DOE/MC/26308 -- 5036
(DE96000558)

IGCC Repowering Project Clean Coal II Project Public Design Report

Annual Report
October 1992 - September 1993

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Work Performed Under Contract No.: DE-FC21-91MC26308

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

By
Combustion Engineering, Incorporated
Windsor, Connecticut

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PUBLIC DESIGN REPORT

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Office of Fossil Energy
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P.O. Box 880
Morgantown, West Virginia 26507-0880

By
Combustion Engineering, Incorporated
1000 Prospect Hill Road
Windsor, Connecticut 06095

October 1993

CE IGCC REPOWERING PROJECT
PUBLIC DESIGN REPORT

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I EXECUTIVE SUMMARY

Combustion Engineering, Inc. (CE) is participating in a $270 million coal gasification combined cycle repowering project that was designed to provide a nominal 60 MW of electricity to City, Water, Light and Power (CWL&P) in Springfield, Illinois. The Integrated Gasification Combined Cycle (IGCC) system consists of CE's air-blown entrained flow two-stage gasifier; an advanced hot gas cleanup system; a combustion turbine adapted to use low-BTU gas; and all necessary coal handling equipment.

The project is currently completing the second budget period of five. The major activities to date are:

- Establishment of a design, cost, and schedule for the project.
- Establishment of financial commitments.
- Acquire design and modeling data.
- Establishment of an approved for design (AFD) engineering package.
- Development of a detailed cost estimate.
- Resolution of project business issues.
- CWL&P renewal and replacement activities.
- Application for environmental air permits.

A Project Management Plan was generated. The conceptual design of the plant was completed and a cost and schedule baseline for the project was established in Budget Period One. This information was used to establish AFD Process Flow Diagrams, Piping and Instrument Diagrams, Equipment Data Sheets, material take offs, site modification plans and other information necessary to develop a plus or minus 20% cost estimate. Environmental permitting activities were accomplished, including the Air Permit Application, completion of the National Environmental Policy Act process, and the draft Environmental Monitoring Plan. At the end of 1992 the DOE requested that Duke Engineering and Services Inc. (DESI) be used to complete the balance of plant cost estimate. DESI was retained to do this work. DESI completed the material take off estimate and included operations, maintenance, and startup in the estimate.

II INTRODUCTION

CE is participating in a $270 million coal gasification combined cycle repowering project that was designed to provide a nominal 60 MW of electricity to City Water, Light & Power (CWL&P) in Springfield, Illinois. The CE project demonstrates IGCC technology in a commercial application by repowering an existing CWL&P Plant in Springfield, Illinois. The project duration was designed to be 126 months, including a 63-month demonstration period.

III PROJECT DESCRIPTION

The IGCC system consists of CE's air-blown, entrained-flow, two-stage, pressurized coal gasifier; an advanced hot gas cleanup process; a combustion turbine adapted to use low-Btu coal gas; and all necessary coal handling equipment. CWL&P's Lakeside Station (Figure 1) was selected as the site for this project. The result of repowering is an IGCC power plant with low environmental emissions and high net plant efficiency. The repowering increases plant output by 40 MWe through addition of the combustion turbine, thus providing a total IGCC capacity of a nominal 60 MWe. Nearly half of the project is funded by the United States Department of Energy (DOE), under Round II of the Clean Coal Technology Program, while CWL&P, State of Illinois, and CE fund the rest.

The IGCC includes CE's slagging, entrained-flow, gasifier operating in a pressurized mode and using air as the oxidant. The hot gas is cleaned of particulate matter (char) which is recycled back to the gasifier. After particulate removal, the product gas is cleaned of sulfur prior to burning in a gas turbine.

The proposed project includes design and demonstration of an advanced hot gas cleanup process for removal of sulfur from the product gas of the gasifier. The sulfur removal method features a newly developed moving-bed zinc titanate system downstream of the gasifier. CE intends to use the General Electric (GE) moving bed, zinc titanate sulfur removal system currently being piloted by General Electric Environmental Systems, Inc. (GEESI) The process data from these pilot tests is expected to be sufficient for the design of a full-scale system to be used in the proposed demonstration.

In this plant, the gasifier will be producing a low-Btu gas (LBG). The LBG will be used as fuel in a standard GE gas turbine to produce power. This gas turbine will have the capability to fire LBG and natural gas (for start-up). Since firing LBG uses less air than natural gas, the gas turbine air compressor will have extra capacity. This extra compressed air will be used to pressurize the gasifier and supply the air needed in the gasification process.

The plant is made up of three major blocks of equipment as shown in Figure 2. They are the fuel gas island which includes the gasifier and gas cleanup, gas turbine power block, and the steam turbine block which includes the steam turbine and the heat recovery steam generator (HRSG).

As major equipment sections are completed, they will be individually started up and brought on-line to produce power. The combined cycle equipment will have the shortest lead time so this equipment will be installed, checked out, and brought into commercial service first. Initially, the gas turbine will be fired on natural gas operating as a combined cycle with a new heat recovery steam generator and a new steam turbine. All of this equipment will be checked out and operated prior to the start-up of the gasification plant.

The last major block of equipment is the fuel gas island including the gasifier and gas cleanup equipment. When this equipment is put into operation, the plant will be a fully integrated coal gasification combined cycle plant.

IV RESULTS

A) Performance Summary

The DOE/CE Cooperative Agreement requires that CE complete the CE IGCC Repowering Project as spelled out in the Statement of Work with funding controlled by a number of Budget Periods.

This report covers work performed through Budget Period 2. This includes the following:

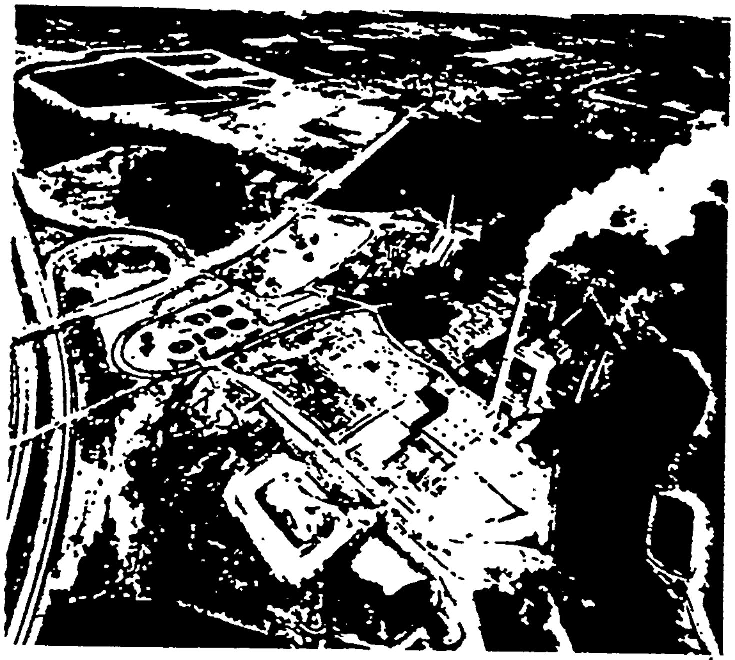
- Establishment of a design, cost, and schedule for the project.
- Establishment of financial commitments.
- Acquire design and modeling data.
- Establishment of an Approved for Design (AFD) engineering package.
- Development of a plus or minus 20% Cost Estimate.
- Resolution of project Business issues.
- CWL&P Renewal and Replacement Activities.
- Application for environmental air permits.

The conceptual design work accomplished during Budget Period 1 was used in Budget Period 2 to develop a more detailed series of process flow diagrams (PFD's) for the gasifier island and the balance of plant. These PFD's were expanded from the original conceptual design PFD's to include all major equipment along with the major control loops. Materials of construction were identified for all of the components and process lines and a Material Flow Diagram (MFD) was developed. From these documents, equipment lists and design data sheets were made for all identified equipment. The data sheets were used to obtain cost information.

A series of general arrangement drawings of the gasifier island and the combined cycle were done to estimate construction costs. Engineering specification packages were made for major components of the plant including the gas turbine, steam turbine, sulfur recovery system, hot gas cleanup system, heat recovery steam generator, booster compressor, coal handling, and slag removal systems. The gasifier and syngas cooler were designed and preliminary drawings made to estimate costs and shop schedule.

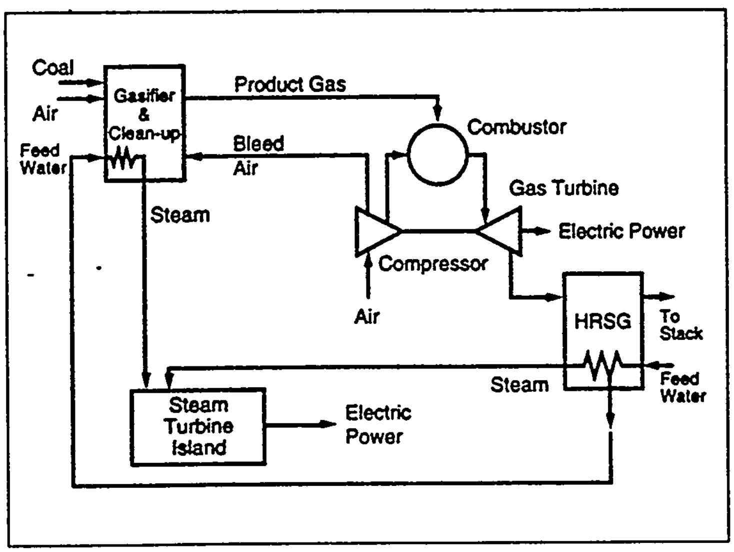
At the end of 1992, the cost estimate was still being developed. Also at this time, the DOE requested that Duke Engineering and Services, Inc. (DESI) be used to complete the cost estimating for the balance of plant and to provide an independent assessment of the plant design. This activity has shown to require more time than was originally estimated and a request was made to extend Budget Period 2 into the first part of 1993.

FIGURE 1



Lakeside Photo

FIGURE 2



Simplified IGCC

DESI revised the site arrangement and completed the cost estimate. The estimate included allowances for operations, maintenance, and startup. The cost estimate was completed in April 1993.

Environmental activities were mainly concerned with supplying the information required for the BACT (best available control technology) demonstration as part of the prevention of significant deterioration (PSD) determination of the air emissions permit application. Both the preliminary and final BACT documents were submitted in 1992. Also, approval of the EA and FONSI were received. The air emissions permit application was submitted in April, 1993, and the Environmental Monitoring Plan draft was submitted in March, 1993.

B) Work Breakdown Structure (WBS)
The Work Breakdown Structure for the Project is shown in Figure 3.

C) Accomplishments

The goals for Budget Period 2 were to complete basic engineering and produce an approved for design (AFD) engineering package and a plus or minus 20% cost estimate. The basic engineering activities have produced AFD process flow diagrams, metallurgical flow diagrams, preliminary control philosophy, piping and instrumentation diagrams, arrangement drawings for the gasifier island and balance of plant, equipment data sheets, and requisition packages for all major equipment and subsystems.

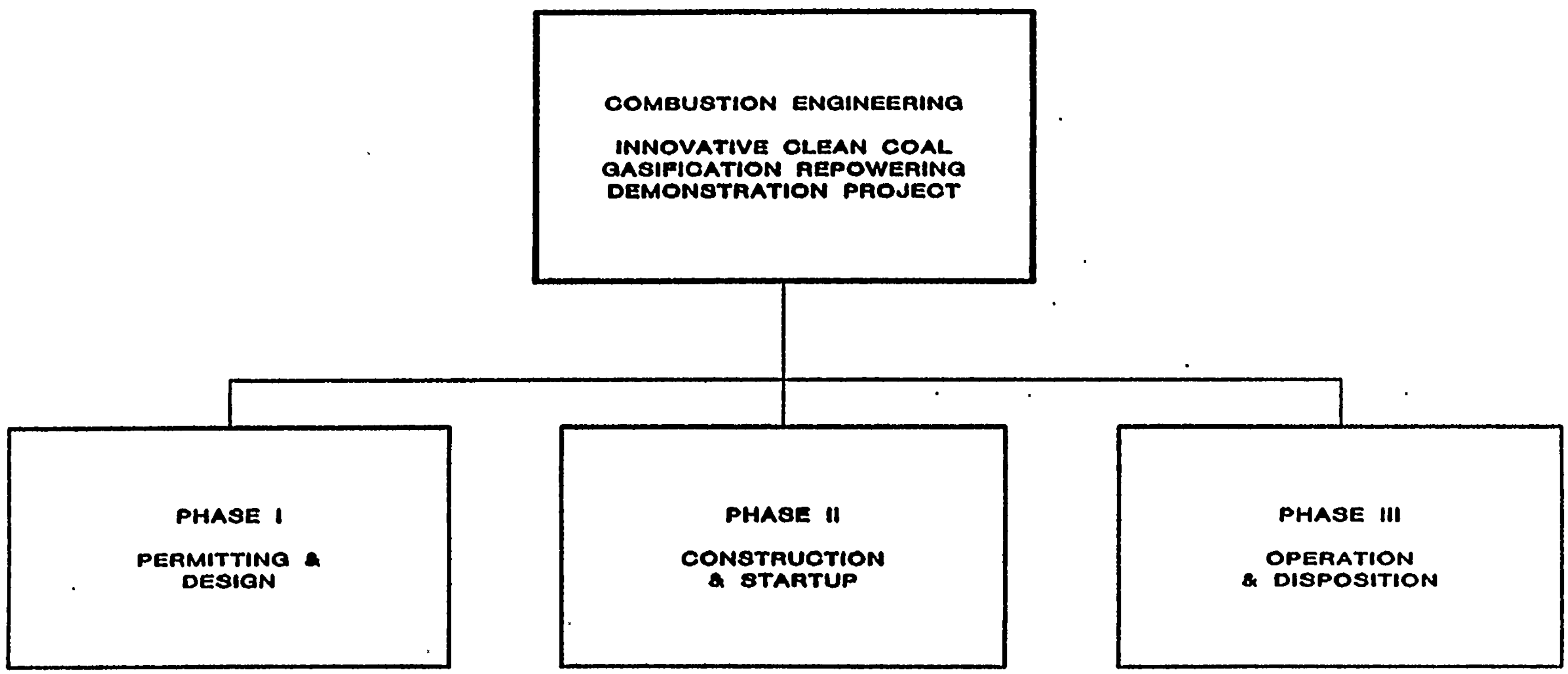
In support of the basic engineering, several IGCC performance studies were made to determine the best heat rate for the plant and to select the equipment configuration. A computer model to calculate plant performance was written. This program was used to evaluate several heat rate sensitive process decisions. These calculations were used to select the plant design basis after consulting with CWL&P. Heat and mass balances were generated for all of the anticipated operating conditions.

The gasifier and heat exchanger initial mechanical design was completed and a series of drawings were made from which the cost and shop schedule could be estimated.

Balance of plant activities were done to design the coal handling yard and the slag handling system. Requisitions packages were completed for the gas turbine, steam turbine, HRSG, booster compressor, and sulfur recovery plant. Arrangement drawings were made for the modifications to the Lakeside building for the combined cycle installation. Arrangement drawings were made for the gasifier island, coal feed yard and other site changes.

FIGURE 3

WORK BREAKDOWN STRUCTURE



1.1 POST-SELECTION ACTIVITIES
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2.2 SHOP FABRICATION
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3.2 OPERATION
3.3 TESTING
3.4 MAINTENANCE & INSPECTION
3.5 AS-OPERATED DRAWINGS UPDATE
3.6 TECHNICAL REPORTS
3.7 PLANT DISPOSITION
3.8 FINAL REPORT
3.9 PROJ. MANAGEMENT, ACCT., & REPORTS

A list of deliverables is given in Table 1 along with the dates they were accomplished.

Table 1

Deliverables	Date
Environmental Impact Volume	December ,1991
Environmental Monitoring Plan Outline	January, 1991
Project Evaluation Plan (PEP) BP1	March, 1991
Project Management Plan (PMP) BP1	May, 1991
EA/FONSI submittal	April ,1991
Zinc Ferrite Design Report (initial)	November,1991
Data Requirements	November, 1991
Project Evaluation Report	November,1991
Continuation Application for BP2	November,1991
1991 Gasification Conference	August, 1991
EA/FONSI	March, 1992
EMP (draft)	March, 1993
PMP BP2	November, 1992
PEP BP2	April, 1992
1991 Annual Report	November, 1992
1992 Gasification Conference	September, 1992
Long Lead Item Report	June, 1993
Design Support Topical Reports	June, 1993
HGCU Topical Report	April, 1993
Gasifier Data Report	May, 1993
Project Evaluation Report	June, 1993
Public Design Report	June, 1993

V. ENVIRONMENTAL DISCUSSION

A) NEPA Support

The provisions of the National Environmental Policy Act (NEPA) apply to the IGCC Repowering Project because project sponsorship and funding by the DOE constitutes a "significant federal action" as defined in the Act. NEPA activities for the project on the part of Combustion Engineering and ABB Environmental Services (ABB-ES) were essentially completed prior to the beginning of 1992. NEPA activities prior to 1992 consisted of preparation of an Environmental Information Volume by ABB-ES, preparation of an Environmental Assessment by DOE, and preparation of a draft Finding of No Significant Impact (FONSI) by DOE. The requirements of NEPA were fulfilled in March of 1992 when DOE issued a Final FONSI.

B) Environmental Monitoring Plan

In the Program Opportunity Notice (PON) for funding of the Innovative Clean Coal Technology program, DOE identified certain requirements for monitoring completed projects to more thoroughly document their environmental effects. The process identified consists of three steps. The first consists of preparation of an Environmental Monitoring Plan Outline (EMPO). The second step involves preparation of an Environmental Monitoring Plan (EMP). The final step involves the implementation of the EMP.

The EMPO was prepared by ABB-ES and submitted and accepted as adequate by DOE prior to 1992. The EMP will add additional detail to the EMPO, based on the final design details for the project. During 1992, significant design details were being developed and revised to make meaningful refinement of the EMPO infeasible. The EMP draft was submitted to DOE in March, 1993.

C) Environmental Permitting

Permitting activities for 1992 focused on preparations for filing an air emission license application (Prevention of Significant Deterioration [PSD]). This focus was due to the relatively long time-line required for conducting pre-filing investigations and the relatively long anticipated agency review period. An attempt was made early in 1992 to "freeze" the project design for permitting purposes. This effort was hampered by the ongoing refinement of the project design. Due to the nature of some of the design developments, the certainty of being able to modify a permit obtained on the basis of the "frozen" design became questionable. As a result, several delays to air permitting activities occurred and substantial portions of the licensing activities required reworking.

Environmental permitting activities related to other media (water and solid waste) were minimal during 1992, again awaiting further design development. Throughout 1992, staff of the Illinois Environmental Protection Agency (IEPA) with responsibility for wastewater and solid waste licensing participated in several project meetings. IEPA staff input was sought and obtained on the identification of potential licensing issues. IEPA staff also provided guidance on the overall licensing requirements for the project and the time frames involved in license review.

D) Air Modeling

During 1992 a significant amount of modeling occurred as part of the impact assessment required as part of the PSD permit application. The impact assessment consists of three major components: screening modeling and refined modeling protocol document; refined modeling of the significant impact zone; and compliance modeling. The first two portions of the impact assessment were submitted to IEPA during 1992. During the impact assessment, several potential problems were encountered. The first was obtaining a layout for the plant that was sufficiently accurate as to be representative of the final project configuration. Several months of delay resulted from significant changes to the plant layout as the design was refined, thereby necessitating rework of previously conducted modeling.

Second, screening modeling predicted violations of air quality standards from the existing Lakeside Generating Station as a result of downwash effects induced by the proposed gasifier structure. Because the predicted violations were relatively small, the decision to proceed with refined modeling was made given the overly conservative nature of the screening model. During refined modeling, very small violations of air quality standards were again demonstrated. ABB-ES modeling staff were able to work within the model to determine the optimal height for the gasifier structure and were able to identify a configuration for the gasifier structure where compliance with all applicable air quality standards was possible. This information was shared with design staff as a design requirement.

Compliance modeling to demonstrate compliance with air quality standards including impacts from other sources (existing) within the significant impact zone was completed during the first quarter of 1993. All of the modeling results are part of the PSD application that was filed with IEPA.

E) BACT Determination

The PSD permit application also includes a Best Available Control Technology (BACT) determination. The purpose of the BACT determination is to establish that the controls proposed for the project are appropriate and comply with the requirements of the Clean Air Act as Amended. The BACT determination included several meetings with staff from the IEPA to present the project, identify issues, define the review process, and coordinate the review of the submitted documents. Both draft and final BACT documents were been submitted to IEPA during 1992. It is believed that all major issues associated with the BACT determination have been resolved including: control technologies, emission limits, and general license conditions. A major success of the BACT determination was obtaining IEPA agreement to defer the requirement for Selective Catalytic Reduction for the control of oxides of nitrogen until after the five year determination period to allow a more accurate evaluation of the IGCC technology and to reduce the costs of the determination.

F) Air Permit

The complete air emission (PSD) application which includes application forms, the BACT demonstration and the modeling results was prepared for filing during the first part of 1993. Processing of the permit application by IEPA is expected to require up to six months and will likely include a public hearing.

G) Other Environmental Permits - The remaining environmental permits needed include: NPDES Permit modification application for submittal to Illinois Environmental Protection Agency (IEPA) by City, Water, Light & Power (CWL&P), operator of the host facility. This will include meetings with IEPA, CWL&P, and project design staff.

Industrial Pretreatment Works Construction Permit for submittal to IEPA by City, Water, Light & Power (CWL&P). This will include meeting with IEPA, CWL&P, design staff, and the Springfield Metro Sanitary District (SMSD).

Industrial Wastewater Discharge Permit for submittal to SMSD by CWL&P. This will require coordination with CWL&P, project design staff, and SMSD.

Special Waste Classification/Special Waste Stream Authorization permit for submittal by CWL&P to IEPA. This will require coordination with the IEPA Solid Waste Unit, CWL&P, and project design staff. The purpose of this permit will be to define the disposal requirements of IGCC slag and zinc titanate from the hot gas clean-up system.

Large-Scale Development Review permit application for submittal to the City of Springfield by CWL&P. This will require coordination with CWL&P, the City of Springfield, the Springfield-Sangamon County Regional Planning Commission, and project design staff and will include participation at one public hearing before the City Council.

VI TECHNICAL DISCUSSION

A DESIGN STUDIES

A number of studies were conducted which addressed both process and mechanical issues. Many of these investigations either required or resulted in calculations related to plant performance. Since, at the time of this work, preliminary design was still underway, process data used for or indicated by any of these studies reflects the state of the plants design at that time, and in some instances may deviate from the mechanical and process data used for the cost estimate. Data utilized for the cost estimate are summarized in Section VI.C: Estimate Basis.

i) IGCC Performance Studies

The program STMCYC was used for calculation of steam cycle performance over a wide range of possible operating conditions for the plant. These performance results were then evaluated and compared for the various design changes. The basic study done to evaluate designs was a load and ambient temperature variation study. Table 2 describes the operating condition envelope considered for this study.

TABLE 2
PLANT OPERATING CONDITIONS

	Ambient Temperature (Deg. F.)			
Gas Turbine Load	95	59	0	
Base	Case 1	Case 2	Case 3	
80%	Case 4	Case 5	Case 6	
30%	Case 7	Case 8	Case 9	

Notes:
- Base gas turbine load refers to design turbine inlet temperature and inlet guide vanes fully open.
- 80 percent gas turbine load refers to design turbine inlet temperature and inlet guide vanes fully closed.
- 30 percent gas turbine load refers to reduced turbine inlet temperature and inlet guide vane fully closed.

The primary purpose for this study was to select and evaluate heat exchanger and other steam cycle components design points. The evaluation of the selected design points were based on the performance calculations from this program for the cases shown in Table 2. The primary result of this study was the selection of design points for all the steam cycle components. Another result of this study was a set of curves which illustrate the steam cycle performance over the operating condition envelope. These curves are not included. Table 3 summarizes the overall plant performance for this matrix of operating conditions. This study was done without considering supplemental firing in the HRSG to reduce the number of variables. This does not affect steam cycle sizing since supplemental firing is not used at off design conditions. The effect of supplemental firing is included in the base design condition discussed later.

The performance for the IGCC is fairly typical of normal natural gas fired combined cycles. Net plant heat rate is fairly constant between 80 and 100 percent load. The gas turbine inlet guide vanes control air flow over this range while maintaining constant turbine inlet temperature. Below about 80 percent load net plant heat rate is degraded sharply. This occurs primarily because of reduced gas turbine inlet temperature which sharply degrades gas turbine thermal efficiency.

Reduced gas turbine inlet temperature also causes a reduction in gas turbine exhaust temperature. This causes HRSG superheater outlet temperature to be reduced. Although the superheater outlet temperature from the gasifier syngas cooler is maintained at set point over this wide load range, the mixed steam temperature to the

TABLE 3
NET PLANT HEAT RATE CALCULATION

AMBIENT TEMPERATURE	(Deg F)	<---------95		-------->	<-------- 59		---------->	<-------- 0		---------->
GAS TURBINE LOAD		BASE	80%	30%	BASE	80%	30%	BASE	80%	30%
Combustion Turbine Generator Output	(kW)	32550	26540	10390	37890	30290	12290	46460	36110	14780
Steam turbine Generator Output	(kW)	31490	28317	13844	33689	29640	13510	36990	31752	12951
Gross Plant Output	(kW)	64040	54857	24234	71579	59930	25800	83450	67862	27731
Plant Auxilary Power	(kW)	8433	7746	4833	9017	8177	5007	10062	8953	5287
Net Plant Output	(kW)	55607	47111	19401	62562	51753	20793	73388	58908	22444
Coal Heat Input	(MM--Btu/hr HHV)	508.425	441.709	253.650	564.551	478.196	270.936	660.070	540.206	297.072
Natural Gas Heat Input (GT)	(MM--Btu/hr HHV)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Natural Gas Heat Input (HRSG)	(MM--Btu/hr HHV)	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Total Fuel Heat Input	(MM--Btu/hr HHV)	508.425	441.709	253.650	564.551	478.196	270.936	660.070	540.206	297.072
Net Plant Heat Rate	(Btu/kWhr)	9143	9376	13074	9024	9240	13030	8994	9170	13236
Plant Thermal Efficiency	(Percent)	37.33	36.40	26.10	37.82	36.94	26.19	37.95	37.22	25.79

steam turbine is lowered and steam turbine thermal efficiency is also degraded. Reduced gas turbine load also causes stack temperature to increase when gas turbine load is below about 80 percent.

ii) Computer Modeling

A computer program was developed to model the steam cycle for the IGCC plant. This program calculates steady state performance for the steam cycle. The primary purpose for this model was to provide a tool for analysis of the cycle when operating at off design conditions.

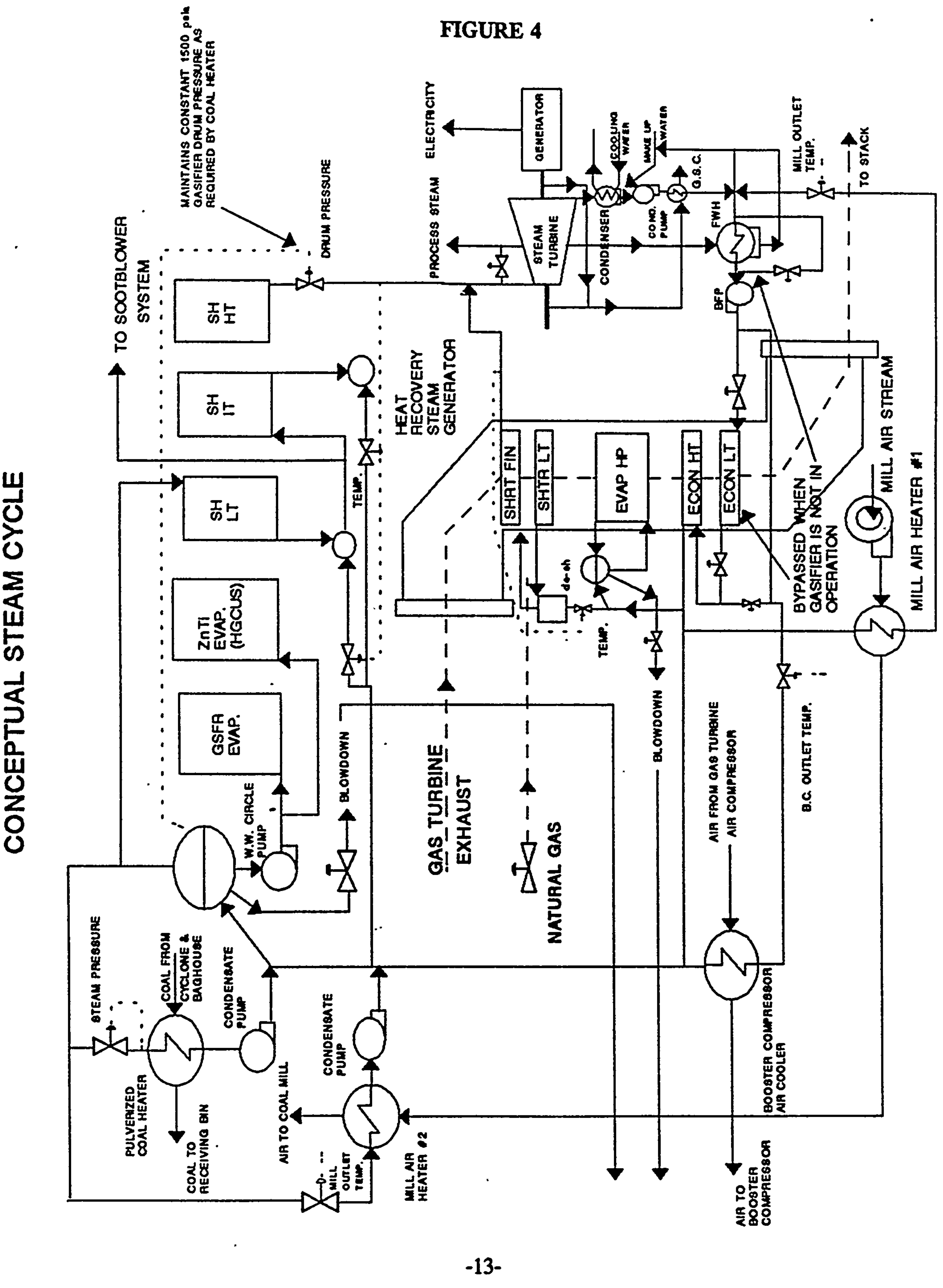
A simplified diagram of the steam cycle is shown in Figure 4. The steam turbine is designed for 1265 psia, 950°F steam conditions. Full load steam turbine output is about 37 MW. There are two main steam generating systems which are in parallel in this cycle. The HRSG generates steam by recovering heat from the gas turbine exhaust stream. In parallel with the HRSG the gasifier heat recovery systems also are recovering heat. The primary heat sources for the gasifier heat recovery systems are the gasifier waterwalls, the syngas cooler, and the desulfurization system evaporator bank.

The steam leaving the turbine enters a derating condenser system. The condensate leaving the condenser system then enters a low pressure feedwater heater. The feedwater leaves the feedwater heater before entering the HRSG at a temperature high enough to avoid acid dew point problems. About 90 percent of the economizer duty is done in the HRSG with the remaining 10 percent done in the booster compressor air cooler which is in a parallel circuit with the HRSG economizer. The booster compressor air cooler is used to maintain the air temperature leaving the booster air compressor at 600°F. The HRSG economizer circuit also provides the heat source for the coal mill system. Mill air heater #1 uses recirculated water from the economizer outlet to heat the air stream for the coal milling operation. The water leaving mill air heater #1 is returned to the feedwater circuit at the entrance of the low pressure feedwater heater. The majority of the feedwater leaving the economizer is biased between the HRSG steam drum and the gasifier steam drum. The water leaving the booster compressor air cooler also feeds the gasifier steam drum.

The water in the HRSG drum is naturally circulated thru the evaporator banks in the HRSG and back to the drum. The steam water mixture is separated in the drum. The separated water is combined with the entering feedwater and then feeds the evaporator banks as described above. The separated steam feeds the superheater circuit where it is heated to 950°F. HRSG steam outlet temperature is controlled by desuperheating spray water. The HRSG also has provisions for supplemental natural gas firing for additional steam generation when required.

The water which feeds the gasifier steam drum is combined with recirculated water and is pumped through the gasifier island evaporator circuits. The steam water mixture generated in these circuits is returned to the drum where the steam and water are separated. A small fraction of the steam leaving the drum feeds the coal heater component and the mill air heater #2 (normally not required) where the steam is

FIGURE 4



CONCEPTUAL STEAM CYCLE
MAINTAINS CONSTANT 1500 psia GASIFIER DRUM PRESSURE AS REQUIRED BY COAL HEATER
DRUM PRESSURE
TO SOOTBLOWER SYSTEM
SH HT
SH IT
SH LT
ZnTi EVAP. (HGCUS)
GSFR EVAP.
W.W. CIRCLE PUMP
BLOWDOWN
TEMP.
HEAT RECOVERY STEAM GENERATOR
GAS TURBINE EXHAUST
NATURAL GAS
STEAM PRESSURE
COAL FROM CYCLONE & BAGHOUSE
CONDENSATE PUMP
PULVERIZED COAL HEATER
COAL TO RECEIVING BIN
AIR TO COAL MILL
MILL OUTLET TEMP.
MILL AIR HEATER #2
PROCESS STEAM
ELECTRICITY
GENERATOR
STEAM TURBINE
CONDENSER
COOLING WATER
MAKE UP WATER
COND. PUMP
G.S.C.
FWH
BFP
MILL OUTLET TEMP.
TO STACK
SHRT FIN
SHTR LT
EVAP HP
ECON HT
ECON LT
de-ah
BYPASSED WHEN GASIFIER IS NOT IN OPERATION
MILL AIR STREAM
MILL AIR HEATER #1
B.C. OUTLET TEMP.
AIR FROM GAS TURBINE AIR COMPRESSOR
BOOSTER COMPRESSOR AIR COOLER
AIR TO BOOSTER COMPRESSOR

condensed at high pressure. The condensate is pumped back to the gasifier drum. The majority of the steam leaving the gasifier steam drum feeds the gasifier superheater circuit where it is heated to 950°F. Gasifier steam temperature control is provided by desuperheating spray water.

Gasifier steam drum pressure is held constant at 1500 psia with a gasifier drum pressure control valve. This is required in order to maintain the heat source for the coal heater at about 600° F. At the time that this work was done, steam was identified as the pressurization, fluidization and transport medium for the coal delivery system. With this design, coal heating is required in order to avoid steam condensation on the pulverized coal. Nitrogen was selected as the coal pressurization, fluidization, and transport gas for the cost estimate design basis. Factors involved in this decision are identified under the coal and char feed system study.

The steam from the gasifier superheat circuit and from the HRSG superheat circuit are combined and flow to the steam turbine. The steam is expanded thru the turbine providing power for the steam turbine generator. Two extractions are taken from the steam turbine. The first extraction, at about 450 psia for the design point, is for process steam uses. The second extraction is for the low pressure feedwater heater.

The basic flow chart and file structure for the main program (STMCYC) is shown in Figure 5. The program STMCYC is a "batch" type program that calls several other programs in a sequential manner until the programs are converged. Convergence is determined by monitoring the property values for the streams which interconnect between the various program modules. Once the changes for all the monitored property values (from one iteration loop to the next) are within the prescribed tolerance values, the program is converged. The main program calls five other programs. Four of these programs (STURBS, HRSG, SGC, CEIGCCHX) were existing design programs used at CE. Some of these existing programs were written in Fortran and others in BASIC programming languages. These programs were used basically as sub-programs called from the main program. Transfer of information between the sub-programs is done with files.

SCINIT is a Fortran initialization program which provides initial guesses for the starting values of all the required input variables for the programs.

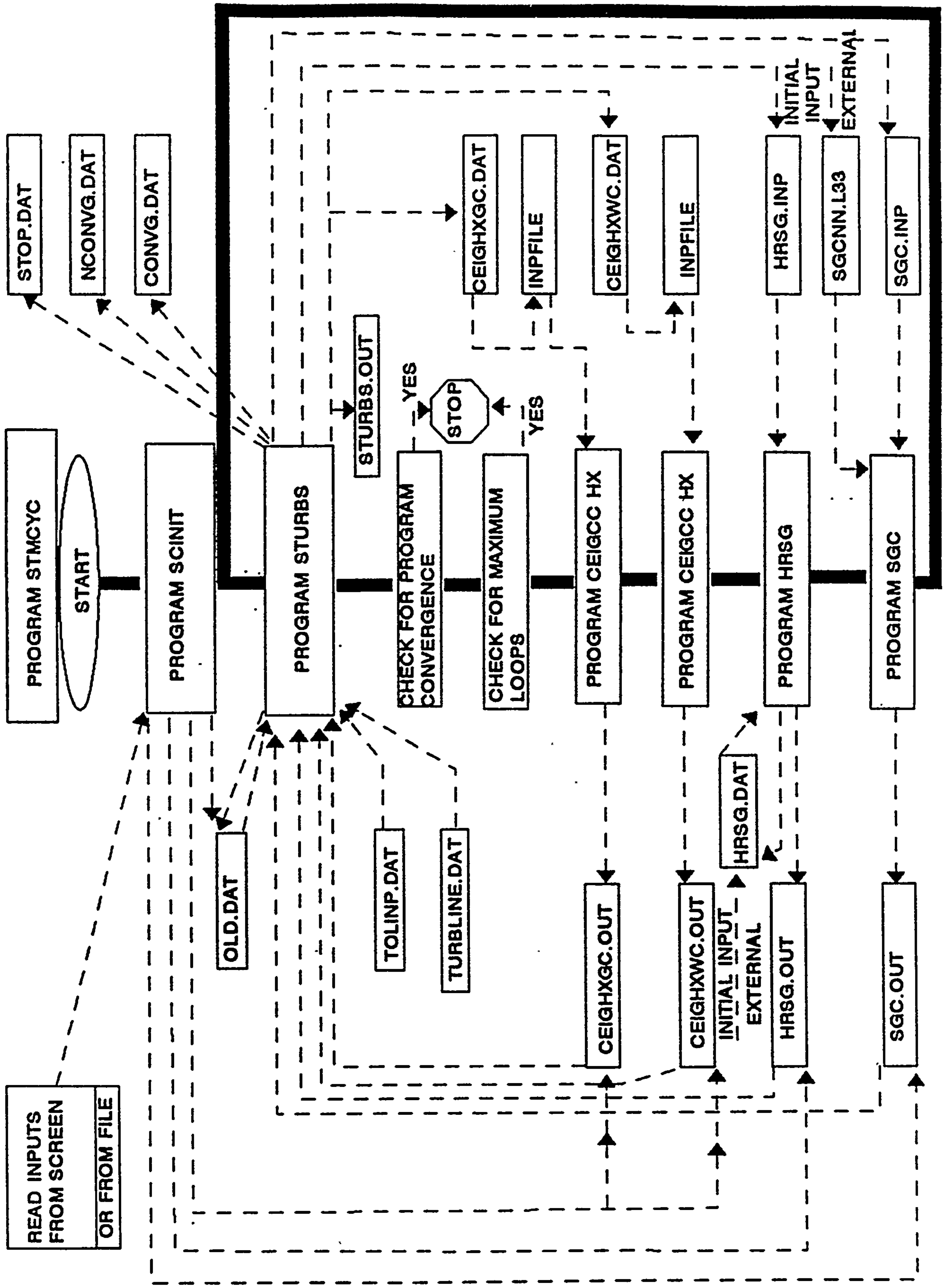
STURBS is a Fortran program which calculates steam turbine performance, condenser performance, boiler feed pump performance and the performance for the low pressure feedwater heater components of the steam cycle. The convergence status for the main program is also determined within this program.

CEIGCCHX is a Fortran program which is used to calculate the performance of external heat exchangers. This program is used for analysis of the Booster Compressor Air Cooler and the Mill Air Heater #1 heat exchangers.

HRSG is a Basic program used to calculate the performance for the Heat Recovery Steam Generator component. The HRSG is used to recover heat from the gas turbine exhaust stream.

FIGURE 5

CWL&P STEAM CYCLE PROGRAM FLOW CHART AND FILE STRUCTURE



SGC is also a Basic program which is used to calculate performance for the Syngas Cooler component of the steam cycle. The Syngas Cooler recovers heat from the Low Btu Gas stream leaving the gasifier.

iii) Heat Rate Sensitive Process Decisions

Several studies were completed to quantify the effects of various process options on net plant heat rate (NPHR). The following list shows some of the various process options which were evaluated.

- Gasifier air temperature study
- HRSG stack temperature study
- HRSG feedwater temperature study
- Supplemental HRSG firing study
- Process steam source option study
- Coal and char feed system study

a) Gasifier Air Temperature Study

Air for the gasification system is extracted from the gas turbine air compressor discharge at about 155 psia for the base gas turbine load, 95°F ambient temperature operating condition. The air extraction condition (temperature, pressure) and the required LBG fuel pressure for the gas turbine are dependent on the gas turbine load and the ambient temperature. The extracted gasifier air stream must be raised in pressure such that the LBG fuel produced is at a pressure high enough to feed to the gas turbine combustor. The required pressure increase to the gasifier air stream is about 130 psi and it is provided by a booster air compressor.

Several options are available for the gasifier air feed system. The simplest system would be to directly feed this air from the gas turbine (without any cooling) to the booster compressor and then to the gasifier. Optionally the air stream to the booster compressor could be cooled.

Cooling of the gasifier air stream prior to entering the booster air compressor would reduce the power requirements for the booster compressor as compared to the uncooled case. If the heat removed from the air was recovered in the steam cycle an increase in the output of the steam turbine would also occur.

For a given gas turbine operating condition, a reduction in gasifier air temperature causes changes to the gasifier operating requirements. The gas turbine still requires the same amount of energy (sensible + chemical) in the LBG fuel stream to provide the required turbine inlet temperature. But if the air feed stream to the gasifier is at a lower temperature, the amount of coal fired in the gasifier must be increased to provide the additional energy required to satisfy the gasifier energy balance. The gasifier stoichiometry would be leaner which would reduce the product gas heating value slightly as gasifier air feed temperature is reduced.

The effect on net plant heat rate favors higher gasifier air temperatures although this effect is not a strong one. Some preliminary studies have shown that reducing gasifier air temperature from 800 to 500°F degrades net plant heat rate by about 0.7 percent.

From a practical standpoint it is difficult to find commercially available booster compressors designed for high compressor outlet temperatures. There are, however, many other types of compressors which do operate at high temperature. Our survey showed that 600°F was about the current practical limit for machines with our design requirements.

b) HRSG Stack Temperature Study

An important decision in the design of a power plant is the design point stack temperature. In order to quantify the effects of stack temperature on net plant heat rate a small study was done. Three stack temperatures were investigated in this study (200, 250, 300°F). The results indicate that about a 36°F change in stack temperature is equivalent to about a one percent change in net plant heat rate. The sensitivity of net plant heat rate to stack temperature is also shown to be very linear.

Because there are small amounts of sulfur dioxide and trioxide in the fluegas leaving the HRSG acid dew point temperature is also a consideration in selection of the stack temperature. Other considerations are net plant heat rate and capital costs. Another important consideration with respect to acid dew point temperature is how stack temperature changes as a function of plant operating conditions. All of these factors were used in selecting the stack exit temperature. For the full load design case (95°F ambient) a stack temperature of 260°F was used as a basis for equipment selection.

c) HRSG Feedwater Temperature Study

The feedwater for the HRSG is provided from the boiler feed pump which takes water from the discharge of the low pressure extraction feedwater heater. The feedwater temperature entering the HRSG can therefore be varied by selecting different steam turbine extraction pressures for the low pressure feedwater heater.

For a given stack temperature, the selected feedwater temperature impacts the size of the HRSG economizer bank and the net plant heat rate. As feedwater temperature is raised closer to the stack temperature the log mean temperature difference for this bank is lowered and the heat transfer surface area requirement is increased. However, with a higher feedwater temperature entering the economizer the HRSG will generate more steam since the pinch point for the cycle is at the economizer cold end. The additional steam generation is partially offset by the additional steam extraction required by the low pressure feedwater heater.

A comparison of feedwater temperatures was done for the 250°F stack temperature case. Two feedwater temperatures were investigated to determine the effect on net plant heat rate (230 and 200°F). The 200°F feedwater temperature, as compared to 230°F, would reduce the amount of main steam generated by about 7,000 lbm/hr causing a reduction in steam turbine output. The low pressure feedwater heater would, however, require about 10,000 lbm/hr less steam extracted from the steam turbine which actually increases output from the steam turbine stages below the extraction pressure. The net effect to the steam turbine is a reduction in power output of about 0.5 MW for the 200°F case as compared to the 230°F case. The reduction in steam turbine power for the 200°F case (as compared to 230°F) would degrade net plant heat rate by about 0.9 percent. The design point HRSG feedwater temperature selected for this cycle was 230°F.

d) Supplemental HRSG Firing Study

One of the primary design requirements for this plant is to provide 60 MW net output at a 95°F. ambient temperature. With the 95°F ambient condition and the gas turbine operating at the Base Load firing condition, the net plant output is calculated to be about 55.6 MW. In order to obtain 60 MW a various options were investigated.

One option investigated was to peak fire the gas turbine. This mode of gas turbine operation runs the gas turbine at higher turbine inlet temperature. With this mode of operation an additional 8% output from the plant is available which would satisfy the 60 MW net output criteria. There are a couple of impacts of operating the gas turbine in this peak firing mode. From a performance standpoint there is an improvement in net plant heat rate of about 1.3 percent as compared to base firing mode. From an operation and maintenance standpoint the inspection intervals and associated maintenance requirements are increased.

Another option available to increase plant output is to fire additional fuel in the HRSG (supplemental HRSG firing) to increase the output of the steam turbine. A study was done to quantify the effects of supplemental HRSG firing on net plant heat rate. This study considered supplemental firing with either LBG or natural gas. The results showed that the incremental thermal efficiency for supplemental firing with LBG was about 21 percent. Similarly, the incremental thermal efficiency for supplemental firing with natural gas is about 29 percent.

The primary reason for the significantly better incremental thermal efficiency with supplemental natural gas firing relates to the throttling process which occurs with supplemental LBG firing. When firing LBG in the HRSG the fraction of the LBG which is fired in the HRSG is throttled from high pressure (about 225 psia) into the HRSG and combusted. The air and coal which was fed to the gasifier to produce this LBG required power to compress. Normally (without supplemental LBG firing) the LBG fuel stream is fed to the gas turbine and combusted. The high temperature and pressure combustion product stream is expanded to about atmospheric pressure in the gas turbine. The expansion process generates significantly more power than was required in the compression step.

Based on this information and associated cost differentials for these options, the customer, CWL&P, decided to specify supplemental natural gas firing in the HRSG as the preferred method to obtain 60MW net output from the plant.

e) Coal and Char Feed System Study

Feeding of coal and char into the gasifier is done with lockhopper type systems. The gas used for lockhopper pressurization and fluidization must be basically inert (very little if any oxygen) and it must be at a pressure high enough to feed the material into the gasifier which is operating at about 270 psia. Ideally the transport gas would also be inert since any oxygen introduced into the reductor zone of the gasifier would consume some of the low btu gas. Some of the options for this fluid are listed below.

- Steam
- Inerted fluegas from the HRSG
- Fluegas from an adjacent boiler
- Nitrogen

Utilization of steam would be convenient but would require the coal to be heated to about 500°F in order to avoid condensing the steam onto the coal particles. The char is collected at about 1000°F and, therefore, steam should work well for this system. The steam could be extracted from the steam turbine or generated in a separate process steam generator.

Fluegas from the HRSG could also be used if it were inerted by burning off the excess oxygen. Typically the oxygen content of the HRSG fluegas ranges between 12 to 16 percent by volume depending on gas turbine load. The oxygen could be burned off with LBG or natural gas. The coal would also have to be heated for this option since this fluegas contains significant quantities of water vapor.

There are several other operating boilers located fairly close to the site and therefore fluegas from one of these boilers could be compressed and used. The coal would also have to be heated for this option since this fluegas also contains significant quantities of water vapor. The advantage of using fluegas from another boiler is that it is much lower in oxygen content than the fluegas leaving the HRSG (typically ranging between 3 and 5 percent by volume) and, therefore, less fuel would have to be consumed to inert this fluegas.

Nitrogen could be purchased and used for this purpose. There will be a small nitrogen use at the plant anyway for other purposes. However the rate of expected usage for the coal and char feed system would be much higher than for the other plant uses. The use of nitrogen does not require the coal to be heated which would reduce capital costs. The compression of the nitrogen was assumed to be provided by simply boiling off the required flow rate utilizing a waste heat source to provide this duty. Therefore, no additional auxiliary power would be required. The amount of nitrogen required for this system adds significantly to the plant operating costs.

The effect on net plant heat rate for these options was investigated in a preliminary study in order to see if any significant efficiency advantages were apparent between the options. Steam was used as the base case for the study and the net plant heat rate ratios are all relative to the steam case. The results shown in Table 4 indicate fairly small differences between the cases. Therefore, the selection criteria was based primarily on capital cost and operating cost differentials between the cases.

Table 4
Net Plant Heat Rate Comparison

Pressurizing, Fluidizing and Transport Fluid Type	NPHR Ratio
Steam	1.000
Inerted fluegas from the HRSG	1.013
Fluegas from an adjacent boiler	1.005
Nitrogen*	0.982

*excludes N_2 plant auxiliary power consumption

The selected fluid for pressurizing, fluidizing, and transport of both the coal and char was initially steam. This selection was made based on the heat rate advantage and was subsequently changed to nitrogen for the purpose of capital cost reduction.

f) Process Steam Source Study

Process steam is used in this plant for several purposes.The total quantity of process steam required for these uses is dependent on the plant operating condition. The quantity is also time dependent due to the batch type of operation required for the coal and char lockhopper systems and the cyclic steam requirements for sootblower system. The time averaged total process steam flow requirement for the Maximum Continuous Rate (MCR), plant operating point is about 15000 lbm/hr.

The pressure requirements for these process steam uses are all at about the same value except for the sootblower steam. Since sootblowing requires high kinetic energy steam with relatively high flow for short time periods the best choice is to use high pressure steam extracted from the gasifier superheater circuit for this duty.

Several potential sources are available for the remaining low pressure process steam requirements as shown in the following list.

1.) Separate process steam generator located in the HRSG
2.) Steam turbine extraction
3.) Utilization of main steam

Because of the cyclic nature of the process steam requirements as described previously, option 1 would have to be designed to generate more than the time averaged quantity of process steam in order to accommodate the peak flow requirements. Any additional steam generated from this system could then be admitted into an admission port on the steam turbine as required in order to handle these fluctuations.

The second option (steam turbine extraction) would have a limited load range where the extraction point pressure would remain above the required value. Once the process steam header pressure drops below the set point pressure as steam turbine load is reduced the process steam extraction source could be switched to the main steam line thru a pressure reduction valve.

A study was done to quantify the effects on net plant heat rate of these various process steam options. Using option 1 for the process steam source is the least efficient method. Option 3 shows a slight improvement in net plant heat rate (about

0.3 percent better than option 1). Option 2 is the most efficient method (about 1.4 percent better than option 3 and about 1.7 percent better than option 1). Capital costs also favor option 2.

Based on the results of this study it was decided to use the turbine extraction as the primary source for the process steam. Once this source was not able to maintain the set point pressure in the process steam header, the main steam line would be used.

g) Cost Reduction Study Heat Rate Effects

A list of several items was developed to reduce the cost of the plant as a part of a plant cost reduction study. Four of the proposed items were identified as items which would cause significant impacts on net plant heat rate. The first item proposed was to eliminate coal mill air heater #1 (which utilizes recirculated water from the economizer as the heat source) and utilize a larger version of coal mill air heater #2 (which uses steam from the gasifier steam drum as the heat source). The second item proposed was to eliminate the high pressure steam generator in the Hot Gas Cleanup Up System and reject this heat to the lake water. The third proposed option was to use lake water for the booster air compressor cooler rather than recovering this heat in the economizer circuit. The fourth proposed option was to eliminate the low pressure feedwater heater in the steam cycle.

Table 5 shows the impacts of the proposed changes to net plant heat rate.

Table 5
Cost Reduction Net Heat Rate Effects

Proposed Cost Reduction Measure	Change to NPHR Btu/Kwhr
Eliminate Coal Mill Air Heater #1	+ 190
Eliminate High Pressure Steam Generator in HGCUS	+ 177
Use Lake Water For Booster Compressor Cooler	+ 245
Eliminate Low Pressure Feedwater Heater	+ 486

h) HRSG Performance Study

The Heat Recovery Steam Generator (HRSG) recovers the major fraction of the total heat added to the steam cycle of this plant. It is designed to generate high pressure superheated steam by recovering heat from the gas turbine exhaust stream. This steam is combined with additional steam generated from the gasifier island and expanded thru a steam turbine for power generation. The HRSG is also used to preheat the feedwater which is supplied to the gasifier island. The capability for additional HRSG steam generation is provided thru the use of supplemental natural gas firing.

The performance design of the HRSG component for this plant was an iterative process. This process involved the consideration of various HRSG design points and performance requirements. Because of the highly integrated steam cycle concept defined for this plant, the design of the HRSG was also very sensitive to the various heat recovery options which were investigated for the gasifier island. Performance design is defined as that part of the design process where heat exchanger surfaces are determined in order to satisfy the various plant performance requirements. Some of the plant performance requirements which impacted the performance design of the

HRSG are listed below.

- Plant output of 60MW net at 95°F ambient temperature
- 1265 psia, 950°F steam conditions
- Acceptable steam cycle performance for the following envelope of plant operating conditions:
    - gas turbine loads from 30 to 100 percent
    - ambient temperatures from 0 to 95°F.
- Acceptable steam cycle performance with the gasifier in both the normal and high performance modes of operation.
- Acceptable steam cycle performance with the gasifier not in operation and the gas turbine firing natural gas for the operating condition envelope defined above.
- Steam cycle arrangement as shown in Figure 4.

Normal and high performance refer to the predicted operation characteristics of the gasifier. Normal performance is the predicted performance using conservative calculations based on The PDU performance operating conditions. By varying operating conditions, it should be possible to achieve much better performance in the higher heating value content and system efficiency. This is refered to here as high performance. The plant is designed for normal performance with consideration being given to operation in the high performance mode.

The basic heating surface performance design for the HRSG is governed primarily by three cases. The primary design case (NPBL-95-S60) is with the gasifier in the normal performance mode of operation, the gas turbine at base load firing LBG at 95 °F. ambient temperature, and a small amount of supplemental natural gas fired in the HRSG. The supplemental natural gas firing in the HRSG is provided such that 292,840 lbm/hr superheater outlet flow is obtained which provides 60 net MW output from the plant. The other two cases are natural gas fired gas turbine cases with the gasifier not in operation. One of these cases (NGBL-95-S0) has no supplemental natural gas firing in the HRSG while the other case (NGBL-95-S60) fires enough supplemental natural gas in the HRSG to generate 236,439 lbm/hr superheater outlet flow such that 60 net MW output is obtained from the plant.

In general, the HRSG is first surfaced as a standard natural gas fired combined cycle HRSG without any supplemental firing (Case NGBL-95-S0). The surface calculations are specified with a 20°F evaporator outlet pinch point temperature difference and 10°F approach for the economizer. The low pressure feedwater heater is bypassed for this case. The booster compressor air cooler and the mill air heater #1 are not used for this case and feedwater is not supplied to the gasifier island. The Low Temperature economizer section is also bypassed in this mode of operation. Four percent desuperheater spray is specified as an additional requirement for surfacing of the evaporator and superheater circuits for this case. This case defines the total superheater surface requirement (HTSH + LTSH) although the split between High Temperature and LT is not specified by the requirements of this case. The evaporator bank surface requirement, and the surface requirement for the HT economizer section are also defined by the specifications for this case.

Case NGBL-95-S60 defines the maximum amount of supplemental natural gas firing for the HRSG and therefore provides the information necessary to locate the supplemental firing burners.

Case NPBL-95-S60 is the case which specifies the total economizer section surface requirement (HT + LT). The surface required for the LT economizer is defined by knowing the total economizer surface requirement from this case and the HT section requirement from case NGBL-95-S0. This case also defines the maximum steam and water pressures during normal operation and the draft loss across the HRSG for this case should be less than 10 in.w.g.

i) Coal Preparation System Alternate

At the time of this investigation, the coal preparation system for this plant consisted of a coal milling system and a coal heating system. The coal must be heated to about 500°F in order to avoid condensation problems in the coal feed system. Steam was used in the coal feed system for lockhopper pressurization/fluidization and as the carrier gas for transport of the pulverized coal to the gasifier.

At the end of budget period 1 the coal preparation system was conceptually arranged as shown in Figure 6. In this system flue gas taken directly from the HRSG is drawn into the pulverized coal heater. The temperature of the flue gas is controlled to maintain the desired pulverized coal temperature leaving the pulverized coal heater. The flow of flue gas is provided by the system fan and is controlled by coal mill load. The gas leaving the pulverized coal heater flows through the system fan and then to the coal mill. The flue gas temperature entering the mill is controlled to maintain the temperature leaving the mill at the set point value. The stream leaving the mill enters a cyclone and baghouse where the pulverized coal is separated from the flue gas. The flue gas leaving the baghouse is vented to the atmosphere. The pulverized coal streams from the cyclone and baghouse are combined and flow through the pulverized coal heater and then into the coal feed system.

Fluegas dampers, a natural gas burner, and a heat exchanger would be required for control purposes. From a control system viewpoint this system was somewhat cumbersome and possibly quite slow in response for some of the controlled variables. Relatively long and expensive flue gas ducts from the HRSG to the coal preparation system would be required. The heat transfer rates for the pulverized coal heater were also expected to be quite low with the use of flue gas and therefore this component could become quite high in capital cost. For these reasons a study was done to investigate other coal preparation system concepts.

The result of this study is shown in Figure 7. In this system air is used as the gas for the coal mill thus eliminating the fluegas ducts from the HRSG to the coal mill. The air flow is again controlled by the coal mill load and is provided by the fans. The air leaving the forced draft fan flows through coal mill air heater #1 where it is heated enough to maintain the outlet of the coal mill at the set point temperature. If coal mill air heater #1 can not provide enough heat, coal mill heater #2 is also used. The air then flows through the coal mill where it dries and conveys the pulverized coal out of the mill. The stream leaving the coal mill enters a cyclone and baghouse for separation of the pulverized coal from the air. The air leaving the baghouse flows through the

FIGURE 6

COAL PREPARATION SYSTEM

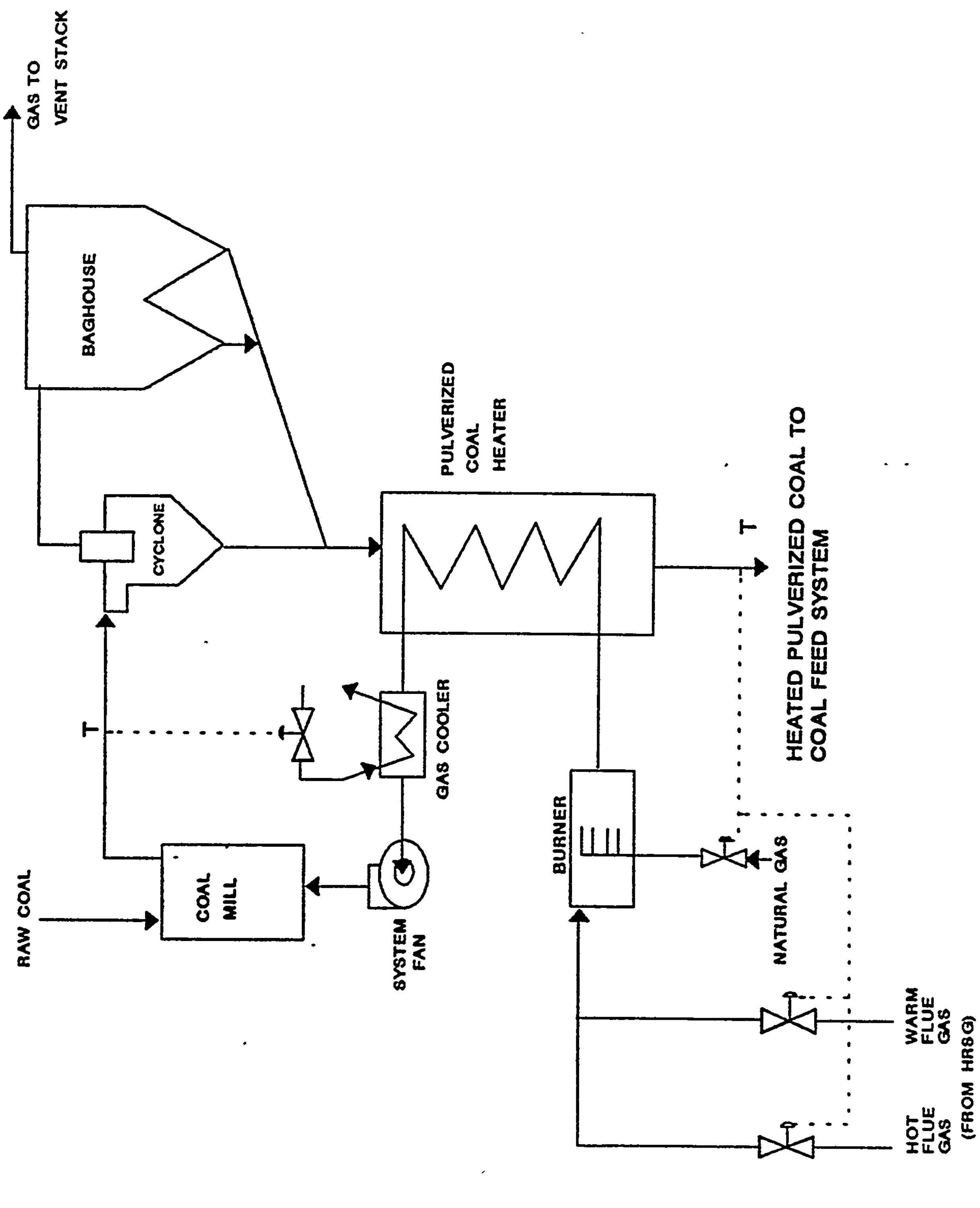
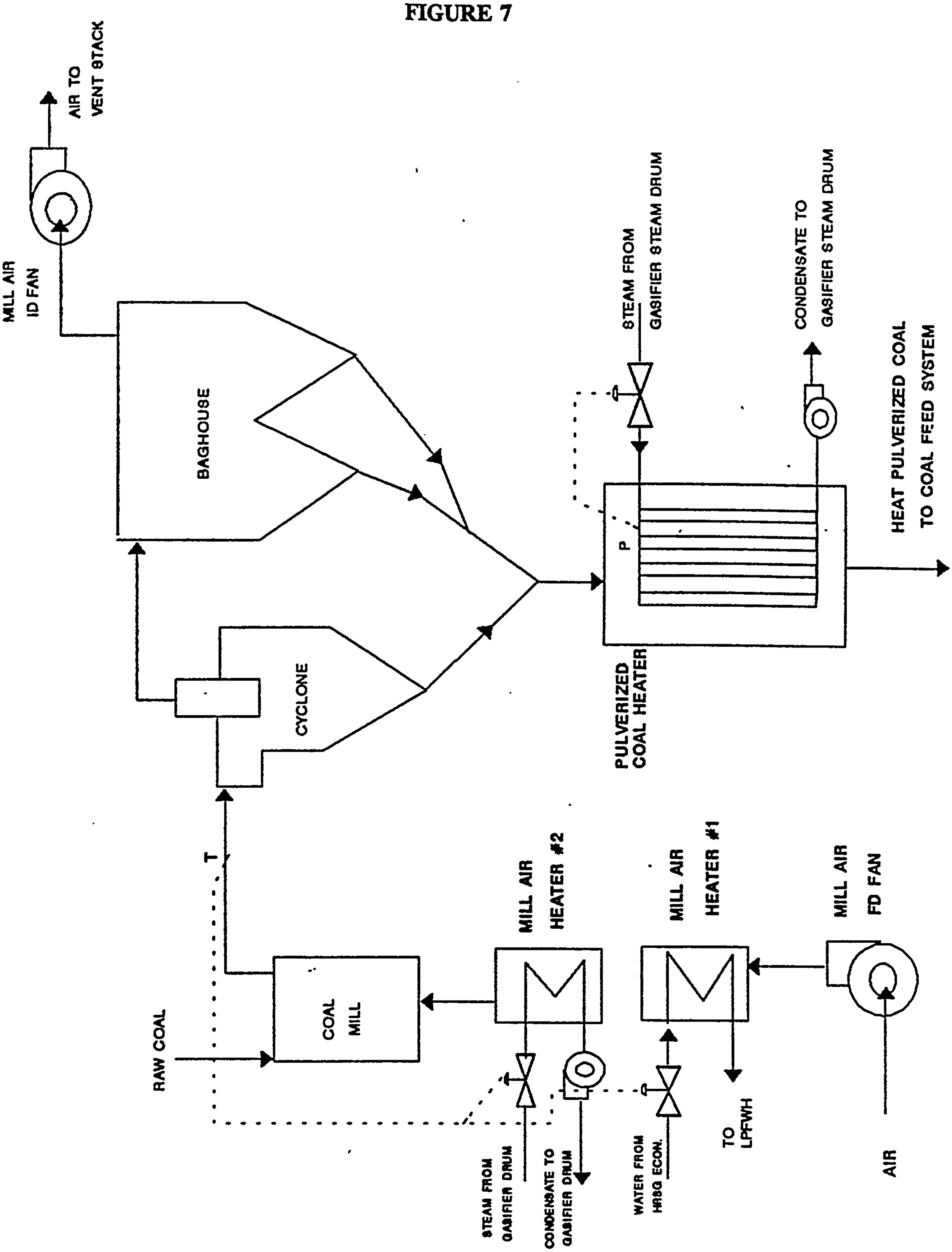


FIGURE 7



COAL PREPARATION SYSTEM

induced draft fan and is then vented to the atmosphere. The pulverized coal streams from the cyclone and baghouse enter the pulverized coal heater where it is heated to the required temperature.

The heat source for coal mill heater #1 is provided from the feedwater stream to the gasifier. The cooled feedwater stream leaving this heat exchanger is returned to the low pressure feedwater heater inlet. In this way the heat source used for this duty is still primarily the low grade heat in the HRSG low temperature flue gas but the system for providing this heat is less costly.

Coal mill air heater #2 uses saturated steam from the gasifier steam drum for the heat source. The condensate is returned to the steam drum. This heat exchanger is only used when coal mill heater #1 can not provide enough heat to satisfy the required coal mill outlet temperature. A separate study has shown this heat exchanger will be used only at high load with ambient temperatures below 0°F.

The heat source for the pulverized coal heater is also saturated steam from the gasifier steam drum. The gasifier drum is controlled to a constant pressure of about 1500 psia with a drum pressure control valve located in the gasifier superheater circuit and therefore provides a constant source temperature of about 600°F for the pulverized coal heater. This system therefore inherently provides protection from overheating of the coal.

Two fans are used (forced and induced draft) as a balanced draft system in order to control the pressure of the coal mill to slightly below atmospheric.

A comparison of net plant heat rate was done for the two systems. The net plant heat rate for the system shown in Figure 7 is only about 0.3 percent worse than the system shown in Figure 6. This is caused by a reduction in steam turbine output of about 0.9 percent which is partially offset by a reduction in the fan power requirement for this system. Figure 7 represents the base case for the coal preparation system. The final design was determined after consideration of an alternate coal feed system described below.

j) Coal Feed System Alternate

At the end of 1992 a study was done comparing three alternate coal feed system designs to the base case. The study scope was limited to only a comparison of net plant heat rates for the cases. This study was based upon preliminary design information and vendor inputs.

Alternate 1 differs from the base case primarily in that nitrogen is used for transport, pressurization, and fluidization of the coal (steam, extracted from the steam turbine, was used for these purposes in the base case). The coal is transported to the gasifier at 200°F as compared to 500°F for the base case. Alternate 1, therefore, does not require a pulverized coal heater system. Additionally the gasifier circulating water pumps are eliminated for this option and the gasifier and SGC evaporative circuits are designed for natural circulation. Other assumptions related to the HRSG are listed below and are consistent with the base case.

- 250°F stack temperature
- 230°F feedwater temperature to the HRSG
- 1265 psia, 950°F steam conditions
- Natural gas supplemental firing amount same as for the base case
- 550°F feedwater to the gasifier

Alternate 2 is the same as Alternate 1 except the coal mill air stream is heated with a natural gas fired burner. The base case and Alternate 1 used recirculation of economizer water through the coal mill air heater #1 heat exchanger as the source for this heat duty. Alternates 1 and 2 were both calculated with the same ground rules as the base case. One of the ground rules shown above was a 250 °F stack temperature. With Alternate 2 the log mean temperature differences for the economizer and evaporator banks were significantly reduced which would increase the size and cost of these components.

Alternate 3 was added as another option. This case is the same as Alternate 2 except it uses the same HRSG surfacing as for the base case. Some of the HRSG ground rules were therefore relaxed for this case. The amount of supplemental firing in the HRSG for this case was calculated such that the total steam flow to the steam turbine is the same as for the base case. The stack temperature for this case increases to about 260 °F and the feedwater temperature leaving the economizer is about 573 °F as compared to 550 °F for all the other cases.

The net plant heat rate differentials between the cases are relatively insignificant. Alternates 1,2,3 require 14,400 lb_m/hr @ 390 psig and 3000 lb_m/hr @ 17 psig of nitrogen at this MCR operating condition which represents a significant additional operating cost as compared to the base case. However, Alternate 3 was initially selected as the plant design basis because it represents the lowest installed cost option. Figure 8 shows a block flow diagram for Alternative 3 .

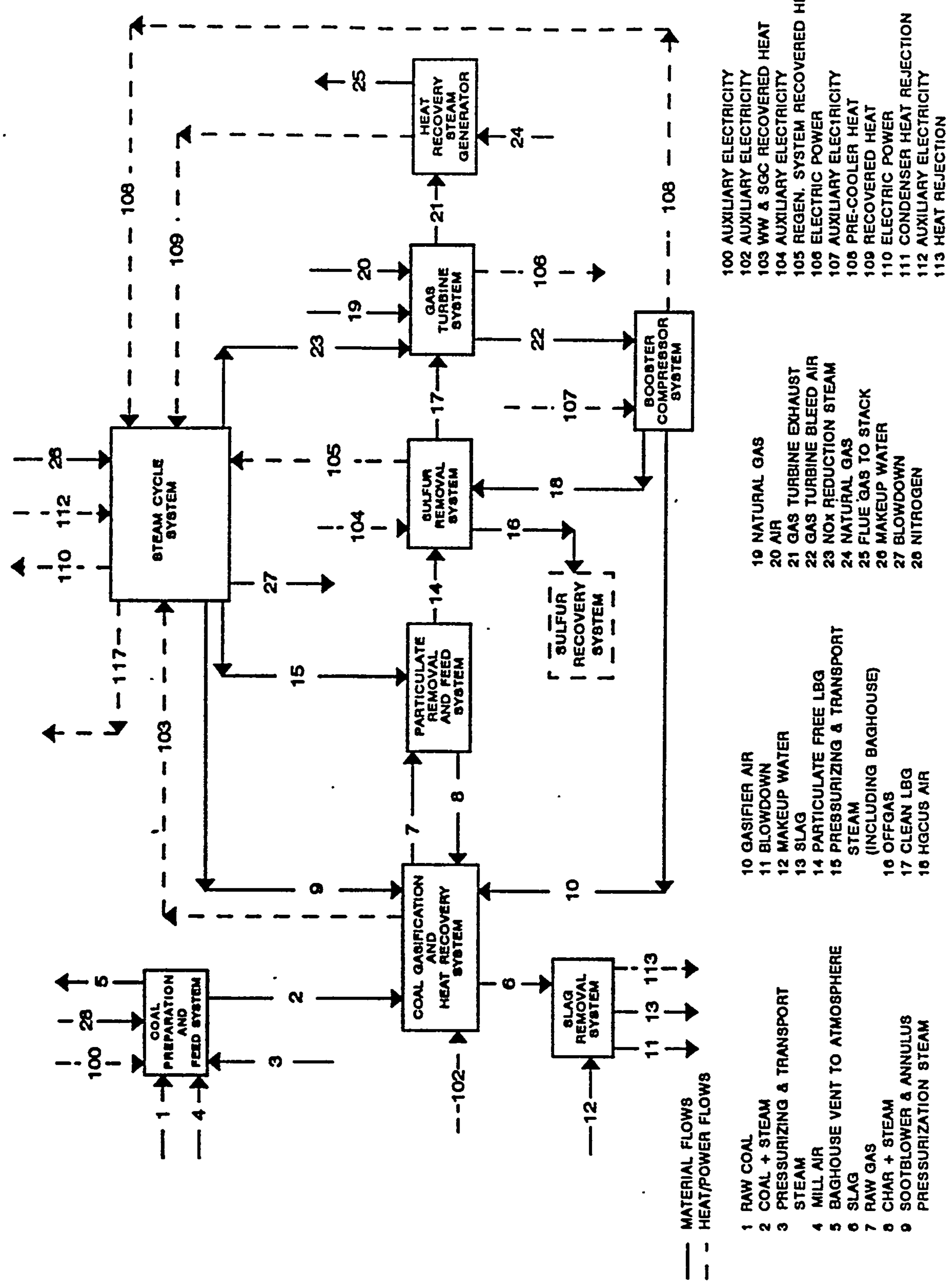
The final design used in the cost estimating incorporated Alternate number 3. This is similar to Figure 7 except that this design used a mill air heater that is fired on natural gas. Hot air is used in the mill to dry the coal and transport the pulverized coal to the coal cyclone and baghouse before being exhausted to the atmosphere. The HRSG surface was kept the same as in the base case. Downstream of the coal prep system, the coal heater (shown in Figure 7) was eliminated when the pressurizing system was changed to nitrogen as described below.

iv) Design Basis

The design basis for the plant was established as described above by selecting the system that best suited the needs of the host site. CWL&P has a primary need for the power that will be generated by this plant during the peak summer months. This condition includes a 95°F. ambient temperature. Several ways of generating this power requirement were investigated and after discussing these methods with CWL&P the design case heat and material balance was selected. This heat and material balance was then used to specify design conditions for all of the systems and equipment specifications. Additional heat and mass balance cases were done for a

FIGURE 8

OVERALL SYSTEM BLOCK FLOW DIAGRAM (ALT-3)



number of possible operating conditions and these were used to adjust design tolerances for equipment and systems.

A design document was generated which listed all of the conditions encountered by the location as well as the normal requirements of CWL&P. This document includes information on weather conditions, site building requirements, environmental codes, fuel composition and all the other information normally generated in building a power plant. This document and the design case heat and material balances constitute the design basis for the plant.

v) Systems Studies

In 1992 numerous system studies were conducted to provide a sound theoretical basis for designs, to determine potential safety hazards and appropriate code application, to develop empirical data for component design, and to ensure constructability and reliability. The systems studied were the coal feed system, the char recycle system and the hot gas cleanup system. The outside resources used for various aspects of the system studies include:

- F. Zenz - Solids Flow
- J. R. Johanson, Inc. - Bin and Lockhopper Design
- T. Hamilton Consulting - NFPA Code
- Lummus Crest, Inc. (LCI) - Safety, Constructability, and Materials
- PEMM Corp - Pulverized Coal Heat Transfer Rate
- General Electric - Hot Gas Clean Up

Considerable in house resources were also used for system studies. Of particular note is the Kreisinger Development Laboratory (KDL) for pneumatic conveying and metallurgy, and Resource Recovery Systems for operating considerations and material handling expertise.

System reliability is a prime consideration for the gasifier at this stage of the project design when the gasifier general arrangements, major component arrangements and P&ID's are being done. Design personnel with start-up and power plant operating experience are being used to access all components and their interfaces for reliable operation. Minor but important revisions have been made and continue to be made to provide the most simple and reliable systems possible for the chosen design. Brief summaries of the more important studies follow:

a) Coal Feed System

In the current design, raw coal discharges from a storage bunker via a volumetric feeder into a pressurized bowl mill pulverizer. The bowl mill pulverizes and dries the raw coal heating it to a temperature of 200°F. A centrifugal fan upstream of the mill provides the mill air used to classify the coal and convey it to a bagfilter. The mill air is heated by gas burners located in the air duct upstream of the coal mill. The receiving bin discharges intermittently and alternately by gravity into two lockhoppers. The lockhoppers are pressurized and intermittently discharge to their associated feed bins. The feed bins continuously discharge coal at high pressure into pneumatic conveying lines. Pressurizing, fluidizing and conveying gas selection is discussed below. Each

conveying line from the feed bins splits to supply the coal burner nozzles located at each firing elevation on the gasifier.

b) **Pressurizing, Fluidizing, and Conveying Gas Study**
Prior to refining the coal feed system lockhopper and feed bin sizes and cycle times, a study was performed to evaluate pressurizing, fluidizing and conveying gas options for the coal feed system. Air, nitrogen, steam, carbon dioxide, and flue gas were the possibilities. The early study looked at the economics and technical aspects of each gas. It concluded that steam was the best option from cost and functional points of view. Carbon dioxide and flue gas were rejected because of technical problems and bad economics. Nitrogen appeared feasible but more costly. Air also appeared more costly and could not be used for pressurizing due to NFPA considerations.

The use of steam would require the use of a fluidized bed steam coil heater between the coal bag filter discharge and the coal receiving bin inlet to bring the coal temperature up to 500°F to prevent condensation in the receiving bin and lockhoppers. As the system design progressed the coal heater became an object of increasing concern for technical, economic, and operating reasons. Also, due to significant reductions in the lockhopper and feed bin sizes the amount of gas to drive the system had decreased appreciably. Consequently, it was decided to do an updated economic evaluation and reliability study to compare nitrogen and steam. The new economic study showed steam to have higher capital cost, but lower operating costs. Although the nitrogen operating costs are higher, they were not prohibitive, and the development of commercial membrane type separation systems allows simple on site nitrogen generation at predictable prices. The reliability study showed that this type of operation with nitrogen has been proven and operated reliably at facilities by others. Similar precedent for steam is very limited . The current design will use nitrogen with provisions for possible future use of steam. Steam and air will continue to be studied for use as a pressurizing and/or conveying medium for coal.

c) **Coal Mill Outlet Temperature**
Normal coal mill outlet temperature is about 140°F as practiced in the United States. Recent experience in Europe with mill outlet temperatures 200°F and above has demonstrated that pulverized coal systems operate with the same or less incidence of fire as in the U.S. T. Hamilton, a consultant on pulverizers and NFPA code, was employed to study this matter. His findings in Europe will be soon published by EPRI. KDL also tested the demonstration coal for characteristics at elevated temperatures. Fire risk factors did not increase significantly until temperature reached 700°F. Based on this study, CE has opted to send 200°F coal to the baghouse. The study shows that mill operation will be safe and that condensation and subsequent hang up in the bagfilter hoppers will be discouraged.

d) **Lockhoppers and Feed Bin Design**
J.R. Johanson, Inc. was employed to develop the parameters for coal and char receiving bin, lockhopper, and feed bin design and operation. Johanson tested coal and char samples to determine bulk and fluidized densities, critical arching and

rat-holing dimensions, hopper angles, and fluidizing characteristics. From these results and the use of their mass flow system models, specific design criteria was developed for the bin configurations, pipe sizes, fluidizing methodology, pressurizing and fluidizing flows, flow control and bin materials. A series of recommendations were issued by J.R. Johanson based on this work. Initial bin diameter was restricted to 12 ft. or less by CE for fabrication reasons. Sizes for all the bins were later optimized to provide the best combination of building height and cycle time.

Further study was conducted by CE to develop the hardware options and their corresponding performance curves for the pressurization and venting of the lockhoppers and feed bins using Johanson's design criteria. The high pressure differentials involved here require sonic flow in the control piping and valves. Careful consideration was taken to develop piping and valve configurations that would minimize abuse of the valves, keep the control loop simple, and maximize reliability.

Study is proceeding on options for fluidizing/pressurizing components in the high pressure bins. Although the flow criteria has been established, a specific means of introduction has not been selected. Several options are being investigated.

The possibility of independently controlling double or triple material flows at the feed bin discharge was investigated with the assistance of J.R. Johanson, Inc. To date, a proven operation using this concept has not been found by Johanson or CE. The instrumentation necessary to support such an operation reliably has not yet been developed. As a result, CE has elected to design the demonstration plant with single discharge from the feed bins with provisions for the future use of dual discharge. Single discharge controlled flow is a proven concept and is in common use in commercial positive pressure pneumatic conveying systems. CE plans to test any new instruments that show true promise in being able to reliably and accurately measure solids flow in a pneumatic transport line.

e) Lockhopper and Feed Bin Test

A test program has been developed to test full scale coal lockhopper and feed bin functions using high pressure air. It is intended to conduct this test prior to fabrication of certain components and construction of the demonstration plant. Because pneumatic systems, and especially unusual pneumatic systems, are not completely predictable from design models, it was decided that a test program would allow the quickest and most certain, if not most cost effective, method of developing a successful coal feed system. The test will be used specifically to finalize hardware details, select an optimum flow regime, and to develop an effective control sequence for pressurizing and fluidizing the lockhopper, feeding from the feed bin, and transport in the conveying lines.

f) Material Handling Valve

A study was conducted to determine which valves in the feed system would require special selection and design to perform reliably with an adequate service life where abrasive solids and/or high pressure differentials on actuation are being controlled. An investigation of various valves in similar operations leaves two viable options for the lockhopper inlet and discharge valves, the feed bin discharge valves, and the lockhopper and feed bin vent valves. It was determined that many of these valves would require major maintenance approximately every 8000 hours of use. Provisions have been incorporated into the demonstration plant design to accommodate quick change out of these valves with minimal disruption, if any, to the gasifier operation.

g) Char Recycle System

In the current demonstration plant design product gas and entrained char leave the gasifier heat exchanger at 1000°F and enter a char cyclone that separates a percentage of the char from the product gas. The char discharges the cyclone by gravity into a char seal bin that provides a pressure seal, and proceeds by gravity into the char receiving bin. The product gas and remaining char exits the cyclone and flows to two high pressure, high temperature 50% bag filters arranged in parallel to remove the remaining char from the product gas. The char discharges from each bag filter by gravity to the char receiving bin. The char receiving bin intermittently and alternately discharges by gravity into two lockhoppers. The lockhoppers are pressurized with super heated steam and intermittently discharge to a common char feed bin. The feed bin continuously discharges into one of two conveying lines using superheater steam as a conveying media. Each conveying line from the feed bin splits four ways to supply the four char reinjection nozzles located at their associated reinjection elevation at the gasifier.

h) Char Bagfilter

Early in 1992 a study was done to determine filter design philosophy. Because of the unusual high temperature and pressure requirements cutting edge technology would be necessary. For this reason the study concluded that the design philosophy should include testing, performance tolerances, and fall back positions for retrofitting filter materials and cleaning media if necessary.

Since then, CE has been collaborating with Mikropul, Flex-Kleen, Research Cottell, Acurex Environmental Corp, 3M, and Westinghouse on specific designs. Several high temperature filter media are being considered: Woven Ceramic (Nextel) Bags, Ceramic Candles, and Sintered Inconel. Although the Inconel and ceramic candles are in commercial use at high temperatures, none of these media are proven in our particular combination of high pressure (300 PSIA), and high temperature (1000°F) using superheated steam as a cleaning media. All of these media are viable candidates for this application. Selection of a filter media is pending further investigation. Tests comparing Nextel to candle filters are scheduled to take place at the TIDD PFBC plant in Brillant, Ohio. Other specific bag filter design concerns for this application are cleaning method (Jet pulse, reverse flow or combination), steam valve duty and design for filter cleaning, structural integrity of components, and corrosion. Investigations in these areas is on going, and significant progress is expected in these areas in early 1993.

i) Char Vessel Material

Metallurgists at LCI and KDL were consulted to help select a bin material that could meet the temperature, corrosion resistance, and friction requirements of all the char vessels. Several options were selected as a result. J.R. Johanson conducted high temperature friction tests on the more promising materials, and a stainless steel alloy that best satisfied all the requirements was found.

j) Char Study

A plan has been developed to obtain and study char to aid char cyclone and bagfilter design. Cyclone and bag filter suppliers will use this char to obtain and to test the performance of Nextel woven ceramic bags. Secrecy agreements between all the concerned parties must be executed before the testing can begin. CE expects char testing to begin in Summer 1993.

k) Hot Gas Clean Up

General Electric Environmental Systems, Inc. (GEESI) continues with their hot gas clean up test program at their corporate Research and Development Center in Schenectady, N.Y. More successful long duration tests were run with the Zinc Titanate Absorber, and the additive Nahcolite was tested to determine its effectiveness in removing halogens from product gas. The results to date are promising.

GEESI also submitted preliminary heat and material balances, process flow diagrams, general arrangements, and some equipment data sheets. These were used for estimating purposes and for arrangement of the gasifier island.

vi) Support Studies

a) Materials Studies

A study was undertaken to determine which materials should be used in the gasifier and other areas of the plant. This was necessary because much of the equipment used will be seeing conditions of temperature, pressure, and composition not usually encountered in previous applications. The purpose of this study was to identify non-standard applications and compare them against the current knowledge of materials in this application.

A preliminary report for recommended materials for use in the gasifier at suggested temperatures and pressures was put together April 30, 1992. The use of alloys with increasing chromium content, reinforced by surface chromizing, was based on the results of laboratory and pilot testing by CE for the Department of Energy (DOE) during the 1977-81 test period as well as the successful use of chromized tubing in sulfidizing atmospheres in operating fossil fuels and chemical recovery boilers. Most of the materials selection is largely based on in house test programs under DOE contract and others are taken from references.

The following equipment was identified as requiring special material consideration: pressure vessel, gasifier water walls, convection section (evaporator, low temperature superheater, intermediate temperature superheater, high temperature superheater), transitional hopper, lock hoppers, flow feed lines, nozzles, and connector section hopper.

A revision of the preliminary report was made in August 1992. Additional equipment was added for material suggestions including: crossover duct, heat exchanger vessel, heat exchanger waterwalls, char and natural gas nozzles. Also, some changes were made in the temperature suggested for the pressure vessel and gasifier water walls. A different material was suggested for the lock hoppers.

The final report was issued in June, 1993. In the final report most suggestions were not changed. More detail was given as to why certain materials would be best for operation based on laboratory and/or field experience and a section for recommendations was included at the end. The recommendations were reviewed by experts in fuel transport and revisions were made to balance cost, constructability, and reliability issues.

b) Permeability of Gasifier Char

A permeability test was done on a small sample of char obtained from an operating unit. These tests were done to help design the char removal system.

The current design of the cyclone and baghouse removal system has a pressure drop across the cyclone to the baghouse that causes gas to go from the cyclone solids discharge through a tank and up to the baghouse preventing particulates to be removed from the baghouse for recycling. The testing of the char sample will allow a modification to the system to allow the particulates to be removed properly from the baghouse. The modification will consist of a column of char that will be located after the cyclone solids discharge that will cause the same pressure drop as between the cyclone and the baghouse. The gas leaking through the column of char will be very small, therefore the velocity of the gas will be negligible and particulates can move freely to the tank to be recycled.

The permeability testing was done at KDL on a small sample of gasifier char. The testing consisted of measuring pressure drops through a sample of gas flow rates.

Three pieces of data were taken at each flow rate: inches of water pressure drop through the sample, inches of water pressure with shunted flow, and the volumetric flow rate measured with a bubble meter. The samples analyzed were two bed heights of a pulverized coal, the char, and the empty cell.

The results of the tests and calculations show the char to be much more permeable than the coal and that the amount of gas leaking through the column will be very small.

c) Kinetic Extruder
The Kinetic Extruder Process was studied to find an improved method for coal delivery across a pressure barrier for Combustion Engineering's Coal Gasification Process. It was believed that a 25 ton/hr kinetic extruder system could provide a smooth flow of pressurized coal to the gasifier while greatly reducing the structural size and cost of the gasifier island. A remaining design concern for the kinetic extruder system in this application is the development of high-temperature seals. At the present time it is desired that a seal capable of 500°F be utilized, though no such equipment has been successfully demonstrated.

Initially it was concluded that a 2 ton/hr (tph) version of the kinetic extruder would replace the 25 tph Extruder if pilot testing was successful. Because of the uncertainty in the ability to develop a mechanical seal that could withstand a significant continuous operation, the 2 tph system was also omitted from the plant layout.

Alternate methods of pulverized coal delivery across a pressure barrier are being evaluated. The most promising at this time is the Dynamic Piston Coal Feeder, developed by Conspray Construction Systems, Inc.

d) Preliminary Hazard Analysis
A Preliminary Hazard Analysis (PHA) was conducted on the CE IGCC Repowering Project by representatives from various disciplines within CE using as a basis the available technical data/documentation. The PHA identified several hazards which will be the basis for a subsequent detailed Hazard And Operability (HAZOP) study which will be performed at a later stage of this project.

The PHA study and documentation followed the sequence of process. Nine hazards are identified which include contained explosion, toxic exposure, corrosion/erosion, thermal burn, fire, noise, vibration, tube rupture and mechanical integrity of equipment. Asphyxiation hazard due to confined space entry was found to be a common hazard to all process equipment. Four categories are assigned to the hazards, these are: negligible, marginal, critical and catastrophic. Two major areas of concern that require further detailed analysis during the design stage are the vent stack and bag filters.

The two main purposes of the PHA are to recognize and identify hazards early in the engineering design and to define the need for action steps that must be taken to ensure that there are no major impediments to the realization of a design that meets the designer risk criteria. The results of this study are included in the report and are also intended to highlight corrective/preventive measures to mitigate these hazards during the detailed engineering phase.

e) Gasification Data
With the help of the DOE, a visit to an operating 200 tpd gasification plant was arranged. The plant was visited to obtain data from tests about the operation of the plant in order to determine whether operation was as expected. Tests have been done on oil burning, ignition, load increasing, steam system safety valves, and gasifier purging with gas and/or oil as fuel. After the success of these tests coal was used to test coal feeding, fuel switch-over, and product gas heating value based on air ratio in the gasifier.

Next, coal gas was fed to a gas turbine to test steam injection, air extraction, coal gas ignition, and fuel switch-over.

In the future the plant will switch to design coal and long-term continuous tests will be conducted. Overall the gasifier ran well with minor problems with the slag grinder, lockhopper valves, and fouling.

Based on this information, the 600 tpd gasifier should work well. The 200 tpd gasifier agrees with predicted values and was equal to baseline performance of CE's demonstration design.

f) Lakeside Boiler Performance on LBG

The possibility of firing low Btu gas (LBG) in the lakeside boilers seven and eight was investigated as an alternative to using the flare. It was later determined that this would be too expensive for the project, but the calculations showed that this approach is feasible from a technical standpoint with certain limitations.

The approach taken uses calculations and computer programs to obtain data on efficiency and performance of the boiler and cyclone furnace and also to investigate potential problems. The following specific problems were investigated: furnace heat absorption profile, heat absorption distribution, convection pass performance, boiler performance, circulation system performance, and metal performance. The unit studied is a pressurized, natural circulation, Babcock & Wilcox cyclone-fired boiler.

The current boiler baseline performance was evaluated at 33 and 18 MW using the daily operating data for a basis. Knowing the boiler efficiency and the output of the unit the coal fired could be calculated. Combustion calculations were then performed to establish air and gas weights.

Calculations for performance were based on 50% gasifier load being diverted to the Lakeside #7 unit. The closest limitation encountered was that of the cyclone at 132 000 lb/hr of LBG. The performance was calculated in the traditional design mode.

An assumption for the primary superheater tube materials had to be made because it is unknown and would not be supplied upon request. The tube material assumed was that of the secondary superheat section. The calculated temperature for the primary superheat steam outlet is higher than typically recommended, but should still be within temperature limits.

The superheater spray water was increased significantly due to the higher gas weight and the higher heat absorption, resulting in a higher primary outlet temperature. The gas weight is greater due to the low Btu value of the gasifier product.

This boiler was designed for coal firing. For the same load, the furnace heat absorption rates will be different for firing low Btu gas due to the increased weight and the cleanliness of the gas walls. The change in absorption rates will affect tube flows and, hence, the ability of cooling the tubes. Therefore, the performance of the circulation system must be analyzed for the low Btu gas firing conditions to assure safe operation.

The waterwall circulation performance was evaluated for three cases: 33MW baseline (coal firing), 18 MW baseline and 18 MW firing low Btu gas. The results show that the difference between the low Btu gas and the baseline case is insignificant and they both have approximately 93% margin of safety. The waterwall will operate safely under the low Btu gas case for 18 MW load.

Also an investigation of the effect of firing low Btu gas on the metal temperatures of the secondary superheater show that both the midwall and the outside wall temperatures are well within the limits of thermal stress and oxidation temperatures. These investigations were conducted due to the concerns of the reduced steam flow and the increase in gas weight. The conclusion of this study is that it is feasible to fire LBG in the Lakeside boilers.

vii) Gasifier and Heat Exchanger

The gasifier and its heat exchanger are utilized to produce a pressurized product gas stream containing char and H2S. Pulverized coal is delivered and combusted in a deficiency of air. Gasification occurs in an entrained reactor. Sensible energy is removed from the gas in a heat exchanger called a Syngas Cooler (SGC). The gas exits the system for char removal and desulfurization. Coal ash is fused and tapped from the bottom of the gasifier as molten slag. All streams to the gasifier are delivered pressurized.

Product gas leaves the gasifier and passes through a crossover and enters the SGC. The bounding walls of the gasifier, crossover, and SGC are water cooled. Located in the SGC is convection superheat surface. The gasifier and SGC are vertically orientated while the crossover is horizontal. The heat transfer surface arrangement is of a configuration that will yield an outlet gas temperature over the operating load range which will satisfy the requirements of the hot desulfurization system. The steam flow generated and the superheating of steam is integrated into the steam cycle.

In the gasifier a stream of molten slag continually flows through a slag tap into a slag tank. Quenched slag is periodically let down from this tank. The slag tank is located just below the gasifier.

The gas pass from the slag floor to the SGC outlet is gas tight and is bounded almost completely by waterwalls. The slag tank and gas pass are contained in pressure vessels. The annulus area between the gas pass and ID of the pressure vessel is pressurized with steam at a pressure slightly higher than the gas pass. With this system the pressure vessels are only exposed to inert non-corrosive gases. A water seal accommodates the differential movements and provides for a gas tight seal between the annulus area and the gas pass. It allows for pressure equalization between the gas pass and annular area during transients. This seal is sized so that during pressure differentials caused by either process effects or mechanical failures the design pressure differential across the waterwalls will not be exceeded.

The heat exchange surfaces are integrated into the cycle and are evaporative and superheat. A separate steam drum is provided for the gasifier island. Preheated water is received from an economizer located in the HRSG. This feedwater is introduced into the steam drum and steam at matching HRSG conditions is produced in the SGC.

The gasifier incorporates several elevations of coal introduction and char introduction. The lowest elevation contains both coal and char. At this level all air and start-up natural gas is introduced. One elevation of emergency water and one elevation of process steam introduction are provided. All injection nozzles are water cooled. This water cooling is not part of the boiler water circulation system and is connected to a manifold system external to the gasifier and SGC. Instrumentation for control and process evaluation is provided.

A circulation system is used for the generation of steam. Steam is generated in the gasifier, SGC, and a heat exchanger in the HGCU system. The steam drum separates the two phase mixture into high purity steam and water. The high purity steam is provided to the superheat system. The separated water is recirculated to the steam generating circuits.

a) Syngas Cooler Performance Studies

A performance sensitivity study was done for the SGC component in order to study the effect of varying some of the key SGC design parameters over the likely ranges for these parameters. The five variables shown in Table 6 were changed over the indicated ranges to quantify the potential impacts to plant performance.

Table 6
Syngas Cooler Performance Sensitivity Study

Sensitivity Variable	Units	Variable Range
Fouling Factor	(hr ft F/Btu)	50% - 150%
Gasifier WW Heat Abs.	(MM-Btu/hr)	50% - 200%
HGCU Evap. Heat Abs.	(MM-Btu/hr)	0 - 200%
Sootblower Steam Flow	(lbm/hr)	0 -15000 #/hr
Superheater Surface Effectiveness Factor	(fraction)	71% - 95%

The STMCYC program was used for this SGC sensitivity study in order to properly account for the effects on other plant components. The sensitivity study base case operating condition used base gas turbine load and 59°F ambient temperature (this was defined as the "maximum design" case). A total of 12 runs were made for this study using the STMCYC program.

The basic result of this study was the selection of design point values for all the SGC sensitivity study parameters as well as other parameters required to design the SGC. Another result of this study was a set of curves which show primarily the SGC performance and secondarily the other steam cycle components performance over the ranges of the sensitivity study variables. In general these results show maximum variations to SGC outlet temperature of about 50°F. SGC outlet steam flow varies by about 10% as compared to the base case. The desuperheating spray water flow varied from 0 to about 18% as compared to about 10% for the base case. Outlet steam temperature was maintained at the 950°F set point in all but one case (200% of base case gasifier waterwall heat absorption) where it fell to about 900°F.

These results indicate that over the range of potential uncertainty of key variables, the performance of the SGC is acceptable. The current design is flexible enough to be able to handle the design requirements even if some of the design assumptions are not exactly as expected.

b) Arrangement Drawings

The gasifier general arrangement is shown in Figure 9, DWG 16990-1E001. The major components shown are the gasifier, crossover, heat exchanger, steam drum, support system and slag lock hopper.

The gasifier has several levels of coal injection and several levels of char injection. Each level consists of four injection locations. The lowest level of coal and the lowest level of char are at the same elevation. At this elevation air is admitted to both the coal and char nozzles in a primary and secondary stream. Incorporated at this level are the natural gas burners for start-up.

The gasifier and heat exchanger vessels are connected together with a horizontal crossover vessel. This assembly is supported by a trunion and U hanger rod system. The trunions are located on each vessel and are supported by U rods. Vessel guides at three gasifier elevations and two heat exchanger elevations and a compensating strut maintain the vessels in alignment. Located beneath the gasifier is the slag lock hopper with its inlet and outlet double valving. A slag grinder housing pressure vessel follows with an external hydraulic motor. Next comes the coal and char elevations. The SGC shows the steam outlet lead with its valving and the gas outlet to which the product gas fuel pipe is connected. On this drawing access removal areas are shown for pressure part removal for the gasifier and heat exchanger.

The cross sectional view of the gasifier is shown in Figure 10, DWG 16990- 1E0101. The pressure vessel has a lower flange to which the slag grinder housing attaches to, a head and a horizonal flange to which the crossover is welded to. A portion of the crossover pressure vessel is shown. Enclosed in the pressure vessel are the following:

slag tank, enclosure for the waterwall supply tubing, water seal, lower inlet header, vertical waterwalls, the crossover waterwalls, upper outlet headers and riser tubes. Penetrating the pressure vessel are: waterwall feed and relief lines, cooling inlet and outlet lines, coal and char burner assemblies, diagnostic and instrumentation connections.

A slag tank is located at the bottom of the vessel. An inner cylindrical and conical shroud is used to funnel the slag to the grinder. The slag tank water temperature is maintained by an auxiliary heat exchanger. Inlet water is introduced at two locations. The first is tangentially just above the shroud and the second is into the water seal. The cooling water outlet is located behind the shroud at a low point. A water jet system is used to ensure that slag build up does not occur on the conical section.

A water tight expansion loop tubing enclosure is provided in an annular area which is approximately at slag tank water level. The supply tubing for the lower waterwall header is introduced into this enclosure. Within this enclosure supply tubing expansion loops are provided to allow for the differential movement which will exist in transients between the waterwalls and the pressure shell. Each of these feed tubes makes a 300 degree arc before rising vertically for introduction to the lower ring header.

Located above the expansion loop tubing enclosure is the water seal. The water in the seal can either flow over into the slag tank or into an annular cavity between the seal and the pressure vessel wall. This cavity is connected to the slag tank water by drain lines located in the expansion loop tubing enclosure. Located in this cavity are pipe sleeve extensions of the expansion loop enclosure. The supply tubing for the lower waterwall ring header passes through these sleeves. This sleeving minimizes any liquid water which could enter the expansion loop tubing enclosure. The secondary feed of cooling water to the slag tank is introduced into the water seal. The annulus is maintained at a pressure above the gas pass and therefore the water level in the water seal exposed to the gas pass is at the rim and continually overflowing into the slag tank.

The area above the water level in the slag tank is vented to ensure that any gases generated will not pass upward to chill the slag tap. This vent is provided by a nozzle in the pressure shell. In the upper part of the expansion loop enclosure a horizontal passage way is provided which connects the nozzle to a vertical passage way which rises up through the gas side of the water seal. This design minimizes the amount of liquid water which could enter the vent line. Additionally another pressure vessel nozzle and horizontal passageway through the upper part of the expansion loop enclosure is provided for a camera to view the surface of the water to ensure successful removal of slag.

Separate stand pipes are used to monitor the level of the water in the slag tank and to ensure that water is not present in the annulus area. These are located adjacent to the pressure vessel and are connected by passage ways and pressure vessel nozzles. The system which monitors the annulus has one connection to the bottom

FIGURE 9

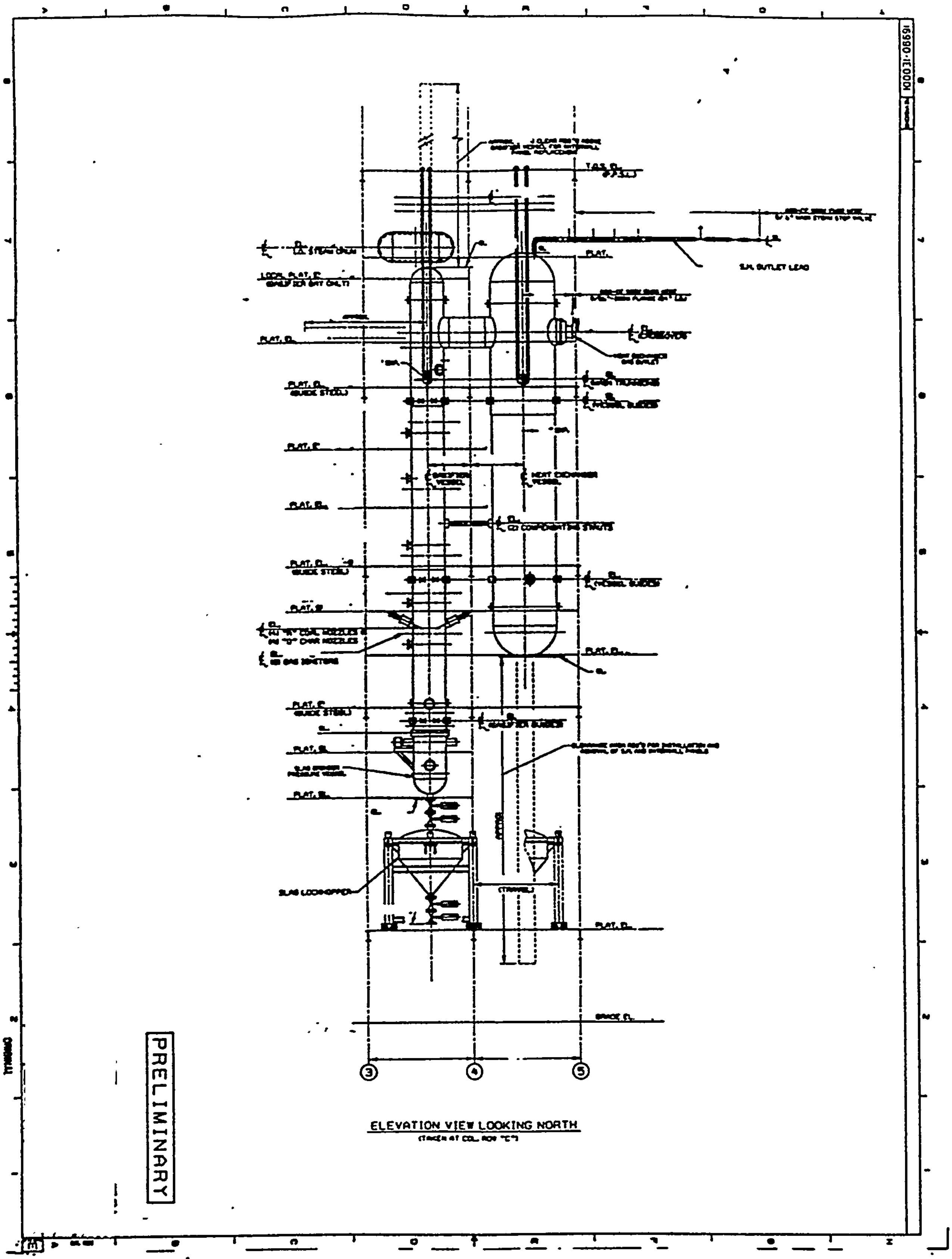
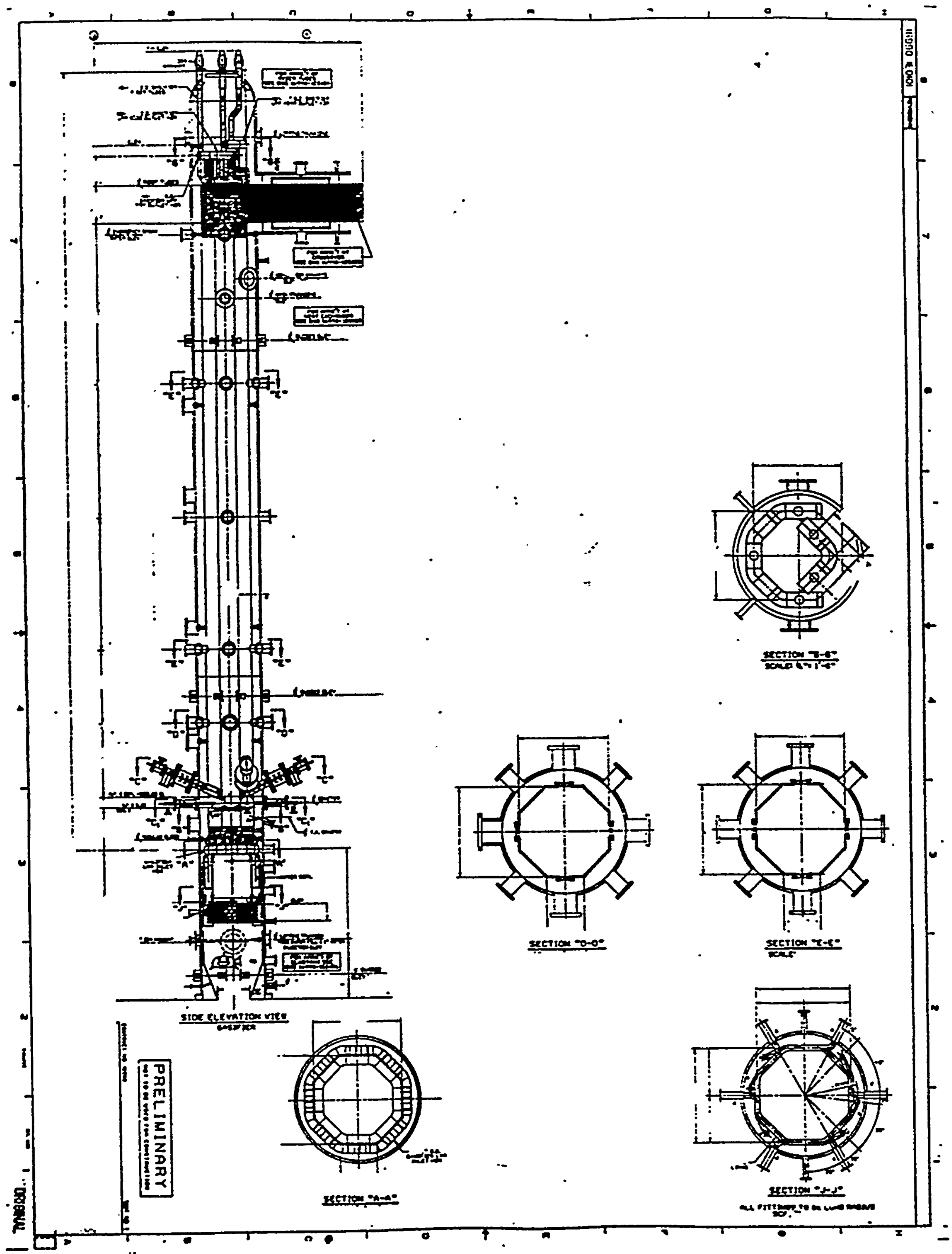

PRELIMINARY
ELEVATION VIEW LOOKING NORTH
SLAG LOCKHOPPER

FIGURE 10


SIDE ELEVATION VIEW
SECTION "B-B"
SECTION "D-D"
SECTION "E-E"
SECTION "A-A"
SECTION "J-J"
PRELIMINARY

of the water seal. This connection is part of a purge system to ensure the water seal stays free of solids.

Additionally located in this area on the pressure vessel is a manway for access and two trunions which will be used for vessel erection. A pressure vessel nozzle is provided for instrumentation which will measure the vertical differential movement between the pressure shell and the pressure parts.

The gas pass walls between the water seal and the slag tap are bounded by the waterwall lower ring header and the waterwalls. Located in this area is a camera which views the slag tap. These waterwalls rise vertically and form the gas tight bounding walls of the gasifier. At the elevation of this header is a nozzle in the pressure vessel which is used to bleed the annulus area.

A separately cooled water cooled floor is provided. Located in this floor is an opening used as a slag tap and as an access manway. The connecting inlet and outlet lines are routed to pressure vessel nozzles.

All surfaces exposed to gas from the slag floor to the outlet of the crossover are studded and covered with refractory. This includes the slag tap, waterwalls and all water cooled nozzles which penetrate into the gas pass. The waterwalls are of membrane type construction. The penetrations into the gasifier gas pass are three elevations of coal, two elevations of char, four elevations of diagnostic water spray, one elevation of emergency water spray, one elevation of process steam, and one elevation of start-up natural gas burners.

The lowest level of coal and the lowest level of char, are at the same elevation. Primary and secondary air are introduced with both coal and char at this elevation. A water cooled rectangular shaped nozzle is attached in an opening in the waterwalls using a seal box design. This provides for a gas tight design. A burner assembly has been specifically designed for this application. This assembly is attached to the pressure vessel and to the water cooled nozzle.

Natural gas burners are located just below the char nozzles. Provisions for future burners are provided just below the coal nozzles. The natural gas burner assemblies are attached to the water cooled nozzles and to their own pressure vessel nozzles.

The pressure vessel has numerous nozzles for instrumentation connection and access. Nozzles which are multi-function are located on the front of the pressure vessel. A total of five of these flange nozzles are located: just below the slag tap, just below the second elevation of char, just above the second elevation of coal, just above the mid point of the upper two coal elevations, and just under the highest coal elevation. These multi-function nozzles may contain some or all of the following: Ircon for gas temperature measurement, gas sample probe and thermocouple, heat flux measurement, annulus pressure measurement, and gas pressure measurement. Additionally provided is instrumentation for measurement of annulus gas temperature in the vicinity of waterwall penetrations.

At the horizontal gasifier outlet plane gas temperature is measured and pressure vessel nozzles are provided. Pressure vessel nozzles are located in the upper head for measurement of upper head annulus temperature.

At the horizontal exit plane of the gasifier some of the waterwall tubing is diverted to provide coverage for the crossover. The crossover is fully enveloped in waterwall tubing. Tubing is supplied from the rear and the front walls of the gasifier. The tubing which originates from the rear wall serpentine in three loops to cover the floor and sides. Tubing which originates from the front wall makes one loop and provides coverage for the roof. All waterwall tubing exits to upper headers. Links connect these headers to the steam drum. A bellows is used to provide a seal between the link and the pressure vessel. The gasifier internals are supported by lugs at the roof of the waterwalls. Rods transfer this loading into the upper head of the gasifier pressure vessel.

The crossover contains provisions for future sootblowing. These provisions are plenums located on the annulus side of the waterwall panels. The plenums are connected using flexible lines to nozzles on the pressure vessels which are capped. By perforating the fins or installing nozzles in the fins of the waterwall panels a sootblowing system can be field installed. Additionally, the crossover pressure vessel has nozzles to connect instrumentation to measure product gas temperature and annulus temperature. The crossover pressure parts and pressure vessel are mated to the SGC.

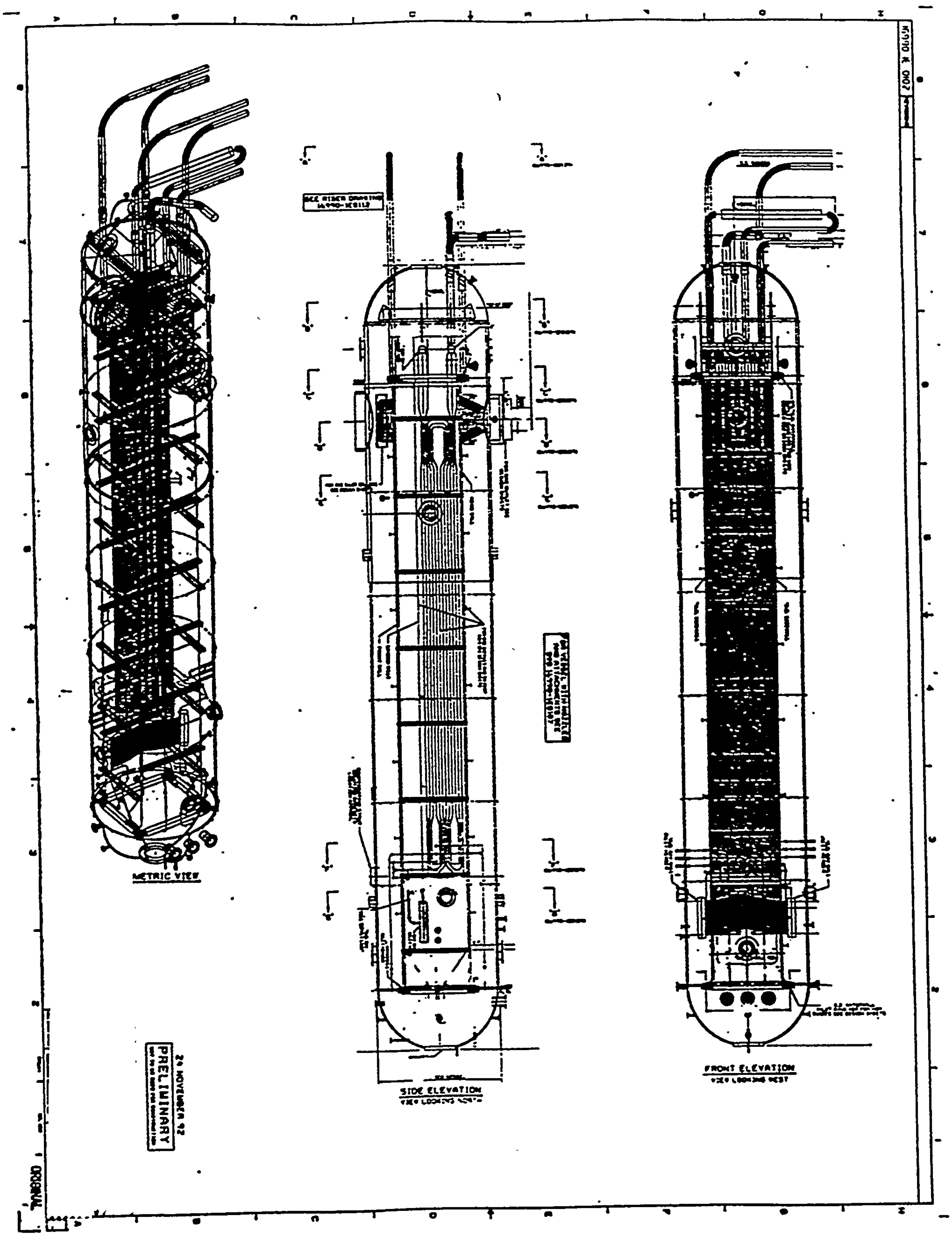
The cross sectional view of the SGC is shown in Figure 11, DWG. 16990-1E0102. The SGC is comprised of a pressure vessel and an internal water cooled gas pass which includes convective heat exchange surface.

The arrangement has two vertical passes. Gas enters horizontally from the crossover and is directed into a downward channel then is redirected into an upflow channel where convective surface is installed. The downflow gas pass and the upflow gas pass share a common division wall. Gas then enters a horizontal transition section which is coupled to a removable pressure vessel nozzle.

The supply for the bounding walls of the gas pass is a ring header which is located in the lower head of the heat exchanger pressure vessel. Headers outboard of the side walls are the supply for the division walls. These inlet headers are fed by supply tubes from the discharge manifold of the circulation system.

The front, side, and rear walls exit directly into an upper ring header. The division wall tubes form a water cooled roof section for both passes before exiting into the upper ring header. This ring header is relieved to the steam drum by riser tubes. The riser tubes are connected to the pressure shell by bellows. These bellows accommodate differential movement and tubing expansion loops are not required.

FIGURE 11



The SGC internals are supported by lugs at the roof of the waterwalls. Rods transfer this loading into a support level. This support level transfers the loads into the pressure shell at the same support elevation as the gasifier.

Where the crossover and heat exchanger pressure parts meet a bellows joint is provided to accommodate differential movements.

At the gas outlet a bellows is used to connect the pressure part opening to the product gas outlet nozzle. A separate nozzle housing is employed to provide maintenance for the latter bellows. This nozzle is bolted to the SGC pressure vessel and the product gas outlet pipe is bolted to it. The detail of this bellows and nozzle is not shown in the drawing.

Superheat pendants are suspended in the upflow or second pass. The pendants are of three intermesh and double loop design. The inlet and outlet headers for the superheat assemblies are single headers which have internal sectioning so as to create a series of four stages. The header closest to the division wall has no link connections to it. It contains one sectioning plate. The header closest to the gas outlet has an inlet link, link to a desuperheat station, link from a desuperheat station and superheat outlet link. It contains three sectioning plates. All links connecting to the superheat penetrating the pressure shell have bellows joints for sealing at the pressure shell. The superheat terminals tubes are sealed to the waterwall tubes with a conventional sealing arrangement where they pass through the gas pass roof.

Gas baffles are used in the second pass to prevent gas channeling at the walls. Around the perimeter of the waterwalls there are five elevations of waterwall reinforcing.

The pressure vessel has additional nozzles which have not been described. The lower head contains a manway, a vessel drain, nozzles to incorporate a future eductor system to be used if the gas pass return bend requires solids removal, annulus pressurizing injection, annulus temperature measurement and nozzles which provide instrumentation to measure relative expansion movements. The cylindrical portion contains nozzles for future sootblower installation, instrumentation for gas temperature measurement and annulus pressure measurement. The upper head contains nozzles for annulus temperature measurement and for superheat instrumentation connection. The gas outlet housing contains a nozzle for gas temperature measurement.

The pressure vessel contains two elevations of guides, two elevations of trunions used for erection, and the main support trunions.

c) Transportation Study

This study was done for rail shipment from the CE shop in Chattanooga, Tennessee to the site. It identified the orientation of the vessels for shipping and components which could be shipped with the vessel. Small interferences were identified and these will be addressed during the final design.

d) Construction Studies

This task involved studies for both construction and maintenance of the pressure parts and the pressure vessel. The gasifier and SGC would be assembled in the shop and would be delivered to the site with their internals. Both vessels would have hydrostatic testing performed in the shop. The vessels would be field erected using erection trunions which are located 90 degrees from the permanent trunions. U rods would support both vessels from structural steel when the vessels are in their final location. At this time the crossover pressure parts would be installed. The boiler tubing would be hydro tested. The crossover pressure shell will be provided in half sections. Measurements will be taken and appropriate corrections will be made to ensure the required fit up. Both half sections will be field welded to the gasifier and heat exchanger pressure vessels and inspected.

The pressure parts of the gasifier and SGC are designed to be serviced without cutting of the pressure shells. The gasifier and crossover are designed with a minimum gap between the waterwalls and the pressure vessel. This does not allow for access to the backside of the waterwall tubing for welding. The SGC, however has a minimal amount of space on the backside of the waterwalls to do welding.

The gasifier vessel has a manway in its upper head and a full diameter flange for the slag grinder attachment at the bottom. The wall tubing does not have any buckstay system for wall reinforcement on the back side. The tubing connections to the upper and lower headers are made for orbital welding guidelines. Therefore, individual panels from the octagon can be removed either from above or in half length sections from below. The concept of using window welds for single tube replacement was found to be industrially acceptable. With this concept individual sections of tubing can be removed without requiring access to the backside of the tube.

The crossover waterwall arrangement is such that it is formed in three major sections and can be assembled and disassembled from within the pressure shell. The assembly of crossover tubing is fed by tubes from the rear wall and front wall of the gasifier. For tubing which originates from the front wall two manways are provided to access the backside of the tubes. Tubing which originates from the front wall and tubing which returns from the crossover can be serviced on both sides of the waterwall roof of the gasifier.

The waterwalls of the SGC are generally accessible from both sides. The superheat pendants are designed to be removed individually or in an assembly. The superheat terminal tubes above the roof are detailed for conventional welding procedures. Assemblies can be cut loose and can be removed through an opening in the return bend of the gas pass and through a manway in the bottom of the pressure vessel. If required, portions of the division wall can be removed and the downflow pass used for service. If the lower pressure vessel head and some of the lower waterwalls are removed the entire superheat module can be removed.

e) **Heat Exchanger Computer Program**

An existing syngas design and performance computer program was initially used. This program was continually updated and improved. Provisions for in-line surface, parallel surface arrangements, improved gas properties and modified iteration techniques were added. In addition the program was independently verified with hand calculations. It was integrated with a computer program used for HRSG performance predictions to allow for complete steam side analysis.

f) **Transient Studies**

The differential movement between pressure parts and the pressure shell during operating transients at locations where those components are attached is required for design. To accommodate these differentials either expansion loops, toggles, flexible piping or bellows are required.

To establish a temperature schedule for the pressure parts as a function of time, preliminary start-up and shutdown performance predictions were made. The cylindrical sections of the pressure shell exchange heat with only waterwalls. The upper head of the SGC exchanges heat with superheat terminal tubing, headers and links and with waterwall headers and riser lines. The lower head of the SGC exchanges heat with waterwall surface and an insulated access door into the gas pass.

In the gasifier, design movements are required for the feed lines which supply the lower ring header and at each elevation of fuel firing. In the SGC, design movements are required for the supply lines which feed the lower waterwall headers. A computer program was developed using numerical techniques to establish a pressure shell temperature profile using a waterwall temperature profile as input.

For the design temperature of the SGC pressure vessel upper and lower heads a computer program was developed which used the surface temperature, area and orientation of surfaces which would exchange heat with the head as input.

Both a performance and structural analysis was performed for the crossover pressure parts. A computer program was developed which predicted circumferential metal temperatures in the pressure shell during heat up and cool down. This used a waterwall temperature profile and considered annular heating of horizontal cylinders. A top to bottom temperature pressure shell differential versus time was generated and used as an input for the structural analysis. The results of this preliminary work indicated that a more complete analysis would be required during the design phase.

The performance of the water seal during transients controls the pressure differential across the waterwalls. The water seal received a cursory design and this established a design pressure differential for the waterwalls. The boundary conditions for a more complete analysis were established and this work will be done during the design phase.

Wherever lines that penetrate the pressure shells have a substantially different temperature than the pressure vessel, the design of the pressure vessel nozzle requires special consideration. The temperature differential can occur during transients or steady state. The special consideration is a design using a thermal sleeve construction. Design pressure vessel nozzle differentials were determined. The SGC product gas outlet nozzle was considered the most unconventional. For this nozzle a finite element model was developed for the design of this nozzle.

g) Circulation System

A circulation system analysis was performed. The waterwall system was designed to ensure that sufficient mass flow exist at all times in the tubing to prevent overheating. Design heat absorption rates and where applicable horizontal differential rates were established. Waterwall metal temperatures were predicted and fin widths between tubes were established. Flow rates for the high heat absorption of the gasifier combustor and horizontal circuits were established. A tube diameter of 1 1/4 inch was selected. This small diameter tube was selected to provide an overall reduced quantity of recirculated water and a tube size which would be easily manipulated during field modification. The reduced quantity of recirculated flow results in a minimum number and size of supply and relief lines. The supply tubing is used to bias the flow as required to circuits.

h) Superheater

The superheat sections are placed last in the SGC gas pass. The high temperature of this surface ensures that the outlet gas temperature over the load range will be maintained high to meet the requirements of the HGCU system. In addition desuperheat spray is used as a method to further increase the quantity of superheat surface. This surface is located in a gas temperature environment were tight spacing can be used and tightly spaced vertical surface was selected.

The superheat section is in a pendant arrangement. The metal temperature in superheat tubing is the sum of the steam temperature plus the rise due to heat transfer. Because of this the leg temperatures of the pendants are different. With this characteristic, the expansion growth of different legs makes the entire assembly distort and arc. A swing or horizontal movement of the bottom results. Each leg of the assembly grows a different amount. The legs are attached together and each leg forms an arc about a common center point. The gap between legs along with the differential vertical movement determines the horizontal movement. The geometry of the assembly selected was of an intermesh of three and a double loop. A center cavity in each return loop is maximized to reduce the swing. In addition each leg is made of materials with different expansion characteristics in an effort to make the growths of all legs equal. Using these two techniques the horizontal movement at the bottom of the assembly is kept to a minimum. The gap that results is still larger than acceptable and gas baffles are installed along the walls to divert the gas toward the middle of the assembly.

The SGC is designed to operate relatively free of fouling. A fouling factor consistent with this condition was used for performance design. Performance was calculated for a range of fouling to ensure that performance can be met and that the proper metals were installed.

The superheat assemblies are arranged in four series stages. This is accomplished by sectioning of the headers. For the gas pass plan selected this arrangement provides the required steam mass flows, tube OD, assembly length, tube spacing and steam side pressure drop. Desuperheat spray injection is provided interstage between the first two stages and the last two stages.

i) Burner Development

The design of the coal burners at elevation A and the char burners at elevation D required development. Both coal and char use the same concept. This burner provides for the introduction of either coal or char, primary air and secondary air into the gasifier gas pass. The burner assembly consists of components which are rigidly connected to the waterwalls of the gasifier and components which are rigidly connected to the pressure vessel. During transient conditions there is vertical differential expansion between the pressure parts and pressure vessel. A design capable of accommodating this differential is required.

Natural gas ignitors are located just below the fuel nozzle assemblies. The ignitor heads share the same waterwall opening as the fuel nozzles. Separate pressure vessel nozzles are provided for the ignitor assemblies just below the fuel burners. The ignitor assembly includes air and natural gas connections. This assembly is allowed to pivot as it is connected to the pressure vessel nozzle with a bellows.

A mock-up was built to demonstrate the fuel nozzle design concept. Construction representatives found that all parts of the assembly were accessible for maintenance. A differential movement test was performed. During this test a movement equal to the maximum predicted was applied for the number of cold start-ups that were expected.

j) Slag Tap

The slag tap is the opening in the floor of the gasifier combustor. This floor is water cooled and has inlet and outlet lines which penetrate the pressure shell. It slopes from the octagonal waterwalls at an angle and has a opening for slag flow. This opening also serves for access. The tubing is arranged in a number of circular hairpin return bends. It is of loose construction with minimum gaps between the tubing. It is supported from beneath by brackets cantilevered off the waterwalls at three locations. An uncooled stainless steel drip edge is located at the ID of the opening. The tubing facing the combustor is studded and covered with refractory. The refractory on the sloping floor is a continuation of the refractory on the vertical waterwalls.

k) Slag Grinder

The slag grinder is enclosed in a separate housing and has an external hydraulic motor drive. This housing has the outside dimensions of the gasifier and is bolted directly to the bottom of the gasifier pressure vessel. The full diameter flange offers many advantages in gasifier initial assembly and maintenance.

A slag quench tank is located in the gasifier pressure vessel. A transitional shut section of the gasifier slag tank directs slag into the grinder. The grinder is a CE

Single Roll Clinker Grinder. The slag grinder is located in the top of the vessel and is supported by brackets welded to the pressure vessel walls. The vessel has a manway for inspection. The bottom end of the vessel has a head which terminates in a flange to which the slag lock hopper inlet valves connect. A discharge cone is welded to the inside of the vessel in the hemispherical region to allow free flow of slag into the lock hopper. Clean out nozzles are provided above the cone.

The supports for the slag grinder are equipped with adapters to allow three directional movement of the grinder so that the shaft alignment can be fine tuned with the vessel wall penetration and the hydraulic motor. The hydraulic motor shaft penetrates the vessel wall to connect the grinder shaft with a split coupling. The wall penetration is sealed with a stack of Grafoil packing rings. The shaft sealing concept simulating actual design conditions will be tested at CE.

The hydraulic motor has an auxiliary power unit and controls.

l) Gasifier and Syngas Cooler Cost Estimate

A comprehensive package was prepared for the fabrication quotes. Included were sixteen drawings, eight sketches, and fourteen documents. This package defined the pressure shells, pressure parts and the internal components. The pressure parts include tubing, headers, piping, and the steam drum.

B PRELIMINARY DESIGN

The object of the previously mentioned design studies was to establish a preliminary design for cost estimating. The equipment and systems used for the preliminary design basis are described below.

i) Coal Storage System

Illinois No.5 coal is washed at the mine and delivered to the site in trucks. The trucks unload into open-top drive-over hoppers, with coal dropping into the receiving hopper. From the receiving hoppers, coal is transported on a covered conveyor to the enlarged active storage pile. This pile has a minimum of 3 1/2 days of live storage capacity added to the existing coal pile. This storage pile serves both the IGCC project and the existing Lakeside units. A telescoping chute transports the coal during loadout onto the active storage pile from the conveyor. The coal pile is conical, approximately 130 feet in diameter and 50 feet high, with a 38 degree angle of repose. A new reclamation hopper beneath the coal pile reclaims coal from the storage pile and conveys it on a covered cleated conveyor to the gasifier building. The reclaim hopper receives material by gravity after it has passed through a grizzly and a dust tight coal valve. The reclaim pit has a new ventilation system and baghouse. The coal dust generated at all enclosed transfer points is controlled by drawing the air in from the area around each transfer point and ducting it to a dust collection baghouse where the air is filtered before being discharged to the atmosphere. The coal is transferred to the raw coal storage bunker in the gasifier building. The coal handling system for the existing Lakeside units remains unchanged and will be available throughout the construction period.

ii) IGCC Coal Pulverizing System

The coal fed to the gasifier is pulverized in the pulverizer while air, heated to 500°F, dries the coal to approximately 3 percent moisture and heats the coal to between 200 and 250°F. The coal is air classified by size in the pulverizer and pneumatically transported to the pulverized coal baghouse. In the baghouse, the coal is separated from the carrier air and the coal flows by gravity into the coal receiving bin. The carrier air, cleaned of particulate matter in the baghouse, is released through the coal vent stack.

a) Raw Coal Storage Bunker

The Raw Coal Storage Bunker stores enough coal for the operation of the gasifier for 24 hours. The bunker feeds the coal through a slide gate shut off valve and connecting pipe to the volumetric coal feeder. The scope of supply includes the raw coal storage bunker including fill provisions, bin vent filter, ladders and access platforms, vibrators, level indicators, slide gate valves, compressed air, instrument connections to the Distributive Control System (DCS) and the connecting coal piping and expansion joints from the slide gate shut off valve at the outlet of the bunker to the volumetric feeder. The Raw Coal Storage Bunker is sized to hold 1,200,000 pounds of coal.

b) Raw Coal Feeder

The raw coal feeder meters the flow of coal to the pulverizing mill. It is a volumetric feeder at the outlet of the raw coal storage bin. The coal feeder is supplied with motor, inlet and outlet piping, instrumentation, gate valves and expansion joints.

c) Pulverizer Mill

The coal pulverizer mill grinds the coal to a fineness that can be transported pneumatically and combusted in the gasifier. It is located below the raw coal feeder. The control of the pulverizer, mill air fan, duct burner and volumetric feeder are through a Programmable Logic Controller (PLC) that is connected to the plant DCS. The mill is located on grade.

d) Mill Air Fan

The mill air fan is part of the coal pulverizing system and supplies the transport and classification air.

e) Pulverized Coal Baghouse

The pulverized coal is entrained in the air leaving the pulverizer and is transported through pipes to the pulverized coal baghouse. The pulverized coal baghouse separates the transport air from the pulverized coal for storage in the coal receiving bin. The scope of supply includes the baghouse, support steel, exhaust ducting including the vent stack, downcomers to the coal receiving bin, pressure and temperature instrumentation including transmitters and bag cleaning system and dry compressed air service for the bag cleaning system.

iii) Coal Feed System

a) Pulverized Coal Receiving Bin

The pulverized coal continuously flows by gravity to the pulverized coal receiving bin. The receiving bin stores the pulverized coal for the intermittent feeding of the lockhoppers. The bins, coal piping to and from the bins, control valves, fluidizing valves, support steel, instrumentation, wiring, and air piping to the control valves are included.

b) Pulverized Coal Handling Valves

There are four pairs of coal handling valves which control the flow of pulverized coal into and out of each of the two lockhoppers. The pair of valves at the inlet of each lockhopper isolate the lockhopper from the receiving bin while the lockhopper is pressurized. The pair of valves at the outlet of the lockhopper isolate the lockhopper from the pulverized coal feed bin while the lockhoppers are depressurized and coal is flowing from the receiving bin into the lockhopper.

c) Pulverized Coal Lockhoppers

The two lockhoppers intermittently receive pulverized coal by gravity flow from the receiving bin, pressurize and feed the pulverized coal to their associated pulverized coal feed bins. There is one lockhopper per feed bin.

d) Pulverized Coal Feed Bin

Each pulverized coal feed bin continuously feeds the coal at a higher pressure than the gasifier operating pressure through its associated flow control valves.

e) Pulverized Coal Flow Control Valves

The gasifier has separate levels where the pulverized coal can be injected for combustion. Each level must be controlled separately. The pulverized coal flow control valves meter the flow of coal to the pickup Tee's and control the firing rate of its respective burner level in the Gasifier. The flow control valves are equipped with actuators and are remotely controlled.

f) Pulverized Coal Pickup Tee's, Stream Splitters and Transport Piping

The pulverized coal pickup Tee's, stream splitters and transport piping carry the pulverized coal from the flow control valves, divide the flow of pulverized coal from each flow control valve into four streams and transport the coal to the burners on the gasifier. The scope of supply includes the pickup Tee's, splitters and transport piping from the Tee's to the coal burners, including pipe hangers and support steel, the nitrogen supply piping to the pickup Tee's and a pressurized nitrogen companion line to the blow out connections of the coal transport lines.

iv) Gasifier/Heat Exchanger/Steam Drum

The gasifier unit is a fusion welded, eight sided water walled pressure vessel. It consists of multiple stages for air, steam, coal and char introduction into the gasifier. The combustion zone is the lower section of the gasifier and the reduction zone is the upper section of the gasifier. In the combustor, coal and recycled char are burned with almost all of the combustion air to form a hot gas to start the gasification reactions and melt the ash in the coal and char. In the oxygen deficient reductor, the rest of the coal reacts with CO2 and water vapor to generate a synthetic gas consisting primarily of N2, CO, H2, water and char. The char consists of unreacted carbon, ash and trace metals from the coal. Collecting the char after it exits the gasifier and reinjecting it into the gasifier provides for complete burnout of all carbon in the fuel, thereby enhancing the efficiency of the process. The product gas flows from the gasifier vessel at a temperature of approximately 2000°F, to the heat exchanger where it is cooled to approximately 1000°F before being piped to the hot gas clean up system. Steam is generated in the water walls of the gasifier vessel and the heat exchanger and superheated in the heat exchanger. Separation of the steam and water occurs in the steam drum. The waterwalls are contained inside of the gasifier and heat exchanger pressure vessels. The superheater elements are located in the gas path of the heat exchanger. Steam leaving the superheater is piped to the turbine for the generation of electric power. The space between the vessel walls and the water walls is pressurized with steam to prevent the product gas from contacting the vessel walls. Air for combustion of the coal is taken from the gas turbine compressor section. A booster compressor raises the pressure to that needed for the gasifier burners. CE supplies and erects the gasifier vessel with all internal components, the heat exchanger vessel with all internal components, the steam drum and all ASME Section I piping and valves. Pressure vessels, hangers and hanger rods, support steel, vessel guides are designed to the codes in force at the time of the contract. CE supplies the instrumentation, wiring, a PLC for the Gasifier Safety Supervisory System, the plant DCS control system, feedwater control valve and desuperheater spraywater control valve. CE supplies all ASME Section I code required block valves for the gasifier and heat exchanger. The safety valves and vent piping are included. The product gas outlet interfaces with the main syngas piping through a bellows attachment located at the outlet of the heat exchanger. The piping includes a manway for access into this piping and through the piping into the gasifier heat exchanger. The design includes process water and piping for the emergency spray water nozzles, cooling water for the burners and nozzles on the gasifier and heat exchanger, feedwater piping to the desuperheater and feedwater check valves.

v) Slag System

a) Slag Tank/Slag Grinder/Slag Grinder Vessel

The high temperatures in the combustion zone of the gasifier melt the slag which flows down the refractory covered water walls of the gasifier to the slag tap. Molten slag drops from the gasifier slag tap into a water filled tank where it is solidified and ground by the slag grinder. Inside the water tank are cooling coils which prevent overheating of the quench water. The water in the slag tank is continuously circulated through an external pump and a water cooled heat exchanger to keep the slag water at a nominal 140°F. Inlet jets are located at the top of the tank and an outlet nozzle is located at the bottom of the tank. The slag grinder is located in a pressure vessel that is bolted to the bottom of the gasifier vessel. All of this equipment, including exterior vessel piping, slag tank water recirculation pump, tube and shell type heat exchanger, control valves and cooling water supply piping are supplied by CE. The slag grinder is a hydraulically powered shear grinding mechanism that is sealed inside of the slag grinder vessel. The agitating nozzle water jets reduce the formation of clinkers by creating thermal stresses in the molten slag as it enters the water filled tank. Makeup water is added to maintain the level of water in the tank. The slag grinder vessel has a support system which is designed to allow the vessel to be rolled out from under the gasifier vessel for major maintenance of the gasifier.

b) Slag Lockhopper/Transport Conveyor System
The slag and water are discharged through a pair of valves to a lockhopper. The lockhopper is isolated from the slag tank by these valves and the pressure is reduced to atmospheric. The slag and water then flow through a second set of valves into a submerged scraper conveyor for dewatering and transport to the load out belt conveyor. The load out belt conveyor carries the slag to a three sided concrete ash storage bin. Ash is loaded from the bin into trucks by a front end loader for disposal offsite. The slag lockhopper and inlet and discharge valves are on a support system that is designed to allow the vessel to be rolled out from under the gasifier vessel for major maintenance of the gasifier.

c) Slag Water Recycling System
The water processing portion of this system consists of collecting and recycling as much of the slag quench and the slag lockhopper water as possible. This recycling will reduce the load on the industrial wastewater treatment facility and minimize the makeup water requirements. The slag water system collects water from the following sources: The water mixed with the slag when it is dropped from the lockhopper, the pyrites sluicing jet pump motive water, the slag basin overflow sump spargers and inventory, the coal reclaim pit sump spargers and inventory and the coal gasifier area sump spargers and inventory. The water is sent to a new concrete lined settling basin located just outside the gasifier building. The slag water settling basin is approximately 30 feet by 40 feet and will hold 32,000 gallons of dead storage and at least 60,000 gallons total volume. The water to the gasifier and slag water lockhopper agitation nozzles, the makeup water to the gasifier slag quench tank, the fill for the slag lockhopper, the pyrites sluicing water and the flushing water for the basin are supplied from this settling basin.

vi) Char Reinjection System

a) Char Cyclone, Seal Bin and Char Removal Bagfilters
Product gas leaves the heat exchanger and flows through the char cyclone and then to the char removal bagfilters. The char removed in the cyclone flows by gravity via the char seal bin to the char receiving bin. Char collected in the bagfilters discharges by gravity to the char receiving bin. The baghouse is cleaned by pulsing the bags with low pressure steam. The filtered product gas is piped to the hot gas clean up system. The char cyclone and char removal bagfilters operate at approximately 1000 ^{o}F and 300 psi.

b) Char Receiving Bin and Char Lockhoppers

The char is collected in the char receiving bin and feeds out intermittently to two char lockhoppers. The flow is controlled into and out of each lockhopper by pairs of char sealing valves. The char lockhoppers are pressurized with steam to a pressure higher than the operating pressure of the gasifier and intermittently discharge to the char feed bin by gravity. The cyclone, seal bin, receiving bin, lockhoppers, feed bin, product gas piping and char piping are thermally insulated and lagged. The char piping between the char receiving bin, lockhoppers and feed bin shall be electrically heat traced to reduce the tendency of the pipe to cool down between char filling cycles. The heat tracing will be sandwiched in layers of insulation and will operate at the 1000°F temperature of the char. During start up and shut down, the lockhoppers and feed bin are pressurized using nitrogen. Inside of each lockhopper, receiving bin and feed bin, there are fluidizing devices to keep the char from compacting and keep the char flowing from vessel to vessel.

c) Char Feed Bin and Transport System

The char feed bin continuously feeds char through the flow control valves at a pressure high enough to overcome the gasifier operating pressure. The char is fed through the flow control valves to char pickup Tee's. When the unit is operating, transport steam is introduced to carry the char to stream splitters where the char flow is divided and piped to the char burners. During start up, nitrogen is the transport medium. The char is reinjected into the gasifier for completion of the gasification process. There is no waste stream other than slag during normal operation.

vii) Hot Gas Clean Up System

The syngas leaving the char removal baghouse has been cleaned of particulate matter. The syngas is expected to consist primarily of N_2, CO, CO_2, H_2 and water with low concentrations of H_2S, COS, CS_2 and chlorides. The sulfur and chlorine compounds must be removed prior to combustion of the syngas in the gas turbine. To maintain the overall thermal cycle efficiency, the gas is not cooled before entering the gas clean up system. The syngas enters the absorber and flows countercurrent to a moving bed of ZnTi pellets. The sulfur compounds (mainly H_2S, COS and CS_2) in the gas shall react with the sorbent. Following sulfur adsorption, sorbent material is conveyed to a lockhopper and then to regeneration. In the regenerator, the metal oxide is regenerated and SO_2 produced. Regenerated sorbent, purged of SO_2 is recycled to the absorber lockhopper. The supply of regenerated metal oxide is slightly depleted during regeneration and handling. Fine particles of sorbent entrained in the cleaned gas stream are captured in a downstream high efficiency cyclone. Because of generation and removal of these fines, the sorbent requires continuous replenishment at an expected rate of less than 1 percent of the continuous sorbent flow. The ZnTi fines, because of their high zinc content, are recycled to the sorbent supplier and do not become a waste byproduct. Chlorides are removed from the gas upstream of the absorber. Nahcolite is injected into the syngas after the char removal baghouse. The Nahcolite converts the chlorine into NaCl which is a solid and can be filtered out and disposed of offsite. Heat generated in the regeneration process is used to generate steam which is piped back to the gasifier steam drum. The clean syngas is piped to the gas turbine for combustion. The SO_2 produced during sorbent regeneration is piped to the sulfuric acid production plant.

viii) Sulfuric Acid Recovery System

The gas stream leaving the regenerator of the hot gas clean up system consists primarily of SO_2 and nitrogen. The gas stream is humidified, cooled and dried so that the moisture remaining in the gas is equivalent to the water content of the product acid. The gas is heated in a recuperative heat exchanger against exiting gases and passed through a four stage catalyst bed, which converts 99+ percent of the SO_2 to sulfur trioxide (SO_3). The bed employs vanadium pentoxide as the catalyst, which is periodically cleaned and replaced as necessary. The mixture is further cooled in another recuperative heat exchanger and passed through either one or two contact absorption towers, where the SO_3 is absorbed into 98 percent H_2SO_4. The acid is transferred to an acid storage tank. The acid is of commercial grade quality and represents a marketable byproduct rather than a waste stream. The sulfuric acid production plant is free standing and separate from the gasifier building and from the Lakeside Station building.

ix) Gasifier Island Building

The gasifier island building houses the coal preparation equipment, gasifier, heat exchanger, steam drum, char recycle system, hot gas clean up system and slag removal system up to the load out conveyor. The building is roofed, insulated and sided with fire rated stairways and an elevator.

x) Gas Turbine

After particulate and sulfur removal, the syngas is fired in the combustion turbine. The turbine is a GE Frame 6, Model 6001 with a rated capacity of 40 MW. The turbine has the capability to be fired with natural gas if the gasifier is out of service. The gas turbine is located in the renovated Lakeside Station building. The exhaust from the gas turbine is at approximately 1030°F at full load. This exhaust gas is routed to the heat recovery steam generator. The air for the combustion of the coal and char in the gasifier is extracted from the compressor section of the gas turbine. A booster compressor controls the amount of air extracted and further increases the pressure of the combustion air. The air is cooled before it enters the gasifier. The heat is captured in a heat exchanger and is used to generate steam for the steam turbine cycle.

xi) Heat Recovery Steam Generator

The heat recovery steam generator (HRSG) takes the hot exhaust gas from the gas turbine and recovers the heat to generate steam. The HRSG is able to fire natural gas to supplement the gas turbine output during high ambient temperature conditions and when the gasifier is off line and the gas turbine is firing natural gas only. The HRSG is located in the Lakeside Station building. The exhaust gas leaving the HRSG is ducted up and over the roof to a new stack. The HRSG is delivered in preassembled modules with final assembly being performed in the field. The inlet ducting is of prefabricated and pre-insulated construction. The outlet ducting is carbon steel and insulated after erection.

xii) Steam Turbine

Steam from the HRSG plus steam from the waterwalls of the gasifier and various gasifier heat exchangers is piped to the steam turbine. The steam turbine operates with steam at 1265 psia and 950°F at the throttle inlet valve. The steam turbine is connected to a synchronous generator that produces 36.4 megawatts. The steam is exhausted from the turbine down into the steam condenser. The condenser cools the steam back to condensate and returns the water back into the cycle. The cooling water for the main condenser comes from the lake water circulation system. The system is designed for a maximum rise in water temperature of 10 °F.

xiii) Nitrogen Supply System

The Nitrogen Supply System (NSS) provides N_2 which is used to pressurize, fluidize and displace coal in the lockhoppers and feed bin. It is also used as the conveying medium in the coal transport lines. Nitrogen is the purge gas in the coal feed vessels, the gasifier, heat exchanger, char feed and recycle vessels, hot gas cleanup, gas turbine, flare and all interconnecting piping. Purging is necessary to prevent explosive mixtures from accumulating in the gasifier area.

The NSS is designed to supply 14,400 lb/hr at 390 psig, 160°F and 3000 lb/hr at 17 psig, 150°F. The emergency reservoir is a liquid storage tank which is filled as required by tank trucks. Liquid N_2 from the storage tank is vaporized at supply pressure. The emergency capacity in the reservoir will supply fifteen minutes of the coal transport requirement and two hours of the purge requirement and is available upon loss of station power. This provides enough gas to clear the feed lines of pulverized coal.

xiv) Plant Control System

The control and information system for the plant is a distributive control system (DCS) with a new control room located adjacent to the existing control room. The DCS consists of a controller, console, data processor and high density I/O subsystems linked together by a data highway. Each subsystem contains its own software services and communicates with other subsystems through a pre-programmed protocol. With the exception of a limited number of local control loops and auxiliary systems, all equipment is operated through the microprocessor based DCS. The plant performance computer is provided with the DCS and interfaces with the LAN and the DCS. The computer is available to provide information and calculations to the operators and the engineering staff. Functions available on the computer system are parameter logs, parameter summaries, trend tracking, trend display and trend plotting.

Various plant maintenance functions can also be tracked and stored so that the system can inform staff of required equipment maintenance. All functions of the plant performance computer are accessible through the DCS control room console workstations or through the DCS engineer's console.

xv) Water Systems

a) Demineralized Water System

The demineralized water system consists of three 40 gpm trains. Normal flow through the demineralizer system is between 40 and 80 gpm, depending on plant load and time of year; the design flow rate is 120 gpm. Potable water, which is taken from the CWL&P municipal water lines located on the plant site, is used as the demineralized water system supply. This water is available at 90 psia, consequently, no demineralized water makeup tanks or pumps are specified.

Continuous makeup to the condenser hotwell is supplied by the demineralizer water system at the normal system flow rate. Demineralized water is also supplied to the chemical injection package, the nitrogen supply system and is an emergency source of cooling for the gasifier cooling water heat exchanger.Each train consists of a skid mounted two bed demineralizer preceded by a carbon filter. In addition, each train contains a mixed bed demineralizer downstream of the two bed demineralizer.

A 25,000 gallon capacity demineralized water storage tank is provided. This tank is sized to hold a normal 10,000 gallons of demineralized water and provide a 15,000 gallon reserve capacity for storage of condensate in the event the HRSG must be drained for maintenance.

Sulfuric acid used for system regeneration is obtained from the sulfuric acid storage tank located near the sulfuric acid plant. Caustic used for system regeneration is supplied by a 3000 gallon storage tank. System wastes are collected by the Waste Water Pretreatment System and sent to the Neutralization Pit.

b) Feedwater Chemical Injection System

Boiler feedwater quality control is provided by a vendor supplied chemical injection package. Specific chemical additives and the treatment program are determined by the chemical injection package vendor. The system conceptual design utilizes phosphate, morpholine and hydrazine additives. Phosphate, a deposit inhibitor, is added directly of the HRSG steam drum and the gasifier steam drum. Hydrazine, used to control corrosion, removes oxygen and passivates iron and copper surfaces. Morpholine is used to neutralize acidity and is injected directly into the feedwater.

c) Circulating Water

Circulation water is taken from the intake tunnel by two motor driven pumps. The flow rate through these pumps is 28,820 gpm each. The discharge pressure is 27 psia. A flow of 50,400 gpm is sent to the surface condenser. The remaining flow is diverted to three different areas. The first area is the slag water makeup pond. This flow accounts for the evaporative loses incurred in the waste water circulation system. The remaining demand for this water involves cooling in the closed loop cooling system. The cooling system consists of two closed loops. The first loop serves the gas turbine generator and the steam turbine generator. The second loop serves the cooling demand from the slag water cooler, gasifier cooling water heat exchanger, nitrogen booster compressor, recycle gas compressor, gasifier air booster compressor, instrument air compressors, condensate booster compressor, HP boiler feedwater pumps and the sulfuric acid plant. The cooling medium is demineralized water and there are high capacity bag filters in each loop to trap any particles that may be in the lines. Each loop also has a surge tank to accommodate any fluctuations in water volume. Cooling water supply pressure has a maximum of 65 psia and a velocity between 5 and 8 fps. Maximum temperature and pressure rises of 10°F and 15 psi, respectively, are allowed.

d) Potable Water System

The potable water system distributes potable quality water to the existing building, the new gasifier building and the surrounding areas. Potable water is supplied to a system header by the existing CWL&P site potable water system. No new makeup pump or storage capacities are employed.

The system supplies the new locker/change room facilities for men and women, located in the Lakeside building adjacent to the plant control room. Each change room is sized to accommodate shifts of six operating personnel, and contains two lavatories, toilets and showers. The Lakeside building facilities also include a separate sink in the control room area kitchen.

This system also supplies the gasifier building restroom facilities. The gasifier building has separate men's and women's restrooms containing a single lavatory and toilet each.

Each building is provided with a service sink, a water cooler for personnel use, a hot water heater, personnel safety showers and eyewash units.

Personnel safety showers and eyewash units are also located in the Neutralization Pit area (waste water pretreatment), the caustic and acid storage areas and adjacent to the sulfuric acid plant.

The potable water system supplies the demineralized water system with 40 to 80 gallons of potable water per minute, up to the design flow rate of 120 gpm. The potable water system supplies the sulfuric acid plant with process water at flow rates of 5 gpm continuous and up to 30 gpm intermittently.

The potable water system also serves as an emergency source of cooling for the gasifier. Gasifier emergency quench pumps are designed to deliver 60 gallons of water per minute at 320 psia. Plant hose stations are supplied by the potable water system at 90 psia.

xvi) Plant and Instrument Air System

Two 100% compressors supply 2000 scfm (maximum) for use as plant and instrument air. Instrument air is dried by means of an air regenerative desiccant dryer that requires 15% of inlet air for regeneration. The maximum and minimum instrument air pressures for instrument and plant air are 110 psia, and 90 psia respectively. A backpressure control valve is located on the plant air supply line from the air receiver. The valve closes if a severe drop in plant air pressure is detected in order to maintain instrument air pressure at 90 psig minimum downstream of the dryers.

xvii) Plant Layouts

a) Gasifier Island

In 1992, Lummus Crest Inc (LCI) developed conceptual equipment layouts using PASCE computer design software for the following systems included in the Gasifier Island Structure:

- Coal Handling and Feeding
- Gasifier and Heat Exchanger
- Slag Removal
- Char Removal and Recycle
- Hot Gas Desulfurization

Early estimates of the expected shape and possible elevation of the gasifier structure were used primarily as input into preliminary air permit modelling studies conducted by ABB Environmental Services in April 1992.

The early 1992 gasifier island layouts also included space in the structure for future installation of a conventional sulfur removal facility based on equipment data developed by LCI. These early layouts were upgraded as the following information and revisions were received

An important factor which prevented further development in the gasifier island layouts was the lack of size and weight of special equipment which are specifically dependent on supplier engineering and quotations. These include the coal baghouse and pulverizing system and the hot char removal equipment -baghouse, cyclone and hot rotary feeders. Requisitions for these equipment were prepared by LCI on a priority basis as the process data became available in October 1992. Competitive quotations were received in early December 1992 and technical evaluations initiated to select a single supplier.

The gasifier island arrangement was revised one more time to reduce the height of the gasifier structure. This was used in the cost estimate.

At the close of 1992, twenty-two gasifier island plans and elevations were identified and initiated. These were to be the basis in conjunction with the P&IDs, equipment sizing and steel structural layouts to develop the definitive cost estimate by April 1993. Figure 12 shows an isometric view of one of the early gasifier island arrangement plans.

b) Lakeside Building

At the completion of Budget Period 1 overall layout studies had been completed to optimize the arrangement in the Lakeside Building of the major combined cycle equipment - (Gas Turbine Generator, HRSG, Steam Turbine Generator and Stack). Per CWL&P requirements the various alternative layouts incorporated provisions for a 'future' combined cycle unit of equal capacity to the CE-IGCC Repowering Project basis. Several alternatives were compared in terms of both performance and cost. The results were submitted to CE and CWL&P and one option was selected as the design basis for Budget Period 2 work.

During 1992 work was concentrated on the civil/structural aspects of the Lakeside Building with respect to foundations, use of existing floors and structures, architectural plans and demolition requirements. This work must be done as the prelude to piping location plans for the smaller auxiliary equipment associated with the combined cycle and utility support systems.

c) Overall Site Plot Plans

An overall conceptual site plan was developed in 1992. The site plan, Dwg E-06851-00010A, was used in early 1992 as a basis for the factored cost estimate prepared by LCI in April. The plan was continually updated as key information became available.

Figure 13 shows a conceptual plot plan of the site. Figure 14 shows an isometric view of the plot plan which makes it easier to visualize the installation.

At the close of 1992, the site plan has been updated to include information for the sulfuric acid plant, construction crane location and water treatment systems associated with the combined cycle and gasifier systems.

The site plan was revised one more time by DESI. Changes made to the coal handling system changed the site layout. Other changes were incorporated to try and reduce the overall plant cost.

xviii) CWL&P Interfaces

CE required significant input from CWL&P to finalize the project design questionnaire, the primary document which defines design bases. Initial input was obtained from CWL&P in 1991, but in April, 1992 the project design questionnaire was issued for approval to CWL&P. CWL&P issued their comments on the document in June, 1992. The project design questionnaire was issued approved for design on August 20, 1992. Following implementation of cost reduction measures, the design questionnaire was updated and reissued in December, 1992.

FIGURE 12

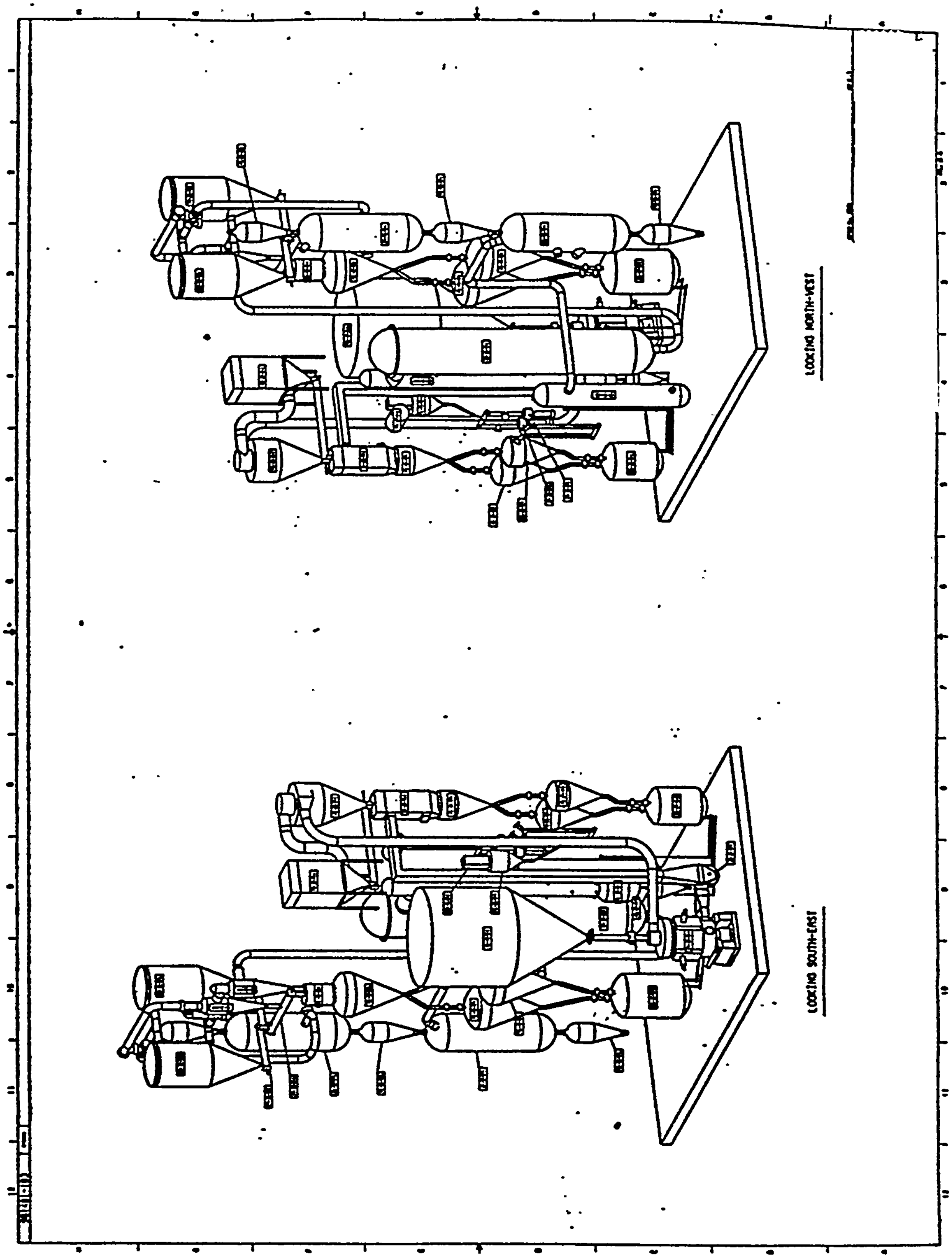
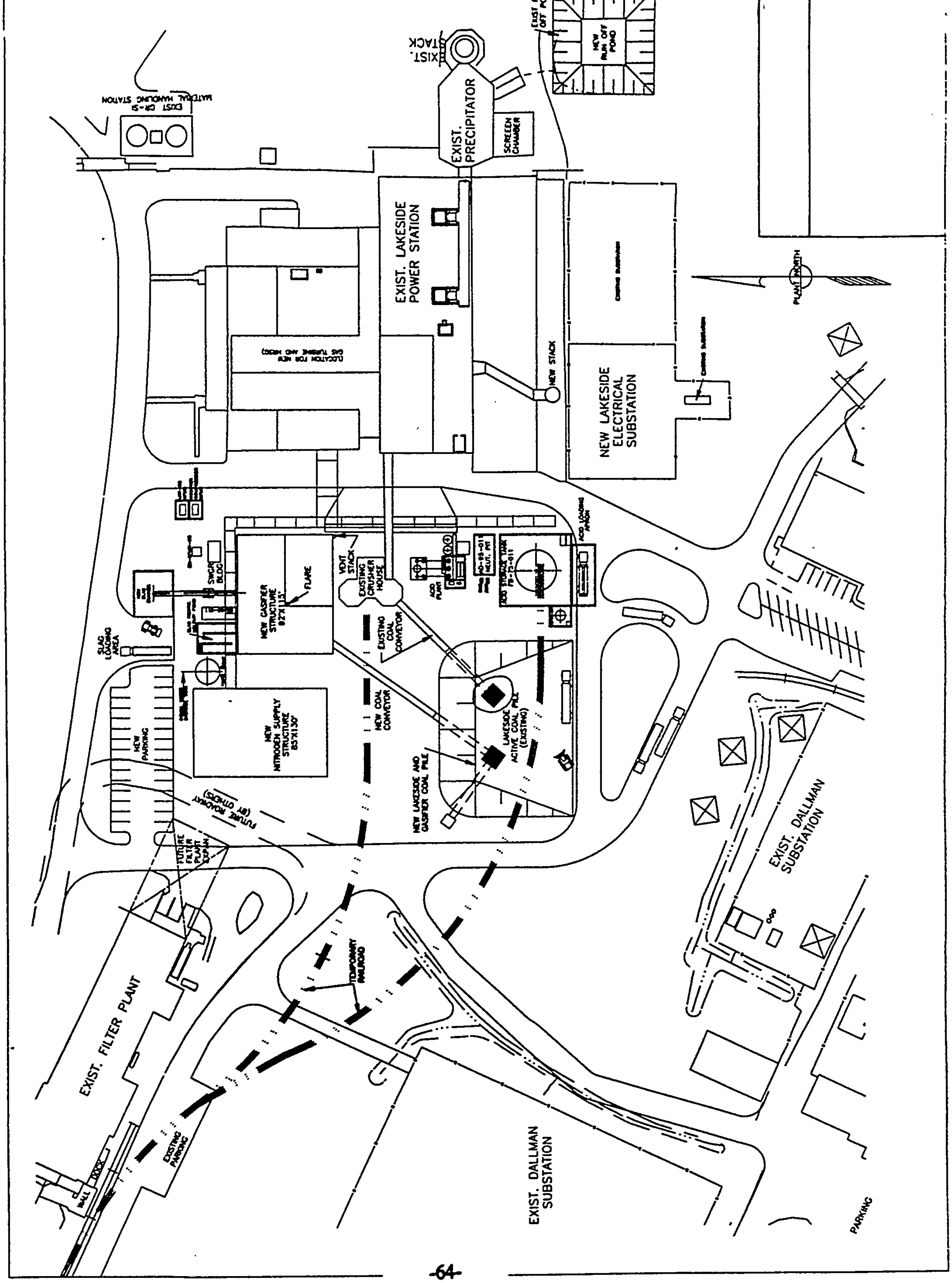


FIGURE 13


EXIST. STACK
NEW RUN OFF POND
EXIST RUN OFF POND
EXIST. PRECIPITATOR
SCREEN CHAMBER
EXIST. LAKESIDE POWER STATION
NEW STACK
NEW LAKESIDE ELECTRICAL SUBSTATION
PLANT NORTH
VENT STACK
EXISTING CRUSHER HOUSE
FLARE
NEW GASIFIER STRUCTURE 82'X115'
SWGR BLDG
ACID PLANT
EXISTING COAL CONVEYOR
NEW COAL CONVEYOR
NEW NITROGEN SUPPLY STRUCTURE 85'X130'
SLAG LOADING AREA
NEW PARKING
LAKESIDE ACTIVE COAL PILE (EXISTING)
NEW LAKESIDE AND GASIFIER COAL PILE
FUTURE ROADWAY (BY OTHERS)
FUTURE FILTER PLANT EXPAN
EXIST. FILTER PLANT
TEMPORARY RAILROAD
EXISTING PARKING
WALL
DOCK
EXIST. DALLMAN SUBSTATION
EXIST. DALLMAN SUBSTATION
PARKING

The following sections describe the information that was developed to generate the cost estimate.

C ESTIMATE BASIS

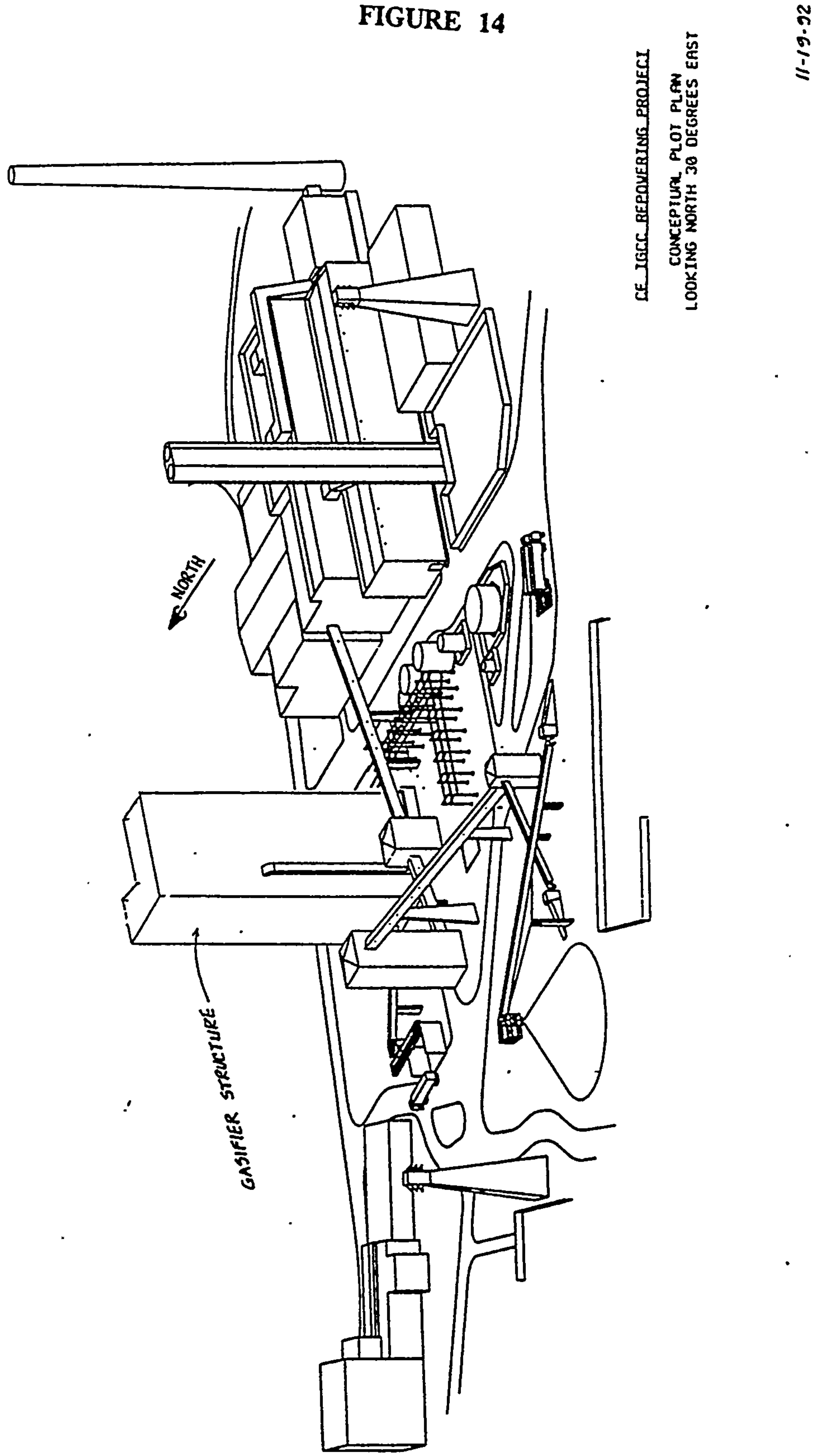
i) Heat and Material Balances

One of the more important requirements during the design process for the plant are the material and energy balances. The development of these balances is iterative. Changes to the balances are required for several reasons. Some of the typical reasons for revisions are process changes, actual equipment performance is refined, design requirements are modified, and additional design requirements are imposed. These balances are therefore updated continuously as the plant design evolves.

The information contained in the material and energy balances is used for several purposes. System duty specifications are developed, overall process control system specifications are defined, equipment data sheets and material specifications are provided and overall plant performance and net plant heat rate are defined based on the information contained in the material and energy balance.

During this project several material and energy balance documents were developed. Several gas turbine loads and various ambient temperature conditions were used for this set of balances. Two levels of detail were defined for these material and energy balances. Level 1 represented a complete detailed material and energy balance. Every stream identified on the process flow diagrams is described in terms of flow, temperature, pressure, composition, and energy. Level 2 energy and material balances were also compiled. These were basically a summary version of the detailed level 1 balance. The level 2 balances were done on a block flow basis. Only the streams entering or leaving a major process block were identified. These streams were also described in terms of flow, temperature, pressure, composition, and energy. Included with the level 2 balance was a table summarizing plant auxiliary power requirements, gas and steam turbine power production, plant fuel heat inputs and net plant heat rate. Figure 15 shows the block flow diagram for the plant. Table 7 shows the net plant heat rate for the MCR operating condition. This operating condition is defined as a 95°F ambient temperature, base load gas turbine firing condition, and supplemental HRSG firing to obtain approximately 60 MW net output from the plant. These data are based upon quotations received in support of the plant preliminary cost estimate and design parameters established in the plant Design Questionnaire. This balance was used as one of the primary design points for the plant. Table 8 gives stream data for Figure 15. This is one of many cases that was calculated for the operating conditions of this plant and approximately represents full load options. Operating condition ranges are discussed elsewhere in this report.

FIGURE 14

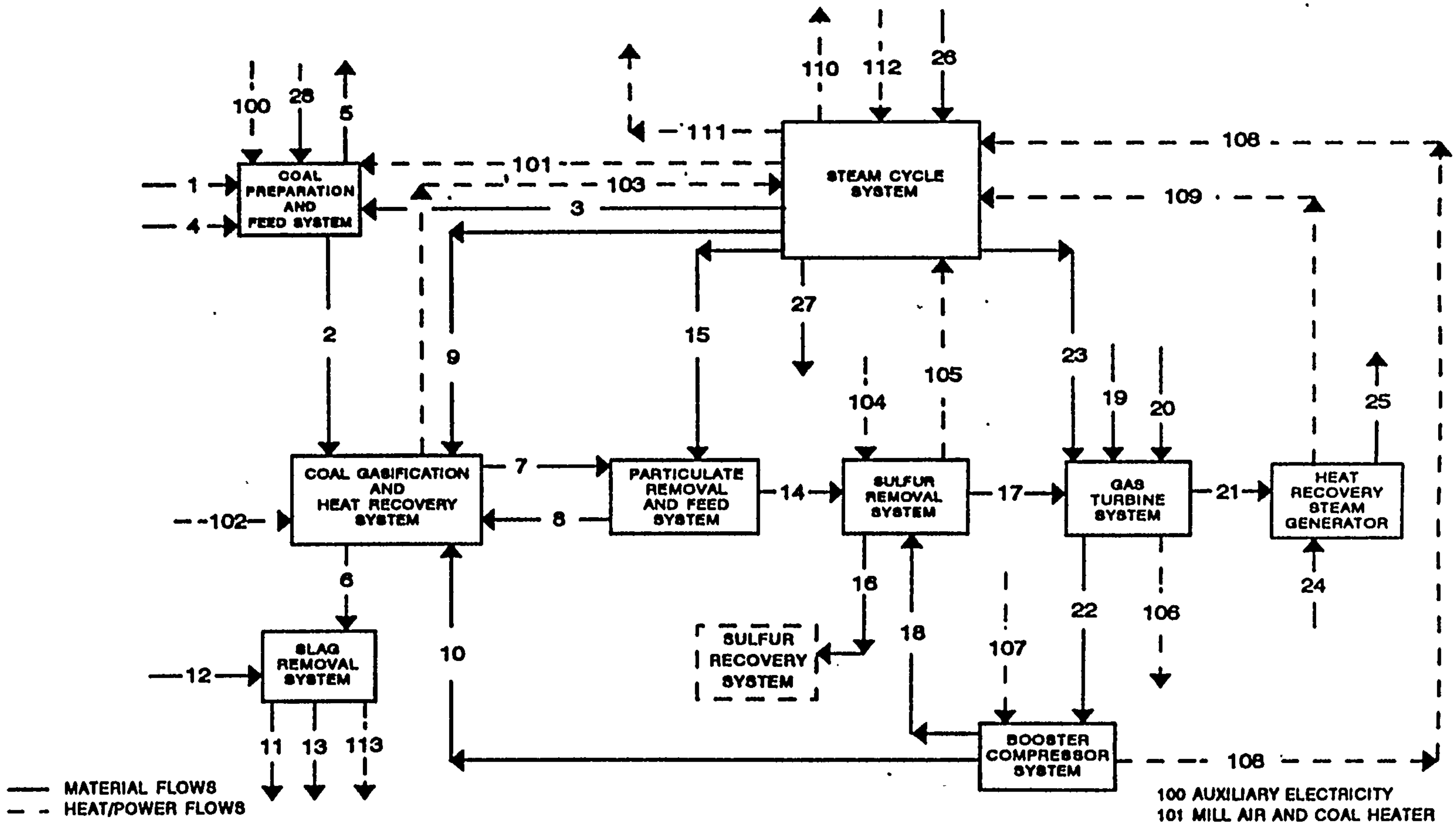


CE IGCC REPOWERING PROJECT
CONCEPTUAL PLOT PLAN
LOOKING NORTH 30 DEGREES EAST
11-19-92
NORTH
GASIFIER STRUCTURE

FIGURE 15

OVERALL SYSTEM BLOCK FLOW DIAGRAM WITH STEAM TRANSPORT

LML
9/15/92



1 RAW COAL
2 COAL + STEAM
3 PRESSURIZING & TRANSPORT STEAM
4 MILL AIR
5 BAGHOUSE VENT TO ATMOSPHERE
6 SLAG
7 RAW GAS
8 CHAR + STEAM
9 SOOTBLOWER & ANNULUS PRESSURIZATION STEAM
10 GASIFIER AIR
11 BLOWDOWN
12 MAKEUP WATER
13 SLAG
14 PARTICULATE FREE LBG
15 PRESSURIZING & TRANSPORT STEAM (INCLUDING BAGHOUSE)
16 OFFGAS
17 CLEAN LBG
18 HGCUS AIR
19 NATURAL GAS
20 AIR
21 GAS TURBINE EXHAUST
22 GAS TURBINE BLEED AIR
23 NOx REDUCTION STEAM
24 NATURAL GAS
25 FLUE GAS TO STACK
26 MAKEUP WATER
27 BLOWDOWN
28 NITROGEN
100 AUXILIARY ELECTRICITY
101 MILL AIR AND COAL HEATER HEAT REQUIREMENT
102 AUXILIARY ELECTRICITY
103 WW & SGC RECOVERED HEAT
104 AUXILIARY ELECTRICITY
105 REGEN. SYSTEM RECOVERED HEAT
106 ELECTRIC POWER
107 AUXILIARY ELECTRICITY
108 PRE-COOLER HEAT
109 RECOVERED HEAT
110 ELECTRIC POWER
111 CONDENSER HEAT REJECTION
112 AUXILIARY ELECTRICITY
113 HEAT REJECTION

Table 7
Net Plant Heat Rate Calculation

		BASE
Coal Transport and LM Pressurization Fluid		STEAM
Combustion Turbine Generator Output	(kW)	32550
Steam Turbine Generator Output	(kW)	37167
Gross Plant Output	(kW)	69717
Plant Auxiliary Power	(kW)	10,300
Net Plant Output	(kW)	59,417
Coal Heat Input	(MM-Btu/hr HHV)	508.400
Natural Gas Heat Input (GT)	(MM-Btu/hr HHV)	0.000
Natural Gas Heat Input (HRSG)	(MM-Btu/hr HHV)	64.300
Natural Gas Heat Input (Mill System)	(MM-Btu/hr HHV)	12.900
Total Fuel Heat Input	(MM-Btu/hr HHV)	585.600
Net Plant Heat Rate	(Btu/kWhr)	9850
Plant Thermal Efficiency	(Percent)	34.60

ii) Process Flow Diagrams and Process Descriptions
Conceptual process flow diagrams (PFD's) were generated during Budget Period 1. Six PFD's for the gasifier island were produced. During Budget Period 2 these PFD's were updated and more detailed information was added. Equipment was selected and the information was incorporated into the system design. Major control loops were added. With the increase in information that the PFD's were required to convey, the number of drawings was increased and each drawing represented a smaller portion of the system. PFD's were also generated for all of the balance of plant equipment and systems. A list of the PFD's is given in Table 9.

Table 9
PROCESS FLOW DIAGRAMS

NUMBER	DESCRIPTION
10001 A	COAL DELIVERY AND HANDLING SYSTEM
10001 B	COAL DELIVERY AND HANDLING SYSTEM
10001 C	COAL DELIVERY AND HANDLING SYSTEM
15001 A	COMBINED CYCLE

TABLE 8

MATERIAL AND ENERGY BALANCE

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13
AIR	0	0	0	122160	130455	0	0	0	0	173538	0	0	0
STEAM (WATER)	0	2045	3943	0	0	0	0	1863	3906	0	4909	7254	2345
PRODUCT GAS	0	0	0	0	0	0	219996	0	0	0	0	0	0
NATURAL GAS	0	0	0	0	0	0	0	0	0	0	0	0	0
OFF GAS	0	0	0	0	0	0	0	0	0	0	0	0	0
FLUE GAS	0	0	0	0	0	0	0	0	0	0	0	0	0
NITROGEN	0	0	0	0	0	0	0	0	0	0	0	0	0
COAL	48826	42485	0	0	0	0	0	0	0	0	0	0	0
CHAR	0	0	0	0	0	0	37241	37234	0	0	0	0	0
SLAG	0	0	0	0	0	3833	0	0	0	0	0	0	3833
TOTAL (LBS/HR)	48826	44530	3943	122160	130455	3833	257237	39097	3906	173538	4909	7254	6178
TEMPERATURE (F)	95	500	672	95	219	3350	1000	1000	672	600	140	95	140
PRESSURE (PSIA)	14.39	322	410	14.39	14.39	269.4	268.4	294.4	410	287.4	14.39	300	14.39
ENERGY (MM BTU/HR)	508.645	520.79	5.123	3.155	16.042	5.322	819.533	379.67	5.075	26.314	0.295	0.109	1.746

STREAM NO.	14	15	16	17	18	20	21	22	24	25	26	27	28
AIR	0	0	0	0	9142	971100	0	182680	0	0	0	0	0
STEAM (WATER)	0	6158	0	0	0	0	0	0	0	0	16936	2929	0
PRODUCT GAS	244291	0	0	223600	0	0	0	0	0	0	0	0	0
NATURAL GAS	0	0	0	0	0	0	0	0	2982	0	0	0	0
OFF GAS	0	0	9837	0	0	0	0	0	0	0	0	0	0
FLUE GAS	0	0	0	0	0	0	1012020	0	0	1015002	0	0	0
NITROGEM	0	0	0	0	0	0	0	0	0	0	0	0	56
COAL	0	0	0	0	0	0	0	0	0	0	0	0	0
CHAR	8	0	0	0	0	0	0	0	0	0	0	0	0
SLAG	0	0	2	0	0	0	0	0	0	0	0	0	0
TOTAL (LBS/HR)	244299	6158	9839	223600	9142	971100	1012020	182680	2982	1015002	16936	2929	56
TEMPERATURE (F)	1000	672	650	1035	600	95	1042	687	95	250	95	600	95
PRESSURE (PSIA)	249.4	410	250	225	287.4	14.39	14.93	155.2		14.39	14.39	1500	14.39
ENERGY (MM BTU/HR	447.865	8.001	1.503	438.22	1.386	25.081	310.945	31.763	62.771	104.856	1.067	1.791	0

STREAM NO.	100	101	102	103	104	105	106	107	108	109	110	111	112	113
ELECTRICITY (KW)	1260	0	320	0	641	0	32550	3019	0	0	36691	0	1512	0
HEAT (MM BTU/HR)	0	19.678	0	105.924	0	9.43	0	0	13.712	266.171	0	222.2	0	3.39

20001 A	COAL MILLING AND LIMESTONE
20001 A	COAL MILLING
20001 B	PULVERIZED COAL HEATING
20001 C	PULVERIZED COAL LOCKHOPPERS
20001 D	PULVERIZED COAL FEED SYSTEM
20001 E	OPERATING DESCRIPTION FOR PC
20001 F	PULVERIZED COAL 2 TPH KINETIC EXTRUDER
30001 A	GASIFIER LEVELS A,D,E,F
30001 B	GASIFIER LEVELS B,C AND HEAT EXCHANGER
30001 C	GASIFIER SLAG REMOVAL
30001 D	GASIFIER STEAM GENERATION
30001 E	COOLING WATER FOR GASIFIER
35001 A	CHAR REMOVAL
40001 A	CHAR LOCKHOPPERS
40001 B	CHAR FEED SYSTEM
40001 C	OPERATING DESCRIPTION FOR CHAR
45001 A	SLAG HANDLING SYSTEM
50001 A	HIGH TEMPERATURE SULFUR REMOVAL SYSTEM
85001 A	BOOSTER COMPRESSOR
95001 A	WASTE WATER COLLECTION AND TREATMENT
95001 B	WASTE WATER COLLECTION AND TREATMENT
115001 A	COMBINED CYCLE
115001 B	BLOWDOWN
115001 C	PROCESS STEAM DISTRIBUTION
150001 A	CONDENSATE POLISH & CHEM INJ SYSTEM
160001 A	LAKE WATER DISTRIBUTION
170001 A	PLANT AND INSTRUMENT AIR DISTRIBUTION
175001 A	POTABLE WATER BALANCE
180001 B	NATURAL GAS DISTRIBUTION

A simplified version of the PFD's is shown in Figures 16 through 19 These figures give the general configuration of the major systems in the gasifier island.

Process descriptions were written for each system. These process descriptions describe the way the system is supposed to operate and contain the preliminary control philosophy. They also contain information on how the system will operate in the startup and shut down mode. The following brief descriptions summarize the overall plant using the PFD's in Figure 16 through 19.

The coal preparation and feed system is designed to pulverize crushed coal, dry and heat it, feed it through a pressure barrier, and meter it into the gasifier. The system utilizes lockhoppers to overcome the pressure barrier and a pressurized feed bin with metering devices to smoothly feed pulverized coal into feed lines. Inert gas will be used to convey the coal to the gasifier, which avoids undesirable reactions between the coal and its transport medium.

Crushed coal from the raw coal bin will be metered into a pulverizer by the raw coal feeder. The pulverized coal will be dried and conveyed to a separation system which is positioned above the feed system (to promote gravity flow into the various feed system vessels). The coal flows by gravity through a coal heater, a receiving bin, then into one of two lockhoppers. Each lockhopper will be capable of pressurizing its contents from atmospheric pressure to the gasifier operating pressure and discharging its contents into a feed bin at this pressure. The lockhoppers will be sequenced in such a way that one will be filling while the other is dumping coal into the feed bin. The feed bin will provide a relatively stable inventory of coal which can be metered smoothly into the gasifier.

Metering devices drop the coal into their respective pickup devices, where an inert gas mixes with the coal and transports it through coal feed lines to the gasifier.

The particulate removal system is utilized to remove all the char in the product gas line and return it to the gasifier. There are two particulate removal devices in series. The first is a cyclone with a barrier filter following. The cyclone removes the larger size particles while the barrier filter removes the remainder. The cyclone may be either a single stage or two stages in series. The barrier filter may be any of the new technologies available. The leading candidate for the barrier filter is a design which is similar to a conventional baghouse, but with an advanced high temperature material for the bags. With the baghouse concept, the particles are collected on the outside of the bags. To remove the collected material a cleaning system and media is required. The method is periodic pulsing. This is called a pulse jet system and is integral with and supplied with the baghouse. The cleaning cycle is established by monitoring the pressure differential across the collector. When a target pressure differential is reached, either all or some of the collecting elements are cleaned. The ungasified char collected from the product gas is repressurized and fed back into the gasifier. Inert gas is utilized to convey the char to the gasifier. Char reclaimed from the product gas is deposited in a receiving bin. From the receiving bin char flows by gravity into one of two lockhoppers, where it is pressurized and gravity fed into the char feed bin. The lockhoppers are sequenced in such a way that one will be filling while the other one is discharging into the feed bin. From the feed bin char is metered through pickup devices and conveyed through feed lines.

FIGURE 16

ABB CE IGCC Flow Diagram

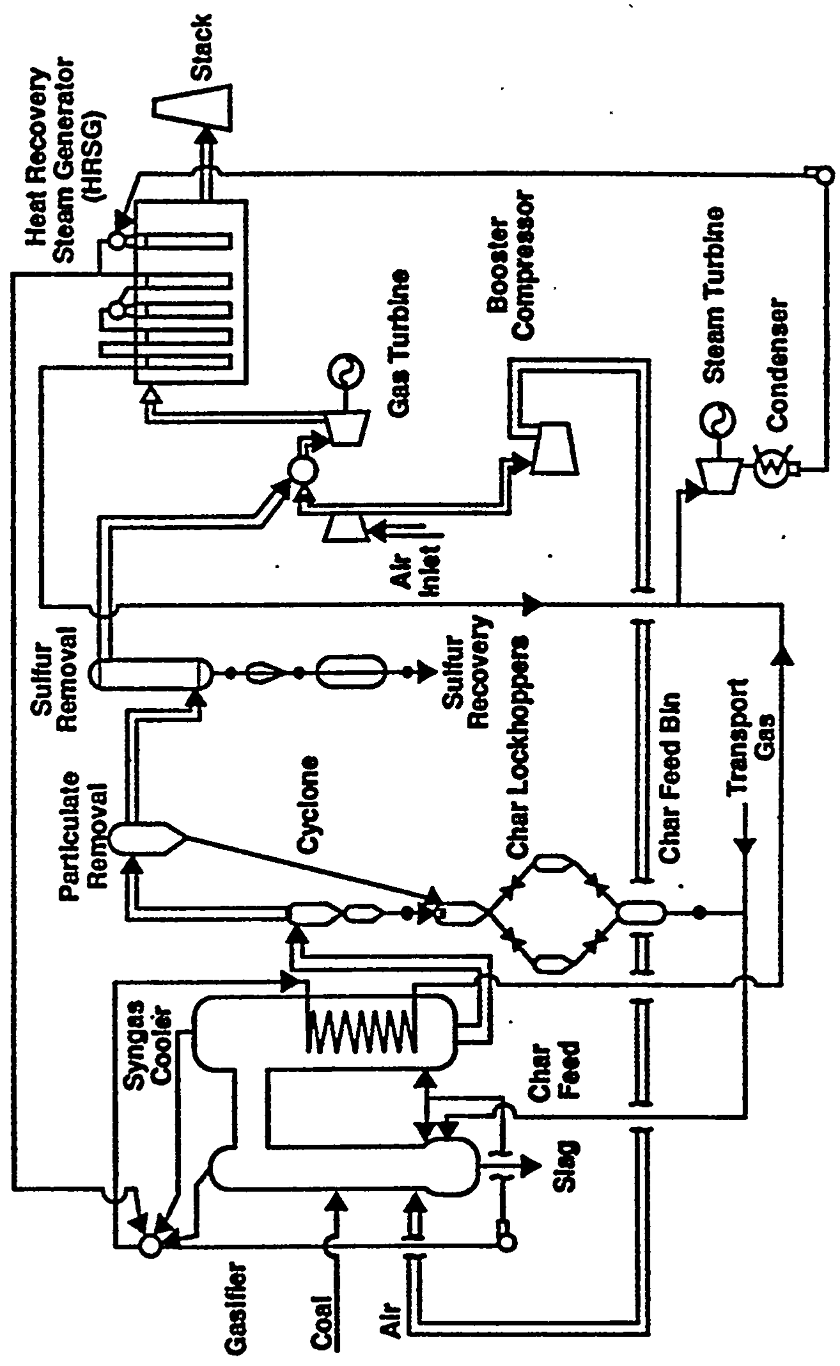


FIGURE 17

Coal Preparation and Feed System

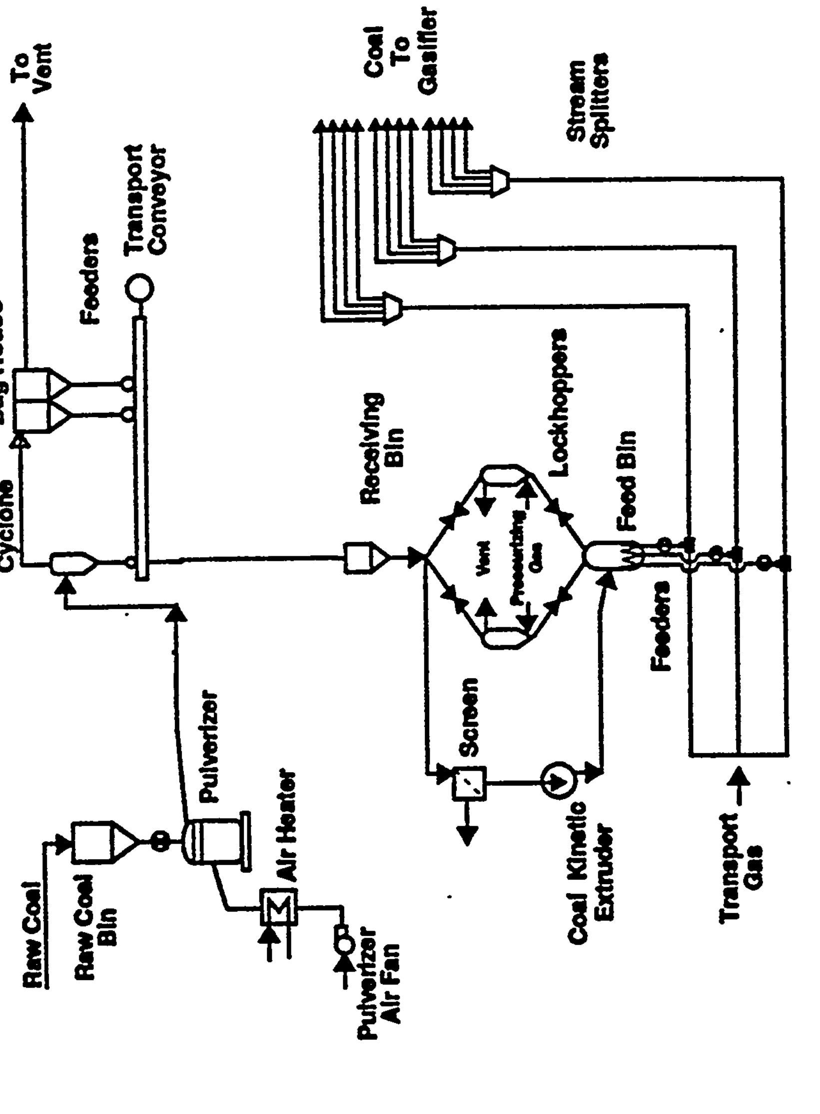


FIGURE 18

Char Recycle System

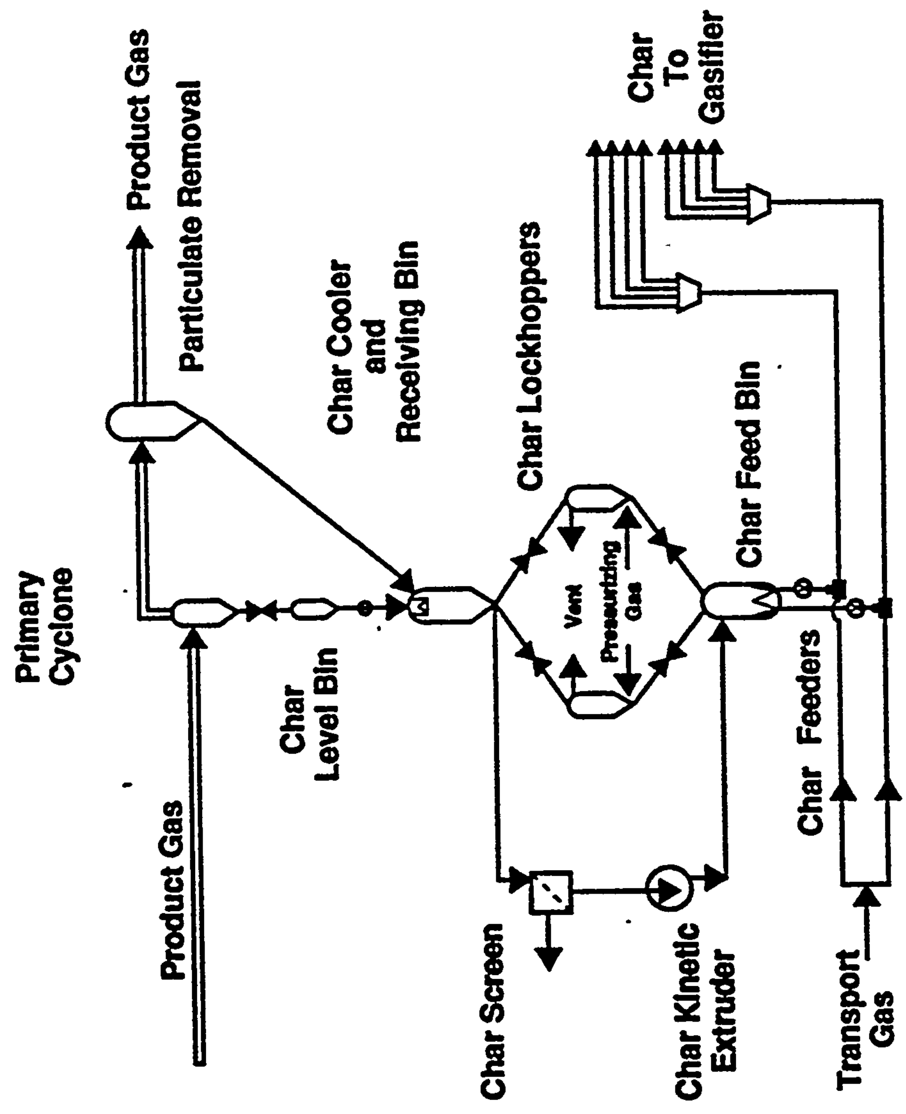
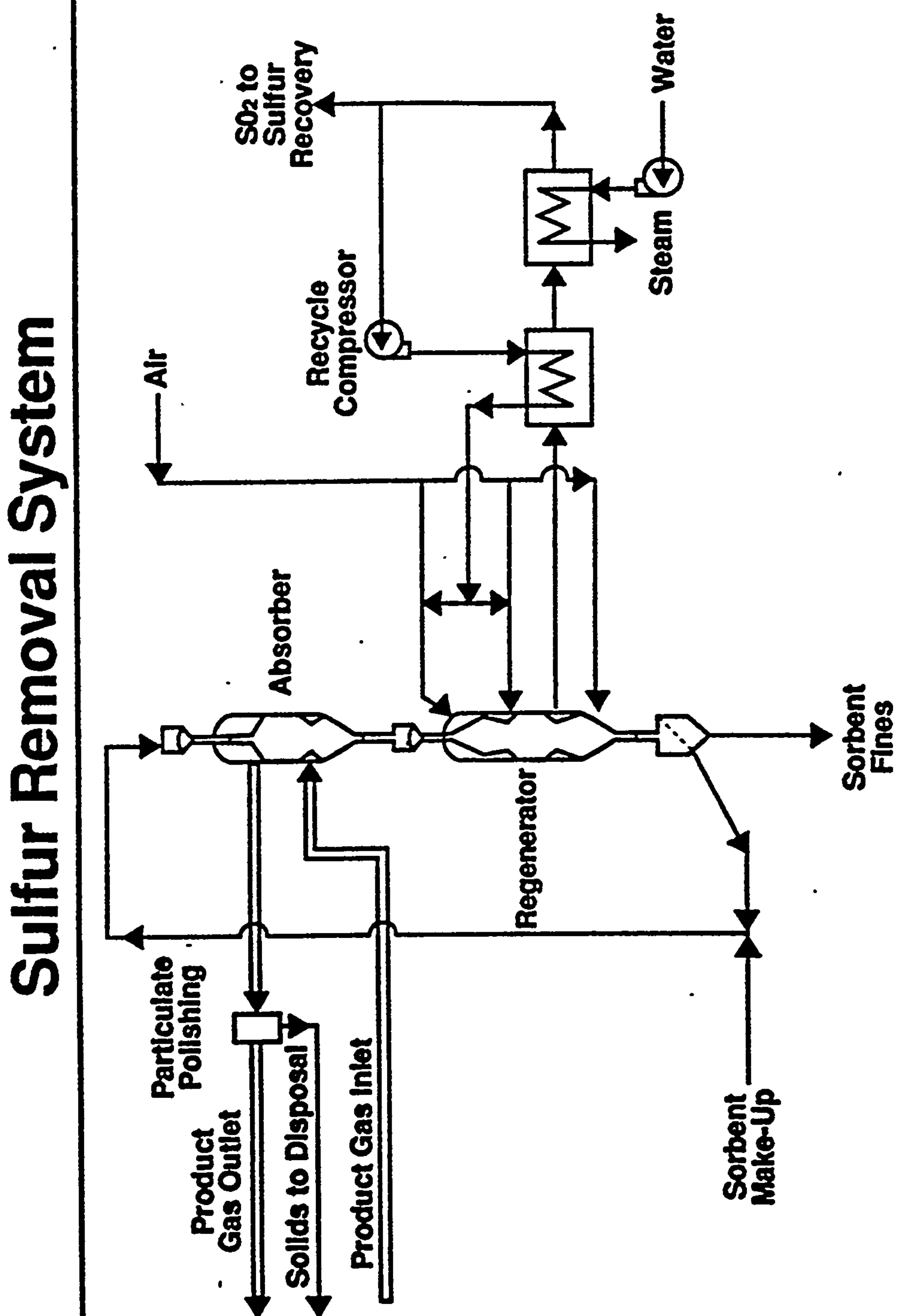


FIGURE 19


Sulfur Removal System
Air
SO_2 to Sulfur Recovery
Water
Recycle Compressor
Steam
Absorber
Regenerator
Sorbent Fines
Particulate Polishing
Product Gas Outlet
Solids to Disposal
Product Gas Inlet
Sorbent Make-Up

The gasifier and its heat exchanger are utilized to produce a pressurized product gas stream containing char and H_2S. Pulverized coal is delivered and combusted in a deficiency of air. Gasification occurs in an entrained reactor. Sensible energy is removed from the gas in the heat exchanger. The gas exits the system for char removal and desulfurization. Coal ash is fused and tapped from the bottom of the gasifier as molten slag. All streams to the gasifier are delivered pressurized.

Product gas leaves the gasifier and passes through a crossover and enters the heat exchanger. The bounding walls of the gasifier, crossover, and heat exchanger are water cooled. The product gas is cooled in the heat exchanger with both water cooled and superheat heat transfer surfaces. The heat transfer surface arrangement is of a configuration that will yield an outlet gas temperature over the operating load range which will satisfy the requirements of the hot desulfurization system. The steam flow generated and the superheating of steam is integrated into the steam cycle.

In the gasifier, the stream of molten slag continually flows through a slag tap into a slag tank. Quench slag is periodically let down from this tank. The slag tank is located just below the gasifier.

Cooling water via inlet and return lines is provided for those components that require it.

The hot gas desulfurization system that CE is considering to use for this system is being developed by GEESI. It is a sorbent system as developed by METC. The GEESI version of this system is known as a moving bed system. Hot product gas enters the absorber vessel at the bottom and reduced sulfur species are removed by reacting with a bed of zinc ferrite or zinc-titanate. Cleaned product gas leaves the reactor at the top. Spent sorbent is removed periodically from the absorber through a lockhopper and enters the regenerator vessel. The sorbent is regenerated with a stream of hot air and recycled back to the absorber. A stream of SO_2 laden gas is produced which is sent to a sulfur recovery system.

iii) Piping and Instrumentation Diagrams

After completing the Approved for Design (AFD) PFD's and the process descriptions, piping and instrumentation diagrams were generated for the entire plant. These P&ID's contain most of the control loops and instrumentation required in the plant and are used to estimate piping and control equipment costs. A list of the P&ID's generated is given in Table 10.

Table 10
PIPING & INSTRUMENTATION DIAGRAMS

NUMBER	DESCRIPTION
20006 A	COAL PULVERIZING SYSTEM SH1
20006 B	COAL PULVERIZING SYSTEM SH2
20006 C	COAL PULVERIZING SYSTEM SH3
20006 D	COAL PULVERIZING SYSTEM SH4

Table 10 (cont'd)

20006 E	PC HEATER PACKAGE & CONDENSATE POT
20006 F	PC RECEIVING BIN
20006 G	PC LOCKHOPPER (FA 20-021)
20006 H	PC LOCKHOPPER (FA 20-021)
20006 J	PC FEED BIN
20006 K	PC TRANSPORT SYSTEM
20006 N	PC KINETIC EXTRUDER
20006 P	PC KINETIC EXTRUDER
20006 Q	PC KINETIC EXTRUDER
30006 A	GASIFIER LEVEL "F" - NATURAL GAS
30006 B	GASIFIER NOZZLES
30006 E	GASIFIER NOZZLES LEVELS "B" and "C"
30006 F	GASIFIER HEAT EXCHANGER - GAS SIDE
30006 G	GASIFIER SLAG COOLING & CRUSHING
30006 H	GASIFIER STEAM SIDE - STEAM DRUM
30006 J	GASIFIER STEAM SIDE RECIRCULATION PUMPS
30006 K	GASIFIER - STEAM SIDE
30006 L	GASIFIER STEAM SIDE HEAT EXCHANGER
35006 A	CHAR REMOVAL CYCLONE
35006 B	CHAR REMOVAL BAGHOUSE
40006 A	CHAR RECEIVING BIN
40006 B	CHAR LOCKHOPPER
40006 C	CHAR LOCKHOPPER
40006 D	CHAR FEED BIN
40006 E	CHAR TRANSPORT SYSTEM
45006 A	SLAG LOCKHOPPER
50005 A	ABSORBER AND SECONDARY CYCLONE
50005 B	SORBENT REGENERATOR SYSTEM
50005 C	REGENERATION SYSTEM
50005 D	SOLID TRANSPORT SYSTEM
50006 A	HOT GAS SULFURIZATION
85006 A	AIR BOOSTER COMPRESSOR
100007 A	GAS TURBINE/GENERATOR
100007 B	GAS TURBINE/GENERATOR AUXILIARIES
100007 C	VENTS AND DRAINS - GAS TURBINE/GENERATOR
110007 A	BOILER FEEDWATER SYSTEM
110007 B	STEAM DRUM - HRSG
110007 C	SUPERHEATER - HRSG
110007 D	EXHAUST GAS AND STACK - HRSG
110007 E	BURNER MANAGEMENT SYSTEM - HRSG
110007 F	HRSG DRAINS
110007 G	HRSG DRAIN SYSTEM
115007 A	MAIN STEAM SYSTEM
115007 B	STEAM TURBINE SYSTEM
115007 C	EXTRACTION STEAM SYSTEM
115007 D	SURFACE CONDUCTOR - HOTWELL
115007 E	SURFACE CONDENSER - CONDENSATE RETURN
115007 F	VACUUM DEAERATOR & MISC. CONDENSATE
115007 G	CONDENSATE SYSTEM
115007 H	LP FEEDWATER HEATERS - VENTS AND DRAINS
115007 J	BLOWDOWN SYSTEM
115007 K	PROCESS STEAM TO DISTRIBUTION
160007 A	CIRCULATING WATER SYSTEM

iv) Metallurgical Flow Diagrams

A materials study was undertaken as described below to make recommendations for materials of construction for those areas of the plant that are not standard industry applications. The results of this study were used to mark up a set of the AFD PFD's. This was done to specify the piping materials and to identify special materials for the gasifier island equipment. The marked up PFD's were formalized into Metallurgical Flow Diagrams and a piping specification was developed which was used in the P&ID development.

v) Equipment Data Sheets

An equipment list was identified from the AFD PFD's. This equipment list is presented in Table 11. Equipment in Table 11 that is listed as the responsibility of CE was estimated by CE. The rest was estimated by the EPC contractor. Major process equipment was identified from this list. Equipment data sheets were generated for each piece of equipment identified. The equipment data sheets include design data such as maximum temperatures, pressures, flows, required operating performance, and materials of construction. The data sheets were used to produce requisitions for quotations for each piece of equipment for the cost estimate. Table 12 lists the equipment data sheets generated for this project with the exception of the gasifier and heat exchanger. The gasifier and heat exchanger were handled as a special case and are described elsewhere in this report.

vi) Start-up/Shutdown/Operating Procedures

A study of the Start-up/Shutdown Procedure was done to check safety procedures and to ensure proper operation of the system. The study includes gasifier start-up, start-up conditions other than "cold start", and shutdown, including planned and emergency. Conditions are stated that involve proper procedure to avoid an explosion. Assumptions are made concerning cleaning and functioning of systems and the availability of safety equipment. The conditions of the start-up can vary depending on the state of readiness of the unit, the reason for being shutdown, the length of time it is in shutdown, and if the bins and lockhoppers are full or empty, or a combination.

After studying the procedure, there is some concern with safety. The changing back and forth from flare stack to vent stack could prove to be unsafe. For the flare system having a dual role a very elaborate safety interlock system should be used and even then there is still a risk of an explosion. At no time when there are combustibles in the flare system, can the oxygen exceed one percent, otherwise there is danger of a severe explosion. Other safer methods of disposing of these gases should be considered as a result of the study.

The start-up and shutdown operating procedures were reviewed in the Preliminary Hazard Analysis, discussed above, to determine if any system or equipment changes were required. The Preliminary Hazard Analysis brought out certain safety concerns particularly in the operation of the flare. These concerns were addressed and the procedures modified to correct the problems. Some equipment changes were also required.

TABLE 11
EQUIPMENT LIST

EQUIP NO	DESCRIPTION	RESPONSIBILITY
	AREA 10	
AD-10-011	RECLAIM PIT	EPC CONTRACTOR
AD-10-031	RECEIVING PIT	EPC CONTRACTOR
AD-10-041	EMERGENCY RECLAIM PIT	EPC CONTRACTOR
FB-10-011	RAW COAL BIN	EPC CONTRACTOR
GA-10-011,012	RECLAIM PIT SUMP PUMPS	EPC CONTRACTOR
GA-10-021,022	EMERGENCY RECLAIM PIT SUMP PUMPS	EPC CONTRACTOR
GA-10-031,032	RECEIVING PIT SUMP PUMPS	EPC CONTRACTOR
FD-10-011X	RECLAIM PIT DUST COLLECTOR	EPC CONTRACTOR
FD-10-021X	CRUSHER HOUSE DUST COLLECTOR	EPC CONTRACTOR
FD-10-031X	RAW COAL BIN DUST COLLECTOR	EPC CONTRACTOR
FD-10-041X	RECEIVING PIT DUST COLLECTOR	EPC CONTRACTOR
FD-10-051X	TRANSFER HOUSE DUST COLLECTOR	EPC CONTRACTOR
FD-10-061X	GASIFIER TRANSFER HOUSE DUST COLLECTOR	EPC CONTRACTOR
FD-10-071X	LAKESIDE II DUST COLLECTOR	EPC CONTRACTOR
FE-10-011X,012X	RECLAIM HOPPERS	EPC CONTRACTOR
FE-10-021X	CRUSHER SURGE BIN	EPC CONTRACTOR
FE-10-031X,032X	RECEIVING HOPPERS	EPC CONTRACTOR
FE-10-041X	EMERGENCY RECLAIM HOPPER	EPC CONTRACTOR
FE-10-051X	TELESCOPING CHUTE	EPC CONTRACTOR
FH-10-011X,012X	RECLAIM FEEDERS	EPC CONTRACTOR
FH-10-021X	RAW COAL BIN DUST COLLECTOR AIRLOCK	EPC CONTRACTOR
FH-10-031X	CRUSHER HOUSE DUST COLLECTOR AIRLOCK	EPC CONTRACTOR
FH-10-041X	CRUSHER FEEDER	EPC CONTRACTOR
FH-10-051X	RECLAIM PIT DUST COLLECTOR AIRLOCK	EPC CONTRACTOR
FH-10-061X	COAL BIN FEED CONVEYOR FEEDER	EPC CONTRACTOR
FH-10-071X,072X	RECEIVING FEEDERS	EPC CONTRACTOR
FH-10-081X	RECEIVING PIT DUCT COLLECTOR AIRLOCK	EPC CONTRACTOR
FH-10-091X	EMERGENCY RECLAIM FEEDER	EPC CONTRACTOR
FH-10-101X	LAKESIDE II DUCT COLLECTOR AIRLOCK	EPC CONTRACTOR
FJ-10-011X	MAGNETIC SEPARATOR	EPC CONTRACTOR
FR-10-011X	SURGE BIN DIVERTER GATE	EPC CONTRACTOR
FR-10-021X	CRUSHER HOUSE DUST COLLECTOR DIVERTER GATE	EPC CONTRACTOR.
FR-10-031X	LAKESIDE II DUST COLLECTOR DIVERTER GATE	EPC CONTRACTOR
FR-10-041X	LAKESIDE II TRIPPER	EPC CONTRACTOR
GA-10-011,021	RECLAIM PIT SUMP PUMP	EPC CONTRACTOR
GA-10-031,032	RECEIVING PIT SUMP PUMP	EPC CONTRACTOR
GB-10-011X	RECLAIM PIT DUST COLLECTOR FAN	EPC CONTRACTOR
GB-10-021X	RECLAIM PIT VENT FAN	EPC CONTRACTOR
GB-10-031X	CRUSHER HOUSE DUST COLLECTOR FAN	EPC CONTRACTOR
GB-10-041X	RAW COAL BIN DUST COLLECTOR FAN	EPC CONTRACTOR
GB-10-051X	RECEIVING PIT VENT FAN	EPC CONTRACTOR
GB-10-061X	RECEIVING PIT DUST COLLECTOR FAN	EPC CONTRACTOR
GB-10-071X	EMERGENCY RECLAIM PIT VENT FAN	EPC CONTRACTOR
GB-10-081X	TRANSFER HOUSE DUCT COLLECTOR FAN	EPC CONTRACTOR

TABLE 11
EQUIPMENT LIST (CONTINUED)

EQUIP NO	DESCRIPTION	RESPONSIBILITY
GB-10-091X	TRANSFER HOUSE VENT FAN	EPC CONTRACTOR
GB-10-101X,102X	CRUSHER HOUSE VENT FANS	EPC CONTRACTOR
GB-10-111X	GASIFIER TRANSFER HOUSE VENT FAN	EPC CONTRACTOR
GB-10-0121X	GASIFIER TRANSFER HOUSE DUST COLLECTOR FAN	EPC CONTRACTOR
GB-10-0131X	LAKESIDE II DUST COLLECTOR FAN	EPC CONTRACTOR
IA-10-011X	TRANSFER HOUSE	EPC CONTRACTOR
IA-10-012X	CRUSHER HOUSE	EPC CONTRACTOR
IA-10-013X	GASIFIER TRANSFER HOUSE	EPC CONTRACTOR
JD-10-011X	RECLAIM CONVEYOR	EPC CONTRACTOR
JD-10-021X	COAL TRANSFER CONVEYOR	EPC CONTRACTOR
JD-10-031X	COAL BIN FEED CONVEYOR 1	EPC CONTRACTOR
JD-10-041X	COAL BIN FEED CONVEYOR 2	EPC CONTRACTOR
JD-10-051X	LAKESIDE II CONVEYOR B	EPC CONTRACTOR
JD-10-061X	STACKER CONVEYOR	EPC CONTRACTOR
JD-10-071X	EMERGENCY RECLAIM CONVEYOR	EPC CONTRACTOR
PY-10-021X	STACKER CONVEYOR BELT SCALE	EPC CONTRACTOR
PY-10-031X	LAKESIDE II CONVEYOR B BELT SCALE	EPC CONTRACTOR
PY-10-041X	COAL BIN FEED CONVEYOR 1 BELT SCALE	EPC CONTRACTOR
PS-10-011	CRUSHER	EPC CONTRACTOR
	AREA 20	
	COAL PREPARATION AND FEEDING	
CB-20-011	COAL VENT STACK	ABB-CE
FA-20-011,012	PULVERIZED COAL FEED BIN(S)	ABB-CE
FA-20-021,022	PULVERIZED COAL LOCKHOPPERS	ABB-CE
FE-20-011	PULVERIZED COAL RECEIVING BIN	ABB-CE
FH-20-081,082,083	PULVERIZED COAL FLOW CONTROL VALVES	ABB-CE
FH-20-091	RAW COAL GRAVIMETRIC FEEDER	ABB-CE
FR-20-011,012,013	PULVERIZED COAL STREAM SPLITTERS	ABB-CE
FR-20-021,022,023	PULVERIZED COAL PICKUP TS	ABB-CE
PA-20-021	COAL PULVERIZING SYSTEM	ABB-CE
GB-20-011X	MILL FAN	ABB-CE
GB-20-021X	ID FAN	ABB-CE
PW-20-011X	PULVERIZER MILL	ABB-CE
	AREA 30	
	COAL GASIFIER AND HEAT EXCHANGER	
BH-30-021	GASIFIER INTERMEDIATE TEMP. DESUPERHEATER	ABB-CE
DC-30-011	GASIFIER	ABB-CE
EA-30-011	GASIFIER HEAT EXCHANGER	ABB-CE
EA-30-031	GASIFIER COOLING WATER HEAT EXCHANGER	EPC CONTRACTOR
FA-30-011	GASIFIER STEAM DRUM	ABB-CE

TABLE 11
EQUIPMENT LIST (CONTINUED)

EQUIP NO	DESCRIPTION	RESPONSIBILITY
FA-30-021X	GASIFIER SLAG TANK	ABB-CE
FA-30-031	CONTINUOUS BLOWDOWN TANK	EPC CONTRACTOR
FA-30-041	SURGE TANK	EPC CONTRACTOR
GA-30-021,022	GASIFIER AREA SUMP PUMP	EPC CONTRACTOR
GA-30-031,032	GASIFIER SYNGAS BLOWDOWN SUMP PUMP	EPC CONTRACTOR
GA-30-041,042	GASIFIER COOLING WATER PUMPS	EPC CONTRACTOR
PS-30-011	SLAG GRINDER	ABB-CE
	AREA 35 **CHAR REMOVAL**	
FA-35-011	CHAR SEAL HOPPER	ABB-CE
FC-35-011	PRIMARY CYCLONE	ABB-CE
FD-35-011, 012	CHAR REMOVAL BAGHOUSE	ABB-CE
FH-35-031,032	CHAR DUMP VALVES	ABB-CE
FH-35-061	CHAR CONTROL VALVE	ABB-CE
	AREA 40 **CHAR RECYCLE**	
EG-40-021	CHAR RECEIVING BIN VENT EDUCTOR	ABB-CE
FA-40-011	CHAR FEED BIN	ABB-CE
FA-40-021,022	CHAR LOCKHOPPERS	ABB-CE
FA-40-031	CHAR RECEIVING BIN	ABB-CE
FH-40-031,032	CHAR FLOW CONTROL VALVES	ABB-CE
FR-40-011,012	CHAR STREAM SPLITTERS	ABB-CE
FR-40-021,022	CHAR PICKUP TS	ABB-CE
	AREA 45 **SLAG HANDLING AND DISPOSAL**	
AD-45-011	SLAG HANDLING SYSTEM OVERFLOW SUMP	EPC CONTRACTOR
AD-45-021	SLAG STORAGE AREA SUMP	EPC CONTRACTOR
EA-45-021	SLAG WATER COOLER	ABB-CE
FA-45-011	SLAG LOCKHOPPER	ABB-CE
FB-45-011	SLAG MAKEUP WATER TANK	EPC CONTRACTOR
FE-45-011	PYRITES HOPPER	ABB-CE
GA-45-011,012	SLAG SYSTEM OVERFLOW SUMP PUMP	EPC CONTRACTOR
GA-45-021,022	SLAG STORAGE SUMP PUMP	EPC CONTRACTOR
GA-45-031,032	SLAG BATH CIRCULATION PUMPS	ABB-CE
GA-45-041,042	GASIFIER SLAG TANK MAKEUP PUMP	EPC CONTRACTOR
GA-45-061,062	PYRITES SLUICE WATER SUPPLY PUMP	EPC CONTRACTOR
JD-45-011	SLAG SCRAPER CONVEYOR	ABB-CE
JD-45-021	SLAG TRANSFER CONVEYOR NO. 1	ABB-CE
JD-45-031	SLAG TRANSFER CONVEYOR NO. 2	EPC CONTRACTOR
JD-45-041	SLAG TRANSFER CONVEYOR NO. 3	EPC CONTRACTOR

TABLE 11
EQUIPMENT LIST (CONTINUED)

EQUIP NO	DESCRIPTION	RESPONSIBILITY
	AREA 50	
	HOT GAS DESULFURIZATION	
DC-50-011	ABSORBER	ABB-CE
DC-50-021	REGENERATOR	ABB-CE
EA-50-011	REGENERATOR GAS HEAT EXCHANGER	ABB-CE
EA-50-021	STEAM GENERATOR	ABB-CE
EC-50-021	START-UP HEATER	ABB-CE
EC-50-011	AIR TRIM HEATER	ABB-CE
FA-50-011	ABSORBER OUTLET LOCKHOPPER	ABB-CE
FA-50-021	ABSORBER INLET LOCKHOPPER	ABB-CE
FA-50-031	REGENERATOR OUTLET LOCKHOPPER	ABB-CE
FA-50-041	SECONDARY CYCLONE LOCKHOPPER	ABB-CE
FA-50-051	REGENERATOR CYCLE LOCKHOPPER	ABB-CE
FB-50-011	SOBENT MAKE-UP SILO	ABB-CE
FC-50-011	SECONDARY CYCLONE	ABB-CE
FC-50-021	REGENERATOR CYCLONE	ABB-CE
FD-50-021,022	FINES SEPARATOR BAGHOUSE	ABB-CE
GB-50-021X	FINES SEPARATOR BAGHOUSE ID FAN	ABB-CE
FE-50-041	REGENERATOR FINES SEPARATOR INLET	ABB-CE
	SORBENT BIN	ABB-CE
FE-50-051	ABSORBER INLET SORBENT BIN	ABB-CE
FE-50-061,062	BUCKET ELEVATOR	ABB-CE
JE-50-011X,012X	HOIST FOR BUCKET ELEVATOR	ABB-CE
FH-50-011	REGENERATOR OUTLET ROTARY FEEDER	ABB-CE
FH-50-021,022	VIBRATING FEEDER	ABB-CE
FL-50-011,012	REGENERATOR FINES SEPARATOR	ABB-CE
GA-50-011	HGCU-EVAPORATOR FEED PUMPS	ABB-CE
GB-50-011	RECYCLE GAS COMPRESSOR	ABB-CE
	AREA 55	
	HOT GAS CLEANUP CATALYST MAKEUP AND FINES HANDLING	
	(TO BE DETERMINED)	
	AREA 60	
	FUEL GAS COOLING AND WET PARTICULATE REMOVAL	
	(DELETED)	
	AREA 75	
	SULFURIC ACID PRODUCTION (EPC CONTRACT)	
AD-75-011X	SULFURIC ACID AREA SUMP	EPC CONTRACTOR
DA-75-011X	GAS DRYER	EPC CONTRACTOR

TABLE 11
EQUIPMENT LIST (CONTINUED)

EQUIP NO	DESCRIPTION	RESPONSIBILITY
DA-75-021X	ACID ABSORPTION TOWER	EPC CONTRACTOR
DC-75-011X	CATALYTIC CONVERTER	EPC CONTRACTOR
EA-75-021X	COOLING WATER CIRCULATION COOLER	EPC CONTRACTOR
EA-75-031X	GAS CHILLING EXCHANGER	EPC CONTRACTOR
EA-75-041X	PRIMARY REGENERATIVE GAS HEATER	EPC CONTRACTOR
EA-75-051X	DRYER CIRCULATION COOLER	EPC CONTRACTOR
EA-75-061X	ABSORPTION TOWER CIRCULATION COOLER	EPC CONTRACTOR
EA-75-071X	AUXILIARY GAS HEATER	EPC CONTRACTOR
FA-75-011X	HUMIDIFIER CIRCULATION TANK	EPC CONTRACTOR
FA-75-031X	DRYER FEED KNOCKOUT DRUM	EPC CONTRACTOR
FA-75-041X	SULFURIC ACID CIRCULATION TANK	EPC CONTRACTOR
FB-75-011X	SULFURIC ACID STORAGE TANK	EPC CONTRACTOR
FD-75-021X	DILUTION AIR INLET FILTER	EPC CONTRACTOR
GA-75-011X,012X	HUMIDIFIER CIRCULATION PUMPS	EPC CONTRACTOR
GA-75-021X,022X	GAS COOLING CIRCULATION PUMPS	EPC CONTRACTOR
GA-75-031X	GAS DRYER CIRCULATION PUMP	EPC CONTRACTOR
GA-75-041X	ACID ABSORBER CIRCULATION PUMP	EPC CONTRACTOR
GA-75-051X,052X	SULFURIC ACID PRODUCT PUMPS	EPC CONTRACTOR
GA-75-061X	SULFURIC ACID AREA SUMP PUMP	EPC CONTRACTOR
GB-75-021X,022X	DILUTION AIR BLOWER	EPC CONTRACTOR
PA-75-011X	WATER CHILLER PACKAGE	EPC CONTRACTOR

AREA 85
GASIFIER AIR SUPPLY

EA-85-011	BOOSTER COMPRESSOR INLET COOLER NO. 1	EPC CONTRACTOR
FD-85-011	BOOSTER COMPRESSOR INLET FILTER/SILENCER	EPC CONTRACTOR
GB-85-011	GASIFIER AIR VARIABLE SPEED BOOSTER COMPRESSOR PACKAGE	EPC CONTRACTOR
PA-85-011X	BOOSTER COMPRESSOR LUBE OIL CONSOLE	EPC CONTRACTOR
EA-85-031X,032X	LUBE OIL COOLERS (PART OF PA-85-011X)	EPC CONTRACTOR
FB-85-021X,022X	LUBE OIL RESERVOIR (PART OF PA-85-011X)	EPC CONTRACTOR
FD-85-021X,022X	LUBE OIL FILTERS (PART OF PA-85-001X)	EPC CONTRACTOR
GA-85-011X,012X	LUBE OIL PUMPS (PART OF PA-85-011X)	EPC CONTRACTOR

AREA 90
FLARE SYSTEM

PA-90-011	FLARE PACKAGE	EPC CONTRACTOR
CB-90-011X	FLARE STACK	EPC CONTRACTOR
CB-90-021X	FLARE TIP	EPC CONTRACTOR
CB-90-031X	FLARE SEAL	EPC CONTRACTOR
CB-90-041X	VENT STACK	EPC CONTRACTOR
GB-90-011X	AIR ASSIST BLOWER	EPC CONTRACTOR
PA-90-021X	FLARE PILOT IGNITION SYSTEM	EPC CONTRACTOR

TABLE 11
EQUIPMENT LIST (CONTINUED)

EQUIP NO	DESCRIPTION	RESPONSIBILITY
	AREA 100	
	GAS TURBINE AND GENERATION	
FD-100-021,022	NATURAL GAS FILTER/SEPARATORS	EPC CONTRACTOR
PA-100-011	GAS TURBINE GENERATOR PACKAGE	EPC CONTRACTOR
EA-100-011X,012X	GTG LUBE OIL COOLERS	EPC CONTRACTOR
EA-100-021X,021X	GENERATOR AIR COOLERS	EPC CONTRACTOR
FD-100-011X	INLET AIR FILTER COMPARTMENT	EPC CONTRACTOR
FD-100-021X	SYNGAS HIGH TEMPERATURE FILTER/STRAINER	EPC CONTRACTOR
GA-100-011X	SHAFT DRIVEN LUBE OIL PUMP	EPC CONTRACTOR
GA-100-012X	A.C. MOTOR DRIVEN LUBE OIL PUMP	EPC CONTRACTOR
GA-100-021X	D.C. MOTOR DRIVEN LUBE OIL PUMP	EPC CONTRACTOR
GA-100-031X	A.C. MOTOR DRIVEN HYDRAULIC PUMP	EPC CONTRACTOR
GE-100-011X	SYNCHRONOUS GENERATOR	EPC CONTRACTOR
GG-100-011X	GAS TURBINE POWER TRAIN W/START MOTOR	EPC CONTRACTOR
PA-100-021X	GENERATOR AUXILIARY COMPARTMENT	EPC CONTRACTOR
PA-100-031X	GENERATOR CONTROL COMPARTMENT	EPC CONTRACTOR
PA-100-041X	AIR EXTRACTION SKID	EPC CONTRACTOR
PA-100-051X	SYNGAS AND NAT. GAS FUEL CONTROL SKID	EPC CONTRACTOR
PA-100-071X	STEAM INJECTION MANIFOLD	EPC CONTRACTOR
PA-100-081X	CO2 FIRE PROTECTION SKID	EPC CONTRACTOR
	AREA 110	
	HEAT RECOVERY STEAM GENERATOR	
BD-110-011	HRSG INLET DUCT	EPC CONTRACTOR
BD-110-021	HRSG OUTLET DUCT	EPC CONTRACTOR
BF-110-011	HEAT RECOVERY STEAM GENERATOR	ABB-CE
BH-110-011X	INTERSTAGE DESUPERHEATER	ABB-CE
FA-110-011	HRSG LOW POINTS DRAIN TANK	EPC CONTRACTOR
GA-110-011,012	HRSG DRAIN TANK PUMP	EPC CONTRACTOR
EC-110-011,012	AMMONIA EVAPORATORS (FUTURE)	ABB-CE
FB-110-011	AQUEOUS AMMONIA STORAGE TANK (FUTURE)	ABB-CE
PA-110-011	HRSG NATURAL GAS DUCT BURNERS PACKAGE	ABB-CE
PA-110-041X	BURNER MANAGEMENT SYSTEM	ABB-CE
BN-110-011X,012X	DUCT BURNERS	ABB-CE
GB-110-011X,012X	FLAME SCANNER COOLING AIR BLOWERS	ABB-CE
PA-110-021	SELECTIVE CATALYTIC RED PACKAGE (FUTURE)	ABB-CE
GB-110-021X,022X	AMMONIA/AIR MIXING FANS (FUTURE)	ABB-CE
	AREA 115	
	STEAM SYSTEM AND GENERATION	
EA-115-061	CYCLE LP FEED WATER HEATER	EPC CONTRACTOR
FA-115-041	HRSG CONTINUOUS BLOWDOWN TANK	EPC CONTRACTOR
FA-115-051	ATOMOSPHERIC BLOWDOWN TANK	EPC CONTRACTOR

TABLE 11
EQUIPMENT LIST (CONTINUED)

EQUIP NO	DESCRIPTION	RESPONSIBILITY
GA-115-011,012	CONDENSATE BOOSTER PUMPS	EPC CONTRACTOR
GA-115-031,032	HP BOILER FEEDWATER PUMPS	EPC CONTRACTOR
PA-115-011	STEAM TURBINE GENERATOR PACKAGE	EPC CONTRACTOR
EA-115-011X,012X	STG LUBE OIL COOLERS	EPC CONTRACTOR
EA-115-021X,022X	GENERATOR AIR COOLERS	EPC CONTRACTOR
EA-115-031X	GLAND STEAM CONDENSER	EPC CONTRACTOR
GA-115-041X	SHAFT DRIVEN LUBE OIL PUMP	EPC CONTRACTOR
GA-115-042X	A.C. MOTOR DRIVEN LUBE OIL PUMP	EPC CONTRACTOR
GA-115-051X	D.C. MOTOR OIL LUBE OIL PUMP	EPC CONTRACTOR
GB-115-011X	GLAND STEAM CONDENSER EXHAUST FAN	EPC CONTRACTOR
GE-115-011X	SYNCHRONOUS GENERATOR	EPC CONTRACTOR
PA-115-021	CONDENSATE CHEMICAL DOSING PACKAGE	EPC CONTRACTOR
FA-115-011X	HYDRAZINE MIXING TANK	EPC CONTRACTOR
FA-115-021X	MORPHALINE MIXING TANK	EPC CONTRACTOR
FA-115-031X	PHOSPHATE MIXING TANK	EPC CONTRACTOR
GA-115-061X,062X	HYDRAZINE DOSING PUMPS	EPC CONTRACTOR
GA-115-071X,072X	MORPHALINE DOSING PUMPS	EPC CONTRACTOR
GA-115-081X,082X	H.P. PHOSPHATE DOSING PUMPS	EPC CONTRACTOR
GA-115-101X	HYDRAZINE TRANFER PUMP	EPC CONTRACTOR
GA-115-111X	MORPHALINE TRANSFER PUMP	EPC CONTRACTOR
GA-115-121X	PHOSPHATE TRANSFER PUMP	EPC CONTRACTOR
GD-115-011X	HYDRAZINE TANK MIXER	EPC CONTRACTOR
GD-115-021X	MORPHALINE TANK MIXER	EPC CONTRACTOR
GD-115-031X	PHOSPHATE TANK MIXER	EPC CONTRACTOR
PA-115-031	STEAM/ WATER SAMPLING ANALYZER PACKAGE	EPC CONTRACTOR
EA-115-041X	SAMPLE COOLER NO. 1	EPC CONTRACTOR
EA-115-051X	SAMPLE COOLER NO. 2	EPC CONTRACTOR
PA-115-041	H. P. STEAM TURBINE BYPASS SYSTEM	EPC CONTRACTOR

AREA 120
GAS EXHAUST STACK

CA-120-011	HEAT RECOVERY STEAM GENERATOR STACK	EPC CONTRACTOR
PA-120-011	CONTINUOUS EMISSIONS MONITORING SYSTEM	EPC CONTRACTOR

AREA 145
DEMINERALIZED WATER TREATMENT

FB-145-011	DEMINERALIZED WATER STORAGE TANK	EPC CONTRACTOR
FB-145-021	CONDENSATE STORAGE TANK	EPC CONTRACTOR
FB-145-031	DEMINERALIZED SYSTEM FEED H2O TANK	EPC CONTRACTOR
GA-145-011,012	DEMINERALIZER SYSTEM MAKEUP WATER FEED PUMPS	EPC CONTRACTOR
GA-145-021,022	CONDENSATE TRANSFER PUMPS	EPC CONTRACTOR
GA-145-031,032	BACKWASH AND DILUTION WATER PUMPS	EPC CONTRACTOR
PA-145-011	DEMINERALIZED WATER TREATMENT PACKAGE	EPC CONTRACTOR

TABLE 11
EQUIPMENT LIST (CONTINUED)

EQUIP NO	DESCRIPTION	RESPONSIBILITY
EA-145-011X	CAUSTIC DILUTION WATER HEATER	EPC CONTRACTOR
FB-145-041X	ACID DAY TANK	EPC CONTRACTOR
FB-145-051X	CAUSTIC DAY TANK	EPC CONTRACTOR
FB-145-061X	BISULFITE STORAGE TANK	EPC CONTRACTOR
FB-145-071X	REVERSE OSMOSIS (R.O.) CLEANING SOLUTION TANK	EPC CONTRACTOR
FB-145-081X	PERMANGANATE SOLUTION TANK	EPC CONTRACTOR
FB-145-091X	R.O. FEED TANK	EPC CONTRACTOR
FD-145-011X,012X	MULTIMEDIA FILTERS	EPC CONTRACTOR
FD-145-021X,022X	5 MICRON GUARD FILTERS	EPC CONTRACTOR
FD-145-031X,032X	REVERSE OSMOSIS UNITS	EPC CONTRACTOR
FG-145-021X	ANION RESIN TRAPS	EPC CONTRACTOR
FG-145-011X	CATION RESIN TRAPS	EPC CONTRACTOR
FG-145-031X	MIXED BED RESIN TRAPS	EPC CONTRACTOR
FO-145-011X	CATION EXCHANGE VESSELS	EPC CONTRACTOR
FO-145-021X	ANION EXCHANGE VESSELS	EPC CONTRACTOR
FO-145-031X	MIXED BED EXCHANGE VESSELS	EPC CONTRACTOR
GA-145-041X,042X	DEMINERALIZER CAUSTIC FEED PUMPS	EPC CONTRACTOR
GA-145-051X,052X	DEMINERALIZER ACID FEED PUMPS	EPC CONTRACTOR
GA-145-061X,062X	NEUTRALIZATION ACID FEED PUMPS	EPC CONTRACTOR
GA-145-071X,072X	NEUTRALIZATION CAUSTIC FEED PUMPS	EPC CONTRACTOR
GA-145-081X,082X	BISULFITE FEED PUMPS	EPC CONTRACTOR
GA-145-091X,092X	ACID FEED PUMPS	EPC CONTRACTOR
GA-145-101X,102X	R.O. FEED PUMPS	EPC CONTRACTOR
GA-145-111X,112X	R.O. BACKWASH WATER PUMPS	EPC CONTRACTOR
GA-145-121X,122X	PERMANGANATE FEED PUMPS	EPC CONTRACTOR
GA-145-131X,132X	MULTIMEDIA FILTER BACKWASH PUMPS	EPC CONTRACTOR
GA-145-141X,142X	ANTISCALANT FEED PUMPS	EPC CONTRACTOR
GA-145-011	BISULFATE MIXER	EPC CONTRACTOR
GA-145-021	ANTISCALANT MIXER	EPC CONTRACTOR
GA-145-031	RO CLEANING SOLUTION FILTER	EPC CONTRACTOR

AREA 150
CONDENSATE POLISHING

PA-150-011	CONDENSATE POLISHER TREATMENT PACKAGE	EPC CONTRACTOR
FG-150-011X,012X	MIXED BED POLISHER RESIN TRAPS	EPC CONTRACTOR
FO-150-011X,012X	MIXED BED CONDENSATE POLISHERS	EPC CONTRACTOR
GA-150-011X,012X	POLISHER CAUSTIC REGENERATION PUMPS	EPC CONTRACTOR
GA-150-021X,022X	POLISHER ACID REGENERATION PUMPS	EPC CONTRACTOR

AREA 160
CIRCULATING WATER SYSTEM

GA-160-011,012	CIRCULATING WATER PUMPS	EPC CONTRACTOR
GA-160-021,022	AUXILIARY COOLING WATER PUMPS	EPC CONTRACTOR

TABLE 11

EQUIPMENT LIST (CONTINUED)

EQUIP NO	DESCRIPTION	RESPONSIBILITY
PA-160-011	STEAM SURFACE CONDENSER PACKAGE	EPC CONTRACTOR
EA-160-011X	STEAM SURFACE CONDENSER	EPC CONTRACTOR
EA-160-021X	FIRST INTERCONDENSOR	EPC CONTRACTOR
EA-160-031X	SECOND INTERCONDENSER & AFTERCONDENSER	EPC CONTRACTOR
EE-160-011X,012X	DEAERATOR STEAM JET EJECTORS	EPC CONTRACTOR
EE-160-021X,022X	FIRST STAGE STEAM JET EJECTORS	EPC CONTRACTOR
EE-160-031X,032X	SECOND STAGE STEAM JET EJECTORS	EPC CONTRACTOR
EE-160-041X,042X	THIRD STAGE STEAM JET EJECTORS	EPC CONTRACTOR
EG-160-011X	VACUUM DEAERATOR	EPC CONTRACTOR

AREA 95

WASTEWATER PRETREATMENT SYSTEM

EQUIP NO	DESCRIPTION	RESPONSIBILITY
AD-95-011	NEUTRALIZATION PIT	EPC CONTRACTOR
AD-95-031	CHEMICAL SPILLAGE SUMP	EPC CONTRACTOR
AD-95-041	SANITARY LIFT STATION	EPC CONTRACTOR
AD-95-051	SULFURIC ACID AREA SUMP	EPC CONTRACTOR
AD-95-061	TRANSFORMER AREA SUMP	EPC CONTRACTOR
AD-95-071	CPI OILY WATER SEPARATOR EFFLUENT SUMP	EPC CONTRACTOR
AD-95-081	GASIFIER AREA SUMP	EPC CONTRACTOR
AD-95-091	DIESEL FIREWATER PUMP AREA SUMP	EPC CONTRACTOR
AD-95-101	CRUSHER HOUSE SUMP	EPC CONTRACTOR
AD-95-111	TURBINE AREA SUMP	EPC CONTRACTOR
AD-95-121	COAL PILE RUNOFF POND	EPC CONTRACTOR
AD-95-131	COAL PILE RUNOFF EFFLUENT SUMP	EPC CONTRACTOR
AD-95-141	TURBINE AREA SANITARY LIFT STATION	EPC CONTRACTOR
AD-95-151	COAL PIPE RUNOFF POND INLET BOX	EPC CONTRACTOR
AD-95-161	NEW LAKESIDE STORMWATER SUMP	EPC CONTRACTOR
BG-95-011	CPI OILY WATER SEPARATOR	EPC CONTRACTOR
EE-95-011	CAUSTIC TANK HEATER	EPC CONTRACTOR
EE-95-021	ACID TANK HEATER	EPC CONTRACTOR
FB-95-011	CAUSTIC STORAGE TANK	EPC CONTRACTOR
FB-95-012	ACID STORAGE TANK	EPC CONTRACTOR
GA-95-011,012	NEUTRALIZED EFFLUENT TRANSFER PUMP	EPC CONTRACTOR
GA-95-021,022	GAS TURBINE AREA SUMP PUMP	EPC CONTRACTOR
GA-95-031,032	STEAM TURBINE AREA SUMP PUMP	EPC CONTRACTOR
GA-95-051,052	COAL PILE RUN-OFF POND EFFLUENT TRANSFER PUMP	EPC CONTRACTOR
GA-95-071,072	SANITARY LIFT STATION PUMP	EPC CONTRACTOR
GA-95-121	CAUSTIC TRANSFER PUMP	EPC CONTRACTOR
GA-95-131	ACID TRANSFER PUMP	EPC CONTRACTOR
GA-95-141,142	NEUTRALIZATION PIT RECIRCULATION PUMP	EPC CONTRACTOR
GA-95-151,152	TRANSFORMER AREA SUMP PUMP	EPC CONTRACTOR
GA-95-161,162	PORTABLE OIL PUMP	EPC CONTRACTOR
GA-95-171,172	CPI OILY WATER SEPARATOR EFFLUENT	EPC CONTRACTOR

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Table 12
EQUIPMENT DATA SHEETS

NUMBER	EQUIPMENT
FR 20 11	PC STREAM SPLITTER
GB 20 11	MILL FAN
GB 20 21	MILL ID FAN
JD 20 11	PC TRANSPORT CONVEYOR
PA 20 11	PC KINETIC EXTRUDER
PS 30 11	GASIFIER SLAG GRINDER
PW 20 11	PC COAL MILL
FA 45 11	SLAG LOCKHOPPER
FA 30 21	GASIFIER SLAG TANK
FA 35 11	CHAR SEAL HOPPER
FC 35 11	CHAR PRIMARY CYCLONE
FD 35 11	CHAR REMOVAL BAGHOUSE
FH 35 21	CHAR TRANSPORT SCREW
FH 35 31	CHAR ROTARY VALVES
FH 35 61	PRIMARY CYCLONE CHAR CONTROL VALVE
BH 40 11	WARM-UP BYPASS DESUPERHEATER
EC 40 11	CHAR SPRAY COOLER
EG 40 21	CHAR RECEIVING BIN VENT EDUCTOR
FA 40 11	CHAR FEED BIN
FA 40 21	CHAR LOCKHOPPERS
FA 40 31	CHAR RECEIVING BIN
FH 40 31	CHAR FLOW CONTROL VALVE ELEVATION
FR 40 11	CHAR STREAM SPLITTER ELEVATION
FR 40 21	CHAR PICK-UP "T" ELEVATION
EA 45 11	SLAG WATER COOLER
GA 20 21	COAL MILL HEATER CONDENSATE PUMP
EC 20 31	COAL MILL HEATER #2
EG 20 21	PC COAL KINETIC EXTRUDER VENT EDUCTOR
EC 20 21	COAL MILL HEATER #1
FA 20 11	PULVERIZED COAL FEED BIN
FA 20 21	PULVERIZED COAL LOCKHOPPERS
FA 20 31	COAL MILL HEATER #2 CONDENSATE POT
FA 20 51	OVERSIZE COAL COLLECTION TANK
FA 20 61	COAL EXTRUDER BIN
FC 20 11	PULVERIZED COAL CYCLONE
FD 20 21	PULVERIZED COAL BAGHOUSE
FE 20 11	PULVERIZED COAL RECEIVING BIN
FE 20 21	PULVERIZER COAL KINETIC EXTRUDER FEED
FH 20 41	PC TRANSPORT CONVEYOR FEEDER
FH 20 51	PC CYCLONE DISCHARGE VALVE
FH 20 71	PC SCREEN FEEDER
FH 20 81	PC FLOW CONTROL VALVE
FH 20 91	RAW COAL GRAVIMETRIC FEEDER
GA 45 31	SLAG BATH CIRCULATION PUMPS
FL 20 11	PC SCREEN
FR 20 12	PC STREAM SPLITTER
FR 20 21	PC PICK-UP "T"

vii) Commissioning/Start-up/Operation/Maintenance Plans

A series of documents concerning maintenance philosophy, commissioning, start-up and normal operation for the Springfield Project were put together to help with the cost estimation for the plant. In the commissioning and start-up phase, the maintenance requirements will be higher than normal due to a much heavier workload that comes from flushing, cleaning and blowing lines, removing valves, installing spool pieces and blinds, and the problems associated with putting new equipment in service. Contract maintenance is suggested for the three phases mentioned to avoid a higher cost.

The term "Initial Operations" is used to describe the entire process of pre-commissioning, commissioning, initial start-up, steady production and performance testing of a plant. The Initial Operations Activities includes a list of duties and responsibilities of the team. It also includes estimated man-months that each job position will require. The purpose of this duty is to see if every position is absolutely necessary and if the time they are needed for the job is correct in order to avoid a higher cost than is necessary.

The commissioning and start-up requires the following services: mechanical completion by test systems, scope of services for start-up and technical services, services provided by Initial Operations Group, method of test system preparation, punch and checkout techniques, tower and vessel inspection procedure.

The final consideration is the client operating staff. This is a plan based on operation of the facility around the clock with the personnel working eight hour shifts. For the combined cycle operation there is a total of thirteen people that would remain until the commencement and start-up activities for the gasification and balance of the plant. A total of twenty-nine would be needed for normal operation for the entire facility .

viii) Test Plans

A test plan for performance evaluation testing at the plant was developed. The test program described in this plan was designed to achieve two objectives, first to provide the information required to set up and to optimize the operation of the facility and secondly to characterize the system response to various operating parameters. These two objectives were broken down into three phases. Phase one addresses the first main objective of set up and optimization of the system. Phases two and three address the second main objective. Phase two covers the characterization of the performance at equilibrium conditions and phase three covers characterization of the dynamic operation of the facility.

Some of the tests include pressure and temperature measurements of instrumentation. Also there are gas analyses and sample collections. Assumptions for the testing and information regarding the purchaser supplied services are included in the test plan. The purpose of the test plan is to identify any problems that may arise and come up with a plan to control any such occurrences.

ix) Cost Estimate

In arriving at the detailed cost estimate for this project the combined technical and commercial expertise from both Duke Engineering and Services and Combustion Engineering were utilized. Table 11 delineates the major equipment by area classification and assigns the estimating and design responsibility.

Detailed engineering selections and drawings were produced for all major components, systems and sub-systems to facilitate optimum price development both internally and externally.

Firm price quotations were requested from a minimum of three vendors for each significant commodity which make up the entire plant scope. These quotations were reviewed in detail by CE and DESI for technical and commercial completeness.

Takeoffs from contract quality drawings were made to quantify interstage piping, instrumentation, valving, power and control wiring, conduit, platforms, walkways, building siding, support structures, concrete work, insulation and lagging.

Heavy structural fabricators were involved in the pricing of the major components of the gasification plant (e.g. gasifier, heat exchanger pressure vessels, steam drum, coal and char receiving bins/lockhoppers, steam turbine, heat recovery steam generator, etc.) to ensure current labor and material costs, as well as optimum designs, were reflected in the pricing.

As part of the process of generating a new project estimate, Utility Engineering of Southwestern Public Service Company was retained at CE's expense to provide an independent analysis of the engineering and estimating efforts of Duke Engineering and Services. As part of this review, a drawing of the steam and water cycle was created for the Budget Period 2 cycle design as created by LCI and a second drawing of the cycle design as priced by DESI. The second drawing differs from the first by the deletion of the second intercooler and after condenser, the substitution of a conventional deaerator for the vacuum deaerator, deletion of the condensate polisher and the deletion of the liquid nitrogen storage system. The cycle which was priced was the second design.

The vacuum deaerator is more expensive than the conventional deaerator but its use results in a more efficient cycle. Given the size of this plant, the budgetary constraints and the intended use, it was decided that the increase in efficiency was not justified and the conventional deaerator was adopted.

The second intercooler and after condenser was originally included for the same reasons as the vacuum deaerator and deleted for the same reasons. This heat exchanger would see limited use and could not be justified for this facility.

The operating pressure of the steam cycle is 1250 psig. At this pressure, normal boiler feedwater treatment is a mixed bed demineralizer using acid and caustic treatment. A condensate polisher is not necessary. As part of the cost reduction program, the condensate polishing system was eliminated.

The liquid nitrogen storage system was originally proposed during the conceptual engineering of Budget Period 1. The storage tank would have been filled by trucks delivering to the site. After the quantity of nitrogen needed for operation was calculated, truck delivery did not appear to be a viable alternate. A nitrogen plant, owned and operated by an outside vendor but located on the facility property, was found to be preferable and was added to the project. There are not interconnects to the steam cycle because the nitrogen will be piped as a gas rather than as a liquid.

Vendor and in-house cost databases were examined with respect to determining pricing relevance to similar designs/materials selection criteria.

Contingent costs were substantially reduced or eliminated; economies of scale, while reflected in the pricing did not positively impact the overall cost of this project.

Construction Labor costs to dismantle existing equipment and erect the new systems/components were based on single shift straight time, 40 hour week and local union labor composite costs. The optimum nature of the total construction price reflects the merging of the quality of the CE discrete design and drawing data to the construction estimating expertise of Duke Engineering and Services. Facilitating the completeness and accuracy of the total construction price was the rather comprehensive analysis of the local site labor conditions which was performed by J. A. Jones.

The site definitely adversely impacted the overall cost of this plant. Especially with respect to those <u>added</u> costs for:

- Supplying and erecting the natural gas supply line into the site;
- Re-constructing the abandoned rail line(s) into the site;
- Utilizing the existing boiler building
- Inability to use existing steam turbine
- Incorporating a steam turbine bypass
- Electrical transmission equipment/switchgear beyond the primary terminals of the transformer.
- Dismantling and re-arrangement costs associated with integrating the <u>new</u> systems/components with the existing systems/components.

x) Cost Reduction Studies

A cost reduction study was undertaken with the intention of identifying areas which may be able to significantly impact the total costs of the plant. A list of 55 items was developed and the cost impact for each item was estimated. The problem with many of the suggestions was that the savings in capital cost was offset by penalties in plant heat rate which increases operating costs. Some of the items affected the safety or reliability of the plant and a decision had to be made whether the savings were justified.

The first attempt at cost cutting was successful, however, by reducing the capacity of some equipment which had been originally sized more conservatively than necessary. This capacity reduction was compatible with the selected design conditions described above. The difference in cost was enhanced by the effects on the plant arrangement due to a reduction in size of some equipment.

VII . Results and Conclusions

The preliminary design of the CE IGCC Repowering project was completed and a cost estimate was generated. This is the first time that a cost estimate of this system has been done to this level of detail. The cost results were higher than were expected. However this estimate is based on a preliminary design.

There are several reasons for these results and the cost numbers should not be construed as final. The reasons include such factors as system capacity, site limitations, complexity of the preliminary design, and first of a kind systems. The capacity factor includes fixed costs that are associated with engineering a plant which would be the same for larger plants. Therefore a larger plant would be expected to give lower per kilowatt costs. Similarly, the fact that this plant is being designed as a first of a kind plant with many systems being designed from scratch adds costs. The site requirements definitely affected the design of the plant which in turn affected costs. The site requirements also impose costs which are not normally considered in the scope of a commercial plant. The complexity of the preliminary design also has an affect. The preliminary design was estimated for the first time with material take offs, detailed process flow diagrams, and piping and instrumentation diagrams. After this cost estimate, the preliminary design can be reviewed and re-evaluated.

The next step for this process is to take the information generated by the preliminary design and cost estimate and to re-engineer the system and process for cost. This is part of the normal design process evolution. As more detailed and accurate information becomes available the cost estimate is updated.