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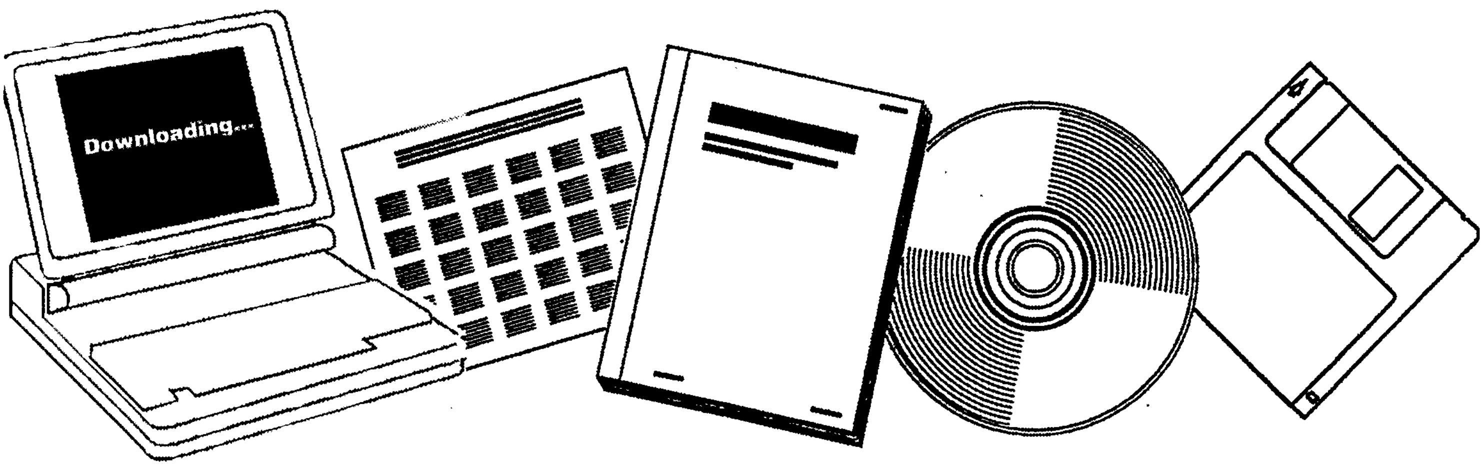
# ECONOMICS AND SITING OF FISCHER-TROPSCH COAL LIQUEFACTION

BOOZ-ALLEN AND HAMILTON, INC.
BETHESDA, MD

JUL 1979



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# ECONOMICS AND SITING OF FISCHER-TROPSCH COAL LIQUEFACTION

OFFICE OF RESOURCE APPLICATIONS
U.S. DEPARTMENT OF ENERGY

July 1979

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# TABLE OF CONTENTS


| | Page Number |
|---|---|
| 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 |

| | | Page Number |
|---|---|---|
| 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 | | |

# INDEX OF EXHIBITS


| | | Page Number |
|---|---|---|
| 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 |

Page Number


| | | |
|---|---|---|
| 3-8 | Coal Slurry Pipeline Overlaying Coalfields 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 |

Page Number

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<br>Fischer-Tropsch | 0.47<br>(0.73-0.82) ± 25% | 0.74<br>(1.00-1.09) ± 25% |
| 1985 | Crude<br>Fischer-Tropsch | 0.93<br>(1.17-1.32) ± 25% | 1.20<br>(1.44-1.59) ± 25% |

- 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.

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# 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.

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# 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 feedstock 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.

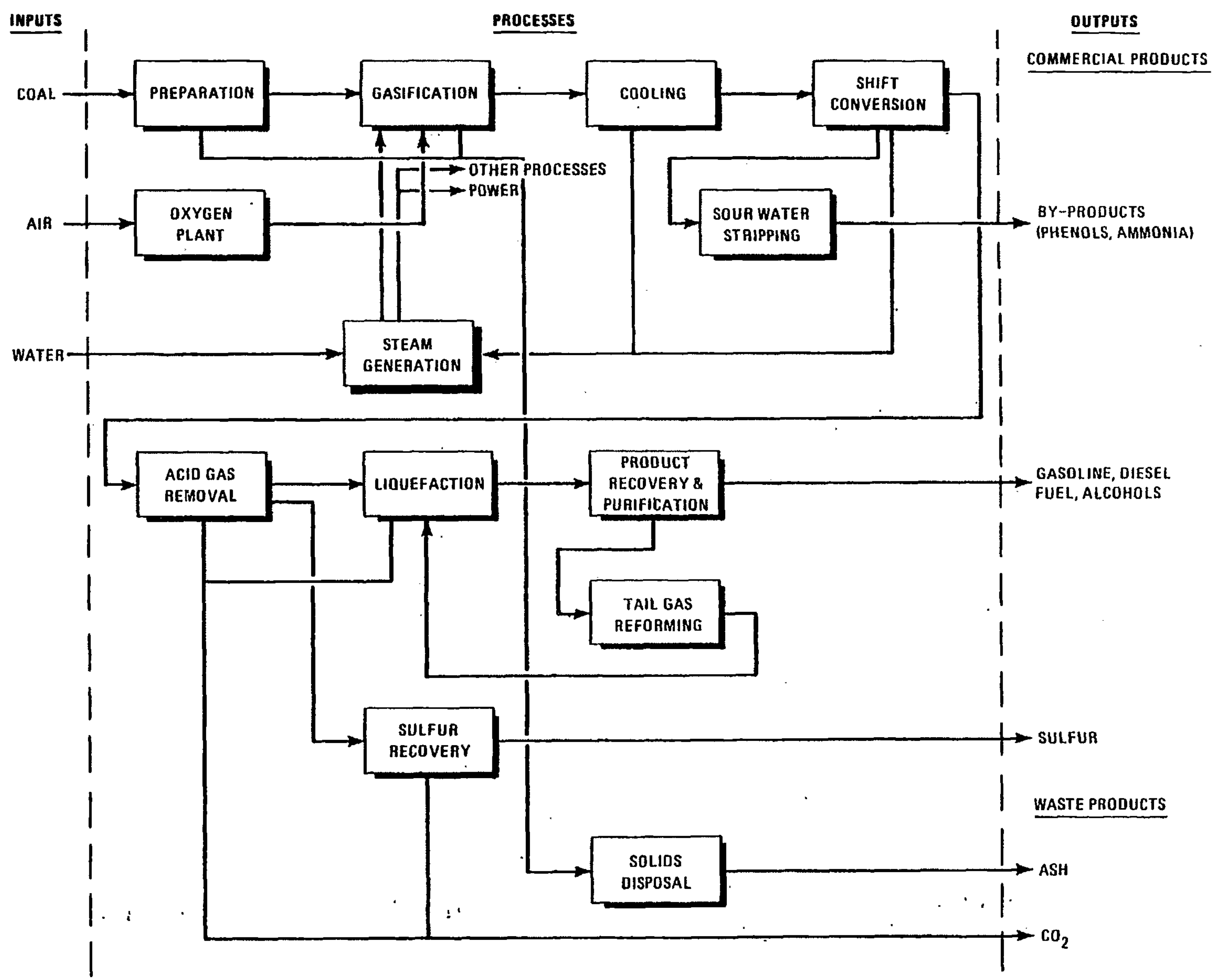
## 2.2 PROCESS DESCRIPTION

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 $H_2$) 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 $C_3/C_4$ stream, a $C_2$ 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-$C_2$-stream is eventually recovered. In the SASOL II plant, the light olefins are polymerized and partially hydrogenated. Medium weights ($C_5$-$C_{12}$) are isomerized, and heavy products ($C_{13+}$) 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

| | Tons Per Stream Day | Percentage of Total |
|---|---|---|
| Liquid Products | | |
| Unleaded Gasoline | 6,010 | 58 |
| Diesel Fuel | 1,055 | 10 |
| Ethylene | 865 | 8 |
| Alcohols | 400 | 4 |
| Subtotal | 8,330 | 80 |
| By-Products | | |
| Tar Products | 840 | 8 |
| Ammonia | 195 | 2 |
| Sulfur | 1,015 | 10 |
| Subtotal | 2,050 | 20 |
| Total | 10,380 | 100 |
| Electricity for Sale | $2.97 \times 10^6$ 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., Fischer-Tropsch Complex Conceptual Design/Economic Analysis for Oil and SNG Production, 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 | $781X10^6$ gal/yr | 125,000 Btu/gal | 97.6 | 65.0 | 35.5 |
| Diesel Fuel | $130X10^6$ gal/yr | 120,000 Btu/gal | 15.6 | 10.4 | 5.7 |
| Ethylene | 317,000 t/yr | $4.0X10^7$ Btu/t | 12.7 | 8.5 | 4.6 |
| Alcohols | 145,000 t/yr | $2.5X10^7$ Btu/t | 3.6 | 2.4 | 1.3 |
| Subtotal | | | 129.5 | 86.3 | 47.1 |
| By-products | | | | | |
| Tar Products | 307,300 t/yr | $4.0X10^7$ Btu/t | 12.3 | 8.2 | 4.5 |
| Ammonia | 71,700 t/yr | $2.4X10^7$ Btu/t | 1.7 | 1.1 | 0.6 |
| Sulfur | 370,000 t/yr | $8.0X10^6$ Btu/t | 3.0 | 2.0 | 1.1 |
| Subtotal | | | 17.0 | 11.3 | 6.2 |
| Electricity | $1,083X10^6$ kWhr/yr | 3,413 Btu/Whr | 3.7 | 2.4 | 1.3 |
| Total | | | 150.2 | 100.0 | 54.6 |
| Coal | $10.95x10^6$ 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

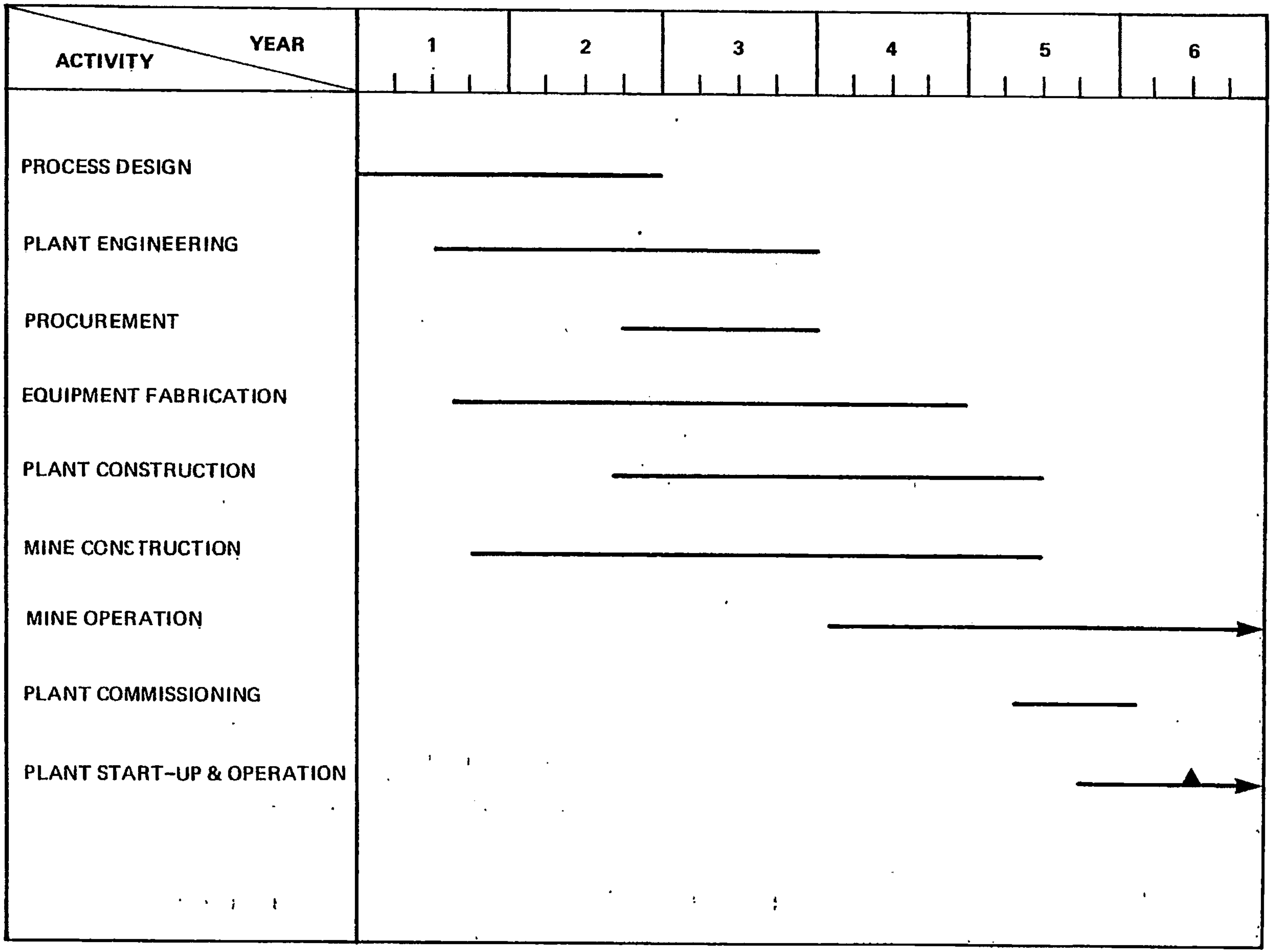
Exhibit 2-5 details the schedule for design, construction, and initial operation of a representative coal liquefaction plant. It is estimated that 6 years will be required from the time permits are obtained and detailed design is authorized. Obtaining the necessary permits could easily add 1 to 2 years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

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

| Component of Crude Oil | Compounds | Percent |
|---|---|---|
| Light Hydrocarbons | $CH_4$ | 10.0 |
| | $C_2H_4$ | 4.0 |
| | $C_2H_6$ | 6.0 |
| | $C_3H_6$ | 12.0 |
| | $C_3H_8$ | 2.0 |
| | $C_4H_{10}$ | 1.0 |
| | $C_{5+}$ | |
| Gasoline Fraction | $C_5 - C_{12}$ | 31.0 |
| Diesel | $C_{13} - C_{18}$ | 5.0 |
| Heavy Oil & Wax | $C_{19} - C_{21}$ | 1.0 |
| | $C_{22} - C_{30}$ | 3.0 |
| | $C_{31}$ | 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



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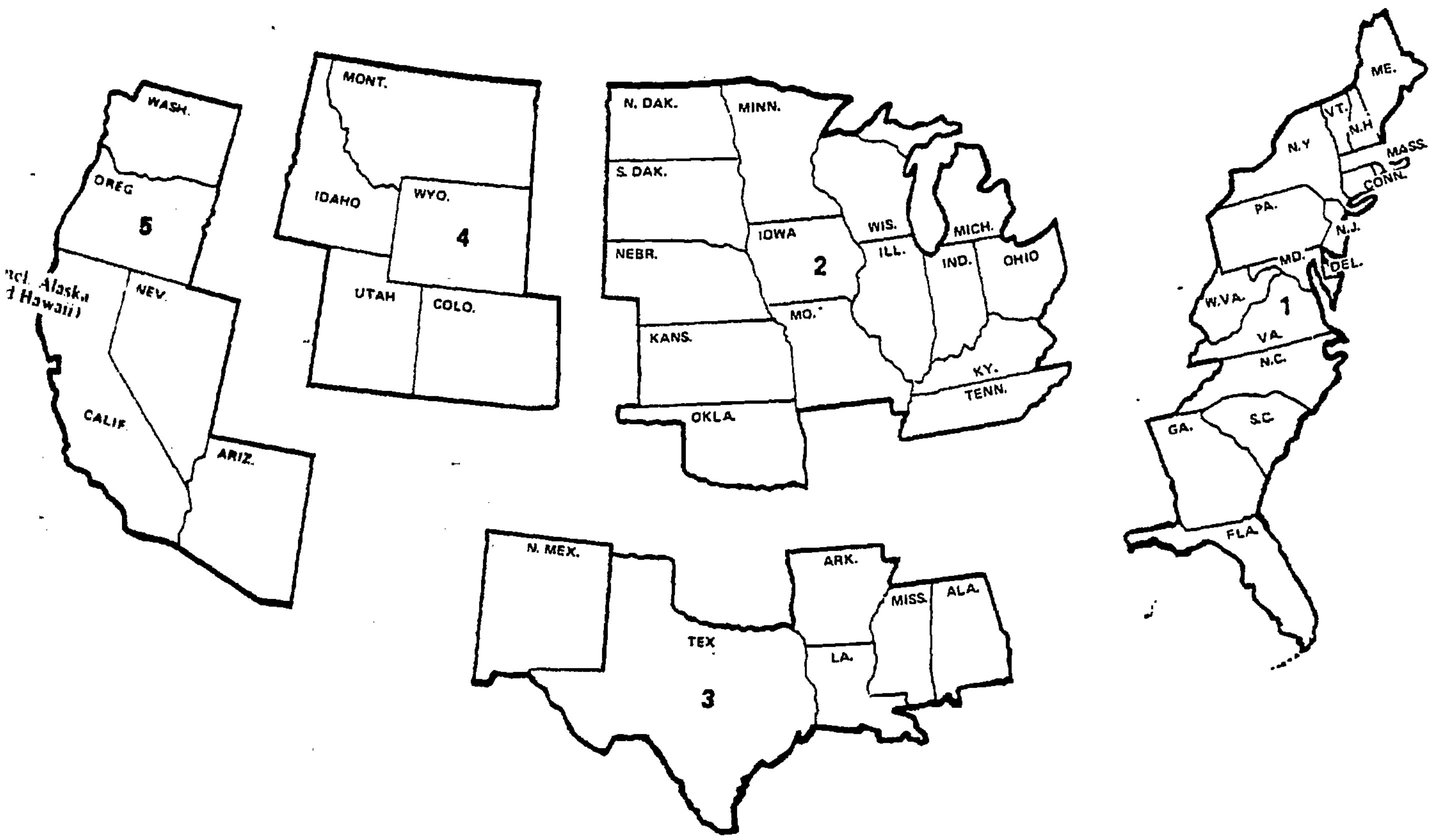
## 3. PLANT LOCATION

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 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | $10^3$bbl/day | % | $10^3$bbl/day | % | $10^3$bbl/day | % | $10^3$bbl/day | % | $10^3$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 |

### 3.1.2 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)

| PAD District | 1985 | 1990 | 1995 |
|---|---|---|---|
| 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

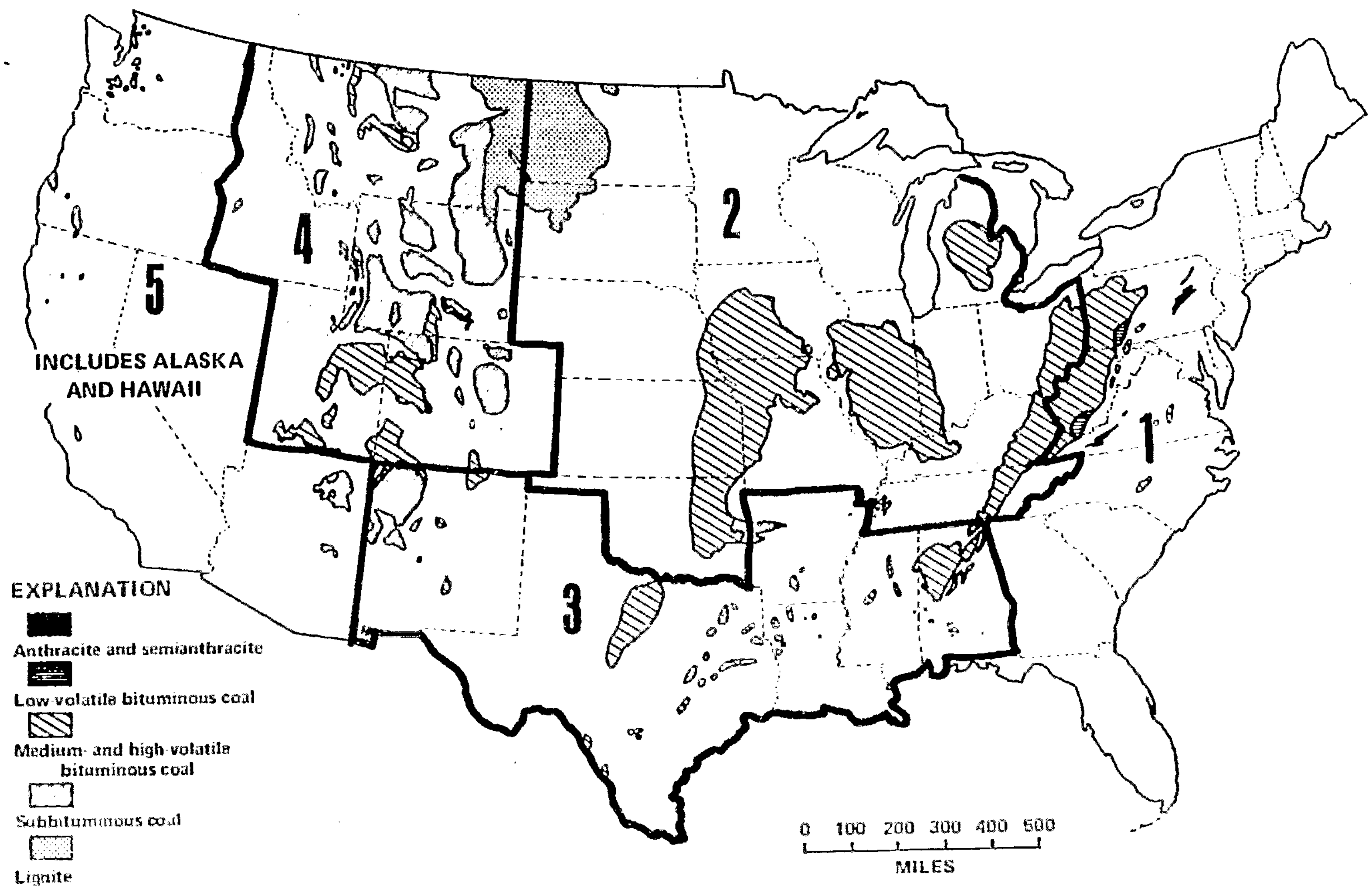


EXHIBIT 3-3
Coal Production and Resources of the U.S.

| | 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:

| Product | Million Tons/Year | Percent by Weight |
|---|---|---|
| Motor Fuels | 2.15 | 64 |
| Ethylene | 0.32 | 10 |
| Tar Products | 0.28 | 8 |
| Ammonia (asN) | 0.07 | 2 |
| Sulfur | 0.37 | 11 |
| Chemicals | 0.15 | 5 |
| | 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.

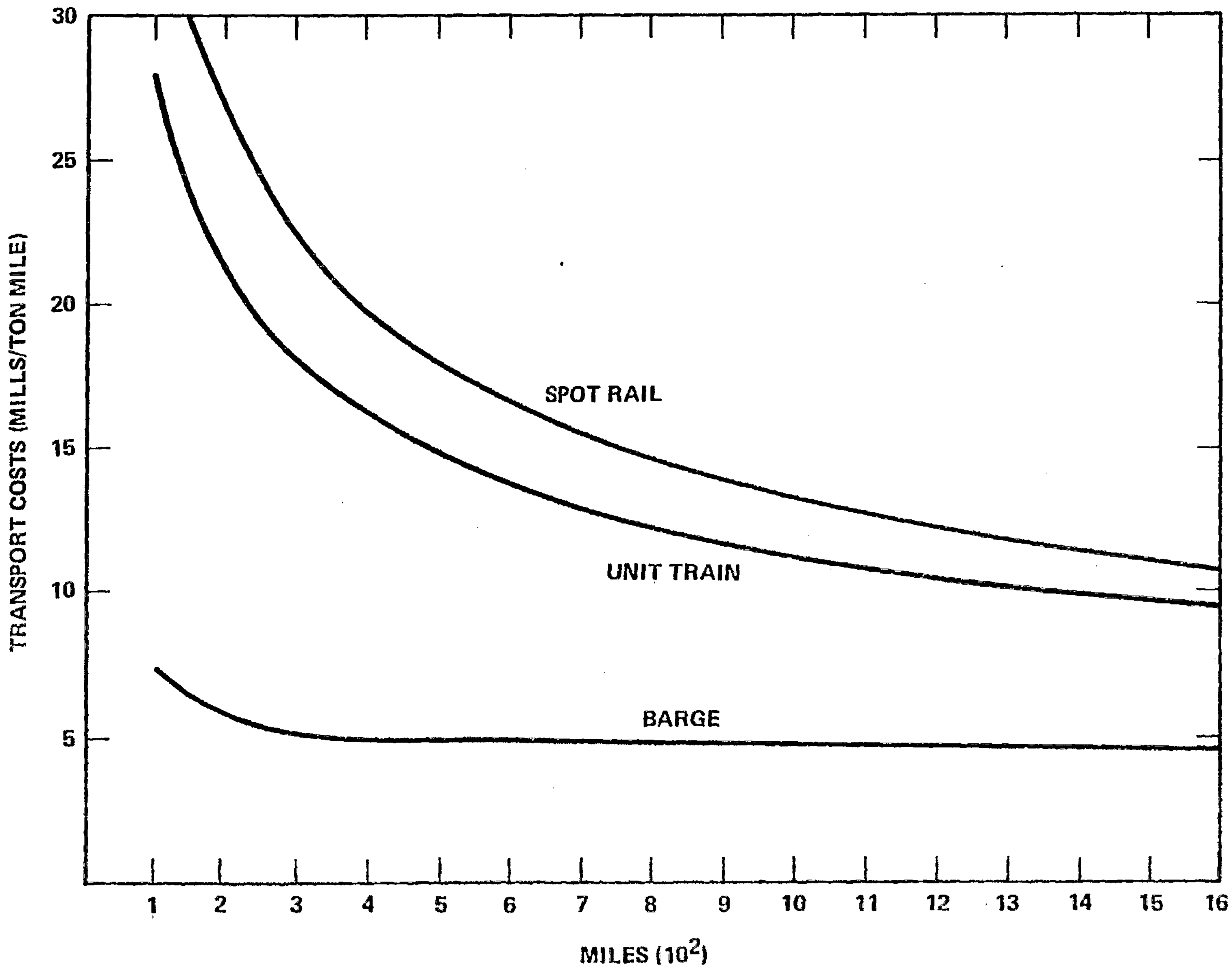
### 3.3.4 Other Products Transportation System

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 | . Moves about 10% of the raw coal shipped in the U.S.<br>. 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.<br>. Most waterway coal movements in 1974 were made on rivers in the Ohio river system, as shown in Exhibit 3.6.<br>. Exhibit 3.6 also shows that the Ohio and Mississippi basins link two coal-rich regions, with coal movements in opposite directions occuring 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:<br>- Needs for different grades of coal<br>- Interplay of spot and long-term delivery markets<br>- Captive production and transportation<br>- Seasonality of supply/demand equilibrium. | . 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. | . Limited to the Ohio and Mississippi basins, thus with no direct access to western coals or to eastern markets. |
| Unit Train | . Railroads currently transport about 70% of all bituminous coal in the U.S.<br>. For the quantities of coal being considered, about 10MMTPY, unit trains are the cheapest form of rail transportation due to:<br>- Special rates, about one-third below ICC-based general rates for conventional trains<br>- Better utilization of equipment<br>- Elimination of standard railroad tie-ups such as classification yards and layover posts<br>- Better coordination between mine production and coal usage. | . The main advantage is the extensive nationwide railroad network already in place, as shown in Exhibit 3.7.<br>. Still the cheapest mode next to barging and slurrying, 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. | . 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).<br>. 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. |
| Slurry Pipeline | . 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.<br>. Several slurry pipelines are being planned as shown in Exhibit 3.8. | . Low cost, estimated in the new long haul projects to be comparable to barging. | . Outcome uncertain due to institutional barriers. |
| Truck | . Trucks move about 10% of the raw coal shipped in the U.S., about the same as barges. | . Flexibility over short distances. | . Not cost effective for large distances or large volumes of coal. |

EXHIBIT 3-5
Modal Coal Transport Costs (1985)




Source: Nagarvala, 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

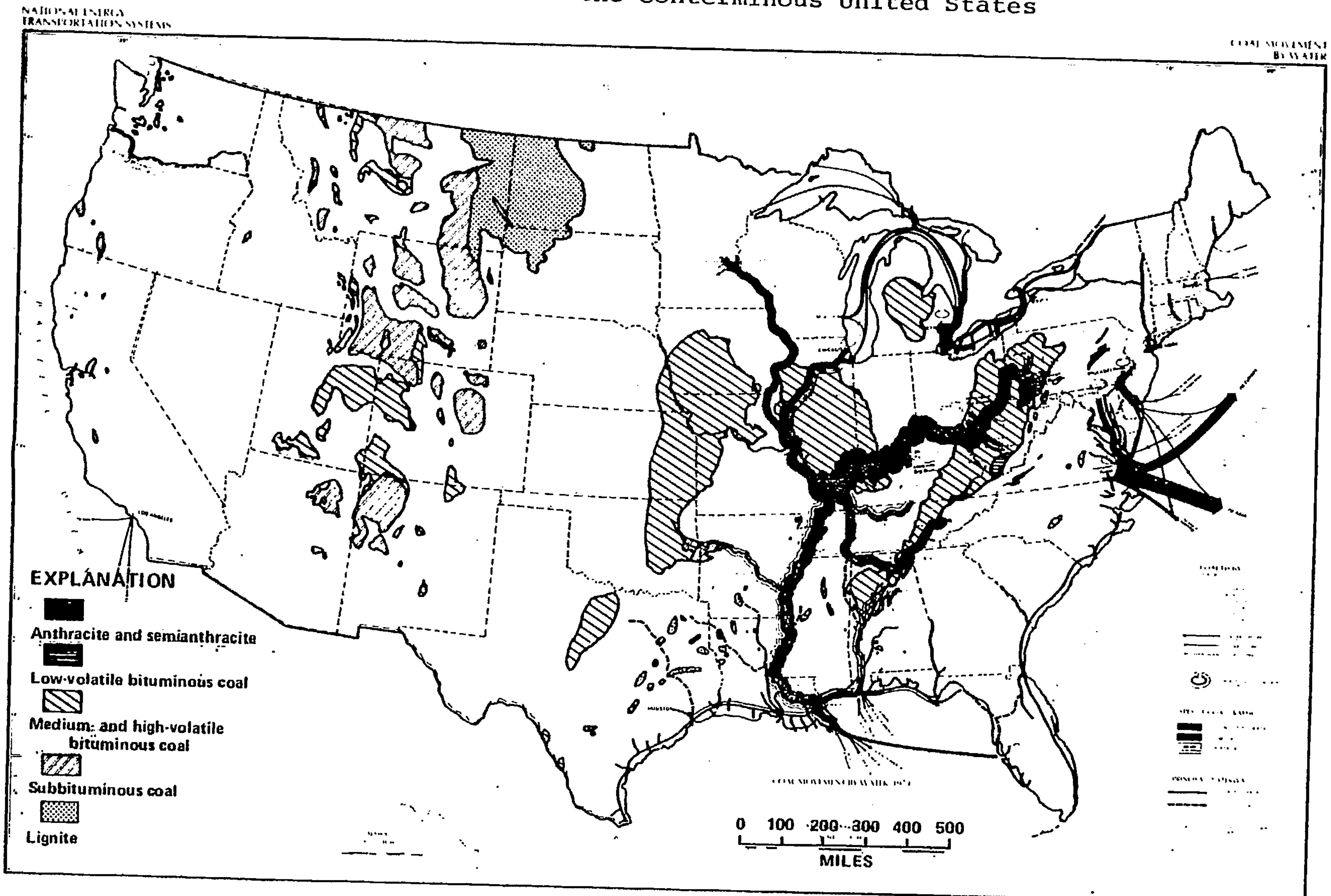


EXHIBIT 3-7
Coal Movements by Railroad Overlaying
Coalfields of the Conterminous United States

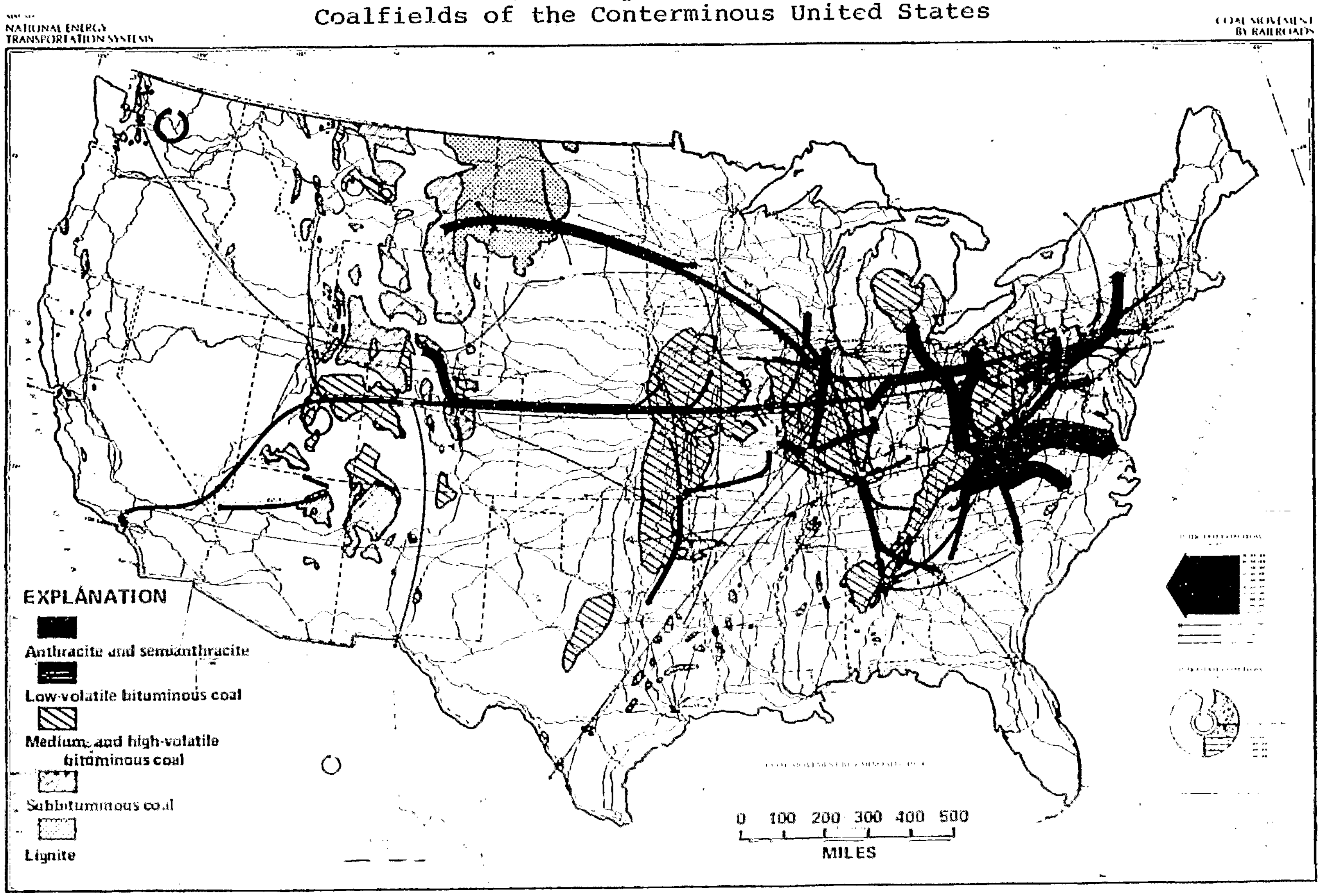


EXHIBIT 3-8
Coal Slurry Pipeline Overlaying
Coalfields of the Conterminous United States

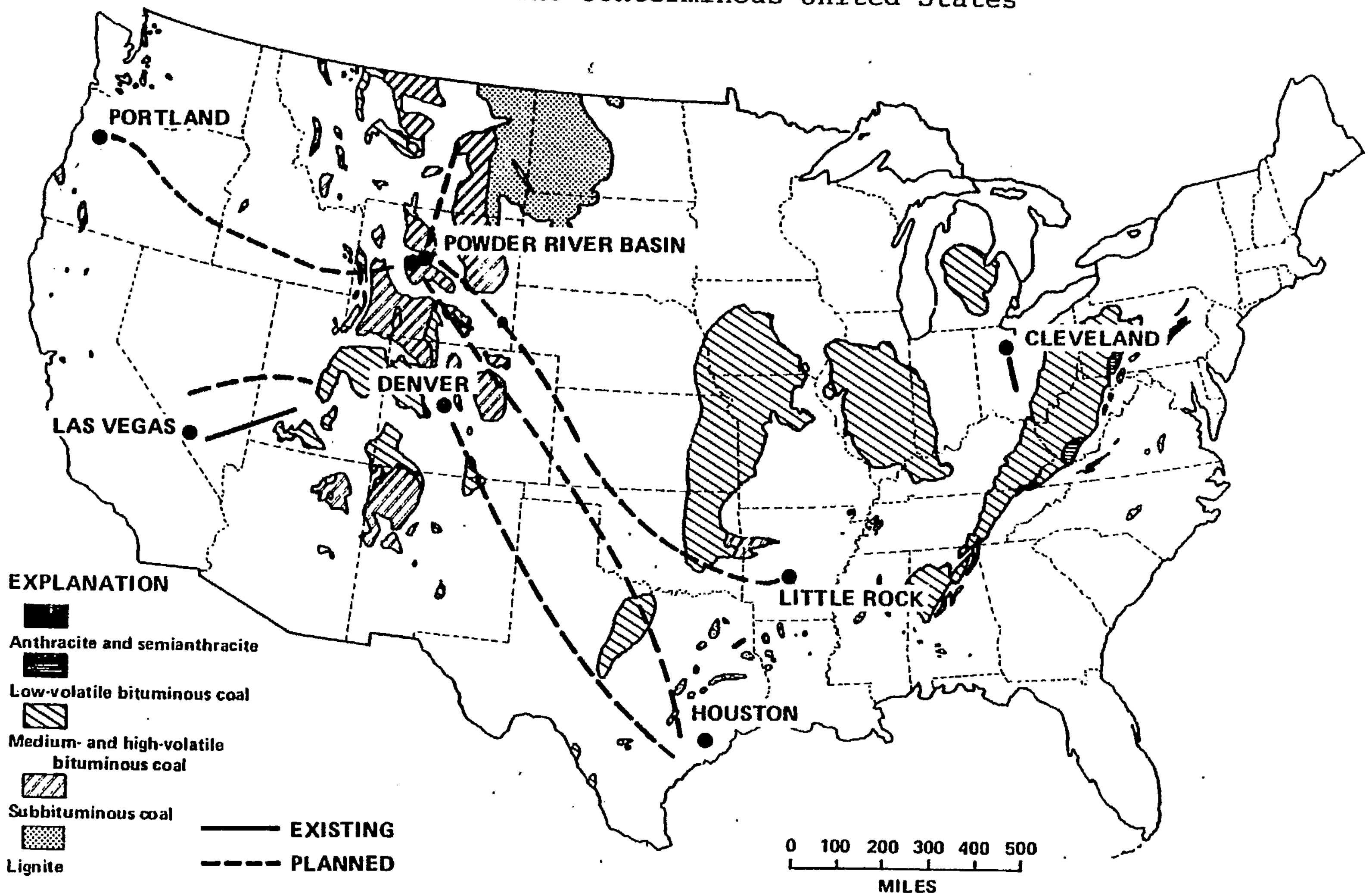
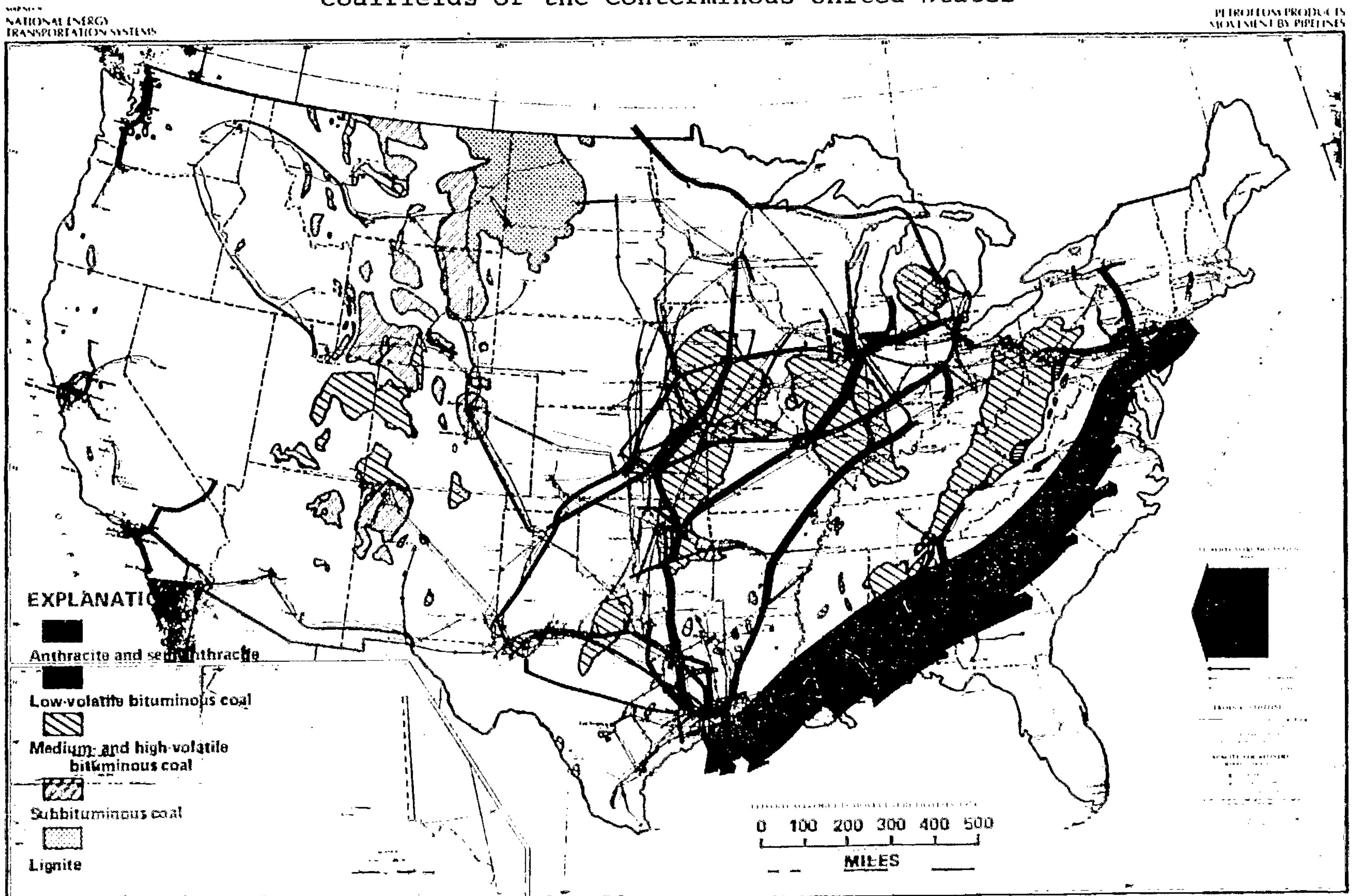


EXHIBIT 3-9
Petroleum Movement by Pipeline Overlaying
Coalfields of the Conterminous United States



3.3.5 Transportation Model

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

Case 1: $$C_1 = \sum_{1}^{6} V_n \cdot X_n \cdot U_n \qquad (1)$$

$C_1$ = 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)

Case 2: $$C_2 = Q \cdot X \cdot U_c \qquad (2)$$

$C_2$ = 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

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

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

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

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:

| Coal | | Fuel | | |
|---|---|---|---|---|
| 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[4] (Cents/Ton Mile) | Transportation Mode |
|---|---|---|---|
| Coal | 10.95 | 1.3<br>0.81<br>0.43 | Unit Train[1]<br>Slurry[2]<br>Barge[3] |
| Motor Fuels | 2.1 | 0.39<br>0.54 | Pipeline[1]<br>Pipeline[2] |
| Ethylene | 0.259 | 2.6 | Rail/Water[1] |
| Tar Products | 0.252 | 2.6 | Rail/Water[1] |
| Ammonia (AS N) | 0.07 | 2.6 | Rail/Water[1] |
| Sulfur | 0.37 | 2.6 | Rail/Water[1] |
| Chemicals | 0.12 | 2.6 | Rail/Water[1] |

(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:

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

  - $F(Q)/Q$ 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[1] | | 1977 Gasoline Demand[2] | | 1977 Crude Production[3] | | Pipelines Availability | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | Crude | Products | Direction | |
| | MM Tons | % | $10^3$ Bbl/Day | % | $10^3$ Bbl/Day | % | | | 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 | | | | |

1 Paul Averitt "Coal Resources of the U.S.," January 1970

2 Federal Highway Administration and National Petroleum News Factbook

3 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 | CONCLU-SION | COAL RESERVES VS. REQUIREMENTS | PIPE-LINES | ENVIRON-MENTAL ACCEPTABILITY | 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

### 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 #6[1] | Eastern[2] Texas Lignite | Wyoming[2] Subbituminous | South[3] African |
|---|---|---|---|---|
| High Heating Value (Btu/lb) | 12,550 | 7,226 | 8,244 | 10,300 |
| FOB 1985 Projection (1978 $/ton)[4] | 23.58 | 9.57 | 8.97 | |
| FOB 1985 Projection (1978 $/MMBtu)[4] | 0.94 | 0.66 | 0.54 | |
| Proximate Analysis (%) | | | | |
| 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 |
| Ultimate Analysis (%) | | | | |
| 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 |

(1) Ralph M. Parson Co.
(2) Keystone's Coal
(3) Sasol
(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.

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# 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.[1] 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.

1 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 | |
|---|---|---|---|---|
| | $10^6$ | % of Total | $\$10^6$/Year | % of Total |
| 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 | 81 | 3.0 | - | - |
| Process Plant Subtotal | 2240 | 82.7 | 164.2 | 87.1 |
| Power Plant | 257 | 9.5 | 8.5 | 4.5 |
| Offsites | 169 | 6.2 | 12.0 | 6.4 |
| 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 ±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.

| | Illinois | Texas | Wyoming |
|---|---|---|---|
| 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 | $1.32/gal | $1.27/gal | $1.17/gal |

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[1]

| | Production (1,000,000 Units/Year) | Unit Price $/Unit | Revenue ($ Millions) | Percent of Total |
|---|---|---|---|---|
| **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 | 2.6 | 0.5 |
| 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 | 29.4 | 5.7 |
| SUBTOTAL | - | - | 79.5 | 15.4 |
| TOTAL | - | - | 518.3 | 100.0 |

[1] 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[1] | 1.38 | 1.33 | 1.21 |
| Constant | 1.26 | 1.23 | 1.13 |
| Oil Prices | | | |
| Increasing at 1%/Year[1] | 1.54 | 1.48 | 1.36 |
| Increasing at 3%/Year[1] | 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[2] | 0.93 | 0.93 | 0.93 |

[1]Real price increases (above inflation).

[2]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)

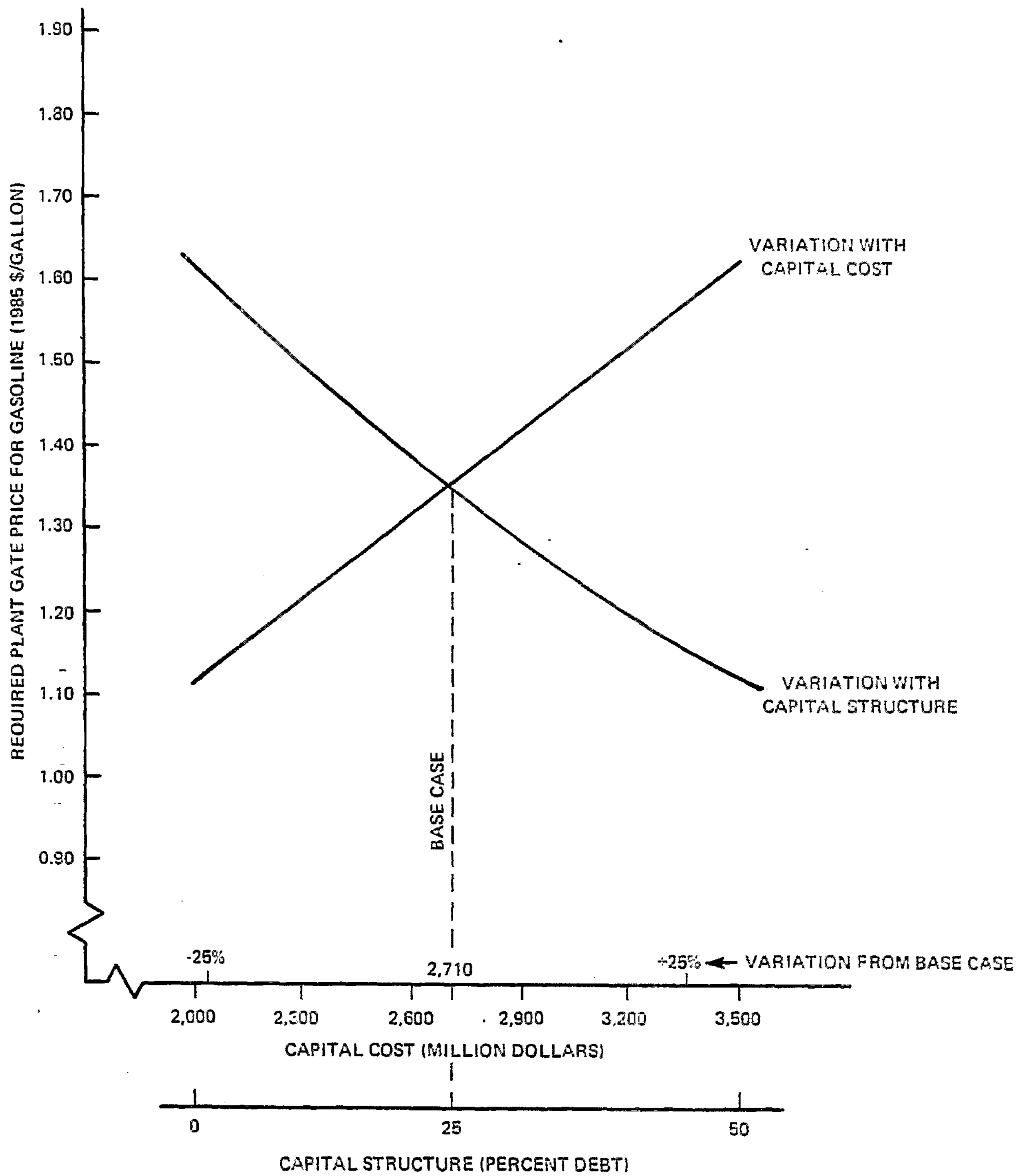
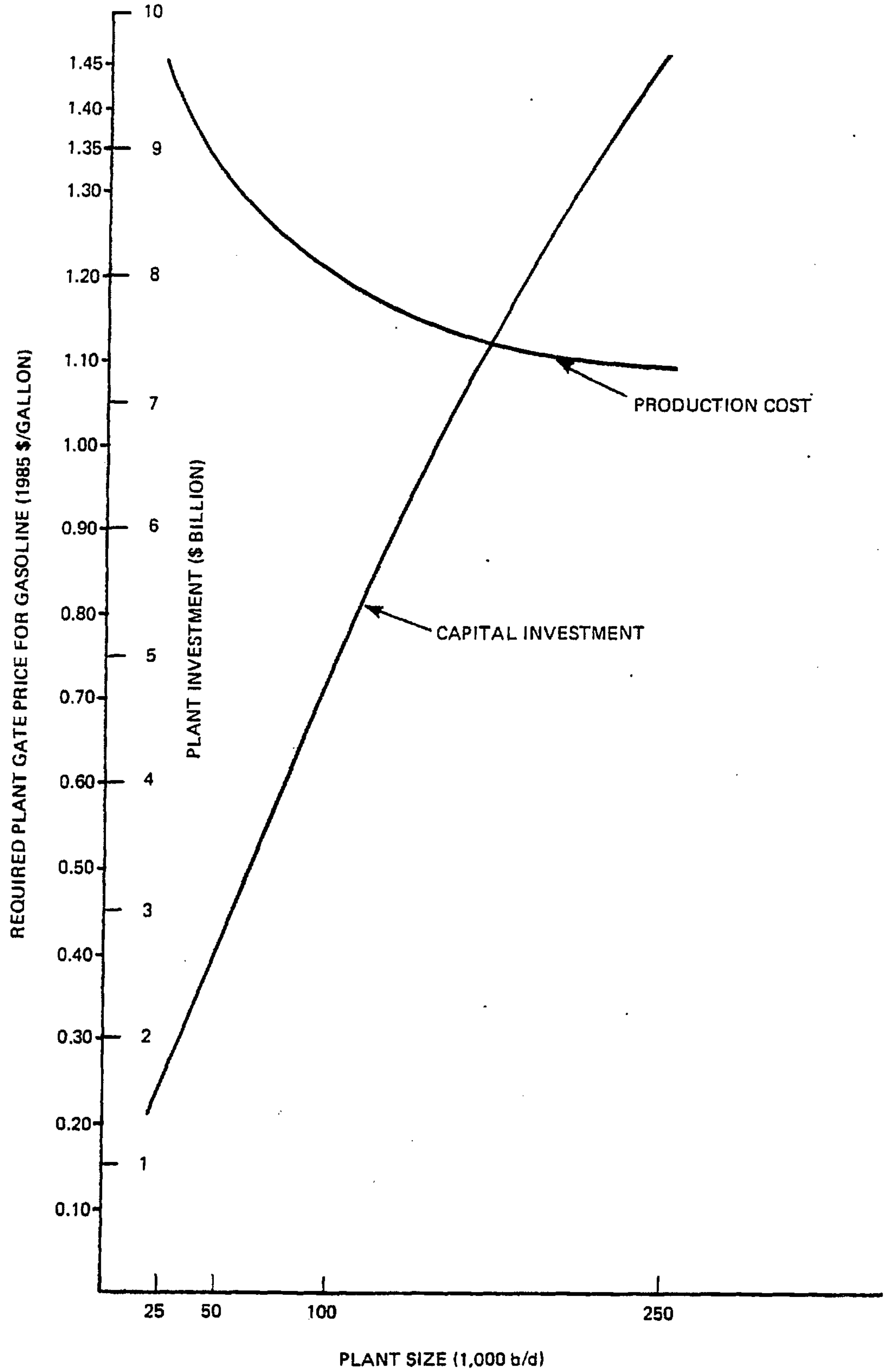


EXHIBIT 4-7
Effect of Size of Fischer-Tropsch Plant on Process Economics (Illinois Location)



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[1] | 0.93 | - | 0.93 | - | 0.93 | - |

[1] 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[1] |
|---|---|---|
| Debt/Equity | 35/65 | -10¢/gal |
| Depreciation | 20-yr Straight line | — |
| By-product Values | Market prices | — |

[1]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

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

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

                 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  PRRNAM(15),INVEST(400),EFFNCY(400),EXPENS(400),
                      1     PLTEXP(400),DEPREC(400),EXTEXP(400)
   ISN 0003            DIMENSION PROPTY(400),INSRNC(400),WORKCP(400)
   ISN 0004            DIMENSION PRDRAT(24),PRICE(24)
   ISN 0005            DIMENSION FEEDRT(24),FEEDPR(24),FRCINV(24)
   ISN 0006            DIMENSION DPFRAC(24),LIFE(24)
   ISN 0007            DIMENSION LL(10)
   ISN 0008            DIMENSION DPRNAM(3)
   ISN 0009            DIMENSION RTNEQ(20)
   ISN 0010            REAL*4 INVEST,INSURE,INTDBT,INCOME,INSRNC,INTRST,INTCON,INTTOT
   ISN 0011            REAL*4 INTDC,INTTDC
   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          STLTAX(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.
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C
C**** NOTE: ALL DOLLAR QUANTITIES ARE INPUTTED AS MILLIONS OF DOLLARS.
C**** NOTE: INTEREST RATES, ONSTREAM FACTORS,ETC. ARE INPUT AS DECIMAL
C FRACTIONS RATHER THAN AS PERCENTAGES.
C
C
C**** NONSUBSCRIPTED VARIABLES
C****
C BALNCE   = TRIAL VALUE OF AMOUNT LEFT AT END OF PROJECT LIFE.
C CMPDFC   = COMPOUNDED INVESTMT FACTOR FOR CONSTR PERIOD USED IF
C            LL(7)=2 AND INTEREST DURING CONSTR IS COMPUTED.
C CNSTLN * = AMOUNT OF CONSTRUCTION LOAN, $MM.
C CREDIT   = TOTAL INVESTMENT TAX CREDIT,  $MM.
C DBTFPC * = FRACTION OF TOTAL INVESTMT IN DEBT  EXAMPLE 0.25
C DELFPR * = DELTA FEED PRICE FOR ITERATION OF FEED PRICE.
C DISFAC   = DISCOUNT FACTOR BASED ON WEIGHTED AVERAGE INTEREST RATE.
C DPFAC    = FACTOR USED FOR ESTIMATING NEW TRIAL VALUE OF PRICE.
C DPLIFE   = DEPRECIABLE LIFE FOR TAX PURPOSES, YEARS   EXMPL 15.0
C DPSTRT   = YEAR IN WHICH DEPRECIATION ALLOWANCE STARTS  EXMPL 5.
C EQFRAC * = FRACTION OF TOTAL INVESTMT IN EQUITY    EXAMPLE 0.75
C            NOTE THAT SUM OF DBTFPC AND EQFRAC MUST BE 1.0
C EQTRY    = TRIAL VALUE OF RATE OF RETURN ON EQUITY.
C ESCCAP * = ESCALATION, CAPITAL INVESTMENTS. FRACTION/YEAR
C ESCWRK * = ESCALATION, WORKING CAPITAL,     FRACTION/YEAR
C ESCEXT * = ESCALATION, EXTR EXPENSES,       FRACTION/YEAR
C ESCEXP * = ESCALATION, OPERATING EXPENSES,  FRACTION/YEAR
C ESCINI * = ESCALATION, PRE-OP EXPENSES,     FRACTION/YEAR
C ESCCON * = ESCALATION, CONSTANT EXPENSES,   FRACTION/YEAR
C ESCFDP * = ESCALATION, FEEDSTOCK PRICES,    FRACTION/YEAR
C ESCPRP * = ESCALATION, PRODUCT PRICES,      FRACTION/YEAR
C EXINIT * = ANNUAL OPERTG EXPNS DURING PRE-OPER PERIOD   EXMPL 0.00
C EXPCON * = ANNUAL CONSTANT OPERTG EXPENS DURING OPER PERIOD  $MM
C FITTXR * = FEDERAL INCOME TAX RATE                 EXAMPLE 0.48
C INSURE * = PROPERTY INSURANCE RATE ON PLANT INVEST EXAMPLE 0.004
C INTCON * = INTEREST RATE DURING CONSTRUCTION (OPTIONAL)
C INTDBT * = ANNUAL INTEREST RATE ON DEBT            EXAMPLE 0.085
C INTDC    = TOTAL INTEREST DURING CONSTRUCTION, USED IF LL(7).GT.0
C INTTOT * = TOTAL INTEREST RATE FOR CONSTRUCTION (OPTIONAL)
C NCARRY * = LIMITING NUMBER OF YEARS FOR TAX-LOSS CARRYOVER   EX. 5
C NCLS   * = NUMBER OF DEPRECIATION CLASSES.
C NCNSTR * = NUMBER OF YEARS OF CONSTRUCTION PERIOD, NEEDED ONLY
C            WHEN SPECIFYING A SCHEDULE OF EXPENDITURES USED FOR
C            CALCULATING INTEREST DURING CONSTRUCTION.
C NCREDT * = LIMIT FOR INVEST. TAX CREDIT CARRY-FORWARD   EXMPL. 7.
C NEQMAX * = NUMBER OF RATES OF RETURN ON EQUITY
C NFDPRS * = NUMBER OF PRICES TO BE USED FOR FEEDSTOCK 1.
C NFEEDS * = NUMBER OF FEEDSTOCKS FOR WHICH PRICE AND RATE ARE GIVEN.
C NPRODS * = NUMBER OF PRODUCTS LISTED.
C NSTRT  * = YEAR IN WHICH STARTUP OCCURS.
C NTRY     = ITERATION NUMBER FOR DETERMINING PRICE
C NTRIES * = MAXIMUM NUMBER OF ITERATIONS ALLOWED.
C NYRS   * = NUMBER OF YEARS OF ANNUAL DATA TO BE READ  EAMPL 24
C            (SAME AS NUMBER OF YRS IN PAYOUT TABULATION, =PROJLF)
C PH     * = HIGHEST PERMISSIBLE PRICE FOR PRODUCT PRICE ITERATION.
C PL     * = LOWEST PERMISSIBLE PRICE FOR PRODUCT PRICE ITERATION.
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C PRBNAM * = IDENTIFICATION OF PROBLEM
C PROJLF * = TOTAL PROJECT LIFE INCL CONSTR PERIOD   EXAMPLE 24.0
C PROPTX * = LOCAL PROPERTY TAX RATE ON PLANT INVEST EXAMPLE 0.02
C PROEXP * = EXPENSES PROP TO ONSTREAM TIME. MM $/YR
C PTRY     = TRIAL VALUE OF PRICE(1) IN ITERATION NTRY.
C RTNEQY   = ANNUAL AFTER-TAX RATE OF RETURN ON EQUITY  EXMPL 0.16
C SALVGE * = SALVAGE VALUE RECOVERED AT END OF PROJECT, $MM.
C STAINC * = STATE INCOME TAX RATE                EXAMPLE 0.04
C STAREV * = STATE GROSS REVENUE TAX RATE              EXAMPLE 0.02
C TOLER  * = TOLERANCE FOR CONVERGENCE OF CASH FLOW TABLE, $MM
C TOLPRC * = TOLERANCE FOR PRODUCT PRICE CONVERGENCE, $/UNIT
C TOTDEP   = TOTAL DEPRECIABLE CAPITAL INVESTMENT,    $MM.
C TOTDNV * = TOTAL DEPR INVESTMT AS INPUTTED. I.E. SUM OF INVEST(N).
C TOTDP2   = TOTAL DEPRECIABLE CAPITAL LESS SALVAGE VALUE,  $MM.
C TOTDP3   = DEPRECIABLE CAPITAL IN A PARTICULAR CLASS (TEMPORARY).
C TXCRED * = FEDERAL INVESTMENT TAX CREDIT             EXAMPLE 0.10
C WRKCAP * = WORKING CAPITAL, TOTAL.       $MM
C YDPREC   = AMOUNT OF ANNUAL DEPRECIATION IN A PARTICULAR CLASS.
C
C**** SUBSCRIPTED VARIABLES
C
C AMORTZ(N)     = AMOUNT OF CAPITAL RETIRED IN YEAR (N),  $MM.
C CAPEND(N)     = TOTAL OUTSTANDING INVESTMENT AT END OF YEAR (N).
C CASHFL(N)     = CASH FLOW AFTER TAXES IN YEAR (N)     $MM.
C CPSTRT(N)     = OUTSTANDING CAPITAL INVESTMENT AT START OF YEAR (N)  $M
C DEPREC(N)     = DEPRECIATION TAKEN FOR TAX PURPOSES IN YEAR (N)   $MM.
C DPFRAC(NCL)* = FRACTION OF TOTAL DEPRECIABLE IN CLASS NCL.
C EFFNCY(N)  * = ONSTREAM EFFICIENCY (PLANT FACTOR) FOR YEAR N  EXMPL .9
C EQYRTN(N)     = AMOUNT ALLOCATED TO RETURN ON EQUITY IN YEAR (N),  $MM.
C EXPENS(N)     = OPERATING EXPENSE YR N, NOT PROPOR TO ONSTREAM TIME
C EXTEXP(N)  * = ADDITIONAL OPERATING EXPENSE FOR YEAR (N)
C FEEDPR(K)  * = PRICE OF FEEDSTOCK (K),   $/UNIT
C FEEDPT(K)  * = CONSUMPTION RATE OF FEEDSTOCK (K), AT 100% ONSTREAM
C            EFFICIENCY,  MM UNITS/YEAR.
C FEDTAX(N)     = FEDERAL INCOME TAX PAID IN YEAR (N)  $MM.
C FEDTXN(N)     = FED INCOME TAX CALCULATED, MAY BE NEGATIVE   $MM.
C FRCINV(N)  * = FRACTIONAL DISTRIBUTION OF DEPR INVEST IN CONSTR PERIOD
C INCOME(N)     = GROSS INCOME FROM SALES IN YEAR (N).
C INTRST(N)     = INTEREST ON DEBT PAID IN YEAR (N).      $ MM.
C INVEST(N)  * = DEPRCBL CAPITAL INVESTMT MADE AT START OF YR N    $MM
C LIFE(NCL)  * = DEPRECIATION LIFE FOR CLASS NCL.
C PLTEXP(N)     = TOTAL ANNUAL EXPENSE IN YEAR (N) EXCL TAXES AND INTERES
C PRICE(K)   * = SELLING PRICE FOR PRODUCT (K), $/UNIT
C PRDRAT(K)  * = BASE PROD. RATE FOR PRODUCT (K), MM UNITS/YEAR
C PROPTY(N)     = LOCAL PROPERTY TAXES PAID IN YEAR (N) $MM.
C RTNEQ(NEQT)* = ANNUAL AFTER-TAX RATE OF RETURN ON EQUITY
C STLTAX(N)     = TOTAL STATE AND LOCAL TAXES IN YEAR (N)    $MM.
C STXABL(N)     = STATE TAXABLE INCOME IN YEAR (N)   $MM
C TAXABL(N)     = FEDERAL TAXABLE INCOME IN YEAR (N).  $MM.
C TOTRTN(N)     = TOTAL RETURN TO DEBT+EQUITY IN YEAR (N). $MM.
C TXCRDT(N)     = INVESTMENT TAX CREDIT TAKEN IN YEAR (N). $MM.
C TXLOSS(N)     = TAX LOSS IN YEAR (N). $MM.
C WORKCP(N)  * = WORKING CAPITAL INVESTMENT AT START OF YEAR N  $MM
C****
C
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          C PLANT STARTUP IS ASSUMED TO OCCUR AT THE START OF YEAR DPSTRT.
          C AND THIS IS THE SAME TIME AT WHICH DEPRECIATION ALLOWANCE BEGINS.
          C
          C****
          C
          C OPTIONS CONTROLLED BY LL SIGNALS INPUTTED ON CARD 1.
          C
          C LL(1) = 0 SUM OF YEARS DIGITS DEPRECIATION FOR TAX PURPOSES
          C LL(1) = 1 STRAIGHT LINE DEPRECIATION FOR TAX PURPOSES
          C LL(1) = 2 DOUBLE DECLINING BALANCE DEPRECIATION FOR TAX PURPOSES
          C LL(2) = 0 OBJECT IS TO DETERMINE PRICE OF MAIN PRODUCT (PRICE(1)).
          C LL(2) = 1 OBJECT IS TO DETERMINE RATE OF RETURN ON EQUITY.
          C LL(3) = 0 PRINT ALL ITERATIONS
          C LL(3) = 1 PRINT FINAL ITERATION ONLY
          C LL(4) = 0 DO NOT ITERATE FEED PRICE.
          C LL(4) = 1 ITERATE FEEDSTOCK(1) PRICE USING DELFPR.
          C LL(5) = 0 NO TAX LOSS CARRYOVER ALLOWED
          C LL(5) = 1 FIVE YEAR TAX CARRYOVER ALLOWED
          C LL(6) = 0 FEDERAL TAX CANNOT GO NEGATIVE
          C LL(6) = 1 FEDERAL TAX CAN GO NEGATIVE
          C LL(7) = 0 INTEREST DURING CONST  NOT ADDED TO DEPR CAPITAL
          C LL(7) = 1 INTEREST DURING CONSTR AT RATE INTTOT ADDED TO DEPR CAPITAL
          C LL(7) = 2 INTEREST DURING CONSTR COMPUTED FROM FRCINV AT RATE INTCON
          C LL(8) = 0 PRINT SUPPLEMENTARY TABLE OF CASH FLOW INFORMATION
          C LL(8) = 1 OMIT  SUPPLEMENTARY TABLE OF CASH FLOW INFORMATION
          C LL(9) = 0 NO ESCALATION
          C LL(9) = 1 ESCALATION FACTORS APPLIED PER CARD 19 INPUTS.
          C
          C
          C**** NOTE: ALL DOLLAR QUANTITIES ARE HANDLED AS MILLIONS OF DOLLARS.
          C**** NOTE: INTEREST RATES, ONSTREAM FACTORS, ETC ARE HANDLED AS DECIMAL
          C FRACTIONS RATHER THAN AS PERCENTAGES.
          C****
          C
          C REENTRY POINTS IN PROGRAM ARE AS FOLLOWS.
          C FOR READING NEW SET OF INPUT DATA CARDS              STATEMENT  1
          C FOR RERUNNING WITH NEW RATE OF RETURN ON EQUITY      STATEMENT 45
          C FOR RERUNNING WITH NEW FEEDSTOCK 1 PRICE            STATEMENT 48
          C FOR CONVERGING THE CASH FLOW PAYOUT TABULATION      STATEMENT 55
          C
          C
          C
          C**** START OF INPUT DATA  *************
          C
          C**** CARD 1.  CONTROL SIGNALS FOR OPTIONS. PROBLEM TITLE.
ISN 0015      1 READ  401,(LL(K),K=1,10),(PBNAM(L),L=1,15)
          C
          C**** CARD 2.  TAX RATES AND CAPITAL STRUCTURE.
ISN 0016      2 READ  403,TXCRED,FITTXR,STAINC,STAREV,PROPTX,INSURE,DBTFRC,EQFRAC
          C
          C**** CARD 3. INTEREST RATES AND OTHER ECONOMIC PARAMETERS. SALVAGE VLU.
          C INTCON AND INTTOT ARE OPTIONAL.
ISN 0017      3 READ  403,INTDBT,PPPEXP,TOLFR,SALVGE,INTCON,INTTOT,CNSTLN
          C
          C**** CARD 4.  PROJECT LIFE, NUMBER OF ITERATIONS ALLOWED, AND NUMBER OF
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          C      FEED PRICES TO BE TRIED. ALSO NEQMAX.
          C**** NEQMAX IS THE NUMBER OF RATES OF RETURN ON EQUITY TO BE USED.
          C      NSTRT IS THE YEAR IN WHICH  LANT STARTUP TAKES PLACE, ALSO
          C      THE YEAR IN WHICH DEPRECIATION ALLOWANCES BEGIN.
          C
ISN 0018        4 READ 400,NYRS,NSTRT,NTRIES,NFDPRS,NEQMAX,NCARRY,NCREDT,NCNSTR
          C
ISN 0019          IF(NTRIES.LT.1)NTRIES=1
ISN 0021          IF(NCNSTR.LT.1)NCNSTR=1
          C
          C**** CARD 5.  DEPRECIABLE CAPITAL INVESTMENT MADE EACH YEAR.  $MM.
ISN 0023        5 READ 403,(INVEST(N),N=1,NYRS)
          C
          C**** CARD 6.  WORKING CAPITAL INVESTMENT MADE EACH YEAR,  $MM.
ISN 0024        6 READ 403,(WORKCP(N),N=1,NYRS)
          C
          C**** CARD 7.  OPERATING EXPENSES EACH YEAR EXCLUSIVE OF TAXES.
ISN 0025        7 READ 403,(EXTEXP(N),N=1,NYRS)
          C
          C**** CARD 8. CONSTANT EXPENSES DURING PRE- AND POST-STARTUP PERIODS.
          C      ALSO LOW & HIGH LIMITS OF PRODUCT PRICE FOR USE IN ITERATION
          C      ALSO DELFPR, THE DELTA FEED PRICE FOR FEEDSTOCK 1.
          C      ALSO TOLPRC, THE TOLERANCE ON PRODUCT PRICE CONVERGENCE.
ISN 0026        8 READ 403,EXINIT,EXPCON,PL,PH,DELFPR,TOLPRC
          C
          C**** CARD 9.  NUMBER OF PRODUCTS FOR WHICH RATES AND PRICES ARE READ.
          C ALSO, NUMBER OF FEEDSTOCKS FOR WHICH PRICES AND RATES ARE READ.
ISN 0027        9 READ 400,NPRODS,NFEEDS
          C
          C**** CARD 10. PRICES OF PRODUCTS INCL. INITIAL ESTIMATE FOR MAIN PROD.
ISN 0028       10 READ 403,(PRICE(N),N=1,NPRODS)
          C
          C**** CARD 11.  ANNUAL PRODUCTION RATES FOR PRODUCTS AT 100% CAPACITY.
ISN 0029       11 READ 403,(PRDRAT(N),N=1,NPRODS)
          C
          C**** CARD 12.  FEEDSTOCK PRICES, $/UNIT, FOR ALL FEEDSTOCKS.
ISN 0030       12 READ 403,(FEEDPR(N),N=1,NFEEDS)
          C
          C**** CARD 13.  FEEDSTOCK CONSUMPTION RATES AT 100% CAPACITY,MM UNIT/YR
ISN 0031       13 READ 403,(FEEDRT(N),N=1,NFEEDS)
          C
          C**** CARD 14.  RATES OF RETURN ON EQUITY.
ISN 0032       14 READ 403, (RTNEQ(NEQT),NEQT=1,NEQMAX)
          C
          C**** CARD 15.  DEPRECIATION CLASSES.
ISN 0033       15 READ 400,NCLS,(LIFE(NCL),NCL=1,NCLS)
          C
          C****
          C**** CARD 16.  FRACTIONS OF TOTAL DEPRECIATION BY CLASS.
ISN 0034       16 READ 403,(DPFRAC(NCL),NCL=1,NCLS)
          C
          C**** CARD 17. PLANT OP. FACTOR FOR EACH YEAR INCL PRE-STARTUP YRS
ISN 0035       17 READ 403,(EFFNCY(N),N=1,NYRS)
          C
          C**** CARD 18.  DISTRIBUTION OF INVESTMENT DURING CONSTRUCTION PERIOD.
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          C THIS IS FOR THE CALCULATION OF THE COMPOUNDED INTEREST DURING
          C CONSTRUCTION.  IF THIS OPTION IS NOT DESIRED,  CARD 18 IS A BLANK CARD
          C AND LL(7) MUST BE LESS THAN 2  AND ENTER NCNSTR=1 ON CARD 4.
          C
ISN 0036      18 READ 403,(FRCINV(N),N=1,NCNSTR)
          C
          C*    CARD 19.  ESCALATION FACTORS.
ISN 0037      19 READ 403, ESCCAP,ESCWRK,ESCEXT,ESCEXP,ESCINI,ESCCON,ESCFDP,ESCPRP
          C
          C**** END OF INPUT DATA    ****************
          C
          C
          C****
          C SAVE THE LOW AND HIGH PRODUCT PRICE LIMITS FOR SUBSEQUENT ITERATIONS.
          C
ISN 0038         PLSAVE=PL
ISN 0039         PHSAVE=PH
ISN 0040         FPSAVE=FEEDPR(1)
ISN 0041         NEQT=1
ISN 0042         RTNEQY=RTNEQ(NEQT)
ISN 0043         DPSTRT=NSTRT
ISN 0044         PROJLF=NYRS
          C
          C      SAVE NSTRT7 FOR INV TAX CREDIT CARRYOVER CALC.
          C      THIS IS FINAL YEAR WHEN INV TAX CREDIT CAN BE TAKEN
ISN 0045         NSTRT7=NSTRT+NCREDT
          C****
          C
          C**** PRINT INPUT DATA        ********
          C****
ISN 0046         NPRNT=0
ISN 0047    1019 CONTINUE
ISN 0048         PRINT 600
ISN 0049         IF(NPRNT.EQ.1) PRINT 655
ISN 0051         PRINT 601,(LL(K),K=1,10),(PRBNAM(L),L=1,15)
ISN 0052         PRINT 603,TXCRED,FITTXR,STAINC,STAREV
ISN 0053         PRINT 604,PROPTX,INSURF,DBTFRC,EQFRAC
ISN 0054         PRINT 605,RTNEQY,INTDBT,PROJLF,DPSTRT
ISN 0055         PRINT 606,PRPEXP,TOLER,SALVGE,CNSTLN
ISN 0056         PRINT 636,INTCON,INTTOT
ISN 0057         PRINT 637,NYRS,NSTRT,NTRIES,NFDPRS
ISN 0058         PRINT 638,NEQMAX,NCARRY,NCREDT,NCNSTR
          C****
ISN 0059         PRINT 701
ISN 0060         PRINT 639
ISN 0061         PRINT 610,(INVEST(N),N=1,NYRS)
ISN 0062         PRINT 701
ISN 0063         PRINT 640
ISN 0064         PRINT 610,(WORKCP(N),N=1,NYRS)
ISN 0065         PRINT 701
ISN 0066         PRINT 641
ISN 0067         PRINT 610,(EXTEXP(N),N=1,NYRS)
ISN 0068         PRINT 701
ISN 0069         PRINT 609
ISN 0070         PRINT 610,(EFFNCY(N),N=1,NYRS)
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ISN 0071          PRINT 701
             C****
ISN 0072          PRINT 611,EXINIT,EXPCON
ISN 0073          PRINT 612,NPRODS
ISN 0074          PRINT 613,( PRICE(N),N=1,NPRODS)
ISN 0075          PRINT 613,(PRDRAT(N),N=1,NPRODS)
             C
ISN 0076          PRINT 634,NFEEDS
ISN 0077          PRINT 610,(FEEDPR(N),N=1,NFEEDS)
ISN 0078          PRINT 610,(FEEDRT(N),N=1,NFEEDS)
ISN 0079          IF(NPRNT.EQ.1) GO TO 1022
             C****
             C**** END OF PRINT INPUT DATA.
             C*       APPLY ESCALATION FACTORS TO INPUT DATA.
ISN 0081          IF(LL(9).EQ.0) GO TO 1022
             C*
ISN 0083          DO 1021 N=1,NYRS
ISN 0084          INVEST(N)=INVEST(N)*(1.+ESCCAP)**(N-1)
ISN 0085          WORKCP(N)=WORKCP(N)*(1.+ESCWRK)**(N-1)
ISN 0086          EXTEXP(N)=EXTEXP(N)*(1.+ESCEXT)**N
ISN 0087     1021 CONTINUE
ISN 0088          NPRNT=1
ISN 0089          GO TO 1019
             C****
ISN 0090     1022 CONTINUE
             C****
             C CALCULATE TOTAL AMOUNT INVESTED.      ZERO ANNUAL DEPRECIATION.
             C
ISN 0091          TOTDNV=0.
ISN 0092          WRKCAP=0.
ISN 0093          DO 22 N=1,NYRS
ISN 0094          DEPREC(N)=0.0
ISN 0095          WRKCAP=WRKCAP+WORKCP(N)
ISN 0096       22 TOTDNV=TOTDNV+INVEST(N)
             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.
             C    IF LL(7)=1, TOTAL INT. DURING CONSTR. INPUT AS A FRACTION
             C    OF THE TOTAL DEPRECIABLE INVESTMENT. THIS FRACTION IS INTTOT.
             C    IF LL(7)=2, INTEREST DURING CONSTR. IS COMPUTED ACCORDING TO
             C    SCHEDULE OF EXPENDITURE OF CONSTRUCTION FUNDS--INPUT
             C    AS ANNUAL FRACTION, FRCINV( ), WHERE N GOES FROM 1 TO NCNSTR
             C    THE INTEREST RATE FOR THIS CALCULATION IS INTCON.
             C
             C
ISN 0097          INTDC=0.
ISN 0098          CMPDFC=0.
ISN 0099       24 IF(LL(7).EQ.1)INTDC=CNSTLN*INTTOT
             C
ISN 0101          INTTOC=0.
ISN 0102          IF(LL(7).LT.2)GO TO 27
             C
             C    CALCULATE COMPOUND FACTOR FOR TOTAL INTEREST DURING CONSTR.
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                C       THIS OPTION IS USED ONLY IF LL(7)=2.                         00003810
  ISN 0104              DO 25 N=1,NCNSTR                                             00003820
  ISN 0105           25 CMPDFC=(CMPDFC+FRCINV(N))*(1.+INTCON)                        00003830
  ISN 0106              INTTOC=CMPDFC-1.                                             00003840
  ISN 0107              INTDC=CNSTLN*INTTOC                                          00003850
                C                                                                    00003860
                C                                                                    00003870
  ISN 0108           27 TOTDEP=TOTDNV+INTDC                                          00003880
                C                                                                    00003890
                C                                                                    00003900
                C       TOTAL INVESTMENT--THE SUM OF DEPRECIABLE AND WORKING CAPITAL 00003910
  ISN 0109              TOTINV=TOTDEP+WRKCAP                                         00003920
                C                                                                    00003930
                C       THE TOTAL OF WRKCAP + SALVGE IS SAVED FOR LATER OUTPUTTING.  00003940
  ISN 0110              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.     00004120
                C       DEPRECIATION IS BASED ON TOTAL DEPRECIABLE CAPITAL LESS SAL- 00004130
                C       VAGE VALUE.                                                  00004135
                C                                                                    00004140
  ISN 0119              TOTDP2=TOTDEP-SALVGE                                         00004150
                C                                                                    00004160
                C       OPTIONS AVAILABLE ARE AS FOLLOWS.                            00004170
                C       LL(1) = 0  SUM OF YEARS DIGITS                               00004180
                C       LL(1) = 1  STRAIGHT LINE                                     00004190
                C       LL(1) = 2  DOUBLE DECLINING BALANCE WITH CONVERSION TO       00004200
                C****                                                                00004210
                C       STRAIGHT LINE.                                               00004215
  ISN 0120              DO 37 NCL=1,NCLS                                             00004220
  ISN 0121              NDLIFE=LIFE(NCL)                                             00004230
  ISN 0122              TOTDP3=TOTDP2*DPFRAC(NCL)                                    00004240
  ISN 0123              DPLIFE=NDLIFE                                                00004250
  ISN 0124              IF(LL(1).EQ.2)GO TO 34                                       00004260
                C                                                                    00004270
  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)/SUM                                       00004330
```

```
ISN 0131          IF(LL(1).EQ.1)FRAC=1./DPLIFE
ISN 0133          N=NSTRT+ND-1
ISN 0134          YDPREC=FRAC*TOTDP3
ISN 0135       32 DEPREC(N)=DEPREC(N)+YDPREC
ISN 0136          GO TO 37
            C
            C     DOUBLE DECLINING BALANCE METHOD WITH CONVERSION TO STRAIGHT
            C     LINE.
            C
ISN 0137       34 NSL=0
ISN 0138          REMNDR=TOTDP3
            C
ISN 0139          DO 36 ND=1,NDLIFE
ISN 0140          NLEFT=NDLIFE-ND+1
ISN 0141          N=NSTRT+ND-1
ISN 0142          IF(NSL.EQ.1)GO TO 35
ISN 0144          DDB=REMNDR*2./DPLIFE
ISN 0145          DSL=REMNDR/NLEFT
ISN 0146          IF(DSL.GE.DDB)NSL=1
ISN 0148          YDPREC=AMAX1(DDB,DSL)
ISN 0149          REMNDR=REMNDR-YDPREC
ISN 0150          GO TO 36
ISN 0151       35 YDPREC=DSL
            C
ISN 0152       36 DEPREC(N)=DEPREC(N)+YDPREC
            C
ISN 0153       37 CONTINUE
            C
            C**** CALCULATE THE SUM OF THE ANNUAL DEPRECIATION EXPENSES.  IT SHOULD
            C     BE EQUAL TO THE TOTAL DEPRECIABLE INVESTMENT LESS SALVAGE
            C     VALUE.
            C
ISN 0154          SUMDEP=0.
ISN 0155          DO 38 N=1,NYRS
ISN 0156       38 SUMDEP=SUMDEP+DEPREC(N)
            C
            C****
            C     PRINT DERIVED DATA.
            C
ISN 0157          PRINT 625
ISN 0158          IF(LL(2).EQ.0)PRINT 632
ISN 0160          IF(LL(2).EQ.1)PRINT 633
ISN 0162          PRINT 642
ISN 0163          PRINT 643,TOTDNV
ISN 0164          PRINT 644,INTDC
ISN 0165          PRINT 645,TOTDEP
ISN 0166          PRINT 646,WRKCAP
ISN 0167          PRINT 647,TOTINV
ISN 0168          PRINT 702
ISN 0169          PRINT 627,TOTDP2
ISN 0170          PRINT 626,SALVGE
ISN 0171          SUM628=SALVGE+TOTDP2
ISN 0172          PRINT 628,SUM628
ISN 0173          PRINT 702
ISN 0174          K631=1+LL(1)
```

```
ISN 0175          PRINT 631,DPRNAM(K631)
ISN 0176          PRINT 610,(DEPREC(N),N=1,NYRS)
ISN 0177          PRINT 701
ISN 0178          PRINT 648,SUMDEP
ISN 0179          PRINT 702
ISN 0180          PRINT 649
ISN 0181          PRINT 650,CMPDFC
ISN 0182          PRINT 651,INTDC
            C
            C     ESCALATION FACTORS ARE PRINTED IF LL(9).NE.0
            C
ISN 0183          IF(LL(9).EQ.0) GO TO 39
ISN 0185          PRINT 702
ISN 0186          PRINT 656
ISN 0187          PRINT 657, ESCCAP, ESCWRK, ESCEXT
ISN 0188          PRINT 658, ESCEXP, ESCINI, ESCCON
ISN 0189          PRINT 659, ESCFDP
ISN 0190          PRINT 660, ESCPRP
ISN 0191       39 CONTINUE
            C
            C     ASSIGN CONSTANT ANNUAL EXPENSES PER INPUT DATA EXINIT AND
            C     EXPCON.
            C
            C     DURING THE PRE-STARTUP PERIOD, THE CONSTANT ANNUAL AMOUNT IS
            C     EXINIT.
            C     DURING THE OPERATIONAL PERIOD, THE CONSTANT ANNUAL AMOUNT IS
            C     EXPCON.
            C
ISN 0192          DO 41 N=1,NSTRT
ISN 0193       41 EXPENS(N)=EXINIT*(1.+ESCINI)**N
ISN 0194          DO 43 N=NSTRT,NYRS
ISN 0195       43 EXPENS(N)=EXPCON*(1.+ESCCON)**N
            C
            C**** REENTER AT 45 FOR ITERATION WITH NEW RATE OF RETURN ON EQUITY.
            C     THE RATES OF RETURN TO BE USED WERE ENTERED ON CARD 14.
ISN 0196       45 CONTINUE
ISN 0197          FEEDPR(1)=FPSAVE
ISN 0198          RTNEQY=RTNEQ(NEQT)
            C
            C****
            C**** CALCULATE AVERAGE PRESENT WORTH OF INCOMES FOR ESTIMATING
            C     PRICE DIFFERENTIALS....USED IN CONVERGENCE ROUTINE.
ISN 0199          RRA=DBTFRC*INTDBT+EQFRAC*RTNEQY
ISN 0200          DISFAC=1./(1.+RRA)
ISN 0201          SUM16=0.
ISN 0202          DO 46 N=1,NYRS
ISN 0203       46 SUM16=SUM16+DISFAC**N *PRORAT(1)*EFFNCY(N)
ISN 0204          DPFAC=(1./(1.-FITTXR-STAINC*FITTXR))*DISFAC**NYRS/SUM16
            C****
            C
            C****
            C
            C     FOR PARAMETRIC STUDY OF FEED PRICE REENTER AT 48 IF LL(4)=1.
            C     NOTE: THE ONLY FEED PRICE THAT IS VARIED IS THE MAIN FEED
            C     NFDPR IS THE NUMBER OF THE ITERATION ON FEED PRICE.
```

```
                 C
  ISN 0205             NFDPP=1
                 C
  ISN 0206          48 CONTINUE
                 C
  ISN 0207             NPRINT=1-LL(3)
                 C
                 C
                 C**** CALCULATE COST OF FEEDS TO PLANT AT 100% ONSTREAM EFFICIENCY.
                 C
  ISN 0208             FDCOST=0.
  ISN 0209             DO 50 N=1,NFEEDS
  ISN 0210          50 FDCOST=FDCOST+FEEDRT(N)*FEEDPR(N)
                 C****
                 C
                 C
                 C     THE TOTAL ANNUAL OPERATING EXPENSE IS PLTEXP(N)--THE SUM OF
                 C     THE CONSTANT ANNUAL EXPENSE, EXPENS(N), PLUS THE AMOUNT
                 C     PROPORTIONAL TO THROUGHPUT, PRPEXP*EFFNCY(N), PLUS ANY ADDED
                 C     ANNUAL AMOUNTS INPUT, EXTEXP(N), PLUS ANNUAL PROPTY INSURE,
                 C     PLUS THE COST OF THE FEEDSTOCKS USED EACH YEAR.  THE LATTER
                 C     IS THE PRODUCT OF THE ONSTREAM EFFICIENCY AND THE CALCU
                 C     LATED FEEDSTOCK COST AT 100% ONSTREAM EFFICIENCY,FDCOST.
                 C     NOTE THAT PLTEXP(N) DOES NOT INCLUDE ANY TAXES.
                 C     IT IS ASSUMED THAT PROPERTY INSURANCE STARTS IN YEAR NSTRT.
                 C     FOR CALCULATION OF EXPENS(N) SEE STATEMENTS 41-43.
                 C
                 C
  ISN 0211             DO 51 N=1,NYRS
  ISN 0212             PLTEXP(N)=EFFNCY(N)*PRPEXP*(1.+ESCEXP)**N + EXPENS(N) + EXTEXP(N)
                      1   + INSRNC(N) + FDCOST*EFFNCY(N)*(1.+ESCFDP)**N
  ISN 0213          51 CONTINUE
                 C
                 C     THIS COMPLETES THE CALCULATION OF THE ANNUAL OP EXPENSES.
                 C
                 C****
                 C
  ISN 0214             PTRY=PRICE(1)
  ISN 0215             EQTRY=RTNEQY
  ISN 0216             NTRY=1
  ISN 0217             EQL=0.00
  ISN 0218             EQH=1.00
  ISN 0219             PL=PLSAVE
  ISN 0220             PH=PHSAVE
                 C
                 C
                 C**** STATEMENT 55 IS THE REENTRY POINT FOR TRIAL CALCULATIONS FOR
                 C     OBTAINING CONVERGENCE OF THE CASH FLOW PAYOUT TABULATION.
                 C     THE TRIAL NUMBER IS NTRY AND THE PRICE IS PTRY.
                 C     IF THE RATE OF RETURN ON EQUITY IS BEING CALCULATED, THE
                 C     NEW TRIAL VALUE IS EQTRY.
                 C
  ISN 0221          55 CONTINUE
                 C
  ISN 0222             PRICE(1)=PTRY
```

```
ISN 0223              RTNEQY=EQTRY
ISN 0224              IF(NTRY.EQ.NTRIES)NPPINT=1
                C****
                C**** ZERO ALL THE ENTRIES IN THE PAYOUT ARRAY FROM THE PREVIOUS TRIAL.
ISN 0226              CALL ZERO
                C****
                C
                C
                C**** CALCULATE ANNUAL PRODUCTION AND INCOME FROM SALES
                C
ISN 0227              DO 60 N=1,NYRS
ISN 0228              TOTPP=0.
ISN 0229              DO 59 NPR=1,NPRODS
ISN 0230           59 TOTPR=TOTPR+PRDRAT(NPR)*PRICE(NPR)
ISN 0231              INCOME(N)=TOTPR*EFFNCY(N)*(1.+ESCPRP)**N
ISN 0232           60 CONTINUE
                C****
                C**** MAIN LOOP STARTS HERE.  CALCULATE PAYOUT TABLE.  NEW ITERATION
                C     REENTERS AT STATEMENT 55. MAX NUMBER OF ITERATIONS = NTRIES.
                C**** CREDIT IS THE TOTAL FEDERAL INVESTMENT TAX CREDIT.
                C
ISN 0233              IF(NPRINT.EQ.0)GO TO 64
                C
ISN 0235              PRINT 616,(PRBNAM(L),L=1,15),FEEDPR(1)
ISN 0236              DBT22=INTDBT*100.00
ISN 0237              RTNEQ2=RTNEQY*100.00
ISN 0238              PRINT 630,NTRY,PRICE(1),DBT22,RTNEQ2,DBTFRC,EQFRAC
ISN 0239              PRINT 617,(KC,KC=1,11)
ISN 0240              PRINT 623
                C
ISN 0241           64 CONTINUE
                C
                C
                C     INITIAL CAPITAL INVESTMENT INCL. CALCULATED INTEREST DURING
                C     CONSTRUCTION. IF LL(7) WAS INPUT AS ZERO, INTDC IS ZERO.
                C
ISN 0242              CPSTPT(1)=INVEST(1)+INTDC+WORKCP(1)
                C
                C**** CALCULATE INV. TAX CRED. BASED ON TOTAL DEPRECIABLE CAPITAL.
ISN 0243              CREDIT=TOTDEP*TXCRED
                C****
                C**** CALCULATE THE PAYOUT TABLE YEAR BY YEAR.
                C****
ISN 0244              NCOMPL=0
                C
                C
                C     THE OBJECT IS TO MAKE THE OUTSTANDING CAPITAL AT THE END OF
                C     THE FINAL YEAR EQUAL TO THE TOTAL WORKING CAPITAL INVESTMENT
                C     PLUS SALVAGE VALUE.  TOTAL WORKING CAPITAL IS ASSUMED TO
                C     REMAIN INVESTED RIGHT UP TO THE END OF THE PROJECT AND IS
                C     RECOVERED INTACT AT THAT TIME.
                C
ISN 0245              DO 80 N=1,NYRS
                C****
                C     INT. ON DEBT &RETURN ON EQUITY BASED ON OUTSTANDING CAPITAL
```

```
  ISN 0246          INTRST(N)=CPSTRT(N)*DBTFRC*INTDBT
  ISN 0247          EQYRTN(N)=CPSTRT(N)*EQFRAC*RTNEQY
              C
              C     STATE TAXABLE INCOME.
  ISN 0248          STXABL(N)=INCOME(N)-PLTEXP(N)-DEPREC(N)-INTRST(N)
              C     STATE AND LOCAL TAXES--NOT PERMITTED TO BE NEGATIVE.
  ISN 0249          STLTAX(N)=STXABL(N)*STAINC
  ISN 0250          IF(STLTAX(N).LT.0.)STLTAX(N)=0.0
  ISN 0252          STLTAX(N)=STLTAX(N)+PROPTY(N)
              C
              C**** STATE REV TAX = STAREV*INCOME(N)--INCLUDED IN STLTAX(N).
  ISN 0253          IF(INCOME(N).GT.0.)STLTAX(N)=STLTAX(N)+STAREV*INCOME(N)
              C
              C
              C     FED TAXABLE INCOME AND FED INCOME TAX BEFORE INV TAX CREDIT.
  ISN 0255          TAXABL(N)=STXABL(N)-STLTAX(N)
  ISN 0256          FEDTAX(N)=TAXABL(N)*FITTXR
              C     FEDTXN(N) IS A CALCULATED TAX WHICH MAY BE NEGATIVE .
  ISN 0257          FEDTXN(N)=FEDTAX(N)
              C     FEDTXN(N) IS SAVED.  FEDTAX(N) MAY BE SUBSEQUENTLY ADJUSTED.
              C****
              C**** IF TAXES ARE ALLOWED TO BE NEGATIVE, GO TO 70.
  ISN 0258          IF(LL(6).GT.0)GO TO 70
              C**** IF TAXES ARE NOT ALLOWED TO BE NEGATIVE, DO THE FOLLOWING.
  ISN 0260          IF(FEDTAX(N).GE.0.)GO TO 66
  ISN 0262          TXLOSS(N)=-FEDTAX(N)
  ISN 0263          FEDTAX(N)=0.
  ISN 0264       66 CONTINUE
  ISN 0265          IF(LL(5).EQ.0)GO TO 69
              C
              C**** FIVE YEAR TAX LOSS CARRYOVER CALCULATION.
              C     NCARRY WAS INPUTTED AND IS NORMALLY 5.
  ISN 0267          NA=N-NCARRY
  ISN 0268          IF(NA.LT.1)NA=1
  ISN 0270          DO 68 NLOSS=NA,N
  ISN 0271          DEDUCT=AMIN1(TXLOSS(NLOSS),FEDTAX(N))
  ISN 0272          FEDTAX(N)=FEDTAX(N)-DEDUCT
  ISN 0273          TXLOSS(NLOSS)=TXLOSS(NLOSS)-DEDUCT
  ISN 0274       68 CONTINUE
              C**** END OF TAX LOSS CARRYOVER CALCULATION.
              C
  ISN 0275       69 CONTINUE
              C****
              C     INVESTMENT TAX CREDIT IS SUBTRACTED FROM INCOME TAX.
  ISN 0276          TXCRDT(N)=AMIN1(FEDTAX(N),CREDIT)
              C     PUT 7-YEAR LIMIT ON CARRY-FORWARD OF INVESTMENT TAX CREDIT.
              C     NCREDT WAS INPUTTED AND IS NORMALLY 7.
              C     NSTRT7 IS THE SUM OF NSTRT AND NCREDT.
  ISN 0277          IF(N.GT.NSTRT7)TXCRDT(N)=0.
  ISN 0279          FEDTAX(N)=FEDTAX(N)-TXCRDT(N)
              C     KEEP TRACK OF REMAINING CREDIT NOT YET USED.
  ISN 0280          CREDIT=CREDIT-TXCRDT(N)
  ISN 0281          GO TO 73
              C
  ISN 0282       70 CONTINUE
```

```
             C      INV TAX CREDIT FOR THE CASE WHEN INCOME TAX CAN BE NEGATIVE
ISN 0283            IF(N.LT.NSTRT)GO TO 73
ISN 0285            FEDTAX(N)=FEDTAX(N)-CREDIT
ISN 0286            TXCRDT(N)=CREDIT
ISN 0287            CREDIT=0.
ISN 0288         73 CONTINUE
             C
             C****  CALCULATE CASH FLOW AFTER TAXES FOR YEAR (N).
ISN 0289            CASHFL(N)=INCOME(N)-PLTEXP(N)-STLTAX(N)-FEDTAX(N)
             C
             C****  CALCULATE TOTAL INTEREST AND RETURN ON EQUITY FOR YEAR (N).
ISN 0290            TOTRTN(N)=INTRST(N)+EQYRTN(N)
             C
             C      AMORTIZATION/RECOVERY OF REMAINING CAPITAL BASED ON CASH FLOW
             C      LESS AMOUNT ALLOCATED TO INT ON DEBT & RETURN ON EQUITY.
ISN 0291            AMORTZ(N)=CASHFL(N)-TOTRTN(N)
             C
             C      AMOUNT OF CAPITAL OUTSTANDING AT END OF YEAR.
ISN 0292            CAPEND(N)=CPSTRT(N)-AMORTZ(N)
             C
ISN 0293            IF(NPRINT.EQ.0)GO TO 76
ISN 0295            PRINT 615,N,CPSTRT(N),EFFNCY(N),INCOME(N),PLTEXP(N),STLTAX(N),
                  1     TXCRDT(N),FEDTAX(N),CASHFL(N),TOTRTN(N),AMORTZ(N),CAPEND(N)
             C
ISN 0296         76 CONTINUE
ISN 0297            CPSTRT(N+1)=CAPEND(N) + INVEST(N+1) + WORKCP(N+1)
ISN 0298            IF(CPSTRT(N+1).LT.0.)CPSTRT(N+1)=0.
ISN 0300            BALNCE=CAPEND(N) - WRKCAP -SALVGE
ISN 0301            IF(N.EQ.NYRS) NCOMPL=1
             C
             C      JUMP OUT OF PAYOUT LOOP IF THE INVESTMENT GETS TOO SMALL.
ISN 0303            IF(BALNCE.LT.0..AND.N.GT.NSTRT)GO TO 82
             C****
ISN 0305         80 CONTINUE
             C
ISN 0306            NCOMPL=1
             C
             C      AT THE END OF THE 80 LOOP THE PAYOUT TABULATION IS COMPLETED
             C      AND PRINTED BUT IS NOT NECESSARILY CONVERGED.
             C
ISN 0307         82 CONTINUE
ISN 0308            IF(NPRINT.EQ.0)GO TO 83
             C****
             C
             C      THE FOLLOWING PRINT STATEMENTS ARE EXPLANATORY NOTES FOR THE
             C      PAYOUT TABULATION.
ISN 0310            PRINT 702
ISN 0311            PRINT 629
ISN 0312            PRINT 619,WRKCAP
ISN 0313            PRINT 800,SALVGE
ISN 0314            PRINT 813,TOT813
             C      TOT813 IS THE TOTAL OF THE PRECEDING TWO LINES.
ISN 0315            PRINT 801
ISN 0316            PRINT 802
ISN 0317            PRINT 803
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ISN 0318            PRINT 804
ISN 0319            PRINT 805
ISN 0320            PRINT 806
ISN 0321            PRINT 807
ISN 0322            PRINT 808
ISN 0323            PRINT 809
ISN 0324            PRINT 810
ISN 0325            PRINT 811
ISN 0326            PRINT 812
ISN 0327            PRINT 624
ISN 0328         83 CONTINUE
               C
               C    TEST FOR CONVERGENCE.  TOLERANCE USED HERE IS INPUTTED.
               C
ISN 0329            IF(DABS(BALNCE).LT.TOLER.AND.NCOMPL.EQ.1)GO TO 88
               C
ISN 0331            IF(NTRY.GE.NTRIES)GO TO 90
ISN 0333            NTRY=NTRY+1
               C****
ISN 0334            IF(LL(2).EQ.1)GO TO 87
               C
               C    ITERATE ON PRICE(1) IF LL(2)=0
               C**** ITERATE PRICE BY AVERAGING THE CURRENT MIN. HIGH AND MAX. LOW.
               C****
ISN 0336            PTRY4=PTRY
ISN 0337            IF(BALNCE.GT.0.)PL=AMAX1(PL,PTRY4)
ISN 0339            IF(BALNCE.LT.0.)PH=AMIN1(PH,PTRY4)
ISN 0341            PRCERR=PH-PL
ISN 0342            IF(PRCERR.LT.TOLPRC)GO TO 88
ISN 0344            IF(NCOMPL.EQ.0.AND.NTRY.LT.9)GO TO 86
ISN 0346            PTRY=PTRY+DPFAC*BALNCE
ISN 0347            IF(PTRY.GE.PH.OR.PTRY.LE.PL.OR.NTRY.GT.5)PTRY=0.5*(PL+PH)
               C****
               C**** REENTER AT 55 FOR NEXT ITERATION UNLESS NTRY=NTRIES.
               C****
ISN 0349            GO TO 55
               C****
ISN 0350         86 PTRY=0.5*(PL+PH)
ISN 0351            GO TO 55
ISN 0352         87 CONTINUE
               C    ITERATE RATE OF RETURN ON EQUITY. SIGNALLED BY LL(2)=1.
               C
ISN 0353            IF(BALNCE.LT.0.)EQL=AMAX1(EQL,EQTRY)
ISN 0355            IF(BALNCE.GT.0.)EQH=AMIN1(EQH,EQTRY)
ISN 0357            EQTRY=0.5*(EQL+EQH)
ISN 0358            GO TO 55
               C****
ISN 0359         88 IF(NPRINT.EQ.1)GO TO 90
ISN 0361            NPRINT=1
ISN 0362            GO TO 55
               C
ISN 0363         90 CONTINUE
               C****
               C**** AT THIS POINT EITHER CONVERGENCE HAS BEEN REACHED OR THE ALLOWED
               C    MAXIMUM NUMBER OF ITERATIONS HAS BEEN MADE.
```

```
                C
                C     HOWEVER, THE FEED PRICE ITERATION, IF REQUIRED, REMAINS
                C     TO BE DONE.
                C
                C     PRINT SUPPLEMENTARY TABLE OF INFORMATION, UNLESS LL(8)=1.
                C
  ISN 0364            IF(LL(8).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),CPSTRT(N),DEPREC(N),INTRST(N),TXCRDT(N),
                     1     TAXABL(N),FEDTAX(N),STXABL(N),EQYRTN(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 REENTRY 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            NFDPR=NFDPR+1
  ISN 0389            IF(NFDPR.GT.NFDPRS)GO TO 100
  ISN 0391            FEEDPR(1)=FEEDPR(1)+DELFPR
  ISN 0392            IF(LL(2).EQ.1)GO TO 48
  ISN 0394            PRICE(1)=PRICE(1)+DELFPR*FEEDRT(1)/PRDRAT(1)
  ISN 0395            GO TO 48
                C
  ISN 0396        100 CONTINUE
                C
                C***** FORMATS  ***********************
                C
  ISN 0397        400 FORMAT(16I5)
  ISN 0398        401 FORMAT(10I2,15A4)
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ISN 0399        403 FORMAT(8E10.0)
ISN 0400        404 FORMAT(20A4)
ISN 0401        600 FORMAT('1',5X,'INPUT DATA SUPPLIED BY USER',/)
ISN 0402        601 FORMAT(' ',5X,'CARD 1',4X,10I4,5X,15A4,/)
ISN 0403        603 FORMAT(' ',5X,'TXCRED,FITTXP,STAINC,STAREV',5X,5F10.4)
ISN 0404        604 FORMAT(' ',5X,'PROPTX,INSURE,DBTFRC,EQFRAC',5X,5F10.4)
ISN 0405        605 FORMAT(' ',5X,'PTNEQY,INTDBT,PROJLF,DPSTRT',5X,5F10.4)
ISN 0406        606 FORMAT(' ',5X,'PFPEXP,TOLFR,SALVGE,CNSTLN ',5X,5F10.4)
ISN 0407        609 FORMAT(' ',5X,'PLANT ONSTREAM FACTOR INPUTTED ON CARD 17 ',
                   1      ' FOR EACH YEAR OF PROJECT LIFE, EFFNCY(N) ',/)
ISN 0408        610 FORMAT(' ',5X,8F15.6)
ISN 0409        611 FORMAT(' ',5X,'EXINIT, EXPCON',20X,4F15.4)
ISN 0410        612 FORMAT('0',5X,'PRICES AND BASE PRODUCTION RATES FOR',I3,
                   1     ' PRODUCTS',/)
ISN 0411        613 FORMAT(' ',5X,10F12.4)
ISN 0412        615 FORMAT(' ',I4,3X,11F11.4)
ISN 0413        616 FORMAT('1',10X,'PAYOUT TABULATION',10X,15A4,
                   1      5X,'FEED PRICE =',F10.2,/)
ISN 0414        617 FORMAT(' ',5X,11I11,/)
ISN 0415        618 FORMAT(' ',10X,20A4)
ISN 0416        619 FORMAT('0',15X,'WORKING CAPITAL RECOVERED INTACT AT END OF ',
                   1     'PROJECT LIFE = ',F15.5)
ISN 0417        620 FORMAT('1',10X,'ADDITIONAL DETAILS OF CALCULATION',5X,15A4,///)
ISN 0418        622 FORMAT(' ',10X,'INVEST       CPSTRT       DEPREC      INTRST ',
                   1     '      TXCRDT       TAXABL       FEDTAX       STXABL       EQYRTN',
                   2     '      PROPTY       FEDTXN',/)
ISN 0419        623 FORMAT(' ',10X,'CPSTRT       EFFNCY       REVENUE      PLTEXP       ',
                   1     'STLTAX       TXCRDT       FEDTAX       CASHFL       TOTRTN       ',
                   2     'AMORTZ       CAPEND',/)
ISN 0420        624 FORMAT('0',10X,'COLUMN 11 PLUS NEW INVESTMENT = NEXT ENTRY OF',
                   1      ' COLUMN 1',//)
ISN 0421        625 FORMAT('1',5X,'DERIVED DATA.  CALCULATED FROM INPUT DATA.',
                   1      5X,'INCLUDES ESCALATION IF CALLED FOR BY USER.',///)
ISN 0422        626 FORMAT(' ',10X,'SALVAGE VALUE AT END OF PROJECT ',10X,F15.5)
ISN 0423        627 FORMAT(' ',10X,'TOTAL DEPRECIATION FOR TAX PURPOSES ',10X,F15.5)
ISN 0424        628 FORMAT(' ',10X,'TOTAL                                  ',10X,F15.5)
ISN 0425        629 FORMAT(' ',15X,'THE LAST ENTRY IN THE FINAL YEAR SHOULD BE ',
                   1     'EQUAL TO THE WORKING CAPITAL INVESTMENT PLUS SALVAGE VALUE'/)
ISN 0426        630 FORMAT(' ',10X,'TRIAL',I3,6X,'PRICE =',F10.4,7X,'DEBT AT',F6.2,
                   1   ' %',5X,'RATE OF RETURN ON EQUITY =',F8.3,' %',5X,'D/E =',
                   2   F5.2,'/',F4.2,///)
ISN 0427        631 FORMAT('0',5X,'CALCULATED ANNUAL DEPRECIATION ALLOWANCES',
                   1      12X,'BY ',A4,' METHOD',/)
ISN 0428        632 FORMAT(' ',5X,'OBJECTIVE IS TO CALCULATE PRODUCT PRICE',/)
ISN 0429        633 FORMAT(' ',5X,'OBJECTIVE IS TO CALCULATE RATE OF RETURN ',
                   1      'ON EQUITY',/)
ISN 0430        634 FORMAT('0',5X,'PRICES AND CONSUMPTION RATES FOR',I3,
                   1     ' FEEDSTOCKS',/)
ISN 0431        635 FORMAT('1',5X,'REPEAT PROBLEM WITH NEW FEED PRICE.',///)
ISN 0432        636 FORMAT(' ',5X,'INTCON,INTTOT              ',5X,5F10.4)
ISN 0433        637 FORMAT(' ',5X,'NYRS,NSTRT,NTRIES,NFDPRS   ',3X,5I10)
ISN 0434        638 FORMAT(' ',5X,'NFQMAX,NCARRY,NCPEDT,NCNSTR',3X,5I10)
ISN 0435        639 FORMAT(' ',5X,'DEPRECIABLE CAPITAL INVESTMT INPUTTED ON CARD 5 ',
                   1      ' FOR EACH YEAR OF PROJECT LIFE, INVEST(N) ',/)
ISN 0436        640 FORMAT(' ',5X,'WORKING CAPITAL INVESTMENT INPUTTED ON CARD 6 ',
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                     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 9-9')                                      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  = INVESTMENT 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
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ISN 0478        909 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')                                 00009810
              C****                                                                     00009820
              C                                                                         00009830
              C       IF THE OBJECT WAS TO DETERMINE THE RATE OF RETURN ON EQUITY,      00009840
              C       WE ARE DONE.                                                      00009850
ISN 0481              IF(LM(2).EQ.1)GO TO 150                                           00009860
              C                                                                         00009870
              C                                                                         00009880
              C**** RERUN PROBLEM WITH NEW RATE OF RETURN ON EQUITY.   REENTRY          00009890
              C       POINT IS AT STATEMENT 45.  NEQMAX = NUMBER OF RATES OF            00009900
              C       RETURN.  THESE RATES OF RETURN WERE ENTERED ON CARD 14.           00009910
ISN 0483              NEQT=NEQT+1                                                       00009920
ISN 0484              IF(NEQT.GT.NEQMAX)GO TO 150                                       00009930
ISN 0486              GO TO 45                                                          00009940
ISN 0487        150 CONTINUE                                                            00009950
              C                                                                         00009960
              C**** CALCULATIONS ARE DONE. GO TO 1 TO READ INPUT DATA FOR NEXT PROBLEM00009970
              C       IF THERE IS NO CARD TO READ.PROGRAM WILL STOP AUTOMATICALLY       00009980
              C****                                                                     00009990
              C                                                                         00010000
ISN 0488              GO TO 1                                                           00010010
              C****                                                                     00010020
ISN 0489              END                                                               00010030
```



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 | 001268 | ND | SF | I*4 | 00126C | PH | SFA | R*4 | 001270 |
| PL | SFA | R*4 | 001274 | DDB | SFA | R*4 | 001278 | DSL | SFA | R*4 | 00127C | EQH | SFA | R*4 | 001280 |
| EQL | SFA | R*4 | 001284 | NCL | SF | I*4 | 001288 | 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 | 001280 | PTPY | SF | R*8 | 0013E8 | ZERO | SF XF | | 000000 | DBT22 | SF | R*4 | 001284 |
| DPFAC | SF | R*8 | 0013F0 | EQTRY | SFA | R*4 | 001288 | INTDC | SF | R*4 | 0012BC | NFDPR | SF | I*4 | 0012C0 |
| NLEFT | SF | I*4 | 0012C4 | NLOSS | SFA | I*4 | 0012C8 | NPRNT | S | I*4 | 0012CC | NSTRT | SF | I*4 | 0012D0 |
| PRICE | SF | R*4 | 001488 | ETRY4 | SFA | R*4 | 0012D4 | RTNEQ | SF | R*4 | 0014E8 | SUM16 | SF | R*4 | 0012D8 |
| 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 | DPLFPR | SF | R*4 | 0012F8 | DEPREC | SF | R*4 | 001538 | DISFAC | SF | R*4 | 0012FC |
| DPFRAC | SF | R*4 | 001878 | DPLIFE | SF | R*4 | 001300 | DPRNAM | F | R*4 | 001BD8 | DPSTRT | SF | R*4 | 001304 |
| EFFNCY | SF | R*4 | 0018E4 | 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 | ESCPRP | SF | R*4 | 001324 | ESCWRK | SF | R*4 | 001328 | EXINIT | SF | R*4 | 00132C |
| EXPCON | SF | R*4 | 001330 | EXPENS | SF | R*4 | 002224 | EXTEXP | SF | R*4 | 002864 | FDCOST | SF | R*4 | 001334 |
| FEDTAX | SFA C | R*4 | 001F40 | FEDTXN | SF C | R*4 | 005780 | FEEDPR | SF | R*4 | 002EA4 | FEEDRT | SF | R*4 | 002F04 |
| FITTXR | SF | R*4 | 001338 | FPSAVE | SF | R*4 | 00133C | FRCINV | SF | R*4 | 002F64 | IBCOM# | F XF | I*4 | 000000 |
| INCOME | SF C | R*4 | 000640 | INSRNC | SF | R*4 | 002FC4 | INSURE | SF | R*4 | 001340 | INTCON | SF | R*4 | 001344 |
| INTDBT | 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 |

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