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Clean Coal Reference Plants: Pulverized Encoal PDF Fired Boiler

Topical Report
December 1995

Work Performed Under Contract No.: DE-AM21-94MC31166

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

By
Gilbert/Commonwealth, Inc.
Reading, Pennsylvania 19607

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(DE96000636)
Distribution Category UC-102

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CLEAN COAL REFERENCE PLANTS
PULVERIZED ENCOAL PDF FIRED BOILER
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ACKNOWLEDGEMENT

This report was prepared by Gilbert/Commonwealth, Inc. (G/C) under US DOE Contract No. DE-AM21-94MC31166, with technical direction by the Morgantown Energy Technology Center (METC). The following organizations and individuals have contributed to the development and preparation of this report:

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EXECUTIVE SUMMARY

The Clean Coal Technology Demonstration Program is a government and industry cofunded technology development effort to demonstrate a new generation of innovative coal utilization processes in a series of full-scale facilities. The goal of the program is to provide the U.S. energy marketplace with a number of advanced, more efficient and environmentally responsive coal-using technologies.

The Morgantown Energy Technology Center (METC) has the responsibility for monitoring the CCT Projects within certain technology categories, which correspond to the center's areas of technology development. These categories include atmospheric fluidized bed combustion, pressurized fluidized bed combustion, integrated gasification combined cycle, mild gasification, and industrial applications.

A measure of success in the CCT program will be the commercial acceptance of the new technologies being demonstrated. The dissemination of project information to potential users is being accomplished by producing a series of reference plant designs, which will provide the users a basis for the selection of technologies applicable to their future energy requirements.

As a part of DOE's monitoring and evaluation of the CCT Projects, Gilbert/Commonwealth (G/C) has been contracted to assist in this effort by producing the design of a commercial size Reference Plant, utilizing technologies developed in the CCT Program. This report, the fourth in a series, describes the design of a 400 MW electric power plant, utilizing a current, state of the art, pulverized coal fired boiler fired with a Process Derived Fuel (PDF) produced by the ENCOAL Corporation, and supplying steam to a steam turbine generator. To meet specified SO_2 emissions targets established for this study, flue gas cleanup is accomplished by wet scrubbing in a duct injection type scrubber. Feed coal for the PDF process is available with reduced sulfur content, and may, in certain applications, not require additional sulfur removal in the power plant.

The intent of the reference plant design effort was to portray a commercial power plant with attributes considered important to the utility industry. The design used for the Reference Plant is based on commercially available components from established vendors with recent sales in the U.S. utility market. This PDF Fired Reference Plant provides a commercially sound basis for comparison with the plants based on other clean coal technologies in this series.

The nominal size of the Reference Plant is 400 MWe, net output, which is comprised of one 100% capacity turbine generator and one 100% capacity boiler. The flue gas particulate removal and desulphurization system utilizes two 50 percent capacity components for items such as fans, and precipitators, and duct injection scrubber modules to enhance plant availability.

Section 3 provides a detailed description of the Reference Plant. Heat balances are shown as well as system diagrams for the major systems and plant layouts showing equipment arrangements. An equipment list is contained in the Appendix A.

To provide uniformity in comparisons of Clean Coal Technologies, a consistent design basis was applied, including the following factors:

- Plant Site and Ambient Design Conditions
- Fuel and Sorbent Characteristics (in this PDF fired unit, fuel and sorbent are the technology variables)
- Plant Capacity and Design Life
- Plant Availability, Approach to Redundancy
- Mature Plant Technology
- Design Steam Conditions
- Approach to Insulation and Lagging
- Preheating/Start-up Requirements
- Modes of Operation, Turndown, Minimum Load
- Control System Design Approach
- Plant Services Requirements
- Structures and Foundations, Soil Bearing Loads
- Heat Recovery Approach
- Applicable Codes and Standards

Reference Plant Design

The PDF Fired Reference Plant design utilizes a balanced draft, natural circulation type, pulverized coal fired boiler. The boiler design and performance reflect current commercial practice in the U.S. utility industry. The flue gas scrubber is a dry type duct injection unit, using lime as a sorbent. Lime slurry is sprayed into the flue gas duct, where it dries and captures SO_2 as a particle. The particulate is then collected in the electrostatic precipitator for disposal.

The PDF Fired Reference Plant is designed to meet applicable Federal, State, and Local environmental standards relating to air, water, solid waste and noise. An initial sulfur content of about 0.7 lb/10^6 Btu coupled with a removal efficiency of 50% results in an SO_2 emission rate of less than 0.35 lb/10^6 Btu. The use of low NO_x burner technology, combined with overfire air, results in NO_x emissions of less than 0.30 lb/10^6 Btu. Air quality regulations concerning other compounds such as CO, CO_2 and air toxics now being considered may have an effect on the design of plants in the time frame being considered here. However, details of the end results of these considerations are not clear at the present time and are not included in this report. The control or reduction of N_2O has not been addressed in this design because N_2O levels are presently unregulated.

The Turbine-Generator is a tandem compound machine, with high pressure (HP), intermediate pressure (IP), and low pressure (LP) sections. The LP turbine is comprised of two double flow sections exhausting downward into two condenser sections.

The PDF Fired Reference Plant uses a 2400 psig/1000°F/1000°F single reheat steam power cycle. The boiler and turbine are designed for a main steam flow of 2,734,000 lbs of steam per hour at 2520 psig and 1000°F at the superheater outlet, throttled to 2415 psia at the inlet to the high pressure turbine. The cold reheat flow is 2,425,653 lb/h of steam at 604 psia and 635°F, which is reheated to 1000°F before entering the intermediate pressure turbine section. The net plant output power, after plant auxiliary power requirements are deducted, is nominally 400 MWe. The overall net plant (HHV) efficiency is nominally 39.0 percent.

The plant is designed to produce additional power output at a combined 5 percent overpressure, valves wide open condition (5% OP/VWO). At this combined condition, plant net output is estimated to be 439 MWe with an efficiency of 39.1 percent based on performance changes noted in the Reference PC Fired Unit (fired with Pittsburgh No. 8 coal). This combined condition is expected to be used on relatively infrequent occasions, to support severe sustained demand conditions.

Economic Analysis

Following the conceptual design of the PDF Fired Reference Plant, an economic analysis was performed to provide capital and O&M costs. Section 4.0 contains this analysis and Appendix B has second level cost details. A brief summary of the costs is given below:

	$ x 1000		$/kW
Total Plant Cost	508,199		1,257
Fixed O&M (1st year)		31.7 $/kW-yr	
Variable O&M (1st year)		2.3 mills/kWh	
Total consumables (1st year)	7,048		3.06
Fuel cost (1st year)	36,359		15.79
Levelized Busbar Cost of Power		74.7 mills/kWh	

Conclusions

The PDF Fired Reference Plant described herein represents current U.S. electric utility practice for a subcritical pressure design suitable for base loading. The economic parameters characterizing this design may be used as a point of reference for comparison with other Clean Coal Technologies. Many design options available to increase efficiency, (such as a supercritical cycle), or to decrease emissions, (such as Selective Catalytic Reduction), are applicable to the other technologies in the Clean Coal Reference series. The economic and emission related effects of each design option may be applied on an individual basis to a specific candidate technology/site combination, to determine its desirability.

Users of this report and others in this series should apply adjustments to the technical factors as well as the economic parameters to suit their own circumstances and expectations. This report, and others in this series, will provide a well defined point of reference for each technology, to facilitate informed and soundly based comparisons and decisions.

1.0 INTRODUCTION

The Clean Coal Technology Demonstration Program (CCT) is a government and industry cofunded technology development effort to demonstrate a new generation of innovative coal utilization processes in a series of full-scale facilities. The goal of the program is to provide the U.S. energy marketplace with a number of advanced, more efficient, and environmentally responsive coal-using technologies. To achieve this goal, a multiphased effort consisting of five separate solicitations has been completed.

The Morgantown Energy Technology Center (METC) has the responsibility for monitoring the CCT Projects within certain technology categories, which, in general, correspond to the center's areas of technology development. Primarily the categories of METC CCT projects are: atmospheric fluid bed combustion, pressurized fluidized bed combustion, integrated gasification combined cycle, mild gasification, and industrial applications.

A measure of success in the CCT Program will be the commercial acceptance of the new technologies being demonstrated. In order to achieve this commercial acceptance it is necessary to provide the potential technology users with project information in a format which allows the technology users to translate the results from the demonstration project to their particular circumstances.

DOE is monitoring project performance and evaluating project operating results. Based on this data, technology vendor input, and in-house expertise, Gilbert/Commonwealth, Inc., was contracted by DOE/METC to assist in this effort, and has developed a 400 MWe Process Derived Fuel (PDF) Fired Reference Plant with Duct Injection Flue Gas Desulphurization design. This Reference Plant design will be comparable with other reference plants. One objective of this work is to produce a series of reference plant designs which will enable the end user to compare and select the technologies to be applied to meet future energy requirements.

This report describes the results of the effort to design a mature, commercial power plant utilizing current state of the art technology and commercially available components, configured to burn a specific PDF produced by the ENCOAL Corporation. This design will serve as a reference for comparison to other, emerging technologies. The plant design and cost estimate provided are of sufficient detail to allow potential technology users to adjust the results to their specific conditions. This report, and the others in this series, will provide a well defined point of reference for each technology, to facilitate informed and soundly based comparisons and decisions.

2.0 PROCESS FOR THE PRODUCTION OF ENCOAL PROCESS DERIVED FUEL

In Section 3.0 of this report a technical and economic analysis is performed for a 400 MWe pulverized coal fired utility boiler that is designed to burn Process Derived Fuel (PDF) produced by ENCOAL Corporation. This section provides a description of the PDF process, characteristics of PDF, and plant scaleup considerations for a 5,000 to 25,000 TPD PDF plant. Information was obtained from published reports and from a site visit to a PDF demo plant in Gillette, Wyoming.

2.1 BACKGROUND INFORMATION

The process for producing PDF was developed by SGI International and SMC Mining Company in 1987. A license for the use of the technology was granted to ENCOAL Corporation, which is a wholly owned subsidiary of SMC Mining Company, who then applied for funding to build a 1,000 TPD demo plant under the U.S. Department of Energy's Clean Coal Technology Program, Round III. In 1989 the project was selected by the DOE for funding, ground breaking was in 1990 and in June 1992 the first PDF was produced. The plant located near Gillette, Wyoming was shutdown in June of 1993 for major modifications and in February 1994 the plant restarted but at half the original production rate.

The plant is now operating successfully and plans are to produce 30,000 tons of PDF for delivery to Wisconsin Power and Light for a test burn in a cyclone boiler. The plant presently produces 250 TPD of PDF and 250 barrels a day of coal derived liquid (CDL), which is similar to low sulfur heavy industrial fuel oil. The CDL is currently being sold to Dakota Gas and other industrial customers who burn it to produce process steam. Feed coal is 500 TPD from the adjacent Buckskin Mine in the Powder River Basin. A total of 3,600 hours of integrated operation has been logged as of July 1994.

2.2 PROCESS DESCRIPTION

The original process developed by SGI was called Liquid From Coal (LFC), and is a mild gasification or pyrolysis process which produces a liquid fuel and a partially de-volatilized solid fuel. Figure 2-1 is a simplified flow diagram of the process. It shows the deactivation operation which was not incorporated in the original design. The deactivation equipment installation was the major modification performed after the June 1993 shutdown.

The primary objective of the LFC process is to remove moisture from sub-bituminous coal while producing stable, low sulfur, high Btu fuels. Conventional drying of this coal produces a product with significant stability problems. The LFC process chemically alters the coal in a pyrolyzer in a manner which helps stabilize the fuel. There are three stages in the process: drying, pyrolyzing, and deactivation.

In the first stage, 2" x 1/8" sized coal is fed to a rotary grate dryer where it is heated by a hot gas stream to remove most of the coal's moisture. No chemical change or de-volatilization occurs here in this carefully controlled atmosphere.

The hot, dry coal then drops to the second stage, a similar rotary grate pyrolyzer, where the temperature is raised to approximately 1,000°F using a hot recycled gas stream. The remaining

ENCOAL Mild Gasification Demonstration Project

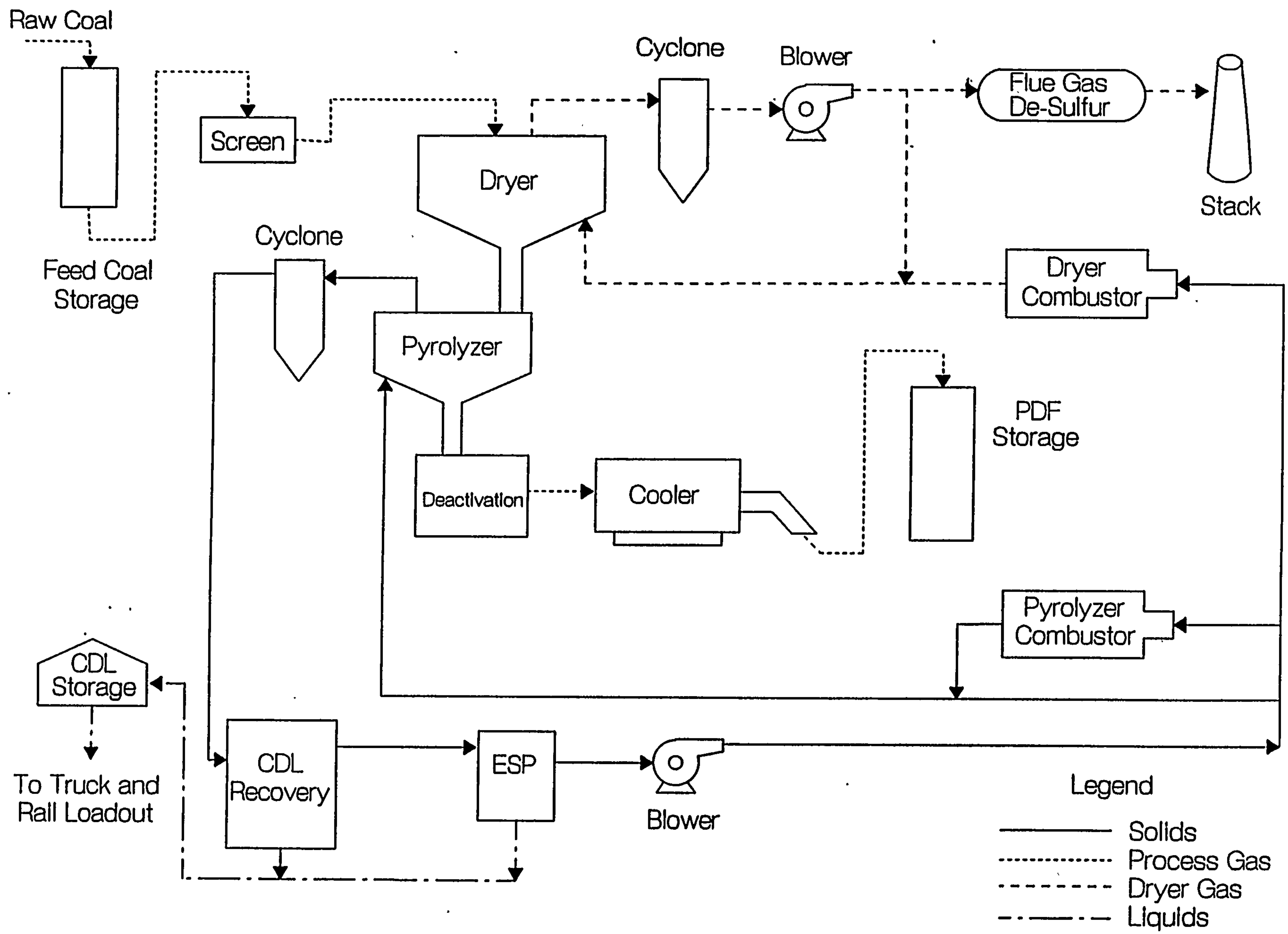


Figure 2-1: Simplified Process Flow Diagram

water is removed and mild gasification produces a gas from which CDL is later condensed. Residual solids are chemically altered and partially devolatilized in this step.

Solids from the rotary grate pyrolyzer are fed to the third stage deactivation unit which is a horizontal, vibrating fluidized bed. At a controlled temperature and oxygen content the coal is stabilized here. It then is sent to a cooler and then to a surge bin. A dust suppressant is added to the solid as it leaves the surge bin on its way to storage silos or ground storage.

The exhaust gas from the first stage dryer is de-dusted in conventional cyclones and then flows to a wet scrubber followed by a horizontal scrubber. In the horizontal scrubber, a sodium carbonate solution removes the sulfur oxides from the flue gas before it exits to the stack. A portion of the exhaust gas from the dryer is blended with exhaust gas from a combustor to provide heat and gas flow necessary for drying.

The exhaust gas from the second stage pyrolyzer goes to a low pressure drop specially designed cyclone to remove particulates. It is then cooled in a quench tower where hydrocarbons are condensed to produce CDL. The gas temperature is kept above the dew point of water so that only CDL is condensed, preventing the formation of water which would present separation and disposal problems. The cooled gas then flows to an array of three electrostatic precipitators (ESP's) where additional CDL is collected. The exhaust from the ESP has a fuel content of approximately 50 Btu/scf and a portion is burned in the pyrolyzer combustor to provide heat for the pyrolyzer. The remainder is burned in the dryer combustor.

Table 2-1 provides a typical analysis of CDL.

Table 2-1
CDL ANALYSIS

Heat Content	144,000 Btu/gal
Specific Gravity	1.07
Ash Content	0.5%
H_2O Content	1.0%
Sulfur Content	0.35 to 0.45%
Sulfur #/MMBtu	0.26
Sediment Content	1.7 to 2.9%

Table 2-2 is a PDF analysis from a recent test. Table 2-3 is a particle size analysis of this same coal.

Table 2-4 compares average results between feed coal and PDF on a moisture, ash free basis (MAF). These are early pilot plant results based on a limited amount of samples.

On the average, product PDF has 3,500 Btu/lb more heat content than the feed coal on an as received basis. The efficiency of the process on a Btu in-out basis is 90.5%.

Table 2-2
PROCESS DERIVED FUEL ANALYSIS

	As Received	Dry Basis
Proximate Analysis		
% Moisture	9.18	
% Ash	7.37	8.03
% Volatile	26.40	28.75
% Fixed Carbon	58.05	63.22
	100.00	100.00
Btu/lb	11324	12333
% Sulfur	0.33	0.36
MAF Btu		13410
Forms of Sulfur		
% Pyritic	0.17	0.19
% Sulfate	0.01	0.01
% Organic (diff)	0.15	0.17
Total	0.33	0.36
% Equilibrium Moisture	8.8	
Ultimate Analysis		
% Moisture	8.18	
% Carbon	68.86	74.99
% Hydrogen	3.24	3.53
% Nitrogen	1.20	1.31
% Sulfur	0.33	0.36
% Ash	7.37	8.03
% Oxygen (diff)	10.82	11.78
	100.00	100.00

Table 2-3
PROCESS DERIVED FUEL
SIEVE ANALYSIS

Passing	Retained on	% Weight	Cumulative Results % Retained	% Passing
--	2" Sq	0.00	0.00	100.00
2" Sq	1" Sq	0.00	0.00	100.00
1" Sq	1/2" Sq	0.32	0.32	99.68
1/2" Sq	No. 4	10.90	11.22	88.78
No. 4	No. 20	75.47	86.69	13.31
No. 20	No. 50	12.29	98.98	1.02
No. 50	No. 100	0.44	98.42	0.58
No. 100	No. 200	0.15	99.57	0.43
No. 200	No. 325	0.14	99.71	0.29
No. 325	0	0.29	100.00	0.00

Table 2-4
COMPARISON OF FEED COAL AND PDF MAF BASIS

	Feed Coal	PDF
Heating Value (Btu/lb)	12,740	13,840
Carbon (%)	73.4	84.0
Hydrogen (%)	5.5	3.6
Nitrogen (%)	1.1	1.3
Volatiles (%)	47.0	32.0

2.3 PDF UTILIZATION CHARACTERISTICS

Due to the unique nature of PDF there are several characteristics that will impact potential users. Tests have been performed on material produced in early pilot plant runs and testing continues on PDF from the demo plant. The process is still being optimized; however, some preliminary conclusions can be made on some of the possible concerns and problems with handling and combustion of the coal in boilers.

- Dustiness - The problem of -100 micron nuisance dust was anticipated. In order to minimize this the feed coal was screened to remove -1/8" coal particles. Provisions were also made to apply a dust suppressant to the finished product. Preliminary results with demo plant PDF show that the amount of dust is comparable or less than run-of-mine coal.

- Spontaneous Combustion - Initially, the PDF produced in the demo plant did not have the stability of the pilot plant PDF. The deactivation step recently introduced has diminished self heating of PDF. This is being supplemented now by outdoor storage pile exposure to atmosphere conditions for a 48 to 72 hour period, followed by indoor storage.

- Flame Stability - Results from pilot plant produced PDF were favorable. No problems were noted and carbon burnout was equivalent to run-of-mine coal. The PDF flame is short and compact as compared to run-of-mine coal which is twice as long. The flame is a clean blue which may require a different type of flame detector. Although hotter, it does not appear to produce more NO_x. Data from pilot plant PDF reported 25 to 32 ppm of carbon monoxide indicating good flame stability.

- Combustion - Predicting how PDF will perform in full scale boilers is difficult. Tests of PDF under lab conditions show a 400°F higher temperature relative to run-of-mine Powder River Basin coal (2700°F versus 2300°F). Two possible reasons for this are heating value and moisture content of the coal particles exiting the burner. A series of model calculations indicates the net effect of heat transfer for PDF compared to run-of-mine coal can vary significantly; therefore, accurate prediction of heat transfer in a full scale boiler is not possible. Field tests, particularly for pulverized-fired units, will be very important.

- Ash Deposition - The ash composition does not change in the production of PDF, but, since there is more ash in PDF than in the original run-of-mine coal, ash loading in the steam generator will be 35 to 40% higher on a lb/MM Btu basis than it would have been with the original coal. The PDF ash appears to be friable and easily removed by wallblowing.

Dustiness, spontaneous combustion, combustion and flame stability properties were determined on PDF produced in the pilot plant and early demo plant runs. These properties may differ when PDF is produced under steady state operation since PDF from the pilot plant and demo plant to date were not generated under optimized, steady state operation.

2.4 PLANT SCALEUP CONSIDERATIONS

A typical 400 MW utility power plant would require about 4,000 TPD. A commercial sized PDF plant would probably have to be sized to produce 5,000 to 25,000 TPD to be commercially viable. The major pieces of process equipment: dryer, pyrolyzer and deactivation fluidized bed, are all commercially available in larger sizes. None of the equipment is of special design and therefore can be scaled-up successfully.

Several changes to the demonstration plant design would be considered in the design at a larger commercial plant.

- The use of coal as the fuel for the combustor providing process heat, rather than natural gas, to minimize or eliminate the use of natural gas in the plant. This would generally be an economic decision, although it could also be based on availability.

- Since there is a lot of heat produced in the plant, cogeneration of electricity can be considered as an option.

- Depending on the characteristics of the coal being converted, a substantial amount of coal fines can be generated. If large enough, economic disposal or use of the fines should be investigated.

- The use of steam turbines as large equipment drivers, rather than electric motors, should be evaluated.

- Energy recovery, which is not a driving force in the design of demonstration plants, would have to be thoroughly evaluated and added where economically viable.

From a process standpoint, some variation in the amounts of CDL and PDF produced can be made by changing certain process parameters. Amounts of each product desired from a commercial plant would have to be evaluated and appropriate parameters established for the plant design.

There appears to be a limit of approximately 12,000 Btu/lb on the Btu content of the PDF, set by the process itself and the resulting characteristics of the CDL concurrently produced.

The demo plant ended 1994 with 22 test runs completed, comprised of over 5,000 hours of operation. The plant's products are being shipped to several sites for test burns, including a power plant in Oklahoma, where 8,000 tons were successfully burned, blended with Powder River Basin coal. ENCOAL Corporation also has contracts with a utility in Wisconsin for 30,000 tons of PDF and a utility in Iowa for a significant tonnage of PDF blended with Powder River Basin coal.

The liquid product is being shipped to several midwestern customers for use in industrial boilers. In addition, a synfuels plant in North Dakota has tested the liquid product and has contracted for ongoing delivery of commercial quantities of the fuel.

SGI International, the original process developer, is actively pursuing commercialization and in conjunction with Mitsubishi Heavy Industries, has agreed to conduct a technical and economic study for a 5,000 metric TPD liquids-from-coal plant for low-rank Chinese coals. Feasibility studies have also been proposed for projects in Indonesia and Poland.

3.0 REFERENCE PLANT DESIGN DESCRIPTION

The PDF Fired Reference Plant Design is based on current state of the art technology deployed in recently designed pulverized coal burning power plants, configured to burn the ENCOAL produced PDF. Emissions of SO_2 and NO_x are limited to the same values established for the other Reference Plants in the series. The conceptual design is described in this section.

3.1 DESIGN BASIS

The plant design basis has a significant influence on equipment selection, plant construction and operation, and resulting capital and operating costs. The following sections describe the basis which has been established for this plant.

3.1.1 Plant Site and Ambient Design Conditions

The plant site is assumed to be in the Ohio River Valley of western Pennsylvania/eastern Ohio/northern West Virginia. The site consists of approximately 300 usable acres (not including ash disposal) within 15 miles of a medium sized metropolitan area, with a well-established infrastructure capable of supporting the required construction work force. The area immediately surrounding the site has a mixture of agricultural and light industrial uses. The site is served by a river of adequate quantity for use as makeup cooling water with minimal pretreatment and for the receipt of cooling system blowdown discharges.

A railroad line suitable for 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 and with overhead restriction of not less 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 yards not more than 300 feet above the site elevation.

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

• Pressure	14.4 psia
• Dry bulb temperature	60°F
• Dry bulb temperature range	(-) 10 to (+) 110°F
• Wet bulb temperature	52°F

A sufficient number of well-trained construction laborers are 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 commodities of bulk construction material are available locally and can be delivered within a reasonable period of time.

3.1.2 Fuel and Sorbent

Plant performance will be based on PDF fuel with properties as described in Section 2.2, and shown in Table 3-1. The properties of PDF will vary somewhat, depending on the feed coal, as some variability exists in the raw coal available. The fuel properties presented on the next page were used in the performance analysis of the PDF fired reference plant. These fuel properties are representative of PDF product with equilibrium moisture after open storage in Wyoming. For PDF that will be shipped to the midwestern or eastern U.S., moisture content will be controlled to be in the 8 to 9% range. This will have a slight impact on the boiler and steam cycle heat balance. Pebble lime sorbent for the duct injection scrubber is received onsite as 98.0% pure CaO. No. 2 fuel oil will be used for unit start-up.

3.1.3 Design Capacity and Spare Capacity

The plant will consist of one pulverized PDF fired, balanced draft, natural circulation boiler coupled to a steam turbine generator that will produce approximately 400 MWe net output. The turbine generator (T-G) is sized and rated at a 100% load heat balance guarantee point. At this design point, the T-G typically operates with some turbine control valve travel remaining to full open. This permits the T-G control system to modulate T-G output in response to signals from the utility load dispatcher.

The T-G is capable of additional generation output above the 100% load guarantee point, which is obtained by operation with the inlet control valves in the maximum travel or wide open position. This condition is commonly referred to as the "valves wide open" or VWO condition. T-G performance is typically predicted (but not guaranteed) at the VWO condition at about 105% load.

Further additional output is possible by increasing the main steam pressure at the turbine inlet by 5 percent, by running the main feed pumps at a higher output (increasing speed of the feedpump turbine drives). This overpressure condition, commonly referred to as 5% overpresssure or 5% OP, yields an additional 3 to 5 percent in output.

For the purposes of this report, it is assumed that the plant will be operated most of the time at the 100% guarantee point, with the VWO capability used for normal peak demand periods, or when other baseloaded units are in forced outages. The 5% OP capability is held in reserve for severe system wide demand periods.

In order to realize the full potential of VWO and/or 5% OP operation, the remaining portions of the plant must be capable of supporting this level of generation. For the purposes of this report, the following design approach is assumed:

- Boiler - designed to support VWO output of the T-G as the guaranteed maximum continuous rating (MCR) of the boiler and its auxiliary equipment (fans, pulverizers, etc.). The 5% OP condition performance is predicted, but not guaranteed. The boiler design must account for this condition for pressure boundary integrity and code compliance.

- Feedwater heater string, condensate pumps, FW pumps and FW booster pumps, main condenser, and any equipment that may directly limit T-G output, are designed with

Table 3-1
TYPICAL PDF ANALYSIS

Constituent	Dry, %	As Received, %
Moisture	Zero	4.83
Carbon	75.25	71.62
Hydrogen	3.46	3.29
Nitrogen	1.13	1.08
Sulfur	0.56	0.53
Ash	8.19	7.79
Oxygen	11.41	10.86
Total	100.00	100.00

	Dry Basis, %	As Received, %
Moisture	--	4.83
Ash	8.19	7.79
Volatile Matter	27.00	25.70
Fixed Carbon	64.81	61.68
Total	100.00	100.00
Sulfur	0.56	0.53
Btu Content	12,389	11,791
Moisture and Ash Free (MAF), Btu	13,494	

	Ash Analysis, %
Silica, SiO_2	22.5
Aluminum Oxide, $Al2_o3$	13.8
Iron Oxide, Fe_2O_3	7.4
Titanium Dioxide, TiO_2	0.8
Calcium Oxide, MgO	26.6
Magnesium Oxide, MgO	5.9
Sodium Oxide, Na_2O	1.8
Potassium Oxide, K_2O	0.2
Sulfur Trioxide, SO_3	19.3
Phosphorous Pentoxide, P_2O_5	0.6
Strontium Oxide, SrO	0.4
Barium Oxide, BaO	0.6
Manganese Oxide, Mn_3O_4	0.1
Total	100.0

Ash Fusion Temperature, °F	Reducing Atmosphere	Oxidizing Atmosphere
Initial Deformation	2295	2395
Spherical	2300	2405
Hemispherical	2305	2415
Fluid	2310	2425

nominal guarantee ratings at the coincident 5% OP/VWO design condition.

- Circulating Water System, including main circulating water pumps and cooling towers, is designed based on an economic optimization at a specific design ambient wet bulb temperature condition. This optimization is typically based on the 100% guarantee output; the 5% OP/VWO condition output is indirectly limited by a higher condensing backpressure than what is obtained at the 100% load guarantee point, at the design ambient wet bulb temperature. Lower values of ambient wet bulb temperature will result in lower condenser backpressure and higher T-G output, up to a limit imposed by the turbine generator.

- Coal/Sorbent/Ash Handling Systems are designed to support the coincident 5% OP/VWO condition. Additional design margins are applied to cover the expected range of fuel and sorbent properties, which affect ash content, sulfur content, etc. These margins may be somewhat smaller than those required for the Pittsburgh No. 8 fired plants in this series, since PDF properties are expected to be relatively more consistent from shipment to shipment.

- Pollution Control Equipment is designed to support the 100% load condition for maximum continuous operation, with the capability of operating for limited time periods at the coincident 5% OP/VWO condition.

- Piping Design (pressure drops and velocities) are established at the 100% guarantee point. Higher pressure drops and velocities prevail at the 5% OP/VWO point, but do not directly limit output. Pressure ratings (pressure and temperature) are established at the VWO condition for continuous operation. The principal piping code (ANSI B31.1.0 Power Piping) permits limited time excursions at higher stresses. This allowance may be utilized to accommodate the 5% OP condition.

- The plant is designed with spare equipment and capacity based on historic potential for failures and service interruptions. Equipment items that are more likely to experience unplanned outages are represented by additional installed capacity. Examples of this type of equipment are (1) coal handling equipment, where 100% redundancy is provided up to the coal silos, and (2) condensate pumps (3 are provided at 50% capacity each). Other components, that historically have not significantly impacted plant availability, are provided with sufficient capacity to support plant operation at the coincident 5% OP/WVO condition, without installed spares, for short term operation (less than one day), and with sufficient capacity to support continuous operation at 100% load for extended time periods.

3.1.4 Plant Life

The plant will utilize components suitable for a 30-year life, with provision for periodic maintenance and replacement of critical parts. Major components requiring periodic maintenance during the plant life will be identified and the cost for the work included in the plant economic analysis.

3.1.5 Plant Availability and Capacity Factor

A levelized capacity factor of 65% is used for the economic evaluation (Section 4) of the PDF Reference Plant described in this report. This factor is based on methodology presented in the Electric Power Research Institute (EPRI) Technical Assessment Guide (TAG).

However, the subject power plant is expected to be capable of achieving a 75 percent levelized capacity factor over its service life operating in a utility system. This represents the actual net plant output as a percent of a hypothetical, but unattainable value of 100%, which represents a plant that is on-line producing power at its design maximum continuous rating for 100 percent of the time. The value of 75 percent is arrived at by consideration of two broad factors: plant availability and utility dispatch preferences.

Plant availability is a measure of the amount of time a given plant is available to produce power, and is generally expressed on an annualized basis. Based on historic data from such sources as the North American Electric Reliability Council, availability for a modern pulverized coal fired electric power plant is expected to be in the range of 83 to 86 percent, considering planned and forced outages. The major historical contributor to both forced and planned outages is the boiler with about 9 percent, and the turbine-generator with about a 6 percent contribution. All other factors combined represent approximately 2 percent of unavailability.

The availability of a given plant varies somewhat over the service life, being somewhat lower during the first year or two of operation as the plant undergoes normal "shakedown," and infant mortality for various items is experienced. Availability may also be reduced in a plant's later years, as equipment wears out. These influences tend to produce a levelized availability at the lower end of the range noted above, or about in the low 80's percent.

The influence of utility dispatching preferences depends on the units operating costs and emissions in relation to the system in which it is embedded. Fuel costs represent about three quarters of a typical coal fired unit's operating costs; therefore, plant thermal efficiency or heat rate plays a major role in determination of dispatch priority. The PDF Reference Plant defined in this report is assumed to be baseloaded for the majority of its service life with a high dispatch priority. Load following operation is assumed for a period of time as the unit enters its third decade of service, with final operation as a reserve unit.

Consideration of the above factors results in an expected value for levelized capacity factor of 75 percent over the unit's service life. However, as noted above, a 65 percent value has been used for economic evaluations in this report, based on EPRI practice. Individual power generators may apply their own expectations and adjust the economic data accordingly.

3.1.6 Maturity of Plant Technology

The plant design will be for a mature technology (i.e., the n^{th} plant). First-of-a-kind considerations such as high design margins, excessive test instrumentation, etc., will not be included in the design. It is expected that sufficient operating and maintenance data will be available to provide guidance on sparing of essential components, and that the design will reflect adequate provisions for maintenance such as pull space, platforms, cranes and hoists, etc.

3.1.7 Steam Conditions

A single reheat steam turbine will be used, with the following nominal steam conditions:

- Main steam: 2400 psig/1000°F
- Reheat steam: 545 psig/1000°F

Plant performance is based on the nominal 2400 psig throttle steam pressure conditions (i.e., pressures, temperatures, and flow rates) with an assumed 1.4/2.0-in. Hg condenser back pressure. Plant design is based on the VWO, 5% OP conditions.

Condensing steam cycle calculations will account for pressure drops in the equipment ducts and piping. The following pressure drops through the steam system piping will be assumed for the heat balance if more accurate estimates cannot be made:

- Main steam: 5 percent
- Cold and hot reheat steam: 5 percent (reheater excluded)
- Extraction steam to feedwater heaters:
  - Extractions below 100 psia: 5 percent
  - Extractions above 100 psia: 3 percent

3.1.8 Insulation and Lagging

Insulation and lagging will be provided on pressure vessels, piping, valves, and all other plant components that are potentially a significant heat-loss source to ambient and that require protection for personnel. The outside surface temperature will be limited to 145°F, with an ambient air temperature and velocity of 100°F and 160 ft/min respectively. If higher temperatures are used, appropriate personnel protection, such as a surrounding cage, will be specified and included.

3.1.9 Preheating

No. 2 oil-fired igniters are provided as the primary means for unit preheat and start-up. Where required, additional preheat sources such as electric/steam trace heaters or steam coil air heaters are provided to prevent cold-end acid corrosion, to preheat refractory, etc. If required, an auxiliary boiler firing No. 2 fuel oil will be provided to meet preheat requirements.

3.1.10 Modes of Operation

The plant is designed for base-load operation with occasional turndown to 25% plant load. The normal operating load range is from 25 to 100%. Below 25% load, the plant is in a start-up or shutdown mode. The high-pressure steam turbine operates at constant pressure over the operating load range.

Heat and material balances were prepared for the plant for the 100% load condition. Control/load following, start-up, and shutdown procedures are established.

3.1.11 Control Systems

An integrated plant wide control and monitoring system (DCS) is provided. The DCS is a redundant micro-processor based, functionally distributed system. The control room consists of multiple video monitor (CRT) and keyboard units. The CRT/keyboard units are the primary interface between the generating process and operations personnel. Minimal dedicated control and monitoring instrumentation is provided to safely shut-down (trip) the unit on a loss of the DCS. The DCS incorporates plant monitoring and control functions for all the major plant equipment. Control of minor plant equipment is included where economically practical.

The following control functions are implemented in the DCS: boiler and combustion controls, burner management, and plant logic. The following monitoring functions, as a minimum, are incorporated: alarming, trending, historical storage and retrieval, sequence of events, logging, and performance calculations.

The design of the DCS complies with the applicable standards of ASME, IEEE, ISA NEMA and NFPA.

The DCS is designed to provide a unit operating availability of 99.5%. Geographic distribution of portions of the DCS is implemented where a cost/benefit analysis identifies an installed cost saving while maintaining the design criteria and availability required above.

The plant equipment and the DCS are designed for automatic response to load changes from minimum load to 100%. Start-up and shut-down routines are implemented as supervised manual with operator selection of modular automation routines available.

3.1.12 Plant Services

The following services/support systems are available at the plant as a part of the balance-of-plant systems. Any additional services required will be identified.

- Auxiliary Power Systems

  - 7200-v system for motors above 3000 hp.
  - 4160-v system for motors from 250 to 3000 hp.
  - 480-v system for motors 0 to 250 hp and miscellaneous loads.
  - Emergency diesel generator (480 v) to supply loads required for safe and orderly plant shutdown. Instruments and controls and other loads requiring regulated (1 percent) 208/120 vac power are supplied from this source.
  - 250 vdc system motors and, via static inverters, uninterruptible ac power for the integrated control and monitoring system, intercommunication.
  - 125 vdc system for dc controls, emergency lighting, and critical tripping circuits including the plant shutdown system.

- Cooling Water

  - Cooling water (from the cooling towers) is available at between 20 and 30 psig, 90°F maximum temperature. The water is periodically chlorinated, and pH is maintained at 6.5 to 7.5. The cooling towers receive makeup water from the river.

- Auxiliary cooling water, which uses demineralized water treated for corrosion control, at 60 to 80 psig and 105°F, is available for small heat loads (e.g., control oil coolers). The pH is maintained at about 8.5.

- Compressed Air

  - Instrument air filtered and dried to -40°F dewpoint at 80 to 100 psig and 110°F (maximum).
  - Service air at 80 to 100 psig and 110°F (maximum).

- Lube Oil

  Lube oil from the conditioning system, with particulate matter removed to 10 μm or lower.

- Hydrogen and Carbon Dioxide

  H_2 and CO_2 for generator cooling and purging from storage.

- Nitrogen

  N_2 for equipment blanketing against corrosion during shutdown and layup.

- Raw Water

  Filtered river water. Additional water treatment will be included for potable water, etc.

3.1.13 Structures and Foundations

A structure or structures are provided to support and permit access to all plant components requiring support to conform with the site criteria defined in Section 3.1.1. The structure(s) are enclosed if deemed necessary to conform with the environmental conditions.

Foundations are provided for the support structures, pumps, tanks, and other plant components. A soil-bearing load of 5000 lb/ft^2 is used for foundation design.

3.1.14 Heat Recovery

Sensible heat in solids streams discharged from the plant is recovered to the extent economically practical.

3.1.15 Codes and Standards

Recognized design codes and standards that are commonly used for the design of commercial fossil-fuel-fired power plants are applied to the extent of ensuring that their requirements are met. Where the existing codes and standards cannot be applied to the design and fabrication of a component, the components will be designed using accepted industry standards. Some of the more important applicable codes and standards are listed in Table 3-2.

Table 3-2
TYPICAL DESIGN CODES AND STANDARDS

- ASME Boiler and Pressure Vessel Code:
  Section I, Power Boilers,
  Section VIII, Divisions 1 and 2, Unfired Pressure Vessels
- ASME/ANSI B31.1, Power Piping Codes and Addenda
- National Fire Code (NFPA) 1992
- OSHA Regulations, 29CFR1910
- Uniform Building Code
- ASCE-7, 1988, Minimum Design Loads for Buildings and Other Structures (Revisions and Redesignation of ANSI A58.1-1982)
- National Electrical Code

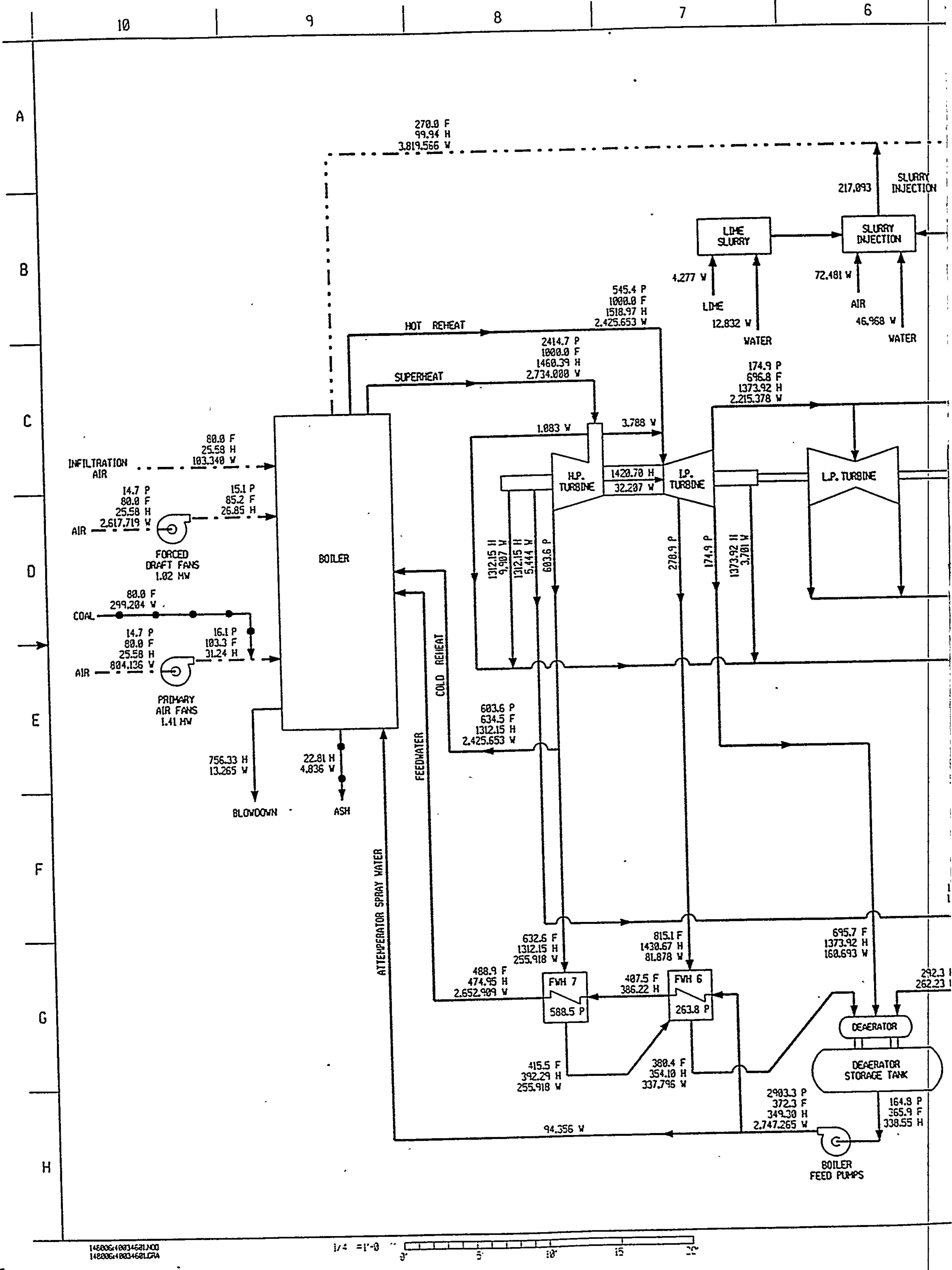
3.2 HEAT AND MASS BALANCE

The steam power cycle is shown schematically in the 100 percent load Heat and Mass Balance diagram, Figure 3-1. The diagram shows state points at each of the major components for the conventional plant. Overall performance is summarized in Table 3-3 which includes auxiliary power requirements.

The plant uses a 2400 psig/1000°F/1000°F single reheat steam power cycle. The high pressure turbine uses 2,734,000 lb/h steam at 2415 psia and 1000°F. The cold reheat flow is 2,425,653 lb/h of steam at 604 psia and 635°F, which is reheated to 1000°F before entering the intermediate pressure turbine section.

Tandem high, intermediate, and low pressure turbines drive one 3600 rpm hydrogen-cooled generator. The low pressure turbines consist of two condensing turbine sections. They employ a dual-pressure condenser operating at 1.4 and 2.0 in Hg at the nominal 100% load design point at an ambient wet bulb temperature of 52°F. For the low pressure turbines, the last stage bucket length is 30.0 inches, the pitch diameter is 85.0, and the annulus area per end is 55.6 square feet.

The feedwater train consists of six closed feedwater heaters (four low pressure and two high pressure), and one open feedwater heater (deaerator). Extractions for feedwater heating, deaerating, and the boiler feed pump, are taken from all of the turbine cylinders.



10
9
8
7
6
A
B
C
D
E
F
G
H
270.0 F
99.94 H
3,819,566 W
217,093
SLURRY INJECTION
LIME SLURRY
SLURRY INJECTION
4,277 W
LIME
12,832 W
WATER
72,481 W
AIR
46,968 W
WATER
545.4 P
1000.0 F
1518.97 H
2,425,653 W
HOT REHEAT
2414.7 P
1000.0 F
1460.39 H
2,734,000 W
SUPERHEAT
174.9 P
696.8 F
1373.92 H
2,215,378 W
1,083 W
3,788 W
INFILTRATION AIR
80.0 F
25.58 H
103,340 W
14.7 P
80.0 F
25.58 H
2,617,719 W
AIR
15.1 P
85.2 F
26.85 H
FORCED DRAFT FANS
1.02 MW
H.P. TURBINE
1420.70 H
32,207 W
I.P. TURBINE
L.P. TURBINE
BOILER
1312.15 H
9,907 W
1312.15 H
5,444 W
603.6 P
278.9 P
174.9 P
1373.92 H
3,701 W
80.0 F
299,204 W
COAL
14.7 P
80.0 F
25.58 H
804,136 W
AIR
16.1 P
103.3 F
31.24 H
PRIMARY AIR FANS
1.41 MW
COLD REHEAT
603.6 P
634.5 F
1312.15 H
2,425,653 W
756.33 H
13,265 W
BLOWDOWN
22.81 H
4,836 W
ASH
FEEDWATER
ATTEMPERATOR SPRAY WATER
632.6 F
1312.15 H
255,918 W
815.1 F
1430.67 H
81,878 W
695.7 F
1373.92 H
160,693 W
488.9 F
474.95 H
2,652,909 W
FWH 7
588.5 P
407.5 F
386.22 H
FWH 6
263.8 P
292.3
262.23
DEAERATOR
DEAERATOR STORAGE TANK
415.5 F
392.29 H
255,918 W
380.4 F
354.10 H
337,796 W
2903.3 P
372.3 F
349.30 H
2,747,265 W
164.8 P
365.9 F
338.55 H
94,356 W
BOILER FEED PUMPS
148006-4003460LN00
148006-4003460LGRA
1/4 =1'-0"
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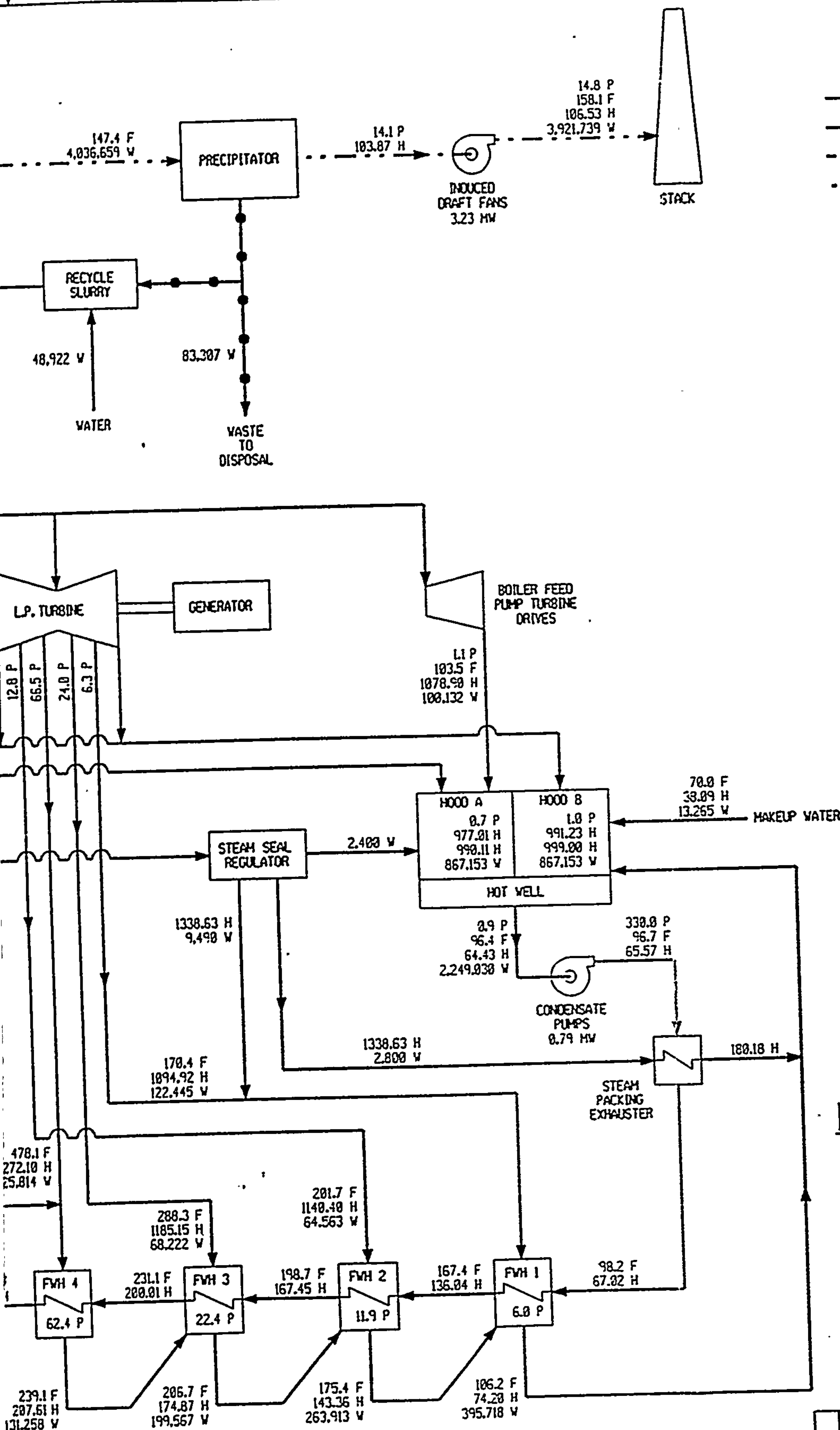
5
10
15
20



LEGEND

———	CONDENSATE, FEEDWATER, OR STEAM
—●—●—	COAL OR ASH
— — —	AIR
— · · —	FLUE GAS
P	PRESSURE, PSIA
F	TEMPERATURE, °F
H	ENTHALPY, BTU/LBM
W	MASS FLOW, LBM/HR
MWe	POWER, MEGAWATTS ELECTRICAL

SYSTEM PERFORMANCE SUMMARY

GROSS POWER :	434.5 MWe
GENERATOR LOSS :	7.4 MWe
TRANSFORMER LOSS :	1.0 MWe
AUXILIARY POWER :	21.7 MWe
NET PLANT POWER :	404.3 MWe
NET PLANT EFFICIENCY :	39.1 %
NET PLANT HEAT RATE :	8726 Btu/kwh

FIGURE 3-1

REVISIONS

STATUS OF DRAWING	DEFINITION
☐ APPROVED	REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
☐ PRELIMINARY	REPRESENTS ACCEPTABLE DESIGN CONCEPTS. SUBJECT TO CHANGE.
☒ CONCEPTUAL	REPRESENTS GENERAL CONCEPTS BASED ON ASSUMPTIONS. CHANGES COULD ENSUE.

CLEAN COAL TECHNOLOGY
ENCOAL REFERENCE PLANT
DEPARTMENT OF ENERGY, METC

PLANT HEAT AND MATERIAL BALANCE

GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

RDM

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Table 3-3

PLANT PERFORMANCE SUMMARY - 100 PERCENT LOAD

STEAM CYCLE	
Throttle Pressure, psig	2,400
Throttle Temperature, °F	1,000
Reheat Outlet Temperature, °F	1,000
POWER SUMMARY	
3600 rpm Generator	
GROSS POWER, kWe (Generator terminals)	427,060
AUXILIARY LOAD SUMMARY, kWe	
Pulverizers	1,600
Primary Air Fans	1,410
Forced Draft Fans	1,020
Induced Draft Fans	3,230
Seal Air Blowers	50
Main Feed Pump (Note 1)	*8,660*
Steam Turbine Auxiliaries	800
Condensate Pumps	800
Circulating Water Pumps	3,400
Cooling Tower Fans	1,800
Coal Handling	180
Lime Handling & Reagent Prep.	230
Ash Handling	1,600
Atomizing Air Compressors (Duct Inj Scr)	2,700
Precipitators	900
Soot Blowers (Note 2)	neg.
Miscellaneous Balance of Plant (Note 3)	2,000
Transformer Loss	1,020
TOTAL AUXILIARIES, kWe	22,740
Net Power, kWe	404,320
Net Efficiency, % HHV	39.1
Net Heat Rate, Btu/kWh (HHV)	8,726
CONDENSER COOLING DUTY, 10^6 Btu/h	1,722
CONSUMABLES	
As-Received PDF Feed, lb/h	299,204
Sorbent, lb/h	4,277

Note 1 - Driven by auxiliary steam turbine, electric equivalent shown
Note 2 - Soot blowing medium is boiler steam. Electric power consumption is negligible.
Note 3 - Includes plant control systems, lighting, HVAC, etc.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 405 MWe. This PDF Fired Reference unit achieves a net plant efficiency of 39.1%, which is an increase of 0.5% over that achieved by the Referenced Pulverized Coal (PC) Unit fueled by Pittsburgh No. 8 coal. This increase in efficiency is achieved although the units are virtually identical in terms of size, boiler selection, steam cycle configuration, heat sink, and other considerations. The net efficiency improvement arises in the following manner:

1. The PDF unit auxiliary load is slightly lower than the Reference PC unit's load. This reduction primarily occurs from reduced ID fan power requirements, which result from elimination of scrubber gas path pressure losses. Elimination of limestone grinding mills and byproduct centrifuges also reduce auxiliary load requirements, but is offset by the addition of atomizing air compressors for the Duct Injection System.

2. The PDF unit gas temperature leaving the boiler is set at 270°F versus 290°F for the Reference PC unit. This reduction in exhaust temperature, which improves boiler efficiency, is feasible because of the relatively low SO_2 concentration in the gas leaving the boiler, and because the gas passes directly into the duct injection scrubber, which is upstream of the electrostatic precipitator (ESP).

The major features of this plant include the following:

- boiler feed pumps are steam turbine driven
- turbine configuration is a 3600 rpm tandem compound, four flow exhaust
- plant has six stages of closed feedwater heaters plus a deaerator

3.3 ENVIRONMENTAL STANDARDS

Environmental standards applicable to the design of an electric utility power plant relate primarily to air, water, solid waste, and noise (Table 3-4). Both State and Federal regulations control emissions, effluents, and solid waste discharged from the plant. Additional environmental regulations may apply on a site-specific basis (National Environmental Policy Act, Endangered Species Act; National Historic Preservation Act, etc.) but will not be considered for this project.

3.3.1 Air Quality Standards

The plant pollution emission requirements under New Source Performance Standards (NSPS), prior to the Clean Air Act Amendments (CAA) of 1990, were as follows:

- SO_x: 90-percent removal
- NO_x: 0.6 lb/10^6 Btu
- Particulates: 0.03 lb/10^6 Btu
- Visibility: 20-percent opacity

The 1990 CAA imposed a two phase capping of SO_2 emissions on a nationwide basis. For a new green grass plant, the reduction of SO_2 emissions that would be required depends on possession or availability of SO_2 allowances by the utility, and on local site conditions. In many cases, Prevention of Significant Deterioration (PSD) Regulations will apply, requiring that Best Available Control Technology (BACT) be used. BACT is applied separately for each site, and results in different values for different sites. In general, the emission limits set by BACT will be significantly lower than NSPS limits. The following ranges will generally cover most cases:

Table 3-4
APPLICABLE ENVIRONMENTAL REGULATIONS

Clean Air Act as amended in 1990, including:

- New Source Performance Standards
- National Ambient Air Quality Standards
- Best Available Control Technology
- Lowest Achievable Emission Rate

Federal Water Pollution Control Act (as amended by the Clean Water Act of 1977), including:

- Section 404 Dredge and Fill
- National Pollution Discharge Elimination System
- Best Available Technology Economically Achievable
- Effluent Guidelines and Standards 40CFR423

Resource Conservation and Recovery Act (RCRA)

OSHA Regulations 29CFR1910

State Regulations

- Air Quality Standards
- Water Quality Discharge Standards
- Solid Waste Disposal Standards

- SO_x: 92 to 95%, based on firing Pittsburgh No. 8 coal at 2.9% sulfur. For this PDF fired plant, SO_2 removal efficiency is set at 50% to provide emission levels comparable to the other Reference plants.
- NO_x: 0.2 to 0.45 lb/10^6 Btu
- Particulate: 0.015 to 0.03 lb/10^6 Btu
- Opacity: 10-20%

For this study, plant emissions are capped at values shown in Table 3-5 below.

Table 3-5
PULVERIZED PDF FIRED BOILER REFERENCE PLANT EMISSIONS

	lb/10^6 Btu	tons/year @ 400 MWe, 65% capacity factor
SO_2	0.35	3760
NO_x	0.30	3200

Best Available Control Technology is not applied to the plant described in this report, since it is a site and time dependent issue. The PDF fuel is very low in sulfur, as delivered. The 50% removal rate assumed in this Reference Design brings the net emissions at the stack down to a level that is comparable to the other Clean Coal Reference Plants. Selective adjustments for additional SO_2 and/or NO_x reduction may be applied by users of this report by applying specific technology increments that suit each case.

Air quality regulations concerning other compounds such as CO, CO_2 and air toxics are being considered by federal authorities at the present time, and may have an effect on the design of plants in the time frame being considered here. However, details of the end results of these considerations are not clear at the present time and are not included in this report.

3.3.2 Water Quality Standards

Waste water, principally cooling tower blowdown, boiler blowdown, ash transport water, and process condensate or purge water, will be discharged following treatment to comply with the Environmental Protection Agency Effluent Guidelines and Standards (Title 40CFR).

3.3.3 Solid Waste Disposal

Spent sorbent, ash, air-pollutant emission control waste, and sludge produced from water treatment will be disposed of according to the nonhazardous waste disposal guidelines of Sections 1008 and 4004 of the Resource Conservation and Recovery Act (RCRA), and applicable state standards, appropriate for the actual plants' location.

Several potential avenues are presently available to dispose of solid wastes from FGD systems. These include disposal in a landfill or sale to a manufacturer of building products. The latter approach requires careful control of the quality of the sulfate (gypsum) produced by the dewatering of spent scrubber reagent. Local business factors will play a significant role in determining the viability of this option. For this conceptual design, disposal to a landfill is the approach taken.

3.3.4 Noise

In-plant equipment will be designed to meet the noise exposure regulations of the Occupational Safety and Health Administration (OSHA). Noise levels from major noise sources (e.g., fans, motors, gas turbines, valves, pumps, and piping) will not exceed 95 dBA at 3 ft. Outdoor noise criteria for on-site sources of noise will be an integrated equivalent level (Leq) of 55 dBA at the property boundary. The minimum distance to the property line will be assumed to be 1000 ft.

3.4 DESCRIPTION OF STEAM GENERATION SYSTEMS

The following sections contain descriptions of the steam generation systems in the plant. The boiler description is based on a commercially available, pulverized coal fired, natural circulation type steam generator. At least two major U.S. manufacturers offer this type of unit; in addition, a forced circulation type boiler is offered by a third U.S. firm. Any one of these units is capable of performing in the plant described herein. For illustrative purposes, a Babcock & Wilcox boiler and accessories are described herein. The balance of the steam generation systems are conventional for this size plant.

3.4.1 Steam Generator and Ancillary Equipment

The 400 MWe pulverized coal fired steam generator described herein is a B&W Carolina Type Radiant Boiler. This section provides brief descriptions of this type of boiler and its principal accessories.

A description of the equipment is included in Appendix A, Major Equipment list. Figure 3-2 illustrates a typical cross section of a 400 MW boiler, similar to the boiler used in this report.

3.4.1.1 General Description

The steam generating unit described herein is a balanced draft Babcock & Wilcox Carolina Type Radiant Boiler. It is arranged with a water cooled dry-bottom furnace, superheater, reheater, economizer, and air heater components. The unit described herein is based on the same boiler design selected for and presented in the Pulverized Coal Fired Reference Plant. The detail design and dimensions of the boiler require adjustment to effectively deal with unblended PDF fuel.

It is expected that a specific burner design will be required in order to optimize efficiency and minimize NO_x production for firing 100% PDF. Also, an increase in furnace dimensions may be expected to accommodate the ash properties of PDF, which will be lignitic in nature, and thus different from those of Eastern bituminous coals, such as Pittsburgh No. 8 coal, the design basis fuel for the Reference Pulverized Coal Plant.

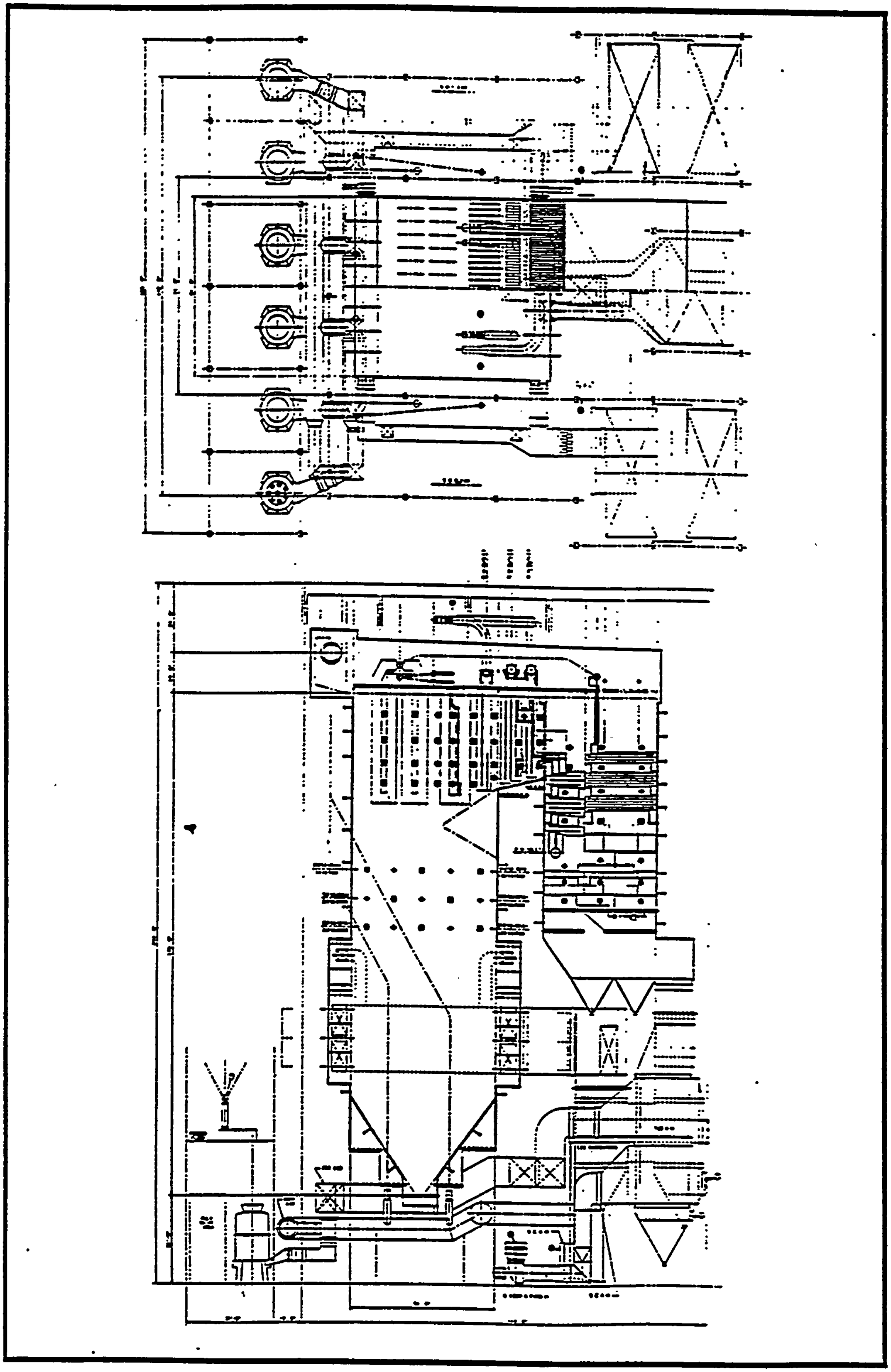
Fuel Flow

Raw PDF is discharged from the feeders to the pulverizers where the primary air is introduced and the fuel is pulverized. The pulverized PDF is transported by the primary air to the burners through a system of pressurized fuel-air piping. The pulverizers are described in Section 3.4.1.5.

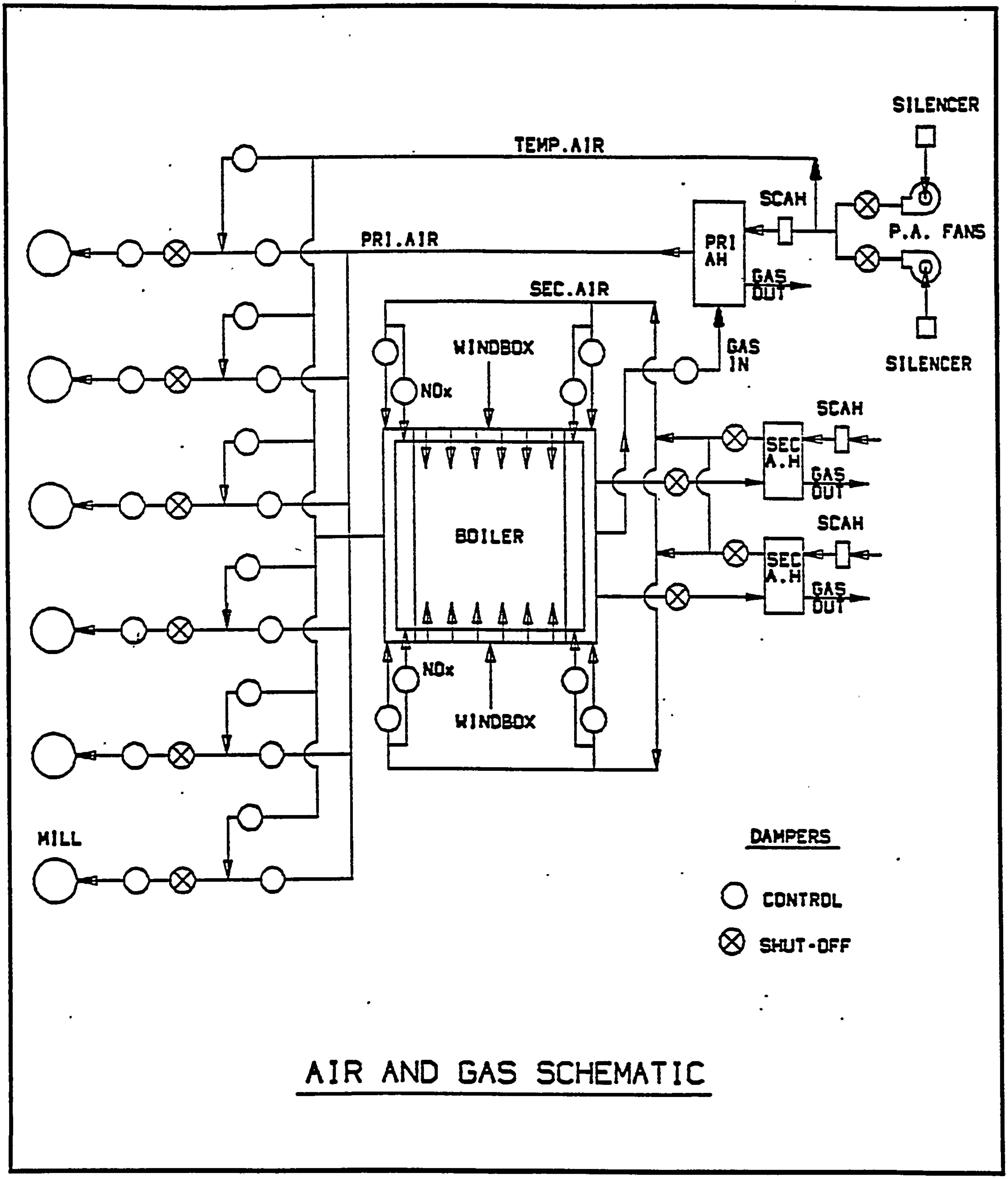
Air and Gas Flow (Figure 3-3)

Air from a forced draft fan is heated in the regenerative air heaters and is distributed to the burner windbox as secondary air. A portion of the combustion air is taken from atmosphere by the primary air fans which provide the pressure to pass this air through the primary air heater and pulverizers to the burners. A portion of the air from the primary air fans is passed unheated around the primary air heater as tempering primary air. The preheated and tempering primary air are mixed at each pulverizer to obtain the desired pulverizer fuel-air mixture outlet temperature.

Hot gas from the furnace passes successively over the platen and pendant sections of the secondary superheater and reheater, located in the convection pass, and out of the high radiant heat transfer zone of the furnace. The gas turns down and crosses in parallel to the horizontal primary superheater and economizer surface on the back pass, and horizontal reheat and economizer surface on the front pass. Gas flows are adjusted by dampers at the outlet of each pass to control reheat steam temperature across the load range. The flue gas then turns



BOILER PLAN AND CROSS SECTION **FIGURE 3-2**



AIR AND GAS FLOW SCHEMATIC **FIGURE 3-3** horizontal across an outlet hopper and enters the air heaters.

<u>Water and Steam Flow</u> (Figure 3-4)

Feedwater enters the bottom header of the economizer. The water passes upward through the economizer and discharges through the outlet header into piping which conducts it to the steam drum. By means of natural circulation, the water flows down through downcomer pipes connecting supply distributor tubes to the lower furnace headers. From the furnace wall headers, the fluid rises through the furnace tubes to the upper enclosure headers. The flow then passes through riser tubes into the steam drum.

The water and steam mixture in the steam drum is separated by cyclone steam separators which provide essentially steam-free water in the downcomers. The steam is further purified by passing it through the primary and secondary steam scrubbers.

Steam from the steam drum passes through multiple connections to the headers supplying the furnace roof tubes and pendant convection pass sidewall tubes. From the furnace roof outlet headers and pendant convection pass sidewall outlet headers, steam passes to the horizontal convection enclosure inlet headers, wall tubes and outlet headers in succession and then flows to the primary superheater.

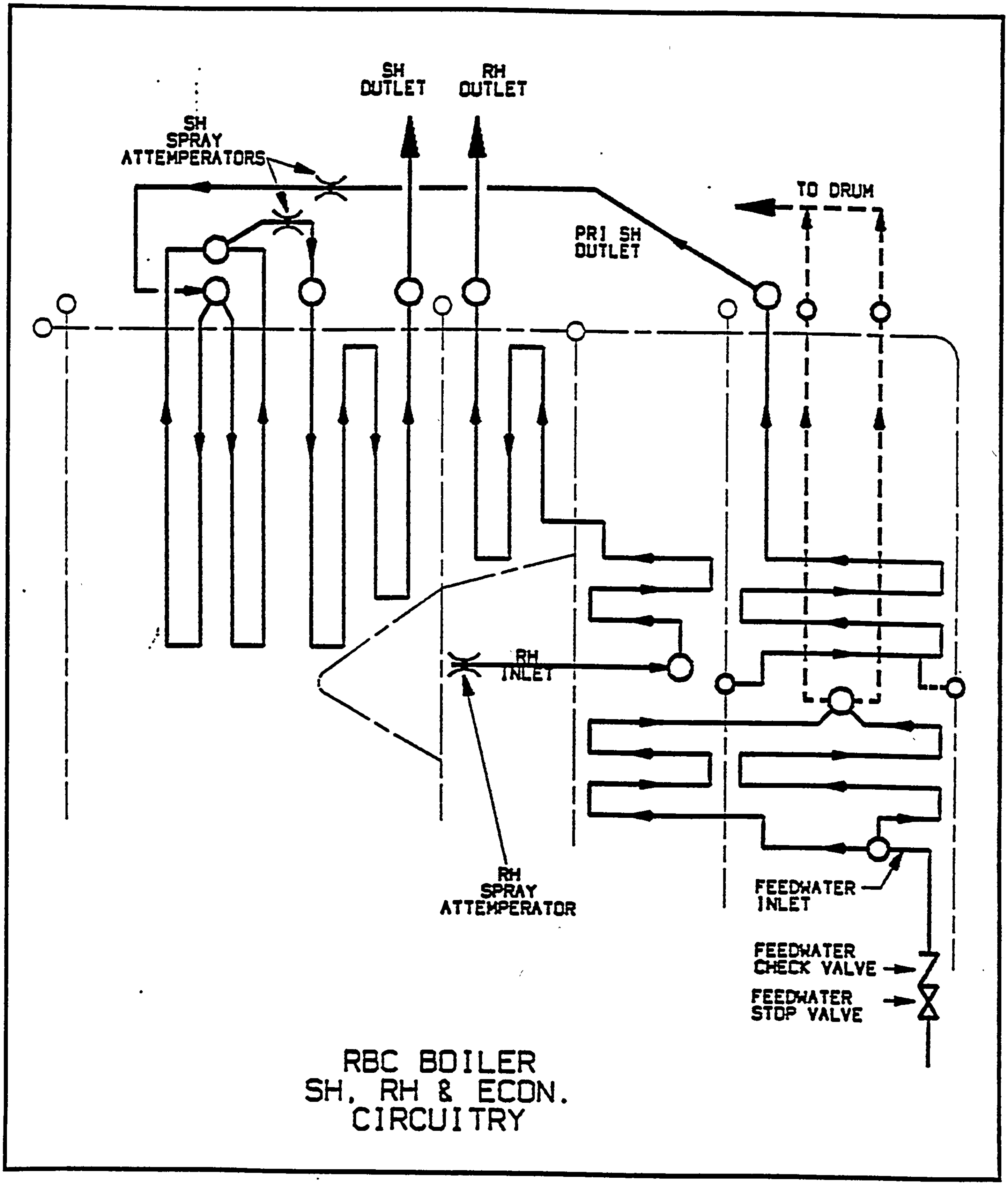
Steam flow rises through the primary superheater and discharges through its outlet header and through connecting piping equipped with spray attemperators. The steam then enters the secondary superheater inlet header and flows through the secondary superheater sections to the outlet header and to the main steam piping.

Cold reheat steam returning from the turbine passes through the reheat attemperators located in the inlet piping to the reheat superheater. It then flows through the reheat superheater sections to the outlet headers and the hot reheat piping.

3.4.1.2 Furnace and Burner Design

The furnace is a single water cooled chamber that, for conceptual design purposes, has a nominal 25% increase in plan area relative to the original design which was sized for Eastern bituminous coals. The resulting furnace is approximately 56 ft wide, 50 ft deep, and 185 ft in height. Detailed design of the boiler for PDF fuel is beyond the scope of this conceptual design and Reference Plant report. A nominal increase in furnace dimensions was applied to the original (pulverized Eastern bituminous coal) design to accommodate the lignitic ash produced by PDF. The furnace geometry is optimized to provide adequate burner spacings, burner zone cooling surface and burner zone residence time for the required NO_x levels.

The low NO_x burners are arranged on the front and back wall in three rows of six burners per wall. All burners supplied with fuel from each pulverizer are arranged in a single row. The burner design for PDF is essentially the same as for bituminous pulverized coal. Since the PDF is processed, it will be more uniform, have less volitiles and have less water, and will produce a more stable flame. A new burner, designed for PDF, may be slightly different is some respects, but the changes will not affect the overall cost of the plant.



STEAM/WATER FLOW SCHEMATIC

FIGURE 3-4

As shown in Figures 3-5 and 3-6, the B&W XCL burner makes use of air staging and fuel staging technology by virtue of its design. The coal nozzle is centrally located in the burner in an arrangement which carefully limits air/fuel interaction in the root of the flame. The fuel element is housed in a single, central flame stabilizer which results in excellent flame stability and turndown, while separating the fuel elements from the combustion air. The coal nozzle features a conical diffuser for even coal distribution. Secondary air introduction to the fuel is regulated by dual air zones with adjustable inner and outer swirl vanes.

Peak NO_x formation is reduced by controlling the rate of combustion and apparent stoichiometry. Hydrocarbon radicals are produced which react with the NO_x formed early in the flame and further reduce NO_x emissions. Combustion air gradually mixes with these products of combustion further downstream to complete char reactions while minimizing NO_x re-formation.

Additional air staging is accomplished by introducing a portion of the combustion air above the uppermost level of burners. This further reduces the formation of NO_x in the combustion zone.

3.4.1.3 Air Heater

The air heater is comprised of two Ljungstrom regenerative type units, which are driven by air motors and rotate at approximately one rpm. Seal leakage is within reasonable tolerances for this balanced draft application.

3.4.1.4 Bottom Ash Removal

Approximately 20 percent of the ash in the fuel is withdrawn as bottom ash. This material falls by gravity to the bottom of a pair of water impounded hoppers located beneath the furnace, at which point it enters a clinker grinder, which reduces the ash into moderate size particles. The ash material is discharged at the bottom of the clinker grinder into the suction entrance of a sluice water motivated jet ejector. The sluice water stream entrains and cools the ash, which is routed to the ash pond. Refer to Section 3.4.6 for additional information regarding other ash collection points in the boiler system.

3.4.1.5 Fuel Feed System

The fuel feed system supplied by the boiler manufacturer interfaces with the balance of plant fuel handling system at the inlet connection in the top center of each coal pulverizer. PDF, as received, is an appropriate size (1 inch X 0), and is fed by a Gravimetric type feeder into each pulverizer. Four of the five pulverizers provided are required to operate to sustain the boiler at 100 percent capacity.

The B&W roll and race type MPS pulverizer, shown in Figures 3-7 and 3-8, employs the roller principle of grinding with a hydraulically loaded spring system providing the required loading to the roller grinding elements. The required capacity is provided by large, low speed grinding elements. The grinding elements of wear resistant Elverite material consist of three rollers and lower grinding ring. The B&W pulverizer is designed to accept a raw coal feed sized to pass through a 1.25 inch ring.

PDF fuel enters the pulverizer, passes through the grinding elements and is partially pulverized. A stream of preheated primary air picks up the partially pulverized fuel from the grinding zone

Babcock & Wilcox

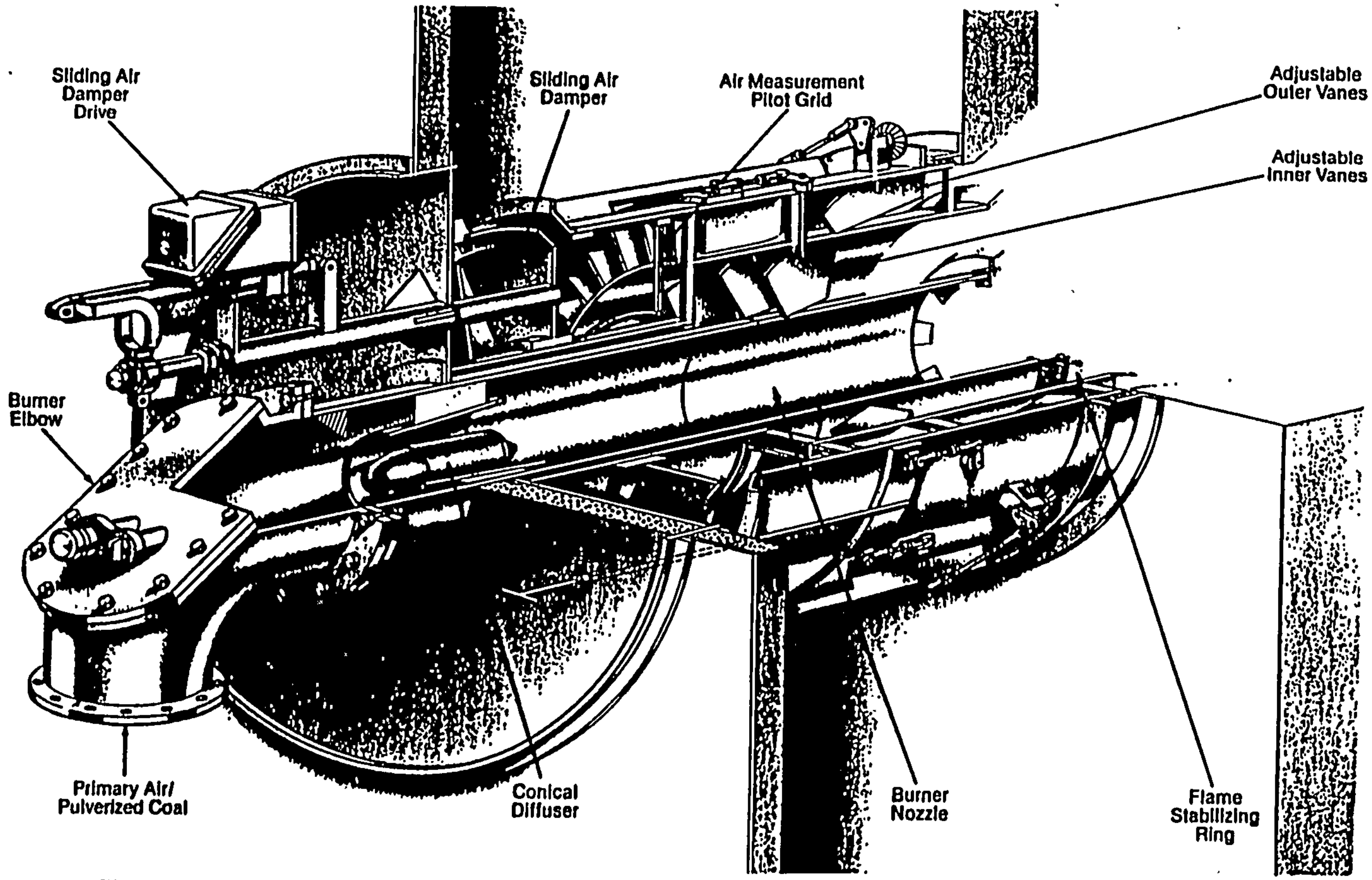


Fig. 9 DRB-XCL™ low NO_x burner for pulverized coal firing.

LOW NO_X BURNER CROSS-SECTION

FIGURE 3-5

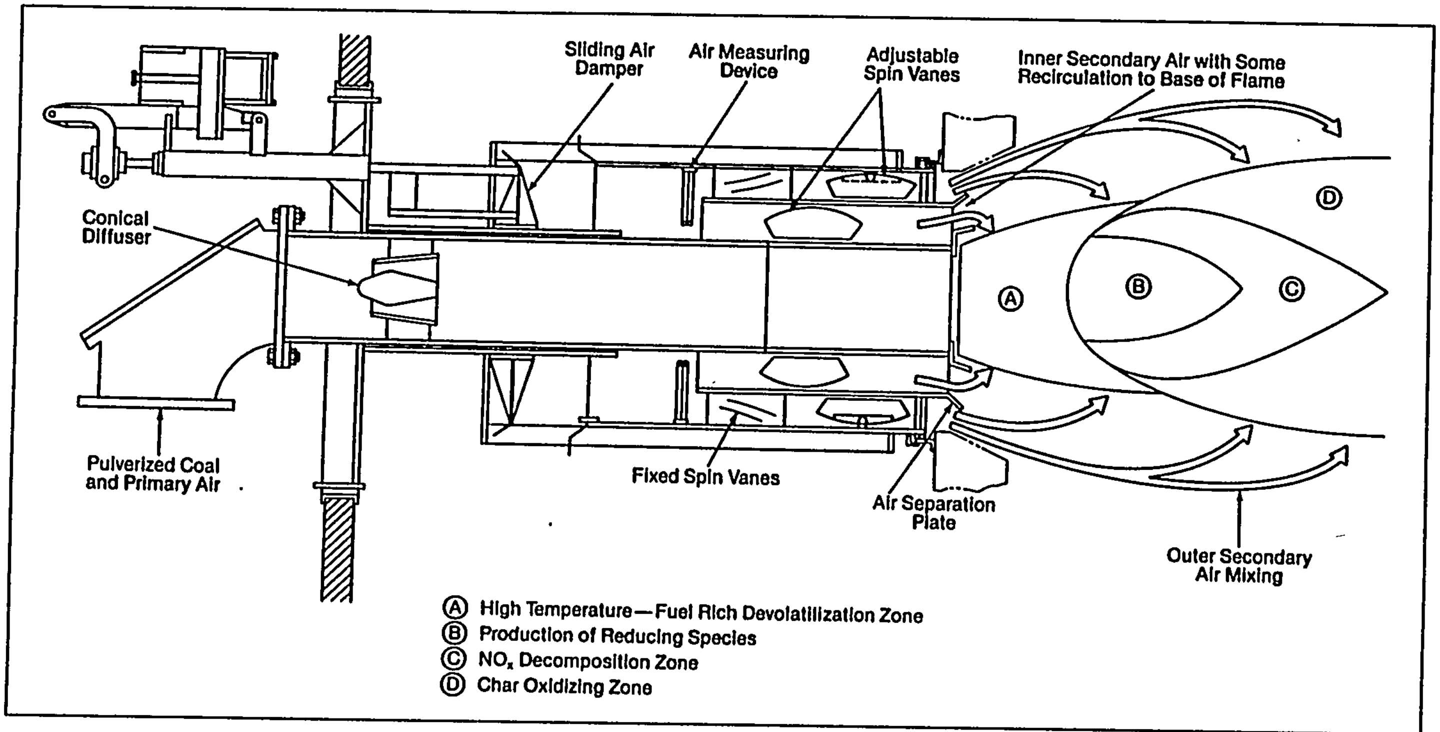


Fig. 11 DRB-XCL™ low NO_x combustion zones.

LOW NO_X BURNER COMBUSTION ZONES

FIGURE 3-6

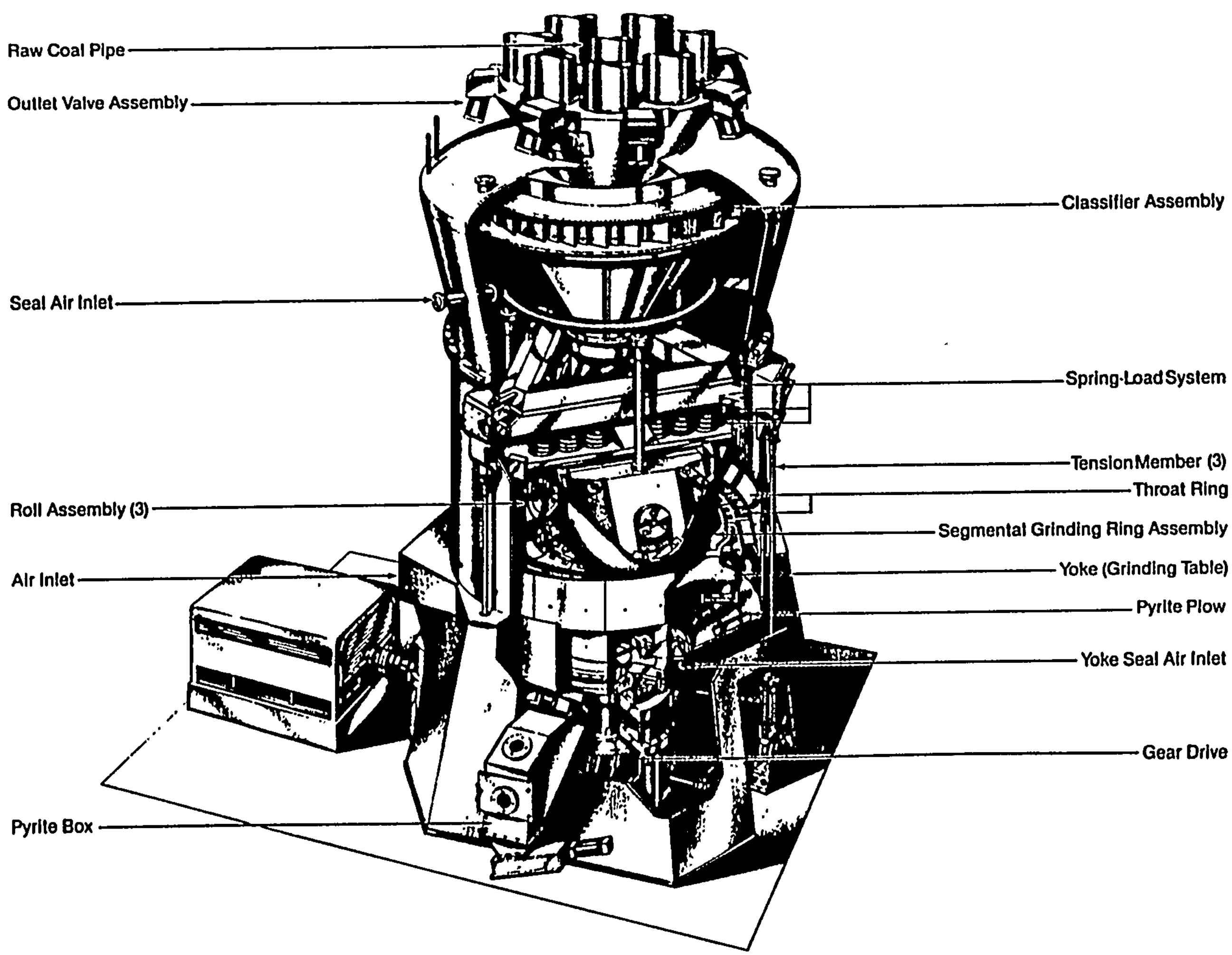
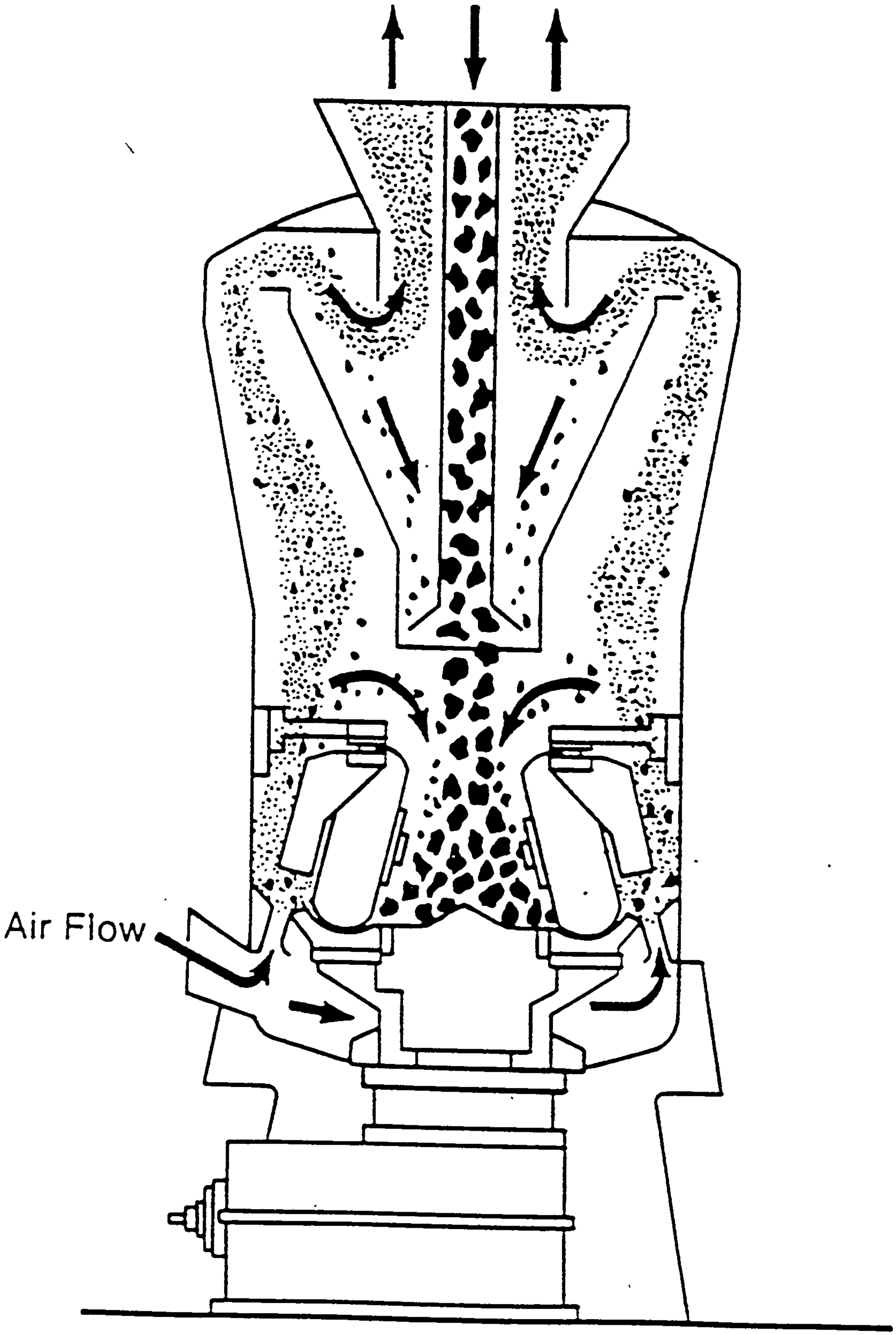


Fig. 1 Babcock & Wilcox MPS pulverizer.

ROLL AND RACE TYPE PULVERIZER CUTAWAY VIEW

FIGURE 3-7



Roll and Race Pulverizer Cross Section

FIGURE 3-8

and carries it to the classifier. There the coarse particles are separated from the fines and returned to the grinding zone while the fines are air-born through the fuel-air piping to the burners. Pyrites are rejected to a discharge hopper from which they are sluiced and routed to the Economizer/Pyrites transfer tank.

Preheated air at the required temperature is obtained by proportioning hot and cold primary air to each pulverizer. Pulverizer isolation is accomplished by means of a double damper arrangement in the primary air connection to each mill. Sealing air is admitted between the two dampers to guard against leakage of hot primary air into an idle pulverizer.

3.4.1.6 Startup Igniter System

A startup igniter using No. 2 oil is provided in conjunction with each pulverized fuel burner for light-off and to stabilize the main burner during start-up and at low loads. The igniters are electrically ignited and air atomized, and are capable of supporting up to 20% of full load when operated as the sole boiler energy input. Natural gas, if it is available, can also be used for startup fuel. Economics, based on geographical location should be used to make the choice.

3.4.1.7 Sootblower System

The boiler is furnished with an automatic sequential soot blowing system, using steam as the blowing medium in an array of approximately 70 electrically driven and operated soot blowers. The system uses a combination of short retractable, long retractable, and long retractable (with extended lance) type blowers to clean the furnace walls, superheater, reheater, air heater and economizer. The system utilizes main steam from the boiler at 2700 psig/790°F; with a total steam consumption of approximately 220,000 lb in each 24 hour period at rated power.

3.4.1.8 Particulate Collection

The flue gas discharged from the boiler (air preheater and duct injection system) is directed through an electrostatic precipitator array comprised of two rigid frame single stage units. Each precipitator unit is divided into five field sections, each in turn, containing four cells. Each cell contains a number of gas passages comprised of discharge electrodes, collecting plates, and ash hoppers supported by a rigid steel casing. Each cell and ash hopper is provided with a rapping system which periodically provides a mechanical shock to the unit to cause the fly ash particles to drop into the hopper, and then out into the collection piping. The precipitators are provided with necessary electrical power and control devices, inlet gas distribution devices, insulators, inlet and outlet nozzles, expansion joints, and other items as required.

Electrostatic precipitators have a long and successful application history on medium to high sulfur coal, and provide very high (up to 99.9%) collection efficiencies with a modest electric power consumption and minimal flue gas pressure drop. Tests run on systems where duct injection systems have been used for sulfur emission control indicate similar collection efficiencies. Their use on this reference PDF fired boiler application represents reasonable expectations for electric utility practice.

3.4.2 <u>Fuel Handling System</u>

The function of the fuel handling system is to provide the equipment required for unloading, conveying, preparing, and storing the fuel delivered to the plant. The scope of the system is from the rotary car dumper and fuel receiving hoppers up to the pulverizer fuel inlet. A schematic diagram of the system is shown on the Fuel Handling Flow Diagram, Figure 3-9. The system is designed to support short term operation at the 5% OP/VWO condition (16 hours) and long term operation at the 100% guarantee point (90 days or more).

3.4.2.1 Operation Description

The 1 x 0 inch PDF fuel will be delivered to the site by unit trains of 100-ton rail cars. The choice of delivery system is site-dependent and may involve other means, such as trucks or barges. For this study, unit trains were selected as the most appropriate. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a rotary car dumper with a hydraulic car positioner. The rotary car dumper will unload the fuel to four receiving hoppers. Coal from each hopper is fed by a vibratory feeder onto a belt conveyor. The fuel is conveyed into a transfer building where a sample is taken from each consignment by a fuel sampling system. The main stream of fuel feeds onto the stacker conveyor.

The fuel is fed into a traversing, double-wing stacker. The fuel can be diverted to either the active pile boom conveyor or the dead pile boom conveyor. Each fixed boom conveyor has luffing capabilities for discharging the fuel into a longitudinal pile. The double-wing stacker traverses on a track between the active and dead storage piles. Each storage pile is lined and provided with a runoff treatment system.

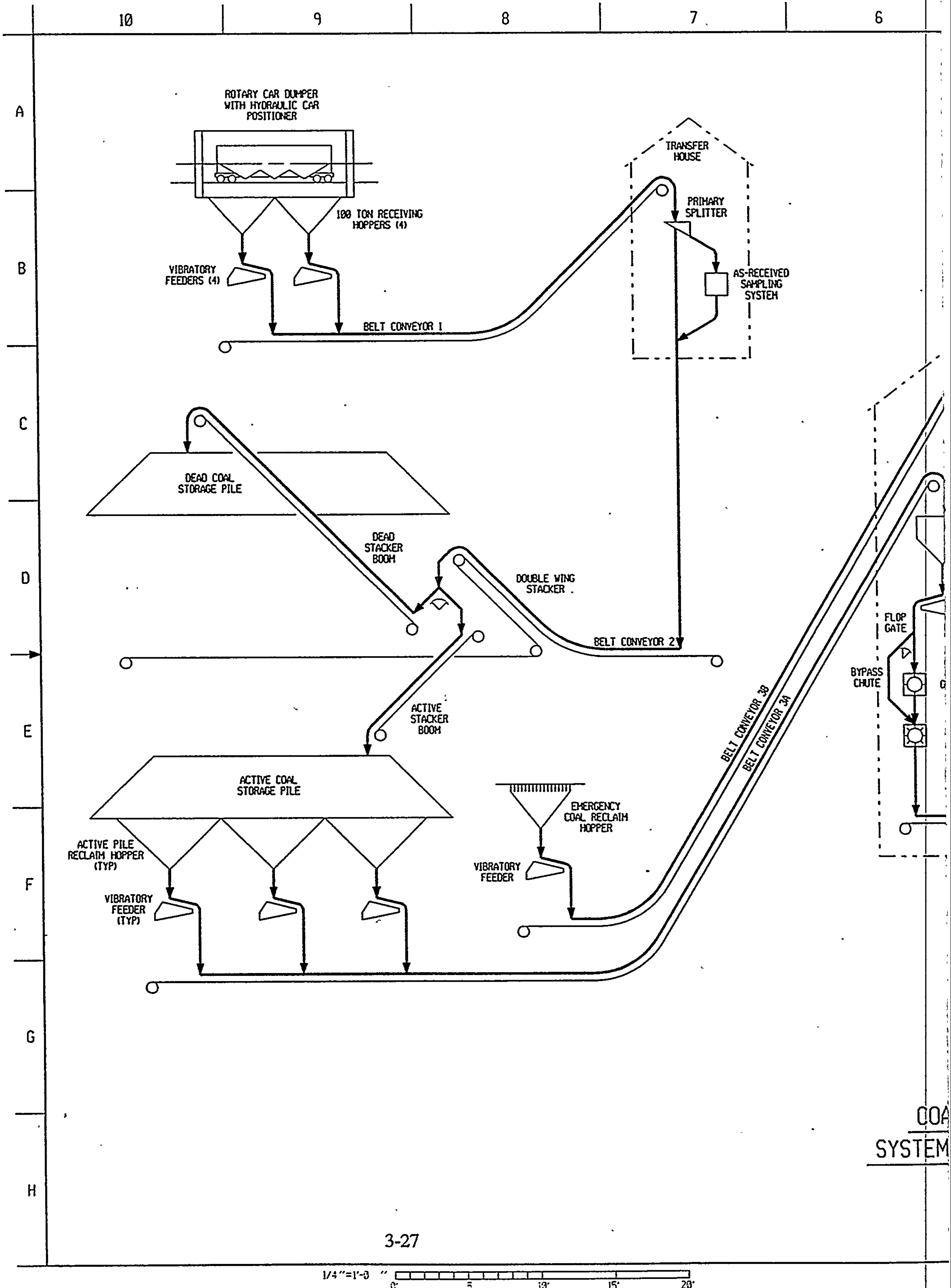
The dead pile boom conveyor discharges the fuel onto the dead fuel storage pile where a bulldozer moves and compacts the fuel. The dead storage area will have an emergency reclaim hopper with a vibratory feeder feeding a belt conveyor. The conveyor discharges the reclaimed fuel into the crusher building's surge bin.

The active pile boom conveyor discharges the fuel onto the active fuel storage pile and is reclaimed via three reclaim hoppers. The fuel is then discharged onto a belt conveyor.

The fuel is conveyed from the reclaim hoppers to the crusher building and is fed into a two-compartment surge bin, provided with a vent filter to reduce dust emissions. Each compartment of the surge bin supplies fuel to a full size vibratory feeder. At the inlet of each crusher, a bypass flop gate allows fuel to be fed to either the crusher, or to a crusher by-pass. The crusher is an impactor type crusher, and is used when the reclaimed PDF fuel has frozen together into large lumps due to freezing weather conditions.

Fuel taken from the crusher discharge, is sampled by a two-strand, swing-hammer type sampling system before entering the boiler building.

Conveyors then feed the sized and sampled fuel to either of the tripper conveyors. Each tripper discharges fuel into a bunker for storage. The bunkers are sized for 16-hour total storage capacity. Conveyors are sized to fill the 16 hour bunkers in less than 6 hours while the plant is operating at full load. The fuel is discharged into the pulverizers via gravimetric feeders.



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ROTARY CAR DUMPER WITH HYDRAULIC CAR POSITIONER
100 TON RECEIVING HOPPERS (4)
VIBRATORY FEEDERS (4)
BELT CONVEYOR 1
TRANSFER HOUSE
PRIMARY SPLITTER
AS-RECEIVED SAMPLING SYSTEM
DEAD COAL STORAGE PILE
DEAD STACKER BOOM
DOUBLE WING STACKER
BELT CONVEYOR 2
ACTIVE STACKER BOOM
ACTIVE COAL STORAGE PILE
ACTIVE PILE RECLAIM HOPPER (TYP)
VIBRATORY FEEDER (TYP)
EMERGENCY COAL RECLAIM HOPPER
VIBRATORY FEEDER
BELT CONVEYOR 3B
BELT CONVEYOR 3A
FLOP GATE
BYPASS CHUTE
COA
SYSTEM
1/4"=1'-0"
0'
5
10'
15'
20'

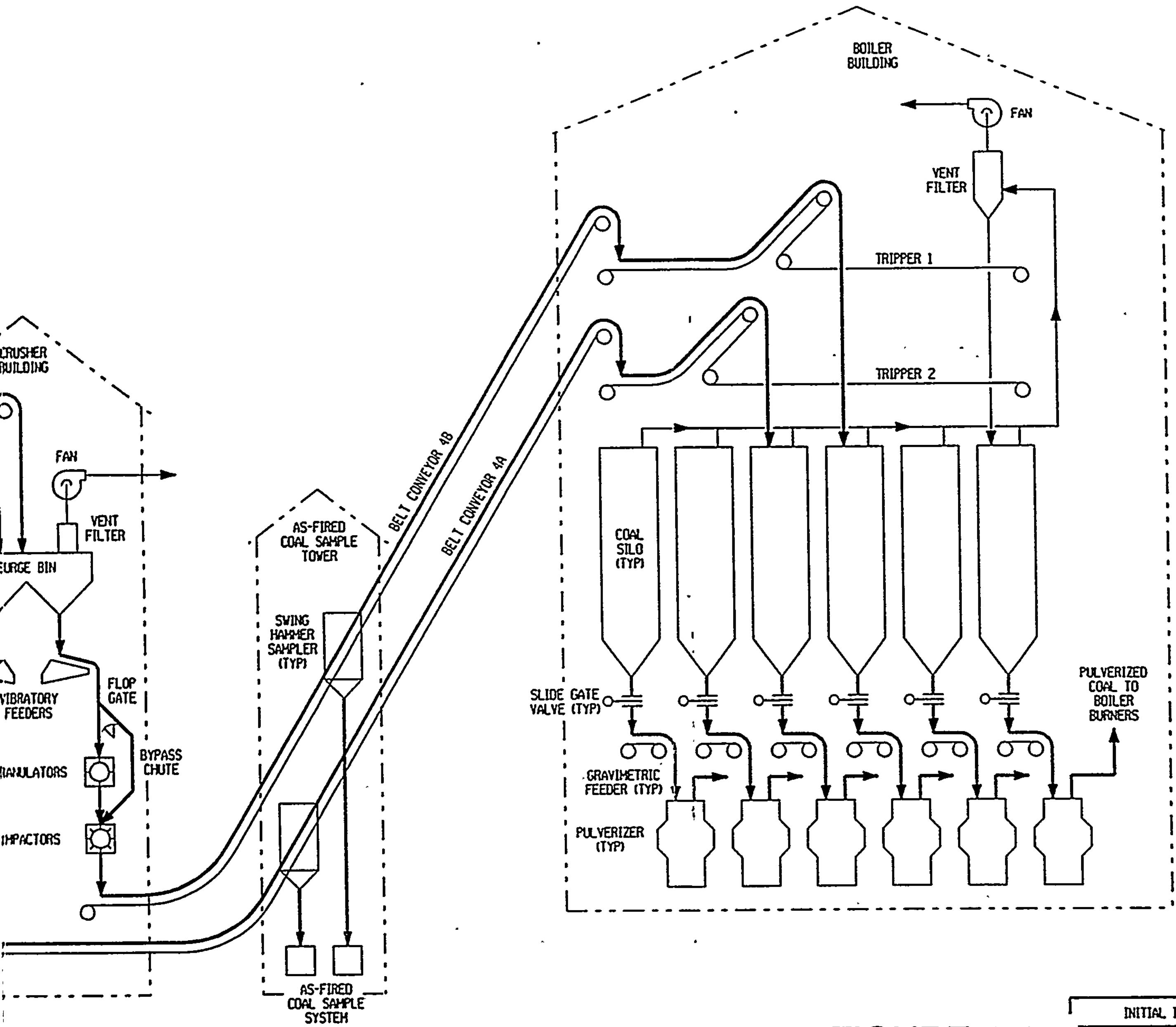

FIGURE 3-9

L HANDLING
FLOW DIAGRAM

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ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-89MC25177

MECHANICAL FLOW DIAGRAM
COAL HANDLING SYSTEM

GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

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3.4.2.2 Technical Requirements and Design Basis

1. PDF Burn Rate

   - Maximum Burn Rate = 325,000 lb/h ≐ 163 tph
     (estimated for the boiler operating at 5 percent OP, VWO continuously)

   - Average Burn Rate = 237,620 lb/h = 119 tph
     (based on Maximum Coal Burn Rate multiplied by an assumed capacity factor)

2. PDF Delivered to the Plant by Unit Trains

   - Three (3) Unit Trains Per Week at Maximum Burn Rate
     Two (2) Unit trains Per Week at Average Burn Rate

   - Each Unit Train Shall Have 10,000 Tons (100-Ton Cars) Capacity
     (Actual ENCOAL PDF unit trains are presently using 110-115 ton cars in unit trains of 11,500 to 11,800 tons)

   - Unloading Rate = 900 tph

   - Total Unloading Time Per Unit Train = 13 hours

   - Conveying Rate to Storage Piles = 900 tph

   - Reclaim Rate = 650 tph

3. Storage Piles with liners, Run-off Collection, and Treatment Systems:

   - Active Storage = 8,640 tons (72 hours)
   - Dead Storage = 259,200 tons (90 days)

System design reflects the concern for maintenance of the fuel handling equipment in that redundant equipment is provided in critical areas. Reclaiming and conveying belts, crushers, and bunker loading equipment fall into this category.

Access platforms and catwalks are provided to permit the periodic lubrication, and observation of all rotating or moving equipment. Conveyors have a main access aisle either on one side or, in the case of two conveyors, between them with grease fittings directed toward this aisle.

On conveyor bridges or in tunnels, small access platforms or aisles on the outboard side give access to idlers for replacement. Monorails serve the conveyor head shafts and their accompanying drive assembly (gear and motor), permitting the removal of heavy pieces to grade.

The crusher building has monorails serving each crusher for rotor, motor, and drive assembly maintenance. For installations with a rotary car dumper, monorails serve the hydraulic pumps that operate the car positioner. A maintenance aisle adjacent to the pumps and their monorail system supports forklift truck traffic.

A hatch, strategically located in the car dumper, allows access to the lowest level in that structure. Equipment below the hoppers is winched or skidded into the hatch area, then hoisted to the surface with a "cherry picker" or truck crane.

3.4.3 SO_2 Removal by Duct Spray Drying (DSD)

Duct injection technology was developed as a low capital cost alternative to conventional flue gas desulfurization scrubber systems where high removal efficiencies are not required. In addition to low capital costs there are other advantages:

- minimal operation and maintenance requirements
- generation of a dry solid waste product

DSD is a process in which pebble lime is slaked and mixed with recycle solids from the Electrostatic Precipitator (ESP) to form a slurry which is injected directly into the flue gas downstream of the air heater. Dual-fluid nozzles, using compressed air to atomize the slurry droplets, are used for slurry injection.

For this PDF fired plant, a DSD system was configured to remove 50% of the SO_2 in the flue gas stream. The following sections provide a description of the system. Figure 3-10 shows a material balance and a process flow diagram, Figure 3-11 presents a Lime Handling and Preparation System Flow Diagram.

3.4.3.1 Sorbent Storage and Preparation

Pebble lime is trucked to the plant site and pneumatically conveyed to a storage silo. From there it is pneumatically conveyed to a dry bin, which feeds a controlled amount to a ball mill slaker. The slaker slurries the pebble lime to calcium hydroxide, using raw water. The slurry product at 25% total solids is screened to remove grit and then pumped to the atomizer feed tank. The slurry is maintained at 170-190°F which is the most reactive temperature.

3.4.3.2 Sorbent Injection System

Fresh lime slurry is injected into the flue gas path using an array of 108-2 gpm dual-fluid nozzles. Compressed air at 80-100 psig is injected into the nozzles to atomize the slurry droplets. The length of the duct is established to allow sufficient residence time to completely evaporate the water before the flue gas enters the ESP. In order to optimize SO_2 removal, the slurry concentration and feed rate are controlled to cool the flue gas to within 50°F of saturation. For this design, this temperature is 150°F.

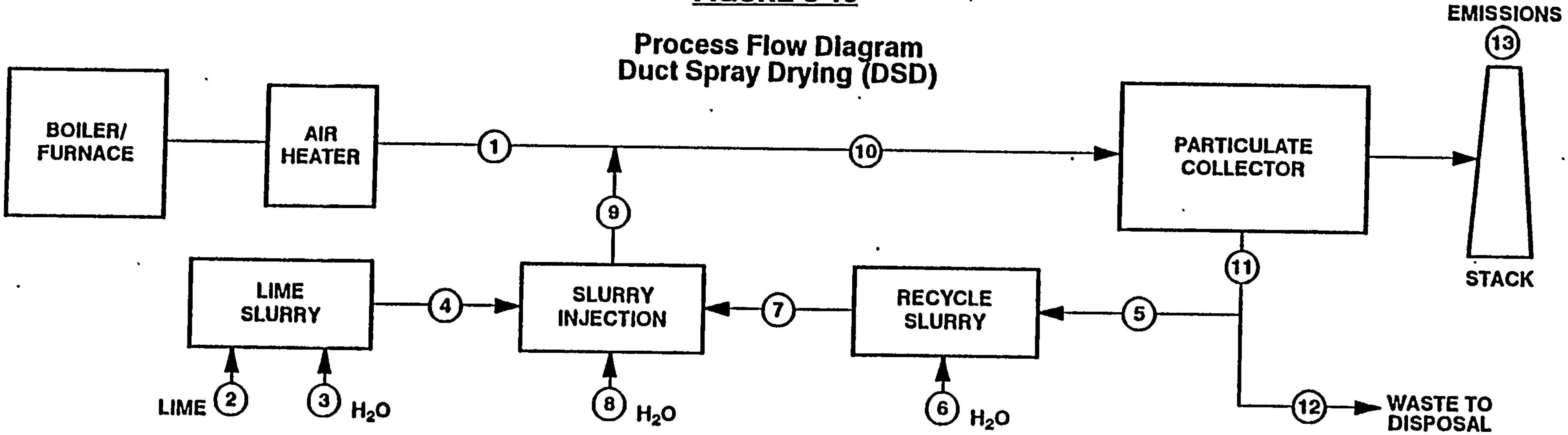
The ESP must have a Specific Collection Area (SCA) of 400 to handle the increased solids loading. Insulation added at various locations to prevent condensation and rotary airlocks should be oversized.

3.4.3.3 Recycle System

To improve sorbent utilization and to maintain a high solids content in the feed slurry, a portion of the solids from the ESP is collected, slurried and mixed with the slaked lime in the atomizer

FIGURE 3-10

**Process Flow Diagram
Duct Spray Drying (DSD)**



1. FLUE GAS DOWNSTREAM OF AIR HEATER

Flue Gas	3,819,566	lbs/hr
Fly Ash	19,026	lbs/hr
SO_2	3,250	lbs/hr
Temperature	270	°F
Wet bulb	100	°F

2. LIME TO SLAKER

CaO	3,128	lbs/hr
Inerts	165	lbs/hr

3. WATER TO SLAKER

H_2O	12,894	lbs/hr

4. FRESH SLURRY

Slurry	17,193	lbs/hr
	25	% solids

5. RECYCLE ASH TO SLURRY

Recycle Solids	32,774	lbs/hr

6. H_2O TO RECYCLE SLURRY

H_2O	49,161	lbs/hr

7. RECYCLE SLURRY

Slurry	81,936	lbs/hr
	40	% solids

8. DILUTION WATER

H_2O	47,197	lbs/hr

9. SLURRY INJECTION

Solids	36,067	lbs/hr
H_2O	109,253	lbs/hr
Atomizing Air	72,836	lbs/hr

10. ESP INLET

Flue Gas	4,036,659	lbs/hr
Solids	55,091	lbs/hr
Temperature	150	°F
Δ T App	50	°F

11. COLLECTED SOLIDS

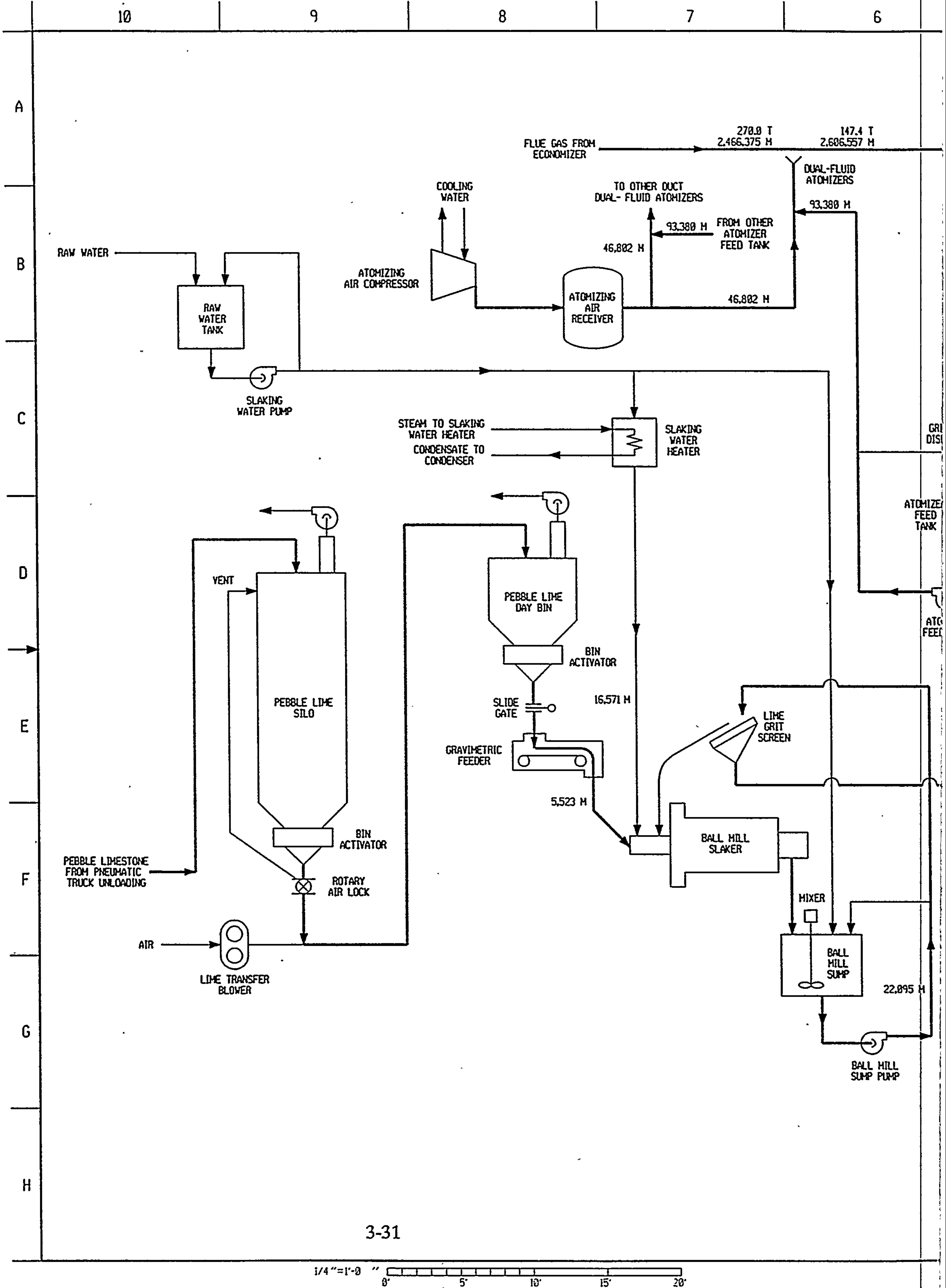
Total Solids	54,875	lbs/hr

12. WASTE TO DISPOSAL

Solids	29,595	lbs/hr
H_2O	6,426	lbs/hr
Total	36,021	lbs/hr

13. EMISSIONS

SO_2	1,625	lbs/hr
Particulate	216	lbs/hr


FLUE GAS FROM ECONOMIZER
270.0 T
2,466,375 M
147.4 T
2,606,557 M
DUAL-FLUID ATOMIZERS
COOLING WATER
TO OTHER DUCT DUAL- FLUID ATOMIZERS
93,380 M
FROM OTHER ATOMIZER FEED TANK
46,802 M
ATOMIZING AIR COMPRESSOR
ATOMIZING AIR RECEIVER
RAW WATER
RAW WATER TANK
SLAKING WATER PUMP
STEAM TO SLAKING WATER HEATER
CONDENSATE TO CONDENSER
SLAKING WATER HEATER
ATOMIZER FEED TANK
VENT
PEBBLE LIME SILO
PEBBLE LIME DAY BIN
BIN ACTIVATOR
SLIDE GATE
16,571 M
GRAVIMETRIC FEEDER
LIME GRIT SCREEN
5,523 M
BALL MILL SLAKER
PEBBLE LIMESTONE FROM PNEUMATIC TRUCK UNLOADING
ROTARY AIR LOCK
MIXER
AIR
LIME TRANSFER BLOWER
BALL MILL SUMP
22,095 M
BALL MILL SUMP PUMP
1/4"=1'-0"
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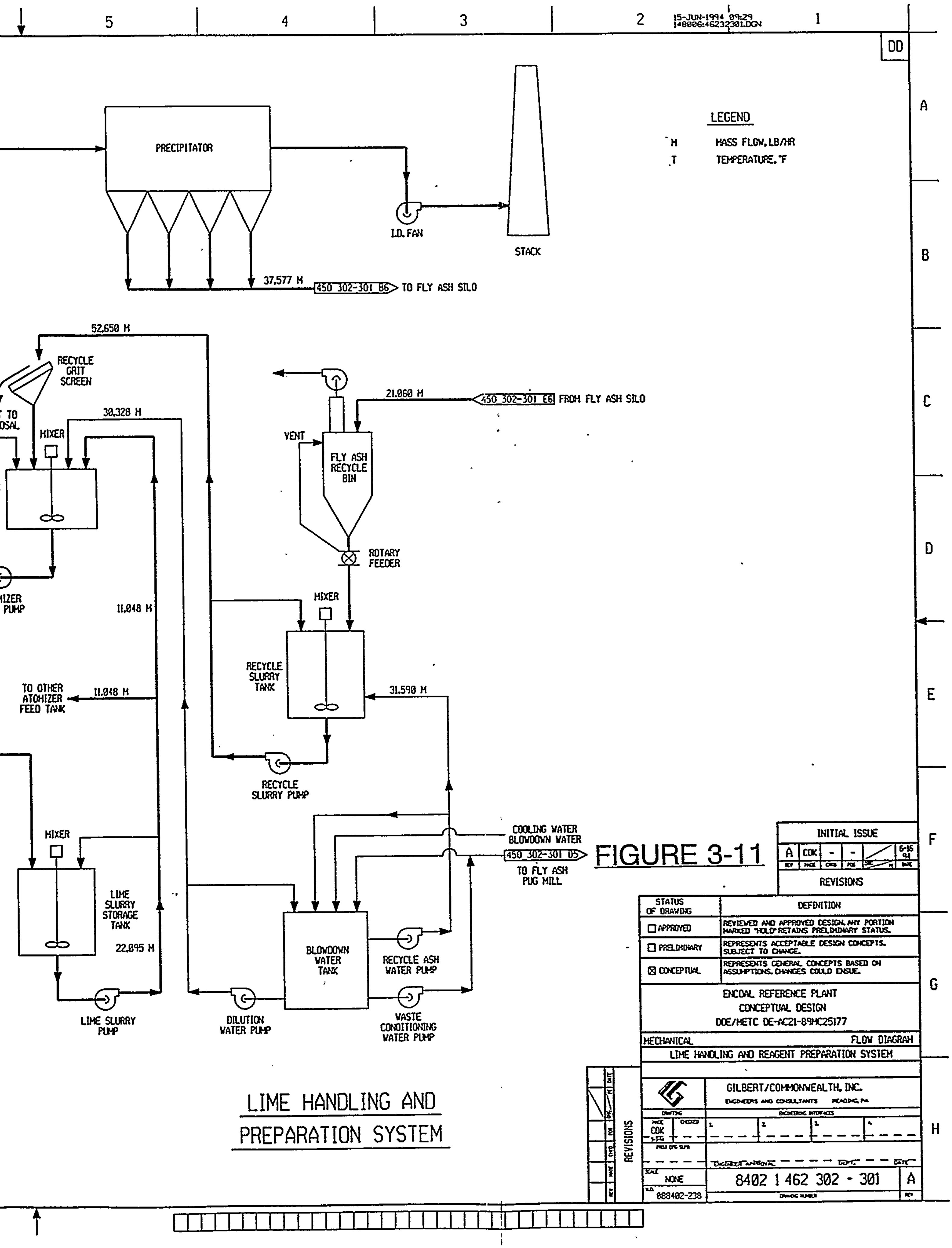
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TO FLY ASH SILO
52,650 M
RECYCLE GRIT SCREEN
TO DISPOSAL
30,328 M
MIXER
21,060 M
450 302-301 E6
FROM FLY ASH SILO
VENT
FLY ASH RECYCLE BIN
ROTARY FEEDER
ATOMIZER PUMP
11,048 M
MIXER
RECYCLE SLURRY TANK
TO OTHER ATOMIZER FEED TANK
11,048 M
31,590 M
RECYCLE SLURRY PUMP
MIXER
COOLING WATER
BLOWDOWN WATER
450 302-301 D5
TO FLY ASH PUG MILL
LIME SLURRY STORAGE TANK
22,095 M
BLOWDOWN WATER TANK
RECYCLE ASH WATER PUMP
LIME SLURRY PUMP
DILUTION WATER PUMP
WASTE CONDITIONING WATER PUMP
LIME HANDLING AND
PREPARATION SYSTEM
INITIAL ISSUE
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ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-89MC25177
MECHANICAL
FLOW DIAGRAM
LIME HANDLING AND REAGENT PREPARATION SYSTEM
GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS
READING, PA
REVISIONS
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FIGURE 3-11

feed tank. Before it is pumped to the feed tank, it is screened to remove grit and large particles. Blowdown water is used to attain the desired feed slurry solids content of 40%.

3.4.3.4 Waste Handling System

The solids collected in the ESP are conveyed to an ash silo for temporary storage. From the silo, ash is fed to a pug mill where it is mixed with blowdown water to control dusting and then trucked to a waste disposal site.

3.4.3.5 General Support Equipment

Support equipment consists of three 11,000 SCFM air compressors (one is a spare), two slaking water pumps, two dilution water pumps, two recycle ash water pumps and two ball mill slakers (one is a spare).

3.4.6 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, preparing, storing, and disposing the flyash and bottom ash produced on a daily basis by the boiler. The scope of the system is from the precipitator hoppers, air heater hopper collectors, and bottom ash hoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash). A schematic diagram of the flyash and bottom ash flow is shown on the Ash Handling Flow Diagram, Figure 3-12. The system is designed to support short term operation at the 5% OP/VWO condition (16 hours) and long term operation at the 100% guarantee point (90 days or more).

3.4.6.1 Operation Description

The flyash collected in the precipitators and the air heaters is conveyed to the flyash storage silo. A pneumatic transport system using low pressure air from a blower provides the transport mechanism for the flyash. Flyash is discharged through a wet unloader, which conditions the flyash and conveys it through a telescopic unloading chute into a truck for disposal.

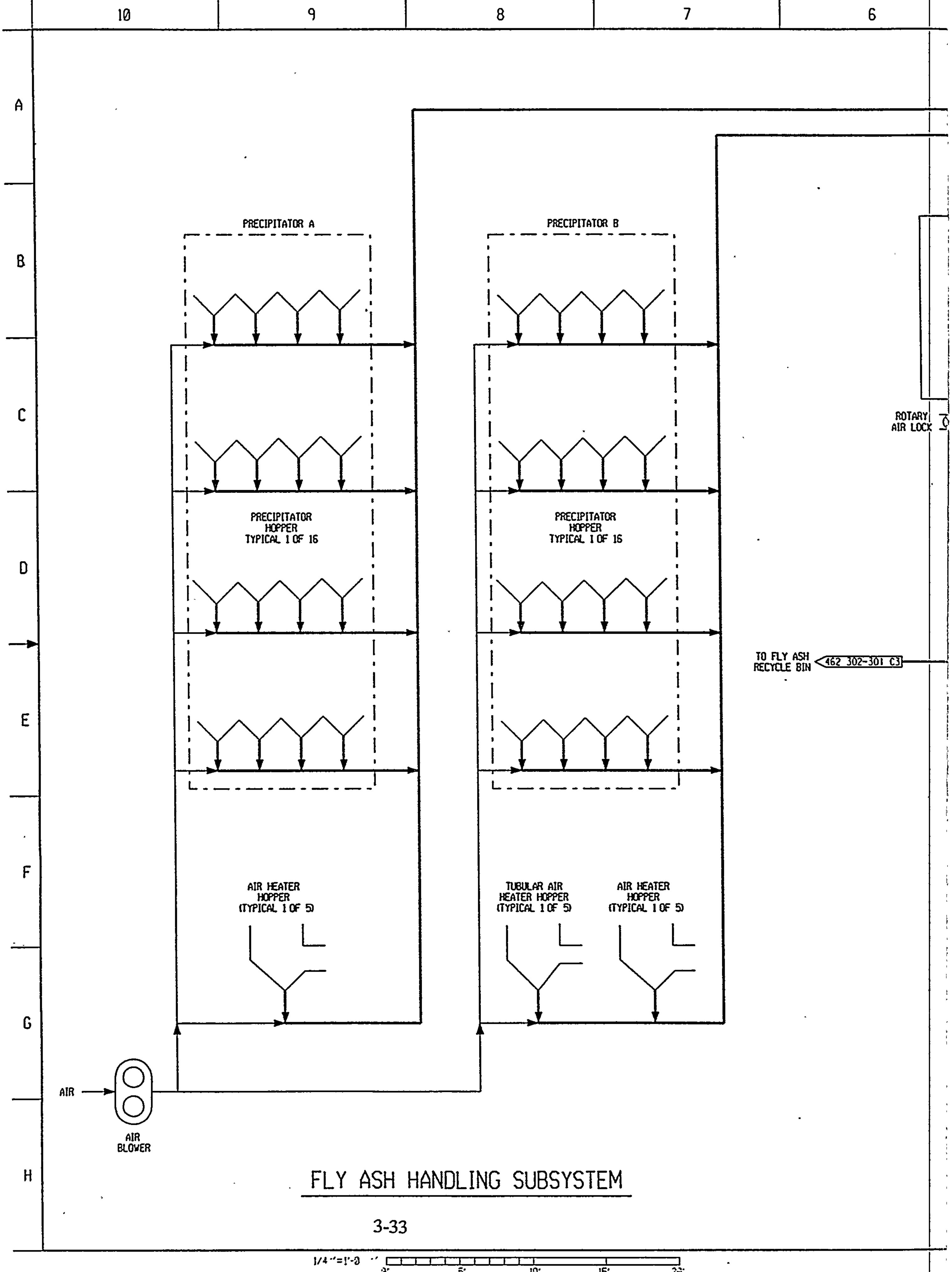
The bottom ash from the boiler is fed into a clinker grinder. The clinker grinder is provided to break up any clinkers that may form. From the clinker grinders the bottom ash is discharged via a hydro-ejector and ash discharge piping to the ash pond.

Ash from the economizer hoppers and pyrites (rejected from the coal pulverizers) are conveyed by hydraulic means (water) to the economizer/pyrites transfer tank. This material is then sluiced, on a periodic basis, to the ash pond.

3.4.6.2 Technical Requirements and Design Basis

A. Bottom Ash:

1. Bottom Ash Generation Rate, 4,836 lb/hr = 2.5 tph
2. Clinker Grinder Capacity = 15 tph
3. Conveying Rate To Ash Pond = 15 tph



FLY ASH HANDLING SUBSYSTEM

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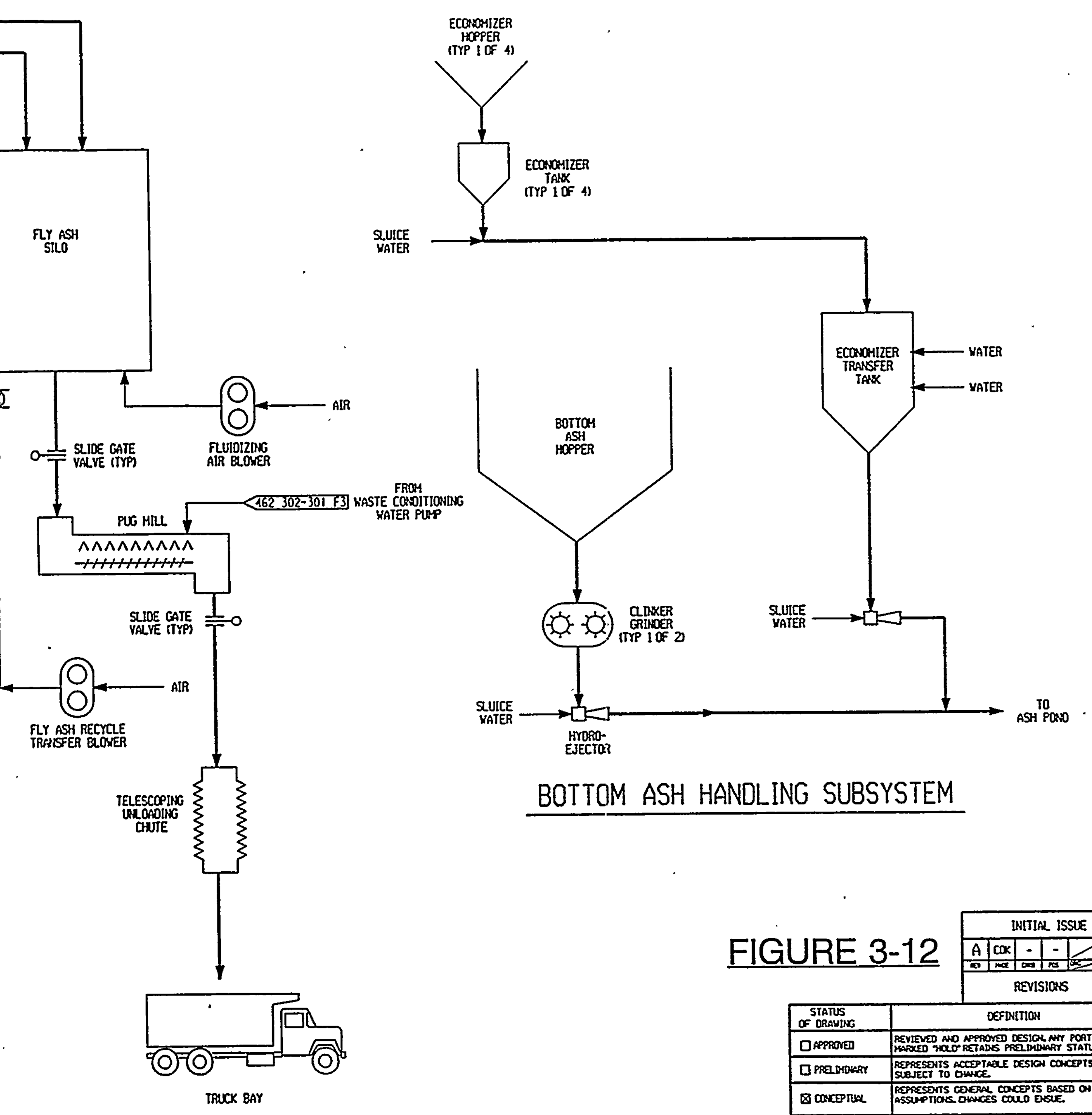

FIGURE 3-12

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CONCEPTUAL DESIGN
DOE/METC DE-AC21-89MC25177

MECHANICAL — FLOW DIAGRAM

ASH HANDLING SYSTEM

GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

MADE: CDK

SCALE: NONE

W.O. 889402-238

8402 1 450 302 - 301 — REV A

REVISIONS

B. Flyash:

1. Generation Rate = 83,307 lb/hr = 42 tph
2. Conveying Rate From Precipitator and Air Heaters = 250 tph
3. Flyash Silo Capacity = 3,024 Tons (72 Hour Storage)
4. Wet Unloader Capacity = 250 tph

3.5 BALANCE OF PLANT

The following section provides a description of the plant outside the boiler system and its auxiliaries. Flow diagrams for the balance of plant are provided in Figure 3-13, Main, Reheat and Extraction Steam, and Figure 3-14, Condensate, Feedwater and Circulating Water.

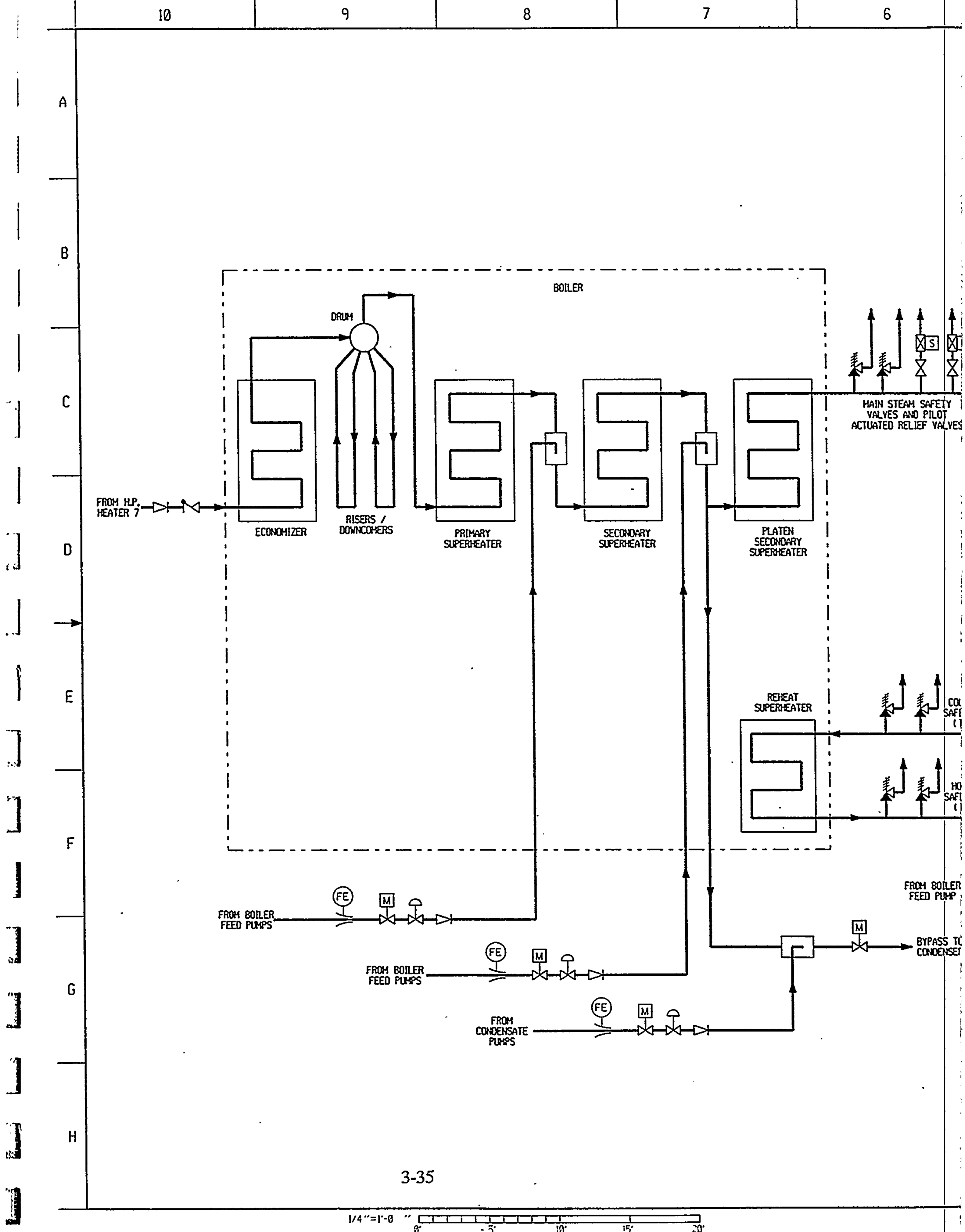
3.5.1 Turbine-Generator and Auxiliaries

The turbine consists of an high pressure (HP) section, intermediate pressure (IP) section and two double flow low pressure (LP) sections all connected to the generator by a common shaft. Main steam from the boiler passes through the stop valves and control valves and enters the turbine at 2400 psig/1000°F. The steam initially enters the turbine near the middle of the high pressure span, flows through the turbine and returns to the boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 530 psig/1000°F. After passing through the IP section, the steam enters a cross-over pipe which transports the steam to the two LP sections. The steam divides into four paths and flows through the LP sections exhausting downward into the condenser.

The heat balance for this reference plant reflects the use of a steam turbine generator that incorporates current state-of-the-art design and manufacturing techniques. Significant gains in turbine adiabatic efficiency have been achieved in the last decade by improved aerodynamic design for the steam path, and by reducing parasitic losses such as shaft seal leakages, and tip and root leakages. The cycle performance, based on use of a steam turbine incorporating these advances, results in an improvement of several percent in heat rate relative to the turbine cycle heat rate calculated based on long established steam turbine performance prediction methods. This is a change from the methods used to define steam cycle performance presented in the AFBC Clean Coal Reference Plant report issued in 1992, and represents a 3% improvement in adiabatic efficiency for the overall turbine.

Turbine bearings are lubricated by a closed loop water cooled pressurized oil system. The oil is contained in a reservoir located below the turbine floor. During startup or unit trip the oil is pumped by an emergency oil pump mounted on the reservoir. When the turbine reaches 95 percent of synchronous speed, oil is pumped by the main pump mounted on the turbine shaft. The oil flows through water cooled heat exchangers prior to entering the bearings. The oil then flows through the bearings and returns by gravity to the lube oil reservoir.

Turbine shafts are sealed against air in-leakage or steam blow out using a labyrinth gland arrangement connected to a low pressure steam seal system. During startup, seal steam is provided from the main steam line. As the unit increases load, HP turbine gland leakage provides the seal steam. Pressure regulating valves control the gland header pressure and dump any excess steam to the condenser. A steam packing exhauster maintains a vacuum at the outer gland seals to prevent leakage of steam into the turbine room. Any steam collected is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BOILER
DRUM
ECONOMIZER
RISERS / DOWNCOMERS
PRIMARY SUPERHEATER
SECONDARY SUPERHEATER
PLATEN SECONDARY SUPERHEATER
REHEAT SUPERHEATER
FROM H.P. HEATER 7
MAIN STEAM SAFETY VALVES AND PILOT ACTUATED RELIEF VALVES
FROM BOILER FEED PUMPS
FROM BOILER FEED PUMPS
FROM CONDENSATE PUMPS
FROM BOILER FEED PUMP
FE
M
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0'
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10'
15'
20'

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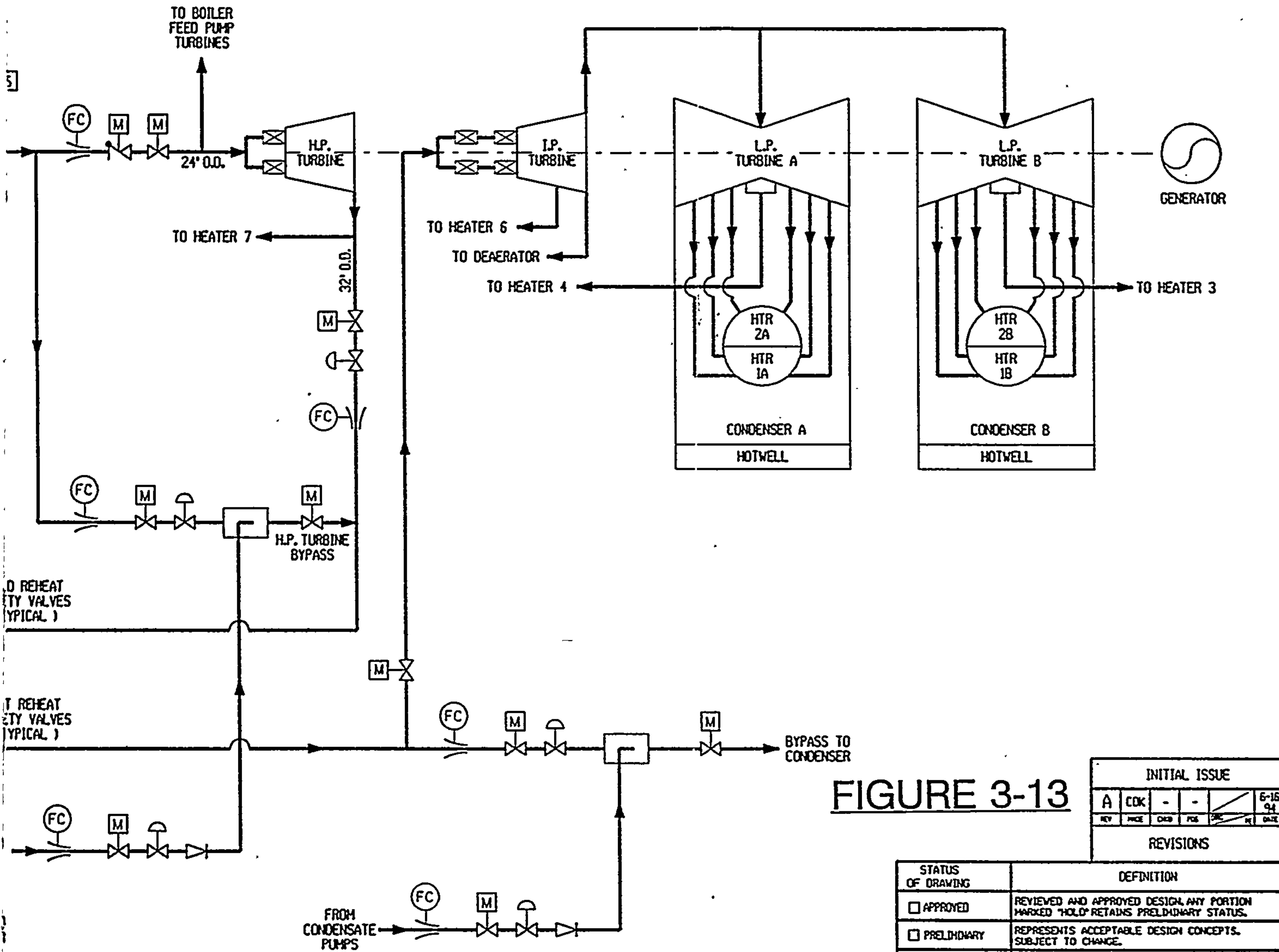

FIGURE 3-13

INITIAL ISSUE					
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REVISIONS

STATUS OF DRAWING	DEFINITION
☐ APPROVED	REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
☐ PRELIMINARY	REPRESENTS ACCEPTABLE DESIGN CONCEPTS. SUBJECT TO CHANGE.
☒ CONCEPTUAL	REPRESENTS GENERAL CONCEPTS BASED ON ASSUMPTIONS. CHANGES COULD ENSUE.

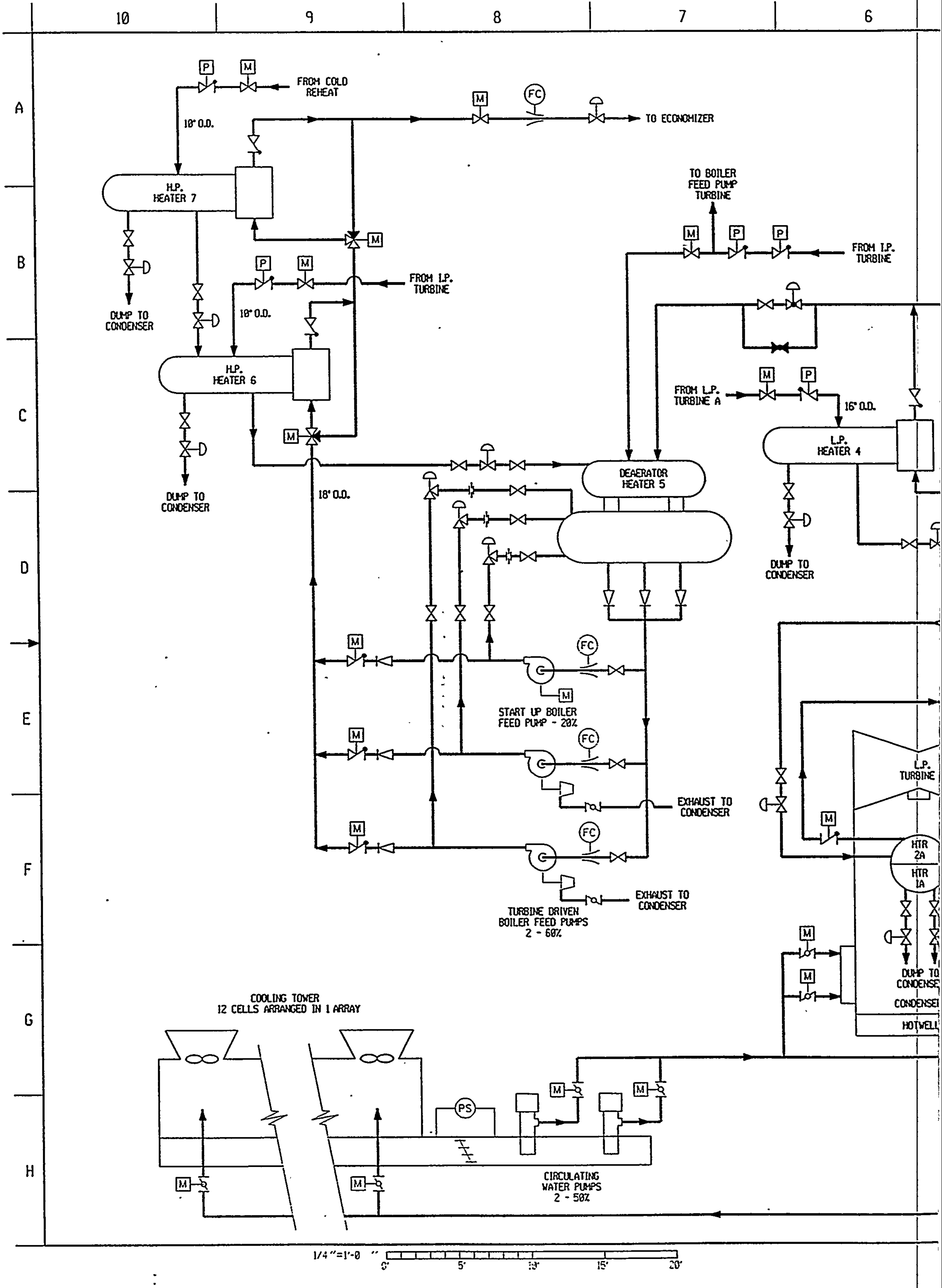
ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-89MC25177

MECHANICAL FLOW DIAGRAM
MAIN, REHEAT AND EXTRACTION STEAM SYSTEMS

GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

DRAFTING MADE COX
SCALE NONE
W.O. 888402-238
8402 1 540 302 - 302 A
DRAWING NUMBER

REVISIONS


10
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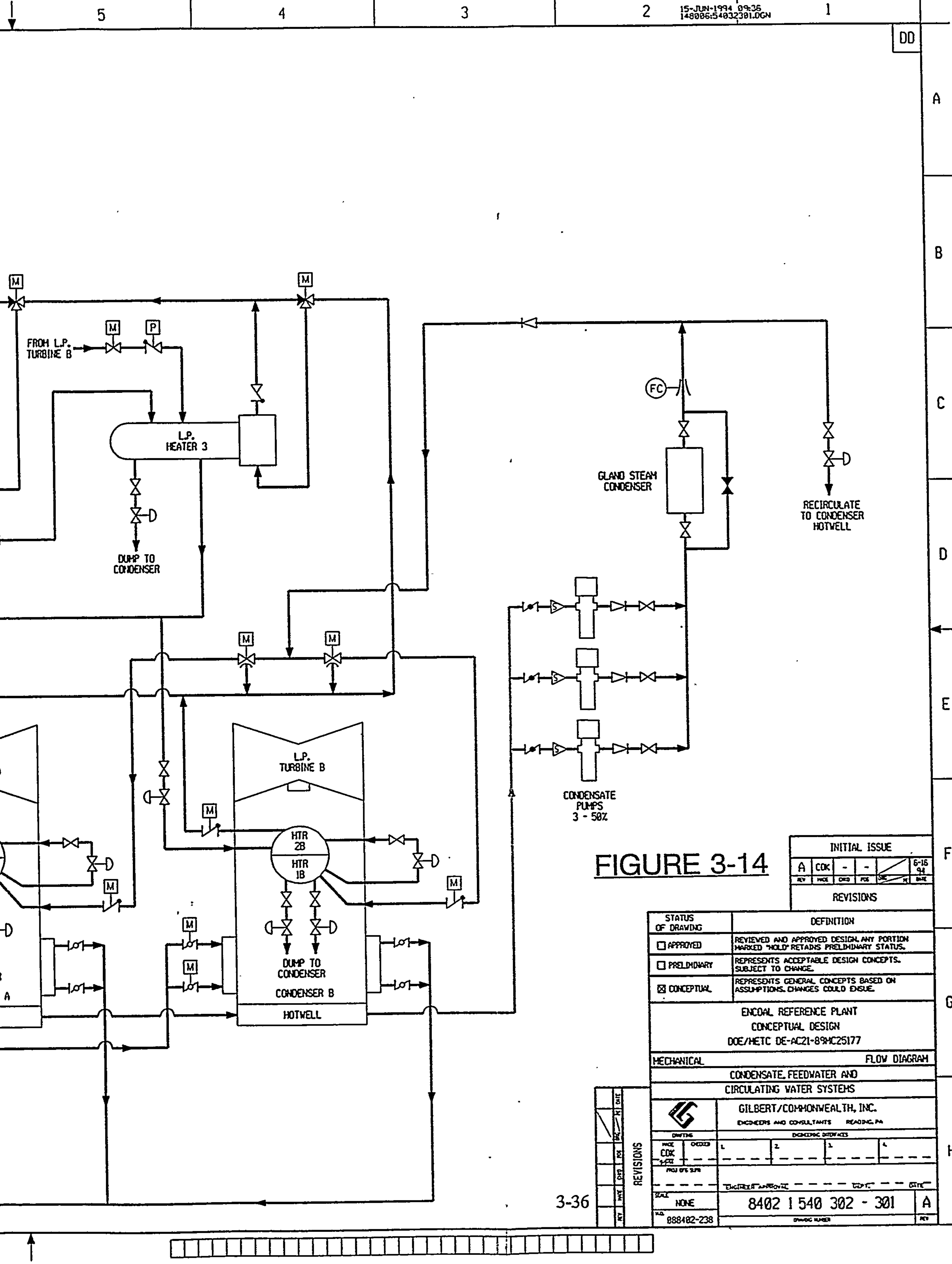
FROM COLD REHEAT
10" O.D.
TO ECONOMIZER
H.P. HEATER 7
FROM I.P. TURBINE
18" O.D.
DUMP TO CONDENSER
H.P. HEATER 6
TO BOILER FEED PUMP TURBINE
FROM I.P. TURBINE
FROM L.P. TURBINE A
16" O.D.
L.P. HEATER 4
DEAERATOR HEATER 5
18" O.D.
DUMP TO CONDENSER
START UP BOILER FEED PUMP - 20%
EXHAUST TO CONDENSER
TURBINE DRIVEN BOILER FEED PUMPS 2 - 60%
L.P. TURBINE
HTR 2A
HTR 1A
DUMP TO CONDENSER
CONDENSER
HOTWELL
COOLING TOWER 12 CELLS ARRANGED IN 1 ARRAY
PS
CIRCULATING WATER PUMPS 2 - 50%
FC
M
P
1/4"=1'-0"
0'
5'
10'
15'
20'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DD
FROM L.P. TURBINE B
L.P. HEATER 3
DUMP TO CONDENSER
GLAND STEAM CONDENSER
FC
RECIRCULATE TO CONDENSER HOTWELL
CONDENSATE PUMPS 3 - 50%
L.P. TURBINE B
HTR 2B
HTR 1B
DUMP TO CONDENSER
CONDENSER B
HOTWELL
INITIAL ISSUE
REVISIONS
STATUS OF DRAWING
DEFINITION
APPROVED
REVIEWED AND APPROVED DESIGN. ANY PORTION MARKED "HOLD" RETAINS PRELIMINARY STATUS.
PRELIMINARY
REPRESENTS ACCEPTABLE DESIGN CONCEPTS. SUBJECT TO CHANGE.
CONCEPTUAL
REPRESENTS GENERAL CONCEPTS BASED ON ASSUMPTIONS. CHANGES COULD ENSUE.
ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-89MC25177
MECHANICAL
FLOW DIAGRAM
CONDENSATE, FEEDWATER AND
CIRCULATING WATER SYSTEMS
GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA
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NONE
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FIGURE 3-14

condensed in the packing exhauster and returned to the condensate system.

The generator stator is cooled with a closed loop water system consisting of circulating pumps, shell and tube or plate and frame type heat exchangers, filters and deionizers, all skid mounted. Water temperature is controlled by regulating heat exchanger bypass water flow. Stator cooling water flow is controlled by regulating stator inlet pressure.

The generator rotor is cooled with a hydrogen gas recirculation system using fans mounted on the generator rotor shaft. The heat absorbed by the gas is removed as it passes over finned tube gas coolers mounted in the stator frame. Stator cooling water flows through these coils. Gas is prevented from escaping at the rotor shafts using a closed loop oil seal system. The oil seal system consists of a storage tank, pumps, filters and pressure controls, all skid mounted.

3.5.1.1 Operation Description

The turbine stop valves, control valves, reheat stop valves and intercept valves are controlled by an electro-hydraulic control system.

The turbine is designed to operate at constant inlet steam pressure over the entire load range and is capable of being converted in the future to sliding pressure operation for economic unit cycling.

3.5.1.2 Technical Requirements and Design Basis

Design Basis

1. Full Load Heat Balance 8441-1-400-314-601 (Figure 3-1)

Components

1. Turbine Generator

• Quantity	1
• Type	Tandem compound, four flow exhaust, single reheat, 30 inch last stage buckets, with direct connected hydrogen cooled generator
Design Data	
• Guarantee Rating	434,500 kw (at Generator Terminals)
• Max. Expected Rating	468,400 kw (5% O.P. VWO, estimated)
• Speed	3600 rpm
• Throttle Pressure	
- Guarantee	2400 psig
- 5% O.P.	2520 psig
• Main Steam Temp.	1000°F
• Reheat Steam Temp.	1000°F
• Throttle Flow	

- Guarantee	2,734,000 lb/h
- 5% O.P.	3,014,185 lb/h (estimated)
• Exhaust Pressure	1.4/2.0 inch Hg
• Number of Extractions	7

2. Auxiliary Equipment
   - Bearing Lube Oil System
   - Gland Steam Seal System
   - Generator Cooling Water System
   - Generator Hydrogen Cooling System
   - Hydrogen Seal Oil System
   - Electro-Hydraulic Control System
   - Exciter

3.5.2 Condensate and Feedwater Systems

The Condensate and Feedwater systems are designed to support continuous operation at the 5% OP/VWO coincident condition.

Condensate

The function of the condensate system is to pump condensate from the condenser hotwell through the steam packing exhauster and four stages of low pressure (LP) feedwater heaters to the deaerator.

The system consists of one main condenser; three 50 percent capacity, motor driven vertical condensate pumps with solid state controlled, variable frequency variable speed electric drives; one gland steam exhauster; four stages of feedwater heaters with the first two stages located in the condenser neck; one deaerator with storage tank; three 50 percent capacity vacuum pumps; and one 250,000 gallon condensate storage tank.

The first two stages of feedwater heating are comprised of two 50 percent capacity, parallel flow, duplex, U-tube exchangers installed in the condenser necks. Heaters Nos. 3 and 4 are 100% capacity, shell and U-tube heat exchangers. The fifth stage is the deaerator.

Condensate is delivered to a common discharge header through three separate pump discharge lines, each with a check valve and a gate valve. A common minimum flow recirculation line discharging to the condenser is provided to maintain minimum flow requirements for the gland steam exhauster and the condensate pumps.

Each LP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. LP feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the condenser. Normal drain level in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

Feedwater

The function of the feedwater system is to pump feedwater from the deaerator storage tank through two stages of high pressure (HP) feedwater heaters to the economizer inlet on the boiler.

The system consists of two 60 percent capacity turbine driven boiler feed pumps; one 25 percent capacity motor driven startup boiler feed pump and two stages of high pressure feedwater heaters.

Each pump is provided with inlet and outlet isolation valves, outlet check valves and individual minimum flow recirculation lines discharging back to the deaerator storage tank. The recirculation flow is controlled by pneumatic flow control valves. In addition, the suctions of the boiler feed pumps are equipped with startup strainers, which are utilized during initial startup and following major outages or system maintenance.

Each HP feedwater heater is provided with inlet/outlet isolation valves and a full capacity bypass. Feedwater heater drains cascade down to the next lowest extraction pressure heater and finally discharge into the deaerator. Normal drain level in the heaters are controlled by pneumatic level control valves. High heater level dump lines discharging to the condenser are provided for each heater for turbine water induction protection. Dump line flow is controlled by pneumatic level control valves.

3.5.2.1 Operation Description

Condensate

Condenser vacuum pump operation is initiated by the operator at local panels. After initiation, vacuum pump operation is automatic throughout the design range of the vacuum pumps. The local panels include alarms for monitoring the performance of the vacuum pumps, with common annunciation in the main control room.

After the initial vacuum is established, and condensate system valves are aligned for normal operation, the system is monitored from the main control board for startup, shutdown, and all load swings. The condensate pumps and heater bypass valves are controlled from the main control room. The condensate transfer pump is arranged for local starting and stopping only, with automatic minimum flow recirculation.

Feedwater

The boiler feed pumps are controlled by the DCS. All critical system malfunctions are alarmed. In the event of heater failure, automatic controls are actuated to prevent turbine water induction damage. An individual heater can be isolated and bypassed from the main control room.

During a startup, the motor driven startup boiler feed pump is used to allow the boiler to be fired. When main steam becomes available, a turbine driven feed pump can be operated to bring the turbine-generator on line. As the main turbine exceeds 60 percent load, the steam source automatically switches over to turbine extraction. If one of the turbine driven feed pumps fails, the motor driven startup feed pump can be operated in parallel with the remaining main feed pump to support approximately 95 percent total plant load.

3.5.2.2 Technical Requirements and Design Basis

Design Basis

1. The systems are sized to pass the flow rates occurring at 5 percent overpressure, valves wide open condition. System components are specified with design margins such as additional head and flow for pumps, and tubes/tube surface for tube plugging and fouling in heaters and condensers.

2. All piping is designed in accordance with ANSI B31.1. All valves are designed in accordance with ANSI B16.34.

3. All heaters, the deaerator/storage tank, and the condenser are designed in accordance with ASME B&PV Code, Section VIII, Div. 1 and HEI Standards.

4. The condensate storage tank is designed in accordance with AWWA D100.

Components (nominal values at 100% load)

Condenser

• Quantity	1
• Type	Two shell, transverse dual pressure with divided waterbox for each shell
• Steam to Condensate at 1.4/2.0 in. Hg.	1,834,438 lb/h (Note 1)
• Net Heat Transfer	1,718 x 10^6 Btu/h
• Circulating Water Flow	202,700 gpm
• Circulating Water Inlet Temp.	75°F
• Circulating Water Temp. Rise	20°F
• Terminal Temp Diff.	6°F
• Condenser Shell Pressure	1.4/2.0 inch Hg. abs.
• Tube Material	90-10 CuNi (main section), 70-30 CuNi (air removal section)

Note 1 - Main and Boiler Feed Pump Turbines

Vacuum Pumps

• Quantity	2
• Type	Rotary-Water sealed
• Holding Capacity at 1 inch Hg abs	25 scfm
• Hogging Capacity at 15 inch Hg abs	2500 scfm
• Speed	470 rpm
• Horsepower	100 hp
• Construction	iron

Condensate Storage Tanks

• Quantity	1
• Type	Field erected, flat roof, internal diaphragm
• Capacity	200,000 gallons, usable volume
• Diameter	36 ft.
• Height	30 ft.
• Internal Coatings	Epoxy-phenolic-Plastic 7155 or equal

Condensate Pumps

• Quantity	3 @ 50% capacity
• Type	Vertical canned centrifugal with variable speed drive (solid state controlled, variable frequency)
• Capacity	2500 gpm
• Total Head	800 ft.
• Horsepower (at design)	650 hp
• Speed (max)	1750 rpm
• Impeller Material	Bronze

L.P. Feedwater Heaters

• Quantity	4
• Type	Horizontal, 2 pass, U-tube
• Feedwater Flow	2,249,030 lb/hr
• Terminal Temp Diff	8°F
• Tube Material	Welded type 304 S.S. with .03% max carbon

Heater No. 1A/1B (Combined Flows)

• Feedwater Inlet Temp.	98.2°F
• Steam Enthalpy	1095 Btu/lb
• Shell Sat. Temp/Pressure	170.1°F/6.8 psia
• Drains Cooler Approach	8°F
• Drains Inlet Flow	263,913 lb/h
• Drains Inlet Enthalpy	143.4 Btu/lb
• Shell Design Condition	50 psig/300°F
• Tube Design Condition	500 psig/300°F

Heater No. 2A/2B (Combined Flows)

• Feedwater Inlet Temp	167.4°F
• Steam Enthalpy	1140.4 Btu/lb
• Shell Sat. Temp/Pressure	201.5°F/11.9 psia
• Drain Cooler Approach	8°F

• Drain Inlet Flow	199,567 lb/h
• Drains Inlet Enthalpy	174.9 Btu/lb
• Shell Design Conditions	100 psig/400°F
• Tube Design Conditions	500 psig/250°F

Heater No. 3

• Feedwater Inlet Temp	198.7°F
• Steam Enthalpy	1185.2 Btu/lb
• Shell Sat. Temp/Pressure	234°F/22.4 psia
• Drains Cooler Approach	8°F
• Drains Inlet Flow	131,258 lb/h
• Drains Inlet Enthalpy	207.6 Btu/lb
• Shell Design Conditions	100 psig/500°F
• Tube Design Conditions	500 psig/350°F

Heater No. 4

• Feedwater Inlet Temp	231.1°F
• Steam Enthalpy	1272.1 Btu/lb
• Shell Sat. Temp/Pressure	295.3°F/62.4 psia
• Shell Design Conditions	150 psig/650°F
• Tube Design Conditions	500 psig/400°F

Deaerator and Storage Tank

• Quantity	1
• Type	Horizontal, spray tray type with internal direct contact stainless steel vent condenser and storage tank
• Design Condition	200 psig/400°F
• Outlet Feedwater Flow	2,747,265 lb/h
• Saturation Temp/Pressure	365.9°F/164.8 psia
• Steam Enthalpy	1373.9 Btu/lb
• Steam Flow	160,693 lb/h
• Condensate Inlet Flow	2,249,030 lb/h
• Condensate Inlet Enthalpy	262.2 Btu/lb
• Drains Inlet Flow	337,796 lb/h
• Drains Inlet Enthalpy	354.1 Btu/lb
• Storage Tank Live Volume	30,000 gal,

Boiler Feed Pumps - Turbine Driven
(at 100% design condition T=364°F)

• Quantity	2 at 60% capacity
• Type	Staged high pressure centrifugal
• Capacity	3,400 gpm
• Total Head	7,200 ft.

• Horsepower	7,800 hp
• Speed	5,500 rpm

Startup Boiler Feed Pumps - Motor Driven
(at cold startup T_{H2O}=90°F)

• Quantity	1 at 25% capacity
• Type	Staged high pressure centrifugal
• Capacity	1,500 gpm
• Total Head	7,200 ft.
• Horsepower	3,500 hp
• Speed	3,600 rpm

HP Feedwater Heaters

• Quantity	2
• Type	Horizontal 2 pass U-tube
• Feedwater Flow	2,652,909 lb/h (total)
• Terminal Temp Diff	+8°F
• Drains Cooler Approach	+15°F
• Tube Material	Welded type 304 S.S. with .03% max carbon

Heater No. 6

• Feedwater Inlet Temp	372.3°F
• Steam Enthalpy	1430.7 Btu/lb
• Shell Sat. Temp./Pressure	405.7°F/263.8 psia
• Drains Inlet Flow	255,918 lb/h
• Drains Inlet Enthalpy	392.3 Btu/lb
• Shell Design Condition	300 psig/(900°F skirt/650°F shell)
• Tube Design Condition	3600 psig/450°F

Heater No. 7

• Feedwater Inlet Temp	407.5°F
• Steam Enthalpy	1312.2 Btu/lb
• Shell Sat. Temp./Press	434.1°F/588.5 psia
• Shell Design Condition	650 psig/650°F
• Tube Design Condition	3600 psig/550°F

3.5.3 Main, Reheat and Extraction Steam Systems

The Condensate and Feedwater systems are designed to support continuous operation at the 5% OP/VWO coincident condition.

Main and Reheat Steam

The function of the main steam system is to convey main steam from the boiler superheater outlet to the high pressure turbine stop valves. The function of the reheat system is to convey steam from the HP turbine exhaust to the boiler reheater and from the boiler reheater outlet to the turbine reheat stop valves.

Main steam at approximately 2520 psig/1000°F exits the boiler superheater through a motor operated stop/check valve and a motor operated gate valve, and is routed in a single line feeding the HP turbine. A branch line off the main steam line feeds the two boiler feed pump turbines during unit operation up to 60 percent load.

Cold reheat steam at approximately 589 psig/635°F exits the HP turbine, flows through a motor operated isolation gate valve, a flow control valve and enters the boiler reheater. Hot reheat steam at approximately 530 psig/1000°F exits the boiler reheater through a motor operated gate valve and is routed in a single line feeding the IP turbine. A branch connection from the cold reheat piping supplies steam to feedwater heater No. 7.

A two stage turbine bypass system is provided for the boiler. The system permits bypassing steam around the HP turbine and around the IP/LP turbine. The system is utilized to start up the boiler.

Extraction Steam

The function of the extraction steam system is to convey steam from turbine extraction points through the following routes:

- from IP turbine exhaust to the boiler feed pump turbines and deaerator
- from HP turbine exhaust (cold reheat) to Heater 7
- from IP turbine to Heater 6
- from LP turbine to Heaters 1,2,3 and 4

The turbine is protected from overspeed on turbine trip, and from flash steam reverse flow from the heaters through the extraction piping to the turbine. This protection is provided by positive closing, balanced disc non-return valves located in all extraction lines except the lines to the low pressure feedwater heaters in the condenser neck. The extraction non-return valves are located only in horizontal runs of piping and as close to the turbine as possible.

Water is prevented from entering the turbine through the use of motor-operated gate valves in each branch of the extraction piping. The header to the deaerator and boiler feed pump turbines has two extraction non-return valves, and the lines to the boiler feed pump turbines each have a manually operated gate valve and a swing check valve. The motor-operated gate valves close automatically on an emergency high-level signal from a level switch located on the heater being supplied with steam or the respective line drain pot. The emergency high water level switch will also energize the solenoid of the air cylinder to close the non-return valve, and actuate an alarm in the control room. The motor-operated gate valve position limit switch opens the drain valves on the corresponding extraction steam drain manifold, which drains to the condenser. The valves cannot be returned to their normal positions until the emergency high water level switch indicates that the water level has fallen below the emergency level.

The turbine trip signal automatically trips the non-return valves through relay dumps. The remote manual control for each heater level control system is used to release the non-return valves to normal check valve service when required to restart the system.

3.5.3.1 Operation Description

All motor operated isolation valves can be operated locally or from the main control room. In the event of high water level in the respective steam line, the valve closes automatically.

All extraction non-return valves close automatically either on a unit trip or when high water level in the respective steam line is detected.

All pneumatic drain pot valves operate automatically during unit startup or on high level.

3.5.3.2 Technical Requirements and Design Basis

Design Basis

1. The systems are sized to pass the flow rates occurring at 5 percent overpressure, valves wide open condition (VWO).

2. All piping is designed in accordance with ANSI B31.1. All valves are designed in accordance with ANSI B16.34.

3. The main steam line is designed for a total pressure drop of 100 psi at VWO, while limiting velocities to 20,000 fpm.

4. The cold reheat line is designed for a total pressure drop of 10 psi at VWO, while limiting velocities to 15,000 fpm.

5. The hot reheat line is designed for a total pressure drop of 20 psi at VWO, while limiting velocities to 20,000 fpm.

6. The extraction steam lines are designed for a total pressure drop of 5 percent of the extraction nozzle pressure while limiting velocities to 1,000 fpm per inch of pipe I.D.

3.5.4 Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam.

The system consists of one counterflow, mechanical draft cooling tower comprised of 10 cells; two 50% capacity vertical circulating water pumps; and carbon steel cement lined interconnecting piping. The cooling tower structure is concrete, with PVC fill and fiberglass fan stacks. The circulating water system is designed based on economic optimization at the 100% load guarantee condition at the specified ambient wet bulb temperature.

The condenser is a twin shell dual pressure type with divided water boxes arranged for series flow of the circulating water. There are two separate circulating water circuits in each box. The water enters condenser A then reverses flow into condenser B, where the discharge returns to the cooling tower. There are two separate cooling circuits through the condensers. One half of each condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

The warm water leaving the condenser is passed through the cooling tower to transfer heat to the atmosphere by evaporation. The air flow is induced by the fans. Drift eliminators are used to remove entrained water droplets. Makeup water, to replace evaporated water, blowdown and drift, enters the cooling tower basin through a motor operated, automatic, level control valve. The tower is equipped with a fill bypass system to prevent freeze-up during cold weather.

The cooling tower discharge water flows to the circulating water pumps. A double set of removable screens, which remove large objects such as leaves, sticks, logs and ice to protect the circulating water pumps and condenser tubes, is installed upstream of the pump suction. These may be pulled out one at a time for cleaning as required. A bubbler type pressure differential switch monitors high pressure drop as an indication of plugging.

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°. 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°. On shutdown, the valve closes fully and as it passes the 15° open position, trips the pump automatically. The valve closes automatically on loss of power to avoid hydraulic surges.

3.5.4.1 Operation Description

Prior to operation, the circulating water lines and tower basin are filled using the tower makeup system. During filling the piping and condenser water boxes are manually vented.

Normal operation is with two circulating water pumps in service. One pump can be used during startup, during periods of reduced load or when half of each condenser shell is out of service for inspection or tube plugging.

3.5.4.2 Technical Requirements and Design Basis

<u>Design Basis</u>

1. The system is sized to pass the flow rates occurring at 5 percent overpressure, VWO condition.
2. The circulating water piping is sized for a maximum velocity between 8 to 10 fps.
3. The cooling tower is designed in accordance with CTI standards.

Components (at nominal 100% design point)

Cooling Tower

• Quantity	1
• Type	Rectangular, counter flow, concrete, mechanical draft
• Water Flow	202,000 gpm
• Inlet Temp.	95°F
• Outlet Temp.	75°F
• Wet Bulb Temp.	52°F

Circulating Water Pumps

• Quantity	2
• Type	Vertical wet pit
• Capacity	101,000 gpm
• Total Head	80 ft.
• Horsepower	2,600 hp
• Speed	450 rpm
• Impeller Material	316 S.S.

3.5.5 Miscellaneous BOP Systems

Many ancillary systems and subsystems support the operation of a power plant such as presented in this report. Descriptions of some of the more prominent systems are described within this section, including liquid waste treatment, auxiliary boiler, fuel oil, service and instrument air, and service water.

3.5.5.1 Liquid Waste Treatment

Industrial wastewater from station operations will be collected, treated in an on-site treatment system, and discharged to an adjacent stream. The industrial waste treatment system will treat wastewater from the following sources:

- Coal pile leachate and runoff
- Limestone storage runoff
- Contaminated yard drains
- Maintenance cleaning wastes
- Cooling tower blowdown
- Demineralizer regenerants
- Filter backwash
- Miscellaneous low volume wastes

The treated effluent will meet U.S. Environmental Protection Agency standards for total suspended solids, oil and grease, pH, and miscellaneous metals.

The industrial waste treatment system employs the following unit processes and operations:

Flow equalization

Contaminated rainfall runoff from the 10 yr - 24 hr. storm is collected in a synthetic-membrane lined 700,000 gallon earthen basin (approximate 167 ft x 80 ft x 7 ft deep) and is pumped to the treatment system at a controlled rate. This basin also equalizes flow from maintenance cleaning wastes. In addition, the 4,500 gallon raw waste sump has sufficient surge capacity to èqual short-term peak flows such as filter backwashes. Three raw waste pumps are provided, each 280 gpm.

Neutralization

Acidic wastewater is neutralized with hydrated lime in a two-stage system. Each neutralization tank is a 6,000 gallon fiberglass tank providing a 7.5 minute reaction time at design flow. Each tank is equipped with a pH probe and controller which automatically feeds lime slurry to the respective tank to control pH. Each tank is equipped with a fixed-mount mixer to completely mix lime slurry with the wastewater. An integral lime storage silo/lime slurry makeup system with 50 ton lime silo, a 0-1,000 lb/h dry lime feeder, a 5,000 gallon lime slurry tank, slurry tank mixer, and 25 gpm lime slurry feed pumps is provided.

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 50 scfm compressor which also furnishes air for operation of sludge pumps and the filter press.

Flocculation

Flocculation to promote particle size growth is provided in a 7,600 gallon fiberglass tank with a 10 minute retention time at design flow. The tank is equipped with a low rpm, variable speed agitator. Polymer emulsion is drawn directly from a 55-gallon drum and is diluted and fed to the flocculation tank by a 100 gallon/h polymer feed unit.

Clarification/Thickening

Overflow from the flocculation tank enters a plate-type clarifier/thickener for suspended solids separation. Solids settle between the inclined plates to the thickener zone while the clarified supernatant rises from the plates to discharge 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 pumped to an 8,000 gallon holding tank which 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 produces a sludge cake of 35 percent by weight dry solids or higher. Filter press cake is dropped from the press into a sludge dump truck or dumpster. Filtrate is returned to the raw waste sump.

The coal pile runoff basin, the raw waste sump, and the lime storage and feed system are located outdoors. The remaining treatment system components are located in a heated building.

3.5.5.1 Auxiliary Boiler Steam System

The auxiliary boiler supplies steam to all plant components normally requiring steam during periods of unit or station shutdown, startup, or in certain cases, normal plant operation. The major interfacing components and systems with the auxiliary boiler are the feedpumps, deaerator, fuel oil storage and supply, forced-draft fan(s), and stack.

The siting and selection of steam conditions for the auxiliary boiler were based on a review of potential system demands, including such components as fuel oil atomizers, fuel oil tank heating, turbine seals, building heating, etc. An auxiliary watertube boiler sized to produce 100,000 lb/h of 400 psig/650°F superheated steam was selected for this installation.

3.5.5.3 Fuel Oil Supply System

A fuel oil storage and supply system sized to accommodate the boiler startup burners and auxiliary boiler was included in the estimate. Number 2 grade fuel oil was selected for use due to anticipated usage and cost considerations, as well as providing future fuel flexibility benefits.

A storage tank capacity of 300,000 gallons was selected, providing an on-site supply of approximately 15 days when firing the auxiliary boiler at maximum rating. Delivery of fuel oil to the station site is designed for receipt by truck. The tank storage area is diked for spill containment, and is located away from buildings, hazardous equipment and materials, and power lines, for reasons of safety.

Unloading pumps, transfer pumps, strainers, regulators, controls, instrumentation, valves, piping, and fittings are included in the design of this system.

3.5.5.4 Station Air Service

<u>Service and Instrument Air System</u>

Service air is provided by any of three, 100 percent capacity single-stage, jacketed, double-acting compressors sized to deliver 800 scfm of air at a discharge pressure of 100 psig. The service air system is also equipped with a common air receiver tank, automatic start pressure control, controls, instrumentation, valving, piping, and fittings. Instrumentation air is provided by the service air system, and is conditioned using duplex regenerative air dryers sized to deliver 400 scfm.

3.5.5.3 Station Service Water

The pumps provided for the various station water services generally take water from either of two suction headers connected directly to the circulating water pump basin.

Service Water

Two service water pumps at 100% capacity each provide the general water requirements for the station. These pumps are single stage, double suction centrifugal pumps, with each pump designated to deliver 6,000 gpm of water against an estimated head of 100 feet. The service water system consists of a loop header around the plant, fitted with segregating valves so that portions of the loop may be closed off while the remainder stays in service.

Cooling water is supplied from this system to equipment such as generator hydrogen and turbine lube oil coolers, FD fans, compressors, mills, boiler feed pumps, etc. Service Water is also used to cool the closed cycle cooling water system loop. A separate header takes water to the ash and dust unloading systems, and car dumper house.

Closed Cycle Cooling Water

A closed cycle cooling water system is used to cool smaller cooling loads and those that require a higher pressure, such as coolers located higher in the plant. Condensate quality water is used as the cooling fluid. System capacity is set at 600 gpm, with two 100% capacity pumps rated at 600 gpm/85 ft of head.

Fire Service Water

The fire service water piping supplies the various hose reels throughout the plant, fire hydrants and the transformer fire fog system. The system is normally under house service water pressure. For fire fighting it receives water from the fire service booster pump and/or the engine driven fire pump.

The fire service booster pump is a two stage centrifugal pump, capable of delivering 700 gpm at 250 feet total head. The engine driven fire pump takes suction directly from the circulating pump suction chamber. The pump is a vertical turbine type, diesel engine drive, and delivers 1,000 gpm of water at a total head of 350 feet.

Makeup Pumps

Two pumps at 100% capacity each are installed to supply water for makeup to the circulating water system, filtered water, service water and ash pond. They are centrifugal pumps equipped with single suction, cast iron vertically split casings. Each pump delivers 5,750 gpm of water against a total head of 100 feet.

Filtered Water Pumps

Two filtered water pumps take water from the clearwell and supply the filtered water tank and the demineralizers. The pumps are centrifugal pumps constructed with single suction, cast iron vertically split casings. Each pump will deliver 200 gpm against a total head of 200 feet.

A filtered and sterile water storage tank is provided, and has a capacity of 15,000 gallons.

All water except that flowing to the demineralizers is taken directly to the storage tank to provide a constant head on the system and to prevent stagnation of water in the tank.

3.5.6 Piping and Valves

Generally, piping and valves will conform to the requirements of ANSI B31.1, Power Piping. Carbon steel piping material will be A106, Gr. B or C, and Chrome Moly piping will be A335, Gr. P22.

In addition to the general requirements, the following are specifics concerning the more critical piping in the plant:

- Condensate Pump Suction - (Design-50 psig/100°F)
  Class- 150; carbon steel-A106 Gr B, all std. wall.

- Condensate Pump Discharge Before Heaters (Design-500 psig/150°F)
  Class 300; carbon steel - A106 Gr B, 2 inch and under-sch 80, 2 1/2 to 18 inch - std. wall

- Boiler Feed Pump Suction (240 psig/400°F)
  Class 300; carbon steel A106 Gr B, std. wall

- Boiler Feed Pump Discharge Before Heaters (3600 psig/450°F)
  Class 2500, carbon steel A106 Gr C, 1/2 to 2 inch - sch 160, 2 1/2 to 6 inch - double extra strong wall, 8 to 18 inch - 1.875 inch min. wall.

- Boiler Feed Pump Discharge After Heater (3600 psig/550°F)
  Class 2500, carbon steel A106 Gr C, 1/2 to 2 inch - sch 160, 2 1/2 to 6 inch - double extra strong wall, 18 inch - 1.875 inch min. wall

- Main Steam Pipe and Valves (Design 2750 psig/1000°F)
  Chrome-Moly A335 Gr P22 pipe, 24 inch O.D. - 3.75 inch min. wall; Class 4500 chrome-moly A217 Gr WC9 valves.

- Hot Reheat Pipe and Valves (Design 650 psig/1000°F)
  Chrome-moly A335 Gr P22 pipe, 32 inch O.D.-1.375 inch min. wall; Class 900 chrome-moly A217 Gr WC9 valves.

- Cold Reheat Pipe and Valves (Design 725 psig/700°F)
  Carbon steel A106 Gr C, 32 inch O.D., 0.875 inch min. wall; Class 600 carbon steel A216 Gr WC9 valves

- Extraction Steam Pipe to Heater No. 6 (Design 350 psig/900°F)
  Chrome-moly A335 P22 pipe, sch 40; Class 300 chrome moly A217 Gr WC6 valves

- Extraction Steam Pipe from Cross Over (Design 200 psig/750°F)
  Carbon steel A106 Gr B pipe, standard wall; Class 300 carbon steel A216 Gr WCB Valves.

- Extraction Steam Pipe from LP Turbine (100 psig/600°F)
  Carbon steel A106 Gr B pipe, standard wall; Class 300 carbon steel A 216 WCB valves

- Circulating Water Pipe (Design 60 psig/100°F)

Carbon Steel, API5L, 108 inch O.D., extra strong (1/2" nominal wall) with 1/2 inch thick cement lining.

3.6 PLANT CONTROL AND MONITORING SYSTEMS

3.6.1 Design Basis

Control and monitoring functions will be implemented in an integrated multi-function distributed control system (DCS). This system will use multiple redundant micro-processors to execute closed loop control strategies, alarm monitoring and reporting, data presentation, data recording, data storage and data retrieval. Conventional panel instrumentation will be held to a minimum, to be used solely for plant shutdown in the case of a major multi-element DCS failure. Geographical distribution of both micro-processor modules and I/O units will be implemented wherever practical to reduce plant wiring and cabling costs. Control valves, transmitters and control drives (actuators) will be standardized and purchased in lots from a single manufacturer to the greatest extent possible.

Proprietary control strategies will be safeguarded via confidentiality agreements to allow implementation in the DCS. Use of specialty control or monitoring systems will be minimized (eliminated if possible). If the required function cannot be technically implemented in the DCS due to processing (execution speed) shortcomings on the part of the DCS, or if the control strategy is programmed in a language where the cost of the conversion to the DCS control language is prohibitive, exceptions may be made. In this case the specialty system supplier will be held responsible to provide either a hardwired interface to the DCS or a communication link compatible with the DCS.

3.6.2 Control Room

The Control Room will utilize cathode ray tube (CRT) and keyboard units for operator interface. Touchscreens will be used to improve operator access to data and control functions. The final number of CRT's and keyboards will be determined from an analysis of the plant's operating modes (baseload, on-off, cycling, on-line load following). Between six and twelve CRT's are envisioned. Color printers will be used for logging data, alarm hardcopy, CRT screen copies, data trending hardcopy, and reports. Minimal hardwired panel instrumentation will be utilized to safely shutdown the plant due to a major multi-element DCS failure.

3.6.3 Automation and Operation

The DCS will be configured to operate all plant equipment in an automated closed loop mode. Plant operators will initiate start-up and shut-down sequences. Operation of individual pieces of equipment will be automated to the greatest extent possible. Operator initiation of the starting and/or stopping of individual equipment will be automated to require as few operator actions as necessary. This will minimize the variations in start-up and shutdown procedures which impact equipment operating life and availability.

The design of the combustion control systems will be a joint, integrated process involving the boiler supplier, the plant designer, the operator/user and the DCS supplier.

The DCS shall be configured to provide closed loop automatic control of the following loops:

- Throttle Pressure
- Coordinated Load Control
- Unit (turbine) Load
- HP Turbine Bypass
- IP/LP Turbine Bypass
- Secondary Pressure/Flow
- Primary Air Pressure/Flow
- Fuel (PDF) Feed/Limestone Feed
- Superheat Steam Temperature
- Reheat Steam Temperature
- Furnace Pressure
- Feedwater Flow and Drum Level
- Deaerator Level
- Feedwater Heater Level
- Supplemental Oil Firing
- Coal/Lime Ratio (SO_2 Control)
- Excess Air/Oxygen
- Condensate Pump Recirculation Flow
- Boiler Feed Pump Recirculation
- Hotwell Level
- Condensate Storage Tank Level
- Generator Hydrogen Temperature
- Turbine Lube Oil Temperature

Conventional logic and control strategies will be used for the majority of the control loops.

Initially the boiler is fired via the start-up oil burners. This operation provides the steam conditions necessary to warm-up and roll the turbine, bring up to speed and synchronize it. As the transition from start-up burners to coal combustion is made, the steam bypass systems will be used to smoothly initiate and stabilize the unit.

Deaerator storage tank level is controlled by a control valve in conjunction with condensate pump speed modulation to minimize energy consumption. Condenser hotwell level is controlled by either discharging condensate back to the storage tank through a spillover line connected to the discharge of the condensate pumps or by admitting condensate by gravity from the storage tank. Control is accomplished using pneumatic control valves.

The boiler's feedwater flow and drum level are controlled by pneumatic control valves in conjunction with pump speed modulation to minimize energy consumption. Hot reheat temperature is controlled by spraying intermediate stage boiler feed pump discharge water into the reheater desuperheaters using pneumatic temperature control valves.

The turbine control system provides the following basic turbine control functions:

- Automatic control of turbine speed and acceleration through the entire speed range, with several discrete speed and acceleration rate settings.

- Automatic control of load and loading rate from no load to full load, with continuous load adjustment and discrete loading rates.

- Standby manual control of speed and load when it becomes necessary to take the primary automatic control out of service while continuing to supply power to the network via the turbine-generator.

- Detection of dangerous or undesirable operating conditions, annunciation of the detected condition, and initiation of proper control response to the condition.

- Monitoring of the status of the control system, including the power supplies and redundant control circuits.

- Testing of valves and controls.

- Prewarming of valve chest and turbine rotor using main or auxiliary steam supply.

The DCS shall be configured to provide on/off control of the following equipment. This control shall be both automatic (process logic) and manual (operator).

- Condensate Pumps
- Boiler Feed Pump Turbines
- Motor Driven BFP
- Secondary Air Fans
- Primary Air Fans
- ID Fan
- Circulating Water Pumps
- Motor Operated Valves
- Motor Operated Dampers
- All Pneumatically Operated Dampers
- Turbine Water Induction Prevention Valves
- Fuel (PDF) Feeders
- Oil Pumps
- Oil Burners
- Cooling Tower Fans

3.6.4 Data Gathering, Reduction and Retrieval

Operating data will be stored for future retrieval and analysis by utilizing the latest, most reliable technology from among magtape, optical disk and other available technologies. Redundant storage devices and mediums may be provided to insure complete one-hundred percent availability of operating data for retrieval and analysis. The types of data to be stored will include the following:

- Turbine Start-Up Log
- Turbine Shut-Down Log
- Boiler Start Up Log
- Boiler Shutdown Log
- Post Trip Logs

- Sequence of Event Logs
- Periodic (Hourly and Daily) Logs
- All Trend Data
- Process Data by Exception Reporting

Means shall be provided to allow plant personnel to modify the collection and storage of data both from a quantity (points to be stored) and a quality (data collection frequency) perspective.

Retrieval of data for analysis shall make allowance for both retrieval at the plant site and at remote locations. Plant site retrieval shall use personal computers for access to and analysis of historical data from the DCS. Personal computer software will be provided to enable spreadsheet analyses and statistical correlation analysis. Remote site data retrieval shall be based on utilizing a mini-computer environment such as DEC Micro-Vax or Hewlett Packard.

3.6.5 Continuous Emission Monitoring System

3.6.5.1 Introduction

The Continuous Emissions Monitoring System (CEMS) consists of four major parts: the flue gas emission analyzers, the opacity monitor, the flue gas flow rate monitor, and the data acquisition and reporting system (DAS). The CEMS provides the plant with the ability to monitor and report emissions in compliance with the Environmental Protection Agency's (EPA) Clean Air Act Amendments.

3.6.5.2 Function

The function of the CEMS is to continuously monitor the emissions of the plant in compliance with the Clean Air Act. The system will provide an accurate measurement of the levels of Sulfur Dioxide (SO_2), Nitrogen Oxides (NO_x), and Carbon Dioxide (CO_2) in the flue gas as well as a measurement of the flue gas opacity and flow. In addition to providing emissions monitoring capabilities, the system will provide emissions and system calibration reports for submittal to the regulatory agency as required by the Clean Air Act.

3.6.5.3 Description

The Continuous Emissions Monitoring System will consist of an Opacity Monitoring System, a CEM Analyzer System, a Flue Gas Flow Rate Monitoring System, and a Data Acquisition System (DAS) as further described below. These systems will provide the control, monitoring, and reporting functions of the CEMS.

The CEM Analyzer System will be a dilution extractive system with the capabilities of monitoring sulfur dioxide (SO_2), nitrogen oxides (NO_x) and carbon dioxide (CO_2) in the flue gas. The system consists of a Sample Dilution Probe, an Umbilical Line, a Sample Conditioning Controller and the analyzers for monitoring SO_2, NO_x and CO_2. The sample dilution probe is mounted on the stack and is connected via the umbilical line to the sample conditioning controller. The controller, along with the analyzers, are mounted in the analyzer rack in the CEM Enclosure.

The CEM Analyzer System automatically samples and analyzes the flue gas and performs automatic calibration checks once every 24 hours using certified calibration gases.

The Flue Gas Flow Rate Monitoring System will utilize an across the stack ultrasonic velocity measurement technique to monitor flue gas flow. The system consists of a stack mounted transducer assembly, an electronics enclosure and a remote monitoring display. The transducer and the remote monitoring display will be located in instrument racks in the CEMS Enclosure. In addition to measuring the flue gas flow rate, the flow gas monitoring system measures the flue gas temperature. The flue gas temperature, along with a separately measured stack pressure, are used to provide an output in standard cubic feet per minute (SCFM) corrected for temperature and pressure.

The CEM Data Acquisition System will provide the control, monitoring, and reporting functions of the CEM system. All of the outputs from the above systems are provided as inputs to the DAS for control and monitoring. The DAS consists of a Data Logger, Programmable Controller, (including the necessary software) and two operator/technician stations. The DAS Data Loggers will be located in the analyzer rack in the CEMS enclosure. The DAS Data Logger not only monitors and stores emissions data from the opacity, flue gas analyzer, and flow rate monitoring systems but provides the sample/calibration sequence control program for the system.

The PC, located in the Environmental Engineers office, polls the DAS Data Logger for emissions data and generates the emissions reports. One of the two Operator/Technician stations will be located in the CEMS Enclosure, the other will be located in the Control Room. A backup Data Logger in conjunction with the PC creates redundant data files for use in the event of a failure of the Primary Data Logger. The analyzers and alarm signals will be interfaced into the plant distributive control system via hard wiring. Other miscellaneous equipment/requirements associated with the CEMS is summarized below.

- Barometric Pressure Transmitter
- Stack Pressure Transmitter
- Calibration Gas Bottles (one set of three)
- Uninterruptible Electric Power Source
- Clean, dry instrument type air

3.6.6 Start-Up Testing and Tuning

Sufficient time will be allotted in the start-up schedule for the complete tuning of the control system in order to meet the operational requirements. Modifications to control strategies will probably be required. These will be generated by the equipment supplier and reviewed with the DCS equipment personnel and plant operating personnel. Modification of software based control strategies shall be made and documented by personnel from the DCS supplier and further tested as to their improved capabilities. The objective of this testing and tuning is to provide complete automatic control of the process by the DCS control system.

3.7 LAYOUT ARRANGEMENT

The arrangement of equipment, systems and structures on site are shown in this section, and the basis for this arrangement is described.

3.7.1 Assumptions

The following assumptions were taken into consideration when developing the site layout arrangement.

- Initially a single unit facility is to be constructed which includes a single pulverized PDF fired boiler connected to a single turbine generator, with a Duct Injection Flue Gas Desulfurization (FGD) system integrated into the facility layout.

- Make provisions in the initial unit site layout arrangement to provide for the addition of a future second unit and the necessary support facilities.

- The circulating water heat sink is a mechanical draft cooling tower.

- Make up and potable water for plant use is filtered and treated on site.

- Plant and sanitary wastes are held and treated on site.

3.7.2 Overall Site Plan

The site layout arrangement is shown in Figure 3-15, and is arranged to include the following considerations.

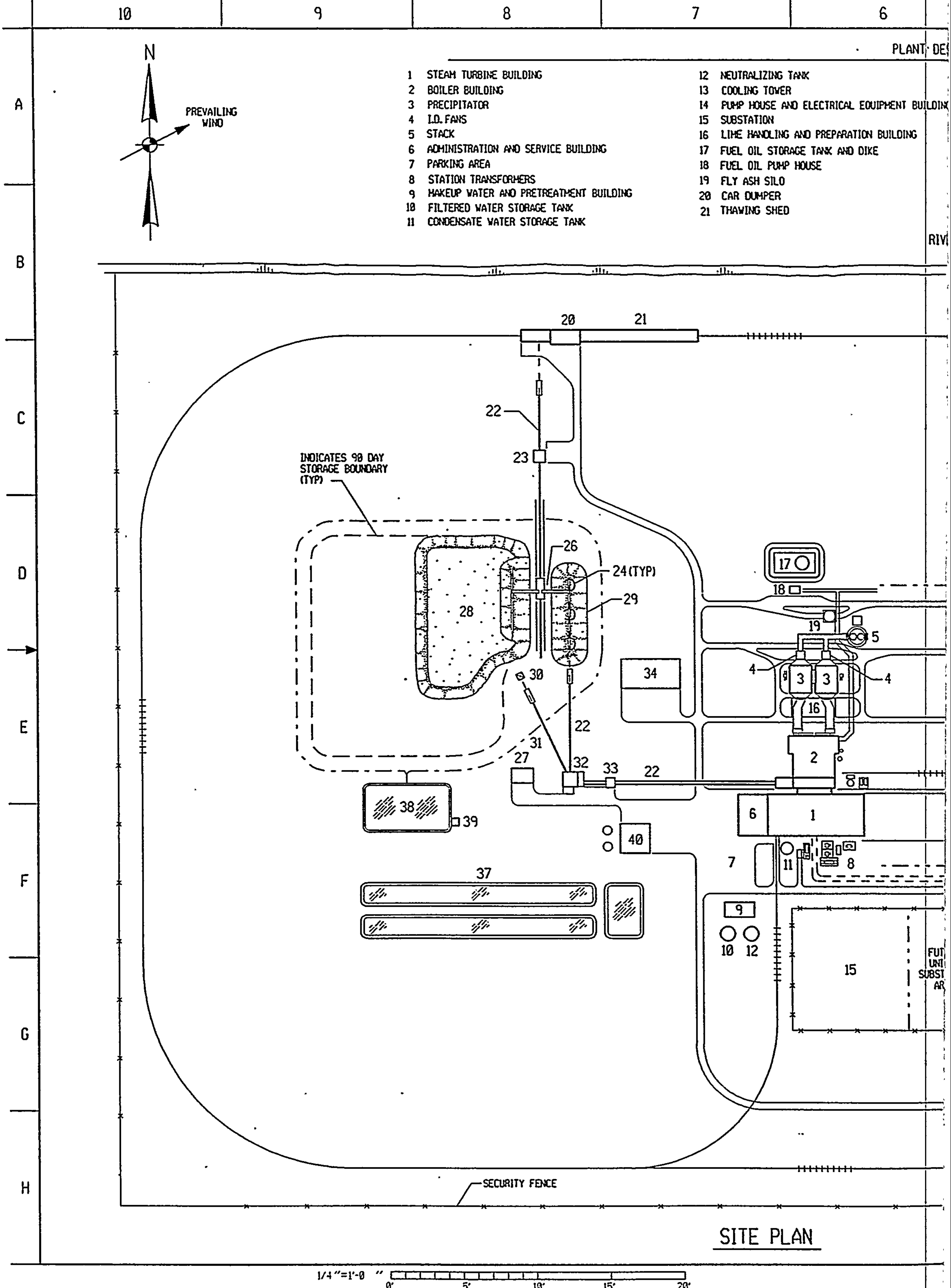
General

The location of structures, facilities, equipment and systems are arranged with consideration given to process flows, costs, construction requirements, rail access, roadways and future unit requirements. The site is approximately 300 acres.

Facilities required for the operation of the first unit which are located in a manner to allow for the addition of a future unit include the following:

- Fuel unloading, storage, and conveying system
- Lime unloading, storage, and conveying system
- Permanent warehouse
- Waste treatment system
- Water supply system and primary treatment equipment
- Administration/service building
- Oil unloading and storage facilities
- Auxiliary boilers
- Diesel generators

The on-site railroad system completely loops around the station. The location of the railroad main line turnout is determined by the length of a unit train of 100 cars, with each car having a capacity of 100 tons. The length of track must be sufficient to store a fully loaded unit train in front of the dumping facility and an empty unit train beyond the dumping facility, with both completely clearing the first station turnout.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PREVAILING WIND
PLANT DE
1 STEAM TURBINE BUILDING
2 BOILER BUILDING
3 PRECIPITATOR
4 I.D. FANS
5 STACK
6 ADMINISTRATION AND SERVICE BUILDING
7 PARKING AREA
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 AND ELECTRICAL EQUIPMENT BUILDIN
15 SUBSTATION
16 LIME HANDLING AND PREPARATION BUILDING
17 FUEL OIL STORAGE TANK AND DIKE
18 FUEL OIL PUMP HOUSE
19 FLY ASH SILO
20 CAR DUMPER
21 THAWING SHED
RIV
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24 (TYP)
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SECURITY FENCE
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5'
10'
15'
20'
SITE PLAN

DD

CRIPTION

22 COAL CONVEYOR
23 TRANSFER BUILDING
24 ACTIVE PILE RECLAIM HOPPERS
25 CONTINUOUS EMISSIONS MONITORING BUILDING
26 DOUBLE WING TRAVELLING STACKER
27 COAL YARD VEHICLE MAINTENANCE GARAGE
28 COAL STORAGE (30 DAY)
29 ACTIVE COAL STORAGE
30 COAL EMERGENCY RECLAIM HOPPER
31 COAL EMERGENCY RECLAIM CONVEYOR
32 COAL CRUSHER BUILDING
33 AS FIRED COAL SAMPLING TOWER
34 WAREHOUSE
35 RIVER WATER INTAKE STRUCTURE
36 GUARD HOUSE
37 WASTE TREATMENT PONDS
38 COAL PILE RUNOFF POND
39 RUNOFF WATER PUMP HOUSE
40 INDUSTRIAL WASTE TREATMENT BUILDING
41 BOTTOM ASH POND

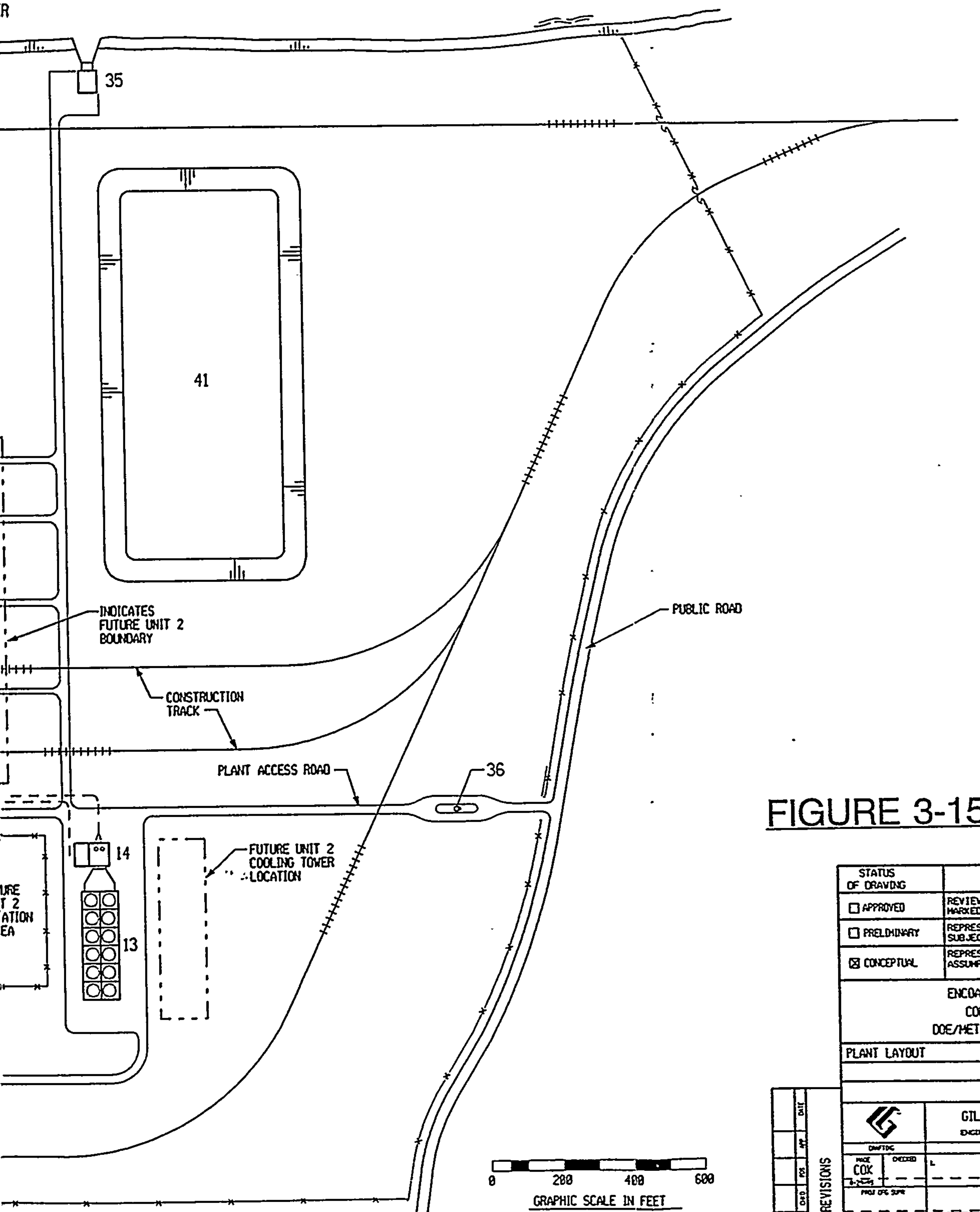

FIGURE 3-15

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☒ CONCEPTUAL	REPRESENTS GENERAL CONCEPTS BASED ON ASSUMPTIONS. CHANGES COULD ENSUE.

ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-89MC25177

PLANT LAYOUT GENERAL ARRANGEMENT

ENCOAL PLANT

SITE PLAN

GILBERT COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

REVISIONS

MADE COX

SCALE 1"=200'-0"

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Plant Waste

The spatial requirements of the plant waste system are site-related. The size of this system is largely determined by the quality of the makeup water and, to a lesser extent, the amount of rainfall. This system will be arranged to handle coal pile runoff along with other plant discharges.

Fuel Handling

Fuel unloading and handling occupy a large percentage of the plant's total land area requirements. An automatic unloading system was selected for illustration on the Plot Plans, using unit trains with swivel-coupled cars, a rotary car dumper, a car positioner, and a thaw shed. The fuel is dumped and conveyed to a transfer tower where it is placed on the belt of a double wing travelling stacker. The two fuel piles which are created are for active and dead storage. Fuel is reclaimed from the active storage pile through under pile hoppers, feeders and a conveyor belt. Reclamation from dead storage piles is by dozing into the emergency reclaim hopper located at the dead storage pile. The area of the dead storage pile is determined by the 90-day minimum requirement and the active pile is rmined by the 72 hour active fuel requirement. The fuel is conveyed to the crusher building where (if required) crushers reduce the fuel to the maximum size accepted by the pulverizers. After crushing, the fuel is transferred to the power block using two redundant conveying systems, with each utilizing a tripper conveyor which discharges the fuel to the bunkers for in-plant storage.

Lime Handling

Lime, in pebble form, is delivered to the site by truck and transferred pneumatically to a storage silo. From the silo the limestone is conveyed to a slaker mill and ground to form a slurry and pumped to the atomizer feed tank. Refer to Section 3.4.3 for a more detailed description of this system.

Power Block

The power block contains the following major areas.

- Steam Turbine Building (one steam turbine)
- Boiler Building
- Duct Injection Flue Gas Desulfurization System
- Control Complex
- Machine Shop
- Auxiliary Boiler and Diesel Generator Building
- Administration and Service Building
- Fly Ash Precipitators (2)
- Stack
- Transformer Area

Yard Area

The following are additional facilities located in the yard.

- Substation
- Cooling Tower
- Cooling Tower Pump House
- Makeup Water and Pretreatment Building
- Industrial Waste Treatment Building
- Fuel Pile Runoff Pond and Pump House
- Warehouse
- Fuel Yard Vehicle Maintenance Garage
- River Water Intake Structure
- Guard House

3.7.3 Power Block

General

The overall plant arrangemnent is shown on Figure 3-16. The cross section shown in Figure 3-17 illustrates the elevation differences through the major areas of the plant. The cross section indicates the elevational relationships between the turbine building and heater bay, the heater bay to the area containing the fuel bunkers, and the elevational relationship of the boiler area to the adjecent areas.

The building housing the turbine generator is 324 ft long and 135 ft wide, and is shown on Figure 3-18. The turbine building is sized to provide sufficient clear area to completely disassemble the turbine-generator and provide adequate laydown space for all parts.

The turbine room width is set taking into consideration the width of the turbine foundation, the physical requirements of the turbine-driven boiler feed pumps located at the ground floor along with sufficient space to locate additional equipment and route systems. Additionally, maintenance provisions and spatial requirements were considered. An equipment access hatch located at the southwest corner of the turbine room provides for truck and railcar access. The turbine room bridge crane which spans the width and travels the length of the turbine room is sized to handle the weight of the turbine generator rotor.

The boiler side of the turbine generator has been designated for the steam seal feed system and the opposite side for the steam seal drains and turbine lube oil system. The boiler feed pump turbines exhaust directly into the main condenser on the boiler side of the machine and the low pressure heater extraction points exit from the low pressure turbine cylinders on the opposite side. The low pressure heaters No. 3 and No. 4 are located on the opposite side of the turbine generator at the mezzanine floor level.

Isolated phase bus ducts are routed directly from the generator end of the machine to the transformer area which is located outside and adjacent to the turbine room.

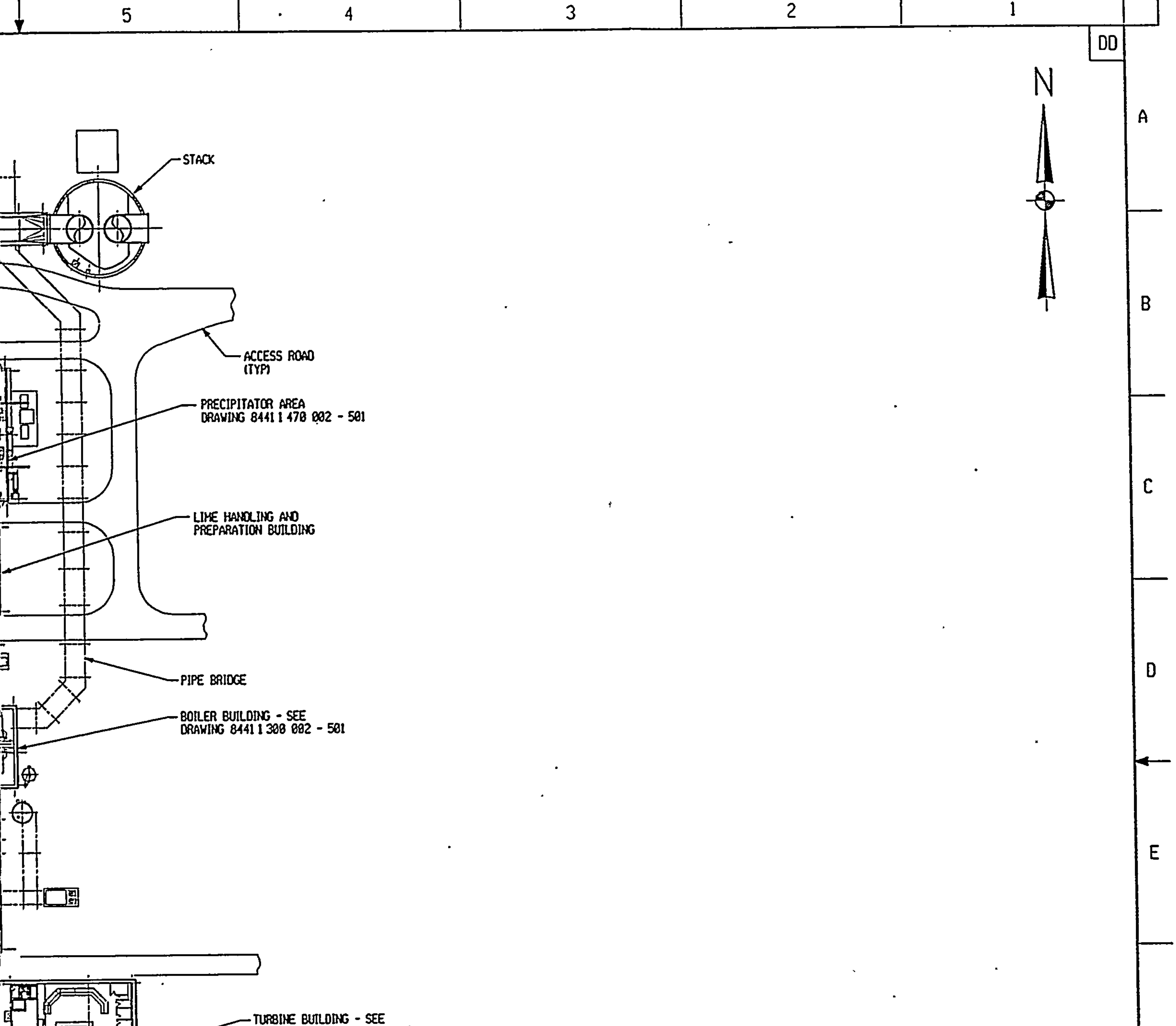

FIGURE 3-16

REVISIONS

STATUS OF DRAWING	DEFINITION
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☐ PRELIMINARY	REPRESENTS ACCEPTABLE DESIGN CONCEPTS. SUBJECT TO CHANGE.
☒ CONCEPTUAL	REPRESENTS GENERAL CONCEPTS BASED ON ASSUMPTIONS. CHANGES COULD ENSUE.

ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-94MC31166

PLANT LAYOUT — GENERAL ARRANGEMENT

PLANT GENERAL ARRANGEMENT

PLAN VIEW

GILBERT/COMMONWEALTH, INC.
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DRAFTING: COK — CHECKED
ENGINEERING INTERFACES: 1. 2. 3. 4.
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SCALE 1" = 50'- 0"
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8441 1 200 002 - 502 — REV A
DRAWING NUMBER

REVISIONS

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GRAPHIC SCALE IN FEET

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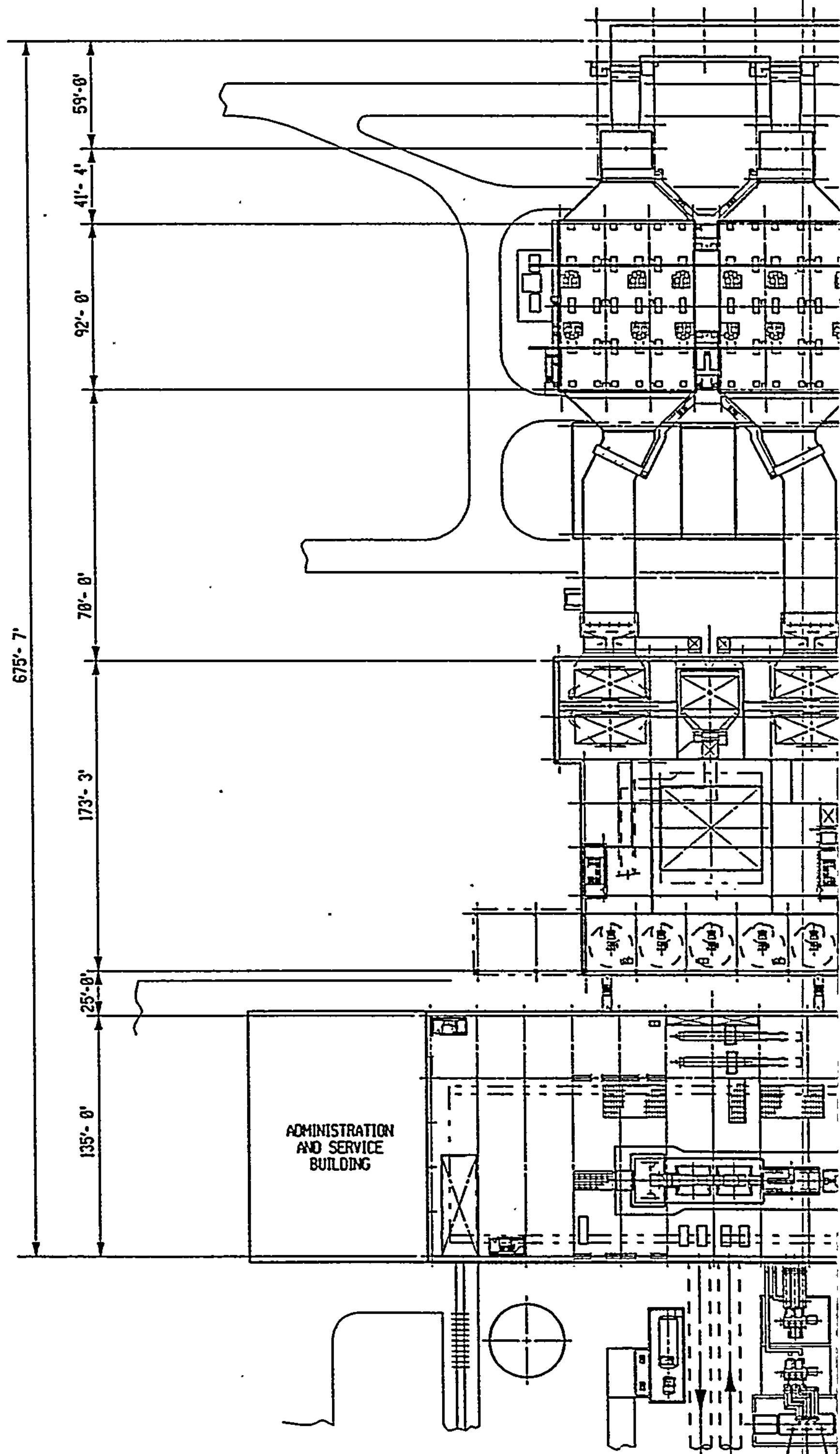
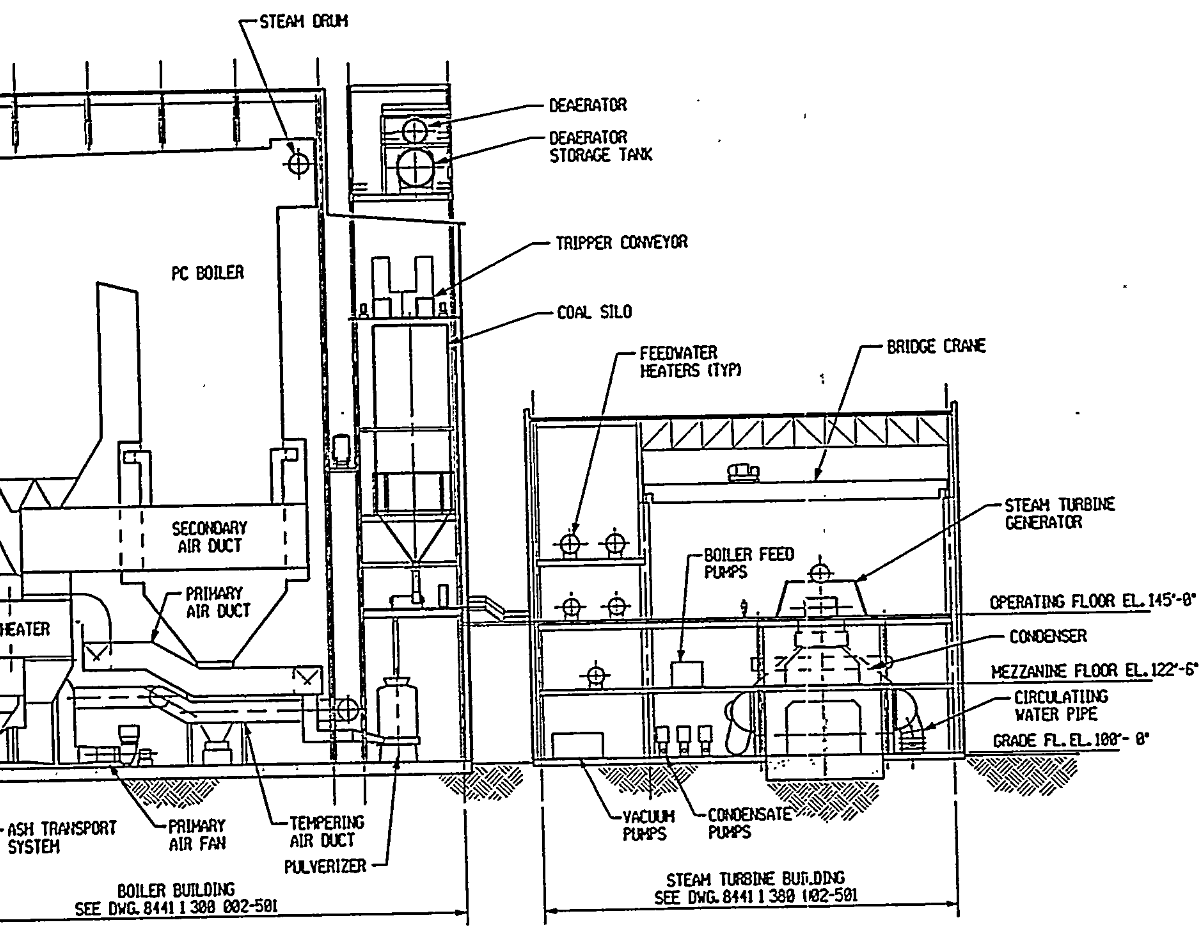


675'- 7"
59'-0"
41'- 4"
92'- 0"
70'- 0"
173'- 3"
25'-0"
135'- 0"
ADMINISTRATION AND SERVICE BUILDING

PLAN VIEW



LOOKING EAST

FIGURE 3-17

REVISIONS

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ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-89MC25177

PLANT LAYOUT — GENERAL ARRANGEMENT
PLANT GENERAL ARRANGEMENT
LONGITUDINAL SECTION

GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

COK

SCALE 1" = 30'- 0"

8441 1 200 002 - 503 A

888402-206

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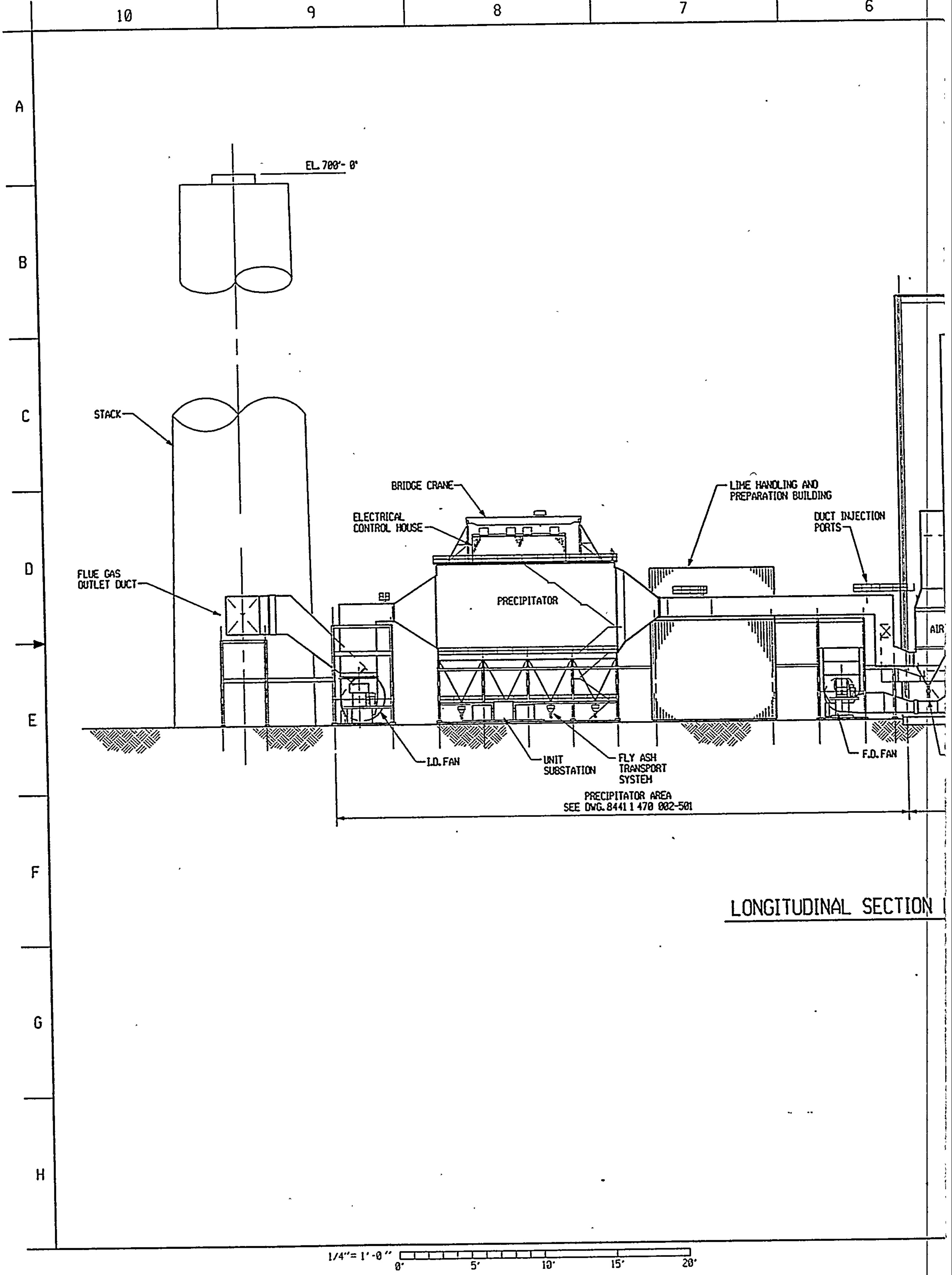
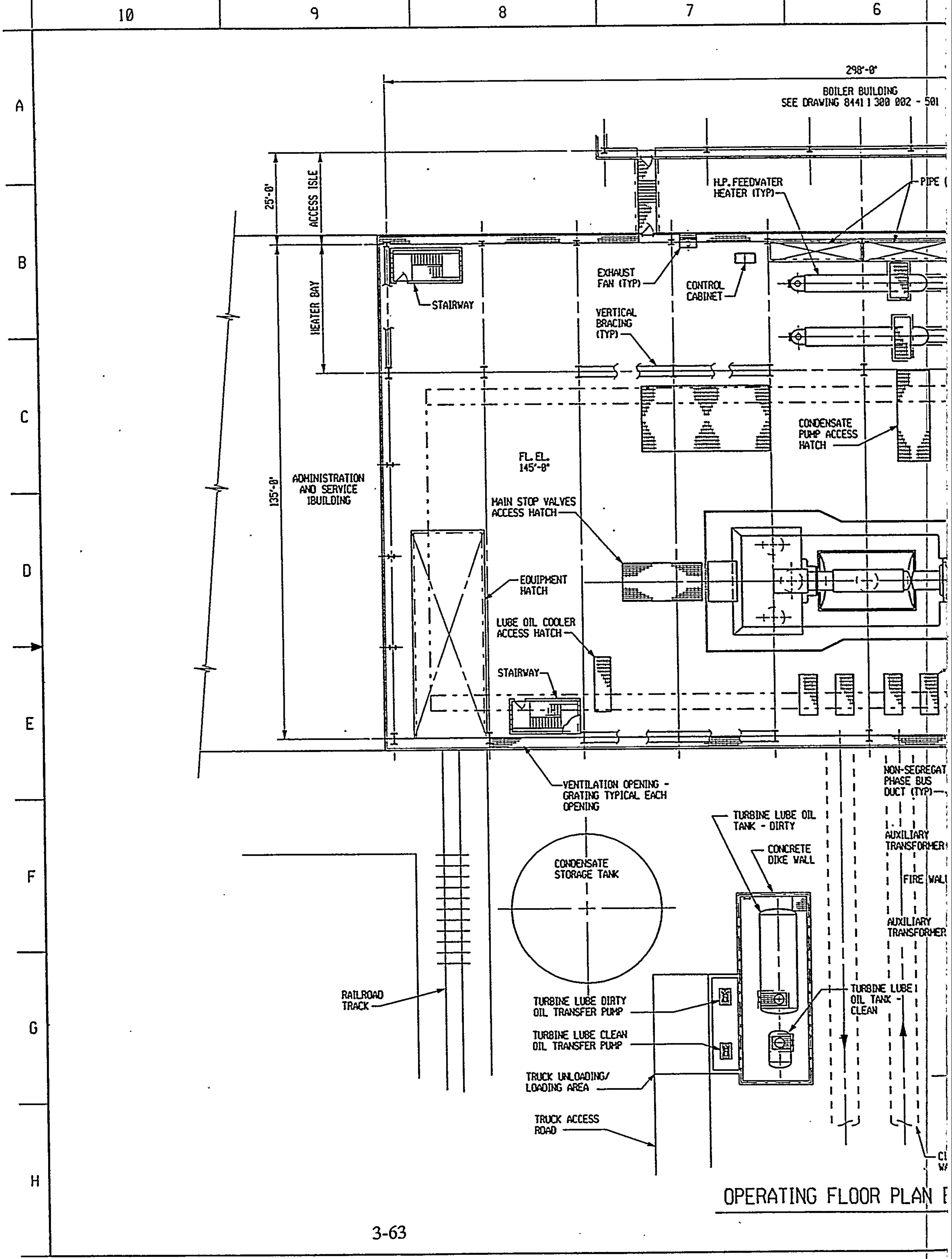


10
9
8
7
6
A
B
C
D
E
F
G
H
EL. 700'- 0"
STACK
BRIDGE CRANE
ELECTRICAL CONTROL HOUSE
LIME HANDLING AND PREPARATION BUILDING
DUCT INJECTION PORTS
FLUE GAS OUTLET DUCT
PRECIPITATOR
AIR
I.D. FAN
UNIT SUBSTATION
FLY ASH TRANSPORT SYSTEM
F.D. FAN
PRECIPITATOR AREA
SEE DWG. 8441 1 470 002-501
LONGITUDINAL SECTION
1/4" = 1'-0"
0'
5'
10'
15'
20'



10
9
8
7
6
A
B
C
D
E
F
G
H
298'-0"
BOILER BUILDING
SEE DRAWING 8441 1 300 002 - 501
H.P. FEEDWATER HEATER (TYP)
PIPE (
25'-0"
ACCESS ISLE
HEATER BAY
EXHAUST FAN (TYP)
CONTROL CABINET
STAIRWAY
VERTICAL BRACING (TYP)
CONDENSATE PUMP ACCESS HATCH
FL. EL. 145'-0"
ADMINISTRATION AND SERVICE BUILDING
135'-0"
MAIN STOP VALVES ACCESS HATCH
EQUIPMENT HATCH
LUBE OIL COOLER ACCESS HATCH
STAIRWAY
NON-SEGREGAT PHASE BUS DUCT (TYP)
VENTILATION OPENING - GRATING TYPICAL EACH OPENING
TURBINE LUBE OIL TANK - DIRTY
CONCRETE DIKE WALL
AUXILIARY TRANSFORMER
FIRE WAL
AUXILIARY TRANSFORMER
CONDENSATE STORAGE TANK
RAILROAD TRACK
TURBINE LUBE DIRTY OIL TRANSFER PUMP
TURBINE LUBE CLEAN OIL TRANSFER PUMP
TURBINE LUBE OIL TANK - CLEAN
TRUCK UNLOADING/ LOADING AREA
TRUCK ACCESS ROAD
OPERATING FLOOR PLAN

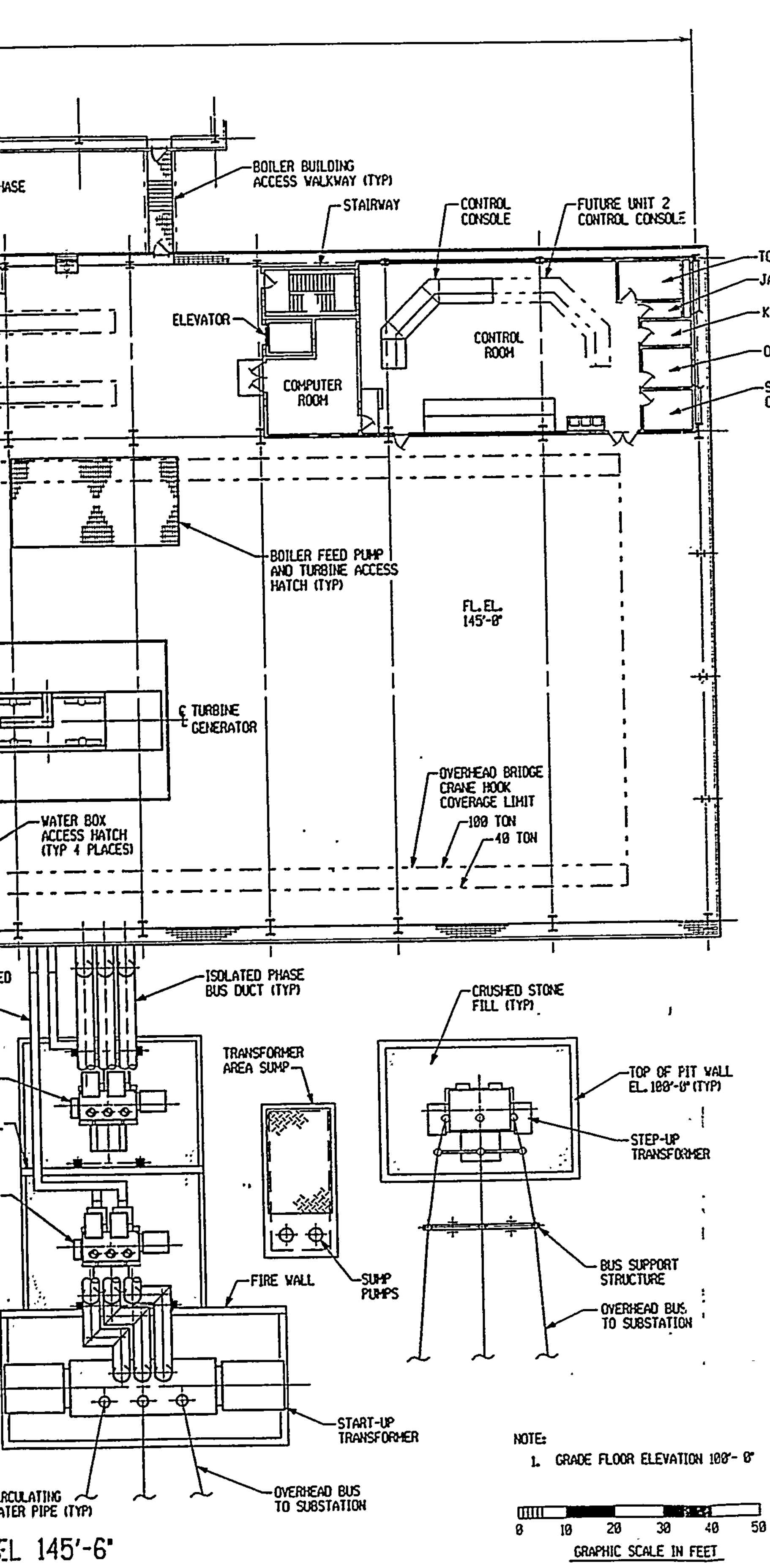


FIGURE 3-18

REVISIONS

STATUS OF DRAWING	DEFINITION
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ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-94MC31166

PLANT LAYOUT — GENERAL ARRANGEMENT
TURBINE BUILDING
OPERATING FLOOR PLAN EL. 145'- 6"

GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

DRAFTING: RWM
SCALE: 1/8" = 1'- 0"
W.O. 088441-206
DRAWING NUMBER: 8441 1 380 002 - 501 REV A

G/C-FILE: 148006:38002501.dgn
G/C-DATE: 30-Aug-95 16:41

Heater Bay

The heater bay is 30 ft wide and extends for most of the length of the turbine room. The purpose of the heater bay is to house components of the feedwater cycle such as the high pressure heaters and deaerator, and to provide a pipe chase for major piping between the boiler and turbine generator. This location within the station provides the most economical piping and equipment arrangement.

Additionally, the heater bay will provide dedicated space for routing horizontal and vertical runs of pipe and cable trays. At the grade floor level, space is reserved to provide a maintenance corridor which interconnects vital equipment areas with the machine shop, repair facilities and to provide for equipment removal capability from the plant.

The heater bay height is established to meet the requirements of the feedwater system requirements including NPSH considerations of the boiler feed pumps.

Boiler Area

The boiler is arranged so that the pulverizers and the coal bunkers/silos are located between the heater bay and the front of the boiler, as shown on Figure 3-19. Flue gas exits on the back side through the Duct Injection Flue Gas Desulfurization System, then through the electrostatic precipitators, and then to the stack.

The length (or depth) of the boiler area is determined by the boiler vendor. A 30 ft wide bay between the boiler and turbine buildings house the fuel silos, gravimetric feeders, pulverizers, and fuel piping to the burners. Additionally, a twenty foot wide bay is provided on the outboard sides of the boiler. These bays house the primary and secondary air fans, associated duct work and in addition, also provide space for routing of systems.

Directly in back of and adjacent to the back of the boiler are the Duct Injection FGD system, the electrostatic precipitators, I.D. fans, and interconnecting duct work. The intent of the arrangement is to keep these facilities as close to the gas outlet ducts of the boiler as possible, but also provide reasonable space for operations and maintenance.

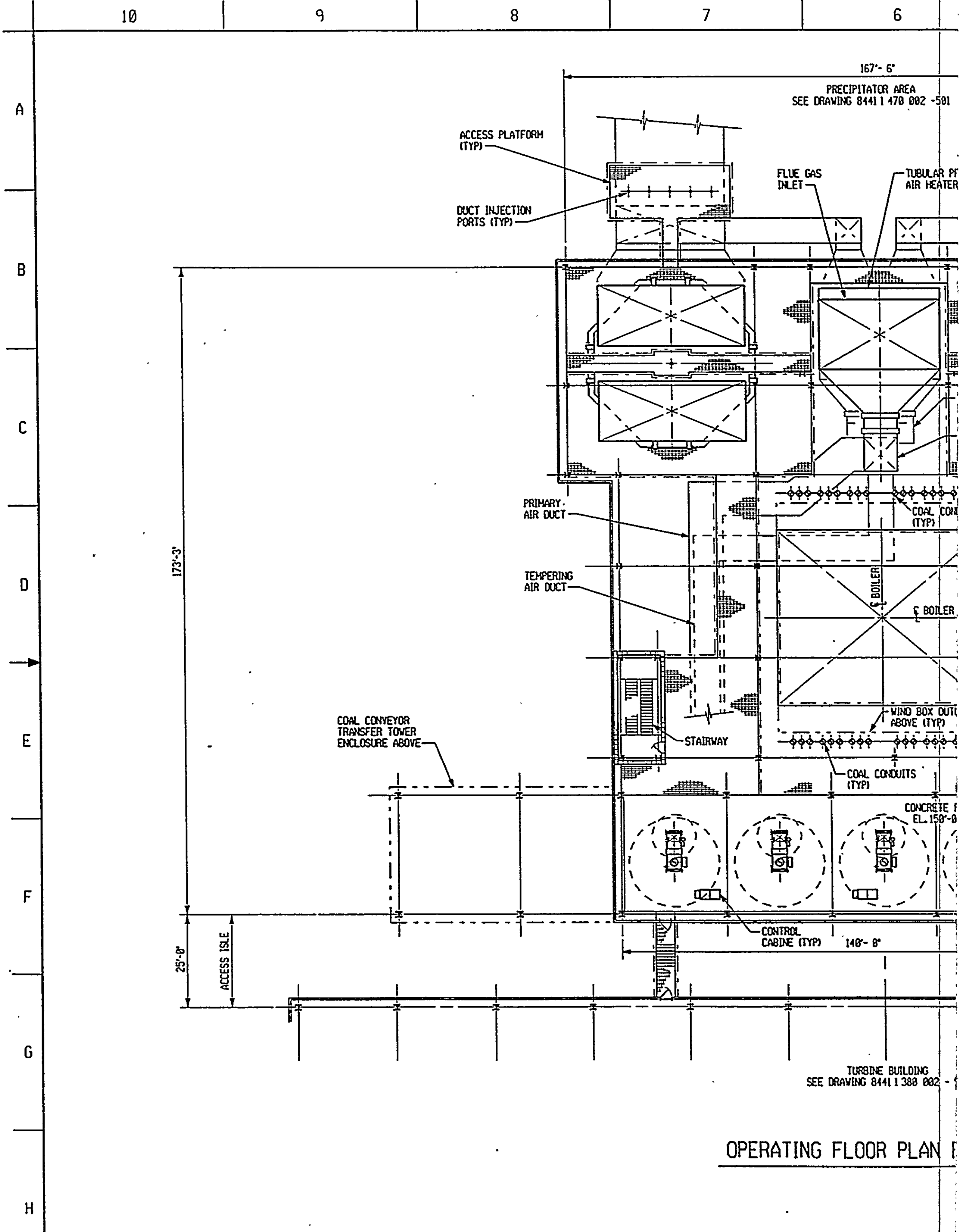
Duct Injection Flue Gas Desulfurization (FGD) Area

The FGD area is located between the boiler and the electrostatic precipitators. The plant stack is located to the east of the precipitators, in a location that accommodates a potential second unit. The precipitator area is shown on Figure 3-20.

Control Complex

The control complex is located at the east end of the turbine building to place it adjacent to the future plant facilities in the event the plant is expanded. The location provides for convenient routing of control systems from all areas of the power block to the control complex.

The control bays of the turbine building will most likely contain the machine shop facility at the grade floor elevation. The upper floors of the complex will contain cable spreading areas, termination areas, control room, office and lavatories, instrument shop and mechanical


10
9
8
7
6
A
B
C
D
E
F
G
H
167'- 6"
PRECIPITATOR AREA
SEE DRAWING 8441 1 470 002 -501
ACCESS PLATFORM
(TYP)
DUCT INJECTION
PORTS (TYP)
FLUE GAS
INLET
TUBULAR PF
AIR HEATER
PRIMARY
AIR DUCT
TEMPERING
AIR DUCT
COAL CON
(TYP)
℄ BOILER
℄ BOILER
WIND BOX OUTL
ABOVE (TYP)
173'-3"
COAL CONVEYOR
TRANSFER TOWER
ENCLOSURE ABOVE
STAIRWAY
COAL CONDUITS
(TYP)
CONCRETE F
EL.158'-0
CONTROL
CABINE (TYP)
140'- 8"
25'-0"
ACCESS ISLE
TURBINE BUILDING
SEE DRAWING 8441 1 380 002 -
OPERATING FLOOR PLAN

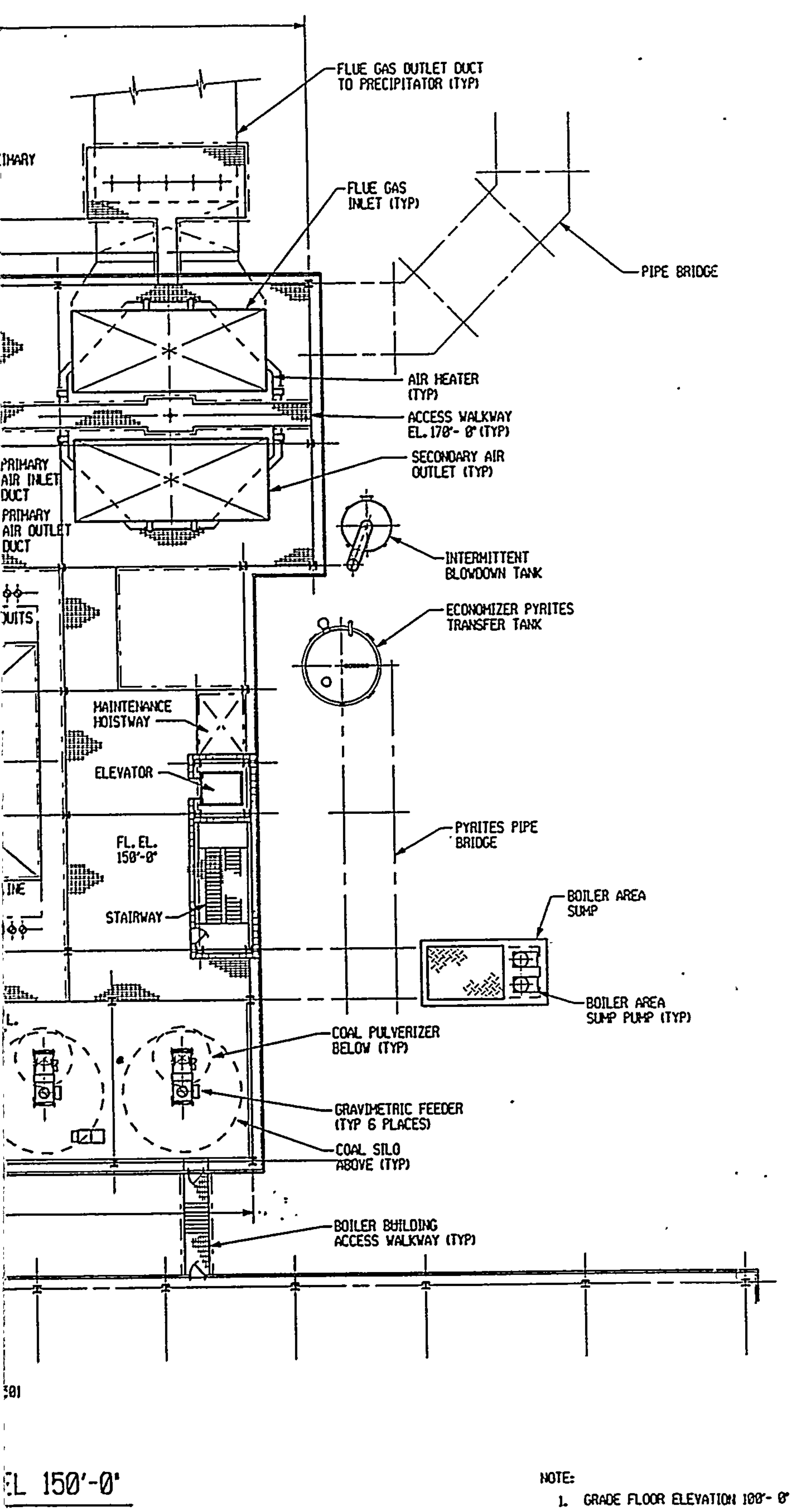


FIGURE 3-19

NOTE:
1. GRADE FLOOR ELEVATION 100'- 0"

0 10 20 30 40 50
GRAPHIC SCALE IN FEET

REVISIONS

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☒ CONCEPTUAL	REPRESENTS GENERAL CONCEPTS BASED ON ASSUMPTIONS. CHANGES COULD ENSUE.

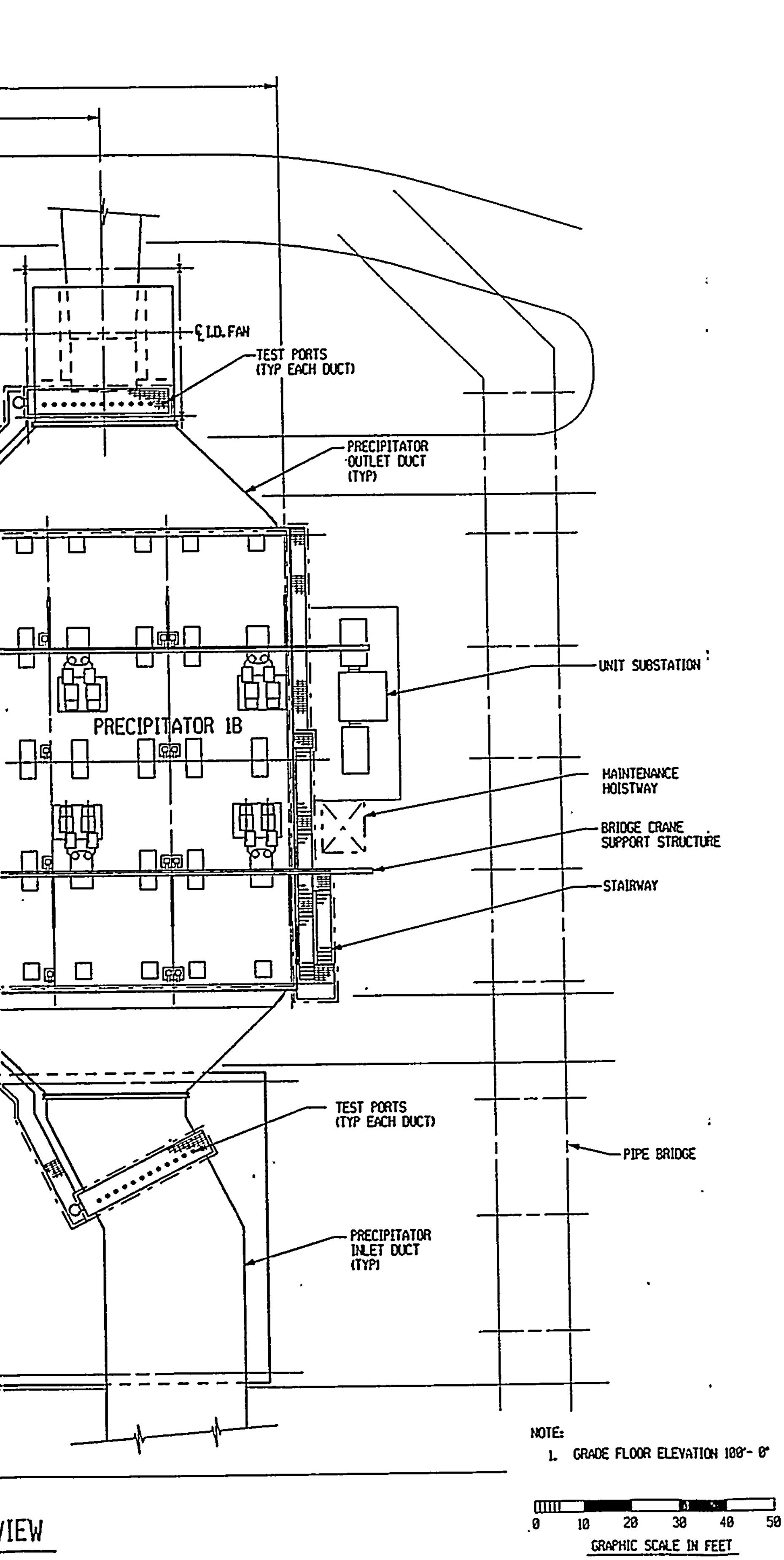
ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-94MC31166

PLANT LAYOUT — GENERAL ARRANGEMENT
BOILER BUILDING
OPERATING FLOOR PLAN EL. 150'- 0"

GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

DRAFTING: COK
SCALE: 1/16" = 1'- 0"
W.O. 088441-206
DRAWING NUMBER: 8441 1 300 002 - 501
REV: A

G/C-FILE: /home1/a4623/30002501.dgn
G/C-DATE: 30-Aug-95 16:38



NOTE:
1. GRADE FLOOR ELEVATION 100'- 0"

FIGURE 3-20

REVISIONS

STATUS OF DRAWING	DEFINITION
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☒ CONCEPTUAL	REPRESENTS GENERAL CONCEPTS BASED ON ASSUMPTIONS. CHANGES COULD ENSUE.

ENCOAL REFERENCE PLANT
CONCEPTUAL DESIGN
DOE/METC DE-AC21-89MC25177

PLANT LAYOUT — GENERAL ARRANGEMENT
PRECIPITATOR AREA
OVERALL PLAN VIEW

GILBERT/COMMONWEALTH, INC.
ENGINEERS AND CONSULTANTS READING, PA

DRAFTING: COX
SCALE: 1/8" = 1'- 0"
888441-206
8441 1 470 002 - 501 A

G/C-FILE: /home1/o4623/47002501.dgn
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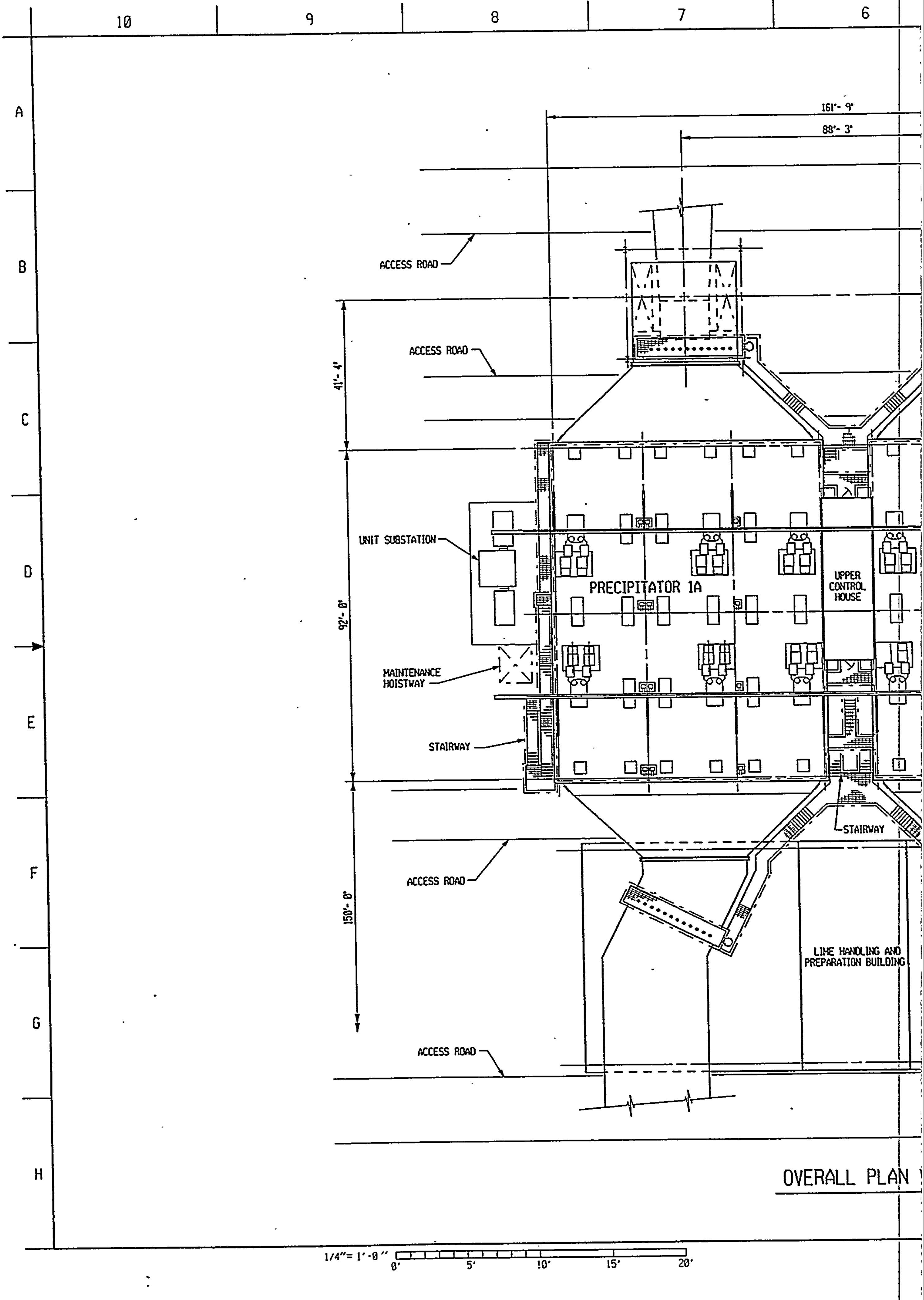

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9
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7
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D
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F
G
H
161'- 9"
88'- 3"
ACCESS ROAD
ACCESS ROAD
41'- 4"
UNIT SUBSTATION
PRECIPITATOR 1A
UPPER CONTROL HOUSE
92'- 0"
MAINTENANCE HOISTWAY
STAIRWAY
STAIRWAY
ACCESS ROAD
150'- 0"
LIME HANDLING AND PREPARATION BUILDING
ACCESS ROAD
OVERALL PLAN
1/4"= 1'-0"
0'
5'
10'
15'
20'

equipment room containing HVAC for the control complex. The size and arrangement and the exact types of areas required will be dependent upon the type of control system selected.

4.0 REFERENCE PLANT ECONOMIC ANALYSIS

The economics of the PDF Fired Reference Plant were developed on the basis of consistently evaluating the capital and operating costs and then performing an economic analysis based on the cost of electricity (COE) as the figure of merit. The conceptual cost estimate was determined on the basis of several major data sources including the detail estimate data from a recently completed major PC fossil plant, the AFBC Reference Power Plant, the estimate details of a recent duct injection installation, major equipment quotes, and inhouse cost data and conceptual estimating of scope not compatible with the above source plant scopes. The difference between the PC plant base case and PDF case is the fuel fired and the desulfurization method.

The emphasis of this effort was placed on obtaining good cost results at the Total Plant Cost (TPC) level. The capital costs at the Total Plant Cost (TPC) level include equipment, materials, labor, indirect construction costs, engineering and contingencies.

Operation and maintenance (O&M) cost values were determined on a first year basis and subsequently levelized over the 30 year plant life to form a part of the economic analysis. Consumables were evaluated on the basis of the quantity required, operation cost was determined on the basis of the number of operators, and maintenance was evaluated on the basis of maintenance costs required for each major plant section. These operating costs were then converted to unit values of $/kW-yr or mills/kWh.

In addition, the following economic assumptions were made:

- Plant book life is 30 years
- Capacity factor is 65 percent
- Plant inservice date is January 1995
- COE determined on a levelized, current dollar basis
- COE methodology was based on EPRI TAG methodology

The capital and operating costs of the plant are combined with plant performance in the comprehensive evaluation of cost of electricity(COE).

4.1 METHODOLOGY

This section describes the approach, basis, and methods that were used to perform capital and operating cost evaluations of the PDF fired power plant. Included in this section are descriptions of:

- Capital Costs (Section 4.2)
  - Bare Erected Cost (Section 4.2.1)
  - Total Plant Cost (Section 4.2.2)
  - Capital Cost Estimate Exclusions (Section 4.2.3)

- Operating Costs and Expenses (Section 4.3)
  - Operating Labor (Section 4.3.1)
  - Maintenance (Section 4.3.2)

- Consumables, including fuel costs (Section 4.3.3)

- Economic Evaluation (Section 4.4)

The capital costs, operating costs, and expenses were established consistent with EPRI Technical Assessment Guide (TAG) methodology and the plant scope identified in Section 3. The cost of each component was quantitatively developed to enhance credibility and establish a basis for subsequent comparisons and modification as the technology is further developed.

- Total plant cost values are expressed in December 1994 dollars.

- The estimates represent mature technology plant, or "nth 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 4.2.3.

- The estimate boundary limit is defined as the total plant facility within the "fence line," including coal receiving and water supply system but terminating at the high side of the main power transformers.

- Site is located 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 water way.

- Terms used in connection with the estimate are consistent with the EPRI TAG.

- 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 4.2.

- Design engineering services, including construction management and contingencies basis, are examined in Section 4.2.2.

- The operating and maintenance expenses and consumables costs were developed on a quantitative basis.

    - The operating labor cost was determined on the basis of the number of operators required.

    - The maintenance cost was evaluated on the basis of relationships of maintenance cost to initial capital cost.

    - The cost of consumables, including fuel, was determined on the basis of individual rates of consumption, the unit cost of each consumable, and the plant annual operating hours.

- The by-product credit for the gypsum is considered to be zero due to the poor marketability of this commodity.

Each of these expenses and costs is determined on a first year basis and subsequently levelized over the life of the plant through application of a levelizing factor to determine the value that forms a part of the economic evaluation. This amount when combined with fuel cost and capital charges results in the figure of merit, COE.

4.2 CAPITAL COSTS

The capital cost, specifically referred to as Total Plant Cost (TPC) for the PDF fired reference plant, was estimated using the EPRI structure. The major components of TPC consist of bare erected cost, engineering and home office overheads and fee plus contingencies.

The capital cost was determined through the process of estimating the cost of every significant piece of equipment, component, and bulk quantity. 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 and will serve as the basis for future evaluation of other clean coal sponsored technologies and permit future cost comparisons if desired. The Code facilitates recognition of estimated battery limits and the scope included in each account. This Code is presented as Table 4-1 along with a listing of scope included in each account.

4.2.1 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

Major equipment prices were based on vendor furnished budget cost information. They include the following:

- Boiler
- Steam Turbine-Generator
- Condenser
- Feedwater Heater
- Deaerator
- Stack
- CEMS
- Transformers
- Batteries
- UPS

Other process equipment, minor secondary systems, and materials were estimated by G/C on the basis of the source PC plant and in-house data consisting of other cost data and relationships, catalog data, and standard utility unit cost data.

The piping system costs for the PDF Fired Reference Plant were estimated on the basis of the corresponding systems in the source PC plant, the AFBC reference plant and in house information on the Duct Injection System.

Table 4-1
CODE OF DIRECT ACCOUNTS SUMMARY

Account Number	Account Title
1	FUEL and SORBENT HANDLING
	Fuel Receiving and Unloading Equipment
	Fuel Stockout and Reclaim Equipment
	Fuel Storage Bin and Yard Crushers
	Other Fuel Handling Equipment
	Sorbent Receiving and Unloading Equipment
	Sorbent Stockout and Reclaim Equipment
	Sorbent Storage Bin and Yard Crusher
	Other Sorbent Handling Equipment
	Fuel and Sorbent Handling Foundations and Structures
2	FUEL and SORBENT PREPARATION and FEED
	Fuel Crushing and Drying Equipment
	Prepared Fuel Storage and Feed Equipment
	Fuel Injection System
	Miscellaneous Fuel Preparation and Feed
	Sorbent Preparation
	Prepared Sorbent Storage and Feed Equipment
	Sorbent Injection System
	Booster Air Supply System
	Foundations and Structures
3	FEEDWATER and MISCELLANEOUS SYSTEMS and EQUIPMENT
	Feedwater System
	Makeup Treatment, Pretreating, and Storage
	Other Feedwater and Condensate Subsystems
	Service Water Systems
	Other Boiler Plant Systems
	Fuel Oil Supply System
	Waste Treatment Equipment
	Miscellaneous Power Plant Equipment
4	BOILER, and ACCESSORIES

Table 4-1 (Continued)
CODE OF DIRECT ACCOUNTS SUMMARY

Account Number	Account Title
5	FLUE GAS CLEAN UP
	Reagent PFBP and Feed
	Other Duct Injection
	ESP
	Other ESP Systems
	Foundations and Supports
6	COMBUSTION TURBINE and ACCESSORIES
7	WASTE HEAT BOILER, DUCTING and STACK
	Ductwork
	Stack
	Foundations
8	STEAM TURBINE GENERATOR, and AUXILIARIES
	Steam Turbine Generator and Accessories
	Turbine Plant Auxiliaries
	Condenser and Auxiliaries
	Steam Piping
	Foundations
9	COOLING WATER SYSTEM
	Cooling Towers
	Circulating Water Pumps
	Circulating Water System Auxiliaries
	Circulating Water Piping
	Make Up Water System
	Component Cooling Water System
	Circulating Water Foundations and Structures
10	ASH/SPENT SORBENT RECOVERY and HANDLING
	Ash Coolers
	Other Ash Recovery Equipment
	Ash Storage Silos
	Ash Transport and Feed Equipment
	Miscellaneous Ash Handling Equipment
	Foundations and Structures

Table 4-1 (Continued)
CODE OF DIRECT ACCOUNTS SUMMARY

Account Number	Account Title
11	ACCESSORY ELECTRIC PLANT
	Generator Equipment
	Station Service Equipment
	Switchgear and Control Equipment
	Conduit and Gable Tray
	Wire and Cable
	Protective Equipment
	Standby Equipment
	Main Power Transformer
	Foundations
12	INSTRUMENTATION and CONTROL
	PC Control Equipment
	Steam Turbine Control Equipment
	Other Major Component Control Equipment
	Signal Processing Equipment
	Control Boards, Panels, and Racks
	Computer and Accessories
	Instrument Wiring and Tubing
	Other Instrumentation and Controls Equipment
13	IMPROVEMENTS TO SITE
	Site Preparation
	Site Improvements
	Site Facilities
14	BUILDINGS and STRUCTURES
	Boiler Building
	Steam Turbine Building
	Administration Building
	Circulating Water Pumphouse
	Water Treatment Buildings
	Machine Shop
	Warehouse
	Other Buildings and Structures
	Waste Treatment Buildings and Structures

The electrical and I&C portion of the PC estimate was developed using material and equipment types and sizes typically used to construct a domestic utility owned and operated power plant.

In most cases the costs for bulk materials and major electrical equipment for this estimate were derived from recent vendor or manufacturer's quotes for similar items on other projects. Where actual or specific information regarding equipment specifications was available, that information was used to size and quantify material and equipment requirements. Where information was not furnished or was not adequate, requirements were assumed and estimated based on information available from project estimates of similar type and size. Areas such as cable and raceway, lighting, paging, heat tracing, and unit heating were done based on project experience for a plant of comparable size with enclosed boiler and turbine buildings in a climate range similar to that of the proposed general location of this plant. Grounding for the project is included in the estimate assuming that a design for a loop type system attached to ground pads on structural steel and installed in slabs will be the accepted method. The section of our estimate for the Distributed Control System was developed from a system specified and designed for a plant of comparable capacity. The cabling for this system is included in the bulk cable portion of the estimate.

The labor cost to install the equipment and materials was estimated on the basis of labor manhours. 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. This was supplemented in limited cases, as required, with equipment labor relationship data to determine the labor cost. The relationships used were based on the in-house historical data and the source plants.

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.

4.2.2 Total Plant Cost (TPC)

The TPC level of the estimate consists of the bare erected cost plus engineering and contingencies.

The engineering costs represent the cost of architect/engineer (A/E) services for design, drafting, and project construction management services. The cost was determined at 12 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 project contingencies are also considered as part of the TPC. A process contingency was added to the estimated cost of the Duct Injection System. Other systems are not in the developmental stage, therefore no process contingency was added.

Consistent with conventional power plant practices, the 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, 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. The contingencies represent costs that are expected to occur.

Table 4-2 provides cost results at the level of the code of accounts for each component of TPC. Appendix C contains a detail estimate listing in the same format as Table 4-2.

In addition to the TPC cost level, the Total Plant Investment (TPI) and Total Capital Requirement (TCR) were determined.

TPI at date of start-up includes escalation of construction costs and allowance for funds used during construction (AFDC), 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 years. Given TPC, cash flow assumptions, nominal interest, and escalation rates, TPI was calculated using:

$$TPI = TPC \times A[(R3-1)/(R-1)]$$

where:

A	=	% cost expended per year = 33.33%
R	=	Compound adjustment factor = (1 + i)/(1 + ea)
i	=	Weighted cost of capital, 9.2%
ea	=	Inflation rate, 4.1%

The apparent escalation rate and the weighted cost of capital (discount rate) are the standard values currently proposed by EPRI.

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 PC plant and thus are not included.

- Preproduction U.S. 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 fixed operating costs - operating and maintenance labor, administrative and support labor, and maintenance materials.

  - 1 month of variable operating costs as full capacity (excluding fuel) - includes chemicals, water, and other consumables and waste disposal charges.

TABLE 4-2

Client: DOE-METC
Project: CLEAN COAL REFERENCE PLANT

Report Date: 17-Nov-95
11:55 AM

TOTAL PLANT COST SUMMARY

Case: ENCOAL (TASK 6)
Plant Size: 404.3 MW,net

Estimate Type: Conceptual

Cost Year 1994 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor		Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies		TOTAL PLANT COST	
				Direct	Indirect				Process	Project	$	$/kW
1	COAL & SORBENT HANDLING	10,653	3,093	8,105	567		$22,418	2,690		3,766	$28,875	71
2	COAL & SORBENT PREP & FEED	10,026		2,615	183		$12,823	1,539		2,154	$16,517	41
3	FEEDWATER & MISC. BOP SYSTEMS	16,758		7,315	512		$24,584	2,950		4,130	$31,665	78
4	PC BOILER & ACCESSORIES											
	4.1 PC Boiler	45,843		19,565	1,370		$66,777	8,013		11,219	$86,009	213
	4.2 Open											
	4.3 Open											
	4.4 Secondary Air System											
5	FLUE GAS CLEANUP	24,433	1,868	14,134	989		$41,425	4,971	2,826	7,383	$56,605	140
6	COMBUSTION TURBINE/ACCESSORIES											
	6.1 Combustion Turbine Generator	N/A		N/A								
	6.2 Combustion Turbine Accessories											
7	HRSG, DUCTING & STACK											
	7.1 Heat Recovery Steam Generator	N/A		N/A								
	7.2 Other Acc't 7 Costs	13,608	285	8,783	615		$23,290	2,795		3,913	$29,998	74
8	STEAM TURBINE GENERATOR											
	8.1 Steam TG & Accessories	35,365		4,807	336		$40,509	4,861		6,805	$52,175	129
	8.2 Turbine Plant Auxiliaries	11,490	344	6,319	442		$18,595	2,231		3,124	$23,951	59
9	COOLING WATER SYSTEM	7,713	3,581	7,127	499		$18,921	2,270		3,179	$24,370	60
10	ASH/SPENT SORBENT HANDLING SYS	10,824	138	19,967	1,398		$32,327	3,879		5,431	$41,637	103
11	ACCESSORY ELECTRIC PLANT	12,585	4,058	9,739	682		$27,064	3,248		4,547	$34,858	86
12	INSTRUMENTATION & CONTROL	9,525		5,863	410		$15,798	1,896		2,654	$20,348	50
13	IMPROVEMENTS TO SITE	1,818	1,015	3,636	254		$6,723	807		1,130	$8,660	21
14	BUILDINGS & STRUCTURES		17,839	21,446	1,501		$40,786	4,894		6,852	$52,532	130
	TOTAL COST	$210,641	$32,220	$139,421	$9,759		$392,041	$47,045	$2,826	$66,287	$506,199	1257

- 25% of full capacity fuel cost for 1 month - covers inefficient operation that occurs during the start-up period.

- 2% 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 at the same number of days as specified for the fuel. In addition, an allowance of 1/2% 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 on 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 320 acres of land at $1,500 per acre.

Each of the TCR cost components, as well as the summary TPC components and the TPI, is shown separately in the Section 4.4.

4.2.3 Capital Cost Estimate Exclusions

Although the estimate is intended to represent a complete power plant, there remain several qualifications/exclusions as follows:

- Sales tax is not included (considered to be exempt).

- On-site fuel transportation equipment (such as barge tug, barges, yard locomotive, bulldozers) is not included.

- Allowances for unusual site conditions (such as piling, extensive site access, excessive dewatering, extensive inclement weather) are not included.

- 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 and ash pond. (The ash disposal cost is accounted for in the ash disposal charge as part of consumables costs)

- Royalties are not included.

4.3 OPERATING COSTS AND EXPENSES

The operating costs and related maintenance expenses (O&M) described in this section pertain to those charges associated with operating and maintaining the PC power plant over its expected life.

The costs and expenses associated with operating and maintaining the plant include:

- Operating labor
- Maintenance
  - Material
  - Labor
- Administrative and support labor
- Consumables
- Fuel cost

The values for these items were determined consistent with EPRI TAG methodology. These costs and expenses are estimated on a first year basis, in December 1994 dollars. The first year costs assume normal operation and do not include the initial startup costs.

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.

The development of the actual values was performed on a G/G 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.

4.3.1 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:

$$OL = \frac{(OJ) \times (\text{labor rate} \times \text{labor burden}) \times (8760\ h/yr)}{(\text{net capacity of plant at full load in kW})}$$

The operating labor requirements were determined on the basis of in-house representative data for the major plant sections (such as coal handling and steam turbine plant). These data were combined to arrive at total plant operating requirements as indicated on Table 4-3.

4.3.2 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 are 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.

TABLE 4-3

OPERATING LABOR REQUIREMENTS		
ENCOAL (TASK 6)		
Operating Labor Rate(base):	25.20 $/hour	
Operating Labor Burden:	35.00 % of base	
Labor O–H Charge Rate:	30.00 % of labor	
Operating Labor Requirements(O.J.)per Shift:		
Category	1 unit/mod.	Total Plant
Skilled Operator	2.0	2.0
Operator	18.0	18.0
Foreman	1.0	1.0
Lab Tech's, etc.	3.0	3.0
TOTAL–O.J.'s	24.0	24.0

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 values. Using the corresponding TPC values, a total annual (first year) maintenance cost was calculated, including both material and labor components. The rates for calculation of maintenance are indicated in Table 4-4.

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 $/kW-y. Variable costs are incremental, directly proportional to the amount of power produced, and expressed in mills/kWh ($/MWh). The equations for these calculations are:

$$\text{Fixed O\&M} = \text{Capacity Factor (CF)} \times \text{Total O\&M (\$/kWy)}$$

$$\text{Variable O\&M} = \frac{(1-\text{CF}) \times \text{Total O\&M (\$/kW-yr)} \times 1000\ \text{mills/\$}}{(\text{CF} \times 8760\ \text{h/yr})}$$

4.3.3 Consumables

The feedstock and disposal costs are those consumable expenses associated with 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 as shown on Table 4-5.

The "water" component pertains to the water acquisition charge for water required for the plant steam cycle, and for miscellaneous services.

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;

TABLE 4-4

MAINTENANCE FACTORS ENCOAL (TASK 6)	
Item/Description	Maintenance %
COAL & SORBENT HANDLING	2.1
COAL & SORBENT PREP & FEED	3.8
FEEDWATER & MISC. BOP SYSTEMS	2.3
PC BOILER & ACCESSORIES	
PC Boiler	3.5
Open	
Open	
Secondary Air System	
FLUE GAS CLEANUP	3.2
COMBUSTION TURBINE/ACCESSORIES	
Combustion Turbine Generator	
Combustion Turbine Accessories	
HRSG, DUCTING & STACK	
Heat Recovery Steam Generator	
Other Acc't 7 Costs	1.5
STEAM TURBINE GENERATOR	
Steam TG & Accessories	1.5
Turbine Plant Auxiliaries	1.7
COOLING WATER SYSTEM	1.3
ASH/SPENT SORBENT HANDLING SYS	3.9
ACCESSORY ELECTRIC PLANT	1.5
INSTRUMENTATION & CONTROL	1.6
IMPROVEMENTS TO SITE	1.2
BUILDINGS & STRUCTURES	1.5

TABLE 4-5

CONSUMABLES, BY-PRODUCTS & FUELS DATA ENCOAL (TASK 6)			
	Consumption		Unit
Item/Description	Initial	/Day	Cost
Water(/1000 gallons)		12,393	0.78
Chemicals*			
MU & WT Chem.(lbs)**	719,892	11,998	0.18
Liquid Eff.Chem.(lbs)**	1,487,183	24,786	0.13
Lime(ton)**	3,079	51	78.03
Other			
Natural Gas(MM Btu)**			2.50
Gases,N2 etc.(/100scf)			0.29
L.P. Steam(/1000 pounds)			
Waste Disposal			
Sludge(ton)			9.25
Ash(ton)		1,058	10.00
By-products			
Sulfuric Acid(pounds)			
Sulfur(pounds)			
Fuel(ton)		3,590	42.68

- 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 lime, required for the duct injection system, unit cost is the EPRI standard limestone cost.

The "other consumables" component consists of startup fuel, gases, primarily the nitrogen required for transport and blanketing and steam but does not contain any significant quantities.

The "waste disposal" component pertains to the cost allowance for off-site disposal of plant solid wastes. The unit cost for disposal is based on an adjusted EPRI value.

The Fuel (PDF) cost was developed on the basis of delivered cost of a low sulfur coal at $1.81/10^6 Btu (FC), the plant net heat rate (HR) 8726 Btu/KWh and the PDF higher heating value (HHV) of 11,791 Btu/lb. This rate is consistant with pricing guidelines from ENCOAL Corporation and compatible with the high sulfur coal price utilized for the PC Reference Plant analysis. In addition other unit costs for PDF were evaluated and used in determining COE, refer to Section 5.0, Item 4.

For the fuel as well as for all feedstock and disposal costs, the quantity per day represents the 100% capacity requirement, while the annual cost values are adjusted for the designated 65% plant capacity factor. The calculation of first year fuel cost occurred as follows:

- $$\text{Fuel (ton/day)} = \frac{\text{HR x kW (plant new capacity) x 24 hours}}{\text{HHV x 2000 lb/ton}}$$

- $$\text{Fuel Unit (per ton) Cost} = \frac{\text{HHV x 2000 lb/ton X FC}}{1 \times 10^6 \text{ Btu}}$$

- Fuel Cost (1st year) = Fuel (t/d) x Fuel Unit Cost ($/t) x 365 days x 0.65 (capacity factor)

Table 4-4 summarizes the quantities and unit costs used to determine the consumable costs including fuel.

4.4 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 to various alternatives. The revenue requirement figure of merit is COE that is the levelized (over plant life) coal pile-to-busbar cost of power 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 consumable operating costs, and the levelized fuel cost.

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 costs, and consumable costs to yield levelized costs over the life of the project. A long term inflation rate of 4.1%/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 0%/yr, this is a change in the recent TAG.). 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 the basis table resulting in a levelized carrying charge of 16.9% and levelization factor of 1.541 for all except coal and 1.0 for coal.

By combining costs, carrying charges, and levelizing factors, a levelized busbar COE for the 65% design capacity factor was calculated along with the levelized constituent values. The format for this cost calculation is:

$$\text{Power Cost (COE)} = \frac{\text{(LCC+LFOM)x 1000mills/\$}}{\text{CF x 8760 h/y}} + \text{LVOM} + \text{LCM} - \text{LB} + \text{LFC}$$

where:

LCC = Levelized carrying charge, $/kW-y
LFOM = Levelized fixed O&M, $/kW-y

LVOM	=	Levelized variable O&M, mills/kWh
LCM	=	Levelized consumable, mills/kWh
LB	=	Levelized byproducts (if any), mills/kWh
LFC	=	Levelized fueled costs, mills/kWh
CF	=	Plant capacity factor, %

The consolidated basis for calculating capital investment and revenue requirements is given in Table 4-6, titled Estimate Basis/Financial Criteria for Revenue Requirement Calculations. The principle cost and economics output for this study are presented in Table 4-7, Capital Investment and Revenue Requirement Summary, which provides key TPC values and other significant capital costs, operating costs, maintenance costs, consumables, fuel cost and the levelized busbar COE.

TABLE 4-6

ESTIMATE BASIS/FINANCIAL CRITERIA for REVENUE REQUIREMENT CALCULATIONS

GENERAL DATA/CHARACTERISTICS

Case Title:	ENCOAL (TASK 6)	
Unit Size:/Plant Size:	404.3 MW,net	404.3 MWe
Location:	Ohio River Valley	
Fuel: Coal/Secondary	Pitts #8	
Energy From Primary/Secondary Fuels	8,726 Btu/kWh	Btu/kWh
Levelized Capacity Factor:	65 %	
Capital Cost Year Dollars:	1994 (December)	
Delivered Cost of Coal/Secondary	1.81 $/MBtu	$/MBtu
Design/Construction Period:	3 years	
Plant Startup Date(year):	1995 (January)	
Land Area/Unit Cost	320 acre	$1,500 /acre

FINANCIAL CRITERIA

Project Book Life:	30 years	
Book Salvage Value:	%	
Project Tax Life:	20 years	
Tax Depreciation Method:	ACRS	
Property Tax Rate:	1.0 % per year	
Insurance Tax Rate:	1.0 % per year	
Federal Income Tax Rate:	34.0 %	
State Income Tax Rate:	6.0 %	
Investment Tax Credit/% Eligible	%	%

	% of Total	Cost(%)
Capital Structure		
Common Equity	46	13.0
Preferred Stock	8	8.4
Debt	46	9.1
Weighted Cost of Capital:(after tax)	9.4 %	

Escalation Rates(Apparent)		
General Escalation:	4.1 % per year	
Coal/Seconary Fuel Price Escalation:	% per year	% per year

TABLE 4-7

CAPITAL INVESTMENT & REVENUE REQUIREMENT SUMMARY			
TITLE/DEFINITION			
Case:	ENCOAL (TASK 6)		
Plant Size:	404.3 (MW,net)	HeatRate:	8,726 (Btu/kWh)
Fuel(type):	Pitts #8	Cost:	1.81 ($/MMBtu)
Design/Construction:	3 (years)	BookLife:	30 (years)
TPC(Plant Cost) Year:	1994 (Dec.)	TPI Year:	1995 (Jan.)
Capacity Factor:	65 (%)		

CAPITAL INVESTMENT		$x1000	$/kW
Process Capital & Facilities		392,041	969.7
Engineering(incl.C.M.,H.O.& Fee)		47,045	116.4
Process Contingency		2,826	7.0
Project Contingency		66,287	164.0
TOTAL PLANT COST(TPC)		$508,199	1257.0
TOTAL CASH EXPENDED	$488,446		
AFDC	$46,140		
TOTAL PLANT INVESTMENT(TPI)		$534,586	1322.2
Royalty Allowance			
Preproduction Costs		14,401	35.6
Inventory Capital		10,944	27.1
Initial Catalyst & Chemicals(w/equip.)			
Land Cost		480	1.2
TOTAL CAPITAL REQUIREMENT(TCR)		$560,411	1386.1

OPERATING & MAINTENANCE COSTS(First Year)	$x1000	$/kW-yr
Operating Labor	7,152	17.7
Maintenance Labor	3,710	9.2
Maintenance Material	5,565	13.8
Administrative & Support Labor	3,259	8.1
TOTAL OPERATION & MAINTENANCE(1st yr.)	$19,686	48.7
FIXED O & M (1st yr.)		31.65 $/kW-yr
VARIABLE O & M (1st yr.)		2.99 mills/kWh

CONSUMABLE OPERATING COSTS(less Fuel)	$x1000	mills/kWh
Water	2,294	1.00
Chemicals	2,244	0.97
Other Consumables		
Waste Disposal	2,509	1.09
TOTAL CONSUMABLES(1st yr.,-fuel)	$7,048	3.06
BY-PRODUCT CREDITS(First Year)		
FUEL COST(First Year)	$36,359	15.79

LEVELIZED OPERATION & MAINTENANCE COSTS		
Fixed O & M	48.5 $/kW-yr	8.5 mills/kWh
Variable O & M		4.6 mills/kWh
Consumables		4.7 mills/kWh
By-product Credit		mills/kWh
Fuel		15.8 mills/kWh
LEVELIZED CARRYING CHARGES(Capital)	234.3 $/kW-yr	41.1 mills/kWh
LEVELIZED BUSBAR COST OF POWER		74.7 mills/kWh
30 Year at a Capacity Factor of:	65%	

5.0 CONCLUSIONS AND RECOMMENDATIONS

The PDF Reference Plant described herein represents an example of current practice for large, central station generating facilities. Many design parameters involving the steam cycle were selected to provide consistency between the various plants in the Clean Coal technology (CCT) series. Although various alternatives are possible for many of the design selections applied herein, these alternatives represent variations on a common theme. Economic parameters and emissions permitting criteria have also been selected for uniformity among the various CCT units.

The PDF Reference Plant described in this report is expected to require a capital expenditure of 1,257 $/kW, and to produce electricity for a levelized cost of 74.7 mills/kWh. Table 5-1 provides a summary of pertinent economic parameters for this Reference Plant.

Table 5-1
PDF PLANT ECONOMIC SUMMARY

	$ x 1000		$/kW
Total Plant Cost	508,199		1,257
Fixed O&M 1st (Year)		31.7 $/kW-yr	
Variable O&M (1st Year)		2.3 mills/kWhr	
Total Consumables (1st Year)	7,048		3.06
Fuel Cost (1st Year)	36,359		15.79
Levelized Busbar Cost of Power		74.7 mills/kWhr	

In comparing these costs with those of the other Reference Plants in this series, several factors should be considered:

1. The Atmospheric Circulating Fluid Bed Combustor (ACFB) Reference Plant design developed for this series of Reference Plants is based on cost data available in early 1992, compared to the PDF Reference data date of December, 1994.

2. Assumptions regarding capital market conditions and inflation rates vary between the ACFB and PDF evaluations. The cost of fuel and sorbent is also different, to suit current market conditions and projections. Table 5-2, below, summarizes these parameters for the two units.

3. ENCOAL's present pricing policy for future PDF sales is based on matching or being slightly less expensive than low sulfur coal at the site being considered. For this application, that level has been established at $1.81/10^6$ Btu. To provide assurance that

Table 5-2
ECONOMIC ASSUMPTION COMPARISON

Unit	ACFB	ENCOAL
Weighted Cost of Capital	11.5%	9.4%
Inflation Rate	5.0%	4.1%
Fuel Cost $\$/10^6$ Btu	1.60	1.81
Sorbent Cost $/ton	16.50	78.00

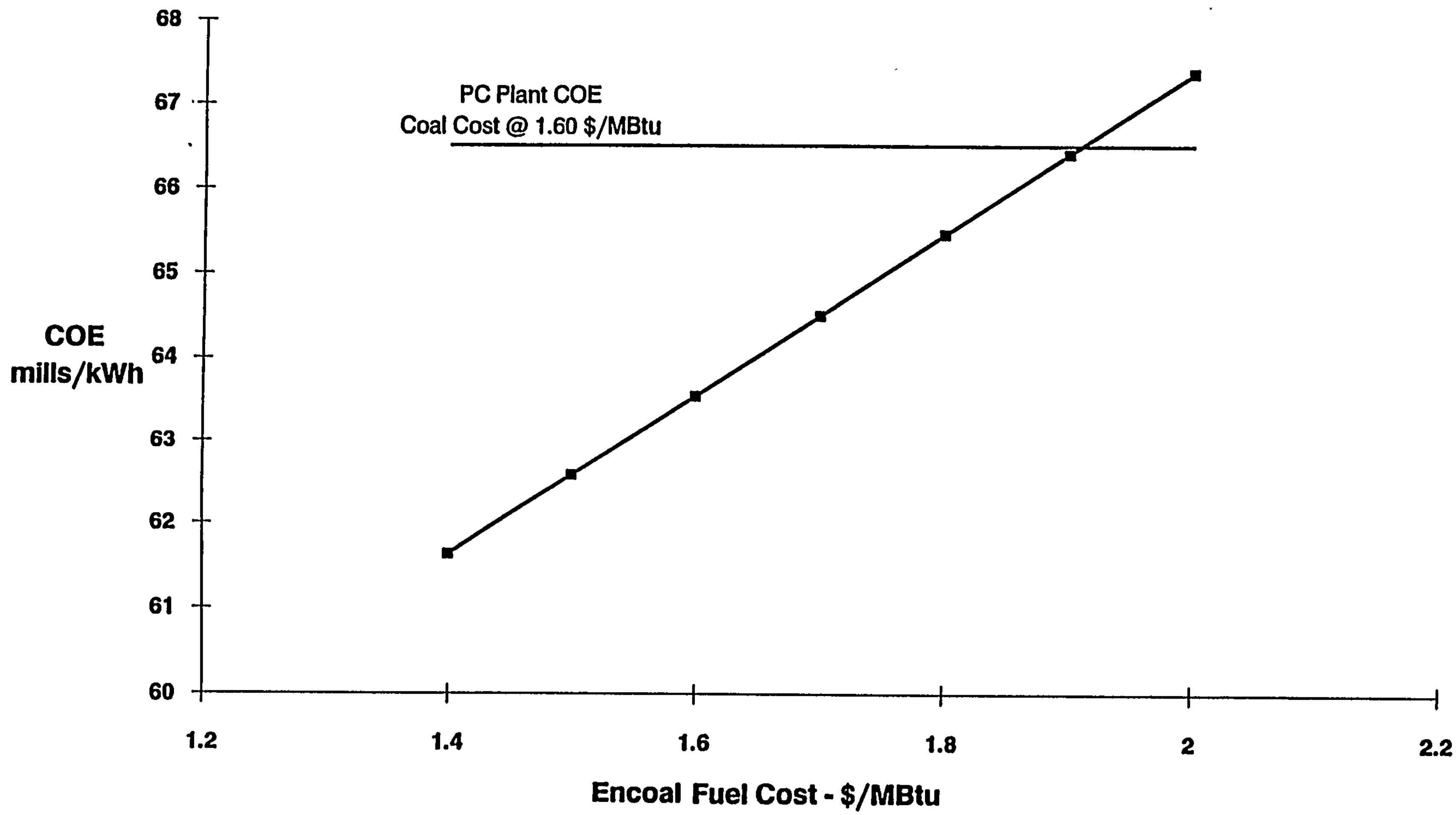
this is a reasonable price, an independant check was made, using estimated PDF production plant costs and transportation prices to estabish a comparable basis.

The results of this analysis indicate that PDF fuel costs, based on cost plus profit based pricing, could result in a COE value 5% lower than the COE based on $\$1.81/10^6$ Btu. Figure 5-1 provides a picture of how the PDF Fueled Plant COE varies with change in PDF cost as compared to the PC Plant COE with its fuel pegged at $\$1.60/10^6$ Btu.

Users of this report and others in this series should apply adjustments to the technical factors as well as the economic parameters to suit their own circumstances and expectations. This report, and the others in this series, will provide a well defined point of reference for each technology, to facilitate informed and soundly based comparisons and decisions.

Figure 5-1

ENCOAL FUEL COST / COE SENSITIVITY



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APPENDIX A

ENCOAL REFERENCE PLANT

MAJOR EQUIPMENT LIST

CONDENSATE AND FEEDWATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cond. Storage Tank	Field Fab.	200,000 gal.	1
2	Surface Condenser	Two Shell, Transverse Tubes	1.83 x 10^6 lb/hr 1.4/2.0 in Hg	1
3	Cond. Vacuum Pumps	Rotary Water Sealed	2500/25 scfm	2
4	Condensate Pumps	Vert. Canned	2500 gpm @ 800 ft	3
5	L.P. F.W. Htr. 1A/1B	Horiz. U tube	2,249,030 lb/hr 98.2°F to 167.4°F	2
6	L.P. F.W. Htr. 2A/2B	Horiz. U tube	2,249,0300 lb/hr 167.4°F to 198.7°F	2
7	L.P. F.W. Htr. 3	Horiz. U tube	2,249,030 lb/hr 198.7°F to 231.1°F	1
8	L.P. F.W. Htr. 4	Horiz. U tube	2,249,030 lb/hr 231.1°F to 292.3°F	1
9	Deaerator and Storage Tank	Horiz. Spray Type	2,249,030 lb/hr 292.3°F to 365.9°F	1
10	B.F. Pumps/Turbines	Barrel Type, Multi-staged, Centr.	3400 gpm @ 7200 ft	2
11	Startup B.F. Pump	Barrel Type, Multi-staged Centr.	1500 gpm @ 7200 ft	1
12	H.P. F.W. Htr. 6	Horiz. U tube	2,652,909 lb/hr 365.9°F to 407.5°F	1
13	H.P. F.W. Htr. 7	Horiz. U tube	2,652,909 lb/hr 407.5°F to 488.9°F	1

CIRCULATING WATER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Cooling Tower	Mech Draft	202,000 gpm 95°F to 75°F	1
2	Circ. W. Pumps	Vert. Wet Pit	101,000 gpm @ 80 ft	2

FUEL (ENCOAL) RECEIVING AND HANDLING SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Rotary Car Dumper and Receiving Hoppers	N/A	100 Ton	4
2	Feeder	Vibratory	225 TPH	4
3	Conveyor #1	54" Belt	900 TPH	1
4	As-Received Coal Sampling System	Two Stage	N/A	1
5	Conveyor #2	54" Belt	900 TPH	1
6	Coal Stacker	Double Wing	900 TPH	1
7	Active Pile Reclaim Hopper	N/A	40 Ton	3
8	Feeder	Vibratory	650 TPH	3
9	Emergency Coal Hopper	N/A	30 Ton	1
10	Feeder	Vibratory	650 TPH	1
11	Conveyor #3A	48" Belt	650 TPH	1
12	Conveyor #3B	48" Belt	650 TPH	1
13	Coal Bin W/ Vent Filter	Compartment	340 Ton	1
14	Feeder	Vibratory	650 TPH	2
15	Flop Gate	N/A	650 TPH	2
16	Crusher	Impactor Reduction	3"x0"-1¼"x0"	2
17	Conveyor #4A	48" Belt	650 TPH	1
18	Conveyor #4B	48" Belt	650 TPH	1
19	As-Fired Coal Sampling System	Swing Hammer	650 TPH	2
20	Conveyor #5A	48" Belt	650 TPH	1
21	Conveyor #5B	48" Belt	650 TPH	1
22	Tripper #1 & 2	N/A	650 TPH	2
23	Coal Silo W/ Vent Filter and Slide Gates	N/A	650 Ton	6
24	Feeder	Gravimetric	40 TPH	5
25	Pulverizer	B&W Type MPS-75	40 TPH	5

LIME HANDLING AND PREPARATION SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Pebble Lime Silo and Bin Activator	Vertical Cyl 20 ft OD, 50 ft ht Conical Bottom	72 hour capacity	1
2	Air Lock	Rotary	20 tph	1
3	Transfer Blower	Positive Displacement	1320 SCFM/12 psig	1
4	Dry Bin and Bin Activator	Vertical Cyl 12 ft OD, 20 ft ht Conical Bottom	10 hour capacity	1
5	Feeder	Gravimetric	5.8 tph	1
6	Slaker	Ball Mill	5 tph	2
7	Slaking Water Heater	Steam Coil	8×10^6 Btu/hr	
8	Sump and Mixer	Covered, Paddle Wheel Mixer	530 gal	1
9	Sump Pump	Horizontal, Centrifugal	56 gpm, 150 ft TDH	3
10	Storage Tank and Mixer	Vertical Cyl 22 ft OD, 30 ft ht		2

DUCT INJECTION SCRUBBER SYSTEM

Equipment No.	Description	Type	Design Condition	Qty.
1	Atomizer Feed Tank and Mixer	Vertical Cyl 9 ft OD, 12 ft ht		2
2	Atomizer Feed Pump	Horizontal, Centrifugal	185 gpm, 150 ft TDH	3
3	Recycle Grit Screen			1
4	Flyash Recycle Bin	Vertical Cyl 16 ft OD, 30 ft ht	8 hour capacity	1
5	Rotary Feeder	Air Lock	24 tph	1
6	Recycle Slurry Tank and Mixer			
7	Recycle Slurry Pump	Horizontal Centrifugal	170 gpm, 150 ft TDH	2
8	Blowdown Water Tank	Vertical Cyl 10 ft OD, 11-1/2 ft ht		1
9	Dilution Water Pump	Horizontal Centrifugal	100 gpm, 50 ft TDH	2
10	Waste Conditioning Water Pump	Horizontal Centrifugal	115 gpm, 100 ft TDH	2
11	Recycle Ash Water Pump	Horizontal Centrifugal	105 gpm, 50 ft TDH	2
12	Raw Water Tank	Vertical Cyl 10 ft OD, 11-1/2 ft ht		1
13	Slaking Water Pump	Horizontal Centrifugal	32 gpm,.50 ft TDH	2
14	Atomizing Air Compressor	Centrifugal	8800 SCFM, 100 psig each, (3 at 50% capacity)	3
15	Atomizing Air Receiver	Vertical Cyl 6 ft OD, 12 ft ht	100 psig	
16	Dual Fluid Atomizers		2 gpm each	108

ASH HANDLING SYSTEM (Flyash)

Equipment No.	Description	Type	Design Condition	Qty.
1	Precipitator Hopper (part of Precipitator scope of supply)			24
2	Air Heater Hopper (part of Boiler scope of supply)			10
3	Air Blower	Positive Displacement	800 cfm/10 psig	2
4	Flyash Silo	Reinf. Concrete	940 tons, 72 hrs	1
5	Slide Gate Valves			2
6	Wet Unloader	Screw	25 tph	1
7	Telescoping Unloading Chute			1

ASH HANDLING SYSTEM (Bottom Ash)

Equipment No.	Description	Type	Design Condition	Qty.
1	Economizer Hopper (part of Boiler scope of supply)			4
2	Bottom Ash Hopper (part of Boiler scope of supply)			2
3	Clinker Grinder		15 tph	2
4	Pyrites Hopper (part of Pulverizer scope of supply included with Boiler)	Note: Not required for ENCOAL firing, but included to provide future fuel flexibility)		6
5	Hydroejectors			13
6	Economizer/Pyrites Transfer Tank	Vertical, Cyl.	32,000 gal	1
7	Ash Sluice Pumps	Vertical, wet pit	2700 gpm	2
8	Ash Seal Water Pumps	Vertical, wet pit	2400 gpm	2

STEAM GENERATOR AND ANCILLARY EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty.
1	Boiler with Air Heater	Natural Circ., Wall Fired	435 MWe, 2,734,000 PPH steam at 2660 PSIG/1000°F	1
2	Primary Air Fan	Axial	402,000 PPH, 87,050 ACFM, 45" WG, 752 HP	2
3	F.D. Fan	Cent.	1,280,310 PPH, 290,760 ACFM, 11" WG, 650 HP	2
4				
5	I.D. Fan	Cent.	1,857,962 PPH, 587,924 ACFM, 32" WG 3,730 HP	2
6	Electrostatic Precipitator	Rigid Frame, Single Stage	587,924 ACFM 287,000 ft² plate area	2
7	Stack	Reinf. Concrete, two FRP flues	60 fps exit velocity 480 ft High x 19 ft Dia. (flue)	1

TURBINE GENERATOR AND AUXILIARY EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty.
1	435 MW Turbine Generator	TC4F30	2400 psig, 1000°F/1000°F	1
2	Bearing Lube Oil Coolers	Shell & Tube	-	2
3	Bearing Lube Oil Conditioner	Pressure Filter Closed Loop	-	1
4	Control System	Electro Hydraulic	1600 psig	1
5	Generator Coolers	Shell & Tube	-	2
6	Hydrogen Seal Oil System	Closed loop	-	1
7	Generator Exciter	Solid State brushless	-	1

MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty.
1	Auxiliary Boiler	Shop Fab. Water Tube	400 psig, 650°F	1
2	Fuel Oil Storage Tank	Vertical, Cylindrical	300,000 gal	1
3	Fuel Oil Unloading Pump	Gear	150 ft, 800 gpm	1
4	Fuel Oil Supply Pump	Gear	400 ft, 80 gpm	2
5	Service Air Compressors	S.S., Double Acting	100 psig, 800 CFM	3
6	Inst. Air Dryers	Duplex, Regenerative	400 CFM	1
7	Service Water Pumps	S.S., Double Suction	100 ft, 6000 gpm	2
8	Closed Cycle Cooling Heat Exch.	Shell & Tube	50% Cap. each	2
9	Closed Cycle Cooling Water Pumps	Horizontal Centrifugal	185 ft, 600 gpm	2
11	Fire Service Booster Pump	2 stage cent.	250 ft, 700 gpm	1
12	Engin. Driven Fire Pump	Vert. Turbine, diesel engine	350 ft, 1000 gpm	1
13	Riverwater Makeup Pumps	S.S., Single Suction	100 ft, 5,750 gpm	2
14	Filtered Water Pumps	S.S., Single Suction	200 ft, 200 gpm	2
15	Filtered Water Tank	Vertical, Cylindrical	15,000 gal	1
16	Makeup Demineralizer	Anion, Cation, and Mixed Bed	150 gpm	2
17	Liquid Waste Treatment System	-	10 years, 25 hr. storm	1
18	Condensate Demineralizer	Mixed bed	2000 gpm	1

APPENDIX B

ENCOAL REFERENCE PLANT

TOTAL PLANT COST - BREAKDOWN

Client: DOE-METC
Project: CLEAN COAL REFERENCE PLANT

Report Date: 17-Nov-95
11:55 AM

TOTAL PLANT COST SUMMARY

Case: ENCOAL (TASK 6)
Plant Size: 404.3 MW,net
Estimate Type: Conceptual
Cost Year 1994 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
1	COAL & SORBENT HANDLING											
	1.1 Coal Receive & Unload	2,768		1,540	108		$4,416	530		742	$5,688	14
	1.2 Coal Stackout & Reclaim	3,629		1,001	70		$4,699	564		790	$6,053	15
	1.3 Coal Conveyors & Yd Crush	3,374		990	69		$4,433	532		745	$5,710	14
	1.4 Other Coal Handling	883		229	16		$1,128	135		189	$1,453	4
	1.5 Sorbent Receive & Unload	w/5.1		w/5.1								
	1.6 Sorbent Stackout & Reclaim											
	1.7 Sorbent Conveyors											
	1.8 Other Sorbent Handling											
	1.9 Coal & Sorbent Hnd.Foundations		3,093	4,345	304		$7,742	929		1,301	$9,972	25
	SUBTOTAL 1.	$10,653	$3,093	$8,105	$567		$22,418	$2,690		$3,766	$28,875	71
2	COAL & SORBENT PREP & FEED											
	2.1 Coal Crushing & Drying	1,749		415	29		$2,193	263		368	$2,824	7
	2.2 Prepared Coal Storage & Feed	8,277		2,200	154		$10,631	1,276		1,786	$13,692	34
	2.3 Coal Injection System											
	2.4 Misc.Coal Prep & Feed											
	2.5 Sorbent Prep Equipment	w/5.1		w/5.1								
	2.6 Prepared Sorbent Storage & Feed											
	2.7 Reagent Handling											
	2.8 Booster Air Supply System											
	2.9 Coal & Sorbent Feed Foundation											
	SUBTOTAL 2.	$10,026		$2,615	$183		$12,823	$1,539		$2,154	$16,517	41
3	FEEDWATER & MISC. BOP SYSTEMS											
	3.1 FeedwaterSystem	5,060		1,624	114		$6,798	816		1,142	$8,756	22
	3.2 Water Makeup & Pretreating	2,349		839	59		$3,246	390		545	$4,181	10
	3.3 Other Feedwater Subsystems	3,664		1,316	92		$5,072	609		852	$6,533	16
	3.4 Service Water Systems	437		270	19		$726	87		122	$935	2
	3.5 Other Boiler Plant Systems	1,806		1,506	106		$3,419	410		574	$4,404	11
	3.6 FO Supply Sys & Nat Gas	168		246	17		$431	52		72	$556	1
	3.7 Waste Treatment Equipment	1,665		977	68		$2,711	325		455	$3,491	9
	3.8 Misc. Power Plant Equipment	1,608		535	37		$2,180	262		366	$2,808	7
	SUBTOTAL 3.	$16,758		$7,315	$512		$24,584	$2,950		$4,130	$31,665	78
4	PC BOILER & ACCESSORIES											
	4.1 PC Boiler	45,843		19,565	1,370		$66,777	8,013		11,219	$86,009	213
	4.2 Open											
	4.3 Open											
	4.4 Interconnecting Pipe	w/4.1		w/4.1								
	4.5 Primary Air System	w/4.1		w/4.1								
	4.6 Secondary Air System	w/4.1		w/4.1								
	4.8 Major Component Rigging		w/4.1	w/4.1								
	4.9 PC Foundations		w/14.1	w/14.1								
	SUBTOTAL 4.	$45,843		$19,565	$1,370		$66,777	$8,013		$11,219	$86,009	213

Client: DOE-METC
Project: CLEAN COAL REFERENCE PLANT

Report Date: 17-Nov-95
11:55 AM

TOTAL PLANT COST SUMMARY

Case: ENCOAL (TASK 6)
Plant Size: 404.3 MW,net
Estimate Type: Conceptual
Cost Year: 1994 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
5	FLUE GAS CLEANUP											
	5.1 Reagent Prep & Feed	6,489	1,853	3,553	249		$12,144	1,457	2,429	2,405	$18,435	46
	5.2 Other Duct Injection	1,945	15	24	2		$1,986	238	397	393	$3,014	7
	5.3 ESP & Accessories	12,699		4,844	339		$17,882	2,146		3,004	$23,032	57
	5.4 Other ESP	3,301		5,712	400		$9,413	1,130		1,581	$12,124	30
	5.5 Product Dewatering	N/A		N/A								
	5.6 Open											
	5.9 Open											
	SUBTOTAL 5.	$24,433	$1,868	$14,134	$989		$41,425	$4,971	$2,826	$7,383	$56,605	140
6	COMBUSTION TURBINE/ACCESSORIES											
	6.1 Combustion Turbine Generator	N/A		N/A								
	6.2 Combustion Turbine Accessories	N/A		N/A								
	6.3 Compressed Air Piping											
	6.9 Combustion Turbine Foundations											
	SUBTOTAL 6.											
7	HRSG, DUCTING & STACK											
	7.1 Heat Recovery Steam Generator	N/A		N/A								
	7.2 Other Acc't 7 Costs											
	7.3 Ductwork	7,658		4,618	323		$12,599	1,512		2,117	$16,228	40
	7.4 Stack	5,950		3,805	266		$10,021	1,202		1,683	$12,907	32
	7.9 HRSG,Duct & Stack Foundations		285	360	25		$670	80		113	$863	2
	SUBTOTAL 7.	$13,608	$285	$8,783	$615		$23,290	$2,795		$3,913	$29,998	74
8	STEAM TURBINE GENERATOR											
	8.1 Steam TG & Accessories	35,365		4,807	336		$40,509	4,861		6,805	$52,175	129
	8.2 Turbine Plant Auxiliaries	178		418	29		$626	75		105	$806	2
	8.3 Condenser & Auxiliaries	4,787		1,339	94		$6,220	746		1,045	$8,012	20
	8.4 Steam Piping	6,524		3,475	243		$10,243	1,229		1,721	$13,193	33
	8.9 TG Foundations		344	1,086	76		$1,507	181		253	$1,941	5
	SUBTOTAL 8.	$46,855	$344	$11,126	$779		$59,104	$7,092		$9,929	$76,126	188
9	COOLING WATER SYSTEM											
	9.1 Cooling Towers	6,228		1,397	98		$7,722	927		1,297	$9,946	25
	9.2 Circulating Water Pumps	887		86	6		$979	118		165	$1,261	3
	9.3 Circ.Water System Auxiliaries	111		16	1		$128	15		22	$165	0
	9.4 Circ.Water Piping		2,051	2,331	163		$4,546	545		764	$5,855	14
	9.5 Make-up Water System	248		375	26		$649	78		109	$836	2
	9.6 Component Cooling Water Sys	240		215	15		$470	56		79	$605	1
	9.9 Circ.Water System Foundations		1,530	2,707	189		$4,426	531		744	$5,700	14
	SUBTOTAL 9.	$7,713	$3,581	$7,127	$499		$18,921	$2,270		$3,179	$24,370	60

Client: DOE-METC
Project: CLEAN COAL REFERENCE PLANT

Report Date: 17-Nov-95
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TOTAL PLANT COST SUMMARY

Case: ENCOAL (TASK 6)
Plant Size: 404.3 MW,net

Estimate Type: Conceptual

Cost Year 1994 ; $x1000

Acct No.	Item/Description	Equipment Cost	Material Cost	Labor Direct	Labor Indirect	Sales Tax	Bare Erected Cost $	Eng'g CM H.O.& Fee	Contingencies Process	Contingencies Project	TOTAL PLANT COST $	TOTAL PLANT COST $/kW
10	ASH/SPENT SORBENT HANDLING SYS											
	10.1 Ash Coolers	N/A		N/A								
	10.2 Cyclone Ash Letdown	N/A		N/A								
	10.3 HGCU Ash Letdown	N/A		N/A								
	10.4 High Temperature Ash Piping	N/A		N/A								
	10.5 Other Ash Recovery Equipment	N/A		N/A								
	10.6 Ash Storage Silos	295		994	70		$1,359	163		228	$1,751	4
	10.7 Ash Transport & Feed Equipment	10,529		18,792	1,315		$30,636	3,676		5,147	$39,460	98
	10.8 Misc. Ash Handling Equipment											
	10.9 Ash/Spent Sorbent Foundation		138	181	13		$331	40		56	$426	1
	SUBTOTAL 10.	$10,824	$138	$19,967	$1,398		$32,327	$3,879		$5,431	$41,637	103
11	ACCESSORY ELECTRIC PLANT											
	11.1 Generator Equipment	1,491		232	16		$1,739	209		292	$2,240	6
	11.2 Station Service Equipment	2,357		744	52		$3,152	378		530	$4,060	10
	11.3 Switchgear & Motor Control	4,100		825	58		$4,983	598		837	$6,418	16
	11.4 Conduit & Cable Tray		1,355	4,173	292		$5,820	698		978	$7,496	19
	11.5 Wire & Cable		2,499	2,449	171		$5,120	614		860	$6,594	16
	11.6 Protective Equipment	178		582	41		$801	96		135	$1,031	3
	11.7 Standby Equipment	1,232		27	2		$1,261	151		212	$1,624	4
	11.8 Main Power Transformers	3,227		147	10		$3,384	406		569	$4,359	11
	11.9 Electrical Foundations		203	561	39		$804	96		135	$1,035	3
	SUBTOTAL 11.	$12,585	$4,058	$9,739	$682		$27,064	$3,248		$4,547	$34,858	86
12	INSTRUMENTATION & CONTROL											
	12.1 PC Control Equipment	w/12.7		w/12.7								
	12.2 Combustion Turbine Control	N/A		N/A								
	12.3 Steam Turbine Control	w/8.1		w/8.1								
	12.4 Other Major Component Control											
	12.5 Signal Processing Equipment	W/12.7		w/12.7								
	12.6 Control Boards,Panels & Racks	296		171	12		$479	57		80	$617	2
	12.7 Computer & Accessories	6,213		179	12		$6,404	768		1,076	$8,248	20
	12.8 Instrument Wiring & Tubing	1,606		4,901	343		$6,851	822		1,151	$8,824	22
	12.9 Other I & C Equipment	1,406		614	43		$2,064	248		347	$2,658	7
	SUBTOTAL 12.	$9,525		$5,863	$410		$15,798	$1,896		$2,654	$20,348	50
13	IMPROVEMENTS TO SITE											
	13.1 Site Preparation			606	42		$649	78		109	$836	2
	13.2 Site Improvements		1,015	1,250	88		$2,353	282		395	$3,030	7
	13.3 Site Facilities	1,818		1,779	125		$3,722	447		625	$4,794	12
	SUBTOTAL 13.	$1,818	$1,015	$3,636	$254		$6,723	$807		$1,130	$8,660	21
14	BUILDINGS & STRUCTURES											
	14.1 Boiler Building		12,236	12,799	896		$25,930	3,112		4,356	$33,398	83
	14.2 Turbine Building		4,034	6,388	447		$10,870	1,304		1,826	$14,000	35
	14.3 Administration Building		522	656	46		$1,224	147		206	$1,577	4
	14.4 Circulation Water Pumphouse		22	21	1		$45	5		8	$58	0
	14.5 Water Treatment Buildings		218	214	15		$446	54		75	$575	1
	14.6 Machine Shop		279	223	16		$518	62		87	$667	2
	14.7 Warehouse		189	226	16		$431	52		72	$555	1
	14.8 Other Buildings & Structures		116	117	8		$242	29		41	$311	1
	14.9 Waste Treating Building & Str.		222	801	56		$1,080	130		181	$1,391	3
	SUBTOTAL 14.		$17,839	$21,446	$1,501		$40,786	$4,894		$6,852	$52,532	130
	TOTAL COST	$210,641	$32,220	$139,421	$9,759		$392,041	$47,045	$2,826	$66,287	$508,199	1257