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Refining and End Use Study of Coal Liquids

Topical Report
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1. Introduction

1.1 Abstract

This report summarizes revisions to the design basis for the linear programing refinery model that is being used in the Refining and End Use Study of Coal Liquids. This revisions primarily reflect the addition of data for the upgrading of direct coal liquids.

1.2 Background - Refining and End Use Study of Coal Liquids

Bechtel National Inc., with Southwest Research Institute, Amoco Oil R&D, and The M.W. Kellogg Co. as subcontractors, initiated a study on November 1, 1993, for the U.S. Department of Energy's (DOE's) Federal Energy Technology Center (FETC) to determine the most cost effective combination of upgrading processes needed to make high quality, liquid transportation fuels from petroleum crude and direct and indirect coal liquefaction products in an existing petroleum refinery.

A key objective is to determine the most desirable ways of integrating coal liquefaction liquids into existing petroleum refineries to produce transportation fuels meeting current and future, e.g. year 2000, Clean Air Act Amendment (CAAA) standards. An integral part of the above objectives is to test the fuels or blends produced and compare them with established ASTM fuels. The comparison will include engine tests to ascertain compliance of the fuels produced with CAAA and other applicable fuel quality and performance standards.

The final part of the project includes a detailed economic evaluation of the cost of processing the coal liquids to their optimum products. The cost analyses is for the incremental processing cost; in other words, the feed is priced at zero dollars. The study reflects costs for operations using state of the art refinery technology; no capital costs for building of new refineries are considered. Some modifications to the existing refinery may be required. Economy of scale dictates the minimum amount of feedstock that should be processed.

1.3 Petroleum refinery linear programming model

In 1995, a model was developed for use in the PIMS (Process Industry Modeling System) linear programming (LP) software to simulate a generic Midwest/PADD II (Petroleum Administration for Defense District II) petroleum refinery of the future.

This "petroleum-only" version of the model establishes the size and complexity of the refinery after the year 2000 and prior to the introduction of coal liquids. It should be noted that no assumption has been made on when a coal liquefaction plant can be built to produce coal liquids except that it will be after the year 2000. The year 2000 was chosen because it is the latest year where fuel property and emission standards have been set by the Environmental Protection Agency. It assumes the refinery has been modified to 1) accept crudes that are heavier in gravity and higher in sulfur than today's average crude mix and 2) meet future product fuel specifications. This model will be used as a basis for determining the optimum scheme for processing coal liquids in a petroleum refinery.

A topical report[1] was issued which summarizes the design basis for this petroleum refinery LP

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1 Topical report "Petroleum Refinery Linear Programming Model Design Basis", Refining and End Use Study of Coal Liquids, March, 1995

model.

1.4 Modifications to the LP model for coal liquid processing

This topical report/addendum supplements the design basis for the petroleum refinery LP model. The primary focus of this addendum is to provide the design basis for direct coal liquid processing in the model. (Due to budgetary concerns, work on the indirect liquid has been suspended.)

In the Refining and End Use Study, two direct coal liquids, POC-1 and POC-2, are being evaluated. POC-1 (referred to as DL1 in this study) was produced from Eastern bituminous coal in the Hydrocarbon Technologies, Inc. (HTI) coal liquefaction system without the use of the in-line hydrotreater. POC-2 (referred to as DL2 in this study) was produced from Western coal in the same system, but with the use of the in-line hydrotreater.

The primary source of the data on these two liquids for this design basis was produced in Task 2 - Feed Characterization and Task 4 - Pilot Plant Testing of the Basic Program. In addition, this addendum summarizes changes to the petroleum refinery model. These revisions were primarily based on Task 4 data on petroleum feed materials.

Key topics covered in this addendum are:

- Revised product slate based on new energy consumption forecast
- Direct coal liquid characterization data
- Description of the LP model coal liquid processing schemes
- Process unit yields for petroleum and coal liquid feeds based on Task 4 pilot plant test data

1.5 Evaluation studies

The results of various evaluation studies will be provided in the final report on the Option 1 section of this study.

2. Refinery design basis

2.1 Location - PADD II

The Petroleum Administration for Defense District II (PADD II) was selected as the basis for the location and product marketing for the generic midwestern refinery used in the LP model. This area encompasses 14 central U.S. states and has 35 refineries with a total refining capacity of approximately 3.4 million barrels per calendar day (bpcd). These 35 refineries range in size from 4,000 bpcd to 410,000 bpcd. Tables 2-1 and 2-2 summarizes the capacity and location of the PADD II refineries.

2.2 Product Slate

Since energy consumption data was not available specifically for PADD II, data for determining the product slate for the refinery model was based on a DOE Energy Information Administration report[2].

This report summarizes energy consumption by U.S. Census Divisions. These divisions are smaller and do not coincide with the PADD districts. However, by combining U.S. Census Divisions 3, 4 and 6, an area approximately equal to PADD II can be obtained. The exceptions are the states Oklahoma, Alabama and Mississippi. The U.S. Census Divisions do not include Oklahoma, but include Alabama and Mississippi. The combined refining capacity data for U.S. Census Divisions 3, 4 and 6 are shown in Tables 2-3 and 2-4.

2.2.1 Comparison of total refinery capacity

A comparison of Tables 2-1 and 2-3 show that the total refining capacity difference between the combined U.S. Census Divisions and PADD II is small (1.5%) and should not impact the LP model results.

2.2.2 Revised product slate

The EIA report provides an estimate of future energy consumption for each of the U.S. Census Divisions in quads per year (10^{15} btu/year). For the three divisions (No. 3, 4, and 6) representing the PADD II region, the energy consumptions were totaled and are summarized in Table 2-5. These rates were then converted to barrels per day (bpsd) and normalized to a 150,000 bpsd crude feed rate. The revised product slate is shown in Table F-1 of the Appendix

2.3 Projected conventional/reformulated gasoline ratio

The split between conventional and reformulated gasoline was previously assumed to be 60/40 on a volume basis. Based on the EIA projections for the year 2000 (shown in Table 2-6), the production ratio between conventional and reformulated gasolines was revised to 75/25.

2.4 Projected regular/premium gasoline ratio

The ratio between regular and premium gasoline was previously assumed to be 60/40. Table 2-7 shows the ratio of regular and premium gasoline consumption for 1995 in PADD II. Approximately 25% of the PADD II market was for premium and mid-grade gasolines. The

[2] "Supplement to the Annual Energy Outlook 1995", Department of Energy/Energy Information Agency, February, 1995, DOE/EIA-0554(95)

regular/premium gasoline ratio was revised to 75/25[3].

[3] Hart's 21st Century Fuels, November, 1995

Table 2-1 PADD II Refinery Total Capacities

States	No. of refineries	Total crude capacity, bpcd
Michigan	4	125,200
Ohio	4	466,400
Indiana	3	435,990
Kentucky	2	224,800
Tennessee	1	90,000
Wisconsin	1	33,200
Illinois	6	906,550
Minnesota	2	314,000
Missouri	0	0
North Dakota	1	58,000
South Dakota	0	0
Nebraska	0	0
Kansas	4	302,950
Oklahoma	7	417,900
Total	35	3,374,990

Table 2-2 Comparison of Refinery Crude Capacity by State - PADD II

	No. of refineries with crude capacity, bpcd				
State	<50,000	50,000 to 90,000	90,001 to 200,000	200,001 to 300,000	>300,000
Michigan	3	1			
Ohio		1	3		
Indiana	2				1
Kentucky	1			1	
Tennessee		1			
Wisconsin	1				
Illinois		2	2	2	
Minnesota		1		1	
Missouri					
North Dakota		1			
South Dakota					
Nebraska					
Kansas		3	1		
Oklahoma	3	4			
Total	10	14	6	4	1

Table 2-3 U.S. Census Divisions 3, 4 & 6 Refining Capacity

States	No. of refineries	Total crude capacity, bpcd	Division - Description
Michigan	4	125,200	3-East North Central
Ohio	4	466,400	3-East North Central
Indiana	3	435,990	3-East North Central
Wisconsin	1	33,200	3-East North Central
Illinois	6	906,550	3-East North Central
Kentucky	2	224,800	6-East South Central
Tennessee	1	90,000	6-East South Central
Alabama	3	130,000	6-East South Central
Mississippi	4	336,800	6-East South Central
Minnesota	2	314,000	4-West North Central
Missouri	0	0	4-West North Central
North Dakota	1	58,000	4-West North Central
South Dakota	0	0	4-West North Central
Nebraska	0	0	4-West North Central
Iowa	0	0	4-West North Central
Kansas	4	302,950	4-West North Central
Total	35	3,423,890	

Table 2-4 Comparison of Refinery Crude Capacity by State - U.S. Census Divisions 3, 4 & 6

	No. of refineries with crude capacity, bpcd				
State	<50,000	50,000 to 90,000	90,001 to 200,000	200,001 to 300,000	>300,000
Michigan	3	1			
Ohio		1	3		
Indiana	2				1
Kentucky	1			1	
Tennessee		1			
Wisconsin	1				
Illinois		2	2	2	
Minnesota		1		1	
Missouri					
North Dakota		1			
South Dakota					
Nebraska					
Kansas		3	1		
Iowa					
Alabama	2	1			
Mississippi	3			1	
Total	**12**	**11**	**6**	**5**	1

Table 2-5 Projected Fuel Consumption for the Year 2000 for U.S. Census Divisions 3, 4 and 6[4]

	Projected		
	Quads/yr	bpcd/ref	%
Gasoline	4.638	113,407	62.55
Kerosene/Jet	0.658	15,007	8.28
No. 2 Fuel Oil	0.694	15,303	8.44
Diesel	1.577	34,774	19.18
Residual Fuel	0.138	2,819	1.56
Subtotal		181,310	100.00
Petro Coke & Asphalt	1.109	22,503	
Total Includ. Coke & Asphalt		203,813	

4 "Supplement to the Annual Energy Outlook 1995", Department of Energy/Energy Information Agency, February, 1995, DOE/EIA-0554(95)

Table 2-6 Percentage Market Share for Gasoline Types by Census Divisions for Year 2000[5]

Gasoline Type	Division 3	Division 4	Division 6
Traditional	76%	74%	92%
Oxygenated (2.7% oxygen)	0%	26%	1%
Reformulated (2.0% oxygen)	24%	0%	7%

Table 2-7 Percentage Market Share for Gasoline Grades for June 1995 for PADD II[6]

	U.S. Gallons	% of Total Gasoline
Regular	2,307,043	73.95
Mid Grade	313,641	10.05
Premium	499,179	16.00
Total	3,119,863	100.00

[5] "Supplement to the Annual Energy Outlook 1995", Department of Energy/Energy Information Agency, February, 1995, DOE/EIA-0554(95)
[6] Hart's 21st Century Fuels, November, 1995

3. Direct coal liquid design basis

3.1 Feed characterization

To properly evaluate the coal liquids using the LP model, characterization data was required on the neat liquids and their fractionated cuts. This data is especially important if the neat cuts are used directly in product blending.

Characterization data for the DL1 and DL2 liquids was obtained in two steps. First, the whole liquids were measured for general properties such as specific gravity, sulfur content. Second, each liquid was then fractionated into four cuts; light naphtha (C5-180°F), medium naphtha (180-350°F), light distillate (350-500°F), and heavy distillate (500+°F).

The properties for the four coal liquid fractions are shown in Tables 3-1 to 3-4 for both liquids. These tables show only property data that was inputed into the model. Additional property data has been reported in various monthly and quarterly progress reports. As noted in these reports, the coal liquids are highly hydrogenated, desulfurized and denitrified.

3.2 Process flow

In the petroleum refinery LP model, each upgrading step (naphtha hydrotreating, catalytic cracking, etc.) is represented by a separate "submodel". Each of these submodels determine key parameters such as the feed material, volumetric yield, utilities, etc. for that particular upgrading step. For the coal liquids, new submodels were created. These submodels "process" only coal liquids and contain the process parameters pertaining to those coal liquid feeds.

The products from the sister petroleum and coal liquid submodels are mixed together before they can be further processed or blended into the required products. For example, the product from the petroleum naphtha hydrotreater is mixed with the product from the coal liquid naphtha hydrotreater. The reason that this is done is that the two submodels represent a single physical upgrading unit operating at a single operating condition. In this physical unit, the petroleum and coal liquids are co-fed and the product yields are based on this feed blend.

Table 3-5 identifies the petroleum and coal liquid submodels for the five upgrading steps that were tested in the Task 4 - Pilot Plant Testing program.

Figures 3-1 to 3-3 are block flow diagrams of the model showing the processing configuration for the coal liquid fractions.

3.2.1 Naphtha processing

Figure 3-1 depicts the processing schemes for the coal liquid naphthas. The light naphtha fraction is sent to the isomerization unit for octane improvement. The medium naphtha is hydrotreated to remove sulfur and nitrogen to 0.5 ppmw for reformer catalyst considerations. The treated medium naphtha is then dehexanized and sent to the reformer for octane improvement. The dehexanizer overhead containing benzene and benzene precursors is blended with the light naphtha for isomerization. As mentioned previously, the model has been configured so that the co-processing of petroleum and coal liquid is simulated.

The yield data shown in Tables C-6A, C-6B and C-6C show that the reformer yields are significantly higher for the two direct coal liquid naphthas than for the petroleum naphtha. These differences result in higher overall values for the direct coal liquids.

3.2.2 Light distillate processing

Figure 3-2 shows the processing scheme for the coal liquid light distillate. Both the DL1 and the DL2 light distillates have excellent sulfur and nitrogen properties. Since the DL2 liquid was more severely hydrogenated during production, its smoke point is slightly higher. Table C-2 shows that hydrotreating the DL1 light distillate results in a small improvement in the smoke point (8.5 to 12.5 mm), while there is no improvement in the smoke point of the DL2 light distillate.

3.2.3 Heavy distillate processing

Figure 3-3 shows the processing for the heavy distillate coal liquid. These distillates can be either sent to blending, to hydrotreating or to catalytic cracking (either directly or through the hydrotreater). Preliminary LP analysis showed that the slight improvement in FCC yield from hydrotreating the DL1 heavy distillate did not justify the costs of hydrotreating (increased capital expenditure, hydrogen, utilities, etc.). For this reason it was decided that conducting pilot plant hydrotreating tests on the DL2 heavy distillate was unnecessary. Therefore, the DL2 heavy distillate bypasses the hydrotreating unit and goes to cat cracking or blending directly.

Figure 3-1 Coal Liquid Naphtha Processing

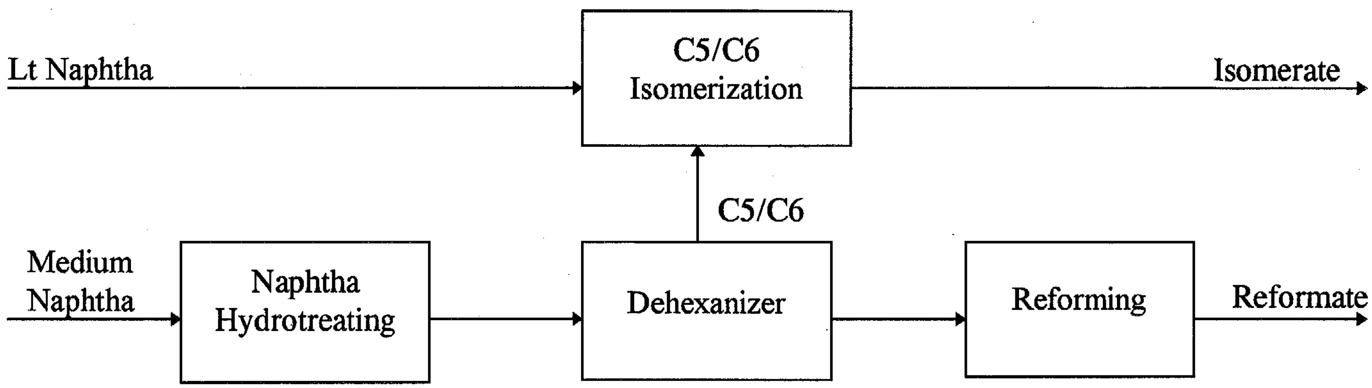

Figure 3-2 - Light Distillate Processing

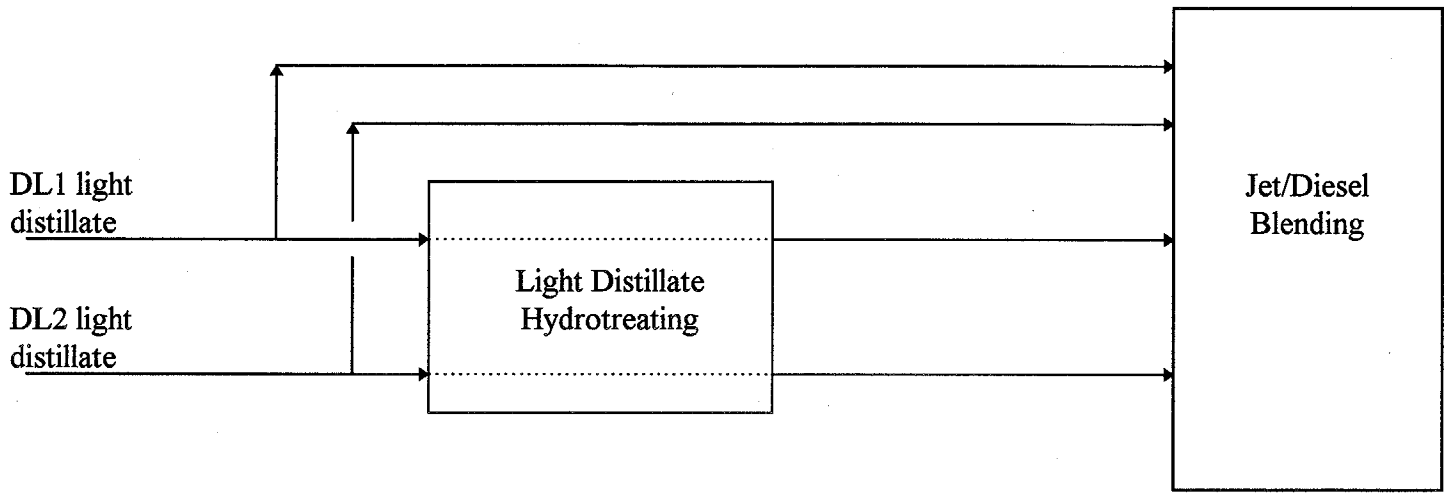

Figure 3-3 - Heavy Distillate Processing

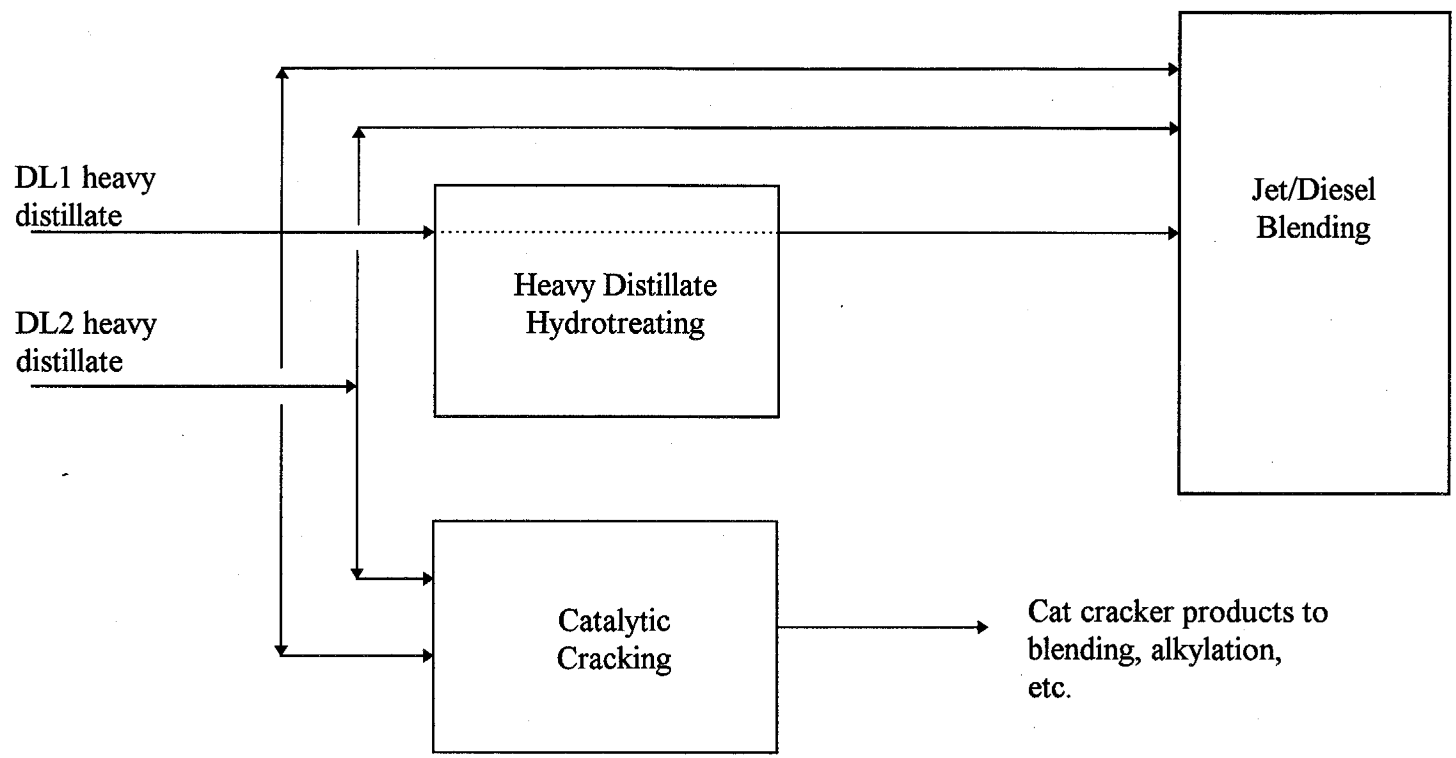

Table 3-1 Properties of DL1 & DL2 Light Naphtha

	DL1	DL2
API	64.7	60.6
Sulfur, wt%	0.015	0.004
Nitrogen, wt%	0.005	<1 ppm
Paraffins, vol%	92.9	97.2
Olefins, vol%	4.4	0.9
Aromatics, vol%	2.7	1.9
RON	78	----
MON	61.6	----

Table 3-2 Properties of DL1 & DL2 Medium Naphtha

	DL1	DL2
API	46.7	49.7
Sulfur, wt%	0.069	0.005
Nitrogen, wt%	0.021	<1 ppm
Paraffins, vol%	83.0	91.9
Olefins, vol%	4.5	0.8
Aromatics, vol%	12.5	7.3
RON	81	<60
MON	78	<60

Table 3-3 Properties of DL1 & DL2 Light Distillate

	DL1	DL2
API	30	32.3
Sulfur, wt%	0.023	0.001
Nitrogen, wt%	0.066	0.005
Paraffins, vol%	36.7	74.3
Olefins, vol%	4.6	1.7
Aromatics, vol%	58.7	24.0
Cetane Index	25.0	27.8
Smoke Point, mm	8.5	14.5

Table 3-4 Properties of DL1 & DL2 Heavy Distillate

	DL1	DL2
API	22.3	23.3
Sulfur, wt%	0.021	0.002
Nitrogen, wt%	0.049	0.004
Paraffins, vol%	46.3	59.7
Olefins, vol%	2.4	3.5
Aromatics, vol%	51.3	36.8
Cetane Index	34.7	34.2
Smoke Point, mm	7.3	10.0

Table 3-5 Submodel Summary

	Petroleum Submodel	DL1 Submodel	DL2 Submodel
Naphtha hydrotreating	SNHT	SNH2	SNH2
Naphtha reforming	SLPR	SLP1	SLP2
Light distillate hydrotreating	SKHT	SKH2	SKH2
Heavy distillate hydrotreating	SDHT, SDH2, SDHS	SDH3	none
Catalytic cracking	SCCU	SCCU[1]	SCCU[1]

[1] For simplification purposes the catalytic cracking model handles both petroleum and coal liquid feeds.

4. Appendices

The tables provided in Appendices B, C, and F were originally included in the topical report on the petroleum refinery model. These tables have been updated and/or revised to include the direct coal liquid upgrading data. The following updated tables are included:

- Appendix B - Process Unit Capacities - (Table B-1)
- Appendix C - Process Unit Yields -

    Naphtha hydrotreating (Table C-1)

    Light distillate/kerosene hydrotreating (Table C-2)

    Heavy distillate hydrotreating (Tables C-3A,B)

    Reforming (Tables C-6A,B,C)

    Catalytic cracking (Tables C-7A,B,C)

- Appendix F - Product slate and prices - (Table F-1).

4.1 Appendix B - Process Unit Capacities

Table B-1 - Unit capacities - 1993 and Base

Plant	1993 Base Capacities, Mbpsd	Year 2000 Base Capacities, Mbpsd
Atmospheric column		145.1
Vacuum column		67.0
Sulfuric acid alkylation	12.0	12.4
Isomerization	8.4	9.7
MTBE/TAME	0.6	1.8
ETBE/TAEE	0.0	0.0
Naphtha hydrotreater	44.9	26.4
Kerosene hydrotreater	6.0	9.6
Low severity cracked distillate hydrotreater	11.6	6.0
High severity cracked distillate hydrotreater	0.0	2.2
Low severity SR distillate hydrotreater	19.0	24.7
Gas oil hydrotreater	16.3	9.2
Atmospheric resid desulfurization	0.0	2.0
Catalytic reformer	38.6	24.4
Catalytic cracker	54.2	54.6
Hydrocracker	6.6	6.6
Delayed coker	17.4	20.4
Depentanizer		35.0
Dehexanizer		26.5
Hydrogen plant	11 MMSCFD	16 MMSCFD
Sulfur plant		162 LT/D

4.2 Appendix C - Process Unit Yields

The values shown in the following tables are the base yields for the given feed quality. For petroleum feeds these yields vary according to certain feed properties. For example, in the hydrotreaters the yield of hydrogen sulfide increases as the feed sulfur content increases. For coal liquid feeds, the yields and properties are fixed.

Table C-1 - Naphtha hydrotreating

Feed	SR & coker medium naphtha	DL1 coal liquid	DL2 coal liquid
Feed API	54.0	46.7	49.7
Feed sulfur content, wt%	1.43	0.069	0.005
% desulfurization	99.9	99.99	99.99
Hydrogen, scf/bbl	100	10	139
Product yields, vol% of feed			
Hydrogen sulfide (FOE)	0.44	0.02	0.00
Methane (FOE)	0.06	0.06	0.06
Ethane (FOE)	0.09	0.09	0.09
Propane	0.06	0.06	0.06
N-Butane	0.35	0.35	0.35
Naphtha	99.2	99.70	99.64
Utilities, per bbl of feed			
Fuel, MMBtu	0.026	0.026	0.026
Power, KWH	0.68	0.68	0.68
Steam, MLbs	0.002	0.002	0.002
Cooling water, MGals	0.001	0.001	0.001
Catalyst and chemicals, $	0.019	0.019	0.019

Table C-2 - Light distillate (kerosene) hydrotreating

Feed	SR Light Distillate	DL1 Light Distillate	DL2 Light Distillate
Feed API	43.4	30.0	32.3
Feed sulfur content, wt%	0.28	0.023	0.001
Feed smoke point, mm	22.1	8.5	14.5
Product smoke point, mm	22.1	12.5	14.5
% desulfurization	90	99	99
Hydrogen, scf/bbl	60	120	120
Product yields, vol% of feed			
Hydrogen sulfide (FOE)	0.08	0.01	0.00
Methane (FOE)	0.20	0.22	0.22
Ethane (FOE)	0.01	0.01	0.01
Propane	0.02	0.03	0.03
N-Butane	0.12		
Naphtha	0.45		
Distillate	99.30	100.08	100.08
Utilities, per bbl of feed			
Fuel, MMBtu	0.029	0.029	0.029
Power, KWH	1.62	1.62	1.62
Steam, MLbs	0.006	0.006	0.006
Cooling water, MGals	0.003	0.003	0.003
Catalyst and chemicals, $	0.038	0.038	0.038

Table C-3A - Heavy distillate hydrotreating - petroleum

Severity and feed type	Low Severity Distillate HDT - Cracked Feed	High Severity Distillate HDT - Cracked Feed	Distillate HDT - SR Distillate
Feed API	34.8	24.3	34.8
Feed sulfur content, wt%	0.77	0.76	0.77
% desulfurization	60	95.5	97
Hydrogen, scf/bbl	100	330	125
Product yields, vol% of feed			
Hydrogen sulfide (FOE)	0.16	0.27	0.26
Methane (FOE)	0.20	0.20	0.20
Ethane (FOE)	0.01	0.01	0.01
Propane	0.02	0.02	0.02
N-Butane	0.15	0.6	0.18
Naphtha	0.58	2.3	0.66
Distillate	100.10	98.30	98.30
Utilities, per bbl of feed			
Fuel, MMBtu	0.031	0.031	0.031
Power, KWH	1.767	1.767	1.767
Steam, MLbs	0.007	0.007	0.007
Cooling water, MGals	0.003	0.003	0.003
Catalyst and chemicals, $	0.041	0.041	0.041

Table C-3B - Heavy distillate hydrotreating - DL1 coal liquid

Feed	DL1 heavy distillate
Feed API	22.4
Feed sulfur content, wt%	0.03
Feed cetane index	34.0
Product cetane index	35.6
% desulfurization	87
Hydrogen, scf/bbl	212
Product yields, vol% of feed	
Hydrogen sulfide (FOE)	0.01
Methane (FOE)	0.23
Ethane (FOE)	0.01
Propane	0.04
N-Butane	0.00
Naphtha	0.00
Distillate	100.60
Utilities, per bbl of feed	
Fuel, MMBtu	0.031
Power, KWH	1.767
Steam, MLbs	0.007
Cooling water, MGals	0.003
Catalyst and chemicals, $	0.041

Table C-6A - Low pressure reforming - petroleum

Severity level	1	2	3	4
Feed API	55.6	55.6	55.6	55.6
Product research octane	88	92	96	100
Product yields, vol% of feed				
Hydrogen (FOE)	5.08	5.84	8.88	15.19
Methane (FOE)	0.63	1.02	1.56	2.44
Ethane (FOE)	1.32	2.05	3.02	4.38
Propane	3.35	6.32	9.71	13.41
Iso-butane	1.21	1.74	2.78	3.61
N-butane	2.59	3.35	4.28	5.62
Reformate	85.75	81.55	75.37	66.52
Utilities, per bbl of feed				
Fuel, MMBtu	0.274	0.277	0.280	0.282
Power, KWH	4.755	4.803	4.852	4.900
Steam, MLbs	0.057	0.057	0.058	0.059
Cooling water, MGals	0.089	0.090	0.091	0.092
Catalyst and chemicals, $	0.083	0.083	0.084	0.085

Table C-6B - Low pressure reforming - DL1 medium naphtha

Severity level	1	2	3	4
Feed API	49.0	49.0	49.0	49.0
Product research octane	88	92	96	100
Product yields, vol% of feed				
Hydrogen (FOE)	6.11	8.9	11.12	14.04
Methane (FOE)	0.08	0.22	0.47	2.03
Ethane (FOE)	0.36	0.94	2.01	3.96
Propane	1.17	2.09	5.02	11.49
Iso-butane	0.25	0.39	0.87	1.78
N-butane	0.50	0.98	1.97	3.98
Reformate	93.94	90.54	85.31	73.95
Utilities, per bbl of feed				
Fuel, MMBtu	0.274	0.277	0.280	0.282
Power, KWH	4.755	4.803	4.852	4.900
Steam, MLbs	0.057	0.057	0.058	0.059
Cooling water, MGals	0.089	0.090	0.091	0.092
Catalyst and chemicals, $	0.083	0.083	0.084	0.085

Table C-6C - Low pressure reforming - DL2 medium naphtha

Severity level	1	2	3	4
Feed API	49.4	49.4	49.4	49.4
Product research octane	88	92	96	100
Product yields, vol% of feed				
Hydrogen (FOE)	3.73	6.52	8.76	11.45
Methane (FOE)	0.00	0.01	0.29	1.27
Ethane (FOE)	0.15	0.29	0.68	2.24
Propane	0.31	0.62	2.23	6.93
Iso-butane	0.14	0.28	0.56	1.67
N-butane	0.20	0.40	1.07	3.08
Reformate	92.86	90.93	87.5	78.71
Utilities, per bbl of feed				
Fuel, MMBtu	0.274	.277	.280	.282
Power, KWH	4.755	4.803	4.852	4.900
Steam, MLbs	0.057	0.057	0.058	0.059
Cooling water, MGals	0.089	0.090	0.091	0.092
Catalyst and chemicals, $	0.083	0.083	0.084	0.085

Table C-7A - Catalytic cracking - petroleum gas oil feed

Reactor outlet temperature	975	1010
Feed API	26.4	26.4
Product yields, vol% of feed		
Hydrogen (FOE)	0.45	0.67
Hydrogen sulfide (FOE)	0.03	0.03
Methane (FOE)	1.06	1.40
Ethylene (FOE)	1.21	1.47
Ethane (FOE)	0.74	0.98
C3 mixture	13.63	15.72
C4 mixture	18.37	19.25
Light naphtha	51.33	48.42
Heavy naphtha	9.03	8.54
Diesel	17.70	17.52
Slurry	4.75	4.71
Naphtha Properties:		
RON, light naphtha	92.8	95.3
heavy naphtha	87.1	89.6
MON, light naphtha	82.8	85.3
heavy naphtha	77.1	79.6
Aromatics, vol%	31.3	36.3
Olefins, vol%	11.1	11.1
Utilities, per bbl of feed		
Fuel, MMBtu/bbl	0.135	0.135
Steam, MLbs	0.038	0.038
Cooling water, MGals	0.012	0.012
Catalyst and chemicals, $	0.113	0.113

Table C-7B - Catalytic cracking - DL1 heavy distillate

Description	Neat	Neat	Hydrotreated	Hydrotreated
Reactor temperature, °F	975	975	1010	1010
Feed API	22.5	22.5	23.3	23.3
Product yields, vol% of feed				
Hydrogen (FOE)	0.63	0.95	0.74	1.11
Hydrogen sulfide (FOE)	0.001	0.00	0.003	0.003
Methane (FOE)	0.64	0.93	0.74	1.07
Ethylene (FOE)	0.79	0.98	0.86	1.08
Ethane (FOE)	0.52	0.71	0.56	0.77
C3 mixture	8.63	9.70	9.42	10.58
C4 mixture	11.90	12.22	12.55	12.86
Light naphtha	53.10	51.46	53.31	51.54
Heavy naphtha	9.37	9.08	9.41	9.10
Diesel	26.96	26.58	25.33	24.92
Slurry	3.37	3.39	3.33	3.36
Naphtha Properties:				
RON, light naphtha	92.8	92.8	92.8	92.8
heavy naphtha	87.1	87.1	87.1	87.1
MON, light naphtha	82.8	82.8	82.8	82.8
heavy naphtha	77.1	77.1	77.1	77.1
Aromatics, vol%	31.3	31.3	31.3	31.3
Olefins, vol%	11.1	11.1	11.1	11.1
Utilities, per bbl of feed				
Fuel, MMBtu/bbl	0.200	0.182	0.199	0.181
Steam, MLbs	0.038	0.038	0.038	0.038
Cooling water, MGals	0.012	0.012	0.012	0.012
Catalyst and chemicals, $	0.113	0.113	0.113	0.113

Table C-7C - Catalytic cracking - DL2 heavy distillate

Reactor outlet temperature	975	1010
Feed API	23.3	23.3
Product yields, vol% of feed		
Hydrogen (FOE)	0.57	1.04
Hydrogen sulfide (FOE)	0.00	0.00
Methane (FOE)	0.71	1.24
Ethylene (FOE)	1.06	1.41
Ethane (FOE)	0.52	0.79
C3 mixture	11.29	13.02
C4 mixture	14.27	14.80
Light naphtha	57.21	55.26
Heavy naphtha	10.10	9.75
Diesel	19.38	17.97
Slurry	3.57	3.56
Naphtha Properties:		
RON, light naphtha	92.8	95.3
heavy naphtha	87.1	89.6
MON, light naphtha	82.8	85.3
heavy naphtha	77.1	79.6
Aromatics, vol%	38.6	41.4
Olefins, vol%	4.7	5.4
Utilities, per bbl of feed		
Fuel, MMBtu/bbl	0.135	0.135
Steam, MLbs	0.038	0.038
Cooling water, MGals	0.012	0.012
Catalyst and chemicals, $	0.113	0.113

4.3 Appendix F - Product Slate and Pricing

Table F-1 - Product slate and pricing

	BPSD	$/BBL
LPG		12.66
Unleaded regular gasoline	54,600	28.25
Unleaded premium gasoline	18,200	29.16
Reformulated regular gasoline	18,200	29.03
Reformulated premium gasoline	6,070	29.76
Kerosene/Jet fuel	12,840	19.36
No. 2 fuel oil	13,100	19.08
Low sulfur diesel	15,770	19.46
High sulfur diesel	13,990	19.08
Low sulfur fuel oil	-	17.70
Asphalt	-	15.6
Anode-grade coke, short tons		75.00
Fuel-grade coke, short tons		3.00
Cat slurry		10.00
Sulfur, long tons		89.60