

350  
6-9-80  
guba

LA. 1374

DOE/ET/2625-9

ECONOMICS AND SITING OF FISCHER-TROPSCH COAL LIQUEFACTION

**MASTER**

By  
James Benefiel  
Martha Fassett

July 1979

Work Performed Under Contract No. ET-78-C-01-2625-009

Booz, Allen & Hamilton, Inc.  
Bethesda, Maryland

**F  
O  
S  
S  
I  
L  
H  
I  
S  
I  
S  
S  
U  
E  
C  
O  
N  
T  
A  
I  
N  
S  
A  
M  
A  
S  
T  
E  
R  
C  
O  
P  
Y**



**U. S. DEPARTMENT OF ENERGY**

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

## DISCLAIMER

**This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency Thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.**

## **DISCLAIMER**

**Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.**

## DISCLAIMER

"This book was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof."

This report has been reproduced directly from the best available copy.

Available from the National Technical Information Service, U. S. Department of Commerce, Springfield, Virginia 22161.

Price: Paper Copy \$8.00  
Microfiche \$3.50

ECONOMICS AND SITING OF  
FISCHER-TROPSCH COAL LIQUEFACTION

OFFICE OF RESOURCE APPLICATIONS  
U.S. DEPARTMENT OF ENERGY

July 1979

Prepared by

BOOZ, ALLEN & HAMILTON INC.  
4330 East-West Highway  
Bethesda, Maryland 20014

John P. Henry, Jr.....Officer-in-Charge

J. Pedro Ferreira.....Project Manager

James Benefiel

Martha Fassett

THIS PAGE  
WAS INTENTIONALLY  
LEFT BLANK

## T A B L E   O F   C O N T E N T S

	<u>Page Number</u>
EXECUTIVE SUMMARY	viii
1. INTRODUCTION	1-1
2. THE FISCHER-TROPSCH PROCESS	2-1
2.1 Background	2-1
2.2 Process Description	2-2
2.1.1 Products	2-5
2.2.2 Inputs	2-5
2.2.3 Energy Balance	2-7
2.2.4 Construction Schedule	2-9
3. PLANT LOCATION	3-1
3.1 Supply and Demand for Petroleum Products	3-2
3.1.1 Supply and Demand in 1977	3-2
3.1.2 Supply and Demand Forecasts	3-4
3.2 Supply of Coal	3-5
3.3 Optimization of Transportation: Coal versus Gasoline	3-5
3.3.1 Materials and Quantities	3-8
3.3.2 Coal Transportation System	3-8
3.3.3 Motor Fuel Transportation System	3-8
3.3.4 Other Products Transportation System	3-8
3.3.5 Transportation Model	3-15
3.3.6 Discussion of Results	3-18

	<u>Page Number</u>
3.4 Siting Criteria	3-19
3.4.1 Few Facilities Case	3-20
3.4.2 Coal Liquids Industry Case	3-22
3.4.3 Sites Selected	3-25
4. PROCESS ECONOMICS	4-1
4.1 Capital Costs	4-3
4.2 Operating Costs	4-5
4.3 Revenue Required (Profitability)	4-5
4.4 Economic Analysis—Baseline Results	4-7
4.5 Effect of Uncertainties	4-8
4.6 Effect of Possible Incentives	4-14
4.7 Comparison With Methanol	4-16

APPENDIX - Cash Flow Model

# I N D E X   O F   E X H I B I T S

		<u>Page Number</u>
ES-1	Sensitivity Analyses of Fischer-Tropsch Gasoline Prices	xi
2-1	Simplified Diagram of Fischer-Tropsch Liquefaction Process	2-3
2-2	Product Yield of Fischer-Tropsch Facility	2-6
2-3	Energy Balance of Fischer-Tropsch Facility (at 100% Capacity)	2-8
2-4	Selectivities of the Fischer-Tropsch Synthol Reactor	2-10
2-5	Construction Schedule for Fischer-Tropsch Facility	2-11
3-1	Petroleum Products Supply/Demand - 1977	3-3
3-2	Coalfields of the Conterminous United States	3-6
3-3	Coal Production and Resources of the U.S.	3-7
3-4	Coal Transportation Systems	3-9
3-5	Modal Coal Transport Costs (1985)	3-10
3-6	Coal Movements by Water Overlaying Coalfields of the Conterminous United States	3-11
3-7	Coal Movements by Railroad Overlaying Coalfields of the Conterminous United States	3-12

	<u>Page Number</u>
3-8 Coal Slurry Pipeline Overlaying Coal- fields of the Conterminous United States	3-13
3-9 Petroleum Movement by Pipeline Overlaying Coalfields of the Conterminous United States	3-14
3-10 Transportation Costs for Different Materials	3 17
3-11 Coal, Gasoline, and Pipeline Data for the 16 Coal-Rich States	3-21
3-12 Characterization Parameters for Coal Liquefaction Plants	3-23
3-13 Characterization Parameters for Coal Liquefaction Plants	3-24
3-14 Representative Coals From PADS 2, 3, 4	3-26
4-1 Key Assumptions Used in the Cash Flow Model	4-2
4-2 Input Assumptions Used in the Financial Analysis	4-4
4-3 Basis for Capital Costs and Operating Costs	4-6
4-4 Contribution to Annual Revenues	4-9
4-5 Effect of Uncertainties on the Required Selling Price of Gasoline From Coal	4-10
4-6 Production Cost as a Function of Capital Cost and Capital Structure (for an Illinois Location)	4-12
4-7 Effect of Size of Fischer-Tropsch Plant on Process Economics (Illinois Location)	4-13
4-8 Effect of Financial Incentives on the Required Selling Price of Fischer- Tropsch Gasoline	4-15

4-9      Comparison of Fischer-Tropsch Gasoline  
            With Alternative Methods for Motor  
            Fuel Production From Coal

4-17

## EXECUTIVE SUMMARY

This study was undertaken to develop a siting methodology and to analyze the economics of producing coal liquids (primarily gasoline) via Fischer-Tropsch synthesis in the U.S. The key findings of this study are summarized below.

1. A regional siting analysis was conducted using coal and petroleum transportation economics. The results from this analysis indicate that:
  - . The major gasoline consuming areas do not match those with the most abundant coal reserves, except in the States of Illinois and Texas.
  - . It is more cost effective to transport gasoline than coal. Therefore future gasoline-from-coal plants should be located in coal-rich regions.
  - . The above statement must be tempered by environmental considerations. For example, due to the high water requirements of the process, location in largely water deficient regions (e.g., the West) should be preceded by careful environmental impact studies.
  
2. A discounted cash flow model was used to develop the required selling price for the main product--gasoline--at several hypothetical locations. The results from this portion of the analysis indicate that:
  - . The costs of gasoline from Fischer-Tropsch, located in Illinois, Texas, and Wyoming and coming onstream in 1985, are projected to be:

Year of Reference	Gasoline Source	Plant Gate Price (\$/gal)	Pump Price (\$/gal)
1978	Crude Fischer-Tropsch	0.47 (0.73-0.82) <u>+ 25%</u>	0.74 (1.00-1.09) <u>+ 25%</u>
1985	Crude Fischer-Tropsch	0.93 (1.17-1.32) <u>+ 25%</u>	1.20 (1.44-1.59) <u>+ 25%</u>

- . The largest component of the final cost of gasoline is capital (56 percent) followed by coal (30 percent), and operating and maintenance (14 percent).
  - . The largest element of the capital cost component is the oxygen plant (27 percent), followed by the synthesis unit (15 percent), the purification unit (13 percent), the power plant (10 percent), the acid gas removal unit (7 percent), the tail gas reforming unit (5 percent), and the gasification and sulfur recovery units (3.5 percent each).
3. Sensitivity analyses were performed to take into account both project uncertainties and possible incentives to stimulate plant investment. These analyses indicate that:
- . Oxygen and power plants utilize mature technologies; therefore, these components of fixed costs (37 percent) should be relatively stable, and cost reduction may only be achieved by the use of gasification processes minimizing oxygen and/or power requirements.
  - . Other process units are less well-developed and are subject to some uncertainty. However, each individual unit contributes such a small portion of total costs that a 67 percent cost overrun for a single unit could be incurred without raising the cost of Fischer-Tropsch gasoline by more than 10¢/gallon.
  - . The required selling price of Fischer-Tropsch gasoline resulting from various incentives and uncertainties is shown on the following page. The range is \$.94/gallon to \$1.55/gallon (1985 \$). This compares with an EIA midcase projection for conventional gasoline of \$.93/gallon at the plant gate in 1985 using 7 percent per year inflation.

The capital intensity--low conversion efficiency of Fischer-Tropsch synthesis makes it non-competitive with conventional petroleum unless multiple financial incentives are used. This may change, however, if crude prices escalate to \$30/barrel (1979 \$) without a corresponding escalation in coal and capital costs.

Companies interested in Fischer-Tropsch facilities would have time in their favor: with the current high rate of inflation, capital-intensive projects like Fischer-Tropsch

facilities will benefit from early implementation, because the cost of products from subsequent competing facilities will contain larger capital charges.

\* \* \* \*

In conclusion the Fischer-Tropsch option for the U. S. is becoming increasingly attractive and may be called upon as a back-up if gasoline shortages persist, oil prices continue to increase dramatically and alternate coal liquefaction processes fail to fully develop.

EXHIBIT ES-1  
Sensitivity Analyses of  
Fischer-Tropsch Gasoline Prices

	Required Selling Price at Plant Gate (1985 \$/gallon)		
	Appalachia	Gulf	Rockies
Base Case	1.32	1.27	1.17
Coal Prices			
.Increasing at 2%/year*	1.38	1.33	1.21
.Constant*	1.26	1.23	1.13
Oil Prices			
.Increasing at 1%/year*	1.54	1.48	1.36
.Increasing at 3%/year	1.13	1.09	1.00
Capital Costs			
.25% above base case	1.55	1.50	1.39
.25% below base case	1.10	1.05	.94
20% Investment Tax Credit	1.25	1.21	1.10
Accelerated Depreciation			
.15 years	1.31	1.26	1.16
.10 years	1.27	1.22	1.12
.5 years	1.22	1.17	1.07
Waiving \$.04/gallon F.E.T. on 10% FT blends	1.28	1.23	1.13
Additional \$5/bbl entitlements	1.26	1.21	1.11
Anticipated Price at Plant Gate for Crude-Derived Gasoline**	0.93	0.93	0.93

\* In real terms.

\*\* Using EIA midcase projections. This corresponds to about \$1.20/gallon at the pump. Under EIA high case projections, the plant gate price would be \$1.08/gallon, which corresponds to \$1.35/gallon at the pump.

## 1. INTRODUCTION

The Department of Energy is developing several coal liquefaction processes that could supplement domestic oil resources and could contribute to reducing this nation's reliance on foreign oil supplies. These projects, while generally making substantial progress, have been subject to schedule delays and cost escalations. Therefore, officials of the Office of Coal Resource Management asked Booz, Allen & Hamilton to assess the economic feasibility of the Fischer-Tropsch process, a commercial process in which the DOE has not had major involvement. Fischer-Tropsch is the only coal liquefaction process that has been proven technologically feasible at commercial-scale operations, having been used to produce gasoline and chemicals in a South African plant since the 1950's.

Several prior studies have shown that the adoption of Fischer-Tropsch technology in the U.S. is not economically justified because of low thermal efficiencies and high capital costs. DOE officials want to know whether the comparative economics of liquid fuels produced by Fischer-Tropsch synthesis have changed due to process improvements, to the aforementioned cost escalation problems with DOE-supported technologies, and to the recent oil price increases. The objective of this study is thus to assess the current process economics for a U.S. sited coal liquefaction plant based on Fischer-Tropsch technology.

## 2. THE FISCHER-TROPSCH PROCESS

In the light of diminishing domestic natural gas and domestic petroleum production, coal--our most abundant fossil energy resource--has received renewed attention as a feed-stock for a variety of processes that produce petroleum-type products. One of these is the Fischer-Tropsch indirect liquefaction process, which has been employed in South Africa for over 25 years. Fischer-Tropsch results in a mix of liquid hydrocarbons from petroleum. If proven economically feasible, this process could help alleviate our dependence on foreign supplies of oil and extend the utilization of our domestic coals into other markets. A secondary benefit from Fischer-Tropsch is that it represents a potentially clean way of utilizing coal, i.e., with minimal airborne emissions.

### 2.1 BACKGROUND

The Fischer-Tropsch process for converting synthesis gas to petroleum-type liquids has been known for approximately half a century.

When adapting the Fischer-Tropsch process for U.S. gasoline production, one must remember that this technology was not originally developed for producing motor fuel principally. Motor fuel can be produced via this method but the efficiency of conversion in the Fischer-Tropsch technology was a route to synthesizing chemicals and fuel fractions from solid fuels. By the partial oxidation of coal to produce carbon monoxide and hydrogen by selective catalysis, the coal carbon is available for re-polymerization to higher hydrocarbons that are more easily made. As such, hydrocarbons varying from alcohols through aldehydes, to paraffins and olefins could be produced along with a fraction of fuel-type paraffins.

The Fischer-Tropsch technology was developed in Germany in the early 1900's. The Germans began the first large-scale operation to produce motor fuels for World War II because of their decreasing conventional crude oil supplies. Rumors persist throughout the scientific community that German motor fuels were of a lower quality than fuels produced from conventional crude. Technological improvements since World War II, however, have reduced this operating disadvantage.

South Africa used the Fischer-Tropsch process to supplement gasoline supply and to reduce dependence on imported crude oil in the 1950's when the world political climate jeopardized its supply. The initial SASOL operation had substantial chemical by-product production and the successful marketing of these high-quality chemicals helped offset the economic penalty associated with gasoline production by the Fischer-Tropsch method. As research and development was conducted simultaneously with the commercial operation, SASOL developed its own catalysts which had higher efficiency of conversion than commercial catalysts purchased initially. Through research and development, SASOL has modified the catalyst quality and the operating conditions to selectively produce any desired hydrocarbon fraction to its maximum. This coupled with the years of operating experience of the first Lurgi gasifier and subsequent synthesis operation has increased SASOL's knowledge of Fischer-Tropsch technology.

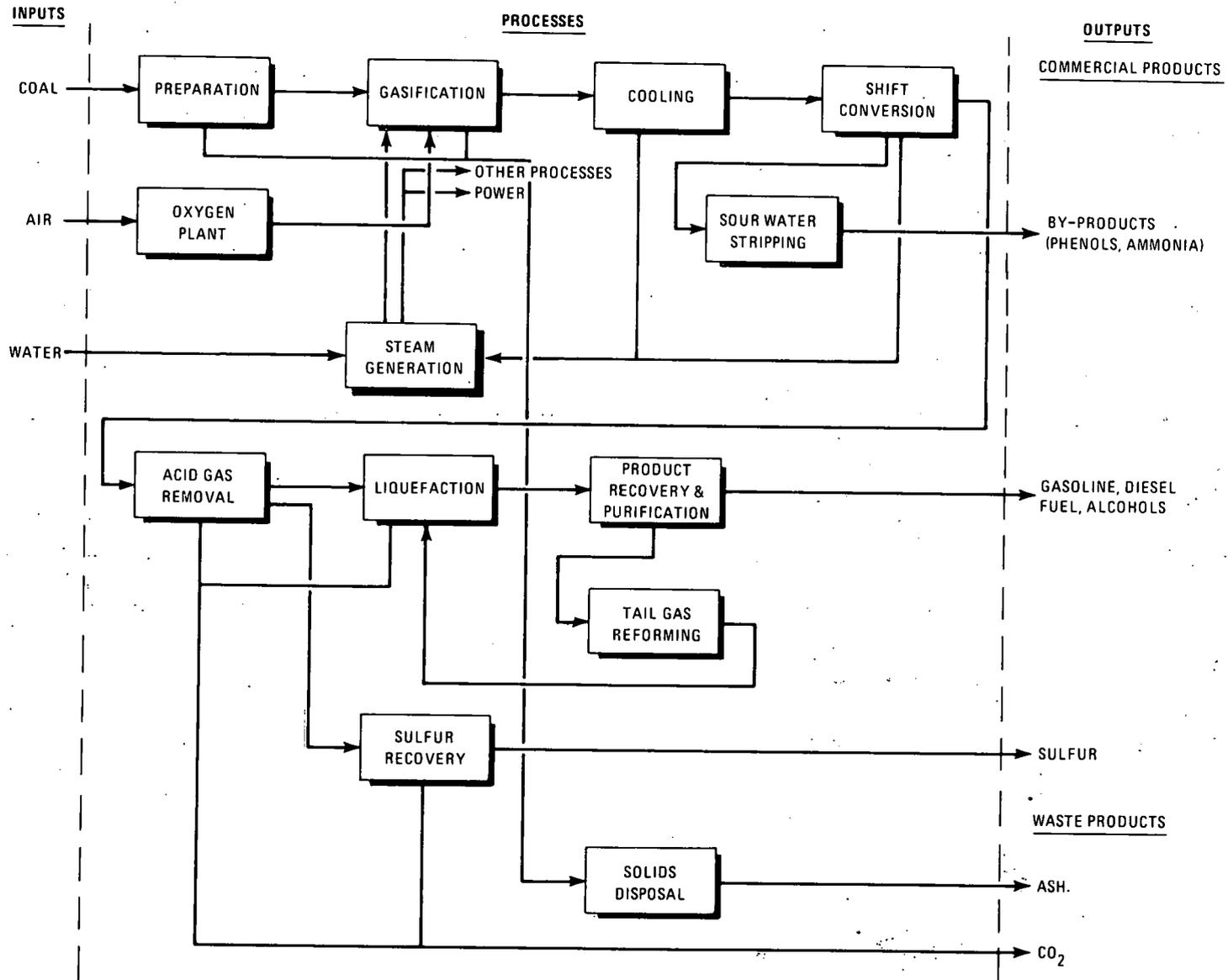
SASOL I currently produces about 6,000 bbl/day of liquid hydrocarbons, with gasoline representing some 50 percent of total energy output, the remainder being a number of high-quality chemical components. A second plant, SASOL II, is scheduled for start-up shortly. This plant minimizes chemical production and incorporates a number of process refinements. SASOL II is the basis for this study. As a result of recent events in Iran, previously South Africa's major oil supplier, the South African Government approved a reported \$4 billion expansion program at SASOL II, doubling the plant's capacity to approximately 100,000 bbl/day of liquid hydrocarbons.

## 2.2 PROCESS DESCRIPTION

A flow sheet of the conceptual plant is shown in Exhibit 2-1. It is apparent from even this simplified flow diagram that a plant based on Fischer-Tropsch technology is necessarily complex. Strict temperature and pressure control is required for certain process steps. The refinery must handle the variety of hydrocarbons that the Synthol reactor produces. Finally, environmental standards require considerable control technology.

A brief description of each stage is given in the following paragraphs.

EXHIBIT 2-1  
Simplified Diagram of Fischer-Tropsch Liquefaction Process



- . The coal preparation unit receives run-of-the-mine coal, then sizes, washes, dries, and delivers it to the first-stage gasifiers, while removing ash and other unsuitable elements.
- . The gasification step is carried out in parallel entrained-flow gasifiers.\* These types of gasifiers, currently under development, will allow a plant to be self-supporting in steam generation without the need for a separate coal-fired boiler. In these units, the feed coal is combined with steam and oxygen to produce synthesis gas (approximately 85 percent CO and H<sub>2</sub>) at 3,000F and 470 psig. The heat of combustion is removed from the synthesis gas through a heat exchanger which generates the steam for process heat or shift conversion. The gas is then passed to a shift converter unit, which adjusts the hydrogen-carbon monoxide ratio to 1.45 optimum for the liquefaction unit. This is accomplished by reacting excess carbon monoxide with steam to form carbon dioxide and hydrogen.
- . The cooled and shifted synthesis gas is then purified through a number of processes to separate tars, sulfur, and carbon dioxide. Acid gases are removed through a phenosolvan plant in which water-soluble phenols and ammonia are separated. Further processing of this effluent in a Claus unit enables recovery of elemental sulfur.
- . The liquefaction step occurs in parallel circulating catalytic fluidized bed reactors. The mix of products is dependent on the catalyst and operating conditions. In SASOL II, liquefaction occurs in the presence of an iron-based catalyst (magnetite) at approximately 300 psig and 600F. Hydrocarbons

---

\* Since the gasification stage itself represents a small proportion of total fixed capital, the key criterion for gasifier selection must be operational reliability. SASOL's gasifiers, Lurgi dry ash, have yet to be proven reliable when fed with U.S. eastern caking coals. As one of this study's objectives is to develop a plant siting methodology, choosing the Lurgi gasifier would unnecessarily restrict the location analysis to western and southeastern coals. Only entrained-flow gasifiers can satisfy the reliability criterion for a possible eastern location. Examples of such gasifiers are the commercially proven low-pressure Kopper-Totzek, and the promising high-pressure Texaco, already operating at the demonstration scale in two plants, with a third under construction.

are removed from the reactor via cyclones. The heavy compounds are separated from the light via condensation. The F-T reaction is highly exothermic and the heat of reaction is used to raise process steam for the other units. Since the coal gasification and liquefaction stages are exothermic, there is no need for an external source of power or heat except for unit start-up.

- . The unconverted (tail) gas is passed to the reforming unit, where methane is oxidized to synthesis gas with a steam-oxygen mixture in the presence of a nickel catalyst.
- . The product recovery unit separates a light oil, a C<sub>3</sub>/C<sub>4</sub> stream, a C<sub>2</sub> stream, and a hydrogen stream. Part of the hydrogen is recycled to the shift converter; the remainder is used for refinery operations and catalyst regeneration. The ethylene-C<sub>2</sub>-stream is eventually recovered. In the SASOL II plant, the light olefins are polymerized and partially hydrogenated. Medium weights (C<sub>5</sub>-C<sub>12</sub>) are isomerized, and heavy products (C<sub>13</sub>+) are cracked to maximize the gasoline fraction, which accounts for approximately 60 percent (by weight) of the total output.

### 2.2.1 Products

Exhibit 2-2 presents a list of products for a conceptual plant. Approximately 60 percent (by weight) of the output is gasoline. Liquid products, which include alcohols and ethylene, represent about 80 percent of the output. Other products include tar products (phenols), ammonia, and elemental sulfur.

### 2.2.2 Inputs

The major inputs to the process plant are:

- . Coal - 30,000 tons per day
- . Oxygen - 20,000 tons per day
- . Water - 12,000 gallons per minute.

The characteristics of the typical coal which produces the product slate for the analysis are:

EXHIBIT 2-2  
Product Yield of Fischer-Tropsch Facility

	<u>Tons Per Stream Day</u>	<u>Percentage of Total</u>
<u>Liquid Products</u>		
Unleaded Gasoline	6,010	58
Diesel Fuel	1,055	10
Ethylene	865	8
Alcohols	<u>400</u>	<u>4</u>
Subtotal	8,330	80
<u>By-Products</u>		
Tar Products	840	8
Ammonia	195	2
Sulfur	<u>1,015</u>	<u>10</u>
Subtotal	2,050	20
Total	10,380	100
<u>Electricity for Sale</u>	2.97 x 10 <sup>6</sup> kWhr/day	

High Heating Value	12,500 Btu/lb
Proximate Analysis	Percentage
Moisture	2.7
Ash	7.1
Volatile Matter	38.5
Fixed Carbon	51.7
Ultimate Analysis	Percentage
Carbon	70.7
Hydrogen	4.7
Nitrogen	1.1
Sulfur	3.4
Oxygen	10.3
Moisture	2.7
Ash	7.1
Source:	Ralph M. Parsons Co., <u>Fischer-Tropsch Complex Conceptual Design/Economic Analysis for Oil and SNG Production</u> , ERDA FE-1775-7, January 1977.

### 2.2.3 Energy Balance

Exhibit 2-3 presents an energy balance for the facility, and these major conclusions can be drawn:

- . Gasoline represents about 65 percent of the energy value of saleable products.
- . Approximately 35 percent of the moisture/ash-free coal energy is converted to gasoline.
- . Liquids account for 86 percent of the energy value of products.
- . The overall plant thermal efficiency as measured by the ratio of the equivalent energy value of products to coal input is 55 percent. This is lower than the value other liquefaction processes can achieve, because:
  - Fischer-Tropsch is an indirect (two-stage) liquefaction process, whereas others are direct (single-stage) processes. Overall conversion ratios are smaller and interstage cooling requirements are larger for Fischer-Tropsch plants than for other processes.

EXHIBIT 2-3  
Energy Balance of Fischer-Tropsch Facility  
(at 100% Capacity)

Product/Input	Output	Heating Value	Energy Content $10^{12}$ Btu/Year	Percentage of Product	Percentage of Coal Feed
Liquid Products					
Regular Gasoline	$781 \times 10^6$ gal/yr	125,000 Btu/gal	97.6	65.0	35.5
Diesel Fuel	$130 \times 10^6$ gal/yr	120,000 Btu/gal	15.6	10.4	5.7
Ethylene	317,000 t/yr	$4.0 \times 10^7$ Btu/t	12.7	8.5	4.6
Alcohols	145,000 t/yr	$2.5 \times 10^7$ Btu/t	3.6	2.4	1.3
Subtotal			129.5	86.3	47.1
By-products					
Tar Products	307,300 t/yr	$4.0 \times 10^7$ Btu/t	12.3	8.2	4.5
Ammonia	71,700 t/yr	$2.4 \times 10^7$ Btu/t	1.7	1.1	0.6
Sulfur	370,000 t/yr	$8.0 \times 10^6$ Btu/t	3.0	2.0	1.1
Subtotal			17.0	11.3	6.2
Electricity	$1,08 \times 10^6$ kWhr/yr	3,413 Btu/whr	3.7	2.4	1.3
Total			150.2	100.0	54.6
Coal	$10.95 \times 10^6$ t/yr	12,550 Btu/lb	275		

- Fischer-Tropsch reactors are relatively low in their selectivities for specific hydrocarbon formation, as shown in Exhibit 2-4. This necessitates a complex petroleum refinery as an integral part of any Fischer-Tropsch plant.

#### 2.2.4 Construction Schedule

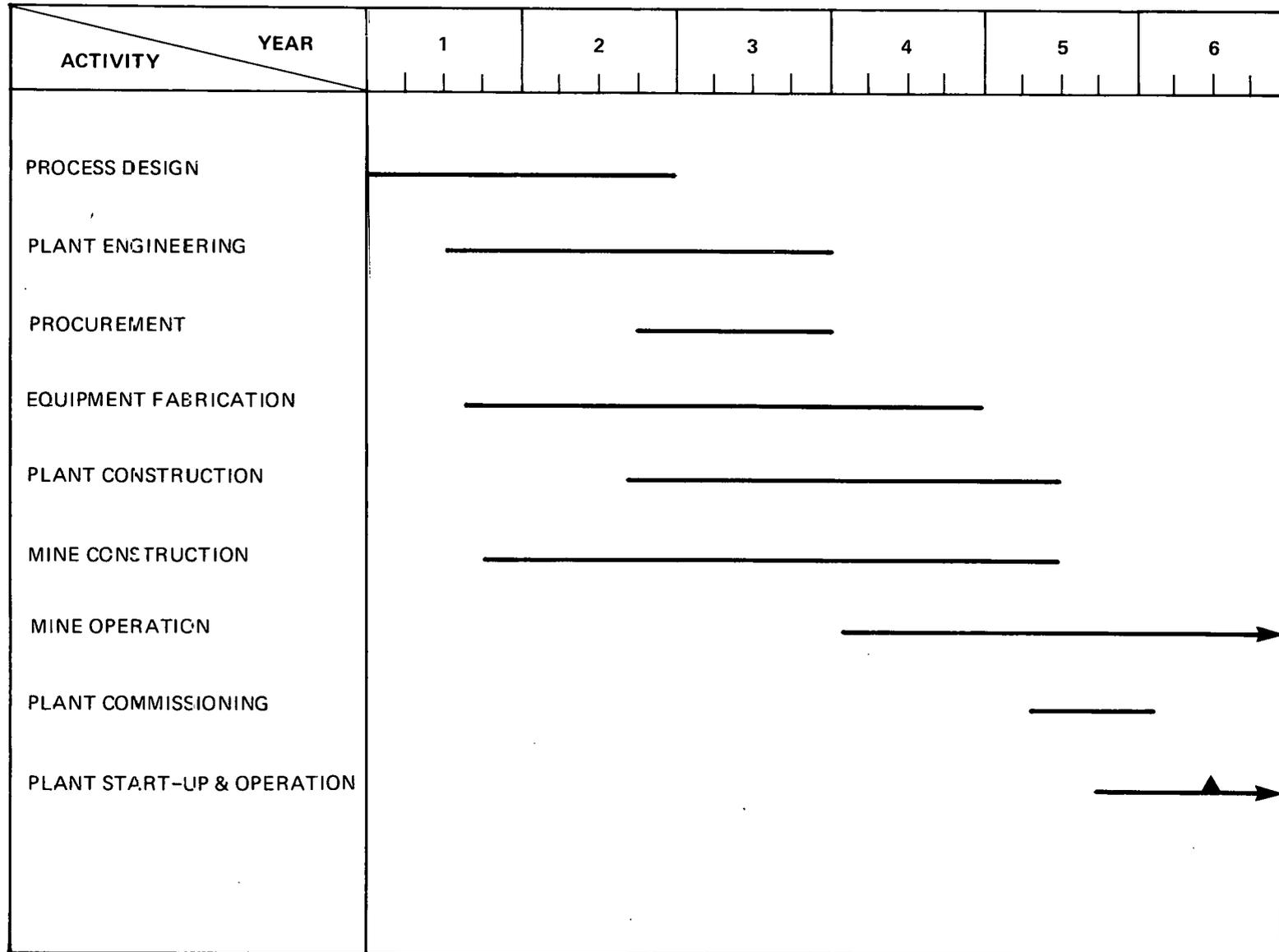
Exhibit 2-5 details the schedule for design, construction, and initial operation of a representative coal liquefaction plant. It is estimated that 6 years will be required from the time permits are obtained and detailed design is authorized. Obtaining the necessary permits could easily add 1 to 2 years to the overall schedule.

EXHIBIT 2-4  
 Selectivities of the Fischer-Tropsch  
 Synthol Reactor

Component of Crude Oil	Compounds	Percent
Light Hydrocarbons	CH <sub>4</sub>	10.0
	C <sub>2</sub> H <sub>4</sub>	4.0
	C <sub>2</sub> H <sub>6</sub>	6.0
	C <sub>3</sub> H <sub>6</sub>	12.0
	C <sub>3</sub> H <sub>8</sub>	2.0
	C <sub>4</sub> H <sub>10</sub>	1.0
	C <sub>5</sub> +	
Gasoline Fraction	C <sub>5</sub> - C <sub>12</sub>	31.0
Diesel	C <sub>13</sub> - C <sub>18</sub>	5.0
Heavy Oil & Wax	C <sub>19</sub> - C <sub>21</sub>	1.0
	C <sub>22</sub> - C <sub>30</sub>	3.0
	C <sub>31</sub>	2.0
Acids		1.0
Nonacid Chemicals		6.0

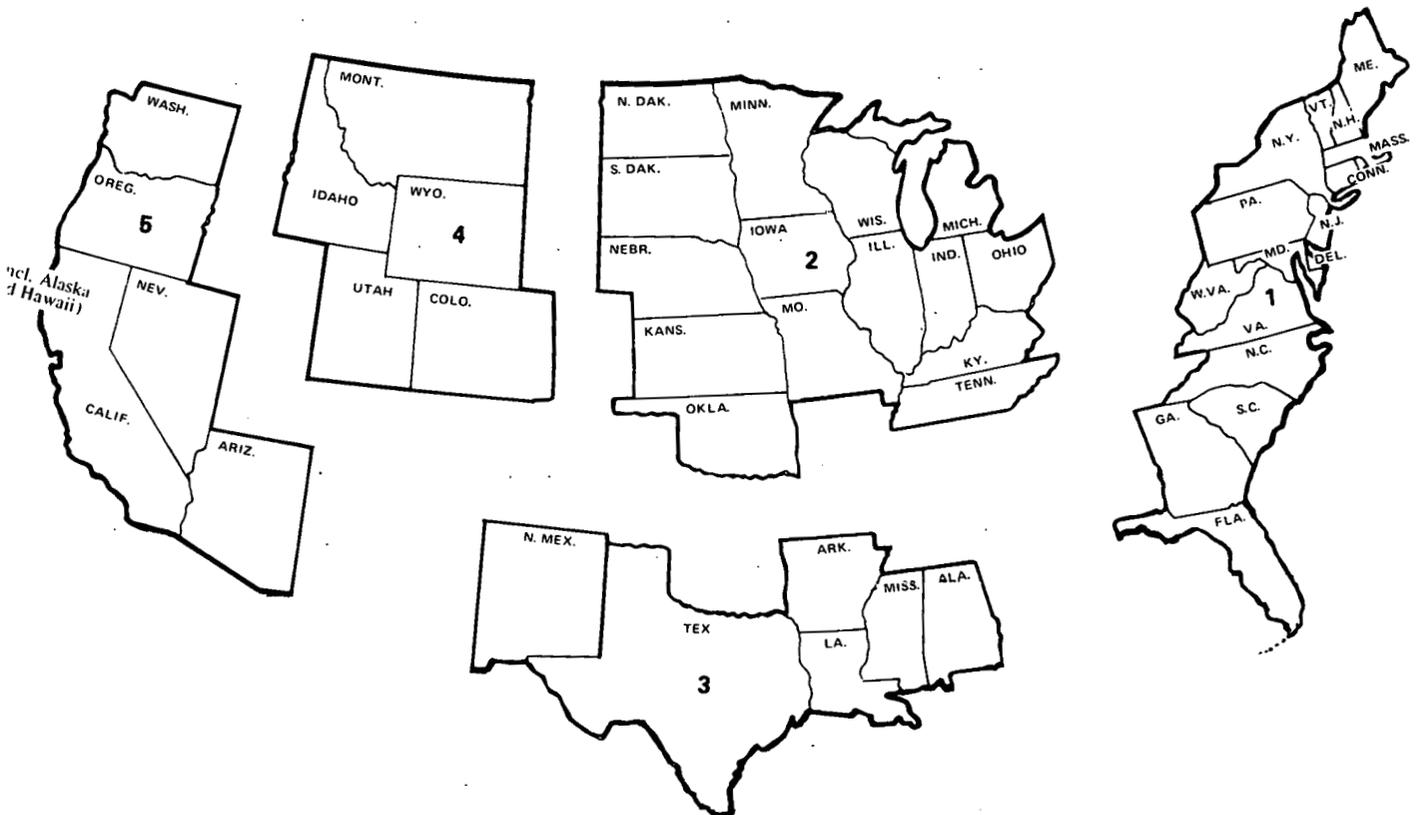
Source: Jan C. Hoogendoorn, "Conversion of Coal Into Fuels and Chemicals in South Africa," Presented at the 3rd International Coal Conference, Sydney, Australia, October 6, 1976.

EXHIBIT 2-5  
Construction Schedule for Fischer-Tropsch Facility



### 3. PLANT LOCATION

To arrive at location criteria for a gasoline-from-coal commercial operation, the supply/demand relationships for products and raw materials must be analyzed. In the ensuing regional analysis, the supply/demand regions considered are the five Petroleum Administration for Defense (PAD) districts shown.



Petroleum Administration for Defense (PAD) Districts

### 3.1 SUPPLY AND DEMAND FOR PETROLEUM PRODUCTS

Actual 1977 data are used in the analysis; forecasts are made for 1985 and 1990.

#### 3.1.1 Supply and Demand in 1977

Petroleum product supply and demand for 1977 are shown in Exhibit 3-1 (Energy Data Reports, EIA).

The table shows that:

- . The U.S. imported just under 7 million bbl/day of crude oil, and all districts except PAD District 4 imported substantial amounts of crude.
- . In addition, although domestic refineries operated above 90 percent of capacity, a historical high, the U.S. still imported over 2 million bbl/day of petroleum products. Therefore, the country is low in refinery capacity as well as in crude production.
- . Refinery undercapacity, however, is not as widely distributed as crude scarcity. PAD District 1, with 35 percent of product demand, has 11 percent of domestic capacity. On the other hand, PAD District 3, with 20 percent of product demand, accounts for 43 percent of domestic capacity. Since all other PAD districts maintain a near balance between product demand and refinery capacity, it is obvious that large flows of petroleum products take place between PAD 3 and 1. Moreover, since PAD 1 imported 80 percent of U.S. product imports, the picture that emerges is that PAD 1 meets its demand for residual oil by imports and the demand for lighter fractions by pipeline transfer from PAD 3.
- . Most crude imported by PAD District 2 enters the country at the Gulf of Mexico and is pipelined from PAD 3. Actual refinery runs in PAD 3 were under 6.5 million bbl/day, while the amount of crude produced and imported was 7.7 million bbl/day. Thus about 1.2 billion bbl/day moved north by pipeline.

EXHIBIT 3-1  
Petroleum Products Supply/Demand - 1977

	Demand For Petroleum Products		Refinery Capacity		Crude Production		Crude Imports		Imports of Petroleum Products	
	10 <sup>3</sup> bbl/day	%	10 <sup>3</sup> bbl/day	%	10 <sup>3</sup> bbl/day	%	10 <sup>3</sup> bbl/day	%	10 <sup>3</sup> bbl/day	%
PAD 1	6,478	35	1,913	11	144	2	1,518	23	1,817	86
PAD 2	5,032	27	4,229	26	891	11	1,416	22	120	6
PAD 3	3,755	20	7,405	43	5,122	62	2,542	38	46	2
PAD 4	544	3	590	3	662	8	43	1	16	1
PAD 5	2,609	14	2,910	17	1,424	17	1,096	16	105	5
TOTAL	18,642	99	17,048	100	8,245	100	6,615	100	2,104	100

3-3

### 3.1.2 Supply and Demand Forecasts

A common feature of all available projections is that, barring a major disruption in international crude supply, the above picture will remain essentially unaltered. The U.S. will continue to depend on imported crude for about 40 percent of its requirements and will depend on imported products to make up for worsening refinery undercapacity. The latest DOE projections are listed below.

#### CRUDE OIL IMPORTS\* (Thousands of bbl/day)

<u>PAD District</u>	<u>1985</u>	<u>1990</u>	<u>1995</u>
1	1,640	991	776
2	1,454	2,144	1,840
3	3,614	3,310	3,162
4	0	0	0
5	200	200	200
Total Crude Oil Imports	6,908	6,645	5,978
U.S. Crude Production	9,053	9,713	9,883
Imports as % of Total Crude	43	41	38
Petroleum Products Imports	1,261	1,339	1,730

\* Supporting computer runs to the Annual Report to Congress, 1978, EIA.

The following conclusions may be drawn from the projections:

- . The U.S. will continue to depend on foreign crude supply for the foreseeable future; therefore, there is room for a domestic coal liquids industry.
- . PAD District 1 crude imports will decline (564,000 bbl/day), reflecting a steady increase in offshore crude production.
- . Petroleum product imports will increase (469,000 bbl/day) to compensate for insufficient refinery capacity.
- . Crude imports will increase in PAD Districts 2 (676,000 bbl/day) and 3 (254,000 bbl/day).
- . There will be no imports into PAD District 4, and a modest and constant level to District 5, which includes Alaska.

### 3.2 SUPPLY OF COAL

Exhibit 3-2 shows the coalfields of conterminous states, and Exhibit 3-3 provides data by PAD districts on 1977 coal production and on U.S. reserves. The table shows that:

- . PAD District 1, with 32 percent of domestic production, contains 11 percent of identified reserves and a mere 5 percent of identified and estimated reserves.
- . PAD Districts 2, 3, and 4 contain 80 percent of identified reserves and 87 percent of identified and estimated reserves.
- . PAD District 4, the smallest in area, contains nearly one-half of all U.S. reserves.

A preliminary conclusion on gasoline and coal supply and demand becomes obvious: the regions with highest demand for products do not match the regions with the largest coal supply potential. Therefore, the relative merits of transporting either coal or gasoline must be factored into the location analysis of a coal liquids industry.

### 3.3 OPTIMIZATION OF TRANSPORTATION: COAL VERSUS GASOLINE

The purpose of this transportation analysis is to determine which of the following two cases entails lower transportation costs:

- Case 1: Plant located at the mine mouth, and products transported to existing petroleum terminals and bulk plants located in fuel-scarce regions.
- Case 2: Plant located in the gasoline-deficient market, and coal transported from the mine to the plant.

The analysis below assumes the use of existing transportation modes for coal, motor fuels and other products. The relative costs and benefits associated with additional (feeder) rail, pipelines and roads specific to the project should be assessed as part of a detailed, site-specific feasibility study. It is assumed, however, that they would have a marginal impact on the overall transportation picture.

EXHIBIT 3-2  
Coalfields of the Conterminous United States

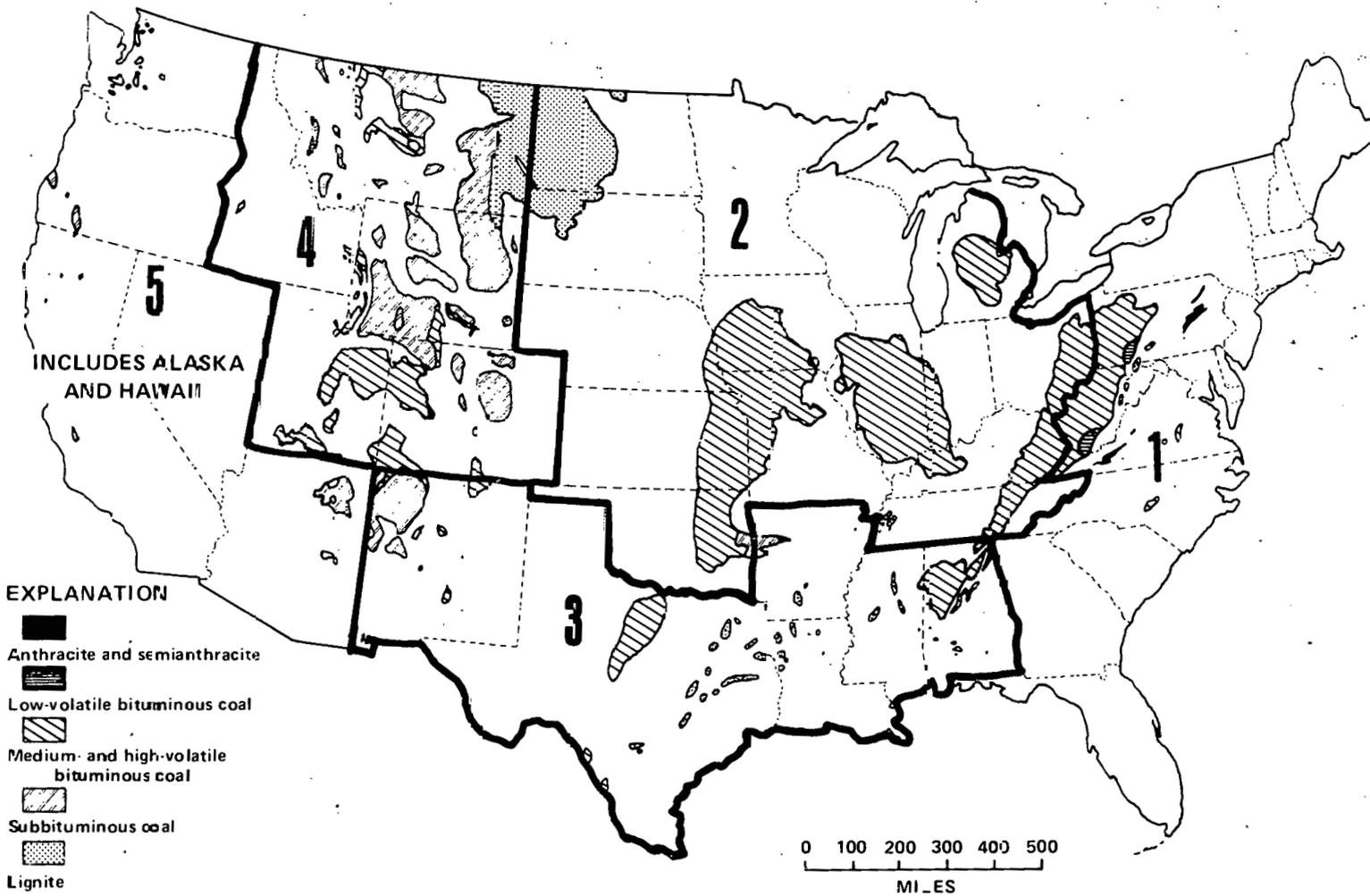


EXHIBIT 3-3  
Coal Production and Resources of the U.S.

	1977 Production 000 Tons	% USA Production	Identified Reserves MM Tons	% Identified USA Reserves	Identified + Estimated (0-3000 Feet) Reserves MM Tons	% USA	Identified + Estimated (0-6000 Feet) Reserves	% USA
PAD 1	219,955	32	193,739	11	203,219	6	206,294	5
PAD 2	306,635	45	703,374	41	1,117,518	31	1,117,518	28
PAD 3	49,810	7	95,410	6	297,066	8	377,066	10
PAD 4	94,980	14	579,889	33	1,643,161	46	1,922,152	49
PAD 5	17,195	2	157,816	9	317,916	9	337,916	8
PAD 5 (Excl. Alaska)	16,530	2	27,737	2	57,837	2	72,837	2
Total	688,575	100	1,730,228	100	3,578,880		3,961,576	
Total (Excl. Alaska)	687,910		1,600,149		3,318,801		3,696,497	

Sources:

- . Production data from Keystone Coal Industry Manual - 1978
- . Reserves from Paul Averitt "Coal Resources of the United States, January 1974," GPO.

### 3.3.1 Materials and Quantities

The Fischer-Tropsch facility is planned to transform 10.95 million tons per year of bituminous coal, HHV 12,550 Btu/lb., into the following products:

<u>Product</u>	<u>Million Tons/Year</u>	<u>Percent by Weight</u>
Motor Fuels	2.15	64
Ethylene	0.32	10
Tar Products	0.28	8
Ammonia (asN)	0.07	2
Sulfur	0.37	11
Chemicals	<u>0.15</u>	<u>5</u>
	3.34	100

### 3.3.2 Coal Transportation System

Raw coal may be moved from the mine to the consumption point by rail, barge, truck or pipeline. Exhibit 3-4 contains a brief description and characterization of each mode. Exhibit 3-5 shows graphically the relationship between unit costs and distance for different modes. Exhibits 3-6 through 3-8 show the long-haul movement of coal in the U.S.

### 3.3.3 Motor Fuel Transportation System

Motor fuels may be transported by truck, barge, train, or pipeline. For the quantities considered in the present case, about 2.15 million tons per year, the only reasonable option for long-distance transport is the pipeline, costing approximately 0.4 cents/ton mile. The existing nationwide pipeline network, shown in Exhibit 3-9, provides some flexibility in plant location.

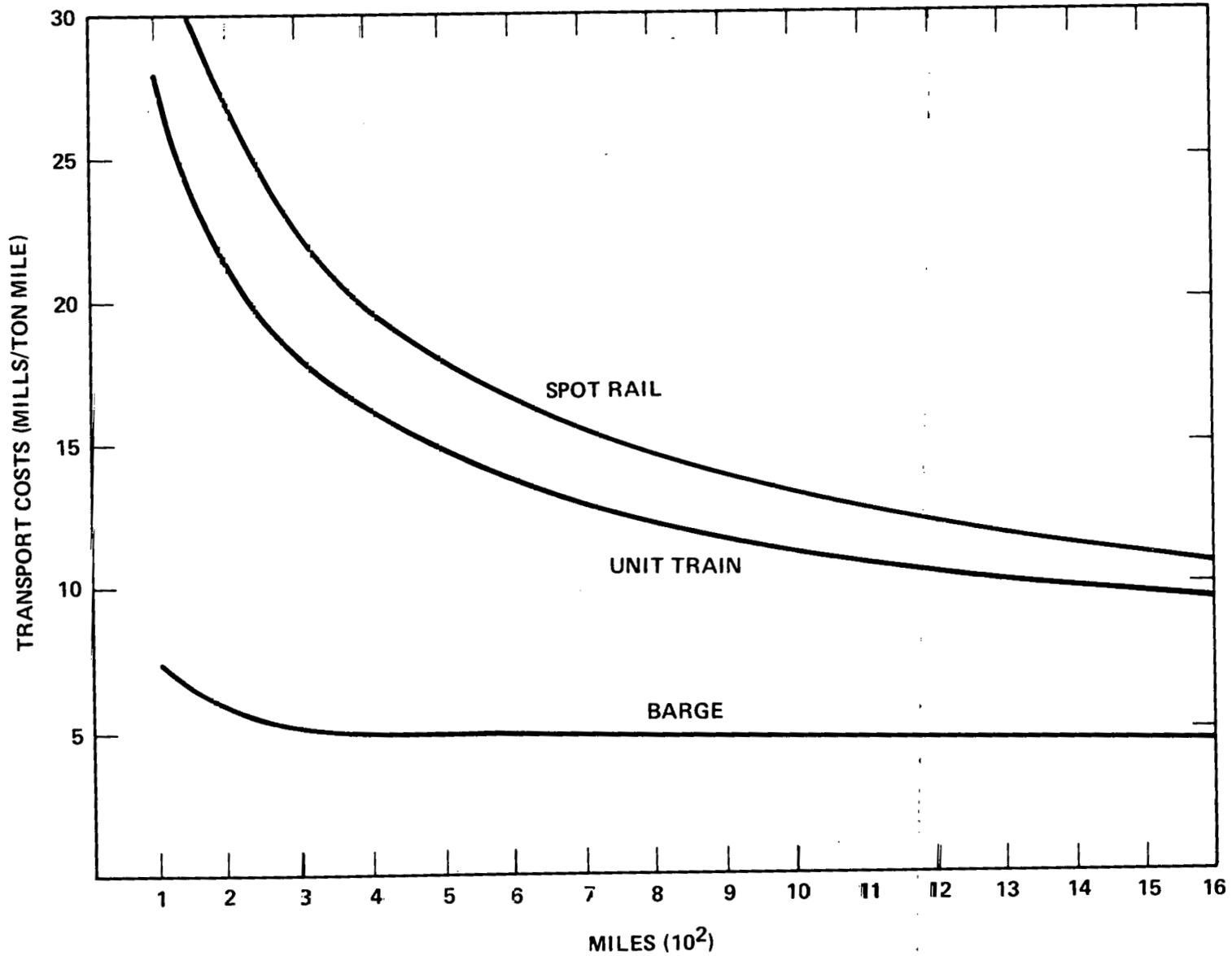
### 3.3.4 Other Products Transportation System

The other products from the liquefaction facility will be transported by truck or train. Ethylene, however, may be an exception if the plant is located near an ethylene-carrying pipeline system.

EXHIBIT 3-4  
Coal Transportation Systems

Mode	Characteristics	Advantages	Disadvantages
Barge	<ul style="list-style-type: none"> <li>· Moves about 10% of the raw coal shipped in the U.S.</li> <li>· Usually requires moving coal from the mine to the barge loading facility by either truck or train, except in the Ohio river valley where barges can be loaded directly from the mine.</li> <li>· Most waterway coal movements in 1974 were made on rivers in the Ohio river system, as shown in Exhibit 3.6.</li> <li>· Exhibit 3.6 also shows that the Ohio and Mississippi basins link two coal-rich regions, with coal movements in opposite directions occurring on almost every waterway. The reasons for this apparently inefficient allocation of coal, a fuel with a larger transport component in its delivered price than any other, include:               <ul style="list-style-type: none"> <li>- Needs for different grades of coal</li> <li>- Interplay of spot and long-term delivery markets</li> <li>- Captive production and transportation</li> <li>- Seasonality of supply/demand equilibrium.</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>· Low cost. A study performed by A. T. Kearney Inc. found that the average rate per ton mile in 1971 was 0.339 cents. A ton mile of 3 mills is often cited as an average figure for barge coal movements. However, the waterway user fee recently passed by Congress should increase barging costs.</li> </ul>	<ul style="list-style-type: none"> <li>· Limited to the Ohio and Mississippi basins, thus with no direct access to western coals or to eastern markets.</li> </ul>
Unit Train	<ul style="list-style-type: none"> <li>· Railroads currently transport about 70% of all bituminous coal in the U.S.</li> <li>· For the quantities of coal being considered, about 10MTPY, unit trains are the cheapest form of rail transportation due to:               <ul style="list-style-type: none"> <li>- Special rates, about one-third below ICC-based general rates for conventional trains</li> <li>- Better utilization of equipment</li> <li>- Elimination of standard railroad tie-ups such as classification yards and layover posts</li> <li>- Better coordination between mine production and coal usage.</li> </ul> </li> </ul>	<ul style="list-style-type: none"> <li>· The main advantage is the extensive nationwide railroad network already in place, as shown in Exhibit 3.7.</li> <li>· Still the cheapest mode next to barging and slurring, both of which have limitations in area covered. In 1974, the average cost of moving coal by unit trains was 1.0 cent/ton mile.</li> </ul>	<ul style="list-style-type: none"> <li>· Although the rail network spans a vast area, many western lines would not be able to support regular unit train movements without substantial track improvement (private communication from DOT).</li> <li>· Rail costs are more route specific than any other means of coal transport. For instance, moving coal by rail west to east costs more than would cost a comparable distance over an uninterrupted route.</li> </ul>
Slurry Pipeline	<ul style="list-style-type: none"> <li>· A slurry pipeline is currently in operation transporting coal from Peabody's Coal Black Mesa, Arizona mine to a utility 300 miles away. Costs are estimated at 0.6-0.7 cents/ton mile.</li> <li>· Several slurry pipelines are being planned as shown in Exhibit 3.8.</li> </ul>	<ul style="list-style-type: none"> <li>· Low cost, estimated in the new long haul projects to be comparable to barging.</li> </ul>	<ul style="list-style-type: none"> <li>· Outcome uncertain due to institutional barriers.</li> </ul>
Truck	<ul style="list-style-type: none"> <li>· Trucks move about 10% of the raw coal shipped in the U.S., about the same as barges.</li> </ul>	<ul style="list-style-type: none"> <li>· Flexibility over short distances.</li> </ul>	<ul style="list-style-type: none"> <li>· Not cost effective for large distances or large volumes of coal.</li> </ul>

EXHIBIT 3-5  
Modal Coal Transport Costs (1985)



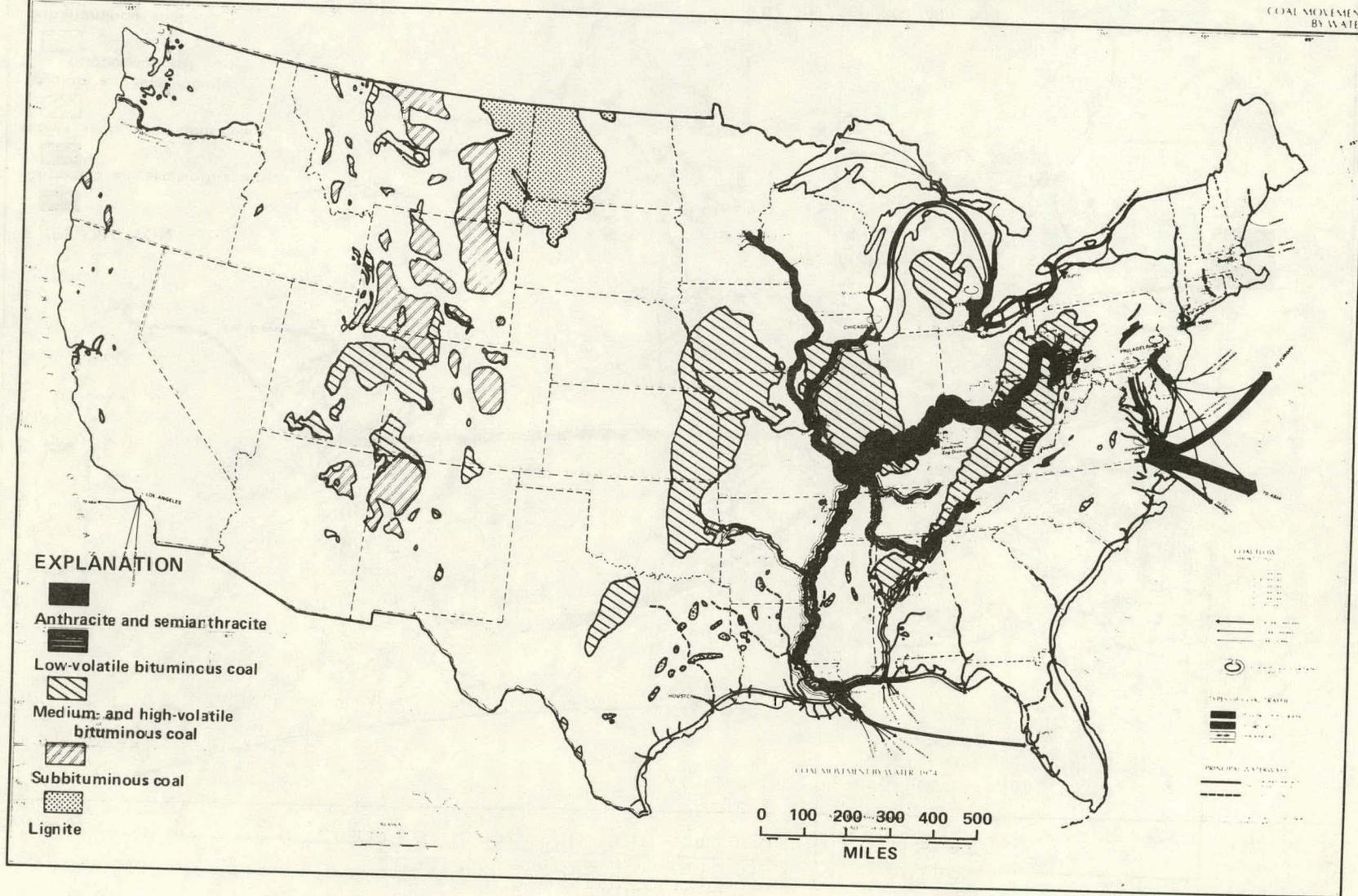
3-10

Source: Nagarwala, Olver, & Ferrel. Regional Energy System for the Planning and Optimization of National Scenarios. The Bechtel Corporation. June 1976, FE 1552-18, p. 101.

# EXHIBIT 3-6 Coal Movements by Water Overlaying Coalfields of the Conterminous United States

MAP NO. 4  
NATIONAL ENERGY  
TRANSPORTATION SYSTEMS

COAL MOVEMENT  
BY WATER



### EXPLANATION

-  Anthracite and semianthracite
-  Low-volatile bituminous coal
-  Medium and high-volatile bituminous coal
-  Subbituminous coal
-  Lignite

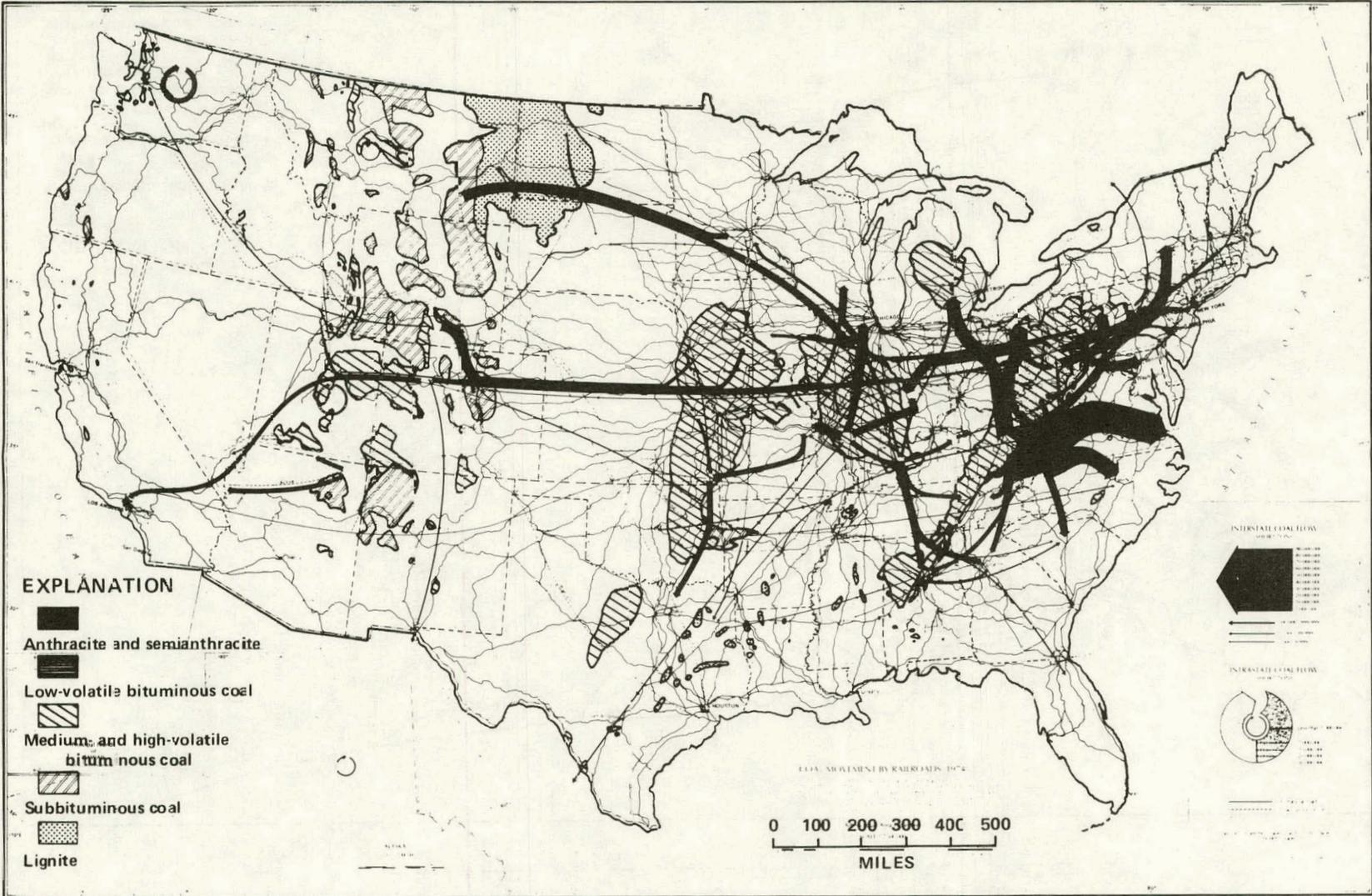
-  COALFIELD
-  WATERWAY
-  DIRECTION OF COAL MOVEMENT
-  INTERNATIONAL WATER
-  PRINCIPAL WATERWAY

0 100 200 300 400 500  
MILES

EXHIBIT 3-7  
 Coal Movements by Railroad Overlaying  
 Coalfields of the Conterminous United States

MAP NO. 1  
 NATIONAL ENERGY  
 TRANSPORTATION SYSTEMS

COAL MOVEMENT  
 BY RAILROADS



3-12

EXHIBIT 3-8  
 Coal Slurry Pipeline Overlaying  
 Coalfields of the Conterminous United States

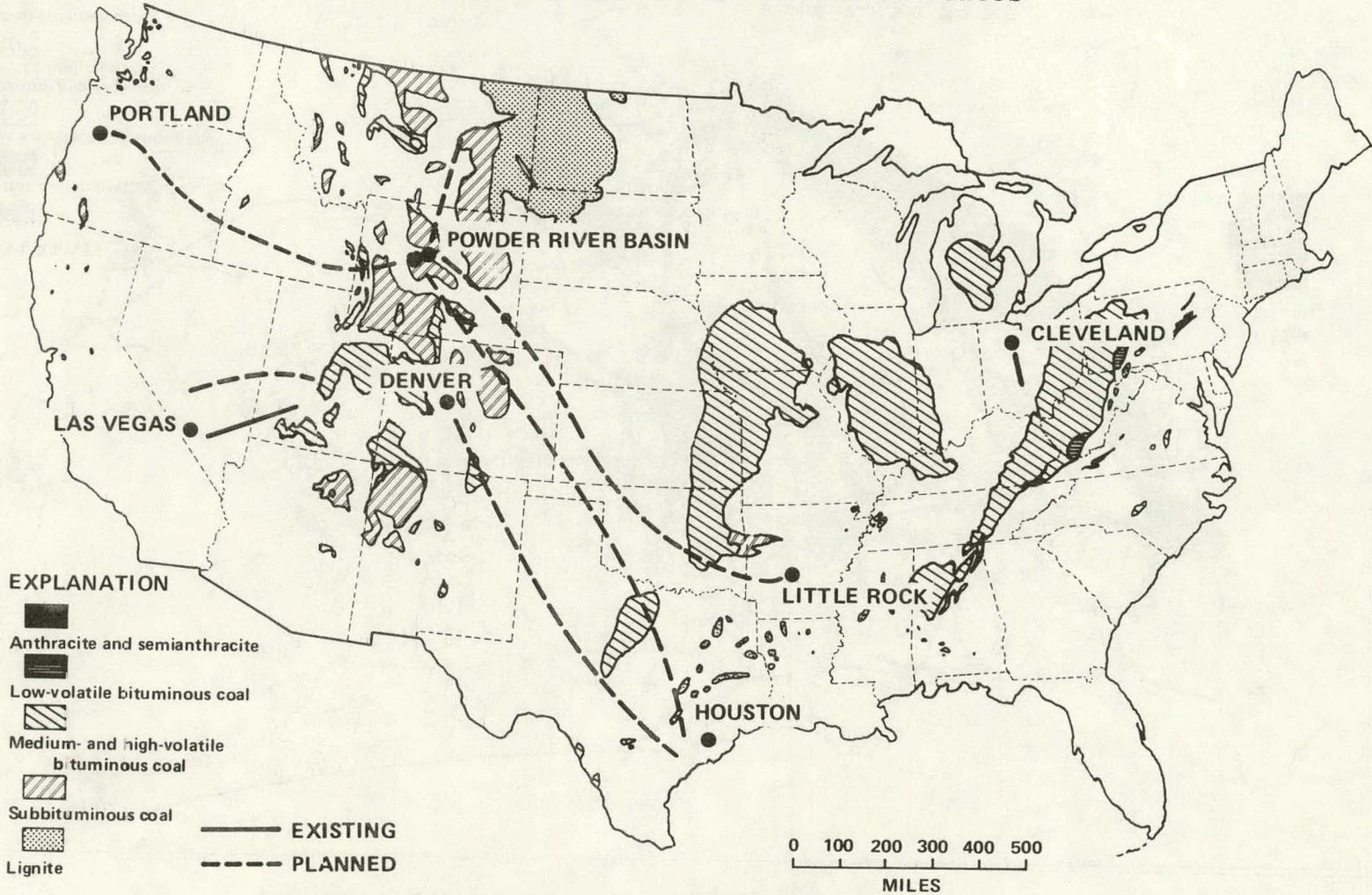
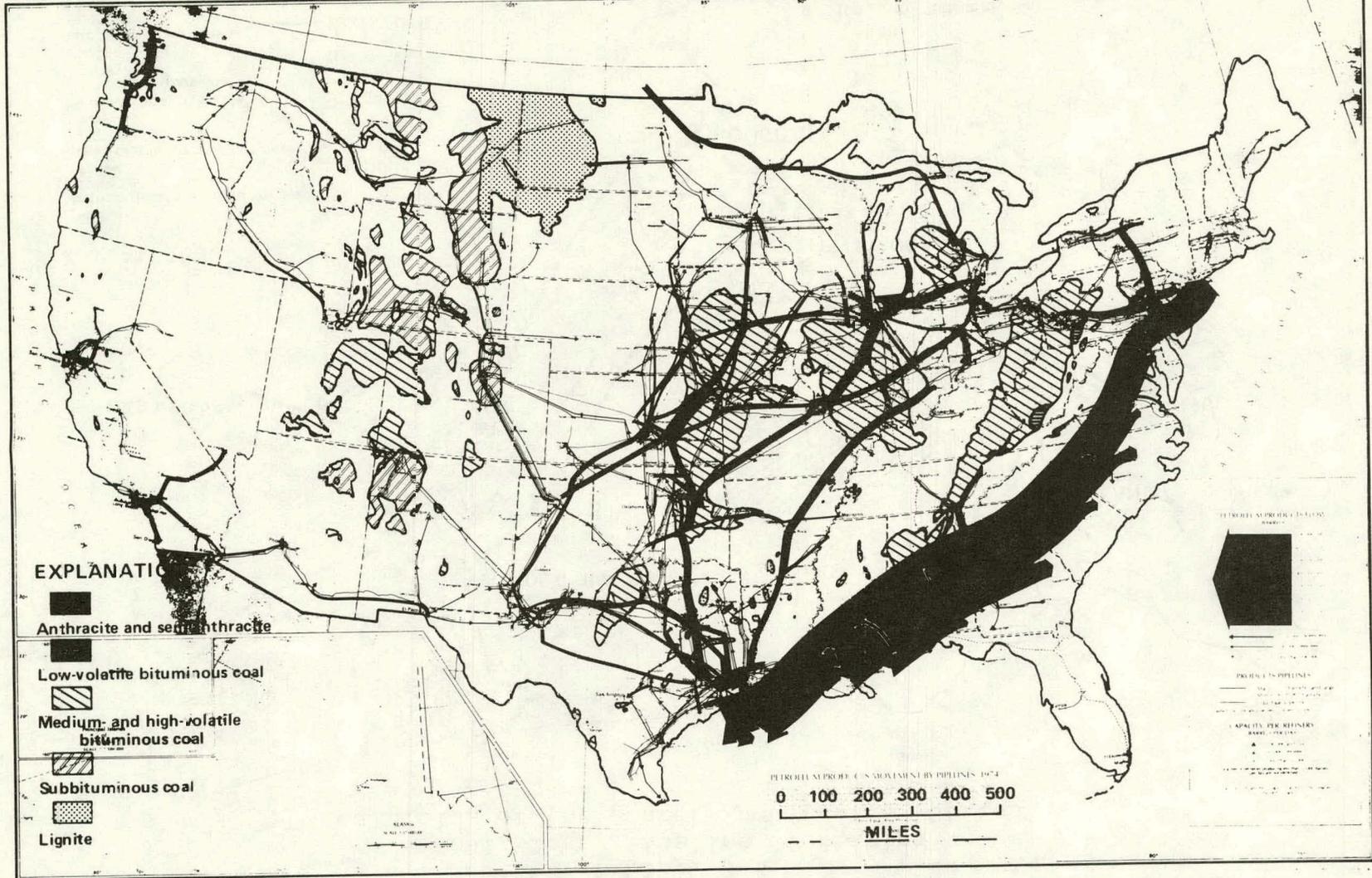


EXHIBIT 3-9  
 Petroleum Movement by Pipeline Overlaying  
 Coalfields of the Conterminous United States

MAP NO. 1  
 NATIONAL ENERGY  
 TRANSPORTATION SYSTEMS

PETROLEUM PRODUCTS  
 MOVEMENT BY PIPELINES



### 3.3.5 Transportation Model

The transportation costs for the two cases can be determined by:

$$\text{Case 1: } C_1 = \sum_1^6 V_n \cdot X_n \cdot U_n \quad (1)$$

$C_1$  = Annual cost of products transportation

$V_n$  = Annual output, in tons, of product n  
(1, motor fuels; 2, ethylene; 3, tar products; etc.)

$X_n$  = Distance from mine to market n (miles)

$U_n$  = Transportation cost for product n  
(cents/ton mile)

$$\text{Case 2: } C_2 = Q \cdot X \cdot U_c \quad (2)$$

$C_2$  = Annual cost of coal transportation

$Q$  = Annual coal tonnage consumed by the plant

$X$  = Distance from mine to market (same as  $X$  in Case 1)

$U_c$  = Coal transportation cost (cents/ton mile).

The ratio  $C_1/C_2$  is the transportation costs ratio associated with alternatives 1 and 2. Therefore,

$\frac{C_1}{C_2} = 1$  means that the alternatives are indifferent to transportation costs.

$\frac{C_1}{C_2} < 1$  means that alternative 1 (plant at mine mouth) has lower transportation costs than alternative 2 (coal transported from mine to plant).

$\frac{C_1}{C_2} > 1$  means that alternative 1 is more costly than alternative 2.

Dividing (1) by (2) yields

$$\frac{C_1}{C_2} = \frac{1}{Q \cdot X \cdot U_c} \sum_1^6 V_n \cdot X_n \cdot U_n \quad (3)$$

Assuming that  $x_1 \dots x_6 = X$ , i.e., all products are transported to the same market, equation (3) becomes:

$$\frac{C_1}{C_2} = \frac{1}{Q \cdot U_c} \sum_1^6 V_n \cdot U_n \quad (4)$$

Exhibit 3-10 shows the amounts of coal and of final products, the transportation costs for different modes, and different estimates for the same mode.

Using all possible combinations of these cost figures, in equation (4), the following  $C_1/C_2$  ratios can be obtained:

<u>Coal</u>		<u>Fuel</u>		
Mode	$U_c$ Cents Per Ton Mile	Mode	$U_1$ Cents Per Ton Mile	$\frac{C_1}{C_2}$
Unit Train	1.3	Pipeline	0.39	0.25
Unit Train	1.3	Pipeline	0.54	0.28
Slurry	0.81	Pipeline	0.39	0.41
Slurry	0.81	Pipeline	0.54	0.44
Barge	0.43	Pipeline	0.39	0.77
Barge	0.43	Pipeline	0.54	0.83

In all cases  $C_1/C_2 < 1$ ; hence, by definition, Case 1 (plant at mine mouth) has lower transportation costs than Case 2, and is therefore the preferred solution.

EXHIBIT 3-10  
Transportation Costs for Different Materials

	Usage/ Yield MM TPY	Transportation Costs <sup>4</sup> (Cents/Ton Mile)	Transportation Mode
Coal	10.95	1.3 0.81 0.43	Unit Train <sup>1</sup> Slurry <sup>2</sup> Barge <sup>3</sup>
Motor Fuels	2.1	0.39 0.54	Pipeline <sup>1</sup> Pipeline <sup>2</sup>
Ethylene	0.259	2.6	Rail/Water <sup>1</sup>
Tar Products	0.252	2.6	Rail/Water <sup>1</sup>
Ammonia (AS N)	0.07	2.6	Rail/Water <sup>1</sup>
Sulfur	0.37	2.6	Rail/Water <sup>1</sup>
Chemicals	0.12	2.6	Rail/Water <sup>1</sup>

- (1) 1974 National Transportation Report Current Performance and Future Prospects, July 1975, Department of Transportation, p. 448.
- (2) Pipeline Transportation to 1990, The Pace Company, January 1976, prepared for Department of Transportation.
- (3) Domestic Waterborne Shipping Analysis, A.T. Kearney, Inc., Chicago, IL 1974, Table 7.
- (4) All units revised to 1978 dollars.

### 3.3.6 Discussion of Results

Coal Heating Value—the motor fuel component of equation (4), the most important single factor in determining  $C_1/C_2$ , can be expressed as the product of two ratios:

$$\frac{V_1 \cdot X_1 \cdot U_1}{Q \cdot X_1 \cdot U_c} = \frac{V_1 \cdot U_1}{Q \cdot U_c} = \frac{F(Q)}{Q} \cdot \frac{U_1}{U_c} \text{ Where } V_1 = F(Q)$$

$F(Q)/Q$  is the gasoline output/coal input ratio, which is a function of process characteristics— $F(Q)$  increasing with increased efficiency—and the type of coal used— $Q$  diminishing with higher coal heat values. Therefore, low process efficiency and/or low-Btu coal will shift the transportation economics further toward choosing a mine-mouth plant. In the conceptual plant being considered, using coal with 12,550 Btu/lb, the ratio is 2.15 million tons/year of motor fuels to 10.95 million tons/year of coal, yielding:

$$\frac{F(Q)}{Q} = \frac{2.15}{10.95} = 0.2$$

$\frac{U_1}{U_c}$  Is the ratio of transportation costs for gasoline and coal. From Table 1,  $U_1/U_c$  varies from 0.3 to 1.3.

In order to make any alternative other than a mine-mouth plant credible, the product of the two ratios should approach 1. However, the highest value is approximately 0.3. In order to achieve a value of 1, the rate of gasoline production per unit of coal would have to multiply several times, and/or the cost of moving coal would have to decrease relative to that of moving gasoline.

- . Solid Waste Disposal--The gasification stage produces a residue (10 to 20 percent of input coal, by weight) in the form of ash or slag. It is assumed in the market-siting case that the residue will be transported back to the mine from the liquefaction plant at no cost and that the material handling costs at the plant and at the mine are absorbed by operations costs other than transportation. However, such handling costs would almost certainly be lower in a mine-mouth plant.
- . Products Other Than Motor Fuels--It was assumed, in the mine-mouth plant case, that the nonfuel products would be railed to the same market as the fuels. Any shortening of this distance for those products, by supplying markets between the mine and the fuel market, will reduce the overall transportation costs of mine-mouth siting, therefore strengthening even further the mine-mouth plant option.

#### 3.4 SITING CRITERIA

The previous sections have established

- . A continuing dependency on imported crude oil by the U.S.
- . A mismatch between the large coal reserve regions and the main gasoline markets
- . The cost-effectiveness of mine-mouth facilities relative to market siting

Therefore the key siting requirements must include

- . Coal availability; at least 10 million tons per year per plant
- . A local gasoline market capable of absorbing the output of the plant(s)

- . If a local market does not exist, there should be existing petroleum products pipelines to move the product inexpensively to other markets
- . Availability of water (about 12,000 gallons per minute)
- . Environmental acceptability.

Since some criteria may be met by one or a few facilities but not for large-scale development requiring many facilities, two scenarios must be considered when applying the siting criteria:

- . One or a few facilities case
- . Many facilities case.

#### 3.4.1 Few Facilities Case—Case 1

There are no rigid criteria for a one-facility project. It can be built anywhere 300 million tons of coal are available (assuming 10 million tons/year for 30 years), there is adequate water for processing, the regional market can absorb the gasoline, and the plant is environmentally acceptable. It is unlikely, though, that it would be built outside the 16 states shown in Exhibit 3-11. Each of these states contains 1 percent or more of U.S. coal reserves, and collectively they account for 95 percent of domestic reserves, excluding Alaska.

The three main factors to be considered for this case are:

- . Coal availability: All states in Exhibit 3-11 can theoretically supply the necessary coal. Each plant will require 10 million tons/year, approximately 1.5 percent of current domestic production
- . Gasoline market: Each state in PAD Districts 1 and 2, except North Dakota and West Virginia can, technically, easily absorb the output of a 50,000 bbl/day facility. On the other hand, each state in PAD Districts 3 and 4, except Alabama, produces more crude than it consumes; thus product pipelines are needed to move gasoline to other markets.
- . Environmental protection: Except in special circumstances, environmental impact should not constitute an obstacle for a proposed Fischer-Tropsch operation. Beyond a limited number of plants, however, demands on water may become a constraint in the West.

EXHIBIT 3-11  
Coal, Gasoline, and Pipeline Data  
for the 16 Coal-Rich States

	Coal Reserves <sup>1</sup>		1977 Gasoline Demand <sup>2</sup>		1977 Crude Production <sup>3</sup>		Pipeline Availability			
	MM Tons	%	10 <sup>3</sup> Bbl/Day	%	10 <sup>3</sup> Bbl/Day	%	Crude	Products	Direction	
									CRUDE	Products
PAD District 1										
Pennsylvania (Excl. Anthracite)	71,540	2	330	4.7	7	.08		✓		Mainly Philadelphia/ Pittsburgh
West Virginia	100,150	3	58	.8	7	.08	✓		From Louisiana	
PAD District 2										
North Dakota	530,602	14	29	.4	64	.8	✓	✓	To Great Lakes	To Minnesota from Montana
Missouri	48,673	1	183	2.5	0	0	✓	✓	From Oklahoma	From Oklahoma to Lakes
Illinois	246,001	7	355	4.9	70	.8	✓	✓	From South	Both Ways
Indiana	54,868	1	186	2.6	15	.18	✓	✓	From Illinois	From Oklahoma
Ohio	47,318	1	353	4.9	28	.34	✓	✓	From Indiana	From Oklahoma
Kentucky	116,340	3	135	1.9	18	.20	✓	✓	From South	From Oklahoma
PAD District 3										
New Mexico	200,947	5	51	.7	239	2.9	✓	✓	To Texas; California	From Texas; California
Texas	128,441	3	549	7.6	3,117	37.8	✓	✓	To Illinois	To East Coast
Alabama	41,262	1	137	1.9	50	0.6		✓		From Texas
PAD District 4										
Montana	471,639	13	33	.5	90	1.1	✓	✓	From Canada to Kansas	Surrounding Areas
Wyoming	935,943	25	24	.3	377	4.6	✓	✓	From Canada to Kansas	Surrounding Areas
Utah	80,359	2	47	.6	91	1.1	✓	✓	From Wyoming	From Wyoming to Idaho
Colorado	434,211	12	92	1.3	108	1.3	✓	✓	From Wyoming	From Wyoming and Texas
PAD District 5 (Excl. Alaska)										
Washington	51,169	1	127	1.8	0	0	✓	✓	From Canada	To Oregon
TOTAL ABOVE	3,559,463	94	2,689	38	4,281	51.88				
TOTAL USA (Excl. Alaska)	3,696,497	100	7,178	100	8,245	100				

<sup>1</sup> Paul Averitt "Coal Resources of the U.S.," January 1970

<sup>2</sup> Federal Highway Administration and National Petroleum News Factbook

<sup>3</sup> Energy Data Reports, EIA.

Exhibit 3-12 shows how the analysis has been summarized. The conclusion for the few facilities case is that all the states mentioned are potentially suitable locations except West Virginia, Kentucky, New Mexico, Montana, Utah and Washington.

#### 3.4.2 Coal Liquids Industry Case—Case 2

The parameters to be considered in this case are:

- . Coal availability: The criteria here is that states without major coal reserves are unlikely to play a significant role in a national coal liquids industry. The growth of that industry will, of course, be limited by the rate at which uncommitted reserves are brought into new production.
- . Pipeline availability: Local or regional markets are not large enough to absorb the output of such an industry; the determining factor is the ability to move large volumes of gasoline to high demand regions—PAD Districts 1 and 2 as well as to California. The highest coal reserve regions (Montana, Wyoming, Colorado, North Dakota) have no product pipelines to California, whereas the two pipelines to the East have small diameters (6 and 8 inches). Texas is equipped to serve PAD 1, and Illinois and Missouri are also well served.
- . Environmental protection: The main problem raised by a high concentration of coal liquids production facilities is the high demand for water, which may become a prohibitive factor in PAD District 4. Standards affecting indirect coal liquefaction technologies pose no insurmountable barriers to the commercial application of these technologies, but may result in additional capital and operating costs.

Exhibit 3-13 summarizes the conclusion for this case.

EXHIBIT 3-12  
 Characterization Parameters for Coal Liquefaction Plants

	FEW FACILITIES CASE			
	COAL RESERVES	GASOLINE DEMAND RELATIVE TO REGIONAL SUPPLY	PIPE- LINES	CONCLU- SION
PAD DISTRICT 1 PENNSYLVANIA (EXCL. ANTHRACITE) WEST VIRGINIA	● ●	● ○	● ○	● ○
PAD DISTRICT 2 NORTH DAKOTA MISSOURI ILLINOIS INDIANA OHIO KENTUCKY	● ● ● ● ● ●	○ ◐ ● ● ● ●	● ● ● ● ● ○	● ● ● ● ● ◐
PAD DISTRICT 3 NEW MEXICO TEXAS ALABAMA	● ● ●	○ ○ ◐	◐ ● ●	◐ ● ●
PAD DISTRICT 4 MONTANA WYOMING UTAH COLORADO	● ● ● ●	○ ○ ○ ○	◐ ● ◐ ●	◐ ● ◐ ●
PAD DISTRICT 5 (EXCL. ALASKA) WASHINGTON	●	◐	◐	◐

- HIGH
- ◐ MEDIUM
- LOW

EXHIBIT 3-13  
Characterization Parameters for Coal Liquefaction Plants

	FEW FACILITIES CASE				COAL LIQUIDS INDUSTRY CASE			
	COAL RESERVES VS. REQUIREMENTS	GASOLINE DEMAND RELATIVE TO REGIONAL SUPPLY	PIPE-LINES	CONCLUSION	COAL RESERVES VS. REQUIREMENTS	PIPE-LINES	ENVIRONMENTAL ACCEPTABILITY	CONCLUSION
PAD DISTRICT 1 PENNSYLVANIA (EXCL. ANTHRACITE) WEST VIRGINIA	● ●	● ○	● ○	● ○	○ ●	● ○	● ●	○ ○
PAD DISTRICT 2 NORTH DAKOTA MISSOURI ILLINOIS INDIANA OHIO KENTUCKY	● ● ● ● ● ●	○ ● ● ● ● ●	● ● ● ● ● ○	● ● ● ● ● ●	● ○ ● ○ ○ ○	○ ● ● ● ● ○	● ● ● ● ● ●	● ○ ● ○ ○ ○
PAD DISTRICT 3 NEW MEXICO TEXAS ALABAMA	● ● ●	○ ○ ●	● ● ●	● ● ●	● ● ○	○ ● ○	○ ● ●	○ ● ○
PAD DISTRICT 4 MONTANA WYOMING UTAH COLORADO	● ● ● ●	○ ○ ○ ○	● ● ● ●	● ● ● ●	● ● ○ ●	○ ○ ○ ○	○ ○ ○ ○	● ● ○ ●
PAD DISTRICT 5 (EXCL. ALASKA) WASHINGTON	●	●	●	●	○	○	●	○

● HIGH    ◐ MEDIUM    ○ LOW

### 3.4.3 Sites Selected

From the previous examination, Illinois and Texas are obvious choices to consider for either of the cases examined. In addition, Wyoming with a large amount of low-cost coal will also be considered. This will be representative of any number of Western coals (e.g., Colorado, Montana, North Dakota).

The characteristics and mining costs, based on average mine-mouth quoted prices, of representative coals from these regions, are shown in Exhibit 3-14. In addition, a South African coal is included for comparison since this represents the only commercial feedstock to an existing F-T operation.

In order to ensure comparability of results among the three sites, certain assumptions relative to markets are required:

- . Markets in PAD Districts 1 and 2 are assumed, since neither District 3 nor 4 is fuel deficient, and there is no product pipeline linking producing districts with District 5.
- . The Texas facility can sell its gasoline in either PAD 1 or PAD 2. It is assumed it will be sold in Illinois (800 miles by pipeline).
- . The Wyoming facility is unlikely to sell its gasoline either in Wyoming or in Colorado; therefore it is assumed it will be sold in Illinois (1,200 miles by pipeline).
- . Therefore for the purpose of this analysis the economics will be based on gasoline sold in Illinois irrespective of plant location. Note that this assumption will yield the highest probable transportation costs for the two alternatives because it is within the realm of possibility that a portion of the output of a plant located in either of these areas would go to local markets.

The following assumptions relative to input and outputs were also used.

- . The Illinois location is the base case, and the liquids yield is based on Illinois coal.

EXHIBIT 3-14  
Representative Coals From PADS 2, 3, 4

	Illinois <sup>1</sup> #6	Eastern <sup>2</sup> Texas Lignite	Wyoming <sup>2</sup> Subbituminous	South <sup>3</sup> African
High Heating Value (Btu/lb)	12,550	7,226	8,244	10,300
FOB 1985 Projection (1978 \$/ton) <sup>4</sup>	23.58	9.57	8.97	
FOB 1985 Projection (1978 \$/MMBtu) <sup>4</sup>	0.94	0.66	0.54	
<u>Proximate Analysis (%)</u>				
Moisture	2.7	31.8	29.8	5.0
Ash	7.1	9.7	6.0	21.5
Volatile Matter	38.5	30.9	30.7	N/A
Fixed Carbon	51.7	27.6	33.5	N/A
<u>Ultimate Analysis (%)</u>				
Carbon	70.7	N/A	N/A	79.6
Hydrogen	4.7	N/A	N/A	4.3
Nitrogen	1.1	N/A	N/A	2.0
Sulfur	3.4	0.9	0.5	1.3
Oxygen	10.3	N/A	N/A	13.6

3-26

(1) Ralph M. Parson Co.

(2) Keystone's Coal

(3) Saso

(4) EIA Annual Report to Congress, 1977 (1978 Dollars).

- . Estimates of the amounts of Wyoming and Texas coals required to produce the same primary products were based on their fixed carbon content compared to the base coal—Illinois.
- . Fixed and operating costs were adjusted for each alternative case due to variations in:
  - Coal handling requirements
  - Ash disposal requirements
  - Sulfur content
  - Transportation cost differentials.
- . By-product yields (e.g., sulfur, electricity) were revised to reflect the various coal characteristics.
- . Regional differentials for constructed costs were not employed as this is not a site-specific analysis.

The overall results, presented in the following chapters, are expressed in terms of the price of gasoline required at the plant gate of an Illinois plant.

#### 4. PROCESS ECONOMICS

The required selling price of gasoline at the plant gate is determined by using a discounted cash flow model based on the process economics of a conceptual Fischer-Tropsch plant. Such models are in widespread use for capital investment decisions and this particular model was originally developed by Oak Ridge National Laboratory.<sup>1</sup> It can be used to determine either the equity rate of return on a proposed project or the required selling price necessary to achieve a given rate of return.

The model computes annual profits based on assigned product, values, capital charges, debt service, operating expenses, feedstock costs, and taxes. It then assigns a time value to these income streams (the so-called discount method) based on input values of financial structure (debt-equity, cost of debt, required return on equity). The program can also be used to calculate the required selling price of products if a DCF percentage return is specified.

Some of the more important conventions used in the model are shown in Exhibit 4-1. The complete program is included in Appendix I.

The model requires input information from the user concerning capital investment, financial structure (e.g., debt-equity ratio and cost of capital), production rates of products, consumption rates of feedstocks, values (prices) of by-products, operating costs, interest rates, tax rates, and depreciation classes. The model allows escalation of capital expenditures, operating expenses, feedstocks, and product prices at different rates over time to reflect anticipated inflation.

<sup>1</sup> Royes Salmon, PRP - A Discounted Cash Flow Program for Calculating the Production Cost of the Product from a Process Plant, Oak Ridge National Laboratory, ORNL-5251.

EXHIBIT 4-1  
Key Assumptions Used in the Cash Flow Model

1. Annual time periods are used.
2. Investments occur at the start of the year.
3. Incomes are received at the end of the year.
4. Expenses and taxes are paid at the end of the year.
5. The project life is the sum of the specified construction period and the specified operating life.
6. The debt-equity ratio is specified and remains constant throughout the project life.
7. Interest on debt and return on equity capital are based on the debt and equity investment outstanding at the start of the year.
8. For income tax purposes, depreciation allowances begin in the year in which startup occurs. Depreciation lives are specified by the user by classes of equipment.
9. When calculating state income taxes, it is assumed that Federal income taxes are deductible as an expense.
10. Working capital is recovered intact at the end of the project life.

Since this conceptual plant produces large quantities of gasoline and utilizes considerable petroleum-refining technology, it was assumed that petroleum refiners would be the potential investors. Thus, the base case investigated consisted of financial parameters typical of the petroleum industry, e.g., 75 percent equity, 25 percent debt; debt interest rate, 9 percent; and an equity rate of return of 15 percent. Other key input values are shown in Exhibit 4-2.

The model is then used to calculate profitability (percent DCF return) if product values are specified, or product values (required price) if DCF return is specified.

#### 4.1 CAPITAL COSTS

Estimates for capital and operating costs were derived using the following procedures:

- . A plant similar in size and state-of-the-art to that conceptually designed by the Ralph M. Parsons Co. for ERDA (ERDA FE-1775-7) in 1977 was modified to produce outputs similar to the SASOL II plant nearing completion in South Africa. Costs, however, are those that the plant would incur in the U.S. using representative U.S. coals.
- . Capital and operating costs were then escalated from the 1975 dollars (year of reference) by extrapolating current costs using indices in the October 2, 1978 issue of the Oil and Gas Journal.

The resulting capital investment schedule for a plant with a nominal 50,000 bbl/day product slate is as follows:

Year	1	2	3	4	5	Total
(\$Millions):	54	176	474	1463	542	2710

This capital investment includes the process plant, utilities and offsites. It does not include investment in a coal mine. For this analysis, coal was assumed to be purchased at prices given in the Energy Information Agency (EIA) PIES model (EIA Annual Report to the Congress). In this way, the specific incentive for investing in a process plant can be investigated. If the investment in the mine were included, alternative investments (e.g., coal production for sale to utility or industrial boilers) would also have to be investigated and ranked. Since EIA's figures are

EXHIBIT 4-2  
Input Assumptions Used  
in the Financial Analysis

Plant Construction Period	5 Years
Plant Lifetime	20 Years
On-Stream Factor	90% (50% During First Year of Operation)
Federal Income Tax Rate	48%
State Income Tax Rate	4%
State Revenue Tax Rate	0
State Property Tax Rate	2.5%
Entitlements Credit	\$1.40/bbl Equivalent
Investment Tax Credit	10% (90% of PFI* Eligible for Credit)

---

\*PFI=Plant Fixed Investment.

intended to be projections of market prices (in this case for coal at the mine mouth), they are assumed to include adequate returns to coal producers.

#### 4.2 OPERATING COSTS

Operating expenses are estimated to be \$189 million per year, exclusive of coal costs. Coal would cost an additional \$218 million per year initially and would increase approximately 1 percent per year in real terms.

Operating expenses include amounts for maintenance material, operating supplies (including catalysts), and operating and maintenance labor (including benefits). These expenses are assumed to be constant throughout the operating lifetime of the plant. This is equivalent to performing a constant-dollar analysis as of the year of start-up (1985).

Exhibit 4-3 breaks down capital and operating costs into the various processes. Because capital costs represent such a large fraction of total production cost, each of the process units was identified on a separate line. Operating expenses, which account for only about 12 to 15 percent of total production cost, are not shown disaggregated.

#### 4.3 REVENUE REQUIRED (PROFITABILITY)

Revenue is computed using input values of production rates of products, plant onstream factors for each year of operation, and product values (prices). If the required price of the principal product (revenue required) is to be determined (i.e., the DCF is specified), values of coproducts must still be input. For this analysis the following coproduct values for the year 1978 were specified, which were based on recent price quotes:

Diesel fuel	\$.40/gallon
Ethylene	\$250/ton
Alcohols	\$20/ton
Tar products	\$85/ton
Ammonia	\$100/ton
Sulfur	\$60/ton
Electricity	\$.03/kWhr

These base year prices were then escalated at 2 percent per year in real terms (i.e., above general inflation) to account for the depletion of competing petroleum resources. This escalation factor is consistent with EIA's midcase projections for crude oil prices during the period

EXHIBIT 4-3  
Basis for Capital Costs  
and Operating Costs

	Capital Cost		Operating Cost	
	<u>10<sup>6</sup></u>	<u>% of Total</u>	<u>\$10<sup>6</sup>/Year</u>	<u>% of Total</u>
Coal Preparation	44	1.6	3.8	2.0
Coal Grinding and Drying	26	1.0	-	-
Gasification	94	3.5	-	-
Purification	356	13.1	-	-
Acid Gas Removal	201	7.4	-	-
Shift Conversion	38	1.4	-	-
Synthesis	410	15.1	-	-
Tail Gas Reforming	121	4.5	-	-
Product Recovery	93	3.4	-	-
Oxygen Plant	726	26.8	-	-
Sulfur Recovery	94	3.5	-	-
Water Reclamation	<u>81</u>	<u>3.0</u>	<u>-</u>	<u>-</u>
Process Plant Subtotal	2240	82.7	164.2	87.1
Power Plant	257	9.5	8.5	4.5
Offsites	<u>169</u>	<u>6.2</u>	<u>12.0</u>	<u>6.4</u>
TOTAL	2710	100.0	188.5	100.0

All dollar values use 1985 as the year of references.

of operation of this plant. Since EIA publishes predictions for 5-year intervals only, the above escalations are approximations of PIES data. The required plant gate price of gasoline quoted in the following section is thus for the base year (1985) only.

#### 4.4 ECONOMIC ANALYSIS-BASELINE RESULTS

The base case shows that the required plant gate price (1985 dollars) of gasoline varies from \$1.17/gallon for Wyoming subbituminous to \$1.32/gallon for Illinois No. 6 coal. These prices are considered to be accurate to within  $\pm 25$  percent. Transportation costs do not exceed \$.02/gallon for any of the cases, so they are not a determining factor, although they will impact the optimum location of the first plant. A breakdown of the plant gate price components is shown below for each location.

	<u>Illinois</u>	<u>Texas</u>	<u>Wyoming</u>
Capital Charge	0.74	0.75	0.76
O&M Expenses	0.18	0.18	0.18
Feedstock	0.40	0.34	0.23
Total	<u>\$1.32/gal</u>	<u>\$1.27/gal</u>	<u>\$1.17/gal</u>

The above values translate to 82, 79, and 73 cents per gallon, respectively, using current (1978) dollars. For comparison purposes, the plant gate price of regular gasoline from crude oil in 1978 averaged about 47 cents per gallon, and approximately 56 cents during the second quarter of 1979.

It is to be noted that even though the basic feedstock material is inexpensive (coal at \$25/ton equates to about \$1.00/MMBtu, whereas oil at \$20/bbl equates to about \$3.50/MMBtu), the low conversion efficiency of the process results in feedstock charges that are only slightly below recent plant gate prices for gasoline. Thus, in order to make Fischer-Tropsch gasoline economically competitive with petroleum-derived gasoline at current (1979) prices, it would be necessary to reduce the projected capital cost of such a facility while simultaneously increasing its overall conversion efficiency.

The rate of return that would result if the plant were forced to sell gasoline at the market price was also investigated. The return varied from <0 percent to 5 percent depending on the plant location. The contribution to annual

revenues for this case is shown in Exhibit 4-4. Note that gasoline contributes about 60 percent of total revenues and liquid products contribute about 85 percent.

It is noted that of the coproducts, only diesel fuel and ethylene provide significant revenues (approximately 10 percent of total) under the base case assumptions. Using current dollars, total annual revenues would be about \$500 million per year if gasoline were sold at market prices. The additional revenue necessary to provide an adequate rate of return for typical oil industry investment would be about \$300 million per year. This could be accomplished only if the price of gasoline is approximately doubled (coproduct prices remain constant) or if all product prices (gasoline plus coproducts) are increased by approximately 50 percent above current market prices.

#### 4.5 EFFECT OF UNCERTAINTIES

Because the base case provided such adverse economics, several scenarios were posed to take into account uncertainty which could affect the results. Sensitivity analyses were conducted to determine the effect of these uncertainties on the required gasoline prices. Exhibit 4-5 shows that the required price can range from as low as \$0.94/gallon to as high as \$1.55/gallon depending on the scenarios employed. It should be noted that eventual costs are more likely to be higher, rather than lower than base-case costs for the following reasons:

- . The conceptual design plant uses some equipment that has not yet been commercially proven (e.g., the entrained-flow gasifier) and is thus subject to problems of scale-up to commercial size.
- . The full impact of recent environmental legislation such as the Clean Air Act Amendments, the Toxic Substances Act, and the Resource Conservation and Recovery Act, cannot be determined because implementing regulations have not yet been developed.

Recalling that capital cost is the major contributor to product cost, individual process steps were investigated for potential impacts. Exhibit 4-3, presented previously, broke down capital cost into its components. From that exhibit, it was apparent that the largest contributors to capital cost are:

EXHIBIT 4-4  
Contribution to Annual Revenues<sup>1</sup>

	<u>Production</u> (1,000,000 Units/Year)	<u>Unit Price</u> \$/Unit	<u>Revenue</u> (\$ Millions)	<u>Percent of</u> <u>Total</u>
Liquid Products				
Regular Gasoline	706 Gallon	0.45	317.7	61.3
Diesel Fuel	118 Gallon	0.40	47.2	9.1
Ethylene	0.285 St	250	71.3	13.7
Alcohols	0.131 St	20	<u>2.6</u>	<u>0.5</u>
SUBTOTAL	-	-	438.8	84.8
By-products				
Tar Products	0.278 St	85	23.6	4.6
Ammonia	0.064 St	100	6.4	1.2
Sulfur	0.335 St	60	20.1	3.9
Electricity for Sale	979 kWhr	0.03	<u>29.4</u>	<u>5.7</u>
SUBTOTAL	-	-	79.5	15.4
TOTAL	-	-	518.3	100.0

<sup>1</sup> Prices are for products at the plant gate using 1978 dollars.

EXHIBIT 4-5  
Effect of Uncertainties  
on the Required Selling Price  
of Gasoline From Coal

	Required Selling Price at Plant Gate 1985 \$/Gallon		
	Appalachia	Gulf	Rockies
Base Case	1.32	1.27	1.17
Coal Prices			
Increasing at 2%/Year <sup>1</sup>	1.38	1.33	1.21
Constant	1.26	1.23	1.13
Oil Prices			
Increasing at 1%/Year <sup>1</sup>	1.54	1.48	1.36
Increasing at 3%/Year <sup>1</sup>	1.13	1.09	1.00
Capital Costs			
25% Above Base Case	1.55	1.50	1.39
25% Below Base Case	1.10	1.05	.94
Anticipated Market Price for Crude-Derived Gasoline at the Plant Gate <sup>2</sup>	0.93	0.93	0.93

<sup>1</sup>Real price increases (above inflation).

<sup>2</sup>Using EIA midcase projections plus 7% inflation. This corresponds to approximately \$1.20/gallon at the pump. The resulting plant gate price under EIA high case projections is \$1.08/gallon, or \$1.35/gallon at the pump.

- . The oxygen plant
- . The Fischer-Tropsch synthesis unit
- . The gas purification and heat recovery unit
- . The steam generation and power plant.

The oxygen and power plants utilize mature technologies. Thus, capital cost estimates for these should be relatively firm. However, the synthesis unit and the purification unit were evaluated further, because these technologies are much less developed. The analysis showed that in order to reduce gasoline prices by \$.10/gallon from baseline, the capital cost for either of these units must be reduced by a factor of three (i.e., by 67 percent). Conversely, either of these units could incur a 67 percent overrun and the required price of gasoline would increase by only \$.10/gallon.

Since the gasifier is posed to cost only one-quarter of either of the above units, its eventual cost should have little bearing on final production cost. For example, if the gasifier capital cost were to increase to double that of the base case, the required selling price of gasoline would rise by only about \$.04/gallon. The gasifier can affect production economics in another way, however. If ultimate efficiencies decline from those currently projected by 5 percentage points, the required selling price would rise approximately \$.10/gallon. This sensitivity is chosen merely to bound the realm of uncertainty. At present, there are no indications that current projections of gasifier efficiencies are too high.

Exhibit 4-6 displays parametrically the effect on required gasoline price for two uncertainties: the resulting capital cost and the variation in capital structure. These uncertainties are included for the following reasons. The completed plant capital cost may vary from the base case as a result of the items discussed above. The capital structure (debt/equity ratio) may vary among companies within the refining industry.

Exhibit 4-7 shows the effect of plant size on process economics. These values were derived using scale factors of .8 for capital cost and .9 for operating cost. These factors are somewhat higher than those used in petroleum refinery costimating. This is because current conceptions of large synthetic fuel plants call for adding additional process streams, rather than increasing the size and throughput of vessels and other equipment.

EXHIBIT 4-6  
 Production Cost as a Function of Capital Cost  
 and Capital Structure (for an Illinois Location)

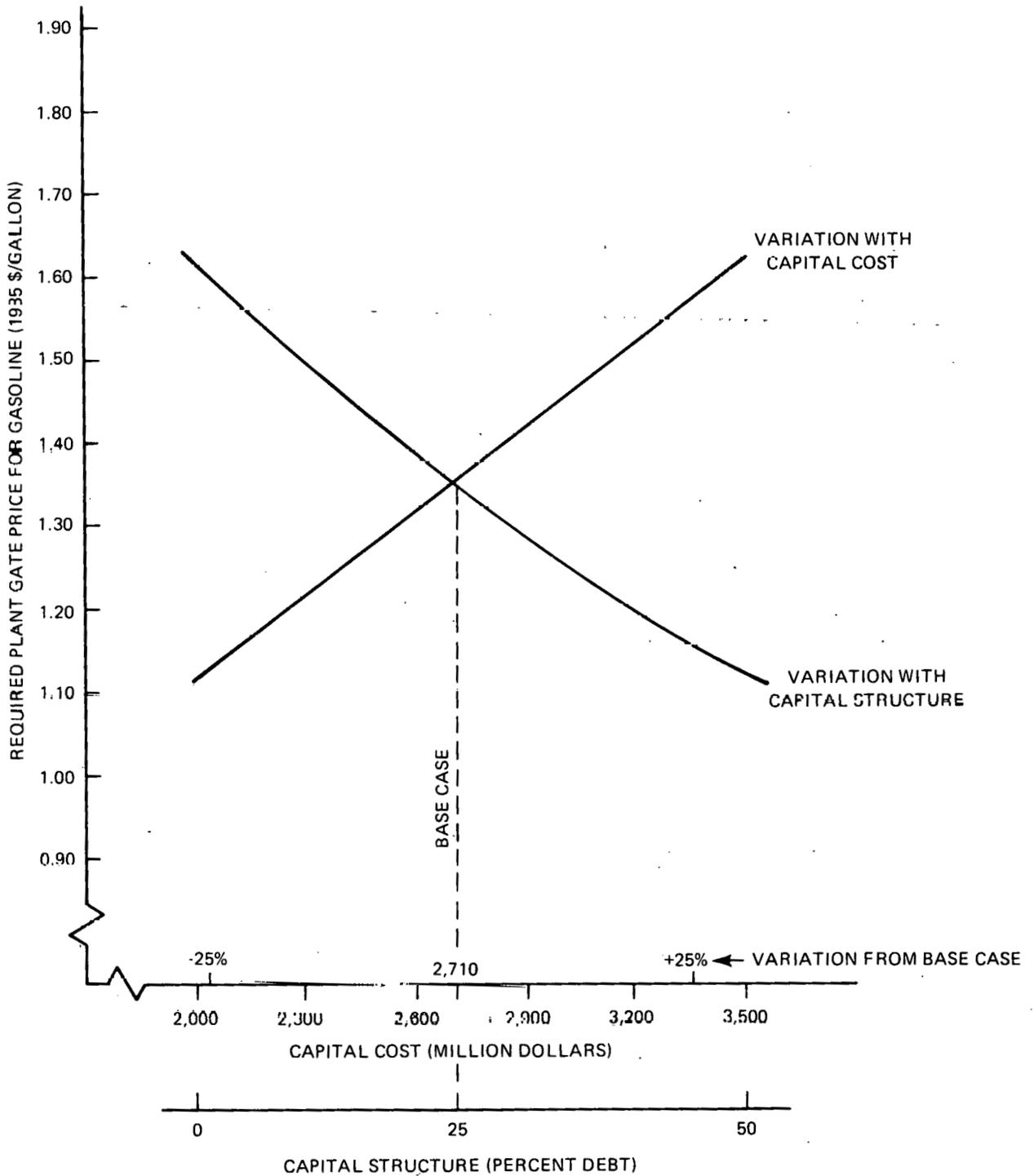
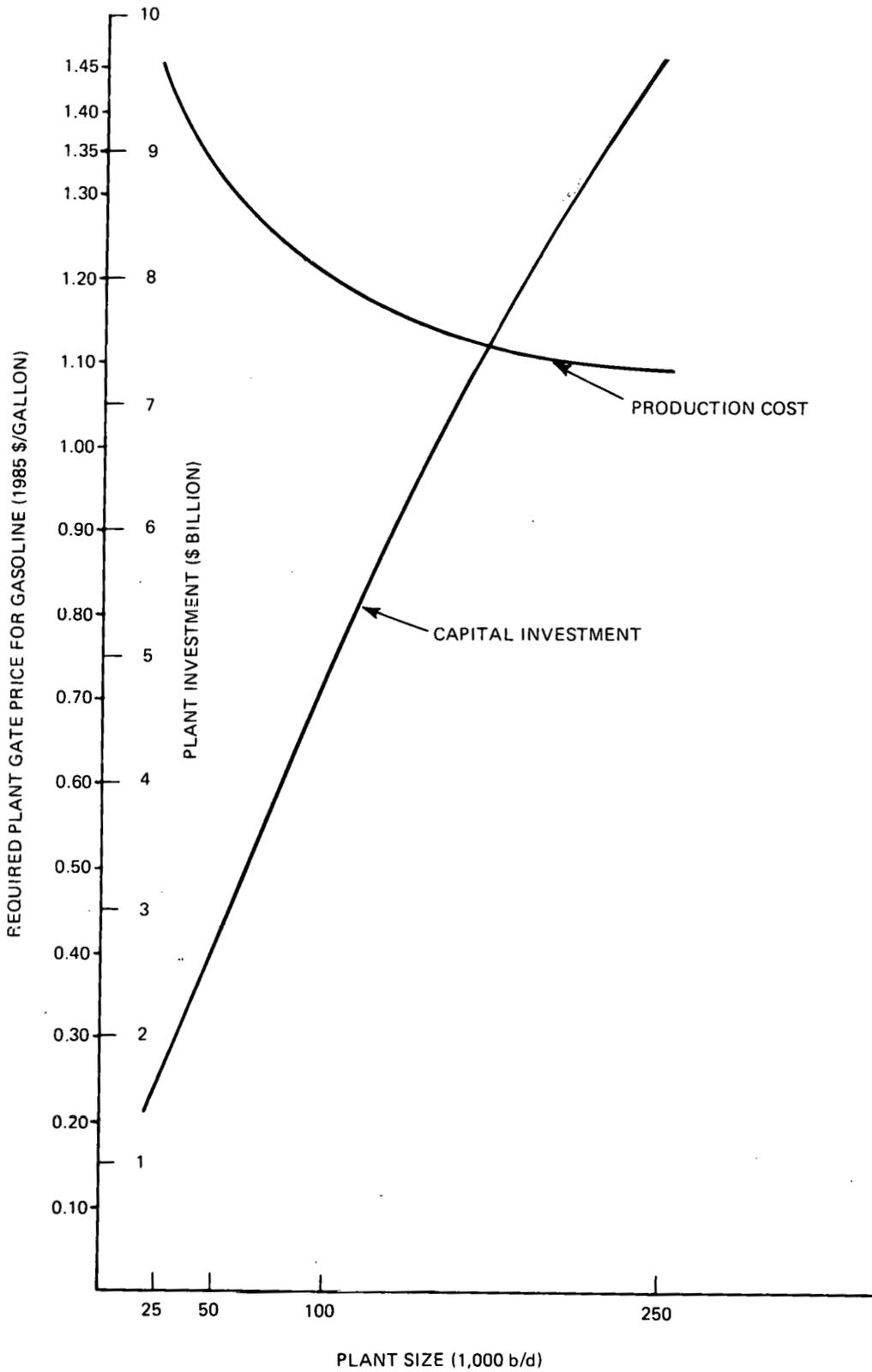


EXHIBIT 4-7  
Effect of Size of Fischer-Tropsch Plant  
on Process Economics (Illinois Location)



The significant aspect of these analyses is that none of the scenarios results in a required price that is as low as predicted for crude-derived gasoline by DOE's Energy Information Agency.

#### 4.6 EFFECT OF POSSIBLE INCENTIVES

Because this first-cut analysis appears to show that Fischer-Tropsch gasoline will not be economic under its own merits, the potential effect of various financial incentives on the required gasoline price was then investigated. The incentives considered included:

- . Allowing an investment tax credit of 20 percent of capital investment instead of the current 10 percent
- . Waiving the \$.04/gallon federal excise tax on gasoline or gasoline blends produced from coal
- . Providing entitlements for coal-derived gasoline.

Note in Exhibit 4-8 that by increasing the investment tax credit to 20 percent of direct fixed investment, the required selling price of Fischer-Tropsch gasoline can be reduced about \$.06/gallon. This would result in a one-time federal tax savings of approximately \$270 million for this 50,000 bbl/day plant.

By allowing the plant capital investment to be amortized over very short periods (e.g., 5 years), the required selling price could be reduced by up to \$.10/gallon. Note this financial incentive would not result in any savings, but would merely defer taxes to a later period.

Another option is to waive the current \$.04/gallon federal excise tax on motor vehicle fuels. If the refiner or marketer recoups this saving, the reduction in required plant gate price would be the \$.04/gallon. A variation of this option is to forgive the tax on blends of coal-derived gasoline, similar to current proposals for gasohol--crop-derived alcohol blended in gasoline. If the \$.04/gallon tax is forgiven on blends of Fischer-Tropsch gasoline, the effect would certainly be to reduce the required plant gate price of Fischer-Tropsch gasoline further. However, the selection of the optional blend ratio for incentives, performance, and ability of the federal government to monitor

EXHIBIT 4-8  
Effect of Financial Incentives  
on the Required Selling Price  
of Fischer-Tropsch Gasoline

	Required Selling Price at Plant Gate 1985. \$/Gallon					
	Appalachia Δ		Gulf Δ		Rockies Δ	
Base Case, without incentives	1.32	-	1.27	-	1.17	-
Investment Tax Credit of 20%	1.25	.07	1.21	.06	1.10	.07
Accelerated Depreciation						
15 Years	1.31	.01	1.26	.01	1.16	.01
10 Years	1.27	.05	1.22	.05	1.12	.05
5 Years	1.22	.10	1.17	.10	1.07	.10
Waiving Federal Excise Tax						
4¢/Gallon	1.28	.04	1.23	.04	1.13	.04
Additional \$5/bbl Entitlements	1.26	.06	1.21	.06	1.11	.06
Anticipated Market Price for Crude - Derived Gasoline at the Plant Gate <sup>1</sup>	0.93	-	0.93	-	0.93	-

<sup>1</sup> Using EIA mid-case projections plus 7% inflation.

compliance is beyond the scope of this study.

Finally, additional entitlements for Fischer-Tropsch gasoline were considered. Entitlements already exist for some synthetic fuels and for small refiners. An additional \$5.00/bbl entitlement would act to reduce the required selling price of Fischer-Tropsch gasoline by about \$.06/gallon. This would not result in any tax savings; the savings would be compensated for by increased cost to a competing petroleum refiner. Under current regulations, domestic refiners would bear the brunt of this incentive because the controlled price of domestic crudes are considerably less than world prices.

Note in Exhibit 4-5 that none of these options acting alone would act to bring the price of Fischer-Tropsch gasoline down to market prices--even at a cost to the public of \$200-\$300 million per year--for this 50,000 bbl/day plant.

For comparison, the following section compares Fischer-Tropsch process economics with selected alternatives. In this way, an understanding may be gained of the commercialization potential of Fischer-Tropsch technology with combinations of incentives and/or mandatory regulations.

#### 4.7 COMPARISON WITH METHANOL

The cost of producing gasoline from coal via the Fischer-Tropsch process was compared with alternative coal to motor fuel processes: the coal-to-methanol and Mobil M gasoline routes. The source of these comparisons is DOE's Methanol Program Overview. The following comparisons are based on the summary figures in the Methanol Program Overview Report, revised as much as possible to provide for treatment consistent with that used in this analysis. Since the raw data was not available, however, some parameters and assumptions may lead to distortions in the comparative results. Booz, Allen has identified the potential effect of the following assumptions which may have been used in the referenced report.

	Probable Value/Assumption	Impact <sup>1</sup>
Debt/Equity	35/65	-10¢/gal
Depreciation	20-yr Straight line	—
By-product Values	Market prices	—

<sup>1</sup>If revised to BAH treatment.

EXHIBIT 4-9  
Comparison of Fischer-Tropsch Gasoline With Alternative  
Methods for Motor Fuel Production From Coal

		CRUDE OIL AT \$20/BBL	F-T GASOLINE	F-T GASOLINE 10% BLEND WITH CRUDE GASOLINE	METHANOL 10% BLEND WITH CRUDE GASOLINE
PLANT GATE PRICE	(¢/gallon)	72	82	73	70.2
TRANSPORTATION	(¢/gallon)	2	2	2	3.1
LOCAL TERMINALLING	(¢/gallon)	3	3	3	3
STATION MODIFICATIONS	(¢/gallon)	-	-	-	1.2
PRICE AT THE STATION	(¢/gallon)	77	87	78	77.5
DEALER MARKUP	(¢/gallon)	8	8	8	8
FEDERAL TAX	(¢/gallon)	4	4	4	4
STATE TAX	(¢/gallon)	10	10	10	10
DELIVERED TO CAR	(¢/gallon)	99	1.09	1.00	99.5
CAR MODIFICATIONS	(¢/gallon)	-	-	-	2
COST TO MOTORIST	(¢/gallon)	99	1.09	1.00	101.5

Note: All entries are in ¢/gallon using 1978 dollars, except for column two which is used as a point of comparison; column 1 approximates the average refiner crude oil acquisition cost; column 2 approximates the current cost of foreign crude. Coal at \$1/MMBtu, equity rate of return = 15%; debt equity = .25/.75.

1 Blended with gasoline derived from crude oil at \$14/bbl.

Source: Derived from Production, Application Systems and Economics of Methanol and Gasoline from Methanol, prepared for DOE by TRW Energy Planning Division, June 1978.

These were selected as relevant comparisons because of their utility as transportation fuels. A 10% blend of methanol in gasoline can be used without major changes to current automobiles. These comparisons are shown in Exhibit 4-9. Note that 10% blends of methanol and Fischer-Tropsch gasoline in gasoline produced from crude oil at an average \$20/bbl have comparable costs. The above comparisons, however, are somewhat distorted by the fact that the cost of methanol was taken from published sources and therefore was not estimated on the same basis as the cost of Fischer-Tropsch gasoline. In addition methanol has about half the Btu content of normal gasoline and therefore the blend results in a slight Btu loss. However, this effect is essentially counterbalanced by the octane boosting property of methanol and the volume change of the mixture.

Fischer-Tropsch gasoline was also compared with the cost of gasoline from the Mobil M gasoline-from-methanol process. An attempt was made to place each plant on an equivalent basis. The main point to be aware of is that the costs of both M gasoline and Fischer-Tropsch gasoline are above current petroleum-based costs and, as such, face considerable commercial uncertainty. This analysis shows that the difference between Fischer-Tropsch and M gasoline is within the limits of uncertainty of this analysis. It should be noted that Mobil is actively developing its proprietary process and, in fact, is investigating direct conversion to reduce production costs. No such sponsor has yet developed for Fischer-Tropsch in the U.S.

\* \* \* \*

In summary, the capital intensiveness and low conversion efficiency of the Fischer-Tropsch indirect liquefaction process makes it noncompetitive with conventional petroleum refining in the midterm (e.g., 5 to 10 years) under normal industry economic conditions. However, if crude oil prices rise to higher levels, coal liquefaction processes may prove to be economical. It appears that other processes under development may become economically attractive before Fischer-Tropsch, although Fischer-Tropsch is the only proven commercially feasible venture at present. The above statement is subject, however, to the successful demonstration and commercialization of these alternative processes. Fischer-Tropsch technology is already in use in commercial-size plants in South Africa; and thus, the Fischer-Tropsch process may be called upon as a backup should petroleum boycotts ensue, world oil prices continue to increase dramatically, and alternative coal liquefaction processes fail for technical, economic, or environmental reasons.

APPENDIX  
CASH FLOW MODEL

REQUESTED OPTIONS: NODECK,NOLIST,NAME(MAIN),OPT(0)

OPTIONS IN EFFECT: NAME(MAIN) NOOPTIMIZE LINECOUNT(57) SIZE(MAX) AUTODBL(NONE)  
SOURCE FRCDIC NOLIST NODECK OBJECT MAP NOFORMAT GOSTMT NOXREF NOALC NOANSF TERM FLAG(I)

A-1

```

C
C
C**** PROGRAM PRPESC. A DISCOUNTED CASH FLOW CODE FOR DETERMINING
C THE PRODUCT PRICE NECESSARY TO GIVE A SPECIFIED RATE OF RETURN
C ON INVESTMENT.
C THIS VERSION IS DATED 10 DECEMBER 1978.
C THE PROGRAM ITERATES ON THE PRICE OF THE MAIN PRODUCT USING THE
C INPUT PRICE AS A FIRST APPROXIMATION.
C AS AN OPTION, THE PROGRAM WILL ITERATE ON THE ANNUAL AFTER-TAX RATE
C OF RETURN ON EQUITY AT A FIXED VALUE OF THE PRODUCT PRICE.
C THIS WILL DETERMINE THE ACTUAL RATE OF RETURN FOR A GIVEN VALUE
C OF THE PRODUCT PRICE.
C THE PRICE OF THE MAIN FEEDSTOCK TO THE PLANT MAY ALSO BE VARIED,
C BY ADDING AN AMOUNT DELFPR EACH TIME.
C PROVISION IS MADE FOR WORKING CAPITAL AND ANY DESIRED CAPITAL
C STRUCTURE UP TO 100% EQUITY.
C INTEREST RATE ON DEBT AND AFTER-TAX RATE OF RETURN ON EQUITY ARE
C INPUTTED. TAXES ARE CALCULATED BY THE PROGRAM.
C INVESTMENTS ARE ASSUMED TO BE MADE AT THE START OF THE YEAR.
C INCOMES, EXPENSES, TAXES, AND RETURNS OCCUR AT THE END OF YEARS.
C
C**** WORKING CAPITAL IS ASSUMED RECOVERED FULLY AT END OF PROJECT LIFE.
C SALVAGE VALUE IS ASSUMED TO BE RECOVERED AT END OF PROJECT LIFE.
C THIS PROGRAM ALLOWS EXPENSES AND PRICES TO BE ESCALATED.
C****
ISN 0002 DIMENSION PRNAM(15),INVEST(400),EFFNCY(400),EXPENS(400),
1 FLTEXP(400),DEPREC(400),EXTEXP(400)
ISN 0003 DIMENSION PROPTY(400),INSPNC(400),WORKCP(400)
ISN 0004 DIMENSION PRDRAT(24),PRICE(24)
ISN 0005 DIMENSION FEEDRT(24),FEEDPR(24),FRCINV(24)
ISN 0006 DIMENSION DPFAC(24),LIFE(24)
ISN 0007 DIMENSION LL(10)
ISN 0008 DIMENSION DPRNAM(3)
ISN 0009 DIMENSION RTNEQ(20)
ISN 0010 REAL*4 INVEST,INSURE,INTDRT,INCOME,INSRNC,INTRST,INTCON,INTTOT
ISN 0011 REAL*4 INTDC,INTTUC
ISN 0012 REAL*8 BALNCE,DPFAC,PTRY
C****
C**** THE FOLLOWING ITEMS ARE ZEROED BEFORE EACH ITERATION.
ISN 0013 COMMON/ZEROS/ CAPEND(400),INCOME(400),EQYRTN(400),
1 STLTX(400),TXCRDT(400),FEDTAX(400),CASHFL(400),
2 TOTRTN(400),AMORTZ(400),STXABL(400),TAXABL(400),
3 CPSTRT(400),INTRST(400),TXLOSS(400),FEDTXN(400)
C****
ISN 0014 DATA DPRNAM /'SYD ','STL ','DDB '/
C****
C****
C**** DEFINITIONS *****
C
C VARIABLES MARKED * ARE INPUTTED.

```

C		00000520
C****	NOTE: ALL DOLLAR QUANTITIES ARE INPUTTED AS MILLIONS OF DOLLARS.	00000530
C****	NOTE: INTEREST RATES, ONSTREAM FACTORS,ETC. ARE INPUT AS DECIMAL	00000540
C	FRACTIONS RATHER THAN AS PERCENTAGES.	00000550
C		00000560
C		00000570
C****	NONSUBSCRIPTED VARIABLES	00000580
C****		00000590
C	BALNCE = TRIAL VALUE OF AMOUNT LEFT AT END OF PROJECT LIFE.	00000600
C	CMPDFC = COMPOUNDED INVESTMT FACTOR FOR CONSTR PERIOD USED IF	00000610
C	LL(7)=2 AND INTEREST DURING CONSTR IS COMPUTED.	00000620
C	CNSTLN * = AMOUNT OF CONSTRUCTION LOAN, \$MM.	00000630
C	CRFDIT = TOTAL INVESTMENT TAX CREDIT, \$MM.	00000640
C	DBTFPC * = FRACTION OF TOTAL INVESTMT IN DEBT EXAMPLE 0.25	00000650
C	DELFPF * = DELTA FEED PRICE FOR ITERATION OF FEED PRICE.	00000660
C	DISFAC = DISCOUNT FACTOR BASED ON WEIGHTED AVERAGE INTEREST RATE.	00000670
C	DPFAC = FACTOR USED FOR ESTIMATING NEW TRIAL VALUE OF PRICE.	00000680
C	DPLIFE = DEPRECIABLE LIFE FOR TAX PURPOSES, YEARS EXMPL 15.0	00000690
C	DPSTRT = YEAR IN WHICH DEPRECIATION ALLOWANCE STARTS EXMPL 5.	00000700
C	EGFRAC * = FRACTION OF TOTAL INVESTMT IN EQUITY EXAMPLE 0.75	00000710
C	NOTE THAT SUM OF DBTFPC AND EGFRAC MUST BE 1.0	00000720
C	EQTRY = TRIAL VALUE OF RATE OF RETURN ON EQUITY.	00000730
C	ESCCAP * = ESCALATION, CAPITAL INVESTMENTS, FRACTION/YEAR	00000740
C	ESCCWP * = ESCALATION, WORKING CAPITAL, FRACTION/YEAR	00000750
C	ESCEXT * = ESCALATION, EXTR EXPENSES, FRACTION/YEAR	00000760
C	ESCEXP * = ESCALATION, OPERATING EXPENSES, FRACTION/YEAR	00000770
C	ESCEINI * = ESCALATION, PRE-OP EXPENSES, FRACTION/YEAR	00000780
C	ESCCON * = ESCALATION, CONSTANT EXPENSES, FRACTION/YEAR	00000790
C	ESCFDP * = ESCALATION, FEEDSTOCK PRICES, FRACTION/YEAR	00000800
C	ESCPRP * = ESCALATION, PRODUCT PRICES, FRACTION/YEAR	00000810
C	EXINIT * = ANNUAL OPERTG EXPNS DURING PRE-OPER PERIOD EXMPL 0.00	00000820
C	EXPCON * = ANNUAL CONSTANT OPERTG EXPENS DURING OPER PERIOD \$MM	00000830
C	FITXFR * = FEDERAL INCOME TAX RATE EXAMPLE 0.48	00000840
C	INSURF * = PROPERTY INSURANCE RATE ON PLANT INVEST EXAMPLE 0.004	00000850
C	INTCON * = INTEREST RATE DURING CONSTRUCTION (OPTIONAL)	00000860
C	INTDRT * = ANNUAL INTEREST RATE ON DEBT EXAMPLE 0.085	00000870
C	INTDC = TOTAL INTEREST DURING CONSTRUCTION, USED IF LL(7).GT.0	00000880
C	INTTOT * = TOTAL INTEREST RATE FOR CONSTRUCTION (OPTIONAL)	00000890
C	NCARRY * = LIMITING NUMBER OF YEARS FOR TAX-LOSS CARRYOVER EX. 5	00000900
C	NCLS * = NUMBER OF DEPRECIATION CLASSES.	00000910
C	NCNSTR * = NUMBER OF YEARS OF CONSTRUCTION PERIOD, NEEDED ONLY	00000920
C	WHEN SPECIFYING A SCHEDULE OF EXPENDITURES USED FOR	00000930
C	CALCULATING INTEREST DURING CONSTRUCTION.	00000940
C	NCREDIT * = LIMIT FOR INVEST. TAX CREDIT CARRY-FORWARD EXMPL. 7.	00000950
C	NEQMAX * = NUMBER OF RATES OF RETURN ON EQUITY	00000960
C	NFDPRS * = NUMBER OF PRICES TO BE USED FOR FEEDSTOCK 1.	00000970
C	NFFEDS * = NUMBER OF FEEDSTOCKS FOR WHICH PRICE AND RATE ARE GIVEN.	00000980
C	NPRODS * = NUMBER OF PRODUCTS LISTED.	00000990
C	NSTRT * = YEAR IN WHICH STARTUP OCCURS.	0001000
C	NTRY = ITERATION NUMBER FOR DETERMINING PRICE	0001010
C	NTRIES * = MAXIMUM NUMBER OF ITERATIONS ALLOWED.	0001020
C	NYRS * = NUMBER OF YEARS OF ANNUAL DATA TO BE READ EXMPL 24	0001030
C	(SAME AS NUMBER OF YRS IN PAYOUT TABULATION, =PROJLF)	0001040
C	PH * = HIGHEST PERMISSIBLE PRICE FOR PRODUCT PRICE ITERATION.	0001050
C	PL * = LOWEST PERMISSIBLE PRICE FOR PRODUCT PRICE ITERATION.	0001060

```

C PRNAM * = IDENTIFICATION OF PROBLEM                00001070
C PROJLF * = TOTAL PROJECT LIFE INCL CONSTR PERIOD   EXAMPLE 24.0    00001080
C PROPTX * = LOCAL PROPERTY TAX RATE ON PLANT INVEST EXAMPLE 0.02  00001090
C PRPEXP * = EXPENSES PROP TO ONSTREAM TIME, MM $/YR  00001100
C PTRY   = TRIAL VALUE OF PRICE(1) IN ITERATION NTRY.  00001110
C RTNEQY = ANNUAL AFTER-TAX RATE OF RETURN ON EQUITY EXMPL 0.16    00001120
C SALVGE * = SALVAGE VALUE RECOVERED AT END OF PROJECT, $MM.      00001130
C STAINC * = STATE INCOME TAX RATE                       EXAMPLE 0.04    00001140
C STAREV * = STATE GROSS REVENUE TAX RATE                 EXAMPLE 0.02    00001150
C TOLER * = TOLERANCE FOR CONVERGENCE OF CASH FLOW TABLE, $MM    00001160
C TOLPRC * = TOLERANCE FOR PRODUCT PRICE CONVERGENCE, $/UNIT      00001170
C TOTDEP = TOTAL DEPRECIABLE CAPITAL INVESTMENT, $MM.             00001180
C TOTDNV * = TOTAL DEPR INVESTMT AS INPUTED. I.E. SUM OF INVEST(N). 00001190
C TOTDP2 = TOTAL DEPRECIABLE CAPITAL LESS SALVAGE VALUE, $MM.     00001200
C TOTDP3 = DEPRECIABLE CAPITAL IN A PARTICULAR CLASS (TEMPORARY). 00001210
C TXCRED * = FEDERAL INVESTMENT TAX CREDIT                EXAMPLE 0.10  00001220
C WRKCAP * = WORKING CAPITAL, TOTAL. $MM                  00001230
C YDPRC  = AMOUNT OF ANNUAL DEPRECIATION IN A PARTICULAR CLASS.  00001240
C                                               00001250
C**** SUBSCRIPTED VARIABLES
C                                               00001260
C                                               00001270
C AMORTZ(N) = AMOUNT OF CAPITAL RETIRED IN YEAR (N), $MM.          00001280
C CAPEND(N) = TOTAL OUTSTANDING INVESTMENT AT END OF YEAR (N).    00001290
C CASHFL(N) = CASH FLOW AFTER TAXES IN YEAR (N) $MM.              00001300
C CPSTRT(N) = OUTSTANDING CAPITAL INVESTMENT AT START OF YEAR (N) $MM 00001310
C DEPPEC(N) = DEPRECIATION TAKEN FOR TAX PURPOSES IN YEAR (N) $MM. 00001320
C DPERAC(NCL)* = FRACTION OF TOTAL DEPRECIABLE IN CLASS NCL.      00001330
C EFFNCY(N) * = ONSTREAM EFFICIENCY (PLANT FACTOR) FOR YEAR N EXMPL .900001340
C EQYRTN(N) = AMOUNT ALLOCATED TO RETURN ON EQUITY IN YEAR (N), $MM.00001350
C EXPENS(N) = OPERATING EXPENSE YR N, NOT PROPOR TO ONSTREAM TIME  00001360
C EXTEXP(N) * = ADDITIONAL OPERATING EXPENSE FOR YEAR (N)          00001370
C FEEDPR(K) * = PRICE OF FEEDSTOCK (K), $/UNIT                  00001380
C FEEDPT(K) * = CONSUMPTION RATE OF FEEDSTOCK (K), AT 100% ONSTREAM 00001390
C EFFICIENCY: MM UNITS/YEAR.                                     00001400
C FEDTAX(N) = FEDERAL INCOME TAX PAID IN YEAR (N) $MM.           00001410
C FEDTXN(N) = FED INCOME TAX CALCULATED, MAY BE NEGATIVE $MM.     00001420
C FRCINV(N) * = FRACTIONAL DISTRIBUTION OF DEPR INVEST IN CONSTR PERIOD00001430
C INCOME(N) = GROSS INCOME FROM SALES IN YEAR (N).                00001440
C INTRST(N) = INTEREST ON DEBT PAID IN YEAR (N). $ MM.           00001450
C INVEST(N) * = DEPRCPPL CAPITAL INVESTMT MADE AT START OF YR N $MM 00001460
C LIFE(NCL) * = DEPRECIATION LIFE FOR CLASS NCL.                 00001470
C PLTEXP(N) = TOTAL ANNUAL EXPENSE IN YEAR (N) EXCL TAXES AND INTERES00001480
C PRICE(K) * = SELLING PRICE FOR PRODUCT (K), $/UNIT             00001490
C PRDRAT(K) * = RASE PROD. RATE FOR PRODUCT (K). MM UNITS/YEAR   00001500
C PROPTY(N) = LOCAL PROPERTY TAXES PAID IN YEAR (N) $MM.         00001510
C PTNEQ(NEQT)* = ANNUAL AFTER-TAX RATE OF RETURN ON EQUITY        00001520
C STLTAX(N) = TOTAL STATE AND LOCAL TAXES IN YEAR (N) $MM.      00001530
C STXABL(N) = STATE TAXABLE INCOME IN YEAR (N) $MM               00001540
C TAXABL(N) = FEDERAL TAXABLE INCOME IN YEAR (N). $MM.           00001550
C TOTRTN(N) = TOTAL RETURN TO DEBT+EQUITY IN YEAR (N). $MM.     00001555
C TXCRDT(N) = INVESTMENT TAX CREDIT TAKEN IN YEAR (N). $MM.     00001560
C TXLOSS(N) = TAX LOSS IN YEAR (N). $MM.                         00001570
C WORKCP(N) * = WORKING CAPITAL INVESTMENT AT START OF YEAR N $MM 00001580
C****
C                                               00001590
C                                               00001600

```

A-4

```

C PLANT STARTUP IS ASSUMED TO OCCUR AT THE START OF YEAR DPSTRT,      00001610
C AND THIS IS THE SAME TIME AT WHICH DEPRECIATION ALLOWANCE BEGINS.    00001620
C                                                                           00001630
C****                                                                    00001640
C                                                                           00001650
C OPTIONS CONTROLLED BY LL SIGNALS INPUTTED ON CARD 1.                 00001660
C                                                                           00001670
C LL(1) = 0 SUM OF YEARS DIGITS DEPRECIATION FOR TAX PURPOSES          00001680
C LL(1) = 1 STRAIGHT LINE DEPRECIATION FOR TAX PURPOSES                00001690
C LL(1) = 2 DOUBLE DECLINING BALANCE DEPRECIATION FOR TAX PURPOSES    00001700
C LL(2) = 0 OBJECT IS TO DETERMINE PRICE OF MAIN PRODUCT (PRICE(1)).  00001710
C LL(2) = 1 OBJECT IS TO DETERMINE RATE OF RETURN ON EQUITY.         00001720
C LL(3) = 0 PRINT ALL ITERATIONS                                       00001730
C LL(3) = 1 PRINT FINAL ITERATION ONLY                                00001740
C LL(4) = 0 DO NOT ITERATE FEED PRICE.                                 00001750
C LL(4) = 1 ITERATE FEEDSTOCK(1) PRICE USING DELFPR.                 00001760
C LL(5) = 0 NO TAX LOSS CARRYOVER ALLOWED                             00001770
C LL(5) = 1 FIVE YEAR TAX CARRYOVER ALLOWED                           00001780
C LL(6) = 0 FEDERAL TAX CANNOT GO NEGATIVE                            00001790
C LL(6) = 1 FEDERAL TAX CAN GO NEGATIVE                               00001800
C LL(7) = 0 INTEREST DURING CONST NOT ADDED TO DEPR CAPITAL          00001810
C LL(7) = 1 INTEREST DURING CONST AT RATE INTTOT ADDED TO DEPR CAPITAL 00001820
C LL(7) = 2 INTEREST DURING CONST COMPUTED FROM FRCINV AT RATE INTCON 00001830
C LL(8) = 0 PRINT SUPPLEMENTARY TABLE OF CASH FLOW INFORMATION       00001840
C LL(8) = 1 OMIT SUPPLEMENTARY TABLE OF CASH FLOW INFORMATION      00001850
C LL(9) = 0 NO ESCALATION                                             00001860
C LL(9) = 1 ESCALATION FACTORS APPLIED PER CARD 19 INPUTS.          00001870
C                                                                           00001880
C                                                                           00001890
C**** NOTE: ALL DOLLAR QUANTITIES ARE HANDLED AS MILLIONS OF DOLLARS. 00001900
C**** NOTE: INTEREST RATES, ONSTREAM FACTORS, ETC ARE HANDLED AS DECIMAL 00001910
C FRACTIONS RATHER THAN AS PERCENTAGES.                               00001920
C****                                                                    00001930
C                                                                           00001940
C REENTRY POINTS IN PROGRAM ARE AS FOLLOWS.                          00001950
C FOR READING NEW SET OF INPUT DATA CARDS                           STATEMENT 1 00001960
C FOR RERUNNING WITH NEW RATE OF RETURN ON EQUITY                   STATEMENT 45 00001970
C FOR RERUNNING WITH NEW FEEDSTOCK 1 PRICE                          STATEMENT 48 00001980
C FOR CONVERGING THE CASH FLOW PAYOUT TABULATION                     STATEMENT 55 00001990
C                                                                           00002000
C                                                                           00002010
C                                                                           00002020
C**** START OF INPUT DATA *****                                     00002030
C                                                                           00002040
C**** CARD 1. CONTROL SIGNALS FOR OPTIONS. PROBLEM TITLE.           00002050
ISN 0015 1 READ 401,(LL(K)*K=1,10),(P=BNAM(L),L=1,15)                00002060
C                                                                           00002070
C**** CARD 2. TAX RATES AND CAPITAL STRUCTURE.                       00002080
ISN 0016 2 READ 403,TXCRED,FITTXR,STATINC,STAREV,PROPTX,INSURE,DBTFRC,EOFRAC 00002090
C                                                                           00002100
C**** CARD 3. INTEREST RATES AND OTHER ECONOMIC PARAMETERS. SALVAGE VLU. 00002110
C INTCON AND INTTOT ARE OPTIONAL.                                    00002120
ISN 0017 3 READ 403,INTOBT,#PPEXP,TOLFR,SALVGE,INTCON,INTTOT,CNSTLN 00002130
C                                                                           00002140
C**** CARD 4. PROJECT LIFE, NUMBER OF ITERATIONS ALLOWED, AND NUMBER OF 00002150

```

	C	FEED PRICES TO BE TRIED. ALSO NEQMAX.	00002160
	C****	NEQMAX IS THE NUMBER OF RATES OF RETURN ON EQUITY TO BE USED.	00002170
	C	NSTRT IS THE YEAR IN WHICH PLANT STARTUP TAKES PLACE, ALSO	00002180
	C	THE YEAR IN WHICH DEPRECIATION ALLOWANCES BEGIN.	00002190
	C		00002200
ISN 0018	4	READ 400,NYRS,NSTRT,NTRIES,NFDPRS,NEQMAX,NCARRY,NCREDIT,NCNSTR	00002210
	C		00002220
ISN 0019		IF(NTRIES.LT.1)NTRIES=1	00002230
ISN 0021		IF(NCNSTR.LT.1)NCNSTR=1	00002240
	C		00002250
	C****	CARD 5. DEPRECIABLE CAPITAL INVESTMENT MADE EACH YEAR. \$MM.	00002260
ISN 0023	5	READ 403,(INVEST(N),N=1,NYRS)	00002270
	C		00002280
	C****	CARD 6. WORKING CAPITAL INVESTMENT MADE EACH YEAR, \$MM.	00002290
ISN 0024	6	READ 403,(WORKCP(N),N=1,NYRS)	00002300
	C		00002310
	C****	CARD 7. OPERATING EXPENSES EACH YEAR EXCLUSIVE OF TAXES.	00002320
ISN 0025	7	READ 403,(EXTEXP(N),N=1,NYRS)	00002330
	C		00002340
	C****	CARD 8. CONSTANT EXPENSES DURING PRE- AND POST-STARTUP PERIODS.	00002350
	C	ALSO LOW & HIGH LIMITS OF PRODUCT PRICE FOR USE IN ITERATION	00002360
	C	ALSO DELFPR, THE DELTA FEED PRICE FOR FEEDSTOCK 1.	00002370
	C	ALSO TOLPRC, THE TOLERANCE ON PRODUCT PRICE CONVERGENCE.	00002380
ISN 0026	8	READ 403,EXINIT,EXPCON,PL,PH,DELFPR,TOLPRC	00002390
	C		00002400
	C****	CARD 9. NUMBER OF PRODUCTS FOR WHICH RATES AND PRICES ARE READ.	00002410
	C	ALSO, NUMBER OF FEEDSTOCKS FOR WHICH PRICES AND RATES ARE READ.	00002420
A-5 ISN 0027	9	READ 400,NPRODS,NFEEDS	00002430
	C		00002440
	C****	CARD 10. PRICES OF PRODUCTS INCL. INITIAL ESTIMATE FOR MAIN PROD.	00002450
ISN 0028	10	READ 403,(PRICE(N),N=1,NPRODS)	00002460
	C		00002470
	C****	CARD 11. ANNUAL PRODUCTION RATES FOR PRODUCTS AT 100% CAPACITY.	00002480
ISN 0029	11	READ 403,(PRDRAT(N),N=1,NPRODS)	00002490
	C		00002500
	C****	CARD 12. FEEDSTOCK PRICES, \$/UNIT, FOR ALL FEEDSTOCKS.	00002510
ISN 0030	12	READ 403,(FEEDPR(N),N=1,NFEEDS)	00002520
	C		00002530
	C****	CARD 13. FEEDSTOCK CONSUMPTION RATES AT 100% CAPACITY,MM UNIT/YR	00002540
ISN 0031	13	READ 403,(FEEDRT(N),N=1,NFEEDS)	00002550
	C		00002560
	C****	CARD 14. RATES OF RETURN ON EQUITY.	00002570
ISN 0032	14	READ 403,(RTNEQ(NEQT),NEQT=1,NEQMAX)	00002580
	C		00002590
	C****	CARD 15. DEPRECIATION CLASSES.	00002600
ISN 0033	15	READ 403,NCLS,(LIFE(NCL),NCL=1,NCLS)	00002610
	C		00002620
	C****		00002630
	C****	CARD 16. FRACTIONS OF TOTAL DEPRECIATION BY CLASS.	00002640
ISN 0034	16	READ 403,(DPFRAC(NCL),NCL=1,NCLS)	00002650
	C		00002660
	C****	CARD 17. PLANT OP. FACTOR FOR EACH YEAR INCL PRE-STARTUP YRS	00002670
ISN 0035	17	READ 403,(EFFNCY(N),N=1,NYRS)	00002680
	C		00002690
	C****	CARD 18. DISTRIBUTION OF INVESTMENT DURING CONSTRUCTION PERIOD.	00002700

```

C THIS IS FOR THE CALCULATION OF THE COMPOUNDED INTEREST DURING          00002710
C CONSTRUCTION. IF THIS OPTION IS NOT DESIRED, CARD 18 IS A BLANK CARD 00002720
C AND LL(7) MUST BE LESS THAN 2 AND ENTER NCNSTR=1 ON CARD 4.          00002730
C                                                                           00002740
ISN 0036      18 READ 403,(FRCINV(N),N=1,NCNSTR)                          00002750
C                                                                           00002760
C*   CARD 19. ESCALATION FACTOR.                                         00002770
ISN 0037      19 READ 403, ESCCAP,ESCWRK,ESCXT,ESCEXP,ESCINI,ESCCON,ESCFDP,ESCRP 00002780
C                                                                           00002790
C***** END OF INPUT DATA *****                                       00002800
C                                                                           00002810
C                                                                           00002820
C*****                                                                    00002830
C SAVE THE LOW AND HIGH PRODUCT PRICE LIMITS FOR SUBSEQUENT ITERATIONS. 00002840
C                                                                           00002850
ISN 0038      PLSAVE=PL                                                    00002860
ISN 0039      PHSAVE=PH                                                    00002870
ISN 0040      FPSAVE=FEEDPR(1)                                             00002880
ISN 0041      NEQT=1                                                       00002890
ISN 0042      RTNEQY=RTNEQ(NEQT)                                           00002900
ISN 0043      DPSTRT=NSTRT                                                 00002910
ISN 0044      PROJLF=NYRS                                                  00002920
C                                                                           00002930
C                                                                           00002940
C SAVE NSTRT7 FOR INV TAX CREDIT CARRYOVER CALC.                         00002950
C THIS IS FINAL YEAR WHEN INV TAX CREDIT CAN BE TAKEN                    00002960
ISN 0045      NSTRT7=NSTRT+NCREDIT                                         00002970
C*****                                                                    00002980
C                                                                           00002990
C***** PRINT INPUT DATA *****                                         00003000
C*****                                                                    00003010
ISN 0046      NPRNT=0                                                       00003020
ISN 0047      1019 CONTINUE                                                00003020
ISN 0048      PRINT 600                                                     00003030
ISN 0049      IF(NPRNT.EQ.1).PRINT 655                                     00003040
ISN 0051      PRINT 601,LL(K),K=1,10),(FIBNAM(L),L=1,15)                 00003050
ISN 0052      PRINT 603,IXCRED,FITXR,STAINC,STAREV                          00003060
ISN 0053      PRINT 604,PROPTX,INSURE,DRTFRC,EGFRAC                       00003070
ISN 0054      PRINT 605,RTNEQY,INTDRT,PROJLF,DPSTRT                       00003080
ISN 0055      PRINT 606,PRPEXP,TOLER,SALVGE,CNSTLN                        00003090
ISN 0056      PRINT 606,INTCON,INTTOT                                       00003100
ISN 0057      PRINT 607,NYRS,NSTRT,NTRIES,NFOPRS                          00003110
ISN 0058      PRINT 608,NEGMAX,NCARRY,NCRFDT,NCNSTR                       00003120
C*****                                                                    00003130
ISN 0059      PRINT 701                                                      00003140
ISN 0060      PRINT 639                                                      00003150
ISN 0061      PRINT 610,(INVEST(N),N=1,NYRS)                              00003160
ISN 0062      PRINT 701                                                      00003170
ISN 0063      PRINT 640                                                      00003180
ISN 0064      PRINT 610,(WORFCP(N),N=1,NYRS)                              00003190
ISN 0065      PRINT 701                                                      00003200
ISN 0066      PRINT 641                                                      00003210
ISN 0067      PRINT 610,(EXTEXP(M),N=1,NYRS)                             00003220
ISN 0068      PRINT 701                                                      00003230
ISN 0069      PRINT 609                                                      00003240
ISN 0070      PRINT 610,(EFFHCY(N),N=1,NYRS)                              00003250

```

```

ISN 0071      PRINT 701                      00003260
C****
ISN 0072      PRINT 611,EXINIT,EXPCON       00003270
ISN 0073      PRINT 612,NPRODS              00003280
ISN 0074      PRINT 613,( PRICE(N),N=1,NP=ODS) 00003290
ISN 0075      PRINT 613,(PRDRAT(N),N=1,NP=ODS) 00003300
C                                                    00003310
C                                                    00003320
ISN 0076      PRINT 634,NFEEDS              00003330
ISN 0077      PRINT 610,(FEEDPR(N),N=1,NFEEDS) 00003340
ISN 0078      PRINT 610,(FEEDRT(N),N=1,NFEEDS) 00003350
ISN 0079      IF(NPRNT.EQ.1) GO TO 1022     00003360
C****
C****      END OF PRINT INPUT DATA.        00003370
C****
C*          APPLY ESCALATION FACTORS TO INPUT DATA. 00003380
ISN 0081      IF(LL(9).EQ.0) GO TO 1022     00003390
C*
C*          DO 1021 N=1,NYRS                00003400
ISN 0083      DO 1021 N=1,NYRS              00003410
ISN 0084      INVEST(N)=INVEST(N)*1.+ESCCAP)**(N-1) 00003420
ISN 0085      WORKCP(N)=WORKCP(N)*1.+ESCWRK)**(N-1) 00003430
ISN 0086      EXTEXP(N)=EXTEXP(N)*1.+ESCFXT)**N    00003440
ISN 0087      1021 CONTINUE                 00003450
ISN 0088      NPRNT=1                       00003460
ISN 0089      GO TO 1019                    00003470
C****
C****      1022 CONTINUE                    00003480
C****
C          CALCULATE TOTAL AMOUNT INVESTED.      ZERO ANNUAL DEPRECIATION. 00003490
C
ISN 0091      TOTDNV=0.                      00003500
ISN 0092      WRKCAP=0.                     00003510
ISN 0093      DO 22 N=1,NYRS                00003520
ISN 0094      DEPRFC(N)=0.0                 00003530
ISN 0095      WRKCAP=WRKCAP+WORKCP(N)       00003540
ISN 0096      22 TOTDNV=TOTDNV+INVEST(N)    00003550
C
C
C          TOTAL DEPRECIABLE CAPITAL IS THE SUM OF INPUTTED DEPRECIABLE
C          INVESTMENT AND INTEREST DURING CONSTRUCTION, INTDC--IT WILL
C          BE ZERO UNLESS LL(7) IS GREATER THAN ZERO. 00003560
C          IF LL(7)=1, TOTAL INT. DURING CONSTR. INPUT AS A FRACTION
C          OF THE TOTAL DEPRECIABLE INVESTMENT. THIS FRACTION IS INTTOT. 00003570
C          IF LL(7)=2, INTEREST DURING CONSTR. IS COMPUTED ACCORDING TO
C          SCHEDULE OF EXPENDITURE OF CONSTRUCTION FUNDS--INPUT 00003580
C          AS ANNUAL FRACTION, FRCINV(N), WHERE N GOES FROM 1 TO NCNSTR
C          THE INTEREST RATE FOR THIS CALCULATION IS INTCON. 00003590
C
C
C          INTDC=0.                           00003600
ISN 0097      INTDC=0.                       00003610
ISN 0098      CMPDFC=0.                      00003620
ISN 0099      24 IF(LL(7).EQ.1)INTDC=CNSTLN*INTTOT 00003630
C
C          INTTOT=0.                           00003640
ISN 0101      INTTOT=0.                      00003650
ISN 0102      IF(LL(7).LT.2)GO TO 27        00003660
C
C          CALCULATE COMPOUND FACTOR FOR TOTAL INTEREST DURING CONSTR. 00003670

```

```

C      THIS OPTION IS USED ONLY IF LL(7)=2.                00003810
ISN 0104      DO 25 N=1,NCNSTR                                00003820
ISN 0105      25 CMPDFC=(CMPDFC+FPICINV(N))*(1.+INTCON:      00003830
ISN 0106      INTTOC=CMDFC-1.                                00003840
ISN 0107      INTDC=CNSTLN*INTTOC                            00003850
C                                                     00003860
C                                                     00003870
ISN 0108      27 TOTDFP=TOTDMV+INTOC                          00003880
C                                                     00003890
C                                                     00003900
C                                                     00003910
ISN 0109      C      TOTAL INVESTMENT--THE SUM OF DEPRECIABLE AND WORKING CAPITAL
      TOTINV=TOTDEP+WRKCAP                                    00003920
C                                                     00003930
C                                                     00003940
ISN 0110      C      THE TOTAL OF WRKCAP + SALVGE IS SAVED FOR LATER OUTPUTTING.
      TOT813=WRKCAP+SALVGE                                   00003950
C                                                     00003960
C****                                                    00003970
C****                                                    00003980
C                                                     00003990
C**** CALCULATE ANNUAL PROPERTY TAXES AND INSURANCE.      00004000
C      THESE ARE ASSUMED TO START IN YEAR NSTRT.           00004010
C                                                     00004020
ISN 0111      DO 28 N=1,NYRS                                  00004030
ISN 0112      PROPTY(N)=0.                                    00004040
ISN 0113      INSRNC(N)=0.                                    00004050
ISN 0114      IF(N.LT.NSTRT)GO TO 28                         00004060
ISN 0116      PROPTY(N)=TOTDEP*PROPTX                         00004070
ISN 0117      INSRNC(N)=TOTDEP*INSURE                          00004080
ISN 0118      28 CONTINUE                                     00004090
C                                                     00004100
C                                                     00004110
C**** CALCULATE ANNUAL DEPRECIATION ALLOWANCES FOR TAX PURPOSES.
C      DEPRECIATION IS BASED ON TOTAL DEPRECIABLE CAPITAL LESS SAL-
C      VAGE VALUE.                                           00004120
C                                                     00004130
C                                                     00004135
C                                                     00004140
ISN 0119      TOTDP2=TOTDEP-SALVGE                            00004150
C                                                     00004160
C                                                     00004170
C      OPTIONS AVAILABLE ARE AS FOLLOWS.                    00004180
C      LL(1) = 0  SUM OF YEARS DIGITS                         00004190
C      LL(1) = 1  STRAIGHT LINE                              00004200
C      LL(1) = 2  DOUBLE DECLINING BALANCE WITH CONVERSION TO
C**** STRAIGHT LINE.                                        00004210
C                                                     00004215
ISN 0120      DO 37 NCL=1,NCLS                                 00004220
ISN 0121      NDLLIFE=LIFE(NCL)                              00004230
ISN 0122      TOTDP3=TOTDP2*DPFRAC(NCL)                      00004240
ISN 0123      DPLIFE=NDLLIFE                                  00004250
ISN 0124      IF(LL(1).EQ.2)GO TO 34                         00004260
C                                                     00004270
C                                                     00004280
ISN 0126      SUM=0.                                          00004280
ISN 0127      DO 30 ND=1,NDLIFE                               00004290
ISN 0128      30 SUM=SUM+ND                                    00004300
C****                                                    00004310
ISN 0129      DO 32 ND=1,NDLIFE                               00004320
ISN 0130      FRAC=(NDLIFE-ND+1)/SLM                         00004330

```

```

ISN 0131      IF(LL(1).EQ.1)FRAC=1./DPLIFE      00004340
ISN 0133      N=NSTRT+ND-1                    00004350
ISN 0134      YDPRFC=FRAC*TOTDP3              00004360
ISN 0135      32 DEPRFC(N)=DEPREC(N)+YDPPREC  00004370
ISN 0136      GO TO 37                        00004380
C
C          DOUBIE DECLINING BALANCE METHOD WITH CONVERSION TO STRAIGHT
C          LINE.                              00004390
C
C          00004400
C          00004405
C          00004410
ISN 0137      34 NSL=0                        00004420
ISN 0138      REMNDR=TOTDP3                  00004430
C          00004440
C          00004450
ISN 0139      DO 34 ND=1,NDLIFE              00004450
ISN 0140      NLEFT=NDLIFE-ND+1              00004460
ISN 0141      N=NSTRT+ND-1                  00004470
ISN 0142      IF(NSL.EQ.1)GO TO 35           00004480
ISN 0144      DDR=REMNDR*2./DPLIFE           00004490
ISN 0145      DSL=REMNDR/NLEFT               00004500
ISN 0146      IF(DSL.GE.DDB)NSL=1           00004510
ISN 0148      YDPRFC=AMAX1(DDR,DSL)          00004520
ISN 0149      REMNDR=REMNDR-YDPPREC          00004530
ISN 0150      GO TO 36                        00004540
ISN 0151      35 YDPRFC=DSL                  00004550
C          00004560
C          00004570
ISN 0152      36 DEPRFC(N)=DEPREC(N)+YDPPREC  00004570
C          00004580
C          00004590
ISN 0153      37 CONTINUE                    00004590
C          00004600
C          00004610
C          00004620
C          00004625
C          00004630
C          00004640
C          00004650
ISN 0154      SUMDP=0.                       00004640
ISN 0155      DO 38 N=1,NYRS                 00004650
ISN 0156      38 SUMDP=SUMDP+DEPREC(N)       00004660
C          00004670
C          00004680
C          00004690
C          00004700
C          00004710
C          00004720
C          00004730
C          00004740
C          00004750
C          00004760
C          00004770
C          00004780
C          00004790
C          00004800
C          00004810
C          00004820
C          00004830
C          00004840
C          00004850
C          00004860
ISN 0157      PRINT 625                      00004710
ISN 0158      IF(LL(2).EQ.0)PRINT 632        00004720
ISN 0160      IF(LL(2).EQ.1)PRINT 633        00004730
ISN 0162      PRINT 642                      00004740
ISN 0163      PRINT 643,TOTDNV               00004750
ISN 0164      PRINT 644,INTDC                00004760
ISN 0165      PRINT 645,TOTDEP               00004770
ISN 0156      PRINT 646,WRKCAP               00004780
ISN 0167      PRINT 647,TOTINV               00004790
ISN 0168      PRINT 702                      00004800
ISN 0169      PRINT 627,TOTDP2               00004810
ISN 0170      PRINT 626,SALVGE               00004820
ISN 0171      SUM628=SALVGE+TOTDP2           00004830
ISN 0172      PRINT 628,SUM628               00004840
ISN 0173      PRINT 702                      00004850
ISN 0174      K631=1+LL(1)                  00004860

```



	C		00005390
ISN 0205	C	NFDPP=1	00005400
	C		00005410
ISN 0206	C	4A CONTINUE	00005420
	C		00005430
ISN 0207	C	NPRINT=1-LL(3)	00005440
	C		00005450
	C		00005460
	C****	CALCULATE COST OF FEEDS TO PLANT AT 100% ONSTREAM EFFICIENCY.	00005470
	C		00005480
ISN 0208	C	FDCOST=0.	00005490
ISN 0209	C	DO 50 N=1,NFEEDS	00005500
ISN 0210	C	50 FDCOST=FDCOST+FEEDRT(N)*FEEDPR(N)	00005510
	C****		00005520
	C		00005530
	C		00005540
	C	THE TOTAL ANNUAL OPERATING EXPENSE IS PLTEXP(N)--THE SUM OF	00005550
	C	THE CONSTANT ANNUAL EXPENSE, EXPENS(N), PLUS THE AMOUNT	00005560
	C	PROPORTIONAL TO THROUGHPUT, PRPEXP*EFFNCY(N), PLUS ANY ADDED	00005570
	C	ANNUAL AMOUNTS INPUT, EXTEXP(N), PLUS ANNUAL PROPTY INSURE,	00005580
	C	PLUS THE COST OF THE FEEDSTOCKS USED EACH YEAR. THE LATTER	00005590
	C	IS THE PRODUCT OF THE ONSTREAM EFFICIENCY AND THE CALCU	00005600
	C	LATED FEEDSTOCK COST AT 100% ONSTREAM EFFICIENCY,FDCOST.	00005610
	C	NOTE THAT PLTEXP(N) DOES NOT INCLUDE ANY TAXES.	00005620
	C	IT IS ASSUMED THAT PROPERTY INSURANCE STARTS IN YEAR NSTRT.	00005630
	C	FOR CALCULATION OF EXPENS(N) SEE STATEMENTS 41-43.	00005640
	C		00005650
	C		00005660
	C		00005670
A-11 ISN 0211	C	DO 51 N=1,NYRS	00005680
ISN 0212	C	PLTEXP(N)=EFFNCY(N)*PRPEXP*(1.+ESCEXP)**N + EXPENS(N) + EXTEXP(N)	00005690
	C	1 + INSRNC(N) + FDCOST*EFFNCY(N)*(1.+ESCFDP)**N	00005700
ISN 0213	C	51 CONTINUE	00005710
	C		00005720
	C	THIS COMPLETES THE CALCULATION OF THE ANNUAL OP EXPENSES.	00005730
	C		00005740
	C****		00005750
	C		00005760
ISN 0214	C	PTRY=PRICE(1)	00005770
ISN 0215	C	EQTRY=RTNEQY	00005780
ISN 0216	C	NTRY=1	00005790
ISN 0217	C	EQL=0.00	00005800
ISN 0218	C	EQH=1.00	00005810
ISN 0219	C	PL=PLSAVE	00005820
ISN 0220	C	PH=PHSAVE	00005830
	C		00005840
	C****	STATEMENT 55 IS THE REENTRY POINT FOR TRIAL CALCULATIONS FOR	00005850
	C	OBTAINING CONVERGENCE OF THE CASH FLOW PAYOUT TABULATION.	00005860
	C	THE TRIAL NUMBER IS NTRY AND THE PRICE IS PTRY.	00005870
	C	IF THE RATE OF RETURN ON EQUITY IS BEING CALCULATED, THE	00005880
	C	NEW TRIAL VALUE IS EQTRY.	00005890
	C		00005900
ISN 0221	C	55 CONTINUE	00005910
	C		00005920
ISN 0222	C	PRICE(1)=PTRY	00005930

ISN 0223	RTNEQY=EQTRY	00005940
ISN 0224	IF(NTRY.EQ.NTRIES)NPRINT=1	00005950
	C****	00005960
	C**** ZERO ALL THE ENTRIES IN THE PAYOUT ARRAY FROM THE PREVIOUS TRIAL.	00005970
ISN 0226	CALL ZERO	00005980
	C****	00005990
	C	00006000
	C	00006010
	C**** CALCULATE ANNUAL PRODUCTION AND INCOME FROM SALES	00006020
	C	00006030
ISN 0227	DO 60 N=1,NYRS	00006040
ISN 0228	TOTPR=0.	00006050
ISN 0229	DO 50 NPR=1,NPRODS	00006060
ISN 0230	50 TOTPR=TOTPR+PRDRAT(NPR)*PRICE(NPR)	00006070
ISN 0231	INCOME(N)=TOTPR*EFFNCY(N)*(1.+ESCRP)**N	00006080
ISN 0232	60 CONTINUE	00006090
	C****	00006100
	C**** MAIN LOOP STARTS HERE. CALCULATE PAYOUT TABLE. NEW ITERATION	00006110
	C REENTERS AT STATEMENT 55. MAX NUMBER OF ITERATIONS = NTRIES.	00006120
	C**** CREDIT IS THE TOTAL FEDERAL INVESTMENT TAX CREDIT.	00006130
	C	00006140
ISN 0233	IF(NPRINT.EQ.0)GO TO 64	00006150
	C	00006160
ISN 0235	PRINT 616,(PRBNAM(L),L=1,15),FEEDPR(1)	00006170
ISN 0236	DBT22=INTDBT*100.00	00006180
ISN 0237	RTNEQ2=RTNEQY*100.00	00006190
ISN 0238	PRINT 630,NTRY,PRICE(1),DBT22,RTNEQ2,DBTFRC,EQFRAC	00006200
ISN 0239	PRINT 617,(KC,KC=1,11)	00006210
ISN 0240	PRINT 623	00006220
	C	00006230
ISN 0241	64 CONTINUE	00006240
	C	00006250
	C	00006260
	C INITIAL CAPITAL INVESTMENT INCL. CALCULATED INTEREST DURING	00006270
	C CONSTRUCTION. IF LL(7) WAS INPUT AS ZERO, INTDC IS ZERO.	00006280
	C	00006290
ISN 0242	CPSTRT(1)=INVEST(1)+INTDC+WORKCP(1)	00006300
	C	00006310
	C**** CALCULATE INV. TAX CRED. BASED ON TOTAL DEPRECIABLE CAPITAL.	00006320
ISN 0243	CREDIT=TOTDEP*TXCRED	00006330
	C****	00006340
	C**** CALCULATE THE PAYOUT TABLE YEAR BY YEAR.	00006350
	C****	00006360
ISN 0244	NCOMPL=0	00006370
	C	00006380
	C	00006390
	C THE OBJECT IS TO MAKE THE OUTSTANDING CAPITAL AT THE END OF	00006400
	C THE FINAL YEAR EQUAL TO THE TOTAL WORKING CAPITAL INVESTMENT	00006410
	C PLUS SALVAGE VALUE. TOTAL WORKING CAPITAL IS ASSUMED TO	00006420
	C REMAIN INVESTED RIGHT UP TO THE END OF THE PROJECT AND IS	00006430
	C RECOVERED INTACT AT THAT TIME.	00006440
	C	00006450
ISN 0245	DO 80 N=1,NYRS	00006460
	C****	00006470
	C INT. ON DEBT & RETURN ON EQUITY BASED ON OUTSTANDING CAPITAL	00006480

ISN 0246	INTRST(N)=CPSTRT(N)*DRTFRC*INTDRT	00006490
ISN 0247	EQYRTN(N)=CPSTRT(N)*EQFRAC*RTNEQY	00006500
	C	00006510
	C STATE TAXABLE INCOME.	00006520
ISN 0248	STXAPL(N)=INCOME(N)-PLTEXP(N)-DEPREC(N)-INTRST(N)	00006530
	C STATE AND LOCAL TAXES--NOT PERMITTED TO BE NEGATIVE.	00006540
ISN 0249	STLTAX(N)=STXABL(N)*STAINC	00006550
ISN 0250	IF(STLTAX(N).LT.0.)STLTAX(N)=0.0	00006560
ISN 0252	STLTAX(N)=STLTAX(N)+PROPTY(N)	00006570
	C	00006580
ISN 0253	C**** STATE REV TAX = STAREV*INCOME(N)--INCLUDED IN STLTAX(N).	00006590
	IF(INCOME(N).GT.0.)STLTAX(N)=STLTAX(N)+STAREV*INCOME(N)	00006600
	C	00006610
	C	00006620
ISN 0255	C FED TAXABLE INCOME AND FED INCOME TAX BEFORE INV TAX CREDIT.	00006630
ISN 0256	TAXAPL(N)=STXABL(N)-STLTAX(N)	00006640
	C FEDTAX(N)=TAXABL(N)*FITTXR	00006650
	C FEDTXN(N) IS A CALCULATED TAX WHICH MAY BE NEGATIVE .	00006660
ISN 0257	FEDTXN(N)=FEDTAX(N)	00006670
	C FEDTXN(N) IS SAVED. FEDTAX(N) MAY BE SUBSEQUENTLY ADJUSTED.	00006680
	C****	00006690
	C**** IF TAXES ARE ALLOWED TO BE NEGATIVE, GO TO 70.	00006700
ISN 0258	IF(LL(6).GT.0)GO TO 70	00006710
	C**** IF TAXES ARE NOT ALLOWED TO BE NEGATIVE, DO THE FOLLOWING.	00006720
ISN 0260	IF(FFDTAX(N).GE.0.)GO TO 66	00006730
ISN 0262	TXLOSS(N)=-FEDTAX(N)	00006740
ISN 0263	FEDTAX(N)=0.	00006750
ISN 0264	65 CONTINUE	00006760
ISN 0265	IF(LL(5).EQ.0)GO TO 69	00006770
	C	00006780
	C**** FIVE YEAR TAX LOSS CARRYOVER CALCULATION.	00006790
	C NCARRY WAS INPUTTED AND IS NORMALLY 5.	00006800
ISN 0267	NA=N-NCARRY	00006810
ISN 0268	IF(NA.LT.1)NA=1	00006820
ISN 0270	DO 68 NLOSS=NA,N	00006830
ISN 0271	DEDUCT=AMIN1(TXLOSS(NLOSS)+FEDTAX(N))	00006840
ISN 0272	FEDTAX(N)=FEDTAX(N)-DEDUCT	00006850
ISN 0273	TXLOSS(NLOSS)=TXLOSS(NLOSS)-DEDUCT	00006860
ISN 0274	68 CONTINUE	00006870
	C**** END OF TAX LOSS CARRYOVER CALCULATION.	00006880
	C	00006890
ISN 0275	69 CONTINUE	00006900
	C****	00006910
	C INVESTMENT TAX CREDIT IS SUBTRACTED FROM INCOME TAX.	00006920
ISN 0276	TXCRDT(N)=AMIN1(FEDTAX(N),CREDIT)	00006930
	C PUT 7-YEAR LIMIT ON CARRY-FORWARD OF INVESTMENT TAX CREDIT.	00006940
	C NCREDIT WAS INPUTTED AND IS NORMALLY 7.	00006950
	C NSTRT7 IS THE SUM OF NSTRT AND NCREDIT.	00006960
ISN 0277	IF(N.GT.NSTRT7)TXCRDT(N)=0.	00006970
ISN 0279	FEDTAX(N)=FEDTAX(N)-TXCRDT(N)	00006980
	C KEEP TRACK OF REMAINING CREDIT NOT YET USED.	00006990
ISN 0280	CREDIT=CREDIT-TXCRDT(N)	00007000
ISN 0281	GO TO 73	00007010
	C	00007020
ISN 0282	70 CONTINUE	00007030

	C	INV TAX CREDIT FOR THE CASE WHEN INCOME TAX CAN BE NEGATIVE	00007040
ISN 0283		IF(N.LT.NSRT)GO TO 73	00007050
ISN 0285		FEDTAX(N)=FEDTAX(N)-CREDIT	00007060
ISN 0286		TXCRT(N)=CREDIT	00007070
ISN 0287		CREDIT=0.	00007080
ISN 0288		73 CONTINUE	00007090
	C		00007100
	C****	CALCULATE CASH FLOW AFTER TAXES FOR YEAR (N).	00007110
ISN 0289		CASHFL(N)=INCOME(N)-PLTEXP(N)-STLTAX(N)-FEDTAX(N)	00007120
	C		00007130
	C****	CALCULATE TOTAL INTEREST AND RETURN ON EQUITY FOR YEAR (N).	00007140
ISN 0290		TOTRTN(N)=INTRST(N)+EQYRTN(N)	00007150
	C		00007160
	C	AMORTIZATION/RECOVERY OF REMAINING CAPITAL BASED ON CASH FLOW	00007170
	C	LESS AMOUNT ALLOCATED TO INT ON DEBT & RETURN ON EQUITY.	00007180
ISN 0291		AMORTZ(N)=CASHFL(N)-TOTRTN(N)	00007190
	C		00007200
	C	AMOUNT OF CAPITAL OUTSTANDING AT END OF YEAR.	00007210
ISN 0292		CAPEND(N)=CPSTRT(N)-AMORTZ(N)	00007220
	C		00007230
ISN 0293		IF(NPRINT.EQ.0)GO TO 76	00007240
ISN 0295		PRINT 615,N,CPSTRT(N),EFFNCY(N),INCOME(N),PLTEXP(N),STLTAX(N),	00007250
	1	TXCRT(N),FEDTAX(N),CASHFL(N),TOTRTN(N),AMORTZ(N),CAPEND(N)	00007260
	C		00007270
ISN 0296		76 CONTINUE	00007280
ISN 0297		CPSTOT(N+1)=CAPEND(N) + INVST(N+1) + WRKCAP(N+1)	00007290
ISN 0298		IF(CPSTRT(N+1).LT.C.)CPSTRT(N+1)=0.	00007300
ISN 0300		BALNCE=CAPEND(N) - WRKCAP -SALVGE	00007310
ISN 0301		IF(N.FQ.NYES) NCOMPL=1	00007320
	C		00007330
	C	JUMP OUT OF PAYOUT LOOP IF THE INVESTMENT GETS TOO SMALL.	00007340
ISN 0303		IF(BALNCE.LT.0..AND.N.GT.NSRT)GO TO 82	00007350
	C****		00007360
ISN 0305		80 CONTINUE	00007370
	C		00007380
ISN 0306		NCOMPL=1	00007390
	C		00007400
	C	AT THE END OF THE 80 LOOP THE PAYOUT TABULATION IS COMPLETED	00007410
	C	AND PRINTED BUT IS NOT NECESSARILY CONVERGED.	00007420
	C		00007430
ISN 0307		82 CONTINUE	00007440
ISN 0308		IF(NPRINT.EQ.0)GO TO 83	00007450
	C****		00007460
	C		00007470
	C	THE FOLLOWING PRINT STATEMENTS ARE EXPLANATORY NOTES FOR THE	00007480
	C	PAYOUT TABULATION.	00007490
ISN 0310		PRINT 702	00007500
ISN 0311		PRINT 625	00007510
ISN 0312		PRINT 615,WRKCAP	00007520
ISN 0313		PRINT 802,SALVGE	00007530
ISN 0314		PRINT 813,TOT813	00007540
	C	TOT813 IS THE TOTAL OF THE PRECEDING TWO LINES.	00007550
ISN 0315		PRINT 801	00007560
ISN 0316		PRINT 802	00007570
ISN 0317		PRINT 803	00007580

ISN 0318	PRINT 804	00007590
ISN 0319	PRINT 805	00007600
ISN 0320	PRINT 806	00007610
ISN 0321	PRINT 807	00007620
ISN 0322	PRINT 808	00007630
ISN 0323	PRINT 809	00007640
ISN 0324	PRINT 810	00007650
ISN 0325	PRINT 811	00007660
ISN 0326	PRINT 812	00007670
ISN 0327	PRINT 624	00007680
ISN 0328	83 CONTINUE	00007690
	C	00007700
	C TEST FOR CONVERGENCE. TOLERANCE USED HERE IS INPUTTED.	00007710
	C	00007720
ISN 0329	IF(DABS(BALNCE).LT.TOLER.AND.NCOMPL.EQ.1)GO TO 88	00007730
	C	00007740
ISN 0331	IF(NTRY.GE.NTRIES)GO TO 90	00007750
ISN 0333	NTRY=NTRY+1	00007760
	C****	00007770
ISN 0334	IF(LL(2).EQ.1)GO TO 87	00007780
	C	00007790
	C ITERATE ON PRICE(1) IF LL(2)=0	00007800
	C**** ITERATE PRICE BY AVEFAGING THE CURRENT MIN. HIGH AND MAX. LOW.	00007810
	C****	00007820
ISN 0336	PTRY4=PTRY	00007830
ISN 0337	IF(BALNCE.GT.0.)PL=AMAX1(PL,PTRY4)	00007840
ISN 0339	IF(BALNCE.LT.0.)PH=AMIN1(PH,PTRY4)	00007850
ISN 0341	PRCEPR=PH-PL	00007860
ISN 0342	IF(PPCFRR.LT.TOLPRC)GO TO 88	00007870
ISN 0344	IF(NCOMPL.EQ.0.AND.NTRY.LT.9)GO TO 86	00007880
ISN 0346	PTRY=PTRY+DPFAC*BALNCE	00007890
ISN 0347	IF(PTRY.GE.PH.OR.PTRY.LE.PL.OR.NTRY.GT.5)PTRY=0.5*(PL+PH)	00007900
	C****	00007910
	C**** REENTER AT 55 FOR NEXT ITERATION UNLESS NTRY=NTRIES.	00007920
	C****	00007930
ISN 0349	GO TO 55	00007940
	C****	00007950
ISN 0350	86 PTRY=0.5*(PL+PH)	00007960
ISN 0351	GO TO 55	00007970
ISN 0352	87 CONTINUE	00007980
	C	00007990
	C ITERATE RATE OF RETURN ON EQUITY. SIGNALLED BY LL(2)=1.	00008000
	C	00008010
ISN 0353	IF(BALNCE.LT.0.)EQL=AMAX1(EQL,EQTRY)	00008020
ISN 0355	IF(BALNCE.GT.0.)EQH=AMIN1(EQH,EQTRY)	00008030
ISN 0357	EQTRY=0.5*(EQL+EQH)	00008040
ISN 0358	GO TO 55	00008050
	C****	00008060
ISN 0359	88 IF(NPRINT.EQ.1)GO TO 90	00008070
ISN 0361	NPRINT=1	00008080
ISN 0362	GO TO 55	00008090
	C	00008100
ISN 0363	90 CONTINUE	00008110
	C****	00008120
	C**** AT THIS POINT EITHER CONVERGENCE HAS BEEN REACHED OR THE ALLOWED	00008130
	C MAXIMUM NUMBER OF ITERATIONS HAS BEEN MADE.	00008130

A-16

```

C
C   HOWEVER, THE FEED PRICE ITERATION, IF REQUIRED, REMAINS
C   TO BE DONE.
C
C   PRINT SUPPLEMENTARY TABLE OF INFORMATION, UNLESS LL(3)=1.
C
ISN 0364   IF(LL(3).EQ.1)GO TO 96
C
ISN 0366   PRINT 620,(PRBNAM(L),L=1,15)
ISN 0367   PRINT 617,(KC,KC=1,11)
ISN 0368   PRINT 622
C****
ISN 0369   DO 95 N=1,NYRS
ISN 0370   PRINT 615,N,INVEST(N),CPSTFT(N),DEPREC(N),INTRST(N),TXCRDT(N),
           TAXABL(N),FEDTAX(N),STABL(N),EQVRTN(N),PROPTY(N),FEDTXN(N)
ISN 0371   95 CONTINUE
C****
ISN 0372   PRINT 702
ISN 0373   PRINT 801
ISN 0374   PRINT 901
ISN 0375   PRINT 902
ISN 0376   PRINT 903
ISN 0377   PRINT 904
ISN 0378   PRINT 905
ISN 0379   PRINT 906
ISN 0380   PRINT 907
ISN 0381   PRINT 908
ISN 0382   PRINT 909
ISN 0383   PRINT 910
ISN 0384   PRINT 911
C****
ISN 0385   96 CONTINUE
C
C
C   NOW REPEAT THE PROBLEM WITH NEW FEED PRICE IF THE FEED PRICE
C   ITERATION OPTION IS BEING USED. THAT IS, IF LL(4)=1.
C   THE ENTRY POINT FOR THIS IS STATEMENT 48, THE COMPLETION
C   POINT IS STATEMENT 100. NOTE THAT THE ONLY FEED PRICE
C   THAT CHANGES IS FEEDPR(1), THE MAIN FEED.
C
ISN 0386   IF(LL(4).EQ.0)GO TO 100
C
ISN 0388   NFDPP=NFDPP+1
ISN 0389   IF(NFDPP.GT.NFDPPS)GO TO 100
ISN 0391   FEEDPR(1)=FEEDPR(1)-DELFFR
ISN 0392   IF(LL(2).EQ.1)GO TO 48
ISN 0394   PRICE(1)=PRICE(1)+DELFFR*FEEDRT(1)/PRDRAT(1)
ISN 0395   GO TO 48
C
ISN 0396   100 CONTINUE
C
C**** FORMATS *****
C
ISN 0397   400 FORMAT(15I5)
ISN 0398   401 FORMAT(10I2,15A4)
00008140
00008150
00008160
00008170
00008180
00008190
00008200
00008210
00008220
00008230
00008240
00008250
00008260
00008270
00008280
00008290
00008300
00008310
00008320
00008330
00008340
00008350
00008360
00008370
00008380
00008390
00008400
00008410
00008420
00008430
00008440
00008450
00008460
00008470
00008480
00008490
00008500
00008510
00008520
00008530
00008540
00008550
00008560
00008570
00008580
00008590
00008600
00008610
00008620
00008630
00008640
00008650
00008660
00008670
00008680

```

ISN 0399	403	FORMAT(AE10.0)	00008690
ISN 0400	404	FORMAT(20A4)	00008700
ISN 0401	600	FORMAT('1',5X,'INPUT DATA SUPPLIED BY USER',/)	00008710
ISN 0402	601	FORMAT(' ',5X,'CARD 1',4X,10I4,5X,15A4,/)	00008720
ISN 0403	603	FORMAT(' ',5X,'TXCRED,FITTXP,STAINC,STAREV',5X,5F10.4)	00008730
ISN 0404	604	FORMAT(' ',5X,'PROPTX,INSURE,DRTFRC,EQFRAC',5X,5F10.4)	00008740
ISN 0405	605	FORMAT(' ',5X,'PTNEQY,INTDBT,PROJLF,DPSTRT',5X,5F10.4)	00008750
ISN 0406	606	FORMAT(' ',5X,'PPPEXP,TOLFR,SALVGE,CNSTLN ',5X,5F10.4)	00008760
ISN 0407	609	FORMAT(' ',5X,'PLANT ONSTREAM FACTOR INPUTTED ON CARD 17 ',	00008770
	1	' FOR EACH YEAR OF PROJECT LIFE, EFFNCY(N) ',/)	00008780
ISN 0408	610	FORMAT(' ',5X,8F15.6)	00008790
ISN 0409	611	FORMAT(' ',5X,'EXINIT, EXPCON',20X,4F15.4)	00008800
ISN 0410	612	FORMAT('0',5X,'PRICES AND BASE PRODUCTION RATES FOR',I3,	00008810
	1	' PRODUCTS',/)	00008820
ISN 0411	613	FORMAT(' ',5X,10F12.4)	00008830
ISN 0412	615	FORMAT(' ',I4,3X,11F11.4)	00008840
ISN 0413	616	FORMAT('1',10X,'PAYOUT TABULATION',10X,15A4,	00008850
	1	5X,'FEED PRICE =',F10.2,/)	00008860
ISN 0414	617	FORMAT(' ',5X,11I11,/)	00008870
ISN 0415	618	FORMAT(' ',10X,20A4)	00008880
ISN 0416	619	FORMAT('0',15X,'WORKING CAPITAL RECOVERED INTACT AT END OF ',	00008890
	1	'PROJECT LIFE = ',F15.5)	00008900
ISN 0417	620	FORMAT('1',10X,'ADDITIONAL DETAILS OF CALCULATION',5X,15A4,///)	00008910
ISN 0418	622	FORMAT(' ',10X,'INVEST CPSTRT DEPRFC INTRST ',	00008920
	1	' TXCRTD TAXABL FEDTAX STXABL EQYRTN',	00008930
	2	' PROPTY FEDTXN',/)	00008940
ISN 0419	623	FORMAT(' ',10X,'CPSTRT EFFNCY REVENUE PLTEXP ',	00008950
	1	'STLTAX TXCRTD FEDTAX CASHFL TOTRTN ',	00008960
	2	'AMORTZ CAPEND',/)	00008970
ISN 0420	624	FORMAT('0',10X,'COLUMN 11 PLUS NEW INVESTMENT = NEXT ENTRY OF',	00008980
	1	' COLUMN 1',/)	00008990
ISN 0421	625	FORMAT('1',5X,'DERIVED DATA. CALCULATED FROM INPUT DATA.',	00009000
	1	5X,'INCLUDES ESCALATION IF CALLED FOR BY USER.',///)	00009010
ISN 0422	626	FORMAT(' ',10X,'SALVAGE VALUE AT END OF PROJECT ',10X,F15.5)	00009020
ISN 0423	627	FORMAT(' ',10X,'TOTAL DEPRECIATION FOR TAX PURPOSES ',10X,F15.5)	00009030
ISN 0424	628	FORMAT(' ',10X,'TOTAL ',10X,F15.5)	00009040
ISN 0425	629	FORMAT(' ',15X,'THE LAST ENTRY IN THE FINAL YEAR SHOULD BE ',	00009050
	1	'EQUAL TO THE WORKING CAPITAL INVESTMENT PLUS SALVAGE VALUE',/)	00009060
ISN 0426	630	FORMAT(' ',10X,'TRIAL',I3,6X,'PRICE =',F10.4,7X,'DEBT AT',F6.2,	00009070
	1	' %,5X,'RATE OF RETURN ON EQUITY =',F8.3,' %,5X,'D/E =',	00009080
	2	F5.2,///,F4.2,///)	00009090
ISN 0427	631	FORMAT('0',5X,'CALCULATED ANNUAL DEPRECIATION ALLOWANCES',	00009100
	1	12X,'BY ',A4,' METHOD',/)	00009110
ISN 0428	632	FORMAT(' ',5X,'OBJECTIVE IS TO CALCULATE PRODUCT PRICE',/)	00009120
ISN 0429	633	FORMAT(' ',5X,'OBJECTIVE IS TO CALCULATE RATE OF RETURN ',	00009130
	1	'ON EQUITY',/)	00009140
ISN 0430	634	FORMAT('0',5X,'PRICES AND CONSUMPTION RATES FOR',I3,	00009150
	1	' FEEDSTOCKS',/)	00009160
ISN 0431	635	FORMAT('1',5X,'REPEAT PROBLFM WITH NEW FEED PRICE.',///)	00009170
ISN 0432	636	FORMAT(' ',5X,'INICON,INTTOT ',5X,5F10.4)	00009180
ISN 0433	637	FORMAT(' ',5X,'NYRS,NSTRT,NTRIES,NFOPRS ',3X,5I10)	00009190
ISN 0434	638	FORMAT(' ',5X,'NEQMAX,NCARRY,NCREDIT,NCNSTR',3X,5I10)	00009200
ISN 0435	639	FORMAT(' ',5X,'DEPRECIABLE CAPITAL INVESTMT INPUTTED ON CARD 5 ',	00009210
	1	' FOR EACH YEAR OF PROJECT LIFE, INVEST(N) ',/)	00009220
ISN 0436	640	FORMAT(' ',5X,'WORKING CAPITAL INVESTMENT INPUTTED ON CARD 6 ',	00009230

A-18

	1	' FOR EACH YEAR OF PROJECT LIFE, WORKCP(N) ',/)	00009240
ISN 0437	641	FORMAT(' ',5X,'OPERATING EXPENSES INPUTTED ON CARD 7 ',	00009250
	1	' FOR EACH YEAR OF PROJECT LIFE, EXTEXP(N) ',/)	00009260
ISN 0438	642	FORMAT(' ',5X,'BREAKDOWN OF TOTAL CAPITAL INVESTMENT',/)	00009270
ISN 0439	643	FORMAT(' ',10X,'TOTAL DEPRECIABLE INVESTMENT AS INPUTTED ',5X,	00009280
	1	F15.5)	00009290
ISN 0440	644	FORMAT(' ',10X,'CALCULATED INTEREST DURING CONSTRUCTION ',5X,	00009300
	1	F15.5)	00009310
ISN 0441	645	FORMAT(' ',10X,'TOTAL DEPRECIABLE INVESTMENT ',5X,	00009320
	1	F15.5)	00009330
ISN 0442	646	FORMAT(' ',10X,'TOTAL WORKING CAPITAL AS INPUTTED ',5X,	00009340
	1	F15.5)	00009350
ISN 0443	647	FORMAT(' ',10X,'TOTAL CALCULATED CAPITAL INVESTMENT ',5X,	00009360
	1	F15.5)	00009370
ISN 0444	648	FORMAT(' ',10X,'SUM OF DEPRECIATION ALLOWANCES ',10X,F15.5)	00009380
ISN 0445	649	FORMAT(' ',5X,'CALCULATION OF INTEREST DURING CONSTRUCTION',/)	00009390
ISN 0446	650	FORMAT(' ',10X,'COMPOUND INVESTMENT FACTOR CMPDFC',13X,F15.5)	00009400
ISN 0447	651	FORMAT(' ',10X,'TOTAL INTEREST DURING CONSTR INTDC',12X,F15.5)	00009410
ISN 0448	655	FORMAT(' ',5X,'PRINT INPUT DATA WITH ESCALATED COSTS',/)	00009420
ISN 0449	656	FORMAT(' ',5X,'ESCALATION FACTORS, FRACTION/YEAR',/)	00009430
ISN 0450	657	FORMAT(' ',10X,'CAPITAL, WORK CAPITAL, EXTP EXP',5X,3F10.4)	00009440
ISN 0451	658	FORMAT(' ',10X,'OPERATING EXPENSES ',5X,3F10.4)	00009450
ISN 0452	659	FORMAT(' ',10X,'PRICES OF ALL FEEDSTOCKS ',5X,3F10.4)	00009460
ISN 0453	660	FORMAT(' ',10X,'PRICES OF ALL PRODUCTS ',5X,3F10.4)	00009470
ISN 0454	701	FORMAT(/)	00009480
ISN 0455	702	FORMAT(/)	00009490
ISN 0456	800	FORMAT(' ',15X,'SALVAGE VALUE RECOVERED INTACT AT END OF ',	00009500
	1	'PROJECT LIFE = ',F15.5)	00009510
ISN 0457	801	FORMAT(' ',10X,'KEY TO CALCULATIONS IS AS FOLLOWS.',/)	00009520
ISN 0458	802	FORMAT(' ',10X,'COLUMN 1 = CAPITAL INVESTMENT OUTSTANDING AT',	00009530
	1	' START OF YEAR INCLUDING WORKING CAPITAL ')	00009540
ISN 0459	803	FORMAT(' ',10X,'COLUMN 2 = ONSTREAM EFFICIENCY (PLANT',	00009550
	1	' OPERATING FACTOR) ')	00009560
ISN 0460	804	FORMAT(' ',10X,'COLUMN 3 = GROSS INCOME FROM SALES ')	00009570
ISN 0461	805	FORMAT(' ',10X,'COLUMN 4 = OPERATING EXPENSES EXCLUDING TAXES')	00009580
ISN 0462	806	FORMAT(' ',10X,'COLUMN 5 = STATE AND LOCAL TAXES ',	00009590
	1	'INCLUDING PROPERTY TAX & INSURANCE')	00009595
ISN 0463	807	FORMAT(' ',10X,'COLUMN 6 = FEDERAL INVESTMENT TAX CREDIT')	00009600
ISN 0464	808	FORMAT(' ',10X,'COLUMN 7 = NET FEDERAL INCOME TAX PAID')	00009610
ISN 0465	809	FORMAT(' ',10X,'COLUMN 8 = CASH FLOW AFTER TAXES')	00009620
ISN 0466	810	FORMAT(' ',10X,'COLUMN 9 = INTEREST ON DEBT AND RETURN ON ',	00009630
	1	'EQUITY BASED ON COLUMN 1')	00009640
ISN 0467	811	FORMAT(' ',10X,'COLUMN 10 = REDUCTION OF OUTSTANDING CAPITAL',	00009650
	1	' INVESTMENT, COLUMN 8-9')	00009660
ISN 0468	812	FORMAT(' ',10X,'COLUMN 11 = OUTSTANDING CAPITAL INVESTMENT AT',	00009670
	1	' END OF YEAR INCL WORKING CAPITAL. COL 1-10')	00009680
ISN 0469	813	FORMAT(' ',15X,'TOTAL',53X,F15.5,/)	00009690
ISN 0470	901	FORMAT(' ',10X,'COLUMN 1 = NEW INVESTMENT MADE AT START OF YEAR')	00009700
ISN 0471	902	FORMAT(' ',10X,'COLUMN 2 = TOTAL CAPITAL AT START OF YEAR')	00009710
ISN 0472	903	FORMAT(' ',10X,'COLUMN 3 = DEPRECIATION ALLOWANCE FOR TAXES')	00009720
ISN 0473	904	FORMAT(' ',10X,'COLUMN 4 = INTEREST ON DEBT')	00009730
ISN 0474	905	FORMAT(' ',10X,'COLUMN 5 = INVSTMENT TAX CREDIT TAKEN THIS YR')	00009740
ISN 0475	906	FORMAT(' ',10X,'COLUMN 6 = FEDERAL TAXABLE INCOME')	00009750
ISN 0476	907	FORMAT(' ',10X,'COLUMN 7 = FEDERAL INCOME TAX PAID')	00009760
ISN 0477	908	FORMAT(' ',10X,'COLUMN 8 = STATE TAXABLE INCOME')	00009770

```

ISN 0478      900 FORMAT(' ',10X,'COLUMN 9 = AFTER-TAX RETURN ON EQUITY')      00009780
ISN 0479      910 FORMAT(' ',10X,'COLUMN 10 = LOCAL PROPERTY TAX PAID')        00009790
ISN 0480      911 FORMAT(' ',10X,'COLUMN 11 = CALCULATED FEDERAL INCOME TAX PRIOR', 00009800
              1      ' TO NONNEGATIVITY CONSTRAINT')
              C****
              C
              C      IF THE OBJECT WAS TO DETERMINE THE RATE OF RETURN ON EQUITY,
              C      WE ARE DONE.
ISN 0481      IF(LL(2).EQ.1)GO TO 150.
              C
              C
              C**** PERUM PROBLEM WITH NEW RATE OF RETURN ON EQUITY. REENTRY
              C      POINT IS AT STATEMENT 45. NEQMAX = NUMBER OF RATES OF
              C      RETURN. THESE RATES OF RETURN WERE ENTERED ON CARD 14.
ISN 0483      NEQT=NEQT+1
ISN 0484      IF(NEQT.GT.NEQMAX)GO TO 150
ISN 0486      GO TO 45
ISN 0487      150 CONTINUE
              C
              C**** CALCULATIONS ARE DONE. GO TO 1 TO READ INPUT DATA FOR NEXT PROBLEM
              C      IF THERE IS NO CARD TO READ PROGRAM WILL STOP AUTOMATICALLY
              C****
              C
ISN 0488      GO TO 1
              C****
ISN 0489      END
    
```

MAIN / SIZE OF PROGRAM 00780E HEXADECIMAL BYTES

NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.	NAME	TAG	TYPE	ADD.		
K	F	I*4	001258	L	F	I*4	00125C	N	SFA	I*4	001260	KC	F	I*4	001264		
LL	SF	I*4	001400	NA	SF	I*4	00126A	ND	SF	I*4	00126C	PH	SFA	R*4	001270		
PL	SFA	R*4	001274	DOB	SFA	R*4	001278	DSL	SFA	R*4	00127C	EQH	SFA	R*4	001280		
FQL	SFA	R*4	001284	MCL	SF	I*4	00128A	NPR	SF	I*4	00128C	NSL	S	I*4	001290		
RRA	SF	R*4	001294	SUM	SF	R*4	001298	FRAC	SF	R*4	00129C	K631	SF	I*4	0012A0		
LIFE	SF	I*4	001428	NCLS	SF	I*4	0012A4	NEQT	SF	I*4	0012A8	NTRY	SF	I*4	0012AC		
NYRS	SF	I*4	0012B0	PTRY	SF	R*8	0013E8	ZERO	SF	XF	000000	DBT22	SF	R*4	0012B4		
DPFAC	SF	R*8	0013F0	EQTRY	SFA	P*4	0012B8	INTDC	SF	R*4	0012BC	NFDPR	SF	I*4	0012C0		
NLEFT	SF	I*4	0012C4	NLOSS	SFA	I*4	0012CC	NPRNT	S	I*4	0012CC	NSTRT	SF	I*4	0012D0		
PRICE	SF	R*4	001488	FTRY4	SFA	R*4	0012D4	RTNEQ	SF	R*4	0014E8	SUM16	SF	R*4	0012DA		
TOLER	SF	R*4	0012DC	TOTPR	SF	R*4	0012E0	FRXPI#	XF	R*4	000000	AMORTZ	SF	C	R*4	003200	
BALNCE	SFA	R*8	0013F8	CAPEND	SF	C	R*4	000000	CASHFL	SF	C	R*4	002580	CMPDFC	SF	R*4	0012E4
CNSTLN	SF	R*4	0012E8	CPSTRT	SF	C	R*4	0044C0	CREDIT	SFA	R*4	0012EC	DBTFRC	SF	R*4	0012F0	
DEDUCT	SF	R*4	0012F4	DELEPR	SF	R*4	0012FA	DEPREC	SF	R*4	001538	DISFAC	SF	R*4	0012FC		
DPFRAC	SF	R*4	001B78	DPLIFE	SF	R*4	001300	DPRNAM	F	R*4	001808	DPSTRT	SF	R*4	001304		
EFFNCY	SF	R*4	001BE4	EQFRAC	SF	R*4	001308	EQYRTN	SF	C	R*4	000C80	ESCCAP	SF	R*4	00130C	
ESCCON	SF	R*4	001310	ESCEXP	SF	R*4	001314	ESCEXT	SF	R*4	001318	ESCFDP	SF	R*4	00131C		
ESCINI	SF	R*4	001320	ESCRP	SF	P*4	001324	ESCWRK	SF	R*4	001328	EXINIT	SF	R*4	00132C		
EXPCON	SF	R*4	001330	EXPENS	SF	P*4	002224	EXTEXP	SF	R*4	002864	FDCOST	SF	R*4	001334		
FEDTAX	SFA	C	R*4	FPUTXN	SF	C	R*4	005780	FEEDPR	SF	R*4	002EA4	FEEDRT	SF	R*4	002F04	
FITXR	SF	R*4	001338	FPSAVE	SF	R*4	00133C	FRCINV	SF	R*4	002F64	IBCMM#	F	XF	I*4	000000	
INCOME	SF	C	R*4	INSRNC	SF	R*4	002FC4	INSURE	SF	R*4	001340	INTCON	SF	R*4	001344		
INTDAT	SF	R*4	001348	INTRST	SF	C	R*4	004800	INTTOC	SF	R*4	00134C	INTTOT	SF	R*4	001350	
INVEST	SF	R*4	003504	NCARRY	SF	I*4	001354	NCNSTR	SF	I*4	001358	NCOMPL	S	I*4	00135C		

A-19