1 OF 1

**CE IGCC Repowering Project
Clean Coal II Project**

**Annual Report
January 1, 1992 - December 31, 1992**

December 1993

Work Performed Under Contract No.: DE-FC21-90MC26308

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

**By
Combustion Engineering, Inc.
Windsor, Connecticut**

MASTER

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CE IGCC REPOWERING PROJECT 1992 ANNUAL TECHNICAL REPORT

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ABBREVIATIONS

ABB	Asea Brown Boveri
ABB-ES	ABB Environmental Services
AFD	approved for design
BACT	Best Available Control Technology
BCAC	booster compressor air cooler
BP1	Budget Period 1
BP2	Budget Period 2
BP3	Budget Period 3
CE	Combustion Engineering
CWL&P	City, Water, Light, and Power
DOE	Department of Energy
EA	Environmental Assessment
EMP	Environmental Monitoring Plan
EMPO	Environmental Monitoring Plan Outline
FONSI	Finding Of No Significant Impact
GE	General Electric
GEESI	General Electric Environmental Systems Inc.
GT	gas turbine
HAZOP	Hazard and Operability
HGCU	Hot Gas Clean Up
HHV	higher heating value
HRSG	heat recovery steam generator
HTSH	high temperature super heater
ID	inside diameter
IEPA	Illinois Environmental Protection Agency
IGCC	integrated gasification combined cycle
KDL	Kreisinger Development Laboratory
kW	kilowatt
LBG	low BTU gas
LCI	Lummus Crest International
LPFWH	low pressure feed water heater
LTSH	low temperature super heater
MAH	mill air heater
MCR	maximum continuous rating
METC	Morgantown Energy Technology Center
MFD	material flow diagram
MW	megawatts
NEPA	National Environmental Policy Act
NFPA	National Fire Protection Authority
NPDES	National Pollution Discharge Elimination System
NPHR	net plant heat rate
OD	outside diameter
PEP	Project Evaluation Plan
PFD	process flow diagram
PHA	Preliminary Hazard Analysis
PMP	Project Management Plan
PON	Program Opportunity Notice
PSD	Prevention of Significant Deterioration
PSIA	pounds per square inch absolute
P&ID	pipng and instrumentation diagram
SGC	syngas cooler
SMSD	Springfield Metro Sanitary District
ST	steam turbine
WBS	Work Breakdown Structure

I EXECUTIVE SUMMARY

CE is participating in a \$270 million coal gasification combined cycle repowering project that will provide a nominal 60 MW of electricity to City, Water, light and Power (CWL&P) in Springfield, Illinois. The IGCC system will consist 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 in the second budget period of five. The major activities during this budget period are:

- 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.

The Project Management Plan was updated. The conceptual design of the plant was completed and a cost and schedule baseline for the project was established previously 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 are continuing. At the end of 1992 the major activities remaining for Budget Period two is to finish the cost estimate and complete the Continuation Request Documents.

II INTRODUCTION

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

III PROJECT DESCRIPTION

The IGCC system will consist 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) will be the site for this project. The result of repowering will be an IGCC power plant with low environmental emissions and high net plant efficiency. The repowering will increase 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 will be 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 will fund the rest.

FIGURE 1

Lakeside Photo

FIGURE 2

Simplified IGCC

The IGCC will include CE's slagging, entrained-flow, gasifier operating in a pressurized mode and using air as the oxidant. The hot gas will be cleaned of particulate matter (char) which is recycled back to the gasifier. After particulate removal, the product gas will be 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 ferrite system downstream of the gasifier. CE intends to use the General Electric (GE) moving bed, zinc ferrite sulfur removal system currently being piloted by GE Environmental Systems, Inc. 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 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 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 will be 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 in Budget Period 2. This Budget Period includes the following:

- 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 that was accomplished during Budget Period 1 was used to develop a more detailed series of process flow diagrams 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. This activity has shown to require more time than was originally estimated and a request has been made to extend Budget Period 2 into the first part of 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 permitting activities will continue into 1993.

B) Work Breakdown Structure (WBS)

The Work Breakdown Structure for the Project is shown in Figure 3.

C) 1992 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. At the end of 1992, the cost estimate is being developed. 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.

WORK BREAKDOWN STRUCTURE

- 1.1 POST-SELECTION ACTIVITIES
- 1.2 COMMERCIAL PLANT DESIGN
- 1.3 PERMITTING & ENVIRON. ACTIVITIES
- 1.4 PLANT DEFINITION & BASIC ENG.
- 1.5 DESIGN SUPPORT
- 1.6 PROJECT PLANS & AGREEMENTS
- 1.7 DETAILED ENGINEERING
- 1.8 PROCUREMENT DOCUMENTS
- 1.9 TECHNICAL REPORTS
- 1.10 PROJ. MANAGEMENT, ACCT., & REPORTS
- 1.11 COWLAP PHASE I R & R

- 2.1 PURCHASED EQUIPMENT & MATERIALS
- 2.2 SHOP FABRICATION
- 2.3 TRANSPORTATION
- 2.4 CONSTRUCTION
- 2.5 AS-BUILT DRAWINGS UPDATE
- 2.6 MANUALS & PROCEDURES
- 2.7 O & M STAFFING & TRAINING
- 2.8 CHECKOUT, STARTUP, MOD'S & ACCEPTANCE
- 2.9 TECHNICAL REPORTS
- 2.10 PROJ. MANAGEMENT, ACCT., & REPORTS
- 2.11 COWLAP PHASE II R & R

- 3.1 PROCUREMENT
- 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

FIGURE 3

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.

The environmental activities centered on the BACT document which was submitted to IEPA in December 1992.

A list of deliverables for budget period 2 is given in Table 1. The first deliverable listed is the EA/FONSI. The Finding of No Significant Impact (FONSI) was issued by the DOE in March of 1992.

The Project Management Plan (PMP) was submitted in February and updated in November. The Project Evaluation Plan (PEP) was submitted in February and issued in April. The 1991 Annual Technical Report was submitted originally in January and after several revisions finally issued in November. A paper was presented at the 1992 Gasification Conference in September. Five other presentations were made at various conferences throughout 1992. The rest of the deliverables on the list are scheduled to be completed in the first part of 1993.

Table 1

Deliverables	Date
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	April, 1993
Design Support Topical Reports	April, 1993
HGCU Topical Report	March, 1993
Gasifier Data Report	December, 1993
BP2 Design Review Package	April, 1993
Project Evaluation Report	April, 1993
Continuation Application	April, 1993
Major Project Evaluation	April, 1993
Public Design Report	June, 1993
1992 Annual Report	February, 1993

D) Work to be Completed During 1993

The work scheduled for 1993 is to complete the deliverables for BP2 as listed in Table 1. This work includes the finishing of the cost estimate and preparing the Continuation Request. If the Continuation Request is granted, work will proceed into BP3. The work items for BP3 in 1993 will be established as part of the Continuation Request documents.

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 ABB 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 Innovative Clean Coal Technology program, DOE identified certain requirements for monitoring completed projects to more thoroughly document their environmental affects. 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. Preparation of the EMP for submittal to DOE is currently scheduled for the first quarter of 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 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 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 timeframes 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 affects 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 is now underway and will be completed during the first quarter of 1993. All of the modeling results will be part of the PSD application that will be 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 will include application forms, the BACT demonstration and the modeling results will be 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) Plans for Other Environmental Permits

Applications for remaining environmental permits will be prepared during the first quarter of 1993 including:

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) 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. Because this study was done before equipment selection, conservative values for auxiliary power were used. These conservative values are shown in the table. 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 turbine inlet temperature constant. 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 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.

**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)	<u>64040</u>	<u>54857</u>	<u>24234</u>	<u>71579</u>	<u>59930</u>	<u>25800</u>	<u>83450</u>	<u>67862</u>	<u>27731</u>
Plant Auxiliary Power	(kW)	8433	7746	4833	9017	8177	5007	10062	8953	5287
Net Plant Output	(kW)	<u>55607</u>	<u>47111</u>	<u>19401</u>	<u>62562</u>	<u>51753</u>	<u>20793</u>	<u>73388</u>	<u>58908</u>	<u>22444</u>
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)	<u>508.425</u>	<u>441.709</u>	<u>253.650</u>	<u>564.551</u>	<u>478.196</u>	<u>270.936</u>	<u>660.070</u>	<u>540.206</u>	<u>297.072</u>
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

B) 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 of this IGCC plant. 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 deaerating 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 thru 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 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.

CONCEPTUAL STEAM CYCLE

FIGURE 4

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. Coal heating is required in order to avoid steam condensation on the pulverized coal. Steam is used for pressurization and fluidization of the coal in the lockhopper system and for transport of the coal to the gasifier in the fuel pipes.

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.

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.

CWL&P STEAM CYCLE PROGRAM FLOW CHART AND FILE STRUCTURE

FIGURE 5

C) 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

i) 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 of our 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.

ii) 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.

iii) 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.

iv) 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 a 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.

v) 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

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

The selected fluid for pressurizing, fluidizing, and transport of both the coal and char was steam.

vi) Process Steam Source Options

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 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.

vii) 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 HGCUS 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

<u>Proposed Cost Reduction Measure</u>	<u>Change to NPHR Btu/Kwhr</u>
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

It is clear that each of these changes would reduce the capital cost of the plant. However heat rate is also an important part of this demonstration project and, therefore, none of these changes were recommended.

viii) HRSG Performance Design

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.

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 LT 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 HT 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.

COAL PREPARATION SYSTEM

FIGURE 6

ix) Coal Preparation System Alternate

The coal preparation system for this plant consists 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 is 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 thru 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 thru 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 thru 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 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 PREPARATION SYSTEM

FIGURE 7

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.

x) 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. The base case is represented by the Approved for Design (AFD) material and energy balance.

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 thru the coal mill air heater #1 heat exchanger as the source for this

TABLE 6
NET PLANT HEAT RATE ALTERNATE CALCULATION

		BASE	ALT-1	ALT-2	ALT-3
		STEAM	N2	N2	N2
Coal Transport And LM Pressurization Fluid	(kW)	32550	32550	32550	32550
Combustion Turbine Generator Output	(kW)	36691	37164	38315	37147
Steam turbine Generator Output					
Gross Plant Output	(kW)	69241	69714	70865	69697
Plant Auxiliary Power	(kW)	8617	8501	8489	8451
Net Plant Output	(kW)	60624	61213	62376	61246
Coal Heat Input	(MM-Btu/hr HHV)	508.425	508.425	508.425	508.425
Natural Gas Heat Input (GT)	(MM-Btu/hr HHV)	0.000	0.000	0.000	0.000
Natural Gas Heat Input (HRSG)	(MM-Btu/hr HHV)	62.726	62.726	62.726	53.258
Natural Gas Heat Input (Mill System)	(MM-Btu/hr HHV)	0.000	0.000	12.937	12.937
Total Fuel Heat Input	(MM-Btu/hr HHV)	571.152	571.152	584.088	574.620
Net Plant Heat Rate	(Btu/kWhr)	9421	9331	9364	9382
Plant Thermal Efficiency	(Percent)	36.23	36.58	36.45	36.38

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.

Table 6 shows the comparison of these cases. This comparison shows power outputs from the gas turbine and steam turbine, fuel inputs from coal and natural gas, auxiliary power consumption estimates, and net plant heat rates. The net plant heat rate differentials between the cases are relatively insignificant. Alternates 1,2,3 require about 8300 lbm/hr of nitrogen at this MCR operating condition which represents a significant additional operating cost as compared to the base case. There are, however, capital cost differences for each of the alternatives as compared to the base case. Alternate 3 probably represents the lowest total plant capital cost although capital costs were not a part of this study and, therefore, were not estimated. The differences in total plant capital costs between these four cases are probably quite small relative to the total. Figure 8 shows a block flow diagram for Alternative 3 and Table 6 is the associated material and energy balance for this case.

D) 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 were 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 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.

OVERALL SYSTEM BLOCK FLOW DIAGRAM (ALT-3)

FIGURE 8

E) 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. - 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:

i) Coal Feed System

In the current design, raw coal discharges 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 two shell and tube heat exchangers in series located in the air duct upstream of the coal mill. The first heater uses hot condensate from the gasifier system, and the second heater uses saturated steam from the gasifier steam drum. 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 four ways to supply the four coal burner nozzles located at each firing elevation on the gasifier.

In December of 1992 the arrangement of the coal feed system began to be assembled and studied using PACE 3 dimensional CAD software. As a result, different space saving and cost cutting options are being studied. Under consideration is a hot gas generator in lieu of the condensate and steam air heaters.

ii) 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 point 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 Shell, MHI, and Inland Steel. Similar precedent for steam is very limited and not encouraging. 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.

iii) 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, ABB 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.

iv) 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 ratholing 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 ABB 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 ABB 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 ABB. The instrumentation necessary to support such an operation reliably has not yet been developed. As a result, ABB 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. ABB 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.

v) 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.

vi) 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.

vii) 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 super heated-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.

viii) Char Bagfilter Study

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, ABB 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 our application. Our 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 Brilliant, Ohio. ABB has also asked several bagfilter companies to propose test programs to demonstrate the use of their technology at high temperature and pressure. 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.

ix) Char Vessel Material Study

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.

OVERALL SYSTEM BLOCK FLOW DIAGRAM WITH STEAM TRANSPORT

LML
9/15/92

FIGURE 9

TABLE 7
NET PLANT HEAT RATE CALCULATION

		BASE
		<u>STEAM</u>
Coal Transport And LM Pressurization Fluid		
Combustion Turbine Generator Output	(kW)	32550
Steam turbine Generator Output	(kW)	36691
		<hr/>
Gross Plant Output	(kW)	69241
		<hr/>
Plant Auxiliary Power	(kW)	8617
		<hr/>
Net Plant Output	(kW)	60624
		<hr/>
Coal Heat Input	(MM-Btu/hr HHV)	508.425
Natural Gas Heat Input (GT)	(MM-Btu/hr HHV)	0.000
Natural Gas Heat Input (HRSG)	(MM-Btu/hr HHV)	62.726
Natural Gas Heat Input (Mill System)	(MM-Btu/hr HHV)	0.000
		<hr/>
Total Fuel Heat Input	(MM-Btu/hr HHV)	571.152
		<hr/>
Net Plant Heat Rate	(Btu/kWhr)	9421
Plant Thermal Efficiency	(Percent)	36.23

x) 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. ABB expects char testing to begin in Summer 1993.

xi) Hot Gas Clean Up Study

General Electric Environmental Systems, Inc. (GEESI) submitted a proposal for doing test work specific to the Springfield Project. ABB reviewed the test proposal and is waiting for a response to comments. Answers are expected in early 1993. In the meantime GEESI continues on 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.

F) 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, additional design requirements are imposed and others. 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 9 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 60 MW net output from the plant. This balance was used as one of the primary design points for the plant.

G) Process Flow Diagrams and Process Descriptions

Conceptual process flow diagrams (PFD's) were generated during BP1. Six PFD's for the gasifier island were produced. During BP2 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 8.

Table 8
PROCESS FLOW DIAGRAMS

<u>NUMBER</u>	<u>DESCRIPTION</u>
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
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 10 through 13. 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 10 through 13.

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.

An alternate coal feeding system which is being considered involves the use of a Kinetic Extruder, designed by MPG (now Penn Trading Co.) and Lockheed. This device would feed coal through the pressure barrier and into the feed bin.

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.

ABB CE IGCC Flow Diagram

ABB
ABEA BROWN BOYCE

FIGURE 10

Coal Preparation and Feed System

FIGURE 11

Char Recycle System

FIGURE 12

Sulfur Removal System

FIGURE 13

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.

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.

A sootblower system will be provided to clean all the water cooled bounding walls and the heat transfer surface in the heat exchanger. 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 GE. It is a sorbent system as developed by METC. The GE 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.

H) Piping and Instrumentation Diagrams

After completing the 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 9.

Table 9
PIPING & INSTRUMENTATION DIAGRAMS

<u>NUMBER</u>	<u>DESCRIPTION</u>
20006 A	COAL PULVERIZING SYSTEM SH1
20006 B	COAL PULVERIZING SYSTEM SH2
20006 C	COAL PULVERIZING SYSTEM SH3
20006 D	COAL PULVERIZING SYSTEM SH4
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

Table 9
PIPING & INSTRUMENTATION DIAGRAMS

<u>NUMBER</u>	<u>DESCRIPTION</u>
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

I) Metallurgical 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.

J) Equipment Data Sheets

An equipment list was identified from the AFD PFD's. 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 10 lists the equipment data sheets generated for this project.

Table 10
EQUIPMENT DATA SHEETS

<u>NUMBER</u>	<u>EQUIPMENT</u>
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

Table 10
EQUIPMENT DATA SHEETS

<u>NUMBER</u>	<u>EQUIPMENT</u>
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"

K) 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. Four elevations of future diagnostic water injection, 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. Steam is used in the coal feed system by an air heater and a coal heater. 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.

i) Syngas Cooler Performance Studies

One of the major components in the steam cycle is the Syngas Cooler (SGC). The design of this component is not as straight forward as some of the other more typical steam cycle components included in this cycle. The complexity of the SGC design is partially due to the relative uncertainty for some of the design parameters of this

component. Another complexity is due to the highly integrated design of this plant. With this high degree of integration, changes to the performance of one component may effect the performance or design requirements of other components. Because of this component to component dependency, an individual component cannot be designed rigorously without integrating the design with the remainder of the cycle.

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 11 were changed over the indicated ranges to quantify the potential impacts to plant performance.

TABLE 11
Syngas Cooler Performance Sensitivity Study

<u>Sensitivity Variable</u>	<u>Units</u>	<u>Variable Range</u>
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.

ii) Initial Mechanical Design

This effort established a base design from which final engineering would begin. Sufficient system layout work was completed to establish a definite schedule and cost. The schedule was for both engineering and shop fabrication. This schedule determined the best fit for the resources of both the shop and the engineering departments involved. In addition, a schedule for LCI's interface requirements was established. These requirements include information exchange, scope split, physical geometry definition, performance requirements, and their construction schedules. The location and types of instrumentation required were determined.

Numerous trade-off studies were performed to resolve technical issues for the base design. With this type of a first generation design the quality and number of support drawings were developed in more detail than those required to initiate a typical pulverized boiler final design.

A final engineering schedule was established to meet the on-site delivery dates. This schedule established the critical path items, manpower requirements and internal deliverables. This schedule identified the following types of releases: engineering, data, material and fabrication for all components.

A package of engineering data was assembled for pricing. Representatives of the CE shops were advised on cost reduction concepts as they reviewed the package. This information with feedback from a construction group was factored into the design.

Co-ordination with LCI was achieved through data sheets, exchange of engineering personnel and drawings. A package was prepared which included drawings and supporting information. The supporting information included performance requirements and physical location data for the gasifier and heat exchanger. The appropriate codes were reviewed to determine the scope split for power piping and for hydro testing. This established the scope split between CE and LCI for all interfaces.

iii) Arrangement Drawings

The general arrangement in side view is shown in Figure 14, 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.

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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. Also shown is a removal area for a possible future crossover soot blower installation.

The general arrangement Figure 15, DWG 16990-1E0002 shows the plan relationship of the steam drum. An elevation section shows the components of a controlled circulation system. These components are a downcomer, suction manifold, two circulation pumps with their suction and discharge valves, a pump bypass system, and the discharge manifold.

The cross sectional view of the gasifier is shown in Figure 16, DWG 16990- 1E0101. The pressure vessel has a lower flange to which the slag grinder housing attaches to, a head and a horizontal 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 of the water seal. This connection is part of 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 a 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 17, 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.

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 terminal 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

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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.

iv) 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.

v) 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 for back

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.

vi) 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.

vii) 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 exchanges 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.

viii) 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.

A mechanical shaft seal circulation pump was selected. A circulation pump by-pass system was incorporated. The by-pass system would be automatically used during loss of circulation pump power events. A preliminary investigation into natural circulation was performed with optimistic results.

ix) 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 where tight spacing can be used and tightly spaced vertical surface was selected. This type of surface operates relatively clean and there is no requirement for sootblowing.

The superheat 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.

x) 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.

xi) 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.

xii) 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 ABB/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 ABB/CE.

The hydraulic motor has an auxiliary power unit and controls.

xiii) Gasifier and Syngas Cooler Cost Estimate

The cost estimate for the gasifier and SGC was assembled with pricing provided by the CE shop in Chattanooga, Tennessee, CE in Windsor and Lummus Crest. A comprehensive package was prepared for the CE shop. Included were sixteen drawings, eight sketches, and fourteen documents. This package defined the pressure shells, pressure parts and most of the internal components. The pressure parts include tubing, headers, piping, and the steam drum. Typical components priced in Windsor included: controls, slag grinder, firing system, support guides and struts, circulation pumps, and expansion joints. Typical Components priced by Lummus Crest include: auxiliary piping, valves, support steel, insulation and lagging, and field erection.

L) Balance of Plant

i) Coal Handling

Coal Delivery and Handling System PFDs were developed by ABB Lummus Crest and issued for client approval in June. Client approval was received in November, and the PFDs were subsequently issued in November as Approved For Design (AFD) documents.

Following issue of the AFD PFDs, work commenced on the development of equipment data sheets for the coal handling equipment. The procurement strategy for this equipment is to have one vendor supply all of the equipment as a package system.

The plan for 1993 was to complete the equipment data sheets to AFD status and develop and issue a requisition to obtain competitive bids for this equipment. After receipt of the bids, ABB Lummus Crest would perform a technical and commercial evaluation and the successful vendor's pricing will be used in the updated cost estimate.

One area of concern was the increased cost of the current coal handling system versus the original concept. The current system includes a common coal pile area for both the gasifier and Lakeside II boilers 7 & 8, as well as a coal stacker. As the plot plan developed, it made sense from a space utilization standpoint to provide a common coal pile. As far as the addition of a coal stacker, this was a requirement that surfaced during the approval process of the conceptual plot plan. CWL&P required the coal stacker on the basis of their experiences at the Dallman Station. It significantly improves the operability of the coal handling system to include a stacker, and from this standpoint ABB Lummus Crest concurred with CWL&P.

ii) Slag Removal and Handling

The flowsheet and layout basis for slag collection and in-plant storage was the result of various comparison studies by ABB Lummus Crest, ABB Combustion Engineering, and CWL&P during Budget Period 1. It is important to note that the original project basis assumed that gasifier bottom slag would be sluiced to existing ash holding ponds on CWL&P property. This concept was rejected during Budget Period 1 due to future permitting concerns. Two alternates were then evaluated; 1) a hydraulic system and 2) a scraper conveyor concept utilizing an on site slag pile with frequent front end loading to trucks. Both alternatives required the gasifier slag to be trucked to an unidentified off-site location for landfill. As the lowest cost alternative, the scraper conveyor option was selected as the basis for Budget Period 2 cost estimates, layouts and basic engineering.

Gasifier slag is quenched in an water filled vessel internal to the gasifier pressure vessel then periodically removed using a single slag lockhopper system. In October 1992, the vessel capacity was increased in size to allow 4 hours holdup. The equipment arrangement and layout for the lower section of the gasifier and lockhopper was also revised. The lockhopper support system was changed by CE so that the vessel could be supported independently of the gasifier and be moved on rails from under the gasifier structure to permit inspection, and replacement of the gasifier water walls and other equipment tied to the gasifier.

ABB Lummus Crest developed the Piping and Instrument Diagram for the slag lockhopper system. The equipment specification covering the slag lockhopper was issued by ABB Lummus Crest for competitive bids in November 1992 and quotations received in December from 4 potential suppliers.

The Process Flow Diagram for the Slag Handling System was issued in November 1992. In December the Piping and Instrument Diagram was initiated. Process data sheets for the Slag Handling System were also completed in November.

iii) Sulfur Recovery

During Budget Period 2 sulfur recovery systems for the CE-IGCC Repowering Project consisted of hot gas desulfurization followed by conversion of sulfur rich regeneration off-gas to a marketable sulfuric acid.

Previously during Budget Period 1, ABB Lummus Crest evaluated several alternative combinations of process technology to determine the best fit for the CE-IGCC project in terms of capital and operating costs, technical maturity and viability and environmental performance. This evaluation, issued to Combustion Engineering and City Water, Light and Power in October 1991, recommended sulfuric acid production as the best fit to meet the project requirements. At that time both the hot gas desulfurization process (provided by General Electric Environmental System Inc.) and more conventional desulfurization technology (COS hydrolysis and ammonia removal followed by MDEA absorption of H_2S) were included in the plant basis of design with the latter as 'back-up contingency' in the event the former 'emerging' technology experienced operational problems. Sulfuric acid production not only was identified by ABB Lummus Crest as the best fit in combination with the two alternate sulfur removal systems but in particular was advantageous if considered only in combination with the hot gas desulfurization process.

As follow-up to the report in January 1992, ABB Lummus Crest provided marketing studies for sulfuric acid production which indicated favorable local midwestern outlets. Local sulfuric acid suppliers/distributors were also contacted to solicit possible business arrangements for the collection and resale of the byproduct sulfuric acid during the CE-IGCC project demonstration period. A promising response was received from G. S. Robbins and Co., Decatur, Illinois.

In March 1992, ABB-CE approved sulfuric acid production as the recommended sulfur recovery option for the project. CWL&P requested more time to make this key design basis decision.

In May 1992, ABB Lummus Crest arranged joint meetings with CE, GEESI and CWL&P at Monsanto Enviro-Chem Inc.'s offices in St. Louis, Missouri. Monsanto presented their background and experience as a leading supplier of sulfuric acid technology and related engineering, procurement and construction capabilities and answered questions and concerns raised by representatives of the project participants. The presentation was followed by a Monsanto arranged plant tour at American Cyanamid's sulfuric acid plant in Hannibal, MO.

In June 1992, CWL&P approved the ABB Lummus Crest recommendation to incorporate the sulfuric acid unit into the project definition.

Following the cost estimate submitted by ABB Combustion Engineering in July, 1992, cost reduction studies resulted in dropping the conventional sulfur removal 'backup' system from the basis of design.

During 1992, ABB Lummus Crest provided a factored cost estimate for conventional sulfur removal systems and coordinated and integrated the hot gas desulfurization process as provided by GEESI into the overall plant design.

With regard to conventional technology, in early 1992 it was decided to limit the scope of work associated with conventional sulfur removal facilities to preparation of a factored cost estimate and to provision of space on plot plans and gasifier structure layouts for "future installation" only. This strategy would minimize up front project capital expenditures while at the same time permit lower future costs should the hot gas desulfurization process require major modifications or replacement during demonstration. Subsequent to this decision ABB Lummus Crest developed equipment data sheets and prepared the factored cost estimate of the conventional sulfur removal facilities.

In August 1992, as part of the Cost Reduction Studies all requirements associated with conventional sulfur removal were deleted from the project scope.

In April 1992, CE completed a contractual agreement with GEESI for Budget Period 1 scope of supply on the Hot Gas Cleanup System. GEESI submitted their completed Budget Period 1 design package in September, 1992.

The GEESI Budget Period 1 package consisted of preliminary process flow diagrams, equipment conceptual data sheets, a suggested equipment layout and piping and instrument diagrams.

An order of magnitude cost estimate for the HGCU was provided by GEESI in June, 1992.

During preparation of the package ABB Lummus Crest and GEESI resolved certain interface issues including overall space requirements, regeneration air supply conditions and source, and off-gas battery limit conditions applicable to the sulfuric acid unit specification.

Major comments still to be resolved with GEESI at year end involved data sheets, equipment mechanical design conditions, P&ID inconsistencies with data sheets, analytical requirements and plant safety and operation details.

Following cost reduction studies in August and September 1992, which established a new plant design coal capacity, ABB Lummus Crest prepared and issued in October a comprehensive Request for Proposal to Monsanto EnviroChem Inc. and Lurgi Corporation to obtain competitive Lump Sum Turnkey Engineering, Procurement and Construction quotations for the sulfuric acid unit.

A proposal was received from Monsanto Enviro-Chem in two parts; 1) a technical definition including preliminary flow sheets, equipment definition, plot plan, operating requirements and basis for air permitting was received in November, 1992, and 2) a commercial proposal was received per request in mid-December 1992. A preliminary technical definition was received from LURGI in December.

As a result Monsanto Enviro-Chem's technical package was used as the basis for Lummus Crest Inc's basic engineering activities at the close of 1992. This included development of the P&ID acid unit interface drawing to coordinate the GEESI and Monsanto units and input into the preparation of BACT and air modeling documents developed by ABB-Environmental Services Inc. The overall plant layouts were also modified based on the Monsanto technical package.

ABB Lummus Crest completed the technical and commercial tabulation for Monsanto Enviro-Chem bid in January, 1993.

iv) Booster Compressor

The AFD data sheets for the booster compressor with the variable speed motor drive were developed by CE and jointly reviewed by ABB CE and ABB Lummus Crest and issued in October, 1992. The AFD data sheets for the booster compressor inlet cooler were issued by ABB Lummus Crest in November, 1992.

A major cost component of this system is the inclusion of a variable speed drive deemed necessary by CE and ABB Lummus Crest to meet goals for efficient operation at gasifier turndown.

The booster compressor PFD showing these pieces of equipment was issued "Approved for Design" in November, 1992.

A requisition for the booster compressor was issued in November, 1992. Bids were received and sent to engineering for bid tabulation on December 17, 1992. Bids were received from Dresser and Allis-Chalmers. Elliott chose not to bid.

A requisition for the booster compressor inlet cooler #1 was issued in November, 1992. Bids were received in January, 1993 from Shell and Tube Inc., Ohmstede Inc. and Hughes-Anderson Inc. Texas Metal Fabricating Co. did not bid. Bid tabulations will be initiated in 1993.

The air booster compressor P&ID was issued for screening in December, 1992. The air booster compressor lube oil system P&ID will be started after supplier drawings were received.

v) Gas Turbine

GE's July, 1991 technical proposal served as the starting point for developing a complete technical package that would serve as the basis for a purchase order from CWL&P to GE. At the time this process started, CWL&P anticipated issuing a purchase order in mid-summer of 1992.

In March 1992, LCI reviewed GE's technical proposal and transmitted those comments and clarifications to GE along with a request to schedule a GE/CWL&P/LCI/CE meeting in April 1992 to resolve the remaining technical issues and assess the commercial impacts of some of the requested changes.

A meeting was held in Springfield on April 9, 1992 with participants from LCI, GE and CWL&P. The meeting resulted in a few additional action items for each of the participants, primarily GE. After receiving the final pricing data from GE, LCI developed a spread-sheet of price adders and deducts and made recommendations to CWL&P regarding items that should or shouldn't be incorporated in the technical package. On May 4, 1992, CWL&P responded to the LCI fax with their final list of adders and deducts that were to be included or excluded from the technical package. This list was transmitted to GE to serve as the basis for an updated GE proposal scheduled to be issued in June 1992.

After issuing the updated proposal, a Design Finalization Meeting was held in Schenectady, New York, with participants from GE, LCI, CWL&P and CE. In GE terminology, the Design Finalization Meeting normally initiates the kickoff of a recently signed purchase order. Since this project had not progressed to the stage of issuing a purchase order, this meeting resulted in the identification of a GE project team and in addressing further technical clarifications. GE also committed to a preliminary drawing schedule which would support LCI cost estimate activities.

Based on the results of the Design Finalization Meeting and further clarifications from LCI and CWL&P, GE issued an updated technical proposal in July, 1992.

However, subsequent to the preliminary cost review, CWL&P decided to defer issuing a purchase order for the gas turbine.

GE did supply the basic arrangement and layout drawings LCI required to complete the plot plan work.

vi) Steam Turbine

Early in the year much discussion ensued regarding the selection of a cycle configuration to achieve the desired 60 MW net plant output at 95°F ambient conditions. Selection of a cycle configuration was necessary to properly size the steam turbine generator and commence with development of the specification and requisition for the turbine.

In late April 1992, LCI completed a cycle study consisting of 3 different modes of operation and presented it to CWL&P for their approval. On May 1, 1992, CWL&P transmitted their decision on the selection of an operating mode. This operating mode became the design basis for the cycle configuration. To achieve 60 MW net plant output at 95°F ambient conditions, the gas turbine would be base loaded on coal gas and the HRSG would be supplementary fired with natural gas.

This decision was needed to proceed with completion of the Combined Cycle Process Flow Diagram. This PFD was issued in early June and approval from CWL&P was

received on June 30, 1992. With an approved PFD LCI commenced on the development of a steam turbine generator specification and requisition.

On July 21, 1992, LCI submitted the steam turbine generator requisition to CWL&P for approval. However, subsequent to the cost review, CWL&P decided to defer the issuing of a purchase order for this equipment.

In October, LCI issued a requisition to six potential suppliers, received bids at the end of October, completed a technical evaluation of the proposals in December and commenced on the commercial evaluation of the bids. The LCI plan for 1993 was to complete the commercial evaluation and utilize the selected supplier's pricing and technical data in the updated cost estimate due in April.

vii) HRSG

The HRSG for this plant is a CE designed unit. Several iterations were carried out in the design of this component. The results of the cycle investigations mentioned earlier were used to come up with the final configuration. After the design basis was established, the arrangement of the HRSG was finalized and a cost estimate was made. The physical dimensions of the HRSG were established on a preliminary basis and this information was used in the plant arrangements generated. At the end of 1992, the detailed physical dimensions were not yet established pending the start of detail design.

viii) Plant Layouts

a) Gasifier Island

In 1992 ABB Lummus Crest Inc. 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 ABB Lummus Crest. These early layouts were upgraded as the following information and revisions were received by ABB Lummus Crest:

August 1992	Deleted requirements for future installation of conventional sulfur removal
September 1992	Received preliminary layouts, equipment data and P&IDs for Hot Gas Desulfurization from GEESI

LOOKING SOUTH-EAST!

LOOKING NORTH-WEST!

[illegible]

October 1992 Received Approved For Design Equipment Data Sheets for coal handling, feeding, char removal and recycle systems from ABB Combustion Engineering

November 1992 Received gasifier/heat exchanger dimensional, layout and maintenance requirements from ABB Combustion Engineering

December 1992 Developed for screening issue of Gasifier Island P&IDs

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 ABB Lummus Crest on a priority basis as the process data become available in October 1992. Competitive quotations were received in early December 1992 and technical evaluations initiated to select a single supplier.

At the close of 1992, 22 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 18 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 ABB Combustion Engineering and CWL&P and one option was selected as the design basis for Budget Period 2 work.

During 1992 ABB Lummus Crest concentrated work 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.

A chronology of the work performed is as follows:

May 1992 Issue of Building Location Grid Plan - Approved for Construction

June 1992 Initiated foundation and floor plans and sections-22 Drawings

- August 1992** Issued standards and details covering anchor bolts, paving, foundations, ladders, cages, handrails, stairs, grating, platform and vessel clips - 11 Drawings.
- October 1992** As part of the Cost Reduction Studies - Relooked at previous layout options and submitted recommendations to CWL&P. CWL&P chose to retain the original layout as the basis for the 1993 cost estimate.
- November 1992** Developed 32 architectural plans and elevations as basis for the 1993 cost estimate (70% complete).
- November 1992** Developed 32 steel framing and cross-section plans as basis for 1993 cost estimate (70% complete).

c) Overall Site Plot Plans

An overall conceptual site plan was developed by ABB Lummus Crest in 1992. The site plan, Dwg E-06851-00010A, was used in early 1992 as a basis for the factored cost estimate prepared by ABB Lummus Crest in April. The plan was continually updated as key information became available. In particular considerable input was developed by working closely with CWL&P with regard to the coal handling and receiving system, construction philosophy, sulfuric acid unit and electrical substation. Integrating traffic and roadway access for coal delivery and slag removal in relation to the existing Dallman and Lakeside facilities was an important accomplishment.

Figure 19 shows a conceptual plot plan of the site. Figure 20 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.

ix) CWL&P Interfaces

ABB Lummus Crest Inc. interfaced with CWL&P in a number of areas to establish a consistent design basis that would enable ABB Lummus Crest to proceed with the Budget Period 2 work. These areas included defining a split of work scope for the electrical system, defining the technical requirements and mapping out a procurement strategy for the gas turbine generator and steam turbine generator, defining coal handling requirements, finalizing the project design questionnaire, reviewing possible cost reduction measures for implementation and defining a ABB Lummus Crest/CWL&P interface strategy for completing the cost estimate.

Efforts began in December, 1991 to establish a split of work scope. A meeting was held among ABB Lummus Crest/CWL&P/Burns & McDonnell personnel to start the process on December 11, 1991. In February 1992, a basic agreement was reached. CWL&P's agent, Burns & McDonnell, would provide the design and the overall one-line

EXIST. STACK.

CE IGCC REPOWERING PROJECT
CONCEPTUAL PLOT PLAN
LOOKING NORTH 30 DEGREES EAST

FIGURE 20

11-19-92

diagram for the high voltage substation. This would be funded through CWL&P's renewal and replacement funds. ABB Lummus Crest would specify, procure and install the high voltage substation equipment utilizing project funding. ABB Lummus Crest's engineering responsibilities would begin with the routing of 13.8 kv cables to the substation transformers.

ABB Lummus Crest 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 CE and CWL&P. CWL&P issued their comments on the document in June, 1992. After receiving approval from ABB Combustion Engineering, 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.

M) Cost Estimate

At the end of 1992 the cost estimate was still being developed. A working cost estimate was established by taking the BP1 numbers and changing the individual line item values as better numbers were established. However, the majority of the cost estimate requires that all of the engineering work described above be done before more accurate numbers are obtained. This method produces intermediate numbers that are usually very conservative and early numbers have been higher than expected. Because of this several studies were undertaken to determine if the cost could be reduced.

N) 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.

As the cost estimate is being developed, additional areas for cost reduction are being identified and evaluated.

O) Support Studies

i) 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.

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.

ii) 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.

iii) Lockheed 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.

iv) Preliminary Hazard Analysis

A Preliminary Hazard Analysis (PHA) was conducted on the CE IGCC Repowering Project by representatives from various disciplines within ABB 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.

v) Gasification Data

With the help of the DOE, a visit to an operating gasification plant was arranged. The plant was visited to obtain data from tests about the operation of the plant in order to see if 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.

vi) 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.

P) 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.

Q) 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 entire facility .

R) 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.

VII SITE RELATED ACTIVITIES

Brand Asbestos Abatement Inc. was awarded the contract for the complete abatement and demolition of Boilers #1-#6 and Turbines #1-#5 and all associated equipment located in the Lakeside Plant #1 and #2. Brand mobilized to the job site in early January 1992 with the first craft labor personnel commencing work on January 20th.

Aires Environmental was retained under contract to CWL&P to handle all air monitoring and sampling along with project management support.

Originally the project was broken into 5 major phases. The first major phase of the abatement was #4 and #5 turbine areas, which was completed February 26, 1992. After completion of the abatement on #4 and #5 turbines the abatement crews moved to the 2nd phase (5 and 6 boilers). Actual phase 2 asbestos removal began in early March 1992 with final air testing and clearance was obtained in early August. Phase 3 (Boilers #1-#4) started in mid-August 1992 along with Otshan Demolishing crews mobilizing and commencing demolition work of #5 and #6 boilers. Final air clearance of Boilers #1-#4 was performed in late December 1992. Phase 4 (Turbines #1-#3) began in early November 1992 with completion scheduled for mid to late January 1993. As of late December 1992, the dismantling and removal of #4 and #5 turbines and auxiliary equipment was estimated to be 85% complete.

Due to abnormal amounts of fly ash and asbestos contaminated material within the boilers, completion of the project is taking longer than expected. For these reasons, a contract extension was requested by Brand, and granted by CWL&P.

Although total construction personnel has varied throughout the project, peak was reached in November 1992 at a little over 100 workers.

Completion of demolition and asbestos abatement is now anticipated in late April 1993.

VIII PROJECT MANAGEMENT

A) Project Management Plan

The Project Management Plan (PMP) was written for this project as required by the Cooperative Agreement between CE and DOE. Revision 1 of this plan for Budget Period 2 (BP-2) was issued by CE to DOE in November of 1992. The PMP will be implemented and maintained by CE throughout the life of the project. This document includes the management procedures that are intended to be used for this project as well as the Statement of Work and the Work Breakdown Structure (WBS).

The PMP was updated from the Budget Period 1 (BP-1) version to show BP-1 in the past tense and to properly focus the current PMP to BP-2. Also, all corrections and inclusions requested by the Department of Energy (DOE) in a letter dated March 30, 1992, were addressed.

The latest updates for permit schedules and delivery dates and cost data for WBS and unallowable cost adjustment were also provided.

B) Schedules

A schedule for the overall project was developed during BP-1. This schedule is shown in Figure 21. The schedule breaks down the project duration into 3 phases and 5 budget periods and shows major milestones.

At the end of 1992, a request was submitted to extend BP2 into 1993. This will affect the schedule shown by a small amount. A new schedule will be submitted with the Continuation Application.

Combustion Engineering IGCC Repowering Project – Schedule and Budget

Project Funding Plan
(Dollars in Millions)

FIGURE 21

END

DATE

FILMED

4/12/94