**FOSSIL FUEL PROCESSING
TECHNICAL/PROFESSIONAL SERVICES**

**LUMMUS CLEAN FUELS
FROM COAL**

PREPARED FOR

MASTER

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A JOINT VENTURE OF
UOP INC. AND
SYSTEM DEVELOPMENT CORPORATION

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FUELS FROM COAL

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ABSTRACT

This report compares two direct, catalytic, hydroliquefaction processes - H-Coal and Lummus Clean Fuels From Coal (LCFFC). These processes are compared for two sets of operating conditions. In the first, the reactors are operated to produce a product suitable for use as fuel oil (fuel oil mode). In the second, the operating conditions are more severe, so the resulting product slates more closely resemble crude oil (syncrude mode). The comparisons are performed using conceptual designs based on "single point" run data, with a design basis of 25,000 tpd (moisture-free basis) of Illinois No. 6 coal.

Although all cost comparisons are well within the estimated 25% accuracy of the estimates, LCFFC shows generally lower costs. Three types of economic evaluation are performed: computation of internal rate of return (IRR) with product values set to estimated market value, computation of overall average product cost (\$/MM Btu) with the discount rate set at 20%, and calculation of average product cost with naphtha credited at estimated market value and the discount rate set at 20%. H-Coal has a lower cost only in the fuel oil mode analysis with naphtha valued at market price.

The processes are also compared with respect to the potential for commercialization and anticipated operability differences. It is concluded that the lower hydrogen content of LCFFC product may offset its advantage of lower cost if it is used as refinery feed, and that the design of the LCFFC reactor may make it harder to control. Suggestions for future research are presented.

FOREWORD

The Department of Energy (and previously the Energy Research and Development Administration) has sponsored development of the Lummus Clean Fuels from Coal (LCFFC) process. Results of the process development program have indicated certain advantages for this process in terms of hydrogen consumption, liquid product yields, and heteroatom removal. Accordingly, it was felt that a comparative analysis should be performed against another direct catalytic hydroliquefaction process. Under Task Order 29 of DOE Contract DEAC01-78ET10159 (formerly Contract ET-78-C-01-3117), UOP/SDC conducted such a comparative study between the LCFFC process and the H-Coal process. The study was to compare the economics, discuss major operability differences and commercialization potential, and point out areas requiring more developmental work on the LCFFC process. The DOE program manager is Mr. J. Shen. The UOP/SDC liquefaction manager is Mr. J. Gantt. The UOP/SDC task manager for this task is Mr. J. Hefferan.

TABLE OF CONTENTS

<u>SECTION</u>		<u>PAGE</u>
1	INTRODUCTION	1-1
2	SUMMARY	2-1
	2.1 Basis of Comparisons	2-1
	2.1.1 Plant Size and Design	2-1
	2.1.2 Economic Assumptions	2-1
	2.2 Summary of Results	2-2
	2.2.1 Economic	2-2
	2.2.2 Product Quality	2-2
	2.3 Commercialization Potential	2-4
3	BASIS OF COMPARISON	3-1
	3.1 Technical	3-1
	3.1.1 Fuel Oil Mode	3-1
	3.1.2 Syncrude Mode	3-1
	3.2 Economic Basis	3-4
	3.2.1 Fuel Oil Mode Process Costs	3-4
	3.2.2 Syncrude Mode Process Costs	3-4
	3.2.3 General Economic Assumptions	3-4
	3.3 Material Balances and Thermal Efficiency	3-8
	3.3.1 Fuel Oil Mode	3-8
	3.3.2 Syncrude Mode	3-8
4	PROCESS DESCRIPTION	4-1
	4.1 Fuel Oil Mode	4-1
	4.1.1 Unit 01 - Coal Preparation	4-1
	4.1.2 Unit 02 - Liquefaction	4-1
	4.1.3 Unit 03 - Gas Processing	4-8
	4.1.4 Unit 04 - Hydrogen Plant	4-8
	4.1.5 Unit 05 - Oxygen Plant	4-10
	4.1.6 Unit 06 - Emission Control System	4-10
	4.1.7 Unit 07 - Effluent Control	4-10
	4.1.8 Unit 08 - Storage	4-11
	4.1.9 Unit 09 - Offsites and Utilities	4-11
	4.2 Syncrude Mode	4-12
	4.2.1 Unit 01 - Coal Preparation	4-16
	4.2.2 Unit 02 - Liquefaction	4-16
	4.2.3 Unit 03 - Light Ends Processing	4-19
	4.2.4 Unit 04 - Gasification	4-20
	4.2.5 Units 05-09	4-20

TABLE OF CONTENTS (Continued)

<u>SECTION</u>		<u>PAGE</u>
5	RESULTS	5-1
	5.1 Economic Analysis	5-1
	5.1.1 Methodology	5-1
	5.1.2 Unit Investment Costs	5-1
	5.1.3 Results of Evaluation	5-7
	5.2 Comparison of LCFFC and H-Coal Processes	5-12
	5.2.1 Comparative Process Performance	5-12
	5.2.2 Anticipated Major Operability Differences	5-24
	5.2.3 Commercialization Potential	5-24
	5.3 Recommendations for Further Work	5-25
6	REFERENCES	6-1
APPENDIX A	SAMPLE CALCULATIONS	A-1

LIST OF TABLES

<u>TABLE</u>		<u>PAGE</u>
3.1	Coal Analysis, Fuel Oil Mode	3-2
3.2	Coal Compositions, Syncrude Mode	3-3
3.3	Cost Assumptions	3-6
3.4	Overall Material Balance, Fuel Oil Mode	3-9
3.5	Net Yield Structure For C-E Lummus Clean Fuel From Coal Process (0.5 Wt% Sulfur Product) Boiler Fuel Case	3-10
3.6	Thermal Efficiency Calculation, Fuel Oil Mode	3-11
3.7	Overall Material Balance For LCFFC, Syncrude Mode	3-12
3.8	Overall Material Balance For H-Coal, Syncrude Mode	3-13
3.9	LCFFC Syncrude Case Net Yield Structure	3-14
3.10	H-Coal Syncrude Case Net Yield Structure	3-15
3.11	Thermal Efficiency Calculation For LCFFC Syncrude Mode	3-16
3.12	Thermal Efficiency Calculation For H-Coal Syncrude Mode	3-17
4.1	Case I - Process Units LCCFC and H-Coal Fuel Oil Mode	4-4
4.2	Case II - Process Units LCFFC and H-Coal Syncrude Mode	4-15
5.1	Constant Economic Data	5-2
5.2	Plant Investment by Unit, Fuel Oil Mode	5-4
5.3	Unit Cost Summary, Syncrude Mode	5-6
5.4	Variable Economic Data Input and Results of Analysis	5-8
5.5	Variable Economic Input and Results of Analysis	5-10

LIST OF TABLES (Continued)

<u>TABLE</u>		<u>PAGE</u>
5.6	Variable Economic Input and Results of Analysis	5-11
5.7	Naphtha Price Sensitivity Study	5-13
5.8	Total Plant Investment Sensitivity Study	5-16
5.9	Operating Conditions and Yield Structure Comparison	5-18
5.10	Nominal Properties of 300°F+ Blended Net Clean Fuel Product	5-19
5.11	LCFFC Syncrude Mode Properties of Products	5-20
5.12	H-Coal Syncrude Mode Properties of Products	5-21
5.13	Product Quality Comparison	5-22
A.1	Economic Evaluation of Conceptual Conversion Plant	A-1
A.2	Estimated Product Values	A-11
A.3	Capital Cost Estimates, Typical Calculation	A-14

LIST OF FIGURES

<u>FIGURE</u>		<u>PAGE</u>
4.1	LCFFC Fuel Oil Mode Overall Block Flow Diagram	4-2
4.2	H-Coal Fuel Oil Mode Overall Block Flow Diagram	4-3
4.3	LCFFC Syncrude (All Distillate) Mode Overall Block Flow Diagram	4-13
4.4	H-Coal Syncrude (All Distillate) Mode Overall Block Flow Diagram	4-14
5.1	Required Fuel Oil Price With Variable Naphtha Credit	5-14

LIST OF TABLES (Continued)

<u>TABLE</u>		<u>PAGE</u>
5.2	Required Syncrude Price With Variable Naphtha Credit	5-15
5.3	Total Liquid Product Price vs Total Plant Investment (Fuel Oil Mode)	5-17

SECTION 1 - INTRODUCTION

The C.E. Lummus Company has been conducting pilot plant work on its Lummus Clean Fuels From Coal (LCFFC) process since 1972. In 1976, the Energy Research and Development Administration (ERDA) agreed to sponsor work on a research program to develop an advanced process for converting coal to clean industrial and transportation fuels using LCFFC technology (Reference 1). The process employs a multiple expanded-bed, catalytic hydroliquefaction reactor section and a proprietary antisolvent deashing technique.

The LCFFC reactor is similar to the H-Coal reactor in that coal slurry and hydrogen travel upwards through an expanded catalyst bed, but differs from the H-Coal reactor in the following ways:

- The multiple series reactor approaches plug flow, whereas the H-Coal reactor's high internal recycle rate effectively produces a stirred tank type reactor; and
- A temperature gradient exists along the reactor.

It is claimed that the plug flow kinetics in the LCFFC reactor lead to these advantages: increased distillate (+400°F) and lower C₁ - C₄ gas make, better desulfurization and denitrogenation, and lower hydrogen consumption. It is also claimed that there is a reduction of thermal hydrocracking reactions, thereby permitting a greater portion of the hydrogen to be used in converting coal to distillate.

These claimed advantages prompted the Department of Energy to request UOP/SDC to compare the LCFFC process to the H-Coal process in terms of economics, potential for commercialization, and differences in operability.

The comparison was to include two operating modes:

- Case I - Fuel Oil Mode

This mode consists of the LCFFC process with a solvent deashing step. Underflow from the deashing step is to be used as feedstock for hydrogen production. This case was to be evaluated using the 1976 Fluor H-Coal Commercial Evaluation (Fuel Oil Mode) (Reference 4) as a basis for comparison.

- Case II - Syncrude Mode

This mode consists of the LCFFC process without the solvent deashing step (employing vacuum fractionation to separate ash residue from distillate material). The vacuum still bottoms stream is to be used for hydrogen production. This case was to be evaluated using the 1976 Fluor H-Coal Commercial Evaluation (Syncrude Mode) as a basis of comparison. At the request of the DOE Program Manager, the basis of comparison was changed to another H-Coal syncrude mode study reflecting latest yield data generated by Hydrocarbon Research, Inc. (Reference 3).

In studying these two cases, the UOP/SDC Joint Venture was asked to:

- develop a basis for comparison for the two cases, including overall process description, overall block flow diagrams, overall material balance and utility summary, and overall thermal efficiency,
- perform an order of magnitude factored cost estimate for each case,
- compare the economics of the two cases,

- comment upon LCFFC technology, anticipated major operability differences, and potential for commercialization, and
- identify areas where more development work on the LCFFC process is needed to realize the full potential of this program.

This study was not intended to yield absolute cost estimates. Rather, it was expected to generate cost estimates sufficient for comparing the economics of an LCFFC based coal liquefaction plant to those of an H-Coal based plant.

Conceptual H-Coal plant designs initially developed by Fluor were broken down into major processing sections (e.g., coal receiving, coal liquefaction, and hydrogen production). Conceptual LCFFC plant designs with the same major sections were created. The sections were compared on a unit by unit basis. The capital costs of the H-Coal base case were scaled to reflect the differences in the LCFFC case. Utility requirements of the two processes were assumed to be equivalent.

The potential for commercialization was also evaluated on a relative basis. The design of the LCFFC reactor was examined to determine how it compensates for known, past operating problems with liquefaction reactors. To the extent possible, LCFFC product was compared to H-Coal product with respect to refining or upgrading requirements.

SECTION 2 - SUMMARY

2.1 BASIS OF COMPARISONS

2.1.1 Plant Size and Design

The purpose of this study was to compare LCFFC to H-Coal for operation in both a syncrude and a fuel oil mode. For both modes, 25,000 tpd of Illinois No. 6 coal throughput is assumed to be the design capacity. Yield structures and operating conditions for each mode using LCFFC were provided to UOP/SDC by C.E. Lummus.

Lummus also provided portions of an in-house boiler fuel study. This study provided process descriptions and total installed cost data; these data were felt to be incompatible with the design for the H-Coal fuel oil mode base case. Instead, process schemes equivalent to the base case H-Coal designs were established for both the syncrude and fuel oil modes. Adjustments were made for major equipment changes in the reactor section, as well as capacity changes caused by the different yield structures and hydrogen requirements. Utility requirements for LCFFC were assumed to be substantially equivalent to requirements for H-Coal in each mode.

It should be noted that the Illinois No. 6 coal composition varied somewhat between cases. Yield structures were not changed to account for these changes in coal composition. In addition, it was assumed that substitution of a vacuum tower for deashing in the Case II syncrude mode does not affect the yield structure. The Case II yield structure was obtained using antisolvent deashing, which allows recycle of non-distillable coal liquids to the liquefaction step as part of the pasting solvent. Recycle of this non-distillable material is said to improve process performance. Distillate recycle would be necessary when using a vacuum tower for ash separation.

2.1.2 Economic Assumptions

In this study, the assumption of private investor financing at 50% debt/50% equity was used. Depreciation schedules based on 16-year, double-declining

balance were assumed. Several product valuation breakdowns were used. The most realistic was felt to be that where all liquid products were assumed to have the same value on a Btu basis. Separation of the products into fractions of different value was felt to be unreasonable because of the unknown processing requirements and the shifting market.

2.2 SUMMARY OF RESULTS

2.2.1 Economic

The results achieved using a fixed rate of return of 20% are representative. Assuming that products are valued on their Btu basis only, LCFFC yields significantly more "fuel oil" product (26%), and slightly more total product (1.4%) at slightly lower cost (0.7%) in the fuel oil mode, and more product (10.3%) at lower cost (5.7%) in the syncrude mode. In both modes, however, H-Coal produces more naphtha, which may command a premium.

2.2.2 Product Quality

2.2.2.1 Density

In general, LCFFC product is denser. The LCFFC fuel oil from the fuel oil mode has an API gravity of -3.9° against -1.8° for H-Coal. In the syncrude mode, LCFFC yields light distillate of 13.4° to H-Coal's 18.5° API, and heavy distillate of -3.2° API to H-Coal's 4.9° API. Naphtha from the Lummus fuel oil mode (48.3° API), however, is lighter than that from the H-Coal fuel oil mode (38.2° API).

2.2.2.2 Heteroatom Removal

Existing yield data show that the LCFFC product has lower heteroatom content while using less hydrogen. This indicates that LCFFC will yield a product of lower heteroatom content at the same level of severity.

SUMMARY OF RESULTS

MODE PROCESS	FUEL OIL		SYNCRUDE	
	LCFFC	H-COAL	LCFFC	H-COAL
Total Plant Cost, MM\$	1,649	1,584	1,779	1,811
Production				
Naphtha (BPD)	3,865	15,531	19,557	23,173
Fuel Oil (BPD)	64,819	51,325	-	-
Light Dist. (BPD)	-	-	14,495	28,092
Heavy Dist. (BPD)	-	-	35,508	15,160
Btu (10 ⁹ Btu/d) ¹	444	438	439	398
Product Quality				
Naphtha				
S/N/O (wt%)	-	0.02 ⁴	NIL/0.19/2.73	0.07/0.24/0.56
°API	48.3	38.2	35.7	52.3
Fuel Oil				
S/N/O (wt%)	0.5/1.2/1.8	0.50 ⁴	-	-
°API	-3.9	-1.8	-	-
Light Dist.				
S/N/O (wt%)	-	-	NIL/0.27/1.29	0.08/0.47/0.99
°API	-	-	13.4	18.5
Heavy Dist.				
S/N/O (wt%)	-	-	0.06/0.41/1.20	0.08/0.63/1.31
°API	-	-	-3.2	4.9
Product Cost				
\$/MM Btu ²	4.58	4.61	4.66	4.94
Thermal Efficiency ³ , %	73.3	68.5	74.0	71.8

¹Total liquid product including naphtha. Does not include C₁ - C₄.

²All liquid products valued equally.

³Includes by-products and C₁ - C₄.

⁴Nitrogen and oxygen contents unavailable.

2.2.2.2.1 Fuel Oil Mode. In the fuel oil mode, LCFFC naphtha has negligible sulfur, oxygen, or nitrogen, while H-Coal has 0.02 weight percent sulfur. The fuel oil product of both has 0.5% sulfur; the amount of nitrogen and oxygen is unknown for H-Coal.

2.2.2.2.2 Syncrude Mode. Sulfur and nitrogen levels for all LCFFC products are lower than those for the comparable H-Coal products. Oxygen levels for LCFFC are higher than for H-Coal in the naphtha (2.73% versus 0.56%) and light distillate (1.29% versus 0.99%) but lower in the heavy distillate (1.20% versus 1.31%).

2.3 COMMERCIALIZATION POTENTIAL

The relative merits of the LCFFC depend on the intended destination of the product. If the intent is to maximize fuels for direct combustion, then LCFFC is superior. The lower hydrogen content of the syncrude may result in a lower value as a refinery feedstock, however.

SECTION 3 - BASIS OF COMPARISON

3.1 TECHNICAL

3.1.1 Fuel Oil Mode

3.1.1.1 Coal Feed

In both the LCFFC and H-Coal fuel oil modes of operation, 25,000 tpd (MF basis) of Illinois No. 6 coal are converted to a low sulfur (0.5 wt%) fuel oil product. Additional coal is required in the LCFFC case for the production of intermediate Btu fuel gas for use in the plant. There were some differences between the Illinois No. 6 coal used for LCFFC and that used for H-Coal, as shown in Table 3.1. Yield structures were not adjusted for the difference in feed coal.

3.1.1.2 Products

While the goal of the process is to produce a fuel oil product, there are by-products. These byproducts include naphtha, phenols, ammonia, and sulfur. The light ends (C_1 - C_4 gases) are used as plant fuel gas for process heating and power generation.

3.1.1.3 Process Blocks

The basic process flow scheme has been taken from the 1976 Fluor study (Reference 4). Adjustments were made for differences in the LCFFC reactor design and process requirements.

3.1.2 Syncrude Mode

3.1.2.1 Coal Feed

As in the Fuel Oil mode, coal input of 25,000 tpd of Illinois No. 6 coal has been assumed as the basis. Because of variations of coal composition within a given coal seam, the Illinois No. 6 coal composition used for the LCFFC material

Table 3.1 Coal Analysis, Fuel Oil Mode

LCFFC

	<u>Wt.% (MF)</u>	<u>Dulong Formula</u>
C	68.25	$\text{HHV (Btu/lb)} = (14,544)C + (62,028) \left(H_2 - \frac{O_2}{8} \right) + (4,050)S$ $= 14,544 (.6825) + 62,028 (.0505 - .1144/8) + 4,050 (.0402)$
H	5.05	
N	1.24	
S	4.02	
O	11.44	
Ash	10.00	$\text{HHV} = 12,335 \text{ Btu/lb}$
	<u>100.00</u>	

H-COAL

	<u>Wt.% (MF)</u>	<u>Dulong Formula</u>
C	70.50	$\text{HHV (Btu/lb)} = (14,544)C + (62,028) \left(H_2 - \frac{O_2}{8} \right) + (4,050)S$ $= 14,544 (.705) + 62,028 (.0540 - .081/8) + 4,050 (.049)$
H	5.40	
N	0.95	
S	4.90	
O	8.10	
Ash	10.15	$\text{HHV} = 13,173 \text{ Btu/lb}$
	<u>100.00</u>	

balance is not the same as that used for the H-Coal material balance. The coals used were also different from those used in the respective fuel oil cases. Compositions are given in Table 3.2.

Table 3.2 Coal Compositions, Syncrude Mode

<u>Component</u>	<u>LCFFC</u>	<u>H-Coal</u>
	<u>Wt%</u>	<u>Wt%</u>
C	71.55	69.76
H	4.95	4.91
N	1.20	1.47
S	3.15	3.47
O	8.39	8.88
Ash	<u>10.76</u>	<u>11.51</u>
	100.00	100.00
High Heating		
Value (Btu/lb)	12,954	12,643

3.1.2.2 Products

The products of operation in the syncrude mode can be divided into three main hydrocarbon fractions and byproducts. The three fractions are naphtha, light distillate (or turbine fuel), and heavy distillate (or distillate boiler fuel). The byproducts produced are propane, butane, ammonia, phenols, and sulfur. A portion of the C₁ - C₄ light ends are used as a plant fuel gas for process heating and power generation. Excess intermediate Btu gas is generated from the residue of the LCFFC process; this is also used to satisfy plant needs.

3.1.2.3 Process Design Basis

The base case design was taken from a 1979 Fluor report (Reference 3). For the LCFFC case, adjustments were made by UOP/SDC to account for the different reactor design and operating requirements.

3.2 ECONOMIC BASIS

3.2.1 Fuel Oil Mode Process Costs

The base case used is that reported by Fluor in 1976 (Reference 4). Supplemental cost information was obtained from a second Fluor study (Reference 3). The process costs for LCFFC were scaled from the base case by considering the changes in each of the nine process blocks.

3.2.2 Syncrude Mode Process Costs

The base case used is the H-Coal syncrude mode evaluation by Fluor (Reference 3). As in the Fuel Oil mode case, unit costs for LCFFC were arrived at by scaling from comparable units in H-Coal.

3.2.3 General Economic Assumptions

3.2.3.1 Investment Cost Inclusions

The following costs were included in arriving at the process investment cost:

- Escalation to September 1980 was applied to unit cost.
- Sales tax was assumed to be 5 percent on all material.
- All direct and indirect construction costs were included.
- All engineering and home office fees were included.

- A contingency of approximately 27 percent on the sum of engineering and home office fees, direct and indirect construction costs, and sales taxes was assumed.

3.2.3.2 Investment Cost Exclusions

The following costs were not included in arriving at the total investment cost:

- The initial charge of catalysts and chemicals,
- Spare parts for equipment,
- Start-up cost,
- Land acquisition cost,
- Process licensing fees, or
- Piling.

3.2.3.3 Cost Assumptions

Table 3.3 shows the assumptions used in evaluating operating costs and interest costs. The analysis performed used these parameters for several variations of the discounted cash flow method used in private investor financing. These variations included:

- setting product prices and determining the internal rate of return,
- setting the discount rate and determining the required cost in \$/MM Btu (all products equal on a Btu basis), and
- setting the discount rate and the value of naphtha and determining the required cost of the rest of the products in \$/MM Btu.

Table 3.3 Cost Assumptions
(page 1 of 2)

Raw Material:

Coal cost (\$1.20/MM Btu)	\$30/st (MF)
Coal requirement (to liquefaction section)	25,000 st/d (MF)

Payroll:

Operator's wage	\$21,851/yr
Number of operators	568
Supervisory and support labor as a percentage of operator wages	30%
Fringe benefits as a percentage of payroll	35%

Other fixed expenses:

Maintenance, % of replaceable capital	3%
Insurance, % of replaceable capital	1%
General and Administrative expense, percentage of payroll plus fringe benefits	60%

Tax items:

Property tax, % of taxable capital	1%
Income tax rate	46%
Investment tax credit	20%

Misc. items:

Inflation rate	6%/yr
Operating days	330
First year operating rate	100%
Construction period	5 years
Project life	20 years

Capital items:

Debt/equity ratio	50/50
Interest on long term debt	8%
Period of long term debt	10 years
Interest during construction	8%
Type of depreciation	Double Declining Balance
Period of depreciation	16 years

Table 3.3 Cost Assumptions
(page 2 of 2)

Cash drawdown schedule, in %

Year of Construction	1	2	3	4	5
Land	100	0	0	0	0
Plant	1	5	22	39	33
Preproduction	0	0	0	0	100
Inventory	0	0	0	0	100
Catalyst and Chemicals	0	0	0	0	100
Royalties	1	5	22	39	33

Working capital:

Interest	8%
Payroll	14 days
Accounts receivable	45 days
Less: Accounts payable	30 days

3.3 MATERIAL BALANCES AND THERMAL EFFICIENCY

3.3.1 Fuel Oil Mode

Table 3.4 shows the overall material balances for H-Coal and LCFFC when operating in the Fuel Oil Mode. As can be seen, LCFFC yields more fuel oil and less naphtha. Table 3.5 gives the net yield structure of the LCFFC reactor product; this information was unavailable for H-Coal. Table 3.6 gives side-by-side thermal efficiency calculations for the two processes.

3.3.2 Syncrude Mode

Table 3.7 shows the overall material balance for LCFFC; Table 3.8 shows that for H-Coal. It can be noted that the H-Coal product is concentrated in the lighter end of the barrel. Tables 3.9 and 3.10 give the net yield structures of LCFFC and H-Coal, respectively. Tables 3.11 and 3.12 show thermal efficiency calculations for LCFFC and H-Coal, respectively.

Table 3.4 Overall Material Balance, Fuel Oil Mode

	<u>LCFFC</u>			<u>H-Coal</u>		
<u>Feed Streams</u>			<u>lb/hr</u>			<u>lb/hr</u>
Coal (MF basis)			2,083,333			2,083,333
Oxygen (as 100%)			431,666			435,667
Supplemental Coal (MF Basis)			14,425			
<u>Product Streams</u>						
<u>Coal Liquids</u>	<u>bpsd</u>	<u>°API</u>	<u>lb/hr</u>	<u>bpsd</u>	<u>°API</u>	<u>lb/hr</u>
Naphtha	3865	48.3	44,330	15,531	38.2	188,702
Fuel Oil	64,819	-3.9	1,049,828	51,325	-1.8	817,458
<u>Byproducts</u>			<u>tpd</u>			<u>tpd</u>
Sulfur			947			1178.4
Ammonia			158			180.2
Phenols			17.9 ¹			17.9
Ash to Disposal (MF Basis)			2989			2700
			<u>MM Btu/hr (LHV)</u>			<u>MM Btu/hr (LHV)</u>
<u>Fuel Gas (to Internal Use)</u>			1737			4337
<u>Intermediate Btu Gas</u>			<u>2600</u>			<u>-</u>
<u>(to Internal Use)</u>						
<u>Total</u>			4337			4337

¹ Assumed equivalent to H-Coal base case

Table 3.5 Net Yield Structure For C-E Lummus Clean Fuel From Coal Process
(0.5 Wt% Sulfur Product) Boiler Fuel Case

COAL FEED			NET PRODUCTS		
Constituents	Wt%	Lbs/Ton	Constituents	Wt%	Lbs/Ton
Carbon	66.2	1,324	Ammonia (NH ₃)	.26	5.1
Hydrogen	4.9	98	Water (H ₂ O)	13.75	275.0
Nitrogen	1.2	24	Carbon Monoxide (CO)	.33	6.6
Sulfur (Total)	3.9	78	Carbon Dioxide (CO ₂)	.22	4.5
Mineral Matter (Sulfur Free)	9.7	194	Methane (CH ₄)	0.83	16.6
Water	3.0	60	Ethane (C ₂ H ₆)	0.85	16.9
Organic Oxygen	11.1	222	Propane (C ₃ H ₈)	0.60	12.0
	100.0	2,000	Butane (C ₄ H ₁₀)	0.22	4.5
Hydrogen Added	1.9	38	Hydrogen Sulfide (H ₂ S)	3.13	62.6
	101.9	2,038	C ₅ - 300°F Naphtha	2.17	43.4
			300-400°F br. Naphtha	1.74	34.8
			400-600°F br. Distillate	12.44	248.8
			600-900°F br. Distillate	7.59	151.8
			Residual Product (+900°F)	27.02	540.4
			Residual Product (+900°F) (Associated with Ash)	20.50	410.0
			Ash & Inorganic Sulfur	10.25	205.0
				101.9	2,038.0

Table 3.6 Thermal Efficiency Calculation, Fuel Oil Mode

LCFFC FUEL OIL MODE					H-COAL FUEL OIL MODE			
HEAT INPUT	FLOW RATE LB/HR	HEAT OF COMBUSTION BTU/LB (HHV) ¹	TOTAL HEAT 10 ⁶ BTU/HR (HHV)	PERCENT OF INPUT	FLOW RATE LB/HR	HEAT OF COMBUSTION BTU/LB (HHV)	TOTAL HEAT 10 ⁶ BTU/HR (HHV)	PERCENT OF INPUT
Coal (MF)	2,083,333	12,335	25,698	100.0	2,083,333	13,173	27,443.7	100.0
Supplemental Coal (MF)	14,425	12,335	178					
<u>HEAT OUTPUT</u>								
Naphtha	44,330	19,200	851.1	3.3	188,702	19,680 ²	3,713.7	13.5
Fuel Oil	1,049,828	16,816	17,654.0	68.2	817,458	17,790 ³	14,542.6	53.0
Ammonia	13,167	9,667	127.3	0.5	15,016	9,667	145.2	0.5
Sulfur	78,829	3,980	313.7	1.2	98,200	3,980	390.8	1.4
Phenol	1,492	13,997	20.9	0.1	1,492	13,997	20.9	0.1
			<u>18,967.0</u>	<u>73.3</u>			<u>18,813.2</u>	<u>68.6</u>

¹ Heat of combustion based on product elemental analysis.

² Estimated by UOP/SDC.

³ Back calculated from H-Coal Base Case Data.

Table 3.7 Overall Material Balance For LCFFC, Syncrude Mode

<u>Feed Streams</u>			<u>lb/hr</u>
Coal (MF basis)			2,083,333
Oxygen (as 100%)			517,333
<u>Product Streams</u>			
<u>Coal liquids</u>	<u>bpsd</u>	<u>°API</u>	<u>lb/hr</u>
Naphtha	19,557	35.7	241,250
Light Distillate	14,495	13.4	206,250
Heavy Distillate	35,508	-3.2	572,083
Propane	2,362	147.6	17,497
Butane	2,542	110.3	21,666
<u>Byproducts</u>			<u>tpd</u>
Sulfur			728
Ammonia			200
Phenols ¹			69
Ash to Disposal (MF Basis)			2,806
			<u>MM Btu/hr (HHV)</u>
Excess Fuel Gas ²			351.0
Fuel Gas to Internal Use			4,527.0

¹ Assumed equivalent to H-Coal base case

² Estimated by UOP/SDC

Table 3.8 Overall Material Balance For H-Coal, Syncrude Mode

<u>Feed Streams</u>		<u>lb/hr</u>	
Coal (MF basis)		2,083,333	
Oxygen (as 100%)		507,783	
<u>Product Streams</u>			
<u>Coal liquids</u>	<u>bpsd</u>	<u>°API</u>	<u>lb/hr</u>
Naphtha	23,173	52.3	259,901
Turbine Fuel	28,092	18.5	386,193
Distillate Boiler Fuel	15,160	4.9	229,279
Propane	4,138	147.7	30,542
Butane	5,797	110.0	49,436
<u>Byproducts</u>		<u>tpd</u>	
Sulfur		853	
Ammonia		286	
Phenols		69	
Ash to Disposal (MF Basis)		2,995	
		<u>MM Btu/hr (HHV)</u>	
Fuel Gas to Internal Use		4,527	

Table 3.9 LCFFC Syncrude Case Net Yield Structure

Basis: Pilot Plant Run - HDS-74

<u>Constituent</u>	<u>Weight % on Moisture Free Coal</u>
Ammonia	0.76
Water	6.47
Carbon Monoxide	0.05
Carbon Dioxide	0.08
Hydrogen Sulfide	2.08
Methane	2.16
Ethane	1.95
Propane	0.84
Butane	1.04
C ₅ - 400°F Naphtha	11.58
400-500°F Light Distillate	9.90
500-850°F Heavy Distillate	27.46
850+ Residual Product	22.76
Unconverted Coal	5.20
Ash	10.76
	<u>103.09</u>
Hydrogen Added	3.09

Table 3.10 H-Coal Syncrude Case Net Yield Structure

Basis: PDU Run 5 (Period 29)

<u>Constituent</u>	<u>Weight % on Moisture Free Coal</u>
CO	0.16
H ₂ S	2.64
NH ₃	1.08
H ₂ O	6.65
CO ₂	0.37
C ₁	3.70
C ₂ -	0.15
C ₂	3.39
C ₃ -	0.06
C ₃	3.33
C ₄	2.42
IBP-100°F	1.72
100-200°F	3.23
200-300°F	4.43
300-400°F	6.89
400-500°F	9.38
500-600°F	8.92
600-700°F	4.71
700-800°F	1.57
800-900°F	1.88
900-975°F	1.92
Residuum	19.00
Unconverted Coal	5.78
Ash	<u>11.51</u>
TOTAL	104.89
Hydrogen Added	4.89

Table 3.11 Thermal Efficiency Calculation For LCFFC Syncrude Mode

<u>HEAT INPUT</u>	<u>FLOW RATE LB/HR</u>	<u>HEAT OF COMBUSTION BTU/LB (HHV)¹</u>	<u>TOTAL HEAT 10⁶ BTU/HR (HHV)</u>	<u>PERCENT OF INPUT</u>
Coal (MF)	2,083,333	12,954	26,987.0	100.0
<u>HEAT OUTPUT</u>				
Naphtha	241,250	19,234	4,640.2	17.2
Light Distillate	206,250	18,260	3,766.1	13.9
Heavy Distillate	572,083	17,293	9,893.0	36.7
Propane	17,497	21,669	379.1	1.4
Butane	21,667	21,321	462.0	1.7
Ammonia	16,667	9,667	161.1	0.6
Sulfur	60,666	3,980	241.4	0.9
Phenols	5,750	13,997	80.5	0.3
Excess Fuel Gas			351.0	1.3
			<u>19,974.4</u>	<u>74.0</u>

COAL ANALYSIS (MF)

<u>Wt. %</u>	<u>Dulong Formula</u>
C 71.55	$\text{HHV (Btu/lb)} = (14,544)C + (62,028)\left(H_2 - \frac{O_2}{8}\right) + (4,050)S$ $= 14,544(.7155) + 62,008\left(.0495 - \frac{.0839}{8}\right) +$ $4,050 (0.0315)$
H 4.95	
N 1.20	
S 3.15	
O 8.39	
Ash 10.76	$\text{HHV} = 12,954 \text{ Btu/lb}$
<u>100.00</u>	

¹ Based on product elemental analysis

Table 3.12 Thermal Efficiency Calculation For H-Coal Syncrude Mode

HEAT INPUT	FLOW RATE LB/HR	HEAT OF COMBUSTION BTU/LB (HHV) ¹	TOTAL HEAT 10 ⁶ BTU/HR (HHV)	PERCENT OF INPUT
Coal (MF)	2,083,333	12,643	26,340.0	100.0
<u>HEAT OUTPUT</u>				
Naphtha	259,901	20,455	5,316.3	20.2
Turbine Fuel	386,193	18,631	7,195.2	27.3
Boiler Fuel	229,279	17,835	4,089.2	15.5
Propane	30,542	21,669	661.8	2.5
Butane	49,436	21,321	1,054.0	4.0
Ammonia	23,833	9,667	230.4	0.9
Sulfur	71,083	3,980	282.9	1.1
Phenols	5,750	13,997	80.5	0.3
			<u>18,910.3</u>	<u>71.8</u>

COAL ANALYSIS (MF)

	<u>Wt.%</u>	<u>Dulong Formula</u>
C	69.76	$\begin{aligned} \text{HHV (Btu/lb)} &= (14,544)C + (62,028)(H_2 - \frac{O_2}{8}) + (4,050)S \\ &= 14,544(.6976) + 62,028(.0491 - \frac{.0888}{8}) + \\ &\quad 4,050 (.0347) \end{aligned}$
H	4.91	
N	1.47	
S	3.47	
O	8.88	
Ash	<u>11.51</u>	HHV = 12,643
	<u>100.00</u>	

¹ Based on product elemental analysis.

SECTION 4 - PROCESS DESCRIPTION

4.1 FUEL OIL MODE

Except for the coal preparation section, the basic design is taken from the Fluor 1976 study (Reference 4). While some differences between the H-Coal and LCFFC processes occur because of the different reactors and material balances, the same general process blocks were used. The descriptions given are those of the base case unless explicitly marked as being deviations. Thus, descriptions of H-Coal are taken from the base case and descriptions specifically for LCFFC represent deviations. Table 4.1 gives a summary of the process units. Figures 4.1 and 4.2 are the block flow diagrams for LCFFC and H-Coal, respectively.

4.1.1 Unit 01 - Coal Preparation

Illinois No. 6 coal received by rail is crushed and dried to the proper size and moisture content in this unit. A coal preparation section equivalent to that used in an EPRI-funded H-Coal study (Reference 3) was assumed for all cases examined in this report.

The coal preparation section receives coal that contains ten percent moisture. Coal is conveyed to a live storage pile sufficient for three days and an emergency dead storage pile sufficient for 30 days. Coal from live storage is crushed and dried simultaneously in roller mills to -20 mesh and less than 2 wt% moisture.

4.1.2 Unit 02 - Liquefaction

The liquefaction section receives the crushed and dried coal from Unit 01 and reacts it with hydrogen at elevated temperature and pressure. The unit is divided into four subunits, described below.

Figure 4.2 H-Coal Fuel Oil Mode
Overall Block Flow Diagram

Table 4.1 Case I - Process Units LCFFC and H-Coal Fuel Oil Mode

<u>UNIT NO.</u>	<u>DESCRIPTION</u>
01	Coal Preparation
02	Liquefaction Coal Slurry Preparation Reaction Reactor Effluent Separation Fractionation and Deashing
03	Gas Processing Lean Oil Absorption Gas Treating (Amine)
04	Hydrogen Plant Gasification Shift Conversion Acid Gas Removal I Hydrogen Compression Acid Gas Removal II (LCFFC only)
05	Oxygen Plant
06	Emission Control Systems Sulfur Plant (Claus) Tail Gas Treating
07	Effluent Control Systems Sour Water Stripping Phenol Recovery
08	Storage
09	Offsites and Utilities

4.1.2.1 LCFFC Plant

4.1.2.1.1 Coal Slurry Preparation. This subunit receives crushed and dried coal from Unit 01. In the LCFFC process, coal is slurried with a 600-900°F nominal boiling range aromatic recycle solvent in a primary mixing tank. The solvent to coal weight ratio is approximately 1.5. From the mixing tank, the coal slurry is pumped to a pasting tank, where the coal is partially dissolved. The temperature of the contents of the tank is maintained by circulating some of the slurry through a heating loop.

4.1.2.1.2 LCFFC Reaction. Partially dissolved coal from the pasting tank is pumped to the LCFFC catalytic reaction section. Expanded bed catalytic reactors operating in a plug flow mode are employed to convert the coal into a mixture of gaseous, distillable, and non-distillable products. Information received from CE-Lummus indicates that ten reactors will be required for this case.¹

4.1.2.1.3 Reactor Effluent Separation. This subunit separates the reactor effluent into gaseous, liquid, and ash-containing liquid product streams.

A portion of the high-pressure, predominantly hydrogen gas stream is routed to Unit 03 for desulfurization, light ends removal, and eventual recycle back to the LCFFC reaction system.

The ash-containing liquid product stream is fractionated at slightly above atmospheric pressure to remove the initial boiling point to 690°F fraction. This material is further separated into a C₁ - C₄ fuel gas stream, a C₅ - 300°F naphtha cut, a light atmospheric gas oil, and a heavy atmospheric gas oil, a portion of which is blended into the fuel oil (clean fuel) product. The remaining portion of the heavy atmospheric gas oil is recycled to the coal slurring section for use as the light fraction of the pasting solvent.

¹Reactor dimensions and assumed design temperature and pressure are 12'-0" diameter x 63'-0" high and 900°F, 2400 psi, respectively.

4.1.2.1.4 Lummus Antisolvent Deashing. This subunit receives the ash-containing liquid bottoms stream from the atmospheric fractionator and mixes it with an antisolvent to precipitate essentially all of the ash.

The overflow stream from settling is fractionated into several streams to recover antisolvent, IBP-900°F pasting solvent, and fuel oil ("Clean Fuel") product. The underflow stream is also fractionated to recover the IBP-900°F pasting solvent and antisolvent retained during ash separation. More IBP-900°F material is recovered in the fractionators than is needed as pasting solvent. The excess constitutes additional production from the LCFFC reaction step and is blended into the product. The remainder of this boiling range fraction is recycled as pasting solvent.

To maintain the desired composition of the recycle antisolvent, a small purge is withdrawn and blended in with the Clean Fuel product. An equivalent amount of purchased, fresh antisolvent is added to the system (not shown in overall block flow or overall material balance).

The ash-rich underflow stream, stripped of solvent, is routed to Unit 04 for conversion into hydrogen via partial oxidation.

4.1.2.2 H-Coal

4.1.2.2.1 Coal Slurry Preparation. This subunit receives crushed and dried coal from Unit 01. In the H-Coal process, coal is slurried with a hot slurry oil consisting of distillate and hydroclone overflow. The coal is maintained in a slurry form by means of mechanical agitators and slurry recirculation facilities.

The same basic function is accomplished here as in the LCFFC process, i.e., to slurry the coal. A minor difference is that the LCFFC process uses a pasting (or digesting) tank to further dissolve the coal. H-Coal and LCFFC coal slurry preparation sections were, therefore, judged equivalent within the scope of this study.

4.1.2.2.2 H-Coal Reaction. The coal-oil slurry is pumped to reactor pressure, mixed with a portion of the recycle-makeup hydrogen, preheated, and charged with the remainder of the hydrogen to the H-Coal catalytic reaction section. Expanded bed catalytic reactors are employed to convert the coal into a mixture of gaseous, distillable, and nondistillable products.

The reactors are equipped with an internal pump that provides sufficient liquid recirculation to maintain the catalyst in an ebullated state and to maintain essentially isothermal conditions across the reactor. This recirculation produces, in effect, a "stirred tank" type reactor as opposed to the LCFFC "plug flow" reactor.

The change in reactor configuration (along with operating temperature and pressure) constitute the only major difference between the two reaction sections. Six H-Coal reactors are needed versus the ten reactors estimated to be required for the LCFFC case. It was assumed for purposes of this study that both the H-Coal and LCFFC reactors have refractory inner liners.

4.1.2.2.3 Reactor Effluent Separator. This subunit separates the H-Coal reactor effluent into its component gaseous, liquid, and ash-containing liquid product streams.

A portion of the high-pressure, predominantly hydrogen, gas stream is routed to Unit 03 for desulfurization, light ends removal, and eventual recycle back to the H-Coal reaction system.

The ash-containing liquid product stream is fed to a battery of hydroclones for further solids concentration. Overflow liquid from the hydroclones is recycled to the coal slurry section. Hydroclone underflow is sent to the next subunit, Fractionation and Deashing, for removal of solids.

4.1.2.2.4 Fractionation and Deashing. This subunit receives the ash-containing hydroclone underflow and separates the unreacted coal and ash. The separation is achieved by a combination of flashing, steam stripping, and solvent precipitation. The antisolvent used is n-decane.

4.1.3 Unit 03 - Gas Processing

A gas processing unit of the same type as that used in the H-Coal base case was used for Unit 03. For purposes of this study the unit is divided into two subunits, described below.

4.1.3.1 Lean Oil Absorption and Stripping

This subunit receives reactor vapor effluent as feed. This hydrogen-rich stream is contacted by a lean oil in a high pressure absorber where heavier hydrocarbons and some sour gases are absorbed. The overhead dry hydrogen-rich gas is recycled back to the reactor. Hydrocarbons and sour gases reclaimed from the oil are combined with other sour gases and light hydrocarbons from product fractionation and sent to the next subsection, Gas Treating.

4.1.3.2 Gas Treating

This subunit employs DGA (Diglycolamine) to scrub the sour gas feed. A sweet product fuel gas is produced for internal plant use. Acid gas from the amine regenerator becomes feed to Unit 06, Emissions Control.

4.1.4 Unit 04 - Hydrogen Plant

Hydrogen is produced in this unit by partial oxidation of the ash-rich underflow from Unit 02. This unit is divided into five subsections.

4.1.4.1 Gasification

In this subunit, the ash-laden stream from deashing is gasified by use of the Texaco Coal Gasification process. The stream is converted via partial oxidation reactions to a hydrogen- and carbon monoxide-rich gas mixture. Ash is removed from the reactor as slag. The gas produced is scrubbed free of soot by quenching with water. The effluent gas stream contains sufficient water for the water-gas shift reaction. For the LCFFC process, only enough gas for

hydrogen make-up needs is sent to the shift unit; the rest is sent to Acid Gas Removal II. For the H-Coal process, all of the gas is sent to the shift unit.

4.1.4.2 Shift Conversion

In this subunit, carbon monoxide is reacted with water to produce hydrogen via the water-gas shift reaction. A sulfur-tolerant shift catalyst is employed. The shifted gas is sent to the next subunit, Acid Gas Removal I.

4.1.4.3 Acid Gas Removal I (AGR I)

This subunit uses the Selexol process (a physical solvent system licensed by Allied Chemical) to remove H_2S and CO_2 from the shifted gasifier effluent. An H_2S -rich acid gas stream and an H_2S -free CO_2 stream are produced when operating in a selective mode. The H_2S -rich stream is routed to Unit 06 for recovery of sulfur. The CO_2 stream is vented to the atmosphere.

4.1.4.4 Hydrogen Compression

Clean hydrogen exiting AGR I is compressed to slightly above reactor pressure, combined with recycle hydrogen from lean oil absorption, and routed to the reactor system.

4.1.4.5 Acid Gas Removal II (AGR II)

The substantial amount of excess gasifier effluent from the LCFFC process is cooled and treated for selective removal of CO_2 and H_2O in this subunit. The Selexol process is selected for this purpose. The intermediate Btu gas recovered is sent to the plant fuel gas system for in-plant use.

The H-Coal process does not produce excess gas, and thus does not need this unit.

4.1.5 Unit 05 - Oxygen Plant

This unit produces oxygen for use in the gasification of deashing underflow. A conventional low pressure cycle oxygen plant is used for this application. Co-product nitrogen is used for stripping in AGR I and II and for inert gas blanketing purposes.

4.1.6 Unit 06 - Emission Control System

The Emission Control System uses a conventional two-stage Claus plant for primary H_2S emission control. In this unit, H_2S from Units 03, 04, and 06 is converted to elemental sulfur.

A Beavon tail-gas treating unit is used for reduction of the Claus plant tail gas stream H_2S content. A small amount of additional sulfur product is also produced in the Beavon unit.

4.1.7 Unit 07 - Effluent Control

Unit 07 uses of the following subunits for control of the plant sour waters.

4.1.7.1 Sour Water Stripping

The Phosam-W® process, licensed by USS Engineers and Consultants, is used for the selective removal of ammonia and H_2S from plant sour waters. An H_2S -rich stream is produced, which is sent to Unit 06 for sulfur recovery. An anhydrous ammonia stream is also produced, which is sent to product storage.

4.1.7.2 Phenol Recovery

Phenolics are present in the effluent water from the Phosam-W® process. The Chem-Pro process, licensed by Chem-Pro Equipment Corporation, is used for removal of these phenolics. This process uses a proprietary solvent in a packaged extraction-distillation system to remove phenols and cresols from

aqueous wastes. The recovered phenolics are sent to product storage, and the treated water is recycled for plant use.

Phenolic yield data for the LCFFC process were unavailable from Lummus. Phenolics yield was, therefore, assumed to be equivalent to that produced in the H-Coal base case.

4.1.8 Unit 08 - Storage

This unit is assumed to be equivalent to the H-Coal base case. Storage for twenty-one days products of naphtha, heavy fuel oil, and ammonia is provided. Sulfur storage capacity is seven days.

4.1.9 Unit 09 - Offsites and Utilities

This unit is assumed equivalent to the H-Coal base case and includes the following offsite and utility systems and services:

- Raw Water Storage and Filtration
- BFW Preparation
- Utility Water System
- Cooling Water System
- Potable Water System
- Fire Water System
- Steam and Power Generation
- Steam and Condensate Distribution
- Steam Superheating
- Boiler Plant Stack
- Plant and Instrument Air
- Inert Gas System
- Fuel Oil and Fuel Gas System
- Flare System & Stack
- Catalyst and Chemical Handling
- Electrical Main Substation

Electrical Distribution
Interconnecting Piping
Site Preparation
Perimeter Fencing
Roads and Parking Areas
Maintenance Equipment
Laboratory Equipment
Mobile Equipment
Fire Protection Equipment
Buildings
Building Furnishings
Communication Systems
Railroads
Storm Water Collection
Oily Water Treatment
Sanitary Treatment
Waste Process Water Treatment
Solid Waste Disposal

The reader is referred to the base case report (Reference 4) for further detailed descriptions of these units.

4.2 SYNCRUDE MODE

In this case, the reactor conditions are established to maximize production of naphtha, light distillate, and heavy distillate. The base case is the H-Coal syncrude mode presented by Fluor (Reference 3). Both LCFFC and H-Coal are assumed to have the same basic process units, as shown in Table 4.2. As before, descriptions are from the base case unless explicitly labeled otherwise. Overall process flow diagrams for LCFFC and H-Coal are given in Figures 4.3 and 4.4, respectively.

Figure 4.4 H-Coal SYNCRUDE (All Distillate)
Mode Overall Block Flow Diagram

Table 4.2 Case II - Process Units LCFFC and H-Coal Syncrude Mode

<u>UNIT NO.</u>	<u>DESCRIPTION</u>
01	Coal Preparation
02	Liquefaction Coal Slurry Preparation Reaction Reactor Effluent Separation Fractionation
03	Light Ends Processing Compression Amine Plant - Gas Plant Light Ends Separation
04	Hydrogen Plant Gasification Shift Conversion Acid Gas Removal I Hydrogen Compression Acid Gas Removal II (LCFFC only)
05	Oxygen Plant
06	Emission Control Systems Sulfur Plant (Claus) Tail Gas Treating
07	Effluent Control Systems Sour Water Stripping Phenol Recovery
08	Storage
09	Offsites and Utilities

2.1 Unit 01 - Coal Preparation

Illinois No. 6 coal is crushed and dried to the proper size and moisture content in this unit. A coal preparation section equivalent to that used in an EPRI-funded H-Coal (Reference 3) study was assumed for all cases examined in this report.

The assumed coal preparation section receives coal that contains ten percent moisture. Coal is then conveyed to a 3-day live storage pile and a 30-day emergency dead storage pile. Coal from live storage is simultaneously crushed and dried in roller mills to -20 mesh and less than 2 wt% moisture.

4.2.2 Unit 02 - Liquefaction

The liquefaction section receives the crushed and dried coal from Unit 01 and reacts it with hydrogen at elevated temperature and pressure. The unit is divided into four subunits, described below.

4.2.2.1 LCFFC Reactor

4.2.2.1.1 Coal Slurry Preparation. This subunit receives crushed and dried coal from Unit 01. In the LCFFC process, coal is slurried with a 600-900°F nominal boiling range aromatic recycle solvent in the primary mixing tank. The solvent to coal weight ratio is approximately 1.5. From the mixing tank the coal slurry is pumped to a pasting tank, where the coal is partially dissolved. The contents of the tank are kept hot by circulating some of the slurry through a heated loop.

4.2.2.1.2 LCFFC Reaction. Partially dissolved coal from the pasting tank is pumped to the LCFFC catalytic reaction section. Expanded bed catalytic reactors, operating in a plug flow mode, are employed to convert the coal into a mixture of gaseous, distillable, and non-distillable products. Information received from CE-Lummus indicates that ten reactors will be required for this case.³

³Reactor dimensions and assumed design temperature and pressure are 11'-0" diameter x 61'-0" high and 900°F, 3000 psi, respectively.

4.2.2.1.3 Reactor Effluent Separation. This subunit separates LCFFC reactor effluent into its component gaseous, liquid, and ash-containing liquid product streams. A reactor effluent separation scheme similar to the H-Coal base case scheme is used. (The reader is referred to the base case report for a detailed description.)

The high pressure gas stream (predominantly hydrogen) is split into two streams. The first portion is compressed and recycled to the reactor. The remaining portion is mixed with intermediate pressure vapors, desulfurized in an amine unit, and fed to a cryogenic unit. Enriched hydrogen from the cryogenic unit is recompressed and joins the recycle and makeup hydrogen gases to the reactor section.

The ash-containing liquid stream is further separated by a series of high-, intermediate-, and low-pressure flash drums. An ash-containing liquid stream from the high pressure flash drum is used as an external liquid recycle stream.

4.2.2.1.4 Fractionation. Light liquids from the series of flash drums are condensed, collected, and sent to a fractionator (operating above atmospheric pressure), where naphtha and light distillate streams are obtained.

Heavy ash-containing liquids from the final low pressure flash are sent to a vacuum tower, where a separation between heavy distillate and ash-containing bottoms is made. A portion of the heavy distillate is used for recycle as pasting solvent to the coal preparation section. The remainder of this stream is then the net heavy distillate production.

The ash-containing bottoms stream is sent to Unit 04 for conversion into hydrogen via partial oxidation.

4.2.2.2 H-Coal Reactor

4.2.2.2.1 Coal Slurry Preparation. This subunit receives crushed and dried coal from Unit 01. In the H-Coal process, coal is slurried with a hot slurry oil

consisting of distillate and hydroclone overflow. The coal is maintained in a slurry form by means of mechanical agitators and slurry recirculation facilities.

The same basic function is accomplished here as in the LCFFC process, i.e., slurrying the coal. A minor difference is that the LCFFC process uses a pasting (or digesting) tank to further dissolve the coal. H-Coal and LCFFC coal slurry preparation sections were, therefore, judged equivalent within the scope of this study.

4.2.2.2.2 H-Coal Reaction. The coal-oil slurry is pumped to reactor pressure, mixed with a portion of the recycle-makeup hydrogen, preheated, and charged with the remainder of the hydrogen to the H-Coal catalytic reaction section. Ten ebullated bed catalytic reactors (13'-0" diameter x 59'-0" high), are employed to convert the coal into a mixture of gaseous, distillable, and nondistillable products.

The reactors are equipped with an internal pump that provides sufficient liquid recirculation to maintain the catalyst in an ebullated state and to maintain essentially isothermal conditions across the reactor. This recirculation produces, in effect, a "stirred tank" type reactor as opposed to the LCFFC "plug flow" reactor.

The change in reactor configuration (along with operating temperature and pressure) constitute the only major difference between the two reaction sections. It was assumed for purposes of this study that both H-Coal and LCFFC reactors employ refractory inner liners.

4.2.2.2.3 Reactor Effluent Separator. This subunit separates the H-Coal reactor effluent into its component gaseous, liquid, and ash-containing liquid product streams.

A portion of the high-pressure, predominantly hydrogen, gas stream is routed to Unit 03 for desulfurization, light ends removal, and eventual recycle back to the H-Coal reaction system.

The ash-containing liquid product stream is fed to a battery of hydroclones for further solids concentration. Overflow liquid from the hydroclones is recycled to the coal slurry section. Hydroclone underflow is sent to the next subunit, Fractionation and Deashing, for removal of solids.

4.1.2.2.4 Fractionation and Deashing. This subunit receives the ash-containing hydroclone underflow and separates the unreacted coal and ash. The separation is achieved by flashing and steam stripping followed by fractionation in a vacuum tower.

4.2.3 Unit 03 - Light Ends Processing

This unit processes the off-gases from Unit 02, Liquefaction. The sequence of operations used was the same as in the H-Coal base case. The unit is divided into three subunits. Brief process descriptions follow.

4.2.3.1 Compression

This subunit receives off-gases from Unit 02 (cryogenic unit purge, sour flash gases, sour fractionator light ends) and compresses them to a pressure of about 400 psig.

4.2.3.2 Amine Plant

This subunit uses conventional treating methods (diglycolamine) to remove H_2S , CO_2 , and COS from the feed. Acid gases are sent to Unit 06 for recovery of sulfur.

4.2.3.3 Gas plant

This subunit separates propane, butane, and light naphtha from the feed stream. Propane and butane are routed to storage (with a portion of the propane required for in-plant fuel use). Residual gas is used partly as gas turbine fuel and partly as feed to the hydrogen recovery unit.

4.2.3.4 Light Ends Separation

A cryogenic unit is used to separate out the heavier hydrocarbons from the gas stream. The resulting hydrogen-enriched gas stream goes to a molecular sieve-pressure swing adsorption (PSA) unit. The recovered high purity hydrogen from the PSA unit is recompressed and recycled to the liquefaction section.

4.2.4 Unit 04 - Gasification

The discussion in Section 4.1.4 is applicable except that the feed to gasification is ash-containing vacuum bottoms from Unit 02.

4.2.5 Units 05-09

The discussions in Sections 4.1.5 through 4.1.9 are applicable.

SECTION 5 - RESULTS

5.1 ECONOMIC ANALYSIS

5.1.1 Methodology

The economic calculations used for this report were based on private investor financing using the discounted cash flow method (DCFM). In this type of analysis, the net amount of cash spent or received in a given year is related to its value in a base year by the discount rate, or the rate at which a dollar would be expected to accrue interest if invested. The discount rate is also referred to as the internal rate of return (IRR), or the average rate at which invested dollars return profits.

To make economic analyses using DCFM, complete pro-forma cash flows for the life of the project must be established. An example of one such analysis is given in Appendix A. Discounted cash flow calculations may be approached in two ways: the IRR may be set at some value, with product prices generated to obtain this IRR, or product prices may be assumed, and the IRR calculated. Both methods are used in this report.

Each case requires 170 pieces of data relating to the economic environment of the plant. Much of the data is constant from case to case; these numbers are given in Section 3 and repeated here for convenience.

5.1.2 Unit Investment Costs

Table 5.2 shows the breakdown of the plant investment cost by unit for the fuel oil mode. Cost data for the H-Coal base case were taken from the two Fluor reports (References 3 and 4) and inflated to September, 1980, dollars. Costs for LCCFC were arrived at by using unit-by-unit comparisons, with the following general results:

- LCCFC Unit 01, Coal Preparation, was assumed to be equivalent to H-Coal.

Table 5.1 Constant Economic Data
(page 1 of 2)

Raw Material:

Coal cost (\$1.20/MM Btu)	\$30/st (MF)
Coal requirement (to liquefaction section)	25,000 st/d (MF)

Payroll:

Operator's wage	\$21,851/yr
Number of operators	568
Supervisory and support labor as a percentage of operator wages	30%
Fringe benefits as a percentage of payroll	35%

Other fixed expenses:

Maintenance, % of replaceable capital	3%
Insurance, % of replaceable capital	1%
General and administrative expense, as a percentage of payroll plus fringe benefits	60%

Tax items:

Property tax, % of taxable capital	1%
Income tax rate	46%
Investment tax credit	20%

Misc. items:

Inflation rate	6%/yr
Operating days	330
First year operating rate	100%
Construction period	5 years
Project life	20 years

Capital items:

Debt/equity ratio	50/50
Interest on long term debt	8%
Period of long term debt	10 years
Interest during construction	8%
Type of depreciation	Double Declining Balance
Period of depreciation	16 years

Table 5.1 Constant Economic Data
(page 2 of 2)

Cash drawdown schedule, in %

Year of Construction	1	2	3	4	5
Land	100	0	0	0	0
Plant	1	5	22	39	33
Preproduction	0	0	0	0	100
Inventory	0	0	0	0	100
Catalyst and Chemicals	0	0	0	0	100
Royalties	1	5	22	39	33

Working capital:

Interest	8%
Payroll	14 days
Accounts receivable	45 days
Less: Accounts payable	30 days

Table 5.2 Plant Investment by Unit, Fuel Oil Mode

Unit	Plant Unit Title	Unit Investment (\$ x 1000) ¹	
		LCFFC	H-Coal
01	Coal Preparation	69,555	69,555
02	Liquefaction		
	Coal Slurry Preparation		
	LCFFC Reaction	483,654	407,596
	Reactor Effluent Separation		
	Fractionation & Deashing		
03	Gas Processing		
	Lean Oil Absorption	32,025	58,228
	Amine Plant		
04	Hydrogen Plant		
	Texaco Gasification		
	Shift Conversion	303,957	289,005
	Acid Gas Removal I		
	Hydrogen Compression		
	Acid Gas Removal II (LCFFC only)		
05	Oxygen Plant	142,538	140,937
06	Emission Control Systems		
	Sulfur Plant (Claus)	34,611	36,870
	Tail Gas Treating		
07	Effluent Control Systems		
	Sour Water Stripping	38,820	38,820
	Phenol Recovery		
08	Storage	77,637	77,637
09	Offsites & Utilities	465,824	465,824
	Total Plant Investment	1,648,621	1,584,472

¹September 1980 dollars.

- LCFFC Unit 02, Liquefaction, was based on 10 reactors of 12'-0" diameter x 63'-0" high, at 2400 psi and 900°F as compared to H-Coal, Unit 02, with 6 reactors of 13'-10" diameter x 39'-0" high, at 3200 psi and 900°F.
- LCFFC Unit 03, Gas Processing, capacity was smaller because of reduced gas yield and reduced hydrogen recirculation rates.
- LCFFC Unit 04, Hydrogen Plant, has a reduction in the shift conversion, acid gas removal and hydrogen compression train, which is offset by an additional acid gas removal unit.
- LCFFC Unit 05, Oxygen Plant, is based on a capacity of 5,327 tons/day.
- LCFFC Unit 06, Emission Control Systems, is based on a capacity of 947 tons/day.
- LCFFC Units 07, Effluent Control Systems; 08, Storage; and 09, Offsites and Utilities, were assumed to be equivalent to H-Coal.

Table 5.3 gives the unit cost breakdown for LCFFC and H-Coal syncrude plants. Costs for the H-Coal case were based on the 1979 Fluor analysis (Reference 3). In deriving costs for the LCFFC units, each unit was compared to the H-Coal case, with the following results.

- LCFFC Unit 01, Coal Preparation, was assumed to be equivalent to H-Coal.
- For LCFFC Units 02, Liquefaction, and 03, Light Ends Processing, capacity was smaller because of reduced gas yield and reduced hydrogen recirculation rates.
- LCFFC Unit 04, Hydrogen Plant, has a reduction in the shift conversion, acid gas removal and hydrogen compression train, which is offset by an additional acid gas removal unit.

Table 5.3 Unit Cost Summary, Syncrude Mode

Unit	Plant Unit Title	Unit Cost (\$ x 1000) ¹	
		LCFFC	H-Coal
01	Coal Preparation	69,555	69,555
02	Liquefaction Coal Slurry Preparation LCFFC Reaction Reactor Effluent Separation Fractionation	570,919	600,967
03	Light Ends Processing Compression Amine Plant Gas Plant Light Ends Separation	55,877	68,143
04	Hydrogen Plant Texaco Gasification Shift Conversion Acid Gas Removal I Hydrogen Compression Acid Gas Removal II (LCFFC only)	338,927	326,929
05	Oxygen Plant	156,298	154,536
06	Emission Control Systems Sulfur Plant (Claus) Tail Gas Treating	29,554	32,513
07	Effluent Control Systems Sulfur Plant (Claus) Phenol Recovery	62,837	62,837
08	Storage	74,814	74,814
09	Utilities	259,350	259,350
10	Offsites	161,128	161,128
Total Plant Investment		1,779,259	1,810,772

¹September 1980 dollars.

- LCFFC Unit 05, Oxygen Plant, is based on a capacity of 6,208 tons/day.
- LCFFC Unit 06, Emission Control Systems, is based on a capacity of 728 tons/day.
- LCFFC Units 07, Effluent Control Systems; 08, Storage; 09, Utilities; and 10, Offsites; were assumed to be equivalent to H-Coal.

5.1.3 Results of Evaluation

The evaluation took three different forms. First, the market prices of the products from each process were estimated, and the associated rates of return for each process were calculated. Second, all product values were assumed equal on a Btu basis, the IRR was set at 20%, and required product values were calculated. Third, the naphtha product of each process was set at current market values, the internal rate of return was set at 20%, and required product prices were established. In addition, sensitivity analyses were performed to assess the effect of different naphtha valuations and different plant investment costs.

5.1.3.1 Rate of Return with Products at Estimated Market Value

In this analysis, an estimate was made of the market value of each of the products produced by each process. An explanation of the logic used for the estimates is appended as Table A.2. The IRR was then calculated using the estimated product prices. It may be noted that the heavy products produced by LCFFC are worth more than those produced by H-Coal in terms of \$/Bbl.

Based on the results indicated in Table 5.4, LCFFC shows a slightly higher IRR than H-Coal for both the Fuel Oil and Syncrude modes. The estimated product prices are somewhat speculative and the calculated IRR should, therefore, be viewed with caution.

Table 5.4 Variable Economic Data Input and Results of Analysis

Comparison: All hydrocarbons values are set at market prices, internal rate of return (IRR) is calculated.

Case Process Mode	1 H-Coal Syncrude	2 LCFFC Syncrude	3 H-Coal Fuel Oil	4 LCFFC Fuel Oil
<u>Results of Analysis</u>				
IRR, %	26.17	29.10	27.72	29.64
<u>Variable Data Input</u>				
Product Prices:				
Fuel Oil	-	-	36.38	37.00
Naphtha, \$/Bbl	33.69	33.69	33.69	33.69
Med. Dist., \$/Bbl	34.44	34.10	-	-
Hvy. Dist., \$/Bbl	36.55	39.06	-	-
Butane, \$/Bbl	18.90	18.90	-	-
Propane, \$/Bbl	17.64	17.64	-	-
Ammonia, \$/st	185.00	185.00	185.00	185.00
Sulfur, \$/st	50.00	50.00	50.00	50.00
Phenols, \$/st	144.00	144.00	144.00	144.00
Fuel Gas, \$/MM Btu	-	2.00	-	-
Production:				
Fuel Oil	-	-	51,325	64,819
Naphtha, Bbl/d	23,173	19,557	15,531	3,865
Med. Dist., Bbl/d	28,092	14,495	-	-
Hvy. Dist., Bbl/d	15,160	35,508	-	-
Butane, Bbl/d	5,797	2,542	-	-
Propane, \$/Bbl	4,138	2,362	-	-
Ammonia, st/d	286	200	180	158
Sulfur, st/d	853	728	1,178	947
Phenols, st/d	69	69	18	18
Fuel Gas, MM Btu/d	-	8,424	-	-
Capital Cost Estimates, \$ x 1000				
Land	2,253	2,253	2,253	2,253
Total Plant Investment	1,810,771	1,779,257	1,584,471	1,648,620
Start-Up & Preproduction	53,784	53,089	49,314	49,334
Inventory Capital	89,378	88,581	85,178	83,811
Initial Catalysts and Chemicals	14,044	8,900	8,240	11,115
Prepaid Royalties	5,175	5,084	4,528	4,704

5.1.3.2 Product Price with Specified Rate of Return

In this analysis, the previous situation was reversed. The IRR was set at 20% and the product price necessary to obtain this 20% IRR was calculated. The calculated price assumes that all hydrocarbon liquids are valued equally.

As indicated in Table 5.5, LCFFC shows a slightly lower product price in terms of \$/MM Btu for both the Fuel Oil and Syncrude modes. Valuation of products in terms of total Btu content is felt to be the most realistic method of comparison, since detailed boiling range data, structural type analyses, and refining response characteristics were not available to evaluate LCFFC coal liquids as refinery supplements.

5.1.3.3 Product Price with Specified Rate of Return and Naphtha at Market Price

The amount of naphtha produced may have marked effect on the economics of the processes. For this reason, four additional cases were calculated where naphtha was valued at the current average petroleum naphtha market price.

Table 5.6 shows the results of these calculations. Even though substantially more fuel oil is produced by the LCFFC process (Case 12), a lower product price is shown for the H-Coal process (Case 11) because of the much larger amount of naphtha produced. As previously shown in Table 5.5, this advantage disappears when naphtha is not valued at a premium relative to the fuel oil. In addition, the derived product prices are much lower those that estimated to be the current market values.

In the syncrude mode (Cases 9 and 10), a small advantage in product price is shown for LCFFC in terms of \$/MM Btu. Again, these product prices are much less than estimated market values.

Table 5.5 Variable Economic Data Input and Results of Analysis

Comparison: Internal rate of return set at 20%, liquid hydrocarbons including naphtha combined, hydrocarbon price is calculated.

Case Process Mode	5 H-Coal Syncrude	6 LCFFC Syncrude	7 H-Coal Fuel Oil	8 LCFFC Fuel Oil
<u>Results of Analysis</u>				
Syncrude, \$/Bbl	29.67	29.38	-	-
Fuel Oil, \$/Bbl	-	-	30.22	29.65
\$/MM Btu	4.94	4.66	4.61	4.58
<u>Variable Data Input</u>				
IRR, %	20	20	20	20
Product Prices:				
Butane, \$/Bbl	18.90	18.90	-	-
Propane, \$/Bbl	17.64	17.64	-	-
Ammonia, \$/st	185.00	185.00	185.00	185.00
Sulfur, \$/st	50.00	50.00	50.00	50.00
Phenols, \$/st	144.00	144.00	144.00	144.00
Fuel Gas, \$/MM Btu	-	2.00	-	-
Production:				
Syncrude, Bbl/d	66,425	69,560	-	-
Fuel Oil, Bbl/d	-	-	66,856	68,684
Butane, Bbl/d	5,797	2,542	-	-
Propane, Bbl/d	4,138	2,362	-	-
Ammonia, st/d	286	200	180	158
Sulfur, st/d	853	728	1,178	947
Phenols, st/d	69	69	18	18
Fuel Gas, MM Btu/d	-	8,424	-	-
Capital Cost Estimates, \$ x 1000				
Land	2,253	2,253	2,253	2,253
Total Plant Investment	1,810,771	1,779,257	1,584,471	1,648,620
Start-Up & Preproduction	53,784	53,089	49,314	49,334
Inventory Capital	89,378	88,581	85,178	83,811
Initial Catalysts and Chemicals	14,044	8,900	8,240	11,115
Prepaid Royalties	5,175	5,084	4,528	4,704

Table 5.6 Variable Economic Data Input and Results of Analysis

Comparison: IRR set at 20%, naphtha value set at market price, remaining liquid hydrocarbons combined, hydrocarbon price is calculated.

Case Process Mode	9 H-Coal Syncrude	10 LCFFC Syncrude	11 H-Coal Fuel Oil	12 LCFFC Fuel Oil
<u>Results of Analysis</u>				
Syncrude, \$/Bbl	27.51	27.69	-	-
Fuel Oil, \$/Bbl	-	-	29.16	29.41
\$/MM Btu	4.39	4.22	4.28	4.50
<u>Variable Data Input</u>				
IRR, %	20	20	20	20
Product Prices:				
Naphtha, \$/Bbl	33.69	33.69	33.69	33.69
Butane, \$/Bbl	18.90	18.90	-	-
Propane, \$/Bbl	17.64	17.64	-	-
Ammonia, \$/st	185.00	185.00	185.00	185.00
Sulfur, \$/st	50.00	50.00	50.00	50.00
Phenols, \$/st	144.00	144.00	144.00	144.00
Fuel Gas, \$/MM Btu	-	2.00	-	-
Production:				
Syncrude, Bbl/d	43,252	50,003	-	-
Fuel Oil, Bbl/d	-	-	51,325	64,819
Naphtha, Bbl/d	23,173	19,557	15,531	3,865
Butane, Bbl/d	5,797	2,542	-	-
Propane, Bbl/d	4,138	2,362	-	-
Ammonia, st/d	286	200	180	158
Sulfur, st/d	853	728	1,178	947
Phenols, st/d	69	69	18	18
Fuel Gas, MM Btu/d	-	8,424	-	-
Capital Cost Estimates, \$ x 1000				
Land	2,253	2,253	2,253	2,253
Total Plant Investment	1,810,771	1,779,257	1,584,471	1,648,620
Start-Up & Preproduction	53,784	53,089	49,314	49,334
Inventory Capital	89,378	88,581	85,178	83,811
Initial Catalysts and Chemicals	14,044	8,900	8,240	11,115
Prepaid Royalties	5,175	5,084	4,528	4,704

5.1.3.4 Sensitivity Analysis

It is clear that naphtha valuation can have a strong impact on the relative economics. Sensitivity analyses have been made for both changes in naphtha value and changes in the investment cost.

The influence of large variations in naphtha price is shown in Table 5.7. As shown in Figure 5.1, at high naphtha prices (\$40/Bbl) a lower product price is shown for the H-Coal fuel oil case. At reduced naphtha prices (\$27/Bbl), the product prices approach each other. Figure 5.2 shows the variation in required syncrude prices. At low naphtha prices, the LCFFC product price is lower. At high naphtha values, the prices approach each other.

Total plant investment (TPI) was also varied to examine the effect it has on product price. Naphtha was combined with the other products, and the discount rate was set at 20%. Results of increasing and decreasing the TPI by 20% are shown in Table 5.8. The fuel oil mode data from Table 5.8 and Table 5.5 are plotted in Figure 5.3.

5.2 COMPARISON OF LCFFC AND H-COAL PROCESSES

5.2.1 Comparative Process Performance

Table 5.9 presents a comparison of operating conditions, hydrocarbon yields, and performance in terms of hydrogen consumption and thermal efficiency. Hydrocarbon yields are taken from individual case yield structures (Tables 5.10, 5.11, and 5.12). Table 5.13 presents a comparison of product quality in terms of heteroatom content, hydrogen content, gravity, and Btu production.

Comparisons between processes using "single point" data, as in this study, are somewhat tenuous, since reactor severity can be changed to produce a new, and possibly more optimum, product slate. Ideally, reactor operating conditions necessary to produce comparable products would be obtained from pilot unit correlations (or kinetic models). For the cases examined in this study, however, some general conclusions can be drawn.

Table 5.7 Naphtha Price Sensitivity Study

Sensitivity analysis: IRR set at 20%, naphtha price varied from \$40/Bbl to \$27/Bbl, remaining liquid hydrocarbons combined, hydrocarbon price is calculated.

Process Mode	H-Coal Syncrude	LCFFC Syncrude	H-Coal Fuel Oil	LCFFC Fuel Oil
<u>Case Number</u>	13	14	15	16
<u>Results of Analysis</u>				
Syncrude, \$/Bbl	24.13	25.22	-	-
Fuel Oil, \$/Bbl	-	-	27.25	29.03
\$/MM Btu	3.85	3.84	4.01	4.44
<u>Variable Data Input</u>				
Naphtha, \$/Bbl	40.00	40.00	40.00	40.00
Naphtha, Bbl/d	23,173	19,557	15,531	3,865
Syncrude, Bbl/d	43,252	50,003	-	-
Fuel Oil, Bbl/d	-	-	51,325	64,819
<u>Case Number</u>	17	18	19	20
<u>Results of Analysis</u>				
Syncrude, \$/Bbl	31.09	30.31	-	-
Fuel Oil, \$/Bbl	-	-	31.19	29.81
\$/MM Btu	4.97	4.62	4.59	4.56
<u>Variable Data Input</u>				
Naphtha, \$/Bbl	27.00	27.00	27.00	27.00
Naphtha, Bbl/d	23,173	19,557	15,531	3,865
Syncrude, Bbl/d	43,252	50,003	-	-
Fuel Oil, Bbl/d	-	-	51,325	64,819

FIGURE 5.1 REQUIRED FUEL OIL PRICE WITH VARIABLE NAPHTHA CREDIT

FIGURE 5.2 REQUIRED SYNCRUDE PRICE WITH VARIABLE NAPHTHA CREDIT

Table 5.8 Total Plant Investment Sensitivity Study

Sensitivity analysis: IRR set at 20%, liquid hydrocarbons, including naphtha, combined, plant investment varied + 20%, hydrocarbon price is calculated.

Process Mode	H-Coal Syncrude	LCFFC Syncrude	H-Coal Fuel Oil	LCFFC Fuel Oil
<u>Case Number</u>	21	22	23	24
<u>Results of Analysis</u>				
Syncrude, \$/Bbl	33.28	32.77	-	-
Fuel Oil, \$/Bbl	-	-	33.36	32.84
\$/MM Btu	5.55	5.19	5.09	5.08
<u>Variable Data Input</u>				
120% of				
Total Plant Investment, \$x1000	2,172,926	2,135,108	1,901,365	1,978,344
<u>Case Number</u>	25	26	27	28
<u>Results of Analysis</u>				
Syncrude, \$/Bbl	26.05	25.98	-	-
Fuel Oil, \$/Bbl	-	-	27.07	26.46
\$/MM Btu	4.34	4.11	4.13	4.09
<u>Variable Data Input</u>				
80% of				
Total Plant Investment, \$x1000	1,448,617	1,423,407	1,267,577	1,318,896

FIGURE 5.3 TOTAL LIQUID PRODUCT PRICE VS. TOTAL PLANT INVESTMENT (FUEL OIL MODE)

Table 5.9 Operating Conditions and Yield Structure Comparison

Mode Process	FUEL OIL		SYNCRUDE	
	<u>LCFFC</u>	<u>H-COAL</u>	<u>LCFFC</u>	<u>H-COAL</u>
<u>Operating Conditions</u>				
Reactor Temp., °F	780-820	850	840	875 ²
Reactor Press., psig	2100	3000	2700	3250 ²
Inlet Hydrogen Rate MSCF/TDC (100% H ₂)	16.8 ¹	34.6	28.8 ¹	43.8 ³
<u>Hydrocarbon Yield (wt% of coal, MF basis)</u>				
Gases (C ₁ - C ₄)	2.58	9.16	5.99	13.05
Naphtha (C ₅ - 300)	2.24	9.06	11.58 ⁴	9.38
Fuel Oil (300°F+)	50.30	39.24	-	-
Light Dist. (400-500°F)	-	-	9.90	9.38
Heavy Dist. (500-850°F)	-	-	27.46	16.14
Total HC	55.12	57.46	54.93	47.95
<u>Performance</u>				
Hydrogen Consumption	1.96	3.24	3.09	4.89
Thermal Efficiency, %	73.3	68.5	74.0	71.8

¹ Based on information received from CE-Lummus.

² Design Conditions of Reactor, Operating Conditions Unknown.

³ Estimated from available data.

⁴ 400°F Endpoint.

Table 5.10 Nominal Properties of 300°F+ Blended Net Clean Fuel Product
(As Produced in Commercial Plant)

<u>Elemental Analysis</u>	<u>Wt. %</u>
(Ash-Free Basis)	
Sulfur	0.5 max.
Hydrogen	6.8
Carbon	89.7
Nitrogen	1.2
Oxygen	<u>1.8</u>
	100.0
Ash Content	0.1 wt. % max.
Specific Gravity @ 60°F	1.11 (-4°API)
Higher Heating Value @ 60°F	16600 Btu/lb (6.45 MM Btu/Bbl)
<u>Viscosity¹ Characteristics</u>	
Oil Temperature required for atomization	250°F
at 100 SSU	
Viscosity @ 122°F	ca. 1200 centistoke ²
<u>Flash Point (PM CC)¹</u>	150°F

¹ With anti-solvent purge blended into Clean Fuel product.

² Clean Fuel is more viscous than typical No. 6 oils at low temperatures. For example, the Clean Fuel product will have a viscosity at 122°F of around 1200 cs, whereas the ASTM guideline spec calls for 638 cs maximum. However, the viscosity temperature slope of Clean Fuel is steeper than for No. 6 oil; oil temperatures required for proper atomization are not much higher than those required for No. 6 oils.

Table 5.11 LCFFC Syncrude Mode Properties of Products

<u>Product Streams</u>		<u>Ultimate Analysis</u>	
Naphtha (35.7° API)			
<u>TBP Cut</u>	<u>Wt%</u>		<u>Wt%</u>
C ₅ /400	100.00	C	85.28
		H	11.80
		N	0.19
		S	TR
		O	2.73
	<u>100.00</u>		<u>100.00</u>
Light Distillate (13.4° API)			
<u>TBP Cut</u>	<u>Wt%</u>		<u>Wt%</u>
400/500	100.00	C	89.12
		H	9.32
		N	0.27
		S	TR
		O	1.29
	<u>100.00</u>		<u>100.00</u>
Heavy Distillate (-3.2° API)			
<u>TBP Cut</u>	<u>Wt%</u>		<u>Wt%</u>
500/850	100.00	C	91.04
		H	7.29
		N	0.41
		S	0.06
		O	1.20
	<u>100.00</u>		<u>100.00</u>

Table 5.12 H-Coal Syncrude Mode Properties of Products

<u>Product Streams</u>		<u>Ultimate Analysis</u>	
Naphtha (52.3° API)			
<u>TBP Cut</u>	<u>Wt%</u>		<u>Wt%</u>
C ₄	1.37	C	85.34
		H	13.79
C ₅ /100	12.98	N	0.24
		S	0.07
100/200	26.10	O	0.56
200/300	35.58		<u>100.00</u>
300/350	21.47		
350+	2.50		
	<u>100.00</u>		
Turbine Fuel (18.5° API)			
<u>TBP Cut</u>	<u>Wt%</u>		<u>Wt%</u>
350/600	100.00	C	88.35
		H	10.11
		N	0.47
		S	0.08
		O	0.99
	<u>100.00</u>		<u>100.00</u>
Distillate Boiler Fuel (4.9° API)			
<u>TBP Cut</u>	<u>Wt%</u>		<u>Wt%</u>
500/800	100.00	C	89.42
		H	8.56
		N	0.63
		S	0.08
		O	1.31
	<u>100.00</u>		<u>100.00</u>

Table 5.13 Product Quality Comparison

Mode Process	FUEL OIL		SYNCRUDE	
	LCFFC	H-COAL	LCFFC	H-COAL
<u>Production, BPD</u>				
Naphtha	3,865	15,531	19,557	23,173
Fuel Oil	64,819	51,325	-	-
Light Dist.	-	-	14,495	28,092
Heavy Dist.	-	-	35,508	15,160
Total	68,684	66,856	69,560	66,425
<u>Production, 10⁹ Btu/d</u>				
Naphtha	20.4	89.1	111.4	127.6
Fuel Oil	423.7	349.0	-	-
Light Dist.	-	-	90.4	172.7
Heavy Dist.	-	-	237.4	98.1
Total	444.1	438.1	439.2	398.4
<u>Product Quality</u>				
Naphtha				
S/N/O (wt%)	N/A	0.02 ¹	NIL/0.19/2.73	0.07/0.24/0.56
H (wt%)	N/A	N/A	11.80	13.79
°API	48.3	38.2	35.7	52.3
Fuel Oil				
S/N/O (wt%)	N/A	0.05 ¹	-	-
H (wt%)	6.8	N/A	-	-
°API	-3.9	-1.8	-	-
Light Dist.				
S/N/O (wt%)	-	-	TR/0.27/1.29	0.08/0.47/0.99
H (wt%)	-	-	9.32	10.11
°API	-	-	13.4	18.50
Heavy Dist.				
S/N/O (wt%)	-	-	0.06/0.41/1.20	0.08/0.63/1.31
H (wt%)	-	-	7.29	8.56
°API	-	-	-3.2	4.9

¹ Nitrogen and oxygen contents unavailable.
N/A - Not available.

Operating in the fuel oil mode, the LCFFC process appears to produce considerably more "fuel oil" product and fuel oil heating value than the H-Coal base case. As indicated in Table 5.9 and 5.13, more fuel oil (of comparable sulfur content) is produced by the LCFFC process using considerably less hydrogen. Overall liquid product Btu production is about equivalent because of the large amount of naphtha produced by the H-Coal case. Thermal efficiency of the LCFFC fuel oil mode remains higher than the H-Coal case (73.8 vs. 68.5), partly because of the much lower light hydrocarbon gas make (.026 lb/lb coal vs. .092 lb/lb coal).

For the particular case examined, essentially all $C_1 - C_4$ and H_2 purge streams are employed in the H-Coal process for in-plant fuel gas use (process heaters, power generation, etc.). If one assumes, as was done in this study, that in-plant fuel gas requirements are comparable between the two processes, then the necessary additional fuel needed by the LCFFC fuel oil process can be derived from the excess intermediate Btu gas stream of Unit 04 along with a small amount of additional coal.

Overall, the LCFFC case appears to be more selective in maximizing fuel oil type product. Whether this selectivity toward the heavier end of the product slate is really due to plug flow kinetics or is simply due to less severe operating conditions is not clear. It may be that H-Coal could reduce its gas and naphtha make by simply choosing different operating conditions. Side-by-side comparisons of plug flow and stirred tank modes, using the same reactor, coal, catalyst, and other operating parameters, would answer this question.

Middle and heavy distillate production is even more pronounced in the syncrude mode, where the LCFFC process produces more liquid fuel Btu's per ton of coal using less hydrogen. In terms of quality, the LCFFC products have generally reduced sulfur and nitrogen content and equivalent or higher oxygen content.

5.2.2 Anticipated Major Operability Differences

The change in reactor configuration between H-Coal and LCFFC is considered by UOP/SDC to result in the only area where significant operability differences will occur.

Control of the hydrogenation exotherm in a plug flow or series of plug flow reactors is expected to be more difficult than in the H-Coal reactors. H-Coal relies on a very high internal recycle rate to eliminate temperature gradients and hot spots. LCFFC appears to rely on an external liquid recycle stream of a much lower volumetric rate to control temperature rise. Sudden temperature excursions in an LCFFC plug flow reactor would probably take longer to control than in a well-stirred H-Coal type reactor.

The difficulty would appear to be further compounded if a series of plug flow reactors are used. Perturbations in one reactor would be expected to easily upset the downstream reactors. Accordingly, much more elaborate reactor control schemes may be required for the LCFFC process.

5.2.3 Commercialization Potential

Within the accuracy of the many assumptions necessitated by this type of comparative study, the LCFFC cases appear at least cost competitive with the H-Coal cases when all liquid products including naphtha are valued equally. Additionally, the LCFFC cases show yield structure advantages in terms of increased middle and heavy distillate (or, for the fuel oil case, residual oil) production.

The potential of the LCFFC process is, however, dependent upon the intended end-use of its products and the value placed upon naphtha co-product. The LCFFC process appears to be advantageous if the intent is to produce a residual fuel oil type main product with naphtha being valued equal to or less than fuel oil. For the cases examined, LCFFC produced more fuel oil type product at a comparable cost. However, if naphtha from coal is also valued at a premium relative to fuel oil, then H-Coal appears more attractive based upon lower required fuel oil product price (Figure 5.1).

It is not clear that the LCFFC process would hold any advantages if the intent is to produce middle and heavy distillate liquids for use as refinery crude supplement. LCFFC syncrude mode products appear heavier and more hydrogen deficient than those produced by H-Coal. It may be that the extra costs incurred in hydrotreating or hydrocracking these liquids to make acceptable refinery feeds will negate the hydrogen consumption advantage obtained in the LCFFC process itself.

If material with a boiling range of approximately 400°F - 850°F is considered collectively as "syncrude," then from Tables 5.11 and 5.12 LCFFC is shown to produce more tons per day of syncrude but of a much lower hydrogen content:

	<u>LCFFC</u>	<u>H-Coal</u>
Syncrude, tons/d	9,340	7,386
Hydrogen, wt%	7.83	9.53

Hydrotreating/hydrocracking yield data, in addition to more extensive product characterization (detailed structural analyses, boiling range data, diolefin content, etc.) are needed to properly evaluate LCFFC coal liquids as refinery crude supplements.

5.3 RECOMMENDATIONS FOR FURTHER WORK

It appears to UOP/SDC that the following items are necessary for realizing the potential of the LCFFC process.

First, and prior to any further development work, it should be firmly determined that the advantages shown by the LCFFC fuel oil mode are in reality due to the claimed "plug flow" mode of operation. H-Coal may very well be able to produce a product slate similar to that of LCFFC (i.e., predominantly middle and heavy distillates) through the proper choice of reactor operating conditions. To avoid redundant Federal support of two hydroliquefaction processes, it is suggested that side-by-side comparisons of a plug flow and well-stirred

hydroliquefaction reactors be made. It is possible that this may be accomplished simply by varying the external liquid recycle on the present LCFFC PDU equipment over a wide range and taking appropriate data (high recycle rate would approach stirred tank, low recycle rate would approach plug flow).

Second, the relationship of external recycle rate to fluidization requirements and reactor temperature control should be examined. An engineering study of these variables on a commercial scale would be advisable.

Third, additional product characterization is required. Detailed structural analyses, boiling range data, diolefin content, etc. are needed to properly estimate the value of LCFFC coal liquids as refinery crude supplements. Actual hydrocracking/hydrotreating data would be the best way to evaluate its value.

SECTION 6 - REFERENCES

1. C. E. Lummus Co., "Development Research Program for Clean Industrial and Transportation Fuels from Coal," Milestone Reports 1-4, under ERDA Contract EX-76-C-01-2514, NTIS No.'s FE-2514-M1, FE-2514-M2, FE-2514-M3, and FE-2514-M4.
2. _____, "Development Research Program for Clean Industrial and Transportation Fuels from Coal, Final Report," working draft, C. E. Lummus Co., Bloomfield, N.J. (unpublished).
3. Fluor Engineers and Constructors, "Engineering Evaluation of Conceptual Coal Conversion Plant Using the H-Coal Liquefaction Process," EPRI AF-1297 RP411-4 (December, 1979).
4. _____, "H-Coal Commercial Evaluation," under ERDA Contract E(4918)-2002, NTIS No. FE-2002-12 (March, 1976).

APPENDIX A - SAMPLE CALCULATIONS

TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
REVENUE

DATA SET NO. 6
CASE 1, SIRR/HCMP/H-C/SC

DOE TASK ORDER 29

IN THOUSANDS OF U.S. DOLLARS UNLESS STATED OTHERWISE

YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994
PRODUCT REVENUE									
NAPHTHA	365,452	387,378	410,621	435,258	461,373	489,855	518,398	549,501	582,471
MEDIUM DISTILLATE	452,890	480,063	508,866	539,398	571,761	606,066	642,430	680,975	721,833
HEAVY DISTILLATE	259,378	274,941	291,437	308,923	327,458	347,105	367,931	390,007	413,407
BUTANE	51,248	54,365	57,627	61,084	64,749	68,634	72,752	77,117	81,740
PROPANE	34,169	36,219	38,393	40,696	43,138	45,726	48,470	51,378	54,460
AMMONIA	24,768	26,254	27,829	29,499	31,268	33,145	35,133	37,241	39,476
SULFUR	19,965	21,163	22,432	23,778	25,205	26,717	28,320	30,020	31,821
MIXED PHENOLS	4,651	4,930	5,226	5,540	5,872	6,224	6,598	6,994	7,413
TOTAL PRODUCT REVENUE	1,212,559	1,285,312	1,362,429	1,444,173	1,530,823	1,622,671	1,720,031	1,823,232	1,932,623
COST OF RAW MATERIALS									
COAL	351,081	372,146	394,475	418,143	443,231	469,825	498,014	527,894	559,568
TOTAL RAW MATERIAL COSTS	351,081	372,146	394,475	418,143	443,231	469,825	498,014	527,894	559,568
GROSS OPERATING MARGIN	861,478	913,166	967,954	1,026,030	1,087,592	1,152,846	1,222,017	1,295,337	1,373,055

TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
REVENUE

DATA SET NO. 6
CASE 1, SIRR/MCMP/H-C/SC

DOE TASK ORDER 29

IN THOUSANDS OF U.S. DOLLARS UNLESS STATED OTHERWISE

YEAR	1995	1996	1997	1998	1999	2000
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PRODUCT REVENUE

NAPHTHA	617,419	654,463	693,731	735,354	779,475	826,243
MEDIUM DISTILLATE	765,143	811,051	859,713	911,295	965,972	1,023,930
HEAVY DISTILLATE	438,211	464,503	492,373	521,915	553,230	586,423
BUTANE	86,649	91,848	97,358	103,200	109,392	115,955
PROPANE	57,728	61,192	64,863	68,755	72,880	77,253
AMMONIA	41,844	44,355	47,016	49,837	52,827	55,997
SULFUR	33,710	35,754	37,899	40,173	42,583	45,138
MIXED PHENOLS	7,858	8,329	8,829	9,359	9,920	10,516

TOTAL PRODUCT REVENUE	2,048,580	2,171,493	2,301,781	2,439,886	2,586,278	2,741,452
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COST OF RAW MATERIALS

COAL	593,141	628,729	666,452	706,439	748,825	793,754
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TOTAL RAW MATERIAL COSTS	593,141	628,729	666,452	706,439	748,825	793,754
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GROSS OPERATING MARGIN	1,455,439	1,542,763	1,635,328	1,733,447	1,837,453	1,947,698
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TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
ANNUAL OPERATING COSTS

DOE TASK ORDER 29

IN THOUSANDS OF U.S. DOLLARS UNLESS STATED OTHERWISE

DATA SET NO. 6
CASE 1, SIRR/MCMP/M-C/8C

YEAR	1986	1987	1988	1989	1990	1991	1992	1993	1994
FIXED OPERATING COSTS									
LABOR:									
PLANT PERSONNEL	18,662	19,782	20,969	22,227	23,560	24,974	26,472	28,061	29,744
SUPERVISION	5,589	5,935	6,291	6,668	7,068	7,492	7,942	8,418	8,923
FRINGE BENEFITS	8,491	9,001	9,541	10,113	10,720	11,363	12,045	12,768	13,534
TOTAL LABOR	32,742	34,717	36,800	39,008	41,348	43,829	46,459	49,246	52,201
MAINTENANCE	106,538	112,930	119,706	126,888	134,501	142,571	151,125	160,193	169,800
INSURANCE	35,513	37,643	39,902	42,296	44,834	47,524	50,375	53,398	56,601
LOCAL TAXES	32,470	34,418	36,483	38,672	40,992	43,451	46,059	48,822	51,751
GENERAL & ADMIN. COSTS	19,651	20,830	22,080	23,405	24,809	26,297	27,875	29,548	31,321
TOTAL FIXED COSTS	226,923	240,538	254,970	270,268	286,484	303,673	321,893	341,207	361,678
VARIABLE OPERATING COSTS									
UTILITIES:									
PROCESS WATER	3,255	3,451	3,658	3,877	4,110	4,356	4,618	4,895	5,189
TOTAL UTILITIES	3,255	3,451	3,658	3,877	4,110	4,356	4,618	4,895	5,189
CATALYST AND CHEMICALS	34,213	36,266	38,442	40,749	43,193	45,785	48,532	51,444	54,531
DISPOSAL COSTS	7,206	7,639	8,097	8,583	9,098	9,643	10,222	10,835	11,486
TOTAL VARIABLE COSTS	44,675	47,355	50,197	53,208	56,401	59,785	63,372	67,174	71,205
TOTAL OPERATING COST	271,598	287,894	305,167	323,477	342,885	363,458	385,265	408,381	432,883

TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
ANNUAL OPERATING COSTS

DATA SET NO. 6
CASE 1, SIRR/MCNP/H-C/SC

DOE TASK ORDER 29

IN THOUSANDS OF U.S. DOLLARS UNLESS STATED OTHERWISE

YEAR	1995	1996	1997	1998	1999	2000	2001	2002	2003
FIXED OPERATING COSTS									
LABOR:									
PLANT PERSONNEL	31,529	33,421	35,426	37,551	39,804	42,193	44,724	47,408	50,252
SUPERVISION	9,459	10,020	10,628	11,265	11,941	12,658	13,417	14,222	15,076
FRINGE BENEFITS	14,346	15,206	16,119	17,086	18,111	19,198	20,349	21,570	22,865
TOTAL LABOR	55,333	58,653	62,172	65,902	69,857	74,048	78,491	83,200	88,192
MAINTENANCE	170,992	190,792	202,239	214,373	227,236	240,869	255,321	270,640	286,879
INSURANCE	59,997	63,597	67,413	71,458	75,745	80,290	85,107	90,213	95,626
LOCAL TAXES	54,856	58,148	61,636	65,335	69,255	73,410	77,814	82,483	87,432
GENERAL & ADMIN. COSTS	33,200	35,192	37,303	39,541	41,914	44,429	47,084	49,920	52,915
TOTAL FIXED COSTS	383,379	406,381	430,764	456,609	484,006	513,046	543,828	576,457	611,044
VARIABLE OPERATING COSTS									
UTILITIES:									
PROCESS WATER	5,500	5,830	6,180	6,550	6,944	7,360	7,802	8,270	8,766
TOTAL UTILITIES	5,500	5,830	6,180	6,550	6,944	7,360	7,802	8,270	8,766
CATALYST AND CHEMICALS	57,802	61,370	64,947	68,843	72,974	77,352	81,993	86,913	92,128
DISPOSAL COSTS	12,175	12,905	13,679	14,500	15,370	16,292	17,270	18,306	19,404
TOTAL VARIABLE COSTS	75,477	80,006	84,806	89,894	95,288	101,005	107,065	113,489	120,298
TOTAL OPERATING COST	458,856	486,387	515,570	546,503	579,293	614,050	650,893	689,946	731,342

TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
ANNUAL OPERATING COSTS

DATA SET NO. 6
CASE 1, SIRR/MCMP/H-C/SC

DOE TASK ORDER 29

IN THOUSANDS OF U.S. DOLLARS UNLESS STATED OTHERWISE

YEAR	2004	2005
FIXED OPERATING COSTS		
LABOR:		
PLANT PERSONNEL	53,267	56,463
SUPERVISION	15,980	16,939
FRINGE BENEFITS	24,236	25,691
TOTAL LABOR	93,483	99,093
MAINTENANCE	304,091	322,337
INSURANCE	101,364	107,446
LOCAL TAXES	92,678	98,239
GENERAL & ADMIN. COSTS	54,000	59,455
TOTAL FIXED COSTS	647,707	686,568
VARIABLE OPERATING COSTS		
UTILITIES:		
PROCESS WATER	9,292	9,849
TOTAL UTILITIES	9,292	9,849
CATALYST AND CHEMICALS	47,655	103,515
DISPOSAL COSTS	20,569	21,803
TOTAL VARIABLE COSTS	127,516	135,167
TOTAL OPERATING COST	775,223	821,735

FIXED OPERATING COSTS

LABOR:

PLANT PERSONNEL

53,267

56,463

SUPERVISION

15,980

16,939

FRINGE BENEFITS

24,236

25,691

TOTAL LABOR

93,483

99,093

MAINTENANCE

304,091

322,337

INSURANCE

101,364

107,446

LOCAL TAXES

92,678

98,239

GENERAL & ADMIN. COSTS

54,000

59,455

TOTAL FIXED COSTS

647,707

686,568

VARIABLE OPERATING COSTS

UTILITIES:

PROCESS WATER

9,292

9,849

TOTAL UTILITIES

9,292

9,849

CATALYST AND CHEMICALS

47,655

103,515

DISPOSAL COSTS

20,569

21,803

TOTAL VARIABLE COSTS

127,516

135,167

TOTAL OPERATING COST

775,223

821,735

TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
PRO FORMA ECONOMIC ANALYSIS

DATA SET NO. 6
CASE 1, SIRR/MCMP/H-C/SC

DOE TASK ORDER 29

IN THOUSANDS OF U.S. DOLLARS UNLESS STATED OTHERWISE

YEAR	1981	1982	1983	1984	1985	1986	1987	1988	1989
TOTAL PRODUCT REVENUE	0	0	0	0	0	1,212,559	1,285,312	1,362,429	1,444,173
LESS: COST OF RAW MATERIALS	0	0	0	0	0	351,081	372,146	394,475	418,143
EQUALS: GROSS OPERATING MARGIN	0	0	0	0	0	861,478	913,166	967,955	1,026,031
LESS:									
FIXED COSTS	0	0	0	0	0	226,923	240,538	254,470	270,268
VARIABLE COSTS	0	0	0	0	0	44,675	47,355	50,197	53,208
EQUALS: GROSS PROFIT	0	0	0	0	0	589,880	625,272	662,788	702,555
LESS:									
INTEREST CHARGE ON:									
LONG TERM DEBT	0	0	0	0	0	103,876	96,705	88,961	80,597
WORKING CAPITAL	0	0	0	0	0	4,895	5,188	5,499	5,829
DEPRECIATION	0	0	0	0	0	369,941	260,721	228,131	199,615
EQUALS: PRETAX INCOME	0	0	0	0	0	111,168	262,657	340,195	416,512
LESS: TAX LOSS CARRY FORWARD	0	0	0	0	0	0	0	0	0
EQUALS: NET TAXABLE INCOME	0	0	0	0	0	111,168	262,657	340,195	416,512
INCOME TAX	0	0	0	0	0	51,137	120,822	156,490	191,596
LESS: INVESTMENT TAX CREDITS	0	0	0	0	0	46,023	108,740	140,841	172,436
EQUALS: NET INCOME TAX	0	0	0	0	0	5,114	12,082	15,649	19,160
PRETAX INCOME LESS NET TAX	0	0	0	0	0	106,054	250,574	324,546	397,352
EQUALS: NET INCOME AFTER TAXES	0	0	0	0	0	106,054	250,574	324,546	397,352
PLUS: DEPRECIATION	0	0	0	0	0	369,941	260,721	228,131	199,615
LESS: RETIREMENT OF DEBT	0	0	0	0	0	89,632	96,803	104,547	112,911
LESS: EQUITY	10,818	51,443	240,400	459,160	536,632	0	0	0	0
EQUALS: CASH FLOW	-10,818	-51,443	-240,400	-459,160	-536,632	386,363	414,492	448,130	484,056
CUMULATIVE CASH FLOW	-10,818	-62,261	-302,661	-761,820	-1,298,452	-912,090	-497,597	-49,467	434,589
LONG TERM DEBT OUTSTANDING	10,818	62,261	302,660	761,820	1,298,451	1,208,819	1,112,016	1,007,469	894,558
WORKING CAPITAL	0	0	0	0	0	54,384	57,647	61,106	64,772
UNDEPRECIATED CAPITAL	0	0	0	0	2,596,905	2,226,963	1,966,242	1,738,111	1,538,496

TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
PRO FORMA ECONOMIC ANALYSIS

DATA SET NO. 6
CASE 1, SIRR/MCNP/H-C/SC

DOE TASK ORDER 29

IN THOUSANDS OF U.S. DOLLARS UNLESS STATED OTHERWISE

YEAR	1990	1991	1992	1993	1994	1995	1996	1997	1998
TOTAL PRODUCT REVENUE	1,530,823	1,622,671	1,720,031	1,823,232	1,932,623	2,048,580	2,171,493	2,301,781	2,439,886
LESS: COST OF RAW MATERIALS	443,231	469,825	498,914	527,894	559,568	593,141	628,729	666,452	706,439
EQUALS: GROSS OPERATING MARGIN	1,087,592	1,152,847	1,222,017	1,295,337	1,373,056	1,455,439	1,542,764	1,635,329	1,733,447
LESS:									
FIXED COSTS	286,484	303,673	321,893	341,207	361,678	383,379	406,301	430,760	456,609
VARIABLE COSTS	56,401	59,785	63,372	67,174	71,205	75,477	80,006	84,806	89,894
EQUALS: GROSS PROFIT	744,706	789,389	836,752	886,957	940,173	996,583	1,056,457	1,119,759	1,186,944
LESS:									
INTEREST CHARGE ON:									
LONG TERM DEBT	71,565	61,809	51,273	39,894	27,605	14,333	0	0	0
WORKING CAPITAL	6,179	6,550	6,943	7,360	7,801	8,269	8,765	9,291	9,849
DEPRECIATION	174,663	152,830	133,726	117,011	102,384	102,384	102,384	102,384	102,384
EQUALS: PRETAX INCOME	492,301	568,200	644,809	722,692	802,382	871,597	945,228	1,008,084	1,074,711
LESS: TAX LOSS CARRY FORWARD	0	0	0	0	0	0	0	0	0
EQUALS: NET TAXABLE INCOME	492,301	568,200	644,809	722,692	802,382	871,597	945,228	1,008,084	1,074,711
INCOME TAX	226,458	261,372	296,612	332,438	369,096	400,934	434,805	463,718	494,367
LESS: INVESTMENT TAX CREDITS	51,341	0	0	0	0	0	0	0	0
EQUALS: NET INCOME TAX	175,117	261,372	296,612	332,438	369,096	400,934	434,805	463,718	494,367
PRETAX INCOME LESS NET TAX									
EQUALS: NET INCOME AFTER TAXES	317,183	306,828	348,197	390,254	433,286	470,662	510,423	544,365	580,344
PLUS: DEPRECIATION	174,663	152,830	133,726	117,011	102,384	102,384	102,384	102,384	102,384
LESS: RETIREMENT OF DEBT	121,944	131,699	142,235	153,614	165,903	179,161	0	0	0
LESS: EQUITY	0	0	0	0	0	0	0	0	0
EQUALS: CASH FLOW	369,902	327,958	339,688	353,650	369,767	393,885	612,807	646,749	682,728
CUMULATIVE CASH FLOW	604,491	1,132,449	1,472,137	1,825,787	2,195,554	2,589,439	3,202,247	3,848,996	4,531,724
LONG TERM DEBT OUTSTANDING	772,614	640,914	498,679	345,065	179,161	0	0	0	0
WORKING CAPITAL	68,658	72,777	77,144	81,773	86,679	91,880	97,392	103,236	109,430
UNDEPRECIATED CAPITAL	1,363,833	1,211,003	1,077,276	960,266	857,882	755,497	653,113	550,728	448,344

TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
PRO FORMA ECONOMIC ANALYSIS

DATA SET NO. 6
CASE 1, SIRR/MCMP/H-C/SC

DOE TASK ORDER 29

IN THOUSANDS OF U.S. DOLLARS UNLESS STATED OTHERWISE

YEAR	1999	2000	2001	2002	2003	2004	2005
TOTAL PRODUCT REVENUE	2,586,278	2,741,452	2,905,938	3,080,292	3,265,107	3,461,012	3,668,671
LESS: COST OF RAW MATERIALS	748,825	793,754	841,378	891,860	945,372	1,002,093	1,062,218
EQUALS: GROSS OPERATING MARGIN	1,837,453	1,947,699	2,064,560	2,188,431	2,319,736	2,458,919	2,606,452
LESS:							
FIXED COSTS	442,006	513,046	543,828	576,457	611,044	647,707	686,568
VARIABLE COSTS	95,288	101,005	107,065	113,489	120,298	127,516	135,167
EQUALS: GROSS PROFIT	1,298,159	1,333,648	1,413,667	1,498,485	1,588,393	1,683,696	1,784,717
LESS:							
INTEREST CHARGE ON:							
LONG TERM DEBT	0	0	0	0	0	0	0
WORKING CAPITAL	10,440	11,066	11,730	12,434	13,180	13,970	14,809
DEPRECIATION	102,384	102,384	102,384	0	0	0	0
EQUALS: PRETAX INCOME	1,185,335	1,220,198	1,299,551	1,486,051	1,575,213	1,669,725	1,769,908
LESS: TAX LOSS CARRY FORWARD	0	0	0	0	0	0	0
EQUALS: NET TAXABLE INCOME	1,185,335	1,220,198	1,299,551	1,486,051	1,575,213	1,669,725	1,769,908
INCOME TAX	525,854	561,291	597,793	683,583	724,598	768,073	814,158
LESS: INVESTMENT TAX CREDITS	0	0	0	0	0	0	0
EQUALS: NET INCOME TAX	525,854	561,291	597,793	683,583	724,598	768,073	814,158
PRETAX INCOME LESS NET TAX							
EQUALS: NET INCOME AFTER TAXES	659,482	658,907	701,758	802,468	850,616	901,652	955,751
PLUS: DEPRECIATION	102,384	102,384	102,384	0	0	0	0
LESS: RETIREMENT OF DEBT	0	0	0	0	0	0	0
LESS: EQUITY	0	0	0	0	0	0	0
EQUALS: CASH FLOW	720,866	761,291	804,144	802,468	850,616	901,652	955,751
CUMULATIVE CASH FLOW	5,252,587	6,013,878	6,818,021	7,620,489	8,471,101	9,372,748	10,328,498
LONG TERM DEBT OUTSTANDING	0	0	0	0	0	0	0
WORKING CAPITAL	115,996	122,955	130,332	138,152	146,441	155,228	164,541
UNDEPRECIATED CAPITAL	345,960	243,575	141,190	141,190	141,190	141,190	141,190

TABLE A-1
ECONOMIC EVALUATION OF CONCEPTUAL COAL CONVERSION PLANT
RESULTS OF ANALYSIS

DATA SET NO. 6
CASE 1, SIRR/MCMP/H-C/SC

DOE TASK ORDER 29

INTERNAL RATE OF RETURN ON
INVESTORS EQUITY (1)

IRR EQUALS: 26.17
ON INVESTORS EQUITY OF \$M 1,298,452
WITH SALVAGE VALUE OF \$M 605,977

IRR EQUALS: 26.09
ON INVESTORS EQUITY OF \$M 1,298,452
WITH SCRAP VALUE OF \$M 0

INTERNAL RATE OF RETURN ON
TOTAL INVESTED CAPITAL (1)

IRR EQUALS: 19.42
ON TOTAL INVESTMENT OF \$M 2,596,903
WITH SALVAGE VALUE OF \$M 605,977

PRODUCT AND RAW MATERIAL VALUES (2)

PRODUCT PRICES, \$/UNIT

NAPHTHA, BBL	33.69
MEDIUM DISTILLATE, BBL	34.44
HEAVY DISTILLATE, BBL	36.55
BUTANE, BBL	18.90
PROPANE, BBL	17.64
AMMONIA, ST	185.00
SULFUR, ST	50.00
MIXED PHENOLS, ST	144.00

RAW MATERIAL COSTS, \$/UNIT

COAL, ST	30.00
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PRODUCTION, UNITS/DAY

NAPHTHA, BBL	23,173
MEDIUM DISTILLATE, BBL	28,092
HEAVY DISTILLATE, BBL	15,160
BUTANE, BBL	5,797
PROPANE, BBL	4,138
AMMONIA, ST	286
SULFUR, ST	853
MIXED PHENOLS, ST	69

INPUT, UNITS/DAY

COAL, ST	25,000
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CAPITAL COST ESTIMATES (2), \$M

LAND	2.253
TOTAL PLANT INVESTMENT	1,810,771
START-UP & PREPRODUCTION	53,784
INVENTORY CAPITAL	89,378
INITIAL CAT & CHEM	10,000

PREPAID ROYALTIES

5.175

(1) VALUES IN DOLLARS FOR YEAR
(2) VALUES IN DOLLARS FOR YEAR

1985
1980

TABLE A-1

A-10

1		1
2		2
3		3
4		4
5		5
6		6
7		7
8		8
9		9
10		10
11		11
12		12
13		13
14		14
15		15
16		16
17		17
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19		19
20		20
21		21
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31		31
32		32
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35		35
36		36
37		37
38		38
39		39
40		40
41		41
42		42
43		43
44		44
45		45
46		46
47		47
48		48
49		49
50		50
51		51
52		52
53		53
54		54
55		55
56		56
57		57

Table A.2 Estimated Product Values
(page 1 of 3)

Calculations for determining the premium price for heavy distillate fuel oil.

Average price (7/1/80, Oil Daily, Chicago and East)

for 0.3% S #4 fuel oil = \$32.925/Bbl

for 1.0% S #4 fuel oil = \$30.550/Bbl

Sulfur premium:

H-Coal heavy distillate = 0.08% S

$X * 1.0\% S + Y * 0.08\% S = 100 * 0.3\% S$

$Y = 100 - X$

$X = 23.9\%$

$Y = 76.1\%$

76.1 gal of 0.08% S oil plus 23.9 gal of 1.0% S oil will yield 100 gal of 0.3% S oil

76.1 gal of 0.08% S oil at \$ Z/Bbl

plus 23.9 gal of 1.0% S oil at \$30.55/Bbl

yields 100 gal of 0.3% oil at \$32.925/Bbl

$Z = \$33.67/\text{Bbl}$

Density premium:

$\$33.67/\text{Bbl} * 363 \text{ \#/Bbl} / 333 \text{ \#/Bbl} = \$36.70/\text{Bbl}$

less .15/Bbl high pour penalty

Equals \$36.55/Bbl

LCFFC heavy distillate = 0.06% S

$X * 1.0\% S + Y * 0.06\% S = 100 * 0.3\% S$

$Y = 100 - X$

$X = 25.5$

$Y = 74.5$

74.5 gal of 0.06% S oil plus 25.5 gal of 1.0% S oil will yield 100 gal of 0.3% S oil

74.5 gal of 0.06% S oil at \$Z/Bbl plus 25.5 gal of 1.0% S oil at \$30.55/Bbl

yields 100 gal of 0.3% S oil at \$32.925/Bbl

$Z = 33.74$

Density premium:

$\$33.74 * 387 \text{ \#/Bbl} / 333 \text{ \#/Bbl} = \$39.21/\text{Bbl}$

Less .15/Bbl high pour penalty

Equals \$39.06/Bbl

Table A.2 Estimated Product Values
(page 2 of 3)

Variable Economic Data Input

Product Prices:

Naphtha

The price of naphtha fluctuates according to market conditions, time, place of sale and quality of product. The average price is currently about \$33.69 per ballel from prices taken from Platt's Oilgram, June 17, 1980 issue.

Medium distillate, H-Coal

This material may be acceptable as a turbine fuel or jet fuel. Accordingly, it was given the value of jet fuel according to the above source.

Medium distillate, LCFFC

This material appeared to be equivalent to #2 fuel oil. It was given the average value for #2 fuel oil for the eastern US according to the July 1, 1980 issue of Oil Daily.

Heavy distillate, H-Coal and LCFFC

Each of the above fuels should command a premium over #4 fuel oil, which it would normally replace, because of its low sulfur content and higher density. A 15¢ per barrel penalty was attached because of the high pour quality of the material. The calculations for determining the price of each are shown above.

Table A.2 Estimated Product Values
(page 3 of 3)

Fuel Oil, H-Coal and LCFFC

The fuel oil produced by each of the processes' fuel oil modes is roughly' equivalent to #6 fuel oil at 0.5% sulfur. The July 1, 1980 issue of Oil Daily was used to determine the average price for this material. A premium was attached due to the higher density of the synfuel materials.

Butane, Propane, Ammonia, Sulfur, and Mixed Phenols

Prices for the above were determined from current published prices.

Capital Cost Estimates

The capital costs for each of the process-modes are shown in Tables 5.2 through 5.3. The calculations for determining the capital cost for land, startup and preproduction, inventory capital, and prepaid royalties are shown in Table A.3.

Table A.3 Capital Cost Estimates, Typical Calculation

Land = 425 acres * \$5,300/acre

Preproduction Costs =

- 30 days payroll costs
- +30 days maintenance supplies
- +30 days make-up catalyst and chemicals
- +30 days water supply
- +30 days ash disposal costs
- +1/4 of 30 days coal cost
- +expected plant and equipment modifications (2% of TPI)

Inventory Capital =

30 days of product inventory valued at 30 days of Operating Costs which is:

- 30 days catalyst and chemicals
- +30 days coal cost
- +30 days payroll costs
- +30 days maintenance supplies
- +30 days insurance costs
- +30 days water supply
- +30 days ash disposal costs

Plus 30 days of raw material inventory which is:

- 30 days coal cost
- 30 days catalyst and chemicals
- miscellaneous fixed charges (2% of TPI)

Prepaid Royalties = TPI x 0.286%

Working Capital Expense =

- 45 days accounts receivable
- +14 days payroll
- 30 days accounts payable
- *9% interest

Inventory capital is a part of the initial total invested capital of the plant. It is used to finance a certain level of inventory which is maintained throughout the life of the plant.

Working capital is used to finance the money outlay necessary for operating the plant on a day-to-day basis. It is refinanced annually at 9% interest. Only the interest cost of working capital is reflected in the pro-forma economic analysis shown in this appendix. This interest expense is accelerated from year to year by inflation.