanol produced. The sulfur byproduct energy credit, predominantly natural gas, is determined to be 440 pounds of sulfur per thousand gallons of methanol, or 0.024 Btu of total energy per Btu of methanol. These results are summarized in Exhibit H-5.

Adjusting for the sulfur credit, the net energy consumed by the methanol production process is 1.92 Btu per Btu of liquid fuel produced. None of the consumed energy is petroleum. Overall energy efficiency, expressed as the higher heating value (HHV) of the products (methanol and sulfur) divided by the energy content of the process inputs (coal), is calculated to be 53 percent.

H.5 Sensitivity Analysis

The energy requirements depend somewhat on the amount of residual water in the methanol. The base case described above produces fuel grade methanol with no more than 0.1 weight percent water. This grade would be suitable for blending with gasoline. If the methanol is to be used neat in an internal combustion engine or as a feed for the Mobil methanol to gasoline process, the methanol can contain as much as 5 percent water. With the higher water content in the product, less energy is used in distillation.

---

[1] *The inclusion of this energy credit presumes that all of the by-product sulfur is used industrially and replaces sulfur which would otherwise be mined. This may not be true for plants in some Western locations due to the availability of by-product sulfur from Alberta and the high transportation costs to Eastern markets. Energy credits would be inappropriate for any sulfur production which does not result in a corresponding reduction in sulfur mining.*

Although most analyses take an energy credit at the heating value of sulfur (3,990 Btu/lb), this analysis uses the fuel required for a typical Frasch sulfur mine as the credit. This is fuel not consumed in sulfur mining and thus available to the rest of the economy because of the methanol manufacture. The energy consumption in mining is close to the heating value of sulfur, and the total sulfur energy credit is small compared to the energy consumed in the process. Therefore, the method of treating the sulfur energy credit has little impact on the overall energy balance.

EXHIBIT H-4: ENERGY CONSUMPTION PER POUND OF MINED SULFUR

	Assumptions	Petroleum Products: Motor Gasoline (gal)	Petroleum Products: Distillate (gal)	Petroleum Products: Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	Btu Petroleum Products	Btu Total Energy
Sulfur mining industry (SIC 1477)	Total production in 1977: 5,822 M long tons (1)							
	Total energy consumption in 1977 (2):							
	— Electricity: Purchased: 45.0 MM kwhr Generated: na (2)					0.0000005*		12
	— Direct Fuels: Gasoline: 0.4 MM gal Distillate: 1.15 MM gal Residual Fuel: na (3) Natural Gas: 43.2 B cu ft Coal: none	0.00003	0.000088	(3)	3.31		16	3,432 (4)
TOTAL SULFUR MINING		0.00003	0.000088	(3)	3.31	0.0000005	16	3,444 (4)

*Based on use of 22,500,000 Btu per ton coal.

Sources:
(1) BOM, 1980.
(2) DOC, 1981.
(3) Data withheld by Census to avoid disclosing operations of individual companies.
(4) Estimated directly from source data. Includes generated electricity, residual fuel, other purchased fuels and undistributed fuels.

EXHIBIT H-5: NET LIQUID FUELS AND TOTAL ENERGY CHANGE
ACHIEVED IN THE PRODUCTION OF 1000 GALLONS OF METHANOL FROM COAL

		Petroleum Products						
	Methanol (gal)	Motor Gasoline (gal)	Distillate (gal)	Residual Fuel (gal)	Natural Gas (cu ft)	Coal (tons)	MBtu Liquid Fuels	MBtu Total Energy
INPUTS								
• FEEDSTOCK: 5.5 tons of bituminous coal						-5.5 (1)		-124,740
• STORAGE: Bulldozers move coal			-0.15				-20	-20
• PROCESS: All energy from feedstock								
OUTPUTS								
• SULFUR: 440 lbs		+0.013	+0.04		+1,460	+0.0002	+10	+1,510
• METHANOL: 1,000 gallons	+1,000						+64,350	+64,350
NET ENERGY PRODUCTION/CONSUMPTION	+1,000	+0.013	-0.11		+1,460	-5.5	+64,340	-58,900

(1) Based on use of 11,340 Btu/lb bituminous coal.

The direct reduction in the energy used in the distillation by increasing the water content from 0.1 to 5 weight percent would be about 0.03 Btu fuel/Btu methanol if the steam for distillation were raised directly in a boiler. This represents the upper limit of potential savings from the purity reduction. In the design used for the base case, part of the steam used in distillation is extracted from the power generation turbine.

Reducing the methanol purity to 95 percent would result in elimination of this steam extraction and would only reduce the fuel consumption by 0.012 Btu/Btu. The exact amount of energy to be saved by changes in purity would vary with the specific design, but would remain a small fraction of the total energy.

The overall energy efficiency of the methanol synthesis is sensitive to the pressure in the gasifier. Because the volume of synthesis gas produced in the gasifier is greater than the volume of oxygen input to the gasifier, increasing the gasifier pressure decreases the energy needed for compression prior to methanol synthesis. There is some flexibility in methanol synthesis pressure, and it can be adjusted to optimize the total system. For commercial processes, methanol synthesis occurs at 1000-2000 psig. The Chem Systems methanol process, which is under development, is expected to operate as low as 500 psig (Chow, 1977). The gasifier and methanol synthesis pressures for the base case were 800 and 1540 psig, respectively.

The energy analysis has been conducted on the basis of a high sulfur eastern bituminous coal. Studies indicate that the Texaco gasifier system is slightly more energy efficient with a typical western bituminous coal than with eastern bituminous (Schlinger, undated; Child, 1979). However, variations from seam to seam in both the eastern and western coal fields make this generalization suspect. As long as the coals are of comparable quality, the energy consumed in the methanol process should be similar.

Methanol from lower-Btu coals would require the input of more energy because more coal slurry must be pumped into the reactor to produce a ton of methanol. This, in turn, means a higher percentage of the coal must be burned to provide heat, more material must be heated to reaction temperature, and more oxygen is consumed and more carbon-dioxide produced per unit of methanol produced. The characteristics of each coal must be investigated on a case-by-case basis, but as a crude approximation, the energy consumed in coal preparation, gasification, and oxygen plant varies inversely with the Btu content of the coal. The energy for acid-gas (carbon-dioxide) removal also increases with decreasing Btu content. The energy used by other downstream operations is relatively insensitive to coal Btu content.

Lower rank coals like lignite and some subbituminous coals are not suitable for the conversion to methanol using the Texaco gasification system described (Chia, 1979). In addition to the low Btu content of these coals, whose impact is discussed above, it is inappropriate to count the tightly bound moisture as slurry water. Moisture content may typically be 30 to 35 percent in lignite and some subbituminous coals (e.g., Wyodak coal). Thus, even more water must be evaporated in the gasifier with these coal types than would be expected on the basis of Btu content alone.

Dry-fed gasifier systems (such as Lurgi) may be suitable for conversion of lower rank coals to methanol. The energy consumed in these systems is not significantly affected by free (unbound) moisture in the range typically found in coal. The evaluation of such systems is beyond the scope of this study.

The sulfur content of the coal has a very small impact on the energy balance. Because steam is generated in the Claus sulfur plant and because an energy credit is obtained for byproduct sulfur, the energy balance improves slightly with increasing sulfur content. These energy credits are directly proportional to the sulfur content. The total steam generated in the sulfur plant with a 4.5% sulfur coal is about 1.5 percent of the total steam used in the plant. Therefore, the impact of sulfur content is very small.

Variations in the ash content of coal should not influence the energy balance significantly, although the grinding of coal, operating conditions of the gasifier, and the slag removal section are more sensitive to ash content than the other sections of the process.

The caking and non-caking coal characteristics would not have any influence on the Texaco process, nor on the overall energy balance of the coal-to-methanol process (Schlinger, 1978).

The coal-to-methanol process plant energy requirements are not sensitive to plant scale.

The overall energy balance is sensitive to the details of process design. Maximum heat recovery is designed into the process analyzed in this study. In an actual commercial installation, the economics of the situation may dictate against maximum heat recovery. Normally, such optimization would not change the overall energy efficiency by more than a few percent.

H.6 Potential for Reduced Energy Consumption

The choice of the technologies for the process will also impact overall energy use. The system analyzed in this study is believed to be most representative of technologies likely to be built in the immediate future. The Chem Systems methanol process appears to be more energy efficient but it is still at the pilot stage of development.

The overall energy efficiency of several methanol processes reported in the literature have been calculated for this report on the basis described above. These efficiencies are compared in the table below. In the cases where electricity was purchased rather than generated within the plant, the energy input was taken at 10,400 Btu per kilowatt hour. In comparing the efficiencies of the various processes, it should be noted that they are affected by the heating value of the coal and the purity of the alcohol produced, as well as on process design.

Process	Gasifier Pressure Psig	Coal Heating Value Btu/lb	Alcohol Purity Percent	Overall Energy Efficiency Percent
A. Texaco/ICI	800	11,340	99.9	53
B. Texaco/Chem Systems	1,200	12,150	97.0	57
C. Koppers-Totzek/Chem Systems	6	12,235	97.5	53
D. BGC Lurgi/Chem Systems	350	12,235	97.5	58
E. Badger/Lurgi	500	12,840	99.5	56

Process A is the Texaco gasifier/ICI methanol system used in this analysis. Process B is based on a conceptual design of the Texaco gasifier/Chem Systems methanol system (Chia, 1979). It also involved a higher gasifier pressure than Process A. Both processes A and B use Selexol gas purification technology.

Process C is based on the Koppers-Totzek gasifier with Chem Systems methanol synthesis (Chow, 1977). Process D uses the British Gas Council Lurgi slagging gasifier with Chem Systems methanol (Chow, 1977). The Koppers-Totzek gasifier is considered commercially proven; the British Gas Council Lurgi is in the near-commercial category. Both use the commercially available Benfield system for gas purification.

Process E is based on a Badger conceptual design that uses Rectisol gas purification and Lurgi methanol synthesis (Badger Plants, Inc., 1978). The gasifier design is an oxygen-blown, slagging wet-bottom, pressurized entrained-bed design which has never been demonstrated.

The conclusion drawn from the above table is that developing technologies have the potential to improve the energy efficiency of methanol manufacture somewhat. It may be several years, however before these efficiencies are realized.

The following partially annotated bibliography contains listings for the sources used in Appendices G and H as well as other sources located in the course of this research.

Argonne National Laboratory, National Coal Utilization Assessment - An Integrated Assessment of Increased Coal Use in the Midwest: Impacts and Constraints, Vol. II. Argonne, IL: Argonne National Laboratory (1977a).

This study was performed as a part of the Argonne National Laboratory Regional Studies Program. The purpose of the Regional Studies Program is to assess the impacts and consequences associated with alternative energy options on a regional basis, and to identify and analyze alternative mitigation and solution strategies for increasing the acceptability of these options.

The National Coal Utilization Assessment (NCUA) is being conducted as a part of the Regional Studies Program. This particular study is focusing on impacts and constraints on increased coal utilization. In addition, a major focal point for the study is the identification and analysis of alternative solution strategies applicable to these constraints and problems. The study results are presented in two volumes. Volume I contains the Executive Summary and Major Findings. Volume II contains detailed information on Energy Supply and Demand, Siting, and Impacts.

Argonne National Laboratory, U.S. Energy Research and Development Administration Survey of Electric Utility Demand for Western Coal. Argonne, IL: Argonne National Laboratory (1977b).

This report presents the results of a survey of electric utility demand for western coal. The sources of survey information are: (1) Federal Power Commission Form 423 data on utility coal purchases covering the period July 1972 through June 1976 and (2) direct survey data on utility coal-purchase intentions for power plants to be constructed by 1985. Price and quantity assembled and presented to illustrate price and market-share trends in individual consuming regions over recent years. Coal source, quality, and quantity data are presented for existing and planned generating plants.

Averitt, P., Coal Resources of the United States, January 1, 1974, U.S. Geological Survey Bulletin 1412. Washington D.C.: GPO (1975).

Badger Plants, Inc., "Conceptual Design of a Coal to Methanol Commercial Plant," Report to the U.S. Department of Energy, FE-2416-24 (1978).

Berkshire, L., U.S. Department of Energy, Process Evaluation Office, Morgantown, West Virginia, Personal Communication, (1981).

Buras, N., "Water Constraints on Energy Related Activities," presented at the American Society of Civil Engineering Specialty Conference Proceedings, Conservation and Utilization of Water and Energy Resources, (August 1979).

Chia, W.S., et al., "Coal-to-Methanol Via New Processes Under Development: An Engineering and Economic Evaluation," C.F. Braun and Co., Report to the Electric Power Research Institute, EPRI AF-1227 (1979).

Child, E.T., "Current Status of the Texaco Coal Gasification Process," presented at the Ammonia from Coal Symposium, Tennessee Valley Authority, Muscle Shoals, AL (May 1979).

Chow, T.K., et al., "Screening Evaluation: Synthetic Liquid Fuels Manufacture," Ralph M. Parsons Company, Report to the Electric Power Research Institute, EPRI AF-523 (1977).

Colorado Energy Research Institute, Net Energy Analysis: An Energy Balance Study of Fossil Fuel Resources. Golden, CO: Colorado Energy Research Institute (April 1976).

This study examines industrial energy production in fossil fuels, emphasizing those of the Western United States. It accounts for the complete direct and indirect energies which must be utilized to produce energy from fossil fuels. These include the direct and indirect energies which "drive" or sub-sidize" the production. It includes those energies sequestered in materials needed to build and operate the industrial production and transportation facilities which either directly or indirectly are necessary for energy production. The study includes all steps in bringing fossil fuels from reserves in the ground to the point of end use (exploration, extraction, conversion, transportation, etc.).

Cuff, D.J., and Young, W.J., The United States Energy Atlas. New York: The Free Press, A Division of Macmillan Publishing Co., Inc. (1980).

Locates and describes the amount and distribution of all energy sources, from nonrenewable resources such as coal, oil, natural gas, and nuclear fuels, to renewable resources, including solar power, windpower, and biomass. Provides information on all energy resources now in use and those proposed for the future, including the relative amounts of each resource by state and region; consumption and transportation patterns by region; the United States' energy needs—past, present, and future; and the position of the United States in world energy supplies.

Hoffman, R., Plant Manager, Potomac Electric Power Company, Morgantown, WV, Personal Communication (1981).

Hydrocarbon Processing, 59, pp. 191-193 (November 1979).

Jenkins, D.M., McClure, T.A., and Reddy, T.S., "Net Energy Analysis of Alcohol Fuels." Washington, D.C.: American Petroleum Institute (November 1979).

Library of Congress, Congressional Research Service, National Energy Transportation, Current Systems and Movements, Vol I, Washington, D.C.: Library of Congress (1977).

Library of Congress, Congressional Research Service, Synfuels from Coal and the National Synfuels Production Program: Technical, Environmental, and Economic Aspects, prepared for the U.S. Senate Committee on Energy and Natural Resources, publication number 97-3, Washington, D.C.: GPO (1981).

McGeorge, A., "Economic Feasibility Study, Fuel Grade Methanol From Coal," Dupont Company, Report to the Energy Research and Development Administration (1976).

Mujadin, M.J., American Natural Service Co., (Grain Plains Gasification Associaties), personal communication (November 18, 1980).

Peele, R. and Church, J.A., eds., Mining Engineers' Handbook, Third Edition, New York: John Wiley and Sons, Section 4: Explosives (1966).

Rogozen, M.B., et. al, "Environmental Impacts of Coal Slurry Pipelines and Unit Trains", in Office of Technology Assessment, Task Reports: Slurry Coal Pipelines, Volume II, Part 2. Springfield, VA: NTIS, #PB-278 677 (1978).

Schlinger, W.G., "Coal Gasification Development and Commercialization of Texaco Coal Gasification Process," unpublished paper, Texaco, Inc., Montebello, CA.

Schlinger, W.G., "The Texaco Coal Gasification Process for Manufacture of Median Btu Gas," presented at the Department of Energy Conference on Coal Use for California, Pasadena, CA (May 1978).

Schlinger, W.G., Falbe, J. and Specks, R., "Coal Gasification for Manufacture of Hydrogen," presented at the joint meeting of the American Chemical Society and the Chemical Society of Japan, Honolulu, Hawaii (April 1979).

Shelton, J.E., "Sulfur," Mineral Commodity Profiles, U.S. Department of Interior, Bureau of Mines Washington, D.C.: Bureau of Mines (July 1979).

TRW, Energy Balances in the Production and End-Use of Alcohols Derived From Biomass. Washington, D.C.: U.S. National Alcohol Fuels Commission (1980).

U.S. Department of Commerce, Bureau of the Census, 1972 Census of Mineral Industries. Washington, D.C.: GPO (1975).

U.S. Department of Commerce, Bureau of the Census, 1977 Census of Manufactures, "Miscellaneous Chemical Products," Industry Series, MIC77-1-28H. Washington, D.C.: GPO (1980a).

U.S. Department of Commerce, Bureau of the Census, 1977 Census of Mineral Industries, "Bituminous Coal and Lignite Mining," Industry Series, MIC77--1-12A, Washington, D.C.: GPO (1980b).

U.S. Department of Commerce, Bureau of the Census, 1977 Census of Mineral Industries, "Chemical and Fertilizer Mineral Mining," Industry Series MIC77-1-14D, Washington, D.C.: GPO (1980c).

U.S. Department of Commerce, Bureau of the Census, 1977 Census of Mineral Industries, "Fuels and Electric Energy Consumed", Industry Series MIC77-SR-5, Washington, D.C.: GPO (1981).

U.S. Department of Energy, Basic Estimated Capital Investment and Operating Costs For Three Coal Mines, Springfield, Virginia: NTIS, FE/EES-781 (1977).

U.S. Department of Energy, Energy Information Administration, Monthly Energy Review, DOE/EIA-003513, Washington, D.C.: GPO (March 1978a).

U.S. Department of Energy, Economic Analysis of Coal Mining Costs for Underground and Strip Mining Operation. Washington, D.C.: GPO (1978b).

U.S. Department of Energy, Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines Utilizing a Continuous Mining System. Washington, D.C.: GPO (1978c).

U.S. Department of Energy, Basic Estimated Capital Investment and Operating Costs for Subbituminous and Lignite Coal Strip Mines, Springfield, VA: NTIS, FE/EES-79/6 (1979a).

U.S. Department of Energy, The Report of the Alcohol Fuels Policy Review, Springfield, VA: NTIS, #DOE-PE-0012 (1979b).

U.S. Department of Energy, Energy Data Reports, Production of Coal, Bituminous, and Lignite. Washington, D.C. (March 30, 1979c).

U.S. Department of Energy, Energy Information Administration, Bituminous Coal and Lignite Production and Mine Operations — 1977. Washington, D.C.: GPO (1979d).

U.S. Department of Energy, Energy Information Administration, Bituminous Coal and Lignite Production and Mine Operations - 1978. Washington, D.C.: GPO (1980 a).

This is the third annual report on bituminous coal and lignite production and mine operations published by the Energy Information Administration (EIA). It is a continuation of the series previously included as a chapter in the Minerals Yearbooks published by the Bureau of Mines, U.S. Department of the Interior.

This report is primarily a compilation of tables and illustrations that detail various aspects of bituminous coal and lignite production and mine operations in the United States in 1978. It covers such basic sectors as production tonnages, mining methods, employment, productivity, coal preparation, values, shipments, and coalbeds mined during the year. The data are from mines that produced 1,000 tons or more. All production tonnages represent marketable coal and as such exclude refuse.

The data are generally listed according to coal-producing States. Some data are also listed by coal-producing county and coal-producing district. To highlight the regional differences of coal production, certain data have been aggregated according to the three major coal-producing regions: Appalachian, Interior, and Western.

U.S. Department of Energy, Energy Information Administration, Monthly Energy Review, DOE/EIA-0035(80/12). Washington, D.C.: GPO (December 1980b).

Presents energy consumption and production statistics by source and sector.

U.S. Department of Energy, Energy Information Administration, 1980 Annual Report to Congress, Vol. III: Forecasts, Washington, D.C.: GPO (1981a).

U.S. Department of Energy, Energy Information Administration, Short Term Energy Outlook, Washington, D.C.: GPO (1981b).

U.S. Department of Energy, Energy Information Administration, Monthly Energy Review, DOE/EIA-0035 (81/03). Washington, D.C.: GPO (March 1981c).

U.S. Department of Interior, Bureau of Mines, Coal — Bituminous and Lignite in 1972, Mineral Industry Surveys. Washington, D.C. (1973).

U.S. Department of Interior, Bureau of Mines, The Reserve Base of Bituminous Coal and Anthracite for Underground Mining in the Eastern United States, Information Circular 8655. Washington, D.C.: GPO (1974a).

U.S. Department of Interior, Bureau of Mines, Fuel and Energy Consumption in the Coal Industries. Springfield, VA: NTIS, #PB-237151 (1974b).

This report presents results for the coal industries: 1) bituminous coal, 2) lignite, 3) bituminous and lignite mining services, 4) anthracite and 5) anthracite mining services. Fuel and electricity consumption is presented in a series of tables for the year 1967, defined as the base year, and for 1971, 1973, and 1974. The major processes represented in these tables are: 1) Mining and 2) Preparation. Fuel and electricity usage are also tabulated by state, Census Bureau Division and Census Bureau Region in the years 1971 and 1973.

U.S. Department of Interior, Bureau of Mines, The Reserve Base of U.S. Coals by Sulfur Content, Part 1, The Eastern States, Information Circular 8680. Springfield, VA: NTIS, #PB-243031 (1975a).

The Bureau of Mines has compiled coal reserve data for the United States as of January 1, 1974, for bituminous and anthracite coalbeds 28 inches or more in thickness to a maximum depth of 1,000 feet and for lignite beds 60 inches thick or greater. These data were organized by State, country, coalbed, and rank. To evaluate the reserve by sulfur content, the reserve and analytical data from the Bureau of Mines energy data bank were synthesized using computer techniques.

U.S. Department of Interior, Bureau of Mines, The Reserve Base of U.S. Coals by Sulfur Content, Part 2, The Western States, Information Circular 8693. Springfield, VA: NTIS, #PB-249702 (1975b).

This Bureau of Mines report delineates the coal reserve base of anthracite, bituminous and subbituminous coals, and lignite, by mining method and sulfur content, for coal-bearing States west of the Mississippi River. The parameters used to establish the reserve base definition are the result of a joint agreement by the Federal Bureau of Mines and the U.S. Geological Survey.

U.S. Department of Interior, Bureau of Mines, The Reserve Base of Coal for Underground Mining in the Western United States, Information Circular 8678. Washington, D.C.: GPO (1975c).

U.S. Department of Interior, Bureau of Mines, Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines, Information Circular 8689. Washington, D.C.: GPO (1975d).

U.S. Department of Interior, Bureau of Mines, Basic Estimated Capital Investment and Operating Costs for Coal Strip Mines, Information Circular 8703. Springfield, VA: NTIS, #PB-252495 (1976a).

U.S. Department of Interior, Bureau of Mines, Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines Developed for Longwall Mining, Information Circular 8720. Washington, D.C.: GPO (1976b).

U.S. Department of Interior Bureau of Mines, Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines, Information Circular 8682A. Springfield, VA: NTIS, #PB-252-567 (1976c).

U.S. Department of Interior, Bureau of Mines, Coal Recovery from Bituminous Coal Surface Mines in the Eastern United States: A Survey, Information Circular 8738. Washington, D.C.: GPO (1977).

U.S. Department of Interior, Bureau of Mines, Projects to Expand Fuel Sources in Eastern States - An Update of Information Circular 8725 - Survey of Planned or Proposed Coal Mines, Coal and Noncoal Conversion Plants, Electric Generating Plants, Oil Refineries, Uranium Enrichment Facilities, and Related Infrastructure in States East of the Mississippi River (as of July 1977), Information Circular 8765. Washington, D.C.: GPO (1978a).

U.S. Department of Interior, Bureau of Mines, Projects to Expand Energy Sources in the Western States - An Update of Information Circular 8719 - Survey of Planned or Proposed Coal Mines; Electric Generating, Coal Conversion, and Waste-to-Fuel Plants; Oil Shale and Tar Sands Projects; Geothermal Facilities; Uranium Mines, Mills, and Enrichment Facilities, Natural Gas Processing and Storage Facilities; Oil Refineries and Terminal Facilities; Railroads; and Coal Slurry, Petroleum, and Natural Gas Pipelines, in States West of the Mississippi River (as of August 1977), Information Circular 8772. Washington, D.C.: GPO (1978b).

U.S. Department of Interior, Bureau of Mines, Minerals Yearbook: 1977, Volume I, Metals and Minerals, Washington, D.C.: GPO (1980).

U.S. Department of Interior, Geological Survey, Synthetic Fuel Development: Earth Science Considerations, Washington, D.C.: GPO (1979).

U.S. Department of Interior, Mining Enforcement and Safety Administration, Active List of Permissible Explosives and Blasting Devices Approved Before December 31, 1975, Informational Report 1046. Washington, D.C. (1976).

U.S. National Alcohol Fuels Commission, Fuel Alcohol: An Energy Alternative for the 1980's. Washington, D.C.: GPO (1981).

U.S. Water Resources Council, Water Requirements, Availabilities, Constraints, and Recommended Federal Actions, Project Independence Blueprint, Final Task Report, Washington, D.C.: GPO (1974).

U.S. Water Resources Council, The Nation's Water Resources, 1975-2000, Vol. I.: Summary, Washington, D.C.: GPO (1978).

Waitzman, Don, Tennessee Valley Authority, personal communication (1981).

Weismantel, G.E., "Coal Stars as 1980's Methanol Feed," Chemical Engineering, 47 (Jan. 12, 1981).

1. Report No.	2. Government Accession No.	3. Recipient's Catalog No.
NASA CR-168093		

4. Title and Subtitle
Energy and Precious Fuels Requirements of Fuel Alcohol Production
Volume IV - Appendices G and H: Methanol from Coal

5. Report Date
December 1982

6. Performing Organization Code
505-31-42

7. Author(s)
Herbert Weinblatt and Geoffrey Back, Jack Faucett Associates, and T. S. Reddy, Battelle Laboratories

8. Performing Organization Report No.
JACKFAU-82-299

10. Work Unit No.

9. Performing Organization Name and Address
Jack Faucett Associates
5454 Wisconsin Avenue
Chevy Chase, Maryland 20815

11. Contract or Grant No.
DEN 3-292

13. Type of Report and Period Covered
Contractor Report

12. Sponsoring Agency Name and Address
U. S. Department of Energy
Office of Vehicle and Engine R&D
Washington, D. C. 20585

14. Sponsoring Agency ~~Code~~ Report No.
DOE/NASA/0292-1

15. Supplementary Notes
Final report. Prepared under Interagency Agreement DE-AI01-81CS50006. Project Manager, George M. Prok, Aerothermodynamics and Fuels Division, NASA Lewis Research Center, Cleveland, Ohio 44135.

16. Abstract
In this study, energy requirements for producing alcohol fuels are estimated and are compared to the energy content of the alcohol produced. The comparisons are developed for three alcohol production alternatives: ethanol from grain, methanol from cellulose, and methanol from coal. In the analysis, alcohol fuel and all nonrenewable fuels are valued on the basis of their higher heating value (in Btu), while byproducts and grain and cellulose feedstocks are valued on the basis of the effect their production would have on the consumption of nonrenewable fuels. The effects of changes in agricultural production were analyzed on the basis of their effects on overall agricultural energy consumption (not on average energy consumption associated with present production). All three alcohol production alternatives were found to be effective means of increasing supplies of liquid fuels. The cellulose-to-methanol alternative, however, produces more energy than it consumes. (The favorable energy balance for this feedstock results largely from the use of cellulose as a boiler fuel as well as a feedstock.) The grain-to-ethanol alternative yields a slightly negative energy balance, while the coal-to-methanol alternative (which uses a nonrenewable fuel as both feedstock and boiler fuel) results in a substantially negative energy balance. The report is presented in four volumes. Volume I (NASA CR-168090) contains the main body of the report, and the other three volumes contain appendices:

II - Appendices A and B: Ethanol from Grain (NASA CR-168091)
III - Appendices C to F: Methanol from Cellulose (NASA CR-168092)
IV - Appendices G and H: Methanol from Coal (NASA CR-168093)

17. Key Words (Suggested by Author(s))
Ethanol
Methanol
Renewable fuels
Biomass conversion
Coal conversion
Net energy
Agricultural energy

18. Distribution Statement
Unclassified - unlimited
STAR Category 44
DOE Categories UC-96, UC-90c, UC-61a, UC-90d

19. Security Classif. (of this report)	20. Security Classif. (of this page)	21. No. of Pages	22. Price*
Unclassified	Unclassified	67	A04

* For sale by the National Technical Information Service, Springfield, Virginia 22161

☆USGPO: 1983 — 659-094/332