EPA-AA-SDSB-82-04

A Technical Report

Refining of Coal-Derived Synthetic Crudes

by

John McGuckin

February 1982

NOTICE

Technical Reports do not necessarily represent final EPA decisions or positions. They are intended to present technical analysis of issues using data which are currently available. The purpose in the release of such reports is to facilitate the exchange of technical information and to inform the public of technical developments which may form the basis for a final EPA decision, position or regulatory action.

Standards Development and Support Branch
Emission Control Technology Division
Office of Mobile Source Air Pollution Control
Office of Air, Noise and Radiation
U.S. Environmental Protection Agency

Table of Contents

Table of Contents (cont'd)

I. Introduction

This report will cover the economics of refining coal-liquids (synthetic crude oils) obtained from the direct liquefaction of coal. These coal-liquids must undergo considerable upgrading before they can be considered environmentally and functionally acceptable end products. These syncrudes are upgraded in operations analagous to those applied to petroleum crudes with the key step being hydrotreating to reduce high nitrogen, oxygen, and sulfur contents. The major products from the coal-liquid refineries are gasoline, distillate and residual oil.

This discussion of the refining of coal-liquids consists of five main sections. The first section discusses the refining of coal syncrude/petroleum crude blends in existing petroleum refineries versus the refining of coal syncrudes in grass-root coal-liquid refineries. The next section is an analysis of grass-root coal-liquid refineries for H-Coal, SRC-II, and EDS syncrudes. It includes an overview of refining costs based on design studies already performed, a discussion of refinery configurations, and a discussion of parameters affecting refining cost. The third section presents an analysis of an integrated coal-liquid/ petroleum refinery. The fourth section compares the costs of processing synthetic crudes in existing refineries versus the costs of processing them in new grass-root refineries. The last section presents an economic summary of the most representative refining costs.

II. Petroleum/Coal-Liquid Integrated Refineries versus Grass-Root Coal-Liquid Refineries

There are two main options for the upgrading of coal syncrudes. One option is to perform the upgrading in grass-roots coal-liquid refineries, applying technology used in many petroleum refineries, but with processing capabilities specifically designed to refine coal-liquids. The other option is to upgrade coal-liquids together with petroleum crudes in existing petroleum refineries by making process alterations as required.

The coal-liquid/petroleum refinery integration option appears to have a number of advantages over the grass-roots coal-liquid refinery. Some of these advantages are:

1. The construction of coal-liquid refineries requires a large capital investment relative to processing at existing refineries, and projected capital shortages makes their construction unlikely.[1]

2. Since the United States' refinery utilization has been declining and refineries are currently operating at about 70

percent of capacity, the excess capacity could be used to upgrade syncrudes. Construction of new refineries would seem unwarranted.[2][3]

3. Since coal syncrudes may well be produced by owners of existing refineries who have the necessary refining technology, coprocessing these syncrudes together with petroleum in their refineries would be a convenient syncrude processing method.[1]

4. Existing refineries have a comfortable degree of flexibility to meet shifts in market demands, thus ensuring a market for the syncrudes.

5. A syncrude/petroleum crude blend would minimize specialized processing required for the synthetic components, and it reduces performance, compatibility, and quality risks associated with using a new product.[4]

A disadvantage is that the feasibility of processing coal syncrudes together with petroleum has not been demonstrated even on a laboratory scale, although it appears to be feasible to process up to 23 percent syncrude with petroleum crude based on the results of a high level refinery computer model.[1] The processing of 100 percent coal liquids in a grass-roots refinery has been shown feasible on a laboratory scale.[5]

From this, it would appear that the most likely path for growth for an oil from coal industry would be through the refining of syncrude/petroleum crude blends in existing refineries. However, there has been only one study[6] performed to date on coal-liquid/petroleum refinery integration. This study will be used to compare the processing of petroleum in a typical large refinery with the processing of 10 percent H-Coal product in an integrated coal-liquid/petroleum refinery.

However, since there has been so little work performed on integrated refineries, this refining discussion will mainly investigate the processing of whole EDS, H-Coal and SRC-II coal-liquids in grass-root coal-liquid refineries, where there is much more information. These refineries would have high capital costs but low operating costs relative to processing in existing refineries. The capital costs derived from the grass-root coal-liquid refineries will then be compared to the capital costs of retrofitting an existing refinery to process coal-liquid/petroleum crude blends. Also, the efficiency of the retrofitted refinery will be compared to the efficiencies of a coal-liquid refinery and a petroleum refinery.

III. Analysis of Grass-Root Coal-Liquid Refineries

A. Introduction

A few studies have been conducted to estimate the cost of refining H-Coal, SRC-II, and EDS coal liquids. These studies will be discussed here in order to determine representative refining costs for each syncrude and to obtain some idea of the processing requirements for the grass-root refineries.

First, an overview of the processing cost estimates for each of the studies will be presented; all costs have been placed on the same economic basis as discussed in a previous report.[7a] Secondly, a brief discussion of the refinery configurations will be presented to obtain some idea of the processing schemes for coal-liquid refineries. Also, the thermal efficiencies of coal-liquid refineries will be discussed. Lastly, the refining studies will be analyzed with respect to some important parameters which affect the cost of refining; these parameters include feedstock properties, product slate, product qualities and level of engineering design conducted for the investment estimate. This discussion will help to determine a representative refining cost for each of the coal syncrudes.

B. Overview of Coal-Liquid Processing Costs

Investment and operating costs for coal-liquid refineries have been reported in a few different studies. The cost estimates for the SRC-II syncrude were made by Chevron and ICF.[5][8] The estimates for the H-Coal syncrude were made by UOP, ICF, and Exxon.[7][8][9] The only estimate available for the EDS syncrude was made by ICF.[8] In addition to these specific studies, Exxon has prepared a rough study which presents a range of costs for upgrading a coal liquid in general.[10]

The economic basis for the refining costs is essentially identical to the basis discussed in a previous report.[7a] In addition the following criteria were used for estimating the refinery processing costs:

1. The plant size for the refineries was adjusted to a feedrate of 54,500 barrels per calendar day (BPCD) using the same capital scaling factor of 0.75, which was discussed in a previous report.[7a]

2. No credit was taken for the sulfur and ammonia byproducts. These costs are small and would have little effect on refining costs.

3. A 1990 real cost (in first quarter 1981 dollars) of $5.39/MMBtu for natural gas was used in those cases where natural gas is consumed.[8]

Tables 1 and 2 present economic summaries of the processing costs for H-Coal, SRC-II, and EDS coal liquids, based on investment and operating costs from the studies mentioned above. Table 1 represents an optimistic case with a capital charge rate of 11.5 percent; Table 2 is based on a higher capital charge rate of 30 percent. The operating costs do not include the cost of the coal syncrude. Therefore, to determine the total product cost, the refining costs would be added to the cost of the syncrude from direct liquefaction and the distribution cost of the products. Table 3 presents the breakdown of refinery products based on a syncrude feedrate of 54,500 BPCD.

With a 11.5 percent capital charge rate, refining costs vary from an average of $1.50/mBtu of product for the H-Coal syncrudes to about $2.00/mBtu for the SRC-II syncrude. With a 30 percent capital charge rate, refining costs vary from an average of $2.30/mBtu for the H-Coal syncrude to about $3.40/mBtu for the SRC-II syncrude.

A comparison of Table 1 with Table 2 shows the effect of increasing the capital charge rate on product cost. For capital intensive processes, as in the Chevron and UOP cases, product costs double with the increase in capital charge rate. For cases with high operating costs, as in the ICF and Exxon (H-Coal) cases, the capital charge rate does not have as great an effect on product cost.

The reason for the large differences in capital and operating costs between the studies lies in the methods used to supply refinery fuel and hydrogen for upgrading. The Chevron refinery utilizes the undesirable residual oil from the syncrude for refinery fuel and hydrogen production via partial oxidation. The UOP refinery uses steam reforming of light napthas for hydrogen production. The ICF refineries purchase refinery fuel and natural gas for hydrogen production via steam reforming. The purchasing of natural gas by the ICF refineries results in relatively high operating costs, while the capital costs for hydrogen production is relatively higher for the Chevron refinery than the UOP and ICF refineries (a partial oxidation unit has a higher capital cost than a steam reformer). A major result of these differences in refinery configuration is that the more capital intensive refineries (Chevron and UOP) produce a higher quality product than the less capital intensive ICF refineries since they consume the residual oil in the process.

Offplot investment is another reason for the large capital cost differences between the studies. Offplot allowances represent 30 and 48 percent of the total capital investment for the Chevron and UOP refineries, respectively; while they represent only about 12 percent for the ICF refineries. This may be the result of differences in the actual designs of the refineries or could be due to the use of different cost estimation procedures.

Table 1

Processing Cost Estimates Using a 11.5% Capital Charge Rate
(Millions of First Quarter 1981 Dollars)

	SRC-II		H-Coal			EDS	
Millions of Dollars	Chevron[5]	ICF[8]	UOP[7]	ICF[8]	Exxon (1974 Study)[9]	ICF[8]	Exxon (1974 Study)[10]
Total Instantaneous Investment	780.9	396.9	454.4	280.4	270.0	328.7	
Total Adjusted Capital Investment*	1033.9	525.5	601.6	371.2	357.5	435.2	
Annual Capital Charge	118.9	60.4	69.2	42.7	41.1	50.0	
Annual Operating Cost	57.7	204.7	41.8	110.4	175.1	158.4	
Total Annual Charge	176.6	265.1	111.0	153.1	216.2	208.4	
Refining Cost							
$/bbl of Product	9.76	13.42	5.75	8.19	10.94	11.03	6.90-14.70
$/mBtu of Product	1.84	2.19	1.06	1.42	2.00	1.87	1.31-2.46

* Includes working capital and start-up costs.

Table 2

Processing Cost Estimates Using a 30% Capital Charge Rate
(Millions of First Quarter 1981 Dollars)

	SRC-II		H-Coal			EDS	
Millions of Dollars	Chevron[5]	ICF[8]	UOP[7]	ICF[8]	Exxon (1974 Study)[9]	ICF[8]	Exxon (1974 Study)[10]
Total Instantaneous Investment	780.9	396.9	454.4	280.4	270.0	328.7	
Total Adjusted Capital Investment*	1022.2	519.5	594.8	367.0	353.4	430.3	
Annual Capital Charge	306.7	155.9	178.4	110.1	106.0	129.1	
Annual Operating Cost	57.7	204.7	41.8	110.4	175.1	158.4	
Total Annual Charge	364.4	360.6	220.2	220.5	281.1	287.5	
Refining Cost							
\$/bbl of Product	20.13	18.25	11.41	11.80	14.22	15.22	
\$/mBtu of Product	3.80	2.98	2.10	2.05	2.60	2.58	

* Includes working capital and start-up costs.

Table 3

Product Slates Based on 54,450
BPCD of Syncrude Charged to Refineries

	SRC-II		H-Coal			EDS
Products, BPCD	Chevron[5]	ICF[8]	UOP[7]	ICF[8]	Exxon (1974 Study)[9]	ICF[8]
LPG	--	--	2,828	--	--	--
Unleaded Regular Gasoline	49,590	9,708	23,585	17,072	36,021	21,054
Unleaded Premium Gasoline	--	--	10,122	--	--	--
No. 2 Fuel Oil	--	--	16,871	22,018	18,147	--
Residual	--	44,434	--	12,109	--	30,710
TOTAL	49,590	54,142	53,406	51,199	54,168	51,764
Product Energy, mBtu/CD*						
LPG	--	--	11,538	--	--	--
Unleaded Regular Gasoline	262,827	51,454	125,001	90,481	190,911	111,586
Unleaded Premium Gasoline	--	--	53,647	--	--	--
No. 2 Fuel Oil	--	--	97,852	127,703	105,253	--
Residual	--	279,936	--	76,285	--	193,472
TOTAL	262,827	331,389	288,038	294,469	296,164	305,058

* The following energy contents (mBtu per barrel) have been assumed:

Gasoline - 5.3
Fuel Oil No. 2 - 5.8
Residual - 6.3
LPG - 4.08

C. Studies Eliminated from Consideration in Development of Refining Costs

As mentioned above, Exxon determined a rough estimate of the cost of distilling, upgrading, and handling the products from direct liquefaction by assuming that the total upgrading cost was proportional to hydrogen consumption.[10] Since this Exxon/1980 study was prepared to give a rough indication of coal liquid refining costs, and was not considered by Exxon to be specific for the H-Coal, SRC-II or EDS syncrudes, it will not be considered further in the discussion of refinery configurations, and refining costs.

Another study which will not be considered further is the Exxon/H-Coal study published in 1974. This study is now outdated, since the feedstock property data were based on a 1967 study by Hydrocarbon Research Institute.[11] The property data indicate low nitrogen and oxygen contents compared to more recent data supplied by Mobil Research and Development Corporation.[7][12] High nitrogen and oxygen contents account for much of the high refining costs of coal liquids. Another factor considered in not using this study is its high operating costs. These costs are the result of purchasing approximately 11,280 fuel oil equivalent barrels per calendar day (FOEB/CD) of refinery fuel, steam reformer feed and fuel, and utilities while yielding about 41,600 FOEB/CD of product. The thermal efficiency of this refinery is only 74 percent. Today's refineries are becoming much more energy self-sufficient and energy efficient and would generate much of this energy from within the refinery.

D. Refinery Configurations

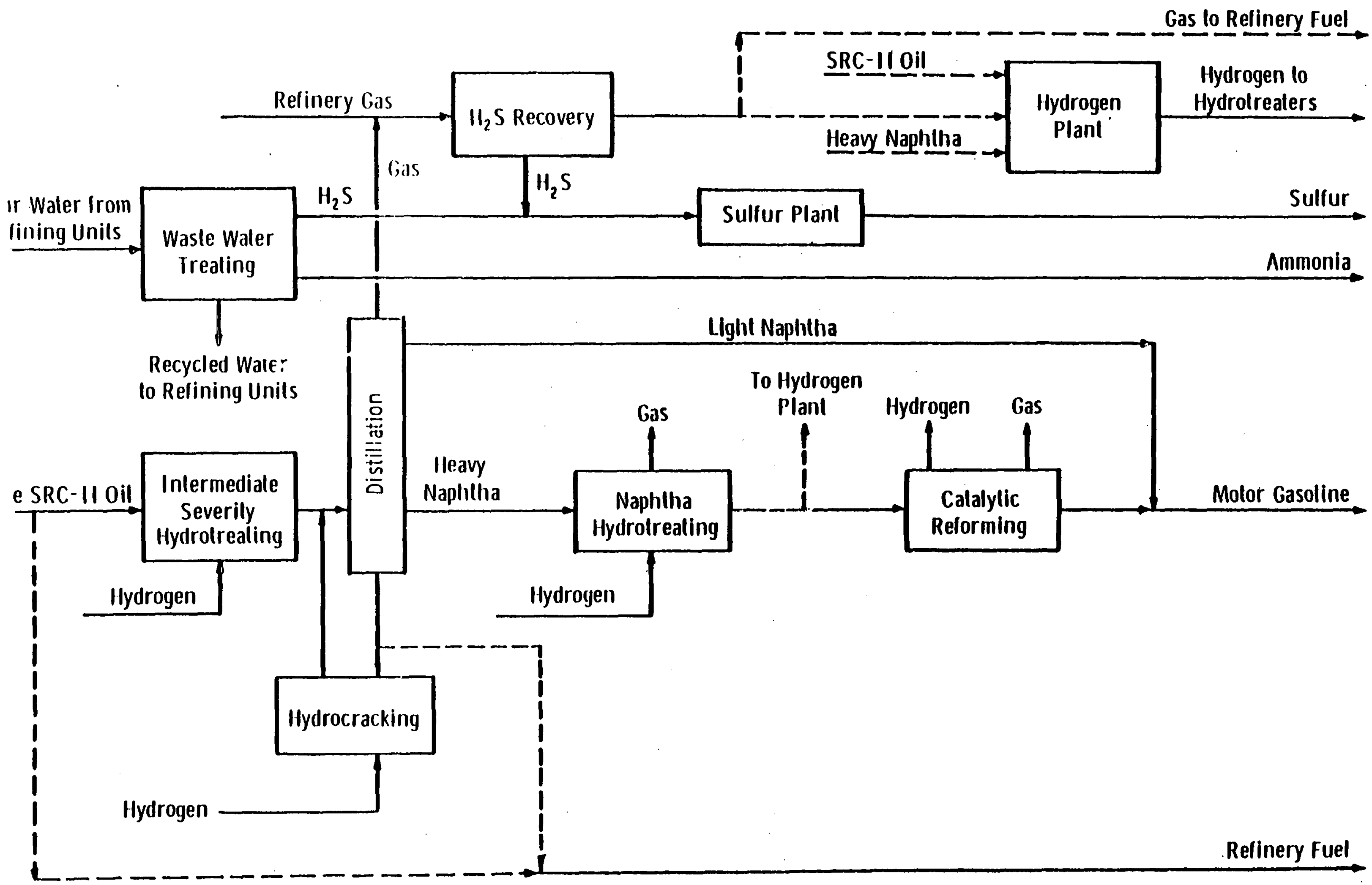
The key step in the refining of syncrudes is hydrotreating which removes the heteroatom impurities and increases the hydrogen content of these materials. Based on feedstock properties and product slates, each study utilized a different refinery configuration. In this section each refinery configuration will be briefly described.

1. Chevron Refinery Configuration[5]

Chevron analyzed six different cases in which different product slates and types of processing were imposed upon the SRC-II syncrude refinery. The two most practical cases are discussed here. The first case in which 100 percent gasoline is produced is shown in Figure 1.[5] Initially, the whole SRC-II syncrude is hydrotreated which provides essentially complete nitrogen removal. The hydrotreated SRC-II oil is then sent to a fractionator where light naptha, heavy naptha, and gas oil fractions are obtained. The light naptha fraction from distillation is sent directly to motor gasoline blending, and the heavy naptha fraction is hydrotreated and then catalytically reformed; the reformate is

FIGURE 1

SCHEMATIC FLOW DIAGRAM
REFINING OF SRC-II OIL BY
HYDROTREATING AND HYDROCRACKING - CASE 4
DOE CONTRACT EF-76-C-01-2315



sent to motor gasoline blending. The gas oil fraction is hydrocracked and then recycled to the fractionator. Total hydrogen consumption is about 2,633 scf per barrel of SRC-II feed.

Refinery furnace fuel and hydrogen plant feed requirements are met with untreated SRC-II oil. However, steam generating boiler plants were assumed to be coal-fired in compliance with DOE regulations. The thermal efficiency of this refinery has been estimated at 83 percent. The thermal efficiency was calculated by considering the higher heating value of all input streams to the refinery, and all product output streams. By-products were not considered as product energy output.

In addition to the above case, Chevron analyzed a case where the requirement to produce 100 percent gasoline (50,000 BPCD) was relaxed to 36,400 BPCD of gasoline and 13,100 BPCD of fuel oil No. 2. This is shown in Figure 2. For this case the refinery utilized a fluid catalytic cracker (FCC) in place of the hydrocracker. However, the FCC processing route appeared economically unattractive. For coal liquid refineries it seems preferable to rely on a flexible hydrocracking system rather than on fluid catalytic cracking, since coal distillates fail to meet the basic requirement for a FCC feed, high hydrogen content.[13] To add sufficient hydrogen to the FCC feeds, severe hydrotreating conditions are required. Therefore, utilizing FCC as a route to gasoline production requires simultaneous installation of hydrocracking facilities resulting in an economic preference for a flexible hydrocracking system rather than a joint FCC/hydrocracking system.[13]

2. <u>UOP Refinery Configuration[7]</u>

The refinery configuration for the UOP/H-Coal case is presented in Figure 3.[7] The key refining step is hydrocracking the total H-Coal distillate to produce gasoline and distillate fuel.

The H-Coal syncrude is first charged to an atmospheric distillation unit where a light naptha overhead cut (C_4-C_6) and bottoms cut (C_6-880°F) are obtained. The light naptha is hydrotreated to remove sulfur and nitrogen and then used as a feedstock for hydrogen production, blended into gasoline, or split into a C_4 and C_5/C_6 fraction for LPG and gasoline blending.

The fractionator bottoms (C_6-880°F) are charged to a naptha/distillate splitter where a variable naptha cut is taken overhead and a variable distillate cut is recovered as bottoms. Variable cuts were incorporated to provide flexilibity in achieving a range of gasoline/distillate product ratios.

The variable naptha cut is processed with a two-stage hydrotreater. The H-Coal naptha requires severe hydrotreating relative to petroleum naptha because of its higher nitrogen and oxygen content. The hydrotreated H-coal naptha is sent to a catalytic reformer. Coal-derived naptha is easily reformable to high octane levels because of its large quantity of high octane aromatics and cycloparaffins.

The variable distillate cut from the naptha/distillate splitter is charged to a hydrocracker. Hydrocracking severity is set by the gasoline/distillate ratio desired. The hydrogen consumption required to hydrocrack the distillate is very high and can range from 2.5-5.0 weight-percent of the charge. Napthas from the hydrocracker are sent to motor gasoline blending while the distillate is sent to the No. 2 fuel oil pool.

Utilities such as fuel and steam are produced internally in the refinery. Only power and water are purchased. The thermal efficiency of the UOP/H-Coal refinery was estimated at 95 percent. This efficiency seems high considering the high severity processing required for the H-Coal oil.

3. ICF Refinery Configuration[8]

ICF assumed that the EDS, H-Coal, and SRC-II syncrudes would be charged to a distillation unit located within the liquefaction battery limits, and that the straight run products from the distillation unit would be the charge feedstocks to a refinery complex. This refinery complex is separate from the liquefaction complex. In the refinery the naptha, distillate, and residual fractions are all charged to hydrotreaters. These hydrotreated streams were then assumed to be the refinery products. Thus, the refining facility was assumed to simply consist of a natural gas-charged steam reformer to produce hydrogen, hydrotreaters, emission control and effluent control equipment, and general offsite allowances. Natural gas, power, water, refinery fuel and catalysts would all be purchased. An analysis of the EDS, H-Coal, and SRC-II feedstock and product properties indicated thermal efficiencies of 79, 84, and 79 percent, respectively.

E. Discussion of Parameters Affecting Product Costs for Coal Liquid Refineries

A number of parameters affect the estimated cost of refining. Feedstock properties, desired product slate, product qualities, and the level of engineering design conducted for the investment estimate are among the most important parameters. To determine representative refining costs for each syncrude, the refining studies will be analyzed with respect to the above parameters.

1. Level of Engineering Design for Investment Estimates

When comparing the level of engineering design work used for the investment estimates, it was found that none of the studies

FIGURE 2

SIMPLIFIED FLOW DIAGRAM
REFINING OF SRC-II OIL BY
MODERATE SEVERITY HYDROTREATING - CASE 5
DOE CONTRACT EF-76-C-01-2315

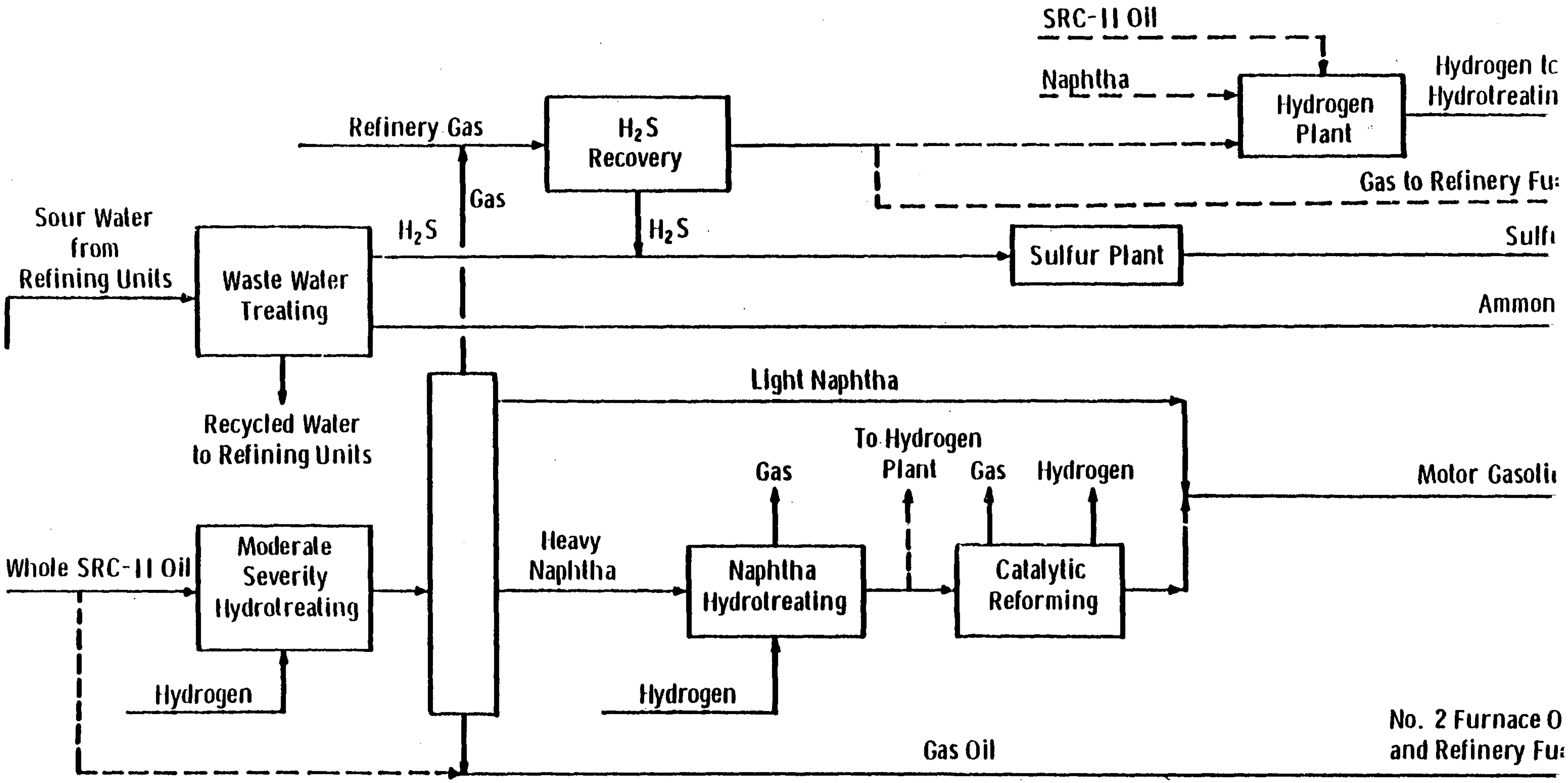
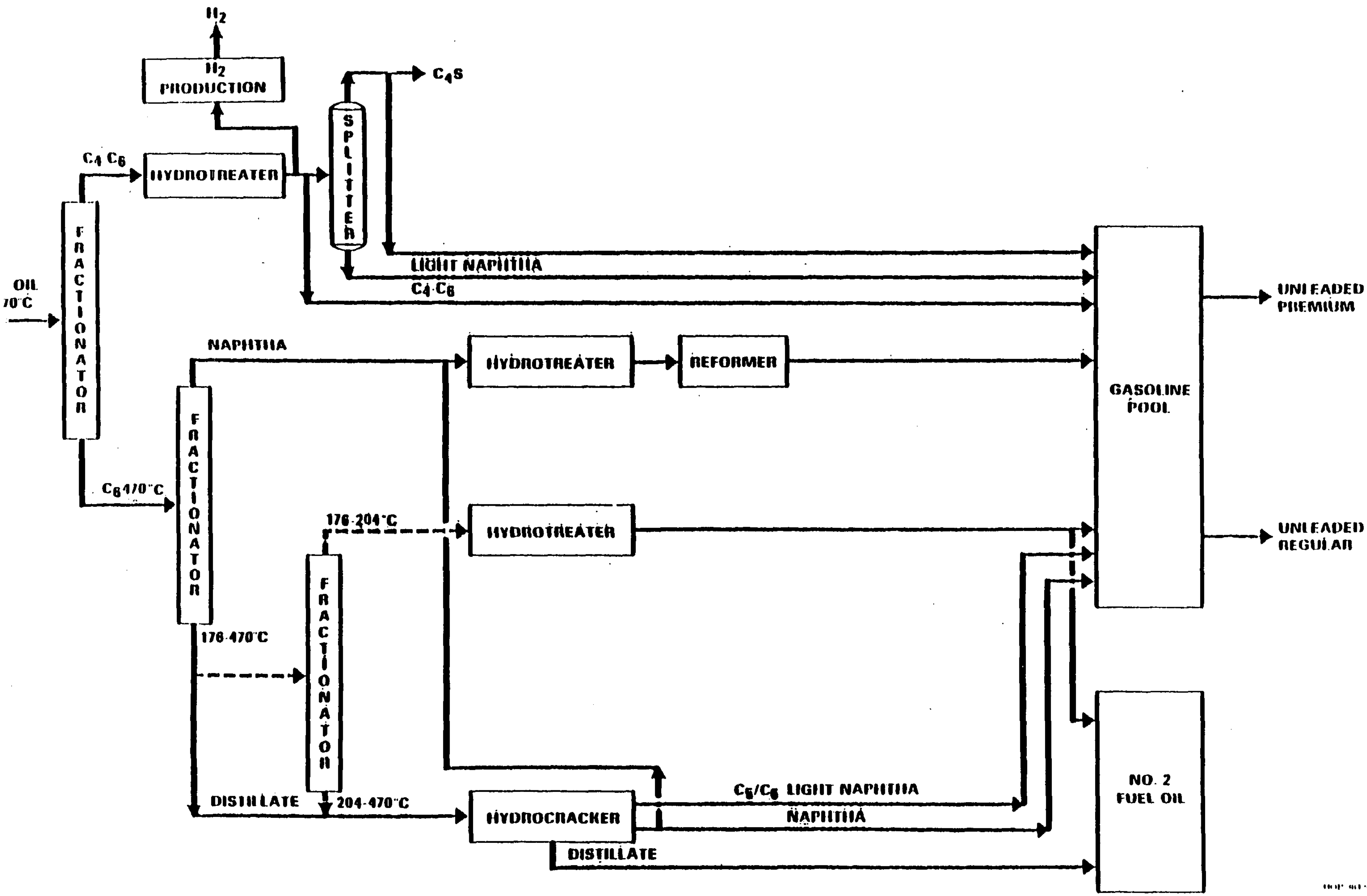


FIGURE 3

COAL OIL REFINERY
HYDROCRACKING CASES WITH LOW TEMPERATURE FRACTIONATION



represented detailed engineering designs.[5][7][8] However, it was found that the Chevron and UOP refining studies were based on more engineering work than the ICF study. The ICF study was intended simply to provide a rough indication of the effect of refining on the cost of liquefaction products.[8]

Chevron based their study on laboratory data, along with general petroleum processing and cost correlations based on refineries constructed by Chevron. The UOP cost estimate was based on their company's experience with refinery construction. ICF's investment costs are based on an estimate of the amount of hydrotreating required to bring the coal liquid products up to the hydrogen levels of existing petroleum products.

Therefore, even though the ICF estimates are based on reasonable methods, these methods are not considered as accurate as those used by Chevron and UOP. However, before it can be concluded that the latter estimates represent the best refining costs, feedstock properties and product slates need to be discussed since these also have significant effects on refining costs.

2. Refinery Feedstocks

A key parameter needed to determine an accurate estimate of refining cost is knowledge of the feedstock properties. In this section the coal liquid properties used by the various studies will be discussed.

Table 4 lists inspections of the feedstocks as reported by the Chevron and UOP refining studies. The hypothetical SRC-II syncrude used in the Chevron refining analysis was derived from Pittsburgh Seam coal. It is a blend of three fractions of SRC-II direct liquefaction product. The fractions were blended to constitute a syncrude typical of SRC-II operation. The H-Coal syncrude used for the UOP refining analysis was derived from Illinois No. 6 coal. It is a C_4-878°F crude obtained from the atmospheric column overhead and bottoms product of the Hydrocarbon Research Institute H-Coal process and inspected by the Mobil Research and Development Corporation.[12] The ICF study did not report feedstock data properly, but did report a breakdown of the syncrude into its basic petroleum product fractions. EDS coal liquid property data as reported by Exxon are presented in Table 5 to obtain some idea of what this refinery feedstock will be like.[14] The EDS coal liquid was derived from Illinois No. 6 coal.

A significant difference between the various studies lies in the fraction of the syncrude represented by the naptha, distillate, and residual cuts. Table 6 presents the volume percent of the syncrudes distilled as a function of boiling point range as used by the various studies. Also included in this table are the product cuts as reported by the main contractors of the direct

Table 4

Refinery Feedstock Property Data

	H-Coal [7]*	SRC-II [5]**
Specific Gravity	0.8733	0.9427
Gravity, °API	30.5	18.6
Total Nitrogen, Wt-%	0.37	0.85
Oxygen, Wt-%	1.72	3.79
Sulfur, Wt-%	0.15	0.29
Carbon, Wt-%	86.7	84.61
Hydrogen, Wt-%	11.0	10.46
Ramsbottom Carbon, Wt-%	-	0.70
Conradson Carbon Residue, Wt-%	0.10	-
Benzene Insolubles, Wt-%	-	0.03
C_7 Insolubles, Wt-%	0.10	-
Ash, ppm	67	40
Bromine Number	41.7	70
Pour Point, °F	-	-80
Viscosity, CS at 100°F	-	2.196
ASTM D 86/D 1160 Distillation, °F at Vol-% Distilled:		
Start/5	-	154/217°F
10/30	-	281/382
50	-	438
70/90	-	484/597
95/End Pt.	-	699/850
Distillation, °F vs. Vol-% Distilled		
13.87 Vol-%	C_4/C_6	-
30.84	C_6/350°F	-
10.4	350/399	-
40.89	399/650	-
3.99	650/880	-

* Derived from Burining Star Mine, Illinois No. 6 coal.

** Derived from Blacksville No. 2 Mine, Pittsburgh Seam coal.

Table 5

EDS Coal Liquid Property Data [14]*

	Naptha	Fuel Oil	Total C_5+ Product
Wt% of Whole Crude	39.0	61.0	100.0
Specific Gravity	0.77	1.03	0.928
Gravity, °API	52.3	5.7	21.0
Carbon, Wt-%	85.2	87.72	-
Hydrogen, Wt-%	13.16	8.89	10.56
Sulfur, Wt-%	0.43	0.51	0.479
Nitrogen, Wt-%	0.06	0.75	0.48
Oxygen, Wt-%	1.15	2.13	1.75
Higher Heating Value,			
Btu/lb	20,076	17,837	18,710
Million Btu/B	5.41	6.43	5.89
15/5 Distillation,			
Wt-% off, °F			
5	92°F	271°F	
10	117	359	
30	184	442	
50	234	623	
70	277	885	
90	322	1030	
95	340	1081	

* Derived from Monterrey Illinois No. 6 coal.

Table 6

Coal Liquid Products as a Volume Percentage of the Whole Coal Syncrude

	Naptha Initial/ (350-380°F)	Distillate (350-380°)/ 650°F	Residual (650° F+)
H-Coal			
UOP [1]	53	43	4
ICF [7]	35	42	23
Fluor Corp. [15]	35	42	23
SRC-II			
Chevron [6]	30	60	10
ICF [7]	19	--	81
PMC [14]	23	71	6
EDS			
ICF [7]	42	--	58
Exxon [13]	43	22	35

liquefaction processes (Exxon/EDS,[14] Pittsburg and Midway Coal Mining Company (PMC)/SRC-II,[15] and Fluor Corporation/ H-Coal,[16]).

The greatest variability lies in the fractions of residual and distillate reported. The correct percentage of residual in the coal liquid syncrude is debatable, and will be determined by future economic conditions. The direct liquefaction processes have the capability of recycling the heavy liquids to the liquefaction reactor or utilizing this heavy material for hydrogen production, thus decreasing the fraction of residue in the syncrude product and yielding a lighter syncrude.

Since the direct liquefaction costs for this study are based on the main contractors' estimates of the naptha, distillate, and residual portions of the syncrudes, for consistency their estimates must be used as the basis for this refining discussion. Therefore, since the H-Coal product fraction used by ICF is identical to that reported by Fluor, it would be considered most accurate. The H-Coal syncrude as reported by UOP should contain less of the naptha fraction and more of the residual fraction. Their refinery would need to have the capability of handling this extra residual material. This would result in higher operating and capital costs for the UOP refinery; therefore, their current refining cost would appear to be an underestimation.

The SRC-II syncrude product fractions used by Chevron are similar to those reported by PMC, while those used by ICF are significantly different. The net effect of the feedstock differences on refining cost for the Chevron case would not be very significant. However, for the ICF case there would be much less residual processing and more distillate processing. The overall effect on the ICF product cost would be to decrease it, since residual processing is more severe than distillate processing. Also, there would be more distillate product from the ICF case and less of the undesirable residual oil.

The EDS syncrude fractions used by ICF differ from Exxon's mainly in the percentage of distillate and residual reported. The effect of this on the ICF case would be to transfer a portion of the residual processing capability to distillate processing. Again the ICF product cost would decrease and there would be more distillate product and less residual oil.

3. Product Slate

The projected future product demand from petroleum refineries is listed in Table 7 with the 1980 product demand listed for comparison (see Chapter VIII).[17] As shown in Table 7, the future demand for gasoline is expected to decline. This decline is largely compensated for by the rise in diesel fuel consumption. The demand for jet fuel is expected to increase slightly

Table 7

Petroleum Product Demand [17]

	1980 Million Barrels/Day	Percent	2000 Million Barrels/Day	Percent
Gasoline	6.8	38.6	5.1	27.6
Jet Fuel	1.1	6	1.6	8.6
Diesel Fuel	1.2	6.8	3.4	18.4
Kerosene	0.2	1.1	0.2	1.1
Distillate	2.0	11.4	1.2	6.5
Residual	2.4	13.6	1.4	7.6
Liquefied Gases	0.8	4.5	0.7	3.8
Other*	3.2	18	4.9	26.4

* Other includes still gases, petroleum coke, asphalt and road oil, lubes and waxes, special napthas, and miscellaneous products.

while the demand for other distillate (fuel oil No. 2) and residual oil is expected to decrease. The percentage of total refinery product represented by transportation fuels increases from 53 percent in 1980 to about 56 percent in 2000. The greatest change lies in the G/D* ratio which changes from 1.5 in 1980 to about 0.8 in 2000.

The key products from refineries will continue to be transportation fuels (gasoline, jet fuel, and diesel fuel) which represents 56 percent of the total refinery output in 2000. Therefore, it is reasonable to require that coal liquid refineries produce at least 56 percent transportation fuels. On the other hand, since properties of coal syncrudes are significantly different from petroleum crudes, syncrude refineries should not neces- sarily have to meet exactly the same product slate as a petroleum refinery. Therefore, a reasonable product slate for coal liquid refineries will be developed below.

Coal liquids are not expected to be good feedstocks for jet fuel production or diesel fuel production. For diesel fuel production, coal liquid distillates need to be severely hydrotreated to reduce the aromatic content to an appropriate amount (less than 25 percent aromatics) so that a product with a cetane number of 36-39 can be obtained.[18][19] These cetane numbers are still lower than the minimum ASTM specification of 40;[20] therefore, additives to boost the cetane number would be required. Similarly, for jet fuel production the aromatic content must be less than 20 percent aromatics; thus, even more severe refining may be required for jet fuel than for diesel fuel.[20] However, since coal liquids are highly aromatic (i.e., high octane), they make good feedstocks for gasoline production. Thus, if the coal liquid refinery would not produce jet fuel, diesel fuel, or kerosene, it would be reasonable to require it to produce at least 56 percent gasoline, thus meeting the overall transportation fuel requirement.

The coal syncrudes contain from 35-60 percent of 350°-650° F distillate. This could conveniently be used as fuel oil No. 2 after hydrotreatment. However, this is far greater than the year 2000 demand of only 6.5 percent fuel oil No. 2. Some of the coal distillate along with some residual oil will have to be processed into gasoline to meet the gasoline requirement. However, there may still be more than 6.5 percent distillate product. Since the coal liquid refineries may not produce much residual oil, because some of it may be hydrocracked to gasoline and other portions may be used for refinery fuel and feedstock for hydrogen production, the year 2000 demand for resid of 7.6 percent could reasonably be added to the 6.5 percent distillate demand to allow a total fuel oil demand of 14 percent.

---

* G/D is the ratio of gasoline to distillate. Distillate includes fuel oil No. 2, diesel fuel, jet fuel, and kerosene.

Of the remaining 30 percent of the year 2000 product slate, 4 percent is represented by liquefied gases and 26 percent by the "other" category (special napthas, asphalt, still gases, and miscellaneous products).

As a result of the above discussion, the following year 2000 product slate for coal liquid refineries can be specified:

Liquefied Gases	-	Up to 4 percent
Gasoline	-	At least 56 percent
Distillate and Residual	-	Up to 14 percent
Other	-	26 percent

The above product slate will be used as the basis for discussing the product yields reported in the refining studies. The low distillate demand (6.5 percent, or 14 percent if no resid is produced) may be the most difficult specification for coal liquid refineries to meet. The product slates from the coal liquid refineries have already been presented in Table 3.

The Chevron refinery produces 100 percent gasoline. Although this is more than what is required, this case does provide an upper limit for processing costs and is certainly reasonable with respect to the production of transportation fuels.

The UOP refinery output is designed to meet a G/D ratio of 2.0, and the only products are gasoline, No. 2 fuel oil and LPG. Sixty-three percent of the total product is gasoline. Therefore, this is more gasoline than required. The only other major product is fuel oil No. 2 (about 30 percent). This is about twice as much as the year 2000 demand for distillate or residual. However, because of the high yield of gasoline from this refinery, its overall product slate can be considered reasonable.

For the ICF cases, the product slates are as follows:

	H-Coal	EDS	SRC-II
Gasoline (%)	31	37	16
Fuel Oil No. 2(%)	43	--	--
Residual (%)	26	63	84

The high quantity of residual produced from these refineries is considered unacceptable since future demand is projected to be only 7.6 percent and because residual is not a premium product. To produce an acceptable product slate, the ICF refineries would need to become more integrated, thus the capital cost for their refineries would increase significantly.

The conclusions drawn from the above discussion are summarized below:

1. The Chevron/SRC-II refinery represents an upper limit for refinery processing cost with respect to product slate since 100 percent gasoline is the product.

2. The UOP/H-Coal product slate is considered reasonable.

3. The product slate from the ICF refineries is unacceptable because of the large amount of residual product. These refineries would need to become more integrated in order to meet an acceptable product slate, thus the capital cost for their refineries would increase significantly.

4. Product Qualities

All of the products from the UOP and Chevron refineries meet ASTM product specifications with the exception of the fuel oil No. 2 for the UOP case. The API gravity of this fuel oil is slightly lower than the specification.

The gasoline from the ICF cases is simply hydrotreated naptha which probably does not meet automotive octane requirements. Laboratory tests have indicated that research octane numbers for EDS, H-Coal, and SRC-II hydrotreated napthas lie between 65-70.[12]. This is far below the present 87 (R + M)/2 octane rating for unleaded gasoline. Catalytic reforming of the hydrotreated naptha would be necessary to meet an 87 (R + M)/2 octane rating. The addition of a catalytic reformer would increase the capital costs of the ICF refineries. This would result in an increased product cost.

To conclude this brief discussion, it is noted that upgrading coal liquids to acceptable end products is technically feasible. However, although coal or refinery products meet ASTM specifications, product properties can still be significantly different from petroleum refinery products.[7]

5. Coal Liquid Refining Costs

Based on the above discussions of grass root coal liquid refineries, representative refining costs can now be determined. Since the Chevron/SRC-II and UOP/H-Coal studies were based on a higher level of engineering design, their cost estimates will be used as the initial basis to determine refining costs for the SRC-II and H-Coal syncrudes. The ICF/EDS case will be used for the initial EDS syncrude refining cost.

Table 8 lists a breakdown of the investment and operating costs in first quarter 1981 dollars for the coal liquid refineries. The operating costs do not include the cost of the syncrudes. Table 9 lists the refining costs based on the costs

Table 8

Investment and Operating Costs for Refineries
(Millions of First Quarter 1981 Dollars)

Investment Costs, Millions of Dollars	SRC-II Chevron[5]	H-Coal UOP[7]	EDS ICF[8]
Onplot Investment	455.6	189.2	261.7
Offplot Investment	227.8	218.9	22.7
Prepaid Royalties	-	-	1.6
Contingency	75.9	40.8	42.7
Initial Catalyst and Chemicals	21.6	5.5	-
Total Instantaneous Investment	780.9	454.4	328.7
Working Capital	108.2	76.5	26.7
Total Capital Investment	889.1	530.9	355.4
Operating Costs, Millions of Dollars per year			
Interest on Working Capital	6.5	4.6	1.6
General and Administrative	-	3.7	3.3
Taxes and Insurance	17.4	11.4	9.9
Maintenance	16.3	9.1	12.2
Catalyst and Chemicals	5.5	13.0*	6.4
Labor	4.4	-	1.8
Utilities	7.6	-	9.47
Refinery Fuel	-	-	-
Hydrogen Plant	-	-	107.6
Overhead	-	-	6.1
Other	-	-	-
Total Annual Operating Costs	57.7	41.8	158.4

* Includes catalyst and chemicals, labor, and utilities.

Table 9

Refining Cost of Coal Liquids

	11.5 Percent CCR		30 Percent CCR		Hydrogen Consumption
	$/FOEB	$/mBtu	$/FOEB	$/mBtu	scf/bbl
Chevron/SRC-II	9.76	1.84	20.13	3.80	2633
UOP/H-Coal	5.75	1.06	11.41	2.10	1150
ICF/EDS	11.03	1.87	15.22	2.58	1728
Revised EDS Cost	7.87	1.47	16.02	3.00	

reported in Table 8 and on capital charge rates of 11.5 and 30 percent. The refining costs are added to the direct liquefaction product costs and the distribution costs of the synthetic products to obtain the total product cost. The revised "EDS refining cost" listed in Table 9 will be discussed in the next section.

It must be understood that the Chevron/SRC-II refinery represents an upper limit to the refining cost since it produces 100 percent gasoline. The UOP/H-Coal refinery would need to be more integrated to enable it to process the greater quantity of residual oil in the H-Coal feedstock as reported by Fluor Corporation. Therefore, the UOP/H-Coal refining cost is likely to be low. It is difficult to determine whether the ICF/EDS refining cost estimate is high or low. Based on Exxon's analysis of the EDS syncrude, the ICF/EDS refinery would not have to handle the quantity of residual oil they assumed; this would result in lower refining costs. However, to meet an acceptable product slate their refinery would need to become more integrated, thus increasing the refining cost.

F. Reconciliation of EDS, H-Coal, and SRC-II Refining Cost Differences

Table 8 indicates that there are significant differences between the capital investment and operating costs for the SRC-II, H-Coal, and EDS refineries. The total instantaneous capital investments (including working capital) is $889 million for the SRC-II refinery, $531 million for the H-Coal refinery and $355 million for the EDS refinery. Much of the capital and operating cost differences can be attributed to product slate and quality, level of engineering design and feedstock properties. In the following paragraphs these differences will be reconciled.

With respect to the level of engineering design, there is a greater probability that the actual capital cost of a project will be more than the estimated cost rather than less as the level of engineering design decreases.[21] For example, a design study prepared to estimate the capital cost to within 30 percent of the actual cost is likely to have a wider positive error for the estimate than negative, eg., +40 and -20 percent. The Chevron study represents the highest level of engineering design between the three studies followed by the UOP study, and then the ICF study. On this basis it is believed that the ICF estimate has the greatest probability of being lower than the actual capital cost followed by the H-Coal and SRC-II studies.

It is believed that ICF's estimate of the offplot investment for the EDS refinery is too low. Offplot investment amounts to 30 percent of the total instantaneous investment for the Chevron study and 48 percent for the UOP study, but only 7 percent for the ICF study. This finding is also confirmed by typical offplot refinery costs.[6] Thus, the resulting ICF/EDS refining costs will also be low.

The high operating cost of the EDS refinery relative to the H-Coal and SRC-II refineries as reported in Table 8 is primarily the result of the EDS refinery purchasing natural gas for hydrogen production. The H-Coal and SRC-II refineries produce hydrogen directly from the coal syncrude or from the light refinery products. The latter process is much more likely to occur in real life since it utilizes low quality products rather than high quality products to produce hydrogen.

With respect to product slate, the Chevron refinery produces 100 percent gasoline while the H-Coal refinery produces 2/3 gasoline and 1/3 fuel oil No. 2, and the EDS refinery produces about 40 percent hydrotreated naptha and 60 percent residual fuel. The SRC-II refinery which produces 100 percent gasoline will consume the largest amount of hydrogen. The total hydrogen consumption for the SRC-II refinery is 2633 scf per barrel of syncrude, whereas the H-Coal/UOP refinery consumes about 1150 scf per barrel, and the EDS refinery about 1728 scf/barrel. Since capital and operating costs are generally proportional to hydrogen consumption, one would expect the Chevron product cost to be the most expensive, followed by the EDS cost, and then the H-Coal cost. Table 9 shows that this is the general trend in the refining costs. Although much of the differences in hydrogen consumption is due to product slate, it must be noted that feedstock properties also have a significant effect on hydrogen requirements.

If the refinery product slate and other parameters were held constant, the general effect of feedstock properties on refining costs can be determined. The refinery feedstock property data are reported in Tables 4 and 5. The most important feedstock property data to compare are the nitrogen, oxygen, and hydrogen contents. Tables 4 and 5 show that the H-Coal oil has the most desirable properties of the three syncrudes, followed by the EDS crude, and then the SRC-II crude. High nitrogen and oxygen contents, and a low hydrogen content account for the high severity hydrotreating and hydrocracking required for the coal syncrudes, and this high severity refining correlates directly with refining cost. The theoretical hydrogen requirement necessary to bring the hydrogen, nitrogen, oxygen, and sulfur levels of the EDS and SRC-II syncrudes up to the quality of the H-Coal oil is 248 scf per barrel for the EDS crude and 469 scf/bbl for the SRC-II crude. This indicates that the SRC-II refinery would require the highest refining cost followed by the EDS and H-Coal refinery. This is roughly confirmed by the cost estimates shown in Table 9.

There is much uncertainty in the refining cost based on the ICF/EDS refinery. As discussed earlier, reasons for this uncertainty include: 1) a low level of engineering effort resulting in uncertain capital and operating costs, 2) the poor quality of the EDS feedstock assumed by ICF relative to that most recently reported by Exxon, and 3) the highly unreasonable product slate from this refinery. For these reasons a cost estimate based on the SRC-II and H-Coal refineries and on the overall quality of the EDS feedstock relative to the H-Coal and SRC-II feedstocks will be determined and used in preference to the ICF-based estimate. The measure of feedstock quality will be based on the theoretical hydrogen requirement necessary to bring the hydrogen, nitrogen, oxygen and sulfur levels of the EDS and SRC-II syncrudes up to the quality of the H-Coal oil. As discussed above this requirement is 248 scf/bbl for the EDS crude and 469 scf/bbl for the SRC-II crude. Therefore, on a linear scale the EDS crude lies 52.9 percent (248/469) of the scale between the other crudes. On this basis the refining cost for the EDS process can be approximated by linearly interpolating between the refining cost shown in Table 9 for the H-Coal and SRC-II crudes. The resulting cost is presented in Table 9 as the "revised EDS cost." This cost ($1.47 - $3.00/mBtu) will be used in preference to the ICF-based estimate ($1.87 - $2.58/mBtu).

In this section studies which have presented refining costs for coal syncrudes have been critiqued. One must realize that these refining costs are the best available at the present time. There are shortcomings with respect to level of engineering effort, in addition to uncertainties in feedstock qualities and product slates. These problems make it difficult to compare cost between studies. It would be desirable if all costs were on a similar basis and derived from a high level of engineering design.

In conclusion the refining costs of whole SRC-II, EDS and H-Coal syncrudes in grass-root refineries has been determined to range from $1.84-3.80, $1.47-3.00, and $1.06-2.10 for each process respectively. The Chevron/SRC-II refining cost represents an upper limit to the refining cost since it produces 100 percent gasoline. The UOP/H-Coal refining cost may be low since it would need to be more highly integrated to enable it to process a greater quantity of residual in the H-Coal feedstock than they assumed. Lastly, the EDS cost is based on the SRC-II and H-Coal costs using the overall quality of the crude feedstock as an indicator of refining cost.

IV. Analysis of an Integrated Coal Liquid/Petroleum Refinery[6]

A. Introduction

Gilder and Burton (UOP Inc.) evaluated the economic feasibility of co-processing H-coal liquid and a petroleum crude in a typical large petroleum refinery located on the Gulf Coast with a refinery capacity of 285,000 barrels per calendar day (BPCD).[6] They analyzed the co-processing of 3, 5, and 10 percent H-Coal liquid charges to the refinery. Only the 10 percent H-Coal liquid charge will be discussed in this report, as even at this H-Coal feedrate (28,500 BPCD) two such refineries would be needed to handle the output of a typical 50,000 BPCD liquefaction plant.

Linear programming techniques were used to provide material balances, capital costs, utilities, and operating cost information. The estimated investment costs reflect prices that were derived by scaling detailed estimates prepared for similar units to UOP standards and specifications.

Their first step was to design a grass-roots petroleum refinery. Then, to co-process the H-Coal liquid in the petroleum refinery the following questions were asked:

1. Can the operating severity of the petroleum refinery process units be increased in order to produce an acceptable product?

2. What modifications to existing units are required to facilitate the processing of H-Coal liquids?

This discussion summarizes their work.

B. Feedstocks

The coal liquid modeled was a C_4 to 880°F distillate material obtained from the atmospheric column overhead and bottoms products of the 3 ton per day H-Coal Process Development Unit located in Trenton, New Jersey. An analysis of the H-Coal liquid has already been presented in Table 4.

The petroleum crudes were selected to represent typical Gulf Coast processing. Louisiana Delta and West Texas Sour are the domestic crudes while a 65/35 Light/Heavy Arabian crude is the foreign crude. Analyses of these crudes are presented in Tables 10a, 10b, and 10c. When added, the H-Coal syncrude took the place of a portion of the foreign crude.

C. Product Slate and Specifications

All refinery products met ASTM specifications (except for LPG which was only required to meet a RVP restriction.) The two refineries were not required to meet identical product slates, but they did meet similar slates, as shown in Table 11.

D. Petroleum Refinery Configuration

The model of the petroleum refinery configuration (in which H-Coal liquid is not processed) is a typical Gulf Coast refinery representative of the complexity and processing flexibility exhibited in the larger refineries of that area. Figure 4 presents a flow diagram of the major processing units utilized in this all-petroleum refinery. A discussion of this flow scheme will not be included here. Interested readers are referred to the referenced study.[20]

E. H-Coal Liquid/Petroleum Refinery Configuration

A diagram depicting the integrated H-Coal/petroleum refinery design is shown in Figure 5. In this refinery the H-Coal liquid (10 percent of total petroleum crude to the refinery) is co-mingled with the Arabian Crude and then fractionated. The resulting fractions are processed in the same general manner as in the petroleum refinery. However, because of the characteristics of the H-Coal liquid, the petroleum refinery had to be modified to include an additional high-pressure naptha hydrotreater (see Figure 5). Operating conditions, product properties, and product yields for each process unit were adjusted to reflect the feedstock quality differences in the various cases.

The H-coal liquid contains much less residual material than the Arabian crude; however, processing to obtain acceptable intermediate products (gasoline, diesel, etc.) from the H-Coal/Arabian crude mixture is more severe than for the Arabian crude alone. The H-Coal liquid properties which have the greatest impact on its ability to be processed are its high nitrogen and oxygen contents, and low hydrogen content.

F. Material Balance

The overall feed and product summary is presented in Table 11. Because the H-Coal material contains high concentrations of naptha and distillate, and a low concentration of resids (unlike the Arabian crude), there is a shift from atmospheric bottoms processing (fluid catalytic cracking, vacuum distillation, etc.) to distillate processing (distillate hydrotreating). Table 12 shows the processing shifts required to achieve the stated yields. Utility usage is listed in Table 13. The refinery is self-sufficient with respect to utilities except for power.

G. Economic Comparison

In this subsection the cost of refining 10 percent H-Coal liquid in the integrated refinery will be compared to processing 100 percent petroleum. The economic basis used here is the same as that used for the grass-root refineries except:

1. No by-product credits were taken

2. A power cost of 4.5¢/kw-hr was used

3. Interest on working capital was not charged as an operating cost.

4. Depreciation was included as an operating cost.

5. The refineries were not scaled to 54,500 FOEB/CD of product.

Table 10a

Arabian Blend Crude
65% Light/35% Heavy[6]

	C_3	C_4	C_5-80	80-190	190-250	250-340	340-565	565+	Total
Volume % of Crude	0.7	1.7	6.8	17.8	9.0	15.0	31.6	17.9	
Weight % of Crude	0.4	1.17	5.2	15.5	8.4	14.6	33.3	21.5	100
Specific Gravity	0.508	0.57	0.6617	0.7504	0.8025	0.8453	0.9123	1.035	0.8645
Sulfur, Wt. %			0.01	0.04	0.23	1.19	2.46	5.0	2.09
Research Octane Number			63.	31.	17.				
Motor Octane Number			62.	29.	16.				
Smoke Point					23.	8.			
Pour Point °C					-48.3	-17.8	26.7	48.9	
Viscosity Index at 50°C					6.7	15.5	28.9	48.2	
Conradson Carbon Wt-%							0.614	22.85	5.1
Paraffins, Vol-%			85.5	64.9	57.7	20.4			
Naphthenes, Vol-%			10.7	20.3	21.1	9.3			
Aromatics, Vol-%			3.8	14.8	19.7	2.5			
Nitrogen, Wt-%						0.01	0.07	0.31	0.091

Table 10b

Louisiana Mixed Delta Crude[6]

	C_3	C_4	C_5-80	80-193	193-250	250-340	340-565	565+
Volume % of Crude	0.3	0.6	2.6	16.5	9.8	27.4	35.1	7.7
Weight % of Crude	0.2	0.4	2.0	14.4	9.3	27.3	37.3	8.9
Specific Gravity	0.508	0.57	0.671	0.754	0.820	0.864	0.912	1.0
Sulfur, Wt. %				0.18	0.04	0.11	0.38	0.80
Research Octane Number-Clear	89.	66.	73.					
Motor Octane Number-Clear	92.	65.	75.					
Smoke Point				19.7				
Pour Point Index					0.35	6.0	100	1000
Viscosity Index at 50°C					7.52	17.12	32.04	42.42
Conradson Carbon Wt-%							0.47	
Paraffins, Vol-%	100		59.9	38.6				
Naphthenes, Vol-%			35.3	50.2				
Aromatics, Vol-%			4.8	11.2				
Nitrogen, Wt-%								

Table 10c

West Texas Sour Crude[6]

	C_3	C_4	C_5–80	80–190	190–250	250–340	340–565	565+
Volume % of Crude	0.5	0.2	7.5	22.8	10.3	16.3	29.6	12.8
Weight % of Crude	0.5	0.2	5.8	20.6	9.9	16.5	31.5	15.0
Specific Gravity	0.508	0.57	0.670	0.775	0.825	0.868	0.928	1.0
Sulfur, Wt. %			0.12	0.31	0.74	1.37	2.19	3.95
Research Octane Number			70.2	57.8				
Motor Octane Number			66.5					
Smoke Point					30			
Pour Point Index					0.35	6.0	100	1000.
Viscosity Index at 50°C					8.32	16.7	32.04	42.24
Conradson Carbon Wt-%						0.07	0.26	19.35
Paraffins, Vol-%				37.8				
Naphthenes, Vol-%				37.6				
Aromatics, Vol-%				24.6				
Nitrogen, Wt-%								

Table 11

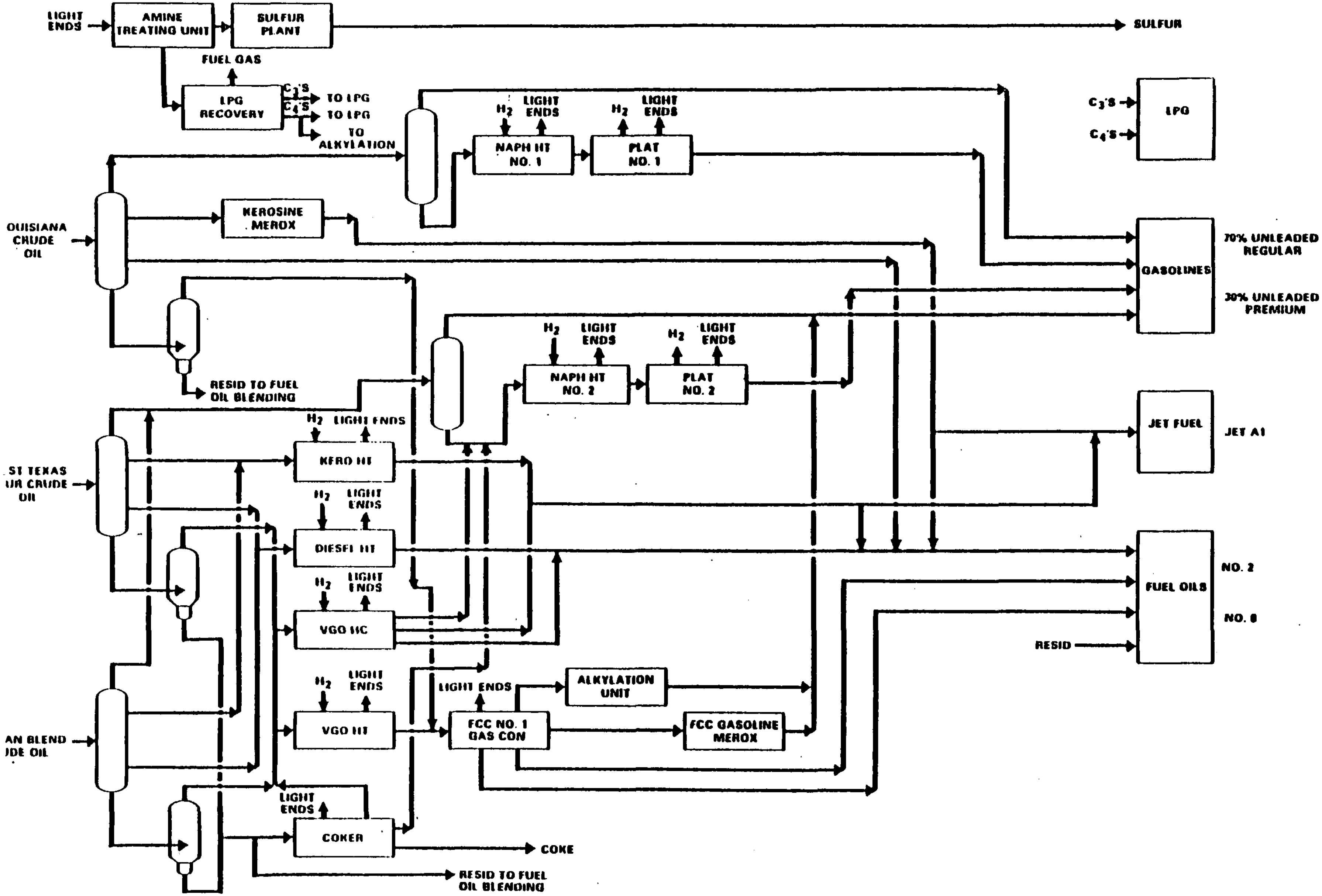
Feed and Product Summary[6]

Yields, BPCD	100% Petroleum	10% H-Coal
Feedstocks		
Louisiana	85,500	85,500
West Texas Sour	85,500	85,500
Arabian Blend	114,000	85,500
H-Coal Liquid	0	28,500
Butanes	12,255	10,260
Total	297,255	295,260
Products		
Unleaded Regular	93,195	91,485
Unleaded Premium	39,900	39,330
Jet Fuel	19,950	19,950
No. 2 Fuel Oil	93,765	98,325
No. 6 Fuel Oil	7,125	6,840
LPG	17,385	15,390
Total	271,320	271,320

FIGURE 4

GULF COAST REFINERY

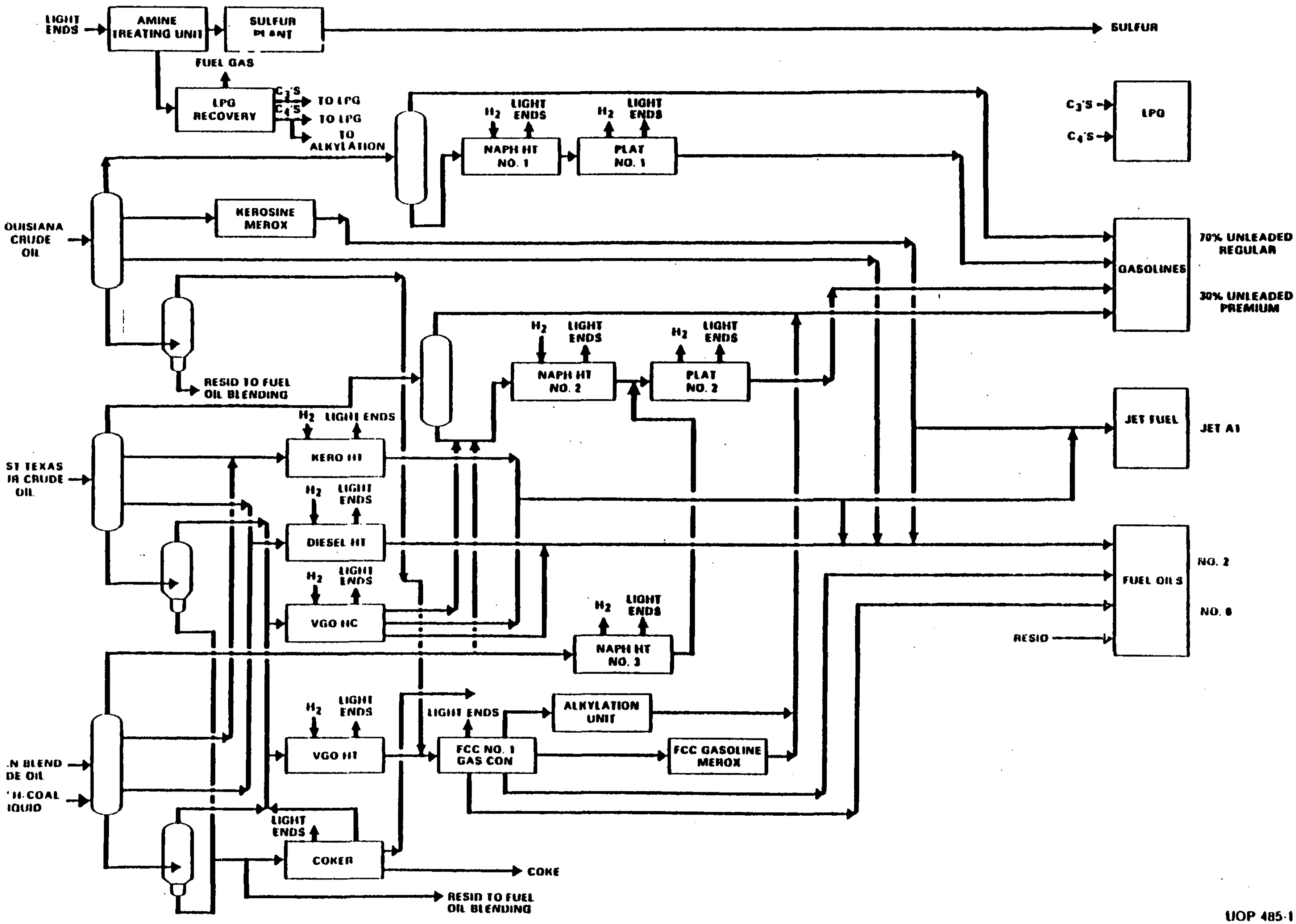
BASE CASE



-34-

FIGURE 5

GULF COAST REFINERY
RAW H-COAL LIQUID CASE



UOP 485-1

Table 14 lists the investment costs and operating costs for both the 285,000 BPCD petroleum refinery and the 285,000 BPCD integrated refinery. The total instantaneous investment (excluding working capital) in first quarter 1981 dollars is $1,383 million for the petroleum refinery and $1,423 million for the integrated refinery. This $40 million investment difference reflects the cost of retrofitting an existing refinery and thus enabling it to co-process 10 percent H-Coal liquid. Part of the capital cost increase for the H-Coal case is due to necessary increases in the capacities of catalytic reforming, kerosene hydrotreating and diesel hydrotreating. The annual operating costs of the integrated refinery are $18 million less than those of the petroleum refinery because of the lower feedstock butane requirement. Part of the lower butane requirement is due to the reduced HF (hydrofluoric acid) alkylation requirement for the integrated refinery; also less butane is needed for gasoline blending on account of the lower gasoline yield for the integrated case. These investment and operating cost differences essentially cancel each other with respect to product cost, as can be seen in Table 15. The product cost/FOEB is nearly the same for both the petroleum and integrated refineries.

V. Economic Comparison of Grass Root vs. Integrated Coal Liquid Refineries

A. H-Coal

The instantaneous capital cost of retrofitting the integrated H-Coal/petroleum refinery is $40 million. The operating cost savings is $18 million. These costs are based on feeding the refinery with 28,500 BPCD of H-Coal liquid which represents 10 percent of the total refinery feedstock. Since liquefaction plants are being designed to produce on the order of 50,000 FOEB/CD of syncrude, approximately two typical large refineries (285,000 BPCD) must be retrofitted in order to co-process H-Coal liquid. Therefore the capital cost increase of retrofitting two existing refineries, each processing 28,500 BPCD of H-Coal liquid, would be $80 million. Likewise the operating cost savings resulting from retrofitting two large petroleum refineries would be $36 million. The overall effect of retrofitting on product cost is negligible since the increased capital cost is balanced by a decreased operating cost.

A capital cost comparison between retrofitting existing refineries to co-process 57,000 FOEB/CD H-Coal versus building new refineries to process 100 percent H-Coal (57,000 FOEB/CD) shows that there is a $390 million capital cost savings for the retrofitting alternative. However, the UOP study upon which these figures are based, analyzed a new grass-roots petroleum refinery with modern technology which was then retrofitted to co-process 10 percent H-Coal liquid. The great majority of the actual refineries being retrofitted will not be new since the United States has

Table 13

Utility Summary[6]

	100% Petroleum	10% H-Coal
Electric Power, kw	31,100	29,900
Steam (42 k/cm^2) ton/hr	288	261
Steam (10.5 k/cm^2) ton/hr	177	161
Steam (3.5 k/cm^2) ton/hr	111	100
Cooling Water, M^3/hr	11,800	11,000
Fuel mBtu/hr	5,754	5,674

Table 14

Investment and Operating Costs
(Millions of First Quarter 1981 dollars)

	100% Petroleum	10% H-Coal
Investment Cost (Millions of Dollars)		
Onplot Investment	552	568
Offplot Investment	691	711
Contingency	124	128
Initial Catlyst and Chemicals	16	16
Total Instantaneous Investment	1383	1423
Working Capital	436	436
Total Instantaneous Capital Investment	1819	1859
Operating Cost (Millions of Dollars per Year)		
Butanes ($32.70/bbl)	146	123
Labor, Catalyst, Chemicals, and Utilities	74	75
Maintenance, Taxes, Insurance, GA and Depreciation	165	170
Total Operating Cost	385	367

Table 15

Refining Costs
(Millions of First Quarter 1981 dollars)

	100% Petroleum		10% H-Coal	
Capital Charge Rate, %	11.5	30	11.5	30
(Millions of Dollars)				
Total Instantaneous Investment	1383	1383	1423	1423
Total Adjusted Capital Investment	1568	1543	1614	1588
Annual Capital Charge	180	463	186	476
Annual Operating Cost	386	386	367	367
Total Annual Charge	560	849	552	843
Refining Cost				
$/FOEB	6.14	9.20	5.97	9.11
$/mBtu	1.04	1.56	1.01	1.55

excess refining capacity; the retrofitted refineries will be older refineries, and the cost of retrofitting the older refineries will probably be more than the cost of retrofitting the new grass-root petroleum refinery modeled by UOP. Therefore the $80 million retrofitting capital cost for co-processing 57,000 FOEB/CD of H-Coal represents a minimum cost. Likewise the operating cost resulting from the retrofitted new refineries also represent a minimum cost. Thus the overall refining cost for processing coal liquids in retrofitted refineries will be more for older petroleum refineries than for new ones.

B. SRC-II

There has not been any work examining an integrated SRC-II petroleum refinery. However, if the results obtained from the H-Coal processing are applied to the SRC-II syncrude by using the ratio of the H-Coal retrofitting cost to grass-root refinery cost, a cost estimate may be obtained for retrofitting two existing refineries enabling them to co-process 10 percent SRC-II syncrude (57,000 FOEB/CD). The instantaneous retrofitting cost calculated by following this procedure is $138 million (1 Q 1981) which is $670 million less than the total instantaneous capital cost of building a new grass-roots, 100 percent SRC-II refinery. It must be noted that the capital cost of the SRC-II grass root refinery is based on a 100 percent gasoline product slate and therefore represents an upper limit to the capital cost.

C. EDS

Because of the uncertainty of the capital cost for the refining of EDS coal liquids developed by ICF, it is difficult to approximate a retrofitting capital cost. However, since the quality of the EDS syncrude is between the quality of the H-Coal and SRC-II crudes, it is expected that the retrofitting cost would also be between those for H-Coal and SRC-II.

VI. Conclusion

The Chevron/SRC-II and UOP/H-Coal studies, together with the revised EDS cost have been found to best represent refining costs for the grass-root coal-liquid refineries. The refining costs vary from about $1.00 per mBtu for the H-Coal syncrude to about $2.00 per mBtu for the SRC-II syncrude when using a capital charge rate of 11.5 percent; they vary from about $2.00 per mBtu for the H-Coal syncrude to $4.00 per mBtu for the SRC-II syncrude when using a capital charge rate of 30 percent. The wide variance in the refining costs of the syncrudes is due to differences in feedstock properties, product slates, and level of engineering design. Based on feedstock properties only, the refining cost of the SRC-II syncrude is expected to be the most expensive, followed by that of the EDS crude and then the H-Coal crude.

The cost of co-processing a 10 percent H-Coal/90 percent petroleum crude blend in a typical large refinery was discussed and compared to the cost of refining 100-percent petroleum. The refining costs are nearly identical and vary from about $1.00 to 1.50 per mBtu depending on the capital charge rate.

The cost of retrofitting existing refineries to process syncrudes was estimated to be $80 million for H-Coal and $138 million for SRC-II. Capital cost savings resulting from processing the synthetic crudes in existing petroleum refineries rather than processing them in new grass root coal liquid refineries range from $390 million for the H-Coal syncrude to $670 million for the SRC-II syncrudes.

When comparing the refining cost of syncrudes from a new grass-roots refinery to those costs from a retrofitted petroleum refinery, it appears that their refining costs are nearly the same. For example, the H-Coal refining cost varies from $1.00-2.00/MBtu for a grass-roots refinery to $1.00-1.50/mBtu for a retrofitted refinery. However, of most importance is the savings in capital investment when refining syncrudes in retrofitted petroleum refineries.

References

1. "Identificaton of Probable Automotive Fuels Composition: 1985-2000," Prepared by SwRI for DOE, HCP/W3684-01/1.

2. Oil and Gas Journal, pp. 22, 45, 79, June 1, 1981.

3. Chemical Engineering, pp. 10, 75, 88, May 18, 1981.

4. "Aviation Turbine Fuels from Shale and Coal Oils," Shaw, Kalfadelis, Johnig, ER&E, Energy and Environment, 3rd Nat. Conf., Sept. 29-Oct. 1, 1975, Hueston Woods State Park, Ohio, AICHE/ENE-E-P3.

5. "Cost Comparisons of Alternative Routes for Converting SRC-II Oil to Distillate Fuels," Sullivan, Frumkin, Chevron Research Co., Presented at the EPRI Conference, San Francisco CA, October, 13-16, 1980.

6. Coal Liquid/Petroleum Refinery Integration, Gilder, Burton, UOP Inc., American Petroleum Institute, Preprint No. 38-80, May, 1980.

7. "Crude Oil vs. Coal Oil Processing Comparison Study," Conser, Garret, Weiszmann, UOP, Presented at AICHE, Boston, MA, August, 19-22, 1979.

7a. "The H-Coal and SRC-II Processes," Heiser, D., EPA-AA-SDSB-81-14, February 1982.

8. Methanol From Coal: Prospects and Performance as a Fuel and as a Feedstock, December 1980, ICF Incorporated.

9. Feasibility Study of Alternative Fuels for Automotive Transporatation, Exxon Research and Engineering Company, June 1974, prepared for EPA, EPA-460/3-74-009-a,b,c.

10. Alternate Energy Sources for Non-Highway Transportation, Exxon Research and Engineering Company, DOE/CS/05438-T1, June 1980.

11. "Project H-Coal," Hydrocarbon Research, Inc., 1967; Office of Coal Research Contract No. 14-01-0001-477.

12. Analytical Studies for the H-Coal Process, Mobil Research and Development Corp., Prepared for DOE, FE-2676-1,3.

13. "Upgrading of Coal Liquids," Annual Report, UOP Inc., Prepared for DOE, FE-2566-42.

14. EDS Coal Liquefaction Process Development, Phase V, EDS Commercial Plant Study Design Update, FE-2893-61, March 1981.

15. "The SRC-II Process," Presented at a discussion meeting on "New Coal Chemistry," Schmid, Jackson, Organized by The Royal Society, London, England, May 21-22, 1980, The Pittsburgh Midway Coal Mining Company.

16. "Engineering Evaluation of a Conceptual Coal Conversion Plant Using the H-Coal Liquefaction Process," Prepared by Fluor Engineers and Constructors, Inc. for the Electric Power Research Institute, EPRI-AF-1297, December, 1979.

17. Energy Review, Data Resources, Inc., Vol. 4, No. 1, Winter, 1980.

18. Refining and Upgrading of Synfuels from Coal and Oil Shales by Advanced Catalytic Processes, Third Interim Report, Processing of SRC-II Syncrude, Chevron Research Co., Prepared for DOE, FE-2315-47, March 1980.

19. "Exxon Donor Solvent Coal Liquefaction Process Development Program Status III," Epperly, Plumlee, Wade, Exxon Research and Engineering Co., Presented at EPRI Conference on Synfuels, San Francisco, CA, October, 13-16, 1980.

20. "American Society for Testing and Materials, Standard Classification of Diesel Fuels Oils (D975)," 1978 Annual Book of ASTM Standards, Part 23, Philadelphia, Pa., Nov. 1977, pp.449

21. Plant Design and Economics for Chemical Engineers, Peters, Timmerhaus, 2nd Edition, 1968, McGraw-Hill.