FOSSIL

DOE/MC/21023-2825, Vol. 1
(DE90000412)

Second-Generation Pressurized Fluidized Bed Combustion Plant Conceptual Design and Optimization of a Second-Generation PFB Combustion Plant, Phase 1, Task 1 Volume I

Topical Report

A. Robertson
R. Garland
R. Newby
A. Rehmat
L. Rubow

September 1989

Work Performed Under Contract No.: DE-AC21-86MC21023

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

By
Foster Wheeler Development Corporation
Livingston, New Jersey

This report has been reproduced directly from the best available copy.

Available to DOE and DOE contractors from the Office of Scientific and Technical Information, P.O. Box 62, Oak Ridge, TN 37831; prices available from (615)576-8401, FTS 626-8401.

Available to the public from the National Technical Information Service, U. S. Department of Commerce, 5285 Port Royal Rd., Springfield, VA 22161.

Price: Printed Copy A99
Microfiche A01

Printed in the United States of America. Office of Scientific and Technical Information, Oak Ridge, Tennessee

DOE/MC/21023--2825-Vol.1

DE90 000412

Second-Generation Pressurized Fluidized Bed Combustion Plant Conceptual Design and Optimization of a Second-Generation PFB Combustion Plant, Phase 1, Task 1 Volume I

Topical Report

A. Robertson
R. Garland
R. Newby
A. Rehmat
L. Rubow

Work Performed Under Contract No.: DE-AC21-86MC21023

For
U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
P.O. Box 880
Morgantown, West Virginia 26507-0880

By
Foster Wheeler Development Corporation
12 Peach Tree Hill Road
Livingston, New Jersey 07039

September 1989

ABSTRACT

This three-volume report presents a conceptual design of a coal-fired second-generation pressurized fluidized bed (PFB) combustion plant and identifies its sensitivity to varying operating conditions and economic factors. Depending upon the conditions selected, the plant can achieve a 45-percent efficiency (based on the higher heating value of the coal used as fuel) and a cost of electricity at least 20 percent lower than that of a conventional pulverized-coal-fired plant with wet limestone, flue gas desulfurization. The proposed plant reaches these performance levels by integrating a coal pyrolyzer/carbonizer with a circulating pressurized fluidized bed combustor (CPFBC). Char produced by the carbonizer is burned in the CPFBC and the low-Btu fuel gas produced by the carbonizer is burned in a topping combustor to heat the CPFBC exhaust gas to 2100°F and higher before it enters the gas turbine. The carbonizer and CPFBC operate with lime-based sorbents for in-situ sulfur capture at ≤1600°F. Components being developed for first-generation PFB plants (gas turbine inlet temperature ≤ 1600°F) protect the gas turbine from corrosion, erosion, and deposition.

Task Reports 2, 3, and 4 also issued under this contract, identify the research and development needs of this type of plant, present an integrated program plan for answering these needs, and present a commercialization plan for the plant.

ACKNOWLEDGMENTS

This work was performed by Foster Wheeler Development Corporation (FWDC) under U.S. DOE Contract DE-AC21-86MC21023. James McClung was the DOE Contracting Officer's Technical Representative and Archie Robertson managed the program for FWDC.

Four companies, working under subcontract to FWDC, played a major role in developing the second-generation pressurized fluidized bed combustion plant conceptual design described in this report. Listed alphabetically, with their key personnel and responsibilities, the team members are:

- Foster Wheeler Development Corporation--Overall program management; conceptual design and cost estimating of the plant carbonizers, circulating pressurized fluidized bed combustors, cyclone separators, external fluidized bed heat exchangers, and associated auxiliaries (e.g., coal and sorbent systems, spent bed material/ash depressurizing and cooling systems):

  Archie Robertson, Program Manager
  David Cranstoun*
  Robert Fitz†
  Richard Mahoney
  Richard McMillan
  T. V. Narayanan
  Jonathan Pitcher
  James Van Hook
  Franklin Zoldak

- Gilbert/Commonwealth, Inc.--Conceptual design and cost estimating of ceramic filters and balance-of-plant-type components; overall plant layout; and performance, emissions, economics, and reliability analyses:

  Lynn Rubow, Project Manager
  Richard Boulay
  Tom Buchanan
  Lon Harvey
  John Hirschenhofer
  Carol Keich
  Surya Maruvada
  Roman Zaharchuk

- Institute of Gas Technology--Preparation of a computer model to predict carbonizer compositions, and heating values:

  J. G. Patel, Project Manager
  Anil Goyal
  Amir Rehmat

- Westinghouse Combustion Turbine Operations--Identification of optimum plant operating conditions; topping combustor and gas turbine/steam turbine conceptual and cost estimates:

  Richard Garland, Project Manager
  Sterling Arlington
  Dennis Horazak

- Westinghouse Research and Development--Process analyses involving combustion efficiency; SO_x, NO_x, alkali, and trace analyses; and gas turbine corrosion, erosion, and deposition evaluations:

  Richard Newby, Project Manager
  Mary Ann Alvin
  Dennis Bachovchin
  Dale Keairns
  Thomas Lippert
  Wen-Chin Yang

Preparation of this report was coordinated by FWDC, with Jean Rabe as editor.

---

*Foster Wheeler Energy Corporation.
†Foster Wheeler USA.

Contents

Contents (Cont)

Contents (Cont)

Contents (Cont)

Tables

Tables (Cont)

Tables (Cont)

Tables (Cont)

Tables (Cont)

Tables (Cont)

Figures

Figures (Cont)

Figures (Cont)

Figures (Cont)

Figures (Cont)

Abbreviations/Acronymns

A/E	Architect/Engineer
ACRS	Accelerated Cost Recovery System
AFB	Atmospheric Fluidized Bed
BACT	Best Available Control Technology
BFP	Boiler Feedwater Pump
BOP	Balance of Plant
CADD	Computer-Aided Design and Drafting
CFBC	Circulating Fluidized Bed Combustors
COE	Cost of Electricity
CPFBC	Circulating Pressurized Fluidized Bed Combustor
CWS	Coal/Water Slurry
DWT	Dead Weight Ton
EFOR	Equivalent Forced Outage Rate
EPA	Environmental Protection Agency
ESPs	Electrostatic Precipitators
FBHE	Fluidized Bed Heat Exchanger
FBN	Fuel-Bound Nitrogen
FGD	Flue Gas Desulfurization
FWDC	Foster Wheeler Development Corporation
FWEC	Foster Wheeler Energy Corporation
G/C	Gilbert/Commonwealth, Inc.
HGCU	Hot Gas Cleanup
HHV	Higher Heating Value
HP	High Pressure
HRSG	Heat Recovery Steam Generator
I&C	Instrumentation and Control
IGT	Institute of Gas Technology
IP	Intermediate Pressure
LHV	Lower Heating Value
LMTD	Log Mean Temperature Differential
LP	Low Pressure
MASBs	Multiannular Swirl Burners
MATE	Minimum Acute Toxicity Effluent
MIT	Massachusetts Institute of Technology
NAO	National Air Oil Burner Company
NERC	North American Electric Reliability Council
NPDES	National Pollutant Discharge Elimination System
NPHR	Net Plant Heat Rate
NSPS	New Source Performance Standards
OJ	Operating Jobs
OLC	Operating Labor Charge
OSHA	Occupational Safety and Health Administration
PaDER	Pennsylvania Department of Environmental Resources
PC	Pulverized Coal
PCBs	Polychlorinated Biphenyls
PFB	Pressurized Fluidized Bed
POM	Polycyclic Organic Material
PSD	Prevention of Significant Deterioration
RAM	Reliability, Availability, and Maintainability
RCRA	Resource Conservation Recovery Act
RSH	Reserve Shutdown Hours
SOH	Scheduled Outage Hours
TAG	Technical Assessment Guide (EPRI)

Abbreviations/Acronymns

TCOT	Topping Combustor Outlet Temperature
TCR	Total Capital Requirement
TPC	Total Plant Cost
TPI	Total Plant Investment
WCTO	Westinghouse Combustion Turbine Operation
WR&D	Westinghouse Research and Development

EXECUTIVE SUMMARY

INTRODUCTION

The electric utility industry needs a new generation of plants that can operate with substantially improved efficiencies and availabilities, accept lower-quality fuels, and easily meet present and future New Source Performance Standards (NSPS). The plants should be low in capital costs, have short design and construction lead times, be highly reliable/available, and be amenable to modularity--all leading to a lower cost of electricity (COE) and a lower risk of surplus capacity. In response to this need, a team of companies led by Foster Wheeler Development Corporation and consisting of:

- Foster Wheeler Energy Corporation
- Gilbert/Commonwealth, Incorporated
- Institute of Gas Technology
- Westinghouse Combustion Turbine Operation
- Westinghouse Research and Development

has embarked upon a DOE-funded three-phase 5-year program to develop the technology for this new type of plant. Quantitatively, the targeted goals for this new plant are a COE at least 20-percent lower than that of a conventional pulverized-coal-(PC)-fired plant with a stack gas scrubber and a 45-percent efficiency (based on the higher heating value of the coal).

During the first phase, the plant will be conceptually designed, the parameters that optimize performance and have a significant impact on COE will be determined, and commercialization and research and development plans will be formulated. In Phase 2 the key components of the plant will be individually tested at the laboratory scale; performance data will be correlated; and the Phase 1 design, cost estimate, and plans will be updated. In Phase 3 the key components will be tested as a fully integrated subsystem at the 5-MWe equivalent scale, system and performance characteristics will be correlated, and the Phase 2 designs and cost estimates will be updated.

This report was prepared as a part of the Phase 1 effort; it presents the conceptual design of the plant and the results of optimization and COE sensitivity studies, and it reveals that the proposed plant will meet the targeted goals. The research and development needs of the plant, together with a program plan addressing these needs, is presented in companion Task 2 and Task 3 Reports. A plan for commercializing the technology, including marketing penetration studies, is presented in a Task 4 Report.

GENERAL CONCLUSIONS

The plant design effort and the COE sensitivity study have shown that second-generation PFB combustion plants can meet or exceed all project goals. Using commercially available gas turbines and depending upon the operating conditions selected, a second-generation PFB combustion plant:

- Can have a COE at least 20 percent lower than that of a conventional PC-fired plant with wet limestone flue gas desulfurization.
- Will probably exceed a 45-percent efficiency based on the higher heating value (HHV) of the coal.

- Meets emissions limits that are half those currently allowed by NSPS, without any unusual operating restraints.
- Operates economically with coals ranging from lignite to highly caking bituminous coals and with either dolomite or limestone sorbents.
- Can be furnished in building block modules as large as 225 to 250 MWe.
- Is amenable to shop fabrication and barge shipment.

Much of the equipment required by a second-generation PFB combustion plant is state of the art and is available with commercial guarantees. The remainder consists of equipment that has been operated at a smaller scale or at atmospheric pressure and, for the purposes of this study, has been scaled up in size, pressure, or both to provide a conceptual design/costing basis. The layout, modularity, manufacture/shipping, and construction methods employed for the plant reflect techniques already utilized in either the utility or other major industries. Thus the baseline plant represents a realistic concept and is in a relatively advanced state of development.

PROPOSED PLANT CONCEPT

The team has proposed an advanced or second-generation pressurized fluidized bed (PFB) combustion combined-cycle plant, shown schematically in Figure 1. The plant operates at a nominal 14-atm compressor pressure ratio and incorporates a 1600°F circulating pressurized fluidized bed combustor (CPFBC) with a conventional 2400 psig/1000°F/1000°F/2.5-in. Hg steam cycle. Fundamentally, the plant operates as follows: Coal is fed to a pressurized carbonizer that produces a low-Btu fuel gas and char. After the fuel gas is cleaned of particulates by a cyclone and cross-flow filter, it is burned in a topping combustor to produce the energy required to drive a gas turbine. The gas turbine drives a generator and a compressor that feeds air to the carbonizer and to the CPFBC. The carbonizer char is burned in the CPFBC with high excess air, and the vitiated air from the CPFBC is used to support combustion of the fuel gas in the topping combustor. Steam generated in a heat recovery steam generator (HRSG) downstream of the gas turbine and in the fluidized bed heat exchanger (FBHE) associated with the CPFBC drives the steam turbine generator that furnishes the balance of electric power delivered by the plant.

To reach 45-percent efficiency, the second-generation plant operates with very high excess air (>100 percent rather than 30 percent) and a gas turbine inlet temperature of 2100°F and higher. Because the gas turbine inlet temperature is much higher than 1500 to 1600°F, the values of PFB combustion plants presently under construction [1],* the plant has been called a second-generation PFB combustion plant. The low-Btu gas is produced in the carbonizer by the pyrolysis/mild devolatilization of coal in a fluidized bed reactor. Char residue is also produced because this unit operates at temperatures much lower than gasifiers currently under development. Left untreated, the fuel gas will contain hydrogen sulfide as well as tar/light oil vapors; therefore, lime-based sorbents are injected into the carbonizer to catalytically enhance tar cracking and to capture sulfur as calcium sulfide. Since sulfur capture is done in-situ, the raw fuel gas is fired hot, and the need for expensive and complex fuel gas heat exchangers and chemical or sulfur-capturing bed clean-up systems characteristic of coal gasification combined-cycle plants presently under development is eliminated.

*References are listed at the end of this Executive Summary.

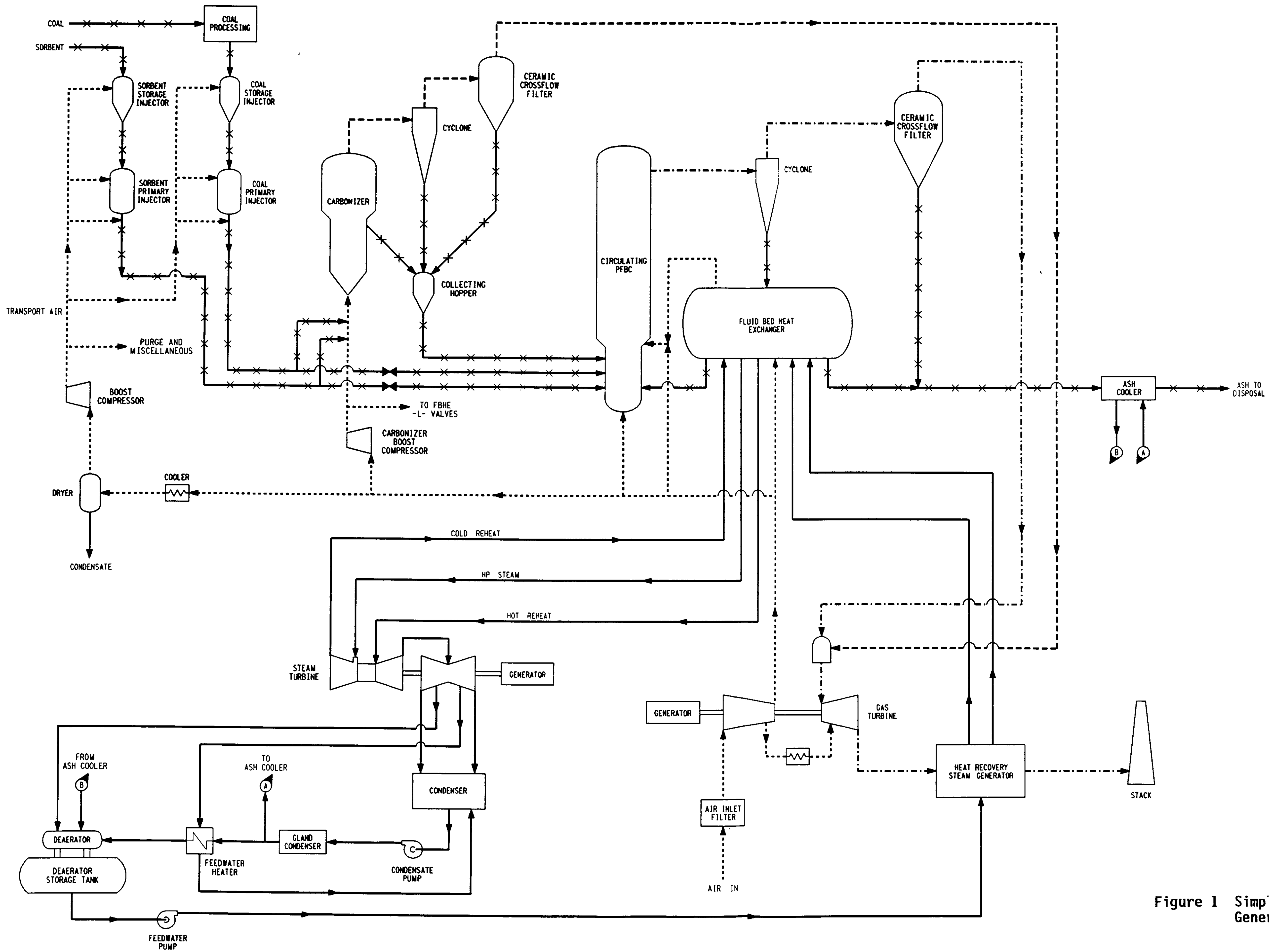


Figure 1 Simplified Schematic of Second-Generation PFB Combustion Plant

The char and calcium sulfide produced in the carbonizer and contained in the fuel gas as elutriated particles are captured by high temperature filters, rendering the fuel gas essentially particulate-free and meeting NSPS. The captured material, together with carbonizer bed drains, is collected in a central hopper and injected into the CPFBC through a nitrogen-aerated nonmechanical valve. The high excess air in the CPFBC transforms the calcium sulfide to sulfate, allowing its disposal as normal CPFBC spent sorbent.

Atmospheric fluidized bed experience has shown that circulating bed performance can be superior to bubbling bed performance (i.e., higher combustion efficiencies and heat-transfer coefficients along with lower SO_2 and NO_x emissions). Because of this superior performance and since second-generation plants may have to meet more stringent future NSPS and ideally should be capable of operating effectively with low-reactivity sorbents, a CPFBC has been chosen. In the CPFBC, the burning char heats the high-excess-air flue gas to 1600°F; surplus heat is transferred to the external FBHE by the recirculation of sorbent between the two units. Controlled recirculation is accomplished with cyclone separators and nonmechanical valves. The CPFBC configuration selected is a vertical, refractory-lined pressure vessel, with all cooling tube surfaces placed in the FBHE. Because of the low fluidizing velocity in the FBHE ($\leq$1/2 ft/s), the risk of tube erosion is virtually eliminated.

The exhaust gases leaving the carbonizer and the CPFBC contain particles of char, sorbent, and fly ash--all of which can erode and foul downstream equipment. To prevent erosion and fouling, a hot gas cleanup (HGCU) system, consisting of ceramic cross-flow filters preceded by cyclone separators, cleans these gases to a stack gas solids loading of <20 ppm before they enter the fuel gas topping combustor and the gas turbine.

The topping combustor consists of metallic-wall multiannular swirl burners (MASBs) in two external combustion assemblies (topping combustors) on opposite sides of the gas turbine. Each MASB contains a series of swirlers that aerodynamically create fuel-rich, quick-quench, and fuel-lean zones to minimize NO_x formation during the topping combustion process. The swirlers also provide a thick layer of air at the wall boundary to control the temperature of the metallic walls.

Figures 2 and 3 depict the integrated carbonizer/CPFBC/FBHE components required for a nominal 225-MWe power block/module.

OPERATING ENVELOPE/FACTORS INFLUENCING PLANT EFFICIENCY

Operating Envelope

The interactions among gas turbine inlet temperature, gas turbine exhaust temperature, plant excess-air level, steam conditions, steam cycle participation, carbonizer and CPFBC operating temperatures, and heat-recovery apparatus configuration produce many possible combined-cycle plant configurations. By operating with very high excess air and incorporating topping combustion to reach gas turbine temperatures of at least 2100°F, the second-generation plant achieves a significantly higher efficiency than first-generation plants (44 to 45 vs. 36 to 39 percent).

Excess air is a key cycle parameter when determining the operating envelope. Figure 4 shows the operating envelope plotted as CPFBC excess air vs. topping combustor outlet temperature (TCOT). Below 1800°F, topping combustion provides little performance or economic advantage. Thus the envelope in Figure 4 has been

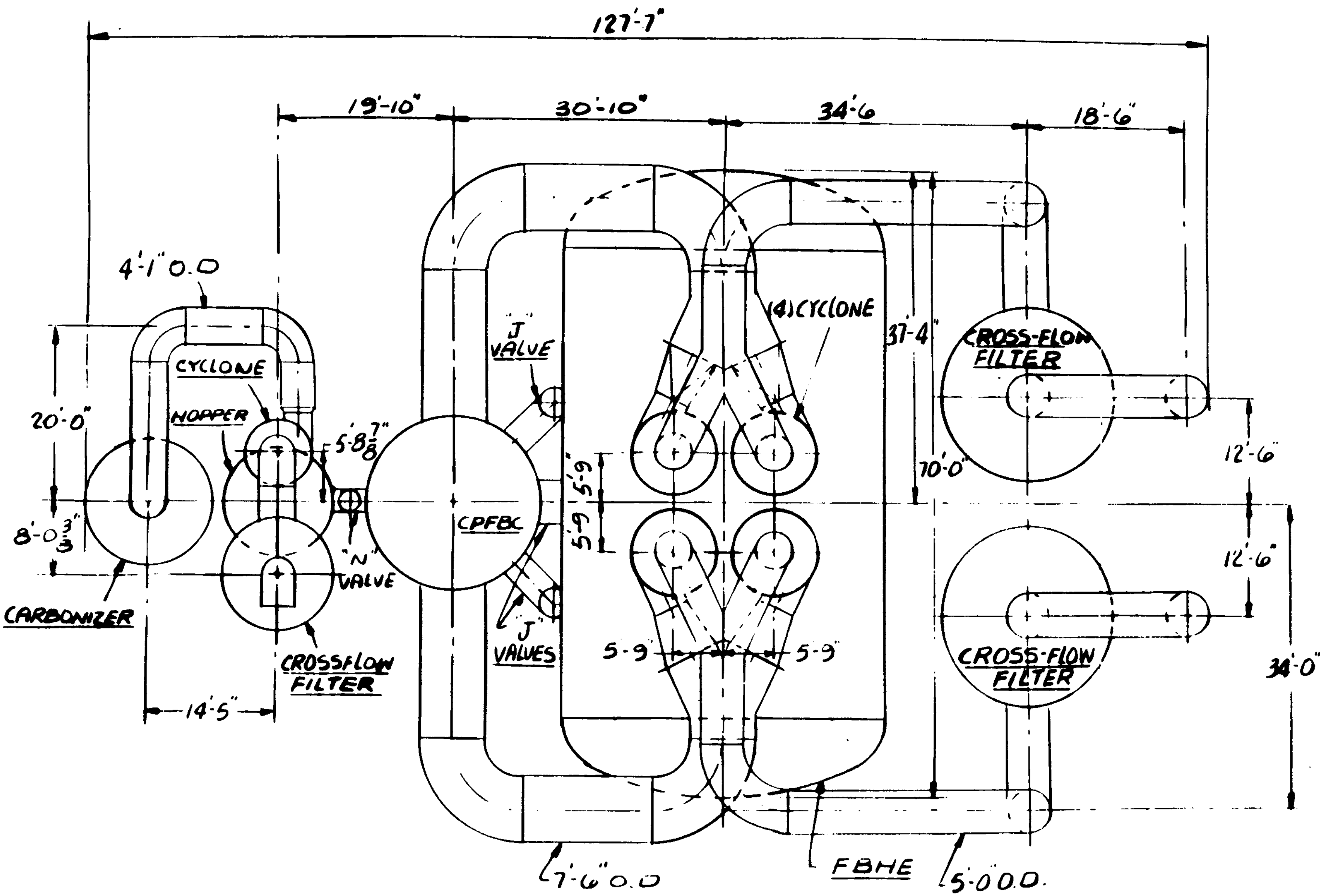


Figure 2 Plan View--Typical Carbonizer/CPFBC/FBHE Module

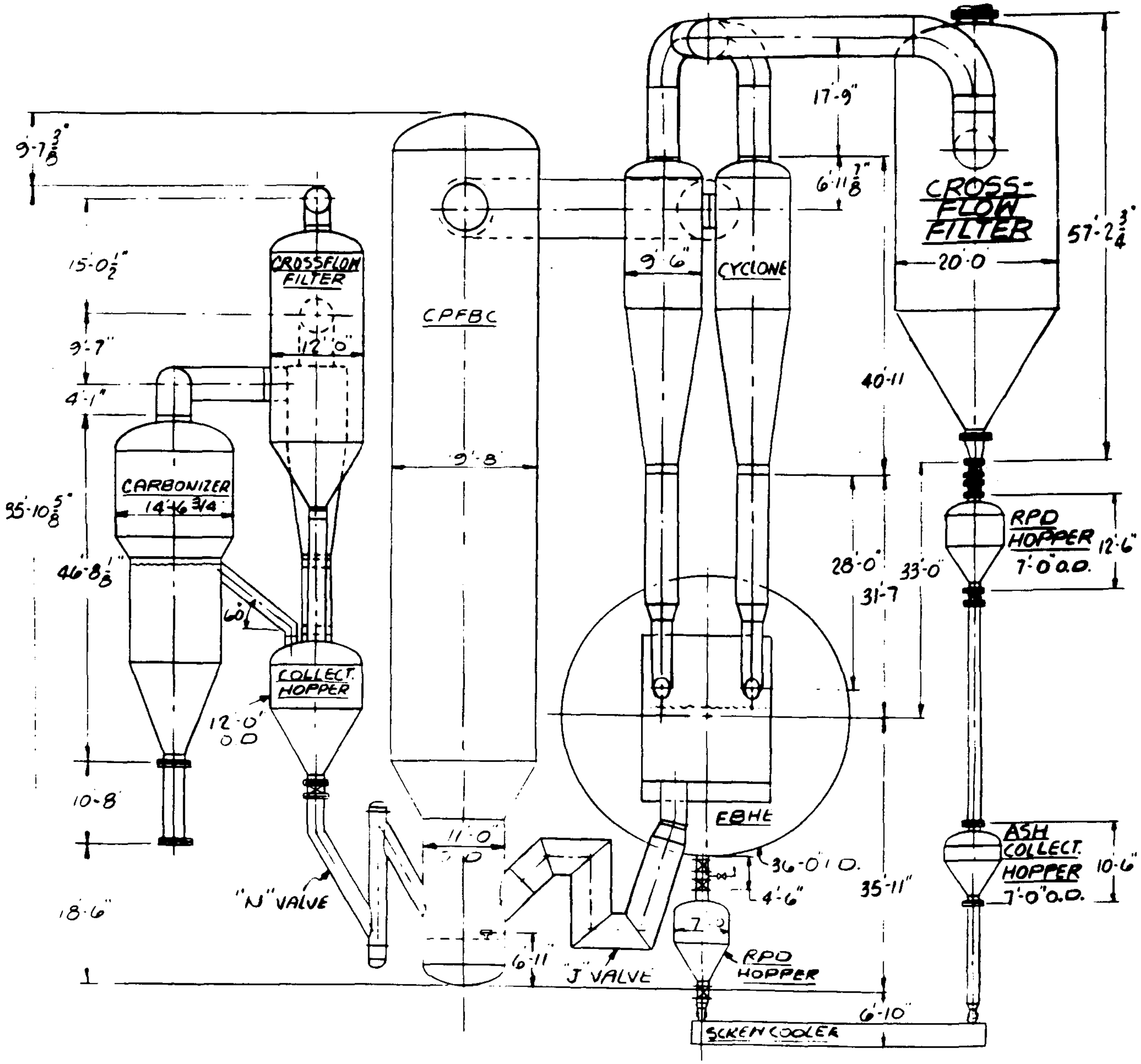


Figure 3 Elevation View--Typical Carbonizer/CPFBC/FBHE Module

limited to operation between 1800°F and the maximum possible (~2550°F), based on the 1500°F carbonizer balance shown in Figure 5. The other limits--no coal to the CPFBC and no steam generation in the CPFBC--are shown along with the upper limit, the minimum allowable excess air level.

One additional line is shown on the envelope--the best efficiency line. Although cycle efficiency is not constant (it increases with increasing TCOT), the highest attainable plant efficiency (lowest heat rate) for this type of PFB combustion combined-cycle plant occurs where the "Best Efficiency at Given TCOT" line intersects the "Zero Coal Feed to Bed" line. Above the best efficiency line, steam generation is the dominant factor. As CPFBC excess air is reduced (coal feed increased), more steam is generated in the FBHE at a given TCOT, the gas turbine to steam turbine power output ratio decreases, and overall plant efficiency diminishes. Below the best efficiency line, less steam is generated and the efficiency again diminishes because of lower quality steam generation. Therefore, the best efficiency line indicates the locus of points where steam cycle participation is optimized.

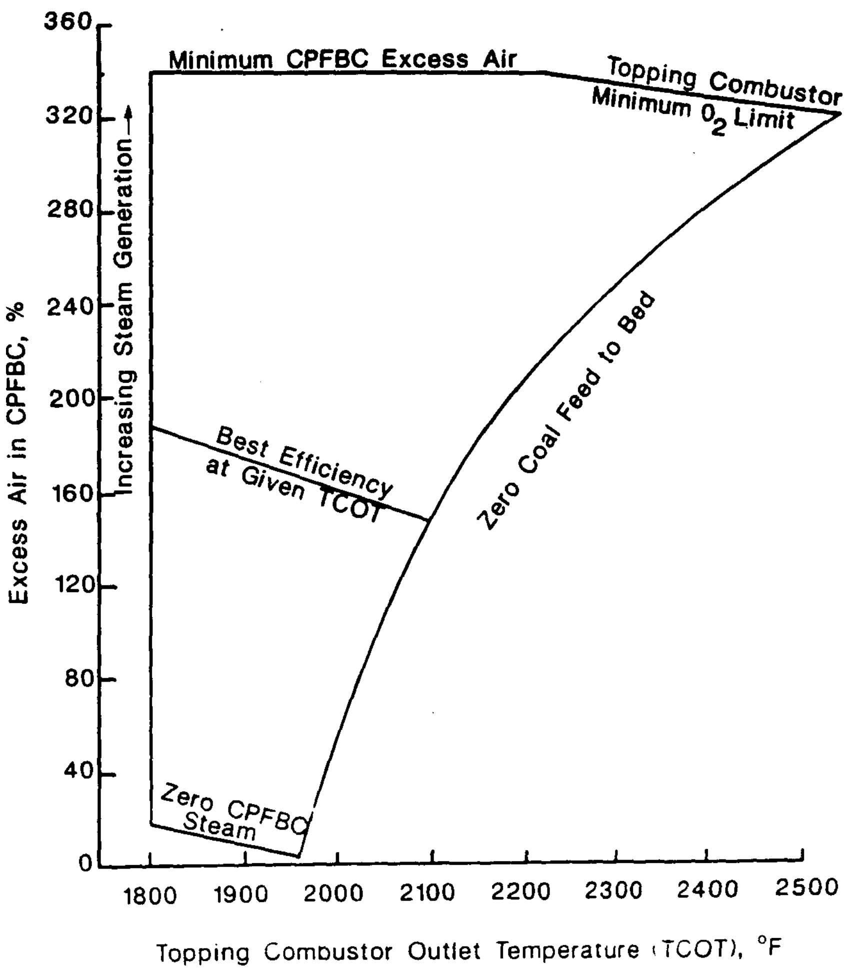


Figure 4 PFB Excess Air vs. Topping Combustor Outlet Temperature as a Function of Operating Limits

Fuel Gas Flow (lb/h)	178.446
HHV (Btu/lb)	1958
LHV (Btu/lb)	1817
Btu/sft^3 (LHV)	127

Char-Sorbent Flow (lb/h) = 85.794

	Char	Coke	Spent Dolomite	
Carbon	41.413	8.168	6.215	MgO
Hydrogen	0.626	0.028	13.212	$CaCO_3$
Sulfur	1.736	0.055	2.266	CaS†
Nitrogen	0.780	0.026	0.510	Inerts
Oxygen	0.441	0.008		
Moisture	---	---		
Ash	10.31	---		

HHV (Btu/lb)	9360
LVH (Btu/lb)	9307

Tar (Flow Rate = 2.436 lb/h)

Atomic Composition:

MW = 13.2721

$CH_{.5741}O_{.0181}N_{.0101}S_{.0082}$

HHV (Btu/lb)	15,800
LHV (Btu/lb)	15,410

Gas (wt%)* (Flow Rate = 176.01 lb/h)

CO	8.93
CO_2	20.76
H_2O	7.66
H_2	0.60
CH_4	2.24
C_2's	2.10
NH_3	0.29
H_2S	0.087
N_2	57.333
HHV (Btu/lb)	1766
LHV (Btu/lb)	1629

CARBONIZER
14 atm
1500°F

70°F

711°F

70°F

Pittsburgh Coal (Ultimate wt%) (Flow Rate = 100 lb/h)

Carbon	71.92
Hydrogen	4.69
Sulfur	2.99
Nitrogen	1.26
Oxygen	6.33
Moisture¶	2.50
Ash	10.31
HHV (Btu/lb)	12,916
LHV (Btu/lb)	12,472

Air (Flow Rate = 134.22 lb/h)

Relative Humidity	50% at 70°F

Plum Run Dolomite (wt%) (Flow Rate = 30.02 lb/h; Ca/S = 1.75)§

$CaCO_3$	54.5
$MgCO_3$	43.3
Moisture	0.5
Inerts	1.7

*Excludes Tar.
†87.5% Sulfur Capture (92% of H_2S Equilibrium Capture).
§If Based on Sulfur Release--Ca/S = 3.7.
¶After Drying.

Rev. D
7/24/87

Figure 5 1500°F Carbonizer Balance

Other Factors Influencing Plant Efficiency

Several of the more important parameters were varied to determine their effects on performance:

Gas Turbine Compressor Ratio. The pressure ratio of the compressor/gas turbine was varied while maintaining the optimum 2100°F TCOT. While the gas turbine power output varied, steam cycle output remained practically constant. The gas turbine-to-steam turbine power ratio or percentage of steam cycle participation varied with the pressure ratio, affecting the overall heat rate. The highest efficiency occurred at a pressure ratio of about 11:1. Steam cycle participation at this point was about 56 percent of the gross output.

Equipment costs, however, are not at a minimum at an 11:1 pressure ratio. The gas turbine, in particular, is sensitive to this fact. For example, the effective flow area of the turbine is 41 percent greater at a 10:1 pressure ratio than when the ratio is 14:1. Flow and turbine inlet temperatures are practically constant in this analysis. Thus the lower turbine inlet pressure dictates taller blade heights, perhaps larger diameters, and higher gas turbine costs. Other components sensitive to gas volumetric flow rates (e.g., carbonizer, CPFBC, cyclones, cross-flow filters, and hot gas piping) become more costly, and COE also rises.

At a higher than 14:1 pressure ratio, gas turbine output drops; steam turbine output remains about the same. Machines with higher pressure ratios require a turbine inlet temperature higher than 2100°F to enhance specific power--even with compressor intercooling.

CPFBC Operating Temperature. To minimize alkali release that might be harmful to the gas turbine and might force incorporation of an alkali getter, 1600°F was set as the upper CPFBC operating temperature limit. Carbonizer coal and plant airflow rates were constant. In a sensitivity study, the effects of a ±50°F variation in the CPFBC operating temperature was investigated. When the CPFBC temperature was dropped to 1550°F by increasing heat transfer to the FBHE, TCOT and turbine exhaust temperatures were comparably lowered. The lower gas turbine exhaust temperature reduced the HRSG duty, and a portion of the HRSG high-pressure steam evaporation and superheating was transferred to the FBHE, where additional heat was available. This shift had very little effect on the plant coal flow rate/excess-air level.

When the temperature was raised to 1650°F, however, the opposite occurred. With a higher TCOT came a higher gas turbine exhaust temperature and more high-pressure steam in the HRSG. FBHE high-pressure steam evaporation and primary superheating rates dropped, but again, there was little change in the plant coal flow rate/excess-air level.

In both cases (a 50°F rise or drop), steam turbine power output remained unchanged--an indication that a major change in plant performance can be directly attributed to a change in gas turbine performance as a result of differing TCOTs. Overall efficiency varied about 0.3 percent both higher and lower than the 1600°F operating value.

Carbonizer Operating Temperature. The carbonizer operating temperature significantly affects the composition and heating value of the char and fuel gas. Higher temperatures increase the amount of coal energy transferred to the fuel gas and move the best efficiency point to a higher topping combustor outlet temperature and a higher percentage of excess air in the CPFBC. Table 1 illustrates the changes resulting from a 100°F rise in carbonizer operating temperature.

Table 1 Comparison of Plant Efficiency Point Data for 1500°F and 1600°F Carbonizer Study Cases

Description	Carbonizer Temperature 1500°F	1600°F
Topping Combustor Outlet Temperature, °F	2100	2350
Coal Flow, lb/h	284,410	302,828
Char Flow, lb/h	151,649	144,775
Fuel Gas Flow, lb/h	489,299	624,761
Fuel Gas (LHV*), Btu/sft^3	127	145
Plant Excess Air, %	148	124
Gas Turbine Output, MWe	195.2	228.3
Steam Turbine Output, MWe	272.3	283.7
Net Plant Output, MWe	452.8	496.3
Net Thermal Efficiency (HHV), %	43.6	44.9
Cost of Electricity, mills/kWh	75.7	72.9

*Lower Heating Value.

Carbonizer Fuel Gas Quality. Atmospheric pressure carbonizing data were extrapolated to determine carbonizer performance for the 1500 and 1600°F cases. Because no carbonizer has operated at second-generation PFB combustion plant operating conditions, we performed an analysis to reveal the sensitivity of plant performance to alternative yield predictions and compositions at 1500°F. The data were extrapolated on the high and low sides of the normal base 1500°F values to obtain roughly a ± 1/3 change in fuel gas heating value and permit determination of their alternative performance levels. Table 2 presents the results of the study and indicates plant efficiency could decrease by as much as 2.4 points if no attempt is made to increase the fuel gas heating value and flow rate by increasing the carbonizer operating temperature.

Recommended Plant Configuration

A jetting fluidized bed configuration was selected for the second-generation plant carbonizer because:

- The data being used to predict its performance were collected in this type unit.
- This configuration has demonstrated its suitability for carbonizing coals ranging from lignite to highly caking bituminous.
- The hydrodynamic scale-up characteristics of this configuration have already been investigated in a cold model up to 10 ft in diameter--the size of the second-generation plant unit.
- This configuration has also proved suitable for coal gasification and is the basis for the present KRW gasifier.

Even so, other configurations may also prove acceptable. The IGT U-Gas gasifier uses a bubbling fluidized bed configuration; it, too, has demonstrated suitability for gasifying lignite and bituminous coals. The KRW gasifier operates with a superficial gas velocity of 1 to 3 ft/s, whereas the IGT gasifier operates

Table 2 **Effect of 1500°F Carbonizer Fuel Gas Quality on Plant Performance and Economics as Determined by Computer Algorithm**

Description	Yield: Weak	Base	Energetic
Fuel Gas HHV (% change)	-33.5	Base	+31.0
Fuel Gas Flow (% change)	-4.3	Base	+5.8
Char HHV (% change)	+3.5	Base	-4.4
Char Flow (% change)	+6.2	Base	-5.9
Combustor Exit Temperature, °F	1905	2100	2320
Steam Turbine Power (% change)	-0.7	Base	+0.8
Gas Turbine Power (% change)	-13.3	Base	+14.4
Net Output (% change)	-6.4	Base	+7.0
Change in Plant Efficiency (Points)	-2.4	Base	+2.0

at 3 to 5 ft/s. Since testing must be performed to identify which configuration yields optimum carbonizer performance, the second-generation plant carbonizer has been sized for an approximately 3 ft/s superficial gas velocity. As a result, its physical dimensions and costs should be reasonable for either configuration.

The gas turbine inlet temperatures quoted by United States manufacturers are those existing at the first-stage turbine blades. Since these temperatures are typically about 100°F lower than combustor outlet temperatures, and since United States manufacturers are now offering gas turbines with allowable inlet temperatures as high as 2300°F, all of the second-generation plant topping combustor temperatures identified in Tables 3 and 4 are within current gas turbine temperature limitations.

A review of the data in Tables 3 and 4 reveals that high-sulfur bituminous-coal-fired second-generation plants operating with either dry pneumatic coal feed to a 1600°F carbonizer or unbeneficiated coarse coal/water slurry feed to a 1500°F carbonizer will meet the targeted goals of 20-percent lower COE and a nominal 45-percent efficiency. In addition, both goals can probably be improved upon by using coal/water slurry feed to a carbonizer operating at 1600°F and higher. Until test data are available for carbonizers operating at these conditions, we are not certain of the ultimate plant COE advantage and efficiency. Even though they most probably do not represent the ultimate in COE advantage and efficiency, both plants meet the project goals and justify proceeding with laboratory-scale testing to verify the performance characteristics predicted for their key components.

Table 3 14-atm Second Generation PFB Combustion Plant Efficiencies and COEs

Carbonizer Temperature (°F)	Plant Pressure (atm)	Feedstock: Coal	Feedstock: Sorbent	Feed Type	Excess Air (%)	Ca/S Sulfur Molar Feed Ratio	Optimum Topping Combustor Temperature (°F)	Alkali Getter: Carbonizer Fuel Gas	Alkali Getter: CPFBC Flue Gas	Net Output (MWe)	Total Plant Cost ($/kW)	HHV Efficiency (%)	COE (mill/kWh)	Percentage Less Than PC Plant
1500	14	Pittsburgh No. 8	Plum Run Dolomite*	Pneumatic	148	1.75	2100	No	No	452.8	907	43.63	75.7	18.8
1500	14	Pittsburgh No. 8	Plum Run Dolomite	Pneumatic	148	1.75	2100	Yes	No	453.13	912	43.60	76.5	17.9
1500	14	Pittsburgh No. 8	Plum Run Dolomite	Pneumatic	148	1.75	2100	Yes	Yes	453.10	917	43.51	76.9	17.5
1500	14	Pittsburgh No. 8	Plum Run Dolomite	Pneumatic	24	1.35	2100	No	No	423.03	830	40.62	74.0	20.6
1500	14	Pittsburgh No. 8	Plum Run Dolomite	Slurry†	106	1.75	2400	No	No	547.62	839	44.15	71.1	23.7
1500	14	Pittsburgh No. 8	Carbon Limestone§	Pneumatic	150	3.00	2100	No	No	448.74	917	43.58	76.5	17.9
1600	14	Pittsburgh No. 8	Plum Run Dolomite	Pneumatic	124	1.75	2350	No	No	496.31	876	44.92	72.9	21.8
1500	14	Texas Lignite¶	Plum Run Dolomite	Pneumatic	111	1.0	2158	No	No	508.66	950	42.66	79.1	28.8
1500	14	Texas Lignite¶	Plum Run Dolomite	Pneumatic	110	1.0	2158	Yes	Yes	509.41	963	42.54	80.8	27.3
1500	14	Texas Lignite**	Plum Run Dolomite	Pneumatic	123	1.0	1980	No	No	425.71	---	41.9	---	---
1500	10	Pittsburgh No. 8	Plum Run Dolomite	Pneumatic	157	1.75	2100	No	No	437.41	978	43.75	79.5	14.7

*From Ohio.
†70 wt% coal/30 wt% water coarse slurry with dry/pneumatic sorbent feed.
§From Lowellville, Ohio.
¶Wilcox Seam lignite dried from 31.8-percent moisture to 25.8 percent.
**Wilcox Seam lignite dried from 31.8-percent moisture to 15 percent.

Table 4 Effects of Pneumatically Fed Alternative Feedstocks on 14-atm Second-Generation PFB Combustion Plant Efficiency and COE*

Feedstock: Pittsburgh No. 8 Coal	Feedstock: Plum Run Dolomite	Excess Air (%)	Ca/S Sulfur Molar Feed Ratio	Net Output MWe	Plant Cost ($/kWh)	Total HHV Efficiency (%)	COE (mill/kWh)	Percentage Less Than PC Plant
-30 mesh	1/8" x 0	148	1.5	453.98	918	43.78	75.6	18.9
-30 mesh	-30 mesh	149	1.37	452.67	915	43.78	75.5	19.0

*Carbonizer Temperature (nominal) = 1500°F; Optimum Topping Combustor Temperature = 2100°F.

SECOND-GENERATION PLANT PERFORMANCE AND ECONOMICS

Because the computer program for determining the plant operating envelope and efficiency factors utilized algorithms, results were useful for relative ranking purposes only. A conceptual plant design was prepared to identify the performance and dimensions of its new components, establish preferred physical arrangements, identify auxiliary needs and parasitic power losses, and determine overall plant performance and costs. Even though the computer study predicted that the second-generation plant performance and COE would be better with a 1600°F carbonizer than with a 1500°F carbonizer, 1500°F was used because it yielded a similar COE and required a smaller extrapolation of the very limited data being used to predict its performance. In addition, the lower temperature would force the plant into a "worst-case" sulfur-capture scenario (tar/light oil vapor levels would be higher) while minimizing potential alkali and topping combustor NO_x problems. This plant, hereafter referred to as the baseline configuration, operated at 14 atm with:

- 1/8-in. x 0 Pittsburgh No. 8 coal
- 1/8-in. x 0 Plum Run dolomite
- Lock-hopper-type dry pneumatic feed systems
- Two carbonizer/CPFBC/HGCU/gas turbine modules
- A 2400 psig/1000°F/1000°F/ 2-1/2 in. Hg steam turbine
- A 1500°F carbonizer temperature
- A 2100°F topping combustor temperature (the optimum based on the identified operating conditions)

Since the plant efficiency and COE are influenced by many factors, we undertook a study to identify which of these factors would have a significant impact on the efficiency and COE. We assessed 23 different alternative assumptions or operating conditions, including a 1600°F carbonizer; a less pessimistic 1500°F carbonizer yield scenario; minimum plant excess air; a 10-atm plant pressure ratio; the use of coal/water feed, limestone sorbent, lignite, etc., by identifying the performance, configuration, and cost changes each would induce in the baseline plant configuration.

Table 3 listed the more important results of this sensitivity study. When operated with a 1500°F carbonizer and a 2.9-percent sulfur Pittsburgh coal, the baseline plant has a 43.63-percent efficiency with 90-percent sulfur capture, and its COE is 18.8 percent lower than the COE for a PC plant with scrubber designed for the same coal (35.9 percent efficiency and 93.2 mills/kWh COE). Analytical calculations indicate that alkali release is more likely in the carbonizer than in the CPFBC. An alkali getter installed in the baseline plant carbonizer fuel gas subsystem has a negligible effect on plant efficiency and increases the COE by 0.8 mills/kWh. If getters are required in both the fuel gas and CPFBC flue gas streams, efficiency will drop by 0.12 percent and COE will increase by 1.2 mills/kWh relative to the baseline plant.

The baseline (1500°F carbonizer) two-module plant operates with 148-percent excess air at its best efficiency point. If designing a second-generation plant for maximum power output is desirable, plant and CPFBC excess air levels can be reduced to approximately 24 and 20 percent respectively by feeding coal to the CPFBC also; 40.62-percent efficiency will result. Feeding coal to the CPFBC greatly increases the FBHE duty, and because of increased steam turbine output, a second carbonizer/CPFBC/HGCU/gas turbine module is no longer required (total plant output is kept at 423 MWe to permit a size comparison of approximately equal units); a considerable reduction in capital cost results and, despite the reduced efficiency, the COE in this situation is 20.6 percent lower than for a PC plant operating at the same 65-percent capacity factor. This finding is interesting. Although not studied, it might be possible for an electric utility to take an existing second-generation plant designed for its best efficiency point and, after appropriate modifications, double its output by feeding coal directly to the CPFBC. Although the efficiency of the plant would be lower, the COE could still be attractive.

The unbeneficiated, coarse, 70 wt% coal/30 wt% water slurry, being considered for first-generation PFB combustion plants, increases the second-generation plant efficiency by 0.52 percentage points because of a higher optimum topping combustor temperature. The slurry preparation and feed system required for this plant eliminates the need for coal drying. Since the slurry preparation/feed system is much less expensive than the baseline plant coal dryer/lock-hopper-type pneumatic transport feed system, there is a 67 $/kW reduction in plant capital cost and a 4.6 mills/kWh reduction in COE, despite the increased gas turbine costs associated with a higher inlet temperature. The COE for a second-generation plant using a coal/water slurry feed system is 23.7 percent lower than that for a PC-fired plant.

The carbonizer reducing atmosphere tends to retard/suppress the calcination of limestone; thus the second-generation plant requires a higher calcium-to-sulfur molar feed ratio with limestone (3.0 vs. 1.75) to achieve the same 90-percent sulfur-capture efficiency obtained with dolomite. However, the total sorbent flow per pound of coal is only about 3 percent higher (dolomite is 54.5-percent calcium carbonate vs. 90.1 percent for the limestone), and the efficiency and COE remain similar.

If the carbonizer temperature is 1600°F rather than 1500°F, baseline plant efficiency improves by 1.29 percentage points. The resultant superior fuel-gas yield/heating-value product lowers the char combustion heat release per pound of coal carbonized and yields a significantly higher optimum topping combustor temperature (2350°F vs. 2100°F). Despite the significant increase in topping combustor/gas turbine costs associated with the higher temperature, the markedly increased cycle efficiency enables the plant to operate with a COE 21.8 percent lower than the COE of a PC-fired plant.

If Texas lignite with approximately 26-percent moisture (5 percent removed during drying) is used, the high-moisture content will create a quenching effect similar to that of the slurry, and the optimum topping combustor temperature will increase to 2158°F. A conventional PC-fired plant with a scrubber, designed for this same 31-percent moisture Texas lignite, will have a 32.98-percent efficiency and a 111.1 mills/kWh COE. A lignite-fired second-generation plant, in contrast, will have a 42.54- to 42.66-percent efficiency and a COE 27.3 to 28.8 percent lower than that of the PC-fired plant, depending upon whether alkali getters are required. Because of the low sulfur content in the lignite (1 percent), NSPS standards require a sulfur-capture efficiency of only 80.6 percent compared with the baseline plant 90-percent value; the lignite plant calcium-to-sulfur molar feed ratio is much lower (1.0 vs. 1.75) because of the lower sulfur and the ability of the lime and other alkalis contained in its coal ash to capture sulfur.

With pressure at 10 atm rather than the 14 atm for the baseline plant, plant efficiency increases by 0.12 percentage points, but COE rises by 3.8 mills/kWh because of increased vessel sizes. Total plant cost increases by $72/kW.

The effects of alternative -30 mesh feedstock sizes have been investigated (Table 4). Although the finer feed sizes lower the plant calcium-to-sulfur feed ratios, they have a minimal effect on both COE and efficiency.

PLANT MODULARITY AND PHASED CONSTRUCTION

The 14-atm operating pressure of the second-generation plant, together with its high bed-to-tube heat-transfer coefficients (compared with PC-fired boiler convective coefficients) reduces PFB combustor island components to sizes that can be shop-assembled and barge-shipped to many potential plant sites. The technology required to fabricate, transport, and erect these components is available, is in use in the petrochemical industry, and has already been proved advantageous for first-generation PFB combustion plants [2]. With this approach, a 42-month construction schedule is possible for the second-generation plant--a savings of approximately 6 months when compared with a conventional PC plant construction schedule. In addition, shop assembly and barge shipment will permit better quality control, reduce costs, and avoid the delays that can be caused by inclement weather. If shipment by barge is not possible, second-generation plant construction time will probably be comparable to the time needed to construct a conventional plant.

Although the baseline plant used two carbonizer/CPFBC/HGCU/gas turbine modules, single-module 225-MWe plants or three- or four-module plants should also be possible and economical. The modularity of the second-generation plant will enable utilities to add power in smaller increments without sacrificing efficiency or economics--an approach that should significantly reduce the risk of embarrassing surplus capacity. Furthermore, it may also be possible to build the plant in phases as follows:

- The second-generation CPFBC plant gas turbine could be installed first and operated as a peaking unit on oil or natural gas.
- As the demand for electric power increased, the HRSG and steam turbine would be added.

- A coal-fired CPFBC complete with HGCU and FBHE could also be provided to reduce the gas turbine oil/natural gas requirement (the CPFBC would provide 1600°F flue gas to the gas turbine) and provide additional steam power.
- In the final phase, the gas turbine oil/natural gas topping combustion fuel requirement would be eliminated by providing the carbonizer.

This phased construction approach would enable a utility to closely match its load growth requirements and generate revenue while later phases of construction were in progress. Since the plant is being brought on in stages, the rate shock associated with the start-up of large generating plants can be reduced.

ENVIRONMENTAL RELEASES

Second-generation CPFBC plant emissions will be well within NSPS allowable limits; spent-bed material/bottom ash should pose no toxicological or waste-disposal problems. The spent material will be comparable to that of first-generation PFB combustion plants and less intrusive to the environment than ash from conventional PC-fired plants.

The CPFBC will enable the second-generation plant to operate economically at a 90-percent sulfur retention level with either dolomite or limestone sorbent. Although a detailed analysis was not performed to identify the most cost-effective means for meeting tighter SO_2 regulations, the baseline plant sulfur-capture efficiency was increased to 95 percent by raising the calcium-to-sulfur feed ratio from 1.75 to 2.0 and making the CPFBC 15 feet higher. Under these conditions plant efficiency decreases by 0.46 percentage points and COE increases by 1.0 mills/kWh.

Despite the baseline plant high-excess-air level (148 percent), the staged combustion technique used in the CPFBC and the use of rich/lean burn MASBs in the topping combustor enable the plant to operate well below the NSPS NO_x allowables (0.28 vs. 0.60 lb/10^6 Btu and maybe as low as 0.10 lb/10^6 Btu).

Ceramic cross-flow filters reduce stack gas particulate loading to less than 20 ppm--well below present and any currently anticipated NSPS values.

In summary, future tightening of NSPS regulations should not impose major technological or economic penalties on the plant.

POTENTIAL FOR IMPROVED PERFORMANCE

The Grand Forks Energy and Denver Coal Research Laboratories have together successfully carbonized eight bituminous, one subbituminous, and two lignite coals [3-5]. Their tests were conducted in air-blown 8- and 10-in.-I.D. jetting fluidized bed reactors operating at essentially atmospheric pressure without sorbent injection. Experimenters at Massachusetts Institute of Technology (MIT) have investigated the effects of pressure and of lime-based sorbents on tar yields and tar cracking [6,7]. Because we know of no carbonizers that have operated at proposed second-generation plant conditions, we have conservatively applied the MIT experience to the Grand Forks Energy and Denver Research Laboratories data to predict carbonizer performance at 14 atm with lime-based sorbents. The data suggest that 1500°F will be the low-temperature limit for second-generation plant carbonizers. Depending upon the coal and the actual temperature involved, a significant increase in tar/light oil vapor levels and reduced equilibriums for sulfur capture by lime-based sorbents can result below 1500°F. Although the incentive is for increased operating temperatures, we arbitrarily set 1600°F as an upper limit to minimize data extrapolation and to reduce the potential for gas turbine hot corrosion and topping combustor NO_x problems.

In the absence of actual second-generation plant test data, carbonizer yields and heating values were determined by modifying the Grand Forks Energy and Denver Research Laboratory data to reflect the effects of pressure and tar cracking observed during experiments at the MIT. These modifications were applied conservatively in that:

- Only 75 percent of the tar was assumed to crack (MIT observed 80- to 90-percent tar cracking at 1472°F).
- Of the cracked tar heating value, 75 percent was assumed to appear as coke, which was transferred to the CPFBC (MIT observed 70 percent).
- All coal nitrogen released during carbonization and not contained in the tar or char solid residue was assumed to appear as ammonia in the fuel gas.

Since the tar was assumed to contain 1.98 wt% sulfur, the first assumption resulted in a higher fuel-gas sulfur content and forced the CPFBC to operate with a higher sulfur-capture efficiency. The second assumption increased steam cycle participation via increased FBHE duties, and the third assumption resulted in increased topping combustor NO_x formation. Despite these conservative assumptions, the second-generation plant emissions, performance, and COE proved very attractive, while still offering the potential for improved performance.

During the baseline plant conceptual design effort, a literature search was undertaken to identify all other data applicable to the prediction of second-generation plant carbonizer performance. The collected data were correlated, a computer model was prepared, and the carbonizer yields and compositions were predicted in a much more rigorous analysis. The computer model predicted a higher performance level for the carbonizer in all cases. For instance, at 14 atm/1500°F, the computer model predicted a fuel gas lower heating value of 2917 Btu/lb and a yield per pound of coal carbonized of 1.45 lb vs. the baseline plant values of 1817 Btu/lb and 1.78 lb respectively--a 31-percent increase in topping combustor heat release per pound of coal carbonized. In addition, the computer model gas contains 17-percent less sulfur and 29-percent less ammonia. If used in the baseline plant, the computer-predicted carbonizer yields and heating values result in a 2218°F optimum topping combustor temperature, an increase of 0.7 percent in cycle efficiency (43.6 to 44.3 percent) and a COE 20.5 percent lower than that of a conventional PC plant with a scrubber. A lower calcium-to-sulfur feed ratio can be used and, in addition, NO_x emissions are lower. Based on these carbonizer performance levels, the performance and economics listed in Tables 1 and 2 may be pessimistic; the carbonizer must be operated at actual second-generation plant conditions to confirm the potential for even higher performance levels.

POTENTIAL DEVELOPMENT AND RESEARCH AREAS

Despite the positive features of second-generation plants, they are not without risk. The development of any new technology always involves some degree of risk. An analysis has been conducted to identify, clarify, and rank the research and development needs of this plant. The results of this analysis, extracted from the Task 2 Report issued under this contract, are summarized in Table 5 [8]. An integrated program plan for satisfying these needs has been formulated and issued as the Task 3 report [9]. As shown in Table 5, our first priority is to develop a reliable, final-stage HGCU device that is practical for large-scale installations; is compatible with carbonizer and CPFBC gases and entrained particulates; and by

Table 5 Overall Ranking of Critical R&D Needs--Second-Generation PFB Combustion Plant

Overall Priority Ranking	Component	Phenomenon Involved	Individual Category Ranking: Basic and Applied Research	Individual Category Ranking: Component Development	Individual Category Ranking: Integrated System	Primary Needs To Be Addressed
1	Final HGCU Stage	Particle Separation	---	1	---	Develop a reliable, final-stage HGCU device that is practical for a large-scale installation; is compatible with carbonizer and CPFBC gases and entrained particulates; protects the topping combustor and gas turbine from corrosion, erosion, and deposition; and meets stack NSPS particulate requirements.
2	Topping Combustor	Combustion of Carbonizer Low-Btu Fuel Gas	1	2	---	Determine the alkali and trace-element releases that are emitted by carbonizer and CPFBC elutriated bed material during topping combustion and determine their tendency to cause combustor and gas turbine slagging, corrosion, erosion, and deposition. Determine overall performance; characterize the topping combustor exhaust gas stream, particularly with regard to NO_x emissions; and develop a durable mechanical design.
3	Carbonizer	Coal Devolatilization	2	3	---	Determine the yields, compositions, heating values, and physical characteristics of the effluents from the air-blown, pressurized devolatilization of coal in a scalable unit in the presence of lime-based sorbents.
4	CPFBC	Combustion of Coal and Char in a Pressurized Circulating Bed	3			Determine overall performance of circulating pressurized fluidized beds with particular regard to NO_x suppression, sulfur-removal efficiency, and sulfation of calcium sulfide.
5	*	Transfer and Circulation of Hot Solids	---	---	1	Demonstrate the ability to safely and reliably transfer hot solids from the carbonizer and its HGCU to the CPFBC and to recirculate hot solids within the CPFBC, hot recycle cyclones, external FBHE loop at smooth, responsive, and controllable rates throughout the entire plant operating envelope.
6	†	Environmental Emission Control	---	---	2	Characterize the emissions of a fully integrated carbonizer, CPFBC, HGCU, and topping combustor subsystem.
7	†	Load-Following Capability	---	---	3	Demonstrate electric utility operating and load-following capabilities.

*Carbonizer, CPFBC, hot recycle cyclones, and external FBHE.
†Carbonizer, CPFBC, hot recycle cyclones, external FBHE, HGCU, and topping combustor.

removing entrained particulates, protects the topping combustor and gas turbine from corrosion, erosion, and deposition while meeting NSPS stack allowables. Analyses conducted during the study indicate that alkali release and NO_x emissions should not be a problem at 1600°F. A high collection efficiency and ability to clean the ceramic cross-flow filter have already been proved in bench- and pilot-scale tests. Relatively large-scale tests with actual PFB combustor gas are under way or are planned for the cross-flow filter. As a result, we recommend that additional studies be conducted to quantify the advantages associated with even higher carbonization temperatures such as 1700°F. Ceramic candle filters, hot electrostatic precipitators (ESPs), screenless granular-bed filters, etc., are candidate alternatives for the cross-flow filter should their performance and economics be found superior. All these devices are being developed under DOE and EPRI programs for first-generation PFB combustion cycles operating with 1500 to 1600°F gas turbine inlet temperatures. They should also be applicable to the second-generation plant. The second most important need is to determine the alkali and trace element levels as well as erosive slag/materials that may be generated from the gas-entrained particulates escaping from the final-stage HGCU device and passing through the topping combustor. The remaining five items are, for the most part, process/performance related and will identify how well the plant will perform in an electric utility environment. Component performance should be investigated first, followed by overall integrated system performance.

From the standpoint of the key plant components, carbonizer and circulating bed combustor operation at atmospheric pressure has been successful. The carbonizers utilized a jetting fluidized bed configuration to prevent the formation of agglomerates and yielded combustible fuel gases and freely flowing chars.

The ability to scale up the jetting fluidized bed has been thoroughly investigated in cold models up to 10 ft in diameter [10]--the size proposed for the second-generation PFB combustion plant, and the jetting bed has successfully demonstrated gasification of bituminous to lignite coals at up to 16-atm operating pressure in the KRW gasifier [11]. Similarly, circulating fluidized beds have been cold-model tested to investigate their hydrodynamics, and numerous atmospheric pressure circulating bed coal combustors are being commercially operated [12-14]. We are not aware of any data that would indicate these types of units would not operate at 10 to 14 atm. Our question is how well the carbonizer and CPFBC will perform--not whether they will work at all.

The situation is similar for the topping combustor; an MASB of the same configuration, but one-quarter the size proposed for the second-generation plant, has already been built and tested by Westinghouse using clean fuel [15]. Although the MASB tests were conducted with high- rather than low-heating-value gas, and 1400°F air rather than 1600°F PFB combustion gas, the performance experienced is encouraging.

Regarding the gas turbine, there appears to be a growing consensus within the PFB combustion community that gas turbine corrosion, erosion, and deposition problems can be solved by:

- Operating the CPFBC at bed temperatures of 1600°F and lower to reduce or minimize alkali release and eliminate the need for an alkali getter
- Utilizing cyclone separators with a final stage filter (e.g., ceramic cross-flow filter, ESP) to protect the gas turbine from erosion and deposition.

The plants studied to date utilize 1500 and 1600°F carbonizers, a 1600°F CPFBC, cyclone separators, and ceramic cross-flow filters to minimize the risk of gas turbine corrosion, erosion, and deposition; alkali getters can be incorporated, if necessary, without seriously compromising plant COE and efficiency.

Based on our investigation, there is a strong technical basis for the second-generation plant. Although many uncertainties exist and must be investigated to confirm the feasibility of the proposed solutions, we are confident that the proposed second-generation plant has an excellent chance of success.

REFERENCES

1. J. D. McClung, "Clean Cost-Effective Kilowatts From Coal," Seminar on Fluidized-Bed Combustion Technology for Utility Applications, Palo Alto, California, May 1988.

2. A. Robertson, "Preliminary Feasibility Analysis of Shop-Assembled Barge-Shipped Pressurized Fluidized-Bed Steam Generators," Foster Wheeler Development Corporation Final Report CS-3156, prepared under EPRI RP1180-15, June 1983.

3. W. S. Landers, et al., "Entrained Bed Carbonization of Bituminous Coal," U.S. Bureau of Mines Report RI6608, 1965.

4. M. Gomez, W. S. Landers, and E. O. Wagner, "Entrained Bed Carbonization of Highly Fluid Bituminous Coals," U.S. Bureau of Mines Report RI7141, June 1968.

5. C. C. Boley and M. M. Fegley, "Design and Operation of Two Refractory-Lined, Internally Heated, Entrained-Bed Carbonizers," Grand Forks Energy Research Center Report GFERC/RI-77/1, U.S. Department of Energy, 1977.

6. J. B. Howard and W. A. Peters, "Fundamental Mechanisms of Coal Gasification," Proceedings of the 6th Annual Gasification Contractors Meeting, Morgantown, West Virginia, DOE/METC-86/6043, June 1986, pp. 46-62.

7. J. P. Longwell, et al., "Applications of Organo-Calcium Chemistry to Control of Contaminant Aromatic Hydrocarbons in Advanced Coal Gasification Processes," DOE Contract DE-RA-21-86MC21074, presented at the Fifth Annual Contractor's Meeting on Contaminant Control in Coal-Derived Gas Streams, Morgantown, West Virginia, May 1985.

8. A. Robertson, et al., "Second-Generation Pressurized Fluidized Bed Combustion Plant: Research and Development Needs," Foster Wheeler Development Corporation Phase 1 Task 2 Report TR-89/06 to the U.S. DOE under Contract DE-AC21-86MC21023, March 1989.

9. A. Robertson, et al., "Second-Generation Pressurized Fluidized Bed Combustion Plant: Integrated R&D Program Plan," draft, Foster Wheeler Development Corporation Phase 1 Task 3 Report to the U.S. DOE under Contract DE-AC21-86MC21023, May 1988.

10. W-c Yang, B. Ettehadieh, and G. B. Haldipur, "Solids Circulation Pattern and Particles Mixing in a Large Jetting Fluidized Bed," AIChE Journal, Vol. 32, No. 12, December 1986.

11. G. B. Haldipur, S. Kim, and J. L. Lucas, "KRW Process Development Unit (PDU) Fluidized-Bed Coal Gasification/Hot Gas Cleanup," Proceedings of the Sixth Annual Gasification Contractors Meeting, M. R. Ghate and L. A. Baker Jarr (eds.), DOE/METC-86-6043, August 1986.

12. B. Hutchinson, "The Pyroflow Boiler at BF Goodrich Company--The First Eighteen Months of Steaming at Henry, Illinois," Proceedings of the 1987 International Conference on Fluidized Bed Combustion, J. P. Mustonen (ed.), Vol. 1, 1987.

13. W. J. Place, "Circulating Fluidized Bed Combustion via Multi-Solid Fluidized Beds (MSFB) in the Industrial Sector," Proceedings of the 1987 International Conference on Fluidized Bed Combustion, J. P. Mustonen (ed.), Vol. 1, 1987.

14. S. L. Darling, et al., "Design of the Scott Paper CFB," Proceedings of the 1987 International Conference on Fluidized Bed Combustion, J. P. Mustonen (ed.), Vol. 1, 1987.

15. R. V. Garland, P. W. Pillsbury, and G. Vermes, "Generic Studies of Advanced Fluidized Bed Air Heater Technology, DOE/CE/40543-5, Westinghouse Electric Corporation, March 1986.

Section 1

INTRODUCTION

1.1 PROGRAM OBJECTIVES

After many years of experimental testing and development work, three coal-fired pressurized fluidized bed (PFB) combustion combined-cycle power plants, ranging from 70 to 130 MWe, are in the design or the construction stage [1-3]. In all three of these plants, the gas turbine inlet temperature is below 1600°F; because of this temperature limit, they are referred to as first-generation PFB combustion plants. As first-generation technology moves closer to commercialization, interest is turning toward the development of a second-generation plant with an even higher efficiency and lower cost of electricity (COE). A COE at least 20 percent lower than that of conventional pulverized-coal (PC)-fired plants with scrubbers and a 45-percent efficiency, based on the higher heating value (HHV) of the coal, have been set as the targeted goals (first-generation plant values are typically 10 and 39 percent respectively). In addition, emissions from the new plant should be well below existing New Source Performance Standards (NSPS) allowables; and the plant should exhibit good availability, be able to handle coals ranging from lignite to bituminous, and utilize modular design and construction techniques.

1.2 PROPOSED PLANT CONCEPT

In response to the desire for a more advanced PFB plant, a team of companies--led by Foster Wheeler Development Corporation (FWDC) and consisting also of Foster Wheeler Energy Corporation (FWEC); Gilbert/Commonwealth, Inc. (G/C); the Institute of Gas Technology (IGT); Westinghouse Combustion Turbine Operation (WCTO); and Westinghouse Research and Development (WR&D) has proposed a plant concept that is a logical extension of first-generation PFB combustion technology. It utilizes a "steam-cooled" PFB combustor (fluidized bed combustion heat release is absorbed by water/steam-cooled tubes) operating at 14 atm/1600°F with a conventional 2400 psig/1000°F/1000°F/2.5-in. Hg steam cycle. To reach efficiency levels that are higher than in first-generation PFB combustion plants, power output is shifted from the steam turbine to the gas turbine using higher excess air (>100 percent rather than 30 percent) and higher gas turbine inlet temperatures (2100°F and above).

In a first-generation plant, a 1650°F PFB combustor temperature is generally accepted as a safe upper limit. Significantly higher temperatures cause increased alkali releases that are harmful to the gas turbine and, depending upon the temperatures and feedstocks involved, increase the risk of sintering and agglomeration in the coal-burning bed.

To achieve a significantly higher gas turbine inlet temperature without increasing bed temperature, we have incorporated topping combustion in the proposed plant. In this arrangement a fuel-supply subsystem generates a coal-derived low-Btu fuel gas that is burned to increase the turbine inlet temperature. There are numerous techniques for generating a fuel gas from coal; they range from relatively inefficient pyrolysis/carbonization (from a carbon-to-gas conversion standpoint) to highly efficient gasification. Compared with carbonization, gasification processes generally operate at a higher pressure and temperature, utilize steam injection, and can be either air or oxygen blown. Although these additional steps achieve high carbon conversion and can achieve a high gas-heating value, they also contaminate the gas with coal impurities (sulfur, alkalis, etc.). Thus fuel gas heat exchangers and chemical or sulfur-capturing bed processes must be incorporated to remove these contaminants. Current capital and operating costs for these cleanup processes are high; thus they are not desirable for an advanced or second-generation PFB combustion plant.

Carbonization, in contrast, produces char and a relatively low-Btu fuel gas that does not require chemical cleanup. The fuel gas, however, contains tar/light oil vapors. As this gas is cooled, these vapors can condense to cause fouling and soot formation in downstream equipment. The coal consumed during the carbonizing process releases its sulfur to the fuel gas as hydrogen sulfide; the tar/light oil vapors can also contain sulfur. If these sulfur streams are allowed to proceed unabated to the topping combustor, they will eventually be released as sulfur dioxide at the plant stack. By a judicious selection of carbonizer operating conditions and the injection of lime-based sorbent into the carbonizer to catalytically enhance the cracking of the tar vapors and to capture the hydrogen sulfide as calcium sulfide, these sulfur releases can be minimized or kept at levels that can be tolerated by the plant. Since these actions eliminate the need for fuel gas chemical cleanup and since the fuel gas will be burned hot, an air-blown carbonizer has been selected for the second-generation plant.

The char and calcium sulfide produced in the carbonizer are injected into the PFB combustor to complete char combustion, capture the char sulfur as calcium sulfate, and oxidize the calcium sulfide to calcium sulfate. Depending upon the desired plant electrical output, raw/fresh coal can also be injected into the PFB combustor to generate, superheat, and reheat additional steam. Since the plant must operate with high excess air to achieve the maximum cycle efficiency, and since minimal effluent flow rates (SO_2, NO_x, and spent sorbent) are desirable, a circulating rather than bubbling PFB combustor is used. Compared with a bubbling-bed unit, a circulating pressurized fluidized bed combustor (CPFBC) operates with a higher fluidizing velocity, uses less sorbent for a given sulfur-capture efficiency (based on atmospheric pressure fluidized bed combustor experience), and generates lower NO_x levels via staged combustion. To minimize the risks of tube erosion, the water/steam-cooled tubes required by the CPFBC are placed in an external fluidized bed heat exchanger (FBHE) operating at low velocities, and sorbent is circulated between the two beds to transfer the CPFBC heat release to the FBHE.

The exhaust gases leaving the carbonizer and the CPFBC contain char, sorbent, coal, and fly ash--all of which can erode and foul the topping combustor and gas turbine. To prevent erosion and fouling, a hot gas cleanup (HGCU) system (ceramic cross-flow filters assisted by cyclone separators) cleans these gases of their particulates (to a stack gas solids loading <20 ppm) before the gases enter the fuel gas topping combustor and the gas turbine. Ceramic candle filters, hot electrostatic precipitators (ESPs), screenless granular-bed filters, etc., are candidate alternatives for the cross-flow filter should their performance and economics be found superior.

The carbonizer low-Btu fuel gas is burned in a topping combustor by mixing it with the 1600°F high-excess-air flue gas from the CPFBC. To minimize NO_x formation and facilitate the use of metallic wall construction, the topping combustor uses low-NO_x rich/lean burn multiannular swirl burners (MASBs) being developed by WCTO.

Operation at elevated carbonizer temperatures minimizes fuel gas tar/light oil vapor levels and releases a greater amount of the incoming coal energy to this gas, thereby raising its heating values and achieving higher and higher gas turbine inlet temperatures. Although these elevated temperatures result in increased stack heat-recovery steam generator (HRSG) duties, there is less char flow to the CPFBC.

The resultant reduction in CPFBC FBHE duty is greater than the increase in HRSG duty, and there is a net reduction in steam turbine output. Since the steam turbine cycle is less efficient than the gas turbine cycle, higher carbonizing temperatures will generally result in increased plant efficiency.

Together, the Grand Forks Energy and Denver Coal Research Laboratories have successfully carbonized eight bituminous, one subbituminous, and two lignite coals. These tests were performed in 8- and 10-in.-I.D., air-blown, jetting fluidized bed reactors operating at essentially atmospheric pressure without sorbent injection [4-6]. Although one bituminous coal was carbonized at up to 1600°F, most of the data were collected in the 900 to 1300°F range, because char production rather than char consumption and tar destruction was the primary goal of these studies. Based on the reported data, 1500°F appears a reasonable lower temperature limit for bituminous-fueled second-generation plant carbonizers. Operation at much lower temperatures results in significantly higher tar/light oil vapor levels and increased char production, depending upon the particular coal involved. In addition, significantly lower temperatures result in reduced sulfur capture via lime-based sorbent/hydrogen sulfide reactions and require the CPFBC to capture sulfur more efficiently, compensating for increased topping combustor fuel gas sulfur release. With regard to an upper temperature limit, the thrust is for as high as possible a temperature without encountering gas turbine hot corrosion or topping combustor NO_x problems or without requiring chemical-type fuel gas cleanup systems.

First-generation PFB combustion alkali-release test experience has indicated that 1600°F may be an upper temperature limit because it does not require an alkali getter to protect the gas turbine from hot corrosion. In the absence of more definitive data, 1500 to 1600°F was selected as the study range for second-generation plant carbonizers. (As will be discussed later, detailed analyses indicate that neither alkali release or NO_x emissions will pose a problem to a 1600°F carbonizer, and higher operating temperatures appear possible and desirable.)

1.3 STUDY APPROACH

Carbonizer yields and heating values significantly affect the performance and economics of a second-generation PFB combustion plant. Other variables--plant excess air level, type of coal feed (pneumatic vs. coal/water slurry), and type of coal, etc.--are also important. Faced with this situation and the process uncertainties involved with a new technology of this type, the following study approach was taken:

- A computer program containing performance and cost algorithms was used to:
  - Define the potential operating envelope of second-generation PFB combustion plants
  - Identify the conditions that optimize its efficiency and COE
  - Identify how sensitive the performance and COE results are to the assumptions and values of the variables used.

Since the data extrapolations required to support performance predictions for a 1500°F carbonizer are less extensive than those for 1600°F, the first two items were conducted with a 1500°F carbonizer, and 1600°F operation was investigated in the parametric sensitivity study. Appendix A identifies the methodologies used to predict carbonizer performance and presents their results; Appendix B describes the computer optimization and parametric sensitivity study.

- Because the computer program relies on cost algorithms, the computed results are useful solely for relative ranking. Therefore, a conceptual design of the plant was prepared to more accurately determine the performance and COE when operating with Pittsburgh No. 8 coal and Plum Run dolomite. Even though the computer study predicted that second-generation plant performance and COE would be better with a 1600°F carbonizer, 1500°F was used because it yielded a similar COE and required a smaller extrapolation of the data being used to predict its performance. In addition, the lower temperature promotes a "worst-case" sulfur-capture scenario (higher tar/light oil vapor levels) while minimizing potential alkali and topping combustor NO_x problems. This plant configuration, with a 1500°F rather than a 1600°F carbonizer and against which all other arrangements are compared, is called the "baseline plant." Section 2 describes the baseline plant in detail, and Sections 3 and 4 describe its economics and environmental impact. Appendices C through F present supporting design data.
- Base plant performance and economic characteristics were then compared with those of a reference conventional PC-fired plant with a stack gas scrubber to identify 1500°F carbonizer plant advantages. Section 5 presents the comparison; the reference PC plant is described in Appendix G.
- The sensitivity of the baseline plant performance and COE to 23 alternative assumptions or operating conditions--a 1600°F carbonizer; a less pessimistic 1500°F carbonizer yield scenario; minimum plant excess air; a 10-atm plant pressure ratio; coal/water feed, limestone sorbent, lignite; etc.--was then assessed by identifying the performance, configuration, and cost changes each would induce in the baseline plant configuration. The results of this sensitivity study are presented in Section 6.
- Based on a better understanding of the second-generation plant from the sensitivity study, specific recommendations regarding efficiency and COE were made for commercial bituminous and lignite coal-fired second-generation PFB combustion plants; these recommendations are contained in Section 7.

1.4 REFERENCES

1. M. J. Mudd and D. A. Bauer, "Tidd PFBC Demonstration Plant: Combined Cycle PFBC Clean Coal Technology," Proceedings of the 1987 International Conference on Fluidized Bed Combustion, Boston, May 1987.

2. P. Almqvist, "The PFBC Plant in Vartan, Stockholm," Proceedings of the 1987 International Conference on Fluidized Bed Combustion, Boston, May 1987.

3. E. Menendez, V. Bencomo, and M. A. Cuenca, "Spain Takes to Pressurized Fluid Bed Combustion: A View to Endesa's 80 MW Demonstration Plant," Proceedings of the 1987 International Conference on Fluidized Bed Combustion, Boston, May 1987.

4. W-c. Yang, "A Criterion For 'Fast Fluidization'," Proceedings of the Third International Conference on the Pneumatic Transport of Solids in Pipes, British Hydromechanics Research Association, April 1976.

5. V. Petersen, et al., "Combustion in the Circulating Fluid Bed: An Alternative Approach in Energy Supply and Environmental Protection," Proceedings of the Sixth International Conference on Fluidized Bed Combustion, Vol. II, U.S. Department of Energy, CONF-800428, UC-90e, August 1980.

6. F. Engstrom, "Development and Commercial Operation of a Circulating Fluidized Bed Combustion System," Proceedings of the Sixth International Conference on Fluidized Bed Combustion, Vol. II, U.S. Department of Energy, CONF-800428, UC-90e, August 1980.

Section 2

SECOND-GENERATION PLANT WITH 1500°F CARBONIZER (BASELINE)

2.1 PLANT SITE DESCRIPTION/CONDITIONS

The plant site is assumed to be in the Ohio River Valley of southwestern Pennsylvania/eastern Ohio. The site consists of approximately 300 usable acres (not including ash disposal) within 15 miles of a medium-sized metropolitan area and with a well-established infrastructure capable of supporting the required construction work force. The area immediately surrounding the site is a mixture of agriculture and light industry. The site is served by a river with adequate flow for use as makeup cooling water after minimal pretreatment and for the receipt of cooling system blowdown discharges. In addition, the river is a navigable waterway suitable for shipping shop-fabricated major components to the site (as described in Section 2.6). A railroad line that can handle unit coal trains passes within 2-1/2 miles of the site boundary. The site is served by a well-developed road network capable of carrying AASHTO* H-20 S-16 loads, with overhead restrictions not lower than 16 ft (Interstate Standard).

The site is on relatively flat land with a maximum difference in elevation within the site of about 30 ft. The topography of the area surrounding the site is rolling hills with elevations within 2000 yd not more than 300 ft above the site elevation.

The site is within Seismic Zone 1, as defined by the Uniform Building Code, and the ambient design conditions are:

Barometric Pressure	14.4 psia
Dry bulb temperature	60°F
Wet bulb temperature	52.5°F

A sufficient work force of well-trained construction laborers is available within a 50-mile radius of the site. Labor conditions are such that a "Project Work Agreement" can be obtained from labor organizations and contractors.

All necessary bulk construction material is available locally and can be delivered within a reasonable period of time.

This generic site has been used to prepare conceptual designs of the second-generation PFB combustion plant (baseline) and the reference conventional plant (PC-fired). Although specific site conditions will dictate design changes, the comparisons in this report should be valid.

2.2 PROCESS DESCRIPTION

The key to the baseline plant concept is the use of an air-blown carbonizer that provides low-Btu fuel gas to a gas turbine topping combustor, while char produced by the carbonizer is burned in a CPFBC, preheating the topping combustor

*American Association of State Highway and Transportation Officials.

oxidant and also generating steam. Figure 6 is an overall second-generation plant process schematic. Figure 7 presents the full-load heat and mass balance diagram of the baseline plant and illustrates the functional arrangement of the major plant systems.

The plant utilizes two identical carbonizer/CPFBC/FBHE/gas turbine modules operating in parallel, together with one steam turbine, to produce 452.8 MWe of net electrical power; for simplicity, however, only one module is shown in Figure 7. Although the two modules share a common stack, their air and flue gas paths, coal and sorbent feed systems, and spent material depressurizing and cooling systems are totally independent. Despite this independence, the modules must be operated at similar firing rates to yield similar steam conditions. The data and flow rates presented in Figure 7 are totals for the overall plant.

2.2.1 Feedstocks

The baseline plant has been designed for Pittsburgh No. 8 coal and Plum Run dolomite. Analyses of these feedstocks are presented in Tables 6 and 7.

2.2.2 Gas and Solids Systems

A description of the plant process begins most easily with the gas turbines, since all other processes are dependent on the gas turbine operating point. Approximately 1/6 the gas turbine compressor airflow is used for gas turbine blade cooling; the balance proceeds to the carbonizer/CPFBC area. This air, at approximately 14 atm/713°F, supplies four distinct subsystems:

- Transport air compressors provide pressurizing and transport air at 50 psi above the carbonizer entry pressure. The air is cooled and dried before being compressed by the transport compressors. The air amounts to 1.5 percent of the air delivered by the gas turbine compressor.
- Carbonizer booster compressors provide air to the carbonizers. These compressors, which provide a 17-psi boost to the carbonizer oxidant, are needed to ensure that the fuel gas will have adequate pressure above the vitiated oxidant at the topping combustors. The compressors are not precooled, and their air use amounts to 6.7 percent of the gas turbine compressed air production.
- FBHE fluidizing air amounts to 14.1 percent of the gas turbine air production.
- The remaining 77.7 percent of gas turbine air proceeds to the CPFBCs as primary and secondary combustion air.

The critical path that establishes pressure drop in the cycle is the flow of air through the FBHEs. Pressure loss through the primary zone of the CPFBCs is less than that in the path through the FBHEs, and pressure losses in the carbonizer and fuel gas cleanup train are compensated for by the carbonizer booster compressors, with little adverse effect on performance.

During full-load operation, all plant coal and sorbent, sized at 1/8-in. x 0, are fed to the carbonizers by pressurized pneumatic solids transport systems manufactured by Petrocarb, Inc. The Petrocarb systems are supplied with pressurizing air by the transport air compressors, which also provide the air that conveys the solids through the transport lines. Additional transport lines connect the Petrocarb injectors with the CPFBCs, but these are normally used only during start-up, shutdown, and part-load operation.

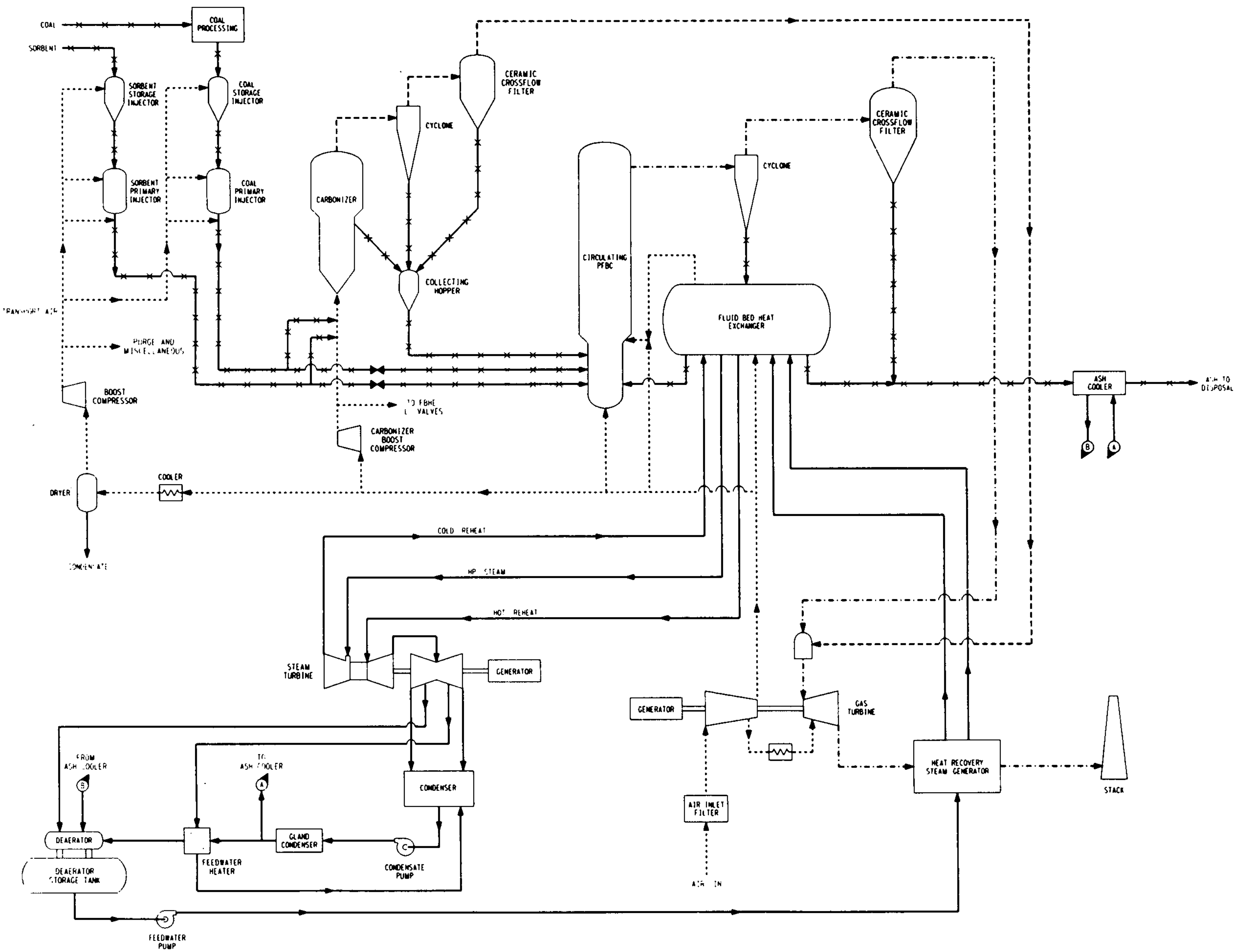
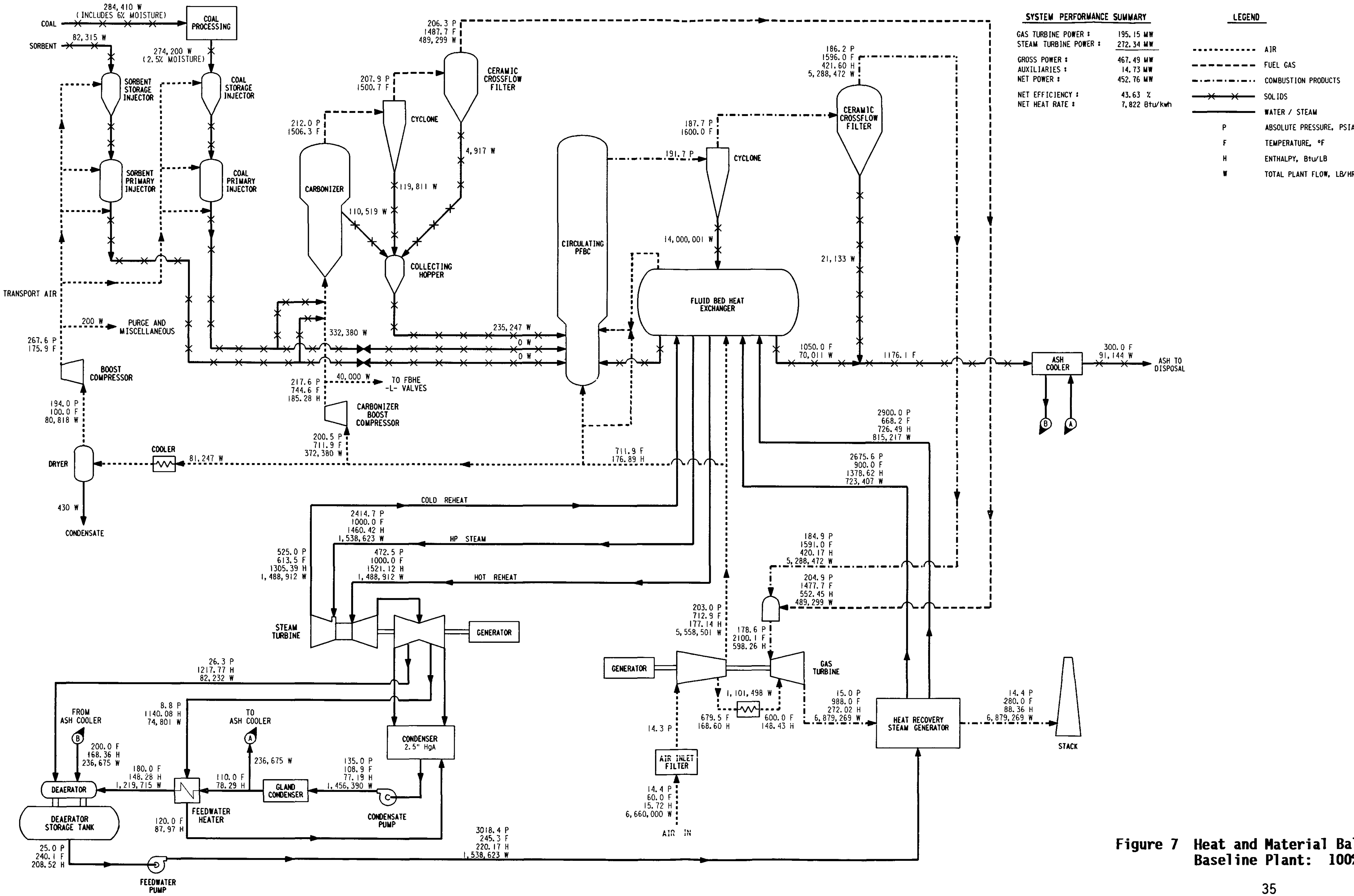


Figure 6 Overall Second-Generation Plant Process Schematic



Dwg. 8333-1-400-009-001, Rev. E

Figure 7 Heat and Material Balance-- Baseline Plant: 100% Load

Table 6 Pittsburgh No. 8 Coal Analysis

Constituent	As Received, %
Carbon	69.36
Hydrogen	5.18
Nitrogen	1.22
Sulfur	2.89
Ash	9.94
Oxygen	11.41
Total	100.00

	As Received, %
Moisture	6.00
Ash	9.94
Volatile Matter	35.91
Fixed Carbon	48.15
Total	100.00
Sulfur	2.89
Btu	12,450

Ash Analysis, %

Silica, SiO_2	48.1	
Aluminum Oxide, Al_2O_3	22.3	
Iron Oxide, Fe_2O_3	24.2	
Titanium Dioxide, TiO_2	1.3	
Calcium Oxide, CaO	1.3	
Magnesium Oxide, MgO	0.6	
Sodium Oxide, Na_2O	0.3	(0.9% in Coal)
Potassium Oxide, K_2O	1.5	(0.15% in Coal)
Sulfur Trioxide, SO_3	0.8	
Phosphorous Pentoxide, P_2O_5	0.1	
Total	100.5	

Ash Fusion Temperature, °F (°C)

	Reducing Atmosphere	Oxidizing Atmosphere
Initial Deformation	2015 (1102)	2570 (1410)
Spherical	2135 (1168)	2614 (1434)
Hemispherical	2225 (1218)	2628 (1442)
Fluid	2450 (1343)	2685 (1474)

Table 7 Plum Run Dolomite

	Dry Basis, %
Calcium Oxide, CaO	31.2
Magnesium Oxide, MgO	21.2
Silica, SiO_2	0.20
Aluminum Oxide, Al_2O_3	0.53
Iron Oxide, Fe_2O_3	0.60
Sulfur Trioxide, SO_3	0.29
Carbon Dioxide, CO_2	45.4
Chlorine, Cl	0.05
Balance	0.53

Water-Soluble Components, % as received	
Sodium as Na_2O	0.013
Potassium as K_2O	0.002

For reliable feed of solids in the Petrocarb systems, surface moisture must be removed from the coal and dolomite. Dryers supplied with a mixture of hot air and flue gas accomplish this task. The air is collected at 629°F from air/air heat exchangers that cool the gas turbine cooling air. Flue gas is collected from the exit of the HRSGs at a nominal 280°F; the flue gas supplies two-thirds the mass flow requirement of the solids dryers. The dryers also consume a small amount of fuel oil during normal operation to heat the air/gas mixture to the 500°F required for efficient drying.

Char and spent sorbent are withdrawn/separated from each carbonizer at three locations--by a bed overflow drain in the carbonizer and by a cyclone and a ceramic cross-flow filter in the fuel gas cleanup system. Solids from the three are collected in a common hopper and fed to each CPFBC by N valves, which are fluidized with a small flow of nitrogen. The CPFBCs burn the carbonizer char and:

- Produce 1600°F vitiated air for the topping combustor and 1600°F sorbent for FBHE steam generation, superheating, and reheating.
- Capture/convert sulfur released as sulfur dioxide during the char combustion process to calcium sulfate.
- Convert calcium sulfide in the carbonizer sorbent residue to calcium sulfate.

To remove elutriated bed material, the exhaust gas from each CPFBC is passed through an HGCU system consisting of cyclones and ceramic cross-flow filters. Solids captured by the cyclones are recirculated to the FBHEs; surplus solids are extracted from them at 1050°F at two points, depressurized in restricted-pipe discharge vessels, and cooled in screw coolers. Solids collected by the cross-flow filters are also depressurized in restricted-pipe discharge vessels and then cooled in screw coolers.

After passing through the HGCU systems, carbonizer and CPFBC flue gases are conveyed to the gas turbine topping combustors by refractory-lined hot-gas piping. Metallic liners in the hot-gas piping from the cross-flow filter to the topping combustor isolate the refractory and prevent any spalled refractory from entering the cleaned gases. The fuel gas is oxidized/burned in the topping combustor MASBs by the CPFBC flue gas, producing a 2100°F gas. The gas expands through the gas turbines, producing about 98 MWe (net) in each of the gas turbine units. An HRSG at each gas turbine cools the gas to 280°F, producing steam and heated feedwater. Gas from each HRSG is then ducted to a common stack.

2.2.3 Steam and Feedwater Systems

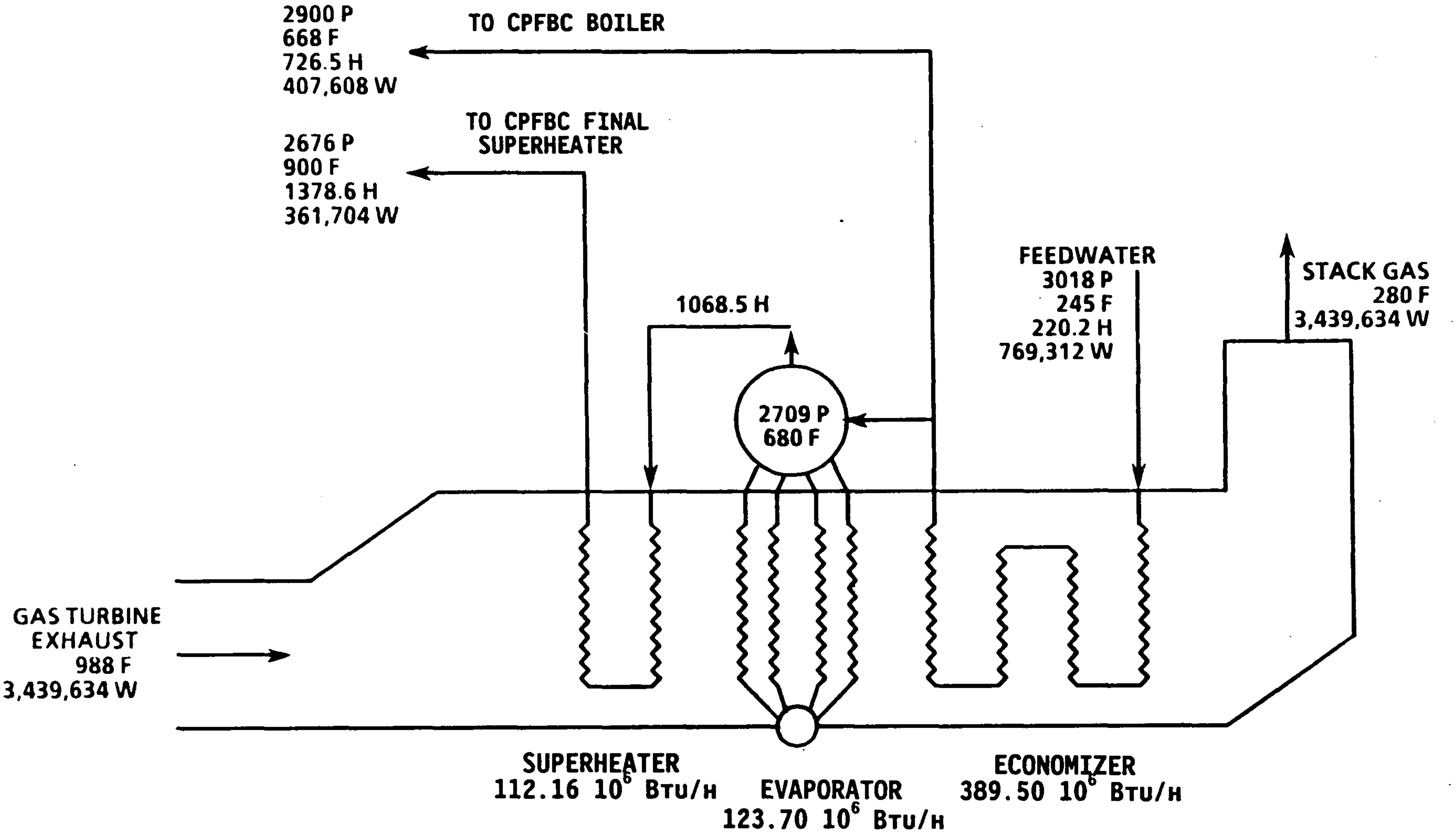
The baseline plant steam turbine is similar to the turbine of a typical, modern 270-MWe power plant. However, the boiler and feedwater heating systems differ considerably from those in standard fossil-fuel-fired plants because of the special characteristics of this PFB combustion cycle. The turbine is a 2400-psig reheat unit with 1000°F nominal temperatures for superheat and reheat steam. The major difference from a conventional steam turbine is that only two extractions are used during normal full-load operation, while a conventional fossil-fuel-fired plant with this size turbine would typically have seven extractions for feedwater heating.

Heating and deaeration of low-pressure condensate are provided primarily by extraction steam. A closed feedwater heater heats condensate to 180°F, and the deaerator operates at 10.6 psig/240°F. About 16 percent of the condensate is diverted around the feedwater heater to cool the ash screw coolers; the hot water leaving the screw coolers is discharged directly into the deaerator. Water from the deaerator is pressurized to 3004 psig by electrically driven booster pumps and feedwater pumps. Two 60-percent capacity pump trains are provided.

The 3004-psig feedwater is divided into two equal streams--one to the HRSG of each module (Figure 8). (Since the modules are identical, only one stream will be discussed.) Upon entering the HRSG, the feedwater is piped to economizer tube sections and heated to 668°F. This heated water is then split into two streams, with 47 percent proceeding to the HRSG steam drum and the balance to the FBHE steam drum. Each stream is evaporated, superheated to 900°F, and piped to a mixing header outside the FBHE. After mixing, the combined 900°F stream is piped to the FBHE and superheated to yield a nominal 1000°F turbine throttle temperature.

The steam from the two FBHEs is blended, and after expanding through the high-pressure (HP) section of the steam turbine, is split into two equal streams (one to each FBHE). The steam is then reheated to a nominal 1000°F, blended, expanded through the steam turbine, and discharged to the plant steam condenser.

The HRSG and FBHE are closely tied in steam production. The HRSG provides 56 percent of the steam cycle thermal input. This heat from the HRSG consists of 100 percent of the plant economizing duty, 47 percent of evaporating duty, and 37 percent of superheating duty. The FBHE provides 43 percent of the steam cycle input, consisting of 100 percent of reheating duty, 63 percent of superheating duty, and 53 percent of evaporating duty. The remaining 1 percent of steam cycle thermal input is provided by the ash screw coolers in the form of condensate heating.



LEGEND

P: ABSOLUTE PRESSURE, PSIA
F: TEMPERATURE, °F
H: ENTHALPY, BTU/LB
W: FLOW RATE, LB/H PER MODULE

Figure 8 HRSG Schematic

2.3 PLANT ARRANGEMENT

The following sections present the basis for and description of the arrangement recommended for the baseline plant.

2.3.1 Approach to Plant Arrangement/Layout

Criteria/constraints considered in the development of the plant arrangement were:

- Consideration of costly lengths of refractory-lined pipe, steam pipe, and electrical bus duct
- Access to the site by barge and rail
- Overland access to the site for large barge-shipped components
- Access to components/systems for maintenance
- Good relationship among systems shared by both power modules
- As few "opposite-hand" arrangements as possible
- Adequate laydown space around components likely to be serviced in place
- Convenient access to plant where needed (e.g., ash transport truck routes, other service roads)
- Most components located above grade
- Enclosure of only those components requiring frequent attendance, in-place service, or other protection
- Consideration for a future second unit
- A safe working distance from the fuel-gas flare system.

Using these criteria, the arrangements described in the next section were prepared. In subsequent phases, additional arrangements can be considered using the developed capital costs as a guide in comparing alternatives.

2.3.2 Plant Site Arrangement

The total site occupies approximately 180 acres, with the power island itself occupying approximately 6.4 acres. As in a PC-fired plant, the smaller area occupied by the combustion equipment is overshadowed by the requirement to bring feedstocks into the plant and to provide interconnecting piping, access roads, parking, plant administration, and a reasonable working space between plant systems.

Overall Site Plan (Figure 9). The second-generation PFB combustion power plant is on a relatively level site adjacent to a navigable waterway, with both rail and highway access. The prevailing wind is from the southwest.

Coal and dolomite are delivered to the site by barge (26)* and then transported from the barge unloader (27) to a transfer point by belt conveyor (28). During normal operation, coal or dolomite is delivered directly to the stacker/reclaimer conveyor (35), which is perpendicular to the barge unloader docking area. With the stacker/reclaimer in this position, the coal and dolomite storage areas

*Numbers in parentheses identify items in the referenced figures, which are presented at the end of Subsection 2.3.

span the site to the north of the main power island. If the stacker/reclaimer is inoperable at the time of barge delivery, coal or dolomite can be deposited directly in their inactive storage piles by emergency stackout conveyors (33,34). The coal and dolomite piles shown are for about 60-days' storage. Coal and dolomite storage capacities can be increased up to 6 months, as shown, in case barge delivery is halted because waterways are frozen.

From storage, coal and dolomite are sent to the crusher building (44) at the west end of the stacker/reclaimer conveyor. They are crushed and conveyed to their 3-day storage silos (47,48) at the southwest corner of the coal yard area and then conveyed to the east, to the coal and dolomite 24-hour storage silos (49,50). Coal and dolomite from the silos are conveyed to the preparation building (51) for final crushing, drying, and screening. This building also houses the Petrocarb pneumatic feed systems for both. The two modules (3) are placed near the coal and dolomite supply to minimize feed system piping.

Ash from the two modules is mechanically conveyed to two ash storage silos (52) on the west side of the steam generation island. Ash is removed from the site by truck, using a dedicated ash haul road with an independent plant entrance. A truck scale (53) along the haul road weighs ash trucks entering and leaving the site.

The two modules are separated by a common pipe bridge extending north and south and linking the steam generation island with the gas/steam turbine buildings.

The gas turbine building (2) is shown to the west of the pipe bridge. The gas turbine discharges are ducted to two HRSGs (8) on the east side of the pipe bridge. The flue gas from the HRSGs is then ducted to a common stack (9). An access road separates the gas turbine and HRSG areas from the steam generator island.

The steam turbine building (1) is south of the pipe bridge, directly adjacent to the gas turbine building. Generator leads exit both turbine buildings along the west wall. A common transformer area (10) extends along the entire length of both turbine buildings. From this area power is transmitted overhead to an adjoining substation (11). By positioning the gas and steam turbines as shown, a common transformer area is created, minimizing bus duct and transmission leads. The gas turbine ducts and HRSGs are also grouped, providing an economical duct arrangement.

Various gas turbine, steam turbine, and steam generation module orientation schemes were attempted. Each layout scheme required splitting either the transformer or HRSG areas. Such a split would have resulted in either longer or turned flue gas ducting and possibly dual stacks or longer transmission lines because the transformer areas would be separated.

A rail spur services the turbine building, providing for heavy equipment installation and removal during and after plant construction.

A maintenance shop building (7) along the south wall of the steam turbine building houses a laboratory and electrical, instrument, and machine shops.

A two-floor administration building (6) adjacent to the turbine and maintenance buildings houses the plant access and locker room area at grade, with administrative offices on the second level. A parking area for plant personnel (13) is south of the administration building.

A three story structure (4) along the east side of the turbine building houses water operation equipment on the first floor and electrical equipment on the second. The third floor houses the control room complex at the same elevation as the steam turbine operating floor. A building extension (5), at grade and to the east, houses the auxiliary boilers and emergency diesel generator.

A river water intake structure (25) at the river's edge east of the steam turbine building provides water to the cooling towers and to the makeup water and pretreatment building (16). In this building, between the river water intake structure and the steam turbine building, river water is treated and stored awaiting use by the demineralized water system at grade level in the control complex structure (4).

Two cooling towers (14) are positioned to the south and east of the makeup water and pretreatment building, as close as possible to the steam turbine building to minimize the length of circulating water piping that carries cooling water to and from the steam turbine condenser. Makeup water is pumped to the cooling towers from the intake structure. A structure adjacent to the cooling towers houses associated electrical switchgear and chlorination equipment. Truck access is provided for chemical delivery and circulating water pump maintenance.

A fuel oil storage tank (19), surrounded by an earthen dike north and east of the makeup water and pretreatment building, can be supplied with oil by either rail car or truck. A rail spur is provided for tank car shipments. A fuel oil pump house (20) is east of the diked area. Oil piping can be carried back to the power island along a nearby pipe bridge (24).

A wastewater treatment facility (21) is located north of the oil storage tank area. Wastewater retention ponds (29,30) are positioned to the east, away from the main power island. Rainwater runoff from both the coal and dolomite storage piles (38,39) is collected in these retention ponds and treated. Other contaminated water is also stored and treated for release.

A fuel-gas flare stack (23) is shown to the east of the oil storage tank in an isolated area of the site. An east-west pipe bridge (24) connects the flare stack with the main pipe bridge on the power island.

<u>Power Island--Plan at Grade (Figure 10)</u>. The Plan at Grade drawing provides additional detail and depicts equipment located at grade. It also shows equipment above grade in "phantom" lines.

Stair towers along the east and west side of the coal injection vessel bay provide access to the various floor levels of the coal preparation building as well as the steam generation modules. A phantom line outlines the various vessels that make up the steam generation modules above.

A single-story structure housing the plant air compressors (5,7,8,9) sits directly to the south of the coal preparation building, between the modules. The compressors are centrally located, as they serve both modules and the coal and dolomite injection systems. The booster compressors take their air supply from main compressed air piping that is carried on the pipe bridge overhead. Also within this building are the CPFBC start-up air heaters (6). A refractory-lined pipe connects the heaters to a compressed air line that supplies primary air to the CPFBC. There are two boiler feedwater recirculation pumps (10) below the FBHE outline (phantom), typical for each steam generation module. Four ash screw coolers (11,12) are also within each module. The two shown at angles receive ash from the FBHE overhead. The two remaining coolers receive ash from the cross-flow filters high in the structure above. The cooled ash is discharged to a conveyor system, below grade, that conveys it to the west and discharges it onto additional conveyors at grade (15). Three sets of stairs provide access to the below-grade area--one east of the steam generation island, one west, and a third centrally located adjacent to the compressor building.

A below-grade ash system was chosen to lower the overall FBHE height. Were the ash conveyed at grade, the coolers would have to be elevated, forcing the FBHEs and some support systems to be raised.

A switchgear building is located south of the compressor structure and between the modules. The 480-V and 4160-V switchgear (13,14) is housed in a building south of the compressor structure, between the modules, providing power for the steam generation island as well as the coal preparation building. Two transformers (16) west of the steam generation island and south of the ash silos take power from the 13.8-kV switchgear and from the 4160-V switchgear.

Stair towers to the FBHEs in the southeast and southwest corners of the structure provide adequate means for entering and leaving both modules.

The combustion turbine building is a high-roof/low-roof configuration. A high bay over the turbine section allows an overhead bridge crane to service the turbines. A common laydown bay between the two turbines (18) houses maintenance. There is truck access to this bay, to move turbine components. An acoustical enclosure (20) surrounds each combustion turbine and the topping combustors. The turbine air inlet (21) directly west of the enclosure is positioned vertically. The combustion turbine exhausts are ducted to the HRSG (30), directly east of the turbine building. Two bypass stacks (29) are positioned between the combustion turbines and the HRSGs. To the east is a common stack (31) serving both HRSGs. A small pipe bridge can be seen paralleling each HRSG. The northern bridge continues past the HRSG carrying the fuel-gas bypass pipe to the flare stack and supporting a pipe valve station. The combustion turbine generators (22) and their auxiliaries (23-27) are within the low-roofed portion of the turbine building. Transformers (47) are in an area west of the turbine buildings, allowing for easy transmission of power to the substation. Power is returned from the substation to the two smaller auxiliary transformers (48) shown to the south. These transformers power the 13.8-kV switchgear in the west end of the steam turbine building.

The steam turbine building lies directly south of the combustion turbine building. Rail access is provided at the southwest corner of the building with an equipment hatch above. Toward the center of the building are the massive concrete columns of the turbine pedestal, along with the steam turbine condenser (42). A room housing the lube oil system (39) is east of the turbine pedestal. The four boiler feedwater pumps, two mains (37) and two boosters (38), are positioned farther to the east. The condensate main (40) and booster pumps (41) are shown on both sides of the turbine pedestal.

The two bays east of the boiler feedwater pumps house the makeup water treatment (35) and condensate demineralizer (36) equipment. An acid and caustic truck unloading station is outside the east wall of the water treatment area.

The auxiliary boilers (34) are housed in a single-story structure east of the water treatment area. An emergency diesel generator (33) is in an attached structure adjacent to the auxiliary boiler building. The demineralized water storage tank (32) is between the auxiliary boiler and plant access road to the east.

The center bay of the machine shop area is to serve as pull space during steam turbine condenser tube removal. A portion of the wall separating the machine shop from the turbine building must be removed during this retubing work.

The grade level plan shows an area in the administration building reserved for plant access control and shower/locker rooms. A room in the southeast corner of the building houses the heating, ventilating, and air conditioning (HVAC) equipment required to condition the air in the administration building and the control complex area.

A stair tower and elevator in the northeast corner of the administration building serve both the administration and the turbine building/control complex areas. A stair tower in the southwest corner of the administration building provides a second means for reaching or leaving the second floor.

Power Island--Plan at El. 120 ft (Figure 11). The plan at 120 ft also shows a portion of the coal preparation building containing the dolomite and coal injection vessels (49,50) along with the vertical sections of the coal and dolomite drag chain conveyors (1,2).

Two air heaters (51) south of the coal preparation building supply hot start-up air to the carbonizer. Each heater is individually housed in an enclosure sharing a common wall with the coal preparation building and is closely coupled to the carbonizer air inlet to minimize refractory pipe length.

The roof of the compressor building is below the air heater enclosures. Two air-to-air heat exchangers (52) on the compressor building roof between the two air heater enclosures receive compressed air from the overhead pipe bridge and discharge the air to two shell-and-tube heat exchangers at grade in the compressor building [(3) in Figure 10]. Several pipes run across the compressor building roof. Two carry the fuel gas from the carbonizer cross-flow filter to the combustion turbines. The others carry compressed air from the combustion turbines to the CPFBC and air-to-air heat exchanger.

The CPFBC vessel (53) is shown in each of the two modules. The large N- and J-valve piping is used for bed material transfers. Two restricted-pipe discharge hoppers (54) are directly south of each CPFBC unit. These hoppers allow draining of the bed material from the FBHE. The bed material is then discharged to the ash screw coolers at grade.

Two ash conveyors (15) run along the west side of the steam generation island. Also seen in Figure 10, they feed ash from the screw coolers to the ash silos (17). The ash unloader rooms for the two ash silos are west of the steam generation island. A pelletizer (56) and fluidizing air blower (57) are shown in each room. An equipment hatch is shown over the road below. A stair between the two silos provides access to the unloader rooms and to the silo roofs.

Refractory-lined flue-gas piping from the ceramic cross-flow filters is shown south of the steam generation island. Two pipes per module are stacked on the pipe bridge. The major piping, fuel gas, compressed air, and flue gas are shown within the combustion turbine building. Bus duct leads (58) run from the combustion turbine generators to their respective transformers.

The fuel-gas bypass pipe runs east along a pipe bridge to the flare stack some distance away. This pipe bridge also supports piping carrying a portion of the flue-gas stream that is diverted from the ducting between the HRSG and stack. This flue gas is combined with heated air from the combustion turbine air cooler and used for coal and dolomite drying.

The turbine building mezzanine is shown at this elevation. Toward the center of the building, the concrete columns of the turbine pedestal can be seen along with the steam turbine condenser (42). A feedwater heater (67) is positioned in the neck of the condenser. Pull space is provided for heater tube removal. The heater tubes are withdrawn through a removable wall section and supported on the roof of the maintenance shop building.

The generator bus duct leads (58) are shown connecting the generator with the transformer west of the turbine building wall. There is an equipment hatch in the southwest corner of the turbine building directly over the rail access bay.

Another equipment hatch north of the turbine pedestal allows for the removal of the vertical can-type condensate pumps located at grade. A room housing the lube oil system (65) is shown east of the turbine pedestal. A pipe chase east of the lube oil enclosure is used by piping associated with the deaerator on the operating floor above.

The two bays on the east end of the turbine building are divided into four areas. The room to the north houses 4160-V (14) and 480-V (13) switchgear, powered by the 13.8-kV switchgear at grade. The room adjacent to the switchgear room provides a termination and cable-spreading area for the control room directly above. Rooms to the south of the termination room house motor control centers (64) that power equipment in the steam and combustion turbine building areas. Batteries (62) and chargers (63) are kept in two rooms east of the motor control center room.

The administration building office area is southeast of the turbine building.

Power Island--Plan at El. 140 ft (Figure 12). A portion of the coal and dolomite preparation building is at the left side of the drawing. The dolomite conveying system (1) is above the dolomite surge bins (72). To the south are the three coal injection vessels (50).

The FBHE (75) is central to each module; the CPFBC (53) is north of the FBHE vessel. Two secondary air pipes connect the FBHE vessel to the CPFBC. Additional secondary air, as well as primary air, is also supplied to the CPFBC from the compressed air piping carried along its pipe bridge from the combustion turbine. A branch line from the compressed air pipe supplies fluidizing air to the FBHE.

A duct for coal and dolomite drying air connects the two compressed air pipes. Air, from the combustion turbine cooling air cooler, and flue gas are mixed to supply the drying air.

The carbonizer vessel (73) can be seen north of the CPFBC and the carbonizer solids collection hopper (74), between the carbonizer and CPFBC.

Main steam, cold, and hot reheat piping lead from the south side of the FBHE. The restricted pipe discharge hoppers (54) for the cross-flow filters are in the bay south of the FBHE.

The combustion turbine air inlets (77) and silencers (78) are on the low roof of the combustion turbine building directly over the turbine generators. Access to the roof area is through the steam turbine building stair tower leading to the southeast corner of the combustion turbine roof.

The steam turbine (80) is shown at the operating floor level. The turbine operating floor provides adequate laydown for turbine dismantling service. The overhead bridge crane hook coverage is indicated. An equipment hatch at the southwest corner of the turbine building provides for turbine component removal to the rail bay at grade. Another equipment hatch north of the turbine is used for removing the condensate pump with the bridge crane.

The deaerator and storage tank (79) are east of the steam turbine, directly over the feedwater booster pumps located at grade.

The two bays east of the turbine building are divided into three areas. The north area houses the computer room. Immediately to the south is the control room, from which all plant systems are controlled. A shift supervisor's office, conference room, kitchen, record storage room, and toilet facilities occupy the area south of the control room. The control complex has a raised floor with ramp access. Access to other plant areas is by an adjacent stairway and elevator.

Power Island--Overall Plan (Figure 13). As in all other plan views, a portion of the coal and dolomite preparation building appears at the left of the drawing. The coal conveying system (2) is shown over the coal surge bins (83). The stairs on either side of the preparation building service the various platforms within the steam generation modules.

The CPFBC cyclones (86) are central to each module, above the FBHE. Large refractory-lined flue gas piping connects the cyclone inlets with the CPFBC to the north. The carbonizer (73) is north of the CPFBC. The carbonizer cyclone (85) and cross-flow filter (84) are between the carbonizer and CPFBC vessels. Refractory-lined fuel-gas piping leaves the filter vessel. Two cross-flow filters (87) for particulate removal are south of the CPFBC cyclones (86). Refractory-lined flue-gas piping connects the CPFBC cyclone outlets to the cross-flow filters.

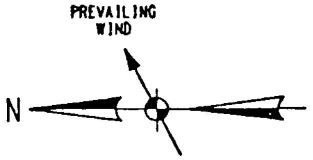
A composite of the major piping systems is shown on this plan. The main steam, cold, and hot reheat piping from each module connect to common steam headers supported on the pipe bridge and running south to the steam turbine building. Feedwater piping for each HRSG is also routed along this bridge to its respective FBHE vessel.

The roofs of the ash silos (17) are visible west of the steam generation island. The ash-conveying system (15) connects the island ash system with the ash silos. Access to the silo roofs is either from the steam generation island by a walkway paralleling the conveyors or from the stairs between the silos.

The overall plan shows the various roof elevations for all structures in the power island.

Power Island--El. Sections A-A and B-B (Figure 14). Section A-A, looking east, illustrates the elevation differences and relative position of major equipment in the three major plant areas--steam generation module, combustion turbine building, and steam turbine building. Section B-B is a view looking north through the combustion turbine building. The elevation differences between the high and low roofs of the combustion turbine building can be seen in this section. The relationship between the combustion turbine building and the pipe bridge, bypass stack, HRSG, and main stack are all shown.

Dwg. 8333-1-200-002-001, Rev. A



PLANT DESCRIPTION

1 STEAM TURBINE BUILDING
2 COMBUSTION TURBINE BUILDING
3 STEAM GENERATION ISLAND
4 CONTROL COMPLEX
5 AUXILIARY BOILER BUILDING
6 ADMINISTRATION BUILDING
7 MAINTENANCE BUILDING
8 HEAT RECOVERY STEAM GENERATOR
9 STACK
10 STATION TRANSFORMERS
11 SUBSTATION
12 WAREHOUSE
13 PARKING
14 COOLING TOWER
15 COOLING TOWER BLOWDOWN POND
16 MAKEUP WATER AND PRETREATMENT BUILDING
17 FILTERED WATER STORAGE TANK
18 CONDENSATE TANK
19 FUEL OIL STORAGE TANK
20 FUEL OIL PUMP HOUSE
21 INDUSTRIAL WASTE TREATMENT BUILDING
22 CONSTRUCTION POND
23 FLARE STACK
24 PIPE BRIDGE
25 RIVER WATER INTAKE STRUCTURE
26 COAL / DOLOMITE BARGE
27 COAL / DOLOMITE BARGE UNLOADING FACILITY
28 COAL / DOLOMITE TRANSFER CONVEYOR
29 COAL PILE RUNOFF POND
30 DOLOMITE PILE RUNOFF POND
31 RUNOFF WATER PUMP HOUSE
32 TRANSFER BUILDING
33 COAL EMERGENCY STOCKOUT CONVEYOR
34 DOLOMITE EMERGENCY STOCKOUT CONVEYOR
35 STACKER / RECLAIMER CONVEYOR
36 STACKER / RECLAIMER
37 COAL YARD VEHICLE MAINTENANCE GARAGE
38 COAL STORAGE (60 DAY)
39 DOLOMITE STORAGE (60 DAY)
40 COAL EMERGENCY RECLAIM HOPPER
41 DOLOMITE EMERGENCY RECLAIM HOPPER
42 COAL EMERGENCY RECLAIM CONVEYOR
43 DOLOMITE EMERGENCY RECLAIM CONVEYOR
44 COAL / DOLOMITE CRUSHER BUILDING
45 COAL CONVEYOR
46 DOLOMITE CONVEYOR
47 COAL STORAGE SILO (3 DAY)
48 DOLOMITE STORAGE SILO (3 DAY)
49 COAL STORAGE SILO (24 HR)
50 DOLOMITE STORAGE SILO (24 HR)
51 COAL PREPARATION BUILDING
52 ASH SILO
53 TRUCK SCALE
54 GUARD HOUSE

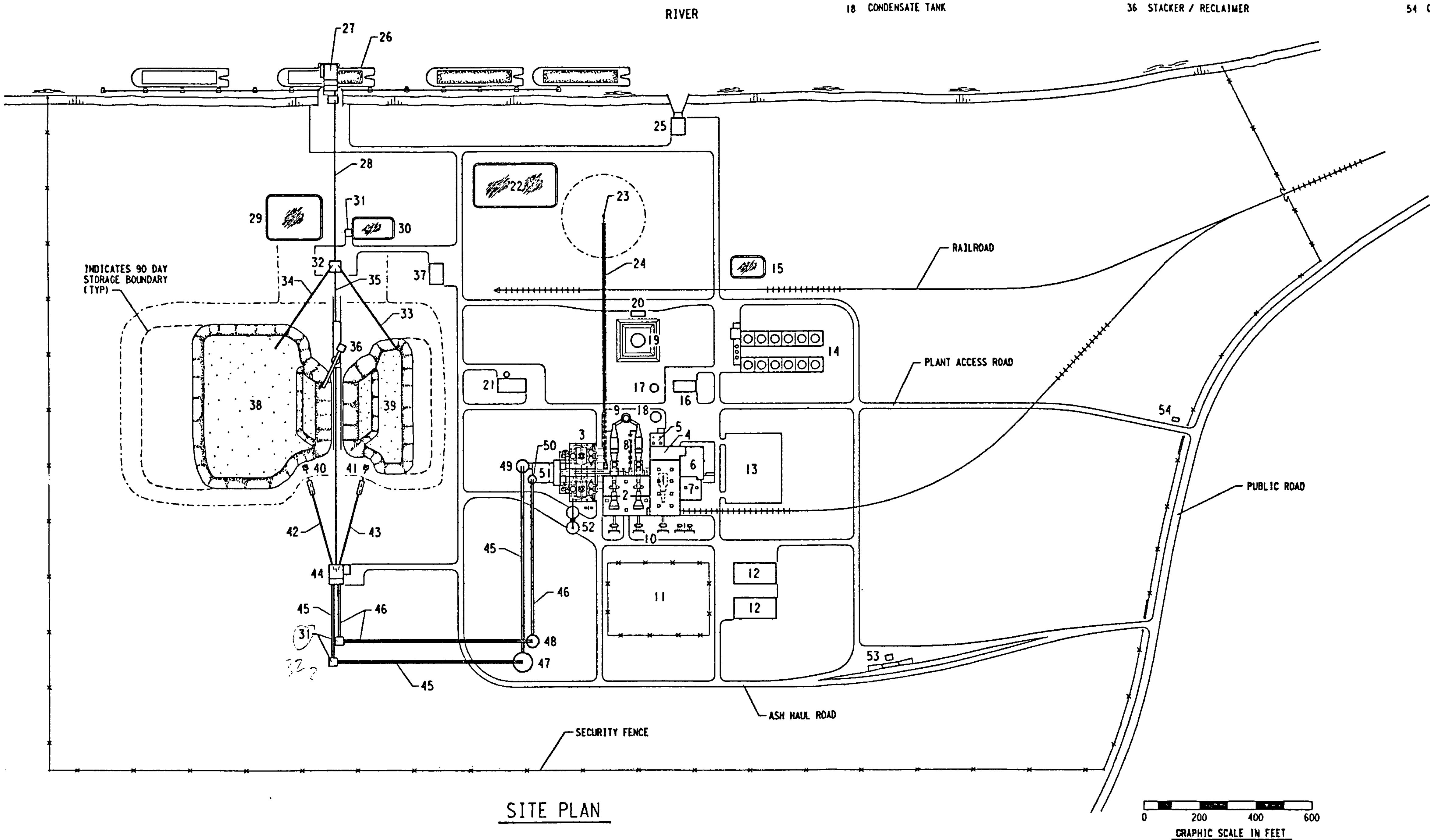


Figure 9 Overall Site Plan

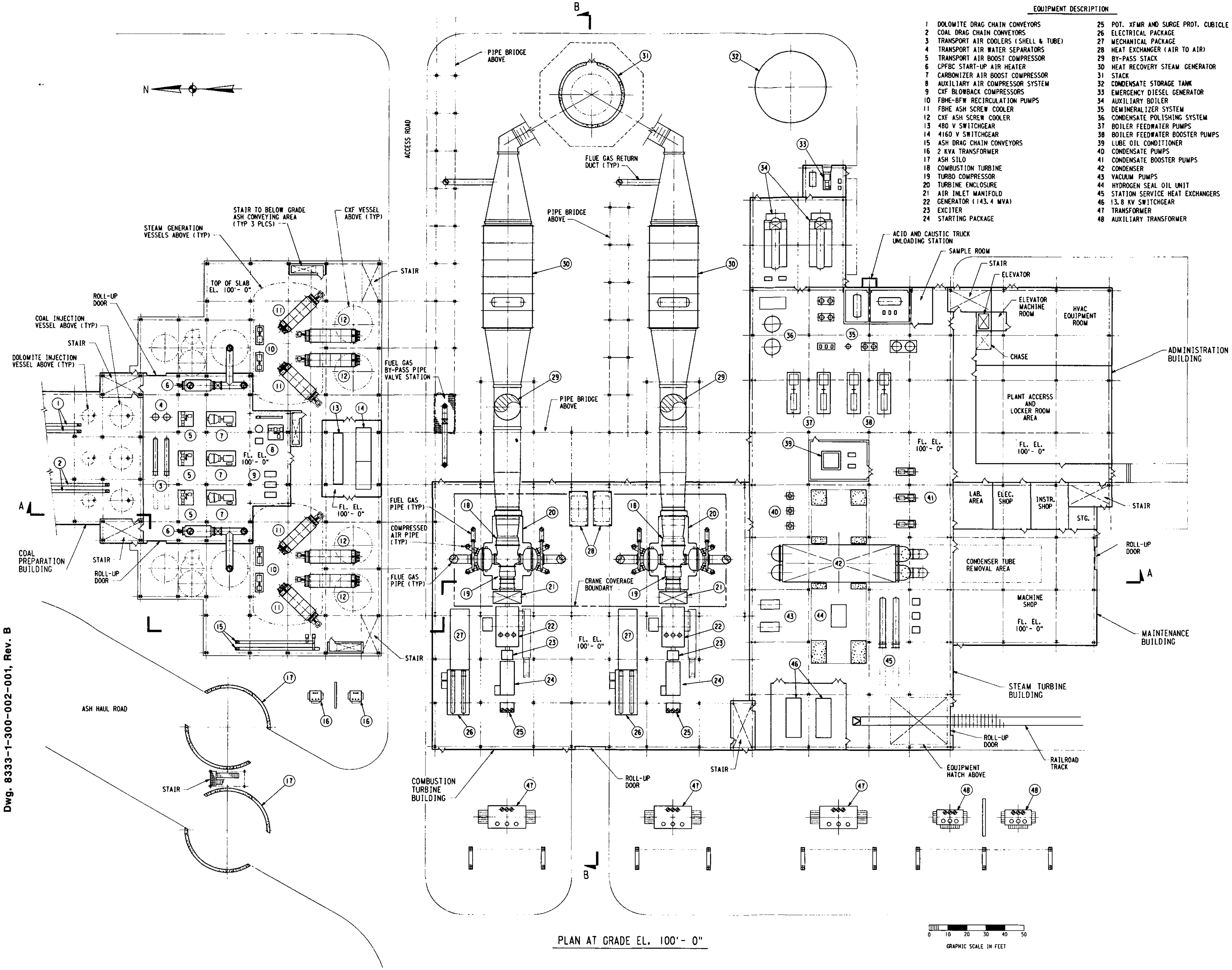


Figure 10 Power Island (El. 100 ft)

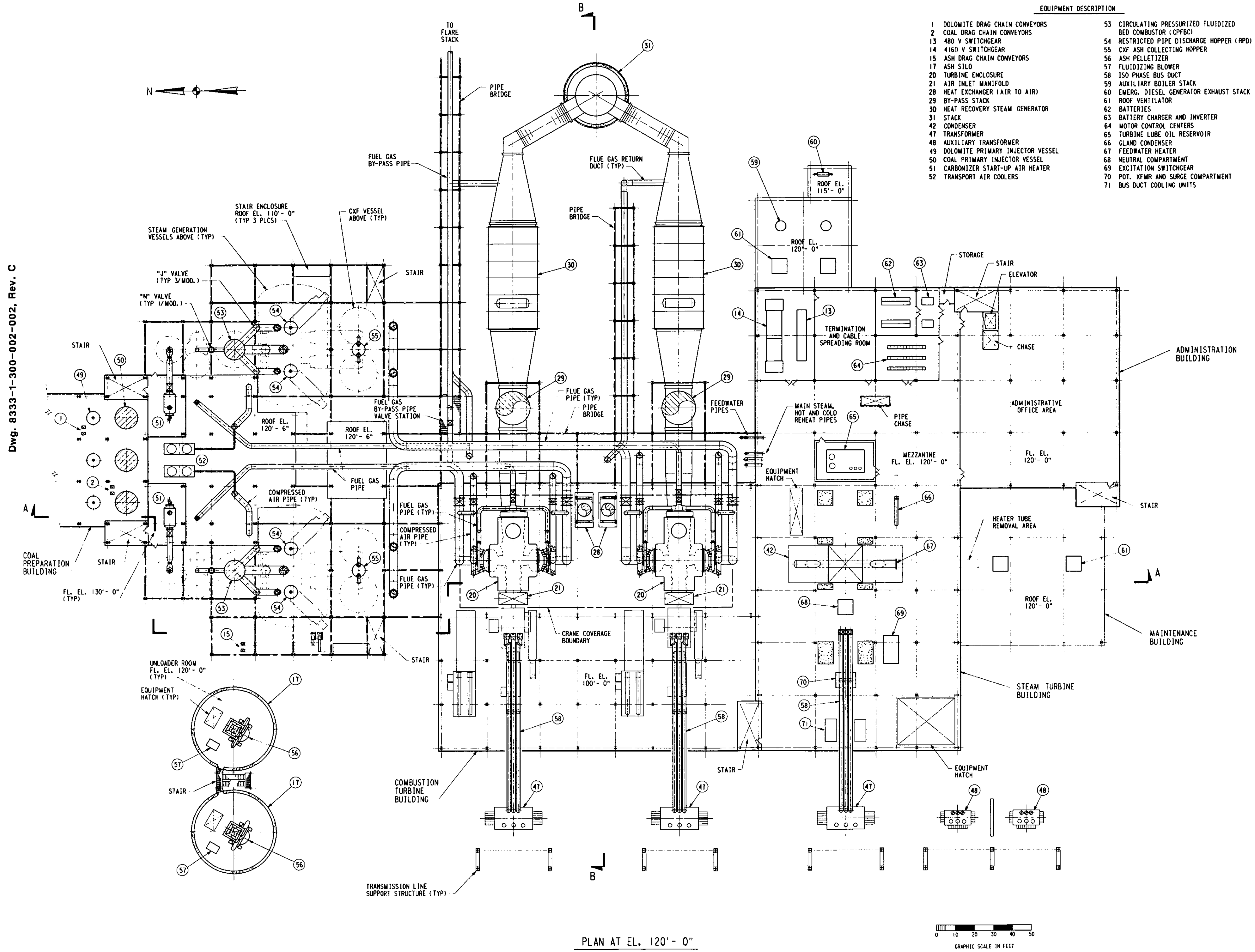


Figure 11 Power Island (El. 120 ft)

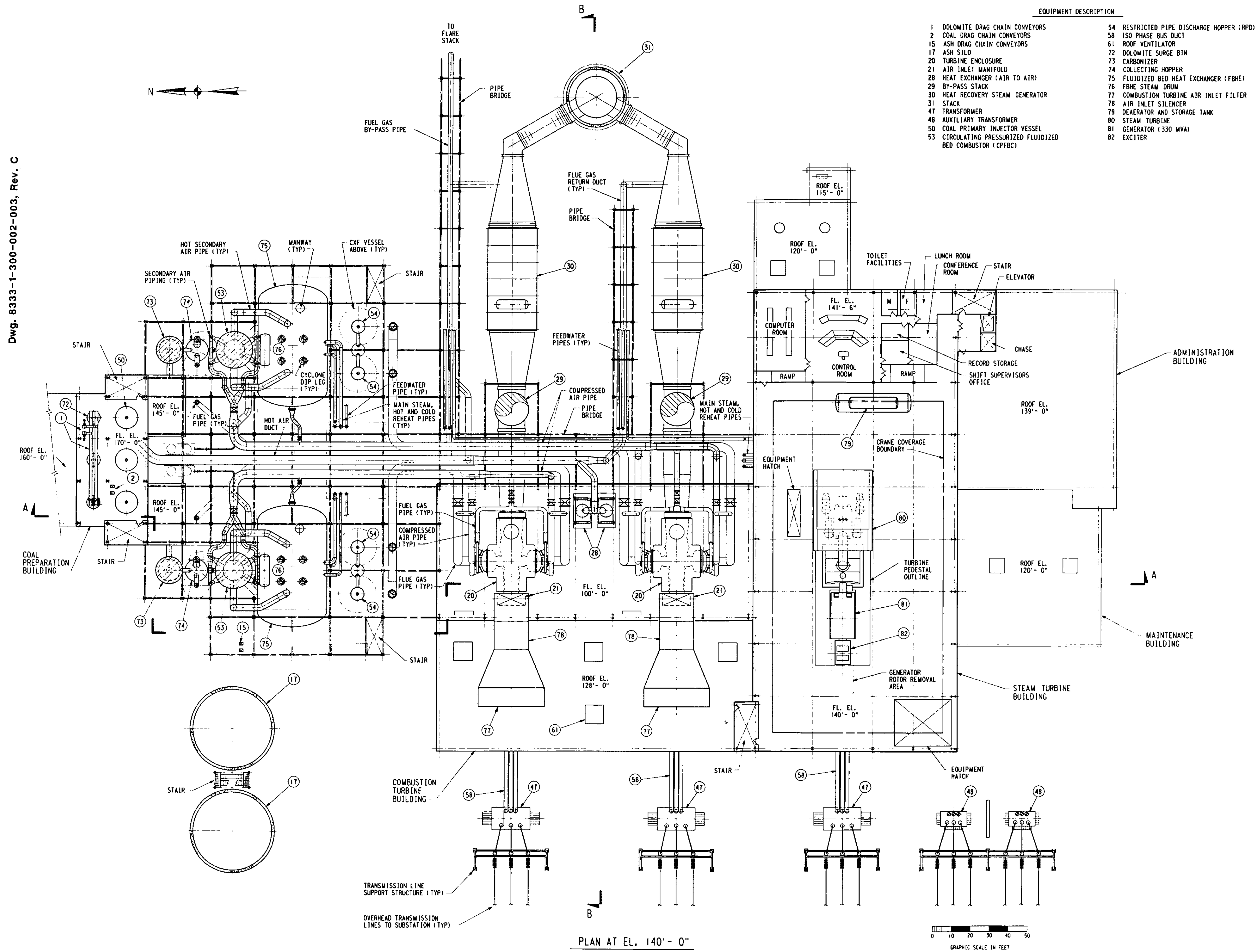


Figure 12 Power Island (El. 140 ft)

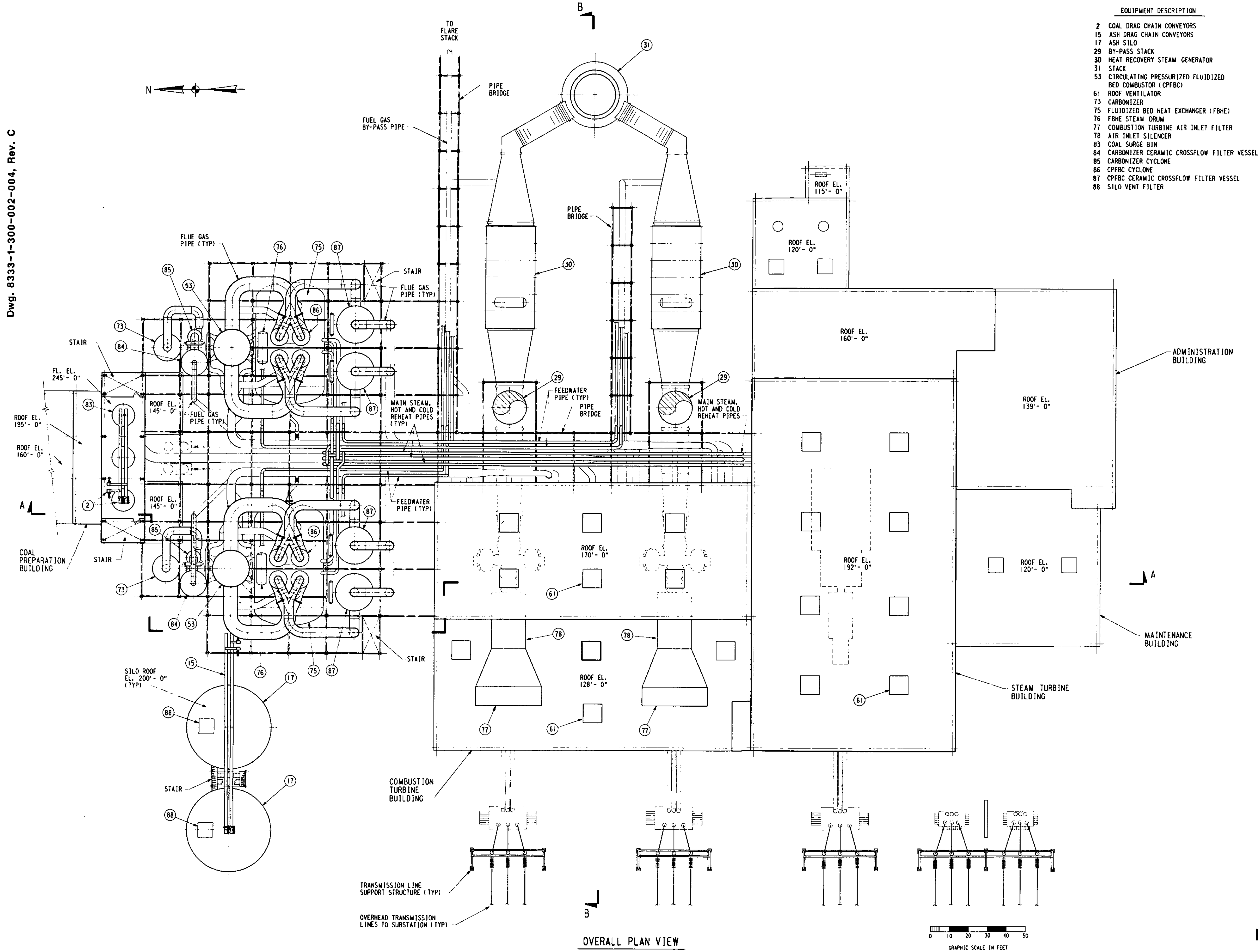
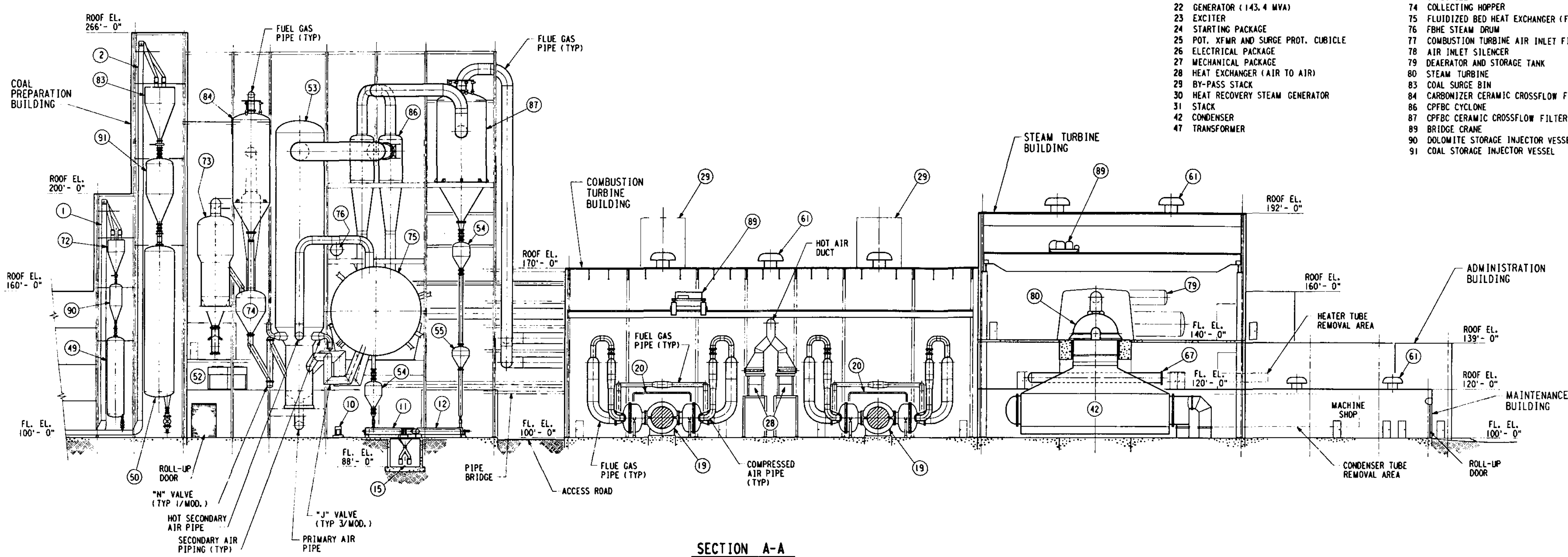


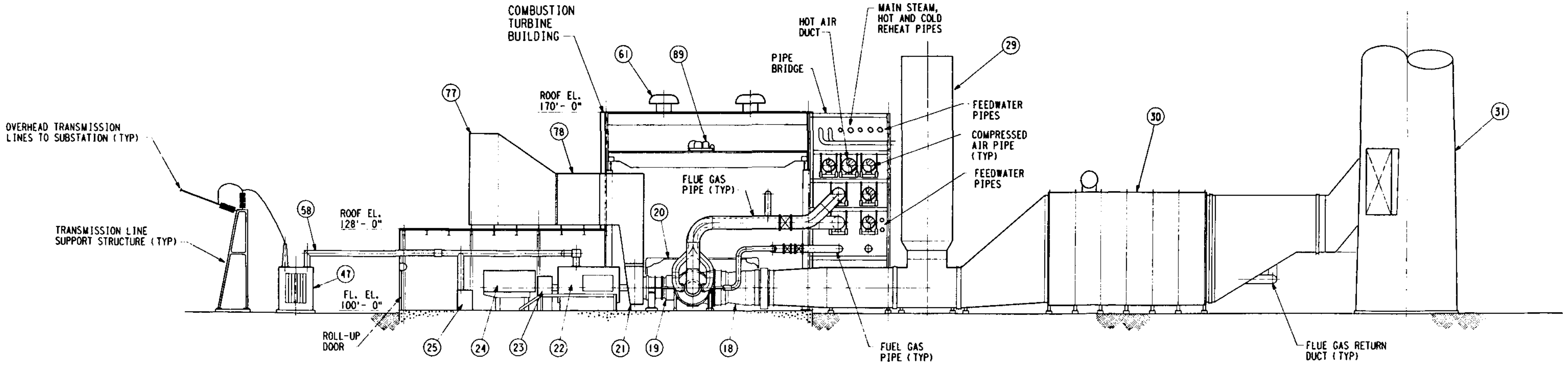
Figure 13 Power Island--Overall Plan



SECTION A-A

EQUIPMENT DESCRIPTION

1 DOLOMITE DRAG CHAIN CONVEYORS
2 COAL DRAG CHAIN CONVEYORS
10 FBHE-BFW RECIRCULATION PUMPS
11 FBHE ASH SCREW COOLER
12 CXF ASH SCREW COOLER
15 ASH DRAG CHAIN CONVEYORS
18 COMBUSTION TURBINE
19 TURBO COMPRESSOR
20 TURBINE ENCLOSURE
21 AIR INLET MANIFOLD
22 GENERATOR (143.4 MVA)
23 EXCITER
24 STARTING PACKAGE
25 POT. XFMR AND SURGE PROT. CUBICLE
26 ELECTRICAL PACKAGE
27 MECHANICAL PACKAGE
28 HEAT EXCHANGER (AIR TO AIR)
29 BY-PASS STACK
30 HEAT RECOVERY STEAM GENERATOR
31 STACK
42 CONDENSER
47 TRANSFORMER
52 TRANSPORT AIR COOLERS
53 CIRCULATING PRESSURIZED FLUIDIZED BED COMBUSTOR (CPFBC)
54 RESTRICTED PIPE DISCHARGE HOPPER (RPD)
55 CXF ASH COLLECTING HOPPER
58 ISO PHASE BUS DUCT
61 ROOF VENTILATOR
67 FEEDWATER HEATER
72 DOLOMITE SURGE BIN
73 CARBONIZER
74 COLLECTING HOPPER
75 FLUIDIZED BED HEAT EXCHANGER (FBHE)
76 FBHE STEAM DRUM
77 COMBUSTION TURBINE AIR INLET FILTER
78 AIR INLET SILENCER
79 DEAERATOR AND STORAGE TANK
80 STEAM TURBINE
83 COAL SURGE BIN
84 CARBONIZER CERAMIC CROSSFLOW FILTER VESSEL
86 CPFBC CYCLONE
87 CPFBC CERAMIC CROSSFLOW FILTER VESSEL
89 BRIDGE CRANE
90 DOLOMITE STORAGE INJECTOR VESSEL
91 COAL STORAGE INJECTOR VESSEL



SECTION B-B

0 10 20 30 40 50
GRAPHIC SCALE IN FEET

Dwg. 8333-1-300-002-005, Rev. C

Figure 14 Power Island Layout--Sections A-A and B-B

2.4 PLANT PERFORMANCE

The performance of the overall baseline plant is presented in this subsection; detailed component performance data are presented in Section 2.5, along with physical descriptions of the components.

2.4.1 Approach

Plant performance was calculated by representing the overall plant cycle with the G/C PROTEUS thermal cycle analysis program. This code produces an overall heat and mass balance for the CPFBC system, the gas turbine, the HRSG, and the steam turbine; in addition it calculates auxiliary powers for major components in the flow streams, such as booster compressors and pumps. Information from the PROTEUS simulation was used to prepare the heat and mass balance diagram and to calculate overall plant performance by transmitting state-point data calculated by PROTEUS to a computer-aided design and drafting (CADD) system, allowing preparation of the system heat and mass balance with minimal human interface and reducing the chance for errors in state-point data.

Pressure drops and heat losses were calculated for the major equipment in the carbonizer, CPFBC, and gas cleanup systems. Figure 15 shows the pressures, pressure drops, and heat losses for this equipment that were used in developing the baseline design. Compared with the performance estimate generated in the optimization study (Appendix B), the baseline plant performance analysis is much more detailed and includes/accounts for:

- Calculated system heat losses and pressure drops
- Correction of the carbonizer heat balance for transport air and heat losses
- Correction of gas turbine power and exhaust gas condition for pressure losses in the air distribution, CPFBC, and cleanup systems
- A two-module plant with a larger and more efficient steam turbine
- Two steam extractions for condensate heating rather than one
- Ash cooler heat for condensate heating
- Representation of transport air requirements and air losses in the cycle
- Inclusion of a carbonizer booster blower to provide acceptable fuel gas pressure
- Calculation of plant air and power auxiliary requirements.

2.4.2 Results

At the full-load design point, all coal and sorbent are fed to the carbonizer. Although there are transport lines leading from the Petrocarb injectors to the CPFBCs, these lines are installed primarily for start-up and part-load operation. Table 8 shows the overall performance for the power plant at full load. Net power for the baseline plant is 452.76 MWe, with a net plant efficiency of 43.6 percent based on the higher heating value of the fuel.

The breakdown of auxiliary power requirements also appears in Table 8. These power requirements are calculated from the flow and head requirements for pumps and compressors in the major process flow streams in the plant. Auxiliary requirements for secondary flow streams, such as coal handling or ash handling, are calculated from the motor powers and duty factors for those systems. Auxiliary requirements for the service water system and for miscellaneous uses (lighting,

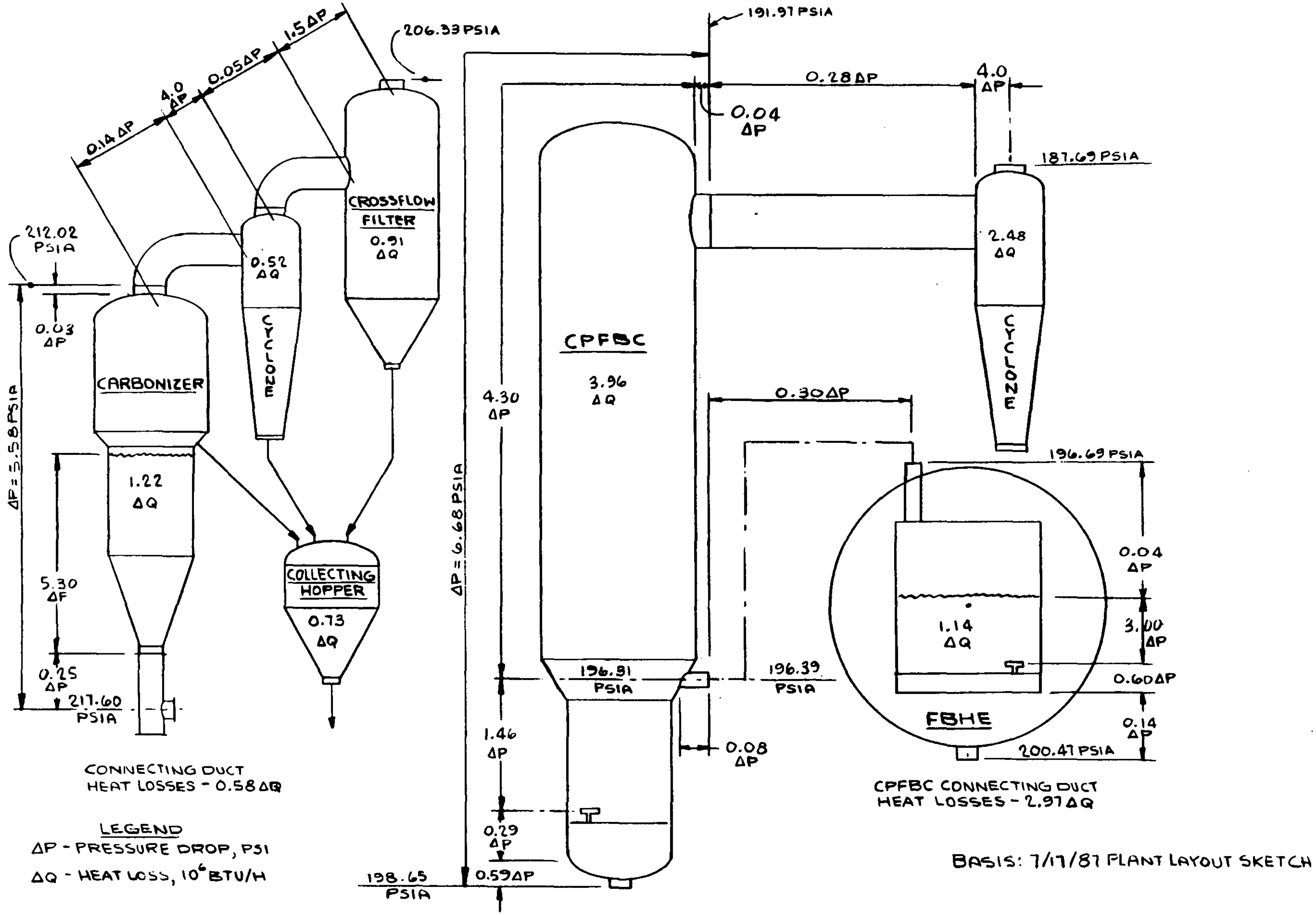


Figure 15 Pressure and Temperature Loss Diagram

Table 8 Overall Performance of Baseline Plant at Full Load

CPFBC/Total Plant Coal Feed Ratio	0.00
Power Summary, kWe	
Gas Turbine Power	195,150
Steam Turbine Power	272,338
Gross Power	467,488
Auxiliaries	(14,731)
Net Power	452,757
Net Efficiency, % (HHV)	43.63
Net Heat Rate, Btu/kWh	782
Consumables and Wastes:	
As-Received Coal Feed, lb/h (6.0% moisture)	284,410
As-Fired Coal Feed, lb/h (2.5% moisture)	274,200
Dolomite Feed, lb/h	82,315
Ash Production, lb/h	91,144
Coal and Dolomite Drying Fuel, gal/h	94
Auxiliary Summary, kWe:	
Transport Booster Compressor	447
Carbonizer Booster Compressor	945
Condensate Pumps	220
Feedwater Pumps	5,412
Boiler Forced-Circulation Pumps	315
Circulating Water Pumps	3,466
Cooling Tower Fans	894
Coal Dryer Forced-Draft Fan	300
Coal Dryer Induced-Draft Fan	238
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	483
Gas Turbine Intercooler Fan	15
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	169
Coal Handling	347
Dolomite Handling	68
Coal and Sorbent Feed	31
Ash Cooling and Handling	106
Service Water	99
Miscellaneous	702
Step-Down Transformer	73
Total Auxiliaries	14,731
Cooling Tower Loads, 10^6 Btu/h:	
Condenser	1322.20
Booster Precooler	12.75
Total Cooling Duty	1334.95

HVAC, controls and computers, shop and instrument air, etc.) are based on the rate of coal feed to the plant.

A tabulation of the input and output streams crossing the plant boundary appears in Table 9. This tabulation is useful for identifying the major energy losses in the power plant cycle and also for verifying the validity of the power cycle performance estimate.

As shown in Figure 7 (heat and mass balance diagram for the plant), flows and powers correspond to total quantities for the entire plant. Since the plant actually consists of two identical modules servicing a single steam turbine, the actual flows per module would be half of those shown in the diagram.

2.4.3 Design Issues and Approaches

The baseline plant was designed to provide a good balance between simplicity and high efficiency. Although there are several areas where different design approaches could have increased plant efficiency, the improvements appeared relatively minor and did not justify the associated increase in plant cost and complexity.

One of these alternative design approaches concerns utilization of waste heat from the turbine cooling air intercooler, which cools a portion of the rotor blade cooling air to 600°F, thereby reducing the amount of air required for that service. The intercooler duty is 22 x 10^6 Btu/h, and the air is at a temperature sufficient for heating HP feedwater. However, using of this heat for feedwater heating in a heat exchanger would introduce an operating risk to the gas turbine, since a leak in a 2900-psi feedwater tube in the heat exchanger would cause entrainment of liquid water droplets in the turbine cooling air. Another alternative is to transfer heat from the air intercooler to feedwater with an intermediate heat-transfer medium, but this method was rejected because of complexity. The approach taken was to utilize the heat from the turbine air intercooler to provide a portion of the heat required for coal drying. The coal and dolomite drying requirement for the total plant amounts to about 520,000 lb/h air or gas at 500°F, and the intercooler can provide about 31 percent of this duty.

With regard to the balance of the drying heat requirement, two alternative design approaches were possible. The first involved extracting gas turbine exhaust gas from the HRSG inlet to achieve the needed temperature and flow at the dryers. This approach was rejected because regulation of three gas lines (intercooler coolant, hot flue gas, and warm flue gas) is complex, and a dryer oil burner is still needed to provide drying heat during start-up of a module. The second approach was to use HP steam or feedwater to heat the drying gas to 500°F. This approach was feasible, but again it introduced additional complexity to the plant and did not eliminate the need for an oil burner in the dryer, since HP steam is not available during start-up. The design approach taken was to use flue gas drawn from the exit of the HRSG at 280°F to satisfy the remainder of the dryer flow requirements. When the intercooler airflow and flue gas streams are mixed, the temperature is only 388°F, so oil burners in the dryers bring the temperature of the drying gas up to 500°F.

Transport and pressurizing air for the Petrocarb solids feed systems is another area where plant efficiency can be increased, but at the expense of greater plant capital cost and complexity. Transport and pressurizing air is provided by bleeding air from the gas turbine compressor discharge, cooling the air to 100°F, and compressing the cooled air to 50 psi above the carbonizer inlet pressure. The advantage of this configuration is that most of the work to pressurize the air is provided by the highly efficient gas turbine compressors, resulting in relatively

Table 9 Input and Output Streams Crossing Plant Boundary (Baseline Plant, Rev. D)

Description	Flow, lb/h	Tempera-ture, °F	Enthalpy, Btu/lb	HHV, Btu/lb	Power, kWe	Energy, 10^6 Btu/h
Inputs:						
Carbonizer Coal	274,200	---	---	---	---	---
CPFBC Coal	---	---	---	---	---	---
Total Coal	274,200	150.0	35.70	12,916.0	---	3551.36
Sorbent Feed	82,315	77.0	7.93	---	---	0.65
Calcination	---	---	---	---	---	(53.41)
Sulfation	---	---	---	---	---	48.09
Gas Turbine Inlet Air	6,660,000	60.0	15.71	---	---	104.63
Transport Compressor	---	---	---	---	447	1.53
Carbonizer Booster	---	---	---	---	945	3.23
Condensate and Feedwater Pumps	---	---	---	---	5,632	19.22
Forced-Circulating Pumps	---	---	---	---	315	1.08
Total Inputs	7,016,515					3676.36
Outputs:						
Gas Turbine Generator Output	---	---	---	---	195,150	666.05
Gas Turbine Generator Loss	---	---	---	---	5,004	17.08
Gas Turbine Radiation Loss	---	---	---	---	---	3.02
Steam Turbine Generator Output	---	---	---	---	272,338	929.49
Steam Turbine Generator Loss	---	---	---	---	5,204	17.76
Fan and Pump Motor Loss	---	---	---	---	220	0.75
Turbine Cooling Air Intercooler Loss	---	---	---	---	---	22.22
Booster Intercooler	---	---	---	---	---	12.75
Booster Intercooler Condensate	430	100.0	68.54	---	---	0.03
Carbon Loss	789	300.0	57.57	14,087.0	---	11.16
Ash Loss	---	---	---	---	---	5.20
HRSG Stack	6,879,269	280.0	88.36	---	---	607.85
Lost Air and Gas						
Transport Compressor Loss	45,166	175.9	37.95	---	---	1.71
Ash Lock-Hopper Blowdown	500	1050.0	269.91	---	---	0.13
Transport Air Heat Loss	---	---	---	---	---	0.22
G/C Scope Hot Gas Piping	---	---	---	---	---	10.75
Carbonizer and Fuel Clean-Up Loss	---	---	---	---	---	7.92
CPFBC and Cyclone Loss	---	---	---	---	---	21.10
CPFBC Cross-Flow Filter	---	---	---	---	---	6.03
Condenser	---	---	---	---	---	1322.20
HRSG Radiation	---	---	---	---	---	12.63
Total Outputs	7,016,509					3676.06
Unaccounted for, lb/h	6					0.30
Unaccounted for, %	0.00					0.01

small air compressors. The major disadvantage of this configuration is that a large amount of medium-grade thermal energy (13 x 10^6 Btu/h) is wasted in the air intercoolers.

Since high-temperature air is neither needed nor desired for pressurization and transport, a plant designed with separate, intercooled transport/pressurizing air compressors that compress ambient air to the needed transport pressure could increase net plant capacity. The separate transport air compressors allow more intercooling, and the lower average temperature during compression more than compensates for the lower compressor efficiency relative to the gas turbine compressors. One disadvantage of this design approach is that the transport air compressors become significantly larger. A more subtle disadvantage of this configuration is that plant control becomes more complex. If a transport compressor is supplied with gas turbine bleed air as its air supply, then the transport compressor provides a "boost" above the gas turbine compressor discharge pressure. The transport compressor can operate at a relatively consistent operating point, and its discharge pressure will automatically track at some level above the gas turbine compressor pressure. On the other hand, if the transport compressor has ambient air as its suction supply, the pressure head available for conveying solids is the pressure difference between the transport air compressor and the gas turbine compressor. This pressure difference could vary widely unless the transport air discharge pressure is controlled accurately to match the gas turbine discharge pressure plus the required pressure difference.

2.4.4 Minimum-Load Operation

Minimum-load can be achieved in several ways. For periods of operation extending over more than 2 or 3 days, the preferred way to operate at minimum load would be to shut down one of the carbonizer/CPFBC/gas turbine/HRSG modules and to run the other module as near full load as possible. The advantage of this mode of operation is that the on-line module can operate near its design point, and the only loss in plant efficiency is the minor penalty associated with operating the steam turbine at 50-percent capacity. The primary disadvantage of this option is that it requires a shutdown and start-up cycle on the idle module.

Another means of achieving minimum load is to keep both modules on line and operate at a reduced firing rate. This would be the preferred method for turning down the plant at night or on the weekend, as it has the advantage of keeping both modules at a warm-and-running condition, allowing them to accept load rapidly.

Baseline plant performance was determined at minimum load, assuming both modules were kept in operation. This approach was taken because it provides insight into how the plant will load follow and identifies a lower bound for the plant efficiency. At minimum load, the plant coal flow rate and net electrical output drop from full-load values to 60 and 49 percent respectively. Approximately 45 percent of the reduced plant coal flow is fed directly to the CPFBCs because the thermal duty of the carbonizer and the gas turbine topping combustor is substantially reduced at minimum load, while the thermal duty of the CPFBC associated with heating the oxidant for the topping combustor remains relatively constant.

The following assumptions were made in establishing the minimum-load performance point:

- CPFBC exit temperature is allowed to fall to 1550°F
- Carbonizer air/coal ratio remains constant
- Gas turbine airflow is reduced 20 percent with the inlet guide vanes

- Steam turbine throttle pressure and temperatures remain constant
- Carbonizer and CPFBC operating pressures are allowed to float with the gas turbine operating pressure.

These assumptions do not represent the recommended method of operating the plant at part load; they are used to provide an initial estimate of a valid part-load operating point. A comprehensive review of possible control modes and a determination of the optimum balance between gas turbine firing temperature, CPFBC operating temperature, and carbonizer/CPFBC coal split is recommended for a more detailed study of the advanced PFB combustion concept.

Figure 16 presents a heat and mass balance for the plant at minimum load with both modules in operation. Table 10 summarizes key operating parameters and compares them with those of the baseline plant. Some of the significant changes from the full-load point are:

- Gas turbine compressor discharge pressure and temperature and all other system gas-side pressures are reduced because of the lower gas turbine airflow and the reduction in firing temperature.
- Coal feed to the carbonizer drops to about 33 percent of the full-load value as a result of the reduction in overall plant coal feed and the diversion of coal to the CPFBC.
- Carbonizer exit temperature drops about 47°F because of the lower carbonizer air temperature and the greater fractional heat losses.
- Carbonizer fluidizing velocity decreases, but the reduction in velocity is less than the reduction in firing rate because there is a concomitant decrease in system pressure.
- CPFBC velocity increases since the reduction in system pressure is greater than the decrease in CPFBC mass flow.

2.5 SYSTEM/COMPONENT DESCRIPTION AND PERFORMANCE

2.5.1 Coal-Handling System

System Functions. The main functions of the coal-handling system are to unload coal from barges and convey it to the coal storage pile area; pile, reclaim, crush, and sample it; convey it to the in-plant storage silo (bunker); and from there, convey it to the Petrocarb injection systems, which feed the carbonizer and CPFBC units.

Design Considerations and Requirements. The coal-handling system design requirements include:

- A coal-handling system designed to unload and pile 2-in. x 0 eastern bituminous coal in the yard stockpiles at a normal maximum rate of 3000 t/h and an average rate of 2500 t/h. The average rate will permit unloading almost 14,000 tons of coal in 5-1/2 hours from 7100-dead weight ton (DWT) open-top steel barges, using a continuous bucket-elevator-type barge unloader.
- Unloaded coal conveyed to a coal pile storage area at the west end of the plant. The conveying system is designed to convey coal at a maximum rate of 3300 t/h, which is 10 percent faster than the normal maximum unloading rate of 3000 t/h to allow for overfilling buckets during barge unloading.

Dwg. 8333-1-400-009-006, Rev. B

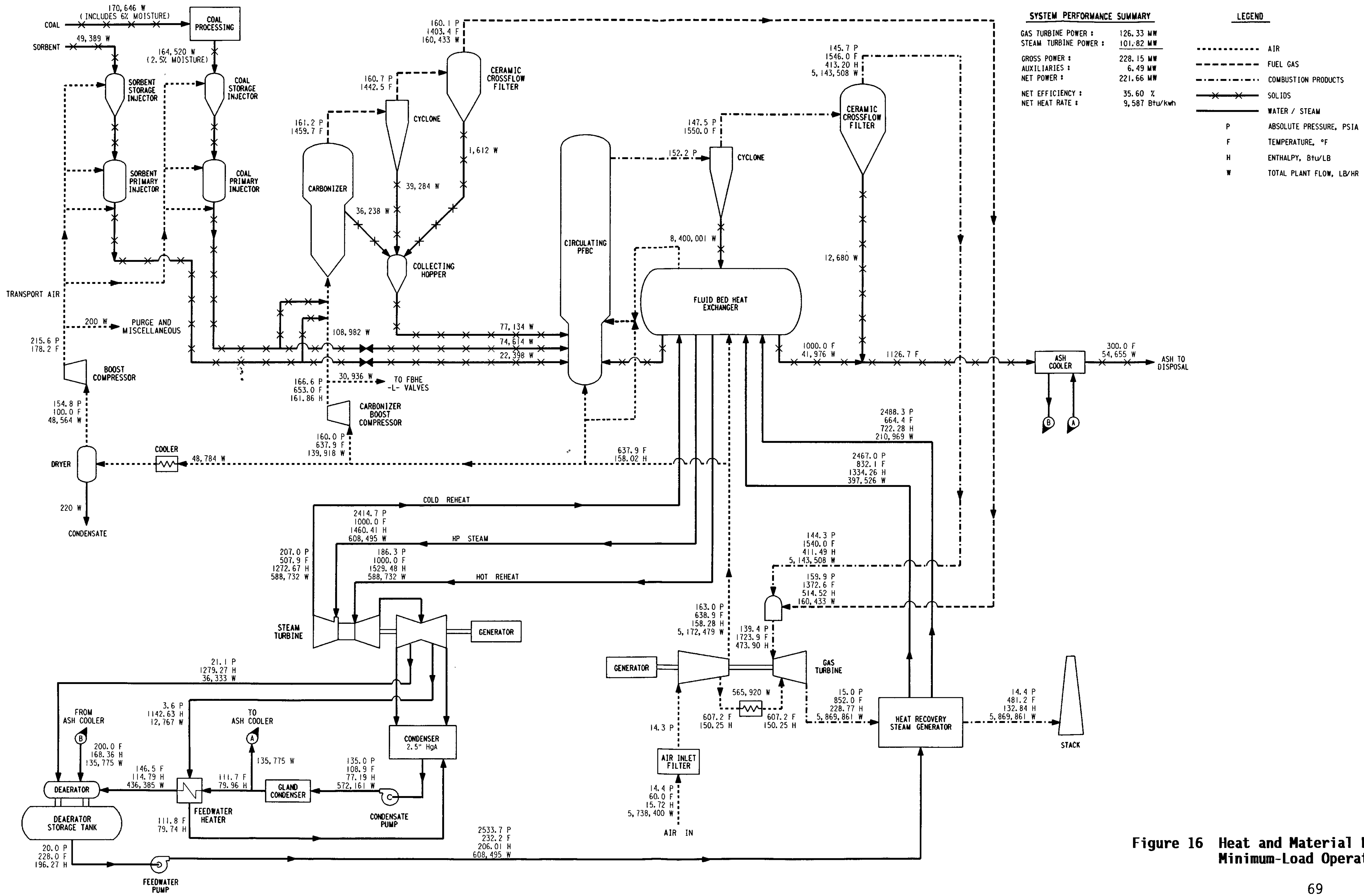


Figure 16 Heat and Material Balance--Minimum-Load Operation

Table 10 Comparison of Baseline Plant Performance at Full and Minimum Load

Category	Full Load	Minimum Load
Power Summary:		
Percentage of Total Plant Coal Flow to:		
Carbonizer	100	54.65
CPFBC	---	45.35
Gas Turbine Power, kWe	195,150	126,328
Steam Turbine Power, kWe	272,338	101,820
Gross Power, kWe	467,488	228,148
Auxiliaries, kWe	(14,731)	(6,490)
Net Power, kWe	452,757	221,658
Net Efficiency, % (HHV)	43.63	35.60
Net Heat Rate, Btu/kWh	7822	9587
Consumables and Wastes:		
As-Received Coal Feed, lb/h (6.0% moisture)	284,410	170,646
As-Fired Coal Feed, lb/h (2.5% moisture)	274,200	164,520
Dolomite Feed, lb/h	82,315	49,389
Ash Production, lb/h	91,144	54,655
Coal and Dolomite Drying Fuel, gal/h	94	6
Operating Parameters:		
Carbonizer Coal Feed, % of design	100.0	32.8
Carbonizer Fluidizing Velocity, % of design	100.0	41.4
CPFBC Fluidizing Velocity, % of design	100.0	121.9
Carbonizer Exit Temperature, °F	1506.3	1459.7
CPFBC Exit Temperature, °F	1600.0	1550.0
Gas Turbine Firing Temperature, °F	2100.1	1724.0

- A storage area with active and inactive storage piles for the plant. The storage pile capacity and configuration have been designed to meet these conditions:

  - A 24,000-ton active storage pile capable of supplying coal for 7 days to the plant when it is operating at 100-percent capacity. It is formed by piling all 24,000 tons of coal on the west side of the yard conveyor. The active storage pile is adjacent to the inactive storage pile.

  - A 620,000-ton inactive storage pile area capable of supplying coal to the plant for 6 months when it is operating at 100-percent capacity. The pile can be reclaimed by bulldozing to the emergency reclaim pile or to the active reclaim pile.

  - An emergency conveyor to continue unloading barges in the event the primary piling system is out of service or the bucket-wheel reclaimer is being used. The conveyor can pile 10,000 tons atop the inactive storage pile before bulldozing is required.

  - An emergency reclaim system with active reclaim capacity of 8000 tons without any bulldozing required.

- A redundant reclaim system ensures an uninterrupted and reliable coal supply to the bunkers. Coal is reclaimed at a normal rate of 800 t/h from either the primary reclaim system (stacker/reclaimer) or from the emergency reclaim system. A 100-percent redundant coal-handling system is also provided from the surge bin outlet to the Petrocarb injection system bunkers. Because double crushing is required to reduce the 2-in. coal to 1/8-in., crushing operations are segregated upstream and downstream of the silo. This separation allows a substantially smaller crusher building and a more compact system layout. A substantial reduction in horsepower is also achieved.

  - Reclaimed coal (2 in. x 0) is conveyed at 800 t/h via the 200-ton surge bin and primary crushers to a 10,200-ton coal storage silo. This silo provides 3 days of 1/2-in. x 0 coal storage and eliminates reclaim work on weekends. The silo can be filled in 13 hours.

  - The 1/2-in. x 0 coal stored in the 3-day silo is fed twice during each daylight shift into a 3400-ton 24-hour storage silo (bunker). Each filling takes 130 minutes.

  - The 1/2-in. x 0 coal stored in the silo (bunker) is continuously conveyed by totally enclosed drag-chain conveyors through crushers, dryers, and coal screens to three 20-ton surge bins at 142 t/h. In the process it is reduced to 1/8 in. x 0 and dried. Totally enclosed drag-chain conveyors were selected to reduce the amount of coal dust and fire hazards associated with dried coal. This type of conveyor also allows high-incline or vertical runs in a minimum of space. Even though this type of conveyor requires more maintenance than belt conveyors, it was chosen because it is dust-tight.

  - Coal is released from the 20-ton storage bins to the Petrocarb coal injection systems.

Major Equipment Descriptions. The alphanumeric equipment tag numbers on each piece of major equipment shown in Figure 17 correspond to those listed in Table 11 (Additional equipment information is presented in Tables 12, 13, and 14.). Portions of the coal-handling system equipment are also used for dolomite handling. Primarily, these include the barge unloader, bucket-wheel stacker/reclaimer, and

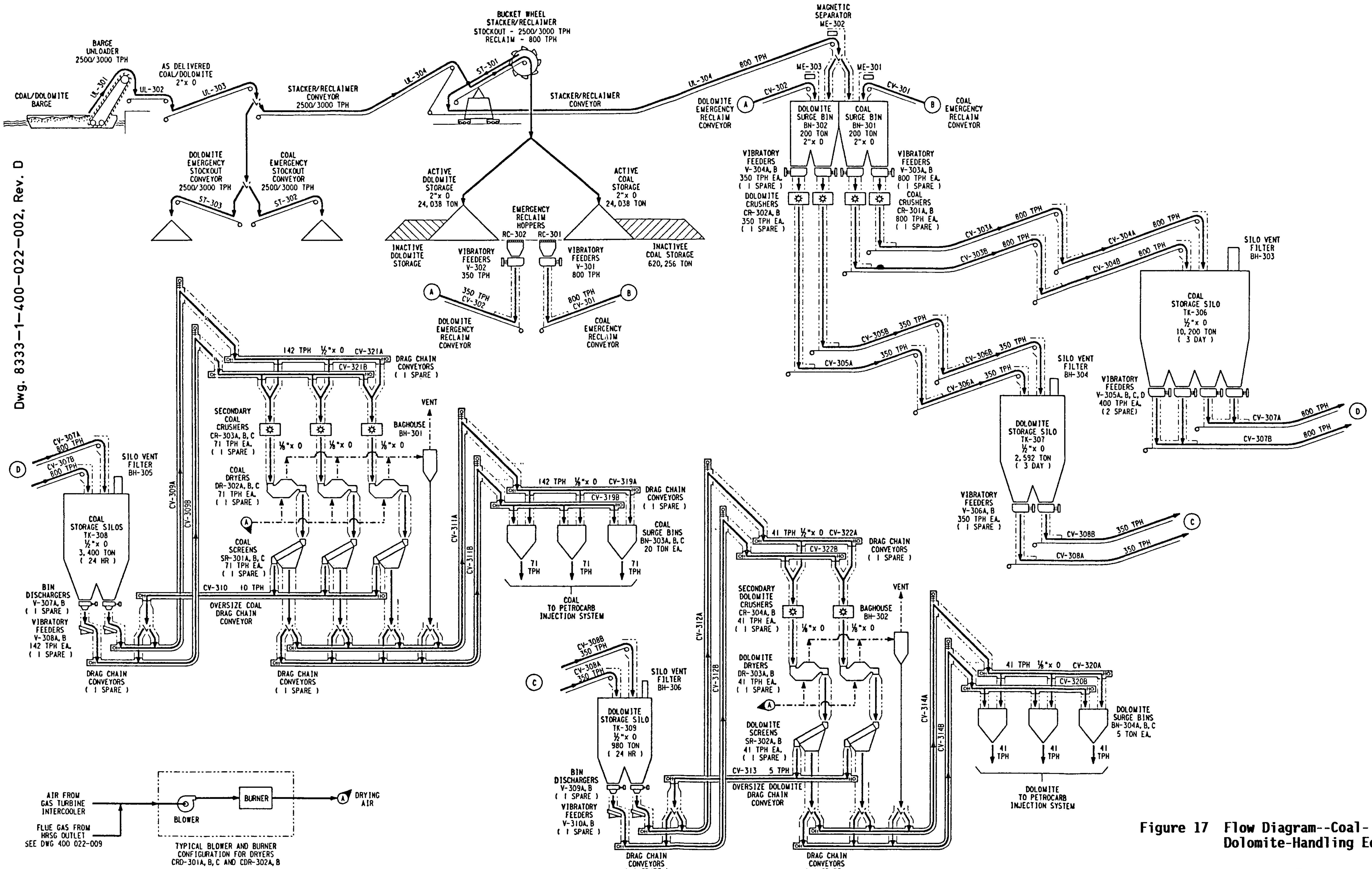


Figure 17 Flow Diagram--Coal- and Dolomite-Handling Equipment

Table 11 Coal- and Dolomite-Handling Equipment

Description	Tag No.	Quantity Required	Dimensions/Operating Data
Barge Unloader	UL-301	1	
Free Digging Rate			3000 t/h
Average Unloading Rate			2500 t/h
Barge Capacity			7100 DWT (max.) 2000 DWT (min.)
Barge Size			40-66 ft wide x 345 ft long
Unloading Cycle Time for Two Barges (Two passes per barge)			340 min
Barge Haul Systems:			
Receive Loaded Barge		1	
Unload Loaded Barge		1	
Park Unloaded Barge		1	
Bucket Elevator (Single Line):			4-ft intervals
Bucket Capacity			75 ft^3/bucket
Bucket Speed			148 ft/min
Bucket Elevator Motor			350 hp; totally enclosed, fan-cooled (TEFC); 1750 rev/min; 4000 V; three-phase; 60 Hz; 1.15 safety factor; Class B insulation
Barge Positioner (hydraulic)			15 hp; 120 V; three-phase; 60 Hz
Barge Haul Motor		2	20 hp; 725 rev/min; continuous 230-V dc, shunt wound Type MDP; Class H insulation)
Capstan Motors		2	15 hp; 1800 rev/min; 460 V; 3-phase; 60 Hz
Conveyor (Gathering)	UL-302		
Belt Speed			525 ft/min
Belt Capacity			3300 t/h
Trough Idlers			35 deg -6 in.; CEMA E6
Return Idlers (Rubber Disc)			CEMA 6
Take-Up			Gravity (enclosed)
Drive			100 hp; TEFC; 1750 rev/min; 460 V; 3-phase; 60 Hz
Belting			72-in., 4-ply polyester reinforcing with 1/4-in. top cover, 3/32-in. bottom cover
Belt Conveyors			See Table 12
Chain Conveyor			See Table 13
Magnetic Separator			
Conveyor (Discharge)	UL-304A	1	
Drive			7 hp
Magnet			11.88 kWe
Conveyor (Discharge)	CV-301A	1	
Drive			3 hp
Magnet			6.171 kWe

Table 11 (Cont) Coal- and Dolomite-Handling Equipment

Description	Tag No.	Quantity Required	Dimensions/Operating Data
Crushers			
Primary Coal Crushers	CR-301A and B	2	
Capacity			800 t/h each
Motor			450 hp, 720 rev/min, 4000 V
Coal Input			2 in. x 0 in.
Coal Output			3/4 in. (Nominal 1/2 in.)
Coal Reduction			4:1
Secondary Coal Crushers	CR-303A, B, and C	3	
Capacity			71 t/h each
Motor			50 hp; 1800 rev/min; 460 V
Coal Input			3/4 in. (Nominal 1/2 in.)
Coal Output			-1/8 in.
Coal Reduction			4:1
Sampling Systems			
"As-Received" Sampling System			Three-stage, automatic proportional for 38-lb samples, with crusher, collector bin, and feeder belts
"As-Fired" Sampling System			Two-stage, incremental method with crusher, sample collector bin, and feeder belts
Vibration Feeders			
Vibration feeders used in the Coal-Handling System are presented in Table 14.			
Flop-Gate Actuators		3	
Shut-Off Gate		2	
Location			200-ton surge bin BN-301A outlet to Crushers CR-301A and B
Manufacturer			Process Equipment Builders, Inc.
Sump Pumps			
Location			Crusher building/reclaim tunnel
Type			VN (vertical slurry pump)
Air Dryer			
Location			Crusher building, Transfer Building 1; Emergency; Reclaim
Manufacturer			Deltech Engineering, Inc.
Type			G Series, heatless dryers
Belt Cleaners			
Location			Head pulley, all conveyors
Belt Scales With Integrator			
Location			Conveyor UL-303, Conveyors CV-303A and B
Accuracy			1/4 of 1 percent
Capacity Range			Conveyor UL-303: 800-4000 t/h Conveyors CR-303A and B: 250-1500 t/h

Table 11 (Cont) Coal- and Dolomite-Handling Equipment

Description	Tag No.	Quantity Required	Dimensions/Operating Data
Telescopic Chute	TC-301A		
Location			Discharge of Conveyor ST302A
Air Compressor			
Location (1)			Barge unloader
Location (2)			Transfer Building 1
Stacker/Reclaimer		1	
Type			Slewing-bucket wheel stacker/reclaimer
Capacity			
Stackout			3300 t/h stacking (max.)
Reclaim			425, 600, and 800 t/h; Average 1200 t/h overload during reclaim
Bypass			0-850 t/h
Storage			24,040 tons active storage, 50-ft-high pile 134 t/ft at 50 lb/ft^3
Travel Distance			330 ft reclaiming; 268 ft-2 in. stacking; 5 ft-0 in. overtravel
Boom Operating Angles			15 deg above horizontal; 13 deg below horizontal; 90 deg from and when stacking; 71 deg from and when reclaiming
Travel Speed			50 ft/min
Bucketwheel			20 ft-0 in. diam with 8-14 ft^3/bucket cell-less
Buckets			Driven by 75 hp TEFC 1800 rev/min; 460 V; 3 phase; 60 Hz motor
Boom			108-ft long slow pivot to centerline of bucketwheel
Bucket Conveyor			
Belt Speed			565 ft/min.
Belt Capacity			3300 t/h (max.)
Trough Idlers			350 ft-6 in. - CEMA E6
Impact Idlers			7-1/2 x 2-1/2 in.; 0 pressure
Return Idlers			Rubber disc 6-in. CEMA E6
Conveyor Length/Rise			113-ft/approximately 30 ft. max.
Takeup			Manual screw
Drive			200 hp; 1800 rev/min; TEFC; 460 V; 3-phase; 60 Hz
Belting			72-in. 1-ply (steel cable) with 1/4-in. top cover and bottom cover; SCOF
Luffing Drive			
Operating Pressure			1500 psig (max.)
Number of Cylinders			2 (10-in. diam x 14 ft-6 in. stroke)
Power Pack			2 10-hp units (10 operating), spare
Moving Gear			
Travel Driven Motors			7.5 hp; 1200 rev/min; TEFC; 460 V; 3-phase; 60 Hz
Slew Drive Assembly			
Number of Drives			2
Drive Motor			2 - 15 hp; 1750 rev/min; shunt wound dc
Lubrication			Automatic and centralized
Splitter Device			Hydraulic-operated chute

Description	UL-303	ST-303	UL-304	CV-302	CV-305A/B	CV-306A/B	CV-308A/B
Function	Conveys coal from barge unloader conveyor to Transfer Building 1	Emergency stacking conveyor Transfer Building 1 to inactive storage pile	Yard conveyor, Transfer Building 1 to crusher building via stacker/reclaimer	Underground reclaim conveyor from emergency reclaim pile to crusher	Conveyors from crusher building to Conveyors CV-306A and B	Transfer material from Conveyors CV-305A and B to Dolomite Storage Silo TK-307A (3 day)	Transfer material from (3 day) Storage Silo TK-307A to (1 day) Storage Silo TK-309A
Quantity	1	1	1	1	2	2	2
Belt Speed, ft/min	525	525	525	520	410	410	410
Maximum Belt Capacity, t/h	3300	3300	3300	800	350	350	350
Trough Idler	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6
Impact Idlers	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-7 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6	35 deg-6 in. CEMA E6
Return Idlers	Rubber disc--6 in. CEMA E6	Rubber disc--6 in. CEMA E6	Rubber disc--7 in. CEMA E6	Rubber disc--7 in. CEMA E6	Rubber disc--6 in. CEMA E6	Rubber disc--6 in. CEMA E6	Rubber disc--6 in. CEMA E6
Conveyor Rise/ Length, ft	52/200	50/220	95/1100	101/390	35/250 (approximately)	78/750	80/605
Takeup	Enclosed gravity double reeved	Gravity (enclosed)	Gravity (enclosed)	Gravity (enclosed)	Gravity	Screw-manual	Screw-manual
Drive	700 hp, 1200 rev/min, 4000 V, 3-phase, 60 Hz, with fluid coupling backstop, and reducer	500 hp, 1200 rev/min, 4000 V, 3-phase, 60 Hz with Voith fluid coupling backstop and reducer	500 hp, 1200 rev/min, 4000 V, 3-phase, 60 Hz with fluid coupling backstop and reducer	200 hp, 1800 rev/min, 460 V, 3-phase, 60 Hz with coupling backstop and reducer	20 hp, 1800 rev/min, 460 V, 3-phase, 60 Hz with coupling backstop and right angle	45 hp, 1800 rev/min, 460 V, 3-phase, 60 Hz with reducer	50 hp, 1800 rev/min, 460 V, 3-phase, 60 Hz with coupling backstop and reducer
Belting	72 in. 3-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	72 in. 4-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	72 in. 4-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	42 in. 4-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	30 in., 3-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	30 in., 3-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant	30 in., 3-ply, polyester reinforcing with 3/16 in. top cover, 3/32 in. bottom cover, MSHA, SCOF, fire resistant

Table 13 Dolomite-Handling System Chain Conveyors

Description	CV-312A and B	CV-313A and B	CV-314A and B
Function	Transfer material from (1 day) Dolomite Storage Silo TK-309 to secondary Dolomite Crushers CR-304A and B via vibratory feeders	Dolomite screens rejects after secondary crusher	From secondary crusher screens to Dolomite Surge Bins BN 304A, B, and C
Quantity	2	1	2
Chain Speed, ft/min	50	5	50
Capacity, t/h	41	4.1	41
Drive, hp	10	1	5
Conveyor Rise/Length, ft	50/100	0/50	85/130
Nominal Size, in.	11	11	11

Table 14 Coal-Handling System Vibration Feeders

Description	V-303A and B	V-305A, B, C, and D	V-307A and B	V-308A and B	V-301A
Function	Activator/Feeder	Activator/Feeder	Bin Activation	Rate Control Feeder	Activator/Feeder
Location	Inlet to Coal Crushers CR-301A and B	Outlet of 3-Day Coal Storage Silo TK-306A	Outlet of 1-Day Storage Silo TK-308A	Outlet from Vibratory Feeder V-307A and B	Emergency Reclaim Tunnel
Quantity	2	4	2	2	1
Motor	5 hp, 720 rev/min, Tenv.	15 hp	10 hp	10 hp	10 hp, 720 rev/min, Tenv.
Capacity	800 t/h of 2 in. x 0 Coal	400 t/h of 1/2 in. x 0 Coal	142 t/h	35-142 t/h of 1/2 in. x 0 Coal	800 t/h of 2 in. x 0 in. Coal
Angle of Declination	0 deg	0 deg	0 deg	0 deg	---
Liner	1/2 in. Stainless Steel	---	---	---	1/2 in. 316 Stainless Steel on Pans and Arch Plate
Controls	Fixed Rate	Fixed Rate	Fixed Rate	Proportional	Automatic Proportional Control

associated conveyors. Shared items are identified by the "dual use" designation in Section 2.5.2 (Table 15).

2.5.2 Dolomite-Handling System

This section describes the dolomite-handling system, including the system function, design requirements, and major equipment shown in Figure 17.

System Functions. The main functions of the dolomite-handling system are to unload dolomite from barges; convey it to the dolomite storage pile area; pile, reclaim, crush, and sample it; and convey it via the in-plant dolomite storage silo (bunker) to the Petrocarb injection systems, which feed the carbonizer and CPFBC units.

Design Requirements. The dolomite-handling system design includes:

- A dolomite-handling system designed to unload and pile Plum Run dolomite, in a size range of 2 in. x 0, to the yard stockpiles at a normal maximum rate of 3000 t/h, with an average rate of 2500 t/h. This rate will permit unloading 15,000 tons of dolomite within 6 hours from 7100-DWT open-top steel barges, using a continuous bucket-elevator-type barge unloader.
- Unloaded dolomite conveyed to a dolomite pile storage area at the west end of the plant. The conveying system is designed to convey dolomite at a maximum rate of 3300 t/h, 10 percent faster than the normal maximum unloading rate of 3000 t/h to allow for overfilling the bucket during the barge-unloading operation.
- A storage area with active and inactive storage piles for the plant. The storage pile capacity and configuration meet the following conditions:
  - A 24,000-ton active reclaim storage pile capable of supplying dolomite to the plant for 24 days when it is operating at 100-percent capacity. This pile is formed by piling all 24,000 tons of dolomite on the east side of the yard conveyor. The active reclaim pile is adjacent to the inactive storage pile.
  - A 178,000-ton inactive storage pile area that is capable of supplying dolomite to the plant for 6 months, when it is operating at 100-percent capacity. The pile can be reclaimed by bulldozing it to the emergency reclaim pile or to the stacker/reclaimer active reclaim pile.
  - An emergency conveyor to continue unloading barges in the event the primary piling system is out of service. The conveyor can pile 10,000 tons atop the inactive storage pile before bulldozing is needed.
  - An emergency reclaim system, with an active reclaim capacity of 8000 tons without any bulldozing.
- A redundant reclaim system to ensure an uninterrupted and reliable dolomite supply to the bunkers. Dolomite is reclaimed at a normal rate of 800 t/h from either the primary reclaim system (stacker/reclaimer) or the emergency reclaim system. There is also a 100-percent redundant dolomite-handling system from the surge bin outlet to the Petrocarb injection systems.
- Careful consideration for safety and equipment maintenance. The system design ensures adequate space and access for operating, maintaining, and removing each piece of equipment:

- Monorails to serve each major piece of equipment with direct access to grade or to an equipment hatch; manual hoists for the short lifts and electric hoists for the long lifts

- Access platforms, stairs, and ladders for all equipment

- Walkways and access aisles on both sides of all conveyors

- Enclosed conveyor galleries that extend over the water and into/between the units

- Emergency escape ladders at intervals from conveyor galleries.

Major Equipment Description. The alphanumeric equipment tag numbers noted with each major equipment item in Table 15 correspond to those in Figure 17.

Portions of the dolomite-handling equipment are common to the coal-handling system; they are designated for dual use, as listed in Table 15.

2.5.3 Coal and Sorbent Feeding

A dense-phase pneumatic transport system marketed by Petrocarb, Inc., was selected to feed 1/8-in. x 0 coal and dolomite into the carbonizer and CPFBC. It was chosen because it represents the latest development in commercially available pressurized feed systems and has been used successfully at Exxon, Leatherhead, and Grimethorpe PFB combustion test facilities.

The plant has six separate Petrocarb injection trains--three for coal and three for dolomite. Separate systems are used because of the differences in densities between coal and dolomite and because of the large flow rates involved. Each module has its own coal and dolomite injection trains (primary) with a spare set of trains shared between the modules. Each primary injection train has two feed lines--one to the carbonizer and one to the CPFBC. The spare injection trains have four feed lines--one to each of the two carbonizers and two CPFBCs.

The coal injection train is illustrated in Figure 18. The system consists of an 11-ft.-I.D. storage injector in series with a 12-ft-I.D. primary injector. In operation, the storage injector is gravity fed from an elevated coal storage bin by opening the interconnecting slide gate and fill valves. Upon completion of the transfer, the fill valve on the storage injector is closed, the vessel is pressurized with air, the isolation valve is opened, and coal flows into the primary injector. The primary injector is pressurized continuously and refilled intermittently by the storage injector without interrupting its outlet feed rate. Rotary feed valves at the bottom of the primary injector control the coal flow rate into pneumatic transport lines that connect/deliver coal to either the carbonizer or the CPFBC.

At full load, coal is transferred from the storage injector to the primary injector at 20-minute intervals. The primary injector coal supply varies from 40 minutes at its lowest level to 1 hour after filling by the storage injector. Since the coal residence time in the feed system is relatively short (1 hour at full load; 1-3/4 hours at minimum load), air pressurizes the injector and transports coal. At shutdown, the injectors are made inert with nitrogen to minimize spontaneous combustion from any coal residue in the system.

Table 15 Dolomite-Handling System

Description	Tag No.	Quantity Required	Dimensions/Operating Data
Barge Unloader	UL-301	1	Dual-use equipment (Table 11)
Belt Conveyors			(Table 13)
Chain Conveyors			(Table 14)
Magnetic Separator			
Location		1	Conveyor UL-304A discharge; dual-use equipment (Table 11)
Location		1	Conveyor CV-302 discharge
Drive			3 hp
Magnet			6171 W
Crushers			
Primary Dolomite Crushers	CR-302A and B	2	
Capacity			350 t/h each
Motor			175 hp; 720 rev/min; 4000 V
Secondary Dolomite Crushers	CR-304A and B	2	
Capacity			41 t/h each
Motor			35 hp; 1800 rev/min; 460 V
Sampling Systems			
"As-Received" Sampling-Type System			Three-Stage; automatic; proportional for 38-lb samples, with crusher, collector bin, and feeder belts
"As-Fired" Sampling-Type System			Two-Stage; incremental method with crusher and sample collector bin and feeder belts.
Vibrating Feeders			Vibrating feeders used in the dolomite-handling system are presented in Table 14.
Flop-Gate Actuators		3	
Shut-Off Gate		2	
Location			200-ton Surge Bin BN-301A; Outlet to Crushers CR-301A and B
Manufacturer			Process Equipment Builders, Inc.
Sump Pumps			
Location			Crusher building/reclaim tunnel
Type			VN (vertical slurry pump)
Air Dryer			
Location			Crusher building, Transfer Building 1; Emergency reclaim
Manufacturer			Deltech Engineering, Inc.
Type			G Series, heatless dryers
Belt Cleaners			
Location			Head pulley, all conveyors
Belt Scales with Integrator			
Location			Conveyor UL-303, dual-use equipment (Table 12)
Conveyors			CV-305A and B
Accuracy			1/4 of 1 percent
Capacity Range			
Conveyor UL-305A			See Table 12
Conveyors CV-305A and B			100 to 700 t/h
Telescopic Chute	TC-301A		
Location			Discharge of Conveyor ST-303
Air Compressor			
Location (1)			Barge unloader, dual-use equipment; See Table 11
Location (2)			Transfer Building 1; dual-use equipment, See Table 11.
Stacker/Reclaimer			Dual-use equipment, See Table 11

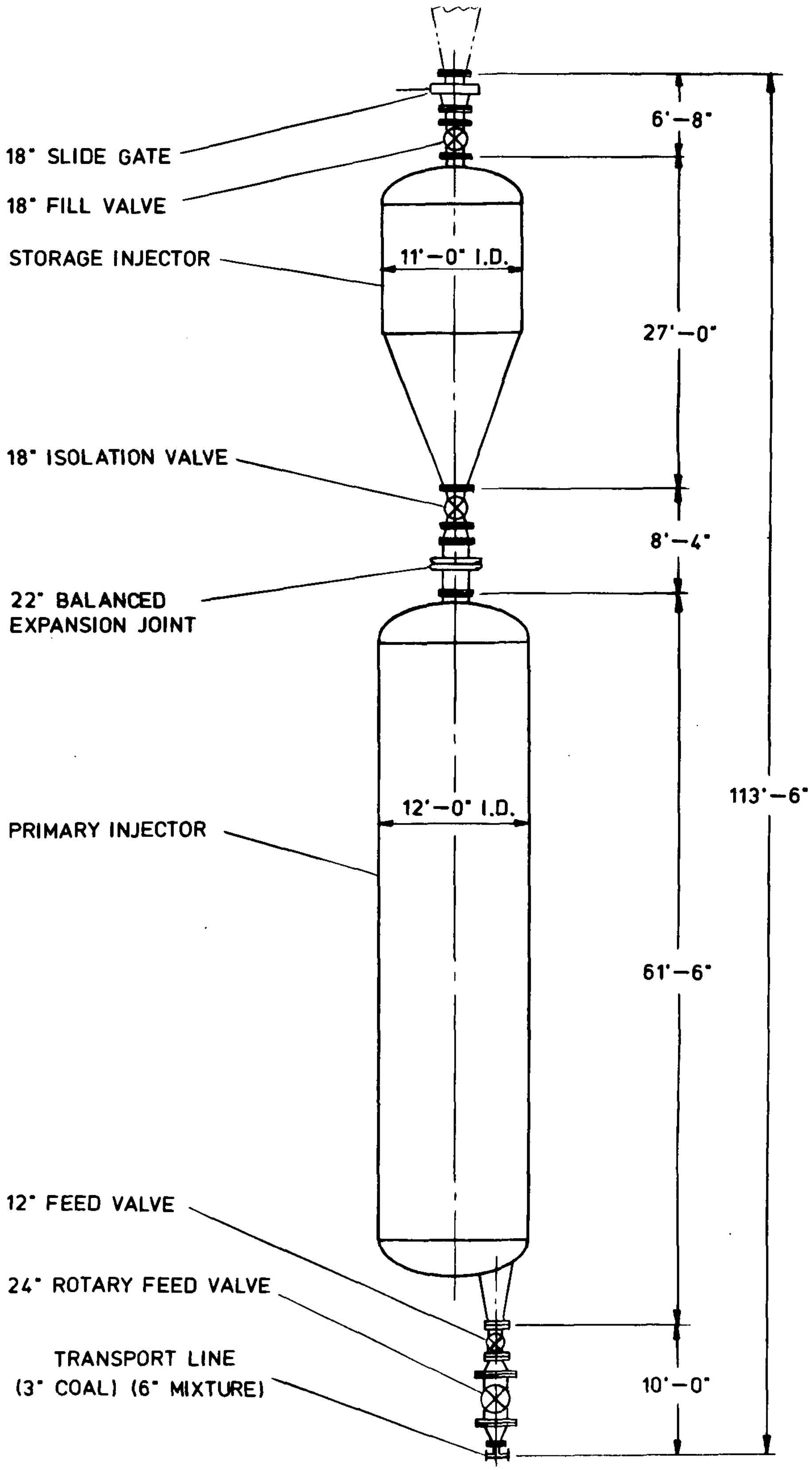


Figure 18 Coal Injection System

The dolomite injection train (Figure 19) consists of a 5-ft-I.D. storage injector in series with a 7-ft-I.D. primary injector; it operates in the same manner as the coal system, except that it need not be made inert at shutdown.

2.5.4 Carbonizer Subsystem

There are two identical carbonizer subsystems (modules) required for the baseline plant, consisting of the carbonizer, cyclone, collecting hopper, and N valve; the carbonizer cross-flow filter is described in Section 2.5.7. This section describes in detail the components of one of the modules. All quantities, flow rates, etc., discussed in this section are based on a single module unless otherwise indicated.

In the carbonizer, coal is devolatilized/consumed at 1500°F in a reducing atmosphere, in the presence of dolomite, to generate a low-Btu fuel gas. Solids entrained in low-Btu gas leaving the carbonizer are collected in a cyclone separator and a nitrogen-pulsed ceramic cross-flow filter. The solids captured by the cyclone and the cross-flow filter drain by gravity, along with the material in the standpipe bed drain from the carbonizer, to a centrally located, refractory-lined hopper. The collected solids drain from the hopper by gravity to a nitrogen fluidized nonmechanical valve, an N valve, below the unit and are injected into the CPFBC for complete combustion. The arrangement of major components of the carbonizer subsystem is illustrated in Figure 20.

Carbonizer. The carbonizer, shown in Figure 21, is a vertical, refractory-lined pressure vessel approximately 47 ft high, with a conical bottom. A 25-ft-deep jetting fluidized bed operates at a superficial gas velocity of approximately 3 ft/s within the lower 10-ft-I.D. zone of the vessel. The upper (freeboard) zone of the vessel is expanded to a 13-ft I.D. to lower the gas velocity to approximately 1-3/4 ft/s and minimize elutriation rates.

Coal, dolomite, and air enter the unit as a vertical, upward-flowing jet, with a superficial velocity of 120 ft/s (hot), through the bottom nozzle (1 ft-5 in. I.D.) and manifold assembly shown in Figure 22. The carbonizer fuel gas, containing elutriated char and sorbent, leaves the 1500°F unit through a 2 ft-8 in. I.D. nozzle at the top of the vessel. A 4-in. bed-overflow nozzle near the midpoint of the vessel limits the bed height to approximately 25 ft. A bottom 4-in.-I.D. nozzle facilitates emptying the unit at shutdown and is also used intermittently to limit the accumulation of clinkers at the bottom of the vessel. Material removed through this bottom nozzle is injected into the CPFBC primary zone via a nitrogen-blown lift line; a slide valve and a ball valve in the drain piping control the flow of solids into this transfer line and provide a pressure-tight shutoff.

There is no heat-transfer surface in the refractory-lined carbonizer. The refractory lining consists of a 5-in. inner layer for thermal resistance and a 3-in. outer layer of hard-faced refractory for erosion resistance. A 20-in.-I.D. manway in the carbonizer provides access for maintenance.

The coal and dolomite, already crushed to 1/8 in. x 0, with total moisture of 2.5 and 0.5 percent respectively, enter the carbonizer at 137,100 lb/h and 41,158 lb/h, along with 17,826 lb/h transport air and 166,190 lb/h fluidizing air at 218 psia/745°F.

Figure 23 identifies the carbonizer yields and compositions per 100 lb of coal fed to the unit. The char/sorbent residue created in the unit exits at approximately 55,260 lb/h through the upper drain nozzle; the balance is elutriated at 62,364 lb/h. The bed overflow is approximately 37 wt% sorbent; the elutriated

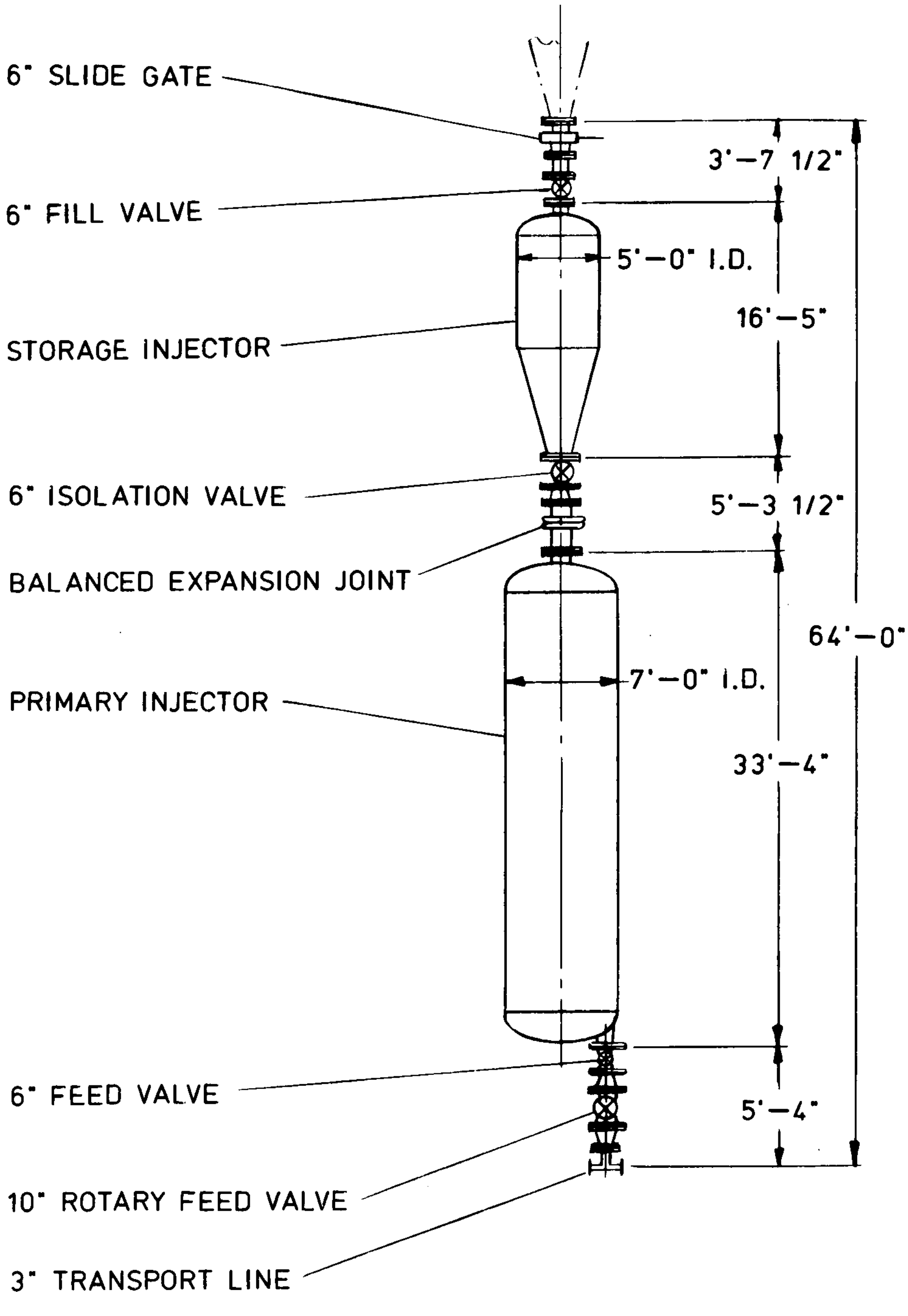


Figure 19 Dolomite Injection System

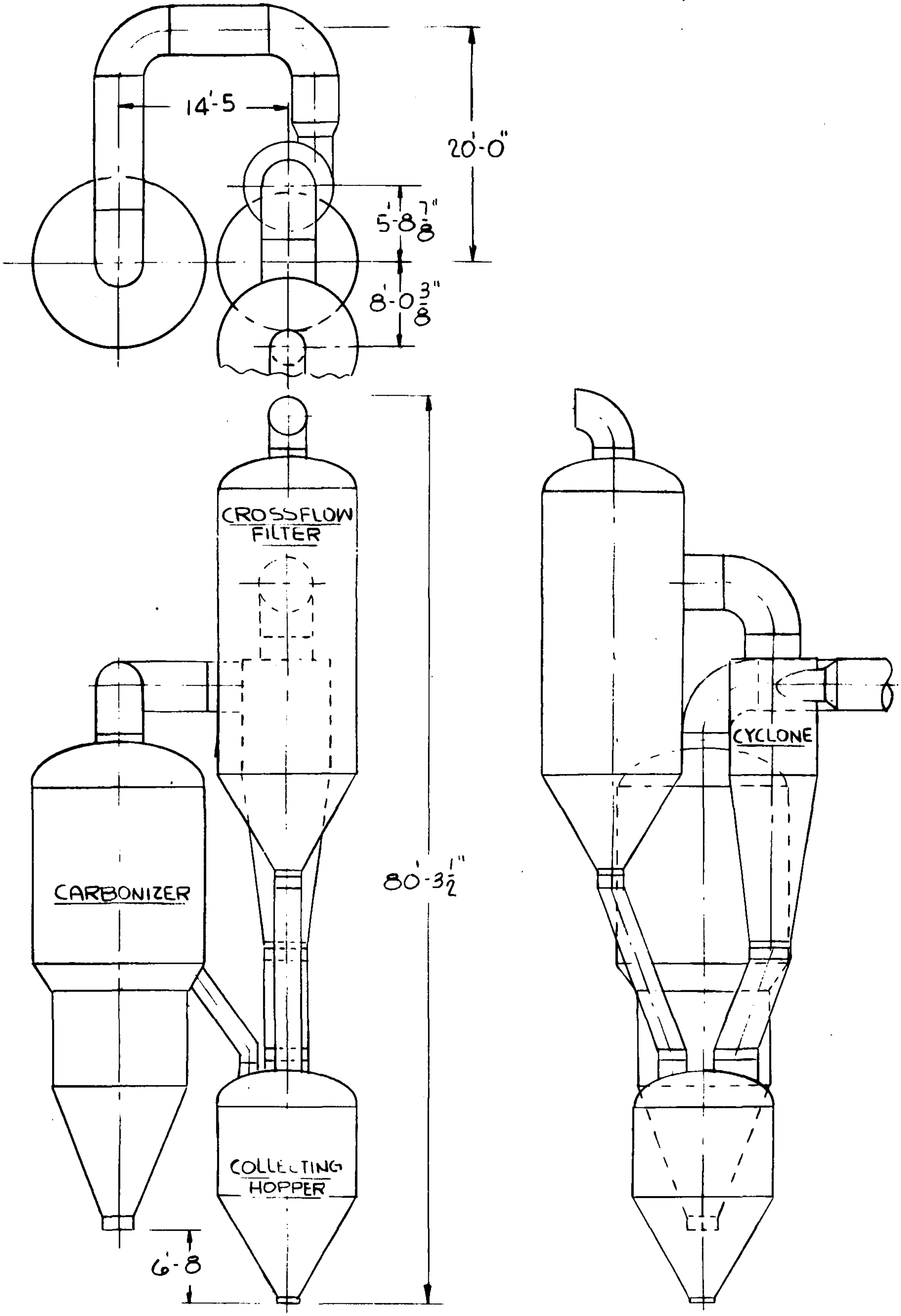
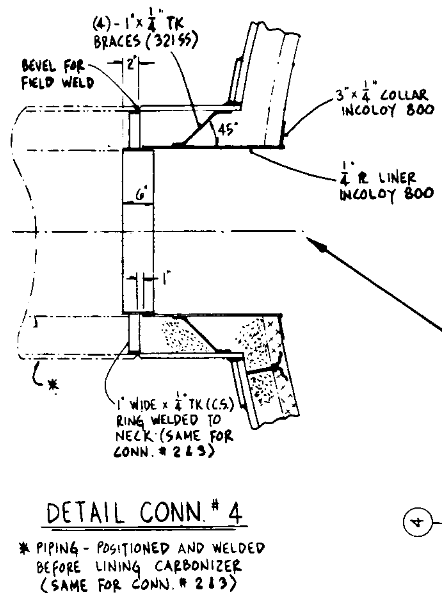
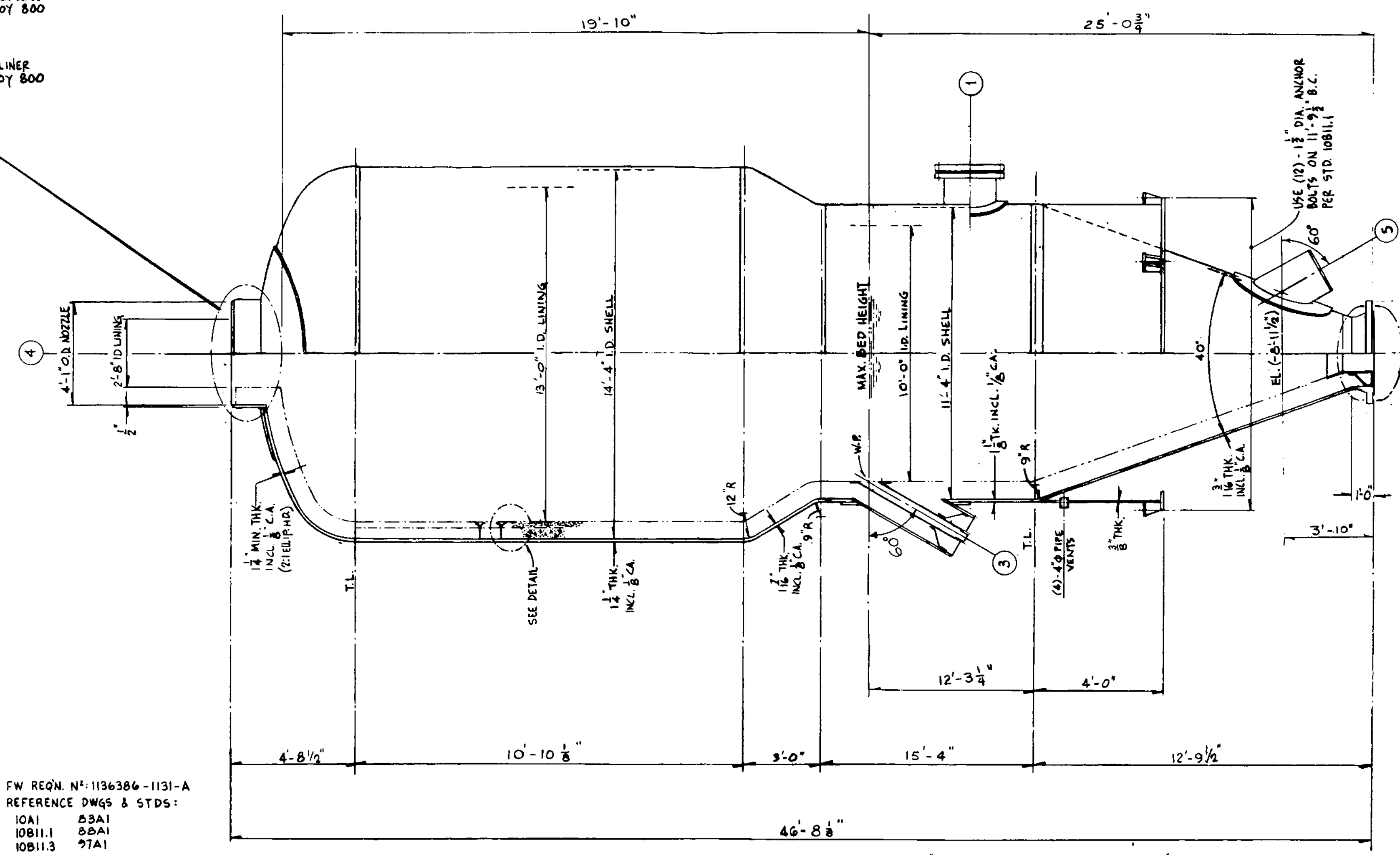


Figure 20 Carbonizer Subsystem

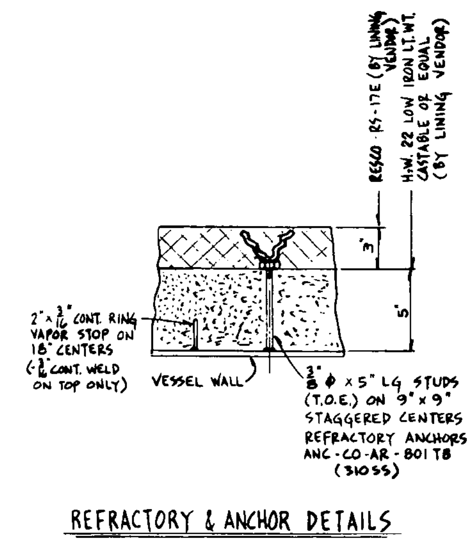
Dwg. 1136383-2-11-2 Rev. 1

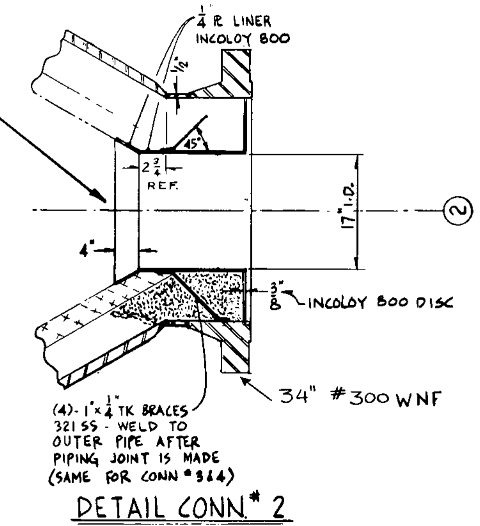




FW REQ'N. Nº: 1136386-1131-A
REFERENCE DWGS & STDS:
10A1 83A1
10B11.1 88A1
10B11.3 97A1

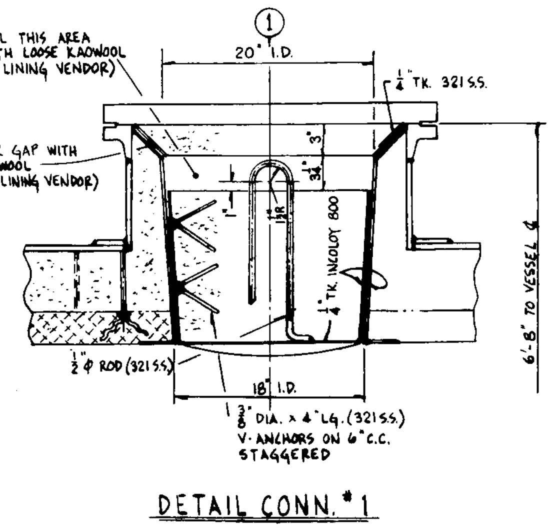
DO NOT FILL VESSEL WITH WATER AFTER REFRACTORY IS INSTALLED

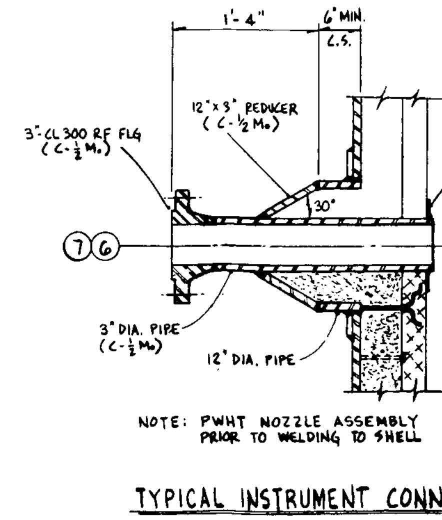




NOZZLE CHART				
CONN. NO.	SIZE	ANSI RATING	SERVICE	NO. REQ'D
1	30"	CL300RF	MANWAY W/ BLIND & HINGES	1
2	34"	CL300RF	INLET	1
3	22" O.D.	WELD END	SOLIDS OVERFLOW	1
4	49" O.D.	WELD END	GAS OUTLET	1
5	22" O.D.	WELD END	BED DRAIN	1
EST 6	3"	CL300RF	T.I.	2
EST 7	3"	CL300RF	P.I.	2

VESSEL DATA		
1	ITEM NO.:	NO. REQ'D: TWO (2)
2	SERVICE:	CARBONIZER
3		
4	OPER. PRESSURE ABOVE LIQUID LEVEL	NORM: PSIG
5		MAX: PSIG
6	DESIGN PRESSURE	INT: 227 PSIG
7		EXT: — PSIG
8	OPER. LIQUID HOLD-UP PRESS.:	— PSIG
9	OPER. PRESS. DROP THRU VESSEL:	5.5 PSIG
10	MAX. RELIEVING PRESS. AT TOP NO.:	227 PSIG
11	MAX. OPER. TEMPERATURE:	1500°F (INTERNAL)
12	DESIGN TEMPERATURE:	650°F (METAL)
13	SPECIFIC GRAVITY PROCESS FLUID:	0.6 (DUST) EST.
14	WIND DATA:	UBC (70 MPH, EXP. C)
15		
16	EARTHQUAKE DATA:	UBC (ZONE 1)
17	CODE: ASME SECT. VIII DIV. 1	STAMPED: YES
18	P.W.H.T. FOR CODE: PARTIAL	FOR PROCESS: NO
19	RADIOGRAPHED:	FULL
20	JOINT EFFICIENCY:	1.0
21	CORROSION ALLOW.:	1/8"
22	MAT'L SHELL:	SA-516-GR. 70
23	MAT'L HEADS:	SA-516-GR. 70
24	MAT'L SUPPORTS:	SA-516-GR. 70
25	MAT'L FLANGES:	SA-105/SA-336-F1
26	MAT'L NOZZLES:	SA-516-70
27	EXTERNAL BOLTING:	
28	INTERNAL BOLTING:	
29	GASKETS:	
30	TYPE OF HEADS:	2:1 ELLIPTICAL / TORICONICAL
31	INSULATION:	NONE
32	PAINT: PREPARATION:	PER STD. 83A1
33	PRIMER:	
34	COATS:	
35	PARTS:	COMPLETE EXTERIOR
36	SHIPMENT:	ONE PIECE
37		
38	EMPTY WGT (METAL WT. ONLY)	100,000 LBS.
39	WATER (ONLY) WGT:	[illegible] LBS.
40	REMOVABLE TRAY WGT:	LBS.
41	PACKING, CATALYST, ETC. WGT:	LBS.
42	INSULATION WGT: (LINING)	[illegible] LBS.
43	GUNITE WGT:	LBS.
44	OPER. BED WT.	[illegible] LBS.





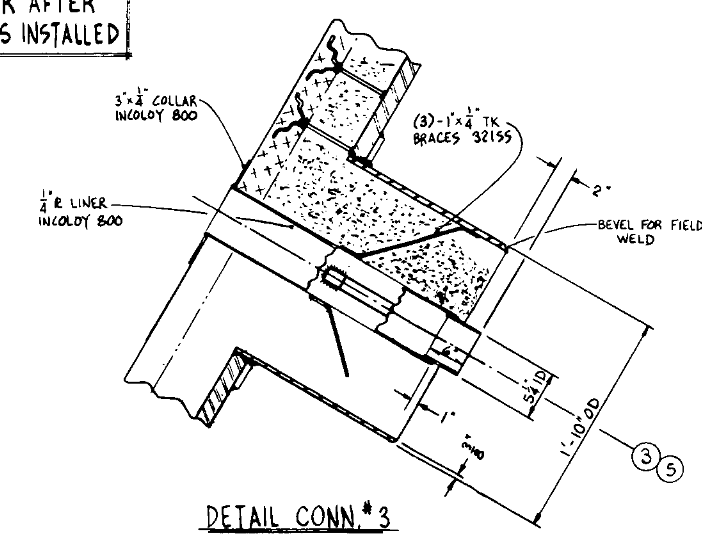
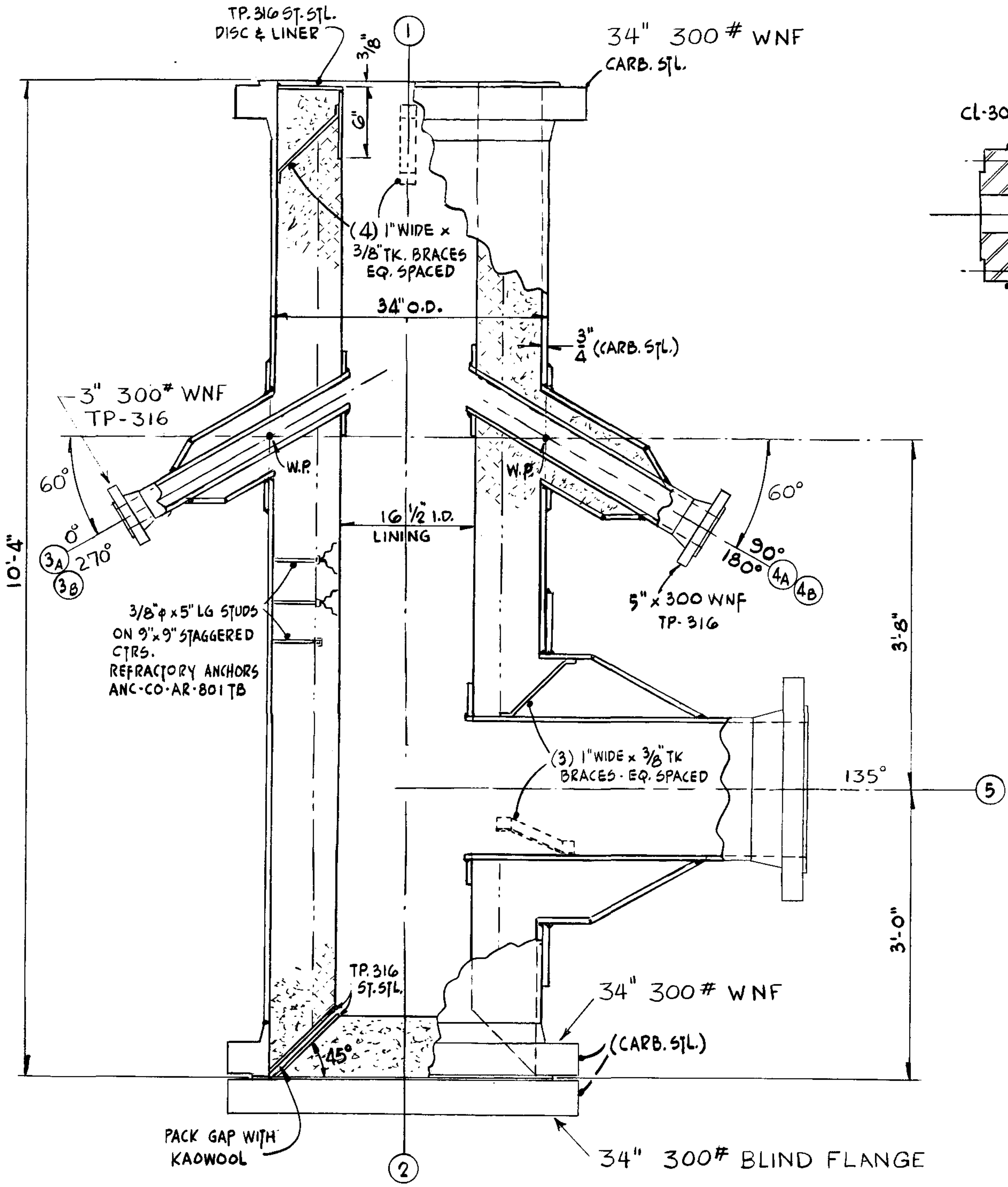
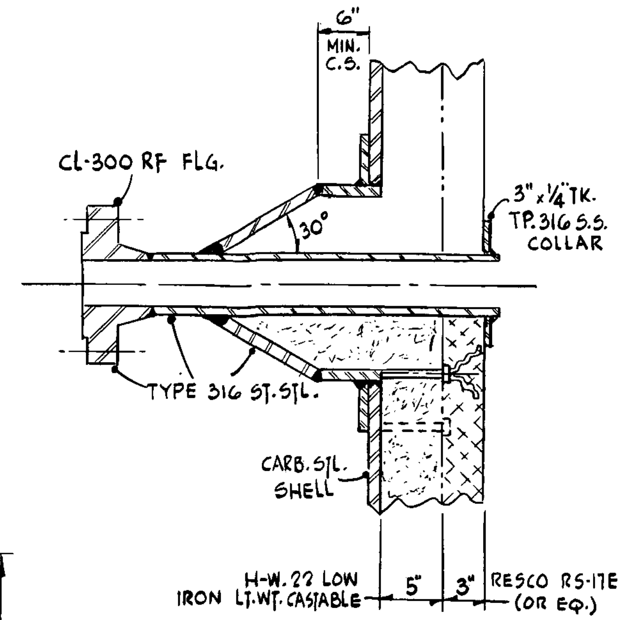


Figure 21 Carbonizer

Dwg. 1136383-3-11-5 Rev. 1





TYP. NOZZLE CONSTRUCTION

DESIGN NOTES:

VESSEL TO DESIGNED & FABRICATED IN ACCORDANCE WITH ANSI/ASME B31.3

CODE STAMP IS NOT REQ'D.

DESIGN PRESSURE · 227 PSIG
DESIGN TEMPERATURE · 1500°F (FLUID)
650°F (METAL)
CORROSION ALLOW - 1/8" C.S / 0.01" S.S.

JOINT EFF. -100%
RADIOGRAPH - FULL

MATERIAL:
- MAIN SHELL:
  - PLATE - SA-516-70
  - FORGE - SA-105
- NOZZLES, LINERS, REDUCERS:
  - PLATE SA-240-316
  - PIPE SA-312 TP-316
  - FITTINGS SA-403-316 WPS
  - FORGE. SA-182 F-316
- GASKETS - SPIRAL WOUND 316 S.S. W/ NON-ASBESTOS FILLER
- BOLTING - SA-193-B7/ SA-194-2H

REFRACTORY TO BE SHOP INSTALLED
HYDRO-TEST REQUIRED

NOZZLE CHART

CONN NO.	SIZE	ANSI RATING	SERVICE	NO REQ'D
1	34"	CL-300RF	CARBONIZER INLET	1
2	34"		MANWAY WITH COVER	1
3	3"		DOLOMITE FEED	2
4	5"		COAL FEED	2
5	18"		MAIN AIR FEED	1

Figure 22 Carbonizer Air/Coal/Sorbent Manifold

Fuel Gas Flow (lb/h)	178.446
HHV (Btu/lb)	1958
LHV (Btu/lb)	1817
Btu/sft^3 (LHV)	127

Char-Sorbent Flow (lb/h) = 85.794

	Char	Coke	Spent Dolomite
Carbon	41.413	8.168	6.215 MgO
Hydrogen	0.626	0.028	13.212 $CaCO_3$
Sulfur	1.736	0.055	2.266 CaS†
Nitrogen	0.780	0.026	0.510 Inerts
Oxygen	0.441	0.008	
Moisture	---	---	
Ash	10.31	---	

HHV (Btu/lb)	9360
LVH (Btu/lb)	9307

Tar
(Flow Rate = 2.436 lb/h)

Atomic Composition:

MW = 13.2721

$CH_{.5741}O_{.0181}N_{.0101}S_{.0082}$

HHV (Btu/lb)	15,800
LHV (Btu/lb)	15,410

Gas (wt%)*
(Flow Rate = 176.01 lb/h)

CO	8.93
CO_2	20.76
H_2O	7.66
H_2	0.60
CH_4	2.24
C_2's	2.10
NH_3	0.29
H_2S	0.087
N_2	57.333
HHV (Btu/lb)	1766
LHV (Btu/lb)	1629

CARBONIZER
14 atm
1500°F

70°F

711°F

70°F

Pittsburgh Coal (Ultimate wt%)
(Flow Rate = 100 lb/h)

Carbon	71.92
Hydrogen	4.69
Sulfur	2.99
Nitrogen	1.26
Oxygen	6.33
Moisture¶	2.50
Ash	10.31
HHV (Btu/lb)	12,916
LHV (Btu/lb)	12,472

Air
(Flow Rate = 134.22 lb/h)

Relative Humidity	50% at 70°F

Plum Run Dolomite (wt%)
(Flow Rate = 30.02 lb/h; Ca/S = 1.75)§

$CaCO_3$	54.5
$MgCO_3$	43.3
Moisture	0.5
Inerts	1.7

*Excludes Tar.
†87.5% Sulfur Capture (92% of H_2S Equilibrium Capture).
§If Based on Sulfur Release--Ca/S = 3.7.
¶After Drying.

Rev. D
7/24/87

Figure 23 1500°F Carbonizer Balance With Dried Pittsburgh No. 8 Coal (Baseline Plant) material is approximately 16 wt% sorbent. The carbonizer operates with an 87.5 percent sulfur-capture efficiency for hydrogen sulfide and has an inlet-to-outlet nozzle air/gas pressure loss of approximately 5.6 psig. The size distribution of the elutriated material, in terms of wt% less than the indicated sizes, is:

Material	10 μm	20 μm	40 μm	100 μm	300 μm	500 μm
Sorbent	15.1	24.0	36.4	58.8	97.4	100
Ash	30.0	50.2	70.3	95.0	100	---
Char	8.3	13.2	20.0	32.4	62.5	91.0

The methodologies used to predict carbonizer yields, sulfur-capture efficiencies, and elutriation rates are described in Appendices A and C.

Cyclone. The carbonizer subsystem has a single cyclone between the carbonizer outlet and the cross-flow filter. Solids captured by the cyclone drain to a collecting hopper and are injected into the CPFBC.

The carbonizer cyclone, illustrated in Figure 24, is 28 ft long and has a 6 ft-1 in. I.D. barrel with a conical section tapering to a 2 ft-1 in. I.D. solids outlet. Low-Btu carbonizer gas is tangentially fed to the cyclone at an inlet velocity of approximately 70 ft/s. Cleaned gas leaves the cyclone through a 3-ft.-I.D. outlet nozzle atop the unit and goes to the cross-flow filter for final cleaning.

The cyclone operates with a normal pressure loss of 4 psi and an overall collection efficiency of approximately 96 percent based on the size distribution specified for the material elutriated by the carbonizer. The cyclone-captured material, approximately 15 wt% sorbent, drains to a collecting hopper through a dipleg/trickle-valve arrangement at 59,906 lb/h. About 2459 lb of elutriated material remains in the 244,650-lb/h cyclone gas stream and proceeds to the cross-flow filter.

Collecting Hopper. The collecting hopper receives captured particulate solids from the carbonizer cyclone and cross-flow filter, as well as material from the carbonizer bed drain. It operates at the carbonizer freeboard pressure with trickle valves on the cyclone and cross-flow filter drain lines providing the required pressure seals. Solids from the collecting hopper drain into the N valve for injection into the CPFBC.

The collecting hopper, illustrated in Figure 25, is a 12-ft-O.D. refractory-lined vessel with a 60-deg conical section to facilitate the gravity flow of solids to the 7-1/4 in.-I.D. outlet. A slide valve on the collecting hopper outlet maintains the solids level within it, ensuring an adequate feed supply to the N valve.

The collecting hopper receives 55,260 lb/h residue from the carbonizer upper drain nozzle and captured material from the carbonizer cyclone and ceramic cross-flow filter at flow rates of approximately 59,906 and 2459 lb/h respectively. All solids enter the collecting hopper at approximately 1500°F. The combined flow is gravity fed to the N valve for injection into the CPFBC.

N Valve. The N valve, shown in Figure 26, is a nitrogen-fluidized non-mechanical valve that controls the transfer of solids from the carbonizer subsystem to the CPFBC. Nitrogen is used for aeration in the valve to preclude combustion of the char in the transfer process. The N valve requires 500 lb/h nitrogen to convey 117,624 lb/h char/sorbent mixture at 1500°F from the carbonizer to the CPFBC.

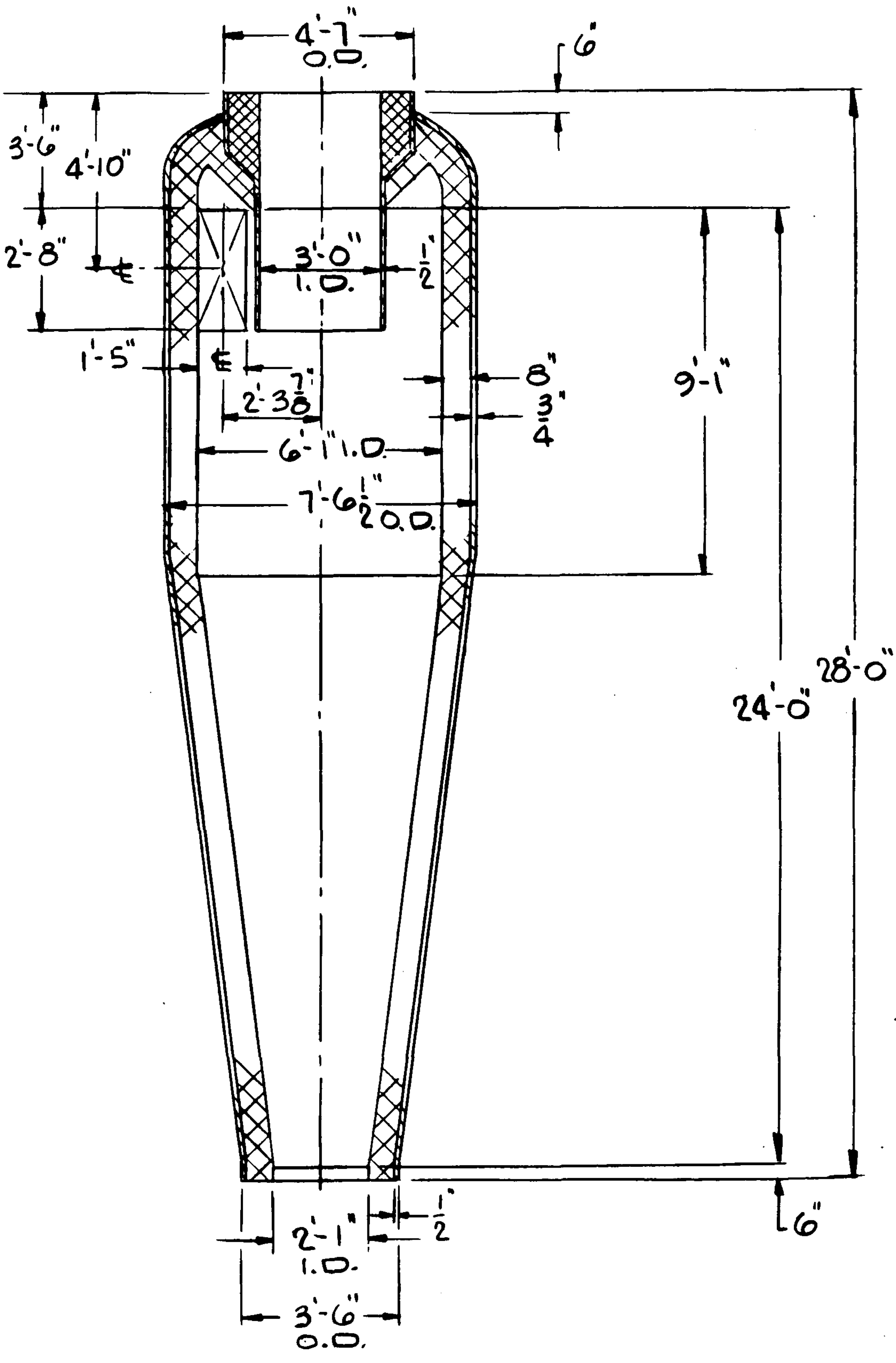
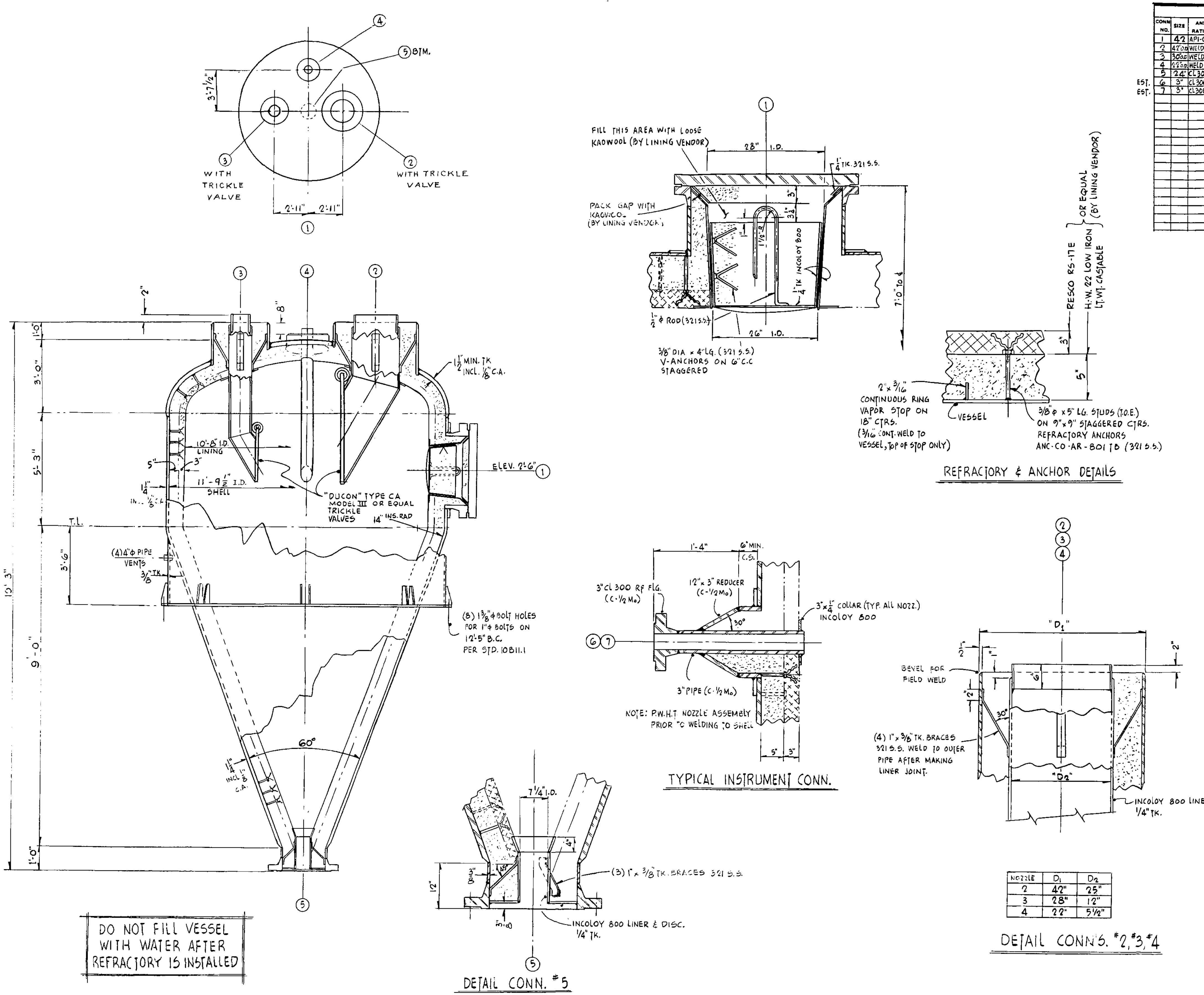


Figure 24 Carbonizer Cyclone

Dwg. 1136383-2-11-3 Rev. 1



NOZZLE	D_1	D_2
2	42"	25"
3	28"	12"
4	22"	5½"

NOZZLE CHART

	CONN NO.	SIZE	ANSI RATING	SERVICE	NO REQ'D
	1	42	API-605	MANWAY W/ BLIND & HINGE	1
	2	42" O.D.	WELD END	CYCLONE INLET	1
	3	30" O.D.	WELD END	FILTER INLET	1
	4	22" O.D.	WELD END	CARBONIZER INLET	1
	5	24"	CL300RF	-OUTLET	1
EST.	6	3"	CL300RF	T.I.	3
EST.	7	3"	CL300RF	P.I.	3

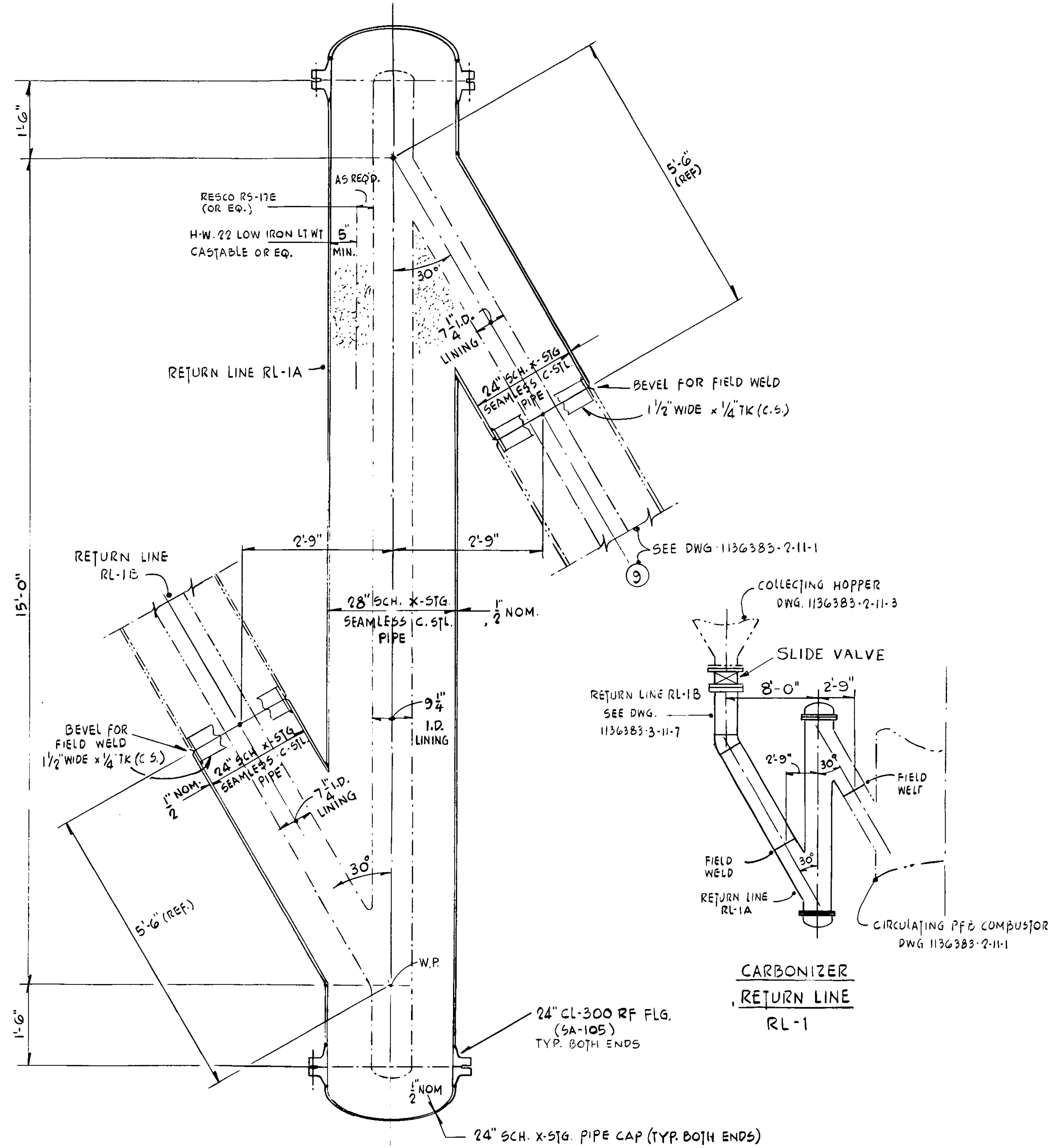
VESSEL DATA

1	ITEM NO: NO. REQ'D: TWO (2)
2	SERVICE: CARBONIZER COLLECTING
3	HOPPER
4	OPER. PRESSURE ABOVE LIQUID LEVEL — NORM: PSIG
5	MAX: PSIG
6	DESIGN PRESSURE — INT: 226 PSIG
7	EXT: PSIG
8	OPER. LIQUID HOLD-UP PRESS: — PSIG
9	OPER. PRESS. DROP THRU VESSEL: 1.5 PSIG
10	MAX. RELIEVING PRESS. AT TOP HD: 226 PSIG
11	MAX. OPER. TEMPERATURE: (INTERNAL) 1500 °F
12	DESIGN TEMPERATURE: (METAL) 650 °F
13	SPECIFIC GRAVITY (PROCESS FLUID): 0.6 (DUST) EST.
14	WIND DATA: UBC (70 MPH, EXP. C)
15	
16	EARTHQUAKE DATA: UBC (ZONE 1)
17	CODE: ASME SECT VIII, DIV 1 STAMPED: YES
18	P.W.H.T. FOR CODE: PARTIAL FOR PROCESS: NO
19	RADIOGRAPHED: FULL
20	JOINT EFFICIENCY: 100%
21	CORROSION ALLOW. / [redacted] 1/8"
22	MAT'L. SHELL: SA-516-70
23	MAT'L. HEADS: SA-516-70
24	MAT'L. SUPPORTS: SA-516-70
25	MAT'L. FLANGES: SA-105 / SA-336-F1
26	MAT'L. NOZZLES: SA-516-70
27	EXTERNAL BOLTING: SA-193-B7 / SA-194-2H
28	INTERNAL BOLTING: —
29	GASKETS: FLEXITALLIC - 316 SS
30	TYPE OF HEADS: TOP (2:1 ELLIP) BTM (TORICON)
31	INSULATION: INTERNAL LINING (BY OTHERS)
32	PAINT: PREPARATION: PER STD. 83A1
33	PRIMER:
34	COATS:
35	PARTS: COMPLETE EXTERIOR
36	SHIPMENT: ONE PIECE
37	
38	EMPTY WGT (METAL WT. ONLY) 42000 LBS.
39	WATER (ONLY) WGT: 68000 LBS.
40	REMOVABLE TRAY WGT: LBS.
41	PACKING, CATALYST, ETC. WGT: LBS.
42	INSULATION WGT: (LINING) 45000 LBS.
43	GUNITE WGT: LBS.
44	OPER. LIQUID WGT: LBS.

FW REQ'N. Nº: 1136386-1131-B
REFERENCE DWGS & STDS:
10A1 83A1
10B11.1 88A1
10B11.3 97A1

Figure 25 Carbonizer Collecting Hopper

Dwg. 1136383-3-11-6 Rev. 0



DESIGN NOTES:

VESSEL TO BE DESIGNED & FABRICATED IN ACCORDANCE WITH ANSI/ASME B31.3
CODE STAMP IS NOT REQ'D.
DESIGN PRESSURE - 220 PSIG
DESIGN TEMPERATURE - 650 °F (METAL)
- 1600 °F (FLUID)

CORROSION - 1/8"
JOINT EFFICIENCY - 100 %
RADIOGRAPH - 100 %

MATERIAL:
PLATE - SA-516-70 (IF USED IN LIEU OF PIPE)
PIPE - SA-106
FORGINGS - SA-105
GASKETS - SPIRAL WOUND 316 S.S. W/ NON-ASB. FILLER
BOLTING - SA-193-B7 / SA-194-2H
REFRACTORY ANCHORS - ANC-CO-AR-801 TB, TYPE 310 S.S. ON 9" STAGGERED CTRS.

RETURN LINE TO BE REFRACTORY LINED IN FAB'R. SHOP

HYDRO-TEST REQ'D.

Figure 26 N Valve

A slide valve upstream of the N valve at the collecting hopper outlet maintains control and gas seal under all upset conditions.

Solids from the collecting hopper enter the N valve at a 60-deg downward slope. Nitrogen aeration gas pneumatically conveys solids up a 15-ft vertical column, reducing pressure for injection into the CPFBC. Solids enter the CPFBC 21 in. above the grid plate, at a 60-deg angle from the horizontal.

The N valve contains no moving mechanical parts subject to wear, seizure, or both; it is constructed of standard carbon steel pipe. The inlet and outlet sections of the valve are 24-in.-O.D. by 1/2-in. nominal wall pipe, with internal refractory reducing the I.D. to 7-1/4 in. The vertical section is composed of a 28-in.-O.D. by 1/2-in. nominal wall pipe with a refractory-lined 9-1/4 in. I.D.

2.5.5 CPFBC Subsystem

The CPFBC Subsystem is illustrated in Figure 27. It consists of the CPFBC, its cyclones, the FBHE, and the J-valve transfer lines. Two identical CPFBC Subsystems (modules) are required for the baseline plant. This section describes the components of one of the CPFBC modules. All quantities, flow rates, etc., discussed in this section are based on a single module unless otherwise indicated.

The char/sorbent mixture from the carbonizer is fed through a nitrogen fluidized nonmechanical valve (N valve) to the CPFBC to complete char combustion and oxidize the calcium sulfide to calcium sulfate. Coal may also be injected into the CPFBC if additional steam-cycle duty is desired. Particulate solids elutriated from the CPFBC are captured by four cyclones operating in parallel; they drain to an external FBHE by gravity. Solids are transferred from the FBHE to the CPFBC using nonmechanical J valves.

In the FBHE, heat is extracted from a portion of the cyclone-collected material by passing it through a series of bubbling fluidized beds containing water-/steam-cooled tubes. The cooled solids from the FBHE are recirculated to the CPFBC to control combustion temperature at 1600°F. The balance of the solids bypasses the heat-transfer surfaces in the FBHE and is returned to the CPFBC with minimal cooling to enhance sulfur capture and carbon utilization.

Flue gas leaves the CPFBC at 1600°F and proceeds through the cyclones and downstream cross-flow filter. From there, the cleaned high-excess-air flue gas supports the combustion of the low-Btu carbonizer fuel gas (1500°F) in the topping combustor, producing a 2100°F gas inlet temperature to the turbine.

Circulating PFB Combustor (CPFBC). The CPFBC is a vertical, 114-ft tall, cylindrical, refractory-lined pressure vessel (Figure 28) with I.D.s of approximately 9 ft-6 in. (reducing zone) and 18 ft (oxidizing zone). The unit is designed for staged combustion of the carbonizer coal/char/sorbent residue to minimize NO_x formation. The lower fuel-rich reducing zone extends from the air distribution grate to the centerline of the conical transition, where the secondary air inlet ports are located; the oxidizing zone extends from the secondary air ports to the top of the combustor. The lower reducing zone operates with a bed approximately 6 ft high; the upper oxidizing zone bed is approximately 71 ft high.

There are two layers of refractory in the upper and lower zones of the CPFBC vessel. Adjacent to the shell, 5 in. of Harbison-Walker 22 low-iron lightweight castable refractory is applied for thermal resistance; 3 in. of Resco RS-17E is applied atop this refractory for erosion protection. In the air plenum, a single 3-in. layer of Harbison-Walker 40-64 is required.

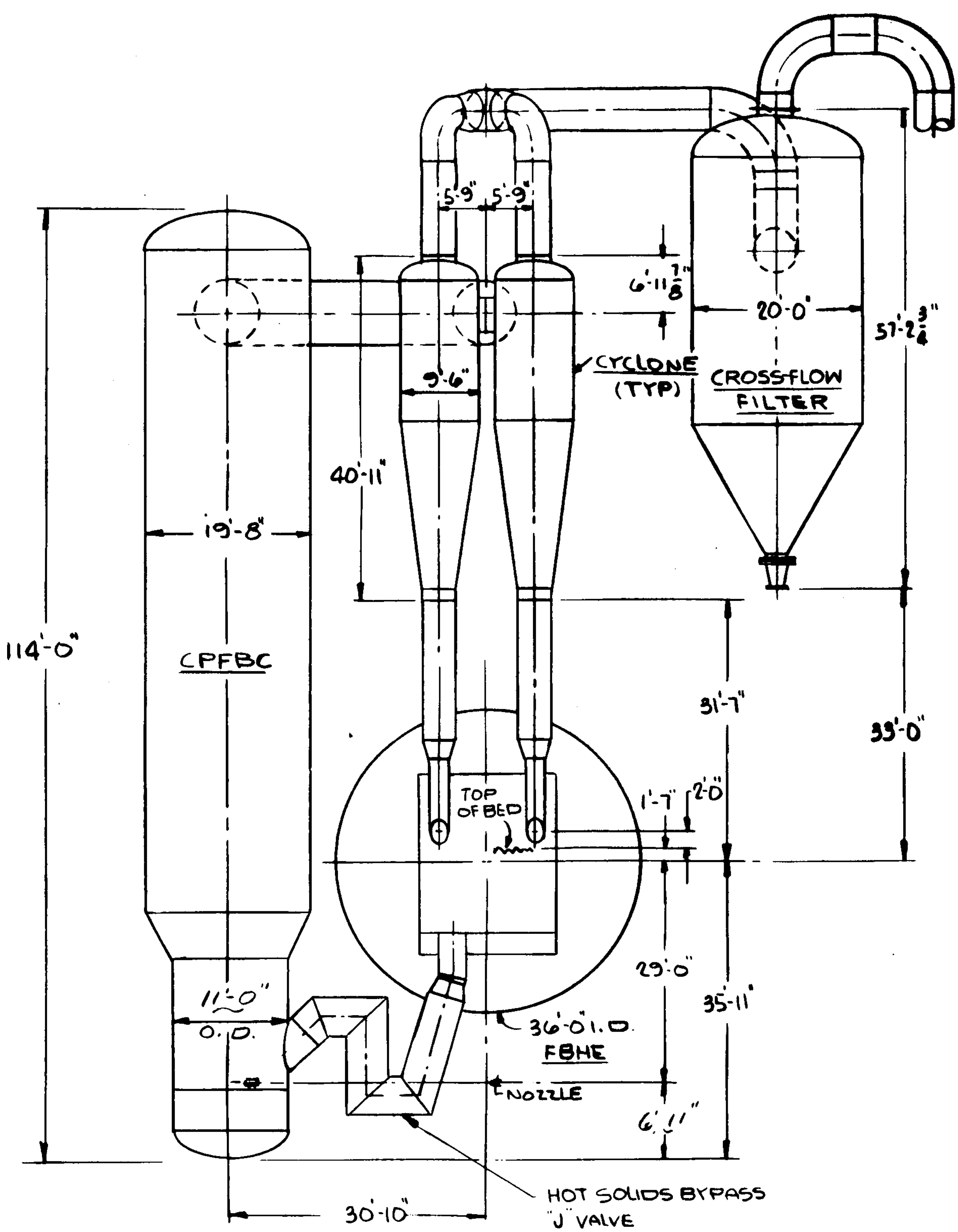
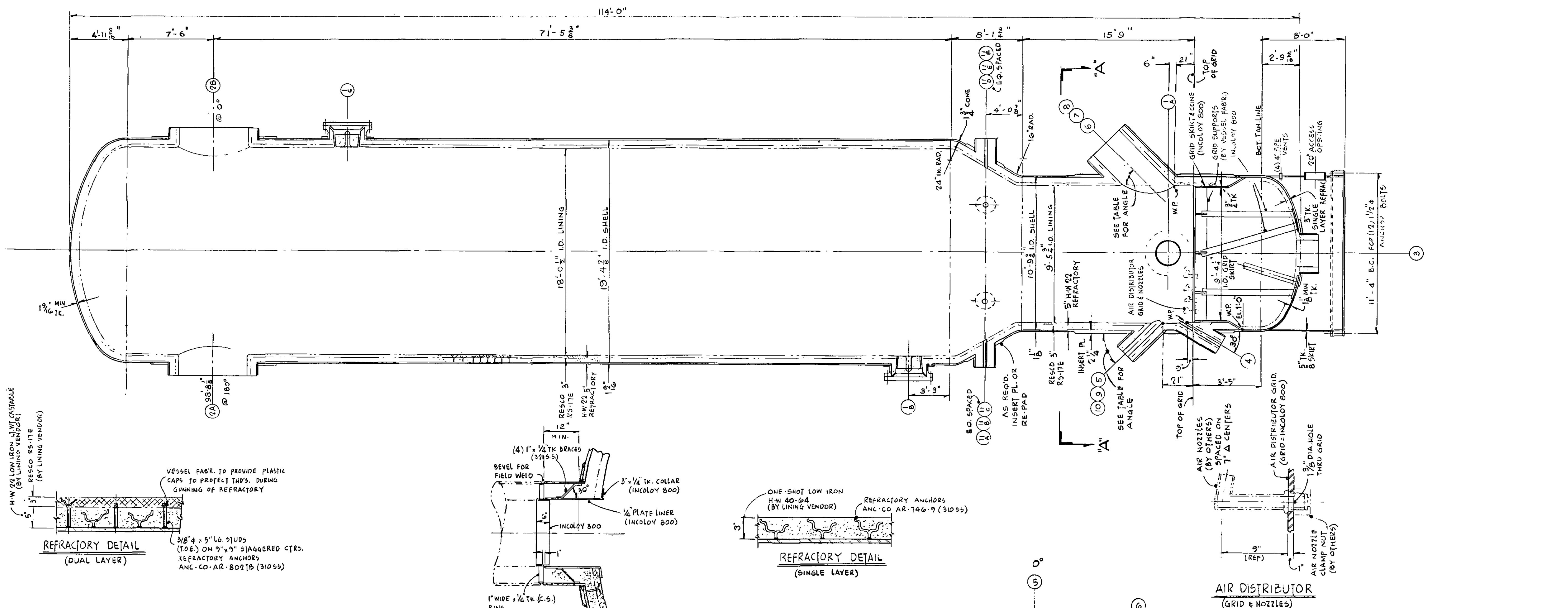
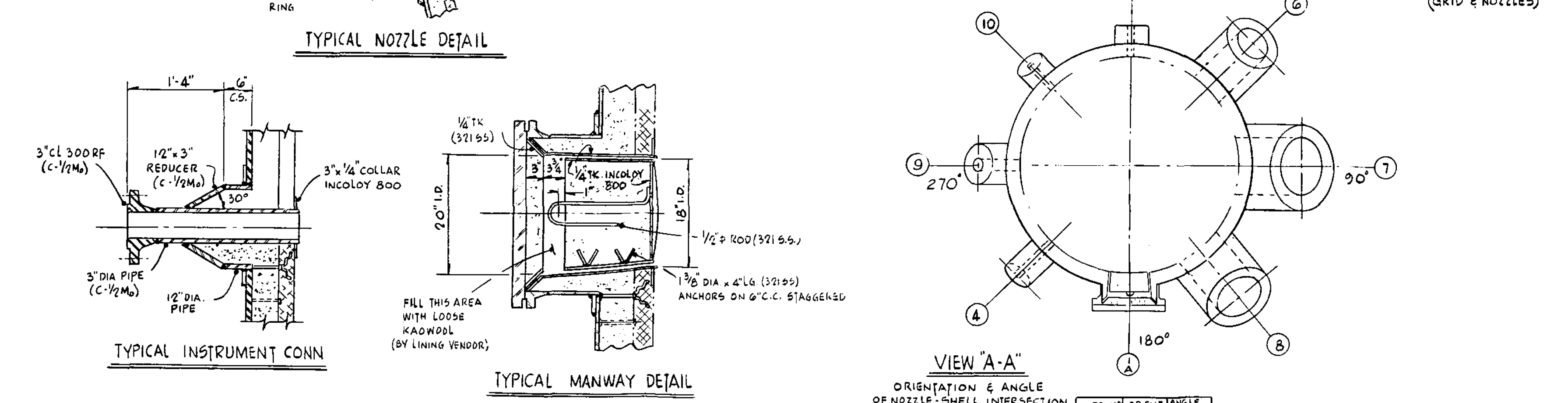


Figure 27 CPFBC Subsystem (Baseline Plant)--Elevation View

Dwg. 1136383-2-11-1 Rev. 1





VESSEL DATA		
1	ITEM NO:	NO. REQ'D: 2, TWO
2	SERVICE: CIRCULATING PFB	
3	COMBUSTOR	
4	OPER. PRESSURE ABOVE LIQUID LEVEL	NORM: 219 PSIG
5		MAX: PSIG
6	DESIGN PRESSURE	INT: 220 PSIG
7		EXT: — PSIG
8	OPER. LIQUID HOLD - UP PRESS:	PSIG
9	OPER. PRESS. DROP THRU VESSEL:	6 PSIG
10	MAX. RELIEVING PRESS. AT TOP HD:	220 PSIG
11	MAX. OPER. TEMPERATURE: 1600°F (INTERNAL)	
12	DESIGN TEMPERATURE: 650°F (METAL)	
EST. 13	SPECIFIC GRAVITY (PROCESS FLUID): 0.6 (DUST)	
14	WIND DATA: U.B.C. (70 MPH, EXP. C)	
15		
16	EARTHQUAKE DATA: UBC (ZONE 1)	
17	CODE: ASME SECT. VIII DIV 1	STAMPED: YES
18	P.W.H.T. FOR CODE: YES	FOR PROCESS: NO
19	RADIOGRAPHED: FULL	
20	JOINT EFFICIENCY: 100%	
21	CORROSION ALLOW. 1/8"	
22	MAT'L. SHELL: SA-516-70	
23	MAT'L. HEADS: SA-516-70	
24	MAT'L SUPPORTS: SA-516-70	
25	MAT'L. FLANGES: SA-105 / SA-336-F1	
26	MAT'L. NOZZLES: SA-516-70 / SA-106-B	
27	EXTERNAL BOLTING: SA-193-B7 / SA-194-2H	
28	INTERNAL BOLTING: —	
29	GASKETS:	
30	TYPE OF HEADS: 2:1 ELLIPTICAL	
31	INSULATION: NONE	
32	PAINT: PREPARATION: PER STD. 83A1	
33	PRIMER:	
34	COATS:	
35	PARTS: COMPLETE EXTERIOR	
36	SHIPMENT: ONE PIECE (BARGE)	
37		
38	EMPTY WGT: (METAL WT.)	460,000 LBS.
39	WATER (ONLY) WGT:	1667000 LBS.
40	REMOVABLE TRAY WGT:	LBS.
41	PACKING, CATALYST, ETC. WGT:	LBS.
42	INSULATION WGT: (LINING)	500,000 LBS.
43	GUNITE WGT:	LBS.
44	OPER. LIQUID WGT:	LBS.

NOZZLE CHART

CONN NO.	SIZE	ANSI RATING	SERVICE	NO REQ'D	I.D. LINING
1	30"	CL300 RF	MANWAY W/ BLIND & HINGE	3	20/18
2	90" O.D.	WELD END	CYCLONE INLET	2	72"
3	42" O.D.		AIR INLET	1	29"
4	20" O.D.		BED DRAIN	1	4"
5	22" O.D.		COAL FEED	1	5" SCH 80
6	38" O.D.		PRI SHTR RETURN	1	25"
7	56" O.D.		FBHE BYPASS	1	39"
8	42" O.D.		SG BED RETURN	1	29"
9	24" O.D.		CARBONIZER RETURN	1	7 1/4"
10	20" O.D.		DOLOMITE FEED	1	3" SCH 80
11	38" O.D.	WELD END	SECONDARY AIR	6	25"
12	3"	CL300 RF	P.I.	12	–
13	3"	CL300 RF	T.I.	12	–

NOZZ. Nº	ORIENT	ANGLE FROM HORIZ
5	0°	0°
6	40°	45°
7	90°	45°
8	140°	45°
9	270°	60°
10	315°	45°

Figure 28 Circulating PFB Combustor (CPFBC)

Primary air at 712°F enters the combustor at 406,977 lb/h through a 3 ft-6 in. O.D. nozzle in the bottom of the CPFBC and pressurizes an air plenum. A bed-floor/air-distributor plate with directional T and L nozzles separates the plenum from the lower reducing zone. Air passes through the nozzles and fluidizes the lower zone. The lower zone operates at a 50-percent air stoichiometry with a superficial gas velocity of approximately 8 ft/s. The outlets of the nozzles are approximately 9 in. above the floor, allowing a stagnant layer of bed material to insulate the distributor plate from the 1600°F combustor temperature. The T-nozzle outlets are inclined slightly downward and aligned to push oversized bed material toward a drain near the top of the distributor plate for removal from the system.

At full load, solids enter the CPFBC via four nozzles; their lowest points are 21 in. above the air distributor. The char/sorbent mixture from the carbonizer, at 1500°F and 117,624 lb/h, enters through Nozzle 9 (7-1/4 in. I.D.). FBHE solids return to the CPFBC via Nozzles 6, 7, and 8. Nozzle 7 (39-in. I.D.) is diametrically opposite Nozzle 9; it returns sorbent material (at approximately 1600°F), that has bypassed the FBHE in-bed tube bundles at 3,631,001 lb/h. Nozzles 6 and 8, 50 deg on either side of Nozzle 7, have 25- and 29-in. in I.D.s; they return 1050°F solids at 1,612,497 and 1,721,497 lb/h. Nozzles 5 (5-1/4-in. I.D.) and 10 (3-1/4-in. I.D.), with centerlines 27 in. above the air distributor plate, feed coal and dolomite respectively to the unit during start-up and minimum-load operation. Nozzle 4, which drains bed material, has a 4-in. I.D.

Secondary air enters the CPFBC at 2,155,460 lb/h, approximately 20 ft above the grid plate floor, through six 2 ft-1 in. I.D. nozzles equally spaced around the CPFBC. The nozzles are diametrically opposed to preclude wall impingement and ensure good mixing. They enter the conical transition between the upper zone (18-ft I.D.) and the lower zone (9 ft-6 in. I.D.) The upper zone operates at 211-percent excess air and 12 ft/s superficial gas velocity. Fluidizing and J-valve air from the FBHE at approximately 1200°F make up 402,495 lb/h secondary air. The balance (1,752,965 lb/h) comes from the compressor discharge at 712°F; the 20,000 lb/h J-valve airflow is assumed to split equally between the FBHE and the CPFBC.

Flue gas and entrained solids leave the combustor at 1600°F through two refractory-lined 6-ft-I.D. nozzles at the top of the vessel. These pipes are symmetrically placed to provide equal loading to the four cyclones.

Three 20-in.-diam manways at various elevations along the CPFBC permit access for maintenance.

The CPFBC operates with an inlet-to-outlet nozzle air/gas pressure loss of about 6.7 psi, a sulfur-removal efficiency of 94 percent, a carbon combustion efficiency of 99.6 percent, and an NO_x release of 187 lb/h (0.211 lb/10^6 Btu). The size distribution of elutriated material from the CPFBC is:

	Weight Less Than					
Material	10 μm	20 μm	40 μm	100 μm	300 μm	500 μm
Sorbent	0.2	0.8	3.9	12.0	32.2	55.2
Ash	1.8	7.1	29.5	87.6	100	---

Methodologies to predict CPFBC sulfur capture, combustion efficiency, and NO_x emissions are described in Appendix C.

Cyclones. The solids recycle system is designed to collect solids entrained in the 1600°F flue gas leaving the CPFBC and deliver them to the external FBHE. Each of the two outlets from the CPFBC supplies a pair of cyclones operating in parallel, and all four cyclones drain directly into the FBHE via dip legs and trickle valves.

Each cyclone (Figure 29) is 40 ft-11 in. high with an 8-ft-I.D. x 18 ft-10 in. long barrel that has 20 ft-10 in. conical section tapering to 2 ft-7 in. at the solids outlet. The gas inlet duct is sized for a 70-ft/s inlet velocity, and the I.D. of the gas outlet tube is 2 ft-9 in.

The CPFBC cyclones operate with a nominal 4-psi pressure loss; they have an overall collection efficiency greater than 99 percent with the particle size distribution specified for the CPFBC elutriated materials. Captured solids drain at approximately 7,000,000 lb/h to the FBHE through a dip-leg/trickle-valve arrangement. Approximately 10,567 lb/h CPFBC elutriated material remains entrained in the 2,644,236 lb/h flue gas stream, leaves the CPFBC cyclones, and proceeds to the CPFBC cross-flow filter.

Fluidized Bed Heat Exchanger. Sensible heat from the particulate solids captured by the CPFBC cyclones is transferred to the steam cycle by the FBHE. Feedwater preheating and a portion of the plant steam generating and primary superheating functions take place in the HRSG downstream of the gas turbine. The balance of the plant steam generation and superheating functions, along with the entire reheating function, is performed in the FBHE.

The design of the FBHE is based on manufacturing and construction techniques developed from atmospheric fluidized bed (AFB) combustion experience and the design of first-generation PFB combustion plants. Design criteria utilized in the FBHE to ensure safe, reliable operation and ease of fabrication, shipment, erection, and maintenance are:

- Horizontal pressure vessel orientation
- Mechanical operators outside the pressure vessel
- Conventional use of manufacturing methods and materials
- Easy access to all internal heat-transfer surfaces and piping.

The unit is shop-assembled to the greatest extent possible, hydrotested, and shipped to the site by barge.

The FBHE is shown isometrically in Figures 30 and 31; design details are presented in Figures 32, 33, and 34. The FBHE consists of seven fluidized cells, six of which contain in-bed tube bundles and all of which are contained in a 2-3/4 in.-thick, 36-ft I.D. x 48-ft-long (tangent-to-tangent) cylindrical pressure vessel. The cells are enclosed by water-cooled, welded, fin-tube construction (MONOWALL^{R}) to form a gas-tight enclosure. Adjacent cells share common water-cooled partition walls. Each cell has a 30-in.-tall water-cooled air plenum, a T-nozzle air distributor, a bed approximately 9-1/2 ft deep, and a freeboard approximately 9 ft high.

All particulate solids captured by the CPFBC cyclones (7,000,000 lb/h) drain to dip leg/trickle valve assemblies in the freeboard of the center bed of the FBHE. This bed has no in-bed tube bundle; its enclosure walls are refractory lined to minimize bed-to-tube heat transfer. From this bed, solids at approximately 1600°F return to the CPFBC at 3,631,000 lb/h through an air-fluidized nonmechanical valve--a J valve. These solids bypass the heat-transfer surfaces of the FBHE and

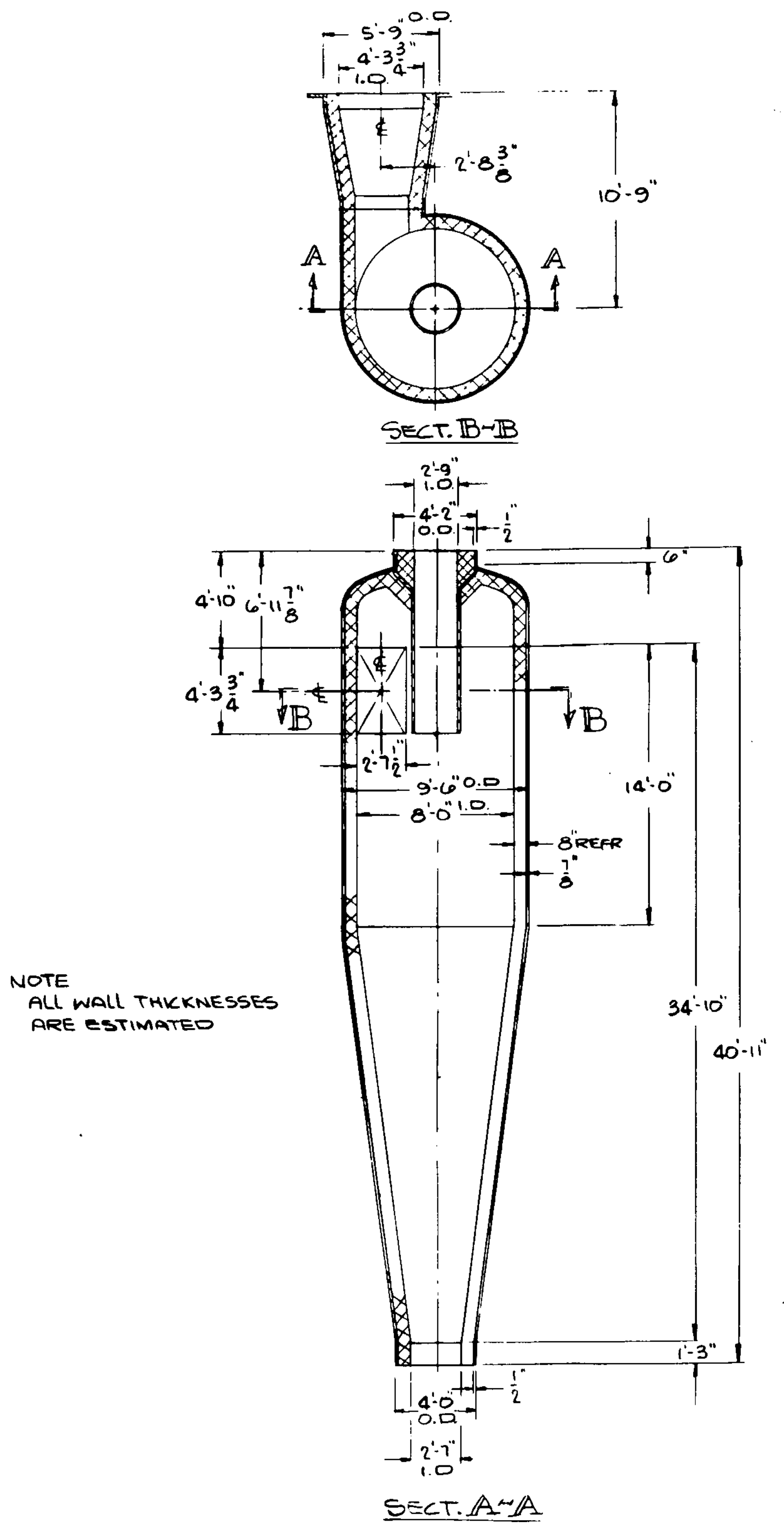


Figure 29 CPFBC Cyclone--Baseline Plant (Four Required)

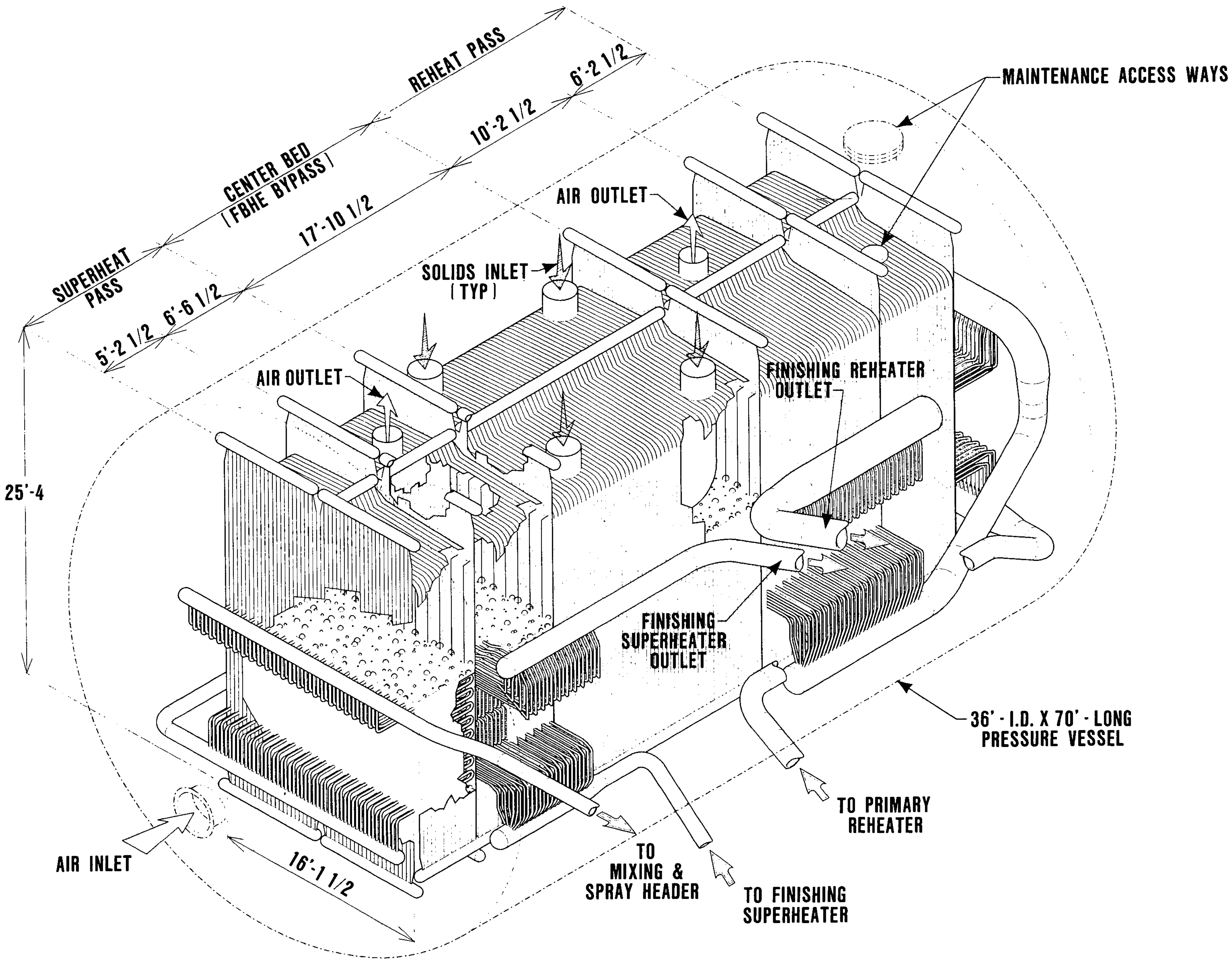


Figure 30--FBHE Isometric

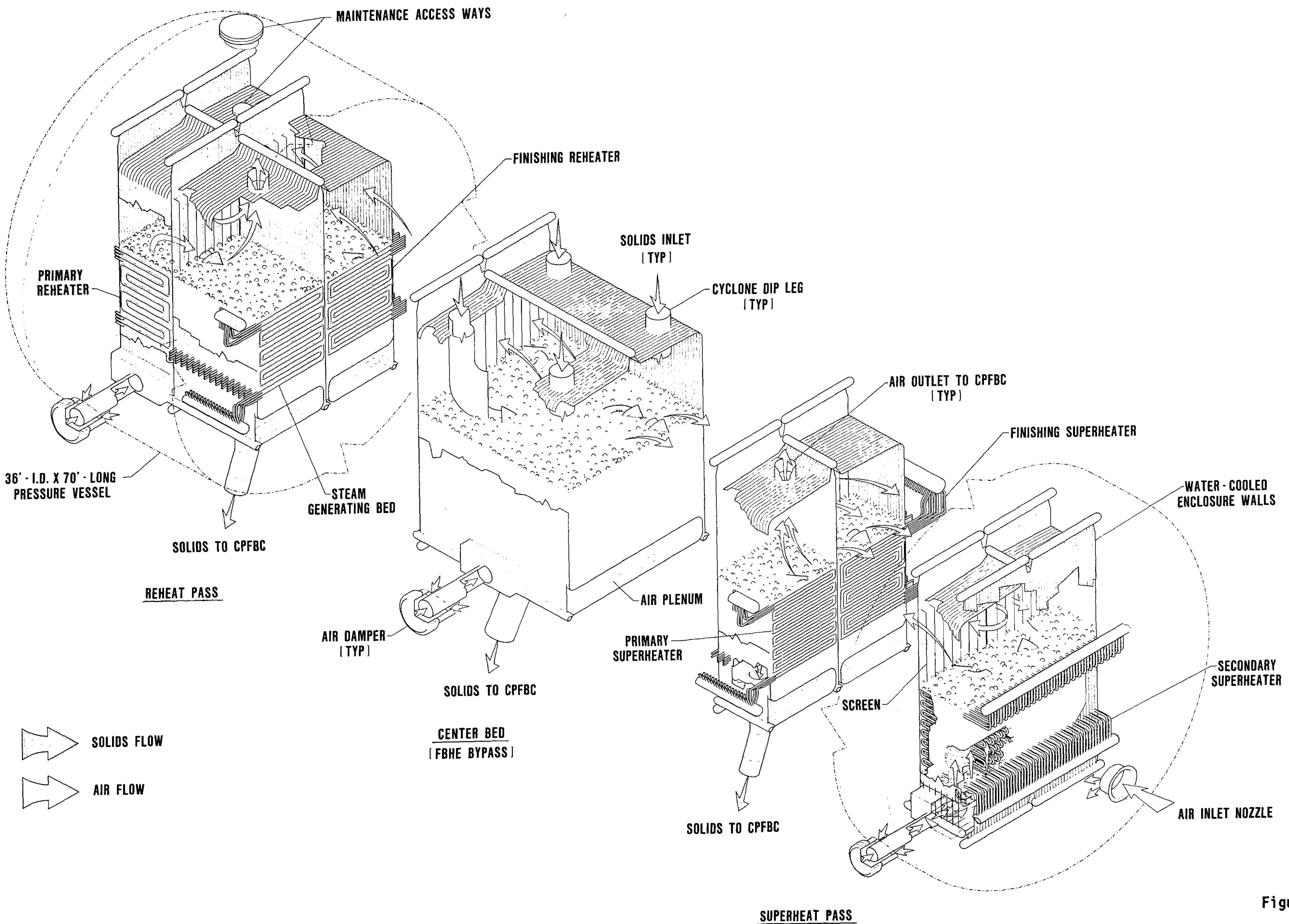


Figure 31--FBHE Subassemblies

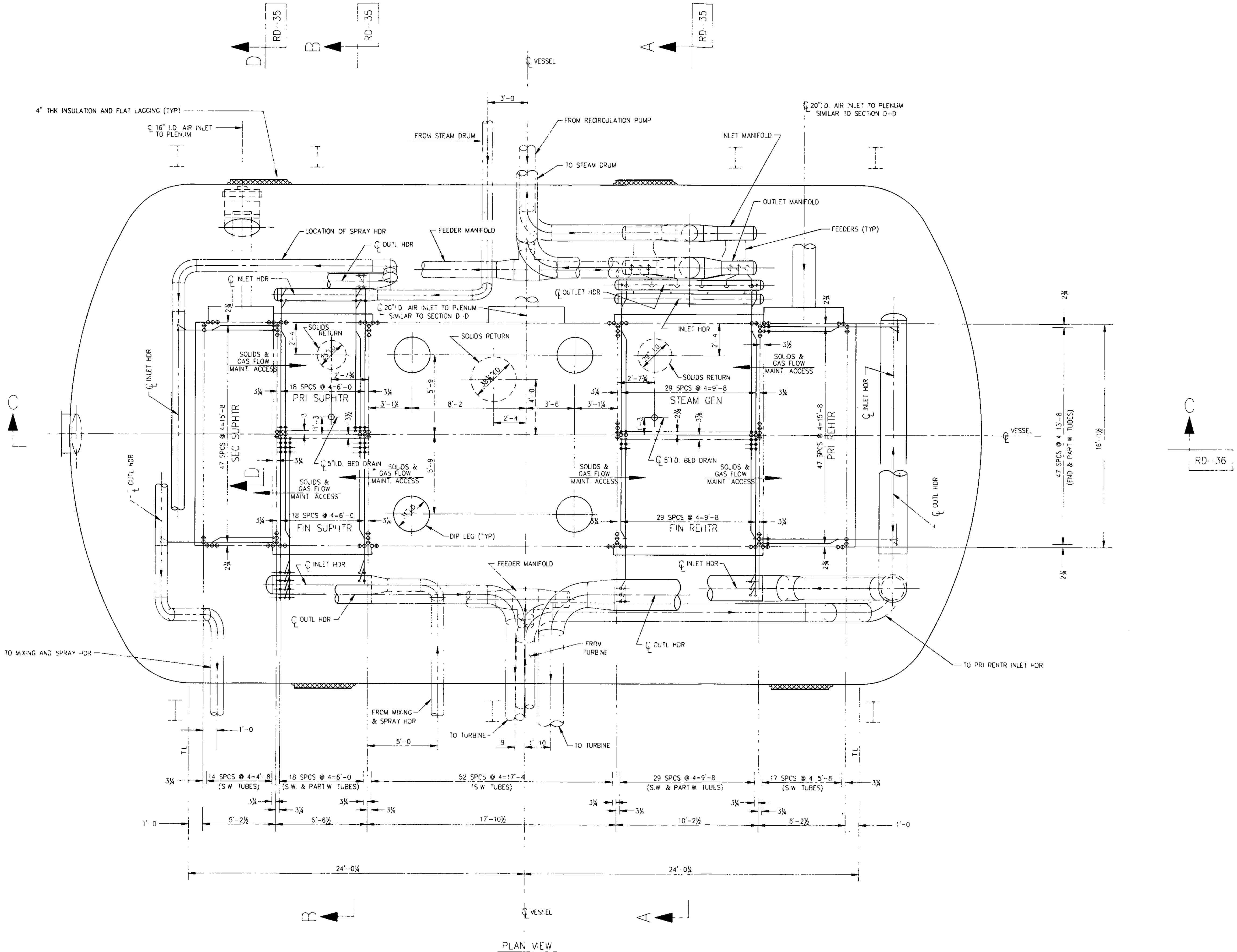
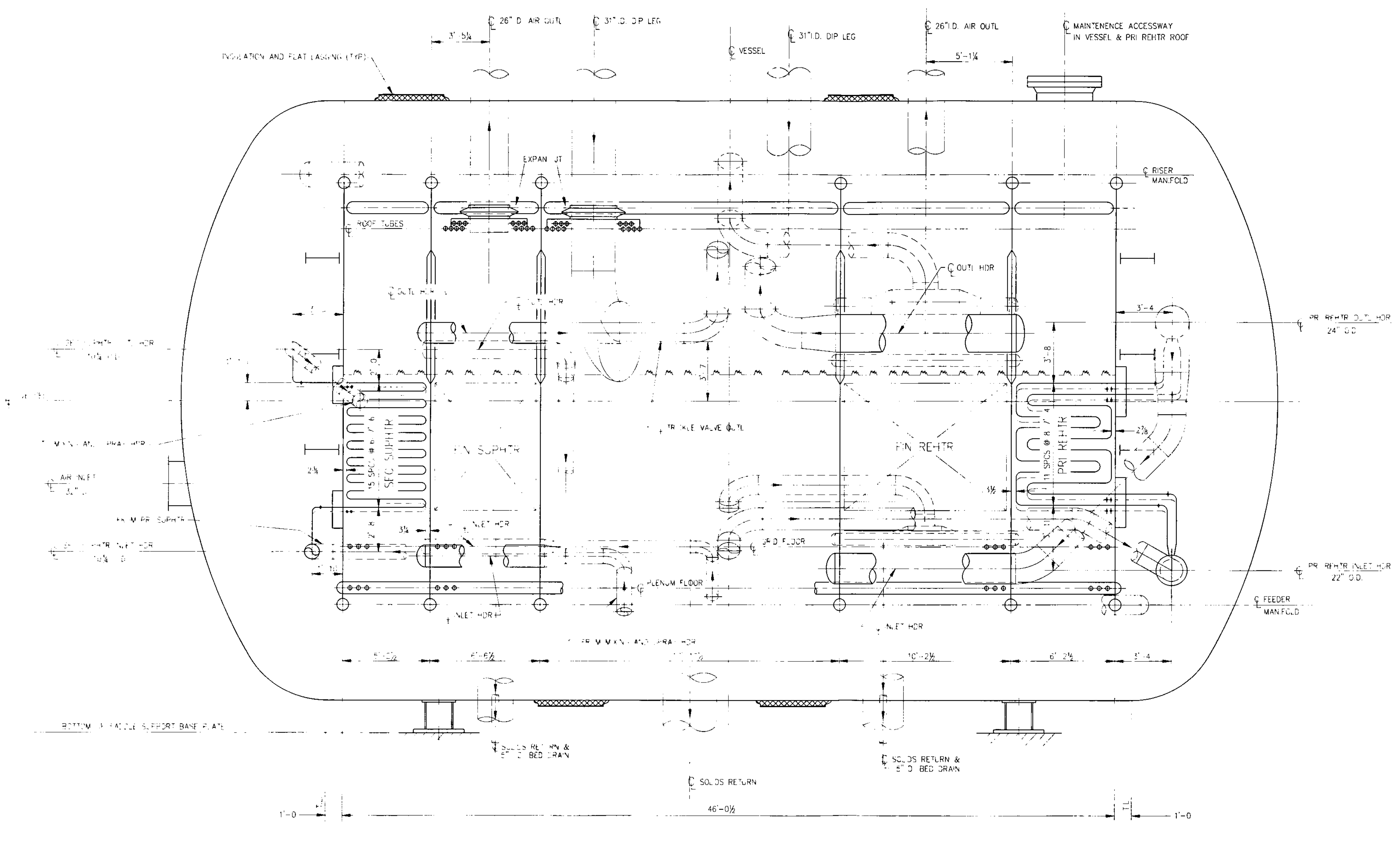


Figure 32 FBHE--Lower Plan View



SIDE ELEVATION

SECTION C-C RD-37
TRANSFER PIPING (NEAR AND FAR SIDE)

Figure 33 FBHE--Section C-C

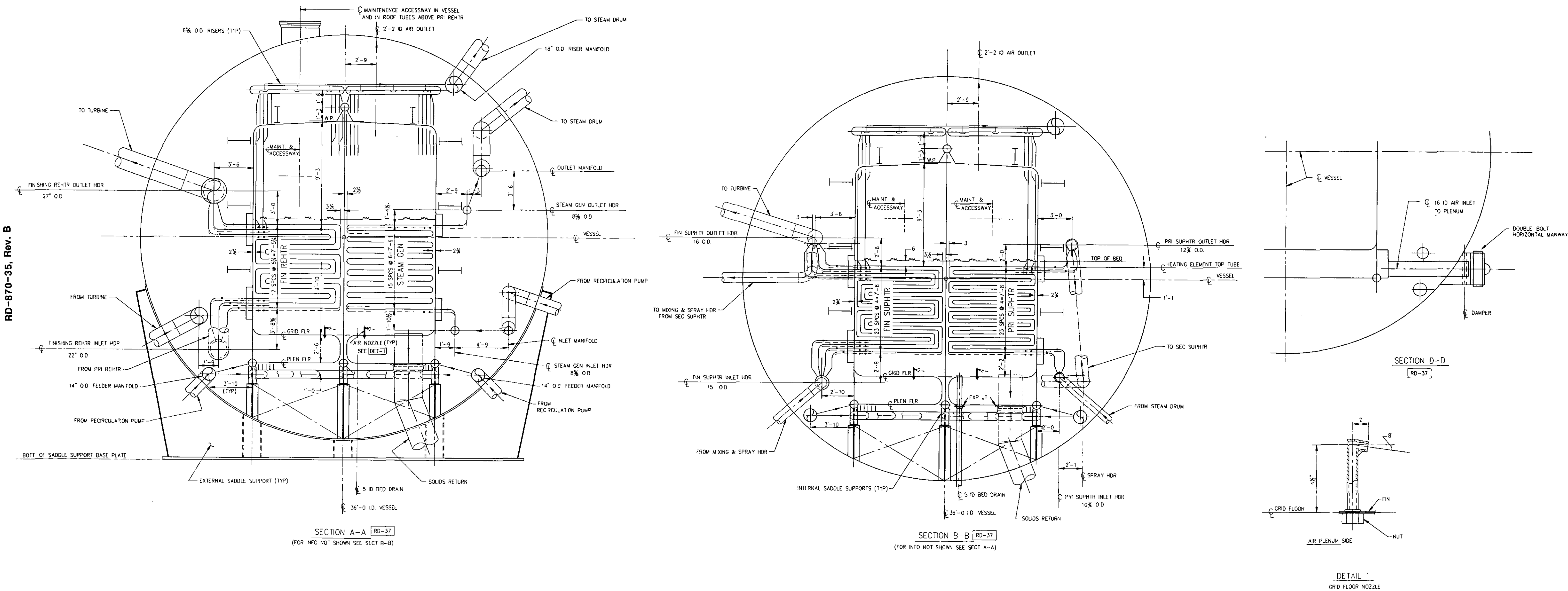


Figure 34 FBHE--Sections A-A, and D-D

return to the CPFBC with minimal cooling to enhance sulfur capture and carbon utilization.

The remaining solids flow in one of two parallel streams cascading through the two, three-bed groupings. Openings in the partition walls between adjacent cells allow solids and air to flow from bed to bed. All FBHE superheating is accomplished in the first solids flow path, the superheater path.

The superheater path consists of the finishing superheater, the secondary superheater, and the primary superheater, arranged in series. All reheat duty and part of the plant steam generating duty take place in the second solids flow path, the reheater path. The reheat path consists of the finishing reheater, the primary reheater, and a steam generating bed arranged in series.

Solids cascade through these heat-transfer passes, cooling to 1050°F. Air-fluidized, nonmechanical J valves in the primary superheater bed and in the steam generating bed return these cooled solids to the CPFBC at 1,630,000 and 1,739,000 lb/h respectively. These cooled solids control the CPFBC operating temperature at 1600°F.

The steam and water circuitry for the FBHE is shown schematically in Figure 35. Saturated water from the steam drum travels through the downcomers at 2,500,000 lb/h to a circulation pump that pumps the water through the steam generation bed tube bundle (728,000 lb/h) and enclosure walls (1,772,000 lb/h). The steam and water mixture from these tubes is collected, manifolded, and returned to the drum, where it is mixed with 407,608 lb/h of outlet economizer water from the HRSG. Steam and water are separated in the steam drum, and saturated steam proceeds to the FBHE.

Saturated steam enters the FBHE primary superheater tube bundle at 407,608 lb/h and is heated from 677 to 734°F. The flow proceeds to the secondary superheater tube bundle for heating to 900°F. From the secondary superheater outlet header, the 900°F FBHE steam leaves the pressure vessel and joins with 361,704 lb/h HRSG steam, also at 900°F, in a mixing header. The combined flow (769,312 lb/h) enters the FBHE vessel for final heating to 1006°F in the finishing superheater tube bundle. Steam from the finishing superheater leaves the FBHE vessel. The superheater flows from both modules are combined, and the total plant superheater flow of 1,538,624 lb/h proceeds to the HP turbine.

Steam from the HP steam turbine at 525 psia/614°F is divided into two streams, with half the flow (744,456 lb/h) going to each module. This steam enters the primary reheater of the FBHE. The primary reheater tube bundle heats the steam from 612 to 785°F, with the finishing reheater tube bundle increasing the temperature to 1001°F. Steam from the finishing reheater leaves the FBHE vessel. The reheat flows from both modules are combined, and the total plant reheat flow of 1,488,912 lb/h proceeds to the intermediate pressure (IP) steam turbine.

Superheat and reheat steam temperatures are controlled primarily by regulating the solids flow rates through their respective passes. Reducing solids flow rate to the heat-transfer passes (i.e., increasing bypass flow) lowers bed temperatures, decreasing log mean temperature differential (LMTD) and heat transfer. Additional steam temperature control and faster response are obtained by injecting atomized water directly into the superheated steam (spray control). Superheater spray control headers are between the primary and secondary superheaters and between the secondary and finishing superheaters. A reheat spray control header is downstream of the primary reheater. All superheater and reheat spray control valve operators are outside the FBHE pressure vessel to facilitate maintenance.

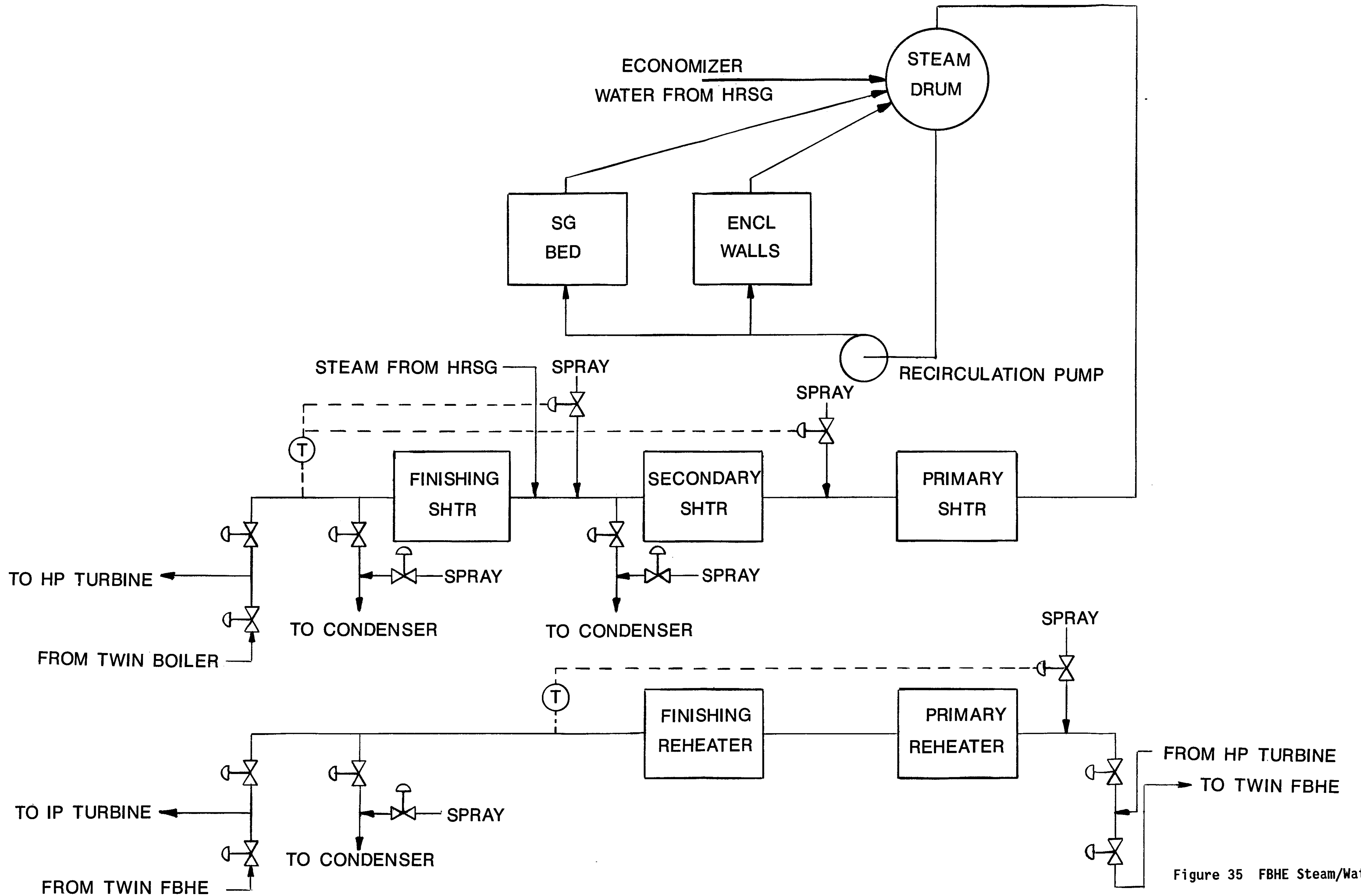


Figure 35 FBHE Steam/Water Circuitry

In-bed tubes in the FBHE heat-transfer passes are arranged in a staggered pattern, starting from approximately 1-1/2 ft above the air distributor T nozzles to near the top of the bed. The in-bed tubes occupy about 20 percent of the bed volume. The space between the air distributor and tube bundle is large enough to permit access for maintenance and repair, yet small enough to limit bubble growth, which has an impact on tubewall wastage. The geometries of the heat exchanger in-bed tube bundles are given in Table 16.

Steam and solids flows in the FBHE are arranged in a counterflow direction to ensure maximum LMTD and minimum tube bundle surface requirements. An external convective heat-transfer co-efficient of 100 Btu/h·ft^2·°F determines in-bed tube heat-transfer for the baseline plant. Heat flux to the enclosure walls in the bed area is calculated using an external convective heat-transfer coefficient of 60 Btu/h·ft^2·°F. Freeboard heat-transfer rates are determined using an emissivity of 0.45. Full-load performance for the FBHE is listed in Table 17.

The arrangement of all steam/water tubing, headers, and piping in the FBHE permits full draining at shutdown. Table 18 lists the superheat and reheat header and transfer-line sizes in the FBHE.

Air at 203 psi and 712°F from the compressor discharge enters the FBHE through an opening in one of the pressure vessel heads. The superheat pass, reheat pass, and center bed have separate air plenums fed through their own air-control dampers. Air enters the annulus of each of these air-control dampers, entering the corresponding air plenum under the beds. This arrangement places the dampers and their operators on the outside of the vessel for easy accessibility. It also keeps the beds at a lower pressure than that inside the pressure vessel. Should a leak develop through the enclosure walls, relatively low-temperature combustion air passes into the cell rather than high-temperature solids and gas into the vessel. The enclosure walls and buckstay system are designed to withstand the pressure differential between the air entering the vessel and the gases passing through the bed.

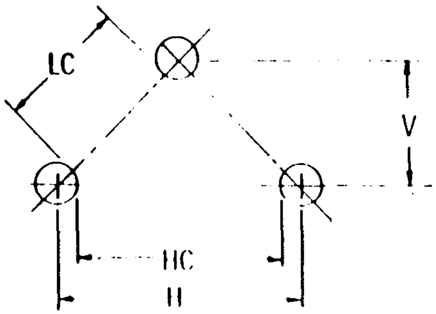
Air enters the beds through T- and L-shaped nozzle air distributors and provides a superficial fluidizing velocity of 1/2 ft/s. Since openings in the partition walls between adjacent cells permit solids to move freely between beds, all beds have the same bed level (approximately 10 ft above the grid plate floor) and essentially the same pressure drop (3 psi).

Air and solids travel the same flow path through the FBHE, with the air leaving the vessel at approximately 1200°F through two 25-in.-I.D. refractory-lined nozzles (one in the roof of the primary superheater bed and the other in the roof of the steam generating bed). This air proceeds to the CPFBC for use as secondary air. Solids are removed from the unit via three J valves and a 5-in.-I.D. in the primary superheater and the steam generator bed. The J valves return their solids to the CPFBC; each 5-in. drain removes 1050°F solids at 17,503 lb/h for depressurizing and cooling.

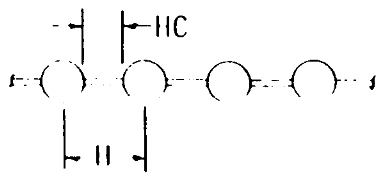
Circulation System. The water/steam circulation system is designed to provide adequate cooling water flows to all steam-generating circuits. Steam-generating in-bed tubes are designed for a water velocity of approximately 7 ft/s at the tube inlet. Enclosure and partition wall tubes that receive a lower heat flux are designed with a 1 ft/s water velocity at the tube inlet. The components of the circulation system are listed in Table 19.

Table 16 FBHE Tube Geometries

Surface	Tube O.D. x Minimum Wall (in.)	Elements	Tubes per Element	Passes per Tube	Tube Centerline Spacing (in.) H	Tube Centerline Spacing (in.) V	Clearance Between Tubes (in.) HC	Clearance Between Tubes (in.) LC	Bundle Height: Rows High	Bundle Height: Bottom-to-Top Tube Centerline (ft-in.)	Tube Packing Density (vol%)
Finishing Superheater	2 x 0.365	19	4	6	8	2	6	2-1/2	24	7 - 8	19.6
Secondary Superheater	2 x 0.220	48	1	16	8	3	6	3	16	7 - 6	13.1
Primary Superheater	2 x 0.210	19	2	12	8	2	6	2-1/2	24	7 - 8	19.6
Finishing Reheater	2-1/4 x 0.210	30	3	6	8	2-5/8	5-3/4	2-1/2	18	7 - 5-1/4	18.9
Primary Reheater	2-1/4 x 0.180	48	2	6	8	4	5-3/4	3-3/8	12	7 - 4	12.4
Steam Generating	2 x 0.190	30	2	8	8	3	6	5-1/4	16	7 - 6	13.1
Enclosure Walls (Steam Generating)	3 x 0.300	607	1	---	4	---	1	---	---	---	---



Tube Bundle



Wall

Table 17 FBHE Full-Load Performance

	Steam/Water Temperature (°F)						
Surface	In	Out	Duty Required (10^6 Btu/h)	LMTD (°F)	Bed Temperature (°F)	h_o ($h_c + h_r$) (Btu/h·ft^2·°F)	U_o (Btu/h·ft^2·°F)
Superheater Pass							
Finishing Superheater	900	1006	71	448	1408	128	83
Secondary Superheater	734	900	65	378	1206	120	85
Primary Superheater	677	734	61	344	1050	114	93
Reheat Pass							
Finishing Reheater	785	1001	88	470	1370	126	80
Primary Reheater	612	785	74	474	1177	118	74
Steam Generating	677	677	76	373	1050	113	102
Enclosure Walls (Steam Generating)	677	677	99	---	---	---	---

Table 18 FBHE Header and Transfer-Line Sizes*

Item (One required/module)	O.D. (in.)	Thickness (in.)	Material	Design Temperature (°F)
Transfer Line to Primary Superheater	10-3/4	0.837	SA-106-C	685
Primary Superheater Inlet Header	10-3/4	0.837	SA-106-C	685
Primary Superheater Outlet Header	12 3/4	1.230	SA-106-C	775
Transfer Line--Primary Superheater to Secondary Superheater	12-3/4	1.230	SA-106-C	775
Secondary Superheater Inlet Header	10 3/4	0.980	SA-106-C	760
Secondary Superheater Outlet Header	10 3/4	1.108	SA-335-P22	915
Secondary Superheater Outlet Transfer Line	10-3/4	1.108	SA-355-P22	915
Finishing Superheater Inlet Transfer Line	14	1.442	SA-335-P22	915
Finishing Superheater Inlet Header	15	1.545	SA-335-P22	915
Finishing Superheater Outlet Header	16	2.759	SA-335-P22	1020
Finishing Superheater Outlet Transfer Line	16	2.759	SA-335-P22	1020
Primary Reheater Inlet Transfer Line	18	0.354	SA-106-C	612
Primary Reheater Inlet Header	22	0.433	SA-106-C	612
Primary Reheater Outlet Header	24	0.617	SA-335-P1	820
Transfer Line--Primary Reheater to Finishing Reheater	22	0.565	SA-335-P1	820
Finishing Reheater Inlet Header	22	0.565	SA-335-P1	820
Finishing Reheater Outlet Header	27	1.298	SA-335-P22	1020
Finishing Reheater Outlet Transfer Line	24	1.154	SA-335-P22	1020

*Superheater Design Pressure 2800 psig; Reheater Design Pressure 700 psig.

Table 19 Circulation System

Item	Quantity/ Module	Size
Steam Drum	1	54-in. I.D.
Downcomers	3	18-in. O.D., Sch 140
Pump Inlet Manifold	1	20-in. O.D., Sch 140
Pump Inlet Isolation Valves	2	16-in. O.D.
Circulation Pumps	2	1 operating/1 stand-by
Pump Outlet Isolation Valves	2	20-in. O.D.
Pump Outlet Manifold	1	20-in. O.D., Sch 140
Partition and Enclosure Wall Circuit		
Transfer lines to feeder manifold	2	12-3/4 in. O.D., Sch 120
Feeders to inlet header	78	6-5/8 in. O.D., Sch 120
Inlet headers	24	8-5/8 in. O.D., Sch 120
Partition and enclosure wall tubes	607	3-in. O.D. Tubes x 0.30-in. Minimum Wall
Outlet headers	24	8-5/8 O.D., Sch 120
Risers	109	6-5/8 in. O.D., Sch 120
Riser Manifold	1	18-in. O.D., Sch 160
Transfer Line--Riser Manifold to Steam Drum	1	18-in. O.D., Sch 160
Steam Generating Bed Circuit		
Transfer line to inlet manifold	1	14-in. O.D. x Sch 160
Feeders	4	6-5/8 in. O.D., Sch 120
Inlet header	1	8-5/8 in. O.D., Sch 120
In-Bed Tubes	60	2-in. O.D. x 0.19-in. Minimum Wall
Outlet header	1	8-5/8 in. O.D., Sch 120
Risers	5	6-5/8 in. O.D., Sch 120
Outlet manifold	1	12-3/4 in. O.D., Sch 160
Transfer Line--Outlet Manifold to Steam Drum	1	14-in. Sch 120

Circulation Pumps

Flow/Module	2,500,00 lb/h (9332 gal/min)
Pump Head	30 psi
Design Pressure	2800 psig
Hydrostatic Test Pressure	4200 psig
Fluid Operating Temperature	677°F
NPSH Required	65 ft

Referring to Figures 32, 33, and 34, water from the circulation pump enters the FBHE through pipes at two points on opposite sides of the vessel and midway along its length to feed the enclosure and partition walls at 1,772,000 lb/h. These pipes tee into feeder manifolds running down each side of the unit. Feeders from the manifolds supply the lower enclosure and partition wall headers. Water and steam generated in these walls collect in headers atop the roof, and risers feed into a riser manifold leading to the steam drum. The steam drum is outside and above the FBHE at an elevation that ensures adequate suction head for the circulation pumps. The circulation system is supplied with two 100-percent pumps, one operating and one spare.

Water from the circulation pump also feeds an inlet manifold for a steam generator tube bundle at 728,000 lb/h. The steam and water mixture leaves the tube bundle outlet header through risers to a riser manifold, which feed the steam drum.

Approximately 436,000 lb/h saturated steam is generated in the FBHE. The enclosure and partition walls generate 305,000 lb/h, with the remaining 131,000 lb/h generated in the steam generating bed. Approximately 29,000 lb/h of the steam generated in the FBHE is condensed in the steam drum to heat the incoming feedwater; the balance (407,608 lb/h) proceeds to the primary superheater.

Tube Bundle Support and Replacement. A typical tube element is shown in Figure 36. Each vertical-plane tube assembly is held together at its ends by a ladder arrangement to form an element. The weight of the tube element is picked up by the ladder pins and is transmitted as a tensile load into the ladder. A hook-and-lug arrangement transmits the element load into the waterwalls, while still permitting the tube bundle elements to expand thermally relative to the colder waterwalls. Stop bars prevent the ladders from shifting on the tubes, and a tie bar at the bottom of the elements ties all the ladders together.

Personnel working in the freeboard region can easily replace or repair a tube element, if necessary, during the life of the unit. By cutting the tube inlets and outlets of an element just inside the enclosure wall and freeing it of the bottom tie-bars, the element can be pulled up and out of the bundle and into the freeboard for repair and maintenance.

There is one 4-ft.-I.D. access way in the pressure vessel and one in the roof of the primary reheater bed. These aligned openings are large enough to permit bringing repair equipment and replacement tube element half-sections into the unit (Figure 37). Maintenance openings in the partition wall freeboards permit moving the equipment and replacement parts to any of the other six beds. From the standpoint of routine maintenance and inspections, the FBHE internals can normally be reached through 18- and 20-in. manways in the pressure vessel and waterwall enclosure walls.

J Valves. Solids are transferred from the FBHE to the CPFBC using the three nonmechanical J valves shown in Figure 38.

The two outer J valves transfer the cooled solids (1050°F) from the superheater and reheater heat-transfer passes of the FBHE. The inlet of the J valve for the superheater pass is in the primary superheater bed. This valve is a 3 ft-2 in. O.D. pipe of 0.5-in.-thick carbon steel with 6 in. of internal refractory. The J-valve inlet for the reheater pass is in the steam generator bed. This valve is a 3 ft-6 in. O.D. pipe, 1/2 in. thick, with 6 in. of internal refractory.

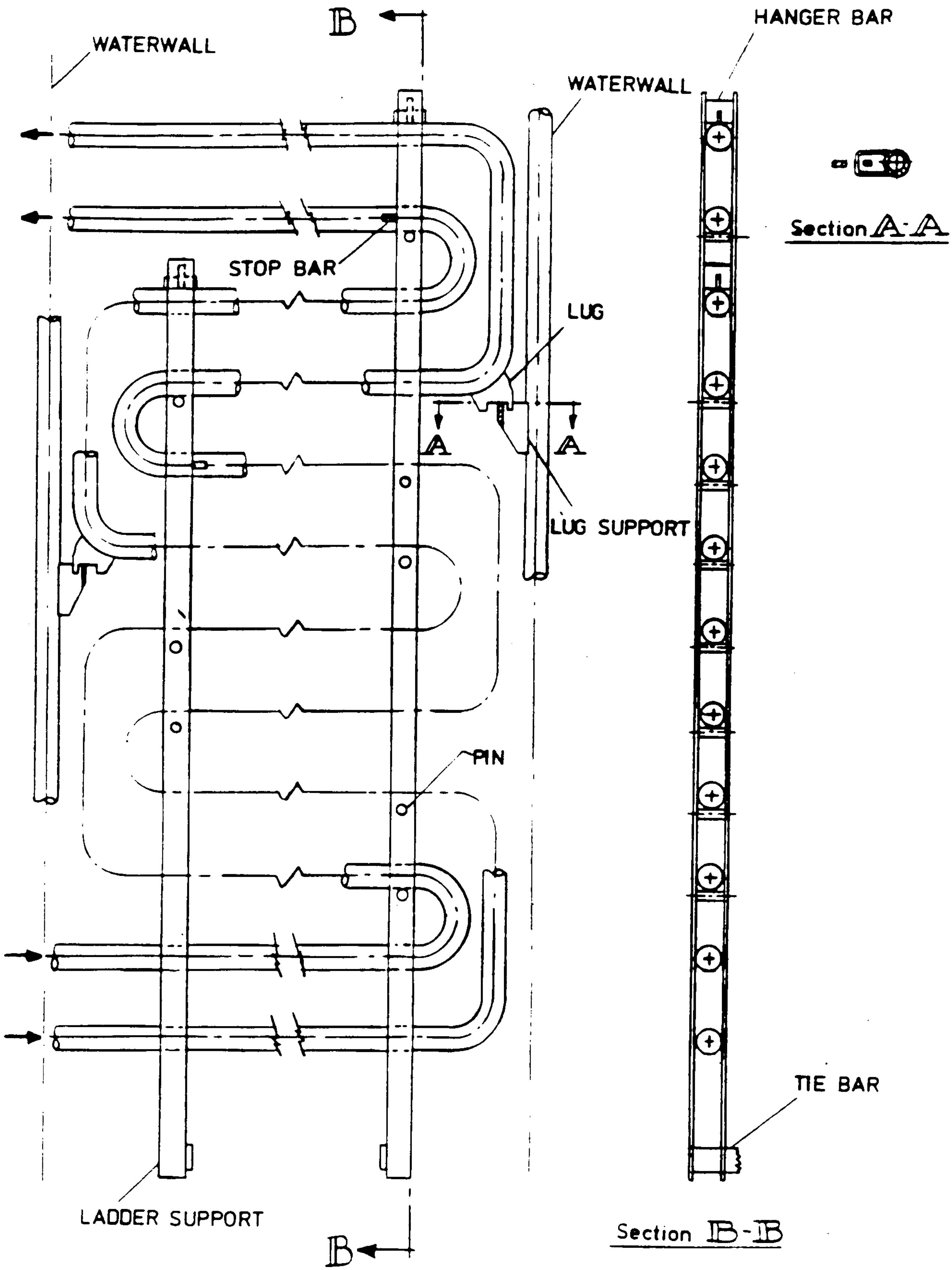


Figure 36 FBHE--Typical Tube Element

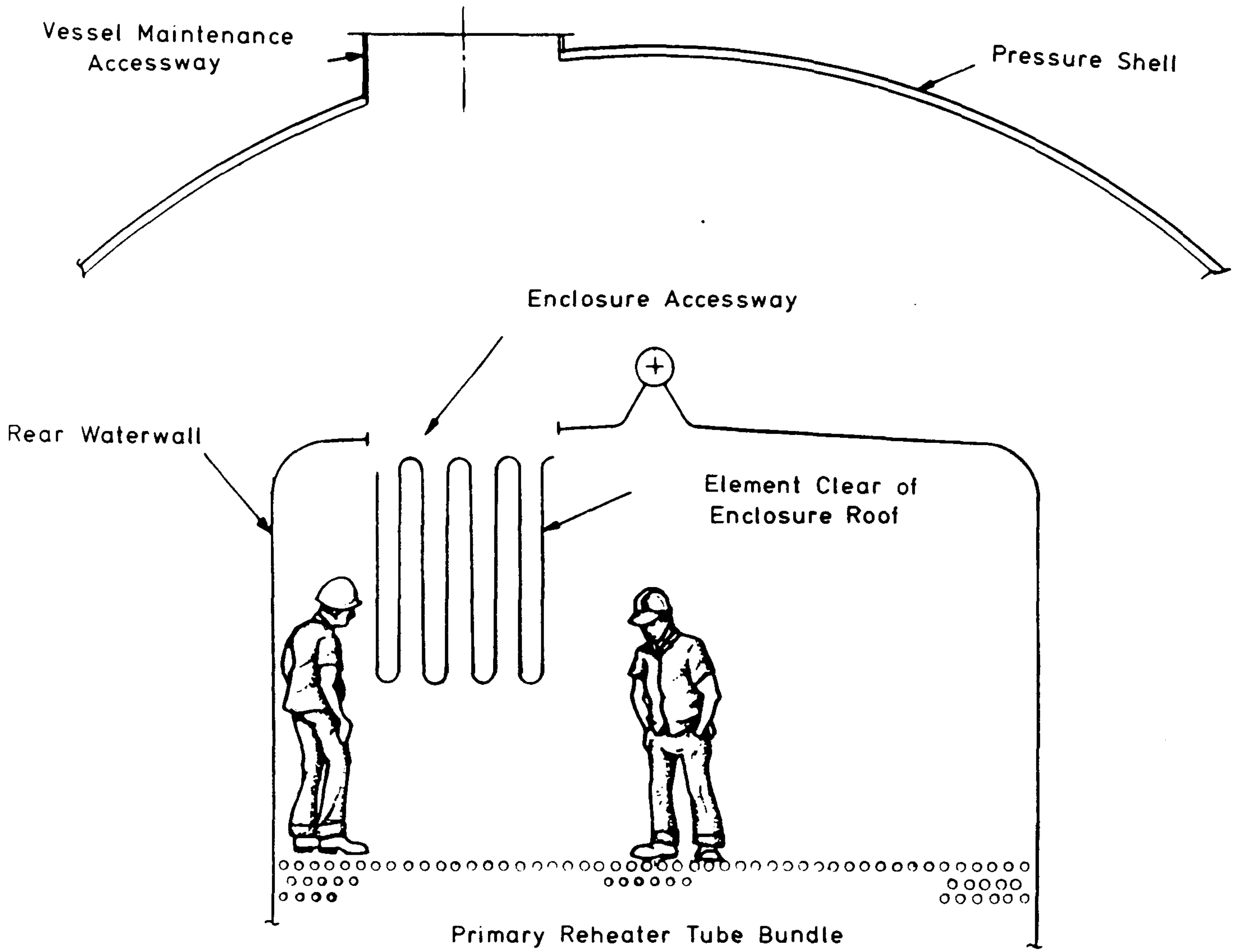


Figure 37 Replacement Tube Element Entering FBHE

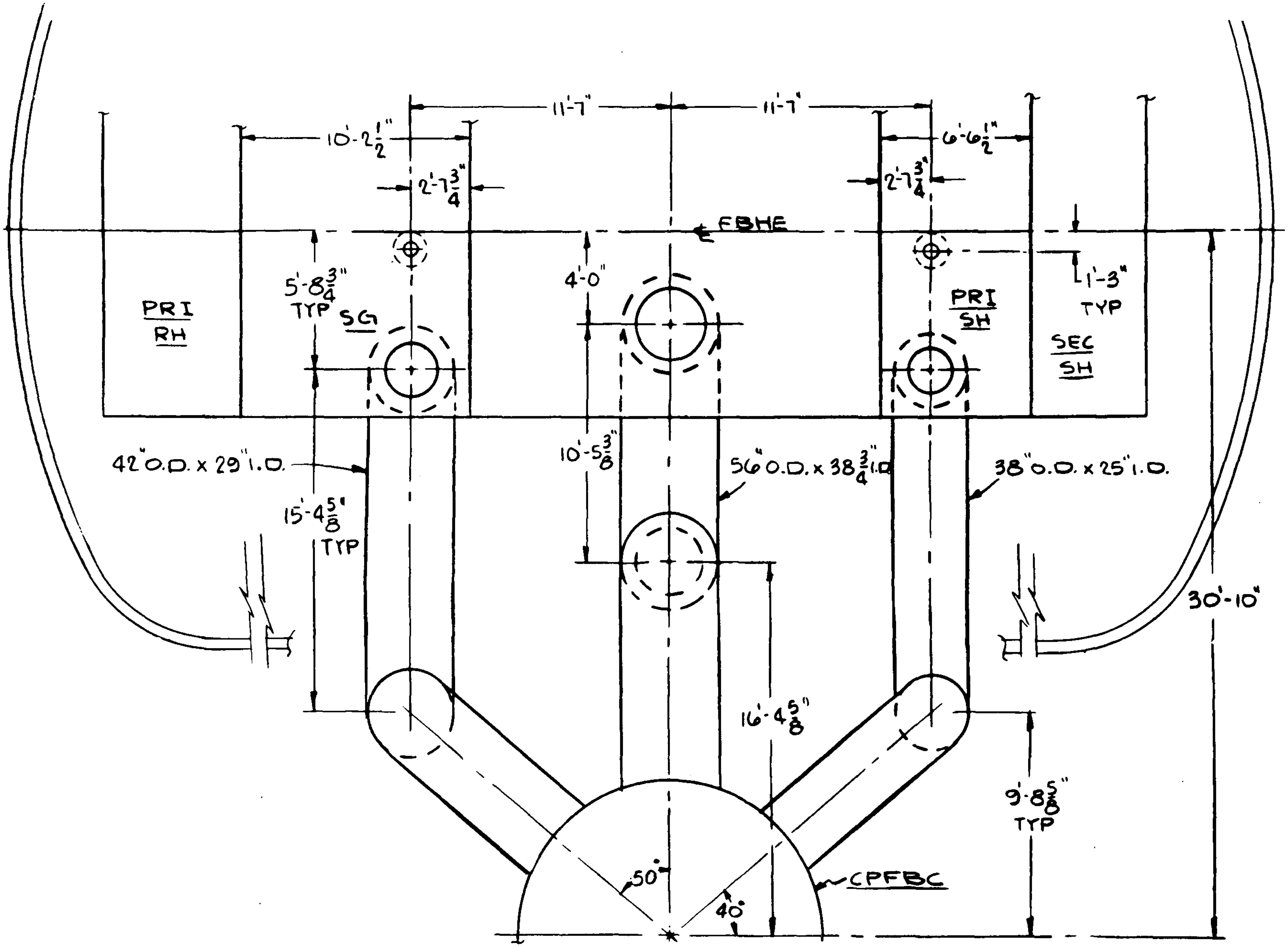


Figure 38 FBHE/CPFBC/J-Valve Arrangement (Baseline Plant)

Solids from the center bed of the FBHE bypass the heat-transfer surfaces with minimal cooling. These solids, at approximately 1600°F, are conveyed through the center J valve--a 4 ft-8 in. O.D. pipe, 5/8-in.-thick carbon steel with 8 in. of internal refractory. These three J valves operate with 20,000 lb/h air (total) from the carbonizer booster compressor at 218 psia/745°F.

2.5.6 Combustion Turbine and Accessories

The use of a CPFBC as the primary combustion system for a combustion turbine requires transporting compressor air to the CPFBC and vitiated air/flue gas back to the turbine. In addition, a topping combustion system must be located in the returning vitiated airflow path, and some of the turbine accessory systems must be changed from the conventional.

Basically, it is the fuel system and turbine center section that require major change, and these items are addressed in this subsection. The axial flow compressor, while somewhat larger in flow capacity than the presently marketed W-501D5 machine, is a conventional state-of-the-art component designed for 950 lb/s flow at ISO* conditions. The effective flow area of the turboexpander is slightly larger than for current machines; it is designed for a 2100°F combustor outlet temperature--a design temperature somewhat below present-day levels. The ceramic cross-flow filters in the carbonizer fuel gas and CPFBC flue gas lines protect the gas turbine from erosion, and the carbonizer and CPFBC operating temperatures are assumed low enough to preclude hot corrosion problems. (An alternative high-alkali-release scenario, involving alkali getters to protect the gas turbine from hot corrosion, is addressed in the Section 6 sensitivity study.) Therefore, no major development programs are required for either the compressor or the expander; they have been provided in standard materials of construction, and a blade life commensurate with oil-fired combustion turbines is assumed.

Combustion Turbine. The combustion zone of the W-501D5 turbine currently in production cannot contain the topping combustion system within the main structural pressure shell. Although the pressure casing can be enlarged both radially and longitudinally to accommodate the topping combustor system as well as its air and vitiated air nozzles, the integrity and rigidity of the main shell would be significantly affected. The penalties for these changes are:

- The dynamic response of the rotor would be compromised because a longer casing means a longer rotor system, a lower critical speed, and increased rotor deflection.
- The enlarged unit could not be shipped as a whole. It would have to be disassembled for shipment and reassembled in the field--at greater cost.

The best solution is an external topping combustion system; two different arrangements were considered. The first entailed two topping combustor assemblies placed on opposite sides of the gas turbine, each containing four MASBs. In the second, each MASB was in its own radial pressure-containment cylinder, and the eight MASBs were equally spaced along the circumference of the machine. Although both arrangements appeared workable, the former was selected, primarily because it was more amenable to fuel gas, vitiated air, and compressor air discharge line manifolding. The selected arrangement is discussed in the following paragraphs; the other arrangement is described in Appendix D.5.

*International Standards Organization: 15°C, 760 mm Hg, and 60 percent relative humidity (inlet).

The selected arrangement, which utilizes two topping combustor assemblies, one on each side of the unit, is shown in Figure 39. Half of the vitiated air from the CPFBC enters one end of each assembly (Figure 40). This air then enters an internal plenum chamber in which four MASBs are mounted. Fuel gas enters the assembly via the four fuel nozzles at the head end of the combustor. Combustion occurs, and the products of combustion are ducted into the main shell for distribution to the first-stage turbine vanes. The annular distribution duct is shown in Figures 41 and 42.

Compressor discharge air leaves the main shell, flowing around the annular duct into the adjacent combustion shells. The air flows around the vitiated air plenums and leaves each combustion assembly via two nozzles (Figures 39 through 42). The radial locations of the fuel nozzles and compressor air discharge ports are shown in the elevation view of the engine (Figure 43).

Topping Combustion System. The individual burners contained in the two external topping combustor assemblies are scaled versions of an MASB tested in a previous DOE-sponsored program [1]. The total number of combustors (eight) is based on the structural requirement of the turbine casing, the combustion shell (Concept 1), and uniform flow distribution to the turbine elements. The diameter of the combustor is based on maintaining the same gas velocity through the combustor as in the test combustor (Table 20).

The individual components of the fuel nozzle/combustor system are shown in Figure 44. An oil nozzle (for engine start-up), a gas nozzle (for normal operation), the primary swirler, and the combustor (MASB) are the major parts of the system. The path of the vitiated air from the plenum to the combustion zone of the combustor via openings in the combustor wall is also shown in Figure 44.

The system is mounted on and supported by a cover plate that bolts to the head end of the combustion shell assembly. The ease of disassembling and maintaining the system is evident in Figure 44. An enlarged view of the head end of the system (Figure 45) shows the separate components that form the combustor system. This system is operated on an auxiliary fuel system (oil) during turbine start-up, before CPFBC combustion.

Table 20 Comparison of Test and Baseline Plant MASBs

	MASBs	
Description	Test	Baseline Plant
Flow (lb/s)	20	91.8
Pressure (psia)	150	206
Air Temperature (°F)	1400	1600
Gas Velocity (ft/s)	172.4	172.6
Diameter (in.)	9.88	19.00
Outlet Temperature (°F)	2000	2100

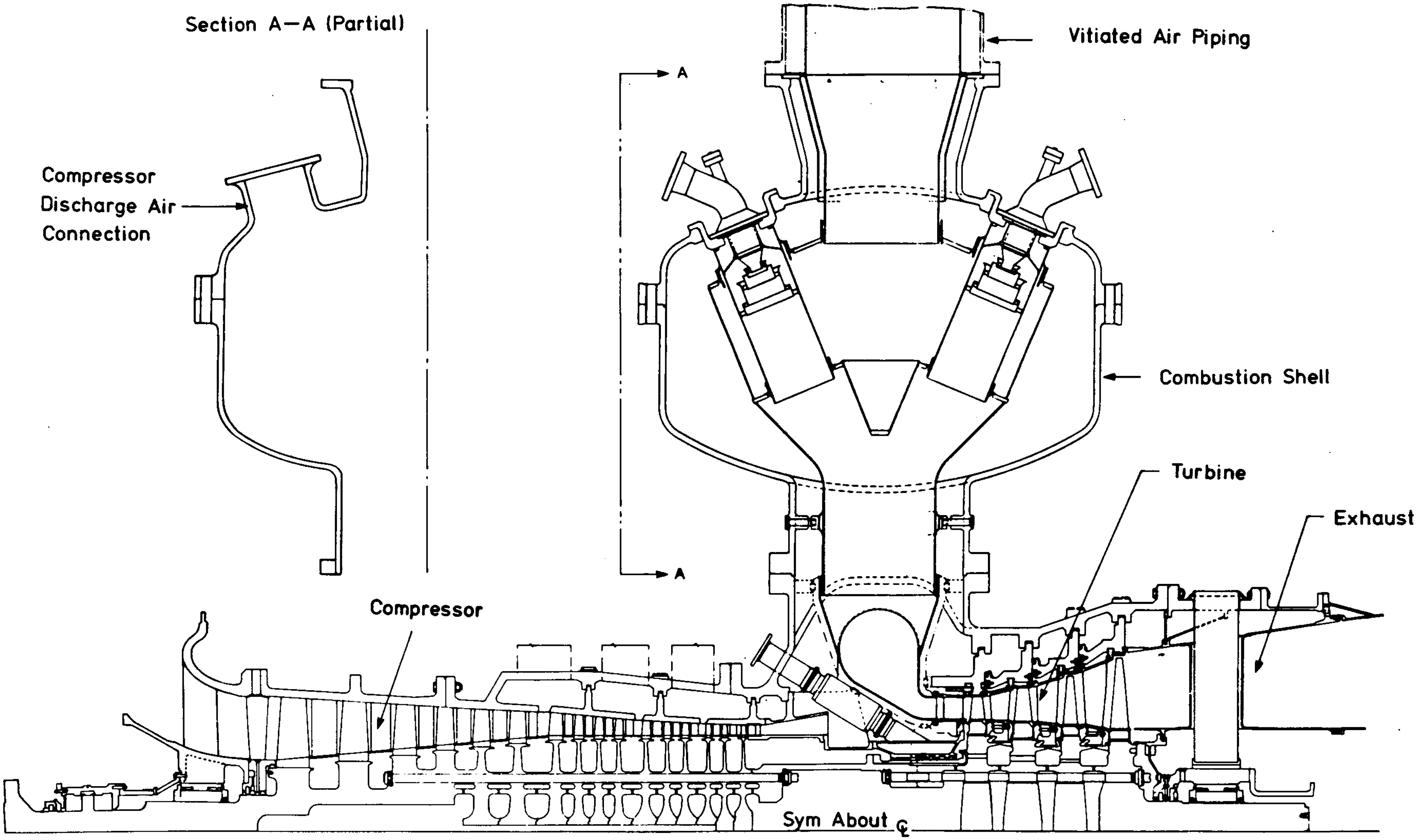


Figure 39 Combustion Turbine Component Arrangement--Plan View (Symmetrical About Centerline)

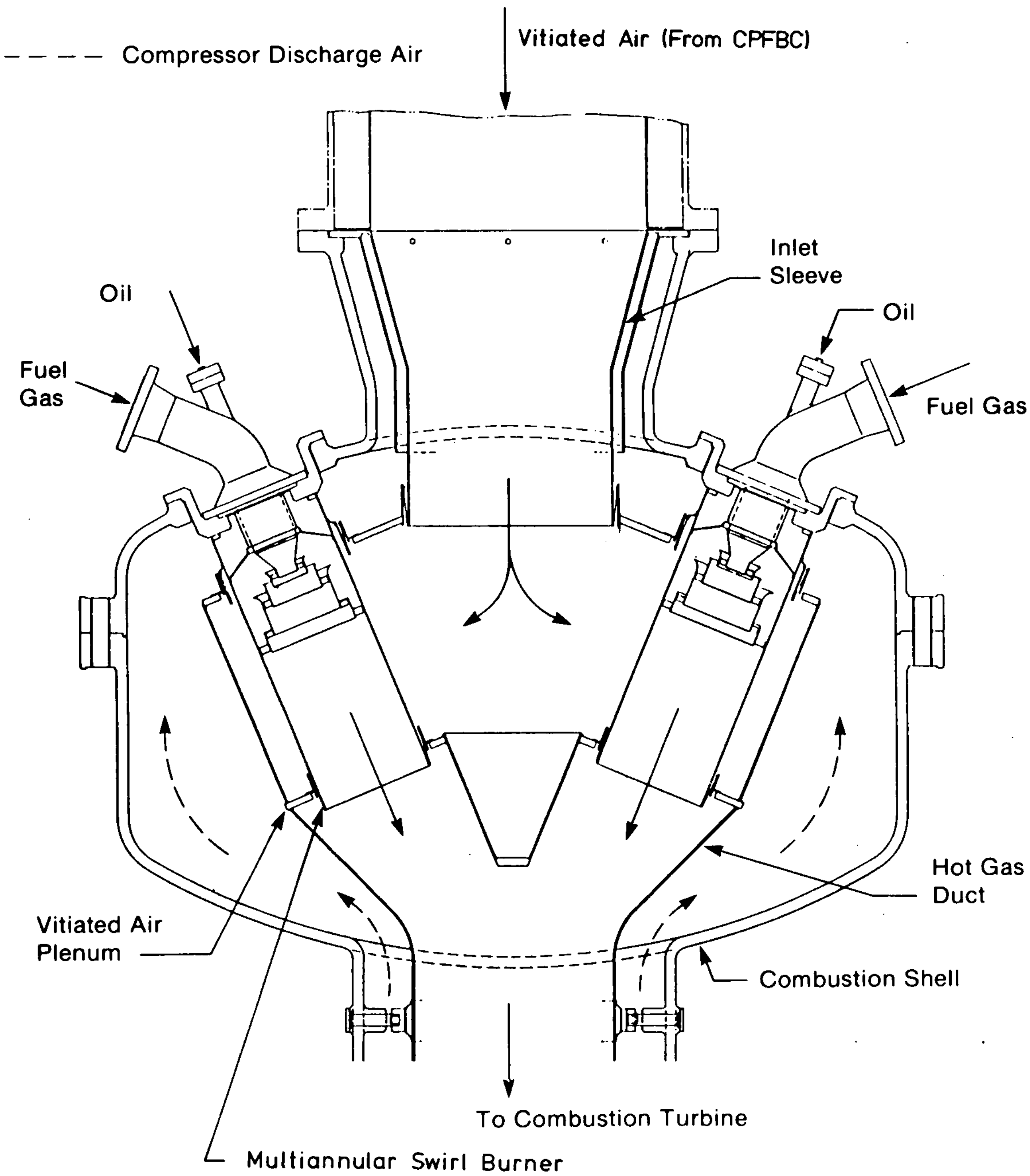


Figure 40 Flow Path of Vitiated Air in Combustion Chambers

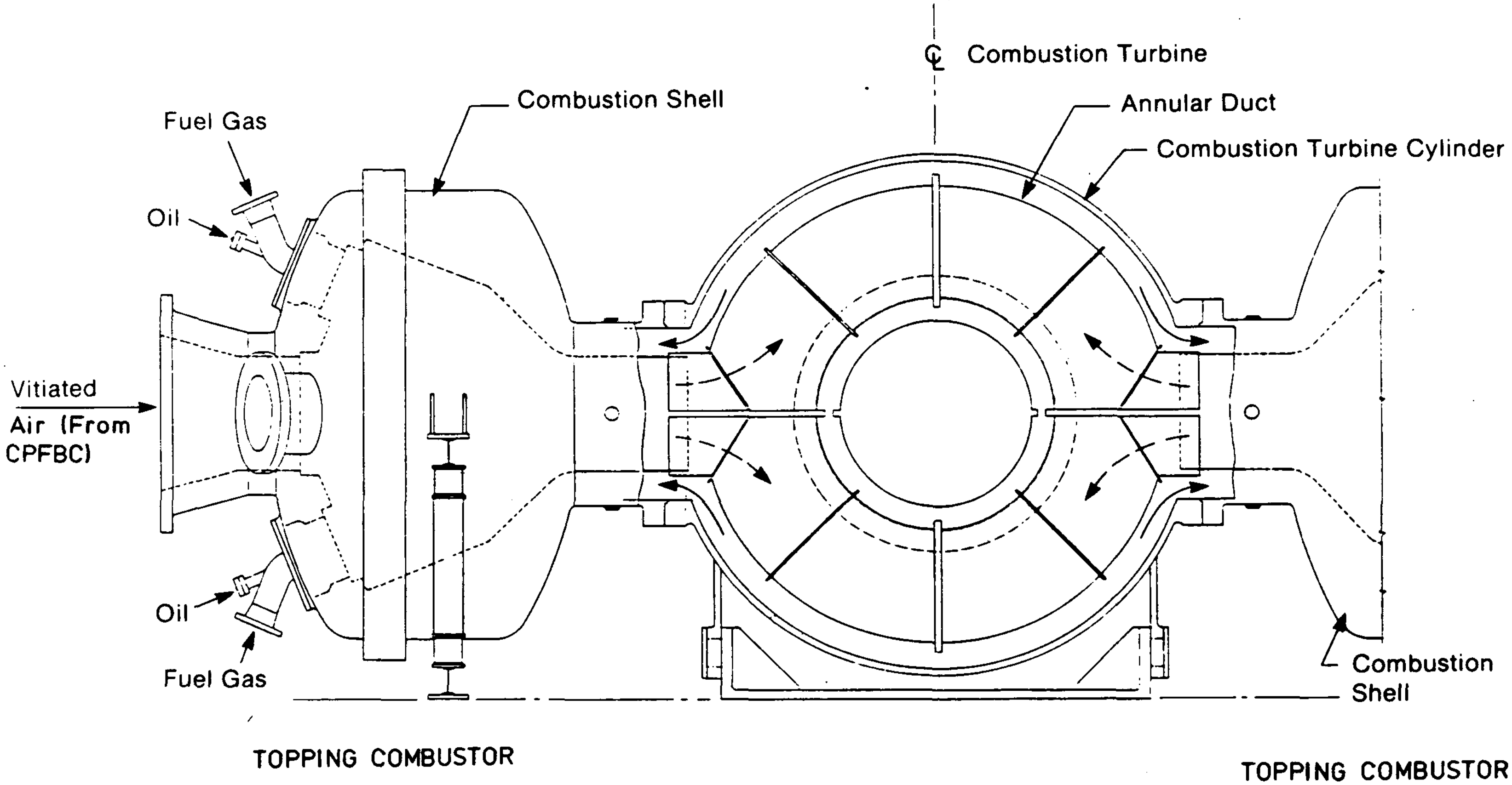


Figure 41 Flow of Vitiated Air and Combustion Products to Main Shell--Sectional View

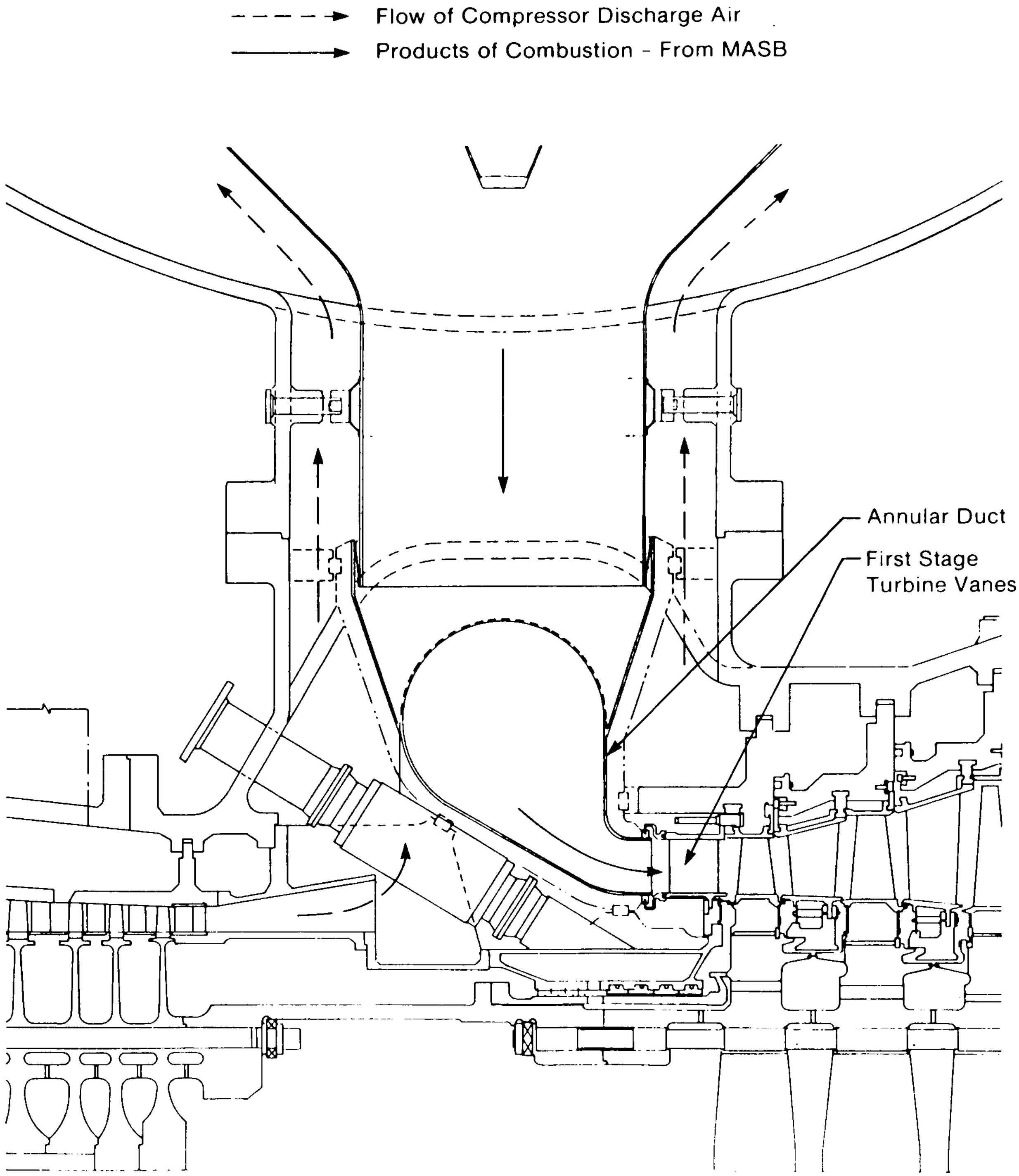


Figure 42 Flow of Vitiated Air and Combustion Products to Main Shell--Enlarged Plan View

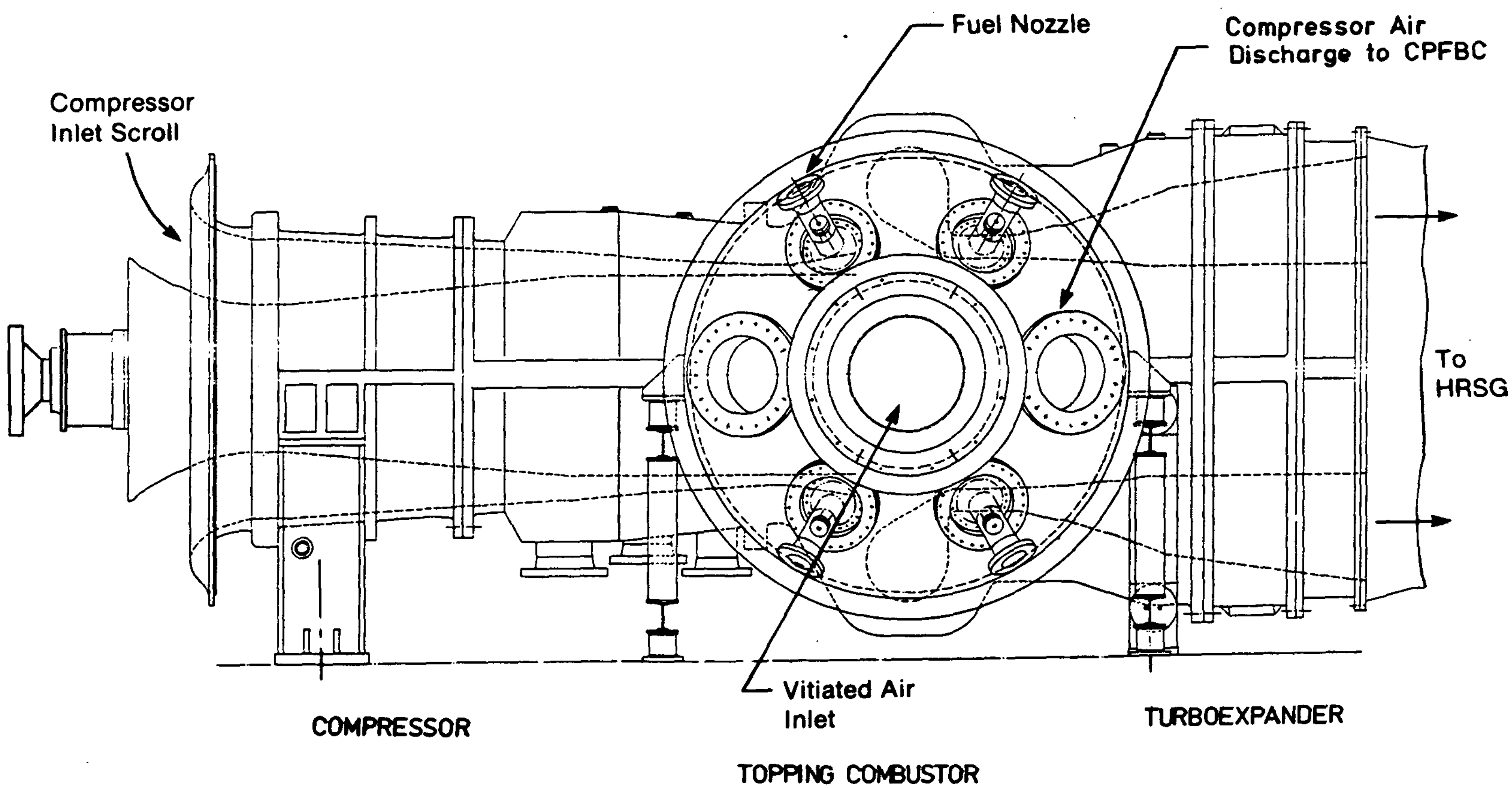


Figure 43 Locations of Combustors, Air Outlet Ports, and Vitiated Air Inlet Ports

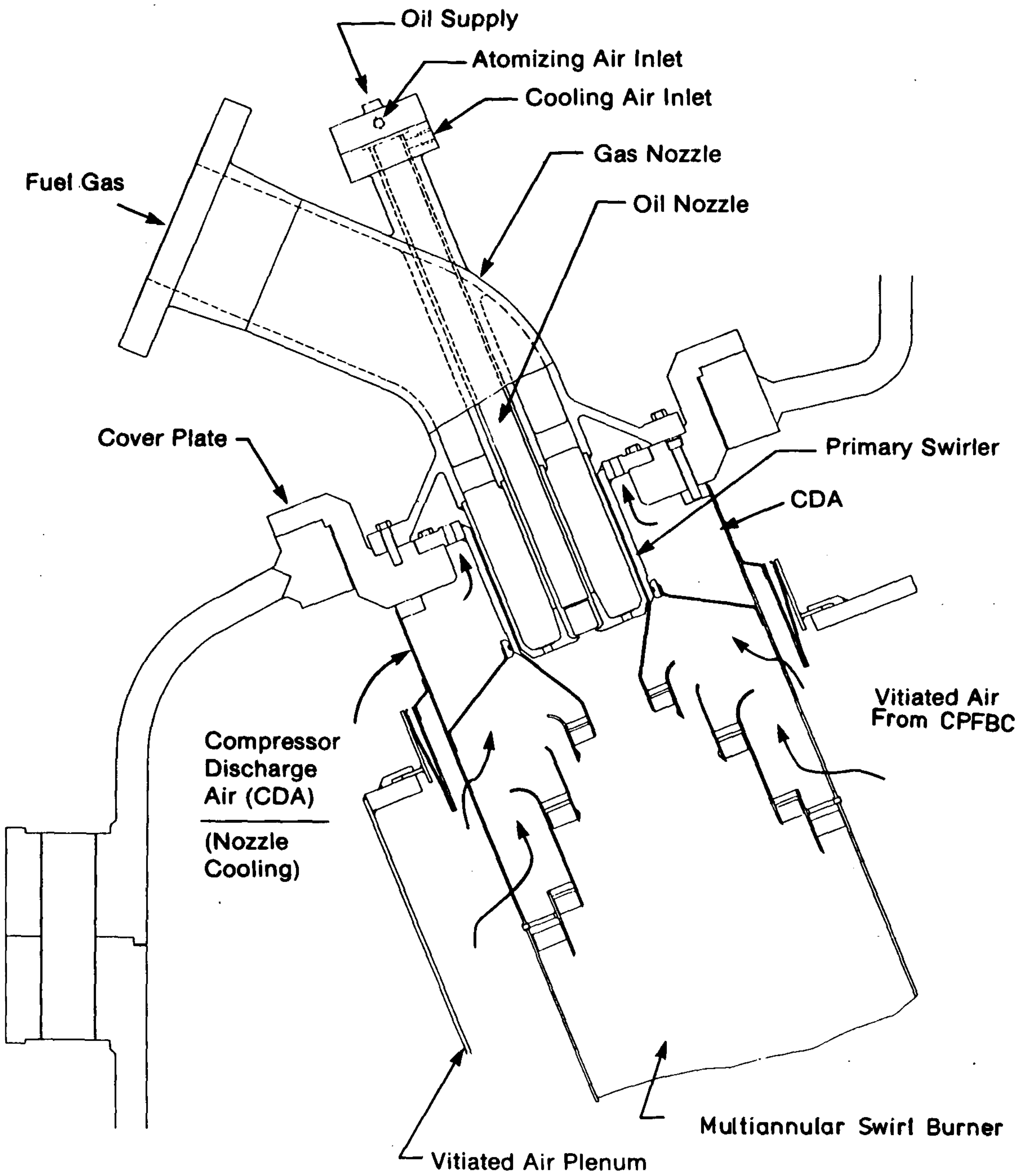


Figure 44 Individual Components of Fuel Nozzle/Combustor System

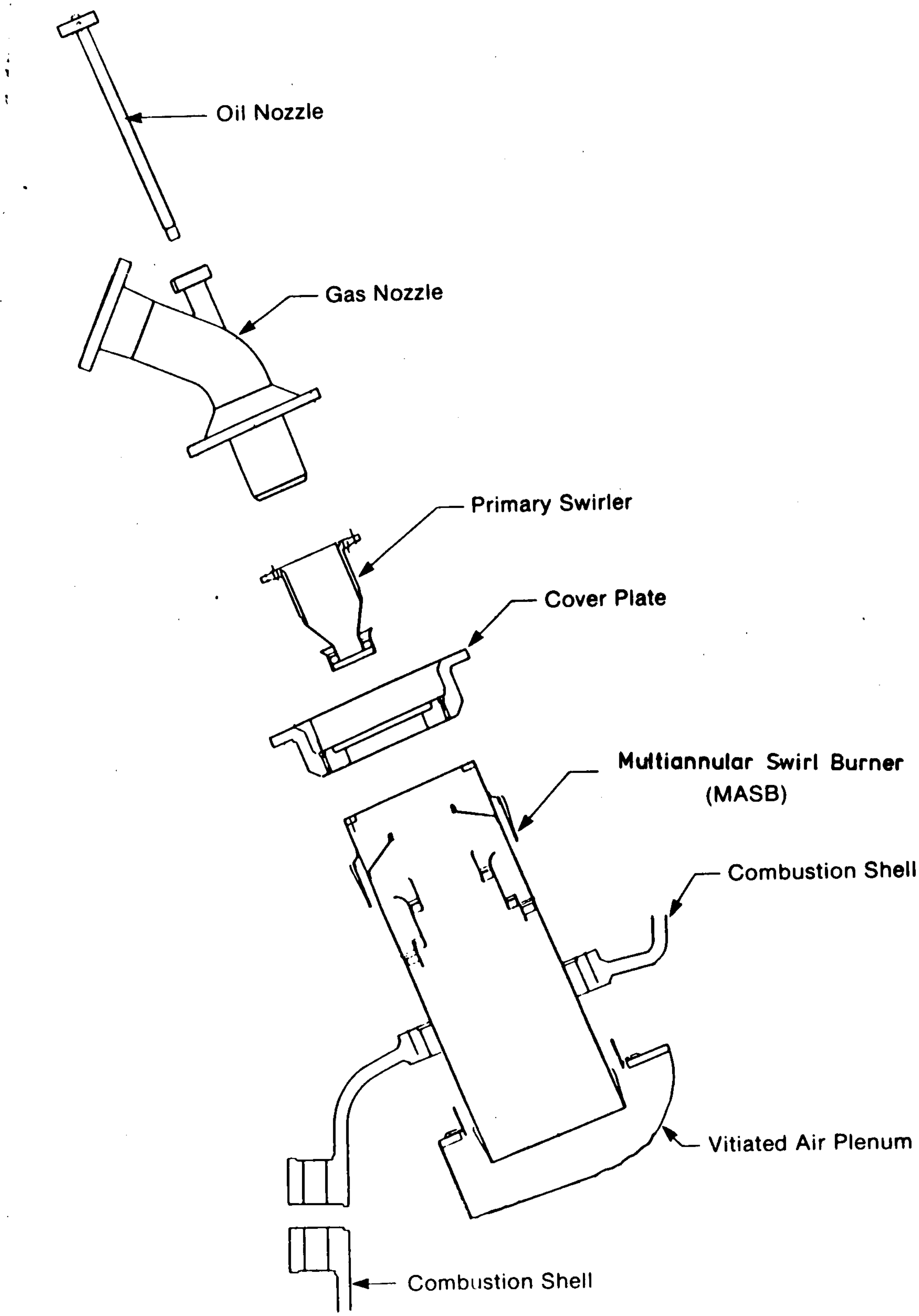


Figure 45 Exploded View of Topping Combustor

During normal operation, when 1500°F fuel gas is passing through the main nozzle, any oil remaining in the oil nozzle will coke and tend to block the free flow of oil during the next start-up cycle. To prevent coking, an external supply of cooling air is circulated around the oil nozzle to lower its metal temperature below the coking temperature of the oil. As a further aid to prevent coking, the atomizing airflow is kept in operation to blow out any oil residue remaining in the nozzle as well as cool the nozzle when the MASB operates with fuel gas.

The combustor/nozzle system is cooled by compressor discharge air flowing through openings in the head end of the combustor, through the primary swirler flange, and out through the annular passage between the fuel nozzle and the primary swirler. Finally, the air impinges against the primary swirler cone.

Materials of Construction for the Topping Combustor. Table 21 lists the materials selected for the baseline plant combustion system together with their anticipated operating temperatures. Many of the components listed separate fuel gas, air, flue gas streams, or a combination; the temperatures reflect the averages of the streams.

Dual-Fuel System. The combustion turbine fuel system has a dual-fuel capability. It can operate with either distillate oil or carbonizer fuel gas. Although the distillate oil is used primarily during start-up, in the event the carbonizer subsystem is inoperative, the plant can continue to operate at full load by feeding coal directly to the CPFBC and oil to the topping combustor.

Table 21 Candidate Materials for Topping Combustion System

Component	Temperature (°F)	Material
Inlet Sleeve	1175	Hastelloy X
Plenum	1175	Hastelloy X
Exhaust Duct	1475	IN617
Annular Duct	1475	IN617*
MASB	1900	IN617*
Gas Nozzle	1500	Fabricated Hastelloy X or Coated, Multi-Met (N155) IN617 (Fabricated)

*Ceramic thermal barrier coating recommended.

Liquid Fuel System. The distillate fuel oil system for the combustion turbine is basically the standard type found on all Westinghouse units. Basic components are the fuel filter, main fuel pump with relief valve, fuel bypass control valve, overspeed trip valve, flow divider, and associated piping. With the exception of the flow divider, the components are in the mechanical package skid. The flow divider ensures equal flow to all fuel nozzles and is usually under the combustion turbine casing in close proximity to the combustor fuel nozzles.

Fuel Gas Valving. The low-Btu gas produced by the carbonizer for the gas turbine combustion system has a heating value of about 10 percent that of natural gas. Although the temperature in the combustor rises by about 500°F in the baseline plant, as opposed to about 1400°F in conventional gas turbine operation, the low-Btu fuel flow is still three to four times greater than the simple cycle natural-gas fuel requirement. In addition, the low-Btu fuel gas temperature is approximately 1500°F, as opposed to about 60°F for natural gas. Because of these factors, the baseline plant fuel gas valving requirements are more severe than those of a natural-gas-fired turbine.

Figure 46 is a schematic representation of the fuel gas system for each module; it identifies the valving involved. The fuel gas is brought from the carbonizer at about 200 psia/1500°F through an 18-in.-I.D. line. A carbonizer vent valve (18-in. nominal I.D.) at a tee joint in this pipe allows full-flow venting of the fuel gas to flare in the event of a system upset. The 18-in. overspeed trip valve is downstream of this tee. Another vent valve between the trip valve and the fuel throttle valve allows venting of the fuel system immediate to the turbine.

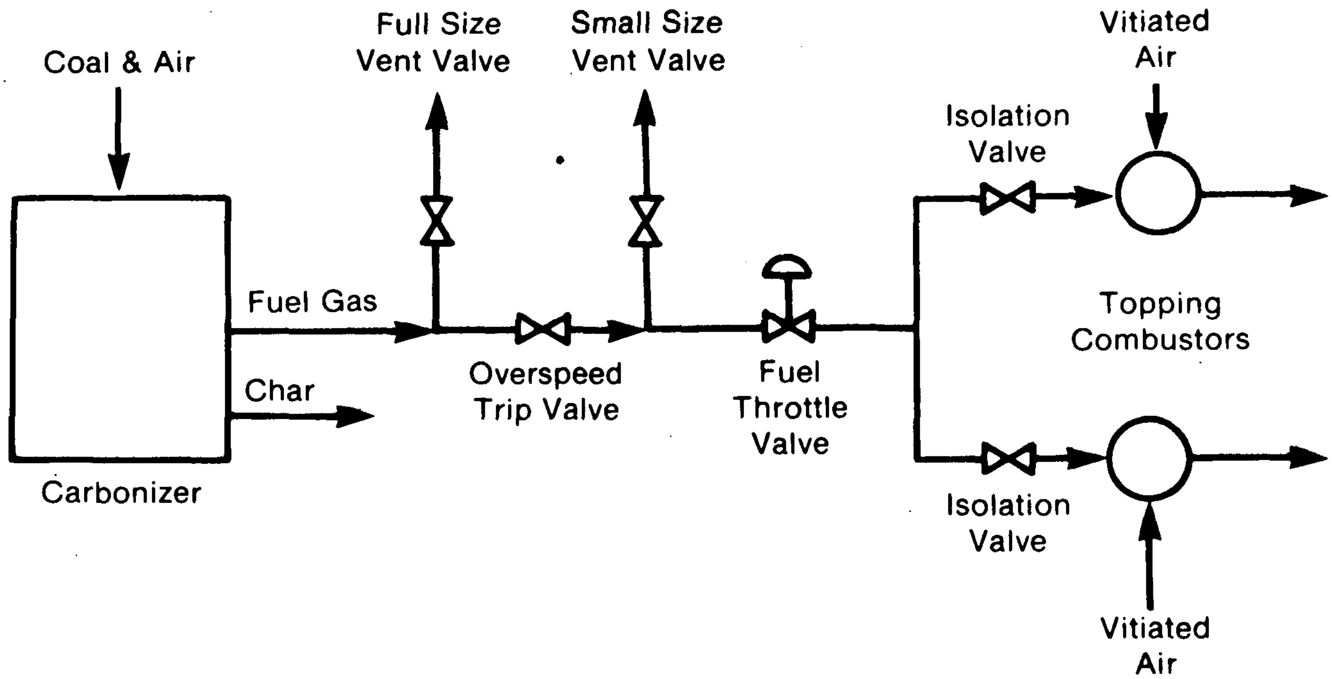


Figure 46 Fuel Gas System Schematic

Just downstream of the fuel throttle valve, the 18-in. pipe splits into two 12-in. lines to feed each set of combustors on either side of the turbine casing. Isolation valves (12-in. nominal I.D.) in these pipes work in conjunction with the overspeed trip valve.

In the event of a plant upset or sudden loss of load, the fuel gas valve system must quickly interrupt gas flow to the turbine and bypass the fuel gas to flare. Because of the relatively large sizes and 1500°F temperature involved, these valves are not currently marketed by the normal gas turbine valve suppliers. However, conversations with these suppliers have indicated that current technology supports their design and manufacture and that an extensive R&D development effort should not be required.

CPFBC Bypass System. The low-Btu fuel gas system contains relatively large valves to regulate or shut off the flow of fuel to the topping combustors in the event of a plant upset, change of load, or loss of load. An additional system of valves is required to ensure overspeed protection for the gas turbine. Because of the large inventory of hot, pressurized air in the CPFBC subsystem and piping, merely shutting off the fuel is not sufficient for overspeed protection. The considerable amount of pressurized air and thermal energy that exists in the CPFBC subsystem from the compressor discharge to the topping combustor inlet must be controlled to prevent excessive overspeed of the gas turbine/generator unit and subsequent catastrophic failure.

Two scenarios relate to the use of the CPFBC bypass system for overspeed protection. The first relates to an externally caused event (e.g., the loss of load when a breaker opens because of some occurrence outside the plant). The second relates to an internally caused event such as loss of lube oil to the turbine/generator bearings.

Loss of Load--External Event. The sudden loss of gas turbine load causes the rapid acceleration of the unit, and the topping combustor fuel system reacts quickly to halt the flow of fuel to the topping combustor. Another system of valves comes into play simultaneously. This system is shown conceptually in Figure 47 and schematically in Figure 48. Although a full analysis and investigation of the design, configuration, operation, and dynamics of this valve system are beyond the scope of this study, the proposed concept should protect the gas turbine from overspeed.

Compressed air is extracted and vitiated air is reintroduced to the hot section of the turbine on both sides of the unit during normal operation. Therefore, two identical sets of valves must work in unison and in conjunction with the fuel system to handle this large volume of air and thermal energy entering and leaving the CPFBC subsystem. At first indication of a loss of load and the resultant acceleration of the gas turbine unit, Valves A, B, and C in Figures 47 and 48 are actuated. Valve A (normally open, 32-in.-I.D. carbonizer/CPFBC inlet valve) closes. At the same time, Valve B (normally closed, 30-in.-I.D. carbonizer/CPFBC bypass valve) opens and Valve C (normally open, 42-in.-I.D. CPFBC outlet valve) closes. In their new positions, the compressor air bypasses the carbonizer and CPFBC subsystems and is routed directly to the topping combustors. Preliminary calculations indicate that the two CPFBC bypass systems, working with the fuel gas bypass system, will protect the gas turbine from overspeed. In addition, there are a few variations of valve operation that can aid in handling this overspeed problem. Because the gas turbine compressor is equipped with inlet guide vanes, flow can be varied to some degree, depending on the vane position. If the inlet guide vanes are partially closed during normal operation, having them fully open during the overspeed event will increase airflow, increasing compressor work and, in turn,

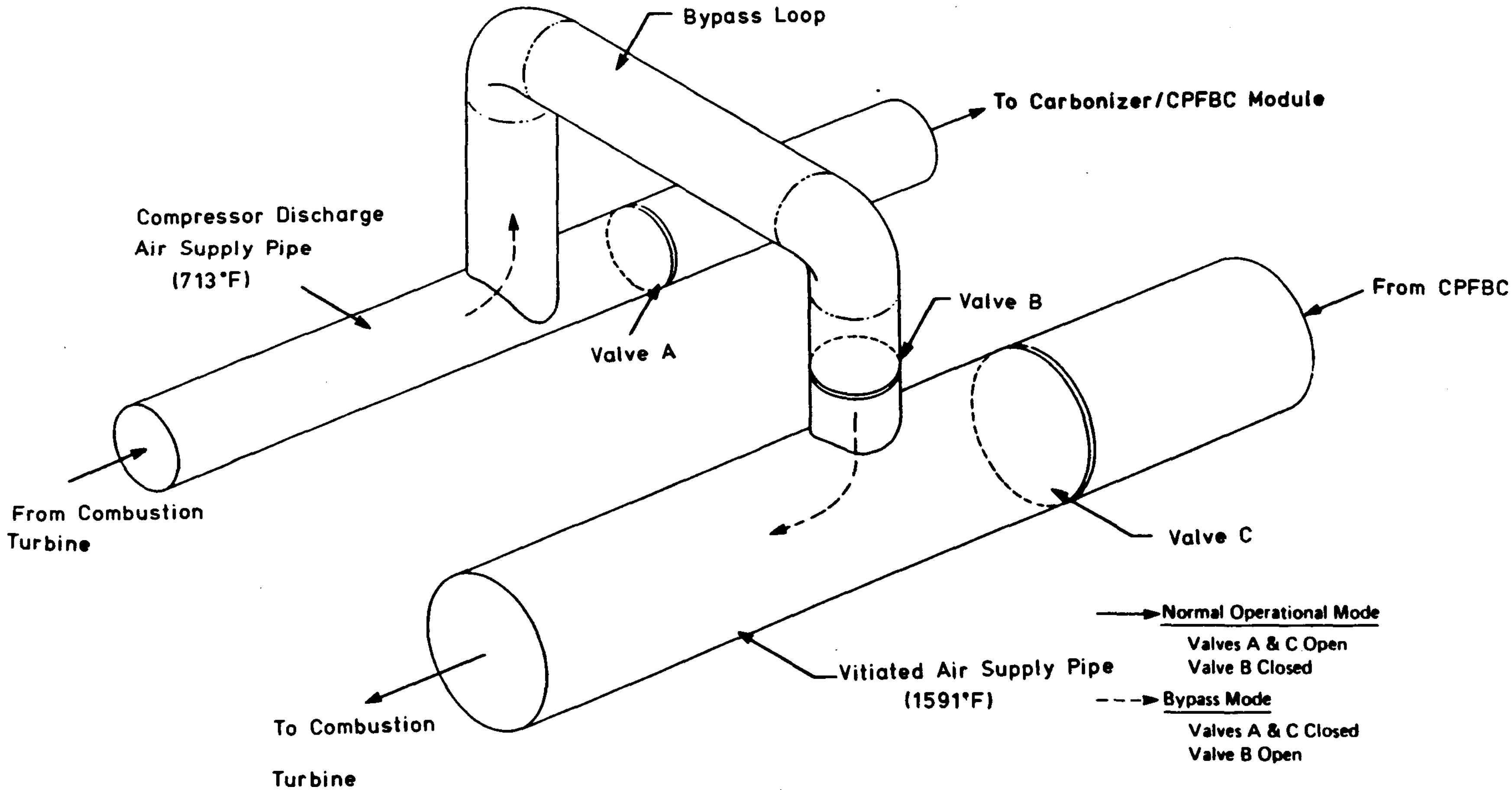


Figure 47 Conceptual Arrangement of CPFBC Bypass System

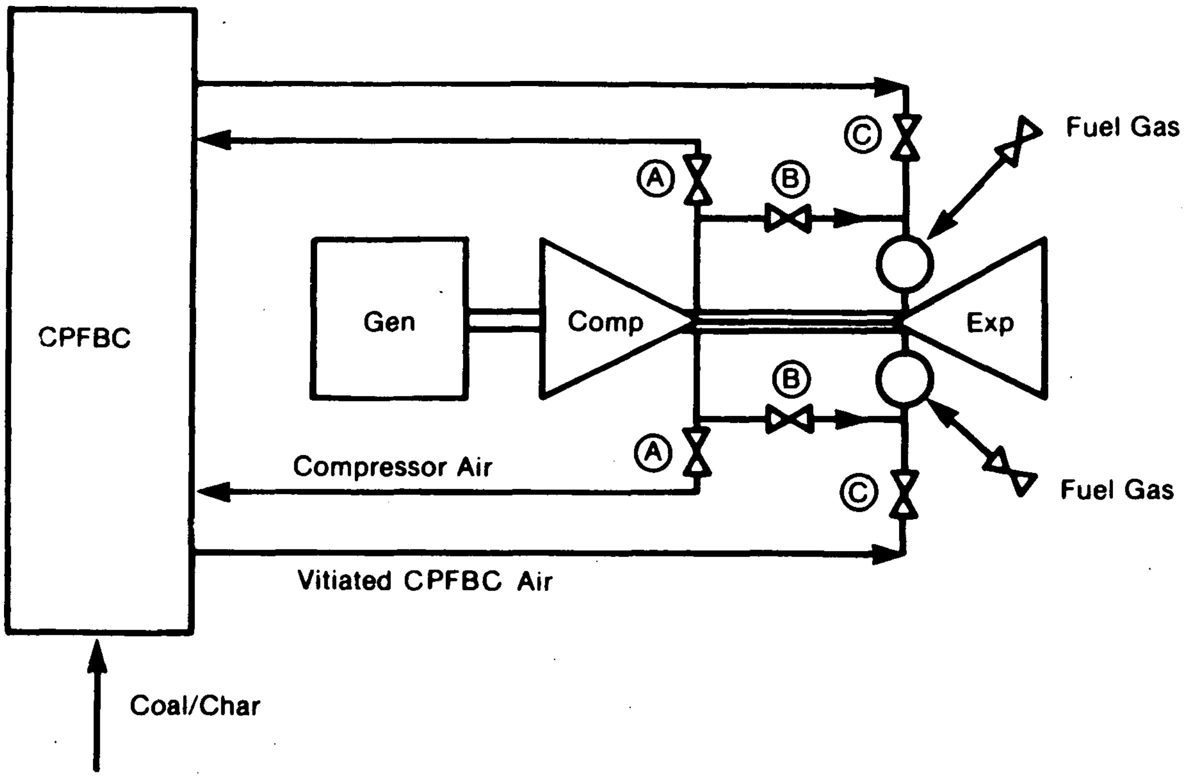


Figure 48 Schematic Arrangement of CPFBC Bypass System

helping decelerate the turbomachinery. In addition, by judicious positioning of the carbonizer/CPFBC bypass valve (Valve B in Figures 47 and 48), the discharge pressure of the compressor can be kept high, increasing the compressor work and gas turbine deceleration even further. Anything that can safely increase compressor work aids in controlling the overspeed problem.

There are several operating levels that the turbomachinery goes through during this rapid train of events. The following paragraphs present a brief look at some of these operating levels and their effects on overspeed.

At the first instant of load loss, steady-state operating parameters prevail. The CPFBC vitiated air at 1591°F (9°F temperature loss between CPFBC and gas turbine) is raised to 2100°F in the topping combustor, and the combined vitiated air and fuel flows enter the turboexpander at the rated inlet pressure (about 180 psia). Immediately upon sensing overspeed, the fuel gas overspeed protection actuates, closing off the fuel flow. Thus the flow to the turbine hot section is reduced about 8-1/2 percent, and the turboexpander inlet temperature approaches 1591°F, the vitiated air temperature.

At this same instant of load loss, the valves in the CPFBC bypass system are actuated. The CPFBC inlet valve (Valve A) closes; the CPFBC bypass valve (Valve B) opens; and the CPFBC outlet valve (Valve C) closes. This set of events, in conjunction with the fuel shutoff event, rapidly rectifies the situation where damage resulting from overspeed could occur. The cooler compressor air mixes with the smaller amount of vitiated air leaking through the CPFBC outlet valve. By adjusting the bypass valve (Valve B), the compressor pressure ratio is elevated, increasing compressor work, which aids the deceleration process.

The amount of air leaking around Valves A and C is of prime importance with regard to unit coastdown time. Under the conditions set forth in this instance (loss of load from an external event), the coastdown time is of lesser importance because none of the gas turbine equipment is at fault. Therefore, normal turbine auxiliaries and components are intact, and the unit can either be resynchronized or shut down and put on turning gear eventually. The section that follows addresses valve leakage and its importance under other load-loss conditions.

Loss of Load--Internal Event. Many of the possible emergency shutdown situations that occur within the plant boundary require the combustion turbine to coast down as rapidly as practical. For example, if high vibration suddenly occurs at one of the turbine or generator bearings, rapid shutdown might be of prime importance to preclude major damage or, possibly, catastrophic failure. Because the large shutoff valves at the compressor discharge and combustor inlet leak to some extent in the closed position, a quantity of hot, vitiated air is mixed with the compressor air that bypasses the CPFBC during the coastdown interval. The amount of leakage is a vital factor in determining the coastdown time. If the quantity leaked is too large, the coastdown is not rapid enough, and another valve has to be put in the CPFBC bypass system to minimize the leakage.

A particularly useful parameter that can be used to gain insight into the amount of leakage tolerable during emergency shutdown is the turbine "Stodola Number, S." This parameter has a variety of other names, including flow parameter and swallowing capacity. It is a measure of the effective flow area of the expander and is a function of flow, temperature, pressure, and rotational speed.

Assuming 3600 rev/min, a simplified version of the Stodola Number is:

$$S = m \cdot (T)^{0.5}/p$$

where

m = Mass flow, lb/s
T = Absolute temperature, °R
p = Inlet pressure, psia

The value for the baseline plant combustion turbine is 228. This number is calculated for expander inlet conditions at rated load.

As mentioned earlier, when the fuel is shut off, there is an almost immediate drop in flow and temperature into the expander since the inlet temperature drops to about 1600°F and the flow diminishes by about 8-1/2 percent to 734.5 lb/s. Using the Stodola formula, the corresponding expander inlet pressure becomes:

$$p = 734.5(2051)^{0.5}/228 = 145.9 \text{ psia}$$

Thus the expander inlet pressure drops from about 180 to 146 psia in about 1 or 2 seconds because fuel is shut off. Acting simultaneously with the fuel shutoff, the CPFBC bypass valving transfers the compressor flow directly to the expander. Ignoring valve leakage for the present and considering only the compressor discharge flow and temperature at the moment of shutdown, the required expander inlet pressure becomes:

$$p = 772(1173)^{0.5}/228 = 116.0 \text{ psia}$$

Because the valves must act within 1 or 2 seconds, the inlet pressure to the expander will be between 116 and 146 psia at the end of that interval. It is certainly less than 146 psia, because the CPFBC shutoff valve eliminates most of the CPFBC flow; and it is certainly more than 116 psia, because there is leaking past the valves. If 10 percent of the compressor flow were still to pass through the CPFBC, the resultant inlet pressure would be about 120 psia. The mixed temperature of the air and CPFBC leakage is about 800°F. With this pressure and temperature, the turbomachinery will certainly be in a coastdown mode, but the deceleration rate needs to be quantified.

As mentioned in the previous subsection, by positioning the bypass valve (Valve B in Figure 47) correctly, compressor work can be increased, which will aid in solving the problem. In addition, there are two booster compressors in the power plant that extract about 6 percent of the turbocompressor airflow for transport air and the carbonizer. If a vent valve were placed in the 12-in. extraction pipe, to open when load dump occurs, leakage past the CPFBC exit valve could be reduced.

Specific information about the valves, a detailed analysis of the dynamics of the power train, and an analysis of the transient behavior of the pressure vessels and piping are required to quantify the gas turbine coastdown characteristics under the referenced loss-of-load conditions. Although such analyses are beyond the scope of this study, we believe that the proposed bypasses and operating techniques can be made to protect the gas turbine during these conditions.

Alternative CPFBC Bypass System. An alternative to the three large valves shown conceptually in Figure 47 is an internal bypass system within the combustion chamber. Figure 49 shows the concept. It has some advantage in that it eliminates two of the external valves and it may inhibit some leaking through the remaining external valve. This concept will be examined in more detail in a later phase of this program.

Installation Configuration. Figures 50 and 51 display the equipment arrangement for the gas turbine installation. Finer details such as enclosures, piping, wiring, fuel system, and the CPFBC bypass system are not included for the sake of clarity. However, hot fuel manifolds with the associated pipes, valves, and connections are present on both sides of the combustion section. Piping and valving for the CPFBC bypass system are also present.

The unit occupies a space approximately 130 x 50 ft. The orientation of the compressor inlet filter, silencer, and duct system impacts both the width and height of the configuration. As shown, the inlet system is at grade level. Overhead orientation, where the inlet air enters the compressor inlet scroll from above, is also possible and has been done many times.

Emissions of Oxides of Nitrogen. There are several factors that affect the formation of NO_x during combustion:

- Pressure
- Combustion air temperature
- Combustor temperature rise
- Fuel/air ratio
- Residence time
- Nitrogenous compounds in the fuel

Pressure has a smaller effect compared with the other factors and, unlike the situation in conventional gas turbines, combustion air temperature is a much more significant factor than temperature rise, simply because it is so high. Since the combustion air enters at 1591°F (a 9°F loss is experienced between the CPFBC outlet and the topping combustor), the rise in combustor temperature needed to reach the plant design temperature (2100°F) is only 509°F. To assess the NO_x formation potential of the MASBs in the combustion turbine under these conditions, we looked at a previous MASB test burning methane and made an assessment of a conventional gas turbine combustor in the topping combustion mode. From these findings, NO_x for the MASB topping combustor was predicted, and total plant NO_x was compiled.

In the DOE-sponsored topping combustor feasibility test [1], the NO_x from the methane-fueled MASB was greater than expected; the difference was caused by a less-than-optimum fuel nozzle configuration, a less-than-optimum swirler orientation, or a combination of the two, which resulted in a center hot spot and a relatively poor combustor temperature exit pattern. That particular test utilized 1400°F vitiated combustion air. The NO_x emission is shown in Figure 52 as line A-B. A Westinghouse computer program was utilized to predict NO_x emissions from a conventional (flame holder) gas turbine combustor operating with 1600°F combustion air and burning methane. The results are shown as line C-D. As the figure shows, the high combustion air temperature and the predictable hot spots for the conventional combustor as a result of high flame temperatures yield a predicted NO_x of about 310 ppm(v) at a 2100°F topping combustor outlet temperature. Although the NO_x from the methane-fueled MASB was higher than desired, it was still considerably lower than predicted for the conventional hardware (compare lines A-B and C-D in Figure 52).

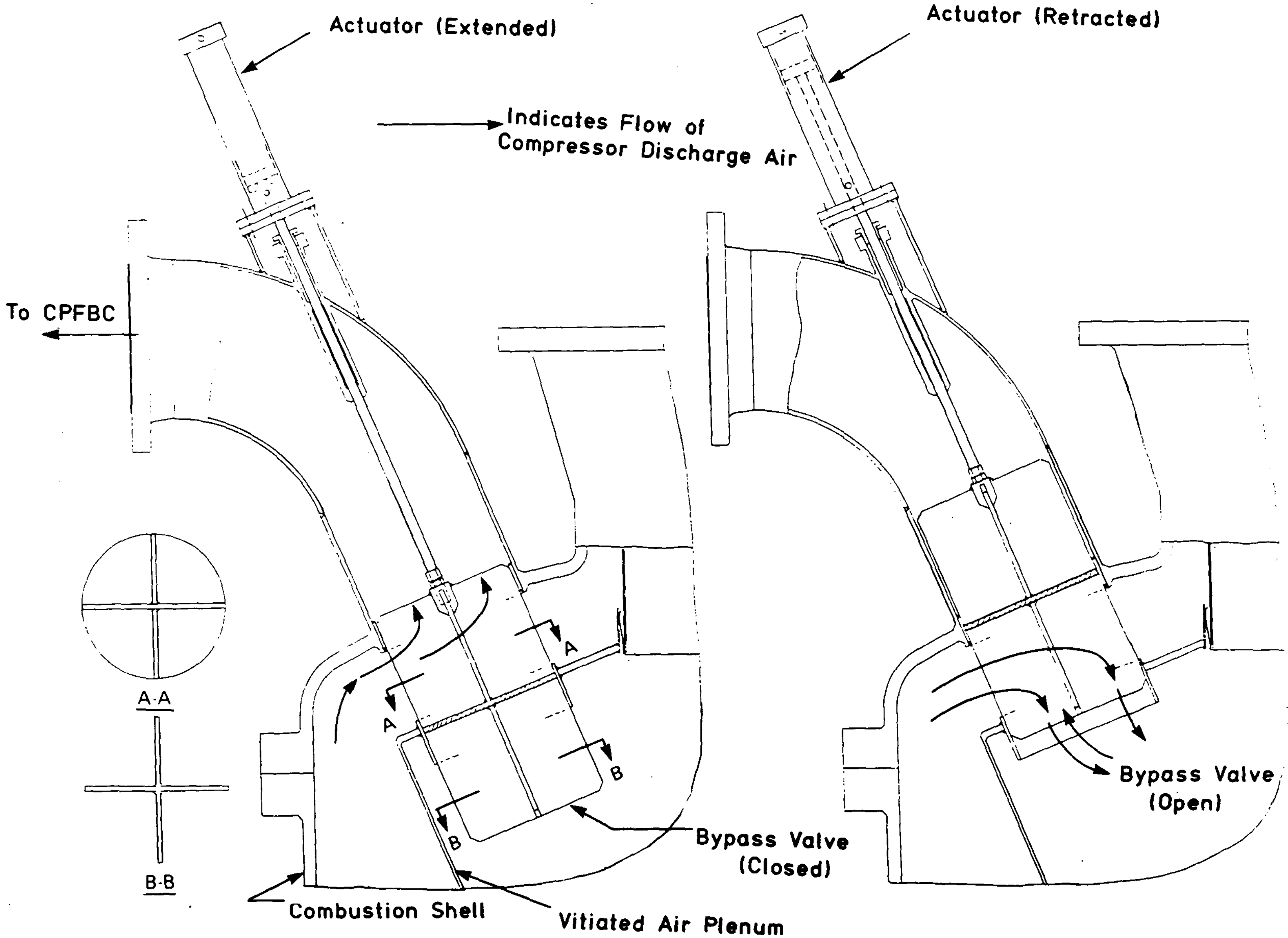


Figure 49 Alternative CPFBC Bypass System

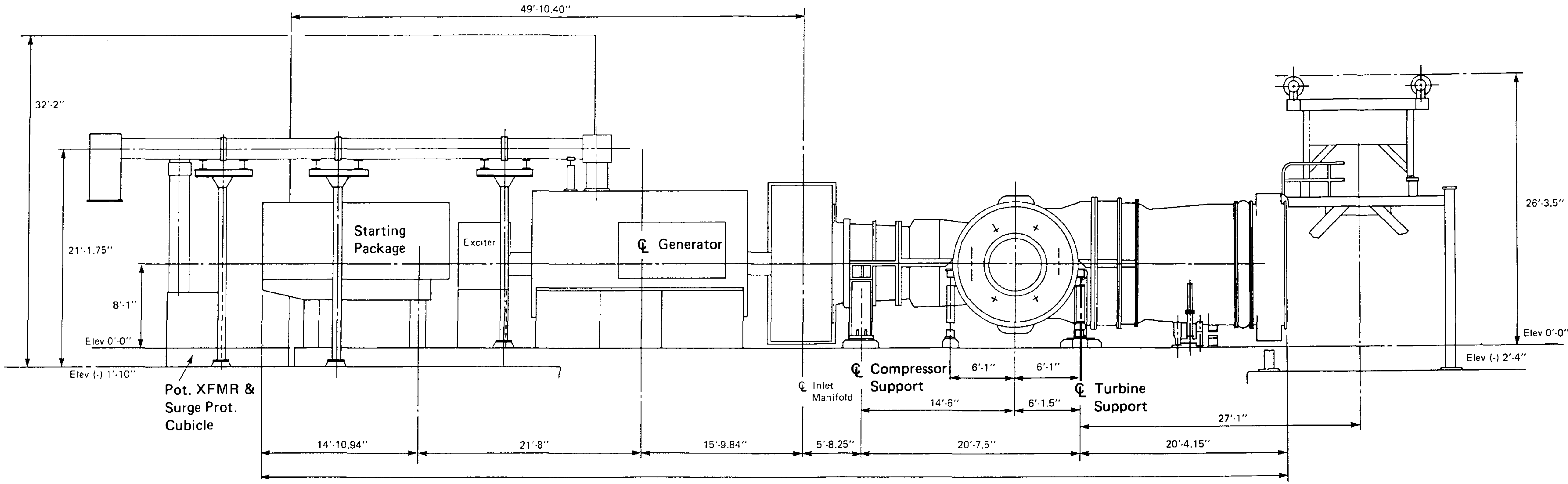


**Figure 50 Equipment Installation--
Gas Turbine (Elevation)**

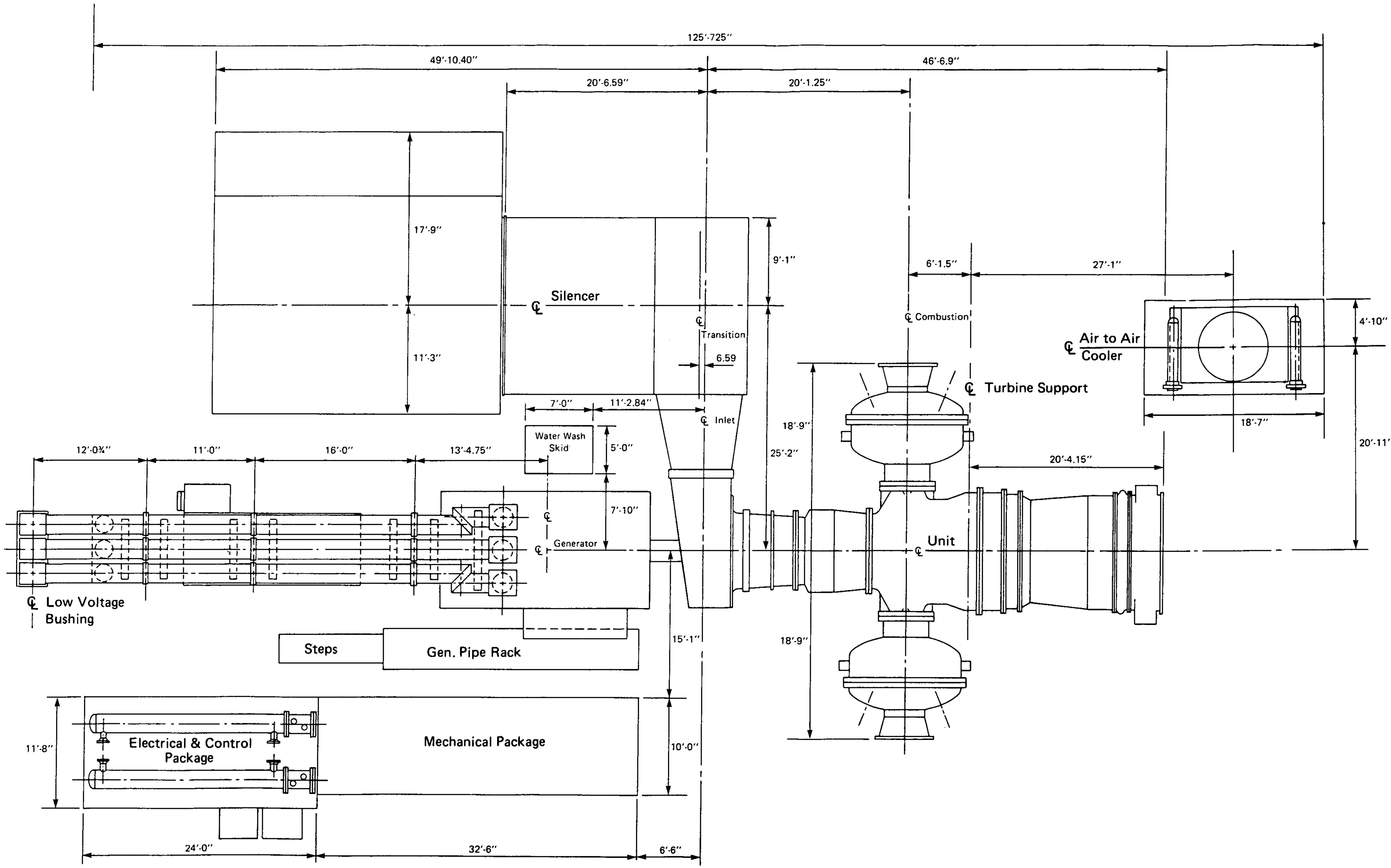


Figure 51 Gas Turbine Equipment Installation--Plan View

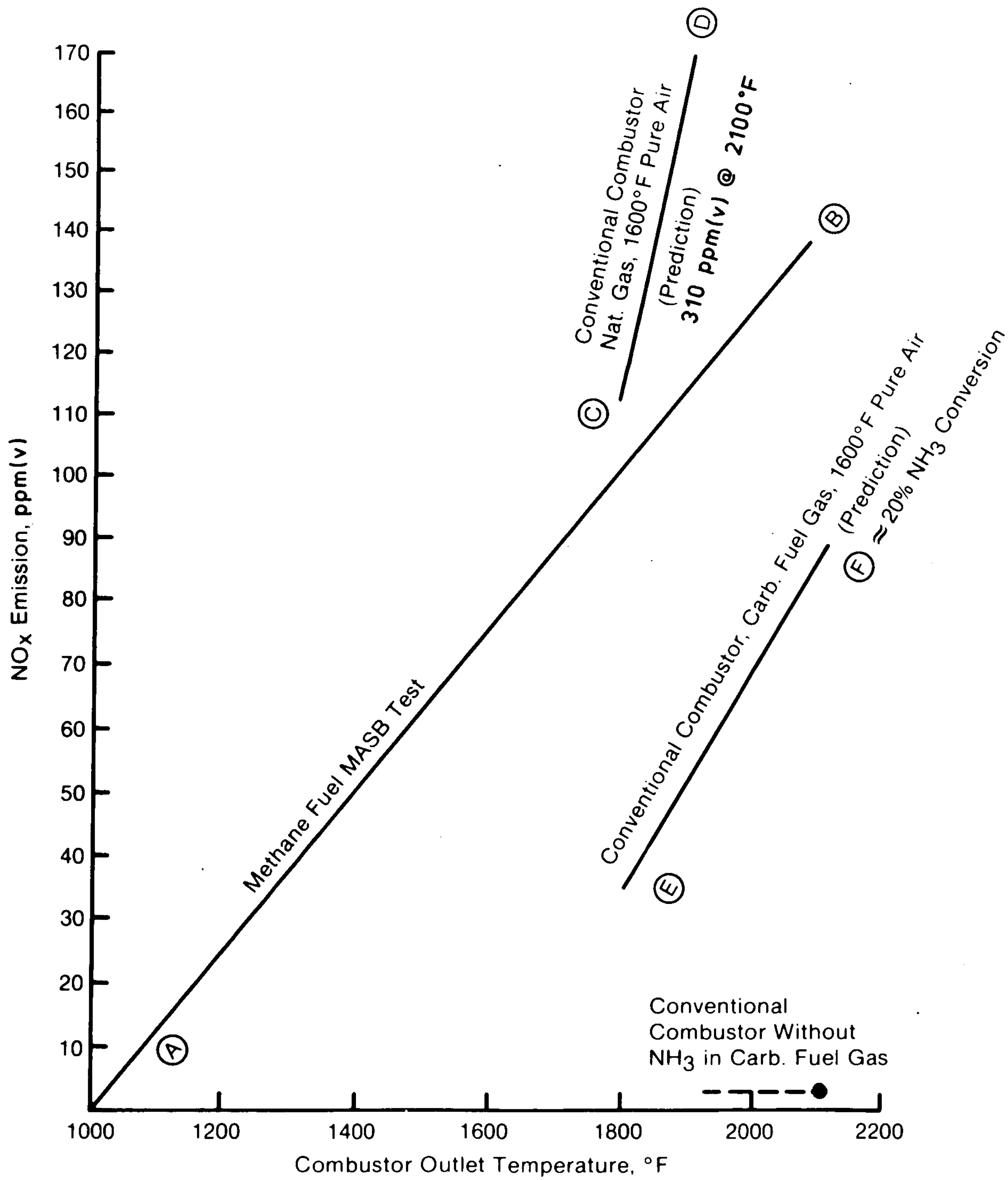


Figure 52 Measured NO_x From MASB Methane-Fired Test and Predicted NO_x Firing Natural Gas and Carbonizer Fuel Gas

The NO_x prediction from the computer program was then applied to a conventional combustor burning the carbonizer fuel gas. The results are shown as line E-F in Figure 52. The curve shows an NO_x value of 88 ppm(v) at 2100°F; the value includes 20 percent of the NH_3 in the fuel converted to NO_x.

When the program was applied again, this time omitting the NH_3 from the fuel gas, the NO_x dropped to a minimal 3 ppm(v), which points up two important characteristics of the carbonizer fuel:

- Because the fuel is a low-Btu fuel, it has a low adiabatic flame temperature. Thus practically no thermal NO_x is formed.
- Since practically all the NO_x formed will be from fuel-bound nitrogen (FBN), both the amount of ammonia in the fuel and the percentage of conversion to NO_x are of paramount importance.

The carbonizer yields and compositions used for the baseline plant design effort assumed the most pessimistic scenario for the formation of NH_3 in the fuel gas (i.e., all nitrogen in gaseous form appears as ammonia and yields 0.29 wt%). Later predictions by the computer model discussed in Appendix A indicates the NH_3 to be about 0.20 wt%. Values of NH_3 measured in the KRW fluidized bed gasifier [2], which operates at 1800°F, are less than 0.05 percent.

In addition to this uncertainty, there is also considerable uncertainty regarding how much of this incoming ammonia will be converted to NO_x. The Westinghouse NO_x prediction program calculated an ammonia-to-NO_x conversion factor of 20 percent using a conventional flame-holder combustor with the carbonizer fuel gas. Because the MASB is a rich/lean combustor, the formation of NO_x caused by FBN or nitrogen in the combustion air will be lower. This fact was confirmed in an MASB combustor test sponsored by NASA Lewis that showed FBN conversion to NO_x to between 4 and 12 percent of the FBN in the fuel [3].

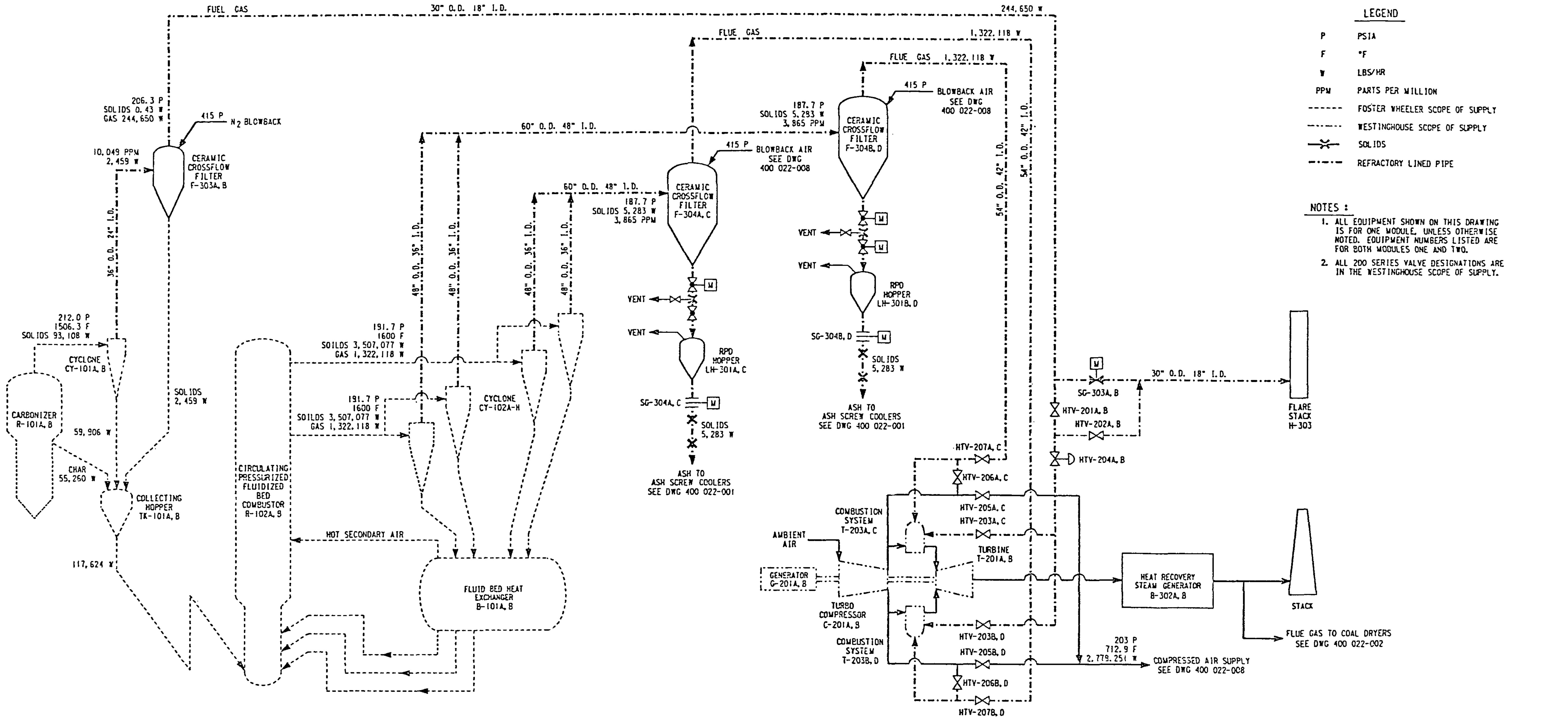
The NO_x in the CPFBC flue gas has been estimated to be 91 ppm(v) based on a correlation (discussed in Appendix C.3) of a limited amount of published circulating fluidized bed staged combustion data. Recognizing that this estimate has considerable uncertainty [±70 ppm(v)] and faced with the fuel gas and ammonia conversion uncertainties just discussed, an analysis was undertaken to identify the NO_x emissions that would result from best case, worst case, and more probable nominal case analyses. As shown in Table 22, the best case used only the "low side" values referenced above [e.g., CPFBC flue gas was 21 ppm(v), fuel gas ammonia was 0.05 wt%] and yielded an NO_x level of 0.065 lb/10^6 Btu at the outlet. The worst-case analysis used only the "high side" values [e.g., CPFBC flue gas was 161 ppm(v), fuel gas ammonia was 0.29 percent] and yielded an NO_x outlet level of 0.519 lb/10^6 Btu. The nominal case uses mid-point values except that the computer-predicted fuel gas ammonia content of 0.20 percent was used, and an NO_x outlet level of 0.279 lb/10^6 Btu is predicted. Despite the high plant excess air level, all three cases are within the NSPS maximum allowable limit of 0.6 lb/10^6 Btu. In the absence of experimental data, the nominal case NO_x emission of 0.28 lb/10 Btu appears to be the more reasonable value and was used for plant emission performance estimates.

2.5.7 Flue Gas System

This section includes design information for the cross-flow filters, high-temperature piping, ductwork, and stack, as depicted in Figure 53.

Table 22 Analysis of NO_x From Topping Combustion

	Best Case	Nominal Case	Worst Case
Assumptions:			
CPFBC Flue Gas NO_x			
lb/h	86	374	662
lb/10^6 Btu	0.049	0.211	0.374
ppm(v)	21	91	161
Fuel Gas Ammonia Content, wt%	0.05	0.20	0.29
Ammonia Conversion to NO_x, %	4	8	12
Basis, ppm(v):			
Topping Combustor NO_x Release			
Thermal Component	3	3	6
Fuel-Bound Component	3	24	51
NO_x at Topping Combustor Outlet	27	118	218
Basis, lb/h:			
Topping Combustor NO_x Release			
Thermal Compound	14	14	27
Fuel-Bound Component	14	106	230
NO_x at Topping Combustor Outlet	114	494	919
Basis, lb/10^6 Btu Heat Release:			
Topping Combustor NO_x Release			
Thermal Component	0.008	0.008	0.015
Fuel-Bound Component	0.008	0.060	0.130
NO_x at Topping Combustor Outlet	0.065	0.279	0.519



Dwg. 8333-1-400-022-009, Rev. B

Figure 53 Fuel and Flue Gas System

Hot Gas Cleanup. G/C has investigated the status of hot gas cleanup test programs using a previous study performed for DOE METC as a starting point [4]. Testing conducted since the study has not significantly enhanced the capabilities or the potential of any of the devices being tested by DOE.

In addition, G/C has collected and reviewed data for the testing of silicon carbide candle filters. Single-filter tests conducted at Westinghouse under simulated PFB combustion conditions [5], multiple-element tests at 1000°F at The University of Aachen in Germany [6], and multiple-filter tests at Grimethorpe [7] in the United Kingdom have shown that, similar to ceramic cross-flow filters, ceramic candle filters can also provide very high collection efficiencies. However, questions regarding long-term mechanical durability remain to be resolved.

Table 23 summarizes the tests done for four candidate cleanup devices. The conditions given are the most extreme. Results of an ESP test at the New York University PFB combustion test facility are not presented in the table because the equipment suffered damage before the collection efficiency could be determined. Each concept shown in the table is a candidate for the second-generation PFB combustion plant and could be employed if proven successful in long-term testing. Since the cross-flow filter has been more extensively tested and has cost advantages [4], it is used as the baseline plant final filtration device.

Cross-Flow Filter Description. The design of the cross-flow filter is based on previous work done by G/C for DOE-METC [4] and published reports by Westinghouse [8] that show refinements to the filter itself and to the internal configuration. Because the carbonizer filter and the CPFBC filters are similar except for size and the type of blow-back cleaning gas, only one description is given. Table 24 summarizes design criteria for both, and Figures 54 and 55 show the configurations of both filters.

The cross-flow filter uses 40 flanged 12- x 12- x 4-in. ceramic elements, manufactured by Coors. These elements are bolted horizontally on cantilevered mounts that attach to a 6-in.-diam. vertical plenum about 19 ft long and form one module. The element flange rests on a gasket and is held in place by a compression ring clamped on top of a compressible gasket.

The plenums are suspended from a tubesheet; this is the most critical design problem for the device. Westinghouse has conducted a mechanical analysis and has arrived at a design that supports the tubesheet on a cylinder suspended from the vessel head. The tubesheet is reinforced with channels.

The vessel height is sufficient to allow filter plenums to be removed from the tubesheet from the bottom, through the manway. The vessel is too large to have a flanged head, which had been a design consideration to aid in filter maintenance. On the clean side of the tubesheet, each plenum has a venturi section into which blowback air is blown. The venturi ensures that the maximum amount of hot, clean gas is mixed with the pulse gas. The internals, fabricated of stainless steel (RA 333), are housed in a pressure vessel lined with 8 in. of refractory.

Filters are blown back on-line with a high-pressure short-duration pulse of nitrogen (for the carbonizer filter) or air (for the CPFBC filters). Blowback pipes (1.5-in. diam) penetrate the pressure vessel to a thermally insulated accumulator sized to ensure blowback pressure and flow. Blowback frequency is controlled by filter pressure drop, which is dependent on the amount of particulates entering the filter vessel. Multiple plenums/modules are blown back simultaneously, and shielding prevents large quantities of dust from entering elements not being blown back.

Table 23 Test Summary--Candidate HGCU Concepts

	Test Maximum							
HGCU Device	Temperature (°F)	Pressure (psia)	Size	Flow Rate (aft^3/min)	Test Duration	PFBC	Collection Efficiency (%)	Comments
Ceramic Cross-Flow Filter [4]	1500	135	6-in. x 6-in.	12	100 h	Actual (ANL)	99.99	Filter delaminated at end of test. Similar filter was also tested successfully for 38 hours under gasifier conditions at METC. [9]
High-Temperature/ High-Pressure Electrostatic Precipitator [4]	1490	83	12-in. diam x 15 ft	1100	24 d	Actual (CW)	99.6	High efficiencies were obtained until internals were distorted by water. Parallel plate design was not tested.
Moving Granular-Bed Filter [4]	1608	14.7	5-ft diam x 5 ft	1800	400 h	Actual AFBC (CPC)	98.8	Filter was not tested at high pressure.
Silicon Carbide Candle Filter [5]	1600	200	60 mm x 1 m	33	---	Simulated PFBC	99.99	ΔP increased above 3.8 ft/ min face velocity. Multiple filters were not tested.

Table 24 Ceramic Cross-Flow Filter Conceptual Design Summary

Description	Carbonizer Filter	CPFBC Filter
Blow-Back Conditions		
Gas	Nitrogen	Air
Cleaning method	On-Line	On-Line
Filter plenums blown back simultaneously	3	6
Pressure, psig	400	400
Pulse duration, s	0.2	0.2
Cycle time between blowback, min	15	30
Blowback requirement, lb/h	56	100
Accumulator dimensions, ft	2 (diam) x 8 (length)	2 (diam) x 8 (length)
System Performance		
Temperature loss, °F	10	4
Clean pressure drop, psia	1.5	1.5
Operating Parameters, Single Module		
Pressure, psia	208	188
Temperature, °F	1488	1599
Design face velocity, ft/s	5	10
Filter collection efficiency, %	99.99	99.99
Gas flow to each vessel, lb/h	244,650	1,322,118
aft^3/min	15,800	89,900
Solids flow to each vessel, lb/h	2459	5283
ppm	10,051	3996
Configuration		
Filter element dimensions, in.	12 x 12 x 4	12 x 12 x 4
Filter elements per plenum	40	40
Plenums per vessel	9	24
Vessels per carbonizer/CPFBC	1	2
Stairmand cyclone precleanup	One 6-ft diam	Two parallel 8-ft diam
Vessel dimensions, ft	15 (O.D.) x 54 (high)	20 (O.D.) x 54 (high)
Vessel refractory		
Insulating layer	3 in. Resco 17EG	3 in. Resco 17EG
Abrasion-resistant layer	5 in. Resco CE80ES	5 in. Resco CE80ES
Vessel internals material	RA 333	RA 333

Dwg. 8333-1-400-028-001, Rev. A

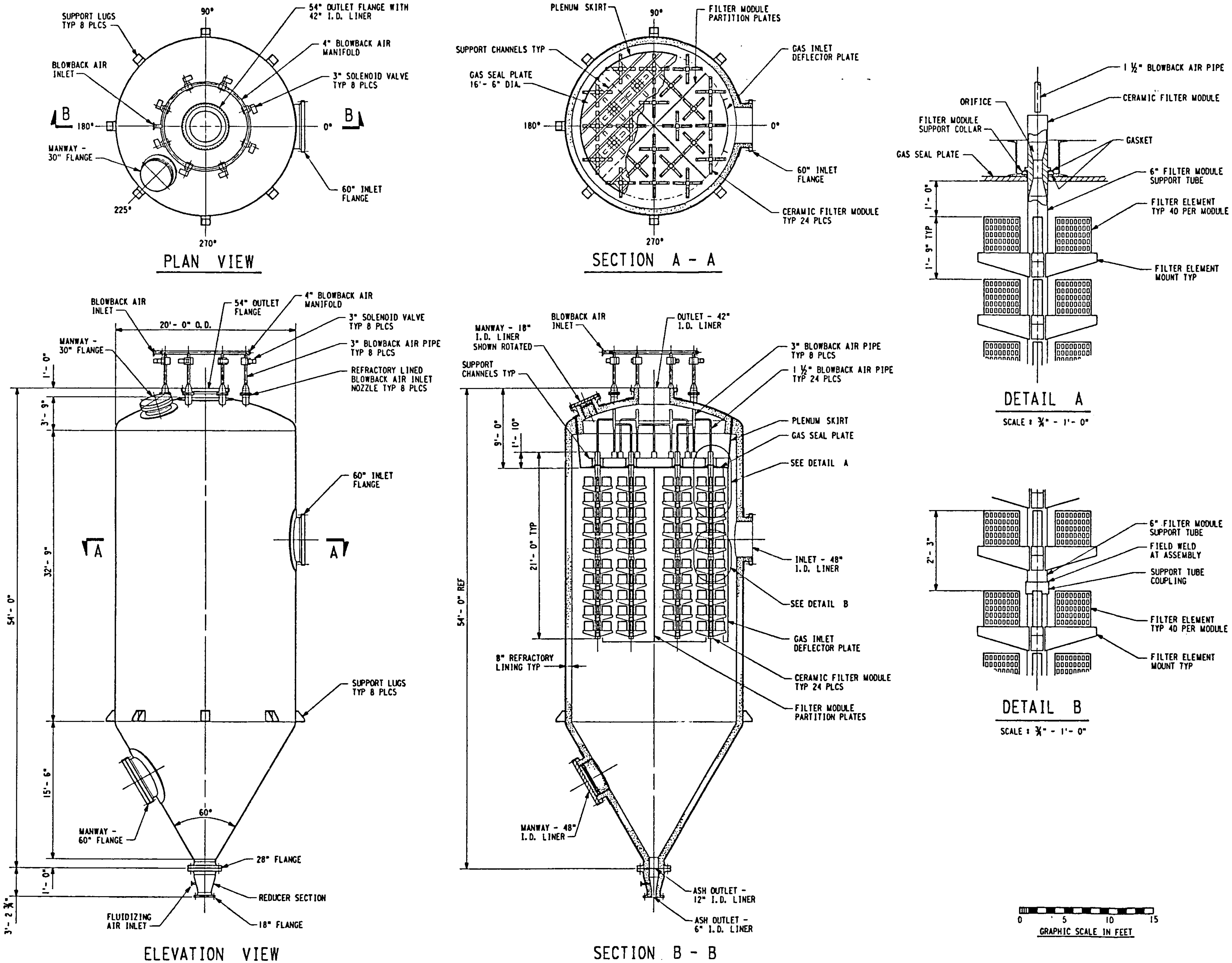


Figure 54 CPFBC Cross-Flow Filter Vessel--Plan, Elevation, Section and Details

Dwg. 8333-1-400-028-002, Rev. A

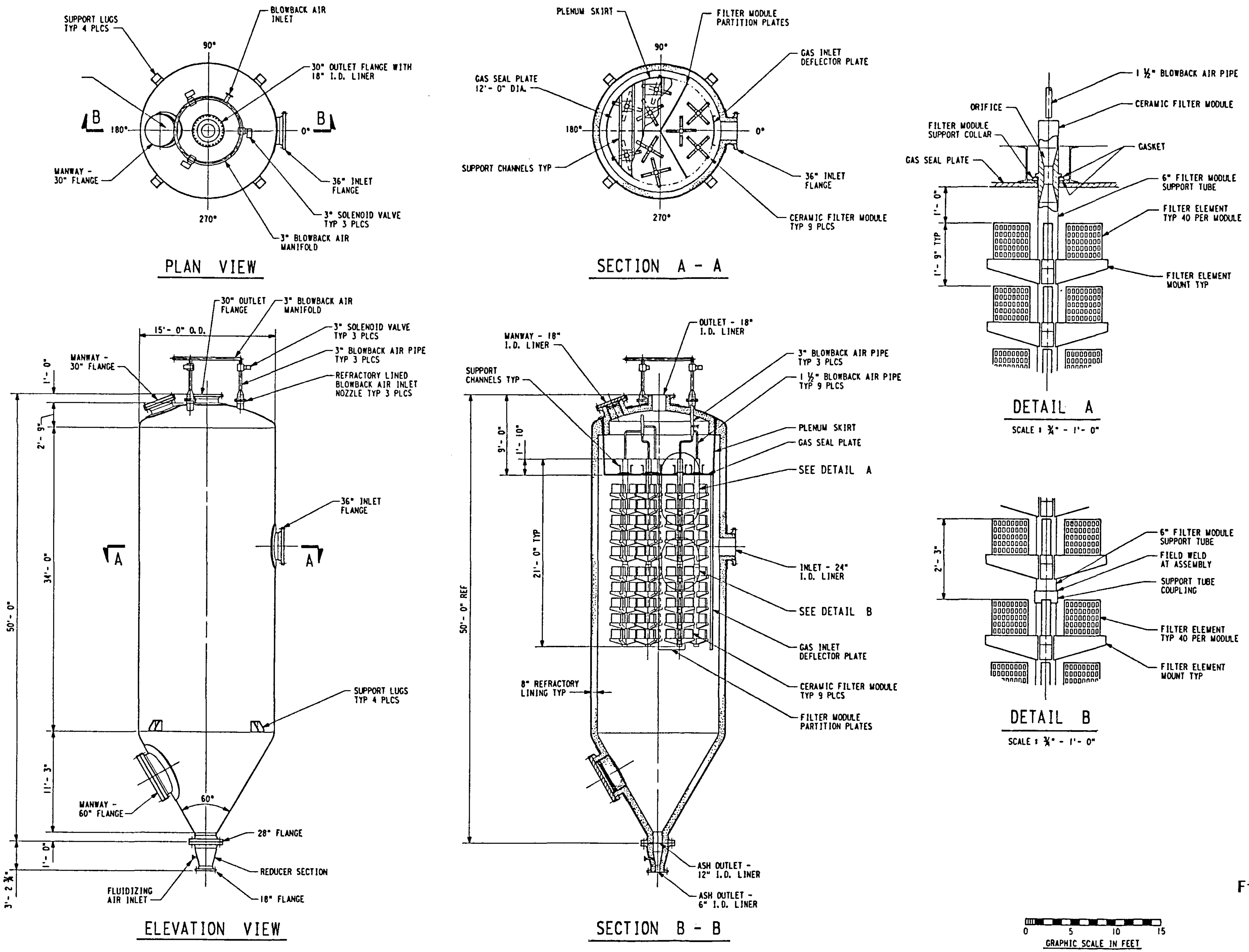


Figure 55 Carbonizer Cross-Flow Filter Vessel--Plan, Elevation, Section, and Details

Carbonizer Cross-Flow Filter. Fuel gas flow from the carbonizer is cleaned first by a single 6.1-ft-diam, high-efficiency (Stairmand-type) cyclone. The cyclone collection efficiency is:

- Ash 91.15 percent
- Sorbent 96.39 percent
- Char 95.99 percent (63.1 wt% going to cyclone)

The cyclone outlet gas enters a 15-ft.-O.D. ceramic cross-flow filter at 244,650 lb/h (15,800 aft^3/min) [dust loading of 2459 lb/h (10,051 ppm)]. Solids are collected on the filter surfaces and periodically blown off using nitrogen at high pressure (400 psig). There are nine filter plenums segmented into three pie-shaped blow-back sections, which are separated by sheet metal panels to prevent blown-off dust from dirtying on-line filter elements. The solids that are dislodged by the nitrogen drop by gravity to a collecting hopper through a pressure-differential-seal dip leg. This collecting hopper also receives cyclone solids and char from the carbonizer. The filter efficiency is 99.99 percent; however, 0.25 lb/h solids (nominal) are estimated to leave the filter with the fuel gas. Pressure drop across the filter is 1.5 psi. The cyclone pressure drop is estimated at 4.0 psi.

CPFBC Cross-Flow Filter. Flue gas from the CPFBC is split into two streams, each at the same 1,322,118 lb/h (87,900 aft^3/min). The dirty flue gas goes to two 8-ft-diam Stairmand high-efficiency cyclones in parallel; they remove ash at 99.876-percent efficiency and sorbent at 99.96-percent efficiency. The gas from each pair of cyclones flows to a 20-ft-diam cross-flow filter, which operates with a dust loading of 5283 lb/h. Each filter vessel contains 24 plenums, separated into four groups of six modules by four panel segments. The cross-flow filters collect essentially all of the particles; they are cleaned periodically by 400-psig air pulses. Only one section is blown back at a time. The dislodged dust falls by gravity to a restricted-pipe discharge hopper, which transfers the dust continuously from high pressure to an atmospheric-pressure water-cooled screw conveyor. The restricted-pipe discharge system eliminates lock hoppers and high-temperature lock-hopper valves.

Potential Failure of Cross-Flow Filter Elements. Westinghouse has considered a design with a coarse filter backup, which could be installed to collect dust in the event of a failed/shattered filter element. Each element in this design would have an individual blow-back pipe. Since the need for this fail-safe design has not been demonstrated, it has not been incorporated into either the carbonizer or the CPFBC filters, but it is available if needed.

A statistical analysis was conducted in an attempt to characterize the failure of individual cross-flow filter elements, their effect on plant particulate emissions, and their potential for meeting NSPS environmental limits without "fail-safe" back-up filters. The Weibull distribution is often used to characterize such failures; it was exercised to determine the effect of various potential filter performance scenarios. The assumptions used were:

- 99.99-percent normal "new" filter element efficiency
- 80-percent filter element efficiency when "failed"
- Allowable NSPS loading of 106 lb/h
- Weibull failure curve shape parameter of 3.44
- 3-year characteristic filter element life.

The filter efficiency when failed represents a fictitious value--a combination of particulates escaping through a crack in the failed filter and the additional gas passing through the element. In tests to date, delamination has been the cause of filter failure, but it has not caused a measurable reduction in collection efficiency. As a result the case being examined is very conservative. Variations examined included:

- Efficiency of a failed single-element filter: 50 to 90 percent
- Characteristic life of a filter element: 1 to 5 years

The results are presented in Figures 56, 57, and 58. Figure 56 shows the rise in outlet loading resulting from a change in assumed characteristic element life; Figure 57 shows that the cross-flow filter will operate for a year without the need for filter replacement if the nominal life of a filter element is 36 months. Figure 58 demonstrates that individual filter element efficiency does not have a significant effect on overall filter efficiency. For design purposes, the nominal life of the filter is the most important parameter. Although these results are based on a statistical analysis, the final design may have to be influenced by a similar analysis, since long-term test data for the filter element are not available. In the meantime, we have assumed that the unit can operate for 1 year without replacement of filter elements. The purpose of this analysis is to show that a cross-flow filter will be a reliable system in a power plant if reasonable element life is achieved and if element failures are not catastrophic.

Hot Gas Piping.

Pipe Sizing Criteria. Pipe sizes to and from the carbonizer cross-flow filter were selected based on the following velocities:

- Dirty gas from carbonizer: 50 ft/s
- Partially cleaned gas from cyclone to cross-flow filter: 100 ft/s
- Clean gas from cross-flow filter to gas turbine: 150 ft/s

All fuel gas interconnecting pipe is lined with a minimum of 6 in. of two-component castable refractory, and final pipe diameters are standard pipe sizes. The clean gas line to the turbine is lined with stainless steel to protect the turbine. This pipe has 5 in. of single-component castable refractory and 1 in. of KAOWOOL between the liner and the refractory. The calculated pipe diameters, based on the stipulated velocities, are given in Table 25.

Pipe diameters for piping from the CPFBC cross-flow filter, shown in Table 25, were calculated using the same criteria used for the carbonizer pipe.

Piping Stress Analyses. Stress analyses were conducted for the carbonizer-to-gas turbine, CPFBC-to-gas turbine, and gas turbine-to-various compressed-air user piping systems shown for the baseline plant. All pressure and thermal expansion stresses are within ANSI/ASME B31.1 Code allowables. They show that expensive and troublesome corrugated expansion joints are not required if pipe supports and restraints are properly positioned.

Stack Design. Calculations were performed to provide a single stack for both HRSGs. The stack design is based on the following parameters:

- Stack height more than 2.5 times the tallest plant structure, resulting in a 300-ft stack

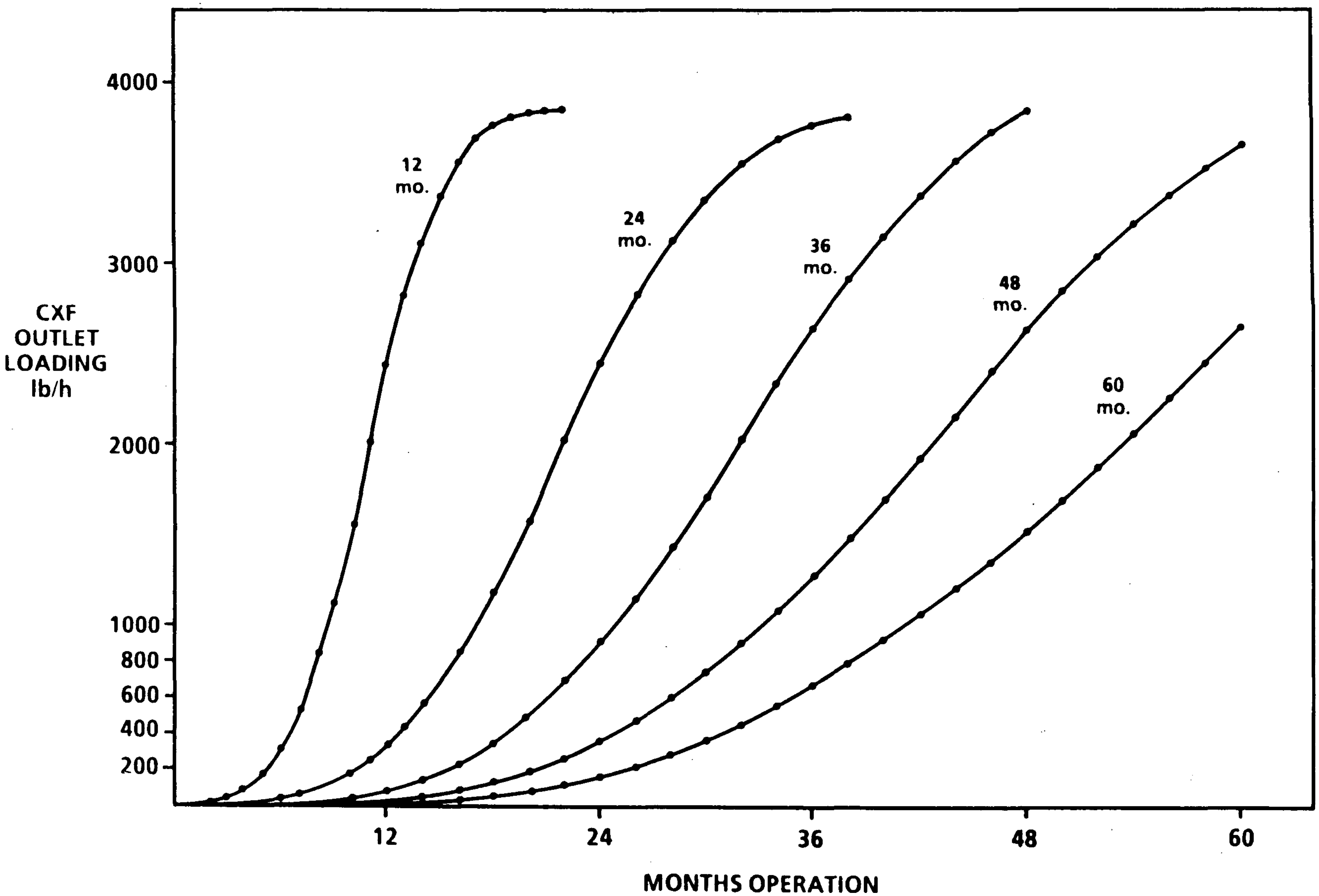


Figure 56 Cross-Flow Filter Outlet Loading vs. Months of Operation for Various Characteristics of Filter Element

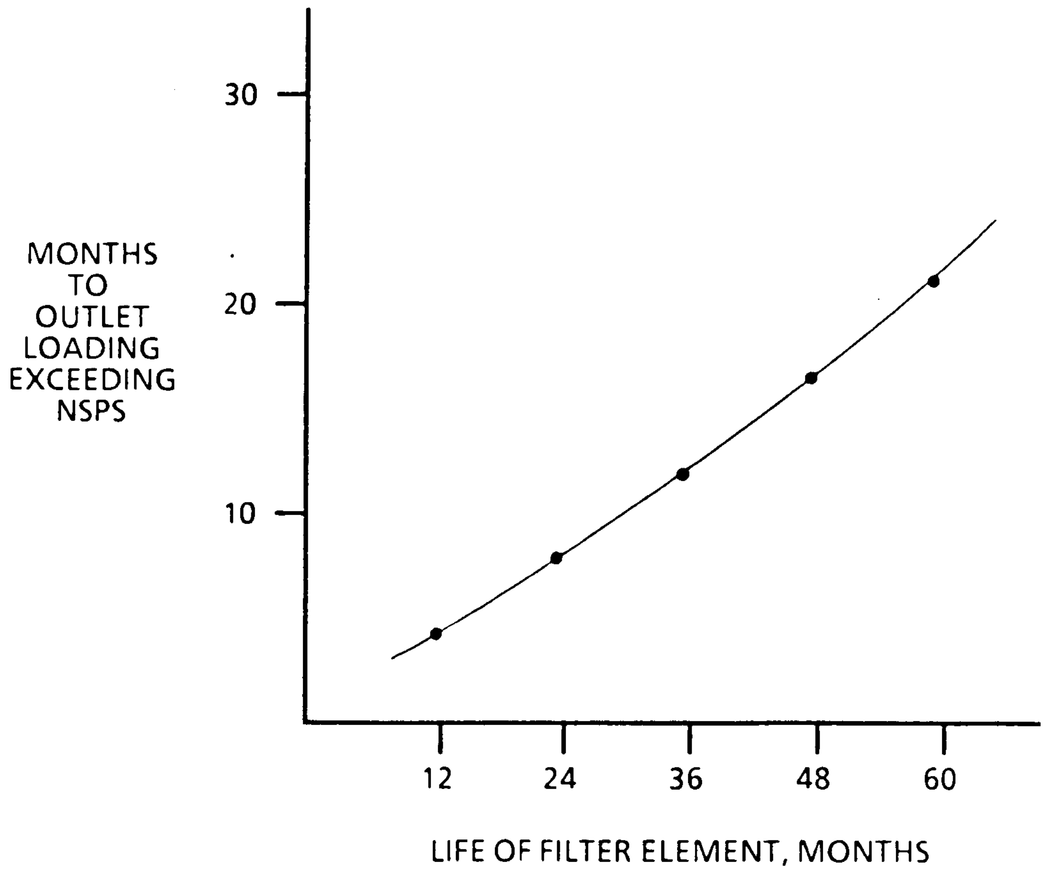


Figure 57 Effect of Element Life on Filer Performance

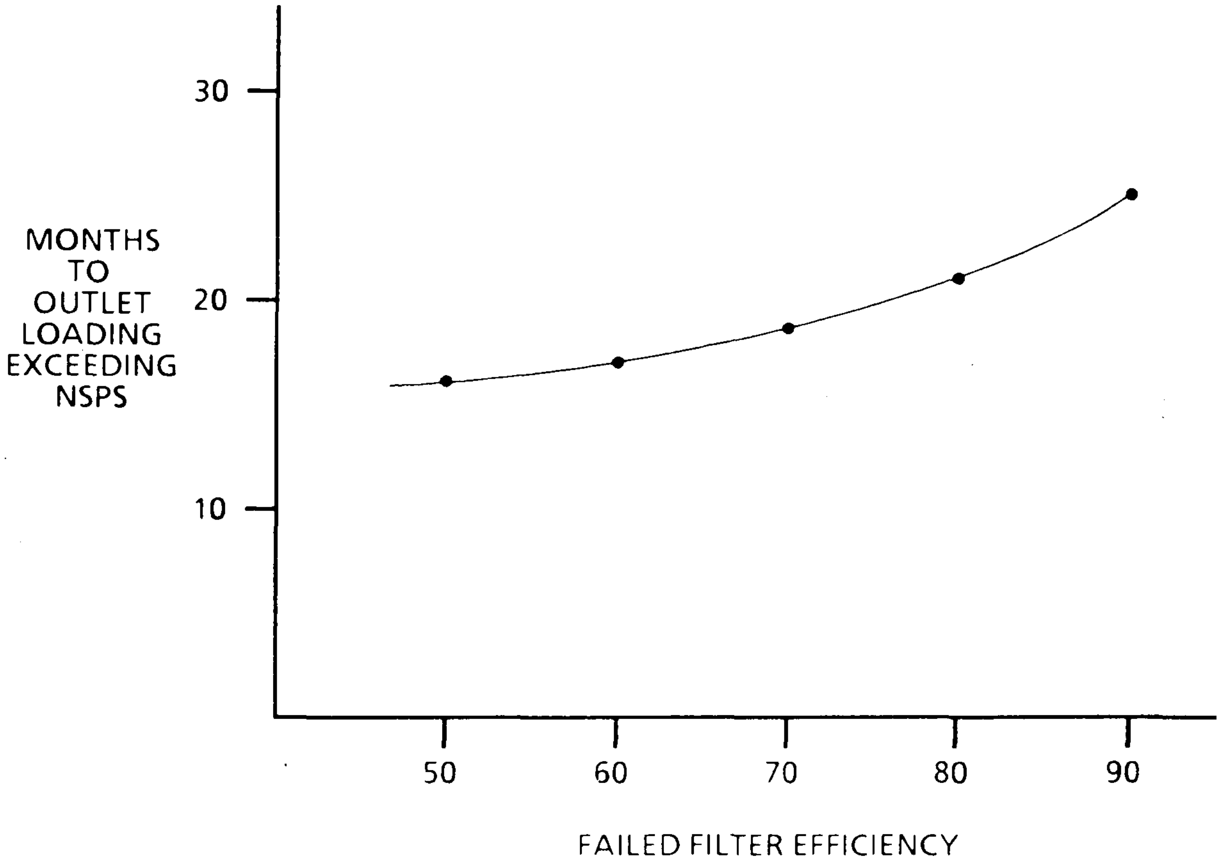


Figure 58 Effect of "Failed" Filter Efficiency on Performance (5-Year Filter)

Table 25 Calculated Pipe Diameters

To and From Carbonizer Cross-Flow Filter	Pipe I.D. (ft)	Pipe O.D. (in.)
Carbonizer to cyclone, 50 ft/s	2.7 (30 in. nominal)	42
Cyclone to cross-flow filter, 100 ft/s	2.0 (24 in. nom.)	36
Cross-flow filter to gas turbine, 150 ft/s	1.6 (lined, 18 in. nom.)	30

To and From CPFBC Cross-Flow Filter	Pipe I.D. (ft)	Pipe O.D. (in.)
CPFBC to cyclones, 50 ft/s	6.12 (6 nom.)	7
Cyclone outlet, 100 ft/s	3.06 (3 nom.)	4
Cyclone to cross-flow filter, 100 ft/s	4.33 (4 nom.)	5
Cross-flow filter to gas turbine, 150 ft/s	3.53 (lined, 3.5 nom.)	4.5

- Stack gas velocity at the top limited to 100 ft/s
- Draft loss in the stack limited to 2 in. H_2O
- Gas flow approximately 2.2×10^6 aft^3/min at 280°F.

On this basis, the stack diameter at the top was calculated to be 22 ft. It tapers to a 35-ft. diameter (exterior) at the bottom using a 0.02-deg slope. The stack is constructed of reinforced concrete with a steel liner. Openings in the shell are provided for access doors, flues, and windows. The stack is complete with internal ladders, platforms, lightning protection, internal lighting and power, and aviation obstruction lighting.

2.5.8 Fuel Gas Bypass and Flare System

A flare stack is required to provide a safe discharge point for combustible gases during start-up, shutdown, and upset conditions. Each carbonizer outlet pipe has a connection to a flare discharge header. The connection will have a slide gate valve to allow gas flow to go to the flare stack in a remote section of the site. These connections were shown in Figure 53.

The flare stack has been sized by the National Air Oil Burner Company (NAO). It consists of a 55-ft self-supporting stack with a 70-in. diameter. The stack is lined for high-temperature service. It includes a 70-in. NAO flare tip, a manual flame-front generator, four flare pilots, and pilot flame monitoring instrumentation. The stack is in an open area, between the river and the main plant, with a clear radial area of 150 ft surrounding it. A single pipe from the carbonizer area to the stack serves both carbonizers. The pipe is not lined with refractory; it is constructed of high-temperature stainless steel. A smaller, secondary line evacuates fuel gas between the emergency shut-off valve and the gas turbine topping combustor. Any other streams of combustible gases that require discharge are also discharged to the flare.

2.5.9 Steam Turbine/Generator, Condenser, and Auxiliaries

Steam Turbine. During the initial efforts aimed at optimizing the combined-cycle plant performance and COE (Appendix B), the configuration and physical dimensions of the steam turbine/generator unit were not determined. The steam conditions (2400 psig/1000°F/1000°F/2.5-in. Hg absolute) were set, but little was known or assumed beyond that. We suspected that fewer extractions for feedwater heating would be required since abundant low-grade heat was available in the heat-recovery unit. We also thought that a standard offering with the appropriate extraction openings could not be applied since the relative flow quantities through the HP/IP and the low pressure (LP) sections would be different because only one or two extraction openings would be used rather than the usual five to seven.

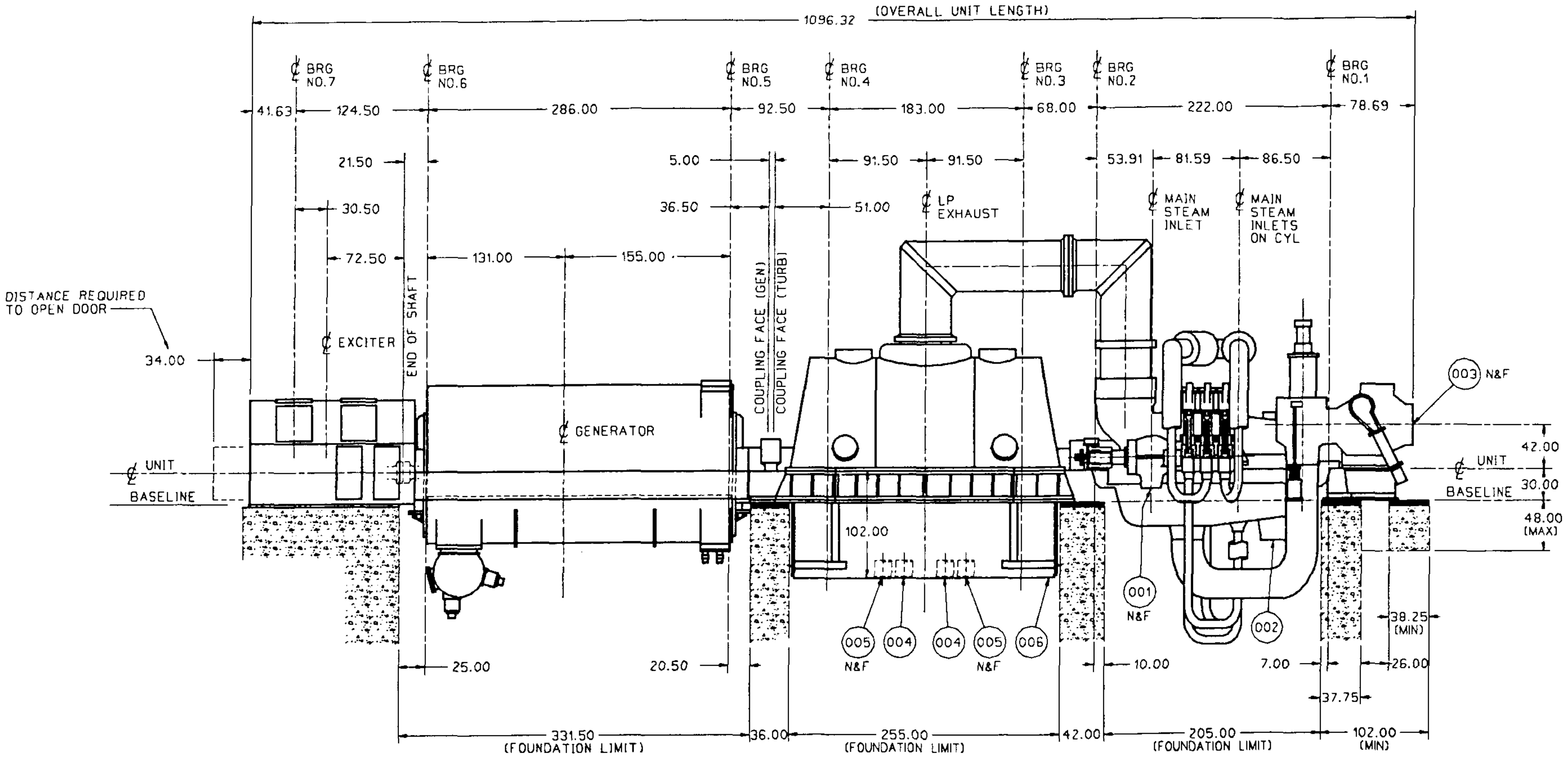
As the optimization analysis progressed, we found that relatively few changes to existing designs would be required. Since these types of units are made of standard building blocks, the mating of an existing HP/IP section with an existing LP section produced the desired configuration. Figures 59 and 60 display the outline of the turbine/generator unit. The connections list on Figure 60 identifies two LP turbine extractions (shown in Figure 59). The choice of two LP extraction points is explained in Appendix B.4, along with other information regarding performance, design options, and turbine cycling operation. The figures also show weights, foundation loadings, operating conditions, and pertinent electricity generating data. The electric generator is a standard frame that can be used in this application without major modification.

2.5.10 Steam and Feedwater

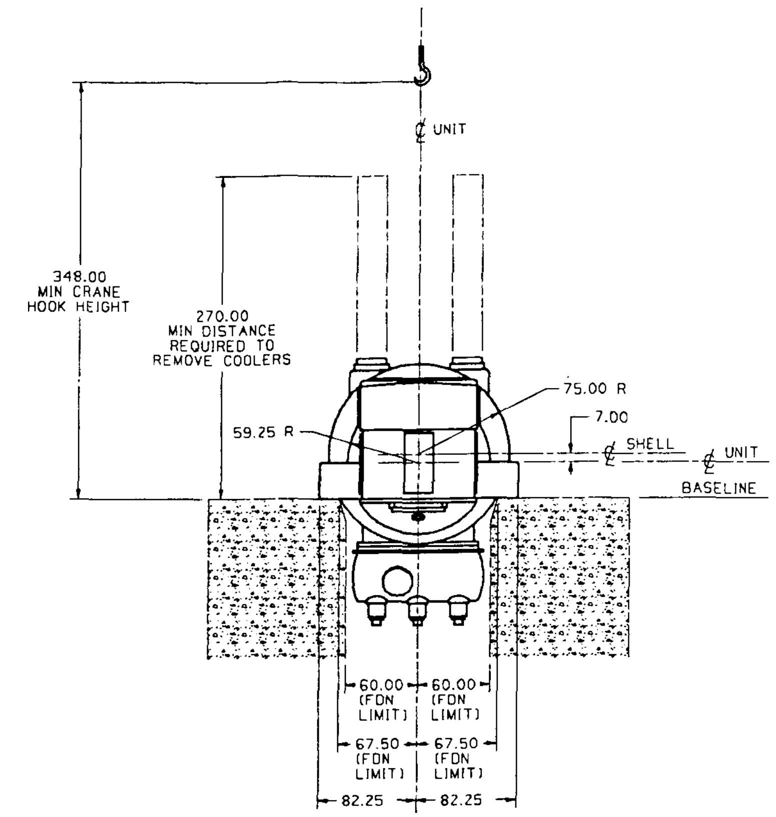
The steam and feedwater system (Figure 61) uses conventional steam-based power generating equipment, and the steam system produces approximately 60 percent of the electrical output of the plant. Included in this section are descriptions of the system function, design criteria, and major equipment.

System Functions. The steam and feedwater system furnishes condensate-quality feedwater to the HRSG and the FBHE. The water--cleaned, preheated, and pressurized to the level necessary for providing steam to the steam turbine/generator--is converted to steam in the HRSGs and FBHEs. It is then sent to the steam turbine/generator. After the usable energy is converted into mechanical energy in the turbine, the exhaust steam is condensed, ready for recirculation.

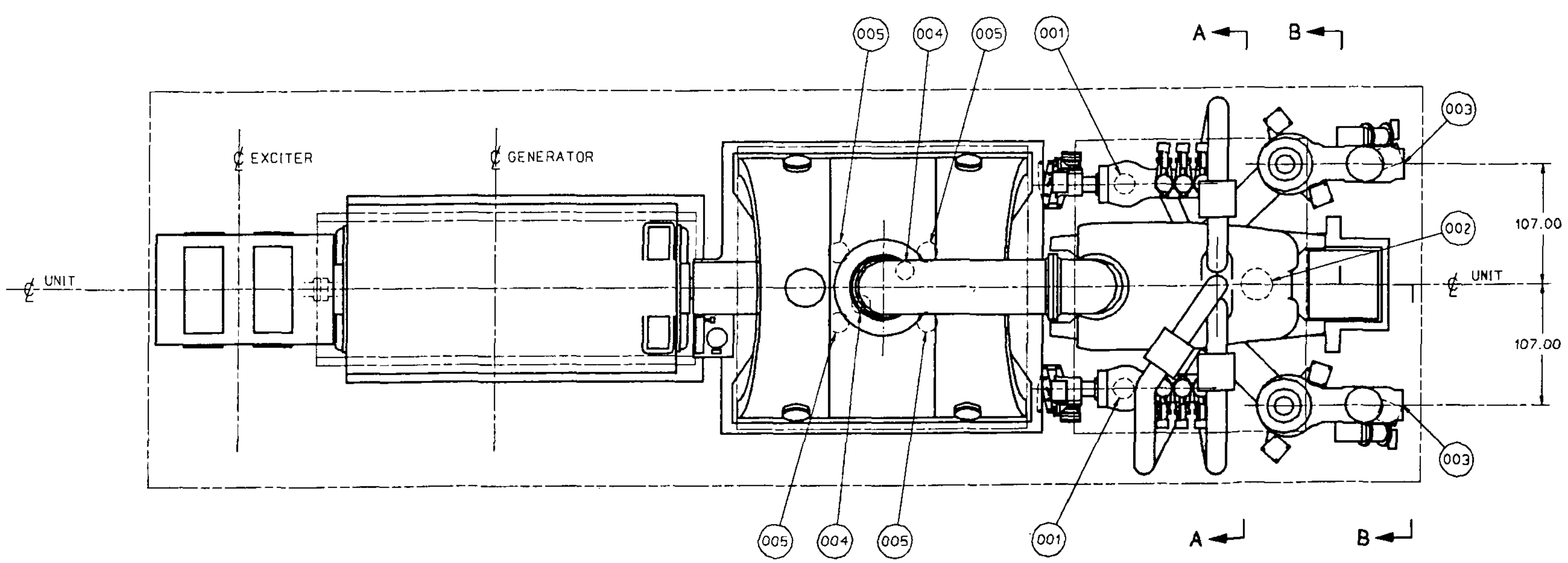
Design Criteria. Design criteria for this system were primarily shown on the plant heat balance (Figure 7), which defines the flows, pressures, and temperatures necessary to produce the electrical power output required of the plant. The nominal turbine steam inlet pressure is 2400 psig, with turbine main and reheat steam temperatures of 1000°F. The condenser pressure is 2.5-in. Hg absolute. Although the steam pressure is normal for a baseload electric utility plant, it is unusually high for a combined-cycle-type system. (Usual ratings would be either 1450 or 1800 psig.) As a result, 2400 psig combined-cycle-type HRSGs are not currently marketed in the United States, but the technology needed to support their



LONGITUDINAL ELEVATION
(FOUNDATION SECTION AT UNIT AXIAL CENTERLINE)

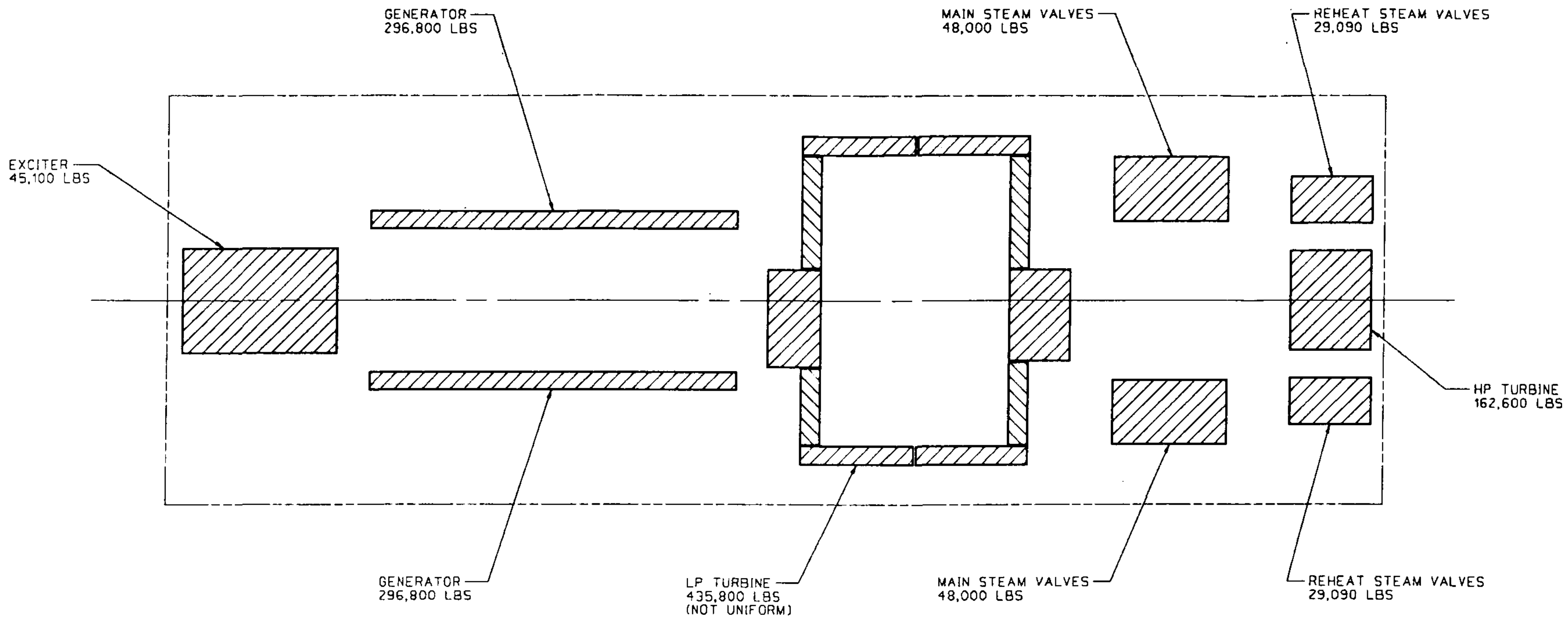


GENERATOR END VIEW

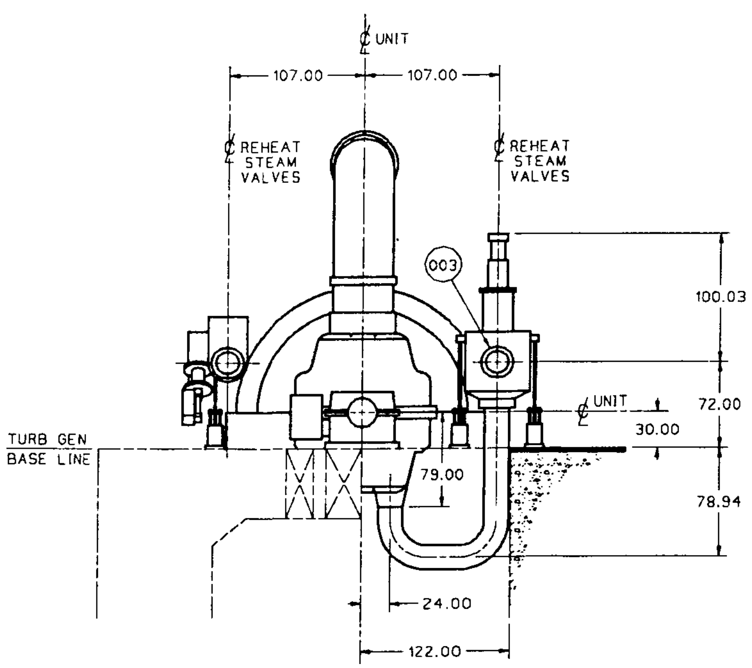


PLAN VIEW

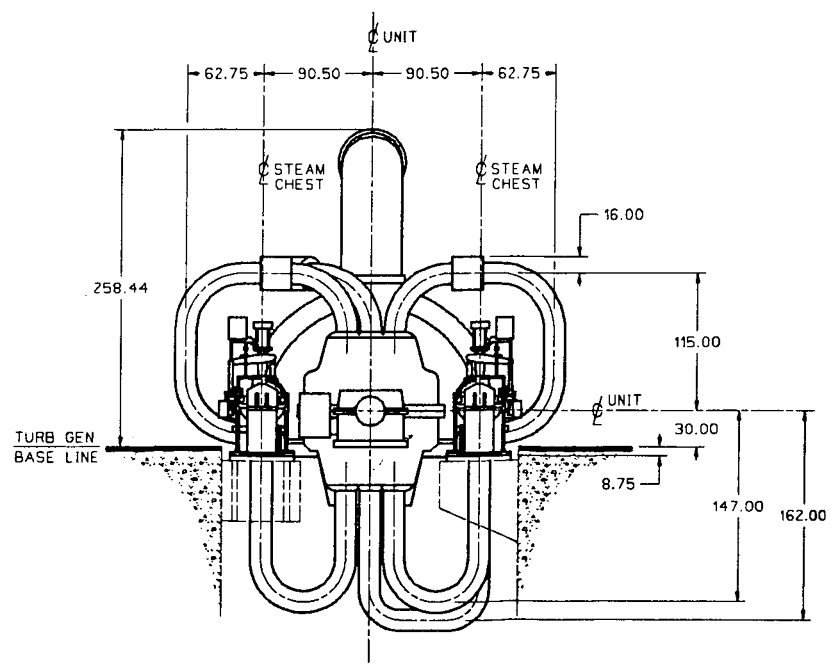
Figure 59 Turbine/Generator Outline--Plan View, Generator End View, and Longitudinal Elevation



LOAD DISTRIBUTION DIAGRAM



SECTION B-B



SECTION A-A

CONNECTIONS LIST			
ITEM	REQ	SIZE	DESCRIPTION
001	2	14.00 - SCH. SPEC.	MAIN STEAM INLETS TO HP TURBINE
002	1	28.00 - SCH. SPEC.	HP TURBINE EXHAUST TO REHEATER (COLD REHEAT)
003	2	24.00 - SCH. SPEC.	IP TURBINE STEAM INLETS (HOT REHEAT)
004	2	16.00 - SCH. STD.	LP TURBINE EXTRACTIONS
005	4	18.00 - SCH. STD.	LP TURBINE EXTRACTIONS
006	1	240.00 X 216.00	LP TURBINE EXHAUST

NOTES

1. LOADS ON FOUNDATION SHOW APPROXIMATE STATIC LOADS. THE FOLLOWING DYNAMIC LOADS MUST BE CONSIDERED ON FOUNDATION DESIGN.

   VERTICAL DIRECTION ______ STATIC LOAD X 0.35
   AXIAL DIRECTION ______ STATIC LOAD X 0.10
   LATERAL DIRECTION ______ STATIC LOAD X 0.25

SPECIFICATIONS

TURBINE

RATING (AT GENERATOR TERMINAL) ______ 266 MW
SPEED ______ 3,600 RPM
MAIN STEAM INLET TEMPERATURE ______ 1,000 °F (538°C)
MAIN STEAM INLET PRESSURE ______ 2,400 PSIG (163 BAR $_g$)
HOT REHEAT STEAM INLET TEMPERATURE ______ 1,000 °F (538°C)
EXHAUST PRESSURE (VACUUM) ______ 2.5 INCHES, H_gA

GENERATOR

RATING ______ 310 MVA
POWER FACTOR ______ .90
SPEED ______ 3,600 RPM
VOLTAGE ______ 22,000 VOLTS

GENERATOR

	POUNDS
TOTAL GENERATOR, WITH EXCITER	638,700
GENERATOR ASSEMBLED	593,600
HEAVIEST PIECE (WOUND STATOR)	435,000
GENERATOR ROTOR	74,300
EXCITER ASSEMBLED	45,100

REQUIRED DISTANCE FROM GENERATOR CENTERLINE FOR FOLLOWING OPERATIONS:

	INCHES
TO REMOVE ROTOR STRAIGHT OUT	479
TO REMOVE ROTOR BY SKEWING	410 X 175

Figure 60 Turbine/Generator Outline--Load-Distribution Diagram and Sections A-A and B-B (Figure 59)

Dwg. 8333-1-400-022-005, Rev. C

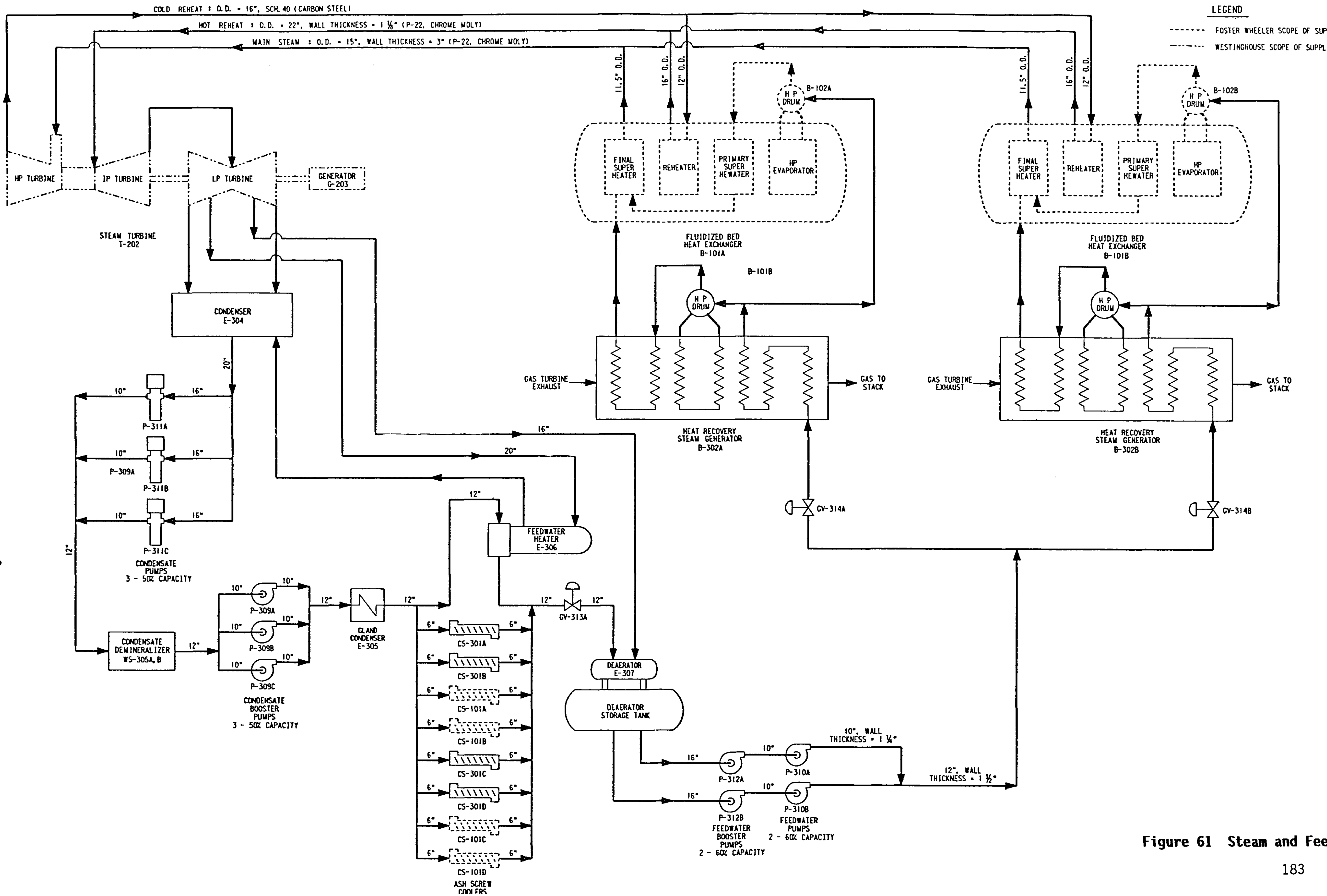


Figure 61 Steam and Feedwater Systems

design and manufacture is available. In the absence of vendor cost-curve data, the baseline plant 2400 psig HRSG costs were based on an extrapolation of lower-pressure designs (1200 to 1800 psig) and costs.

Feedwater heating is accomplished in three stages. Two extraction points on the low-pressure turbine provide steam for heating at 8.8 psia in a closed heater and 26.3 psia in a direct-contact deaerating heater. A portion of the feedwater bypasses the closed heater and is routed through the ash coolers to extract the heat contained in the ash and recover it for use in the power cycle.

Major Equipment. This section lists and describes the major equipment contained in the steam and feedwater system. Some equipment shown on the system diagram (Figure 61) is not listed since, by definition, it is part of a different system. The unlisted equipment and the location of descriptions are:

Equipment	Section
Steam turbine/generator	2.5.9
Ash screw coolers	2.5.15
FBHE	2.5.5

- Steam Condenser (E-304A). The steam condenser condenses steam exhausted from the main steam turbine/generator and deaerates the condensate.

Steam flow, lb/h	1,381,589
Duty, 10^6 Btu/h	1327.4
Back pressure, in. Hg absolute	2.5
Circulating water temperature inlet, °F	84
Effective tube length, ft-in.	44 - 3
Number of tubes	13,054
Tube material	90:10 CuNi
Velocity, ft/s	7.0
Circulating Water, gal/min	182,030
Surface, ft^2	151,220

- Condensate Pumps (P-311A, B, and C). The condensate pumps take water from the steam condenser and raise the water pressure to the level necessary to provide suction pressure for the condensate booster pumps. Three 50-percent pumps are provided.

Type pump	Vertical Canned
NPSH	0 at pump suction
Total Hydraulic Head, ft	250
Stages	6
Bowl size, in.	12
Speed, rev/min	1770
BHP	125

- Condensate Demineralizer (WS-305A and B). Particulates and contaminants are continuously removed from the condensate by the condensate demineralizers. Two 100-percent capacity units are provided.

Diameter, ft	8.5
Unit capacity, gal/min·ft^3	50

Capacity, gal/min	2835
Regeneration	External
Design pressure, psig	150

- Condensate Booster Pumps (P-309A, B, and C). The condensate booster pumps take suction from the water provided at pressure by the condensate pumps; they have adequate head to deliver the condensate to the deaerator. Three 50-percent pumps are provided.

Type pump	Horizontal Split Case
Stages	1
NPSH required, ft	10
Total Hydraulic Head, ft	450
Capacity, gal/min	1650
Speed, rev/min	1750
BHP	264

- Feedwater Heater (E-307A). The temperature of the feedwater is raised in a closed feedwater heater for one stage of regenerative feedwater heating.

Steam side:	
Pressure, psia	8.8
Enthalpy, Btu/lb	1140.1
Flow, lb/h	83,350
Water side:	
Pressure, psia	200
Inlet Temperature, °F	110
Flow, lb/h	1,219,715

- Deaerator (E-308A). The last stage of feedwater heating before the steam generators is an open, direct-contact heater with a deaerating function. One full-size deaerator is provided.

Steam flow, lb/h	82,232
Steam pressure, psia	25.0
Steam enthalpy, Btu/lb	1217.8
Water flow, lb/h	1,456,390
Inlet water temperatures, °F	180 and 200
Outlet water temperature, °F	240

- Feedwater Booster Pumps (P-312A and B). Feedwater pressurizing is broken into two physical stages. The feedwater booster pumps provide the first stage. Two 60-percent pumps are provided.

Capacity, gal/min	2100
Total Hydraulic Head, ft	3625
NPSH required, ft	20
Pump type	Horizontal split case
Number of stages	7
BHP	2213
Speed, rev/min	3550

- <u>Feedwater Pumps (P-310A and B)</u>. The second stage of feedwater pressurizing is performed by the feedwater pumps. Since there are no high-pressure feedwater heaters, the pressurizing requirement was split in half. As a result, the feedwater pumps are identical to the feedwater booster pumps, except for the pressure. Two 60-percent pumps are provided.

- <u>Heat-Recovery Steam Generators (B-302A and B)</u>. Heat is recovered from the exhaust of the combustion turbine. Feedwater is heated, boiled, and superheated with the recovered heat. The HRSGs work in conjunction with the FBHEs to provide the total steam flow for the power cycle. Two HRSGs are provided, one associated with each combustion turbine.

Gas Side:	
Flow, lb/h	3,439,634
Temperature In, °F	988.0
Temperature Out, °F	280
Water/Steam Side:	
Flow In, lb/h	769,312
Pressure In, psia	3018
Temperature In, °F	245.3
Stream 1 (Out):	
Flow, lb/h	407,608
Pressure, psia	2900
Temperature, °F	668.2
Stream 2 (Out):	
Flow, lb/h	361,704
Pressure, psia	2676
Temperature, °F	900

2.5.11 Cooling Water System

System Function. The cooling water system (Figure 62) is designed to supply cooling water to the condenser of the steam turbine/generator. The water is pumped from a cooling tower flume by three 50-percent capacity, vertical, circulating water pumps, which discharge into a common circulating water pipe. The water flows through the condenser to the cooling tower and back to the flume for reuse.

Design Criteria. The circulating water flume is designed for a velocity of 1 ft/s and uniform distribution to each pump. The flume and cooling tower basin are constructed of reinforced concrete. The flow velocity in the pump discharge piping is limited to 12 ft/s.

The makeup to the cooling tower is river water, which is drawn into the system by vertical wet-pit-type pumps through trash racks and traveling water screens.

The circulating water system is also designed to supply cooling water to two station-service heat exchangers that provide the cooled condensate through the closed-cycle system to all major equipment heat exchangers in the main turbine generator and boiler areas.

Dwg. 8333-1-400-022-003 Rev. D

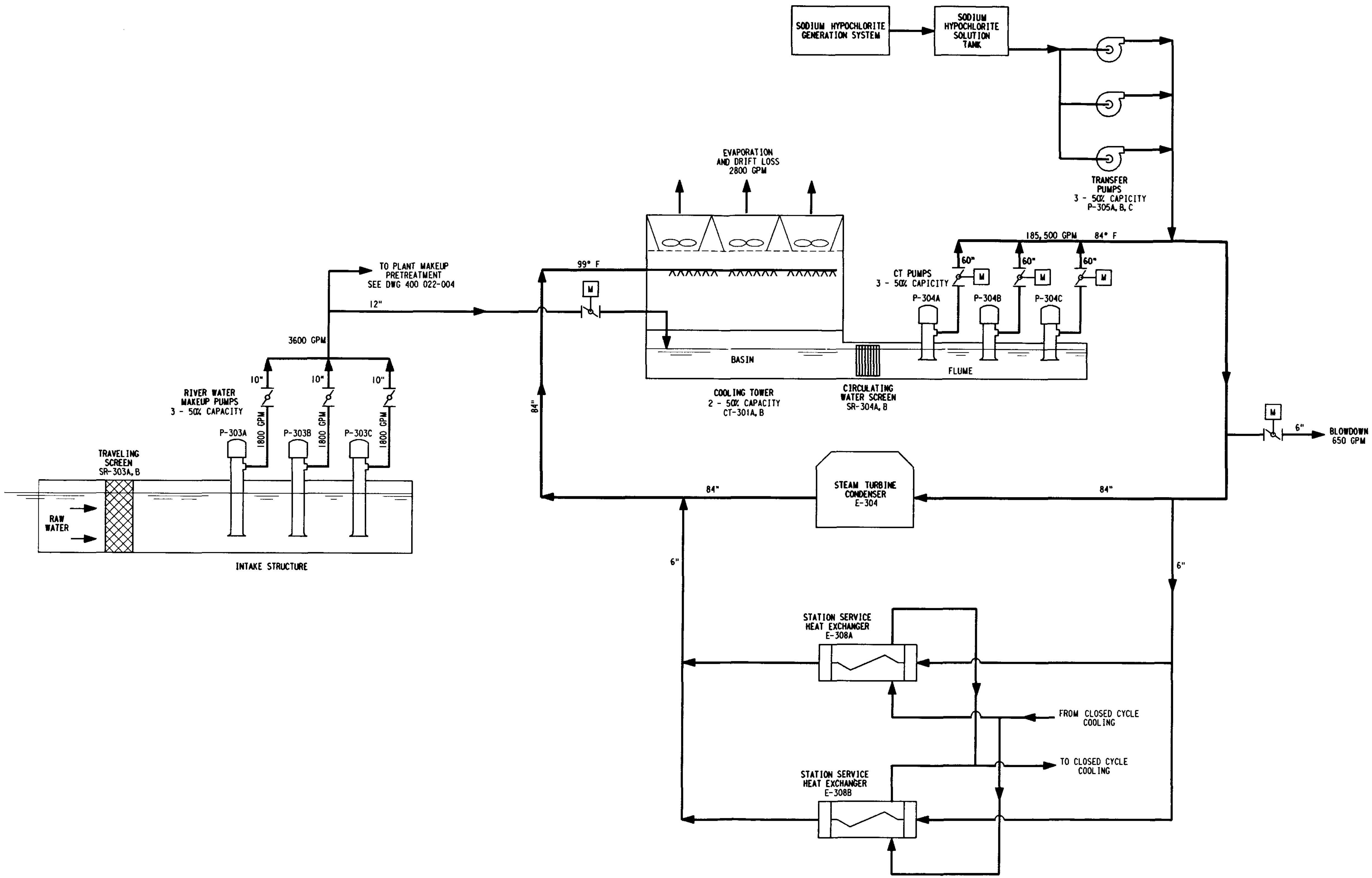


Figure 62 Cooling Water System

Major Equipment. Major equipment in the cooling water system consists of:

- **Cooling Tower**. Two mechanical, induced-draft cooling towers provide the means to cool 179,200 gal/min water at 99°F inlet temperature and 84°F outlet temperature with an atmospheric wet bulb temperature of 75°F. Each tower includes six independent cells with an induced-draft fan.

  The warm water leaving the condenser passes through the cooling tower to transfer heat to the atmosphere by evaporation into the airflow induced by the fans. Drift eliminators remove entrained water droplets.

  The cooling tower basin is designed to resist the maximum uplift of soil and water when completely empty. Makeup water (to replace evaporated water, blowdown, and drift) enters the cooling tower basin through a motor-operated, automatic, level-control valve.

  Cooling tower effluent water flows through a flume to the circulating water pumps. This flume includes a local-level indicator and a level transmitter to notify the control room of the level and to transmit a high- or low-level alarm.

- **Circulating Water Screens (SR-304A and B)**. A double set of 1/2-in. mesh, removable screens, which remove large objects such as leaves, sticks, logs, and ice, protects the circulating water pumps and condenser tubes from plugging. These screens, installed upstream of the pump suction, are galvanized iron. They slide into structural steel channels and can be pulled out one at a time for cleaning. Although they are designed to withstand a differential pressure of 3.5 ft of water, normal operation is with less than 6 in. of water.

- **Circulating Water Pumps (P-304A, B, and C)**. Three identical, circulating water pumps are provided, each 50-percent of the design capacity. The pumps are vertical, with above-surface discharge and pull-out construction. One pump can be used for start-up; two are required for design load.

  Each pump has a motor-operated discharge butterfly valve. The pump discharge valve is interlocked with the pump motor starting circuit so that the valve is first opened approximately 15 deg. The motor starts automatically when the valve reaches that position. After the pump is up to speed, the system is full, and stable flow is established, the valve is opened to 90 deg. On shutdown, the valve closes to 15 deg and then trips to the closed position after the motor has stopped. To avoid hydraulic surges, the valve closes automatically upon loss of power.

- **Station-Service Heat Exchangers (E-308A and B)**. Two 50-percent capacity station-service heat exchangers are required for full load, although only one heat exchanger is required during winter. The circulating water passes through the shell side of the heat exchanger, and the filtered makeup water passes through the tubes.

- **Traveling Water Screens (SR-303A and B)**. Two vertical, traveling, water screens clean the plant makeup water obtained from the river. Each screen is furnished with galvanized steel baskets. The main frame of the screen is two-post construction. Overlapping side-guard seals are designed to prevent the passage of debris around the outside of the screen frame. The screen is motor-driven through an enclosed, gear-type speed reducer. The slow-speed shaft of the reducer turns the screen head shaft through a chain drive.

- **River Water Makeup Pumps (P303A, B, and C)**. One 100-percent capacity, vertical, wet-pit-type makeup water pump runs continuously at all loads and during shutdown when cooling water is required. A second 100-percent capacity pump is provided for standby.

2.5.12 Cycle Makeup Pretreatment System

The primary function of the cycle makeup pretreatment system shown in Figure 63 is production of filtered water for domestic uses, the cycle makeup demineralizer, and plant service water systems. Storage, a part of this system, accommodates variations in the rate of production and use of water. The system is designed to produce 120 gal/min partially softened, filtered water from raw water taken from the river.

The filters, coagulator, and filtered water distribution pumps are in the water treatment building. The system consists of these major components:

- **Coagulator (TK-303)**. The coagulator is a constant-rate water treatment and clarification unit of the sludge-recirculation type. It is a circular steel shell containing a center cone and draft tube, a sludge recirculator, a settling zone, and a sludge scraper.
- **Dry Chemical Feeders (BN-305 and 306)**. There are two dry chemical feeders--one for coagulation and one for pH adjustment. The dry chemical feeder feed rate is manually adjustable and constant when raw water is flowing to the coagulator.
- **Hypochlorite Solution Feeder (TK-302)**. The unit consists of a PVC-lined steel hypochlorite reservoir tank equipped with a motor-driven agitator and two 100-percent capacity, positive-displacement, diaphragm-type pumps. The hypochlorite solution feed rate is manually adjusted to be proportional to the raw water flowing to the coagulator.
- **Gravity Filters (F-302A, B, and C)**. Three steel, single-compartment, gravity filters, coated with coal-tar epoxy, are rated at 2 gal/min·ft_2. One unit is a spare. Each minimum-valve-type filter in the filter compartment is sealed on the influent side; each contains 30 in. of sand. The underdrain for each compartment consists of stainless steel strainers in a carbon steel flat-bottom plate. The inlet and backwash outlet piping is connected to the sealed filter influent compartment. The backwash water storage zone above the filter compartment is connected to the underdrain collection chamber by a riser pipe.
- **Filtered-Water Transfer Pumps (P-306A, B, and C)**. The filtered water transfer pumps are electric-motor-driven, vertical, turbine-type pumps that transfer water from the filtered water wetwell to the external storage tank. There are three 50-percent capacity pumps, including one spare. Normally, no more than two pumps operate simultaneously, and then only when high makeup is necessary.
- **Filtered-Water Storage Tank (TK-304)**. The filtered water storage tank is a field-erected, vertical, cylindrical, steel tank with a conical roof. The tank is on grade near the water treatment building. A caged ladder gives access to the tank roof. A vent at the center of the roof is designed to prevent entry of birds, insects, and air-borne debris.
- **Filtered-Water Distribution Pumps (P-307A, B, and C)**. The three filtered-water distribution pumps are electric-motor-driven, horizontal, centrifugal pumps, each 50-percent capacity, that distribute water from the storage tank to the various filtered water uses in the plant.

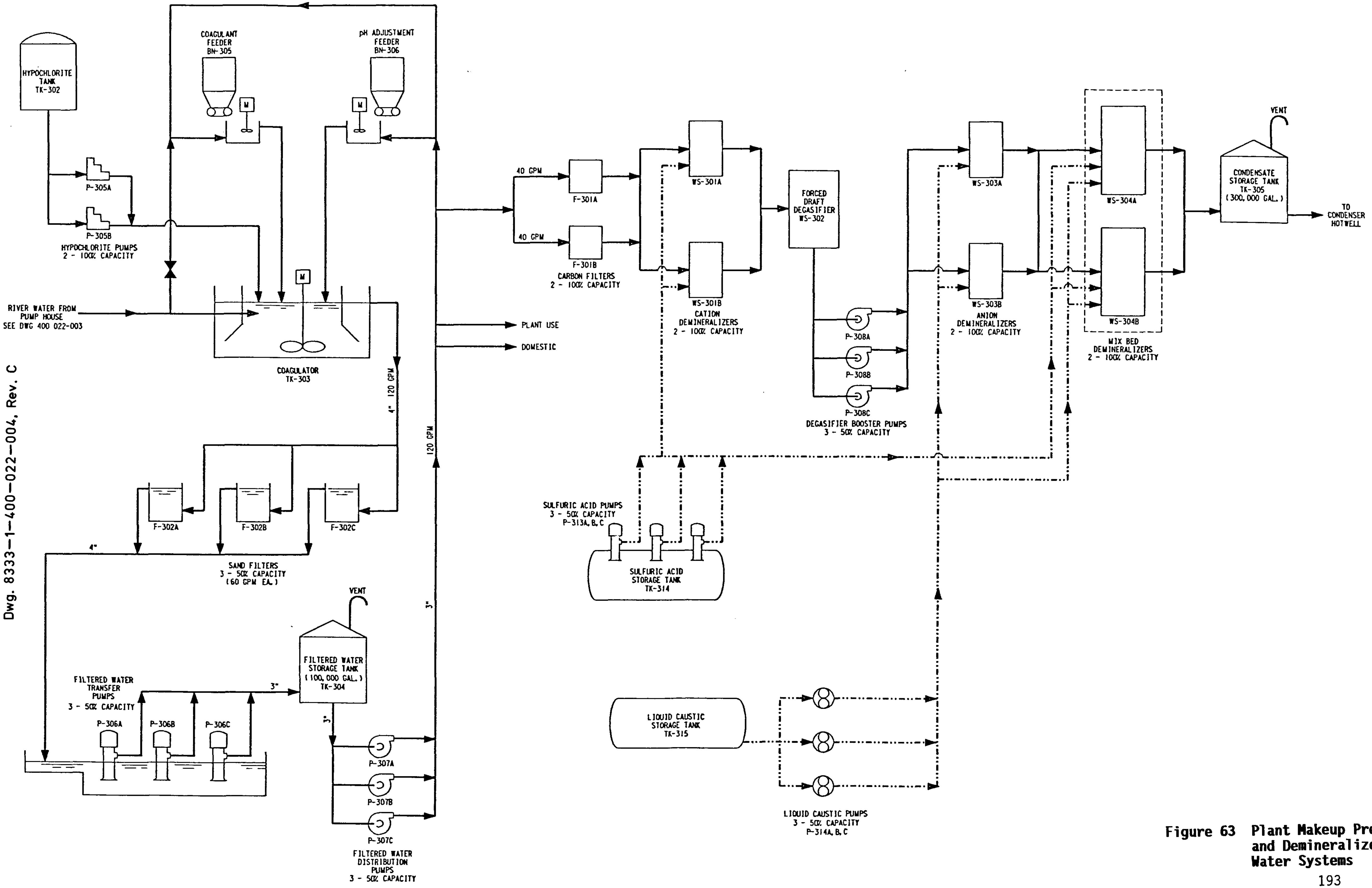


Figure 63 Plant Makeup Pretreatment and Demineralized Makeup Water Systems

2.5.13 Demineralized Makeup Water System

System Function. The demineralized water system shown in Figure 63 provides a makeup supply of acceptable-quality demineralized water to the feedwater system. The demineralizer system is supplied by filtered water from the filtered-water storage tank. The demineralized water system removes dissolved solids from the inlet water via ion exchange, utilizing strong acid cation and strong base anion units and a mixed-bed demineralizer. A forced-draft degasifier system removes carbon dioxide from the cation effluent to reduce the subsequent ion-exchange loading on the anion units.

System Description. The cycle makeup demineralizer system consists of two skid-mounted trains, each capable of delivering 40 gal/min. Each train consists of a carbon filter, a cation demineralizer, an anion demineralizer, and a mixed-bed demineralizer, in that order. A common forced-draft degasifier downstream of the cation demineralizer can meet the system requirements with both trains in operation. Three 50-percent capacity booster pumps downstream of the degasifier deliver water to the anion demineralizers. Normally, one train satisfies the system requirements and the second train is in a regenerated standby condition. During normal operation, the system is monitored, and unacceptable conditions are brought to the operator's attention by an alarm.

The cation and anion demineralizers of each train are designed for regeneration after 24 hours of operation, and the mixed-bed demineralizer is regenerated after 4 to 6 regenerations of the cation and anion demineralizers. Cation and anion demineralizer regeneration requirements are based on throughput, conductivity, or both; and the basis for regenerating the mixed bed is throughput, conductivity, silica content, or a combination. The effluent from the mixed-bed demineralizer is monitored continuously for conductivity and silica.

Regeneration of the demineralizers is automatic when manually initiated, and the regeneration system can be overridden for manual operation. Any faults in the regeneration process are brought to the operator's attention by an alarm, and the process reverts automatically to a safe shutdown condition until the operator can clear the faults.

Equipment Description.

- **Carbon Filter (F-301A and B)**. Each holds approximately 50 ft^3 of activated charcoal to remove the chlorine and organics from the effluent water of the pretreatment filters. The filter vessel is mounted on the skid with interconnecting piping, valves, controls, and instrumentation.
- **Cation Demineralizer (WS-301A and B)**. Each holds 28 ft^3 of cation resin, to a bed depth of 48 in. The demineralizer vessel is mounted on the skid with piping, valves, and instrumentation. Installed inside the demineralizer are Type 316 stainless steel influent, effluent, and regenerant distribution systems. The unit is complete with service backwash, regenerant, drain, resin filling, resin removal, and vent piping; valves; controls; and instruments.
- **Forced Degasifier (WS-302)**. The common forced-draft degasifier is mounted above an integral storage tank. The degasifier reduces the dissolved CO^2 and O_2 from the cation demineralizer effluent. The vessel is mounted with piping, valves, controls, and instrumentation.
- **Anion Demineralizer (WS-303A and B)**. Each anion demineralizer holds 22 ft^3 of anion resin, to a bed depth of 36 in. The demineralizer vessel is mounted on the skid with interconnecting piping, valves, controls, and instrumentation.

The unit is complete with service backwash, regenerant, drain, resin filling, resin removal, and vent piping; valves; controls; and instruments.

- **Mixed-Bed Demineralizer (WS-304A and B)**. Each unit holds 15 ft^3 of mixed resin, to a bed depth of 36 in. This unit provides the polishing function for removal of the very low concentrations of dissolved solids which have leaked through the two single-bed demineralizers. The vessel is mounted on the skid with interconnecting piping, valves, controls, and instrumentation. The unit is complete with service, backwash, acid and caustic regenerant, drain, resin filling, resin removal, and vent piping; valves; controls; and instruments.
- **Regenerant Chemical Pumps, Piping, and Valves (P-313A, B, and C; P-314A, B, and C)**. Pumps transfer regenerant chemicals from the respective storage tanks to the chemical dilution mixing tees. Sulfuric acid pumps (vertical, centrifugal, submerged-type) are top-mounted on the acid storage tank. Sodium hydroxide pumps (reciprocating, diaphragm-type) are mounted on a concrete pad. The adjustment of the pump stroke length is manual. A damper on the pump discharge line reduces pressure fluctuation. The caustic storage tank and caustic lines are heat-traced to prevent freezing. Piping, valves, controls, and instrumentation are included with the pumps.

2.5.14 Compressed Air System

Compressed air system requirements, depicted in Figure 64, are based on the baseline heat and mass balance (Figure 7).

System Functions. Compressed air is used primarily in the carbonizer and CPFBC to carbonize and burn the coal. These requirements and others are shown in Table 26. Except for "shop air" and "instrument air," the gas turbine compressor supplies the entire plant with compressed air at 203 psia.

The turbocompressor air pressure is adequate for the CPFBC, but it must be increased by a booster compressor to 218 psia for the carbonizer and to 268 psia to pressurize the coal and dolomite lock hoppers and pneumatically transport the coal and dolomite.

Design Criteria.

- The design criteria for the booster compressors are set by the process pressure needs listed in Table 26. Sizing is based on using a full-sized compressor for each module and a spare full-sized unit tied in to both module pipe systems with appropriate valving.
- The instrument air is typical: 40 psig with a -40°F pressure dewpoint. Shop air is also standard at 100 psig. Neither use is shown in the overall heat and mass balance.
- A small amount of service air is needed at the highest pressure (267.6 psia) for purging and miscellaneous uses.
- Transport and lock hopper pressurizing air pressure and flow rates are based on information from Petrocarb (described in Section 2.5.3).
- The ceramic cross-flow filter booster compressor size and pressure were determined using data from Westinghouse test reports of laboratory-scale units and projections of commercial-size plants.

Dwg. 8333-1-400-022-008, Rev. H

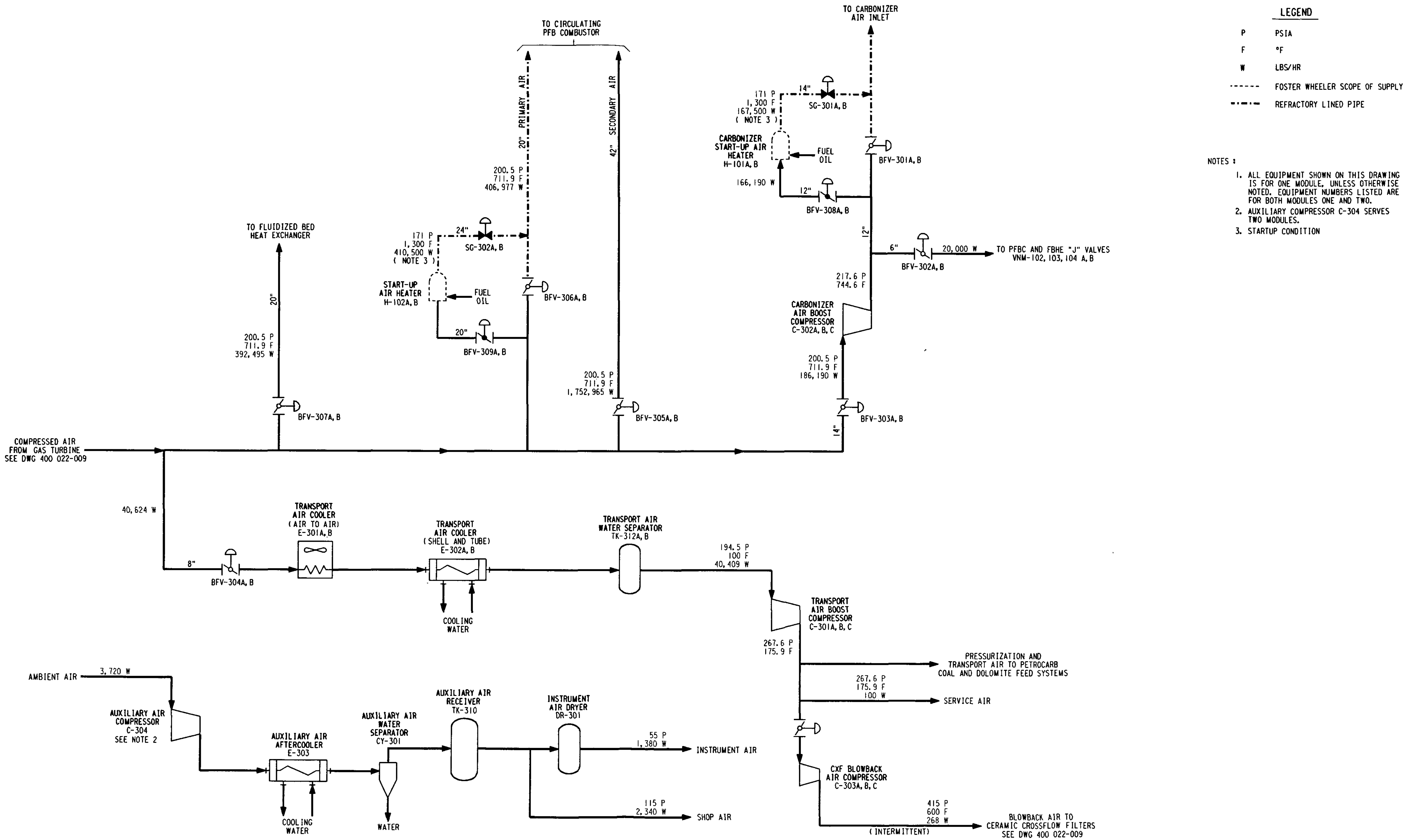


Figure 64 Compressed Air System

Table 26 Compressed Air Requirements

	Flow/Module, lb/h	Pressure, psia	Temperature, °F
FBHE Fluidizing Air	392,495	200.5	712
CPFBC Primary Air	406,977	200.5	712
CPFBC Secondary Air	1,752,965	200.5	712
Carbonizer	186,190	217.6	745
Coal and Dolomite Pressurizing and Transport Air	40,309	267.6	176
Ash J Valves	20,000	217.6	745
Service Air	100	267.6	176
Shop Air and Instrument Air	3,720	115	180

System Description.

- **Carbonizer Booster Compressor.** The carbonizer requires air at 217.6 psia to overcome line losses and gas turbine fuel pressure drops. The FBHE J valves also require air at 217.6 psia. A booster "blower" was chosen to do this because a compressor would need precooling. The design is a straight radial blade (10) unit operating at 3600 rev/min, with spindle bearings. The wheel diameter is 34.75 in. and nominal operating power is 614 BHP. Because of the combination of 217.6 psia outlet pressure and 712°F inlet temperature, this is a custom-designed blower.

- **Petrocarb Transport Air Booster Compressor.** Air for the Petrocarb system is first cooled in a two-stage air heater/shell-and-tube heat exchanger system and then dewatered in a separator before being boosted to 267.6 psia. In addition to its primary uses to pressurize the Petrocarb vessel and for transport air, this compressor supplies air for purging, for the inlet to the cross-flow filter blowback compressor, and for other miscellaneous uses. For this service, 291-BHP (nominal operating power), 718 ft^3/min reciprocating compressors were selected.

  Two transport air coolers are located upstream of the compressor--an air-cooled heat exchanger (9 ft wide x 16 ft long) and a water-cooled shell-and-tube exchanger (35-in. diam x 20 ft long). The temperature range is split between air-cooled and water-cooled exchangers to avoid depositing dissolved solids on the tubes because of the hot (712°F) inlet temperature (i.e., the tubewall temperature could reach a point where the cooling water would vaporize on contact).

- **Auxiliary Air Compressor**. The auxiliary air compressor supplies 100 psig air for instruments and for miscellaneous intermittent shop uses. Only one compressor is needed for two modules since there is a tie-in to the turbocompressor air line. The reciprocating air compressor chosen is rated for 627 ft^3/min at 125 BHP. Ambient air is used for the inlet.

  An aftercooler, a cyclone water separator, and a 100-ft^3 air receiver follow the compressor. The instrument air system has a typical fixed-cycle air dryer (alumina) and cartridge filters.

- **Ceramic Cross-Flow Filter Blowback Compressor**. The cross-flow filter blowback compressor receives 268 psia air from the Petrocarb air system and boosts the pressure to 415 psia. The compressor selected is a reciprocating type rated for 30 ft^3/min and 18 BHP. Each module has a full-sized compressor, and there is one full-sized spare tied in to both systems.

  Table 27 presents operating parameters for these four compressed air subsystems.

- **Control Valves**. Control valves for the compressors are high-performance, metal-seated butterfly valves, which are available up to 48 in. in diam and rated up to 500 psia at 1200°F. The higher-temperature valves (1300°F) following air preheaters are slide-gate, custom-built valves. These, however, are not control valves and will be either closed or wide open. Table 28 summarizes sizes and conditions for these valves.

2.5.15 Ash-Handling System

The ash-/spent sorbent-handling system required for the baseline plant is shown in Figure 65.

System Functions. The overall function of the ash handling system is to receive fly ash from the CPFBC ceramic cross-flow filter and bed ash from the FBHE; to depressurize, cool, and convey that ash to storage silos; to prepare the silo-stored ash for discharge; and to feed it to disposal trucks.

Design Criteria. As the plant mass balance diagram (Figure 7) shows, the total ash flow from the plant is 91,144 lb/h for coal and dolomite feed rates of 274,200 and 82,315 lb/h respectively at 100-percent baseline plant load. The total ash flow comprises 70,011 lb/h bed ash from the FBHEs and 21,133 lb/h fly ash from the cross-flow filters.

Restricted-pipe discharge hoppers and screw coolers depressurize and cool each of the four bed ash and four fly ash streams to ambient pressure and 300°F. The balance of the system shown constitutes the ash-handling system described in the next subsection.

System Description.

- **Restricted-Pipe Discharge Hoppers and Screw Coolers**. Figure 66 shows the restricted-pipe discharge and water-cooled, variable-speed screw cooler arrangement for each FBHE bed drain line; four are required for the plant. Bed material drains from the FBHE as a packed bed via a 22 ft-5 in. long, 5-in.-I.D., refractory-lined pipe that extends into the restricted-pipe discharge hopper vessel.

  The hopper operates at essentially atmospheric pressure; the FBHE 14-atm pressure dissipates across the drain line packed bed (HP air must flow through the interstices of the packed bed). A slide valve at the outlet of the hopper controls

Table 27 Compressor Operating Parameters

Operating Parameter	Petrocarb Transport C-301 A,B,C	Carbonizer Gasification C-302 A,B,C	Auxiliary Air C-304A	Cross-Flow Filter Blowback C-303 A,B,C
Inlet Pressure, psia	195	200	Ambient	268
Inlet Temperature, °F	100	712	Ambient	176
Outlet Pressure, psia	268	218	115	415
Outlet Temperature, °F	176	745	180	600
Flow, lb/h per module	40,409	186,190	3720	268

Table 28 Large Compressed-Air Process Valves

Control Valve Service	Valve No.	Valve Size, in.	Design aft^3/min	Pressure, psia	Temperature, °F
Carbonizer	BFV-301	12	5,675	217.6	745
FBHE J-Valve	BFV-302	6	683	217.6	745
Carbonizer Booster Compressor	BFV-303	14	6,712	200	712
Petrocarb Booster Compressor	BFV-304	8	1,439	203	712
CPFBC Secondary Air	BFV-305	42	62,410	200	712
CPFBC Primary Air	BFV-306	20	14,683	200	712
FBHE Fluidizing Air	BFV-307	20	14,148	200	712
Carbonizer Preheater Inlet	BFV-308	12	5,675	217.6	745
Carbonizer Preheater Outlet	SG-301	14	10,631	171	1300
CPFBC Preheater Inlet	BFV-309	20	14,810	200.5	713
CPFBC Preheater Outlet	SG-302	24	26,054	171	1300

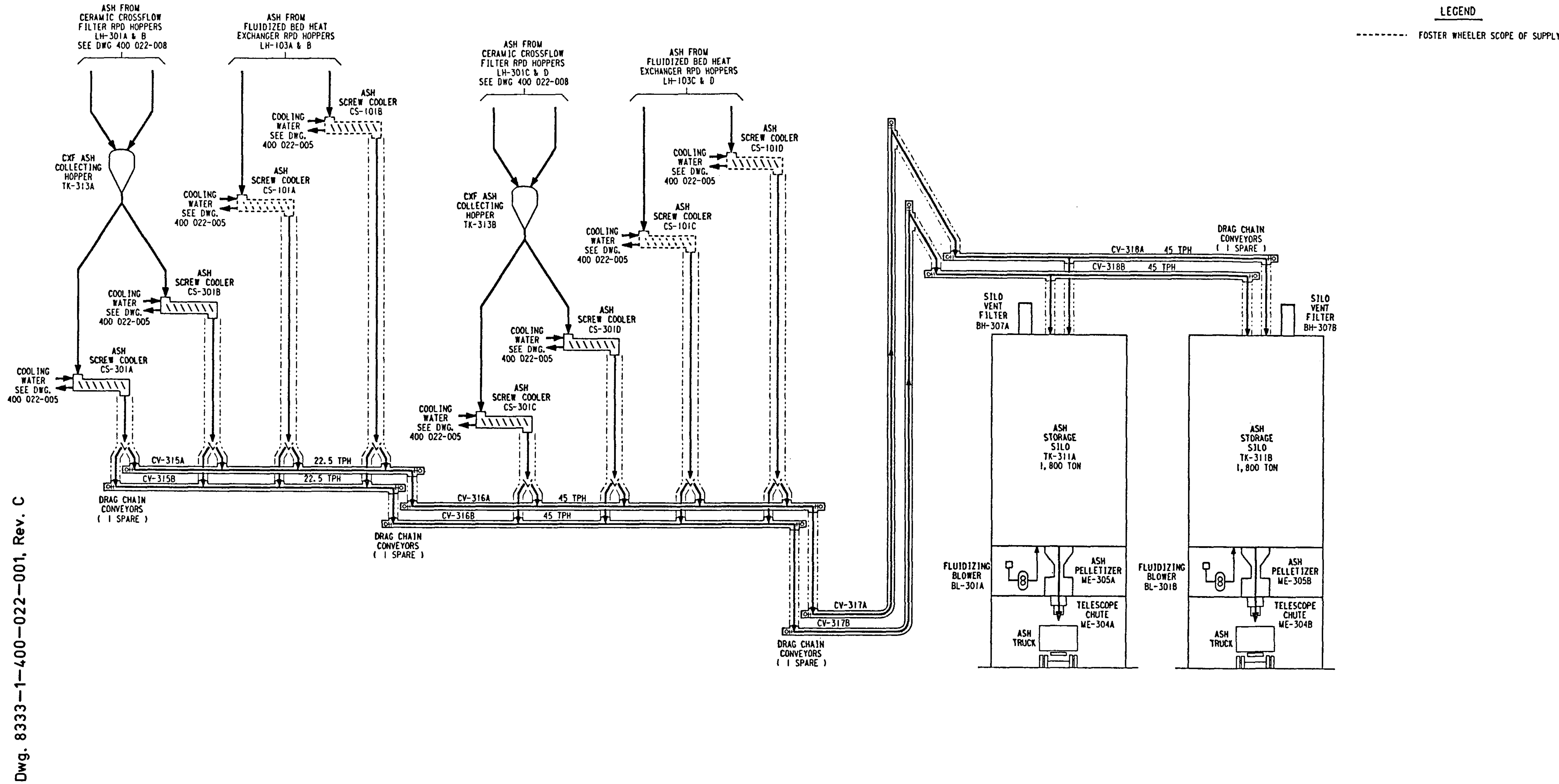


Figure 65 Ash-Handling System

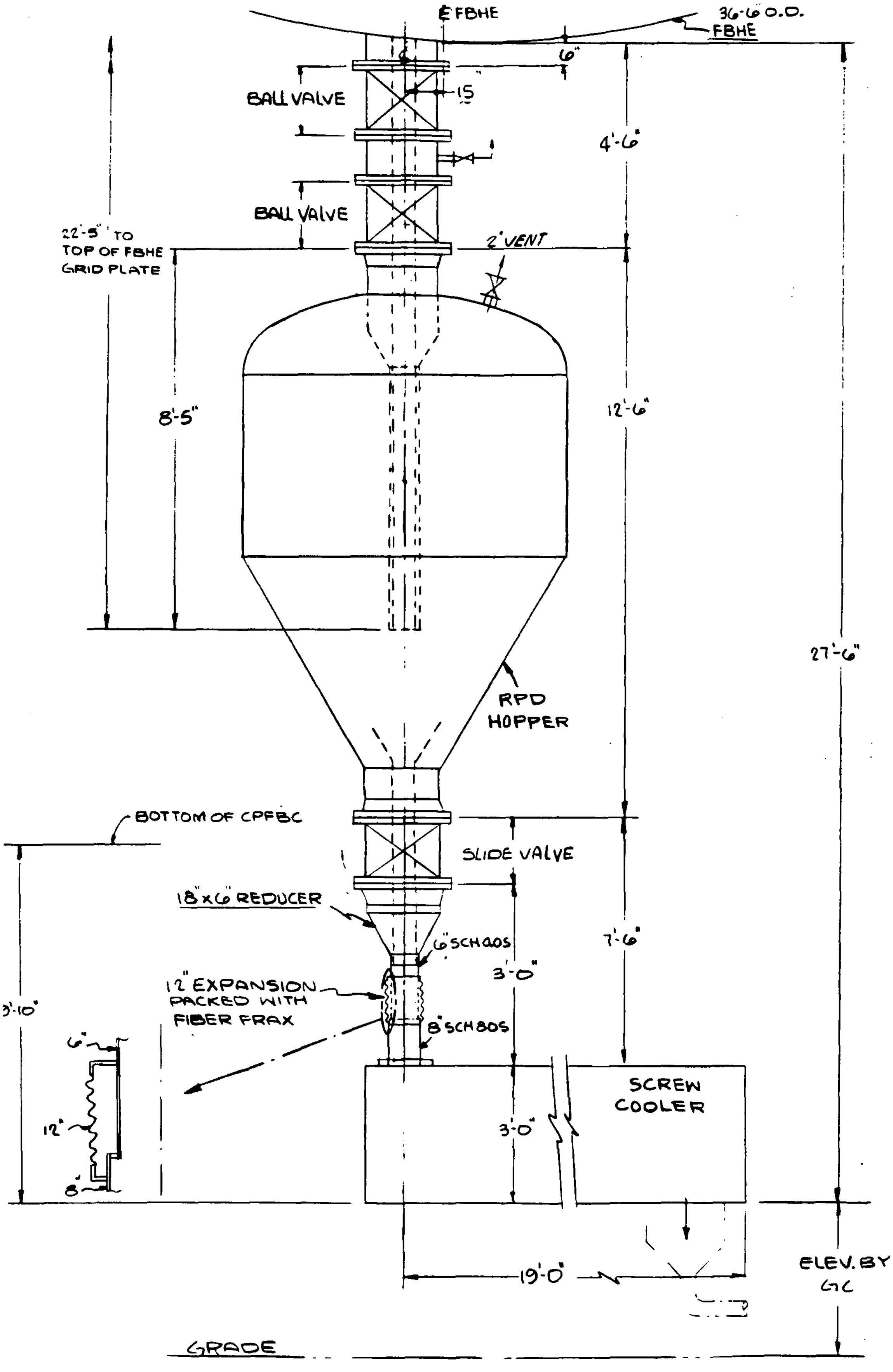


Figure 66 Spent Bed Material Depressurizing and Cooling (Baseline Plant)

the solids drain rate; the bed drain rate and the rate of air blowdown that must be vented from the hopper increase when the valve is opened. At full load the total plant blowdown concomitant with the 70,011 lb/h solids drain rate is 500 lb/h. The restricted-pipe discharge hopper is designed to withstand the full system pressure (14 atm). As shown in Figure 67, a refractory lining insulates the pressure vessel from the elevated temperature of the solids. The depressurized solids drain from the hopper to a screw cooler and are cooled to 300°F.

Even though each FBHE has two restricted-pipe discharge/screw cooler trains, an FBHE can continue to operate at full load with only one train in service; however, the solids drain temperature will rise to approximately 450°F. During this time the inoperative train can be isolated from the FBHE for maintenance and repair using the double ball valves in the restricted-pipe discharge inlet line.

Four identical ceramic cross-flow filters, restricted-pipe discharge hoppers, and screw coolers are used in the baseline plant. Each hopper and screw cooler has been sized to accommodate twice the normal full-load flow of 1600°F ash (10,566 vs. 5283 lb/h). This provision enables the plant to continue to operate at full load without suffering a significant loss in performance in the event the CPFBC cyclone collection efficiency should deteriorate with time or is less than expected (particle breakthrough can be double expected values).

The restricted-pipe discharge hopper/screw cooler arrangement used by the four plant ceramic cross-flow filters is similar to that of the FBHE, except that an intermediate hopper(s) is placed between the restricted-pipe discharge hopper and the screw cooler. This intermediate hopper collects the solids/ash from the restricted-pipe discharge hopper drains of two ceramic cross-flow filter vessels, transferring them to two parallel, operating screw coolers below. If either screw cooler should become inoperable, the intermediate hopper enables the entire drain flow to proceed to the operating cooler; thus the two cross-flow filters and module involved can continue to operate at full load while still maintaining a solids discharge at 300°F. If all four restricted-pipe discharge hoppers and screw coolers continue in operation, the system can operate with a cyclone particle loss three to four times larger than expected before reaching a 450°F solids discharge temperature.

- **Drag-Chain Conveyors (CV-315A and B)**. Irrespective of the distribution between fly ash and bed ash, the total ash flow from the plant remains at 91,144 lb/h (45.6 t/h). The drag-chain conveyors receive ash from the ash screw coolers (CS-101A, B, C, and D and CS-301 A, B, C, and D). Parallel drag-chain conveyors have been arranged to provide 100-percent mechanically redundant capacity of 45 t/h each. In addition, a design factor of 1.89 has been applied to accommodate any backups and surges in the system, yielding rated design conveying capacity of 85 t/h for each conveyor.

  Pneumatic conveying systems were considered, but the mechanical system was chosen for several reasons. The ash flow rate and the plant layout (i.e., distances that ash must be conveyed) exceeded reasonable limits for vacuum systems and were borderline for pressure systems. In addition, the economics of a split system would not compare favorably with the mechanical system proposed.

- **Ash Storage Silos (TK-311A and B)**. The two ash silos are designed for a combined capacity of 3600 tons, providing for more than 3 days of storage at the baseline 100-percent load ash flow rate of 45.6 t/h. The inlets are sized to accommodate the maximum conveying capacity of 85 t/h. The outlet of each silo is sized to discharge to three 20-ton trucks every hour, through ash pelletizing equipment, for a combined discharge rate of 120 t/h for both silos.

Dwg. 1136386-2-11-4, Rev. 1

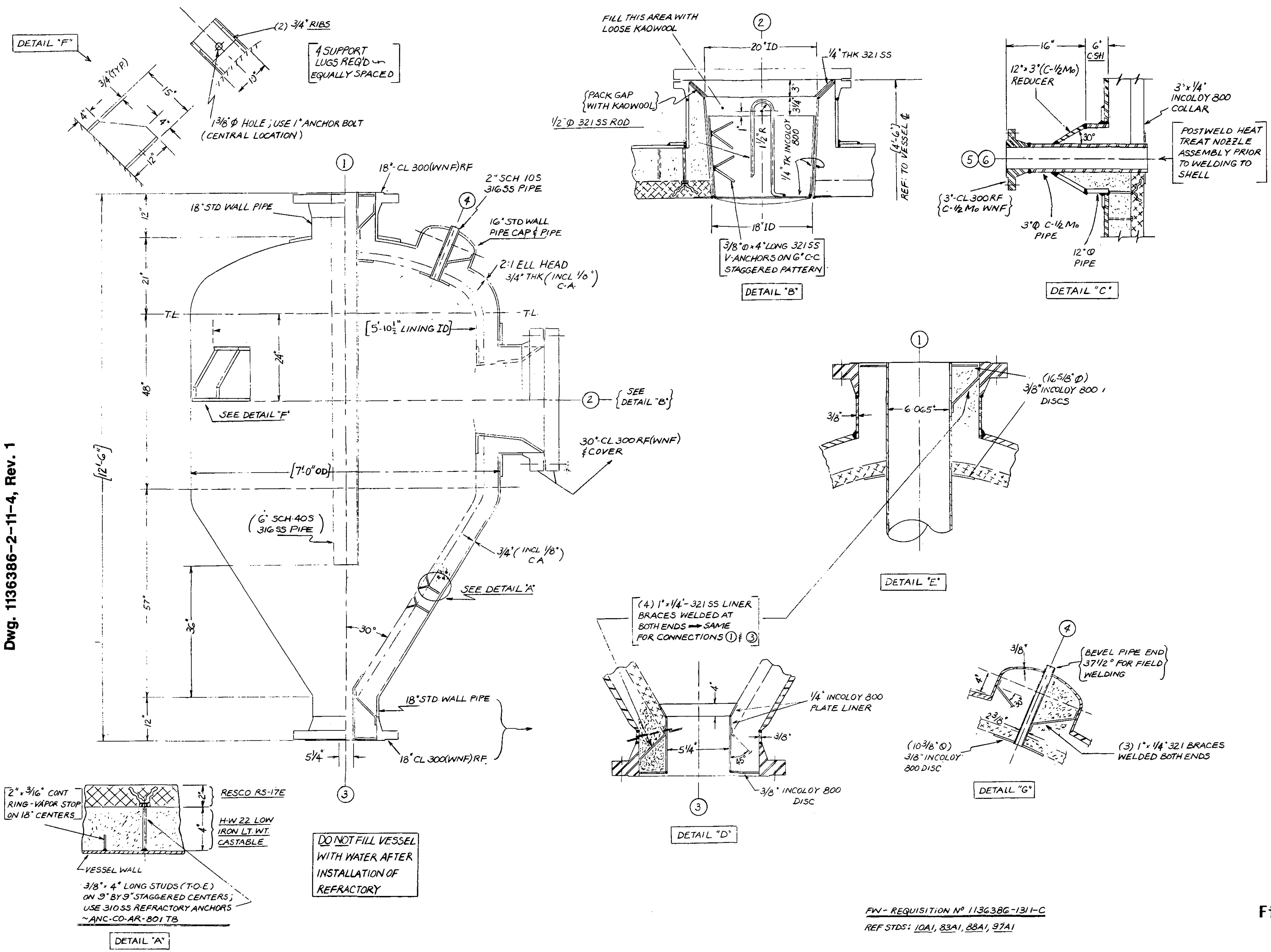


Figure 67 Restricted-Pipe Discharge Hopper

- **Ash Pelletizers (ME-305A and B)**. The pelletizers provide 100-percent mechanical redundancy at an ash removal rate 1.33 times the maximum ash generation rate. With both pelletizers running, the ash removal rate is 2.66 times the maximum generation rate. Operation in this mode allows both filled silos to be emptied in 48 hours, while the plant continues operation at 100-percent baseline load.

Major Equipment Description. The alphanumeric equipment tag numbers of each piece of major equipment listed correspond to those shown in Figure 65.

- Restricted-Pipe Discharge Hoppers

	LH-103 A, B, C, and D	LH-301A, B, C, and D
Quantity	Two per module	Two per module
Design Pressure	220 psig	200 psig
Outside Diameter	7 ft-1-1/2 in.	7 ft-1-1/2 in.
Overall Height (Flange to Flange)	12 ft-6 in.	12 ft-6 in.
Refractory Lining	6 in.	6 in.
Restricted-Pipe Inlet	6-in. I.D. nominal	6 in. I.D. nominal

- Ash Screw Coolers

	CS-101 A, B, C, and D	CS-301A, B, C and D
Quantity	Two per module	Two per module
Ash Temperature, In/Out	1050/300°F	1600/300°F
Cooling Water Temperature, In/Out	110/200°F	110/200°F
Ash Mass Flow/Cooler	17,502 lb/h	5283 lb/h
Cooling Water Flow/Cooler Driver	234 gal/min, 15 hp, directly coupled, variable speed, 3.1 rev/min nominal screw speed, 4:1 turndown	123 gal/min, 10 hp, directly coupled, variable speed, 1.8 rev/min nominal screw speed, 4:1 turndown

- Drag-Chain Conveyors

	CV-315 A and B	CV-316 A and B	CV-317 A and B	CV-318 A and B
Quantity	2	2	2	2
Chain Speed (ft/min)	53	45	85	45
Capacity (t/h)	45	85	85	85
Drive (hp)	5	10	50	15
Conveyor Rise/Length (ft)	3/90	3/90	105/112	0/95
Size (in.)	15	25	15	25

- Ash Storage Silos

Quantity/Type	Two elevated concrete cylindrical silos, one cone bottom each with fluidizing outlet blower and nozzles.
Capacity	1800 tons each
Inlets	Two each silo via drag-chain conveyors at 85 t/h each (one operating, one spare)
Outlets	One vertical gravity drop via isolation valve to ash pelletizer at 60 t/h.

- Ash Pelletizers

Quantity	Two
Capacity	60 t/h each
Drivers	Two 25-hp ac motors

2.5.16 Plant Electrical Equipment

Plant power generation is delivered by two combustion turbine generators and one steam turbine/generator. The electrical scope includes the in-plant auxiliary loads and associated distribution system up to the high-voltage side of the three generator step-up transformers and two plant auxiliary transformers. The electrical system is depicted in Figures 68 and 69.

The utilization voltages are 13.8 kV, 4160 V, 480 V, 480/277 V, and 208/120 V. The generation voltages are 13.8 kV for the combustion turbine units and 22 kV for the steam turbine unit. Each generator supplies power through an iso-phase bus duct and dedicated step-up transformer to an overhead connection to a high-voltage transmission line.

Each of the two auxiliary power transformers receives power from a high-voltage transmission line and is connected to 13.8-kV switchgear by a segregated bus duct. The 13.8-kV switchgear feeds the large motors, miscellaneous plant feeders, and 4160-V switchgear. The 4160-V switchgear feeds associated motors and a 480-V switchgear which, in turn, feeds 460-V motors, feeders, and motor control centers.

Aerial, triplexed cable runs throughout the plant area on wood pole lines to furnish 13.8-kV power to remote electrical loads.

A 460-V unit-essential motor control center receives normal power from a 480-V substation and emergency power from an alternative diesel/generator source. The unit-essential motor control center feeds a battery, battery charger, redundant charger, and dc panel. A dc supply from the panel feeds an ac inverter for an uninterruptible power supply to computer and critical power supplies, with an alternative feed directly from the unit-essential motor control center through a regulating transformer.

The combustion turbine/generator units are supplied as packages, which include: starting package, electrical/control package, isolated-phase bus, surge equipment and potential transformers in a cubicle, and fire protection. Equipment basic-impulse levels will be sized to suit the site conditions.

Dwg. 8333-1-802-206-001, Rev. B

NOTES:

1. ONLY MAJOR MOTORS SHOWN.
2. 0.25 TO 200 HP - 460V.
   250 TO 1000 HP - 4000V.
   1500 HP & UP - 13.2V.
3. BIL LEVELS
   115KV - 550 BIL
   138KV - 650 BIL
   230KV - 1050 BIL
   500 KV - 1675 BIL
4. FOR ELECTRICAL EQUIPMENT OUTLINE SEE DRAWING 8333 1 802 206 - 002.

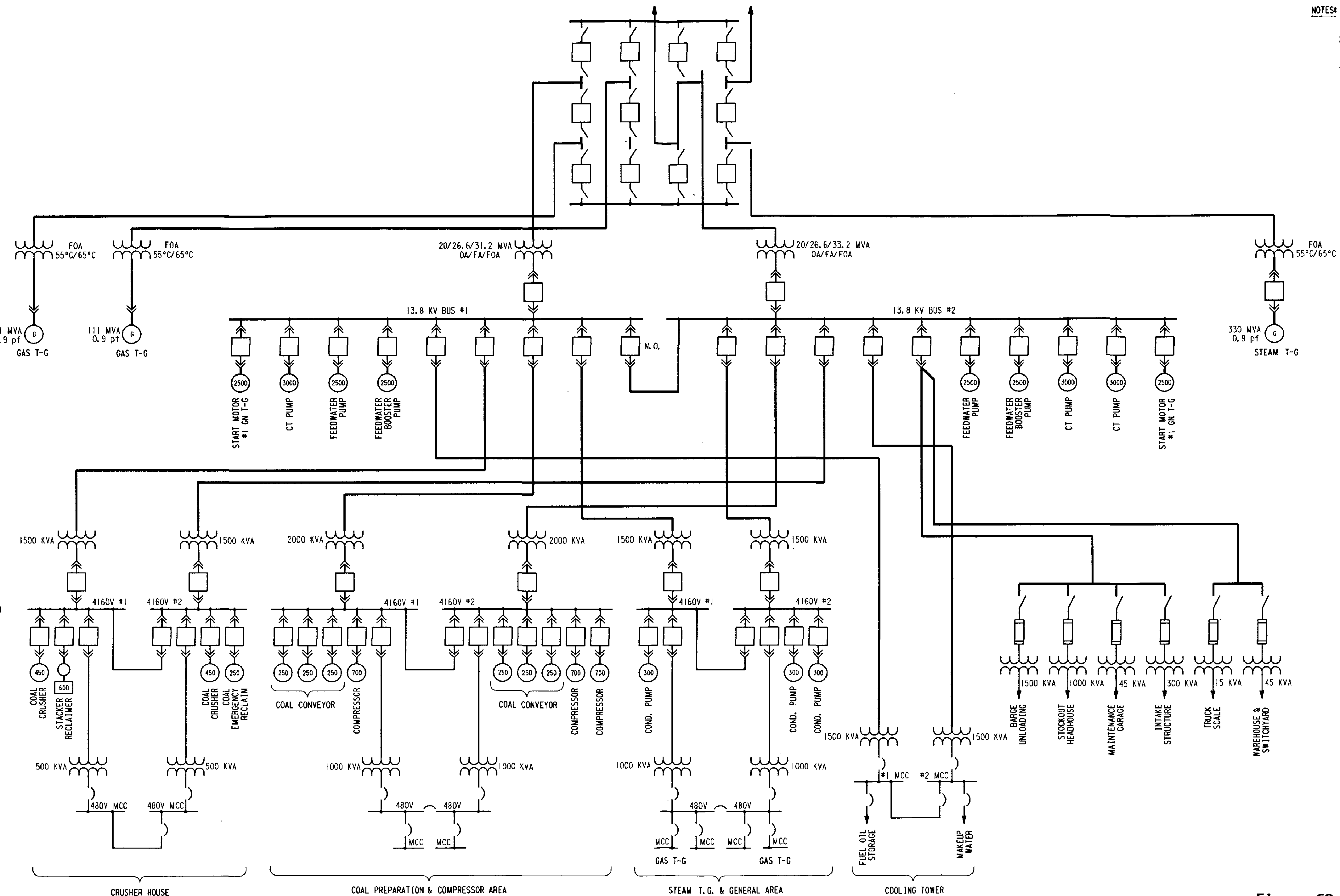
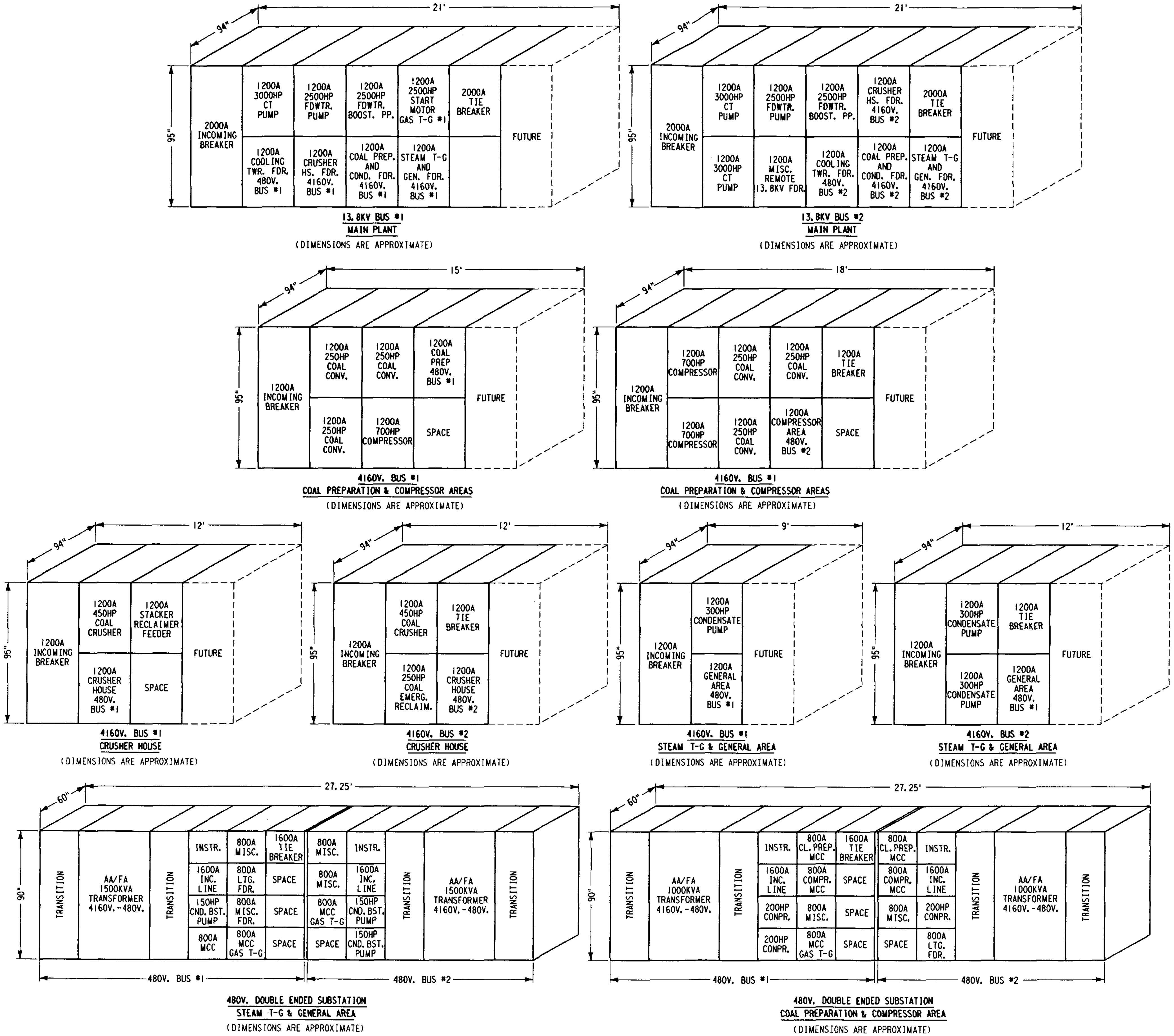


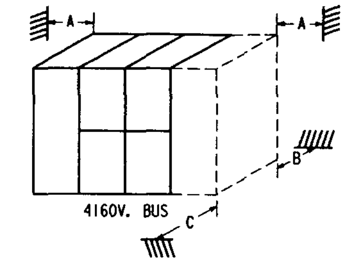
Figure 68 Electrical System--One-Line Diagram

Dwg. 8333-1-802-206-002, Rev. A



NOTES:

1. FOR ELECTRICAL ONE LINE DIAGRAM SEE DRAWING 8333 1 802 206 - 001.
2. MINIMUM CLEARANCE DIMENSIONS:



A - 3' MINIMUM
B - 3' REAR ACCESS
C - 70" AISLE - SINGLE
76" AISLE - DOUBLE

Figure 69 Electrical Switch Gear Equipment Outline

Generators.

- **Combustion Turbine/Generator**. Each combustion turbine drives a 13.8-kV, three-phase, 60-Hz generator rated at 111 MVa at 0.9 power factor. It is hydrogen cooled with shaft-mounted axial blowers for circulating cooled hydrogen through the generator. The generator is complete with turning gear, seal system, lube-oil system, and starting system, which includes a 13.8-kV starting motor and clutch. The exciter is a shaft-driven, air-cooled, brushless type.
- **Steam Turbine/Generator**. The steam turbine drives a 3600 rev/min, 0.50, standard continuous rating, 22 kV, three-phase, 60-Hz generator rated at 310 MVa, 0.9 power factor at 60-psig hydrogen pressure, hydrogen inner-cooled. The generator is complete with turning gear, seal system, and lube-oil system. The shaft-driven exciter system consists of a permanent magnet pilot exciter, an ac exciter with a rotating armature and stationary field winding, and an air-to-water heat exchanger.

Generator Step-Up Transformer. The main step-up transformers are three-phase, 60 Hz, 55°C/65°C rise, forced-oil and -air rating, cooled, sized to carry the maximum generator output (minus the parasitic demand loads) at rated power factor and 95-percent rated voltage with a 30°C average ambient. The limiting generating factor is the turbine. The transformer impedance is standard for the MVa rating and consistent with voltage regulation and short-circuit current considerations. The transformer has delta-connected low-voltage and solid-grounding wye high-voltage windings. It is equipped with two 2-1/2 percent, no-load, full-capacity taps on the high-voltage windings and high-voltage metal oxide surge arresters. Current transformers within the proper accuracy classes provide both relay protection and incoming/outgoing metering.

Station Service Transformers. The station service transformers are three-phase, 60-Hz, 65°C rise, forced-air self-cooled forced-oil and -air rating, cooled, and sized to carry the maximum demand load on 80-percent self-cooled rating at rated power factor and 95-percent rated voltage with a 30°C average ambient. The transformer impedance is standard for the MVa rating and consistent with voltage regulation and short-circuit current considerations. The transformer has delta-connected high-voltage and wye-connected low-voltage windings brought out for a low-resistance grounding system. It is equipped with two 2-1/2 percent, no-load, full-capacity taps. In addition to standard accessories, the transformer has tank-mounted secondary resisters (10-second rated) enclosed in metal grills for grounding the neutral of each low-voltage winding. Bushing current transformers with the proper accuracy class satisfy metering and relaying requirements.

Auxiliary Transformers. The auxiliary medium- or low-voltage power transformers are three-phase, 60 Hz, 65°C rise (dry- or cast-resin type for indoor or oil-immersed for outdoor). They have one stage of fan cooling and are sized to carry the maximum demand load on 80 percent of the self-cooled or dry transformer self-cooled rating at rated power factor and 95 percent rated voltage with a 30°C average ambient. The transformer impedance is standard for the MVa rating and consistent with voltage regulation and short-circuit current considerations.

Bus Duct. An isolated-phase bus connects the generator line terminals to the main step-up transformer. The bus duct section between the generator and main step-up transformer is rated to carry rated generator MVa continuously at 95 percent of rated generator voltage without exceeding a 65°C conductor temperature rise for a maximum 40°C ambient temperature.

A segregated-phase bus connects the station service transformer to the 13.8-kV switchgear. The segregated-phase bus is rated to carry the maximum transformer current continuously at 95 percent of rated voltage without exceeding a 65°C conductor temperature rise for a maximum 40°C ambient temperature.

Protective Relaying. Protective relays in the electrical system permit isolation of faulted or overloaded equipment and cables as quickly as possible to minimize equipment damage and limit the extent of system outages. The generators, step-up transformers, and station-service transformers have primary and backup relaying.

Medium-Voltage Switchgear. The medium-voltage switchgear consists of 13.8- and 4.16-kV metal-clad, NEMA I* assemblies feeding large motors, power transformers, and 480-V load centers. Each switchgear line-up includes provisions for future additions on one end. The switchgear assembly incorporates drawout circuit breakers equipped with current transformers, protective and auxiliary relays, ammeters, indicating lights, cable terminations, and other special required devices.

Low-Voltage Unit Substations. The 480-V unit substations have double-ended switchgear with integral transformers at each end and a normally open tie breaker separating the two switchgear buses. The transformer associated with each power center is the dry-type, three-phase, fan-cooled rated, dry transformer OA/AA (self-cooled/forced-air) rating, connected delta on the high-voltage winding and solidly grounded wye on the low-voltage winding. The transformers are sized for the running load plus 20-percent margin based on the forced-air rating. Standard transformer impedances are used. The switchgear is 600-V class in a NEMA-I metal enclosure with drawout components. Motors rated 101 through 200 hp are, as is normal, supplied directly from load-center breakers. A three-phase dry-type transformer with disconnect and a 120/208-V circuit breaker are provided where required.

Motor Control Centers. Motor-control centers are located throughout the plant in areas of concentrated loads. They are 460 V, in NEMA enclosures to suit the environment, made of standard modules, 20 in. deep. All devices are front-mounted, except those made of valve-reversing starters, which can have rear-mounted components.

Essential Power System. The essential power system provides power to essential auxiliaries required for shutdown in the event of a total blackout of a unit or the complete plant. System components are:

- Emergency generator
- Essential motor control center
- 480-V ac essential-power panel

A diesel-engine-driven emergency generator supplies shutdown power to the essential motor control center. Major loads supplied from the essential motor control center are:

- Turbine auxiliary lube-oil pump and turning gear
- Essential lighting
- Boiler feed pump turbine oil pump and turning gear
- Selected sump pumps
- Battery chargers

---

*National Electrical Manufacturers Association.

The essential motor control center is supplied through an automatic transfer switch from either a 480-V power center or the emergency generator. Loss of voltage at the transfer switch starts the emergency generator; when rated voltage and frequency are achieved, the switch transfers the essential motor control center to the generator.

Uninterruptible Power Supply System. The uninterruptible power supply system furnishes a reliable source of 120-V ac power and control voltage to equipment vital for plant operation and shutdown. The system consists of:

- An inverter
- A static switch
- A manual bypass switch
- A 120-V ac vital-ac distribution panel.

The inverter takes normal power from the 125-V dc power system. The inverter output is connected to a static switch; upon failure of the inverter, the switch automatically transfers it to an alternative 120-V ac supply.

The uninterruptible power supply is sized to feed these loads plus 20-percent margin:

- Combustion controls and burner management
- Turbine generator/electrohydraulic control system
- Turbine supervisory instruments
- Recorders and indicators
- Other essential instrumentation
- Critical components of plant control systems

Direct Current Power System. A 125-V dc system furnishes control power to the switchgear and for power feeds to the uninterruptible power supply, emergency lighting, and motors such as those that drive the emergency bearing and seal-oil pumps. The system consists of a battery, two battery chargers, and dc distribution panels. Battery capacity provides emergency lighting and control power for orderly plant shutdown, enables uninterrupted operation of vital equipment via the uninterruptible power supply system, and enables breaker operation to set up a plant restart.

Motors. Except for special applications, all ac motors are squirrel-cage induction-type with Class B insulation, are designed for full-voltage starting, and have the lowest possible locked-rotor current consistent with good performance and design. The motors match the inertia and speed-torque requirements of the driven equipment. Where required, medium-voltage motors are designed to start and accelerate the connected load with an applied voltage of 80 percent of rated voltage.

Motor voltage ratings and power supply source are shown in Table 29.

Motor enclosures are normally fully guarded, open, drip-proof for indoor service and weather-protected NEMA Type II for outdoor service. Motors 200 hp and lower are totally enclosed, fan-cooled (TEFC) for outdoor service. Regardless of size, all motors subject to fire protection spray water are totally enclosed, fan cooled unless limited by size to a totally enclosed, noncooled (TENC) enclosure. Explosion-proof motors are provided where required for service in hazardous locations.

Table 29 **Motor Voltage Rating and Power Supply Service**

Horsepower	Voltage	Phase	Supply Source
1500 and up	13,200	3	3.8-kV switchgear
250 to 1000	4,000	3	4.16-kV switchgear
125 to 200	460	3	480-V switchgear
1/2 to 100	460	3	480-V motor control center or individual starter
Less than 1/2*	115	1	Lighting cabinets or 120-V distribution panels

*Fractional hp motors less than 1/2 hp used for reversing service, such as motors on valve operators, are 3-phase, 460-V starter.

Totally enclosed and explosion-proof motors have a 1.00 service factor. Drip-proof and weather-protected motors have a 1.15 service factor, except where an adequate margin is already available. The service factor is not infringed upon by normal continuous loads.

All medium-voltage motors include resistance temperature devices for overload detection, and motors over 1500 hp have six leads and three donut-type current transformers mounted in the terminal box for self-balanced primary-current differential protection. All medium-voltage motors and valve motor operators have space heaters, and all outdoor motors above 50 hp have space heaters that automatically activate when the motor is idle.

Grounding/Lightning/Cathodic Protection. The grounding system is a permanent and continuous system designed to provide safety to personnel, protection to equipment, and a minimum input of electrical noise to control and instrumentation signals.

The plant grounding grid is made of buried copper grounding loops around each building, a buried grounding grid in the switchyard for step-and-touch potential protection, and buried grounding grids for step-and-touch potential on both sides of fences and gates where applicable. The grounding grid is designed for a resistance to ground of less than 1 ohm. All grids and loops are connected at two places (minimum).

All building, structural, and outdoor tank steel is connected by copper cable to the main plant ground grid. Electrical continuity is maintained for all structural steel used as a grounding path. All medium-voltage equipment is connected to the plant grounding grid by copper cable. Small miscellaneous equipment lower than 600 V, in remote locations, may be grounded to the building steel and conduit system, providing electrical continuity to ground is maintained. Electronic devices have isolated signal grounds, chassis and enclosure grounds, and electrical power-source grounds for safety and to minimize electrical noise inputs to the controllers from external sources. Instrument cable shields are grounded at one end only to prevent circulating currents, unless otherwise recommended•by the instrument manufacturer.

Metal-oxide-type station lightning arresters on the high-voltage side of the main step-up transformers and station service transformers protect insulation from voltage surges. The chimney cooling tower and tall buildings are protected by air terminals in accordance with the Lightning Protection Code NFPA No. 78.

Underground structural steel, pipes, tanks, and wharf areas are protected from harmful galvanic corrosion by cathodic protection. The cathodic protection system is designed in accordance with guidelines established by the National Association of Corrosion Engineers (NACE). The cathodic protection consists of individual galvanic sacrificial anodes or an impressed-current system, as determined by field test and design.

Heat Tracing. Where required, freeze protection is provided for all outdoor piping, gauges, and instrumentation with self-regulated parallel-type heat cable. Space heaters are utilized for items that are not suitable for heating cable application. Heating cable circuits are supplied from distribution panels similar to those used for lighting circuits and are controlled by thermostats.

Lighting. Normal, emergency, and egress lighting is provided for the station, service building, remote buildings, and associated outdoor areas within the plant boundary.

Normal lighting is energized from three-phase four-wire lighting panels throughout the station. Each lighting panel is fed from locally mounted 480-/277-V panels or 480-208Y/120-V transformers that are fed from the nearest motor control center. Yard and roadway lighting is supplied at 277 V from the nearest motor control center or power distribution cabinet.

Lighting illumination levels are calculated in accordance with recommended levels of illumination in an electric supply station, as listed in Part 1, Section 11, of the latest edition of the National Electrical Safety Code.

Emergency dc lighting in the station building and in the control room permits safe egress. For outlying miscellaneous buildings, emergency lighting is from self-contained battery-charged lamp units. Office areas, shops, laboratories, and the control and computer rooms have fluorescent fixtures. High-intensity discharge fixtures are installed in indoor plant areas. Incandescent fixtures are used for the emergency lighting system and for exit lights. Fixtures are explosion-proof in hazardous areas of the coal-handling system.

Wire for lighting systems is Type RHW (moisture and heat-resistant rubber cable), run in either conduit or tray. All fluorescent and pendant lighting fixtures have Type SO high-temperature flexible cord for wiring from the outlet box to the fixture. Conduit used for lighting systems can be rigid, IMC (intermediate conduit), EMT (intermediate conduit), or a combination of these, depending on the application.

Communication System. An intraplant communication system consists of one paging and five party lines. The speech input to the paging amplifiers is from handsets throughout the plant area and in the control room. Each handset has its own solid-state amplifier. Where required, noise-canceling microphones, speaker-muting controls, and appropriate enclosures are provided. Public telephone lines are installed for administrative areas and the main control room. All communication system interconnecting wiring is installed in conduit.

Miscellaneous Small Power Systems. Miscellaneous, small power systems provide the plant with electrical supply for convenience outlets, food preparation, storage equipment, office and building services, and similar requirements. The systems are 208Y/120-V, three-phase, four-wire supply. They consist of step-down transformers (fed from the plant low-voltage distribution), panelboards, and branch circuit wiring feeding various loads. There are 48-V welding outlets throughout the plant.

2.5.17 Plant Instrumentation and Control

The primary input to the overall control system is the station load demand, supplied by an operator or generated by a utility's automatic dispatching system. Typically, for maximum flexibility and integrity, an integrated total-plant distributed-control system is installed. Measurements are made throughout the plant to ensure adequate control of start-up/shutdown sequences, plant load following, and module coordination and to provide protection during upsets and off-design conditions. The operator has all the information at his disposal, primarily in the form of video displays, to control the plant effectively. Full or partial manual control is also available at all times. Control loops are configured to preclude major disturbances if any sensor information is not available (i.e., the loop holds the current set point so that the operator can take the appropriate manual action). The system also has the means for safe control and shutdown by the operator under emergency conditions.

A modern, distributed-control system is used; its integrity is enhanced by redundant control elements and backup for sensors where necessary. For example, the multiplexed data transmission of plant control parameters is achieved by a data highway system (an optical fiber or coaxial cable communication system) with fault checking and redundant backup. It provides communication among all distributed components. An uninterruptible power supply (Section 2.5.16) for the essential instrumentation and control equipment supports control system operation for a period sufficient to supervise an orderly shutdown. Redundancy for the operator interface functions is provided by the multiple monitors and keyboards used for control, display, and alarm.

To achieve full-load status during start-up, load on the first CPFBC module must be gradually increased; the module is then maintained on hold, and the steam from it is blended with steam from the second module. The question of steam bypass capability has been considered in this control system to the extent necessary to establish a preliminary blending scheme and to promote further definition requirements. The purpose of blending is to match steam pressures and temperatures; how the various steam pressures, temperatures, and flows should be controlled during steady-state excursions must be determined first, however.

Steady-State Control. Steady-state control of the plant has been examined briefly. Discussion or diagrams are not included where standard power plant control practices are applicable.

From a control standpoint, the second-generation PFB combustion plant can be designed to operate in any of the following modes:

- Gas turbine leading--steam turbine following

- Steam turbine leading--gas turbine following
- Coordinated/integrated gas turbine/steam turbine control.

To determine which of these control modes is optimum for a second-generation plant would require very detailed transient and steady-state analyses beyond the scope of this study. Since the coordinated approach is expected to be slightly more expensive than the other two, and since it has proved the best means for controlling the Cool Water Integrated Coal Gasification Combined Cycle Plant [10], the baseline plant has been designed with a control system in which both the steam turbine and gas turbine megawatts develop the necessary steam turbine and steam generation system demand signals. These signals are modified by any steam turbine megawatt and steam pressure errors and are then used to develop demand signals that are applied to the two modules shown in Figure 70.

For this discussion, each module is considered to consist of a combustor section and a steam generator section. The single steam turbine is interfaced with both modules via a turbine bypass system. The combustor section is shown in Figure 71, the heat recovery section in Figure 72, and the bypass system in Figure 73.

The primary purpose of the bypass system is to facilitate start-up and shutdown; it is discussed later. The carbonizer, combustor, and HRSG units are discussed in the following subsections.

Carbonizer Control. The carbonizer is operated as a fluidized bed coal combustor during start-up; at a point yet to be determined in its load ramp, it will make the transition from combusting (fuel lean) to coal devolatilizing/gasifying (fuel rich) conditions. When operated as a combustor, an increase in the coal-to-air feed ratio results in an increase in bed temperature; when operated as a carbonizer, an increase in the coal-to-air feed ratio results in a decrease in bed temperature. To ensure proper control at all times, each carbonizer has two identical programmable controllers, identified as PC1 in Figure 71. These controllers determine and provide the proper carbonizer airflow rate at all times. One backs up the other, and each receives input from process analyzers that measure O_2, CO, CO_2, and possibly other species. In addition, as indicated, all important carbonizer pressures, temperatures, and flow rates are measured. We suggest that these two programmable controllers be independent of the distributed system except for sharing process information with that system. Based on the variables measured, and using preprogrammed carbonizer computer models for each operating regime (i.e., combustor vs. carbonizer), overall mass and energy balances are prepared in real time; they keep the operators constantly apprised of carbonizer performance. The development of this controller should be a high-priority item and should be specified and installed at the start of any carbonizer testing program.

PC1 should not be expanded into a control system for the carbonizer as a whole, but rather should be developed to be a highly responsive, highly reliable, low-maintenance, intelligent, process analyzer system that can interface with any distributed system. The technical risks in developing this approach are low, but the high-reliability analyzers and sampling systems need to be developed and checked out over a period of time on an actual carbonizer.

Combustor Control. The master controller for the plant communicates with the two modules and the steam turbine and gas turbine control subsystems, directing them to either increase or decrease load.

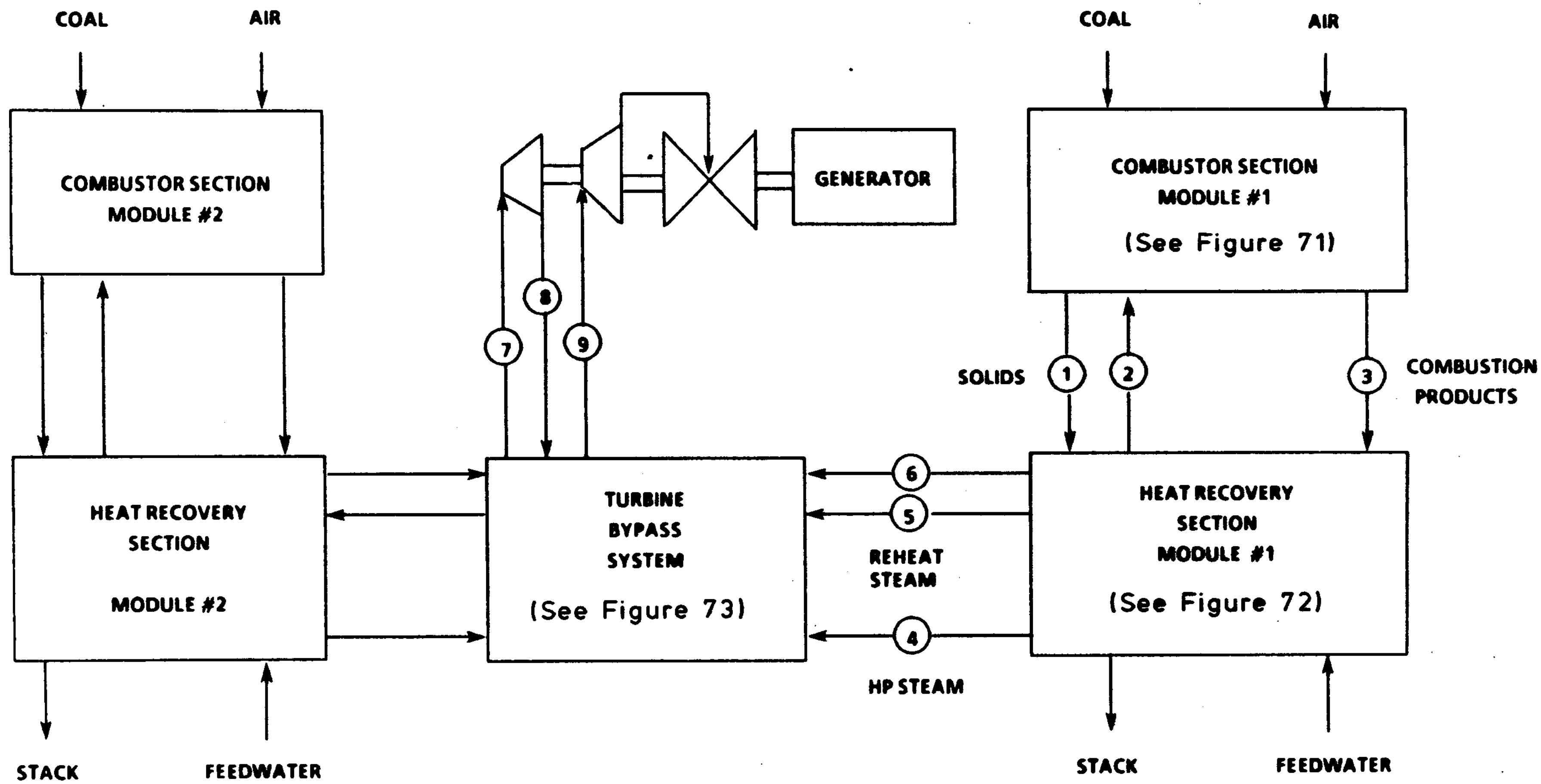


Figure 70 Simplified CPFBC Power Plant

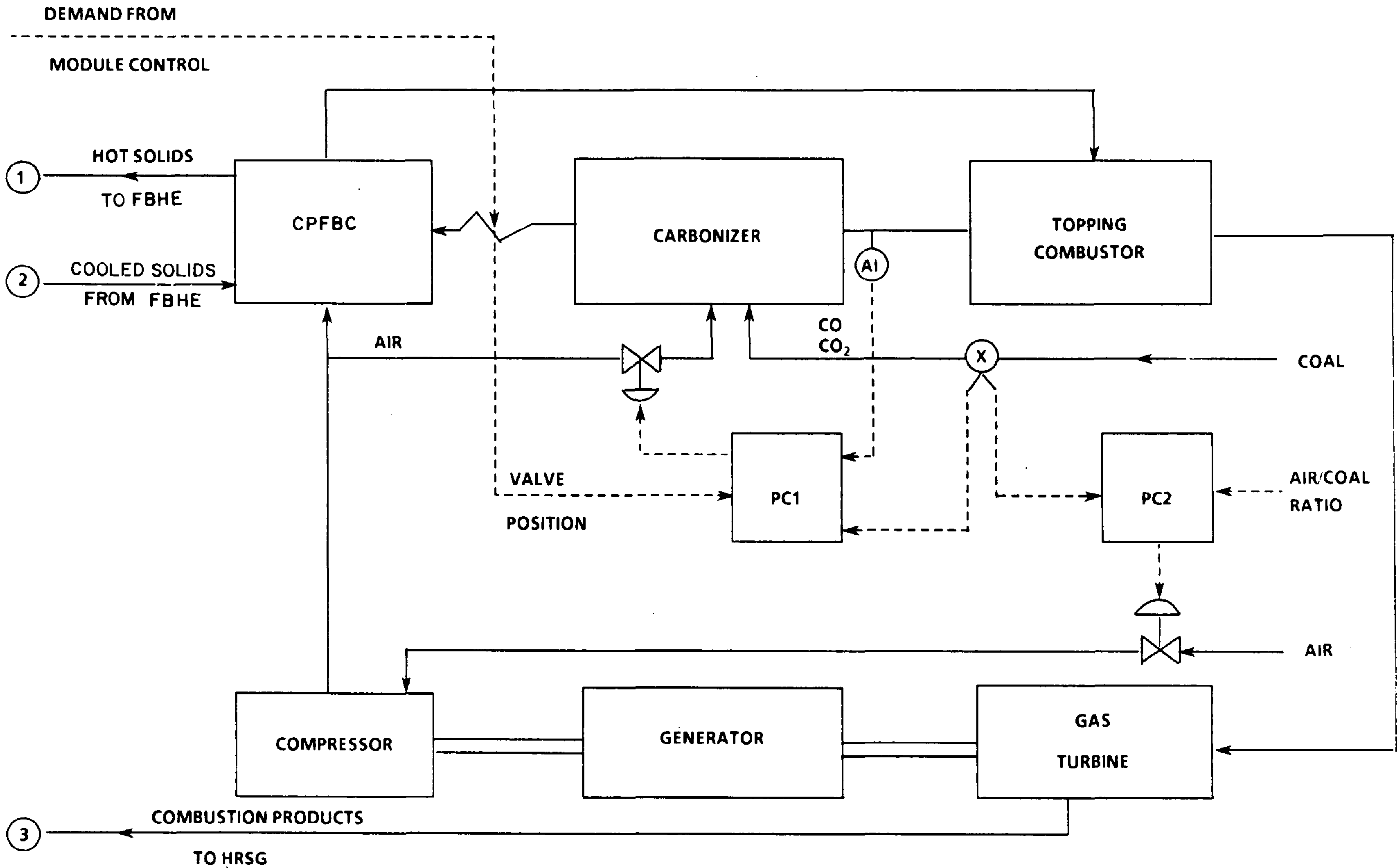


Figure 71 Combustor Section

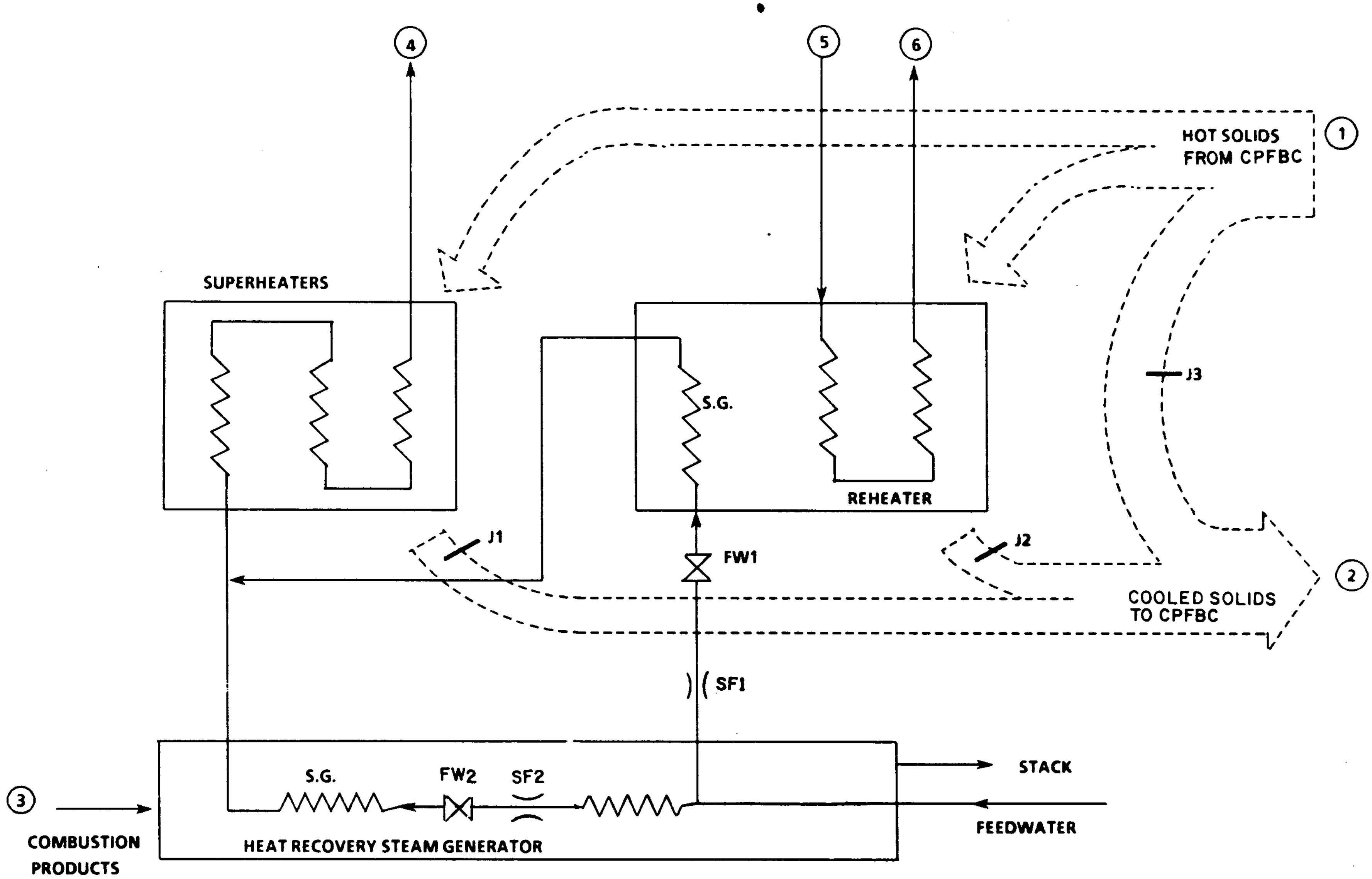


Figure 72 Heat-Recovery Section

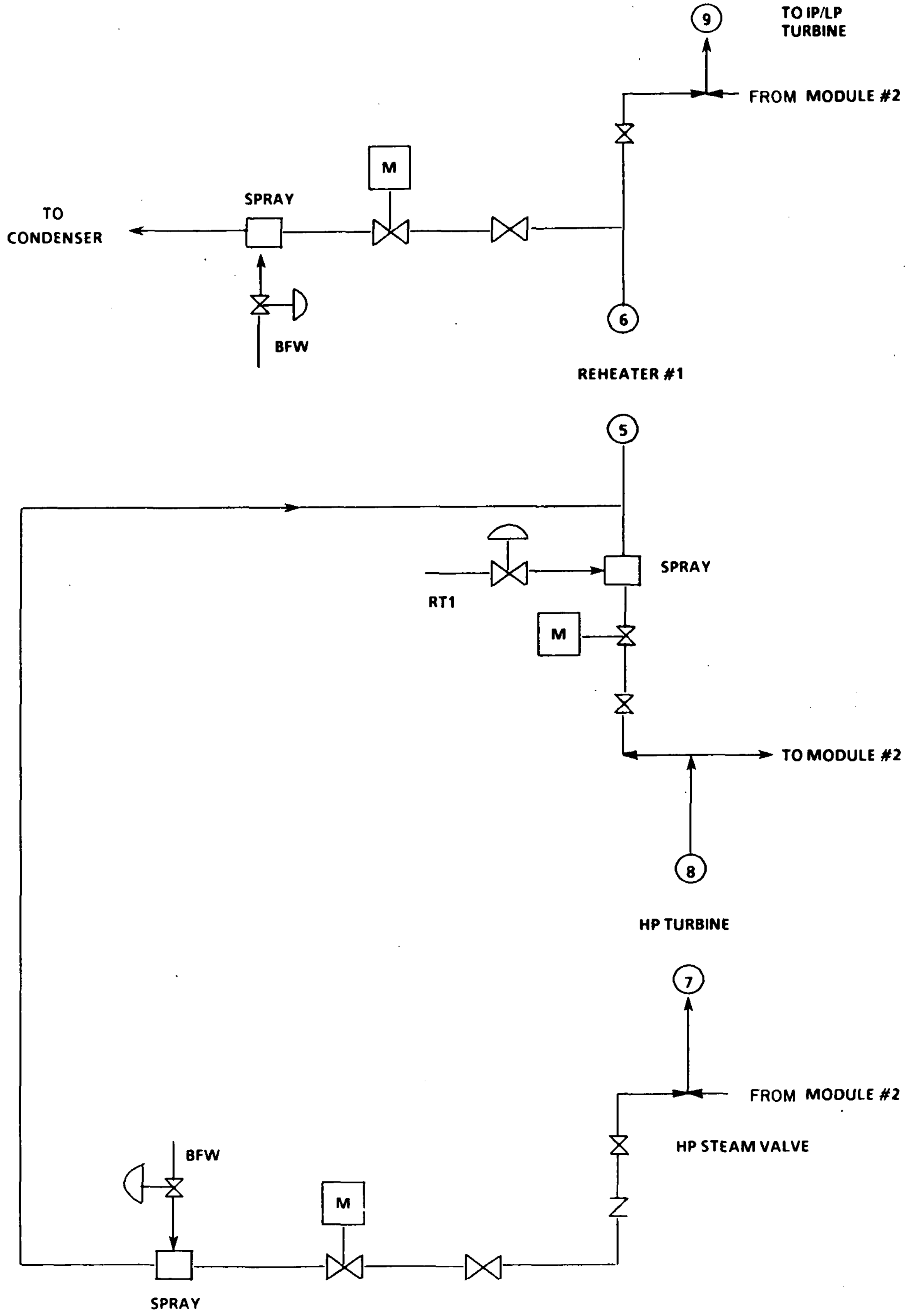


Figure 73 Turbine Bypass System

Based upon Figure 71 and assuming normal module operation near full load, two actions should apparently be taken simultaneously:

- Modify the N- and J-valve settings as a function of load (subject to appropriate rate of change limits)
- Modify the coal flow rate as a function of load (subject to appropriate limits).

The second action causes a corresponding change in the dolomite flow; at the same time, a change should be made in the gas turbine inlet guide vane setting to provide a predetermined overall plant air/coal ratio (which will vary somewhat with load). These changes have an impact on the carbonizer control system referenced in the previous section. The results are a change in air rate to the carbonizer and a simultaneous but delayed change in the rate of char production.

As a result of these two actions, the air rate to the CPFBC should settle down to a new value, and the load change will be absorbed by the combustor subsystem. If necessary, the controller represented by PC1 can bias the air/coal ratio to improve the overall performance of the system. (The logic represented by PC2 is only a very small part of the logic implemented on the distributed system. Unlike PC1, it is not a separate controller.)

Steam Generator Control. The steam generator consists of an HRSG, which recovers heat from the gas turbine exhaust stream, and the FBHE, which recovers heat from solids circulated through the CPFBC. The system is shown in Figure 72.

The steam generator requires two control subsystems: a feedwater control system and a steam-temperature control system. These two systems are described briefly in the following paragraphs.

A feedwater pump maintains the correct pressure in the feedwater supply header (Figure 72), and the feedwater control valves FW1 and FW2 are controlled using a standard feedwater control scheme based on measurements of drum pressure, drum level, feedwater flow, and steam flow. The measurements for the first three variables are not shown, but the steam flow measurements are indicated by flow meters at SF1 and SF2.

The philosophy for steam temperature control is to position the spray valves ST1 and RT1, shown in Figure 73, in response to short-term transient temperature changes and to make long-term changes to the J-valves (J1, J2, and J3) shown in Figure 72.

Start-up and Shutdown. A complete analysis, involving plant/component dynamic analysis, and a rigorous controls design were not the intent of this study; however, sufficient information is available to conclude that operation of a 500-MWe second-generation PFB combustion plant is feasible and well within present-day equipment/controls design. Emergency loss-of-load conditions are discussed conceptually in Section 2.7.

To develop a tentative start-up scheme, we had to assume a steam blending approach. This approach, outlined in the following paragraphs, was used as a basis for describing the emergency shutdown procedures in Section 2.7.

Steam temperature from the superheater and reheater is controlled by a combination of J valves (which control solids flow rates) and spray attemperators; during start-up and shutdown, they are assisted by a finishing superheater bypass. The spray attemperators control short-term steam temperature variations; the

J valves provide long-term steam temperature control. The bypass raises the final steam temperature to the required setpoint during start-up and steam blending operations. Each bypass contains a control valve, isolation valve, and desuperheating system for bypassing steam around the HP and IP/LP turbines, as shown in Figure 73.

The bypass system provides a means to start up either CPFBC, raise the pressure of the steam generated by the second CPFBC, match the pressure and temperature of the first CPFBC, and blend the two steam flows in a controlled manner.

A variety of control schemes is possible, and final decisions can be made later. For the purpose of this preliminary description, we have assumed that the HP steam valve remains closed until the steam temperatures and pressure are properly matched. Therefore, the system should be designed so that the LP bypass steam flow is equal to the HP bypass flow. The control valve in the cold reheat line should be modulated to match the HP steam flow. In this way the two modules can have different steam outputs.

The design requirements for the carbonizer, CPFBC, FBHE, and HRSG will dictate the time required for cold start-up to full load. In addition, the general requirements of refractory heat-up limits, condensation in hot filter elements, and plant safety dictate additional limitations in the start-up procedures. The changes in each of the major components during the start-up procedure are summarized in Section 2.7.

2.5.18 Miscellaneous Auxiliary Systems

Included in this section are the following systems:

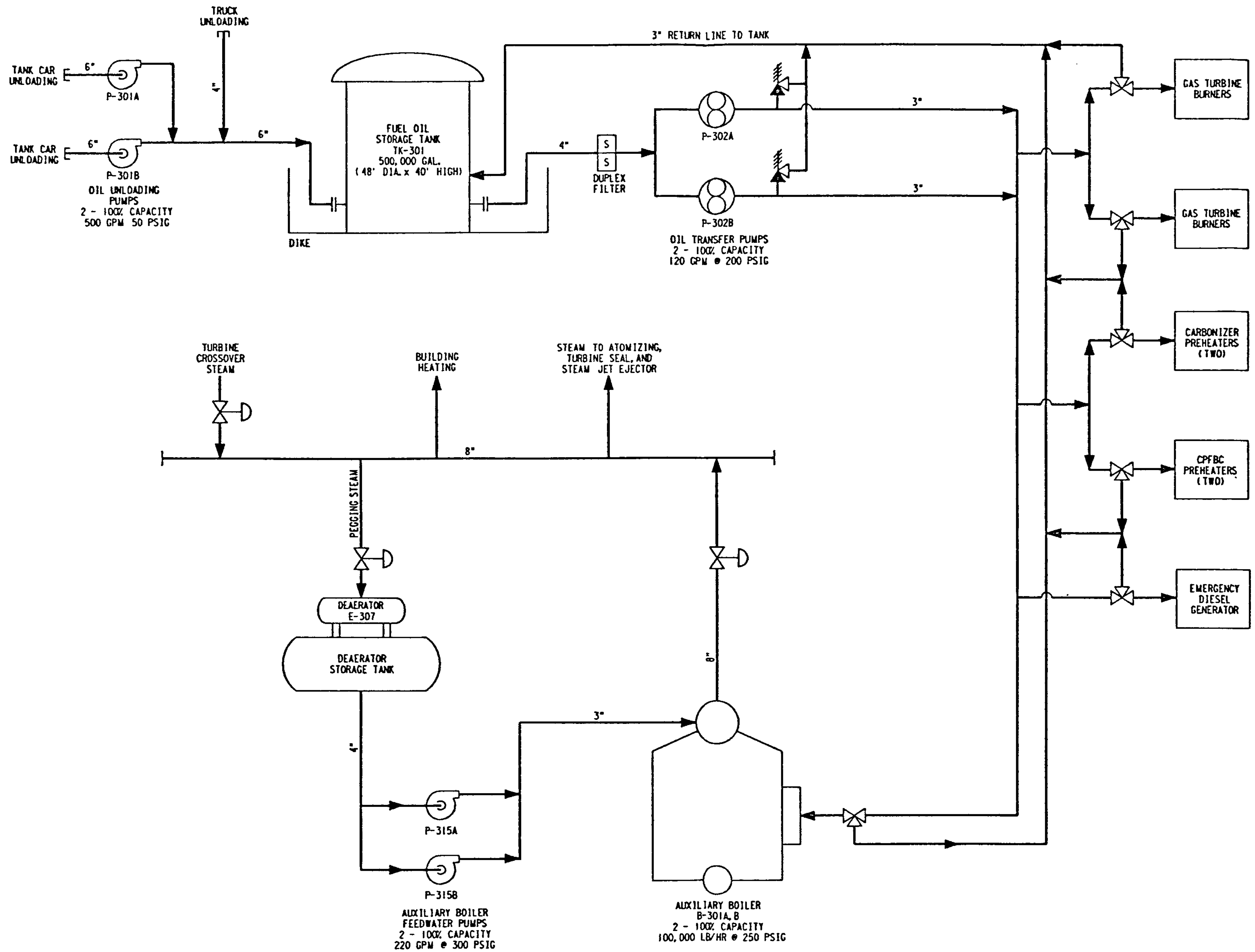
- No. 2 fuel oil
- Nitrogen supply and distribution
- Auxiliary steam system
- Industrial waste treatment system

No. 2 Fuel Oil System. The No. 2 fuel oil receiving and storage system is depicted in Figure 74. The unloading and storage system consists of two 100-percent-capacity oil-unloading pumps, an oil-storage tank, and two 100-percent-capacity oil-transfer pumps. Oil is received at the site via railroad tank cars or truck. It is pumped from the tank car using the unloading pump(s) and delivered to the 500,000-gal storage tank. Each unloading pump has a capacity of 500 gal/min. Oil from the storage tank is pumped to the burners, to other uses, or both, using one of the transfer pumps. The oil-storage tank is enclosed in a dike to confine any oil spill in case of an accident.

The fuel oil system also has sufficient storage to replace the carbonizer heating duty to the topping combustor for 3 days in the event both carbonizers are shut down. With regular 3-day fuel oil delivery, the plant is capable of continuous full-load operation with both carbonizers out of service and direct coal feed to the two CPFBCs.

Nitrogen Supply and Distribution. This system provides nitrogen for conveying, blanketing, purging, and other miscellaneous uses, where an inert gas is required for safety or to avoid problems created by moisture.

Nitrogen is stored on site in a series of three 11,000-gal liquid nitrogen tanks. Each tank is a double-walled vessel that separates the liquid nitrogen from the tank wall with an evacuated and insulated space. The vaporizing requirement for the nitrogen supply is met with water-bath vaporizers, heated with plant steam. The system includes interconnecting cryogenic piping and valves, water-circulating piping, and automatic controls. Nitrogen is distributed through the plant through



Dwg. 8333-1-400-022-006, Rev. C

Figure 74 Fuel Oil and Auxiliary Steam System

a manifolded piping system. Delivery of nitrogen to the plant is either by truck on a daily basis or by rail car on a weekly basis. Plant nitrogen requirements are presented in Table 30.

Nitrogen required for coal storage blanketing was determined by calculating breathing losses and working losses. Since the residence time of coal within the Petrocarb feed system is 1 hour at full load and less than 2 hours at minimum load, the system is pressurized with air rather than nitrogen. However, upstream bunkers and hoppers are continuously made inert with nitrogen. At shutdown, the Petrocarb feed system is purged with nitrogen, forming an inert atmosphere to prevent spontaneous combustion/fires in any coal residue remaining in the system. An 11,000-gal storage tank contains 1,025,700 sft^3 nitrogen--enough for approximately 6 days of continuous operation.

Table 30 Plant Nitrogen Requirements

Plant Use	Use Rate lb/h	Use Rate sft^3/h
Blowback gas for the carbonizer ceramic cross-flow filters that intermittently clean the elements (reboiler provides 400-psig gas)	56	730
Conveying/sealing gas to operate the N valves which convey char from the carbonizers to the CPFBCs	1,000	13,000
Blanketing/inerting for all coal storage bunkers	450	5,880
Miscellaneous, including purge of fuel gas instrumentation and sampling systems	100	1,310
Total	1,606	21,000

Auxiliary Steam System. The auxiliary steam system shown in Figure 74 is designed to supply the following during plant start-up:

- Steam to turbine seal system
- Steam to jet ejector
- Pegging steam to deaerator
- Building heating
- Miscellaneous steam for process, steam tracing, etc.

The auxiliary steam system supplies steam to the building heating system to maintain the temperature of the enclosed space well above the freezing point (approximately 45°F) during a winter plant outage. The system includes two 100-percent capacity boilers (auxiliary boilers), two 100-percent capacity feedwater pumps, and other related auxiliary equipment. Each auxiliary boiler is designed to burn No. 2 fuel oil and can provide 100,000 lb/h steam at 250 psig saturated condition. Each feedwater pump is sized for 220-gal/min capacity at 700-ft discharge head. A separate connection is provided on the plant main deaerator for the feedwater suction. One auxiliary boiler is maintained in a standby condition when the plant is operating with one module only.

Industrial Waste Treatment System. The industrial waste treatment system for the baseline plant employs the following unit processes and operations:

- Flow Equalization. Contaminated runoff and leachate from a storm over a synthetic-membrane-lined coal pile (design based on the worst recorded storm in 10 years during a 24-hour period) is collected in a synthetic-membrane-lined earthen basin. Contaminated runoff from the dolomite storage pile is similarly collected in a separate earthen basin, which also receives contaminated yard drains. Both basins are designed to settle heavy sediment and equalize the peak flow rates from the "design" storm. A common pump station collects the discharge from the two basins, and the combined wastewater is pumped to the treatment system at a controlled rate.

  The treatment system employs a flow-equalization tank designed to equalize flow from the following sources:

  - Material storage pile runoff collection basins
  - Plant floor drain sumps which receive miscellaneous low-volume wastes, boiler blowdown, water treatment filter backwashes, and equipment cooling water
  - Discharge from a batch demineralizer-regenerant neutralization tank.

- Neutralization. Acidic wastewater is neutralized with hydrated lime in a two-stage system. Each fiberglass neutralization tank provides 10 minutes of reaction time at design flow. Each tank is equipped with a fixed-mount mixer, which completely mixes lime slurry with the wastewater, and with a pH probe and a controller, which automatically feeds lime slurry to the tank to control pH. An integral lime storage silo/lime slurry makeup system consists of a 50-ton lime silo, dry lime feeder, lime slurry tank, slurry tank mixer, and lime slurry feed pumps.

- Oxidation. Air is fed to the second-stage neutralization tank through a sparger pipe to oxidize any remaining ferrous iron to the ferric state. The air is supplied by a set of centrifugal blowers.

- Flocculation. Flocculation to promote particle size growth is provided in a fiberglass tank with a 10-minute retention time at design flow. The tank is equipped with a low-rev/min, variable-speed agitator. Polymer emulsion is drawn directly from a 55-gal drum and is diluted and fed to the flocculation tank by a polymer feed unit.

- Clarification/Thickening. Overflow from the flocculation tank enters a plate-type clarifier/thickener to separate suspended solids. Solids settle between the inclined plates to the thickener zone while the clarified supernatant liquid rises above the plates and discharges through flow-distribution orifices. The integral thickener section includes a picket-fence-type scraper mechanism, which further concentrates the sludge.

- Sludge Dewatering. Thickener sludge is piped to a holding tank; the procedure allows one-shift operation of the dewatering equipment and provides some further thickening. From the holding tank, the sludge is pumped to a plate-and-frame filter press for dewatering. The filter press provides a sludge cake of 30 wt% or higher dry solids. The filter press cake is dropped from the press into a sludge dump truck or dumpster. Filtration is returned to the flow-equalization tank.

Cooling tower blowdown is collected and treated separately in an earthen basin to remove only the suspended solids before the blowdown is discharged to the receiving stream. The basin is designed for sludge removal by drag-line or front-end loaders and trucks.

2.5.19 Civil, Architectural, and Structural Plant Aspects

Building structures enclose the following plant components (Figure 8):

- Steam turbine
- Gas turbines
- Administrative area, controls complex, and maintenance area
- Auxiliary boilers
- Emergency generator
- Coal preparation equipment
- Selected areas of the steam generation module housing compressors and critical equipment
- Vehicle maintenance area
- Warehouses
- Makeup water pretreatment equipment
- Wastewater treatment equipment.

Additionally, supporting structures, foundations, or both, are provided for the balance-of-plant components shown in Figures 8 through 13.

Codes and Standards. The following are applicable in establishing structural engineering design criteria and steel and concrete construction requirements:

- The BOCA Basic Building Code, or comparable governing code, based on plant location.
- American National Standards Institute, "Minimum Design Loads for Buildings and Other Structures," ANSI A58.1.
- Local building codes, as applicable.
- American Concrete Institute
  - ACI 301, "Specification for Structural Concrete for Buildings"
  - ACI 318, "Building Code Requirements for Reinforced Concrete"
  - ACI 307, "Specification for the Design and Construction of Reinforced Concrete Chimneys"

- American Institute of Steel Construction

  - AISC, "Specification for the Design, Fabrication, and Erection of Structural Steel for Buildings

  - AISC, "Code of Standard Practice for Steel Buildings and Bridges.

Building/Structure Description.

Structures.

- Building structures and equipment supports are steel framed, AISC Type 2 construction, with bracing for transfer of lateral forces.
- Building foundations are anticipated to be spread footings and mats, based on the assumption that rock will be found near the ground surface. Should the subsurface exploratory program and geotechnical evaluation that would be conducted for the specific site prove differently, the most economical deep foundations would be selected at that time. Caissons, steel piles, cast-in-place or precast piles, and composite piles are possible alternatives if shallow foundations prove unfeasible.
- Barge unloading facility with dolphins (closely driven piles tied together) supporting reinforced-concrete caps, with a protective fendering system. Pile type will be determined upon evaluation of the geotechnical data.

Improvements to Civil Engineering Aspects.

- Surface Design.

  - The site is conceptually designed to conform, where feasible, with existing drainage patterns and contours.

  - Final earth grade adjacent to equipment and buildings will be at least 6 in. below the finished floor slab, with a minimum slope away from the building to normal grade of 0.5 percent.
- Access Roadways and Parking. The plant roads are all two lanes with a paved shoulder, with the pavement type and thickness selected based on the soil-bearing value of the subgrade and the anticipated vehicular axle loads. Road cross sections are crowned to achieve positive drainage; they slope away from the crown at a slope of at least 2 percent.
- Railroad Development. A railroad spur is extended from existing tracks into the plant site. All elements necessary to provide access to the plant site are furnished, including, for example, grading, ties, ballast, rails, switches, and road crossings.
- Coal Storage, Dolomite Storage, and Ponds. The material storage areas and the associated runoff ponds are protected to conform to all State and Federal regulations.

  - The coal pile and the coal pile runoff pond are lined with a 30-mil PVC liner.

  - The dolomite storage runoff pond and the cooling tower pond are lined with a bentonite/clay liner.

  - The construction pond is unlined.

Materials of Construction.

- Structural Steel. ASTM A36, unless otherwise dictated by design requirements
- Exterior Walls. Insulated metal siding
- Interior Partitions
  - Metal studs with two layers of gypsum board on each face
  - Concrete masonry units (normal weight) where required for fire barriers, stairwells, lavatories, and other selected locations
- Elevated Floors. Metal floor deck and reinforced concrete slab
- Roof. Metal deck, rigid insulation, and single-ply membrane roofing.
- Stairs. Open grating.

2.6 MODULAR CONSTRUCTION AND SCHEDULE

The baseline plant is modular; its largest components are amenable to shop assembly and shipment by barge. Because this supply approach can result in better quality control, a shorter construction schedule, and lower total costs [11,12], shop assembly and barge shipment were chosen for many of the major plant components.

2.6.1 General Approach

The approach in this study was to conceptually evaluate major plant components and apply engineering judgment to reach a decision on the extent of shop fabrication and degree of modularity. The following steps were taken:

- Determine weights of larger components and potential modular plant sections
- Evaluate appropriateness of modularity, barge shipping, rail shipping, or field construction
- Consider the position/timing of each module as a part of the overall construction schedule
- Consider the scheduling and ability to receive components by barge rather than by rail to determine the shipping method for each module
- Include appropriate costing to account for the delivery and erection of each module.

2.6.2 Modular Components/Systems Considered

The modular components/systems considered for this study are shown in Table 31. Whether a component/system is to be shipped by barge or rail will depend upon the supplier of the equipment, supplier location, schedule constraints, and other factors. For this reason, a component small enough for rail shipment may be shipped by barge if it is convenient to do so.

2.6.3 Fabrication of Major Components

Large Refractory-Lined Vessels. Large vessels can be lined with refractory in the field. The slight increase in field-work cost associated with this lining is offset because shipping weight, lift at the site, and overland transport at the site are all reduced. The carbonizer, CPFBC, and cross-flow filters are included

Table 31 Components/Systems Considered for Modular Construction/Shipment

Component/System	Approximate Number of Units	Size L x W x H or D x L (ft)	Shipping Weight for Each Unit (ton)	Possible Method of Shipment
FBHE	2	37 x 70	815	Barge
FBHE Screw Cooler	4	---	40	Barge or Rail
FBHE-BFW Recirculating Pump	4	---	24	---
FBHE Restricted-Pipe Discharge Hopper	4	7 x 13	20	Rail
CPFBC*	2	20 x 107	380	Barge
CPFBC Cyclone	8	10 x 41	45	Barge or Rail
CPFBC Start-Up Heater	2	---	15	Rail
Carbonizer*	2	15 x 47	130	Barge
Carbonizer Collecting Tank	2	12 x 23	155	Barge
Carbonizer Cyclone	2	8 x 28	70	Barge or Rail
Carbonizer Start-Up Heater	2	---	13	Rail
Cross-Flow Filter--CPFBC*	2	20 x 54	104	Barge
Cross-Flow Filter--Restricted-Pipe Discharge Hopper	4	---	---	---
Cross-Flow Filter Screw Cooler	4	---	---	---
Cross-Flow Filter--Carbonizer*	2	15 x 54	52	Barge
Coal Storage Vessel	3	12 x 27	101	Barge or Rail
Coal Injector Vessel	3	12 x 62	312	Barge or Rail
Dolomite Storage Vessel	3	6 x 16	23	Rail
Dolomite Injector Vessel	3	7 x 33	89	Barge or Rail
Steam Turbine HP/IP Case	1	24 x 10 x 12	90	Barge or Rail
Steam Turbine HP/IP Rotor	1	7 x 21	26	Barge or Rail
Steam Turbine LP Case	1	25 x 21 x 18	122	Barge or Rail
Steam Turbine LP Rotor	1	17 x 25	63	Barge or Rail
Steam Turbine Generator Stator	1	24 x 14 x 16	218	Barge or Rail
Steam Turbine Generator Rotor	1	5 x 29	37	Barge or Rail
Steam Turbine Generator/Exciter	1	13 x 8 x 9	23	Rail
Main Steam Valves	2	14 x 5 x 10	24	Rail
Reheat Steam Valves	2	10 x 7 x 14	15	Rail
Gas Turbine Assembly	2	46 x 38 x 15	175	Barge
Gas Turbine Generator	2	23 x 12 x 16	170	Barge
Gas Turbine Enclosure	2	38 x 25 x 18	80	Barge
Gas Turbine Mechanical Package	2	33 x 10 x 10	38	Rail
Gas Turbine Electrical Package	2	24 x 10 x 10	23	Rail
Gas Turbine Starting Package	2	17 x 12 x 15	17	Rail
Gas Turbine Generator/Exciter	2	6 x 7 x 12	7	Barge or Rail

*Weight does not include internals or refractory.

in this category. The remainder of the vessels will likely have refractory installed before delivery. This decision is also site-specific and could change, depending on the manufacturer's capability, construction schedule constraints, and site conditions.

Fluidized Bed Heat Exchanger. The FBHE is 37 ft in diameter and nearly 70 ft long. The external insulation specified for the FBHE is installed in the field. The fluidized bed sections that are primarily waterwall enclosures and serpentine tube elements are shop-fabricated, assembled, interconnected, and then inserted in the FBHE vessel. Connections with headers and external nozzles, inspection, and hydrotesting are completed, and the unit is shipped by barge to the site. If the boiler manufacturer does not have barge-shipping capability, the boiler parts can be shipped by rail as subassemblies to a pressure vessel supplier with these facilities and assembly capabilities [11,12].

Subassemblies can also be fabricated at the vessel manufacturer's shop, depending upon the location and capability of the shop and on the schedule.

Gas Turbine/Generator Assembly. The gas turbine generating system features modular construction to facilitate shipment and assembly. The system is preassembled to the maximum extent permitted by shipping limitations. Where possible, subsystems have been grouped and installed in auxiliary packages to minimize field assembly. These packages are completely assembled and wired at the factory and require only interconnections at the site. The pipe rack assemblies supplied eliminate the need for piping fabrication during construction.

Table 31 lists the major components for the gas turbine electric generating system with their approximate weights and dimensions.

Steam Turbine/Generator Assembly. Because of its size and weight, the steam turbine generating system cannot achieve the degree of modularity that is achieved by its gas turbine counterpart. The LP case can be shipped as an assembled component minus the rotor; it is listed that way in Table 31. However, once the apparatus reaches the site, the case must be disassembled to some extent to install the rotor and other component parts. A similar situation exists for the HP/IP steam turbine section. The generator rotor is also shipped separately. Although modular shipment of the exciter and main steam valves is possible, complete steam turbine generating system modularity is not recommended.

Balance-of-Plant Modular Components. The baseline plant balance of plant (BOP) systems/components are similar to those of a PC-fired plant. Many of these systems/components may be amenable to shop assembly and barge shipment. However, our ultimate objective was to identify the baseline plant cost advantage; therefore, the BOP systems were not investigated for shop assembly and barge shipment. Since the baseline steam plant output is about half that of a PC-fired plant, many more baseline plant components can probably be shipped by barge, but such a detailed analysis was beyond the scope of this study.

2.6.4 Module Transport and Erection

Based on an earlier study [11], numerous manufacturers appear to have access to waterways and can shop assemble and load PFB combustion vessels on barges. These barges are commercially available and have been used extensively by the petrochemical industry. The report for the study just referenced identifies potential barge-shipping companies and lists seven specific barges that should be capable of transporting the major baseline plant components. Given 6 months' notice in today's economic climate, shipment of such large components can easily be arranged.

Considerable utility experience in barge-shipping and erection of large steam generator vessels also exists as a result of the expanding nuclear industry in the 1960s and 1970s. Several vessels weighing approximately 800 tons have been shipped and erected. Several contractors in the United States specialize in transporting/rigging this heavy equipment. Thus there appear no major obstacles to proceeding in a similar way with this PFB combustion plant design.

The CPFBC and FBHE vessels, as well as other equipment being transported by barge, can be moved from the barge to the construction site by crawler/transporters similar to the one shown in Figure 75.

Figure 76 shows a crawler/transporter being positioned under a 36-ft-diam catcracker vessel aboard a shallow-draft oceangoing ship. Figures 77 and 78 show the transporter unloading the vessel from the ship and delivering it to the construction site. Each crawler/transporter can carry 700 tons. They are rented as a pair for $30,000/mo. The bearing pressure of the transporter on the road is about 4600 lb/ft^2, about half the load-bearing capacity of many United States interstate highways. Once the crawlers have transported and positioned the load at the job site, the load is generally jacked to the desired elevation and the permanent support structure is completed.

2.6.5 Construction Sequence and Schedule

The formulation of comprehensive shop-fabrication, barge-transport, barge-unloading, and site-erection activities and integration of all of these into a detailed schedule is beyond the scope of this study. Such a plan requires a detailed investigation into the delivery time and other requirements for all vendors, a study of all site requirements and potential barge-loading arrangements, and a study to optimize construction sequencing. However, sufficient analysis was done to provide costs to the required level of detail.

The conceptual project schedule is shown in Figure 79. The total elapsed time from the completion of preliminary engineering until commercial operation is 3-1/2 years. Barge unloading takes place within 6 months, which may be shortened depending upon the logistics of shipping, distance from the barge to the power island, number of components to be shipped, etc. This schedule could conceivably be shortened to 3 years, depending upon the evolution of the shop fabrication process for the FBHE and other long-lead items.

2.7 PLANT OPERATING PHILOSOPHY

The concept for the baseline second-generation PFB combustion plant is a baseloaded plant with occasional turndown to 50-percent load. If the plant is required to operate at full load for 5 days and at 50 percent for the weekend, normal demand fluctuations can be met by reducing the output on each of the two modules.

If operating at 50 percent for extended periods, one module will be shut down entirely.

Plant operation is initiated by starting one CPFBC module and generating steam to bring the steam turbine on line. To achieve full-load status, the load on the first CPFBC module is increased gradually; steam from the second module is then blended with steam being produced by the first. The second module start-up sequence overlaps the first module sequence so that the first module is on hold for less than 1 hour. From a control-system design viewpoint, each module has a start-up system that provides steam for the common steam turbine. In the conceptual design

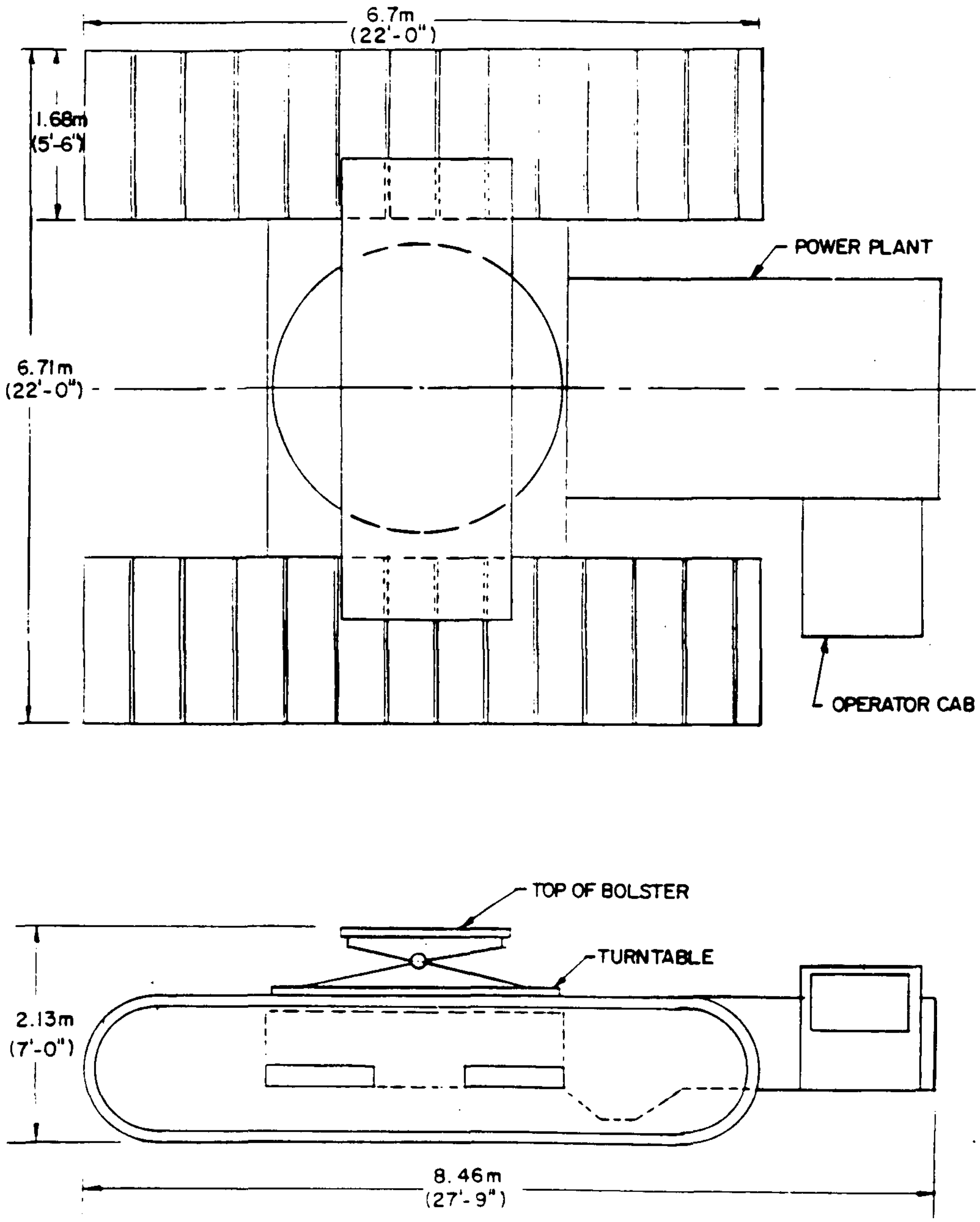


Figure 75 Typical Crawler/Transporter

Figure 76 Crawler Being Positioned To Raise Vessel

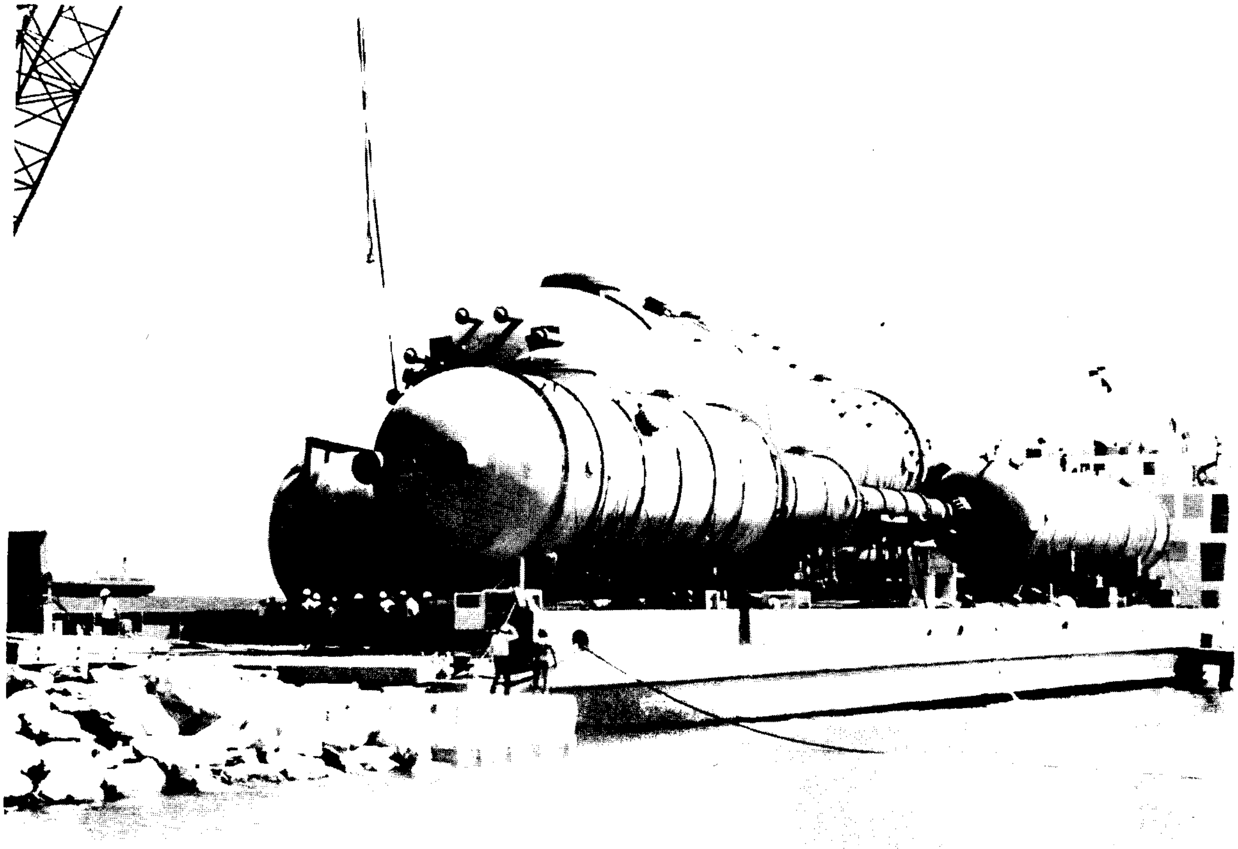


Figure 77 Crawlers Moving Vessel From Ship

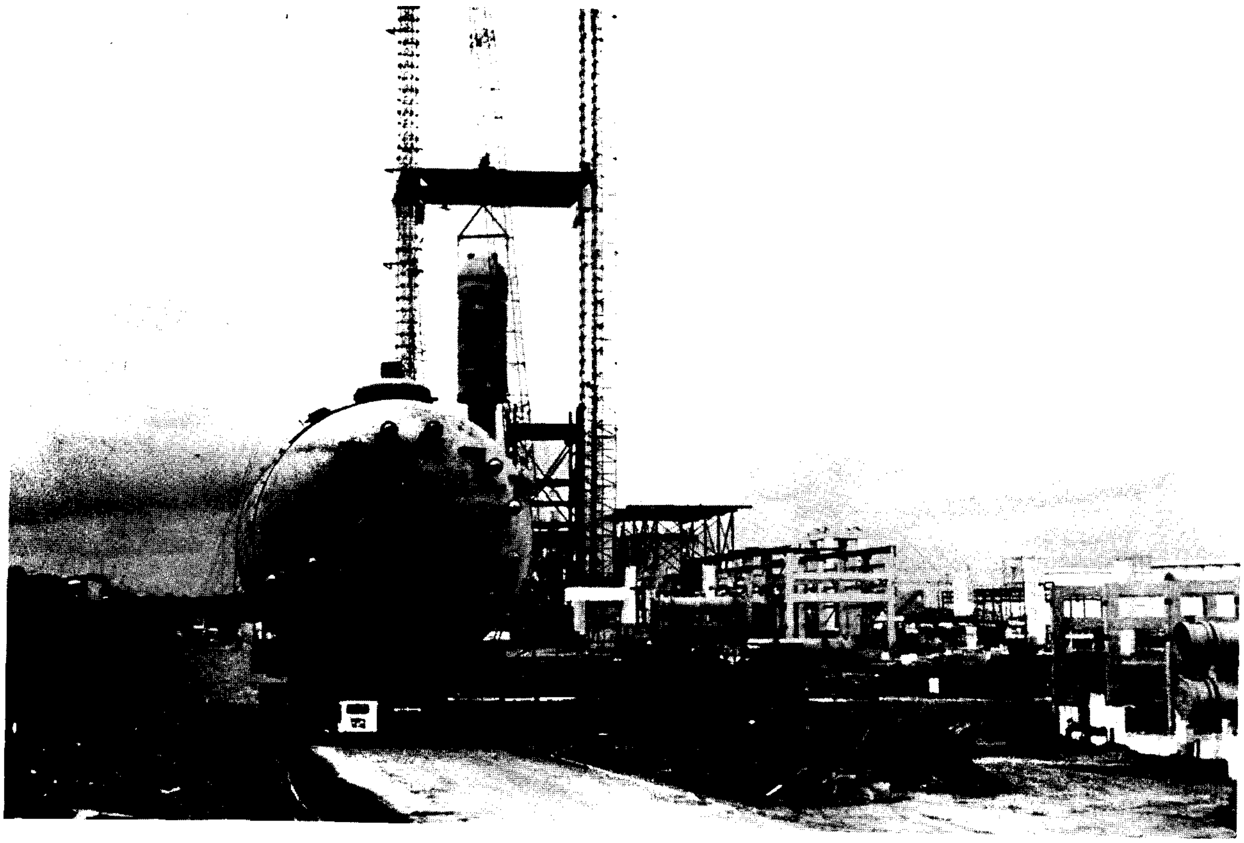


Figure 78 Crawlers Transporting Vessel to Job Site

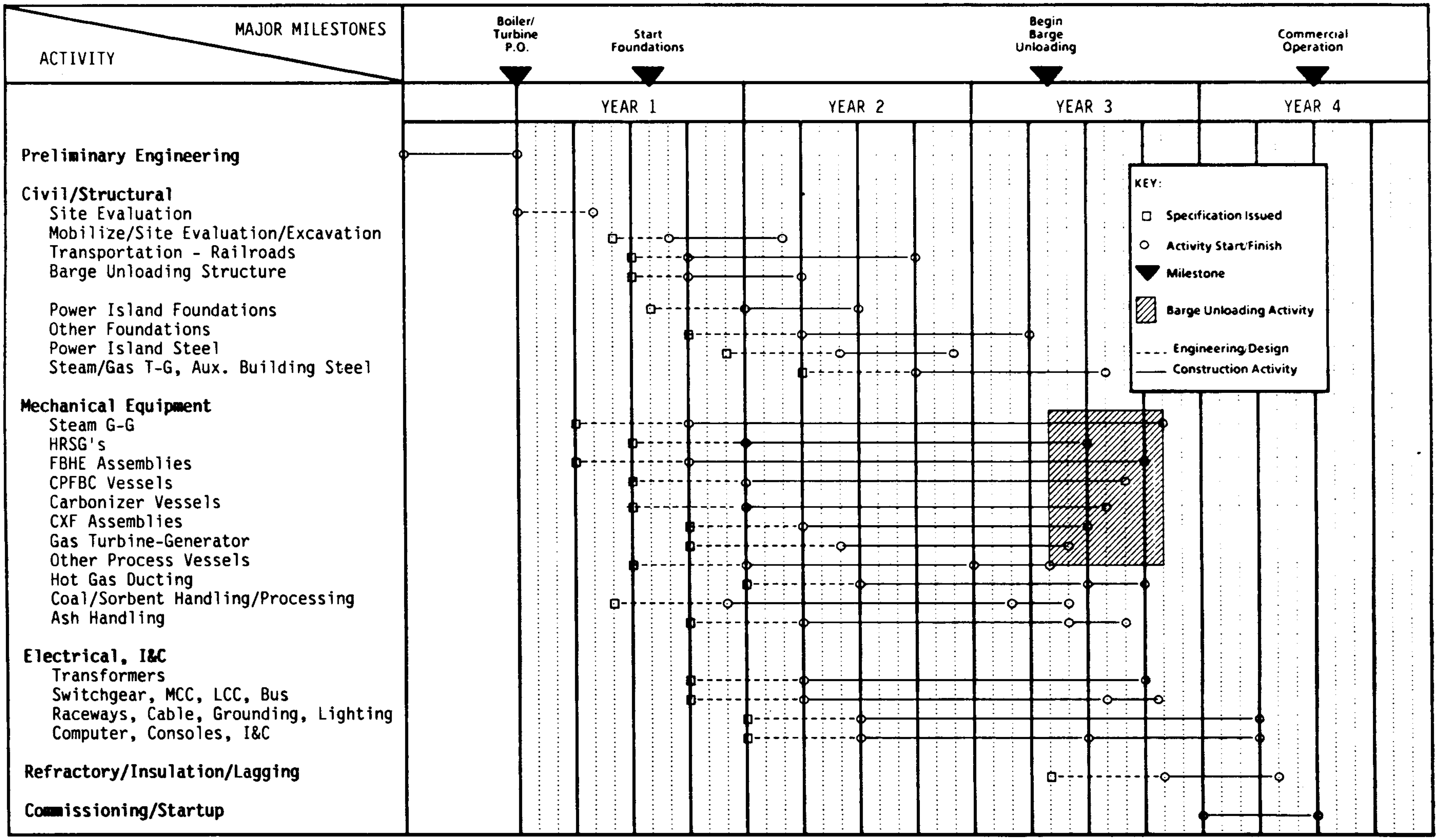


Figure 79 Summary Schedule for Conceptual 450-MWe Second-Generation PFB Combustion Plant

phase, it is more important to decide how the steam from the two modules should be blended rather than when this blending should take place. The purpose of the blending control system is to match the steam pressures and temperatures of the second module with those of the on-line module while maintaining steam production at the required level.

2.7.1 Plant Duty Cycle

The actual duty cycle imposed on the plant varies according to the application. But for the purposes of this conceptual design and to facilitate economic evaluations in accordance with EPRI's TAG guidelines (65-percent capacity factor), the load diagram shown in Figure 80 has been assumed. As shown in the figure, two outages are planned annually during off-peak times, totaling 6 weeks. The total planned load factor is 70 percent, and the unplanned outage is assumed to be about 5 percent. The method of meeting system demand varies, depending upon the demand cycle. If operating at full load for 5 days and at 50 percent for the weekend, the plant meets demand by reducing the output on each of two modules. If operating at 50-percent load for extended periods, one module is shut down entirely; the other is operated at 100 percent. During this time, maintenance on the idle carbonizer/CPFBC/gas turbine module can be performed.

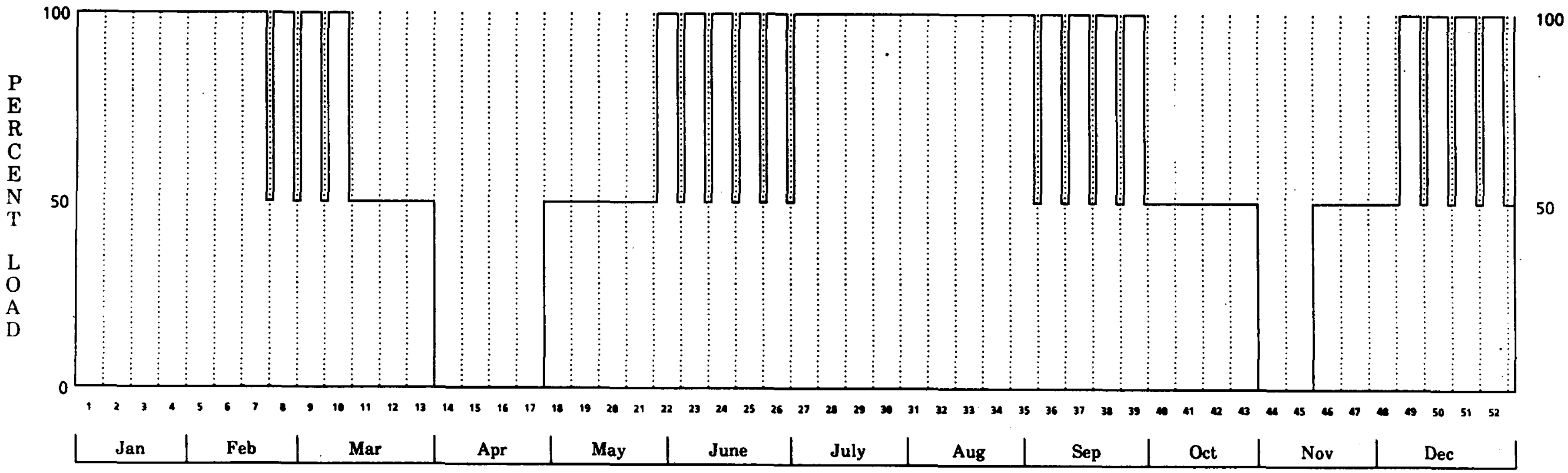
The assumed duty cycle may be unrealistic for two reasons. First, the plant is modular and, if designed properly, should be able to take advantage of this modularity and achieve a higher availability and load factor than a conventional PC-fired plant with a scrubber. Second, and perhaps more important, the baseline plant is projected to achieve a plant efficiency of nearly 44 percent. Because of this high efficiency, a utility system would assign the baseline plant a high dispatch priority, and the plant would essentially be in service whenever available. It is not unrealistic to assume that a capacity factor of 80 to 85 percent could be achieved for the n^{th} plant, depending on the utility's nuclear capacity and daily load swings.

Although in all probability the baseline plant loading will be higher than that shown in Figure 80, this load diagram has been assumed for both the reference PC-fired plant and the baseline PFB combustion plant. Since the baseline plant will be predominantly base loaded throughout its lifetime, features often incorporated to accommodate extended/efficient low-load operation and rapid start-up/shutdown (e.g., variable pressure and 50-percent steam bypass) have not been considered. The question of steam bypass capability has been considered in the operating philosophy, but only to the extent necessary to promote further definition of requirements.

2.7.2 Steady-State Control

Steady-state plant control was examined further in Section 2.5.17. To outline the plant control philosophy, we have considered that each module consists of a combustor section and a steam generator section. The system was shown in Figure 67, where the numbered flow streams are referenced to provide additional control system philosophy information.

The carbonizer is essentially a low-Btu gasifier. We anticipate that a dedicated, intelligent, and responsive carbonizer control system will be required. The proposed system, discussed in more detail in Section 2.5.17, is based upon the use of two dedicated and identical programmable controllers, each capable of continuously calculating and controlling the air rate to the carbonizer based on appropriate pressure, temperature, flow, and stream composition measurements. The remainder of the plant is controlled by a state-of-the-art distributed system.



Notes:

1. Total planned operation = 7728 hours (88%)
2. Total planned load factor = 70%
3. Unscheduled outage not indicated.
4. 50% weekend load accomplished by bringing each module to 50% load.
5. 50% extended load accomplished by shutting down one module.
6. Plant loading segments:
   a. Full load 7 days/week, 24 hours/day, 14 weeks
   b. Full load 5 days/week, 24 hours/day, 18 weeks
      50% load 2 days/week, 24 hours/day, 18 weeks
   c. 50% load 7 days/week, 24 hours/day, 14 weeks
   d. 0% load (scheduled outage), 6 weeks

Figure 80 Baseline Plant Assumed Duty Cycle

As discussed in Section 2.5.17, the distributed system master controller communicates with the two CPFBC modules and the steam turbine control subsystem. Load-distribution logic should be developed to determine whether a given part-load demand should be satisfied by one or two CPFBC modules. Emphasis in the conceptual design is being placed on establishing a preliminary scheme for starting up the first CPFBC and then bringing the second CPFBC module on line in a controlled manner. A proposed scheme is described in Section 2.5.17.

The steam generator consists of an HRSG, which recovers heat from the gas stream, and an FBHE, which recovers heat from solids circulated through the combustor. The steam generator requires two control subsystems: a feedwater control system and a steam temperature control system. A conventional feedwater control system is used. For steam temperature control, the philosophy is to position spray attemperator valves in response to transient temperature changes and to make long-term changes to the J valves that control the circulation of the hot solids to and from the combustor. These streams are numbered 1 and 2 in Figure 67.

The question of steady-state control has not yet been addressed in sufficient detail to permit establishing a steam-blending strategy. The approach we have taken is to generate a preliminary control system description to be used as a starting point for preliminary plant design.

2.7.3 Start-up and Shutdown

Performance Goals. A complete analysis involving plant/component dynamic analysis and a rigorous controls design were not the intent of this study. However, sufficient information is available to conclude that operation of a 453-MWe second-generation PFB combustion plant is feasible and well within present-day equipment/controls design. Emergency loss-of-load conditions are also discussed conceptually. Some R&D is necessary to provide information to design the components involved in pressure/exhaust relief of the system to prevent gas turbine overspeed and also to safely vent pressurized carbonizer gas to the flare system. The Task 4 Report discusses this need. The design criteria considered for plant operation are presented in Table 32.

The procedures for plant cold start-up, warm start-up, controlled shutdown, and emergency shutdown are described in Section 2.5.17.

Steam Blending. Steam temperature from the superheater and reheater is controlled by a combination of J valves (which control solids residence time), spray attemperators, and a finishing superheater bypass. The bypass raises the final steam temperature to the required setpoint during start-up and during steam blending

---

Table 32 Operating Requirements/Goals for Second-Generation PFBC Plant

Cold Start:	0 to 100-percent load in 16 hours
Warm Start (from weekend shutdown):	0 to 100-percent load in 6 to 8 hours
Hot Start:	4 to 6 hours
Ramp Rates:	3-percent/min between 50- and 100-percent load

operations. Each bypass contains a control valve, isolation valve, and desuperheating system for bypassing steam around the HP and IP/LP turbines. The bypass system provides the means to start up either CPFBC, raise the pressure and temperature of the steam generated by the second CPFBC, match the pressure of the first boiler, and blend the two steam flows in a controlled manner.

Start-Up Sequence. The design requirements for the carbonizer, CPFBC, FBHE, and HRSG will dictate the time required for cold start-up to full load. The general requirements of refractory heat-up limits, condensation in hot filter elements, and plant safety dictate additional limitations in the start-up procedures. A summary of the changes in each of the major components during the start-up procedure is presented in Table 33.

Cold Start-Up. The carbonizer/CPFBC units and the steam turbine start-up are closely coordinated. The heat-up of large refractory-lined components is most likely the limiting factor in the initial portion of the start-up sequence. The planned sequence is:

- In the first step, one gas turbine unit, driven by an electric motor, is started on liquid fuel fired directly into the dual-fuel topping combustor. Variable inlet guide vanes in the compressor are adjusted during the start-up sequence to provide efficient operation and control airflow. The second gas-turbine unit

Table 33 Plant Start-Up Sequence

Step*	Description	Time, h
1	Start Gas Turbine on Fuel Oil	0.25
2	Heat Up Carbonizer and CPFBC Units	3.0
3	Establish Shallow Beds in the Carbonizer and CPFBC Units	2.0
4a	Start Up First HRSG	
4b	Fire Coal in Carbonizer and CPFBC Beds	2.5
4c	Synchronize Gas Turbine	
5	Establish Reducing Conditions in Carbonizer	1.0
6	Start Up and Load Steam Turbine to 6 Percent	4.0
7	Bring First Module to Full Load	1.0
8	Blend Steam From Second Module	1.0
9	Bring Both Modules to Full Load	1.0

*Steps 1 through 7 are repeated for the second module after a 1- to 4-hour delay.

start-up closely follows the first unit. The exhaust gas from both gas turbines is vented to the stack until Step 4, and steam from the auxiliary boiler cools the heating surfaces in the FBHE.

- With airflow established to the carbonizer and CPFBC units, auxiliary burners begin to heat these vessels and the interconnecting hot-gas ducting and hot-gas cleanup units. The rate of heating is limited by the refractory in the hot-gas path, probably on the order of 200 to 300°F/h.
- In the third step, dolomite beds are established in both CPFBC units; the carbonizer is then started up as described in Section 2.5.17.
- In the fourth step, warm-up of the first HRSG begins. The isolation damper is modulated to heat the HRSG and to initiate steaming at a controlled rate. Steam pressure increases, and the drain valves are closed. A steam bypass valve opens when the specified pressure setpoint is reached, and the HRSG start-up is complete when the bypass damper is fully closed. At this point the HRSG is used in place of the auxiliary boiler.

  When the carbonizer and CPFBC dolomite beds reach 1100 to 1200°F, coal is fed to each bed and combustion is begun; the carbonizer and CPFBC bed temperatures increase to 1500 and 1600°F respectively. The beds are built up to operating levels; and the CPFBC operates as a "bubbling bed," with recirculating solids flow held to a minimum. The CPFBC and FBHE beds operate in an oxidizing mode and at high excess air to control temperature. This condition is considered "idle."

  Approximately 1 hour into this start-up stage, the second module is similarly started and brought to idle. CPFBC heat input is increased until a synchronous idle point is reached for both gas-turbine units, and the plant begins to produce power.
- Rolling, synchronizing, and initial loading of the steam turbine is initiated in the fifth step, when the main steam reaches approximately 1000 psia/700°F. The steam turbine control system automatically brings the turbine up to speed by slowly opening the high-pressure steam valve and partially closing the bypass valves shown in Figure 73. The steam turbine load is then gradually increased to 25-percent plant load (50-percent CPFBC load for Module 1) and the bypass valves are closed.
- Additional coal is now fed to the carbonizer, while airflow is lowered and a reducing condition is established. Excessive carbonizer exit temperature is prevented by direct nitrogen injection, if necessary. Char production in the carbonizer and transport to the CPFBC now begins.
- The unit is brought to full load while controlling steam turbine temperature differentials and gradually adjusting fuel feed and airflow split to the carbonizer and CPFBC. At the full-load design point, coal feed to the CPFBC is unnecessary, and char produced in the carbonizer supplies the entire heat input required.

Warm Start-Up. Start-up from a warm condition is generally required after a weekend or overnight shutdown. Heat is stored in the refractory-lined components and in the bed material inventory within the CPFBC and carbonizer units, as well as in the parts of the plant made up of plant metal. Thus start-up times are a result of temperature change limitations imposed by each system. We expect that the carbonizer and CPFBC refractory can be maintained above 1000°F for several days while the FBHE is cooled to avoid excessive tube material problems. The start-up sequence used in cold start-up is still followed, but the duration is correspondingly shorter.

Hot Start-Up. Start-up from a hot condition occurs following a generator trip or plant component failure that only causes a momentary shutdown. All components are hot, and we expect that the plant can be brought on line within 1 to 2 hours.

2.7.4 Emergency Conditions

Steam Turbine Loss of Load. The contingency action that follows a steam turbine loss of load depends, to a large extent, on the start-up philosophy adopted. Assuming the use of a 50-percent bypass for start-up, it follows that the same steam bypass system used in start-up will be available for both controlled and emergency shutdown.

In an emergency situation, both steam bypasses are open and the superheater and reheater safety valves lift. In a short period of time--the length of which is dependent upon the response time of the steam generator--the superheater safety valves reseat, and the HP steam flow is reduced to match the capacity of the LP bypass. At this time the reheater safety valves close. Since a great deal of heat remains in the FBHE beds, feedwater flow is maintained; steam continues to be generated to protect the steam generator tubes from overheating.

Gas Turbine Loss of Load. If sudden loss of electric load should occur, the unloaded gas turbine, if uncontrolled, would accelerate rapidly because of the large pressurized volume provided by the combustor, gas-cleanup system, and piping components. Under these conditions the primary control actions are as described in Section 2.5.6.

Dynamic simulation of the process will be necessary to investigate various load-rejection/emergency-stop alternatives and develop a coordinated control action. In particular, if the inlet guide vanes are partially closed, they should be fully opened to absorb a maximum amount of compressor power.

Other Contingencies. Normal shutdown procedures or emergency procedures used in typical power plant operations can be used for remaining contingencies, except for those related to the failure of any downstream unit, which would necessitate diverting fuel gas to flare. The flare system to be installed in the carbonizer is designed primarily for use during carbonizer start-up, but is sized to accept the gas flow that would have to be diverted from the gas turbine in the event of gas turbine loss of load.

Loss of solids recirculation through the combustor or a steam leak in the FBHE would cause an emergency shutdown of one CPFBC module. The steam bypass system could be designed so that the second module remained on line, but the bypass control system for this purpose might have to be more sophisticated than the one outlined in Section 2.5.17.

2.8 RELIABILITY AND AVAILABILITY ASSESSMENT

2.8.1 Basis and Approach

The rationale for undertaking a reliability, availability, and maintainability (RAM) assessment of the second-generation PFB combustion cycle is that, like any power-generating unit, it is capital-intensive and a complex combination of electrical and mechanical components subject to random failure as well as wear. Additionally, a highly efficient unit such as a second- generation PFB combustion plant will be high on any utility's commitment schedule (i.e., it will be scheduled to operate whenever it is capable of operation, at the highest capacity available). For these reasons it is desirable not only to determine what proportion of time the PFB combustion plant can produce power, but also to take cost-effective measures to increase plant availability to the maximum feasible level.

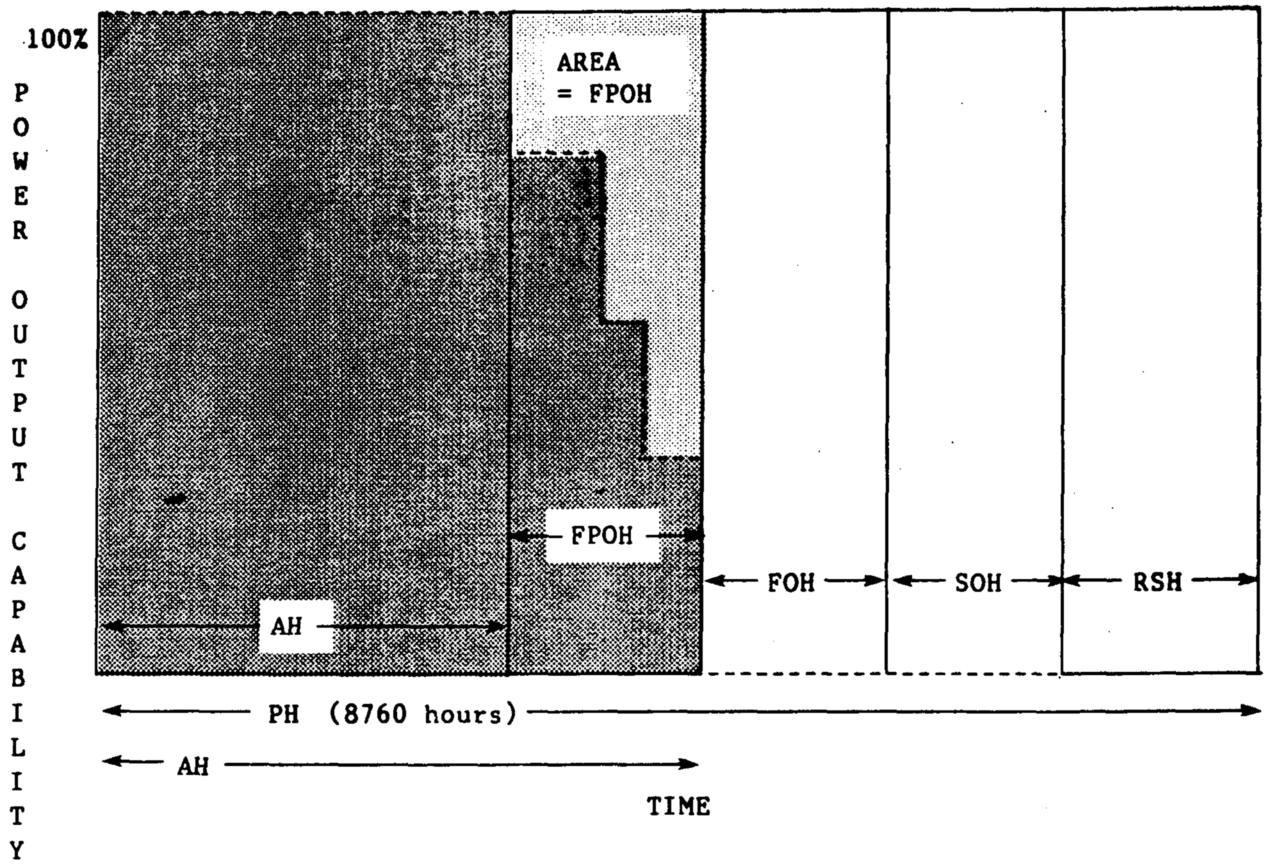
RAM techniques have been applied in the electric utility industry for over 2 decades and have reached a mature state, with standard and generally accepted definitions of terminology and methodology. The North American Electric Reliability Council (NERC) has a historical data base on the performance of power plants and their components for all present-day methods of power generation, ranging from fossil and nuclear base-load steam plants to load-leveling units such as pumped storage. The Council publishes Generating Availability Data Summary reports, which include the annual and 10-year performance of various types of generating units and their components. EPRI has developed assessment methodologies for advanced generation technologies, such as gasification combined cycles, and has developed computer programs such as UNIRAM for RAM assessment.

The approach taken for the RAM assessment was to use utility-accepted RAM methodology and EPRI's UNIRAM computer code, with component data from the NERC data summary and EPRI data bases supplemented by engineering estimates for new components, to determine the RAM indices for the baseline plant. This RAM assessment was based on information from NERC and EPRI [13-15], as well as input from team members. In addition to overall plant RAM measures, the team used the component criticality ranking option of the UNIRAM computer code to determine the 15 components that have the greatest impact on plant reliability.

RAM Terminology. Some of the terms used in RAM analyses, such as "reliability" and "availability," have general and vague connotations of dependability. In RAM work each of these terms and others such as "maintainability" have very specific definitions in terms of probability under specified conditions of operation. In this RAM assessment, the following industry-standard definitions apply:

- Reliability. The probability that an item (device, component, or plant) will perform satisfactorily for at least a given period of time when used under stated conditions.
- Availability. The probability that an item will be operational at a random instant in time. An equivalent definition is the fraction of time the item is capable of operation.
- Maintainability. The probability that a failed item can be restored to service in a given length of time when maintenance is performed under stated conditions.

These basic terms apply primarily to individual components which are bistate devices [i.e., they are either up (100-percent capacity) or down (0-percent capacity)]. A power plant usually has more than two operating capacity states because of a component failure or derating from other causes such as exceeding environmental parameters. Other measures, such as equivalent availability and system effectiveness, must thus be used to describe the operation of the unit. Figure 81 represents some of these concepts.



where

PH = Period hours, usually 8760 hours (1 year)
AH = Available hours (at >0% capability)
FOH = Forced outage hours (full--no power output)
SOH = Scheduled outage hours (assumed full)
FPOH = Forced partial outage hours
EFOH = Equivalent forced outage hours.

Figure 81 RAM Terminology

The concept of equivalent forced outage hours can be illustrated with an example. If a carbonizer with 50-percent throughput capacity, required to operate the plant, is down for 10 hours, it is equivalent to a full plant outage of 5 hours (0.5 x 10 = 5). The Equivalent Availability (A_E) is defined as:

$$A_E = (PH - SOH - FOH - EFOH)/PH$$

and the Effectiveness (E) as:

$$E = (PH - SOG - FOG - EFOH)/(PH - SOH)$$

Effectiveness is Equivalent Availability between scheduled outages, or:

$$A_E = E(PH - SOH/PH)$$

Two other terms commonly defined and calculated are Forced Outage Rate (FOR) and Equivalent Forced Outage Rate (EFOR); in terms of the diagram,

$$FOR = FOH/(FOH + SOH)$$

and

$$EFOR = (FOH + EFOH)/(PH - SOH)$$

These measures are often used in describing plant performance when conducting reliability analyses of an entire utility power system.

Equivalent Availability is the best measure of plant performance for the purposes of this RAM assessment. It describes most accurately the usefulness of a plant. If the plant is never shut down when it is available (zero reserve shutdown hours), which is a reasonable operating scenario for a low-heat-rate plant like the baseline plant, the equivalent availability is also the capacity factor of the plant.

RAM Methodology. The availability of a complex system such as a PFB combustion power plant is a function of the reliability and maintainability of the components and their functional configuration. An availability model is a device to relate the availability of the total system to the performance and arrangement of the components. For a bistate system, an availability block diagram can be constructed and probability calculus used to obtain the system availability as a function of the availability of the constituent parts. The many components in the baseline plant, as well as the existence of partial-capacity states, make a more sophisticated technique necessary. Thus the team used UNIRAM, a computer program developed under EPRI's aegis. Using state estimation and state enumeration techniques, UNIRAM computes plant performance indices, including Equivalent Availability, Effectiveness, Availability, Forced Outage Rate, and Equivalent Forced Outage Rate.

The plant is divided into subsystems based on capacity throughput and designed redundancy. A fault tree is constructed for each subsystem, the level of development being components for which reliability and availability data are available. Figure 82 is an example of the fault tree used for the carbonizer subsystem. Input to the UNIRAM computer code includes number and throughput capacity of subsystems, arrangement of the subsystems and their interrelationships in the plant, and data on failure frequency and restoration time for each component.

2.8.2 Analysis

We divided the baseline plant into the subsystems listed in Table 34.

The plant availability block diagram (Figure 83) is a series connection of the 15 subsystem groups. Since the assessment is for a mature or n^{th} plant, there is designed redundancy or excess capacity in only a few ancillary systems, a normal practice in utility power plants.

In addition to using data bases from the NERC and EPRI for applicable components, individual team members provided component data based on previous studies, judgment, and accumulated data bases on equipment in their scope.

Table 34 Baseline Plant Subdivisions Used for RAM Analysis

Subsystem	Number and Capacity
Steam Turbine and Generator	One, 100%
Sorbent Preparation	Two, 100%
Coal Preparation 1	Two, 100%
Coal Preparation 2	Three, 50%
Petrocarb Feed	One 100% carbonizer with one spare
Carbonizer	Two, 50%
CPFBC	Two, 50%
FBHE 1*	Two, 50%
FBHE 2	Two, 50%
Gas Turbine and Generator	Two, 50%
HRSG	Two, 50%
Condensate	Three, 50%
Cooling Water 1	Two, 50%
Cooling Water 2	Two, 50%
Feedwater	Two, 60%

*UNIRAM limitation on number of components per subsystem necessitated dividing the FBHE subsystem into two.

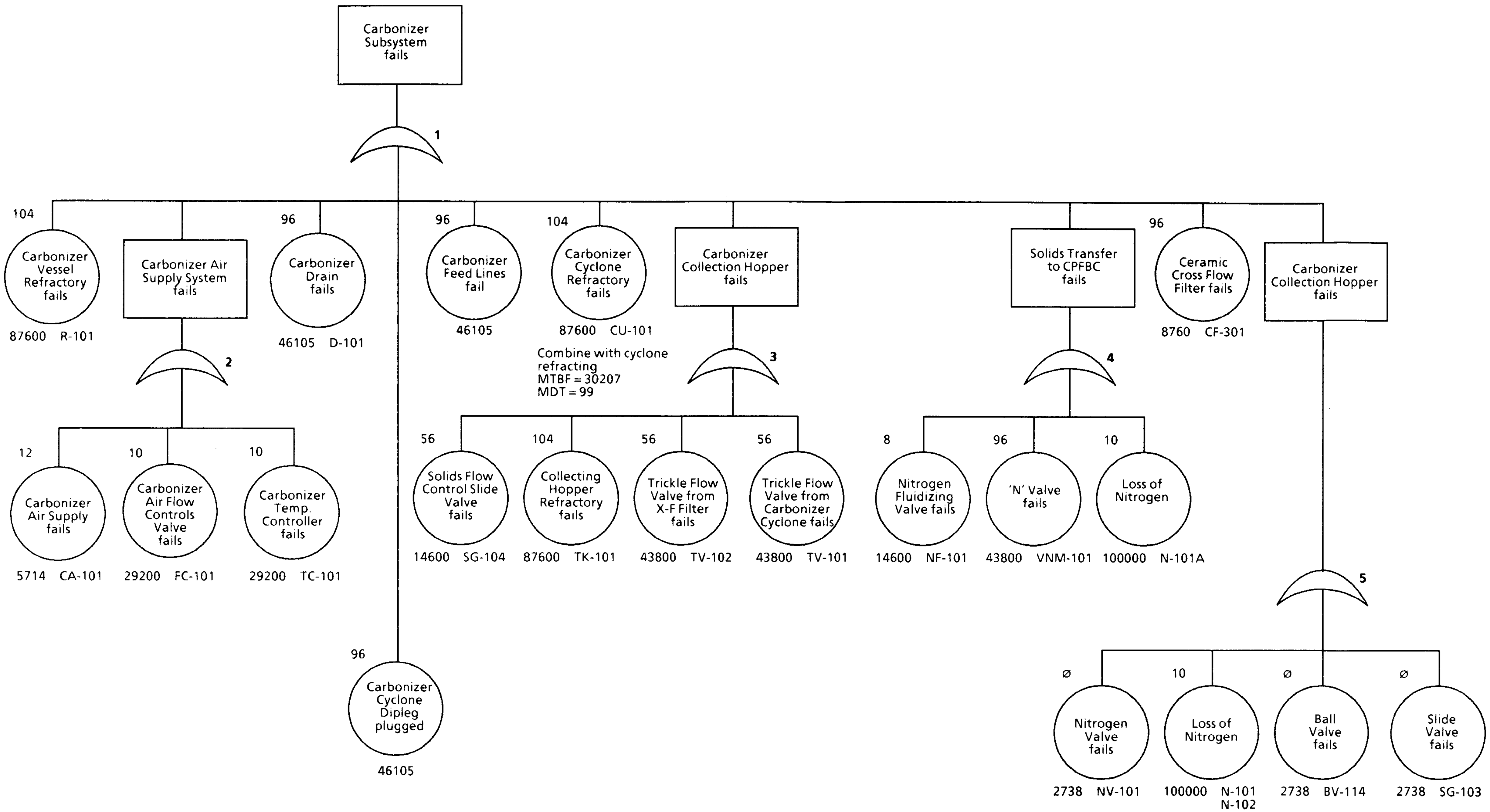


Figure 82 RAM Analysis Fault Tree--Carbonizer

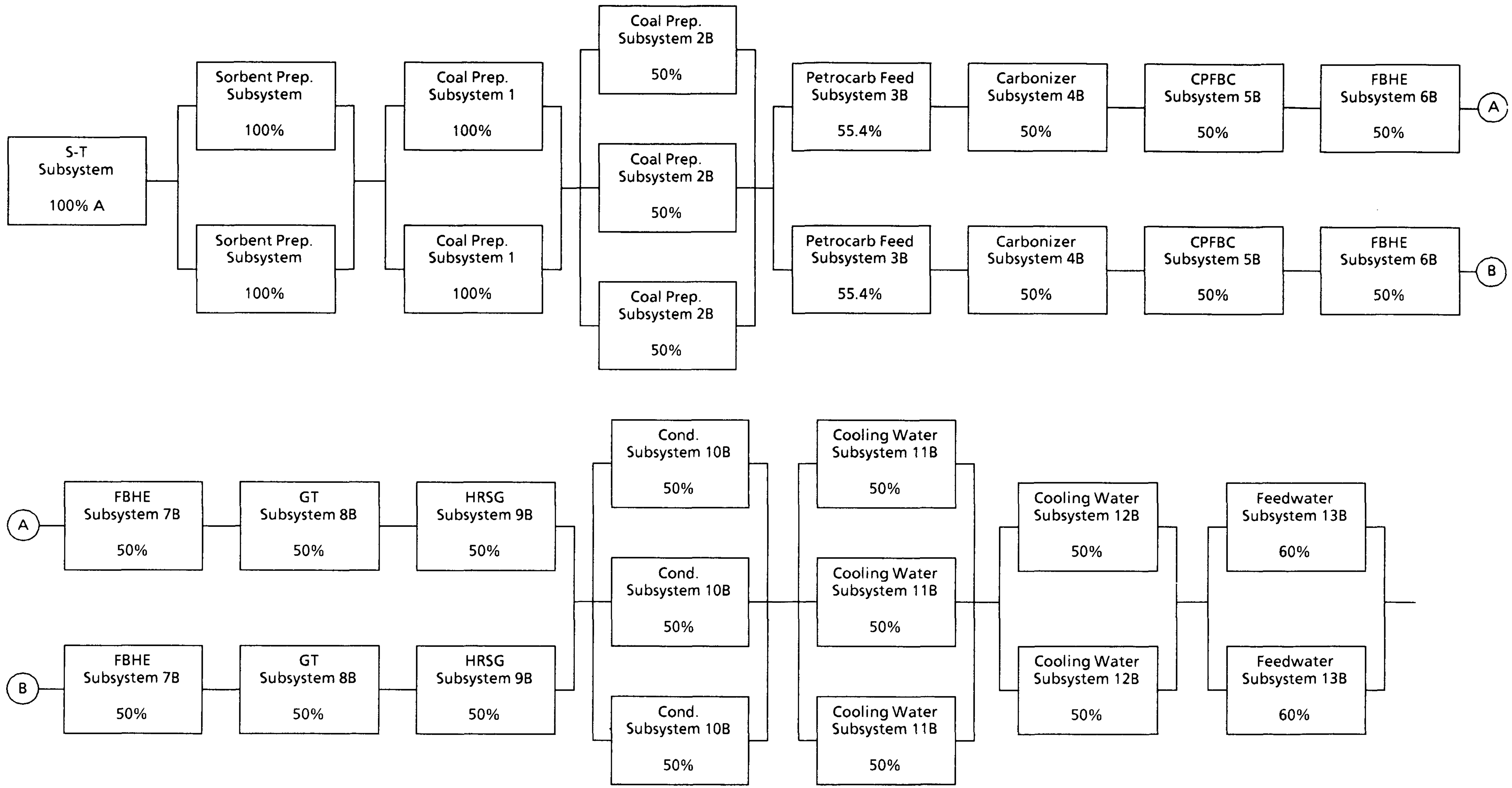


Figure 83 Basic Subsystem Availability Block Diagram

Assumptions and Ground Rules.

- Equipment basically functions as designed.
- Human error can be neglected (this may be reevaluated once operating procedures are available).
- Structural problems can be ignored as a cause of forced outage.
- Coal and dolomite unloading and handling (up to 3-day storage silos) are not included in the RAM model because of redundancy and storage capacity in relationship to component mean time to repair.
- Makeup water pretreatment system is not included in the RAM model because of redundancy and storage capacity in relationship to component mean time to repair.
- Ash storage silos and ash removal by truck are a batch process and do not impact plant operation.
- Plant will be on scheduled outage for 6 weeks (1008 hours) annually.
- The mean time between failures of each component is based on operating hours. Data and estimates from team members were adjusted to account for a utility power plant service factor of approximately 80 percent. Mean time between failures of components in the topping cycle arranged in two half-capacity trains were also adjusted to account for the reduced exposure to failure.
- Equipment used only during plant start-up, such as the fuel oil system and start-up air heaters, was not included in the RAM model.

Results. The subsystem fault trees and the availability block diagram were input to the UNIRAM computer code. The output of UNIRAM for the base case is shown in Table 35.

In addition to scheduled outage for 6 weeks (1008 hours), the plant is scheduled to be operated at 50-percent capacity for 18 weekends annually, by operating each module at 50-percent load, and about 5 weeks annually at 50-percent load, by shutting down one 50-percent module, accounting for 882 equivalent hours of reserve shutdown. Plant RAM measures consist of:

- Effectiveness: 83.08%
- Forced Outage Rate: 4.5%
- Equivalent Forced Outage Rate: 16.92%
- Equivalent Availability: 75.23%
- Availability: 84.96%

These results correspond to a capacity factor of 65 percent. The overall baseline plant has a mean time between failure value of 2082 hours and a mean time to repair value of 56 hours. The component criticality run produced the results listed in Table 36.

The criticality ranking factor for a component is the amount by which plant EFOR decreases if that component is made perfectly reliable with the rest of the plant at baseline values of reliability. Criticality factors are not additive.

The performance indices obtained are functions of the system configuration and especially of the mean times between failures and mean times to component repair. In the absence of a historical data base on PFB combustion system components such as combustors, FBHEs, cyclones, cross-flow filters, or restricted-pipe

Table 35 Base-Case Results From UNIRAM

Plant State	Availability (%)	Output Capability (%)	Days Annually
1	70.37	100.00	201.4
2	1.48	60.00	4.2
3	23.64	50.00	67.7
4	4.50	---	12.9
Total			286.2

Table 36 Results of Component Criticality Computer Run

Rank	Component	Criticality
1	Steam turbine	1.1154
2	Restricted-pipe discharge hopper ball valve (cross-flow filter)	1.0472
3	Restricted-pipe discharge hopper slide gate valve (cross-flow filter)	1.0472
4	HRSG	0.8455
5	Cyclone (CPFBC)	0.8357
6	Cross-flow filter (carbonizer)	0.6973
7	Cross-flow filter (FBHE)	0.6973
8	Gas turbine	0.4802
9	Restricted-discharge pipe hopper ball valve (FBHE)	0.4651
10	Restricted-discharge pipe hopper slide gate valve (FBHE)	0.4651
11	Steam turbine generator	0.3366
12	Trickle valve (cyclones to FBHE)	0.3210
13	Feedwater booster pump	0.2952
14	Feedwater pump	0.2952
15	Condenser	0.2476

discharge hoppers, the chosen RAM parameters are based on team members' engineering judgment. When prototype components are built and tested, the data obtained should be validated and the RAM of an advanced PFB combustion system should be reevaluated.

Cycle Variations Considered.

Petrocarb Feed System. An alternative configuration for the Petrocarb feed system was studied. The spare Petrocarb systems, which can supply coal and dolomite to either of the two modules in the plant, were removed. The change in plant Equivalent Availability is 0.3 percent or 26 extra hours of equivalent forced outage annually. The yearly savings associated with the spare Petrocarb feed system are $300,000, assuming a replacement energy cost of $25/MWh. The estimate of capital cost differential was $1.3 million; thus the spare Petrocarb feed system has a payback period of slightly over 4 years, which makes it a good investment.

Oil Firing To Bypass the Carbonizer. An alternative firing mode studied involved firing oil in the gas turbine combustors to replace carbonizer fuel gas heat release. The difference in plant availability is about 3 percent, assuming perfect availability of oil. The economic viability, at least for short periods of emergency operation, can be assessed on the basis of $\$/10^6$ Btu oil and coal. Such an assessment was not attempted in this study.

2.8.3 Conclusions

The results obtained are reasonable given the subjective assessment of the expected performance of PFB combustion-related components. The assessment performed results in confidence that an n^{th} plant based on second-generation PFB combustion technology will perform about as well as a state-of-the-art fossil-fuel-fired plant with sulfur-removal equipment and will be acceptable to utility planners as an alternative technology for meeting NSPS when installing additional system capacity.

2.9 REFERENCES

1. R. V. Garland, P. W. Pillsbury, and G. Vermes, "Generic Studies of Advanced Fluid Bed Air Heater Technology," Report DOE/CE/40543-5, prepared by Westinghouse Electric Corporation, Combustion Turbine Systems Division, under DOE Contract DE-AC02-82CE40543, March 1986.

2. D. A. Lewandowski, J. Weldon, and G. B. Haldipur, "Application of the KRW Coal Gasification Hot Gas Cleanup Technology to Combined Cycle Electric Power Generation," presented at the American Institute of Chemical Engineers Boston National Meeting, August 1986.

3. T. P. Sherlock, et al., "Low NO_x Heavy Fuel Combustor Concept Program" NASA Report Cr-165614, February 1982.

4. L. N. Rubow, et al., "Technical and Economic Evaluation of Ten High Temperature, High Pressure Particulate Cleanup Systems for Pressurized Fluidized Bed Combustion," Department of Energy Report DOE/MC/19196-1654, prepared by Gilbert/Commonwealth under Contract DE-AC21-82MC19196, July 1984.

5. T. E. Lippert and D. F. Ciliberti, "Ceramic Filter Elements for High-Pressure, High-Temperature Gases, Report CS-4382, prepared by Westinghouse Electric Corporation under EPRI Research Project 1336-6, January 1986.

6. H.-P. Schiffer, U. Renz, and O. J. Tassiker, "Hot Gas Cleanup Research on the Aachen Pressurized Fluidized Bed Combustor," presented at the 1988 Seminar on Fluidized-Bed Combustion Technology for Utility Applications, Palo Alto, California, May 1988.

7. A. J. Leitch, G. K. Burnard, and G. P. Reed, "Performance of a Large Ceramic Element Filter Module on a Pressurised Fluidised-Bed Combustor," presented at the 1988 Seminar on Fluidized-Bed Combustion Technology for Utility Applications, Palo Alto, California, May 1988.

8. T. Lippert, "Ceramic Crossflow Filter for Hot Gas Cleaning," Proceedings, Conference on Gas Cleaning at High Temperatures, Surrey, England, September 1986.

9. D. F. Ciliberti, "Performance Evaluation of a Ceramic Cross-Flow Filter on a Bench-Scale Coal Gasifier," Proceedings of the Sixth Annual Contractors Meeting on Contaminant Control in Coal-Derived Gas Stream, K. E. Markel and D. C. Cicero (eds.), DOE/METC-86/6042, June 1986.

10. Electric Power Research Institute, "Cool Water Coal Gasification Program: 4th Annual Progress Report," Project 1459, AP-4832, October 1986.

11. Foster Wheeler Development Corporation, "Preliminary Feasibility Analysis of Shop-Assembled Barge-Shipped Pressurized Fluidized-Bed Steam Generators," EPRI Final Report CS-3156, under EPRI Contract RP1180-15, A. Robertson, principal investigator, June 1983.

12. BBC Brown Boveri, et al., "PFBC Turbocharged Boiler Design and Economic Study, Vol. 1," Final Report CS-5487, under EPRI Contracts RP2428-1 and -2, November 1987.

13. North American Electric Reliability Council, "Generating Assessment Data Summary: Equipment Availability and Component Cause Code Reports for 1976 - 1985," 1985.

14. Electric Power Research Institute, "Guide for the Assessment of the Availability of Gasification-Combined-Cycle Power Plants," EPRI AP-2202, January 1982.

15. Electric Power Research Institute, "Component Failure and Repair Data for Coal-Fired Power Plants," EPRI AP-2071, October 1981.

Section 3

PLANT ECONOMIC ANALYSIS

This section describes the approach, basis, and methods that were used to perform an economic evaluation of the second-generation PFB combustion power plant. The results of this effort are presented at the composite level--expressed as the levelized COE, and at the component level--consisting of the capital cost and operating costs and expenses, including fuel cost. Results of this evaluation based on a 30-year life are summarized in Table 37.

The evaluation approach is summarized in the following section. Succeeding discussions examine the components of the COE in the order they were developed and presented in Table 37.

Table 37 Summary--Capital Costs and Economics* (Second-Generation PFB Combustion Power Plant)

Item	$	Unit Cost
Total Capital Requirement (TCR)	469,504,000	1037 $/kW
Operating and Maintenance	17,211,000	38 $/kW·yr
Consumables	8,693,000	3.3 mills/kWh
Fuel	36,096,000	14.5 mills/kWh
Levelized Busbar COE†	---	75.7 mills/kWh

*Based on net plant electrical output of 452.8 MW, a 65-percent capacity factor, a total plant cost (TPC) expressed in December 1987 dollars, and first-year costs expressed in December 1987 dollars.

†COE levelized over 30 years at 65-percent capacity factor.

3.1 EVALUATION APPROACH

The figure of merit in this evaluation is the COE. The capital cost, operating costs and expenses, and the COE were established consistent with EPRI Technical Assessment Guide (TAG) [1] methodology, the project Ground Rules Document, and the plant scope identified in Section 2. The specific components of the COE, identified in Figure 84, indicate the proportion of their contribution to COE. The cost

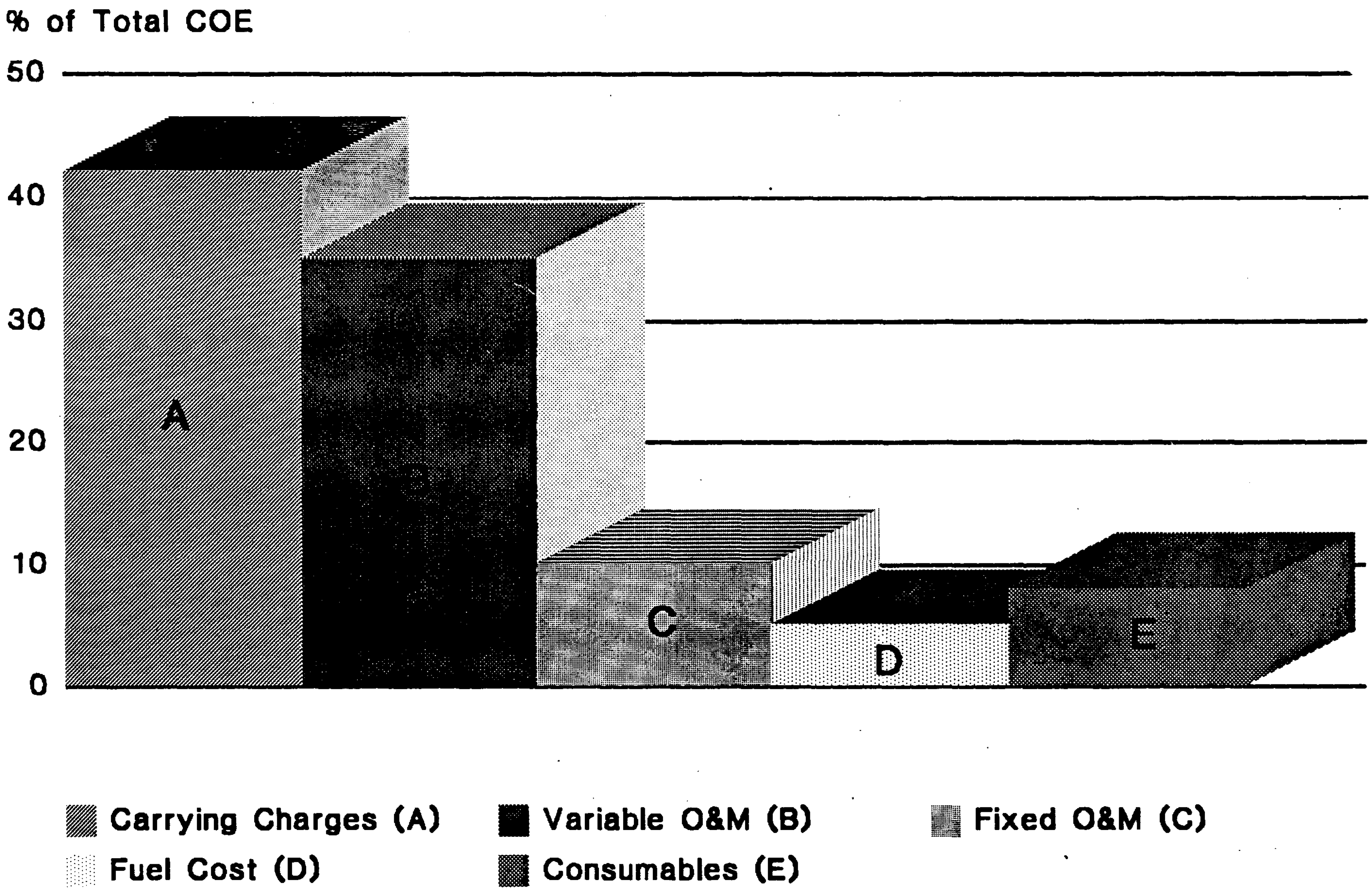


Figure 84 Components of Plant COE

of each component was quantitatively developed to enhance credibility and establish a basis for subsequent comparisons and modification as the technology is further developed.

The carrying charge value, the largest component of the COE, is determined directly as the product of the fixed charge rate and the capital cost of the plant. The approach to evaluating the capital cost of the plant consists of evaluating the installed equipment and material cost of each identified component of the plant. The sum of these individual costs, added to the estimate of engineering services, contingencies, escalation and financing charges, and owner's costs, yielded the total capital requirement (TCR) for the plant. The general estimate basis and assumptions are identified below and are supplemented by more specific considerations in Appendix F:

- Total plant cost values are expressed in December 1987 dollars.
- The estimate represents a mature technology plant, or "n^{th} plant" (i.e., it does not include costs associated with a first-of-a-kind plant).
- The estimate represents a complete power plant facility with the exception of the exclusions listed in Section 3.2.5.
- The estimate boundary limit is defined as the total plant facility within the "fence line," including the barge unloading pier but terminating at the high side of the main power transformers.
- Site location is specifically within the Ohio River Valley, southwestern Pennsylvania/eastern Ohio, but not specifically sited within the region except that it is considered to be located on a major navigable waterway.
- Terms used in connection with the estimate are consistent with the current EPRI TAG [1].
- Costs are grouped according to a process/system-oriented code of accounts; all reasonably allocable components of a system or process are included in the specific system account in contrast to a facility, area, or commodity account structure.
- The basis for equipment, materials, and labor costing is described in Section 3.2.1.
- Design engineering services, including construction management and contingencies basis, are examined in Section 3.2.2.
- The fuel cost component of the COE was developed on the basis of a straightforward calculation involving the plant size, plant heat rate, coal heating value, coal unit cost, plant annual operating hours, and a levelizing factor. Section 3.3.5 contains a more specific treatment of this calculation.
- The operating and maintenance expenses and consumables costs were developed on a quantitative basis.
    - The operating cost is determined on the basis of the number of operators required.
    - The maintenance cost is evaluated on the basis of relationships of maintenance cost to initial capital cost
    - The cost of consumables is determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours.

Each of these expenses and costs is determined on a first-year basis and levelized over the life of the plant through application of a levelizing factor to determine the value that forms a part of the COE. These costs and expenses are individually examined in greater detail in Section 3.3.

3.2 CAPITAL COSTS

The capital cost, specifically referred to as TCR for the mature second-generation PFB combustion power plant, was estimated using the EPRI methodology identified in Figure 85. The major components of TCR consist of bare erected cost, total plant cost (TPC), total plant investment (TPI), and owner's costs.

The capital cost was determined through the process of separately estimating the cost of every significant piece of equipment, component, and bulk quantity identified. A Code of Accounts was developed to provide the required structure for the estimate. The Code facilitates the consistent allocation of individual costs that were developed by various companies. The selected code structure, though not identical, is similar to other PFB combustion estimate code structures to permit future cost comparisons if desired. The Code facilitates recognition of estimated battery limits and the scope included in each account. The summary level of this Code is presented in Table 38. The expanded Code of Accounts for the PFB combustion plant is included in Appendix F.

The result of the evaluation process, to the level of TPC, is presented in summary form in Table 39. An expanded summary of the TPC is included in Appendix F. The development of the values that constitute the TPC level of the capital cost estimate as well as the TPI and TCR levels, is described in the subsections that follow. These subsections are supplemented by identification of specific estimate exclusions and discussions of the approach used to verify that the resultant PFB combustion plant estimate is a good representation of expected capital cost.

3.2.1 Bare Erected Cost

The bare erected cost level of the estimate, also referred to as the sum of process capital and general facilities capital, consists of the cost of: factory equipment, field materials and supplies, direct labor, indirect field labor, and indirect construction costs.

Factory equipment or major equipment costing was determined by the various project team members:

- Carbonizer and related equipment: Foster Wheeler
- CPFBC and related equipment: Foster Wheeler
- Combustion Turbine Package: Westinghouse CTO
- Steam Turbine/Generator: G/C
- Balance-of-Plant (BOP) Major Systems: G/C
- Other BOP (Vendor quotes not available): G/C

G/C obtained budgetary quotes for all the major BOP equipment. Upon receipt of each individual quote, its value was compared with the expected value for that component or system to confirm that cost levels were appropriate and to verify that

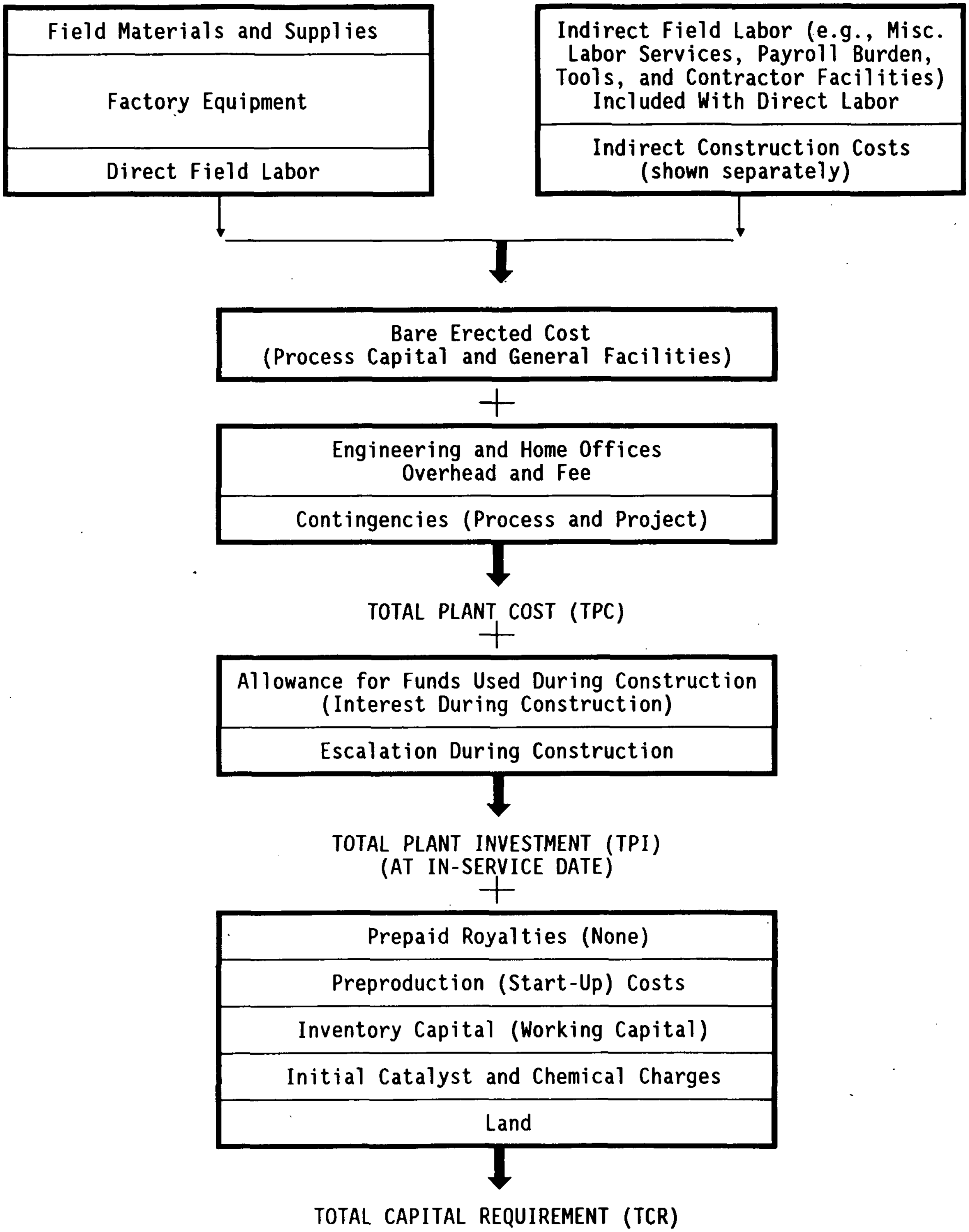


Figure 85 Components of Capital Costs

Table 38 Code of Direct Accounts Summary

Account Number	Account Title
1	COAL and SORBENT HANDLING
1.1	Coal Receiving and Unloading Equipment
1.2	Coal Stackout and Reclaim Equipment
1.3	Coal Storage Bin and Yard Crushers
1.4	Other Coal-Handling Equipment
1.5	Sorbent Receiving and Unloading Equipment
1.6	Sorbent Stackout and Reclaim Equipment
1.7	Sorbent Storage Bin and Yard Crusher
1.8	Other Sorbent-Handling Equipment
1.9	Coal and Sorbent Handling Foundations and Structures
2	COAL and SORBENT PREPARATION and FEEDING
2.1	Coal Crushing and Drying Equipment
2.2	Prepared Coal Storage and Feed Equipment
2.3	Coal Injection System
2.4	Miscellaneous Coal Preparation and Feed
2.5	Sorbent Preparation
2.6	Prepared Sorbent Storage and Feed Equipment
2.7	Sorbent Injection System
2.8	Booster Air Supply System
2.9	Foundations and Structures
3	FEEDWATER and MISCELLANEOUS SYSTEMS and EQUIPMENT
3.1	Feedwater System
3.2	Makeup Treatment, Pretreating, and Storage
3.3	Other Feedwater and Condensate Subsystems
3.4	Service Water Systems
3.5	Other Boiler Plant Systems
3.6	Fuel Oil Supply System
3.7	Waste Treatment Equipment
3.8	Miscellaneous Power Plant Equipment
4	CARBONIZER, CPFBC BOILER, and ACCESSORIES
4.1	Carbonizer
4.2	CPFBC
4.3	CPFBC Heat Exchanger (FBHE)
4.4	Interconnecting Pipe
4.5	Miscellaneous CPFBC Equipment
4.6	Other CPFBC Equipment
4.8	Major Component Rigging
4.9	Foundations and Supports
5	HOT GAS CLEAN-UP and HOT GAS PIPING
5.1	Carbonizer Gas/Tar Cross-Flow Filter Module
5.2	CPFBC Gas Cross-Flow Filter Module
5.3	Hot Gas Piping
5.4	Blowback Air Supply System
5.9	Foundations and Supports

Table 38 (Cont) Code of Direct Accounts Summary

Account Number	Account Title
6	COMBUSTION TURBINE and ACCESSORIES
6.1	Combustion Turbine Generator
6.2	Combustion Turbine Accessories
6.3	Compressed Air Piping
6.9	Foundations and Supports
7	HRSG, DUCTING, and STACK
7.1	Heat Recovery Steam Generator
7.2	HRSG Accessories
7.3	Ductwork
7.4	Stack
7.9	Foundations
8	STEAM TURBINE GENERATOR, CONDENSER, and AUXILIARIES
8.1	Steam Turbine Generator and Accessories
8.2	Turbine Plant Auxiliaries
8.3	Condenser and Auxiliaries
8.4	Steam Piping
8.9	Foundations
9	COOLING WATER SYSTEM
9.1	Cooling Towers
9.2	Circulating Water Pumps
9.3	Circulating Water System Auxiliaries
9.4	Circulating Water Piping
9.5	Make-Up Water System
9.6	Component Cooling Water System
9.9	Circulating Water Foundations and Structures
10	ASH/SPENT SORBENT RECOVERY and HANDLING
10.1	Ash Coolers
10.2	FBHE Ash Depressurizing Equipment
10.3	HGCU Ash Depressurizing Equipment
10.4	High-Temperature Ash Piping
10.5	Other Ash-Recovery Equipment
10.6	Ash Storage Silos
10.7	Ash Transport and Feed Equipment
10.8	Miscellaneous Ash-Handling Equipment
10.9	Foundations and Structures
11	ACCESSORY ELECTRIC PLANT
11.1	Generator Equipment
11.2	Station Service Equipment
11.3	Switchgear and Control Equipment
11.4	Conduit and Cable Tray
11.5	Wire and Cable
11.6	Protective Equipment
11.7	Standby Equipment
11.8	Main Power Transformer
11.9	Foundations

Table 38 (Cont) Code of Direct Accounts Summary

Account Number	Account Title
12	INSTRUMENTATION and CONTROLS
12.1	Carbonizer/CPFBC/FBHE Control Equipment
12.2	Combustion Turbine Control Equipment
12.3	Steam Turbine Control Equipment
12.4	Other Major Component Control Equipment
12.5	Signal Processing Equipment
12.6	Control Boards, Panels, and Racks
12.7	Computer and Auxiliaries
12.8	Instrument Wiring and Tubing
12.9	Other Instrumentation and Controls
13	IMPROVEMENTS TO SITE
13.1	Site Preparation
13.2	Site Improvements
13.3	Site Facilities
14	BUILDINGS and STRUCTURES
14.1	Gas Turbine Building
14.2	Steam Turbine Building
14.3	Administration Building
14.4	Circulating Water Pump House
14.5	Water-Treatment Buildings
14.6	Machine Shop
14.7	Warehouse
14.8	Other Buildings and Structures
14.9	Waste-Treatment Buildings and Structures

Table 39 Baseline 452.8 MWe PFBC Plant Total Cost Summary (1987 $/1000 Conceptual)

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost	Other*	Contingencies Process	Contingencies Project	Total Plant Cost $/1000	Total Plant Cost $/kW
1	COAL AND SORBENT HANDLING	20,136	3,131	8,875	621	---	32,763	2,130	---	5,234	40,127	88.6
2	COAL AND SORBENT PREPARATION AND FEEDING	14,581	1,529	4,265	299	---	20,673	1,344	657	3,401	26,074	57.6
3	FEEDWATER AND MISCELLANEOUS SYSTEMS AND EQUIPMENT	6,009	6,090	5,794	406	---	18,299	1,189	---	2,923	22,411	49.5
4	CARBONIZER, CPFBC BOILER, AND ACCESSORIES											
4.1	Carbonizer	3,055	---	755	53	---	3,863	251	1,352	820	6,286	13.9
4.2	CPFBC	6,015	---	1,460	102	---	7,577	493	1,515	1,438	11,023	24.3
4.3	CPFBC Heat Exchanger	20,046	---	4,200	294	---	24,540	1,595	4,908	4,656	35,700	78.8
4.4	Interconnecting Pipe	1,288	5,253	4,084	286	---	10,911	709	399	1,803	13,822	30.5
5	HOT GAS CLEAN-UP AND PIPING	10,850	7,140	8,715	610	---	27,314	1,775	1,387	4,572	35,048	77.4
6	COMBUSTION TURBINE and ACCESSORIES											
6.1	Combustion Turbine Generator	45,870	---	2,162	151	---	48,183	3,132	4,818	8,420	64,554	142.6
6.2	Combustion Turbine Accessories	---	1,347	1,868	131	---	3,345	217	---	534	4,097	9.0
7	HRSG, DUCTING, AND STACK											
7.1	HRSG	17,860	---	3,770	264	---	21,894	1,423	3,284	3,990	30,591	67.6
7.2	HRSG Accessories	500	819	1,622	114	---	3,054	199	---	488	3,741	8.3
8	STEAM TURBINE GENERATOR, CONDENSER, AND AUXILIARIES											
8.1	Steam Turbine Generator and Accessories	23,150	---	1,620	113	---	24,883	1,617	---	3,975	30,476	67.3
8.2	Turbine Plant Auxiliaries	1,400	3,074	4,606	322	---	9,403	611	---	1,502	11,516	25.4
9	COOLING WATER SYSTEM	3,618	2,524	2,714	190	---	9,046	588	---	1,445	11,079	24.5
10	ASH/SPENT SORBENT RECOVERY HANDLING SYSTEM	5,530	143	1,553	109	---	7,335	477	869	1,302	9,982	22.0
11	ACCESSORY ELECTRIC PLANT	5,227	2,123	5,352	375	---	13,077	850	---	2,089	16,016	35.4
12	INSTRUMENTATION AND CONTROL	5,655	675	4,032	282	---	10,644	692	---	1,700	13,037	28.8
13	IMPROVEMENTS TO SITE	---	2,983	5,422	380	---	8,784	571	---	1,403	10,758	23.8
14	BUILDINGS AND STRUCTURES	---	6,011	5,006	350	---	11,367	739	---	1,816	13,922	30.7
	TOTAL COST	190,790	42,840	77,874	5,451	---	316,955	20,602	19,189	53,512	410,258	906.1

*Engineering, Construction Management, Home Office, and Fee.

the quoted scope represented the required scope. The list of major equipment that was costed on the basis of vendor quotes includes:

- Coal and dolomite handling, including the barge unloader
- Coal, dolomite, and ash storage silos
- Deaerator and heat exchangers
- Major pumps, blowers, and compressors
- Water-treating packages
- Oil and water storage tanks
- Chimney
- Condenser
- Cooling tower
- Ash coolers, pelletizers, and drag conveyors.

The list of quoted equipment is not complete, but it does identify the major quotes received. The table presented at the end of this subsection indicates that 80 percent of equipment cost was quoted and includes recognition of quotes furnished by Foster Wheeler and Westinghouse.

The estimate of the cost for the ceramic cross-flow filters was conceptually developed consistent with the approach described in a recent report that evaluated the cost of 10 high-temperature/high-pressure particulate cleanup systems [2]. Since the ash-removal system is not the same as in the referenced report and since Foster Wheeler provided the cost of the precleaning cyclones, only the device and accessories costs were derived from the reference. Westinghouse provided a more current price for the ceramic filter elements that replaced the unit price previously used. A G/C in-house model was used to evaluate the cost of the HRSG. Since the model does not adequately address the steam condition requirements, costs were adjusted to compensate for the higher pressure. In addition, process contingency was considered for this component because at the stated conditions, an HRSG is apparently not offered and would require some design development by vendors.

Other equipment, minor secondary systems, and materials were estimated by G/C on the basis of budgetary level vendor quotes or in-house data consisting of other project cost data and relationships, catalog data, and standard utility unit cost data.

On an estimating discipline basis, other materials and equipment were estimated in the following manner: Piping costs for major systems were developed by estimating the required quantities and applying appropriate unit costs. Minor piping and system costs were determined from data for similar systems that were adjusted for length and capacity as required by appropriate scaling factors. Electrical and instrumentation and control (I&C) equipment was evaluated on the basis of quotes or current in-house cost data. The electrical and I&C bulk commodities (i.e., wire and cable, conduit, cable tray, terminations) were determined on the basis of estimates of the number and general sizes of power and control circuits. Civil and structural items were estimated on the basis of conceptual quantities that were defined or implied on the plot plan and the layout and elevation drawings. Appropriate unit costs were applied to these quantities to arrive at civil and structural costs, including architectural items in the PFB combustion plant.

The labor cost to install the equipment and materials was estimated on the basis of unit man hours applied to the appropriate quantities to arrive at total installation man hours for each item or bulk quantity. These man hours were then evaluated using a variety of wage rates. The unit man hours source was standard in-house data that is customarily applied to evaluating labor for utility power plants. Shop fabrication was considered in the cost to install major components. Labor costing was determined on a multiple contract labor basis with the labor cost including direct and indirect labor costs plus fringe benefits and allocations for contractor expenses and markup. In addition, a craft labor mix was specified for each major work operation with a fraction of cost allocated to provide for the cost of construction equipment required for that work operation. The result of this process was a series of composite work operation wage rates for determining the labor costs shown on the previously identified estimate summary.

The indirect labor cost was estimated at 7 percent of direct labor to recognize the cost of construction services and facilities not provided by the individual contractors. The latter cost represents the estimate for miscellaneous temporary facilities such as construction road and parking area construction and maintenance; installation of construction power; installation of construction water supply and general sanitary facilities; and general and miscellaneous labor services such as jobsite cleanup and construction of general safety and access items.

Figure 86 indicates the contribution of each category of cost in bare erected cost as well as an indication of the ratio of quoted equipment to total equipment and total bare erected cost.

3.2.2 Total Plant Cost (TPC)

The TPC level of the estimate consists of the bare erected cost plus engineering and contingencies. Figure 87 indicates the relative contribution of each component of TPC.

The engineering costs shown in Table 39 represent the cost of architect/engineer (A/E) services for design/drafting and project construction management services. The cost for the PFBC plant engineering was determined at 6-1/2 percent applied to the bare erected cost on an individual account basis. The cost for engineering services provided by the equipment manufacturers and vendors is included directly in the equipment costs.

Allowances for process and project contingencies are also considered as part of the TPC. Some of the process technology used in the various systems is still in the development stage. Continuing process development tends to increase the cost of plant components as problems are discovered and resolved. In an attempt to account for the uncertainty in equipment design, performance, and cost, a process contingency was added to the estimated cost of pertinent components and systems.

The criteria for determining the process contingency factors was the EPRI TAG [1] guidelines. Specific factors were applied to the non-commercial components and the resulting percents by account level are shown in Table 40.

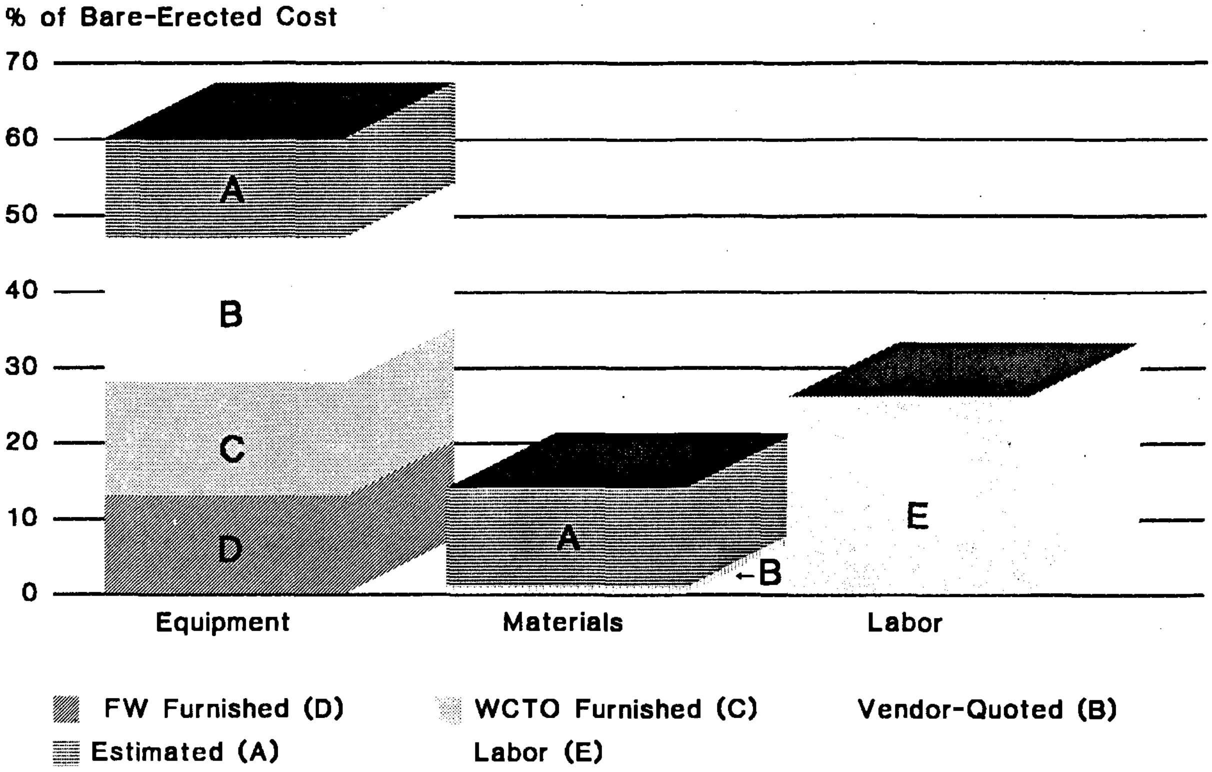


Figure 86 Components of Bare Erected Cost

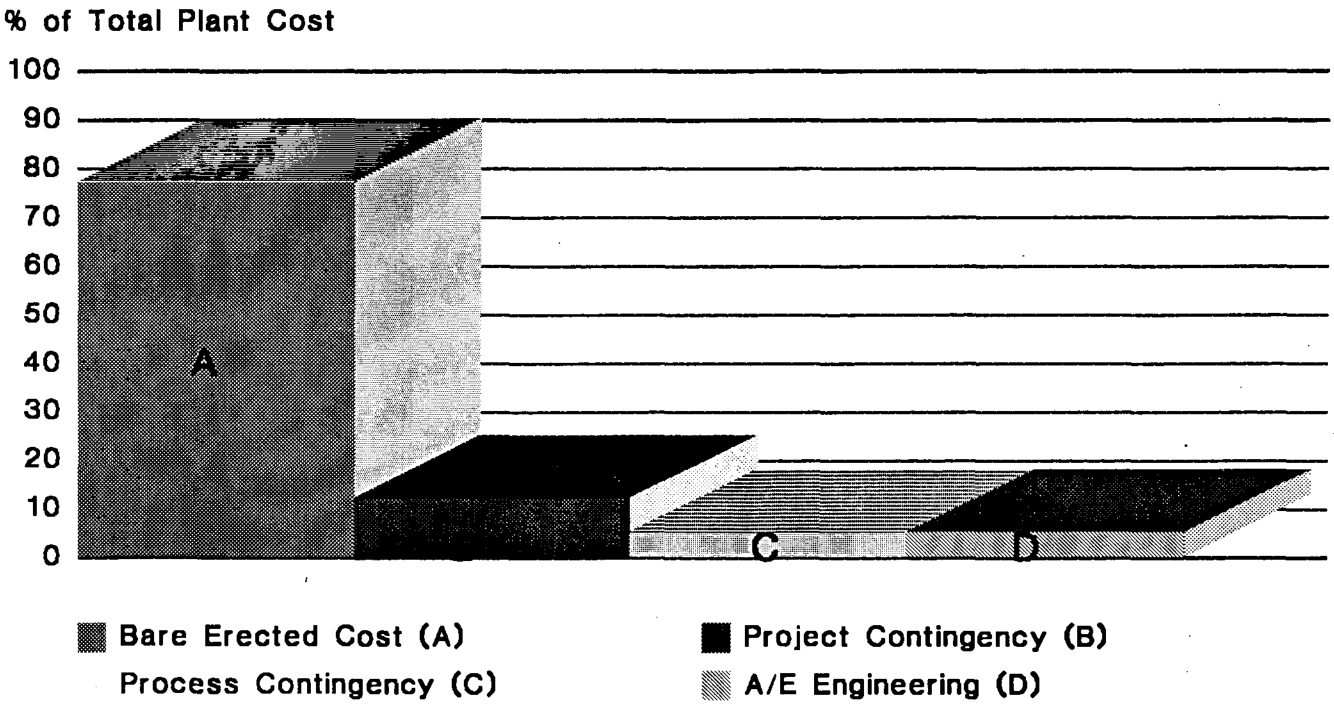


Figure 87 Components of Total Plant Cost

Table 40 Process and Project Contingency Factors

Item/Description	Contingency Factors (%) Process	Project
COAL AND SORBENT HANDLING	0.0	15
COAL AND SORBENT PREPARATION AND FEED	3.2	15
FEEDWATER AND MISCELLANEOUS BOP SYSTEMS	0.0	15
CARBONIZER, CPFBC, AND FBHE		
Carbonizer	35.0	15
CPFBC	20.0	15
FBHE	20.0	15
Other CPFBC Equipment	3.7	15
HOT GAS CLEANUP AND PIPING	5.1	15
COMBUSTION TURBINE/ACCESSORIES		
Combustion Turbine Generator	10.0	15
Combustion Turbine Accessories	0.0	15
HRSG, DUCTING AND STACK		
Heat Recovery Steam Generator	15.0	15
HRSG Accessories	0.0	15
STEAM TURBINE GENERATOR		
Steam Turbine Generator and Accessories	0.0	15
Turbine Plant Auxiliaries	0.0	15
COOLING WATER SYSTEM	0.0	15
ASH/SPENT SORBENT HANDLING SYSTEM	11.8	15
ACCESSORY ELECTRIC PLANT	0.0	15
INSTRUMENTATION AND CONTROL	0.0	15
IMPROVEMENTS TO SITE	0.0	15
BUILDINGS AND STRUCTURES	0.0	15

The specific factors that were applied to arrive at the relationships indicated in Table 40 are:

Item	Percent	Comment
Coal/Sorbent Injection	5	Developmental for some components within this system
Carbonizer	35	Developmental, laboratory-scale basis
CPFBC	20	Developmental, but simple and with AFBC basis
FBHE	20	Developmental, but design methodology known
CPFBC Interconnecting Pipe	15	Char-transfer area
Cross-Flow Filter	20	Developmental filters now being tested, but final commercial offering may include additional systems
Gas Turbine	10	Composite includes consideration for topping combustor and potential upgrade to turbine materials
HRSG	15	Feasible, but design does not exist
Ash Depressurization	50	No existing large units; alternative is lock hopper system

At the level of TPC, the net effect of process contingency is an increase in TPC of nearly 50 \$/kW or nearly 6 percent. The equivalent change at the TCR level is 5-1/2 percent, since all items are not directly affected by a change in TPC. At the level of COE, without considering process contingency, the result would be 2 percent lower or slightly higher than 74 mills/kWh.

Consistent with conventional power plant practices, a general project contingency was added to the total plant cost to cover project uncertainty and the cost of any additional equipment that could result from a detailed design. Based on EPRI criteria, the cost estimate contains elements of Classes I, II, and III level estimates. As a result, on the basis of the EPRI guidelines and prudent judgment, a nominal value of 15 percent was used to arrive at the plant nominal cost value. This project contingency is intended to cover the uncertainty in the cost estimate itself, whereas the process contingency covers the uncertainty in the technical development level of specific equipment. In both cases the contingencies represent costs that are expected to occur.

3.2.3 Total Plant Investment (TPI)

The TPI at date of start-up includes escalation of construction costs and allowance for funds used during construction, formerly called interest during construction, over the construction period. TPI is computed from the TPC, which is expressed on an "overnight" or instantaneous construction basis. For the construction cash flow, a uniform expenditure rate was assumed, with all expenditures taking place at the end of the year. The construction period is estimated to be 3-1/2 years. Given TPC, cash flow assumptions, nominal interest, and escalation rates, TPI was calculated using:

$$TPI = TPC[A(R^3-1)/(R-1) + A/2(R^3)]$$

where

A = Percent cost expended annually = 28.6 percent

R = Compound adjustment factor = $(1 + i)/(1 + e_a)$

i = Weighted cost of capital, 12.5 percent

e_a = Inflation rate, 6 percent

The apparent escalation rate and the weighted cost of capital (discount rate) are the standard values proposed by EPRI.

3.2.4 Total Capital Requirement (TCR)

The TCR includes all capital necessary to complete the entire project. TCR consists of TPI, prepaid royalties, preproduction (or start-up) costs, inventory capital, initial chemical and catalyst charge, and land cost:

- Royalties costs are assumed inapplicable to the mature PFBC plant and thus are not included.
- Preproduction Costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant start-up. They are estimated as follows:
  - 1 month of fixed operating costs--operating and maintenance labor, administrative and support labor, and maintenance materials.
  - 1 month of variable operating costs at full capacity (excluding fuel)-- includes chemicals, water, and other consumables and waste disposal charges.
  - 25 percent of full capacity fuel cost for 1 month--covers inefficient operation that occurs during the start-up period.
  - 2 percent of TPI--covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity.
- Inventory capital is the value of inventories of fuel, other consumables, and by-products, which are capitalized and included in the inventory capital account. The inventory capital is estimated as follows: Fuel inventory is based on full-capacity operation for 60 days. Inventory of other consumables (excluding water) is normally based on full-capacity operation for the same number of days as specified for the fuel. In addition, an allowance of 1/2 percent of the TPC equipment cost is included for spare parts.
- Initial catalyst and chemical charge covers the initial cost of any catalyst or chemicals that are contained in the process equipment (but not in storage, which is covered in inventory capital). No value is shown because costs are minimal and included directly in the component equipment capital cost.
- Land cost is based on 200 acres of land, as estimated from the plot plan drawing, at \$7,500 per acre.

Each of the TCR cost components, as well as the summary TPC components and the TPI, is shown separately in Section 3.4 (Table 46), expressed in \$1000 and \$/kW (net).

3.2.5 Capital Cost Estimate Exclusions

Although the estimate is intended to represent a complete PFBC plant, there remain several qualifications/exclusions as follows:

- Sales tax is not included (considered to be exempt).
- On-site fuel transportation equipment is not included (i.e., barge tug, barges, yard locomotive, bulldozers).
- Allowances for unusual site conditions, such as piling, extensive site access, excessive dewatering, extensive inclement weather, are not included.
- Shoreline protection is not included except for the area adjacent to the barge unloading area as protection against facility erosion.
- Switchyard (transmission plant) is not included. The costed scope terminates at the high side of the main power transformer.
- Ash disposal facility is excluded, other than the 3-day storage in the ash-storage silos (the ash disposal cost is accounted for in the ash disposal charge as part of consumables costs; refer to Section 3.3.3).
- Royalties.

3.2.6 Estimate Account Consistency

Even though significant attention was directed at maintaining consistent and reasonable costing approaches for estimating the PFBC plant components and systems, supplementary comparisons seemed advisable to verify the estimate. This PFBC design study includes comparison of results to a conventional PC-fired plant (Section 5.5) and, at the TPC level of cost, this developed PC-fired plant value was confirmed (refer to Appendix G). Therefore, the PC-fired plant summary account values seem appropriate for comparisons to verify the corresponding PFBC plant values.

Table 41 was developed for the purpose of account-level comparisons. The TPC and $/kW values on the table were based on values in Table 39 for the PFBC plant and Table G-3 for the PC-fired plant. The "Other" unit cost values that appear in Table 41 were developed, as required, to more clearly recognize the estimating relationships that are not apparent by examining only the total plant $/kW values. The "Comments" column of the table either identifies the differences between the PFBC plant and PC-fired plant for that particular account, reconciles differences, or qualifies the basis for the "Other" unit cost values.

Because the purpose of this effort was to verify the individual account values, comparisons were not developed for the TPC sum of individual accounts. Section 5.5 addresses comparisons--PFBC vs. PC--at the TPC level, as well as comparison of all other contributors to the total COE.

3.3 OPERATING COSTS AND EXPENSES

The operating costs and related maintenance expenses described in this section pertain to those charges associated with operating and maintaining the second-generation PFBC power plant over its expected life.

Table 41 Summary Account--TPC Comparison PFBC vs. Reference PC-Fired Plant

Account No.	Title	PFBC TPC ($/1000)	PFBC TPC $/kW	PFBC TPC Other	PC-Fired Plant TPC ($/1000)	PC-Fired Plant TPC $/kW	PC-Fired Plant TPC Other	Comments
1	Coal Handling	40.127	89	---	37.918	75	---	PC does not include yard 3-day storage silos at $14/kW. Adjusted PFBC = 89 $/kW - 14 $/kW = 75 $/kW
2	Coal and Sorbent	26.074	58	---	---	---	---	PC-fired plant equivalent scope is Preparation and Feeding included with Boiler
3	Feedwater and Miscella-	22.411	49-1/2	82 $/kW	48.366	96	90 $/kW	$/kW based on steam turbine generator size (approximates feedwater flow); PC-fired plant costs higher because of feedwater heater trains and steam-driven FW pumps
4	PFBC/PC-Fired Boiler	66.830	148	235 $/lb 43 $/lb	94.835	188	250 $/lb 24 $/lb	$/lb based on coal flow (lb/h) $/lb based on main steam flow (lb/h)
5	HG Cleanup/Flue Gas	35.048	77	---	153.274	304	---	Significantly higher PC-fired plant cleanup cost and unit cost because of ESP and FGD vs. second-generation PFB combustion plant with cross-flow filters (cyclones w/ Acct 4)
6	Combustion Turbines	8.648	152	---	---	---	---	PC-fired plant has no equivalent scope
7	HRSG, Ducting and Stack	34.332	76	---	19.587	39	---	Second-Generation PFB combustion plant has HRSG at 71 $/kW vs. PC-fired plant with induced-draft fans at 4 $/kW; difference in ductwork cost at 23 $/kW and difference in stack cost at 9 $/kW--both higher for PC-fired plant.
8	Steam Turbine Generator	31.607	70	116 $/kW	60.458	120	113 $/kW	$/kW based on steam turbine generator size
	Other Turbine Plant	10.385	23	38 $/kW	25.505	51	47 $/kW	Difference in Other $/kW primarily because of condenser with BFP steam and higher labor to erect condenser
9	Cooling Water System	11.079	24-1/2	41 $/kW	21.933	43-1/2	41 $/kW	---
10	Ash/Spent Sorbent	9.982	22	---	13.766	27	---	Differences caused by PC with multiple ash collections including wet and dry systems plus fly-ash transfer to FGD system
11	Accessory Electric Plant	16.016	35	1087 $/kW	31.281	62	948 $/kW	Based on plant auxiliary load, second-generation PFB combustion plant higher value results from three main transformers vs. one for PC-fired plant
12	Instrumentation and Control	13.037	29	---	13.223	26	---	---
13	Improvements to Site	10.758	24	54,000 $/ acre	15.969	32	69,000 $/ acre	Based on plant acre size; difference because of disproportionate size relationships (i.e., coal pile drainage PC-fired plant vs. second-generation PFB combustion plant at +1/3, MW at +11%
14	Buildings and Structures	13.922	31	60.887	121	---	---	Significant difference from building sizes (i.e., Boiler Building at +43 $/kW, Steam Turbine Generator Building at +25 $/kW, and all water makeup and treating and waste treating at 2 x second-generation PFB combustion plant)

The costs and expenses associated with operating and maintaining the plant include:

- Operating labor
- Maintenance
  - Material
  - Labor
- Administrative and support labor
- Consumables
- By-Product credit (if applicable)
- Fuel cost

The values for these items were determined consistent with EPRI TAG [1] methodology. These costs and expenses are estimated on a first-year basis, December 1987 dollars. The first-year costs assume normal operation and do not include the initial start-up costs, which were computed separately (see Section 3.2.4). A levelizing factor is applied to these first-year costs and expenses to arrive at appropriate values that contribute to the total COE.

The operating labor, maintenance material and labor, and other labor-related costs are combined and then divided into two components; fixed O&M, which is independent of power generation, and variable O&M, which is proportional to power generation. The first-year operating and maintenance cost estimate allocation is based on the plant capacity factor.

The other operating costs, consumables and fuel, are determined on a daily 100-percent operating capacity basis and adjusted to an annual plant operation basis equivalent to operating at 100-percent load for 65 percent of the year (plant capacity factor).

The development of the actual values was performed on a G/C model that is consistent with TAG. The inputs for each category of operating costs and expenses are identified in the succeeding subsections along with more specific discussion of the evaluation processes. The results of these evaluations are included in Section 3.4 (Table 46) expressed on a first-year basis in terms of absolute cost and unit cost, either as mills/kWh or \$/kW·yr, and on an equivalent levelized basis.

3.3.1 Operating Labor

The cost of operating labor was estimated on the basis of the number of operating jobs (OJ) required to operate the plant (on an average-per-shift basis). The operating labor charge (OLC) expressed in first year \$/kW was then computed using the average labor rates:

$$OLC = \frac{(OJ) \times (\text{labor rate} \times \text{labor burden}) \times (8760\ h/yr)}{(\text{net capacity of plant at full load in kW})}$$

Table 42 indicates the number of operating jobs, the operating labor rate, and the operating labor burden that were used to determine the first-year operating labor cost. The operating labor requirements were determined on the basis of in-house representative data for the major plant sections (e.g., coal handling, steam turbine plant). These data were supplemented by estimates of the manpower required for the carbonizer, CPFBC, and HGCU sections to arrive at total plant operating requirements.

3.3.2 Maintenance

Since the development of the maintenance labor and maintenance material costs are so interrelated in this methodology, their cost bases are discussed together. Annual maintenance costs, according to EPRI's methodology [1], are

Table 42 Plant Operating Labor Requirements

Operating Labor Rate (Base):	17.40 \$/h
Operating Labor Burden:	35% of base
Labor Overhead Charge Rate:	30% of labor

Operating Labor Requirements (Operating Jobs) per shift:

Category	Total Plant
Skilled Operator	3.0
Operator	19.0
Foreman	1.0
Laboratory Technicians, etc.	3.0
Total Operating Jobs	26.0

estimated as a percentage of the installed capital cost. The percentage varies widely, depending on the nature of the processing conditions and the type of design.

On the basis of G/C in-house data and EPRI guidelines for determining maintenance costs, representative values expressed as a percentage of system cost were specified for each major system. The rates were applied against individual estimate accounts and are summarized by major system in Table 43. Using the corresponding TPC values, a total annual (first-year) maintenance cost was calculated, including both material and labor components.

Since the maintenance costs are expressed as maintenance labor and maintenance materials, a maintenance labor/materials ratio of 40:60 was used for this breakdown. The operating costs, excluding consumable operating costs, are further divided into fixed and variable components. Fixed costs are essentially independent of capacity factor and are expressed in \$/kW·yr. Variable costs are incremental, directly proportional to the amount of power produced, and expressed in mills/kWh. Separation of operating costs into fixed and variable components was based on the assumption that the portion of the operating cost that is fixed is proportional to the expected nominal capacity factor for the plant. The balance of the cost is expressed as a variable component. The assumption is predicated on EPRI guidelines and other utility experience that indicates that base-loaded plants tend to have a relatively high fixed component of the operating cost, whereas peaking and intermediate plants have high variable components that correlate with the capacity factor. The equations for these calculations are:

$$\text{Fixed O\&M} = \text{Capacity Factor (CF)} \times \text{Total O\&M (\$/kW·yr)}$$
$$\text{Variable O\&M} = [(1 - \text{CF}) \times \text{Total O\&M (\$/kW·yr)} \times 1000 \text{ mills/\$}]/(\text{CF} \times 8760 \text{ h/yr})$$

The administrative and support labor cost is the only O&M overhead charge included in the cost studies. It is a charge for administrative and support labor, which is taken as 30 percent of the operating and maintenance labor. General and administrative expenses are not included.

Table 43 Baseline PFBC Plant Maintenance Factors

Item/Description	Maintenance Percent
COAL AND SORBENT HANDLING	2.6
Coal and Sorbent Prep and Feed	3.1
Feedwater and Miscellaneous BOP Systems	1.9
CARBONIZER, CPFBC, AND FBHE	
Carbonizer	5.0
CPFBC	4.5
FBHE	4.0
Other CPFBC Equipment	1.8
Hot Gas Cleanup and Piping	6.7
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	3.5
Combustion Turbine Accessories	1.4
HRSG, DUCTING AND STACK	
HRSG	2.0
HRSG Accessories	1.4
STEAM TURBINE GENERATOR	
Steam Turbine Generator and Accessories	1.5
Turbine Plant Auxiliaries	1.8
Cooling Water System	1.6
Ash/Spent Sorbent Handling System	3.2
Accessory Electric Plant	1.5
Instrumentation and Control	1.7
Improvements to Site	1.3
Buildings and Structures	1.4

3.3.3 Consumables

The feedstock and disposal costs are those consumable expenses associated with PFB combustion power plant operation. Consumable operating costs are developed on a first-year basis and subsequently levelized over the 30-year life of the plant. The consumables category consists of water, chemicals, other consumables, and waste disposal. The quantities and unit costs that were used to develop the corresponding cost values are indicated in Table 44 and examined separately.

The "water" component pertains to the water acquisition charge for water required for the plant steam cycle, miscellaneous services, and the ash pelletizer. The total quantity of 5,575,000 gal/d consists of a 4-percent fraction for feedwater and miscellaneous turbine plant services and 93 percent for cooling tower makeup and blowdown, with the balance for the ash pelletizer supply.

Table 44 Plant Consumables, By-Products, and Fuels Data

Item/Description	Initial	Consumption/ Day	Unit Cost
Water(/1000 gal)	---	5,575	0.715
Chemicals			
Makeup and Water Treatment (lb)	---	5,110	0.14
Liquid Effluent (lb)	---	13,520	0.1
Dolomite (ton)	59,268	987.8	17.9
Other			
Secondary Fuel (gal)	250,500	4,175	0.75
Gases, N_2, etc.(/100 sft^3)	302,400	5,040	0.29
Waste Disposal Sludge (ton)	---	---	---
PFBC Ash (ton)	---	1,093.7	7.6
By-products Sulfuric Acid (lb)	---	---	---
Sulfur (lb)	---	---	---
Fuel (ton)	---	3,413.5	44.57

The "chemicals" component consists of:

- A composite water makeup and treating chemicals requirement in which unit cost and the ratio of chemicals to water were based on data from comparable plants
- The liquid effluent chemical category, representing the composite chemical requirement for wastewater treating, in which unit cost and quality were developed similar to the water makeup and treating chemicals
- The dolomite required for injection into the PFBC boiler in which the unit cost is the EPRI standard limestone cost, which is comparable to the expected dolomite cost.

The "other consumables" component consists of fuel oil and gases. The fuel oil quantity accounts for coal drying (54 percent), PFB and carbonizer start-up heaters and miscellaneous use (35 percent) plus fuel for the auxiliary boiler (11 percent). The gases category is primarily for the nitrogen required for transport and blanketing. The unit cost for gases was based on pricing furnished by an industrial gas supplier.

The "waste disposal" component pertains to the cost allowance for off-site disposal of plant solid wastes. The 1094 t/d ash represents the combined FBHE and cleanup system quantity. The unit cost for disposal is based on an adjusted EPRI value [1].

3.3.4 By-Product Credit

The by-product section of Table 44 has no cost (credit) indicated because no significant marketable by-product is recognized. Because of the stable nature of the pelletizer ash product, this material may have commercial value under some circumstances. However, since this potential is not currently quantified, a credit was not recognized.

3.3.5 Fuel Cost

The fuel (coal) data in Table 44 were developed on the basis of the EPRI cost for delivered coal (FC) of $\$1.79/10^6$ Btu, the net plant heat rate (NPHR) of 7822 Btu/kWh, and the coal HHV of 12,450 Btu/lb. For the coal as well as for all feedstock and disposal costs, the quantity per day in Table 44 represents the 100-percent capacity requirement, while the annual values indicated in Section 3.4 are adjusted for the designated 65-percent plant capacity factor. The calculation of first-year fuel cost is:

$$\text{Fuel (t/d)} = \frac{\text{NPHR x kW (plant new capacity) x 24 h/d}}{\text{HHV x 2000 lb/t}}$$

$$\text{Fuel Unit Cost (\$/t)} = \text{HHV x 2000 lb/t x FC x } 10^{6}$$

$$\text{Fuel Cost (1st year)} = \text{Fuel (t/d) x Fuel Unit Cost (\$/t) x 365 d/yr x 0.65 (capacity factor)}$$

3.4 COST OF ELECTRICITY (COE)

The revenue requirement method of performing an economic analysis of a prospective power plant is widely used in the electric utility industry. This method permits the incorporation of the various dissimilar components for a potential new plant into a single value that can be compared with various alternatives. The revenue requirement figure-of-merit is the levelized (over plant life) coal pile-to-busbar cost of energy expressed in mills/kWh. The value, based on EPRI definitions and methodology, includes the TCR, which is represented in the levelized carrying charge (sometimes referred to as the fixed charges), levelized fixed and variable operating and maintenance costs, levelized consumables operating costs, and levelized fuel cost.

The basis for calculating capital investment and revenue requirements is given in Table 45. Table 46, the capital investment and revenue requirement summary, is the principal cost and economics output for this study. Key TPC values from Table 39 are combined with other significant costs, including operating costs, maintenance costs, consumables, and fuel cost, resulting in the levelized busbar COE.

The levelized carrying charge, applied to TCR, establishes the required revenues to cover return on equity, interest on debt, depreciation, income tax, property tax, and insurance. Levelizing factors are applied to the first-year fuel, O&M, and consumables costs to yield levelized costs over the life of the project. A long-term inflation rate of 6 percent/yr was assumed in estimating the cost of capital and in estimating the life-cycle revenue requirements for other expenses (except that fuel was escalated at 6.8 percent/yr).

To represent these varying revenue requirements for fixed and variable costs, a "levelized" value was computed using the "present worth" concept of money based on the assumptions shown in Table 45 and resulting in a levelized carrying charge of 17.3 percent and a levelizing factor of 1.75 for all other-than-coal costs and 1.9 for coal cost.

Table 45 Estimating Basis/Financial Criteria for Review Requirement Calculations

GENERAL DATA/CHARACTERISTICS

Case Title:	Baseline PFBC Plant
Unit Size:	452.8 MW, net
Plant Size:	452.8 MWe
Location:	Ohio River Valley
Fuel:	Pittsburgh No. 8
Plant Heat Rate-Full Load:	7822 Btu/kWh
Average:	7822 Btu/kWh
Levelized Capacity Factor:	65%
Capital Cost Year Dollars:	1987 (December)
Delivered Cost of Coal:	1.79 \$ x 10^6 Btu (at start-up)
Design/Construction Period:	3.5 years
Plant Start-Up Date (year):	1988 (January)
Land Area:	200 acre
Unit Cost:	\$7,500/acre

FINANCIAL CRITERIA

Project Book Life:	30 years
Book Salvage Value:	0%
Project Tax Life:	15 years
Tax Depreciation Method:	ACRS
Property Tax Rate:	1.0% annually
Insurance Tax Rate:	1.0% annually
Federal Income Tax Rate:	34.0%
State Income Tax Rate:	6.0%
Investment Tax Credit (% Eligible):	0

CAPITAL STRUCTURE

	% of Total	Cost (%)
Common Equity	35	15.2
Preferred Stock	15	11.5
Debt	50	11.0
Weighted Cost of Capital	12.5	

ESCALATION RATES (Apparent)

General Escalation:	6.0% annually
Fuel Price Escalation:	6.8% annually

Table 46 Capital Investment and Revenue Requirement Summary

Title/Definition Case:	Baseline PFBC Plant		
Plant Size:	452.8 MW (net)	Heat Rate:	7822 Btu/kWh
Fuel (type):	Pittsburgh No. 8	Cost:	1.79 $\$/10^6$ Btu
Design/Construction:	3.5 yr	Book Life:	30 yr
TPC (Plant Cost) Year:	1987 (Dec.)	TPI Year:	1988 (Jan.)
Capacity Factor:	65%		

	$ x 1000	$/kW
CAPITAL INVESTMENT		
Process Capital and Facilities	316,955	700.1
Engineering (including construction maintenance, home office, and fee)	20,602	45.5
Process Contingency	19,189	42.4
Project Contingency	53,512	118.2
Total Plant Cost (TPC)	410,258	906.1
Total Plant Investment (TPI)	443,961	980.6
Royalty Allowance	---	---
Preproduction Costs	12,585	27.8
Inventory Capital	11,458	25.3
Initial Catalyst and Chemicals (with equipment)	---	---
Land Cost	1,500	3.3
Total Capital Requirement (TCR)	469,504	1037.0

OPERATING AND MAINTENANCE COSTS (1st yr)	$ x 1000	$/kW·yr
Operating Labor	5,350	11.8
Maintenance Labor	3,663	8.1
Maintenance Material	5,494	12.1
Administrative and Support Labor	2,704	6.0
Total Operation and Maintenance (1st yr)	17,211	38.0

Fixed O&M (1st yr) 24.71 $/kW·yr

Variable O&M (1st yr) 2.34 mills/kWh

Table 46 (Cont) Capital Investment and Revenue Requirement Summary

	$ x 1000	mills/kWh
CONSUMABLES OPERATING COSTS (less fuel)		
Water	946	0.37
Chemicals	4,685	1.82
Other Consumables	1,090	0.42
Waste Disposal	1,972	0.76
Total Consumables (1st yr, less fuel)	8,693	3.37
By-Product Credits (1st yr)	---	---
Fuel Cost (1st yr)	36,096	14.00
LEVELIZED OPERATING AND MAINTENANCE COSTS		
Fixed O&M	43.1 $/kW·yr	
Variable O&M	4.1 mills/kWh	
Consumables	5.9 mills/kWh	
By-Product Credit	0.0 mills/kWh	
Fuel	26.6 mills/kWh	
LEVELIZED CARRYING CHARGE (Capital)	179.4 $/kW·yr	
LEVELIZED BUSBAR COST OF POWER	75.7 mills/kWh	

By combining costs, carrying charges, and levelizing factors, a levelized busbar COE for the 65-percent design capacity factor was calculated at 75.7 mills/kWh and reported in Table 46 along with the levelized constituent values. The format for this cost calculation is:

$$\text{Power Cost (COE)} = (\text{LCC} + \text{LFOM}) \times \frac{1000 \text{ mills/\$}}{\text{CF} \times 8760 \text{ h/yr}} + \text{LVOM} + \text{LCM} - \text{LB} + \text{LFC}$$

where

LCC = Levelized carrying charge, \$/kW·yr

LFOM = Levelized fixed O&M, \$/kW·yr

LVOM = Levelized variable O&M, mills/kWh

LCM = Levelized consumable, mills/kWh

LB = Levelized by-products (if any), mills/kWh

LFC = Levelized fueled costs, mills/kWh

CF = Plant capacity factor, %

3.5 REFERENCES

1. Electric Power Research Institute, TAG™ - Technical Assessment Guide, Vol. 1, EPRI P-4463-SR, Palo Alto, California, December 1986.

2. Gilbert/Commonwealth, Inc., "Technical Economic Evaluation of Ten High-Temperature, High-Pressure Particulate Cleanup Systems for Pressurized Fluidized Bed Combustion," DOE/MC/19196-1654, July 1984.

Section 4

ENVIRONMENTAL IMPACT

4.1 SUMMARY

The environmental impact of the second-generation PFB combustion plant has been addressed based on previously stated plant design assumptions and a plant site in southwestern Pennsylvania along the Ohio River. General siting requirements are based on Federal and Commonwealth of Pennsylvania regulations. Because a specific site is not being proposed in this study, site-specific aspects of a typical environmental assessment are not provided. However, PFB combustion plants and conventional PC-fired plants would similarly affect air quality, geology, hydrology, water quality, land use, cultural resources, vegetation, wildlife, aquatic ecology, and other components of a proposed site. The disposal of solid waste from the PFB combustion plant would have less of an effect on the environment than disposal from a conventional PC-fired plant because a smaller area is needed for PFB combustion wastes.

A summary of second-generation PFB combustion emissions is presented in Table 47. The air emissions shown represent the design effort to meet NSPS requirements; in the case of NO_x and particulates, an improvement over NSPS requirements is shown. A comparison of these values with those from a conventional fossil-fuel-fired plant is presented in Section 5.6.

Table 47 Comparison of Second-Generation PFB Combustion Plant Emissions With NSPS

	Regulatory Standard	Second-Generation PFB Combustion Emissions
Air Emissions		
SO_2, lb/10^6 Btu	---	0.60 (standard)
Maximum allowable	1.2	
To 0.6	90%	
Below 0.6	70%	
NO_x, lb/10^6 Btu	0.6	0.28
Particulates, lb/10^6 Btu	0.03	0.00057 (new)
Solid Waste, lb/h	---	91,144
Water Effluents, gal/d		
Coal Pile Runoff		30,000
Dolomite Pile Runoff		4,000
Cooling Tower Blowdown		936,000
Demineralizer Regenerants		10,000
Filter Backwash		20,000
Miscellaneous		60,000

The following sections present the results of a conceptual analysis of the environmental impact of the second-generation PFB combustion facility. PFB combustion technology has demonstrated or projected that it can meet existing standards and that it is capable of further reducing environmental impact, at a cost, as addressed in the COE Sensitivity Studies. An attractive feature of PFB combustion becomes apparent when the emissions rates per megawatt produced are examined--the PFB combustion plant is very efficient. While this efficiency is not significant in meeting Federal regulations, which are indexed to Btu input, many State and local regulations consider tons per year within a geographical area, which makes a highly efficient plant meeting Federal regulations very attractive to a utility.

4.2 AIR EMISSIONS

In the discussions that follow, the second-generation PFB combustion plant is assumed to have a 453-MW net output and 43.6-percent net plant efficiency.

4.2.1 Sulfur Dioxide

Regulatory Standards. The SO_2 regulatory standards for a PFB combustion facility in the Commonwealth of Pennsylvania are guided by the Environmental Protection Agency (EPA) and the Standards for Stationary Sources, New Source Performance Standards (NSPS). The EPA has given Pennsylvania the authority to enforce NSPS. The NSPS limits for SO_2 reduction mandate a 90-percent reduction to 0.6 $lb/10^6$ Btu, a 70-percent reduction if emissions are below 0.6 $lb/10^6$ Btu, and a maximum allowable emissions level of 1.2 $lb/10^6$ Btu.

Assuming that the southwestern Pennsylvania area is an attainment area, a Prevention of Significant Deterioration (PSD) application must be completed and filed with the Pennsylvania Department of Environmental Resources (PaDER). This application will identify SO_2 as a major pollutant (greater than 40 t/yr) requiring a PSD evaluation, including Best Available Control Technology (BACT) and a computer dispersion analysis of the stack emissions.

The ambient concentration standards for SO_2 are 80 $\mu g/m^3$ (0.03 ppm) annually, 365 $\mu g/m^3$ (0.14 ppm) maximum within 24 hours, and 1300 $\mu g/m^3$ (0.5 ppm) maximum within 3 hours. The PSD evaluation would need to show that these standards are neither violated nor approached, (concentration within 90 percent of the standard).

Plant Emission Rates. A second-generation PFB combustion facility, using dolomitic limestone in the carbonizer and CPFBC units, should have little difficulty in reducing SO_2 emissions by 90 percent, bettering NSPS requirements for this coal. The NSPS requirement for SO_2 emissions is 0.6 $lb/10^6$ Btu, corresponding to approximately an 86-percent reduction.

SO_2 emissions are controlled by adjusting the flow of dolomite to achieve the Ca/S ratio required to meet the standard. The baseline plant provides some design margin below the standard, and significant further reduction is possible; but for the purposes of environmental assessment, compliance with the NSPS standard is assumed, at an emissions rate of 0.60 $lb/10^6$ Btu or 2125 lb/h SO_2. This emissions rate amounts to 25.5 t/d and 9307 t/yr maximum, or 6050 t/yr at a 65-percent loading factor. A PSD review would be required, since SO_2 emissions exceed the PSD allowable of 40 t/yr.

Impact Analysis. Using a 65-percent loading factor, stack emissions of SO_2 from the PFB combustion facility would be up to 25.5 t/d. Dispersion of stack SO_2 emissions needs further analyses by computer to determine the level of ambient concentration. However, with the assumed conditions of location and terrain, a computer analysis would probably show a low impact that would not endanger the ambient standards.

4.2.2 Nitrogen Oxides

Regulatory Standards. Pennsylvania has also been given authority from the EPA to enforce the NSPS for NO_x. For a new source in Pennsylvania, NSPS for NO_x are 0.6 lb/10^6 Btu input. External controls for NO_x are costly and not used on a large scale by U.S. electric utilities, so the reduction must come from boiler design and operation. A PFB combustion plant designed with the intention to meet the NSPS should be able to perform within the allowable limit.

Ambient standards for NO_x are 100 $\mu g/m^3$ (0.05 ppm). Computer dispersion analyses would be required to show the predicted ambient concentration and that the standard is not violated. In addition, a PSD application, including computer dispersion analysis, would be required for emissions of over 40 t/yr.

Plant Emission Rates. Sources of NO_x production in the second-generation PFB combustion system are the CPFBC and the topping combustor. Some of the ammonia (NH3) produced in the carbonizer is converted to NO_x in the CPFBC along with some conversion of fuel-bound nitrogen. This process is discussed in Sections 2.5.4, 2.5.5, and 2.5.9. An additional contribution to NO_x production is made in the topping combustor, as discussed in Section 2.5.9. The net result of these contributions is a projected NO_x stack emission of 0.28 lb/10^6 Btu, or 992 lb/h. A PFB combustion facility, designed by the manufacturer with intent to meet the NSPS, should be able to perform within the standard on a daily basis.

Impact Analysis. The impact of the NO_x stack emissions from the PFB combustion plant needs to be analyzed by computer modeling. With design intent to meet stack emission standards, the impact from the ambient concentrations would apparently also be within the ambient standards.

NO_x emissions from the CPFBC are less than half those permitted by NSPS; thus a lower ambient impact could be expected.

4.2.3 Particulates

Regulatory Standards. Particulate standards under NSPS for a new source in Pennsylvania are 0.03 lb/10^6 Btu input. Primary ambient standards for particulates are 75 $\mu g/m^3$ annual geometric mean. Secondary standards are 260 $\mu g/m^3$ maximum in 24 hours and 60 $\mu g/m^3$ annual geometric mean.

An emissions rate exceeding 25 t/yr would require a computer dispersion analysis and a PSD application.

Plant Emissions Rates. The PFB combustion plant, with high-temperature/high-pressure ceramic cross-flow filters for final particulate cleanup, is expected to easily meet NSPS requirements of 0.03 lb/10^6 Btu input. The porous ceramic provides a "total" filter with an estimated 99.99-percent efficiency when new, exceeding the efficiency of current bag filters. In the new condition, the expected emissions rate is 2 lb/h (0.00057 lb/10^6 Btu); but if individual filter elements are assumed to fail and outlet loading to increase gradually to NSPS before maintenance is required, the maximum emissions rate will be 106 lb/h (0.03 lb/10^6 Btu). For the purpose of this analysis, NSPS emissions rates are assumed to provide the necessary design margin.

The emissions rate of 106 lb/h amounts to 1.3 t/d, or 464 t/yr (302 t/yr at 65-percent load), requiring a PSD computer dispersion analysis (over 25 t/yr) for impact on ambient standards. However, the optimistic 2-lb/h rate, amounting to 9 t/yr, is well under the PSD review limit of 25 t/yr; thus no PSD review would be required.

Impact Analysis. Emissions of 106 lb/h (464 t/yr) exceed the 25 t/yr PSD significant emissions rate and would need to be evaluated and compared with the ambient standards for compliance.

4.3 SOLID WASTES

4.3.1 Characteristics

Spent bed material and particulates captured by the ceramic cross-flow filters are the two major solid waste streams from the PFB combustion plant. The amount of waste generated is a function of fuel and sorbent characteristics as well as the level of SO_2 and particulate control. Based on design parameters previously presented, the proposed PFB combustion facility will produce approximately 46 t/h solid waste. Over 250,000 t/yr would be generated at the expected 65-percent loading.

Primary constituents of the solid waste streams are shown in Table 48. Coal ash and $CaSO_4$ make up over 65 percent of the solid waste production.

4.3.2 Regulatory Aspects

Solid waste disposal and any leachate generated are regulated by both Federal and State agencies. Applicable Federal regulations include those under the Resource Conservation Recovery Act (RCRA) and the National Pollutant Discharge Elimination System (NPDES). In Pennsylvania, solid waste disposal is regulated by the Solid Waste Management Act and the NPDES permitting program, which is part of the Clean Streams Law.

Table 48 PFB Combustion Ash Constituents and Production Estimates

Constituents	lb/h
Coal ash	29,541
MgO	16,784
CaO	12,477
Dolomite Inerts	1,305
$CaSO_4$	30,973
CaS	64
Total	91,144

Power-generation wastes are specifically excluded from Federal regulations (Subtitle D of RCRA); however, concentrations of eight RCRA elements (arsenic, barium, cadmium, chromium, lead, mercury, selenium, and silver) in the leachate from the PFB combustion plant solid waste could result in the by-products being classified as hazardous. Based on recent research, using the U.S. EPA extraction procedure, all the by-products are well below levels at which they would be classified toxic under RCRA regulations [1]. Barium, selenium, and chromium were present in the highest concentrations. Trace elements are discussed in detail in the following sections. Other components of the leachate, which may be of concern in certain circumstances, are pH, calcium, total dissolved solids, and sulfate [1,2]. (Section 4.5 discusses water effluents.)

In addition to the leachate, another potential concern is the heat release from the PFB combustion plant solid waste material upon contact with water. This release is primarily from hydration of the CaO portion to form calcium hydroxide. Heat releases may represent an occupational safety concern, but they are not expected to be an environmental regulatory concern.

4.3.3 Disposal

As a nonhazardous material, PFB combustion plant wastes may be disposed of in a landfill. PaDER solid waste permits will be required for the disposal site. Handling, transportation, and disposal are similar to those for conventional PC plants with dry scrubbers. If water is added to the solid waste and the material is compacted, the permeability will be reduced, and the need for a liner to control leachate may be eliminated [1].

Based on a 65-percent loading and a bulk density of 80 lb/ft^3, approximately 149 acre·ft/yr are required for landfill disposal of all ash. For the 30-year life of the plant, 4470 acre·ft are required.

4.3.4 Ash Utilization

An alternative to disposal of PFB combustion plant solid waste is commercial utilization. Several applications have been studied: concrete/road construction, agriculture, industry, and mining [3-5].

Preliminary results indicate that fluidized bed combustion spent bed material can be used as a no-cement concrete for mine subsidence and ventilation control, base construction for roadways, and conventional concrete/standard concrete masonry construction. Fluidized bed combustion plant ash has also been used in brick making in the United Kingdom.

Various experiments indicate that spent bed material is an effective material for liming agricultural areas, when applied at 10 to 50 t/acre. Spent bed material neutralizes acidic soil and supplements trace metals required for plant growth.

Spent bed material has also been used to treat industrial and municipal wastes. The lime component has been used as a sorbent for SO_x scrubbers and as a reagent for stabilizing sludges.

4.4 TRACE ELEMENT RELEASE AND TOXICITY

This section contains an estimate of the release of trace elements in the coal and sorbent to the environment, an assessment of the toxicity of the released components, and a comparison of the results with those from the first-generation PFB combustion plant. A review of the literature was conducted to compare the equilibrium-projected trace element concentrations and toxicity levels released during PFB combustion, made by Westinghouse in 1981 [6], with data generated in the field since the time of that study [7-32]. Generally, the field data support the equilibrium partitioning of the trace elements within the solid, liquid, and gaseous phases. A brief summary of the trace elements partitioning mechanism and elemental distribution which results during coal combustion is presented. This summary is followed by an assessment of the projected trace element toxicity releases in the second-generation PFB combustion baseline plant. The trace element concerns are essentially identical with those for first-generation PFB combustion plants and should not hinder the development of the technology.

The literature indicates that the fate of trace and minor elements during combustion depends not only on the affinity, concentration, and distribution of each element within the inorganic or organic-associated coal matrix, but also on process conditions such as temperature, heating rate, exposure time at elevated temperatures, the localized reducing or oxidizing environment surrounding the burning coal particle, and the solids-removal systems. During combustion, volatiles, including pyrolyzed organics, are released from the coal particle in either attached or detached flames, depending on the thermal properties of the coal and on the physical constraints of the system. The chemical transformations within the organic material during rapid heating and combustion are kinetically limited for particles smaller than 100 μm and diffusion limited for larger particles. Initially, conditions at the particle surface are reducing, with limited diffusion of oxygen through the boundary layer. Nonvolatiles may be trapped within the organic matrix or released directly into the effluent gas phase. The more volatile elements within the mineral matrix of the coal particle may vaporize in either their original or reduced state.

The coal particle fractures during combustion, in part because of internal burning, forming liquid ash droplet agglomerates. The ash agglomerates may expand through release of internal gases, forming cenospheres, or may burst the particles into a shower of submicron particles. Alternatively, the cenospheres may coalesce with adjacent particles. Entrapped within the melted matrix of the cenosphere are volatile species, which undergo a secondary process and form an ashed sphere packed with smaller spheres (plerospheres).

Not all of the trace elements contained in the coal particle are volatilized during combustion. Under these conditions a sizeable portion becomes entrapped within the liquid matrix, where volatilization is diffusion limited. Similarly, nonvolatiles that are expected in the solid ash residues may be transferred into the effluent gas if associated with organic matter.

When the last combustible volatile species is consumed, the condition of the particle surface changes from a strongly reducing to a mildly oxidizing environment. Although not originally present within coal as oxides, most trace volatile elements exist in an oxidized state following combustion. Various volatile trace oxide complexes may condense on entrained-ash fines at various stages within the system. Elements forming chemical compounds with particularly high vapor pressures (mercury, selenium) may be completely released from the stack as gas phases.

Factors that determine how and in what form the trace elements are emitted from coal, and to what extent they are distributed in the various combustion products, include the:

- Concentration of the element in the coal being burned

- Physical and chemical properties of the elements and their compounds
- Type and operating conditions of the combustion unit
- Efficiency of emission-control devices used.

Typically, bromine, germanium, beryllium, antimony, boron, and organic sulfur are considered to be distributed within the organic coal structure, while sulfide-forming elements such as zinc, arsenic, cadmium, iron, zirconium, mercury, lead, hafnium, and manganese, as well as pyritic sulfur, are considered to be distributed within the inorganic ash phase of the coal structure [7].

Partitioning of the trace and minor elements in a conventional boiler occurs between the volatile stack gas emissions and the solid ash formation of either the slag or the fly ash. Lyon's analysis of the ash and outlet gases at the Allen Steam Plant in Memphis [8] indicated that the trace and minor elements can be classified as:

- Elements that readily are incorporated into slag formations (aluminum, cobalt, chromium, iron, potassium, manganese, sodium, silicon, titanium, vanadium, and possibly nickel). These elements do not volatilize in the combustion zone, but form a melt of rather uniform composition, divided almost equally between the fly ash entering the ESP and the slag fraction. There is no apparent tendency to concentrate these elements on ash particles leaving the ESP.
- Elements that are concentrated in the inlet ESP fly ash instead of the slag and in the outlet ESP fly ash instead of the inlet ESP fly ash (arsenic, cadmium, copper, gallium, lead, selenium, zinc, and possibly molybdenum). These elements volatilize upon combustion. With the removal of the slag in the combustion zone, lead has no opportunity to condense on the slag, but condenses or becomes adsorbed on the fly ash as the flue gas cools.
- Elements that remain completely in the gas phase (mercury, chlorine, and bromine).

Natusch, Wallace, and Evans proposed a volatilization-condensation or adsorption mechanism that accounted for the relationship between the trace element concentration and the ash particle size [9]. As the temperature of the flue gas decreases, volatiles condense and chemically react with, or are adsorbed onto, the ash particle surface. Lyon [8], Cowherd, et al. [10], and Cato [11] demonstrated that, in a conventional boiler, the concentration of the condensed element is inversely proportional to the ash particle size.

The volatile trace and minor elements emitted in the stack gases may be toxic. Cowherd, however, indicated that the concentration of emissions from conventional utility boilers at ground level is lower than the corresponding threshold limit value for the various inorganic trace and minor elements, with only the concentration of beryllium approaching the level of potential concern [10]. Limited information is reported on potentially hazardous organic emissions. Polycyclic organic material (POM) and polychlorinated biphenyls (PCBs) could possibly be formed within the combustor before complete oxidation.

The concentration of the trace elements released during coal combustion is dependent on:

- Physical coal cleaning
- Boiler design
- Fuel feed mechanisms
- Flue gas characteristics

- Combustion temperature
- The use of particulate control technologies.

Physical coal cleaning is considered an effective means of reducing trace elements in emissions by removing them from the coal. It is expected to be most effective in removing arsenic, cadmium, mercury, and molybdenum--since these elements tend to be associated with inorganic constituents of the coal removed by physical coal cleaning [12]. Chromium, nickel, vanadium, and selenium are associated with both the organic and inorganic portions, so they will be removed to some extent by physical coal cleaning. Since beryllium is associated with the organic portion of the coal, physical coal cleaning will not be an effective means for stopping beryllium emissions.

Combustion modification techniques (i.e., low-excess air, staged combustion, FGD, or low-NO_x burners), altering the oxygen concentrations or temperature in the flame zone may affect the oxidation of volatile trace element compounds. However, the effects of these techniques on trace element emissions have not been documented because of insufficient data. Most trace elements tend to be enriched on small fly ash particles, and their collection is best accomplished by high-efficiency particulate-removal technologies such as fabric filters, ESPs, and wet scrubbers. Mercury and selenium tend to remain, completely or in part, in the vapor phase. Technologies that cool the flue gas stream (wet scrubbers, FGD systems) are the most efficient collection techniques for these elements.

In terms of the secondary effects of pollutant control, trace elements removed by the various particulate-removal systems and SO_2/NO_x control technologies would then be associated with the liquid or solid waste generated by these technologies.

Fabric filters and ESP designs for high-efficiency removal of the fine particulates are considered the most effective means for control of trace-element emissions. Fabric filters achieve over 99-percent collection of all trace elements, with the exception of mercury and selenium. ESPs are also considered to have a high degree of trace-element control, achieving greater than 95-percent removal of trace-element emissions, with the exception of mercury and selenium. Removal efficiencies are much lower for mercury and selenium, since these elements remain as volatile species. Dual alkali/venturi scrubbers for FGD achieve collection efficiencies ranging from 55 percent for mercury to 99 percent for cadmium. The dual alkali/FGD system preceded by an ESP is expected to achieve 97-percent mercury removal.

Unlike the basic concepts that have been proposed for the release of trace and minor elements from coal particles during combustion and the subsequent formation of ash, release mechanisms for sulfur-sorbent (calcium magnesium carbonates) and alkali-getter (aluminosilicate clays) materials projected for use in fluidized bed combustion systems have not been reported. Release of alkalis (sodium and potassium) from candidate sorbents has been achieved within 10 to 20 minutes at projected 1600°F desulfurizer temperatures [13]. The flame emission spectroscopic technique used in the investigation indicated that alkali release was proportional to the alkali-chloride content of the getter material, instead of the alkali bound within the clay minerals. The authors' data also indicated that alkali release increased as reaction temperatures rose and that release increased significantly during calcination of the dolomite.

Chemical equilibrium models have been proposed which project the numerous pathways by which trace and minor elements react with, or repartition within, the clay lattice of the coal structure during combustion [6]. At equilibrium, the trace and minor elements do one of the following:

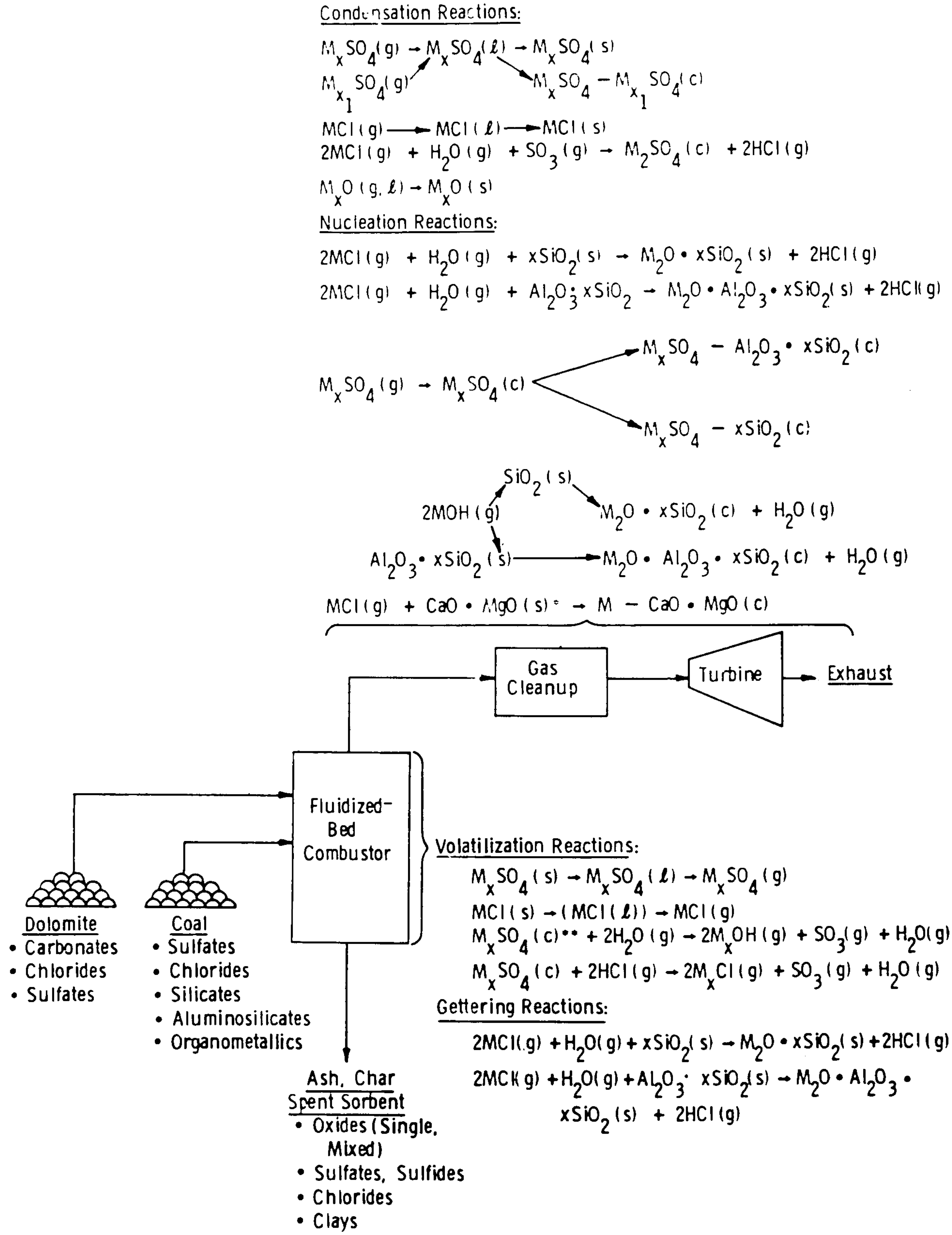
- Volatilize completely
  - Beryllium
  - Fluorine
  - Mercury
  - Lead
  - Molybdenum
  - Bromine
  - Boron
  - Phosphorus
  - Copper
  - Arsenic
  - Cadmium
  - Selenium
- Volatilize partially
  - Cobalt
  - Molybdenum
  - Tin
  - Chromium
  - Nickel
  - Chlorine
- Remain as stable solid complexes
  - Iron
  - Titanium
  - Aluminum
  - Silicon
  - Vanadium
  - Zinc
  - Zirconium
  - Gallium

The distribution of these elements within the various solid, liquid, or gaseous phases is independent of the process operating pressure. However, the distribution of the sodium, potassium, antimony, and germanium phase is projected to be dependent on the process operating pressure.

Projections utilizing the equilibrium approach are based not only on the trace and minor element reaction with the feed carbon, hydrogen, oxygen, nitrogen, sulfur, and chlorine, but also on the interaction with the clay structure. A schematic of the trace and minor element equilibrium partitioning reactions is shown in Figure 88. Previous comparisons of the projected emissions concentration from first-generation PFB combustion plants with toxicity data for both air and land minimum acute toxicity effluent concentrations indicate that beryllium, fluorine, mercury, lead, cobalt, chromium, bromine, phosphorus, copper, arsenic, cadmium, and selenium are potentially hazardous if directly emitted as gaseous species from the CPFBC outlet. Beryllium, cobalt, chromium, iron, molybdenum, nickel, titanium, vanadium, zinc, antimony, tin, zirconium, and germanium are potentially hazardous if directly emitted as solid particulates at the CPFBC outlet.

The following discussion utilizes the thermodynamic equilibrium projections for the partitioning of the trace and minor elements into the various solid, liquid, and gaseous streams at 14 atm/1500°F (the pressure and temperature identified in the second-generation PFB combustion baseline plant). The alkali components sodium and potassium are not considered here because they are not of toxic concern and because they are estimated in Appendix D for the evaluation of turbine protection.

Tables 49 and 50 present estimates of the trace and minor element partitioning in the various solid, liquid, and gas phases for the 14-atm/1500°F carbonizer and for the 14-atm/1600°F CPFBC. Volatilization of beryllium, fluorine, mercury, lead, cobalt, chromium, molybdenum, manganese, nickel, bromine, boron, phosphorus, copper, antimony, arsenic, cadmium, and selenium from the coal occurs in both the



*CaO · MgO = Representative of either half- or fully calcined, or sulfated sorbent material
** (c) = condensed = solid + liquid

Figure 88 Chemical Pathways in Fluidized Bed Combustion Systems

Table 49 Partitioning of Trace and Minor Elements in the 14-atm/1500°F Carbonizer

Element	Estimated Concentration by Weight (Coal)	Projected Solids Retention (Phase)	Projected Volatiles Release (Phase)
Be	1.61 ppm	98% (BeO, BeO·Il_2O_3)	2% [$Be(OH)_2$]
F	60.94 ppm	---	100% (HF)
Hg	0.20 ppm	---	100% (HgO, Hg)
Pb	34.78 ppm	---	100% ($PbCl_4$, $PbCl_2$)
Co	9.57 ppm	95% (Co_3O_4)	5% ($CoCl_2$)
Cr	13.75 ppm	97% (Cr_2O_3)	3% [$CrO_2(OH)_2$, CrO_2Cl_2]
Fe	1.92%	100% (Fe_2O_3)	---
Mo	7.54 ppm	---	100% [$MoO_2(OH)_2$, MoO_2Cl_2]
Mn	49.40 ppm	99% (Mn_2O_3)	1% ($MnCl_2$)
Ni	21.07 ppm	98% (NiO)	2% ($Ni(OH_2)$)
Ti	0.07%	100% (TiO_2)	---
Br	15.42 ppm	---	100% (Br, BrH)
B	102.21 ppm	---	100% (H_3BHO_3)
P	71.10 ppm	---	100% [$(P_2O_5)_2$]
Cu	15.16 ppm	---	100% (Cu_3Cl_3, CuCl)
V	32.71 ppm	100% (V_2O_5)	---
Zn	272.29 ppm	100% (ZnO)	---
Sb	1.26 ppm	99% (SbO_2)	1% ($SbCl_3$)
Sn	4.79 ppm	100% (SnO_2)	---
Zr	72.46 ppm	100% (ZrO_2)	---
As	14.02 ppm	84% (As_2O_5)	16% (AsCl)
Cd	2.52 ppm	---	100% (CdO, CdCl)
Se	2.08 ppm	---	100% (SeO)
Ga	3.12 ppm	100% (Ga_2O_3)	---
Ge	6.59 ppm	100% (GeO_2)	---

Table 50 Partitioning of Trace and Minor Elements in the 14-atm/1600°F CPFBC

Element	Estimated Concentration by Weight (Coal)	Projected Solids Retention (Phase)		Projected Volatiles Release (Phase)	
Be	1.61 ppm	94%	(BeO, $BeO \cdot Al_2O_3$)	6%	[$Be(OH)_2$]
F	60.94 ppm	---		100%	(HF)
Hg	0.20 ppm	---		100%	(HgO, $HgCl_2$, Hg)
Pb	34.78 ppm	---		100%	($PbCl_4$, $PbCl_2$)
Co	9.57 ppm	92%	(Co_3O_4)	8%	($CoCl_2$)
Cr	13.75 ppm	83%	(Cr_2O_3)	7%	[$CrO_2(OH)_2$, CrO_2Cl_2]
Fe	1.92%	100%	(Fe_2O_3)	---	
Mo	7.54 ppm	---		100%	[$MoO_2(OH)_2$, MoO_2Cl_2]
Mn	49.40 ppm	99%	(Mn_2O_3)	1%	($MnCl_2$)
Ni	21.07 ppm	96.5%	(NiO)	3.5%	[$NiCl_2$, $Ni(OH)_2$]
Ti	0.07%	100%	(TiO_2)	---	
Br	15.42 ppm	---		100%	(Br, BrH)
B	102.21 ppm	---		100%	(H_3BO_3, BHO_2)
P	71.10 ppm	---		100%	[$(P_2O_5)_2$]
Cu	15.16 ppm	---		100%	($CuCl$, Cu_3Cl_3)
V	32.71 ppm	100%	(V_2O_5)	---	
Zn	272.29 ppm	100%	(ZnO)	---	
Sb	1.26 ppm	99%	(SbO_2)	100%	($SbCl_3$, $SbCl$, SbO)
Sn	4.79 ppm	100%	(SnO_2)	---	
Zr	72.46 ppm	100%	(ZrO_2)	---	
As	14.02 ppm	47%	(As_2O_5)	53%	($AsCl$, AsO)
Cd	2.52 ppm	---		100%	(CdO, Cd, $CdCl$)
Se	2.08 ppm	---		100%	(SeO)
Ga	3.12 ppm	100%	(Ga_2O_3)	---	
Ge	6.59 ppm	100%	(GeO_2)	---	

carbonizer and CPFBC. A comparison of these two tables indicates that, as a result of the higher combustor temperatures, higher concentrations of beryllium, cobalt, chromium, nickel, antimony, and arsenic are released during coal combustion.

Projected trace and minor element products in the carbonizer are presented in Table 51. Carbonizer temperatures promote 100-percent retention of the feed iron, titanium, zinc, silicon, zirconium, gallium, and germanium as solid oxides, and vanadium as a liquid oxide. Greater than 95 percent of the feed beryllium, cobalt, chromium, molybdenum, nickel, and antimony are retained as solid oxides, while 84-percent of the feed arsenic is retained as a solid oxide.

PFB combustion temperatures enhance volatilization of the trace and minor elements as gaseous chlorides, sulfates, hydroxides, or hydrides. Table 52 summarizes the projected trace and minor element gas-phase concentrations at the entrance to the topping combustor when only char/coke/ash from the carbonizer are fed into the CPFBC, with the assumption that HGCU systems at both the carbonizer and CPFBC outlets have achieved 100-percent removal of the generated fines. Comparison of the projected topping combustor inlet concentrations with the air minimum acute toxicity effluent values indicates that beryllium, fluorine, mercury, antimony, cobalt, nickel, bromine, phosphorus, copper, arsenic, cadmium, and selenium exceed the toxic air emissions level. This list is identical to previous estimates for the first-generation PFB combustion plant.

4.5 WATER EFFLUENTS

Industrial wastewater from station operations is collected, treated in an on-site system, and discharged to an adjacent stream. In addition to boiler blowdown, the industrial waste treatment system treats wastewater from the following sources:

- Coal Pile Runoff. The coal pile is assumed to be lined with an impervious liner, and a leachate collection system is installed above the liner. Runoff and leachate from rainfall over the contributory coal pile area are collected in a desilting pond. The total volume to be treated on an average basis is estimated at 30,000 gal/d. Coal pile runoff is characterized by a low pH, high acidity, and high heavy metals concentrations. These wastes are normally treated by conventional lime neutralization, oxidation, precipitation of heavy metals, and solids removal.
- Dolomite Storage Runoff. The assumption is that the dolomite storage pile does not require lining, reducing the runoff by that quantity of rainfall which seeps through the pile. The total volume to be treated on an average basis is estimated at 4000 gal/d. Runoff from the dolomite storage pile contains mostly suspended solids. The pH of the runoff is between 6 and 8; the concentration of heavy metals is negligible. Treatment is required for suspended solids only. However, since the runoff is alkaline, it is advantageous to mix it with the acidic runoff and leachate from the coal pile to take advantage of the available alkalinity.
- Contaminated Yard Drains. Some yard drains will be contaminated by blowing coal dust and road dirt. The volume to be treated depends upon the contributing drainage area and the intensity of the rainfall. The yard drains may contain suspended solids, low acidity, low concentrations of metals, and some oil and grease. The contaminated yard drains will probably be treated with the dolomite storage pile runoff.

Table 51 Projected Trace Element Products in the 14-atm/1500°F Carbonizer

Element	Retention	Volatilization
Be	98% as BeO, $BeO \cdot Al_2O_3$	2% as $Be(OH)_2$
F	---	100% as HF
Hg	---	100% as Hg or HgO
Pb	---	100% as $PbCl_4$, $PbCl_2$
Co	95% as Co_3O_4	5% as $CoCl_2$
Cr	97% as Cr_2O_3	3% as $CrO_2(OH)_2$, CrO_2Cl_2
Fe	100% as Fe_2O_3	---
Mo	---	100% as $MoO_2(OH)_2$
Mn	99% as Mn_2O_3	1% as $MnCl_2$
Ni	98% as NiO ($NiO \cdot Fe_2O_3$)	2% as $Ni(OH)_2$
Ti	100% as TiO_2 ($Al_2O_3 \cdot TiO_2$)	---
Br	---	100% as Br, BrH
B	---	100% as H_3BO_3, BHO_2, $(HBO_2)_3$
P	---	100% as $(P_2O_5)_2$
Cu	---	100% as Cu_3Cl_3, CuCl
V	100% as liquid V_2O_5 ($MgO \cdot V_2O_5$, $Na_2O \cdot V_2O_5$)	---
Zn	100% as $ZnSO_4 \cdot ZnO$	---
Sb	99% as SbO_2	1% as $SbCl_3$
Sn	100% as SnO_2	---
Zr	100% as ZrO_2 ($ZrO_2 \cdot SiO_2$)	---
As	84% as As_2O_5	16% as AsCl
Cd	---	100% as CdO, CdCl
Se	---	100% as SeO
Ga	100% as Ga_2O_3	---
Ge	100% as GeO_2	---

Table 52 Projected Trace and Minor Element Gas-Phase Concentrations at the Topping Combustor

Component	Concentration at Topping Combustor (ppb)	Air MATE* Value (ppb)		Assessment
Be	10.52	1.7	(Be)	Exceeds MATE
F	5699	1,690	(HF)	Exceeds MATE
Hg	18.71	0.084	($HgCl_2$)	Exceeds MATE
Pb	3253	126	(Fume)	Exceeds MATE
Co	94.29	64	(Fume)	Exceeds MATE
Cr	235.9	422	(Salts)	Acceptable
Fe	---	4,220	(Fume)	Acceptable
Mo	705.2	4,220	(Mo)	Acceptable
Mn	70.92	4,220	(Mn)	Acceptable
Ni	89.50	84	(Ni)	Exceeds MATE
Ti	---	8,430	($TiCl_4$)	Acceptable
Br	1442	590	(Br_2)	Exceeds MATE
B	9561	75,870	(B)	Acceptable
P	6653	843	(H_3PO_4)	Exceeds MATE
Cu	1418	169	(Fume)	Exceeds MATE
V	---	420	(V)	Acceptable
Zn	---	570		Acceptable
Sb	1.8	420	(Sb)	Acceptable
Sn	---	1,750	($SnCl_4$)	Acceptable
Zr	---	4,220	(Zr)	Acceptable
As	740.5	1.78	(As)	Exceeds MATE
Cd	235.7	0.74	(Cd)	Exceeds MATE
Se	194.5	9.1	(Se)	Exceeds MATE
Ga	---	4,170	(Ga)	Acceptable
Ge	---	510	(GeH_4)	Acceptable

* Minimum Acute Toxicity Effluent.

- Cooling Tower Blowdown. Blowdown from a natural-draft cooling tower basin is estimated at 936,000 gal/d. Cooling tower blowdown characteristics include suspended solids, high dissolved solids, neutral pH, and low concentrations of chlorine residual. The blowdown from the cooling tower is treated separately in a desilting pond for suspended solids removal before it is discharged to the river.

- Demineralizer Regenerants. Water treatment demineralizers are backwashed and regenerated daily. The total volume of regenerant wastes is estimated at 10,000 gal/d. Typical demineralizer regenerant wastes include extremely high and low pH, high dissolved solids, and some heavy metals. By definition [40 CFR 261.22 and PA Code 75.261(g)(3)], demineralizer regenerant wastes are corrosive, hazardous wastes because they have a pH of 2.0 or below, or 12.5 or above. Because of the high concentration of acids and caustics in the regenerant wastes, the wastes are batch-treated separately from other waste sources to a pH range within the corrosive, hazardous waste limits. The partially treated waste is then combined with other wastes for complete treatment.

- Filter Backwash. Water-treating filters are backwashed daily, with the total volume of backwash estimated at 20,000 gal/d. Filter backwash is typically high in suspended solids with a neutral pH. Backwash wastes are combined with other plant wastes for final treatment.

- Miscellaneous Low-Volume Wastes. Miscellaneous low-volume wastes consist of plant floor drains, contact cooling water, equipment drains, and boiler blowdown. Daily flow rates are estimated at 60,000 gal/d. Low-volume wastes are combined with other plant wastes for final treatment by neutralization, oxidation, precipitation, and sedimentation. Since there are no air preheaters in the PFB combustion unit, there are no maintenance or metal-cleaning wastes requiring treatment. Also, since there are no wet-bottom ash hoppers, and bottom ash and fly ash are both removed in a dry state, there is no requirement for treating ash-hopper-seal wastes.

The effluent from the treatment system will meet regulatory requirements for total suspended solids, total iron, pH, oil, grease, and total manganese. Final effluent limitations will be established in a Part 1 NPDES permit obtained by application to PaDER. The effluent limitations are dependent on the size and quality of the receiving stream and the anticipated treated effluent characteristics. Based on similar facilities in western Pennsylvania, the effluent limitations should be:

	Daily Average (mg/L)	Daily Maximum (mg/L)
■ Total Suspended Solids	30	100
■ Oil and Grease	15	20
■ Total Iron	4	7
■ Total Manganese	2	4

and a pH between 6 and 9. Additional metals limits may be imposed, depending on the receiving stream.

Construction of the system will also require a Part II Water Quality Management Permit, a Stream Encroachment Permit, and approval of a Soil Erosion and Sedimentation Control Plan from PaDER.

4.6 NOISE

In-plant noise is subject to the regulations promulgated by the U.S. Department of Labor Occupational Safety and Health Administration (OSHA) under 29 CFR-1910.95. Individual major noise sources in this facility should be specified not to exceed 95 dB continuous A-weighted sound level at 3 ft. Multiple similar units in some areas must be architecturally enclosed. Partition walls separating relatively noisy plant areas from administrative and control room areas must be acoustically designed. Outdoor noise criteria consist of both OSHA (adjacent to equipment) or property-line (assumed to be at 1000 ft from the plant building periphery) noise limits, whichever is more stringent. The property-line noise criterion is recommended at 55 dB maximum integrated hourly equivalent A-weighted sound level at normal operating conditions. Abnormal operating conditions, such as actuation of a safety-relief valve, are subject to a recommended criterion of 80 dB maximum A-weighted sound level. If the PFB combustion plant is located in Pennsylvania, there are no applicable statewide noise regulations, but local municipalities may have quantitative criteria as part of the noise elements of zoning ordinances. Noise from all components of the PFB combustion facility can be controlled using conventional acoustical materials and construction practices. Nevertheless, the application of conventional acoustical engineering requires attention to the unique aspects of this facility, several of which are briefly addressed in the following paragraphs:

- Gas Turbine Enclosures. Whether to locate the gas turbines within close-fitting all-weather enclosures, such as is common for outdoor installations, or to substitute an architectural building enclosure, would be a matter of aesthetics and maintenance, were it not for acoustics. In terms of far-field, property-line noise levels from the gas turbines alone, there may be little difference between the two enclosures. However, OSHA prescribes an absolute maximum noise level of 115 dB A-weighted for all routinely accessible areas. Therefore, bare gas turbines would be prohibitively loud in terms of near-field OSHA levels. The most effective standard offering of close-fitting all weather enclosures for the gas turbines ensures acceptable near-field levels, with ear protection, in the vicinity of the units; these may prove adequate in terms of far-field property-line levels as well. If further property-line noise level reductions appear necessary, the building enclosure could be added, but it may be advisable in any case for aesthetics and maintenance.

  In the baseline design, the gas turbines and topping combustors are within a close-fitting enclosure. A building enclosure also houses the gas turbine, generator, and accessories.

- Steam Turbine Building. The thermal lagging supplied with the steam turbine incorporates sufficient acoustical effectiveness within the turbine hall building.

- Gas Turbine Inlet. Gas turbine inlet silencers are always included, but with optional gradations of increasing effectiveness. The degree of optional silencing, and whether extra silencers are necessary, is a site-specific matter.

- Gas Turbine/HRSG Exhaust. Normally, waste heat boilers, such as those employed in the baseline design, function as moderately effective silencers themselves. The 300-ft stack provides additional exhaust silencing, obviating the need for silencers at the HRSG exit. However, silencers are required and are installed on the exhaust gas bypass stack to meet the 55 dB(A) limit when the bypass is operating.

- Administration Building/Control Room. Building partition walls separating the control room and offices from the steam turbine hall merely require care and attention in acoustical design. Conventional materials and routine acoustical engineering suffice.
- Compressor Room. Compressors in Systems C301, C302, and C303 are all enclosed in a separate room within the building in the fuel gas generating area. The typically high sound levels from multiple large units and the large number of wall piping penetrations require care and attention to limit noise. Masonry walls are commonly specified for such rooms.
- Piping. All fuel-gas and steam piping and all pressure-reducing stations are potential sources of excessive noise. Experience suggests no additional acoustical treatment is needed for the refractory-lined fuel-gas and flue-gas piping.
- Relief Valves. The atmospheric relief of turbine by-pass steam is equipped with blow-off silencing. Continuous blow-off streams, such as from deaerators, are equipped with silencing.
- External Coal and Ash Handling. Depending upon site specifics, the 55 dB(A) at 1000 ft may be compromised by the coal- or ash-handling facilities. Many such problems are minimized at the design stage by allowing acoustical considerations in the plant layout. In the baseline design, crushers are housed within a building that is given acoustical treatment. In any event, good maintenance practices and quality equipment are always as important as engineered control measures in ensuring continued compliance with noise criteria.

4.7 REFERENCES

1. S. Tavoulareas, W. Howe, and D. Golden, "EPRI's Research on AFBC By-Product Management," Proceedings of the 1987 International Conference on Fluidized Bed Combustion: FBC Comes of Age, Vol. 2, J. P. Mustonen (ed.), May 1987, pp. 916-926.

2. S. Chiu, "An Evaluation of the Environmental and Technical Aspects of Pressurized, Fluidized-Bed Combustors," Argonne National Laboratory Technical Memo ANL/EES-TM-257, 1983.

3. J. L. Harness, Y. C. Chung, and D. A. Mays, "Shawnee AFBC Demonstration Project Ash Utilization Program," Proceedings of the 1987 International Conference on Fluidized Bed Combustion: FBC Comes of Age, Vol. 2, J. P. Mustonen (ed.), May 1987, pp. 927-934.

4. C. E. Carr and T. W. Price, "The Disposal and Utilization of AFBC Residues," Proceedings of the 1987 International Conference on Fluidized Bed Combustion: FBC Comes of Age, Vol. 2, May 1987, pp. 935-946.

5. A. E. Bland, et al., "Production of No-Cement Concretes Utilizing Fluid Bed Combustion Waste and Power Plant Flyash," Proceedings of the 1987 International Conference on Fluidized Bed Combustion: FBC Comes of Age, Vol. 2, J. P. Mustonen (ed.), May 1987, pp. 947-953.

6. M. A. Alvin, "Trace and Minor Element Reactions in Fluidized-Bed Combustion Processes," Westinghouse Research and Development Center, Pittsburgh, Final Report, EPA-600/7-82-050, under Contract EPA-68-02-3110, July 1982.

7. T. M. Pacyna, "Emission Factors of Trace Metals from Coal-Fired Power Plants," Norsk Institute for Luftforskning, K. Jeller (ed.), Norway, December 1981.

8. W. S. Lyon, Trace Element Measurements at the Coal-Fired Steam Plant, Robert E. Krieger Publishing Company, Cleveland, 1977.

9. D. F. S. Natusch, J. R. Wallace, and C. A. Evans, Jr., "Toxic Trace Elements; Preferential Concentration in Respirable Particles," Science, Vol. 183, January 1984, pp. 202-204.

10. C. Cowherd, Jr., et al., "Hazardous Emission Characterization of Utility Boilers," Midwest Research Institute, Kansas City, Missouri, Final Report, EPA/650/2-75/066, under Contract EPA-68-02-1324, July 1975.

11. G. A. Cato, "Field Testing: Trace Element and Organic Emissions from Industrial Boilers," KVB Engineering, Inc., Tustin, California, Final Report, EPA/600/2-76086b, under Contract EPA-68-02-1074, October 1976.

12. J. H. E. Stelling and S. J. Call, "Control of Criteria and Non-Criteria Pollutants from Coal/Liquid Mixture Combustion," Radian Corporation, Final Report, EPA 600/7-84-001, under Contract EPA-68-02-3171, January 1984.

13. L. N. Yannopoulos, J. L. Toth, and A. Pebler, "Experimental Determination of Alkali Impurity Release from Various Dolomites, Combustion and Flame, Vol. 30, 1977, pp. 61-69.

14. M. Bezacinsky, et al., "To The Problem of Trace Elements and Hydrocarbon Emissions from Combustion of Coal," Journal of Hygiene, Epidemiology, Microbiology, and Immunology, Vol. 28, 1984, pp. 129-138.

15. E. R. Krishnan and H. C. Vinson, "Trace Emissions from Coal and Oil Combustion," Environmental Progress, Vol. 1, 1982, pp. 290-295.

16. B. Freedman, "Trace Elements and Organics Associated with Coal Combustion in Power Plants: Emissions and Environmental Impacts," 64th Proceedings of the CIC Coal Symposium, 1982, pp. 616-631.

17. J. M. Ondov and A. H. Biermann, "Effects of Particle-Control Devices on Atmospheric Emissions of Minor and Trace Elements from Coal Combustion," 2nd Symposium on the Transfer and Utilization of Particulate Control Technology, Denver, July 1979.

18. N. F. Surprenant, et al., "Emissions Assessment of Conventional Stationary Combustion Systems: Vol. V: Industrial Combustion Sources", TRW, Inc., Redondo Beach, California, Final Report, EPA-600/7-81-003C, under Contract EPA-68-02-2197, 1981.

19. J. M. Ondov and A. H. Biermann, "Physical and Chemical Characterization of Aerosol Emissions from Coal-Fired Power Plants," Symposium on Environmental and Climatic Impact of Coal Utilization, J. Singh and A. DePak (eds.), Academic Press, New York, 1980, pp. 1-20.

20. R. D. Smith, "The Trace Element Chemistry of Coal During Combustion and the Emissions from Coal-Fired Plants," Progress in Energy and Combustion Science, Vol. 6, 1980, pp. 53-119.

21. J. M. Allen and K. M. Duke, "Multimedia Emissions from Pressurized Fluidized-Bed Combustion of Coal," Proceedings of the 71st Annual Meeting, Air Pollution Control Association, Vol. 5, 1978.

22. American Boiler Manufacturers Association, "Inorganic Trace Elements and Polynuclear Aromatic Hydrocarbon Emissions", Emissions and Efficiency Performance of Industrial Coal Stoker Fired Boilers," Vol. 2, DOE/Et/10386-T1, August 1981.

23. C. T. Ford and A. A. Price, "Evaluation of the Effect of Coal Cleaning on Fugitive Elements," Bituminous Coal Research, Inc., Final Report to DOE on Phase III, July 1982.

24. T. F. Boyer, et al., "Evaluation of the Effect of Coal Cleaning on Fugitive Elements," Final Report, Phase II, Bituminous Coal Research, Inc., U.S. DOE Contract, July 1981.

25. D. Van Buren and L. R. Waterland, "Environmental Assessment of a Coal/Water Slurry Fired Industrial Boiler," Vol. 1 and 2, Final Report, July 1983 - April 1985, Acurex Corporation, Mountain View, California, EPA Contract V.1 EPA/600/7-86/012A - Contract EPA-68-02-3188, V.2 EPA/600/7-86/012B - Contract EPA-68-02-3188, April 1986.

26. M. R. Fuchs, et al., "Environmental Assessment: Source Test and Evaluation Report - Stoic Low-Btu Gasifier," Final Report, Jun. 1980 - Dec. 1981, Radian Corporation, Austin, Texas, EPA Contract 600/7-86/1006, Contract EPA-68-02-3137, February 1986.

27. R. DeRosier, "Environmental Assessment of a Firetube Boiler Firing Coal/Oil/Water Mixtures," Vols. 1 and 2, Final Report, February 1981 - November 1983, Acurex Corp., Mountain View, CA, EPA Contract Vol. 1 - EPA/600/7-84/095A, Vol. 2 - EPA/600/7-84/095B, EPA-68-02-3188, September 1984.

28. R. J. Demski, J. T. Yeh, and J. I. Joubert, "Control of Sulfur Dioxide, Chlorine, and Trace Element Emissions from Coal-Fired Boilers by Fabric Filtration," 3rd Symposium on Transfer/Utilization of Particulate Control Technology, Orlando, Florida, March 1981.

29. B. R. Hubble, "Fluidized-Bed Combustion: A Review of Environmental Aspects," Argonne National Laboratory, Illinois, U.S. DOE Contract W-31-109-ENG-38 ANL/ECT-12, January, 1982.

30. R. M. Felder, et al., "Rates and Equilibria of Devolatilization and Trace Element Evolution in Coal Pyrolysis," Final Report, September 1979 - June 1981, North Carolina State University at Raleigh, EPA Contract 600/7-82-027 Contract EPA-CR-804811, April 1982.

31. J. O. Burlingame, et al., "Field Tests of Industrial Coal Stoker Fired Boilers for Inorganic Trace Element and Polynuclear Aromatic Hydrocarbon Emissions," Final Report, August 1977 - November 1979, KVB, Inc., Minneapolis, U.S. DOE EPA-600/7-81-167, Contract DOE/EF-77-C-01-2609, October 1981.

32. R. R. Hall, M. M. McCabe, and D. McGrath, "Material Balance in Atmospheric Fluidized-Bed Combustion of North Dakota Lignite," GCA Corporation, U.S. DOE/FC/10281-1, Contract AC18FC10281, March 1982.

Section 5

COMPARISON WITH CONVENTIONAL PULVERIZED-COAL-FIRED PLANT

Pertinent features of the second-generation PFB combustion plant (baseline) and an equivalent comparable conventional PC-fired plant described in Appendix G are compared in this section. Specifically, plant arrangement, performance, construction characteristics, reliability, economics, and environmental characteristics are compared. Because of its higher efficiency and use of CPFBCs and ceramic cross-flow filters, baseline plant emissions will be significantly lower than those of a PC-fired plant. On a per-megawatt basis, SO_2 releases are 18 percent lower, NO_x releases are 47 percent lower, and particulate releases are 99 percent lower. In addition, modularity enables the baseline plant to use shop assembly and barge shipment techniques for many of its components; the results are significantly lower construction costs and shorter schedules.

5.1 PLANT ARRANGEMENT

Plant arrangements are a result of imposed site conditions, technology requirements, plant access logistics, and utility preference. There is not a great difference between either type of plant with regard to arrangement, since most of the area required for the plant is for the coal pile, coal delivery/conveying systems, electrical substation, cooling towers, parking, access roadways, etc. The power island, where the primary differences in the plants occur, is only 4 percent (approximately) of the total plant area; thus an increase in this area is not significant as far as land use is concerned. Because the baseline plant is more efficient than a PC-fired plant with a scrubber, many of the storage requirements for the plant are lower (e.g., 90 days of coal storage represents a smaller storage area per megawatt; ash storage silos are smaller). The remainder of Section 5.1 compares the general arrangement and various other items within the power island to show how the two plants differ.

5.1.1 Plant Site Arrangement

The site plans for the second-generation baseline plant and the reference PC-fired plant are shown in Figures 89 and 90. Coal is unloaded, stored, and reclaimed in a similar manner for both plants. Dolomite and coal in the baseline plant share coal unloading equipment; in the PC-fired plant, limestone is delivered by rail and stored in enclosed silos to protect it from the weather.

Coal is delivered by barge to both plants, but the baseline plant uses barge unloading to a greater extent because all large plant components are shipped by barge.

The SO_2 scrubber system occupies a significant area of the PC-fired plant arrangement shown. For this reason, the layouts are not quite compatible, because situating the PC-fired plant cooling towers on the west side of the plant was more advantageous. In the baseline plant, the cooling towers and the flare stack are to the east. Plant road and rail access to both plants are from the south. Other facilities are located in an economical way to satisfy the requirements for reasonable access set forth in Section 2.3 (Plant Arrangement).

Dwg. 8333-1-200-002-001, Rev. A

PLANT DESCRIPTION

1 STEAM TURBINE BUILDING
2 COMBUSTION TURBINE BUILDING
3 STEAM GENERATION ISLAND
4 CONTROL COMPLEX
5 AUXILIARY BOILER BUILDING
6 ADMINISTRATION BUILDING
7 MAINTENANCE BUILDING
8 HEAT RECOVERY STEAM GENERATOR
9 STACK
10 STATION TRANSFORMERS
11 SUBSTATION
12 WAREHOUSE
13 PARKING
14 COOLING TOWER
15 COOLING TOWER BLOWDOWN POND
16 MAKEUP WATER AND PRETREATMENT BUILDING
17 FILTERED WATER STORAGE TANK
18 CONDENSATE TANK
19 FUEL OIL STORAGE TANK
20 FUEL OIL PUMP HOUSE
21 INDUSTRIAL WASTE TREATMENT BUILDING
22 CONSTRUCTION POND
23 FLARE STACK
24 PIPE BRIDGE
25 RIVER WATER INTAKE STRUCTURE
26 COAL / DOLOMITE BARGE
27 COAL / DOLOMITE BARGE UNLOADING FACILITY
28 COAL / DOLOMITE TRANSFER CONVEYOR
29 COAL PILE RUNOFF POND
30 DOLOMITE PILE RUNOFF POND
31 RUNOFF WATER PUMP HOUSE
32 TRANSFER BUILDING
33 COAL EMERGENCY STOCKOUT CONVEYOR
34 DOLOMITE EMERGENCY STOCKOUT CONVEYOR
35 STACKER / RECLAIMER CONVEYOR
36 STACKER / RECLAIMER
37 COAL YARD VEHICLE MAINTENANCE GARAGE
38 COAL STORAGE (60 DAY)
39 DOLOMITE STORAGE (60 DAY)
40 COAL EMERGENCY RECLAIM HOPPER
41 DOLOMITE EMERGENCY RECLAIM HOPPER
42 COAL EMERGENCY RECLAIM CONVEYOR
43 DOLOMITE EMERGENCY RECLAIM CONVEYOR
44 COAL / DOLOMITE CRUSHER BUILDING
45 COAL CONVEYOR
46 DOLOMITE CONVEYOR
47 COAL STORAGE SILO (3 DAY)
48 DOLOMITE STORAGE SILO (3 DAY)
49 COAL STORAGE SILO (24 HR)
50 DOLOMITE STORAGE SILO (24 HR)
51 COAL PREPARATION BUILDING
52 ASH SILO
53 TRUCK SCALE
54 GUARD HOUSE

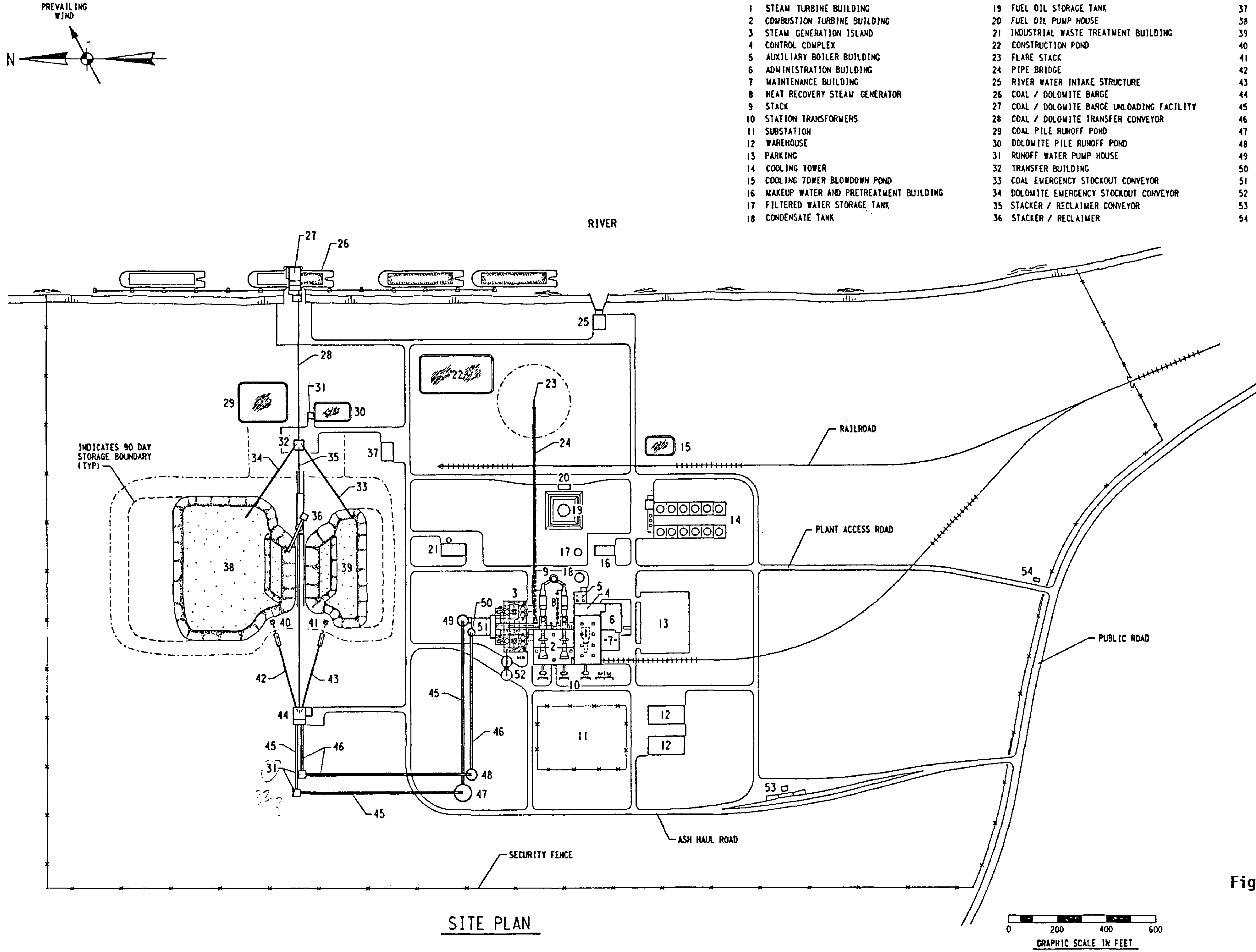
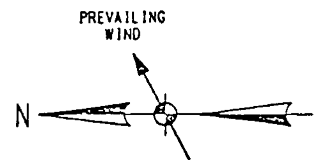
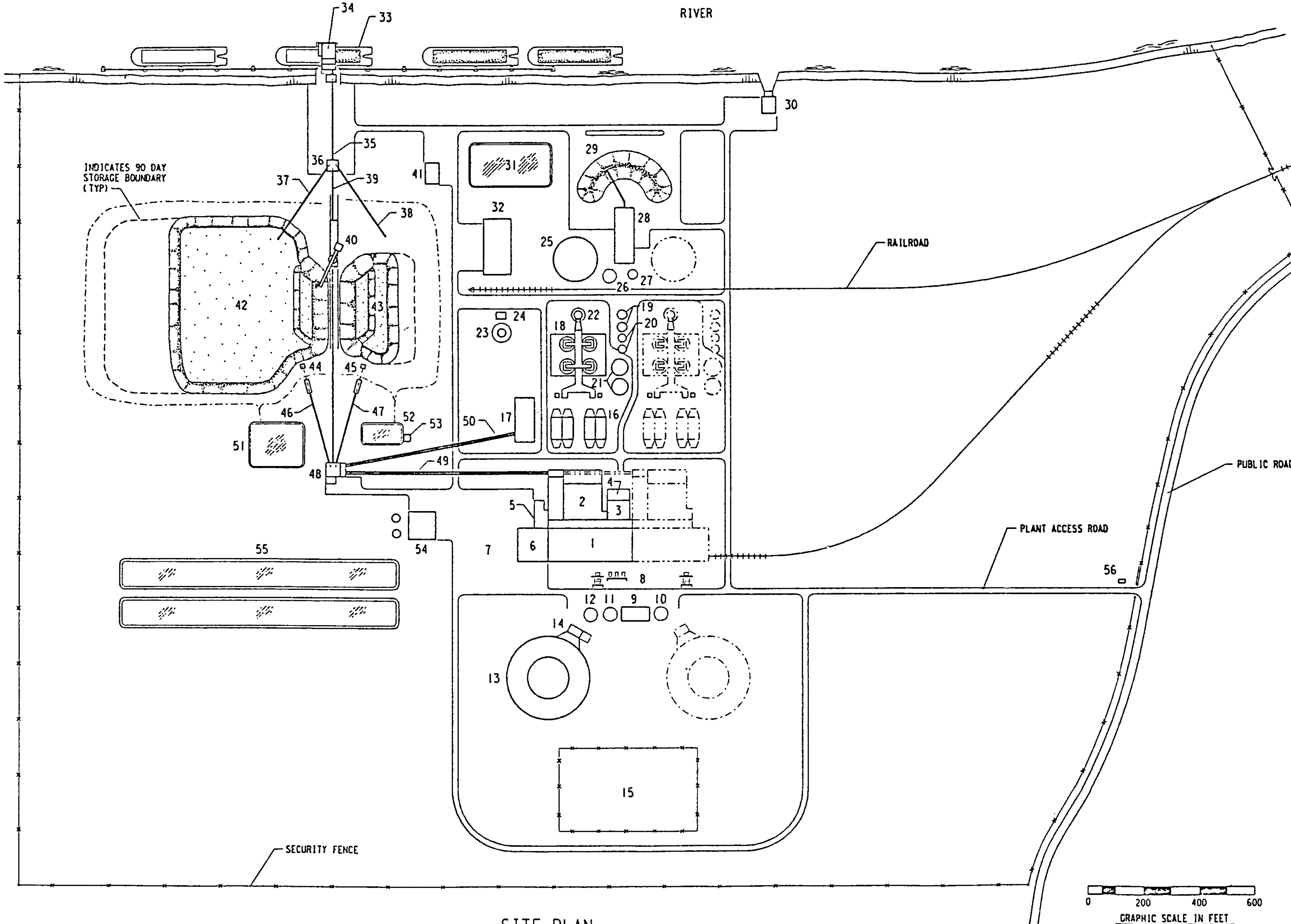


Figure 89 Second-Generation PFB Combustion Baseline Plant Site Plan

PLANT DESCRIPTION

1 STEAM TURBINE BUILDING
2 BOILER BUILDING
3 CONTROL COMPLEX
4 MACHINE SHOP
5 AUXILIARY BOILER AND DIESEL GENERATOR BUILDING
6 ADMINISTRATION AND SERVICE BUILDING
7 PARKING
8 STATION TRANSFORMERS
9 MAKEUP WATER AND PRETREATMENT BUILDING
10 FILTERED WATER STORAGE TANK
11 CONDENSATE WATER STORAGE TANK
12 NEUTRALIZING TANK
13 COOLING TOWER
14 PUMP HOUSE
15 SUBSTATION
16 PRECIPITATORS
17 LIMESTONE PREP AND FGD CONTROL BUILDING
18 FGD SYSTEM
19 DUST SILO
20 DEWATERING BIN
21 BOTTOM ASH WATER RECIRCULATION TANK
22 STACK
23 FUEL OIL STORAGE TANK AND DIKE
24 FUEL OIL PUMP HOUSE
25 FGD SYSTEM THICKENER
26 SURGE TANK
27 RECIRCULATION TANK
28 SLUDGE PREPARATION BUILDING
29 SLUDGE STOCKOUT PILE
30 RIVER WATER INTAKE STRUCTURE
31 CONSTRUCTION POND
32 WAREHOUSE
33 COAL / LIMESTONE BARGE
34 COAL / LIMESTONE BARGE UNLOADING FACILITY
35 COAL / LIMESTONE TRANSFER CONVEYOR
36 TRANSFER BUILDING
37 COAL EMERGENCY STOCKOUT CONVEYOR
38 LIMESTONE EMERGENCY STOCKOUT CONVEYOR
39 STACKER / RECLAIMER CONVEYOR
40 STACKER / RECLAIMER
41 COAL YARD VEHICLE MAINTENANCE GARAGE
42 COAL STORAGE (60 DAY)
43 LIMESTONE STORAGE (60 DAY)
44 COAL EMERGENCY RECLAIM HOPPER
45 LIMESTONE EMERGENCY RECLAIM CONVEYOR
46 COAL EMERGENCY RECLAIM CONVEYOR
47 LIMESTONE EMERGENCY RECLAIM HOPPER
48 COAL / LIMESTONE CRUSHER BUILDING
49 COAL CONVEYOR
50 DOLOMITE CONVEYOR
51 COAL PILE RUNOFF POND
52 LIMESTONE PILE RUNOFF POND
53 RUNOFF WATER PUMP HOUSE
54 INDUSTRIAL WASTE TREATMENT BUILDING
55 WASTE TREATMENT PONDS
56 GUARD HOUSE





SITE PLAN

Dwg. 8333-1-200-002-010, Rev. A

Figure 90 Conventional PC-Fired Reference Plant Site Plan

The approach to component enclosure has been to enclose only those components requiring frequent attention, in-place service, or other protection. Since the working parts of many baseline plant components are housed within their own pressure vessels, maintenance will often take place within the vessels; thus the vessels themselves are the enclosure. Although the two plants look quite different, the degree of design conservatism is similar. The extent of enclosure for any plant will be dependent upon experience with PFB combustion plants, climate, and utility preference.

5.1.2 Power Island Comparison

The power islands of the plants differ considerably, but the land occupied by both is approximately equivalent. The PC-fired plant is not a combined cycle; therefore, all the power output is from the steam turbine. The resultant difference in steam plant size creates a different "look" for the plant, since the smaller space needed for the steam turbine-related equipment is replaced in the baseline plant by gas turbines and associated equipment.

Table 53 compares some key power island components. Although the comparisons do not address all interrelationships between components, shared duty, and auxiliary equipment required by each plant, a general conclusion can be drawn that the two plants are nearly equivalent.

The second-generation PFB baseline plant has a slight edge; its layout is more compact, primarily because of the requirement for a scrubber in the PC-fired plant.

5.1.3 Coal/Sorbent/Ash Storage

As shown in Table 53, the PFB combustion baseline plant coal storage area is considerably smaller than the area for the PC-fired plant. The difference is due to the efficiency advantage of the baseline plant. However, the baseline plant sorbent storage is larger, despite the efficiency advantage, because of the higher calcium-to-sulfur ratio required.

5.2 PERFORMANCE

The baseline plant has a considerable performance advantage over conventional PC-fired plants. Table 54 compares the baseline plant performance with that of the PC-fired plant used as a reference plant for this study.

Net output power for the baseline plant is 452.8 MWe, 9.6 percent lower than the nominal 500-MWe (actually 500.9-MWe) PC-fired plant used for comparison. The baseline plant produces 42 percent of its gross power with the gas turbines and 58 percent with the steam turbine; the PC-fired plant gets all of its power from the steam turbine. Gross steam turbine/generator power for the baseline plant is 50 percent that of the PC-fired plant gross power. Auxiliary losses are considerably lower for the baseline plant. Its major auxiliary savings result from the elimination of forced- and induced-draft fans, elimination of wet scrubber losses, and reduction in cooling system pump and fan power because of the smaller steam cycle. The heat rate of the baseline plant is 17.8 percent lower than that of the PC-fired plant.

Factors affecting operating costs, in addition to the fuel cost, include the consumption rates of sulfur sorbent and water and the disposal of wastes from the plants. As shown in Table 54, the baseline plant consumes 80 percent more

Table 53 Comparison of Power Island Component/System Sizes

	Second-Generation PC-Fired Reference Plant	PFB Combustion Plant (Baseline)
Power Production, MWe		
Steam Turbine Output	540.4	272.3
Gas Turbine Output	---	195.2
Gross Plant Output	540.4	467.5
Net Plant Output	500.9	452.8
Power Production Plan Areas, ft^2		
Steam Generator Area	36,000	14,000*
Gas Generator Area	---	5,000†
Total Steam/Gas Generation Area	36,000	19,000
Building Areas, ft^2		
Steam Turbine Building	37,000	21,500
Gas Turbine Building	---	24,000
Other Buildings§	47,000	47,000
Total Building Areas	84,000	92,500
Other		
Height of Tallest Structure, ft	240	170
Coal storage area (90 days), ft^2	485,000	360,000
Sorbent storage area (90 days), ft^2	60,000	100,000
Total feedstock storage, ft^2	545,000	460,000
Total storage adjusted to 452.8 MWe, ft^2	492,665	460,000

*Includes HRSG and FBHE.
†Includes Carbonizer and CPFBC.
§Administration, control, machine shop, maintenance, warehouse.

Table 54 Performance Comparison--Reference PC-Fired Plant and Baseline Second-Generation PFB Combustion Plant

Description	Reference PC-Fired Plant	Second-Generation PFB Combustion Plant (Baseline)	Percentage Change
Overall Plant Performance:			
Gas Turbine Power, MW	---	195.2	---
Steam Turbine Power, MW	540.4	272.3	-49.6
Gross Power, MW	540.4	467.5	-13.5
Auxiliaries, MW	39.5	14.7	-62.8
Net Power, MW	500.9	452.8	-9.6
Net Plant Efficiency, % (HHV)	35.9	43.6	+21.4
Net Plant Heat Rate, Btu/kWh (HHV)	9,515	7,822	-17.8
As-Received Coal Feed, lb/h	382,928	284,410	-25.7
Sorbent Feed, lb/h:			
Dolomite Feed	---	82,315	---
Limestone Feed	43,606	---	---
Lime Feed	2,019	---	---
Total	45,625	82,315	+80.4
Water Consumption, 10^3 gal/day:			
Cooling Tower Makeup	9,979	5,210	---
Boiler Makeup/Miscellaneous	580	220	---
Flue Gas Desulfurization	662	---	---
Ash Pelletizer	---	144	---
Total Water Consumption	11,221	5,575	-50.3
Waste Products, lb/h:			
Ash and Spent Sorbent	7,612	91,144	---
Fixed Sludge	70,740	---	---
Total Solid Wastes	78,352	91,144	+16.3

sorbent for sulfur capture than the PC-fired plant consumes. However, the baseline plant consumes less than half the water needed to operate the reference PC-fired plant.

Solid wastes produced by the PC-fired plant consist of bottom ash recovered from the boiler and fixed sludge produced by the flue gas desulfurization system. All solid wastes from the baseline plant are ash and spent sorbent. The baseline plant generates about 16 percent more solid waste than the PC-fired plant.

5.3 CONSTRUCTION

The cost of erecting the baseline plant is approximately 40 percent lower than that of a similar size PC-fired plant with a scrubber, the disparity being attributed to a much lower field labor cost. Although the construction activities of both plants are similar in many respects, there are several radically different areas that account for most of the variations in construction costs.

Areas of similarity occur primarily in the balance-of-plant category, involve approximately the same number of man hours, and consist of:

- Site facilities
- Yard work
- Structures (excluding the steam generation module and boiler building)
- Balance-of-plant systems
  - Steam cycle equipment and subsystems
  - Cooling water system
  - Miscellaneous systems
  - Accessory electric plant (equipment and bulk materials).

The most significant difference in plant construction man hours and costs is attributable to the erection of the PC-fired plant boiler compared with the baseline plant equivalent (i.e., two carbonizers, CPFBCs, and FBHEs). The PC-fired boiler erection effort involves in excess of one-half million labor man hours--a labor requirement dictated by the field assembly of the boiler package, including erection of boiler hangers, drum, waterwall panel assemblies, pressure piping, tubebank assemblies, downcomers, and other interconnecting piping and headers; welding of all pressure-pipe connections; installation of burners; and assembly of air heaters, coal pulverizers, and many other components.

The effort to erect the carbonizers, CPFBCs, FBHEs, and their accessories is about 40 percent that of the PC-fired boiler effort and essentially involves the rigging of major shop-fabricated and assembled components. Although these shop-assembled vessels are quite heavy, they are manageable with present-day erection methods. The major erection steps for these components consist of unloading them from the barge and placing them on the transporter, transporting them to the point of erection, rigging and setting the vessels in place, trimming out the components not installed before shipment, and completing the interconnecting conventional and refractory-lined piping.

The second area of major difference is in the construction/erection of gas cleanup equipment. In the PC-fired plant, this activity involves the field assembly of the ESP and FGD systems; in the comparable baseline plant, efforts include the erection of shop-assembled cyclones and ceramic cross-flow filters. The erection steps required for the cyclones, cross-flow filters, lock hoppers, and auxiliaries are similar to those for the carbonizer, CPFBC, and FBHE, except that the components weigh less, there is less trim work, and there are fewer interconnections required. Since the baseline plant HGCU equipment operates at high pressure, albeit at higher temperature, the net effect is that the volume of gas being cleaned in the baseline plant is roughly one-seventh that of the gas to be cleaned in the PC-fired plant. The volumes of the cleanup devices involved are also very different because of the basic design and operating disparity; for instance, the ESP is roughly 3,000,000 ft^3 in volume, while the cross-flow filters are just under 70,000 ft^3.

Another area of construction advantage for the baseline plant is in the ash-handling system. Although the ash-handling system in the baseline plant is larger, the cost of erection labor is lower and the overall cost is only one-third the cost for the PC-fired plant because the latter must have both wet and dry ash systems. The dry system is similar in both plants except that transport is pneumatic in the PC-fired plant rather than by drag-chain conveyor in the baseline plant. The wet system in the PC-fired plant has no equivalent; it consists of a grinding and sluicing system with hydro-bins for dewatering the ash. The wet system removes the bottom ash and pyritic ash.

As indicated earlier, the construction of steel structures is essentially the same for both plants except for the steam-generation module of the baseline plant and the boiler/steam turbine building of the PC-fired plant. The PC-fired plant boiler building has about twice the volume. In addition, the PC-fired boiler is hung from the top of a structure incorporated in the building structure; the baseline plant components are bottom supported at a much lower elevation, outside the turbine building. Hence the PC-fired plant boiler building requires considerably more structural steel. In addition, a significantly smaller portion of the baseline plant structure is enclosed. These factors result in the need for a substantially larger field labor crew to complete the PC-fired plant, even though construction methods are similar in both cases. Another significant difference between the two plants is the degree of equipment setting that is accomplished in conjunction with the erection of structural steel. In the PC-fired plant, the frame setting of such components as the deaerator, feedwater heaters, and secondary air heaters is coordinated with main building steel erection. For the baseline plant, all major component rigging will most likely be coordinated with steel erection in the steam-generation module area.

An area of plant erection that appears at first to favor the PC-fired plant is the erection of the electricity-generating equipment. The PC-fired plant scope consists of one medium-sized steam turbine/generator and accessories; the baseline plant consists of one steam turbine/generator package, two gas turbine/generator packages and two HRSGs. The PC-fired plant turbine/generator is field-erected, including installation of upper and lower casings, rotors, bearings and seals, shells, crossover pipe, steam chests, stop throttle valves, intercept and stop valves, generator, exciter, E-H control system, gland seal system, and hydrogen cooling system plus accessories. Because the turbine/generator in the baseline plant is smaller, it is more modular and requires less manpower for erection. The gas turbines are also modular; they are assembled from a few major shipping modules that need much less field assembly work than the PC-fired plant turbine/generator. The gas turbine modules involved are the combustion turbine assembly (compressor section, combustion system, and power turbine), the generator and exciter module, and the auxiliary equipment, consisting of the starting package assembly, the electrical/control package assembly, the air-to-air cooler assembly, and the mechanical package assembly. In addition, the HRSGs are constructed from major shop-assembled shipping modules designed to minimize field erection. Even though the baseline plant generation components consist of three major elements, compared with one element for the PC-fired plant, their extensive shop assembly and shipping in modules makes the total baseline plant erection effort similar to that of the PC-fired plant turbine/generator erection effort. The PC-fired plant cooling water systems and cooling tower are twice the size of those in the baseline plant. When erection is combined with the electricity generating equipment, the baseline plant clearly has the advantage--nearly 15 percent lower than the PC-fired plant.

On an overall basis, the baseline plant requires an average work force of approximately 300 construction workers for 42 months; the PC-fired plant needs approximately 600 workers for 48 months. Ignoring the 6-month shorter construction schedule, baseline plant modularity permits working on more tasks simultaneously. As a result, the risk of lost productivity associated with congestion is less likely to occur on the baseline plant construction site. Careful planning and close coordination of barge shipments/deliveries should further shorten the baseline plant construction schedule without a loss of efficiency/productivity. As a result, one unit could be on line sooner, generating revenue while reducing the total plant investment cost.

5.4 RELIABILITY AND AVAILABILITY ASSESSMENT COMPARISON

The North American Electric Reliability Council publishes a Generating Availability Data Summary [1], which indicates that PC-fired boilers in the 400- to 599-MWe range are available an average of 78.35 percent of the time, with an equivalent availability of 72.97 percent, an effective forced outage rate (EFOR) of 15.6 percent, and a capacity factor of 56.86 percent. In addition, 347 reserve shutdown hours (RSH) and 1223 scheduled outage hours (SOH) are typical yearly values. In Table 55, these values are listed and compared with those calculated in Section 2.8 for the baseline plant. The baseline plant has a higher availability and a slightly higher equivalent availability than the reference PC-fired plant. The difference between availability and equivalent availability is 9.73 percentage points for the baseline plant and 5.38 percentage points for the PC-fired unit because the former utilizes two 50-percent capacity modules. Availability and EFOR apply to the portion of the year excluding SOH and RSH. With total SOH and RSH of 1890 vs. 1570 for the reference PC-fired plant, the baseline plant is less exposed

Table 55 Reliability, Availability, and Maintainability (RAM) Indices and Operating Profiles for PFB Baseline Second-Generation Combustion Plant and PC-Fired Plant with FGD

Index/Parameter	Reference PC-Fired Plant With FGD	Second-Generation PFB Combustion Plant (Baseline)
Availability, %	78.4	85.0
Equivalent Availability, %	73.0	75.2
Effective Forced Outage Rate, %	15.6	16.9
Capacity Factor, %	56.9	65.1
Scheduled Outage Hours	1223	1008
Reserve Shutdown Hours	347	882

to failure, and the mean time between failures has been adjusted according to the method used by EPRI contractors in other PFB combustion studies [2] to reflect when the plant is actually being called upon to operate. The differences in availability and related indices are primarily from differences in exposure time; the baseline plant should not necessarily be construed as inherently more reliable than a comparable PC-fired unit because:

- The PC-fired plant data reflect a composite average of actual operating data for plants of varying sizes and duty cycles; the baseline plant developmental components reflect best estimates.
- The "state of the art" in conventional fossil-fuel-fired plants is associated with larger sizes, which are not directly comparable.
- Inherent design differences in existing plants may have consequences that cannot be easily evaluated/identified in this type of study.

The results for the baseline plant are a function of the "mean time between failures" and "mean time to repair" values supplied by team members and used in the UNIRAM (unified RAM) analysis.

The fossil-fuel data base also includes units of different vintages, ranging from about 10 to 25 or 30 years. Therefore, the numbers for the PC-fired plant are a composite of diverse units; they do not represent the performance of any one plant. A new plant commissioned today should perform somewhat better than the composite. The results are comparable, however; and the baseline plant has adequate projected performance. Because of its high efficiency, the baseline plant will probably be subjected to fewer RSH than modeled in this analysis, and its capacity factor will be higher than assumed. In conclusion, UNIRAM has demonstrated that baseline plant availability will be comparable to that of a similar-size conventional PC-fired plant with FGD and that a capacity factor of 65 percent can be achieved.

5.5 COST/ECONOMIC COMPARISONS

The costs of the baseline plant are presented and discussed in Section 3, and a similar analysis is presented in Appendix G for a PC-fired plant with a scrubber. In Table 56, the capital investment and revenue requirements of each of these plants are summarized to facilitate a comparison of these two different technologies. The comparisons presented in the table follow the order of the Section 3 second-generation baseline plant cost development; since the electrical output of the two plants is not exactly the same (i.e., 453 vs. 501 MWe), unit cost relationships ($/kW) are not in exactly the same ratio as absolute costs.

5.5.1 Capital Investment

As shown in Table 56, the total baseline plant cost is 31 percent lower than the cost of the PC-fired plant; on a $/kW basis, the baseline plant cost is only 24 percent lower because of the larger electrical output by the PC-fired plant. The baseline plant cost advantage can be traced to several specific cost categories; the first is Process Capital and Facilities, which gives the baseline plant a 34-percent cost advantage based on absolute value, or a 27-percent cost advantage based on a $/kW unit cost. The entries in this category have been examined at the system account level to verify that the estimate of each account for each plant was consistent and normalized and to identify the basis for differences. Two items are primarily responsible for these cost differences. Based on gross power, the unit costs of the PC-fired boiler and flue gas cleanup equipment are 40 percent higher

Table 56 Comparison of Second-Generation PFB Combustion (Baseline) and PC-Fired Plant Economics--Consolidated Capital Investment and Revenue Requirement Summary

Description	Baseline PFB Combustion Plant		PC-Fired Plant		Baseline/PC-Fired Plant Relationships--% Change from PC-Fired Plant	
	Plant Size: 452.8 MW. (net) Fuel: Pittsburgh No. 8 Design/Construction: 3.5 yr TPC (Plant Cost) Year: 1987 (Dec.) Capacity Factor: 65% Heat Rate: 7822 Btu/kWh Cost: 1.79 $/106 Btu Book Life: 30 yr TPI Year: 1988 (Jan.)		Plant Size: 503.8 MW. (net) Fuel: Pittsburgh No. 8 Design/Construction: 4.0 yr TPC (Plant Cost) Year: 1987 (Dec.) Capacity Factor: 65% Heat Rate: 9515 Btu/kWh Cost: 1.79 $/106 Btu Book Life: 30 yr TPI Year: 1988 (Jan.)			
	$ x 1000	$/kW	$ x 1000	$/kW	$ Basis (%)	$/kW Basis (%)
Capital Investment:						
Process Capital and Facilities	316,955	700.1	483,208	964.7	-34	-27
Engineering (Including Construction Maintenance, Home Office, and Fee)	20,602	45.5	36,241	72.4	-43	-37
Process Contingency	19,189	42.4	---	---	---	---
Project Contingency	53,512	118.2	77,917	155.6	-31	-24
Total Plant Cost (TPC)	410,258	906.1	597,366	1192.6	-31	-24
Total Plant Investment (TPI)	443,961	980.6	655,066	1307.7	-32	-25
Royalty Allowance	---	---	---	---	---	---
Preproduction Costs	12,585	27.8	17,604	35.1	-28	-20
Inventory Capital	11,458	25.3	14,554	29.1	-21	-12
Initial Catalyst and Chemicals (with equipment)	---	---	---	---	---	---
Land Cost	1,500	3.3	1,725	3.4	-13	-3
Total Capital Requirement (TCR)	469,504	1037.0	688,838	1375.3	-32	-24
Operating and Maintenance Costs (1st yr):						
Operating Labor	5,350	11.8	5,967	11.9	-10	---
Maintenance Labor	3,663	8.1	5,393	10.8	-32	-24
Maintenance Material	5,494	12.1	8,089	16.1	-32	-24
Administrative and Support Labor	2,704	6.0	3,408	6.8	-21	-12
Total Operating and Maintenance Costs (1st yr)	17,211	38.0	22,857	45.6	-25	-16

Table 56 (Cont) Comparison of Second-Generation PFB Combustion (Baseline) and PC-Fired Plant Economics--Consolidated Capital Investment and Revenue Requirement Summary

Description	Baseline PFB Combustion Plant		PC-Fired Plant		% Change from PC-Fired Plant	
	$ x 1000	$/kW	$ x 1000	$/kW	$ Basis (%)	$/kW Basis (%)
Fixed Operating and Maintenance (1st yr), $/kW·yr	24.71		29.48		---	-16
Variable Operating and Maintenance (1st yr), mills/kW	2.34		2.79		---	-16
Consumable Operating Costs (1st yr less fuel):						
Water	946	0.37	1,886	0.66	-50	-44
Chemicals	4,685	1.82	3,673	1.29	+28	+43
Other Consumables	1,090	0.42	150	0.05	+625	+706
Waste Disposal	1,972	0.76	2,415	0.85	-18	-9
Total Consumables (1st yr less fuel)	8,693	3.37	8,123	2.85	7	+18
By-Product Credits (1st yr):	---	---	---	---	---	---
Fuel Cost (1st yr):	36,096	14.00	48,577	16.78	-25	-17
Levelized Operation and Maintenance Costs:						
Fixed Operating and Maintenance, $/kW·yr	43.1		51.8		-17	
Variable Operating and Maintenance, mills/kW	4.1		4.9		-16	
Consumables, mills/kW	5.9		5.0		+18	
By-Product Credit, kW	---		---		---	
Fuel, mills/kW	26.6		32.4		-18	
Levelized Carrying Charges (Capital): mills/kW	179.4		237.9		-25	
Levelized Busbar Cost of Power (mills/kWh):	75.7		93.2		-19	

than the entries for CPFBC, auxiliaries, and HGCU. Expressed on an installed basis, this cost difference rises to over 85 percent because the baseline plant uses shop-assembled/barge-shipped components; in contrast, the PC-fired plant boiler, FGD system, and ESP are field-erected components. The second most significant category difference is the PC-fired plant steam turbine plant and cooling system vs. the baseline plant turbine and steam turbine and cooling system entry, where the PC-fired plant installed unit cost is 20 percent lower than the baseline plant unit cost. The total bare erected cost in the first category is more than 2-1/2 times that of the second, leading to the overall Process Capital and Facilities percentages (34 percent lower on an absolute basis and 27 percent lower on a $/kW basis). Smaller additional contributing factors can be found by studying Table 40 (Section 3) and Table G.3 (Appendix G) in detail.

Because the baseline plant construction schedule is 6 months shorter than the PC-fired plant schedule and fewer field construction man hours are required, construction management cost is lower. These factors account for most of the differences in overall engineering requirements, which, in turn, amount to 6-1/2 and 7-1/2 percent of process capital and facilities costs for the baseline plant and the PC-fired plant respectively. These differences, together with capital and facilities cost differences, yield a baseline plant engineering cost that is 43 percent lower than the cost for a PC-fired plant on an absolute basis.

Since the PC-fired plant is conventional, it requires no process contingency; whereas, a process contingency of 6 percent of total process capital and facility costs has been applied to the baseline plant. A 15-percent overall project contingency has been assigned to both plants.

5.5.2 Total Plant Investment (TPI)

The baseline TPI is 32 percent lower than the PC-fired plant TPI (25 percent on a $/kW basis); the savings is attributed to the shorter construction schedule. The annual distribution of construction costs was assumed to be 28.6/28.6/28.6/14.2 percent for the baseline plant vs. 25/25/25/25 percent for the PC-fired plant. This distribution reflects the shorter construction time for the PFB combustion plant (3.5 vs. 4 years). Unless a detailed construction plan and procurement schedule are prepared, an assumption of equal expenditures is best.

5.5.3 Total Capital Requirement (TCR)

Preproduction costs are also lower, resulting from a 16-percent lower fixed and variable operating cost and a 17-percent lower fuel cost when measured on a per-kilowatt basis.

The baseline plant requirement for coal inventory expressed on a $/kW basis is 17 percent lower than that of the PC-fired plant; this advantage, however, drops to 12 percent when total inventories--including sorbent, fuel oil, and nitrogen--are included. The baseline plant requires 13 percent less land than the PC-fired plant because of its smaller coal storage area and the elimination of ESP and FGD facility space. These differences translate into a 24-percent saving for the baseline plant on a $/kW basis at the TCR level.

5.5.4 Operating and Maintenance Costs

The PC-fired plant requires three more operators per shift than the baseline plant. These operators are needed to cover the FGD, the ESP, and their associated ash systems. Because of the larger PC-fired plant electrical output, the operating labor costs of the two plants expressed on a $/kW·yr basis are equal. In all other operating cost categories, baseline plant costs are lower. Maintenance costs were determined as a percentage of equipment costs, and the same criteria were applied to both plants. Even though the baseline plant percentages were higher in some instances, much lower equipment costs resulted in an overall lower maintenance cost. The fixed and variable operating and maintenance costs reflect the operating and maintenance relationships described in Section 3 and yield a 16-percent savings for the baseline plant on a $/kW basis.

5.5.5 Consumables Operating Costs

Baseline plant consumables operating costs on a $/kW basis are 18 percent higher than those for the PC-fired plant. Even though the PC-fired plant water and water-treating chemical costs are higher (its steam cycle is nearly double), the cost of dolomite for the baseline plant is nearly 60 percent higher than the PC-fired plant limestone and lime costs.

The "Other Consumables" category indicates a very substantial advantage for the PC-fired plant. The secondary fuel requirement for the baseline plant is nearly five times as great as for the PC-fired plant (a relatively small quantity of fuel is needed for periodic PC-fired plant start-ups). In contrast, the baseline plant uses significantly more fuel for start-up, including fuel for the start-up heaters to gradually heat the refractories. The baseline plant also requires fuel for supplemental firing in the coal dryers. The "Other" category advantage for the PC-fired plant is further widened by the PFB combustion plant need for nitrogen, used for char transport and coal storage blanketing. This gas requirement accounts for nearly one-third of the cost of consumables in the "Other" category. The other remaining consumable category is "Waste Disposal." Baseline plant solid waste flow rates exceed those from the PC-fired plant by 17 percent; but as a result of the higher sludge-disposal charge associated with the PC-fired plant FGD system waste, baseline plant costs are 18 percent lower or 9 percent lower on a $/kW basis.

5.5.6 Fuel Cost

The Fuel Cost component indicates a decided advantage for the baseline plant at a 25-percent lower cost and a 17-percent lower $/kW cost. The unit cost advantage is directly correlated with the difference in net plant heat rate. The lower absolute cost is a function of both the lower heat rate and the slightly smaller plant.

5.5.7 Levelized COE Costs

The levelized component of COE values exhibits the same relationships as its first-year counterparts. Collectively, they amount to a 19-percent lower COE for the baseline plant (75.7 vs. 93.2 mills/kWh).

5.6 ENVIRONMENTAL COMPARISON WITH CONVENTIONAL PC-FIRED PLANT

The effects that the second-generation PFB combustion plant and the conventional PC-fired plant have on the environment are compared in this section. Both plants affect the environment similarly with regard to geology, hydrology, water quality, land use, cultural resources, vegetation, wildlife, aquatic ecology, and other components of a proposed site. Therefore, the comparisons highlight air emissions, solid wastes, water effluents, and trace elements where differences exist between the two plants. A significant advantage becomes apparent when the plants are compared on the basis of emissions rate per megawatt (electric) produced; since the PFB combustion plant is much more efficient. While not important for current

Federal regulations, which are indexed by Btu input, many State and local regulations consider tons per year within a specified geographical area as the criterion, making a highly efficient plant meeting Federal regulations more attractive to a utility. The following subsections address these issues in more detail.

5.6.1 Air Emissions

The conventional PC-fired plant produces 501 MWe compared with 453 MWe for the PFB combustion plant; their efficiencies are 35.9 and 43.6 percent respectively. These factors were taken into consideration when developing the tables for this section; the advantage of the PFB combustion plant is demonstrated on a per-unit basis.

Sulfur Dioxide. Even though both plants must operate with a 90-percent sulfur-capture efficiency, the PFB combustion plant emits 18 percent less SO_2 per megawatt of power than the PC-fired plant. The 501-MWe "controlled"* conventional system (adjusted to PFB combustion plant net output) emits approximately 2586 lb/h, 31 t/d, or 11,326 t/yr SO_2 (7362 t/yr at a 65-percent capacity factor), which converts to 0.60 lb/10^6 Btu. The PFB combustion plant emits 2125 lb/h, 25.5 t/d, or 9307 t/yr SO_2 (6050 t/yr at 65-percent capacity factor), which also converts to 0.60 lb/10^6 Btu. The real difference is in the efficiency advantage--lower emissions per megawatt from a PFB combustion plant. These values and the projected results from a "controlled" conventional system (external SO_2 scrubber) are shown in Table 57. As the table shows, the PFB combustion plant has nearly an 18-percent advantage when comparing tons SO_2/yr/MWe, favoring local compliance of a plant or number of plants.

Oxides of Nitrogen. The comparison of a PFB combustion plant with a comparable PC-fired conventional system shows some advantages for the former, which emits approximately 47 percent less NO_x. Emissions from a conventional system are expected to be about 2968 lb/h, 36 t/d, or 12,998 t/yr NO_x (8449 t/yr at a 65-percent capacity factor), which converts to 0.600 lb/10^6 Btu. Experimental results from advanced firing methods project a somewhat lower potential NO_x emission for conventional units, but the 0.6 lb/10^6 Btu has been used for comparison. The PFB combustion plant is expected to emit approximately 0.28 lb/10^6 Btu, which equates to 1577 lb/h, 19 t/d, or 6905 t/yr NO_x (4489 t/yr at a 65-percent capacity factor). As with the SO_2, the advantage of the PFB combustion plant and its higher efficiency results in a lower emissions rate and lower lb/unit output (Table 58). The inherently lower NO_x production in the process is an additional advantage.

Particulates. Pilot-scale tests of ceramic cross-flow filters have indicated that this barrier-type filter can clean gases to particulate levels much lower than normally achieved by conventional particulate-removal devices. Since no large-scale cross-flow filter systems have been operated to date, uncertainty exists regarding the ultimate particle-collection efficiency of this new system in a power plant application. To bracket the uncertainty level involved, baseline plant particulate emissions have been determined assuming the expected cross-flow filter performance and then assuming a performance no better than a conventional device. In Table 59 these two levels of performance are compared with conventional PC-fired

*501 MWe, reduction to 0.49 to meet standard (adjusted to 452.8 MWe-PFB combustion plant size).

Table 57 SO_2 Emissions Comparison

Description	PC-Fired Plant Uncontrolled*	PC-Fired Plant Controlled†	Baseline Plant
lb/h	20,700	2586	2125
t/d	248	31	25.5
t/yr§	90,667	11,326	9307
t/yr¶	58,933	7362	6050
t/yr/MWe	130.2	16.3	13.4
lb/10^6 Btu	0.6	0.6	0.6

*501 MWe, EPA AP-42 (adjusted to 452.8 MWe--PFB combustion plant size).
†501 MWe, reduction to 0.49 to meet standard (adjusted to 452.8 MWe-PFB combustion plant size).
§100-percent capacity factor.
¶65-percent capacity factor.

Table 58 NO_x Emissions Comparison

Description	Conventional System Uncontrolled*	Conventional System Controlled†	Baseline Plant
lb/h	3452	2968	1577
t/d	41	36	19
t/yr§	15,120	12,998	6905
t/yr¶	9628	8449	4489
t/yr/MWe	19.6	16.9	9.9
lb/10^6 Btu	0.698	0.60	0.28

*501 MWe, EPA AP-42 (adjusted to 452.8 MWe--PFB combustion plant size).
†501 MWe, burner designed to keep lb/10^6 Btu to 0.60 (adjusted to 452.8 MWe--PFB combustion plant size).
§100-percent capacity factor.
¶65-percent capacity factor.

Table 59 Particulate Emissions Comparison

Description	PC-Fired Plant Meets NSPS*	Baseline Plant: Meets NSPS†	Baseline Plant: Cross-Flow Filters §
lb/h	134	106	2
t/d	1.6	1.27	0.024
t/yr ¶	588	464	8.8
t/yr**	382	302	5.7
$lb/10^6$ Btu	0.03	0.03	0.00057
t/yr/MWe	0.84	0.66	0.013

*501 MWe, meeting 0.03 $lb/10^6$ (adjusted to 452.8 MWe--PFB combustion plant size).
†PFB combustion, meeting 0.03 $lb/10^6$.
§Cross-flow filters perform as expected.
¶100-percent capacity factor.
**65-percent capacity factor.

PC-fired plant FGD equipment performance. Assuming both plants operate with conventional particulate-removal technology efficiencies (0.03 $lb/10^6$ Btu), because of the baseline plant higher operating efficiency, its particulate releases on a per-megawatt basis are 20.9 percent lower than the PC-fired plant releases. If the cross-flow filter system performs as expected, the baseline plant particulate release rate will be less than 1/1000 that of the PC-fired plant on a per-megawatt basis. This level of efficiency reduces the baseline plant particulate emissions to well under 25 t/yr, thereby exempting the plant from a "Prevention of Significant Deterioration" particulate evaluation analysis and thus eliminating one regulatory procedure.

5.6.2 Solid Wastes

Solid waste produced by a fluidized bed combustion system differs from that produced by a PC-fired plant with an FGD system. Fluidized bed combustion produces dry solids residues; conventional FGD scrubbers produce liquid sludge, which is up to 35-percent liquid even after dewatering. Residues from fluidized bed combustion waste are primarily spent sorbent, unreacted dolomite and coal, and fly ash. FGD sludge is primarily calcium sulfite with some calcium sulfate. The fluidized bed combustion residues can be blended for fixation/stabilization; FGD sludge has a tendency to liquefy. The quantities of solid waste produced by the baseline plant are about 30 percent higher than those from a PC-fired plant with a limestone FGD system (Table 60). However, the effect on the land may be considerably different if the FGD waste is removed to a pond or a landfill without treatment. In this case the baseline plant produces less waste than the other. Although dry fluidized bed combustion or PFB combustion wastes can be directly disposed of in a landfill with successful reclamation of the land, a pond receiving FGD waste must be committed for the operating life of the plant and beyond.

Table 60 Solid Waste Production Comparison

Units	PC-Fired Plant* (Sorbent: Limestone)	Baseline Plant (Sorbent: Dolomite)
lb/h	70,828	91,144
t/d	850	1094
10^3 t/yr †	310	399
10^3 t/yr§	202	259

*Values adjusted to 452.8 MWe to match PFB combustion plant output.
†100-percent capacity factor.
§65-percent capacity factor.

5.6.3 Water Effluents

In comparing the treated wastewater effluent from the baseline and PC-fired plants, the following assumptions were made for the latter:

- Bottom ash sluice wastewater is recycled through dewatering bins and a treatment system. The only discharge to the receiving stream is the blowdown from the recycle system.
- The floor drain system includes sufficient capacity to collect bottom ash hopper seal water overflow.
- An SO_2 scrubber is included for treatment of flue gases.

Table 61 presents estimates of daily wastewater flow rates for typical waste sources for both the baseline and PC-fired plants. The total daily flow to be treated from the PC-fired plant is more than two times higher than from the baseline plant. Its environmental impact on the receiving stream is greater, as shown in Table 62, which compares waste effluents for specific discharge parameters. The two factors that account for the difference in total daily discharge flows between the two units shown in Table 62 for water treatment, boiler blowdown, cooling-tower blowdown, and coal-pile runoff waste sources are:

- The baseline plant is approximately seven points more efficient than a PC-fired plant.
- Only 58 percent of net power for the baseline plant is produced by steam turbines; all power for the PC-fired plant is generated by steam turbines.

Since the solid residue from the baseline plant is handled in a dry state by cyclones, drag conveyors, and pneumatic handling equipment, there is no discharge of ash wastes to a receiving stream. The PC-fired plant employs a wet, bottom ash hopper in which bottom ash is sluiced by high-capacity high-head pumps to mechanical dewatering bins. Although a recycle system reduces the total discharge to the receiving stream, a 72,000 gal/d blowdown rate is still required. Floor drains and

Table 61 Comparison of Environmental Impact of Sources of Waste (gal/d)

Waste Source	Conventional Plant: 500.9-MW PC-Fired Plant With Scrubber	Conventional Plant: 452.8-MW PC-Fired Plant With Scrubber*	Second-Generation PFB Combustion Plant: Baseline Plant	Second-Generation PFB Combustion Plant: 1600°F Carbonizer Plant	Comments
Ash Transport Water	73,252	65,100	---	---	Represents blowdown from assumed recycle
Low-Volume Wastes					
Water Treatment	43,152	38,350	10,000	10,418	
Boiler Blowdown	146,504	130,200	58,100	60,425	
Floor Drains	3,000	3,000	2,000	2,000	
Ash-Hopper-Seal Water	508,600	452,000	---	---	
Air Preheater Washes	4,051	3,600	---	---	Represents average; occurs once/yr at 1.4 x 10^6 gal
Cooling Tower Blowdown	1,699,083	1,510,000	936,000	975,966	
Material Storage Runoff					
Coal Pile Storage	39,945	35,500	30,000	31,943	
Dolomite Storage	2,532	2,250	4,000	4,259	
Total	2,520,119	2,240,000	1,040,000	1,085,011	

*Values adjusted to 452.8 MWe to match baseline plant output.

Table 62 Treated Waste Effluent Comparison

Parameters	PC-Fired Plant* mg/L	PC-Fired Plant* lb/d	Baseline Plant mg/L	Baseline Plant lb/d
pH	6-9	---	6-9	---
Suspended Solids	30	560	30	260
Total Iron	4	75	4	35
Oil and Grease	15	280	15	130
Total Manganese	2	37	2	17

*Values adjusted to 452.8 MWe to match baseline plant output.

sumps in the baseline plant receive equipment drains, cooling water, and washdown wastes only, which are estimated at 2000 gal/d. Similar flow rates are generated by the PC-fired plant for the same sources; however, the PC-fired boiler requires a wet-seal trough to seal expanding boiler walls hung from above the unit. The boiler seal trough requires a continuous discharge flow rate of 2 to 4 gal/min/ft of boiler hopper perimeter for cooling. The continuous discharge is contaminated by ash, and approximately 500,000 gal/d ash hopper seal trough wastes require treatment.

5.6.4 Trace Element Releases

Although a detailed trace element release analysis was not prepared for the reference PC-fired plant, baseline plant releases are expected to be lower and more benign. Published first-generation PFB combustion plant data list trace element values [3]; the releases from the baseline plant should be similar.

5.6.5 Noise

Although the baseline plant has several unique aspects, conventional acoustical engineering practices should suffice, and the noise levels should be comparable to those from a PC-fired plants.

5.7 REFERENCES

1. North American Electric Reliability Council, "Generating Assessment Data Summary: Equipment Availability and Component Cause Code Reports for 1976 - 1985," 1985.

2. Fluor Engineers, Inc., et al., "PFBC Turbocharged Boiler Design and Economic Study," EPRI CS-5487, November 1987.

3. M. A. Alvin, "Trace and Minor Element Reactions in Fluidized-Bed Combustion Processes," Westinghouse Research and Development Center, Pittsburgh, Final Report, EPA-600/7-82-050, under Contract EPA-68-02-3110, July 1982.

Section 6

SECOND-GENERATION PFB COMBUSTION PLANT COE SENSITIVITY STUDY

Since a new technology is the basis for the second-generation plant, an analysis was undertaken to identify the parameters and assumptions that have a significant impact on plant performance and economics. We investigated 23 different parameters, divided into the eight groups shown in Table 63.

In the first group, "Cost Factors," the sensitivity of the plant COE to varying fuel and sorbent costs, construction interest rates, and equipment costs was investigated. In the second group, alternative plant operating conditions and carbonizer performance levels were analyzed. The third group covered alternative feedstock sizes; the fourth investigated the effects of an alternative sorbent (limestone) and an alternative coal (lignite). Groups 5 through 8 considered alternative feed systems, tightened plant emissions restrictions, the use of alkali getters, and the effects of a reduced carbon conversion/combustion efficiency.

The cost factor study was straightforward in that the varied parameters affected the plant costs only. Groups 2 through 8, however, affected both performance and costs. Each of these study cases was treated as a new and separate plant design effort in that each step involved in the development of the baseline plant design was addressed, although in less detail. In each study case, components were resized to enable their continued operation at baseline plant design velocities. Each case involved:

- Prediction of carbonizer yields and compositions
- Selection of a preferred topping combustion temperature
- Trade-off of carbonizer and CPFBC sulfur-capture performance levels
- Estimate of component heat-transfer and pressure losses
- Preparation of a detailed plant heat and material balance
- Identification of changes to baseline plant component designs and performance levels or generation of new designs
- Estimate of new plant costs
- Determination of the new plant COE according to baseline plant procedure.

With the exception of the one computer-predicted 1500°F balance, all carbonizer balances used in the sensitively study were generated by hand, using the methodology described in Appendix A, because the carbonizer computer model was not operational until the end of the study. Each balance generally required several days to prepare and involved mass, atom, and energy balances. In some cases, when the carbonizer balance was integrated with the plant performance model, differences in transport air temperatures, fluidizing air temperatures, etc., caused the plant carbonizer temperatures to deviate from the detailed balance value. This discrepancy was reduced by a slight adjustment of the carbonizer air-to-coal ratio. A small change in the ratio had little effect on carbonizer yields and composition, but a sizable effect on carbonizer temperature. The question naturally arose as to whether this accuracy was justified in light of the large amount of time required to "close" on a desired temperature. Because the CPFBC flue-gas flow rate is, in most cases, more than 10 times larger than the fuel-gas flow rate, a 40°F difference in carbonizer temperature causes less then a 4°F deviation in the topping combustor temperature. Most times the plant efficiency was close to that of the baseline

Table 63 Parameters Investigated in COE Sensitivity Study

	Section Described
Cost Factors (assumed changes in costs)	6.1
Coal costs (-50% and +300%)	
Sorbent costs (-50% and +100%)	
Cost of money during construction (-25% and +100%)	
Total plant equipment costs (-25% and +50%)	
Alternative Operating Conditions	6.2
Computer-predicted 1500°F carbonizer	6.2.1
1600°F carbonizer plant	6.2.2
Minimum-excess-air plant	6.2.3
10-atm pressure, 1500°F carbonizer plant	6.2.4
Alternative Feedstock Sizes	6.3
-30 mesh coal and 1/8 in x 0 dolomite	
-30 mesh coal and dolomite	
Alternative Feedstocks	6.4
1500°F carbonizer plant with limestone sorbent	6.4.1
Lignite-fired, 1500°F carbonizer plant	6.4.2
Alternative Feed Systems	
Undried coal and sorbent	6.5.1
Coal/water slurry	6.5.2
Tightened Plant Emissions	
1500°F carbonizer plant with 95% sulfur capture	6.6.1
NO_x one-half of NSPS allowable	6.6.2
Particulates one-half of NSPS allowable	6.6.3
Products of Combustion Harmful to Systems (alkalis)	6.7
Baseline plant with alkali getter in fuel gas stream	
Baseline plant with alkali getter in fuel gas and flue gas streams	
Lignite-fired plant with alkali getter in fuel gas and flue gas streams	
98-Percent Carbon Combustion Efficiency	6.8

plant and, since the objective of the sensitivity study was to identify parameters with a significant impact on plant performance and cost, carbonizer temperature discrepancies up to ±45°F were accepted based on a case-by-case review.

In 10 of the sensitivity study cases, the new plant operating conditions and carbonizer performance were similar to those of the baseline, with minimal effect on plant efficiency, as indicated by the parametric computer study conducted in Appendix B. Therefore, those 10 cases were conducted with the 2100°F optimum topping combustor temperature of the baseline plant. In 6 cases the carbonizer performance and plant operating conditions departed significantly from baseline plant values, and new optimum topping combustor temperatures were determined using the methodology described in Appendix B. The study cases involving an increased carbonizer operating temperature, high-moisture coal, and a coal/water slurry feed are examples.

A heat and material balance was prepared for each new plant. For small changes in flow, and when operating conditions were close to those of the baseline plant, a ratio of auxiliary requirements and parasitic losses from baseline values was used. When component sizes or operating conditions departed significantly from the baseline, new designs and performance estimates were prepared.

Component costs were developed in several ways. The team members determined the cost of the equipment within their scopes of supply based on the new designs or design changes that were required to meet the new plant heat and material balance. When flow rates and operating conditions were similar to the baseline, the ratio of vessel/equipment costs was based upon the controlling parameter involved and engineering costs were kept constant. For instance, operation with undried coal/sorbent increases the carbonizer volumetric flow rate by 5 percent and necessitates about a 2-1/2 percent increase in its I.D. Because of the small change involved, a new, detailed design was not prepared; instead, costs were determined by scaling the baseline plant carbonizer and its cyclone costs by the gas volumetric flow rate raised to the 0.7 power. The CPFBC and its cyclones were similarly priced. Solids flow rate or duty was the controlling parameter for items such as lock hoppers and screw coolers. With regard to the FBHE, since small duty changes can be accommodated by changing tube sizes and spacings and do not require a change in the enclosing pressure vessel dimensions, only the heat-transfer surface costs were scaled based on duty to the 0.7 power. When large FBHE duty changes were involved, such as in the minimum-excess-air plant, the FBHE was resized; new tube surface areas, tube weights, and vessel weights were calculated; and the unit was repriced using appropriate $/lb values. When there were significant changes in either flow rates or operating conditions, new conceptual designs and cost estimates were also prepared. The coal/water slurry case is an example of this; a slurry preparation and pumping system was conceptually designed, vendor quotes were obtained, and installed costs were estimated. Slurry feed increases the carbonizer fuel-gas volumetric flow rate by approximately 106 percent, causing about a 44-percent increase in its I.D. Because of the large increase, the vessel was resized, its new steel weight and refractory requirements were determined, and its cost was determined by using the same $/lb steel cost and $/ft^2 refractory cost quoted by vendors for the baseline plant.

Balance-of-plant component and system costs were redetermined via factored adjustments to costs previously developed. For new components, such as the alkali-getter systems, a new estimate was developed. For changes in flow, system costs were adjusted even though the "frame size" or range of the equipment did not change (e.g., if flow changed by 10 percent, and this change did not dictate going to the next frame size, the cost was still factored on a flow basis to obtain a true representation of the cause and effect of the parameter being studied). Each individual trade-off was judged to determine how small a change should be recognized.

Using the new component and system costs and the plant heat and mass balance, a new COE was calculated. The process was the same as with the baseline plant, with the exception that less detail was included in the recognition of changes to all plant accounts. A new layout was not prepared for each case; however, the effects of changes to structural/civil, electrical, and piping were taken into account. The formatting of COE and capital cost results is identical to that for the baseline plant, since the baseline plant cost spreadsheet was used to account for the changes. A new spreadsheet was set up for each case, with the baseline as a starting point. This procedure minimized errors, since all changes were accounted for and the calculation procedures, equations, and constants were consistent. Trade-offs were then compared for consistency at the account level to ensure that the inputs had an appropriate effect on the result. Since each study case was treated as a change to the baseline plant, COE and efficiencies can be compared and used for relative ranking purposes.

Each case is separately described in detail in the following sections, and the cases are compared in Section 6.9. All of the cases studied used two carbonizer/CPFBC/FBHE/gas turbine modules except for the minimum-excess-air plant, which needed only one module to produce 423 MWe.

6.1 COST FACTOR VARIATIONS

The baseline plant Total Capital Requirement (TCR) and Cost of Electricity (COE) were calculated using economic factors suggested by EPRI in the Technical Assessment Guide (TAG) [1]. Since feedstock costs, plant equipment costs, and interest rates will vary with time, an analysis was undertaken to reveal how sensitive the baseline plant COE is to variations in these parameters. Table 64 identifies the values studied and reveals their impact on second-generation PFB combustion and conventional PC-fired plant COEs.

The first variables investigated were fuel and sorbent costs. A 300-percent increase in the cost of coal raises the COE of both plants by more than 100 percent. Since the PFB combustion plant is more efficient than the PC-fired plant, the former's COE advantage increases from 17.5 to 35.2 mills/kWh and yields a final advantage of 18.3 percent. Conversely, a 50-percent reduction in coal costs lowers the PFB combustion plant COE advantage from 17.5 to 14.6 mills/kWh and raises the advantage to 19.1 percent. Final PFB combustion plant COE advantages of 16.9 and 19.7 percent respectively result from a 100-percent increase and a 50-percent decrease in sorbent cost level. The minimum PFB combustion plant COE advantage is realized at the 100-percent increase in sorbent cost level. This minimum advantage, however, could be increased by incorporating design changes that would reduce the sorbent consumption rate.

A 100-percent increase and a 50-percent decrease in interest on funds during construction result in PFB combustion plant COE advantages of 20.0 percent and 18.4 percent respectively. A 50-percent increase and a 25-percent decrease in equipment costs result in COE advantages of 20.1 and 17.8 percent respectively. Higher interest during construction and higher equipment costs result in the greatest COE advantages for the PFB combustion plant because of its shorter construction schedule and lower contribution of capital cost to total COE. Since no PFB combustion plants are in operation, maintenance costs have been expressed as a percentage of equipment costs; the comparable PC-fired plant costs reflect

Table 64 Effects of Cost-Factor Variations on COE

Description	PC-Fired Plant With Scrubber COE (mills/kWh)	PC-Fired Plant With Scrubber COE Change (mills/kWh)	PC-Fired Plant With Scrubber (%)	Second-Generation PFB Combustion Plant (Baseline) COE (mills/kWh)	Second-Generation PFB Combustion Plant (Baseline) COE Change (mill/kWh)	Second-Generation PFB Combustion Plant (Baseline) (%)	PC-Fired vs. Baseline (% of COE)
Baseline Values	93.2	---	---	75.7	---	---	-18.8
Coal Cost Change:							
+300%	192.9	+99.7	+107.0	157.7	+82.0	+108.3	-18.3
-50%	76.6	-16.0	-17.8	62.0	-13.7	-18.1	-19.1
Sorbent Cost Change:							
+100%	94.6	+1.4	+1.5	78.6	+2.9	+3.8	-16.9
-50%	92.4	-0.8	-0.9	74.2	-1.5	-2.0	-19.7
Change in Interest on Funds During Construction:							
+100%	100.8	+7.6	+8.2	80.6	+4.9	+6.5	-20.0
-50%	91.4	-1.8	-1.9	74.6	-1.1	-1.5	-18.4
Equipment Cost Change:							
+50%	118.1	+24.9	+26.7	94.4	+18.7	+24.7	-20.1
-25%	80.7	-12.5	-13.4	66.3	-9.4	-12.4	-17.8

typical utility expenditures. Consequently, a 50-percent rise in equipment costs also raises PFB combustion plant maintenance costs by 50 percent. If the maintenance cost increase is ignored, the PFB combustion plant COE is 90.9 mills/kWh rather than 94.4 mills/kWh, resulting in an even higher COE advantage of 23.0 percent.

The influence of plant capacity on COE was investigated for both PFB combustion and PC-fired plants; the results are presented in Figure 91. As the figure shows, an increase in capacity factor from 65 to 80 and 90 percent lowers the baseline plant COE from 75.7 to 67.5 to 63.3 mills/kWh respectively. Although increased capacity factors lower the COEs of both plants, the baseline plant COE advantage appears to decrease with an increased capacity factor. However, in a typical utility plant dispatching environment, the baseline plant would be dispatched more frequently than the PC-fired plant because of its lower operating costs. Hence it would have a higher capacity factor and its COE advantage would be greater than 18.8 percent.

The relative rankings of competing technologies are often influenced by the particular assumptions used in the analysis. However, the cost factor analysis summarized in Table 64 and Figure 91 confirms the superiority of the PFB combustion plant COE advantage and shows it to be between 16 and 20 percent over the range of variables considered.

6.2 ALTERNATIVE OPERATING CONDITIONS

6.2.1 Computer-Predicted 1500°F Carbonizer

Plant Performance and Required Equipment Changes. The carbonizer yields and compositions used in designing the baseline plant were determined by extrapolating a pertinent, but limited, data base. As discussed in Appendix A, a rigorous computer analysis, which includes correlations developed from a more extensive data base, predicts that the carbonizer fuel gas will actually contain much more energy and less sulfur and ammonia than in the baseline plant. Since this difference will improve plant performance and economics, the effects of the new gas were investigated.

Figure 92 identifies the 14-atm/1500°F carbonizer yields and compositions predicted by the computer model described in Appendix A. Compared with the carbonizer balance used in the baseline plant, the fuel-gas heating value (LHV) is increased by 65 percent and the sulfur and ammonia levels are reduced by 17 and 29 percent respectively. Despite a 23-percent reduction in fuel-gas yield, the topping combustor heat release per pound of coal carbonized is 28 percent higher. The optimum topping combustor temperature for this new fuel gas is 2218°F. Figure 93 presents the plant heat and material balance for these new conditions. Tables 65 and 66 present detailed performance and equipment data for the plant. The plant efficiency of 44.33 percent at a net plant output of 470.34 MWe represents a 0.7-percentage point efficiency increase over the baseline plant.

The systems and equipment arrangements required by this plant are identical to those of the baseline plant, but physical dimensions differ slightly because of differences in flow rate and temperature. For instance, the carbonizer fuel-gas volumetric flow rate is about 18-1/2 percent lower, thus about a 9-1/2 percent decrease in its I.D is needed. The flue-gas volumetric flow rate, CPFBC I.D., and carbonizer and CPFBC vessel heights remain unchanged. The total FBHE heat-transfer surface area shrinks by approximately 6 percent because of a 9.7-percent reduction in the duty requirement.

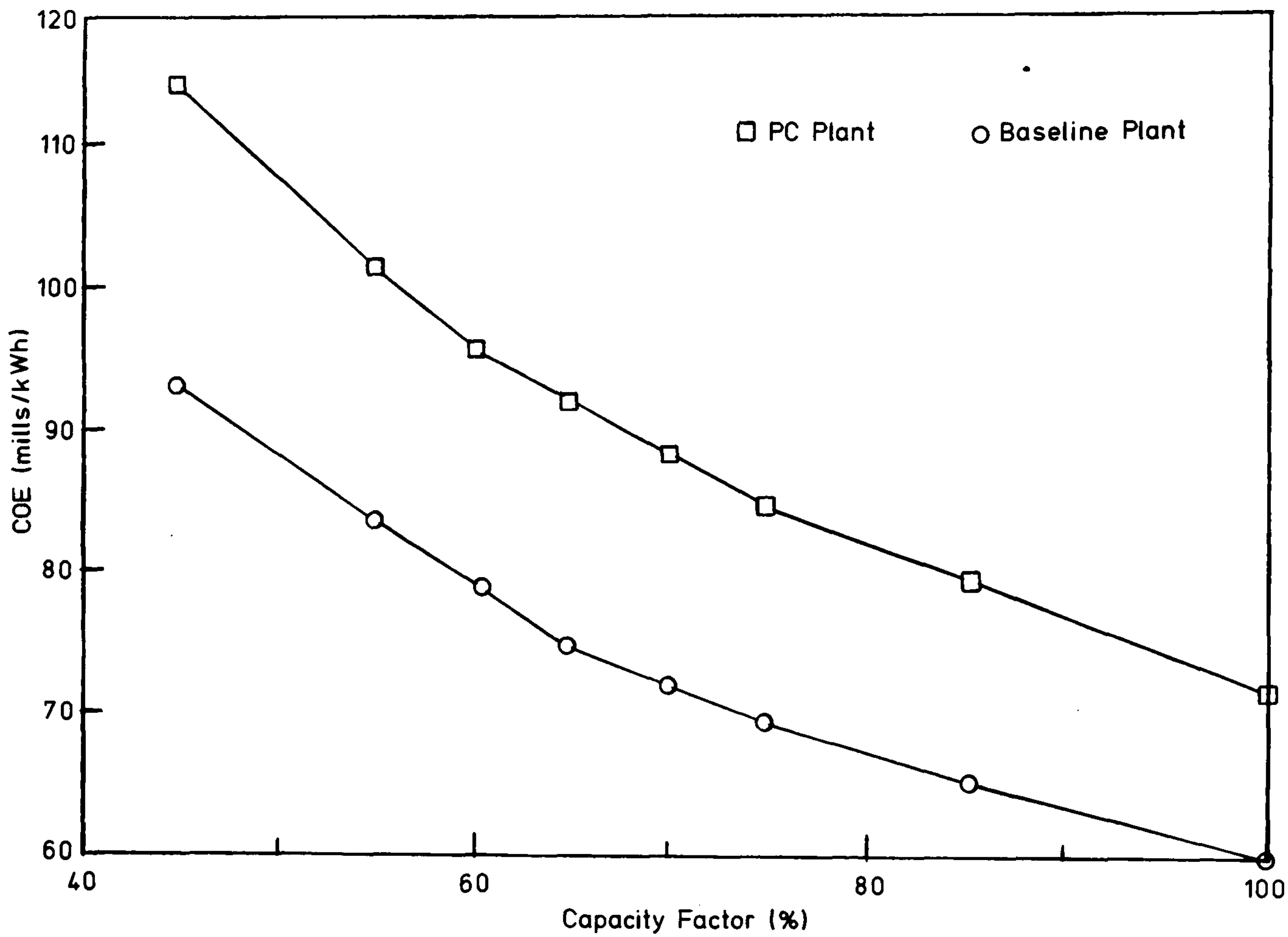


Figure 91 Effect of Capacity Factor on COE

Fuel Gas Flow (lb/h)	145.218	
HHV (Btu/lb)	3139	
LHV (Btu/lb)	2917	
LHV (Btu/SCF)	207.2	(Gas Only)

Char-Sorbent
(Flow = 82.532 lb/h)

	Char	Soot	Spent Dolomite	
Carbon	45.132	1.031	6.214	MgO
Hydrogen	0.748	0.004	12.648	$CaCO_3$
Sulfur	1.635	0.007	2.676	CaS†
Nitrogen	0.813	0.003	0.510	Inerts
Oxygen	0.804	0.001		
Moisture	--	--		
Ash	10.306	--		
Total	59.438	1.046	22.048	
HHV (Btu/lb)	11830	14568		
LHV (Btu/lb)	11711	14536		

Tar
(Flow Rate = 2.799 lb/h)

MW = 13.0449

Atomic Composition:

$CH_{0.462}O_{0.018}N_{0.0076}S_{0.0053}$

HHV (Btu/lb)	15485
LHV (Btu/lb)	15147

Gas*
(Flow Rate = 142.419 lb/h, 5.318 mol/h)

	wt %	mol %
CO	11.26	10.77
CO_2	20.47	12.46
H_2O	5.80	8.63
H_2	0.54	7.20
CH_4	3.60	6.00
C_2H_6	0.957	0.852
C_2H_4	2.975	2.840
NH_3	0.204	0.321
H_2S	0.082	0.065
N_2	52.36	50.06
COS	0.020	0.009
C_3's	0.787	0.495
C_4's	0.134	0.062
C_6H_6	0.192	0.066
C_7H_8	0.374	0.109
C_6H_5OH	0.244	0.069
HHV (Btu/lb)	2896	
LHV (Btu/lb)	2677	

CARBONIZER
14 atm
1500°F

70°F

70°F

711°F

Pittsburgh Coal
(Flow Rate = 100 lb/h)

Carbon	71.945
Hydrogen	4.690
Sulfur	2.993
Nitrogen	1.258
Oxygen	6.308
Moisture¶	2.500
Ash	10.306
HHV (Btu/lb)	12913
LHV (Btu/lb)	12469

Air

(Flow Rate = 97.731 lb/h)

(Relative Humidity: 50% at 70°F)

O_2	22.586	lb/h
N_2	75.388	
Moisture	0.757	
	97.731	

Plum Run Dolomite
(Flow Rate = 30.02 lb/h; Ca/S = 1.75)§

	wt %	lb/h
$CaCO_3$	54.5	16.362
$MgCO_3$	43.3	12.998
Moisture	0.5	0.150
Inerts	1.7	0.510
Total	100.0	30.020

* Excludes Tar.
† 92% Approach to H_2S/Sorbent Reaction Equilibrium.
§ If Based on Sulfur Release -- Ca/S = 3.88
¶ After Drying.

Rev. B
10/23/87

Figure 92 Computer-Model-Predicted 1500°F Carbonizer Balance

Dwg. 8333-1-400-009-113, Rev. B

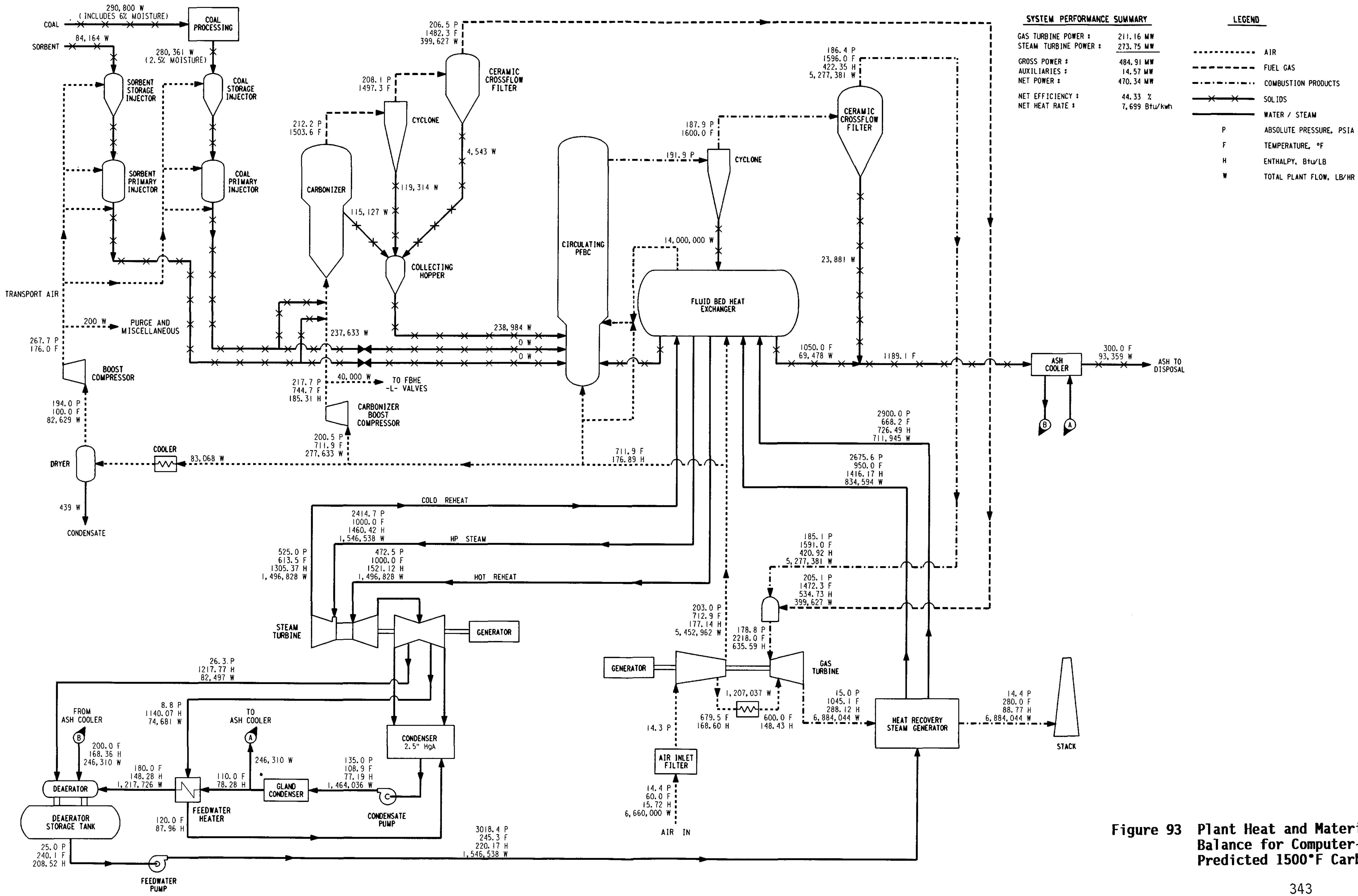


Figure 93 Plant Heat and Material Balance for Computer-Model-Predicted 1500°F Carbonizer

Table 65 Performance Summary--Computer-Model-Predicted 1500°F Carbonizer Second-Generation Plant

Power Summary	
Gas Turbine Power, kWe	211,155
Steam Turbine Power, kWe	273,755
Gross Power, kWe	484,910
Auxiliaries, kWe	(14,567)
Net Power, kWe	470,343
Net Efficiency, % (HHV)	44.33
Net Heat Rate, Btu/kWh	7699
Consumables and Wastes	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	290,800
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	280,361
Dolomite Feed, lb/h	84,164
Ash Production, lb/h	93,359
Coal and Dolomite Drying Fuel, gal/h	96
Auxiliary Summary, kWe	
Transport Boost Compressor	457
Carbonizer Boost Compressor	706
Condensate Pumps	221
Feedwater Pumps	5,440
Boiler Forced-Circulation Pumps	273
Circulating Water Pumps	3,487
Cooling Tower Fans	900
Coal Dryer Forced-Draft Fan	307
Coal Dryer Induced-Draft Fan	243
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	486
Gas Turbine Intercooler Fan	17
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	173
Coal Handling	355
Dolomite Handling	70
Coal and Sorbent Feed	33
Ash Cooling and Handling	109
Service Water	101
Miscellaneous	718
Stepdown Transformer	72
Total Auxiliaries	14,567

Table 66 Comparison of Baseline and Computer-Predicted Carbonizer Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline (14-atm/1500°F Carbonizer)	Computer Predicted (14-atm/1500°F Carbonizer)
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	484.91
Auxiliaries, MWe	14.73	14.57
Net Power, MWe	452.76	470.34
Net Plant Efficiency, %(HHV)	43.63	44.33
Net Plant Heat Rate, Btu/kWh	7822	7699
As-Received Coal Feed, lb/h	284,410	290,800
Dolomite Feed, lb/h	82,315	84,164
Ash Production, lb/h	91,144	93,359
Gas Turbine Parameters		
Topping Combustor Exit Temperature °F	2100.1	2218.0
Generator Output, MWe per Module	97.58	105.58
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	124.42
Superheating	186.27	155.30
Reheating	160.60	161.47
Total FBHE Duty (per module), 10^6 Btu/h	488.82	441.19
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	679.33
UA, 10^6 Btu/h·°F per Module	10.501	10.651
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1546.54
Generator Output, MWe	272.34	273.76
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1342.83

The outward appearance of the gas turbine/generator remains essentially unchanged. However, the diameter of the fuel system throttle valves becomes smaller--from 18 to 16 in., the cooling airflow to the first turbine blade stage increases, and the 8.2-percent increase in power output necessitates a slightly larger generator and slight changes to the turbine auxiliaries.

The HRSG superheater outlet temperature rises from 900 to 950°F; despite an 8.6-percent increase in its duty, little change is required in its total heat-transfer surface area because the gas turbine outlet temperature rise from 988 to 1045°F. The plant steam flow rate and turbine output are increased by 1/2 percent; hence little change is required to the steam turbine and its concomitant system.

COE Results. The COE results are presented and compared with those of the baseline plant in Table 67. The increased electrical output of the new plant contributes slightly to the $/kW improvement in capital cost, but the largest effect is due to the improved heat rate. As a result, each category of cost is lowered, and there is a reduction in COE greater than 2 percent for the new plant.

Discussion. Plant performance based on the carbonizer balance predicted by the computer model shows a considerable improvement over the baseline plant performance. The primary reason is the greater ratio of fuel-gas energy to char energy predicted by the computer model. This improved ratio results in a higher optimum firing temperature for the gas turbine and, because of increased gas turbine output, results in a higher gas turbine-to-steam turbine power ratio.

The improved COE is a straightforward result of improved plant efficiency and increased power output. Additional capital cost is included to allow for the increased gas turbine firing temperature, but this cost is more than offset by the increased power and efficiency.

6.2.2 1600°F Carbonizer Plant

Plant Performance and Required Equipment Changes. Figure 94 identifies the yields and composition predicted for a 14 atm/1600°F carbonizer via extrapolation of the Grand Forks-Denver Research data discussed in Appendix A. Compared with the baseline 1500°F carbonizer operating at the same calcium-to-sulfur feed ratio, the fuel gas heating value and yield increase by 9.1 percent and 19.9 percent respectively on a per pound of coal carbonized basis; the sulfur content decreases by 4.7 percent; and the ammonia content increases by 13.2 percent. The topping combustor heat release per pound of coal carbonized is 34.7 percent higher and results in a new optimum topping combustor temperature of 2350°F.

Figure 95 presents the heat and material balance for a second-generation plant operating with this carbonizer balance and a 2350°F topping combustor. The NO_x releases predicted for the plant components are listed in Table 68. Based on a nominal case analysis (discussed in Section 2.5.6), the plant NO_x emissions are estimated at 0.30 lb/10^6 Btu, or 1/2 the NSPS allowable. Tables 69 and 70 present detailed performance and equipment data. The 44.92-percent efficiency at a net plant output of 496.31 MWe represents an efficiency increase of 1.29 percentage points over the baseline plant.

The system and equipment arrangements required by this plant are identical to those of the baseline plant, but physical dimensions differ slightly because of differences in flow rate and temperature. For instance, the carbonizer has a fuel-gas flow rate roughly 34 percent higher than baseline, necessitating about a 16-percent increase in its I.D.s. The CPFBC flue-gas volumetric flow rate and I.D. are roughly 5 and 3 percent smaller respectively. The carbonizer bed and vessel

Table 67 Comparison of Baseline Plant and Computer-Predicted Carbonizer Plant Economic Data

	Second-Generation Plant Configuration		
	14 atm/1500°F Carbonizer		
	Baseline	Computer-Predicted	Percentage Change
Unit Size, MWe net	452.8	470.3	---
Net Plant Heat Rate, Btu/kWh	7822	7699	-1.6
Total Plant Cost, $/kW	907.1	886.3	-2.3
Total Plant Investment, $/kW	981.6	959.1	-2.3
Total Capital Requirement, $/kW	1038.0	1014.4	-2.3
First Year Costs:			
Total O&M, $/kW·yr	38.0	36.7	-3.4
Fixed O&M, $/kW·yr	24.7	23.9	-3.2
Variable O&M, mills/kWh	2.34	2.26	-3.4
Consumables, mills/kWh	3.37	3.31	-1.8
Fuel Cost, mills/kWh	14.0	13.8	-1.4
Levelized O&M:			
Fixed, $/kW·yr	43.2	41.6	-3.7
Variable O&M, mills/kWh	4.1	3.9	-4.9
Consumables, mills/kWh	5.9	5.8	-1.7
Fuel, mills/kWh	26.6	26.2	-1.5
Levelized Carrying Charge, $/kW·yr	179.6	175.5	-2.3
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	74.1	-2.1

Fuel Gas Flow (lb/h)	213.99
HHV (Btu/lb)	2189
LHV (Btu/lb)	2041
LHV (Btu/sft^3)	145

Char-Sorbent Flow (lb/h) = 76.819

	Char	Coke	Spent Dolomite
Carbon	36.176	5.035	6.215 MgO
Hydrogen	0.516	0.016	12.974 $CaCO_3$
Sulfur	1.704	0.018	2.441 CaS†
Nitrogen	0.756	0.012	0.510 Inerts
Oxygen	0.126	0.010	---
Moisture	---	---	---
Ash	10.31	---	---

HHV (Btu/lb)	8839
LVH (Btu/lb)	8777

Tar (Flow Rate = 1.50 lb/h)

Atomic Composition:

$CH_{.54}O_{.018}N_{.010}S_{.0082}$

HHV (Btu/lb)	15,800
LHV (Btu/lb)	15,410

Gas (wt%)* (Flow Rate = 212.491 lb/h)

CO	14.541
CO_2	17.719
H_2O	4.106
H_2	0.514
CH_4	2.768
C_2's	2.100
NH_3	0.272
H_2S	0.077
N_2	57.903
HHV (Btu/lb)	2093
LHV (Btu/lb)	1947

CARBONIZER
14 atm
1600°F

70°F

711°F

70°F

Pittsburgh Coal (Ultimate, wt%) (Flow Rate = 100 lb/h)

Carbon	71.92
Hydrogen	4.69
Sulfur	2.99
Nitrogen	1.26
Oxygen	6.33
Moisture¶	2.50
Ash	10.31
HHV (Btu/lb)	12,916
LHV (Btu/lb)	12,472

Air (Flow Rate = 160.79 lb/h)

Relative Humidity	50% at 70°F

Plum Run Dolomite (wt%) (Flow Rate = 30.02 lb/h Ca/S = 1.75)§

$CaCO_3$	54.4
$MgCO_3$	43.3
Moisture	0.5
Inerts	1.7

*Excludes tar.
†87.5% sulfur capture.
§If based on sulfur release--Ca/S = 4.2.
¶After drying.

Rev. B 8/26/87

Figure 94 1600°F Carbonizer Balance

Page(s) Missing

from

Original Document

Table 68 1600°F Carbonizer Plant NO_x Releases/Emissions

<u>Assumptions</u>:	
CPFBC Flue Gas NO_x	
lb/h	356
lb/10^6 Btu	0.189
ppm(v)	91
Fuel Gas Ammonia Content, wt%*	0.187
Ammonia Conversion to NO_x, %	8
<u>Pounds per Hour Basis</u>:	
Topping Combustor NO_x Release	
Thermal Component	88
Fuel-Bound Component	128
NO_x at Topping Combustor Outlet	572
<u>Pounds per 10^6 Btu Heat Release Basis</u>:	
Topping Combustor NO_x Release	
Thermal Component	0.047
Fuel-Bound Component	0.068
NO_x at Topping Combustor Outlet	0.304

*Value predicted by carbonizer computer model.

Table 69 1600°F Carbonizer Second-Generation Plant Performance Summary

Power Summary	
Gas Turbine Power, kWe	228,249
Steam Turbine Power, kWe	283,652
Gross Power, kWe	511,901
Auxiliaries, kWe	(15,590)
Net Power, kWe	496,311
Net Plant Efficiency, %(HHV)	44.92
Net Plant Heat Rate, Btu/kWh	7598
Consumables and Wastes	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	302,828
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	291,957
Dolomite Feed, lb/h	87,645
Ash Production, lb/h	97,073
Coal and Dolomite Drying Fuel, gal/h	100
Auxiliary Summary, kWe	
Transport Boost Compressor	482
Carbonizer Boost Compressor	1,269
Condensate Pumps	229
Feedwater Pumps	5,638
Boiler Forced-Circulation Pumps	232
Circulating Water Pumps	3,614
Cooling Tower Fans	933
Coal Dryer Forced-Draft Fan	319
Coal Dryer Induced-Draft Fan	253
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	503
Gas Turbine Intercooler Fan	18
Nitrogen Supply	0
Barge Unloading and Stacker/Reclaimer	180
Coal Handling	369
Dolomite Handling	72
Coal and Sorbent Feed	34
Ash Cooling and Handling	113
Service Water	105
Miscellaneous	747
Stepdown Transformer	78
Total Auxiliaries	15,590

Table 70 Comparison of Baseline and 1600°F Carbonizer Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline (14-atm/1500°F Carbonizer)	14-atm/1600°F Carbonizer
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	511.90
Auxiliaries, MWe	14.73	15.59
Net Power, MWe	452.76	496.31
Net Plant Efficiency, %(HHV)	43.63	44.92
Net Plant Heat Rate, Btu/kWh	7,822	7,598
As-Received Coal Feed, lb/h	284,410	302,828
Dolomite Feed, lb/h	82,315	87,645
Ash Production, lb/h	91,144	97,073
Gas Turbine Parameters		
Topping Combustor Exit Temperature °F	2100.1	2350.0
Generator Output, MWe per Module	97.58	114.12
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	105.98
Superheating	186.27	145.92
Reheating	160.60	167.66
Total FBHE Duty (per module), 10^6 Btu/h	488.82	419.56
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	742.12
UA, 10^6 Btu/h·°F per Module	10.501	9.700
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1602.94
Generator Output, MWe	272.34	283.65
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1391.95

height increase by 3 ft; the CPFBC height remains unchanged. The FBHE duty is about 14-percent lower and requires about a 6-percent decrease in its total heat-transfer surface area.

The outward appearance of the gas turbine/generator remains essentially unchanged; however, fuel-gas piping and valve sizes increase by about 25 percent, the cooling airflow to the turbine blades is 20 percent higher, a more complicated hot section blade-cooling scheme is utilized, and a larger electric generator and accessory package are provided to accommodate the 17-percent increase in power output.

The HRSG superheater outlet temperature increases from 900 to 930°F and there is a 19-percent increase in HRSG duty. Despite this, there is about an 8-percent reduction in HRSG heat-transfer surface area because of the increased LMTD provided by the much higher gas turbine outlet temperature (1110 vs. 988°F). The plant steam flow rate and turbine output are increased by about 4 percent and necessitate little change from baseline plant values.

COE Results. The results of the COE analysis are presented in Table 71. This case has the best result of all the trade-offs conducted with dry pneumatic coal feed, with a 3.7-percent improvement in COE over the baseline plant. As in the computer-predicted carbonizer case, the improvement is primarily the result of the improvement in heat rate and increased power output, even though the gas turbine costs are higher because of the increased topping combustor outlet temperature (2350°F vs. 2100°F).

Discussion. The 2350°F topping combustor temperature raises the plant gas turbine power output by approximately 17 percent. Since the steam cycle increase is only about 4 percent, the overall gas turbine-to-steam turbine power ratio increases by about 12 percent and the plant efficiency increases by 1.29 percentage points. Although the 100°F increase in carbonizer operating temperature lowers the CPFBC char heat release and FBHE duty, the gas turbine exhaust temperature is 122°F higher. Hence the HRSG duty increases and results in a net 4-percent increase in steam cycle duty.

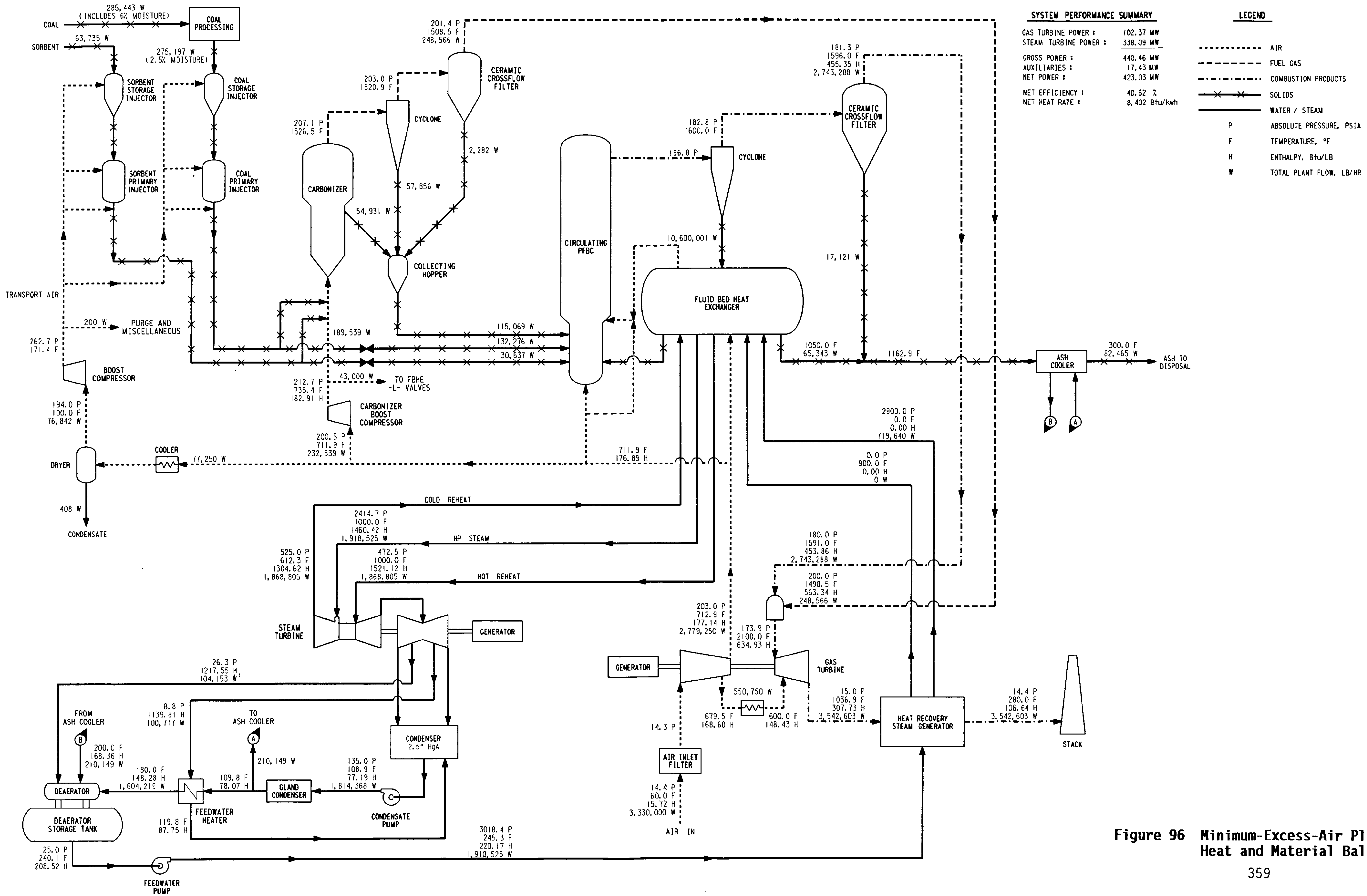
Design parameters in the steam generating equipment become more favorable with this plant. Smaller heat-exchange surfaces are required in the FBHE because of its reduced duty. The higher exhaust temperature of the gas turbine permits a design HRSG steam temperature of 950°F rather than the 900°F in the baseline plant. Despite the higher exit steam temperature and greater duty in the HRSG, less surface area is needed because of the larger average LMTD in the HRSG.

6.2.3 Minimum-Excess-Air Plant

Plant Performance and Equipment Changes. The minimum-excess-air plant operates with essentially the same 14 atm/1500°F carbonizer balance as the baseline plant, but coal is fed directly to the CPFBC as well as the carbonizer. Figure 96 presents the heat and material balance for this plant and Tables 72 and 73 present detailed performance and equipment data. Although both plants operate with approximately the same coal input, the new excess air level for the plant is 23.6 percent because only one gas turbine is involved. The plant requires a lower Ca/S feed ratio for 90-percent sulfur capture because most of the plant sulfur is now released in the CPFBC, which operates with a higher sulfur-capture efficiency than the carbonizer. Since the CPFBC excess air is now reduced from 211 percent to 20.2 percent, the NO_x emissions are lower. As shown in Table 74, total plant NO_x emissions are expected to be about 0.13 lb/10^6 Btu.

Table 71 Comparison of Baseline and 1600°F Carbonizer Plant Economic Data

	Second-Generation Plant Configuration		
	Baseline (14-atm/ 1500°F Carbonizer)	14-atm/ 1600°F Carbonizer	Percentage Change
Unit Size, MWe net	452.8	496.3	---
Net Plant Heat Rate, Btu/kWh	7822	7598	-2.9
Total Plant Cost, $/kW	907.1	875.8	-3.5
Total Plant Investment, $/kW	981.6	947.8	-3.5
Total Capital Requirement, $/kW	1038.0	1002.1	-3.5
First Year Costs:			
Total O&M, $/kW·yr	38.0	35.6	-6.3
Fixed O&M, $/kW·yr	24.7	23.2	-6.1
Variable O&M, mills/kWh	2.34	2.19	-6.4
Consumables, mills/kWh	3.37	3.24	-3.9
Fuel Cost, mills/kWh	14.0	13.6	-2.9
Levelized O&M:			
Fixed, $/kW·yr	43.2	40.4	-6.5
Variable O&M, mills/kWh	4.1	3.8	-7.3
Consumables, mills/kWh	5.9	5.7	-3.4
Fuel, mills/kWh	26.6	25.9	-2.6
Levelized Carrying Charge, $/kW·yr	179.6	173.4	-3.5
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	72.9	-3.7



Dwg. 8333-1-400-009-104, Rev. C

Figure 96 Minimum-Excess-Air Plant Heat and Material Balance

Table 72 Performance Summary: Second-Generation Minimum-Excess-Air Plant

Power Summary	
CPFBC/Total Plant Coal Feed Ratio	48.07
Gas Turbine Power, kWe	102,371
Steam Turbine Power, kWe	338,094
Gross Power, kWe	440,465
Auxiliaries, kWe	(17,435)
Net Power, kWe	423,030
Net Plant Efficiency, %(HHV)	40.62
Net Plant Heat Rate, Btu/kWh	8402
Consumables and Wastes	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	285,443
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	275,197
Dolomite Feed, lb/h	63,735
Ash Production, lb/h	82,465
Coal and Dolomite Drying Fuel, gal/h	94
Auxiliary Summary, kWe	
Transport Boost Compressor	399
Carbonizer Boost Compressor	423
Condensate Pumps	274
Feedwater Pumps	6,749
Boiler Forced Circulation Pumps	1,030
Circulating Water Pumps	4,318
Cooling Tower Fans	1,114
Coal Dryer Forced-Draft Fan	301
Coal Dryer Induced-Draft Fan	239
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	602
Gas Turbine Intercooler Fan	7
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	161
Coal Handling	348
Dolomite Handling	53
Coal and Sorbent Feed	31
Ash Cooling and Handling	96
Service Water	99
Miscellaneous	704
Stepdown Transformer	87
Total Auxiliaries	17,435

Table 73 Comparison of Baseline and Minimum-Excess-Air Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline (148-Percent Excess Air)	Minimum-Excess Air
Modules	2	1
Overall Plant Performance		
Gross Power, MWe	467.49	440.47
Auxiliaries, MWe	14.73	17.44
Net Power, MWe	452.76	423.03
Net Plant Efficiency, %(HHV)	43.63	40.62
Net Plant Heat Rate, Btu/kWh	7822	8402
As-Received Coal Feed, lb/h	284,410	285,443
Dolomite Feed, lb/h	82,315	63,735
Ash Production, lb/h	91,144	82,465
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2100.0
Generator Output, MWe per Module	97.58	102.37
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	936.74
Superheating	186.27	737.45
Reheating	160.60	404.60
Total FBHE Duty (per module), 10^6 Btu/h	488.82	2078.79
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	705.26
UA, 10^6 Btu/h·°F per Module	10.501	4.368
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1918.52
Generator Output, MWe	272.34	338.09
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1662.88

Table 74 Minimum-Excess-Air Plant NO_x Releases/Emissions

Assumptions:	
CPFBC Flue Gas NO_x	
lb/h	322
lb/10^6 Btu	0.091
ppm(v)	74
Fuel Gas Ammonia Content, wt%*	0.20
Ammonia Conversion to NO_x, %	8
Pounds per Hour Basis:	
Topping Combustor NO_x Release	
Thermal Component	14
Fuel-Bound Component	108
NO_x at Topping Combustor Outlet	444
Pounds per 10^6 Btu Heat Release Basis:	
Topping Combustor NO_x Release	
Thermal Component	0.004
Fuel-Bound Component	0.030
NO_x At Topping Combustor Outlet	0.125

*Value predicted by carbonizer computer model.

Of all the sensitivity cases studied to date, the minimum-excess-air case results in the most significant change in plant configuration. By feeding coal directly to the CPFBC, as well as to the carbonizer, only one carbonizer/CPFBC/topping combustor/gas turbine module is required to produce 423 MWe of net power. Compared with the baseline plant, the gas turbine power output is reduced by approximately 48 percent; the steam turbine power output is approximately 24 percent greater. This drastic reduction in gas turbine-to-steam turbine power ratio lowers the plant efficiency by 3.01 percentage points. The minimum-excess-air plant HRSG duty is about 13 percent larger on a per-module basis than in the baseline. Despite the increase, the HRSG will be much smaller than in the baseline plant because its sole function is to preheat boiler feedwater; all steam generation and superheating are shifted to the CPFBC FBHE. As a result, the FBHE duty is over four times as great as that required by the baseline plant. The CPFBC-to-FBHE solids circulation rate and pressure losses increase accordingly, and the cyclone dip leg and CPFBC vessel heights increase by 15 ft to provide the required cyclone/FBHE pressure seal. In addition, two identical FBHE vessels, operating in parallel, are needed to provide the increased duty, and each has approximately 250 percent more surface than each baseline plant unit. Figures 97 and 98 present the plan and elevation views of the required carbonizer/CPFBC/FBHE arrangement.

The steam turbine, while remaining geometrically similar to the base-case turbine, is about 24-percent or 64.5 MWe larger in output. Piping, accessories, the LP section, the electric generator--all are about 25 percent larger.

__COE Results__. Table 75 presents the COE results. The capital costs and attendant carrying charges are considerably lower than in the baseline plant because of the smaller HRSG and the elimination of one module. However, the higher heat rate and fuel cost brings the COE back to within a 2-percent improvement over the baseline plant.

__Discussion__. The equipment arrangement for the minimum-excess-air plant is notably different from that of the baseline plant because only a single carbonizer/CPFBC/FBHE/gas turbine module is required. Heating duty in the FBHE for this plant is more than 300-percent greater than the duty in one FBHE module of the baseline plant. Two pressure vessels contain the FBHE for this design rather than the single pressure vessel per module of the baseline plant.

Gas turbine heat recovery is totally different from that of the baseline plant. Because of the large amount of high-grade heat available from the FBHE, steam production is no longer required in the HRSG (a misnomer, since the HRSG for this design option no longer generates steam). Instead, the HRSG acts as a feedwater heater for the FBHE, heating all the plant feedwater to 586°F. Surface area in the HRSG is less than half that of each of the baseline plant HRSGs because of the larger average temperature difference between the gas and feedwater.

Table 75 shows the minimum-excess-air plant to have a slight COE advantage over the baseline plant. However, this COE estimate is likely overly optimistic for the minimum-excess-air case. Because of the lower efficiency and higher operating cost of this plant, it would not be dispatched as frequently as the baseline plant on a typical utility system. In addition, the single-module design would probably not have as high an availability as the two-module baseline plant. Comparing the two plants using the same capacity factor is unfair to the baseline design, but evaluating the differences in availability and capacity factor for this design option is beyond the scope of the sensitivity study.

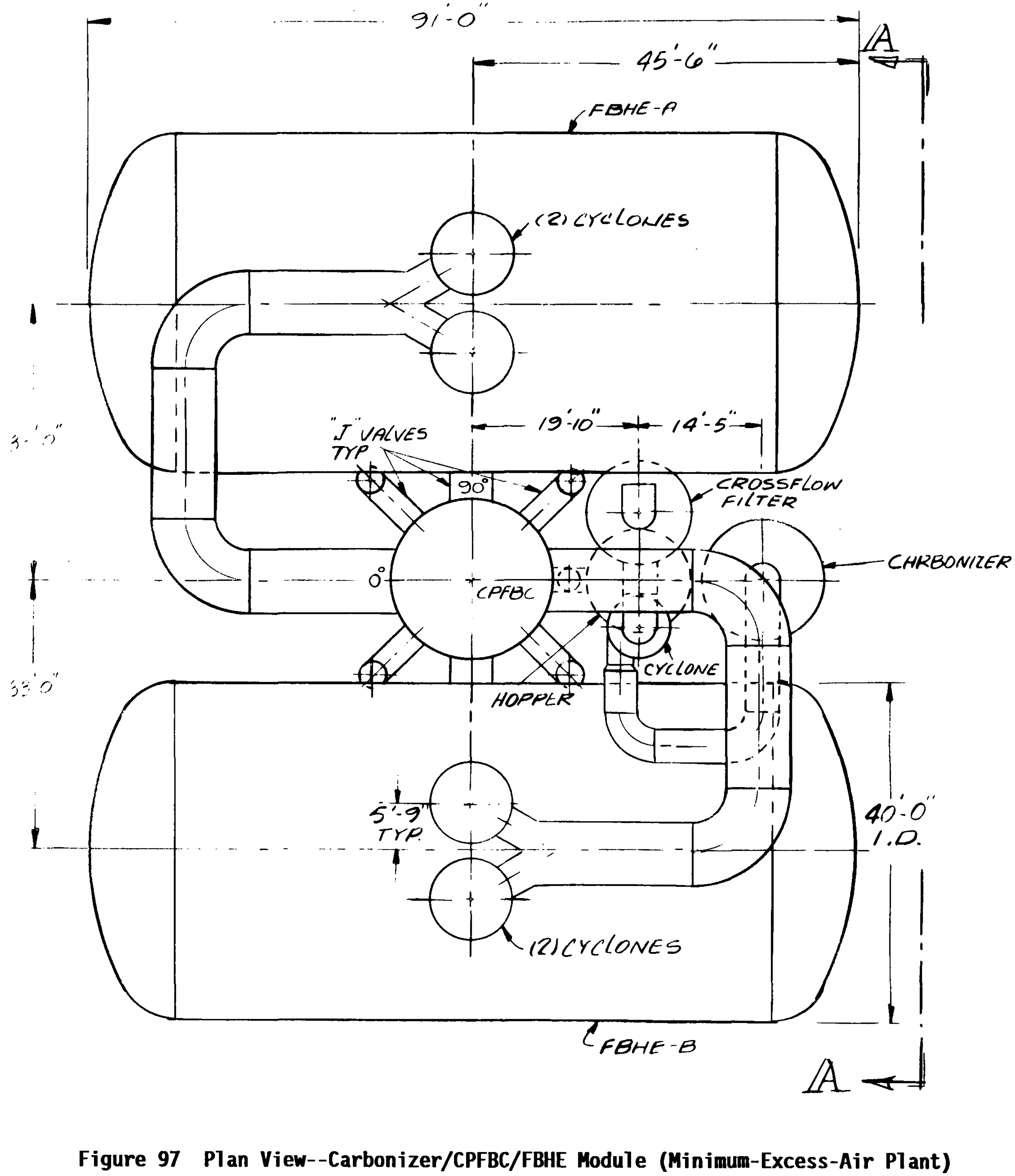


Figure 97 Plan View--Carbonizer/CPFBC/FBHE Module (Minimum-Excess-Air Plant)

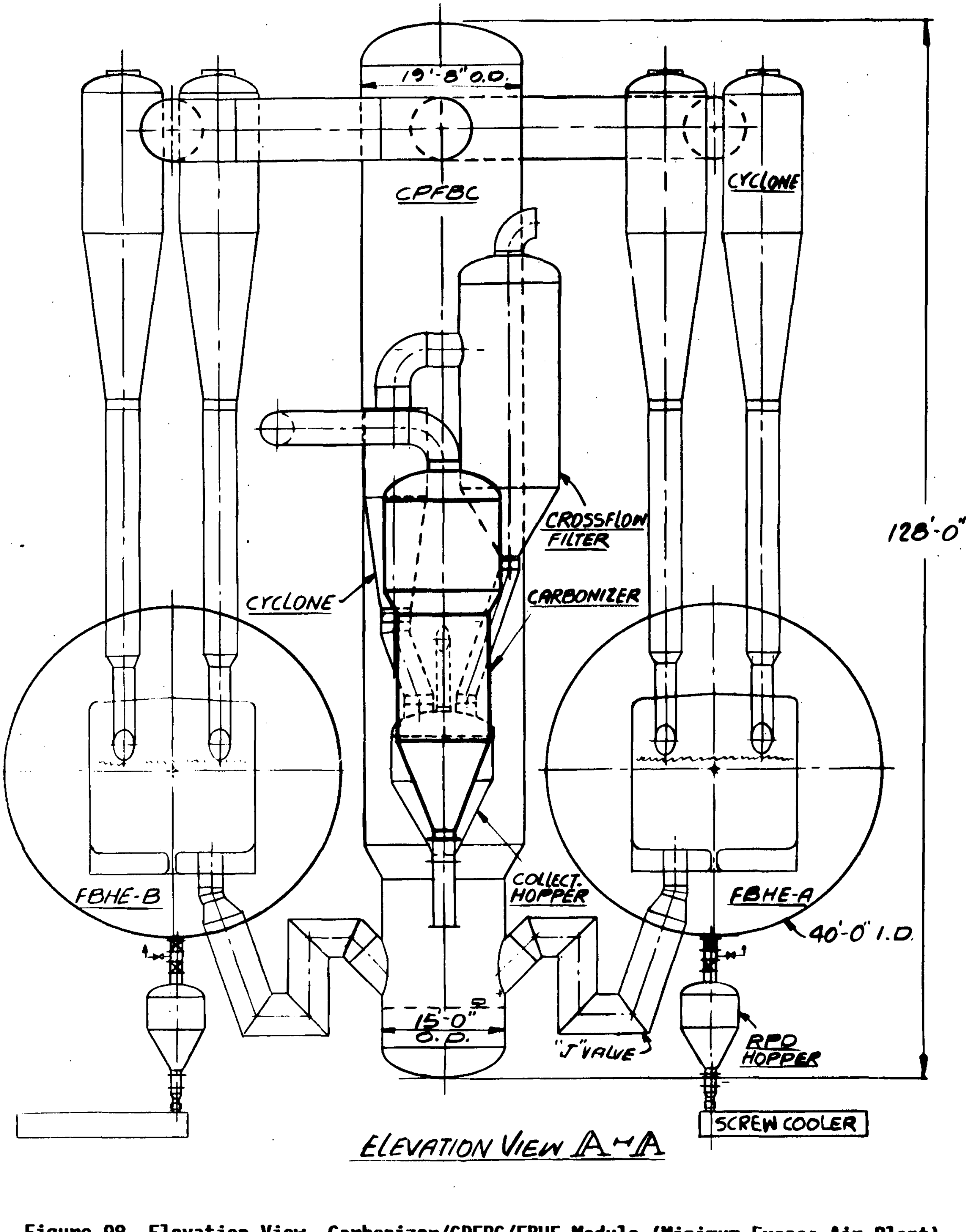


Figure 98 Elevation View--Carbonizer/CPFBC/FBHE Module (Minimum-Excess-Air Plant)

Table 75 Comparison of Baseline and Minimum-Excess-Air Plant Economic Data

	Second-Generation Plant Configuration		
	Baseline	Minimum Excess Air	Percentage Change
Unit Size, MWe net	452.8	423.0	-6.6
Net Plant Heat Rate, Btu/kWh	7822	8402	+7.4
Total Plant Cost, $/kW	907.1	830.0	-8.5
Total Plant Investment, $/kW	981.6	898.2	-8.5
Total Capital Requirement, $/kW	1038.0	953.8	-8.1
First Year Costs:			
Total O&M, $/kW·yr	38.0	35.4	-6.8
Fixed O&M, $/kW·yr	24.7	23.0	-6.9
Variable O&M, mills/kWh	2.34	2.18	-6.8
Consumables, mills/kWh	3.37	3.17	-5.9
Fuel Cost, mills/kWh	14.0	15.0	+1.07
Levelized O&M:			
Fixed, $/kW·yr	43.2	40.1	-7.2
Variable O&M, mills/kWh	4.1	3.8	-7.3
Consumables, mills/kWh	5.9	5.5	-6.8
Fuel, mills/kWh	26.6	28.6	+7.5
Levelized Carrying Charge, $/kW·yr	179.6	165.0	-8.1
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	74.0	-2.3

6.2.4 10-atm/1500°F Carbonizer Plant

Plant Performance and Equipment Changes. Figure 99 identifies the yields and compositions predicted for a 10-atm/1500°F carbonizer via an extrapolation of the Grand Forks-Denver Research data discussed in Appendix A. Figure 100 presents the heat and material balance for this new plant and Tables 76 and 77 present detailed performance and equipment data. The 10-atm plant continues to operate with a 2100°F topping combustor (the optimum firing temperature is relatively insensitive to pressure between 10 and 14 atm), and the plant efficiency is 0.12 percentage points higher than the baseline plant efficiency.

The PFB combustion island component arrangements are identical to those of the baseline plant, but physical dimensions differ because of flow rate and operating pressure differences. For instance, the carbonizer fuel gas volumetric flow rate is roughly 45 percent higher than the baseline plant, necessitating about a 20-percent increase in its I.D.s; the CPFBC flue gas volumetric flow rate is roughly 52 percent higher, necessitating about a 23-percent increase in I.D.s. The carbonizer and CPFBC vessel heights remain similar to baseline plant values. Compared with the baseline plant, the CPFBC FBHE duty is roughly 31 percent lower, requiring an 18 percent decrease in its heat-transfer surface area.

Although the gas turbine output is 2.7 percent less than in the baseline plant, the hot valving, piping, and blade path of the gas turbine are 25 to 30 percent larger because of the lower pressure. The gas turbine compressor contains fewer high-pressure stages because of the lower operating pressure of the cycle, and its discharge temperature is reduced to 591°F (baseline plant value is 711°F). Because of the lower temperature involved, the heat exchanger provided in the baseline plant to cool a portion of the compressor air for gas turbine blade cooling is eliminated. Since this heat exchanger was a source of hot air for coal drying in the baseline plant, the 10-atm plant uses an oil-fired burner to reheat a portion of the HRSG exhaust gas.

The steam turbine is essentially identical to the baseline unit, although the output is 3.9 percent lower.

COE Results. Table 78 shows the 10-atm plant COE is 5.0 percent higher than the baseline plant value because plant equipment costs are higher. This difference is not surprising. The lower pressure increases the gas volumetric flow rates and the diameters of the gas-carrying components increase accordingly, along with refractory requirements, structures, length of piping, and other supporting services to the components.

Discussion. The primary differences in plant configuration between the 10- and 14-atm plants are the gas turbines, the larger equipment sizes needed to accommodate the greater volumetric flow of gases, the coal and dolomite drying systems, and an increase in the design temperature of the HRSG superheater.

The major source of heat for solids drying in the baseline plant is heat rejected by the turbine cooling air intercooler. At the lower operating pressure of the 10-atm plant, the cooling air extracted from the gas turbine compressor is cool enough to be used without intercooling, so the intercooler heat source is no longer available for coal drying. All the coal drying gas is taken from the HRSG exit and is heated to 500°F by oil burners in the dryers. The oil flow required for this plant is 216 gal/h, 130 percent more than the oil consumption of the baseline plant.

Fuel Gas Flow (lb/h)	185.308
HHV (Btu/lb)	1975
LHV (Btu/lb)	1827
LHV (Btu/sft^3)	128

Char-Sorbent Flow (lb/h) = 84.344

	Char	Coke	Spent Dolomite	
Carbon	41.712	6.797	6.215	MgO
Hydrogen	0.586	0.022	12.937	$CaCO_3$
Sulfur	1.675	0.024	2.467	CaS†
Nitrogen	0.756	0.017	0.51	Inerts
Oxygen	0.316	---	---	
Moisture	---	---	---	
Ash	10.31	---	---	

HHV (Btu/lb)	9028
LVH (Btu/lb)	8964

Tar (Flow Rate = 2.023 lb/h)

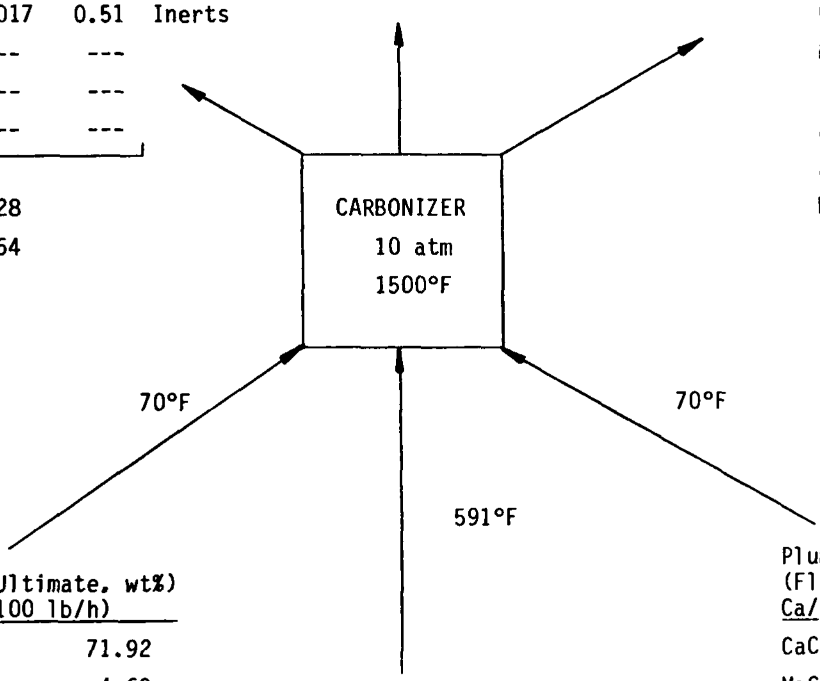
Atomic Composition:

$CH_{.54}O_{.018}N_{.010}S_{.0082}$

HHV (Btu/lb)	15.800
LHV (Btu/lb)	15.410

Gas (wt%)* (Flow Rate = 183.285 lb/h)

CO	9.166
CO_2	20.331
H_2O	7.027
H_2	0.584
CH_4	2.517
C_2's	1.992
NH_3	0.309
H_2S	0.091
N_2	57.983
HHV (Btu/lb)	1822
LHV (Btu/lb)	1677



Pittsburgh Coal (Ultimate, wt%) (Flow Rate = 100 lb/h)

Carbon	71.92
Hydrogen	4.69
Sulfur	2.99
Nitrogen	1.26
Oxygen	6.33
Moisture¶	2.50
Ash	10.31
HHV (Btu/lb)	12.916
LHV (Btu/lb)	12.472

Air (Flow Rate = 139.632 lb/h)

Relative Humidity	50% at 70°F

Plum Run Dolomite (wt%) (Flow Rate = 30.02 lb/h Ca/S = 1.75)§

$CaCO_3$	54.5
$MgCO_3$	43.3
Moisture	0.5
Inerts	1.7

*Excludes tar.
†87.5% sulfur capture (92% of equilibrium H_2S capture).
§If based on sulfur release--Ca/S = 4.2.
¶After drying.

Rev. 0 8/31/87

Figure 99 10-atm/1500°F Carbonizer Balance

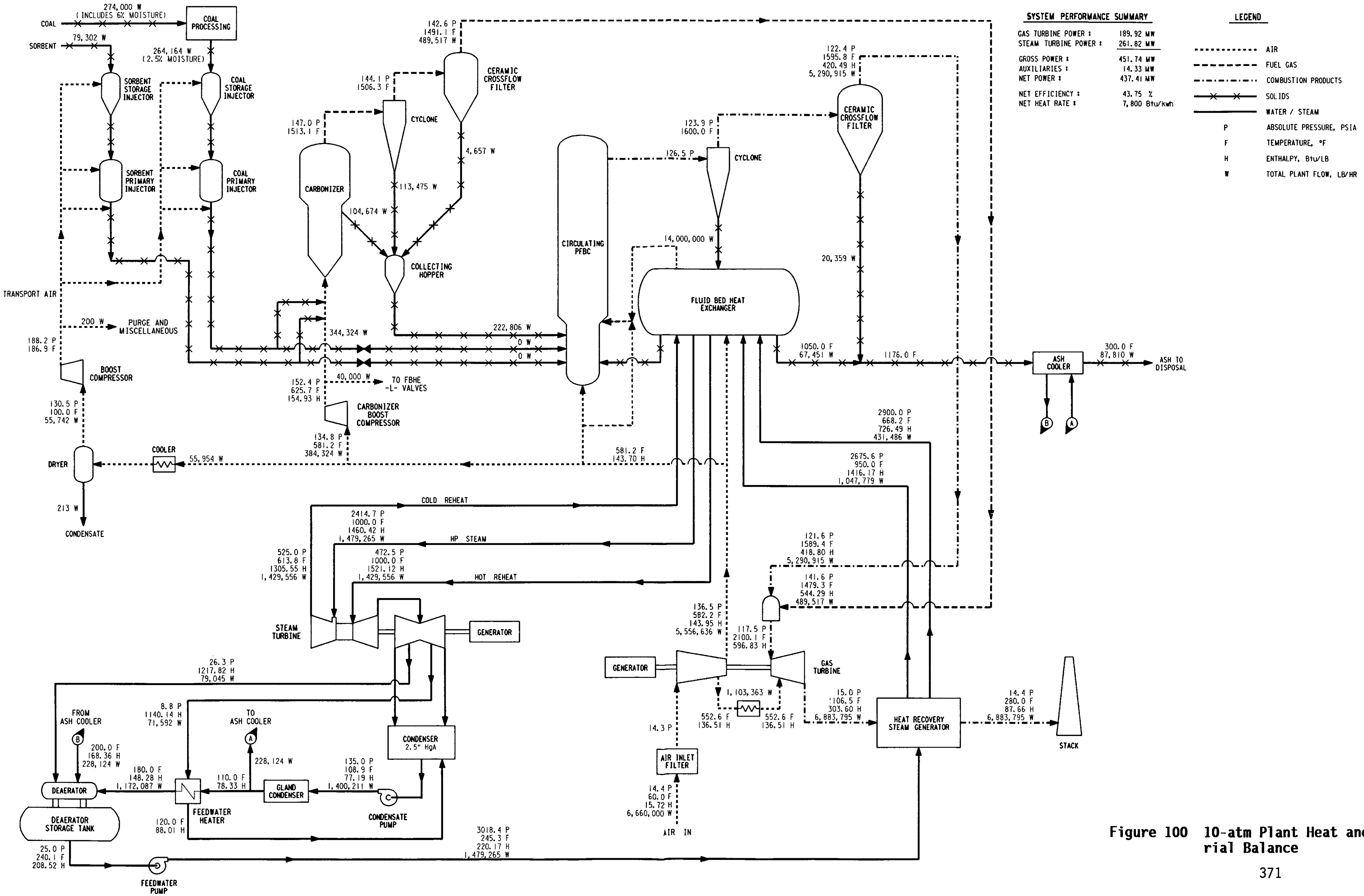


Figure 100 10-atm Plant Heat and Material Balance

Dwg. 8333-1-400-009-108, Rev. C

Table 76 10-atm Second-Generation Plant Performance Summary

<u>Power Summary</u>	
Gas Turbine Power, kWe	189,918
Steam Turbine Power, kWe	261,820
Gross Power, kWe	451,738
Auxiliaries, kWe	(14,330)
Net Power, kWe	437,408
Net Plant Efficiency, % (HHV)	43.75
Net Plant Heat Rate, Btu/kWh	7800
<u>Consumables and Wastes</u>	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	274,000
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	264,164
Dolomite Feed, lb/h	79,302
Ash Production, lb/h	87,810
Coal and Dolomite Drying Fuel, gal/h	216
<u>Auxiliary Summary, kWe</u>	
Transport Boost Compressor	353
Carbonizer Boost Compressor	1,304
Condensate Pumps	212
Feedwater Pumps	5,203
Boiler Forced Circulation Pumps	164
Circulating Water Pumps	3,317
Cooling Tower Fans	856
Coal Dryer Forced-Draft Fan	289
Coal Dryer Induced-Draft Fan	229
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	464
Gas Turbine Intercooler Fan	---
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	163
Coal Handling	334
Dolomite Handling	66
Coal and Sorbent Feed	31
Ash Cooling and Handling	102
Service Water	95
Miscellaneous	676
Stepdown Transformer	71
Total Auxiliaries	14,329

Table 77 Comparison of Baseline and 10-atm Plant Performance Data

	Second-Generation Plant Configuration: Baseline (14-atm Carbonizer)	Second-Generation Plant Configuration: 10-atm Carbonizer
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	451.74
Auxiliaries, MWe	14.73	14.33
Net Power, MWe	452.76	437.41
Net Plant Efficiency, Percent (HHV)	43.63	43.75
Net Plant Heat Rate, Btu/kWh	7822	7800
As-Received Coal Feed, lb/h	284,410	274,000
Dolomite Feed, lb/h	82,315	79,302
Ash Production, lb/h	91,144	87,810
Gas Turbine Parameters		
Topping Combustor Exit Temperature °F	2000.1	2100.1
Generator Output, MWe per Module	97.58	94.96
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	75.41
Superheating	186.27	106.11
Reheating	160.60	154.09
Total FBHE Duty (per module), 10^6 Btu/h	488.82	335.61
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	735.81
UA, 10^6 Btu/h·°F per Module	10.501	12.358
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1479.2
Generator Output, MWe	272.34	261.82
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1277.4

Table 78 Comparison of Baseline and 10-atm Plant Economic Data

	Second-Generation Plant Configuration		
	Baseline	10 atm	Percentage Change
Unit Size, MWe net	452.8	437.4	---
Net Plant Heat Rate, Btu/kWh	7822	7800	-0.2
Total Plant Cost, $/kW	907.1	977.9	+7.8
Total Plant Investment, $/kW	981.6	1058.2	+7.8
Total Capital Requirement, $/kW	1038.0	1117.2	+7.6
First Year Costs:			
Total O&M, $/kW·yr	38.0	41.4	+8.9
Fixed O&M, $/kW·yr	24.7	26.9	+8.9
Variable O&M, mills/kWh	2.34	2.54	+8.5
Consumables, mills/kWh	3.37	3.62	+7.4
Fuel Cost, mills/kWh	14.0	14.0	---
Levelized O&M:			
Fixed, $/kW·yr	43.2	46.9	+8.6
Variable O&M, mills/kWh	4.1	4.4	+7.3
Consumables, mills/kWh	5.9	6.3	+6.8
Fuel, mills/kWh	26.6	26.6	---
Levelized Carrying Charge, $/kW·yr	179.6	193.3	+7.6
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	79.5	+5.0

Even with the slight heat rate improvement, the lower fuel consumption does not compensate for the increase in capital cost of the pressurized gas-carrying components. Even though the 10-atm pressure allows a reduction in vessel wall thicknesses from 14 atm values, the increased diameters result in both increased vessel weights and costs because costs for closure head, refractory, foundations, structural steel, and hot gas ducting, for example, also increase.

6.3 ALTERNATIVE FEEDSTOCK SIZES--PLANT PERFORMANCE AND EQUIPMENT CHANGES

Two studies were performed to determine the effect of finer feedstock grinds on plant economics and performance. The first alternative investigated the use of a -30 mesh coal grind while keeping the dolomite sorbent at 1/8 in. x 0. The second considered a -30 mesh grind for both the coal and the dolomite. These designs are presented in Figures 101 and 102. The baseline plant 14 atm/1500°F carbonizer balance was the starting point for the studies.

Both alternative plants achieve 90-percent sulfur capture with lower Ca/S feed ratios (1.5 and 1.37) and reduced carbonizer bed heights (20 vs. 25 ft). In both cases the major reason for the reduction is an increase in carbonizer sulfur-capture efficiency (95 vs. 87-1/2 percent) brought about by an increase in bed sorbent content (char content of bed decreases). Reducing the sorbent feed size to that of the coal (-30 mesh) improves the CPFBC sulfur-capture efficiency (90 vs. 89 percent) and enables the Ca/S feed ratio to be lowered to 1.37. The carbonizer pressure loss increases from 5.6 to 8.5 psi because of the higher bed sorbent content, while the CPFBC pressure loss and other plant parameters remain unchanged. Both plants yield an increase in efficiency of 0.15 percentage points. Tables 79 through 81 present detailed performance and equipment data for the two plants.

The use of -30 mesh coal significantly increases the potential for spontaneous combustion and explosion, so the lock hopper coal feed systems of both plants are pressurized with nitrogen rather than air; air still transports the coal from the lock hopper rotary feed valve to the carbonizer. Because of the 14-atm pressure involved, the nitrogen consumption rate is very high (approximately 350 t/d), and a cryogenic air separation system is provided for the plant for economic reasons. The cryogenic system occupies a plan area of approximately 100 x 100 ft, increases the plant parasitic losses by 2.5 MWe, and produces oxygen as well as nitrogen. Although the oxygen could be injected into the plant or upgraded for sale as a byproduct, it is assumed to be vented to atmosphere. Despite the added parasitic loss, the plant efficiency increases. The compressor airflow that was previously cooled, boosted in pressure, and lost when the lock hopper feed system was depressurized is now passed through the gas turbine for additional work. This added output, together with reduced sorbent requirements, enables the plant to operate with a slight increase in efficiency.

With the exception of the nitrogen supply system the plant equipment arrangement remains unchanged from the baseline configuration. Equipment dimensions differ slightly because of slight differences in flow rates, and the carbonizer bed and vessel heights associated with the -30 mesh coal, 1/8 in. x 0 dolomite case are reduced by 5 ft.

COE Results. The COE results are presented in Table 82. Very small changes are noted in heat rate and capital costs; and depending upon the feedstock sizes, the COEs are 0.1 to 0.2 mills/kWh lower than for the baseline plant. The reduction in capital cost provided by reduced carbonizer vessel heights, lower dolomite feed

Dwg. 8333-1-400-009-103. Rev. C

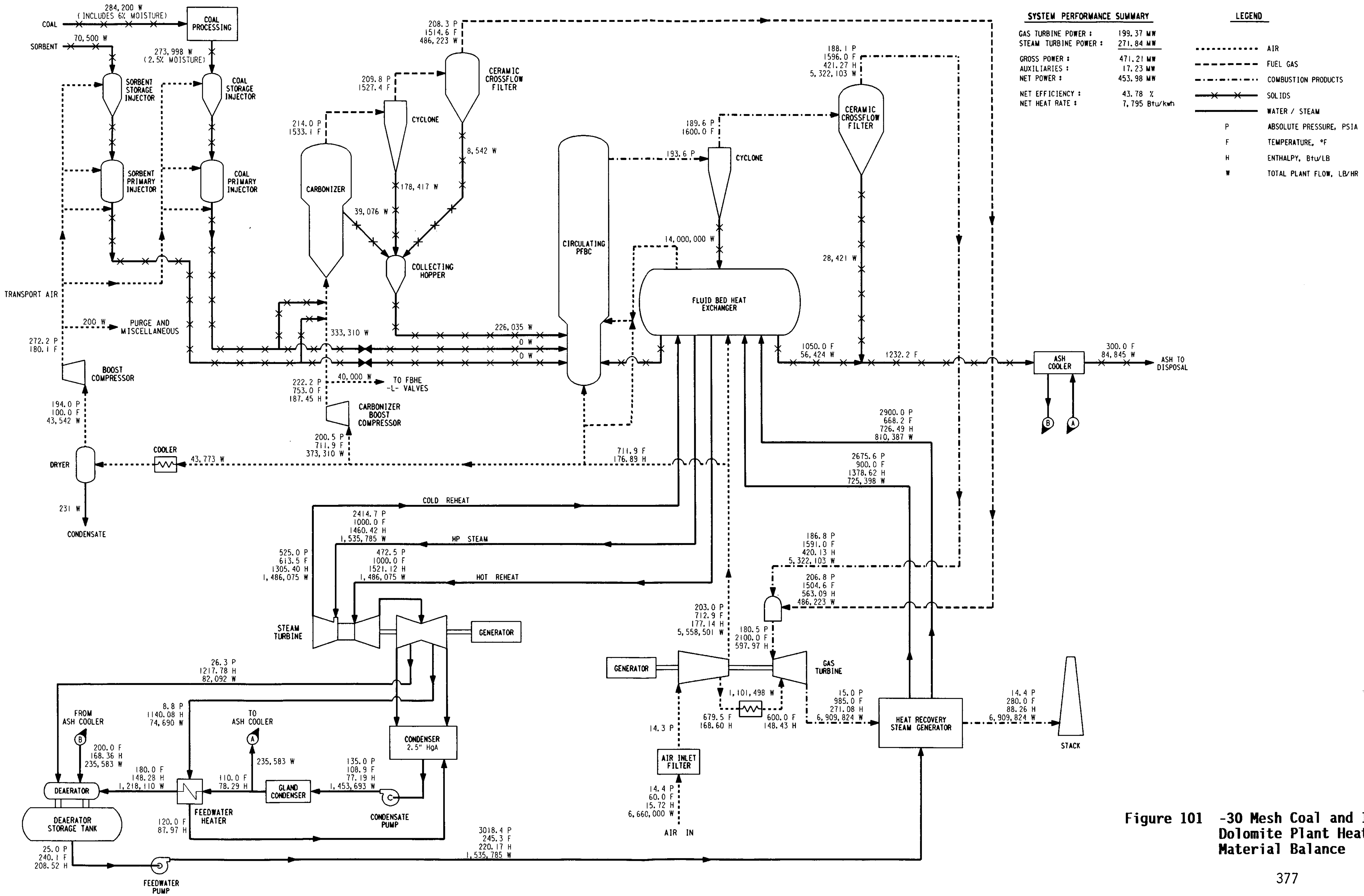


Figure 101 -30 Mesh Coal and 1/8 in. Dolomite Plant Heat and Material Balance

Dwg. 8333-1-400-009-102, Rev. C

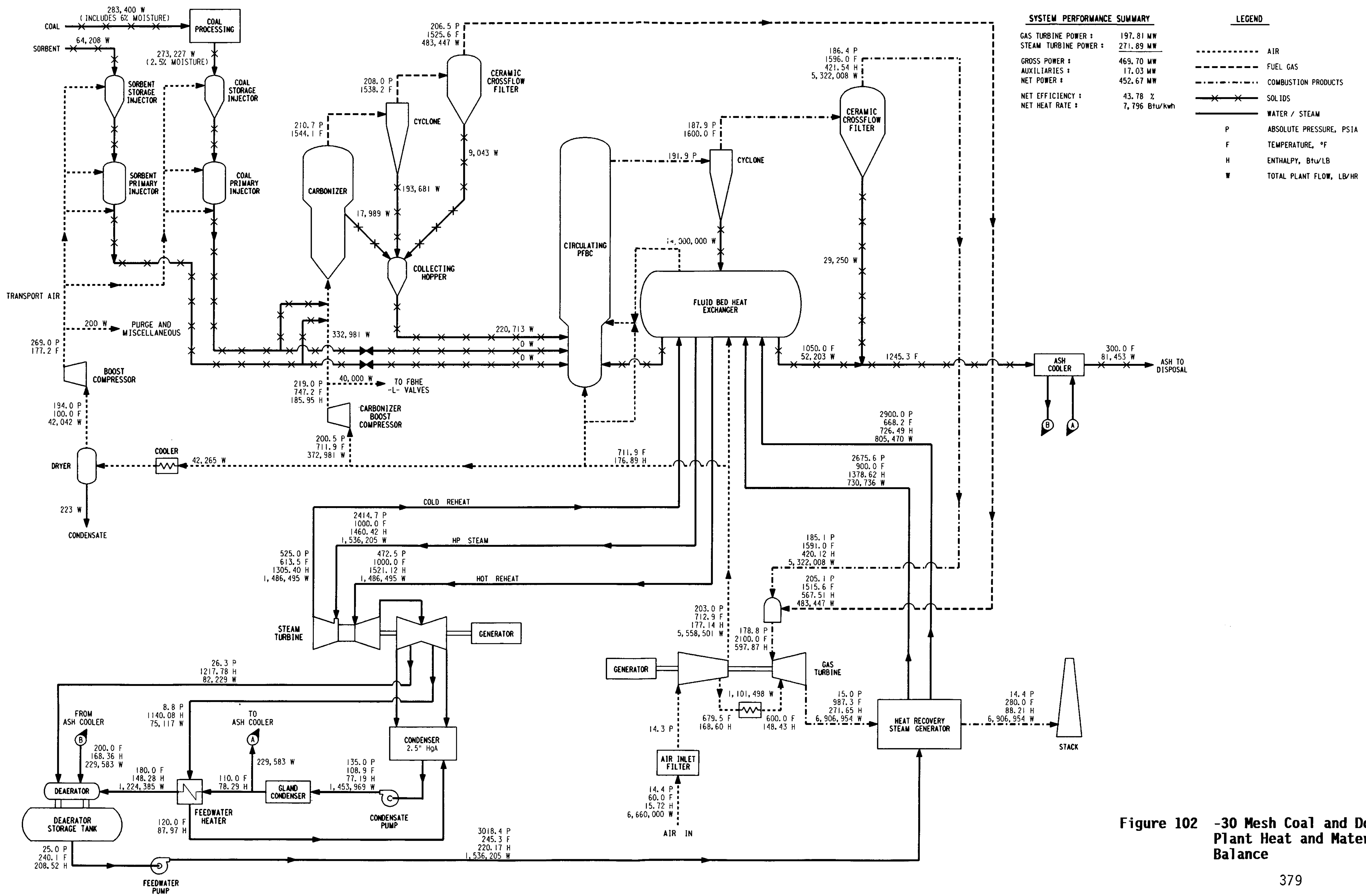


Figure 102 -30 Mesh Coal and Dolomite Plant Heat and Material Balance

Table 79 Effect of Dolomite Feed Size on -30 Mesh Coal Plant Performance

	Dolomite Feed Size	
	-1/8 in. x 0	-30 mesh
Power Summary		
Gas Turbine Power, kWe	199,372	197,809
Steam Turbine Power, kWe	271,835	271,893
Gross Power, kWe	471,207	469,702
Auxiliaries, kWe	(17,228)	(17,029)
Net Power, kWe	453,979	452,673
Net Plant Efficiency, % (HHV)	43.78	43.78
Net Plant Heat Rate, Btu/kWh	7795	7796
Consumables and Wastes		
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	284,200	283,400
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	273,998	273,227
Dolomite Feed, lb/h	70,500	64,208
Ash Production, lb/h	84,845	81,453
Coal and Dolomite Drying Fuel, gal/h	94	94
Auxiliary Summary, kWe		
Transport Boost Compressor	254	236
Carbonizer Boost Compressor	1,191	1,021
Condensate Pumps	220	220
Feedwater Pumps	5,402	5,404
Boiler Forced Circulation Pumps	309	316
Circulating Water Pumps	3,444	3,443
Cooling Tower Fans	889	889
Coal Dryer Forced-Draft Fan	300	299
Coal Dryer Induced-Draft Fan	238	237
Gas Turbine Auxiliaries	400	400
Steam Turbine Auxiliaries	482	482
Gas Turbine Intercooler Fan	15	15
Nitrogen Supply	2,500	2,500
Barge Unloading and Stacker/Reclaimer	164	160
Coal Handling	347	346
Dolomite Handling	58	53
Coal and Sorbent Feed	31	31
Ash Cooling and Handling	99	95
Service Water	99	99
Miscellaneous	701	699
Stepdown Transformer	86	85
Total Auxiliaries	17,228	17,029

Table 80 Comparison of Baseline and -30 Mesh Coal Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline (1/8 in. x 0 Coal and Dolomite)	-30 Mesh Coal and 1/8 in. Dolomite
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	471.21
Auxiliaries, MWe	14.73	17.23
Net Power, MWe	452.76	453.98
Net Plant Efficiency, % (HHV)	43.63	43.78
Net Plant Heat Rate, Btu/kWh	7822	7795
As-Received Coal Feed, lb/h	284,410	284,200
Dolomite Feed, lb/h	82,315	70,500
Ash Production, lb/h	91,144	84,845
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2100.0
Generator Output, MWe per Module	97.58	99.69
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	141.63
Superheating	186.27	185.42
Reheating	160.60	160.29
Total FBHE Duty (per module), 10^6 Btu/h	488.82	487.34
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	625.33
UA, 10^6 Btu/h·°F per Module	10.501	10.764
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1535.78
Generator Output, MWe	272.34	271.84
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1326.54

Table 81 Comparison of Baseline and -30 Mesh Coal and Dolomite Plant Performance Data

	Second-Generation Plant Configuration: Baseline (1/8 in. x 0 Coal and Dolomite)	Second-Generation Plant Configuration: -30 Mesh Coal and Dolomite
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	469.70
Auxiliaries, MWe	14.73	17.03
Net Power, MWe	452.76	452.67
Net Plant Efficiency, % (HHV)	43.63	43.78
Net Plant Heat Rate, Btu/kWh	7822	7796
As-Received Coal Feed, lb/h	284,410	283,400
Dolomite Feed, lb/h	82,315	64,208
Ash Production, lb/h	91,144	81,453
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2100.0
Generator Output, MWe per Module	97.58	98.90
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	140.77
Superheating	186.27	184.69
Reheating	160.60	160.34
Total FBHE Duty (per module), 10^6 Btu/h	488.82	485.80
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	627.28
UA, 10^6 Btu/h·°F per Module	10.501	10.735
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1536.20
Generator Output, MWe	272.34	271.89
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1326.16

Table 82 Comparison of Baseline and Alternative Feed Size Plant Economic Data

	Second-Generation Plant Configuration		
	Baseline (1/8 in. x 0 Coal and Dolomite)	-30 Mesh Coal and 1/8 in. x 0 Dolomite	-30 Mesh Coal And Dolomite
Unit Size, MWe net	452.8	454.0	452.7
Heat Rate, Btu/kWh	7822	7795	7796
Total Plant Cost, $/kW	907.1	918.3	915.3
Total Plant Investment, $/kW	981.6	993.7	990.5
Total Capital Requirement, $/kW	1038.0	1049.6	1046.3
First Year Costs:			
Total O&M, $/kW·yr	38.0	39.4	39.4
Fixed O&M, $/kW·yr	24.7	25.6	25.6
Variable O&M, mills/kWh	2.34	2.42	2.42
Consumables, mills/kWh	3.37	2.92	2.93
Fuel Cost, mills/kWh	14.0	13.95	13.95
Levelized O&M:			
Fixed, $/kW·yr	43.2	44.7	44.7
Variable O&M, mills/kWh	4.1	4.2	4.2
Consumables, mills/kWh	5.9	5.1	5.1
Fuel, mills/kWh	26.6	26.5	26.6
Levelized Carrying Charge, $/kW·yr	179.6	181.6	181.0
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	75.6	75.5

system costs, etc. are essentially negated by the rise in cost associated with the cryogenic nitrogen supply system.

Discussion. The Grand Forks Energy and Denver Research Laboratories have investigated the effects of coal feed size on carbonizer yields and compositions. Feed sizes ranging from 1/8 in. x 0 to 1/2 in. x 0 were tested; no significant effect was observed. Although this insensitivity might be attributed to the high elutriation rates of their turbulently slugging, jetting fluidized bed test units, our analysis has assumed that the finer coal feed size (-30 mesh rather than 1/8 in. x 0) does not improve fuel gas yields or heating values; only sulfur-capture factors were taken into consideration. Reducing the coal feed size while keeping the carbonizer fluidizing velocity constant lowers the carbonizer bed coal/char content. Since this change increases the bed sorbent content, a significant increase in carbonizer sulfur-capture efficiency results, and the Ca/S feed ratio required to yield a 90-percent plant sulfur-capture efficiency drops from 1.75 to 1.5. A finer sorbent feed size can only be used simultaneously with a finer coal feed size, otherwise the carbonizer sorbent content and sulfur-capture efficiency will decrease. Since dolomite is much denser than coal, a reduction in the dolomite feed size to -30 mesh does not appreciably change the carbonizer sulfur-capture efficiency, but it does improve the CPFBC sulfur-capture efficiency; consequently, an even lower Ca/S feed ratio (1.37) can be used. To minimize spontaneous combustion and potential risk of explosion, coal feed lock hopper systems operating with -30 mesh coal must be pressurized with nitrogen rather than air. Although consideration was given to cascading vent nitrogen from one lock hopper feed system to the other to minimize the plant nitrogen consumption, a cryogenic air separation system was found the most economical means for meeting this nitrogen requirement. The cost, parasitic loss, and increased complexity associated with this cryogenic system negates the cost savings and performance improvements provided by reduced Ca/S feed ratios, and there is little incentive under these conditions to use finer feed sizes. If the -30 mesh coal were to be fed as a slurry, however, the lock hopper coal feed and cryogenic systems that negate the advantages of finer feed size would be eliminated. Unfortunately, time did not permit this additional point to be studied, and a fine coal feed size is recommended for reanalysis in Phase 2.

6.4 ALTERNATIVE FEEDSTOCKS

6.4.1 Limestone Sorbent

Plant Performance and Equipment Changes. The carbonizer yields and heating values predicted for the baseline plant served as the starting point for this analysis. Figure 103 is the heat and material balance for the new plant when operating with Carbon limestone (analysis in Table 83). This limestone is mined in Lowellville, Ohio. Although its reactivity is similar to that of the baseline plant

Table 83 Carbon Limestone Analysis

$CaCO_3$	90.1
$MgCO_3$	1.42
Inerts*	8.48

*Al_2O_3, Fe_2O_3, TiO_2, Na_2O, K_2O, etc.

Dwg. 8333-1-400-009-106. Rev. C

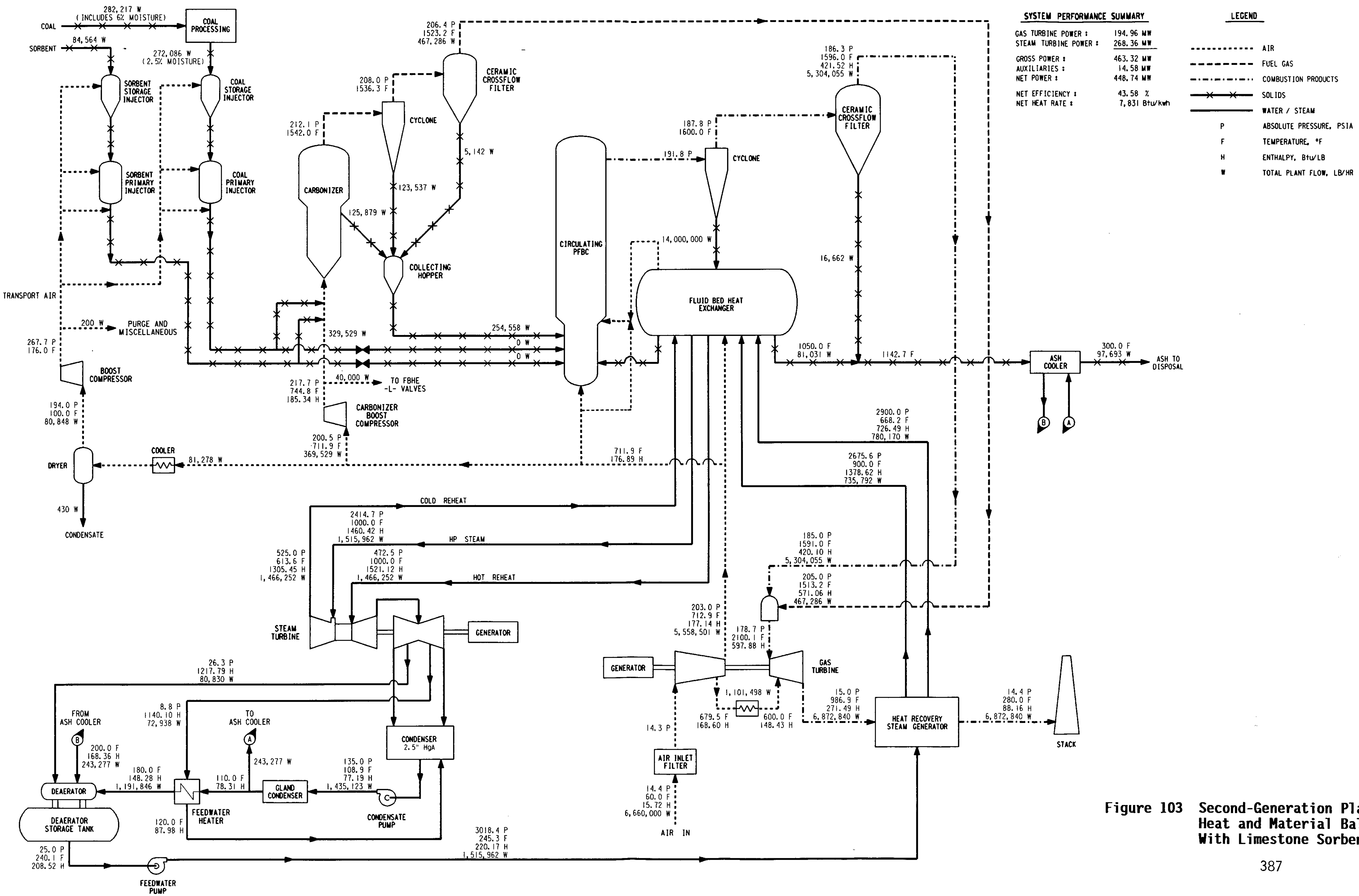


Figure 103 Second-Generation Plant Heat and Material Balance With Limestone Sorbent

sorbent (Plum Run dolomite) only a small portion of the Carbon limestone calcines in the carbonizer, and a much larger Ca/S molar feed ratio is required (3.0 vs. 1.75). Based on this feed ratio, the carbonizer and CPFBC operate with sulfur-capture efficiencies of 89.5 and 93 percent and provide an overall plant sulfur-capture efficiency of 90.2 percent. Tables 84 and 85 present detailed performance and equipment data. The net output of this plant, 448.7 MWe at a 43.58-percent efficiency, represents a decrease in efficiency of 0.05 percentage points from the baseline.

The system and equipment arrangements required by the new plant are identical to those of the baseline, but physical dimensions differ because of flow rate differences. Although the plant Ca/S feed ratio is much larger than the baseline (3.0 vs. 1.75), the limestone flow rate on a pound-per-hour basis is only 2.7 percent higher, since the limestone has a much larger calcium carbonate content than the dolomite (90.1 vs. 54.5 percent). Hence, there is little change to the sorbent processing and feeding systems. The I.D.s. of the carbonizer are reduced about 1-1/2 percent because the fuel gas volumetric flow rate is roughly 3 percent lower than in the baseline plant. The CPFBC flue gas volumetric flow rate and the carbonizer and CPFBC vessel heights remain essentially unchanged from baseline plant values. Compared with the baseline plant, the CPFBC FBHE duty is about 3 percent lower, requiring minimal change in its heat-transfer surface area. Because of the higher limestone ash content and flow rate, the plant has a spent-bed-material/ash flow rate about 7 percent higher; and its depressurizing, cooling, storage, and disposal equipment are also slightly larger than in the baseline plant.

COE Results. As shown in Table 86, operation with limestone increases the total plant cost and COE by about 1 percent compared with the baseline plant.

Discussion. When limestone is substituted for dolomite, plant efficiency drops by 0.05 percentage points and plant cost and COE rise by about 1 percent. As a result, second-generation plants can be operated economically with either dolomite or limestone sorbents; the choice of sorbent to be used will be influenced by local availability and such other factors as reactivity, calcium content, and supply and disposal costs.

6.4.2 Lignite Coal

Plant Performance and Equipment Changes. The lignite coal selected for study is mined from the Texas Wilcox Seam. Table 87 lists its analysis. The lignite has an as-received moisture content of 31.8 percent, sulfur and ash contents of 1.0 and 14.3 percent respectively, and a higher heating value of 6500 Btu/lb. Figures 104 and 105 identify the yields and compositions expected from a 14 atm/1500°F carbonizer operating with this lignite dried to moisture contents of 25.8 and 15 wt% respectively. The 25.8 wt% (or nominal 26 wt%) moisture level reflects a "light" drying operation performed on the coal to facilitate its ability to flow in chutes, hoppers, etc. Although 6 wt% drying may provide adequate flow, a deeper level of drying was also investigated to determine whether it improved plant performance or economics. Comparison of Figures 104 and 105 reveals that the topping combustor heat release of the lightly dried coal fuel gas is 21.1 percent higher than that of the deeply dried coal (per pound of coal carbonized). Because of the temperature-quenching effect of the coal moisture, the lightly dried lignite requires a higher carbonizer air-to-coal ratio which, in turn, reduces its fuel gas tar level and char yield. In both cases the fuel gas yield and heating value are significantly different from those of the baseline plant. Also, plant efficiencies peak at different topping combustion temperatures, 2158°F for the lightly dried and 1980°F for the deeply dried lignite.

Table 84 Second-Generation Plant Performance With Limestone Sorbent

<u>Power Summary</u>	
Gas Turbine Power, kWe	194,963
Steam Turbine Power, kWe	268,355
Gross Power, kWe	463,318
Auxiliaries, kWe	(14,579)
Net Power, kWe	448,739
Net Plant Efficiency, %(HHV)	43.58
Net Plant Heat Rate, Btu/kWh	7,831
<u>Consumables and Wastes</u>	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	282,217
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	272,086
Dolomite Feed, lb/h	84,564
Ash Production, lb/h	97,693
Coal and Dolomite Drying Fuel, gal/h	93
<u>Auxiliary Summary, kWe</u>	
Transport Boost Compressor	448
Carbonizer Boost Compressor	943
Condensate Pumps	217
Feedwater Pumps	5,333
Boiler Forced Circulation Pumps	318
Circulating Water Pumps	3,417
Cooling Tower Fans	882
Coal Dryer Forced-Draft Fan	298
Coal Dryer Induced-Draft Fan	236
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	476
Gas Turbine Intercooler Fan	15
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	169
Coal Handling	344
Dolomite Handling	70
Coal and Sorbent Feed	32
Ash Cooling and Handling	114
Service Water	98
Miscellaneous	697
Stepdown Transformer	73
Total Auxiliaries	14,579

Table 85 Comparison of Baseline and Limestone Sorbent Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline Dolomite Sorbent	Limestone Sorbent
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	463.32
Auxiliaries, MWe	14.73	14.58
Net Power, MWe	452.76	448.74
Net Plant Efficiency, % (HHV)	43.63	43.58
Net Plant Heat Rate, Btu/kWh	7822	7831
As-Received Coal Feed, lb/h	284,410	282,217
Sorbent Feed, lb/h	82,315	84,564
Ash Production, lb/h	91,144	97,693
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2100.1
Generator Output, MWe per Module	97.58	97.48
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	136.35
Superheating	186.27	180.03
Reheating	160.60	158.12
Total FBHE Duty (per module), 10^6 Btu/h	488.82	474.50
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	623.70
UA, 10^6 Btu/h·°F per Module	10.501	10.984
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1515.96
Generator Output, MWe	272.34	268.36
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1316.01

Table 86 Comparison of Baseline and Limestone Sorbent Plant Economic Data

	Second-Generation Plant Configuration		
	Baseline Dolomite Sorbent	Limestone Sorbent	Percentage Change
Unit Size, MWe net	452.8	448.7	
Net Plant Heat Rate, Btu/kWh	7822	7831	0.1
Total Plant Cost, $/kW	907.1	917.2	+1.1
Total Plant Investment, $/kW	981.6	992.5	+1.1
Total Capital Requirement, $/kW	1038.0	1049.5	+1.1
First Year Costs:			
Total O&M, $/kW·yr	38.0	38.5	+1.3
Fixed O&M, $/kW·yr	24.7	25.0	+1.2
Variable O&M, mills/kWh	2.34	2.36	+0.9
Consumables, mills/kWh	3.37	3.51	+4.2
Fuel Cost, mills/kWh	14.0	14.0	0.0
Levelized O&M:			
Fixed, $/kW·yr	43.2	43.6	+0.9
Variable O&M, mills/kWh	4.1	4.1	0.0
Consumables, mills/kWh	5.9	6.1	+3.4
Fuel, mills/kWh	26.6	26.7	+0.4
Levelized Carrying Charge, $/kW·yr	179.6	181.6	+1.1
Levelized Busbar Cost, mills/kWh (at 65 percent capacity factor)	75.7	76.5	+1.1

Table 87 Texas Lignite Analysis (Wilcox Seam)

Proximate Analysis, wt%	As-Received
Moisture	31.8
Volatile Matter	30.5
Fixed Carbon	23.4
Ash	14.3
Total	100.0

Ultimate Analysis, wt%	As-Received
Moisture	31.8
Hydrogen	2.47
Carbon	39.2
Nitrogen	0.5
Oxygen	10.73
Sulfur	1.0
Ash	14.30
Total	100.00

Heating Value	
HHV, Btu/lb	6500

Ash Composition, % by wt% ash	As-Received
CaO	13.56
MgO	2.57
Fe_2O_3	3.84
Na_2O	0.30
K_2O	0.48
SiO_2	50.79
Al_2O_3	20.31
TiO_2	1.58
SO_3	6.40
Cl	0.03
Miscellaneous	0.14
Total	100.00

Fuel Gas Flow (lb/h)	171.614
HHV (Btu/lb)	1174
LHV (Btu/lb)	1067
LHV (Btu/sft^3)	72

Char-Sorbent Flow (lb/h) = 45.64

	Char	Coke	Spent Dolomite	
Carbon	23.388	0.726	1.295	MgO
Hydrogen	0.457	0.002	2.371	$CaCO_3$
Sulfur	0.643	0.002	0.747	CaS†
Nitrogen	0.340	0.001	0.106	Inerts
Oxygen	0	0.002	---	
Moisture	---	---	---	
Ash	15.560	---	---	

HHV (Btu/lb)	8412
LHV (Btu/lb)	8322

Tar (Flow Rate = 0.217 lb/h)

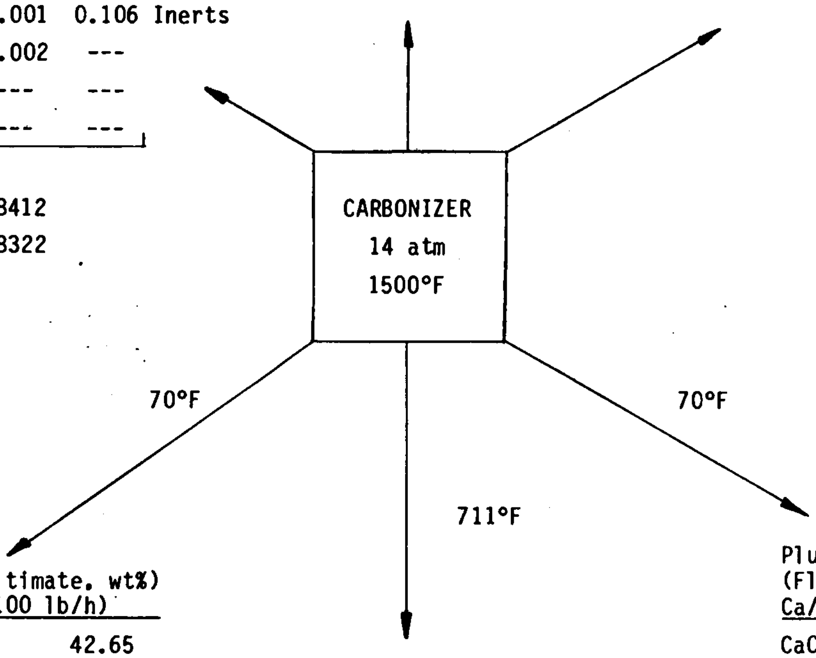
Atomic Composition:

$CH_{.42}O_{.043}N_{.0055}S_{.0038}$

HHV (Btu/lb)	14,800
LHV (Btu/lb)	14,516

Gas (wt%)* (Flow Rate = 171.397 lb/h)

CO	5.718
CO_2	25.654
H_2O	16.410
H_2	0.654
CH_4	2.073
C_2's	0
NH_3	0.140
H_2S	0.069
N_2	49.282
HHV (Btu/lb)	1157
LHV (Btu/lb)	1050



Texas Lignite (Ultimate, wt%) (Flow Rate = 100 lb/h)

Carbon	42.65
Hydrogen	2.69
Sulfur	1.09
Nitrogen	0.54
Oxygen	11.67
Moisture¶	25.80
Ash	15.56
HHV (Btu/lb)	7073
LHV (Btu/lb)	6575

Air (Flow Rate = 111.00 lb/h)

Relative Humidity	50% at 70°F

Plum Run Dolomite (wt%) (Flow Rate = 6.254 lb/h Ca/S = 1.00)§

$CaCO_3$	54.5
$MgCO_3$	43.3
Moisture	0.5
Inerts	1.7

*Excludes tar.
†75% sulfur capture.
§If based on sulfur release--Ca/S = 2.5.
¶6% moisture removed via drying.

Rev. A 10/12/87

Figure 104 1500°F Carbonizer Balance--26 wt% Moisture Texas Lignite

Fuel Gas Flow (lb/h)	149.84
HHV (Btu/lb)	1106
LHV (Btu/lb)	1009
LHV (Btu/sft^3)	69

Char-Sorbent Flow (lb/h) = 58.445

	Char	Coke	Spent Dolomite	
Carbon	31.646	1.439	1.482	MgO
Hydrogen	0.708	0.0030	2.839	$CaCO_3$
Sulfur	0.786	0.0045	0.766	CaS†
Nitrogen	0.423	0.0031	0.122	Inerts
Oxygen	0.401	0.0030	---	
Moisture	---	---	---	
Ash	17.819	---	---	

HHV (Btu/lb)	9033
LHV (Btu/lb)	8924

Tar (Flow Rate = 0.430 lb/h)

Atomic Composition:

$CH_{.42}O_{.043}N_{.0055}S_{.0038}$

HHV (Btu/lb)	14,800
LHV (Btu/lb)	14,516

Gas (wt%)* (Flow Rate = 149.41 lb/h)

CO	5.809
CO_2	25.129
H_2O	14.923
H_2	0.607
CH_4	1.790
C_2's	0
NH_3	0.155
H_2S	0.081
N_2	51.506
HHV (Btu/lb)	1067
LHV (Btu/lb)	970

CARBONIZER
14 atm
1500°F

70°F

711°F

70°F

Texas Lignite (Ultimate, wt%) (Flow Rate = 100 lb/h)

Carbon	48.86
Hydrogen	3.08
Sulfur	1.25
Nitrogen	0.62
Oxygen	13.37
Moisture¶	15.00
Ash	17.82
HHV (Btu/lb)	8102
LHV (Btu/lb)	7677

Air (Flow Rate = 101.124 lb/h)

Relative Humidity 50% at 70°F

Plum Run Dolomite (wt%) (Flow Rate = 7.16 lb/h Ca/S = 1.0)§

$CaCO_3$	54.5
$MgCO_3$	43.3
Moisture	0.5
Inerts	1.7

*Excludes tar.
†75% Sulfur capture.
§If based on sulfur release = 2.8.
¶Dried to 15% Moisture.

Rev. C
10/9/87

Figure 105 1500°F Carbonizer Balance--15 wt% Moisture Texas Lignite

Figures 106 and 107 and Table 88 present heat and material balances and detailed plant performance and equipment data for the two new lignite plants; in Tables 89 and 90 their performance data are compared with the baseline plant data. Despite a higher stack moisture loss, the plant using lightly dried lignite has a higher efficiency than the one using deeply dried lignite (42.66 vs. 41.95 percent) because of its higher gas turbine output (266.1 vs. 191.9 MWe) and higher gas turbine-to-steam turbine power ratio (0.748:0.630). Since deeper drying is expected to require a more complex (greater fire potential) and more expensive processing system, the lightly dried lignite was selected for further study.

Compared with the baseline plant, the plant using 26 wt% moisture lignite produces 12.4 percent more power (508.7 vs. 452.8 MWe), but with a 0.97-percentage point lower efficiency (42.66 vs. 43.63 percent).

A Ca/S molar feed ratio of 1.0 is required to provide the plant using lightly dried lignite with an overall sulfur-capture efficiency of 80.9 percent (NSPS requires 80.6-percent sulfur capture for this low-sulfur coal). The carbonizer continues to operate with a 25-ft expanded bed height, but now provides only a 75-percent sulfur-removal efficiency. The CPFBC-to-FBHE sorbent circulation rate remains at the baseline value and provides a CPFBC sulfur-capture efficiency of 81.0 percent. Because of its high calcium content, the lignite ash captures approximately 28 percent of the coal sulfur.

With regard to equipment layouts, the PFB combustion island component arrangements are identical to those of the baseline plant, but physical dimensions differ because of flow rate differences. The carbonizer coal flow and fuel gas volumetric flow rate are roughly double those of the baseline plant, necessitating about a 43-percent increase in the carbonizer I.D. The CPFBC flue gas volumetric flow, in contrast, is about 7-1/2 percent lower, necessitating about 4-percent reduction in its inside gas-flow-path diameters. As a result, the total gas turbine flow rate is only about 2 percent larger than that of the baseline plant, but the fuel gas valving, piping, and topping combustor flow areas are roughly double. The carbonizer and CPFBC vessel heights remain unchanged from baseline plant values. Compared with the baseline, the CPFBC FBHE duty is roughly 10-1/2 percent higher, requiring a 22-percent increase in its heat-transfer surface area. Since the spent-bed-material/coal ash flow rate is 27 percent larger than that of the baseline plant, depressurizing, cooling, storage, and disposal equipment are also larger.

Table 91 compares the performance of the second-generation PFB combustion plant using lightly dried Texas lignite with that of a conventional PC-fired plant with scrubber designed for the same as-received coal. (The details of the PC-fired plant are presented in Appendix H). The PFB plant shows substantially better performance in most areas. Although the net power of the two plants is about the same, the PFB plant coal flow rate is about 20 percent lower because of its significantly higher efficiency (42.66 vs. 32.98 percent). Even though the sorbent consumption rate of the PFB plant is almost three times that of the PC-fired plant, its solid waste disposal rate is only about 9 percent higher and its water consumption rate about 44 percent lower than PC-fired plant values.

<u>COE Results</u>. Table 92 compares the economic data of a second-generation PFB plant operating with Texas lignite dried to a nominal 26 wt% moisture level with that of the Pittsburgh No. 8 baseline plant and then with that of conventional PC-fired plants with scrubbers. The use of lignite instead of bituminous coal increases the second-generation PFB total plant cost by 4.7 percent and its COE by 4.5 percent. The lignite coal flow rate is 120 percent higher than in the baseline plant. Despite a 56 percent lower sorbent flow rate, the increased coal flow, together with increased fire protection and increased coal handling complexity and

Dwg. 8333-1-400-009-115, Rev. B

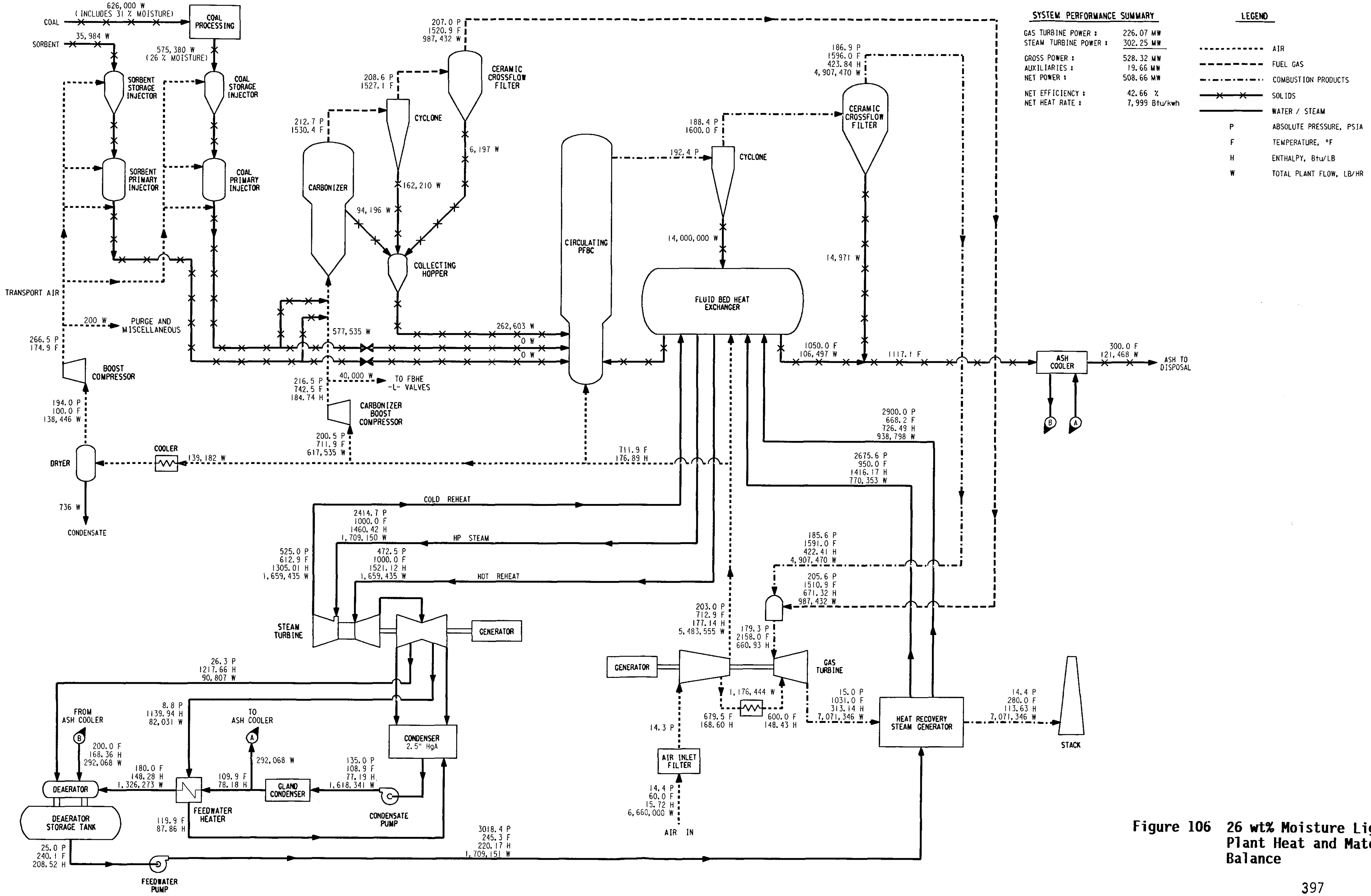
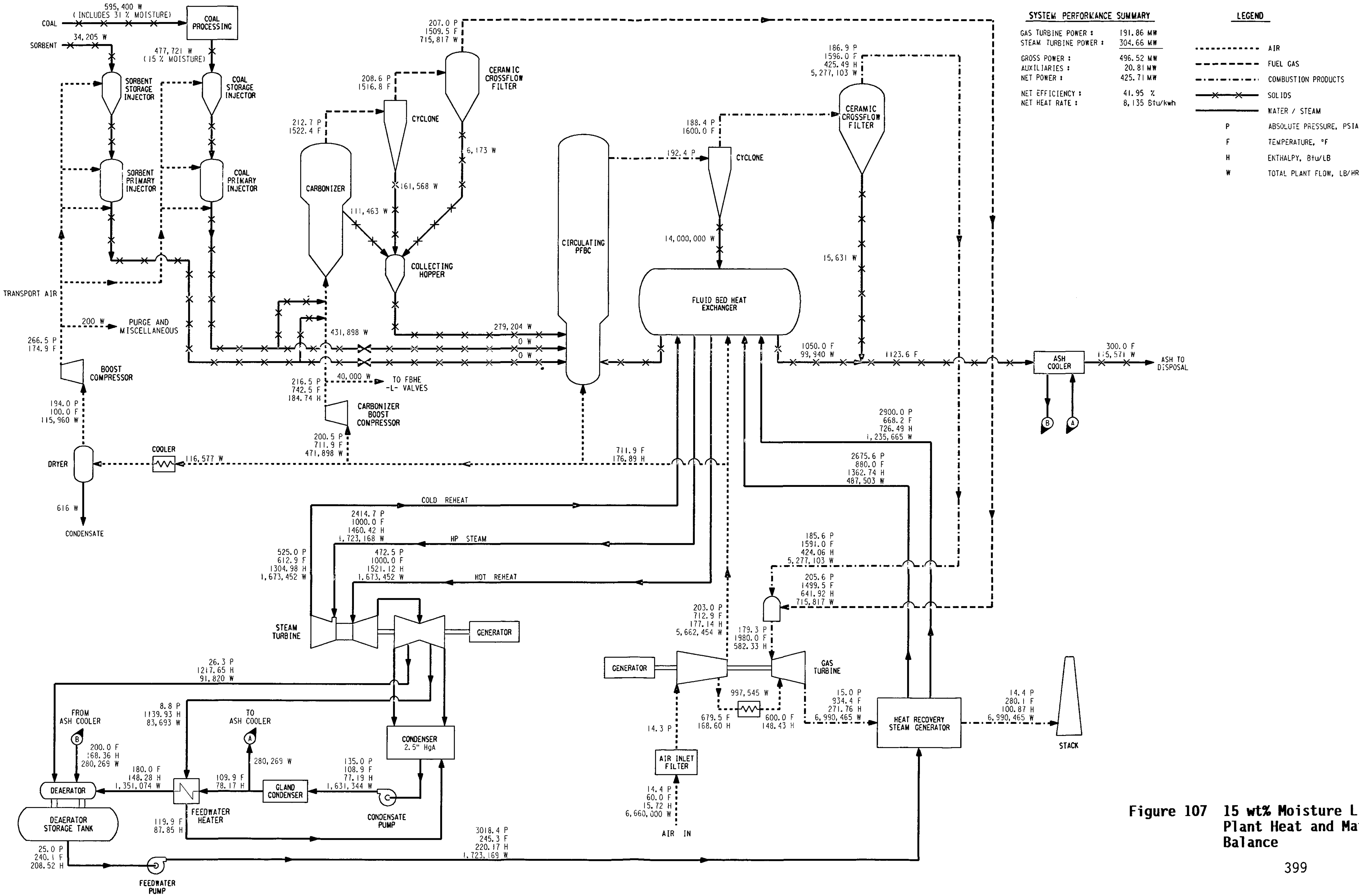


Figure 106 26 wt% Moisture Lignite Plant Heat and Material Balance



Dwg. 8333-1-400-009-114, Rev. B

Figure 107 15 wt% Moisture Lignite Plant Heat and Material Balance

Table 88 Performance Summaries for 15- and 26-wt% Moisture Lignite Plants

	Second-Generation Plant Configuration	
	Deeply Dried Lignite	Lightly Dried Lignite
As-Fired Lignite Moisture Content, wt%	15.0	25.8
Power Summary		
Gas Turbine Power, kWe	191,862	226,071
Steam Turbine Power, kWe	304,659	302,254
Gross Power, kWe	496,521	528,325
Auxiliaries, kWe	(20,808)	(19,664)
Net Power, kWe	475,713	508,661
Net Plant Efficiency, % (HHV)	41.95	42.66
Net Plant Heat Rate, Btu/kWh	8135	7999
Consumables and Wastes		
As-Received Coal Feed, lb/h (Includes 31.8% moisture)	595,400	626,000
As-Fired Coal Feed, lb/h	477,721	575,380
Dolomite Feed, lb/h	34,205	35,984
Ash Production, lb/h	115,571	121,468
Coal and Dolomite Drying Fuel, gal/h	958	444
Auxiliary Summary, kWe		
Transport Boost Compressor	633	755
Carbonizer Boost Compressor	1,120	1,466
Condensate Pumps	246	244
Feedwater Pumps	6,061	6,012
Boiler Forced Circulation Pumps	475	361
Circulating Water Pumps	3,905	3,885
Cooling Tower Fans	1,008	1,002
Coal Dryer Forced-Draft Fan	1,820	994
Coal Dryer Induced-Draft Fan	1,571	831
Gas Turbine Auxiliaries	400	400
Steam Turbine Auxiliaries	541	537
Gas Turbine Intercooler Fan	14	18
Nitrogen Supply	---	---
Barge Unloading and Stacker/Reclaimer	290	305
Coal Handling	726	764
Dolomite Handling	28	30
Coal and Sorbent Feed	55	58
Ash Cooling and Handling	134	141
Service Water	207	218
Miscellaneous	1,469	1,545
Stepdown Transformer	104	98
Total Auxiliaries	20,808	19,664

Table 89 Comparison of Baseline and 15-wt% Moisture Lignite Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline 2.5 wt% Moisture Pittsburgh No. 8	15 wt% Moisture Texas Lignite
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	496.52
Auxiliaries, MWe	14.73	20.81
Net Power, MWe	452.76	475.71
Net Plant Efficiency, %(HHV)	43.63	41.95
Net Plant Heat Rate, Btu/kWh	7822	8135
As-Received Coal Feed, lb/h	284,410	595,400
Dolomite Feed, lb/h	82,315	34,205
Ash Production, lb/h	91,144	115,571
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	1980.0
Generator Output, MWe per Module	97.58	95.93
FBHE Duties, 10^6 Btu/hr per Module		
Evaporation	141.95	215.96
Superheating	186.27	261.30
Reheating	160.60	180.86
Total FBHE Duty (per module), 10^6 Btu/h	488.82	658.12
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	591.33
UA, 10^6 Btu/h·°F per Module	10.501	8.456
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1723.17
Generator Output, MWe	272.34	304.66
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1503.87

Table 90 Comparison of Baseline and 26-Percent Moisture Lignite Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline 2.5 wt% Moisture Pittsburgh No. 8	26 wt% Moisture Texas Lignite
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	528.33
Auxiliaries, MWe	14.73	19.66
Net Power, MWe	452.76	508.66
Net Plant Efficiency, %(HHV)	43.63	42.66
Net Plant Heat Rate, Btu/kWh	7822	7999
As-Received Coal Feed, lb/h	284,410	626,000
Dolomite Feed, lb/h	82,315	35,984
Ash Production, lb/h	91,144	121,468
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2158.0
Generator Output, MWe per Module	97.58	113.04
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	164.08
Superheating	186.27	197.47
Reheating	160.60	179.32
Total FBHE Duty (per module), 10^6 Btu/h	488.82	540.87
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	698.34
UA, 10^6 Btu/h·°F per Module	10.501	9.690
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1709.15
Generator Output, MWe	272.34	302.25
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1496.20

Table 91 Comparison of Lignite-Fired Second-Generation PFB Combustion and Conventional PC-Fired Plant Performance Data

	Conventional PC-Fired Plant With Scrubber	Second-Generation PFB Combustion Plant
As-Fired Coal Moisture, wt%	31.8	25.8
Overall Plant Performance		
Net Power, MWe	508.66	490.70
Net Plant Efficiency, %(HHV)	32.98	42.66
Net Plant Heat Rate, Btu/kWh	10,348	7,999
As-Received Coal Feed, lb/h	781,019	626,000
Dolomite Feed, lb/h	---	35,984
Lime Feed, lb/h	12,828	---
Water Consumption, 1000 gal/d		
Cooling Tower Makeup	9,979	5,839
Boiler Makeup and Miscellaneous	580	244
Flue Gas Desulfurization	560	---
Ash Pelletizer	---	192
Total Water Consumption, 1000 gal/d	11,119	6,275
Waste Products, lb/h		
Ash and Spent Sorbent	111,600	121,468
Sludge	126,645	---
Total Wastes, lb/h	238,245	121,468

Table 92 Comparison of Baseline, Lignite Fired Second-Generation PFB, and PC-Fired Plant Economic Data

	Baseline (Pittsburgh No. 8 Coal)	Lightly Dried Texas Lignite	Percentage Change From Baseline to Lignite-Fired PFB Plant Values	Conventional Lignite-Fired PC Plant With Scrubber	Percentage Change in Lignite-Fired Plant Dollars--Second-Generation Relative to PC-Fired
Unit Size, MWe net	452.8	508.7	---	490.7	---
Net Plant Heat Rate, Btu/kWh	7822	7999	+2.3	10,348	-22.7
Total Plant Cost, $/kW	907.1	949.6	+4.7	1417.2	-33.0
Total Plant Investment, $/kW	981.6	1027.6	+4.7	1554.0	-33.9
Total Capital Requirement, $/kW	1038.0	1085.7	+4.6	1633.3	-33.6
First Year Costs:					
Total O&M, $/kW·yr	38.0	39.2	+3.2	54.8	-28.5
Fixed O&M, $/kW·yr	24.7	25.5	+3.2	35.6	-28.4
Variable O&M, mills/kWh	2.34	2.41	+3.0	33.7	-28.5
Consumables, mills/kWh	3.37	2.98	-11.6	4.19	-28.9
Fuel Cost, mills/kWh	14.0	15.2	+8.6	19.7	-22.8
Levelized O&M:					
Fixed, $/kW·yr	43.2	44.5	+3.0	62.2	-28.5
Variable O&M, mills/kWh	4.1	4.2	+2.4	5.9	-28.8
Consumables, mills/kWh	5.9	5.2	-11.9	7.3	-28.8
Fuel, mills/kWh	26.6	28.9	+8.7	37.4	-22.7
Levelized Carrying Charge, $/kW·yr	179.6	187.8	+4.6	282.6	-33.5
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	79.1	+4.5	111.1	-28.8

storage, accounts for nearly half of the higher total lignite plant cost. The balance of the increase is attributed to a one-third larger ash handling system, an 11-percent larger steam cycle, and increased topping combustor and gas turbine costs (fuel gas flow rate is twice as large and gas turbine inlet temperature 58°F higher than in the baseline plant). Of all the entries shown in Table 92, the consumables category, which reflects the difference between lower sorbent and increased coal dryer fuel oil costs, is the only one in which the lignite plant costs are lower than the baseline. Despite this, the lignite-fired second-generation PFB plant is very attractive vis-a-vis a PC-fired plant designed for the same lignite. Compared with the PC-fired plant, the lignite-fired PFB total plant costs and COE are 33.0 and 28.8 percent lower respectively. The major reasons for the lower total plant costs are the higher PC-fired plant flow rates (25 percent coal and 96 percent waste), 40 percent higher boiler costs, 40 percent higher gas cleanup costs, and one-third larger boiler building structure volume. Although the PC-fired plant sorbent flow rate is about one-third that of the lignite plant (12,828 vs. 35,984 lb/h), the differences in coal and waste flow rates are about five to six times larger, and the PC-fired plant requires two additional operators.

Discussion. Compared with the baseline plant, the lignite-fired carbonizers operate with considerably higher air-to-coal/carbon ratios, the ratios increasing with higher moisture content in the lignite. When the air-to-coal ratio increases, carbonizer tar and char consumption rises and releases the additional heat required to vaporize the high moisture content of the lignite and superheat it to 1500°F. For a given coal, increased carbonizer char consumption lowers the steam cycle heat input via the CPFBC/FBHE; and an increase in the carbonization feed rate is needed to return the steam cycle heat input to its previous value. Since a need for additional fuel gas results, the topping combustor temperature increases. Hence, increased fuel moisture content via reduced drying or water injection (slurry feed) will result in higher carbonizer air-to-coal feed rates and higher optimum topping combustor temperatures. Because of differing fuel gas qualities and yields and differing char CPFBC heat release rates per pound of coal carbonized, lignite-fired plant performance is optimal at topping combustor temperatures different from the baseline plant (1980°F and 2158°F vs. 2100°F). When performance of fuels with differing with different fuel moisture content is compared, the lightly dried or higher moisture lignite results in a higher topping combustor temperature, a higher gas turbine-to-steam turbine power ratio, and hence a higher efficiency. Despite its higher stack moisture loss, the efficiency of the plant using lightly dried lignite is within 1 percent of the baseline plant (42.66 vs. 43.63) because of the useful power produced by the expansion of the fuel moisture through the gas turbine.

Comparison of the lightly dried lignite and baseline second-generation PFB plants with their comparable PC-fired plant reveals that the lignite-fueled PFB yields the larger increase in efficiency (9.68 vs. 7.73 percentage points) and the larger COE reduction (28.8 vs. 18.8 percent). Although both PFB plants operate with 1500°F carbonizers, the lignite plant carbonizer air-to-coal ratio is much higher, and hence a greater portion of its coal energy is transferred to its fuel gas. If the baseline plant were to be operated with the same lignite air-to-carbon ratio, its carbonizer temperature would be over 1600°F and its efficiency greater than 44.9 percent. If this increase in carbonization temperature proves excessive, the carbonizer temperature can be maintained at 1500°F by using coal/water slurry or water injection as a quench. Until further analysis is performed, we are not certain whether second-generation PFB plants will be more advantageous with low- or high-grade fuels. In either event, second-generation PFB plants will generate electricity from lignite coal at a much lower cost than a lignite PC-fired plant.

6.5 ALTERNATIVE FEED SYSTEMS

6.5.1 Undried Coal and Sorbent

Plant Performance and Equipment Changes. Coal and dolomite are injected into the baseline plant carbonizer by lock-hopper-type, dense-phase, pneumatic-transport feed systems. To ensure proper flow of the coal and dolomite, the feed system manufacturer limits feedstock surface moisture to approximately 1 percent. Although the dolomite surface moisture is normally less than 1 percent, this value can be exceeded during wet weather. Since the coal will most always require drying, both coal and sorbent drying systems have been incorporated in the plant. In the event a feed system could be developed to handle coals with as-received surface moisture, an analysis was performed to determine the effect of feedstock moisture on plant performance and economics. To show this effect clearly, the topping combustor temperature was kept at the baseline plant value of 2100°F.

The carbonizer yields and heating values predicted for the undried feedstocks are presented in Figure 108; as expected, they are very similar to those of the baseline plant. Figure 109 presents the heat and material balance for the plant when operating with as-received moisture levels of 6 percent for the Pittsburgh No. 8 coal and 0.5 percent for the Plum Run dolomite. Tables 93 and 94 present detailed performance and equipment data for the plant and compare them with the baseline data. The plant output is reduced by approximately 20 MWe (432.82 vs. 452.76 MWe), and the efficiency is 1.37 percentage points lower than the baseline plant (42.26 vs. 43.63 percent).

Aside from the elimination of the drying systems, the PFB combustion island component arrangements are identical to those of the baseline plant, but physical dimensions differ slightly because of flow rate differences. For instance, the coal, sorbent, and ash flow rates are about 5 percent lower; the carbonizer fuel gas volumetric flow rate is roughly 3 percent higher than the baseline, necessitating about a 1-percent increase in the carbonizer I.D. The CPFBC flue gas volumetric flow rate is about 0.5 percent lower, and its diameters remain essentially at baseline values. Similarly, the carbonizer and CPFBC vessel heights remain unchanged from baseline plant values. Compared with the baseline, the CPFBC FBHE duty is reduced by roughly 18 percent, requiring a 5-percent decrease in its heat-transfer surface area. Although the HRSG duty is about 0.25 percent lower, its required surface area is about 46 percent higher because of smaller temperature differences caused by increased steam flow and slightly reduced gas turbine discharge temperature and gas flow rate.

COE Results. The COE results are compared with the baseline plant in Table 95. Although the coal and sorbent drying systems have been eliminated and total plant costs lowered by about 0.5 percent, total plant costs expressed on a $/kW basis are 4 percent higher because of the lower electrical output of the plant. The lower output and efficiency associated with the undried feedstocks are reflected in all the values except consumables, in which the oil needed for coal drying is eliminated.

Discussion. Compared with the baseline plant, the undried feedstock plant operates with a slightly higher carbonizer air-to-coal ratio to provide additional heat for vaporizing the feedstock moisture and superheating it to 1500°F. Since this higher airflow raises carbonizer char consumption, and since the carbonizer coal flow is not raised as compensation (topping combustor temperature is kept constant), the heat transferred to the steam cycle via the CPFBC FBHE is reduced by

Fuel Gas Flow (lb/h)	187.854
HHV (Btu/lb)	1911
LHV (Btu/lb)	1766
LHV (Btu/sft^3)	123

Char-Sorbent Flow (lb/h) = 80.646

	Char	Coke	Spent Dolomite
Carbon	39.624	6.487	6.006 MgO
Hydrogen	0.539	0.021	12.458 $CaCO_3$
Sulfur	1.603	0.022	2.400 CaS†
Nitrogen	0.722	0.016	0.493 Inerts
Oxygen	0.302	0.013	---
Moisture	---	---	
Ash	9.940		

HHV (Btu/lb)	8938
LVH (Btu/lb)	8876

Tar (Flow Rate = 1.931 lb/h)

Atomic Composition:

$CH_{.54}O_{.018}N_{.010}S_{.0082}$

HHV (Btu/lb)	15,800
LHV (Btu/lb)	15,410

Gas (wt%)* (Flow Rate = 185.923 lb/h)

CO	8.434
CO_2	20.955
H_2O	8.162
H_2	0.614
CH_4	2.318
C_2's	2.026
NH_3	0.297
H_2S	0.087
N_2	57.107
HHV (Btu/lb)	1767
LHV (Btu/lb)	1624

CARBONIZER
14 atm
1500°F

70°F

711°F

70°F

Pittsburgh Coal (Ultimate, wt%) (Flow Rate = 100 lb/h)

Carbon	69.36
Hydrogen	4.52
Sulfur	2.89
Nitrogen	1.21
Oxygen	6.08
Moisture¶	6.00
Ash	9.94
HHV (Btu/lb)	12,452
LHV (Btu/lb)	11,988

Air (Flow Rate = 139.50 lb/h)

Relative Humidity	50% at 70°F

Plum Run Dolomite (wt%) (Flow Rate = 29.0 lb/h Ca/S = 1.75)§

$CaCO_3$	54.5
$MgCO_3$	43.3
Moisture	0.5
Inerts	1.7

*Excludes tar.
†87.5% sulfur capture (92% of equilibrium H_2S capture).
§If based on sulfur release--Ca/S = 4.2.
¶As received.

Rev. B 10/8/87

Figure 108 1500°F Carbonizer Balance With Undried Coal and Sorbent

Dwg. 8333-1-400-009-105, Rev. C

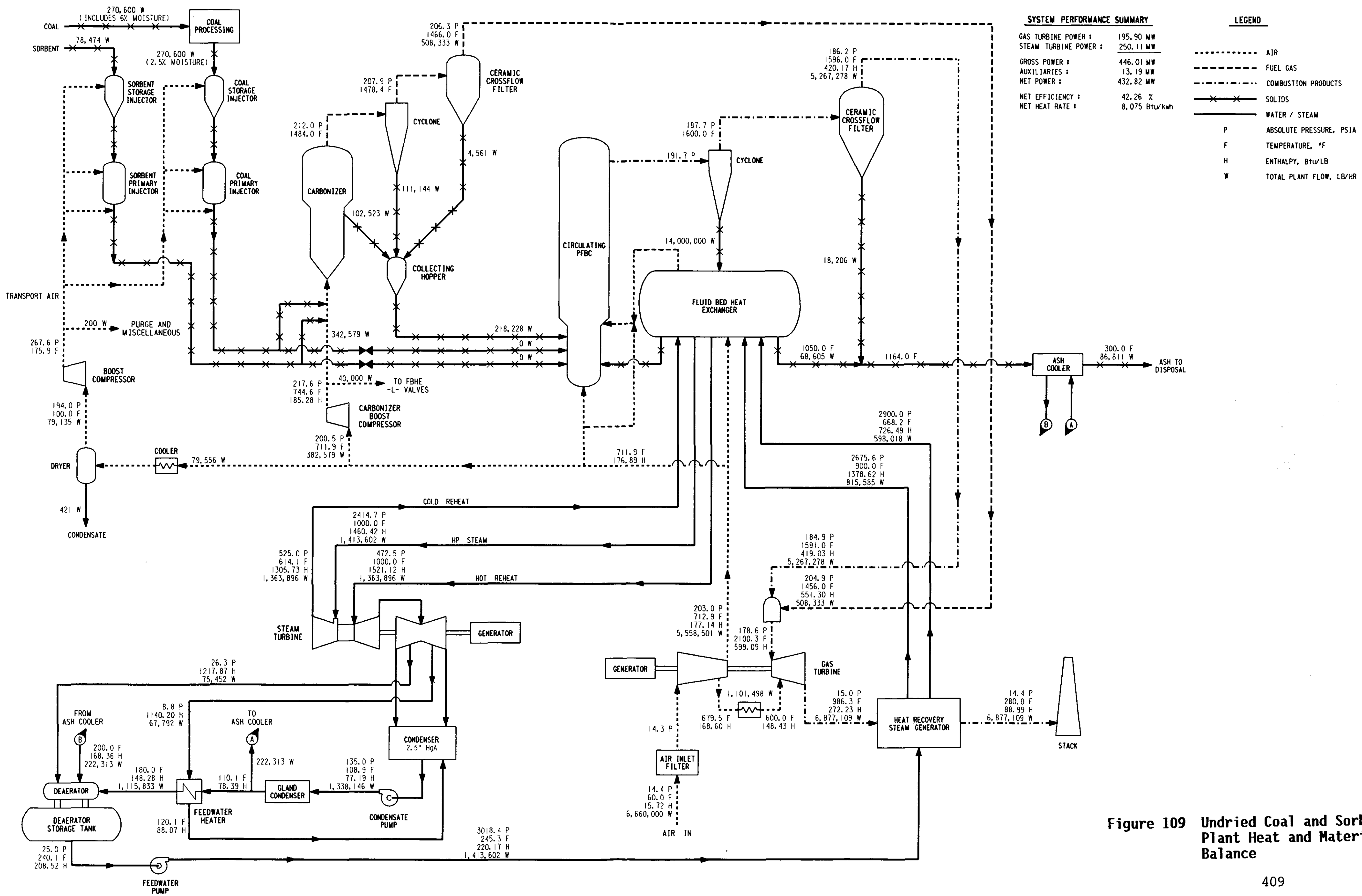


Figure 109 **Undried Coal and Sorbent Plant Heat and Material Balance**

Table 93 Performance Summary--Second-Generation Plant With Undried Coal and Sorbent

<u>Power Summary</u>	
Gas Turbine Power, kWe	95,899
Steam Turbine Power, kWe	250,111
Gross Power, kWe	446,010
Auxiliaries, kWe	(13,193)
Net Power, kWe	432,817
Net Efficiency, % (HHV)	42.26
Net Heat Rate, Btu/kWh	8075
<u>Consumables and Wastes</u>	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	270,600
As-Fired Coal Feed, lb/h (Includes 6.0% moisture)	270,600
Dolomite Feed, lb/h	78,474
Ash Production, lb/h	86,811
Coal and Dolomite Drying Fuel, gal/h	---
<u>Auxiliary Summary, kWe</u>	
Transport Boost Compressor	438
Carbonizer Boost Compressor	970
Condensate Pumps	202
Feedwater Pumps	4,972
Boiler Forced Circulation Pumps	230
Circulating Water Pumps	3,185
Cooling Tower Fans	822
Coal Dryer Forced-Draft Fan	---
Coal Dryer Induced-Draft Fan	---
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	444
Gas Turbine Intercooler Fan	15
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	161
Coal Handling	330
Dolomite Handling	65
Coal and Sorbent Feed	31
Ash Cooling and Handling	101
Service Water	94
Miscellaneous	668
Stepdown Transformer	66
Total Auxiliaries	13,193

Table 94 Second-Generation Plant Performance With and Without Feedstock Drying

	Second-Generation Plant	
	Baseline (Dried Feedstock)	Undried Feedstock
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	446.01
Auxiliaries, MWe	14.73	13.19
Net Power, MWe	452.76	432.82
Net Plant Efficiency, % (HHV)	43.63	42.26
Net Plant Heat Rate, Btu/kWh	7822	8075
As-Received Coal Feed, lb/h	284,410	270,600
Dolomite Feed, lb/h	82,315	78,474
Ash Production, lb/h	91,144	86,811
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2100.3
Generator Output, MWe per Module	97.58	97.95
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	104.52
Superheating	186.27	148.29
Reheating	160.60	146.88
Total FBHE Duty (per module), 10^6 Btu/h	488.82	399.69
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	623.81
UA, 10^6 Btu/h·°F per Module	10.501	15.374
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1413.60
Generator Output, MWe	272.34	250.11
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1226.52

Table 95 Baseline and Undried Feedstock Plant Economic Data

	Second-Generation Plant Configuration		
	Baseline (Dried Feedstock)	Undried Feedstock	Percentage Change
Unit Size, MWe net	452.8	432.8	---
Net Plant Heat Rate, Btu/kWh	7822	8075	+3.2
Total Plant Cost, $/kW	907.1	942.8	+3.9
Total Plant Investment, $/kW	981.6	1020.2	+3.9
Total Capital Requirement, $/kW	1038.0	1078.2	+3.9
First Year Costs:			
Total O&M, $/kW·yr	38.0	39.6	+4.2
Fixed O&M, $/kW·yr	24.7	25.6	+3.6
Variable O&M, mills/kWh	2.34	2.44	+4.3
Consumables, mills/kWh	3.37	3.19	-5.3
Fuel Cost, mills/kWh	14.0	14.5	+3.6
Levelized O&M:			
Fixed, $/kW·yr	43.2	44.9	+3.9
Variable O&M, mills/kWh	4.1	4.3	+4.9
Consumables, mills/kWh	5.9	5.6	-5.1
Fuel, mills/kWh	26.6	27.5	+3.4
Levelized Carrying Charge, $/kW·yr	179.6	186.5	+3.8
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	78.0	+3.0

18 percent. An overall 8-percent reduction in steam cycle duty results, leading to a 22-MWe reduction in steam turbine power output--the chief cause of the lower plant electrical output.

An improvement in plant efficiency of about 0.25 percentage points could be achieved if the heat rejected by the gas turbine cooling air intercooler were utilized to heat feedwater. In the baseline plant, the air used to cool this intercooler provides heat to the coal dryers, while this heat is rejected in the plant using undried coal. However, from an operating point of view, recovery of this heat with feedwater is not advisable, since leakage of the 2900 psi feedwater would result in water droplets being entrained in the turbine cooling air, risking potentially catastrophic damage to the gas turbine. If another use for the hot air were found, then some improvement in plant efficiency would be realized.

The results of the other sensitivity study cases dealing with high-moisture fuels, such as lignite and coal/water slurry, indicate that an increase in feedstock moisture requires an increase in the topping combustor temperature to achieve maximum plant efficiency. Thus if undried coal could be fed to the carbonizer, the plant should be designed for a higher gas turbine firing temperature, resulting in a net plant output somewhat higher than the baseline plant output and a net plant efficiency comparable to the baseline. A corresponding improvement in COE would also result. However, this is a moot point for the time being, as reliable pneumatic transport of coal with significant surface moisture has not been demonstrated.

6.5.2 Coal/Water Slurry Feed

Plant Performance and Equipment Changes. Figure 110 presents the yields and compositions predicted for a 14 atm/1500°F carbonizer operating with a 70-percent coal/30-percent water slurry feed. The slurry is formed from Pittsburgh No. 8 coal crushed to the distribution shown in Table 96, with water added in the proportion shown in Figure 111--no reagents or surfactants are added. Dolomite is pneumatically injected into the carbonizer. Because of the quenching effect of the slurry, the carbonizer air-to-carbon feed ratio increases by about 55 percent to maintain the 1500°F temperature. This higher airflow consumes the tar and lowers the char yields/volatile content.

Compared with the baseline plant, the fuel gas yield is 22 percent higher, but its heating value drops by 19 percent to 1475 Btu/lb.

Figure 112 depicts the heat and material balance for the new plant and Tables 97 and 98 present detailed performance and equipment data. Because of the lower char heat release and FBHE steam duty per pound of coal carbonized, the carbonizer coal flow rate increases by about 20 percent and the optimum topping combustor temperature increases to 2406°F. This change raises the gas turbine power output by 34 percent (261.6 vs. 195.2 MWe), the steam turbine output by 11 percent (303.6 vs. 272.3 MWe), and the overall plant output by 21 percent (547.6 vs. 452.8 MWe). The gas turbine-to-steam turbine power ratio increases by about 20 percent, and the overall plant efficiency increases by 0.52 percentage points (44.15 vs. 43.63 percent). The carbonizer and CPFBC bed operating conditions and sulfur-capture efficiencies remain essentially at baseline plant values.

With the exception of the coal preparation and feed systems, the PFB combustion island component arrangements are identical to those of the baseline plant, but some physical dimensions are changed because of flow rate differences. The carbonizer fuel gas volumetric flow rate is roughly 106 percent higher than in the baseline plant, necessitating about a 44-percent increase in its I.D.; the fuel gas piping, valves, and MASB sizes are increased accordingly. The CPFBC flue gas

Fuel Gas Flow (lb/h)	218.467
HHV (Btu/lb)	1613
LHV (Btu/lb)	1475
LHV (Btu/sft^3)	101

Char-Sorbent Flow (lb/h) = 50.440

	Char	Coke	Spent Dolomite	
Carbon	24.608	0.748	4.422	MgO
Hydrogen	0.300	0.002	9.363	$CaCO_3$
Sulfur	1.149	0.003	1.639	CaS†
Nitrogen	0.518	0.002	0.363	Inerts
Oxygen	0	0.001	---	
Moisture	---	---	---	
Ash	7.322	---	---	

HHV (Btu/lb) 7960
LVH (Btu/lb) 7907

Tar (Flow Rate = 0.222 lb/h)

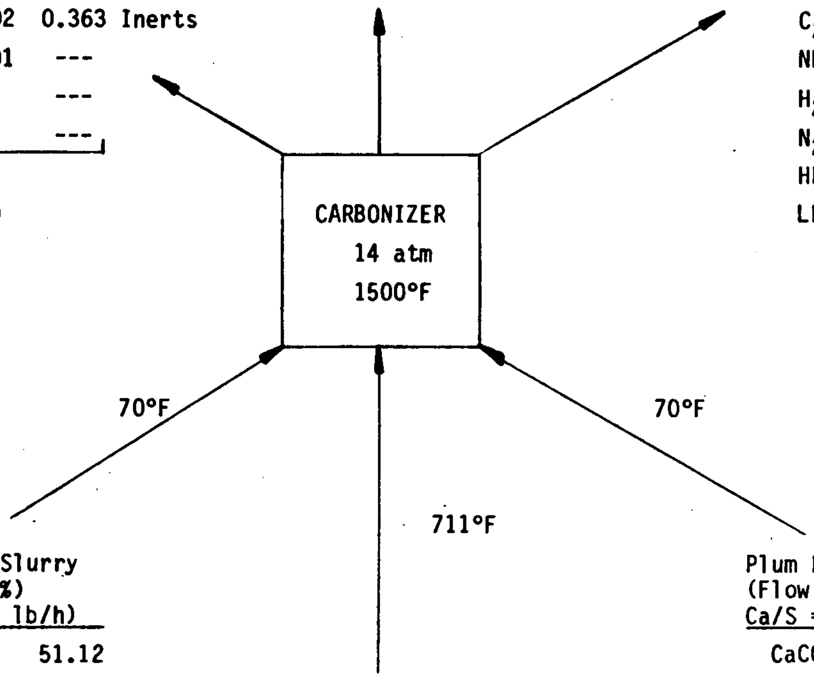
Atomic Composition:

$CH_{.54}O_{.0.18}N_{.01}S_{.0082}$

HHV (Btu/lb) 15,800
LHV (Btu/lb) 15,433

Gas (wt%)* (Flow Rate = 218.245 lb/h)

CO	5.773
CO_2	24.425
H_2O	13.223
H_2	0.568
CH_4	2.534
C_2's	1.698
NH_3	0.207
H_2S	0.118
N_2	51.454
HHV (Btu/lb)	1599
LHV (Btu/lb)	1461



Pittsburgh Coal Slurry (Ultimate, wt%) (Flow Rate = 100 lb/h)

Carbon	51.12
Hydrogen	3.33
Sulfur	2.13
Nitrogen	0.89
Oxygen	4.48
Moisture	30.73
Ash	7.32
HHV (Btu/lb)	9176
LHV (Btu/lb)	8571

Air (Flow Rate = 147.55 lb/h)

Relative Humidity 50% at 70°F

Plum Run Dolomite (wt%) (Flow Rate = 21.357 lb/h Ca/S = 1.75)§

$CaCO_3$	54.5
$MgCO_3$	43.3
Moisture	0.5
Inerts	1.7

*Excludes tar.
†75% sulfur capture.
§If based on sulfur release--Ca/S = 3.8.

Rev. D 9/14/87

Figure 110 1500°F Carbonizer Balance With 70:30 Coal/Water Slurry Feed

Table 96 Size Distribution of Pittsburgh No. 8 Slurry Coal (Nominal 1/8 in. x 0 Coal Size)

Size (microns)	wt% Above Indicated Size
3300	<0.1
1700	14.2
1000	24.3
850	28.7
500	36.8
250	46.7
125	56.6
63	66.2
51	66.8
40	69.1
32	72.4
25	75.9
20	79.6
16	82.9
10	88.1
5	93.7
2	97.8

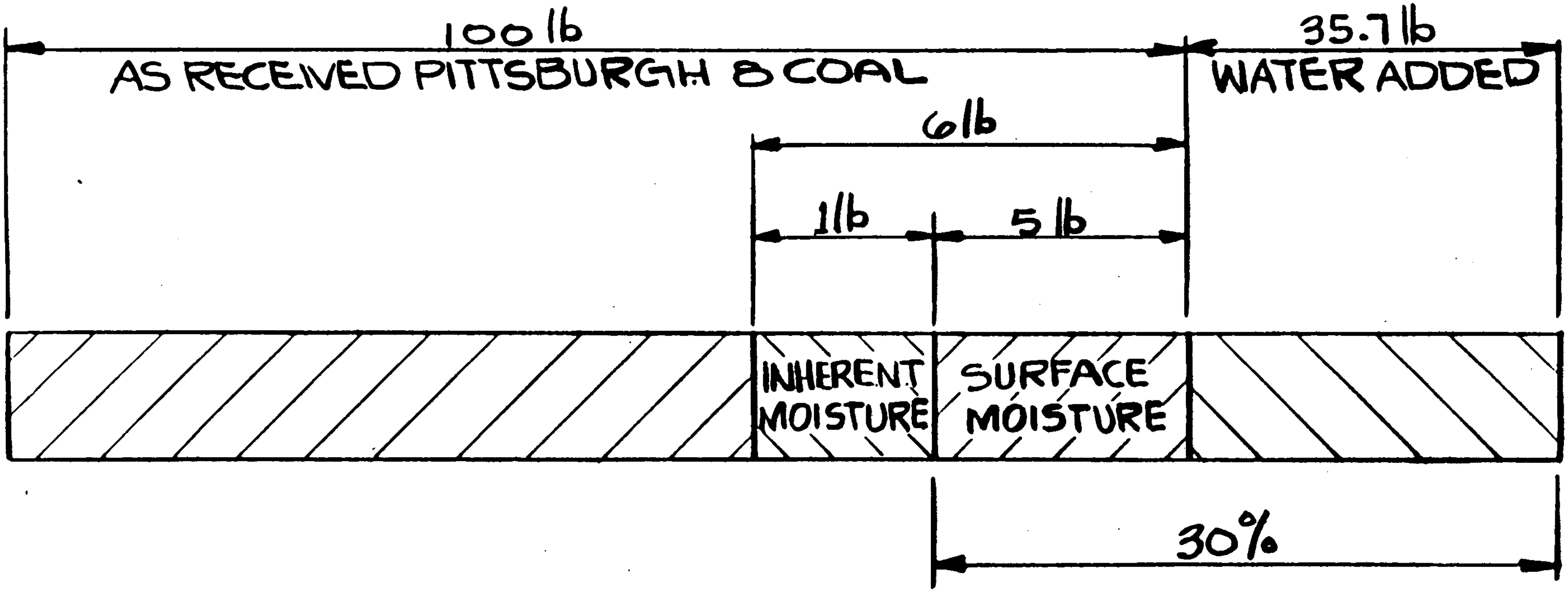


Figure 111 Pittsburgh No. 8 Coal/Water Slurry Composition

Dwg. 8333-1-400-009-112, Rev. B

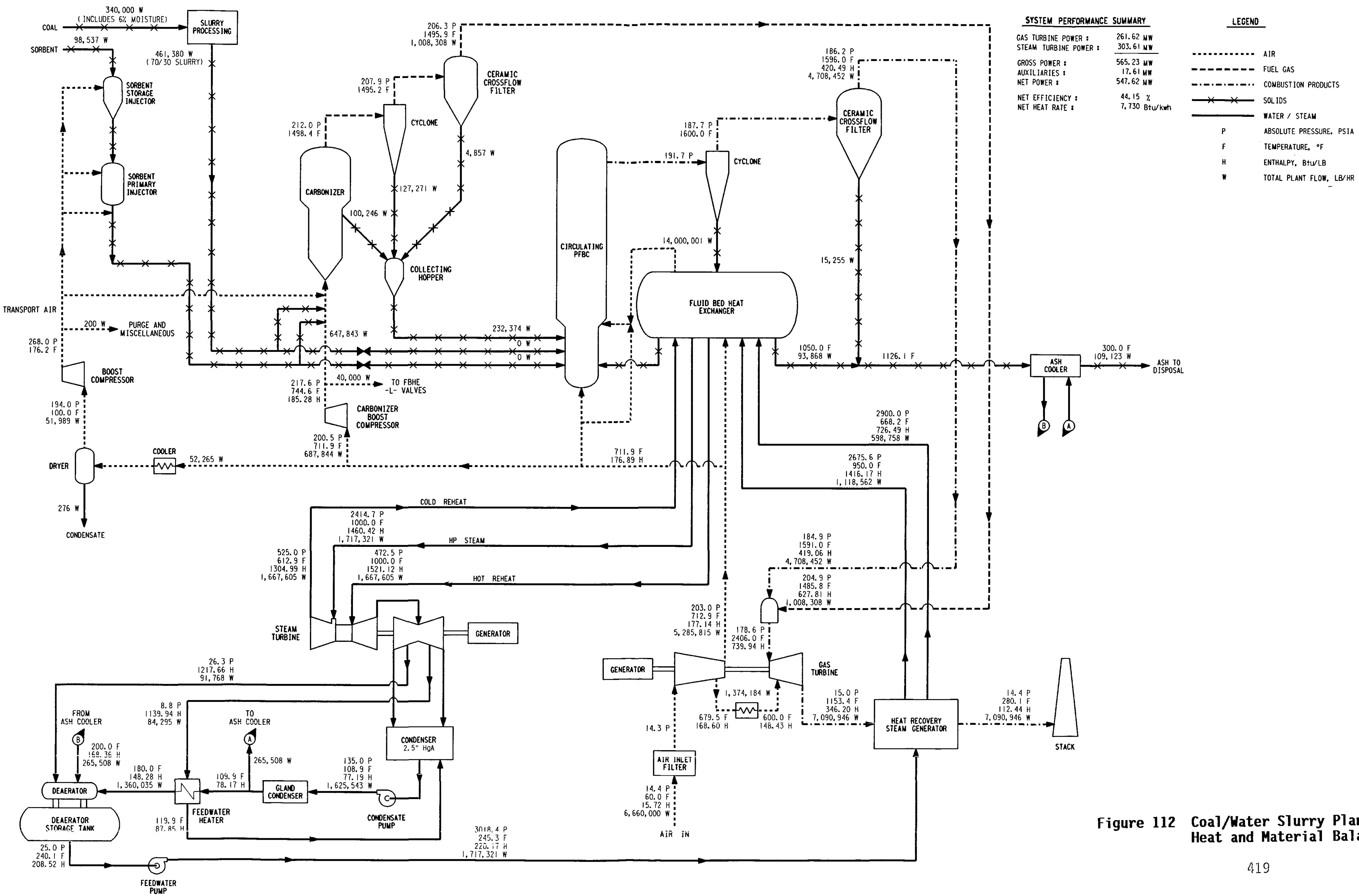


Figure 112 Coal/Water Slurry Plant Heat and Material Balance

Table 97 Coal/Water Slurry-Fueled Second-Generation Plant Performance Summary

<u>Power Summary</u>	
Gas Turbine Power, kWe	261,620
Steam Turbine Power, kWe	303,612
Gross Power, kWe	565,232
Auxiliaries, kWe	(17,607)
Net Power, kWe	547,625
Net Efficiency, %(HHV)	44.15
Net Heat Rate, Btu/kWh	7730
<u>Consumables and Wastes</u>	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	340,000
Coal Slurry Feed, lb/h	461,380
Dolomite Feed, lb/h	98,537
Ash Production, lb/h	109,123
Coal and Dolomite Drying Fuel, gal/h	---
<u>Auxiliary Summary, kWe</u>	
Transport Boost Compressor	289
Carbonizer Boost Compressor	1,745
Condensate Pumps	246
Feedwater Pumps	6,041
Boiler Forced Circulation Pumps	228
Circulating Water Pumps	3,862
Cooling Tower Fans	997
Coal Dryer Forced-Draft Fan	---
Coal Dryer Induced-Draft Fan	---
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	539
Gas Turbine Intercooler Fan	19
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	202
Coal Handling	415
Dolomite Handling	81
Coal and Sorbent Feed	9
Ash Cooling and Handling	127
Slurry Preparation	1,362
Service Water	118
Miscellaneous	839
Stepdown Transformer	88
Total Auxiliaries	17,607

Table 98 Comparison of Baseline and Coal/Water Slurry Fueled Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline, Dry, Pneumatic Feed	Coal/Water Slurry Feed
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	565.23
Auxiliaries, MWe	14.73	17.61
Net Power, MWe	452.76	547.62
Net Plant Efficiency, % (HHV)	43.63	44.15
Net Plant Heat Rate, Btu/kWh	7822	7730
As-Received Coal Feed, lb/h	284,410	340,000
Dolomite Feed, lb/h	82,315	98,537
Ash Production, lb/h	91,144	109,123
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2406.0
Generator Output, MWe per Module	97.58	130.81
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	104.27
Superheating	186.27	139.83
Reheating	160.60	180.22
Total FBHE Duty (per module), 10^6 Btu/h	488.82	424.32
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	820.49
UA, 10^6 Btu/h·°F per Module	10.501	9.720
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1717.32
Generator Output, MWe	272.34	303.61
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1487.46

volumetric flow rate, in contrast, is roughly 11 percent lower and requires about a 6-percent reduction in its I.D. The gas turbine discharge flow is increased by only 3 percent, and the carbonizer and CPFBC vessel heights remain similar to those in the baseline plant. Compared with the baseline plant, the CPFBC FBHE duty is roughly 13 percent lower, requiring a 6-percent decrease in its heat-transfer surface area. The 165°F higher gas turbine discharge temperature improves HRSG temperature differences and, despite a 50°F increase in superheater outlet temperature (950 vs. 900°F), enables a 7-percent reduction in the HRSG surface area. Because of the 20-percent increase in coal feed rate, the spent bed material/ash depressurizing, cooling, and storage systems are similarly 20 percent larger.

The equipment required for the coal/water slurry feed system is divided into two groups:

- Preparation and storage
- Transport

The preparation and storage subsystem is illustrated schematically in Figure 113. It utilizes two 100-percent capacity weigh-belt feeders (170 t/h capacity each) and two 100-percent capacity crushers that turn 2 in. x 0 as-received coal into a -1/8 in. product. Each crusher discharges to a vibrating screen, the oversized material being returned to the crusher inlet and the acceptable material proceeding on to the coal/water slurry tank, where it is mixed with water and maintained in suspension by a central mixer. Each tank has a 1-hour holding capacity when full, and sufficient equipment and excess capacity ensure smooth, continuous operation in the event of equipment failure or during maintenance. During normal operation, both trains can be operated at 50-percent capacity, or one train can be operated at full capacity (depending on plant demand) with the other shut off.

The coal/water slurry transport system is illustrated in Figure 114. Each carbonizer requires a full-load flow rate of approximately 400 gal/min; each has three 50-percent capacity pumps (200 gal/min each), the third pump serving as a spare. The pumps selected for this service are of the progressive cavity type and are equipped with variable speed drives. Each carbonizer may be fed by any two pumps operating at full capacity or all three pumps operating at reduced capacity. For start-up or low-load operating conditions, the coal/water slurry can be pumped to the CPFBC by these same pumps.

Each 50,000-gal coal/water slurry storage tank is provided with an 800-gal/min circulation pump that can transfer slurry to disposal or to the other storage tank. In addition, these pumps may be used to circulate CWS out of a storage tank and back into the same storage tank to enhance solids suspension or to temporarily substitute for a failed tank mixer.

<u>COE Results</u>. The coal/water slurry-fueled plant COE analysis is presented in Table 99 along with baseline plant values. The slurry-fueled plant COE is 6.1 percent or 4.6 mills/kWh lower than the baseline plant. Even though the 21-percent higher electrical output provides the coal/water slurry-fueled plant with a slight economy-of-scale advantage, the major contributor to the cost advantage is the coal preparation and feed system cost which is $38/kW lower than the baseline plant.

<u>Discussion</u>. Similar to the lignite-fueled plant, the coal/water slurry-fueled plant operates with a considerably higher carbonizer air-to-coal ratio than the baseline plant. The higher airflow increases carbonizer tar and char consumption and provides the additional heat required to vaporize the slurry water and superheat it to 1500°F. Since increased char consumption per pound of coal carbonized reduces the steam cycle heat input via the CPFBC/FBHE, the carbonizer coal

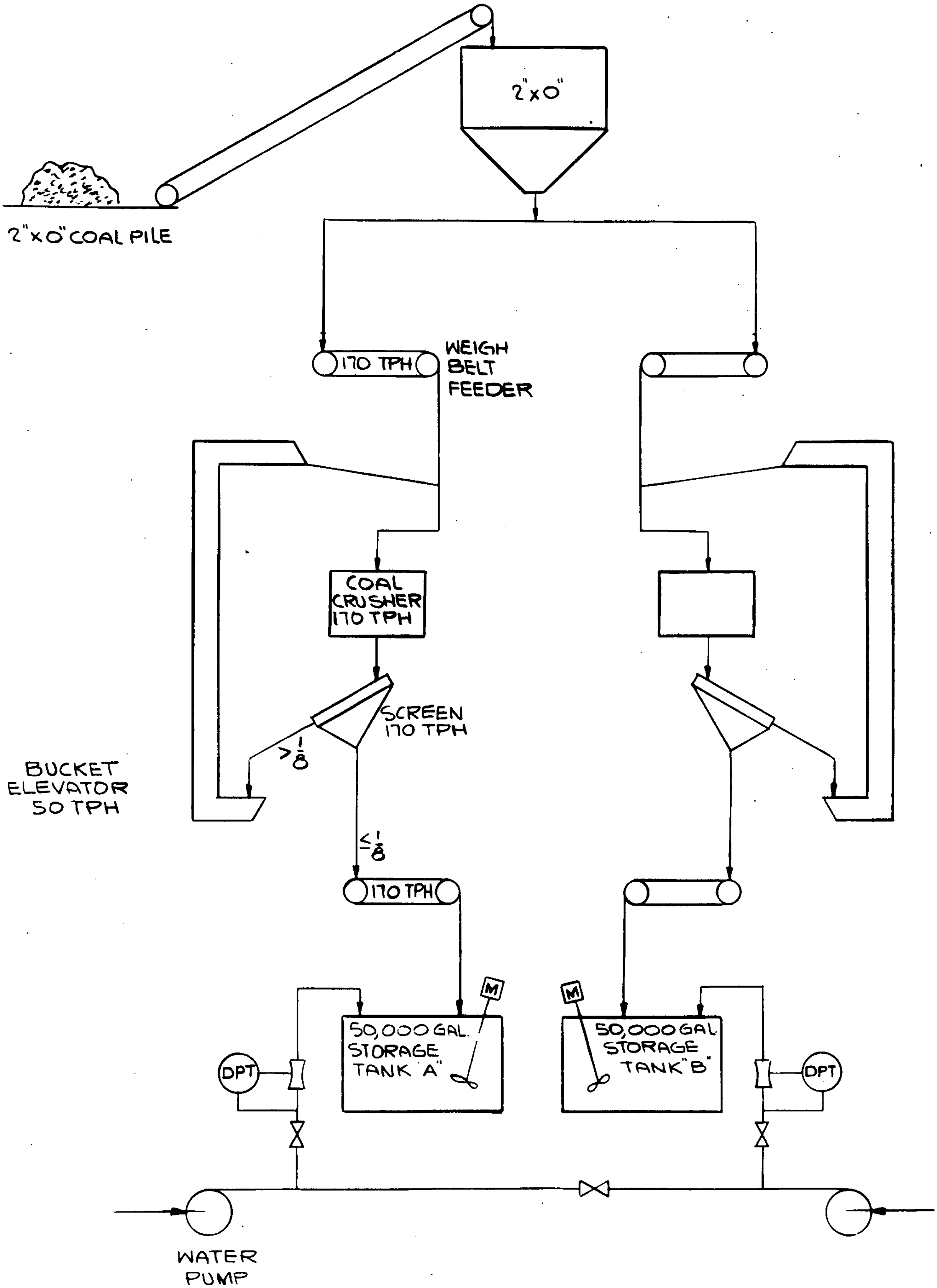


Figure 113 Coal/Water Slurry Preparation and Storage

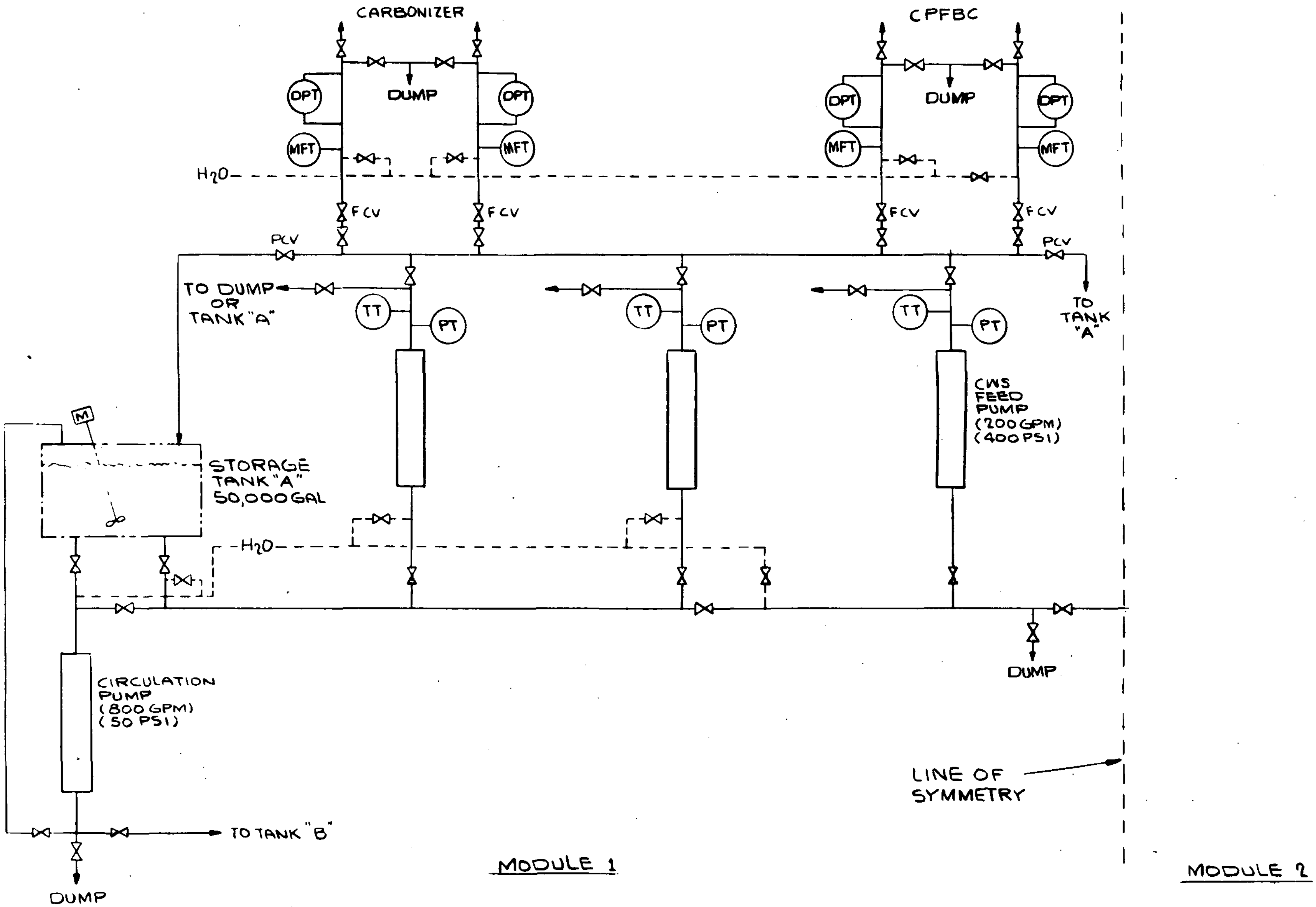


Figure 114 Coal/Water Slurry Transport System

Table 99 Comparison of Baseline and Coal/Water Slurry Fueled Plant Economic Data

	Second-Generation Plant Configuration		
	Baseline (Dry Coal Feed)	Coal Water Slurry Feed	Percentage Change
Unit Size, MWe net	452.8	547.6	---
Net Plant Heat Rate, Btu/kWh	7822	7730	---
Total Plant Cost, $/kW	906.1	839.3	-7.5
Total Plant Investment, $/kW	980.6	908.2	-7.5
Total Capital Requirement, $/kW	1037.0	961.2	-7.4
First Year Costs:			
Total O&M, $/kW·yr	38.0	33.2	-12.6
Fixed O&M, $/kW·yr	24.7	21.6	-12.6
Variable O&M, mills/kWh	2.34	2.04	-12.8
Consumables, mills/kWh	3.37	3.07	-8.9
Fuel Cost, mills/kWh	14.0	13.8	-14.3
Levelized O&M:			
Fixed, $/kW·yr	43.2	37.6	-13.0
Variable O&M, mills/kWh	4.1	3.6	-12.2
Consumables, mills/kWh	5.9	5.4	-8.5
Fuel, mills/kWh	26.6	26.3	-1.1
Levelized Carrying Charge, $/kW·yr	179.6	166.3	-7.4
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	71.1	-6.1

feed rate must increase to maintain the steam cycle conditions at 2400 psig/1000°F/1000°F. Even though the fuel gas heating value is reduced and diluted because the slurry water doubles its steam content, the fuel gas flow rate per pound of coal carbonized is significantly higher and the topping combustor temperature increases to 2406°F. The gas turbine output increases by 34 percent and its increased discharge temperature (1153°F vs. 988°F) and flow rate increase the HRSG steam cycle duty by 31 percent. Despite a 13-percent reduction in FBHE duty, the steam turbine output increases by 11 percent and the electrical output of the slurry-fueled plant is approximately 95 MWe higher than the baseline plant (547.6 vs. 452.8 MWe). The improved gas turbine-to-steam turbine power ratio more than compensates for the increased stack moisture loss, giving the slurry-fueled plant an efficiency 0.52 percentage points higher (44.15 vs. 43.63 percent) and a COE 4.6 mills/kWh lower than the baseline plant. Since the topping combustor (gas turbine inlet) temperature was increased to the value giving the slurry-fueled plant its optimum efficiency, the singular effects of coal/water slurry feed have not been identified. As with the plant using undried feedstock, if the topping combustor temperature had not been increased, the slurry-fueled plant would probably have shown a loss in efficiency and a much smaller change in COE. In any event, coal/water slurry feed appears attractive and should be investigated experimentally.

6.6 TIGHTENED PLANT EMISSIONS REGULATIONS

6.6.1 Sulfur-Capture Efficiency of 95 Percent

Plant Performance and Equipment Changes. The second-generation PFB combustion plant sulfur-capture efficiency can be increased to 95 percent by maintaining the CPFBC solids circulation rate at the baseline value and increasing the Ca/S feed rate to 3.0. Alternatively, the CPFBC vessel (secondary zone) height can be increased by 20 ft for a concomitant increase in gas residence time and sulfur capture and a reduction in the Ca/S feed ratio to 2.0. The second approach was selected for analysis because of its one-third lower sorbent flow rate and reduced waste-disposal requirements.

The carbonizer yields and heating values predicted for the baseline plant served as the starting point for this study case. Figure 115 presents the heat and material balance for the second-generation PFB plant operating with 95-percent sulfur-capture efficiency. The required 95-percent sulfur capture is achieved by increasing the plant calcium-to-sulfur molar feed ratio to 2.0 (from 1.75) and the CPFBC vessel height by 20 ft to gain an additional 1.5 seconds of gas residence time. These changes increase the carbonizer and CPFBC sulfur-capture efficiencies to 96.5 and 97.0 percent respectively and the carbonizer and CPFBC pressure losses by 0.9 and 4.3 psi respectively. The optimum topping combustor temperature is essentially unchanged at 2100°F. Detailed performance and equipment data for the plant are presented Tables 100 and 101. Compared with the baseline plant, the coal feed rate is about 1 percent higher, the net electrical output about 0.25 percent higher (454.0 vs. 452.8 MWe), and the efficiency about 0.5 percent lower (43.17 vs. 43.63 percent).

The PFB combustion island component arrangements are identical to those of the baseline plant, but physical dimensions differ slightly because of flow-rate differences. For instance, the carbonizer fuel gas volumetric flow rate is roughly 1-1/2 percent lower than in the baseline plant, necessitating less than a 1-percent decrease in carbonizer I.D. The CPFBC has a volumetric flow rate about 3-1/2 percent larger, requiring about a 2-percent increase in its I.D. The carbonizer bed and vessel heights are unchanged, but the CPFBC secondary zone and vessel heights are increased by 20 ft. Compared with the baseline plant, the CPFBC FBHE duty is

Dwg. 833-1-400-009-111, Rev. B

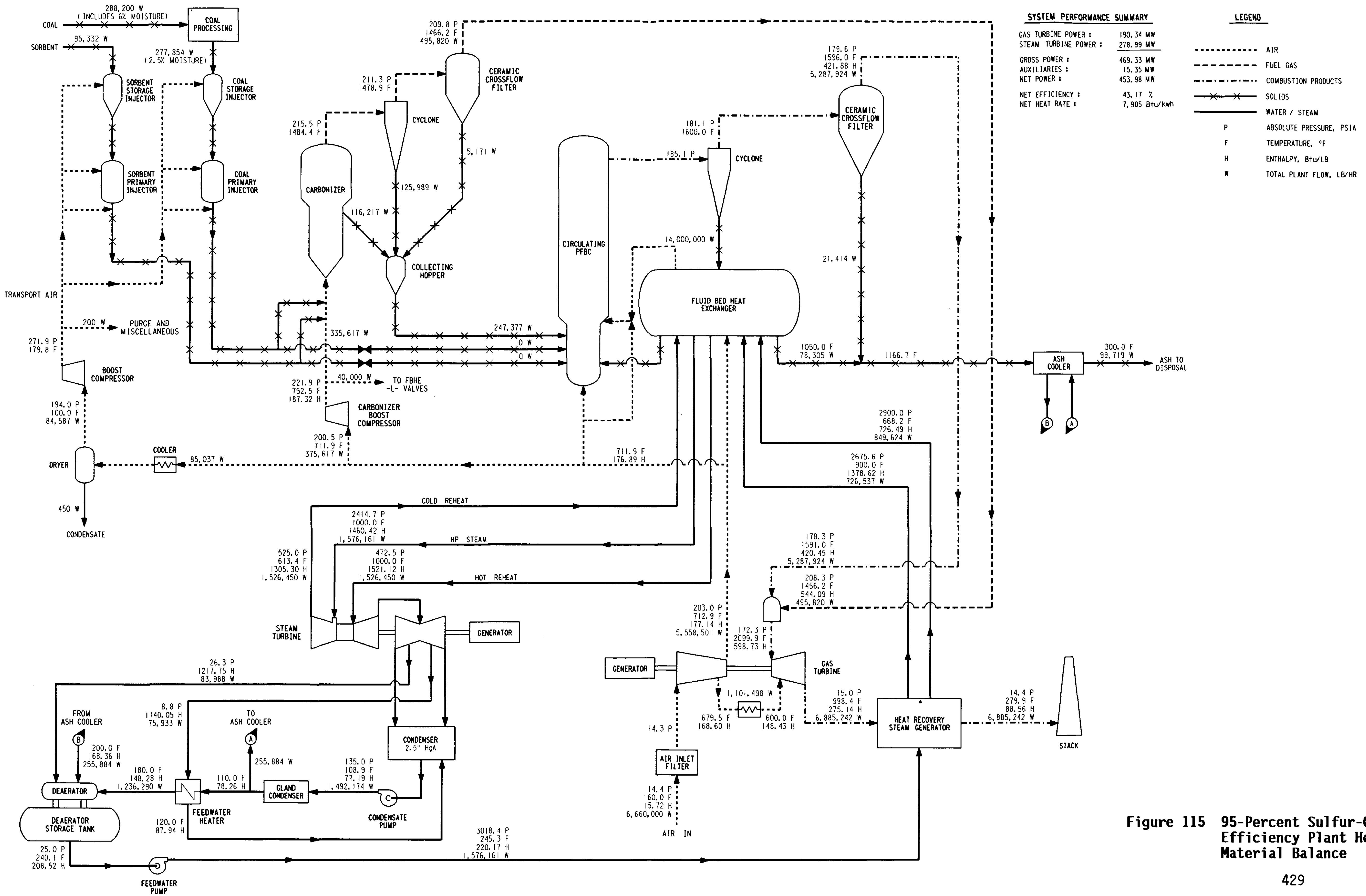


Figure 115 95-Percent Sulfur-Capture Efficiency Plant Heat and Material Balance

Table 100 95-Percent Sulfur-Capture Efficiency Plant Performance Summary

Power Summary	
Gas Turbine Power, kWe	190,340
Steam Turbine Power, kWe	278,985
Gross Power, kWe	469,325
Auxiliaries, kWe	(15,347)
Net Power, kWe	453,978
Net Efficiency, %(HHV)	43.17
Net Heat Rate, Btu/kWh	7905
Consumables and Wastes	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	288,200
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	277,854
Dolomite Feed, lb/h	95,332
Ash Production, lb/h	99,719
Coal and Dolomite Drying Fuel, gal/h	95
Auxiliary Summary, kWe	
Transport Boost Compressor	492
Carbonizer Boost Compressor	1,184
Condensate Pumps	225
Feedwater Pumps	5,544
Boiler Forced Circulation Pumps	329
Circulating Water Pumps	3,556
Cooling Tower Fans	918
Coal Dryer Forced-Draft Fan	304
Coal Dryer Induced-Draft Fan	241
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	495
Gas Turbine Intercooler Fan	15
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	177
Coal Handling	352
Dolomite Handling	79
Coal and Sorbent Feed	34
Ash Cooling and Handling	116
Service Water	100
Miscellaneous	711
Stepdown Transformer	76
Total Auxiliaries	15,347

Table 101 Comparison of Baseline and 95-Percent Sulfur-Capture Efficiency Plant Performance Data

	Second-Generation Plant Configuration: Baseline (90-Percent)	Second-Generation Plant Configuration: 95-Percent
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	469.33
Auxiliaries, MWe	14.73	15.35
Net Power, MWe	452.76	453.98
Net Plant Efficiency, %(HHV)	43.63	43.17
Net Plant Heat Rate, Btu/kWh	7822	7905
As-Received Coal Feed, lb/h	284,410	288,200
Dolomite Feed, lb/h	82,315	95,332
Ash Production, lb/h	91,144	99,719
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2099.9
Generator Output, MWe per Module	97.58	95.17
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	148.49
Superheating	186.27	193.00
Reheating	160.60	164.73
Total FBHE Duty (per module), 10^6 Btu/h	488.82	506.22
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	635.92
UA, 10^6 Btu/h·°F per Module	10.501	9.854
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1576.16
Generator Output, MWe	272.34	278.99
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1369.46

about 4 percent higher, requiring a minimal change in heat-transfer surface area. The gas turbine discharge temperature is 10.4°F higher, which permits reducing the HRSG heat-transfer surface by 6 percent, despite a 1.7-percent increase in its duty. The spent bed material/ash depressurizing, cooling, and storage equipment is slightly larger to reflect a 7-percent increase in solid waste flow rate.

Comparison With PC-Fired Plant With Scrubber. In Table 102 the performance of the 95-percent sulfur-capture efficiency second-generation PFB combustion plant is compared with that of a PC-fired plant using wet limestone FGD to achieve the same sulfur-removal efficiency. The PC-fired plant achieves 95-percent sulfur capture by a combination of higher:

- Adipic acid concentration
- pH (the stoichiometric ratio)
- Liquid-to-gas ratio.

This approach is derived from a study performed by Bechtel [2], based on test data from the EPA Shawnee Test Facility. The use of adipic acid to improve sulfur capture is optional for meeting present NSPS standards, but would be a requirement for improving sulfur-removal efficiency to 95 percent. The Shawnee data show that there are essentially no performance or economic penalties for designing a wet FGD for 95-percent sulfur capture, but the second-generation PFB combustion plant experienced a loss in efficiency of 0.46 percentage points. Despite this loss in efficiency, the second-generation plant operates with an efficiency 7.4 percentage points higher (43.2 vs. 35.8 percent) than the PC-fired plant. With regard to consumables, the second-generation plant sorbent requirement is 2-1/2 times that of the PC-fired plant, but water requirements are about 44 percent lower.

COE Results. The COE results for PC-fired and second-generation PFB combustion plants operating with 95-percent sulfur capture are presented in Table 103. When the sulfur capture increases to 95 percent, PC-fired and second-generation plant COEs rise by 0.6 and 1.0 mills/kWh respectively. The PC-fired plant rise is attributed to the adipic acid subsystem and its acid consumption; the PFB combustion plant increase is attributed to higher coal and sorbent flow rates. Compared with the PC-fired plant, the second-generation PFB combustion plant has a COE approximately 18 percent lower (76.7 vs. 93.8 mills/kWh).

Discussion. The second-generation PFB combustion plant sulfur-capture efficiency was increased to 95 percent by increasing the CPFBC gas residence time (vessel height) by about 1-1/2 seconds and the plant Ca/S feed ratio to 2.0. The taller CPFBC vessel increases the flue gas pressure loss and decreases the gas turbine inlet pressure by 6.3 psi. An alternative approach that should result in a lower loss of plant efficiency would be to keep the CPFBC vessel unchanged and increase the Ca/S feed ratio to 3.0. Since time did not permit a trade-off study, the lower sorbent consumption approach was selected. Even though it may not be the most economical design, the total proposed second-generation PFB combustion plant costs and COE are 24.0 and 18.2 percent lower respectively than those of a comparable PC-fired plant. Even if air emission regulations were to be tightened to the extent that allowable SO_2 emissions must be cut in half, the proposed second-generation PFB combustion plant would continue to be superior to that of PC-fired plants with wet FGD.

Table 102 **Comparison of Second-Generation and PC-Fired 95-Percent Sulfur Capture Plant Performance Data**

	PC-Fired Plant With Wet FGD	Second-Generation Plant
Overall Plant Performance		
Gross Power, MWe	540.4	469.3
Auxiliaries, MWe	39.6	15.3
Net Power, MWe	500.5	454.0
Net Plant Efficiency, %(HHV)	35.8	43.2
Net Plant Heat Rate, Btu/kWh	9525	7905
As-Received Coal Feed, lb/h	382,928	288,200
Sorbent Feed, lb/h		
Dolomite Feed	---	95,332
Limestone Feed	43,606	---
Lime Feed	2,019	---
Total Sorbent Feed	45,625	95,332
Waste Products, lb/h		
Ash and Spent Sorbent	7,612	99,719
Fixed Sludge	70,740	---
Total Waste Products	78,352	99,719
Water Consumption, 1000 gal/d		
Cooling Tower Makeup	9,979	5,345
Boiler Makeup and Miscellaneous	580	225
Flue Gas Desulfurization	662	---
Ash Pelletizer	---	158
Total Water Consumption	11,221	5,728

Table 103 Comparison of Second-Generation and PC-Fired Plant Economic Data for 95-Percent Sulfur Capture

	Second-Generation Plant			PC-Fired Plant With Wet FGD		
	Baseline (90-Percent Sulfur Capture)	95-Percent Sulfur Capture	Change From Baseline to 95-Percent Sulfur Capture, %	90-Percent Sulfur Capture	95-Percent Sulfur Capture	Second-Generation as a Percentage of PC-Fired Plant Values (Both With 95-Percent Sulfur Capture)
Unit Size, MWe net	452.8	454.0	---	500.9	500.8	---
Heat Rate, Btu/kWh	7822	7905	---	9515	9525	---
Total Plant Cost, $/kW	907.1	908.7	+0.2	1192.6	1195.3	76.0
Total Plant Investment, $/kW	981.6	983.3	+0.2	1307.7	1310.6	75.0
Total Capital Requirement, $/kW	1038.0	1040.7	+0.3	1375.3	1379.0	75.5
First Year Costs:						
Total O&M, $/kW·yr	38.0	38.1	---	45.6	45.7	83.4
Fixed O&M, $/kW·yr	24.7	24.7	---	29.7	29.7	83.2
Variable O&M, mills/kWh	2.34	2.34	---	2.8	2.8	83.6
Consumables, mills/kWh	3.37	3.71	---	2.85	3.12	118.9
Fuel Cost, mills/kWh	14.0	14.15	---	17.0	17.1	82.7
Levelized O&M:						
Fixed, $/kW·yr	43.2	43.2	+0.0	51.8	51.9	83.2
Variable O&M, mills/kWh	4.1	4.1	+0.0	4.9	4.9	83.7
Consumables, mills/kWh	5.9	6.5	+10.0	5.0	5.5	118.2
Fuel, mills/kWh	26.6	26.9	+1.1	32.4	32.4	83.0
Levelized Carrying Charge, $/kW·yr	179.6	180.0	+0.2	237.9	238.6	75.4
Levelized Busbar Cost, mills/kWh (at 65 percent capacity factor)	75.7	76.7	+1.3	93.2	93.8	81.8

6.6.2 NO_x at Half of NSPS Allowable

The baseline plant is expected to operate with an NO_x emission rate of 0.28 lb/10^6 Btu. Since this value is less than one-half of the NSPS-allowable value of 0.6 lb/10^6 Btu for bituminous coal and since lower NO_x emissions can be achieved by reducing the plant excess air (see minimum excess air case in Section 6.2.3), no analysis was performed. A one-half reduction in the presently allowed NSPS NO_x emission rate will have no effect on plant performance or economics.

6.6.3 Particulate at Half of NSPS Allowable

The baseline plant is expected to operate with a stack gas particulate release rate of 0.0006 lb/10^6 Btu. Since this value is much less than half of the particulate loading of 0.03 allowed according to NSPS, no analysis was performed. A one-half reduction in the presently allowed NSPS particulate emission rate will have no effect on plant performance or economics.

6.7 PRODUCTS OF COMBUSTION HARMFUL TO SYSTEMS: ALKALI "GETTER" SYSTEMS FOR PITTSBURGH AND LIGNITE COALS

Plant Performance and Equipment Changes. The baseline plant carbonizer and CPFBC operating temperatures have been set at values that are expected to preclude gas turbine alkali problems (i.e., 1500 and 1600°F respectively). Since PFB combustion gas alkali levels cannot yet be predicted with a high degree of certainty and since maximum permissible alkali limits have not yet been demonstrated for gas turbines operating with PFB gas, an analysis was undertaken to identify the impact of an alkali getter system on a second-generation PFB plant. The Pittsburgh No. 8 coal-fired plant was examined, followed by the Texas lignite-fired plant. In the Pittsburgh No. 8 case, getter systems were applied sequentially to identify the impact of each--first in the carbonizer gas stream and then in both the carbonizer and CPFBC gas streams. Since (as will be discussed later) a carbonizer fuel gas alkali getter system had a minimal effect on plant performance and economics, only the carbonizer/CPFBC alkali getter case was studied with lignite coal.

The alkali getters use packed beds of 1/4-in. thick by 1/2-in. diameter pellets of emathlite, an inexpensive, absorptive clay material. The clay reacts with alkali vapors to form an alkali aluminosilicate glass. The reaction occurs by adsorption of alkali vapors onto the outer surface of the pellets, followed by diffusion of the alkali across the product layer, and finally by reaction with fresh getter in the pellet interior. The getter pellets, located downstream of the HGCU to minimize plugging with ash, are contained in a refractory-lined pressure vessel. The vessel is filled with pellets that are replaced with fresh pellets twice each year. Detailed descriptions of alkali releases, vapor levels entering the gas turbine, and getter design details are given in Appendix C, Sections 5 and 6.

Pittsburgh Coal. Figures 116 and 117 illustrate heat and material balances for the baseline plant with alkali getters installed in the carbonizer gas stream only and in both the carbonizer and CPFBC gas streams. Tables 104, 105, and 106 present detailed performance and equipment data for the two plants, with their carbonizer performance remaining as predicted for the baseline. Both plants continue to operate with a 2100°F topping combustor temperature and both produce approximately 453 MWe of power. The carbonizer-only alkali getter system lowers plant efficiency by 0.03 percentage points (43.60 vs. 43.63 percent). Incorporation of the second, or CPFBC, getter system lowers the efficiency by another 0.09 percentage points (43.51 vs. 43.60 percent). The flow rates and operating conditions of the

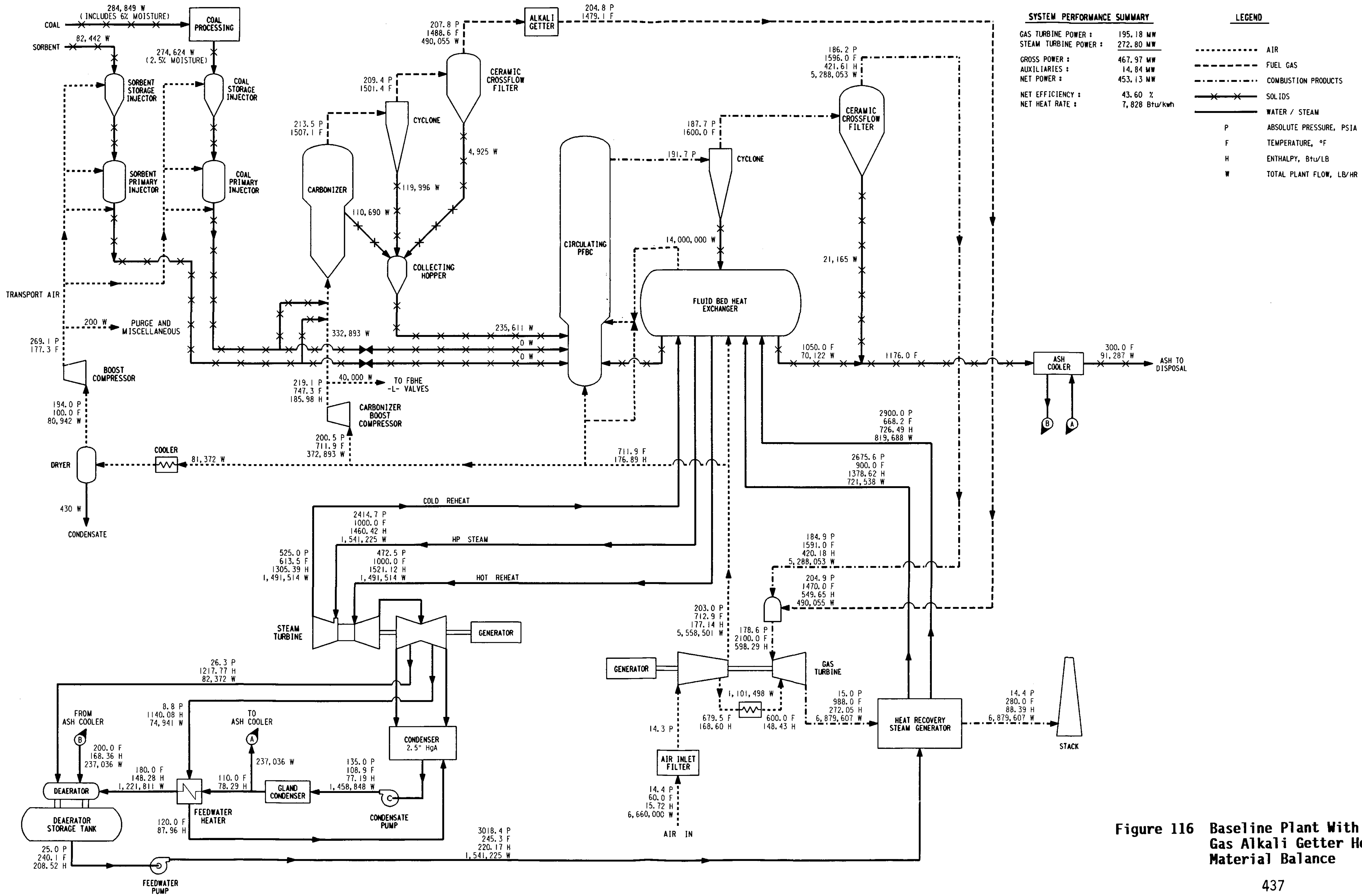
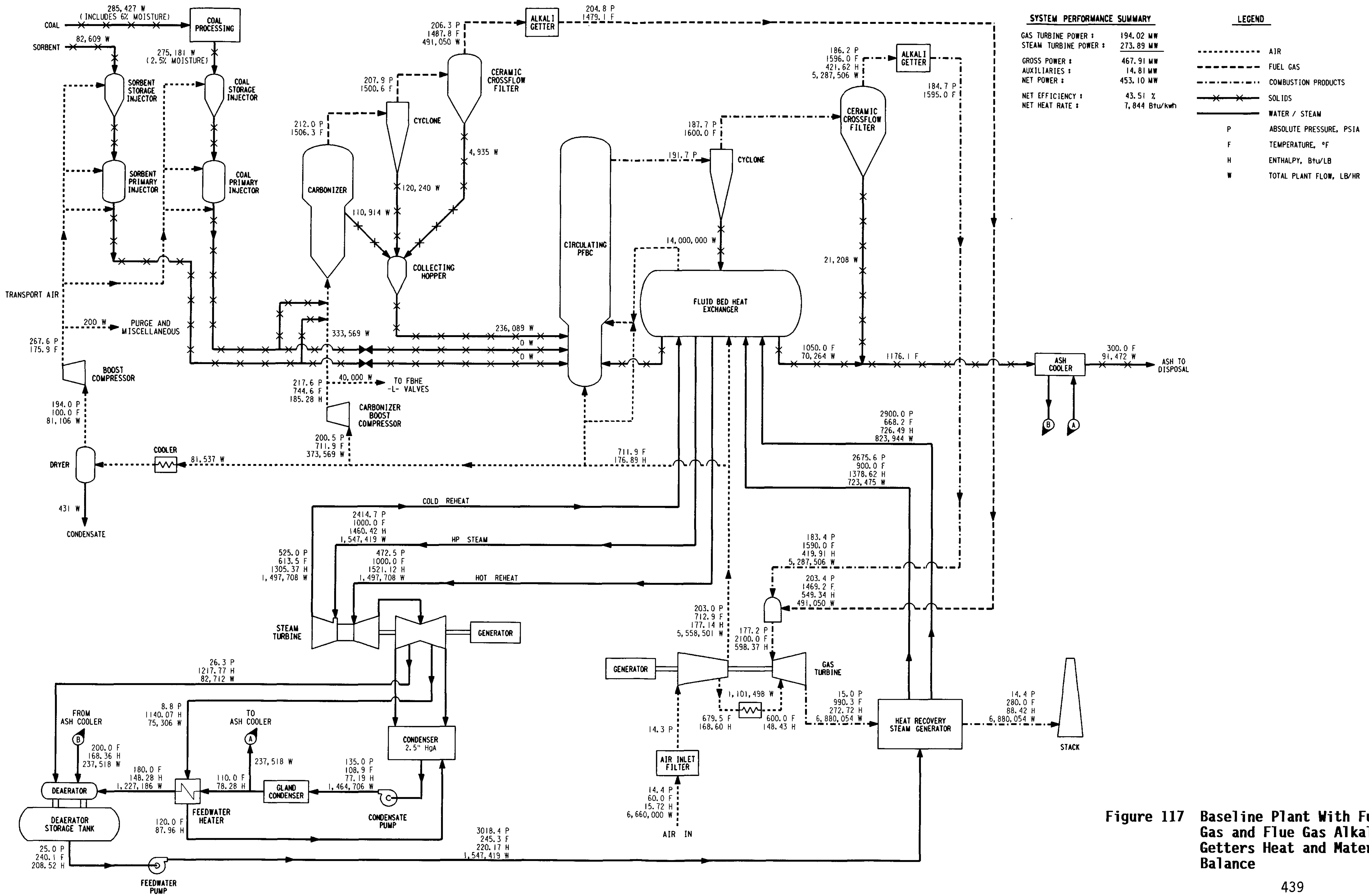


Figure 116 Baseline Plant With Fuel Gas Alkali Getter Heat and Material Balance

Dwg. 8333-1-400-009-109, Rev. C



Dwg. 8333-1-400-009-110, Rev. C

Figure 117 Baseline Plant With Fuel Gas and Flue Gas Alkali Getters Heat and Material Balance

Table 104 Performance Summary for Baseline Plant with Alkali Getter Systems

	Alkali Getter Locations	
	Carbonizer	Carbonizer and CPFBC
Power Summary		
Gas Turbine Power, kWe	195,176	194,019
Steam Turbine Power, kWe	272,796	273,889
Gross Power, kWe	467,972	467,908
Auxiliaries, kWe	(14,842)	(14,807)
Net Power, kWe	453,130	453,101
Net Efficiency, %(HHV)	43.60	43.51
Net Heat Rate, Btu/kWh	7828	7844
Consumables and Wastes		
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	284,849	285,427
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	274,624	275,181
Dolomite Feed, lb/h	82,442	82,609
Ash Production, lb/h	91,287	91,472
Coal and Dolomite Drying Fuel, gal/h	94	94
Auxiliary Summary, kWe		
Transport Boost Compressor	456	448
Carbonizer Boost Compressor	1,024	948
Condensate Pumps	220	221
Feedwater Pumps	5,421	5,443
Boiler Forced Circulation Pumps	316	318
Circulating Water Pumps	3,472	3,486
Cooling Tower Fans	896	900
Coal Dryer Forced-Draft Fan	301	301
Coal Dryer Induced-Draft Fan	238	239
Gas Turbine Auxiliaries	400	400
Steam Turbine Auxiliaries	484	486
Gas Turbine Intercooler Fan	15	15
Nitrogen Supply	---	---
Barge Unloading and Stacker/Reclaimer	169	170
Coal Handling	348	348
Dolomite Handling	68	68
Coal and Sorbent Feed	32	32
Ash Cooling and Handling	106	106
Service Water	99	99
Miscellaneous	703	704
Stepdown Transformer	74	74
Total Auxiliaries	14,842	14,807

Table 105 Effects of Fuel Gas Alkali Getter on Baseline Plant Performance

	Second-Generation PFB Plant Configuration	
	Baseline (No Alkali Getter)	Baseline (With Carbonizer Alkali Getter)
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	467.97
Auxiliaries, MWe	14.73	14.84
Net Power, MWe	452.76	453.13
Net Plant Efficiency, %(HHV)	43.63	43.60
Net Plant Heat Rate, Btu/kWh	7822	7828
As-Received Coal Feed, lb/h	284,410	284,849
Dolomite Feed, lb/h	82,315	82,442
Ash Production, lb/h	91,144	91,287
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2100.0
Generator Output, MWe per Module	97.58	97.59
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	143.26
Superheating	186.27	187.05
Reheating	160.60	160.89
Total FBHE Duty (per module), 10^6 Btu/h	488.82	491.20
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	625.45
UA, 10^6 Btu/h·°F per Module	10.501	10.448
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1541.23
Generator Output, MWe	272.34	272.80
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1337.24

Table 106 Effects of Fuel Gas and Flue Gas Alkali Getters on Baseline Plant Performance

	Second-Generation PFB Plant Configuration	
	Baseline (No Alkali Getter)	Baseline (With Carbonizer Alkali Getter)
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	467.91
Auxiliaries, MWe	14.73	14.81
Net Power, MWe	452.76	453.10
Net Plant Efficiency, %(HHV)	43.63	43.51
Net Plant Heat Rate, Btu/kWh	7822	7844
As-Received Coal Feed, lb/h	284,410	285,427
Dolomite Feed, lb/h	82,315	82,609
Ash Production, lb/h	91,144	91,472
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2100.0
Generator Output, MWe per Module	97.58	97.01
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	144.00
Superheating	186.27	187.94
Reheating	160.60	161.57
Total FBHE Duty (per module), 10^6 Btu/h	488.82	493.51
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	627.65
UA, 10^6 Btu/h·°F per Module	10.501	10.325
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1547.42
Generator Output, MWe	272.34	273.89
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1342.63

two getter cases remain very similar to those of the baseline plant, but gas-side pressure losses are higher. The pressure loss of the fuel gas alkali getter is accommodated by an increase in the carbonizer boost compressor discharge pressure. As a result, the gas turbine continues to operate at baseline plant pressures, and the plant efficiency loss is minimized.

The fuel gas alkali removal/getter vessel required by each module is shown in Figure 118. The unit, approximately 17 ft-6 in. in diameter by 30 ft-9 in. tall, operates with a 26.2 ft deep bed, a superficial gas velocity of 1.2 ft/s, and a bed pressure loss of 1.04 psi.

Analyses presented in Appendix C.6 indicate that most of the alkalis will be released in the carbonizer and only minimal gettering will be required in the CPFBC flue gas. Hence the CPFBC flue gas getter system will operate with a much higher gas loading (pounds of gas per pound of pellet) and utilize higher gas velocities and shallower beds. The CPFBC flue gas alkali getter (also shown in Figure 119) is 15 ft-3 in. in diameter by 18 ft-10 in. long and operates with an 18-in. deep bed, a superficial gas velocity of 6-1/2 ft/s, and a bed pressure loss of 1.12 psi.

The alkali getter systems are operated as single batch units. No operator attention is required, but pressure losses and alkali levels are monitored. If either of these should increase to unacceptable levels, the units must be shut down and the used pellets removed and replaced with fresh pellets. Pellet removal and replacement, which can be accomplished in less than a week using a rail car unloader and elevator, is envisioned to occur twice a year during normal shutdown/maintenance periods. The pellet consumption rates are estimated to be 360 and 38 t/yr for the carbonizer and CPFBC respectively. With the exception of the alkali getter systems, the plant equipment remains essentially identical to that of the baseline plant.

Recognizing that considerable uncertainty surrounds PFB combustion gas alkali predictions, analytical calculations predict combined sodium-potassium vapor concentrations of 85 and 0.053 ppm(v) for the carbonizer and CPFBC gas streams respectively. Without gettering they will yield (together) a 7.2 ppm(v) concentration at the gas turbine topping combustor inlet.

Incorporation of the fuel gas alkali getter will lower the carbonizer concentration from 85 to 0.01 ppm(v) and yield a mixed concentration of 0.047 ppm(v). The addition of the flue gas alkali getter lowers the CPFBC concentration from 0.05 to 0.02 ppm(v) and, together with the gettered carbonizer gas, yields a mixed concentration of 0.019 ppm(v). Although a maximum permissible alkali vapor limit has not yet been demonstrated for gas turbines operating with PFB combustion gas, these alkali levels are close to the 20 to 50 ppb(v) limits established for conventional gas turbine fuels. Significant uncertainty surrounds this analysis, but it does appear that alkali getters can be incorporated in the plant without seriously affecting plant efficiency or COE.

Texas Lignite. Figure 119 presents the heat and material balance for the lightly dried, 25.8-percent moisture lignite-fired second-generation PFB plant described in Section 6.7, but with alkali getter systems in the carbonizer fuel gas and CPFBC flue gas flow paths. Tables 107 and 108 present detailed performance and equipment data for this new plant. Carbonizer performance remains as predicted in Section 6.7, and the plant continues to operate with a 2150°F topping combustion temperature. The alkali getter systems increase the fuel gas and flue gas path pressure losses by 1.5 psi, and there is a loss in plant efficiency of 0.12 percentage points (42.54 vs. 42.66 percent). The coal, sorbent, and ash flow rates

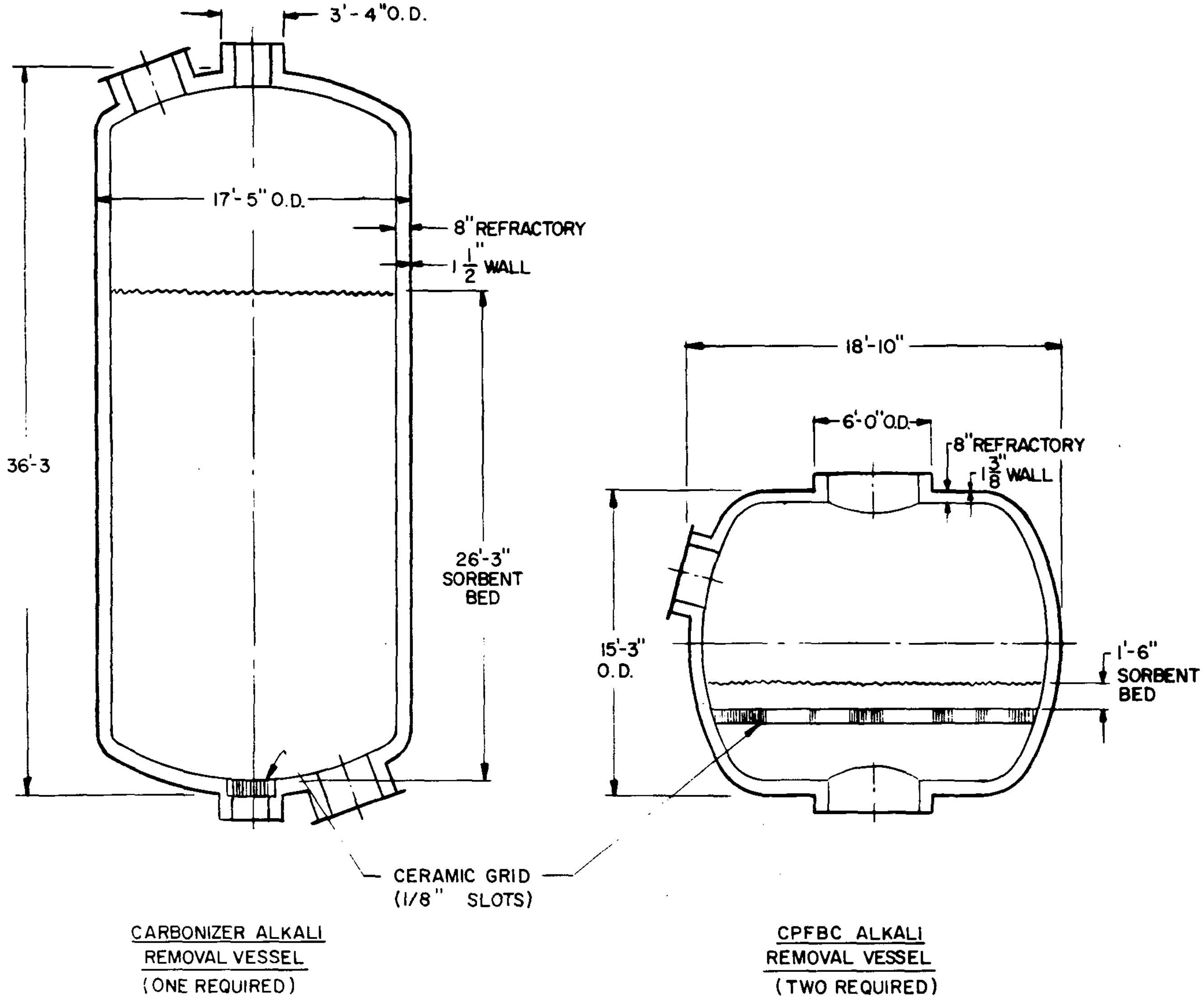


Figure 118 Carbonizer and CPFBC Alkali Removal Vessels

Dwg. 8333-1-400-009-116, Rev. B

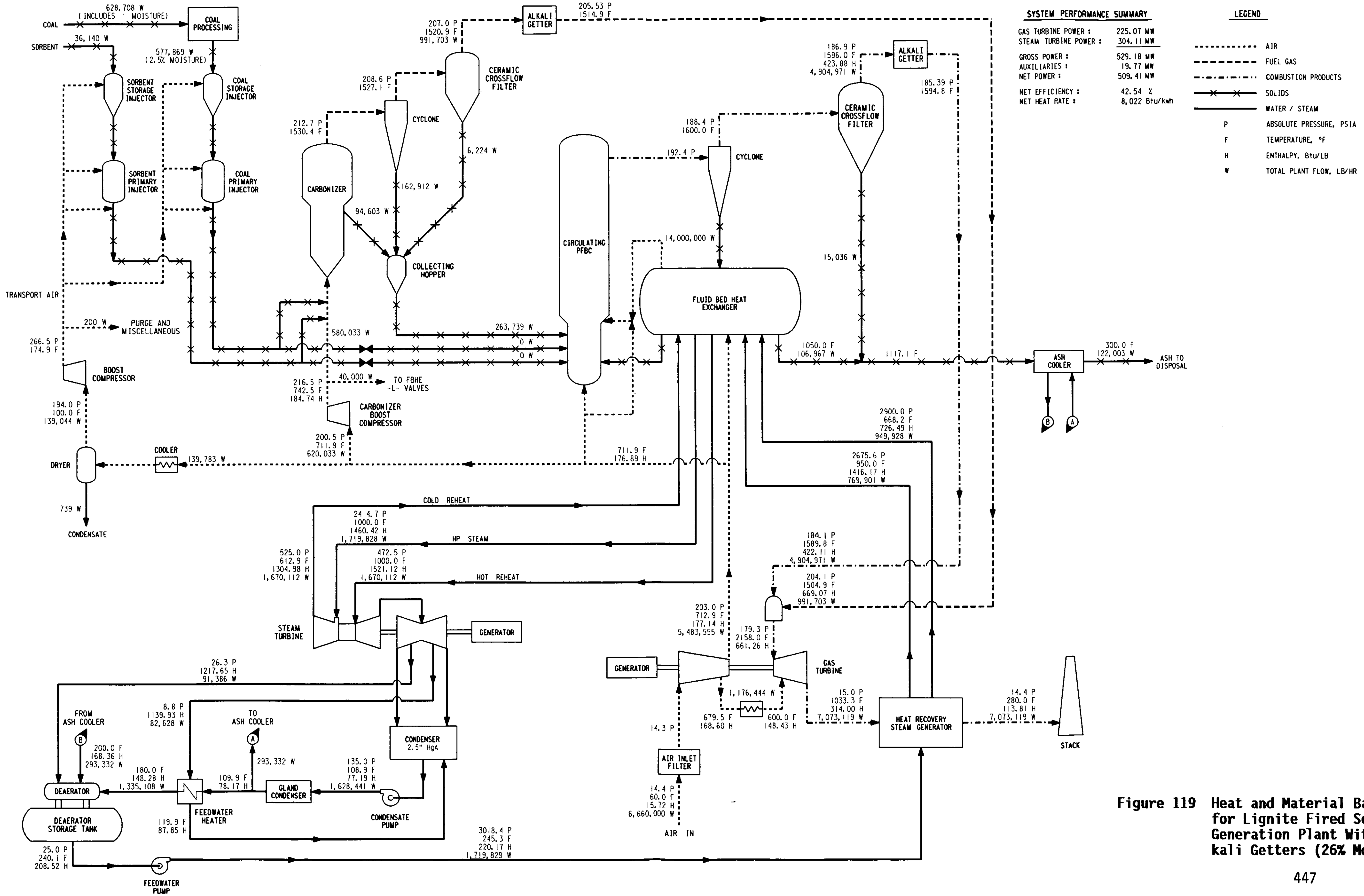


Figure 119 Heat and Material Balance for Lignite Fired Second-Generation Plant With Alkali Getters (26% Moisture)

Table 107 Lignite-Fired and Alkali-Gettered Second-Generation Plant Performance Summary

	Alkali Getter Locations	
	No Alkali Getters	Carbonizer and CPFBC
Power Summary		
Gas Turbine Power, kWe	226,071	225,073
Steam Turbine Power, kWe	302,254	304,109
Gross Power, kWe	528,325	529,182
Auxiliaries, kWe	(19,664)	(19,774)
Net Power, kWe	508,661	509,408
Net Efficiency, %(HHV)	42.66	42.54
Net Heat Rate, Btu/kWh	7999	8022
Consumables and Wastes		
As-Received Coal Feed, lb/h (Includes 31.8% moisture)	626,000	628,708
As-Fired Coal Feed, lb/h (Includes 25.8% moisture)	575,380	577,869
Dolomite Feed, lb/h	35,984	36,140
Ash Production, lb/h	121,468	122,003
Coal and Dolomite Drying Fuel, gal/h	444	446
Auxiliary Summary, kWe		
Transport Boost Compressor	755	759
Carbonizer Boost Compressor	1,466	1,472
Condensate Pumps	244	246
Feedwater Pumps	6,012	6,050
Boiler Forced Circulation Pumps	361	365
Circulating Water Pumps	3,885	3,910
Cooling Tower Fans	1,002	1,009
Coal Dryer Forced-Draft Fan	994	998
Coal Dryer Induced-Draft Fan	831	835
Gas Turbine Auxiliaries	400	400
Steam Turbine Auxiliaries	537	540
Gas Turbine Intercooler Fan	18	18
Nitrogen Supply	---	---
Barge Unloading and Stacker/Reclaimer	305	306
Coal Handling	764	767
Dolomite Handling	30	30
Coal and Sorbent Feed	58	58
Ash Cooling and Handling	141	142
Service Water	218	219
Miscellaneous	1,545	1,552
Stepdown Transformer	98	98
Total Auxiliaries, kWe	19,664	19,774

Table 108 Comparison of Lignite-Fired Second-Generation Plants With and Without Alkali Getters

	Second-Generation PFB Plant Configuration	
	Lightly Dried Lignite Without Getter	Lightly Dried Lignite With Getters
Alkali Getter Locations	None Provided	Carbonizer and CPFBC
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	528.33	529.18
Auxiliaries, MWe	19.66	19.77
Net Power, MWe	508.66	509.41
Net Plant Efficiency, %(HHV)	42.66	42.54
Net Plant Heat Rate, Btu/kWh	7999	8022
As-Received Coal Feed, lb/h	626,000	628,708
Dolomite Feed, lb/h	35,984	36,140
Ash Production, lb/h	121,468	122,003
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2158.0	2158.0
Generator Output, MWe per Module	113.04	112.54
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	164.08	166.02
Superheating	197.47	199.60
Reheating	179.32	180.49
Total FBHE Duty (per module), 10^6 Btu/h	540.87	546.11
HRSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	698.34	700.89
UA, 10^6 Btu/h·°F per Module	9.690	9.564
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1709.15	1719.83
Generator Output, MWe	302.25	304.11
Cooling Tower Heat Rejection, 10^6 Btu/h	1496.20	1505.69

are increased by about 0.5 percent. The plant electrical output remains essentially unchanged.

The sizing and operating philosophy used to conceptually design the alkali getter systems for the baseline plant were applied similarly to the lignite-fired second-generation plant. Because of the much higher alkali content of the lignite, a large amount of alkali is projected to remain in the char-sorbent residue transferring from the carbonizer. Therefore, larger getters are required, especially for the CPFBC. The carbonizer fuel gas getter consists of a single vessel approximately 22 ft-5 in. in outside diameter by 43 ft tall. It will contain 320 tons of pellets and operate with a superficial gas velocity of 1.2 ft/s, a bed depth of 27.9 ft, and a bed pressure loss of 1.01 psi. The CPFBC flue gas getter will consist of two vessels, 17 ft-1 in. in outside diameter by 25 ft-7 in. long, operating in parallel. Each vessel contains 74 tons of pellets and operates with a superficial gas velocity of 4 ft/s, a bed depth of 3 ft, and a bed pressure loss of 1.12 psi.

Analytical calculations predict combined sodium-potassium vapor concentrations of 91.2 and 0.49 ppm(v) for the carbonizer and CPFBC gas streams respectively. Without gettering, a mixed concentration of 10.00 ppm(v) is obtained at the gas turbine topping combustor inlet. Incorporation of these getters lowers the carbonizer and CPFBC alkali vapor levels to concentration levels of <0.01 and 0.02 ppm(v) respectively and yields a level of less than 0.019 ppm(v) at the gas turbine topping combustor.

With the exception of the alkali getter systems the plant equipment remains essentially the same as in the Section 6.7 plant.

COE Results. The economics of the alkali-gettered plants are presented in Table 109. The addition of alkali getters does not cause a significant increase in capital cost for either the Pittsburgh- or lignite-fueled plants.

The largest impact is found in the "Consumables" category, because getter material must be replenished twice yearly at a material cost of $2,200/ton. For the Pittsburgh coal, adding the carbonizer fuel gas getter results in only a 1-percent increase in COE, but adding getters to both the carbonizer and CPFBC results in a 1.6 percent increase. For the lignite coal, alkali getters were provided for both the carbonizer and CPFBC gases, resulting in a 2.0 percent rise in COE.

Discussion. Installation of an alkali getter in the carbonizer fuel gas line results in a negligible performance penalty--only a small increase in the pressure delivered by the carbonizer booster compressor is needed to compensate for the increased pressure drop associated with the carbonizer alkali getter.

Installation of alkali getters in both the carbonizer fuel gas and CPFBC flue gas streams results in an efficiency loss four times greater than with a getter on the carbonizer alone. The efficiency loss is higher because the CPFBC alkali-getter pressure loss lowers the gas turbine inlet pressure, which reduces the expansion ratio across the gas turbine because there is no booster compressor in the CPFBC circuit. Installation of carbonizer and CPFBC alkali getters in the lignite-fired second-generation plant causes a similar loss in efficiency. In any event, the second-generation plant can incorporate alkali getters without suffering a severe loss in efficiency or increase in COE.

Table 109 Effects of Alkali Getter Systems on Second-Generation Plant Economics

	Pittsburgh Coal			Lignite Coal	
	Baseline (No Alkali Getter)	Baseline With Single Getter	Baseline With Two Getters	No Getter	Two Getters
Alkali Getter Location	None Provided	Carbonizer	Carbonizer and CPFBC	None Provided	Carbonizer and CPFBC
Unit Size, MWe net	452.8	453.1	453.1	508.7	509.4
Net Plant Heat Rate, Btu/kWh	7822	7828	7844	7999	8022
Total Plant Cost, $/kW	907.1	911.8	917.4	949.6	962.5
Total Plant Investment, $/kW	981.6	986.7	992.7	1027.6	1041.6
Total Capital Requirement, $/kW	1038.0	1043.5	1049.8	1085.7	1100.5
First Year Costs:					
Total O&M, $/kW·yr	38.0	38.1	38.3	39.2	39.5
Fixed O&M, $/kW·yr	24.7	24.8	24.9	25.5	25.7
Variable O&M, mills/kWh	2.34	2.34	2.35	2.41	2.43
Consumables, mills/kWh	3.37	3.71	3.76	2.98	3.58
Fuel Cost, mills/kWh	14.0	14.0	14.0	15.19	15.23
Levelized O&M:					
Fixed, $/kW·yr	43.2	43.3	43.4	44.5	44.9
Variable O&M, mills/kWh	4.1	4.1	4.1	4.2	4.2
Consumables, mills/kWh	5.9	6.5	6.6	5.2	6.2
Fuel, mills/kWh	26.6	26.7	26.7	28.9	29.0
Levelized Carrying Charge, $/kW·yr	179.6	180.5	181.6	187.8	190.4
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	76.5	76.9	79.1	80.8

6.8 98-PERCENT CARBON COMBUSTION EFFICIENCY

Plant Performance and Equipment Changes. Although there are numerous atmospheric pressure circulating fluidized bed combustors (CFBCs) in commercial operation, there is no circulating bed operating experience at the second-generation plant pressure. Since the combustion characteristics of the carbonizer char are also unknown, uncertainty exists regarding CPFBC combustion efficiency. Consequently, an analysis was undertaken to determine the sensitivity of plant performance and economics to carbon conversion/combustion efficiency. Even though the overall carbon combustion efficiency of the baseline plant is expected to be over 99.6 percent, a value of 98 percent was arbitrarily assumed.

Figure 120 is the heat and material balance for a second-generation plant operating with a 98-percent carbon combustion efficiency; Tables 110 and 111 present detailed performance and equipment data. The carbonizer performance level and the topping combustor temperature remain as predicted for the baseline plant. Compared with the baseline, the new plant efficiency is 0.51 percentage points lower (43.12 vs. 43.63 percent), and the net power output is 5.7 MWe lower (447.1 vs. 452.8 MWe) lower, most of which is due to reduced steam turbine output caused by a 5-percent reduction in CPFBC char heat release and FBHE duty.

The systems and equipment arrangements required by the new plant are identical to those of the baseline plant. Carbonizer and CPFBC volumetric flow rates and dimensions remain essentially unchanged; the FBHE contains slightly less surface area, but the HRSG area is about 7 percent greater.

COE Results. Economic data for the 98-percent carbon combustion efficiency plant is presented and compared with the baseline plant in Table 112. The lower combustion efficiency (98-percent) increases the plant COE by 1.3 percent (77.0 vs. 75.7 mills/kWh), primarily because the 1.2-percent increase in plant heat rate and corresponding power loss (447.1 vs. 452.8 MWe) is reflected in all unit-cost accounts.

Discussion. The major effect of a shortfall in carbon combustion efficiency is a loss in power from the bottoming cycle. Gas turbine output remains essentially unchanged, while steam turbine output drops by about 2.1 percent because of reduced CPFBC char heat release and FBHE steam cycle duty.

The overall effect on plant performance is still quite nominal, as a fivefold increase in unburned carbon loss (98.0- vs. 99.6-percent carbon combustion efficiency) results in only a 1.25-percent loss in power and a 0.51-point loss in plant efficiency (43.12 vs. 43.63 percent). These small effects indicate that carbon combustion efficiencies in this range will not have a major effect on plant performance or COE.

6.9 SUMMARY

In the performance portion of the sensitivity study, 15 different plants--involving alternative operating conditions, feedstocks, design assumptions, etc.--were investigated. Tables 113 and 114 present the detailed power and economic data, and Table 115 identifies the COE advantage and efficiency of each plant studied, along with other pertinent data. For the Pittsburgh No. 8 second-generation plants, the COE advantage ranges from a low of 14.7 to a high of 23.7 percent, and the net plant efficiencies range from 40.62 to 44.92 percent. The COE is highest for the 10-atm pressure plant (79.5 mills/kWh); the slurry-fed plant has the lowest COE (71.1 mills/kWh). Although the 1600°F carbonizer plant has the highest

Dwg. 8333-1-400-009-101, Rev. C

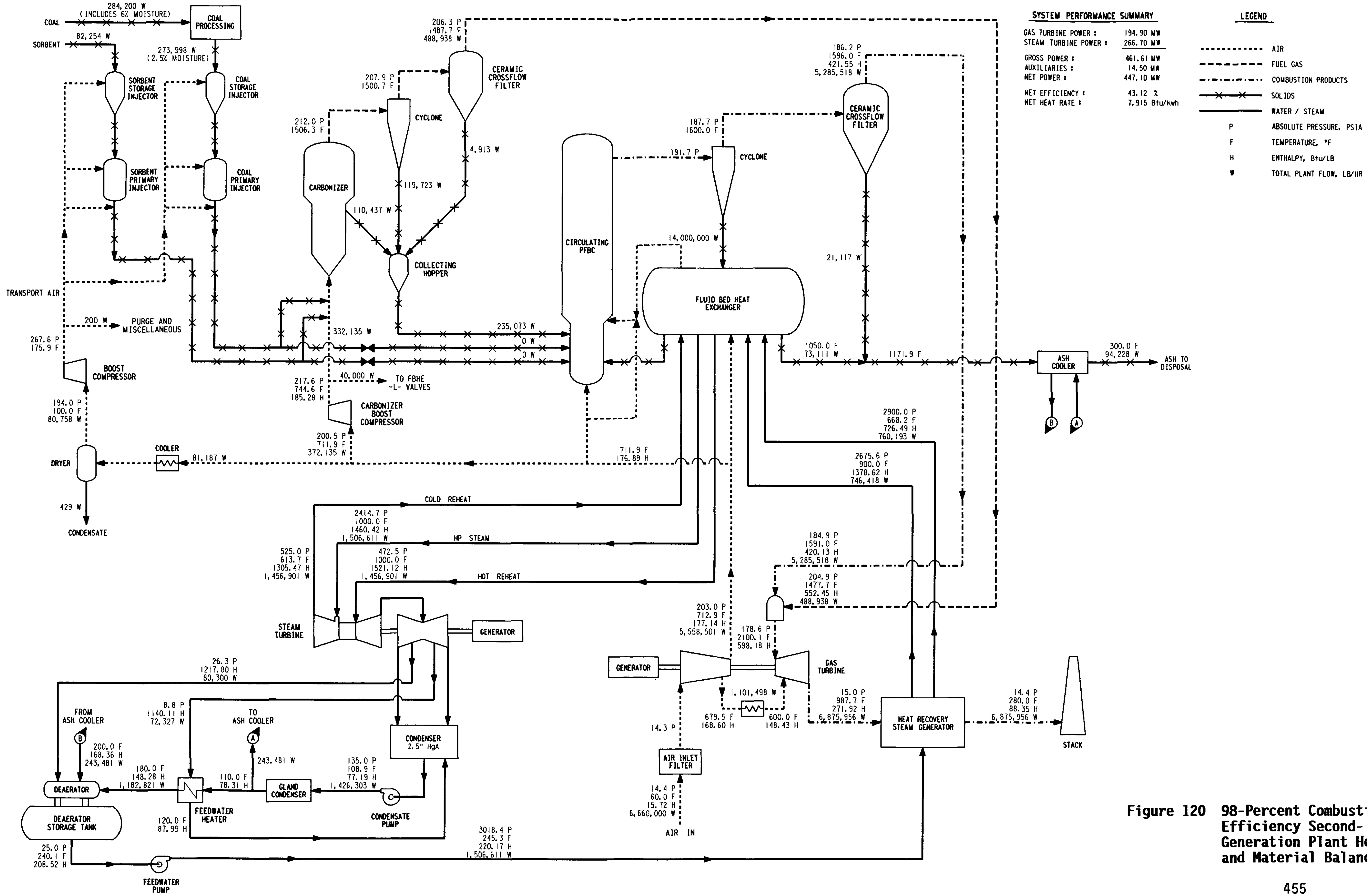


Figure 120 98-Percent Combustion Efficiency Second-Generation Plant Heat and Material Balance

Table 110 98-Percent Carbon Combustion Efficiency Second-Generation Plant Performance Summary

<u>Power Summary</u>	
Gas Turbine Power, kWe	194,904
Steam Turbine Power, kWe	266,703
Gross Power, kWe	461,607
Auxiliaries, kWe	(14,503)
Net Power, kWe	447,104
Net Efficiency, %(HHV)	43.12
Net Heat Rate, Btu/kWh	7915
<u>Consumables and Wastes</u>	
As-Received Coal Feed, lb/h (Includes 6.0% moisture)	284,200
As-Fired Coal Feed, lb/h (Includes 2.5% moisture)	273,998
Dolomite Feed, lb/h	82,254
Ash Production, lb/h	94,228
Coal and Dolomite Drying Fuel, gal/h	94
<u>Auxiliary Summary, kWe</u>	
Transport Boost Compressor	447
Carbonizer Boost Compressor	944
Condensate Pumps	215
Feedwater Pumps	5,300
Boiler Forced Circulation Pumps	301
Circulating Water Pumps	3,396
Cooling Tower Fans	876
Coal Dryer Forced-Draft Fan	300
Coal Dryer Induced-Draft Fan	238
Gas Turbine Auxiliaries	400
Steam Turbine Auxiliaries	473
Gas Turbine Intercooler Fan	15
Nitrogen Supply	---
Barge Unloading and Stacker/Reclaimer	169
Coal Handling	347
Dolomite Handling	68
Coal and Sorbent Feed	32
Ash Cooling and Handling	110
Service Water	99
Miscellaneous	701
Stepdown Transformer	72
Total Auxiliaries, kWe	14,503

Table 111 Comparison of Baseline and 98-Percent Carbon Combustion Efficiency Plant Performance Data

	Second-Generation Plant Configuration	
	Baseline (99.6-Percent Carbon Combustion Efficiency)	98-Percent Carbon Combustion Efficiency
Modules	2	2
Overall Plant Performance		
Gross Power, MWe	467.49	461.61
Auxiliaries, MWe	14.73	14.50
Net Power, MWe	452.76	447.10
Net Plant Efficiency, %(HHV)	43.63	43.12
As-Received Coal Feed, lb/h	284,410	284,200
Dolomite Feed, lb/h	82,315	82,254
Ash Production, lb/h	91,144	94,228
Gas Turbine Parameters		
Topping Combustor Exit Temperature, °F	2100.1	2100.1
Generator Output, MWe per Module	97.58	97.45
FBHE Duties, 10^6 Btu/h per Module		
Evaporation	141.95	132.86
Superheating	186.27	176.63
Reheating	160.60	157.09
Total FBHE Duty (per module), 10^6 Btu/h	488.82	466.58
HGSG Parameters		
HRSG Duty, 10^6 Btu/h per Module	625.40	624.80
UA, 10^6 Btu/h·°F per Module	10.501	11.257
Steam Turbine Parameters		
Main Steam Flow, 10^3 lb/h	1538.62	1506.61
Generator Output, MWe	272.34	266.70
Cooling Tower Heat Rejection, 10^6 Btu/h	1334.95	1307.99

Table 112 Comparison of Baseline and 98-Percent Carbon Combustion Efficiency Plant Economic Data

	Second-Generation Plant Configuration		
	Baseline (99.6-Percent Carbon Combustion Efficiency)	98-Percent Carbon Combustion Efficiency	Percentage Change
Unit Size, MWe net	452.8	447.1	---
Heat Rate, Btu/kWh	7822	7915	+1.2
Total Plant Cost, $/kW	907.1	918.7	+1.3
Total Plant Investment, $/kW	981.6	994.2	+1.3
Total Capital Requirement, $/kW	1038.0	1051.3	+1.3
First Year Costs:			
Total O&M, $/kW·yr	38.0	38.5	+1.3
Fixed O&M, $/kW·yr	24.7	25.1	+1.6
Variable O&M, mills/kWh	2.34	2.37	+1.3
Consumables, mills/kWh	3.37	3.43	+1.8
Fuel Cost, mills/kWh	14.0	14.2	+1.4
Levelized O&M:			
Fixed, $/kW·yr	43.2	43.7	+1.2
Variable O&M, mills/kWh	4.1	4.1	+0.0
Consumables, mills/kWh	5.9	6.0	+1.7
Fuel, mills/kWh	26.6	27.0	+1.5
Levelized Carrying Charge, $/kW·yr	179.6	181.9	+1.3
Levelized Busbar Cost, mills/kWh (at 65-percent capacity factor)	75.7	76.7	+1.3

Table 113 Performance Sensitivity Study

Plant Configuration	Baseline	Computer-Predicted Carbonizer	1600°F Carbonizer	Minimum Excess Air	10 atm	-30 Mesh Coal and 1/8-in. Dolomite	-30 Mesh Coal and Dolomite	Limestone Sorbent	Lightly Dried Texas Lignite	Undried Coal	Coal/ Water Slurry Feed	95-Percent SO_2 Capture	NO_x, Half NSPS	Particulate, Half NSPS	Baseline With Fuel Gas Getter	Baseline With Fuel and Flue Gas Getters	Lightly Dried Texas Lignite With Getters	98-Percent Carbon Combustion Efficiency
Report Section	---	6.2.1	6.2.2	6.2.3	6.2.4	6.3	6.3	6.4.1	6.4.2	6.5.1	6.5.2	6.6.1	6.6.2	6.6.3	6.7	6.7	6.7	6.8
Unit Size, MWe net	452.8	470.3	496.3	423.0	437.4	454.0	452.7	448.7	508.7	432.8	547.6	454.0	Same as Baseline	Same as Baseline	453.1	453.1	509.4	447.1
Heat Rate, Btu/kWh	7822	7699	7598	8402	7800	7795	7796	7831	7999	8075	7730	7905			7828	7844	8022	7915
Fixed Costs:																		
Total Plant Cost, $/kW	907.1	886.3	875.8	830.0	977.9	918.3	915.3	917.2	949.6	942.8	839.3	908.7			911.8	917.4	962.5	918.7
Total Plant Investment, $/kW	981.6	959.1	947.8	898.2	1058.2	993.7	990.5	992.5	1027.6	1020.2	908.2	983.3			986.7	992.7	1041.6	994.2
Total Capital Requirement, $/kW	1038.0	1014.4	1002.1	953.8	1117.2	1049.6	1046.3	1049.5	1085.7	1078.2	961.2	1040.7			1043.5	1049.8	1100.5	1051.3
Fixed O&M, $/kW·yr	43.2	41.6	40.4	40.1	46.9	44.7	44.7	43.6	44.5	44.9	37.6	43.2			43.3	43.4	44.9	43.7
Levelized Costs:																		
Variable O&M, mills/kWh	4.1	3.9	3.8	3.8	4.4	4.2	4.2	4.1	4.2	4.3	3.6	4.1			4.1	4.1	4.2	4.1
Fixed and Variable O&M, mills/kWh	11.7	11.2	10.9	10.9	12.6	12.1	12.1	11.8	12.0	12.2	10.2	11.7			11.7	11.7	12.1	11.8
Fuels and Consumables, mills/kWh																		
Consumables	5.9	5.8	5.7	5.5	6.3	5.1	5.1	6.1	5.2	5.6	5.4	6.5			6.5	6.6	6.2	6.0
Fuel	26.6	26.2	25.9	28.6	26.6	26.5	26.6	26.7	28.9	27.5	26.3	26.9			26.7	26.7	29.0	27.0
Total	32.5	32.0	31.6	34.1	32.9	31.6	31.7	32.8	34.1	33.1	31.7	33.4			33.2	33.3	35.2	33.0
Carrying Charge, $/kW·yr	179.6	175.5	173.4	165.0	193.3	181.6	181.0	181.6	187.8	186.5	166.3	180.0			180.5	181.6	190.4	181.9
Carrying Charge, mills/kWh	31.5	30.8	30.5	29.0	33.9	31.9	31.8	31.9	33.0	32.8	29.2	31.6			31.7	31.9	33.4	31.9
Levelized Busbar Cost, mills/kWh	75.7	74.1	72.9	74.0	79.5	75.6	75.5	76.5	79.1	78.0	71.1	76.7			76.5	76.9	80.8	76.7

Table 114 Key Sensitivity Study Performance Data

Plant Configuration	Baseline	Computer-Predicted Carbonizer	1600°F Carbonizer	Minimum Excess Air	10 atm	-30 Mesh Coal and 1/8-in. Dolomite	-30 Mesh Coal and Dolomite	Limestone Sorbent	Lightly Dried Texas Lignite	Undried Coal	Coal/Water Slurry Feed	95-Percent SO_2 Capture	Baseline With Fuel Gas Getter	Baseline With Fuel and Flue Gas Getters	Lightly Dried Texas Lignite With Getters	98-Percent CPFBC Combustion Efficiency
Report Section	---	6.2.1	6.2.2	6.2.3	6.2.4	6.3	6.3	6.4.1	6.4.2	6.5.1	6.5.2	6.6.1	6.7	6.7	6.7	6.8
Power Summary, kWe																
Gas Turbine Power, kWe	195,150	211,155	228,249	102,371	189,918	199,372	197,809	194,963	226,071	195,899	261,620	190,340	195,176	194,019	225,073	194,904
Steam Turbine Power, kWe	272,338	273,755	283,652	338,094	261,820	271,835	271,893	268,355	302,254	250,111	303,612	278,985	272,796	273,889	304,109	266,703
Gross Power, kWe	467,488	484,910	511,901	440,465	451,738	471,207	469,702	463,318	528,325	446,010	565,232	469,325	467,972	467,908	529,182	461,607
Auxiliaries, kWe	(14,731)	(14,567)	(15,590)	(17,435)	(14,330)	(17,228)	(17,029)	(14,579)	(19,664)	(13,193)	(17,607)	(15,347)	(14,842)	(14,807)	(19,774)	(14,503)
Net Power, kWe	452,757	470,343	496,311	423,030	437,408	453,979	452,673	448,739	508,661	432,817	547,625	453,978	453,130	453,101	509,408	447,104
Net Efficiency, % (HHV)	43.63	44.33	44.92	40.62	43.75	43.78	43.78	43.58	42.66	42.26	44.15	43.17	43.60	43.51	42.54	43.12
Net Heat Rate, Btu/kWh	7822	7699	7598	8402	7800	7795	7796	7831	7999	8075	7730	7905	7828	7844	8022	7915
Consumables and Wastes																
As-Received Coal Feed, lb/h	284,410	290,800	302,828	285,443	274,000	284,200	283,400	282,217	626,000	270,600	340,000	288,200	284,849	285,427	628,708	284,200
Dolomite Feed, lb/h	82,315	84,164	87,645	63,735	79,302	70,500	64,208	84,564	35,984	78,474	98,537	95,332	82,442	82,609	36,140	82,254
Ash Production, lb/h	91,144	93,359	97,073	82,465	87,810	84,845	81,453	97,693	121,468	86,811	109,123	99,719	91,287	91,472	122,003	94,228
Coal and Dolomite Drying Fuel, gal/h	94	96	100	94	216	94	94	93	444	---	---	95	94	94	446	94

Table 115 Key Sensitivity Study Performance and Economic Data

Plant Configuration	COE mills/ kWh	COE Advantage (%)	Plant Efficiency based on HHV (%)	Total Plant Cost $/kW	Fuel and Consumables Cost (mills/kWh)	Plant Net Output (MWe)	Gas Turbine-to-Steam Turbine Power Ratio
Baseline	75.7	18.8	43.63	907.1	32.5	452.8	0.717
Computer-Modeled Carbonizer	74.1	20.5	44.33	886.3	32.0	470.3	0.771
1600°F Carbonizer	72.9	21.8	44.92	875.8	31.6	496.3	0.805
Minimum Excess Air	74.0	20.6	40.62	830.0	34.1	423.0	0.303
10-atm	79.5	14.7	43.75	977.9	32.9	437.4	0.725
-30 Mesh Coal and 1/8 in. Dolomite	75.6	18.9	43.78	918.3	31.6	454.0	0.733
-30 Mesh Coal and Dolomite	75.5	19.0	43.78	915.3	31.7	452.7	0.728
Limestone Sorbent	76.5	17.9	43.58	917.2	32.8	448.7	0.727
Texas Lignite							
Lightly Dried	79.1	28.8	42.66	949.6	34.1	508.5	0.748
Deeply Dried	---	---	41.95	---	---	475.7	0.630
Undried Coal	78.0	16.3	42.26	942.8	33.1	432.8	0.783
Coal/Water Slurry	71.1	23.7	44.15	839.3	31.7	547.6	0.862
Tightened Plant Emissions							
95-Percent Sulfur Capture	76.7	18.2	43.17	908.7	33.4	454.0	0.682
NO_x 1/2 of NSPS	<------------	------------	------------	See Baseline	------------	------------	------------>
Particulate 1/2 of NSPS	<------------	------------	------------	See Baseline	------------	------------	------------>
Alkali Getters							
Pittsburgh No. 8--Fuel Gas	76.5	17.9	43.60	911.8	33.2	453.1	0.715
Pittsburgh No. 8--Fuel and Flue Gas	76.9	17.5	43.51	917.4	33.3	453.1	0.708
Lignite--Fuel and Flue Gas	80.8	27.3	42.54	962.5	35.2	509.4	0.740
98-Percent Carbon Combustion Efficiency	76.7	17.7	43.12	918.7	33.0	447.1	0.731

efficiency (44.92 percent), it does not have the lowest COE; its COE is 2.5 percent higher than that of the slurry-fed plant (72.9 vs. 71.1 mills/ kWh). Nevertheless, it still has a 21.8 percent COE advantage. In the analysis conducted with the computer-predicted carbonizer balance, which predicts a higher carbonizer performance level, the baseline plant efficiency is increased by 0.70 percentage points (44.33 vs. 43.63 percent), and the COE is reduced by 2.1 percent (74.1 vs. 75.7 mills/kWh). Hence all the values listed in Table 115 may underestimate second-generation plant capabilities. In addition, the sensitivity study data indicates that the peak plant COE advantage and efficiency may occur with an alternative not yet studied--a slurry-fed carbonizer operating higher than 1600°F. Even though the ultimate COE advantage and efficiency of a second-generation PFB combustion plant have not yet been identified, the sensitivity study reveals that the proposed type of second-generation PFB combustion plant can meet the project goals of a 20-percent COE advantage and an efficiency of 45 percent.

The use of the Texas lignite rather than Pittsburgh No. 8 coal increases the second-generation plant COE. Depending upon whether alkali getters are incorporated in the plant, the COE and efficiency become 79.1 or 80.8 mills/kWh and 42.66 or 42.54 percent. The COE and efficiency of PC-fired plants with wet limestone flue gas desulfurization are 93.2 mills/kWh and 35.9 percent for Pittsburgh No. 8 coal and 111.2 mills/kWh and 32.98 percent for Texas lignite. Hence the lignite-fired second-generation plant has the highest COE advantage of all the plants studied (28.8 or 27.3 percent).

Despite significant changes in operating conditions, feedstocks, design conditions, etc., the 15 different plant configurations yielded only a 9.7 mills/kWh change in COE, but changing from Pittsburgh No. 8 to Texas lignite increases the COE of a PC-fired plant by 18.0 mills/kWh. The relative insensitivity of COE to a wide range of variables, plus its high efficiency and low COE, will make the second-generation plant attractive throughout the entire United States. More specifically, the proposed second-generation PFB combustion plant will operate economically and effectively:

- With coals ranging from lignite to highly caking bituminous
- With limestone or dolomite sorbents
- With SO_2, NO_x, and particulate emissions less than half current NSPS-allowed values
- With finely ground (-30 mesh) to relatively coarse (-1/8 in.) feedstocks
- With or without alkali getter systems.

When a plant fired with Pittsburgh No. 8 is operated with a slurry-fed carbonizer at 1600°F and above, its COE advantage and efficiency will be higher than 20- and 45-percent respectively.

6.10 REFERENCES

1. Electric Power Research Institute, TAG™ - Technical Assessment Guide, Vol. 1, EPRI P-4463-SR, Palo Alto, California, December 1986.

2. Argonne National Laboratory and Bechtel Group, Inc., "Design of Advanced Fossil-Fuel Systems," ANL/FE-83-9, May 1983.

Section 7

CONCLUSIONS

The baseline plant design effort and the COE sensitivity study have shown that second-generation PFB combustion plants can meet or exceed all project goals. Using commercially available gas turbines and depending upon the operating conditions selected, a second-generation PFB combustion plant:

- Can have a COE at least 20 percent lower than that of a conventional PC-fired plant with wet limestone flue gas desulfurization
- Will probably exceed a 45-percent efficiency based on the higher heating value of the coal
- Meets emissions limits that are half those currently allowed by NSPS, without any unusual operating restraints
- Operates economically with coals ranging from lignite to highly caking bituminous coals and with either dolomite or limestone sorbents
- Can be furnished in building block modules as large as 225 MWe
- Is amenable to shop fabrication and barge shipment.

Much of the equipment required by a second-generation PFB combustion plant is state of the art and is available with commercial guarantees. The remainder consists of equipment that has been operated at a smaller scale or at atmospheric pressure and, for the purposes of this study, has been scaled up in size, pressure, or both to provide a conceptual design/costing basis. The layout, modularity, manufacture/shipping, and construction methods employed for the plant reflect techniques already utilized in either the utility industry or other major industries. Thus the baseline plant represents a realistic concept and is in a relatively advanced state of development.

The carbonizer performance level (i.e., the amount of coal energy transferred to the fuel gas) is a major determinant of overall plant efficiency. A 14-atm coal-fired second-generation PFB combustion plant operating with a 1500°F carbonizer and dry pneumatic coal feed (the baseline plant configuration) has a 2100°F optimum topping combustor temperature, a COE 18.8 percent lower than a conventional PC-fired plant, and a 43.63-percent efficiency. An increase in carbonizer operating temperature of 100°F (1600°F vs. 1500°F) significantly improves the carbonizer performance level, raises the optimum topping combustor temperature to 2350°F, and increases the plant efficiency by 1.29 percentage points; the COE advantage and efficiency of this new plant are 21.8 and 44.92 percent respectively. Slurry feed instead of dry pneumatic coal feed is another means for improving carbonizer performance. A 1500°F carbonizer operating with a 70-percent coal/30-percent water slurry feed raises the optimum topping combustor temperature to 2400°F and plant efficiency by 0.51 percentage points and yields a COE advantage and efficiency of 23.7 and 44.2 percent respectively.

In all three of these plants, the carbonizer performance level was determined via a conservative extrapolation and adjustment of coal carbonization data collected by the Grand Forks Energy and Denver Research Laboratories. A computer model that correlates published applicable coal pyrolysis, carbonization, and devolatilization data predicts improved carbonizer performance levels. When applied to the 1500°F dry pneumatic coal feed carbonizer case (the baseline plant), the plant efficiency increased by 0.70 percentage points and yielded a COE advantage and efficiency of

20.5 and 44.3 percent respectively. Thus the COE advantages and efficiencies reported for all three plants may be underestimated; their true plant performance levels may be higher. The combination of coal slurry feed and carbonizer temperatures of 1600°F and higher should result in an even better COE advantage and efficiency. Until carbonizer, CPFBC, HGCU, and topping combustor test data are collected at these operating conditions and until temperature limits are established for the metallic components in the fuel and flue gas systems (e.g., cross-flow filter structural members, fuel gas valves, MASBs), we are not certain how high the COE advantage and efficiency will ultimately be for this type of plant. Even though the coal slurry/1500°F carbonizer and dry pneumatic coal feed/1600°F carbonizer plant values are probably lower than the ultimate plant values, they meet the project goals; are reasonable; are attractive from COE, efficiency, and emissions standpoints; and are sufficient in themselves to justify proceeding to experimental testing.

A summary of conclusions regarding the baseline second-generation plant conceptual design and the COE sensitivity study follows:

- <u>Baseline (1500°F Carbonizer) Plant Conceptual Design</u>.
  - A two-module 14-atm second-generation PFB combustion plant operating with dry pneumatic Pittsburgh No. 8 coal feed to a 1500°F carbonizer and utilizing a 2100°F topping combustor and a 2400 psi/1000°F/1000°F/2.5-in. Hg steam cycle produces 453 MWe of net power.
    - COE advantage is 18.8 percent (based on a 65-percent capacity factor)
    - Efficiency is 43.63 percent (based on the coal higher heating value).
  - On a utility system, the high efficiency of the PFB combustion plant would cause it to be dispatched more frequently than a lower efficiency conventional plant; therefore, the true cost advantage is better than 18.8 percent. This advantage is not obvious when comparing two plants at the same capacity factor.
  - At approximately 50-percent load, the specified minimum load point, the plant can operate with either one or two modules in service. If two modules remain in operation, the coal flow rate to each module drops by 40 percent, yielding carbonizer, CPFBC, and topping combustor operating temperatures of 1460, 1550, and 1724°F respectively. Under these conditions the plant pressure drops to approximately 11 atm, the carbonizer and CPFBC volumetric gas flow rates are 42 percent and 126 percent of full-load values, and the efficiency is 35.60 percent. For extended operation at minimum load, either module can be shut down and the other returned to its full firing rate to yield a significantly improved efficiency.
  - Plant environmental releases per megawatt of power produced are significantly lower than those from a conventional PC-fired plant with a scrubber. When operating with a dolomite of average reactivity, a calcium-to-sulfur molar feed ratio of 1.75 provides a plant sulfur-capture efficiency of 90 percent; NO_x and particulate emissions are lower than half the NSPS allowable; and solid wastes are not hazardous and can be disposed of, with proper permits, in landfills.

- The reliability/availability of the PFB combustion plant is comparable to a conventional PC-fired plant with flue gas desulfurization, but the modular nature of the plant should ultimately allow it to be significantly better than the conventional plant.

- The site layout for the PFB combustion plant is not significantly different from a similarly sized conventional plant site in terms of overall space, access, and height.

- Second-generation PFB combustion plants can be constructed in modular building blocks up to 225 MWe; key components can be shop-assembled and barged-shipped, providing improved quality control and a shorter construction schedule.

■ COE Sensitivity Study.

- Plant COE advantage and efficiency can be significantly increased by improving the carbonizer performance level.

  -- A 70-percent coal/30-percent water slurry feed instead of a dry pneumatic coal feed increases the baseline plant efficiency by 0.70 percentage points and yields a COE advantage and efficiency of 23.7 and 44.15 percent respectively.

  -- A carbonizer temperature increase of 100°F (1600°F vs. 1500°F) raises the baseline plant efficiency by 1.29 percentage points and yields a COE advantage and efficiency of 21.8 and 44.92 percent respectively.

- Lowering the plant operating pressure from 14 to 10 atm results in a minor efficiency improvement, but provides a more noticeable rise in COE.

  -- COE increases by 3.8 mills/kWh (79.5 vs. 75.7 mills/kWh) because components and structures are physically larger.

  -- Baseline plant efficiency increases by 0.12 percentage points (43.75 vs. 43.63 percent).

- The electrical output of a second-generation plant module can be doubled by operating it at minimum excess air (24 vs. 148 percent); although the efficiency of this type of plant is significantly reduced, its lower capital cost still results in an attractive COE advantage.

  -- COE advantage increases from 18.8 to 20.6 percent.

  -- Efficiency is 40.62 vs. 43.63 percent.

- Incorporation of fuel gas and flue gas alkali getter systems, if required, has only a relatively minor impact on plant efficiency and COE.

  -- Baseline plant COE advantage is 17.5 vs. 18.8 percent.

  -- Efficiency is 43.51 vs. 43.63 percent.

- Variations in cost factors (e.g., equipment costs, cost of money during construction, fuel and sorbent costs) will have differing impacts on the baseline plant COE advantage. With regard to the extremes encountered:

  -- A 50-percent increase in baseline and PC-fired plant equipment costs increases the COE advantage to 20.1 percent.

- -- A 100-percent increase in baseline and PC-fired plant sorbent costs decreases the COE advantage to 16.9 percent unless baseline plant operating conditions are revised to enable operation with a lower calcium-to-sulfur feed ratio.

- Lignite-coal-fired second-generation PFB combustion plants are efficient and economical. Compared with a lignite-PC-fired plant with scrubber, a second-generation PFB combustion plant operating with a 1500°F carbonizer has:

  -- A COE advantage of 28.8 percent.

  -- An efficiency of 42.66 vs. 32.98 percent.

- Since the carbonizer and CPFBC both contribute to the plant SO_2 release, their individual sulfur-capture efficiencies must be coordinated via a judicious selection of operating conditions. Baseline plant SO_2 releases can be cut in half (sulfur-capture efficiency increases from 90 to 95 percent) by increasing the Ca/S feed ratio from 1.75 to 2.0 and the CPFBC vessel height from 114 to 129 ft.

  -- COE rises by 1.0 mills/kWh.

  -- Plant efficiency drops by 0.46 percentage points.

- Coal and dolomite feed sizes have only a minor effect on plant COE and efficiency, but they can lower the plant Ca/S requirement.

  -- A coal feed that is -30 mesh instead of 1/8-in. x 0 lowers the baseline plant Ca/S feed ratio of 1.75 to 1.50 because of improved carbonizer sulfur capture (bed sorbent content increases).

  -- Coal and dolomite feeds that are -30 mesh instead of 1/8-in. x 0 lower the baseline plant Ca/S feed ratio from 1.75 to 1.37 because of improved sulfur capture in the carbonizer (higher bed sorbent content) and CPFBC (smaller mean particle diameter of circulating sorbent).

- Second-generation PFB combustion plants can also be operated efficiently and economically with limestone sorbent. The use of limestone rather than dolomite increases the baseline plant sorbent flow rate by 3 percent.

  -- COE advantage decreases by 0.8 mills/kWh (17.9 vs. 18.8 percent).

  -- Efficiency drops by 0.05 percentage points (43.58 vs. 43.63 percent).