

HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM

Phase I — Program and System Definition

**Topical Report — Overall Plant Design Description
Low BTU Combined Cycle Electric
Power Plant**

**GENERATION SYSTEMS DIVISION
WESTINGHOUSE ELECTRIC CORPORATION**

Lester, Pennsylvania 19113

Date Published — January 1977

**PREPARED FOR ENERGY RESEARCH
AND DEVELOPMENT ADMINISTRATION**

Under Contract No. EX-76-C-01-2290

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED *EB*

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

TABLE OF CONTENTS

SECTION	PAGE
ABSTRACT.	xii
INTRODUCTION	xiii
CONCLUSIONS AND RECOMMENDATIONS.	xiv
1 DESIGN OBJECTIVES	1
1.1 Environmental	1
1.1.1 Ambient Conditions	1
1.1.2 Emissions	1
1.1.3 Effluents	2
1.1.4 Sound	3
1.1.5 Aesthetics	3
1.1.6 Seismic And Equipment Loads	4
1.2 Operational	5
1.3 Availability	6
2 SYSTEM DESCRIPTION	9
2.1 Gasification System	9
2.1.1 Gasification Selection	15
2.1.1.1 Introduction	15
2.1.1.2 The U-GAS Gasifier Development	17
2.2 Combined Cycle	17
3 HEAT AND MATERIAL BALANCE	23
3.1 Combustor Turbine Cycle	23
3.2 Steam Turbine Cycle	23
3.3 Gasification System	25
3.3.1 Coal Composition	25
3.3.2 Material Balance	25
3.3.3 Heat Balance	39
3.4 Overall Cycle - Heat and Material Balance	39
4 GASIFICATION SYSTEM.	47
4.1 Coal Injection	47
4.1.1 Lock Hoppers	47
4.1.2 Lock Hopper Cycle	48
4.1.3 Lock Gas System.	48
4.2 Coal Gasification.	49
4.2.1 Pretreatment	49
4.2.2 Gasifier.	50
4.2.3 Ash-Agglomeration	51
4.2.4 Gasifier Fines Return	52

TABLE OF CONTENTS (Continued)

SECTION	PAGE
4.3 Process Waste Heat Boiler	52
4.3.1 Description of Waste Heat Boiler	52
4.3.2 Features of the Process Waste Heat Boiler	54
4.4 Water Scrubber.	55
4.4.1 Discussion of Particulate Removal.	55
4.4.2 Venturi Scrubbers.	55
4.5 Gas Purification	57
4.5.1 Objective.	57
4.5.2 Definitions	58
4.5.3 Process Selection	59
4.5.4 Comparison of Selected Purification Process	63
4.6 Sulfur Production	65
4.6.1 Discussion.	65
4.6.2 Description of the Claus Plant.	65
4.7 Ammonia and Sour Gas Stripping	66
4.7.1 Processes Options.	66
4.7.2 Description of Stripping Process	67
4.7.3 Design Considerations	67
4.8 Process Water Purification	67
4.8.1 Design Basis	68
4.8.2 Description of Flow	68
4.9 Air Booster Compressor	71
4.9.1 Process Description	71
4.10 Sulfur Storage and Loading Systems	72
4.10.1 Sulfur Storage	72
4.10.2 Sulfur Loading	72
4.11 Fuel Gas Reheater.	73
5 POWER BLOCK	77
5.1 The Combustion Turbine-Generator	77
5.2 Heat Recovery Steam Generator (HRSG)	84
5.3 Steam Turbine, Generator and Exciter	89
5.4 Main Condenser and Condensate Pumps	92
5.5 Feedwater Heating	95
5.6 Boiler Feedpumps	96
5.7 Instrument Air System	96

TABLE OF CONTENTS (Continued)

SECTION	PAGE
6 BALANCE OF PLANT	99
6.1 Coal Handling	99
6.1.1 Coal Receiving, Stacking, Storage and Reclaiming	100
6.1.2 Coal Crushing and Transfer	105
6.2 Waste Handling, Storage and Removal	105
6.2.1 Solid Wastes	107
6.2.2 Liquid Wastes	111
6.3 Boiler Feedwater Treating and Storage	112
6.4 Cooling Water Systems	114
6.4.1 Main Circulating Water System	116
6.4.2 Auxiliary Cooling Water	117
6.5 Start-Up and/or Standby Fuel System	119
7 SITE PLAN	121
7.1 Site and Site Development	129
7.1.1 General Site Description	129
7.1.2 Detailed Site Description	130
7.1.2.1 Railroad Facilities	130
7.1.2.2 Drainage and Waste Disposal	130
7.1.2.3 Water Supplies	131
7.1.2.4 Roadways	131
7.1.2.5 Landscaping	132
7.1.2.6 Switchyard	132
7.1.2.7 Coal Storage Area	132
7.1.2.8 Ash Disposal Area	132
7.1.2.9 Distillate Fuel Oil Storage Area	132
7.1.2.10 Bulk Gas Storage Area	132
7.2 Plot Plan	133
7.3 Plant Island Arrangement	134
7.3.1 Transformers and Switchgear	135
7.3.2 Station Building	135
7.3.3 Heat Recovery Steam Generators	136
7.3.4 Control Building	136
7.3.5 Gasification System and the Associated Lock Gas System	136
7.3.6 Gas Purification Areas	137

TABLE OF CONTENTS (Continued)

SECTION	PAGE
7.4 Plant Island Elevation	137
7.5 Site Plan — Gasification System Plot Plan	138
7.5.1 Alternative Disposition of Sections	139
 8 ELECTRICAL SYSTEM	 143
8.1 Design Criteria	143
8.1.1 General	143
8.1.2 Generators and Switchgear	143
8.1.3 Auxiliary Power Systems	143
8.1.4 Control Panels and Electronic Equipment Panels	145
8.1.5 Motors	145
8.1.6 Miscellaneous Electric System Equipment	145
8.1.7 Lighting	146
8.2 Electrical One-Line HV System	147
8.2.1 Generators	147
8.2.1.1 Gas Turbine Generators	147
8.2.1.2 Steam-Turbine Generator	147
8.2.2 Main, Auxiliary and Startup Transformers	148
8.3 Electrical One-Line 5 KV System	148
8.3.1 Switchgear 4160 Volts	148
8.3.2 480-V Auxiliary System Equipment	148
8.3.3 Generator Auxiliary Package	149
8.3.4 Motors	149
8.3.5 125-V DC System	150
 9 HOT-GAS CLEANUP	 151
9.1 System Description	151
9.2 Equipment Availability	155
9.3 Turbine Effects	155
9.4 Cycle Diagram and Heat Balance	155
 10 MAINTENANCE	 163
10.1 Maintenance Program	163
10.1.1 General	163
10.1.2 Maintenance Program Development	164
10.1.3 Phase I Maintenance Planning	165
10.2 Set Down Space and Access	165
10.3 Special Tools and Handling Facilities	165

D

TABLE OF CONTENTS (Continued)

SECTION	PAGE
12.4	Generation, Part Load 189
12.4.1	Gasification System 189
12.4.2	Power Block 189
12.4.3	Balance of Plant 189
12.5	Shutdown 190
12.5.1	Gasification System 190
12.5.1.1	Planned Shutdown of the Gasification System from Normal Operation to Hot, Ready-To-Start. 190
12.5.1.2	Planned Shutdown of the Gasification System from Hot, Ready-To-Start Mode to Cold Ready-To-Start 190
12.5.1.3	Planned Shutdown from Cold, Ready-To- Start to Cold Standby 191
12.5.2	Power Block 191
12.5.2.1	Power Generation to Hot, Ready-To-Start. . 191
12.5.2.2	Hot, Ready-To-Start to Cold, Ready- To-Start 192
12.5.2.3	Cold, Ready-To-Start to Cold Standby. . . . 192
12.5.3	Balance of Plant 193
12.6	Abnormal Conditions 193
12.6.1	Gasification System 193
12.6.2	Power Block 193
12.6.3	Balance of Plant 194

LIST OF ILLUSTRATIONS

FIGURE		PAGE
1	Noise Rating Curves	4
2-1	Area Interfaces	10
2-2		14
2-3	Conceptual U-GAS Reactor	14
2-4	Coal Derived Gaseous Fuel Combined Cycle Schematic Diagram . . .	21
3-1	Gas Turbine Heat and Material Balance - Coal Gas Combined Cycle	24
3-2	Steam Turbine Material Balance Coal Gas Combined Cycle.	24
3.3.2-1	Coal Gasification Flow Diagram Gasifier.	31
3.3.2-2	Coal Gasification Flow Diagram Cleanup.	33
3.3.2-3		35
3.3.2-4		37
3.4-1	Coal Derived Gaseous Fuel Combined Cycle Schematic Fuel Temperature = 620 ⁰ F Fuel Heated by Feedwater.	43
4.2-1	Schematic Diagram of Ash Agglomeration	53
4.8.2-1		69
5.1-1		78
5.1-2	Starting Package	82
5.1-3	Mechanical Package	82
5.1-4	Electrical and Control Package	84
5.2-1	HRSG	85
5.2-2	HRSG Auxiliary Package	88
5.3-1	Steam Turbine Auxiliary Package	92
5.4-1	Two-Pass Rectangular Surface Condenser	93
5.7-1	Plant Air Package	98
5.7-2	Instrument Air System	98
6.1-1	Coal Handling System	101
6.1-2	Coal Handling System Elevation Looking East Conveyor No. 1 and No. 2	103
6.1-3	Coal Handling System Elevation Looking North Conveyor No. 3 and No. 4	103
6.1-4	Coal Handling System Elevation Looking North Conveyor No. 5	104

LIST OF ILLUSTRATIONS (Continued)

FIGURE		PAGE
6.1-5	Coal Handling System Elevation Looking East Conveyors No. 6A and 6B.	106
6.1-6	Coal Handling System Elevation Looking North Conveyors No. 7A and 7B	106
6.1-7	Ash Handling System Elevation Looking North	108
6.1-8	Ash Handling System Elevations Looking East	109
7-1		123
7-2	Plant Island General Arrangement Combined Cycle Gas Turbine System Low-Btu Coal Gasification	125
7-3	Plant Elevation Looking West	127
7-4	Key Plot Plan Coal Gasification Plant ERDA HTTT Program	140
7-5	Gasification Section Site Plan	140
7-6	Gasification Lock Gas System Site Plan	141
7-7	Selexol & Scrubber Site Plan	141
7-8	Elevation Gasifier Section	142
8-1	Coal Gasification Plant Single Line Diagram	144
9.1-1	Schematic Representation of Material Flow	154
9.4-1	Coal Derived Gaseous Fuel Combined Cycle Schematic Based on Hot-Gas Cleanup Fuel Temperature = 1400 ^o F	157
10-1	Maintenance Characteristic Identification Chart	166
11-1	FMECA Worksheet	170
11-2	Fault Tree Segment for FMECA (20-1-4) Using Westinghouse Simplot	172
11-3	Availability of the Reference Design	176

LIST OF TABLES

TABLE	PAGE
2.1-1 Illinois No. 6 Coal Properties	11
2.1-2 Illinois No. 6 Coal	12
2.1-3 Illinois No. 6 Coal Ash Analysis	13
3.3.1-1 ERDA High Temperature Turbine Technology Program Coal Properties and Analysis	26
3.3.2-1 Material Balance	28
3.3.3-1 Heat Balance Gasification System	40
3.3.3-2 Heat Balance Around the Gasifier Section	41
3.4-1 Flow Ratios for the Coal Gas - Fired Combined Cycle Plant	46
4.5.3-1 Processes for the Removal of H ₂ S From Low & Intermediate Btu Gases	61
4.5.4-1 Gas Purification Processes	64
4.5.4-2 Steam-Power Equivalent for Purification	64
6.3-1 Water Analysis After Demineralization	113
6.4-1 Assumed North River Water Analysis	115
6.4.1-1 Water Analysis After Treatment	118
6.4.2-1 Auxiliary Cooling Water Requirements	120
9.3-1	156
9.4-1 Flow Ratios for the Coal Gas-Fired Combined Cycle Plant	160
9.4-2 Gas Constituents Leaving the Gasifier at 1900 Degrees Fahrenheit	161
9.4-3 Gas Constituents Entering Gas Turbine Combustors at 1400 Degrees Fahrenheit	161
9.4-4 Exhaust Gas Constituents Leaving the Gas Turbine at 1221 Degrees Fahrenheit	162
11-1 Criticality Categories for FMECA	173
11-2 Expected Capacity Factors For a 4 Train Plant	177

HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM (

Overall Plant Design Description Low-Btu Combined Cycle Electric Power Plant

ABSTRACT

This report presents a systems design description for a combined cycle based on a High Temperature Turbine Technology 2600°F combustion turbine operating with a low Btu coal-derived gaseous fuel. The Overall Plant Design is based on Westinghouse combined cycle PACE experience and achieves a calculated heat rate of 8,336 Btu/KwHr. at a power output of 925 megawatts.

The plant incorporates four combustion gas turbines and a steam turbine at 2400 psig-1000°F-1000°F - 2.5 In. HgAbs., in a combined cycle suitable for base load application. The plant employs reheat with a number of interfaces between the steam-related components and the gasifier and "cold" fuel gas cleanup apparatus. The major interfaces include feedwater to and superheated steam from the gasifier system, hot reheat steam to the gasifier, process steam from gas cleanup to cold reheat, hot water to and from the gas cleanup system and a fuel heater which utilizes economizer water. The combustion turbines provide compressed air to the gasification system and receive the clean low-Btu gaseous fuel. The information presented in this report constitutes the Overall Plant Design Description, including material on cycle and plant configuration, site plan, and the control system. In addition, the design requirements of the power plant are defined to include an integrated program on maintenance and reliability. Techniques available to analyze power plant equipment and systems from a reliability and availability viewpoint are described. Finally, a dissertation on various plant operating modes is presented along with a segment on a cycle utilizing an alternate high temperature "hot" fuel gas cleanup system.

HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM

Overall Plant Design Description Low-Btu Combined Cycle Electric Power Plant

INTRODUCTION

In the process of developing a High Temperature Turbine Technology 2600°F combustion turbine, it was recognized that the primary application when utilizing coal-derived fuels would be in the combined cycle. The ECAS studies showed that the method of reaching the lowest cost of electricity was through the utilization of coal in combustion turbine combined cycle systems. In order to assure that the turbine element under development would provide an optimum fit in its ultimate application, a reference design for a combined cycle was made to identify those requirements imposed on the turbine design by this particular application. In order to insure realistic results, the overall system design incorporates applicable information from Westinghouse PACE Combined Cycle Program. The C. T. Main Co., an Architect Engineer with considerable utility experience, was employed as part of the design team with responsibility for areas relating to overall plant site development, electrical system design criteria and balance of plant systems. In addition, the Foster Wheeler Energy Corporation with the Institute of Gas Technology were assigned the responsibility for the gasifier and gas cleanup systems. To provide a realistic set of site conditions, the "Middletown, U.S.A." site was selected. This site is near a major user of electrical energy, has access to major and secondary roadways, a major railroad and river water supply. The overall plant design description includes all aspects of the power generating system from coal handling to plant electrics, operation and waste removal. It reveals that the only major areas requiring technical development are the combustion turbine with the capability of burning low-Btu, coal-derived gaseous fuel and the fuel gasification and cleanup systems.

HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM

Overall Plant Design Description Low-Btu Combined Cycle Electric Power Plant

CONCLUSIONS AND RECOMMENDATIONS

The Reference Design on which the Overall Plant Design Description was based is a combined cycle power generating plant, utilizing four combustion turbine boiler sets to achieve a total capability of approximately 925 MWs with a heat rate of 8,336 Btu/KwHr. The plant includes an IGT-U-GAS coal gasification system with Selexol Sulfur removal. In preparing the total design definition of the plant, the major areas requiring technology that does not exist today are:

- (a) the coal gasification system producing raw coal gas;
- (b) the 2600°F combustion gas turbine;
- (c) the technology related to the cleanliness of the fuel gas required for acceptable turbine hot part life.

Other than the three areas cited above, all of the technology required to construct a power plant of the type described exists today, either in the power generating industry or the chemical process industry. The principle risk would be in combining the various systems and pieces of equipment without allowing sufficient time for proper integration and shakedown during the phases of design and initial operation.

In investigating the Reliability potential for the overall system, it appears that the use of four combustion turbine power trains in the plant would result in very high availabilities with regard to achieving a significant fraction of the total rated capacity. This characteristic of multi-unit combustion turbine combined cycles has been borne out by current combined cycle power plant experience.

Because of the complexity of the plant, it is expected that the system would be applied principally for base load power generation and would have a limited capability to take load swings.

In the reference power plant, the raw fuel gas was cleaned through the use of venturi scrubbers which result in the requirement to remove most of the sensible heat from the fuel gas, dropping its temperature from 1900°F to less than 100°F. Studies indicated that a significant improvement in plant performance can be achieved if the gas can be cleaned hot. This hot gas cleanup utilizing granular bed filters and iron oxide sulfur removal offers the potential of improving the heat rate to a level of 7,740 Btu's per KwHr. In hot gas cleanup, since significantly less steam is produced in the gasification

system, there is also the possibility that a practical means of converting liquid fuel fired combined cycle plants to coal gasification systems may be achieved. For these reasons, hot-gas clean up merits additional investigation.

Other areas where additional investigation would be appropriate include cost evaluation, controllability and gasifier effects. The cycle optimization studies were all related to obtaining the best possible heat rate with little attention to the ultimate cost of electricity. Final cycle selection should be based on trade-off studies evaluating the contribution to heat rate improvement of each cycle modification versus the cost of the associated equipment and its effect on plant availability. When coal gasification is used in combination with a combined cycle power plant, the control parameters become considerably more complex. Since the availability of fuel supply at any point in time depends on the operating characteristics of the gasification plant, investigations should be conducted that relate the dynamic characteristics of an electric utility to the total power generating system. The plant as presented in this report is based on utilization of the IGT U-GAS Gasification System and is further restricted by the design parameters which were selected. Additional studies are appropriate to determine the effects of other gasifier types on the design requirements of the HTTT engine. In addition, some of the design selections for the gasifier used, such as the source and conditions of gasifier steam should be investigated, since this could effect not only overall cycle performance but also the fuel burning characteristics and heat value which would relate to engine design.

During the initial cycle study phase, calculations were performed using a current combustion turbine. These calculations resulted in performance levels competitive with present day steam fossil plants. It would therefore appear most beneficial if, in parallel with the development of the high temperature turbine, a demonstration plant utilizing current technology was undertaken so as to bring the total system to a state of utility acceptance concurrent with the commercial availability of the high temperature turbine, itself.

Specific recommendations are:

- (1) Continue work to conclusively establish the feasibility of hot-gas cleanup for high temperature combustion turbine systems.
- (2) Perform further studies on the controllability of coal gasification combined cycles when applied in base load to a utility system.
- (3) Perform additional cycle analysis to insure the compatibility of the combustion turbine with all of the gasification systems under development.
- (4) Perform the plant evaluation studies necessary to insure that the cycle selected provides the lowest cost of electricity.
- (5) Proceed at the earliest possible time with a complete power generating plant to provide the real operational hardware experience necessary for a utility acceptance.

SECTION 1

DESIGN OBJECTIVES

This plant, through the gasification of coal into a clean combustible fuel, will provide a highly efficient integrated system for the production of electrical energy, while satisfying siting and environmental criteria.

The power generation system will be based on an advanced technology high temperature combustion turbine with a heat recovery steam generator and a steam turbine in a combined cycle.

The plant will be designed for base load power generation and will follow characteristics established for base load central station units for design life and operating procedures.

The design of the plant will take into account technology and methods which will provide a reasonable expectancy of achieving an availability higher than that of today's operational central station units.

1.1 ENVIRONMENTAL

1.1.1 Ambient Conditions

The plant design point shall be based on ambient conditions of 59°F dry bulb, 60% relative humidity, 29.92" Hg barometer and a condenser pressure of 2.5" Hg absolute. Further, the plant shall be capable of operating or maintaining itself in a shutdown condition throughout an ambient temperature range of -5°F to 105°F.

1.1.2 Emissions

As is generally the case in development projects, existing codes and regulations are not entirely applicable. This is the situation with exhaust emissions for an on-site coal derived, low-btu gas-fueled combustion turbine-steam turbine generating plant.

An EPA emission rule exists for fossil coal-fired steam generating plants (EPA 42 CFR, PART 466) and a proposed emission standard for combustion turbines is pending, but neither is specifically applicable to this plant without further interpretation and addendums. For this study, the exhaust emissions of the coal gasification plant will adhere to the steam-generating plant emission rule (EPA 42 CFR, PART 466). The principal emissions in a fossil-fired power generating plant are: nitrous oxides (NO_x), sulfur dioxide (SO₂), and particulates.

The amount of SO₂ produced is to a significant degree proportional to the quantity of sulfur in the fuel. The NO_x level is a function not only of the quantity of fuel-bound nitrogen, but also of the thermal NO_x, resulting from high pressures and temperatures in the combustion chambers. Since coal is the primary fuel and often has high levels of bound nitrogen; (i.e., 1.5% wt.) and sulfur; (i.e., 3.5% wt.) there is potential to produce significant quantities of NO_x and SO₂.

In the production of the low-Btu gas through the coal gasification process, the bound nitrogen in the coal combines with hydrogen to form ammonia (NH₃) and the sulfur reacts with hydrogen to form hydrogen sulfide. (H₂S). If these compounds are allowed to remain in the fuel gas, they will oxidize to NO_x and SO₂ during combustion and ultimately will emit from the heat recovery steam generator stack. It is, therefore, a distinct advantage and in certain instances, a necessity, to remove these polluting constituents prior to combustion.

The two basic types of gas cleanup systems to be considered for the removal of hydrogen sulfide are known as the dry system and the wet system. In the wet gas cleanup for hydrogen sulfide removal, the ammonia in the gas is also removed in sufficient quantity to significantly reduce NO_x formation and emission resulting from fuel-bound nitrogen carryover. The wet gas cleanup process is flexible and designs can be selected for varying amounts of hydrogen sulfide removal, and consequently, ammonia removal. Because of this flexibility, the wet gas cleanup process, with its potential in aiding stack emission control, will be used in the design of this plant.

The amount of hydrogen sulfide removal will be dependent upon the final limit imposed due to metallurgical restrictions in the combustion turbine and heat recovery steam generator, or upon regulated exhaust emissions. The final determination involving economic evaluations of equipment will be made in Phase II.

1.1.3 Effluents

The plant design shall allow only uncontaminated aqueous drains that meet the standard set forth in EPA 40 CFR Chapter I, Subchapter N, Part 423, to pass from the plant into surrounding waterways, run-offs or sewerage systems. All chemical and hydrocarbon contaminated drains of equipment and area drains of the plant, itself, will be segregated for collection and holding within the plant boundary. The holding areas will permit access for chemical sampling and treatment, such that the neutralized or treated effluent may be reused or discharged from the plant. Provision shall be made for storage and disposal of contaminated wastes.

Attention will be focused on equipment and drains in the coal storage and handling areas, gas cleaning area, chemical storage area, and water treatment areas.

Solid effluents, such as the waste products of the gasification process, shall be collected and appropriately stored for proper disposal. Light, dustlike wastes that can become airborne will be confined in closed conveyances and vessels.

1.1.4 Sound

Emphasis shall be placed on the design, selection and location of plant equipment for near-field (3-5 feet) sound levels and duration of exposure to operating and maintenance personnel. Table G-16 of OSHA, Paragraph 1910.95, will be used for exposure times for different sound levels.

Where possible, operating equipment having high noise emission levels shall be located in low maintenance or unmanned areas. If it is not possible to so locate the item, adequate sound attenuation shall be provided through installation of case-mounted sound deadening materials; installation of sound attenuating covers; or selection of quieter equipment performing the same function.

The overall plant is also considered a point noise source when observed at a distance from the plant. The observed distance is known as the "far-field", and is defined as a distance of 4x plant length from the plant boundary. The plant boundary is further defined as an imaginary boundary at the extremity of the equipment supplied and is not to be taken as the site boundary.

The ISO Standard shall be the reference document in the design for "far-field" effects. This standard lists multi-sound level bands, each designated by a Noise Rating number (NR). Figure 1 displays the range of the Noise Ratings and the center frequency decibel level of each.

Sound attenuation of operating components integrated into the overall plant shall be designed to meet NR 50 in the far-field. This level is characteristic of central station design practice. The sound pressure level (SPL) corresponding to NR 50 for the octave center frequencies are listed as follows:

Octave Center Frequency - Hertz							
63	125	250	500	1000	2000	4000	8000
75	65.5	58.5	53.5	50	47.2	45.2	43.5
Sound Pressure Levels - db							

The assumption is made that the existing ambient sound levels at the site are 10 db or more below the levels of NR 50.

1.1.5 Aesthetics

The external appearance of the plant shall have a design commensurate with present day utility practice.

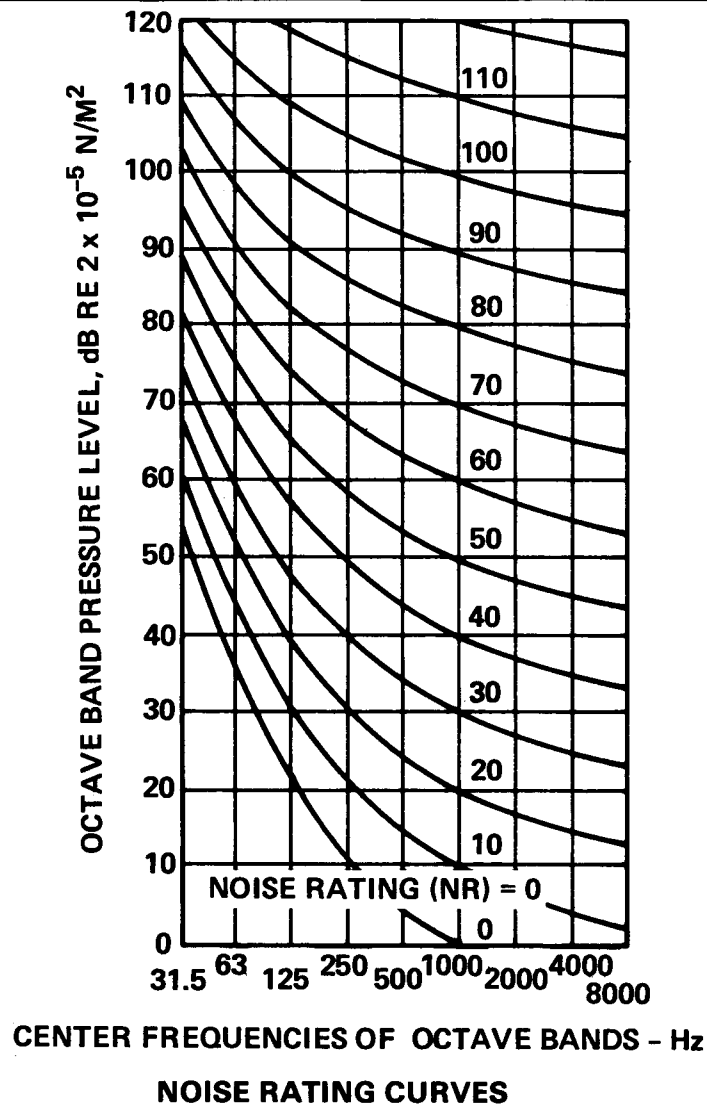


Figure 1

In achieving an aesthetically pleasing plant, the turbine-generator units, along with their associated auxiliaries, shall be housed in a central enclosure.

Overall plant height shall be held to as low a silhouette as practical. Roof lines and areas shall be kept clear and clean, wherever possible.

1.1.6 Seismic And Equipment Loads

The Middletown site described in WASH 1230 is classed as a Zone 1 site, as designated by the Uniform Building Code, for seismic design criteria. All plant equipment shall be designed accordingly.

The Uniform Building Code shall be followed for designating as live and dead loads on equipment and enclosures.

1.2 OPERATIONAL

The plant shall be designed for continuous year-around operation, taking into account required maintenance for reliable operation, with minimum number of starts and stops. Equipment design life shall be commensurate with central station practice.

The plant shall be capable of starting from a cold standby condition and being loaded to the plant base rating in time, T ,

where

$$T = t_1 + t_2 + t_3.$$

t_1 = time for gasifier to reach minimum load.

t_2 = steam turbine rotor warming soak period.

t_3 = loading time for steam turbine.

Although it is possible to keep the steam turbine and other parts of the plant warm for an extended period during a total shutdown by using auxiliary steam and electric heaters, such complexities will not be employed for the reference design base plant.

Each combustion turbine shall have its own independent gasification source and heat recovery steam generator, with this equipment array designated as a gasifier train. In the coal gasification plant, the plant cycle integrates multi-gasifier trains via a common steam header to allow independent gasifier train operation with the steam turbine generator. Steam header bypass to the condenser and associated control will allow gasifier train operation without the steam turbine generator, as long as the condenser is available.

Plant start-up shall be performed sequentially by first starting a gasifier train, commencing steam turbine rotor warmup, and starting the remaining gasifier trains.

Design plant turndown shall be such that complete gasifier trains can be removed from operation, with the remainder of the plant operating at a reduced output. Minimum gasifier train operation shall be one (1) in conjunction with the steam turbine-generator portion of the plant.

The overall plant control system shall allow complete plant operation with control room operator personnel, and the assistance of roving operators. This is to include coal and waste product handling. Water analysis shall be performed by a chemist on a single shift/day basis.

1.3 AVAILABILITY

The term "Availability" is a statistical number that is influenced by many factors. As used herein, these factors will be classified as physical, those relating directly to equipment selection, and human-related, those indirectly associated with the plant operation.

Before actual availability values and the factors affecting the values are discussed, it is first necessary to define the term.

$$\text{Availability} = \frac{\text{Available Hours}}{\text{Period Hours}} \times 100\%.$$

This definition used by EEI is a general definition applicable to components, individual generating units, or the plant as a whole, and considers if the plant is available for service, whether or not it is actually in service. Further, plant capacity is not used in statistically determining plant availability. It shall be considered separately in determining the Plant Capacity Factor defined as:

$$\frac{\text{Net Generation, KW}}{\text{Period Hours} \times \text{Max. Dependable Capacity, KW}} \times 100\%.$$

The ideal goal is to have a plant with 100% Availability at 100% Capacity Factor. Historical data (EEI Reports on fossil-fired power plants) shows that in practice, the average availability is 86% at a capacity factor of 66%.

Physical factors affecting overall plant availability include cycle configuration, number of generating units in the plant, operating conditions, unit sizes, and redundant measures.

Based on experience to date, plant availability and capacity factors are higher in a plant having multi-gasifier train units in conjunction with the steam turbine, and manifolding or interconnecting of like fluid systems, such as fuel gas and steam, to permit independent operation.

Operating steam conditions of the plant will be less than supercritical. This is in agreement with the ECAS Study, which showed that high efficiency plants producing low cost electricity are attainable, using moderate steam pressures. Further, steam conditions in the sub-critical region will allow maximum utilization of existing technology backed by extensive operating experience. The tentative steam conditions selected in this study, along with steam turbine rating, will be subject to economic review in Phase II.

Where no operating experience is available on a major component, such as the gasification equipment, the design shall emphasize availability of power generation (even at reduced capacity) through the judicious equipment selection, and use of redundancy

of critical control functions, alternate fuel oil firing of the combustion turbines, and possible manifolding of combustion turbines and gasifiers to permit one-on-one operation of uncommon train units.

Other factors indirectly influencing availability are human-related and can be controlled by thoughtful and complete programs in the design, manufacturing, construction, training, operating and maintenance phases.

The plant design program shall commence with the development of a PERT schedule. The schedule shall include detail events and interfaces necessary through the periods of design, manufacture, construction, start-up and testing. Critical paths shall be identified in the PERT schedule that could affect the timely completion of the project. The completed schedule shall be reproduced and distributed in order that it may serve as the principal communication link between all involved parties as to the events that must take place and the adequacy and importance of each.

Through this method of scheduling and updating of events, it will be possible to program efforts well in advance of the actual requirement. Job completion events are highlighted and task omissions, which repeatedly lead to high risk decisions, will be minimized.

Timely design reviews are to be included. A detailed scale model of the plant will be constructed as the design progresses and used in conjunction with the design reviews. Through the process of design reviews, Quality Assurance shall identify critical human-performed functions in the manufacture and construction of the plant.

Accordingly, strict quality assurance acceptance and check-off procedures shall be established and implemented.

The prototype plant schedule will include a full scale operational test period prior to the manufacture of commercial plants. The plant design shall include a test and design verification program that will allow necessary changes to be made prior to operation of succeeding commercial plants.

Plant availability can be improved by a keen awareness and understanding of the plant operation and equipment by the operating and maintenance personnel. To achieve this, the plant design shall include both Operating and Maintenance Manuals, along with the establishment of a formal training program that is to be made available to plant operating and maintenance personnel. This program will emphasize operating procedures, equipment limitations, preventive maintenance and spare parts stocking and the affect of each upon plant availability.

SECTION 2

SYSTEM DESCRIPTION

For purposes of discussion, the combined cycle power generating system can be divided into three major subsystem areas:

- the gasification system which produces a clean gaseous fuel from coal for the combustion turbine and in cleaning the fuel, recovers sulfur as a by-product;
- the power block which converts fuel gas and steam thermal energy from the gasification system into electrical energy;
- and, the balance of plant, which includes all of the peripheral systems which service the gasification system and power block.

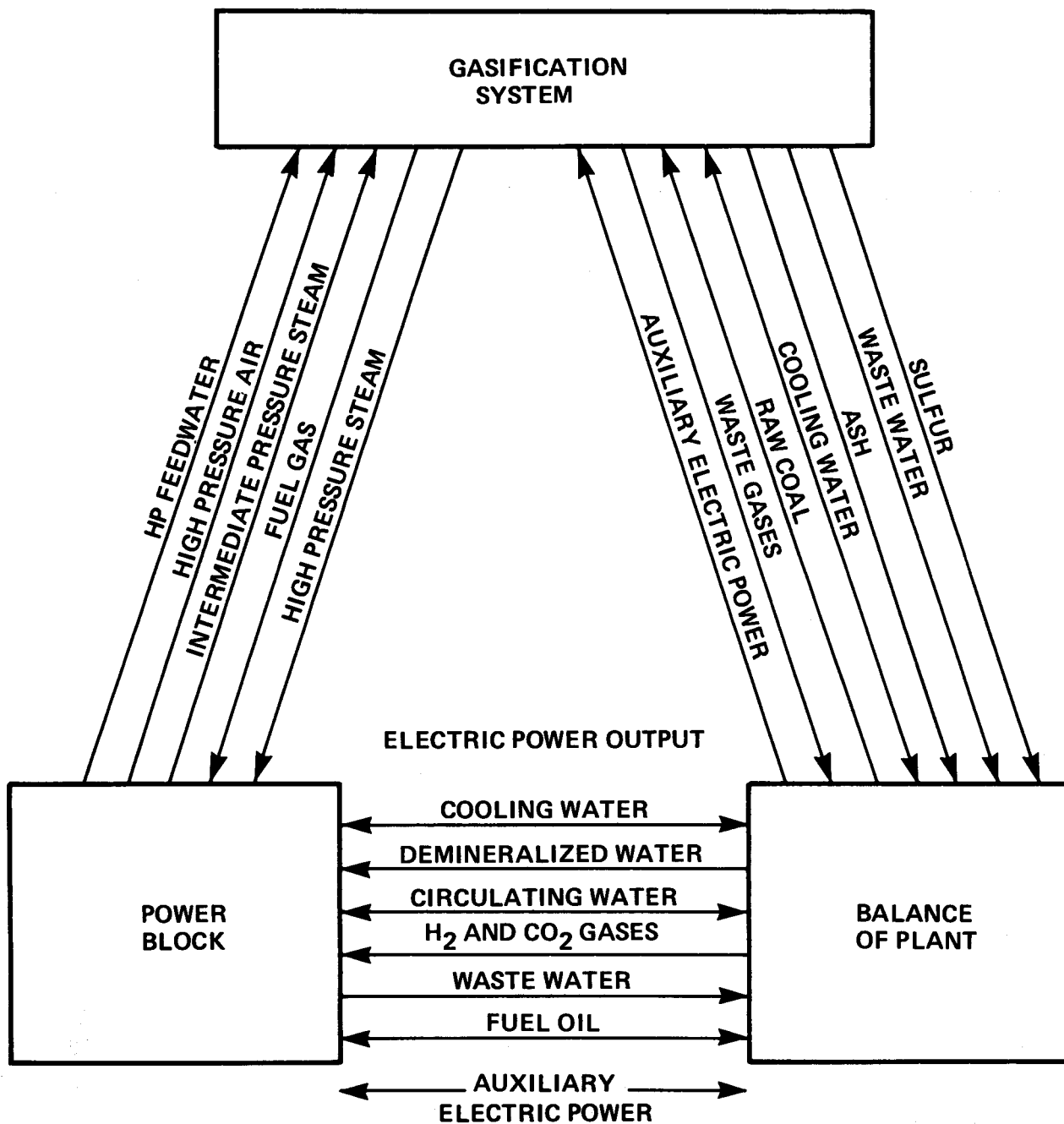
Cycle studies utilizing the heat balances of the gasification system components, ECAS study results (Reference 1), and steam turbine design parameters were performed to optimize and simplify the energy interface between the gasification system and the power block. In accomplishing this, high overall efficiency is achieved with minimum interdependence of the two energy blocks upon each other contributing to cycle and plant simplicity.

An energy and product interface diagram of the three major subsystem areas of this plant is displayed by Figure 2-1.

This section will address itself to greater detail of the gasification system and the power block combined cycle, while the balance of plant area consisting of independent services to the plant will be covered later in Section 6.

2.1 GASIFICATION SYSTEM

The gasification system includes processing units to convert a highly caking bituminous coal, Illinois No. 6, described in Tables 2-1.1, 2-1.2 and 2-1.3 to a low-Btu gas suitable for use in a combustion turbine and sufficiently clean to prevent pollution of the atmosphere with combustion products. The basis of most gasification systems is the reaction of carbon with steam to produce carbon monoxide and hydrogen. This reaction proceeds at high temperatures and to generate these temperatures, air is added to the coal and steam fed to the gasifier. The reactions of coal and air



AREA INTERFACES
Figure 2-1

TABLE 2.1-1
ILLINOIS NO. 6 COAL PROPERTIES

Proximate Analysis (As Received) %	
Moisture	13.0
Volatile	36.7
Fixed Carbon	40.7
Ash	9.6

Ultimate Analysis (As Received) %	
Ash	9.6
Sulfur	3.9
Hydrogen	5.9
Carbon	59.6
Nitrogen	1.0
Oxygen	20.0

Higher Heating BTU/LB	10930
Average Softening Temperature °F	1979
Initial Deformation Temperature °F	1990 - 2130
Fluid Temperature °F	2090 - 2440

produces the temperatures required for the steam-carbon reaction. Hot gases from the gasification reaction are cooled in a gas cooler. The gases are scrubbed in a water scrubber to remove entrained particulates and to condense process water. The cooled scrubbed gases are then purified by removal of sulfur compounds and any traces of particulate. The gas is now suitable for use in a combustion turbine. The acid gases removed in the gas purification section are sent to a conventional Claus plant to produce elemental sulfur. The tail gas from the Claus plant is further treated to remove the last traces of sulfur compounds; or, oxidized to convert the sulfur compounds to sulfur dioxide before discharge to the atmosphere.

The flow through the system may be followed by reference to the schematic flow diagram Figure 2-2, indicating the processing components required for the gasification system.

**TABLE 2.1-2
ILLINOIS NO. 6 COAL**

Trace Element Analysis: PPM in Coal	
Beryllium	0.6-7.6
Fluorine	50-167
Arsenic	8-45
Selenium	--
Cadmium	--
Mercury	0.04-0.49
Lead	8-14
Boron	13-198
Vanadium	8.7-67
Chromium	5-54
Cobalt	1.2-10
Nickel	5-37
Copper	3.1-25
Zinc	0-53
Gallium	1.5-8
Germanium	0.4-27
Molybdenum	0.6-8.5
Tin	0.1-5
Yttrium	1-13
Lanthanum	0.2-24
Uranium	10

The key processing component is the gasifier. A U-GAS type gasifier, Figure 2-3, was selected. It was developed by the Institute of Gas Technology and incorporates the pretreating step. Overall, this gasifier may be divided into four sections - a pretreater, used to destroy the caking tendency of the coal; a fluidized gasification bed; an ash agglomerating zone; and a fines reinjection system.

Excessive caking will destroy the fluidization of the coal in the gasifier and, therefore, must be controlled. Caking tendencies possessed by some types of coal are eliminated in the pretreater through a controlled partial oxidation process. The pretreater off-gas and the pretreated char then flow to the gasifier fluidized bed.

**TABLE 2.1-3
ILLINOIS NO. 6 COAL
ASH ANALYSIS**

Ash Analysis %	
SiO ₂	46.6
Al ₂ O ₃	19.3
Fe ₂ O ₃	20.8
TiO ₂	0.8
P ₂ O ₅	.24
CaO	7.7
MgO	.9
Na ₂ O	.2
K ₂ O	1.7
SO ₃	2.4

Grindability H.G.I.	
Range	52-66
Average	55

Trace Element Analysis % W in Ash	
Lithium	.017-.039
Scandium	.007-.008
Manganese	.020-.062
Strontium	.058-.070
Barium	.029-.047
Ytterbium	.0003-.0011
Bismuth	.0001-.0002

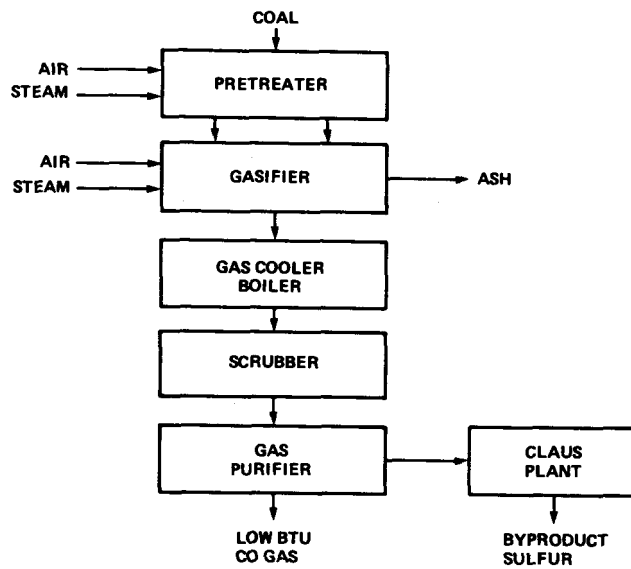
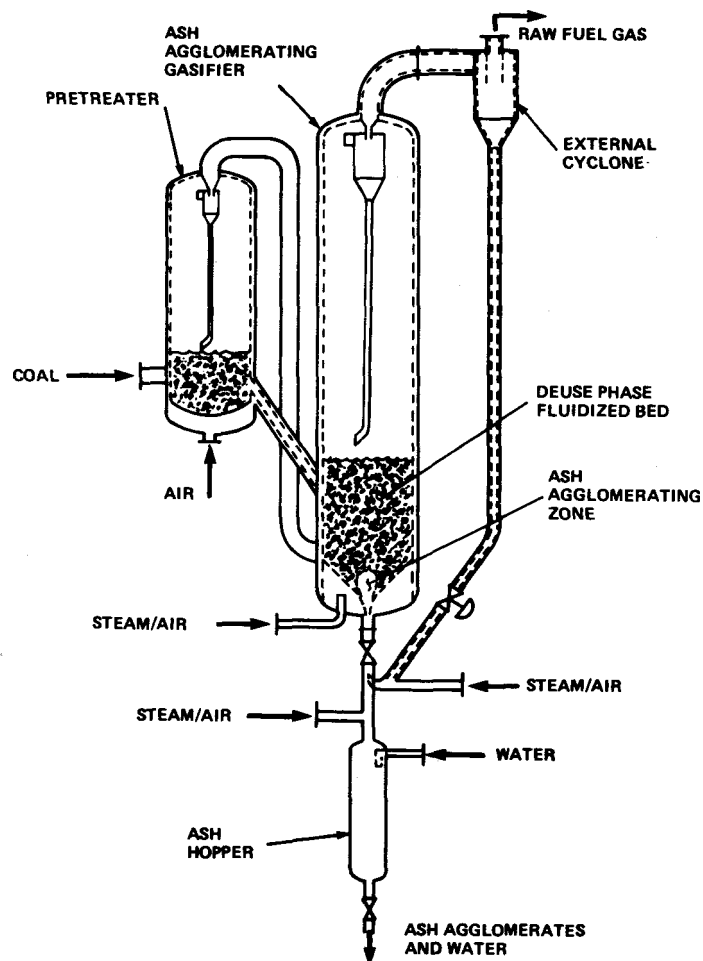


Figure 2-2



CONCEPTUAL U-GAS REACTOR

Figure 2-3

The single-stage gasification process consists mainly of a 1900°F carbon-rich, dense phase fluidized bed of coal reacting simultaneously with steam and air to produce carbon monoxide, carbon dioxide, and hydrogen. There are two reaction zones within the bed having different chemistry, temperature, and functions. The larger is a non-slugging zone at about 1900°F, in which most of the coal is gasified. The superficial gas velocity is about 2 to 3 ft/sec. The smaller zone is an ash-agglomerating zone at the bottom of the gasifier. It has a higher temperature close to the coal-ash softening point and the superficial gas velocity is an order of magnitude higher. In the turbulent agglomerating zone, ash particles preferentially adhere to other ash particles and grow in the form of spheroidal pellets; when these reach a certain size and weight, they can fall out through the bottom injection throat countercurrent to steam and air flow.

Gasification products flow upward through the fluidized bed and then through the disengaging space above the fluidized bed. Gas then enters a first-stage of cyclone separation from which char fines are collected and returned to the fluidized bed. Small size and large surface area promotes high gasification rates for these fines. The gas then enters a second-stage cyclone from which the char fines are returned to the ash-agglomerating zone where they are gasified. The fines then adhere to and are discharged with, the ash agglomerates. The ash residue from the gasifier is collected in a water filled hopper and transported in a water slurry to an ash handling facility.

Hot gases from the gasifier cyclones are cooled to 300°F in a gas cooler which generates high pressure steam.

The gases are then scrubbed with water in venturi scrubbers to condense process water and to remove ammonia and the last traces of particulate matter. The water is sent to a sour water stripper and then to a waste water treating system. From the scrubbers, the gas goes to a purification system to remove sulfur compounds such as H₂S and COS. The sulfur compounds which, after conversion, may be easily stored or sold on the open market, are converted to elemental sulfur in a Claus plant.

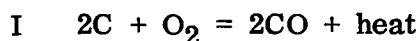
The tail gas from the Claus plant may be incinerated if the total SO₂ from the system meets the pollution requirements. Otherwise the sulfur components may be converted to H₂S and some of the tail gas recycled back to the Claus unit.

2.1.1 Gasification Selection

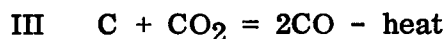
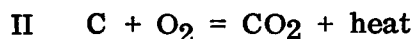
2.1.1.1 INTRODUCTION

The gasification of coal requires solids-gas contact at high temperature to produce a fuel gas suitable for use in a combustion turbine. The gasification reactions must occur at high temperature in order to establish reasonably rapid reaction rates and to

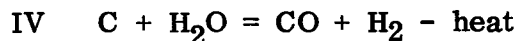
satisfy thermodynamic requirements. A very simple view of the gasification of coal to produce a combustion turbine low-Btu fuel gas is the partial oxidation of carbon with oxygen according to the overall reaction:



A more probable mechanism may be the local reaction of carbon with oxygen to form carbon dioxide, a highly exothermic reaction, followed by the reaction of carbon dioxide with more carbon to form carbon monoxide, as follows:



The initial reaction, II, to form carbon dioxide releases large quantities of heat, raising the local temperature above the melting point of ash. In order to control the temperature rise in the reactor and to produce a more stable operation, steam, as a moderator, is added with the air or oxygen going to the gasifier. Steam absorbs part of the heat of reaction I or II by the sensible heat of the steam and also by steam reacting with carbon endothermically to produce hydrogen and carbon monoxide, as follows:



Both the steam required for the steam-carbon reaction and the oxygen required for the generation of carbon monoxide and heat may contact the solid coal simultaneously as occurs in most gasifiers. Coal is a much more complex substance than carbon, and other gases and solids are produced than those shown in the above reactions. Coal pyrolysis alone produces a range of products, of which methane is predominant. The other products undergo chemical reactions to form NH_3 , H_2S , COS , H_2O , as well as a solid ash residue.

Gasifiers may be classified as

- fixed bed,
- fluidized bed,
- or entrained flow.

Fixed bed gasifiers have the advantages of high experience factor and this concept is a true countercurrent gas-solids flow reaction, which increases thermal efficiency. However, they have serious disadvantages, such as producing large quantities of tars and phenols. They also require a limited size range of coal, producing large amounts of coal byproduct fines with limited markets. Fixed bed gasifiers require large amounts of process steam and many moving parts.

The entrained flow gasifiers produce no tars and no coal fines and have no moving parts. However, they have the disadvantage of containing relatively little "holdup" — increasing instability and the chance of upset.

The fluidized bed processes of which U-GAS is an example, have the advantage of no moving parts, produce no tars or phenols, and have no coal fines. They have good thermal efficiency and have a high "holdup" of about one hour of coal which increases operating stability. They also can handle coals with any caking tendency as long as a pretreater is used to destroy the free swelling index of the coal.

2.1.1.2 THE U-GAS GASIFIER DEVELOPMENT

The U-GAS Process conceived and developed by the Institute of Gas Technology (IGT) is a second-generation coal-gasification process which incorporates

- simple control,
- reliable operation (helped by the absence of moving parts),
- turn-down capability,
- acceptance of any coal as feed,
- ability to use coal fines,
- resistance to process upsets with a high degree of tolerance,
- and, importantly, the capability to produce fuel gas environmentally acceptable under present or foreseeable standards of the Environmental Protection Agency.

The key features of the U-GAS Process are the selective removal of low-carbon spherical ash particles from the fluidized bed by an ash-agglomerating technique, and the steam-air gasification of char in a fluidized bed allowing a high carbon inventory in the gasifier.

The features and functions of the gasifier, gas cooling and gas cleanup apparatus are discussed in detail in Section 4 of this report.

2.2 COMBINED CYCLE

The heart of the combined cycle power block is the high temperature, simple open cycle combustion turbine engine. (A schematic of the combined cycle fueled by coal-gas is shown on Figure 2-4.) In the engine compressor, air is compressed to approximately fifteen (15) atmospheres and is discharged into a chamber where the high pressure air stream is divided. Approximately nineteen (19) mass percent of the

flow is directed to the gasification system for use in the treater and fluidized beds to produce low-Btu fuel gas. Another small stream of high pressure air is taken outside of the turbine and cooled before it is returned to cool hot blading and other critical parts. The remaining air is discharged into the combustors, where fuel is added and burned, raising the gas temperature to 2600°F. The hot high pressure gases are then expanded through a multi-stage turbine, developing shaft power to drive both the compressor and the electrical-generator.

The hot exhaust gases from the combustion turbine are ducted to an unfired exhaust heat recovery steam generator (HRSG).

The HRSG for the combustion turbines has heat exchanger coil sections designated superheater, reheater, high pressure evaporator, economizer and low pressure evaporator arranged in the gas flow path as shown in Figure 2-4.

The steam generated in the high pressure evaporator passes through the superheater and is raised in temperature before mixing with the high pressure, high temperature steam generated in the gasification system. This combined steam flow enters the high pressure (HP) steam turbine and expands thru the turbine to a pressure approximately one-fourth the throttle pressure. The steam from the HP turbine exhaust then returns to the reheater of the HRSG, where its temperature is raised to the same level as that of the superheater outlet steam. Approximately 94% of the steam coming from the reheater goes to the intermediate pressure (IP) turbine, the remainder going to the gasification system.

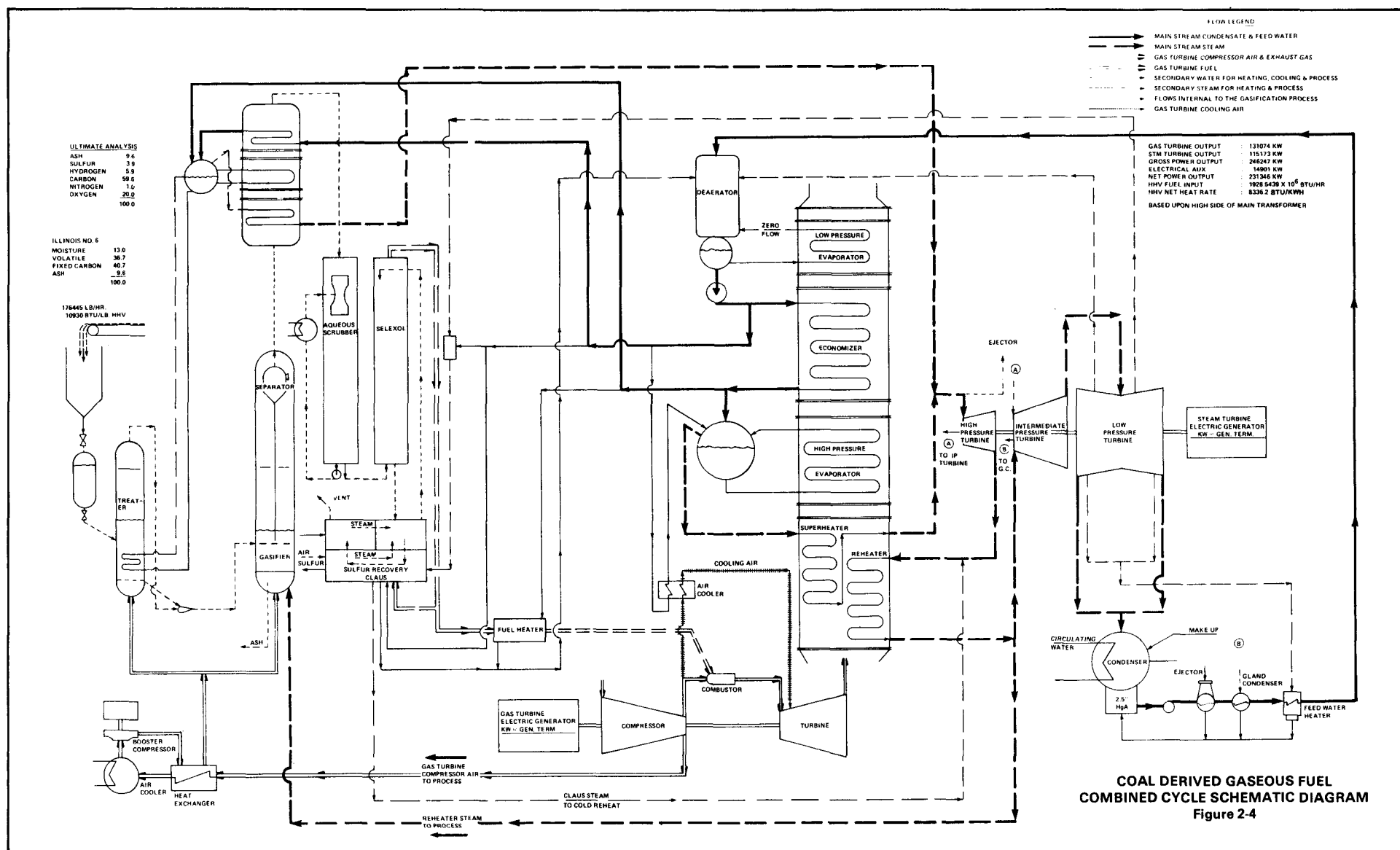
In the IP steam turbine, the steam is again partially expanded. The discharge of the IP turbine is piped to the low pressure (LP) steam turbine to complete the expansion and then goes to a condenser operating at a 2.5"Hg absolute pressure.

The economizer of the HRSG takes the high pressure water supplied by the boiler feedpump and heats this water to just below the saturation temperature of the HP drum. The economizer water stream is then split into three portions. Of these, one portion goes to the gas cooler high pressure drum, a second portion goes to the HRSG high pressure drum and a small third portion goes to a heat exchanger which heats the clean fuel gas going to the combustion turbine.

The HRSG exhaust gas (stack) temperature of approximately 280°F established in conjunction with a low pressure (27.6 psia) evaporator section, allows the gas side surface of the low pressure evaporator to operate safely above the sulfur dew point of the exhaust gas. The low pressure steam is used in a deaerating feedwater heater, augmented by low pressure steam extracted from the LP turbine.

Condensate from the condenser hotwell is pumped back to the deaerating heater of the HRSG through a feedwater heater system which is supplied with low pressure steam extracted from the LP turbine.

Boiler feedpump water for the high pressure drum of the gasification system is taken from the deaerator, as is the required condensate quality water for the gas cleanup. Circulating water for the condenser is cooled by a wet cooling tower. A separate, auxiliary cooling tower provides the cooling water for the plant heat exchangers.



SECTION 3

HEAT AND MATERIAL BALANCE

3.1 COMBUSTOR TURBINE CYCLE

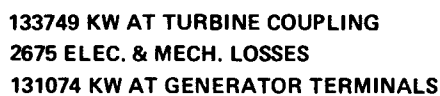
The combustion turbine heat and material balance shown on Figure 3-1 represents the turbine used in the low-Btu coal gas combined cycle. Atmospheric air at ISO conditions (59°F and 29.92 In. HgA with 60% Relative Humidity) is compressed to a 15 to 1 pressure ratio. A portion of the compressed air is bled to the air heat exchanger where it is cooled prior to injection into critical components of the turbine expander hot section. Another portion of the compressed air is directed to the gasifier—to a booster compressor-cooler arrangement, where its pressure is boosted for use in the treater and gasifier.

The remaining compressed air is boosted in temperature by mixing with and burning the 620 degrees Fahrenheit purified low-Btu gas being produced by the gasifier and gas cleanup system, raising the mixture temperature to 2600F. The hot gas mixture expands in the combustion turbine expander where the work of air compression is provided for the compressor. Energy in excess of that required for work of compression is used in a small part by the turbine bearings and in the larger part by an electric generator attached to the gas turbine shaft at the compressor end. The expander gas inlet temperature is 2600° Fahrenheit and the exhaust temperature is just over 1221 degrees Fahrenheit. Inlet loss to the compressor is 1% (approximately 4 inches of water) while the exhaust back pressure is 5% (approximately 20 inches of water).

3.2 STEAM TURBINE CYCLE

The steam turbine heat and material balance is shown on Figure 3-2. The quantities shown represent those that correspond to a coal gas combined cycle plant utilizing one combustion turbine and one steam turbine. However, the actual plant will contain four gas turbines and one large reheat steam turbine, and the complete-plant quantities can be calculated by multiplying flows and kilowatts from Figure 3-2 by four.

Figure 3-2 lists the major quantities for the steam turbine balance plus those interfacing with other components of the system that affect the steam turbine. Throttle flow at 2400 psig-1000°F expands through the high pressure turbine. The high pressure turbine exhaust steam mixes with a smaller quantity of steam from the gas cleanup system and is reheated to 1000°F with the major part of it returned to the intermediate pressure turbine. A portion of the hot reheat steam is directed to the gasifier



where it is used in the coal gasification process. The intermediate pressure steam expands through the intermediate section and is then sent to the low pressure turbine. Three low pressure extraction ports serve to: (1) provide steam to the gas cleanup process; (2) provide for feedwater heating in a closed heater; and (3) provide for final feedwater heating and deaerating prior to entering the gas cooler and HRSG economizers. The low pressure exhaust steam is condensed at a pressure of 2.5 inches of Mercury absolute. The makeup water entering the condenser serves to balance the system since the gasifier steam and some gas cleanup steam and water are not returned to the system. The kilowatt output at the electric generator terminals is 115,173.

3.3 GASIFICATION SYSTEM

3.3.1 Coal Composition

The coal used to feed the Gasification System is Illinois No. 6 seam and is the same as that used in the "ECAS" Study. (Energy Conversion Alternative Study MAS-3-19406). Sample analysis and properties are presented in Table 3.3.1-1 together with heating value, grindability, free swelling index, ash analysis and trace element analysis.

3.3.2 Material Balance

The material balance listed by components (four (4) gas turbine subsystems) is presented. The flow streams numbered 1 through 20 in Table 3.3.2-1 are further identified by diamond-shaped symbols on Figures 3.3.2-1 through 3.3.2-4. It is based upon the analysis of coal presented in Table 3.3.1-1 and the employment of the IGT "U-Gas" gasification system followed by cooling and scrubbing the gas, then purification in a Selexol-type unit. Sulfur is recovered in a modified Claus-type unit. Some of the data and assumptions in calculation of the material balance are:

- (1) Physical data obtained from API "Technical Data Books", Volumes I and II, 1970 Edition.
- (2) Cyclone and Scrubber balances obtained from API Manual on Disposal of Refinery Wastes, 1975 Edition.
- (3) Selexol purification of H_2S obtained from Allied Chemical Corporation; Sulfinol and Adip data obtained from Shell Development Company.
- (4) Claus plant data obtained from American Oil Company.
- (5) Material balance around the pretreater-gasifier was obtained from IGT. (Institute of Gas Technology)
- (6) In calculating fluidized bed elutriation, it was assumed that particle density drops from 80.5 LB/CF in the coal to 55.8 LB/CF in the char.

TABLE 3.3.1-1
ERDA HIGH TEMPERATURE TURBINE TECHNOLOGY PROGRAM
COAL PROPERTIES AND ANALYSIS

Illinois # 6 Seam
Marcoupin County
BOM TP 641 Sample

Proximate Analysis	As Received	Moisture Free	Moisture And Ash Free
Moisture	13.0	-	-
Volatile	36.7	42.18	47.42
Fixed Carbon	40.7	46.78	52.58
Ash	9.6	11.03	-
	<u>100.0</u>	<u>100.00</u>	<u>100.00</u>
Ultimate Analysis			
Ash	9.6	11.03	-
Sulfur	3.9	4.48	5.04
Hydrogen	5.9	5.11	5.74
Carbon	59.6	68.52	77.02
Nitrogen	1.0	1.15	1.29
Oxygen	<u>20.0</u>	<u>9.71</u>	<u>10.91</u>
	100.0	100.00	100.00
Heating Value Btu/Lb*	10930	12563	14120

*Higher Heating Value in constant volume calculated by Dulong Formula.

Grindability H.G.I.	
Range	52-66
Average	55
Free Swelling Index	
Range	1-6.5
Average	4.5
Ash Analysis	
SiO ₂	46.6
Al ₂ O ₃	19.3
Fe ₂ O ₃	20.8
TiO ₂	0.8
P ₂ O ₅	.24
CaO	7.7
MgO	.9
Na ₂ O	.2
K ₂ O	1.7
SO ₃	2.4
Ash Average Softening Temperature °F	1979
Initial Deformation Temperature °F	1990-2130
Fluid Temperature °F	2090-2440

TABLE 3.3.1-1 (Continued)

**Illinois # 6 Seam
Marcoupin County
BOM TP 641 Sample**

Trace Element Analysis:	ppm in Coal
Beryllium	0.6-7.6
Fluorine	50-167
Arsenic	8-45
Selenium	- - -
Cadmium	- - -
Mercury	0.04-0.49
Lead	8-14
Boron	13-198
Vanadium	8.7-67
Chromium	5-54
Cobalt	1.2-10
Nickel	5-37
Copper	3.1-25
Zinc	0-53
Gallium	1.5-8
Germanium	0.4-27
Molybdenum	0.6-8.5
Tin	0.1-5
Yttrium	1-13
Lanthanum	0.2-24
Uranium	10
Trace Element Analysis:	%W in Ash
Lithium	.017-.039
Scandium	.007-.008
Manganese	.020-.062
Strontium	.058-.070
Barium	.029-.047
Ytterbium	.0003-.0011
Bismuth	.0001-.0002

**TABLE 3.3.2-1
MATERIAL BALANCE**

Stream Name	1 As Received Coal	2 Steam	3 Air	11 Ash Residue
Component	Lbs/Hr	Lbs/Hr	Lbs/Hr	Lbs/Hr
C	422,149			7,968
H	31,519	19,103		2,184
N	7,083		1,575,197	1,251
O	59,851	151,612	475,665	-
S	27,624			1,435
Ash	67,997			67,863
Moisture	92,079		13,185	-
Total	708,302	170,715	2,064,047	80,431
Lbs/Sec.	196.75	51.08	569.68	22.34
°F	60	1,000	700	1,900
PSIA	350	400	350	300

Stream No. Name	4 Raw Gas		5 Makeup Water		6 Scrubber Sour Water	
Component	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr
CO	23,587.1	660,682			0.6	16
CO ₂	9,025.6	397,207			35.3	1,556
H ₂	18,250.7	36,794			0.5	1
CH ₄	1,802.5	28,920				
H ₂ S	791.7	26,983			4.2	144
COSZ	23.3	1,406				
N ₂	56,142.6	1,580,516			0.8	24
NH ₃	35.3	603			33.9	579
	109,658.8	2,733,11			75.3	2,320
H ₂ O	7,111.4	128,119	3,555.7	64,060	10,045.1	180,973
Char	-	1,403				1,107
Total						
	116,770.2	2,862,633	3,555.7	64,060	10,120.4	184,400
MW	24.5		18.02		18.11	
Lbs/sec	795.18		17.79		51.22	
°F	1,900		80		180	
PSIA	330		375		300	

TABLE 3.3.2-1 (Continued)
MATERIAL BALANCE

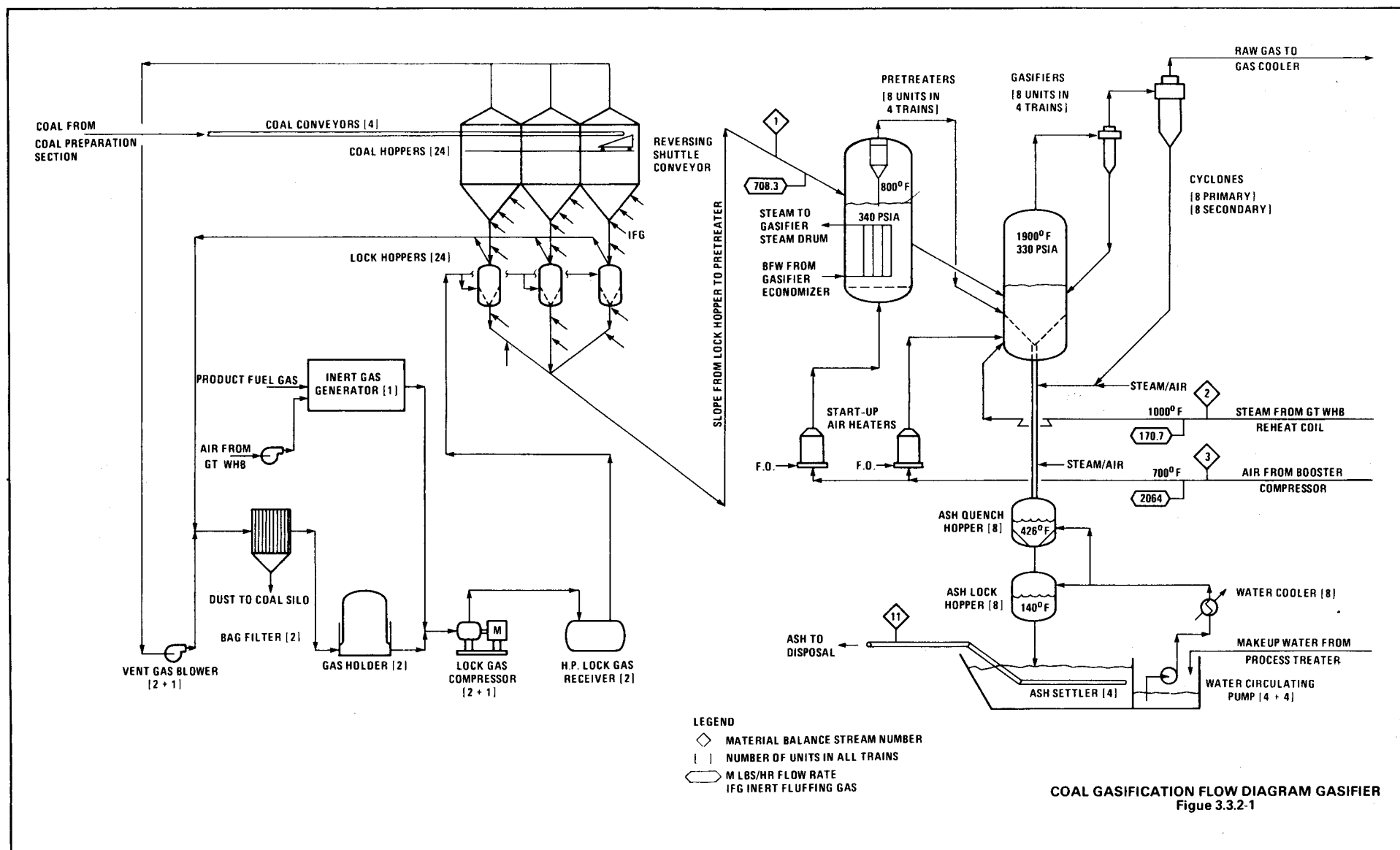
Stream No. Name	7 Scrubbed Gas		8 Purified Gas From Selexol		9 Acid Gas	
	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr
CO	23,586.5	660,666	23,582.3	660,536	4.2	130
CO ₂	8,990.3	395,651	7,693.2	338,577	1,297.1	57,074
H ₂	18,250.2	36,793	18,249.5	36,792	0.7	1
CH ₄	1,802.5	28,920	1,800.4	28,884	2.1	36
H ₂ S	787.5	26,839	6.4	218	781.1	26,621
COS	23.3	1,406	15.5	933	7.8	473
N ₂	56,141.8	1,580,492	56,136.9	1,580,357	4.9	135
NH ₃	1.4	24	0.6	10	0.8	14
	109,583.5	2,730,791	107,484.8	2,646,307	2,098.7	84,484
H ₂ O	622.0	11,206	122.3	2,203	163.3	2,942
Char	-	296	-	-	-	-
Total	110,205.5	2,742,293	107,706.1	2,648,510	2,262.0	87,426
MW	24.88		24.61		38.65	
Lbs/Sec	761.75		735.70		24.29	
°F	120		99		120	
PSIA	300		290		23.4	

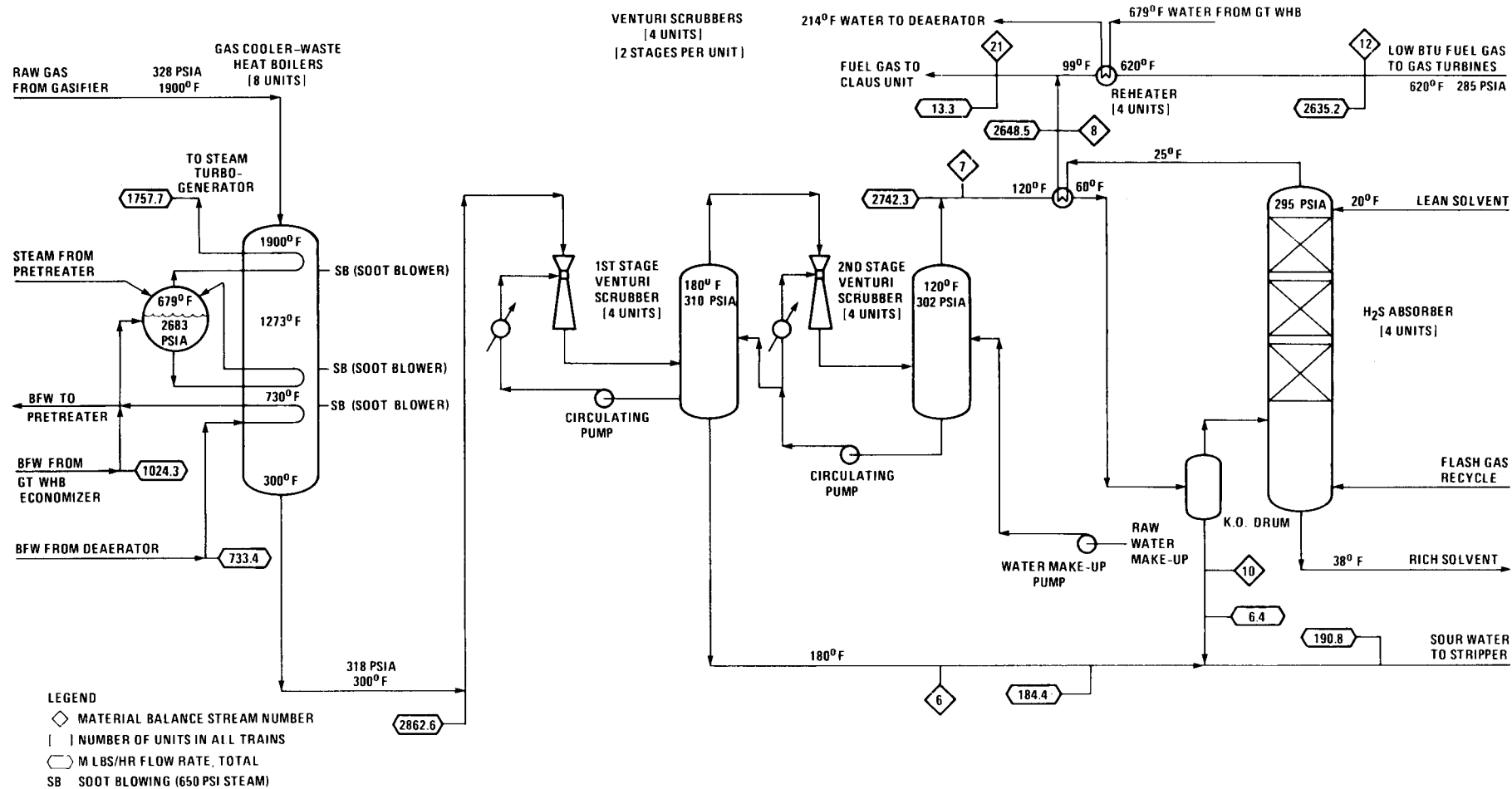
Stream No. Name	10 Selexol Sour Water & Char		21 Purified Fuel Gas To Claus		12 Purified Fuel Gas To Gas Turbines	
	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr
CO			118.5	3,320	23,463.8	657,216
CO ₂			38.7	1,702	7,654.5	336,875
H ₂			91.7	185	18,157.8	36,607
CH ₄			9.1	145	1,791.3	28,739
H ₂ S			0.03	1	6.4	217
COS			0.08	5	15.4	928
N ₂			282.1	7,942	55,854.8	1,572,415
NH ₃			-	-	0.6	10
			540.2	13,300	106,944.6	2,633,007
H ₂ O	336.4	6,061	0.6	11	121.7	2,192
Char	-	206	-	-	-	-
	336.4	6,357	540.8	13,311	107,066.3	2,635,199
MW	18.02		24.61		24.61	
Lbs/Sec.	1.77		3.70		732.00	
°F	60		99		620	
PSIA	50		290		285	

TABLE 3.3.2-1 (Continued)
MATERIAL BALANCE

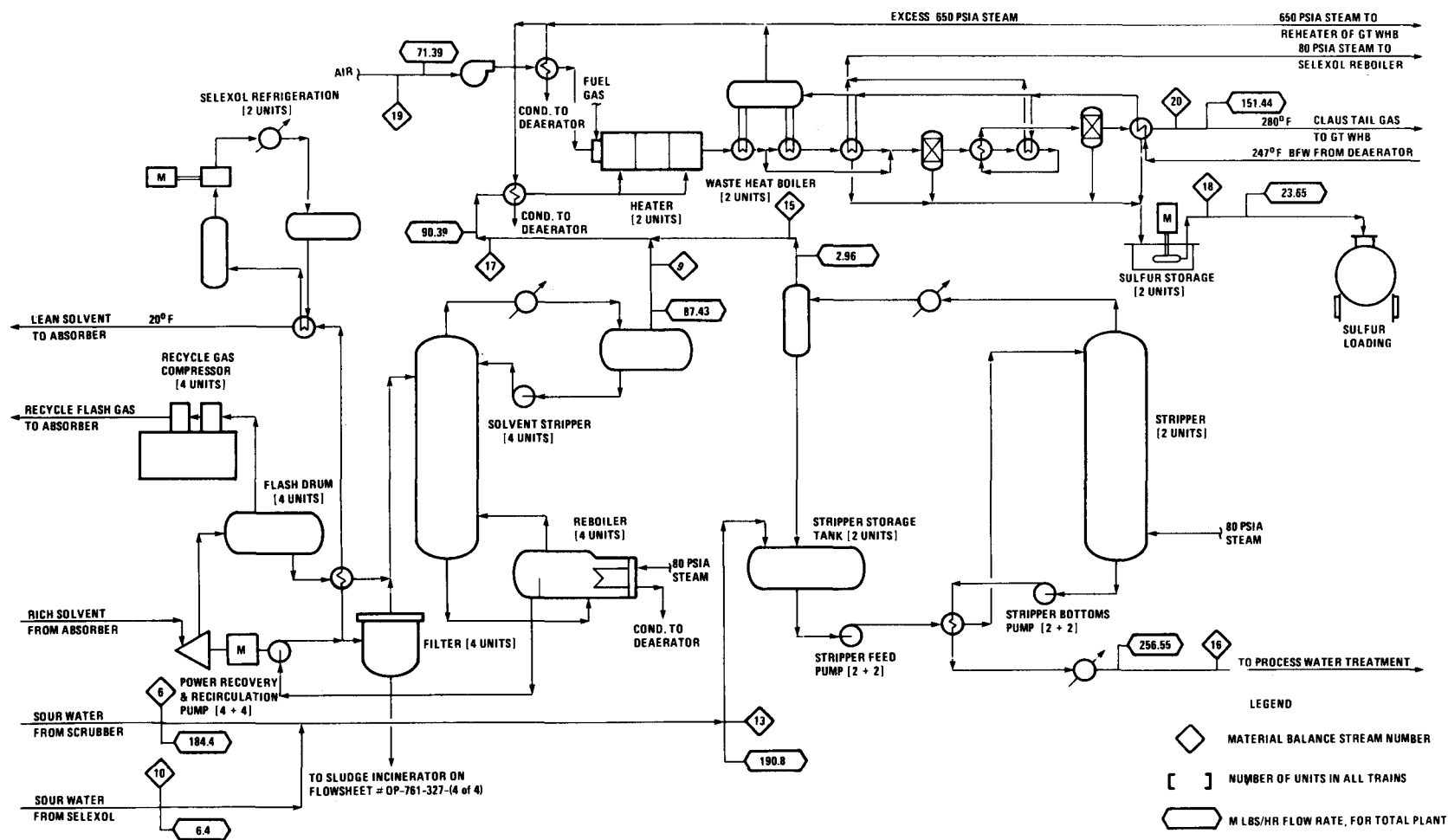
Stream No Name	13 Stripper Feed Streams 10 + 6		14 Steam To Stripper		15 Stripper Gas		16 Stripper Waste Water	
Component	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr
CO	0.6	16			0.6	16		
CO ₂	35.3	1,556			35.3	1,556		
H ₂	0.5	1			0.5	1		
CH ₄								
H ₂ S	4.2	144			4.2	144		
COS								
H ₂	0.8	24			0.8	24		
NH ₃	33.9	579			33.9	579		
	75.3	2,320			75.3	2,320		
H ₂ O	10,381.5	187,034	3,816.5	68,758	35.6	642	14,162.4	255,150
Char	-	1,403					-	1,403
Total	10,456.8	190,757	3,816.5	68,758	110.9	2,962	14,162.4	256,553
MW	18.11		18.02		26.71		18.02	
Lbs/Sec.	52.99		19.10		0.82		71.26	
°F	176		307		180		160	
PSIA	100		75		23.4		50	

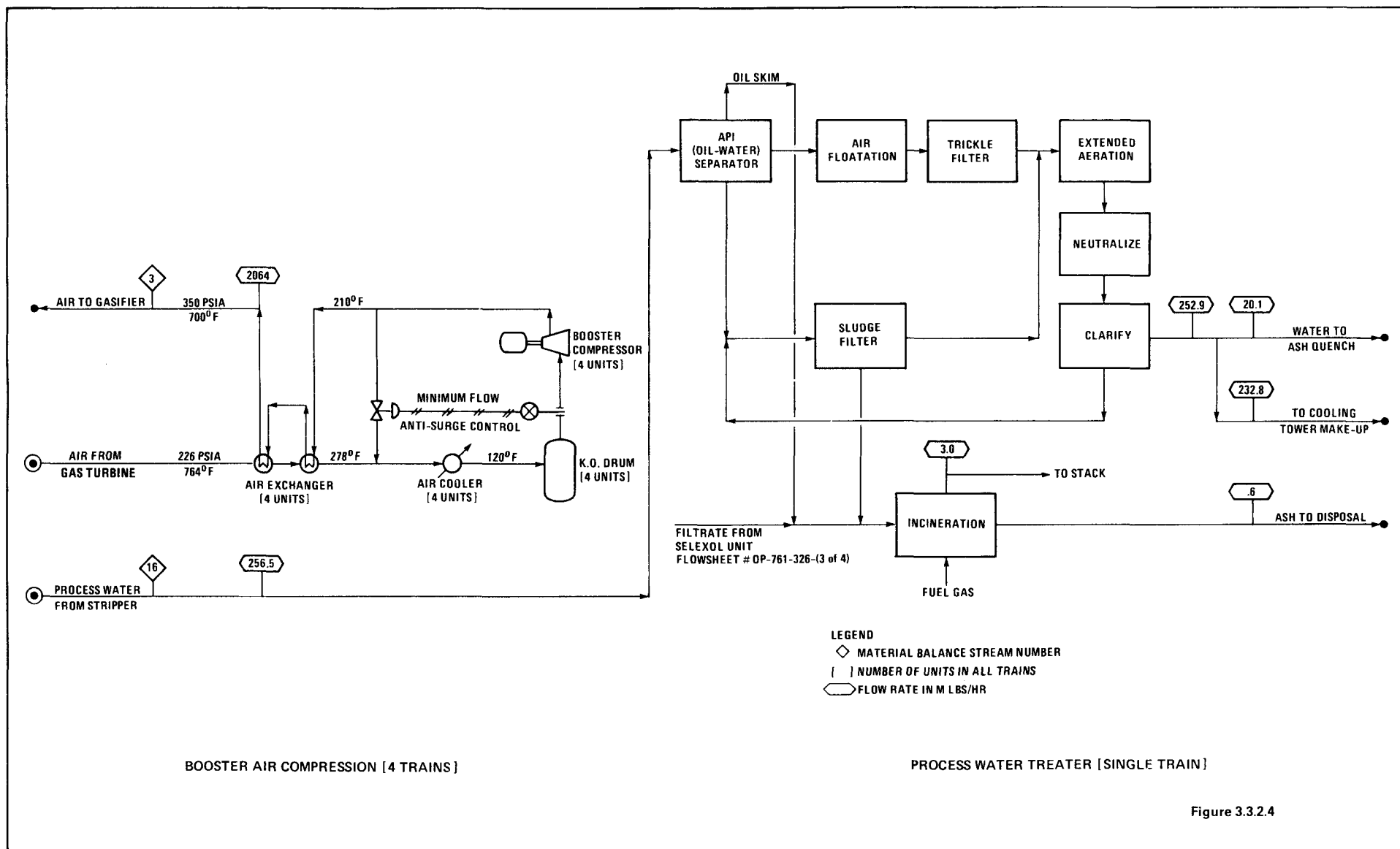
Stream No. Name	17 Claus Feed Strip + Acid Gas		18 Liquid Sulfur Product		19 Air To Claus Unit		20 Claus Tail Gas To GT WHB	
Component	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr	Mols/Hr	Lbs/Hr
CO	4.8	146					27.1	760
CO ₂	1,332.4	58,630					1,476.1	64,963
H ₂	1.2	2					23.5	47
CH ₄	2.1	36					-	-
H ₂ S	785.3	26,765					23.0	785
COS	7.8	473					6.4	386
N ₂	5.7	159			1,946.1	54,521	2,244.5	62,798
NH ₃	34.7	593						
O ₂					517.4	16,558		
CS ₂							6.1	465
SO ₂							11.5	738
S ₆							0.14	27
S ₈							0.49	126
S ₁			737.5	23,649			1.55	50
	2,174.0	86,804	737.5	23,649	2,463.5	71,079	3,820.4	131,145
H ₂ O	198.9	3,584			17.0	307	1,126.3	20,291
Total	2,372.9	90,388	737.5	23,649	2,480.5	71,386	4,946.7	151,436
MW	38.09		32.07		28.78		30.61	
Lbs/Sec.	25.11		6.57		19.83		42.07	
°F	122		280		60		280	
PSIA	23.4		14.7		14.7		16.0	





COAL GASIFICATION FLOW DIAGRAM CLEANUP
Figure 3.3.2-2





3.3.3 Heat Balance

Heat balances are presented in Table 3.3.3-1 for the entire gasification system and in Table 3.3.3-2 around the pretreater gasification unit. A small fraction of the heat of combustion introduced with the coal represents heat losses from the equipment.

3.4 OVERALL CYCLE - HEAT AND MATERIAL BALANCE

The combined cycle diagram shown on Figure 3.4-1 shows the major components, interfaces, flows, temperatures, enthalpies and pressures for the coal gas-fired plant. Gross kilowatt output based on one gas turbine and one steam turbine is 246,247. The electrical auxiliaries allotted for this configuration are 14,901 KW which results in a net power output equal to 231,346 KW with a net higher heating value heat rate of 8336.2 Btu/KwHr. Using a plant configuration comprised of four gas turbines and one large steam turbine yields a net plant output of 925,384 kilowatts.

The major components shown on the diagram do not represent all of the major equipment items needed to permit the plant to operate. For example, details of the coal handling apparatus, circulating water equipment, ash and sulfur disposal details, and more exact definition of the gasifier system are not included since they do not affect the heat and material balance of the power plant itself. However, the basic train of events in the system is the following:

Coal enters the treater (sometimes referred to as the pretreater) where it is partially oxidized to accomplish an encrusting process for ease of transfer to the fluidized bed. The treater off-gas also goes to the gasifier. More hot air and steam further oxidize and gasify the coal into a raw coal gas at 1900°F, plus some char and ash. The gas cooler, also referred to as the process waste heat boiler, performs its function reducing the raw gas temperature to 300°F and, at the same time, producing high pressure steam for the steam turbine and heating a portion of the feedwater. The scrubbers and gas cleanup apparatus ultimately produce a fuel gas at 99°F whose sulfur content is 200 parts per million by weight. A by-product of the cleanup process is 650 psi, dry and saturated steam which is sent to the HRSG for further heating and steam turbine use.

The fuel is heated by feedwater to 620°F before it enters the combustors. The gas turbine produces over 131,000 kilowatts and provides 1,221°F exhaust gas to the heat recovery steam generator (HRSG). The steam produced in the HRSG along with the gas cooler steam are joined and fed to the steam turbine. The HRSG also reheats the steam and heats feedwater as well. The total steam generated in the gas cooler and HRSG enable the steam turbine to produce over 115,000 KW.

TABLE 3.3.3-1
HEAT BALANCE GASIFICATION SYSTEM

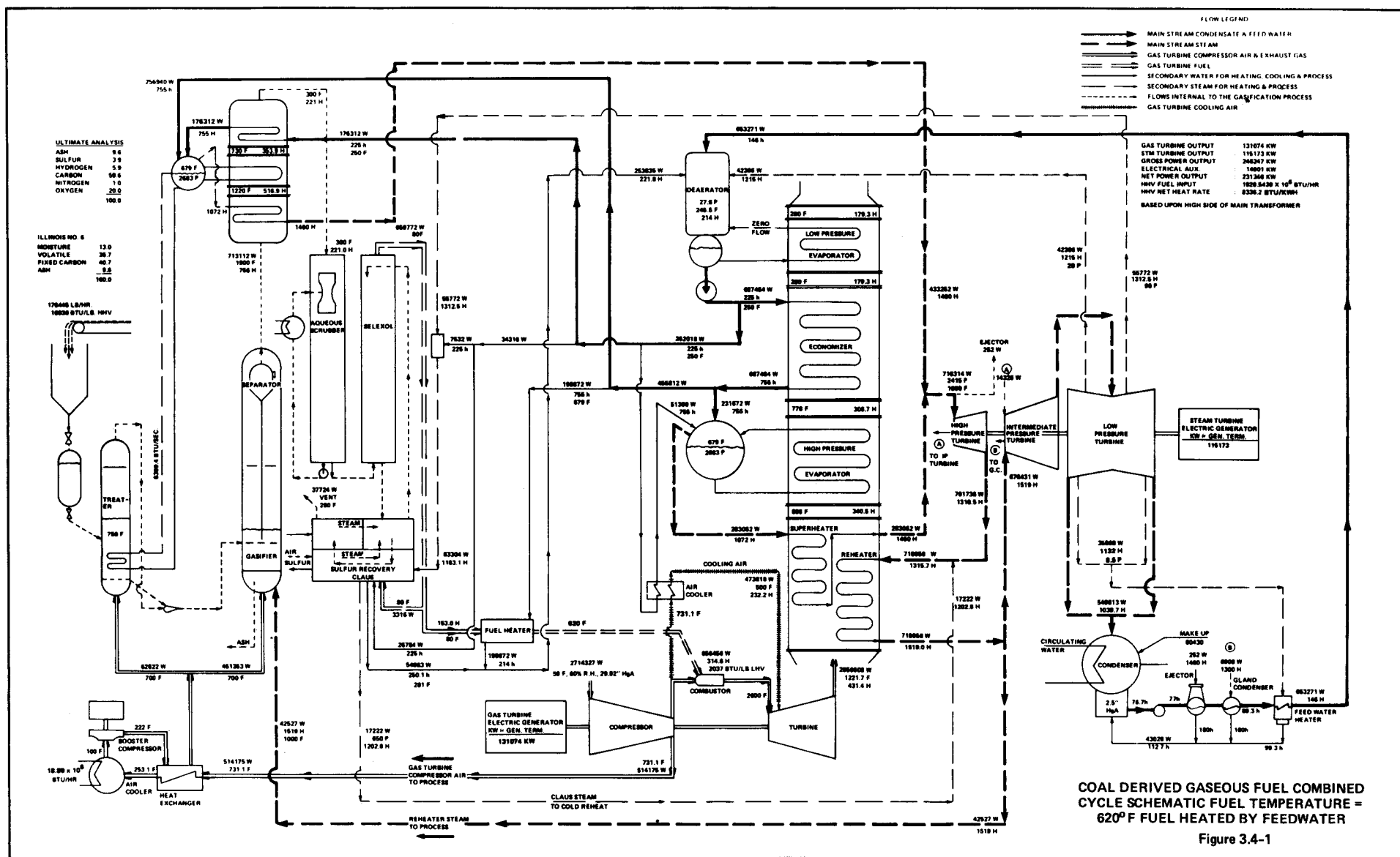
Datum: Water a 32°F

Heat Input	Lbs/Hr	Temp. °F	Cp Btu/Lb °F	H,h, HHV	MM Btu/Hr
1. Coal					
a) HHV	708,302			10,930	7,741.74
b) Sensible		59	0.28	0.28	5.35
2. Air Dry	2,136,256	731.7	0.243		363.22
Wet	13,584	731.7		1,399.3	19.01
3. Steam to Gasifier	170,715	1,000		1,522.4	259.90
4. Process Water	64,060	80		48.02	3.08
5. Steam @ 80 PSIA	250,503	312		1,183.1	296.37
6. BFW (Cond. Well)	107,519	109		76.94	8.27
7. Power Input	37,415 KW @ 3,412 BTU/KWH				127.66
8. Fuel Gas (or F.O.)					
Sensible	6,065	97	0.26	17.42	0.11
HHV				2,196	13.32
	<u>3,460,620</u>				<u>8,838.03</u>

Heat Output	Lbs/Hr	Temp °F	H, h, C HHV _p	MM Btu/Hr
1. Ash Residue (Sens)	81,081	140	0.19	1.66
(HHV)			3,095	250.95
2. Sulfur (Sens)	23,649	280	0.26	5.86
(HHV)			3,982	94.17
3. Claus T.G. (Sens)	151,436	280	0.25	9.39
LH + HHV			270.48	40.96
4. Fuel Gas Sens	2,635,199	99	0.242	42.73
LH + HHV			2,198.98	5,794.75
5. Waste Water T _o ^o C.T.	213,011	120	1.0	18.74
T _o ^o Ash	40,541	140	1.0	4.38
6. Steam (650 PSIA SAT)	69,135	495	1,202.3	83.12
7. Cond. + BD	224,835	312	282	63.40
8. Heat from WHB				1,628.63
9. Heat Lost to C.W.				659.26
10. Incinerator Gas	21,733	1,200	1,637.5	35.59
11. Heat Loss				104.44
	<u>3,460,620</u>			<u>8,838.03</u>

TABLE 3.3.3-2
HEAT BALANCE AROUND THE GASIFIER SECTION

INPUT	Lbs/Hr	Temp °F	Cp Btu/Lb °F	H, h, HHV	MM Btu/Hr
Coal	708,302	59			
a) HHV				10,930	7,741.74
b) Sensible			0.28		5.35
Air					
a) Dry	2,051,402	700	0.248		339.84
b) H ₂ O	13,185	700		1,378.3	18.17
Steam	170,175	1,000		1,522.4	259.07
	<u>2,943,064</u>				<u>8,364.17</u>
OUTPUT					
Ash	80,431	1,900			
a) HHV				3,095	250.95
b) Sensible			0.21		31.55
Raw Gas	2,862,633	1,900			
a) HHV				(135.96 Btu/Slf)	6,024.70
b) Sensible + LAT			(0.36)		1,925.86
	<u>2,943,064</u>				<u>8,233.06</u>
Heat to Pretreat Coil					92.48
					<u>8,267.75</u>
Heat Loss					38.63
					<u>8,364.17</u>



The main system interfaces are:

1. Gas turbine compressor air is directed to the treater and gasifier.
2. Hot reheat steam is directed from the HRSG to the gasifier.
3. Superheated steam is sent from the gasifier gas cooler to the steam turbine.
4. Deaerator water is pumped to the gas cleanup system.
5. Condensate quality water is sent from gas cleanup to the deaerator.
6. Dry and saturated, 650 psi steam is directed from the gas cleanup system to the cold reheat line.
7. A small portion of clean fuel gas is used in the gas cleanup system.
8. The boiler feedpump discharge stream is split with a portion going to the gas cooler, a portion going to the air cooler heat exchanger and a portion going to the HRSG economizer.
9. Steam is extracted from the steam turbine, mixed with feedwater to attain saturation and sent to the gas cleanup system.
10. A portion of the HRSG economizer discharge is sent to the gas cooler drum, the fuel heater and the HRSG drum. The discharge water from the fuel heater is sent to the deaerator.

For the purpose of sizing a gasifier and its peripheral equipment, the following ratios regarding air, fuel, water, steam and coal were used. See Table 3.4-1.

The cycle as shown will undergo further refinement in a later phase of the program. Higher fuel temperatures show promise of improving the efficiency. The higher fuel temperatures can be achieved either by superheated steam, gas turbine exhaust gas or gasifier raw gas heat transfer. Further, changes in the fuel heating arrangement may reveal a benefit in changing the steam conditions and feedwater heating schemes as well.

It should be noted that the material and heat balance data presented in Sections 3.3.2 and 3.3.3 are representative of a power plant made up of four combustion turbines and one large steam turbine. The quantities shown on the plant heat balance diagram, Figure 3.4-1, pertain to one combustion turbine and one small steam turbine. If the single turbine quantities are multiplied by four and compared to the data in Section 3.3, slight discrepancies, less than 1/2%, will be evident. The small differences are due to lesser iterations with regard to the gasification heat and material balance that occurred after the power plant heat and material balance had been calculated. Timing and scheduling of the overall project precluded a recalculation of the power plant heat balance to reflect these small changes.

TABLE 3.4-1
FLOW RATIOS FOR THE COAL GAS—FIRED COMBINED CYCLE PLANT

Based upon 2600 degrees Fahrenheit turbine inlet temperature with coal gas at 620 degrees Fahrenheit and an LHV = 2037 Btu/Lb.

1. Purified Fuel to Gas Turbine	1.0
2. Raw Gas From the Gasifier	1.0863
3. Air @ 700F to Treater	0.09570
4. Air @ 700F to Gasifier	0.68756
5. Air From Gas Turbine (Items 3 and 4)	0.78326
6. Coal to Process	0.26878
7. Steam @ 400 psi, 1000F to Gasifier	0.06478
8. 80 psi Steam to Clean Up	0.09643
9. 700 psi Water @ 247F to Clean Up	0.04080
10. Hot Water @ 50 psi, 281F to Deaerator	0.08373
11. Gas Clean-Up Blowdown	0.00118
12. 650 psi Steam From Gas Clean-Up to Cold Reheat	0.02624
13. Purified Fuel to Gas Clean Up	0.00505
14. Make Up Water of Condensate Quality	0.09206
15. Other Make Up Water	0.02431

SECTION 4

GASIFICATION SYSTEM

4.1 COAL INJECTION

The injection of crushed coal from storage silos operating at atmospheric pressure to the gasification section operating at 340 psia requires a method of both transport of coal to the point of injection as well as increasing the pressure on the coal to that pressure required for gasification. The type of injection systems may include:

1. Elevation of the coal by means of conveyors or elevators followed by increase of pressure with conventional lock hoppers.
2. Lock hoppers at grade followed by pneumatic transport and elevation of the coal.
3. Slurry of the coal in oil or water followed by pumping to the required pressure and elevation.
4. Extruding the coal with or without a lubricant into the high pressure of the process.

Extruding has been ruled out as the extruded material at high pressure will not form the proper size particles necessary for a good fluidized bed type of gasification. Similarly, the slurry method has been abandoned as injecting an excess of water or oil into the process which cannot be tolerated. Conventional lock hoppers with gravity feed are chosen because the pneumatic system, while very reliable, consumes more energy to elevate and transport the coal than conveyors or elevators.

4.1.1 Lock Hoppers

Three lock hoppers are chosen for each gasifier instead of one or two because a three-lock hopper system allows a savings in compression energy by recovering part of the compression energy by depressuring an empty lock hopper into another filled lock hopper at low pressure. Three lock hoppers also have the advantage of reliability in case one fails; then, two lock hoppers may handle most of the coal by cycling on a slightly shorter cycle. Stellited ball valves have operated over reasonable periods without excessive maintenance.

The sequence of valve operation can be automated by means of valve actuators so that manual attention to the operation is not required.

Multiple lock hoppers for each treater-gasifier have also been chosen because metering of uniform flow rates is not required in the selected gasification system, since it has a large inventory of coal, in excess of one hour.

It is proposed to use three lock hoppers per gasifier, operating on a thirty-minute cycle, so that a hopper dumps every ten minutes.

4.1.2 Lock Hopper Cycle

The lock hopper timing cycle allows a bit more time for depressuring as the three-lock hopper system must allow for depressure in stages. The timing sequence for any one lock hopper is as follows:

<u>Operation</u>	<u>Minutes</u>
1. Depressure	5
2. Equalize	1
3. Fill with coal	9
4. Repressure	3
5. Empty coal	9
6. Close coal outlet	1
7. Standby	2
	30

With the hoppers following each other at ten-minute intervals and taking nine minutes to empty, coal will be entering the pretreater-gasifier system 90 percent of the time.

4.1.3 Lock Gas System

The lock gas system must utilize a gas low in oxygen to prevent spontaneous combustion with coal dust. It is proposed to use an inert gas generator. Although called "inert," up to 5 percent O_2 will not react with the coal. For start-up the inert gas generator will be fired with oil, but for normal operation the inert gas generator will be fired with low-Btu product fuel gas. The inert gas blowdown will be collected and recycled and makeup must be sufficient for pressuring the coal in the lock hopper plus a small additional amount to account for leaks in the coal bin system.

The coal bins feed the lock hoppers and are also maintained in an atmosphere of inert gas. The gas enters the coal bin from the lock hopper by means of an equalizing line and also enters with the inert fluffing gas used to maintain flow of the coal. That gas which enters the coal bin is removed by means of a vent blower which returns the gas to the gas compressor via a bag filter and a variable volume gas storage tank.

The gas released from the lowest pressure lock hopper passes through a bag filter and is held in a telescoping gas storage tank before compression to 350 psig for lock hopper pressuring. Dust from the bag filter is returned to the coal bins.

4.2 COAL GASIFICATION

As previously stated, the gasifier selected for this project is the IGT U-GAS which is a fluidized bed, agglomerating ash type of gasifier.

The four identifying features of the U-Gas reactor are: 1) pretreatment of coal, 2) steam- air gasification, 3) selective ash removal by ash agglomeration, and 4) fines return. Although steam- air gasification and ash agglomeration are intertwined and occur simultaneously in the same fluidized bed, they have been separately identified and their development studied individually. All four have been tested and proven successful in large-scale or in pilot plant operation. With all fluidized bed gasification processes, it is necessary to pretreat coal with a high free swelling index before gasification in order to prevent caking. If coals with low free swelling index are to be gasified, then pretreatment is not necessary.

4.2.1 Pretreatment

If finely divided coal is heated to high temperatures, the coal will pass through a plastic stage. The particles will exude tarry materials and soon all particles will be stuck to each other, caking the coal. Coal injected into a high temperature fluidized bed will have a tendency to cake and destroy fluidization. The tendency to cake will be a function of the "free swelling index" of the coal. Subbituminous, anthracite or lignite coals will not cake since they have very low free swelling indices ($FSI \approx 1.0$). The bituminous coals in general have medium to high FSI or caking tendencies. Therefore, if it is the intention to operate the gasifier with bituminous coals, it is necessary to pretreat the coal in order to destroy its caking tendency.

Many U.S. coals require a step called pretreatment before they can be satisfactorily processed in fluidized-bed reactors at elevated temperatures. Tests with the reaction system proposed for this program indicate that pretreatment will also be required.

Many coals from the Eastern United States are considered to be "agglomerating." Historically, this agglomerating tendency was described as a "softening" of the coal particle as it was heated through its "plastic range," about 600°F to 900°F. The softened coal particles would adhere to each other, causing an increase in the average particle size, characterized as agglomerating or caking. These coals, when examined by time-lapse or slow-motion microphotography of heated particles, would actually turn fluid in the plastic range and resolidify at higher temperatures. The explanation presented for this effect was a softening of the coal, actually dissolving into its low-melting constituents, followed by polymerization of the melt to a different form of coal, characterized as coke or char. These studies, at other laboratories, have provided a graphic illustration of the phenomenon that must be overcome.

The historic approach to pretreatment is light oxidation of the coal particles with air at temperatures in the range of 700°F to 800°F. Other approaches have also been considered, but the air-pretreatment appears well suited for incorporation into the proposed flow sheet.

Although the volatile matter content of the pretreated coal appeared to be the controlling parameter for this coal, the mechanism for achieving this devolatilization must be considered. After examination of energy balances, material consumption, and energy requirements of the overall desulfurization system, the specifications for the pretreatment system were written. These specifications included the following:

- Operating temperature — 750°F to 800°F
- Minimum residence time — 20 minutes
- Oxygen feed — 1 SCF O₂/lb. dry coal
- Fluidization velocity — 1 ft/s measured at operating conditions.

With these operating conditions, the pretreater off-gas contains significant heating value in the form of reducing gases, tars, and coal fines. Most of the fines are returned to the bed by an internal cyclone. The gases and tars are piped to the gasifier.

The pretreater temperature is held to a moderate level by removing heat from the fluidized bed by means of coils in the pretreater bed generating steam.

Coal in the size range of 1/4 x 0 requires pretreatment at 750°F to 800°F with a residence time of about 1/2 hour. During this time, the surface of the coal is oxidized by exposure to oxygen in air at the pressure of gasification which is about 350 psia. The gas products of combustion plus some tars and coal fines are taken overhead from the pretreater to the gasifier. The solid particles of pretreated coal in the fluidized bed are conveyed by gravity with the help of an inert gas used for "fluffing." This is an aeration step consisting of many small injection points of inert gas used to maintain solids flow by means of expanding voidages in the flowing solids. The solids are injected into the bottom section of the gasifiers.

4.2.2 Gasifier

The gasifiers as well as most of the towers, reactors and vessels in the plant have been limited to about 13-14 feet in diameter to allow for shop fabrication to ensure better, more economical methods of vessel fabrication.

The fluidized bed in the gasifier operates at 1900°F and 330 psia. The free-board height above the fluidized bed also operates at 1900°F. Adequate metals have not been developed for pressure stressed parts to operate in this atmosphere and therefore, it is proposed to line the gasifier (and pretreater) with an insulating refractory liner. However, in the high temperature zone, there are no exposed metal parts other than

some instrument lines. The perforated grid is metal, probably Inconel; however, the grid is partially protected by being cooled by the steam and air passing through the holes in the grid.

The grid, placed in a cylindrical gasifier, is of conical shape with the central portion consisting of a pipe which serves the function of an ash agglomeration unit. A high concentration of air mixed with steam passes upward through the central pipe at a higher velocity than the average through the grid. A dilute zone of higher temperature gas and particles is formed immediately above the conical center of the grid. The higher temperature fuses the ash particles but does not fuse the char particles. The ash particles agglomerate to a larger size and fall by gravity down the central agglomerating venturi.

4.2.3 Ash-Agglomeration

The ash agglomeration technique used in the U-GAS Process is an extension of work by Godel and Jequier, conducted in France during the 1950's. Their work described the phenomenon of ash agglomeration whereby particles of high-ash content can be successfully removed from a dense-phase fluidized-bed of high carbon content.

The ash-agglomeration phenomena (withdrawal of high-ash content particulates from a high-carbon-content fluidized gasification zone) can best be understood by reference to Figure 4.2-1. This shows the essential features of the ash-agglomeration zone of the gasifier. A dense-phase fluidized bed high in carbon content is illustrated by 7. Gasifying agents — steam and oxygen — are introduced at two locations in the bottom of the gasifier vessel at 2 and 3. Gasifying agents introduced at 2 go through a plenum indicated by 1 and through a series of grid holes into the dense-phase fluidized-bed zone. Another stream enters at 3 and flows up through a restricted venturi opening at 4 at velocity high enough to form a jet of gas which has a definite solids-gas interface region. The gas jet region is 5. Surrounding this jet region is a lean-phase fluidized zone at 6. The oxygen in the gasifying medium flowing through 4 and into the jet in 5 creates a high-temperature zone, at or slightly in excess of the ash-softening temperatures, at the interface between 5 and 6. This high-temperature interface zone burns carbon from the particles in the zone; the turbulence and mixing action of the jet causes collisions between the high-temperature ash particles which are now at their softening point. The particles agglomerate or stick together. The carbon particles in 7 will not adhere or will not be wet by the sticky ash particles, and they remain as discrete individual particles still high in carbon content. The ash particles agglomerate and increase in size until the terminal velocity of such particles exceeds the velocity through the throat of the venturi in Section 4.

This is the technique of the ash agglomeration that allows selective withdrawal of high-ash-content particles from a high-carbon-content fluidized bed. Adjustment of the relative flow of gasifying mediums through 2 and 3 allows for differentiation in the height and the geometry of the high-temperature envelope, and will allow for withdrawal of ash agglomerate particles of various size ranges.

The flow rates of the gasifying agents through the two locations for different feed materials is important to the successful operation of the ash agglomeration gasifier systems. Obviously the geometry and size of the venturi, the angle of the plenum, and the size of the various components again are important to the successful operation of the ash agglomeration principle and will depend on various operating parameters.

IGT has successfully operated an ash agglomeration gasifier with a 4-foot-ID fluidized bed and appropriately sized venturi and plenum sections (as shown in Figure 4.2-1, with a variety of feed materials ranging from metallurgical coke prepared from Eastern bituminous coals to chars prepared by Project COED (Reference 2) from various Illinois and Western Kentucky bituminous coals. All operations have been at low pressure, utilizing as gasifying agents: air-steam mixtures, air-oxygen-steam mixtures, and steam-oxygen mixtures. The gasifier has operated at temperatures in the range of 1,870°F to 2,050°F. Since operation began in early 1974, over 1,300,000 pounds of coal char have been processed. The unit has been operated over 3,000 hours, during more than 60 experimental test runs. Data taken over long-term operations have proven the success in operations while withdrawing high-ash content agglomerates from the fluidized bed. Obviously, these tests have also produced information on steam-air gasification in conjunction with ash agglomeration.

4.2.4 Gasifier Fines Return

Some mechanism for handling coal fines is necessary in operation of a fluidized-bed gasifier to ensure high carbon utilization and ability to accept as-crushed coal feed. Two cyclone stages are incorporated, both external to the gasifier vessel. The first-stage cyclone returns fines to the fluidized bed.

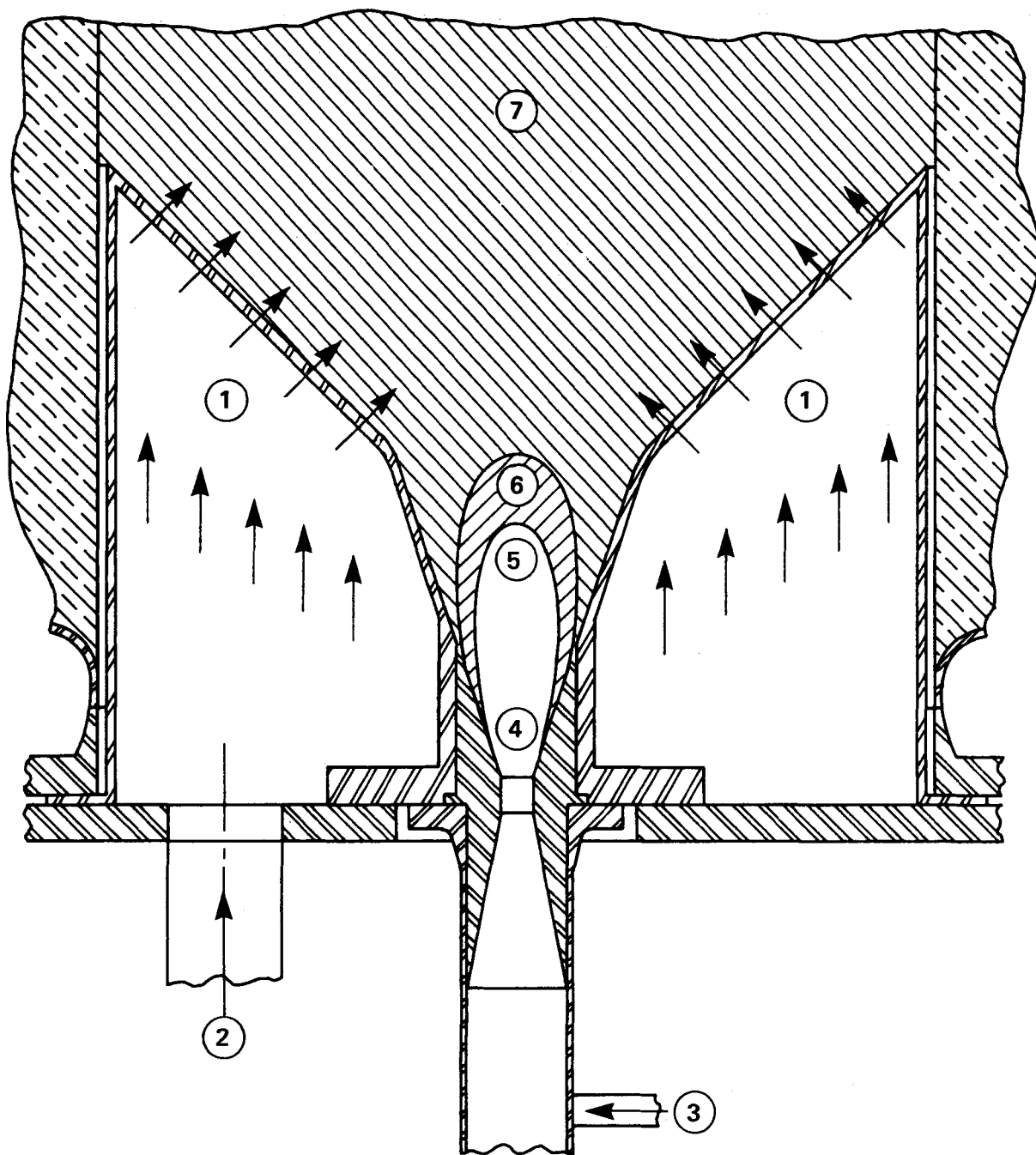
The high-temperature zone in the fluidized bed, required for ash agglomeration, also provides a means of gasifying to extinction coal fines from the second-stage cyclone, which may have been present in the feed or generated within the gasifier. By introducing the coal fines into the ash-agglomerating zone, fines are gasified and stick to ash agglomerates within the envelope, 5 and 6 in Figure 4.2-1. The ash in the fines leaves the system as part of the ash agglomerates being discharged.

4.3 PROCESS WASTE HEAT BOILER

Raw gas from the gasifier cyclones at a temperature of 1900°F and a pressure of 330 psia is cooled in order to remove particulates in a water scrub and also to remove acid gas by means of a low temperature solvent. Cooling the gas is accomplished by means of indirect heat transfer to steam production in a process waste heat boiler.

4.3.1 Description of Waste Heat Boiler

The hot raw gas at 1900°F and 330 psia enters the top of the Waste Heat Boiler and in the first section the hot-gas contacts superheater tubes. Saturated steam from a boiler



- 1 PLENUM CHAMBER
- 2 PLENUM CHAMBER GAS INLET
- 3 VENTURI GAS INLET
- 4 VENTURI CONSTRICTION
- 5 GAS-PHASE VENTURI JET
- 6 LEAN-PHASE SOLIDS ZONE
- 7 DENSE-PHASE SOLIDS FLUIDIZED BED

SCHEMATIC DIAGRAM OF ASH AGGLOMERATION

Figure 4.2.1

drum enters the superheater tubes at 679^oF and 2683 psia and is heated to 1000^oF and 2495 psia. The superheater section also has tempering water injection at the inlet to prevent the steam exit temperature from exceeding 1000^oF. Without attemperation, the exit temperature of superheated steam could exceed 1000^oF when the tubes are new or recently cleaned or when operating under partial load such that the temperature profile shifts. In the superheater section, the gas is cooled from 1900^oF to 1220^oF at which temperature it enters the evaporation section. Here vaporization occurs with saturated steam entering an elevated steam drum. The saturated water from the steam drum circulates by differential density driving force and natural circulation to the vaporizer tube inlet. The gas temperature is cooled to 730^oF in the vaporizer section. The gas now enters the economizer section where deaerated boiler feed water is preheated from 250^oF to 679^oF. The gas in the economizer section is cooled to 300^oF at which temperature the gas leaves the Process Waste Heat Boiler and flows to the scrubber. Heated water from the economizer section at 679^oF enters the steam drum.

The three sections of economizer, vaporizer and superheater are contained in two parallel vertical shells for each train. The shell is refractory lined and the carbon steel or low alloy shell of the vessel is internally clad with alloy to prevent corrosion in case of condensation of acid gases behind the refractory.

4.3.2 Features of the Process Waste Heat Boiler

The Process Waste Heat Boiler has the following features:

1. Soot Blowers

Raw gas from the gasifier has some entrained char or ash which may tend to foul the heat transfer to the steam side. To keep the surface of the tubes free of char or ash solids and to remove any aqueous or organic condensates a set of soot blowers is provided. Short blasts of steam on an intermittent basis will be added by the soot blowers. The blasting steam will be automatically controlled in order to save on utilities.

2. Tempering Water

Tempering water, described previously, will be injected into the superheater coils to control the superheater outlet temperature.

3. Feed Rates

In order to take advantage of the temperature differential driving force in the economizer section so that the surface provided may be used to the best advantage, the boiler feed water rate to the economizer is fixed to provide a uniform temperature differential at the inlet and outlet of the economizer. Additional water, saturated at 679^oF, is added to the steam drum from the gas turbine waste heat boiler. By increasing the duty in the vaporizer and superheat sections and decreasing the duty in the economizer section, more superheated steam may be generated than if the evaporation and economizer flow were equal.

4.4 WATER SCRUBBER

Water scrubbing the raw gasifier gas, after heat recovery serves two purposes. First, the gas must be cool prior to gas purification and secondly, the fuel gas must be scrubbed almost free of particulate matter in order to reduce deposition and corrosion in the gas turbine.

4.4.1 Discussion of Particulate Removal

Particulates in the fuel gas consists of coal, char or ash fines depending upon the degree of gasification of the coal. From pilot plant operating data the fines are probably char or a char-ash mixture. The size range of particles may be similar to the smaller sizes in the coal feed; however, the particle density of the char is lower than that of the coal.

In order to remove the bulk of the char elutriated from the gasifier fluidized bed, two stages of cyclones are used on the gasifier effluent. Cyclones, generally, do not remove more than about 90 percent of the fines elutriated. Commercial cyclones under the conditions of density, loading etc., of the U-Gas gasifier will not remove particles of less than 10 microns with any degree of efficiency. The first-stage cyclone will remove 25 micron particles with a 50 percent efficiency and the second-stage cyclone will remove 10 micron particles with a 50 percent efficiency.

In addition to cyclones, other possible particulate removal methods are electrostatic precipitators, wet scrubbers (venturi type) and dry filters. The dry filters such as bag filter and packed beds may be very efficient provided the integrity of the filtering medium is maintained. Due to high maintenance and high pressure drop the dry filters were deemed second best. The electrostatic precipitators were ruled out because of low efficiency and high costs. Wet venturi scrubbers with cyclone separators were chosen due to high efficiencies of dust removal, moderate pressure drop and the ability to incorporate gas cooling in the same device as particle removal. In the venturi scrubber, high velocity gas in the throat of the venturi scrubber causes relative motion between the liquid and the gas containing the particles to be separated. The dust is impacted (inertial impingement) on the surface of the liquid droplet and the liquid is collected by passing the venturi effluent into a cyclonic separator where liquid and solids are removed from the gas stream.

4.4.2 Venturi Scrubbers

There are many types of venturi scrubbers, all based on the principle of the venturi tube. In the venturi tube, the total energy of the fluid (or aerosol) is the same at every cross-section, and pressure and head are converted into velocity energy.

In its simplest form, the scrubber consists merely of a constriction in the duct carrying the aerosol, in which linear velocities of 200 to 700 feet per second are maintained. To collect submicron-sized particles effectively, high throat velocities of over 300 feet

per second are required. Lower throat velocities, with a higher liquid consumption, are tolerable for good efficiencies on large size particles.

In practical implementation, the throat constriction is usually the throat of the venturi tube which has a converging section, a relatively long throat, and a diverging section. The scrubbing liquid is injected into the throat section in the form of low-velocity jets. Frequently, the throat is of rectangular cross-section and of adequate length to accommodate liquid injection nozzles. The throat is followed by a divergent section. The liquid droplets containing aerosol particles are disengaged in an after-separator that follows the venturi. Cyclonic separators are frequently used for this purpose.

In the venturi scrubber, the predominant mechanism of collection is by inertial impingement. To obtain a high collection efficiency, it is essential that the spray droplets be of small size, and that there be a high relative velocity of the aerosol particle as it impinges on the droplet. The disintegration of the liquid into fine spray droplets is caused by the gas velocity. Although there is a short contact time, intimate contact is obtained by the extreme turbulence in the venturi section.

The effectiveness of the venturi scrubber is enhanced by the conditioning of dust particles by condensation. This aids in particle growth as the larger surface area of the wet particles tends to help agglomeration and subsequent collection.

Several types of venturi scrubbers are available, and the principal differences involve the introduction and removal of the liquid. It is apparent that the design of the water injection system is of considerable importance particularly in obtaining efficiency of removal of submicron sized particles. The flooded disc (variable-throat-orifice scrubber) is a comparatively recent development, in which the scrubbing efficiency and pressure drop may be adjusted by changing the position of a distributing disc in the venturi throat.

In general, effective dust removal in the venturi scrubber is directly related to the energy used in the process. For example, the greater the energy consumption, up to a practical limitation, the greater the efficiency of collection.

The venturi scrubber is the most efficient of the wet scrubbers and is nearly comparable in efficiency to fabric filters. A 99.7-percent removal efficiency on a standard dust for what is termed a medium-energy venturi scrubber and 99.9-percent removal efficiency for a so-called high-energy venturi scrubber was indicated in the literature. Unlike fabric filters, however, which are confined to dust removal, this scrubber has found extensive application as a gas cooler and gas-removal device. Venturi scrubbers have high power costs but low maintenance requirements. If dust loadings are not too high and certain precautions are observed to prevent jet cloggings, scrubbing liquor can be recirculated.

The aqueous scrubber also removes water soluble gaseous contaminants and salts which are removed to the water stripper and water treatment plant. The scrubber thus

) removes ammonia which would otherwise be converted to NO_x in the gas turbine combustor. Ammonia is converted to nitrogen in the Claus Unit. Salts, which are highly corrosive to the high temperature metals in the gas turbine, are removed in the scrubber water which is sent to the stripper and eventually to the water treatment plant.

4.5 GAS PURIFICATION

4.5.1 Objectives

The purposes of gas purification in a coal gasification, combined cycle power plant are the requirements to meet emission standards and the protection of the gas turbine.

1. Emission Standards

Meeting EPA Standards for new power plants emissions with respect to oxide of sulfur, oxides of nitrogen, and particulates imposes cleanup requirements on a coal gasification combined cycle system. The standards set for solid fossil fuels fired power plants will be assumed to apply to the gas turbine combined cycle plant. These standards are (12):*

- Particulates 0.1 lbs/mm Btu
- Sulfur Oxides 1.2 lbs/mm Btu
- Nitrogen Oxides 0.7 lbs/mm Btu

In order to meet the above standards when feeding Illinois No. 6 coal to the gasifier, the gasification plant including the cleanup system must remove 84 percent of the sulfur in the coal, 77 percent of the nitrogen in the coal, and 99 percent of the ash in coal before releasing the combustion products to the atmosphere.

2. Protection of the Gas Turbine

- Nitrogen Compounds: Any ammonia or organic nitrogen compounds which may appear as NO_x after combustion are not harmful to the turbine metallurgy, and therefore, the controlling case is the emission standards in the combustion off-gases. Remaining nitrogen compounds act as a fuel for the turbine and should not be removed except for the amount needed to meet the emission requirements.
- Sulfur Compounds: In order to meet emission standards, only 84 percent of the sulfur in coal need be removed. However, for better turbine metal life, additional sulfur removal from the raw gasifier gas will be evaluated.

*All numbered references are listed at the end of Section 4.

- Trace Elements: It is known that alkali and other metals are harmful to the gas turbine; and every effort is made to reduce, eliminate, or not to introduce metals such as sodium, potassium, and vanadium.
- Particulate: Particulate matter, entrained from the gasifier, in the fuel gas is erosive and corrosive to the gas turbine. Ash content is particularly harmful due to blade deposition and must be reduced to less than 1 PPM by weight. Dust loadings will be evaluated in the cyclones and scrubber designs.

4.5.2 Definitions

1. Low Temperature Cleanup Systems are those sulfur removal systems which operate below 300°F. Intermediate Temperature Cleanup Systems are those sulfur removal systems which operate between 300°F and 1000°F. High Temperature Cleanup Systems are those sulfur removal systems operating above 1000°F.
2. Chemical Solvent Process
Those processes which use an aqueous solution to react with acid gases, such as H₂S and CO₂, at temperatures below 300°F and the solution is capable of regeneration by means of heat. Typical of such solvents is the use of 15 percent to 20 percent monoethanolamine in water to react with H₂S and CO₂.
3. Physical Solvent Process
Those processes using a solvent, either organic or aqueous, which dissolves certain gases preferentially due to different solubility in solution. Typically, the preferred solvent dissolves H₂S to the exclusion of other gases. An example of such a solvent is the Selexol process of Allied Chemical Company, which uses a dimethyl ether polyglycol. Regeneration is accomplished by pressure letdown, heat, or both.
4. Scrubbing
Any process in which the gas is washed with a liquid. To obtain good contact between gas and liquid for efficient removal of contaminants, certain proprietary devices are generally used such as "Venturi" scrubbers.
5. Direct or Single Step Conversion of H₂S to Elemental Sulfur
Processes for the conversion of H₂S in a gas to elemental sulfur in a single process unit. The H₂S is absorbed in either a chemical or physical solvent and an oxygen carrier is introduced, which converts the H₂S to elemental sulfur. Examples of Direct Conversion Processes are Ferrox, Manchester, Thylox, Stretford, Takahax, Townsend, and Wackenroder.

4.5.3 Process Selection

The selection of processes suitable for cleanup of raw gas from a U-Gas coal gasification is predicated upon those characteristics most desirable for the removal of impurities with the least adverse effect on the gas turbine. The gasifier operates in a reducing atmosphere and, therefore, most of the sulfur in the coal is converted to H_2S and some of the nitrogen in the coal is converted to NH_3 . To meet emission requirements for both oxides of sulfur and nitrogen, it is necessary to reduce the sulfur and ammonia content of the gas. In addition, the sulfur may be further reduced to protect the turbine from sulfide attack. From an ecological point of view, the best way of handling the sulfur problem is to convert the sulfur, as H_2S , in the gas to the relatively inert solid or molten elemental sulfur. In special situations, conversion of H_2S to sulfuric acid may be practical; however, in most cases sulfuric acid is less desirable than elemental sulfur due to its corrosivity and its greater weight than elemental sulfur which restricts the economical shipping distance. Therefore, an important function of the gas purification system is the removal of most of the H_2S and conversion to elemental sulfur for shipment to market.

H_2S may be removed from the raw gas by means of chemical solvents, physical solvents, direct conversion processes to elemental sulfur and by absorption on solids.

Examples of chemical solvents are (1, 2, 3):

- Ethanolamines
- Econamines
- Alkazid
- Benfield (Catacarb)
- Tripotassium phosphate
- Vetrocoke

Some physical solvents are (9, 10, 11, 13):

- Purisol
- Rectisol
- Selexol
- Sulfinol (partly chemical)
- Fluorsolvent
- Adip

Direct conversion processes are (5, 6, 7):

- Stretford
- Ferrox
- Thylox
- Townsend
- Wackenroder

Characteristics of some of these solvents are presented in Table 4.5.3-1. An inspection of this data indicates that some solvents are purely organic such as Selexol, Sulfinol, Adip, Rectisol, Purisol and ethanolamine with other solvents composed of inorganic salts such as Benfield or salts of organic acids such as Alkazid.

Since we cannot ensure that zero amount of solvent will ever entrain into the gas turbine, we would eliminate from consideration those processes where the solvents are harmful to the gas turbine. This eliminates all solvents containing sodium, potassium, vanadium, and arsenic. We are also concerned with a certain selectivity which would eliminate ethanolamines. Selectivity refers to the removal of H_2S with a minimum removal of other gases, such as CO_2 , and with very small amounts of fuel gas removed with the acid gases. Although the CO_2 has no heating value, it adds to the power production because it increases the mass of gas passing through the gas turbine from high temperature and pressure to lower temperature and pressure. This leaves Selexol, Sulfinol, Adip, Rectisol, Fluorsolvent, and Purisol as well as the single step processes, such as Townsend.

The single step processes converting H_2S directly to elemental sulfur may be classified as Liquid Phase Claus Plants. For the past fifty years, many patents have been issued on systems using water, such as the Wackenroder process; aqueous solutions, such as Aqua Claus (8); and organic compound, such as glycols, used by the Townsend process (5). None of these processes has had industrial acceptance and for most of these processes, very few plants exist. The normal operating procedure, is to burn some product sulfur to make SO_2 , which is contacted with the solutions (DEG, water, etc.). The SO_2 laden solution is then contacted with the gas stream containing H_2S . The reaction of H_2S and SO_2 produces elemental sulfur and water.

The solution is heated to melt the sulfur, and in the organic solvents the heat also drives off the water. From the little published data (7), the yields are generally poor with a conversion of only 40 percent to 60 percent of H_2S .

Poor conversion in some of the liquid phase Claus processes plus a lack of commercial experience tend to rule out the selection of this type of process.

SELECTIVE SOLVENTS

Organic solvents which rely on physical solution of acid gases usually are selective. From a preliminary review of the literature* the Rectisol (9) process, although applied to fixed bed Lurgi gasifiers with high tar production, must be eliminated due to excessive complexity and cost, high refrigeration requirements, and possible high solvent losses due to the high vapor pressure of methanol solvent. Purisol (9) will also be eliminated due to high cost associated with high circulation rates, scarcity of solvent, and high viscosity of solvent at operating conditions. This leaves Selexol, Sulfinol and Adip.

*Hydrocarbon Processing Volume 4, Page 99, April 1973.

TABLE 4.5.3-1

PROCESSES FOR THE REMOVAL OF H₂S FROM LOW & INTERMEDIATE BTU GASES

Process	Sorbent or Solvent	Removes	Temp. ^o F	Type
Amine	Mono or Diethanolamine in Water	H ₂ S, CO ₂	70-120	Chemical
Econamine	Diglycolamine (50 to 70%) in Water	H ₂ S, CO ₂	70-120	Chemical
Alkazid (DIK)	Potassium Salt of Dimethylamine Acetic Acid in Water	H ₂ S & small amount of CO ₂	70-100	Chemical
Benfield (Catacarb)	{ Hot Potassium Carbonate 25% + In Water Plus Catalyst	CO ₂ , H ₂ S	100-250	Chemical
TPP	Tripotassium Phosphate 20/40% in H ₂ O	H ₂ S, Some CO ₂	120	Chemical
Vetrocoke	Potassium Arsinide Activated with Arsenic in Water	H ₂ S	50-120	Chemical
Stretford (Takahax)	Na ₂ CO ₃ with Vanadium & ADA Catalyst	H ₂ S	50-120	Chemical
Purisol	N-methyl -2- Pyrolidone	H ₂ S, CO ₂	0-100	Physical
Fluorsolvent	Propylene Carbonate	H ₂ S, CO ₂	0-100	Physical
Selexol	Dimethyl Ether Polyethylene Glycol	H ₂ S, Some CO ₂	0-100	Physical
Rectisol	Methanol	H ₂ S, Some CO ₂	-60 to -20	Physical
Sulfinol	Sulfolene plus DIPA	H ₂ S, Some CO ₂	80-120	Mostly Physical
Ferrox	Iron Oxide in Sodium Carbonate Solution	H ₂ S	80-100	Single Step
Townsend	Reacts SO ₂ with H ₂ S in Glycol Solution	H ₂ S to S	80-120	Single Step
Thylox	Sodium Arsenate with Air Conversion to Elemental Sulfur	H ₂ S to S	80-120	Single Step
Wackenroder	Reacts SO ₂ with H ₂ S in Water Solution	H ₂ S to S	120-300	Single Step
ADIP	Alkanolamine	H ₂ S, Some CO ₂	80-120	Mostly Physical

SELEXOL

Selexol (13), a process developed by Allied Chemical Company, uses dimethyl ether polyglycol as the circulating solvent. The absorption requires moderate refrigeration operating at about 30°F to 40°F. H₂S is more soluble than COS which is more soluble than CO₂. In theory it is possible to reduce the sulfur content of a gas to any low concentration provided enough solution is circulated; however, total sulfur removal is usually not practical especially when some of the sulfur to Selexol is COS. The sulfur in the off gas is usually better than 25/30 percent of H₂S due to the selectivity of the solvent. This concentration is sufficiently high in H₂S to feed to a Claus Plant. The solvent does not degrade and needs no reclaiming. The low vapor pressure of the solvent means low evaporation losses. Selectivity is obtained by means of the selectivity of the solvent to H₂S as well as by flashing the rich solution from the absorber and recycling the flashed gas back to the absorber. The solvent is noncorrosive and nonfoaming.

SULFINOL

Sulfinol (10) (11), a process licensed by Shell Development Company, uses Tetrahydrothiophene dioxide with alkanolamine and water. The solution, partly a physical solvent, partly chemical, is selective toward H₂S. A simple absorber-stripper combination is used. The absorber usually operates at 100°F to 120°F and may require no, or very little refrigeration. The COS in the feed gas is removed for the most part by hydrolysis in the absorber. The processes require low solution circulation rates and have low losses. A reclaimer is required as the solution will degrade over long periods of time.

THE ADIP PROCESS

The Adip Process (10) was developed by Shell Development Company and uses a high concentration alkanolamine as a solvent. It is somewhat more selective towards the removal of H₂S in an H₂S/CO₂ mixture than is Sulfinol. The process has many of the advantages of a purely physical solvent such as Selexol, Rectisol or Purisol. These are: low solvent circulation rates, low heat capacity of the solvent, low utilities, low degradation rates, low corrosion rates, low foaming tendencies. Adip also has the advantage that the solvent is somewhat less expensive than other solvents such as Sulfinol or Selexol.

The flow sheet for Selexol, Sulfinol and Adip are all similar. An absorber using trays or packing washes out the H₂S and some CO₂ from the sour gas along with traces of the other fuel gas components. Selexol requires refrigeration to cool the solvent to the absorber, while the others operate at ambient temperatures. The solution laden with gas from the bottom of the absorber is flashed by dropping pressure through a recovery turbine. The solution is stripped in a reboiler stripper, lean solution is cooled and returned to the absorber. Stripper overhead acid gases are sent to the Claus unit.

4.5.4 Comparison of Selected Purification Processes

A comparison of the gas purification processes; Selexol, Sulfinol and Adip, was performed for various purities of sulfur content in the treated gas. Results of this comparison for eight cases are shown in Table 4.5.4-1. It can be seen that the Selexol is the most selective process towards H_2S removal and requires the least amount of steam for regeneration. However, Sulfinol requires less power than Selexol because the Selexol process requires extra power for refrigeration. To compare all processes on the same basis the power required can be converted to a steam requirement.

To equate power to 50 psig, low pressure steam, an assumed steam turbo-generator operating at about 70 percent efficiency requires 21 lbs/hr of 50 psig steam (condensing) to produce one KW. Converting all the power requirements for each of the eight cases to equivalent 50 psig steam allows the comparison of the total energy requirements for each case. These are presented in Table 4.5.4-2. It can be seen from this table that at the 50 to 100 ppm by volume sulfur purification level, Sulfinol uses less equivalent total steam than Selexol. At all higher levels of sulfur retention in the treated gas, Selexol uses less equivalent total steam than Sulfinol.

In the 1000 to 1200 ppm by volume sulfur range, Adip uses slightly more equivalent total steam than Sulfinol; however, both use about twice the equivalent total steam than does Selexol.

The above comparison, while valid for the Purification Plant, is actually modified slightly if the overall equivalent total steam usage of the Purification and the Claus Plant are considered in conjunction. The equivalent total steam usage of the Claus Plant is somewhat less for the cases with Claus feed gas having the higher sulfur content, i.e., for the cases with the higher selectivity.

In view of the above discussion a base case is chosen using Selexol in the 200 ppm by volume range of sulfur in the treated gas, producing an H_2S concentration of 34.6 percent (volume) in the vent gas (acid gas) from the regenerator of the Purification Unit. This is Case II in the Table 4.5.4-1.

**TABLE 4.5.4-1
GAS PURIFICATION PROCESSES**

Case No.	I	II	III	IV	V	VI	VII	VIII
Solvent Type	← SELEXOL →				← SULFINOL →			ADIP
Sulfur in Treated Gas H ₂ S + COS ppm by vol. (dry)	87	202	400	1,204	36	374	872	1,209
L. P. Steam 80 psia LBS/HR x 1000	528.4	202.4	174.0	152.0	577.7	466.2	443.0	565.2
I. P. Steam 300 psia LBS/HR x 1000					27.4	16.6	14.8	
Total Steam	528.4	202.4	174.0	152.0	605.1	482.8	457.8	565.2
Power KW	23,444	10,560	10,200	9,100	2,972	2,738	2,676	1,783
Cooling Water GPM	37,920	15,800	14,076	12,353	46,700	36,800	34,700	46,500
Mol. % H ₂ S + COS in dry acid gas	28.8	37.6	37.7	37.5	10.3	13.8	15.9	24.1
Mol. % CO ₂ Coabsorbed	22.0	14.4	13.9	12.4	76.0	54.0	40.0	22.0

**TABLE 4.5.4-2
STEAM-POWER EQUIVALENT FOR PURIFICATION**

Assume 21 lbs. of Steam at 50 psia Produce 1 KWHR

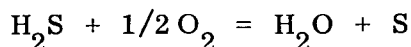
Case No.	Process	Sulfur in Treated Gas PPM Vol.	Power Required KW	Steam Required LBS/HR x 100	Steam Equivalent To Power LBS/HR x 100	Total Steam LBS/HR x 100
I	Selexol	87	23,444	528.4	492.3	1,020.7
II	Selexol	202	10,560	202.4	221.8	424.2
III	Selexol	400	10,200	174.0	214.2	388.2
IV	Selexol	1,204	9,100	152.0	191.1	343.1
V	Sulfinol	36	2,972	605.1	62.4	667.5
VI	Sulfinol	374	2,738	482.8	57.5	540.3
VII	Sulfinol	872	2,676	457.8	56.2	514.0
VIII	ADIP	1,209	1,783	565.2	37.4	602.6

4.6 SULFUR PRODUCTION

4.6.1 Discussion

The gasification of coal produces sulfur compounds. The amount and type of sulfur compounds depends upon the coal and the process. The U-GAS process produces mostly H_2S with small amounts of carbonyl sulfide and perhaps traces of other compounds such as carbon disulfide and thiocyanides. In order to both meet pollution requirements as well as to protect the gas turbine it is necessary to reduce the sulfur content in the fuel gas to the turbine to a low value by removing most of the sulfur in the raw product gas. The removal of H_2S from the fuel gas is discussed in the Gas Purification Section 4.5. For coals with very low sulfur it may be possible to burn the H_2S and exhaust the combustion products through the gas turbine waste heat boiler with all the sulfur leaving the system as SO_2 . This is possible as long as the amount of sulfur dioxide released falls within the pollution restrictions of 1.2 lbs of SO_2 per million Btu of coal. However, with Illinois No. 6 coal the sulfur content of the coal of 3.9 wt percent is too high to release as SO_2 to the atmosphere and most of the sulfur in the raw gas must be converted to elemental sulfur and separately removed. Elemental sulfur is a very stable solid at ambient temperature and it can be easily disposed by sale or storage.

Elemental sulfur can be formed from H_2S (or other sulfur compounds) by partial oxidation in a conventional Claus unit with sulfur produced by the following overall reaction:



Similar chemistry may be obtained via other processes such as Stretford, Townsend or Wackenroder.

A slightly modified Claus type process was chosen as being the more economical, and having had more on-stream usage than most of the other processes. A Claus type process also has the advantage of converting ammonia to nitrogen and water, provided that the temperature levels are maintained properly in various parts of the Claus plant.

4.6.2 Description of the Claus Plant

Sour gas from the Sour Water Stripper Section 4.7 and from the Selexol Gas Purification unit are fed to the Claus unit and partially combusted with air, both gas and air being preheated with steam to obtain high combustion temperatures. The sour gas contains a large quantity of CO_2 and in order to produce a high combustion temperature it is necessary to add a small quantity of product fuel gas to the combustion chamber. The products of combustion are cooled in a steam generator which condenses and removes some liquid sulfur. The cooled gas is sent to the first catalytic reactor at a temperature high enough to prevent plugging of the catalyst with liquid sulfur and high enough to prevent an

excess of carbonyl sulfide formation. The gases are reheated by heat exchange or by hot gas bypass and sent to the second reactor. Gases are again cooled to condense liquid sulfur at the same time generating low pressure steam. The tail gas is sent to the gas turbine heat recovery steam generator for reaction to SO₂ and subsequently vented to the atmosphere with the exhaust gases. All the liquid sulfur streams are collected and sent to the sulfur storage pit.

The conversion of gaseous sulfur compounds to liquid sulfur is over 90 percent and the SO₂ discharged from the combusted Claus unit tail gas is 0.66 lbs SO₂/million Btu of coal. That SO₂ discharged from the combustion of fuel gas in the gas turbine is 0.18 lbs SO₂ per million Btu of coal for a total of 0.84 lbs SO₂ per million Btu of coal. No ammonia or NO₂ exits with the tail gas from the Claus unit as both gases are dissociated to free nitrogen and water vapor.

4.7 AMMONIA AND SOUR GAS STRIPPING

Sour process water containing sulfur compounds, ammonia, CO₂ and minor traces of salts must be stripped and purified before disposal to the river or reuse. Besides dissolved gases and salts the process water also contains solid fines of char which have been washed out in the venturi scrubber system. The solids will be removed in the Process Water Purification System as described in Section 4.8.

4.7.1 Processes Options

The most elementary process and the one chosen for this proposal is the removal of ammonia and sour gas from the waste water by steam stripping. The gases are sent to the Claus unit where the sulfur is recovered and the ammonia is converted to nitrogen. The stripped water containing dissolved salts, solid char and some traces of organics is sent to Process Water Purification.

The amount of ammonia produced by the IGT U-Gas process may be sufficient to recover and purify for sales. However, a detailed economic study would be required to justify the added equipment for ammonia recovery and is not included herein.

The recovery of ammonia from sour gases or from sour water can be accomplished by a variety of proprietary means. Some of these are U.S. Steel "PHOSAM" process which uses an ammonium phosphate solution to absorb the ammonia which is then stripped from solution and concentrated to form a pure anhydrous ammonia product. Other processes licensed by Chevron Research and by Lurgi-Lentz, utilize distillation at moderately high pressure to separate ammonia from acid gas. Older processes use acids such as sulfuric acid to form ammonium sulfate and strip-out the acid gases. The ammonium sulfate is then concentrated and crystallized and in some cases sold as a fertilizer.

4.7.2 Description of Stripping Process

Sour water is collected from both the Water Scrubbing Section and from the Selexol Gas Purification Section and sent to a holding tank. The water is pumped from the holding tank to the top of the stripper tower via a feed-product exchanger. The stripper tower is an alloy clad tower with alloy trays to reduce corrosion. Direct steam injection is used in the bottom of the stripper. From the bottom of the stripper the water flow is pumped via an exchanger and a cooler to the Process Water Purification section. Steam and ammonia with the sour gases from the top of the stripper are sent to an alloy condenser. Condensed steam from the stripper overhead condenser which is contaminated with sour gas is sent back to the stripper feed tank and the ammonia and sour gases are sent to the Claus unit.

4.7.3 Design Considerations

Design considerations follow recommendations of the API Committee on Refinery Environmental Control (CREC) API publications #927 and #944. The sour gases are relatively easy to strip but the ammonia is more difficult. In order to meet an ammonia concentration of 20 mg/liter, it is necessary to use about 40 actual trays in the stripper and a fairly high steam stripping rate of three lbs of steam per gallon of fresh feed. The trays are valve type which have a good turndown ratio of 3 or 4 to 1. The stripper operates at low pressure allowing the use of low pressure stripping steam. The condenser operates at 180°F instead of at 100–120°F because at low temperatures the ammonium salts may plate out and plug the condenser.

4.8 PROCESS WATER PURIFICATION

Water condensed from process gas must be treated and purified before disposal or possible reuse. Condensed process water always contains sulfur compounds such as H₂S and in addition depending upon the point of condensation, water may contain ammonia, CO₂, cyanides and traces of salts such as potassium and sodium chlorides, fluorides, sulfides, sulfites, thiocyanides, etc. During normal operation of the U-gas process, it is not expected that any organics or phenols would be formed. However, during upset or startup conditions some organics may form and during normal operation on a large scale some organics may form even if no indication of these components occurred in the pilot plants. It is therefore necessary to design the waste water purification system to remove organic compounds from the maximum possible concentration to a low level suitable for river discharge.

The process condensate water is derived from two main sources. The first is the scrubber water which contains both sour water as well as a small amount of coal char entrained from the gasifier cyclones. The second process stream comes from the Selexol unit which due to low temperature operation condenses water vapor in the gas and results in a sour water. A small amount of oily rainwater and equipment wash-down water is also treated in this unit.

4.8.1 Design Basis

The process waste water treatment system consists essentially of pretreatment by gravity separation and air flotation for removal of oils and solids, followed by biological treatment to remove organics. To guard against upset conditions which may produce phenols and organics in the process water, a complete air flotation plus biological oxidation system has been included. If extended future tests of the IGT U-GAS system on various coals reveal that an extensive treatment is not required, then this treatment system will be replaced with a less sophisticated system.

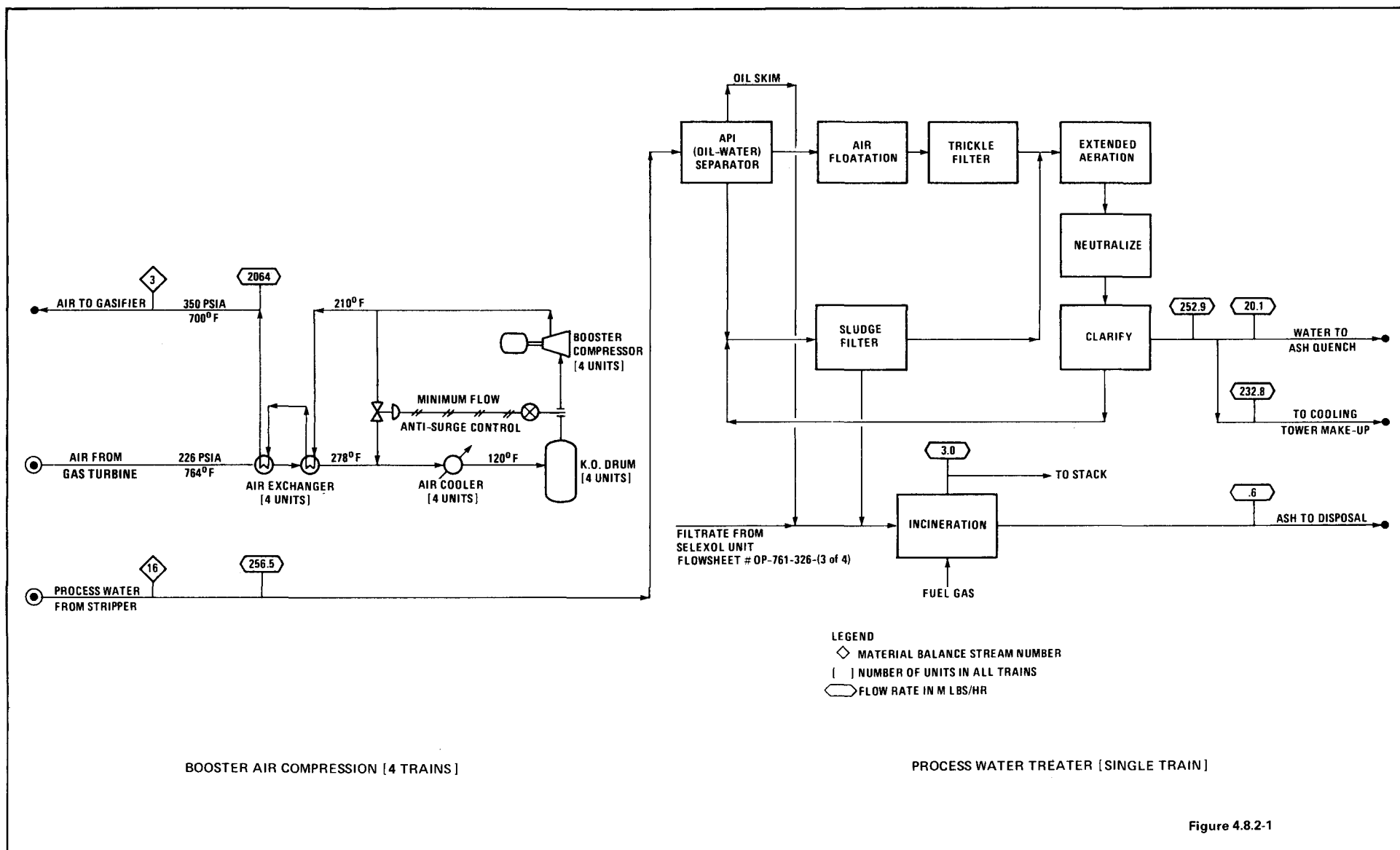
A trickling filter has been installed prior to extended aeration to prevent shock loading of the microorganisms in the basin.

4.8.2 Description of Flow

The treatment system is shown on Process Flow Diagram, Figure 4.8.2-1. Wastewater streams flow to a gravity separator for removal of floatable oil and settleable solids. A diversion box is provided for diverting excess rainwater run-off to a surge basin during periods of heavy rainfall. This water is worked off through the wastewater treating system after the rain ceases. During normal operations, the wastewater flows through the diverter to gravity separation. The effluent from the gravity separator flows into an air flotation unit where very small droplets of oil and finely divided solids are removed. Oil is reduced to a level acceptable for biological oxidation. Equipment for addition of chemicals, such as polyelectrolytes, is provided to aid flocculation of finely divided droplets and solids. After leaving the air flotation unit, the water enters a trickling filter. The water trickles through the plastic packing in this unit. Biological matter on the packing reduces organics, primarily phenols, in the wastewater and converts them to carbon dioxide and water. The efficiency of this unit is low, but these biota, as compared to those in an extended aeration basin, are more resistant to shock loadings of organics. Therefore, the trickling filter will serve as a roughing filter prior to extended aeration. If phenol is present in appreciable quantity, the filter will reduce phenol to a level that will prevent it from being toxic to biota in the aeration basin. Water leaving the filter is half recycled back to the filter, half fed to the extended aeration unit. Therefore, the recycle flow will be equal to the feed-forward flow. In the aeration basin active biological sludge, with aeration supplied by mechanical surfacifiers, rapidly consumes the organic substances in the water.

The mixture of treated water and suspended microorganisms from the biological oxidation unit flows into clarifiers where the microorganisms settle to the bottom and are returned to the inlet of the biological oxidation unit. The clarified water then flows to cooling water makeup.

Oil separated from water in the gravity separator is sent to a holding tank. Sludge from the gravity separator and the air flotation unit is dewatered in a gravity thickening tank; the sludge is further thickened in a rotary vacuum sludge filter then disposed



of by incineration and landfill. Excess biological sludge from the biological oxidation unit is sent to a sludge thickener, where it is concentrated to about 4 percent solids. From the thickener, the sludge is treated to improve its filterability and is filtered to further concentrate the solids. The biodegradeable filter cake is incinerated and the ash trucked to disposal.

The clear water separated from the primary sludges (those from gravity settling and air flotation) in the oil decant tank and in the sludge settling tanks is returned by gravity to the inlet of the gravity separator. The filtrate from the primary sludge filter is pumped to air flotation. Water separated from secondary sludge in the secondary sludge thickener and secondary sludge filtrate are returned to the biological oxidation basin.

The foam float from the air flotation unit drains by gravity to a sump from where it is transferred to the float separation tank. The oil which separates is sent to tankage with the oil from the gravity separator. Water which separates is returned to the air flotation unit.

4.9 AIR BOOSTER COMPRESSOR

The gas turbine air compressor compresses air from the iso-condition of 59°F, 60 percent relative humidity and 29.92 in. Hg. Abs. to 731.1°F and 218 psia. Most of the air at discharge pressure and temperature is used in the turbine combustor. Some is used as a cooling medium for the turbine. A portion of the compressor discharge (19 Wt. percent) is used to gasify coal. The gasifier system plus combustor have a pressure drop which must be balanced by increasing the air pressure to the gasifier above that delivered by the gas turbine compressor. A booster compressor on that portion of the air to the gasification section is provided to compensate for the various pressure drops in the fuel gas production system.

The compressed air discharge from the gas turbine compressor is at 731.1°F because that compressor has no interstage cooling. In order to increase efficiency of the booster compressor, the suction temperature is lowered as far as possible with heat exchange and cooling water.

4.9.1 Process Description

Compressed air from the gas turbine compressor is sent to the booster compressor system. Booster Compressor suction air is regeneratively cooled in a heat exchanger against the Booster Compressor discharge air. The Suction air is further cooled in a water cooled exchanger to 100°F to 120°F and then the air enters the booster compressor. Air is compressed with a comparatively low compression ratio. Discharge air is regeneratively heated in the heat exchanger and sent to the gasifier section. The Booster Compressor is a single stage machine with no intercooling and no after cooling.

4.10 SULFUR STORAGE AND LOADING SYSTEMS

Sulfur may be stored as a solid or as a liquid. Extremely large production facilities usually store sulfur as a solid. The liquid from production facilities is usually pumped into large diked ponds where the sulfur solidifies into huge blocks. The solid sulfur is blasted with explosives or mechanically broken into small pieces for shipment to users. The sulfur may also be flaked or prilled. Smaller installations usually store sulfur as a liquid at about 300°F. The liquid is pumped into insulated tank cars or trucks and transported to market. The tank cars have internal steam or electric coils and the user keeps the car warm until it is ready to be pumped out.

4.10.1 Sulfur Storage

Liquid storage of sulfur may occur in insulated tanks above ground level or in large covered sumps below ground level. An economic study is required to choose one method over the other. However, from past experience with similar size installations in petroleum refineries or in gas fields, the large below-ground storage was chosen as probably being more economical. The sulfur storage pit is heated with steam which has been generated in the Claus unit to keep the sulfur at 250°F to 300°F. For this purpose, the pit has coils of carbon steel pipe placed at intervals to keep the sulfur molten. The sulfur drain lines to the pit and the sulfur discharge lines from the pit all have steam tracing plus insulation to keep the sulfur molten.

4.10.2 Sulfur Loading

Sulfur is discharged from the pit by means of a vertical submerged pump operating intermittently when loading tank cars. Loading racks are designed to accommodate one or more tank cars. Liquid sulfur is usually top loaded with swing points or flexible couplings and with automatic cut-off to prevent overflow of the tank cars. Similar loading devices may be used for tank trucks. Molten sulfur should not be allowed to stand in loading or unloading lines. The lines should be blown out with air or steam and drained back to the sulfur pit. Directions for loading and unloading may be obtained from the Manufacturing Chemists Association, Inc., "Chemical Safety Data Sheet 50-74."

Steam heating and tracing of molten sulfur in piping, tanks and equipment requires close temperature control. At a low temperature, below 240°F, the molten sulfur will solidify and, at a temperature of about 320°F, the viscosity of the sulfur rises sharply with rising temperature. The optimum temperature for fluid molten sulfur is between 250°F and 300°F.

4.11 FUEL GAS REHEATER

Purified fuel gas from the Selexol unit which is sent to the gas turbine leaves the Selexol unit at 99°F. The combined cycle power plant efficiency could be improved if the fuel gas could be heated to a higher temperature than 99°F because the energy content of the fuel gas adds to both the gas turbine power as well as to the steam turbine power.

Possible methods of heating the fuel gas are:

1. Using low or intermediate pressure steam obtained from the steam turbine. This method would help unload the low pressure stages of the steam turbine but unfortunately the fuel gas could not be heated much higher than 400°F to 450°F depending upon the steam pressure.
2. Use hot water from the economizer section of the gas turbine heat recovery unit sending the water, after heat transfer back, to the deaerator. This method can heat the fuel gas to 620°F. However, the hot water from the economizer is at high pressure which must be let down to deaerator pressure wasting pumping power and requiring an expensive heat exchanger due to the fact that the water is at almost 3000 psi.
3. The fuel gas may be heated by direct exchange with hot process gas by placing coils in the process waste heat boiler or it may be heated by flue gas in the gas turbine heat recovery unit. The product fuel gas may be heated to 700°F to 1000°F by this means.
4. The product fuel gas may be heated by a combination of the above methods. For instance, the fuel gas may be heated to 400°F by use of 650 psi steam after which it may be further heated to 900°F in the process waste heat boiler.

The Phase I combined cycle heat balance is based upon the hot water system of reheating the fuel gas, as described in paragraph 2. During Phase II, the other alternatives will be investigated in order to increase the cycle efficiency.

REFERENCES

For Section 4.5 Gas Purification

1. Goar, B.G.
"Today's Gas Treating Processes"
Oil & Gas Journal, p.75, July 12, 1971
Oil & Gas Journal, p.84, July 19, 1971
2. Goar, B.G.
"Sulfur Recovery Processes"
Hydrocarbon Processing, 47, No. 9, p.248, September 1968
3. Swain, C.D.
"Gas Sweetening Processes"
Hydrocarbon Processing, p.127, March 1970
4. Maddox, R.N. and Burns, M. D.
"Least Gas Sweetening"
Oil & Gas Journal, p.131, August 14, 1967
5. Townsend, F.M. and Reid, L.S.
Petroleum Refiner, November 1958
6. Diah, I.G., Shemilt, L.W. and Ponter, A.B.
"Sulfur by Simultaneous Absorption of H_2S and SO_2 "
Chemical & Process Eng., p.75, October 1971
7. Wackenroder
"Production of Clean Fuel Gas from Bituminous Coal"
PB-232-695, p.213
Consolidation Coal Company for EPA, December 1973
8. Kayford, J.S., Vanbrocklin, L.P. and Kuck, M.A.
"Stauffer, Aqua Claus Process"
AIChE Meeting, New Orleans, March 1973
9. Hochgesand, G.
"Rectisol & Purisol"
I&EC, Vol. 62, No. 7, p.37-43, 1970

REFERENCES (Continued)

10. Sulfinol and Adip

Oil & Gas J.I., Vol. 10, No. 9, p.109, September 1970

11. Sulfinol

Hydrocarbon Processing, 44, No. 4, p.137, 1965

12. Federal Register

13. Sweny, J. W.

"Selexol Solvent Process in Fuel Gas Treating"

AICHE 81st National Meeting, Kansas City, Missouri, April 11, 1976.

SECTION 5

POWER BLOCK

The equipment referred to as part of the Power Block includes the combustion and steam turbine-generator units and the major equipments directly associated such as the main steam condenser, feedwater heaters, boiler feedpumps, HRSG's and instrument air system.

5.1 THE COMBUSTION TURBINE-GENERATOR

The combustion turbine-generator unit will be an integrally-designed plant with all support and control systems such that the interfaces to the remainder of the power block or plant be limited to:

- (a) Control signals in and out;
- (b) Fuel in;
- (c) Electric power out;
- (d) Exhaust energy out;
- (e) Cooling water in and out;
- (f) Generator gases in.

A typical layout of the equipment in this portion of the plant is shown in Figure 5.1-1.

Both the turbine and generator will be designed to operate at 3600 rpm, with drive through the cold end of the turbine, permitting direct connection through a reliable solid type coupling.

Air to the compressor of the combustion turbine will be ducted axially in an elevated system over the generator to a top oriented inlet to the compressor. The duct system will contain the necessary acoustic treatment for airborne noise emitted from the duct opening and radiated noise transmitted through the duct walls.

In addition, the inlet air duct system will be fitted with an inlet air filter and an evaporative air cooler. These two (2) auxiliary appurtenances can have a major effect on maintaining a high operating plant efficiency.

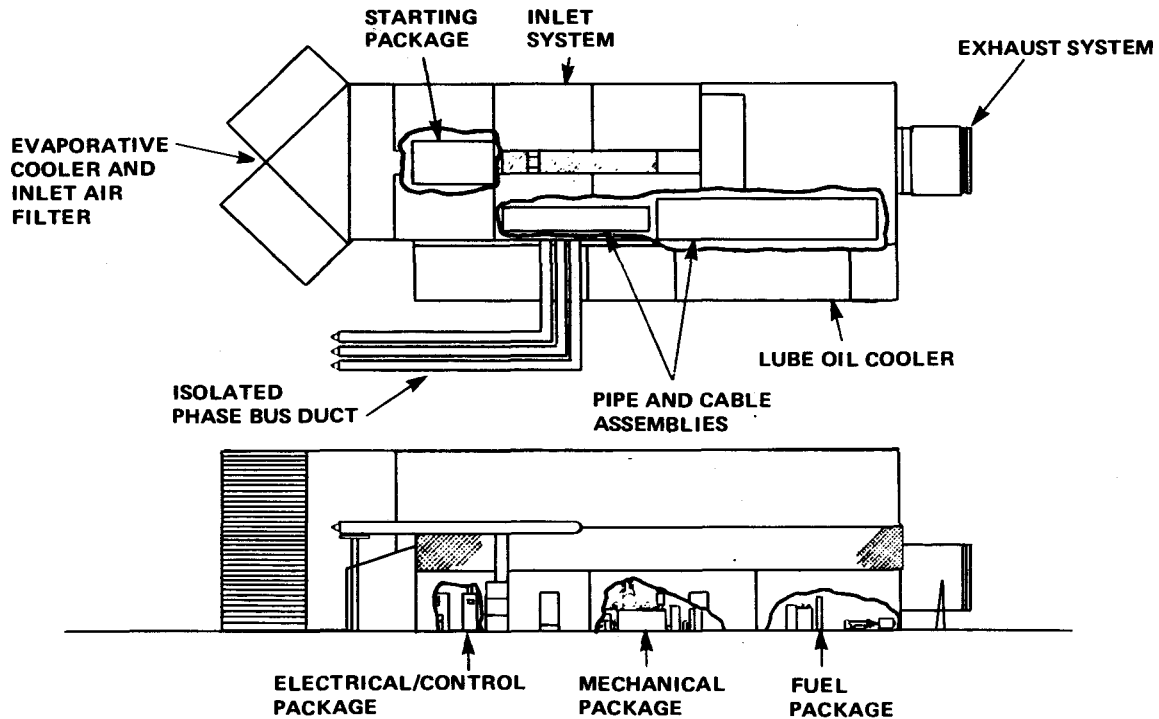


Figure 5.1-1

The primary function of the inlet air filter is to prevent duct particles and other air-borne impurities from entering the machine.

The original concern of dust and impurities entering the machine was that they would collect on the blading of the axial flow compressor, causing fouling and a significant deterioration of power output. When internal cooling air passages in turbine vanes and blades were introduced on turbines having higher firing temperatures, the concern for air cleanliness became even greater. Fouling or plugging of cooling passages in the turbine area can lead to metal hot spots and eventual mechanical failure.

On Westinghouse turbines, the cooling air flow for critical passages is taken from the compressor discharge external to the machine for cooling, and since the mass flow is small relative to the compressor intake flow, it is filtered independently of the compressor inlet air. This arrangement had the following advantages for both the user and the manufacturer:

1. Cleanliness to the cooling air system was insured, even without an inlet air filter installed.
2. Redundancy and an even cleaner cooling air system would result on machines having an inlet filter.

3. Partial restoration of power lost due to compressor fouling is possible by injecting a dry agent, such as ground pecan shells, into the air stream of the operating unit. The separate turbine cooling air filter permits this procedure without adverse effect to the cooling system.

Turbines operating at the higher firing temperatures become more susceptible to corrosion attack by the alkaline metals, sodium and potassium. It is necessary to control the quantitative amount of these elements in the turbine through fuel oil selection and/or treatment and filtering of the inlet air for base load applications.

More recently, with operating time on the latest generation of turbines increasing and turbine conditions being examined, there is the possibility of even other airborne contaminants causing corrosion of turbine hot parts. It is important to include the inlet air filter in the basic plant design.

As there are many choices of filter media having a wide range of efficiency, the media can be selected to suit the site ambient and/or operating limits as they may dictate.

The evaporative air cooler reduces the high ambient temperature effect on the combustion turbine power output (10% for a 20°F temperature change) by humidifying the inlet air and lowering its temperature to within a few degrees of the ambient wet bulb temperature. When operating, the evaporative cooler also acts as a water wash type filter to the incoming air.

The turbine will be fitted with a combustion system (piping, nozzles and combustors) capable of burning both the primary low-btu gas and the backup distillate oil without a physical equipment changeover.

The exhaust gases from the turbine will be ducted axially to the HRSG, thus keeping duct pressure drop losses to a minimum. Included as part of the ducting is an expansion joint, that permits independent thermal growth of the turbine and ducting, without exceeding mechanical stress limits of either one.

Because of the inherent capability of the combustion turbine to develop more power at reduced ambients, the design of the turbine and generator will permit an excess of ISO rating to be generated without exceeding mechanical and thermal limits.

The generator will be a conventionally hydrogen-cooled machine packaged to minimize field installation time. In addition to the hydrogen gas system, a carbon dioxide system is provided to permit safe purging of the generator, as required.

The hydrogen and carbon dioxide systems are mounted in an auxiliary control enclosure on the side of the generator. This subassembly is factory assembled, but shipped separately.

The exciter for the generator will be of the brushless type, consisting of three (3) major components. These are: the permanent magnet generator, the ac exciter, and the rotating rectifier. These components are all mounted on a single shaft in an "exciter package", located on the starting equipment end of the generator.

Isolated phase bus duct will be used to carry the electrical energy from the generator out to the switchyard. The bus duct will be connected to top-mounted bushings at the generator and will then be directed out to the side of the machine before turning axially toward the switchyard. This arrangement minimizes possible interference when maintenance is performed on the starting package, exciter or generator.

The packaging (maximum factory assembly) will be done within the limits of rail transportation, but most importantly, will be designed, so as to minimize package interfaces and maximize functional or fluid system factory testing of individual packages.

Each package assembly has an enclosure complete with access doors, lighting, heating and ventilation. The turbine unit will also be housed in a field erected enclosure.

Even though the turbine, generator and their associated auxiliary packages will be installed within a large central turbine-generator room, the individual enclosures serve several important functions.

1. They provide an acoustic barrier for radiated noise being emitted from operating equipment.
2. They allow for separate environment control, unique to the equipment enclosed.
3. On factory assembled packages, the enclosure serves as a shipping container.

An optional Halon gas fire protection system will be designed into each enclosure, with the exception of the starting package. This type of system suppresses flame, while maintaining a life-supporting atmosphere, requiring no release time delay, as in other systems.

The major auxiliary packages of the combustion turbine-generator unit are:

Starting Package — This package has several functions with regard to the main turbine-generating shafting. First, it provides the breakaway torque necessary to accelerate the shafting from a standstill. Secondly, it provides the necessary torque to accelerate the shaft system to ignition and self-sustaining speed of the combustion turbine. Thirdly, it provides the torque necessary to slow roll the shaft system after a shut-down to prevent thermal distortion or bowing of the rotor shaft.

An additional starting function, that of supplying atomizing air to the fuel oil nozzles during the ignition period, is incorporated into this package.

The equipment necessary to provide these functions is assembled on a common steel fabricated bedplate and consists of: an electric motor, torque converter and hydraulic fluid cooling system, turning gear, clutch and atomizing air blower. The package will have its own electrical distribution system, requiring only a single AC and DC feeder source. Figure 5.1-2 shows the layout of this package.

Mechanical Package — This package assembles the lube oil system, generator seal oil system, a pressure switch and gauge cabinet assembly (part of the control system) and the dry chemical storage for the turbine exhaust bearing fire protection system, on a fabricated steel bedplate. The arrangement of the equipment is shown by Figure 5.1-3.

All components of the lube oil and generator seal oil system are mounted internally to the package, except the lube oil cooler. This shell and tube cooler will be mounted horizontally on the roof of the package. Its location will not interfere with the vertical removal space required for maintenance on the vertical reservoir mounted lube oil pumps.

The pressure switch and gauge assembly houses in a central cabinet, pressure gauges, pressure regulators, switches, transducers for the display and control of the various unit-related fluid systems. It serves as the interface panel between fluid and electrical control signals.

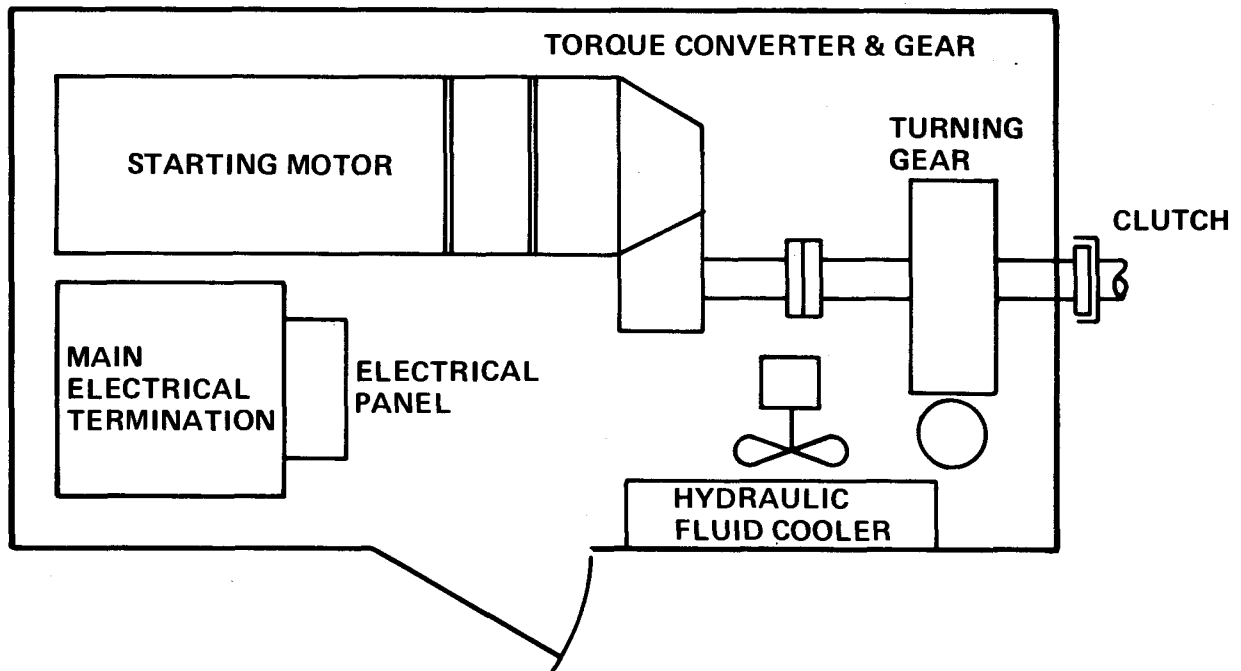
Space within this package will be set aside so that water or steam injection equipment for NOx emission control can be added, should it be necessary.

Fuel Package — It is intended for this package to have assembled within it, all of the major components of the fuel systems. This would include all filters, valves, pumps, interconnecting piping, associated controls and interconnecting conduit and tubing.

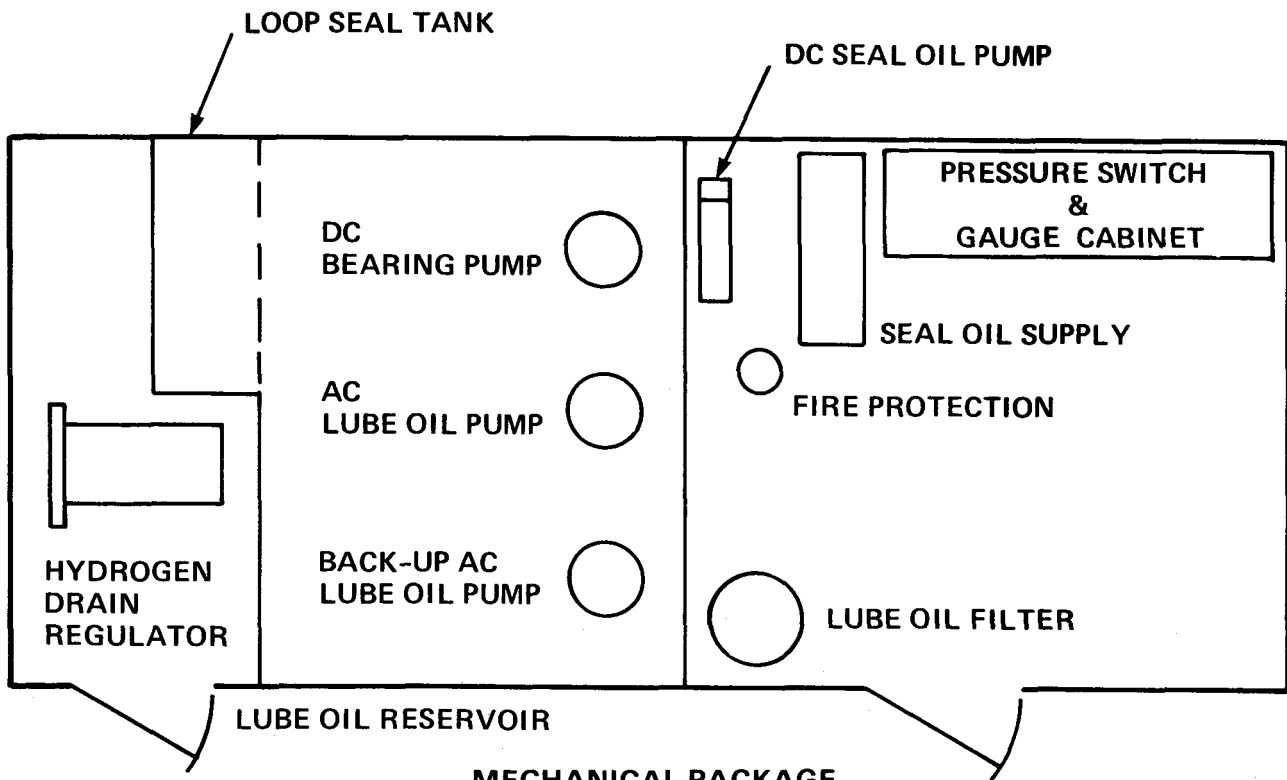
It is advantageous to group the fuel systems in a separate package, so as to minimize and simplify gas detection systems, fire protection systems and the classification of associated electrical equipment, as required by code or desired by the customer.

With the primary fuel being the low-Btu gas, a large diameter (24 inch) transport system of pipe and valves will be required. Also, with the fuel gas being delivered from the gasifier at a temperature of approximately 600°F, the line and valves must be insulated to minimize heat loss and to provide personnel protection. Thermal expansion of the line plus valve selection considering line size, temperature, and pressure drops, will all receive special attention.

In the final plant design and pipe layout, it may be determined that it is economically desirable to remove the gas system from this package and route it as an independent line for field installation.



STARTING PACKAGE
Figure 5.1-2



MECHANICAL PACKAGE
Figure 5.1-3

Unit space heaters will not be included in this package, as the installed components are not sensitive to freeze conditions. Electrical heat tracing will be installed on the fuel oil lines to maintain acceptable line viscosity under low ambient conditions.

Since the only heat source in this package during operation is the primary fuel gas line, temperature control within the enclosure is more easily maintained and less subject to a rapid escalation in the event of a ventilating fan or power failure than that of the turbine enclosure. As this package adjoins the turbine enclosure, it is a more suitable location for the Halon gas fire protection spheres of the turbine enclosure.

Space only will be provided in this package for additive injection into the liquid fuel system for control of opacity of the exhaust stack gases should it become necessary for any reason in the future.

Electrical and Control Package — Assembled on a common bedplate are the major electrical and control components of the unit. These items include the AC and DC motor control centers, the generator voltage regulator, protective relay panel,

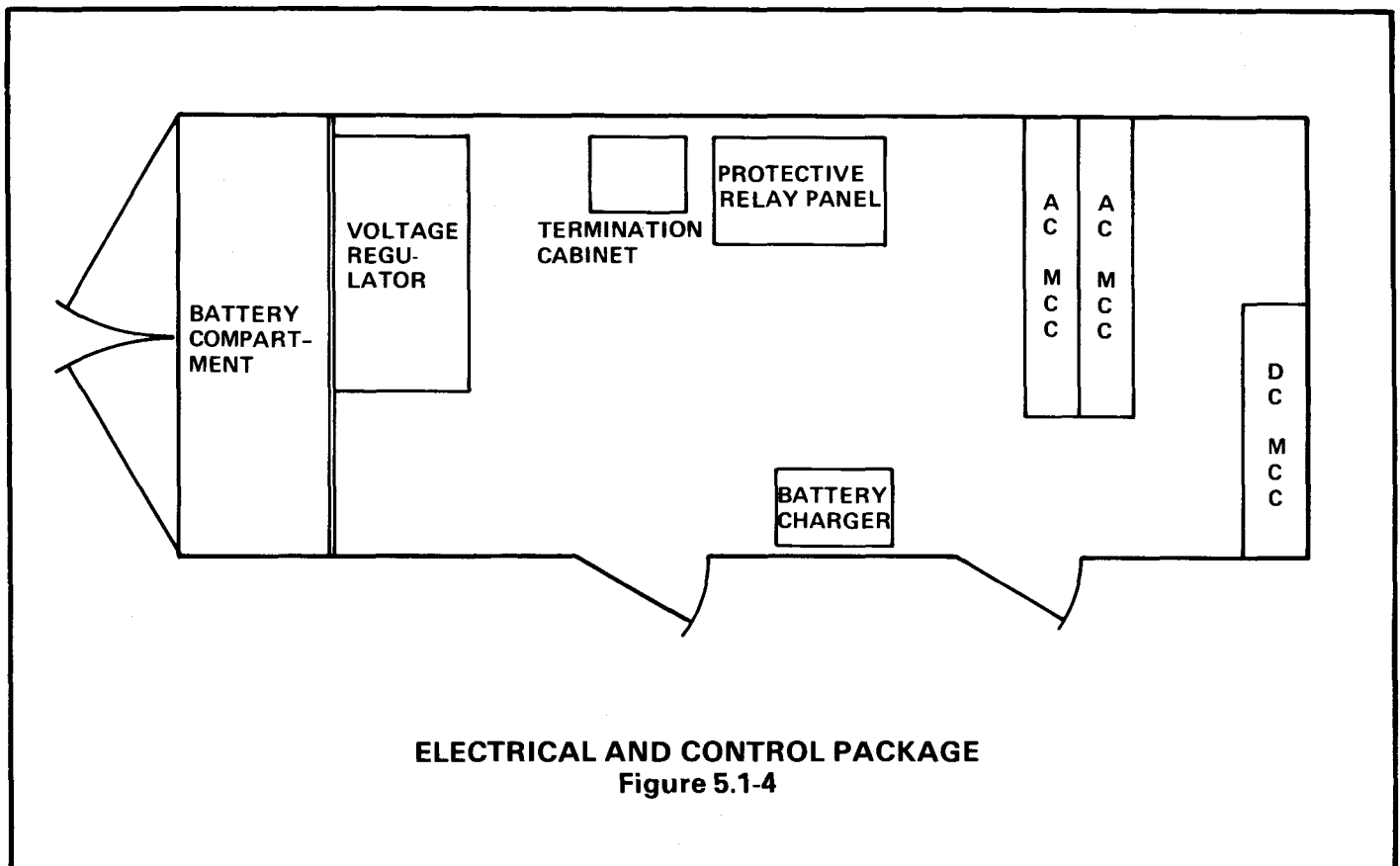
emergency batteries for the unit, along with a rectifier battery charger and an interface panel for making the control connections to the central control room.

The AC and DC motor control center houses the breakers, motor starters, overload protection and relays necessary to interface the various auxiliary loads of the plant with the main control system.

The voltage regulator, part of the generator excitation system, is a static system used to control the excitation of the brushless shaft driven exciter, thus the output of the generator. Although located in the package, the regulator control mode (manual or automatic) and the necessary raise-lower control functions will be selected at the central control panel.

The protective relay panel mounts the relays required to properly protect the generator from an electrical malfunction. This includes: generator differential, generator ground fault, negative sequence, overcurrent, and reverse power relay. The panel is designed, however, to accommodate additional protective relays, such as, transformer differential, voltage balance and/or loss of field relays. Relay trips will be displayed locally by the respective relays and will also be annunciated in the central control room.

The electrical equipment installed in this package is sensitive to climatic conditions, such as temperature changes, humidity, and dust. Therefore, the atmosphere within this package will be controlled by the use of air conditioners and electric space heaters.



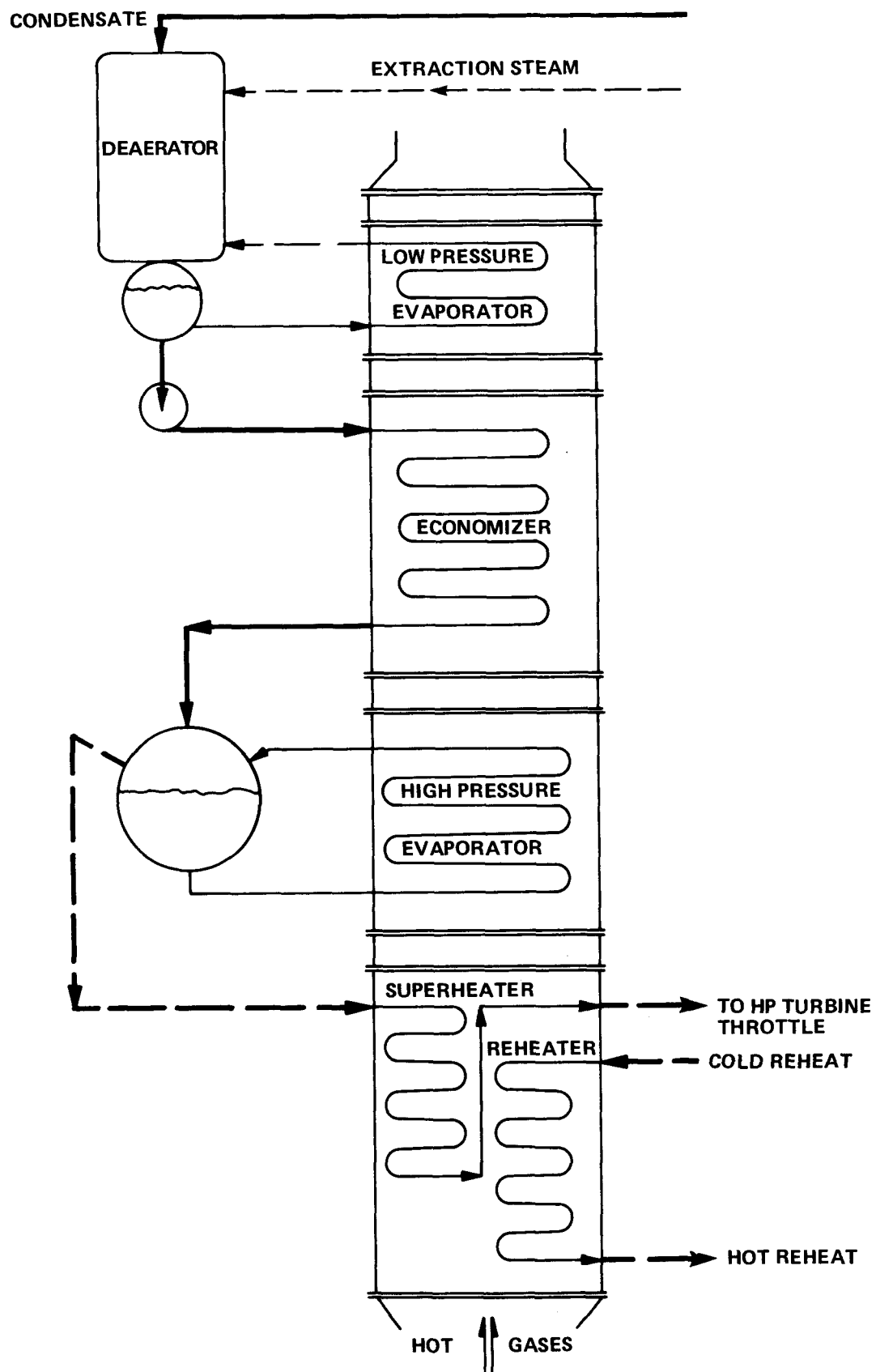
5.2 HEAT RECOVERY STEAM GENERATOR (HRSG)

The HRSG will receive its energy input from the combustion turbine in the form of hot exhaust gas. The gas will be at the temperature as discharged from the turbine, and will not receive any additional energy through supplemental firing.

The function of the HRSG is to recover this otherwise lost turbine exhaust energy and transform it into steam and heated feedwater through appropriate heat transfer surface for ultimate use in the steam turbine.

For this study, a forced circulation type HRSG will be used for rapid load follow and more effective factory packaging of the tube surface.

Gas flow from the turbine will enter the HRSG axially and be directed upward to the heat transfer surface by turning vanes. The heat transfer sections of the HRSG will have horizontal tubes of serpentine design with the sections stacked in a vertical gas flow path. A schematic arrangement of the HRSG is displayed in Figure 5.2-1.



.HRSG
Figure 5.2-1

The high pressure steam drum will be vertically oriented and fitted with internal moisture separators to prevent carryover into the superheater. The low pressure evaporator will be connected to a storage drum and deaerating feedwater heater assembly. Steam extraction from the steam turbine will maintain the energy balance in the deaerator.

Separate motor-driven circulating pumps in each of the high and low pressure evaporator circuits will move the water from the drums into the respective evaporator sections. The boiler feedpump takes its suction from the low pressure storage drum.

As the heat transfer process on the water side of the evaporator section is isothermal, the log mean temperature difference is the same for a counterflow or parallel flow design. The design will be parallel flow to permit operation at part loads under natural circulation in the event of a circulating pump malfunction.

A complete water management analysis of the HRSG system must be part of the detail design process under all operating modes to insure proper equipment sizing and selection. Areas having particular interest are:

1. Control of drum swell upon startup. This includes sizing of the drum and blowdown systems; selection of drum level controls and the feedwater valve; and establishment of proper operating sequence of pumps and valves.
2. High pressure circuit circulation rate. Circulating pump selection, along with sizing of the pipe system and installed components, must provide proper circulation rates at all times to prevent "boil dry" situations.
3. Control of the boiler feedpump NPSH particularly during a hot, ready-to-start condition. This includes providing a means of maintaining pressure in the deaerating-low pressure drum by high pressure steam addition and shutoff of condensate flow to reduce chilling of the drum water.
4. Maintaining a minimum evaporator tube (low pressure) surface temperature so as to avoid the sulfur dewpoint during all phases of operation.
5. Feedwater flow control of the economizer sections to avoid excessive steaming conditions at any operating points.
6. Failure analysis of water and steam circuits to insure compliance with ASME codes for proper relief devices.

The HRSG will match the operating modes of the plant and the combustion turbine without exceeding operating limits of any components or the system, as a whole. Where an operational limit of a component is approached, a control interface is established so as to realign systems to permit continued operation within limits.

The total exhaust gas flow of the combustion turbine will pass through the HRSG. Bypass stacks and associated louvres or dampers will not be employed. The simple straight through gas flow holds performance at the highest level, since leakage, characteristic of the bypass arrangement, will not exist.

The HRSG will normally be operated in the wet (full of water) condition. During certain standby conditions, it will be desirable to retain heat in the HRSG for a hot, ready-to-start condition, or, for freeze protection. To this end, the exhaust stack of the HRSG will be fitted with a motor-operated, open-closed cover.

To minimize corrosion of the internal dry surfaces during short, idle periods when the HRSG is full, or in prolonged periods when it is drained and empty, an inert gas system will be used. Pump seals and valves within the system, protected by the inert gas, will be selected, keeping in mind secondary leakage of the inert gas, and that it must be minimal.

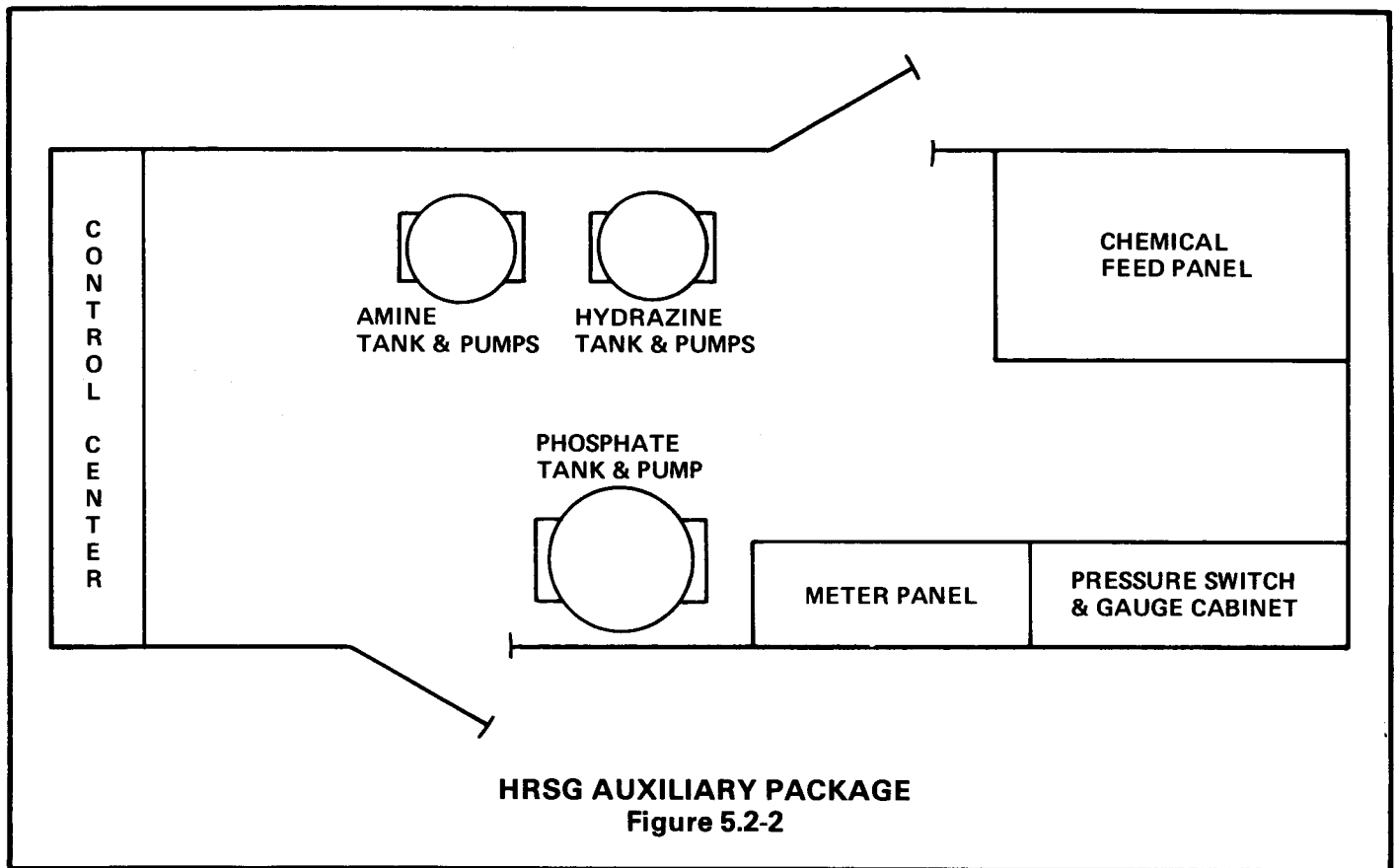
Access ladders, platforms and walkways are provided to permit operator access to all elevated operating components.

The design of the HRSG follows the packaging philosophy used throughout the plant. This includes maximum factory pre-assembly of ductwork and breaching between the turbine and HRSG inlet; the tubed heat transfer sections; the exhaust stack; steam drums; and, an auxiliary package.

The HRSG auxiliary package contains associated systems and equipment having numerous, mechanical and electrical interconnections between components within the system, making it desirable for factory assembly and check-out. Further, many of the components and systems are sensitive to the hot environment near the HRSG and/or to freezing, making a controlled environment installation an operational advantage. A typical arrangement of the equipment in this package is shown in Figure 5.2-2.

The principal system assembled into the HRSG auxiliary package is the chemical feed system. The purpose of this system is to monitor boiler water and chemically treat it to maintain the required water chemistry. The system is comprised of sample coolers, an instrument panel, chemical tanks and injection pumps. Also included in the package is a pressure switch and gauge cabinet, which houses the pneumatic, hydraulic and electrical control devices for the HRSG; a meter panel to indicate steam and condensate flows for each HRSG; and a control center for the distribution of electrical power and control of auxiliary loads associated with the HRSG.

Environmental control of this package will be provided by a weathertight enclosure, containing thermostatically operated ventilation fans and electric space heaters.



Package fabrication will include:

1. Open floor grating to permit heating of space below floor level containing fluid lines.
2. Equipment drains manifolded to a single floor drain point.
3. Isolating partition and floor splash plate to prevent moisture from entering electrical control center.
4. The emergency chemical contamination shower will be located external to the package, so as to avoid interference with internally-installed electrical apparatus.

5.3 STEAM TURBINE, GENERATOR AND EXCITER

The steam turbine generator unit will be axially arranged on a common shaft system. The steam turbine will be a three (3) case unit, having a common high pressure-intermediate pressure cylinder, and two (2) low pressure cylinders, each having two (2) sets of exhaust blading. This type unit is known as a tandem (in-line) compound (more than one cylinder) quadruple exhaust condensing reheat unit.

The high-pressure-intermediate pressure turbine is of the combination impulse and reaction type. The steam enters the high pressure element through two throttle valve steam chest assemblies, one located at each side of the turbine. The steam chest outlets are connected to the H. P.-I. P. casing through inlet sleeves, each connected to its nozzle chamber by a slip joint. Half of the inlet sleeve connections are in the base and half are in the cover. The steam passes through the impulse stage and high pressure blading to the reheater, through two exhaust openings in the outer casing base.

The steam returns from the reheater to the intermediate pressure element through two interceptor-reheat stop valve assemblies, one located at each side of the turbine. The four outlets of these valve assemblies are connected to the I. P. casing inlet sleeves which are connected to the inner casing by slip joints. The steam passes through the intermediate pressure element reaction blading to two exhaust openings in the outer casing cover. Each of these exhaust openings is connected through a separate crossover pipe to an opening in the casing cover of one of the low pressure turbines. A pressure balance expansion joint is provided at the low pressure turbine end of each crossover pipe to accommodate the thermal expansion of the crossover pipe and at the same time balance the internal pressure force.

Each double flow low pressure turbine is a straight reaction double flow type element with steam entering at the center of the blade path and flowing toward an exhaust opening at each end, then downward into a combined exhaust into the condenser.

Openings are provided in the casings through which steam is extracted for feedwater heating.

The unit is provided with two steam chest-throttle valve assemblies, one located at each side of the turbine casing. Each steam chest contains four plug-type governing valves which are controlled by an electric hydraulic governing system through individual servo-actuators, one mounted on each governing valve. The throttle valves, which are located horizontally at one end of each steam chest are also controlled by servo-actuators.

The generator driven by the steam turbine will be a hydrogen inner-cooled machine with an air-cooled brushless exciter. With the inner cooled generator, hydrogen gas is circulated through openings in the rotor and stator coils to improve the dissipation of the heat generated. This is in addition to the cooling of the stator laminations and the rotor forging and end turn retaining ring found in the conventionally cooled machine.

The brushless exciter and the hydrogen and carbon dioxide gas systems will be the same as those for the generator used with the combustion turbine.

The steam turbine and the generator and exciter will be factory assembled as required to establish and verify operating clearances. Due to the physical size of the assembled equipment exceeding shipping limits, it will be necessary to ship subassemblies to the installation site for final assembly.

At points where the rotor penetrates the outer cylinders, some means is needed to prevent leakage of air into or steam from the cylinders. Glands, with their labyrinth type seal rings, and the gland sealing steam system are provided to perform this function. The gland sealing steam system contains the valves to regulate sealing steam pressure to the glands, and a desuperheater, to control sealing steam temperature to the glands of the low pressure turbine.

Air-operated drain valves are provided for the main inlet steam piping, the first-stage chamber, the HP-IP outer cylinder and the reheat-inlet steam piping drain systems. These valves will be operated automatically through the various operating modes to insure that no water enters the turbine.

The exhaust of the low pressure turbines will have a spray water system that will prevent overheating of the turbine exhaust from low speed operation up to approximately 10 percent load. This spray system will also be used to control exhaust temperature when large amounts of steam are being bypassed directly to the condenser.

The steam turbine will be limited in operating conditions to the following:

1. The turbine will be designed with a 5% throttle flow margin above the flow required to meet the maximum rated output with extraction points in service. This procedure is standard in allowing for manufacturing tolerances.
2. With governing valves wide open and the extraction points in operation, the turbine will safely operate at 105% of its rated throttle pressure.
3. The maximum operating exhaust pressure is 5" Hg absolute.
4. The limiting exhaust casing temperature is 250 degrees Fahrenheit.

There are two fluid systems provided for the operational control of the steam turbine-generator unit, the electro-hydraulic (EH) fluid system and the lube and seal oil system. Each system is separate and individual, but is interlocked through an interface emergency trip valve to insure a unified effective trip system.

The function of the EH high pressure fluid system is to provide a motive force for positioning the turbine steam valves in response to an electrical control signal.

The lube and seal oil system satisfies the requirements for bearing lubrication and the generator hydrogen seals. In addition, this system provides the medium to hydraulically operate the mechanical overspeed trip mechanism and manual trip lever.

Due to the physical size of the lube and seal oil system, packaging and shop assembly of this system to the same degree as was done on the combustion turbine units is prohibitive. Therefore, design effort will focus upon a minimum of subassemblies for minimum interfacing. Major lube system subassemblies will include the lube oil reservoir which mounts the main oil pump ejector, backup and emergency lube oil pumps, backup seal oil pump-vapor extractor and associated interconnecting pipe; and the shell and tube, oil to water lube oil coolers.

A common fabricated base assembly will contain the remaining auxiliary mechanical equipment. This equipment includes the EH high pressure fluid system, seal oil system, steam turbine and condenser pressure switch and gauge assemblies and the chemical feed system for treating the condensate.

A typical skid arrangement of this equipment is given in Figure 5.3-1. The high working pressure of the EH system necessitates the use of a synthetic fluid. The fluid is stored in a stainless steel reservoir assembly, upon which is mounted a duplicate system of fluid pumps, controls, filters and heat exchangers. The system is so arranged that one pump and one set of the various control components function, while the duplicate set serves as a standby system.

On generating units of this size, it is more desirable to have seal oil conditioning separate from the bearing oil supply because of the relative fluid demands (quantity, pressure and temperature) between the bearing and hydrogen seals.

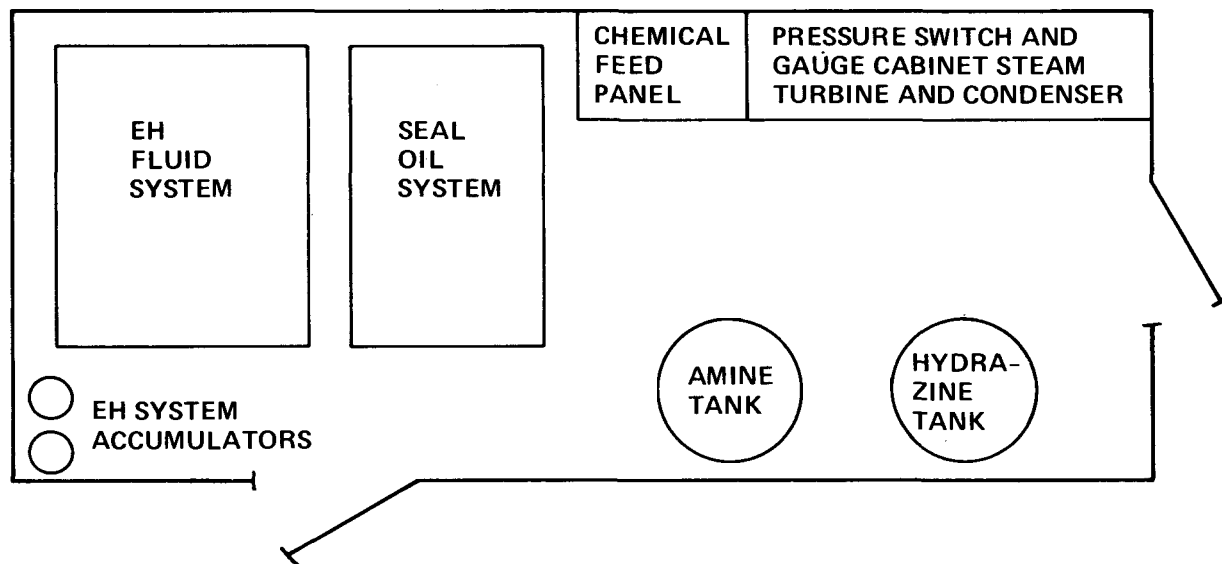
The generator hydrogen seal oil system consists of booster pumps, coolers, filters, and regulating valves. This system receives oil from the lube oil system and conditions it to the temperature and pressure requirements of the shaft seals.

A combined steam turbine-condenser pressure switch and gauge assembly mounts in a central cabinet housing pressure gauges, regulators, switches and transducers for the display and control of the related fluid systems. A bulkhead will be provided for fluid connections, and a terminal board for all external electrical connections.

The amine and hydrazine chemical solution tanks and pumps used for treating condensate pumped from the condenser hotwell will also be mounted and interconnected on this auxiliary assembly. A separate control panel for use with the chemical treatment will be mounted on the skid so as to give local visibility and control.

An enclosure containing lighting, heating and ventilation will house the above auxiliary equipment. Provision will be made to add a Halon gas fire protection system as an option.

An electrical and control package essentially a duplicate to that provided on the combustion turbine-generator, and described earlier, will also be provided for the steam turbine generator.



STEAM TURBINE AUXILIARY PACKAGE

Figure 5.3-1

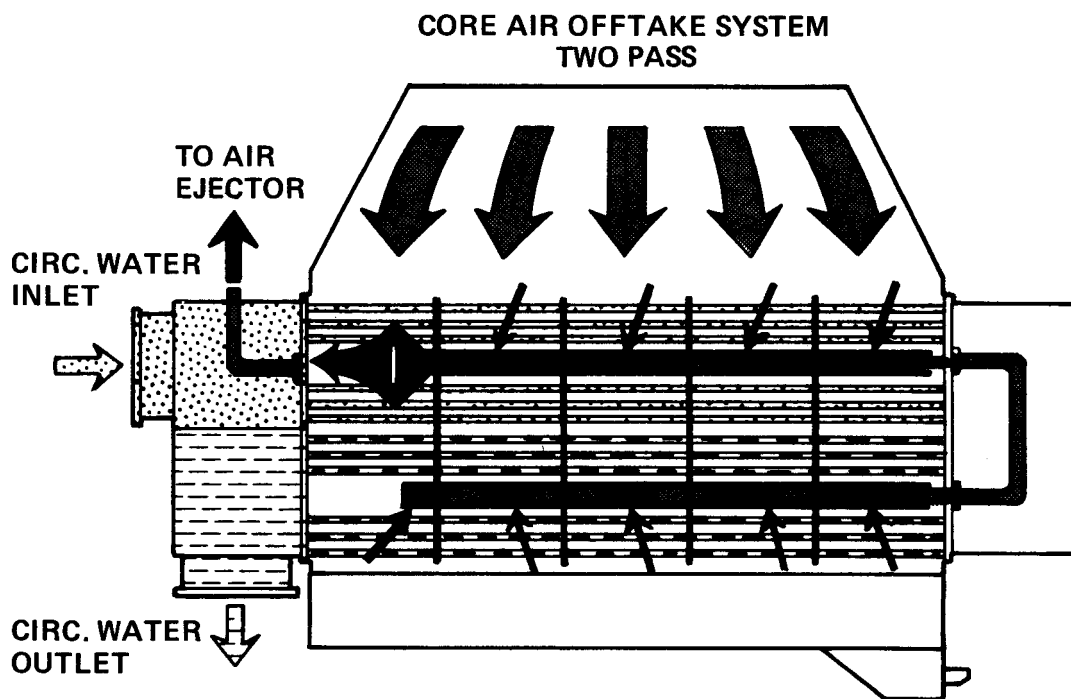
5.4 MAIN CONDENSER AND CONDENSATE PUMPS

The condenser will consist of two (2) sections (tubes horizontal and normal to turbine axis) each floor-mounted beneath an exhaust opening of the steam turbine. Connection to the exhaust cylinders of the steam turbine will be through expansion joints, allowing independent thermal movement of each without exceeding mechanical limits. The tube bundles will be arranged using the Westinghouse radial flow concept, assuring an evenly distributed steam flow pattern radially inward to the core. With an air offtake located in the core, equal venting of all portions of the tube banks is thus assured.

The mixture of air and steam reaching the core enters the air offtake pipe through orifices carefully sized to control the venting along the length. Air and gases flow through the vent pipe to the cold end where a baffle arranged transversely to the flow causes the vent mixture to cross several rows of the coldest tubes before it enters the offtake pipe leading to the air ejectors.

This final pass over the coldest tubes reduces the amount of steam in the vented gases to a minimum.

This air offtake system is illustrated in Figure 5.4-1. Another important function of the condenser is to insure that the leaving condensate is free of dissolved gases, particularly oxygen, which can cause corrosion in other parts of the cycle. Since the quantity of gas that a liquid can hold in solution depends on the nearness of the liquid



TWO-PASS RECTANGULAR SURFACE CONDENSER
Figure 5.4-1

temperature to its saturation temperature, if there is no subcooling, there can be no gas. Therefore, the condensate formed must be as close as possible to the saturation temperature. The radial flow design provides this capability.

There are two (2) condenser arrangements available with regard to circulating water flow. First, there is the single pass design where the circulating water from the balance of plant enters one end of the condenser, passes through the tubes and exits on the other end. Then there is the two (2) pass condenser, where the circulating water passes through the upper half tubes of the bundle in one direction and then reverses its flow through the lower tubes before exiting.

Further, two (2) single flow condensers can be connected to the circulating water system for either parallel or series flow. The series flow arrangement produces a difference in operating vacuum of the two (2) condensers and likewise the connected LP turbines due to the entering water temperature.

There are technical considerations associated with each arrangement, with each having an economic value for final optimization of the heat rejection system.

This analysis was performed in the ECAS advanced steam cycle study and a two (2) pass condenser was selected for use on an equivalently rated steam unit. The condenser used in this plant will therefore be of the two (2) pass design, connected for parallel circulating water flow. Manholes will be provided in the waterboxes and shell, permitting maintenance access to the tubes and hotwell. A crossover duct will connect the condenser shells for equal vacuum operation. The condenser air offtakes, discussed earlier, are connected to steam driven air ejectors. A large volume hogging ejector is used for air removal and for establishing a vacuum during startup, while the primary ejectors are used to remove the air during operation. The exhaust of the hogging ejector will be directed to the atmosphere, since it has only limited operation. The exhaust of the primary ejectors is directed to an air ejector condenser, where the latent heat of condensation is transferred to the condensate coming from the hotwell.

The condenser shells will be provided with auxiliary connections as follows:

1. A connection for steam bypassed from the turbine.
2. A breakable diaphragm as an emergency limit to the exhaust pressure imposed on the steam turbine and condenser.
3. Drain and vent connections as required by the steam turbine. Connections with a fluid temperature above 650°F will be connected by a thermal sleeve.

Waterboxes will be divided so as to allow tube cleaning, inspection and repair, if necessary, by reducing load rather than a total unit outage. In addition, the hotwell

of each condenser will be divided to assist in locating tube leakage. This is accomplished by taking conductivity readings in the line from each hotwell compartment to the condensate pumps.

Each condenser section will be factory assembled, with the tube bundles shipped as an assembly. The condenser shell will be shipped in pre-fabricated sections for final field assembly and welding.

The condensate pumps will be motor-driven centrifugal pumps of the vertical can type. Three (3) 50% capacity pumps will be installed, with one of the pumps being a backup. The characteristic head curve of each pump will be identical and each will be capable of parallel operation. Each pump will be fitted with a washable suction strainer and a discharge check valve, the installed elevation of the latter being below the hotwell condensate level assuring full lines to the idle pump(s) and avoiding liquid surges on start-up.

5.5 FEEDWATER HEATING

Condensate pumped from the condenser hotwell to the HRSG recovers energy from the steam used to power the air ejectors and to seal the glands on the steam turbine shafting. This is accomplished by passing the condensate through two (2) separate series connected heat exchangers - the air ejector condenser and the gland steam condenser.

In addition, since there is insufficient energy in the HRSG exhaust gases above the 280°F minimum stack temperature to heat the incoming condensate flow of the HRSG, it is necessary to extract steam from the steam turbine at the operating pressure of the deaerator. This higher pressure extraction steam flow can be reduced by adding a feedwater heater operating at a lower steam extraction pressure. The addition of a feedwater heater to the cycle improves overall performance.

The air ejector condenser will be of the shell and tube design, with the condensate passing through the tubes. The condenser will have a trapped drain allowing the collected condensate to be returned to the main condenser hotwell. The condenser will have an orificed vent for operating at atmospheric pressure.

The gland steam condenser construction will be similar to that of the air ejector condenser. A motor driven exhaustor, connected to the shell side of the gland condenser, removes the air and other non-condensable vapors that have leaked through the glands, and discharges them to the atmosphere. This condenser must operate at a sufficient vacuum so as to maintain the slightly sub-atmospheric pressure at the glands. The drain of this condenser is also trapped, and the condensate returned to the main condenser hotwell.

The low pressure feedwater heater raises the temperature of the condensate going to the HRSG by absorbing heat from low pressure steam extracted from the steam turbine. To maximize the energy transfer, the feedwater heater will contain a drain cooler, thus recovering sensible heat in the hot condensate of the extracted steam. The drain cooler will have a 10°F approach to the entering condensate temperature. The feedwater heater will be a two (2) pass, horizontal shell and tube type heater suitable for being located in the condenser neck. To minimize air-in leakage, the shell will be of welded construction with no flanged joints.

All heat exchangers will be constructed in accordance with the ASME Unfired Pressure Vessel Code, Section VIII.

5.6 BOILER FEEDPUMPS

The function of the boiler feedpump is to raise the pressure of the condensate flow to satisfy HRSG and steam system losses and yet produce rated throttle pressure.

Each HRSG will have a full capacity (approximately 25% of the steam turbine throttle flow) boiler feedpump which will take its suction from the storage tank of the deaerating feedwater heater and discharge the high pressure water for use in both the HRSG and the gasification system for the production of steam.

Each pump will be suitable for outdoor installation adjacent to the HRSG so as to minimize suction line losses. The net positive suction head (NPSH) of the pump will be sufficient to avoid cavitation under all modes of operation, which include steady-state and transient variations of suction pressure and temperature.

5.7 INSTRUMENT AIR SYSTEM

The instrument air system supplies the air used as the motive force and the control medium by the pneumatic valves throughout the power block. As a part of the control system, the instrument air supply will be dry, oil free, and obtained from an independent and reliable source.

The central source for all instrument air will be an air package. This package will be self-contained and capable of supplying all of the air required from its air compressors. This is necessary since no bleed air will be available from the gas turbine compressors when the plant is in a cold standby or ready-to-start operating mode.

The air package assembly is made up of two (2) independent systems; the instrument air system and the service air system. Each system is complete, with its own compressor, aftercooler, air separator and receiver tank. The instrument air system also has an air dryer, with a back-up to positively assure dry air in the event of a malfunction. Both systems will be interconnected to provide maximum operating

flexibility along with redundancy for the instrument air supply. These systems are described in greater detail in the plant reference design.

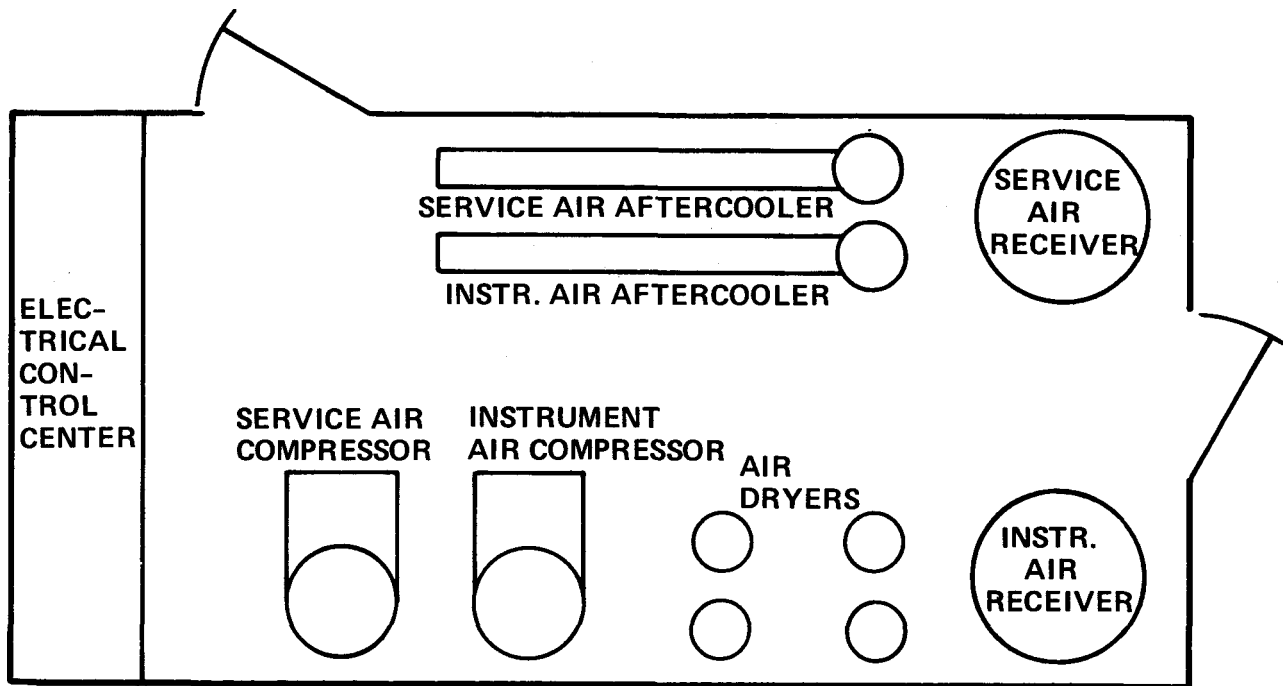
In addition to the air handling equipment, the air package assembly is completed by an electrical control center and an enclosure having lighting, ventilation and heating.

A typical equipment arrangement of the air package is given in Figure 5.7-1.

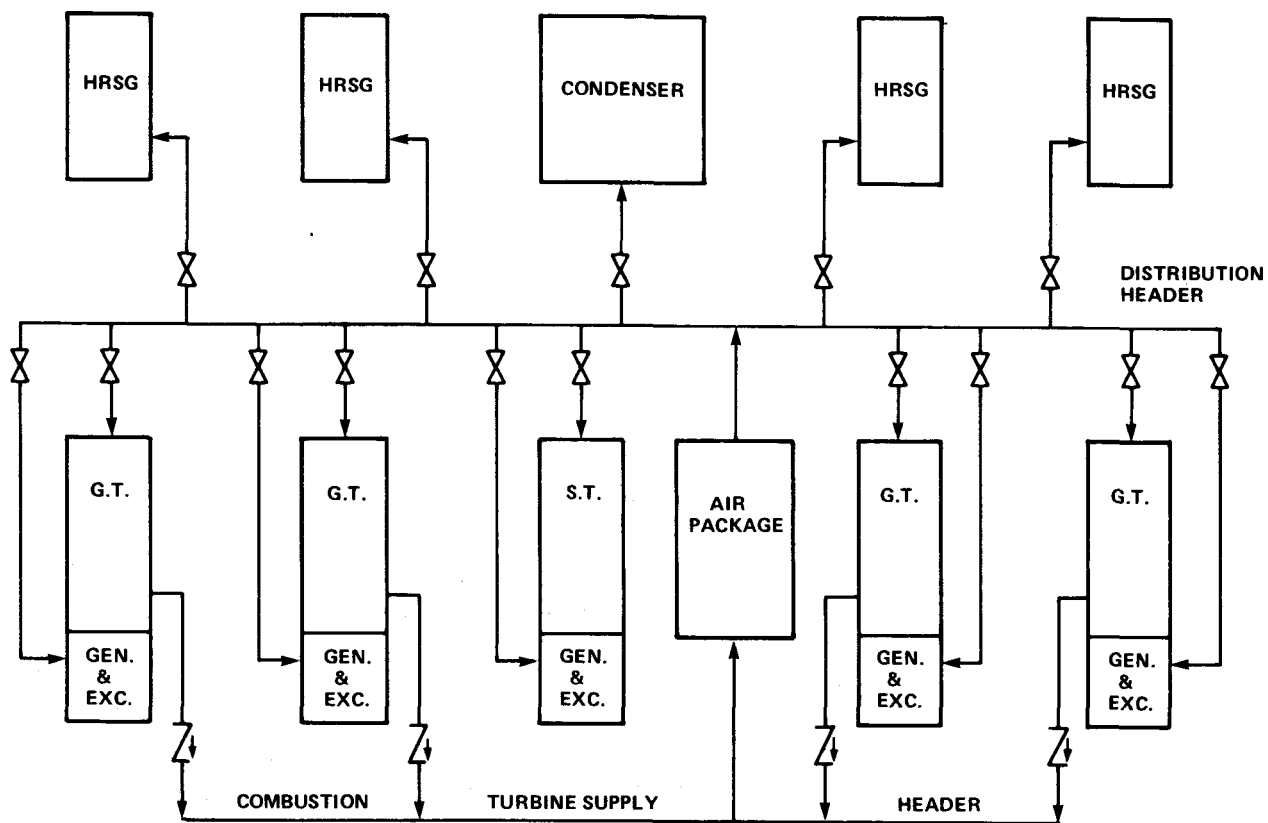
Since compressed air is part of the combustion turbine cycle, it will be used as the principal supply to the air package, when the plant is operating. This places the air package compressors in a standby condition. By manifolding the air supply from the combustion turbines to each of the air systems, the total operating air requirements will be shared by the operating units. This arrangement offers several steps of redundant supply.

Dry instrument air from the air package is delivered to the pneumatic devices of each major component from a distribution header. Shutoff valves for maintenance will be on each line from the distribution header. In addition, each pneumatically operated valve having a manual bypass will have shutoff valves in the pneumatic lines to permit valve maintenance. Piping or tubing used in the system downstream of the air package will be non-corrosive.

A schematic of instrument air within the power block is shown in Figure 5.7-2.



PLANT AIR PACKAGE
Figure 5.7-1



INSTRUMENT AIR SYSTEM
Figure 5.7-2

SECTION 6

BALANCE OF PLANT

The balance of plant includes the primary cycle auxiliary mechanical equipment and supporting subsystems necessary for the operation of the plant. Included is 1) the coal handling, receiving, storage, stacking, reclaiming, and crushing equipment; 2) distillate fuel oil receiving, storage and transfer equipment for gas turbine startup and shutdown, for auxiliary boiler, emergency diesel-driven generator and fire pump operation, and for station operation during construction of the gasification systems; 3) boiler feedwater storage and treatment equipment for maintaining water quality limits necessary for plant operation; 4) heat rejection equipment including cooling towers, circulating equipment, and chemical treatment equipment for algae control for both the main circulating and auxiliary cooling water systems; and 5) a waste handling system providing for the collection and disposal of ash, storm water, and other plant wastes.

6.1 COAL HANDLING

The primary fuel for the station is Illinois No. 6 Seam Marcoupin County BOM TP641 bituminous coal with an "as received" moisture content of 13% and a nominal size of 6 x 0 inches. The station full-load heat balance calculation shows the total coal usage rate is 708,302 lbs/hr (355 tons/hr).

The following assumptions were made in order to calculate the coal delivery technique and requirements.

- Station capacity factor equals 65%
- Delivery method by rail in either unit-trains or individual cars
- Car capacity equals 100 tons/car
- Average train speed equals 25 mph
- Distance from the point of origin of the train (coal mine) to the station equals 750 miles
- Coal loading time at the mine equals four hours maximum

- Coal unloading time at the site equals four hours maximum
- Average train downtime equals four hours

Based on the above assumptions, the coal is transported to the site by two unit-trains of approximately 83 railroad cars each. The total cycle time (time per round trip) for each unit-train equals 72 hours (three days). During normal unit-train operation, both trains arrive at the site once during each three-day period. Spare cars for the unit-trains are provided.

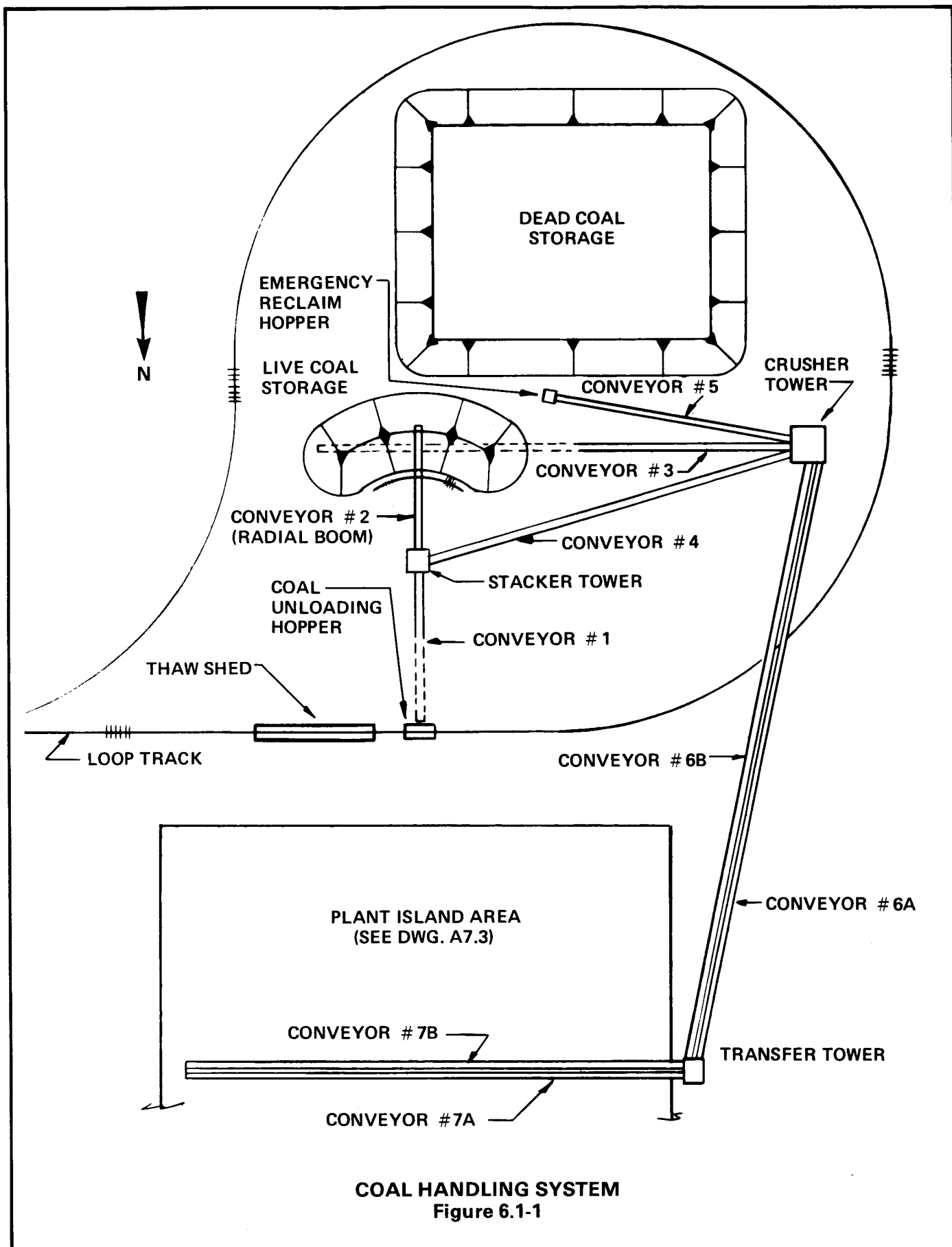
For unit-train operation, a loop track, thaw shed and unloading facility are provided at the site to assure continuous once-through operation. The loop track and the other major elements of the coal handling system are shown on the Plot Plan, Figure 7-1, and Figure 6.1-1 of this Section. The loop track and other railroad facilities are described in Section 7.1 of this Report. Based on the relatively short haul distance assumption of 750 miles from the mine to the station and the low annual coal usage of approximately 2,025,000 tons at the assumed station capacity factor of 65 percent, bottom dump coal unloading was selected over rotary-car dumping for the coal unloading facility. The thaw shed is provided for handling coal arriving in a frozen state.

Coal receiving, storage, stacking and reclaiming are described in Subsection 6.1.1 (following), of this Report. The equipment and coal storage areas for these services are also shown on the Plot Plan, Figure 7-1, and Figure 6.1-1, the Coal Handling System. Also selected, considering the relatively low usage rate, was the radial boom stockpile conveyor with telescopic chute for stacking out the coal, and the underground hoppers for reclaiming the coal from the live storage pile in lieu of a complex, rail mounted stacker/reclaimer machine.

Subsection 6.1.2 of this Report describes coal crushing, transfer and storage. Again the equipment for these services is also shown on the Plot Plan, Figure 7-1, and Figure 6.1-1, the Coal Handling System. Not shown are the coal hoppers at the gasification systems. The hoppers are the final coal storage point prior to pretreatment and gasification and are shown on the Plant Island General Arrangement and Elevation, Figures 7-2 and 7-3, respectively, and are described in the gasification system sections of this Report. Beyond thawing at delivery and crushing to a nominal size of 1/4 x 0 inches, no other coal pretreatment is provided in the coal handling system prior to delivery to the coal hoppers at the gasification systems.

6.1.1 Coal Receiving, Stacking, Storage and Reclaiming

As described in Subsection 6.1 of this Report, coal is delivered to the plant by unit-trains, each on the average composed of eighty-three 100-ton capacity bottom dump railroad cars.



As shown on the Plot Plan, Figure 7-1, and Figure 6.1-1, coal is unloaded into a receiving hopper, transported on Conveyor No. 1 to the Stacker Tower, and either stacked out to the live storage pile on Conveyor No. 2 or transported on Conveyor No. 4 directly to the Crusher Tower.

The coal receiving hopper has a storage capacity of 200 tons and is able to receive and handle precrushed 6 x 0 inch nominal size coal. The coal is fed from the hopper through two reciprocating feeders onto inclined belt Conveyor No. 1 at a maximum feed rate of 2500 tons per hour. The maximum feed rate of Conveyor No. 1 equals the estimated maximum coal delivery rate, based on assumptions in Section 6.1 of this Report. Conveyor No. 1 transports the coal to the stacker tower surge bin, and is equipped with a belt scale for continuous weighing and recording of coal quantities delivered to the station and a metal detector.

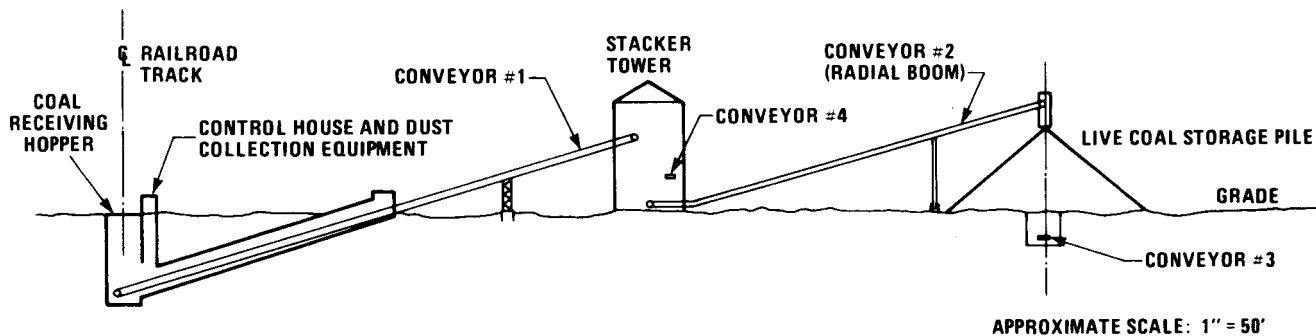
From the stacker tower surge bin, coal is normally fed onto Conveyor No. 2, the radial boom stockpile conveyor with telescopic chute, to be stacked out to the live storage pile. Conveyor No. 2 has a maximum feed rate of 2500 tons per hour, which is equal to the maximum feed rate for Conveyor No. 1. Conveyor No. 2 has a total span equal to 200 feet, based on a maximum conveying angle of 18 degrees, 40 percent of which is the cantilever span. From the stacker tower surge bin, coal can also be fed onto inclined belt Conveyor No. 4 for transport directly to the crusher tower.

The live coal storage pile is sized to supply the normal plant operating coal requirements between unit-train deliveries and equals approximately 25,000 tons of coal, the equivalent of three average unit-train deliveries or three days full-load station operation. The live coal storage pile configuration is based on a maximum pile height of 45 feet, a maximum angle of repose of 35 degrees, and a live coal storage unit weight of 50 pounds per cubic foot.

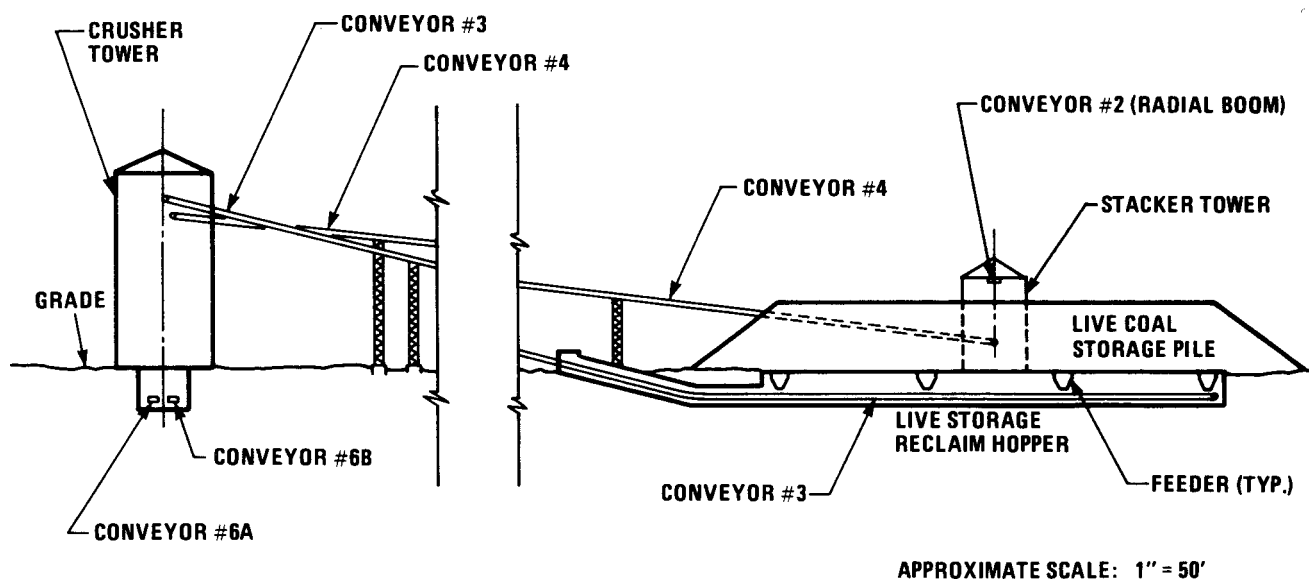
Adjacent to and south of the live coal storage pile is the dead coal storage pile, as shown in the Plot Plan, Figure 7-1, and Figure 6.1-1. The dead coal storage pile provides the coal supply for the plant during disruptions of normal unit-train delivery and equals approximately 330,000 tons of coal, the equivalent of 60 days station operation at a 65 percent capacity factor. The dead coal storage pile configuration is based on a maximum pile height of 40 feet of compacted coal, a maximum angle of repose of 35 degrees, and a compacted coal unit weight of 70 pounds per cubic foot.

Coal reclaiming equipment is shown on the Plot Plan, Figure 7-1, Figures 6.1-2, 6.1-3 and 6.1-4.

Figure 6.1-3 shows the stacker tower, live coal storage pile, inclined belt Conveyors Nos. 3 and 4 and the crusher tower. During normal station operation coal is fed by four vibrating feeders from the live storage pile onto Conveyor No. 3 and transported to the crusher tower. Conveyor No. 3 is rated at 710 tons per hour, twice the full-load plant firing rate, to allow scheduled downtime for equipment maintenance.

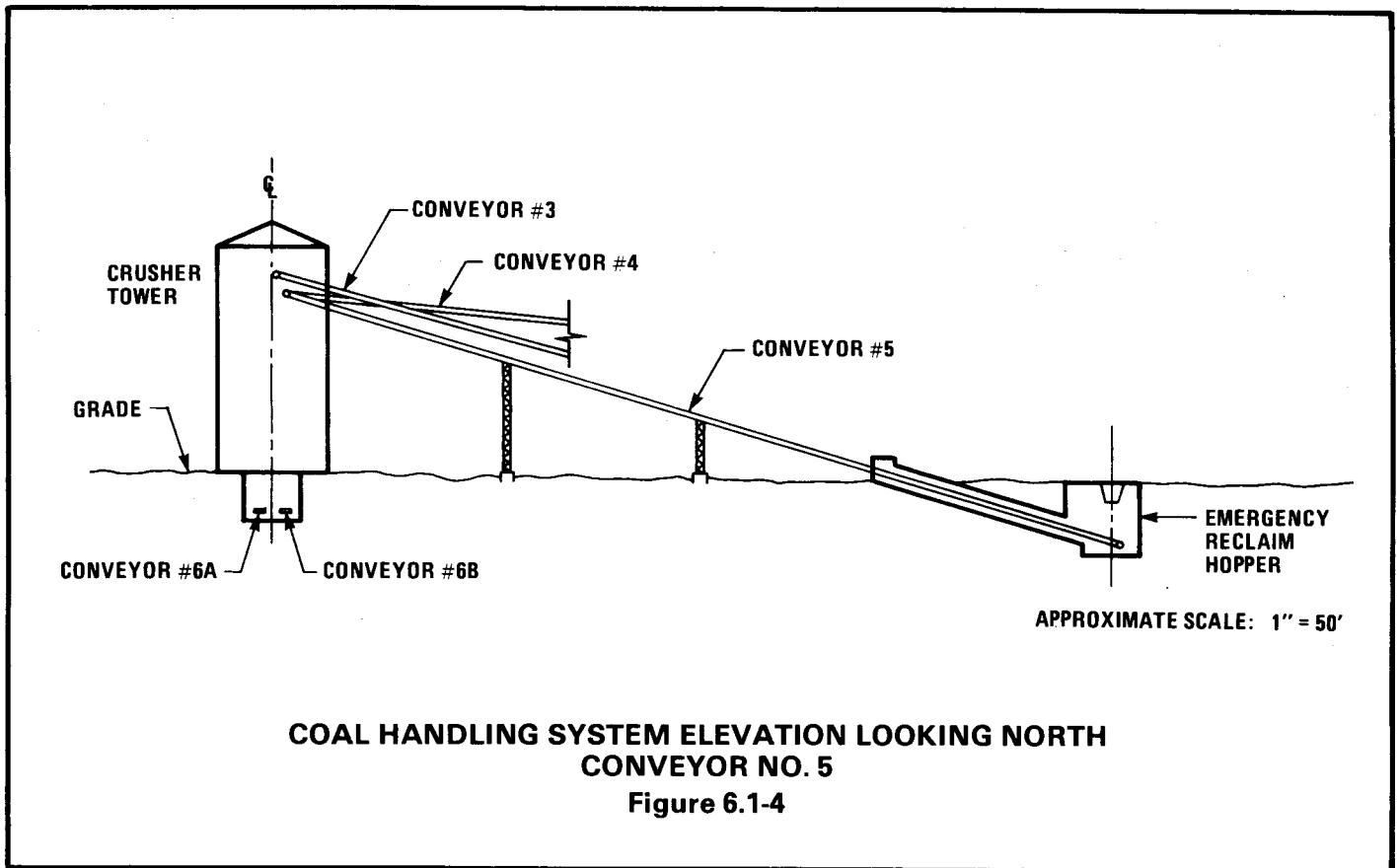


**COAL HANDLING SYSTEM ELEVATION LOOKING EAST
CONVEYOR NO. 1 AND NO. 2**
Figure 6.1-2



NOTE: NOT SHOWN ARE CONVEYOR #5
AND THE EMERGENCY RECLAIM
HOPPER; SEE FIGURE 6.1.1C.

**COAL HANDLING SYSTEM ELEVATION LOOKING NORTH
CONVEYOR NO. 3 AND NO. 4**
Figure 6.1-3



During abnormal conditions when there is insufficient coal supply in the live coal storage pile and a unit-train is delivering coal, coal can be transported directly from the stacker tower to the crusher tower on Conveyor No. 4. Conveyor No. 4 is rated at 355 tons per hour, the full-load plant firing rate. When Conveyor No. 4 is in operation coal is still supplied to the stacker tower at rates as high as 2500 tons per hour. All coal not fed to Conveyor No. 4 is fed to and stacked out to the live storage pile on Conveyor No. 2.

Figure 6.1-4 shows the emergency reclaim hopper, inclined belt Conveyor No. 5 and the crusher tower. During periods of abnormal operation when Conveyor No. 3 is out of service, when there is insufficient coal supply in the live coal storage pile, or when coal is not being delivered to the plant and transported directly to the crusher tower by Conveyor No. 4, coal can be reclaimed using the emergency reclaim hopper. Coal is moved by bulldozer from the live or dead coal storage piles to the emergency reclaim hopper, fed onto Conveyor No. 5 and transported to the crusher tower at rates up to 355 tons per hour, the full-load plant firing rate.

Both coal storage piles are managed by bulldozers. Dust removal and suppression equipment for coal dust control is provided at all transfer points. Vacuum cleaning equipment is provided at selected locations to remove dust from equipment and struc-

tures in order to aid in dust control, and for maintenance and housekeeping. A water spray fire protection system is provided for the coal handling system. The coal handling system is designed for automatic operation, with the main coal handling system control panel located in the main plant control room and local controls provided at selected points in the system.

6.1.2 Coal Crushing and Transfer

As shown on the Plot Plan, Figure 7-1, and Elevation, Figure 7-3 and Coal Handling System, Figures 6.1-1, 6.1-5 and 6.1-6, coal is supplied to the crusher tower, crushed, transported on either Conveyor 6A or 6B to the transfer tower, and then transported to the coal bins at the gasification system areas on either Conveyor 7A or 7B.

Coal is transported to the crusher tower surge bin on inclined belt Conveyor Nos. 3, 4 or 5 (see Section 6.1.1 of this Report). From the surge bin, coal is fed by vibrating feeders into one of the two crushers where it is crushed to a 1/4 inch x 0 nominal size. The crushed coal is then discharged from the crusher through a flap valve and chute onto either inclined belt Conveyor 6A or 6B. Each crusher and Conveyors 6A and 6B are sized for a maximum rate of 710 tons per hour, twice the full-load plant firing rate, providing redundancy in case of equipment malfunction and scheduled downtime for equipment maintenance.

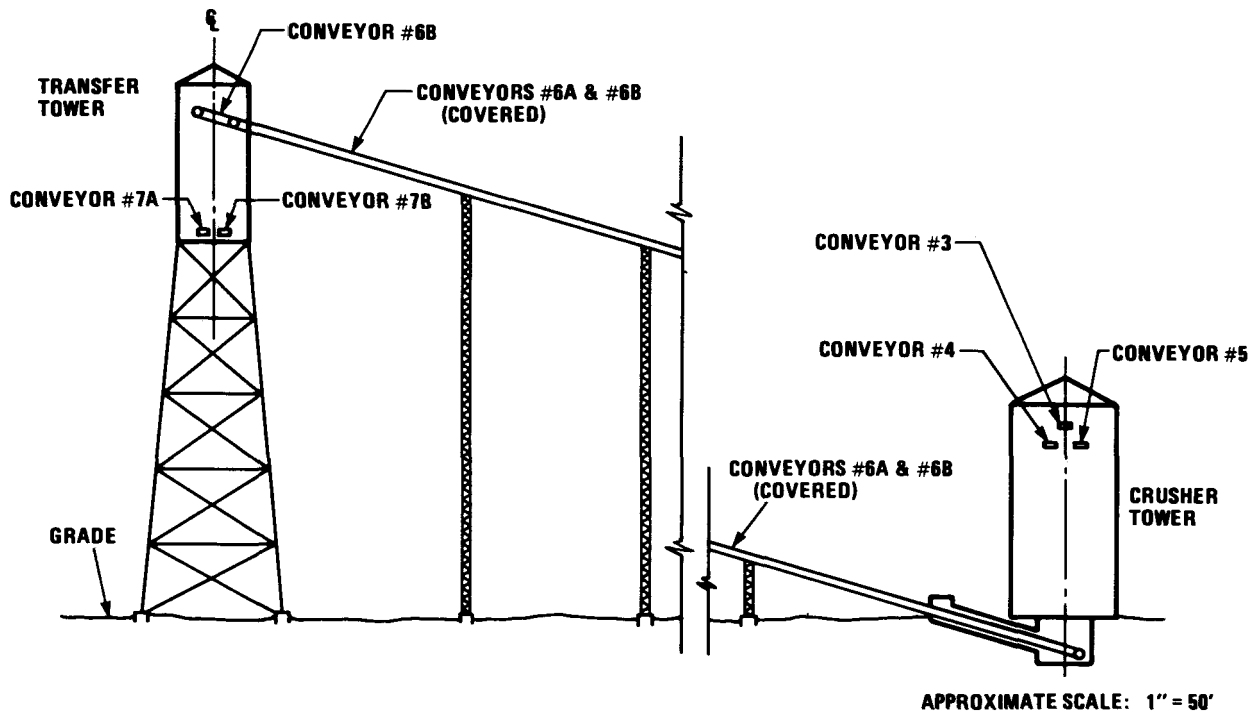
Covered Conveyors 6A and 6B supply the crushed coal to the transfer tower surge bin. The transfer tower surge bin has a capacity of 118 tons, equivalent to 20 minutes full-load station operation. Vibrating feeders from the transfer tower surge bin feed coal onto either tripper Conveyor 7A or 7B. Tripper Conveyors 7A and 7B supply coal to the coal bins at the gasification areas and are each sized for a maximum rate of 710 tons per hour, providing redundancy in case of equipment malfunction and scheduled downtime for equipment maintenance. The coal bins at the gasification areas are described in the gasification system sections of this report and are sized for four hours full-load station operation.

As in Subsection 6.1.1 of this Report, dust removal and suppression equipment, vacuum cleaning equipment, fire protection equipment, and automatic and local controls are provided.

6.2 WASTE HANDLING, STORAGE AND REMOVAL

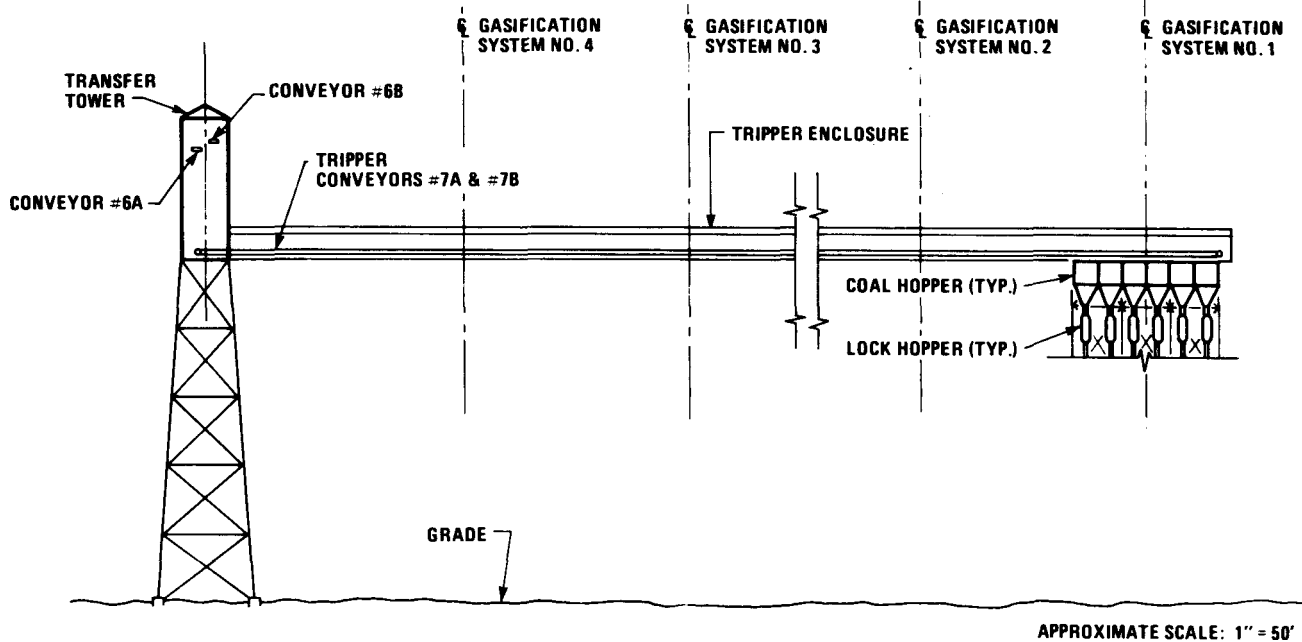
The waste handling and storage at this station is designed to provide the maximum containment and reuse possible so as to comply with regulations protecting the environment.

The solids waste is primarily the ash resulting from the coal gasification process, and amounts to approximately 1000 tons per day when the station is at full capacity.



**COAL HANDLING SYSTEM ELEVATION LOOKING EAST
CONVEYORS NO. 6A AND 6B**

Figure 6.1-5



**COAL HANDLING SYSTEM ELEVATION LOOKING NORTH
CONVEYORS NO. 7A AND 7B**

Figure 6.1-6

The ash is collected in bins located at the process and then trucked to an on-site fill area. The ash storage area provides for a 30-year storage of the ash when it is compacted and stored to a height of 40 feet.

Storm water runoff from the ash storage area and other areas where the water could become contaminated, such as the coal handling and storage area, is collected in the Storm Water and Wastes Holding Pond. Here, the storm water is mixed with other station liquid wastes before being clarified and treated as needed for reuse as part of the station water supply. The primary use of the water is for makeup to the evaporative-type cooling towers.

The only waste leaving the site is molten sulfur from the gasification process. The sulfur is not actually being considered a waste product as it may be saleable in its elemental form.

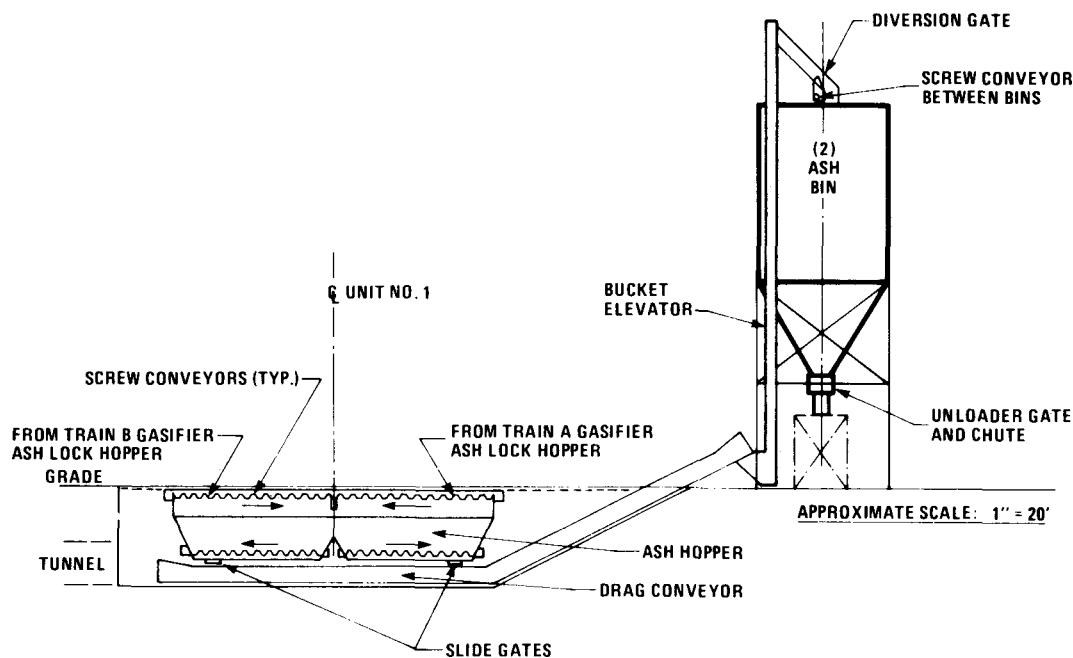
6.2.1 Solid Wastes

The solid wastes produced by the station are 1) the ash from the gasifiers, 2) ash from the incinerator at the Process Water Treater Plant, and 3) any suspended solids settling out of the water in the two site ponds. Elemental sulfur is produced, but its disposal is in a molten condition and is described in Subsection 6.2.2 of this report.

The eight station gasifiers produce a total of 80,431 lbs/hr of agglomerated ash at full-load operation. This ash results primarily from the ash content of the coal (9.6 percent) plus pyrites, unbound carbon and sulfur (see Subsection 4.2.3 of this report and Figure 3.3.2-1).

Each of the gasification systems has its own ash handling system. The agglomerated ash with water at 140°F is periodically dumped from the two ash lock hoppers, one for each gasifier, into a common ash hopper (see Subsection 4.1.1 of this report). The ash hopper is 60 ft. long, 10 ft. wide, and 14 ft. deep and is constructed of Cor-Ten steel. It has a cover through which the two ash disposal pipes from the lock hoppers project. The ash hopper is located in a pit with its cover at grade level (see Figures 6.1-7 and 6.1-8 of this Section). The ash hopper has sufficient volume to hold 100 tons of coal at a density of 50 pounds per cubic foot. This provides space for more than one hour's inventory of coal from the two gasifiers and pretreaters when the gasification system is shut down to either the 'cold-ready-to-start' or 'cold-stand-by' modes, in case of an ash handling system failure.

In order to achieve the storage volume of a long hopper with only two receiving points, two 16" diameter screw conveyors are positioned on the hopper centerline just below the cover. These screw conveyors are run only when ash or coal must be stored in the hopper. Otherwise the ash drops straight through to the two hopper outlet gates and onto the ash disposal system drag conveyor. The screw conveyors are driven by 10-HP motors, and act as leveling or distribution conveyors by moving the ash or



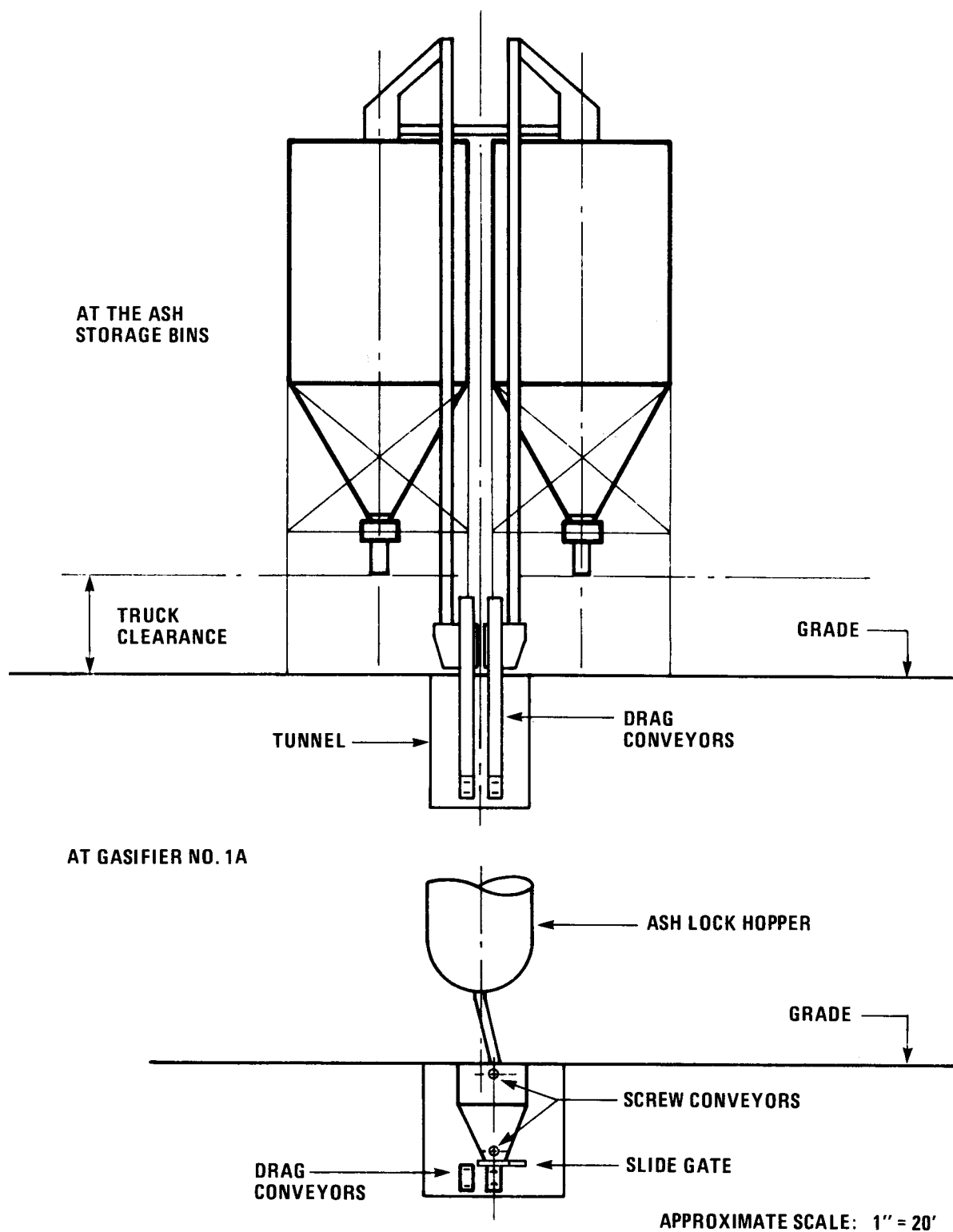
ASH HANDLING SYSTEM ELEVATION LOOKING NORTH

Figure 6.1-7

coal towards the center of the hopper. To convey the stored material from the center of the hopper back to the two hopper outlet gates, located at the ends of the hopper, two 16" diameter screw conveyors driven by 10-HP motors are positioned in the bottom of the hopper trough section.

The hopper is equipped with 2-foot by 2-foot air-operated outlet slide gates, positioned directly beneath the ash disposal pipes from the lock hoppers. During normal operation, the ash and water drop straight down onto the drag conveyor running beneath the gates and on the centerline of the ash hopper. The drag conveyor is constructed of hardened alloy chain with an abrasion-resistant liner plate approximately 2 feet wide by 3-1/2 feet high on the floor of the conveyor casing. A water level is maintained in the conveyor casing at about half-full and excess water overflows into the water circulating pump wetwell as shown on Figure 3.3.2-1, Section 3.3.2 of this report. A baffle and fine screen protect the tail sprocket from suspended or floating debris. Each conveyor is sized for 20 tph, twice the expected ash production rate, and is driven by either a 10-HP or 15-HP motor depending on the unit conveying distance. The return chain is positioned above the carrying chain.

The drag conveyor is a horizontal inclined style as shown in Figure 6.1-8. The ash is discharged aboveground into a receiving hopper for the bucket elevator. Free water drains back from the inclined portion of the conveyor to the horizontal section so that entrained water leaving with the ash is approximately 15% by weight.



**ASH HANDLING SYSTEM
ELEVATIONS LOOKING EAST**
Figure 6.1-8

A 12" by 7" bucket elevator with rappers carries the ash vertically from grade level to a discharge point approximately 15 feet above the top of the 73'-3"-high ash bin. The bucket elevator is positioned at the side of the ash bin and is driven by a 7-1/2-HP motor. An inclined chute conveys the dumped ash to the center of the 24-ft. -diameter ash bin. A diverting gate permits the isolation of the ash bin by directing the ash onto a 12"-diameter horizontal screw conveyor, driven by a 3-HP motor, which conveys the ash into the adjacent ash bin.

Each Gasification System has an ash bin sized to store 650 tons of ash at a density of 90 pounds per cubic foot. This provides ash storage for 64 hours of full-load operation, allowing for two-day shutdowns of the ash disposal operation. Each bin has drainage features allowing any free water to drain back to the drag conveyor water circulating pump wetwell. The bins are constructed of steel and have cone-shaped bottoms. The outlet of each bin is equipped with a hydraulically-operated gate and chute for filling trailer trucks. The gate operation is controlled through a local controller by the truck operator.

The ash is transported from the ash bins to the on-site ash storage area by three trailer trucks, each with a 22-cubic-foot capacity. The three-truck operation is based on one shift per day (7 hours), five days per week, at a station capacity factor of 65%. A greater capacity factor or a truck outage for maintenance would require either second shift duty or six or seven day-per-week operation.

The ash from the incinerator at the Process Water Treater Plant equals 600-lbs/hr. (See Section 4.8.2 and Figure 4.8.2-1 of this report.) The ash is simply conveyed from the incinerator into an ash storage bin for truck removal. One trailer truck disposes of the ash to the on-site ash storage area approximately once every two days.

The Clean Water Holding Pond is of sufficient capacity to provide for the settling of suspended solids found in the river water makeup to the pond. The Storm Water and Wastes Holding Pond is also sized to allow for the settling of suspended solids found in the storm water runoff, underflow wastes from the station clarifiers and the plant floor drains. It may be necessary at times to dredge these ponds to their original depths, thereby restoring their original storage volumes and retention times. The dredged material can be trucked to either the ash storage area or, if desired, to other on-site fill areas.

The ash storage area is sized to store the 30-year accumulation of ash and other solid wastes at full-load plant operation at a 65% capacity factor. The ash storage area is located south of the coal handling and storage area, and is described in Section 7.1 of this Report. Site preparation including grading, embankments, and roadways are planned to permit continuous solids disposal operations. Solid wastes disposal is by section of the ash storage area, followed by the sealing of each filled section with a layer of topsoil and seeding with a suitable fast-growing grass.

6.2.2 Liquid Wastes

Liquid wastes result primarily from 1) the treatment and demineralizing of station makeup water, 2) water collected by the station floor drains and equipment drains, 3) boiler blowdown water, 4) process waste water from the gasification systems, and 5) molten elemental sulfur. Although sulfur is listed as a waste product it may be a saleable byproduct as it is in its elemental form.

Areas subject to oil spills are isolated by curbing, and these areas are drained by a separate drainage system from the regular station floor drain system. The oil drains are collected in a sump and then pumped to an API oil/water separator which is part of the Process Water Treater Plant for the gasification systems (see Figure 4.8.2-1).

The underflow waste from the clarifiers and the backwash wastes from the water treatment filters and demineralizers are collected in sumps near the Water Treatment Building and Chemical Treatment Building. From these sumps the waste water is then pumped to the Storm Water and Wastes Holding Pond.

Boiler blowoff and blowdown are piped to blowoff tanks where they are cooled before draining to the house sump. The blowoff and blowdown are then combined with the station floor and equipment drains, also collected in the house sump, and pumped to the Storm Water and Wastes Holding Pond.

The majority of the process waste water from the gasification Process Water Treater Plant is pumped to the Storm Water and Wastes Holding Pond. The remainder of the water is used as makeup for ash quenching in the gasifier ash quench and lock hoppers (see Section 4.8.2 and Figures 3.3.2-1 and 3.3.2-4 of this Report).

Contaminated storm runoff water from the gasification system areas, lock-gas system area, Selexol and scrubber areas, Claus plants and their associated sulfur storage areas, stripper and waste water treatment area, future tail-gas treater area, coal handling and storage areas, fuel-oil handling and storage areas and ash handling and storage areas are all collected in the Storm Water and Wastes Holding Pond. Here, the storm water is combined with other station liquid wastes described above and mixing, dilution, neutralization and settling of suspended solids can occur. The water is then clarified and treated in the clarifier and Chemical Treatment Building before being pumped to the Clean Water Holding Pond for reuse as station water supply.

The molten elemental sulfur is collected, stored and maintained at 280°F in a pit adjacent to each Claus plant. The two pits have a combined storage capacity of five days full-load plant operation. From the pits the sulfur is pumped into railroad tank cars or trucks for off-site resale or disposal (see Section 4.10 and Figure 3.3.2-3 of this Report).

6.3 BOILER FEEDWATER TREATING AND STORAGE

In order to prevent deposits of solids on the internal surfaces of the boiler and to prevent carryover of dissolved solids to the steam turbine, which can decrease thermal efficiency and cause damage to the steam turbine, treatment of the boiler feedwater is of prime consideration in power plant design. Included in this Section is the pretreatment of station makeup water and demineralization of HRSG makeup water.

The equipment for the boiler feedwater pretreatment plant consists of a circular steel, concrete bottom, upflow clarifier, followed by three circular steel valveless gravity filters, clearwells, and the necessary number of service water transfer pumps to supply water to the HRSG feedwater makeup demineralizers and gasification plant. Auxiliary equipment includes the necessary lime and coagulant chemical feeders, tanks, chemical feed pumps and chlorination system for prechlorination of raw water, flow split box, recycle pump, supply headers, piping, valves, flow meters, instruments and controls.

The pretreatment equipment is sized for a net flow of 600 gpm taking into account:

- 520 gpm required for the gasification system
- 60 gpm required by the demineralizers for HRSG blowoff and blowdown (plus regeneration water)
- Necessary flow for sludge blowdown and filter backwash requirements.

The clarifier, filters and clearwells are installed outdoors and adjacent to the water treatment building housing the demineralizer equipment and laboratory. Chemical feed equipment pumps and controls are also installed at ground floor level inside the building with lime and alum storage above the chemical feed room. The water treatment building is located west of the plant island and north of the coal transfer tower.

The demineralizer system consists of a two-train arrangement with each train sized to deliver 300 gpm of process water and HRSG feedwater makeup. Each demineralizer train is provided with an activated carbon purifier, strong acid cation unit, strong base anion unit, and a mixed bed polishing unit. The primary cation and anion exchangers are designed for a 24-hour period between regenerations. The capacity of each train's mixed bed unit is such that it becomes exhausted and requires regeneration between the ninth and tenth regeneration of the primary units. In normal operation, one train is continued in service with the other train regenerated and maintained in standby condition. The composition of demineralizer effluent is shown in the Table 6.3-1.

TABLE 6.3-1
WATER ANALYSIS AFTER DEMINERALIZATION

Constituent	Composition After Demineralization
Calcium (Ca^{++}) ppm as CaCO_3	0
Magnesium (Mg^{++}) "	0
Sodium (Na^+) "	0.05
Potassium (K^+) "	0.05
Hydroxide (OH^-) "	0.05
Carbonate (CO_3^{--}) "	0
Sulfate (SO_4^{--}) "	0
Chloride (Cl^-) "	0.05
Nitrate (NO_3^-) "	0
Fluoride (F^-) "	0
Total Hardness "	0
Methylorange (MO) (total alkalinity) "	0.1
Silica (SiO_2) "	0.01
Iron (Fe) Total "	
Manganese (Mn) "	0
Turbidity (JTU) "	0-1
Color (Pt Units) "	0
Carbon Dioxide (CO_2) ppm as CO_2	0
pH	6.5 - 7.5

Demineralizer control systems and auxiliary mechanical equipment are designed for remote manual or semi-automatic pushbutton operation. All demineralizer equipment is located inside the water treatment building. The strong acid and caustic storage tanks are located outdoors, adjacent to the water treatment building. Demineralized effluent is pumped to the two 100,000-gallon condensate storage tanks for use as process water, makeup to the HRSG feedwater system, and makeup to the auxiliary boiler feedwater system. The condensate storage tanks are located just south of the main control building.

6.4 COOLING WATER SYSTEMS

Closed-loop type cooling water systems are used at the station for condensing the exhaust steam from the steam turbine, for cooling equipment, and for cooling other cycle fluid streams. The collected heat is rejected to the atmosphere by evaporative-type cooling towers.

The major portion of the cooling load is the condensing of the exhaust steam from the steam turbine. The equipment in the main circulating water loop consists of a cooling tower with basin, two half-size circulating water pumps, main condenser (see Section 5.4) and large-diameter circulating water piping. The main circulating water system is described in Section 6.4.1 of this report.

The cooling of equipment and other cycle fluid streams is done independently of the circulating water system by the auxiliary cooling water system. Cooling water pumps supply water to the equipment and heat exchangers located throughout the plant. The cooling water is pumped from the auxiliary cooling water system cooling tower basin, through the equipment, and returned to the cooling tower. The auxiliary cooling water system is described in Section 6.4.2 of this report.

The source for the plant cooling water supply is the North River, assumed to be a tributary of the Mississippi-Missouri River Basin. For design purposes in this study, the assumed North River water analysis tabulated in Table 6.4-1 (from the ECAS study Reference 1) was used. The ECAS study water analysis makes identical assumptions for the source of the plant cooling water supply and is based on 1974 Water Quality Records for the states of Missouri, Illinois, Indiana and Ohio.

The North River water is pumped into the Clean Water Holding Pond, located parallel to the North River northwest of the plant island, by three 50% capacity river intake pumps, located at an intake structure near the northwest corner of the pond. The Clean Water Holding Pond provides storage and clarification of the river water for cooling tower makeup and other station supplies. As part of the pretreatment facility, the pond capacity is sufficient to accomplish initial sedimentation and removal of the bulk and suspended solids in the river water. As part of the general water management system, the pond receives treated water from the Storm Water and Wastes Holding Pond. A spillway, located in the northwestern corner of the pond, has been provided for overflow to the river.

TABLE 6.4-1
ASSUMED NORTH RIVER WATER ANALYSIS

Constituent		Max.	Avg.	Min.
Calcium (Ca)	ppm as CaCO_3	188	143	105
Magnesium (Mg)	"	131	118	74
Sodium (Na)	"	50	50	50
Potassium (K)	"	5	4	2
Total Cations	"	374	315	231
BiCarbonate (HCO_3)	"	217	162	77
Carbonate (CO_3)	"			
Sulfate (SO_4)	"	95	111	128
Chloride (Cl)	"	34	27	24
Nitrate (NO_3)	"	27	14	1.6
Fluoride (F)	"	0.8	0.7	0.4
Total Anions	"	374	315	231
Total Hardness	"	319	261	179
Methylorange (MO) (total alkalinity)	"	217	162	77
Silica (SiO_2)	"	9	8	7
Iron (Fe) total	"	5.2	3.4	2.2
Manganese (Mn)	"	0.17	0.15	0.13
Color (Pt Units)		60	40	20
Turbidity (JTU)		300	175	50
Total Dissolved Solids	ppm as CaCO_3	547	438	319
pH		8	7.6	7.14
Carbon Dioxide (CO_2)	ppm as CO_2	3.4	6	7.14

6.4.1 Main Circulating Water System

The main circulating water system consists of a cooling tower and basin, circulating water pumps, main condenser and circulating water piping. The system is designed to condense the exhaust steam from the steam turbine.

The cooling tower serving the main circulating water system is an 8-cell, induced mechanical draft, double cross flow, evaporative (wet) design. The tower is located west of the plant island and orientated parallel to the predominant wind direction. Each cell is 43 feet wide, 85 feet deep and 65 feet high. All cells are in line and mounted at ground level over a common cast-in-place concrete basin. Each cell has a 32-foot-diameter propeller fan located in the exhaust stack. The fans are driven through speed reducers by 200 HP electric motors.

The tower is sized to reject 2150×10^6 Btu/hr. by evaporation and convection, based on an ambient dry bulb temperature of 59°F with a 60% relative humidity, which corresponds with a wet bulb temperature of 51.4°F . The heat load of the main circulating water system is at the ISO ambient conditions. The total water flow is 220,000 gpm.

The tower is basically constructed of precast concrete sides, dividing walls, louvers, and distribution deck. The tower fill is a perforated polyvinyl-chloride slating carried by a network of plastic-coated wire. Other components are of plastic, steel-reinforced plastic or fiberglass, all of which contributes to a durable and long-lasting tower.

The water is circulated from the cooling tower basin, through the main condenser and back to the flow distribution deck of the tower by two 50% capacity, vertical axial-flow, submerged-type circulating water pumps of the single-stage, mixed-flow impeller design.

The discharge of each pump is equipped with an expansion joint and motor-operated butterfly valve. The valve operation is controlled relative to the starting and stopping of the pump so as to eliminate the need for discharge check valves and to prevent sudden changes in flow.

The circulating water pump wetwell is separated from the tower basin by removable screens which prevent collected debris that have been washed from the air passing through the tower from entering into the circulating water system.

The concentration of dissolved salts in the water is limited by tower water blowdown to the river from the pump wetwell.

The 102-inch circulating water pipe, which loops from the cooling tower to the condenser at the steam turbine-generator is a reinforced concrete water pipe, steel cylinder type, AWWA Standard C300 series. Bell and spigot type connections are used at the joints.

Tower water makeup to replace that lost from the cycle due to evaporation, blowdown, drift, carryover and leakage comes from the Clean Water Holding Pond. Water flows by gravity from the pond to the tower basin and the amount required is controlled by a basin-water-level flow control valve.

The 8600 gpm of makeup water supplied from the Clean Water Holding Pond to the cooling tower basin is acid-treated and chlorinated at the cooling tower. The strong acid storage tank and chlorine storage containers are adjacent to a chemical treatment building located south of the Clean Water Holding Pond and east of the main circulating water system cooling tower.

Acid feed equipment is used for the reduction of calcium alkalinity in the cooling water tower. The equipment is identical to that provided for neutralization of storm and waste water except that acid feed is controlled to maintain the pH of the circulating water in the cooling tower within a pH range of 6.9 to 7.5.

Chlorination equipment is provided for shock chlorination of the cooling tower water in order to retard the growth of slime, algae and other forms of aquatic life on cooling tower surfaces, and on the cooling water side of the main condenser, auxiliary equipment coolers, pumps and piping. The equipment includes the necessary number of evaporators and chlorinators sized to maintain a chlorine feed rate of 4 ppm at the design circulating rate for the cooling tower system.

All water required for station makeup is chlorinated, lime-softened, clarified and filtered using normal cold process treatment procedures. Coagulation and precipitation of calcium carbonate and entrained solids during treatment causes the entrainment and removal of iron, manganese, and other trace metals and organic matter. The expected composition of the filtered effluent is shown on the following Table 6.4.1-1.

6.4.2 Auxiliary Cooling Water

The auxiliary cooling water system includes the auxiliary water cooling tower and four auxiliary cooling water pumps. The cooling tower is located southeast of the main circulating water system cooling tower. The pumps are located outdoors at the north end of the auxiliary cooling water cooling tower basin. The pumps are installed on a deck above the basin wetwell. The wetwell is separated from the tower basin by a removable screen which protects the pumps from any foreign material entrapped in the basin, and prevents this material from entering the auxiliary cooling water system. The pumps furnish cooling water to the various coolers in the power blocks, steam turbine area and the gasification systems, as well as other miscellaneous heat exchangers throughout the station. The cooling water is supplied and returned via two 42" buried steel pipes, coated and wrapped externally.

TABLE 6.4.1-1
WATER ANALYSIS AFTER TREATMENT

Constituent	Composition After Lime Softening
Calcium (Ca^{++}) ppm as CaCO_3	35
Magnesium (Mg^{++}) "	118
Sodium (Na^+) "	50
Potassium (K^+) "	5
Hydroxide (OH^-) "	trace
Carbonate (CO_3^{--}) "	37
Sulfate (SO_4^{--}) "	109
Chloride (Cl^-) "	34
Nitrate (NO_3^-) "	27
Fluoride (F^-) "	1
Total Hardness "	153
Methylorange (MO) (total alkalinity) "	37
Silica (SiO_2) "	8
Iron (Fe) Total "	
Manganese (Mn) "	0.3
Turbidity (JTU) "	1
Color (Pt Units) "	0
Carbon Dioxide (CO_2) ppm as CO_2	0
pH	9 - 10.2

The cooling tower serving the auxiliary cooling water system is a four-cell tower, identical to the tower described in Section 6.4.1 of this Report. The tower is sized to reject 820×10^6 Btu/hr by evaporation and convection, based on an ambient dry bulb temperature of 59°F with a 60% relative humidity, which corresponds to a wet bulb temperature of 51.4°F. The heat load represents the auxiliary cooling water system at the ISO ambient conditions.

The four auxiliary cooling water pumps are each rated at 25 percent capacity. Each pump is a single-stage, double-suction, vertical type.

Four quarter-size strainers with automatic self-cleaning backwash features are installed adjacent to the pumps in the cooling water supply pipeline to the plant.

Table 6.4.2-1 lists the station auxiliary cooling water requirements. Water treatment for the auxiliary cooling water system is identical to that described for the main circulating water system in Subsection 6.4.1 of this report.

6.5 A START-UP AND/OR STANDBY FUEL SYSTEM

A No. 2 distillate fuel oil system is provided for the startup and shutdown requirements of the gas turbines; for auxiliary boiler and diesel engine-driven equipment; for gas turbine operation (abnormal operating conditions) when gasification systems are down for maintenance; and during initial plant operation prior to completing construction of the gasification system.

The system includes equipment for unloading fuel oil from rail tank cars and tank trucks. The unloading facility is located southeast of the plant island area between the loop track and the passing track, allowing for the unloading and storage of fuel oil tank cars without interfering with the normal delivery of coal. Three hose stations are provided for rail unloading, which allows three 23,000-gallon tank cars to be unloaded simultaneously through the bottom. The hose stations are located so as to permit connection to three tank cars spotted in the unloading area without shifting. The unloading station is connected to a header in a trench and to two 500-gpm screw-type pumps for fuel unloading and transfer. In addition to the rail tank car unloading equipment, within the same area is a separate unloading station for tank trucks. Two 200-gpm gear-type pumps are provided for this service.

The oil storage facilities shown on the Plot Plan, Figure 7-1, consist of two 143,200-barrel capacity, cone roof, flat bottom storage tanks located inside diked areas. The oil storage is equivalent to 10 days station operation at a 75% capacity factor. Two fuel forwarding skids located adjacent to the tanks discharge the fuel oil to the gas turbine fuel skids located adjacent to each gas turbine in the station building, the underground day tank located near the auxiliary boiler, and other small day tanks for the diesel-engine drives. All piping is underground and recirculation lines returning to the storage tanks are provided.

TABLE 6.4.2-1
AUXILIARY COOLING WATER REQUIREMENTS

Steam Turbine Unit	
Lube oil cooler	2200 gpm
Generator H ₂ cooler	2300 gpm
Exciter air cooler	210 gpm
Hydraulic fluid cooler	75 gpm
Each Gas Turbine Unit	
Lube oil cooler	750 gpm
Generator H ₂ cooler	1000 gpm
Exciter air cooler	75 gpm
HRSB blowdown tank	225 gpm
HRSB sample cooler	20 gpm
Air compressor aftercooler	15 gpm
Air compressor water jacket	15 gpm
H. P. boiler water circulator	15 gpm
Boiler feed pump	40 gpm
Plant Gasification Systems	
Gasifiers (8)	6150 gpm total
Scrubbers (8)	29000 gpm total
Absorbers (4)	15800 gpm total
Booster Compressor Lube Console (4)	1000 gpm total
Booster Compressor Air Cooler (4)	10520 gpm total
Inert Gas Generator	770 gpm total
Stripper Waste Water Cooler	4220 gpm total
Miscellaneous Cooling Requirements	900 gpm total

SECTION 7

SITE PLAN

The Middletown site selected for the combined cycle gas/steam turbine station with integrated LBTU gasification is situated on a flood plain, 25 miles south of a major population center. The characteristics of the site are ideal, with access to major and secondary roadways, a major railroad and river water supply. The topography is gently rolling with no major topographical features.

The actual land requirement for the station, exclusive of the access track right-of-way, is 335 acres as shown on the Plot Plan, Figure 7-1. Included on the Plot Plan is the plant island area, switchyard, clean water holding pond, cooling towers, coal handling and storage area, ash storage area, distillate fuel oil handling and storage area, storm water and wastes holding pond, and all major station buildings excluding those in the plant island area. Railroad and roadway systems are shown entering the station from the east. Grade elevation for the station area is approximately 20 feet above mean river level, with the necessary diking and grading as required, indicated on the Plot Plan. The Plot Plan was developed by locating the switchyard on the north side of the plant in the direction of the major user of electricity; and developing a compact arrangement for the coal, ash, cooling tower and pond areas in relation to the plant island. Details of the Plot Plan are described in Subsection 7.2 of this Report.

The Plant Island General Arrangement is shown on Figure 7-2 and is further described in Subsection 7.3 of this Report. The arrangement was developed by taking into consideration the overall plant complexity; optimization of the station building size; the traditional close coupling of the heat recovery steam generators to the gas turbine exhausts; and minimizing the lengths of hot and cold reheat steam, condensate, compressed air, and particularly main steam and fuel gas piping. Another consideration was to maintain a clear direct path from the electric generators to the switchyard.

The Plant Elevation, Figure 7-3, corresponds to the Plant Island General Arrangement Drawing and shows a view of the plant looking west from a section line located between the Unit No. 1 and No. 2 gas turbines and gasification systems. The view extends from the main transformers on the north side of the plant island up to and including the south end of the gasification system. The view includes all major equipment and the station building. The Elevation is further described in Subsection 7.4 of this Report.

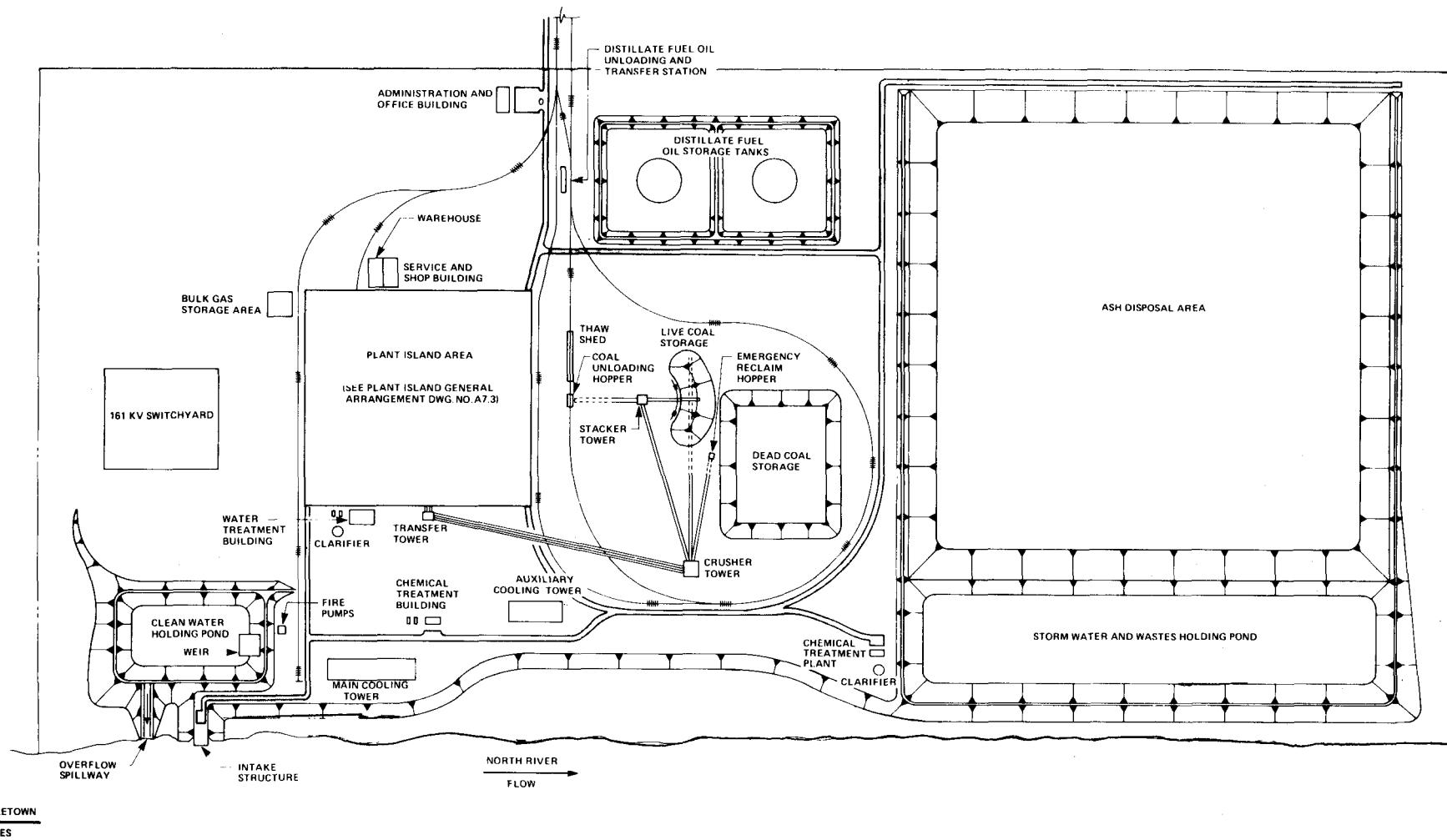
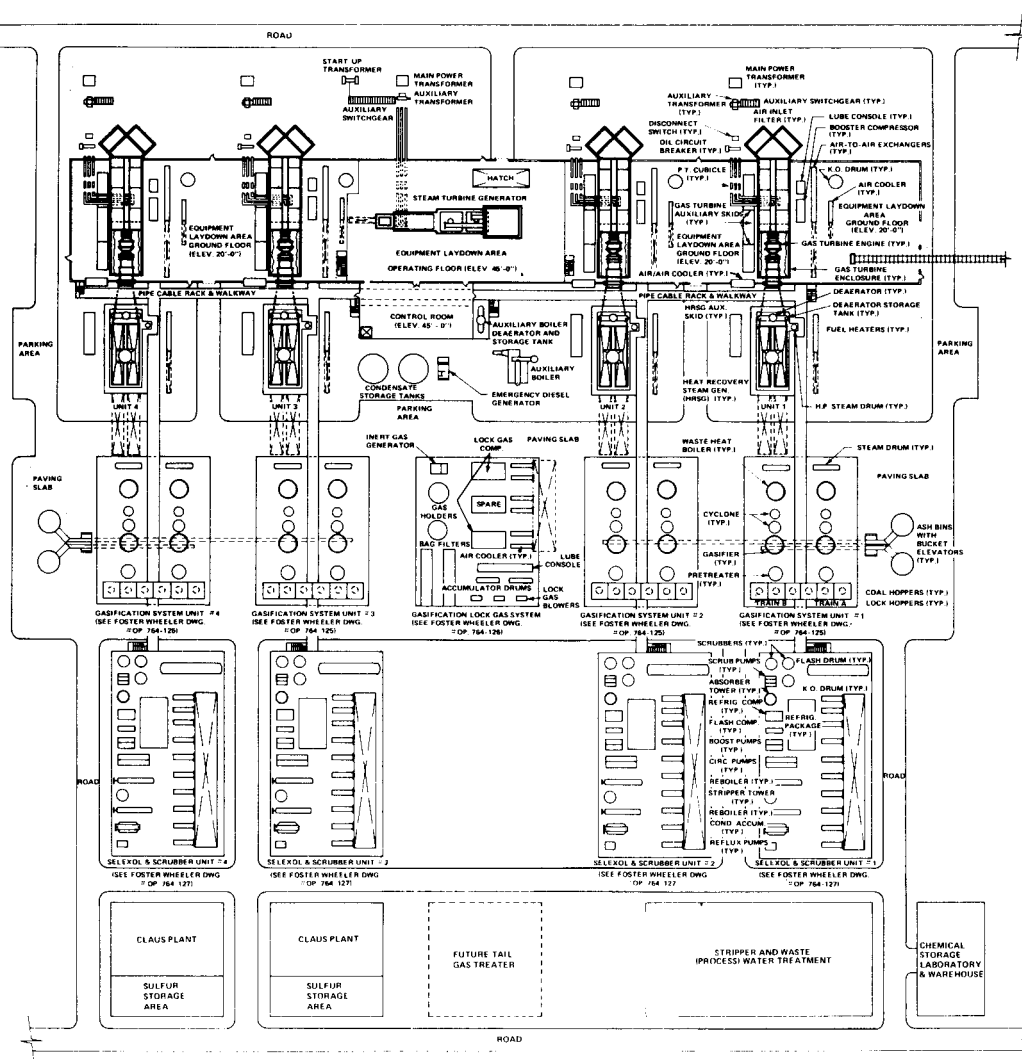
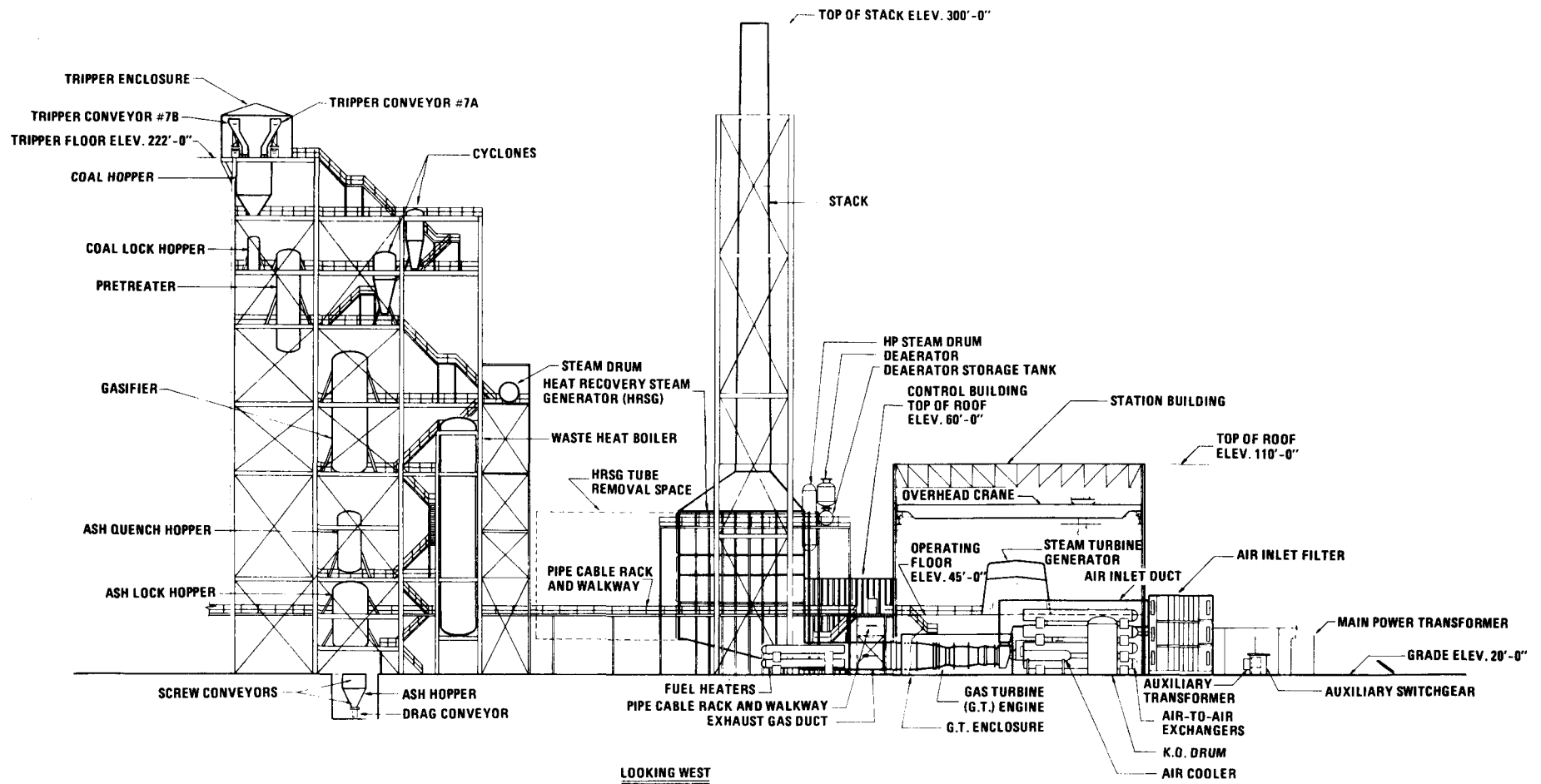


Figure 7-1



**PLANT ISLAND GENERAL ARRANGEMENT
COMBINED CYCLE GAS TURBINE SYSTEM
LOW-BTU COAL GASIFICATION**
Figure 7-2



PLANT ELEVATION LOOKING WEST
Figure 7-3

7.1 SITE AND SITE DEVELOPMENT

The Middletown site as described in WASH 1230 Section 2, modified to reflect fossil power plant siting, is being used for the combined cycle gas/steam turbine system with integrated LBTU gasification. The layout and general arrangement of the items covered in this section are shown on the Plot Plan and Plant Island General Arrangement Drawings, Figure Numbers 7-1 and 7-2, respectively.

7.1.1 General Site Description

The Middletown site is located on the east bank of the North River, 25 miles south of Middletown. The site is a flood plain approximately 2600 feet wide, running easterly from the river to hills whose top elevations vary from 150 to 200 feet above mean river level. Beyond this area, the topography is gently rolling with no major topographical features. The plant site extends from river level to elevations fifty feet above river level.

The North River is approximately one half mile wide with a 100 year maximum level of eight feet above mean level (taken as zero elevation).

Access to the site is provided by five miles of existing secondary road connecting to a state highway. The secondary road needs no improvement. Railroad access is accomplished by constructing a spur to a major railroad located near the site. The assumed length of the railroad spur to the site is five miles. All plant shipments for both construction and operation, including fuel delivery, are assumed to be overland.

Power and water for construction are available at the southwest corner of the site.

The site for the plant is approximately 5600 feet long and 2600 feet wide, or about 335 acres.

The plant island area, including all primary structures and the switchyard, is located approximately 900 feet from the east bank of the river, on the northern half of the site. The plant island area is leveled and filled to an elevation 20'-0" above mean river level. Buildings on the plant island are discussed in detail in Subsection 7.3 of this Report.

From weather bureau records: site surface winds are predominantly southwesterly at 4-10 knots during warm months, and westerly 6-13 knots during cold months. The hills tend to channel winds to a north-south direction. A maximum instantaneous wind velocity of 100 mph has been recorded at the site. No significant damage from severe meteorological phenomena in the last fifty years has been recorded.

Soil profiles showing site soil and geological characteristics include alluvial soil and rock fill to a depth of eight feet; Brassfield Limestone to a depth of thirty feet; blue weathered shale and fossiliferous Richmond Limestone to a depth of fifty feet. The

allowable soil bearing is 6,000 psf and rock bearings are 18,000 psf and 15,000 psf for Brassfield and Richmond strata, respectively. No underground cavities exist in the limestone. The site lies within a zone 1 earthquake design area.

7.1.2 Detailed Site Description

7.1.2.1 RAILROAD FACILITIES

Approximately four miles west of the mainline, one mile east of the site, the main access track to the plant separates into two tracks, the main access track (loop track) and a parallel passing track.

Entering the site from the east the passing track subdivides with the spur used primarily for the removal, delivery and servicing of major plant equipment. The spur subdivides with one track entering and extending approximately 60 feet into the main station building, and its other track extending around the north end of the plant island and running west to the cooling towers. Following its initial subdivision, the passing track passes the distillate fuel oil unloading and transfer station; extends past the plant island, for use in removing sulfur from the two sulfur storage areas (one at each Claus plant; and then connects to the loop track.

Also entering the site from the east, adjacent to the passing track is the loop track. This track also passes the distillate fuel oil unloading and transfer station, then goes through the thaw shed, over the bottom dump unloader, circles the coal storage area, and completes its loop by connecting to itself just prior to where it initially enters the thaw shed. This loop track is provided for coal delivery by the once-through operation of coal unit trans. Details of the coal delivery are included in Subsections 6.1 and 6.1.1 of this Report.

The loop track and passing track are interconnected just prior to passing the distillate fuel oil unloading and transfer station. This interconnection is intended to facilitate the handling of railroad traffic on the site and prevent unnecessary down time of the coal unit trains.

In addition to the site land requirement of 335 acres, an additional 91 acres is required for the five miles of main access track and one mile passing track from the main line to the site. A 150-foot-wide right-of-way is assumed for these tracks.

7.1.2.2 DRAINAGE AND WASTE DISPOSAL

Drainage south of the plant island area is collected and empties into the 1950 foot x 500 foot storm water and wastes holding pond, located at the southwest corner of the site. Storm drainage from the switchyard area is collected in area drains and transferred to the 600 foot x 350 foot clean water holding pond.

In the plant island area, catch basins and storm sewers are located as required with ultimate discharge into the storm water and wastes holding pond. Inside the station building water collected from equipment and floor drains is first treated in oil separators and is then pumped from a station sump to the storm water and wastes holding pond.

Immediately north of the storm water and wastes holding pond is a clarifier and chemical treatment building. Pumps, located in the chemical treatment building, take suction from the pond and discharge to the clarifier. Following treatment in the clarifier, the water is pumped to the clean water holding pond. This treatment process is discussed in Section 6.4 of this Report.

Sewage disposal facilities consist of a packaged primary and secondary treatment system with effluent chlorination.

7.1.2.3 WATER SUPPLIES

The clean water holding pond, located northwest of the plant island, is fed by the river through the intake structure and by treated water from the storm water and wastes holding pond. The clean water holding pond is surrounded and protected by earthen dikes, has an overflow spillway into the river at its northwest corner, and a reinforced concrete overflow weir on its south side.

Water for the fire protection loop and the raw water treatment plant is supplied by pumps taking suction from the clean water holding pond at the overflow weir.

Water for cooling tower makeup is also supplied from the clean water holding pond. The evaporative mechanical draft cooling towers are situated west of the plant island and south of the clean water holding pond. Details of the cooling towers are discussed in Subsections 6.4, 6.4.1, and 6.4.2 of this Report.

Potable water service is supplied from wells or river water. All sanitary and potable water is chlorinated.

7.1.2.4 ROADWAYS

The main plant entrance road enters on the east side of the site and subdivides with one branch extending northward parallel to the east side of the plant island to service the administration, warehouse and service buildings. The main plant road also branches off at a number of other locations to provide full access to the switchyard, intake structure, cooling towers, water and chemical treatments buildings, coal storage and handling areas, distillate fuel oil unloading, transfer and storage areas, ash disposal area and the clean water and storm water and wastes holding ponds.

To provide vehicular access in the plant island area, concrete paving slabs cover the area at the station building and gasification and lock gas subsystems. Numerous roadways connect the two large paving slabs and additional roadways from the gasification area extend through the Selexol and scrubber, and Claus plant areas.

All roadways and parking areas are constructed of asphalt on a 6" flexible base material.

7.1.2.5 LANDSCAPING

A chain-link type fence topped with three strands of barbed wire is used around the plant perimeter and is grounded in certain areas. Selected areas are seeded with grass and additional landscaping is provided at the administration building.

7.1.2.6 SWITCHYARD

A 400 foot x 450 foot switchyard is located parallel to the east side of the clean water holding pond and north of the plant island transformer area.

7.1.2.7 COAL STORAGE AREA

The coal storage area, circled by the loop track, is located directly south of the plant island approximately in the center of the site. The coal storage area is leveled and filled to an elevation of 20'-0" above the mean river level. Details of the coal handling system structures located in the coal storage area are described in Subsection 6.1 of this Report.

7.1.2.8 ASH DISPOSAL AREA

Ash accumulated during the plant operation is conveyed by truck to and deposited at the southern end of the site in the 1950 foot x 1900 foot ash disposal area. The area is bounded on the north and south sides by earthen dikes. Immediately west of and adjacent to the ash disposal area is the storm water and wastes holding pond. In addition to the site drainage, any runoff from the ash disposal area is collected in this pond. Earthen dikes bound the storm water holding pond on the north, south and west sides. Details of the ash handling and other waste handling systems are covered in Subsections 6.2, 6.2.1 and 6.2.2 of this Report.

7.1.2.9 DISTILLATE FUEL OIL STORAGE AREA

Located southeast of the plant island, and just south of the distillate fuel oil unloading and transfer station, is the distillate fuel storage area. Individual earthen dikes surround the two distillate fuel oil tanks. Details of the distillate fuel system are covered in Subsection 6.5 of this Report.

7.1.2.10 BULK GAS STORAGE AREA

To the north of the plant island, east of the switchyard is a bulk gas storage area. The equipment in this area is supported on either side with a reinforced concrete slab or pedestal supported as may be required.

7.2 PLOT PLAN

The Plot Plan for the combined cycle gas/steam turbine station with integral LBTU gasification, Figure 7-2, shows the plant island area, switchyard, clean water holding pond, cooling towers, water and chemical treatment buildings, clarifiers, storm water and wastes holding pond, ash storage area, coal handling and storage area, distillate fuel oil unloading and storage area, other major buildings, major dikes, and the roadways and railroad which serve the site.

The plant island area is located in the northern half of the site. Details of the plant island are shown on the Plant Island General Arrangement, Figure 7-2, and described in Subsection 7.3 of this Report.

To the north of the plant island, the side nearest the major population and load center, are the transformers and switchyard.

To the northwest of the plant island and parallel to the North River is the Clean Water Holding Pond. The pond capacity maintains a limited storage of cooling tower and other station makeup water and is of sufficient size to accomplish initial sedimentation and removal of suspended solids in the river water. A spillway is provided at the northwestern corner of the pond for overflow to the river. South of the spillway and adjacent to the river is an intake structure containing three 50 percent river water supply pumps that discharge into the Clean Water Holding Pond. Two fire pumps, one motor driven and one diesel-engine driven, are located on the south side of the pond to provide fire protection for the station.

The two cooling towers are located west of the plant island and south of the Clean Water Holding Pond, such that the cooling water supply and return lines for the condenser and auxiliary cooling water system lie in clear direct routes from the towers to the plant and back. Further descriptions of the cooling towers are included in Subsections 6.4.1 and 6.4.2 of this Report.

The chemical treatment building and equipment for cooling tower water is located east of the main circulating water cooling tower and south of the Clean Water Holding Pond. Water supplied from the pond to both cooling towers for makeup is chlorinated and acid-treated at the tower basins. A detailed description of cooling tower water treatment is included in Subsections 6.4.1 and 6.4.2 of this Report.

The water treatment building, equipment, and clarifier are located between the cooling tower water chemical treatment building and the plant island. This equipment treats the water required for feedwater makeup. Water supply is from the Clean Water Holding Pond. The clarifier is installed outdoors, adjacent to the water treatment building which houses the demineralizer and laboratory. The location of the water treatment building and equipment is also in close proximity to the condensate storage tanks. A detailed description of the water treatment system for feedwater makeup is included in Subsection 6.3 of this Report.

A Storm Water and Wastes Holding Pond is located south of the cooling towers and parallel to the river for the purpose of collecting station storm water, contaminated plant wastes and runoff from the ash storage area. Water is pumped from the pond to an adjacent clarifier where it is treated, prior to being pumped to the Clean Water Holding Pond to supplement the station makeup water requirements. The storm water chemical treatment building, equipment and clarifier are located just north of the Storm Water and Wastes Holding Pond. Details of station liquid wastes and their treatment are described in Subsection 6.2.2 of this Report.

Located just east of the Storm Water and Wastes Holding Pond is the ash storage area, which is provided to store ash and other station solid wastes for the 30-year life of the plant. Ash is collected on the east and west sides of the plant island area and transported by truck to the ash storage area. Details of the ash handling system and storage area are included in Subsection 6.2.1 of this Report.

Coal is delivered to the site by rail and a loop track is provided for once-through unit-train operation. The loop track is located in the center of the site between the plant island and ash storage areas. Located within the loop track is the coal receiving, transfer, storage, reclaiming and crushing equipment, and the live and dead coal storage piles. Located to the north of the loop track and west of the plant island is additional coal transfer equipment. Details of the coal handling system are included in Subsections 6.1, 6.1.1 and 6.1.2 of this Report.

Located to the east of the loop track is the distillate fuel oil unloading and storage area. Included in this area are the two liquid fuel storage tanks. Just to the north of the fuel oil storage area is the distillate fuel oil unloading and transfer station. Details of the distillate fuel oil system are included in Subsection 6.5 of this Report.

To the east of the plant island area are the shop and service, warehouse, administration buildings, and the bulk gas storage area.

Railroads and roadways enter the site from approximately the center of its east border. The railroad facilities are provided primarily for once-through coal unit-train operation and are also used for equipment maintenance, delivery and removal; plant construction; removal of sulfur wastes; and delivery of distillate fuel oil. Not shown on the Plot Plan, to the east of the site, is the five miles of access track connecting the site railroad track to the main line and the one mile passing track. Numerous roadways are provided throughout the site to facilitate access to equipment and for ash removal to the storage area.

7.3 PLANT ISLAND ARRANGEMENT

The plant island arrangement for the combined cycle gas/steam turbine system with integrated LBTU gasification is shown on Figure 7-3. The arrangement drawing shows the 1) main power transformers with their associated auxiliary switchgear, transformers,

and circuit breakers; 2) the station building; 3) the heat recovery steam generators; 4) the control building; 5) the ash handling areas; 6) the gasification systems and the associated lock gas system; 7) the Selexol and scrubber areas; 8) the Claus plants and their associated sulfur storage areas; 9) the future tail gas treater area; 10) the stripper and waste water treatment area; and 11) the chemical storage, laboratory and warehouse building.

For Phase I of this study the arrangement of the buildings and equipment listed above was based on locating the various components in order to produce a compact plant island while providing space for maintenance, having a single station building as small as possible, and minimizing the lengths of the major piping systems. In order to further optimize the plant island arrangement detailed cost evaluations of a variety of arrangement options will be made in Phase II. The arrangement also attempts to maximize the same handedness of units for ease of design and construction, while being symmetrical about the steam turbine in order to keep major steam piping system lengths equidistant.

7.3.1 Transformers and Switchgear

The five main power transformers and their associated auxiliary transformers and switchgear, the four gas-turbine generator disconnect switches and oil circuit breakers, and the start-up transformer are located on the north side of the station building. This arrangement locates the equipment in a direct line between the generators and the switchyard.

7.3.2 Station Building

The station building houses the steam turbine-generator, condenser, and four gas turbine-generators with their respective auxiliary skids and booster compressor subsystems.

The steam turbine-generator is located on an operating floor in the center of the building with adequate space provided for removal of the generator rotor along the unit axis, and for laydown of parts during maintenance periods. A partial mezzanine floor is provided below the operating floor for locating the feedwater heater and auxiliary mechanical and electrical equipment. The condenser, condensate pumps, instrument air compressor skid and other auxiliary equipment are located on the ground floor level. A hatch is provided in the operating floor for equipment maintenance and removal. The control room is at the steam turbine operating floor level.

At the ground floor level to the east and west of the steam turbine are two gas turbine-generator units. Adjacent to each gas turbine-generator unit are its auxiliary skids, P.T. cubicle, air-to-air cooler and booster compressor subsystem. The booster compressor subsystem is used to supply air to the gasification system and each includes a

booster compressor, lube console, four stacked air-to-air exchangers, knockout drum and air cooler. The gas turbine-generator units are located on 140'-0" centers with the unused space between the units and the space at the east end of the station building available for equipment laydown during maintenance periods.

Running the length of the station building is an overhead crane for equipment maintenance. A railroad track enters the station building on the east end and is used for equipment delivery and removal.

7.3.3 Heat Recovery Steam Generators

The heat recovery steam generators (HRSG's) one for each gas turbine unit, are located outside the south wall of the station building, close coupled with ducting to its respective gas turbine. Vertical steam drums and deaerator equipment are supported by the structural steel members supporting the HRSG. Additional structural steel is provided to support the stack. An auxiliary equipment skid is located to the west of each HRSG and includes the chemical feed system, motor control center, and other auxiliaries. To the east of each HRSG are two stacked fuel heaters used to heat the fuel gas prior to delivery to the gas turbine engine.

7.3.4 Control Building

A control building is located to the south and at the center of the station building. The control building is a three level building with the control room at the operating floor level; a cable spreading room on an intermediate level; and an electronics room, small instrument shop, and some chemical treatment equipment located on the ground floor level.

Located outside and to the south of the control building are common plant equipment items including two condensate storage tanks and an emergency diesel driven generator. To the southeast of and supported by the control building at the operating floor level is the auxiliary boiler deaerator and deaerator storage tank. Outside at grade level and also to the southeast of the building is the auxiliary boiler.

Running along the entire south wall of the station building and between the control building and station building, at the cable spreading room level, is a pipe/cable rack and walkway. The pipe/cable rack and walkway also branches off on the east side of each HRSG and runs south through the center of the gasification systems to the Selexol and scrubber units. The primary purpose of these racks is to support the piping systems and cable trays running between the various equipment areas. The racks also provide access to equipment during maintenance periods.

7.3.5 Gasification System and the Associated Lock Gas System

Located to the south of the HRSG's are the four gasification systems, each with two complete gasification trains. The gasification systems are located as close to the station building as practical in order to minimize the lengths of major piping systems particularly main steam, feedwater and compressed air.

Above the gasification system coal hoppers, but not shown on Figure 7-2, are the tripper conveyors for the delivery of coal from the coal storage area and crushers to the gasifier pretreaters. The tripper conveyors are described in Section 6.1.2 of this Report. Also shown on Figure 7-2 is the ash handling equipment located to the east of gasification system No. 1 and to the west of gasification system No. 4. The ash handling equipment requires good access as trucks are continually moving in and out of the area to remove the ash to the ash storage area. The ash handling equipment is described in Subsection 6.2.1 of this Report.

Located in the center of the four gasification systems is the gasification lock gas system. This system is used primarily to supply lock gas to the lock hoppers within each of the gasification systems.

7.3.6 Gas Purification Areas

Located to the south of the gasification systems are the various gas purification areas including the Selexol and scrubber units (one for each gasification system); Claus plants and their associated sulfur storage areas; a stripper and waste water treatment area; a gasification chemical storage, laboratory and warehouse building; and space has been provided for future tail gas treatment equipment. In arranging these areas, primary consideration was given to minimizing the distance between the gasification system and its associated Selexol and scrubber unit and for providing good access to the sulfur storage areas for ease in sulfur removal.

7.4 PLANT ISLAND ELEVATION

A partial elevation view of the combined cycle gas turbine system with integrated LBTU gasification is shown on Figure 7-3. The elevation corresponds to the Plant Island General Arrangement, Figure 7-2, and shows a view looking west from a section line located between the Unit No. 1 and No. 2 gas turbine-generators and gasification systems. The view extends from the main transformers on the north side of the plant island up to and including the south end of the gasification system. Not shown on the elevation, to the south of the gasification system are the Selexol and scrubber, and stripper and waste water treatment areas.

Shown to the right of the station building are the main power transformer, auxiliary transformer and switchgear, and inlet air filter structure. Each inlet air filter supplies clean air to its associated gas turbine.

Located within the station building are the gas turbine-generators and their auxiliaries, booster compressor subsystems, and steam turbine-generator and its auxiliaries. The gas turbine-generator units are located on the ground floor, elevation 20'-0". Located on the near side of each gas turbine-generator is its associated booster compressor subsystem. The booster compressor subsystem equipment shown includes the knockout drum, air cooler and four air-to-air exchangers. Between the gas turbine-generator

and the air-to-air exchangers, but not shown are the booster compressor and lube console. On the far side of each gas turbine-generator, and also not shown are the gas turbine auxiliary skids, air-to-air cooler, iso-phase bus-work and the Potential Transformer cubicle.

The steam turbine-generator is shown on the operating floor at elevation 45'-0". Beneath the operating floor, but not shown is the partial mezzanine floor, condenser, feedwater heater, and various steam turbine-generator auxiliaries. Above the steam turbine-generator is an overhead crane, provided primarily for equipment maintenance. The crane runs the length of the station building over the four gas turbine-generators and the steam turbine generator.

Each gas turbine exhausts to its close coupled heat recovery steam generator (HRSG), located to the left of the station building, through a duct supported in a manner suitable for thermal expansion. Each HRSG is provided with a tapered circular stack, to an elevation of approximately 300 feet, to carry the HRSG exhaust gases above the nearby gasifier towers and coal handling equipment. The stack height was estimated since air quality and stack optimization studies were not conducted during Phase I of the study. On the near side of each HRSG are two fuel heaters used for heating the LBTU gas. To the far side of each HRSG and not shown in the HRSG auxiliary skid.

A combination pipe/cable rack and walkway is provided on the left side of the station building with branches running southward along the near side of each HRSG, through the center of each gasification area and up to its associated Selexol and scrubber unit. The primary purpose of the structure is to provide support for various piping and cable systems. The structure also provides access to the HRSG's and gasification areas.

Partially shown between the HRSG and the station building, and behind the combination pipe/cable rack and walkway is the main station control building.

Directly to the left of each HRSG is its associated gasification system. Each gasification system consists of two identical gasification trains. Each train includes a steam drum, a waste heat boiler, two cyclones, a gasifier, lock and quench ash hoppers, and a pretreater. Each train also includes three coal hoppers and three lock hoppers, fed by two tripper conveyors. Beneath the two ash lock hoppers in each gasification system is an ash hopper and ash conveying equipment.

7.5 SITE PLAN — GASIFICATION SYSTEM PLOT PLAN

The site plan for the gasification system is shown on key Plot Plan, Figure 7-4, and on supplementary Figures 7-5, 7-6 and 7-7. An elevation drawing of the gasification section is shown on Figure 7-8. The gasification system is divided into four trains, corresponding to the four gas turbines. Each of the four gasification trains has a gasification section, a gas purification section and an air booster section located

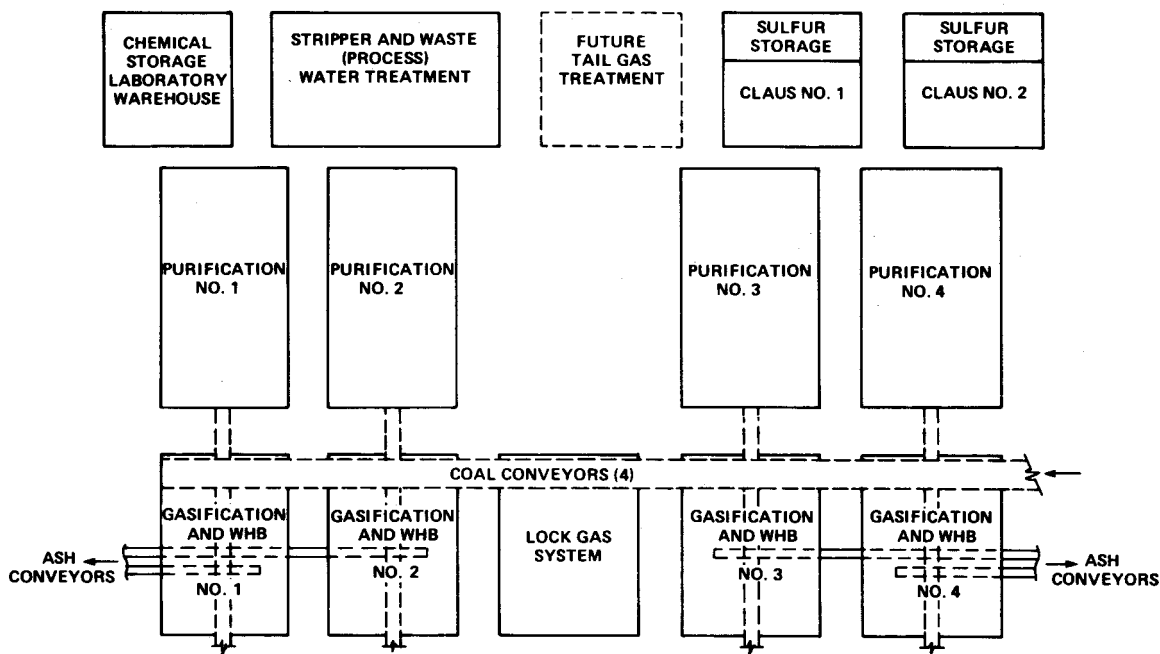
adjacent to the gas turbine. The Claus unit for sulfur recovery is divided into two trains and other facilities such as lock gas compression, waste water treating and laboratory and chemical storage buildings are single train units.

7.5.1 Alternative Disposition of Sections

Each train of the gasifier system may be planned in a number of different configurations. Some of the options are:

- Layout of gasification and purification sections in-line with the gas turbine producing four parallel trains.
- Layout of the gasification section and purification section in a side-by-side arrangement.

The side-by-side arrangement was discarded due to excessive conveyor length for both coal and ash. The in-line sections of the gasification, gas purification and gas turbine may be arranged following the flow sheet; i. e. , gasification followed by purification followed by the gas turbines. This arrangement would produce the shortest gas lines between sections. However, it has the disadvantage of requiring very long high-pressure steam and boiler feedwater lines. Therefore, the final arrangement, shown on Plot Plan, Figure 7-4, indicates a layout with the purification section followed by the gasification section. The booster compressor is located inside the gas turbine building. This illustrated arrangement produces the shortest high pressure steam lines at the expense of somewhat longer fuel gas lines.



KEY PLOT PLAN COAL GASIFICATION PLANT ERDA HTTT PROGRAM
Figure 7-4

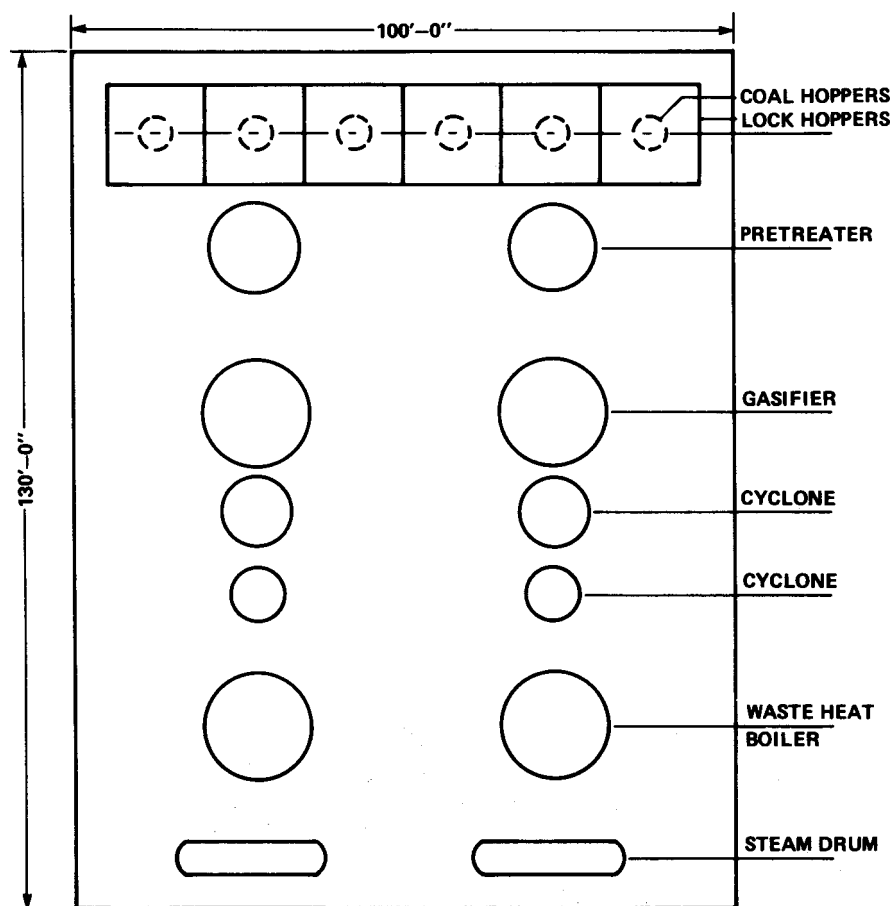
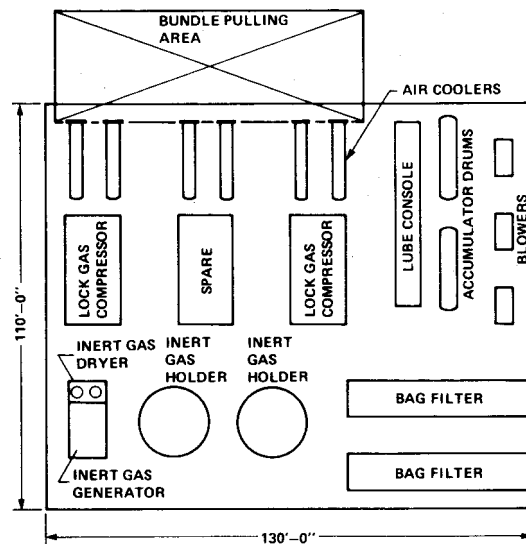


Figure 7-5 GASIFICATION SECTION SITE PLAN



TOTAL NO. OF UNITS	NAME	SIZE
3	LOCK GAS COMPRESSOR	30' x 17'
3	LOCK GAS BLOWER	4' x 6'
2	DISCHARGE GAS ACCUMULATOR	6' ϕ x 20' LONG
2	GAS HOLDER	20' ϕ x 40' HIGH
2	BAG FILTER	10' x 50'
6	AIR COOLERS (COMP INTER)	1'-6" ϕ x 20' LONG

Figure 7-6 GASIFICATION LOCK GAS SYSTEM SITE PLAN

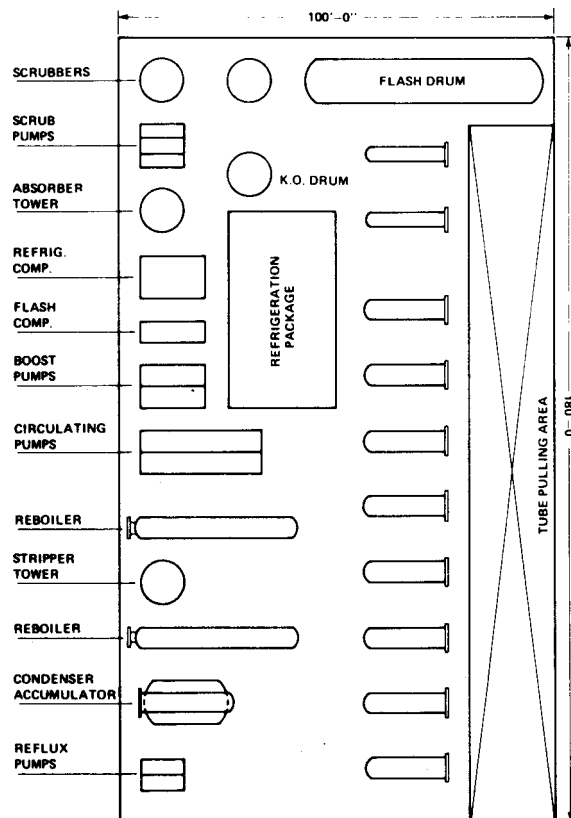
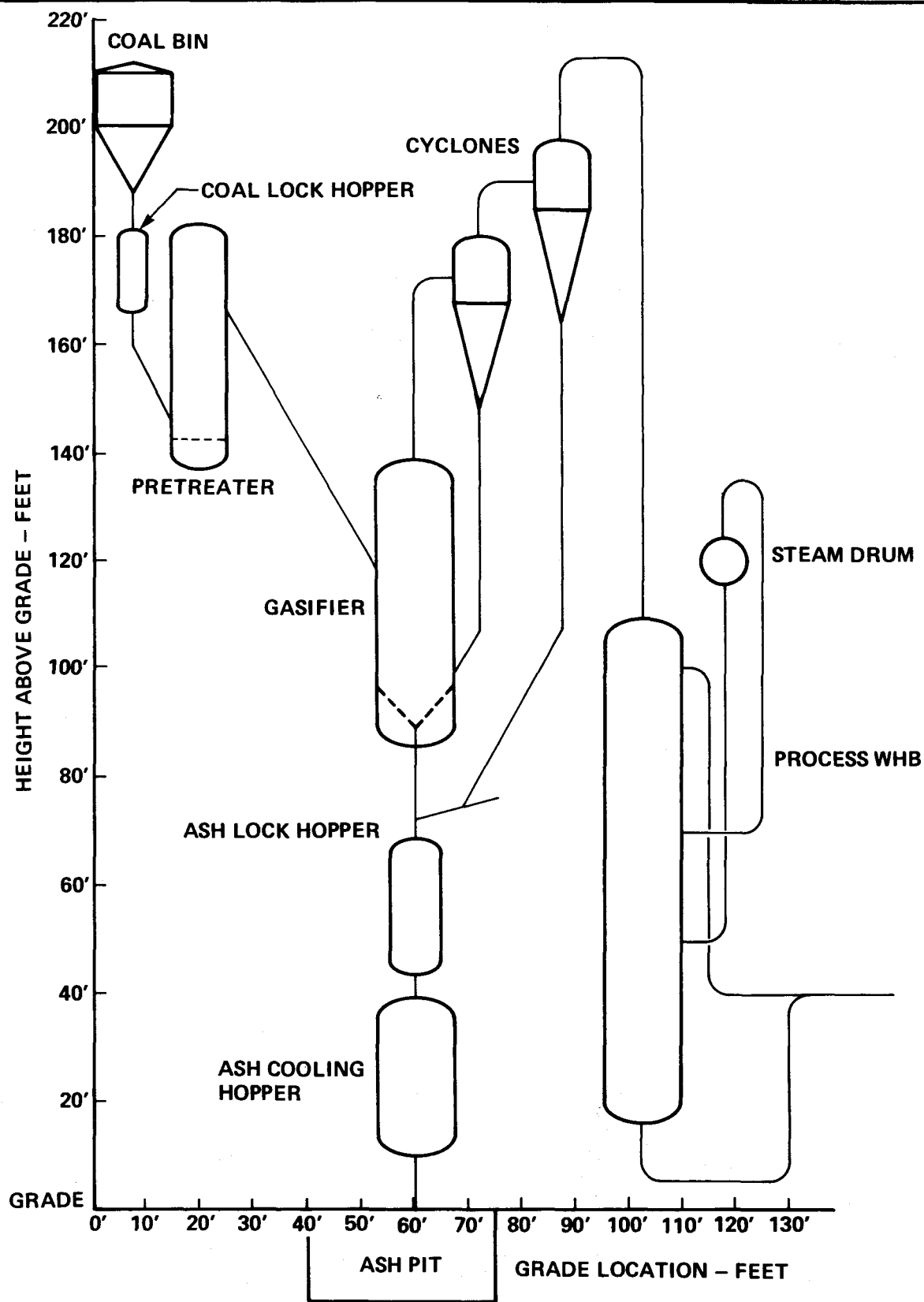


Figure 7-7 SELEXOL & SCRUBBER SITE PLAN



ELEVATION GASIFIER SECTION
Figure 7-8

SECTION 8

ELECTRICAL SYSTEM

The plant electrical system for the reference design is defined on Figure 8-1 and discussed in this section. The system is representative of current Westinghouse PACE practice and conventional power plant design.

8.1 DESIGN CRITERIA

8.1.1 General

The electric power system for the station is designed to be electrically self-sufficient and to provide adequate, redundant and reliable power sources for all electrical equipment during start-up, normal operation, shut down and emergency conditions.

8.1.2 Generators and Switchgear

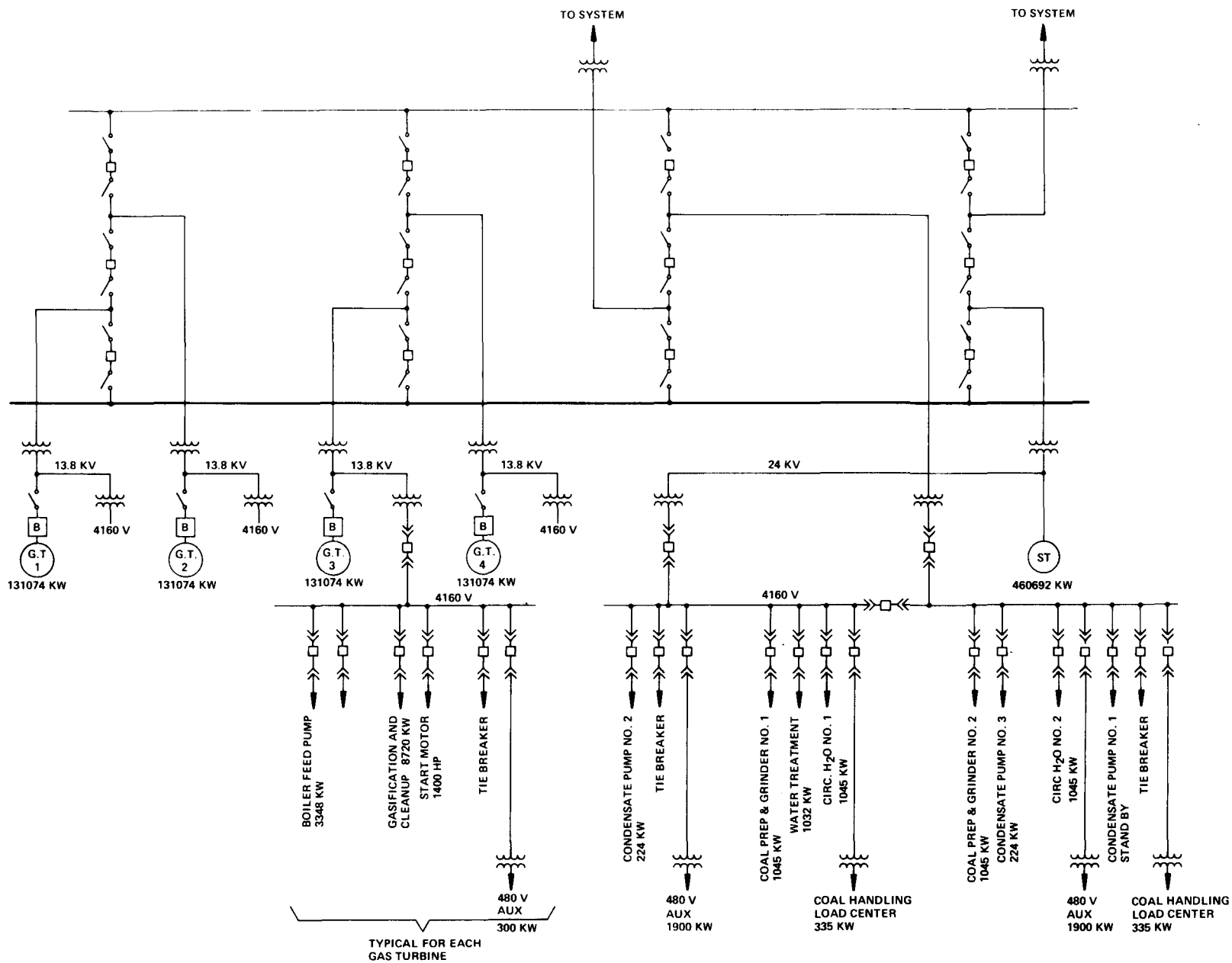
The stations has five generators, four 131 MW, 13.8 kv, 60 Hz gas turbine generators, and one 461 MW, 24 kv, 60 Hz steam turbine generator. The output of these generators, less the station auxiliary load, is stepped up to the station 161 kv switchyard by their associated main transformers. The station startup transformer is fed from the switchyard to provide power for station startup, shutdown and post-shutdown requirements.

8.1.3 Auxiliary Power Systems

The station auxiliary electrical systems consist of auxiliary transformers, one associated with each generating unit; 4160 V and 480 V ac distribution systems; a 120 V ac vital instrumentation and control system; a 125 V dc system; a 480 V emergency diesel-driven generator unit; and the associated switchgear, distribution panels, auxiliary equipment and motors.

The station does not have blackout start capability.

An emergency diesel-driven generator is provided as the on-site standby power source to supply station essential loads upon loss of all normal and reserve power sources. The essential loads consist of steam turbine generator shutdown loads, gasification subsystem shutdown loads, essential ac lighting load, vital ac system, battery chargers and other emergency loads as required. The station 120 V vital ac system



COAL GASIFICATION PLANT SINGLE LINE DIAGRAM
Figure 8-1

supplies uninterruptable power for the station instrumentation and other vital equipment. Each turbine unit has its own associated 125 V d-c batteries and battery chargers included in its auxiliary package.

8.1.4 Control Panels and Electronic Equipment Panels

Central and local control boards and panels and central computer and electronic equipment panels necessary for the control of all systems in the station are provided. The central panels, located in Control and Electronics Equipment Rooms are required for the safe and reliable operation of the station. Local control stations are located throughout the station.

8.1.5 Motors

All AC motors are the squirrel-cage induction type designed for full voltage starting with the lowest locked rotor current consistent with good performance and design. Motors larger than 250 HP are rated 4000 V, 3-phase, 60 HZ. Motors 200 HP and smaller to 1/2 HP and all motor-operated valve actuator motors are rated 460 V, 3-phase, 60 HZ. Fire pump motors are rated 460 V, 3-phase, 60 HZ. Fractional HP motors below 1/2 HP are rated 115 V, single-phase, 60 HZ. All AC motors are suitable for operation at the rated load with a combined variation of 10% above or below the rated voltage and frequency provided that the frequency variation does not exceed 5%. All AC motors, except the gas turbine starting motors, are able to accelerate their loads to full speed at 80% of the rated voltage at the motor terminals. The gas turbine starting motors are capable of accelerating their loads to full speed at 90% of the rated voltage at the motor terminals.

8.1.6 Miscellaneous Electric System Equipment

A station grounding grid is buried beneath the grade surface. The conductors are of sufficient size to carry the maximum ground fault current and to limit step and touch potentials to safe values under any fault condition. A separate instrumentation grounding is provided, connecting to the ground grid at one point only.

Communications from the station are accomplished by a limited number of outside lines. Internal communications primarily consist of a private automatic system and public address system. Telephones and loud speakers are located at selected points throughout the station. A cathodic protection system is provided for corrosion control, as necessary.

Normal, emergency and essential lighting is provided for the station building and selected outdoor areas. Normal and essential lighting panels are energized continuously from station motor control centers through individual local 480-120/208 V

four-wire dry type distribution transformers. The distribution transformer energized 120/208 V local lighting panels are dispersed throughout the station and associated outlying areas. Emergency lighting is supplied for illuminating vital areas and egresses.

Freeze protection transformers and panels with circuit monitoring provisions are furnished to provide protection for all equipment and piping subject to freezing.

8.1.7 Lighting

Normal, emergency and essential lighting is provided for the station building and selected outdoor areas. An essential lighting panel is energized continuously from the normal plant auxiliary system through individual 480-120/208 volt four-wire dry-type lighting transformers energized from the 480 V essential MCC. The essential lighting panels, dispersed throughout the plant and outlying areas as necessary, are sectionalized to handle the essential a-c lighting load.

The remainder of the a-c lighting (normal lighting) is energized continuously from the unit auxiliary system through individual 480-120/208 volt four-wire dry-type transformers mounted locally and energized from nearby motor control centers. Local lighting transformers and lighting panels are conveniently located throughout the station building and outlying areas.

Emergency d-c lighting for vital areas and egress lighting is fed from emergency sections of the various lighting panels. The d-c lighting is energized automatically upon loss of normal a-c lighting.

Outdoor lighting is controlled by photoelectric cells. A selector switch is provided to facilitate manual override or automatic operation of the outdoor lighting.

Control room lighting is so designed to provide glare-free lighting on the control board and includes ceiling fixtures and emergency a-c lighting.

The design illumination levels are based on levels recommended by the IES. Lighting fixtures are of the industrial fluorescent type for indoor areas, except for high bay installations where mercury vapor or high-pressure sodium types are used. For other areas, industrial incandescent fixtures, mercury vapor or high-pressure sodium fixtures are used. Outdoor illuminated areas include the intake structure, fuel unloading area, oil storage area, parking lots and transformer bays.

8.2 ELECTRICAL ONE-LINE HV SYSTEM

8.2.1 Generators

8.2.1.1 GAS TURBINE GENERATORS

The gas turbine generators are located on the ground floor of the building as shown on the Plant Island General Arrangement, Figure 7-3. The units are arranged so as to provide adequate space for operation, inspection and laydown of equipment during overhauls.

Each turbine-generator-exciter is factory assembled to check critical alignments, then disassembled to the level required by shipping regulations.

Each unit consists of a hydrogen-cooled generator with water coolers and a suitably-rated, direct-connected, air-cooled, brushless exciter with permanent magnet generator. The hydrogen-cooled generator assemblies include the stator core and winding, rotor and winding, bearings with vibration detectors, hydrogen cooling system, current transformers, neutral grounding transformer and resistor, temperature detectors and the three main leads at the top of the unit.

The brushless exciter assembly includes a permanent magnet generator with a permanent magnet field and armature, an ac exciter with rotating armature with a station field winding and regulator, a rotating rectifier with silicon diodes, bearings with vibration meters, temperature detectors, current transformer, and internally connected leads.

The hydrogen auxiliary control enclosure is mounted on the side of the generator, making it accessible for maintenance and inspection purposes.

8.2.1.2 STEAM-TURBINE GENERATOR

The steam-turbine generator is pedestal mounted and located in the center of the station building, as shown on the Plant Island General Arrangement, on the operating floor at elevation 25 ft. The unit is arranged so as to provide adequate space for operation inspection and the laydown of equipment during overhauls. The equipment arrangement is shown on the Plant Island General Arrangement, Figure 7-3.

The steam turbine, the generator and the exciter will be factory-assembled to check alignments and then disassembled and shipped as subassemblies. The physical size of the units, when assembled, exceeds the allowable shipping limits.

The generator will be a hydrogen inner-cooled machine with an air-cooled brushless exciter.

8.2.2 Main, Auxiliary and Startup Transformers

The main, auxiliary and startup transformers are located outdoors physically separated from each other as shown on the Plot Plan.

The transformers are of sealed construction with completely welded tanks and covers. The main and startup transformer high-voltage bushings are cover-mounted with terminals to accommodate overhead 161 kv conductors from the switchyard. These units are also provided with three station type lighting arrestors mounted adjacent to the HV bushings.

Each transformer is provided with a no-load tap changer, sudden pressure relay, temperature and oil level gauges, indicators and detectors, auxiliary cooling power equipment and accessory equipment for control, monitoring and protection of the unit.

Fire walls are to be installed between transformers and the units are protected by automatic water spray systems to extinguish oil fires quickly and prevent spread of fire.

8.3 ELECTRICAL ONE-LINE 5 KV SYSTEM

8.3.1 Switchgear 4160 Volts

The 4160-V switchgear are outdoor, metal-clad units rated 4160 volt, with 250 MVA interrupting capacity, horizontal drawout air circuit breakers. Each switchgear assembly consists of main incoming breaker unit, auxiliary units, feeder breaker units, bus, instrument transformers, relays, instruments, meters and control devices. These outdoor units incorporate features of weatherproofing, ventilation, heating and breaker transport truck.

8.3.2 480-V Auxiliary System Equipment

The distribution transformers associated with the station 480-V power centers and motor control centers are indoor dry type. The transformer high-voltage connection is suitable for copper cables entering from above or below with required compression-type terminal lugs. A low-voltage terminal compartment is provided for connection to the 480-V power center switchgear or motor control center buses. Transformers have Class H insulation for 150°C rise above 40°C ambient temperature. Four 2-1/2% full-capacity no-load taps are provided on each unit.

The 480 V-power center switchgear is indoor, metal enclosed with drawout-type air circuit breakers individually housed in front compartments with rear compartments for buses and power cable connections. Power and control cables are into the switchgear through the bottom or top as required. Solid state trip devices are

provided for each circuit breaker to achieve selective system coordination. All required instrument transformers, control devices, meters and relays are provided in the switchgear.

The 480-V motor-control centers are indoor rated 480 V and braced for fault conditions of 22,000 amperes rms symmetrical. The motor control centers include combination starters, breakers and other accessories and are completely factory assembled and tested. Separate compartments are provided for each combination starter, circuit breaker, vertical and horizontal buses. Provisions for power and control cables to enter from top or bottom are available.

The motor control centers for the gas-turbine generators' auxiliary equipment are included in the auxiliary package located adjacent to the corresponding unit. The motor control centers for the steam-turbine generator auxiliary equipment and other motor control centers are to be located throughout the plant in areas of electrical load concentration.

A motor control center is provided to supply power to the station equipment considered vital to safety of personnel and equipment during and after shutdown or during emergencies. This MCC is normally supplied from a 4160/480 V transformer, but upon loss of normal on-site and off-site power, it is supplied from the station emergency diesel driven generator. The loads normally connected to this MCC are essential ac lighting, vital ac system, battery chargers, turbine-generator shutdown loads as required and other emergency loads as necessary.

8.3.3 Generator Auxiliary Package

Each gas turbine is provided with an electrical auxiliary package, pre-packaged for shipment and located in the station building adjacent to the generator. The gas turbine-generator package contains the generator voltage regulator, protective relay panel, ac and dc motor centers, battery charger, battery and hydrogen monitor panel. The steam turbine generator auxiliary package contains equipment items which are functionally equivalent to those in the gas turbine generator auxiliary packages.

8.3.4 Motors

Unless specifically noted, motors have Class B insulation and are induction type, Design B.

Indoor motors are of drip-proof construction. Motors located outdoors are of weather-protected Type I construction with filters or are totally enclosed, fan-cooled. 4,000-volt motors and all 460-volt motors 25 HP and larger are furnished with space heaters that are automatically energized when the motor is idle.

8.3.5 125-V DC System

In addition to the 125-V DC batteries and battery charges included in the gas turbine auxiliary packages, the station is provided with a common 125-V dc system with associated batteries, battery chargers and distribution panels for supplying the station common dc requirements. The 125-V dc system provides continuous and reliable 125-V dc power source for control, monitoring, instrumentation and dc motor loads required for normal operation and orderly shutdown of the station.

SECTION 9

HOT-GAS CLEANUP

9.1 SYSTEM DESCRIPTION

The combined cycle power plant operating on coal-gas with a fuel gas cleanup system can be separated into three basic components: (1) the power island which contains the power generating equipment, heat recovery steam generators and supporting equipment; (2) the gasification system including the coal handling equipment; and, (3) the gas cleanup and disposal apparatus. In a system using hot cleanup, the power island and gasification system are very similar and in some instances exactly the same as those described in Section 2. The purification of the fuel gas in the hot cleanup method, however, is entirely different from that described in Section 2, where the fuel gas was cooled, scrubbed and purified at low temperature. But the function of either system is the same - (1) reduce the harmful components in the fuel gas to levels that meet emission regulations; and (2) avoid damage to the combustion turbine and heat recovery steam generator.

There are three basic pollutants that require apparatus to extract them from the fuel gas:

- Hydrogen Sulfide;
- Particulates;
- Ammonia, alkali metals and other trace elements.

SULFUR REMOVAL

Three hot cleanup systems show some promise of attaining an acceptable performance level for the desulfurization of coal-gas: The basic systems are: (A) Limestone; (B) Iron Oxide; (C) Liquid Metals, Liquid Salts, etc.

- (A) Limestone — The limestone method of desulfurization is somewhat misnamed in that the process utilizes dolomite. Dolomite ($\text{MgCa}(\text{CO}_3)_2$) contains the elements that make up limestone (CaCO_3). Under proper conditions, the limestone is calcined, (CaO), allowing it to react with H_2S to form CaS and H_2O .

The calcium sulfide is not an environmentally acceptable compound nor is the idea of constant replacement of the spent dolomite an economically acceptable factor. In addition, the other major compounds, calcium carbonate (CaCO_3) and magnesium oxide (MgO) in the spent sorbent also pose a disposal problem. It is, therefore, advisable to regenerate the spent sorbent, thereby reducing the amount of makeup sorbent requirements to a minimum. However, whether the cleanup process is once-through or regenerative, the physical removal of the sulfur must be considered as part of the system. On regenerative systems, the captured sulfur must be converted to some other form, preferably elemental sulfur. In the direct disposal method, the spent sorbent can be converted to acceptable compounds, including gypsum.

- (B) IRON OXIDE — The removal of the hydrogen sulfide from the raw gas can be achieved by passing the raw gas through a bed of iron oxide. The mixing of H_2S and Fe_2O_3 forms iron sulfide and water. As in the case of dolomite, the regeneration of the spent sorbent is a major item and must be considered in the overall economics of the cleanup system. The reaction of the iron sulfide with oxygen can yield SO_2 or elemental sulfur, depending upon the particular conditions. The formation of elemental sulfur is somewhat more complicated, since it requires an air and water spray stream along with a carbon disulfide wash. If the SO_2 reaction is used, elemental sulfur can be manufactured by commercially available means, such as the "Resox" system. The production of the SO_2 is highly exothermic, however, and careful control of the reaction is required.
- (C) ALTERNATE CONCEPTS — A variety of other methods have been investigated as possible avenues for hot-gas cleanup. Molten salts (Lithium, Sodium and Potassium carbonates acting as solvents for calcium carbonate) mixing with the raw gas form sulfides which can be regenerated. The regeneration is similar to the processes suggested in the dolomite method of gas cleanup. The molten salts system introduces a number of major problems, however. Trace amounts of alkali metals could reach the turbine hot section. In addition, there are basic metallurgical and operational problems within the cleanup system itself that indicate the molten salts method of cleanup is not readily adaptable to the coal gasification combined cycle power plant.

Several liquid metal sorbent processes have been investigated including mercury, sodium, potassium, zinc, lead, tin and others. There is not much information available on these items. Their very nature suggests possible problems with metal and metal oxide carryover to the combustion turbine. Several metals and metal oxides including cobalt, manganese, molybdenum, tungsten and copper have been investigated as candidates for hot-gas cleanup processes. Although all of them show promise as high-temperature sulfur sorbents, they are all more expensive than iron oxide. Since iron oxide performs so well, there is very little incentive to look at the more expensive metals.

PARTICULATE REMOVAL

The removal of dust, fines and the other forms of particulates in the fuel gas stream must be removed to a safe level before entering the gas turbine. It is not possible to state what the acceptable limits are for a particular combustion turbine without careful testing but it is obvious that the size and amounts of particulate must be small to avoid clogging of cooling passages, erosion and corrosion of critical hot parts and premature failure of seals. Pollution regulations also dictate the necessity for particulate removal. There are a variety of apparatus available for the removal of particulates. Cyclone separators serve to collect the larger particles but the use of granular bed filters are required to collect the smaller ones. Several systems are under development at present—each showing its particular promise and potential problems. One of the more significant problem areas is the back-flushing cleanup process of the granular bed filter. There is potential for significant penetration of particles while cleanup is in progress. Further effort is required to develop the equipment to its full commercial potential.

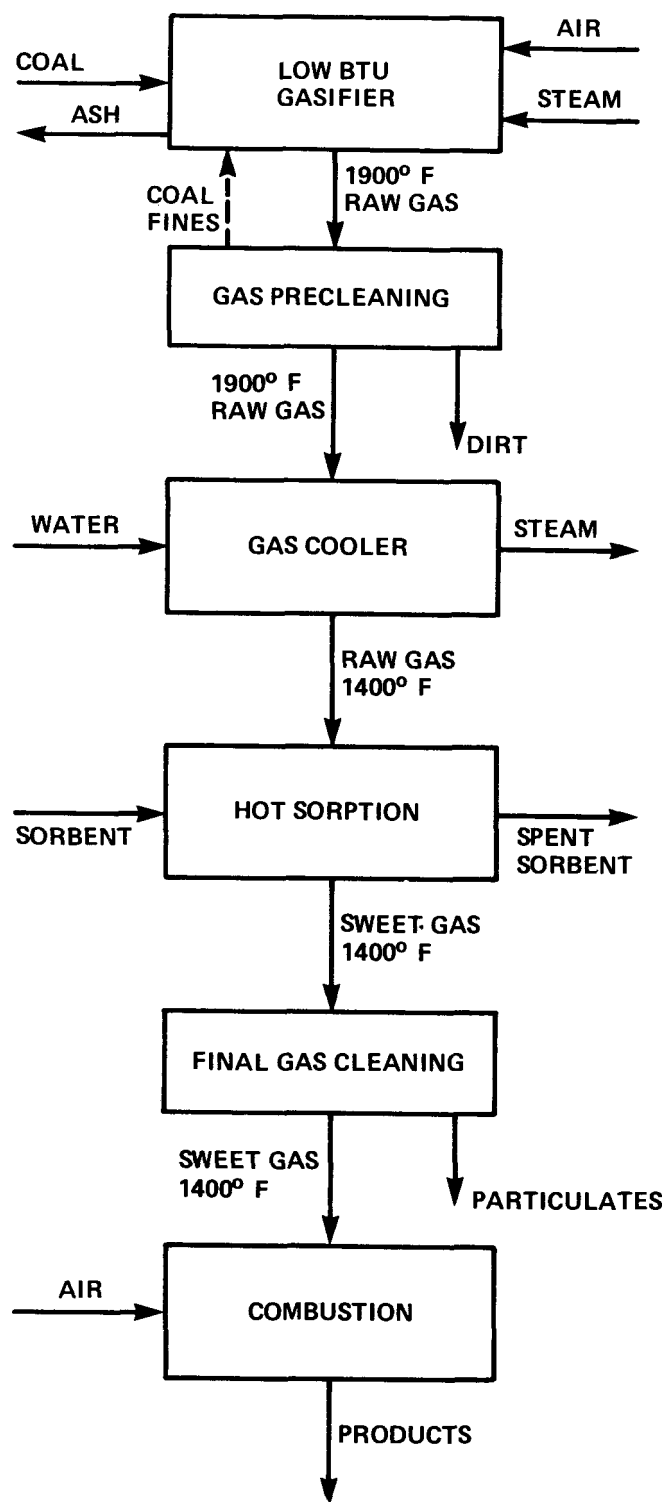
AMMONIA AND TRACE METALS

In the gasification process, a small amount of ammonia is generated. In the "cold" cleanup process, the major portion of the NH_3 is removed by the scrubber. In the hot cleanup arrangement, the NH_3 carries through and becomes a major factor in the production of NO_x in the combustion turbine. Therefore, it may be necessary to resort to staged combustion or use water/steam injection in order to comply with anti-pollution laws.

In practically all of the schemes discussed, the possibility of trace amounts of potentially harmful metals and metal oxides being carried over to the combustion turbine exists. Sulfidation, erosion and other hot section problems, some of which may not yet be known, could arise from the operation of a particular hot-gas cleanup system. The chance of failing to meet an emission regulation is also present.

A schematic representation of the material flow for the coal gasification process with hot-gas cleanup is displayed on Figure 9.1-1. Gasification and pre-cleaning is practically identical to the equipment described in Section 2.

Since the raw gas leaves the gasifier at 1900°F , a gas cooler is required. The gas cooler generates steam to be sent to the steam turbine, although not in quantity equal to that of the "cold" cleanup cycle. The reduced amount of steam being produced in the gas cooler altered the HRSG component duties sufficiently to cause a change in the feedwater heating system. This will be addressed further in the discussion of the cycle diagram and heat balance.



SCHEMATIC REPRESENTATION OF MATERIAL FLOW
Figure 9.1-1

The temperature of the raw gas entering the cleanup apparatus has been set at 1400°F. This temperature is not so much a limitation of the cleanup equipment as it is a limit on the turbine combustor, piping and manifold in order to maintain design integrity.

In the calculation of the cycle performance, it is assumed that the gas maintains 1400°F temperature at combustor inlet.

9.2 EQUIPMENT AVAILABILITY

Although various components of the entire hot-gas cleanup process have functioned in a variety of capacities and instances, to date there is no single system of appropriate size and scope to demonstrate that any hot-gas cleanup method of removing sulfur and particulates is a safe, viable, environmentally acceptable and economically desirable solution.

All of the systems that are being developed pose their own particular problems in some or all of the following areas: turbine operation, physical removal of spent products, environmental suitability, equipment metallurgical operational integrity, and economics. This does not preclude the eventual solution to all of the problems; but, it indicates that a functioning combined cycle power plant fuelled by coal gas and cleaned by the hot cleanup method cannot be the main thrust for the development of a coal-gas fired plant at the earliest possible date.

At this point, it appears that a plant using the hot-gas cleanup system will become a later generation of coal-gas combined cycle plants.

9.3 TURBINE EFFECTS

The performance of the combustion turbine changed appreciably for a number of reasons when it was switched from the "cold" cleanup cycle to the hot-gas cleanup mode of operation. Although the hydrogen sulfide is removed from the fuel gas in both instances, the water vapor remains in the hot-gas case, thus changing the fuel gas molecular weight and heating value. In addition, the air bleed/turbine fuel ratio also changed, even though the coal, steam and air ratios in the gasification system, itself, remained unchanged. These factors coupled with the fuel temperature increase from 620°F to 1400°F affected flows, temperatures, pressures and output. Table 9.3-1 lists the various turbine parameters at 2600°F turbine inlet temperature for both cleanup processes.

9.4 CYCLE DIAGRAM AND HEAT BALANCE

The combined cycle diagram shown on Figure 9.4-1 shows the major components, interfaces, flows, temperatures, enthalpies and pressures for the hot cleanup coal-gas combined cycle plant. Gross kilowatt output based on one gas turbine and one steam

TABLE 9.3-1

A comparison of various turbine parameters between "cold" and "hot" methods of fuel gas cleanup based on ISO conditions and 2600F turbine inlet temperature

Item	Description	Cold	Hot
1.	Inlet Air Flow	754 lb/sec.	754 lb/sec.
2.	Bleed Air Flow	142.83 lb/sec.	126.45 lb/sec.
3.	Cooling Air Flow	131.62 lb/sec.	131.62 lb/sec.
4.	Fuel Low Heat Value	2037 Btu/Lb.	1917 Btu/Lb.
5.	Fuel Gas Molecular Wt.	24.61	24.37
6.	Fuel Gas Temperature	620F	1400F
7.	Fuel Gas Flow	182.35 lb/sec.	173.64 lb/sec.
8.	Compressor Pressure Ratio	15.0	15.2
9.	Compressor Disch. Temp.	731.1F	736.2F
10.	Exhaust Gas Flow	793.50 lb/sec.	801.17 lb/sec.
11.	Exhaust Gas Temp.	1221.7F	1219.3F
12.	Power at Coupling	133,749 KW	138,750 KW
13.	Thermal Efficiency	34.14%	39.52%

turbine is 230,689. The electrical auxiliaries allotted for this configuration are 10,097 kw which results in a net power output equal to 220,592 kw with a net higher heating value heat rate of 7,740.3 Btu/KwH. Using a plant configuration comprised of four gas turbines and one large steam turbine yields a net plant output of 882,368 kw. It must be pointed out, however, that all electrical auxiliaries and utilities required for gas cleanup and supporting apparatus have not been included in their entirety due to the uncertainty of the type of cleanup process, mode of sorbent regeneration and method of sulfur and particulate disposal. It necessarily follows that the performance shown will be affected adversely by the added utilities and interfaces that will be required. These added utilities and interfaces will take the form of additional fuel, steam or water from the cycle, and electric power in varying degrees, depending upon the particular type of gas cleanup process.

Other major components not shown on the diagram whose power requirements have been accounted for in the electrical auxiliaries are the coal handling and crushing apparatus, gasifier auxiliaries, circulating water equipment, ash handling equipment and main power transformers.

The basic train of events in the system is the following:

Coal enters the treater (sometimes referred to as the pretreater) where it is partially oxidized to accomplish an encrusting process for ease of transfer to the fluidized bed. The treater off-gas goes to the gasifier. More hot air and steam further oxidize and gasify the coal into a raw coal-gas at 1900 degrees Fahrenheit, plus some char and ash. The gas cooler performs its function, reducing the raw gas temperature to 1400^oF and at the same time producing high-pressure steam for the steam turbine. The gas cleanup apparatus ultimately produces a fuel gas at 1400^oF whose sulfur content is targeted in the range of 200 parts per million by weight.

The gas turbine produces almost 136,000 kilowatts and provides 1,219^oF exhaust gas to the heat recovery steam generator (HRSG). The steam produced in the HRSG, along with the gas cooler steam are joined and fed to the steam turbine.

The amount of steam being generated in the gas cooler is less than the amount produced in the cycle using "cold" gas cleanup since the gas is cooled to 1400^oF rather than 300^oF. The reduction in steam also reduces the economizer duty in the HRSG. The end result is the elimination of the closed heater because the low pressure coil in the HRSG now performs a major portion of the feedwater heating. The HRSG also reheats the steam and heats feedwater as well. The total steam generated in the gas cooler and HRSG enable the steam turbine to produce over 94,000 KW.

The main system interfaces are:

1. Gas turbine compressor air is exported to the treater and gasifier.
2. Hot reheat steam is exported from the HRSG to the gasifier.
3. Superheated steam is sent from the gasifier gas cooler to the steam turbine.
4. The boiler feedpump discharge stream is split with a portion going to the air cooler heat exchanger and a portion going to the HRSG economizer.
5. A portion of the HRSG economizer discharge is sent to the gas cooler drum and the HRSG drum.

Table 9.4-1 lists the various flow ratios for fuel, air and steam that relate to the coal-gas combined cycle with hot-gas cleanup. The table is incomplete with regard to quantities for the gas cleanup apparatus due to lack of definition. Tables 9.4-2, 9.4-3 and 9.4-4 list the gas constituents for the fuel before and after cleanup and the exhaust gas constituents being discharged from the combustion turbine.

TABLE 9.4-1
FLOW RATIOS FOR THE COAL GAS-FIRED COMBINED CYCLE PLANT

Based upon 2600 degrees Fahrenheit turbine inlet temperature with coal gas at 1400 degrees Fahrenheit and an LHV = 1917 Btu/Lb.

1. Purified Fuel to Gas Turbine	1.0
2. Raw Gas From the Gasifier	1.0100
3. Air @ 700 ^o F to Treater	0.08898
4. Air @ 700 ^o F to Gasifier	0.63927
5. Air From Gas Turbine (Items 3 and 4)	0.72825
6. Coal to Process	0.24991
7. Steam @ 400 psi, 1000F to Gasifier	0.06023
8. Make Up Water of Condensate Quality	0.06023

Note: Quantities relating to the gas clean up system are not included.

TABLE 9.4-2
GAS CONSTITUENTS LEAVING THE GASIFIER AT 1900 DEGREES FAHRENHEIT

Constituent	Weight Percent
Carbon Monoxide - CO	23.09
Carbon Dioxide - CO ₂	13.88
Hydrogen - H ₂	1.29
Methane - CH ₄	1.01
Hydrogen Sulfide - H ₂ S	0.94
Carbonyl Sulfide - COS	0.05
Nitrogen - N ₂	55.24
Ammonia - NH ₃	0.02
Water - H ₂ O	4.48
	100.00

TABLE 9.4-3
GAS CONSTITUENTS ENTERING GAS TURBINE COMBUSTORS AT 1400 DEGREES FAHRENHEIT

Constituent	Weight Percent
Carbon Monoxide - CO	23.37
Carbon Dioxide - CO ₂	14.05
Hydrogen - H ₂	1.30
Methane - CH ₄	1.02
Hydrogen Sulfide - H ₂ S	0.00
Carbonyl Sulfide - COS	0.05
Nitrogen - N ₂	55.64
Ammonia - NH ₃	0.02
Water - H ₂ O	4.55
	100.00

TABLE 9.4-4
EXHAUST GAS CONSTITUENTS LEAVING THE GAS TURBINE AT 1221 DEGREES FAHRENHEIT

Constituent	Weight Percent
Oxygen - O ₂	12.02
Carbon Dioxide - CO ₂	11.62
Water - H ₂ O	4.50
Nitrogen - N ₂	70.80
Sulfur Dioxide - SO ₂	0.01
Argon and Other Traces	1.05
	100.00

SECTION 10

MAINTENANCE

10.1 MAINTENANCE PROGRAM

10.1.1 General

The Phase I Maintenance Program consists of an outline of the approach to be taken in structuring the final maintenance program.

An optimum program should result in the most cost effective utilization of the system being serviced. The formulation of the program will consider the reliability of the design and the functional and physical relationships between subsystems in planning a maintenance program which will maximize plant availability.

The ultimate objective of a maintenance program is to reduce forced outage time to zero, while realizing the maximum possible output from the plant. The development of the maintenance program will be based upon the following information:

- Component mean time between failure estimates based on design analyses, and past performance of identical or similar components.
- The accessibility of components for servicing.
- The effect of each component upon its functional loop, and the impact of that loop upon the generating capability of the plant.

This type of information can evolve during the definition and design phases of the program, and is further upgraded with data derived from the testing performed during Phase II and Phase III.

With the plant in operation, the maintenance program enters its final phase, that of implementation. Further refinement of the program should be carried on during the entire operating life of the plant. This refinement is based upon:

- Revised mean time between failure data resulting from the operation of new designs incorporated into the system.
- Analyses of data recorded during the operation of the plant. Such analyses should include a search for changes in performance and operating characteristics, and the identification of time-related trends for the purpose of scheduling maintenance in a timely and economical manner.

10.1.2 Maintenance Program Development

The two fundamental questions which a maintenance program must address are:

- What action must be taken.
- When the action must be taken.

The What action is based upon the detailed design of components and upon their physical location in the plant. What actions are defined by instructions which include the parts and equipment needed to perform the work. The preparation of these instructions requires a level of definition of the plant systems which is not within the scope of Phase I. For this reason, work on maintenance instructions will not be initiated during Phase I; however, the plant and subsystem designs have been reviewed with respect to the allocation of adequate space and facilities to maintain the systems. Design features of the plant and equipment which provide for Maintainability are discussed in Sections 10.2 and 10.3.

The When action is concerned with performing the required maintenance on the plant in a timely manner in order to preclude failures, while minimizing the effect of the maintenance outage time. Factors contributing to a When decision consist of the following:

1. Component mean time between failure estimates which define the intervals at which components must be serviced in order to have a high probability of precluding failures.
2. The effect of components upon the operation, safety, and performance of the system. This information modifies the priorities established by the mean time between failure estimates, in that components whose failure effect is tolerable from a performance, operation and safety aspect need not dictate the interval between scheduled maintenance outages.
3. The location of a component in a functional (steam supply, circulating water, etc.) loop affects its maintenance cycle, in that scheduled maintenance outage periods may be dictated by other components in the loop.
4. The physical location of a component can influence its maintenance cycle by virtue of its accessibility with respect to other components. The design will be such that access to critical components will require the minimal removal of less critical components.

Prior to the startup of the plant, a program for reviewing operating data must be defined in order to detect trends in the performance of plant components. Analyses of these trends can then be used to modify the maintenance schedule. For this reason, operating instrumentation will be reviewed during the design period to assure that sufficient data will be recorded to permit detecting impending failures.

10.1.3 Phase I Maintenance Planning

The maintenance planning performed in Phase I consists of a Maintenance Characteristic Identification Chart (Figure 10-1), which indicates the probable source of maintenance information for each of the major plant systems.

10.2 SET DOWN SPACE AND ACCESS

The arrangement of the major components and equipment trains within the plant allows sufficient set down space to permit the simultaneous disassembly and repair of all of the major components.

The overhead cranes in the turbine hall service the assembly and disassembly of the plant turbines and generators. The set down area covered by the cranes is sufficient to support this activity.

In the (HRSG) area, ladders, walkways and platforms will provide access to smaller components for maintenance and repair. The overhauling of the larger components in this area may require the use of portable cranes and rigging equipment. Clearance is provided on all sides of clusters of major system components to permit the entry of maintenance equipment, and, for the removal of system components, if necessary.

Space has been identified for the tube removal of heat transfer equipment items; and, care has been taken in the location of the auxiliary skids to allow space for the replacement of skid-mounted equipment.

10.3 SPECIAL TOOLS AND HANDLING FACILITIES

Special tools and handling facilities required for maintenance and repair work will be identified in Maintenance Instructions. These Instructions require a level of hardware definition which is not within the scope of Phase I; therefore, the identification of special tools and handling equipment has not been accomplished during Phase I.

During the hardware design period, the requirements for special tools and handling facilities will be reviewed with the objective of minimizing the number required.

Major Plant System or Component	Maintenance Requirements Source
Steam Turbine	Steam turbine is similar to existing units in operation. Maintenance planning will utilize data accumulated from field operation.
Steam Condenser	Design is similar to existing units. Maintenance data to be extracted from field experience with these units.
Steam Turbine Generator	Similar units are in operation. Maintenance planning will be based upon operational data from the field.
Gas Turbine Compressor	Similar to W501. Maintenance requirements will be based on W501 field experience.
Gas Turbine Combustors	New design for higher firing temperature. Maintenance program will be based on reliability analyses and test data.
Gas Turbine Turbine	New design. Cooling system performance is essential for long turbine life. Maintenance information will be from reliability analyses and verification test program.
Gas Turbine Generator	Similar units are in operation. Maintenance planning will be based upon operational data from the field.
Lube and Seal Oil Systems	System is composed of proven commercially available components. Maintenance planning will be based on vendor data and field experience.
Starting System	Similar to the W501 unit. Maintenance requirements will be obtained from W501 field experience.
Heat Recovery Steam Generator	Similar to PACE units. Maintenance requirements will be based on PACE field experience.

Figure 10-1
MAINTENANCE CHARACTERISTIC IDENTIFICATION CHART

Major Plant System or Component	Maintenance Requirements Source
Plant Control System	Design based on PACE System. Maintenance planning will rely upon field experience.
Coal Pre-Treatment System	Coal injection lock hoppers and coal inlet and outlet valves will require careful analyses. These analyses will be the basis for the maintenance planning.
Coal Gasifier	Relatively new design and maintenance requirements must be based upon reliability analyses and limited operational experience.
Gas Cooling (Waste Heat Boiler)	Gas cooler operation is similar to HRSG steam generation. Maintenance data from HRSG field operation will be the basis of planning.
Gas Purification Water Scrubber	System is composed of proven commercially available components. Maintenance planning will be based upon vendor product data.
Gas Purification Selexol System	System will utilize commercially available components. Maintenance planning will rely upon component vendor data and system reliability analyses.
Sulfur Production System (Claus Unit)	Maintenance planning will be based upon existing on-stream experience and the results of reliability analyses.
Gas Purification Process Water Treater	Reliability analyses will form the basis of the maintenance plan. Particular attention will be given to the effect of corrosion on the system components.
Balance of Plant Systems	Majority of the BOP systems are of a conventional design and are made up of proven commercial components and the maintenance requirements for these systems will be based on component vendor data and field experience.

Figure 10-1
MAINTENANCE CHARACTERISTIC IDENTIFICATION CHART (Continued)

SECTION 11

RELIABILITY, MAINTAINABILITY AND AVAILABILITY

11.1 OBJECTIVE

Dependable operation of the plant in consonance with the design objectives cited in Section 1 is the principle objective of designing for reliability. It encompasses an integration of the necessary technologies to attain a system which maximizes the return on the investment as well as meeting the necessary safety and environmental requirements.

To achieve the best return on investment the design for reliability must include the broader system goals of availability and plant capacity factor, so that the design approach is more logically described as a design for Reliability, Maintainability and Availability, or simply "design for RMA".

As discussed by many others, the incorporation of space systems technology into industrial/commercial applications has led to broader understanding and utilization of the technology. Applying this broader understanding has resulted in the use of the plant capacity factor term as a bridge between one shot or "how long" missions and those with the additional dimension of "how much".

Design for RMA must therefore have as its objective the optimization of a design from the viewpoint of reliability, maintainability and availability tempered by an objective to maximize the plant capacity factor.

11.2 APPROACH

To assure that the above noted objectives are achieved, the technologies identified are being used as part of the design process in order to impact concept selection.

Failure Mode Effects and Criticality Analyses (FMECA) are being performed at the system level to identify single failure points—those related to safety and/or complete shutdown—and to assess the impact of other failures on plant availability and capacity factor. The format chosen for performing the system FMECA is shown typically in Figure 11-1.

SYSTEM FAILURE MODE EFFECTS AND CRITICALITY ANALYSIS * * * WORK SHEET

COMPONENT/SUBSYSTEM: _____
REFERENCE: SYSTEM FLOW DIAGRAM SCHEME IV

PREPARED BY: _____
REVISION: _____

SHEET ____ OF ____
DATE: 12-1-76
DATE: 9-2-76

FAILURE MODE (CODE =)	PHASE	EFFECTS ON SYSTEM OPERATION		DETECTION METHOD	CRIT CATEGORY
		WITHOUT COMPENSATION	CORRECTIVE ACTION		

FMECA WORKSHEET
Figure 11-1

Fault tree analysis will be performed to establish failure mode causes for selected failure modes. This is done to augment the FMECA in areas where more detailed definition of subtier components is available and to develop a manageable use of the technique for Phase II.

RMA modelling has been initiated to the extent possible during Phase I. This has been done to assess the reference design, the impact of failure mode effect removal, and to initiate effort in establishing availability criteria for the major units of the reference design.

11.3 FAILURE MODE EFFECTS AND CRITICALITY ANALYSES (FMECA)

Utilizing the layouts and flow diagrams developed for the system described in Section 2 of this Report, a FMECA will be completed at the system level, using the format shown in Figure 11-1, and implemented by well-documented procedures.

In order to assess the importance of each failure effect, criticality factors were developed. The categories were derived on the basis of safety and effect on power output. Table 11-1 lists the chosen criticality categories.

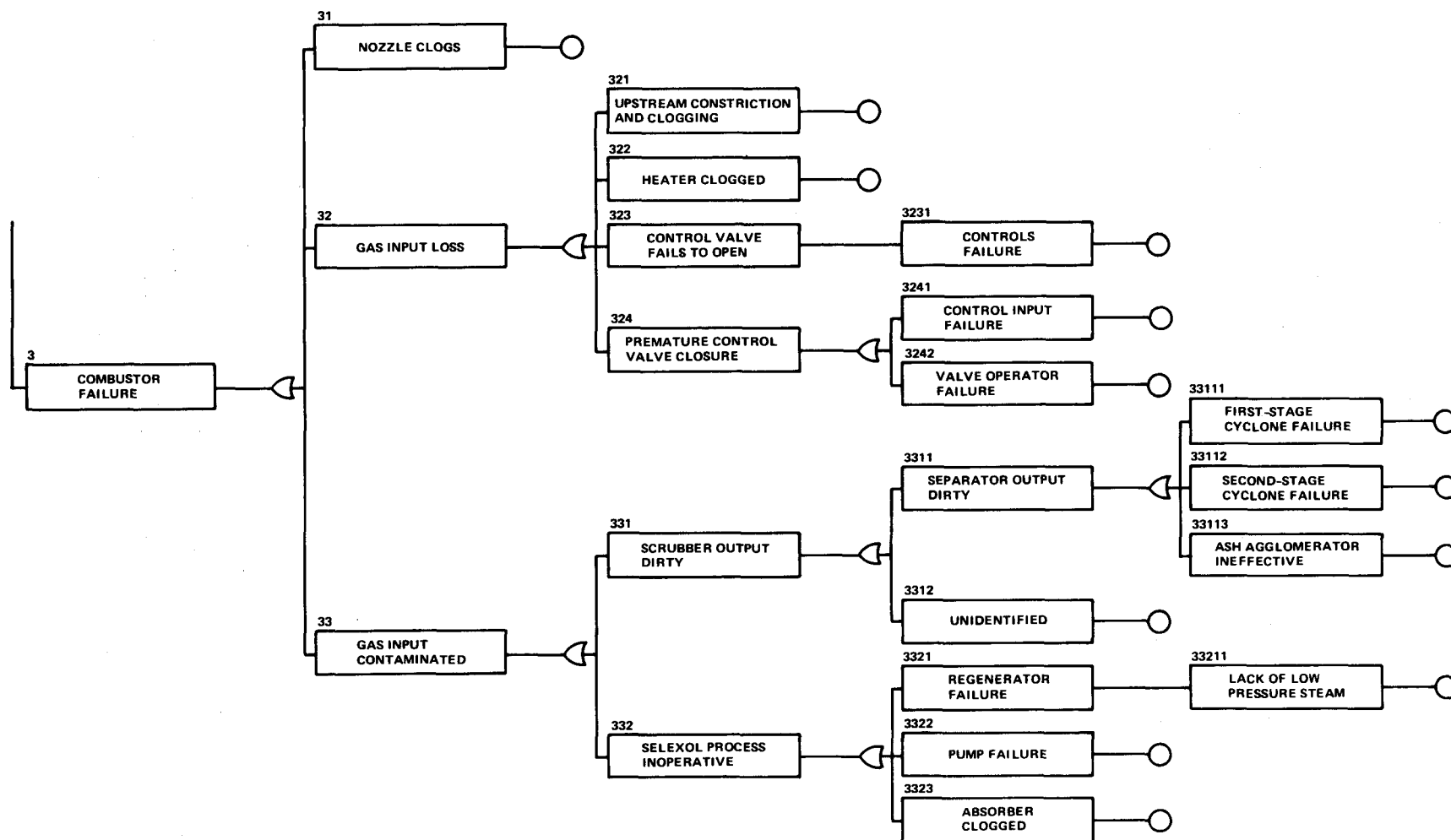
Items in category A or S are generally considered single failure points for purposes of this study. Single failure points require well considered risk evaluations, usually mandating design alternatives and contingency plans for either eliminating the effect or reducing risk to an acceptable level. During Phase I of this program no attempt to study failure probabilities in detail has been made. As definition of components develops in ensuing phases, these data will permit tradeoffs in those areas identified as sensitive to component failure rate.

11.4 FAULT TREE ANALYSIS (FTA)

Fault Tree Analysis has been performed, using certain system failure modes as undesired events and proceeding downward to levels of detail consistent with the present study. More extensive use of FTA in Phase II is planned to develop definitive failure mechanisms and to augment the reliability/availability modeling. A typical fault tree, generated using the Westinghouse Simplot method, is shown in Figure 11-2.

11.5 RMA MODELLING

The potential effect of component reliability and maintainability on system's availability and on life cycle costs cannot be ignored, particularly in the early design phase. In addition, the plant capacity factor as it is understood in the power generation community provides important criteria in designing for RMA.



FAULT TREE SEGMENT FOR FMECA (20-1-4) USING WESTINGHOUSE SIMPLOT
Figure 11-2

TABLE 11-1
CRITICALITY CATEGORIES FOR FMECA

A	100% Loss of Power Output
B	75 - 100% Loss of Power Output
C	50 - 75% Loss of Power Output
D	25 - 50% Loss of Power Output
E	10 - 25% Loss of Power Output
F	0 - 10% Loss of Power Output
S	Possible personnel safety effect

In a base load plant such as the reference design, a principle objective is to have the plant available at rated output the highest possible fraction of the time. On the other hand it is drastic to have a base load plant susceptible to any significant number of single failure points such that plant reliability must be very high, even out of reach, in order to pay off in terms of capacity factor. The number of single failure points and the plant capacity factor can be improved by utilizing quasiredundant systems, such as in the combined cycle systems, wherein the increase in the number and cost of maintenance actions is offset by the improved capacity factor.

In the reference design, four coal gasification/gas turbine trains interact with a single steam turbine to comprise the system. Each train is essentially independent and, at the time of this analysis, contributes approximately twenty-five percent to the power output, fourteen percent as direct output and eleven percent as output from the steam turbine. Final heat balance iterations may change these ratios requiring adjustments to the model in Phase II. In the event of an independent failure of a single train, then, power output is reduced by approximately twenty-five percent (exclusive of any control makeup). A model for plant availability in terms of various power ratings can be developed which underlines the inherent advantage of the reference design.

For the full plant rating, all gas turbines and the steam turbine must be available, so that a model, to represent the condition is:

$$A_{(100\%)} = SG^4$$

where

S is the steam turbine subsystem availability

and

G is the gas turbine subsystem availability.

If it is assumed that the steam turbine is independent of the gas turbine train, then a binomial model could be used to show the advantage accrued in the reference design. However, there are certain constraints and interdependencies which preclude the use of a simple binomial model. When all the system states are defined in terms of on-off states for the major components and it is recognized that certain states are disallowed because of impracticality, then the model appears as below.

$$\begin{aligned}a_{100} &= SG^4 = A_{(100\%)} \\a_{75} &= 4S (1-G) G^3 \\a_{55} &= (1-S) G^4 \\a_{50} &= 6S (1-G)^2 G^2 \\a_{40} &= 4 (1-S) (1-G) G^3 \\a_{30} &= 6 (1-S) (1-G)^2 G^2 \\a_{25} &= 4S (1-G)^3 G \\a_{15} &= 4 (1-S) (1-G)^3 G\end{aligned}$$

where

a_i is the system state availability.

Thus

a_{100} is the availability for the plant at full rating with all trains operating,

and

a_{55} is the availability of the plant for the state of all gas turbine trains operative and the steam turbine inoperative.

The availability of the system for some minimum power is defined as the collection of those acceptable system state availabilities,

so that:

$$A_{100} = a_{100}$$

$$A_{75} = a_{100} + a_{75}$$

$$A_{50} = a_{100} + a_{75} + a_{55} + a_{50}$$

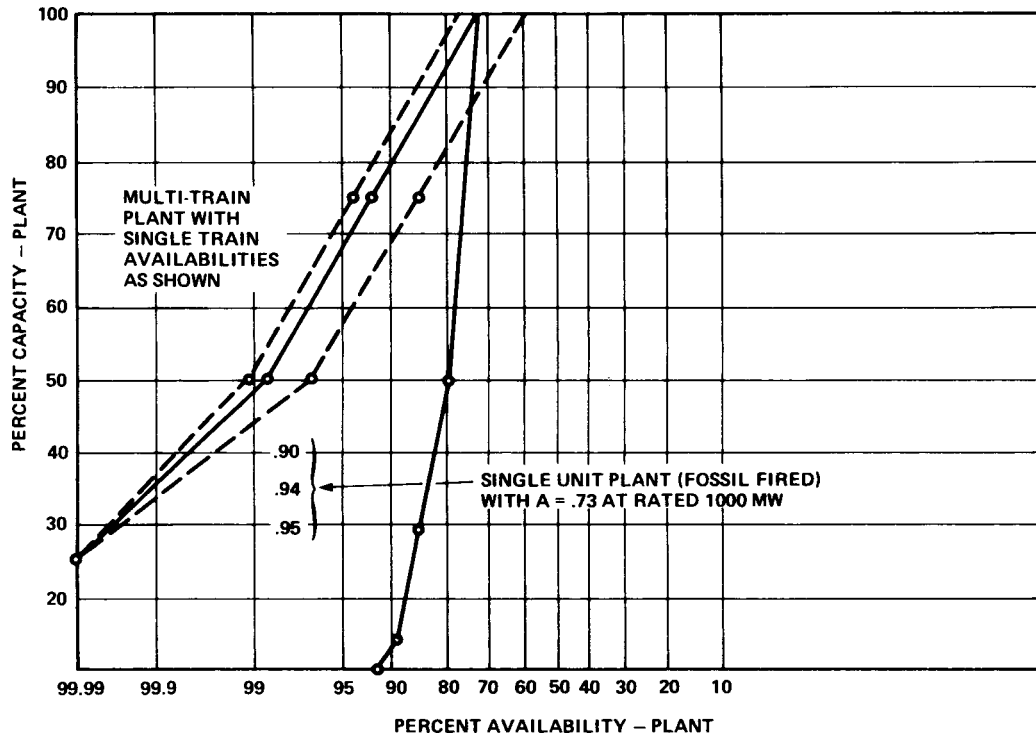
$$A_{25} = a_{100} + a_{75} + a_{55} + a_{50} + a_{40} + a_{30} + a_{25}$$

$$A_{15} = a_{100} + a_{75} + a_{55} + a_{50} + a_{40} + a_{30} + a_{25} + a_{15}$$

The partial sums in the model clearly demonstrate the advantage of the combined cycle systems in terms of accrued availability improvement.

Figure 11-3 shows curves which are a plot of plant availability versus output power for various major component availabilities. These example curves point out the possible advantages of the quasiredundant configuration used for the reference design. The curve for the single unit plant shows availability for power output below plant rating improving over rated load performance, but also establishing an availability that reflects all the areas of nonimprovement, such as average stress failures, procedural difficulties, maintenance, complexity, etc., which are not affected by plant output. The corresponding curve for the reference design permits comparison to a single unit plant of size equivalent to the reference design. Starting with an availability of approximately 73 percent for a plant of this size, it is seen that the single unit plant availability may go as high as 92 percent based on FEA data* for a plant of 1/10 size.

*See Figure 1, Page 18 of "A Report on Improving the Productivity of Electric Power Plants," dated March 1975 (Reference No. 3).



AVAILABILITY OF THE REFERENCE DESIGN
Figure 11-3

Comparing this with the curve of $A = .94$, it is seen that significant improvement in availability is obtained for partial power operation. With an initial reference design availability below the single unit plant availability such as for $A = .90$, the gains for partial power are so rapid they still show the reference design favorably. If indeed the assumed curve for the single unit plant is reasonable, potentially large gains in plant performance are realizable with the reference design.

CAPACITY FACTOR

Consider these effects on capacity factor. In a base load plant operation the demand tends to approach plant rating. Under these conditions, the plant capacity factor is more directly related to the plant availability and its output capability at that time. This is a decided advantage for the reference design. If one defines an expected value for capacity factor by

$$\hat{CF} = \sum A_i C_i$$

where

A_i is the availability for capacity C_i over the exclusive interval i , then computes for comparison the expected capacity factor for the reference plant and also for the single unit fossil plant, the results shown in Table 11-2 are obtained. These results indicate that, for the examples used,

a significant gain in capacity factor can be realized using the quasi-redundant approach of the reference design. Put another way, forced outages and maintenance on the reference design will, for the most part, result in only partial power loss.

The impact of this approach has not been assessed in detail, but its potential appears significant and worthy of study. This benefit must be measured against the cost of increased maintenance actions required by the 4 individual trains. Furthermore, the modelling described above requires in-depth analysis of data as well as model refinement more appropriately done in Phase II where explicit design and performance data will be obtained.

**TABLE 11-2
EXPECTED CAPACITY FACTORS FOR A 4 TRAIN PLANT**

Plant	Single Train Availability	Plant Availability (Rated Output)	Expected Capacity Factor CF
(1) Fossil	.73	.73	.81
Comb Cycle	A .95	.77	.94
	B .94	.73	.93
	C .90	.59	.88

For example:

Assume that the major unit availabilities are identical:

$$S = .94$$

$$G = .94$$

Plant Availability (Rated Output)

$$A = SG^4 = .94^5 = .73$$

Expected Capacity Factor

$$\begin{aligned}
 CF &= \sum C_i A_i \\
 &= 100a_{100} + 75a_{75} + 55a_{55} + 50a_{50} + 40a_{40} + 30a_{30} + 25a_{25} + 15a_{15} \\
 &= 100 (.734) + 75 (.188) + 55 (.047) + 50 (.018) + 40 (.012) + 30 (.001) + \\
 &\quad 25 (.0008) + 15 (0) = 91.5 \%
 \end{aligned}$$

AVAILABILITY DESIGN CRITERIA

Availability goals can be established for the principal units of the reference design using techniques like those described above. In fact, the unit availability of .94 represents a goal, which, when achieved, will result in a system availability comparable to the single unit plant availability shown in Table 11-2. Availability goals for the steam turbine subsystem and the gas turbine trains can be apportioned according to their individual reliability/maintainability characteristics, using well-known techniques, in conjunction with the FMECA. For example, knowing that

$$A = A^1 = A^{X_1} \cdot A^{X_2} \cdot A^{X_3} \dots A^{X_1}$$

where

$$\sum_k X_k = 1$$

The apportionment for the two different trains becomes

$$A = A^{X_1} A^{X_2} A^{X_3} A^{X_4} A^{X_5}$$

where

the proportionality factors X_k represent the most logical mix based on R, M, A characteristics as seen analytically and based on realistic appraisals of past performance.

Finally, since

$$X_2 = X_3 = X_4 = X_5,$$

the availability goals for the reference design become

$$S = A^{X_1}$$

$$G = A^{X_2}$$

For example, if system availability, A, is chosen as .73 (the fossil plant availability shown in Figure 11-3, then the availability of each major unit is given by

$$S = .73^{X_1}$$

$$G^4 = .73^{4X_2} \text{ and } X_1 + 4X_2 = 1$$

Assume that, based on complexity and performance history, steam turbine units exhibit higher availability than gas turbines. This results in a normalized steam turbine rating of say $1/2X_2$,

so that

$$1/2X_2 + 4X_2 = 1$$

and

$$X_2 = .22$$

$$X_1 = .11$$

Finally the goals for the major units become:

$$S = .73^{.11} = .97,$$

and

$$G = .73^{.22} = .93$$

The selection of A in the first place will bear significantly on efforts to achieve the unit goals. Trades between unit and system goals using expected capacity factor as an ultimate evaluation are possible. Likewise the optimization of unit number (i. e., how many trains) in a combined cycle system could be affected by choice of system availability goal, particularly if this goal is defined for the rated output of a base loaded plant.

A basic approach to establishing unit goals in Phase II will be to take full advantage of our experience in these systems and identifying the necessary R and M improvements to achieve an availability goal for rated plant output.

SECTION 12

OPERATION MODES

The integrated coal gasification plant must be capable of operating in various modes from cold standby to power generation and back to cold standby. These modes include both steady-state and transient conditions.

The steady-state operating modes for the plant are:

1. Cold Standby;
2. Cold, Ready-to-Start;
3. Hot, Ready-to-Start;
4. Generation, Rated Load;
5. Part Load.

The transient operating modes occur in passing from one steady-state condition to another. In addition, abnormal operating conditions must also be considered as transient cases.

The discussions that follow summarize the status of the full plant, the various subsystems within the plant, and related auxiliary equipment during the various operating modes.

12.1 STANDBY AND READY-TO-START

Prior to actual running operation, it is possible for the plant to be in any one of three steady-state modes. These modes include: Cold Standby; Cold, Ready-to-Start; and Hot, Ready-to-Start. A general definition for each of these modes follows.

COLD STANDBY

In the cold standby operating mode, the plant is shut down.

Equipment is generally placed in this mode when an extended outage is expected. Auxiliary power is available to the plant, but conservation of auxiliary power and operating materials, such as hydrogen gas, is recognized. Idle fluid systems and equipment are protected, as required by ambient temperature.

COLD, READY-TO-START

In this mode, the plant is shut down, but subsystem auxiliaries are in operation and fluid systems are maintained, such that the plant is capable of being started by the control room operator.

In effect, this mode is one step advanced beyond the cold standby mode, resulting in fewer manual functions (less time consuming) to be performed at the local equipment level before initiating a start.

HOT, READY-TO-START

In the hot, ready-to-start mode, the plant is shut down but is capable of reaching rated power output in approximately one (1) hour upon a start initiated by the control room operator.

12.1.1 Gasification System

12.1.1.1 COLD STANDBY

In order for the Gasification System to be in cold standby, the units are shut down and the equipment is in the following condition:

- All pressure vessels are purged and blanketed with nitrogen or inert gas at atmospheric pressure.
- Anthracite coal or coke breeze is available in the bunkers above the lock hoppers.
- Selexol solution adequate to fill the Purification unit is in the storage tank under a nitrogen blanket.
- All water containing equipment such as scrubbers, reboilers, waste heat boilers, etc., are drained if freezing conditions exist.
- After draining all equipment containing water or steam, the equipment will be flushed and cleaned, drained and purged with nitrogen.
- Any coal or ash remaining in the pretreater or the gasifier will be drained to the ash quench pit so that the pretreater and gasifier are empty.

With the gasification system in the cold standby condition, equipment inspections and minor maintenance can be performed. This includes:

- Inspecting and replacing refractory as needed in the pretreater, gasifier and waste heat boiler.
- Checking and adjusting instruments for normal operation and replacing thermocouples or other instrumentation as needed.
- Inspecting and cleaning heat transfer equipment, such as exchangers and reboilers.

12.1.1.2 COLD, READY-TO-START

In this mode, the Gasification System is in the following condition:

- Coke (not coal) has been added from the bunkers to the lock hoppers.
- Water will be added to the scrubber system.
- Selexol will be transferred from storage to the base of the absorber and regenerator.
- Steam tracing will be started in the Claus Unit and in other units if freezing conditions exist.
- Pneumatic or electronic instrumentation will be activated and checked. Automatic lock hopper sequences will be activated and checked.
- Startup air heater will be activated and dried out at low temperature and low heat input.
- Compressors will be checked and rolled over.
- Glycol and oil cooling and sealing systems will be started.

12.1.1.3 HOT, READY-TO-START

In this mode, lock hoppers are on automatic sequence and coal or char in the pre-treater and gasifier are slumped on the grid. Water is circulated in scrubbers and Selexol solution is circulating in the purification unit. The Claus unit is operating on a very low capacity by burning a small amount of fuel gas or LPG. The hot, ready-to-start condition may be held for twenty-four (24) to forty-eight (48) hours.

A pre-condition of this mode is that all systems will reduce rapidly to atmospheric pressure and will not increase to operating pressure until the air booster compressor is started.

12.1.2 Power Block

12.1.2.1 COLD STANDBY

In the power block, the HRSG will be filled under a nitrogen blanket, or if freeze conditions exist, the HRSG will be drained and filled with nitrogen. All pumps, including lube oil, are "off" and the generator(s) are vented to the atmosphere.

Placing subsystem equipment in the cold standby condition requires operator functions to be performed at the equipment itself. Although the equipment must be available to start to be in this mode, startup from the control room is not possible until realignment functions, local to the equipment, are performed. These functions include repositioning local AUTO-ON-OFF switches, purging and refilling the generators with hydrogen and refilling the HRSG's.

12.1.2.2 COLD, READY-TO-START

In this mode, the lube oil and generator seal oil systems of the turbine generator units will be operating with hydrogen maintained in the generator and the shafts on slow roll by turning gear operation. Water will be in the HRSG and if freeze conditions exist, the boiler feedpump, heaters, and heat tracing will be in operation. The condenser will be at atmospheric pressure with the vacuum break valve open. The instrument air system will be in operation, providing control air as required.

12.1.2.3 HOT, READY-TO-START

The lube and seal oil systems of the turbine generator units are in operation with hydrogen in the generator(s) and the units on turning gear. In addition, the steam turbine rotor is warm, from previous operation, and steam is being supplied to the gland seals. Steam is also powering the main air ejectors to hold condenser vacuum.

Steam at a minimum pressure of approximately 150 psig for the glands and the air ejectors is provided by the warm HRSGs from previous operation. During this period, the main boiler feedpump is kept in operation, providing additional energy to the high pressure drum to help maintain the minimum steam pressure. The time period that this hot, ready-to-start condition can be held will vary depending upon ambient conditions and the cooldown rate of the HRSGs and the steam turbine rotor.

12.1.3 Balance of Plant

12.1.3.1 COLD STANDBY

Plant services, such as cooling towers, circulating and cooling water systems are shut down and freeze-protected or drained if freeze conditions exist; if a prolonged outage is expected, it is possible for certain systems having heating systems for freeze protection to be drained for energy conservation. Corrosion protective measures will be taken as final design criteria dictates.

Systems associated with on-site storage will be selectively operated as inventory or conditions dictate. This includes fuel receiving, fuel storage demineralizer and waste handling systems.

The operation of the plant auxiliary boiler will be under manual control by the operator from the central control room and will depend upon ambient conditions.

12.1.3.2 COLD, READY-TO-START

In this mode, the condensate makeup, cooling water and circulating water systems are filled and vented, and minimum circulation is maintained by operation of one (1) of the 50 percent capacity pumps of each system.

Systems associated with on-site storage, such as condensate, fuel and wastes, will be selectively operated as inventory or conditions dictate.

The auxiliary boiler will be hot, but will not be supplying any steam unless freeze conditions exist. This will provide an immediate steam source for the hogging air ejector and gasification system when a plant start is initiated. Startup of plant services, such as: condensate makeup, circulating and cooling water, distillate fuel forwarding, auxiliary boiler, auxiliary diesel-generator and auxiliary fire pump will be from the control room by the operator. The auxiliary diesel-generator and fire pump will also start automatically on an emergency alarm condition.

12.1.3.3 HOT, READY-TO-START

The status of plant services in this mode is essentially the same as that for cold, ready-to start, except that the auxiliary boiler will be augmenting the standby steam requirements as may be necessary. During this period, the operator will cycle idle pumps to verify plant readiness.

12.2 STARTUP

12.2.1 Gasification System

12.2.1.1 COLD STANDBY TO COLD, READY-TO-START

The transition from cold standby to cold ready-to-start includes filling the coal hoppers and lock hoppers with coke breeze crushed to the proper size as well as adding water to the scrubbers and adding Selexol solvent to the purification unit.

Steam tracing will be started at the Claus Unit to prevent sulfur from freezing. Glycol and oil cooling sealing systems will be started.

Steam at 400 psig as well as power and cooling water are all available. These utilities are obtained from the balance of plant services for initial unit startup. Successive starting units will take steam from the operating plant.

Startup heaters firing oil as fuel will be used to slowly dry out and heat up the pretreater, gasifier and waste heat boiler.

12.2.1.2 COLD, READY-TO-START TO FULL OPERATION

The startup heaters firing oil fuel will preheat the gasifier to about 1000°F and the pretreater to about 700°F. The products of combustion are vented to the flare after passing through the waste heat boiler. Steam flow is started to the gasifier keeping the temperature at 1000°F. The waste heat boiler is placed into operation producing 600 psig steam. The scrubbers and Selexol systems are started by circulating water and solvent.

Coke (not coal) is manually dumped from the coal hoppers to the lock hoppers and pressured into the pretreater and into the gasifier. Air is started at a low rate of flow from the booster compressor to both the pretreater and the gasifier. Steam and air are adjusted to keep the temperature rise down to 50-100°F per hour in the gasifier. Pressure is gradually increased to operating conditions by closing down on the vent valve. All gases from the Selexol unit are vented to flare. Coke levels in the pretreater and the gasifier are adjusted by regulating the coke feed from the lock hoppers. The ash quench and ash removal systems are activated by circulating water and starting ash conveyor equipment, respectively. The control is now passed to the control room and the coke feed is controlled by the automatic sequencer. After stable conditions have been obtained, coal is added to the bunkers by starting the coal conveyor system and the purified gas is cut into the gas turbo-generator system. As steam is generated in the waste heat boiler, it is bypassed to the condenser in sufficient flow to dry out the superheater. When minimum superheat temperature is obtained and the boiler brought up to pressure, the generated steam is admitted to the steam turbine. Superheated low pressure steam is sent to the gasifier and air steam ratio adjusted to maintain proper temperatures in the fluidized beds. The Claus Unit is started and liquid sulfur is stored in the sulfur pit.

12.2.1.3 HOT, READY-TO-START TO FULL OPERATION

From the hot, ready-to-start condition to full operation, it is possible to control all operation from the control room. Superheated steam is passed into the gasifier at a low rate in order not to cool the fluidized bed. Air is gradually introduced from the booster compressor regulating the steam-air ratio to maintain a reasonable temperature rise. The coal injection is then started by means of the automatic sequencer. With all the temperatures at the proper levels, it is not necessary to start on coke. Coal may be fed directly to the gasification section. The ash removal system is started and at steady-state conditions, the fuel gas can be cut into the gas turbo-generator instead of flaring. Liquid sulfur is pumped from the pit to tank cars or trucks for disposal.

12.2.2 Power Block

12.2.2.1 COLD, READY-TO-START TO POWER GENERATION

If the plant is in the cold standby condition, it must first be brought up to the cold, ready-to-start condition. This transition is a series of manual operator functions, such as ensuring that lube oil and hotwell water levels are proper and that the HRSG is filled, if previously drained. The generator must be purged with carbon dioxide and filled with hydrogen. Control valve sequencing and pump operation are manual functions initiated by the operator from the control room.

Once the power block equipment has been placed in a "Ready-to-Start" condition, startup of the plant is under the control of the operator from the control room. The fuel system for the combustion turbine will automatically align itself for "fuel oil" operation for startup.

Upon start, an electric starting motor will engage and accelerate the combustion turbine shaft from turning gear speed of approximately 2 rpm to ignition speed and assist in acceleration to self-sustaining speed at which time the starting motor will shut down and disengage from the turbine generator shaft. The turbine will continue to accelerate under automatic control to synchronous speed of 3600 rpm and minimum load of 4 MW on breaker closure. This minimum load is initially picked up to prevent the turbine generator from tripping due to reverse current.

High pressure air from the combustion turbine compressor is now made available to the gasification process. During this period with the combustion turbine exhausting its hot gases into the HRSG, steam is generated and condenser vacuum will be established. Excess steam from the HRSG over that needed for startup auxiliaries, along with that generated by the gasifier, is used to roll the steam turbine rotor for its warmup period. Excess steam over that required for turbine roll is bypassed to the condenser.

During the steam turbine warmup period, the combustion turbine may be loaded, if required by system demand. If the loading required by system demand results in combustion turbine exhaust temperatures over that required to produce the steam temperature required for the steam turbine rotor, then steam temperature going to the turbine will be controlled by allowing steam from the high pressure drum to bypass the HRSG superheater and reheater.

Steam flow will be controlled using the bypass valve, which directs excess steam to the condenser.

12.2.2.2 HOT, READY-TO-START TO POWER GENERATION

With the power block equipment in the Hot, Ready-to-Start mode, it shall be possible to start and load the plant completely from the control room.

The starting sequence will be as previously described in the "Cold, Ready-to-Start to Power Generation" section, except it will not be necessary to establish condenser vacuum or roll the steam turbine rotor for a warmup period.

Depending upon the steam turbine rotor temperature at the time of startup, it may be necessary to load the combustion turbine generator and gasifier to achieve the steam temperature required for initial roll of the steam turbine.

12.2.3 Balance of Plant

12.2.3.1 COLD, READY-TO-START TO POWER GENERATION

Bringing the balance of plant systems up to the cold, ready-to-start condition from cold standby requires a series of manual operator functions to be performed as in the power block.

Startup of idle system pumps to bring the system up to 100 percent capacity will be performed manually from the control room.

The distillate fuel forwarding pumps will be started on the start signal for the combustion turbines. At the same time, steam from the auxiliary boiler will be available to the gasification system and to the hogging air ejector.

Steam generated by the HRSG(s) will gradually reduce the steam coming from the auxiliary boiler to zero.

At approximately minimum load on the combustion turbine, the operator will initiate an automatic fuel transfer to the coal-derived low-Btu gaseous fuel, provided the supply conditions are satisfied. Startup of the demineralizer and coal-handling systems will be performed locally at the equipment by an assistant operator. Fuel receiving and waste handling will also be local manual functions. Operation or throughput of the demineralizer is independent of plant load and is set locally at the equipment.

12.3 GENERATION, RATED LOAD

In this mode, the plant is operating and generating power at rated power output.

12.3.1 Gasification System

Until steady-state conditions are attained, all fuel gas production will be flared; the fuel gas having passed through the Selexol system to purify the flared gas. Ash is collected, stored and removed by conveyor. At full steady-state production, the fuel gas will be sent to the gas turbines from the purification unit. Air and steam rates to the gasifier are adjusted to maintain the desired fuel gas production rate.

12.3.2 Power Block

Once the turbines, both combustion and steam, have reached or exceeded minimum load and the operator has selected rated load, power output will automatically be increased to the rated output of each generator for the existing ambient conditions. At this point, the plant is generating rated power at its highest efficiency. All fluid systems, such as steam, water and fuel gas will be in a balanced steady-state condition.

12.3.3 Balance of Plant

With the plant generating power at rated load, critical fuel and water services to the power block are operating at 100 percent capacity. The demineralizer plant will normally be operating although down periods can be tolerated, depending upon demineralized water storage and demand. Fuel receiving and waste handling will be conducted as conditions dictate.

12.4 GENERATION, PART LOAD

12.4.1 Gasification System

The capacity of the Gasification System can be reduced by cutting the number of gasifiers or by reducing any single gasifier output. The reduction of capacity of a single gasifier may be achieved by reducing both the air and steam flow while maintaining both air and steam in the same ratio as at full capacity. The ratio must be maintained in order to operate at the same temperature regardless of capacity.

Since the pretreater-gasifier system operates on a fluidized bed system, it is possible to reduce capacity to 50 percent of normal operation. Lower capacities may cause poor fluidization. Other items of equipment such as the scrubbers, purifiers, Claus Units and waste heat boilers can operate at a 50 percent decrease in gas rate with little or no adjustment. A lower gas rate means lower solvent circulation rates are possible in purification unit. The purification unit will operate satisfactorily at the design circulation rate even at low gas rates, but at an inefficient use of utilities. At low gas rates the waste heat boiler superheater sections will have to have tempered water addition to prevent the superheat from rising too high and damaging the tubes.

12.4.2 Power Block

Operating at load points other than full rated power of the plant shall be performed in a sequence so as to accomplish optimum performance within operating limits of the equipment.

The combustion turbine will have adjustable compressor inlet guide vanes which, upon closing, will reduce mass air flow, fuel flow and turbine power at essentially a constant turbine exhaust temperature. In turn, this will reduce steam production in the HRSG and gasification system with a minimum reduction in steam temperature. Steam turbine output is reduced, but minimizing thermal cycling and its effect on operating life.

From rated plant output, plant load will first be reduced by closing the compressor inlet guide vanes of the combustion turbines. Where the number of operating combustion turbine units is four (4), load reduction down to approximately 75 percent can be obtained with this type of operation. Further load reduction at optimum plant performance may be reached below the guide vane limit by shutting down a gasifier train and restoring the on-line units to full rated power.

12.4.3 Balance of Plant

At reduced plant loads, it will be necessary to reduce the operating capacity of the demineralizer. Should the throughput be reduced below an efficient operating level for an extended period, it may be necessary to place the system on intermittent duty.

Depending upon the load point and ambient conditions, the operator may reduce the plant auxiliary electrical load by shutting down one of the half-size pumps associated with the condensate, cooling water or circulating water systems. Cooling tower fan operation will be automatically controlled.

12.5 SHUTDOWN

In removing the plant from power generation, it will be returned to one of the non-running steady-state modes, as defined earlier under Paragraph 12.1.

12.5.1 Gasification System

12.5.1.1 Planned shutdown of the gasification system from normal operation to hot, ready-to-start involves the following steps:

- Flare product gas from purification unit.
- Stop air flow to agglomeration section of the gasifier.
- Reduce air flow to pretreater and gasifier to low rate.
- Stop feed of coal by interruption of coal automatic feed sequencer.
- Reduce steam flow to pretreater and gasifier.
- Stop air flow to pretreater-gasifier.
- Depressure system.
- Maintain steam flow at low rate to purge out the unit.
- Stop steam flow.
- Stop ash quench system.
- Maintain scrubber and purification circulation at low rates.
- Adjust Claus Unit to operate on low flow of fuel gas or LPG.

It may be noted that hot char and ash will slump to the grid at about 1200°F to 1600°F in the gasifier and this temperature will gradually decrease with time.

12.5.1.2 Planned shutdown of the gasification system from hot, ready-to-start mode to cold ready-to-start, follows the same sequence described in the hot, ready-to-start paragraph above except the following steps will be initiated from the control room after the coal flow is cut off:

- Maintain air flow at low rate to gasifier and to pretreater.
- Transfer all coal from pretreater to gasifier.
- Cut off air flow to pretreater and gasifier but maintain steam flow.

- Depressure system.
- Cut off steam flow, but maintain all steam tracing.
- Cool down.
- Purge with nitrogen.
- Dump all char from gasifier, pretreater and any coal in lock hoppers to ash system.
- Stop circulation pumps and compressors.
- Drain all water filled systems such as scrubbers, reboilers and waste heat boilers in the event that freezing conditions exist.

12.5.1.3 PLANNED SHUTDOWN FROM COLD, READY-TO-START TO COLD STANDBY

This operation includes all the steps in the paragraph 12.5.1.2 above; however, in addition the equipment will be purged, drained, cleaned and inspected. All coal will be removed from coal hoppers and lock hoppers. Selexol solvent will be transferred to storage tank under a nitrogen blanket. The sulfur storage pit will be pumped out into tank cars and all steam tracing will be stopped and drained. The pretreater and gasifier will be entered when cool and purged and any ash or char will be cleaned out. After inspection and any repair, the equipment will be buttoned-up and held under a nitrogen blanket.

12.5.2 Power Block

12.5.2.1 POWER GENERATION TO HOT, READY-TO-START

As previously stated, it is not the intent to have incorporated into the plant design an extended hot standby condition. However, it is possible that certain components of the plant, namely, the steam turbine rotor, heat recovery steam generator, and the condenser can be maintained in a warm standby condition for a finite period after an operational shutdown.

To place the Power Block equipment in the Hot, Ready-to-Start condition from a generating load point, steam turbine load will first be reduced by automatic closing of the inlet guide vanes on the combustion turbine compressor as the fuel is decreased. This will hold the combustion turbine exhaust temperature high, but reduce gas flow through the boiler, thus generating less steam. The combustion turbines will then be further unloaded with the steam generated in the boiler(s) bypassed to the condenser.

On shutdown, stack covers on the heat recovery boilers shall be closed at approximately 600 rpm of the combustion turbine in order to hold the residual heat of the turbines and HRSGs. The boiler feedpumps shall remain operating, as will the air ejectors and the steam turbine gland steam system.

Both combustion and steam turbine-generator units will be maintained on turning gear with rated generator hydrogen pressure held.

The Hot Ready-to-Start period on the Power Block equipment will end when any one of the following conditions occurs:

- a. Loss of condenser vacuum;
- b. Loss of gland steam;
- c. Steam turbine rotor temperature below minimum warmup temperature.

12.5.2.2 HOT, READY-TO-START TO COLD, READY-TO-START

With the plant in the hot, ready-to-start mode, the next lower progression mode of cold, ready-to-start is obtained either by changing conditions as outlined in paragraph 12.5.2.1, or by operator selection. In either case, the operator from the control room will initiate the following:

1. Shut off gland steam to the steam turbine and open the steam turbine bypass valve.
2. Open the vacuum break valve of the condenser.
3. Vent the generators to 0.5 psig hydrogen pressure minimum.

The combustion and steam turbine lube, seal oil and turning gear systems will remain in operation and the instrument air system will be left in automatic. The stack covers on the HRSGs may be left closed if ambient temperatures are below freezing to minimize draft through the combustion turbine and HRSG.

12.5.2.3 COLD, READY-TO-START TO COLD STANDBY

In placing the power block in the cold standby condition from the cold, ready-to-start mode, the operator from the control room will secure all pumps and realign control valves. The turbine lube and turning gear systems must be maintained for the specified rotor cooldown periods before they can be secured. In addition, the generators must be purged with carbon dioxide before the lube and turning gear systems are shut off. The HRSGs will be placed under a nitrogen blanket and the instrument air system will be secured.

Manual functions local to some of the equipment will be performed such as the opening of drain valves and repositioning on-off-auto switches at local control panels. Environmental systems of equipment and enclosures will remain in automatic for protection of equipment.

12.5.3 Balance of Plant

Return of the balance of plant equipment to one of the non-running steady-state modes is performed manually by the operators. In general, the function follows the detailed shutdown sequence of the power block and is performed at the discretion of the operator when a safe or other demanding condition is satisfied. For example: it would be unwise to secure the cooling water system entirely, immediately after a shutdown, even if the final state is to be cold standby. The residual heat remaining in the turbines and transferred to the lube and seal oil systems must first be dissipated.

12.6 ABNORMAL CONDITIONS

12.6.1 Gasification System

Whenever a malfunction occurs a transient condition will exist and the plant control will automatically take the following corrective action:

1. Pressure increase will automatically open purified gas flow to flare. If pressure rise is very rapid then relief valves will blow down equipment to flare. After back pressure or relief valves are actuated, the air flow to fire the gasifier will be cut out and the coal feed stopped.
2. Temperature increase in gasifier will automatically cut off the air to the gasifier and the coal feed will be stopped.
3. Level increase in gasifier, pretreater or lock hopper will stop coal feed and cut down air flow until the reason for high level can be found.
4. Loss of power, instrument air or cooling water will automatically open fuel gas product to flare and cut down on air flow.
5. Loss of boiler feedwater to the waste heat boiler will result in plant shutdown by cutting off air flow to the gasifier-pretreater.
6. Loss of steam from the hot reheat header to the gasifier will result in bypassing steam from the main steam header to the gasifier. If this is not sufficient, the gasifier will automatically shut down the plant.

12.6.2 Power Block

Whenever a system trip or malfunction occurs, a transient operating condition will exist. Upon such an event, the equipment or plant shall be designed to automatically react by at least one of the following, in order of priority.

- a. System realignment - such as transfer to a backup system.
- b. Removal of generating equipment from the electrical system - by generator breaker opening on a generator or switchyard electrical fault.
- c. Steam bypass to condenser on a steam turbine trip.
- d. Turbine-generator trip to Standby Condition - in the event of a mechanical malfunction, such as excessive vibration, which would be damaging if continued operation were allowed.

12.6.3 Balance of Plant

A trip of malfunction in a balance of plant system shall cause automatic steps to be taken to minimize the effect on overall plant operation. For the most part, the final corrective measure to maintain plant operating integrity will be based upon the decisions of the operator.

The first automatic action that will be taken will be a transfer to a redundant component, such as a pump.

The second automatic action that will be taken is to signal the operator through supervisory instrumentation of the malfunction. This will alert the operator to take corrective action if he has the option. Such action could include reducing plant load in the event of a restriction on condenser circulating water, shutting down one of the circulating water pumps correcting the problem, and restoring all systems to original status.

Balance of plant equipment will be designed for self-protection in the event the operator does not take corrective action after an alarm signal.

REFERENCES

Reference
Number

- 1 ECAS — Energy Conversion Alternative Study, MAS-3-19406.
- 2 Char Oil Energy Development, by FMC Corporation, Detailed In Office of Coal Research R&D Report No. 11, Vols. 1 and 2.
- 3 "A Report on Improving the Productivity of Electric Power Plants:
Prepared By: FEA Inter Agency Task Group on Power Plant Reliability, March, 1975.