Alternative Fuels Monitor:
Coal Gasification and Indirect Liquefaction

Prepared for
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Contents

CHAPTER	PAGE	TITLE
FOREWORD		
CHAPTER 1	1.1	TECHNOLOGY DESCRIPTION
	1.1	Coal Gasification
	1.4	Indirect Liquefaction
CHAPTER 2	2.1	PROJECTED OUTPUTS
	2.5	Production Capacity
	2.7	Production Costs
	2.10	Capacity Utilization Rate
CHAPTER 3	3.1	PROJECTED INPUTS
	3.1	Capital
	3.1	Coal as Feedstock
	3.1	Land
	3.5	Manpower
	3.5	Water
	3.8	Equipment
CHAPTER 4	4.1	COLLATERAL ACTIVITIES
	4.1	Financial Initiatives
	4.5	Pending Legislation
	4.5	Existing Regulations
	4.5	Institutional Participants
CHAPTER 5	5.1	SITES
	5.4	USGS
	5.4	BOM
	5.7	SRI
CHAPTER 6	6.1	PROJECT LIST
	6.3	Commercial
	6.7	Demonstration
	6.10	Pilot

FOREWORD

The Energy Processes Division (EPD) of the Environmental Protection Agency (EPA) will be coordinating the effort to develop pollution control guidance documents for the various synfuels technologies. To establish priorities, the EPD needs to know the commercialization status of various alternative fuel technologies. To support this effort, the EPD has commissioned monitoring reports on various strategic aspects of the four major technology groups most likely to benefit the United States: coal gasification and indirect liquefaction; oil from shale; direct coal liquefaction; and ethanol from biomass and waste. These Alternative Fuel Technology Monitors will screen the information on and provide an internally consistent and logically ordered view of activities in the relevant alternative fuel industries.

The first monitor is on coal gasification and indirect liquefaction. Although the guidance document on indirect coal liquefaction will cover only the Lurgi, Koppers-Totzek, Texaco, Fischer-Tropsch, methanol production, and M-gasoline processes, the monitor considers additional technologies in order to provide a comprehensive view of the emerging industry. Specific topics covered include the technologies under consideration; current projects in the United States and abroad; production capacity and projected output to the end of the century; estimated inputs necessary to achieve these levels; potential plant sites; and supporting activities in the public and private sectors.

The production capacity and output estimates presented in the monitor reflect our judgment on the deployment of various facilities. This judgment, expressed as ranges to acknowledge uncertainty, is based on estimates made by a variety of organizations, on announced plans be developers, and on our conclusions regarding several factors influencing production capacity. These output estimates cannot be directly compared with other estimates for three reasons. First, no source has provided estimates as comprehensive as ours; second, assumptions vary widely among studies; and third, most sources do not distinguish between actual production and production capacity.

1 TECHNOLOGY DESCRIPTION

Coal gasification involves the chemical reaction of coal with steam or hydrogen and oxygen or air to produce gaseous fuels. Low-Btu (90-200 Btu/scf) gas is formed by reacting coal with steam and air. To produce high-Btu gas (970-1000 Btu/scf) with a heating value equivalent to pipeline-quality natural gas, coal is reacted with steam and oxygen, producing a medium-Btu gas (300-650 Btu/scf). The medium-Btu gas is then upgraded by increasing the proportion of hydrogen in the gas mixture during catalytic methanation, resulting in high-Btu gas (see Exhibit 1).

Indirect liquefaction is an extension of coal gasification. In indirect liquefaction processes, coal is gasified to produce a mixture of hydrogen and carbon monoxide. These gases are then recombined with the aid of catalysts to produce liquid compounds (see Exhibit 1).

COAL GASIFICATION

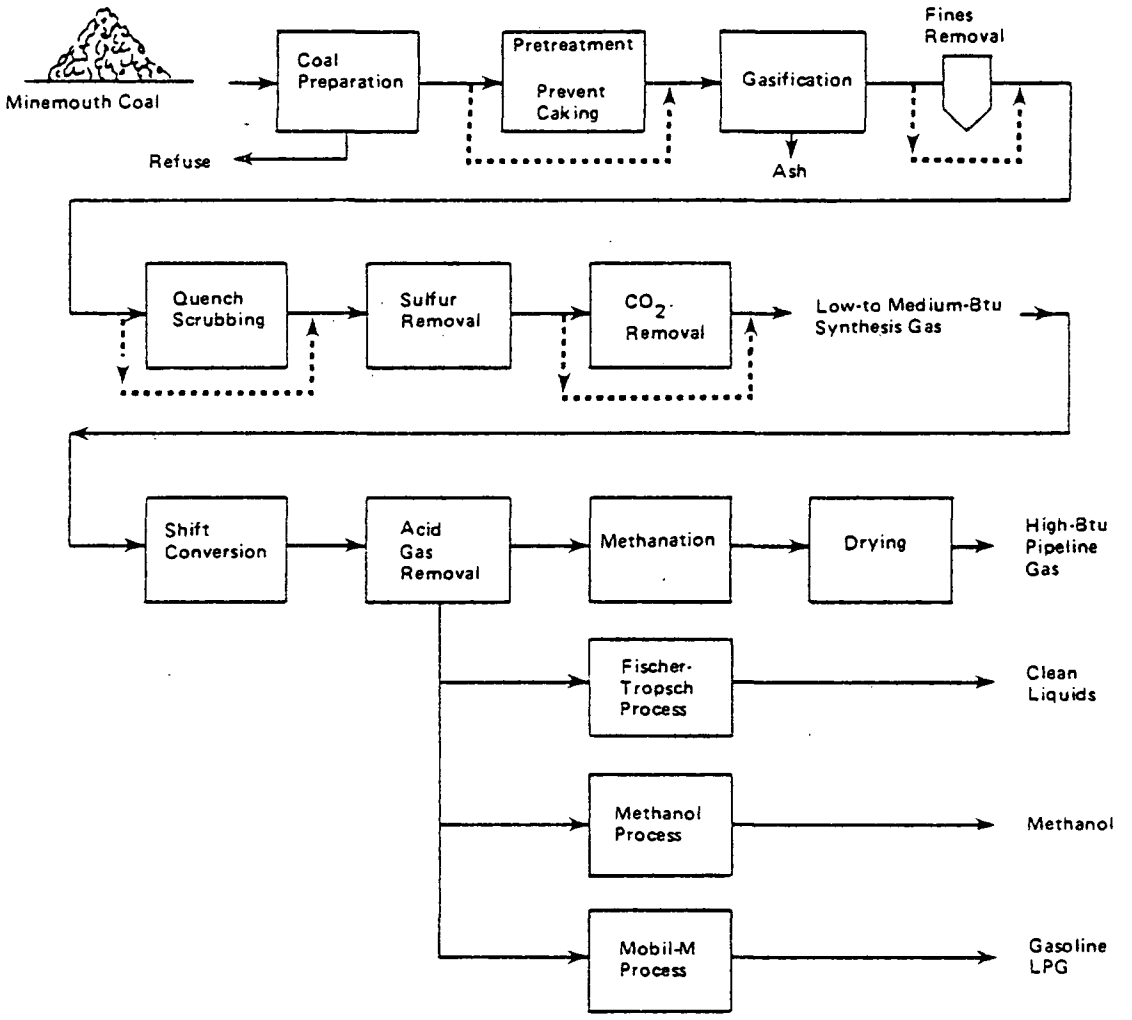
Coal gasification processes include: Wellman-Galusha, Slagging Lurgi, Hydrane Process, Bi-Gas, Synthane, Stoic, Two-Stage Entrainment Gasification System, KILNGAS, In-situ, IGT-HYGAS, and IGT-U-Gas. Two third-generation processes, which produce more methane in the initial gasifier, are flash hydropyrolysis, developed by Rockwell International and Cities Service, and catalytic gasification, under development by Exxon Research and Engineering.

These technologies are at different stages of market readiness (see Exhibit 2). The Lurgi, Koppers-Totzek, and Texaco processes are available for commercial licensing.

Lurgi Process. Coal enters a high-pressure gasifier, covering a fixed bed at temperatures averaging about 800°C. As oxygen and steam flow past the coal, it combines with hydrogen in the steam, resulting in medium-Btu gas.

Exhibit 1

Block Diagram of Coal Gasification and Indirect Liquefaction



Source: The Coal Gasification and Liquefaction Manual, Volume I and Chemical and Engineering News, August 27, 1979

Exhibit 2

Market Readiness of Various Technologies

Gasification	Status
Lurgi*	9
Koppers- Totzek *	9
Texaco*	7
In-situ	5
Wellman-Galusha*	9
Riley-Morgan*	9
Chapman-Willputte*	9
Slagging Lurgi	7
Synthane	6
Hydrane	5
Bi-Gas	6
Stoic - Foster Wheeler	9
Two-stage Entrainment	6
Flask hydropyrolysis	1
Catalytic gasification	1
KILNGAS	5
TOSCOAL	4
COED-COGAS	7
IGT-HYGAS	7
IGT-UGAS	7
Indirect Liquefaction	
Fischer-Tropsch*	9
Methanol*	9
M-gasoline*	6

Key

0: proposed process
1: successful laboratory operation
2: economic studies completed
3: competitive cost established
4: pilot plant designed
5: pilot plant operating
6: successful pilot runs
7: demonstration plant design begun
8: demonstration plant operating
9: proven demonstration plant

SOURCE: Engineering Societies Commission on Energy, Inc., Hagler, Bailly & Company.

*** Processes for which pollution control guidance documents will be issued.**

Koppers-Totzek Process. This process is based on the entrained bed concurrent flow principle and uses the partial combustion of pulverized coal in oxygen and steam. (Other processes use fixed or fluidized bed gasifiers.) Entrained ash is solidified and removed by scrubbers, resulting in a medium-Btu gas.

Texaco Process. In this process, a concentrated slurry of ground coal in water is pumped to a pressurized entrained bed downflow gasifier, where it is mixed with oxygen. The slag is then quenched in water and the hot gases directed through a heat recovery section, where the raw synthesis gas is cooled and scrubbed to remove entrained particulates and flyash.

In-situ Process. In this process, coal is gasified underground by the injection of air or oxygen and steam into the underground reaction zone through boreholes drilled into the seam. The partially oxidized coal produces low- or medium-Btu gas, which leaves through the borehole and is cleaned and upgraded on the surface.

INDIRECT LIQUEFACTION

The commercially proven liquefaction processess are the Fischer-Tropsch and methanol production processes. The M-gasoline process is also important but not yet ready for the market (see Exhibit 2).

Fischer-Tropsch Process. After coal is converted to synthesis gas, the hydrogen-carbon monoxide mixture is reacted over an iron catalyst, yielding a variety of liquids and gases that must be sorted out before use. Operating conditions can be varied within limits to increase yields of certain products.

Methanol Production Process. This is a specialized application of a Fischer-Tropsch reaction, favoring production of methanol from the synthesis gas.

M-gasoline Process. Developed by Mobil Oil Co., this process involves converting methanol directly to high-octane gasoline. The process uses a separate catalytic conversion applied to any alcohol (in this case, methanol) to produce a gasoline equivalent.

2 PROJECTED OUTPUTS

The main outputs of the gasification and indirect liquefaction technologies will be high-Btu gas (i.e., pipeline quality), low- to medium-Btu gas (mostly medium-Btu), and a variety of liquid fuels, including gasoline, jet fuel, and middle distillates, which will be produced in accordance with the projected demand pattern for refined petroleum products.*

In addition, coal conversion technologies yield a variety of co-products such as tars, sulfur, ammonia, and phenols (see Exhibit 3).

To determine the product mix from indirect liquefaction plants, producers had first projected the overall pattern of demand for petroleum products with a view towards producing products whose market share was likely to grow fastest. Initially, their plans had called for a higher percentage of heavier products to meet the need for boiler fuel. Now, however, companies intend to produce more light premium products and relatively little heavy products. This switch reflects changed expectations about the future growth rates in demand for various petroleum products.

The high-Btu gas will be used to supplement natural gas in its traditional uses. The low- to medium-Btu gas will be used in industrial applications such as baking and glass making where clean process heat is important. Liquid fuels will be used mostly in transportation and premium petrochemicals manufacture. The co-products will be used in a wide range of petrochemical applications. In most cases, the output from an alternative fuels plant will be used as a captive source of supply for the firm or consortium operating the facility.

Commercial coal gasification and indirect liquefaction facilities will not produce alternative fuel until 1985 and not in significant quantities until 1990 (see Exhibit 4).

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*Gasoline, jet fuel, and middle distillates (chiefly diesel) will be in greatest demand, while demand for Number 6 fuel oil, which is used mostly by utilities, is likely to drop as government regulations reduce utility oil consumption by 80 percent by 1990.

Exhibit 3

COAL GASIFICATION AND INDIRECT LIQUEFACTION PRODUCTS AND THEIR USES

Process	Products	Co-Products	Uses
Coal gasification			
Lurgi	Low- to medium-Btu gas, pipeline quality gas	Sulfur, tars, phenols, heavy hydrocarbons (e.g., diesel oil, parafin waxes)	Industrial process heat for low-temperature application (e.g., baking); petrochemical feedstock; methanol production; residential cooking and space heating; electric power generation for peak load shaving; industrial and commercial space heating; as a source of direct combustion in all processes requiring clean heating.
Koppers-Totzek	Medium-Btu gas, pipe-line-quality gas	Sulfur	
Texaco	Medium-Btu gas, pipe-line-quality gas	Sulfur, ammonia, hydrogen	
Indirect liquefaction			
Fischer-Tropsch (fixed bed/German)	Diesel oil, parafin waxes	Gasoline, LPG, SNG, ammonia, oxygenated compounds (e.g., alcohols, ketones, organic acids)	Chemical manufacturing; automotive, aircraft, and marine fuels; solvents; illumination; cooking; space heating; electricity generation

Exhibit 3 cont'd

COAL GASIFICATION AND INDIRECT LIQUEFACTION PRODUCTS AND THEIR USES

Process	Products	Co-Products	Uses
Fischer-Tropsch (fluidized bed/ American Synthol)	LPG, gasoline	Diesel oil, furnace oil, waxy oil, alcohols and ketones, parafins, aromatics, carbonyls	Chemical manufacturing; automotive, aircraft, and marine fuels; solvents; illumination; cooking; space heating; electricity generation
Methanol	Methyl fuel, methanol	Sulfur, tars, heavy oils, tar acids, ammonia	Automotive and aircraft fuels; chemical manufacturing; lubricants; solvents
M-gasoline	Gasoline, LPG, butanes	SNG, sulfur, ammonia	Automotive and aircraft fuels; chemical manufacturing; solvents; illuminants; cooking and space heating fuel

Exhibit 4

Production, 1985-2000
(thousand bpdoe)

Fuel Type	1985	1990	1995	2000
High-Btu Gas	20 - 33.5	145 - 225	275 - 425	550 - 800
Low - to Medium - Btu Gas*	–	100 - 250	300 - 550	400 - 700
Liquids	–	125 - 175	475 - 600	675 - 1,000
Total	**20 - 33.5**	**370 - 650**	**1,050 - 1,575**	**1,625 - 2,500**

* Predominantly Medium-Btu

SOURCE: Hagler, Bailly & Company, based on capacity projections by DOE; Bechtel National, Inc.; Amoco; Booz-Allen; Council on Environmental Quality; IERL - Research Triangle Park.

In 1990, total production using these technologies could range from 0.37 million barrels per day of oil equivalent (mbdoe) to 0.65 mbdoe, with liquids accounting for between 27 percent and 33 percent of total output. By 2000, total production could be 1.6-2.5 mbdoe, with liquids providing about 40 percent and high-Btu gas 32-34 percent of the output.*

It is somewhat difficult to directly compare our estimates with those made by others. Other estimates have tended to be either less comprehensive or very aggregate. In general, we are within the range of other estimates. Booz·Allen estimates medium-Btu gas output of 0.3 mbdoe by 1990, which is well above our upper estimate. Bechtel's estimate of high-Btu gas production is well within the range we project through 2000. ESCOE projects gas from coal output at 0.15 mbdoe by 1990, which is considerably below our lower estimate. ESCOE's coal liquids projection of 1.35 mbdoe by 1990 is much greater than our estimate even if direct coal liquefaction were considered. The CEQ foresees total coal-derived alternative fuels production at 1.25 mbdoe by 1990, which is again considerably above our optimistic estimate even if direct coal liquefaction were factored in. DOE expects methanol from coal to range from 0.68 to 1.03 mbdoe by 2000, compared with our estimate of 0.275 - 0.35 mbdoe.

In the absence of firm and consistent information, we speculate that the Lurgi and Texaco processes will dominate the high-Btu gasification industry until the mid 1990s. We expect these two processes to account for all high-Btu gas production through 1990. Even by 2000, either process may account for 25-30 percent of the high-Btu gasification industry's output. Other processes could account for 15-20 percent of the output by 1995 and 40-50 percent of the output by 2000 (see Exhibit 5).

*These estimates reflect our judgment based on projections made by a variety of organizations including Department of Energy (DOE), Bechtel National, Inc., consulting firms, and energy companies.

Exhibit 5

Estimated Production of High-Btu Gas and Liquids by Technology
(thousand bpdoe)

	1985	1990	1995	2000
High-Btu Gasification				
Lurgi	20 - 33.5	60 - 100	100 - 150	140 - 235
Koppers-Totzek/Texaco	-	60 - 100	100 - 150	140 - 235
Other	-	25	75 - 125	270 - 330
Indirect Liquefaction				
Fischer-Tropsch	-	50	75 - 100	100 - 150
M-gasoline	-	25 - 35	100 - 150	150 - 300
Methanol processes	-	50 - 65	200 - 250	275 - 350
Other	-	0 - 25	100	150 - 200

SOURCE: Hagler, Bailly & Company based on announced projects and corporate intentions and telephone conversations with potential producers.

In the indirect liquefaction industry, we expect the methanol processes to make the greatest contribution through the end of this century. Their relative share of output, however, could decline from 40-60 percent in 1990 to 35-40 percent in 2000. The Fischer-Tropsch processes, similar to those used by Sasol, may have as much as 40 percent of the market share by 1990, but we suspect their share could fall to 15 percent by 2000 as the M-gasoline and other processes are deployed (see Exhibit 5).

The level of output in the period between 1985 and 2000 will depend upon installed capacity and the capacity utilization rate.

PRODUCTION CAPACITY

The installed production capacity will be a function of total production costs (feedstock plus process), technological uncertainties, equipment availability, regulations, resource ownership, and the availability of capital. On the basis of these factors, total installed capacity will not exceed 0.81 mbdoe by 1990 and 2.8 mbdoe by 2000 (see Exhibit 6).

PRODUCTION COSTS

With the prices of alternative fuels influenced by world fossil fuel market conditions, the ability of alternative fuel technologies to compete will be critically dependent on the ability of alternative fuels plants to generate economic returns for their owners, which in turn depends on production costs. Production costs will vary by technology, the cost of coal, and the costs of transporting coal from the mine mouth to the production facility. Actual costs confronting a producer will also depend on subsidies that the federal government may make available.

Total costs are generally expected to average around $40 per barrel of oil equivalent (boe), although specific processes are likely to vary considerably. DOE recently estimated total costs for high-Btu gas production at $44/boe while Cameron Engineers estimated costs at $35-53/boe. DOE estimated indirect liquefaction costs at $30-35/boe while Cameron Engineers estimated these costs at $48-53/boe.

Exhibit 6

Production Capacity, 1985-2000
(thousand bpdoe)

Fuel Type	1985	1990	1995	2000
High-Btu Gas	27.0 - 45.0	180 - 280	230 - 500	610 - 890
Low- to Medium-Btu Gas	–	125 - 310	350 - 650	445 - 780
Liquids	–	155 - 220	560 - 705	750 - 1,100
Total	**27.0 - 45.0**	**460 - 810**	**1,140 - 1,855**	**1,805 - 2,770**

SOURCE: Hagler, Bailly and Company, based on estimates by Engineering Societies Commission on Energy Inc., DOE, Bechtel, National, Inc., Booz-Allen, Amoco, Council on Environmental Quality.

These cost estimates imply that the liquid alternative fuels will be competitive with light distillates and petrochemical feedstocks derived from crude oil in the 1985-2000 period. Gaseous alternative fuels are likely to compete well with imported LNG, Canadian and Mexican pipeline gas imports, and free market domestic gas production after 1990. Prior to 1990, alternative gaseous fuels will probably be only marginally competitive with conventional natural gas but fairly competitive with Algerian LNG. After 1990, economic returns from alternative fuels production are likely to be enough to promote rapid deployment of alternative fuels facilities.

Technological Uncertainties

Technological uncertainties could easily prevent a rapid build up of capacity. Except for the Lurgi and Fischer-Tropsch processes, the technology of coal gasification and indirect liquefaction is not completely proven on a commercial scale. According to an estimate by Mechanical Technologies, Inc., 19 necessary pieces of equipment (4 percent of the required items) need significant additional work before they can be used with confidence in full-scale commercial plants. Another 68 pieces of equipment (15 percent of the required items) need some work.

Equipment Availability

Distillation towers, heat exchangers, compressors, large pumps, thick wall pressure vessels, and air separation plants could generally be in short supply for at least the next 10-15 years.

U.S. dependence on imports of such critical minerals as chromium, cobalt, and the platinum group could prevent significant increases in the production capacity of certain nickel and iron alloys needed for fabricating gasification and liquefaction equipment.

Regulations

Five factors make the regulatory system critical to success. First, rules to implement legislation frequently go beyond the intent of the original law. Second,

jurisdictional disputes arise among state, local, and federal agencies. Third, frequently only conditional permits are granted. Fourth, the period for public hearings can be extended almost indefinitely, and fifth, there is enormous uncertainty about new regulations and rules that could later halt or change the economics of a project.

Resource Ownership

Although physical resources are large enough to support a huge United States coal-based alternative fuels industry, there are only limited available sites capable of sustaining a large alternative fuels plant. Additional federal leases will be necessary to make available mining sites on attractive coal properties. These sites must become available in time for firms to acquire water and access rights as needed.

Availability of Capital

Investment requirements for a 50,000 barrel per day (bpd) facility could be as much as $2.25 billion in 1980 dollars. Only a few large companies or consortia can undertake such massive investment. Banks will be wary of lending unless the government provides an array of guarantees and incentives to alternative fuels producers since government policy and regulation can drastically influence the profitability of a project. Large capital market financing will be forthcoming only if rolled-in gas pricing, loan guarantees, tax credits, accelerated depreciation, and price and purchase commitments are provided.

CAPACITY UTILIZATION RATE

In the initial phases of development, the coal-based alternative fuels industry is likely to be plagued by a low capacity utilization rate. The reasons for this low rate are likely to be equipment failure and the need for frequent maintenance of parts subject to high pressure and temperature. In the early years of Sasol I, valves wore out in a matter of days and the plant had to be shut down several times a year for major maintenance, equipment cleaning, and parts replacement.

Projected output is based on capacity utilization rates of 0.75 in 1985, 0.80 by 1990, 0.85 by 1995, and a steady state 0.9 by 2000. The 0.9 rate is only a few points below the utilization rate of a complex refinery. The 0.75 rate assumes a plant shutdown at least once a month for repair, cleaning, and parts replacement.

3 PROJECTED INPUTS

The major factors of production in the coal gasification and indirect liquefaction industry will be capital, coal as feedstock, land, manpower, water, and equipment.

CAPITAL

We expect cumulative investments in the fuel production plants through the end of this century will be $67-$117 billion in 1980 dollars. Of these amounts, about 45 percent would be for indirect liquefaction and about 35 percent for high-Btu gasification (see Exhibit 7). We estimated capital costs on the basis of capacity projections shown in Exhibit 6 and an investment of $40,000-$45,000 per daily barrel of installed capacity.

COAL AS FEEDSTOCK

Total feedstock coal requirements are expected to be 710,000-1,090,000 short tons per day in 2000 (see Exhibit 8). The maximum projected feedstock coal requirements will rise from about 0.5 percent of projected U.S. coal output in 1985 to over 25 percent in 2000. In calculating the requirements for coal, we assumed a thermal conversion efficiency of 67 percent for gasification and 55 percent for indirect liquefaction, an average coal energy content of 21.6 million Btu/short ton, and the production estimates in Exhibit 4.

LAND

About 6,300-11,600 acres of land should be disturbed by mining of feedstock coal through the year 2000 (see Exhibit 9). Starting from insignificant amounts in 1985, cumulative land disturbed will increase appreciably with the growth of the industry.

In computing land disturbed from coal mining to meet feedstock requirements, we used the production figures in Exhibit 4 and made four assumptions:

- Two-thirds of feedstock coal needs will be met by surface-mined coal

Exhibit 7

Investment Costs, 1985-2000
($ billion)

Fuel Type	1985	1986-1990	1991-1995	1996-2000
High-Btu Gas	1.0 - 2.0	6.5 - 10.5	6.0 - 10.0	11.5 - 17.5
Low- to Medium-Btu Gas	–	5.0 - 14.5	4.0 - 6.5	3.5 - 6.0
Liquids	–	6.0 - 10.0	16.0 - 22.0	7.5 - 18.0
Total	**1.0 - 2.0**	**17.5 - 34.5**	**26.0 - 38.5**	**22.5 - 41.5**

SOURCE: Hagler, Bailly & Company.

Exhibit 8

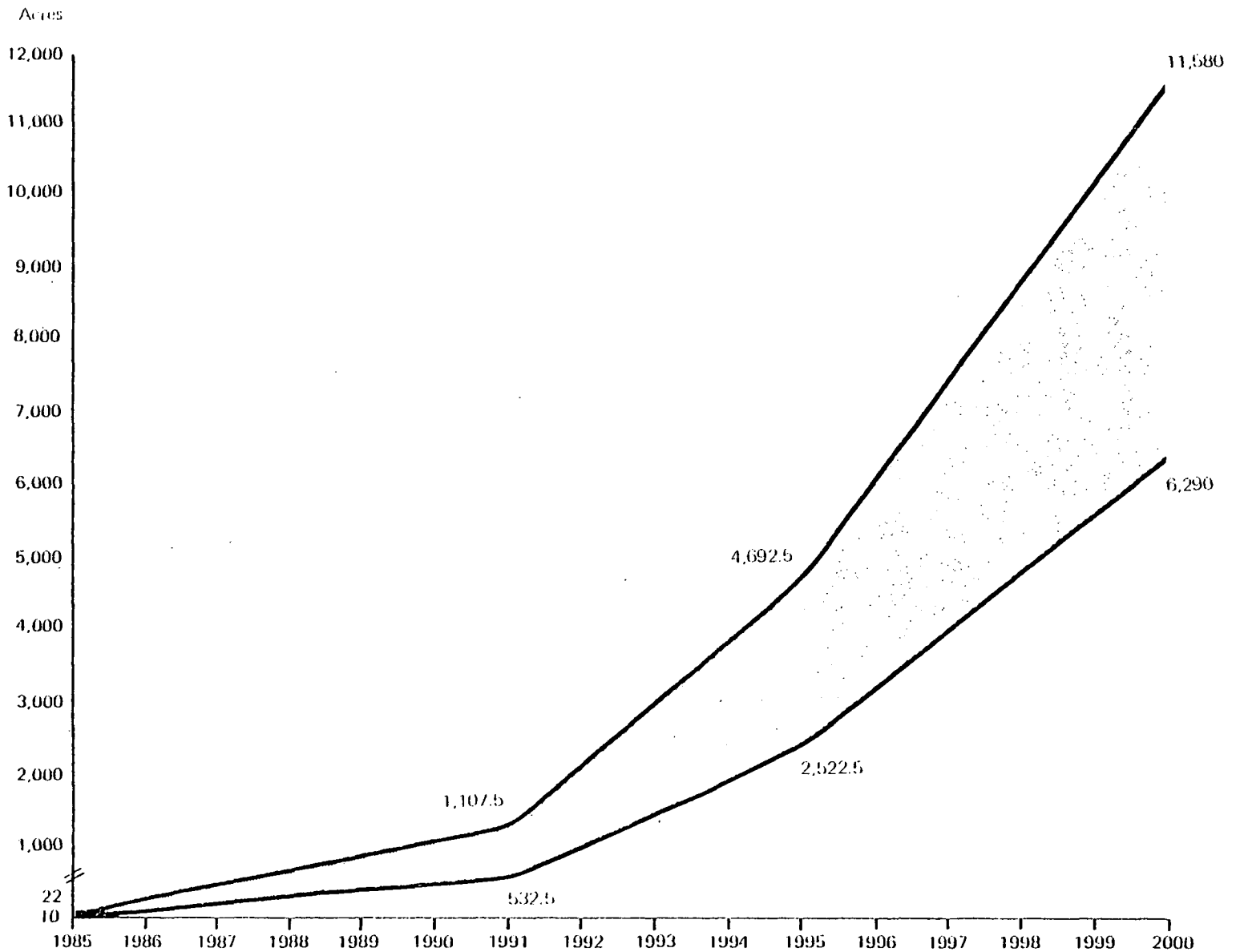
Feedstock Coal Requirements, 1985-2000
(thousand short tons per day)

Fuel Type	1985	1990	1995	2000
High-Btu Gas	8 - 13.5	58 - 90	110 - 170	220 - 320
Low- to Medium-Btu Gas	--	40 - 100	120 - 220	160 - 280
Liquids	--	60 - 85	230 - 290	330 - 490
Total	**8 - 13.5**	**158 - 275**	**460 - 680**	**710 - 1,090**

SOURCE: Hagler, Bailly & Company.

Exhibit 9

Cumulative Land Disturbance From Coal Mining, 1985 - 2000



Source: Hagler, Bailly & Company

- The average seam thickness will be 100 feet
- Bituminous coal will have a distribution of 75-94 pounds per cubic foot (lb/ft^3) and sub-bituminous coal 65-80 lb/ft^3
- There will be an average 153,000-190,000 short tons of coal per surface acre of mine.

MANPOWER

Manpower needs will include home office and field staff for plant design, construction, and startup as well as engineering and technical staff for operations and maintenance once the plant is functioning. Assuming 0.12 design and construction person-years per daily barrel of installed capacity* and the capacity projection in Exhibit 6, preoperations manpower needs should increase dramatically from 3,200-5,400 person-years in 1985 to 60,000-100,000 person-years annually in the 1990s (see Exhibit 10). Assuming 0.0175 operating and maintenance person-years per daily barrel of installed capacity,* operations manpower needs by 1985 are less than 1,000 person-years but will grow steadily to 30,000-50,000 person-years by 2000 as capacity is built up (see Exhibit 11).

WATER

The water requirements of the alternative fuel plants can easily be satisfied in most regions of the United States as far as physical resources are concerned. However, political and regulatory concerns could limit the availability of water to alternative fuel facilities.**

*Estimates of person-year required developed by Bechtel National, Inc.

**Resource availability confirmed by a telephone conversation with Dr. Ronald Probstein of Massachusetts Institute of Technology who agreed that perceptions of water scarcity in the west, rather than a physical shortage, are the cause of controversy about the water needs of alternative fuel plants.

Exhibit 10

Design, Construction and Start Up, 1985-2000
(person-years)

Fuel Type	1985	1990	1995	2000
High-Btu Gas	3,200 - 5,400	18,700 - 20,600	17,200 - 26,400	34,700 - 47,000
Low- to Medium-Btu Gas	–	16,100 - 37,700	12,400 - 17,800	11,000 - 15,800
Liquids	–	18,900 - 26,400	48,600 - 58,900	23,100 - 49,000
Total	**3,200 - 5,400**	**53,700 - 84,700**	**78,200 - 103,100**	**68,700 - 111,800**

SOURCE: Hagler, Bailly & Company; Bechtel National, Inc.

Exhibit 11

Labor Requirements for Operation and Maintenance, 1985-2000
(person-years)

Fuel Type	1985	1990	1995	2000
High-Btu Gas	460 - 780	3,180 - 4,930	5,670 - 8,770	10,710 - 15,580
Low- to Medium-Btu Gas	–	2,190 - 5,480	6,190 - 11,340	7,790 - 13,640
Liquids	–	2,740 - 3,830	9,800 - 12,380	13,150 - 19,480
Total	**460 - 780**	**8,110 - 14,240**	**21,660 - 32,490**	**31,650 - 48,700**

SOURCE: Hagler, Bailly & Company; Bechtel National, Inc.

In a coal-based alternative fuel facility, the major uses of water are for hydrogen, cooling, waste disposal, and environmental control. According to Professor Ronald Probstein, a typical coal gasification plant will consume 15.6-25 gallons of water per million Btu of output. The needs of an indirect liquefaction plant are similar. These estimates assume that all effluent water is recycled or reused and none is discharged.*

J. Harte and M. El-Gassier, writing in Science (1978), also estimated water use by gasification plants. Their estimates range from 25 to 173 gallons per million Btu. ERDA, too, developed estimates in 1977 and concluded that 27-126 gallons per million Btu would be needed.

The upper level of the Harte-El-Gassier and ERDA estimates appear excessive by an order of magnitude. We have used the Probstein estimates.

Total water requirements will be an insignificant 1.8-4.9 million gallons per day (mgd) in 1985. Water needs will grow steadily during the 1990s and reach 140-330 mgd by 2000 (see Exhibit 12).

EQUIPMENT

The equipment needed by the alternative fuels industry can be classified as process engineering and other. Within the process engineering category, the largest items by value will be fabricated vessels and within the other category, instruments and controls will account for more than half the value of equipment installed (see Exhibit 13).

On the basis of a recent marketing study by Frost & Sullivan, Inc. and our capacity projections, we estimate that the annual value of process equipment installed by the industry will rise from well under $1 billion in 1985 to $12-$21 billion by 2000. Other equipment, which will have an annual value of less than $250 million in 1985, will rise to $4-$8 billion by 2000. (See Exhibit 14).

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*In certain instances, the assumption of zero discharge may not be economically valid. Consequently, water requirements may be somewhat higher than forecast in Exhibit 12.

Exhibit 12

Water Requirements, 1985-2000
(million gallons per day)

Fuel Type	1985	1990	1995	2000
High-Btu Gas	1.8 - 4.9	13.1 - 32.6	24.9 - 61.6	49.8 - 116.0
Low- to Medium-Btu Gas	–	9.0 - 36.0	27.2 - 79.8	36.2 - 101.5
Liquids	–	10.0 - 19.7	38.0 - 67.5	54.0 - 112.5
Total	**1.8 - 4.9**	**32.1 - 88.3**	**90.1 - 208.9**	**140.0 - 330.0**

SOURCE: Hagler, Bailly & Company, based on Ronald F. Probstein's "Water for a Synthetic Fuels Industry," *Technology Review*, August/September, 1979.

Exhibit 13

Equipment Requirements, 1985-2000

Process Engineering Equipment	Percent of Value
Fabricated vessels	33.7
Heat exchanger	13.0
Rotating machinery	9.7
Materials handling equipment	2.2
Packaged plants	16.2
Turbine generator sets	2.6
Poilution control devices	1.5
Miscellaneous other	21.0
	100

Other Equipment	
Piping	26.0
Valves	20.0
Instruments and Controls	54.0
	100

Exhibit 14

Equipment Requirements, 1985-2000
($ million)

	1985		1990		1995		2000	
	Process Engineering	Other	Process Engineering	Other	Process Engineering	Other	Process Engineering	Other
High Btu Gas	320 - 640	120 - 240	2,070 - 3,340	760 - 1,230	1,910 - 3,180	700 - 1,170	3,660 - 5,570	1,350 - 2,050
Low- to Medium Btu Gas	-	-	1590 - 4440	585 - 1650	1,270 - 2,070	470 - 760	1,110 - 1,910	410 - 700
Liquids	-	-	7,160 - 13,680	2,640 - 5,040	8,280 - 12,260	3,050 - 4,510	7,160 - 13,210	2,640 - 4,860
Total	**320 - 640**	**120 - 240**	**10,820 - 21,460**	**3,985 - 7,920**	**11,460 - 17,510**	**4,220 - 6,440**	**11,930 - 20,690**	**4,400 - 7,610**

SOURCES: Hagler, Bailly & Company; Frost & Sullivan, Inc.

4 COLLATERAL ACTIVITIES

Collateral activities as used in this document refer to those actions that occur in parallel to and in support of alternative fuels development. The term encompasses federal financial initiatives, pending legislation, existing regulations, and institutional participants.

FINANCIAL INITIATIVES

Developers of commercial projects can select from several financing methods: project financing, self-financing, and corporate financing. Project financing involves securing debt against the cash flows of a specific project; self-financing involves a corporation's use of internally generated cash; corporate financing involves borrowing against the entire assets of a firm or consortium undertaking a venture. Alternative fuels producers can combine the three financing options, although potential producers are reluctant to use the latter two because of the large, long-term investment needs and the high capital exposure involved. The massive investment needs of a coal gasification or indirect liquefaction plant would preclude financing from corporate cash flow and the project risk would make firms reluctant to use corporate financing. With project financing, long-term contracts for the sale of a project's output (e.g., high-Btu gas) serve as the collateral against which a lender provides funds. An even more secure form of collateral is a debt guarantee by which lenders would be protected even if the project failed to produce any fuel. The preference for project financing implies the need for external financing, including assistance from the federal government.

The Energy Security Act of 1980 calls for the establishment of a Synthetic Fuels Corporation (SFC) to provide such financial assistance for commercial alternative fuels projects. These incentives, which are designed to reduce the financial risk of building and operating an alternative fuels plant, include the following:

1. Purchase agreements, price guarantees, and loan guarantees covering up to 75 percent of the project costs

2. Loans covering up to 49 percent of initially estimated project costs (unless this limits the financial viability of the proposed project, in which case up to 75 percent would be authorized)

3. Minority (i.e., less than 50 percent) equity interest in a joint venture in which the government could provide up to 75 percent of projected costs.

This order reflects the government's ranking according to preferred incentive. Multiple forms of financial assistance are authorized only if required for the success of a project and necessary to satisfy the goals and purposes of the Act.

Rulings by the Federal Energy Regulatory Commission (FERC) could also be considered federal financial incentives. Specifically, rulings that permit gas utilities to build into their rate base provisions for indemnifying the debt for a coal gasification plant could effectively reduce the risk of the project to the utility. However, this FERC ruling may not necessarily be available to all gas utilities who may be interested in gasification plants and at this time does not apply to liquid fuels plants. Moreover, one FERC ruling indemnifying debt has been challenged by consumers. Consequently, FERC provisions are, at best, a supplement to SFC initiatives.

The success of the various SFC initiatives will depend on how useful they are considered by the parties with highest financial risk in alternative fuels production, that is, by financial lending institutions. These institutions will want to minimize losses in the event a project fails and will therefore prefer the incentive that leads to the lowest net present value of exposure. Lenders will continue to select their first preferred incentive until it is no longer available, then move on to their next preference, and so on down to the threshold at which the incentive does not make the project attractive enough to induce any investment.

For those financial lending institutions involved in alternative fuels development, loan guarantees are the preferred incentive. We believe minority equity participation by the government would be the next in preference.

Purchase guarantees and price commitments would probably be employed least. These incentives are less desirable because if a project fails to produce or to operate at anticipated levels, the lenders carry the full financial risk.

The precise effect of all these financial incentives on the coal gasification and indirect liquefaction industry is difficult to estimate owing to uncertainty about the share of available funds allocated to a particular incentive or technology. If there are no restrictions on the amount available for a technology, then most of the incentives (from the first $20 billion at any rate) will probably be exhausted by assistance for oil shale projects, which seem to be the most financially viable at present. If there are restrictions on how the first $20 billion is allocated, and assuming about $7 billion will be available for coal gasification and indirect liquefaction projects, $5 billion may be available for loans covering up to 50 percent of project costs. Since a 50,000 b/d plant requires approximately a $2 billion investment, the first round of federal financial incentives could support five plants, or 250,000 b/d of production. These federal financial incentives could therefore substantially help the fledgling industry reach production levels at about the middle of the range of production forecasts presented in this Monitor.

The Great Plains gasification project by American Natural Resources (ANR) provides an interesting case study of the complexity of federal incentive initiatives for alternative fuels development. In fact, this project will be the first test of the effectiveness of federal financial initiatives. The ANR project suggests that small federal loan guarantees (in this case, only 20 percent of total project costs) may not be enough to induce banks to lend.

The four participating companies, led by ANR, had received Federal Energy Regulatory Commission (FERC) approval of a financing plan for the $1.5 billion plant. Under this plan, gas customers of the four participating companies would guarantee project debt in the event of failure. However, four groups representing the customers of the participating gas companies opposed the plan on the grounds that they should not assume the risk of an untried project. These groups claim that the risks should be assumed by all taxpayers. Under the FERC proposal, ratepayers alone assume the burden if the ANR gasification plant does not operate successfully (i.e., at least 70 percent of the time).

DOE agreed to consider guaranteeing the first-year debt of $225 million if the four opposing groups withdrew objections. This DOE guarantee would allow groundbreaking this summer, although consumer protest could postpone start-up for a year. Despite DOE assurances,

two of the groups refuse to drop the suit because the FERC order would set a precedent allowing ratepayers to assume the burden of debt coverage in future plants. Moreover, DOE's 1-year guarantee would cover no more than 20 percent of the project's cost. If litigation continues, DOE's loan guarantee will not be forthcoming and construction will be delayed for a full year. The Ohio Consumer's Council, one of the opposing groups, officially refused to drop its court challenge, and Michigan and New York will probably reject the DOE loan guarantee. The fourth member in the opposition group, General Motors, has not yet determined its position on the proposal.

Nonetheless, ANR may continue its request for DOE funding because FERC had ordered it to seek federal financial backing as an alternative to risks and costs to be assumed by ratepayers. If so, DOE must continue processing the application, although approval is unlikely. Financial institutions have refused to back the plant unless the court challenges are dropped, and unless DOE is assured of future financial support for the ANR facility, DOE officials will be unable to approve the loan guarantee.

If the courts rule in favor of consumer groups and the federal government provides no financing guarantee, the Great Plains consortium will have great difficulty in finding financial backing. Specifically, if Canadian gas prices decline in real terms, the Great Plains' high-priced gas will have no market. The project will most likely be terminated. However, should the courts uphold the pass-through of costs to consumers, the Great Plains project would continue and encourage rapid development of other alternative fuel plants.

Earlier rulings may set conflicting precedents for the current case. The court ruled that if the Northwest Alaskan Pipeline was not completed by the announced date, the project partners must absorb the loss. However, the chance of failure in the Alaskan Pipeline Project was minimal. In another jurisdiction, it was ruled that consumers would not pay for a nonfunctioning Three Mile Island Power plant.

PENDING LEGISLATION

Several pieces of legislation that could affect alternative fuels projects are under consideration. Many pertain to environmental impacts, while some are aimed at organizational and funding mechanisms. Exhibit 15 lists some relevant pending congressional bills.

The most important piece of pending legislation affecting alternative fuels development is the Energy Security Act. The Act was passed by the Senate during the week of June 16, and by the House during the week of June 23. The bill will provide $20 billion in financial incentives for developing alternative fuels. The bill does not provide for minimizing the effects of environmental laws and regulations; all projects are still subject to federal, state, and local environmental land use and siting laws.

EXISTING REGULATIONS

Various existing government regulations will influence alternative fuel development. The environmental regulations listed in Exhibit 16, which are subject to yearly review, will continue to affect the costs and site determination of coal gasification and indirect liquefaction projects.

INSTITUTIONAL PARTICIPANTS

The institutional participants who have assisted or will assist in developing or organizing an alternative fuels industry are organized into three divisions: legislative participants, executive participants, and associations and industry.

Legislative Participants

In drafting the Energy Security Act, a conference committee resolved the differences between the House and Senate version of synfuels legislation. This committee was composed of members of the committees with Synfuels Jurisdiction from both branches of Congress. Their structures are as follows:

Exhibit 15

PENDING LEGISLATION

LEGISLATION	PURPOSE	STATUS
ENERGY		
Underground Coal Gasification and Uncoventional Gas Research and Development Act (S. 2774)	Establish a 10-year program to faster production and commercialization of uncoventional gas resources and underground coal gasification.	Referred to the Senate Energy Committee and awaiting hearing. (Chances for enactment are good.)
ENVIRONMENTAL		
Authorization and Amendment the Solid Waste Disposal Act (S.1156)	Re-authorize the Solid Waste Disposal Act and exempt certain high-volume, low-risk wastes (e.g., mining wastes and wastes generated by the combustion of fossil fuels) from regulation as hazardous waste.	Passed in lieu of H.R. 3994. Conferees have been appointed but no action taken since.
RARE II		
Legislation (H.R. 6607, 5586, 370, 6607; S.812, 2007, 2031, 2568, 2741)	Recommend inclusion roadless areas of national forest lands into the Wilderness System. Of the 33 states with pending legislation, Colorado and South Dakota are the only states with high potential for alternative fuels development.	5 of 33 states have initiated legislation. The South Dakota bill would set aside only a small area in the Black Hills. Action on Colorado wilderness lands is stalled because of disagreement among the senators about which lands to set aside.

Exhibit 15 con't

PENDING LEGISLATION

LEGISLATION	PURPOSE	STATUS
SUPERFUND AND RELATED LEGISLATION		
Environmental Emergency Response Act (S.1480)	Provide for liability, compensation, cleanup, and emergency response for hazardous substances and mandate cleanup of inactive hazardous waste disposal sites.	Forwarded to Senate Environment and Public Works Committee in May, referred to Subcommittees on Environmental Pollution and Resource Protection; marked up June 4 and June 10.
Oil, Hazardous Substances, and Hazardous Waste Response Liability, and Compensation Act (S.1431)	Original superfund proposal (committee-generated). This Act differs from S.1480 in that it contains provisions for oil spills.	Referred to Senate Environment and Public Works Committee and Subcommittees on Environmental Pollution and Resource Protection; considered September 28. Senate is mainly considering S.1480, which was requested after S.1341 was submitted. No action currently being taken on S.1341.
Hazardous Waste Post-Closure Liability Act (S.1325)	Amend Solid Waste Disposal Act by requiring accumulation of funds during the operating lives of hazardous waste management facilities to allow payment of damages and liability claims	Same as S.1341

Exhibit 15 con't

PENDING LEGISLATION

LEGISLATION	PURPOSE	STATUS
SUPERFUND AND RELATED LEGISLATION con't		
Amendment to Solid Waste Disposal Act (S.1046)	Establish a program for identification and reclamation of abandoned hazardous waste sites.	Pending in Senate Committee on Environmental and Public Works.
Oil, Hazardous Substances, and Hazardous Response, Liability, Compensation Act of 1979 (HR 4566)	Provide response, liability, and compensation for oil, hazardous substances, and wastes and establish a liability fund.	Hearings held in House Committee on Interstate and Foreign Waste Commerce, Subcommittee on and Transportation and Commerce October 11, 1979. Pending since June 1979 in Merchant Marine and Fisher Committee, Subcommittee on Coast Guard and Navigation. Referred in July 1979 to Committee on Public Works and Transportation, Subcommittee on Water Resources.
Hazardous Waste Containment (HR 7020)	Establish guidelines for the release of hazardous wastes form inactive waste sites that endanger public health and environment.	Reported out of Commerce Act Committee May 16, 1980, and out of Ways and Means Committee June 18, 1980.

Exhibit 16 con't

ENVIRONMENTAL REGULATIONS

Regulation	Sponsoring Agency	Purpose
Under Revision		
Hazardous Emission Standards for Carcinogens	EPA	Increase regulation of airborne carcinogens through the establishment of additional hazardous air pollutant emission standard for suspect carcinogens. If many people faced exposure to airborne emissions, EPA would institute stringent technology-based standards on specific sources. This regulation would affect coal mining and combustion.
Prevention of Significant Deterioration and Nonattainment Area Requirements	EPA	Revise EPA's procedures for review of new and modified stationary sources of pollution. The revised regulations will affect which alternative fuel facilities will be subject to EPA or state review, which pollutants will be subject to control, and what level of control will be imposed on a facility.
Approval of State Implementation Plan Revisions	EPA	Strengthen emission limitations on existing, new, or modified sources. The revisions were needed because of the failure of many state plans to achieve ambient air quality standards for certain pollutants within the time specified by Congress.

Exhibit 16 con't

ENVIRONMENTAL REGULATIONS

Regulation	Sponsoring Agency	Purpose
Under Revision con't		
Regulation of Underground Injection Wells	EPA	Repropose minimum procedural requirements for issuance of permits and minimum operating, monitoring, and reporting requirements for underground injection wells that could endanger drinking water supplies. This requirement would significantly affect in-situ coal gasification.
Existing		
National Ambient Air Quality Standards	EPA	Establish maximum levels of pollutants compatible with the protection of public health and welfare and be included in state implementation plans to control pollutants for which there are ambient air quality standards.
Requirements for State Implementation Plans	EPA	1. Establish state and local emission control requirements on existing and new sources; 2. Establish review procedures for new facilities; 3. Impose criteria for technology-based control requirements on new and modified existing facilities to prevent sigificant deterioration of air quality or to allow growth in nonattainment areas.

Exhibit 16 con't

ENVIRONMENTAL REGULATIONS

Regulation	Sponsoring Agency	Purpose
Under Revision con't		
Noncompliance Penalties	EPA	Establish a formula for determining noncompliance with the Clean Air Act and for assessing required penalties. With few exceptions, sources not in compliance with state implementation plan requirements as of July 30, 1979, would be assessed penalties equal to the economic benefit derived from noncompliance.
Establishment of Significant Deterioration of Air Quality Increments	EPA	Develop increments for prevention of significant deterioration of air quality for four additional pollutants: hydrocarbons, ozone, carbon monoxide, and oxides of nitrogen. If accepted, this regulation would limit the amount of new emissions of such pollutants permitted in clean air areas.
Consolidated Permit Regulations	EPA	Combine procedures for issuing federal permits under the Clean Air, Solid Waste Disposal, Safe Drinking Water, and Clean Water Acts. This regulation would allow for joint application and data submission, as well as joint permit review by federal and state officials.
Permit Regulations for Water Pollutant Discharge	EPA	Stipulate more stringent requirements for issuance of permits regulating discharges of toxic water pollutants.

Exhibit 16 con't

ENVIRONMENTAL REGULATIONS

Regulation	Sponsoring Agency	Purpose
Existing con't		
New Source Performance Standards	EPA	Create technology-based operating standards for air pollutant emissions from new and modified sources. These standards for fossil-fuel fired power plants have special applications for facilities using certain alternative fuels.
National Emission Standards for Hazardous Air Pollutants	EPA	Establish strict emission limitations for specific pollutants not covered by ambient air quality standards.
Requirements for Issuance of National Pollutant Discharge Elimination System Permits	EPA	Establish procedures and requirements for issuance of permits to allow discharges of pollutants into navigable waters. Permit conditions will include technology-based standards required by the Clean Water Act and any additional limitations necessary to protect water quality standards.
Toxic Water Quality Standards	EPA	Establish health or environmental requirements for specific pollutants imposed on a category-by-category basis on stationary sources.

Exhibit 16 con't

ENVIRONMENTAL REGULATIONS

Regulation	Sponsoring Agency	Purpose
Existing con't		
Hazardous Substances	EPA	Designate hazardous substances subject to Clean Water Act regulations and identify which harmful quantities must be reported if spilled in navigable waters and for which liability for cleanup expenses will exist.
Requirements of Issuance of Corps of Engineers Permits for Construction in Navigable Waters or Discharge of Dredged or Fill Material	DOD	Establish procedures and requirements for issuance of such permits.
Surface Mining Regulations	DOI	Establish policies and environmental standards for control of surface mining activities pursuant to the Surface Mining Control and Reclamation Act of 1977.
Procedures for Environmental Impact Statements	CEQ	Set forth CEQ's requirements for federal agencies' issuance of environmental impact statements on major federal actions significantly affecting the environment. The legislation was established pursuant to NEPA.
Regulations Governing Issuance of Environmental Impact Statements	CEQ	Establish individual agency requirements for issuance of environmental impact statements, which must conform with CEQ regulations.

House of Representatives Committee with Synfuels Jurisdiction. Most legislation dealing with government financial aid to commerce and industry is the responsibility of the Banking Committee, as is any matter dealing with the control of prices of commodities, rents, or services. The Interstate & Foreign Commerce (to be re-named Energy & Commerce in January 1981) Committee has jurisdiction over all petroleum, natural gas, and electrical power issues. The Science & Technology Committee is responsible for scientific, environmental, and energy R&D, while the Agriculture Committee will contribute to any biomass-based energy development.

Other committees that are not participating directly but will influence synfuels developments include the Appropriations Committee, which approves all spending of federal funds; Government Operations, which could have oversight responsibility for SFC and parts of DOE and EPA involved with synfuels; and the Interior and Insular Affairs Committee, which is responsible for water issues, public lands, and environmental issues.

Senate Committee with Synfuels Jurisdiction. This group includes the Committee on Energy & Natural Resources, which has responsibility for all energy matters, and the Banking and Agriculture committees, whose responsibilities are similar to those for their colleagues in the House. Other Senate committees involved include the Appropriations and Intergovernmental Affairs committees, whose responsibilities are also comparable to the corresponding House committees. Finally, the Environmental & Public Works Committee is responsible for environmental policy and R&D and for water resources.

Executive Participants

Executive participants in the alternative fuels industry consist of the Department of Energy (DOE) and the Synthetic Fuels Corporation (SFC). The SFC is part of the Energy Security Act.

DOE. Within DOE, Resource Applications and Fossil Energy are responsible for managing the development of alternative fuels. The Office of the Assistant Secretary for Environment is responsible for effectively addressing the environmental research, assessment, and control issues related to current and developing energy technologies. Within Resource Applications, the alternative fuels

program is largely carried out in the Office of Coal Resource Management, which is responsible for encouraging commercialization of specific technologies. There are divisions for coal liquids, low- and medium-Btu coal gasification. The Office of Coal Resource Management issues solicitations for feasibility studies and cooperative agreements. The feasibility studies program is designed to accelerate the design and planning efforts leading to the construction and operation of commercial-scale alternative fuel production facilities by non-federal entities. Cooperative agreements are targeted to projects that are in the advanced development stage.

Alternative fuels commercialization is the responsibility of the Office of Project Management. This office is currently determining which high-Btu synthetic gas plant to fund in FY 1981: the Illinois Coal Gasification Group's COGAS project or Conoco Coal Development's Noble County, Ohio project. At least six other projects may come under the auspices of the Project Management office.

The Office of the Assistant Secretary for Environment (ASEV) formulates and manages specific environmental responsibilities and functions mandated by the National Environmental Policy Act and other environmental legislation. Responsibilities entail overviewing the energy technology RD&D activities to assure the environmental, health, and safety (EH&S) acceptability of those developments, and conducting R&D necessary for DOE to resolve EH&S uncertainties and conflicts. Environment's Technology Assessment program in FY 1980 will include substantial progress on alternative fuels assessment. ASEV is supported by the Environmental and Safety Engineering program to make independent evaluations on environmental control aspects of DOE's energy research program and national energy policies. In FY 1981, emphasis will be placed on technologies that convert coal from a solid to a premium liquid or gas. The Biological and Environmental Research Program has initiated a series of site-specific research projects to evaluate potential health and environmental problems associated with coal gasification and liquefaction process developments. The overall objective of these projects is to develop a data base for evaluating health and environmental effects of commercializing an alternative fuel technology.

Overall coordination of the DOE alternative fuels program will be provided by an Oversight Committee, composed of the Assistant Secretaries of Resource Applications and Fossil Energy, with representatives of the Assistant Secretaries for Conservation and Solar, and Policy and Evaluation. If Congress establishes the SFC, the DOE organization will be readjusted. The Fossil Energy program will probably continue to manage an alternative fuels RD&D program to do the research to prove existing technologies and bring forth future technologies. The role of Resource Applications in future alternative fuels policy is uncertain.

SFC. The key provision of the Energy Security Act establishes the SFC for a 12-year period, with an initial budget of $20 billion. Within 4 years, the corporation will submit a comprehensive strategy covering future investment plans, which Congress will review and vote on within 90 days.

Before this comprehensive strategy is adopted, the SFC may assist three projects of its own if the projects demonstrate needed technologies and no private financial backer can be found. These plants would be constructed and operated by private contractors. The SFC could also purchase or lease a limited number of existing private plants on a temporary 5-year basis, subject to congressional veto. SFC must offer such purchase agreements first to the Defense Department. SFC funding will come from a special Energy Security Reserve, which the Treasury Department will control.

Until the SFC begins operation, the President may offer up to $3 billion in industry purchase agreements, loans, and loan guarantees through existing agencies. Once the SFC is functioning, the President may intervene in an emergency when the SFC is unable to meet defense fuel needs on its own. Specifically, he may build or acquire government plants, or mandate supply from private alternative fuels producers.

Associations and Industry

Many trade associations and private industry organizations are involved in promotion of alternative fuels: the Gas Research Institute, Electric Power Research Institute, and most major petroleum companies. The Fluor Corporation is playing a major role in developing indirect liquefaction

in the United States. In conjunction with SASOL (South Africa's energy company), Fluor reached an agreement with Texas Eastern Transmission Corporation to evaluate the costs of a Sasol-type plant in the United States. The Fluor study considers the Ohio River Valley for potential sites, estimates costs, and determines ways to tailor SASOL technology to U.S. coal product specifications and environmental standards.

The National Council on Synthetic Fuels Production is a nonprofit corporation to promote the commercial production of alternative fuels from domestic resources. It is the only private participant entirely devoted to alternative fuels developments. The Council will provide a forum to define and develop industry opinions and positions on critical issues and will serve as an advocate for its members before Congress and other government entities.

Members of the National Council on Synthetic Fuels Production (as of June 9, 1980), include:

Airco Energy Co.
Air Products & Chemicals
Amerigas
Arco Coal Co.
Ashland Synthetic Fuels
The Badger Co.
The BDM Co.
Bechtel National
Burns & Roe - Humphreys & Glasgow
Cities Service Co.
Combustion Engineering
Conoco Coal Development
Consolidated Natural Gas
Davy Inc. (formerly Davy McKee)
Dow Chemical
Dynalectron
Fluor
General Electric
George Hyman Construction
Gulf Oil
Institute of Gas Technology
Mobil Oil
Multi-Mineral Corp.
Northern Natural Gas
Occidental Petroleum
Panhandle Eastern Pipeline
Phillips Petroleum
Pullman-Kellogg
Southern California Gas
Standard Oil of California (Chevron)
Standard Oil of Indiana (Amoco)
Standard Oil of Ohio
Stone & Webster Engineering
Sunoco Energy Development
Texaco
TOSCO
Union Oil Company of California
UOP, Inc.
Wheelabrator-Frye

5 SITES

Only the ANR Great Plains gasification project has reached a stage where actual plant construction can begin (completion scheduled for 1984). However, as mentioned in section 4, construction at that site may be delayed until financing is assured. However, the United States is identifying potential sites for planned coal conversion facilities. Most coal gasification and indirect liquefaction production will be in EPA Regions 3, 4, and 8. Estimated gas and liquid fuel production for the ten EPA regions from 1985-1995 is listed in Exhibit 17.

The most important criteria for identifying potential sites for coal gasification and indirect liquefaction are the availability of coal reserves and water resources and the existence of favorable environmental conditions. Other factors considered include the existence of an in-place transportation system, coal mining infrastructure, and labor supply, all of which affect the cost of the project. The previous level of coal production activity will also influence the cost of siting: for example, reclamation costs may be higher in the eastern states because the area is more densely populated and has already undergone extensive mining.

The most prominent site selection studies have been conducted by three organizations: SRI International, the Bureau of Mines (BOM), and the U.S. Geological Survey (USGS). No one study considered all the above criteria. The USGS and BOM studies based siting on the availability of coal and water reserves. Both identified the same eight regions as having high potential for siting a coal conversion facility. The one difference between the two sets of results is that the USGS study included fewer counties in the Appalachian region because it considered the level of previous coal mining. The SRI study focused on the environmental aspects of site selection. However, SRI did not consider such factors as resource availability, transportation of resources and products, availability of markets, or choice of conversion technology.

In all, 120 counties were identified in common by the three studies as potentially suitable for siting coal gasification and indirect liquefaction facilities. These counties are listed by state in Exhibit 18. All

Exhibit 17

Estimated Gas and Liquid Fuel Production by EPA Region, 1985-1995
(thousand bpdoe)

EPA Region	1985			1990			1995		
	Low- to Medium-Btu Gas	High-Btu Gas	Liquids	Low- to Medium-Btu Gas	High-Btu Gas	Liquids	Low- to Medium-Btu Gas	High-Btu Gas	Liquids
1. Maine, Vermont, New Hampshire, Massachusetts, Rhode Island, Connecticut				20 - 40			40 - 70		
2. New York, New Jersey, Puerto Rico, Virgin Islands							20 - 35		
3. Delaware, Maryland, Pennsylvania, Virginia, West Virginia, District of Columbia				20 - 50			40 - 100	20 - 40	50 - 75
4. Alabama, Georgia, Florida, Mississippi, North Carolina, South Carolina, Tennessee, Kentucky				20 - 40	20 - 25	50	50 - 100	40 - 50	100 - 125
5. Illinois, Indiana, Ohio, Michigan, Minnesota, Wisconsin				20 - 40	50 - 75		50 - 70	75 - 115	75
6. Arkansas, Louisiana, Oklahoma, Texas, New Mexico				20 - 40		0 - 25		20 - 40	50 - 75
7. Iowa, Kansas, Missouri, Nebraska							20 - 35		
8. Colorado, Utah, Wyoming, Montana, North Dakota, South Dakota		20 - 33.5		0 - 40	75 - 125	75	40 - 70	100 - 140	150 - 175
9. Arizona, California, Nevada, Hawaii							20 - 35	20 - 40	25
10. Alaska, Idaho, Oregon, Washington						0 - 25	20 - 35		25 - 50

SOURCE: Hagler, Bailly & Company.

Exhibit 18

Overlapping Counties with Potential for Coal Gasification and Indirect Liquefaction Development

Colorado:
Garfield
La Plata
Jackson
Routt

Illinois:
Bond
Bureau
Clinton
Crawford
Douglas
Edgar
Fayette
Franklin
Fulton
Gallatin
Greene
Grundy
Hamilton
Henry
Jackson
Jefferson
Knox
La Salle
Lawrence
Livingston
Logan
McLean
Macon
Macoupin
Madison
Marion
Menard
Montgomery
Perry
Putnam
Randolph
St. Clair
Saline
Sangamon
Washington
White

Indiana:
Gibson
Knox
Posey
Sullivan
Vanderburgh
Vermillion
Vigo
Warrick

Kentucky:
Henderson
Hopkins
McLean
Muhlenberg
Ohio
Pike
Union
Webster

Montana:
Big Horn
Custer
Dawson
Musselshell
Richland
Rosebud
Sheridan
Treasure
Yellowstone

New Mexico:
McKinley
San Juan

North Dakota:
Hettinger
McLean
Mercer
Oliver
Stark
Ward
Williams

Ohio:
Athens
Belmont
Carroll
Columbiana
Harrison
Jefferson
Meigs
Monroe
Morgan
Muskingum
Noble
Perry
Stark
Tuscarawas

Pennsylvania:
Armstrong
Butler
Cambria
Clarion
Clearfield
Fayette
Greene
Indiana
Somerset
Washington
Westmoreland

Utah:
Carbon

West Virginia:
Barbour
Boone
Harrison
Lewis
Logan
Marion
Marshall
Monongalia
Ohio
Preston
Taylor
Upshur
Wester
Wetzel

Wyoming:
Cambell
Carbon
Converse
Johnson
Lincoln
Sheridan

three studies were in almost complete agreement on potential sites in Kentucky, Ohio, Pennsylvania, West Virginia, and Wyoming. Overlapping sites are also scattered in Colorado, Montana, New Mexico, North Dakota, and Utah. Assuming that each county can support only one 50,000 bdoe coal conversion plant, a conservative assumption, all three studies would agree that potential sites could support 6 mbd of alternative fuels production.

In the following sections, we briefly discuss the USGS, BOM, and SRI studies.

USGS

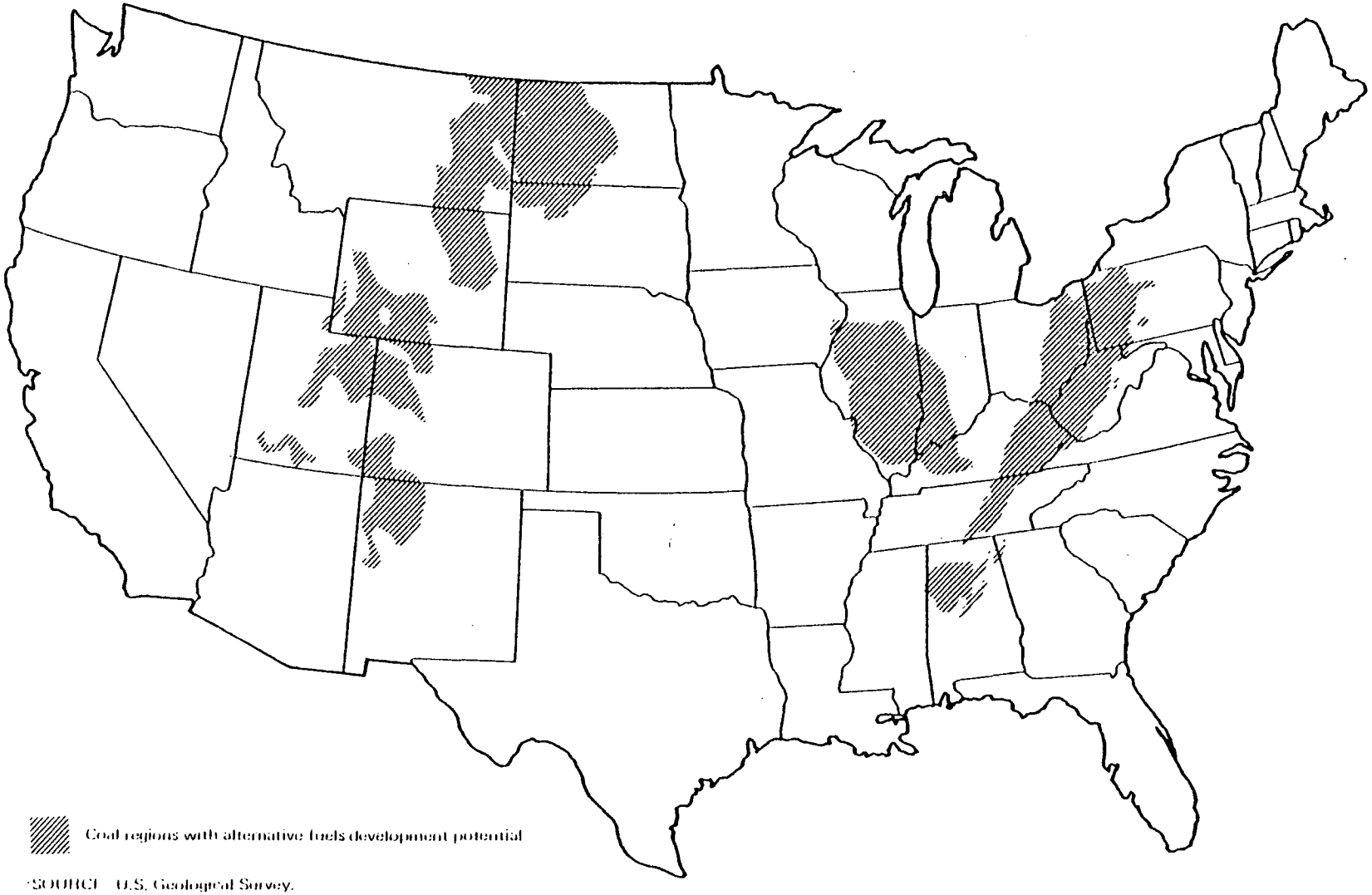
The USGS study primarily considered proximity to coal reserves when determining potential sites. These sites were then studied to determine adequacy of water resources. The resulting potential sites are mapped in Exhibit 19. (USGS noted that siting is further constrained by federal, state, and local government guidelines, although this factor was not part of the USGS siting criteria.) USGS found only a few areas with water supplies inadequate to support alternative fuels development; however, the water supply in many areas is fully appropriated. Using geological criteria, USGS characterized the potential of the eastern and western regions for alternative fuels development. The eastern regions of the United States will be constrained by environmental problems and large existing populations, which would greatly increase costs. In the West, some coal beds may prove difficult for underground mining techniques, although site-specific geologic knowledge is lacking for several regions. As in the East, the major constraint to coal-based alternative fuels development will be prior commitment of coal reserves, particularly to steel and power industries.

BOM

BOM used adequacy of coal reserves, availability of water supplies, and existence of an in-place coal mining industry or the possibility of expansion as its siting criteria. Existence of an in-place industry is important, as otherwise the need for start-up activities will delay the project. Once BOM had identified sites according to these criteria (indicated in Exhibit 20), it narrowed down suitable sites by considering factors such as ownership, commitment of the reserves to other uses, bed

Exhibit 19

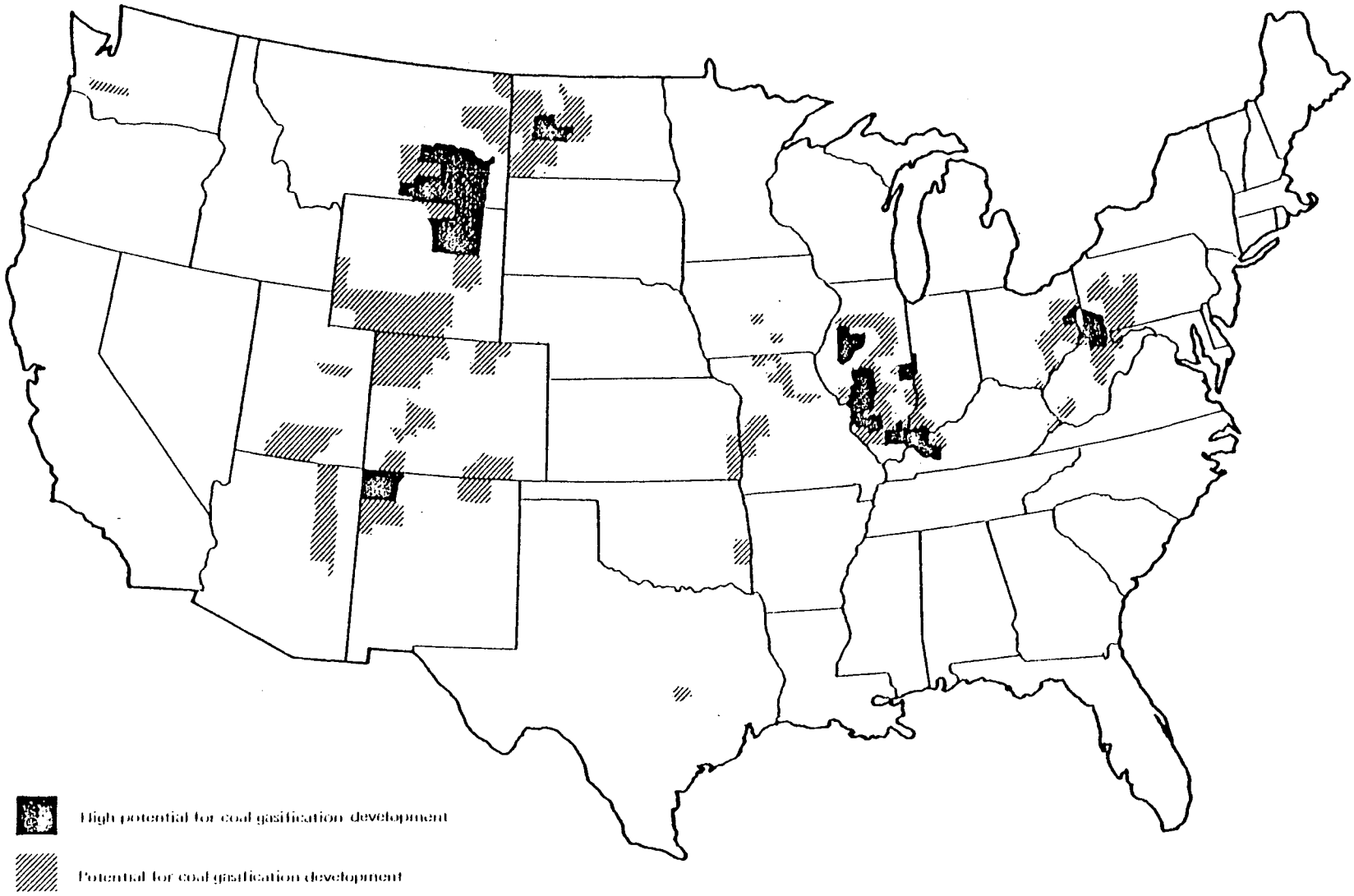
U.S. Coal Sources for Alternative Fuels Production



SOURCE: U.S. Geological Survey.

Exhibit 20

Sites for Coal Gasification and Indirect Liquefaction Plants



SOURCE: Bureau of Mines

thickness, number of beds constituting the reserves, and feasibility of underground and strip mining. Some potential sites may be unattractive because of differing ownership of coal reserve beds or blocks. Thin coal beds may provide adequate reserves, but mining would entail acquisition and use of large land areas. Again, reserves could be located among several townships or several beds, which requires consideration of transportation costs, feasibility of multiple-bed mining, and larger capital-investment requirements.

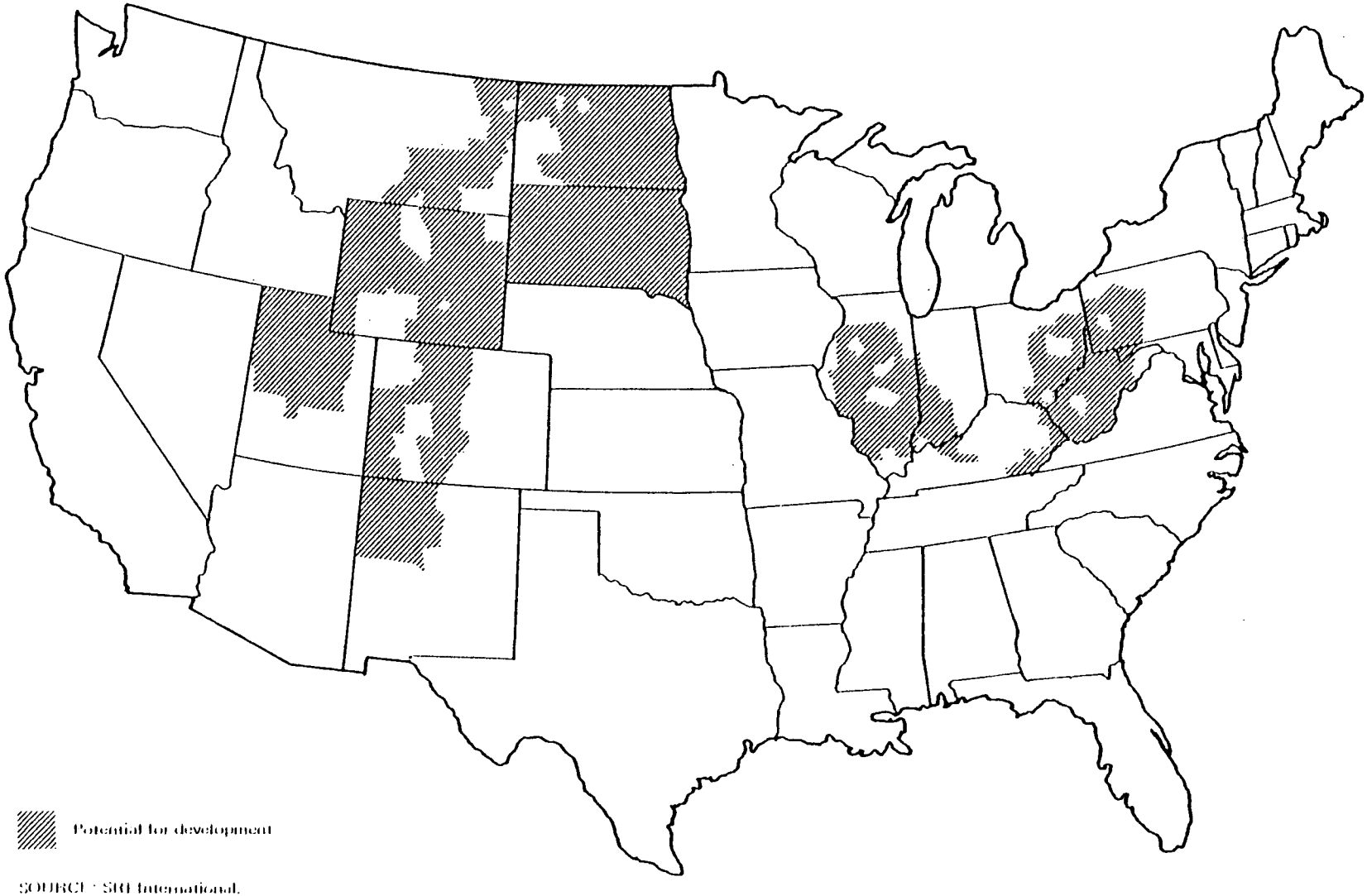
However, any or all of these disadvantages may be outweighed by proximity of the site to markets or existing transmission lines. Although BOM could not determine the impact of all these considerations, it did use the factors to narrow down sites with high potential to the eight regions noted in Exhibit 20. The BOM methodology succeeded in narrowing down potential sites more than the USGS or SRI studies.

SRI

The SRI study was the narrowest in scope of the three studies. Siting potential was based on the relative ease of locating alternative fuel plants as determined from earlier environmental impact statements. SRI made three assumptions: only environmental aspects of plant siting will be considered; environmental laws and regulations will not be relaxed in the foreseeable future; and producers will be most interested in alternative liquid fuels. Given these assumptions and other related factors, the Illinois Basin area appears to offer the most significant opportunities, although numerous other regions could be acceptable given investment of time and money to overcome conflicts and mitigate impacts (see Exhibit 21). However, the SRI study overstates the potential for locating alternative fuel plants because much of the available coal in many areas is already committed to other uses.

Exhibit 21

Sites for Coal Gasification and Indirect Liquefaction Plants



Potential for development

SOURCE: SRI International.

6 PROJECT LIST

In addition to ANR's gasification project in North Dakota, there are numerous gasification and indirect liquefaction projects in various stages of development in the United States. In general, these projects can be classified as commercial, demonstration, or pilot plants. Several of the projects listed on the following pages are of special significance. The TVA medium-Btu project, listed on page 6.5, will be the first large-scale medium-Btu commercial project. This plant will also use a technology other than the Lurgi, with the choice being among the Texaco, Koppers-Totzek, and Babcock & Wilcox processes.

Southern California Gas (SCG) is planning a gasification process in conjunction with the Navajo Indians. This cooperation with Indians could prove important because much of available western coal lies on Indian reservations. SCG is conducting a feasibility study of a gasification project with the Crow Indians.

Several plants are advanced R&D projects, many sponsored by DOE. DOE's program is made up of four field projects: 1) low-Btu gasification of low-rank coal, directed by the Laramie Energy Technology Center; 2) medium-Btu gasification of low-rank coal, directed by Lawrence Livermore Laboratory (LLL); 3) underground gasification of eastern swelling bituminous coal, direct by Morgantown Energy Technology Center; and 4) underground gasification of steeply dipping coal beds, directed by Gulf R&D Company.

LLL at the University of California has studied the technical and economic feasibility of employing solar power in coal conversion. After two years of research, laboratory officials conclude the process is sound. Solar application uses less coal in the conversion process: one-half as much coal as the Lurgi process. Additionally, the process requires only 35 percent of the oxygen needed in the Lurgi method. Solar conversion does not need a separate oxygen plant to provide oxygen for the process since the coal is gasified with carbon dioxide in the focal range of a solar central receiver plant.

Chem Systems and Union Carbide submitted proposals for funding of development of two indirect coal liquefaction processes. The Chem Systems process produces methanol from synthetic gas at a cost 10-15 percent lower than currently known processes, and the Union Carbide research involves a new catalyst that would convert synthesis gas directly to high-quality liquids. Under the Chem Systems proposal, DOE would finance 80-90 percent of a 35 barrel per day pilot plant to produce methanol from synthesis gas. The cost savings would result from improved heat recovery. Union Carbide's new catalyst circumvents the need for product upgrading before conversion to methanol.

Mobil is exploring a new coal gasification process that requires smaller quantities of hydrogen than existing gasifiers. Reducing the hydrogen volumes would significantly lower the costs of Mobil's coal-to-methanol process. Lurgi U.S., the U.S. branch of the German firm, is also researching Mobil's M-gasoline process.

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- COMMERCIAL

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Car-Mox Low-Btu Gasification Nitro, WV	Car-Mox gasifier	Steam, carbon monoxide	2.3-3.5 MMSCF/day	Fike Chemicals, Inc. (304) 755-3336	Began operating late 1978; currently not operating because of technical difficulties in feeding coal	Fike Chemicals
Low-Btu Gasifiers for Commercial Use York, PA	Wellman-Galusha	Low-Btu gas	2.8 MMSCF/day	Glen-Gery Corp. R. W. Dammann (215) 777-6578	Start-up in October 1977	50% Acurex-Aerotherm Corp. 50% DOE
Low-Btu Gasifiers for Commercial Use Duluth, MN	Lurgi-Stoic (Foster-Wheeler)	Low-Btu gas	8.3 MMSCF/day	University of Minnesota; DOE Warren Soderburg (612) 373-4521	Start-up October 1978; periodic shut-downs for equipment modification	50% DOE; 50% University of Minnesota
Caterpillar Tractor York, PA	Wellman-Incan-descent	Low-Btu gas	15 MMSCF/day	Caterpillar Tractor; Black, Sivalls & Byson, Inc. Stan Curtis (717) 757-0528	Construction completed June 1979; start-up August 1979	

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- COMMERCIAL (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Enrecon Coal Gasifier Golden, CO	Fluidized bed, medium-Btu process	Medium-Btu gas	3.5 MMSCF/day	Enrecon, Inc. (303) 534-3653	Start-up began in December 1979, full operation in spring 1980	Enrecon, Inc.
Low-Btu Gasifiers for Commercial Use Pike County, KY	Wellman-Galusha	Low-Btu gas	8.3 MMSCF/day	DOE; Appalachian Regional Commission, Commonwealth of Kentucky Mike Newton or Dave Maneval (ARC) (202) 673-7984	Construction began October 1978, 90% complete today; fully operational by spring 1981	50% DOE; 25% Kentucky DOE; 25% Appalachian Regional Commission
Forest City Coal Gasification Forest City, IA	Entrained or fluidized bed	Hydrogen	34.6 MMSCF/ day	Billings Energy Corp.	Groundbreaking by January 1, 1982	State of Iowa; Forest City; funding request through DOE
Coal Gasifier Wood River (East Alton), IL	KILNGAS	Low-Btu gas	69.2 MMSCF/day, increasing to 461.1-576.4 MMSCF/day by 1984	Allis-Chalmers Gerald Peterson (414) 475-2884	Engineering design in process; ground-breaking scheduled for fall 1980; operational by 1983	Allis-Chalmers, State of Illinois; request pending at DOE and participating utilities

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- COMMERCIAL (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Chemicals from Coal Kingsport, TN	Partial oxidation (Texaco)	Industrial chemicals		Tennessee Eastman Co. (615) 246-2111	Construction to begin in late 1980; start-up in mid-1983	Tennessee Eastman Co.
Great Plains Gasification Mercer County, ND	Lurgi fixed bed	High-Btu gas	125 MMSCF/ day	Great Plains Gasification Associates Al Browning, Mgr. (313) 965-8300	Construction to begin in 1980; scheduled for completion in 1984	Great Plains seeking loan guarantee; opposition to passing plant costs on to customers
Burnham Coal Gasification Four Corners Area Navajo reservation	Lurgi	Pipeline gas	72 MMSCF/ day	El Paso Natural Gas; Ruhrgas AG; Pacific Gas & Electric Mr. Yungert (915) 543-3140	Project being restructured as private industry consortium, with start-up in first quarter of 1985	Request in to DOE for process engineering completion by fall 1980; to be privately operated after September 1980

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- COMMERCIAL (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Nokota Bismark, ND	Lurgi gasification with methanol synthesis units	Methanol, Natural gas	85,000 barrels/day + 3,000 barrels/day gasoline blending stock	Nokota Co./ Fluor Engineering, San Francisco, California Galen Andersen (Nokota) (701) 223-6188	Construction to begin in 1982; start-up in fall 1985, with commercial operations in 1986	Request for DOE funding pending
Southern California Gas Co. (with Navajo Indians) Navajo reservation	Lurgi	High-Btu Methane gas	125 MMSCF/ day, increasing to 250 MMSCF/ day	Southern Calif. Gas Co. Robert Rudzik Project Manager (213) 689-3586	Construction to begin mid-1982; completed and operating in 1986	DOE request pending
Mountain Fuel Supply Company (MFSC) SNG Emery, UT	Slagging Lurgi or MFSC concept	Pipeline gas	125 MMSCF/ day; increasing to 250 MMSCF/ day	MFSC Ralph Coats, Director of Research (801) 534-5463	Start-up planned for 1988, with facility in operation by 1990	MFSC, Inc.
Gasification Easter, Wyoming	Lurgi with methanation	Pipeline gas	137.5 MMSCF/day	Panhandle Eastern Pipeline Co. Dan Zowell (713) 520-1190	In holding stage	

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- DEMONSTRATION

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Industrial Fuel Gas Demonstration Plant Baskett, KY	Texaco	Industrial fuel gas; ammonia	98 MMSCF/ day	W. R. Grace	Design completed early 1980s; 150 tpd unit operating since 1978	DOE funded 100% of design, will fund 50% of construction and operating costs if continued in 1980
TVA Ammonia From Coal Muscle Shoals, AL	Texaco partial oxidation process	Ammonia; SNG	Gasifier- .1 MMSCF/ hour retrofitted to existing 225 tpd ammonia plant	TVA Mr. Burnett (205) 386-2601	Plant construction completed in mid-1980; 3-year demonstration of half-time operation planned	TVA
Industrial Fuel Gas Demonstration Plant Memphis, TN	IGT-U-Gas (Foster-Wheeler) with methanation	Medium-Btu industrial fuel gas	175 MMSCF/day	Memphis Light, Gas & Water Division, Delta Refinery (901) 528-4011	Construction started 1980; completed 1983; full operation in 1985	DOE funded 100% of design, will fund 50% of construction and operating costs if continued in 1980

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- DEMONSTRATION (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
High-Btu Gas Perry Co., IL	COED-COGAS (Dravo)	High-Btu gas; fuel oil; naptha	23 MMSCF/ day; 1,120 b/d fuel oil; 360 b/d naphtha	Illinois Coal Gasification Corp. DOE contact: Jim Malcolm 353-5987	Start-up in mid-1984	DOE funded 96% of design, will split construction and operational costs 50/50 with industry if project wins competition with Conoco Coal Project (description on next page
TVA Medium-BTU Coal Gasification Demonstration Plant Tennessee Valley Region (specific site to be determined)	Five processes under consideration (Texaco, Koppers-Totzek Lurgi, Babcock and Wilcox)	Medium-Btu gas (250 Btu)	1,000 MMSCF/day	To be determined from 10 firms TVA contact: Bob Brookshire (615) 755-6515	Narrowing of process choices to two by 1980. Final decision in fall 1980. Construction of first TVA module to be completed in December 1984; operation by 1985.	TVA
High-Btu Gas Noble Co., OH	BGC-Lurgi slagger (Foster-Wheeler) with methanation	High-Btu gas	19 MMSCF/ day	Conoco Coal Development Co. DOE contact Robert Verner 353-5988	Completed by mid-1984; fully operational by 1987	DOE funded 100% of design and will split construction and operating costs 50/50 with

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- DEMONSTRATION (cont'd)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
High-Btu Gas (con't)						industry if project wins competition with Illinois coal project
Fuel Gas Utility Lake Charles, La	Combustion Engineering	Utility fuel gas	150 MW	Gulf States Utilities, Combustion Engineering, Inc. John Honey 296-1240	Not yet determined	DOE funded 100% of design, will fund 50% of construction and operating costs
High-Btu Gas Western Kentucky	IGT-HYGAS (Bechtel)	High-Btu gas	83 MMSCF/ day	IGT, Texas Gas Transmission Co., State of Kentucky Paul Fedde (502) 926-8686	Site-specific plans not yet defined	DOE funded 100% of design, but didn't select for high-Btu demonstration

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- PILOT

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Synthane Pilot Test Allegheny, PA	Synthane	High-Btu gas		Lummus Co., DOE	Start-up in 1976; presently deactivated and in stand-by status	1979 DOE review: decision to deactivate
Medium-Btu gasification of low-rank coal Gillette, Wyoming	In-situ	Medium-Btu gas		DOE, Lawrence Livermore Laboratories (LLL) LLL Washington office 634-2400	Completed two underground coal gasification tests	DOE
Underground gasification of Eastern coal Princeton, West Virginia	In-situ	Low-to-medium-Btu gas		DOE, Morgantown Energy Technology Center (METC) (304) 599-7764	Field test currently being conducted	DOE
HYGAS Pilot Plant Chicago, IL	IGT-HYGAS	High-Btu gas	1.3 MMSCF/ day	DOE, Gas Research Institute, IGT Fred Zerkle (IGT) (202) 785-3511 Abner Flowers (GRI) (312) 567-6600	Start-up in 1972. Will begin testing peat in 1980; completely switching to peat after October 1980, but will maintain capability to use coal.	DOE/IGT

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- PILOT (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Low-Btu Gasification of Low-rank Coal Hanna, Wyoming	In-situ	Low-Btu gas		DOE, Laramie Energy Technology Center (LETC) (307) 721-2011	LETC has successfully conducted field tests since 1972	DOE
Texaco Coal Gasification Process Development Montebello Research Laboratory, CA	Texaco	SNG	.3 MMSCF/ day	Texaco James L. Dunlap Vice Pres. Alternative Energy (914) 253-4000	In operation	Texaco
IGT U-Gas Chicago, Illinois	U-Gas	Medium-Btu gas	1.3 MMSCF/ day	IGT, DOE	Start-up in 1974	DOE
Advanced Coal Gasification System for Electric Power Generation Waltz Mill, PA	Westinghouse Process (Fluidized bed gasification, combustion, and dry ash agglomeration within single vessel)	Low- and medium-Btu gas	1 MMSCF/ day	Westinghouse Electric Corp. Morton Blinn (412) 722-5497	Start-up in 1975	DOE; Westinghouse Electric Corp.

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- PILOT (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
GEGAS-D Schenectady, NY	Fixed bed coal gasifier	Low-Btu gas	2.8 MMSCF/day	General Electric Company (GE) L. G. Ostermann 637-4295	Checkout runs began February 1976	GE
Bi-Gas Homer City, PA	Bi-Gas	High-Btu pipeline gas	2.1 MMSCF/day	Revised: DOE and Stearns-Rogers, Inc. formerly Phillips Petroleum Co. for Bituminous Coal Research	Start-up in 1976; will continue through FY 81	
KILNGAS Oak Creek, WI	KILNGAS (Allis-Chalmers)	Low-Btu gas	6.9 MMSCF/day	Allis-Chalmers Gerald Peterson (414) 475-2884	In operation since 1975	Allis-Chalmers and participating utilities
Two-Stage Entrained Gasification System Windsor, CT	Two-stage entrainment gasification system	Low-Btu gas	.6 MMSCF/ hour	Combustion Engineering, Inc. (CE); DOE; EPRI John Hunney (CE) 296-1240	Dedicated in October 1977	

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- PILOT (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Tri-Gas Monroeville, PA	BCR fluidized bed	Low-Btu gas	.1 MMSCF/ day (plant operated for 48-hour period once every 3 weeks)	Bituminous Coal Research, Inc. (BCR) Earle Diehl, Mgr. (412) 327-1600	Start-up October 31, 1977; in operation through October 1980	DOE; BCR
Firing of Iron Ore Pelletizing Furnace with Low-Btu Furnace Gas Twin Cities, MN	Wellman-Galusha	Low-Btu gas	4.2 MMSCF/ day	Twin Cities Research Center John C. Nigro Project Supervisor BOM (612) 735-4638 Mr. Dunham BOM-D.C. (202) 634-1004	Test performed November 1978; operations began December 1978	U.S. Bureau of Mines/DOE/EPA

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- PILOT (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
Fast Fluidized Bed Gasification Lawrence Township, NJ	Fast fluidized bed gasification process	Low- or medium-Btu gas	.6 MMSCF/ day	Hydrocarbon Research, Inc. (HRI) Marvin Rakow (609) 896-1300	Construction and initial operations completed	DOE; HRI
Howmet Aluminum Lancaster, PA	Wellman-Galusha	Low-Btu gas	3.3 MMSCF/ day	Howmet Aluminum Corp. Wilham Klaide (717) 393-9641	Construction started in 1979	
Chemically Active Fluid Bed San Benito, TX	Chemically active fluidized bed (Exxon)	Sulfur free Low-Btu gas	23 MSCF/day (based on a 24-hour day)	Central and South-west Corp., Foster-Wheeler (F-W) Energy Corp., EPA Roland Fridell (F-W) 298-7750	Start-up in 1979	Design and engineering funded by EPA
Underground Gasi-fication of Steeply Dipping Beds Rawlins, Wyoming	In-situ	Low- to medium-Btu gas		DOE, Gulf R&D Co.	First test began October 1979; tests to be conducted over a 5-year period	DOE

U.S. COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS -- PILOT (con't)

Project/ Location	Subtechnology	Product	Size	Operator/ Contact	Status	Source of Funding
General Motors Coal Gasification Saginaw, MN	Stoic (Foster-Wheeler)	Low-Btu gas	.3 MMSCF/ day	General Motors	Start-up in March 1980	General Motors
Slagging Gasifier Development Grand Forks, ND	Slagging fixed bed	Low-Btu gas		Grand Forks Energy Technology Center (701) 795-8000	Relocated in October 1979; steady-state operations scheduled to begin second quarter FY 80	DOE; Grand Forks Energy Technology Center; Stearns-Roger, Inc.
TOSCOAL Process Development Golden, CO	TOSCOAL process	Medium- to high-Btu gas, char; oil	.7 MMSCF/ day	TOSCO Corp. Robert Hall Research Division (303) 425-6021	Development continuing with pilot plant program	TOSCO Corp.
Mountain Fuel Supply Company (MFSC) Coal Gasification Process Salt Lake City, UT	Entrained flow, oxygen-blown gasifier/ slagging (MFSC & Ford, Bacon & Davis)	Medium-Btu gas	1.7 MMSCF/ day	MFSC; Ford, Bacon & Davis Ralph Coats (801) 534-5463	Detailed engineering design 80% complete	Seeking DOE funding

7 INTERNATIONAL ACTIVITIES

The most important operating alternative fuels plant in the world is the Sasol complex in South Africa, which is based on indirect liquefaction technology. The first plant, Sasol One, has been operating for 25 years. Sasol One uses the Lurgi gasification process and both the German Arge (fixed bed) and American Synthol (fluidized bed) types of Fischer-Tropsch reactor. Sasol Two, which will begin operating in 1980, will use only the fluidized bed reaction (see Exhibit 22 for a diagram describing the Sasol Two process). The Lurgi gasifiers produce raw synthesis gas as well as tar, oils, and gas liquids. Upon gasification, the raw gas is purified in a Rectisol unit, common to all Sasol plants. The purified gas is then reacted with an iron-based catalyst in a Fischer-Tropsch fluidized bed reactor. Hydrogen and light hydrocarbons are recycled into the synthesis gas stream used as feedstock for the Synthol unit.

A product refinery then produces LPG, gasoline, diesel fuel, fuel oil, jet fuel, and a variety of chemicals. The Sasol Two unit, a $2.8 billion complex, will consume 40,000 tons per day of coal to produce 20 commercial products, in particular gasoline and diesel fuel. By varying the catalysts in the Fischer-Tropsch reactors and adjusting primary processing facilities, primary product mix can be altered from 80 percent gasoline/20 percent diesel fuel to a 50/50 mixture. In combination, Sasol One and Sasol Two will produce enough gasoline to meet 30-40 percent of South Africa's gasoline needs.

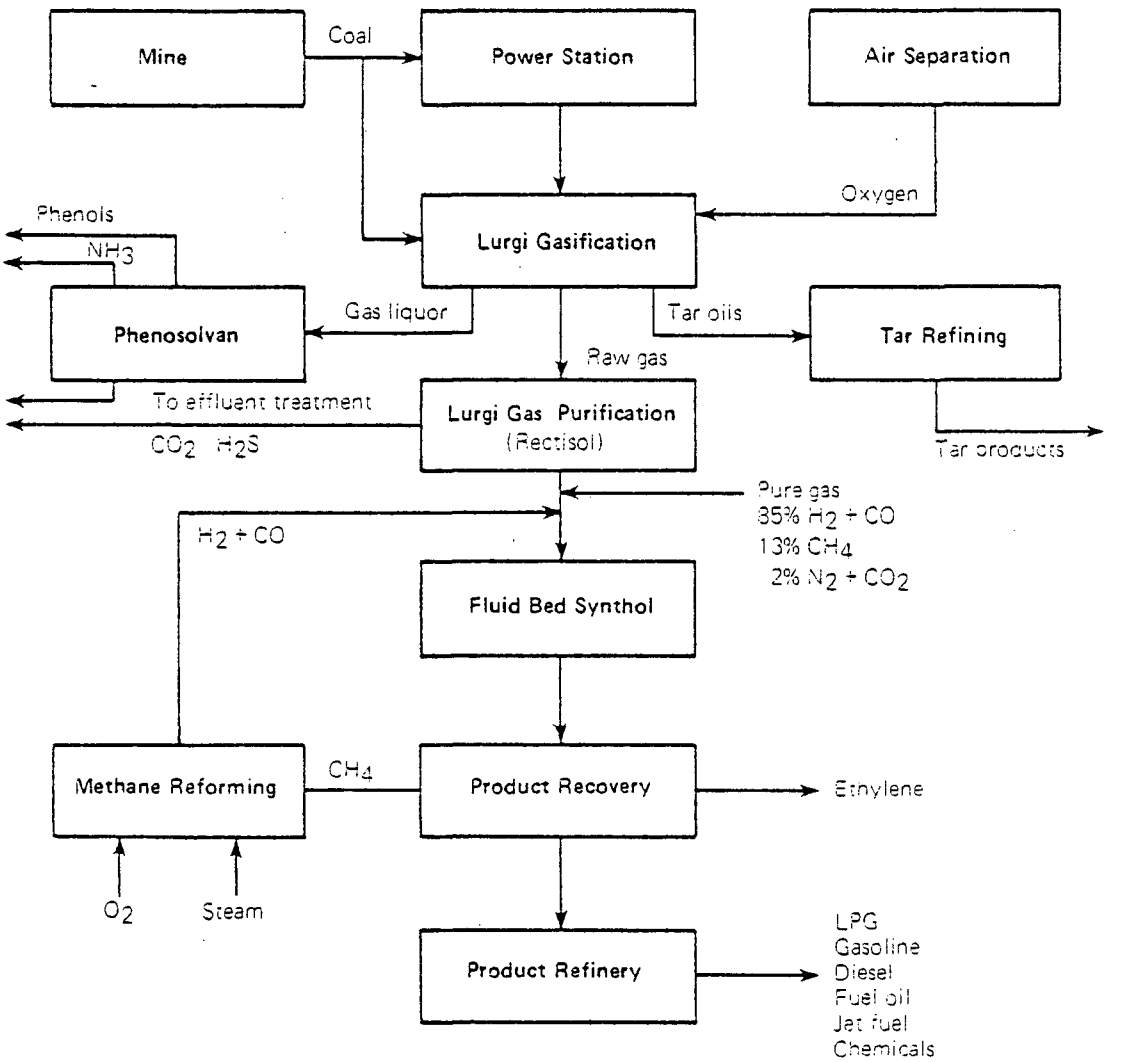
Upon completion of the Sasol Two project, construction will begin on Sasol Three, which is almost a duplicate of the Sasol Two plant. Sasol Three will require an investment of $3.8 billion. When Sasol Three begins scheduled production in 1984, the entire Sasol complex will produce about 112,000 bpdoe, half of South Africa's needs.

There are multilateral, bilateral, and single-nation alternative fuels projects worldwide.

The three multilateral activities are the Tokyo and Venice summit conferences and the International Energy Agency (IEA) annual review.

Exhibit 22

Sasol Two Indirect Liquefaction Process



SOURCE: *Oil and Gas Journal.*

At the Tokyo Summit Conference in June 1979, representatives of the United States, France, Great Britain, Canada, Italy, Germany, and Japan formed the International Energy Technology Group (IETG). The objective of the group was to define goals for alternative fuels development as a means of (1) encouraging a worldwide effort and (2) highlighting the desire and capabilities of members to cooperate in development programs. Specifically, the IETG was to draw up a commission of OECD and IEA members to carry on the purpose of the IETG. Following preparation of a report of recommendations, the IETG disbanded in March 1980.

The IEA, in its 1979 review, recommended that alternative fuels be developed as quickly as possible in member countries and that public support for the commercial demonstration of alternative fuels technologies be increased where necessary. In addition, the IEA recommended that vigorous efforts be made to pursue President Carter's proposal to expedite the development of alternative fuels.

The seven major industrial democracies just completed their 1980 summit meeting in Venice. The nations agreed to produce the energy equivalent of 15-20 million barrels of oil per day from nonoil sources by 1990. Half of this increase will come from greater use of coal, with the remainder coming from increased use of nuclear power, natural gas, renewable energy sources, and alternative fuels, some of which would be derived from coal. The summit representatives ratified several of the IEA oil-use reduction goals.

Bilateral and single-nation alternative fuels projects are presented in charts on the following pages. Of the single-nation projects, West Germany has more, and more varied, coal gasification and indirect liquefaction plants than any country besides the United States. Most use the Lurgi-fixed bed technology for production of synthesis gas, but a large pilot plant uses the Texaco-entrained bed process and two other pilot plants (one under consideration) will use the Winkler process. The Netherlands also has a major alternative fuels project: a large gasification plant based on Texaco technology will produce electricity for Rotterdam beginning in 1986.

BILATERAL COAL GASIFICATION PROJECTS

Countries	Subtechnology	Product	Size	Companies Involved	Status	Source of Funding
U.S. Department of Energy (DOE)/ West Germany						
Ludwigshafen, West Germany	Methanol synthesis	Ethylene, propylene	Will produce 396,000 lb/d of synthetic liquids	BASF, Mobil Oil Co., Unde, URBK	Completed in spring 1980	Participants will share in $1.6 million in cost
DOE/West Germany						
Wesseling, West Germany	M-gasoline	Gasoline	Will convert 100 b/d of methanol	Mobil, two West German firms	Planned	Participants will share equally in $33 million costs
Belgium/West Germany						
Hensies, Belgium	In-situ	Low- to medium-Btu gas	-	-	Planned	Part of a 1976 cost-sharing agreement between Belgium and West Germany

COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS
BY INDIVIDUAL COUNTRIES

Country	Subtechnology	Product	Size	Companies Involved	Status
South Africa					
Sasolburg*	Lurgi/Fischer-Tropsch	Oil, solid waxes, diesel, gasoline	20,000 liquid fuels	Sasol I	Started-up in 1955
Secunda*	Lurgi/Fischer-Tropsch	Transportation fuels, tar products, ammonia, sulfur	40,000 bbl of liquid fuels per day	Sasol II	Full production in 1982
Sasolburg*	Lurgi/Fischer-Tropsch	Transportation fuels	More than 50,000 bbl of liquid fuels	Sasol III	Full production in 1984
Modder Fontein	Koppers-Totzek	Medium-Btu gas, ammonia	88 MMSCF/day, 1,000 tpd	African Explosive Chemicals Industry; Krupp-Koppers, GmbH (Essen, West Germany); McLachlan & Lager, Ltd. (South Africa); TRW, Inc.	Analysis of technology near completion.
West Germany					
Oberhausen-Holten	Texaco entrained bed	Synthesis gas	Pilot plant (319,670 tpd)	Ruhrgas AG Ruhrkohle AG/Steag AG	Start-up in 1976

* Sasol complex is described in detail on page 7.1.

COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS
BY INDIVIDUAL COUNTRIES

Country	Subtechnology	Product	Size	Companies Involved	Status
West Germany cont'd					
Furstenhausen/Saar	Saarberg/Otto slag bath gasification	Synthesis and reduction gas	Pilot plant (250 tpd)	Saarbergwerke AG, Gr. C. Otto & Co. GmbH	1978-1982
Frechen (Cologne)	Reinbaum HTW (Winkler)	Synthesis gas	Pilot plant (132.3 tpd)	Hoechst-Uhde, Rheinische, Braun Kohlenwerke AG	Start-up in mid-1978
Dortmund	VEW process	Electric power	Pilot plant (24 tpd); demonstration plant (360 tpd)	Vereinigte Elektrizitatswerke, Westfalen AG	
Netherlands					
Moerdijk	Shell-Koppers	Synthesis gas	1,000 tpd	Royal Dutch/Shell	Start-up in late 1983
Rotterdam	Texaco	Electricity	One gasifier and one 25 MW gas turbine, followed by a second gasifier and gas turbine and a steam turbine	City of Rotterdam, Rotterdam Energy Utility (GEB), Arnheim Electrical Testing Laboratory (KEMA)	Design scheduled for completion by end of 1980; first stage of project to begin operating in 1986, second stage in 1989

COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS
BY INDIVIDUAL COUNTRIES

Country	Subtechnology	Product	Size	Companies Involved	Status
Belgium					
Hensies	In-situ	Synthesis or combustion gas	Pilot plant	Institut pour le Development de la Gazeification Souterraine; S.A. (Coppee-Rust N.V. (Leige division)	Start-up in late 1981
Brazil					
Sao Jeronimu	Koppers-Totzek	Gas for production of ammonia and later for home use	Will eventually become a large chemical complex	Petrobras, Krupp-Koppers	Start-up in 1982
Japan					
Iwaki City	Hitachi			Japan Electric Power Development Company	Construction began December 1979
Poland					
Libiaz (outside Katowice)	Koppers-Totzek	Medium-Btu gas	Three 4-head gasifiers	Kopex (Poland's state agency); Krupp Koppers GmbH. Separator (state-owned engineering office)	Construction to begin in 1982; start-up in 1984

COAL GASIFICATION AND
INDIRECT LIQUEFACTION PROJECTS
BY INDIVIDUAL COUNTRIES

Country	Subtechnology	Product	Size	Companies Involved	Status
Canada					
Manalta Coal, Ltd., Vesta mine (90 mi. southeast Edmonton, Alberta)	In-situ			Alberta Research Council, 4 government agencies, 11 industry participants	5-year test is planned, but details are still being negotiated
Great Britain	Entrained flow gasifier coupled with base of fixed bed gasifier (composite gasifier)		Pilot plant (100 tpd)	British Gas Corporation (BGC), British Department of Energy	To be designed constructed, and operated over a 6-year period
Yugoslavia	Lurgi (East Germany)	Medium-Btu gas (for combustion); hydrogen (for ammonia synthesis)	25 MMSCF/day 21.5 MMSCF/day	Kosovo combine/ gasification plant, Kosovo Institute; Mining Institute of Belgrade; Radium Corp. of Texas; Institute of Applied Nuclear Energy of Belgrade	Phases II and III (analytical work) being finalized; Phase IV (study of fugitive emissions) on-going