SECTION 1

INTRODUCTION

This report describes the results of a conceptual design and economic evaluation for a conceptual Fischer-Tropsch plant responsive to U.S. demands and economic requirements.

A primary objective of this conceptual design is to define the characteristics and projected economics of a commercial coal mining and conversion complex to be constructed and operated in the 1980's and 1990's. Key target characteristics of the design include:

- Large size, simplicity, and reliability
- Energy efficiency
- Where justified, incorporation of advanced concepts now in development to achieve stated objectives
- Definition of incentives for further development work required to convert the concepts to reality.

Fischer-Tropsch technology provides potential for broad product flexibility. A range of product spectrums can be produced by proper selection of catalyst, reactor configuration, and operating conditions such as feed gas composition, temperature, pressure, and space velocity.

It is important to recognize that the design presented here represents only one of a large number that can be developed to exploit Fischer-Tropsch technology.

1.1 OBJECTIVES

Objectives of the work described in this report include:

- Develop a conceptual design for a commercial grass-roots coal con version complex based on Fischer-Tropsch technology. The complex is to be responsive to U.S. requirements. It is to include facilities required to:
  - mine coal
  - clean and wash coal
  - convert coal to ecologically-acceptable, premium liquid and gaseous fuels

- Produce fuels at a price competitive with alternate sources
- Develop projected economics for the complex to include the project and financial parameters for design, engineering, procurement, construction, and start-up
- Recommend development work required to assure successful commercial performance of the complex.

1.2 REPORT ORGANIZATION

A summary of key elements in this report is presented in Section 2 to aid in rapid assimilation of the contents.

Sections 3 through 6 present key technical elements of the design. Design parameters and design bases used are summarized in Section 3. Section 4 describes project scope and major units included in the complex. Here major plant units and material flows are depicted in the form of a block flow diagram. A plot plan and artist's rendition of the plant complex are also presented. Section 5 contains detailed descriptions of the separate units that make up the complex. The detailed process flow diagrams with material balances are presented in Section 6.

Sections 7 through 10 summarize key product characteristics and energy-utilization factors for the design. Section 7 presents projected marketability and characteristics of products of the complex. The material balance for the complex is depicted in Section 8. Overall energy balance is presented in Section 9. The utility summary, by unit, is given in Section 10.

Important environmental factors are summarized in Section 11. Facilities included to ensure that effluent streams are properly treated to meet environmental standards are described here. Section 12 presents a summary of plant start-up procedures, recognizing that during normal operation steam requirements for the complex will be generated by process heat recovery facilities.

The list of major equipment size and materials is presented in Section 13. This equipment list, combined with design information previously summarized in the report, provides the basis for the estimate of fixed capital investment. A detailed projected economic assessment is given in Section 14, including capital investment requirements, discounted cash flow (DCF) rate of return printout and key economic sensitivity factors.

The remainder of the report presents supporting data, analyses, and recommendations for future development effort to ensure that the plant will perform as projected.

SECTION 2

SUMMARY

A conceptual design and economic evaluation has been completed for a project to design, engineer, procure, construct, start up, and operate an industrial complex which will mine high-sulfur coal and convert it to a nil sulfur product mix using Fischer-Tropsch technology. The objective was that the complex should be responsive to future U.S. energy requirements and be competitive with alternate energy sources. The results are summarized in this report.

The design basis was developed in cooperation with representatives of ERDA and the work was done with their guidance and support.

As conceived, the complex is located in the Eastern Region of the U.S. Interior Coal Province, which includes portions of Illinois, Indiana and Kentucky. It will mine approximately 40,000 TPD of run-of-mine (ROM) coal from which it will produce about 30,000 TPD of clean, sized coal as feed to the Fischer-Tropsch plant. Here the coal will be gasified, the gases purified, and then reacted to produce liquid products plus substitute natural gas (SNG). The products will be separated and refined ready for sale. Plant products will have an energy value of approximately 525 billion Btu/day, which is about twice the energy value of commercial coal gasification plants planned for construction in the U.S. The plant will consist of two production lines. The plant is designed to meet environmental standards. It should be noted that the design is one of many that can be developed using Fischer-Tropsch technology.

Products from the plant include about 260 MMSCFD of SNG and approximately 50,000 BPD of liquid products. The liquids consist of LPGs, light and heavy naphthas, diesel fuel, fuel oil, and oxygenates (consisting primarily of alcohols). All petroleum liquids produced contain nil sulfur, nitrogen and particulate matter and can be referred to as premium fuels.

Estimated time needed to design, procure, construct and start up the facility is 57 months. The estimated fixed capital investment is approximately $1.5 billion; all economics have been based on fourth quarter 1975 dollars. The total capital investment required is estimated to be about $1.75 billion. In addition to fixed capital requirements, this total includes the cost of initial raw materials, catalysts and chemicals, working capital, allowance for startup costs, and allowance for land acquisition. The cost of financing during design and construction depends on the method of financing, and was added to the $1.75 billion for the separate project cases reported.

The fixed capital investment estimate was independently evaluated by the U.S. Army Engineer Division, Huntsville, Alabama (USAEDH). This work was done under contract to ERDA, Contract No. EX-76-C-01-1759. The USAEDH estimate was approximately 10% lower than Parsons, and they report an indicated overall estimate confidence factor of $\pm 10\%$.

Annual operating costs for the complex are predicted to be about $190 million. Plant population is approximately 2100 people.

Predicted required product selling prices, expressed as dollars per million Btu, for a 12% DCF rate of return and a twenty-year project operating life are:

FINANCING METHOD		
100% Equity	$\frac{\text{Debt}}{\text{Equity}}$ Ratio = 65/35	Break-Even
3.25	2.50	1.45

These values correspond to about $14.80 and $19.40 per barrel equivalent for the 65/35 Debt/Equity (D/E) ratio and 100% equity cases, respectively, based on a heating value of 6 million Btu per barrel. Full details of the economic analysis, including complete sensitivity analyses, are presented.

PROCESS AND PLANT FACTORS

Key characteristics of the complex include:

- Large captive coal mine.
- Use of high capacity gasifiers - each gasifier vessel projected to produce 250+ million Btu/day of energy products.
- Fischer-Tropsch converter design that permits high throughput and recovery of reaction heat at 1,200 pound per square inch steam.
- Design for high thermal efficiency. Predicted thermal efficiency is approximately 70%, expressed as Btu's in salable products divided by Btu's in feed coal, times 100. Predicted efficiency is the result of considerable technical and economic analysis of alternates. Results of these analyses are reported.

The Fischer-Tropsch converter design is based on application of flame-sprayed catalyst (FSC) techniques which have been demonstrated experimentally by what is now the Pittsburgh Energy Research Center (PERC) of ERDA. Similar reactor designs were used for the shift and methanation reaction sections. This type of reactor is projected to provide efficient recovery of reaction heat as steam at a pressure of 1,200 pounds per square inch. As a result, all steam required to operate the plant, produce the necessary captive power requirements, and also produce excess power for sale is generated in the process sections;

a fuel-fired utility plant is not required for normal operation. All utilities are internally generated, i.e., feeds to the process plant consist of coal, air, and water.

This design is intended to aid in defining the potential for large, second-generation coal conversion plants. It incorporates a number of concepts and equipment items that careful analyses indicate have potential advantages and good probability for high performance. A number of these items is based on commercialization of expected favorable results of an in-progress development program. Key developments required and recommendations for continued development are presented. Comments regarding projected plant performance are presented.

The products, having nil sulfur, nitrogen, and particulate matter, represent premium grade fuels from an environmental standpoint. They also have characteristics which make them attractive as potential feedstocks for high value petrochemical and chemical manufacture.

Details of the design, operating efficiencies, and economic projections are presented in this report.

SECTION 3

DESIGN PARAMETERS

This section describes the raw material utilization, the products, and the basic design parameters/criteria used.

3.1 GENERAL CHARACTERISTIC

- A significant characteristic is that products have nil sulfur, nitrogen, and solids contents
- The design is based on use of a single feed-coal analysis which is typical of coal mined in the Eastern Region of the U.S. Interior Coal Province
- Process waste water is reused in order to minimize water consumption
- The plant is designed to meet environmental standards

3.2 DESIGN BASIS

A summary of the Design Basis is included as Appendix A. The Design Basis was intended to state the philosophy and data base to be used for the development of the conceptual commercial plant.

A number of key design parameters are summarized in the following paragraphs of this section.

3.3 PLANT LOCATION

The plant was considered to be located in the Eastern Region of the U.S. Interior Coal Province, which includes portions of Illinois, Indiana, and Kentucky. The site conditions used for equipment design are summarized in the Basic Design Criteria document presented as Appendix B of this report. The plant complex was to be close to the coal mine and to a river.

3.4 SCOPE

The coal conversion complex is a grassroots facility with a captive coal mine to supply the necessary feed coal. Excess generated electrical power will be sold.

3.5 RAW MATERIALS

The raw materials consist of the following:

(1) Coal

(a) ROM coal will be produced in a captive mine

(b) The proximate and ultimate analysis of coal feed to the process plant are:

Proximate Analysis (composition weight percent) is:

Item	%
Moisture	2.7
Ash	7.1
Volatile Matter	38.5
Fixed Carbon	51.7
	100.0
Heating Value	12,550 Btu/lb

Ultimate Analysis (composition weight percent) is:

Item	
Carbon	70.7
Hydrogen	4.7
Nitrogen	1.1
Sulfur	3.4
Oxygen	10.3
Moisture	2.7
Ash	7.1
	100.0

(2) Oxygen - 98% purity, produced captively by air separation.

(3) Water

(a) Process water from the river

(b) Potable water from wells

3.6 PRODUCTS

The principal products are listed in the following table:

Product	Characteristics	Production Rate* (approximate)
SNG	1,035 BTU/SCF HHV	258,700,000 SCFD
C_4s	37 PSIG	3,500 BPD
Naphtha	nil sulfur, UOP K=12.3	20,000 BPD
Oxygenates	mixed alcohols	4,000 BPD
Diesel Fuel	nil sulfur, 60-plus cetane	16,000 BPD
Fuel Oil	nil sulfur, low viscosity	5,000 BPD
Sulfur	99.9% sulfur	1,000 STPD
Power for Sale	13,800 volts	3,352,000 kWh

*Stream Days

3.7 PRIMARY PROCESS UNITS

The complex consists of two trains and contains the following primary units:

(1) A unit to crush, wash, and prepare the coal for gasifier feed

(2) Facilities to dry the coal

(3) An entrainment type, two-stage slagging gasifier, to primarily produce a mixture of carbon monoxide and hydrogen (synthesis gas)

(4) A synthesis gas heat recovery and dust removal unit

(5) A water gas shift reaction unit to increase the hydrogen content of the synthesis gas

(6) A unit to remove acid gases from the synthesis gas (syngas)

(7) A unit to desulfurize the acid gases removed from the synthesis gas

(8) A Fischer-Tropsch synthesis unit to convert syngas to hydrocarbons

(9) A unit to remove carbon dioxide produced in the Fischer-Tropsch synthesis unit from the recycle gas

(10) A unit to recover hydrocarbons from the Fischer-Tropsch synthesis tail gas and separate liquid products

(11) A unit to make SNG by methanation of the Fischer-Tropsch tail gas

(12) A unit to recover product oxygenates and dispose of organic acid solution

(13) A unit to recover process water and recycle it to the steam generators

(14) A unit to convert superheated steam generated in the process to electrical power

(15) A unit to provide oxygen to the coal gasifier

3.8 EQUIPMENT SPARES

Equipment considered to have a relatively high operating factor (greater than 95%) is not spared. Equipment predicted to require periodic maintenance and whose failure would materially limit production is spared.

3.9 EFFLUENT TREATMENT AND NOISE CONTROL

All effluent streams will be treated to meet environmental standards. Disposal of solid waste will be integrated with coal mining to provide haul-away and proper disposal. Equipment will be designed to meet OSHA noise level requirements.

3.10 RAW MATERIAL AND PRODUCT STORAGE

Facilities are provided for storage of a 14-day feed coal inventory and a 30-day product storage inventory.

3.11 ANCILLARY FACILITIES

Adequate ancillary facilities are provided to service this square-mile industrial complex and its personnel population of approximately 2,100.

SECTION 4

SUMMARY FACILITY DESCRIPTION

A block flow diagram is shown in Figure 4-1. The complex includes a captive coal mine with the capacity to produce approximately 15 million TPY for 20 years. Units are included which will clean, wash, crush, and size the coal and feed it to the process units.

Facilities for the production of oxygen and all required utilities are included in the design as well as for the treatment and disposal of solid, liquid, and gaseous effluent streams. The design is based on a site location capable of providing 18,000 acre-feet of water per year for process requirements and utilities makeup. Well water is used for all potable and sanitary water requirements.

The land area required for the life of the project for mining the required coal is estimated to be about 47 square miles; approximately 500 acres should be allotted to the initial plant complex.

4.1 PROCESS UNITS

The process consists of the reaction of coal with oxygen and steam at elevated temperature and pressure to produce a synthesis gas, purification and adjustment of composition of the gas, and catalytic reaction of the gas to form principally hydrocarbon liquids. Unreacted tail gas and methane are further processed to produce SNG.

Approximately one-half of the carbon in the coal is reconstituted into hydrocarbons with greater hydrogen content than the feed coal, heat being supplied primarily by heat of reaction released from the gasifier, water gas shift, Fischer-Tropsch synthesis and methanation steps. Efficient heat recovery provides all process needs for power and steam plus saleable electric power.

A plot plan is shown at the end of this section as Figure 4-2 and an artist's conceptual drawing of the complex is shown in Figure 4-3. A photograph of a model of the complex appears as Figure 4-4.

4.2 PLANT CAPACITY

The design feed rate of prepared coal to the gasifier is 30,000 TPSD to produce about 525 billion Btu per stream day of SNG, liquid products, approximately 140 MW of electrical power for sale, and about 1000 TPD of sulfur.

Table 4-1 summarizes product quantities expressed as barrels of fuel oil equivalent; quantities in tons and heating value are also given. The overall thermal efficiency is predicted to be about 70%.

4.3 ENERGY BALANCE FACTORS

In normal operation all steam is generated by heat recovery from process streams and reactors. Steam generation facilities provided are therefore used only during startup and as standby units.

Table 4-1 - Fischer-Tropsch Products
Projected Quantities and Heating Values

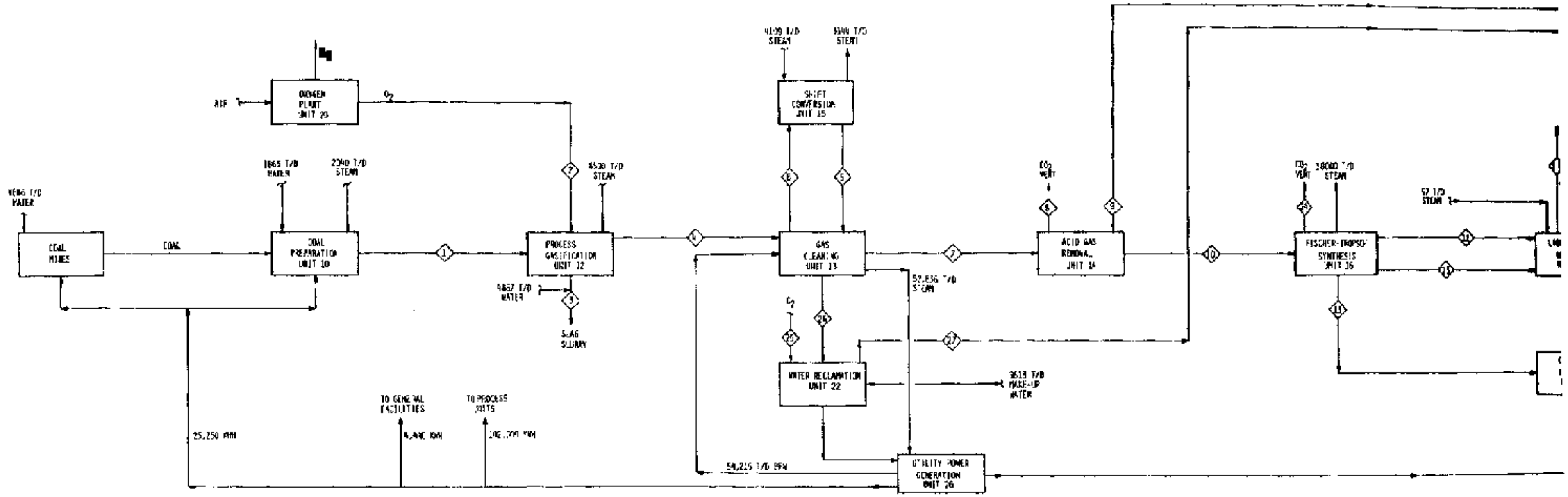
Product	BPSD	TPSD	Product Unit HHV	Total Heating Value (Billion Btu/Day)	% of Coal HHV
SNG	42,505 [a]	6,588	1,035 Btu/scf	267.78	35.56
C_4s	3,534	343	21,035 Btu/lb	14.42	1.92
Naphthas	20,175	2,378	20,625 Btu/lb	98.08	13.03
Oxygenates	3,913	458	12,505 Btu/lb	11.46	1.52
Diesel fuel	16,075	2,105	20,255 Btu/lb	85.27	11.32
Premium fuel oil	4,959	713	19,865 Btu/lb	28.33	3.76
Subtotal Fuels	91,161	12,585		505.34	67.11
Sulfur	1,284 [a]	1,014	3,990 Btu/lb	8.09	1.07
Subtotal Products	92,445	13,599		513.43	68.18
Power	1,815 [a]			11.43 [b]	1.56
Total	94,260			524.86	69.70

(a) Equivalent fuel oil at 6,300,000 Btu/bbl.

(b) Heating value equivalent to 139.6 MW. at theoretical conversion of 3415 Btu per kWh. Applicable heat rate would be at least 9,500 per kWh. This would increase thermal efficiency by 2.8 to 72.5%.

NOTES:

1. SIZE AND QUANTITY SHOWN HERE FOR ONE TRAIN OF A TWO TRAIN PLANT, EACH TRAIN CHARGING 25,000 T/D COAL TO THE PROCESS PLANT TO MAKE 292 BILLION BTU/D THERMAL PRODUCT OUTPUT.



STREAM NO.	1	2	3	4	5	6	7	8	9	10
STREAM NAME	COAL FEED	OXYGEN	SLAG SLURRY	RAW SYN GAS	SHIFTED SYN GAS	SYN GAS TO SHIFT	DUST FREE SYN GAS	CO_2 VENT	ACID GAS	SHIFT SYN GAS
FLOW, T/D										
H_2	-	-	-	1337	667	361	1583	0.24	-	1552
CO	-	-	-	14032	1883	5698	14109	200 PPMV	-	14176
CO_2	-	-	-	7357	9566	2761	14305	11486	2343	570
CH_4	-	-	-	827	845	38	477	1	-	845
H_2S	-	-	-	531	182	182	550	5 PPMV	545	0.3 PPMV
N_2	-	171	-	321	101	101	329	-	4	331
O_2	-	4903	-	-	-	-	-	-	-	-
H_2O	404	-	4984	3604	2157	1843	808	40	20	1
NH_3	-	-	-	5	1.7	1.3	-	-	-	-
COS	-	-	-	14	1	4	19	-	19	-
SO_2	-	-	-	2	0.3	0.8	2	-	2	-
ASH	1028	-	2100	-	-	-	-	-	-	-
CHAR	-	-		35	0.4	0.1	-	-	-	-
COAL (MAF)	13526	-	-	-	-	-	-	-	-	-
TOTAL T/D	[illegible]	[illegible]	7086	[illegible]	13998	[illegible]	31860	11531	2936	[illegible]

STREAM NO.	11	12	13	14	15	16	17	18	19	20	21	22
STREAM NAME	ALCOHOL SOLUTION	F-T GAS	F-T LIQUID	C_3/C_4'S	STRIPPED F-T GAS	BUTANE	LIGHT NAPHTHA	HEAVY NAPHTHA	DIESEL	FUEL OIL	SNG	ALCOHOL MIX
FLOW, T/D												
H_2	-	397	0.5	-	398	-	-	-	-	-	4	-
CO	-	1653	6	-	1630	-	-	-	-	-	5	-
CO_2	4	138	0.5	13	126	-	-	-	-	-	106	-
N_2	-	374	1	-	389	-	-	-	-	-	379	-
H_2O	2430	27	-	-	-	-	-	-	-	-	-	14
C_1	-	1004	8	5	1095	-	-	-	-	-	2510	-
$C_2=$	-	45	7	6	63	-	-	-	-	-	-	-
C_2	-	256	9	47	376	-	-	-	-	-	77	-
$C_3=$	-	41	4	26	18	-	-	-	-	-	-	-
C_3	-	141	35	107	53	-	-	-	-	-	137	-
$C_4=$	-	105	25	106	1	28	-	-	-	-	-	-
C_4	-	391	46	252	1	148	3	-	-	-	163	-
C_5	-	71	38	1		3	43	-	-	-	-	-
C_6	-	143	97	-	2	2	198	-	-	-	1	-
LIGHT NAPHTHA	-	56	270	-	8	-	154	1	-	-	-	-
HEAVY NAPHTHA	-	47	557	-	2	-	17	580	10	-	-	-
DIESEL	-	7	1165	-	-	-	-	11	1028	41	-	-
FUEL OIL	-	-	332	-	-	-	-	-	10	321	-	-
ALCOHOLS	221	-	-	-	-	-	-	-	-	-	-	269
ACID SALTS	41	-	-	-	-	-	-	-	-	-	-	-
TOTAL T/D	2784	[illegible]	2541	557	3659	174	414	592	1048	362	3314	283

STREAM NO.	24
STREAM NAME	CO_2 VENT
FLOW, T/D	
H_2	-
CO	-
CO_2	7167
CH_4	-
H_2S	-
N_2	-
O_2	-
H_2O	108
NH_3	-
COS	-
SO_2	-
COD	-
ORGANICS	-
CHLORIDES	-
CARBONATES	-
SOLIDS	-
TOTAL T/D	7174

FIG. 4-3

4-3

4-3 A B

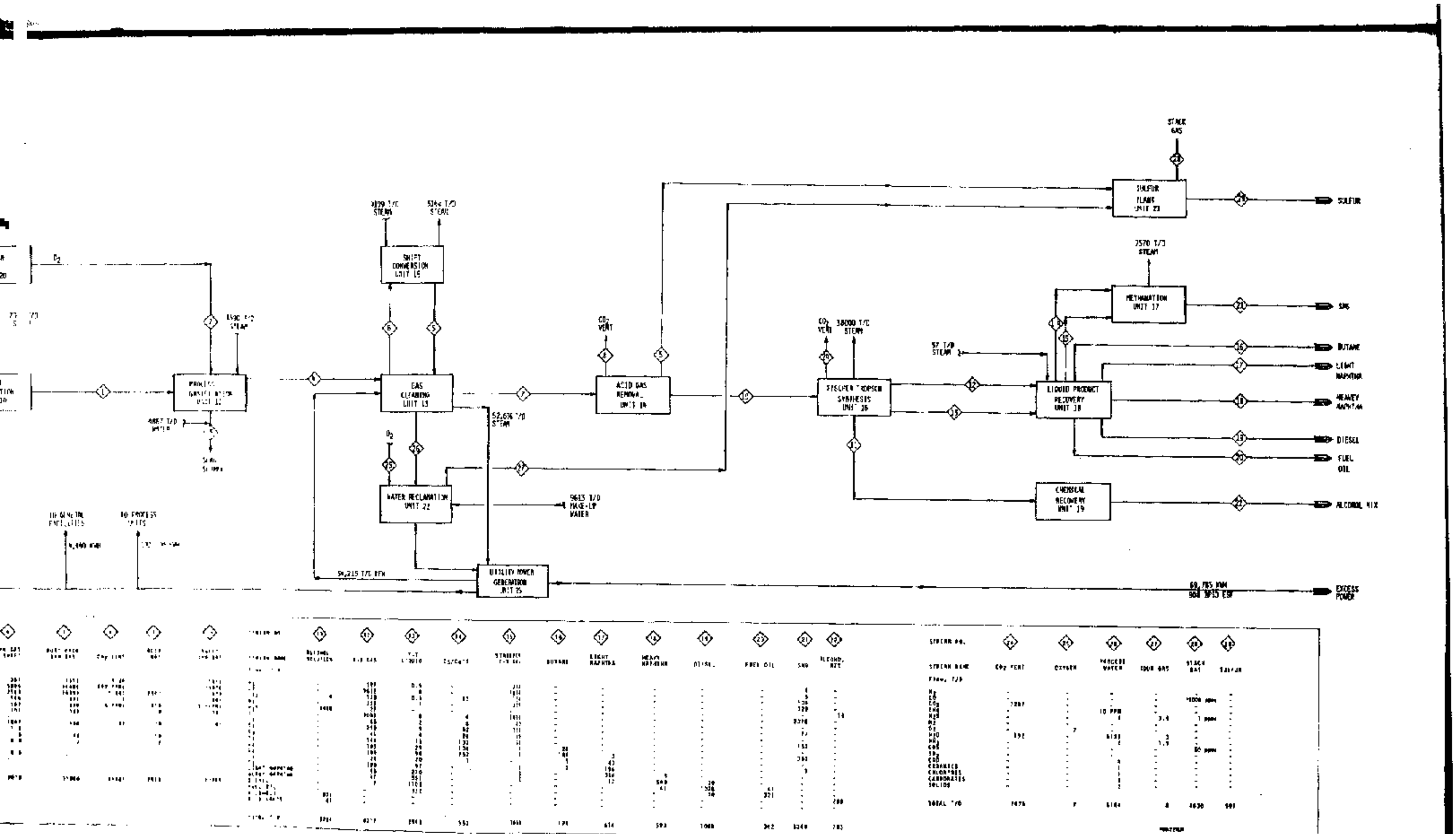


FIG. 4-1

4-3 B

4-3 C

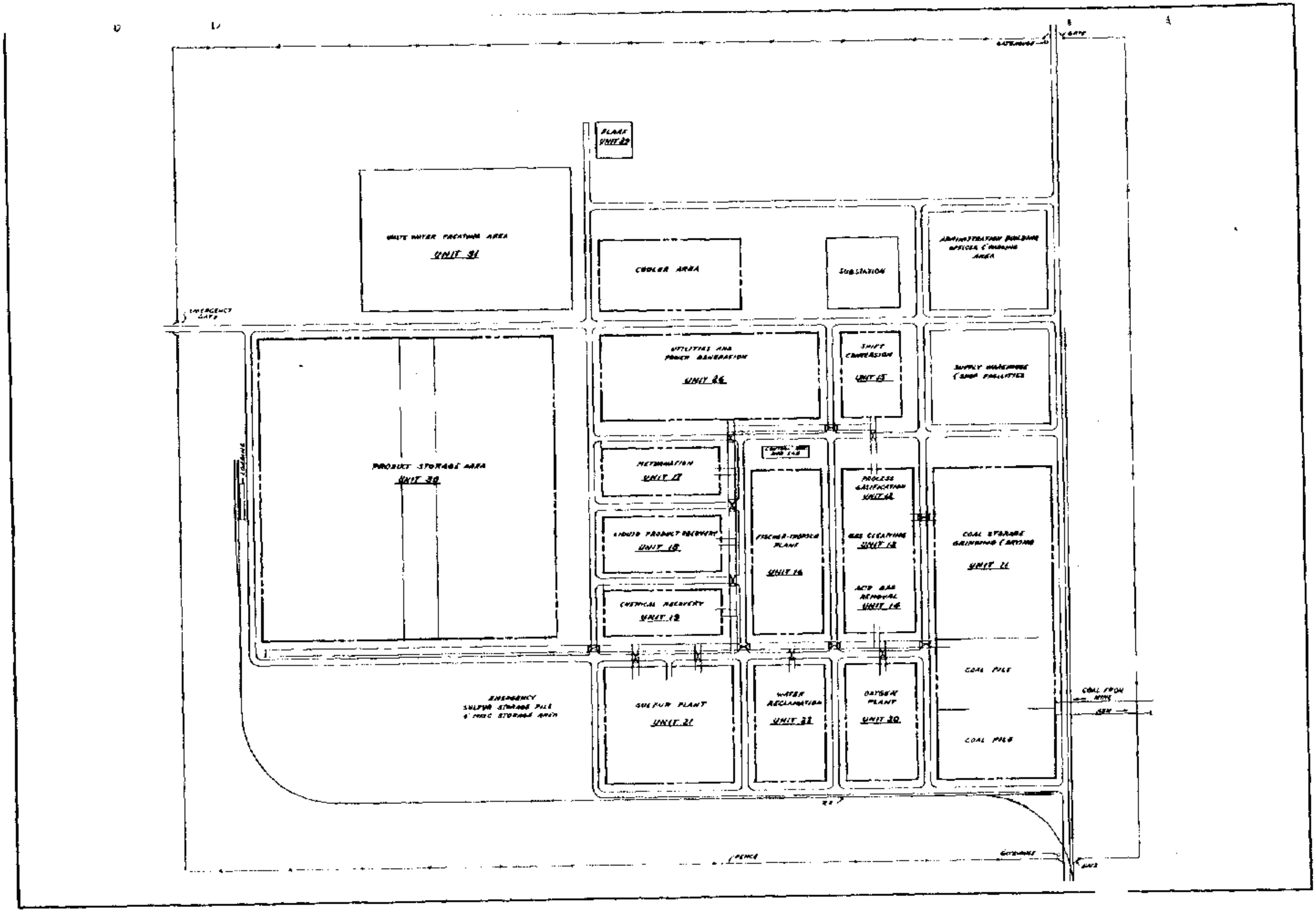


Figure 4-2 - Plant Plot Plan

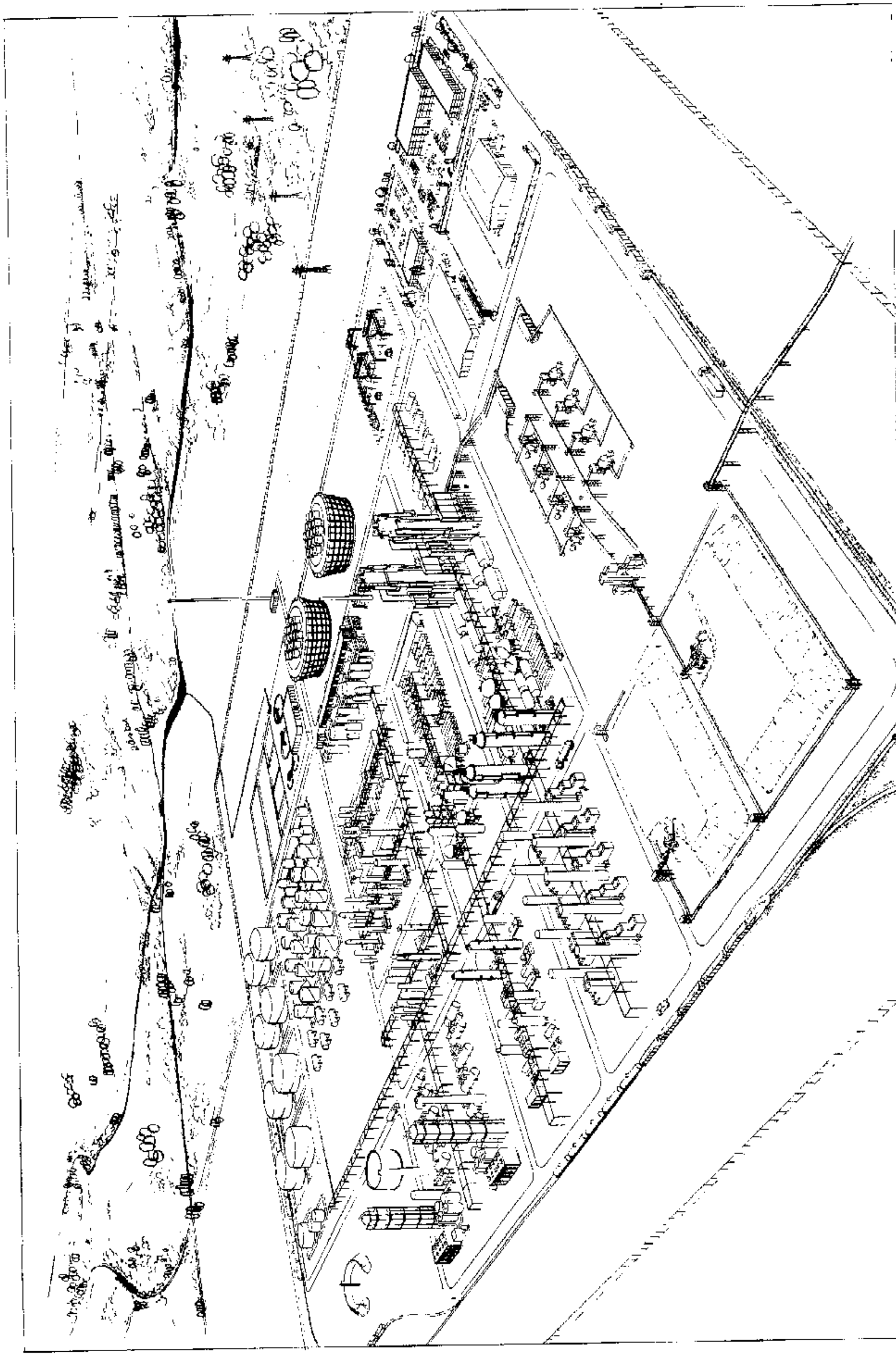
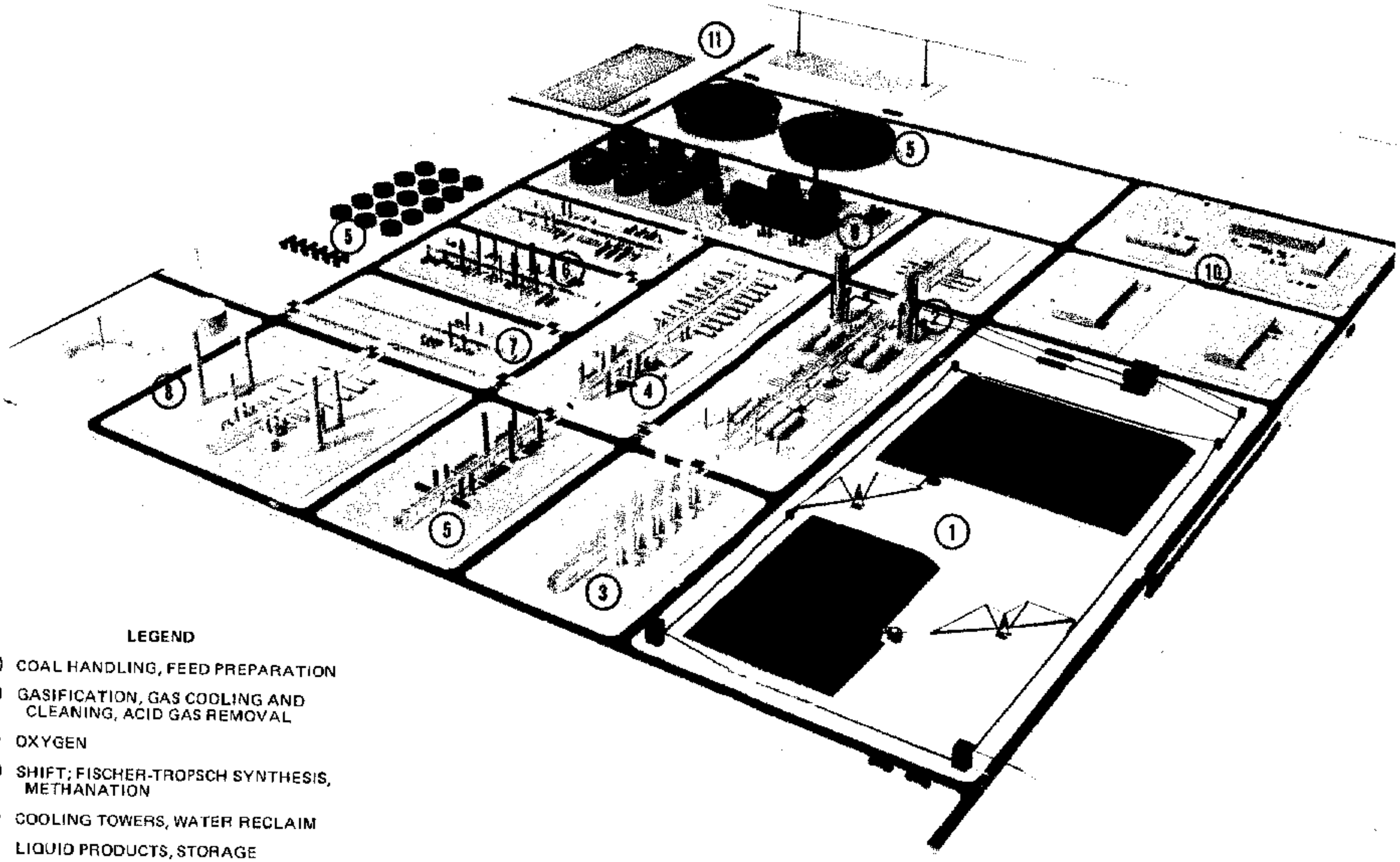


Figure 4-3 - Artist's Conceptual Drawing



LEGEND

1. COAL HANDLING, FEED PREPARATION
2. GASIFICATION, GAS COOLING AND CLEANING, ACID GAS REMOVAL
3. OXYGEN
4. SHIFT; FISCHER-TROPSCH SYNTHESIS, METHANATION
5. COOLING TOWERS, WATER RECLAIM
6. LIQUID PRODUCTS, STORAGE
7. CHEMICAL RECOVERY
8. SULFUR RECOVERY
9. UTILITIES
10. BUILDINGS
11. WATER TREATING

Figure 4-4 - Model of Conceptual Fischer-Tropsch Plant Design

SECTION 5

UNIT DESCRIPTIONS

Descriptions of the separate units which are a part of the Fischer-Tropsch conceptual commercial plant design are presented in this section. The following units are described:

Unit No.	No. of Trains	Unit	Flowsheet No.	Paragraph No.
09	-	Coal Mine	---	5.1
10	1	Coal Preparation	R-10-FS-1	5.2
11	1, 2	Coal Storage, Grinding, and Drying	R-11-FS-1	5.3
12	2	Process Gasification	R-12/13/14-FS-1	5.4
13	2	Heat Recovery/Gas Cleaning	R-12/13/14-FS-1	5.5
14	2	Acid Gas Removal	R-12/13/14-FS-1	5.6
15	2	Shift Conversion	R-15-FS-1	5.7
16	2	Fischer-Tropsch Synthesis	R-16-FS-1	5.8
17	2	Methanation	R-17-FS-1	5.9
18	2	Liquids Product Recovery	R-18-FS-1	5.10
19	2	Chemicals Recovery	R-19-FS-1	5.11
20	2	Oxygen Plant	---	5.12
21	2	Sulfur Recovery	R-21-FS-1, -2	5.13
22	2	Water Reclamation	R-22-FS-1	5.14
23	2	Steam Distribution	---	5.15
24	1	Shops and Buildings	---	5.16
25	1	Fire Water System	R-25/27/28/31-FS-1	5.17

Unit No.	No. of Trains	Unit	Flowsheet No.	Paragraph No.
26	2	Power Generation	R-26-FS-1	5.18
27	1	Potable and Sanitary Water System	R-25/27/28/31-FS-1	5.19
28	1	Raw Water System	R-25/27/28/31-FS-1	5.20
29	2	Plant Flare System	---	5.21
30	1	Product Storage	---	5.22
31	1	Effluent Water Treating	R-25/27/28/31-FS-1	5.23
32	-	Site Preparation, Roads and Railroad	---	5.24

Process flow diagrams are located in Section 6. Utilities for each unit are defined in Section 10, and the equipment lists are presented in Section 13.

5.1 UNIT 9: COAL MINE

The strip mine consists of four integrated mining faces. The average seam thickness is 5 feet and the average overburden depth is 60 feet. The coal is a high-volatile C bituminous variety.

A mining plan was formulated, and capital and operating costs were estimated. Cost estimates include land acquisition and the expense of relocating any existing buildings, roads, pipelines, and related items that would interfere with the mining operation.

5.1.1 PRODUCTION REQUIREMENTS

The mine will produce 40,000 TPD of ROM coal for 330 operating days per year, or 13,200,000 TPY.

Coal density is 1,800 tons per acre-foot. A coal seam 5 feet thick will provide 9,000 tons per acre. Allowing for losses during mining, an average of 4.5 acres will be mined each day.

With an average overburden thickness of 60 feet, overburden stripping requirements will average 435,600 bank cubic yards (BCY) per day or 143,750,000 BCY per year.

5.1.2 MINING PLAN

Approximately 1,500 acres of coal per year will be mined. Over a 20-year mine life, 30,000 acres or approximately 47 square miles will be mined out.

The mine has been divided into four separate areas or mining units. Each unit will develop a pit approximately 3.5 miles in length, and produce 10,000 TPD of coal. A mining unit consists of the following.

- A large stripping dragline to remove the overburden and expose the coal seam
- Rotary drills to drill the overburden
- Loading and hauling equipment to remove the coal
- Auxiliary equipment, such as dozers, graders, scrapers, to support each operation

The four mining units will be supported by a centralized shop facility and other equipment that will be available when required.

The general mine layout has two primary rotary breakers located between the four mining areas. Coal will be hauled from the pits to the breakers by truck, and after crushing will be transported by belt conveyers to the coal preparation plant. This scheme separates the pits sufficiently to avoid congestion, yet permits close supervision (see Figure 5-1).

The coal mining width in each pit is 150 feet. With a pit length of 3.5 miles, mining will advance along the cut at about 325 feet per day. Thus each cut will be completed in about 57 days, resulting in 6.2 strip cuts in each pit per year.

5.1.3 MINING SEQUENCE

A. Preproduction Stripping

During the preproduction period, main haul roads will be constructed, and the initial starting cuts will be made. At each pit, the initial starting cut will be approximately 150 feet wide, 20 feet deep, and will extend the full length of the pit. About 2,150,000 BCY of upper overburden will be removed in this operation. Since the starting cut is made only once during the life of the pit, and is done prior to full-scale production, it is treated as a preproduction capital cost.

B. Overburden Stripping

The overburden covering the coal seam consists of two types of material. The upper 20 feet of overburden consist of topsoil and unconsolidated gravels, sands, and soils. The lower 40 feet are made up of limestone and clayey shale that have to be drilled and blasted. Since it is required that the mined-out areas be restored to approximately the original surface contour and that plantings be made on the reclaimed ground, the topsoil and upper overburden must be placed on top of the spoiled lower overburden.

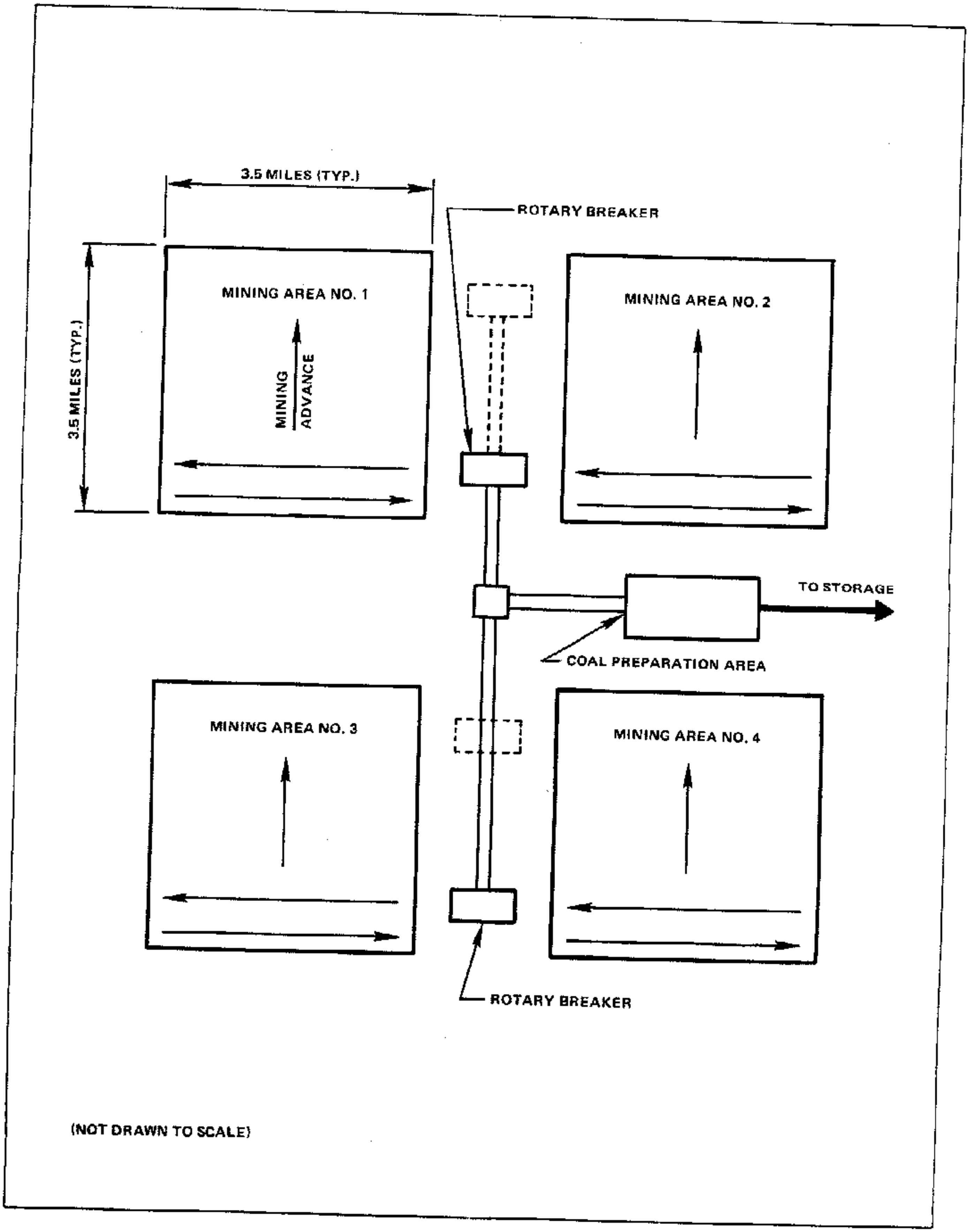


Figure 5-1 - Sketch of Mine and Working Plan

Stripping both the blasted lower overburden and the unconsolidated gravels and soils will be accomplished with one large walking dragline at each pit.

An average of about 109,000 BCY per day of overburden will be removed at each pit to uncover the coal. A large stripping dragline, with an operating radius of 292 feet, equipped with a 175-cubic yard bucket has the capability of removing the required yardage, and placing the topsoil portion on top of the spoiled overburden.

The preproduction cut exposes the lower overburden so it can be drilled and blasted. Rotary drills are used to drill a pattern of holes the full width of the cut. When the drills have advanced along the cut to a safe distance, the holes are blasted.

The dragline operation follows the drilling and blasting. The dragline operates from within the cut and on top of the blasted lower overburden. With a working radius of 292 feet, it is able to dig and cast the blasted lower overburden to the spoil area and then swing to the side and make a chop cut to dig the upper overburden from the next adjacent cut.

The upper overburden is then cast to the spoil area placing it on top of the spoiled lower overburden. Operating in this manner, the dragline removes the blasted material from the working cut (and exposes the coal seam) and also removes the upper overburden from the next working cut.

Since the draglines have the capability of spreading the spoiled overburden, a minimum amount of dozer work will be required to level the spoil areas and restore the mined-out areas to their approximate original surface contours.

C. Coal Mining

The coal mining will closely follow the stripping operation. At each pit, a dozer will work in the cut on top of the exposed coal making a final cleanup of the overburden that was left by the dragline. After cleaning the coal seam, the dozer is available to rip any coal that requires ripping prior to loading with the mining shovel.

The mining shovel and haulage trucks will operate at the bottom of the coal seam in each of the four pits. A 15-cubic-yard electric shovel will load coal to the 120-ton capacity bottom-dump coal haulers, which will transport the coal out of the pit to the breaker stations. The breakers will be periodically relocated in relation to the shovel locations in order to minimize truck haulage distances.

D. Waste Disposal

Solid waste from the washing plant will be returned to the pits in 120-ton bottom-dump coal haulers. This waste product will be dumped in the mined-out strips and will be covered with overburden from subsequent stripping operations.

5.2 UNIT 10: COAL PREPARATION

This unit processes the ROM coal to separate and discard inerts to produce a quality product with a minimum of loss. This is accomplished by size reduction, water jigging, wet screening, liquid cycloning, and centrifuging. Flow diagram R-10-FS-1 describes the processing flow from coal receipt from the mine haulers to the washed coal delivery conveyor servicing the clean coal stockpile in Unit 11.

The ROM coal is expected to have approximately 15% in-place impurities. Dilution in mining operations is estimated at 5 to 20%, making a total reject fraction of 20 to 35%.

The ROM haulers discharge into either of two 400-ton-capacity field hoppers, 10-2601 and 10-2602, having fixed grizzly surfaces with 2-foot-square openings. These hoppers each discharge, via apron feeders 10-0501 and 10-0502, directly onto vibrating grizzly units, 10-2723 and 10-2724, having 3-inch-square openings. The 3-inch by 0 grizzly undersize is received on a belt conveyor system, 10-2003 and 10-2004, which delivers it to the coal preparation plant. The oversize material, 2-foot by 3-inch size, from the individual grizzly units, discharges to two feeder units, 10-0503 and 10-0504, which deliver to two rotary coal breakers, 10-2101 and 10-2102, having 3-inch apertures. The raw coal in this feed, after breaking to minus 3-inch size, discharges and combines with the vibrating grizzly undersize material being transported to the preparation plant. The breaker oversize that does not meet the minus 3-inch size during breaking, mainly stone, discharges via belt conveyors 10-2001 and 10-2002 into 300-ton refuse hoppers, which are serviced by empty coal haulers on waste return haulage operations. The breaker units are located near the mine to minimize haulage distances. Roadways provide ready access to units handling waste haulage.

The final segment of the sized raw coal conveyor system, 10-2004, discharges - continually sampled by primary feed sampler 10-0901 - to a battery of five vibrating screens, 10-2702 through 10-2706, equipped with water sprays. Here the raw coal is separated into three size fractions. The coarse fractions, 3-inch by 1-1/2-inch and 1-1/2-inch by 3/4-inch, are sent to a Baum jig, 10-3101. The middlings, 1-1/2-inch by 3/4-inch material, may be directed either to the jig or cyclone circuits as may be required. The raw coal screen undersize slurry, stream 5, flows to the primary liquid cyclone sumps, 10-3201 to 10-3204.

The jig yields a "float" clean coal product which, after dewatering on sieve bend screens 10-2707 and 10-2708, continues onto vibrating double-deck screens 10-2709 and 10-2710. Here, the coarse top-deck oversize material, plus 1-1/2-inch, is sent directly to the washed clean coal conveyor, 10-2007, for dispatch to the clean coal stockpile. The oversize from the bottom screen, minus 1-1/2-inch plus 28 mesh, is directed to the coarse coal centrifuge, 10-2273, where the coal is dewatered and deposited on the clean coal conveyor, 10-2007. The sieve bend underflow and the vibrating screen underflow are combined and sent to cyclone primary feed sumps 10-3201 to 10-3204.

The jig middling product, consisting of locked coal and stone material, is crushed to minus 3/4-inch size by middlings roll crusher 10-2103. The crushed product, Stream 19, is directed to cyclone secondary feed sumps 10-3205 and 10-3206. The jig waste product is discharged and sent to vibrating screen 10-2701, where the plus 3/4-inch material is dewatered and discharged onto plant refuse conveyor 10-2006 for transfer to plant refuse hopper 10-2603. The undersize refuse screen material flows to the secondary liquid cyclone circuit sumps.

The primary cyclone feed sump contents, consisting of the undersize material from the raw coal screens and clean coal screens, are pumped to a battery of primary cyclones, which yield a low specific gravity clean coal overflow product. This product is delivered to a battery of dewatering sieve bends which, in turn, feed a battery of wet, vibrating screens, 10-2717 through 10-2722, where the minus 3/4-inch plus 9 mesh product is removed and sent for further dewatering to a battery of centrifuges, 10-2201 through 10-2212. The centrifuges discharge the coal product to conveyor 10-2007 with the other clean coal size fractions. The centrifuge liquid discharge stream returns to the fine clean coal screens.

The underflow high specific gravity primary cyclone product flows to the secondary feed sumps, 10-3205 and 10-3206, where it joins the crushed jig middling product and the refuse screen underflow to form the feed to the battery of secondary cyclones, 10-2775 through 10-2782. The overflow low-specific gravity product joins the other materials, forming the primary cyclone circuit feed. The secondary cyclone underflow product goes to the plant sump for pumping to the tailings pond.

A clean water circuit is provided that treats the primary cyclone clean coal product screen undersize material by means of successive closed circuit classifying and polishing cyclone batteries, 10-27101 through 10-27196 and 10-27201 through 10-27224. Clean water from the classifying cyclones becomes recovered plant water going to the head tank, 10-1901, which provides screen spray water and jig dilution water. Makeup water is recovered, in part, from the tailings pond.

The coal losses from the coal preparation plant are estimated to be approximately 1% by weight of the clean coal product stream. This amounts to approximately 3% of the total waste stream.

Slag slurry from the gasifier area, Unit 12, is dewatered in sieve bend screens at the refuse area. The separated wet solids are returned with the Unit 10 refuse stream to the mine sites for burial with the overburden in exhausted pit areas. The separated water provides a major portion of the makeup water required for the coal preparation area.

5.3 UNIT 11: COAL STORAGE, GRINDING, AND DRYING

5.3.1 CLEAN COAL STOCKPILING, BLENDING, AND RECLAIM

Drawing No. R-11-FS-1 depicts the principal equipment and operations for Unit 11. Figure 5-2 is a plan of the stockpile area.

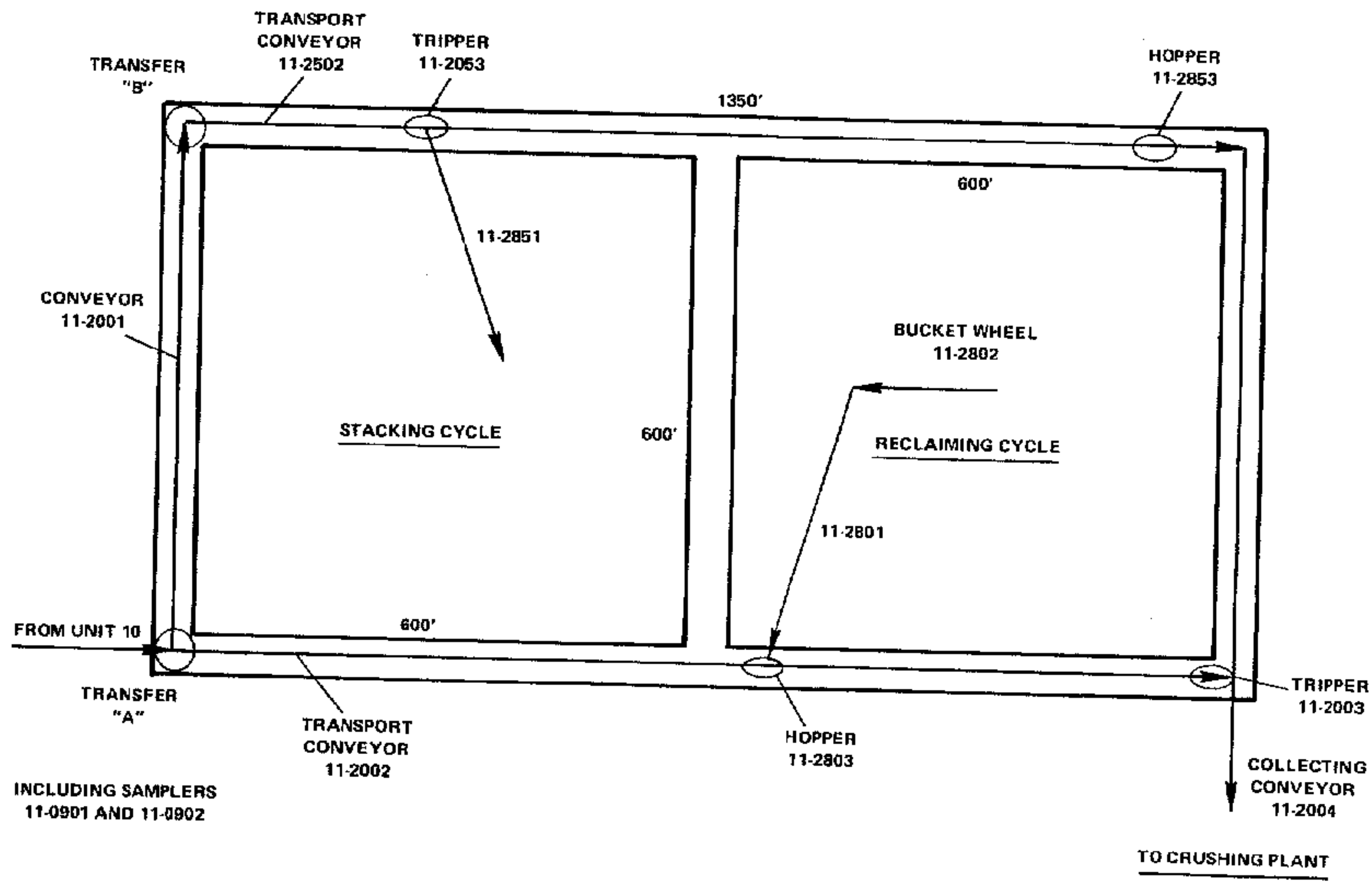


Figure 5-2 - Stockpile Area Plot Plan
and Operating Diagram

The stockpiling, blending, and reclaim system will reclaim on a first in/first out (FIFO) basis. The system requires minimum conveyor length, transfer points, and land area. One hundred percent live storage is provided. Operating costs are low because no tunnel ventilation is required. Continuous control sampling and analysis provide the capability to blend feed coal within a 300-Btu heating value range.

Referring to Figure 5-2, minus 3-inch cleaned coal produced in the preparation plant is conveyed through either of two transfer points, A or B. A continuous sampling and sample grinding system, 11-0901 and 11-0902, samples the coal as it leaves the delivery belt. Each transfer point discharges onto one of two transport conveyors, 11-2002 and 11-2052, extending along each side of the stockpile area. Each is provided with rails upon which self-propelled belt trippers 11-2003 and 11-2053 will discharge into either of two self-propelled crawler-mounted reversible stacking/reclaim conveyors, 11-2801 and 11-2851. These reversible stacking/reclaim conveyors have a working radius of 320 feet, a discharge height of 75 feet, and are capable of unattended and programmed stacking singly over one-half the stockpile area. The two units together will cover the width of the stockpile area.

In the reclaim mode, bucket wheel reclaimer 11-2802 will discharge into either of two self-propelled hoppers, 11-2803 and 11-2853, mounted upon either of the two transport belt conveyors. Beyond the working radius of the bucket wheel reclaimer, either of the self-propelled stacking conveyors can be interposed to discharge into either of the two self-propelled reclaim hoppers. These are mounted upon their respective transport conveyor rail tracks as are conveyor trippers 11-2003 and 11-2053. Operation of either transport belt in the reclaim mode requires positioning of the reclaim hoppers between the trippers and the transfer points, A or B. Conversely, the tripper should be located ahead of the hopper in the stacking cycle. Each stockpile transport conveyor will be able to work in a stacking or reclaim mode without interfering with the other transport conveyor working in the opposite mode.

Maximum stockpile area necessary will be 1,350 feet long by 700 feet wide for live storage of 470,000 tons, with stockpile depth limited to 30 feet to minimize oxidation. The FIFO system is amenable to the 470,000-ton storage criteria and will further provide blending of the coal feed to the gasifiers to a controlled 300-Btu-per-pound range. The system will ensure elimination of dead storage (over 90 days) as well as compaction and sealing.

5.3.2 COAL GRINDING

There are two grinding and coal drying trains in the plant. The reclaimed coal moves to a main plant feed conveyor, 11-2004, which delivers the coal to a splitter chute feeding two conveyors, 11-2005 and 11-2055, each of which serves one of the two size reduction and drying process trains. Each of these feed conveyors takes the blended coal to a feed bin which delivers it, via vibrating feeders operating under discharge hoppers, to four cage mills, 11-2101 to 11-2104, operating in parallel. These mills produce a ground material that meets the gasifier feed size requirements, minus 20 mesh by 0. This ground material moves to the dryer unit by an enclosed box belt conveyor, 11-2006.

5.3.3 COAL DRYING

The material from the stockpile contains approximately 8% moisture (combined inherent moisture and surface water) and the gasifier feed is to have a nominal 2.7% moisture. The drying is accomplished using process steam from the plant steam system. The Hydro-aire steam dryer, 11-3401, a combined fluid bed and steam tube drying unit, utilizes a steam-heated inert gas as the fluidizing medium entering the bottom plenum. The fluidized coal moves across a series of compartments separated by weirs. The coal particles are further heated by direct contact with steam tubes located over the plenum in the various weir compartments.

The dried product moves from the dryer via box belt conveyors 11-2007 and 11-2008 to one of two belt elevators, 11-2009 and 11-2010, each of which delivers the product to a pair of elevated feed hoppers arranged radially around a gasifier unit. Each gasifier has a total of four feed hoppers. Each individual hopper is of a bifurcated design to accommodate a pair of screw feeders which inject the coal into the gasifier. The feed injection level is at an elevation of 90 feet.

Design features include the following. Incoming feed conveyors are equipped with magnets and metal detectors to protect the grinding and drying equipment. Belt scales and samplers monitor key flows so as to maintain accurate quantity and quality control. Carbon dioxide is used to provide an inert atmosphere for the coal from grinding to final feed hoppers. The units and conveyors are all grounded to dissipate static charge. Materials handling units are a fully encased design with provision for dust venting through bag filters at all transfer points. Box-type rubber belt conveyors and elevators are used because the fluid character of the ground coal requires positive means of transport with minimum sparking potential.

Fire protection at the stockpile includes a fire water line and local foam cylinders. When coal is stored more than 15 days, the compacting equipment is used to reduce the likelihood of oxidation and spontaneous ignition of the coal. Normal operation would not require such compacting.

5.3.4 OPERATIONAL RELIABILITY

The design of the clean coal receiving, stockpiling, blending, and reclaim systems provides a flexibility that allows sustaining of normal operations. The storage capacity is adequate to provide a reclaim-only cycle of up to two weeks at the nominal rate if the fresh feed system is interrupted. Fresh feed can be bypassed directly to the grinding and drying plant. This should be considered as a temporary emergency measure, since the coal cannot be blended to maintain close Btu control. In the event of stoppage of either longitudinal stockpile conveyor when on reclaim cycle, the other unit can be operated as both the stacking and the reclaim belt until the stoppage is corrected.

The two parallel grinding facilities can maintain the required grinding rate with three of the four parallel grinding units. Maintenance and parts replacement can be scheduled to avoid production loss.

The steam-heated dryer units have a high operating factor since the only moving parts are the blowers. The service with clean coal is not as severe as with the usual material dried by such units as salt and coke.

The steel-encased rubber box belt conveyors and belt elevators have long term, well-established operational reliability for handling large tonnages of fine problem materials. Both types of units are encased and have provisions for dust venting and maintaining an inert atmosphere.

5.3.5 MAINTENANCE RELIABILITY

The stockpile materials handling systems are all readily field maintained since they are open to inspection. All belt speeds are midrange in terms of operational levels. The belt conveyors are mostly accessible because they are ground-mounted. The crawler-mounted equipment has little need for heavy maintenance since their movement is occasional, and the operational hours are minimal. The bucket-wheel reclaimer unit has very low maintenance requirements since the duty is not strenuous. Such units have very good records in similar-sized coal applications. All units are electrically powered.

The cage grinding mills must receive scheduled attention for maintenance and wear replacement. The grinding facility design allows for such a maintenance cycle. Since wear is an estimatable condition, quick inspection and replacement can be planned. Maintenance problems originating from tramp material entering the mills with the coal feed are minimized by upstream magnets.

5.4 UNIT 12: PROCESS GASIFICATION

Synthesis gas (syngas) for the Fischer-Tropsch synthesis reaction is made by the steam-oxygen gasification of coal. The process is shown on flow diagram R-12-13-14-FS-1 in Section 6.

The gasifier is a two-stage entrainment slagging type. It represents a modification of the BI-GAS design which is being developed under ERDA contract. A drawing of the gasifier is presented in Figure 5-3. The overall gasifier dimensions are approximately 20 feet OD by 200 feet tall. It is operated at a pressure of approximately 470 psig.

Solid feeders are used to inject the coal into the gasifiers.

There are two gasifier lines. For simplicity, only one of the two lines will be described in the following text.

Coal is gravity fed from the overhead bins, 11-2605 and 11-2606, to four solids feeders, 12-2001 to 12-2004. This type of feed system is under development by several contractors in the ERDA program. The design is based on use of a modified extruder/compression screw feeder. The coal is injected into the bottom area of the upper stage, Stage II, of the gasifier, 12-2501. Superheated steam is simultaneously fed to this upper stage. The ground coal is pyrolized and reduced to char by the hot syngases rising from the 3,000°F

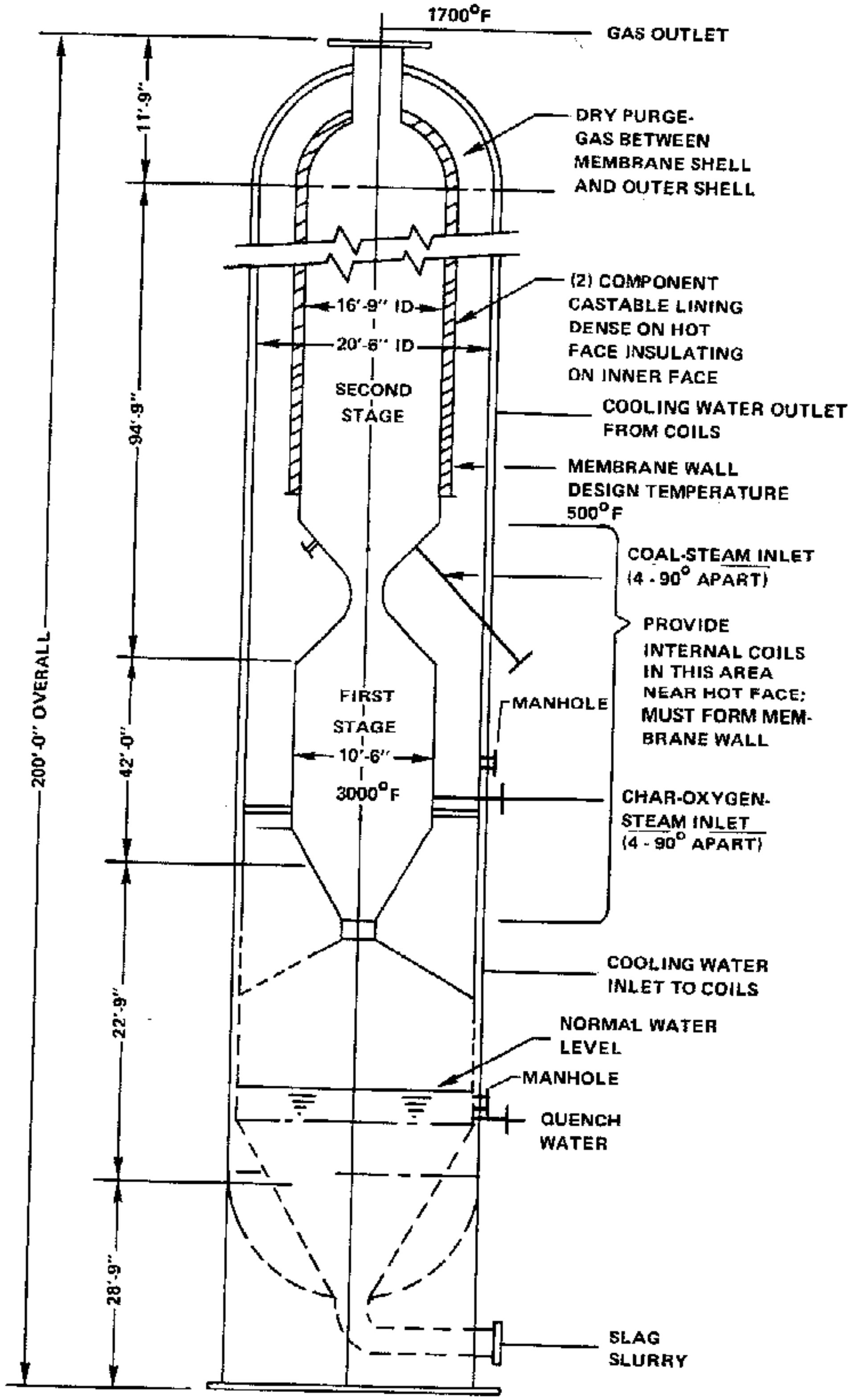


Figure 5-3 - Sketch: Two-Stage Gasifier

lower, or Stage I, gasifier section. The resulting char/gas mixture is carried overhead at a 1,700°F nominal outlet gas temperature. The char/gas mixture leaves the top of the gasifier in four parallel streams, which flow downward through steam generator 13-1601 and then to Unit 13 solids-removal equipment.

Char recovered from the Unit 13 gas cleaning equipment is fed into the gasifier's Stage I at four points, 90-degrees apart, by solids feeders 12-2005 to 12-2008. Simultaneously, superheated steam and oxygen are fed to the lower zone; they react with the char to form raw synthesis gas.

Ash becomes molten in the 3,000°F lower stage combustion zone. It drains down the sides and flows through the bottom drain opening into the lower water quench zone. Water is circulated to the quench zone at 140°F. Quenching at this temperature chills and solidifies the slag, the majority of it having the consistency of a coarse sand. The slag/water slurry passes out the bottom drain of the gasifier and through crusher 12-2101 to break up any clinkers.

The slurry is pumped through liquid cyclone 12-2201, which separates most of the water as overflow and recycles it through air cooler 12-1303 back to the gasifier quench zone. Makeup water is also added. The cyclone underflow is a thick, pumpable slurry that flows to atmospheric-pressure degassing tank 12-1202 through a pressure let-down valve. The released gases are compressed by vent-gas compressor 12-1802 and transferred to the gasifier via the lower-stage steam line. The depressurized slag/water slurry is pumped to the coal preparation area for disposal.

Operating conditions selected for the gasifier result in a raw dry syngas composition of approximately 85 volume percent carbon monoxide plus hydrogen ($CO + H_2$) and 2% methane. Mechanical design features include a boiling-water cooled refractory chamber for the lower stage, where oxygen feed at 650°F and superheated steam at 1,050°F react with char entering at 950°F. The steam-feed rate can be adjusted to moderate the reaction and keep the temperature at the desired operational level. The upper-stage feed coal and superheated steam are injected into the throat that connects the lower and upper stages.

Control features incorporated into the gasifier design include:

(1) Close flow measurement and ratio control of coal, oxygen, and steam feeds. Proportions would be controlled on the basis of continuous gas analyses of the clean gas upstream of the shift conversion step. Automatic instantaneous shutdown occurs if the feed ratios are incorrect.

(2) The temperature profile of the gasifier from the lower stage combustion chamber to the gasifier discharge duct will be continually monitored.

(3) Shutoff valves in each of the four outlet syngas lines located at the top of the gasifier permit continuity of gasifier operation in the case of malfunction of a Unit 13 heat recovery/solids separation line.

5.5 UNIT 13: HEAT RECOVERY AND GAS CLEANING

The process is described in drawing No. R-12-13-14-FS-1. Syngas with entrained char leaves the top of the gasifier at a design temperature level of 1,700°F. The hot syngas is cooled to 950°F in process steam superheater 13-1601-01, 1,200-psig syngas steam generator 13-1601-02, and 1,200-psig steam superheater 13-1601-04. Syngas and char at 950°F go to high-efficiency cyclones 13-2201 and 13-2202 (char recovery efficiency is 97 to 98% at this point). The char is returned to the lower stage of gasifier 12-2501 via solids feeders 12-2005 to 12-2008.

The syngas stream produced in cyclone 13-2202 is further cooled from 950°F to 650°F in 1,200-psig steam generator 13-1601-03. The syngas then goes to hot electrostatic precipitator 13-2203 where additional char is removed. This recovered char is also recycled to gasifier Stage I by solid feed pumps 12-2005 to 12-2008.

Approximately 30% of the syngas effluent from the precipitator is fed to Unit 15 shift conversion, and the remainder bypasses shift conversion. The bypass stream and shift converter effluent are then combined; by this procedure, the hydrogen-to-carbon-monoxide ratio is increased from 0.85 to 1.45. The shifted syngas stream at 650°F is fed to BFW Heater 13-1301 to cool to 490°F, then to BFW Heater 13-1302, which reduces the temperature to 330°F.

The 330°F syngas effluent from the BFW heaters is then contacted with water in Venturi Scrubber 13-2205 to reduce trace dust loading. The Venturi liquid is recovered and recycled. The syngas passes to syngas hot condensate receiver 13-1201, which is a four-tray unit to provide gas scrubbing action. Steam condensed from the syngas and the scrubbing water are sent to water reclamation Unit 22 for treatment.

The scrubbed syngas is further cooled in chemical separation reboiler 13-1303, BFW heater 13-1305, and syngas air cooler 13-1306. The condensed liquid at 110°F is separated in syngas cold condensate receiver 13-1202. This item also has four wash trays, and receives scrubbing water from Units 16, 17, and 18. The condensate and scrubbing water are pumped to syngas hot condensate receiver 13-1201.

The cool syngas is given a final treatment in cold electrostatic precipitator 13-2204, to remove trace quantities of particulates. The clean syngas then is fed to acid gas removal Unit 14 for carbon dioxide and hydrogen sulfide removal.

5.6 UNIT 14: ACID GAS REMOVAL

The cool syngas from Unit 13 contains acid gases consisting of carbon dioxide, hydrogen sulfide, and organic sulfur compounds. These are removed by a proprietary physical solvent absorption process. The material balance is shown in drawing R-12-13-14-FS-1.

The plant reduces the sulfur content of the treated syngas to 0.1 ppmv. This plant consumes a large quantity of steam and utilities (see Table 10-1). The energy consumed in this unit represents about 20% of the overall plant efficiency loss.

Carbon monoxide concentration in the CO_2 vent stream is predicted to be less than 200 ppm.

5.7 UNIT 15: SHIFT CONVERSION

The shift conversion unit (shown on Flow Diagram R-15-FS-1) is designed to increase the hydrogen to carbon monoxide molar ratio in the synthesis gas from process gasification Unit 12 for feed to the Fischer-Tropsch synthesis Unit 16. The syngas from the coal gasifier in Unit 12 contains hydrogen and carbon monoxide in a molar ratio of about 0.85 to 1. The CO shift-conversion unit increases the H_2-to-CO molar ratio of a portion of this stream to approximately 8 by means of the "water gas shift" reaction:

$$CO + H_2O \rightleftharpoons CO_2 + H_2$$

Approximately 30 vol% of the total syngas goes to shift conversion The balance bypasses the shift unit. The ratio of the two gas streams will be adjusted to achieve the design H_2-to-CO ratio in the recombined gas streams of 1.45 to 1.

Raw syngas, after cooling and removal of particulate matter in the gas cleaning Unit 13, enters the shift conversion unit at 650°F and 452-psig. 500-psig steam is added to the gas so that the steam-to-dry-gas molar ratio in the shift reactor feed is 0.63 to 1.

Three parallel shift reactors, 15-2501/02/03, together with the associated reaction-heat recovery facilities, are provided to convert approximately 80% of the CO in the converter feed to carbon dioxide and hydrogen. The shift reactors are of a unique isothermal design which supports the catalyst on a cooled plate surface. They are similar in mechanical design to the Fischer-Tropsch synthesis reactor shown in Figure 5-4. A cobalt-molybdate sulphided catalyst is proposed for this service. The "water gas shift" reaction is exothermic, and the resultant heat of reaction is removed by boiling Dowtherm inside the catalyst plate support tubes. The evaporated Dowtherm is used to generate 1,300-psig steam in Generators 15-1301/02/03. Shifted syngas is returned to gas cleaning Unit 13 at 650°F and 451-psig.

Facilities are provided for the in situ steam/air regeneration of the shift catalyst.

5.8 UNIT 16: FISCHER-TROPSCH SYNTHESIS

The Fischer-Tropsch synthesis unit shown on Flow Diagram R-16-FS-1 is designed to produce liquid hydrocarbons from carbon monoxide and hydrogen (syngas). Representative chemical reactions are:

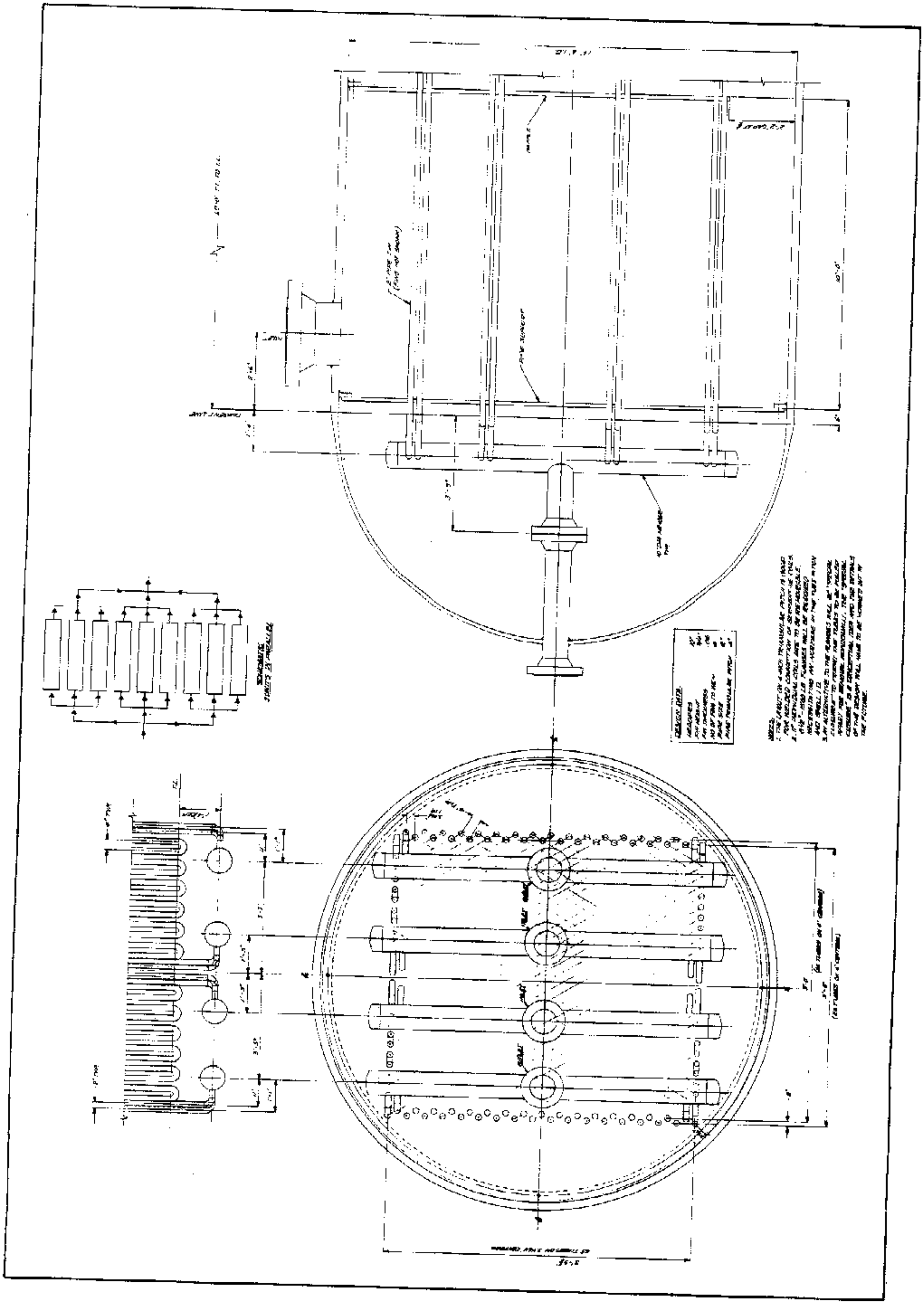


Figure 5-4 - Synthesis Reactor

$$(2n+1)H_2 + nCO \rightleftharpoons C_nH_{2n+2} + nH_2O$$

$$2nH_2 + nCO \rightleftharpoons C_nH_{2n} + nH_2O$$

$$(n+1)H_2 + 2nCO \rightleftharpoons C_nH_{2n+2} + nCO_2$$

$$nH_2 + 2nCO \rightleftharpoons C_nH_{2n} + nCO_2$$

An iron catalyst is used. Straight chain paraffin and olefin hydrocarbons are the principal products. Trace quantities of cyclics and diolefins as well as small quantities of oxygenates are formed.

Clean nil sulfur syngas from acid gas removal Unit 14 enters the Fischer-Tropsch synthesis unit at 406.5-psig design. It contains 39.0 mol% CO and 56.5 mol% H_2, plus small amounts of CH_4, CO_2, H_2O, and N_2. It is preheated in heat exchanger 16-1301-02 to 556°F, and passes through one of two zinc oxide (ZnO) guard reactors (16-2502) operated in parallel. The ZnO removes trace sulfur compounds, such as hydrogen sulfide and carbonyl sulfide, prior to entering the synthesis loop. The zinc oxide beds are replaced periodically as they become depleted.

The syngas effluent from the ZnO guard chambers is mixed with recycle process gases, and the combined stream preheated to the synthesis reactor in-let temperature of 571°F by the 1,300-psig steam in the Fischer-Tropsch reac-tor preheater 16-1302. The hot syngas then enters the Fischer-Tropsch synthesis loop.

The heart of the synthesis loop is nine parallel synthesis reactors per train, 16-2501-01 through 16-2501-09. They are designed to provide isothermal reaction conditions. The catalyst is applied to an extended external heat ex-changer surface, which contacts the syngas. Boiling water inside the heat exchange tubes removes the approximately 2.5 billion Btu/hr of heat liberated in each train by the highly exothermic synthesis reaction. The catalytic sys-tem used is based on the results of development work reported by ERDA's PERC. A sketch of the Fischer-Tropsch synthesis reactor is shown in Figure 5-4.

Also included in the synthesis loop are associated reaction heat-recovery equipment, a recycle compressor, reactor feed/product heat exchangers, and product recovery facilities.

The reactor effluent is cooled and partially condensed at 194°F and 394.5-psig by heat exchange against the fresh feed in heat exchanger 16-1301-02 and process gas recycle in exchanger 16-1301-01. A solution of caustic is sprayed into the partially condensed product immediately after the exchangers to neutralize organic acids. The condensed hydrocarbon and neutralized aqueous phases are then separated in Fischer-Tropsch hot-product separator, 16-1202. The separated aqueous phase flows under level control to the alcohol stripper in chemical recovery Unit 19. The separated liquid hydrocarbon is cooled to 110°F in air cooler 16-1303 and pumped to Fischer-Tropsch liquid extractor 16-1101, where it is contacted with process water to remove dissolved alcohols. These alcohols are subsequently recovered from the aqueous phase by the alcohol still in chemical recovery Unit 19.

Uncondensed product gas exiting 16-1202 flows to carbon dioxide removal unit 16-2801, where the CO_2 content of the combined stream is reduced to 0.84%; CO_2 must be reduced in the recycle gas stream since CO_2 and also H_2O decrease the rate of synthesis in the Fischer-Tropsch reactor. A hot potassium carbonate system is used for CO_2 removal. Overhead condensate, Stream 14, is pumped to the alcohol still in chemical recovery Unit 19 for alcohol recovery. Carbon dioxide vent gases from the system are scrubbed with process water in the Fischer-Tropsch CO_2 scrubber in order to recover additional alcohols from the gas stream before discharge to the atmosphere. Water and recovered alcohols are pumped from the Fischer-Tropsch CO_2 scrubber to extractor 16-1101.

Effluent gases from the CO_2 removal unit are cooled from 193°F to 121°F by heat exchange in 16-1304 against boiler feed water, and then combined with liquid hydrocarbon product from Fischer-Tropsch extractor 16-1101. The combined process stream is cooled and partially condensed at 110°F and 389-psig by air cooler 16-1306. Condensed water and liquid hydrocarbons are removed in Fischer-Tropsch product separator 16-1203. Separated water is pumped to syngas cold condensate receiver 13-1202 in gas cleaning Unit 13. Separated hydrocarbon liquids flow by level control to liquid product recovery Unit 18.

Approximately 84% of the gas from the Fischer-Tropsch cold product separator, 16-1203, is recycled by compressor 16-1801 to the Fischer-Tropsch reactors. The balance of the Fischer-Tropsch gas product is sent to liquid product recovery Unit 18 for processing to produce SNG.

5.9 UNIT 17: METHANATION

The methanation unit shown on Flow Diagram R-17-FS-1 is designed to produce a substitute natural gas (SNG) containing not more than 0.1 mol% CO, and having a higher heating value (HHV) of 1,035 Btu per scf, from stripped Fischer-Tropsch gas stream flowing from liquid product recovery Unit 18.

The stripped Fischer-Tropsch gas stream contains 17 mol% CO, 0.8 mol% CO_2, 57 mol% H_2, and 18 mol% CH_4 and has an HHV of 484 Btu per scf. The methanation unit converts the low Btu gas to methane-rich high Btu gas by the following chemical reactions:

$$CO + 3H_2 \rightleftharpoons CH_4 + H_2O$$

$$CO_2 + 4H_2 \rightleftharpoons CH_4 + 2H_2O$$

$$C_nH_{2n} + H_2 \rightleftharpoons C_nH_{2n+2}$$

$$C_nH_{2n+2} + (n-1)\ H_2 \rightleftharpoons nCH_4$$

Sulfur-free stripped Fischer-Tropsch gas enters the synthesis loop of methanator reactor 17-2501 at 90°F and 385-psig design. The synthesis loop is composed of three parallel methanation reactors, together with the associated reaction heat recovery facilities, a recycle compressor, and reactor feed/product exchangers. The fresh feed is mixed with recirculated process gases, and the combined stream raised to the methanation reactor inlet temperature of 571°F by heat exchange with the reaction products in 17-1301, and by 1,300-psig steam methanation reactor feed preheater 17-1302.

The methanation reactors are of a unique isothermal design, similar to the Fischer-Tropsch synthesis reactors, which support the catalyst on a cooled plate surface. The catalyst used is a metallic nickel catalyst developed in experimental operations.

The methanation reactions are highly exothermic and the resultant heat of reaction is removed by boiling Dowtherm contained inside the catalyst plate support tubes. The evaporated Dowtherm is used to generate 1,300-psig steam in steam generators 17-1309, and to regenerate SNG dryer 17-3401.

Reactor operating conditions are selected so that CO_2 methanation is suppressed in order that sufficient hydrogen is available to achieve the desired degree of CO methanation.

Reaction products are cooled to 227°F by heat exchange against the reactor feed in 17-1301, and partially condensed at 120°F and 376-psig in air cooler 17-1303, then recycled through the product cooler. Condensed water is removed in recycle compressor suction receiver 17-1202, and flows under level control to SNG pipeline compressor suction receiver 17-1203. Approximately 72% of the gas from receiver 17-1202 flows to recycle compressor 17-1801 for recirculation back to the methanation reactors.

Net product gas from separator 17-1202 is heated by heat exchange in 17-1307 to 520°F, and flows to second-stage one-pass reactor 17-2502 for methanation of the CO_2, and for final CO methanation should a breakthrough of CO occur from the methanation reactor. The final methanation reactor is an adiabatic fixed-bed radial-flow reactor employing a pelleted, reduced nickel-type catalyst. Sufficient CO_2 is methanated to reduce the final SNG product CO_2 content below 1.5 mol%.

Product gas leaves the final methanator reactor at 550°F, and has a HHV of approximately 907 Btu per scf. The final methanator gas is combined with a mixed light-hydrocarbon stream from liquid product recovery Unit 18 so that the HHV of the final SNG product is equal to 1,035 Btu per scf. The light hydrocarbon stream is vaporized into the methanator gas stream so that the combined stream enters the hydrotreater reactor at 500°F.

Hydrotreater reactor 17-2503 is an adiabatic fixed-bed radial-flow reactor employing pelleted cobalt-moly catalyst for the saturation of alkenes in the light hydrocarbons by residual hydrogen in the methanator gas.

Product gas leaves the hydrotreater at 550°F and is cooled to 210°F by heat exchange against the final methanator feed in 17-1306, and partially condensed at 120°F and 360-psig by SNG pipeline compressor suction air cooler 17-1304. Condensed water is removed in SNG pipeline compressor suction receiver 17-1203, and, together with water from the recycle compressor suction, pumped to gas cleaning Unit 13.

The hydrotreated gas is compressed from 360-psig to 1,010-psig by SNG pipeline compressor 17-1802, and, after cooling to 120°F and separation of condensed water, dried to a water dewpoint of 32°F at 1,000-psig in 17-3401 prior to entering the gas transmission line.

A package gas glycol (TEG) contactor and regenerator is specified for SNG drying unit 17-3401. Glycol is regenerated using Dowtherm from the methanator waste-heat recovery section.

5.10 UNIT 18: LIQUID PRODUCTS RECOVERY

Liquid product recovery Unit 18 (depicted on Drawing R-18-FS-1) is designed to recover light hydrocarbon liquids from the product Fischer-Tropsch gas, and to fractionate the Fischer-Tropsch liquids into hydrocarbon products.

Sixty percent of the propylene/propane content of the Fischer-Tropsch gas is recovered. The balance is allowed to remain in the gas to increase its heating value. Ethylene and heavier hydrocarbons not recovered from the gas in lean oil absorber 18-1101 are hydrocracked to methane in downstream methanation Unit 17. The hydrocarbons recovered from the gas stream and Fischer-Tropsch liquid are separated into C_4 LPG, light naphtha, heavy naphtha, diesel oil, and fuel oil. A light hydrocarbon stream containing C_2, C_3 and some C_4s is separated from the carbon monoxide in CO stripper 18-1104 and used to increase the calorific value of the SNG product.

Fischer-Tropsch tail gas from Unit 16, entering the recovery unit at 110°F and 385-psig design is dried by contact with an 80 wt% solution of TEG. The dewpoint depression obtained is 80°F below an estimated 50% gas hydrate temperature. The contacted gas and TEG stream is cooled by heat exchange in 18-1301 and refrigeration in 18-1302 to -20°F, and separated into gas, condensed hydrocarbons, and rich TEG streams in cold separator 18-1207. The gas stream next enters the bottom of lean oil absorber 18-1101 where propylene and heavier hydrocarbons are absorbed by a presaturated lean oil stream. Overhead gas from the absorber is contacted with a spray of lean oil and chilled to -20°F in presaturator chiller 18-1303, the oil thereby becoming saturated with light ends contained in the overhead gas stream. Vapor from the presaturator, now stripped Fischer-Tropsch gas, is used to cool the incoming rich Fischer-Tropsch gas and TEG by heat exchange in 18-1301.

Condensed hydrocarbons join with rich oil from the bottom of the absorber, and the combined rich stream is then warmed in heat exchanger 18-1304 by the hot lean oil stream returning to the presaturator from lean oil stripper 18-1103. The rich oil and hydrocarbons mixture flows to the upper feed tray of lean oil fractionator 18-1102.

Fischer-Tropsch liquid from Unit 16 enters the recovery unit at 110°F and 385-psig, is heated in heat exchanger 18-1319 to 191°F, and flows to the lower feed tray of lean oil fractionator, 18-1102.

The lower section of the lean oil fractionator strips hexane and lighter components from the oil while heavier waxy components are refluxed to the bottom of the column. The lean oil from upper-side stream stripper 18-1103, is wax-free while carbon monoxide, hexane, and lighter hydrocarbons go overhead.

The stripped lean oil is pumped to the presaturator after being cooled to -2.5°F by the rich oil stream. The lean oil stream pumped from 18-1103 is comprised of 2 mol% C_5, 51 mol% C_6, 43 mol% C_7, and 4 mol% C_8. Hydrocarbon products are collectively recovered by lean oil fractionator 18-1102. A 500-psig steam-heated lean oil fractionator reboiler, 18-1306, supplies column stripping vapor. The top section of the fractionator is a rectifying section which prevents the loss of lean oil in the stripped vapors. The lean oil fractionator overhead is partially condensed at 110°F and 50-psig to provide reflux to the top section and a net overhead liquid product.

Uncondensed vapors from the lean oil fractionator are compressed to 400 psig by compressor 18-1801, and combined with the fractionator net overhead liquid product. The combined stream is cooled to 110°F and flows to the top tray of CO stripper 18-1104. The CO stripper is a refluxed stripper designed to remove CO and CO_2 from the lean oil fractionator net overhead product. The overhead is partially condensed at -20°F and 385-psig to provide stripper reflux. A refrigerated overhead condenser is used to minimize the loss of propylene and propane in the stripper overhead. The lean oil fractionator and CO stripper are water wet since full-range Fischer-Tropsch liquid product is saturated, and this dissolved water will enter both columns. Vapor from the top of the CO stripper is contacted with a spray of 80 wt% TEG solution to prevent hydrate formation in the refrigerated overhead condenser. Reflux is preheated to 53°F in heat exchanger 18-1309 by column overhead vapor prior to entering the column. Vapors from the CO stripper overhead receiver are combined with the stripped Fischer-Tropsch gas and flows to methanator Unit 17. CO stripper reboiler 18-1311 is heated with 50-psig steam.

Stripped product from the CO stripper is heated in depropanizer feed/bottoms exchanger 18-1312 to 249°F, and enters depropanizer 18-1105. The depropanizer is a reboiled fractionator designed to produce an overhead liquid product of mixed light ends for blending into the SNG produced in the methanator Unit 17. Sufficient light ends are produced to increase the higher heating value of the SNG to 1035 Btu/scf. The depropanizer overhead is totally condensed at 120°F and 285-psig to produce reflux, and a liquid distillate which is pumped to Unit 17. Depropanizer reboiler 18-1314 is heated by 135-psig steam.

Light naphtha from the bottom of the depropanizer is cooled from 318°F to 260°F in heat exchanger 18-1312 with the depropanizer feed, and then flows to naphtha stabilizer 18-1106. The naphtha stabilizer is a reboiled fractionator designed to recover 98% of the butylene and butanes as a mixed LPG product. The stabilizer overhead is totally condensed at 120°F and 85-psig in 18-1315 to provide column reflux and a net liquid distillate, which is pumped to product storage from depropanizer overhead receiver 18-1205. Stabilized light naphtha from the bottom of the stabilizer is cooled in heat exchanger 18-1319 with Fischer-Tropsch liquid and by air cooling in 18-1322 to 120°F before flowing to product storage. The naphtha stabilizer reboiler is heated by 135-psig steam.

The heavy oil from the bottom of lean oil fractionator 18-1102 flows through fuels fractionator charge heater 18-1317, where it is heated and vaporized by 500-psig steam prior to entering fuels fractionator 18-1107 flash zone. The fuels fractionator is a nonreboiled fractionating column operating under vacuum. Products from the fuels fractionator are heavy naphtha, diesel oil, and heavy fuel oil. Feed enters the column flash zone at 450°F and 320 mmHg pressure. The diesel fraction is withdrawn through side stripper 18-1108 where it is steam stripped to obtain the specified diesel product flash point. Stripped diesel product pumped from the bottom of the side stripper is cooled to 120°F by heat exchange with Fischer-Tropsch liquid in 18-1320 and air cooler 18-1323 before flowing to product storage.

Heavy fuel oil, condensed above the flash zone combined with flash zone liquid, is steam stripped in the bottom section of fuels fractionator column 18-1107 to improve product recoveries. Heavy fuel oil, pumped from the bottom of the fractionator, is cooled to 191°F in heat exchanger 18-1321 with Fischer-Tropsch liquid, and then flows to water treating Unit 22. Here it is used to extract oil from waste water. The fuel oil returned from Unit 22 is cooled by air cooling to 140°F in 18-1324, and sent to the fuel oil rundown tankage. Stripping steam, vaporized reflux, and heavy naphtha product from the top of the fuels fractionator column are condensed at 110°F and 155 mmHg in 18-1318. Reflux is pumped back to the top of the column and heavy naphtha is run down to product storage. Condensed stripping steam is separated in the overhead receiver, 18-1206, and pumped to the Unit 13 scrubbers.

Uncondensed steam and oil, together with noncondensible gases, are withdrawn by package evacuation unit 18-2804. Steam and oil recovered by the evacuation unit are returned to the fuels fractionator overhead receiver.

Package refrigeration unit 18-2801 is provided to meet process refrigeration loads.

Water rich TEG from cold separator 18-1207 and CO stripper overhead receiver 18-1203 is reconcentrated in package ethylene glycol regenerator unit 18-2805. A steam reboiled rectifying column is used for TEG reconcentration.

5.11 UNIT 19: CHEMICAL RECOVERY

Flow Diagram R-19-FS-1 shows the flow sequence for the separation of chemicals, mainly oxygenates with a high alcohol content, from water. The source of oxygenate-water solution is Fischer-Tropsch synthesis Unit 16.

Oxygenate solution feed from the Fischer-Tropsch liquid scrubber 16-1101 is heated by exchange with Alcohol Still 19-1101 water bottoms before it is fed to the alcohol still. The still is reboiled by a hot synthesis gas exchanger in Unit 13. Feed is also preheated. The overhead alcohol mix product is condensed in air cooler 19-1303 and sent to storage, while the noncondensables are recycled to the Fischer-Tropsch CO_2 Scrubber 16-1102 in Unit 16. The alcohol still bottoms are cooled and used as process water in the Fischer-Tropsch CO_2 scrubber in Unit 16. Net product water bottoms goes to Unit 13 for scrubbing and reuse.

Alcohol/salt solution feed from the Fischer-Tropsch Hot Receiver, 16-1202, is heated by exchange with Alcohol Stripper 19-1102 salt solution effluent in heat exchanger 19-1505. The stripper is also reboiled by the hot syngas exchanger. The organic acid-salt solution results from neutralization of the acid formed in the Fischer-Tropsch synthesis. The overhead alcohol vapor mix from the alcohol stripper is recycled to the Alcohol Still 19-1101, while the salt solution effluent is sent the triple-effect evaporator system, 19-2301/2302/2303 for recovery.

The feed to the triple-effect evaporator is mainly a combination of the salt solution from Alcohol Stripper 19-1102 and the blowdown from the various boilers in the plant. Other possible feed streams are the BFW settlers bottoms and the deionizer wash water from Unit 22. Evaporator feed amounts to approximately 600 GPM. The evaporator condensates are sent to boiler feed water storage, while the concentrated salt solution is used as spray water in the coal preparation area for recycle to the gasifier for slag.

5.12 UNIT 20: OXYGEN PLANT

This is a plant with established design available from commercial air separation plant suppliers. The cold box for low-temperature fractionation is in 2,000 TPD modular size. The Fischer-Tropsch plant is designed to operate on 98% oxygen purity while the oxygen plant can operate at 99.5% oxygen purity. Compressor drives are power-plant-type steam turbines. Total capacity of 20,000 TPD of oxygen is provided.

5.13 UNIT 21: SULFUR RECOVERY

5.13.1 CLAUS PLANT

Acid gas from Unit 14 is fed to a Claus-type three-stage sulfur recovery unit utilizing a proprietary process for handling lean H_2S acid gases. A typical unit is shown on Process Flow Diagram B-21-FS-1. Typically in a Claus type sulfur plant, the acid gas is first passed through a knockout drum before entering the reaction furnace. The chemistry of the process involves converting the H_2S to elemental sulfur according to the following equation:

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O \qquad (1)$$

Any hydrocarbons in the acid gas are burned to CO_2 and H_2O.

The reactions are exothermic, and the heat liberated generates 150-psig steam in the reaction furnace boiler, and 50-psig steam in the sulfur condensers.

The process gas from the first condenser passes through three stages of catalytic conversion, each stage is comprised of a reheater, a catalyst bed, and a sulfur condenser. The sulfur from each condenser is drained to a recovery pit, and the tail gas from the final condenser is fed to a tail gas treating unit where substantially complete removal of the remaining sulfur compounds is achieved before discharge to the atmosphere.

5.13.2 TAIL GAS TREATING UNIT

The tail gas sulfur-removal unit is shown on Process Flow Diagram B-21-FS-2. Several commercial redox processes are available for reducing the sulfur content of sulfur recovery unit tail gas to an environmentally acceptable level. The Beavon sulfur removal process, which is capable of reducing the sulfur content in the tail gas to less than 100 ppm, was used as the basis for the estimates of this study.

Hydrogenation and hydrolysis are used to convert essentially all sulfur compounds to hydrogen sulfide. This gas is then cooled, and passed into a contactor where the hydrogen sulfide is absorbed by the redox solution and oxidized to elemental sulfur. The purified tail gas is vented to the atmosphere. The reduced redox solution is reoxidized by contact with air and subsequently recirculated to the contactor. Elemental sulfur is removed in the air-blowing step as a froth which is pumped to a sulfur melter to be melted under pressure, separated from the redox solution, and transferred to sulfur product storage. The decanted redox solution is returned to the system.

The chemical reactions are:

<u>Hydrogenation and Hydrolysis</u>

$$SO_2 + 3H_2 \longrightarrow H_2S + 2H_2O \qquad (1)$$

$$S + H_2 \longrightarrow H_2S \qquad (2)$$

$$COS + H_2O \longrightarrow H_2S + CO_2 \qquad (3)$$

$$CS_2 + 2H_2O \longrightarrow 2H_2S + CO_2 \qquad (4)$$

<u>Hydrogen Sulfide Extraction</u>

$$H_2S + 1/2\ O_2 \longrightarrow S + H_2O \qquad (5)$$

The purified tail gas is odorless and contains typically less than one ppm of H_2S and less than 50 ppm of total sulfur compounds, mainly COS.

The sulfur product is yellow and better than 99.9% pure.

5.14 <u>UNIT 22: WATER RECLAMATION</u>

Sour water, in the amount of approximately 1,000 GPM per train, will be treated to render it suitable for reuse as boiler feed water (Process Flow Diagram R-22-FS-1 depicts the process). The principal sources of sour water are process gasification Unit 12, the Fischer-Tropsch synthesis Unit 16, methanation Unit 17, and liquid-product recovery Unit 18. The sour water from these process units is fed to and/or ultimately recycled to the Syngas Hot Condensate Receiver 13-1201, from which the sour water is fed to water reclamation Unit 22. The sour water contains: ammonia, hydrogen sulfide, oil, phenol, thiocyanate, cyanide, chloride, carbonate, bicarbonate, and solids.

The hot water from Syngas Hot Condensate Receiver 13-1201 is cooled by exchange with the cold condensate of Syngas Cold Condensate Receiver 13-1202 before it is fed to three-bed sour water extraction Column 22-1103. In this column, tar and oil in the water are extracted by using the fuel oil product from Fuels Fractionator 18-1107 as the extracting medium. The oil-free water is fed to sour water Stripper 22-1101 after being cooled by exchange with the cold condensate from the syngas cold condensate receiver.

Most of the ammonia and hydrogen sulfide in the water from sour water extraction Column 22-1103 will be stripped out in sour water Stripper 22-1101, and sent to sulfur plant Unit 21. Any traces of oil will be skimmed and recycled to the sour water extraction column. The stripped water will be further treated in oxidation process 22-2501.

In the oxidation process, stripped water from the sour water stripper is mixed with oxygen and pumped through an exchanger system. Here, the temperature is increased to the point at which the reaction between oxidizable material and oxygen will proceed autogenously. This oxidation, which takes place in the subsequent reaction vessel (Oxidizer 22-2501) raises the temperature because of the released heat of reaction. This released heat is recovered by exchanging the oxidizer effluent with the incoming water stream. Then, the spent oxygen, carbon dioxide, and steam are recycled to Gasifier 12-2501; whereas the effluent is sent to the BFW settler.

The oxidizer water effluent, containing mainly solids, chlorides, carbonates, and dissolved vapors, is mixed with a neutralizing agent and fed to BFW Settler, 22-2201. The flashed vapors are cooled, and the condensed steam is refluxed to the settler, while the uncondensables are sent to the vent recovery system. The stream of settled solids in the water is sent to triple-effect evaporator 19-2301/2302/2303.

The chlorides-carbonates water from the BFW settler is cooled, filtered, and fed to BFW Deionizer 22-2801, along with a fresh makeup boiler feed water, where cations and anions are removed. The level of removal produces a high-quality boiler-feed water. The deionized water-flushing stream is sent to the triple-effect evaporator.

5.15 UNIT 23: STEAM DISTRIBUTION

Since the Fischer-Tropsch process produces all the steam required for operations, heating, and power generation, conventional steam boilers are not provided for normal operation. The steam distribution system, therefore, consists of steam mains which interconnect steam-producing and steam-consuming locations within the plant.

A startup steam boiler has been provided (this will be discussed in the section on startup).

A steam distribution is comprised of four systems, one for each of the pressure levels; nominally 1,200, 500, 135, and 50 psig.

5.16 UNIT 24: SHOPS AND BUILDINGS

This unit is composed of the various building facilities necessary for the operation of the complex. The buildings are listed in Table 13-21, along with their general type descriptions and approximate sizes.

The shops, storage, field office, and miscellaneous small buildings are of insulated metal construction. The larger buildings are of tiltup concrete construction, which is slightly lower in cost than the concrete-block type. The smaller medical and security buildings are of concrete block.

The changehouse and cafeteria buildings were sized on the basis of 30 and 15 square feet, respectively, per person at expected peak occupancy. Work schedules would be staggered to minimize sizes of the required facilities.

5.17 UNIT 25: FIRE WATER SYSTEM

The water for this system is supplied by pumps which take suction from Biopond 31-5302 (refer to Drawing No. R-25/27/28/31-FS-1). The water is delivered to a firewater loop at 100-psig. One electric motor-driven and one steam-driven pump, each with a capacity of 3,000 gpm, provide the 6,000 gpm required. One diesel engine-driven pump of 3,000 gpm standby (spare) is provided. A steam-driven jockey pump will maintain pressure on the system during periods when there is no demand. Hydrants and monitors connected to the loop are located strategically in all units. Oil-product storage tanks are protected by hydrants, and a foam system.

5.18 UNIT 26: POWER GENERATION

Process Flow Diagram Drawing No. R-26-FS-1 depicts steam generation and flows to process and electrical generator consumption.

The high efficiency of the Fischer-Tropsch process is a result of central power-plant concepts of heat recovery and power generation. The utility power generation is by two 120,000 kW turbine generators for each train. Drives below 15,000 kW in size for process operations are electrical, except large turbines for air and oxygen compression, which are central power-plant-type. The large quantity of process heat that is available is used to generate and superheat steam. By using extraction turbines, an efficient cycle gives 140 MW of marketable power. Of the steam generated, 274.2 MW equivalent is used for air and oxygen compression, and 441 MW equivalent is used for electrical generation.

Steam is generated for use at 1,200 to 1,250 psig and a temperature of 950°F. The air and oxygen compressor turbines are 500-psig extraction turbines. Large quantities of process steam are extracted from the power, air, and oxygen turbines at 500-psig, 135-psig, and 50-psig for use in the gasifier, acid gas removal, product recovery, and water reclamation units. Water-cooled vacuum condensers provide 2.25 inches of mercury absolute pressure for final condensation.

The nominal 1,200-psig steam (1,265 to 1,365 psig generation pressures) is provided during startup by startup Boilers 26-1601 and 26-1602. This steam flow can be used for limited power generation by turbine generator 26-0101, and starting-up of an oxygen plant unit, flowing to air and oxygen compressor turbines 26-0103 and 26-0105, respectively. During the startup period two gas turbine generator sets, 26-0109 and 26-0110, are also used to provide initial electricity totalling 30,000 kW.

During normal operations, 1,200-psig steam is produced in the syngas heat exchangers and Units 15, 16, and 17 reactors. This high-pressure steam flows through distribution lines to generator turbines 26-0101, 26-0102, and the oxygen plant air compressors and oxygen compressors steam turbines 26-0105, 26-0106, 26-0103, and 26-0104, respectively.

The lower-pressure steam levels are obtained from the various extraction steam turbine stages. The generator turbines discharge steam at 285-psig, 135-psig, and 55-psig. The oxygen plant steam turbines discharge steam at 500-psig. Steam from these sources flows to the various process units. The 500-psig steam flows through syngas heat exchangers for superheating, and onto the gasifier as reaction steam.

This intermediate pressure steam also flows through Unit 26 heat exchangers 26-0307, 26-1308, 26-1309, and 26-1310 for heating boiler feed water. The lower-pressure steam levels are also used at various points in the process and also in Unit 26 for heating of boiler feed water in heat Exchangers 26-1311 and 26-1312. The steam turbines for both the electric generators and the oxygen plant compressors are condensing turbines with the final-stage discharge to 2.25 inches Hg water-cooled condensers. Condensate from these sources joins the various condensate and boiler feed water makeup streams, which flow to deaerators 26-1313 and 26-1314. From the deaerators, the boiler feed water is pumped back through the aforementioned boiler-feed water heaters and back through the steam-generating process equipment.

The plant energy balance shows a surplus of electrical power while providing for all usage including the mine and coal preparation. 140 MW of excess power is available for outside use and sale. In addition, 500,000 pounds per hour of superheated steam can be generated in standby boilers and 30 MW standby electrical power by two 15 MW gas turbines. This amounts to 6 percent of the power of one train and 5.7 percent of the steam produced by the Fischer-Tropsch complex. These boilers will be used for initial startup. Startup of the second train gasifier is accomplished using power and steam from the operating train.

The multitude of small transformer units required for initial power usage are included in the design and estimate as part of the generating equipment. The excess electric power would be delivered to the outside utility at the generated 13.8 KV and 60 Hz.

5.19 UNIT 27: POTABLE AND SANITARY WATER SYSTEMS

Potable water is obtained from a deep well equipped with a 250-gpm well pump (refer to Drawing No. R-25/27/28/31-FS-1). A 75-gpm circulating pump and a full-capacity spare pump are included to assure a reliable supply.

A water treatment and filtration system to sterilize and render the water suitable for drinking and other sanitary usage is included. The distribution system for this water is of galvanized piping.

5.20 UNIT 28: RAW WATER SYSTEM

Water in the amount of 12,000 gpm will be pumped from a river. Following screening for trash removal, water flows by gravity to a concrete river water Basin 28-4101 which provides about 20 hours residence for settling. The pumps will be mounted in the clear well of this basin. Drawing No. R-25/27/28/31-FS-1 depicts the design of this process.

The entire system will receive further clarification in mechanical sludge blanket clarifier 28-2401, aided by coagulants and clarifying chemicals.

Makeup water for the cooling water system receives additional conventional chemical treatment to inhibit corrosion and to control algae. Two round mechanical draft cross-flow cooling towers, 28-1701 and 1702, are provided for handling 600,000 gpm of cooling water. Since an excess of electric power is produced within the complex, the operation of the cooling tower fans poses no economic hardship, being more than compensated for by a markedly lower capital investment.

Makeup water for the boilers in the power plant and other areas is also chemically treated before joining the clean condensates, and thence sent to the boiler deaerator.

5.21 UNIT 29: PLANT FLARE SYSTEM

Two plant flares provide for combustion of vented gases on operation of pressure safety valves, or manual venting of the system. A knockout drum is provided to accumulate and return condensed liquid to the process system or water to waste water recovery.

5.22 UNIT 30: PRODUCT STORAGE

Approximately 30-days product storage is provided for liquid products. Butane storage is atmospheric and refrigerated. A one-month inventory of chemicals is provided in chemical storage tanks for Dowtherm and physical solvent. The storage tank farm and its facilities are common to the two trains.

Pump facilities for loading out product are included. The design is based on most of the liquid products being shipped to contract customers via pipeline and/or barge with a smaller percentage being shipped by rail and truck.

5.23 UNIT 31: EFFLUENT WATER TREATING

Contaminated water from process areas will be treated in a manner to render it suitable for reuse in the plant and the mine. The sources of effluent water are principally cooling-tower blowdown, demineralizing system blowdown, and sanitary sewage effluent. Other waste water streams are oily water skimmed from pumps and compressors cooling-water system, laboratory waste water, oily water from unit area drain, and oily surface runoff water from process areas.

Waste water from coal washing is directed to a tailings pond where the solids settle out, and the clarified water is recycled. Makeup is supplied from slag dewatering and cooling tower blow down. Cooling-tower blow down is also used for mine area dust abatement.

The treatment sequence of process waters (shown in Drawing No. R-25/27/28/31-3101) is joined by laboratory waste water, oily drain water, and by oily surface runoff water from curbed process areas after passing through a surge Storm Water Pond 31-5301. Waste water from the oily water sump is pumped through a sand-filtering system after which oil and water are separated in oil water Separator 31-1202. The separated oil is recycled to Gasifier 12-2501, whereas the separated water is discharged to Bio-Pond 31-5302 after being joined by any excess neutralized cooling-tower blowdown, boiler blowdown, demineralizer wash water, and sanitary sewage treatment plant effluent. The suspended solids will settle in the pond and will be removed for land fill, while the pond will serve as a reservoir for the Fire Water System Unit 25. Solids collected from filter backwashing can also be used for land fill.