RESEARCH GUIDANCE STUDIES TO
ASSESS GASOLINE FROM COAL BY
METHANOL-TO-GASOLINE AND SASOL-TYPE
FISCHER-TROPSCH TECHNOLOGIES

INTERIM REPORT

MAX SCHREINER

MOBIL RESEARCH AND DEVELOPMENT CORPORATION
PRINCETON, NEW JERSEY 08540

CONTRIBUTORS:

H. FRITZSCHE (LURGI MINERALOELTECHNIK GMBH)
A. J. DIMATTIO (MOBIL RESEARCH AND DEVELOPMENT CORP.)
A. M. PESKIN (AMERICAN LURGI CORP.)

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ABSTRACT

The primary purpose of this study is to provide a technical and economic comparison between the commercial Fischer-Tropsch technology and the new Mobil methanol-to-gasoline technology for the production of motor gasoline. Several technical sensitivity cases are also part of the study.

Two conceptual plant complexes - Base Case I: Mobil Technology and Base Case II: Fischer-Tropsch Technology - have been developed. They are self-supporting, grass roots facilities assumed to be located in a Wyoming coal field. Plant size is equivalent to the proposed large commercial SNG plants. Except for the Mobil methanol conversion technology, all processes used are commercial. Co-production of all products has been assumed. Products have been upgraded to meet U.S. market specifications.

A summary comparison between the two base cases is as follows:

	<u>Base Case I</u>	<u>Base Case II</u>
Technology	Mobil Methanol Conversion	Fischer-Tropsch
Net Coal Input, MST/SD	26.1	27.7
Product Output, Bbl/SD(1)	50,075	48,760
SNG, %	48.5	59.4
Gasoline, %	44.0	27.9
Others, %	7.5	12.7
Thermal Efficiency (HHV), %	62	58
Processing Steps (2)	9	18

(1) SNG converted to barrels FOE @ 6.0 MMBtu/Bbl

(2) From clean syn gas to final co-products

The Mobil technology is somewhat more efficient and more effective in producing gasoline. Moreover, the number of processing steps required is considerably fewer.

All products meet the target specifications.

The technical discussions of the sensitivity cases and the economic phase of the study will be added in the final report.

SUMMARY

The following interim report only covers the technical development of the two base cases. In the final report, the technical development of the sensitivity cases, the economic phase and the conclusions will be added.

The primary purpose of this scoping study is to provide a technical and economic comparison between the commercial Fischer-Tropsch technology and the new Mobil methanol-to-gasoline technology for the production of motor gasoline. The primary coal gasification step uses the commercial Lurgi dry-ash, moving-bed pressure gasifier. Several technical sensitivity cases are also part of the investigation. The base and sensitivity cases developed are summarized below:

	Base Cases		-----Sensitivity Cases-----				
	I	II	I-A	I-B	I-C	I-D	II-A
<u>Capacity Basis</u>	Constant Syngas		Constant Syngas			Base Case I Gasoline	Constant Syngas
<u>Technology</u>							
Gasification*	L	L	L	L	L	W	L
Conversion	Mobil Fixed Bed	Fischer-Tropsch	MeOH only	Mobil Fixed Bed	Mobil Fluid Bed	Mobil Fixed Bed	Mobil Direct Route
<u>Major Products</u>							
SNG	X	X	X	-	X	-	X
Gasoline et al	X	X	-	X	X	X	X
Methanol	-	-	X	-	-	-	-

*L - Commercial Lurgi moving-bed pressure gasifier.

W - Winkler fluid-bed pressure gasifier under development.

The study bases adopted, essentially, follow those established in "Coal Gasification Commercial Concepts Gas Cost Guidelines", Reference 1. The conceptual plant complex developed for each case is a self-supporting, grass roots facility, assumed to be located adjoining a strip mine in Wyoming. Plant size is equivalent to the large 280 MMSCF/SD commercial SNG plants under consideration for Western coal. Except for the Mobil technology, all processes used are commercially available.

Co-production of all products has been generally assumed. No marketing restrictions have been imposed. Products, however, have been upgraded to meet U.S. market specifications, or in the case of SNG, to be interchangeable with pure methane.

The overall material balances for Base Case I and II are shown below:

Technology	Case I Mobil Methanol Conversion	Case II Fischer-Tropsch
Input		
Coal, as received, T/SD	27,334	27,698
Water, gpm	8,320	8,750
Output		
SNG, MMSCF/SD	148.5	173.3
C ₃ LPG, Bbl/SD	1,555	1,107
C ₄ LPG, Bbl/SD	2,205	146
10 RVP Gasoline, Bbl/SD	22,045	13,580
Diesel Oil, Bbl/SD	--	2,307
Heavy Fuel Oil, Bbl/SD	--	662
Alcohols, Mlb/SD	--	510
Sulfur, T/SD	61	61
Ammonia, T/SD	102	102
Coal Fines (excess), T/SD	1,230	0
Power (excess), MW	6.0	6.0
Thermal Efficiency (HHV), %	62.2	57.8

The Mobil technology is somewhat more efficient and more effective in producing gasoline. The different yield patterns of the two technologies are readily seen. A higher hydrocarbon liquid/SNG thermal split (HHV) is obtained with the Mobil technology.

HC Liquid/SNG

Case I:	47/53
Case II:	34/66

The steam/power balance is satisfactory for both cases as only minor amounts of surplus power are obtained. In Case I, the thermal balance does not require the usage of all the coal fines produced during coal crushing. Greater energy requirements result in an additional 1,594 T/SD of coal being fired in Case II. For both cases, about 6 barrels of water are required per barrel of total FOE product.

The plant complexity necessary to convert the synthesis gas into marketable products is much greater when using the Fischer-Tropsch technology. The conceptual plant designs call for 18 units in Case II compared to only 9 units in Case I.

The SNG properties are summarized below:

Technology	Case I Mobil Methanol Conversion	Case II Fischer-Tropsch
Composition, %		
H ₂	1.7	3.8
C ₁	95.5	89.7
C ₂ =	--	1.0
C ₂	0.2	2.3
C ₃ =	--	1.0
C ₃	0.1	0.1
C ₄	0.1	--
CO ₂	0.5	0.5
Inerts	1.9	1.6
	<u>100.0</u>	<u>100.0</u>
Heat of Combustion (HHV), Btu/SCF	980	1,003
Compatibility Indexes (vs. Pure Methane)		
Lifting (I ₁)	1.03*	0.99
Flash-Back (I _f)	1.02	1.06
Yellow-Tip (I _y)	1.05	0.97*

*Between preferable and objectionable values.

The SNG compositions differ reflecting the nature and amount of the offgases from the methanol conversion and Fischer-Tropsch sections. Both appear interchangeable with pure methane.

The estimated unleaded 10 RVP gasoline properties are in summary:

Technology	Case I Mobil Methanol Conversion	Case II Fischer-Tropsch	Target
Gravity, °API	61.4	67.2	--
Octane, Unleaded			
Research	93	91	--
Motor	83	83	82 min.
(R+M)/2	88	87	87 min.
Volatility			
Reid Vapor Pressure, lb.	10	10	--
V/L Ratio (=20), °F	@ 129.5	@ 127.3	@ 140 max.
Composition			
Olefin, %	11	20	20 max.
Durene, %	4.6	--	5 max.

Both gasolines meet all target specifications. Case I gasoline, however, bests the octane targets by one number.

The F-T fuel oils are of excellent quality, except perhaps their somewhat high cloud (pour) points. The diesel fuel could be marketed under specifications for engines in service requiring frequent speed and load changes. The clean, non-metal heavy fuel oil would be a superior turbine fuel.

Further investigation of the cooling tower design parameters, after the completion of this report, has reduced significantly the fresh water requirements. In addition, offsite unit vendors have provided more accurate utility requirements for their units. These data will be incorporated in the final report.

SECTION 1 STUDY SCOPE

This study has been prepared as a joint effort by Mobil Research and Development Corporation, Lurgi Mineraloeltechnik GmbH and American Lurgi Corporation.

1.1 BASE CASES

The primary purpose of this scoping study is to provide a technical and economic comparison between the commercial Fischer-Tropsch technology and the Mobil methanol-to-gasoline technology for the production of motor gasoline from a U.S. coal. The primary coal gasification step uses the Lurgi dry-ash, moving-bed pressure gasifier.

Base Case I is the co-production of gasoline and SNG using the Mobil methanol-to-gasoline technology currently being developed through joint funding by ERDA and Mobil Research and Development Corp. The methanol is first produced from the coal derived synthesis gas.

Base Case II is the co-production of gasoline and SNG using the state-of-the-art Sasol-type Fischer-Tropsch technology. The F-T products undergo extensive upgrading to become marketable under U.S. specifications.

1.2 SENSITIVITY CASES

In addition to the above base cases, the following technical sensitivity cases have also been evaluated:

Case I-A uses the same technology and synthesis gas production as in Base Case I, except the Mobil methanol-to-gasoline technology is eliminated and methanol and SNG are the co-products.

Case I-B uses the same technology and synthesis gas production as in Base Case I except the co-production of SNG is eliminated. A reforming unit converts methane into synthesis gas which is recycled to produce additional methanol and, ultimately, additional gasoline.

Case I-C uses the same technology and synthesis gas production as in Base Case I except the Mobil methanol-to-gasoline process uses a fluid-bed reactor in place of the fixed-bed reactor used in Base Case I.

Case I-D uses the non-commercial Winkler fluid-bed pressure gasification technology in place of the commercial Lurgi gasification technology. The Winkler technology is under active development in Germany. The methanol synthesis was adjusted for the different synthesis gas composition. The gasification and methanol synthesis steps yield the same quantity of methanol as obtained in Base Case I. Because of the low methane production in the Winkler gasifier, SNG manufacture has been eliminated.

Case II-A uses the same technology and synthesis gas production as in Base Case II except the Mobil direct route technology currently under development through joint funding by ERDA and Mobil Research and Development Corp. is substituted for the Sasol-type Fischer-Tropsch.

1.3 PLANT COMPLEX DEFINITION

For each base case, a conceptual plant complex has been developed. This complex is a self-supporting, grass roots facility encompassing all process and offsite units. Except for the Mobil and Winkler technologies, all technologies used in the plant design are commercially available. Location has been assumed to be adjacent a strip coal mine in the State of Wyoming. Products manufactured are available at the plant gate for shipment to the market place.

1.4 DATA SOURCES

The process information contained in this scoping study is based on either published or licensor data. (See References.) Much of the coal gasification information was derived from the proposed commercial Western SNG plants. In fact, the conceptual plant complexes developed in this study are nearly identical to these plants up through the production of clean synthesis gas. The combining of the processes used to obtain marketable SNG and gasoline from the synthesis gas, for the most part, is based on the in-house experience of the study participants. Licensors were not contacted for information specific to this report.

No process or design optimization back-up studies have been made. In addition, no specific laboratory work was done for this study. As needed, in-house correlations, data banks, engineering programs, cost estimating programs, etc., were used.

Investment estimates are principally derived from in-house data. Where obtainable, vendor quotes, however, have been used for the offsite units.

1.5 SCOPE OF WORK

The work performed for each of the two base cases includes:

- material balance
- utility balance
- plant thermal efficiency
- block flow diagram
- simplified process flow diagrams
- equipment lists with major equipment dimensions

Each process unit is identified and briefly described with pertinent design considerations indicated. For the hydrocarbon upgrading processes, a technology critique is also included. In addition, the design bases used for the methanol-to-gasoline and the Fischer-Tropsch units have been outlined in some detail.

For each sensitivity case, the work performed has been reduced to include only:

- overall simplified material balance
- approximate utility balance
- plant thermal efficiency
- simplified block flow diagram

Discussion is limited to the changes in the base case brought about by the sensitivity. The discussion of the Winkler pressure gasifier and its application in Sensitivity Case I-D, as supplied by the Davy Powergas Inc., however, is included in Appendix C.

Scoping or budget quality investment estimates have been developed for the base cases. The investment for each process and offsite unit is identified. Estimates of the manpower catalyst requirements and chemical wages are also provided. The investment estimates for the sensitivity cases, for the most part, have been factored from the base cases. New sensitivity unit investments, e.g., Winkler gasifier, have been developed.

The plant complex economics have been calculated using both utility financing and private investor financing. Sensitivity of the unit cost towards coal price, SNG price, byproduct values and investment and operating cost shifts has also been developed for the base cases. An abbreviated economic analysis is presented for the sensitivity cases.

1.6 UNIT SUMMARY - BASE CASES

The plant complex is comprised of a series of interconnected process units, utility and support facilities (offsite units) and general plant facilities (infrastructure) as defined below:

PROCESS UNITS

<u>Unit No.</u>	<u>Description</u>
<u>Base Case I</u>	
101	Gasification (Lurgi Coal Pressure Gasification)
102	Raw Gas Shift
103	Raw Gas Cooling
104	Shifted Gas Cooling
105	Gas Purification (Rectisol)
106	Sulphur Recovery (Stretford)
107	Gas Liquor Separation
108	Phenol Recovery (Phenosolvan)
109	Ammonia Recovery (Chemie Linz/Lurgi)
110	Methanol Synthesis (Lurgi Low Pressure Process)
111	H ₂ Recovery (Pressure Swing)
112	Methanation
113	CO ₂ Recovery (MEA Wash)
114	SNG Drying (TEG Wash)
150	Methanol Conversion (Mobil)
151	Naphtha Hydrotreating
152	Fractionation
153	HF Alkylation
<u>Base Case II</u>	
201 to 209	Identical to Base Case I
210	Hydrocarbon Recovery (Heptane Wash)
211	H ₂ Recovery (Pressure Swing)
212	Methanation
213	CO ₂ Removal (MEA Wash)
214	SNG Drying (TEG Wash) and Compression
250	F-T Synthesis
251	Naphtha Hydrotreating
252	F-T Product Fractionation
253	F-T Product Hydrotreating
254	Hydrotreated Product Fractionation
255	Catalytic Reforming
256	C ₅ /C ₆ Isomerization
257	Catalytic Polymerization
258	HF Alkylation
259	Poly Gasoline Hydrogenation
260	Light Ends Recovery
261	H ₂ Purification
262	Alcohol Recovery

OFFSITE UNITS
(Base Case I and II)

<u>Unit No.</u>	<u>Description</u>
121/221	Oxygen Production (Air Separation)
122/222	Boiler
123/223	Main Superheater
124/224	Superheater
125/225	Electrostatic Stackgas Precipitator
126/226	Stackgas Clean-Up
127/227	Instrument and Plant Air
128/228	Coal Handling
129/229	Ash Handling
131/231	BFW Preparation (Deaerator & Demineralizer)
132/232	CW Make-Up Preparation
133/233	CW Towers
134/234	Electric Power Generation
135/235	Waste Water Treatment (Biological)
136/236	Relief and Blow Down Facilities
137/237	Storage
138/238	Interconnecting Piping
141/241	Refrigeration Unit
154/270	Gasoline Blending
271	F-T Catalyst Preparation

INFRASTRUCTURE
(Base Case I and II)

Office Buildings
Cafeteria
Maintenance Shops
Warehouse
Laboratory
Fire Protection System
Electric Distribution System
Truck and Railroad Unloading/Loading Facilities
Sewers
Roads and Parking Lots
Fencing
General Lighting
Communication and Security

SECTION 2 STUDY DESIGN BASES

Where applicable, the plant design bases adopted for this study are generally those established by C.F. Braun & Co. for ERDA in "Coal Gasification Commercial Concepts Gas Cost Guidelines" (Reference 1). A discussion of the principal bases follows.

2.1 PLANT CAPACITY

For both base cases, the plant capacity is based upon the gasification of 1,272 Mlb/hr of DAF coal. This amount of coal produces 742 MMSCF/SD of dry, purified synthesis gas for feed to methanol synthesis (Base Case I) or feed to Fischer-Tropsch synthesis (Base Case II). For reference, this capacity is equivalent to the capacity of the large 280 MMSCF/SD commercial SNG plants under consideration for the United States and, thus, is similar to the Guidelines plant size.

In the sensitivity cases, the gasification rate and synthesis gas yield are the same as used in the base cases, except for Sensitivity Case I-D. In this sensitivity, the 10 RVP gasoline product is the same as the Base Case I.

Because of differing energy requirements, the total coal charge, however, is not the same among the various cases.

2.2 DESIGN PHILOSOPHY

The overall plant complex has been designed using multiple trains, spare equipment and intermediate storage to provide an overall onstream factor of 92 percent. (See Sub-Sections 3.7 and 4.7.)

2.3 FEEDSTOCKS

The only feedstocks to the plant complex, besides air, are mined coal and fresh water. In addition, small quantities of chemicals, solvents and catalysts are required.

2.3.1 Coal

Gasification and boiler-firing are based on a coal having the properties listed in Table 2.1. This coal is a low sulfur, Wyoming sub-bituminous coal. Its properties differ slightly from the base Montana sub-bituminous coal in the Guidelines.

TABLE 2.1
STUDY COAL PROPERTIES
(Wyoming Sub-Bituminous Coal)

	<u>As Received</u>	<u>Dry and Ash Free (DAF)</u>
<u>Proximate Analysis, wt. %</u>		
Moisture	28.0	--
Ash	5.1	--
Fixed Carbon	33.8	50.5
Volatile Matter	33.1	49.5
	<u>100.0</u>	<u>100.0</u>
<u>Ultimate Analysis, wt. %</u>		
C		74.45
H		5.10
O		19.25
N		0.75
S		0.45
		<u>100.00</u>
<u>Calorific Value, Btu/lb</u>		
High Heating Value (HHV)	8,509	12,720
Low Heating Value (LHV)	7,893	12,236
-----Atmosphere-----		
<u>Fusion Properties of Ash, °F</u>	<u>Oxidizing</u>	<u>Reducing</u>
Softening Point	2,335	2,335
Melting Point	2,360	2,360
Flow Point	2,440	2,430
<u>Mineral Analysis of Ash</u>		
	<u>Wt. %</u>	
SiO ₂	19.0	
Al ₂ O ₃	14.0	
Fe ₂ O ₃	6.0	
MgO	7.8	
CaO	36.0	
Na ₂ O	2.7	
K ₂ O	0.2	
SO ₃	7.0	
BaO	0.2	
TiO ₂	1.0	
P ₂ O ₅	1.8	
Undetermined	4.3	
	<u>100.0</u>	

2.3.2 Fresh Water

The quality of the untreated fresh water assumed is the Western location water quality established in the Guidelines. In summary, the total dissolved solids are 496 ppm and the total hardness is 232 ppm CaCO_3 . It has been assumed that the water is available at the plant gate.

2.4 CLIMATIC CONDITIONS

Essentially, the climatic conditions established in the Guidelines have been used. In summary, they are:

Atmospheric pressure, psia	12.3
Air temperature (average), $^{\circ}\text{F}$	50
Relative humidity (average), %	70
Summer wet bulb, $^{\circ}\text{F}$	66
Summer dry bulb, $^{\circ}\text{F}$	95

2.5 PLANT SITE CONDITIONS

No major site development, other than leveling and grubbing, has been assumed. No piling is assumed to be required.

2.6 ENVIRONMENTAL REGULATIONS

The plant complex has been designed to meet all existing local and federal environmental regulations, as of July, 1977, for liquid and gaseous effluents.

Boiler stack gas clean-up facilities for SO_2 removal are provided to reduce the SO_2 emissions to 0.2 pounds of SO_2 per million Btu of fired heat. This emission target is more severe than the boiler SO_2 limitation in the Guidelines, but it is representative of the design limits placed on the latest proposed Western SNG plants. In addition, an electrostatic precipitator is included to reduce the particulate matter from the boiler to 0.1 pound per million Btu of fired heat. (Note: For the purposes of determining the "boiler" fired duty, the main superheater is included and LHV is the basis.)

Sulfur emissions from the process units are reduced by treating all sulfur containing offgases in a sulfur recovery unit. The tail gas stream containing 10 ppm H_2S from this unit is incinerated in the boiler to eliminate the hydrocarbons and to convert the COS and H_2S to SO_2 for removal in the stack gas clean-up facility. Only about 5% of the sulfur in the total coal charge escapes as SO_2 , amounting to about 5 T/SD of sulfur.

All aqueous liquid effluents are treated and recycled. Blowdown water is used for ash slurring, dust control, etc..

The wet ash and solid wastes, e.g., from stack gas clean-up and water treating, are sent to the mine for disposal.

2.7 PRODUCTS

Except as discussed below, this study is based on the concept that all products are marketable. Other than quality specifications, no marketing restrictions have been imposed. Products have been credited with their highest potential market value. The major products, however, are SNG and motor gasoline. A product summary is tabulated below:

<u>Product</u>	<u>Base Case</u>		<u>----Sensitivity Case----</u>				
	<u>I</u>	<u>II</u>	<u>I-A</u>	<u>I-B</u>	<u>I-C</u>	<u>I-D</u>	<u>II-A</u>
SNG	X	X	X	-	X	-	X
Methanol	-	-	X	-	-	-	-
Gasoline	X	X	-	X	X	X	X
Propane LPG	X	X	-	X	X	X	X
Butane LPG	X	X	-	X	-	X	X
Diesel Oil	-	X	-	-	-	-	-
Heavy Fuel Oil	-	X	-	-	-	-	-
Alcohols	-	X	-	-	-	-	-
Ammonia	X	X	X	X	X	-	X
Sulfur	X	X	X	X	X	X	X
Electric Power (excess)	X	X	X	X	X	X	X
Coal Fines (excess)	X	-					

The Lurgi gasifier produces phenols, naphtha, oil and tar which are recovered during raw gas cooling. For expediency, the phenols, oil and tar are used as boiler fuel. Although technically possible, the upgrading of these materials into saleable products would have little, if any, effect on the plant complex economics. On the other hand, the gasifier naphtha is hydrotreated for gasoline blending, principally, because this aromatic stock is needed to yield a satisfactory 10 RVP gasoline in the Fischer-Tropsch case.

The Fischer-Tropsch reaction produces a small quantity of acids. They have been neutralized with caustic as recovery is not economical (8).

Ammonia and hydrogen sulfide obtained during raw syn gas purification are recovered as anhydrous ammonia and sulfur.

2.8 PRODUCT SPECIFICATIONS

2.8.1 SNG

The SNG product is interchangeable with pure methane in accordance with procedures described in the Guidelines. In addition, it meets the following limitations:

Carbon monoxide	0.1 vol. %
Hydrogen sulfide	0.25 grains/100 SCF
Total sulfur	10 grains/100 SCF
Water	4 lb/MMSCF,

and is available at the plant gate @ 1,000 psig.

2.8.2 Hydrocarbon Products

The target specifications are primarily based on the 1976 Annual Book of ASTM Standards and represent industry guidance for establishing product properties between buyer and seller. Properties and comments specific to the various hydrocarbon products can be found in the discussion and tables included in Sub-Section 3.2 and 4.2.

2.8.3 Alcohols

No specifications have been established. The alcohol product has been upgraded to be essentially free of water, acids, aldehydes and ketones.

2.8.4 Byproducts

Ammonia: Agriculture grade is produced. (With a relatively small increase in costs, chemical grade ammonia could be produced by the ammonia recovery process used in the study.)

Sulfur: The product is a liquid at 95.5% purity.

Electric Power: Excess electric power is produced at 6,000 volts.

2.9 COAL BALANCE

The minimum coal size specification for the Lurgi gasifier used in the study is 1/4 inch. The minus 1/4 inch coal is used as boiler fuel. When crushing the study coal, it has been estimated that the coal preparation plant yields 83.5% 2" to 1/4" gasifier coal and 16.5% minus 1/4" fines. Since the study basis calls for the combustion rather than recovery of the gasifier tar, oil and phenols, a surplus of fine coal is possible. When this occurs, the excess fines are sold in accordance with the Guidelines.

2.10 UTILITY BALANCE

The general design bases calls for in-plant power and steam generation and, if possible, no export of these items. The utility balances were developed towards this goal, but detailed utility rebalancing calculations are outside the limits of this scoping study. Thus, a small surplus of electric power is available for export. In the base cases, it amounts to less than 5% of the total steam and electric power required to operate the complex.

SECTION 3

BASE CASE I

MOBIL METHANOL-TO-GASOLINE TECHNOLOGY

3.1 MATERIAL BALANCE

The overall material balance is shown below:

<u>Input</u>	<u>Mlb/hr</u>
Coal, as mined	2,227.8 ⁽¹⁾
Air	5,733.8
Water	4,157.4
	<u>12,169.0</u>
 <u>Output</u>	 <u>Mlb/hr</u>
Coal fines	102.5 ⁽²⁾
Ash	140.1
Products	530.9 ⁽³⁾
Byproducts	13.7
Blowdown water	508.8
Stack and vent losses	10,873.0
	<u>12,169.0</u>

(1) 27,334 T/SD

(2) 1,230 T/SD

(3) 50,075 Bbl/SD

Overall plant consumptions per barrel of product, converting SNG into a FOE barrel, are:

Coal:	0.521 T
Water:	5.69 Bbl
Air:	1.37 T

Stack and vent losses amount to about 2.6 tons per barrel of product. The C₃ plus hydrocarbon yield (85.4% 10 RVP gasoline) is 0.509 Bbl/Bbl of converted methanol.

Appendix A contains the complete, detailed material balance for Base Case I.

BASE CASE I
3.2 PRODUCT YIELDS AND QUALITY

Stream numbers are given below for reference to the material balance sheets in Appendix A and process diagrams in Sub-Section 3.4.

3.2.1 SNG (49)

<u>Quantity</u>	16,306.3 lb-mol/hr
	265.4 Mlb/hr
	148.5 MMSCF/SD

Composition (Only compounds greater than 0.1% are listed: see Appendix A for detailed composition.)

	<u>Percent</u>
Hydrogen	1.7
Methane	95.5
Ethane	0.2
Propane	0.1
Butane	0.1
Carbon dioxide	0.5
Inerts (N ₂ + Ar)	1.9
	100.0

Other

Heat of combustion (HHV)	980 Btu/SCF
Carbon monoxide (0.1% max.)	0.02%
Water	0.01%
Sulfur	None

Compatibility Indexes (versus pure methane)

<u>Index</u>	<u>Calculated</u>	<u>Preferable</u>	<u>Objectionable</u>
Lifting, I _l	1.03	under 1.0	above 1.06
Flash-back, I _f	1.02	under 1.15	above 1.2
Yellow-tip, I _y	1.05	above 1.0	under 0.8

The SNG product is of satisfactory quality and is compatible with pure methane. The inerts from the oxygen stream for gasification, however, give rise to a lifting index value between the preferable and objectionable values. From a processing standpoint, there is little that can be done to reduce this value. The selection of a more expensive oxygen plant yielding a 99+% pure product, however, would alleviate this problem. (The SNG product, on the other hand, has a lifting index value better than the preferable value when compared with the high methane natural gas standard cited in the A.G.A. Research Bulletin Number 36. This gas has a 5.0% inerts content.)

3.2.2 Gasoline (50)

Quantity

22,045 Bbl/SD
235.7 Mlb/hr

Blending

<u>Component</u>	<u>Wt. %</u>
Mixed butanes	2.4
Alkylate	3.2
Stabilized gasoline	87.8
Hydrotreated gasifier naphtha	6.6
	<u>100.0</u>

Properties

Estimated properties and a comparison with unleaded gasoline specifications are presented in Table 3.2.1. Table 3.2.2 gives a more detailed listing of the principal unleaded gasoline specifications.

The 10 RVP gasoline is of excellent quality and meets all specifications. Its octane rating is estimated to be about one above the specification number. Volatility and composition are similar to present-day gasolines. Although the content of the troublesome durenene is below the target maximum of 5.0 wt. %, it would be preferable if it were below 4.0 wt. %. (2)

3.2.3 Mixed Butanes (103)

Quantity

2,205 Bbl/SD
18.3 Mlb/hr

Properties

Estimated properties and a comparison with LPG specifications are shown in Table 3.2.3.

This product is a satisfactory commercial butane fuel. Because of the high iso-butane content of 76 vol. %, it has, however, a higher potential economic value as an alkylation unit feedstock.

3.2.4 Propane LPG (102)

Quantity

1,555 Bbl/SD
11.5 Mlb/hr

Properties

Estimated properties and a comparison with LPG specifications are shown in Table 3.2.3.

This product is a satisfactory commercial propane fuel.

3.2.5 Byproducts

Sulfur (29)

Quantity

61 T/SD

Impurities

0.5 wt. %

Anhydrous Ammonia (17)

Quantity

103 T/SD

Impurities (mainly water)

0.5 wt. % max.

Grade

agricultural

Excess Power (6,000 volts)

5.96 MW(e)

3.2.6 Coal Fines (2.1)

Quantity

102.5 Mlb/hr

The thermal requirements do not require the use of all the fines produced in the coal preparation unit.

TABLE 3.2.1

COMPARISON OF PRINCIPAL UNLEADED GASOLINE SPECIFICATIONS
WITH ESTIMATED METHANOL-TO-GASOLINE GASOLINE PROPERTIES-
CASE I

	<u>Estimated MTG Unleaded Gasoline Properties</u>	<u>Specification</u>
Gravity, °API	61.4	
Octane Numbers		
Research	93	
Motor	83	82 min.
(Research + Motor)/2	88	87 min.
Volatility		
Reid Vapor Pressure, lb	10.0	
Distillation, °F		
IBP	85.5	
10%	110.5	158 max.
30%	146.1	
50%	200.0	170/250 min./max.
70%	262.8	
90%	336.9	374 max.
EP	388.6	437 max.
V/L Ratio (=20), °F	@ 129.5	@ 140 max.
Sulfur, wt. %	Nil	0.10 max.
Composition, vol. %		
Paraffins	51.3	
Olefins	11.3	20 max. (target)
Naphthenes	8.7	
Aromatics	28.7	
Durene Content, wt. %	4.6	5 max. (target)
Molecular Weight	94.3	

TABLE 3.2.2
PRINCIPAL UNLEADED GASOLINE SPECIFICATIONS

	ASTM D439 ⁽¹⁾	OTHER	POSSIBLE WAIVERS
Octane Numbers			
(Research + Motor)/2, min. (D2699 and D2700)	87		
Motor, min. (D2700)	82		
Volatility			
Reid Vapor Pressure, max. (D323)	15 ⁽²⁾		15.5-16.0 (in winter)
Distillation, °F (D-86)			
10% Evap. max. temp.	158 ⁽²⁾	(140 avg.)	
50% Evap. min./max. temp.	170/250 ⁽²⁾	(avg. 240 max.)	
90% Evap. max. temp.	374 ⁽²⁾	(370 avg.)	
End Point, max. temp.	437		383 ⁽⁶⁾
% Recovered, min.	-	95 ⁽³⁾	446 ⁽⁶⁾
% Residue, max.	-	2 ⁽³⁾	No Spec.
V/L Ratio, max. °F @ 20 (D2533)	140 ⁽²⁾		
Existent Gum, max. mg/100 mls (D381)	5		
Sulfur, max. wt. % (D1266)	0.10	0.05 ⁽⁴⁾	0.15 ⁽⁶⁾
Benzene, max. wt. %		5 ⁽⁷⁾	
Bromine Number, max. (D1159)	-	30 ⁽⁴⁾	
Induction Period, min. (D525)	-	240 ⁽⁵⁾	
Corrosion, max. (D130)	No. 1		
Lead Content, max. g/USG (D2547 or D2599)	0.05		

(1) 1976 Annual Book of ASTM Standards

(2) Lower max. limits apply according to season, geographical location, and individual state specification.

(3) Applicable in several states.

(4) California

(5) Recommended

(6) ASTM ES-1-74 (Emergency) specifications for conventional (not unleaded) gasoline.

(7) Federal specification.

TABLE 3.2.3

COMPARISON OF PRINCIPAL LPG SPECIFICATIONS WITH
ESTIMATED METHANOL-TO-GASOLINE LPG PROPERTIES-
CASE I

	<u>Commercial Propane ASTM D1835*</u>	<u>Est. MTG C₃ LPG Properties</u>	<u>Commercial Butane ASTM D1835*</u>	<u>Est. MTG C₄ LPG Properties</u>
Vapor Pressure at 100°F, max. psig (D1267)	208	171	70	52
-27- Volatile Residue				
Butane and Heavier, max. vol. %	2.5	1.9	-	-
Pentane and Heavier, max. vol. %	-	-	2.0	0.7
Corrosion, max. (D1838)	No. 1	No. 1	No. 1	No. 1
Sulfur, grains (D2784)	15	None	15	None

* 1976 Annual Book of ASTM Standards

BASE CASE I
3.3 THERMAL EFFICIENCY

Table 3.3.1 is a summary of the overall plant thermal efficiency, which is defined as the combustion heat of the products, byproducts and excess power divided by the combustion heat of the total coal feed. The efficiency has been calculated using both the high and low heating values.

TABLE 3.3.1

METHANOL-TO-GASOLINE CASE I - THERMAL EFFICIENCY

	Quantity, Unit/SD	High Heating, Value (HHV)	Total HHV, MMBtu/hr	Percent of Input	Low Heating, Value (LHV)	Total LHV MMBtu/hr	Percent of Net Input
Input							
Coal, DAF	18,286 T	12,720Btu/lb	19,383	-	12,236Btu/lb	18,646(1)	-
Fines(excess)	(823 T)	"	(872)	-	"	(840)	-
Net Coal	17,463		18,511			17,806	
Output							
SNG	148.52MMSCF	980.4Btu/SCF	6,067	32.8	882.6Btu/SCF	5,462	30.7
C ₃ LPG	1,555 Bbl	3.816MMBtu/Bbl	247	1.3	3.509MMBtu/Bbl	227	1.3
C ₄ LPG	2,205 Bbl	4.191MMBtu/Bbl	385	2.1	3.865MMBtu/Bbl	355	2.0
10 RVP							
Gasoline	22,045 Bbl	5.105MMBtu/Bbl	4,689	25.3	4.771MMBtu/Bbl	4,382	24.6
Sub-Total	-	-	11,388	61.5		10,426	58.6
Sulfur	61 T	3,780 Btu/lb	19	0.1	3,780 Btu/lb	19	0.1
Ammonia	103 T	9,693 Btu/lb	83	0.5	8,020 Btu/lb	69	0.4
Power(excess)	5.96 MW(e)	3,415 Btu/kWH	20(2)	0.1	3,415 Btu/kWH	20(2)	0.1
Total			11,510	62.2		10,534	59.2

(1) If LHV of as mined coal used (7,893 Btu/lb), overall LHV thermal efficiency becomes 61.3%.

(2) Direct thermal conversion used.

BASE CASE I
3.4 PROCESS DESCRIPTIONS

The discussions below follow the block flow diagram (BFD) or the process flow diagram (PFD) as noted. These diagrams are placed at the end of the discussion. Detailed compositions and flows of the numbered streams are found on the material balance sheets in Appendix A.

3.4.1 General (BFD ZO-GEM-6894)

Sized coal is received from the offsite Coal Handling Unit 128 (see Sub-Section 3.5) and is gasified in Coal Pressure Gasification Unit 101. The raw gas generated is partially converted in Raw Gas Shift Unit 102 to meet Methanol Synthesis Unit 110 requirements, and is cooled in Raw Gas Cooling Unit 103 and Shifted Gas Cooling Unit 104 before flowing to Gas Purification Unit 105. This unit removes the H_2S , CO_2 and naphtha from the raw gas. The purified gas (synthesis gas), is compressed and fed into Methanol Synthesis Unit 110. The crude methanol is used as feed to Methanol Conversion Unit 150, which converts the methanol into gasoline. Stabilized gasoline is recovered in Fractionation Unit 152. Additional gasoline is produced in HF Alkylation Unit 153 by alkylating the olefins recovered in Unit 152. C_3 LPG and mixed butanes are also recovered in the alkylation unit. The naphtha recovered within Gas Purification Unit 105 is upgraded in Naphtha Hydrotreating Unit 151.

The gasoline product is produced from stabilized gasoline, hydrotreated naphtha, alkylate and a portion of the mixed butanes in the offsite Gasoline Blending Unit 154. (See Sub-Section 3.5.)

The purge gas of Methanol Synthesis Unit 110, containing mainly the methane of the synthesis gas, is sent to the SNG upgrading train. This train consists of Methanation Unit 112, where unreacted CO and H_2 and higher hydrocarbons are converted to additional methane, CO_2 Removal Unit 113 for upgrading the methane to SNG quality, and SNG Drying Unit 114.

The hydrogen necessary for hydrotreating is produced in H_2 Recovery Unit 111 by absorption from a side stream of the purge gas from Methanol Synthesis Unit 110. The offgas of Unit 111 is recompressed to the SNG upgrading train pressure.

The H_2S contained in the Gasification Unit 105 offgas is converted in Sulphur Recovery Unit 106 to sulphur.

The gas liquors condensed in Units 101, 103, 104 and 105 are pumped to Gas Liquor Separation Unit 107, where dusty tar and oil are recovered. The gas liquor is processed further in Phenol Recovery Unit 108 and Ammonia Recovery Unit 109.

Sulphur and anhydrous ammonia are saleable products. Dusty tar, oil and phenols are not further upgraded, but are used as fuel.

3.4.2 Gasification Unit 101 (PFD ZO-GEM-6895 and 6896)

Purpose of the Unit is to convert coal into raw synthesis gas.

Technology Used

As defined in the scope of the study, the Lurgi Coal Pressure Gasification Process is used. This is a partial oxidation process by addition of oxygen and steam in the Lurgi countercurrent moving bed pressure gasifier.

Coal Handling Inside the Gasification Building

The well-sized coal is transported from Coal Handling Unit 128 to the top of the gasifiers by two-100 percent capacity inclined belt conveyors. During normal operation, each belt conveyor operates at 50 percent capacity and feeds two horizontal conveyors which run between two rows of gasifiers. Two spare horizontal conveyors are provided.

Coal is fed from the horizontal conveyors to the coal bunkers, 101-Y-01, by means of mobile automatic stations, each of which consists of a tripper and a reversible belt. Four stations have been provided with two stations normally operating.

All coal handling in the gasification building is controlled from a central control room.

Process Description

Gasification (PFD ZO-GEM-6895)

The well-sized coal is charged from the coal bunkers, 101-Y-01, into the gasifiers via automatically operated coal locks, 101-D-02. The bed of coal is gasified in countercurrent flow with the gasification agent. While travelling from the top to the bottom of the gasifier, the coal is dried, devolatilized and gasified.

The gasification agent is a mixture of oxygen and steam which is introduced into the bottom of the gasifier through a rotating grate. The ash is removed by this grate and discharged via the semi-automatic Ash Lock 101-D-03 and flows to Ash Handling Unit 129.

The steam addition moderates the gasifier temperature to below the ash liquefaction point. The partial combustion of the coal with the oxygen supplies the heat necessary for the gasification reactions.

The hot raw gas leaving the gasifier is cooled and scrubbed in Wash Cooler 101-E-01 with recycled gas liquor. By this operation the crude gas is saturated with steam and the dust and the heavy tars are removed. Before leaving the unit, further cooling takes place in Waste Heat Boiler 101-E-01 where 100 psig steam is produced.

The dusty gas liquor leaving the wash cooler and the waste heat boiler is sent to Gas Liquor Separation Unit 107.

Lock Gas Recompression Section of Unit 101 (PFD ZO-GEM-6896)

When the coal locks are depressured, raw gas is released. The portion which is released down to about 70 psig is fed to the last stage of Lock Gas Recompressor 101-C-41 after passing through Venturi Scrubber 101-D-41. The portion which is released down to atmospheric pressure is fed to the first stage of this recompressor via Lock Gas Holder 101-F-41.

The small quantity escaping during the charging operation of the coal locks, 101-D-02, is not recompressed due to the presence of air and is exhausted by Coal Lock Suction Fan 101-C-01 through Venturi Scrubber 101-F-05 to the atmosphere.

The lock gas recompressor also compresses the Gas Purification Unit 105 recompression gas and the main compressor syngas losses of Methanol Synthesis Unit 110 (Base Case I only).

3.4.3 Raw Gas Shift Unit 102 (PFD ZO-GEM-6897)

Purpose of the Unit is to increase the H_2/CO ratio of the raw synthesis gas to meet the requirements for methanol conversion. Only a sidestream of the raw gas has to be converted.

The exothermic shift reaction is as follows:

No additional steam is required for the reaction, since sufficient steam is contained in the raw gas.

In addition to the conversion of CO, most of the unsaturated hydrocarbons, higher phenols, HCN and organic sulfur are hydrogenated and the tar is hydrocracked into oil and naphtha.

Technology Used

For CO conversion in the raw gas generated in the Lurgi gasifier, Lurgi has developed a technology using commercial catalysts.

Process Description

The water content of the raw gas from Gasification Unit 101 is adjusted by cooling in the 50 psig Waste Steam Generator 102-E-04. In Separator 102-F-01, the condensed gas liquor is separated from the raw gas. The condensed gas liquor then flows to Gas Liquor Separation Unit 107 via Raw Gas Cooling Unit 103.

In Heat Exchangers 102-E-01, 02 and 03, the raw gas is heated to reaction temperature by heat exchange against the shifted gas. The raw gas then flows to Prereactor 102-D-01, which serves primarily as a guard bed trapping polymerized hydrocarbons and dust. The prereactor can be bypassed and regenerated when the pressure drop across the catalyst bed becomes excessive.

The partially shifted gas from the prereactor flows to Reactors 102-D-02 and 03 for further conversion. The shifted gas from 102-D-03 is cooled in Exchangers 102-E-01 and 02 against the raw feed gas and then flows to Shifted Gas Cooling Unit 104.

Provisions have been made to periodically regenerate the catalyst using steam and air.

3.4.4 Raw Gas Cooling Unit 103 (PFD ZO-GEM-6898)

Purpose of the Unit is to cool the raw synthesis gas coming from the gasifiers to a temperature as low as possible using cooling water, thereby reducing the downstream refrigeration requirements for gas purification.

Within the dictated temperature limitations, heat is recovered by the production of LP steam.

During cooling the raw gas, gas liquor, containing tar, oil, phenols and ammonia, is condensed.

Technology Used

The technology used has been developed by Lurgi for the special requirements of the Lurgi Coal Gasification Process.

Process Description

The raw gas is first cooled in the 50 psig Steam Generator 103-E-01. It is then cooled in the 20 psig Steam Generator 103-E-102. To further reduce the raw gas temperature, it is cooled by air in 103-E-03 and by cooling water in 103-E-04. To prevent the formation of ammonium carbonate, which could plug the tubes, gas liquor is injected into 103-E-04.

The gas liquor condensed in these steam generators and Trim Cooler 102-E-04 flows to Tarry Gas Liquor Tank 103-F-04. Part of the gas liquor is recycled to Wash Cooler 101-E-01 in Unit 101; the balance is sent to Gas Liquor Separation Unit 107.

3.4.5 Shifted Gas Cooling Unit 104 (PFD ZO-GEM-6899)

Purpose of the Unit is to cool the hot shifted gas to a temperature as low as possible using cooling water, thereby reducing the refrigeration requirements for gas purification. (See Paragraph 3.4.4).

Technology Used

The technology used has been developed by Lurgi for the special requirements of the Lurgi Coal Gasification Process.

Process Description

The shifted gas is first cooled in the 100 psig Steam Generator 104-E-01. The shifted gas is then cooled in the 20 psig Steam Generator 104-E-02. To further reduce the shifted gas temperature, it is cooled by air in 104-E-03 and by cooling water in 104-E-04. To prevent the formation of ammonium carbonates, which could plug the tubes, gas liquor is injected into 104-E-04.

After 104-E-04, the shifted gas is compressed by Booster Compressor 104-C-01 in order to overcome the pressure drop of Raw Gas Shift Unit 102. The compressed shifted gas is then cooled by 104-E-05 and combined with the cooled raw gas from Unit 103.

The gas liquor from the coolers and steam generators flows to Gas Liquor Separation Unit 107.

3.4.6 Gas Purification Unit 105 (PFD ZO-GEM-6900)

Purpose of the Unit is to remove the sulfur compounds and carbon dioxide from the raw gas to the desired levels required by the methanol conversion unit. Naphtha, hydrogen cyanide and water are also removed.

Technology Used

The selected Lurgi Rectisol Process purifies the raw gas by physical absorption using cold methanol as the absorption agent. The Rectisol process is currently in successful commercial operation. The application of this process is most economic at a high partial pressure of CO₂ in the feed gas.

Although a high selectivity of sulphur removal can be achieved to meet the requirements of the Claus sulphur recovery process, the non-selective route has been chosen using the Stretford sulphur recovery process. The Rectisol/Stretford combination is believed to be the most economic system for a low sulphur coal, based on previous studies for commercial-sized SNG plants.

The Naphtha and Methanol Recovery Section (NMR) of the Rectisol process has been developed to meet special requirements of the Lurgi Coal Gasification Process.

Process Description

The Refrigeration Unit 141 maintains the two temperature levels of -45°F and 32°F required for gas purification.

Absorber Section

The feed gas is cooled sequentially in 105-E-01 with synthesis gas, in 105-E-02 with $+ 32^{\circ}\text{F}$ refrigerant, in 105-E-03 with synthesis gas and flash gases and in 105-E-04 with -45°F refrigerant. The feed gas, after cooling, enters the prewash section of Absorber 105-D-01 where it is washed with a small quantity of methanol to remove the naphtha, HCN, and water. The main section of the absorber consists of a low and a middle section, with an intermediate chilling loop, where the gas is scrubbed with flash regenerated methanol to remove the bulk of sulphur compounds and carbon dioxide. From the main section the gas flows to the fine wash section in the top of the absorber. In the fine wash section, the gas is scrubbed with hot regenerated methanol to remove the remaining sulphur compounds and carbon dioxide to the specified level for methanol synthesis. The gas then exits the unit by heat exchange with the feed gas, and the syngas flows to Methanol Synthesis Unit 110.

Regeneration Section

The rich methanol leaving the bottom of Absorber 105-D-01 is now regenerated in Flash Regenerator 105-D-02. The laden methanol is flashed in several steps down to a slight vacuum, where dissolved gases are released. Gas from the first flash stage is sent to Lock Gas Compressor 101-C-41 to recover the bulk of the co-absorbed CH_4 , CO , and H_2 . The other flash gases are sent to Sulphur Recovery Unit 106.

A portion of the bottoms of the flash regenerator becomes the semi-lean solution used in the middle section of the absorber, while the remainder is further regenerated in Hot Regenerator 105-D-03 by a steam heated reboiler. The fully regenerated methanol (lean methanol) is used in the top section of Absorber 105-D-01. The offgas leaving the hot regenerator is combined with the above described flash gases and sent to Sulphur Recovery Unit 106.

Naphtha and Methanol Recovery Section

The methanol from the prewash section of Absorber 105-D-01 is flashed in Prewash Flash Column 101-D-04 before it is sent to the naphtha and methanol recovery section, which is shown as a block on the PFD.

This block consists of: (1) Mixer-Settler Extractor for recovering of naphtha, (2) Azeotrope Tower for fine recovery of naphtha, and (3) Methanol Water Tower for recovering of the prewash methanol.

The extraction agent is boiler feed water, which is recovered from the bottom of the methanol water tower and sent to Waste Water Treatment Unit 135.

The recovered naphtha, which contains all of the organic sulphur compounds and about 50% of the HCN contained in the raw gas is sent to Naphtha Hydrotreating Unit 151.

The remaining 50% of the HCN will leave the NMR section as a HCN offgas which is recycled by the Lock Gas Compressor 101-C-41 to Raw Gas Shift Unit 102 for conversion to ammonia.

3.4.7 Sulphur Recovery Unit 106 (PFD ZO-GEM-6901)

Purpose of the Unit is to recover the sulphur from the various acid gases of the plant complex. The sulphur is recovered as elemental sulphur with a purity of 99.5%.

Technology Used

The Stretford Process which was developed by the British Gas Corp. is used to generate salable, solid sulphur from low concentration H₂S gases. (These gases are not suited for the Claus process).

The Stretford Process is an absorption process using a sodium carbonate solution with additives.

The overall chemical reaction including absorption and regeneration is written as:

Process Description

The feed gas is contacted countercurrently in Absorption Column 106-D-01 by the circulating Stretford solution. The H₂S-free gas exits the top of the absorber and goes to Unit 122 to be incinerated. It contains less than 10 ppm of H₂S. None of the COS in the feed gas, however, is absorbed.

The rich Stretford solution enters Reaction Chamber 106-D-02 which provides the time necessary for the completion of the chemical reaction. Then, the rich Stretford solution flows by gravity to Oxidizer 106-D-03, where it is contacted with air. In 106-D-03, the Stretford solution is oxidized for reuse, and the sulphur particles float to the top of the liquid as a froth.

The regenerated Stretford solution overflows from the oxidizer into Solution Pump Tank 106-F-01, and, after cooling, it is recycled back to the absorber.

The sulphur froth from the oxidizer flows by gravity to Pump Tank 106-F-02, from which it is pumped to Sulphur Vacuum Filter 106-F-03. From there it flows by gravity to Sulphur Melter 106-E-02 and on to Melted Sulphur Accumulator 106-F-04.

3.4.8 Gas Liquor Separation Unit 107 (PFD ZO-GEM-6902)

Purpose of the Unit is to separate by gravity the dusty tar, oil and co-absorbed gases from the various gas liquor streams.

Technology Used

The technology used has been developed by Lurgi for the special requirements of the Lurgi Coal Gasification Process.

Process Description

Dusty Gas Liquor

The dusty gas liquor coming from the waste heat boiler in Unit 101 and from 103-F-04 in Unit 103 is cooled in 107-E-01 and mixed with the cooled gas liquor from Units 103 and 104. The mixture then flows into Tar Separator 107-F-01 via Expansion Vessel 107-F-02. In the tar separator, tar is settled out in the conical bottom section and pumped to Tank 107-F-10.

The gas liquor leaving 107-F-01 flows by gravity to Oil Separator 107-F-04. The oil separated in 107-F-04 flows by gravity to Oil Tank 107-F-08. The gas liquor flows by gravity to Surge Tank 107-F-07.

Oily Gas Liquor

The oily gas liquor coming from Heat Exchangers 104-E-01 and 02 of Shifted Gas Cooling Unit 104 is cooled and then mixed with the gas liquor coming from Gas Purification Unit 105. This combined stream flows by gravity, via Expansion Vessel 107-F-03, into Separator 107-F-05, where the separated oil flows by gravity to Oil Tank 107-F-08.

Gas Liquor

The gas liquor leaving Separator 107-F-05 flows by gravity to Final Separator 107-F-06, where it is combined with the gas liquor from Surge Tank 107-F-07.

The gas liquor separated in 107-F-06 flows by gravity to Final Surge Tank 107-F-09, and from there, it is pumped to Phenol Recovery Unit 108 for further treating. The oil recovered in 107-F-06 flows by gravity to Oil Tank 107-F-08.

Tar and Oil

The tar is burned in Boiler Unit 122. The oil is fuel for Superheaters 123 and 124. The various expansion gases are scrubbed in Ammonia Scrubber 107-D-01 for ammonia recovery and then sent to Sulphur Recovery Unit 106.

3.4.9 Phenol Recovery Unit 108 (PFD ZO-GEM-6903)

Purpose of the Unit is to recover phenolic components from the gas liquor.

Technology Used

For the removal of phenols, the Lurgi Phenosolvan Process is provided. It is a solvent extraction process using di-isopropyl ether as the solvent. The Phenosolvan Process has been commercially used in syngas and town gas plants based on Lurgi Pressure Coal Gasification and is under consideration for the proposed U.S. SNG plants.

Process Description

The gas liquor coming from Gas Liquor Separation Unit 107 flows to Sand Filters 108-F-02, where any remaining solids are removed. The filters are backwashed with cleaned gas liquor and the mud liquor from the filters is returned to Unit 107. From the sand filters, the cleaned gas liquor flows to Saturation Column 108-D-01, where it is saturated with CO₂ in order to increase the efficiency of extraction.

The saturated gas liquor flows by gravity to the multi-stage, mixer settler type extractor, 108-D-02, to be divided into a phenolic-solvent phase and a dephenolized-gas-liquor phase.

The dephenolized gas liquor flows to Raffinate Settler 108-F-06 for the purpose of recovering the remaining solvent. From there the gas liquor is pumped to Ammonia Recovery Unit 109.

The phenolic-solvent phase from the extractor flows, via Extract Settler 108-F-07, to Extract Receiver 108-F-08. It then is pumped, via Partial-Feed Evaporator 108-E-02, into Solvent Regenerator 108-D-04. In the overhead of this column, the bulk of the solvent is recovered and pumped back to Extractor 108-D-02. The bottom product is a phenol-solvent mixture which is pumped into Phenol Tower 108-D-05, where the remaining solvent is stripped out using live steam.

The overhead solvent-water mixture of 108-D-05 is returned to Extract Settler 108-F-07. The bottom product of phenols is pumped to Main Boiler Unit 122 to be burned.

A small portion of the phenols is recycled, partly for recovering solvent from the offgases in Vent Scrubber 108-D-06 and partly for recovering solvent from Unit 109 offgases in Phenol Solvent Scrubber 108-D-03. In the upper part of the phenol solvent scrubber, these offgases are scrubbed by waste water for phenol recovery, before being sent to Sulphur Recovery Unit 106.

3.4.10 Ammonia Recovery Unit 109 (PFD ZO-GEM-6904)

Purpose of the Unit is to recover the ammonia from the gas liquor before final treatment for use as cooling water make-up.

Technology Used

The technology used has been jointly developed by Chemie Linz and Lurgi, mainly for the purpose of removing ammonia from the Lurgi gasifier gas liquor. The product is a salable ammonia of either agriculture or chemical grade.

Ammonia recovery in the Chemie Linz/Lurgi Process is accomplished by the use of stripping and scrubbing techniques without the addition of chemicals or solvents.

Process Description

After heating, the gas liquor enters Deacidifier 109-D-01, where the remaining gases and phenosolvan solvent are stripped out by reboiler steam. The gases leaving the stripper are scrubbed with cooled waste water under elevated pressure to remove ammonia. The stripped gases are sent back to Phenol Recovery Unit 108. The gas liquor containing the ammonia leaves the bottom of the deacidifier and is pumped after cooling to Total Stripper 109-D-02, where all the ammonia and the remaining gases are stripped out by reboiler steam under atmospheric pressure.

The bottom product of the total stripper is the clean gas liquor containing less than 100 ppm free ammonia. It is sent after cooling to Waste Water Treatment Unit 135 for final treating.

The overhead vapors from the total stripper are partially condensed in the bottom of Acid Gas Scrubber 109-D-03 in order to increase the ammonia concentration. The condensate is refluxed back to the total stripper.

In Acid Gas Scrubber 109-D-03, the vapors are scrubbed by a recycled aqueous ammonia solution from the process. The heats of reaction and condensation are removed by cooled pump-arounds.

The bottom stream of the acid gas scrubber, which contains free ammonia and ammonium salts, is pumped by 109-G-05 to Ammonia Stripper 109-D-04. The bottoms of the ammonia stripper, containing a highly concentrated stoichiometric ammonium salt solution, is recycled back to 109-D-01. The stripped ammonia from the ammonia stripper overhead flows to the acid gas scrubber for recovery.

The ammonia vapor flowing overhead from Acid Gas Scrubber 109-D-03 is condensed and dried by compressing and cooling in the Ammonia Liquefying and Drying (ALD) Section before being sent to storage.

A small liquid stream containing water and organic substances is removed in the ALD Section and sent to the main waste water stream.

3.4.11 Methanol Synthesis Unit 110 (PFD ZO-GEM-6905)

Purpose of the Unit is to produce methanol from the purified synthesis gas.

Technology Used

For the production of methanol, the Lurgi Low Pressure Methanol Synthesis Process has been selected. This process offers maximum safe operation due to its highly developed reactor design and has wide commercial usage.

The (H_2 + CO) conversion is 85.2 mol. %.

Process Description

The synthesis gas is compressed, Syngas Compressor 110-C-01, to about 1100 psig and mixed with the recycle gas stream. The Recycle Gas Compressor 110-C-02 compresses the mixture to overcome the pressure losses of the recycle loop. This loop consists of Heat Exchanger 110-E-03 (heating syngas/recycle gas against methanol/recycle gas), Reactor 110-D-01, Condensers 110-E-04 and 05, and KO Drum 110-F-01, in which the unconverted gas is separated for recycling.

The high pressure methanol liquid is expanded into Expansion Vessel 110-F-03 for degassing; the methanol is sent to Methanol Conversion Unit 150.

The expansion gas of 110-F-03 is recompressed in H_2 Recovery Unit 111 and sent to Methanation Unit 112.

To eliminate the concentration of inerts in the recycle gas, a portion of the recycle gas is purged continuously and fed to Methanation Unit 112.

3.4.12 H₂ Recovery Unit 111 (PFD ZO-GEM-6908)

Purpose of the Unit is to recover hydrogen for hydrotreating the gasifier naphtha. The hydrogen source is a slip stream from the methanol unit purge gas.

Technology Used

Because of the relatively high CO₂ content of the feedgas, the Pressure Swing Process of Union Carbide Corp. is used.

Process Description

The main equipment of the unit are four parallel pressure-swing absorbers, 111-D-01; one is in operation and three are in regeneration. During operation, essentially all of the non-hydrogen components and a portion of the hydrogen are absorbed. The remaining hydrogen leaves the absorber at a purity of over 98%.

Regeneration is by pressure reduction in 3-stages with the final pressure being nearly atmospheric. The regeneration cycle is controlled automatically by motor values. An absorption/regeneration cycle requires several minutes.

The desorbed gases, called pressure-swing offgases, are recompressed by Compressor 111-C-01 back into the methanol unit purge gas stream before being changed to Methanation Unit 112. Gas Holder 111-F-01 on the suction side of the compressor, is necessary for buffering the non-static, pressure-swing off gas flow from the regenerating absorbers. Compressor 111-C-01 also recompresses the expansion gas from Unit 110.

3.4.13 Methanation Unit 112 (PFD ZO-GEM-6906)

Purpose of the Unit is the production of SNG meeting the specifications for compatibility with existing pipeline gases. In addition, the CO content must be lowered to less than 0.1%.

The principal reactions in methanation are described by the following equations:

Other minor reactions include the hydrogenation of ethylene to ethane and the cracking of ethane to methane.

Technology Used

The Lurgi Methanation Process is used. This process is the first process developed for the methanation of high CO concentration gases, and has been included in the proposed commercial U.S. SNG plants.

Process Description

The feed gas is made up of the purge and expansion gases from Methanol Synthesis Unit 110.

The methanation unit consists of two down-flow, fixed-bed reactors in series. The feed gas is heated in 112-E-06 and 03 against the second reactor, 112-D-02, product. Steam is injected in the feed gas and the gas is also diluted with a portion of the methanated gas from the first reactor, 112-D-01. The dilution gas is compressed by Recycle Compressor 112-C-01, after having been cooled in 112-E-01 and 02. MP steam is generated in 112-E-01.

The net reactor effluent from the first reactor flows to the second, or clean-up, reactor in which final methanation takes place. The clean-up reactor effluent is heat exchanged against the feed and cooled in Exchangers 112-E-04 and 05.

Process water condensed from the reactor effluent stream is collected and routed to BFW Preparation Unit 131.

The methanated gas leaves the unit for further treating in CO₂ Removal Unit 113.

3.4.14 CO₂ Removal Unit 113 (PFD ZO-GEM-6907)

Purpose of the Unit is to lower the CO₂ content in the SNG to about 0.5%, thereby improving its quality.

Technology Used

The Amine Guard Process of Union Carbide Corp. uses a monoethanol amine solution as the absorbant. This process offers better economics than a conventionally designed MEA wash system and provides complete protection against corrosion. A MEA process was chosen because the specified low final CO₂ content does not allow the use of a hot potassium carbonate process and the partial pressure of CO₂ in the feed gas is too low for economical use of a physical absorption process, such as Rectisol.

Process Description

The Methanation Unit 112 product gas and the offgases of Fractionation Unit 152 are charged to Absorber 113-D-01 in which the CO₂ is washed out by counter-current flow with lean MEA solution. In the top of the absorber, the gas is scrubbed with a small flow of BFW to recover trace amounts of MEA. The purified gas then flows to SNG Drying Unit 114.

The absorber bottoms product (rich MEA solution) is expanded after heat exchange in 113-E-01 into MEA Regenerator 113-D-02, where the CO₂ and other co-absorbed compounds are stripped from the MEA solution. The steam in the regenerator overhead is condensed in Condensers 113-E-04 and 05, and the remaining offgases are sent to Boiler Unit 122 for incineration. The steam condensate is refluxed to the top of the regenerator. The lean solution from the bottom of the regenerator is pumped back to the Absorber 113-D-01, after being cooled in 113-E-01, 02 and 03.

The offgases of Fractionation Unit 152 are compressed to the SNG pressure by Light Gas Compressor 113-C-01. After compression, the gas is cooled and the heavier hydrocarbons, which condense, are returned to Unit 152.

3.4.15 SNG Drying Unit 114 (PFD ZO-GEM-6907)

Purpose of the Unit is to dry the wet SNG to a water content of 4 lb/MMSCF before its introduction into the SNG pipeline system.

Technology Used

The TEG Wash Process, a commercial process for drying natural gas, is used.

Process Description

The drying agent is a mixture of triethylene glycol (TEG) and other ethylene glycols.

The SNG is contacted countercurrently in Water Absorber 114-D-01 with lean TEG. The water-rich TEG flows from the absorber to TEG Regenerator 114-D-02, which is heated by fuel gas. The steam stripped from the TEG is discharged to the atmosphere. The small reflux stream required is condensed within the vent tube by air cooling.

The regenerated TEG is stored in 114-F-01, where it is cooled by the rich TEG, before being pumped into the top of Water Absorber 114-D-01.

3.4.16 Methanol Conversion Unit 150 (PFD ZO-GEM-6915)

Purpose of the Unit is to dehydrate crude methanol to LPG and gasoline hydrocarbons which can be marketed directly without further processing.

Technology Used

Mobil has demonstrated a simple catalytic process to dehydrate methanol to the stoichiometric yield of hydrocarbons (44%) and water (56%).

This development has been reported under ERDA Contract No. E(49-18)-1773, and in references cited. The hydrocarbons are predominately in the gasoline boiling range (C_4 to C_{10}), and the gasoline is chemically conventional consisting of highly branched paraffins (51%), highly branched olefins (13%), naphthenes (8%) and aromatics (28%). Its unleaded research octane number (RON) ranges from 90 to 100. Essentially, no hydrocarbons larger than C_{10} and no oxygenates are produced.

Small amounts of CO, CO₂ and coke and trace amounts of formic acid and acetone in the water product are formed as by-products. After fourteen days on stream, enough coke accumulates on the catalyst to require regeneration. The catalyst is regenerated by coke combustion in a controlled manner to limit the maximum temperature to 900°F. Since the catalyst converts other oxygenates and is tolerant to water, crude methanol without any purification can be charged directly, thereby simplifying the methanol synthesis.

From laboratory investigations, the reaction path from methanol to hydrocarbons appears to be reasonably well represented by:

The reaction is highly exothermic with the heat of reaction being about 740 Btu/lb of methanol. Therefore, the principal problem in designing a reactor system is heat removal. In the fixed bed reactor system, this problem is minimized by dividing the above overall reaction (and reactor system) into two steps. In the first, methanol is partially dehydrogenated to form an equilibrium mixture of methanol, dimethyl ether and water. About 20% of the heat of reaction is released in this first step without any recycle for temperature control. In the second step, where hydrocarbon conversion takes place, a large recycle gas stream (from 6/1 to 9/1 ratio) is used to limit the temperature rise across the bed to about 125°F.

While other systems, such as quenched reactor, tubular heat exchange reactor, or fluidized bed reactor could be designed, the fixed bed, gas recycle system has been well demonstrated and is readily scaleable to higher throughputs.

The commercial process design conditions, yields and catalyst properties used in this study are shown in Tables 3.4.1, 3.4.2 and 3.4.3, respectively. These data were developed from ERDA Contract No. E(49-18)-1773 and represent the best estimate at this time of a commercial fixed bed operation.

TABLE 3.4.1

PROCESS DESIGN CONDITIONS FOR FIXED BED
METHANOL CONVERSION UNIT 150

I. Nominal Operating ConditionsFeed Composition (See Material Balance Stream 37.)

Methanol	18,360.3 lb. mol/hr.
Water	1,382.4 lb. mol/hr.
Others	42.5 lb. mol/hr.
	<u>19,785.2 lb. mol/hr. (52,585 B/SD)</u>

Base Yields (See following Table 3.4.2.)*Reactor ConditionsFirst Reactors (DME)

Pressure, Inlet	315 psig
Temperature, Inlet	566°F
Temperature, Outlet	768°F
Space Velocity	6 lb. fresh feed/hr/lb. catalyst
Catalyst	Mobil first stage catalyst
Estimated Ultimate Catalyst Life	1 year

Second Reactors (M-Gasoline)

Pressure, Inlet	300 psig
Temperature, Inlet	625°F
Temperature, Outlet	752°F
Space Velocity	1.84 lb. fresh feed/hr/lb. catalyst
Molar Recycle Ratio	7.5/1 (based on fresh feed)
Catalyst	Mobil second stage catalyst
Estimated On-Stream Time Before Regeneration	14 days
Estimated Ultimate Catalyst Life	1 year

II. Regeneration Conditions

Aged Catalyst Coke Level (Second Reactors) 30 wt. % on catalyst (Controlled oxygen content and controlled maximum temperature procedure similar to conventional petroleum naphtha pretreater/reformer regeneration is employed.)

TABLE 3.4.1 (continued)

III. Metallurgy

The basic metallurgy for the Methanol Conversion Unit 150 is carbon steel. Reactors have a 304SS internal liner over 3" of refractory to minimize the effects of any possible temperature excursions. The high pressure separator, 150-F-01 in process flow diagram ZO-GEM-6915, has a PVC lining to protect against the acid water (pH=3.5). The tubes of Exchangers 150-E-01, 06 and 07 are 316SS to protect from acid water corrosion. In addition, the shell of Exchanger 150-E-01 is carbon steel with 316SS lining. The acid water lines are PVC lined.

- * Yields are the average over 14 days of operation before catalyst regeneration. Although yield shifts are significant during the 14 days (see Reference 2), the 5-reactor system, Unit 150 design basis, minimizes the yield shift effects.

TABLE 3.4.2

METHANOL CONVERSION UNIT 150
 BASE FEED AND PRODUCT COMPOSITION
 (Basis: 100 Lb-Mole Methanol in Feed)

Component Names	Feed	Product
Coke (as CH _{0.8})	.000	.128
Acetone	.000	.129
Formic Acid	.000	.163
Methanol	100.000	.000
Dimethylether	.000	.000
Water	7.529	106.951
Carbon Monoxide	.000	.017
Carbon Dioxide	.000	.053
Hydrogen	.000	.040
Methane	.000	.746
Ethane	.000	.193
Ethene	.000	.018
Propane	.000	1.474
Propene	.000	.064
N-Butane	.000	.665
I-Butane	.000	2.155
Butenes	.000	.270
N-Pentane	.000	.268
I-Pentanes	.000	2.353
Pentenenes	.000	.435
Cyclopentane	.000	.047
Methylcyclopentane	.000	.214
N-Hexane	.000	.113
I-Hexanes	.000	1.991
Hexenes	.000	.297
Methylcyclohexane	.000	.062
N-Heptane	.000	.026
I-Heptanes	.000	.786
Heptenes	.000	.292
1,3-Dicyclopentane, cis	.000	.233
I-Octanes	.000	.228
Octenes	.000	.301
N-Propylcyclopentane	.000	.299
N-Nonane	.000	.015
I-Nonanes	.000	.084
Nonenes	.000	.116
N-Butylcyclopentane	.000	.071
I-Decanes	.000	.024
Decenes	.000	.045
Benzene	.000	.036
Toluene	.000	.280
Ethylbenzene	.000	.070
m- + p-Xylenes	.000	.876
o-Xylene	.000	.240
1,2,4-Trimethylbenzene	.000	.818
1,3,5-Trimethylbenzene	.000	.034

TABLE 3.4.2 (continued)

<u>Component Names</u>	<u>Feed</u>	<u>Product</u>
p-Ethyltoluene	.000	.292
I-Propylbenzene	.000	.014
1,2,4,5-Tetramethylbenzene	.000	.436
1,2,3,5-Tetramethylbenzene	.000	.063
1,2,3,4-Tetramethylbenzene	.000	.023
p-Diethylbenzene	.000	.198
Penta-Methylbenzene	.000	.068
2-Methylnaphthalene	.000	.017
Total Lb-Mole	<u>107.529</u>	<u>124.832</u>
Weight (lbs)	3,339.846	3,339.846

TABLE 3.4.3
METHANOL CONVERSION UNIT 150
CATALYST PROPERTIES

-----Mobil Catalysts-----		
	<u>First Stage</u>	<u>Second Stage</u>
Type	Extrudate	Extrudate
Geometry	1/16" x 3/16"	1/16" x 3/16"
Bulk Density	35 lb/cu ft	36 lb/cu ft
Crush Strength	50 lb/in	33 lb/in
Cost	*	*

- * Since Mobil has no specific commercial experience in making the second stage catalyst in the amounts required for a major syn fuels industry, an accurate cost cannot be given at this time. We are sure, however, that its cost will contribute only a minor portion to the total gasoline cost and, therefore, its addition at a later time will not alter any current economic evaluation study conclusions.

Process Description

Depressured crude methanol, pumped (150-G-01) to reaction pressure and vaporized in Heat Exchangers 150-E-01 and 02, flows to DME Reactor 150-D-01, where it is catalytically converted to an equilibrium mixture of methanol, dimethylether and water. Inlet operating conditions are 315 psig and 566°F.

The equilibrium mixture then flows to the M-Gasoline reactors (150-D-02), of which five are operating and one is undergoing regeneration. A gas recycle stream from Separator 150-F-01, after compression (150-C-01) and heat exchanged (150-E-04 and 05) against the reactor effluent, is fed along with the equilibrium mixture into the M-Gasoline reactors. The recycle stream controls the temperature rise. Its temperature is maintained to give a reactor inlet temperature of 625°F.

Cooling of Reactor 150-D-02 effluent occurs as follows: (1) Steam Generator 150-E-03, (2) the recycle stream and methanol feed heat exchangers, (3) BFW Heat Exchanger 150-E-06 and (4) Air Trim Cooler 150-E-07. Separator 150-F-01 operating conditions are 248 psig and 155°F. The purge gas flow is limited to that only required for control. The liquid hydrocarbon product is pumped (150-G-02) to Unit 152. A small amount, five gpm, of hydrocarbon product is recycled from the separator to the inlet of BFW Exchanger 150-E-06 for durene crystallization control.

Regeneration of the M-Gasoline reactors takes place about once every 14 days. After a reactor is taken off line, it is depressured and purged with nitrogen until there is less than about 1 to 5 vol. % of hydrocarbons present. Then the reactor is pressured to about 150 psig with nitrogen flow through Recycle Compressor 150-C-02. The temperature is maintained at 650°F by use of Furnace 150-B-01. Air is introduced slowly until oxygen content reaches about 1 vol. %. The maximum catalyst bed temperature is maintained at less than 850°F. When the oxygen content in the recycle gas becomes higher than 0.1 vol. %, the inlet temperature is slowly raised while maintaining a maximum temperature of 900°F in the bed. The hot spent regeneration gas is cooled by heat exchange with the fresh regeneration gas (150-E-08) and Fan Cooler 150-E-09. Condensed water is removed via Drum 150-F-02.

3.4.17 Naphtha Hydrotreating Unit 151 (PFD ZO-GEM-6908)

Purpose of the Unit is to obtain a clean, odor free, stable material from the raw gasifier naphtha for gasoline pool blending. Reaction conditions chosen will substantially saturate the raw naphtha olefins with little aromatic-ring hydrogenation, thereby reducing the octane rating as little as possible.

Technology Used

Hydrotreating is a versatile process in which the quality of a wide variety of petroleum materials can be improved with the proper choice of catalyst and operating conditions. It is used commercially to remove impurities such as sulfur, nitrogen and oxygen, to saturate olefinic double-bonds and to improve the odor, color, stability and burning characteristics. Generally, catalysts and conditions employed result in as little as possible carbon-bond cracking. Pressures range from 200 to 1,000 psig, and temperatures from 400 to 750°F. Typical liquid hourly space velocities are from 1 to 10 volume of oil per hour per volume of catalyst. Hydrogen-rich gas recycle may or may not be used depending upon the severity of operation. Since hydrogenation reactions are exothermic, multi-bed reactors with a hydrogen recycle quench are used to control reactor temperatures when the hydrogen consumption is large. A large number of catalysts have been developed. Various cobalt-molybdena catalysts with alumina supports; however, account for the bulk of the applications. This catalyst is oxygen regenerable, and quite rugged in nature. Commercial processes are licensed by BP Trading, IFP, Exxon, Gulf, Shell, Union Oil and Standard Oil (Indiana).

Process Description

The raw naphtha is pumped (151-G-01) to reactor pressure, heat exchanged with the reactor effluent in Exchanger 151-E-01, heated to reactor temperature in Fired Heater 151-B-01, and charged to Reactor 151-D-01. A portion of the hydrogen feed is mixed and heated with the naphtha; the remainder is used as a cold quench for temperature control in the multi-bed reactor. The reactor effluent is further cooled (151-E-02 and 03) before flushing in Separator 151-F-01. A small BFW flushing stream is added before 151-E-01.

The hydrogen-rich vapor passes first through an amine tower for hydrogen sulfide control, and then split into recycle and purge gas streams. The purge gas is incinerated in Boiler Unit 122. After compressing (151-C-01), the recycle and hydrogen make-up are combined before separating into the hydrogen feed and quench streams.

The separator liquid product is charged to Stabilizer 151-D-05. The light gas/hydrogen sulfide overhead products are sent to Sulfur Recovery Unit 106. Condensed Accumulator 151-F-03 liquids are refluxed. Cooled (151-E-06 and 07) stabilized naphtha is sent to offsite Blending Unit 154. A small sour water stream is also obtained from Separator 151-F-01.

Regeneration systems are provided for Reactor 151-D-01 and the rich amine solution from Absorber 151-D-02.

3.4.18 Fractionation Unit 152 (PFD ZO-GEM-6916)

Purpose of the Unit is to obtain a low C₂ concentration alkylate unit charge and a stabilized gasoline for pool blending.

Process Description

The high pressure condensate (stream 58) from the SNG train is flashed in Drum 150-F-01. The depressured liquid and the hydrocarbon product from Unit 150 are fed to Deethanizer 152-D-01. The ethane-rich tower overhead and the flash drum vapors are sent to Unit 113 in the SNG train. The deethanizer bottoms after being cooled in Deethanizer Side Reboiler 152-E-02 is fed to Stabilizer 152-D-02. Products are cooled alkylation feed (overhead) and stabilized gasoline (bottoms). Both towers employ steam reboilers (152-E-01 and 05).

3.4.19 Alkylation Unit 153 (PFD ZO-GEM-6916)

Purpose of the Unit is to increase the gasoline yield by the reaction between iso-butane and butene/propene and to yield commercial grade propane and butane liquified petroleum gases.

Technology Used

Alkylation, in petroleum refining, normally means the reaction of butene and/or propene with iso-butane to produce a higher molecular weight iso-paraffin. For example:

Alkylation can occur without catalysts, but commercially, acid catalysts are used with sulfuric acid and hydrogen fluoride being the two most important. Unlike the simple reaction above, a mixture of isomers is obtained. In addition, polymerization occurs, and "sludge" is yielded requiring catalyst regeneration. Alkylation, highly exothermic, liberates 600 to 700 Btu/lb of iso-butane. Commercial processes are licensed by Phillips Petroleum, UOP Process and Stretford Engineering.

Process Description

The iso-butane/olefin fresh feed is first mixed with the cooled HF acid/iso-butane recycle streams (153-E-16), and then, this mixture is charged to the combined Reactor/Settler 153-D-01. The reactor effluent - inert hydrocarbons, excess iso-butane and alkylate - after heating (153-E-01 and 02) is fed to Deisobutanizer 153-D-02. Products are a C₃/i-C₄ overhead, mixed-butanesside-cut and alkylate bottoms. The overhead mixture, after condensing in Condensers 153-E-08 and 09, is pumped (153-G-01) into Depropanizer 153-D-03 for separation into the C₃ LPG product and excess iso-butane recycle.

The hydrogen fluoride is recycled from Reactor/Settler 153-D-01. A continuous slip stream from the acid recycle is purified in a conventional HF rerun unit (not shown).

Not shown on the simplified process flow diagram are a HF stripper in the C₃ LPG stream and caustic washes in the product streams to remove all traces of acid.

3.4.20 Unit Capacity Summary

The capacities of the principal process units have been summarized below in conventional flow rates:

<u>Unit No.</u>	<u>Name</u>	<u>---Capacity, Unit/SD---</u>	
		<u>Input</u>	<u>Output</u>
101	Gasification	22.8 MT coal	1,755 MMSCF
102	Raw Gas Shift	331 MMSCF	-
105	Gas Purification	1,062 MMSCF	742 MMSCF
110	Methanol Synthesis	742 MMSCF	53.3 M Bbl
150	Methanol Conversion	52.6 M Bbl	25.7 M Bbl
151	Naphtha Hydrotreating	1.3 M Bbl	-
152	Fractionation	25.7 M Bbl	-
153	Alkylation	5.3 M Bbl (750 Bbl/SD alkylate)	-
	SNG Train	213 MMSCF	148 MMSCF

1) The steam/BFW circuit of the complex is shown simplified as it is described in detail within the separate steam/BFW balance Z0-GEM-6910.

Prepared	Date	Name	GEM	Lurgi
Checked	25.7.77	Beck	00-0865	00-0865
Standard				
Orig. Scale	Title/Characteristic features:			Drawing No.
✓	BLOCK FLOW DIAGRAM			Z0-GEM-6894
Orig. Size	COAL TO GASOLINE CONV.			MRDC/ERDA STUDY
A0	VIA METHANOL			EF-76-C-01-2447
	BASE CASE I			Submitted for:
				Reviewed by:
				Reference Log:

Prepared	Date 2.6.77	Name VI	GEM 00-0865	Lampson Longf. Mitchell/Brinkhoff GmbH Frankfurt/Main
Checked				
Standard				
Orig. Iss.	Title/Characteristic Features			Drawing No.
7	PROCESS FLOW DIAGRAM RECOMPRESSION SECTION OF THE GASIFICATION UNIT			ZO-GEM-6096 MRDC/ENDA STUDY EP-76-C-01-2447
Orig. Iss.	UNIT 101/201 BASE CASE 1/II			Approved by _____ Supervised by _____ Drawing by _____
AD

ITEM NO.	NAME	OPER. APPROX. SPARE I.D. LENGTH T-F
102-B-01	SHIFT START-UP HEATER	1 x 0
102-D-01	SHIFT PREHEATER	2 x 0 11'-0" SPHERE
102-D-02	FIRST SHIFT REACTOR	2 x 0 13'-6" / 34'
102-D-03	SECOND SHIFT REACTOR	2 x 0 13'-6" / 34'
102-E-01	FIRST SHIFT H.E.	2 x 0
102-E-02	SECOND SHIFT H.E.	2 x 0
102-E-03	THIRD SHIFT H.E.	2 x 0
102-E-04	50 PSIG STEAM GENERATOR	2 x 0
102-F-01	FEED GAS LIQUOR SEPARATOR	2 x 0
102-F-02	50 PSIG STEAM DRUM	2 x 0

◇	STREAM NUMBER
○	PISTON
○	TEMPERATURE
◇	FLOW RATE DRY GAS
◇	FLOW RATE STEAM AND LIQUIDS

NOTES:
 STREAMS WITHOUT STREAM NUMBERS
 ARE NOT INCLUDED IN THE OVERALL
 MATERIAL BALANCE.
 THIS PFD IS IDENTICAL FOR BASE CASE I AND II
 EXCEPT AS NOTED

Prepared	00777 VI	GEM	00-0865
Checked			
Designed			
Drawn			
By			
Check			
Scale			
Notes	PROCESS FLOW DIAGRAM RAW GAS SHIFT		
Unit	UNIT 102/202	Base Case I/II

EQUIPMENT LIST		
ITEM NO.	NAME	OPER. SPARE
103-E-01	50 PSIG STEAM GENERATOR	3 + 0
103-E-02	20 PSIG STEAM GENERATOR	3 + 0
103-E-03	COOLER	3 + 0
103-E-04	TREN COOLER	3 + 0
103-F-01	20 DRUM	3 + 0
103-F-02	50 PSIG STEAM DRUM	3 + 0
103-F-03	20 PSIG STEAM DRUM	3 + 0
103-F-04	TARRY GAS LIQUOR TANK	1 + 0
103-G-01	TARRY GAS LIQUOR PUMP	1 + 1

- ◇ STREAM NUMBER
- PRESSURE PSIG
- TEMPERATURE °F
- ▱ FLOW RATE DRY GAS (lbmol/hr)
- ▭ FLOW RATE STEAM AND LIQUIDS (MMBtu/hr)

NOTES:
THIS PFD IS IDENTICAL FOR
BASE CASE I AND II

STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Approved	11/77	YI	GEM	00-0865	Longf. (Monsieur) (Monsieur)
Checked					
Standard					
Orig. Scale	Title/Characteristics/Features				
1/	PROCESS FLOW DIAGRAM				
	RAW GAS COOLING				
Orig. Set	UNIT 103/203 BASE CASE I/II				
A0	Submitted for:				
	Reviewed by:				
	Approved by:

EQUIPMENT LIST		
ITEM NO.	NAME	OPER. SPARE
104-C-01	BOOSTER COMPRESSOR	1 + 0
104-E-01	100 PSIG STEAM GENERATOR	1 + 0
104-E-02	20 PSIG STEAM GENERATOR	1 + 0
104-E-03	COOLER	1 + 0
104-E-04	TRIP COOLER	1 + 0
104-E-05	FINN COOLER	1 + 0
104-F-01	FLASH X.O. DRUM	1 + 0
104-F-02	SECOND X.O. DRUM	1 + 0
104-F-03	100 PSIG STEAM DRUM	1 + 0
104-F-04	20 PSIG STEAM DRUM	1 + 0

◇	STREAM NUMBER	
○	PRESSURE	PSIA
□	TEMPERATURE	°F
▭	FLOW RATE DRY GAS	lbmol/hr
▭	FLOW RATE STEAM AND LIQUIDS	MBBtu/hr

NOTES:
THIS PFD IS IDENTICAL FOR
BASE CASE I AND II

STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	Date	Rev	GEM	LOGON
Checked	1.8.77	VI	00-0865	Longf. Mineral/Blackburn/Smith
Number				Frankfurt (Main)
Orig. Scale	Title/Characteristic Features			
/	PROCESS FLOW DIAGRAM			
	SHIFTED GAS COOLING			
Orig. Set	UNIT 104/204	BASE CASE I/II	Drawing No. Z0-GEM-6899	
AD			HPC/ENCA STUDY	
			EF-76-C-01-2447	
			Submitted by	
			Reviewed by

EQUIPMENT LIST		
ITEM NO.	NAME	OPER. APPROX. + SPARE I.D. LENGTH T-T
105-C-01	VACUUM BLOWER	2 + 0 3 STAGES
105-D-01	ABSORBER	4 + 0 13' - 2" / 172'
105-D-02	FLASH REGENERATOR	4 + 0 11' - 8" / 182'
105-D-03	HOT REGENERATOR	2 + 0 5' - 10" / 118'
105-D-04	PREWASH FLASH TOWER	2 + 0 4' - 0" / 35'
105-E-01	FIRST MIXED GAS/SYN GAS H.E.	2 + 0
105-E-02	FIRST MIXED GAS CHILLER	2 + 0
105-E-03	SECOND MIXED GAS/SYN GAS H.E.	2 + 0
105-E-04	SECOND MIXED GAS CHILLER	4 + 0
105-E-05	ABSORBER P/A CHILLER	4 + 0
105-E-06	HOT REGENERATOR REBOILER	2 + 0
105-E-07	HOT REGENERATOR OVER CONDENSER	2 + 0
105-E-08	HOT REGENERATOR OFFGAS CHILLER	2 + 0
105-E-09	FLASH REGENERATED/HOT REGENERATED METHANOL H.E.	2 + 0
105-E-10	LADEN METHANOL CHILLER	4 + 0
105-E-11	RECTISOL OFFGAS/LIQUID REFRIGERANT H.E.	2 + 0
105-E-12	FIRST PREWASH FLASHED METHANOL/WASTE HEAT H.E.	2 + 0
105-E-13	SEC. PREWASH FLASHED METHANOL/WASTE HEAT H.E.	2 + 0
105-F-01	CAUSTIC SODA TANK	1 + 0 Not Shown on PFD
105-F-02	REGENERATED METHANOL TANK	1 + 0
105-F-03	FRESH METHANOL TANK	1 + 0
105-F-04	RECTISOL HOT REGENERATOR REFLUX DRUM	2 + 0
105-F-05	MIXED GAS LIQUOR SEPARATOR	2 + 0
105-G-01	RECTISOL INJECTION METHANOL PUMP	2 + 2
105-G-02	PREWASH FLASH TOWER EFFLUENT PUMP	2 + 2
105-G-03	RECTISOL PREWASH FLASH TOWER SEC. STAGE FEED PUMP	2 + 2
105-G-04	CAUSTIC SODA INJECTION PUMP	2 + 0 Not Shown on PFD
105-G-05	ABSORBER P/A PUMP	4 + 2
105-G-06	ABSORBER TOP FEED PUMP	2 + 2
105-G-07	ABSORBER MAIN FEED PUMP	2 + 21
105-G-08	ABSORBER TOP FEED BOOMER PUMP	4 + 2
105-G-09	HOT REGENERATOR REFLUX PUMP	2 + 2
105-G-10	FLASH REGENERATOR TOP FEED PUMP	2 + 2
105-G-11	REGENERATED METHANOL PUMP	2 + 0 Not Shown on PFD
105-G-12	FRESH METHANOL PUMP	2 + 0
105-G-13	MAKE UP METHANOL PUMP	1 + 0

NOTES:
 STREAMS WITHOUT STREAM NUMBERS ARE NOT INCLUDED IN THE OVERALL MATERIAL BALANCE.
 THIS PFD IS IDENTICAL FOR CASE I AND II EXCEPT AS NOTED

Prepared	20.7.77	VI	GEM	LUTON
Checked			00-0865	Lurgi Mineralabs. GmbH Frankfurt (Main)
Standard				
Orig. Scale	Title/Characteristics/Revision			Drawing No.
/	PROCESS FLOW DIAGRAM GAS PURIFICATION (RECTISOL)			ZO-GEM-6900
Orig. Size	UNIT 105/205 BASE CASE I/II			MRDC/ERDA STUDY EF-76-C-01-2447
A				Approved by

EQUIPMENT LIST		
ITEM NO.	NAME	OPER. APPROX. - SPARE, L.D. LENGTH, T.
106-C-01	AIR BLOWER	2 x 0
106-D-01	ABSORBER	8 x 0 17'-9" / 210'
106-D-02	REACTION CHAMBER	2 x 0 20'-9" / 39'
106-D-03	OXIDIZER	2 x 0 36'-6" / 28'
106-E-01	SOLVENT HEATER	2 x 0
106-E-02	SULPHUR MELTER	2 x 0
106-F-01	SOLUTION PUMPING TANK	2 x 0
106-F-02	SLURRY TANK	2 x 0
106-F-03	SULPHUR VACUUM FILTER	2 x 0
106-F-04	MELTED SULPHUR ACCUMULATOR	2 x 0
106-G-01	LEAK SOLUTION PUMP	2 x 1
106-G-02	SLURRY PUMP	2 x 1
106-G-03	RECYCLE PUMP	2 x 1
106-G-04	MELTED SULPHUR PUMP	1 x 1
106-G-05	RICH SOLUTION INTERMEDIATE PUMP	4 x 2

STREAM NUMBER
 PRESSURE PSIG
 TEMPERATURE °F
 FLOW RATE DRY GAS Normal / hr
 FLOW RATE STEAM AND LIQUIDS 20000 / hr

NOTES:
 STREAMS WITHOUT STREAM NUMBERS
 ARE NOT INCLUDED IN THE OVERALL
 MATERIAL BALANCE.
 THIS PFD IS IDENTICAL FOR
 BASE CASE I AND II

Prepared	Date	Rev	GEM	 Large International Group Product Range
Checked	23.7.77	VI	00-0865	
Drawn				
By				
By				
PROCESS FLOW DIAGRAM SULPHUR RECOVERY (STRETFORD)			Project No. Z0-GEM-6901 HRO/EROA STUDY EF-76-C-01-2447 Location Date	
UNIT 106/206			BASE CASE I/II

EQUIPMENT LIST			
ITEM NO.	NAME	OPER. APPROX. SPARE I.D.	LENGTH T.
107-C-01	VENT BLOWER	1 + 0	
107-D-01	AMMONIA SCRUBBER	1 + 0	6'-0" 40'
107-E-01	DUSTY GAS LIQUOR COOLER	3 + 0	
107-E-02	OILY GAS LIQUOR COOLER	1 + 0	
107-E-03	OILY GAS LIQUOR TRIM COOLER	1 + 0	
107-E-04	AMMONIA SCRUBBER P/A COOLER	1 + 0	
107-E-05	GAS LIQUOR COOLER	1 + 0	
107-E-06	GAS LIQUOR TRIM COOLER	1 + 0	
107-F-01	DUSTY GAS LIQUOR TAR SEPARATOR	3 + 0	29'-0" 42'
107-F-02	DUSTY GAS LIQUOR EXPANSION VESSEL	3 + 0	
107-F-03	OILY GAS LIQUOR EXPANSION VESSEL	1 + 0	
107-F-04	DUSTY GAS LIQUOR OIL SEPARATOR	3 + 0	12'-6" 52'
107-F-05	OILY GAS LIQUOR SEPARATOR	1 + 0	12'-6" 65'
107-F-06	FINAL GAS LIQUOR SEPARATOR	3 + 0	12'-6" 58'
107-F-07	GAS LIQUOR TANK	1 + 0	
107-F-08	OIL TANK	1 + 0	
107-F-09	GAS LIQUOR SURGE TANK	1 + 0	
107-F-10	TAR TANK	2 + 0	
107-F-11	VENT K.O. DRUM	1 + 0	
107-F-12	API PIT	1 + 0	
107-F-13	H2S VENT K.O. DRUM	1 + 0	
107-G-01	DUSTY TAR P/A PUMP	3 + 3	
107-G-02	GAS LIQUOR INJECTION PUMP	1 + 1	
107-G-03	GAS LIQUOR PUMP	1 + 1	
107-G-04	GAS LIQUOR TRANSFER PUMP	1 + 1	
107-G-05	OIL TRANSFER PUMP	1 + 1	
107-G-06	SUMP PUMP	1 + 1	
107-G-07	SLURRY PUMP	1 + 1	
107-G-08	AMMONIA SCRUBBER P/A PUMP	1 + 1	
107-G-09	TAR TRANSFER PUMP	1 + 1	
107-Y-01	DUSTY GAS LIQUOR EXP. VESSEL	3 + 0	
107-Y-02	OILY GAS LIQUOR EXP. VESSEL	1 + 0	

◆ STREAM NUMBER
 ○ PRESSURE PSIG
 ○ TEMPERATURE °F
 ▭ FLOW RATE DRY GAS lbmol/hr
 ▭ FLOW RATE STEAM AND LIQUIDS Mlb/hr

NOTES:
 STREAMS WITHOUT STREAM NUMBERS ARE NOT INCLUDED IN THE OVERALL MATERIAL BALANCE.
 THIS PFD IS IDENTICAL FOR BASE CASE I AND II

Prepared	Date	Rev	GEM	Lurgi
Checked	01/07/77	V1	00-0865	
Drawn				Lurgi (Germany) GmbH
Orig. No.	PROCESS FLOW DIAGRAM			Drawing No. Z0-GEM-69.02
	GAS LIQUOR SEPARATION			MDC/ERDA STUDY EF-76-C-01-2447
Orig. No.	UNIT 107/207			BASE CASE I/II

EQUIPMENT LIST				
ITEM NO.	NAME	OPPR.	APPROX. SPARE I.D. LENGTH T-1	
109-D-01	DEACIDIFIER	1 + 0	12'-6"/82'	
109-D-02	TOTAL STRIPPER	2 + 0	12'-2"/115'	
109-D-03	ACID GAS SCRUBBER	1 + 0	8'-6"/174'	
109-D-04	STRIPPER	1 + 0	3'-0"/32'	
109-E-01	FEED WASTE HEAT E.E.	1 + 0		
109-E-02	DEACIDIFIER FEED/EFFLUENT H.E.	1 + 0		
109-E-03	DEACIDIFIER REBOILER	1 + 0		
109-E-04	DEACIDIFIER EFFLUENT COOLER	1 + 0		
109-E-05	TOTAL STRIPPER REBOILER	2 + 0		
109-E-06	TOTAL STRIPPER EFFLUENT COOLER	1 + 0		
109-E-07	DEACIDIFIER REFLUX COOLER	1 + 0		
109-E-08	ACID GAS SCRUBBER LOWER P/A COOLER	1 + 0		
109-E-09	ACID GAS SCRUBBER MIDDLE P/A COOLER	1 + 0		
109-E-10	ACID GAS SCRUBBER UPPER P/A COOLER	1 + 0		
109-E-11	AQUEOUS AMMONIA RECYCLE COOLER	1 + 0		
109-F-01	AMMONIA COLLECTING DRUM	1 + 0		
109-G-01	DEACIDIFIER BOTTOMS PUMP	1 + 1		
109-G-02	WASTE WATER PUMP	1 + 1		
109-G-03	TOTAL STRIPPER REFLUX PUMP	1 + 1		
109-G-04	ACID GAS SCRUBBER LOWER P/A PUMP	1 + 1		
109-G-05	STRIPPER FEED PUMP	1 + 1		
109-G-06	STRIPPER EFFLUENT PUMP	1 + 1		
109-G-07	ACID GAS SCRUBBER MIDDLE P/A PUMP	1 + 1		
109-G-08	ACID GAS SCRUBBER UPPER P/A PUMP	1 + 1		
109-G-09	PRODUCT PUMP	1 + 1		

◆ STREAM NUMBER
 ○ PRESSURE PSIG
 □ TEMPERATURE °F
 ▭ FLOW RATE DRY GAS lbmol/hr
 ▨ FLOW RATE STEAM AND LIQUIDS Hbm/hr

NOTES:
 STREAMS WITHOUT STREAM NUMBERS ARE NOT INCLUDED IN THE OVERALL MATERIAL BALANCE.
 THIS PFD IS IDENTICAL FOR BASE CASE I AND II

Project	207771	GEM	00-0865	20-GEM-6904
Client				
Design No.				
Design Title	PROCESS FLOW DIAGRAM AMMONIA RECOVERY			
Design Subtitle	ICHEME - LINZ / LURGII			
Design Date	UNIT 109/209	BASE CASE VII

-69-

EQUIPMENT LIST		
ITEM NO.	NAME	OPER. + SPARE
110-C-01	SYNGAS COMPRESSOR	2 + 0 (2 STAGES)
110-C-02	RECYCLE COMPRESSOR	2 + 0
110-D-01	REACTOR	1 + 0
110-E-01	SYNGAS COMPRESSOR INTERCOOLER	2 + 0
110-E-02	SYNGAS COMPRESSOR TRIM COOLER	2 + 0
110-E-03	REACTOR FEED/EFFLUENT H.E.	2 + 0
110-E-04	CONDENSER	2 + 0
110-E-05	TRIM CONDENSER	2 + 0
110-F-01	K.O. DRUM	2 + 0
110-F-02	REACTOR STEAM DRUM	2 + 0
110-F-03	EXPANSION VESSEL	2 + 0

	STREAM NUMBER	
	PIE VALVE	PSIG
	TEMPERATURE	°F
	FLOW RATE DRY GAS	lbmol/hr
	FLOW RATE STEAM AND LIQUIDS	Wt% / hr

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Issued	Date	Name	GEM		Lurgi	
Checked	28.07.77	VI	00-0865		Lurgi (Main)Frankfurt (Main)	
Standard						
Orig. Scale	Title/Characteristic Features		Drawing No.		Z0-GEM-6905	
	PROCESS FLOW DIAGRAM				STUD: ERGA STUD	
	METHANOL SYNTHESIS				EF-76-C-01-24	
Orig. Size	UNIT 110		BASE CASE I		Submitted for Approved by Checked by

EQUIPMENT LIST			
ITEM NO.	NAME	OPER. APPROX. - SPAN I.D. LENGTH T-T	
112-B-01	REDUCTION SYSTEM HEATER	1 * 0 Not shown on PFD	
112-C-01	RECYCLE COMPRESSOR	2 * 0	
112-D-01	REACTOR	2 * 0 9'-9" 13'	
112-D-02	CLEAN-UP REACTOR	2 * 0 8'-4" 16'-6"	
112-E-01	STEAM GENERATOR	2 * 0	
112-E-02	RECYCLE/BFW H.E.	2 * 0	
112-E-03	FIRST FEED/PRODUCT H.E.	1 * 0	
112-E-04	PRODUCT GAS CONDENSER	1 * 0	
112-E-05	PRODUCT GAS TRIM CONDENSER	1 * 0	
112-E-06	SECOND FEED/PRODUCT H.E.	1 * 0	
112-E-07	PRODUCT GAS/BFW H.E.	1 * 0	
112-E-08	REDUCTION SYSTEM COOLER	1 * 0 Not shown on PFD	
112-F-01	FIRST K.O. DRUM	1 * 0	
112-F-02	SEC. K.O. DRUM	1 * 0	
112-F-03	THIRD K.O. DRUM	1 * 0	
112-F-04	FOURTH K.O. DRUM	1 * 0	
112-F-05	REDUCTION SYSTEM K.O. DRUM	1 * 0 Not shown on PFD	

◇	STREAM NUMBER	
○	PRESSURE	PSIG
□	TEMPERATURE	°F
▭	FLOW RATE DRY GAS	lbmol/hr
▭	FLOW RATE STEAM AND LIQUIDS	lb/hr

NOTE:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	08/77 YI	GEM	00-0885	Large Equipment/Process Control
Checked				
Drawn				
Orig. Iss.		PROCESS FLOW DIAGRAM		20-GEM-0906
		METHANATION		PROCESS STUDY
		UNIT 112		EF-76-C-01-2447
		BASE CASE I

EQUIPMENT LIST			
ITEM NO.	NAME	OPER. APPROX.	SPARE L.D. LENGTH T-T
113-C-01	LIGHT GAS COMPRESSOR	1 x 0	
113-D-01	CO ₂ ABSORBER	1 x 0	7'-0"/51"
113-D-02	REGENERATOR	1 x 0	7'-0"/51"
113-E-01	LEAN/RICH H.E.	1 x 0	
113-E-02	COOLER	1 x 0	
113-E-03	TRIM COOLER	1 x 0	
113-E-04	REGENERATOR OVHD CONDENSER	1 x 0	
113-E-05	REGENERATOR OVHD TRIM CONDENSER	1 x 0	
113-E-06	REGENERATOR REBOILER	1 x 0	
113-F-01	FILTER	1 x 0	
113-F-02	REGENERATOR REFLEX DRUM	1 x 0	
113-F-03	REGENERATOR OFFGAS D.O. DRUM	1 x 0	
113-F-04	LIGHT GAS K.O. DRUM	1 x 0	
113-G-01	SOLUTION PUMP	1 x 1	
113-G-02	REGENERATOR REFLEX PUMP	1 x 1	
114-D-01	WATER ABSORBER	1 x 0	
114-D-02	TRIM REGENERATOR	1 x 0	
114-E-01	TRIM COOLER	1 x 0	
114-F-01	TRIM DRUM	1 x 0	
114-G-01	TRIM PUMP	1 x 1

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	2/27/77	VI	GEM	00-0865	Lurgi
Checked					Lurgi (Minerals) GmbH
Standard					Frankfurt (Main)
Orig. Scale					
File/Characteristics					
Process Flow Diagram	CO ₂ REMOVAL (MEA WASH)			Z0-GEM-6907	
	SNG DRYING (TEG WASH)			MRDC/ERDA STUDY	
	UNIT 113/114			EF-78-C-01-2447	
Base Case I

EQUIPMENT LIST			
ITEM NO.	NAME	OPER. APPROX.	*SPARE I.D. LENGTH T.
151-C-01	PRESSURE SWING OFFGAS RECOMPRESSOR (3 STAGES)	1 + 0	
151-D-01	PRESSURE SWING ADSORBER	4 + 0	
111-F-01	PRESSURE SWING OFFGAS HOLDER	1 + 0	
151-B-01	REACTOR FEED HEATER	1 + 0	
151-C-01	RECYCLE COMPRESSOR	1 + 1	
151-D-01	REACTOR	1 + 0 3'-0"	30'
151-D-02	AMINE WASH TOWER	1 + 0	
151-D-03	NAPHTHA STABILIZER	1 + 0 3'-0"	70'
151-E-01	REACTOR FEED/EFFLUENT H.E.	1 + 0	
151-E-02	REACTOR EFFLUENT COOLER	1 + 0	
151-E-03	REACTOR EFFLUENT TRIM COOLER	1 + 0	
151-E-04	STABILIZER REBOILER	1 + 0	
151-E-05	STABILIZER OVER CONDENSER	1 + 0	
151-E-06	STABILIZED NAPHTHA COOLER	1 + 0	
151-E-07	STABILIZED NAPHTHA TRIM COOLER	1 + 0	
151-F-01	REACTOR EFFLUENT FLASH DRUM	1 + 0	
151-F-02	AMINE WASH OVER K.O. DRUM	1 + 0	
151-F-03	STABILIZER REFLUX DRUM	1 + 0	
151-G-01	FEED PUMP	1 + 1	
151-G-02	STABILIZER REBOILER PUMP	1 + 1	
151-G-03	STABILIZER REFLUX PUMP	1 + 1	
151-G-04	AMINE CIRCULATION PUMP	1 + 1	

- STREAM NUMBER
- PRESSURE PSIG
- TEMPERATURE °F
- FLOW RATE DRY GAS lbmol/hr
- FLOW RATE STEAM Mlbs/hr
- AND LIQUIDS

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	26.07.77 VI	GEM	Lurgi
Checked		00-0865	Lurgi Mineralölservice GmbH Frankfurt (Main)
Standard			
Orig. Scale	Title/Characteristic features: PROCESS FLOW DIAGRAM H ₂ RECOVERY (PRESSURE SWING) & NAPHTHA HYDROTREATING UNITS 111/151 BASE CASE I		Drawing No. ZQ-GEM-6908 MRD/ERDA STUDY EF-78-C-01-2447
Orig. See	A		Submitted by: Approved by: Checked by:

EQUIPMENT LIST				
ITEM NO.	NAME	OPER.	APPROX. SPARK D.	LENGTH T-T
152-D-01	DEETHANIZER	1 + 0	8'-0"	80'
152-D-02	STABILIZER	1 + 0	6'-6"	105'
152-E-01	DEETHANIZER REBOILER	1 + 0		
152-E-02	DEETHANIZER SIDESTREAM/BOTTOMS H.E.	1 + 0		
152-E-03	STABILIZER OVHD CONDENSER	1 + 0		
152-E-04	STABILIZER OVHD PRODUCT COOLER	1 + 0		
152-E-05	STABILIZER BOTTOMS REBOILER	1 + 0		
152-E-06	STABILIZER SIDE REBOILER	1 + 0		
152-E-07	STABILIZER BOTTOMS COOLER	1 + 0		
152-E-08	STABILIZER BOTTOMS TRIM COOLER	1 + 0		
152-F-01	LIGHT GAS FLASH DRUM	1 + 0		
152-F-02	STABILIZER REFLUX DRUM	1 + 0		
152-G-01	STABILIZER REFLUX PUMP	1 + 1		

153-D-01	REACTOR/SETTLER	1 + 0	6'-6"	50'
153-D-02	DEISOBUTANIZER	1 + 0	9'-6"	165'
153-D-03	DEPROPANIZER	1 + 0	5'-0"	100'
153-E-01	DEISOBUTANIZER FEED/EFFLUENT H.E.	1 + 0		
153-E-02	DEISOBUTANIZER FEED HEATER	1 + 0		
153-E-03	MIXED BUTANES COOLER	1 + 0		
153-E-04	DEISOBUTANIZER SIDE REBOILER	1 + 0		
153-E-05	DEISOBUTANIZER BOTTOMS REBOILER	1 + 0		
153-E-06	MIXED BUTANES TRIM COOLER	1 + 0		
153-E-07	DEISOBUTANIZER BOTTOMS TRIM COOLER	1 + 0		
153-E-08	DEISOBUTANIZER OVHD CONDENSER	1 + 0		
153-E-09	DEISOBUTANIZER OVHD TRIM CONDENSER	1 + 0		
153-E-10	DEPROPANIZER FEED HEATER	1 + 0		
153-E-11	DEPROPANIZER REBOILER	1 + 0		
153-E-12	DEPROPANIZER OVHD CONDENSER	1 + 0		
153-E-13	DEPROPANIZER OVHD PRODUCT COOLER	1 + 0		
153-E-14	DEPROPANIZER BOTTOMS COOLER	1 + 0		
153-E-15	DEPROPANIZER BOTTOMS TRIM COOLER	1 + 0		
153-E-16	COOLER	1 + 0		
153-F-01	HF COOLER	1 + 0		
153-F-02	DEPROPANIZER REFLUX DRUM	1 + 0		
153-G-01	DEPROPANIZER FEED PUMP	1 + 1		
153-G-02	DEPROPANIZER REFLUX PUMP	1 + 1		
153-G-03	HF ACID RECYCLE PUMP	1 + 1		

- ◇ STREAM NUMBER
- PRESSURE PSIG
- ◊ TEMPERATURE °F
- ▭ FLOW RATE DRY GAS lbmol/hr
- ▭ FLOW RATE STEAM AND LIQUIDS Hlbs/hr

NOTE :
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	Date	Name	GEM	Lurgi
Checked	27.7.77	V1	00-0865	Lurgi Mineralölservice GmbH Frankfurt (Main)
Standard				
Orig. Scale	Title/Characteristics features			Drawing No.
/	PROCESS FLOW DIAGRAM FRACTIONATION & ALKYLATION			ZO-GEM-6916
Orig. Size	MRDC/ERDA STUDY EF-76-C-01-2447			Submitted for
A	UNITS 152/153 BASE CASE I			By

BASE CASE I
3.5 OFFSITE UNITS

Unless stated otherwise, units are shown on Block Flow Diagram ZO-GEM-6894 in Sub-Section 3.4. In addition, units such as boilers, generators and water treaters are also included in Steam/BFW Balance ZO-GEM-6910 in Sub-Section 3.6. The schematic flow diagrams (SFD) are placed at the end of this section.

3.5.1 Oxygen Production Unit 121

Purpose of the Unit is to produce the oxygen required for the gasification of the coal.

Description

The oxygen production unit is an air separation unit including the following:

- air filter
- air compressor
- air cooling
- cold box
- power recovery turbine, including electric power generator
- oxygen compressor
- nitrogen release stack
- liquid nitrogen storage tank 5,000 ft³ (for start-up, etc.)
- nitrogen evaporator, capacity 500 lb-mol/hr
- emergency liquid air evaporator
- liquid oxygen storage tank

Normal Capacity

Oxygen quantity (calculated as 100%): 14,060 lb-mol/hr
Oxygen purity: 98.06%

Design Capacity

105% of normal

Note: In addition, 600 lb-mol/hr of instrument air is supplied to the complex from this unit. (See Unit 127.)

3.5.2 Boiler Unit 122

Purpose of the Unit is to generate high pressure (HP) steam for the balance of the power requirements not provided by the various MP and LP steam generators using process waste heat.

Description

The boiler is a coal fired boiler complete with all necessary equipment required to produce 1609 psig steam, including provisions to burn the supplemental fuels and incinerate the sour offgases listed below. Efficiency assumed is 83%.

Main Fuel

Fine coal (composition listed in Sub-Section 2.3)
Quantity 274.0 Mlb/hr
Low heating value, as received 7,893 BTU/lb
(See Unit 128 process description.)

Supplemental Fuels

- Oil (from Gas Liquor Separation Unit 107)
Quantity 35.90 Mlb/hr
Low heating value 16,700 BTU/hr
- Tar (from Gas Liquor Separation Unit 107)
Quantity 42.85 Mlb/hr
Low heating value 15,700 BTU/lb
- Phenols (from Phenol Recovery Unit 108)
Quantity 15.26 Mlb/hr
Low heating value 7,800 BTU/lb

Incineration Fuel

- Sour offgases (mainly from Sulphur Recovery Unit 106)
Quantity 1,592.4 Mlb/hr
Low heating value 274 BTU/lb

Note: The heat content of these gases (30 BTU/SCF) has not been included in the boiler thermal balance.

Normal Capacity 2,291.2 Mlb/hr

Design Capacity 120% of normal

3.5.3 Main Superheater Unit 123

Purpose of the Unit is to superheat the HP steam generated in the boiler for more economic use in the various HP steam turbines.

Description

The main superheater consists of all equipment necessary to produce HP steam at outlet conditions of 986°F and 1,566 psig. It is an integral part of the boiler system. Unit 122 includes the fuel requirements for the superheater. A 43.2 Mlb/hr slip stream of boiler steam is not superheated.

3.5.4 Superheater Unit 124

Purpose of the Unit is to superheat surplus medium and low steam produced in the process units.

Description

The superheater consists of all equipment necessary to superheat MP and LP steam as follows:

	<u>MP Steam</u>	<u>LP Steam</u>
Inlet Pressure, psig	571	100
Outlet Pressure, psig	550	85
Inlet Temperature, °F	483	338
Outlet Temperature, °F	748	502

In addition, each coil is controlled individually and is able to be inactive while the other is fully operating.

The superheater is designed to burn part of the oil recovered in the Gas Liquor Separation Unit 107. Efficiency assumed is 79%.

Quantity of oil	15.81 Mlb/hr
Low heating value	16,700 BTU/lb

Normal Capacity

Coil 1: MP steam superheating	765.5 Mlb/hr
Coil 2: LP steam superheating	842.7 Mlb/hr

<u>Design Capacity</u>	105% of normal
------------------------	----------------

3.5.5 Electrostatic Stack Gas Precipitator Unit 125

Purpose of the Unit is the removal of particulate matter to meet the state and federal environmental requirements for coal fired boilers. (See Sub-Section 2.6)

Description

The unit consists of all equipment required to remove the dust from Boiler Unit 122 stack gas to a level which is compatible with the downstream Stack Gas Clean Up Unit 126. The stack gas leaving Unit 126 will contain 0.1 pound of particulates per million BTU of fuel fired.

<u>Normal Capacity</u>	167.8 Mlb-mol/hr
------------------------	------------------

<u>Design Capacity</u>	120% of normal
------------------------	----------------

3.5.6 Stack Gas Clean-Up Unit 126

Purpose of the Unit is to remove SO₂ from the stack gas to meet the state and federal regulations for coal fired boilers. (See Sub-Section 2.6)

Description

The unit consists of all equipment required to remove SO₂ from the stack gas of Boiler Unit 122 to a level of 0.2 pounds SO₂ per million BTU of fuel fired. The SO₂ absorbant is a lime slurry. The clean stack gas is discharged to the atmosphere via a 300 foot stack.

<u>Normal Capacity</u>	167.8 Mlb-mol/hr, containing 36.1 lb-mol/hr SO ₂
------------------------	--

<u>Design Capacity</u>	120% of normal
------------------------	----------------

3.5.7 Instrument and Plant Air Unit 127 (not shown)

Purpose of the Unit is to supply instrument air for Air Separation Unit 121 and the boiler area only, and to supply plant air for maintenance purposes. (*)

Description

The unit consists of all equipment, such as compressors and dryers, to produce instrument and plant air. The instrument air is available at 85 psig and -10°F dew point. The plant air will be available at a pressure ranging from 85 to 140 psig.

Design Capacity

Plant air	100 lb-mol/hr
Instrument air	50 lb-mol/hr

(*) Instrument air for the total complex (estimated to be 600 lb-mol/hr, normal) is supplied by the Air Separation Unit 121, from a point where the air is pressured and dried.

3.5.8 Coal Handling Unit 128

Purpose of the Unit is to prepare the as mined coal into suitable feedstocks for the gasifiers and boiler and to provide coal storage.

Technology Used

Commercial-type coal crushing and screening facilities are used to produce well-sized coal for gasification and fines for boiler firing.

The well-sized coal is in the range of 1/4" to 2", containing approximately 15% oversize and 7% undersize.

Process Description (SFD ZO-GEM-6909)

The coal is delivered by trucks from the adjacent mine area. They operate six days per week delivering approximately 32,000 tons per day. Trucks flood unload into the truck dump station having four dump pockets, each with a feeder outlet designed to accommodate two trucks simultaneously. The coal drops into a bin and is fed into the four primary crushers by four plate feeders.

Crushers reduce the size to minus 8" with a minimum generation of fines. The product of the primary crushers discharges onto two belt conveyors for weighing and conveying to the primary screening station using 8" x 20" single deck screens. The minus 2" product is fed to two belt conveyors and the plus 2" product is discharged into secondary crushers, which reduce the oversize coal to minus 2".

The minus 2" coal is then conveyed to a transfer station from where the coal is directed to the live or dead storage piles or, through a by-pass conveyor, directly to secondary screening. Normally, the conveyor to the live storage will be used. The live storage area is sufficient for about six full days of plant production. The dead storage area is sufficient to feed the plant for approximately 30 days.

Coal is reclaimed from live storage via conveyors and is transferred to the secondary screening building for final sizing into gasifier and boiler feeds. In this building, the coal is fed to the screens through variable rate vibrating feeders. The oversize from each screen falls onto two collecting conveyors for sampling and transfer to the gasifier building feed conveyors. The undersize product (minus 1/4") also falls onto two collecting belts for transfer to the fines silo.

Two belt conveyors, equipped with scales and samplers, carry the fines from the storage silo to Boiler 122.

Normal Capacity

Gasifier feed (1/4" to 2")	1,901.3 Mlb/hr
Fine Coal (minus 1/4")	376.5 Mlb/hr

3.5.9 Ash Handling Unit 129

Purpose of the Unit is to receive hot ash from the gasifier ash locks and cool the ash to a suitable temperature for continuous transport and disposal without formation of dust.

Technology Used

The ash handling system is a hydraulic sluiceway system similar to the ash system used commercially by Sasol. It has proven to be very satisfactory for handling the ash from a large number of gasifiers.

Process Description (SFD ZO-GEM-6911)

The ash from the gasifiers discharges into totally enclosed sluiceways located below grade under the gasifiers. The ash from the gasifiers is quenched by a large circulating stream of water which is recycled from the thickener clear overflow. Exhaust Fan 129-C-01 exhausts a mixture of air and water (steam) from the sluiceway. The stream of air and water is quenched with water sprays before being released to the atmosphere to reduce the water content of the stream and to eliminate any dust.

The mixture of ash and water flows by gravity to Duplex Spiral Classifier 129-Y-01 which separates the bulk of the ash from the water. Fine ash and water from the classifier flow by gravity into Classifier Sump 129-F-01 while solids from the classifier are fed to Conveyor 129-Y-02.

The water and fines from the classifier sump are pumped to Thickener 129-F-02 which is a cone bottom center feed rake thickener. The clear overflow from the thickener flows to Thickener Overflow Sump 129-F-03. From this sump, water is pumped back to the sluiceway by Thickener Overflow Sump Pump 129-G-02. The bottoms of the thickener is pumped by 129-G-01 to Filter 129-F-04. Filtrate is recycled to the thickener by 129-G-04. Solids are fed to the conveyor. The conveyor discharges the solids from the filter and from the classifier into Ash Storage Bin 129-F-05.

3.5.10 BFW Preparation Unit 131

Deaerator (131/1)

Purpose of Section 131/1 is to deaerate the boiler feed water (BFW) before steam generation.

Description

The deaerator section uses commercial-type deaeration equipment to remove dissolved gases from steam condensate and fresh water.

The dissolved gases in these streams are removed by heat supplied from Heat Exchanger 150-E-06. (See PFD ZO-GEM-6915.)

After deaeration, the BFW is pumped to the various steam generators. Stripped dissolved gases are vented to the atmosphere.

Normal Capacity

	<u>Temp., °F</u>	<u>Flow, Mlb/hr</u>
MP condensate	483	86.5
LP condensate	284	972.3
Vacuum condensate	207*	2,461.3
Methanation Unit 112 process condensate	288	103.0
BFW make-up water	207*	2,066.9
Total	<u>221</u>	<u>5,690.0</u>

* After heating in 150-E-06

Design Capacity 120% of normal capacity

Operating Pressure 17.6 psia

Demineralizer (131/2)

Purpose of Section 131/2 is to provide the high quality water required for high pressure steam generation.

Description

Commercial-type equipment is used. The fresh water is filtered, softened and demineralized before flowing to Deaerator 131/1. (The assumed fresh water analysis is reported in Sub-Section 2.3).

<u>Normal Capacity</u>	2,066.9 Mlb/hr
<u>Design Capacity</u>	120% of normal
<u>Operating Temperature</u>	68°F (*)

(*) The difference of 20°F in the fresh water temperature listed in Sub-Section 2.3 results from the use of this fresh water stream for direct cooling of air in the Oxygen Production Unit 121.

3.5.11 Cooling Water Make-Up Preparation Unit 132

Purpose of the Unit is to treat the fresh water required to replace losses in the cooling water system.

Description

The fresh water is softened and chemically treated to become suitable for make-up to the cooling tower system. Commercial-type equipment is used. In addition to treated fresh water, the biologically treated water from Waste Water Treatment Unit 135 and the humidity of the air condensed in Air Separation Unit 121 are also used as cooling tower make-up.

The CW make-up requirement has been estimated as follows:

	<u>Percent of CW Circulation</u>
Evaporation losses	2.60
Drift	0.07
Blow-down (*)	<u>0.33</u>
Total	3.00

(*) Blow-down is based on a hardness of the softened water of 35 ppm CaCO₃.

Normal Capacity

	<u>Mlb/hr</u>
Treated fresh water	2,090.5
Treated water from Unit 135 and humidity from Unit 121	<u>1,994.9</u>
Total	4,085.4

Design Capacity

Softening	200% of fresh water
Chemicals	115% of total water

3.5.12 Cooling Water Tower Unit 133

Purpose of the Unit is to supply the cooling water necessary for the steam turbine condensers and for the process/offsite unit trim coolers.

Description

Standard commercial-type cooling towers and pumps are used to provide 75°F cooling water. The cooling towers are designed for a maximum wet bulb temperature of 66°F. Make-up water is supplied to the cooling towers from Cooling Water Make-Up Preparation Unit 132.

Normal Capacity (*)

	<u>GPM</u>
Steam turbine condenser duty (temperature rise 75 to 100°F and discharge pressure 50 psig)	191,400
Trim cooler duty (temperature rise 75 to 97°F avg. and discharge pressure 64 psig)	81,725
Total	<u>273,125</u>

Design Capacity 115% of normal

(*) The CW capacity is based on air cooling to 130°F and trim cooling below 130°F.

3.5.13 Electric Power Generation Unit 134

Purpose of the Unit is to generate the electric power requirements for the plant complex.

Description

Electric power is generated from commercial-type power generators driven by steam turbines using waste steam from the process units. Two levels of steam are used to generate electric power. Generator 134-M-01 uses 48 psig, 378°F steam with Condensing Turbine 134-T-01. Generator 134-M-02 uses superheated 85 psig steam with Back Pressure Turbine 134-T-02 exhausting to 50 psig.

Electric power is generated at 6,000 Volts; stepdown transformers are provided.

Normal Capacity

	MW	Steam Flow, Mlb/hr
134-M-01	43.5	883.4
134-M-02	7.9	842.7

Design Capacity

110% of normal

3.5.14 Waste Water Treatment Unit 135

Purpose of the Unit is to treat the waste and acid waters of the total complex so that they can be used as part of the cooling water make-up requirements.

Description

The waste water treatment unit is a commercial-type, biological treatment process using air. In addition, the acid water will be neutralized using caustic soda.

Normal Capacity

<u>Composition</u>	<u>Flow, Mlb/hr</u>
Organic acids and phenols	4.8
Acetone plus C ₆ ⁺ containing some H ₂ S	2.2
Ammonia	1.3
Water	1,974.8
Total	1,983.1

Design Capacity

110% of normal capacity regarding to water flow rate
130% of normal capacity regarding to components.

3.5.15 Flare and Blow-Down Facilities 136 (not shown)

Purpose of the Unit is to provide relief for all liquid and gaseous effluents from the complex.

Description

A commercial-type flare system burns all gaseous streams coming from either process vents or safety valves. The blow-down facility consists of a holding pond to collect the cooling tower and steam system blow-down streams.

Normal Capacity

Blow down water to holding pond 508.8 Mlb/hr

Design Capacity 130% of normal

3.5.16 Storage 137 (not shown)

The following is a summary of the intermediate, product and chemical storage tank capacities which are not located within the process and offsite units:

Product Storage (15 days)

Anhydrous ammonia	1,700 ton (refrigerated)
Sulphur	1,000 ton (covered)
Gasoline	364,000 Bbl (floating roof)
Propane LPG	26,000 Bbl (pressure)
Mixed butane	37,000 Bbl (pressure)

Intermediate Storage (15 days)

Methanol	870,000 Bbl (floating roof)
Raw gasifier naphtha	22,000 Bbl (floating roof)

Chemical Storage

Diisopropyl ether	1,500 Bbl
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<u>Coal Fines</u> (7 days)	8,700 T (silo)
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3.5.17 Interconnecting Pipeway 138 (not shown)

Purpose of the Unit is to provide piping and racks for connection between the various process units and between the process and offsite units.

3.5.18 Refrigeration Unit 141

Purpose of the Unit is to supply the refrigeration requirements for the plant complex.

Description

An ammonia absorption refrigeration system is used. This process uses the 20 psig waste steam which cannot be utilized in another way. Two temperature levels of refrigeration are provided.

Normal Capacity

	---Duty, MMBtu/hr---	
<u>Temperature Level</u>	<u>+32°F</u>	<u>-45°F</u>
Purification Unit 105 and ammonia storage	25.5	70.5
<u>Design Capacity</u>		110% of normal

3.5.19 Gasoline Blending Unit 154

Purpose of the Unit is to blend in-line the various components continuously and automatically into a 10 RVP gasoline product.

Description

A typical commercial in-line blending operation is carried-out as follows:

- Component samples are test blended in the laboratory to determine the proper blending and additive recipe.
- Blending recipe requirements are entered into the blending control system.
- After initial checking, operation is placed on-stream and the gasoline product is sent to final storage.

Equipment consists of rundown tanks, the blending control system with valves, flow meters, analyzer and controllers, and pumps.

NOTES:
 STREAMS WITHOUT STREAM NUMBERS
 ARE NOT INCLUDED IN THE OVERALL
 MATERIAL BALANCE.
 THIS SFD IS IDENTICAL FOR BASE CASE I AND II
 EXCEPT AS NOTED

	Date	Name	G E M 00-0865	LURGI Lurgi Mineralölservice GmbH Frankfurt (Main)
Prepared	2.8.77	VI		
Checked				
Standard				
Orig. Scale	Title: Characteristic Features			Drawing No.
1/	SCHEMATIC FLOW DIAGRAM COAL HANDLING UNIT 128/228 BASE CASE I/II			ZO-GEM-6909
				MRDC/ERDA STUDY
				EF-76-C-01-2447
Orig. Size				Submitted by
A0				Supervised by
				Reviewed by

EQUIPMENT LIST

ITEM NO.	NAME	OPER. + SPARE
129-C-01	EXHAUST FAN	4 + 0
129-F-01	CLASSIFIER SUMP	2 + 0
129-F-02	THICKENER	4 + 0
129-F-03	THICKENER OVERFLOW SUMP	2 + 0
129-F-04	FILTER	4 + 0
129-F-05	ASH STORAGE BIN	2 + 0
129-G-01	THICKENER BOTTOMS PUMP	4 + 0
129-G-02	THICKENER OVERFLOW SUMP PUMP	2 + 2
129-G-03	CLASSIFIER SUMP PUMP	2 + 2
129-G-04	FILTRATE PUMP	4 + 0
129-Y-01	DUPLEX SPIRAL CLASSIFIER	4 + 0
129-Y-02	CONVEYOR	2 + 2

	STREAM NUMBER	
	PRESSURE	PSIG
	TEMPERATURE	°F
	FLOW RATE DRY GAS	lbmol/hr
	FLOW RATE STEAM AND LIQUIDS	Mtbs/hr

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.
THIS SFD IS IDENTICAL FOR BASE CASE I AND II

Prepared	29/07/77	VI	GEM	00-0865	Lurgi
Checked					Lurgi Mineraltechnik GmbH
Standard					Frankfurt (Main)
Orig. Scale	SCHEMATIC FLOW DIAGRAM				Drawing No. 20-GEM-6911
	ASH HANDLING SYSTEM				MRDC/ERDA STUDY
	(OFF SITE UNIT)				EF-76-C-01-2447
Orig. Site	UNIT 129/229				Submitted by
A	BASE CASE I/II				Reference No.

BASE CASE I
3.6 UTILITY REQUIREMENTS AND STEAM/BFW BALANCE

3.6.1 Utility Requirements

Utility requirements for the individual units can be found as follows:

<u>Utility</u>	<u>Source</u>
Fuel	Type and stream number: BFD ZO-GEM-6894 (Sub-Section 3.4) Quantity and composition: Material balance sheets (Appendix A)
Power	BFD ZO-GEM-6894
Cooling water	BFD ZO-GEM-6894
Boiler feed water	Steam/BFW Balance ZO-GEM-6910 (Sub-Section 3.6)
Steam	Steam/BFW Balance ZO-GEM-6910

In addition, offsite Sub-Section 3.5 contains utility information.

3.6.2 Steam/BFW Balance

The steam and boiler feed water flows are shown on Drawing ZO-GEM-6910. The steam/electric power balance is acceptable in accordance with the study bases. Only about 6 MW(e) is surplus in comparison with 249 MW of total electric and steam power required in the plant complex. In addition, except for about 43 Mlb/hr of 20 psig steam, all steam produced is utilized.

EQUIPMENT LIST		
ITEM NO.	NAME	OPER. + SPARE
131-C-01	VACUUM BLOWER STEAM TURBINE CONDENSORS	1 + 1
131-G-01	BFW MAKE-UP PUMP	1 + 1
131-G-02	VACUUM CONDENSATE PUMP	1 + 1
131-G-03	LP BFW PUMP	2 + 1
131-G-04	MP BFW PUMP	1 + 1
131-G-05	HP BFW PUMP	3 + 2
131-E-01	LP STEAM SURPLUS CONDENSER	1 + 0
134-M-01	MAIN ELECTRIC POWER GENERATOR	2 + 0
134-M-02	SECOND ELECTRIC POWER GENERATOR	1 + 0
101-T-01	LOCK GAS COMPRESSOR STEAM TURBINE	1 + 0
104-T-01	SHIFTED GAS BOOSTER COMPRESSOR STEAM TURBINE	1 + 0
105-T-01	RECTISOL VACUUM BLOWER HP STEAM TURBINE	4 + 0
105-T-02	RECTISOL VACUUM BLOWER LP STEAM TURBINE	4 + 0
105-T-03	RECTISOL ABSORBER MAIN FEED PUMP STEAM TURBINE	4 + 0
110-T-01	METHANOL SYNTHESIS SYNGAS COMPRESSOR STEAM TURBINE	2 + 0
110-T-02	METHANOL SYNTHESIS RECYCLE COMPRESSOR STEAM TURBINE	2 + 0
111-T-01	PRESSURE SAFING OFFGAS RECOMPRESSOR STEAM TURBINE	1 + 0
112-T-01	METHANATION RECYCLE COMPRESSOR STEAM TURBINE	1 + 0
121-T-01	OXYGEN COMPRESSOR STEAM TURBINE	1 + 0
121-T-02	AIR COMPRESSOR STEAM BACK PRESSURE TURBINE	1 + 0
121-T-03	AIR COMPRESSOR STEAM CONDENSING TURBINE	1 + 0
131-T-01	BFW MAKE-UP PUMP STEAM TURBINE	1 + 0
131-T-02	VACUUM CONDENSATE PUMP STEAM TURBINE	1 + 0
131-T-03	LP BFW PUMP STEAM TURBINE	1 + 0
131-T-04	MP BFW PUMP STEAM TURBINE	1 + 0
131-T-05	HP BFW PUMP STEAM TURBINE	1 + 0
134-T-01	MAIN ELECTRIC POWER GENERATOR STEAM TURBINE	2 + 0
134-T-02	SECOND ELECTRIC POWER GENERATOR STEAM TURBINE	1 + 0
122	BOILER	3 + 0
123	MAIN SUPERHEATER	3 + 0
124/1	550 PSIG STEAM SUPERHEATER	1 + 0
124/2	100 PSIG STEAM SUPERHEATER	1 + 0
131/1	DEAERATOR	3 + 0
131/2	DEMINERALIZER	1 + 0

1) Vacuum steam level 17 psia 120°F 5.8% condensed 1,055 BTU/lb
 C.W. requirements 75/100°F for all steam turbine condensers
 are 2,404 MM BTU/hr corresponding to 191,800 GPM

Prepared	15.6.77	Name	Brah	GEM	00-0865	Lurgi
Checked						Lurgi Mineraltechnik GmbH
Standard						Frankfurt/Main
Orig. Scale		Title/Characteristic features			Drawing No.	
		STEAM/BFW BALANCE			20-GEM-6910	
		COAL TO GASOLINE CONV.			MRDC/ERDA STUDY	
		VIA METHANOL			EF-76-C-01-2447	
		BASE CASE I			Scheduled for:	
					Supervised by:	
					Reference Eng.	

BASE CASE I
3.7 TRAIN PHILOSOPHY

The train philosophy for the various units was selected on the basis of providing a plant complex having an onstream factor of 92%. Consequently, parallel trains have been used for many units to give flexibility in both operation and maintenance. Also, because of the large size of the complex, some units must be divided into parallel trains. In the methanol conversion and hydrocarbon processing area, however, intermediate storage is used to provide this flexibility.

In addition, all normally operating pumps, reciprocating compressors and conveyors are provided with an 100% spare.

The following is a summary of the train philosophy used for each unit:

Gasification Unit 101

Two parallel trains, each containing 14 Lurgi gasifiers, are used. Each gasifier includes a wash cooler, waste heat boiler and other associated equipment.

Only 25 gasifiers will be required to produce the design synthesis gas quantity. The other three spare gasifiers can be withdrawn from service for maintenance.

Raw Gas Shift Unit 102

Two parallel trains are provided because of reactor size limitations and to provide operating flexibility.

Raw Gas Cooling Unit 103

Three parallel trains are provided due to the size limitation of the heat exchangers.

Shifted Gas Cooling Unit 104

One train is provided since the heat exchange equipment is small and a centrifugal booster compressor is provided.

Gas Purification Unit 105

The absorber and regenerator section is divided into four parallel trains to allow towers to be shop fabricated. All the other sections of the unit are divided into two parallel trains for operating flexibility.

Sulphur Recovery Unit 106

The absorber section is divided into four parallel trains due to the large size of the absorbers. In addition, because of the height requirements of the absorbers, each train will contain two absorbers in series. All other sections of this unit are divided into two parallel trains for operating flexibility.

Gas Liquor Separation Unit 107

The dusty gas liquor separation equipment is divided into three trains to provide operating flexibility and to keep the equipment reasonably sized.

Phenol Recovery Unit 108

The phenol extraction section is divided into two parallel trains for operating flexibility and for reasonably sized equipment.

Ammonia Recovery Unit 109

The total stripper and associated equipment is divided into two parallel trains because of size limitations.

Methanol Synthesis Unit 110

Because of manufacturing size limitations, this unit is divided into four parallel reactor trains. Also, two feed/recycle centrifugal compressors are provided for operating flexibility.

H₂ Recovery Unit 111

One train is provided.

Methanation Unit 112

Two parallel reactor trains are provided for operating flexibility.

CO₂ Removal Unit 113

One train is provided.

SNG Drying Unit 114

One train is provided.

Methanol Conversion Unit 150
Naphtha Hydrotreating Unit 151
Fractionation Unit 152
Alkylation Unit 153

All are single train units. They are decoupled from the gasification and methanol synthesis sections by 15 days of tank capacity for the crude methanol and raw naphtha. In addition, Unit 150 has the following reactor configurations for efficient operability:

<u>Reactors</u>	<u>Design</u>
First-stage DME	2 in parallel for possible 3 to 6 month regeneration
Second-stage M-Gasoline	6 in parallel for 14 day cyclic regeneration

Offsite Units

The offsite units are designed for a minimum of two parallel trains. In cases where commercial-sized equipment is too large with two trains, the number of trains has been increased.

SECTION 4
BASE CASE II
FISCHER-TROPSCH TECHNOLOGY

4.1 MATERIAL BALANCE

The overall material balance is shown below:

<u>Input</u>	<u>Mlb/hr</u>
Coal, as mined	2,308.2 ⁽¹⁾
Air	6,820.8
Water	4,374.9
Other	7.9
	<u>13,511.8</u>
 <u>Output</u>	 <u>Mlb/hr</u>
Ash	147.4
Products, including alcohols	519.7 ⁽²⁾
Byproducts	13.7
Blowdown water	526.6
Stack and vent losses	12,298.5
Other	5.9
	<u>13,511.8</u>

(1) 27,698 T/SD

(2) 48,760 Bbl/SD

Overall plant consumptions per barrel of product, converting SNG into a FOE barrel, are:

Coal:	0.568 T
Water:	6.15 Bbl
Air:	1.68 T

Stack and vent losses amount to about 3.0 tons per barrel of product.

Appendix B contains the complete, detailed material balance for Base Case II.

BASE CASE II
4.2 PRODUCT YIELDS AND QUALITY

Stream numbers are given below for reference to the material balance sheets in Appendix B and process diagrams in Sub-Section 4.4.

4.2.1 SNG (49)

<u>Quantity</u>	19,023.3 lb-mol/hr
	315.4 Mlb/hr
	173.3 MMSCF/SD

Composition (Only compounds greater than 0.1% are listed; see Appendix B for detailed composition.)

	<u>Percent</u>
Hydrogen	3.8
Methane	89.7
Ethene	1.0
Ethane	2.3
Propene	1.0
Propane	0.1
Carbon dioxide	0.5
Inerts (N ₂ + Ar)	1.6
	100.0

Other

Heat of combustion (HHV)	1,003 Btu/SCF
Carbon monoxide (0.1% max.)	0.07%
Water	0.01%
Sulfur	None

Compatibility Indexes (versus pure methane)

<u>Index</u>	<u>Calculated</u>	<u>Preferable</u>	<u>Objectionable</u>
Lifting, I _l	0.99	under 1.0	above 1.06
Flash-back, I _f	1.06	under 1.15	above 1.2
Yellow-tip, I _y	0.97	above 1.0	under 0.8

The SNG product is of satisfactory quality and is interchangeable with pure methane. The olefin nature of the Fischer-Tropsch light gases, however, gives rise to a yellow-tip index value slightly below the preferable value. If the olefins prove troublesome in actual tests, an expensive hydrogenation step for olefin saturation could be added.

4.2.2 Gasoline (50)

Quantity

13,580 Bbl/SD
140.9 Mlb/hr

Blending

<u>Component</u>	<u>Wt. %</u>
Mixed butanes	2.7
Light hydrocarbons	2.9
Alkylate	2.7
Light polymer gasoline	16.3
Hydrogenated heavy polymer gasoline	14.3
C5/C6 isomerate	25.1
Reformate	23.8
Hydrotreated gasifier naphtha	11.0
	<u>100.0</u>

Properties

Estimated properties and a comparison with unleaded gasoline specifications are presented in Table 4.2.1.

This gasoline meets all specifications. Compared to typical present-day gasolines, it is slightly lower in gravity and contains fewer aromatics.

Heavy polymer gasoline hydrogenation has been added in order to meet the olefin target of 20 vol. % max. Without hydrogenation, the following are estimated:

$$\begin{aligned}(\text{Research} + \text{Motor})/2 &= 88.5 \\ \text{Olefin, vol. \%} &= 28\end{aligned}$$

Mobil and industry experience with high olefinic gasolines is limited. Consequently, marketing such a gasoline would require extensive testing and, perhaps, additive package reformulation.

TABLE 4.2.1

COMPARISON OF PRINCIPAL UNLEADED GASOLINE SPECIFICATIONS
WITH ESTIMATED FISCHER-TROPSCH GASOLINE PROPERTIES -
CASE II

	<u>Estimated F-T Unleaded Gasoline Properties</u>	<u>Specifications</u>
Gravity, °API	67.2	
Octane Numbers		
Research	91	
Motor	83	82 min.
(Research + Motor)/2	87	87 min.
Volatility		
Reid Vapor Pressure, lb	10.0	
Distillation, °F		
IBP	86.5	
10%	108.9	158 max.
30%	137.3	
50%	186.0	170/250 min./max.
70%	249.6	
90%	335.2	374 max.
EP	420.6	437 max.
V/L Ratio (=20), °F	@127.3	@140 max.
Sulfur, wt. %	Nil	0.10 max.
Composition, vol. %		
Paraffins	60.5	
Olefins	19.9	20 max. (target)
Naphthenes	3.1	
Aromatics	16.5	
Molecular Weight	93.1	

4.2.3 Diesel Fuel (117)

Quantity

2,307 Bbl/SD
25.4 Mlb/hr

Properties

Estimated properties and a comparison with diesel fuel specifications are shown in Table 4.2.2.

This product could be marketed as a premium diesel oil, Grade No. 1-D, for engine service requiring frequent speed and load changes. Its relatively high estimated cloud point, however, could preclude it being marketed in cold weather regions.

4.2.4 Heavy Fuel Oil (118)

Quantity

622 Bbl/SD
7.4 Mlb/hr

Properties

Estimated properties and a comparison with gas turbine fuel oil specifications are shown in Table 4.2.3.

Because of the non-existent sulfur and metals contents, this product could be marketed as a premium gas turbine fuel.

4.2.5 Alcohols (156)

Quantity

2,025 B/SD
510 Mlb/hr

Composition

Composition of the mixed alcohol product is:

	<u>Wt. %</u>
Ethanol	59
I-propanol	14
N-propanol	14
2-butanol	4
I-butanol	1
N-butanol	5
2-pentanol	1
N-pentanol	1
C ₆ plus	1
	<u>100</u>

The alcohol product is essentially free of acids, aldehydes, ketones and water.

TABLE 4.2.2

COMPARISON OF PRINCIPAL DIESEL FUEL SPECIFICATIONS WITH
ESTIMATED FISCHER-TROPSCH DIESEL FUEL PROPERTIES - CASE II

	<u>DIESEL FUEL-ASTM D975(1)</u>			<u>Estimated F-T Diesel Fuel Properties</u>
	<u>Grade No. 1-D</u>	<u>Grade No. 2-D</u>	<u>Other</u>	
Gravity, °API	-	-		56
Cetane Number, min. (D613 or D976)	40	40	45(2)	>50
Volatility				
90% min./max. °F (D86)	-/550	540/640(5)		520
Flash Point, °F min. (D93)	100	125		125
Cloud Point, °F (D2500)	(3)	(3)		10-20
Viscosity, Kin. @ 100°F min./max. (D445)	1.4/2.5	2.0/4.3		2
Sulfur, wt. % max. (D129)	0.50	0.50	(4)	None
Corrosion, max. (D130)	No. 3	No. 3		No. 1
Carbon Residue on 10% Resid., max. (D524)	0.15	0.35		Trace

(1) 1976 Annual Book of ASTM Standards.

(2) Various engine builders' requirements.

(3) Varies with marketing region; maps included in ASTM D975.

(4) Varies in individual states, some as low as 0.3%.

(5) 540/680 90% min./max. proposed but currently not accepted by industry.

TABLE 4.2.3

COMPARISON OF PRINCIPAL FUEL OIL AND GAS TURBINE FUEL OIL SPECIFICATIONS WITH
ESTIMATED FISCHER-TROPSCH HEAVY FUEL OIL PROPERTIES - CASE II

<u>Fuel Oil</u>	<u>Fuel Oil No. 5 (Light) ASTM D396*</u>	<u>Gas Turbine F.D. No. 3 - GT ASTM D2880*</u>	<u>Estimated F-T Hvy. Fuel Oil Properties</u>
Gravity, °API	-	-	41
Volatility			
Flash Point, °F min. (D93)	130 or Legal	130 or Legal	150
Distillation	-	-	-
Ash, wt. % max. (D482)	0.10	0.03	Trace
Viscosity, SSU at 100°F, min. (D445)	150	45	Satisfactory
Sulfur, wt. % (D129)	Legal	-	None
Metals, ppm (wt.) max.			
Vanadium	-	2	0
Sodium + Potassium	-	5	Trace
Calcium	-	10	0
Lead	-	5	0

*1976 Annual Book of ASTM Standards.

4.2.6 Butane LPG (139)

Quantity

146 Blb/SD
1.2 Mlb/hr

Properties

Estimated properties and a comparison with LPG specifications are shown in Table 4.2.4.

This product is a satisfactory commercial butane fuel.

4.2.7 Propane LPG (138)

Estimated properties and a comparison with LPG specifications are shown in Table 4.2.4.

This product is a satisfactory commercial propane fuel.

4.2.8 Byproducts

Sulfur (29)

Quantity
Impurities

61 T/SD
0.5 wt. %

Anhydrous Ammonia (17)

Quantity
Impurities (mainly water)
Grade

103 T/SD
0.5 wt. % max.
agricultural

Excess Power (6,000 volts)

7.01 MW(e)

TABLE 4.2.4

COMPARISON OF PRINCIPAL LPG SPECIFICATIONS WITH
ESTIMATED FISCHER-TROPSCH LPG PROPERTIES - CASE II

	Commercial Propane <u>ASTM D1835*</u>	Est. F-T C ₃ LPG <u>Properties</u>	Commercial Butane <u>ASTM D1835*</u>	Est. F-T C ₄ LPG <u>Properties</u>
Vapor Pressure at 100°F, max., psig (D1267)	208	178	70	37
Volatile Residue				
Butane and Heavier, max. vol. % (D2163)	2.5	1	-	-
Pentane and Heavier, max. vol. % (D2163)	-	-	2.0	1
Corrosion, max. (D1838)	No. 1	No. 1	No. 1	No. 1
Sulfur, grains (D2784)	15	None	15	None

*1976 Annual Book of ASTM Standards.

BASE CASE II
4.3 THERMAL EFFICIENCY

Table 4.3.1 is a summary of the overall plant thermal efficiency, which is defined as the combustion heat of the products, byproducts and excess power divided by the combustion heat of the total coal feed. The efficiency has been calculated using both the high and low heating values.

TABLE 4.3.1

FISCHER-TROPSCH CASE II - THERMAL EFFICIENCY

	Quantity, Unit/SD	High Heating Value (HHV)	Total HHV, MMBtu/hr	Percent of Input	Low Heating Value (LHV)	Total LHV MMBtu/hr	Percent of Input
Input							
Coal, DAF	18,530 T	12,720Btu/lb	19,642	-	12,236Btu/lb	18,894 ⁽¹⁾	-
Methanol	4 T	9,790Btu/lb	3	-	8,610Btu/lb	3	-
			19,645			18,897	
Output							
SNG	173.26MMSCF	1,003.3Btu/SCF	7,243	36.9	904.7Btu/SCF	6,531	34.6
C3 LPG	1,107Bbl	3.815MMBtu/Bbl	176	0.9	3.514MMBtu/Bbl	162	0.9
C4 LPG	146Bbl	4.321MMBtu/Bbl	26	0.1	3.991MMBtu/Bbl	24	0.1
10 RVP Gasoline	13,580Bbl	5.023MMBtu/Bbl	2,842	14.5	4.682MMBtu/Bbl	2,649	14.0
Diesel Fuel	2,307Bbl	5.345MMBtu/Bbl	514	2.6	4.994MMBtu/Bbl	480	2.5
Hvy. Fuel Oil	622Bbl	5.682MMBtu/Bbl	147	0.7	5.326MMBtu/Bbl	138	0.7
Sub-Total			10,949	55.7		9,984	52.8
Alcohols	510Mlb	13,630Btu/lb	290	1.5	12,380Btu/lb	263	1.4
Sulfur	61 T	3,780Btu/lb	19	0.1	3,780Btu/lb	19	0.1
Ammonia	103 T	9,693Btu/lb	83	0.4	8,020Btu/lb	69	0.4
Power	6.01MW(e)	3,415Btu/kWH	20 ⁽²⁾	0.1	3,415Btu/kWH	20 ⁽²⁾	0.1
Total			11,361	57.8		10,355	54.8

(1) If LHV of as mined coal used (7,893 Btu/lb), overall LHV thermal efficiency becomes 56.8%.

(2) Direct thermal conversion used.

BASE CASE II
4.4 PROCESS DESCRIPTIONS

The discussions below follow the block flow diagram (BFD) or the process flow diagram (PFD) as noted. These diagrams are placed at the end of the discussion. The gasification, raw gas treating and byproduct recovery units, however, are identical to those in Base Case I; consequently, their PFD's are found in Sub-Section 3.4. Detailed compositions and flows of the numbered streams are found on the material balance sheets in Appendix B.

4.4.1 General (BFD ZO-GEM-6988)

Sized coal is received from the offsite Coal Handling Unit 228 (see Sub-Section 4.5), and is gasified in Gasification Unit 201. A portion of the raw gas generated is converted in Raw Gas Shift Unit 202 to meet the H_2/CO ratio requirements of F-T Synthesis Unit 250. The raw gas and shifted gas are cooled in Raw Gas Cooling Unit 203 and Shifted Gas Cooling Unit 204, respectively, before flowing to Gas Purification Unit 205. This unit removes the H_2S , CO_2 and naphtha from the raw gas. The H_2S contained in the purification unit offgas is converted to sulphur in Sulphur Recovery Unit 206. The purified gas (synthesis gas) is sent to F-T Synthesis Unit 250 where it is converted to hydrocarbon products.

The gas liquor condensed in Units 201, 202, 203, 204, and 205 flows to Gas Liquor Separation Unit 207 in which dusty tar and oil are recovered. The gas liquor is further processed in Phenol Recovery Unit 208 and Ammonia Recovery Unit 209 before flowing to Waste Water Treatment Unit 235.

The products from the F-T synthesis are upgraded and recovered in the following units: F-T Product Fractionation Unit 252, F-T Product Hydrotreating Unit 253, Hydrotreated Product Fractionation Unit 254, Catalytic Reforming Unit 255, C_5/C_6 Isomerization Unit 256, Catalytic Polymerization Unit 257, HF Alkylation Unit 258, Poly Gasoline Hydrogenation Unit 259, Light Ends Recovery Unit 260 and Alcohol Recovery Unit 262. The final products produced in these units are gasoline, diesel fuel oil, heavy fuel oil, n-butane LPG, propane LPG and alcohols.

In addition to the liquid products, SNG is produced in the SNG-upgrading train from the light gases produced in F-T Synthesis Unit 250. This train consists of Hydrocarbon Recovery Unit 210, Methanation Unit 212, where unreacted CO , H_2 and hydrocarbons are converted to methane, CO_2 Removal Unit 213, and SNG Drying and Compression Unit 214.

The hydrogen required for hydrotreating the F-T synthesis products and the naphtha from gasification is produced from hydrogen containing offgases in Hydrogen Recovery Unit 211 and Hydrogen Purification Unit 261.

4.4.2 Gasification Area (BFD ZO-GEM-6988)

Because the study basis calls for the same synthesis gas production in both base cases, the units in the coal gasification area, including gas treating and product recovery, are identical.

<u>Unit</u>	<u>PFD ZO-GEM</u>
201-Gasification (In Base Case I, Lock Gas Compressor 101-C-41 recompresses the syngas compressor losses. In Base Case II, these losses have been neglected.)	6895 & 6896
202-Raw Gas Shift	6897
203-Raw Gas Cooling	6898
204-Shifted Gas Cooling	6899
205-Gas Purification	6900
206-Sulfur Recovery	6901
207-Gas Liquor Separation	6902
208-Phenol Recovery	6903
209-Ammonia Recovery	6904

Consequently, descriptions of these units are not repeated in this sub-section.

4.4.3 Hydrocarbon Recovery Unit 210 (PFD ZO-GEM-6973)

Purpose of the Unit is to remove and recover heavy hydrocarbons from the Fischer-Tropsch synthesis purge gas to meet methanation feedstock specifications.

Technology Used

The commercial process used is a low temperature heptane wash. This process is conventionally used to handle a gas containing CO₂ because the operating temperature is high enough to prevent freezing of the CO₂.

Process Description

The feedgas is cooled against the product gas and by refrigeration in 210-E-01, 02, and 03 to condense the bulk of the higher hydrocarbons before being charged to Wash Absorber 210-D-01. To prevent freezing of water, a small alcohol stream is injected into the feedgas. In the absorber, the feed gas flows counter-currently to the heptane solvent which is pumped from Heptane Regenerator 210-D-02 through Heat Exchanger 210-E-05 and Chiller 210-E-04 to the top of the absorber.

The rich heptane leaving the absorber is fed to the heptane regenerator in which the absorbed hydrocarbons are removed by fractionation. The regenerator overhead product vapor is compressed by 210-C-01, cooled and combined with the liquid stream which is condensed from the feed gas in front of the absorber. The combined stream is sent to F-T Product Fractionation Unit 252.

The absorber overhead product gas flows to Methanation Unit 212.

4.4.4 H₂ Recovery Unit 211 (PFD ZO-GEM-6974)

Purpose of the Unit is to recover hydrogen for use in the plant hydrogenation/hydrotreating units. The feedstock is a slip stream of the product gas from hydrocarbon recovery.

Technology Used

Because of the relatively high CO₂ content of the feedgas, the Pressure Swing Process of Union Carbide Corp. is used.

Process Description

The unit consists of four parallel pressure-swing absorbers, 211-D-01, with one onstream and the other three undergoing regeneration. During operation, essentially all of the non-hydrogen components and a portion of the hydrogen are absorbed. The remaining hydrogen leaves the absorber at a purity of over 98%.

Regeneration is by pressure reduction in 3-stages with the final pressure being nearly atmospheric. The system is controlled automatically by motor values. An absorption/regeneration cycle requires several minutes.

The desorbed gases, called pressure-swing offgases, are recompressed by Compressor 211-C-01 and returned to the SNG upgrading train as feed to Methanation Unit 212. Gas Holder 211-F-01, on the suction side of the compressor, is required for buffering the non-static, pressure-swing

offgas flow from the regenerating absorbers.

For clarity purposes, the hydrogen-source streams and the hydrogen-feed streams are shown as part of the PFD for Units 211 and 251. Hydrogen compressors 211-C-03 and 04 are also included.

4.4.5 Methanation Unit 212 (PFD-ZO-GEM-6975)

Purpose of the Unit is the production of SNG meeting the specifications for interchangeability with existing pipeline gases. In addition, the CO content must be lowered to less than 0.1%.

Technology Used

The Lurgi Methanation Process is used.
(For addition comments, see Paragraph 3.4.13.)

Process Description

The feedgas is the purge gas from F-T Synthesis Unit 250, from which the bulk of the higher hydrocarbons has been removed in Hydrocarbon Recovery Unit 210 in order to prevent fouling of the methanation catalyst.

The methanation unit consists of two down-flow, fixed-bed reactors in series. The feedgas is heated in 212-E-03, 04, and 05 against the second reactor, 212-D-02, product. Steam is injected in the feedgas, and the gas is also diluted with a portion of the methanated gas from the first reactor, 212-D-01. The dilution gas is compressed by Recycle Compressor 212-C-01, after having been cooled by 212-E-01 and 02. MP steam is generated in 212-E-01.

The net reactor effluent from the first reactor flows to the second, or clean-up, reactor in which final methanation takes place. The clean-up reactor effluent is heat exchanged against the gas feed and cooled in Exchangers 212-E-06 and 07.

Process water condensed from the reactor effluent stream is collected and routed to BFW preparation Unit 231.

The methanated gas leaves the unit for further treating CO₂ Removal Unit 213.

4.4.6 CO₂ Removal Unit 213 (PFD ZO-GEM-6976)

Purpose of the Unit is to lower the CO₂ content in the SNG to about 0.5%, thereby improving its quality.

Technology Used

The Amine Guard Process of Union Carbide Corp. is used. (For additional comments, see Paragraph 3.4.14.)

Process Description

The Methanation Unit 212 product gas and the light gases from F-T Product Fractionation Unit 252 are charged to Absorber 213-D-01, in which the CO₂ is removed by a countercurrent stream of lean MEA solution. In the top of the absorber, the gas is scrubbed with a small flow of BFW to recover trace amounts of MEA solution. The purified gas then flows to SNG Drying and Compression Unit 214.

The absorber bottoms product (rich MEA solution) is expanded after heat exchange in 213-E-01 into MEA Regenerator 213-D-02, where the CO₂ and other co-absorbed compounds are stripped from the MEA solution. The steam in the regenerator overhead is condensed in Condensers 213-E-04 and 05, and the remaining offgases are sent to Boiler Unit 222 for incineration. The steam condensate is refluxed to the top of the regeneration. The lean solution from the bottom of the regenerator is pumped back to Absorber 213-D-01 after being cooled in 213-E-01, 02 and 03.

4.4.7 SNG Drying and Compression Unit 214 (PFD ZO-GEM-6976)

Purpose of the Unit is to dry the wet SNG to a water content of 4 lb/MMSCF and to compress the dried SNG for delivery into the SNG pipeline system.

Technology Used

The TEG Wash Process, a commercial process for drying natural gas, is used.

Process Description

The drying agent is a mixture of triethylene glycol (TEG) and other ethylene glycols.

The SNG is contacted countercurrently with lean TEG in Water Absorber 214-D-01. The water-rich TEG flows from the absorber to TEG Regenerator 214-D-02 which is heated by fuel gas. The steam stripped from the TEG is discharged to the atmosphere. The small reflux stream required is condensed within the vent tube by air cooling.

The regenerated TEG is stored in 214-F-01, where it is cooled by the rich TEG before being pumped into the top of Water Absorber 214-D-01.

The dried SNG is compressed by 214-C-01 for delivery into the SNG pipeline system.

4.4.8 Fischer-Tropsch Synthesis Unit 250 (PFD ZO-GEM-6977)

Purpose of the Unit is to synthesize hydrocarbons by reacting hydrogen and carbon monoxide.

Technology Used

Since the early 20's when Fischer and Tropsch produced higher hydrocarbons from carbon monoxide and hydrogen, the amount of research and development in the field of carbon monoxide hydrogenation has been overwhelming. Today, this chemistry can produce a full range of petrochemical and oil products, including methane (methanation), methanol, and liquid hydrocarbons and waxes (Fischer-Tropsch). Before 1940, commercial Fischer-Tropsch plants were operating in Germany, France and Japan. Low price crude oil after World War II precluded any further commercial use of F-T technology, the exception being Sasol in Sasolburg, South Africa. This plant, completed in 1955, is still in operation (Sasol I) and a large expansion is currently in progress (Sasol II). It is the Sasol technology, as reported in the literature, which is the technical basis for Unit 250 development.

Although a typical F-T product is a complicated mixture, the following overall equations illustrate the process:

These equations do not indicate the reaction mechanism, but they do show the stoichiometric relationship between reactants and products. Except for the water gas shift reaction, all reactions are highly exothermic. The F-T product includes paraffins, mono-olefins, aromatics, alcohols, aldehydes, ketones and fatty acids with carbon numbers from 1 through 35+. Small amounts of diolefins and esters can also be produced. Branching does occur but it is predominantly a single-methyl branched structure. Yield selectivity and composition is highly dependent upon the catalyst, reaction conditions and reactor type.

Commercial catalysts include cobalt (fixed-bed) and iron (fixed-and fluid-bed.) Both are promoted for improved activity and selectivity. Operating conditions range from 200 to 325°C and from atmospheric to 25 atm pressure, depending upon products desired, catalyst and reactor design. For example, conditions for the Sasol I medium pressure units are reported to be (15):

<u>Type</u>	<u>Fixed-Bed</u>	<u>Fluid-Bed</u>
Catalyst Base	Fe	Fe
Temperature, °C	220-255	320-330
Pressure, psig	360	330

Although iron is the base for both units, catalyst preparation and formulation are entirely different and very specific for each unit type.

The principal problem in designing the reactor is heat removal. Fixed-bed reactor designs are some form of a heat exchanger with catalyst being cooled by boiling water or circulating oil. Fluid-bed reactors include internal tube bundles for reaction heat removal.

As stated previously, Unit 250 is based on Sasol-type fluid-bed technology, derived mainly from references cited which include both Sasol articles and those reporting on Sasol operation. The projected commercial fluid-bed process design conditions and yields are as follows:

1. Feed Ratio $\text{H}_2/(2\text{CO} + 3\text{CO}_2) = 1.03$ Ratio is critical. (9) (12)

2. Basic yields (7) (8)

	<u>C atoms</u>	<u>H atoms*</u>	<u>H₂O atoms*</u>
C ₁	10	40.00	-
C ₂ =	4	8.00	-
C ₂	6	18.00	-
C ₃ =	12	24.00	-
C ₃	2	5.33	-
C ₄ =	8	16.00	-
C ₄	1	2.50	-
C ₅ plus	8	16.50	-
light oil	35	69.30	1.25
heavy oil	7	13.84	0.08
alcohols	6	11.28	2.70
acids	1	0.21	0.90
	<u>100</u>	<u>224.96</u>	<u>4.93</u>

*Estimated by MRDC.

3. Yields adjusted by MRDC to obtain 85.0% conversion of (CO + H₂) (8)

CO: 17,806.5 lb-mol/hr reacted = 96.25% conversion
H₂: $\frac{37,857.6}{55,664.1}$ lb-mol/hr reacted = 80.57% conversion
= 85.0% conversion

C ₁	28,843.6 lb/hr
C ₂ =	10,087
C ₂	16,219
C ₃ =	30,262
C ₃	5,285
C ₄ =	20,175
C ₄	2,612
C ₅ plus	21,196
light oil	89,397
heavy oil	17,181
alcohols	23,744
acids	<u>5,110</u>
	<u>270,111.6</u>

A detailed yield breakdown is presented in Table 4.4.1.

TABLE 4.4.1

FISCHER-TROPSCH CONVERSION UNIT 250
PRODUCT COMPOSITION

Component	MW	Syn Gas Feed, lb/hr	From Feed Gas, lb/hr	From Reaction, lb/hr	From C ₅ Plus (2), lb/hr	From Light Oil (3), lb/hr	From Heavy Oil (4), lb/hr	Total, lb/hr	Total, lb-mol/hr
N ₂	28.02	8,658.2	8,658.2					8,658.2	309.0
CO ₂ (1)	44.01	127,629.0	136,871.1					136,871.1	3,110.0
CO(1)	28.01	518,185.0	13,542.8					13,542.8	483.5
H ₂ (1)	2.016	94,721.8	18,824.2					18,824.2	9,337.4
C ₁	16.04	199,858.4	199,858.4	28,843.6				228,702.0	14,258.2
C ₂ ⁼	28.05	589.0	589.0	10,087.0				10,676.0	380.6
C ₂	30.07	8,329.4	8,329.4	16,219.0		40.2		24,588.6	817.7
C ₃ ⁼	42.08			30,262.0		1,099.6		31,361.6	745.3
C ₃	44.09			5,285.0		201.2		5,486.2	124.4
C ₄ ⁼	56.10			19,036.0		2,145.5		21,181.5	377.6
I C ₄ ⁼	56.10			1,139.0		134.1		1,273.1	22.7
N C ₄	58.12			2,612.0		402.3		3,014.3	51.9
1-C ₅ ⁼	70.13				7,690.0	3,754.7		11,444.7	163.2
IC ₅	70.13				3,204.0	1,564.4		4,768.4	68.0
NC ₅	72.15			(2)	1,922.0	938.7		2,860.7	39.6
1-C ₆ ⁼	84.16			21,196.0	3,684.0	4,337.4		8,021.4	95.3
I C ₆ ⁼	84.16				2,210.0	2,602.4		4,812.4	57.2
NC ₆	86.17				1,473.0	1,734.9		3,207.9	37.2
200	97				1,013.0	8,824.9		9,837.9	101.4
250	110					15,329.4		15,329.4	139.4
300	127/122					8,330.0	527.7	8,857.7	69.9
350	144			(3)		13,345.0		13,345.0	92.7
400	165/163			89,397.0		6,740.4	627.4	7,367.8	44.6
450	187					9,812.9		9,812.9	52.5
500	211/210					2,977.5	1,627.1	4,604.6	21.8
550	238/232					5,081.5	993.7	6,075.2	25.7
600	260						2,185.0	2,185.0	8.4
650	288						1,707.9	1,707.9	5.9
700	315			(4)			2,944.1	2,944.1	9.3
750	350			17,181.0			2,199.8	2,199.8	6.3
800	380						1,424.7	1,424.7	3.7
850	409						1,082.7	1,082.7	2.6
900	440						366.7	366.7	0.3
1,000 Plus	510						1,494.2	1,494.2	2.9
Alcohols	51.34	42.0	42.0	23,744.0				23,786.0	463.3
Acids	65.26			5,110.0				5,110.0	78.3
H ₂ O(1)	18.016			301,186.1				301,186.1	16,717.7
		958,012.8	386,715.1	571,297.7	21,196.0	89,397.0	17,181.0	958,012.8	48,326.0
			(958,012.8)						

(1) Yields reflect shift equation equilibrium.

4. Light and heavy oil carbon atom distribution and distillation, alcohol yield breakdown, and acid yield breakdown are from Reference 7.
5. Reactor design parameters used are:
 - Heat of reaction (MRDC estimate): 4,550 Btu/lb total product
 - Fresh feed charge: 207 MNm³/hr per reactor.

The literature, (10) & (14), refers to a second generation fluid-bed reactor being from 2 to 3 times the size of Sasol I. Reference 8 used a Sasol I reactor scale-up of 2 in their study. Using Reference 8 as the basis, the above charge rate per reactor represents a scale-up of 2.1. Five reactors are employed with one being a spare.

- Recycle mole ratio (15): 2/1
- Catalyst fill (MRDC estimate from (9) (12)):
335 metric tons per reactor.
- Operating conditions (7)
 - vapor feed temperature: 160°C
 - catalyst and vapor outlet temperature: 340°C
 - vapor outlet pressure: 300 psia
- Catalyst life (7) (8): 50 days

Process Description

The synthesis gas from Purification Unit 205 and the recycle gas are compressed together in Compressor 250-C-01, heat exchanged against a portion of the reactor effluent in Exchanger 250-E-01 and charged to the fluid-bed Reactor 250-D-01. After mixing with the circulating hot Fe catalyst, reaction takes place as the mixture flows up the reactor through tube bundles in which oil is pumped (250-G-01) for heat removal (temperature control). At the top of the reactor, the mixture enters a large vessel in which cyclones are installed for iron/vapor separation. The hot oil is circulated to Steam Generator 250-E-02 where 200 psig steam is produced.

Because of the expected fouling nature of the reactor effluent, it is washed and cooled from 645°F to 340°F in Effluent Wash Tower 250-D-02 by a recycle stream from the bottoms of Vapor Cold Wash Tower 250-D-03. A relatively clean, hot stream is withdrawn from Effluent Wash Tower 250-D-02 for cooling. Its heat is used for heating the reactor vapor feed (250-E-01), boiler feed water heating (250-E-06) and LP steam generation (250-E-07 and 08). A hot heavy oil is withdrawn from the bottom and sent to Fractionation Unit 252.

The overhead vapor is cooled in BFW Exchanger 250-E-03 and Condensers 250-E-04 and 05. It is then water washed in Wash Tower 250-D-03. The overhead vapor is split into recycle and purge gas streams. The latter is sent to Hydrocarbon Recovery Unit 210. The condensed liquid is also split into 2 streams: cold recycle to Tower 250-E-02 and light oil product to Wash Tower 250-D-04 for final water washing. The light oil is sent to Fractionation Unit 252. The used wash water, containing the alcohols and acids from the Fischer-Tropsch reaction, flows to Alcohol Recovery Unit 262.

4.4.9 Naphtha Hydrotreating Unit 251 (ZO-GEM-6974)

Purpose of the Unit is yield a clean, saturated stabilized naphtha for gasoline pool blending from the raw gasifier naphtha.

Technology Used

See Paragraph 3.4.17.

Process Description

Identical to Unit 151. See Paragraph 3.4.17.

4.4.10 F-T Product Fractionation Unit 252 (ZO-GEM-6978)

Purpose of the Unit is to separate the F-T reactor product into light gases, feedstocks for the polymerization and hydrogenation units and a 850+ residuum for boiler fuel.

Technology Used

Because of the uncertainty as to the effect of steam on the remaining alcohols and acids, a 4-tower, dry system is used.

Process Description

The heavy oil is heated in Furnace 252-B-01, flashed in Drum 252-F-01, and charged to Vacuum Tower 252-D-01. Vacuum is maintained by 252-C-01. The tower has an upper pump-around system. The overhead vapors and excess pump-around liquid are condensed/cooled in Condenser 252-E-03 and pumped (252-G-15) to the top of Absorber/Deethanizer 252-D-02. Vacuum residue (bottoms) is pumped (252-G-03) to Boiler Unit 222.

Feed to Absorber Deethanizer 252-D-02 consists of (1) light oil from Unit 250, (2) hydrocarbons recovered in Unit 210, (3) vacuum tower overhead, and (4) lean oil from Naphtha Splitter 252-D-04. The hydrocarbon stream from Unit 210 is first flashed in Drum 252-F-03. The absorber deethanizer has an upper and middle pump-around systems. The light gases are split into a fuel gas stream and a feed stream to CO₂ Removal Unit 213 in the SNG train. The deethanizer bottoms are sent to Debutanizer 252-D-03.

In 252-D-03, the propene/butene feed for Polymerization Unit 257 is obtained. The debutanizer uses a fired reboiler, 252-B-02.

The debutanizer bottoms, after cooling in Cooler 212-E-11, is charged to Splitter 252-D-04, in which naphtha is removed to obtain a heavier lean oil for recycling to Absorber Deethanizer 252-D-02. The tower bottoms (lean oil) and the overhead naphtha are recombined to become the feedstock for Hydrogenation Unit 253. The naphtha splitter also uses a fired reboiler, 252-B-03.

4.4.11 F.T. Product Hydrotreating Unit 253 (ZO-GEM-6979)

Purpose of the Unit is to saturate the olefins and to destroy the remaining alcohols and acids.

Technology Used

See Paragraph 3.4.17.

Process Description

The feed is pumped to reactor operating pressure (253-G-01), mixed with part of the hydrogen feed, heat exchanged against the reactor effluent in Exchanger 253-E-01, and finally heated to reactor operating temperature in Heater 253-B-01. Because of the high hydrogen consumption, Reactor 253-D-01 consists of multi-beds using a cold hydrogen quench for temperature control. A two-stage flash system is used: High Temp. Flash Drum 253-F-01 and Low Temp. Flash Drum 253-F-02. Liquid products are combined to become feed to Fractionation Unit 254. The hydrogen-rich gases from Drum 253-F-02 are split into hydrogen recycle and hydrogen feed for Poly Gasoline Hydrogenation Unit 259. The hydrogen recycle is compressed in Compressor 253-C-01, and then mixed with the make-up hydrogen. Reaction water collected in the low temperature drum is sent to Waste Water Treatment Unit 235.

Regeneration facilities for the hydrotreating catalyst are provided.

4.4.12 Hydrotreater Product Fractionation Unit 254 (ZO-GEM-6979)

Purpose of the Unit is to separate the hydrotreated product into a pentane/hexane stream for isomerization, a C₇/380 naphtha for reforming, a diesel oil product and a heavy fuel oil product.

Technology Used

A conventional 3-tower system is used.

Process Description

After heating in Heater 254-B-01, the hydrotreater product is charged to Main Fractionator 254-D-01, in which stripping steam is introduced at the bottom. The heavy fuel oil product is withdrawn from the bottom and after cooling sent to storage. A small amount of the heavy fuel oil, Stream 173.2, has been used in the final adjustment of the plant fuel balance. A side-cut is withdrawn to Steam Stripper 254-D-02 from which the diesel oil product, after cooling, is pumped to storage.

The light gases, butanes, pentanes/hexanes, naphtha and steam in the overhead product are cooled in Condensers 254-E-01 and 02, and separated in Reflux Drum 254-F-01. Light gases become a feed to Light Ends Recovery Unit 260. Water is pumped (254-G-09) to Waste Water Treatment Unit 235. The hydrocarbon liquid is split into reflux for the main fractionator and feed for Debutanizer 254-D-03.

In the debutanizer, essentially all the butanes are recovered and sent to Light Ends Unit 260. The debutanizer bottoms are charged to Naphtha Splitter 254-D-04. In the splitter, the pentanes and hexanes are fractionated from the heavy naphtha, or reformer charge and after cooling pumped (254-G-07) to Isomerization Unit 256. The cooled heavy naphtha is pumped (254-G-08) to Reforming Unit 255.

4.4.13 Catalytic Reforming Unit 255 (ZO-GEM-6980)

Purpose of the Unit is to increase the anti-knock quality of the C₇/380 naphtha.

Technology Used

Since its commercial introduction in 1950, catalytic reforming with platinum-based catalysts has become the major process for naphtha octane improvement (and aromatics production) in the petroleum industry. Reactions include: (1) dehydrogenation of naphthenes, (2) cyclization of straight-chain paraffins and subsequent dehydrogenation, (3) isomerization of paraffins and cyclopentane derivatives and (4) hydrocracking of paraffins and naphthenes. The formation of aromatics is the principal objective.

Catalytic reforming is carried out over a wide range of reaction conditions, the most important being pressure. Other variables include recycle gas rate, temperature, space velocity and catalyst particle size. Thermodynamically, dehydrogenation is favored by low pressure and high temperatures. These conditions, however, also favor the formation of coke. Fortunately, coke formation can be substantially suppressed by operating in an atmosphere of hydrogen without significant retardation of the dehydrogenation reactions. Typical reactor conditions are:

Pressure, psig	100-700
Recycle gas, SCF/Bbl	2,500-10,000
Temperature, °F	850-1,000
Space velocity, wt/hr/wt	1-3

In recent years, bimetallic catalysts - platinum plus other metal promoters, such as rhenium - have been commercialized. Their improved selectivity and activity permit reforming at lower pressures and higher severities, without shortening regeneration cycle times, than when using the previous standard platinum-on-alumina catalyst.

The principal problem in the design of catalytic reformers is heat balance. Reactions which produce aromatics are very endothermic. Although the exothermic hydrocracking reactions are partially offsetting, large amounts of heat must be supplied to the reaction zone. In fixed-bed units, the heat is supplied by employing multiple reactors in series with intermediate reheating of the reactants. As conditions dictate, a unit may be designed to operate either in a cyclic-or semi-regenerative mode of operation.

Most feedstocks are hydrotreated first to remove arsenic, sulfur and nitrogen compounds. Otherwise, these materials would poison the platinum catalyst. The cost of hydrotreating is easily justified by the extension of the reforming catalyst life.

Commercial processes are licensed by IFP, UOP Process, Houdry, Exxon, Chevron Research and Standard Oil (Indiana).

Process Description

The naphtha feed is pumped (255-G-04) to reactor operating pressure, mixed with the hydrogen-rich recycle gas, heat exchanged against Reactor 255-D-03 effluent in Exchanger 255-E-01 and heated to reactor operating temperature in Heater 255-B-01. The naphtha/hydrogen mixture then flows through three reactors in series, 255-D-01, 02 and 03, and is reheated before the second and third reactors in Heaters 255-B-02 and 03.

The third reactor effluent is cooled in 255-01, 02 and 03 and flashed in Drum 255-F-01. The hydrogen-rich overhead is split into a recycle gas stream and a feed stream to H₂ Purification Unit 261. The bottoms are pumped (255-G-03) to Stabilizer 255-D-04 for light ends fractionation. The butanes and lighter are sent to Light Ends Unit 260. After cooling, the stabilized reformat is sent to Gasoline Blending Unit 270.

Off-stream regeneration facilities are provided.

4.4.14 C₅/C₆ Isomerization Unit 256 (ZO-GEM-6981)

Purpose of the Unit is to increase the anti-knock quality of the pentanes and hexanes. Besides raising the pool octane, increasing the octane of the lighter gasoline constituents improves the octane balance between the front and back ends of the gasoline blend.

Technology Used

The first commercial isomerization units for the improvement of motor gasoline were announced in 1957. Isomerization requires the use of a catalyst. There is little heat evolved, and the reaction is limited by equilibrium and rate considerations. An economic balance is made between higher branched-chain ratios at low temperatures and higher reaction rates at high temperatures. Side reactions also must be considered in the selection of conditions.

Platinum-containing catalysts are favored in current commercial processes. They are promoted by the injection of trace amounts of organic chloride. The addition of a small amount of hydrogen suppresses the polymerization of the traces of olefins formed during the isomerization reaction and the formation of coke during hydrocracking reactions. Specifications for feedstock impurities, e.g., sulfur, water, benzene and C₇'s, vary considerably between the commercial processes. Licensors, however, have in recent years improved significantly impurity tolerances. Although operating conditions chosen generally allow a catalyst life of two or more years, should accidental deactivation occur, the catalyst can be easily regenerated and reactivated to full activity.

Typical reaction conditions are:

Temperature, °F	250-550
Pressure, psig	200-500
Space velocity, vol/hr/vol	1-5
H ₂ /hydrocarbon mole ratio	0.5-4

Processing conditions are generally milder for butane isomerization than for pentane or hexane isomerization.

Commercial processes are licensed by BP Trading, Shell Research and UOP Process.

Process Description

To maximize the octane improvement, Isomerization Unit 256 includes n-pentane recycling. The C₅/C₆ product from Unit 254 and the pentane products from isomerization are fed to Deisopentanizer 256-D-01. The overhead product, pentane isomerate, also contains the butanes and iso-pentane in the fresh feed and from 3 to 5 vol. % of n-pentane. After cooling, it is sent to Gasoline Blending Unit 270.

The n-pentane/hexane bottoms are mixed with recycle and make-up hydrogen, heated via Exchanger 256-D-04 and Heater 256-D-01 and passed over the catalyst in Reactor 256-D-02. The reactor effluent is cooled and flashed in Separator 256-F-02. A hydrogen-rich offgas is obtained for recycling via Compressor 256-G-01 and for hydrogen recovery in Unit 211.

The separator liquid is sent to Stabilizer 256-D-03 where the butanes and lighter are fractionated. The stabilizer offgases from Reflux Drum 256-F-03 after caustic washing are sent to H₂ Purification Unit 261, and the excess reflux to Light Ends Recovery Unit 260.

The stabilizer bottoms are charged to Depentanizer 256-D-04. The overhead product is pumped (256-G-04) to the deisopentanizer for recovery of the recycle n-pentane. The tower bottoms, hexane isomerate, after cooling, are sent to Gasoline Blending Unit 270.

4.4.15 Catalytic Polymerization Unit 257 (ZO-GEM-6982)

Purpose of the Unit is to polymerize the propene/butene mixture from the Fischer-Tropsch reaction into higher molecular weight compounds which are suitable for gasoline blending.

Technology Used

Catalytic polymerization has been a commercial process since about 1934 for the conversion of C₃ and C₄ olefins into a higher molecular weight poly gasoline. With a propene feed, trimers predominate and with a butene feed, dimers are the major products. Since the advent of catalytic reforming yielding a source of iso-butane, however, polymerization has generally been replaced by alkylation.

Olefin polymerization is catalyzed by acids and conversions are 85% or better. There is a large exothermic heat of reaction - about 400 Btu/lb of butene and about 670 Btu/lb of propene -, and a recycle stream is often used for temperature control. Commercial catalysts are mainly phosphoric acid on solids, such as kieselguhr and quartz chips.

The water content of the feed is critical. Optimum concentration, however, differs with the catalyst type, reactor operating conditions and feed composition. The olefin feed can be either "dried", saturated with water at a controlled temperature, or mixed with injected water.

The principal reactor design problem is temperature control. Multi-beds with liquid quench or tubular heat exchanger reactors generating steam are used. Typical operating conditions are:

Temperature, °F:	300 - 425
Pressure, psig:	400 - 1,500
Space velocity,	
Gal/hr/lb:	0.1 - 0.5

UOP Process and Chevron Research offer processes for licensing.

Process Description

The cat poly feed is pumped (257-G-01) to water saturation pressure and saturated in Water Settler 257-F-01. Because of the high concentration of olefins, only a portion of the fresh feed is mixed with the low olefin containing recycle stream, heated to reaction temperature in Exchanger 257-E-01 and Heater 257-E-02, and charged to the inlet of Reactor 257-D-01. The remaining cool fresh feed and, if needed, recycle are used as a quench for interbed cooling.

After passing through Acid K.O. Drum 257-F-02 and Heat Exchanger 257-E-01, the reactor effluent is split into the recycle stream and the feed for Debutanizer 257-D-02. The overhead product, consisting of unreacted olefins, iso-butane and inert propane and n-butane, is cooled and pumped to Alkylation Unit 258. The poly gasoline (bottoms) is sent to Splitter 257-D-03, where it is separated at the C₉ - C₁₀ boiling range. The light poly gasoline is pumped (257-G-03) to Gasoline Blending Unit 270 and the heavy poly gasoline is pumped (257-G-04) to Hydrogenation Unit 259.

4.4.16 H.F. Alkylation Unit 258 (ZO-GEM-6982)

Purpose of the Unit is to increase the gasoline yield by the catalytic alkylation of iso-butane and unpolymerized C₃ and C₄ olefins.

Technology Used

See Paragraph 3.4.19.

Process Description

Except for an additional iso-butane-rich feed stream, identical to H.F. Alkylation Unit 153. See Paragraph 3.4.19.

4.4.17 Poly Gasoline Hydrogenation Unit 259 (ZO-GEM-6983)

Purpose of the Unit is to saturate the olefins in the heavy cat poly gasoline.

The olefin target concentration for the 10 RVP gasoline product is 20 vol. % maximum. To meet this specification, the poly gasoline is split and the heavy gasoline is hydrogenated. Preliminary gasoline blending indicated that the C₉ and higher olefins should be hydrogenated and the unit has been sized accordingly. Final blending results, however, show that C₉ olefin hydrogenation is not necessary. Consequently, Unit 259 is sized conservatively.

Technology Used

See Paragraph 3.4.17.

Process Description

The heavy cat poly gasoline after mixing with the make-up/recycle hydrogen is heated via the reactor effluent in Exchanger 259-E-01 and brought-up to the operating temperature by Heater 259-B-01. Reactor 259-D-01 uses multi-beds with hydrogen quench for temperature control. The effluent is cooled in Coolers 259-E-02 and 03, and flashed in Drum 259-F-01. The overhead is split into recycle and offgas streams.

The bottoms liquid flows to Stabilizer 259-D-02. After cooling the stabilizer offgases are combined with the offgases from Flash Drum 259-F-01 and sent to H₂ Purification Unit 261. The cooled stabilized heavy gasoline is sent to Gasoline Blending Unit 270.

Catalyst regeneration facilities are provided.

4.4.18 Light Ends Recovery Unit 260 (ZO-GEM-6980)

Purpose of the Unit is to separate the light gasoline and iso-butane from the hydrocarbon-rich offgases.

Process Description

Offgas streams from Units 254, 255 and 256 are first flashed in Drum 260-F-02. The overhead vapors are compressed (260-C-01) and the liquid is pumped (260-G-01) to the operating pressure of Deethanizer 260-D-01.

The low-pressure offgas from Unit 254 is first compressed and then flashed with the offgas from Unit 261 in Drum 260-F-01. The drum liquid is charged to Deethanizer 260-D-01.

The deethanizer overhead is combined with Drum 260-F-01 overhead and Stabilizer 255-D-04 uncondensed gases and sent to the fuel gas header. The feed to Debutanizer 260-D-02 is the deethanizer bottoms. In the debutanizer, the additional iso-butane feed for Unit 258 is fractionated from the light gasoline which is sent to Gasoline Blending Unit 270.

4.4.19 H₂ Purification Unit 261 (ZO-GEM-6984)

Purpose of the Unit is to obtain from the hydrogen-rich offgases a hydrogen make-up stream of 90% purity.

Technology Used

Commercial cryogenic technology, such as offered by Linde Div. of Union Carbide Corp., is used.

Process Description

Two of the three feed streams require compressing (261-C-01 and 02) before charging to the system. The combined feed is first cooled in Cooler 261-E-01 by the +32°F refrigerant from Refrigeration Unit 241 and flashed in Drum 261-F-01 for heavy hydrocarbon and water removal. The gases then pass through the Molsieve Section 261-D-01 for final drying and CO₂ removal. In Cold Box Section 261-D-02, the make-up hydrogen is recovered and sent to Unit 211 for final compression. The cold box hydrocarbon gases are compressed in Compressor 261-C-03 and mixed with the liquids separated in Flash Drum 261-F-01. The resultant mixture is a feed for Light Ends Recovery Unit 260.

4.4.20 Alcohol Recovery Unit 262 (ZO-GEM-6985)

Purpose of the Unit is to prepare a marketable alcohol mixture product and to recover methanol for make-up to Rectisol Unit 205.

Technology Used

Because of the limited alcohol information available to MRDC, the design of this unit is general in nature. Distillation is used to separate the bulk of the water and acids from the raw alcohols. Methanol is then fractionated from the alcohol mixture. A benzene azeotropic system is used for final water removal. The final step is the hydrogenation of the aldehydes and ketones to improve the marketing value of the alcohol mixture.

Process Description

The alcohol/acid water mixture from F-T Synthesis Unit 250 flows to Fractionator 262-D-01 in which the alcohols are distilled from the acidic water. Because alcohol-water azeotropic mixtures occur, a portion of the water distills overhead with the alcohols. The alcohols, together with a heavy alcohol recycle stream from Methanol Tower 262-D-03, are next charged to Alcohol Splitter Tower 262-D-02 from which a crude methanol overhead product is obtained. The crude methanol is redistilled in the methanol tower to obtain an acceptable make-up material for Gas Purification Unit 205. The higher boiling alcohols (bottoms) are returned to the alcohol splitter tower.

The bottoms stream from Alcohol Splitter Tower 262-D-02 is fed to Heavy Alcohol Tower 262-D-04 into which benzene is added to remove, via the benzene-water azeotrope, the remaining water. The azeotropic overhead is pumped to Tower 262-D-05, where 50 psig steam is used to strip the benzene which is then returned to Tower 262-D-04.

The alcohol bottoms stream from Alcohol Tower 262-D-04 is pumped to Hydrogenation Section 262-D-06 where the aldehyde and ketone impurities are hydrogenated to their corresponding alcohols. Make-up hydrogen is supplied from H₂ Recovery Unit 211 and the purge gas is returned to the same unit. A small portion of the upgraded alcohol mixture is sent to Hydrocarbon Recovery Unit 210 for the prevention of ice formation during the cold hydrocarbon washing operation.

The waste water streams from Towers 262-D-01 and 05 are pumped (262-G-02 and 09) after cooling (262-E-13) to Waste Water Treatment Unit 235.

4.4.21 Unit Capacity Summary

The capacities of the principal process units are summarized below in conventional flow rates:

<u>Unit No.</u>	<u>Name</u>	<u>--Capacity, Unit/SD--</u>	
		<u>Input</u>	<u>Output</u>
201	Gasification	22.8 MT coal	1,755 MMSCF
202	Raw Gas Shift	331 MMSCF	-
205	Gas Purification	1,062 MMSCF	742 MMSCF
210	Hydrocarbon Recovery	277 MMSCF	235 MMSCF
250	F-T Synthesis	742 MMSCF	18.1 MBbl
251	Naphtha Hydro-treating	1.3 MBbl	-
253	F-T Prod. Hydro-treating	11.4 MBbl	-
255	Catalytic Reforming	4.3 MBbl	-
256	C5/C6 Isomerization	4.0 MBbl	-
257	Polymerization	6.5 MBbl	-
258	Alkylation	2.4 MBbl (550 Bbl/SD alkylate)	-
259	Poly Gaso. Hydro-genation	1.2 MBbl	-
260	Light Ends Recovery	1.0 MBbl	-
261	H ₂ Purification	8 MMSCF	6 MMSCF
262	Alcohol Recovery	510 Mlb	-
	SNG Train	235 MMSCF	173 MMSCF

EQUIPMENT LIST		
ITEM NO.	NAME	OPER. APPROX. *SPARE I.D. LENGTH T-T
210-C-01	OFF-GAS COMPRESSOR	1 + 0
210-D-01	ABSORBER	1 + 0 13'-0" 110'
210-D-02	REGENERATOR	2 + 0 13'/8"-6' 111'
210-E-01	WARM FEED/PRODUCT GAS H.E.	1 + 0
210-E-02	COLD FEED/PRODUCT GAS H.E.	1 + 0
210-E-03	FEED GAS CHILLER	1 + 0
210-E-04	CHILLER	1 + 0
210-E-05	HEAT EXCHANGER	1 + 0
210-E-06	REGENERATOR REBOILER	2 + 0
210-E-07	REGENERATOR OVHD CONDENSER	2 + 0
210-E-08	REGENERATOR OVHD TRIM CONDENSER	2 + 0
210-E-09	OFF-GAS CONDENSER	1 + 0
210-E-10	OFF-GAS TRIM CONDENSER	1 + 0
210-F-01	COLD FEED K.O. DRUM	1 + 0
210-F-02	REGENERATOR REFLUX DRUM	2 + 0
210-G-01	HEPTANE PUMP	1 + 1
210-G-02	REGENERATOR REFLUX PUMP	2 + 1
210-G-03	CONDENSATE PUMP	1 + 1
210-G-04	ALCOHOL INJECTION PUMP	1 + 1

	STREAM NUMBER	
	PRESSURE	PSIG
	TEMPERATURE	°F
	FLOW RATE DRY GAS	lbmol/hr
	FLOW RATE STEAM AND LIQUIDS	Wbbs/hr

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE

Prepared	Date	Name	GEM	Lurgi
Checked	13.7.77	VI	00-0865	00-0865
Standard				
Orig. Scale	Title/Characteristic features		Drawing No.	
1/	PROCESS FLOW DIAGRAM		Z0-GEM-6973	
	HYDROCARBON RECOVERY		MRDC/ERDA STUDY	
	(HEPTANE WASH)		EF-76-C-01-2447	
Orig. Size	UNIT 210		BASE CASE II	
A0

EQUIPMENT LIST		
ITEM NO.	NAME	OPER. APPROX. *SPARE I.D. F.NOM T-T
212-B-01	REDUCTION SYSTEM HEATER	1 + 0 NOT ON PFD
212-C-01	RECYCLE COMPRESSOR	2 + 0
212-D-01	REACTOR	2 + 0 11'-4" / 8'-3"
212-D-02	CLEAN-UP REACTOR	2 + 0 8'-9" / 10'-3"
212-E-01	STEAM GENERATOR	2 + 0
212-E-02	RECYCLE/RPW H.E.	2 + 0
212-E-03	FIRST FEED/PRODUCT H.E.	1 + 0
212-E-04	SECOND FEED/PRODUCT H.E.	1 + 0
212-E-05	THIRD FEED/PRODUCT H.E.	1 + 0
212-E-06	PRODUCT COOLER	1 + 0
212-E-07	PRODUCT TRIM COOLER	1 + 0
212-E-08	REDUCTION SYSTEM COOLER	1 + 0 NOT ON PFD
212-F-01	FIRST K.O. DRUM	1 + 0
212-F-02	SECOND K.O. DRUM	1 + 0
212-F-03	THIRD K.O. DRUM	1 + 0
212-F-04	REDUCTION SYSTEM K.O. DRUM	1 + 0 NOT ON PFD

	STREAM NUMBER	
	PRESSURE	PSIG
	TEMPERATURE	°F
	FLOW RATE DRY GAS	lbmol/hr
	FLOW RATE STEAM AND LIQUIDS	Mlbs/hr

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	12.7.77	VI	GEM	00-0865	Lurgi
Checked					Lurgi Minnopolis GmbH
Standard					Frankfurt (Main)
Orig. Scale	1/4" Characteristic Features:				Drawing No.
	PROCESS FLOW DIAGRAM				Z0-GEM-6975
	METHANATION				MRDC/ERDA STUDY
					EF-76-C-01-2447
Orig. Size	UNIT 212				Submitted for
A0	BASE CASE II				Supervised by
					Reference Org.

EQUIPMENT LIST		QPM	APPROX.
ITEM NO.	NAME		SIZE, L.P. LENGTH, T.H.
213-D-01	CO ₂ ABSORBER	1 + 0	16' - 4" / 61'
213-D-02	REGENERATOR	1 + 0	16' - 4" / 61'
213-E-01	LEAN/RICH H.E.	1 + 0	
213-E-02	COOLER	1 + 0	
213-E-03	TRIM COOLER	1 + 0	
213-E-04	REGENERATOR OVER TRIM CONDENSER	1 + 0	
213-E-05	REGENERATOR OVER TRIM CONDENSER	1 + 0	
213-E-06	REGENERATOR REBOILER	1 + 0	
213-E-07	CO ₂ ABSORBER WASH WATER COOLER	1 + 0	
213-F-01	FILTER	1 + 0	
213-F-02	REGENERATOR REFLUX DRUM	1 + 0	
213-F-03	REGENERATOR OFFGAS D.O. DRUM	1 + 0	
213-G-01	SOLUTION PUMP	1 + 1	
213-G-02	REGENERATOR REFLUX PUMP	1 + 1	
214-C-01	SNG COMPRESSOR	1 + 0	
214-D-01	WATER ABSORBER	1 + 0	
214-D-02	TED REGENERATOR	1 + 0	
214-E-01	TED COOLER	1 + 0	
214-E-02	SNG COMPRESSOR COOLER	1 + 0	
214-F-01	TED DRUM	1 + 0	
214-F-02	SNG COMPRESSOR SUCTION DRUM	1 + 0	
214-G-01	TED PUMP	1 + 1

NOTES:
 STREAMS WITHOUT STREAM NUMBERS
 ARE NOT INCLUDED IN THE OVERALL
 MATERIAL BALANCE.

Project	20777 VI	GEM	00-0865	LAUNCH
Checked				Large (Hatched) Sheet
Standard				Frankfurt (Hatched)
Orig. Scale	1/4" = 1'-0"	Title/Characteristic Features		Drawing No.
		PROCESS FLOW DIAGRAM		ZO-GEM-0976
		CO ₂ REMOVAL		MRDC/ERDA STUDY
		& SNG DRYING & COMPR.		EF-76-C-01-2447
Orig. Rev	A0	UNIT 213/214		BASE CASE II

EQUIPMENT LIST				
ITEM NO.	NAME	OPER. *SPARE	APPROX. I.D. LENGTH T.F.	
250-C-01	SYNGAS & RECYCLE COMPRESSOR	3+0		
250-D-01	F-T REACTOR SYSTEM	4+1	10'-6"	100'
250-D-02	F-T EFFLUENT WASH TOWER	4+0	18'-6"	50'
250-D-03	F-T VAPOR COLD WASH TOWER	2+0	20'-0"	50'
250-D-04	LIGHT OIL WASH TOWER	1+0	12'-0"	35'
250-E-01	F-T FEED/EFFLUENT SIDE STREAM H.E.	1+0		
250-E-02	F-T WASTE HEAT	1+0		
250-E-03	200 PSIG STEAM GENERATOR	1+0		
250-E-04	F-T WASTE HEAT/BFW H.E.	1+0		
250-E-05	F-T WASTE HEAT TRIM CONDENSER	1+0		
250-E-06	F-T BFW TRIM HEATER	1+0		
250-E-07	F-T WASTE HEAT	1+0		
250-E-08	50 PSIG STEAM GENERATOR	1+0		
250-F-01	COMPRESSOR SUCTIONAL DRUM	3+0		
250-F-02	HOT OIL SURGE DRUM	1+0		
250-G-01	HOT OIL CIRCULATION PUMP	3+1		
250-G-02	F-T EFFLUENT SIDE STREAM PUMP	4+2		
250-G-03	F-T EFFLUENT WASH TOWER REFLOX PUMP	2+1		
250-G-04	WASH WATER PUMP	1+1		

	STREAM NUMBER	
	PRESSURE	PSIG
	TEMPERATURE	°F
	FLOW RATE DRY GAS	lbmol/hr
	FLOW RATE STEAM AND LIQUIDS	mlbs/hr

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	Date	Name	GEM	Lurgi
Checked	14.7.77	VI	00-0865	Lurgi Mineraltechnik GmbH
Standard				Frankfurt (Main)
Orig. Scale	Title/Characteristic features		Drawing No.	
1/4"	PROCESS FLOW DIAGRAM F-T SYNTHESIS		Z0-GEM-6977	
Orig. Size	UNIT 250		MRDC/ERDA STUDY EF-76-C-01-2447	
A0	BASE CASE II		Submitted for: Reviewed by: Reference Eng.

EQUIPMENT LIST			
ITEM NO.	NAME	OPEN. +SPARE	APPROX. I.D. LENGTH T-T
252-B-01	HEAVY OIL HEATER	1 + 0	
252-B-02	DEHUTANIZER REBOILER	1 + 0	
252-B-03	SPLITTER REBOILER	1 + 0	
252-C-01	VACUUM TOWER OVHD BLOWER	1 + 0	
252-D-01	HEAVY OIL VACUUM TOWER	1 + 0	4'-8" 25'
252-D-02	ANSORBER/DEHUTANIZER (AB/DE)	1 + 0	7'-6" 125'
252-D-03	DEHUTANIZER	1 + 0	7'-0" 117'
252-D-04	NAPHTHA SPLITTER	1 + 0	11'-0" 41'
252-E-01	VACUUM TOWER P/A COOLER	1 + 0	
252-E-02	VACUUM TOWER HTMS COOLER	1 + 0	
252-E-03	VACUUM TOWER OVHD CONDENSER	1 + 0	
252-E-04	LEAN OIL TRIM COOLER	1 + 0	
252-E-05	AB/DE FEED/LEAN OIL H.E.	1 + 0	
252-E-06	AB/DE TOP P/A COOLER	1 + 0	
252-E-07	AB/DE BOTTOM P/A COOLER	1 + 0	
252-E-08	AB/DE REBOILER	1 + 0	
252-E-09	DEHUTANIZER OVHD CONDENSER	1 + 0	
252-E-10	DEHUTANIZER OVHD TRIM CONDENSER	1 + 0	
252-E-11	SPLITTER FEED COOLER	1 + 0	
252-E-12	SPLITTER OVHD CONDENSER	1 + 0	
252-E-13	LEAN OIL COOLER	1 + 0	
252-E-14	SPLITTER BOTTOMS COOLER	1 + 0	
252-F-01	HEAVY OIL FLASH DRUM	1 + 0	
252-F-02	VACUUM TOWER OVHD ACCUMULATOR	1 + 0	
252-F-03	HEPTANE WASH OFF STREAMS	1 + 0	
252-F-04	DEHUTANIZER REFLUX DRUM	1 + 0	
252-F-05	SPLITTER REFLUX DRUM	1 + 0	
252-G-01	VACUUM TOWER P/A PUMP	1 + 1	
252-G-02	VACUUM TOWER HTMS PUMP	1 + 1	
252-G-03	LEAN OIL FEED PUMP	1 + 1	
252-G-04	AB/DE TOP P/A PUMP	1 + 1	
252-G-05	AB/DE BOTTOM P/A PUMP	1 + 1	
252-G-06	AB/DE REBOILER PUMP	1 + 1	
252-G-07	DEHUTANIZER REFLUX PUMP	1 + 1	
252-G-08	DEHUTANIZER REFLUX PUMP	1 + 1	
252-G-09	SPLITTER REFLUX/PRODUCT PUMP	1 + 1	
252-G-10	SPLITTER REBOILER PUMP	1 + 1	
252-G-11	SPLITTER BOTTOMS PUMP	1 + 1	
252-G-12	LEAN OIL PUMP	1 + 1	
252-G-13	VACUUM TOWER ACCUM. PUMP	1 + 1	
252-G-14			
252-G-15

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	15.7.77	VI	GEM	Lurgi
Checked			00-0865	Lurgi Mineralölservice GmbH
Standard				Frankfurt (Main)
Orig. Scale	Title/Characteristic Feature			Drawing No.
	PROCESS FLOW DIAGRAM			ZO-GEM-6978
	F-T PRODUCT			MRDC/ERDA STUDY
	FRACTIONATION			EF-76-C-01-2447
Orig. Rev.	A0	UNIT 252	BASE CASE II	Submitted for
				Reviewed by
				Reference Log

EQUIPMENT LIST			
ITEM NO.	NAME	OPER. *SPARE	APPROX. I.D. LENGTH T-T
253-B-01	HYDROTREATER FEED HEATER	1 + 0	
253-C-01	HYDROTREATER RECYCLE COMPRESSOR	1 + 0	
253-D-01	HYDROTREATER REACTOR	1 + 0	6'-0" 30'
253-E-01	HYDROTREATER FEED/EFFLUENT H.E.	1 + 0	
253-E-02	HT FLASH OVHD/LT FLASH BTMS. H.E.	1 + 0	
253-E-03	HT FLASH OVHD CONDENSER	1 + 0	
253-E-04	HT FLASH OVHD TRIM CONDENSOR	1 + 0	
253-E-05	QUENCH HYDROGEN COOLER	1 + 0	
253-F-01	HIGH TEMP FLASH DRUM	1 + 0	
253-F-02	LOW TEMP FLASH DRUM	1 + 0	
253-F-03	HYDROTREATER FEED PUMP	1 + 0	
253-G-01	HYDROTREATER FEED PUMP	1 + 1	
254-B-01	MAIN FRACTIONATOR FEED HEATER	1 + 0	
254-D-01	MAIN FRACTIONATOR	1 + 0	9'-6" 58'
254-D-02	DISTILLATE FUEL OIL STRIPPER	1 + 0	4'-6" 80'
254-D-03	DEBUTANIZER	1 + 0	6'-6" 71'
254-D-04	NAPHTHA SPLITTER	1 + 0	2'-6" 20'
254-E-01	MAIN FRACTIONATOR OVHD CONDENSER	1 + 0	
254-E-02	MAIN FRACTIONATOR OVHD TRIM CONDENSER	1 + 0	
254-E-03	DFO PRODUCT/DEBUTANIZER FEED H.E.	1 + 0	
254-E-04	DFO PRODUCT COOLER	1 + 0	
254-E-05	HFO PRODUCT/DEBUTANIZER FEED H.E.	1 + 0	
254-E-06	HFO PRODUCT COOLER	1 + 0	
254-E-07	DEBUTANIZER FEED HEATER	1 + 0	
254-E-08	DEBUTANIZER OVHD CONDENSER	1 + 0	
254-E-09	DEBUTANIZER OVHD TRIM CONDENSER	1 + 0	
254-E-10	DEBUTANIZER REBOILER	1 + 0	
254-E-11	NAPHTHA SPLITTER OVHD CONDENSER	1 + 0	
254-E-12	NAPHTHA SPLITTER REBOILER	1 + 0	
254-E-13	PENTANE/HEXANE TRIM COOLER	1 + 0	
254-E-14	NAPHTHA SPLITTER BTMS COOLER	1 + 0	
254-F-01	MAIN FRACTIONATOR REFLUX DRUM	1 + 0	
254-F-02	DEBUTANIZER REFLUX DRUM	1 + 0	
254-F-03	NAPHTHA SPLITTER REFLUX DRUM	1 + 0	
254-G-01	MAIN FRACTIONATOR REFLUX PUMP	1 + 1	
254-G-02	DEBUTANIZER FEED PUMP	1 + 1	
254-G-03	DFO PRODUCT PUMP	1 + 1	
254-G-04	HFO PRODUCT PUMP	1 + 1	
254-G-05	DEBUTANIZER REFLUX PUMP	1 + 1	
254-G-06	NAPHTHA SPLITTER REFLUX PUMP	1 + 1	
254-G-07	NAPHTHA SPLITTER OVHD PRODUCT PUMP	1 + 1	
254-G-08	NAPHTHA SPLITTER BTMS PUMP	1 + 1	
254-G-09	WASTE WATER PUMP	1 + 1	

◊ STREAM NUMBER
 ○ PRESSURE PSIG
 □ TEMPERATURE °F
 ▭ FLOW RATE DRY GAS lbmol/hr
 ▨ FLOW RATE STEAM AND LIQUIDS Mbs/hr

NOTES:
 STREAMS WITHOUT STREAM NUMBERS
 ARE NOT INCLUDED IN THE OVERALL
 MATERIAL BALANCE.

Prepared	15.7.77	VI	GEM	00-0865	Lurgi
Checked					Lurgi Mineraltechnik GmbH
Standard					Frankfurt (Main)
Orig. Scale					
Editor/Characteristics					
Process Flow Diagram					
F-T PROD HYDROTREATER & FRACTIONATION					
Units 253/254					
BASE CASE II					
Drawing No.					20-GEM-6979
MRDC/ERDA STUDY					EF-76-C-01-2447
Submitted for					
Supervised by					
Reference Data

ITEM NO.	NAME	OPER.	APPROX. I.D.	LENGTH	T-T
255-B-01	FIRST REFORMING REACTOR HEATER	1	0		
255-B-02	SEC. REFORMING REACTOR HEATER	1	0		
255-B-03	THIRD REFORMING REACTOR HEATER	1	0		
255-C-01	REFORMER RECYCLE COMPRESSOR	1	0		
255-D-01	FIRST REFORMING REACTOR	1	0	6'-0"	18'
255-D-02	SEC. REFORMING REACTOR	1	0	6'-0"	18'
255-D-03	THIRD REFORMING REACTOR	1	0	6'-0"	18'
255-D-04	STABILIZER	1	0	5'-0"	100'
255-E-01	REFORMING REACTOR FEED/EFFLUENT H.D.	1	0		
255-E-02	REFORMING REACTOR EFFLUENT COOLER	1	0		
255-E-03	REFORMING REACTOR EFFLUENT TRIM COOLER	1	0		
255-E-04	STABILIZER FEED/BOTTOMS H.E.	1	0		
255-E-05	STABILIZER OVHD CONDENSER	1	0		
255-E-06	STABILIZER OVHD TRIM CONDENSER	1	0		
255-E-07	REFORMATE COOLER	1	0		
255-E-08	REFORMATE TRIM COOLER	1	0		
255-E-09	STABILIZER REBOILER	1	0		
255-F-01	REFORMER EFFLUENT FLASH DRUM	1	0		
255-F-02	STABILIZER REFLUX DRUM	1	0		
255-G-01	STABILIZER REFLUX & PRODUCT PUMP	1	1		
255-G-02	STABILIZER REBOILER PUMP	1	1		
255-G-03	STABILIZER FEED PUMP	1	1		
255-G-04	REACTOR FEED PUMP	1	1		
260-C-01	DEHYDROGENIZER FEED COMPRESSOR	1	1		
260-D-01	DEHYDROGENIZER	1	0	2'-0"	80'
260-D-02	DEHYDROGENIZER	1	0	2'-0"	103'
260-E-01	LOWER DEHYDROGENIZER FEED COMPRESSOR COOLER	1	0		
260-E-02	DEHYDROGENIZER OVHD CONDENSER	1	0		
260-E-03	DEHYDROGENIZER REBOILER	1	0		
260-E-04	ISO-BUTANE TRIM COOLER	1	0		
260-E-05	DEHYDROGENIZER OVHD CONDENSER	1	0		
260-E-06	DEHYDROGENIZER REBOILER	1	0		
260-E-07	DEHYDROGENIZER BOTTOMS COOLER	1	0		
260-E-08	DEHYDROGENIZER BOTTOMS TRIM COOLER	1	0		
260-E-09	DEHYDROGENIZER FEED COOLER	1	0		
260-F-01	UPPER DEHYDROGENIZER FEED FLASH DRUM	1	0		
260-F-02	LOWER DEHYDROGENIZER FEED FLASH DRUM	1	0		
260-F-03	DEHYDROGENIZER REFLUX DRUM	1	0		
260-F-04	DEHYDROGENIZER REFLUX DRUM	1	0		
260-G-01	LOWER DEHYDROGENIZER FEED PUMP	1	1		
260-G-02	DEHYDROGENIZER REFLUX PUMP	1	1		
260-G-03	DEHYDROGENIZER REFLUX PUMP	1	1		
260-G-04	ISO-BUTANE PUMP	1	1		

NOTES: Streams without stream numbers are not included in the overall material balance.

Prepared	207.77 VI	GEM	Lurgi
Checked		00-0865	Lurgi Mineral/Chemicals GmbH Frankfurt (Main)
Standard			
Orig. Scale			
Drawn			
Supervised			
PROCESS FLOW DIAGRAM		Z0-GEM-6980	
CATALYTIC REFORMING		MRDC/ERDA STUDY	
& LIGHT ENDS RECOVERY		EF-76-C-01-2447	
UNITS 255/260		BASE CASE II

EQUIPMENT LIST				
ITEM NO.	NAME	OPER.	APPROX. I.D.	LENGTH T-T
256-B-01	ISOMERIZATION REACTOR HEATER	1 + 0		
256-C-01	ISOMERIZATION RECYCLE COMPRESSOR	1 + 1		
256-D-01	DEISOPENTANIZER	1 + 0	8'-0"	176'
256-D-02	ISOMERIZATION REACTOR	1 + 0	9'-0"	27'
256-D-03	STABILIZER	1 + 0	4'-0"	100'
256-D-04	DEPENTANIZER	1 + 0	5'-0"	129'
256-E-01	DEISOPENTANIZER OVHD CONDENSER	1 + 0		
256-E-02	DEISOPENTANIZER OVHD TRIM CONDENSER	1 + 0		
256-E-03	DEISOPENTANIZER REBOILER	1 + 0		
256-E-04	ISOMERIZATION REACTOR FEED/ EFFLUENT H.E.	1 + 0		
256-E-05	ISOMERIZATION REACTOR EFFLUENT COOLER	1 + 0		
256-E-06	ISOMERIZATION REACTOR EFFLUENT TRIM COOLER	1 + 0		
256-E-07	STABILIZER FEED/BOTTOMS H.E.	1 + 0		
256-E-08	STABILIZER OVHD CONDENSER	1 + 0		
256-E-09	STABILIZER OVHD TRIM CONDENSER	1 + 0		
256-E-10	STABILIZER REBOILER	1 + 0		
256-E-11	DEPENTANIZER OVHD CONDENSER	1 + 0		
256-E-13	DEPENTANIZER REBOILER	1 + 0		
256-E-14	DEPENTANIZER BOTTOMS COOLER	1 + 0		
256-E-15	DEPENTANIZER BOTTOMS TRIM COOLER	1 + 0		
256-F-01	DEISOPENTANIZER REFLUX DRUM	1 + 0		
256-F-02	ISOMERIZATION HP SEPARATOR	1 + 0		
256-F-03	STABILIZER REFLUX DRUM	1 + 0		
256-F-04	DEPENTANIZER REFLUX DRUM	1 + 0		
256-G-01	DEISOPENTANIZER REFLUX/PRODUCT PUMP	1 + 1		
256-G-02	STABILIZER REFLUX PUMP	1 + 1		
256-G-03	DEPENTANIZER REFLUX PUMP	1 + 1		
256-G-04	PENTANE RECYCLE PUMP	1 + 1		
256-G-05	REACTOR FEED PUMP	1 + 1		
256-G-06	HEXANE ISOMERATE PUMP	1 + 1		

◇ STREAM NUMBER
 ○ PRESSURE PSIG
 □ TEMPERATURE °F
 ▭ FLOW RATE DRY GAS lbmol/hr
 ▨ FLOW RATE STEAM Mlbs/hr
 ▩ AND LIQUIDS

NOTES:
 STREAMS WITHOUT STREAM NUMBERS
 ARE NOT INCLUDED IN THE OVERALL
 MATERIAL BALANCE.

Prepared	Date	Name	GEM	Lurgi
Checked	21.7.77	VI	00-0865	Lurgi (Main)
Drawn				
Rev.				
Title/Characteristic features:			Drawing No.	
C5/C6 ISOMERIZATION			Z0-GEM-6981	
UNIT 256			MRDC/ERDA STUDY	
BASE CASE II			EF-76-C-01-2447	
Submitted by:			Submitted by:	
Submitted by:			Submitted by:

EQUIPMENT LIST			
ITEM NO.	NAME	OPER. APPROX.	*SPARE I.D. LENGTH T
257-D-01	CAT POLY REACTOR	2 + 0 7'-6"	48
257-D-02	DEBUTANIZER	1 + 0 4'-6"	90
257-D-03	GASOLINE SPLITTER	1 + 0 4'-0"	73
257-E-01	CAT POLY REACTOR FEED/EFFLUENT H.E.	1 + 0	
257-E-02	CAT POLY REACTOR FEED HEATER	1 + 0	
257-E-03	RECYCLE COOLER	1 + 0	
257-E-04	DEBUTANIZER OVHD CONDENSER	1 + 0	
257-E-05	RECYCLE TRIM COOLER	1 + 0	
257-E-06	DEBUTANIZER REBOILER	1 + 0	
257-E-07	GASOLINE SPLITTER OVHD CONDENSER	1 + 0	
257-E-08	GASOLINE SPLITTER OVHD PRODUCT COOLER	1 + 0	
257-E-09	GASOLINE SPLITTER REBOILER	1 + 0	
257-E-10	GASOLINE SPLITTER BOTTOMS COOLER	1 + 0	
257-E-11	GASOLINE SPLITTER BOTTOMS TRIM COOLER	1 + 0	
257-E-12	C3/C4 TRIM COOLER	1 + 0	
257-F-01	CAT POLY FEED WASH WATER SETTLER	1 + 0	
257-F-02	CAT POLY EFFLUENT ACID R.O. DRUM	1 + 0	
257-F-03	DEBUTANIZER REFLUX DRUM	1 + 0	
257-F-04	GASOLINE SPLITTER REFLUX DRUM	1 + 0	
257-G-01	CAT POLY FEED PUMP	1 + 1	
257-G-02	DEBUTANIZER REFLUX/PRODUCT PUMP	1 + 1	
257-G-03	GASOLINE SPLITTER REFLUX/PRODUCT PUMP	1 + 1	
257-G-04	GASOLINE SPLITTER BOTTOMS PUMP	1 + 1	
257-G-05	REACTOR FEED PUMP	1 + 1	
257-G-06	WATER PUMP	1 + 1	

258-D-01	REACTOR/SETTLER	1 + 0 4'-6"	34
258-D-02	DEISOBUTANIZER	1 + 0 8'-0"	161
258-D-03	DEPROPANIZER	1 + 0 4'-0"	101
258-E-01	DEISOBUTANIZER FEED/EFFLUENT H.E.	1 + 0	
258-E-02	DEISOBUTANIZER FEED TRIM HEATER	1 + 0	
258-E-03	NORMAL BUTANE COOLER	1 + 0	
258-E-04	DEISOBUTANIZER SIDE REBOILER	1 + 0	
258-E-05	DEISOBUTANIZER BOTTOMS REBOILER	1 + 0	
258-E-06	N-BUTANE TRIM COOLER	1 + 0	
258-E-07	ALKYLATE TRIM COOLER	1 + 0	
258-E-08	DEISOBUTANIZER OVHD CONDENSER	1 + 0	
258-E-09	DEISOBUTANIZER OVHD TRIM CONDENSER	1 + 0	
258-E-10	DEPROPANIZER FEED HEATER	1 + 0	
258-E-11	DEPROPANIZER REBOILER	1 + 0	
258-E-12	DEPROPANIZER OVHD CONDENSER	1 + 0	
258-E-13	PROPANE LPG TRIM COOLER	1 + 0	
258-E-14	ALKYLATION RECYCLE COOLER	1 + 0	
258-E-15	ALKYLATION RECYCLE TRIM COOLER	1 + 0	
258-E-16	HF COOLER	1 + 0	
258-F-01	DEPROPANIZER REFLUX DRUM	1 + 0	
258-G-01	DEPROPANIZER FEED PUMP	1 + 1	
258-G-02	DEPROPANIZER REFLUX PUMP	1 + 1	
258-G-03	ALKYLATION RECYCLE PUMP	1 + 1	

- ◇ STREAM NUMBER
- PUMP
- HEATER
- ▭ FLOW RATE DRY GAS (tonnes/hr)
- ▭ FLOW RATE STEAM AND LIQUIDS (m³/hr)

NOTES
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Prepared	22.7.77 VI	GEM	Lurgi
Checked		00-0865	Lurgi Mineralölservice GmbH Frankfurt/Main
Standard			
Orig. Scale	1/	PROCESS FLOW DIAGRAM	Drawing No. 20-GEM-694
Orig. No.	A0	CATALYTIC POLYMERIZATION & HF ALKYLATION	MRDC/ERDA STUDI EF-76-C-01-24
		UNITS 257/258	BASE CASE II

EQUIPMENT LIST				
ITEM NO.	NAME	OPER. SPARE	APPROX. I.D.	LENGTH T-T
259-B-01	FEED HEATER	1 + 0		
259-C-01	RECYCLE COMPRESSOR	1 + 1		
259-D-01	HYDROGENATION REACTOR	1 + 0	3'-6"	30'
259-D-02	STABILIZER	1 + 0	3'-6"	70'
259-E-01	HYDROGENATION FEED/EFFLUENT H.E.	1 + 0		
259-E-02	HYDROGENATION EFFLUENT COOLER	1 + 0		
259-E-03	HYDROGENATION EFFLUENT TRIM COOLER	1 + 0		
259-E-04	STABILIZER OVHD CONDENSER	1 + 0		
259-E-05	STABILIZER OVHD TRIM CONDENSER	1 + 0		
259-E-06	STABILIZER REBOILER	1 + 0		
259-E-07	STABILIZER BOTTOMS COOLER	1 + 0		
259-E-08	STABILIZER BOTTOMS TRIM COOLER	1 + 0		
259-F-01	HYDROGENATION EFFLUENT FLASH DRUM	1 + 0		
259-F-02	STABILIZER REFLUX DRUM	1 + 0		
259-G-01	FEED PUMP	1 + 1		
259-G-02	STABILIZER REFLUX PUMP	1 + 1		
259-G-03	STABILIZER REBOILER PUMP	1 + 1		

	STREAM NUMBER	
	PRESSURE	PSIG
	TEMPERATURE	°F
	FLOW RATE DRY GAS	lbmol/hr
	FLOW RATE STEAM AND LIQUIDS	Min/hr

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE

Prepared	Date	Name	GEM	Lurgi
Checked	12.7.77	VI	00-0865	Lurgi Mineralöls GmbH
Standard				Frankfurt (Main)
Orig. Scale	Title/Characteristic features			Drawing No.
1/	PROCESS FLOW DIAGRAM			Z0-GEM-6983
	POLY GASOLINE			MRDC/ERDA STUDY
	HYDROGENATION			EF-76-C-01-2447
Orig. Size	UNIT 259			Supervised by
A0	BASE CASE II			Signature

EQUIPMENT LIST				
ITEM NO.	NAME	OPER. *SPARK	APPROX. T.D.	LENGTH T-F
201-C-01	COLD BOX MAIN FEED COMPRESSOR	1 * 1		
201-C-02	COLD BOX SEC. FEED COMPRESSOR	1 * 1		
201-C-03	COLD BOX HC PRODUCT COMPRESSOR	1 * 1		
201-D-01	MOI. SIEVE ADSORBER	2 * 0		
201-D-02	CHLD BOX SECTION	1 * 0		
201-E-01	MOI. SIEVE FEED CHILLER	1 * 0		
201-E-02	COLD BOX HC PRODUCT COOLER	1 * 0		
201-F-01	MOI. SIEVE FLASH DRUM	1 * 0		
201-F-02	COLD BOX HC PRODUCT K.O. DRUM	1 * 0

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE

Prepared	Date	Name	GEM	Lurgi
Checked	12.7.77	VI	00-0865	Lurgi Mineralbedeutung GmbH
Standard				Frankfurt (Main)
Orig. Scale	Title/Characteristic Features			Drawing No.
/	PROCESS FLOW DIAGRAM			ZO-GEM-6984
	H ₂ PURIFICATION			MRDC/ERDA STUDY
Orig. Size	Submitted for			EF-76-C-01-2447
A0	UNIT 261			Supervised by
	BASE CASE II			Reference Org.

EQUIPMENT LIST				
Item No.	Name	Oper. +Spare	Approx. I.D.	Length T
262-D-01	ALCOHOL WATER FRACTIONATOR	1 + 0	12'-0"	140'
262-D-02	ALCOHOL SPLITTER	1 + 0	3'-0"	83'
262-D-03	METHANOL TOWER	1 + 0	2'-6"	73'
262-D-04	HVY ALCOHOLS TOWER	1 + 0	15'-0"	77'
262-D-05	ALCOHOL RECOVERY STEAM STRIPPER	1 + 0	5'-0"	78'
262-E-01	ACID WATER FRACTIONATOR REBOILER	1 + 0		
262-E-02	ACID WATER FRACTIONATOR OVHD CONDENSER	1 + 0		
262-E-03	ACID WATER FRACTIONATOR OVHD TRIM CONDENSER	1 + 0		
262-F-04	ALCOHOL SPLITTER REBOILER	1 + 0		
262-E-05	ALCOHOL SPLITTER OVHD CONDENSER	1 + 0		
262-E-06	ALCOHOL SPLITTER OVHD TRIM CONDENSER	1 + 0		
262-E-07	METHANOL TOWER REBOILER	1 + 0		
262-E-08	METHANOL TOWER OVHD CONDENSER	1 + 0		
262-E-10	HVY ALCOHOLS TOWER REBOILER	1 + 0		
262-E-11	HVY ALCOHOLS TOWER OVHD CONDENSER	1 + 0		
262-E-12	HVY ALCOHOL TOWER STMS COOLER	1 + 0		
262-E-13	ACID WATER COOLER	1 + 0		
262-F-01	ACID WATER TOWER REFLUX DRUM	1 + 0		
262-F-02	ALCOHOL SPLITTER REFLUX DRUM	1 + 0		
262-F-03	METHANOL TOWER REFLUX DRUM	1 + 0		
262-F-04	HVY ALCOHOLS TOWER REFLUX DRUM	1 + 0		
262-G-01	ACID WATER TOWER REFLUX/PRODUCT PUMP	1 + 1		
262-G-02	ACID WATER PUMP	1 + 1		
262-G-03	ALCOHOL SPLITTER REFLUX PUMP	1 + 1		
262-G-04	METHANOL TOWER FEED PUMP	1 + 1		
262-G-05	METHANOL TOWER REFLUX/PRODUCT PUMP	1 + 1		
262-G-06	HVY ALCOHOL TOWER REFLUX PUMP	1 + 1		
262-G-07	STEAM STRIPPER FEED PUMP	1 + 1		
262-G-08	ALCOHOL HYDROGENATION FEED PUMP	1 + 1		
262-G-09	STEAM CONDENSATE PUMP	1 + 1

NOTES:
STREAMS WITHOUT STREAM NUMBERS
ARE NOT INCLUDED IN THE OVERALL
MATERIAL BALANCE.

Desig.	22.777	VI	GEM	Lurgi
Issued			00-0865	Lurgi Mineraltechnik GmbH
Revised				Frankfurt (Main)
Standard				
Eng. Scale	Title/Characteristic Features			Drawing No.
				ZO-GEM-6985
				MRDC/ERDA STUDY
				EF-76-C-01-2447
Orig. Size	UNIT 262			Submitted for
A0	BASE CASE II			Supervised by
				Reference Eng.

BASE CASE II
4.5 OFFSITE UNITS

Majority of the offsite units in Base Case II are very similar to those in Base Case I. Consequently, descriptions are not repeated; differences, principally capacities, are discussed below.

Unless stated otherwise, units are shown on Block Flow Diagram ZO-GEM-6988 in Sub-Section 4.4. In addition, units such as boilers, generators and water treaters are also included in Steam/BFW Balance ZO-GEM-6986 located in Sub-Section 4.6.

4.5.1 Oxygen Production Unit 221

Identical to Unit 121.

4.5.2 Boiler Unit 222

Differences are as follows:

Main_Fuel

Fine coal quantity (composition listed in Sub-Section 2.3)	406.90 Mlb/hr
--	---------------

Supplementary Fuels

/ - Oil quantity (from Gas Liquor Separation Unit 207)	46.49 Mlb/hr
- Vacuum tower residue (from Fractionation Unit 252)	
Quantity	2.0 Mlb/hr
Low heating value	17,750 Btu/lb

Incineration_Fuel

Sour offgases (mainly from Sulfur Recovery Unit 206)

Quantity	1,826.5 Mlb/hr
Low heating value	243 Btu/lb

NOTE: The heat content of these gases (30 Btu/SCF) has not been included in the boiler thermal balance.

<u>Normal Capacity</u>	3,111.3 Mlb/hr
------------------------	----------------

4.5.3 Main Superheater Unit 223

Capacity is changed as follows:

<u>Normal Capacity</u>	3,111.3 Mlb/hr
------------------------	----------------

4.5.4 Superheater Unit 224

Duties are as follows:

	<u>200 psig Steam</u>	<u>100 psig Steam</u>
Inlet pressure, psig	200	100
Outlet pressure, psig	185	85

	<u>200 psig Steam</u>	<u>100 psig Steam</u>
Inlet temperature, °F	387	338
Outlet temperature, °F	586	469

Fuel consists of a portion of the oil recovered from Gas Liquor Separator Unit 107:

Oil quantity 5.22 Mlb/hr

Normal Capacity

Coil 1: 200 psig steam superheating	78.7 Mlb/hr
Coil 2: 100 psig steam superheating	777.1 Mlb/hr

4.5.5 Electrostatic Stack Gas Precipitator Unit 225

Normal Capacity 216.5 Mlb-mol/hr

4.5.6 Stack Gas Clean-Up Unit 226

Normal Capacity 216.5 Mlb-mol/hr containing
48.1 lb-mol/hr SO₂

4.5.7 Instrument and Plant Air Unit 227 (not shown)

Identical to Unit 127 (Estimated instrument air requirement for the total complex is 750 lb-mol/hr; see Paragraph 3.5.7.)

4.5.8 Coal Handling Unit 228 (See SFD ZO-GEM-6909, Sub-Section 3.5.)

Gasifier well-sized coal production is identical to Base Case I. Because of the higher energy requirements in Base Case II, the quantity of boiler feed coal is increased to 406.9 Mlb/hr.

4.5.9 Ash Handling Unit 229 (See SFD ZO-GEM-6911, Sub-Section 3.5.)

Identical to Unit 129

4.5.10 BFW Preparation Unit 231

Deaerator (231/1)

Normal Capacity

	<u>Temp., °F</u>	<u>Flow, Mlb/hr</u>
MP condensate	479	346.6
LP condensate	297	1,628.5
Vacuum condensate	173*	2,190.7
Methanation Unit 212 process condensate	288	110.8
BFW make-up water	173*	2,090.4
Total	221	6,367.0

*After heating in 250-E-03.

Demineralizer (231/2)

Normal Capacity

2,090.4 Mlb/hr

4.5.11 Cooling Water Make-Up Preparation Unit 232

Normal Capacity

Mlb/hr

Treated fresh water	2,284.5
Treated water from Unit 235	
and humidity from Unit 221	<u>1,961.9</u>
Total	4,246.4

4.5.12 Cooling Water Tower Unit 233

Normal Capacity

GPM

Steam turbine condenser duty	174,300
Trim cooler duty	<u>109,590</u>
Total	283,890

4.5.13 Electric Power Generation Unit 234

Description

Generator 234-M-01 uses 48 psig, 378°F steam with Condensing Turbine 234-T-01. Back Pressure Turbine 234-T-02 of Generator 234-M-02 is fed with two superheated streams:

185 psig steam:	78.7 Mlb/hr
85 psig steam:	<u>777.1</u>
Total	855.8

Normal Capacity

	<u>MW</u>	<u>Steam Flow, Mlb/hr</u>
234-M-01	46.9	955.4
234-M-02	8.9	855.8

4.5.14 Waste Water Treatment Unit 235

Normal Capacity

<u>Composition</u>	<u>Flow, Mlb/hr</u>
Organic acids and phenols	8.9
Ammonia	1.3
Water containing some H ₂ S	<u>2,093.4</u>
Total	2,103.6

4.5.15 Flare and Blowdown Facilities 236 (not shown)

Normal Capacity

Blowdown water to holding pond 526.6 Mlb/hr

4.5.16 Storage 237 (not shown)

The following is a summary of the product, intermediate and chemical storage tank capacities which are not located within the process offsite units:

Product Storage (15 days)

Anhydrous ammonia	1,700 ton (refrigerated)
Sulfur	1,000 ton (covered)
Gasoline	224,000 Bbl (floating roof)
Diesel fuel	38,000 Bbl (cone roof)
Heavy fuel oil	11,000 Bbl (cone roof)
Propane LPG	18,500 Bbl (pressure)
Butane LPG	2,400 Bbl (pressure)
Alcohols	34,000 Bbl (floating roof)

Intermediate Storage

Hydrotreater Unit 251 feed (15 days)	22,000 Bbl (floating roof)
Hydrotreater Unit 253 feed (15 days)	188,000 Bbl (floating roof)
Reformer Unit 255 feed (5 days)	24,000 Bbl (floating roof)
Polymerization Unit 257 feed (2 days)	14,000 Bbl (pressure)

Chemical Storage

Diisopropyl ether	1,500 Bbl
Methanol	1,000 Bbl

4.5.17 Interconnecting Pipeway 238 (not shown)

Requirements are somewhat larger than in Base Case I because of the greater number of onsite units needed for F-T product upgrading.

4.5.18 Refrigeration Unit 241

Normal Capacity

<u>Temperature Level</u>	<u>Duty, MMBtu/hr</u>	
	<u>+ 32°F</u>	<u>- 45°F</u>
Purification Unit 205		
including ammonia storage	25.5	70.5
HC Recovery Unit 210	-	43.4
H ₂ Purification Unit 261	2.1	-
	<u>27.6</u>	<u>113.9</u>

4.5.19 Gasoline Blending Unit 270

Except for additional blending steams, identical to Unit 154.

4.5.20 F-T Catalyst Preparation Unit 271

Purpose of the Unit is to prepare from magnetite iron ore (Fe_3O_4) a promoted, reduced iron catalyst for the fluid-bed Fischer-Tropsch reactors.

Technology Used

The catalyst plant design is based on literature articles describing: (a) the manufacture of iron ammonia catalysts, (16), and (b) the Sasol catalyst plant (13). An overall general design has only been developed. Promoters used and dosages, concentrate specifications, specific operating conditions, etc., are confidential and, thus, unavailable. This unit has been added to the offsites because of the quantity of fused catalyst required and the problems of shipping the sensitive catalyst under a H_2 or inert gas atmosphere.

Process Description

Catalyst preparation consists of 3 steps: iron ore purification, catalyst fusion and size reduction, and catalyst reduction. Equipment contained in the iron ore purification area includes:

- Ore unloading and storage
- Rotary drier for moisture removal before grinding
- Rod mill for size reduction required by air table
- Air separation table for tailings removal
- Concentrate storage

Concentrate yield has been assumed to be 50 percent.

Equipment in the catalyst fusion and size reduction step includes:

- Electric resistance furnace for melting/intimate mixing of concentrate and promoters
- Gyratory crusher and ball mill for size reduction required by the fluid-bed reactor
- Air separator for elimination of fines and oversize particles
- Catalyst storage

Equipment required in catalyst reduction includes:

- Fluidized-bed reactor for contact of hydrogen and unreduced F-T catalyst
- Hydrogen heater
- Heat exchangers for condensing water product
- Hydrogen recycle compressor
- Recycle gas drier for moisture control
- Reduced catalyst storage under H_2 or inert gas atmosphere

Reduction takes place under elevated temperature and pressure.

BASE CASE II
4.6 UTILITY REQUIREMENTS AND STEAM/BFW BALANCE

4.6.1 Utility Requirements

Utility requirements for the individual units can be found as follows:

<u>Utility</u>	<u>Source</u>
Fuel	Type and stream number: BFD ZO-GEM-6988 (Sub-Section 4.4) Quantity and composition: Material balance sheets (Appendix B)
Power	BFD ZO-GEM-6988
Cooling water	BFD ZO-GEM-6988
Boiler feed water	Steam/BFW Balance ZO-GEM-6986 (Sub-Section 4.6)
Steam	Steam/BFW Balance ZO-GEM-6986

In addition, offsite Sub-Section 4.5 contains utility information.

4.6.2 Steam/BFW Balance

The steam and boiler feed water flows are shown on Drawing ZO-GEM-6986. The steam/electric power balance is acceptable in accordance with the study bases. Only about 6 MW(e) is surplus in comparison with 257 MW of total electric and steam power required in the plant complex. In addition, all steam produced is utilized.

BASE CASE II
4.7 TRAIN PHILOSOPHY

The train philosophy for the various units was selected on the basis of providing a plant complex having an onstream factor of 92%. Consequently, parallel trains have been used for many units to give flexibility in both operation and maintenance. Also, because of the large size of the complex, some units must be divided into parallel trains. In the hydrocarbon processing area, however, intermediate storage is used to provide this flexibility.

In addition, all normally operating pumps, reciprocating compressors and conveyors are provided with an 100% spare.

Since the same train philosophy is used for Base Case II as is used in Base Case I, only the philosophy of the new units in Base Case II are discussed below.

Hydrocarbon Recovery Unit 210

Because of size limitation, two parallel trains are provided.

F-T Synthesis Unit 250

Using a conservative scale-up factor of 2 over current commercial fluid-bed reactors, four reactors are required. In addition, a spare reactor is provided for catalyst changing and maintenance. Size considerations also require multiple towers, compressors, and pumps; see equipment list on PFD ZO-GEM-6977 in Sub-Section 4.4.

F-T Product Upgrading Units 252 Through 262

These units are single trains as equipment sizes are small enough to be shop fabricated. The only exception is Catalyst Polymerization Unit 257 which is provided with two reactors for operating flexibility.

To achieve operating flexibility in the upgrading area, feedstock storage capacity has been provided for the following units:

Naphtha Hydrotreating Unit 251	-	15 days
F-T Product Hydrotreating Unit 253	-	15 days
Catalytic Reforming Unit 255	-	5 days
Catalytic Polymerization Unit 257	-	2 days

Offsite Units

The offsite units are designed for a minimum of two parallel trains. In cases where commercial-sized equipment is too large with two trains, the number of trains has been increased.

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