DOE/MC/24132 -- 5037
(DE96000559)
Volume I

Tidd PFBC Demonstration Project First Three Years of Operation

Topical Report

April 1995

Work Performed Under Contract No.: DE-FC21-87MC24132

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

By
Ohio Power Company
Columbus, Ohio

DISCLAIMER

DOE/MC/24132 -- 5037
(DE96000559)
Distribution Category UC-103
Volume I

Tidd PFBC Demonstration Project
First Three Years of Operation

Topical Report

Work Performed Under Contract No.: DE-FC21-87MC24132

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

By
Ohio Power Company
1 Riverside Plaza
Columbus, Ohio 43216-6631

April 1995

DOE/MC/24132 -- 5037

Tidd PFBC Demonstration Project
First Three Years of Operation
Volume I

DOE

Forward

This Final Report on the Ohio Power Company's Tidd PFBC Demonstration Plant covers the period from initial plant startup through completion of the first three years of operation on February 28, 1994.

The Tidd Pressurized Fluidized Bed Combustion (PFBC) Demonstration Plant is the first utility-scale pressurized fluidized bed combustor to operate in combined-cycle mode in the United States. The plant is owned and operated by Ohio Power Company (OPCo) and is located on the banks of the Ohio River, approximately 75 miles downstream of Pittsburgh, Pennsylvania.

The 45-year old pulverized coal plant was repowered with PFBC components in order to demonstrate that PFBC combined-cycle technology is an economic, reliable, and environmentally superior alternative to conventional technology in using high-sulfur coal to generate electricity.

This project received cost sharing from the U.S. Department of Energy (DOE), administered by the Morgantown Energy Technology Center in accordance with DOE Cooperative Agreement No. DE-FC21-87 MC24132.000. The project also received cost sharing from the State of Ohio, under the Ohio Coal Development Office agreement No. CDO/D-86-28.

Detailed design work on the project began in May, 1986, and site construction work started in April, 1988. Unit start-up was initiated in November, 1990 and the first combined cycle operation was achieved on November 29, 1990. The three-year demonstration period started on February 28, 1991. A fourth year of plant operations was begun on March 1, 1994 and is not addressed as part of this report.

Section 1.0 of this report is an executive summary of the first three years of operations of the Tidd PFBC Demonstration Plant. Section 2.0 is an introduction to the plant and a brief description of the plant systems and layout. Section 3.0 covers the project history, three year overview and operating statistics. Section 4.0 addresses unit testing that was accomplished during the first three years. Section 5.0 reviews the significant process related findings and plant modifications required during the first three years. Section 6.0 describes the individual PFBC systems installed in the plant, a brief system description, and their operational and modification overview. Appendix I is an operational narrative of each of the unit runs. Appendix II is a line item log of each run listing the significant operations, testing, and outage requirements of each unit run. Appendix III is a log of the operational hours and statistics of each run. Appendix IV provides the plant general arrangement drawings.

The report was prepared by the American Electric Power Service Corporation as agent for the Ohio Power Company. Assistance and input for this report was provided by the staff of the Tidd PFBC Demonstration Plant. The following individuals prepared this report:

American Electric Power Service Corporation, Columbus, Ohio:

David A. Bauer	James L. Corey
John D. Hoffman	Mario Marrocco
Michael J. Mudd	William P. Reinhart
Greg. D. Soulsby	H. Kevin Stogran
Eugene E. Gloss	

Ohio Power Company, Tidd PFBC Demonstration Plant, Brilliant, Ohio:

Ronald A. Baker	Stephen W. Burge
Russel W. Gwin	Wayne L. Irons
Thomas R. Marosi	Dennis J. Rathburn
William S. Smith	

Table of Contents

Table of Contents

Table of Contents

Table of Contents

Table of Contents

Table of Contents

Table of Contents

Listing of Tables

Table of Contents

Listing of Figures

Table of Contents

Table of Contents

Listing of Plant and Equipment Photographs

Acronyms and Abbreviations

AB	ASEA Babcock - A business partnership between a subsidiary of ABBC and the Babcock & Wilcox Company (USA)
AFBC	Atmospheric Fliudized Bed Combustion
AEP	American Electric Power Company, Inc.
AEPSC	American Electric Power Service Corporation, a subsidiary of AEP
ABBC	ABB Carbon - a subsidiary of ASEA-Brown Boveri (subcontractor)
ABB Stal	ABB Stal - a subsidiary of ASEA-Brown Boveri
Al_2O_3	Aluminum Oxide
B&W	The Babcock & Wilcox Company (subcontractor)
Btu	British Thermal Units
Btu/#	British Thermal Units per Pound
BWCC	The Babcock & Wilcox Construction Company (subcontractor)
BOP	Balance of Plant
CaO	Calcium Oxide
Cl	Chlorine
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CTF	Component Test Facility
CWP	Coal Water Paste
DOE	Department of Energy (United States)
EMP	Environmental Monitoring Plan
EPA	Environmental Protection Agency
ESP	Electrostatic Precipitator
Fe_2O_3	Iron Oxide
GT	Gas Turbine
HGCU	Hot Gas Clean-Up
HP	High Pressure
HPC	High Pressure Compressor
HPT	High Pressure Turbine
HVAC	Heating, Ventilating & Air Conditioning
I&C	Instrumentation & Control
lbm	Pounds Mass

Acronyms and Abbreviations

K_2O	Potassium Oxide
kva	Kilovolt Amperes
KW_e	Kilowatts Electrical
LP	Low Pressure
LPC	Low Pressure Compressor
LPT	Low Pressure Turbine
MgO	Magnesium Oxide
mm	Millimeters
mmBtu	Million Btu
MW_e	Megawatts Electrical
MW_t	Megawatts Thermal
NCB	National Coal Board
NDE	Nondestructive Examination
NOVAA	Northern Ohio Valley Air Authority
NO_x	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
OEPA	Ohio Environmental Protection Agency
OCDO	Ohio Coal Development Office - a part of Ohio Department of Development
OPCo	Ohio Power Company
pf	Power Factor
PFBC	Pressurized Fluidized Bed Combustion
POPS	Plant Operations and Performance System
ppb	Parts Per Billion
rpm	Revolutions per Minute
SiO_2	Silicon Oxide
SO_2	Sulfur Dioxide
SO_3	Sulfur Trioxide

1.0 Executive Summary

1.1 Introduction

The Tidd Pressurized Fluidized Bed Combustion (PFBC) Demonstration Plant is the first utility-scale pressurized fluidized bed combustor to operate in combined-cycle mode in the United States. The plant is owned and operated by Ohio Power Company (OPCo) and is located on the banks of the Ohio River, approximately 75 miles downstream of Pittsburgh, Pennsylvania.

The 45-year old pulverized coal plant was repowered with PFBC components in order to demonstrate that PFBC combined-cycle technology is an economic, reliable, and environmentally superior alternative to conventional technology in using high-sulfur coal to generate electricity.

The PFBC related equipment was supplied by ASEA Babcock, a partnership between ASEA Brown Boveri Carbon (ABB Carbon) and the Babcock & Wilcox Company (B&W). American Electric Power Service Corporation (AEPSC) engineered and designed the plant. Construction of the PFBC Island and modification of the existing facility were performed by Ohio Power Company.

This project received cost sharing from the U.S. Department of Energy (DOE), administered by the Morgantown Energy Technology Center in accordance with DOE Cooperative Agreement No. DE-FC21-87 MC24132.000. The project also received cost sharing from the State of Ohio, under the Ohio Coal Development Office agreement No. CDO/D-86-28.

Detailed design work on the project began in May 1986, and site construction work started in April 1988. Unit start-up was initiated in November 1990 and the first combined-cycle operation was achieved on November 29, 1990. The three-year demonstration period started on February 28, 1991.

This report reviews the experience of the 70-MW_e Tidd PFBC Demonstration Plant during the first three years of operation.

1.2 Operating Overview

The Tidd PFBC Demonstration Plant accumulated 6057 hours of coal-fired operation during its first three years of operation. The achievements during that period were significant in establishing PFBC as a viable option for base-load, coal-fired generation. The highlights of those years are noted below:

1991 - The initial operation of the unit was consistent with the expectations associated with demonstration technology. The first year of operation was plagued with poor unit reliability and availability. The primary focus of operation was on debugging of plant systems. A number of systems including the cyclone ash removal, coal preparation, sorbent preparation, boiler circulation controls and sorbent injection systems presented significant challenges to continuous operation. Installation of additional boiler in-bed tube surface, modification to the fluid bed air distribution ducts, complete overhaul of the cyclone ash removal systems, modification and installation of systems to combat boiler post-bed combustion, and installation of economizer sootblowers each contributed to unit down time. The unit operated for less than 1,000 hours, however, gradual but constant improvements in operability were being achieved.

1992 - From January to early March the unit fired coal for over 400 hours. At that point cracks were discovered in the root area of a number of gas-turbine low-pressure blades. A nine-week outage was required for replacement of the blades. This was followed by the longest continuous run of the first three years (740 hours). PFBC Island acceptance tests were completed during this period. The unit met all performance guarantees except gas turbine power output. After June, unit operation was significantly more reliable, permitting a number of unit performance tests to be completed. The most significant problems during this period were fuel nozzle and secondary cyclone ash removal line pluggages. Other factors contributing to down time were bed sintering problems when attempting to operate with magnesian limestone sorbent and erratic operation of the ceramic hot gas filter system. Despite these operating difficulties, the unit achieved approximately 2,400 hours on coal fire.

1993 - The first two months of the year saw continued improvements in operations, with four unit tests completed and improved unit operating characteristics and sorbent utilization achieved. Testing was interrupted in mid February with the on-line failure of several gas-turbine blades. The subsequent extended outage (20 weeks) included a complete overhaul of the gas turbine along with replacement of the boiler sparge ducts and installation of an improved secondary-ash removal system. The remaining six months of the year saw greatly increased availability and the completion of 28 unit tests. Despite the extended gas-turbine rebuild outage, the unit operated for approximately 2,300 hours.

1994 - The first two months of 1994 continued to demonstrate improved operations and three more unit tests were completed. Unit reliability and availability was quickly achieving acceptable levels for a demonstration unit.

The initial three-year test program was completed at the end of February 1994. Over those three years, the unit fired coal for a total of 6,056 hours. The key operating statistics are presented in Table 1.1.

Table 1.1 - Key Operating Statistics

Key Operating Statistics October 1990 through February 1994					
Yearly Data	1990 3 Months	1991	1992	1993	1994 2 Months
G. T. Operating Hours	457	1482	2914	2544	586
Coal Fire Hours	61	795	2367	2310	525
Unit Availability	4.1%	9.6%	28.7%	26.6%	37.6%
Gross Capacity Factor @ 70 MWG	0.4%	3.6%	17%	15.5%	24.2%
Number of Runs	9	43	29	16	4
Gross Unit Output Factor @ 70 MWG	10.7%	37.3%	59.2%	58.2%	64.3%
Maximum Gross Unit Load Achieved	N/A	53 MW	71 MW	64 MW	61 MW

1.3 Significant Findings

The significant findings for the first three years of operation include:

The unit was able to meet or exceed all of its guarantee conditions except gas turbine output. The process was able to meet its design sulfur retention of 90% and was able to demonstrate sulfur retention in excess of 95%.

The process emitted lower NO_x emissions than design.

The combustion efficiency was better than design.

The early operation was plagued by difficulties associated with the materials handling systems. However, design changes were successful in addressing and resolving these issues.

The gas turbine was the leading cause of unit unavailability during the first three years of operation. The Low-Pressure Turbine blades were replaced once due to cracks and once due to a catastrophic failure of a Low-Pressure Turbine blade. In addition, the Low-Pressure Compressor stationary blades were replaced due to cracks at the guide vane ring attachments. However, it is important to note that the above failures were all related to the design of the gas turbine rather than to its operation in a PFBC plant.

The gas turbine blades experienced noticeable, but minor erosion. The most significant erosion was experienced in the Low-Pressure Turbine variable-pitch inlet guide vanes.

The in-bed tube bundle did not experience any widespread erosion that would require significant maintenance. Minor localized erosion was detected and addressed during the early operation of the unit.

There was one tube leak in the in-bed tube bundle during the first three years of operation. This leak indirectly resulted from an air leak in a maintenance door which caused localized high velocity erosion.

1.4 Significant Modifications

The various sections of this report detail the system modifications implemented during the operation of the plant. Some of the significant modifications include:

Modifications to the in-bed tube bundle to increase the heat absorption capability (Section 6.2).

Modifications to the coal preparation system to increase the fines content of the Coal Water Paste and to address pluggage of the coal lines and fuel feed nozzles (Section 6.7).

Modifications to the sorbent injection system by increasing the number of sorbent feed lines to improve sorbent utilization (Section 6.9)

Modifications to the cyclone ash removal system to resolve pluggage of the system (Section 6.10).

Modifications to the gas turbine to address resonant frequency fatigue failure of LP blades. (Section 6.13).

Modifications to the economizer to address harmonic vibration of the tube platens and to address fouling (Section 6.16).

Modifications to the control system to improve the control stability (Section 6.19).

1.5 Unit Performance

A total of 47 unit performance tests were conducted during the three-year test program. Performance goals and guarantees were verified during the acceptance test (Test 6), conducted on June 14, 1992. During this test the unit was operated at 142" bed level, 1551 F bed temperature, and 93% sulfur retention. The unit achieved a firing rate of 188.7 MW_t with a gross output of 60.1 MW_e. The calcium-to-sulfur molar ratio during this test was 1.71 normalized to conditions of 90% sulfur retention at 1580 F bed temperature using the Grimethorpe correlation, or 2.23 Ca/S ratio normalized to 95% sulfur retention at 1580 F bed temperature. SO_2 and NO_x emissions were both better than design and well within the permit limitations. SO_2 emissions were 0.35 lbs/mmBtu while NO_x emissions were 0.17 lbs/mmBtu during the test period. A combustion efficiency of 99.4% was calculated for the test.

1.6 Conclusion

The Tidd PFBC Demonstration Plant successfully demonstrated the viability of PFBC technology, proving that the process could effectively control sulfur emissions from high-sulfur coal. The ability of a gas turbine to operate in a PFBC combined-cycle mode, utilizing exhaust gases from the PFBC process to drive a gas turbine, has been demonstrated. While some erosion was observed, the amount was acceptable. The ability of an in-bed tube bundle to perform acceptably in a bubbling bed environment was confirmed. The erosion of the in-bed tubes proved negligible. The systems required to apply PFBC Technology to electric power generation were demonstrated and, in many cases, refined at Tidd. As is with any new technology, there were numerous equipment and system shortfalls. The identification and solution of these problems will provide important benefits to the commercialization of PFBC technology as it is applied to a full-scale commercial PFBC Plant in the future.

2.0 Introduction

The Tidd Pressurized Fluidized Bed Combined-Cycle (PFBC) Demonstration Plant is the first PFBC combustor to operate in combined-cycle mode in the United States. The plant is owned and operated by Ohio Power Company (OPCo) and is located on the banks of the Ohio River, approximately 75 miles downstream of Pittsburgh, Pennsylvania.

The 45-year old pulverized-coal power plant was repowered with PFBC components in order to demonstrate that pressurized fluidized bed combustion combined-cycle technology is an economic, reliable, and environmentally superior alternative to conventional technology in using high-sulfur coal for power generation.

The PFBC-related equipment was supplied by ASEA Babcock, a partnership between ASEA Brown Boveri Carbon (ABB Carbon) and the Babcock & Wilcox Company (B&W). American Electric Power Service Corporation (AEPSC) engineered and designed the plant. Construction and modification of the existing facility were performed by Ohio Power Company.

The project received cost sharing from the U.S. Department of Energy (DOE), administered by the Morgantown Energy Technology Center in accordance with DOE Cooperative Agreement No. DE-FC21-87 MC24132.000. The project also received cost sharing from the State of Ohio, under the Ohio Coal Development Office agreement No. CDO/D-86-28.

Detailed design work on the project began in May 1986, and site construction work started in April 1988. Unit startup was initiated in October 1990. The first combined-cycle operation was achieved on November 29, 1990, and the three-year demonstration period began on February 28, 1991. This report reviews the operating experience during the first three years of operation.

2.1 Process Overview

A fluidized bed consists of a mass of granular particles with an air stream flowing upward through the particles. As the velocity of the air increases to about three feet per second, the particles are maintained in a highly turbulent suspended state. The bed in this state is said to be fluidized and, in general, behaves like a fluid.

This fluidized motion permits excellent surface contact between the air and the particles. When a combustible material, such as coal, is introduced into the bed, this mixing permits almost isothermal conditions and efficient combustion. The operating temperature of the bed is determined by the fuel heat release in the bed, the excess air, and the rate of heat removal from the bed. The temperature range is established by the coal characteristics; for Eastern coals, the bed temperature range is 1350 F to 1700 F.

In a fluidized bed, the SO_2 generated during combustion is removed by adding a sorbent, such as dolomite or limestone, to the bed. Dolomite, composed primarily of calcium carbonate and magnesium carbonate ($CaCO_3$ - $MgCO_3$), dissociates when heated to form the porous and reactive complex of magnesium oxide-calcium carbonate (MgO - $CaCO_3$) to react with sulfur dioxide. At fluidized bed temperatures, the reaction of this complex with sulfur dioxide (SO_2) forms an inert magnesium oxide-calcium sulfate complex (MgO $CaSO_4$). This is expressed chemically as:

$$CaCO_3 \bullet MgCO_3 + Heat \longrightarrow MgO \bullet CaCO_3 + CO_2$$

$$MgO \bullet CaCO_3 + SO_2 + 1/2\ O_2 \longrightarrow MgO \bullet CaSO_4 + CO_2$$

Under pressurized conditions, calcination and sulfation do not necessarily occur as two separate reactions. Laboratory research has determined that a significant part of the sulfur capture occurs by direct diffusion of the SO_2 molecule into the calcium carbonate which replaces the CO_2 in the carbonate.

The magnesium oxide-calcium sulfate complex produced in these reactions is a dry granular by-product which can be easily managed.

In addition to reduced SO_2 emissions, NO_x emissions from a fluidized bed are lower than from a conventional pulverized coal boiler. The lower combustion temperature in a fluidized bed minimizes thermal NO_x generation. A conventional pulverized coal fired unit, which operates at combustion temperatures of 3200 F, typically generates NO_x emissions of 0.6 to 0.7 lbm per million BTU; a fluidized bed which has a combustion temperature of typically less than 1600 F generates approximately 0.3 lbm of NO_x per million BTU.

During combustion, the fluidized bed will contain less than 1 percent combustible material. The balance consists of dolomite and inert material (reacted dolomite and ash). Because of this low percentage of combustibles and the low combustion temperature, the fluidized bed can burn a much wider range of fuels than conventional combustion processes. Fuels with very low or high heating value, low or high ash content, low or high sulfur content, and low or high ash fusion temperatures can be burned in a fluidized bed.

Boiler tubes submerged in a fluidized bed are used to generate steam to drive a steam turbine-generator. Because of the turbulent nature of the bed particles, overall heat transfer rates 4 to 5 times greater than in a conventional furnace are achieved in these tubes. Therefore, the total amount of boiler surface is significantly reduced compared with a conventional boiler, resulting in capital-cost savings.

Fluidized beds can be operated under various conditions, the most distinguishing of which is pressure. Combustion in fluidized beds operating at pressures of about one atmosphere or less are referred to as Atmospheric Fluidized Bed Combustion (AFBC). Fluidized bed combustion at much higher pressures is referred to as Pressurized Fluidized Bed Combustion (PFBC). Tidd is a pressurized, bubbling-bed process.

Because of the higher pressure, the exhaust gases from a PFBC have sufficient energy to drive a gas turbine while the steam generated in the in-bed boiler tubes drives a steam turbine. This combined-cycle configuration allows a power plant design which is more economic and efficient than alternatives.

In PFBC, the higher operating pressure allows for the use of deep beds which result in a long residence time that yields high combustion efficiency and a high level of sulfur removal with lower sorbent requirements. A PFBC power plant permits burning a wide range of coals in an environmentally compatible manner. Intimate contact of the coal and dolomite enables a consistent, high degree of sulfur removal during combustion. Relatively low combustion temperatures and the deep bed result in low NO_x emissions. The waste products, both fly ash and bed ash, are dry, benign, and manageable. The high pressure and high in-bed heat transfer allow a reduction in plant size with corresponding material savings. The combined-cycle operation results in high generating efficiency.

2.2 Tidd Cycle

Figure 2.1 provides a composite cycle schematic which shows how PFBC was incorporated into the original Tidd Unit 1 conventional steam cycle. The Tidd Unit 1 steam cycle was a 1940's vintage cycle, with original steam conditions of 900,000 #/hr steam flow at 1300 psia and 925 F with no reheat. The plant produced an output of 110 MW_e at a cycle efficiency of 31%. As configured for PFBC operation, the plant was designed for a steam flow of 440,000 #/HR at 1300 psia and 925 F, to produce a gross electrical output of 56.7 MW_e from the steam turbine and 16.9 MW_e from the gas turbine with a net cycle efficiency of 34%. Table 2.1 provides the full load design values.

Table 2.1 - Full-Load Process Design Values

Full Load-Process Design Values	
Feedwater / Steam Cycle	
Feedwater Flow	424,110 lb/hr
Economizer Inlet Temperature	299 F
Final Feedwater Temperature	478 F
Final Feedwater Pressure	1850 psig
Main Steam Flow	439,560 lb/hr
Main Steam Temperature	925 F
Main Steam Pressure	1320 psig
Steam Turbine Output	56.7 MWG
Air/Gas Cycle	
LP Compressor Outlet Pressure	71 psig
LP Compressor Outlet Temperature	326 F
HP Compressor Outlet Pressure	192 psig
HP Compressor Outlet Temperature	572 F
Air Flow	646,000 lb/hr
Bed Temperature	1580 F
HP Turbine Inlet Pressure	165 psig
HP Turbine Inlet Temperature	1525 F

Full Load-Process Design Values

LP Turbine Inlet Pressure	47 psig
LP Turbine Inlet Temperature	986 F
Economizer Inlet Temperature	766 F
Economizer Outlet Temperature	350 F
Gas Flow	724,000 lb/hr
Excess Air	25%
Gas Turbine Output	16.9 MWG
Solids	
Coal Flow (Dry)	57,300 lb/hr
Coal Water Paste Flow	72,620 lb/hr
Sorbent Flow(1)	27,760 lb/hr
Bed Height (2)	126 in
Cyclone Ash Flow	13,690 lb/hr
Bed Ash Flow	9,820 lb/hr

NOTES: (1) At calcium-to-sulfur molar ratio of 1.64 for 90% sulfur retention.
(2) Bed height was increased to 142" in December 1991.

The design full-load heat balances for the steam side and the gas side of the combined cycle are shown in Figures 2.2 and 2.3, respectively.

In the gas cycle, ambient air enters the low pressure compressor section of the gas turbine and is compressed to 71 psig. The air is then cooled by condensate in the gas turbine intercooler. The air then enters the high pressure compressor where it is further compressed to 192 psig and 572 F.

The hot compressed air is then directed through the outer annulus of a coaxial air/gas pipe into the pressure vessel. Once inside the pressure vessel, the hot air is routed through a series of internal cyclone ash coolers where the air is further heated before it is directed into the fluidized bed via a system of sparge ducts.

The coal is fed to the bed as a coal-water paste (25% nominal water content by weight). The sorbent is injected into the bed by a pneumatic transport system.

After leaving the fluidized bed zone, the hot gases and entrained ash particles enter the freeboard zone above the bed. The hot gases and entrained ash then pass into seven parallel primary cyclones, and through six secondary cyclones and one hot-gas cleanup slip stream which operates in parallel to the other six secondary cyclones. The cyclones were designed to remove 98% of the entrained ash from the gas stream. The gas is cleaned sufficiently to pass through the gas turbine without deleterious erosion of the gas turbine components.

After exiting the cyclones and hot-gas cleanup slip stream, the gas is collected in a manifold and exits the pressure vessel. The gas is directed through the inner pipe of the coaxial pipe, past the hot gas intercept valves and into the high-pressure gas turbine at 1525 F and 165 psig where the hot gas is expanded. The gas then enters the low-pressure turbine where it is further expanded and then cooled to 350 F in the turbine exhaust gas economizer.

After the economizer, the gas enters the electrostatic precipitator where it is further cleaned to meet the New Source Performance Standards (NSPS) of 0.03 lbm/million BTU before being emitted to the atmosphere via the Cardinal Unit 1 flue gas stack.

The steam cycle is a Rankine cycle with a once-through Benson-type boiler. Condensate from the condenser is heated from 74 F to 259 F in three stages of low-pressure heaters and the gas turbine intercooler as it is pumped to the deaerator by the hotwell and condensate booster pumps. From the deaerator, the feedwater is pressurized by the tank pumps and further heated to 295 F by the single high-pressure heater before being fed to the suction of the feedwater pump. The flow is further pressurized by the feedwater pump and directed to the economizer where heat in the gas exiting the gas turbine further preheats the feedwater to 478 F. From there the subcooled feedwater is routed to the pressure vessel and enters the boiler at 478 F and 1880 psig.

The boiler is a subcritical once-through steam generator that employs a pump assisted circulation loop and a moisture separator for startup and shutdown. The boiler provides steam at 1350 psig and 925 F.

2.3 Plant Description

2.3.1 Site Description

The 70 MW_e Tidd PFBC Demonstration Plant is located at the Ohio Power Company Tidd Plant on the Ohio River in Brilliant, Ohio. The PFBC module repowered Tidd Unit 1, a 110 MW_e steam plant. The original Tidd Unit 1 was commissioned in September 1945, deactivated in 1976, and retired in 1979.

The Tidd Plant offered an ideal site for the PFBC Demonstration Plant for the following reasons:

Existing plant equipment such as coal handling systems, plant services, and high voltage connection to the existing 138,000-volt switchyard could be utilized.

The demonstration plant could be erected and placed in service in much less time than if a Greenfield site was selected.

Cost savings could be realized in developing the combined cycle aspect of PFBC by utilizing the Unit 1 existing steam turbine-generator, condenser, and feedwater system.

The open space adjacent to Unit 1 provided an unobstructed location for the PFBC plant.

The site is adjacent to the Ohio River which is conducive to barge shipment of large modular components to the site.

2.3.2 Plant Layout

The new PFBC power island, which includes the combustor, gas turbine, and coal and sorbent systems, was installed in a new building constructed adjacent to the original Tidd Unit 1. The new economizer, electrostatic precipitator, ash silos, and electrical control building are located nearby. Figure 2.4 provides a rendering of the Tidd Plant.

Much of the original Tidd balance of plant equipment was refurbished and reused. The steam cycle utilizes many of the original components, including the steam turbine/generator, condensate and feedwater heaters, and pumps.

Many of the service buildings, control and piping systems were also reused. The original structures for storing and handling coal were used for both coal and dolomite, as was the 138,000 volt switchyard.

Major new equipment that was installed includes the pressurized fluidized bed combustor and related components (including the boiler, bed ash reinjection system, and cyclones), the gas turbine, coal and sorbent preparation and injection systems, the economizer, the electrostatic precipitator, ash removal and disposal systems, and electrical components (including transformers and switchgear). It was also necessary to construct new foundations, buildings, and piping and electrical systems needed to integrate the PFBC system with the balance of the plant.

2.4 Plant Systems

2.4.1 Pressure Vessel

A single cylindrical pressure vessel contains the boiler, cyclones, cyclone ash coolers, and bed ash reinjection system. This arrangement allows the components within the vessel to be designed for a relatively low differential pressure, even though the process pressure is relatively high.

The pressure vessel is externally insulated and is designed for internal operating conditions of 675 F and 185 psig It consists of a vertical cylindrical shell about 70 feet high and 44 feet in diameter, with elliptical heads.

The pressure vessel heads include removable service openings that allow for the removal of internal components. In addition, internal and external service platforms, lifting devices, and access doors were provided to permit service and maintenance of both the internal and external systems.

2.4.2 Boiler

The PFBC boiler enclosure was designed with membrane water wall construction. At normal operating loads, the boiler is a subcritical, once-through unit. There are three major sections in the boiler: the boiler bottom, the bed zone, and the freeboard.

The boiler bottom consists of fluidizing air ducts arranged on top of a pair of membrane water wall hoppers. The hoppers, which remain full of ash during operation, direct the spent bed material to the bed ash removal system.

The bed zone is an 11-feet 8-inch deep tapered, fluidized bed in which the superheater and evaporator sections are submerged. At full load, all of the evaporator and superheater surfaces are submerged within the bed. At reduced loads, the bed level is lower, and portions of the surface are exposed. The surface above the bed cools the gases before they flow to the gas turbine.

The freeboard section above the bed is internally insulated to minimize heat loss of the gases which drive the gas turbine.

2.4.3 Bed Ash Reinjection System

Bed level is the main controlling parameter in the PFBC boiler. The bed ash reinjection system permits rapid change in the unit load by transferring bed material to and from a pair of reinjection vessels located inside the combustor pressure vessel.

Air from the combustor pressure vessel transports the bed material to the reinjection vessels, and "L" valves transport the material from the reinjection vessels back to the bed. The transport air flow is separated from the ash and vented outside the combustor into the main combustion flue gas. The reinjection vessels are normally at the same pressure as the boiler; however, during load decreases, they are at a slightly lower pressure, accomplished through controlled venting.

2.4.4 Cyclones

To reduce particulate flowing to the gas turbine, the exhaust gases leaving the upper part of the boiler freeboard pass through a series of cyclones. At Tidd, there were originally seven parallel strings of cyclones, each with two stages of separation. However, one of the secondary cyclones was replaced with a hot-gas cleanup slip stream filter. The gas is conveyed from the boiler to the first stage cyclones through connecting flues. Gas flows from the second stage cyclones to a manifold and then exits the pressure vessel, and is routed to the inner portion of a coaxial pipe and past the hot gas intercept valves on its way to the gas turbine.

2.4.5 Gas Turbine/ Generator

The gas turbine at the demonstration project is the ABB Stal GT-35P machine. The turbine is arranged in line on two shafts. The variable-speed, low-pressure compressor is mechanically coupled to its driving low-pressure turbine on one shaft. The high-pressure turbine drives both the constant-speed high-pressure compressor and the electric generator. An epicyclic gear reducer couples the electric generator to the high-pressure shaft.

2.4.6 Steam Turbine/ Generator

The original steam turbine at the Tidd Plant was a 110 MW_e, 1800 rpm condensing turbine/ generator. It is contained in a single casing directly connected to a 0.9 pf, 111,111-kva, 3-phase, 60-cycle, 13,800-volt generator. The PFBC boiler produces less main steam flow than the original Tidd boilers; therefore, the steam turbine produces 57 MW_e at full load.

2.4.7 Economizer

The once-through turbine exhaust gas economizer at Tidd recovers heat from the gas turbine exhaust to preheat the feedwater. Tidd's economizer is a modular design, with the flue gas flowing horizontally across vertical, in-line, spirally-finned water tubes. It was installed in series with the condensate heaters and replaced the original high-pressure feedwater heaters.

2.4.8 Electrostatic Precipitator

After leaving the economizer, the gas enters the electrostatic precipitator. Here, the gas is further cleaned of particulate to the NSPS level of 0.03 lbm per million Btu. The gas is then released to the atmosphere via the flue gas stack.

2.4.9 Coal Handling, Preparation, and Injection Systems

The Tidd PFBC Demonstration Plant utilizes coal-water-paste (CWP) fuel, with a water content of 25% by weight, which is injected into the fluidized bed. Coal is weighed and sampled prior to placement in the coal storage area. A 30-day supply of coal is maintained in the storage area which has adequate space for storage of two smaller piles of test coals, each with a seven-day supply. Mobile equipment is used to maintain the storage piles and to reclaim coal from storage.

Coal, from storage, is loaded into rotary car dumper hoppers and delivered by a system of belt conveyors and transfer stations to three bunkers located in the main plant building. The conveyors are totally enclosed and are provided with dust collection and fire protection systems. Weighing, crushing, screening, and magnetic separation equipment are provided in the system. The three bunkers have a total storage capacity of 1350 tons, and are filled by a conveyor equipped with a traveling tripper.

A new conveyor system was installed below the original Tidd bunkers to convey coal to the coal preparation system, which is located in the new combustor building. The coal, one inch or less in size and stored in a surge hopper with a storage capacity of 45 tons, is fed into a double-roll crusher by a vibratory feeder. Crushed coal, all of which is 6 mm (¼ inch) or less in size, is transported by a system of conveyors onto a triple-deck screen to eliminate undesirable oversized pieces over 10 mm (3/8 inch) and then through a weigh feeder into a pug mill type mixer. Subsequent to the startup of the unit, a system was installed to recirculate a portion of the crushed coal back to the crusher to increase the fines content of the coal. Coal moisture content is measured on the weigh feeder and an appropriate amount of water is added to the coal in the mixer to prepare the CWP.

Prepared CWP is continuously fed into a paste tank from which six parallel coal injection pumps draw the CWP and deliver the it to the boiler. Each pump delivers the fuel flow into the boiler through a dedicated fuel nozzle. The nozzles penetrate the pressure vessel and boiler enclosure walls. High-pressure compressed air is used to break up the CWP at the discharge of the nozzles. The coal injection pumps are hydraulically operated piston pumps. The fuel flow rate is controlled by varying the speed of the pumps.

2.4.10 Sorbent Handling, Preparation, and Injection Systems

Sorbent (dolomite or limestone) is unloaded by a temporary conveying system to the storage area, separate from the coal piles. A 30-day supply of sorbent is maintained in the storage area which has adequate space for storage of two smaller piles of test sorbents, each with a seven-day supply. Mobile equipment is used to maintain the storage piles and to reclaim sorbent from storage. Reclaimed sorbent is loaded into the reclaim hopper and delivered to a bunker by the same belt conveyors that conveys coal to the bunkers. The sorbent bunker has a total storage capacity of 650 tons. A new conveyor system was installed below the sorbent bunker to convey sorbent to the sorbent preparation system, which is located in the combustor building. The sorbent is stored in a 70-ton capacity surge hopper, from which it is fed into an impact dryer mill. The size of the sorbent (1/8 inch) is controlled by a vibrating screen and heated air flowing through the mill. The sized material is swept from the mill by the hot air and then sorted by a cyclone separator and a bag house. A vibrating screen, located at the outlet to the cyclone separator, diverts oversized material back to the mill. The final product is transported by conveyor into a 200-ton sorbent storage hopper. The hopper has two outlets to feed the sorbent injection system.

Lockhoppers receive the prepared sorbent at atmospheric pressure. When full, the lockhoppers are isolated from the storage vessel and pressurized to a level slightly higher than the combustor. Variable speed rotary feeders meter the flow of sorbent to pneumatic conveying pipes. When the lockhoppers are empty, they are isolated from the combustor and are vented to the atmosphere through a bag filter. When completely depressurized, they are refilled.

Subsequent to the initial operation of the plant, a system was installed to receive and feed sorbent fines into the coal water paste system.

2.4.11 Ash Removal and Handling Systems

Fine ash, collected in the cyclones, is continuously removed by a pneumatic transport system. The ash is cooled and a portion of the heat is recovered in the combustion air. Depressurization requires no lockhoppers or valves. The ash from the primary cyclones is conveyed to a cyclone and a bag filter separator located atop the cyclone ash storage silo. The ash from the secondary cyclones is transported by means of a pressurized pneumatic ash transport system to discharge in the flue gas exhaust duct upstream of the electrostatic precipitator.

Granular bed ash is continuously removed by gravity from the boiler bottom hoppers in order to maintain the desired bed level. Two parallel lockhoppers, each serving one of the bottom hoppers, are filled and emptied independently. When full, the lockhoppers are depressurized by venting and emptied by gravity into a common atmospheric pressure hopper. From there, the ash is fed onto an enclosed conveyor system and transported to the bed ash storage silo.

The fly ash collected in the electrostatic precipitator is pneumatically conveyed by means of a vacuum removal system to the cyclone ash silo.

The cyclone ash and fly ash silo is a 22-foot-diameter, flat-bottom, elevated storage silo with an active storage capacity of 260 tons. Conditioning equipment installed in the cyclone ash silo removes cyclone ash from the storage bin, wets it to minimize fugitive dusting, and transfers it to open type dump trucks for disposal. Dry cyclone ash may also be loaded into dry bulk carrier trucks for sales or testing purposes.

The bed ash silo is a 22-foot-diameter, conical-bottom storage silo, adjacent to the cyclone ash silo. Active storage capacity is 220 tons. The bed ash is unloaded from the bin to open-type dump trucks for disposal. Because of the granular nature of bed ash, wetting of the ash is not necessary.

Both bed ash and cyclone ash are disposed in an Ohio EPA permitted area that has been used to dispose of over 8.5 million tons of fly ash from Cardinal Plant. From the storage silos located at the plant site, the ash is loaded into dump trucks that are covered and weighed prior to departure for the disposal site. Spray curtains and truck washes at the silos reduce dusting during loading operations and remove ash which adheres to the vehicles during loading. The dump trucks haul the ash to the disposal site, where the ash is dumped from the trucks, spread, wetted to optimum moisture content, and finally compacted.

2.4.12 Control System

A distributed programmable logic system is used to collect signals and measurements. The control system, a Bailey Network 90, uses twenty process control units divided into the following nodes: gas turbine, combustor, steam turbine, balance of plant, hot gas clean up, and safety. These units perform the control of individual plant items, and also most of the coordinating control, interlocking, and automatic function involving groups of related items.

2.5 Feedstocks

The Tidd Plant was designed to burn Pittsburgh # 8 coal, and Plum Run Dolomite. Tables 2.2 and 2.3 provide their analyses.

In addition to the design Pittsburgh #8 coal, the Tidd Plant has conducted tests using Ohio 6A and Peabody Anker coals. The Tidd Plant has also conducted tests using Plum Run Greenfield and Peebles dolomites, National Lime Carey dolomite, and National Lime Delaware limestone.

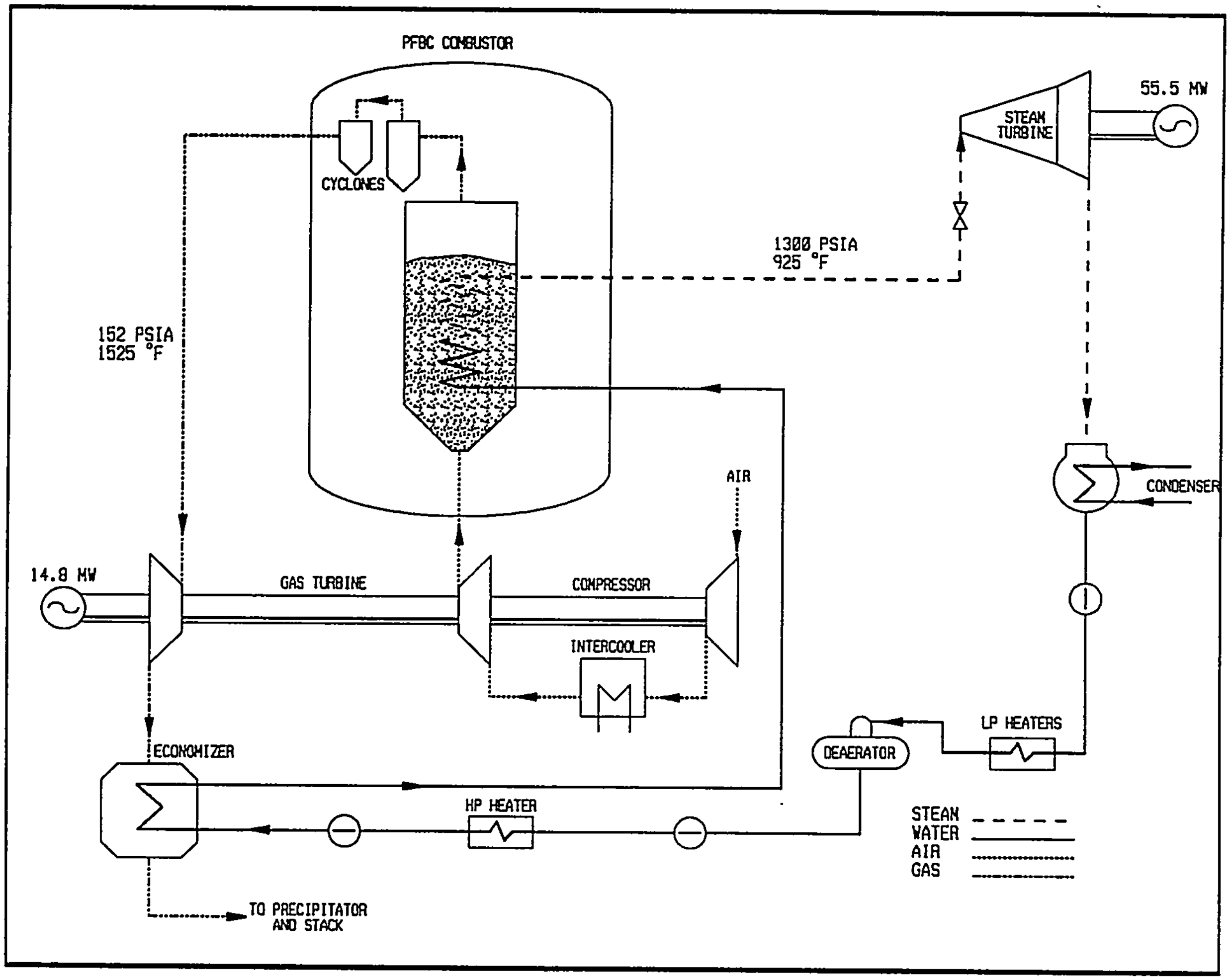
Table 2.2 - Design Coal Analysis

Design Coal Analysis (Pittsburgh #8)		
	As Received	**As Fired**
Carbon %	66.45	52.43
Hydrogen %	4.58	3.62
Nitrogen %	1.36	1.07
Oxygen %	7.45	5.88
Sulfur %	3.36	2.65
Ash %	11.85	9.35
Moisture %	4.95	25.00
BTU/#	12,223	9651

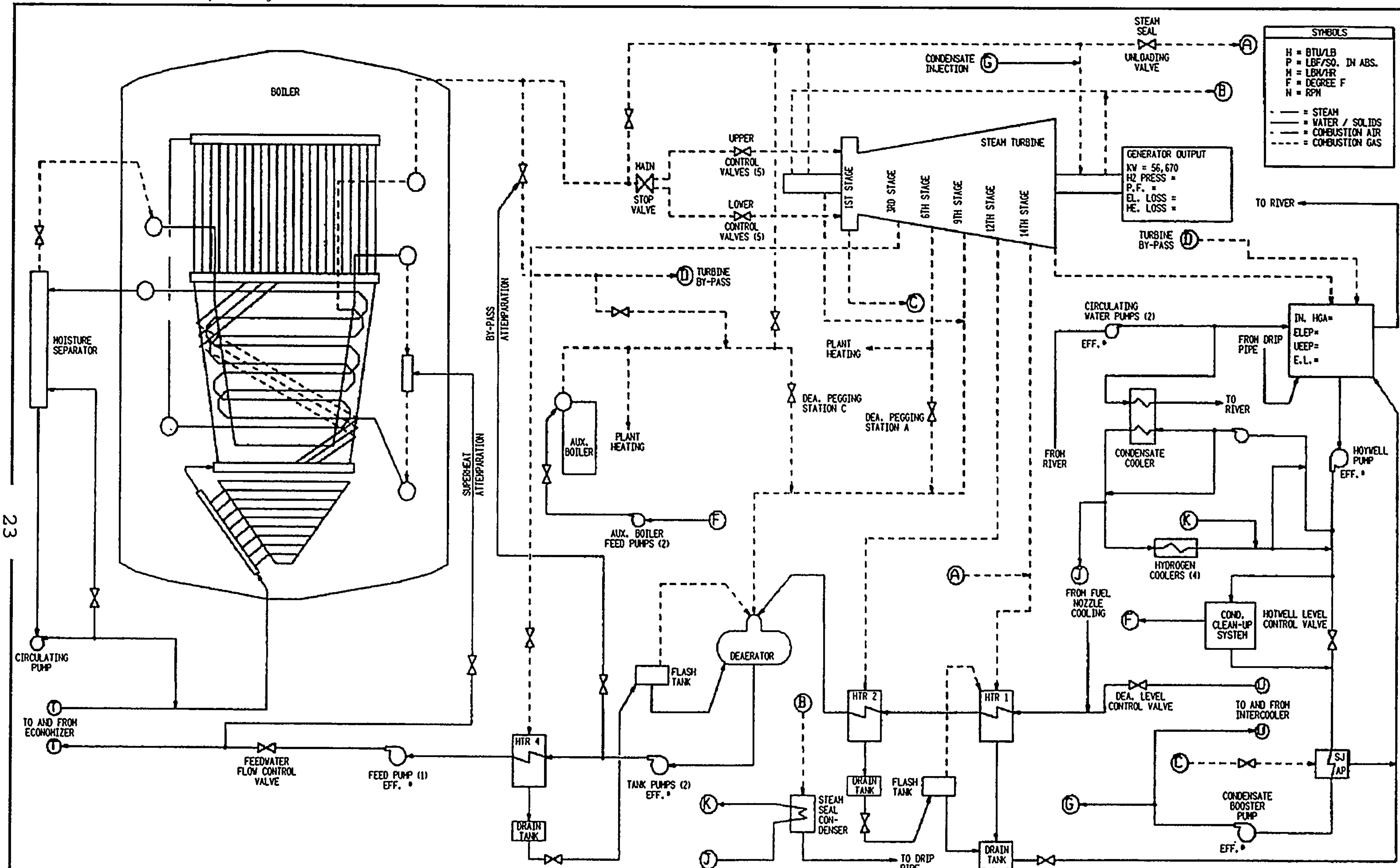
Table 2.3 - Design Sorbent Analysis

Design Sorbent Analysis (Plum Run Greenfield)	
Moisture %	0.1
Carbon Dioxide-CO_2 %	46.0
Calcium Oxide-CaO %	29.3
Magnesium Oxide-MgO %	21.0
Silicon Dioxide-SiO_2 %	2.1
Aluminum Oxide-Al_2O_3 %	0.4
Iron Oxide-Fe_2O_3 %	0.54
Sodium Oxide-Na_2O %	0.06
Potassium Oxide-K_2O %	0.05
Sulfur Trioxide-SO_3 %	0.4
Chlorine-Cl %	0.05

Figure 2.1 - Composite Cycle Diagram



/usr6/mech tdd u doe figure2.dgn



REFERENCE DATA AND NOTES

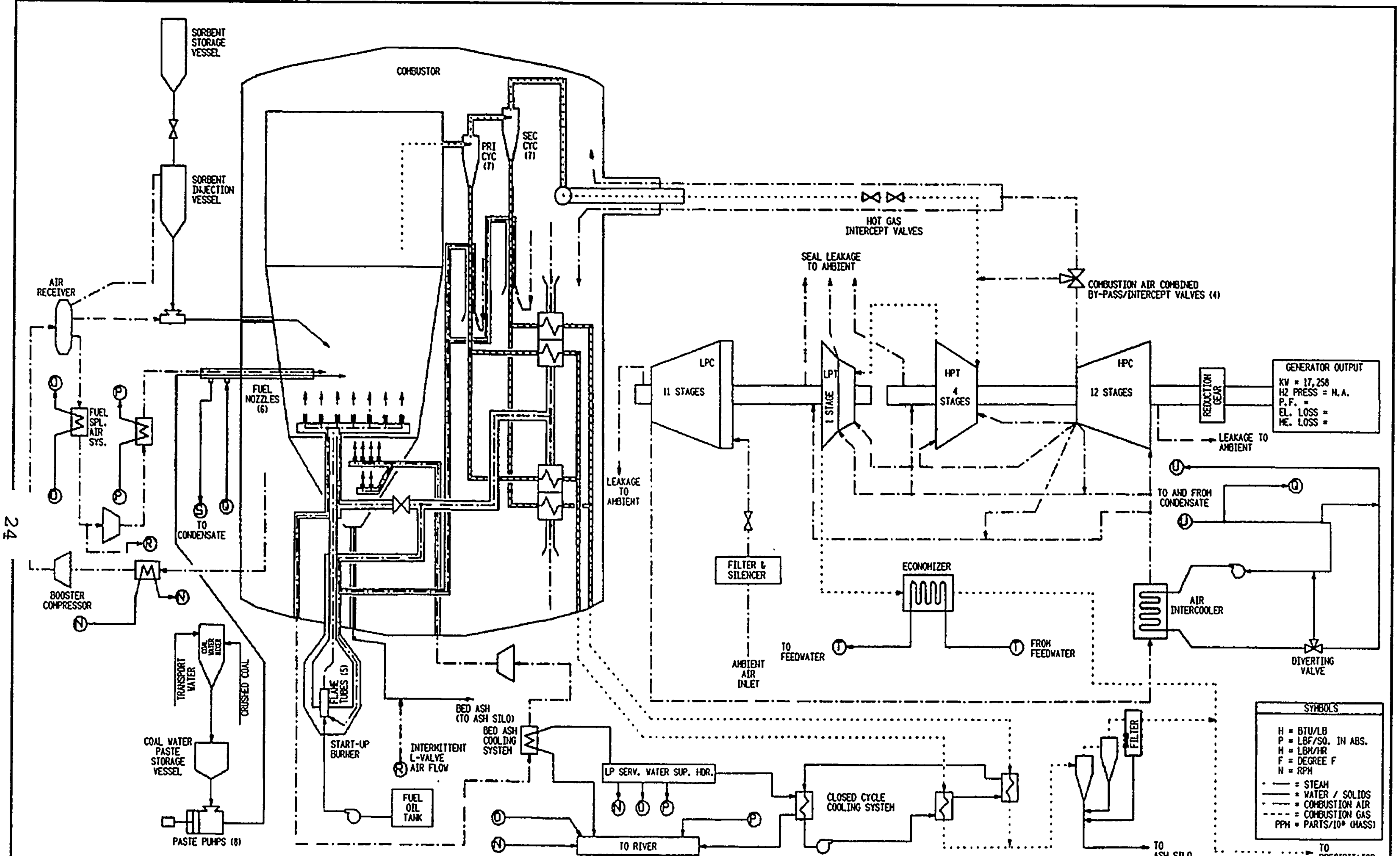
CALC. BY:

APPR. BY:

DATE: 3/29/94

STEAM SIDE HEAT BALANCE
FIGURE 2.2

usr6 mech/tidd/u doe/figure2.dgn



REFERENCE DATA AND NOTES

CALC. BY:

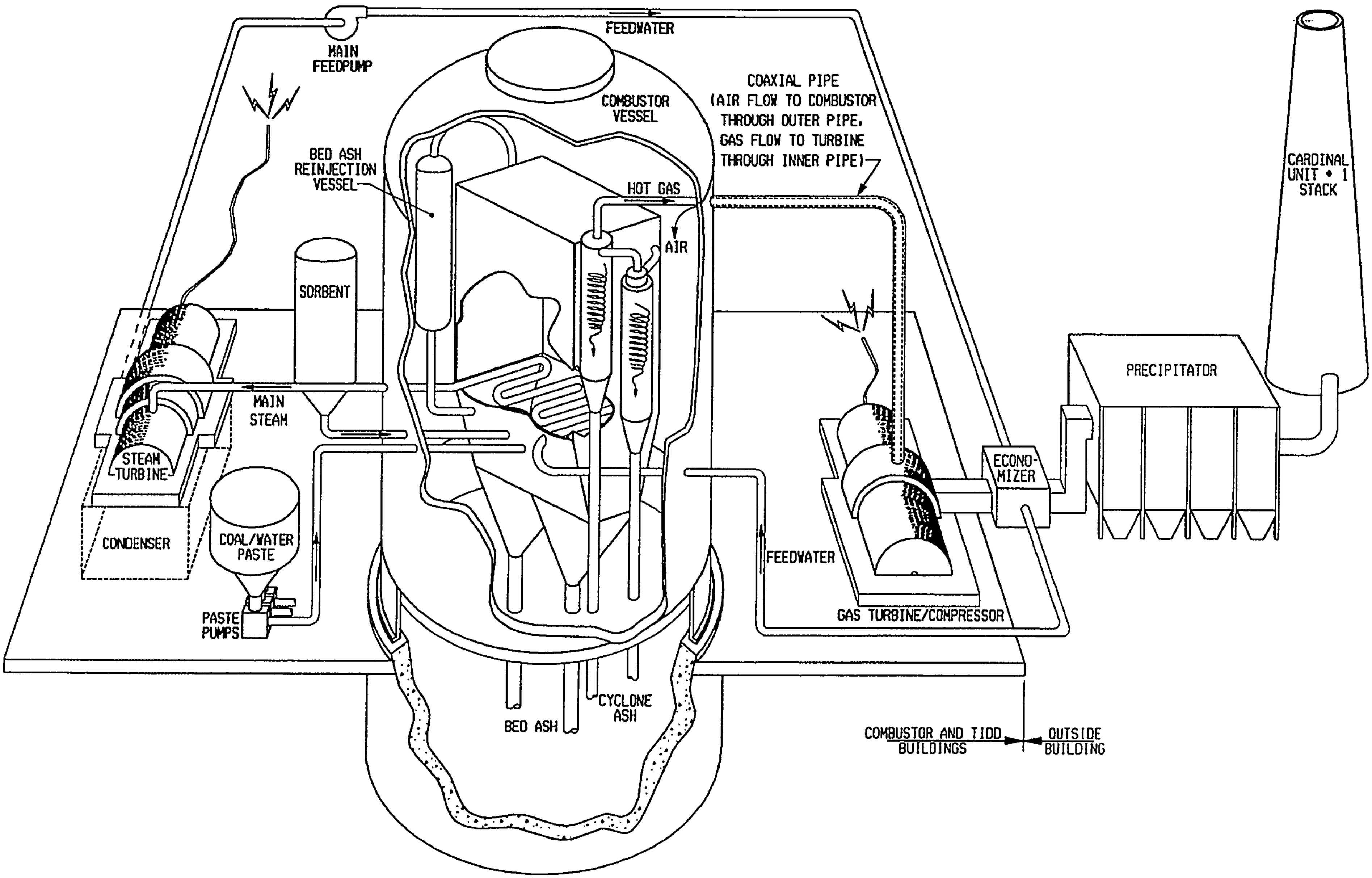
APPR. BY:

DATE: 3/29/94

GAS SIDE HEAT BALANCE

FIGURE 2.3

/usr6 mech tidd u doe/figure.shl



TIDD PFBC DEMONSTRATION PLANT

3.0 Project History and Overview

This section presents an overview of the project and its operational data. More detailed information can be found in the individualized system Section 6.0 and the appendix. Appendix I includes a short narrative of each operational run. Appendix II is a listing of each operational run including operating times, run objectives, major accomplishments, operational problems, unit shutdown reasons, and major outage work.

3.1 Project Schedules

3.1.1 Project Schedule Overview

The overall project schedule was based on a four-year engineering, design, and plant construction period followed by a three-year plant demonstration period. The actual schedule for the most part followed the original project schedule for the engineering, design, and construction of the Tidd PFBC Demonstration Plant. As with any ambitious demonstration program on an emerging technology, the actual three-year testing program was challenged by a series of technological hurdles. Each of these hurdles were met and overcome on an effective basis but did impact the detailed testing planned for the original three-year test program.

Major milestones in the program:

February 11, 1987 - Department of Energy Cooperative Agreement is effective.

April 1988 - Site construction activities begin.

November 29, 1990 - First Combined-Cycle operation is achieved.

March 1, 1991 - Three-Year Demonstration period begins.

July 1992 - PFBC Island Acceptance tests completed.

July 1992 - Longest operational run completed during first three years of operation, 740 continuous hours of coal fire.

February 1994 - End of the three-year test program.

3.1.2 Detailed Project Schedules

The schedules for construction startup, and the first three years of the demonstration period are detailed in the following:

Figure 3.1.1 - The Tidd PFBC Construction Schedule - 1986 through 1990.

Figure 3.1.2 - The Tidd PFBC Startup Schedule - 1990.

Figure 3.1.3 - The Tidd PFBC 1991 Schedule - First year of the demonstration period.

Figure 3.1.4 - The Tidd PFBC 1992 Schedule - Second year of the demonstration period.

Figure 3.1.5 - The Tidd PFBC 1993 Schedule - Third year of the demonstration period.

Figure 3.1.6 - The Tidd PFBC 1994 Schedule - The last two months of the three-year period and the start of the fourth year of the demonstration period.

3.2 Initial Plant Startup Overview

3.2.1 System Pre-Operational Summary

The initial plan for plant startup was based on a sequential pre-operation and startup of individual systems as they were released from Construction. The intent was to test each of the systems on an individual basis before they were integrated into the combined cycle operation. The pre-operational sequence was structured so that each subsequent system built on systems that were previously tested until the entire plant was operational. This process began in the spring of 1990 and was completed by December, 1990 with the integrated operation of the combined cycle.

Major milestones in the pre-operation program:

Boiler hydrostatic pressure test completed on April 4, 1990.

Motor the gas turbine via the frequency converter on June 7, 1990.

Combustor vessel released to Operations on July 9, 1990.

Paralleled gas turbine and pressurized combustor on August 6, 1990.

Fired bed preheater and achieved 1450 F in boiler windbox on August 22, 1990.

Boiler bottom modification outage from September 4, 1990 through October 9, 1990.

Chemical cleaning of the boiler and economizer on September 14-16, 1990.

Combustor and gas turbine in operation with bed material in bed first time on October 19, 1990.

The steam turbine was paralleled on October 30, 1990. Extensive bed level adjustment tests with bed reinjection system were conducted during this period.

Testing of boiler injection system with 40 inches of bed level fired by the bed preheater to 1150 F on November 4, 1990.

Initial on-line testing of the fuel injection system on November 9, 1990. Coal fire was achieved for the first time for approximately 10 hours.

Initial combined-cycle operation achieved with the gas turbine, combustor, and steam turbine all in service with a coal fire on November 29, 1990. Also on this date, the first positive generation was obtained from the gas turbine.

The remainder of the year was dedicated to further testing of the unit and achieving higher bed levels and unit load. During this period, unit operation up to 50 inches bed level was achieved. However, problems were encountered with freeboard and cyclone fires, secondary cyclone pluggage and vertical separator level control.

3.2.2 Unit Testing Accomplishments

No unit testing was conducted on the combined-cycle during the pre-operational period.

3.2.3 Modification Summary

Sister PFBC units were being commissioned by ABB Carbon in Europe in early 1990. The European units and Tidd are very similar and therefore, the lessons learned in the startup of the European units could be directly applied to the Tidd PFBC unit. One such area was with the bed ash cooling system. Preliminary testing in Europe found that the bed ash cooling system was inadequate to cool the ash to the required levels. As a result, a modification was developed, installed, and tested on the European unit. Studies by ABB Carbon indicated that a similar modification was required on the Tidd PFBC unit. Therefore, prior to the combined-cycle startup, the boiler bottom and bed ash hoppers were modified.

Key outage modifications included:

Doubling the number of ash cooling pipes.

Installation of a new cooler in bed ash removal line.

Installation of bed ash hopper boiler wall insulation.

Installation of new bed ash cooling distribution "hats".

3.2.4 Operating Statistics

Table 3.2.1 lists the key operating statistics for 1990. A more detailed listing of operating hours can be found in Appendix A-III.

Table 3.2.1 -1990 Operating Statistics - June through December 1990

1990 Operating Statistics - June through December 1990	
Number of Runs	9
Total Hours of Gas Turbine Operation	457.6 hours
Total Hours of Coal Fire Operation	60.9 hours
Unit Availability	4.1%
Gross Unit Capacity Factor @ 70 MWG	0.44%
Gross Output Factor For Year @ 70 MWG	10.72%

3.3 First Year Overview

3.3.1 Operational Summary

The operating experience from the Tidd PFBC facility has been one of gradual and constant improvement starting with the initial combined-cycle operation in November 1990. This section summarizes the first year of combined-cycle operations which includes the period from January 1991 through December 31, 1991. The start of the three-year demonstration period was March 1, 1991.

During the period from January 1991 through December 1991, the unit fired coal for a total of 795 hours, with the longest continuous run being 110 hours. During that period, the unit was plagued with numerous problems, the most significant being cyclone ash removal system plugs, fires at the cyclone gas inlets and in the ash dip legs, coal feed system plugs, economizer fouling and tube leaks, and boiler vertical separator level control problems. In addition, heat absorption of the boiler in-bed tube surface was found to be inadequate and the air distribution sparge ducts experienced excessive distortion. During this period a number of minor design revisions were incorporated that led to improved unit operability; however, a major outage was scheduled in the Fall 1991 in order to correct the major unit deficiencies.

3.3.2 Operational Details

During the first three months of 1991, the unit had a total of 15 operating runs totaling 113 hours of coal fire operation, the longest of which was 33 hours. All of these runs were impacted by poor availability and reliability of the cyclone ash removal system, specifically the secondary ash removal system. As discussed later in this report, the secondary ash removal system was plagued by frequent pluggage of the ash removal piping. During these 15 runs, minor modifications were made in an attempt to improve system operation. Eventually, by March 1991, the ash removal system had achieved the minimum reliability required to allow extended combined-cycle operations.

From April through September 1991, the unit had a total of 25 operating runs totaling 643 hours of coal fire operation, the longest of which was 110 hours. During this period, the secondary ash system operated more reliably and, thus, the emphasis of the program shifted to the planned test program. System testing during this period included the boiler injection system for a slumped bed condition, refinement of unit controls including the vertical separator level controls, steam temperature, combustion, bed level, and bed temperature controls. Problems encountered during this period included economizer tube leaks, deterioration of the primary ash removal system, volatile fires in the boiler freeboard and primary cyclones, frequent pluggage of the coal paste pumps, poor coal paste quality, insufficient boiler in-bed tube surface area, and general Network-90 control logic problems. As time progressed, it became obvious that several major modifications were needed. These included installation of additional boiler in-bed tube surface, economizer sootblowers, a freeboard mixing system to combat the volatile fire problems, and installation of new sparge duct expansion joints. What was not obvious was the deterioration of the primary ash removal system and the corrosion of the coal paste injection system. As summer progressed, problems were increasing in the primary ash removal system. Three outages were caused when a primary cyclone plugged during operation. Initially, these plugs were blamed on other system upsets. But it was later found that air inleakage due to flange leaks was a significant problem in the ash removal system. Also, corrosion was observed in the coal preparation mixer.

In mid September, during an attempt to start the unit, severe corrosion was found throughout the coal paste injection pumps. As a result, the unit was shut down to affect major modifications to a number of troublesome systems.

The unit was returned to service in early December 1991. After a series of short runs, the unit began to operate more reliably; however, run durations were still limited by operating problems. From early December through the end of the year, the unit operated for three more runs totaling 38 hours of coal fire operation. This period was basically a shakedown of the modifications completed during the fall outage.

3.3.3 Unit Testing Accomplishments

Most of 1991 was dedicated to debugging and modifying the unit to improve reliability and availability. Due to the short operating runs that were experienced during 1991, it was not possible to conduct accurate tests. In the summer of 1991, B&W conducted several tests to obtain data required for the design of additional in-bed tube surface.

Unit Performance Tests 1, 2 and 3 were also conducted during summer 1991. Test 1 was conducted at a bed level of 126 inches, Test 2 at 76 inches of bed level, and Test 3 was at 90 inches. Due to unstable operating conditions, the results of these three tests are questionable. No additional performance tests were conducted until 1992. Test results are presented in Section 4.2.

3.3.4 Modification Summary

During the first year, numerous modifications were made in an attempt to improve the operating reliability of various systems. Some of the major modifications included:

Modifications to the primary and secondary ash removal systems in order to improve the operation of the ash systems.

Installation of test sootblowers in the economizer to reduce ash fouling.

Replacement of eroded sorbent tee bends.

Repairs to the coal paste mixer due to corrosion of the mixer paddles and support arms.

Modifications to sorbent distribution piping inside the boiler bed in order to improve sorbent utilization.

Numerous modifications to sorbent injection system valves to improve their operation.

Installation of fuel nozzle skateboards to improve in bed fuel distribution.

Numerous modifications to the boiler O_2 analyzer system.

Numerous modifications to the Net-90 control system logic.

Modifications to the boiler vertical separator level instrumentation to improve level indication and control.

Installation of a gas turbine sound enclosure.

Testing of shortened dip leg on secondary cyclone #21.

Repair of vibration-induced leaks in the economizer.

Modifications and repairs to the sorbent preparation hammer mill crusher and related system components.

Addition of surface to the boiler in-bed tube bundle in order to increase the heat absorption and steaming capacity.

Replacement of the expansion joints in the air distribution sparge ducts with a revised design.

Installation of a steam induced mixing system in the boiler freeboard to provide mixing in the freeboard volatiles and fine char escaping the bed.

Modifications to the cyclone ash removal system, including a complete overhaul of the primary ash system and tee bend modifications on the secondary ash removal system and routing of the secondary transport line to the economizer outlet duct.

Installation of sootblowers and anti-vibration ties in the economizer.

Overhauling the coal preparation and coal injection system to address corrosion of the wetted surfaces in the system.

Modifying the coal injection nozzles to eliminate secondary splitting air.

Eliminating the secondary cyclone bellow boxes and cut off the cyclone dip legs.

3.3.5 Operating Statistics

Table 3.3.1 lists the key operating statistics for the first year of operations. A more detailed listing of operating statistics can be found in Appendix A-III.

Table 3.3.1 - 1991 Operating Statistics - January through December 1991

1991 Operating Statistics - January through December 1991		
Number of Runs During Year	43	
Total Hours of Gas Turbine Operation	1482.4 hours	
Total Hours of Coal Fire Operation	795.3 hours	
Unit Availability	9.66%	
Gross Unit Capacity Factor @ 70 MWG	3.61%	
Gross Output Factor For Year @ 70 MWG	37.33%	
Statistics per Operating Run	Average	Maximum
Coal Fire Hours	15.6 hours	109.7 hours
Gas Turbine Hours	29.1 hours	119.7 hours
Outage Hours Prior to Run	149.1 hours	2128 hours
Maximum Gross Unit Load Achieved	16.1 MW	53.0 MW
Gross Unit Generation	433.8 MWHr.	3473 MWHr.
Gross Unit Output Factor @ 70 MWG	17.8%	59.3%

3.4 Second Year Overview

3.4.1 Operational Summary

This section summarizes the second year of unit operation covering the period from January 1, 1992, through December 31, 1992. While a number of key problems still hampered the unit, a significant improvement in unit availability was achieved during this period. During 1992, the unit operated for a total of 2914 hours of coal fired operation; more than three times that achieved the prior year.

During the first quarter of 1992, the unit fired coal for a total of 492 hours, with most of those hours achieved in four runs of 80 hours or longer. The longest continuous run of this period was 154 hours on coal. In mid-March, problems were experienced with light-off of the bed preheater and cracks were discovered on a few of the gas turbine's low pressure turbine blade roots. A unit outage followed and lasted until late May, during which repairs were made to the gas turbine and the bed preheater. In addition, the Advanced Particle Filter (APF) bypass piping system was installed. Shortly after startup, corrosion problems were experienced in the APF piping system. A major redesign of the bypass hot gas piping was initiated to address this issue. In order to permit continued operation of the unit while the redesign and piping modification activities were underway, the gas cleaning system was configured to operate on six strings of cyclones.

Upon returning to service in early June, the unit operated continuously for 740 hours, which was the longest run of the entire three-year test period. The unit acceptance tests were conducted during that run. From late July through the end of the year the unit accomplished three additional continuous runs of 421, 285 and 101 hours, with numerous extremely short runs between them.

The most significant operating problems during the year were post-bed combustion, cyclone ash removal system plugging and coal nozzle plugging. By the end of 1992, both the post-bed combustion and secondary cyclone ash removal problems were minimized; however, coal feed system plugging was still a major cause of unit outages. In addition to these PFBC-related issues, problems with the APF system contributed significantly to the down time experienced in the latter half of the year.

3.4.2 Operational Details

From the beginning of January through the middle of March 1992, the unit had a total of 11 operating runs totaling 492 hours of coal fire operation, the longest of which was 154 hours. These runs were impacted by a number of problems including coal nozzle and pump plugging, secondary cyclone ash removal system plugging, sorbent-based tube bundle deposits, post-bed combustion induced primary cyclone dip leg fires and control logic related issues. The dip leg fire problem was resolved during this period through commissioning of the freeboard injection system (Refer to Section 5.1 of this report).

In early January a valve installed in the secondary ash removal line for system warm-up purposes was opened to lower the system backpressure in hopes of clearing a plugged ash removal line. The test was successful and led to installation of a more permanent line to accomplish this activity, termed "blowdown". Secondary cyclone ash removal "blowdown" proved to be an effective on-line means to clear most plugs that occurred in secondary ash removal lines. This provision minimized the impact of the plugging problem.

Coal feed system plugging was significant during this period. The main reason for this was a combination of insufficient fines from the crushing process combined with the need to produce drier coal paste to minimize post-bed combustion. In order for the drier paste to be pumpable, the crushing process has to produce adequate fines. With insufficient fines the paste pumpability was marginal.

The sorbent-based tube bundle deposit phenomenon (Refer to Section 5.9 of this report) was believed to be precipitated by either modifications made to feed sorbent closer to the fuel nozzles or by poor sorbent dispersion in the bed due to reduced sorbent transport system velocities. This problem manifested itself as uneven and reduced tube bundle absorption, and in one case was the cause for a manually induced unit shutdown due to the extent of the deposit. The problem disappeared after the sorbent nozzle outlets were returned to just inside the boiler front wall and the transport velocity was increased.

The last run of this period was an aborted startup due to the inability to light the bed preheater. During the outage that followed, cracks were discovered in the root area of a number of the gas turbine's low pressure turbine blades. The extended outage necessitated by this finding kept the unit out of service from mid-March through late May, which provided an opportunity to install the APF slipstream piping system in the filter bypass mode.

Upon returning to service in late May, the APF slipstream piping experienced corrosion-induced failure of an expansion joint after only 35 hours of coal-fired operation. In order to permit operation of the unit while the affected hot gas piping was redesigned and modified, the unit was configured to operate with six cyclone strings. Following a 2-1/2 week outage to accomplish this modification, the unit was returned to service and achieved a continuous coal fire run of 740 hours. During that run, which was the longest of the entire three year period, the unit acceptance tests and the associated 30-day endurance test were completed.

From the end of July through October 1, 1992, the unit remained in the six cyclone string configuration and completed eight unit runs. Seven of these runs were of very short duration. Problems experienced included excessive fuel feed at coal fire due to a setpoint error, three instances of fuel nozzle plugs that were non-cleanable with the gas turbine in service, one instance of a boiler pressure sensing line fitting leak inside the combustor vessel, and two instances of excessive sinter formation and deteriorated bed conditions when attempting to test a magnesian limestone in place of dolomite as the sorbent. The only run of significant duration during this period was a 421-hour run in August 1992, during which preliminary tests were conducted with part of the sorbent fed in with the coal paste.

During a 3-1/2 week outage in early October, the redesigned APF piping system was reconnected with flow through the APF.

From late October through the first week of December 1992, the unit ran configured with the APF in service. During this time the unit experienced four operational runs. The two longest runs of this period (101 and 285 hours) both ended due to problems with the APF system. Regarding the short runs, one was aborted during startup due to plugged primary cyclones, and another run of 76 hours ended because of coal crushing problems related to excessive moisture in the incoming coal. In the last run of this period, corrosion problems were again experienced in the APF piping system, so the unit was returned to the six cyclone string configuration while the problem was resolved.

During the last three weeks of December, three relatively short runs were experienced. Two of these runs were ended due to fuel system plugging problems. These problems were precipitated by coal crushing problems associated with a switch to Ohio No. 6A coal. The last run of the year was aborted after 49 hours of coal firing due to air inleakage in a primary cyclone dip leg bellows box, which masked the ability to determine whether that cyclone's ash removal line was functioning.

3.4.3 Unit Testing Accomplishments

Nine performance tests (Tests 4 through 12) were conducted during 1992. These included tests 6 and 7 conducted in June, which were the unit acceptance tests. They were conducted at the full 142 inches bed height, a bed temperature of 1540 F, and a sulfur retention level of approximately 90% with Pittsburgh No. 8 coal and Plum Run Greenfield dolomite.

A series of four performance tests (Test 8 through 11) were conducted in August to perform a rough evaluation of the impact of feeding sorbent with the coal paste. Temporary sorbent feed equipment was used to accomplish this task. Test 8 was a baseline with only pneumatic feed of the normally prepared -6 mesh sorbent. Tests 9 and 10 were with half and full feed of the -6 mesh sorbent with the coal paste, respectively. Test 11 was with half of the sorbent fed as fine material with the coal paste (8.2 micron surface mean diameter), while the remainder was fed pneumatically as -6 mesh material. These tests were all conducted at a bed height of approximately 115 inches, a bed temperature of 1540 F and a sulfur retention level of approximately 90% with Pittsburgh No. 8 coal. The sorbent was Plum Run Greenfield except for the fine material which was Plum Run Greenfield Peebles. These tests proved that sorbent of varying size consists could be fed with the coal paste with no significant operating difficulties. This provided a sufficient confidence level to proceed with implementation of the sorbent fines admission system, which replaced the temporary equipment for feeding sorbent with the paste.

Performance Test 12 was also notable in that it was run with Ohio No. 6A coal. It was conducted at 115 inches bed height, a bed temperature of 1540 F and a sulfur retention level of 90% with Plum Run Greenfield dolomite as the sorbent.

3.4.4 Modification Summary

With unit availability improving, the need for modifications was dramatically reduced during 1992 as compared to the previous year. However, a number of key modifications were implemented during the year that led to further improvements in operating reliability. The key modifications are as follows:

Installed permanent secondary ash removal "blowdown" piping from the system warm-up valve to atmospheric bed ash hopper.

Installed four additional economizer sootblowers to combat economizer fouling.

Made numerous modifications to the paste tank agitators, the paste tank itself, and the feed chute from the coal preparation system in attempts to improve the homogeneity of the paste between the north and south sections of the tank. The most significant improvement was attained when the paste mixer was relocated and the outlet chute was split to feed into both tank halves.

Revised the secondary ash removal line routing external to the combustor vessel and replaced all the 90-degree tee bends with long-radius elbows.

Temporarily modified the sorbent injection nozzles. This included extensions further into the vessel. Tees were later added to feed the sorbent under the center four fuel nozzles. This modification was abandoned during the first quarter due to the occurrence of sorbent-based deposits in the tube bundle.

Made numerous modifications to the coal crusher in order to improve system reliability and the ability to attain sufficient fines in the crushed coal. The modifications included a crusher inlet coal wetting nozzle, grooves in the crusher rolls and a recycle loop from the sizer back to the crusher inlet. The recycle loop provided a dramatic improvement in the ability to produce sufficient fines.

Installed blades with a modified root design in the gas turbine low pressure turbine to mitigate the cracking problem.

Installed the APF system piping, which eliminated the S21 secondary cyclone. The system was first installed with the APF bypassed, then later with the APF in the flow path. Modifications were also made to the gas collection pipe and the primary cyclone ash removal system to permit six-string cyclone operation when the APF system was down.

Installed temporary provisions to store and feed sorbent fines into the coal paste as well as temporary provisions to feed sorbent from the 200-ton prepared sorbent silo into the coal paste. Began design and procurement activities for a permanent system to store 500 tons of off-site prepared sorbent and feed it with the coal paste.

A number of material changes were tried for the fuel nozzle outlet pieces in an attempt to eliminate thermal gradient induced cracking and spalling. A high nickel super-alloy proved very successful.

3.4.5 Operating Statistics

Table 3.4.1 lists the key operating statistics for the second year of operations. A more detailed listing of operating statistics can be found in Appendix A-III.

Table 3.4.1 - 1992 Operating Statistics - January through December 1992

1992 Operating Statistics - January through December 1992		
Number of Runs During Year	29	
Total Hours of Gas Turbine Operation	2914.4 hours	
Total Hours of Coal Fire Operation	2367.1 hours	
Unit Availability	28.7%	
Gross Unit Capacity Factor @ 70 MWG	17.0%	
Gross Output Factor For Year @ 70 MWG	59.2%	
Statistics per Operating Run	Average	Maximum
Coal Fire Hours	71.7 hours	740.0 hours
Gas Turbine Hours	88.3 hours	782.3 hours
Outage Hours Prior to Run	189.2 hours	1574.2 hours
Maximum Gross Unit Load Achieved	30.7 MW	71.0 MW
Gross Unit Generation	3166 MWHr.	35395 MWHr.
Gross Unit Output Factor @ 70 MWG	26.5%	72.4%

3.5 Third Year Overview

3.5.1 Operational Summary

This section summarizes the unit operation during the last 14 months of the three-year test program covering the period from January 1, 1993 through February 28, 1994. While gas turbine related outages caused significant unit downtime in 1993, the remainder of this period saw further improvements in unit availability. During this 14-month period the unit operated on coal for a total of 2837 hours. A total of 35 unit performance tests were conducted during this period, mostly related to evaluating the baseline sorbent utilization performance as well as evaluating the performance changes associated with variations in the feed method, size, and type of sorbent.

The most significant downtime during this 14-month period was due to problems with the gas turbine. In early February 1993, it threw two low-pressure turbine blades, resulting in extensive damage to the machine. Repair activities resulted in a 20-week outage that lasted through late June of that year. This long outage afforded the ability to perform other major modifications and repairs, most notably replacement of the fluidizing air sparge ducts and implementation of a totally revised secondary cyclone ash removal system.

Operational problems were more varied and less frequent in these final 14 months, indicating that the design evolution was reaching a stage of maturity. Continuing nuisance plugging problems associated with the secondary cyclone ash removal system were completely eliminated through the system redesign implemented in the Spring of 1993. The only recurrent problem during this period was plugging of primary cyclone ash removal lines during startup. This problem resulted in three aborted unit startups that necessitated combustor entry to effect cleaning, thereby resulting in significant unit downtime. This problem was attributed to degradation of the system's leak tightness integrity, which continued to degrade during the last 14 months despite extensive routine maintenance.

3.5.2 Operational Details

The first run of 1993 was fairly long, at 273 hours, but came to a premature end due a control system communication fault. During the run, the problems experienced in late 1992, when attempting to crush Ohio No. 6A coal, continued. Insufficient crushing capacity led to bed-height limitations, at times forcing operation to bed heights of 80 inches. A switch to Pittsburgh No. 8 coal in the middle of the run confirmed that the problem was coal related, since the coal preparation system capacity limitations disappeared with the coal switch. The run immediately following was aborted during startup due to bed preheater lighting problems, and the run after that came to an abrupt end after just 20 hours on coal when the gas turbine threw two low-pressure turbine blades. Damage caused as result of this failure necessitated a major rebuild of the gas turbine's high-pressure and low-pressure turbines, as well as the high-pressure compressor. The APF system, which had been out of service since early December 1992, was returned to service during this outage.

Upon returning to service in late June, the unit underwent two planned short runs to evaluate the gas turbine's operation. This was then followed by a successful 426-hour run that came to an end due to

APF system ash removal problems. The next four unit runs were all very short due to a variety of problems. These runs consisted of an aborted startup due to a failed gas turbine vibration instrument, a 54-hour coal fire run that ended due to problems with the local controller of one of the fuel pumps, an aborted startup due to a plugged primary cyclone, and a 115-hour test run that came to a rapid end due to deteriorating bed conditions associated with sintering that occurred when the sorbent was switched from dolomite to magnesian limestone. The last run of the third quarter was a highly successful 596-hour run that ended due to an erosion induced leak that occurred in the sorbent transport piping system outside of the combustor vessel. During the outage following that run, the unit was reconfigured to the six cyclone string arrangement in order to permit resolution of an APF filter element problem that was experienced late in the run.

The last quarter of 1993 saw five operational runs, two of which were very successful, accumulating 487 and 236 hours, respectively. The longest of these ended due to deteriorating bed conditions, which were initially thought to be due to an in-bed deposit. No such deposit was found, and excessive sinter collection in the bed was later postulated as the most likely cause of the poor bed conditions. The 236-hour run ended due to a leak incurred in a temporary four-point sorbent distribution piping system, which was installed just prior to that run. The other three runs of the quarter were all aborted startups, two due to plugged primary cyclones and one due to a leaking sorbent feed system piping flange. The primary cyclone plugging problem that occurred this quarter, as well as last, were attributed to deterioration of that system's leak tightness, combined with the low-transport flows associated with the low process pressure that exist during unit startups. After the last run of this quarter, cracks were discovered in the brazing attachments of many of the gas turbine's low pressure compressor guide vanes. This resulted in a one-month outage to effect a repair. The APF system was reconnected during that outage. During the two long runs of this period, attempts were made to operate the unit at full-bed height. Repeated attempts resulted in excessive sinter formation and deteriorating bed conditions at mean bed temperatures above approximately 1500 F. This sintering occurred while using the normal Plum Run Greenfield dolomite as the sorbent. While excessive sintering had occurred periodically with dolomite, no repeatable sintering condition had been experienced up to that point when using dolomite.

During the first two months of 1994, the unit experienced four operational runs, two of which were fairly successful, accumulating 332 and 151 hours, respectively. The 332-hour run ended due to a in-bed tube leak, whereas, the 151-hour run ended due to problems with the sorbent booster compressor. Despite modifications made in an attempt to eliminate the sintering problems experienced at high load in the last quarter of 1993, such sintering continued to be experienced during these two runs and was not resolved as the three-year test program came to an end. (Refer to Section 5.2 for more information on the sintering problem) The short runs in this period were both aborted startups; one due to a non-isolatable APF system gas analyzer tubing leak, and the other due to a plugged primary cyclone. This plug was not related to system leak tightness problem, but was due to melted coal ash caused by a primary cyclone dip leg fire. Such a fire had not been experienced since early 1992, after which implementation of the freeboard mixing system mitigated the problem. The cause of this fire, which occurred despite freeboard mixing being in service, was attributed to high carbon carryover during startup due to excessively high splitting air flows.

3.5.3 Unit Testing Accomplishments

During the final 14 months of the three-year unit test program, a total of 35 unit performance tests were conducted. A large number of these tests were conducted to establish a baseline for sorbent utilization performance with two-point pneumatic feed of the normal prepared -6 mesh Plum Run Greenfield dolomite. These baseline tests included tests at varying bed heights and sulfur retention levels. Due to the inability to attain sufficient air flow in the warmer months of the year and other problems in the colder months early in 1993, no baseline tests were run at full-bed height. Most of the baseline tests were run with Pittsburgh No. 8 coal; however, three tests early in 1993 were conducted with Ohio No. 6A coal.

In addition to the baseline performance tests, a number of tests were run with various changes to evaluate their effects on sorbent utilization performance. These tests included the following variations, all of which were run with Pittsburgh No. 8 coal:

Feeding of part of the sorbent as very fine material (<10 micron surface mean diameter) with the coal paste.

Changes in sorbent supply including tests with Plum Run Peebles dolomite and National Lime Carey dolomite. An attempt to test a magnesian limestone failed for the third time due to excessive and uncontrollable bed sintering. The first two attempts occurred in 1992 and, in both situations, limestone feed was initiated early in the startup. This third attempt was conducted in order to determine whether startup conditions (i.e. the presence of sand in the start bed) played a role in the sintering with limestone. In the third try the unit was first started and stabilized on dolomite, then switched to the limestone.

Testing of improved pneumatic sorbent distribution through the installation of temporary extensions and tees on the ends of the original two sorbent feed nozzles.

Testing of improved sorbent distribution by splitting in two both of the original two sorbent feed lines inside the combustor air space. This resulted in four separate pneumatic sorbent feed points that penetrated through the boiler front wall.

The combination of four pneumatic sorbent feed points and part of the sorbent fed as very fine material with the coal paste.

In addition to the above variations, some of these tests were repeated at various bed temperatures in order to evaluate the impact of that parameter on sorbent utilization.

Test results are presented in Section 4.2.

3.5.4 Modification Summary

The following major modifications were implemented in the final 14 months of the three-year test program:

Completed installation of the Sorbent Fines Admission System, used to store off-site purchased sorbent material (usually fines) and feed it into the coal paste.

Due to extensive gas turbine damage incurred when the low pressure turbine threw two blades in February 1993, the low- and high-pressure turbines, as well as the high-pressure compressor, were extensively rebuilt. Some design modifications were incorporated during the rebuild, and they are discussed in Section 6.13.

Replaced the sparge ducts due to excessive distortion that had accumulated over time. The replacement ducts were fabricated without the end fluidization tubes, and in their place a separate active end fluidization system was installed utilizing high-pressure air supplied from the sorbent booster compressor.

The secondary ash removal system underwent a total redesign with separate lines run for each cyclone dip leg to the economizer outlet.

The unlined sorbent transport piping at the bottom of the "goal post" section of the piping was replaced with a ceramic-lined section due to an erosion-induced leak.

The ball-type sorbent transport isolation valves at the combustor were changed to a design in which the ball port matched the inner diameter of the piping. Prior to this, the ports were larger, which induced downstream turbulence and pipe erosion, resulting in a pipe leak.

Temporary extensions and tees were installed on the two sorbent feed nozzles inside the boiler in order to feed sorbent directly under the center four fuel nozzle outlet "skateboards". These were later removed after severe erosion damage was discovered in the pipes.

The sorbent injection nozzles were modified from the original two-point design to a four-point design. This entailed bifurcating the nozzles in the combustor vessel air space and adding two additional boiler front wall penetrations. The redesign resulted in a total of four feed points through the boiler front wall.

Modified the fuel nozzles to a two-stage splitting air configuration similar to the original design that was in place up until the Fall of 1991. The redesign was undertaken due to the sintering problem experienced at high load in late 1993.

In order to maintain the APF gas inlet temperature below 1400 F, a tempering air line was installed between the combustor vessel and the APF inlet hot gas pipe.

The upper stainless steel sections of the boiler startup zone insulation liner were removed along both sidewalls in an attempt to minimize ash bridging in the region. This was done to eliminate the possibility of ash buildup along the sidewalls, which may have contributed to the erosion induced tube leak experienced in the boiler side wall in January 1994.

3.5.5 Operating Statistics

Table 3.5.1 lists the key operating statistics for the third year of operations and Table 3.5.2 has the operating statistics for the first two months of 1994. A more detailed listing of operating statistics can be found in Appendix A-III.

Table 3.5.1 - 1993 Operating Statistics - January through December 1993

1993 Operating Statistics - January through December 1993		
Number of Runs During Year	16	
Total Hours of Gas Turbine Operation	2544 hours	
Total Hours of Coal Fire Operation	2310.7 hours	
Unit Availability	26.6%	
Gross Unit Capacity Factor @ 70 MWG	15.5%	
Gross Output Factor For Year @ 70 MWG	58.3%	
Statistics per Operating Run	Average	Maximum
Coal Fire Hours	144.4 hours	596.6 hours
Gas Turbine Hours	159.0 hours	615.6 hours
Outage Hours Prior to Run	363.6 hours	3385.4 hours
Maximum Gross Unit Load Achieved	34.4 MW	64 MW
Gross Unit Generation	5929 MWHr.	24586 MWHr.
Gross Unit Output Factor @ 70 MWG	35.1%	74.6%

Table 3.5.2 - 1994 Operating Statistics - January through February 1994

1994 Operating Statistics - January through February 1994		
Number of Runs During Year	4	
Total Hours of Gas Turbine Operation	586.5 hours	
Total Hours of Coal Fire Operation	525.9 hours	
Unit Availability	37.6%	
Gross Unit Capacity Factor @ 70 MWG	24.2%	
Gross Output Factor For Year @ 70 MWG	64.3%	
Statistics per Operating Run	Average	Maximum
Coal Fire Hours	131.5 hours	332.8 hours
Gas Turbine Hours	146.5 hours	344.3 hours
Outage Hours Prior to Run	200 hours	448.4 hours
Maximum Gross Unit Load Achieved	57.5 MW	61 MW
Gross Unit Generation	6001.8 MWHr.	15705 MWHr.
Gross Unit Output Factor @ 70 MWG	53%	67.3%

3.6 Operating Statistics and Graphs

3.6.1 Operating Statistics

Table 3.6.1 contains a summary of the key operating statistics for the three-year demonstration period. Table 3.6.2 contains a summary of the average and maximum operating statistics for each year. An explanation of some of the terms and calculations used in these tables are as follows:

Gas Turbine Operating Hours - Total number of operating hours on the gas turbine from the time the gas turbine is rolled by the frequency converter until the gas turbine breaker is tripped to shut the turbine down or disconnect it from the distribution grid.

Coal Fire Operating Hours - Total number of coal-fire operating hours from the time the coal injection system is ordered on by the unit operators via the control system until the time the combustor trips and also causes a trip of the coal fire.

Steam Turbine Operating Hours - Total number of steam-turbine operating hours from the time the steam turbine generator is paralleled to the time the combustor trips. For simplicity, the combustor trip time was used for the calculations. In fact, the steam turbine generator trips within minutes of a combustor trip.

Yearly Unit Availability - Total steam-turbine operating hours in a year divided by the number of hours in a year.

Yearly Gross Capacity Factor @ 70 MWG - Total gross generation from both the steam turbine and the gas turbine divided by the number of hours in a year times 70 MW. Does not deduct generation required to motor the gas turbine at startup since that power requirement is considered part of the plant's auxiliary power requirements for each run.

Yearly Gross Unit Output Factor @ 70 MWG - Total gross generation from both the steam turbine and gas turbine divided by the total steam turbine operating hours in the year times 70 MW.

A complete listing of the operating times for each run is listed in Appendix A-III.

Table 3.6.1 - Key Operating Statistics October 1990 through February 1994

Key Operating Statistics October 1990 through February 1994						
Operating Data	1990	1991	1992	1993	1994	Project Totals
Number of Runs	9	43	29	16	4	101
Gas Turbine Operating Hours	457	1482	2914	2544	586	7985
Coal Fire Operating Hours	60	795	2367	2310	525	6057
Steam Turbine Operating Hours	71	846	2523	2327	533	6301
Yearly Unit Availability	4.1%	9.6%	28.7%	26.6%	37.6%	21.4%
Yearly Gross Capacity Factor @ 70 MWG	0.4%	3.6%	17%	15.5%	24.2%	11.9%
Yearly Gross Unit Output Factor @ 70 MWG	10.7%	37.3%	59.2%	58.2%	64.3%	55.8%
Yearly Maximum Gross Unit Load Achieved	N/A	53 MW	71 MW	64 MW	61 MW	N/A
Outage Hours	1674	7913	6261	6433	883	23163
Gross Unit Generation MWHr.	537	22123	104508	94866	24007	246041
Hours in the Period	1745	8760	8784	8760	1416	29465

Table 3.6.2 - Avg. and Max. Run Operating Stats Oct. 1990 through Feb. 1994

Average and Maximum Run Operating Statistics October 1990 through February 1994					
Average and Maximum Run Data	1990	1991	1992	1993	1994
Average Gas Turbine Operating Hours	21.8 Hrs	29.1 Hrs.	88.3 Hrs.	159 Hrs.	146 Hrs.
Average Steam Turbine Operating Hours	5.1 Hrs.	16.6 Hrs.	76.5 Hrs.	145 Hrs.	133 Hrs.
Average Coal Fire Operating Hours	4.3 Hrs.	15.6 Hrs.	71.7 Hrs.	144 Hrs.	131 Hrs.
Maximum Coal Fire Operating Hours	14.7 Hrs.	110 Hrs.	740 Hrs.	597 Hrs.	332 Hrs.
Average Outage Time Between Runs	100 Hrs.	149 Hrs.	189 Hrs. See Note 1	363 Hrs See Note 2	200 Hrs.
Average Gross Unit Output Factor @ 70 MWG	5.5%	17.8%	26.5%	35.1%	53%

Table Note 1 - Average Outage Hours in 1992 would have been 141 hours if the 1574-hour gas turbine overhaul outage is not included in the average.
Table Note 2 - Average Outage Hours in 1993 would have been 152 hours if the 3385-hour gas turbine overhaul outage is not included in the average.

3.6.2 Operating Statistical Graphs

The following graphs present key operating data in columnar form on a yearly basis for 1990 through 1994:

Figure 3.6.1 - Yearly and Project Unit Availability Factors

3.7 Economic Evaluation Report

3.7.1 Tidd Plant Costs

The estimated cost of the Tidd PFBC Demonstration Plant, as awarded in the Cooperative Agreement was $167,500,000. Of this amount, DOE provided $60,200,222 (35.9%) in cost sharing. In addition, the State of Ohio, through the Ohio Coal Development Office provided $10,000,000. The balance was funded by Ohio Power Company. Cost growths associated with Phases I and II of $9,929,339 were incurred. Cost sharing associated with that cost growth was applied to the continued operation of Tidd for another year beyond the original three years.

3.7.2 Commercial PFBC Plant Capital Costs

Commercial Plant Capital Costs

The focal point of the Tidd PFBC Demonstration Program has been to develop the technology for scale up to a commercial-size power plant of greater than 300 MW_e. For the AEP system and other U.S. power systems as well, the commercial prospects for the PFBC technology lie in the larger sized PFBC unit, based around ABB Carbon's P800 combustor and the GT-140P gas turbine. In a Greenfield application, a P800 PFBC facility is expected to provide a net unit output under spring ambient temperature conditions of approximately 380 MW_e. The full-load net unit heat rates are expected to be 8720 Btu/kwhr for a subcritical plant and 8527 Btu/kwhr for a supercritical plant. In both cases the GT-140P gas turbine generator accounts for approximately 70 MW_e of the output.

NOTE: These unit ouput numbers are higher than the nominal 350 MW_e P800 unit output figure that has been identified in the past. The reason for this increase is a change in the philosophy for sizing of the boiler with respect to the GT-140P's seasonal air flow capacity variations. In the past, a smaller boiler was employed such that full load firing of the unit would be possible at ambient temperatures up to 85 F. Thus the design would not take advantage of the higher air flow capacity of the GT-140P gas turbine at lower ambient temperatures. The latest thinking is to size the boiler larger to fire a higher full load heat input based upon the air flow capacity of the GT-140P at an ambient temperature of 65 F. In this manner, at ambient temperatures below 85 F the unit output is greater than with the 85 F boiler design due to higher steam flow and consequently higher steam turbine generator output. The maximum firing rate is then attained at 65 F and remains nearly constant as temperature falls below that value. At ambient temperatures above 65 F, the maximum firing capability of the unit with a 65 F design boiler gradually decreases to where at 85 F it attains the same value as for the 85 F design boiler. From an operating perspective, this means that at temperatures above 65 F the unit will not be able to operate at full bed height with full bed temperature. A reduction in either will be needed.

AEP has investigated possible repowering applications on the AEP system using the P800 PFBC Island. The most extensive cost-estimating effort involved repowering of a 400 MW_e Net supercritical unit. With a 65 F design boiler, this investigation identified that the repowered unit would provide a net output of 370 MW_e under spring conditions. With 70 MW_e coming from the GT-140P gas turbine, the steam turbine would be operating at approximately 75% of original capacity. The full-load net unit heat rate was calculated at 8874 Btu/kwhr under spring conditions. The overnight capital cost for this repowering, which included a significant amount of balance of plant work, was estimated to be $365 million dollars (1994 $).

AEP has not done any cost estimate work recently for a Greenfield P800 PFBC facility. However, ABB Carbon has done recent estimating work on this with another U.S. utility. That effort resulted in an estimate of $436 million (1994 $) as the overnight capital cost for a Greenfield P800 PFBC facility integrated with a subcritical steam cycle.

The capital costs in both the Greenfield and repowering estimates noted above reflect costs for a first-of-a-kind commercial P800 PFBC island. As with any new technology, there will be a learning curve that should eventually result in significant reduction in capital costs as the technology matures.

Commercial Plant Construction

The latest estimate for construction of a P800 based PFBC facilty is between 42 and 48 months.

Commercial Plant Operation and Maintenance Costs

As part of the repowering evaluation noted above, an estimate was made for the yearly operation and maintenance costs of such a facility. The operation costs were developed, based on the experience from the Tidd PFBC Demonstration plant. The maintenance cost estimate was developed by combining a Tidd-experience-based estimate for the PFBC island components with an AEP-system-based estimate for the balance of plant componnets. The yearly operation and maintenance costs (in 1994 $) for a 370 MW_e net output unit repowered with PFBC are as follows:

Operation	$ 4.4 Million/yr
Maintenance	$ 9.5 Million/yr

The costs noted in the above table include all fixed and variable operation costs except for the cost of raw sorbent and coal, and the cost of ash disposal. The maintenance costs reflect all fixed and variable maintenance costs for the repowered PFBC facility except for the major periodic gas turbine and boiler refurbishment costs. These periodic costs along with their expected frequency are noted in the following table:

Major Maintenance Item	Frequency	Cost (1994 $)
Refurbish GT Turbine Blading	Every three years	$1.5 Million
Refurbish GT Compressor Blading	Every twelve years	$1.5 Million
Replace boiler tube bundle	Every ten years	$15.0 Million

3.8 PFBC Technology Assessment

The Tidd PFBC Demonstration Plant accumulated 6057 hours of coal-fired operation during its first three years of service. The achievements during that period were significant in advancing PFBC technology. The unit met or exceeded all of its guarantee conditions except gas turbine output. Sulfur retention of 90% at a guaranteed Ca/S molar ratio of less than 2.0 was demonstrated. Sulfur retention of 95% was also achieved. Process NOx emissions were lower than the guaranteed 0.5 lbm per million BTU. Overall process performance clearly showed that PFBC was capable of meeting current and future environmental standards for base load, coal-fired power generation.

The Tidd PFBC Demonstration plant successfully demonstrated the viability of PFBC technology. Process performance was shown to control sulfur emissions to existing standards while achieving Ca/S molar ratios which were established to be economically feasible. Continued testing and process optimization aimed at enhancing sulfur capture and reducing the Ca/S ratio is planned for the fourth year of testing. Operation to date has clearly demonstrated that significant process improvements are achievable. The goal of 90% sulfur retention at a Ca/S of 1.6 is clearly within the process capability and is expected to be demonstrated and surpassed.

NOx emissions have been well below anticipated levels. The Tidd plant typically emits 0.3 lbm of NOx per million BTU. No extraordinary measures were taken to reduce NOx. The demonstration at Tidd coupled with experience at other PFBC units has clearly shown that NOx emissions levels of less than 0.1 lbm per million BTU are obtainable with minor system enhancements.

The first three years of operation have confirmed the expectations of PFBC technology and have clearly defined avenues for further testing in the fourth year. In addition, PFBC systems have been tested, modified, and refined to the point where the design and construction of a base-load commercial size unit is now feasible. Future testing is expected to strengthen the basis for commercial deployment of this technology by demonstrating significant improvements in environmental performance and by confirming further the survivability of the gas turbine and "in-bed" tube bundle.

3.9 Environmental Monitoring Plan Overview

In support of the PFBC project and in conjunction with the Cooperative Agreement with DOE, an Environmental Monitoring Plan (EMP) was written and implemented. The purpose of the EMP is to produce an environmental, health, and safety data base relative to operation of the Tidd PFBC Demonstration Plant and for application to future replication of the PFBC technology.

The EMP consists of compliance monitoring and supplemental monitoring. Compliance monitoring is that monitoring required by permits and regulations. Supplemental monitoring covers other sources and parameters not required under compliance monitoring. The environmental monitoring is performed on a quarterly basis. Quarterly reports, detailing results of the environmental monitoring, are forwarded to DOE within 60 days of the quarter's end. An annual report, summarizing the four quarters of environmental monitoring during the previous year, is submitted to DOE by the end of March of the following year. The annual report also covers the previous year's health and safety monitoring, which is reported only on an annual basis.

Environmental monitoring consists of sampling and analyzing wastewater, solid waste, and air-related wastestreams. Sources for wastewater sampling include the condenser pit sump, combustor building sump, wastewater collection sump, the PFBC ash disposal area groundwater monitoring wells, coal pile runoff, dolomite pile runoff, once-through cooling water discharge, and, for background information, the Ohio River intake water. For solid waste, the PFBC bed ash, PFBC fly ash, and any chemical metal cleaning wastes are sampled and analyzed. Also for supplemental information, the coal and sorbent are analyzed. Air-related wastestreams that are sampled include the flue gas from the PFBC combustor and the gas turbine exhaust gas. Other miscellaneous wastestreams are sampled as the need arises.

Health and safety monitoring consists of three components - industrial hygiene, medical surveillance, and safety. Airborne contaminants are analyzed for exposure assessments, medical surveillance of employees is conducted through physicals, and safety training is performed regularly.

EMP reports on the operations phase of the PFBC project have been filed with DOE, beginning with the first quarter of 1991 and continuing through the present. Details on the wastestreams and parameters analyzed and the results of monitoring are contained in the EMP reports.

Figure 3.1.1 Tidd PFBC Construction Schedule

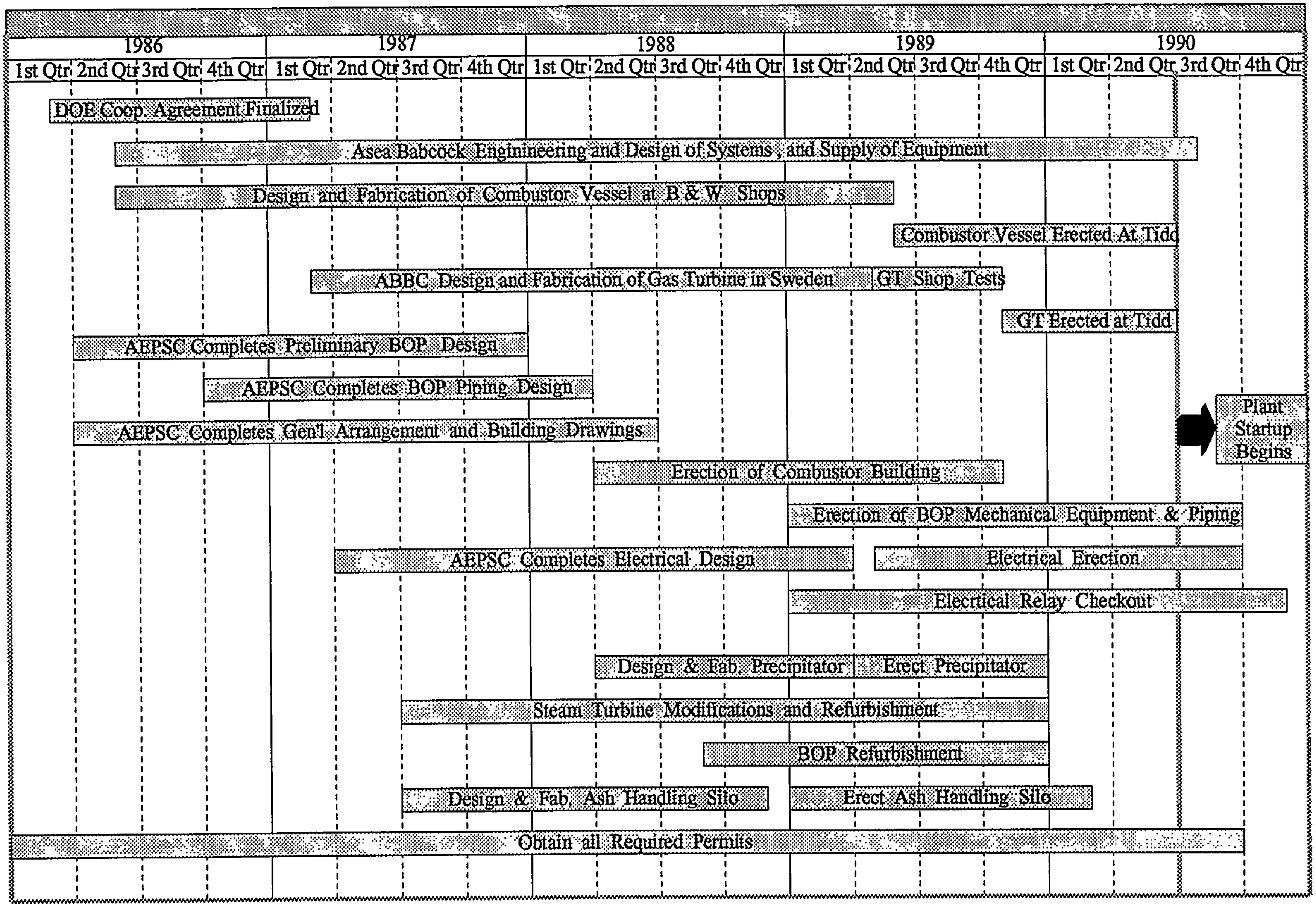


Figure 3.1.2 Tidd PFBC Startup Schedule

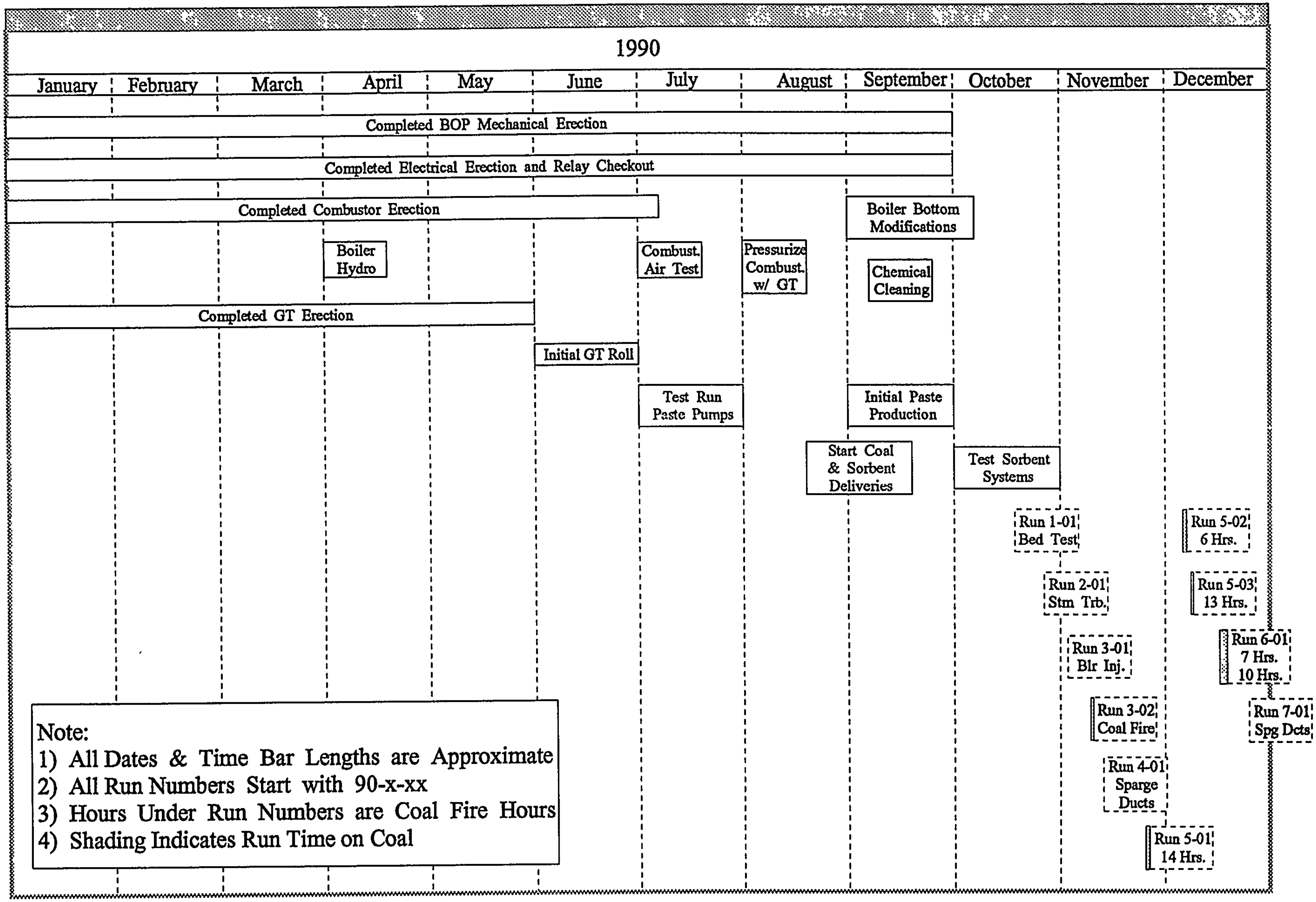


Figure 3.1.3 **Tidd PFBC 1991 Schedule**

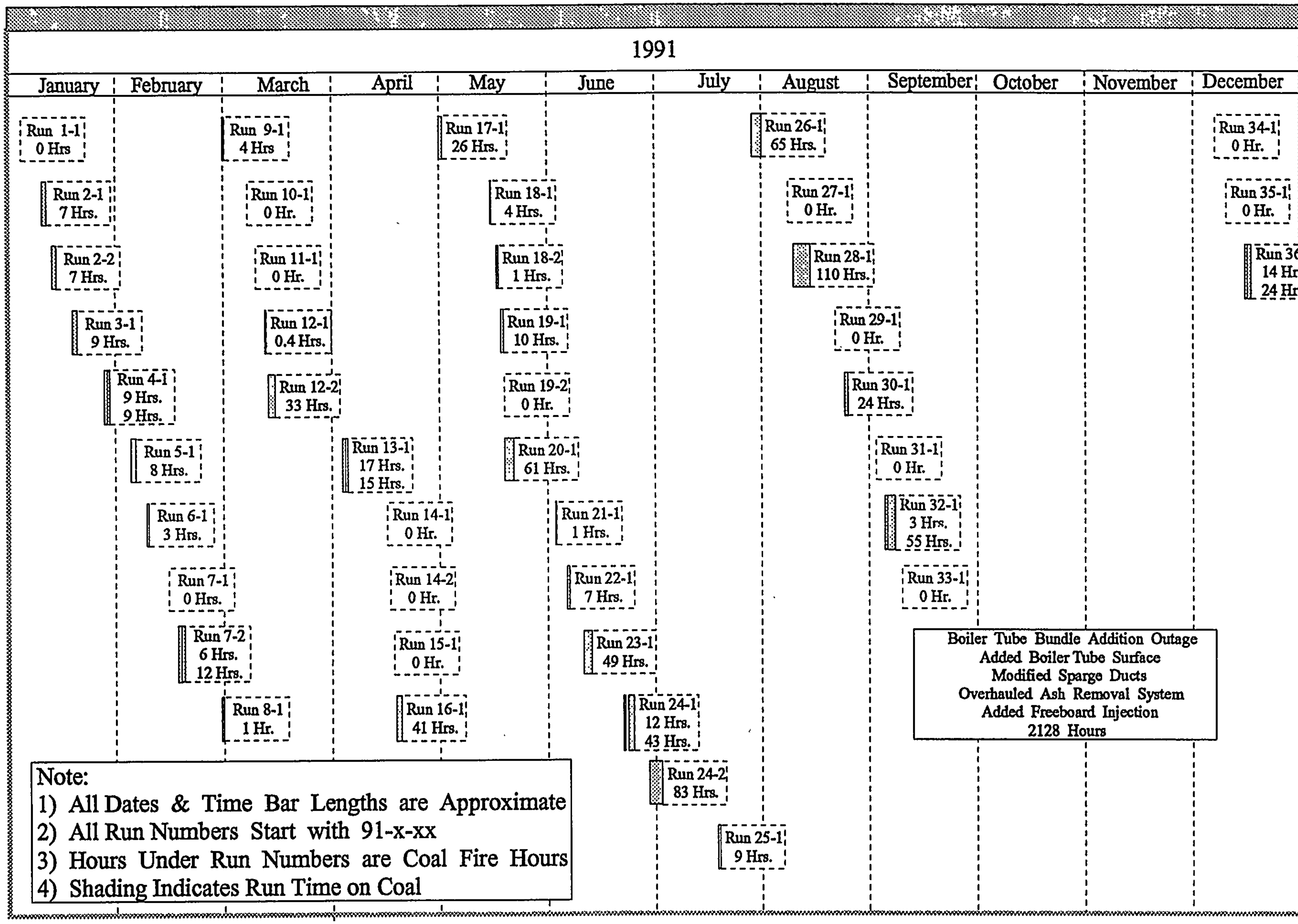


Figure 3.1.4

Tidd PFBC 1992 Schedule

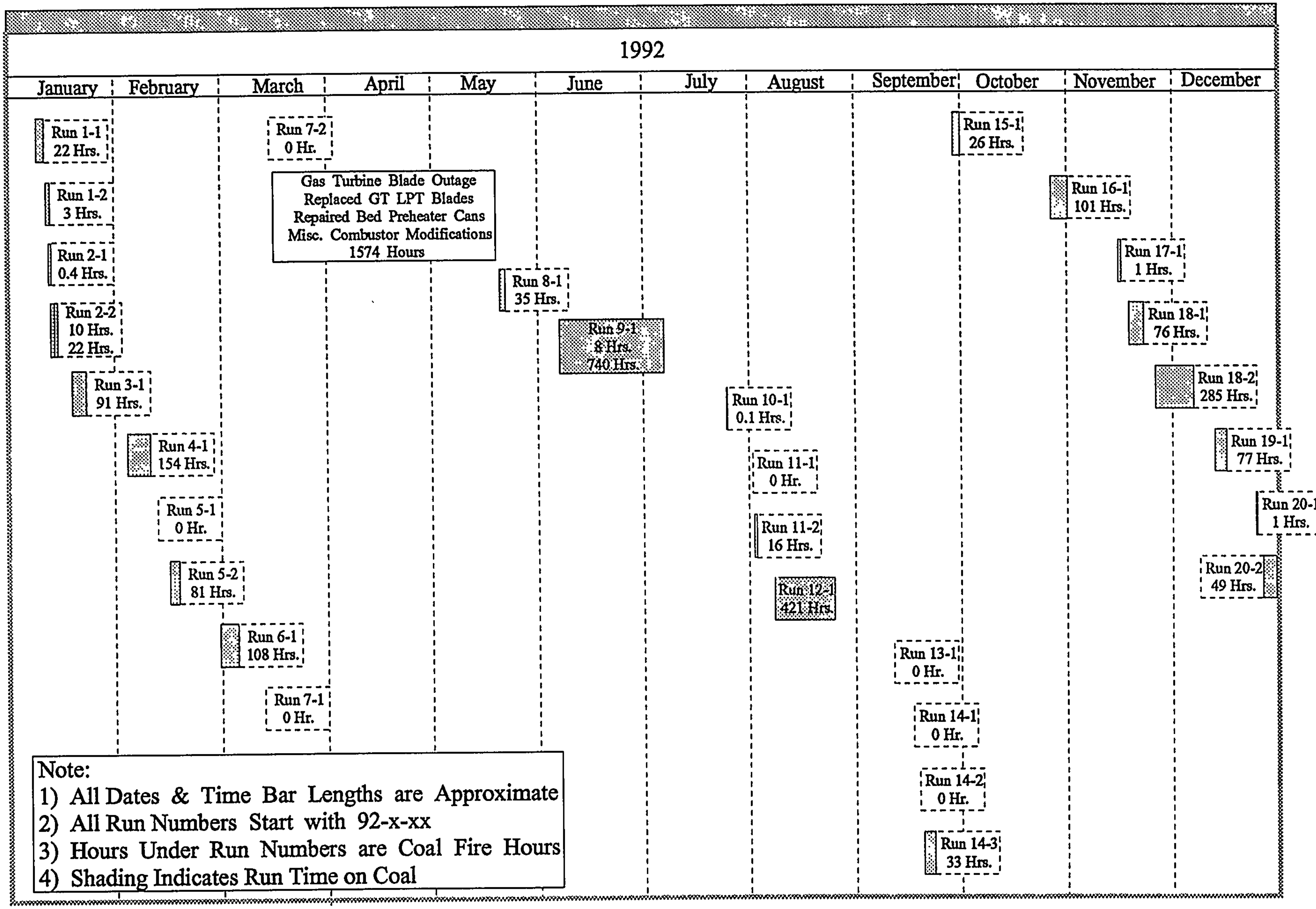


Figure 3.1.5 Tidd PFBC 1993 Schedule

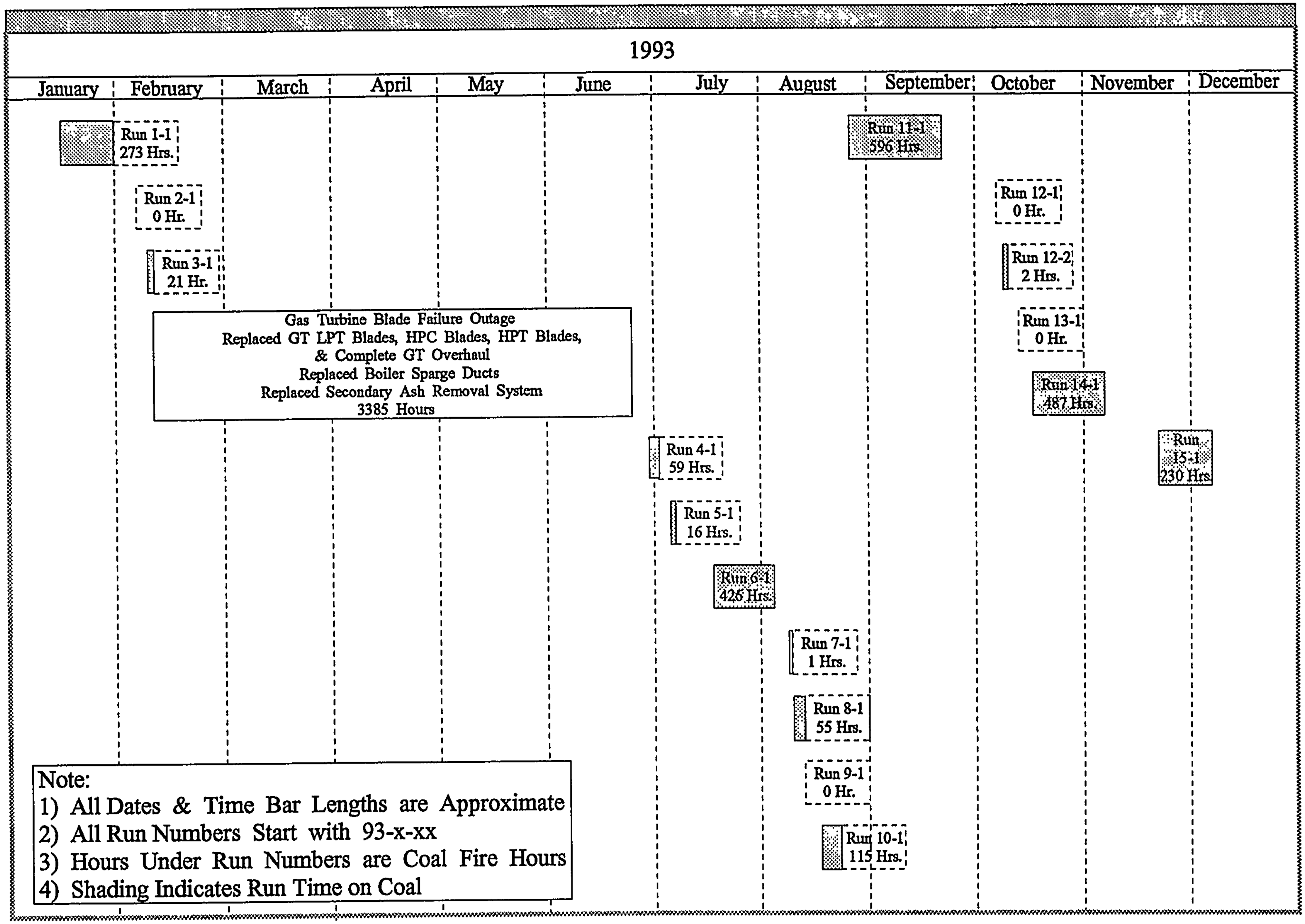


Figure 3.1.6 **Tidd PFBC 1994 Schedule**

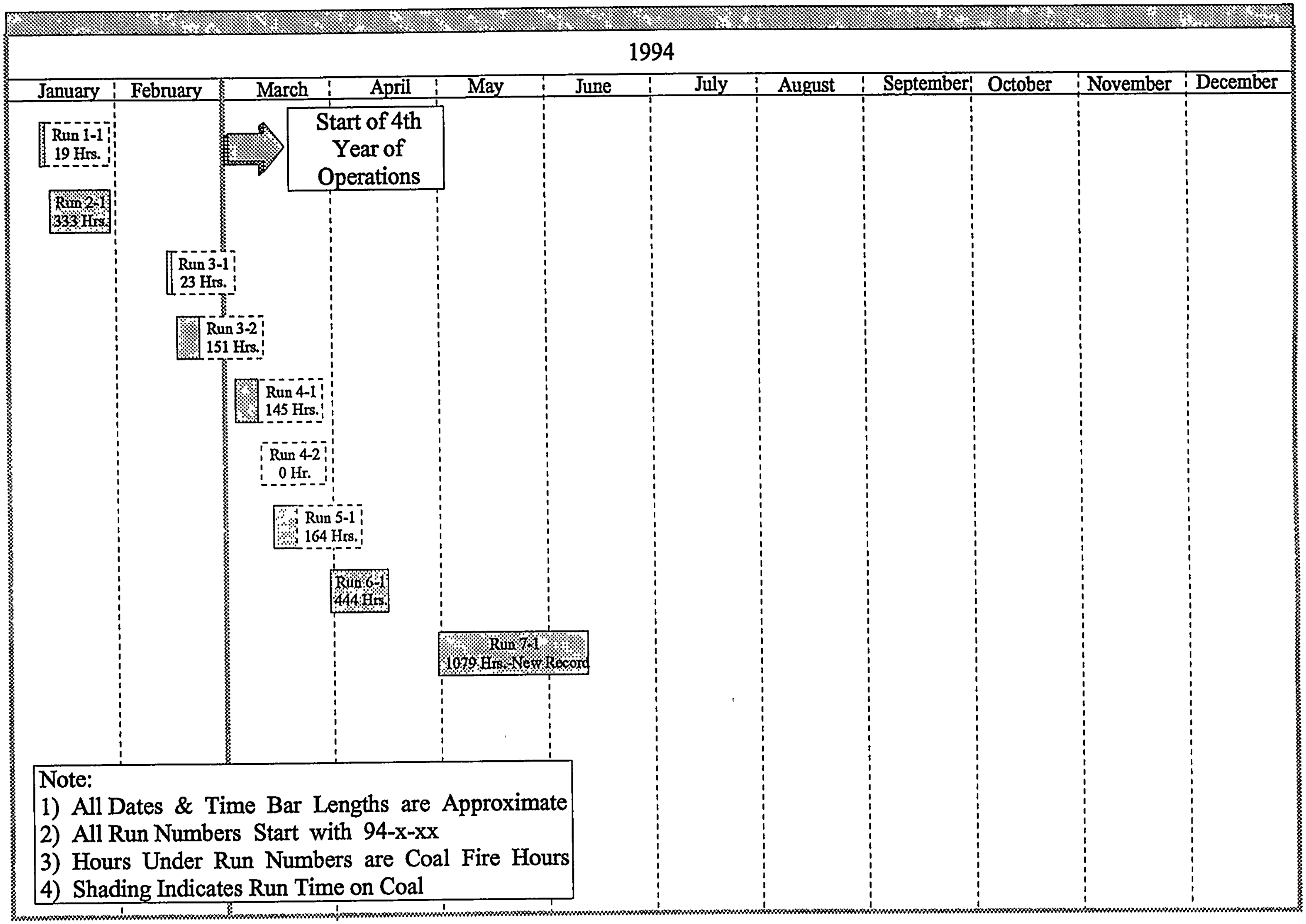
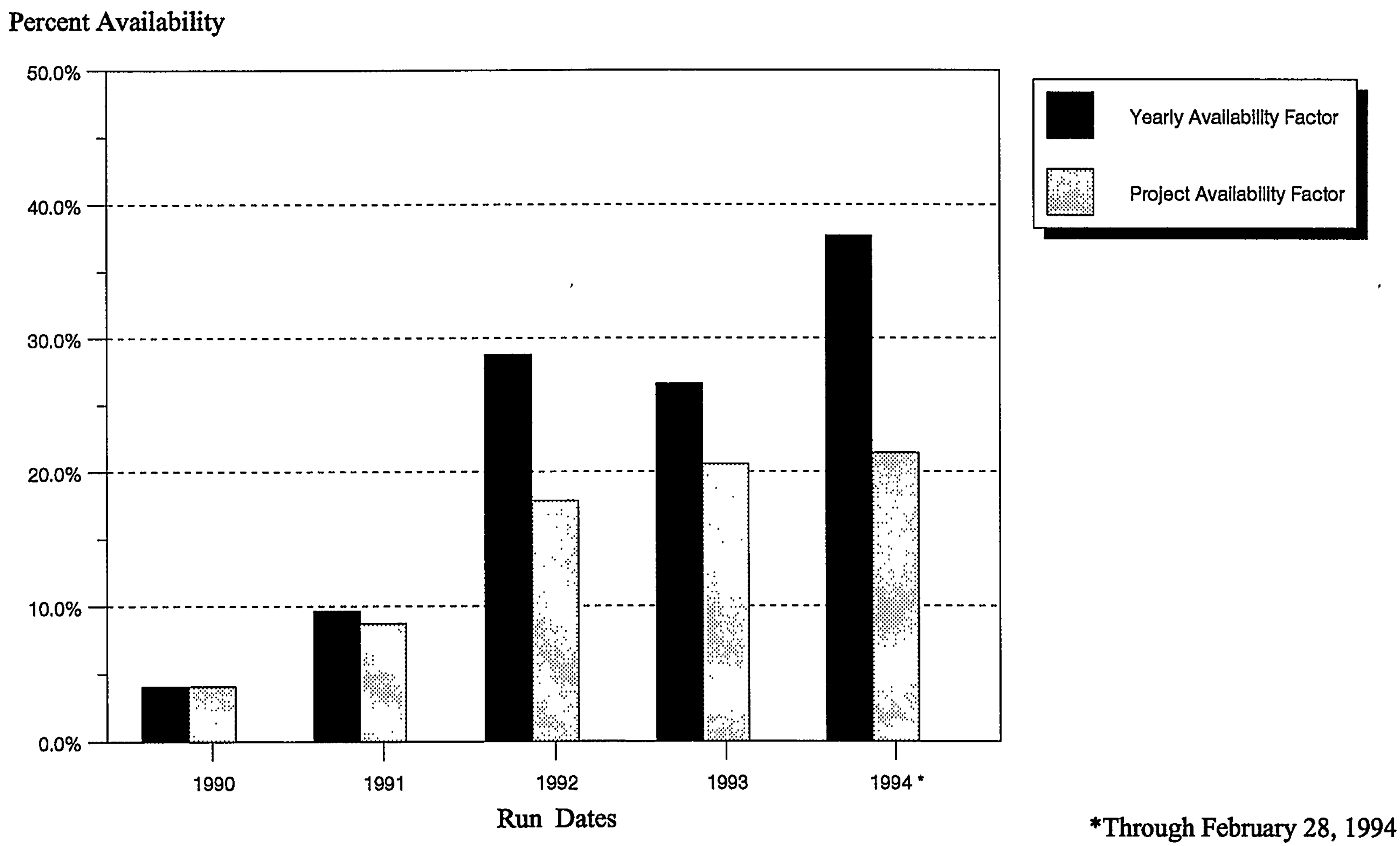
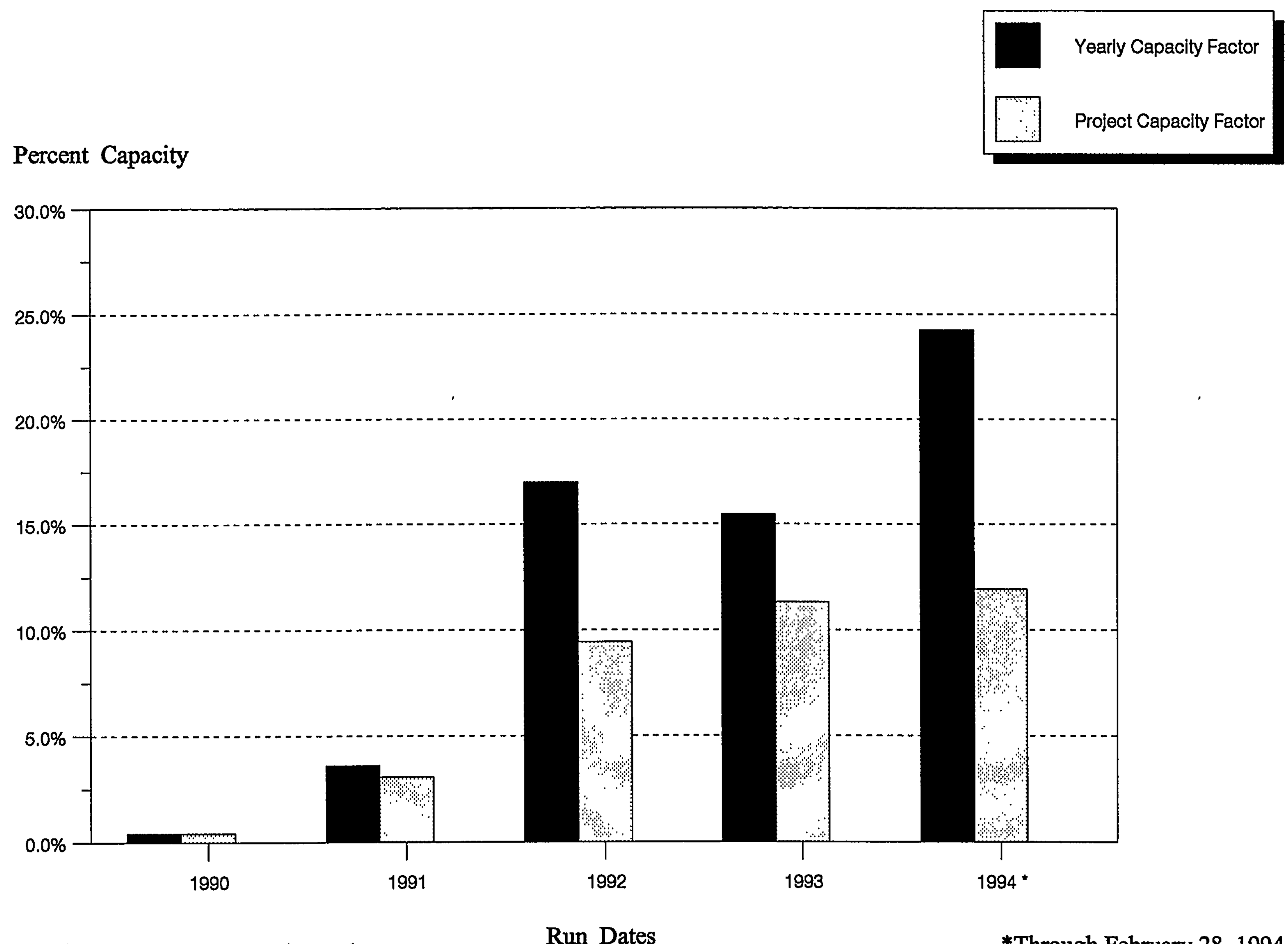


Figure 3.6.1 Yearly and Project Availability Factors



*Through February 28, 1994

Figure 3.6.2 Yearly and Project Capacity Factors



Based on 70 MW Gross Unit Load

*Through February 28, 1994

Figure 3.6.3 Yearly and Project Gross Output Factors

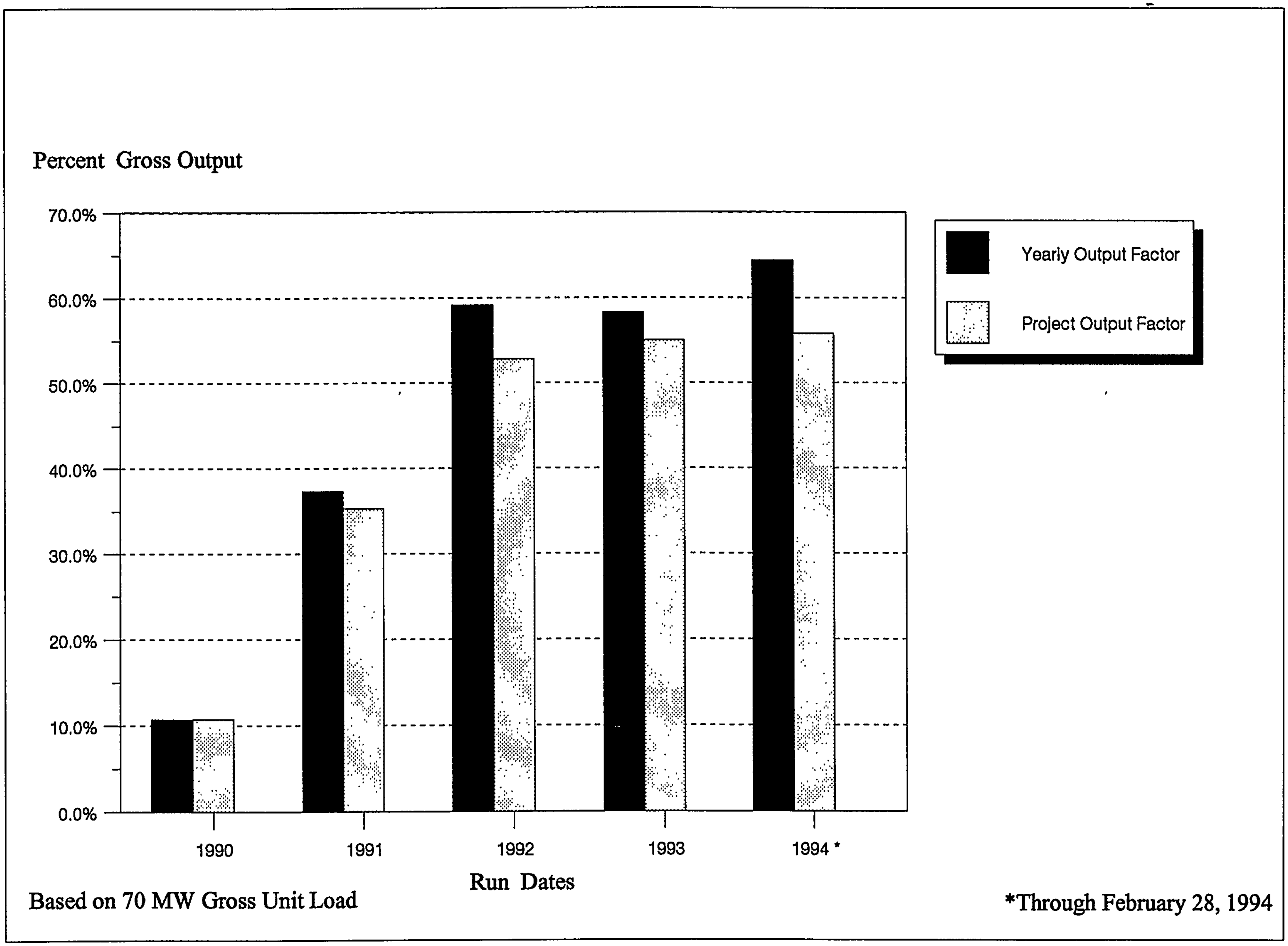
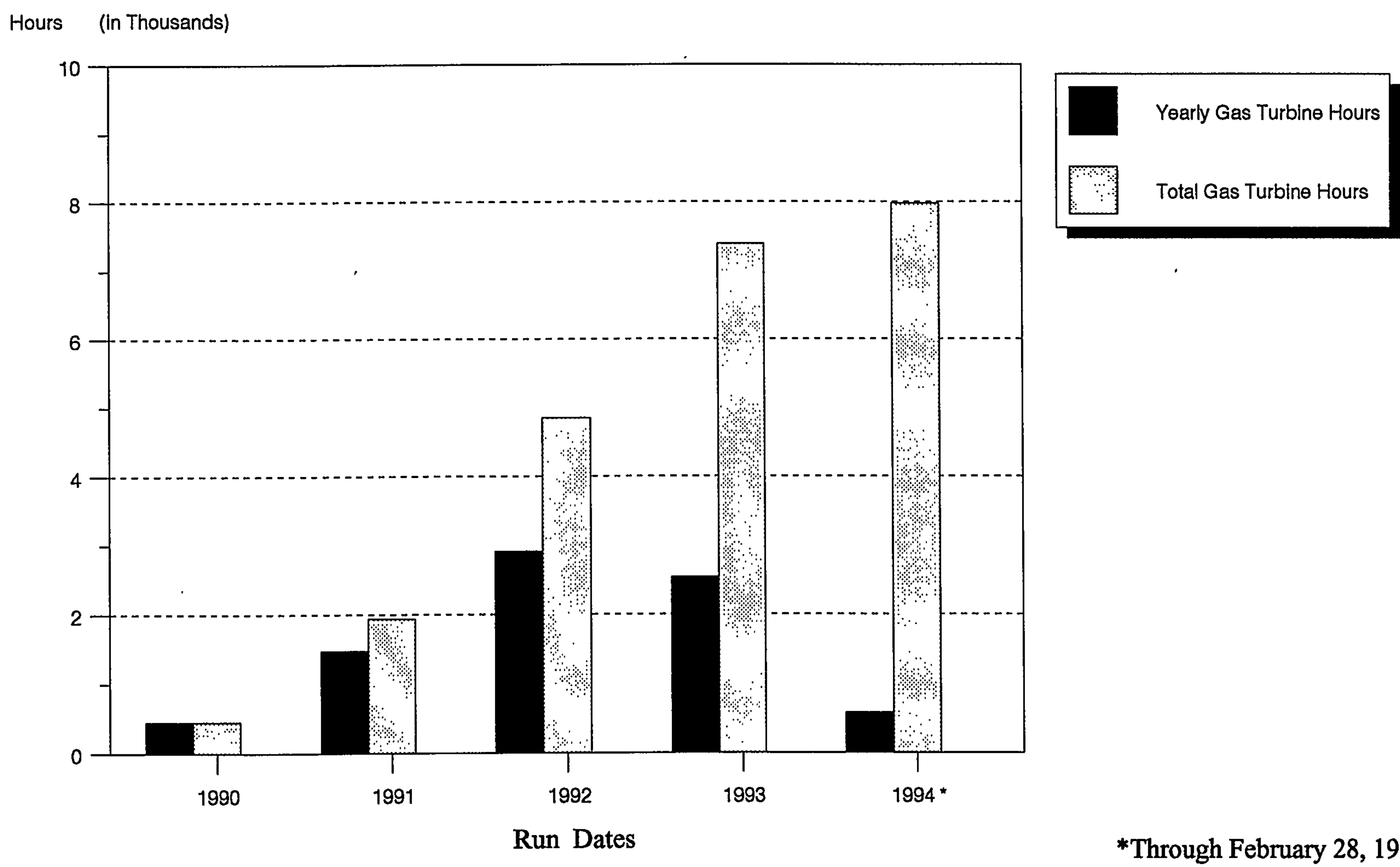


Figure 3.6.4 Yearly and Project Gas Turbine Operating Hours



*Through February 28, 1994

Figure 3.6.5 Yearly and Project Coal Fire Operating Hours

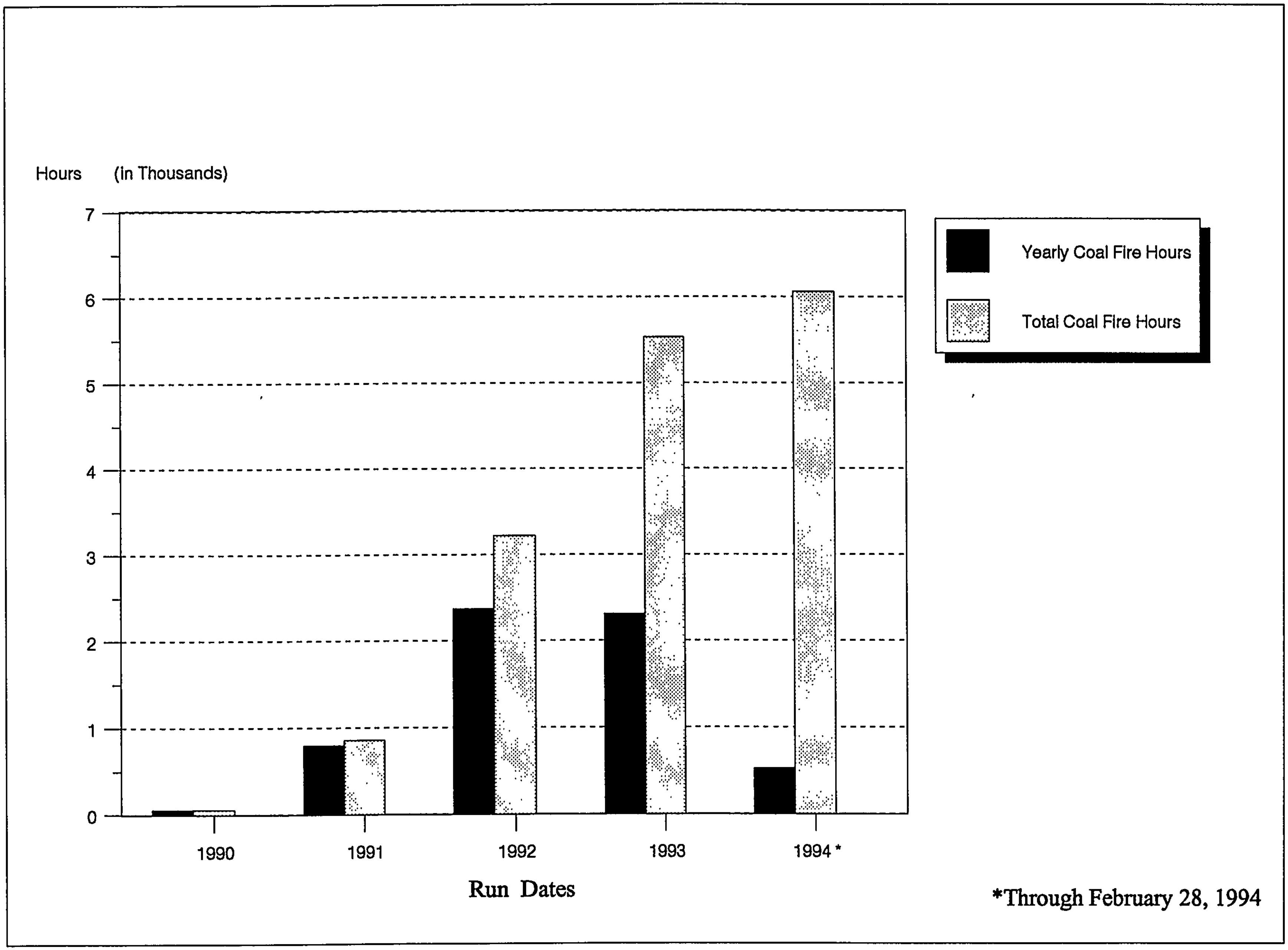
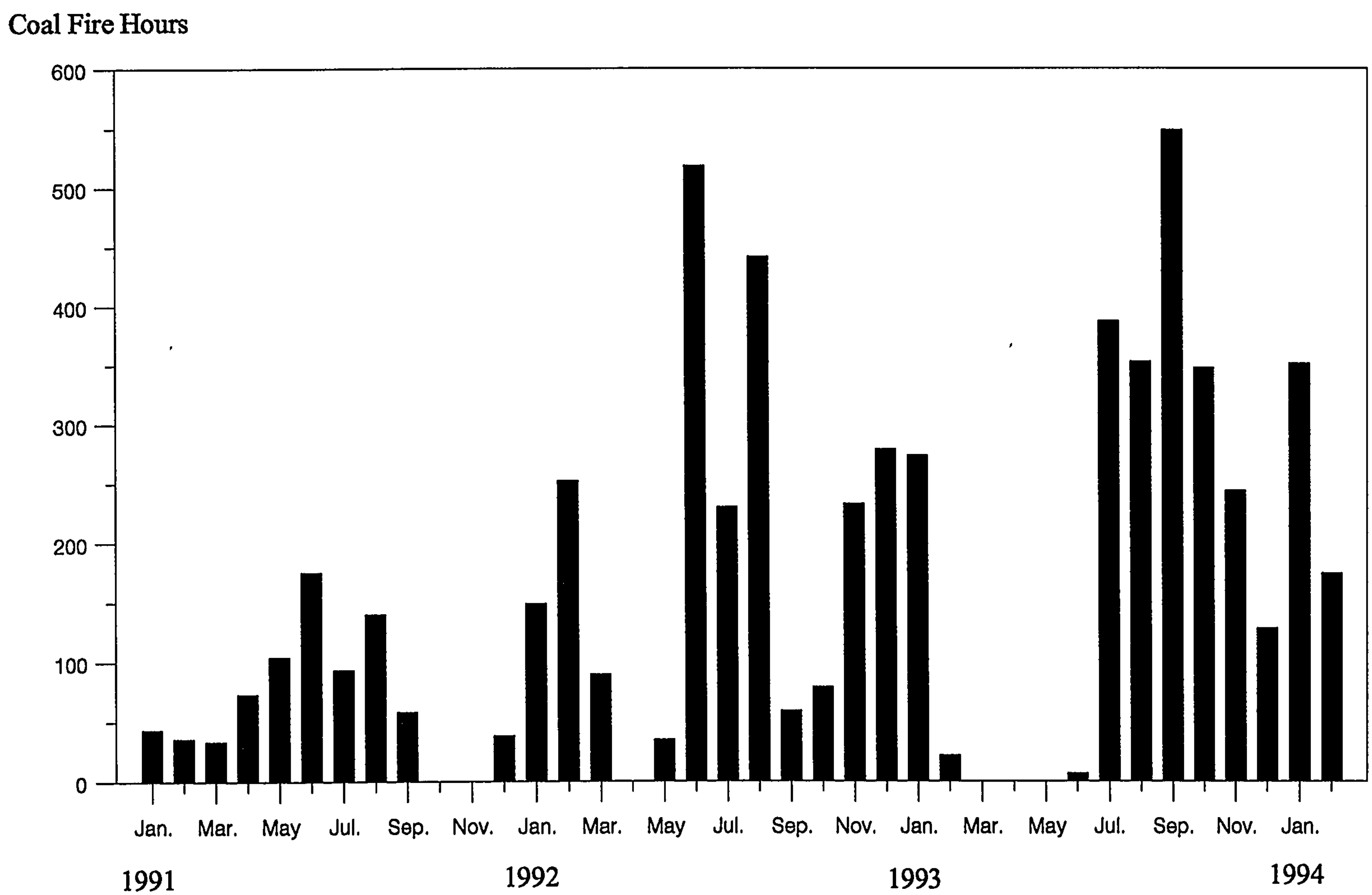


Figure 3.6.6

Coal Fire Hours on a Monthly Basis



*Through February 28, 1994

4.0 PFBC Island Testing and Data Collection

Section 4.0 discusses the Tidd three-year test program including goals and objectives, contract acceptance tests and results, unit performance tests and results, and the availability of key operating components compiled over the three year project.

4.1 Test Program Goals and Objectives

The overall objective of the Tidd three-year test program was to provide the database and experience to be applied to the detailed design, operation, control, and maintenance of large-scale commercial PFBC combined-cycle plants.

The major goals of the test program were:

To demonstrate that a gas turbine could operate in a PFBC combined-cycle mode with acceptable life between rebuilds, have acceptable availability, and be readily controlled.

To demonstrate in-bed tube bundle survivability.

To demonstrate that PFBC could achieve better than 90% sulfur capture at a calcium-to-sulfur molar ratio of less than 2.0 and NO_x emissions less than 0.25 lb/mmBtu.

To investigate the commercial potential of PFBC ash.

To demonstrate the viability of the equipment and systems required to apply PFBC technology to electric power generation.

To demonstrate PFBC as an economic alternative to pulverized coal-fired plants with flue gas desulfurization and to other clean coal technologies.

These goals were accomplished through performance tests, equipment inspections, and studies. This section of the report details the testing completed during the three-year test program and present results and evaluation of that testing.

4.2 Test Program Description

A total of 47 unit performance tests were conducted during the three-year test program. The primary goal of the tests was to demonstrate that PFBC could achieve design performance. Tests were conducted to evaluate sorbent utilization, combustor performance, gas turbine/compressor performance, SO_x and NO_x emissions. During the later portion of the test program, the emphasis was to optimize sorbent utilization. This was done by evaluating unit performance with various sorbent types, sizes, feed methods, and bed distribution. Sorbent utilization is discussed in Sections 4.4 and 5.3 of this report.

The initial performance tests (Tests 1, 2, and 3) were conducted prior to adding boiler tube surface during the Fall 1991 outage. During the initial performance tests, the design full bed height was 126 inches; with the additional tube surface, full bed height is now 142 inches. Discussions of the boiler tube modifications are included in Section 6.2.

Unit acceptance tests (Tests 6 and 7) were conducted in June 1992 to confirm contractual guarantees. These tests are described in Section 4.3.

All baseline tests, as well as the unit acceptance tests, were conducted with the design coal and sorbent (i.e., Pittsburgh #8 coal and Plum Run Greenfield dolomite). The sorbent was fed pneumatically by two sorbent feed points while the coal was injected as a paste. Variations to the baseline data included tests with National Lime Carey dolomite, Plum Run Peebles dolomite, Ohio No. 6A coal, coarse sorbent in paste, sorbent fines in paste, and increased sorbent feed points. Several attempts were made to test the unit with limestone, however, problems with bed sintering caused these tests to be aborted. The problems of bed sintering are discussed in Section 5.2.

Each performance test was conducted by bringing the unit up to the desired load (i.e., bed level and temperature) and setting the firing rate. The outlet SO_2 emissions were set to the desired level by controlling the sorbent flow. After the unit reached steady-state operating conditions, data collection and materials sampling were initiated.

Typical data collection and materials sampling lasted for a period of 12 to 24 hours. The steadiest operating interval in the data collection period was selected for evaluation. The evaluation period was usually four to 12 hours in length.

Process data collection consisted of downloading on-line Plant Operation Performance System (POPS) data points to an ASCII data file. Each data point was then averaged over the evaluation time period and used as an input to a program developed to calculate plant performance parameters.

Materials sampling typically consisted of collecting coal, coal water paste, sorbent, bed ash, and cyclone ash samples over the data collection period for chemical analysis. The results of the chemical analysis were used as additional inputs to the calculation program. Due to the lead and lag times of the materials handling systems, the sorbent sampling period was typically 12 hours ahead of the data collection period, coal sampling was two hours ahead of data collection, and bed ash sampling was 12 hours behind data collection. All other materials sampling periods were at the same time intervals as data collection.

The calculation program used the process and chemical analysis data as inputs to calculate variables essential for unit evaluation. Key variables included coal water paste flow, flue gas flow to the high pressure turbine, excess air, sulfur retention, calcium-to-sulfur molar ratio, NO_x emissions, and combustion efficiency. To determine the values for coal water paste flow, the calculations were iterated until an energy balance on the pressure vessel was achieved. The air flow bypassing the bed was calculated based on oxygen levels in the freeboard and downstream of the gas turbine (Oxygen in the freeboard was determined by averaging the oxygen levels measured downstream of each of the seven primary cyclones.) Mass and heat balance closures were calculated and used to determine the accuracy of the performance tests.

An availability database was compiled over the last two years of the project. This database provides the necessary information to evaluate the equipment performance and availability required for commercialization of PFBC systems and equipment. This database is presented in Section 4.10.

4.3 Contract Acceptance Tests

Contract acceptance tests were conducted on June 14 and 15, 1992, during the 31-day run, and are designated as Performance Test Numbers 6 and 7, respectively. These tests were conducted after the installation of additional boiler tube surface that was completed during the Fall 1991 outage. The tests were conducted at full bed height, with the maximum firing rate and bed temperature attainable. Test results for key parameters are presented in Table 4.3.1, with expected values noted for comparison.

Although the unit operated as expected and near design, the following limitations prevented the unit from achieving full output: firing rate during the tests was limited due to both air delivery and in-bed tube bundle absorption deficiencies; steam flow was impacted by both in-bed and economizer absorption deficiencies; gross unit output was affected by all of the above, plus reduced steam cycle and gas turbine efficiency.

Table 4.3.1 - Acceptance Test Performance Data

Acceptance Test Performance Data			
Test Number	6	7	Expected Values(1)
Test Date	June 14, 1992	June 15, 1992	
Unit Firing Rate (MW_t)	188.7	183.2	206.3
Gross Unit Output (MW_e)	60.2	58.6	72.5
Mean Bed Temperature (F)	1551	1532	1580
Bed Level (inches)	142	142	126
Excess Air (%)	19.8	20.9	25.0
Main Steam Flow (kpph)	395	390	442
Sulfur Retention (%)	92.7	93	90.0
Actual Ca/S Molar Ratio	2.07	2.26	-
Ca/S Ratio (@ 90% SR, 1580 F Tbed)	1.71	1.77	1.64
NO_x Emissions (lb/mmBtu)	0.17	0.17	0.50(2)
Combustion Efficiency (%)	99.4	99.2	99.0
Economizer Outlet Gas Temp (F)	419	419	352

Notes for Tables 4.3.1, 4.3.3, 4.3.4, 4.3.6, 4.3.7, 4.3.8 and 4.7.1: (1) Expected values reflect adjustments to design values based on actual gas turbine shop test data. The contractual acceptance test goals and guarentees are listed on Table 4.3.3. (2) NO_x Expected Design value is the Permit Limit.

4.3.1 Acceptance Test Parameters

The unit was operated from 6/9/92 through 7/10/92 to complete the contract required 30-day reliability run. During the 30-day period, the unit operated at a capacity factor of 69.4%. A 100-hour full load endurance run, where the unit was operated at the highest achievable load, was also completed during this operating period. Following successful completion of the objectives of the run, the unit was removed from service for inspections. Test run parameters are presented in Table 4.3.2.

Table 4.3.2 - Acceptance Test Parameters

Acceptance Test Parameters		
Start Time (coal fire)	June 9, 1992	18:00 hours
Stop Time (combustor trip)	July 10, 1992	14:00 hours
Total Gas Turbine Operating Hours	782.5	
Total Coal Fire Hours	740.0	
100-Hour Endurance Run Completed	June 15, 1992	
30-Day Reliability Run Completed	July 9, 1992	
Capacity Factor	69.4%	

ASTM coal samples were obtained every two hours during the test periods using the automatic coal sampler. Sorbent samples were obtained in 12-hour composites, beginning approximately 24 hours before the test periods began. A grab sample of coal paste was obtained for moisture analysis every two hours during the test periods. Bed ash samples were obtained in two-hour composites between eight and 12 hours after the test periods. One cyclone ash sample was obtained from the rotary unloader just following the test periods.

4.3.2 Acceptance Test Goals and Guarantees

The performance of the unit compared to goal and guarantee parameters is summarized in Table 4.3.3. The unit met all performance guarantees except gas turbine MW_e output. The maximum heat input was limited to approximately 91% of the full-load expected value by the reduced air available for combustion and fluidization (due to gas turbine leakage) and by gas turbine inlet temperature limitation due to post-bed combustion and low in-bed heat absorption.

4.3.3 Acceptance Test Process Performance

Unit heat input was limited to approximately 91% of the expected value of 206 MW_t. Although air flow to the compressor was at the full-load design value, excess leakage (11.8% calculated versus 4.4% expected) caused a reduction in air flow available to sustain combustion. During the tests, the low pressure compressor speed was approximately 100 RPM below the operating limit of 5650 RPM. While a slight increase in air flow could have been obtained by increasing the LPC speed, the HPC outlet temperature which was at its limit of 572 F precluded this increase. The intercooler heat duty was approximately 15% above expected. Table 4.3.4 presents process performance results and expected values.

Table 4.3.3 - Performance Goals and Guarantees

Performance Goals and Guarantees				
Test Number	6	7	Goal	Guarantee
Test Date	June 14, 1992	June 15, 1992		
Gas Turbine Output (MW_e)	13.2	12.5	16.8	15.0
Main Steam Temperature (F)	923	922	925±10	925±10
Ca/S Ratio (@ 90% SR, 1580 F Tbed)	1.71	1.77	1.64	2.00
NO_x Emissions (lb/mmBtu)	0.17	0.17	0.25	0.60
Combustion Efficiency (%)	99.4	99.2	—	98.0
Corrected Water Side DP (psid)	557	558	648	687
Gas Side Pressure Drop (psid)	24.1	24.5	24.0	N/A
G.T. Apparent Heat Rate (Btu/kwh)	48,857	50,209	42,200	N/A
Economizer Gas Outlet Temperature (F)	419	419	322-355	N/A
Mean Bed Temperature (F)	1551	1532	1580	N/A
Gas Flow to HPT (kpph)	643.5	630.6	719.0	N/A
Gas Temperature to HPT (F)	1541	n/a	1525	N/A
Excess Air (%)	19.8	20.9	25.0	N/A
Air Flow to Combustor (kpph)	587.6	575.8	655.2	N/A

Table 4.3.4 - Acceptance Test Process Performance

Acceptance Test Process Performance			
Test Number	6	7	Expected Values
Test Date	June 14, 1992	June 15, 1992	
Bed Level (inches)	142	142	126/ 142*
Mean Bed Temperature (F)	1551	1532	1580
Mean Cyclone Inlet Temperature (F)	1557	1540	1549
Freeboard Oxygen (percent wet)	3.3	3.4	4.0
Excess Air (percent)	19.8	20.9	25.0
Firing Rate (MW_t)	188.7	183.2	206.3
Firing Rate (percent)	91.5	88.8	100
Gas Turbine Output (MW_e)	13.2	12.5	15.4
Steam Turbine Output (MW_e)	47.0	46.1	57.1
Gas Temperature to Stack (F)	419	419	N/ A
Gross Unit Heat Rate (Btu/kwh)	10,608	10,670	9713
Coal Water Paste Flow (lbs/hr)	67,900	66,100	72,924
Coal Water Paste Moisture (percent)	25.2	25.3	25.0
Sorbent Flow (lbs/hr)	20,930	22,050	18,882
Bed Ash Flow (lbs/hr)	9880	9880	9811
Cyclone Ash Flow (lbs/hr)	15,034	18,883	13,943
Final Feedwater Flow (klb/hr)	378	374	426
Final Feedwater Temperature (F)	457	455	485
Final Feedwater Pressure (psia)	1758	1747	1868
Attemperation Flow (klb/hr)	16.7	16.5	15.5
Attemperation Temperature (F)	308	308	299
Main Steam Flow (klb/hr)	395	390	442
Main Steam Temperature (F)	923	922	925
Main Steam Pressure (psia)	1324	1324	1335

* Revised design value.

A bed temperature of 1580 F and 7% more air to the bed would have been required to achieve full load at 20% excess air. During colder winter months adequate air flow was available for full-load operation. However, a firing rate of 206 MW_t was still not achievable due to limited bed temperature operation, caused by excessive sintering, which results in poor bed temperature and evaporator temperature distributions.

4.3.4 Gas Turbine Air Leakage

The air flow bypassing the combustor was determined from the measured change in oxygen in the gas stream between the freeboard and the economizer inlet and verified by heat balance calculations. During the test periods, the average leakage was 11.8% of the calculated air flow to the high pressure compressor, versus an expected value of 4.4%. In order to determine the site of the air leakage, ABB Carbon installed a set of test thermocouples around the high-pressure gas turbine and intercept valve. Potential identified sites for air leakage that could be repaired included the air bypass valve seating and HPT inlet body seal. Modifications were made during the Spring 1993 gas turbine outage to minimize leakage at these locations. See Section 6.13 for modification details.

4.3.5 Environmental Performance

The environmental performance of the unit demonstrated emissions that were better than design and well within the permit limitations during the test periods. Table 4.3.5 presents SO_2 and NO_x emissions for the test periods.

Table 4.3.5 - SO_2 and NO_x Emissions

SO_2 and NO_x Emissions			
Test Number	6	7	Permit Limit
Test Date	June 14, 1992	June 15, 1992	
SO_2 Emissions (lb/mmBtu)	0.35	0.35	*
NO_x Emissions (lb/mmBtu)	0.17	0.17	0.50

*Note: SO_2 permit emissions limit is based on 90% SO_2 removal which is dependent on the coal sulfur content. The permit SO_2 emissions limit for Test No. 6 was 0.48 lb/mmBtu and for Test No. 7 was 0.50 lb/mmBtu.

4.3.6 Sorbent Utilization

Sulfur capture versus design is presented in Table 4.3.6 above. The calcium-to-sulfur molar ratios were predicted at 90% and 95% sulfur retention at the design bed temperature of 1580 F using an emperical correlation developed at Grimethorpe. See Section 4.5 for discussion on the Grimethorpe correlation.

Table 4.3.6 - Sorbent Utilization

Sorbent Utilization			
Test Number	6	7	Expected Value
Test Date	June 14, 1992	June 15, 1992	
Sulfur Retention (%)	92.7	93.0	90.0
Actual Ca/S Molar Ratio	2.07	2.26	—
Mean Bed Temperature (F)	1551	1532	1580
Ca/S Ratio corrected to 90% SR, 1580 F	1.71	1.77	1.64
Ca/S Ratio corrected to 95% SR, 1580 F	2.23	2.31	—

4.3.7 Gas Turbine/Compressor Performance

The gas turbine output of 13.2 MW_e was 12% below the guarantee of 15 MW_e. It is likely that, even if air leakage and firing rate were at design, it would not be possible to meet the guarantee output. Additional details on the gas turbine/compressor performance are contained in Section 5.5. Gas turbine performance data for the acceptance tests are contained in Table 4.3.7.

Table 4.3.7 - Gas Turbine Performance

Gas Turbine Performance			
Test Number	6	7	Expected Value
Test Date	June 14, 1992	June 15, 1992	
Gas Turbine Output (MW_e)	13.2	12.5	15.4
Air Leakage (%)	11.8	11.8	4.4
LPC Inlet Temperature (F)	59	62	59
LPC Outlet Temperature (F)	356	363	345
LPC Outlet Pressure (psia)	57	58	59
LP Shaft Speed (rpm)	5526	5585	5364
HPC Outlet Temperature (F)	572	573	572
HPC Outlet Pressure (psia)	175	174	174
HPC Inlet Air Flow (kpph) *indicated*	680	680	679
HPC Inlet Air Flow (kpph) *calculated*	668	656	679
Air Flow to PV (kpph)	588	576	649
Int. Valve Inlet Temperature (F) *test instr.*	1541	n/a	1535
HPT Inlet Temperature (F) *test instr.*	1528	n/a	1526
HPT Inlet Pressure (psia)	151	150	146
LPT Outlet Temperature (F)	738	728	782
LPT Outlet Pressure (psia)	15.3	15.3	14.8
Intercooler Heat Duty (kw)	4740	4830	4200

4.3.8 Dust Loading to the Gas Turbine

Testing to determine the dust loading to the gas turbine was performed on June 23, 1992, by Environmental Source Samplers, Inc. Their results indicate that the dust loading to the gas turbine was 313 ppm versus a performance goal of 250 ppm. This test was run with only six of the original seven cyclone strings in service and at least one secondary cyclone plugged.

4.3.9 Bed Characteristics

During the acceptance tests, mean bed temperature was limited to 1551 F and 1532 F (for Tests 6 and 7 respectively) in order to maintain normal operating limits on bed temperature and evaporator temperature distributions. During the run, egg sinters were found in the bed ash. It is not clear what effect this had on unit performance. Additional detail on the bed sintering phenomenon is contained in Section 5.2 of this report.

4.3.10 Economizer Performance

Economizer performance data is shown in Table 4.3.8. With four sootblowers in service, the economizer could not be maintained clean during the test periods. This resulted in high gas losses and caused a 10 klb/hr reduction in steam flow. (1.3 MW_e penalty). Four additional sootblowers were installed following the acceptance tests to improve economizer performance. Even with eight sootblowers in service, the economizer performance remains below design.

Table 4.3.8 - Economizer Performance

Economizer Performance			
Test Number	6	7	Expected Value
Test Date	June 14, 1992	June 15, 1992	
Feedwater Flow (klb/hr)	378	374	426
Inlet Water Temperature (F)	308	308	299
Inlet Water Pressure (psia)	1758	1747	1868
Outlet Water Temperature (F)	457	455	485
Gas Flow (klb/hr)	718	705	733
Inlet Gas Temperature (F)	738	728	782
Inlet Gas Pressure (psia)	15.3	15.3	14.8
Outlet Gas Temperature (F)	419	419	352
Draft Loss (psi)	0.6	0.5	—

4.3.11 Ash Analysis

The observed loss of CO_2 from the sorbent in the cyclone ash was less than the extent of sulfation in both samples. This could be due to unreacted sorbent fines ($MgCO_3 \bullet CaCO_3$) escaping the bed along with some highly sulfated ash particles ($MgO \bullet CaSO_4$). The highly sulfated ash (greater than 75% sulfation) would cause the apparent sulfation of the cyclone ash to be in an acceptable range, while the unreacted sorbent fines would give CO_2 in excess of what would be expected due to incomplete half-calcination of the $MgCO_3$.

4.3.12 Acceptance Test Conclusions

In general, the unit performed acceptably except for the gas turbine MW_e output and compressor capacity. The unit completed the contract-required 30-day reliability run with 100 hours at the highest achievable load. All performance guarantees were met except gas turbine MW_e output.

Several performance goals were not met. Of primary importance were the Ca/S ratio, mean bed temperature, and air flow to the combustor. In order to demonstrate that PFBC can be operated efficiently, these goals must be demonstrated during future testing at Tidd (or shown that they can be achieved on future units).

The remainder of the test program will place emphasis on sorbent utilization with the goal of achieving the contract goal of 1.64 Ca/S ratio at 90% sulfur retention. Additionally, the test program will place emphasis on minimizing bed sintering to allow operation at the design bed temperature of 1580 F. Full-bed temperature is required to achieve full firing rate and to improve sorbent utilization.

Finally, the air flow to the combustor must be increased to allow full-load operation. This issue has limited full-load operation to winter months when the gas turbine/compressor capacity is greater due to the colder ambient air. Future testing at Tidd will have the objectives of resolving the bed sintering and sorbent utilization issues with full-load testing occurring during winter months. Gas turbines supplied to future PFBC units must be capable of providing full air flow all year long. This will be accomplished by improved manufacturing tolerances and design of the gas turbine/compressor to provide greater air flow and less air leakage.

4.4 Sorbent Utilization Testing

Performance tests were conducted at sulfur retention levels from 82% to 95%, and at various bed levels and temperatures. The highest bed temperature achieved during a performance test was 1552 F. Problems with sintering prevented testing the unit at higher bed temperatures. The actual sulfur retention and Ca/S molar ratio were calculated for each test; correlations developed at Grimethorpe were used to normalize the Ca/S ratio to conditions of 1580 F bed temperature and 90% or 95% sulfur retention. This allows for direct comparison of test results even though actual test conditions may have varied from test to test. See Section 4.5 for discussion on the Grimethorpe correlation.

A summary of test conditions and results is contained in the following Tables 4.4.1 and 4.4.2. Graphical results are presented in Figures 4.4.1 and 4.4.2.

Optimization of sorbent utilization consisted of testing the unit under various conditions that were expected to affect sulfur capture. During the three-year test program, tests were conducted with three different sorbent types, adding coarse sorbent or sorbent fines to the coal paste, modifying the sorbent distribution to the bed, increasing the number of sorbent feed points, and changing the sorbent size consistency.

Evaluation of the data presented in Figure 4.4.1 shows that improvements in sorbent utilization were obtained when: operating with sorbent fines in the paste, utilizing four sorbent injection points, and feeding finer sorbent. Operation with sorbent tees installed at the ends of the two original sorbent feed points did not show appreciable improvement. Of the three sorbent types tested (Plum Run Greenfield, Plum Run Peebles, and National Lime Carey) the most reactive sorbent was found to be the Plum Run Greenfield dolomite. Another interesting finding was that better sorbent utilization was achieved while operating with Ohio 6A coal. Although the reasons for this improvement are unclear, additional testing is planned for the fourth year of Tidd operation to confirm and explain this finding.

The test results at 115-inch bed level show a large scatter of data and relatively large steps of improvements in Ca/S ratio. The best results obtained at this bed level while burning Pittsburgh #8 coal were achieved with a finer grade of Plum Run Greenfield dolomite. During tests with the finer sorbent (Tests 45, 46, and 47) the average Ca/S ratio was 1.94 normalized to 90% sulfur retention and 1580 F bed temperature. The finer sorbent grade was achieved by a change in the sorbent crusher sheave diameter to increase crusher speed. During these tests sorbent size consisted of less than 1% over 8-mesh, approximately 41% less than 60-mesh, and a surface mean diameter of approximately 430 microns. Typical sorbent sizes have been approximately 4 to 8 % over 8-mesh, 30 to 35% less than 60-mesh, and a surface mean diameter of 500 microns. Additional testing to optimize sorbent size is planned for the fourth year of Tidd operation.

At 142-inch bed level, there was much less scatter in the test data. The best test results were obtained during Tests 6 and 44. Test 6 was conducted with Pittsburgh #8 coal, Plum Run Greenfield dolomite, and the two original sorbent feed points. A normalized Ca/S ratio of 1.71 was calculated for this test. Test 44 was conducted with the same coal and dolomite but used the four point sorbent injection system and 23% of the sorbent was fed as fines mixed with the coal paste. A normalized Ca/S ratio of 1.73 was calculated for this test.

In order to demonstrate that sulfur retention levels of 95% can be attained in the PFBC process, a total of 8 tests (Nos. 21, 22, 23, 28, 29, 35, 36, and 44) were conducted at this retention level. Figure 4.2.2 shows the Ca/S ratio adjusted to 95% vs. bed height for all tests. The only test conducted at full bed level and 95% actual sulfur retention was Test 44. A Ca/S ratio of 2.25 corrected to 1580 F bed temperature was calculated for this test.

Additional details and insight on sorbent utilization can be found in Section 5.3 of this report.

Table 4.4.1 - Performance Test Conditions

Test	Date	Coal	Sorbent	Bed Level (")	Bed Temp. (F)	Notes
1	06/25/91	Pittsburgh #8	P. R. Greenfield	127	1535	Prior to boiler surface addition
2	08/09/91	Pittsburgh #8	P. R. Greenfield	76	1531	Prior to boiler surface addition
3	08/12/91	Pittsburgh #8	National Lime	90	1530	Prior to boiler surface addition
4	02/05/92	Pittsburgh #8	P. R. Greenfield	131	1535	
5	02/07/92	Pittsburgh #8	P. R. Greenfield	131	1535	
6	06/14/92	Pittsburgh #8	P. R. Greenfield	142	1551	Acceptance Test
7	06/15/92	Pittsburgh #8	P. R. Greenfield	142	1532	Acceptance Test
8	08/12/92	Pittsburgh #8	P. R. Greenfield	117	1544	
9	08/18/92	Pittsburgh #8	P. R. Greenfield	116	1547	Half sorbent in paste
10	08/20/92	Pittsburgh #8	P. R. Greenfield	116	1548	All sorbent in paste
11	08/25/92	Pittsburgh #8	P. R. Greenfield	115	1552	Sorbent fines in paste
12	12/16/92	Ohio 6A	P. R. Greenfield	119	1538	
13	01/22/93	Ohio 6A	P. R. Greenfield	117	1540	
14	01/25/93	Ohio 6A	P. R. Greenfield	81	1540	
15	01/27/93	Ohio 6A	P. R. Greenfield	117	1541	
16	01/29/93	Pittsburgh #8	P. R. Greenfield	119	1539	
17	07/22/93	Pittsburgh #8	P. R. Greenfield	95	1533	
18	07/22/93	Pittsburgh #8	P. R. Greenfield	95	1533	

Test	Date	Coal	Sorbent	Bed Level (")	Bed Temp. (F)	Notes
19	07/26/93	Pittsburgh #8	P. R. Greenfield	81	1534	
20	07/27/93	Pittsburgh #8	P. R. Greenfield	81	1535	
21	07/28/93	Pittsburgh #8	P. R. Greenfield	80	1535	
22	07/29/93	Pittsburgh #8	P. R. Greenfield	80	1536	
23	07/31/93	Pittsburgh #8	P. R. Greenfield	81	1535	
24	08/04/93	Pittsburgh #8	P. R. Greenfield	77	1532	
25	08/05/93	Pittsburgh #8	P. R. Greenfield	78	1529	
26	08/13/93	Pittsburgh #8	P. R. Greenfield	118	1539	
27	08/13/93	Pittsburgh #8	P. R. Greenfield	118	1538	
28	08/21/93	Pittsburgh #8	P. R. Greenfield	119	1542	
29	08/21/93	Pittsburgh #8	P. R. Greenfield	118	1544	
30	08/23/93	Pittsburgh #8	P. R. Greenfield	118	1541	
31	09/02/93	Pittsburgh #8	P. R. Greenfield	113	1537	Sorbent fines in paste
32	09/04/93	Pittsburgh #8	P. R. Greenfield	79	1538	Sorbent fines in paste
33	09/11/93	Pittsburgh #8	P. R. Greenfield	120	1539	
34	09/13/93	Pittsburgh #8	P. R. Peebles	84	1536	
35	09/14/93	Pittsburgh #8	P. R. Peebles	83	1537	
36	09/16/93	Pittsburgh #8	National Lime	83	1536	
37	09/17/93	Pittsburgh #8	National Lime	83	1536	
38	09/23/93	Pittsburgh #8	P. R. Greenfield	128	1539	
39	10/19/93	Pittsburgh #8	P. R. Greenfield	116	1481	Sorbent tees installed
40	10/21/93	Pittsburgh #8	P. R. Greenfield	114	1540	Sorbent tees installed
41	10/31/93	Pittsburgh #8	P. R. Greenfield	114	1543	Sorbent tees installed
42	11/02/93	Pittsburgh #8	P. R. Greenfield	141	1539	Sorbent tees installed
43	11/28/93	Pittsburgh #8	P. R. Greenfield	115	1541	4 Sorbent injection points
44	12/02/93	Pittsburgh #8	P. R. Greenfield	141	1480	4 Sorbent points-fines in paste
45	01/18/94	Pittsburgh #8	P. R. Greenfield	115	1538	Finer sorbent
46	01/19/94	Pittsburgh #8	P. R. Greenfield	114	1533	Finer sorbent
47	01/21/94	Pittsburgh #8	P. R. Greenfield	114	1499	Finer sorbent

Table 4.4.2 - Performance Test Results

Test	Date	Firing Rate MW_t	Unit Output MW_e(gross)	Sulfur Ret. Percent As Tested	Ca/S Ratio @90%SR 1580 F	Ca/S Ratio @95%SR 1580 F
1	06/25/91	165	49	93.6	1.64	2.13
2	08/09/91	107	26	82.2	2.68	3.49
3	08/12/91	128	32	89.4	2.76	3.59
4	02/05/92	187	62	89.8	1.97	2.57
5	02/07/92	177	59	90.0	2.22	2.88
6	06/14/92	188	60	92.7	1.71	2.23
7	06/15/92	183	58	93.0	1.77	2.31
8	08/12/92	164	51	89.4	2.52	3.28
9	08/18/92	162	50	89.9	3.03	3.94
10	08/20/92	169	54	91.1	3.13	4.07
11	08/25/92	162	49	89.3	2.78	3.61
12	12/16/92	162	52	89.3	2.14	2.79
13	01/22/93	161	52	90.2	1.85	2.41
14	01/25/93	108	29	88.5	2.35	3.06
15	01/27/93	159	50	91.5	1.96	2.55
16	01/29/93	163	52	89.2	2.22	2.88
17	07/22/93	124	33	87.7	2.43	3.16
18	07/22/93	125	34	88.6	2.58	3.36
19	07/26/93	106	25	88.9	2.32	3.01
20	07/27/93	108	26	87.4	2.70	3.51
21	07/28/93	102	24	94.6	2.39	3.11
22	07/29/93	105	25	94.5	2.45	3.19
23	07/31/93	106	25	94.2	2.55	3.32
24	08/04/93	103	25	82.5	2.56	3.33
25	08/05/93	104	25	82.6	2.71	3.52
26	08/13/93	159	49	90.6	2.41	3.14
27	08/13/93	163	50	89.1	2.45	3.19
28	08/21/93	166	52	95.3	2.36	3.07
29	08/21/93	167	51	94.3	2.14	2.78
30	08/23/93	163	50	90.1	2.22	2.88
31	09/02/93	156	47	90.6	2.06	2.68
32	09/04/93	108	27	92.8	2.21	2.88
33	09/11/93	161	50	86.3	2.02	2.62

Test	Date	Firing Rate MW_t	Unit Output MW_e(gross)	Sulfur Ret. Percent As Tested	Ca/S Ratio @90%SR 1580 F	Ca/S Ratio @95%SR 1580 F
34	09/13/93	111	28	89.4	2.70	3.52
35	09/14/93	112	29	94.0	2.94	3.82
36	09/16/93	112	30	95.0	2.94	3.82
37	09/17/93	113	29	90.1	2.70	3.52
38	09/23/93	171	54	91.0	2.59	3.36
39	10/19/93	152	46	87.9	2.29	2.98
40	10/21/93	162	51	90.5	2.24	2.92
41	10/31/93	161	51	90.5	2.07	2.69
42	11/02/93	176	58	91.2	1.84	2.39
43	11/28/93	167	52	91.1	2.03	2.63
44	12/02/93	169	54	95.2	1.73	2.25
45	01/18/94	163	53	90.6	1.97	2.56
46	01/19/94	159	51	90.2	1.92	2.50
47	01/21/94	152	48	89.1	1.94	2.52

4.5 Grimethorpe Correlation

In order to allow direct comparison of test results, even though actual test conditions may have varied between tests, the calcium-to-sulfur molar ratios presented in this report have been normalized to specific test conditions for sulfur retention (90% or 95%), bed level, and bed temperature 1580 F using the following correlation developed at Grimethorpe:

$$\ln(1-R) = -A \cdot C \cdot t^{1/2} \cdot \exp(-4650/T)$$

where:

R = sulfur retention, dimensionless
C = calcium-to-sulfur molar ratio, dimensionless
t = in-bed gas residence time, seconds
T = bed temperature, degrees kelvin
A = constant, sorbent reactivity index

The sorbent reactivity index, A, is a constant for a given test and is a measure of the sorbent's reactivity at a given test configuration. Sorbent type, size, feed method, and distribution within the bed are all variables that may affect the sorbent's reactivity. After conducting a performance test, the sorbent reactivity index is calculated using the Grimethorpe equation solved for A:

$$A = -\frac{\ln(1-R)}{C \cdot t^{1/2} \cdot \exp(-4650/T)}$$

The performance data can now be normalized to any reference sulfur retention value, Ca/S ratio, or bed temperature by substituting the desired reference value into any one or two of the above variables and solving the Grimethorpe equation for the variable of interest. By substituting the calculated sorbent reactivity index value for A, 0.90 for R, and 1133K (1580 F) for T, and solving the Grimethorpe equation for C, the calcium-to-sulfur molar ratio is predicted for 90% retention at 1580 F bed temperature. Note that when correlating test data for bed height, the actual variable in the Grimethorpe equation being tested is "t" (in-bed gas residence time) which is equal to bed level divided by the superficial fluidizing velocity.

The Grimethorpe correlation was verified to be reasonably accurate for bed levels from 80" to 142", bed temperatures from 1480 F to 1540 F, and sulfur retention levels from 85% to 95%. The Grimethorpe correlation has not been validated for bed temperatures above 1540 F due to lack of tests at higher temperatures because of bed sintering problems.

In order to verify the accuracy of the Grimethorpe correlation, test series, each consisting of two performance tests, were conducted where all test variables except one is held constant. By comparing the normalized test data for sorbent utilization, the validity of the Grimethorpe equation can be determined for the specific variable of interest. The following Table 4.5.1 shows test series and data used in verifying the Grimethorpe equation for bed height, bed temperature, and sulfur retention.

Results from the tests show that the normalized Ca/S ratio varies by less than 3.5% for each of the test series. This is normally within the scatter of test results for tests of similar conditions. Hence, the Grimethorpe correlation appears to be valid.

Table 4.5.1 - Test Series for Verification of Grimethorpe Equation

Test Number	Bed Height (inches)	Bed Temp. (F)	Sulfur Retention (%)	Ca/S Ratio (actual)	Ca/S Ratio (@ 142" bed ht, 1580 F, 90% SR)
Tests For Changes in Bed Height					
14	81	1540	89	2.40	1.78
15	117	1541	92	2.28	1.78
% Error					0.0%
41	114	1543	91	2.28	1.85
42	141	1540	91	2.11	1.83
% Error					1.1%
Tests For Changes in Bed Temperature					
39	116	1482	88	2.59	2.08
40	115	1540	91	2.49	2.01
% Error					3.5%
46	114	1533	90	2.13	1.72
47	114	1499	89	2.22	1.74
% Error					1.1%
Tests For Changes in Sulfur Retention					
23	81	1535	94	3.45	1.92
24	77	1532	83	2.14	1.88
% Error					2.1%
29	118	1544	94	2.87	1.95
30	118	1541	90	2.41	2.02
% Error					3.5%

4.6 Combustor Performance

Combustion efficiency is calculated based on the measured unburned carbon in the cyclone ash and bed ash and carbon monoxide in the flue gas.

The best combustion efficiencies achieved at Tidd were 99.5% to 99.7% which occurred at bed levels in excess of 110 inches. The average combustion efficiency for tests greater than 110 inches was 99.4%, while an average of 99.0% was achieved for tests at bed levels below 100 inches. Combustion efficiency performance goal at full-bed level and temperature and 25% excess air, is 99.0%.

Tests conducted at Grimethorpe show that combustion efficiency is a function of in-bed gas residence time, excess air, bed temperature, and volatile matter in coal. The in-bed gas residence time is a function of bed level. At bed levels greater than 110 inches, the gas residence time is 3.4 to 4.4 seconds. Figure 4.6.1 shows combustion efficiency versus excess air for tests conducted at bed levels greater than 110 inches. A general improvement in combustion efficiency is seen as the excess air is increased from 20% to 40%. There was little correlation in combustion efficiency versus temperature at Tidd. This is partly due to the fact that Tidd operated in the narrow bed temperature range of 1480 to 1550 F. Grimethorpe was tested at temperatures from 1400 to 1675F. The impact of volatile matter in coal versus combustion efficiency was not tested at Tidd.

4.7 Gas Turbine/ Compressor Performance

The gas turbine/compressor performance data for full load tests are presented in Table 4.3.7 for the acceptance tests (Tests 6 and 7), and in Table 4.7.1 for Tests 42 and 44. The highest gas turbine output was 13.2 MW_e achieved during Tests 6 and 42 which is 12% below the guarantee value of 15.0 MW_e. Gas turbine air leakage was determined by the measured changes in oxygen levels in the gas stream at the freeboard and downstream of the gas turbine. Durig the acceptance tests, a leakage rate of 11.8% of the HPC inlet air flow was calculated. A leakage rate of 9.8% was calculated during Test 42. The design leakage rate is 4.4%.

ABBC has noted the following causes for below-design gas turbine performance:

Low air flow capacity of the LPC.

Low efficiency of the LPC.

High internal air leakages in the gas turbine.

ABBC has attributed these inefficiencies primarily to poor tolerances achieved during fabrication of this first-of-a-kind gas turbine and feels that these problems are fully resolvable on a commercial unit.

The reduced compressor capacity and excessive leakage have resulted in reduced air flow available to the combustor, which has limited maximum bed height and firing rate during the warmer months of the year.

Table 4.7.1 - Gas Turbine Performance

Gas Turbine Performance			
Test Number	42	44	Expected Values
Test Date	11/2/93	12/2/93	
Gas Turbine Output (MW_e)	13.2	12.3	15.4
Air Leakage (%)	9.8	N/A	4.4
LPC Inlet Temperature (F)	28	49	59
LPC Outlet Temperature (F)	295	334	345
LPC Outlet Pressure (psia)	55	57	59
LP Shaft Speed (rpm)	5127	5396	5364
HPC Outlet Temperature (F)	572	571	572
HPC Outlet Pressure (psia)	174	178	174
HPC Inlet Air Flow (kpph) *indicated*	659	680	679
HPC Inlet Air Flow (kpph) *calculated*	620	680	679
Air Flow to PV (kpph)	555	585	649
Int. Valve Inlet Temperature (F)	1515	1469	1535
HPT Inlet Temperature (F) *test instr.*	N/A	N/A	1526
HPT Inlet Pressure (psia)	148	152	146
LPT Outlet Temperature (F)	735	682	782
LPT Outlet Pressure (psia)	15.6	15.5	14.8
Intercooler Heat Duty (kw)	2045	3977	4138

4.8 NO_x Emissions

The NO_x emissions levels at Tidd are below the original expected values. Figure 4.8.1 shows NO_x emissions (percent nitrogen conversion) versus percent oxygen in the freeboard for various performance tests. As expected, an increase in oxygen concentration results in an increase in NO_x emissions. The Tidd PFBC permit limit for NO_x is 0.5 lb/mmBtu. The data in Figure 4.8.1 represents NO_x emissions levels of 0.17 to 0.34 lb/mmBtu. NO_x emissions were also measured independently by Environmental Source Samplers, Inc. during annual stack compliance tests. These results are presented in Section 4.9.

4.9 Environmental Compliance Tests

In accordance with environmental regulations, initial tests for particulate and gaseous emissions were required for certification of the Continuous Emissions Monitoring Systems (CEMS) and annual gaseous emissions tests are required for Relative Accuracy (RA) testing of the CEMS. Due to the sporadic nature of operation during the first year, testing could not be conducted during that year.

Environmental compliance tests were conducted on February 7, 1992 to determine compliance with SO_2, NO_x, CO, CO_2 and particulate emissions limitations, and to certify the CEMS. On August 23, 1993 annual RA testing to determine compliance with the SO_2, NO_x, and CO_2 monitors was completed. All tests were conducted by Environmental Source Samplers, Inc.. EPA Method 6C was used for SO_2 sampling, EPA Method 7E for NO_x sampling, EPA Method 10 for CO sampling, and EPA Method 5 for particulate sampling. Test results are presented in Table 4.9.1. along with permit limitations. All environmental emissions limitations were met during the tests.

On February 7, 1992 additional tests required for the Environmental Monitoring Plan were conducted at the precipitator inlet and results used to determine precipitator collection efficiency. EPA Method 17 was used for this test series. With an inlet dust loading of 498.7 lbm/hr and an outlet dust loading of 14.6 lbm/hr, a collection efficiency of 97.1% was calculated.

Table 4.9.1 - Environmental Compliance Tests

Environmental Compliance Tests			
Test Date	2/7/92	8/23/93	Permit Limit
Unit Conditions			
Unit Gross Output (MW_e)	60.0	51.3	
Stack Gas Temperature (F)	415	418	
Stack O_2 (percent, dry basis)	6.1	6.0	
Stack CO_2 (percent, dry basis)	13.1	12.7	
Test results			
SO_2 (lb/mmBtu)	0.5067	0.3997	*
NO_x (lb/mmBtu)	0.2379	0.2280	0.5000
CO (lb/mmBtu)	0.0008	n/a	0.0100
Particulate (lb/mmBtu)	0.0192	n/a	0.0300

*NOTE: SO_2 permit limit is based on 90% SO_2 removal which is dependent on the sulfur content of the coal. On 2/7/92 the limit was 0.5110 lb/mmBtu and on 8/23/93, 0.4970 lb/mmBtu.

4.10 Reliability and Availability of Key Operating Components

4.10.1 Availability Background and Data Collection

This section addresses the availability of individual components within the plant cycle. Data was recorded using the AEP System Generating Availability Data System (AEP-GADS) which is an on-line component tracking system for unit availability within the AEP System. This system is used by the AEP System to report generating unit statistics to the North American Electric

Reliability Council (NERC-GADS). This data is in accordance with NERC-GADS and IEEE Standard 762 requirements for standard definitions for use in reporting electric generating unit reliability, availability, and productivity.

Due to the nature of the Tidd PFBC Demonstration Project, component availability reporting requirements were adjusted to reflect the anticipated operation of the plant and its testing program. Tidd PFBC was designed and operated as a demonstration test facility. As such, sufficient component redundancy, high availability, electrical generation output requirements were considered of secondary importance to the Tidd PFBC mission. It should also be noted that the following data must be viewed in light of the fact that the systems were designed intentionally without commercial plant redundancy, that startup and shakedown of the plant were affected by the first-of-a-kind nature of the project, and that the unit was not load dispatched resulting in operation and outage durations that did not always have the urgency of a commercial plant. The intent of this data is to provide a means to assess the readiness of the technology and systems for commercial operation, not to represent Tidd PFBC as a commercially operated plant. The mission of unit testing and shakedown of the plant was the most urgent issue, and that drove all other decisions, modifications, and operating plans. In addition, due to the extended startup and commissioning program encountered at Tidd, data was not recorded during 1991. Component data was recorded starting January 1, 1992 through February 28, 1994. In addition, the following constraints were also imposed on the data collection process.

All lost MWHr outages and curtailments were recorded for both the PFBC Island (including the HGCU system) and the balance of plant components.

For the PFBC Island, data entries were also made for component failures even if those failures did not result in a loss of megawatt generation. This was done to track failures of PFBC Island components and how they may impact unit operation and availability. These non-MWHr loss curtailments are discussed in detail in Section 4.10.3.

Unit load curtailments were not recorded in AEP-GADS for reduced unit load due to unit testing requirements or ambient weather conditions that impacted unit operations. Therefore, if a specific performance test was conducted at 115" and approximately 57 MW, no load curtailment was recorded. Likewise, if ambient weather conditions prevented the gas turbine air flow to reach full load during the summer, again no load curtailment was recorded. The impact of these types of load curtailments are discussed in other sections.

The gross maximum unit load achievable at Tidd as used in the AEP-GADS calculations is 70 MWG.

Due to the nature of the Tidd PFBC Demonstration program, unit events that impacted availability were not broken down into scheduled, planned, or forced outages or curtailments. During the demonstration period, Tidd did not have any annual or planned outages. Instead, repairs and/or modifications were worked into unit outages as appropriate or required to support the test program. For example, once the length of the gas turbine blade failure outage was known in early 1993, programs were initiated to replace the secondary cyclone ash removal system and the boiler sparge ducts within the time the unit was out of service for the gas turbine outage. When known modifications were developed for the unit, the designs were completed and the material procured and shipped to the plant. At the next appropriate outage, the outage length was adjusted to permit the installation of that component or system modification. Outage times were also adjusted to support the next series of performance testing as required.

For unit availability, the unit was reported to be in service from the time the steam turbine generator breaker was closed, paralleling the unit to the system grid, until the time the combustor tripped. The steam turbine generator breaker would always open within minutes or sooner after a combustor trip. For official GADS reporting, a conventional coal-fired unit is in service for the entire time the steam turbine generator is connected to the electrical grid. Currently, AEP-GADS reporting procedures do not take into consideration a PFBC Combined-Cycle type of unit where there is a gas turbine, steam turbine, and combustor. Therefore, in order to meet the intent of AEP-GADS as closely as possible, the steam turbine generator breaker closure to combustor trip reporting method was used at Tidd.

4.10.2 Component Redundancy

During the design phase of the PFBC Island, a decision was made to limit redundancy of components in the plant due to the relatively short life of the demonstration period. Therefore, there were no spare components installed on any of the PFBC Island systems. Where there was more than one component installed, i.e. paste pumps, all were required to be in service to achieve full-load operation.

The other area of redundancy was with spare parts and storeroom stock. Again, during the design phase, the decision was made that if a part could be obtained from a suppliers stock within 24 hours, then that part would not be stocked at Tidd. The maintenance history shows that this type of stocking arrangement did not adversely impact operations. In fact, there were only one or two incidences when this impacted operations.

In the case of larger spare parts, there were very few capitalized spare parts, such as spare valve assemblies, etc., stored at Tidd. This did impact outages on a frequent basis, especially in the case of large valves in solids material transport systems. In these systems, certain valves would require repair/rebuilds periodically. In many instances, the valves were shipped to a vendor's repair facility. A typical example would be the sorbent transport system isolation valves at the combustor vessel wall. These valves would require rebuilding approximately every three months. During an outage, the valves would be removed from the line at the beginning of the outage, sent out for seven days to be rebuilt, and then reinstalled in the transport line near the end of the outage.

4.10.3 Non-MWHr Lost Curtailments

In order to track PFBC equipment outages that could have an impact on unit operations, an entry was made into the AEP-GADS system for each PFBC component that failed while the unit was in service. If the failure resulted in a lost-MWHr curtailment, the lost generation period was entered into AEP-GADS. However, other component failures also occurred and could have impacted unit load, but did not. These were also entered into AEP-GADS but with no loss in generation. Those events are summarized in Table 4.10.1 for the years 1992 through 1994. Instead of lost MWHrs, they are summarized by the total and average number of hours that those failures lasted. Percentages are also calculated for the percent of time the failures occurred during both a calendar year basis and the amount of time the unit was actually in service. The hours used in the calculations are as follows:

Year	Calendar Hours	Unit Operating Hours
1992	8784	2523
1993	8760	2326
1994 (2 months only)	1416	533

Note that the reporting period for 1994 was two months only. Therefore, the hours used in the percentage calculations for non-curtailment events are based on the short period, which results in unusually large percentages for each event listed in 1994. The following is a description of the major failures and their potential impact on unit operations that year if the event would have resulted in an outage or possible load curtailment for that year.

1992 Non-MWHr Lost Curtailments

Refer to Table 4.10.1.

Secondary ash removal plugged - (57.35% of operating time) - After the extensive ash line pluggages and outages that were experienced in 1991, a decision was made to continue to operate the unit even if a secondary ash line became plugged in service. Prior to that, the unit was removed from service to unplug the ash line. Secondary ash line pluggages in 1992 were a common event and every run had at least one ash line plugged sometime during the run. Experience had shown that the unit could operate with one ash line plugged without visible adverse impact on gas-turbine blade erosion. However, unit operation was not continued if a second secondary ash line plugged. Secondary ash line pluggages were almost eliminated after the system was redesigned in Spring 1993. It should be noted that further investigation is required to determine what total impact there is on the gas turbine during operation with one secondary cyclone out of service.

Bed reinjection vessels - (12.21% of operating time) - On two occasions during 1992, the reinjection bottom "L" valves had become blocked in service and prevented material from being fed out of the vessel and back into the bed. This blockage resulted in that reinjection vessel being forced from service, which impacted the ability of the unit to respond to quick load changes. Since Tidd did not usually require quick load changes, this failure did not impact unit availability. However, in a commercial plant, this type of failure would have a direct impact on the unit's ability to load follow. In one event during 1992, blockage of both reinjection "L" valves resulted in a unit outage. See Section 4.10.36 for details.

Precipitator - (2.91% of operating time) - High precipitator outlet opacity was frequently encountered on unit startup. Since the unit was in its startup mode, no unit load curtailments were encountered.

Coal injection paste pumps - (2.78% of operating time) - During 1991 and the first half of 1992, pluggage of the paste nozzles was a common problem. The pluggage was usually caused when coarse coal would accumulate in one paste pump or injection line and would become unpumpable. The paste pump would then stop pumping due to high differential pressure in the line. Bed firing conditions would become unstable and the unit usually tripped within a few minutes upon a loss of a paste pump. As operations experience was gained, the ability to operate the unit with one paste pump out of service improved, and by 1992 the unit could be operated with one pump out of service. In Spring 1992, modifications to the coal preparation system and the installation of the coal recycle loop made a dramatic improvement on the coal paste consistency and the reliability of the crushed coal product. This improved paste product resulted in a significant reduction in paste pump and line pluggages.

Coal preparation coal crusher - (2.58% of operating time) - Prior to the installation of the coal preparation system recycle loop, the crushed coal quality reliability was poor. Crusher skewing and feed problems resulted in frequent crusher trips, system capacity limitations, and insufficient fines in the product which resulted in a unit load curtailment. See Section 4.10.3 for details on the unit outages. However, during unit test periods at low load, the poor performance of the crusher did not require a load curtailment.

Sorbent injection - (2.41% of operating time) - During 1990 through 1993, the sorbent injection system experienced frequent problems caused by a variety of components. These included valve problems, rotary feeder problems, and control logic problems for the sorbent injection system. When these problems occurred, they usually required the plant to switch from dual lockhopper train operation to a single train operation. In this manner, the unit could continue to operate without requiring a load curtailment or outage. However, operation in this manner was risky, and could result in an outage.

The remaining events for 1992 represented a very low percentage and are not discussed further but are shown in Table 4.10.1

1993 Non-MWHr Lost Curtailments

Secondary ash removal plugged - (20.09% of operating time) - As outlined above, the secondary ash lines continued to plug in service until the system was redesigned in the Spring 1993. After that date, the lines have operated with a 99% availability.

HGCU high differential pressure - (8.99% of operating time) - Early during the testing of the HGCU system with very fine ash, the filter cake was very tenacious, and the HGCU filter pressure drop became unstable at higher operating temperatures. This unstable pressure drop resulted in several load curtailments as well as ultimate breakage of several candle filter elements. It is likely that if the HGCU filter was not just a slipstream system, such a high pressure drop across the filter would have resulted in a more severe load curtailment.

Sorbent injection - various components - (6.27% of operating time) - As outlined above, sorbent injection problems continued to occur until 1993 when the remaining problem valves were replaced and changes were made to the rotary feeders and drives.

Sorbent preparation - various components - (1.70% of operating time) - As longer operating times were achieved in 1993, the availability during those long runs of the sorbent preparation system became more critical. The system was not capable of extended operation (more than a few weeks) without extensive maintenance. Due to the presence of a 200-ton surge hopper between the sorbent preparation and injection systems, it is possible to perform limited maintenance or experience a short term component failure and not result in a load curtailment. Therefore, with the longer continuous operating runs, sizing screen failures, erosion holes, and other component failures occurred. These were frequently repaired on an emergency basis and the sorbent preparation system returned to service before the 200-ton surge hopper was emptied of sorbent.

The remaining events for 1993 represented a very low percentage and are not discussed further but are shown in Table 4.10.1

1994 Non-MWHr Lost Curtailments (Note: 2 months only)

Note: The 1994 operating year was only from January 1, 1994 through February 28, 1994. This represented 1416 calendar hours and 533 hours of operating time. As such, curtailments during this period are shown at a higher percentage due to the short operating achieved over the two months.

HGCU annubar impulse line leak - (23.36% of operating time) - The gas flow in the HGCU system is measured by an annubar installed downstream of the HGCU filter. The sensing line from this annubar corroded at the point where the acid dew point of the gas was reached. The sensing line was isolated upstream of the leak, and the PFBC unit continued to operate. After the sensing line was repaired, it was heat traced to resolve the problem.

Frozen coal - (19.08% of operating time) - During the extreme cold of early 1993, typical of coal-fired power plants during extreme cold periods, the unit experienced frozen coal problems with the coal handling system. These problems were in the original plant coal-handling system and were not PFBC-related.

The remaining events for 1992 represented a very low percentage and are not discussed further but are shown in Table 4.10.1

Table 4.10.1 - Listing of Non-MWHr Lost Curtailments

Listing of Non-MWHr Lost Curtailments						
System #	Description	Number of Occurrences	Total Hours	Average Hours	Percent of Total Year	Percent of Operating Time
1992						
271	Secondary ash removal plugged	22	1447	65.8	16.47%	57.35%
274	Bed reinjection vessels	2	308.1	154.1	3.51%	12.21%
328	Precipitator	1	73.5	73.5	0.84%	2.91%
266	Coal injection paste pumps	22	70.1	3.2	0.80%	2.78%
262	Coal preparation coal crusher	2	65.2	32.6	0.74%	2.58%
268	Sorbent injection	10	60.9	6.1	0.69%	2.41%
333	HGCU compressor	3	49.8	16.6	0.57%	1.97%
333	HGCU piping	4	44.5	11.1	0.51%	1.76%
252	Bed preheater	1	1.2	1.2	0.01%	0.05%
1993						
271	Secondary ash removal plugged	2	467.2	233.6	5.33%	20.09%
333	HGCU high differential pressure	1	209.2	209.2	2.39%	8.99%
268	Sorbent injection - various components	10	145.9	14.6	1.67%	6.27%
264	Sorbent preparation - various components	7	39.6	5.7	0.45%	1.70%
333	HGCU compressor	1	22.8	22.8	0.26%	0.98%

Listing of Non-MWHr Lost Curtailments						
System #	Description	Number of Occurrences	Total Hours	Average Hours	Percent of Total Year	Percent of Operating Time
310	Gas turbine casing leak	1	22.6	22.6	0.26%	0.97%
272	Bed ash removal conveyors	1	7	7.0	0.08%	0.30%
266	Coal injection paste pumps	2	6.4	3.2	0.07%	0.28%
310	Gas turbine instrumentation	1	5	5.0	0.06%	0.21%
266	Coal injection splitting air compressor	1	4.9	4.9	0.06%	0.21%
271	Primary ash system discharge feeder	1	4.7	4.7	0.05%	0.20%
999	Balance of plant - misc	2	4.5	2.3	0.05%	0.19%
274	Bed reinjection vessels	2	2.4	1.2	0.03%	0.10%
1994						
333	HGCU annubar casing leak	1	124.5	124.5	8.79%	23.36%
999	Frozen coal	1	101.7	101.7	7.18%	19.08%
266	Coal injection paste tank agitator	1	8.7	8.7	0.61%	1.63%
266	Coal injection paste pumps	3	7.9	2.6	0.56%	1.48%

4.10.4 1992 Availability Data

This section addresses the outages and load curtailments that occurred during the 1992 calendar year. The major events that year are discussed below and all of the outages or load curtailments are listed in Table 4.10.2. For each type of event, the total lost MWHr for outages and curtailments are divided by the total possible generation to calculate the Equivalent Forced Outage Rate (EFOR).

Gas Turbine LPT blades - (EFOR = 13.96%) - In March 1992, cracks were found in the gas turbine low-pressure turbine blades which required a 51-day outage to replace the blades.

HGCU system - (EFOR = 9.88%) - In May 1992, the Hot Gas Clean Up slipstream system was installed. The outages and curtailments listed for HGCU include outages for failure of a HGCU piping expansion joint, time to disconnect and later reconnect the system to the PFBC Island, and other curtailments due to hot spots, high differentials, etc. It should be noted that the HGCU system was an experimental slipstream process that was not integral to the PFBC Island process.

Combustor inspections - (EFOR = 8.31%) - On at least three occasions in 1992, the unit was removed from service after a series of performance tests for the sole purpose of component inspections after the previous long run. In a commercial plant, these type of outages would not occur.

Coal injection nozzles and lines - (EFOR = 8.27%) - During 1990 through 1992 the unit was very susceptible to curtailments and outages caused by poor coal paste quality. Without the proper mixture of fines in the crushed coal, the paste became unpumpable, the paste lines plugged and the pumps stop pumping. The pluggage was usually caused when coarse coal accumulated in one paste pump or injection line and became unpumpable. The paste pump would then stop pumping due to high differential pressure on the line. Bed firing conditions would become unstable, and the unit usually tripped within a few minutes upon loss of a paste pump. As operations experience was gained, the ability to operate the unit with one paste pump out of service improved and, by 1992, the unit could be operated with one pump out of service. In Spring 1992, modifications to the coal preparation system and the installation of the coal recycle loop made a dramatic improvement on the coal paste consistency and the reliability of the crushed coal product. This improved paste product resulted in a significant reduction in paste pump and line pluggages.

Boiler gas side tube bundle deposit inspection - (EFOR = 4.92%) - In late summer, after testing injecting sorbent fines in with the paste, the combustor was shut down for inspections or the tube bundle. During that outage other modifications and repairs were made to the unit.

Bed preheater - (EFOR = 4.15%) - The availability of the bed preheater has been a problem throughout the project. Just prior to the G. T. LPT blade problem, failures were found in the preheater burner cans that required their replacement. In addition, on other occasions due to dirt, valve problems, and igniter problems, unit startups were delayed when the preheater could not be started.

HGCU ash removal piping - (EFOR = 3.52%) - During November 1992, the unit was removed from service when ash bridged across the bottom of the APF hopper and plugged up in the ash removal system. The unit was removed to prevent ash from building up into the APF vessel.

Gas Turbine LPT - (EFOR = 3.43%) - During October 1992, the coupling between the gas turbine LPC and LPT became loose in service when the coupling bolts backed out. When this was discovered during the following outage, the outage was extended to repair the coupling and shaft damage caused by the loose coupling.

Bed dynamics - (EFOR = 2.89%) - During the first several years of the project, the unit experienced bed sintering as addressed in Section 5.2. Sometimes the bed sintering problems resulted in only a load curtailment on the unit due to poor bed dynamics. On other occasions, usually when firing limestone, the bed dynamics became so unstable that the unit was removed from service.

Auxiliary transformer protection - (EFOR = 2.49%) - During a run in January 1992, while starting a feed pump, an auxiliary transformer trip occurred due to some incorrect wiring on the transformer protection circuit.

Secondary cyclone ash removal cooler and piping - (EFOR = 2.41%) - In the beginning of 1992, the unit was out of service for installation of a dip leg stirring air system in all of the secondary cyclone dip legs in order to improve secondary ash line transport availability. This was eliminated when the secondary ash removal system was redesigned in 1993.

Bed ash reinjection vessels - (EFOR - 1.63%) - As addressed in Section 4.10.3, the reinjection vessel "L" valves were prone to blockage. During this particular unit startup, the south reinjection "L" valve became plugged. At coal fire, the firing controls tripped the unit due to an incorrect control setting. Once the unit tripped there was insufficient material left in the one operable reinjection vessel to continue with the startup, so the unit was removed from service.

Boiler water/steam - misc. leak - (EFOR = 1.42%) - A leak was found in a boiler drain connection outside of the boiler but inside of the combustor. The unit was removed from service to fix the leak.

Primary cyclones plugged - (EFOR = 1.31%) - Two outages occurred late in the year due to problems with the primary cyclones. During a startup in November 1992, high ash elutriation rates, during startup bed building, overwhelmed the primary cyclones and plugged several cyclones. At the end of the year, during operation, an air leak developed in a primary cyclone bellows box and gave the indication that the primary cyclone was plugged. The unit was shut down to investigate the problem.

Primary cyclones plugged - fire - (EFOR = 1.26%) - In early January 1992, a series of events resulted in an ash fire that plugged the primary #15 cyclone and ash removal line, requiring the unit to be removed from service. Thirty minutes before the trip, the sorbent system tripped from service for unknown reasons. Ten minutes later a paste pump tripped and remained out of service. The resultant upset in bed temperatures and lack of ash loading to the cyclones caused an increase in cyclone temperatures and fire in several cyclones. The high cyclone temperatures resulted in ash sintering in the cyclones and pluggage of the ash line suction nozzle.

The remaining events for 1992 represent a small percentage and are not discussed further, but are shown in Table 4.10.2.

Table 4.10.2 - Listing of 1992 Lost MWHr Curtailments and Outages

Listing of 1992 Lost MWHr Curtailments and Outages							
System No.	Description	Unit Outages			Curtailments		Total MWHr EFOR
		Outages # Times	Lost MWH	Calc Hours	Curtail. # Times	Lost MWH	
310	Gas Turbine LPT blades	1	85834	1226.2	0	0	13.96%
333	HGCU system - piping, expansion joints, tie-in outages, etc.	4	58968	842.4	2	1790	9.88%
211	Combustor inspections	3	51079	729.7	0	0	8.31%
266	Coal injection nozzles & lines	8	50435	720.5	4	427	8.27%
225	Boiler gas side tube bundle deposit inspection	1	30261	432.3	0	0	4.92%
252	Bed preheater	3	25487	364.1	0	0	4.15%
333	HGCU ash removal piping	1	21623	308.9	0	0	3.52%
310	Gas Turbine LPT	1	21084	301.2	0	0	3.43%
222	Bed dynamics	2	17794	254.2	0	0	2.89%
611	Auxiliary transformer protection	1	15330	219.0	0	0	2.49%
271	Secondary cyclone ash removal cooler and piping	1	14833	211.9	0	0	2.41%
274	Bed ash reinjection vessels	1	10003	142.9	0	0	1.63%
225	Boiler water/steam - misc. leak	1	8722	124.6	0	0	1.42%
231	Primary cyclones plugged	2	8078	115.4	0	0	1.31%
231	Primary cyclone plugged - fire	1	7770	111.0	0	0	1.26%
262	Coal prep crusher	1	1064	15.2	2	2242	0.54%

Listing of 1992 Lost MWHr Curtailments and Outages							
		Unit Outages			Curtailments		Total MWHr EFOR
System No.	Description	Outages # Times	Lost MWH	Calc Hours	Curtail. # Times	Lost MWH	
266	Coal injection paste pumps	3	2296	32.8	1	10	0.38%
510	Controls - Net-90 logic problem - other	1	1421	20.3	0	0	0.23%
333	HGCU filter	0	0	0.0	1	1187	0.19%
262	Coal prep sizer	1	1092	15.6	0	0	0.18%
262	Coal prep feeders/conveyors	1	875	12.5	0	0	0.14%
327	Economizer	1	840	12.0	0	0	0.14%
510	Controls - Net-90	1	798	11.4	0	0	0.13%
414	Steam turbine generator instrumentation	0	0	0.0	1	660	0.11%
510	Controls - field instruments	1	630	9.0	0	0	0.10%
310	Gas Turbine HPT	1	581	8.3	0	0	0.09%
310	Gas Turbine instrumentation	1	525	7.5	0	0	0.09%
252	Bed preheater oil system	1	469	6.7	0	0	0.08%
510	Controls - human error	2	357	5.1	0	0	0.06%
999	Balance of plant - all other	0	0	0.0	1	257	0.04%
264	Sorbent prep - screen/feeder	0	0	0.0	1	145	0.02%
1000	1992 Subtotals	46	438249	6260.7	13	6718	72.37%

4.10.5 1993 Availability Data

This section addresses the outages and load curtailments that occurred during the 1993 calendar year. The major events that year are discussed below and all of the outages or load curtailments are listed in Table 4.10.3. For each type of event, the total lost MWHr for outages and curtailments is divided by the total possible generation to calculate the Effective Forced Outage Rate (EFOR).

Gas Turbine LPT blades - (EFOR = 38.00%) - In February 1993, failure of LPT first-stage blades occurred in service which required a 138-day outage to replace the blades and rebuild the gas-turbine.

Primary cyclones plugged - (EFOR = 8.08%) - Four outages occurred in 1993 because of plugs in the primary cyclone ash removal system. In most cases, these plugs occurred as a result of air inleakage into the system. Air inleakage into the primary ash system has been a continuing problem at Tidd and is the result of gasket failures in the ash cooler return chambers. Due to the replacement cost of these assemblies, this problem was not modified at Tidd but instead was addressed as a maintenance issue during every outage. Occasionally, an upset occurred at startup that would result in pluggage of an ash line. As the air inleakage into the system increased over time, the capacity of the system decreased and the system's ability to handle upsets diminished.

Bed dynamics - (EFOR = 6.93%) - During the first several years of the project, the unit experienced bed sintering as addressed in Section 5.2. Sometimes the bed sintering problems resulted in only a load curtailment on the unit due to poor bed dynamics. On other occasions, usually when firing limestone, the bed dynamics became so unstable that the unit had to be removed from service due to high bed and evaporator temperatures.

Gas Turbine LPC - (EFOR = 6.35%) - In late 1993, during a routine inspection, cracks were found in several LPC stationary guide vanes and on an inner guide ring. The unit remained out of service into 1994 for replacement of the damaged components.

Sorbent injection piping/ valves - (EFOR = 5.40%) - As operating time on the unit increased, failures in non-lined steel sections of the sorbent injection piping occurred with more frequency.

Gas Turbine LPT - (EFOR = 3.48%) - After the gas turbine blade failure in earlier 1993, the gas turbine was instrumented for dynamic testing when the unit was returned to service. The unit was started up and tested for a short period and then shut down to remove the test blades and instrumentation equipment from the turbine shaft.

Gas Turbine HPT - (EFOR = 2.57%) - The unit was curtailed at a reduced load for 426 hours in the summer 1993 due to high vibration on the gas-turbine number five bearing. During the subsequent outage, a balance shot was installed and the high vibration problem was resolved.

HGCU filter - (EFOR = 1.42%) - The unit was removed from service in August 1993 when ash plugged the HGCU filter hopper and started to build up in the HGCU vessel.

Combustor inspections - (EFOR = 1.41%) - In late January 1993, the unit tripped due to a Network-90 control fault. After the trip, it was decided to keep the unit out of service for several days to complete some outage inspections and minor repairs/ modifications.

The remaining events for 1993 represent a small percentage and are not discussed further, but are shown in Table 4.10.3

Table 4.10.3 - Listing of 1993 Lost MWHr Curtailments and Outages

Listing of 1993 Lost MWHr Curtailments and Outages							
System No.	Description	Unit Outages			Curtailments		Total MWHr EFOR
		No. of Outages	Lost MWH	Calc Hours	Curtail. # Times	Lost MWH	
310	Gas Turbine LPT blades	1	232995	3328.5	0	0	38.00%
231	Primary cyclones plugged	4	49525	707.5	0	0	8.08%
222	Bed dynamics	2	42210	603.0	1	282	6.93%
310	Gas Turbine LPC	1	38920	556.0	0	0	6.35%
268	Sorbent injection piping/valves	3	33103	472.9	0	0	5.40%
310	Gas Turbine LPT	2	21322	304.6	0	0	3.48%
310	Gas Turbine HPT	0	0	0.0	1	15777	2.57%
333	HGCU filter	1	6328	90.4	3	2388	1.42%
211	Combustor inspections	1	8624	123.2	0	0	1.41%
252	Bed preheater	2	4081	58.3	0	0	0.67%
262	Coal prep crusher	0	0	0.0	3	3672	0.60%
266	Coal inj. splitting air compressor	1	3290	47.0	0	0	0.54%
310	Gas Turbine instrumentation	1	2282	32.6	0	0	0.37%
999	Balance of plant - all other	3	1897	27.1	0	0	0.31%
510	Controls - Net-90	1	1680	24.0	0	0	0.27%
266	Coal injection paste pumps	1	1456	20.8	0	0	0.24%
252	Bed preheater oil system	1	1064	15.2	0	0	0.17%
264	Sorbent prep - screen/feeder	0	0	0.0	1	705	0.11%
225	Boiler water/steam - other	1	168	2.4	0	0	0.03%
1000	1993 Subtotals	26	448945	6413.5	9	22824	76.94%

4.10.6 1994 Partial Year Availability Data

This section addresses the outages and load curtailments that occurred during 1994. Please note that this period was for only January and February. The fourth year of operations began on March 1, 1994 and will be discussed in a separate report. The major events during the first two months are discussed below and all of the outages or load curtailments are listed in Table 4.10.4. For each type of event, the total lost MWHr for outages and curtailments are divided by the total possible generation to calculate the Equivalent Forced Outage Rate (EFOR). **The EFOR percentages are relatively high, since the calendar period was only 1416 hours.**

Boiler water/steam-tube bundle - (EFOR = 29.86%) - In late January 1994, the unit was removed from service when a boiler sidewall tube failed and steam cut several tube bundle tubes in the bed. The sidewall failure was the result of air inleakage across a faulty boiler door gasket, located below the waterwall tube failure.

Gas turbine LPC - (EFOR = 15.61%) - The gas turbine LPC guide vane outage in late 1993 carried over, and was completed in early 1994.

Primary cyclones plugged - (EFOR = 8.30%) - During the gas turbine LPC outage above, adjustments were made to the coal injection splitting air flow rate in an attempt to improve combustion. The adjustment was excessive and resulted in significant amounts of unburned carbon carryover into the cyclones at startup. The unburned carbon ignited in the cyclones, forming sinters and plugging several ash lines shortly after startup.

Sorbent injection booster compressor - (EFOR = 5.85%) - During normal operation, the sorbent booster compressor guide vanes stuck open and the compressor went into surge and tripped. Dirt and corrosion on the guide vanes was found to be the problem for the sticking vanes.

The remaining events for 1994 represent a small percentage and are not discussed further, but are shown in Table 4.10.3

Table 4.10.4 - Listing of 1994 Lost MWHr Curtailments and Outages

Listing of 1994 Lost MWHr Curtailments and Outages							
System No.	Description	Unit Outages			Curtailments		Total MWHr EFOR
		Outages # Times	Lost MWH	Calc Hours	Curtail. # Times	Lost MWH	
225	Boiler water/steam-tube bundle	1	29596	422.8	0	0	29.86%
310	Gas Turbine LPC	1	15470	221.0	0	0	15.61%
231	Primary cyclones plugged	1	8225	117.5	0	0	8.30%
268	Sorbent injection booster compressor	1	5796	82.8	0	0	5.85%
333	HGCU piping	1	931	13.3	0	0	0.94%
266	Coal injection splitting air compressor	1	882	12.6	0	0	0.89%
999	Balance of plant - all other	1	322	4.6	0	0	0.32%
222	Bed dynamics	0	0	0.0	1	305	0.31%
252	Bed preheater oil system	1	210	3.0	0	0	0.21%
266	Coal injection paste pumps	0	0	0.0	1	98	0.10%
266	Coal injection nozzles & lines	0	0	0.0	1	13	0.01%
1000	1994 Subtotals	8	56854	812.2	4	417	57.78%

4.10.7 General Redundancy Recommendations and Conclusions

This section addresses the general issue of the need for redundancy on various systems and components. Further details on system and component operations, modifications and recommendations can be found under the appropriate system number in Section 6.0 System

Summaries. Below is a listing of the major systems in the plant and some suggested redundancy considerations for a commercial 70-MW unit. These recommendations are based on the final configuration of the plant and does not address previous modifications made to the original plant and system designs.

Boiler Systems:

This section includes the boiler, boiler bottom, freeboard, tube bundle, combustor vessel, economizer, and auxiliary equipment, such as the O_2 analyzer system, freeboard injection, etc.

The availability of the boiler, freeboard, and tube bundle are acceptable. The boiler wall liners must be improved for longer life. The oxygen analyzer system must be improved to reduce excessive maintenance requirements. Consideration should be given for spare analyzers to permit on-line maintenance of them without impacting unit operations. The tube bundle operation appears to be acceptable, but may require some improvements on support structure. The boiler bottom ash cooling method must be improved to permit higher ash flowrates without overheating. The boiler circulation pump operation was acceptable after bearing material improvements were implemented, and all construction debris was finally purged from the system. A complete spare pump rotor should be considered for quick changeout if problems occur.

Improvements must be made to the combustor vessel to reduce outage length times. These include an extensive combustor vessel cooling and ventilation system for use during shutdowns and outage work. Installation of maintenance aids, such as a vacuum header system, compressed air system, and complete lighting system throughout the combustor vessel, are essential.

A proper conventional insulation lagging system is required on all insulated surfaces in the combustor to improve cleaning of surfaces and personal protection in tight areas.

The economizer must be designed to permit adequate sootblowing of finned tube surfaces and ease in cleaning of ash buildup along the floor and ductwork bottom. Sufficient sootblowers are required to optimize cleaning ability. Ductwork casing must address the corrosive nature of the ash buildup and high SO_3 levels, given the environment of an exterior ductwork economizer module.

Gas Turbine Systems:

This section covers the gas-turbine compressor, turbine, and generator, along with auxiliary systems required, such as control fluid, lube oil, and gas-turbine cleaning.

The gas turbine unit was the most significant cause of unavailability during the first three years of operation of the Tidd PFBC Demonstration Plant. Major impacts in availability occurred as the result of LPT blade cracks discovered during Spring 1992, LPT blade failures that occurred in Spring 1993, and LPC guide vane blade attachment brazing cracks found late in 1993. In addition, excessive air leakage from the HPC to the HPT resulted in reduced air availability to the combustor. All of these problems and the associated downtime and reduced unit output are mainly attributable to design flaws associated with the initial production run of ABB Stal GT-35P machines. Second- and later-generation machines will undoubtedly experience improved availability and performance from design changes that were implemented as a result of the experiences at Tidd and its sister units in Europe. However, outages induced by GT problems will likely remain as the main cause of unit outages and downtime in future generation PFBC commercial plants. For this reason, as well as the need for periodic overhauls, future commercial units would benefit from having spare GT compressor and turbine modules maintained on site. Had such spares been maintained at Tidd, it is estimated that the 138-day LPT blade failure outage experienced in Spring 1993 would have been reduced to a period of 10 to 14 working days. This would have reduced the EFOR for that outage from 38% to 3.8%. With respect to planned periodic overhauls, availability of the spares would minimize the length of outage needed. The removed modules could be rebuilt under reduced time constraints after the unit is returned to service.

The availability of the rest of the gas turbine auxiliary equipment, the generator, and associated components appeared to be acceptable during the demonstration period. No installed redundancy would be required. However, two of three instrumentation trip logic arrangements should be included for vibration, control fluid pressure, lube oil tank levels, and other critical pressures and temperatures.

Coal Preparation and Injection:

This section includes the coal paste preparation and paste injection systems and the fuel nozzles in the fluidized bed. The coal yard-to-plant bunker systems are not addressed. Tidd utilized the original plant systems, which were designed for 800 tons/hour and which do not represent the true requirements for a 70-MW PFBC plant.

The double-roll coal crusher installed as part of the coal preparation system was found to be a highly power-efficient device with low operating cost for crushing coal to the size consist required for the PFBC technology. The major issue with the crusher was its crushed product quality reliability and constant uncertainty of how it would crush coals from different sources and mines. Experience has shown that this crusher, in its recycle mode of operation, was sufficient to crush Pittsburgh #8 coal from a specific mine. However, before any other coal was tested at the plant, a test crushing was required to see if the coal could be prepared at the capacities required. In most cases, the alternate coal source could not be used due to poor crusher product quality reliability. It is anticipated that this issue could be overcome with installation of a second 100% redundant coal preparation system and crusher of the same design as Tidd. The availability and flexibility could be further enhanced by the installation of a slipstream vertical wet ball mill similar to those used in the limestone industry. This mill would provide the ability to produce additional paste fines to complement the roller mills and produce a consistent paste product.

The installation of two 100% or three 50% redundant coal preparation systems would address all other redundancy issues with coal preparation individual components.

The coal paste injection system should include the installation of a seventh paste pump and injection nozzle as a minimum. While operation of Tidd was achievable with five pumps, bed stability was risky. The seventh pump would permit pump maintenance to occur without undue risk to the unit. Flexibility would also be achieved if a fuel nozzle plugged at startup or operation. Tidd did not proceed with startup if a nozzle plugged, but a spare pump and nozzle would provide sufficient operational flexibility.

The location and number of fuel injection points in the bed was an ongoing issue. Due to the complexity of the nozzles and vessel penetrations, modifications could not be accomplished to resolve this issue. At a minimum, more nozzles would be required and their location in the bed would need to be resolved.

Sorbent Preparation and Injection:

This section includes the sorbent preparation and injection systems. The sorbent handling system from the Tidd yard utilized the existing Tidd plant coal handling system. Like the coal handling system, it was significantly oversized, and is not addressed here.

The sorbent preparation system was a significant maintenance issue throughout the Tidd project life. Modifications were continuously being made to the system in an effort to improve its wear life or improve the product size consist of the prepared sorbent. At its very best, the sorbent preparation system was only capable of 30 continuous days of operation before it needed major overhaul maintenance on the crusher, cyclone, screens, and ductwork/chutes. At a minimum, the system needs 100% redundancy, plus significant improvements on wear rates and product size distribution. Further research would be required to find a crusher that can withstand the abrasive nature of the dolomite and remain in service for longer than 30 to 45 days. Improvements are also required on the system's ability to produce the desired size distribution.

The sorbent injection system would require the two lockhopper trains to be reconfigured in series on the transport line instead of parallel so that the sorbent injection into the bed would be constant. The existing design alternates between lockhopper trains and results in a pause in flow rate between lockhoppers. Ceramic lining of all components in the injection piping system is required, along with special coating of all transport line valves.

Cyclone Ash Removal:

This section addresses both the primary and secondary ash removal systems and their associated cyclones.

The primary ash removal system continues to be a major maintenance issue that can impact unit availability. For economic reasons, the primary ash system internal ash coolers and piping tee bends were not replaced during the demonstration period with a more reliable design. Instead, the system was maintained with extensive gasket replacement. However, at high loads and temperatures, excessive numbers of gaskets would burn out, impacting system availability. For a commercial plant, the primary ash system would need to be flangeless and air tight. In addition, all the ash lines should penetrate the combustor vessel so that if pluggage occurred, the line could be blown down. In addition, all the primary cyclone dip legs should penetrate the combustor vessel so that they can be cleaned out from outside the vessel if the cyclones become plugged. If the system were adequately designed and airtight, it should be very reliable. There is no practical method of having redundancy on the ash lines or cyclones.

Secondary ash lines and cyclones as modified at Tidd are adequate for a commercial plant design, provided spare bends are available and worn bends are replaced periodically.

Bed Ash Removal:

This section covers the bed ash removal system from the boiler bottom to the ash silos.

In general, this system has been problem-free after several modifications early in the project. Isolation and venting valves continue to be maintenance issues, and could be considered for redundant valves. A complete redundant lockhopper train would enhance operations capabilities and flexibility if a valve failed in service.

Several failures of the transport conveyor belts occurred but did not impact unit operations, since a vacuum truck was used to remove bed ash while the belts were being repaired.

Valves in Solid Transport Systems:

An extensive and routine amount of maintenance was required in valves located in lines that transported solid materials such as sorbent injection, bed ash removal, HGCU, and cyclone ash removal. Generally, it was found through experience that the right combination of valve materials would survive in these harsh operating conditions. This included body and ball materials, coatings, seats, and clearances. However, experience has also shown that valves installed in material transport lines need to have complete spares stored at the plant so that the valves can be changed during a short outage and the old valves can be shipped out for repair/ rebuild.

Figure 4.4.1 - Ca/S Molar Ratio vs. Bed Height at 90% SR.

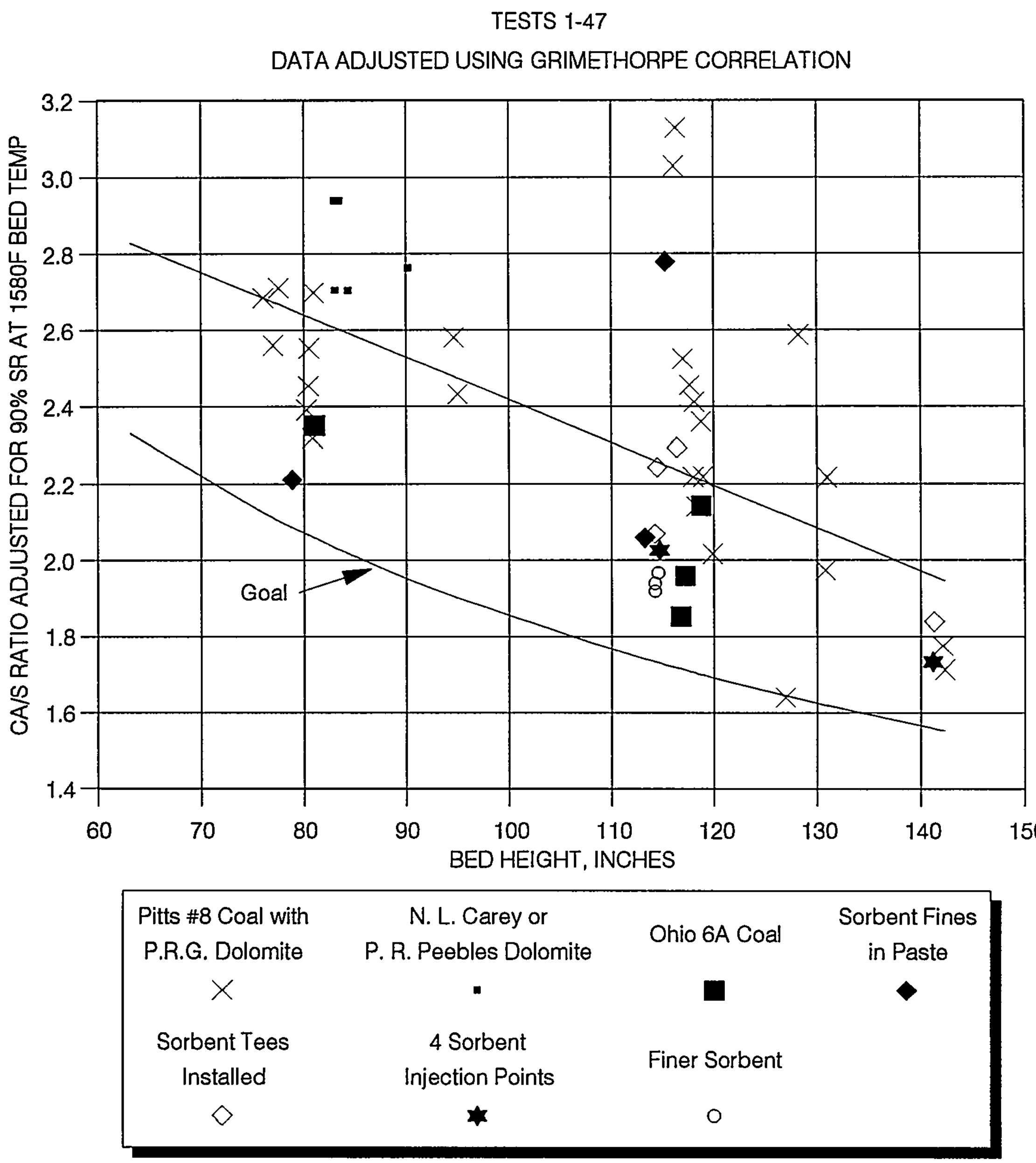
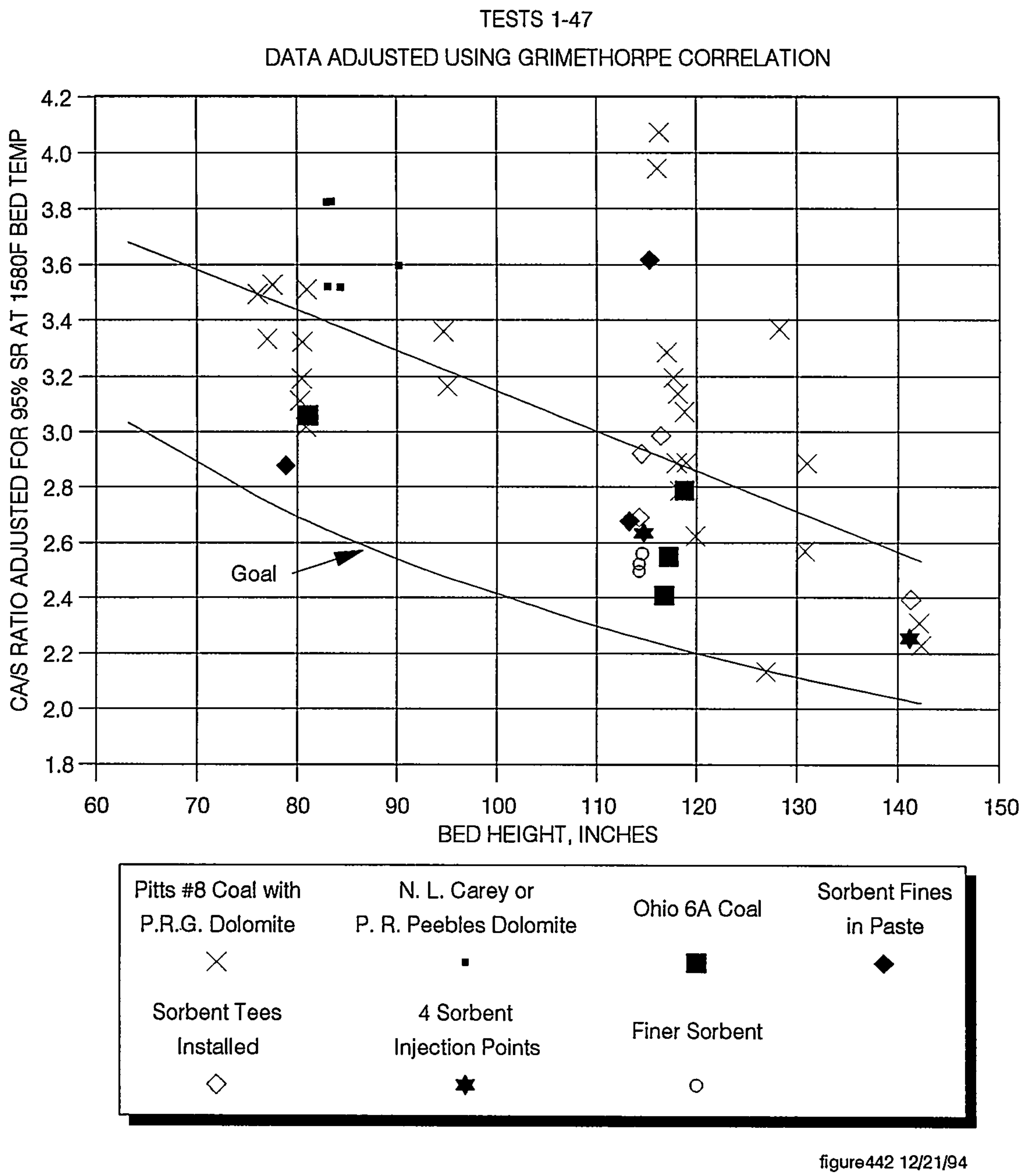


figure441 12/21/94

Figure 4.4.2 - Ca/S Molar Ratio vs. Bed Height at 95% SR.



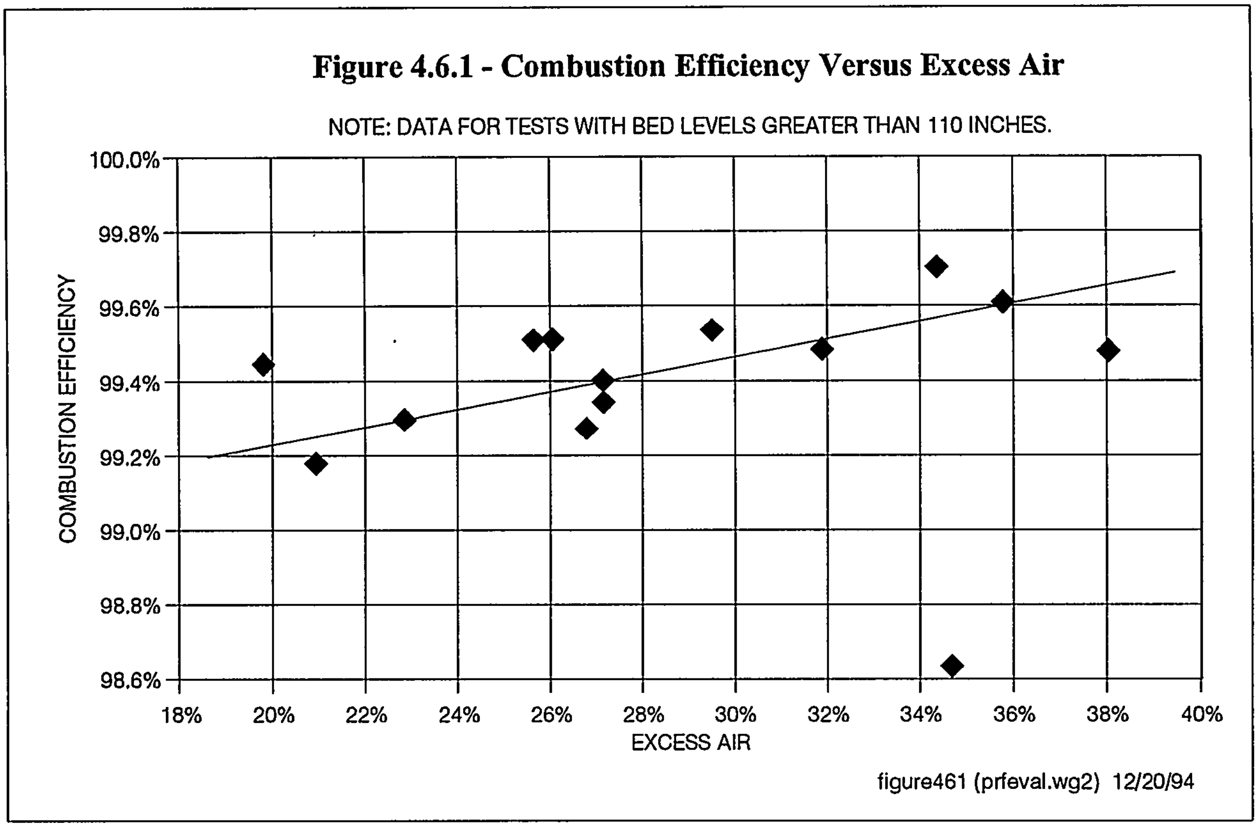


Figure 4.6.1 - Combustion Efficiency Versus Excess Air
NOTE: DATA FOR TESTS WITH BED LEVELS GREATER THAN 110 INCHES.
COMBUSTION EFFICIENCY
100.0%
99.8%
99.6%
99.4%
99.2%
99.0%
98.8%
98.6%
18%
20%
22%
24%
26%
28%
30%
32%
34%
36%
38%
40%
EXCESS AIR
figure461 (prfeval.wg2) 12/20/94

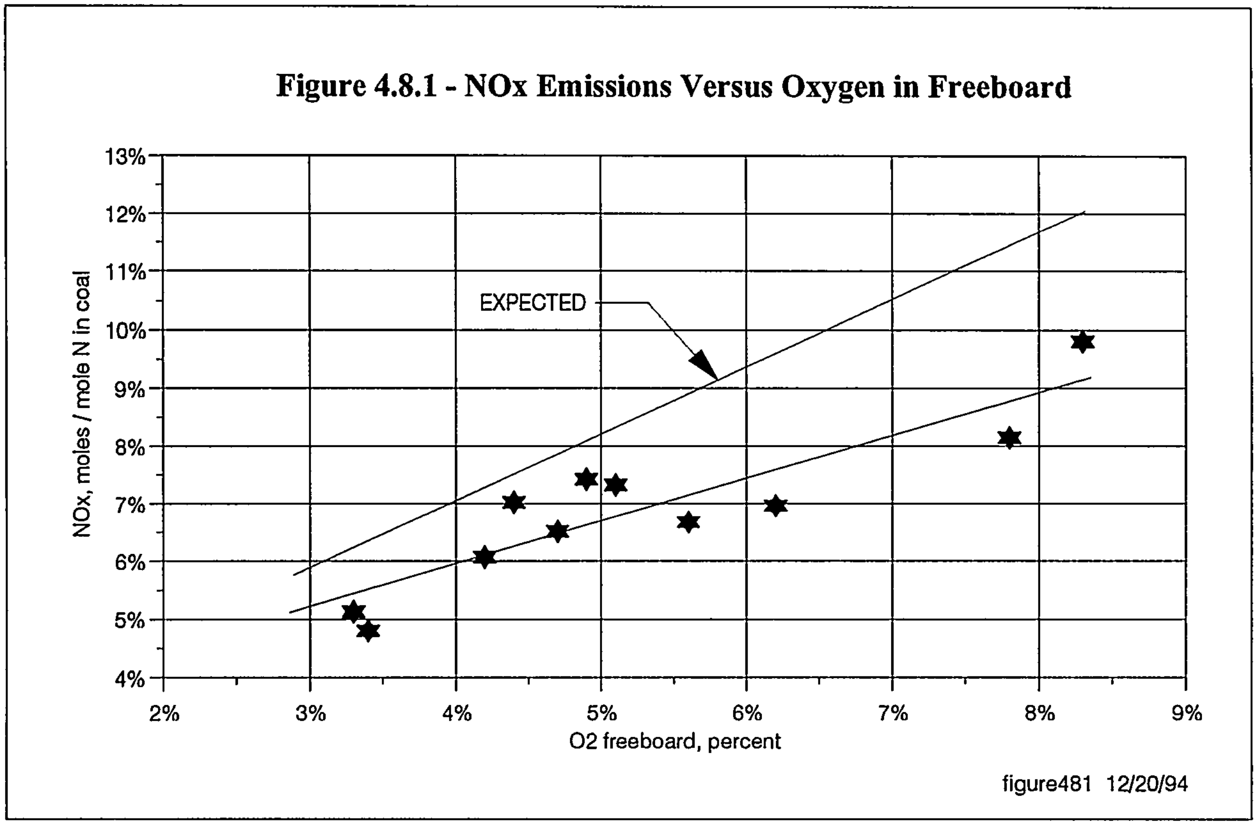


Figure 4.8.1 - NOx Emissions Versus Oxygen in Freeboard
13%
12%
11%
10%
9%
8%
7%
6%
5%
4%
NOx, moles / mole N in coal
EXPECTED
2%
3%
4%
5%
6%
7%
8%
9%
O2 freeboard, percent
figure481 12/20/94

5.0 Significant Findings

Section 5.0 discusses in overview the main issues that impacted unit operations.

5.1 Post-Bed Combustion

5.1.1 Background

The design basis of ABB Carbon's bubbling-bed PFBC process assumes that complete combustion of both the coal volatiles and char takes place within the fluidized bed. Furthermore, in order to maximize the available energy to the gas turbine, the gas path between the top of the tube bundle and the gas turbine inlet is insulated. Therefore, the freeboard, cyclones, gas collection manifold, crossover pipe and gas turbine inlet temperatures closely follow the bed temperature when operating at full bed height.

Given the above design criteria, any post-bed combustion would result in excessive gas temperatures downstream of the fluidized bed. Such excessive temperatures would not be tolerable, since cost-effective material selection allowed little margin over the relatively high (1526 F - 1580 F) expected full-load operating temperatures.

5.1.2 Experience

During the first year of unit operation, two distinct types of post-bed combustion were identified; fine char combustion in the cyclone dip legs and volatile combustion at the cyclone inlets.

The fine char combustion was evidenced by certain primary cyclone dip leg temperatures rising well above the temperatures in the other cyclone dip legs. This type of post-bed combustion resulted in melting of the ash in the affected dip legs, which then plugged the associated ash removal lines.

Volatile combustion at the cyclone inlets was evidenced by a rise in the bulk gas-stream temperature in some, but not all, of the cyclone strings. The high temperatures in the affected cyclone string(s) approached the material temperature limit trip points, and at higher loads resulted in sufficient rise in the temperature of the gas collected from all of the strings to encroach on the gas turbine material temperature limitations.

5.1.3 Causes

It has been theorized that the post-bed volatile combustion is caused by highly localized release of coal volatiles near the fuel nozzle discharge points. The volatiles then pass vertically up through the bed with the air/combustion gases. Due to the high concentration of the volatiles in these regions, there is insufficient oxygen available to completely burn them. Therefore, some of the volatile compounds escape the bed unburned. In addition, there is high localized evaporation of paste moisture in these regions, which likely also passes up with the volatiles thus diluting the air available for volatile combustion. These regions of unburned volatiles, steam and combustion gases are called "plumes". When these plumes reach the cyclone inlets they mix with high oxygen concentration gases from other regions of the bed. If the freeboard temperature is high enough, the volatiles burn, raising the temperature of the gas. Validation of this theory was provided by measuring oxygen concentrations in the boiler freeboard directly above a fuel discharge and at varying distances away from it. This data, collected in March 1991, revealed extremely low oxygen concentrations directly above a fuel nozzle while other regions away from the fuel nozzles had oxygen concentrations well above the average of the bulk gas. The fuel discharge region plume problem is attributed to excessive scale-up in the ratio of bed-plan-area-per-fuel-nozzle between the pilot plant design and the P200 Tidd design.

One theory regarding post-bed char combustion is that it is caused by elutriation of unburned fine char particles throughout the bed at intermediate bed heights where the freeboard gas temperature is sufficiently high to support combustion, yet the bed residence time is low. The fine char, which is not very reactive, rapidly escapes the bed due to its small size and gathers in the primary cyclones. It then becomes concentrated in the cyclone dip legs, providing conditions necessary to sustain char combustion. It is believed that at higher bed heights, longer in-bed residence times result in less char carryover. Hence the problem disappears. An alternate theory postulates that fine char is released at the fuel discharge region and passes up within the above-noted plumes. The char is not burned in the bed due to insufficient oxygen availability within the plumes, hence the char burns in the cyclone dip legs where it becomes concentrated. It is likely that the mechanisms from both of these theories are involved in the dip-leg char combustion.

5.1.4 Modifications

The first modifications applied to help resolve the plume problem were installing fuel deflectors ("skateboards") in the bed just above each of the six fuel-nozzle outlets, and apportioning more of the fluidizing/combustion air to these regions (Refer to Section 6.2.2 for more details). The next step was to reduce the fuel splitting air, which results in larger paste lumps within the bed, thus slowing down the devolatization of the coal. The volatiles would then be better spread out through the bed as the paste lumps migrated away from the fuel discharge regions.

The splitting air reduction was taken one step further during the Fall 1991, when the fuel nozzles were modified to a new single-stage-splitting-air configuration. (Refer to Section 6.8 for more details). The intent of this change was to eliminate fine splitting of the coal paste, thus slowing down the volatile release. Atmospheric testing of the two-stage nozzle had shown that the secondary splitting air tended to overly split the outer portion of the fuel-nozzle discharge cone.

In addition to the above-noted fuel nozzle modification, a freeboard gas mixing system was installed in the boiler in the Fall 1991 outage (Refer to Section 6.1 for more details). The mixing system was intended to cause the volatiles in the plumes to burn in the freeboard, thus spreading the associated heat release over the entire gas stream. This would eliminate concentration of the heat release in one or two cyclones, thus minimizing temperature extremes. However, this did not affect the temperature of the gas downstream in the gas collection manifold, hence gas turbine temperature limitation issues would not be mitigated by this modification.

By the first quarter of 1992 it was recognized that the consistency of the coal paste had a significant impact on the amount of post-bed combustion. Coal paste with sufficient fines was shown to produce a more cohesive paste product, which did not split as finely and which resulted in less post-bed combustion. During the Spring 1992, a recirculation loop was added to the coal preparation system. Through proper setting of the amount of recirculation to the coal crusher, the ability to produce sufficient coal fines to make the desired paste product was achieved (Refer to Section 6.7 for more details).

5.1.5 Results

A significant impact on fine-char combustion in the primary cyclone dip legs was noted in early 1992, when initiation of freeboard mixing brought an in-progress dip-leg fire under control. While freeboard mixing was originally intended mainly for control of localized cyclone string gas temperature extremes associated with post-bed volatile combustion, this experience revealed that it also had positive effects on the dip-leg combustion problem. This positive experience played a major role in the subsequent continual use of freeboard mixing. The net effect of freeboard mixing appeared to be that of equalizing the dip-leg temperatures. This experience appears to validate the plume-related theory of post-bed char combustion, since positive effects from mixing indicate that the concentration of fines was localized prior to the initiation of the mixing. Dip-leg combustion did recur once with freeboard mixing. This event occurred in early 1994 after re-implementation of dual-stage fuel splitting air was employed in an attempt to prevent excessive sinter formation. The dip-leg fire occurred during a unit start-up in which the secondary splitting air flow was inadvertently set too high.

While the installation of the "skateboards", the higher apportionment of air and the reduced and modified fuel splitting all appeared to help in regard to the post-bed volatile combustion problem, the most significant and repeatable improvements were noted with the improved coal paste and the freeboard mixing system. Freeboard mixing acted as intended to spread out the heat release associated with post-bed volatile combustion, thereby causing it to occur in the freeboard. Improved coal paste, on the other hand, acted directly on the cause, resulting in dramatic reductions in the post-bed heat release. By the end of the three-year operating period, sustained operation with little or no post bed combustion was the norm. However, when there were upsets in coal paste preparation system operation (thereby greatly increasing the paste moisture), dramatic increases in freeboard gas temperature would still occur.

5.1.6 Recommendations for a Commercial Plant

It is apparent from the Tidd experience that the most significant consideration regarding post bed combustion is proper coal paste preparation. Every effort should be made to make the coal paste preparation process more reliable. Another critical aspect is adequate distribution of the coal paste. Even with proper coal paste, low freeboard oxygen measurements still exist above the fuel nozzle outlets. This indicates that there is still highly localized combustion, which undoubtedly makes the unit more susceptible to variations in coal paste quality. An increase in the number of fuel feed points would be a positive step in this regard. Finally, freeboard mixing should be strongly considered for implementation, since it provides a means to minimize the impact of any unwanted post-bed combustion.

5.2 Bed Sintering

5.2.1 Background

Given the relatively low design mean bed temperature of 1580 F and the fact that the burning coal particles are within 300 - 500 F of the bed temperature, the bubbling bed PFBC process should theoretically avoid problems associated with melting of the coal ash constituents. In practice, however, the calcium from the sorbent/bed material can flux the ash constituents resulting in lower melting point eutectics. These eutectics can cause agglomerations which can severely upset the bed.

5.2.2 Experience

Agglomeration of bed particles in the form of hollow egg shaped sinters in the size range of 1/2 - 2 inches was experienced. These agglomerations, called "egg sinters", were generally present all of the time in small quantities, Under these conditions the egg sinters created no significant operating problems, since they were drained away as fast as they were made. However, under some operating conditions the rate of "egg sinter" formation was so great that they accumulated in the bed. When this occurred, the bed conditions would deteriorate due to their collection in undrainable regions at the bottom of the bed and their tendency to become lodged in the tube bundle. Due to the significant ash storage volume in the boiler bottom hoppers, excessive sintering would first show up as deteriorating bed conditions prior to being noticed in increased quantities in the bed drains. Such deterioration included decreasing bed density and tube-bundle absorption, widely varying bed temperatures within the tube bundle region, evaporator outlet leg temperatures gradually becoming dramatically uneven (with some in high alarm and others at saturation) and decreasing bed temperatures just above the tops of the sparge nozzles. If left to continue, the bed conditions would deteriorate until a unit trip would either occur automatically due to three of the lower bed thermocouples dropping below 1200 F, or be initiated manually due to extremely high temperatures on some of the evaporator outlet legs.

When using dolomite as the sulfur sorbent, such excessive sintering was found to occur occasionally at various bed heights, but consistently occurred at full-bed height when the bed temperature was increased above 1500 - 1520 F. In three attempts to use a "magnesian" limestone, which had a much lower magnesium content than dolomite, the "egg sinter" formation rate was excessive under all operating conditions, and in all cases a unit trip resulted due to extremely poor bed conditions.

5.2.3 Causes

From visual observation of the "egg sinters" it was readily apparent that they were formed from bed ash particles that fused together around lumps of burning coal paste; whereafter the coal paste would eventually burn out leaving the hollow sinters. Due to the relatively large size of the sinters, it was furthermore theorized that the larger paste lumps were prone to sintering since such larger lumps would burn at higher temperatures than the smaller paste lumps.

Due to the excessive and uncontrollable "egg sinter" formation that occurred with the magnesian limestone, a decision was taken in the Fall of 1993 to perform a more thorough investigation into the mechanisms involved in the formation of the sinters. The University of North Dakota Energy and Environmental Research Center (UNDEERC) was commissioned to perform a chemical characterization investigation into the causes of the sinters and into the reasons why limestone was more prone to sintering than dolomite. This investigation (refer to UNDEERC Report No. 94-EERC-01-1 for further information) provided the following key findings:

The melt fusing the bed particles was most likely due to calcium from the sorbent-based bed particles fluxing the potassium-alumina-silicate clays from the coal ash.

Smaller paste lumps would likely be less prone to sintering since there would be less coal ash per unit of paste lump surface area.

Increased quantities of magnesium in the sorbent would raise the eutectic temperatures of the possible constituent mixtures, thus the tendency to form sinters would be less likely.

The study also resulted in the following explanation as to the steps involved in the sinter formation:

Coal particles in individual split paste lumps stick together and the lump's surface becomes sticky as heating occurs upon injection into the bed.

Sorbent based bed particles stick to the surface of the paste lumps.

As the coal burns, coal ash is left at the surface and interacts with the calcium in the bed particles.

The melt occurs, fusing the bed particles together.

The coal burns out, leaving the hollow sinter.

5.2.4 Attempts at Resolving the Problem

When using dolomite as the sorbent, excessive sintering could generally be brought under control through a reduction in bed height and bed temperature. Such operational changes, while generally effective, are not considered acceptable solutions to the problem. Operation at full-bed height and at the design bed temperature (1580 F) will be necessary in a commercial PFBC facility in order to attain the desired cycle efficiency, as well as the maximum attainable sorbent utilization.

One factor investigated in an attempt to solve the sintering problem was increased coal paste splitting. While initial speculation into the cause of the sinters (as well as the findings from the UNDEERC investigation) indicated that finer splitting of the paste should decrease the likelihood of sinter formation, this was not borne out in practice. Significant increases in splitting air flow tested in early 1994 showed only moderate improvements in the sintering tendency. It is possible that the extremely cohesive coal paste, necessitated by the limited number of fuel feed points and the associated post-bed combustion, may be less sensitive to splitting air flow changes.

5.2.5 Present Status

Excessive "egg sinter" formation has not been resolved at Tidd. With dolomite as the sorbent, this problem has prohibited sustained operation at full bed height with bed temperatures in excess of 1500 - 1520 F. In addition, sustained unit operation was not possible at any load condition with limestone as the sorbent.

5.2.6 Possible Future Investigations

The increased propensity to sinter at higher firing rates associated with high bed heights and higher bed temperatures offers a clue as to how to resolve the "egg sinter" problem. In light of this, it has been speculated that the highly localized fuel release associated with the limited number of fuel feed points unit may be a key factor in the formation of the sinters. Investigations into improved fuel distribution, through additional fuel nozzles or the bifurcation of the existing six fuel nozzles, would be necessary to test this theory.

The UNDEERC report indicated that the swelling and sticking tendency of the coal plays a major role in the sinter formation. Testing of coals with lower swelling tendencies would determine whether that speculation is valid. However, resolution of the sintering problem through changes in the fuel supply is not a solution to the problem, since fuel flexibility is a must for any coal burning technology to be competitive. Even so, successful operation with a low swelling coal would provide an additional important clue into possible resolution of the sintering problem.

Testing at the NCB (CURL) PFBC pilot facility produced similar "egg sinters" when using limestone as the sorbent with Pittsburgh No. 8 coal fed as a paste. These sinters were eliminated when the fluidization velocity was increased from 3 to 4 ft/sec. Since fluidization velocity cannot easily be changed at Tidd, the only way to achieve a marked increase in the effective fluidization would be to decrease the bed particle size. Feeding of finer sorbent would result in such a finer bed.

5.3 Sorbent Utilization

5.3.1 Background

As a result of the Clean Air Act Amendments of 1990, both new and existing plants must combine improved efficiencies with superior control of SO_2 and NOx emissions in order to remain competitive in today's power generation market. PFBC has been shown to be one of the more promising of the emerging Clean Coal Technologies based, in part, on its touted capabilities of efficiently removing 90 to 95% of the sulfur. In order to keep PFBC as an economically viable option for commercial power generation, sulfur retention and calcium-to-sulfur molar ratios (Ca/ S) must be demonstrated at levels better than design.

One of the primary goals of the Tidd test program has been to optimize sorbent utilization. Although improvements (in the order of 10 to 15% from early baseline tests at 115" bed level) have been achieved, sorbent usage remains 10 to 15% above the original goal values. During the last three years a great deal of information has been gathered about the mechanisms involved with in-bed sulfur capture and sorbent utilization. This section of the report details the testing conducted over the last three years, the results of that testing and an evaluation of those results.

5.3.2 Baseline Performance Tests

A total of 47 performance tests were conducted, at various conditions, to evaluate the unit for changes in sorbent utilization. Performance test conditions and results are presented in tabular and graphical form in Section 4.4 of this report. All test results have been normalized to 1580 F bed temperature and either 90 or 95% sulfur retention using correlations developed at Grimethorpe (Refer to Section 4.5 for more details).

Most of the tests were conducted using Pittsburgh #8 coal and Plum Run Greenfield dolomite. The sorbent was fed pneumatically, using the original two sorbent feed points. All tests conducted at these conditions are designated as "baseline" performance tests. Most of the tests were conducted at the 115" bed level.

Results from early tests at baseline conditions revealed an average Ca/S ratio of 2.2 at 115" bed level, adjusted to 90% sulfur retention and 1580 F bed temperature. These results are approximately 30% above the goal Ca/S ratio of 1.7 adjusted for 115" bed level.

5.3.3 Sorbent in Paste Tests

The issue of sorbent distribution and its impact on sorbent utilization has been of primary concern since early in the test program. Improved sorbent distribution could be obtained by mixing sorbent with the coal water paste or by physical modifications to the sorbent distribution piping.

In 1992, it was believed that the lower-than-expected sorbent utilization was due to poor sorbent distribution within the bed, including regions of high sorbent fines concentrations. The fines could be imagined as "plumes" which would escape the bed without fully reacting. This theory seemed to be supported by analysis of the cyclone ash samples which showed that only 30-40% of the CaO in the ash had been sulfated.

It was thought that by mixing sorbent with the paste, the sorbent would be more evenly distributed due to the additional feed points. Also, the sorbent fines would tend to be carried around the bed as agglomerates of coal and sorbent particles thus increasing in-bed residence time and eliminating the "plumes" of sorbent fines. Since the sorbent fines would have a longer residence time and better contact with SO_2, sulfation of the fines would be greatly improved. Sulfation rates as high as 60 to 75% of the fines were expected, but were never actually achieved.

In order to test this theory, tests with half and all of the normal prepared sorbent mixed with the paste (Tests 9 and 10); and also with sorbent fines mixed with the paste (Tests 11, 31, and 32) were conducted. No improvements in sorbent utilization were seen while operating with the normal prepared sorbent mixed with the paste. However, the tests with sorbent fines in the paste did show improvements of approximately 10%; the reasons are not obvious.

For example, results from Test 31(conducted at 115" bed level with 53% of the sorbent fed as fines mixed with the coal water paste) indicated a normalized Ca/S ratio of 2.06 at 90% sulfur capture (an improvement of 6% over baseline test results). The sorbent fines were from Plum

Run Peebles formation (minus 325-mesh particle size), while the dry sorbent feed was Plum Run Greenfield prepared on site (100% less than 6-mesh). Analysis of the cyclone ash revealed a sulfation rate of only 26%, indicating that a large amount of sorbent fines was still escaping the bed unreacted. The improvements in sorbent utilization might be explained by the increase in bed ash sulfation rate due to the lower bed ash drain rate and thus increased residence time of the coarser non-elutriable particles. The cyclone ash/bed ash split shifted from approximately 60%/40% to 75%/25%, while the bed ash sulfation rate increased to 47% (typical bed ash sulfation rates are 30 to 40%).

Additional testing with sorbent fines mixed in the paste and variations in sorbent fines ratio is required in order to explain the improved sorbent utilization noted in the above tests. Tests are planned during the fourth year of operation to further investigate these issues.

5.3.4 Improved Sorbent Distribution Tests

Sorbent distribution was still felt to be a key variable in improving sorbent utilization. One theory suggested that the lower-than-expected sorbent utilization was caused by localized regions of high SO_2 concentrations at the fuel discharge points due to volatile plumes. These SO_2 plumes would escape the bed without having adequate time or surface contact with the sorbent. During the summer of 1993, six SO_2 sampling probes were installed at strategic locations above the bed to measure SO_2 at suspected areas of high concentration. The SO_2 plumes were in fact confirmed to exist. In order to improve contact between the SO_2 plumes and sorbent, it was decided to install sorbent tees at the ends of the original two sorbent injection nozzles to direct the sorbent towards the regions of high SO_2 concentration (Refer to Section 6.9 for more details). During the fall of 1993, four performance tests (Tests 39 through 42) were conducted in this configuration with little or no improvement seen in sorbent utilization. Upon inspection following this run, both sorbent tees were found to be severely eroded and one leg of one tee was found to be completely plugged with sorbent. Since the actual time of erosion and plugging of the sorbent tees during the run is not known, it remains uncertain whether the sorbent redistribution actually had any impact on sorbent utilization.

During the outage that followed, the sorbent piping was reconfigured to include four sorbent distribution points penetrating the boiler wall at locations between the coal injection nozzles. This allowed improved sorbent distribution to regions between the SO_2 plumes without the erosion potential of tees at the ends of the nozzles. Due to the accelerated schedule for this test, the nozzles were not designed for erosion resistance; however, ceramic lined pipe was being procured and would be installed permanently if test results were positive (Refer to Section 6.9 for more details).

Two tests were conducted with the four-point sorbent injection system before the piping wore out. The first test (Test 43) was at 115" bed level and showed approximately 10% improvement over baseline tests results. The second test (Test 44) was at 142" bed level and included fines in the paste. Only three previous tests were conducted at full bed level - all with relatively good results and little scatter in data. The results from Test 44 were as good as the best test at this bed level (Test 6). Since all four tests at full bed level showed little scatter in results, it can be postulated that as bed level is increased (and thus residence time is increased), sorbent distribution has less impact on sulfur capture.

Following this run the unit was returned to service with the two-point sorbent injection system until the permanent ceramic lined piping could be obtained. The final three tests of the three-year test program were conducted with the two-point injection system using finer sorbent (Refer to Section 5.3.5 for more details). In February 1994, the permanent ceramic lined piping system was installed duplicating the four-point configuration outlined above. Testing into the fourth year of operation will include continued evaluation of the four-point sorbent injection system.

5.3.5 Finer Sorbent Testing

Sorbent size gradation (or size consist) is a variable that has been known to affect sorbent utilization and bed conditions. Finer sorbent particles have a greater surface area on a unit-mass basis, hence contact with combustion gases is improved. Lab tests conducted in 1993 by the University of North Dakota Energy and Environmental Research Center have shown that the larger bed-ash particles obtained from Tidd contain unreacted sorbent at the centers where the combustion gases were not able to make good contact; i.e., the gases could not fully penetrate the larger sorbent particles. The increased surface area afforded by smaller sorbent particles should allow the particles to react more completely and thus enhance sorbent utilization. Additionally, the finer sorbent should result in a finer, better fluidized bed; and thus improve bed mixing, contact with combustion gases and thereby enhance sulfur capture.

Tests to optimize sorbent sizing were not conducted until late in the three-year test program, due in part to the concern of overloading the cyclone ash removal system and not being able to maintain bed level when operating with finer material. However, as bed sintering was being evaluated, it seemed that a better fluidized bed was required to reduce sintering as well as to improve sorbent utilization. The modifications required to the sorbent preparation system in order to induce large changes in sorbent size variations would be costly and irreversible during operation. Hence, changes to sorbent sizing had to be somewhat subtle in order to avoid the risk of operating with unfavorable conditions that would result in unit shutdown. During the winter of 1993-94, the sorbent crusher speed was increased to induce a slightly finer grade of sorbent size.

In January 1994, three performance tests (Tests 45 through 47) were conducted at 115" bed level to evaluate system performance with the finer sorbent. The average Ca/S ratio was 1.94 adjusted to 90% sulfur retention and 1580 F bed temperature. This represented an improvement of 12% over the baseline performance tests. During these tests sorbent size consisted of less than 1% over 8-mesh and approximately 41% less than 60-mesh. Typical sorbent sizes have been approximately 4 to 8% over 8-mesh and 30 to 35% less than 60-mesh. The improvements made in sorbent utilization appeared to be fairly significant for the slight change in sorbent size.

Continued testing to optimize sorbent sizing is planned for the fourth year of Tidd operation. This includes tests of various "custom" sorbent sizes prepared at the stone quarries, as well as modifications to Tidd's sorbent preparation system in order to obtain the required throughput at reduced sorbent sizes.

5.3.6 Tests with Alternate Sorbent Types

Three Ohio dolomites (Plum Run Greenfield, Plum Run Peebles, and National Lime Carey) were tested to evaluate the sorbent's reactivity. Tests were conducted during the summer of 1993 at approximately 80" bed level, using Pittsburgh #8 coal, and feeding the sorbent pneumatically using two feed points. All test results were normalized to 1580 F bed temperature and 90% sulfur retention using the Grimethorpe correlation (Refer to Section 4.2.2 for additional details).

Tests 19 through 25 with Plum Run Greenfield dolomite resulted in an average Ca/S ratio of 2.52 at 80" bed level, or 1.90 predicted at full bed-level.

Tests 34 and 35 with Plum Run Peebles dolomite resulted in an average Ca/S ratio of 2.82 at 83" bed level, or 2.16 predicted at full-bed level.

Tests 36 and 37 with National Lime Carey dolomite resulted in an average Ca/S ratio of 2.82 at 83" bed level, or 2.16 predicted at full-bed level.

The above test results show that the Plum Run Greenfield is more reactive by approximately 12% than the other dolomites tested. Several attempts were made to test the unit with limestone, however, problems with bed sintering caused the bed and evaporator temperature profiles to become uneven which eventually led to unit shutdown. Discussion of the bed sintering problems encountered during limestone testing is contained in Section 5.2.

5.3.7 Conclusion and Summary

Improvements in sorbent utilization have been achieved by operating with sorbent fines in the paste, with the four-point sorbent injection system, and also by operating with a finer sorbent size. Each of the above variables has shown improvements in the order of 10 to 15% from the "baseline" test results at 115" bed level. Much less scatter is seen in the test results for full bed height tests. No obvious improvements have been seen at full-bed level while operating with four-point sorbent injection and fines in the paste.

The best sorbent utilizations achieved, at 115" bed level while utilizing finer sorbent, was an average Ca/S ratio of 1.94 adjusted to 1580 F bed temperature and 90% sulfur capture. The best test results obtained at full-bed level are at "baseline" conditions where a normalized Ca/S ratio of 1.71 was obtained. Sorbent utilization remains approximately 10 to 15% below goals.

The greatest potential for additional improvements in sorbent utilization is by further optimizing sorbent particle size. Tests at 115" bed level with finer sorbent showed dramatic improvements for the relatively minor changes made in sorbent size. No tests have been conducted at full-bed level with finer sorbent.

The four-point sorbent distribution system appears to help with sorbent utilization (at least at reduced bed levels), and thus plans are to install the permanent ceramic-lined four-point feed system and continue evaluation of improved distribution into the fourth year. Additional benefits may be seen when operating with both finer sorbent and the four-point feed system.

Further tests should be conducted to investigate the improved sorbent utilization noted while operating with sorbent fines in the paste. This may entail actually separating the fines during production of plant-prepared sorbent and diverting them into the paste. The tests conducted during the three-year test period with fines in the paste involved too many variables to actually understand the causes of improved sorbent utilization.

With respect to sorbent type, the most reactive sorbent tested was the Plum Run Greenfield dolomite. Additional attempts at operating with limestone will be made during the fourth year if sintering can be controlled. It is believed, based on CTF testing, that limestone will be less reactive on a Ca/S ratio but, if fed sufficiently fine, will be more reactive on actual mass of sorbent basis. It should also be noted that when screening for sorbents to be used for a commercial unit, selection should be based on delivery cost to the plant site as well as on reactivity based on petrographic examinations and pressurized TGA testing.

5.4 Boiler Heat-Transfer Surface Modification

5.4.1 Background

Due to the combined-cycle nature of the PFBC process, proper heat absorption by the boiler in-bed tube surface is critical to insure that the unit operates at the design unit output and efficiency. If there is too much absorption there will not be sufficient oxygen available to attain the true design full-load condition of full-bed height at full-design bed temperature. In such a case the bed level or bed temperature must be lowered to reduce the absorption, and, hence the firing rate. Either of these actions would have the effect of a lower-than-design gas turbine inlet temperature, which would lower the output and efficiency of the gas turbine and, hence, the overall cycle. Conversely, if the heat absorption is insufficient, the overall steam production and firing rate will be below design, resulting in reduced steam cycle and overall unit output. It should be noted that in such a case, the gas turbine inlet temperature limitations preclude the ability to increase the bed temperature to achieve higher heat absorption. It should also be noted that with either excessive or insufficient tube bundle absorption, the gas turbine exhaust economizer conditions, feedwater flow rate, gas flow rate, and inlet gas temperature are affected, which impacts the overall cycle efficiency and output.

5.4.2 Experience

The original Tidd in-bed tube bundle was designed to absorb 128 MW of thermal energy at a fully submerged bed height of approximately 126" with a mean bed temperature of 1580 F. During the first year of unit operation, it was determined that the in-bed tube bundle absorption reached a maximum of approximately 73% of the original design value at a true fully submerged bed height of approximately 120".

In light of the magnitude of the absorption shortfall, a decision was taken in the middle of 1991 to install additional surface. Due to the pervasive nature of the post-bed combustion experienced up to that time (Refer to Section 5.1 for more details), a lower design bed temperature of 1540 F, for achieving the full tube-bundle absorption, was selected. The lower temperature would permit up to a 40 F gas temperature rise in the freeboard (approximately 1% post-bed heat release) without exceeding the design gas turbine inlet temperature (1526 F, allowing for the 54 F design heat loss in the cyclones, gas collection manifold and crossover pipe). In order to achieve the higher absorption the following changes were made:

Four rows of tubes were added to each evaporator circuit. The additional rows extended beyond the top of the original tube bundle.

Two rows of tubes were added to each secondary superheater circuit. The additional rows extended beyond the top of the original tube bundle.

Part of the shielding on the primary superheater circuits was removed.

All of the shielding on the evaporator and secondary superheater outlet legs as well as the primary superheater inlet and outlet legs was removed.

With this new arrangement, the tube bundle became fully submerged at a new full bed height of 142". In spite of the additional surface and the use of actual Tidd heat absorption data for the redesign, the modified in-bed tube bundle still had a heat absorption shortfall of approximately 7% at the revised design bed temperature of 1540 F.

5.4.3 Causes

The heat transfer to tubes submerged in a fluidized bed is extremely high due to the bed particle-to-tube-surface contact. However, the degree of heat transfer can vary dramatically with particle size and activity. Evidence of this phenomenon was seen regularly at unit start-ups, when the use of 16 X 30 mesh sand in the start bed resulted in relatively high initial steam flow and firing rates. As the bed matured to its normal material make-up (mostly spent sorbent), the steam flow and firing rate would decay as much as 15% at fixed bed height and temperature conditions.

The original shortfall revealed that the Tidd tube-bundle heat transfer was at the lower end of the possible range of heat transfer predicted from the pilot plant data, whereas a middle of the range value was used in the design. It is likely that part of the reason for this is the tight design of the tube bundle. In order to minimize bubble growth and hence tube bundle erosion, the Tidd tube bundle was designed on the tight end of the acceptable spacing range.

The reason for the remaining shortfall after the redesign is believed to be due to tube-bundle fouling due to sintering; however, large bed particle size, less fluidizing air due to gas turbine leakage, and suspected zones of reduced fluidization along the side walls may also be contributing factors.

5.4.4 Present Status

As of the end of the three-year test period, the in-bed tube bundle absorption remained low at approximately 93% of the original design value.

5.4.5 Possible Future Investigations

Operating experience towards the end of the three-year test program revealed that the unit could be run for extended periods with little or no post-bed combustion. In light of this, it should then be possible to raise the mean bed temperature to the original design value of 1580 F, which would increase the tube bundle heat absorption thereby compensating for some of the shortfall. This was intended to be done during the period from October 1993 through February, 1994 when sufficient air was available from the gas turbine compressor to support full load firing (Refer to Section 5.5 for more details). However, excessive "egg sinter" formation prevented extended operation at any temperatures above 1540 F. If the sintering problem is resolved without inducing additional post-bed combustion, it may be possible to operate the unit in such a manner during the fall and winter months of the extended fourth year of unit operation.

Additional investigations planned for the extended fourth year of operation include the use of finer sorbent feed to attain a finer bed. The expectations are that a finer bed will result in increased particle activity which might reduce the magnitude of the bed sintering problem. Successful minimization of the sintering problem would likely improve heat transfer due to reduced fouling. In addition, if the finer bed does result in increased bed particle activity, this factor may improve the heat transfer directly.

5.5 Gas Turbine Compressor Air Flow Capacity Shortfall

5.5.1 Background

The gas turbine compressor is designed to provide a varying mass flow rate of combustion air at a nearly constant volumetric flow rate, allowing the bed to operate with a nearly constant fluidization velocity across the load range.

The ABB Stal GT-35P gas turbine/compressor used at Tidd is a two-shaft machine, where the air-mass-flow rate is controlled by varying the speed of the LP-compressor. The maximum capacity is limited by the LP compressor maximum speed (5650 RPM) and the HP compressor discharge temperature. The HP compressor discharge temperature, which is set by combustor vessel material considerations, is controlled by the intercooler cooling water flow rate. Being a volumetric machine, the gas turbine compressor's air mass flow delivery capability varies with ambient temperature. With cool ambient temperatures the mass flow delivery capability is higher than at high ambient temperatures. When designing a PFBC facility, the gas turbine compressor must be sized to provide the air mass flow required for full-load firing at a specified maximum design ambient temperature. In addition, the compressor intercooler must be sized sufficiently large to handle the necessary intercooler heat rejection at the specified maximum cooling water temperature. The required intercooler heat rejection capability is determined by the maximum desired air mass flow, the LP and HP compressor pressure ratios and efficiencies, and the maximum permissible HP compressor discharge temperature. The amount of intercooling required increases with rising ambient temperature. At Tidd, the intercooler cooling water supply is the condensate system, which rises in temperature as the river water temperature increases. This means that during the warmer months of the year, the cooling capability of the intercooler decreases while the required cooling demand increases.

Insufficient air mass flow delivery from the gas turbine compressor can limit firing rate in the PFBC unit, necessitating reductions in either bed height or bed temperature.

5.5.2 Experience

The Tidd PFBC unit was expected to be capable of achieving full load firing rate of approximately 208 MW_t at ambient temperatures up to 85 F. In the spring immediately following the boiler surface addition of late 1991 (Refer to Section 5.4 for more details) it became apparent that the gas turbine compressor air mass flow delivery capability was still well below design. Although full-load firing rate at that time was only 93% of the original design due to continued below-design tube bundle heat absorption, unit load was further limited due to insufficient air at ambient temperatures above 60 F. The condition gradually worsened through the summer, as the intercooler inlet water temperature increased along with the river water temperature. Maximum air flow capacity was generally evidenced by reaching the full speed of the LP compressor in early summer, whereas in late summer the intercooler heat rejection capacity actually became the limiting factor. As fall approached and the ambient air and river water temperatures dropped, the air mass flow delivery capacity of the compressor increased and the air shortage induced firing rate limitations disappeared. This scenario was repeated during the warmer months of 1993.

5.5.3 Causes

The following causes were identified as contributing factors to the compressor air flow delivery shortfall:

The most significant factor was excessive air leakage from the compressor discharge into the turbine. The excessive leakage essentially robbed the combustor of some of the air that the compressor was delivering. There is a normal level of air "leakage" between these components that provides the turbine disc cooling and seal air flows. However, test data revealed that leakages were much higher than original design. During the major gas turbine rebuild in spring 1993, modifications were made in an attempt to minimize the excessive leakage. A slight reduction in the leakage rate was attained by these modifications.

The other factors causing the reduced air flow capacity were below design LP compressor capacity and efficiency. No specifics on the physical cause of these problems have been identified. It should be noted that decreased LP compressor efficiency results in excessive temperature rise throughout that component, which necessitates more intercooling.

5.5.4 Present Status

Due to the high cost associated with resolving the compressor air flow delivery deficiency issue, and the realization that foregoing full-load operation during the warmer months had no significant impact on the overall unit test program, a decision was made not to address this problem. Therefore, the compressor air delivery capacity shortfall remained at the end of the three-year test period.

5.6 Cyclone Ash Removal Systems

5.6.1 Background

The cyclone ash removal system was one of the major development issues at ABB Carbon's Component Test Facility (CTF). The system originally included a standard lockhopper ash removal system. However, due to the severe service, that design was abandoned in favor of a continuous passive transport system which did not require any lockhoppers or valves. The system was installed at the CTF and was further developed to cool and depressurize the ash through a pneumatic transport system. A significant aspect of the CTF system was that it included only one primary and one secondary ash removal line since the CTF only had one cyclone string. The lines were not combined together.

The original Tidd cyclone ash removal system was based on 14 parallel ash lines eventually combining into one single ash line. These lines were designed to remove the primary and secondary ash that was separated from the flue gas flow in the cyclones, to cool and depressurize the ash, and transport it to the cyclone ash storage silo which was located outside of the combustor vessel building. This system was similar to the CTF concept, but involved seven primary and seven secondary ash lines combining into one single line versus the separate lines at the CTF. The system uses the pressure of the combustor vessel as the motive force to transport the ash out to the silo. Once at the silo, a final pressure reduction is made and the ash is fed into the silo.

5.6.2 Experience

As soon as combined-cycle operation began, problems occurred in the cyclone ash removal system. The first event occurred in a primary cyclone ash removal line caused by a fire in the cyclone and resultant sinter blockage of the ash line suction nozzle. This type of event is not considered an ash system malfunction. But starting in early 1991, the secondary ash system had a major impact on unit operations. Almost every startup was aborted within hours of coal fire due to a plugged secondary cyclone ash line. In fact, the unit did not achieve more than 10 hours of continuous coal fire operation until well into March 1991 due to this problem. Throughout the first five months of 1991, modifications were made to the ash system in an attempt to improve reliability of the secondary ash removal system. These modifications included: adding purge air to the secondary ash line suction nozzle in the bellows box; eliminating the external ash cooler; reducing the number of passes in the internal cooler; decoupling the secondary ash system from the primary system; installing an enlarged external secondary ash line, and modifications to address possible condensation concerns.

Finally in April 1991, the secondary ash system began to operate with improved reliability, and longer coal fire runs were achieved. But in June 1991, the primary ash system began to impact unit operations. Between June and September 1991, the primary ash system plugged three times, resulting in immediate unit shutdown.

During the Fall 1991, an extensive inspection of the entire ash removal system revealed numerous design problems and material defects. The primary ash removal system, internal to the combustor, was completely dismantled and inspected. Numerous castings were rejected due to casting imperfections, the internal coolers were reworked due to design/shop fabrication flaws and a new type of ash line gasket was installed. The secondary ash system was also extensively overhauled, with the tee-bend castings being replaced by an all-welded piping system. In an attempt to minimize air infiltration, all castings (and flanged fittings) were removed in the secondary ash system except for the suction nozzles, internal cooler collection headers and the piping downstream of the header.

The modifications resulted in significant improvement in ash system and unit operations, but problems still existed. It was decided that the unit would continue to operate with one secondary cyclone and ash line plugged. As anticipated, this permitted longer operating runs.

However, these runs were usually achieved only when operation was continued with at least one plugged secondary ash line. The 740-hour run in June 1992 was achieved with the secondary cyclone S24 ash line plugged the entire time. Throughout 1992, various modifications were made to improve system reliability.

In early 1993, the entire secondary ash removal system was replaced. Instead of parallel lines combining into one line, six separate lines were installed from the cyclone dip leg to the economizer duct. The line size was also increased to enhance transport capability. Since its replacement, system availability has been greater than 99%.

The evolution of the primary ash removal system, however, has not been as successful. Air leakage into the system has become a major maintenance issue. In order to minimize air inleakage and maintain system integrity, significant numbers of ash line and cooler gaskets must be replaced on a routine basis. At times, some gaskets on the internal ash coolers have been replaced every two to four outages. Due to the cost of modifying the gasket area and the short time remaining in the Tidd project, a decision was made to continuously replace gaskets versus making a design modification to eliminate the problem.

5.6.3 Causes

The majority of the ash removal system problems can be generalized into four causes: system air inleakage, deposition in the lines, insufficient line capacity and untested combining of parallel ash lines into one single line.

System Air Inleakage/ Line Deposition

In a pneumatic transport system, air or gas is the transport medium in the system. In the Tidd ash removal system, differential pressure between the combustor vessel and the ash silo is the motive force to drive the gas and ash through the ash lines. The hot gas and ash enter the ash line at the suction nozzle in the cyclone dip leg. At that point, a pressure difference already exists between the inside of the dip leg and the combustor vessel environment, due primarily to the pressure drop across the sparge ducts, the fluidized bed and the cyclones. As the ash/gas proceed down the ash line, the pressure in the line decreases and the pressure differential between the combustor vessel and the ash line becomes even greater.

If the flange connections in the line are not tight, air will leak into the line and offset an equal amount of gas coming from the cyclone bellows box. If the leak is significant, the gas quantity coming from the suction nozzle may be insufficient to support transport, and the line upstream from the air leak will shut down. This phenomenon occurred frequently. An air leak in an ash line would restrict capacity coming out of the suction nozzle until there was an upset in the system. At that point, a larger amount of ash would try to enter the ash line with the reduced gas quantity, the ash line velocities would drop and the ash line would plug.

A similar air inleakage problem existed on the secondary ash removal system until Fall 1991 when the flanges were replaced with an all-welded design.

Insufficient Transport Capacity

Insufficient transport capacity was another problem that impacted the original secondary ash removal line. During the system design period, assumptions were made about transport line velocities in the secondary ash removal system. The actual velocities in the system were much lower than expected and the system's overall transport capacity was lower. Once modifications were made to the system to increase the transport velocities, the system reliability was improved.

Combining Parallel Ash Lines

In the CTF, there was only one primary and one secondary cyclone with corresponding ash lines. The systems were modified to improve their reliability and operation, but no experience was achieved on impacts of combining parallel ash lines into one line. At Tidd, the design was complicated further by combining parallel secondary ash lines together, then combining the secondary ash system into the primary ash system to form a single line. If the unit operated smoothly with no upsets, this system may have worked. But at Tidd, each time the combined-cycle and fluidized bed had an upset resulting in a transient increase to the steady-state ash flow, the ash removal system suffered negative impacts.

For a blockage to form in an individual ash line, it must be capable of withstanding the full system pressure drop. However, with seven lines operating in parallel a blockage in one line will experience only a fraction of that pressure. As a result, the propensity for blockage is much greater in such a configuration.

In addition, since all the parallel ash lines were located inside the combustor vessel with only one ash line exiting the vessel, there was no way for manual intervention in a plugged ash line. Once plugged, the line either unplugged on its own or remained plugged for the remainder of the run.

When the new secondary ash lines were installed with six separate lines exiting the combustor vessel, the benefit of individual ash lines was quickly realized. If a line plugged, the differential across the line was the full process pressure. With the valve stations located outside of the vessel, the equipment was available to the plant operators to manually intervene and unplug a blocked line. In the case of the new secondary ash lines, manual intervention was required only on a few occasions.

5.6.4 Present Status

The current secondary ash removal system design appears to be acceptable. The system has operated with greater than 99% reliability since installation. Long-term service and erosion considerations are the only issues still open.

The primary ash removal system, however, continues to be troublesome. The current flange and gasket design of the components inside of the combustor vessel is not acceptable. Air inleakage into the system must be eliminated. The design with seven lines combining into one line inside the combustor is also not acceptable. If Tidd were a long-term commercial plant, this system would be redesigned with an all-welded type design, and each ash line would penetrate the combustor vessel wall. Provisions would be made to clear an ash line if it plugged while in service.

5.6.5 Possible Future Investigations

Aside from the need to redesign the primary ash removal system, one other significant outstanding issue persists: the infrequent formation of super-hard deposits in the internals of the ash line. Throughout the Tidd project, a super-hard high-fusion-temperature deposit would occasionally build up on high-impact bends in both the secondary and primary systems.

In the primary system, these deposits were not considered significant since their buildup and resultant reduction in ash line internal diameter was not significant. However, the same deposit appeared in both the original and redesigned secondary ash systems. Investigations of the deposit failed to determine the cause for this buildup, its correlation to other ash materials in the process, or when and where the deposit would occur.

5.7 Coal Preparation System

5.7.1 Background

The coal preparation system at ABB Carbon's Component Test Facility, was not similar to the coal preparation system that was installed at Tidd. The CTF system consisted of a hammer mill that crushed coal to a size distribution with relatively large particles. In order to obtain the proper size distribution for paste pumping and good combustion, prepared fines were then mixed into the output of the hammer mill to achieve an acceptable paste product.

After numerous bench-scale tests, ABB Carbon selected the Krupps Polysius double-roll crusher for their PFBC plants. Fifty-five-gallon barrels of Pittsburgh #8 coal were shipped to Germany and the Polysius crusher was tested for its ability to crush this coal in a bench-scale test. Once selected, the crusher was never full-scale tested on this coal nor tested in combination with the other components of the system. As such, a true coal preparation system was never tested nor demonstrated at the CTF.

5.7.2 Experience

Problems were encountered with the coal crusher from the initial operation of the combined cycle plant. At first, coal crusher operation was very erratic and unpredictable. The coal prep system was designed to produce a paste with a fines fraction of 14% minus 325 mesh. During 1991, the coal crusher produced a paste product with 10% to 15% minus 325 mesh fines. In order to improve the pumpability of this type of paste, the moisture content of the paste was kept high which had significant impacts on combustion. The wetter the coal, the more prone the unit was to post bed combustion (Refer to Section 5.1). Without sufficient fines in the paste, segregation in paste pump suction boxes and fuel nozzle line pluggage would often occur.

Throughout 1991, the Tidd crusher operated with poor reliability and crushing performance. At other European PFBC plants, however, the crushers were performing as expected, producing the desired prepared coal product. Comparisons were made back and forth as to why the crushers worked at other PFBC plants and not at Tidd. Initially it was thought that the crusher was underpowered for the coal that was being used at Tidd, therefore, during the 1991 fall outage, the motors and drives were changed out to 200 hp drives from their original 150 hp motors. Operation did not significantly improve with the larger motors and variable speed drives.

Testing conducted during fall 1991 resulted in a new control method to better control the crusher and improve the paste quality. At first, this was considered a breakthrough until several unit runs later when crusher reliability again became marginal.

In the spring of 1992, a new recycle loop control scheme was developed. In this scheme, as much as 50% of the crushed coal was recycled back through the coal crusher and further crushed. With the additional crushing achieved through recycling of the crushed coal, the minus 325 size fraction was significantly improved. Depending on the amount of recycle, up to 30% of the coal would be crushed to below 325 mesh. The system was adjusted and optimized until 20% of the coal could be crushed to the minus 325 mesh size fraction on a routine basis. With the increased fines in the paste product, the water content of the paste could be reduced with a corresponding reduction in post-bed combustion.

However, even with the recycle loop, the making of good paste was dependent on the coal characteristics. If the coal became too dry or too wet, problems could be expected with the coal crusher. Changes in either coal type or coal characteristics usually resulted in unpredictable crusher performance.

The coal injection paste pumps were shown to be the best on-line indicators of good paste. If the crusher was not producing the proper size consist of coal, the fines in the paste would decline and within an hour, the fuel injection line differential pressure increased until the paste pump tripped from service. In extreme cases, several paste pumps would trip from service within a short time of each other. When more than one paste pump is out of service, bed temperature profile across the bed is very uneven and requires extensive pump biasing to avoid a unit trip. The loss of more than one pump usually resulted in a trip.

5.7.3 Causes

As discussed above, no direct indication has yet been found between the quality and characteristics of the coal and how the coal reacts in the coal crusher. Table 5.7.1 provides a typical analysis of the Pittsburgh #8 seam and the Ohio #6A coal that have been crushed at Tidd. The analyses are very similar, yet experience has shown that the Ohio #6A coal cannot be reliably crushed in sufficient quantity in the coal preparation system, while the #8 coal was routinely crushed to an acceptable product

Table 5.7.1 - Typical Coal Analysis

Typical Coal Analysis		
As Received Basis	Pittsburgh #8	Ohio #6A
	Partially washed	Fully washed
Moisture (%)	5.3	5.8
Ash (%)	12.2	10.7
Volatile (%)	35.5	37.8
Fixed Carbon (%)	47.0	45.7
Sulfur(%)	3.3	3.2
Btu/#	12,187	12,370
Grindability	55	53

Experience has showed that the only acceptable evaluation of the suitability of a coal for use in the coal crusher was to actually test crush the coal in the crusher. Usually this testing at Tidd consisted of an initial limited test crushing of 150 tons of the proposed coal. If successful, this limited test was followed up by a larger test of 2,000 to 3,000 tons of coal. Only after the second test was successfully completed would the coal be judged as initially acceptable. The final testing could only occur over several months of on-line testing of the coal. This final testing permitted the coal to be crushed under various conditions including wet and dry swings in the coal quality.

It should be noted that the only coal tested at Tidd that was found to be acceptable over the long term was the Pittsburgh #8 coal that came from the Betsy Mine and Harrison Wash Plant. Other coals tested included an Ohio #6A from the Harrison Mine and wash plant, an Ohio #5 & 6 from the Sands Hill Mine, and lower sulfur coal from the Peabody Anker Mine.

5.7.4 Present Status

To date, the unpredictable reliability of the coal crusher due to changes in coal quality remains a significant problem. Whenever the coal changes, the crusher is still prone to tripping out due to crusher skewing or other problems. If the crusher can be maintained in service, the ability to maintain system capacity and achieve sufficient throughput to match the combustion flow requirements is still an issue.

However, if the coal quality is consistent, the crusher has been shown to be a reliable crusher, producing the required size consist needed for good pumpability and combustion. All of this is achievable at a low energy-consumption.

5.7.5 Possible Future Investigations

A commercial plant coal crusher would need to be capable of crushing a wide range of coals and mixtures of coals without impacting the crusher operations or unit availability. The existing coal crusher could be suitable if the only coal supply was a Pittsburgh #8 coal stored in an enclosed coal yard. Since this is not practical in a commercial plant setting, an alternate coal preparation system would be required to be developed and tested for a commercial plant. Such a system may require redundant coal preparation systems. It has been shown that the production of adequate quantities of minus 325 fines is related to crusher throughput. Generally a crusher operating at lower capacity or in a recirculation mode provides the desired size gradation of product. Many of the problems experienced at Tidd were attributable to the installation of a single 100% crusher. An alternate coal preparation system design might consider the use of multiple primary crushers with recirculation or with a secondary crusher to produce a sufficient quantity of minus 325 mesh fines for blending into the desired end product.

5.8 Impact of the Gas Turbine Blading Problems on Unit Availability

5.8.1 Gas Turbine Blading Problem Experience

The unit experienced three major incidents with the ABB Stal GT-35P gas turbine/ compressor unit. The first occurred in March of 1992, when cracks were discovered in the root area of nine of the low pressure turbine (LPT) blades. The second occurred in February of 1993, when the LPT threw two blades causing significant damage to the LPT as well as the high pressure turbine (HPT) and the high pressure compressor (HPC). The third significant event occurred in December of 1993 when cracks, which had previously been discovered in the retaining brazing of the approximately 18 guide vanes, had propagated to the point where refurbishment became necessary.

5.8.2 Unit Outage Impact

The incident in 1992 resulted in a 9-week outage in order to replace all of the LPT blading.

The incident in the Spring of 1993 resulted in a 20-week outage in order to effect a major rebuild of the LPT, HPT and HPC sections of the gas turbine.

The December, 1993 event resulted in extending an in-progress outage by approximately 3-1/2 weeks in order to replace the affected guide vane rings in the LPC.

5.8.3 Overall Impact on Unit Availability

In order to assess the impact of gas turbine problems on unit availability, the actual yearly availability for 1992 and 1993 as well as an "Adjusted Availability" are presented in Table 5.8.1 below. The "Adjusted Availability" is calculated by reducing the maximum time achievable for the year (denominator in the availability equation, normally 8760 hours) by the outage impacts for that year, while keeping the actual hours of operation (numerator in the availability equation) the same. The "Adjusted Availability" can also be viewed as the overall availability that would have been achieved had the unit been as available during these GT outages. The "Adjusted Availability" is presented only to provide a rough comparison of how these significant gas turbine outage events impacted the overall unit availability. In viewing this information it should be noted that the 9 week outage in 1992 and the 12 week outage in 1993 provided an opportunity to make significant repairs and modifications to other PFBC components, which in-turn led to improved availability of the unit.

Table 5.8.1 - Adjusted Availability

	Full Year	Adjusted Year
1992		
Availability	28.7%	35.0%
Service Hours	2523 Hrs.	2523 Hrs.
Outage Hours	6260 Hrs.	4686 Hrs.
Calendar Hours	8784 Hrs.	7210 Hrs.
1993		
Availability	26.6%	48.9%
Service Hours	2326 Hrs.	2326 Hrs.
Outage Hours	6433 Hrs.	2433 Hrs.
Calendar Hours	8760 Hrs.	4760 Hrs.

5.9 Tube Bundle Clinkers

5.9.1 Background

In the PFBC boiler design, there is no consideration for tube bundle deposits and the on-line removal since coal ash melting and hence slagging and fouling are not anticipated. The formation of clinkers, therefore results in poor unit performance and typically forces a unit shut down.

5.9.2 Experience

Early in 1992, the unit experienced three runs during which large clinkers consisting of fine partially reacted sorbent had formed in the tube bundle. The first such incident occurred in January 1992. Nothing unusual was noted during the run, but in the outage that followed, a 2-1/2' x 1' x 1' clinker was found in the tube bundle. The clinker was located 18" up into the tube bundle centered along the sorbent feed nozzle in the right hand side of the boiler at approximately the same depth as the fuel nozzle outlets. At the time of that run, the sorbent nozzles were straight pipes extending into the boiler to about the same depth as the fuel nozzles, and they had been in that configuration since June, 1991. No such formation had been experienced prior to January 1992.

After the next unit run (February 2 -10, 1992), two of the same type clinkers were found. One was approximately 100 cu. ft. in size, and was found in the north side of the tube bundle centered above the fuel discharge points spanning side to side from above No. 2 fuel nozzle to above the No. 3 fuel nozzle. The second was a much smaller clinker, located in the south side of the boiler directly above the No. 4 fuel nozzle discharge. During the next outage, an attempt was made to eliminate the problem through changing the point of sorbent discharge. Tees and deflector plates were installed on the ends of each of the sorbent nozzles to direct the pneumatic sorbent feed under the four center-most fuel nozzle discharge "skateboards".

In support of the next run, Babcock & Wilcox's "First-of-a-Kind" (FOAK) evaporator outlet leg thermocouples (which are located on every evaporator circuit outlet leg) were closely monitored for evidence of clinkers. Part way into an 81 hour run that followed (February 16 - 21, 1992), a series of evaporator outlet leg thermocouples near fuel nozzle No. 3 had dropped to saturation indicating reduced heat transfer to those tubes. After the planned testing was completed, the unit was shut down for inspection of the tube bundle. The inspection revealed a small clinker located in the north side of the tube bundle directly above the No. 3 fuel nozzle. Due to concerns that the feed of sorbent into the fuel discharge region might be a contributing factor to the formation of the clinkers, a decision was made to cut off the tees and extensions and have the two sorbent feed nozzles discharge just 6" inside the boiler front wall. This restored the feed arrangement to its original configuration.

In the middle of the following run (February 28 - March 5, 1992), the evaporator outlet leg temperature readings gave rough preliminary indications that a clinker might be forming. About this same time, a discovery was made that the sorbent transport velocity had been lowered prior to the run in January, during which the clinker phenomenon first appeared. The transport velocity had been lowered to minimize the potential for erosion. In light of this finding and the rough indication that a clinker was forming, a decision was taken to increase the transport velocity back up to the higher level. In the outage that followed no clinker was found in the bundle, but some pieces of clinker material were found laying in the slumped bed material. Two explanations were postulated:

> Despite the rough indications noted, no clinkers ever formed during the run, and the pieces found were remnants of clinker material that was not fully removed in previous runs.
>
> A clinker did form, but stopped growing when the sorbent transport velocity was increased. The clinker then broke up over the rest of the run leaving behind the remnants found.

In spite of numerous variations in sorbent feed configuration, including re-implementation of extensions and tees and operation with dramatic variations in sorbent transport velocity, no such clinkers were experienced in the following two years of operation.

Chemical and microscopic analyses of samples of the first clinker that occurred revealed the following key findings:

The clinker was formed from very fine particles of sorbent that were fairly well sulfated.

The clinker was formed under oxidizing conditions.

The sample had very little carbonate, indicating that the non-sulfated calcium carbonate had calcined. This indicates that the formation occurred in either a very high temperature region or a low CO_2 region where calcination could take place.

5.9.3 Causes

The cause of the sorbent clinkers experienced in early 1992 is not known at this time. It is speculated that the following factors may have contributed to their formation:

Feeding of the fresh sorbent in close proximity to the fuel discharge points.

Low velocity at the sorbent nozzle discharge causing reduced dispersion of the fresh sorbent into the bed.

With one exception, all of the clinkers were formed in the north side of the tube bundle. It is known that prior to paste tank inlet chute modifications made late in 1992, the paste in the north side of the tank had a higher moisture content than that in the south. It is also interesting to note that by late 1993 when the sorbent nozzle extensions and tees were retried and no clinkers were formed, the overall paste moisture had been lowered due to improved coal crushing.

5.9.4 Present Status

In-bed clinker formations of the type described above have not recurred since early 1992 in spite of numerous changes to the sorbent injection system; including feeding part of the sorbent directly with the coal paste and operating for periods of time with reduced transport velocities. However, the cause of the clinkers experienced in early 1992 remains unexplained.

6.0 System Summaries

6.1 System 211 - Combustor Vessel

6.1.1 System Description

System Purpose and Function

The function of the Tidd pressure vessel is to maintain the system boundary between the PFBC design pressure of 185 psig and atmospheric pressure. The pressure vessel design is based on the premise that combustion temperature is contained within the steam generator while pressure is contained by the combustor vessel. This separation of the pressure boundary from the thermal boundary allows the design of a conventional waterwall design for the boiler (Refer to Section 6.2) as opposed to the requirement of extensive refractory insulation if the thermal boundary and pressure boundary were to be achieved with the same component. The pressure vessel also permits internal PFBC process components, including the boiler, cyclones, cyclone connecting pipes, and bed-ash reinjection vessels to be designed to withstand lower differential pressures than otherwise would be the case.

Various studies were conducted to establish the optimum configuration of the pressure vessel. Several options were evaluated, most noteworthy of which were a spherical shape and a cylindrical shape. A sphere nominally requires one half the thickness of a cylinder for a given pressure and diameter, however, the material savings for the shell were insufficient to offset the higher fabrication costs of a sphere as opposed to a cylinder, since the primary cost associated with the fabrication the vessel are associated with heads and not the cylinder shell itself. The cylinder was ultimately selected as the most cost-effective design for the Tidd pressure vessel. The optimum orientation of the cylinder was determined to be vertical in order to make use of the cylinder wall to top support the internal components by means of support brackets installed in the internal side of the shell. With this configuration the longitudinal pressure forces place the shell in tension. Hence, while the dead weight of the pressure vessel places the shell in compression, the stresses on the pressure vessel wall are reduced during operation compared to other orientations.

General Description

The combustor vessel consists of a vertical cylindrical shell, 44 ft. in diameter (ID), with 1.8:1 elliptical heads. The shell and heads are 2 7/8 inches minimum thickness, and are fabricated from SA-299 carbon steel. The heads include removable service openings which allow for removal of components. Internal and external platforms are provided as necessary for equipment access.

The pressure vessel is bottom supported on a steel skirt to carry the weight of the vessel and provide a means of attachment for the transport beams used during shipping. The pressure vessel, skirt, and base stand 69'-10 7/8" high.

The vessel is provided with externally-mounted safety valves for over-pressure protection. Thermocouples are installed on strategic locations of the pressure vessel to detect abnormal metal temperatures. The vessel is externally insulated to minimize heat loss, and to provide for personnel protection.

The Tidd combustor pressure vessel was designed for an internal design pressure of 185 psig. The vessel was shop-fabricated and hydrostatically tested at 278 psig. The operating and design temperatures of the pressure vessel are 572 F and 675 F, respectively. The vessel was designed, fabricated, tested, and inspected in accordance with the ASME Pressure Vessel Code, Section VIII, Division 1.

There are 106 penetrations on the Tidd Pressure vessel. All of the penetrations were installed during fabrication, and prior to the stress relieving and hydrostatic testing.

Figure 6.1.1 is an illustration of the combustor vessel fabrication assembly method. Figure 6.1.2 is an outside sideview of the combustor vessel assembly.

Photo 6.1.1 is a picture of the combustor vessel being shipped from B&W's shop facilities to the Tidd Plant via an Ohio River barge. Photo 6.1.2 shows the combustor vessel being off loaded at the Tidd site. Photo 6.1.3 shows the sideview of the combustor vessel in the plant after installation and Photo 6.1.4 shows the equipment atop the combustor vessel. This includes the oxgyen analyzer system, safety valves, and combustor depressurization valves.

Key Instrumentation and Controls

There are no controls directly associated with the function of the combustor pressure vessel. Thermocouples were installed to monitor temperatures of several locations along the vessel wall and certain nozzles. In addition, pressure is monitored in the pressure vessel.

6.1.2 System Modifications

The pressure vessel has performed as intended without any significant modifications. However, additional penetrations were installed to provide both additional instrumentation and process needs. These process needs have been associated with providing air to the cyclone ash removal system, separating the secondary cyclone ash removal system.

A belly drain was activated in the lower portion of the pressure vessel, in order to confirm a water leak inside the pressure vessel. A level alarm was installed in the dip leg of the belly drain to indicate the accumulation of water at that location.

6.1.3 Operating Experience Overview

The operating experience of the pressure vessel has been good, with no problems reported. A non-destructive examination of the large bed preheater and air/ gas penetration welds during the spring 1993 gas turbine outage revealed no cracks in these critical regions.

6.1.4 Summary and Conclusions

The Tidd Pressure Vessel has performed without any significant problems. The shop fabrication, testing and shipment of the pressure vessel successfully demonstrated the viability of modularization of this component.

6.2 System 22 - Boiler

6.2.1 System Description

System Purpose and Function

The boiler is the heart of the PFBC combined-cycle process (Refer to Figure 6.2.1). It contains the fluidized bed where the combustion of coal takes place with high-pressure air delivered from the gas turbine compressor and where the SO_2 generated from the coal combustion is captured by reaction with calcium in the sorbent-based bed. Tubes submerged within the bed absorb a large portion of the heat released during combustion, generating and superheating the steam for the bottoming-steam turbine cycle. The hot gases released from coal combustion provide the energy to drive the topping-gas turbine cycle.

The boiler interfaces with the following systems:

The coal and sorbent injection systems which respectively feed the coal paste and dry sorbent into the fluidized bed.

The bed ash removal system which drains excess bed material from the boiler bottom hoppers in order to maintain the desired bed height.

The process air system which takes a portion of the compressor air flow from the boiler windbox, cools it, then returns the majority of this flow to air distribution devices located at various points in the boiler bottom for direct-contact cooling of the bed ash drains.

The gas cleaning cyclones which receive the combustion gases from the boiler freeboard area.

The combustor vessel which contains and supports the boiler.

The bed reinjection system which transfers bed material directly between the fluidized bed and the system's two storage vessels to permit relatively rapid bed level changes.

The feedwater system which supplies preheated feedwater and attemperator spray flow.

The main steam system to which it delivers superheated steam.

The boiler ventilation system which evacuates gas or air from the boiler to assist in unit cool down.

The combustor depressurization system which provides both boiler enclosure under pressure and over pressure protection relief via rupture discs.

The bed preheating system which provides hot gas for heating the start-bed to a temperature sufficient to ignite the coal (approximately 1200 F).

General Description

Air/ Gas Side

The boiler enclosure is constructed of membraned tubes cooled by boiler feedwater. The enclosure consists of three main sections: the bottom hoppers, the lower furnace, and the upper furnace. (Refer to Figure 6.2.2).

The boiler bottom hoppers collect, cool, and direct the bed ash drains to the bed ash removal system. They also contain the boiler windbox and the fluidizing air sparge ducts. Air from the combustor vessel is directed (via the ash pipe channel plenum and the cyclone ash coolers) into the boiler windbox through the central duct. During bed preheating, closure of a damper directs the air through the bed preheater to attain gas temperatures as high as 1500°F. Air or hot gas from the windbox is distributed into the bed by the sparge ducts. The ducts span the entire bottom of the fluidized bed and sit at the top of the boiler bottom, protruding slightly into the lower furnace enclosure. The fluidizing air is distributed by sparge nozzles. Sufficient pressure drop is maintained through the nozzles to insure even distribution of the fluidizing/ combustion air. Spaces between the ducts provide the area for bed ash drains. Once drained below the ducts, the bed ash is directed down through the bottom hopper to the bed ash removal system. The process air system, which supplies the bed ash cooling air, takes its air from the boiler windbox. The air is cooled and returned to the boiler bottom for direct contact cooling of the draining bed ash. This cooling air then passes up between the sparge ducts and into the bed where it assists in fluidization and provides part of the combustion air. The total cooling air flow is sufficiently low to avoid fluidization in the bed drain regions between the sparge ducts.

The lower furnace enclosure contains the fluidized bed and the in-bed tube bundle. The first two feet of the fluidized bed is the startup zone, which has no boiler tubes. The lower furnace enclosure walls are internally insulated in this zone in order to minimize the start bed heat loss. This region also contains the coal and sorbent feed nozzles, as well as the bed ash reinjection storage vessels' ash removal and supply nozzles. The in-bed tube bundle sits just above the startup zone and extends up to the full-load bed height of approximately 142 inches. The enclosure wall tubes are fully exposed throughout the height of the tube bundle.

The upper furnace enclosure begins just above the top of the tube bundle and forms the boiler freeboard area which allows for disengagement of larger elutriated ash particles. Two openings along each sidewall and three openings along the rear wall direct the gases from the freeboard into the seven separate gas-cleaning cyclone strings. The walls of the freeboard are internally insulated to minimize gas heat loss and maximize the gas turbine inlet temperature. Four openings in the roof of the upper furnace enclosure provide interface to the boiler over/under pressure rupture discs and boiler ventilation system.

Water/Steam Side

The boiler is a subcritical, once-through steam generator that employs a pump-assisted circulation loop and a vertical separator for startup and shutdown (Refer to Figure 6.2.3). The boiler bottom, lower furnace and upper furnace enclosures are arranged in series to provide preheating of the boiler feedwater while cooling the membraned enclosure tubes. The water is directed from the upper furnace enclosure into the in-bed evaporator tubes, which heat the water to saturation, generate the steam, and provide a slight degree of steam super heat. The steam is then directed from the evaporator into the in-bed primary superheater tubes, which provide sufficient super heat for spray attemperation. The steam then passes from the primary superheater through the attemperator and into the in-bed secondary superheater where heating to the final main steam temperature occurs. At loads below approximately 40%, the evaporator is operated with a fixed circulation flow rate of 40% of full-load flow. The wet steam exiting the evaporator is directed through a centrifugal-action vertical separator which separates the water droplets from the steam. The collected liquid is fed into the boiler circulation pump which directs it back in with the feedwater flow to the boiler bottom enclosure. The dry steam from the vertical separator is directed to the primary superheater. At loads above 40%, the boiler circulation pump is out of service and the boiler operates in a true once-through fashion. When sufficient load is attained to maintain dry evaporator outlet conditions, the vertical separator is bypassed to minimize steam-side pressure drop.

The boiler circulation system incorporates a high-pressure nitrogen-pressurized water injection tank and a low-flow, high-head make-up pump to provide for tube cooling in the event of a loss of feedwater. The injection tank provides an initially high feedwater flow rate in the first critical minutes, while the make-up pump provides a lower flow rate for long-term boiler feedwater make-up. The operation of both the boiler circulation pump and the boiler make-up pump are critical for a controlled shutdown. Both of these pumps have back-up diesel generator power in the event of a black plant trip.

Photo 6.2.1 is a picture of the vertical separator next to the combustor vessel. Photo 6.2.2 shows the existing steam turbine that was reused for the PFBC application.

Key Instrumentation and Controls

Air/ Gas Side

Bed height and bed temperature are the main load-defining parameters at Tidd. These are operator-adjusted parameters which define unit load. The combustion master signal follows the bed height. This load demand is then trimmed by the bed temperature controller. The indicated bed height is also used to control the bed ash removal and the bed ash reinjection systems during bed height (load) changes. Low flue gas oxygen overrides are provided to prevent sub-stoichiometric combustion.

Bed height is monitored by a series of seven differential pressures measured between the bottom of the bed and various heights in the bed. The top taps of four of these are at varying bed heights within the normal operating bed height range. These four taps, which sequentially become submerged as the bed height is increased, are used in the calculation of the bed density. The top taps of the other three differential pressure measurements are all located at the same height in the boiler freeboard. The middle value of these three readings and the calculated bed density are used to calculate the bed height.

Thirty-two thermocouples spread throughout the bed monitor bed temperature. The measured mean bed temperature provides feedback to the combustion master signal to attain the fuel-flow rate needed to maintain the operator-specified mean bed temperature set-point. Only the thermocouples that are submerged at a given bed height are included in the mean bed temperature calculation. At normal operating bed heights, the lowest six thermocouples, which are at a bed height of 4 inches, are not included in the mean-bed temperature calculation. They are instead used to indicate excessive bed sinter collection as evidenced by a deviation in their readings relative to the mean bed temperature.

Water/Steam Side

In the normal unit load range of 40-100%, the boiler operates in a once-through manner with feedwater flow regulated to maintain the desired main steam temperature. Evaporator outlet temperature and pressure are used in the feedwater control loop to maintain a slight degree of superheat in the combined evaporator outlet line. Attemperator spray is utilized to trim the evaporator outlet superheat. Modulation of the steam turbine control valve regulates the turbine inlet pressure to a constant value of 1300 psia, hence the turbine follows the boiler.

At loads below 40%, the feedwater flow control is a three-point level control system using the vertical separator level error along with the indicated feedwater and steam flow rates to control the feedwater flow control valve. The boiler circulation pump delivered flow is regulated to maintain a fixed boiler circulation flow rate, which is the total of the feedwater flow and the boiler circulation pump delivered flows. In this mode the attemperator spray flow is used only to control the main steam temperature in the event of high temperature excursions.

In the event of a loss of feedwater, the gas turbine is tripped causing the air flow to cease and the bed to immediately slump. When this occurs, the tube-bundle absorption rate is reduced to less than 5% of normal within the first few minutes. The initially high water demand, required to protect the in-bed tubes, is met by flow delivered from the boiler injection tank into the feedwater supply line via a high-capacity control valve. Lower long-term make-up demands are met by the low-capacity boiler make-up pump via a small control valve which feeds directly to the vertical separator. The boiler circulation pump maintains high circulation flow rates through the boiler enclosure and evaporator circuits keeping them cool, while a control valve vents sufficient flow from the main steam line to atmosphere to cool the superheater circuits.

Thermocouples are employed on approximately one fourth of all evaporator, primary, and secondary superheater outlet legs. These measurements are generally used for generation of high temperature alarms, which indicate unusual conditions associated with those components. In addition to the alarm function, the evaporator outlet leg temperatures have been particularly good indicators of uneven bed conditions. Due to the evaporator's low temperature rise and high enthalpy pickup associated with the change of state from water to steam, these outlet leg temperature indications are very sensitive to uneven heat transfer conditions. Slight variations in overall heat absorption between circuits can result in dramatic variations of outlet leg temperature, with saturation temperature generally being the lowest reading.

6.2.2 System Modifications

Bed-Ash Cooling

Evaluation of the Tidd bed-ash cooling system, prior to unit startup, indicated that the system would not be capable of cooling the bed ash drains to the desired temperature. A design modification was implemented to provide additional cooling air to lower parts of the bottom hoppers. The revised bed-ash cooling system has performed very well.

Sparge Ducts

The air-distribution sparge ducts exhibited a propensity to thermal deformation very early in unit operation. This phenomenon was attributed to uneven thermal growth between the duct tops and bottoms during bed preheating. This caused the ducts to bow in a convex manner when viewed from the top, during which time ash collected under the ducts and prevented them from returning to their original positions after preheating. The net effect was a racheting up of the duct ends over successive startups. Restraints were added at the ends of the ducts to limit this upward movement, and knife-edged skirts were added along the duct bottoms to prevent ash build up under the ducts. Neither of these measures were successful in resolving the problem.

During the first quarter of 1991, a number of the sparge nozzles were extended into the ducts to draw air/ gas from the bottom of the ducts, thereby minimizing the differential temperature between duct tops and bottoms. However, degradation of the sparge ducts continued despite this modification.

By the fall of 1991, this convex bowing of the sparge ducts had resulted in excessive distortion and cracking of bellows-type expansion joints located near the center of the boiler. The bellows expansion joints were replaced with machined slip joints to accommodate both axial and angular movements.

Throughout 1992, the majority of the sparge ducts gradually began to sag downward over their spans from the middle of the boiler to the side walls. This sagging was believed to be caused by end forces imposed by ash packed at the end of the ducts as they expanded during bed preheating. The sparge-duct arms were completely replaced in Spring 1993. The new duct arms employed the same inward extended nozzles noted above; however, the end tie down system was revised. The previously modified slip joints were reused. In order to address the compressive end forces during bed preheating, the duct-end fluidization system was changed from a passive system that apportioned part of the duct air to the end regions at all times to an active system that used higher-pressure air (from the sorbent air receiver) to provide a blast to clean the ends of the ducts periodically during bed preheating. From July 1993 through February 1994 the new ducts experienced 14 unit startups with no signs of distortion.

Post Bed Combustion

Significant post-bed combustion was experienced shortly after initial coal fire. Unburned carbon elutriated from the bed would concentrate in the cyclone dip legs where combustion would occur, resulting in excessively high dip leg temperatures. In addition, unburned volatiles would escape from the bed and burn at the inlet of some of the cyclone strings, resulting in excessively high gas temperatures through the affected strings. Post-bed combustion at high bed heights resulted in challenges to the maximum allowable gas turbine temperature. These problems of post-bed combustion were attributed to the limited number of coal feed points (six) and the resultant high localized fuel release. (Refer to Section 5.1 of this report for more details.) Fuel discharge deflectors, "skateboards", were added in the bed above the fuel nozzle outlets, and the sparge duct nozzles directly below these areas were modified to provide higher air flow to the fuel discharge regions. Side extensions were later added to enlarge the width of the skateboards. The skateboards and additional air flow provided some help in combatting post-bed combustion; however, the biggest improvements in this area were achieved through changes in coal paste quality. In the first quarter of 1994, the skateboards were moved slightly toward the rear wall of the boiler. This change affected the fore/aft temperature distribution in the bed, providing evidence that the skateboards do have an impact on fuel distribution. On the negative side, the skateboards create a defluidized zone directly above them, which collect sinters and undoubtedly contribute to the reduced heat transfer in the bed.

Since the freeboard was relatively quiescent with negligible lateral mixing of the localized volatile plumes, volatiles and excess oxygen were unable to mix until they reached the turbulent zone near the cyclone inlets. Then, post-bed combustion of volatiles would typically manifest itself at the inlet to just one or two of the cyclone inlets. Thus the heat release associated with it would be concentrated in one or two cyclone strings, resulting in extremely high temperatures in the affected strings. Therefore, a steam-injection-induced freeboard-gas-mixing system was installed to spread the heat release of post-bed volatile combustion over the entire gas stream. This system was commissioned early in 1992 and was shown to spread out the heat release of the volatiles and alleviate cyclone dip leg fires. It also had the effect of evening out the oxygen levels in the seven individual cyclone strings. This system was in use almost continuously when firing coal from early 1992 through the end of the three-year test period.

In-Bed Surface

The original in-bed surface, which was fully submerged at an indicated bed height of approximately 126 inches, provided only 73% of the design in-bed absorption. During the second quarter of 1991, shields were removed from the outlet legs of the evaporator, primary superheater and secondary superheater in the freeboard to help increase the tube bundle absorption. In Fall 1991, in-bed tube surface was added. Four rows of evaporator and two rows of secondary superheater surface were added at the top of the existing bundle and part of the shielding on the bottom horizontal tubes of the primary superheaters was removed. Due to concerns about post bed combustion, the design bed temperature used for sizing the additional surface was selected as 1540 F versus the original 1580 F temperature. At the new full-bed height of 142 inches at a bed temperature of 1540 F, the in-bed absorption is still approximately 7% below the original design value. The below-design heat transfer is believed to be due to collection of sintered material in the tube bundle, which is probably made worse by the relatively tight tube side spacing.

In addition to the insufficient heat absorption, the unit experienced localized low heat transfer to the platens nearest the boiler sidewalls. These platens, which are evaporator circuits, typically run in saturation even though the evaporator outlet header mix of all of the circuits is slightly superheated. To combat this problem, the shields on the lower four rows of the evaporator were removed from the two platens nearest each side wall (eight circuits total). The unit then experienced high alarm temperatures on the second, third, and fourth tubes in from each wall, particularly at loads just above once-through operation. Shields were reinstalled on the bottom two rows of these circuits during the first quarter of 1992. Despite having no shielding, both of the evaporator circuits nearest the sidewalls continue to run at saturation. The cause of this is believed to be boiler wall effects compounded by agglomerations which are typically found between the end circuits and the boiler sidewalls. The second circuit in from each sidewall also typically runs at saturation. The noted wall effects and agglomerations are probably the cause. The third and fourth circuits in from the walls generally run with the expected slight degree of superheat, revealing that the two rows of shielding are appropriate for these circuits.

Insulation/ Bed Liner

The boiler startup zone insulation liner originally consisted of insulating board protected from the bed by a segmented stainless steel liner attached by studs. Shortly after initial unit startup, the stainless steel liner began to warp excessively, pulling away from the wall in some locations and exposing the insulation to the bed. The startup zone insulation and liner was modified during Fall 1991. Due to access difficulty, all but the upper 14 inches of the insulation and liner were replaced. The new insulation system used fiberboard insulation protected from the bed by silicon carbide tiles and castable silicon carbide refractory. The tiles covered the majority of the wall and were held in place with studs and nuts with the studs spot welded to the wall tubes and membranes. Castable refractory was used at wall penetration areas such as the fuel nozzles. The upper 14 inches of the existing insulation system was kept since it was in good condition, and access to remove it was limited. During the first quarter of 1992, the top row of ceramic tiles began to pull away from the boiler wall. This problem was attributed to incorrect stud material in this top row and the design of the interface to the upper stainless steel section. The interface design was revised, and the studs were replaced. After these changes, the ceramic tiles and castable refractory has held up well; however, periodic repairs are needed as individual tiles will sometimes crack and fall off. The remaining portions of the stainless steel liner continued to warp with the sidewalls being the worse area. The sections of the stainless steel liner along the sidewalls were removed in early 1994. Castable refractory was used to cap off the top of the lower tile liner sections. The use of refractory tiles, while not totally maintenance-free, proved to be an acceptable liner design for the startup zone.

Vertical Separator

The unit experienced large vertical separator level swings during start up and steam generator transients. These swings complicated the tuning of the feedwater flow control loop and resulted in numerous combustor trips. For the most part, these problems were resolved through extensive tuning and reconfiguration of the control loops, combined with increased operator attention and procedure changes. However, upon achieving once-through operation, the unit again began to experience vertical separator level swings. It was determined that the swings, above once-through, were false indications caused by pressure fluctuations in the vicinity of the top (low pressure) taps of the differential pressure transmitters used for level indication. The top taps of the differential pressure transmitters were lowered away from the steam inlets in Fall 1991. This modification proved to be successful in eliminating the false level indication swings.

Feedwater

The feedwater check valve was originally located upstream of the economizer. In August, 1991 the economizer experienced a major tube rupture which caused a loss of feedwater and rapid depressurization of the boiler. The feedwater check valve was relocated to the feedwater line downstream of the economizer, but upstream of the tie point from the boiler injection tank, in order to protect the boiler. In addition, control logic was added to recognize such an event as a "loss of feedwater" incident and initiate a gas turbine trip and feedwater injection.

Bed Temperature Monitoring

The original 18 in-bed thermocouples were augmented with 14 more in Spring 1991. This provided a much better picture of the bed conditions, not only for the surface redesign activities ongoing at this time, but also for day-to-day operation.

Oxygen Analyzers

The original boiler gas outlet oxygen analysis system consisted of three low-temperature micro fuel cell transducer type analyzers that sampled gas from three locations in the boiler freeboard. Gas samples were taken from slipstreams of combustion gases that were established by venting the gases to atmosphere via small-bore tubing. A needle valve in the slipstream line controlled the gas flow. The samples were washed with water, and a pump downstream of the water wash was used to draw the sample from the slipstream. This system had the following problems:

The analyzer cells did not indicate accurately until they were exposed to CO_2 for 12 - 24 hours, and after that they experienced excessive calibration drift.

The slipstream needle valves experienced excessive erosion due to the high dust loading and high velocity through the valves. As the needle valves wore, the slipstream flow rate would increase. This, in-turn, caused excessive erosion to the slipstream tubing, resulting in tubing failure and air in-leakage inside the combustor vessel. In addition, high slipstream flow rate raised the pressure at the gas sample extraction point, causing excessive sample flow rates and resulting in over-temperature and damage to the analyzer's tygon sample tubing.

The slipstream lines and needle valves also experienced frequent plugging due to the high ash concentration of the gas.

Wash water flow rate control problems resulted in a number of other problems, particularly sample line plugging. In a number of incidents, water from the O_2 analyzers made its way back through the gas slipstream lines during unit shutdown, resulting in flooding of the associated secondary cyclone ash removal lines and causing ash-line plugging. In addition, loss of water incidents occurred, resulting in excessive temperature and damage to the analyzer internals.

The sample pumps experienced numerous failures.

Flue gas acidic condensation resulted in slipstream and sample line corrosion and plugging.

In addition to the mechanical problems, significant deviations in oxygen concentrations were noted between the three analyzers, revealing stratified boiler freeboard gas conditions and raising concerns that the sample points might not be representative of the average flue gas conditions.

The oxygen analysis system underwent a number of evolutionary changes in order to improve its accuracy and reliability and to provide more complete measurement of the boiler exhaust gases. The major modifications are summarized as follows:

The oxygen analyzers were replaced to a new design that employed high-temperature zirconium oxide cells. The new design eliminated the water wash and sample pump through the use of air aspiration to draw the sample and a ceramic filter to clean the sample of particulate.

The gas sample points were relocated downstream of the primary cyclones in order to reduce the slipstream gas dust loading. In addition, a total of seven analyzers were installed to insure representative measurement of the entire boiler outlet gas.

The slipstream needle valves were replaced with fixed orifices and the lines were configured to minimize ash plugging and permit easy clean out in the event that plugging was experienced. The orifice design eventually was changed from metal to ceramic to preclude excessive erosion.

Periodic high-velocity air purging was employed to avoid plugging of the vent lines. This purge resulted in excessive particulate emissions to atmosphere, so the vents were configured to discharge into the boiler ventilation system (thus collecting the particulate in that system's dust collector).

High-temperature heat trace and insulation was employed on the slipstream and sample lines to avoid acidic condensation.

The above changes eliminated most of the noted system problems; however, slipstream line plugging and erosion were still experienced. From a practical standpoint, the system reliability was improved sufficiently to obtain accurate and representative oxygen measurements, which, in-turn, permitted extended runs and provided sufficient data for combustor performance evaluations.

6.2.3 Operating Experience Overview

The water/steam systems generally operated very reliably, once the vertical separator problems were addressed. The only exception was the occurrence of persistently uneven evaporator outlet leg temperatures experienced at high bed heights near the end of the three-year operating period. This problem was precipitated by uneven heat transfer conditions in the bed believed to be caused by sintering. Resolution of bed sintering is an ongoing effort. It should be noted however, that the Tidd evaporator is very sensitive to uneven heat absorption, since the slope of the temperature versus enthalpy curve is relatively high at the low operating pressures of this unit.

The most significant operating issues, on the air/gas side of the boiler, were bed sintering and post-bed combustion. (Refer to Section 5.0 of this report for details).

The steam generator equipment held up very well over the operating period. Erosion of the in-bed tube bundle, once considered a major liability for the bubbling bed PFBC process, proved to be no major issue. The most significant erosion was very localized near the fuel discharge skateboards. This erosion was attributed to high velocity flow patterns caused by the skateboards and the additional air nozzles located under them, and was repaired through pad welding. The only other significant erosion was pock marking on the inlet sections of secondary superheater tubes. This condition is also very localized, and is most likely linked to the lack of sufficient oxide layer formation due to the relatively low secondary superheater inlet temperature. This erosion did not progress to the point requiring repairs. A full inspection and evaluation of the tube bundle will be performed after decommissioning to fully assess in-bed tube erosion.

The emergency bed cooling system which provides back-up feedwater from the boiler injection tank and boiler make-up pump in the event of a loss of feedwater event, was successfully tested from a bed height of 110 inches during the second quarter of 1991. This test verified the proper operation of this critical systems components and controls. Confirmation of the adequacy of this system, to provide sufficient feedwater to provide the boiler make-up for a full load trip, remains to be demonstrated.

6.2.4 Summary and Conclusions

Except for resolution of the bed sintering issue, the experience from Tidd indicates that the boiler and related systems are in a state of commercial readiness from a functional perspective. Additional testing is planned, for the extended fourth year of unit operation, to address the sintering issue.

6.3 System 231 - Gas Cleaning Cyclones

6.3.1 System Description

System Purpose and Function

In a PFBC Combined Cycle, hot gas from the fluidized bed combustion process drives the gas turbine. Particulate matter entrained in the gas stream would quickly erode the gas turbine internals if left untreated. The required gas cleaning is accomplished by directing the gas through a series of mechanical cyclones. These cyclones are designed to remove 98 to 99% of the entrained ash. The cyclones also function to partially cool the collected ash before delivering it to the cyclone ash removal system. The clean gas from these cyclones is collected in a gas manifold and routed to the gas turbine by a coaxial gas turbine cross-over pipe.

The gas cleaning system interfaces with many of the other PFBC systems in the plant as follows:

Receives hot ash and gas from the boiler freeboard at the cyclone inlets.

Delivers hot ash and bleed gas to the cyclone ash removal system in the cyclone dip legs.

Delivers cleaned gas to the gas turbine via the coaxial pipe between the combustor and gas turbine.

Provides a sample gas stream for the O_2 analyzers.

General Descriptions

The original gas cleaning system is shown in the simplified drawing on Figure 6.3.1.

The gas cleaning system consists of seven sets of Van Tongeren high-efficiency mechanical cyclones arranged in parallel. Each set consists of two cyclones in series: a primary cyclone and a secondary cyclone. The primary cyclone removes approximately 97 to 98% of the particles from the gas stream. The secondary cyclone then removes approximately 33% to 50% of the remaining particles from the gas stream. The combined two-cyclone train removes approximately 98% to 99% of the particulate from the gas. The remaining very fine particles (under 10 microns) continue in the gas stream and pass through the gas turbine before entering the economizer and precipitator.

The gas enters the seven cyclone strings from the boiler freeboard. The seven cyclones are evenly spaced around the two sidewalls and the rear wall of the boiler. The primary cyclones are installed around the boiler as follows: #11 and #12 are on the left sidewall; #13, #14 and #15 are on the rear wall, and #16 and #17 are on the right sidewall.

The original plant design included seven strings of two cyclones. However, as part of the Hot Gas Cleanup System installation, the secondary cyclone in the string feeding the HGCU system was removed and the hot gas was routed directly from the #11 primary cyclone to the HGCU system.

A small amount of hot gas moving through each cyclone is used to pneumatically transport the ash out of the cyclone and through the cyclone ash removal system.

Ash and hot gas separated in the primary cyclones is cooled at the bottom of each of the primary cyclone dip legs. Hot ash and gas pass through an air cooler in the bottom of the dip leg and are cooled by combustion air that is directed down through the outer sections of the concentric pipe. The ash and gas then enter the ash transport pipe for pneumatic transport out of the combustor.

Similarly, the hot ash and gas (which is separated out of the flow path in the secondary cyclones) are directed down through the cyclone dip leg without additional cooling in the secondary cyclone dip leg. Originally, the secondary cyclones were also equipped with dip leg coolers, but these were eliminated during the modifications to the secondary ash removal system. Refer to Section 6.10. Once the ash and gas reach the bottom of the secondary cyclones, they are pneumatically transported out of the combustor vessel.

After it is cleaned, the gas leaves the secondary cyclone and enters a series of manifolds at the top of the combustor vessel. These manifolds collect the gas from the seven cyclone trains and merge the flow into a single pipe before it exits the combustor vessel and is subsequently routed to the gas turbine.

The primary and secondary cyclones are essentially the same design except in overall size. The primary cyclone has a ceramic-lined zone at the bottom of the cyclone cone in order to minimize erosion. The primary cyclone is approximately 33 feet long from the top of the cyclone to the ash line pickup pot location. The secondary cyclones were originally a few feet longer, but the lower portion of their dip legs was removed. They are now about 20 feet long. Secondary cyclone diameter is approximately 80% of the largest diameter of a primary cyclone.

The cyclones are made of a high-grade stainless steel material in order to withstand the high operating temperatures and resist erosion of the walls.

Key Instrumentation and Controls

The gas cleaning system is a passive system. There are no controls required for its operation. The major requirement is system surveillance for ash pluggage of the ash removal lines, ash pluggage of the dip leg bottom, or for cyclone fires caused by high carbon carryover. Operational surveillance of the cyclones is achieved by two thermocouples: one in each primary cyclone inlet gas stream and one on the outside metal of the cyclone just above the dip leg. The latter thermocouple measures the ash and gas temperature of the stream exiting the bottom of the cyclone on its way to the ash removal system. By monitoring this temperature, plugs in the ash removal system can be identified. When the ash removal system is plugged, this dip leg temperature will immediately drop, indicating a drop in gas flow out the bottom of the cyclone. Fires in the cyclones can usually be detected by a sudden rise in the dip leg temperature. Presence of cyclone fires can also be detected by comparing the cyclone inlet temperature and dip leg temperature.

6.3.2 System Modifications Completed

In general, the primary and secondary cyclones have operated satisfactorily at the Tidd PFBC Demonstration Plant. Removal of the ash from these cyclones, however, has been a major problem. Refer to Section 6.10 for details. A number of modifications have been required on the cyclones, and are listed below.

Primary Cyclone Heat Shields

High carbon carryover into the primary cyclones and resulting high carbon concentrations in the lower sections of the cyclone has been a problem resulting in uncontrollable cyclone fires. (Refer to Section 5.1). These fires can usually be eliminated through proper coal paste preparation. However, in an attempt to reduce the risk of cyclone fires, a modification was made in Spring 1992. This modification involved the removal of insulation around the cyclone bottom discharge cones and the installation of radiant heat shields. By removing the insulation in this area, the metal temperature of the cyclone was reduced, thus reducing the chance of spontaneous combustion in the cyclone.

Secondary Cyclone Dip Leg Modification

The secondary cyclone dip legs were removed during Fall 1991 in an attempt to improve the secondary ash removal system capacity. Prior to this modification, ash would build up in the bottom 20 feet of the dip-leg pipe and restrict or prevent the flow of ash from the dip leg. The bottom 15 feet of the dip leg, along with the dip-leg cooler were removed from the cyclone in 1991. The bottom of the dip leg and the ash-line pickup pot are now only a few feet below the bottom cone of the cyclone. This modification did not improve ash removal system capacity as originally envisioned. While the buildup of ash in the bottom of the cyclone was reduced, the ash removal system continued to have serious capacity problems until Spring 1993 when the system was replaced in its entirety.

6.3.3 Operating Experience Overview

The operating experience of the cyclones has been relatively good. In general, the cyclones have had five major problems over the operational period. These include cyclone fires, ash removal pluggage, ash falls during startup, dip-leg cooler air leaks, and primary cyclone refractory erosion. These are discussed in detail below:

Primary Cyclone Fires

The primary cyclones have been subject to cyclone fires since initial operation of the unit. Generally, cyclone fires have been the result of high carbon carryover into the cyclones. The carbon concentrated in the lower sections of the cyclones where it combined with the high concentration of O_2 in the cyclone and ignited in the dip leg. This resulted in melting and fusing of ash particles. Once the particles fused, they fell to the bottom of the cyclone dip leg where they cooled into a solid form. These clinkers were drawn into the inlet of the primary ash removal line, plugging the line. Screen cages were installed around the inlets of the suction nozzle to prevent these clinkers from blocking the ash lines. These cages, while effective at times, could still be blocked by sinters when a significant cyclone fire occurred.

Cyclone Ash Pluggage

One of the most persistent problems with cyclones was pluggage of the ash removal system. Pluggages in either the primary or secondary cyclones were immediately noticeable. The cyclone dip legs would quickly fill with ash to a point near the top of the cyclone cone. Once the primary cyclone was filled, the ash would be carried over into the secondary cyclone and would quickly overwhelm the secondary ash removal system. At that point, the secondary cyclone would begin to fill with ash. When both a primary and secondary cyclone plugged and filled with ash, untreated gas would reach the gas turbine and result in high rates of erosion. Over the first three years of operation, this scenario occurred only once–in late 1990. The unit operated for several hours until it was verified that both cyclones were plugged. Subsequent inspection revealed noticeable gas turbine erosion. Based on these observations, a policy was established to trip the unit as soon as cyclone pluggage was suspected.

It was very difficult to operate the unit for any extended time period without experiencing secondary cyclone pluggage. Secondary cyclone pluggages were originally handled in the same fashion as primary cyclone pluggage - the unit was shutdown. However, by mid 1991 it became apparent that secondary cyclone pluggages had little impact on gas turbine erosion. Therefore, from mid 1991 to early 1993, the unit was operated for a considerable amount of time with secondary cyclones plugged.

All secondary cyclones have operated properly since the secondary cyclone ash removal system was replaced in spring 1993. Since that time, the secondary cyclones have only been out of service collectively for only a few hours.

Cyclone Ash Falls

Ash falls or ash peelings in the cyclones during unit startups were first observed in Fall 1991, during a lengthy outage when the interior walls of the primary and secondary cyclones began a slow, but constant, peeling of ash coating off their interior walls. As time passed, the amount of peelings increased. The #12 primary and #22 secondary were sandblasted near the end of the outage to remove all the ash buildup on the walls. Upon startup of the unit, all of the cyclones except #12 and #22 plugged immediately upon bed preheating. The unit was shut down. Subsequent inspection revealed that the ash falls overwhelmed the ash removal line pickup nozzles causing pluggage of the system. The bottom 2' to 5' of each cyclone was filled with ash peeled from the cyclone walls. The exact cause of this phenomenon has never been identified. Presently, ash layer buildup is sandblasted out of the cyclones during every shutdown. No startup ash falls of significance have occurred since this procedure was implemented.

Dip-Leg Cooler Air Leaks

The cyclones and cyclone ash removal system operate at a lower pressure than the air space of the combustor vessel. Therefore, any leaks in these systems result in cooler air flowing into the cyclones and dip legs. During early 1991, leaks developed in the primary dip-leg bellows boxes, which are located at the bottom of the dip legs. When these leaks were sufficiently large, significant quantities of air would flow into the dip leg. This would displace the hot ash and gas from entering the ash line and result in cyclone dip-leg pluggage. In order to eliminate this problem, all of the flanges in the primary dip-leg bellows boxes were seal welded while the bellows boxes in the secondary cyclones were eliminated.

Primary Cyclone Refractory

The discharge section of the bottom cone of the primary cyclone is refractory lined to minimize erosion in this area. The refractory was installed over a diamond-shaped mesh that was welded to the cyclone walls. This refractory has worked well, with no problems encountered over the three years of operation. The only noteworthy item of concern was the buildup of a very hard deposit on this refractory. During each shutdown or startup, round sections of refractory, about the size of the mesh, would spall off and drop to the bottom of the dip leg where they would remain until the bellows box was cleaned. These quarter-sized spallings would have the super-hard deposit on one side and the white refractory on the other side. Generally, they were 1/4" thick.

While these "refractory chips" never plugged an ash removal suction nozzle, they had the potential to do so if left to accumulate over time in the bottom of the bellows box. Also, the flaking of these chips off the refractory was found to be a self-limiting process, and has not required any maintenance work on the cyclone refractory.

Secondary Cyclone Stirring Air

A dip-leg stirring air system was installed in the bottom of the secondary cyclone dip legs. This system consisted of an individual small-bore air line leading from a valve station outside the combustor to each of the secondary dip legs. The line branched into three nozzles spaced 120° apart and tangential to the circumference of the dip-leg pipe. In addition, each of these three tangential lines had small orifices which permitted combustor vessel air to purge into the dip leg on a continuous basis. Outside of the combustor vessel, each of these six lines were connected by an isolation valve to the sorbent injection compressed air system.

The intent of this system was two-fold. The first purpose was to provide a passive purge air path to the bottom of the dip leg that would keep the ash buildup on the floor of the dip leg stirred up. The second purpose was to provide an active system that could blast the dip leg with much larger amounts of purge air in case the dip leg became plugged.

The effectiveness of the passive purge air was nozzles was questionable. The impact of the manual purge air blast system was noticeable. However, several vibration fatigue failures occurred in these active purge air line. These failures caused significant quantities of combustor air to enter the dip-leg, causing operating difficulties. Therefore, in early 1993, the stirring air system was eliminated.

6.3.4 Summary and Conclusions

In general, the gas cleaning cyclones worked exceptionally well considering their pioneering application to this service environment. They were internally inspected twice, once during Fall 1991 and again in Spring 1993; no significant erosion was found.

The modifications made to both the primary and secondary cyclones were done solely to improve the capacity and reliability of the ash removal systems and were not done as a result of cyclone operation. The final system configuration is shown in Figure 6.3.2.

6.4 System 235 - Combustor Depressurization

6.4.1 System Description

System Purpose and Function

There are three types of trips which must be considered in the design of a PFBC plant: black plant trip, combustor trip, and gas turbine trip. The combustor depressurization system controls depressurization of the combustor vessel in such events. During depressurization, the system minimizes the burnoff of the volatiles of the coal remaining in the bed while preventing sintering and gasification of the coal char in the bed material. The system also serves as a path to vent steam in the event of a large steam leak inside the boiler enclosure that activates the boiler enclosure rupture disk.

General Description

During a normal combustor trip, the coal feed is stopped while the gas turbine continues to operate. The air from the gas turbine compressor burns out the char and cools the bed before it is slumped. In the event of a black plant or a gas turbine trip, the air flow ceases rapidly and the bed defluidizes. The bed, which contains a quantity of unburned carbon, slumps at full temperature. The compressed air in the combustor vessel is bottled up, however, gas flow continues through the cyclone ash removal system and the gas turbine intercept valve. This flow path induces a small quantity of air to flow through the bed. This small flow of air could result in continued combustion in the slumped bed. Since the ability to transfer the heat to the in-bed boiler tubes is greatly reduced by the slumped bed condition, localized overheating and sintering could occur. Further, the lack of sufficient oxygen in the vicinity of the combustion could result in gasification of the coal char, especially in the upper regions of the slumped bed. The combustor depressurization system is designed to replace any air in the bed with nitrogen. This is accomplished by controlling the discharge of the stored air in the pressure vessel, while feeding nitrogen into the bed in such a manner as to displace the air in the bed. The nitrogen feed to the bed prevents the air flow from the pressure vessel into the slumped bed.

The design details of this system are proprietary, therefore the instrumentation and controls of the system are not discussed in this document.

Photo 6.4.1 is a picture of the combustor depressurization valves located atop the combustor vessel.

6.4.2 Operating Experience Overview

The combustor depressurization system has operated successfully when a gas turbine trip has occurred. During the early operation of the unit, some adjustments were required in some of the valves, orifices, and pressure regulators. However, none of the problems experienced were significant.

6.4.4 Summary and Conclusions

The combustor depressurization system has performed as intended. However, the combustor depressurization system is rather complex and requires a significant amount of nitrogen when it is activated. Alternate methods of addressing the concerns of gasification and sintering in a hot slumped bed should be addressed in future PFBC plants.

6.5 System 252 - Bed Preheating

6.5.1 System Description

System Purpose and Function

The PFBC bed material must be heated above the ignition point of the coal before coal combustion can begin. The function of the bed preheating system is to preheat the bed by the combustion of fuel oil in a controlled manner until the boiler bed reaches the temperature (1200°F). Once coal ignition is achieved, the bed preheating system is removed from service.

The system interfaces with the fuel oil supply system and the process air system which is used for purging the burners. The system also interfaces with the boiler air supply ducts and central duct that feed the windbox.

General Description

The main components of the system are the receiver tank, fuel oil pump, spill flow burners, and associated piping and valves. Fuel oil is supplied to the receiver tank from the plant fuel oil system. The pump takes suction from the receiver tank and supplies fuel oil to the burners housed in a preheating combustor. Unburned fuel oil is recirculated back to the receiver tank. A motor-operated valve controls the back pressure at the burners and hence the firing rate of the burners. The burners are termed "spill flow" because they receive a constant amount of fuel oil throughout their load range, and the excess fuel oil that is not burned is recirculated back to the receiver tank.

The fuel oil pump is a gear-type positive displacement pump rated at 28 gpm.

The burners are fed from dedicated fuel oil chambers which incorporate needle valves. These valves open and close the discharge nozzles to the burners. All burners are in service at the same time. When the system is in service, all of the combustion air is diverted through the burners. The combustion gases from the burners discharge into a common hot gas tube which directs the flow to the boiler windbox via the central duct. Two spark plugs are used to ignite the burners. A flame scanner is used to monitor the fuel oil ignition process.

The system is designed to be fired in a range from 20.5 to 102 million BTU/hr., which corresponds to fuel flow rates of 2.6 to 13 gpm.

A simplified sketch of the system is shown in Figure 6.5.1.

Photo 6.5.1 is a picture of the bed preheater module attached to the bottom of the combustor vessel.

Key Instrumentation and Controls

Pressure is measured upstream of the burners and in the purge air supply. The burner needle valve closing air pressure is measured to indicate whether the valves are open or closed. Temperature is measured at the outlet of all five burners, as well as in the gas duct between the preheating combustor and boiler bottom. Other instrumentation includes a flame scanner and a level switch in the receiver tank.

System Control Overview

The bed preheating firing rate is regulated by the recirculation control valve. This valve is positioned by a motor operator to achieve and maintain the preheating gas temperature set point. Control signals are generated from the thermocouple located in the common hot gas duct from the five burners. The recirculation control valve is located in the common return line from all five burners and, therefore, controls all burners to the same output level. Makeup to the receiver tank is regulated by a float valve on the tank.

6.5.2 System Modifications Completed

The major modification made to the system was to change the ring header that connected the five burners into a manifold configuration. This change was made to facilitate the removal of a single needle valve by enlarging the access area around the valves.

An alternate purge air supply was tied into the system from the L-valve receiver air tank, which operates at a higher pressure than the original process air supply. This revision was made to improve purging of the system and allow purging during unit operation.

The tie-in point of dry air into the purge air line was moved to prevent the dry-air system pressure from being pulled down when the process air pressure is lower than dry-air pressure. The spark plugs were modified so that the cable connection was not exposed to high temperatures. The flame scanner was moved to an observation port and a redundant scanner was added. Needle test valves were also added. The flame head louvers cracked and were replaced in kind.

6.5.3 Operating Experience Overview

Overall, the bed preheating system worked very well. A problem of sticking needle valves sometimes caused difficulty in lighting the burners, but otherwise the system has been reliable. Maximum allowable burner temperature differentials were increased from ±180°F to ±350°F to keep the system from tripping out of service. Another issue was difficulty in lighting of the bed preheater on hot restarts. When the combustor vessel temperature is much above 300°F, lighting of the bed preheater has been erratic.

6.5.4 Summary and Conclusions

The bed preheating system was changed very little from initial to final configuration. It proved to be a very reliable system. The few improvements that were made were minor. One source of concern is the failure of the burner louvers, since the reason for the failure has not been established.

6.6 System 261 - Sorbent Preparation

6.6.1 System Description

System Purpose and Function

In a PFBC Combined-Cycle plant, granular sorbent is injected into the fluidized bed to act as the absorbent material to capture SO_2 produced through combustion of the coal, and to provide material to maintain a bed. The level of sulfur reduction desired can be altered by varying the rate of fresh sorbent fed into the bed.

The sorbent preparation system crushes the as-received raw sorbent into a properly sized product which is then fed into the fluidized bed boiler by the sorbent injection system.

The sorbent preparation system interfaces with many of the other plant systems as follows:

Obtains raw sorbent from the sorbent handling system.

Delivers crushed and sized sorbent to the sorbent injection system.

Obtains fuel oil for the sorbent dryer from the plant fuel oil system.

Obtains dry compressed air from the plant dry-air system for bin vent filter pulse cleaning and for pneumatic transport of waste ultra-fine material to the storage bin.

General Description

Raw sorbent (typically No. 57 stone, 1" x 8 mesh) is conveyed into the plant by the plant coal handling system and is stored in a dedicated 550-ton bunker. The sorbent is then conveyed into the combustor building where it is stored in a 70-ton sorbent feed hopper. Sorbent from that hopper is discharged into a vibrating feeder, which controls the flow rate of raw sorbent to the impact/dryer mill.

The main components in the crushing/ drying process are configured in a warm air recirculation loop operating entirely under vacuum. The sorbent is crushed in the impact dryer mill until sufficiently fine particles are air swept to a cyclone separators. The air from the cyclone is boosted in pressure and recirculated to the impact/ dryer mill. Collection of the ultra-fine dust not collected in the cyclone separator is accomplished by a bag filter. A fan on the discharge of the bag filter induces flow, and maintains the vacuum on the system's air recirculation loop. Make-up air to the system is drawn through an oil-fired air heater, which can warm the make-up air to as high as 1000 F in order to maintain a sufficient mill discharge temperature (typically 180 F) for sorbent drying.

The material collected in the cyclone separator is fed by gravity through a rotary air lock into a vibrating screen. The oversize material from the screen is recycled back to the impact/ dryer mill. The material which passes through the screen falls onto a cleated belt conveyor which transports the material into the 200 ton prepared sorbent storage vessel. This vessel feeds the two sorbent injection system lockhopper trains.

The ultra-fine material collected in the baghouse is fed out of the bag filter collection hopper by gravity by a rotary air lock. This fine material can either be fed by gravity into the cleated belt conveyor, thus mixing with the main prepared sorbent stream, or it can be transported pneumatically to an 8 ton storage bin.

The 70-ton sorbent feed hopper, the 200-ton prepared sorbent storage silo and the 8 ton sorbent fines bin each have dedicated bin vent filters with integral air blowers for evacuation and particulate cleaning of displaced air. In the case of the sorbent fines bin, the bin vent filter also evacuates the fines transport air.

The sorbent preparation system is shown in Figure 6.6.1.

Photo 6.6.1 is a picture of the sorbent impact/ dryer mill and its inlet feeders and hoppers.

Key Instrumentation and Controls

The impact/ dryer mill discharge temperature controls the make-up air heater firing rate.

The air heater discharge temperature is used to trip the heater on high temperature.

The bag house air inlet temperature is used to shut down the system on high temperature for bag material protection.

Differential pressure measurements across the impact/dryer mill are used for momentary starting/stopping of the vibratory feeder on low/high readings.

Differential pressure across the cyclone separator is used for system shut-down on high measured differential, which indicates a plugged cyclone.

Differential pressure measurement across the system bag filter is used in adjustment of the on/off time of cleaning air pulses.

Differential pressure is measured on the heater discharge duct. Low differential trips the heater. The heater oil supply pressure is also measured, and trips the heater on low oil pressure.

The air heater employs a flame detector used by its flame safeguard control system.

High level switches in the cyclone separator, bag filter collection hoppers, and the prepared sorbent storage vessel shut down the vibratory feeder on high levels. A high-level switch in the 70-ton sorbent feed hopper shuts down the raw sorbent feed conveyor, and a low-level switch trips the preparation system. Low-level switches in the prepared sorbent storage vessel initiate a low-level alarm.

Plugged chute switches are provided at the inlet to the sorbent feed hopper and prepared sorbent storage vessel.

System Control Overview

The feed of raw sorbent to the impact/dryer mill is controlled by the vibratory feeder. Venturi plates with a manually adjustable opening width are employed above the crushing zone. Adjustment of this opening affects the velocity through this region which, in turn, affects the maximum size of particle that can be swept from the crushing zone. A velocity separator is employed at the top of the impact/dryer to classify the mill discharge material size. The separator can be manually lowered or raised to fine tune the product size.

The flow rate in the system's recirculation loop follows the fan's characteristic curve, varying only with changes in system pressure drop. Manually adjustable vanes are employed on the fan discharge for proper system flow setup.

The evacuation air flow rate follows the evacuation fan's characteristic curve. That fan also has manually adjustable discharge vanes for system set-up.

The air heater oil firing rate is modulated by a local controller to maintain the operator adjustable impact/dryer mill discharge air temperature. This local controller also interrupts/restores the vibratory feeder operation on high/low mill differential pressure settings.

6.6.2 System Modifications Completed

Impact/Dryer Mill

The crushing zone components, including the hammers, rotor (particularly the rotor end discs) and the crushing box bottom and back liner plates, experienced excessive erosion. The following changes were implemented to combat the erosion:

Hard facing material was installed on the hammer tips. This modification dramatically extended hammer life; however, the weld build-up required reapplication at approximately 250-hour intervals.

The crushing box back and end liner plates were replaced with an abrasion-resistant alloy steel; however, this was not effective. A later modification, which included plating with a chromium carbide abrasion resistant coating, proved very successful.

The rotor was replaced with a harder erosion-resistant material. This reduced the erosion rate; however, weld buildup was still required periodically.

The rotor speed was increased. It was felt that fine material was residing in the crushing zone too long, thereby contributing to the erosion and to the prepared product's excessive minus 60 mesh fines concentration. It was felt that the higher rotor speed would help sweep the finer materials out of the crushing zone, thus minimizing the creation of excessive fines and the erosion. This change was made in late 1993 and had no apparent impact on the erosion or the product sizing; however, it did result in increased system capacity.

In addition to the erosion problem, excessive pressure drop through the mill was thought to be contributing to system capacity and product sizing problems (excessive fines). Excessive mill pressure drop caused the system fan to run back on its curve, thereby reducing the system's recirculation air flow rate. The following changes were made to the crusher:

A six foot extension piece was added to the velocity separator outlet duct, thereby allowing it to be extended down closer to the venturi discharge. This change had no impact on the mill pressure drop and, interestingly, had no significant impact on final product sizing.

The venturi plates were modified to permit a wider opening. This change decreased the mill pressure drop, thereby increasing the recirculation flow rate.

Cyclone Separator

The cyclone separator experienced excessive erosion in both the cylindrical top section and the conical section below it. The conical section was replaced with an erosion-resistant plate material; however, the new material was not successful. The next modification implemented consisted of lining both the cylindrical and conical sections with castable refractory. This modification was also unsuccessful. The refractory wore away rapidly. A second type of refractory was sprayed atop the worn material, but the new refractory experienced localized failures. The problem was finally resolved by installation of ceramic tiles in the cylindrical section and the use of a different abrasion resistant plate material in the conical section.

Air Recirculation Fan

The recirculation fan experienced excessive erosion of both the casing and the rotor. The erosion problem was resolved through application of an abrasion-resistant metal spray coating.

Due to excessive system pressure drop, the fan was operating with reduced air flow output. This problem, in conjunction with excessive system air in-leakage downstream of the impact/dryer mill (particularly at the vibratory feeder inlet and outlet expansion joints), caused reduced air flow through the mill. In order to increase the mill air flow, the speed of the fan was increased in late 1993. This change did increase the mill air flow, and resulted in an increase in system capacity; however, the fines concentration in the prepared product was not reduced.

The outlet of the fan originally employed four manually adjustable flow control vanes. The sealing components for these vanes became a source of significant air in-leakage. Since system air flow was generally below design, two of the four vanes were modified to fixed vanes, thereby eliminating their seals and the associated air in-leakage. In addition, the seal packing of the remaining two adjustable vanes was modified to reduce air in-leakage.

Vibrating Screen

The screen experienced significant blinding problems which led to failure of the screen inserts. The original screen inserts were 8-mesh cloth attached to a metal frame by adhesive. These failed rapidly, so the inserts were changed to an 8-mesh wire screen with a metal frame. These also experienced relatively rapid tearing at the screen-to-frame interface. In order to strengthen the screen inserts and, at the same time, reduce the blinding problem, the inserts were changed to a 6-mesh screen; however, the wire diameter was specified at two sizes larger than standard 6-mesh screen wire. The result was a relatively strong screen insert, which had an open area larger than 8 mesh but somewhat smaller than 6 mesh. This screen insert dramatically reduced the incidence of failure; however, such failures still occurred periodically. In addition, the screen was still susceptible to system upsets which resulted in screen blinding. Such blinding caused excessive quantities of fine material to flow back to the impact/dryer mill along with the oversized recycle product. These recycle fines were suspected as key contributors to the system's prepared product capacity and excess fines problems.

In addition to modifications to the screen inserts, weights were added to the screen assembly to increase the vibration amplitude in an attempt to minimize the screen blinding. This change was not successful.

Attempts were made in late 1993 to reduce the product sizing for relatively short-duration tests in order to evaluate the impact on bed dynamics and sorbent utilization. Through a combination of reduced system air in-leakage and the re-implementation of the 8-mesh wire screen inserts, the prepared product was made somewhat finer without a significant increase in minus 60-mesh fines. The 8-mesh screens inserts again experienced excessive blinding and rapid failure, thus use of the finer screen inserts became an operational liability, and this practice was abandoned.

Air Heater

The most significant problem with the air heater was insufficient air flow caused by excessive system air in-leakage. With reduced air flow the heater outlet air temperature would run hotter for a given firing rate. The low air flow problem was combatted through periodic system repairs made to minimize air in-leakage, particularly at the vibrating feeder inlet and outlet expansion joints. In addition, the over-temperature trip control function was relocated from the local controller to the main plant control computer in order to improve its reliability.

Another problem experienced with the heater was backflow of air through the heater. This occurred whenever the 70-ton sorbent feed hopper was run empty with the system in operation. In such instances, large quantities of air would leak in through the hopper and the feeder resulting in positive system pressure upstream of the impact/dryer mill. In order to eliminate this problem, an additional level switch was added in the 70-ton sorbent feed hopper to shut down the system on extreme low level. In addition, the air heater's air intake point was relocated in order to avoid equipment damage in the event that air backflow occurred. No additional backflow events occurred after implementation of the feed hopper low level trip interlock.

Vibratory Feeder Expansion Joints

The expansion joints at the inlet and outlet of the vibratory feeder experienced numerous failures. These failures resulted in dramatically increased system air in-leakage. These failures were not readily apparent, and were usually found after a major deterioration in system product was noted. The expansion joint at the outlet of the feeder was the worst of the two, since it was exposed to much higher temperatures. Numerous changes in material compounds were attempted in order to minimize the problem. However, these components continue to be a significant problem area.

System Ducting

The system ducting in the air recirculation loop experienced excessive erosion in a number of locations. The most notable areas were at the vertical-to-horizontal 90-degree elbows upstream of the cyclone separator and downstream of the recirculation fan. This problem was addressed by periodic patching of the eroded areas.

Cleated Belt Conveyor

The cleated belt conveyor experiences accumulation of large quantities of fine sorbent along the bottom of the conveyor's horizontal inlet section, which causes periodic conveyor operating problems. A number of modifications were made to combat this problem. However, the problem has not been resolved, and additional changes are being considered.

Prepared Sorbent Storage Vessel

Segregation of material sizing was experienced in the 200-ton prepared sorbent storage vessel. The segregation resulted in finer material being fed to the east sorbent injection vessel than was being fed to the west vessel. Deflector plates were added in the discharge chute between the cleated belt conveyor and storage vessel. The deflectors were successful at mixing the material, and minimized size segregation. However, segregation problems reappeared, and additional changes are being considered.

The two outlet cones of the storage vessel each incorporate a bin activator to ensure proper material flow. Use of these activators was discontinued, when it was determined that the vibration caused damage to flexible outlet joints and the material flowed without the aid of the activators.

6.6.3 Operating Experience Overview

This system was plagued with numerous operating problems which required extensive operator and maintenance attention. The main problems with the system were insufficient capacity, high concentrations of minus 60-mesh fines, system air in-leakage and component erosion. Through the modifications noted above, the erosion problem was greatly reduced and the capacity improved. However, at the end of the three-year test program this system still required extensive maintenance work, produced well below design capacity, had a high prepared-product fines concentration and was susceptible to significant product upsets due to sporadic air in-leakage problems. In addition, the system proved to be very inflexible in producing varying prepared product sizes. This latter factor was an obstacle to properly evaluating the impact of sorbent sizing on such things as bed dynamics and sorbent utilization.

6.6.4 Summary and Conclusions

Proper and reliable sorbent preparation is critical for operation of a PFBC facility. The system employed at Tidd was inadequate for the task at hand in that it was not flexible, had marginal capacity, necessitated extensive maintenance attention, and had product variability problems. Findings from the Tidd operating experience have provided the operating database necessary for designing and specifying the systems and components for future commercial facilities.

6.7 System 262 - Coal Preparation

6.7.1 System Description

System Purpose and Function

In a PFBC Combined Cycle plant, crushed and sized coal is mixed with water to produce a pumpable coal/ water paste. The coal preparation system crushes the raw coal to a specific size consist that can be easily mixed into a paste which can be pumped into the fluidized bed.

The coal preparation system interfaces with many of the other PFBC systems in the plant as follows:

Obtains raw coal from the plant coal handling system.

Provides crushed and sized coal to the coal injection system.

Obtains water for mixing with the coal from the high-pressure service water system.

The plant dust collection system is connected to all conveyers to prevent coal dust from discharging from the system.

General Description

Raw coal is conveyed into the plant by the original plant coal handling system. The coal is stored in three of the plant bunkers in the old plant's bunker room. The coal is then routed by a conveyor into the combustor building where it is stored in a 45-ton surge hopper until it is fed into the coal preparation system.

Coal from the 45-ton surge hopper is discharged from the hopper through a slide gate into a vibrating feeder, which controls the flow of raw coal to the crusher feed hopper, which supplies the high-pressure double-roll Krupp Polysius crusher.

Coal is fed from the crusher to a short conveyor before it dumps into a vertical cleated-belt conveyor that deposits coal into a three-layer screen sizer.

A sizer prevent particles which are greater than 1/2" to be mixed into the coal paste product. Particles between 1/2" and 1-1/2" are recycled back into the coal crusher to be recrushed. The sizer directs particles which are greater than 1 1/2" into a dumpster for removal.

The crushed coal that passes through the sizer, is routed to the feed hopper. The feed hopper is equipped with a manually operated slide gate which permits coal to enter the vibratory feeder. The vibratory feeder deposits the coal onto a belt weigh feeder, whose speed is controlled to maintain a constant level in the feed hopper.

The weigh feeder throughput is determined by the coal flow coming into the feed hopper. The moisture content of the incoming coal, combined with the fuel mass flow and the desired moisture setpoint (as selected by the operator) are utilized to control the coal paste moisture content. A control valve allows high-pressure service water to enter the mixer and create the proper coal-water ratio. This ratio is usually in the order of 25% water by weight (total weight). The coal water paste flows from the mixer into the coal injection system fuel storage tank.

The system is normally run in a batch mode. When the paste tank level reaches approximately 60" of paste, the vibratory feeder is stopped. The remainder of the equipment is left running or shut down as required.

The coal preparation system is shown in Figure 6.7.1.

The most significant piece of equipment in this system is the coal crusher itself. The crusher is a double- roller type mill. Each roll is controlled by a separate variable speed motor and the entire machine is controlled by a programmable logic controller (PLC). The crusher was manufactured by Krupps Polysius of Germany and is commonly used in the concrete clinker industry. Its experience in the USA coal crushing industry is very limited.

The crusher is capable of crushing 83,000 pounds per hour of raw coal. One roll is fixed to the crusher frame while the other is movable with a constant force applied from a hydraulic system.

Each crusher roller was originally driven by a 150-hp motor via a belt-driven gear reducer and variable-speed control unit. The rolls have a replaceable roll shell of highly wear-resistant NI-HARD material. The rolls, when worn, can be machine-ground in place. There is a set minimum clearance between the two rollers. Range spacers, mounted to the fixed roll, allow adjustment of this clearance. The hydraulic force applied to the movable roller is also adjustable and both settings are determined by the coal quality. When properly set, the hydraulic force and roller clearance settings can handle coal quality changes up to ±20°H (°H is the Hardgrove Index for grindability of coal. The typical Pittsburgh #8 coal used at the Tidd Plant coal is 57°H.)

The crusher has several support systems; hydraulic oil, grease lubrication, and oil lubrication systems.

The hydraulic system consists of an externally-mounted hydraulic unit that includes a tank, pump, filter, an accumulator, four single-acting plunger cylinders, and valving.

The hydraulic system produces the grinding force necessary to crush coal. It utilizes the sliding blocks of the movable roller to exert a force in the direction of the fixed roller that is proportional to the hydraulic fluid pressure. The hydraulic system also acts as a hydraulic spring that allows the movable roller to pull back and increase the opening between the two rollers when ungrindable material enters the crusher. Once such material has passed through, the roller springs back into position. The interface between the hydraulic oil and the mechanical force from the grinding roll is at the plunger cylinders. The movable roller has four plunger cylinders, two at each roller end. Mechanical force from the grinding roll is applied at one end and hydraulic force on the other end.

The hydraulic system also has two piston accumulators, one for each set of plungers. A floating piston separates a gas chamber at the top and an oil chamber at the bottom. The hydraulic spring action takes place in the accumulator as the gas in the gas chamber is compressed to absorb the force of the movable roller due to a large or an ungrindable passing between the rollers. As the material passes through, the gas expands and forces the piston down which returns the movable roller to its original position.

The hydraulic system also has a hand-operated hydraulic pump and two reversing cylinders with pistons. This allows the movable roller to be hydraulically jacked in the reverse direction for maintenance purposes.

The grease lubrication system pneumatically injects grease into the roller bearings, guide rails, and the bearing seals. It consists of a pneumatically actuated grease barrel pump, a filter, a bi-directional pneumatically-operated valve, and six distributors.

The bi-directional valve directs grease to either the primary or secondary lubricating points. The primary points are all bearings and the secondary points includes the guide rails, and the non-located bearing seals. The distributors evenly distribute grease to all lubrication points served by the same supply line.

The oil lubrication system force-feeds lubricating oil to two gear reducers. Each gear reducer has an independent system consisting of an oil reservoir, oil pump, and oil cooler.

Photo 6.7.1 is a picture of the doulbe roll coal crusher. Photo 6.7.2 is a picture of the paste mixer discharge and the paste slump test station where the operators checked the paste quality. Photo 6.7.3 shows the coal weigh belt feeder and hopper in the upper right, the sorbent fines admission equipment in the center, and the coal paste mixer in the lower portion of the picture.

Key Instrumentation and Controls

The coal preparation system is a cascading type control system which requires equipment downstream to be operational before a given piece of equipment can be started up. Likewise, if a piece of equipment trips out of service, all equipment upstream of that component will sequentially trip out of service.

The coal crusher is controlled by a Programmable Logic Controller (PLC) that monitors many of the operational aspects of the coal crusher. These include roll speed, torque, gap, roll skewing, bearings, hydraulic subsystem conditions, power requirements and many other operational parameters. If a fault or abnormality is detected, the crusher will trip from service.

Operation of the system is based on a sequential cascade. Once the prepared paste tank reaches a specific low-level set point, the coal prep system will automatically begin operation. The coal mixer is placed in service followed by the coal conveyers to the coal crusher. The crusher then starts, followed by the crusher feed screw and the 45-ton hopper vibratory feeder. Once this part of the system is started, and level builds in the hopper, the coal weigh belt feeder starts and is automatically controlled to maintain a level in the hopper. At this point, coal paste is flowing into the coal paste tank. The coal prep system will continue to operate until the coal paste tank reaches its high-level set point.

6.7.2 System Modifications Completed

There have been several modifications completed on this system over the three-year period. These include:

Crusher Control Logic

The original crusher control logic was based on a variable-speed coal weight belt feeder to maintain fuel paste tank level and a variable-speed crusher to maintain level in the weigh belt feeder inlet hopper. Shortly after the crusher was started up, this crusher control philosophy was found unacceptable.

A new crusher control philosophy was developed based on torque and speed control. The crusher speed varied to match output requirements. The crusher inlet screw feeder then applied a force on the rolls of the crusher and this force was controlled by the torque of the screw feeder. This method of control was utilized during the first year of operation. However, the crusher was never able to produce the 18-20% minus 325-mesh fines required to produce good pumpable paste.

Larger motors and drives were installed in Fall 1991. A series of coal crusher tests followed to optimize coal crusher operation and improve reliability. An outcome of those tests was the development of a new coal crusher control philosophy called gap control. In gap control, the crusher inlet screw feeder runs unloaded, the vibratory feeder upstream of it is adjusted to control the crusher feed-rate and the crusher roll speed controls the gap between the rolls. This control scheme was abandoned because it failed to provide the required reliability.

Another series of crusher tests was conducted in Spring 1992 to determine the effect of recycling up to 50% of the crushed coal back to the crusher. In the recycle control mode, the weigh belt feeder is controlled to maintain a level in the hopper above it. The coal crusher speed is set by the operator. The gap is a function of the roller speed and throughput but is generally about 7 mm. The screw feeder runs full speed. The vibratory feeder speed is adjusted to maintain a 50% level in the hopper. Operation in the recycle mode was successful in producing the desired product quality.

Pumpability Test Loop

The original coal prep system design included a paste pumpability slipstream test loop for testing the quality of the paste. This loop was designed to extract a small slipstream sample of paste and pump it through a test loop of piping and bends. The characteristics of the paste were determined, based on the pumping power requirements and the pressure drop through the system. The paste sample quality could be correlated back to an acceptable paste quality. The test loop experienced significant plugging problems, and was replaced by a manual slump test procedure utilizing a concrete slump cone.

Larger Coal Crusher Drives

The crusher was originally supplied with 150 hp motors and variable speed drives. Larger, 200 hp motors and drives were installed to increase torque and improve product fineness.

Replacement of Coal Mixer Internal Components

The original paddles in the coal paste mixer were manufactured of a hardened carbon steel material.
Severe corrosion was discovered in June 1991. The mixer paddles, liners and arms showed significant deterioration. Over the next several months, new stainless steel arms, paddles and mixer liners were fabricated and installed. Operation since then has been acceptable, with only weld buildup required on the paddles to replace eroded material.

Crusher Roll Grooves

The original coal crusher rolls were provided with smooth surfaces. The friction generated proved to be inadequate to draw the coal into the rollers in the quantity required to meet unit load demands. ABBC recommended that three circumferential grooves be machined into the fixed roll, to increase the friction. Over the next several years, additional grooves were added. Today, both the stationary and movable rolls are grooved.

Miscellaneous System Modifications

A number of other modifications were completed on the system. These include:

The physical characteristics of the coal entering the crusher had significant impact on crusher performance. Each time the coal characteristics changed, the crusher experienced operational problems and required adjustment. The equipment manufacturer suggested the addition of water sprays at the crusher inlet to stabilize coal surface moisture. These sprays were used intermittently to add water, improving the adhesion between the coal and the rolls.

Crusher roller skewing (a condition in which the gap between the rolls is significantly different from one side of the roll to the other) had been a problem. The problem was attributed to the manner in which coal flowed into the top of the crusher feed hopper. A movable damper was installed in the crusher feed hopper inlet chute to distribute the coal equally along the rollers. This effectively minimized skewing trips.

Crusher Recycle Loop

The coal crusher proved incapable of producing crushed coal with at least 20% minus 325-mesh fines. After numerous attempts to revise the crusher controls, a coal recirculation system was installed. This system provided the means to recirculate up to 50% of the crushed coal to the crusher. This modification involved installation of an adjustable damper at the inlet to the sizer bypass chute. This damper could divert up to 50% of the coal around the sizer and into the sizer bypass chute. This coal was then routed back to the crusher. Subsequent testing showed that recycling resulted in a final coal product in the desired size range of 20% minus 325-mesh fines. In fact, the minus 325-mesh size fraction could be increased to as high as 30%. The high degree of recycle did not have significant impact on the system's throughput capacity when crushing Pittsburgh #8 coal.

6.7.3 Operating Experience Overview

Coal crusher reliability was poor during the first 18 months of operation. The crusher would frequently trip out unexpectedly. The coal product produced did not contain the proper size distribution required to produce good pumpable paste. Paste with insufficient fines requires additional water to maintain its pumpability characteristics. Many unit trips occurred when paste pumps or fuel nozzles plugged. Higher moisture in the paste resulted in freeboard and/or cyclone fires.

The recycle operational mode proved most effective at improving both coal paste product consistency and crusher availability. However, recycle was not a cure-all of the coal preparation system. Crusher reliability could suddenly falter when the characteristics of the raw coal changed significantly. Analysis of coals that worked well in the crusher and coals that caused the crusher to react poorly did not provide characteristic variables that could be used to predict crusher operation. It was found that on-line testing of a specific coal in the crusher was the only acceptable method to determine if that coal could be crushed in sufficient quantities to support operation.

6.7.4 Summary and Conclusions

The coal preparation system included a single crusher. The system was marginally acceptable when crushing Pittsburgh #8 coal, however, it suffered from lack of capacity when crushing of other coals. A great many of the crusher problems were the result of the need to achieve a specific product gradation while maintaining the throughput required to sustain unit operation. The availability of a redundant crusher would have eliminated the need to push the single machine to its limits and would have improved both reliability and product quality. The option of installing a redundant crusher was explored and determined not to be cost effective for Tidd, considering its relatively short life. A second option - the installation of a slipstream coal crusher was also considered. This crusher would be operated to provide the minus 325-mesh size fraction for blending with the primary crusher product. Shop tests on several crusher models proved successful, but the option was not exercised due to the limited life of the project and the long lead time required for the slipstream crusher.

The system that was originally installed at Tidd was modified until it was acceptable for Tidd operations. These modifications included larger motor drives, control logic changes and the installation of a recycle loop. The limited capacity of a single crusher and the need to recycle crushed material in order to achieve desired product size consist, presented significant challenges to operation. The system was made to function acceptably when crushing Pittsburgh #8 coal. However, its ability to crush sufficient quantities of other coals was never demonstrated.

6.8 System 266 - Coal Paste Injection

6.8.1 System Description

System Purpose and Function

The coal injection system provides controlled feed of coal/ water paste (CWP) to the fluidized bed boiler. The system incorporates provisions to ensure proper splitting of the coal paste to achieve the proper combustion characteristics of the paste droplets.

The coal injection system interfaces with the following systems:

The coal preparation system which provides the prepared coal paste.

The sorbent injection system which provides air from the sorbent booster compressor for fuel splitting.

The condensate system which provides cooling water flow to the fuel nozzles.

The well-water system which provides back-up cooling water to the fuel nozzles in the event of a black plant trip.

The low-pressure service water system which provides cooling water to the splitting air compressor precooler and aftercooler, as well as the coal injection pump hydraulic fluid coolers.

The high-pressure service water system which provides water for wetting and cleaning of the coal injection nozzles.

The compressed air system which provides compressed air for fuel line cleaning.

The economizer sootblower system to which cooled pressurized air is provided as the sootblowing medium.

The bed ash removal system and bed ash reinjection System to which cooled pressurized air is supplied for L-Valve fluidizing air.

The nitrogen system which provides back-up fuel splitting flow and splitting medium during fuel line reversing.

General Description

The coal paste injection system incorporates six hydraulic-driven dual-piston pumps to pressurize and provide the motive force to feed the coal paste into the boiler. The six pumps are arranged in parallel, each taking suction from the bottom of the common fuel tank, and each pump feeding through its own dedicated fuel line and fuel nozzle. The nozzles are water-cooled and insulated to prevent drying out of the paste. Double shut-off valves at the inlet to the fuel nozzles ensure pump isolation from the pressurized boiler. The outer shut-off valve is a three-way valve which aligns each pump's discharge to either the boiler or to a dedicated recirculation line back to the fuel tank. The recirculation line is used at system startup to establish proper paste pump operation and at pump and system shutdown to provide a means to empty the fuel lines. Each pump incorporates an integral discharge isolation valve used to prevent back flow from the boiler when transferring between the two pistons which alternately fill and pump the fuel.

The fuel tank which receives the prepared coal paste from the coal preparation system is designed to ensure balanced flow to the six coal injection pumps and to provide a buffer volume to compensate for minor irregularities in the flow of prepared paste from the coal preparation system. Agitators in the fuel tank prevent sedimentation of the coal water paste.

Splitting of the coal paste is achieved with high-velocity air at the fuel nozzle outlets. Splitting air is provided by the splitting air compressor. Nitrogen is provided from the nitrogen buffer tank in the event of inadequate splitting air flow. This nitrogen supply is also used to provide fuel nozzle purge after a gas turbine trip.

Figure 6.8.1 presents a simplified flow diagram for the system as originally installed and Figure 6.8.2 shows the final configuration of the system.

Photo 6.8.1 is a picture of the bottom of the paste tank and the paste pumps under the paste tank. Photo 6.8.2 shows the discharge end of a paste pump and the paste line rising up to the burner deck. Photo 6.8.3 shows the burner deck and the six fuel injection nozzles and the two sorbent injection nozzles. Photo 6.8.4 shows the coal paste splitting air compressor.

Key Instrumentation and Controls

Differential pressure measurements on each fuel line between the coal injection pump discharge and the fuel nozzle inlet provide interlock control for normal opening and emergency closing of the fuel line isolation valves. These measurements also provide a relative indication of coal paste pumpability.

A dedicated thermocouple at the inlet of each fuel nozzle provides the signal for emergency fuel line isolation, on high temperature, to prevent back flow of hot bed material out of the combustor.

Level indications on the fuel tank were originally intended for use in automatic control of the coal preparation system production rate by speed control of the belt weigh feeder. In actual practice the coal preparation rate is set manually by the operators, and these tank level instruments are used for indication and low level alarms.

The piston pump hydraulic drive's swash plate angle output signal serves to estimate coal injection pumps output and provide feedback to the pump controllers which regulate pump flow rates. These signals are also fed back to the Network-90 for pump flow indication.

Flow meters on each fuel nozzle splitting air supply lines indicate the individual line splitting air flow rates and are utilized in the control of the splitting air compressor inlet/bypass valves to regulate total splitting air flow.

System Control Overview

The total fuel flow demand follows the fuel master signal which follows the combustion master signal as trimmed by the mean bed temperature signal. Essentially, the overall fuel feed rate is controlled to maintain the operator-adjustable bed-temperature setpoint. The total fuel demand is divided by the number of pumps in operation to produce the individual pump demands. The individual pump demands are trimmed by operator-adjustable pump biasing to achieve even bed temperatures. The individual local pump controllers adjust the pump stroke rate to satisfy the demand.

The total fuel splitting air flow is regulated by the splitting air compressor inlet throttle valve at low loads and by the splitting air compressor bypass valve at higher loads. The total splitting air flow demand was originally a programmed demand curve versus process pressure, designed to achieve constant splitting flow momentum. This control evolved to an operator-adjustable setpoint demand. The individual splitting air flow indications are summed to provide a flow feedback signal to the control system. Equalization of the six individual line flows is accomplished through manual adjustment of needle valves in the splitting air supply lines. The needle valves can also be used to bias the individual line flow rates.

6.8.2 System Modifications Completed

Revised Splitting Air Flow Meters

Splitting air flow was reduced by approximately 70% during the middle of 1991 in an attempt to mitigate post-bed combustion. This change resulted in the splitting air flow meters being out of range. These were replaced with new meters, in smaller bore pipe sections, that could accurately measure the reduced flows.

Fuel Tank Agitators

As the prepared coal paste began to be dried to the proper consistency during 1991, the fuel tank agitator motors began to overload. This was first addressed by increasing the size of the agitator motors from 25 to 30 hp. A number of changes were then made to the agitators in attempts to reduce the power demand. These included removal of the top row of blades and revisions to the blade angles. The latter eventually proved effective with all rows of blades being in place.

Splitting Air Configuration

The original fuel nozzle design incorporated both primary and secondary splitting. The fuel nozzles were subsequently modified to address post-bed combustion concerns. The size of the primary splitting air nozzle was significantly reduced and the secondary splitting air was eliminated. This modification was intended to alter the paste splitting to produce more consistent sized paste lumps (large enough to eliminate post-bed combustion yet small enough to prevent sintering). This modification was moderately successful in reducing the degree of post-bed combustion (Refer to Section 5.1 of this report for more details on post-bed combustion), however, insufficient fuel splitting was considered a possible culprit in the excessive "egg sinter" formation (Refer to Section 5.2 of this report for more details on "egg sinters") experienced in late 1993 and early 1994 at high unit loads. Due to that excessive "egg sinter" experience, the fuel nozzles were modified in early 1994, in an attempt to produce finer splitting. The primary air nozzle size was increased in diameter, and the annular secondary splitting air ports were reinstalled. The former was done to increase general splitting by permitting higher splitting air flow rates, and the latter to eliminate the collection and subsequent dripping of large paste lumps off the outer face of the fuel nozzle assembly. In addition, the primary splitting air nozzle relocated further inside the paste nozzle to ensure that its discharge jet would cover the entire area of the paste outlet. Operation with this configuration resulted in smaller sinters indicating that finer splitting was indeed occurring, but this did not eliminate the problem. Also, post-bed combustion was more pronounced at the higher splitting air flows. This design was in service at the end of the three-year test period.

Coal Pump Wetted Parts Corrosion

The chrome plating on the carbon steel coal injection pump cylinders, spectacle plate, cutting ring and discharge valve was found to be flaking off, and corrosion of parent metal was occurring. In addition, corrosion was found on the painted carbon steel suction lines, suction boxes and S-tubes in places where the paint had flaked off. These corrosion related problems were attributed to sulfuric acid attack from the coal paste, and they were solved through a change from chrome plated carbon steel to chrome plated stainless steel, and a change in paint compound.

Modifications to Minimize Paste Consistency Variations in the Fuel Tank

The fuel tank, which provides suction to the CWP pumps is comprised of two adjacent round tanks that are interconnected. The paste from the coal preparation system originally fed into the far side of the south section. The tank agitators were expected to mix the paste sufficiently to ensure homogeneous consistency of the paste in both sections of the tank. In practice; however, the north section tended contain wetter paste than the south section. This paste inconsistency led to post-bed combustion problems in the north side of the boiler and more frequent plugging of the No. 4, 5, and 6 coal nozzles, which were fed from the drier south section of the tank. Numerous modifications were made to improve mixing including defectors at the tank interconnection point and reversing of the paste tank agitators' direction of rotation. While such changes helped, they were not fully successful. The problem was eventually resolved by relocating the mixer, thereby allowing the discharge chute to feed both sections of the tank.

Fuel Nozzle Outlet Section Cracking

The outlet sections of the second generation fuel nozzle experienced cracking and erosion of the small diameter discharge sections. These outlet sections were exposed to large temperature gradients which caused cracking then spalling, which eventually resulted in increased nozzle outlet diameters. The degree of the problem and the life of these components was greatly improved through a switch from Cerium micro-alloyed austenitic stainless steel to a high chromium nickel base superalloy. The latter material appears to provide commercially acceptable nozzle outlet section life.

6.8.3 Operating Experience Overview

The coal injection system functioned very reliably. This is particularly evident when considering the fact that there was no installed redundancy in the system. The most significant problem was plugging of the nozzles, lines, and pumps. While plugs occurred in the system, the plugging was actually a symptom of paste preparation system problems. Paste plugs were not prevalent in the first six months of unit operation, which is likely due to the fact that paste moisture content was kept relatively high. Plugging began to be a significant issue by the middle of 1991, when paste moisture was being reduced in order to combat post-bed combustion. Improvements in coal crushing achieved in the middle of 1992 permitted the production of dryer more pumpable paste. With these improvements, the incidence of paste line plugging dramatically decreased, however, occasional problems still were experienced whenever there were upsets in the paste preparation system. Another factor which helped minimize plugging was the splitting of the fuel tank inlet chute to directly feed both sections of the tank, thereby eliminating the presence of drier-than-average product in the south section of the tank.

The fuel nozzle cleaning procedure following combustor trips evolved during the first two years of operation, to provide a very reliable fuel nozzle/ fuel line cleaning operation after combustor trips and in the case where a single line plugged. The addition of nitrogen to the splitting air tubes, coupled with the addition of high pressure nitrogen connections to the system, were significant in reducing down time due to fuel system pluggages. The ability to clean the fuel injection system after a gas turbine trip was never adequately demonstrated.

6.8.4 Summary and Conclusions

The experience from Tidd indicates that using concrete industry based piston pumps to feed coal in the form of coal water paste to a pressurized PFBC unit is both reliable and effective, provided that the paste is properly prepared. Notwithstanding the paste preparation issue, the most significant issue for designing a coal injection system will be ensuring adequate fuel distribution and providing adequate redundancy to allow for multiple pumps being out of service. Sintering continues to be a significant problem during high-load operation (Refer to Section 5.2). There is a strong indication that the sintering problem may, in part, be the result of inadequate fuel distribution.

6.9 System 268 - Sorbent Injection

6.9.1 System Description

System Purpose and Function

Granular calcium based sorbent is injected into the fluidized bed to capture the SO_2 released during coal combustion and to provide the required bed material. The level of sulfur reduction desired can be achieved by varying the rate of fresh sorbent injection into the bed.

The sorbent injection system is a pneumatic conveying system which transports the crushed sorbent from two parallel feed injection lockhoppers and blows it into the fluid bed boiler. The sorbent is injected into the bed by several injection nozzles which are located at the same elevation as the fuel injection nozzles.

The sorbent injection system interfaces with many of the other PFBC systems in the plant as follows:

Injects crushed sorbent into the fluidized bed boiler.

Obtains the crushed sorbent from the 200-ton storage hoppers in the sorbent preparation system.

Obtains transport air from the combustor vessel.

Obtains sorbent compressor precooler cooling water from the low-pressure service water system.

Vents the sorbent injection lockhoppers to the baghouse in the boiler ventilation system.

Provides compressed air to both the fuel nozzles for fuel spitting, to the sparge duct end fluidization system, and to the economizer sootblowers.

General Description

The sorbent injection system is a dilute-phase pneumatic conveying system. Transport air is supplied from the pressure vessel through an air precooler and booster compressor. The compressed air is stored in a large air receiver buffer tank. The sorbent is conveyed from the sorbent feed lockhopper to the fluid bed by the sorbent transport pipe. The transport pipe is a single line from the lockhopper to the combustor vessel. The line is bifurcated prior to penetrating the combustor vessel. The two lines are again bifurcated inside the vessel to supply four sorbent feed nozzles. The sorbent is fed into the transport lines from one of two alternating-feed lockhoppers by rotary feeders.

A dual sorbent feed lockhopper system provides a nearly continuous feed of sorbent into the fluid bed. As one lockhopper is being used to feed sorbent into the transport pipe, the other lockhopper is depressurized, vented and loaded with fresh sorbent from the 200-ton sorbent storage lockhopper located directly above the sorbent lockhoppers.

The sorbent injection system is shown in the simplified drawing on Figure 6.9.1.

A single-stage centrifugal type compressor taking suction from the combustor vessel, through a precooler and filter, compresses the air to 1.5 times the compressor inlet pressure and discharges to an 1100 ft^3 air receiver tank. The buffer tank provides air to the transport system, the economizer sootblowers, the fuel nozzle splitting air system, and several other minor users.

The original transport pipe was a composite type pipe, with an inner layer of abrasion resistant material and a carbon steel outer pressure retaining pipe. Crosses were used at all changes in flow direction to mitigate erosion damage.

Full-port ball valves were used wherever the valves where subject to sorbent flow. The sorbent lockhopper isolation valves incorporated two different types of valve as a test of their applicability to this type of service. One lockhopper had conventional full-port ball valves. The other lockhopper had sliding disc type valves. Problems with the sliding disc valve were immediate and are discussed in detail in Section 6.9.2.

Star type rotary feeders, equipped with variable-speed drives, are used to meter sorbent from the lockhoppers into the sorbent feed system. Sorbent feed rate is varied in order to achieve the desired sulfur reduction in the fluidized bed.

Photo 6.9.1 is a picture of the bottom of the sorbent lockhopper, the rotary feeder and the sorbent transport line.

Key Instrumentation and Controls

The sorbent injection system is controlled by the plant's Network-90 control system. The control system is designed to automatically step through the programmed sequence, provided the control system receives feedback indicating that the prerequisite action has been completed. The system will immediately shut down at any point in the sequence if it does not receive this positive feedback.

The lockhopper load cells are the central control input for this system. The control system begins feeding sorbent to the fluidized bed from one lockhopper and begins filling the other with fresh sorbent, based on load cell indication. These load cells also provide sorbent flow rate indication through rate of vessel weight change.

The correct air-to-sorbent ratio is maintained in the sorbent transport pipe by monitoring and controlling the velocity in the air supply line to the sorbent pickup pot, located just below the rotary feeders. Backflow of hot ash/ gas into the sorbent transport piping is prevented by a ball type isolation valve which automatically shuts when a thermocouple on the sorbent transport line indicates excessive temperature. The sorbent transport system will automatically shut down upon valve closure.

6.9.2 System Modifications

There were several major modifications completed on this system. These are detailed below:

Lockhopper Isolation Valves:

The original plant design included the test installation of two different types of lockhopper isolation valves.

Originally, Everlasting sliding double-disc valves were installed to provide inlet and outlet isolation on the east lockhopper train. Neles severe-service full-port ball valves were on the west sorbent lockhopper train. This side-by-side comparison provided operating experience with different valve types in this difficult application.

Problems were encountered with all four valves (both styles and manufacturers). The Neles ball valve on the discharge of the west lockhopper train would bind in operation. Several modifications were completed on this valve. The first included flipping this valve over so that the tight seal was on the reverse side of the material flow. The spring-loaded seat was also replaced by a rigid fixed seat. The binding of the valve still continued, so a larger actuator was installed on the valve. This seemed to solve most of the problems on this valve.

Operation of the Everlasting valves was more erratic. Sorbent material would build up in the dead spaces in the valve body cavity, restricting disc movement. Purge air was added to the valve body but this was not sufficient to prevent sorbent buildup. In late 1991, the valve was switched with the Neles ball valve and was reinstalled on top of the west sorbent lockhopper. The Everlasting valve, in combination with dead-space purge air has operated acceptably on the inlet of both lockhoppers provided adequate purge air is maintained.

The Neles ball valve, was installed with modified seats and a larger operator on the discharge of the east lockhopper in late 1991. Operation of both Neles valves as bottom isolation valves has been acceptable.

The final configuration utilized Neles ball valves with rigid seats and larger actuators mounted as the bottom discharge isolation valve on both sorbent lockhoppers. The Everlasting valves, with purge air installed to blow the dead air spaces, are installed on the tops as inlet isolation valves on both lockhoppers.

Other Valve Modifications

A number of other sorbent system valves had to be modified after startup. These included valves in the lockhopper vent lines and in the sorbent transport lines. All of these valves were Cooper valves with full port stainless steel balls and floating seats. The valves would begin to bind and stick when exposed to the fine sorbent dust in the sorbent transport system. The problem was related to dust accumulating behind the seat, creating a tight clearance, which would then bind the ball. On numerous occasions, these valves were dismantled, cleaned, modified and reinstalled only to bind up again during the next operational run. These valves were eventually replaced.

Transport Piping Upgrade

The original sorbent transport pipe was made out of SolidResist pipe which is a composite type pipe. Crosses were installed at all directional changes. The crosses were designed with dead legs in the direction of flow to absorb the impact and erosion in the bend prior to the 90° change in direction.

The discharge ends of the crosses in the sorbent injection transport pipe began to fail after approximately 350 hours of service. Temporary repairs were made by reinforcing the eroded area with plate and then building ceramic-filled boxes around the tee bends. All of the crosses were replaced with ceramic lined elbows, in Fall 1991. The ceramic used was a high alumina material, ½ inch thick. At the end of the three-year period, the material still appeared to be in good condition. The straight sections of pipe were not replaced at that time.

In August 1992, an inspection of the sorbent transport pipe downstream of the combustor isolation valves revealed severe erosion of the pipe adjacent to the combustor isolation valve. It was determined that a mismatch in the bore diameters, between the pipe and the isolation valve, resulted in erosion in the pipe. The pipe was replaced with a test section of a carburized, 310H stainless steel.

The first straight section of sorbent pipe failed due to erosion after approximately 4800 hours of operation. Several days later, another hole developed just downstream of the combustor isolation valve. This leak was located in the carburized pipe that was installed in September,

1992. Both leaks were due to disturbances in the flow path inside the pipe which resulted in accelerated erosion of the straight pipe. A program was implemented to replace all of the SolidResist straight piping with ½ inch thick ceramic- lined pipe. Routine inspection of the ceramic sections installed in late 1991 indicate no erosion of the ceramic sections.

Rotary Feeders

Sorbent is fed from each lockhopper by a star type rotary feeder. Numerous problems were identified early in operation. Binding of the rotary assembly, packing and bearing problems, and control range at low feeder speeds were common, due to the severe dust loading.

The first problem that developed on the feeder was with control range of the feeder at lower speeds. During initial combined cycle operations, it was found that the feeder could not be slowed sufficiently to satisfy low sorbent feed requirements. The feeder sprocket was changed, in December, 1990 to improve low-speed characteristics.

The need to operate at lower speeds precipitated another problem. The existing feeder drive system could not produce sufficient torque at low speeds to overcome binding in the feeder and the weight of the sorbent on top of the feeder. Purge air was introduced to the end cavities of the feeder to keep material from building up between the rotor and the end housing near the shaft packing to reduce binding.

The 1.5 hp feeder motors were replaced with 3 hp motors. This reduced the binding problems that were occurring at the lower feeder speeds.

Pickup Pots

The transition from the rotary feeder discharge to the sorbent transport pipe is a severe service location. The sorbent is dropped down from the rotary feeder into a large area where it is picked up in the sorbent transport air and swept into the sorbent transport pipe. Originally, the pickup pots were fabricated from stainless steel plate. These were replaced within the first year. Over the next year, the inside surface of the pot was weld repaired with hard surfacing weld rod in order to reduce the erosion rate. Finally, in the spring of 1993, the pickup pots were replaced with ceramic lined pots. The ceramic has withstood the erosion and remain in good condition.

Sorbent Distribution Piping

The original plant design included two sorbent injection nozzles penetrating the combustor and boiler front wall at the same elevation as the fuel nozzles. The nozzles were between the #2 and #3 fuel nozzles and between the #4 and #5 fuel nozzles. Since early 1991, the question of sorbent distribution in the bed and its impact on sorbent utilization has been of primary concern. Several different types of sorbent distribution nozzles and configurations were tested to evaluate the impact of sorbent distribution on sorbent utilization. These tests included simple tees installed on the end of the two existing sorbent nozzles, tees with skateboards above them, and a redesigned four-point distribution system. The mechanical aspects of these modifications are briefly discussed below and the performance evaluation is discussed earlier in Section 5.3.

Original Two-Point Injection Nozzles

The original sorbent injection points were located between the fuel nozzles as discussed above and only extended into the fluidized bed about 6". Later, they were extended to about a four foot penetration. Still later in the project, the nozzles were cut off and again only extended six inches into the fluid bed. This configuration is considered the base for sorbent utilization improvements.

Initial Tees on Four Foot Nozzles

In May 1991, in the first attempt to test redistribution of sorbent in the bed, standard 90° pipe tees were installed on the end of both sorbent injection nozzles in the bed. At the time, the sorbent injection nozzles extended four feet into the bed. The tees were removed after one run, when it was suspected that they were contributing to primary cyclone pluggages.

Tees With Skateboards

The next attempt at sorbent redistribution occurred in February 1992. During this test, tees were again installed on the ends of four feet sorbent nozzles. In addition, short pipe sections were installed on the ends of the tees and directed sorbent flow toward the adjacent fuel nozzles. Sorbent diverter plates, known as "skateboards" (which extended from the sorbent pipe to the coal skateboard), were installed. The entire configuration was intended to distribute the sorbent in the bed and to obtain some mixing with the fuel under the coal skateboard. This modification was abandoned due to an on-going problem with in-bed deposits. (Refer to Section 5.9).

Higher Velocities With Tees

In September 1993, heavy wall tees were reinstalled on the end of four foot extensions on the sorbent nozzles in the bed. The tees were directed at the fore to aft centerline of the coal skateboards. No sorbent skateboards were installed, but the tees had pipe extensions that directed the sorbent over to the coal skateboards. Orifices were installed on the four ends of the tees in order to try and maintain velocity. The tees also had splitter plates installed down the centerline of the common inlet lines in an attempt to evenly distribute the sorbent between the two discharges. This configuration operated for 487-hours. No sorbent clinker formations were observed. The tees were found to be severely eroded at the splitter plates and orifices. One leg of one tee was found totally plugged with sorbent. The tees were removed since no significant increase in sorbent utilization was observed.

Four Point Distribution

The four point distribution system was originally installed as a temporary test arrangement. This configuration involved splitting the two sorbent pipes into four pipes outside of the boiler and then penetrating the boiler front wall with four separate sorbent nozzles. In addition, the nozzles only penetrated six inches into the fluidized bed and the flow direction was from the front wall to the rear wall. All of the piping incorporated conventional pipe sections made from heavy wall stainless steel. The two new boiler penetration points were between the #1 fuel nozzle and the reinjection nozzle on the right side of the boiler, and a mirror image on the left side. Sorbent was now injected between the #1 and #2, #2 and #3, #4 and #5 and #5 and #6 fuel nozzles. (See Figure #6.9.2 for a layout of these nozzles.) This temporary piping eroded rapidly, necessitating a return to the original two-point feed configuration until ceramic line piping was obtained.

Ceramic Distribution Pipe

In early February 1994, a permanent ceramic-lined sorbent distribution system was installed that duplicated the four-point configuration outlined above. The unit was returned to service with an intent to run future operations in this configuration.

6.9.3 Operating Experience Overview

During the initial six to nine months of operation, the sorbent injection system availability and reliability was poor. Numerous valve, feeder and control logic problems resulted in the system tripping out of service. Restarting the system was time consuming and difficult. Resolution of valve problems has been an on-going project. The worst valves were repaired, replaced, or relocated within the first year of operation. However, valve operation reliability was still an issue on several valves well into the third year of plant operation.

Reliability of the sorbent transport system has also been affected by the transport piping. Since the first erosion failure occurred after 350 hours of coal fire operation, replacement of sections of the sorbent transport system has been an ongoing project. The ceramic pipe sections that have been installed appear to be acceptable for this type of application. Little or no wear is indicated to date.

Since early 1992, the general availability of the sorbent injection system has been acceptable.

6.9.4 Summary and Conclusions

After experiencing poor availability and reliability during the first year of operations, the sorbent injection system is now operating at an acceptable level. The mechanical difficulties with the system appear to have been rectified.

6.10 System 271 - Cyclone Ash Removal

6.10.1 System Description

System Purpose and Function

In a PFBC Combined Cycle, the hot ash and gas that is separated from the flue gas stream by the gas cleaning cyclones is routed out of the combustor vessel by the cyclone ash removal system. The ash/gas stream is depressurized and cooled in the transport system before it reaches the ash storage silo.

The primary and secondary ash removal systems remove ash from the primary and secondary gas cleaning cyclones.

The primary and secondary ash removal systems were originally interconnected and discharged to the cyclone ash storage silo. However, during the course of the three-year period, the systems were decoupled and now function independently.

The primary ash removal system interfaces with the following systems:

The primary cyclones where it receives the hot primary ash/gas stream.

The boiler combustion air system which provides heated air used to cool the primary ash while heating the combustion air.

The closed cycle cooling system which cools the primary ash.

The cyclone ash storage silo which receives cooled, depressurized primary cyclone ash.

The precipitator inlet duct which receives the gas used to transport primary ash to the cyclone ash silo.

The secondary ash removal system interfaces with the following systems:

The secondary cyclones where it receives the hot secondary ash/ gas stream.

The economizer outlet duct which receives the cooled, depressurized ash/ gas stream.

Both the primary and secondary ash removal systems receive purge air from the combustor vessel which is bled into the ash transport stream to help purge the system and cool the ash.

Photo 6.10.1 is a picture of the primary cyclone external ash coolers. Photo 6.10.2 is the primary cyclone ash transport dis-entrainment equipment located atop the cyclone ash silo.

General Description

The cyclone ash removal system was modified extensively. Therefore, the system description is broken into two parts, the original cyclone ash removal system and the final two independent ash removal systems.

The Original Cyclone Ash Removal System

Figure 6.10.1 shows a schematic diagram of the original cyclone ash removal system.

The seven parallel strings of primary and secondary cyclones provide for particulate cleaning of the main gas stream to levels adequate for admission to the gas turbine. The ash separated in these cyclones is pneumatically conveyed from the combustor to the storage silo. Bleed gas, taken from the cyclones, provides the transport medium. The flow of the gas/ ash stream is induced by the pressure difference between the cyclones, which operate at pressures up to 155 psig, and the atmospherically vented storage silo.

Inside the combustor, the gas/ ash stream from each of the 14 cyclones was cooled by combustion air in two stages; the cyclone dip-leg coolers and the air-cooled cyclone-ash coolers. Use of combustion air for cooling provided for heat recovery to the process. In addition to being cooled, the ash/ gas streams were partially depressurized while still within the combustor vessel. All seven primary cyclone ash lines were headered into a common ash removal line. All secondary cyclone ash lines were headered in a similar fashion.

External to the combustor vessel, the primary and secondary cyclone ash removal lines were directed to dedicated water-cooled ash coolers; four ash coolers arranged in series served the primary stream, while the flow from the secondary cyclones was cooled by a single ash cooler.

After this third stage of cooling, the secondary cyclone ash stream was directed through a pressure reducer, and headered with the primary ash/ gas stream downstream of its associated water cooled heat exchanger.

The common gas/ ash stream was routed from the combustor building to a final pressure reducing station on top of the cyclone ash silo. The ash was then separated from the gas by a cyclone and cyclone bag filter. Downstream of the ash-separation equipment, the gas, which was cleaned to a level acceptable for stack emission (30 ppm by weight), was directed to the main gas stream at the precipitator inlet and flowed with the main gas out through the stack. The ash, separated in the cyclone and cyclone bag filter, was fed into the silo by dedicated rotary feeders.

The system was designed to remove ash collected in the primary and secondary cyclones at a maximum rate of 25,700 lbs ash/ hr.

Final Primary Ash Removal System Configuration

The primary ash removal system has not been significantly reconfigured. The major modifications involved the decoupling of the secondary ash removal system from the primary system, installation of suction nozzle screens in the bellows boxes, installation of purge air to the suction nozzles, and material upgrades to the system depressurization orifice.

The final system consists of the seven ash lines, one from each dip leg bellows box, routed through the combustor to the internal primary ash cooler. At the discharge of the cooler, the seven lines are combined into one and penetrate the combustor vessel wall. Outside of the combustor vessel, the primary ash flows through four external water-cooled heat exchangers and is then routed to the top of the cyclone ash storage silo. At that point, the hot ash/ gas stream undergoes a final depressurization stage in the discharge orifice, enters a cyclone separator where the majority of the ash is separated out of the gas stream and then enters the bag filter. In the bag filter, the remaining ash is separated from the gas stream before the clean gas is routed to the precipitator. The ash from the cyclone and baghouse is deposited into the cyclone ash silo where it is stored for later disposal off site.

The final primary ash removal system configuration is shown on Figure 6.10.2.

The individual components of the primary ash removal system are described below:

Cyclone Dip Leg Coolers

The cyclone dip leg cooler is comprised of a concentric pipe around the dip leg. A portion of the combustion air is routed through this annulus to provide dip-leg cooling. The flow of cooling air is induced by the pressure difference between the pressure vessel and the boiler.

Air Cooled Cyclone Ash Coolers

Each of the seven cyclone ash removal streams is directed through a dedicated air-cooled ash cooler internal to the combustor. The gas/ash streams are both cooled and partially depressurized in the coolers. The cooling function is achieved by directing combustion air over the piping labyrinth, which results from the numerous flow direction changes with interconnecting straight runs. The seven individual ash coolers are located in a duct which directs combustion air from the pressure vessel to the boiler windbox.

External Primary Ash Coolers

The primary cyclone ash stream is routed to four water-cooled ash coolers located in the basement of the combustor building. These heat exchangers are of the shell-and-tube type, with the ash/gas flow inside the tubes. There is a single ash/gas path through each heat exchanger, and the four coolers are arranged in series.

The closed-cycle cooling system provides the cooling water to the external primary ash coolers. The cooling water flow path is arranged in series through all four of the heat exchangers and is counter to the gas flow.

To avoid acidic condensation in the internal piping of these heat exchangers, the minimum allowable cooling water temperature entering the heat exchangers is 370 F. This provides adequate margin to avoid acid condensation.

The normal operating water side pressure within the coolers is higher than the maximum gas/ash side operating pressure at the cooler inlet. Therefore, the potential for leakage is from the water side into the ash/gas side.

Ash Removal Piping

The majority of the ash removal piping, including that within the air-cooled and water-cooled ash coolers, incorporates straight runs of pipes with "T-bends" to minimize erosion. The ash removal system piping materials were selected and configured to minimize erosion.

Primary Ash/Gas Cyclone Separator

A cyclone separator is employed atop the cyclone ash silo to separate primary ash from the gas stream. It is designed to separate approximately 95% of the ash from the conveying gas. Ash collected in the cyclone is fed directly into the silo by a rotary feeder at the cyclone discharge leg.

Primary Ash/Gas Baghouse

A bag filter, with a cyclonic action tangential gas inlet, is employed as the second and final stage of ash separation. It is designed to clean the ash removal conveying gas to a particulate level of approximately 30 ppm. Exhaust gas from the filter is ducted to the inlet of the precipitator.

Ash Feeders

Constant speed rotary feeders are used to discharge ash from the cyclone separator and the cyclone bag filter, respectively, into the silo. They also provide a pressure seal between the dust separation equipment, which operates at pressures up to 2.9 psig, and the atmospherically vented silo.

Modified Secondary Ash Removal System Configuration

The secondary ash removal system was totally redesigned and replaced during the three-year operations period covered by this report. The following is a description of the secondary ash removal system in its final configuration.

The revised secondary ash removal system consists of six individual ash lines routed from the cyclone dip-leg suction nozzles to the economizer discharge duct. These lines are staged in increasing internal diameters from the suction nozzle to the economizer outlet duct. (Note: One secondary cyclone was removed as part of the HGCU project, leaving only six cyclones.)

Flow orifices were installed in the ash lines just prior to the economizer duct in order to monitor ash line flow rates and maintain desired velocities in the ash line.

The original suction nozzles were reused, but drilled out to a larger internal diameter. The purge air nozzles which direct purge air into the inlet of the suction nozzles were also retained, but their orifice size was changed.

All of the ash lines utilized long-radius bends to accomplish flow direction change instead of the cast tee bends that were installed in the original system design.

In order to reduce the temperature of the ash/gas mixture in each ash line to achieve the design requirements of its corresponding combustor penetration, the ash is cooled by axial fins welded to the exterior of the ash lines which are located in the combustor. There are no forced convection heat exchangers built into the redesigned ash removal system.

Each ash removal line is equipped with a blowdown/blowback valve station which is designed to permit on-line clearing of a plugged secondary ash line.

The revised secondary ash removal system is shown in Figure 6.10.3.

Key Instrumentation and Controls

Both of the primary and secondary ash removal systems are passive systems. There are no controls required for operation. The major requirement is system surveillance for ash line pluggage. Operational surveillance of the ash removal system is accomplished through a series of thermocouples placed strategically along the ash lines and by a pressure transmitter located at the discharge end of the ash lines.

The final thermocouples are located at the top of the cyclone ash storage silo and are mounted on the inlet piping to the discharge orifice and the baghouse discharge piping. Again, these thermocouples are used to monitor the operational status of the final ash disentrainment equipment located atop the cyclone ash storage silo.

System Control Overview

The two ash removal systems are essentially passive. The only controls involved are for starting and stopping the rotary ash feeders located below the primary ash removal final ash disentrainment cyclone and baghouse.

There are several correlations, however, built into the control system to indicate transport problems in either system. The pressure on the common primary ash removal line is compared to an operating curve based on the combustor vessel pressure. If the pressure at the discharge orifice is below a sliding set point, an alarm is activated.

Likewise, the pressure in each secondary ash line is compared to the expected pressure, and if the actual pressure drops below a set point an alarm is activated.

6.10.2 System Modifications

The cyclone ash removal systems for both the primary and secondary cyclones have been significantly modified. The primary ash removal system was decoupled from the secondary ash removal system and has had several modifications made to the system itself. The secondary ash removal system was totally replaced. The final system configuration is discussed earlier, in

Section 6.10.1. The following is a brief overview of the more significant modifications made to each of these systems:

Primary Ash Removal System

The plant began initial operation with bed material on October 19, 1990, and progressed in steps up to the first coal-fired combined-cycle operation. During the run the week of December 15, 1990, the first cyclone ash removal problems occurred.

The following sections address the problems identified in the primary ash removal system:

Internal Ash Cooler Return Chambers

The internal ash coolers are an integral part of the ash cooling system designed to cool the ash to an acceptable level for discharge from the combustor vessel. Air inleakage in the primary ash system became a major issue in June through August 1991. During that period, air testing of the system revealed significant numbers of gaskets on the cooler return chambers and tee bends to be leaking so severely that the system could not be pressurized for an air leakage test. Many gaskets had to be replaced and bolts retorqued before the system could pass an acceptable leakage test.

Subsequently, the entire ash system was disassembled. A detailed inspection revealed that a combination of shop fabrication and design oversights caused a significant air leakage problem. There were significant mismatches in the mating flanges between the ash cooler pipe flanges and the return chamber casting flanges. This resulted in a reduction in seating surface of the gasket between the return chamber and the pipe flange. This 63% reduction in gasket seating surface resulted in an ineffective gasketing installation.

This problem was corrected by machining down the faces of the pipe flanges to achieve a flat and continuous gasket sealing surface. This modification appeared to be successful until mid 1993 when failures of the graphite gasket began to occur. A program to replace all of these gaskets was initiated in early 1994.

Internal Ash Cooler Return Chamber End Caps

The end of each ash cooler return chamber has a rectangular end cap which is removable for inspection of the return chamber. This end cap has a raised-face sealing surface for the gasket.

This flange was found to be a major source of air leaks. Temperature was determined to be a significant factor - the hottest return chambers leaked worst and the coolest usually did not leak at all.

A detailed inspection of these end caps revealed several design and fabrication flaws. The first was with the bolt holes cast into the end caps. The holes were designed to be 10 mm but, in fact, were slightly larger. The bolt hole location tolerance was $\pm$ 0.5 mm, which was difficult to achieve. The bolts were hex head cap screws with washer faces. The washer face O.D. was smaller than specified

All of these factors resulted in many of the end cap bolts being off center in the end cap holes, and one side of the bolt slipping down into the bolt hole. The resultant improper torquing resulted in ineffective sealing.

In addition, inspections revealed the faces of the castings to have significant sand pits. These pits sometimes were on the narrow raised-face gasket surface. Pits in this area compromised an already marginal gasket condition. Some of the end caps were later ground down to eliminate the pits in the gasket area.

All of these bolts were replaced, along with the addition of standard flat washers and graphite gaskets in 1991. While this improved the air inleakage problem, leakage of these flanges continues to be a routine maintenance concern. At present, approximately 20% of these gaskets are replaced during any routine outage.

Casting Quality

All of the tee bends, cooler return chambers, and cooler outlet collection headers in the original ash removal system, were cast from an erosion-resistant material. While this material was very effective against erosion, the quality of the castings was marginal. Many of the castings exhibited sand pits and gas vent holes, which showed up in the gasket seating area. These were replaced or repaired.

Primary Suction Nozzle Strainers And Purge Air Nozzles

A number of ash removal suction nozzle blockages were attributed to either ash sinters formed in the cyclone when a primary cyclone fire occurred or to spalling chips of cyclone refractory which break off the refractory in the cyclone. An effective modification to prevent suction nozzle blockage was installation of strainer cans around the circumference of the suction nozzle.

There have been no instances of blocked suction nozzle inlets from refractory chips or ash sinters, except during a significant ash fire in a primary cyclone.

Since the suction nozzles take their ash/ gas stream flow off the bottom of the bellows boxes, the suction nozzles can easily be overwhelmed with ash from a cyclone ash fall or ash loading upset or "burp". This results in a pluggage of the ash line, with no reliable method to re-establish transport flow. In order to maintain a reliable source of transport flow into the ash line, a small orificed purge line was installed to channel air into the inlet of the suction nozzle. This line takes air directly from the combustor vessel and routes it directly into the suction nozzle, thereby maintaining transport flow even if gas flow from the cyclone dip leg is reduced or eliminated.

Modifications to the Secondary Ash Removal System

The original design for the system was based on achieving sufficient velocities within the system to transport the ash. It was also believed that the systems were balanced sufficiently, so that the secondary system could be coupled downstream to the primary ash removal system without any negative impacts on either system. The actual velocities in the system proved to be too low, and were revised upwards. The systems were decoupled after it was determined that the expected balance between the two systems was not achievable. These two modifications significantly improved system reliability.

The next major challenge was to eliminate ash buildup in the long secondary cyclone dip legs. This ash could suddenly collapse into the dip leg, and overwhelm the suction nozzle. A companion problem also existed in providing sufficient motive force to keep the dip leg clear of ash at low pressure vessel pressures, such as those encountered at start up and shutdown. (These concerns are discussed in the gas cleaning cyclone Section 6.3.)

After exhausting most possibilities for making the original secondary ash removal system reliable, a decision was made to replace the system in its entirety with a new system based on independent ash lines. This system is shown in Figure 6.10.3.

First Quarter 1991 Modifications

Problems with the secondary cyclone ash removal system started shortly after unit start up. Five of seven secondary cyclones plugged 7-1/2 hours into initial coal fire. The pluggages were attributed to low transport capacity during a unit upsets. As a result, fluidizing purge air nozzles were installed that would keep the inlet area around the suction nozzle fluidized and permit orderly flow of ash into the suction nozzle.

Pluggages during subsequent runs confirmed that the transport capacity of the secondary ash system was marginal, especially at low combustor vessel pressures. A multi-step program was initiated to improve transport capacity. The first step was to reduce the internal ash cooler from an eleven-pass cooler to a three-pass cooler. Since this would increase the ash temperature leaving the combustor, the bypassed external ash cooler was reinstalled to aid in further ash cooling. This proved helpful, but did not eliminate the problem.

Subsequently, the secondary and primary ash removal systems were decoupled, and the secondary ash removal line was routed into the precipitator inlet duct. In addition, extensive air flow tests were conducted on all seven ash lines within the combustor vessel.

The results of these air flow tests were significant. The original design assumed a high rate of erosion potential resulting from high velocities, and the system was designed to address those concerns. The air flow tests showed that the actual velocities in the ash lines were significantly lower than design.

Modifications were made, during subsequent outages, to increase system capacity and eliminate other potential causes of pluggage. These modifications included:

Reinstallation of the secondary suction nozzle fluidizing nozzles.

Installation of "hot boxes" on the boiler bottom to feed hot air to the secondary fluidizing nozzles.

Elimination of the secondary cyclone dip leg coolers.

Implementation of a new combustor vessel startup prewarming procedure.

Increasing transport capacity by increasing the external secondary ash line to 1.6 times the original area.

Pluggage problems continued to impact the system. A decision was made in mid 1991 to operate the unit, even if one secondary cyclone was plugged.

The following is a discussion of problems that were encountered after the first quarter of 1991:

Transport System Integrity

The secondary ash system was plagued by air leakage and deposit blockage in the ash cooler collection headers.

Throughout Summer 1991, the secondary ash system suffered five ash line plugs. Originally, it was thought that transport capacity problems were surfacing again. However after inspections, it was found that blockage of the combined ash line was the problem. The ash pipe in the thermal sleeve through the combustor vessel wall had slipped out of its seating ring. The resultant slippage had significantly restricted the area of the combined ash line. At the same time, a hard deposit had built up on the collection header between the #24 and #25 ash lines.

Again, this buildup significantly restricted the cross section of the ash transport line. These problems were corrected.

Flange Air Inleakage Modifications

As discussed in the primary ash removal section, air inleakage at return chamber and tee bend flanges also impacted the secondary ash removal system. Since the early indications were that the secondary ash was not erosive, a decision was made in Fall 1991 to weld the system up solid.

All of the cast tee bends and return chambers in the seven individual ash lines were replaced by prefabricated stainless steel 90° tees, with a dead leg in the direction of flow. The return chambers were replaced by two 90° tees in series.

This modification eliminated all flanges in the secondary ash line between the suction nozzle flange up to the collection header flange.

Ash Cooler Return Chamber Erosion/Replacement

The internal secondary ash cooler return chambers were replaced in Fall 1991 with solid welded stainless steel return bends. These were subsequently eliminated.

Total Secondary Ash Removal System Replacement

The entire secondary ash removal system was replaced in early 1993. Six new lines were run from the suction nozzles to the economizer outlet duct.

6.10.3 Operating Experience Overview

Primary Ash Removal Experience

The primary ash removal system operating experience has been acceptable, but its maintenance requirements are excessive and unacceptable for a commercial size plant.

Over the first two years of operations, the primary cyclone ash removal system had limited impact on unit operation. However, the need to routinely repair leaks in the primary system in order to minimize air inleakage and maximize system reliability was stressed.

The current primary ash removal system is capable of performing the required function, as long as the system air leakage rate is minimized through extensive routine maintenance.

Secondary Ash Removal Experience

The original secondary ash removal system was not capable of performing its design function. The first two years of unit operations were only completed after it was acknowledged that unit operations would have to continue despite secondary cyclone pluggages. The reliability and availability of this system was totally unacceptable. No amount of maintenance could be completed to assure trouble-free operation of the system during the next operation run. The secondary ash removal system was truly the "Achilles Heel" of the plant.

At the beginning of the third year of operation (1993), it was decided to replaced the entire secondary ash system with a new system consisting of six independent ash lines. Since that system was installed, the secondary ash system has operated at almost 100% reliability. Since June 1993, the secondary ash system has only plugged on two occasions, and has suffered one deposition/erosion-related failure.

Shortly after the revised system was installed, an ash fall occurred in all six secondary cyclones during startup. Once coal fire was achieved with a corresponding higher combustor vessel pressure, all six lines were unplugged via the ash line blowback valve stations. Each line was isolated back to the economizer, high-pressure sorbent air was blown back up the line into the dip leg and then flow was re-established to the economizer. Each line was cleared individually and returned to service immediately once the blowback was completed. On another occasion, a hard deposit of ash bridged over the ash line orifice in one ash line at the economizer. The line was isolated from the combustor, the deposit rodded out and the line returned to service.

The erosion failure occurred in December 1993, on a long-radius bend outside of the combustor. A very hard deposit had built up inside the ash line and resulted in erosion of the ash line in the same vicinity as the deposit. The ash line was isolated at the combustor, the failure was isolated within the specially designed bend, and the ash line was placed back into service. All of this was accomplished within 20 minutes of the original failure.

To date, the only problem that has impacted the secondary ash line availability is the buildup of an extremely hard deposit in the ash line that resulted in the erosion failure. These deposits occur in high impact areas with no regularity, and can not be predicted. To date, there is no explanation of the cause of the deposits.

6.10.4 Summary and Conclusions

The cyclone ash removal system has had the significant impact on unit operations, availability and reliability. The original secondary ash removal system design did not work. The redesigned system installed in early 1993 was very successful and clearly demonstrates that pneumatic ash transport is viable for this type of application.

The current system achieved and surpassed its operation goals for availability, reliability, and maintainability. However, the system requires optimization to minimize gas transport requirements.

The primary ash removal system as installed is a partial success. The overall system design appears to be acceptable however major equipment modifications would be required before the system could be commercialized. The ability to maintain the system must be thoroughly evaluated for a commercial system. The air inleakage problems associated with the hundreds of bolted flanges must be resolved. The ability to unplug ash line pluggages on-line must be fully developed. The system shows good promise but must be improved further before it can be considered a commercial system.

6.11 System 272 - Bed Ash Removal

6.11.1 System Description

System Purpose and Function

The function of the bed ash removal system is to remove cooled bed ash from the boiler and combustor and convey it to the bed ash silo. The system removes ash in a controlled manner to maintain the desired fluidized bed level.

The system interfaces with various air systems such as process air for lockhopper pressurization, compressed air and splitting air for valve operation, and boiler ventilation for lockhopper depressurization.

General Description

The system consists of two parallel trains of lockhoppers and valves, a common lower bed ash hopper, screw conveyor, three conveyor belts, two transfer stations, and interconnecting piping.

Ash is removed from the boiler and combustor by gravity via two ash lockhopper trains. Two ash removal lines connect to the two bottom hoppers of the boiler and run vertically out through the bottom of the combustor into a pair of L-valves. The L-valves are used to meter the flow of ash. From the L-valves the ash flows vertically into the top of the lockhoppers. When the lockhoppers become full, they are isolated from the boiler and depressurized. Their contents are then emptied by gravity into the lower bed ash hopper which operates at atmospheric pressure. The ash in the lower hopper is fed via a screw conveyor onto an enclosed conveyor system which transports it to the bed ash silo.

Two ball valves are used to isolate the lockhoppers. The valves controlling the flow of bed material into and out of the lockhoppers are arranged with two valves in series. One valve is used for material isolation and the other for pressure isolation.

The bed ash removal system is designed to discharge bed ash at rates of up to 25,000 pounds per hour using one of the two trains. The conveying system is designed to handle 50,000 pounds per hour of ash.

Simplified process sketches of the system are shown in Figures 6.11.1 and 6.11.2.

Photo 6.11.1 is a picture of the bed ash lockhoppers located below the combustor vessel.

Key Instrumentation and Controls

Key instrumentation in the system includes ash temperatures at various points upstream of the lockhoppers, ash level in the lockhoppers and lockhopper pressure. The ash temperatures are important because of the low temperature limit of the ash conveying system (212 F). The lockhopper level measurement is used to indicate when the lockhoppers are full. The lockhopper pressure is used to indicate that the lockhopper has been pressurized or depressurized as desired.

The lower bed ash hopper is equipped with a high-level alarm, flow switches in the inlet lines from the lockhoppers to the lower hopper, and a flow switch in the chute from the lower hopper to the conveyor. These instruments provide system status indication.

Key instrumentation on the conveyor belts include belt speed and belt misalignment sensors.

System Control Overview

Bed ash is continuously removed using the bed ash removal system. The removal rate is controlled by the duration of the pause between air pulses to the L-valves. The pause duration is varied in response to the bed-level error. The removal rate demand is generated from the bed level error. When a lockhopper becomes full it is isolated from the boiler, depressurized, and emptied into the lower hopper. The ash then flows out of the hopper into the screw conveyor and then onto the Flexowell conveyor belt. The ash is then transferred to the ash silo via two additional conveyors.

6.11.2 System Modifications

The major modifications made to the system were completed in 1990 to improve cooling of bed ash material discharging from the boiler. (Refer to Sections 5.2 and 6.2.2)

Several additional, minor modifications were made to improve the reliability of the system. The two ball valves used for lockhopper pressurization were modified with larger actuators to ensure smooth valve operation. The solenoid valves in the air lines to the L-valves were replaced and restrictive orifices removed because the pressure drop across the original valves was insufficient to allow the valves to operate. The drip chute on the end of one of the conveyors was enlarged to prevent ash build-up around the conveyor rollers.

6.11.3 Operating Experience Overview

The bed ash removal system proved to be one of the more reliable systems at Tidd. The system operated as designed and without excessive maintenance. The few trouble spots were ball valve seat wear and conveyor belt and roller wear. Occasionally, high ash temperature in the boiler bottom hopper bottoms was encountered. Good flowability of the bed ash undoubtedly contributed to the high reliability of the system.

6.11.4 Summary and Conclusions

The overall performance of the system proved excellent. No forced outages were ever caused by the bed ash removal system.

6.12 System 274 - Bed Ash Reinjection

6.12.1 General System Description

System Purpose and Function

Bed height is the main load-defining parameter in a PFBC cycle. The integrated unit control scheme employed at Tidd uses bed height to control the combustion master signal, as well as the bed ash removal system.

The bed ash reinjection system's main function is to permit relatively rapid changes in bed height (load). Through the use of two storage vessels located within the combustor vessel, bed ash can either be transferred from the bed to the storage vessels to lower the bed height, or stored bed ash can be fed from the vessels into the bed to raise the bed height.

The bed reinjection system also serves to store sufficient material (spent bed ash and sand) for establishing the initial bed during unit startups.

The bed ash reinjection System interfaces with the following systems:

The startup zone of the boiler to which it delivers stored bed material for raising bed height and from which it transfers bed material to the reinjection vessels to lower the bed height.

The combustor vessel, from which air is taken to provide fluidization air to the L-valves that are used to control the drain rate from the reinjection vessels to the bed, and to provide transport air to the lift line which is used to move material from the bed to the storage vessels.

The bed ash removal system, from which air is taken to provide fluidization air to the L-valves at low unit loads.

The combustion gas flue upstream of the economizer, to which the reinjection vessels are vented during bed level decreases.

The combustor vessel air supply, which is directed through the reinjection vent gas coolers to act as the cooling medium for the gas/air vented during bed height reductions.

The low-pressure nitrogen system, which supplies nitrogen to the L-valves to block air from the bed from flowing through them during load decreases and provides a high-pressure gas source for unplugging them, and to the reinjection vessels to inert them after a load decrease is completed.

General Description

The system employs two 635-cubic foot vessels located within the combustor vessel to provide storage for up to 100,000 lbs. of bed material. Each vessel has its own dedicated lift line and L-valve, thus the system is configured as two separate parallel trains. The storage vessels, which are called reinjection vessels, are internally lined with insulating refractory. Ports on the tops of the vessel permit vessel filling during unit outages. Such filling is accomplished by feed from a bulk truck through flexible hosing that is temporarily routed into the reinjection vessels.

Since there are no valves in the lift lines, the reinjection vessels operate at the pressure of the bed when the system is idle or feeding to the boiler. The feed to the boiler is accomplished by gravity, and the feed rate is controlled by on/off pulsing of the fluidizing air to the L-valves. At high-pressure vessel conditions, which are indicative of high unit air flows, the fluidizing air is supplied from the combustor vessel. Whereas, at low-pressure vessel conditions, the fluidizing air is supplied from the higher pressure (about 1.5 times combustor pressure) sorbent air supply. In addition, the L-valves can be supplied fluidizing gas from the nitrogen system. This higher pressure source is used for the first few pulses if the L-valves have not been operated for a period of time, in order to ensure that the L-valves initially unplug.

During bed height reductions, the reinjection vessels are vented to the main gas flue to establish a lower pressure than exists in the bed. The gas vent rate is controlled by fixed orifices. The system design incorporates the ability to increase the venting rate at low loads by opening a second parallel vent orifice in each vent line. The vented gas is cooled by passing it through a tube-type heat exchanger which uses combustor air to cool the gas to below 750 F. The lift line's suction nozzle inside the boiler consists of the lift line and a larger annular pipe. When the lift line is in use, lift line transport air is fed into the annular area of the suction nozzle where it then flows down along the outside of the lift line and into the lift line opening. Regulation of the transport-air flow rate controls the rate of ash removal from the bed. During load decreases, the lower pressure in the reinjection vessels would permit gas/air from the bed to flow up through the L-valve and the standing column of ash. Flow of such oxygen-laden gas would present a potential for combustion of any char contained in the stored bed material, resulting in locally high temperatures and the risk of sinter formation. In order to preclude such gas backflow, nitrogen is fed into the outlet area of the L-valves during the load-decrease operation. After completion of the load-decrease operation, nitrogen is then fed directly into the reinjection vessels to inert them.

Figure 6.12.1 shows the final system configuration. The only significant change from the original was the addition of the manual isolation valves in the higher pressure air supply lines to the L-valves.

Key Instrumentation and Controls

Differential pressure measurements between the reinjection vessels and their associated suction nozzle air supply line give an indication of the pressure difference between the bed and the vessels. These signals are used as both ash-transport flow rate indication and as feedback in the control of the air flow to the suction nozzle.

Load cells on the reinjection vessels give an indication of the mass of material stored in the vessels.

Thermocouples at various heights inside the reinjection vessels are used to provide alarm, load-reduction stop sequence, and initiation of nitrogen purging on high temperature.

Thermocouples on the reinjection vent and lift lines provide alarm and load-reduction stop sequence initiation on high temperature.

System Control Overview

During load increases, the rate of ash admission to the bed is controlled by the pulse rate of fluidizing air to the L-valve. In automatic operation, the L-valve pulsing demand is set by the control system in response to the bed level deviation signal; however there is an adjustable maximum-rate-of-change limiter. In manual operation, the operator sets the L-valve pulsing demand directly.

During load decreases, the rate of ash transport to the reinjection vessels is controlled by regulation of the transport air flow. Within limits, decreased transport air flow causes a higher differential between the bed and the reinjection vessels which results in increased ash transport. The air flow is regulated to achieve a specified differential pressure. In automatic operation, the desired differential pressure is set by the control system in response to the bed level deviation signal; however, there is an adjustable maximum rate of change limiter. In manual operation, the operator sets the desired rate of change directly.

6.12.2 System Modifications Completed

Vent Line Orifice

The main vent line orifices were reduced in size to eliminate excessive venting capacity.

Low Load L-Valve Fluidizing Air Isolation Valve

A tight shutoff manual ball type isolation valve was added in the air supply line to the L-valve to eliminate air leakage which caused material to flow when the L-valve was not being pulsed.

Vent Line Isolation Valves

The vent line isolation valves experienced difficulty in closing completely, resulting in leakage. These valves, which originally relied only on the actuator's spring to effect closure, were modified to have control air assist in the closing.

L-Valve Restriction Plates

For cost-effective design and procurement, the L-valves for Tidd and its sister units were all made the same size even though the specified maximum rate of load change for Tidd was only half that of the other units (2% per minute versus 4%). In order to limit the maximum ash flow rate and provide sufficient capacity turndown, restriction plates were incorporated into the Tidd L-valve vertical inlet leg. Due to problems with plugging of the L-valves, these restriction plates were removed. This modification was of some benefit.

6.12.3 Operating Experience Overview

The bed ash reinjection system generally functioned reliably in achieving desired bed height changes. The maximum system rate of change capability was specified as 2% per minute; however, due to concerns about unit controllability, the system was generally operated with a maximum rate of change of 1% per minute.

The most significant operating issue with the system was occasional plugging in the feed lines from the reinjection vessels to the bed. Such plugs or restrictions were caused by large chunks of agglomerated bed material becoming lodged at the L-valve restriction plates. Removal of the restriction plates moved the choke point further upstream to the standpipe inlets located inside the reinjection vessels. It is now suspected that the bed agglomerations which are causing the plugs are not being formed in the reinjection vessels, but are rather being drawn out of the bed by the suction nozzle and lift line.

When attempting to use spent bed ash to start the unit, the bed material tended to break up excessively. This resulted in problems with overloading of the primary cyclone ash removal system, which experienced numerous plugs. Feed material attrition also taxed the storage capability of the reinjection system in regard to its ability to attain sufficient startbed height. These problems were solved at Tidd through the use of sand for the initial start bed.

When the material stored in the reinjection vessels was finer than normal, uncontrollable material outflow was sometimes experienced when no fluidizing air flow was admitted to the L-valves.

The system controls include a recirculation mode to circulate material from the bed when operating at steady bed heights for extended durations. This mode of operation was intended to insure that the material stored in the vessels was relatively hot. It was felt that high feed rates of ash cooled to the combustor vessel temperature would present an excessive heat sink to the bed during rapid load increases, which were likely not tolerable by the bed temperature controls. The recirculation system was never used during the three-year test period, and no significant bed temperature control problems were experienced. However; as noted above, the maximum rate of load change used was typically kept to less than 1% per minute.

6.12.4 Summary and Conclusions

The bed ash reinjection system functioned very reliably and can for the most part be considered a fully commercial design. The ability for a PFBC unit to follow a load change demand has only been demonstrated at relatively low rates of change; however, this is not seen as a major issue at this time. Occasional plugging of the L-valves remains the only significant problem associated with this system.

6.13 System 310 - Gas Turbine/ Compressor

6.13.1 System Description

System Purpose and Function

In a PFBC Combined-Cycle plant, the gas turbine utilizes the energy in the gas exiting the combustor to drive an electrical generator and to drive two air compressors in series, which supply pressurized combustion air to the combustor.

The gas turbine interfaces with many of the other plant systems as follows:

Drives the gas turbine generator to produce electrical energy.

Utilizes the lubricating oil system to maintain bearing lubrication.

Utilizes the control fluid system to provide hydraulic power to the valves.

Obtains water for the intercooler from the condensate system.

General Description

The gas turbine is a two-shaft machine. The two mechanically independent shafts are coupled aerodynamically. The first shaft consists of a low-pressure compressor (LPC), and a low-pressure turbine (LPT). The second shaft consists of a high-pressure turbine (HPT), a high-pressure compressor (HPC), a reduction gear, and an electrical generator.

The gas turbine is designed to take relatively clean gas from the combustion process and expand it through an HPT section and LPT section. The energy extracted by the HPT drives an electrical generator and an HPC. The energy extracted by the LPT is used to drive a LPC.

The LPC and HPC are aerodynamically in series with an intercooler located between them. Outside air is pulled through the air intake filter, located on the roof of the combustor building, into the LPC where initial compression takes place. As a byproduct of the compression process, the air temperature is also increased. The air flows through an intercooler where the air temperature is reduced to improve the HPC volumetric efficiency and to avoid exceeding the combustor vessel design inlet air temperature. After the intercooler, the air is compressed through the HPC. The compressed air then proceeds to the combustor through a cold intercept/bypass valve and the outer annulus of the crossover pipe. The air is then used for combustion and various other processes.

The HPT and LPT are aerodynamically in series. Combustion gas flows from the boiler through two stages of cyclone separators where most of the entrained ash is removed. The relatively clean combustion gas flows through the inner annulus of the coaxial crossover pipe, and through the hot intercept valve. The gas then is expanded through the HPT and LPT. The gas then proceeds through the gas exhaust duct, economizer, precipitator, and out the stack.

The gas turbine is located in the combustor building inside an enclosure built for noise reduction. The enclosure has forced ventilation system that utilizes a filter and silencer on the inlet and a silencer on the exhaust.

Photo 6.13.1 is an overhead picture of the gas turbine. Photo 6.13.2 is a sideview picture of the gas turbine.

Key Instrumentation and Controls

Compressor inlet temperature is used in the calculation of air flow, and compensated pressure ratio and speed for surge protection.

Compressor outlet temperature is used in the control of intercooler recirculation. It is also used in a differential temperature calculation, as a permissive, for the cooling down period following a gas turbine trip. It will also trip the combustor on high temperature for combustor and gas turbine material protection.

Turbine inlet temperature is used as a combustor and gas turbine trip for gas turbine material protection. It is also used with turbine disk temperatures in differential temperature calculations for both a permissive for the cooling down period following a gas turbine trip, and for a gas turbine trip during bed preheater operation to prevent minimum blade-tip clearance problems.

Turbine outlet temperatures are used as a permissive for the cooling down period after a gas turbine trip.

Compressor inlet and outlet pressures are used for pressure ratio calculations for surge trip protection.

Casing vibration measurements are used to protect the gas turbine from high vibration.

Shaft speed measurements are used for tripping the turbine on rotor overspeed, as a permissive for operating the intercept valves, the calculation for surge trip protection, and numerous other permissive and controlling functions.

System Control Overview

The gas turbine is initially rolled to speed by using the generator as a motor. After synchronization, the generator continues to provide power, up to 8 MW, to provide air flow for combustor warming (utilizing heat of compression), bed preheating, and coal ignition. As gas temperature from the combustor increases, less power is required from the generator to maintain a given air flow. This is due to the turbine's use of energy in the gas to drive the compressors and the generator. The gas turbine will achieve positive generation after coal fire has been initiated.

Air flow changes are made by adjusting the position of the LPT guide vanes. Because the compressor is a constant volume machine, every revolution of the shaft compresses a given volume of air. To increase the air flow, it is necessary to increase the speed of the LP shaft. The LPT guide vanes regulate how much of the total energy drop from the combustor to the LPT outlet is used by the HPT and the LPT.

An air-flow increase is accomplished by closing the LPT guide vanes. Throttling the guide vanes has the effect of requiring more energy to expand the gas mass flow through the LPT, causing a greater pressure drop through the LP turbine. As more energy is used to expand the gas through the LP turbine, the LP shaft speed is increased. The increased speed of the LPC causes a corresponding increase in air mass flow through the compressor. The HPC operates at a constant speed and compresses the output from the LPC. As the air-mass flow increases, the combustor pressure vessel pressure slowly increases. During the time period that the LPT is using more energy from the combustor, there is less energy available to the HPT. Of that energy, a given amount is required to drive the HPC at 6218 RPM. Therefore, there is less energy available for generation, i.e., MW output will drop. After air flow reaches its set-point value, the LPT guide vanes will begin to open as more energy becomes available at the HPT inlet due to the gradually increasing gas-mass flow from the combustor. LP speed and pressure vessel pressure will stabilize. The higher energy level, as well as the more open guide vanes, allow the HPT to use more energy to drive the generator and increase MW output.

An air flow decrease is accomplished by opening the LPT guide vanes. Opening of the guide vanes requires less energy to expand the gas through the LPT. The smaller energy drop will have the effect of reducing energy to drive the LPC. Thus LPC speed and air-mass flow will decrease. Also, the greater energy level available to the HPT, due to the reduced LPT pressure drop, will temporarily increase gas turbine MW output. As the air flow from the LPC decreases, the output from the HPC will also decrease, and pressure vessel pressure will gradually close to maintain the set-point due to the reduced gas mass flow to the HPT. The energy available for generation from the HPT and MW output will decrease.

6.13.2 System Modifications Completed

Seal/Cooling Air Orifices

The V10, V12 and V13 seal/cooling air orifices in the gas turbine were resized early in 1991 to balance the HP turbine 4th stage and LPT inlet and outlet disk temperatures. The V6 seal/cooling-air orifices were resized in Spring 1992, following a testing program with an adjustable orifice, to increase the temperature at the inlet of the 1st stage of the HP turbine. One of the two was further modified for the addition of an external dry-air supply for startups. The HPT inlet seals were modified during the 1993 LPT blade failure outage, requiring the installation of the variable orifice in place of the fixed orifice that did not have the external air supply.

Cold Air Intercept/Bypass Valves

The cold air intercept/bypass valves (called bypass valves for this section) had problems with sticking in the lower bushings early in 1991. The lower bushings were machined to a larger inside diameter twice and the effective length of the bushing was reduced once. A new design bushing and a sleeve for the valve stem were installed during the bed addition outage in Fall 1991. There have been no further problems with valve sticking.

The bypass valve seat was replaced with a new design seat during the LPT blade failure outage in Spring 1993. The old seat was a non-contact slip-fit design. The new design was a positive closure valve seat. This was modified to help reduce air leakage. Testing following the outage showed some improvement in air leakage from this and other modifications performed during the outage.

Lubricating Oil Piping

The lube oil piping to the reduction gear on the gas turbine cracked at one of the four inlet pipe stubs. The cracked pipe was seal welded and a fillet was welded on all four inlet pipes at the stress riser location. The four fixed pipes from the header to the inlet stubs were replaced with flexible hoses to reduce potential future problems due to reduction gear vibration. This modification was completed during the bed addition outage in Fall 1991.

Intercooler Heater

Experiences of repeated problems with the sticking air bypass valves in their bushings have pointed out the value and benefit of maintaining dry air in the turbines during shutdown periods. A heater was added to the intercooler recirculation loop to warm the air flowing through the HPC from natural chimney draft. The warmed air would then flow through the turbines, eliminating condensation problems. The heater was added during the bed addition outage in Fall 1991.

Reduction Gear Vibration Indication

Reduction gear vibration indication had been erratic during early operation. The vibration transducers were found to be bolted to the rounded flange of the gear casing, causing flexing of the transducers and resultant erratic readings. Flat spots were machined into the flange in July 1991 to mount the transducers. This helped the symptoms but did not solve the problem over the load range. Boxes were manufactured for mounting over the transducers to protect them from suspected magnetic fields. It was found that the best arrangement was mounting the transducers on top of the boxes (bolted to the flange) with the transducer mounting arrangement changed from a three-bolt design to a center-stud design. This modification helped with agreement between station indication and portable vibration test equipment indication, but problems remained with the erratic indication. A capacitor was installed in the electronics to filter the high frequency vibration. This provided some minor benefit. A mechanical filter was supplied by ABBC to install between the accelerometers and the boxes. This did not seem to provide any benefit. The grounding system was changed, which greatly improved vibration indication. The mechanical filters were eventually removed, and a high temperature glue was used to provide better mechanical fastening.

LPT Guide Vane Ring

The LPT inlet guide vanes experienced some sticking problems due to combustor ash in the guide vane pivot bushings. The bushings were modified during the bed addition outage in Fall 1991. The modification included enlarged bushings and a new seal rings in the outer guide vane ring. There have not been any additional problems with sticking guide vanes at Tidd since the modification.

The unit experienced five gas turbine trips prior to November 1990, related to failure of the LPT guide vane position feedback loop to NET 90. A redundant feedback signal was installed to prevent false trips and to help locate the problem. The redundant feedback loop did prevent several false trips.

A guide vane linkage sticking problem at another PFBC plant in Europe caused a modification of the linkage ball joints, bushings, and bolt material during the LP turbine blade outage in Spring 1993. Tidd did not experience any problems with the guide vane linkages prior to or after the modification.

HPT Casing Seal Air

An internal HPT casing erosion problem was found at another PFBC plant in Europe in Summer 1991. The modification performed at Tidd to eliminate the erosion involved plugging the internal seal air passage and welding in new seal air connections from the V3 (PCV-P040) and V9 (FCV-P045) seal air valves. The erosion on the Tidd HPT casing was mild enough that no repair to the casing was required. The modification was performed during the LPT blade failure outage in 1993.

HPT Inlet Thermocouples

The HPT inlet thermocouples were modified due to air leakage concerns between the inner and outer coaxial pipes. A second thermocouple was added to the 90-degree elbow in the coaxial pipe and the attachment was changed to a threaded connection to the inner pipe. This modification was performed during the bed addition outage in Fall 1991. Air leakage reduction from this modification was to small to measure.

Intercept Valve Casing

The intercept valve casing attachment to the HPT was modified during the bed addition outage in Fall 1991. The connection originally used two piston seal rings to provide the seal between the air and gas side of the connection. Due to air leakage concerns, the connection was modified to include a bellows assembly. The air leakage reduction from this modification was insignificant.

HPT Outlet Pressure Tap

The HPT outlet pressure tap was discovered to be plugging with combustor ash periodically in Fall 1991. This pressure was important to help trip the turbine if the LPT inlet guide vanes closed without warning due to the feedback loop problems. The tap was modified to provide a continuous supply of purge air from the plant dry air supply piped to the V6 orifice. No more plugging problems were experienced.

Speed Transducers

The zero speed transducers supplied with the gas turbine for the HP and LP shafts had failed by Fall 1991, due to overheating. They were replaced with higher temperature pickups from a different manufacturer. An access hole was cut in the reduction gear cover to provide access to the pickups without removing the entire cover.

Seal Air Valve

The seal air valves V3 (PCV-P040) and V9 (FCV-P045), both experienced sticking problems by Fall 1991. A modification was made to be able to jack each valve open if it stuck on gas turbine startup. This modification was used several times.

HPT Eccentricity Indication

Eccentricity was tested on the gas turbine during the initial startup. A proximeter type probe was permanently installed for the test. Portable test equipment from Europe was used for the testing. Similar test equipment, modified to supply a signal compatible with the plant controls was purchased for installation. It proved to be a much more difficult and expensive job than originally considered to make the electronics compatible. This modification was abandoned.

Control Fluid

The control fluid system had problems with the trip header pressure dropping below the trip limit when the two control fluid pumps switched running/ stand-by condition. A constant air bleed valve was installed in the control fluid pump discharge lines to prevent the stand-by pump from becoming air-locked. This modification did not prevent the trip header pressure from dipping during pump transfer. This was finally solved by slightly lowering the control fluid temperature set-point. The air bleed valves did help prevent startup problems following maintenance when the pumps were inadvertently not filled with oil. This modification was installed in Spring 1992.

LPC Throttle Valve

The LPC throttle valve is a barrel-shaped cylinder that seals the inlet to the LPC while the de-humidifier is operating. The valve was originally designed to be closed by three hydraulic cylinders spaced around the valve. However, it was found to be extremely difficult to keep the cylinders operating in unison to keep the valve from becoming jammed. The hydraulic cylinders were removed and the valve was closed by hand with a chain-fall. The valve did not seal well in the open position during operation, allowing dirt to bypass the air inlet filters. The valve was sealed from the outside with various materials with limited success. The valve V-seal was reversed and a shim installed underneath to give it greater compression during the 1992 gas turbine outage. This provided a good seal with no leakage. The outside of the valve was sealed with RTV after it was decided not to close the valve for gas turbine dehumidification (the intercooler heater was installed).

HPT Outlet Guide Vane Ring

The HPT outlet guide vane ring had a single anti-rotation pin. This pin broke, allowing the ring to rotate at one of the PFBC plants in Europe. A second anti-rotation pin was installed from the outside of the Tidd HPT casing during the 1992 gas turbine outage.

Air Intake Hood

The gas turbine air intake housing was installed with louvers to prevent rain from clogging the intake filters. However, during Winter 1991, the air intake filters were plugged with snow three times which caused the filter by-pass blow-in doors to open. A modification was installed in 1992 to replace the louvers with weather hoods. The weather hoods, which are designed for both rain and snow, did not completely prevent snow from plugging the air intake filters. A thin filter blanket was used to collect the snow until the blanket also plugged. The thin filter blanket was then easily removed to remove the snow.

Low Pressure Turbine Blades

The LPT was opened for inspection in Spring 1992 after cracks were found in the LPT blade roots at a PFBC plant in Europe. Nine blades on the Tidd LPT were found cracked below the platform at the front corner of the suction side of each blade. The cracks were determined to have been caused by a resonant frequency vibration problem that caused high-cycle fatigue. The blades were replaced by ABBC with a new design blade that was to reduce the stresses from resonant frequency vibration. Modifications included trimming the trailing edge, machining a larger radius in the blade root hook fit, shot peening the blade root hook fit and installing dampener buttons between the blades.

In February 1993, the LPT threw two blades. The cracks were determined to have initiated from under the platform at the rear of the suction side of each blade. The blades again were redesigned to eliminate the problem with high-cycle fatigue from resonant frequency vibration. The modifications included trimming the support beam from under the rear suction side of the blade platform, and rounding and blending the rear corner of the suction side of the blade root. After replacement of the entire row of blades, a visual inspection of the inlet and outlet side of the blade roots was performed after approximately every 500 hours of operation.

HPT Shaft Seal

Sealing air for the HPT is supplied by the HPC via the V6 orifices and from seal leakage from the HPC exhaust. Inadequate sealing at the inlet of the HPT allowed leakage of this sealing air to the gas flow through the HPT. This seal was modified during the 1993 LPT blade failure outage. The air leakage rate was reduced by this and other modifications performed during the outage.

LPT Flow Guide Manhole

Visual inspection of the LPT blade airfoils was difficult due to a lack of borescope inspection plugs and the distance from the exhaust flow guide turning vanes. A manhole was cut in the exhaust flow guide to allow access to the blades and guide vanes for visual inspection. This modification was performed during the LPT blade failure outage in 1993.

6.13.3 Operating Experience Overview

In general, very little was required in the way of routine maintenance for the gas turbine. The gas turbine had several chronic problems that were difficult to find and remedy. The first problem noted involved the electronics. The European instrumentation, in general, had compatibility problems with American-made equipment. This caused considerable hours of effort to "debug" erratic indications. Many of these problems were caused by different sensitivities and different grounding philosophies. The second major problem was air leakage from the calculated air flow through the HPC to the LPT exhaust, as determined by air available to the combustor calculations. A test program was conducted after the 1993 LPT blade failure outage to help locate the air leaks. A number of modifications were performed, as noted in the sections above, and some leakage was reduced. The third major problem and the most damaging to gas turbine availability, was the LPT blade design. Several long outages were initiated by cracks in the LPT blade roots. The blade root problem necessitated a series of tests to determine operating ranges that were detrimental to the LPT blades. Once these ranges were identified, unit operation had to be modified to avoid them.

Other problems experienced, that did not require modifications, include LPC stationary guide vane cracking in the first and second stages. ABBC recommended a modification following the discovery of the cracks in December 1993. The guide vane rings were repaired and inspected periodically for any new cracks. A more rigid cleaning schedule was imposed to reduce the risk of further cracking. Another problem was ash plugging of the HPT seal air passages where the seal air thermocouples were located. This caused some operational uncertainty at first, due to high temperatures.

6.13.4 Summary and Conclusion

The gas turbine as installed in Tidd is not usable as a commercial unit. The LPT blade and guide vane ring design inadequacies and air leakage were both major problems for this unit.

6.14 System 317/318 - Gas Turbine Generator and Frequency Converter Systems

6.14.1 System Description

System Purpose and Function

The high-pressure gas turbine of the PFBC Combined-Cycle is coupled to a Motor/Generator for conversion of mechanical power to electrical power at 13.8 KV, three phase. During system startup the motor/generator acts as a motor powered by the frequency converter for variable speed operation. This adjustable speed drive (ASD) allows the high-pressure compressor to increase gas flow slowly for proper warming of the turbine and incremental startup gas flow/pressure through the boiler. Once full speed operation is attained and the motor/generator is synchronized to the grid, the ASD is disconnected and de-energized. The startup process continues as the motor supplies approximately 8MW to stabilize combustion. As the startup progresses the Gas Turbine begins to produce power, causing the motor to automatically switch to generator mode.

General Description

System 317 - Gas Turbine Generator (GTG)

The stator is a "box" design allowing the stator core with windings to rest directly on the foundation, thus ensuring that all static and dynamic forces are transferred directly into the foundation. The GTG has split bearings with replaceable liners.

The stator consists of a laminated steel core with ventilation slots and three-phase diamond coil winding system. The entire core and coil assembly is vacuum pressure impregnated to secure the coils in the slots and cure the coil insulation.

The GTG is a four-pole synchronous machine with a salient pole rotor and solid-pole plates. The rotor has a rigid cast steel body to which forged steel stub shafts are bolted The field windings are single-layer multiple-turn heavy copper with a layer of insulation between turns. Fans mounted on the ends of the rotor provide ventilation for the stator core and windings.

The GTG is enclosed by bolted steel plates providing protection and direction of cooling air flow. The GTG is totally enclosed with air to water heat exchangers to cool the recirculating air

Excitation for synchronous motor and generator operation is supplied from the excitation panel of system 318.

The generator characteristics are as follows:

Speed	1800 RPM
Rated Output Power	22,500 KVA @ 0.8 Power Factor 18,000 KW
Rated Output Current	941 Amperes
Rated Output Voltage	13,800 Volts
Rated Frequency	60 HZ

Exciter, Direct Driven Brushless, Asynchronous

Rated Field Voltage	105 VDC
Rated Field Current	450 Amperes

System 318 - Gas Turbine Starting and Excitation System

System 318 is a variable frequency and voltage three-phase power source used to start the Gas Turbine motor/generator. The system also supplies excitation current for motor/generator voltage control. The variable frequency/voltage portion of the system is used for starting the G.T. motor/generator only. Once full-speed operation is attained and the motor/generator is synchronized to the grid, the frequency converter is disconnected and de-energized. The exciter system, however, is in operation during both startup and synchronized operation of the motor/generator. The exciter supplies field current to the G.T. motor/generator for motor and generator operation. The frequency converter is not designed for dynamic braking of the motor/generator and is not in operation during coast down from 1800 RPM to barring speed (42 RPM).

The system consists of: Transformers 10C and 10D, the frequency converter cabinets Y-1 through Y-5, and the voltage regulator/excitation cabinet F-1. Control of the system is via main control room MCS screens, control panel "B 12" and local control at the Y-1 and Y-2 cabinet. The "frequency converter" defined as equipment between XF-10C & XF 10D is switched into operation by 13.8KV breakers 1C4 and 1C1. The converter is a 12-pulse variable-frequency, three-phase source rated for starting service only.

Key Instrumentation and Controls

The gas turbine generator instrumentation includes RTDs for indication/alarm of cooling air temperature, bearing temperature, lubricating oil temperature and stator winding temperature.

Vibration probes are located on both bearings for vibration indication and alarm. Potential and current transformers are included for protection and control.

The frequency converter system transformers 10C and 10D include instruments for oil liquid level, pressure and temperature. The transformers are also equipped with winding temperature indication/alarm and sudden pressure switches for protection.

The frequency converter can be operated locally or remotely from the Net 90 MCS screens.

The gas turbine generator protection includes generator differential relays, overall differential relays, neutral grounding with ground fault relaying, under-frequency overcurrent relaying, overvoltage relaying, and overfrequency relaying.

Frequency converter protection includes main power supply undervoltage, auxiliary supply undervoltage, thyristor overload, system overcurrent, asymmetry, thyristor fuse protection, power supply voltage monitoring, overspeed, cooling air pressure monitoring, and voltage/frequency comparison.

Exciter protection includes exciter undercurrent, exciter overcurrent, and loss of excitation.

6.14.2 System Modifications Completed

No revisions were required on this system.

6.14.3 Operating Experience Overview

The system has operated exceptionally well, with all control, indication, and alarms functioning as expected.

6.14.4 Summary and Conclusions

The Gas Turbine Generator has operated as designed with adequate capacity for this application. The same is true for the ASD, the acceleration and horsepower required for startup is well within the capacity of the ASD. The excitation control performed as expected, no problems with this system.

6.15 System 328 - Precipitator

6.15.1 System Purpose and Function

The Electrostatic Precipitator (ESP) removes the particulate matter from the flue gas in order to meet the New Source Performance Standards for particulate emissions of 0.03 lb/ million BTU, and a unit opacity not to exceed 20%. The ESP was designed for a removal efficiency of 96.5%, based on an inlet dust loading of approximately 400 #\hr, and a flue gas flow of 275,000 acfm at 350 F.

General Description

The ESP, manufactured by Flakt, Inc. is located downstream of the economizer and is comprised of a single precipitator casing (see Figure 6.15.1). It is approximately 64 feet high; including hoppers and support steel, 39 feet wide and 72 feet long. The ESP has four electrical bus sections (fields) in the direction of the gas flow. The ESP is designed for a removal efficiency of 96.5% with any three fields in service. The fourth field is an installed spare.

Four Transformer Rectifier (T/R) sets, one for each field, provide the power to the ESP. Eight ash hoppers, four parallel to the gas flow and two perpendicular to the gas flow, collect the ash below the fields. The ash is removed from the ash hoppers by means of a vacuum-type ash removal system. The ash hoppers have a valley angle of 55°, and are heat traced to maintain the lower portion of the hoppers above 150 F during unit startup and 300 F when the unit is operating.

The ESP is of the rigid-wire frame "European" design. The 32 feet high precipitator collecting plates use 12 inch spacing in the first two fields and 16 inch spacing in the last two fields. The total collecting surface area is 106,575 square feet. Rapping of the plates and wire frames is accomplished by internal tumbling hammers, which strike anvils attached to the bottom of the frames.

The ESP utilizes an Energy Management System (EMS) to operate the ESP at the lowest input power that will maintain opacity within compliance. The EMS continuously adjusts the power to the T/R sets to maintain the opacity setpoint.

Photo 6.15.1 is a picture of the precipitator sideview and the nitrogen buffer tank located beside it.

Key Instrumentation and Controls

Each precipitator T/R set is controlled from an independent control panel. In addition, the sequencing of the rappers is controlled by means of a microprocessor. The EMS controller monitors the opacity and controls the T/R set controllers and rapper controller.

A nuclear level detector was installed approximately 10 feet above the bottom of each hopper to detect a high hopper level.

System Control Overview

The ESP is energized prior to gas turbine roll. All four fields are energized during normal operation. The EMS operates to minimize the power to the ESP based on the indicated opacity downstream.

6.15.2 System Modifications

In late 1992 a temporary humidification system was tested to address high opacity, which was experienced during startups. In addition, upgraded controls were installed as a test, which automatically adjusted the semipulse ratio, voltage, and current as required to overcome back corona.

6.15.3 Operating Experience Overview

The ESP has met its design guarantees during its initial performance testing. However, opacity exceedances have occurred during the following operational events:

During startup and at low-bed levels, when the flue gas is at reduced temperature.

When operating at very high calcium-to-sulfur molar ratios, which results in an increased quantity of unreacted sorbent in the ash and a lower concentration of SO_3 in the flue gas.

The opacity exceedances were due to the very fine ash particle size, and monitoring problems associated with the installation of the opacity meter. Although opacity exceedances have occurred, the particulate emissions have remained below the permit limits. (Refer to Section 4.3, Environmental Compliance Tests.)

A humidification system was installed at the ESP inlet in 1992. However, not enough heat was available in the flue gas to vaporize the water, and the precipitator inlet screen and nozzles plugged. The opacity exceedances during startup continued to be a problem during the entire operational period. It is believed that these problems were due to the higher resistivity of the ash at a lower gas temperature and when containing a larger amount of unreacted sorbent.

Because the ESP is energized prior to coal fire, the ash tends to adhere to the plates and wires, and must be rapped off with the field de-energized.

Pluggage of the ash hoppers has been a chronic problem at Tidd. The mean particle size of the ash collected by the ESP is about 2 microns, and the angle of repose of the ash has been measured to be 90°.

6.15.4 Summary and Conclusions

Operation of the Electrostatic Precipitator at the Tidd PFBC Demonstration Plant has demonstrated two important features:

The ability of an ESP to successfully collect the high-resistivity and very fine (mean particle size less than 2 microns) ash from the PFBC process.

The viability of 16 inch plate spacing in this application as opposed to the norm of 12 inch plate spacing.

The high opacity during start up has been an ongoing issue with the ESP, however, it is believed that if this were an issue with a commercial plant, a humidification system or SO_3 injection system could be installed to improve ESP performance during start up.

6.16 System 327 - Economizer

6.16.1 System Description

System Purpose and Function

The purpose of the economizer is to increase the thermal efficiency of the PFBC cycle by recovering heat that would otherwise be lost through the stack. The function of the economizer is to transfer heat from the gas turbine exhaust gas to the boiler feedwater. This serves to preheat the feedwater while cooling the gas prior to admission to the precipitator.

General Description

The economizer is expected to receive 733,000 pounds per hour of gas from the LP (low pressure) gas turbine exhaust and reduce the gas exhaust temperature from 782 F to 352 F, while pre-heating 426,000 pounds per hour of feedwater from 299 F to 485 F.

The economizer is arranged with the gas flowing horizontally across vertical in-line tubes with spiral-wound extended surface fins. The gas-side enclosure is a carbon steel casing with internal insulation and lining.

There are a total of 840 tubes arranged 30 deep by 28 wide in ten tube banks. The sequence of water flow through the tube banks is counter to the flow of gas over the tube banks. Each tube bank consists of an eight inch upper header, an eight inch lower header and 84 tubes arranged three rows deep by 28 rows wide. The tubes are all two inch O.D. by 0.180 inch thick min. wall with 0.075 inch thick by 3/4 inch high spiral-wound fins spaced four per inch.

Water enters the economizer at the upper header of the last (10th) tube bank (in the direction of gas flow) and exits at the upper header of the first tube bank. Water flows downward through the even- numbered banks and upward through the odd-numbered banks. Four inch diameter jumper tubes pass the flow between the headers of adjacent tube banks. There are four jumper tubes (spaced perpendicular to the gas flow) per tube bank interconnection.

The upper and lower headers of the tube banks are located inside the casing; thus the tubes do not penetrate the casing. Baffle plates are incorporated to prevent the gas from bypassing above the upper headers and below the lower headers.

All of the jumper tubes penetrate the casing. The upper ones are fixed to the casing, whereas the bottom penetrations incorporated expansion joints which are packed with insulation. This allows differential thermal expansion between the tube banks and the casing.

The economizer is 22 feet 8 inches long by 10 feet 6½ inches deep by 23 feet 11 inches tall (as measured to the outside of the casing. The casing is fabricated from 3/16 inches thick carbon steel with 3 inches of internal insulation and a 16 gauge carbon steel liner. The casing was designed for a continuous pressure rating of ±25 in. w.g. Transient pressure conditions of ±35 in. w.g. were also considered.

A schematic of the original design is shown in Figure 6.16.1.

Photo 6.16.1 is a picture of the economizer showing the sootblower platforms and sootblowers installed along side of the economizer. Also note the secondary ash lines that discharge into the economizer outlet duct.

Key Instrumentation and Controls

There are no controls directly on the economizer. Key instrumentation includes gas side differential pressure alarm and gas inlet and outlet temperature. Water-side instrumentation is included within the scope of the feedwater system.

6.16.2 System Modifications

The major modification to the economizer was the addition of eight air-powered soot blowers which were required to remove accumulated ash from the fin-tubed economizer surfaces. Four soot blowers were added in Fall 1991 and four more were added in 1992.

Anti-vibration bars were installed between economizer tubes to preclude gas flow induced vibration.

A large (12 inch) drain line was installed with a loop seal from the gas side of the economizer to prevent the gas side from flooding in case of a large tube leak in the economizer.

The vent and drain piping external to the economizer was heat traced and insulated for freeze protection.

Due to a fabrication error, the economizer did not include seals between the casing and the lower return bends of the economizer. These bends were enclosed in metal boxes attached to the bottom of the casing to seal the gas side from atmospheric pressure.

A schematic of the final economizer configuration is shown in Figure 6.16.2.

6.16.3 Operating Experience Overview

The economizer experienced gas-side fouling due to ash particles collecting between the fins on the tubes. In August 1991, the economizer experienced a large feedwater leak which is believed to have been caused by vibration of the tubes due to high gas velocity which, in turn, was caused by ash accumulation on the tubes. Following this event, four soot blowers and anti-vibration bars were installed in the economizer to prevent future occurrences. The economizer fouling was greatly reduced, but not eliminated entirely. Therefore, four additional soot blowers were installed in 1992. Since installation of the eight soot blowers, the unit has performed better but ash deposition has not been eliminated entirely.

The economizer performance following modification remained below design, resulting in higher exit gas temperature and lower final feedwater temperature. This off-design performance impacted steam flow by approximately 10,000 pounds per hour and reduced steam turbine generator output by approximately 1.3 MW at full load.

6.16.4 Summary and Conclusions

The original design was based on the prediction that ash would not foul the economizer. However, this design premise proved erroneous, the finned tubes formed a trap in which ash would collect and result in high gas velocities, tube vibration and ultimately, failure of the tube-to-header connections. Economizer performance remains below design despite the addition of eight soot blowers.

6.17 System 340 - Gas Turbine Lube Oil

6.17.1 System Description

System Purpose and Function

The function of the gas turbine generator lubricating oil system is to supply oil at the 122 F temperature and 29 psig to lubricate and cool the turbine and generator bearings and reduction gear. The lubricating oil system has an evacuation system which keeps all bearing casings under a slight vacuum. This causes a sealing air flow across the bearing shaft seals, preventing oil leakage. Additionally, the system has in-line oil filters to remove particulates which could result in damage to the bearings.

The gas turbine lube oil system interfaces with the following plant systems:

Provides lube oil to all of the gas turbine and generator shaft bearings.

Obtains cooling water from the LP service water system.

General Description

The lubricating oil system for the gas turbine consists of a skid-mounted oil unit and associated piping. The skid-mounted oil unit consists of a 1799-gallon oil tank, two full-flow A.C. oil pumps, one 90% flow D.C. emergency oil pump, two full-flow oil coolers, two full-flow oil filters, and an evacuation system. The evacuation system consists of two oil vapor fans, mounted on the oil tank, and a flame arrester.

The lubricating oil flow requirements for startup, shutdown, and emergency operation are provided by two A.C. motor driven main oil pumps and one D.C. emergency bearing oil pump. During normal operation either of the main oil pumps supplies oil to the bearings and reduction gear. The stand-by main oil pump starts automatically upon loss of power of the operating main oil pump or a drop in pump discharge pressure below 41 psig. The emergency oil pump activates upon failure of the stand-by main oil pump or upon decreasing lubricating oil pump discharge pressure below 41 psig for two seconds.

The oil leaving the main oil pump passes through both oil coolers, which are in series. Under normal operating conditions low-pressure service water will be valved to only one cooler. A temperature control valve bypasses oil around the coolers to maintain oil to the bearings at a temperature of 122 F.

The oil from the coolers passes through one of two oil filters operating in parallel and then on to the bearings and reduction gear. This oil returns to the oil tank by gravity into a separate compartment in the lube oil tank.

This compartment is designed to trap any contaminants coming with the return oil. From this compartment, the oil flows over the top of one of the walls and further onto a gently sloping plate where it is spread out in a thin, wide flow to enhance the deaeration of the oil.

Key Instrumentation and Controls

Lube oil temperature will provide a combustor trip on temperature above 140 F. Lube oil pump discharge pressure provides an auto start of the stand-by AC and DC pump on low pressure, and a gas turbine trip on extreme low pressure.

6.17.2 System Modifications Completed

The only modification to this system was the installation of a demister in the vapor extractor exhaust piping during the 1991 outage.

6.17.3 Operating Experience Overview

The gas turbine lube oil system has functioned reliably with very few operational problems.

6.17.4 Summary and Conclusions

The gas turbine lube oil system design used at Tidd is sufficiently reliable for use in a commercial P200 PFBC facility.

6.18 System 350 - Gas Turbine Control Fluid

6.18.1 System Description

System Purpose and Function

The function of the gas turbine control fluid system is to supply control fluid at a proper temperature and pressure to the servomotors of the combustion air combined intercept/ bypass valves, hot-gas intercept valves, low-pressure compressor inlet throttle valve, low-pressure compressor inlet guide vanes, and the low-pressure turbine variable inlet guide vanes. Additionally, the system cleanses the control fluid of particulates and acidic formations which could damage the hydraulic control components.

The gas turbine control fluid system interfaces with the following plant systems:

Provides control fluid to the GT combined intercept and bypass valve assembly.

Provides control fluid to the LPT inlet guide vane assembly, LPC inlet guide vane assembly, and the LPC inlet throttle valve.

Obtains cooling water from the LP service water system.

General Description

The control fluid system consists of three circuits - the main circuit in which control fluid is pumped from a storage tank to the servomotors of the controlled equipment and returned to the storage tank, a cooling circuit, and a regeneration circuit. The equipment for all three circuits is mounted on a single skid. The main control fluid circuit consists of the control fluid storage tank, two 100% capacity supply pumps, a pressure accumulator, and a piping system for delivery and return of the control fluid. The control fluid cooling circuit equipment consists of two 100% capacity pumps, two 100% capacity coolers, and associated piping for delivery and return to the storage tank. The coolers are connected in series on the control fluid side, and in parallel on the cooling water side. The control fluid regeneration circuit consists of one pump, one regeneration filter, and one fine filter with associated piping.

Under normal operating conditions, suction to the in-service control fluid pump is taken from the bottom of the storage tank. The control fluid discharging from the pump passes through a check valve, the in-service filter, and then to the servomotors of the controlled equipment. The control fluid drains from the servomotors return to the storage tank. The control fluid temperature is controlled by a manual temperature control valve on the water inlet side of the coolers. Temperature is maintained at 113 F. System supply pressure is maintained constant at 725 psig by the supply pumps which are of the positive displacement type. A piston-type pressure accumulator stabilizes the pressure in the event of flow fluctuations or interruption of the pump motor power supply. Overpressure protection in the supply header is provided by a relief valve, which bypasses control fluid supply to the tank.

The in-service control fluid cooler pump takes suction from the tank and supplies 7.4 gpm of control fluid to the in-service cooler. Each of the two control fluid cooler pumps is coupled to the same shaft as a control fluid supply pump, so that one AC motor drives each control fluid supply/control fluid cooler pump combination.

Control fluid requirements for startup, normal operation, shutdown, and emergency operation is supplied by one set of control fluid supply/control fluid cooler pumps. The redundant set of pumps on stand-by are activated by decreasing supply pressure, which can be caused by pump failure, motor failure, leakage, or a plugged filter.

A small quantity of control fluid (0.8 gpm) is pumped through the regeneration circuit equipment. Suction is taken from the bottom of the storage tank, and the regenerated fluid is returned to the storage tank.

Key Instrumentation and Controls

Control fluid header pressure is used to start the changeover sequence to the standby control fluid pump. Control fluid supply pressure to the intercept valves initiates a gas turbine trip due to low pressure. Control fluid reservoir temperature is used to control the cooling water control valve to the coolers.

6.18.2 System Modifications Completed

The control fluid system had problems with the trip header pressure dropping below the trip limit when the two control fluid pumps switched operating conditions. A constant air bleed valve was installed in the control fluid pump discharge lines to prevent the stand-by pump from becoming air-locked. This modification did not prevent the trip header pressure from dipping during pump transfer. This was finally solved by lowering the control fluid temperature setpoint slightly. The air bleed valves did help following maintenance when the pumps were inadvertently not filled with oil. This modification was installed in Spring 1992.

6.18.3 Operating Experience Overview

The GT control fluid system has functioned reliably with very few operational problems.

6.18.4 Summary and Conclusions

The GT control fluid system design used at Tidd is sufficiently reliable for use in a commercial P200 PFBC facility.

6.19 System 500 - Network-90 Control System

6.19.1 System Description

System Purpose and Function

The Tidd PFBC Combined Cycle utilizes a distributed programmable logic system called Network-90. It was manufactured by the Bailey Controls Company in Wickliffe, Ohio. The purpose of the system is to collect data from the plant such as pressures, temperatures, flows, analog and digital states, etc., and then process it for control and coordination of the PFBC systems and most balance-of-plant systems. Alarm supervision is provided to warn the operator of abnormal conditions. Network-90 also performs the trip and override protection functions to prevent unsafe process conditions. Additionally, the system provides the operator interface for these systems. Process flow diagrams with real-time data are displayed on touch-sensitive CRT screen displays. Operator actions and commands are implemented via a keyboard. Trends, reports, lists, and data storage are also provided by Network-90.

The control system interfaces with virtually all other systems to form the integrated PFBC cycle. Power distribution switchgear is the only equipment not controlled or monitored by Network-90.

General Description

The original Network-90 control system is shown in the simplified drawing on figure 6.19.1.

The heart of the control system is the Process Control Unit or "PCU". All inputs and outputs are terminated in the PCU cabinets. The cabinet houses equipment to convert inputs to digital information and convert digital information to outputs. The conversion equipment or "slaves" are connected to master modules. The master modules are central processing units that store and execute the control program. The primary master modules are called multifunction processors or "MFP". Each PCU can hold three MFPs. The MFPs within a PCU communicate with each other via a Module Bus.

Multiple PCUs communicate across a redundant twisted pair of cables called the Plant Loop. Each PCU is equipped with loop interface equipment to allow the Module Bus to communicate with the Plant Loop and consequently other PCUs. PCUs report to the Plant Loop by the exception report method. Data will only be updated on the loop if the maximum time has elapsed (usually 1 minute), the maximum percentage change has been reached (usually 1% of scale), or an alarm state has been recognized.

Each PCU uses three different voltage power supply sets. The 5-volt d.c. Module Power Supplies are dedicated to master modules and slaves. Most field-mounted instruments are powered by 24-volt d.c. Analog Power Supplies and 125-volt d.c. power supplies are used to wet all input contacts.

Operator interface is provided by the Management Command System consoles or "MCS". The MCS is connected to the loop via loop interface equipment. A disk drive stores the process flow diagram screens and the alarm database. Process data storage is also available. Each MCS can support up to four high-resolution touch-sensitive CRT screens, four printers, four keyboards, and one reel-to-reel tape back up. A maximum of 10,000 data base points are configurable. Alarm Annunciator Display Panels or "ADS" panels were provided on each console. Operator commands, reports, logs, and trends are generated from the MCS.

Operator interface screens were designed in four groups. "Mimic" screens are process flow diagrams with real-time data and active equipment symbols for "pop-up" control stations. "PAC" screens are horizontal lists of process variable values with the functional name and setpoint. This screen also includes control stations and trends. "Perm" screens list all system and equipment permissives and identify the state needed for operation and present status. Alarm screens list pertinent information about an abnormal condition. This message is also printed. Typical Gas Turbine Mimic screens are shown on Figures 6.19.3 through 6.19.7.

Computer Interface Units or "CIUs" allow non-Network-90 computers to interface with the Plant Loop. Engineering Workstation personal computers communicate with the plant loop through the CIU. Workstations are used to monitor and tune values on line. Control programs are created off line and loaded in the MFPs using a workstation.

Thirty-two panel-mounted Digital Control Stations were supplied with the system. They allow the operator to have direct control of the output to equipment. These devices were reserved for critical final control elements used in startup, shutdown and emergency cooling functions. Each MFP can support eight Digital Control Stations in a daisy chain configuration.

Uninterruptable power to the system is supplied by the plant 250-volt d.c. batteries through three static switch inverters. Back-up power is supplied from plant lighting. All power sources are isolated by transformers. A dedicated ground grid was installed during construction.

The original system included the following equipment:

8 Process Control Units which include 16 MFPs and 23 relay/ termination cabinets

2 MCS consoles which include 2 high-resolution touch-sensitive CRT screens and 2 keyboards each.

2 printers

1 engineering workstation with printer

2 computer interface units

Photo 6.19.1 is a picture of the control room showing the operator interface MCS units.

6.19.2 System Modifications

The final Network-90 control system is shown in the simplified drawing on figure 6.19.2.

The original master modules were to be redundant Multifunction Controllers or "MFC". In the event that the main module would fail, the backup would immediately take over. Before the system left the factory floor it was discovered that 20 seconds was needed for the backup to take over. During this time, all variables would hold their last good values. This was determined to be unacceptable. The MFCs were upgrade to MFPs which required only 6 seconds for the back up module to take control.

System checkout was designed for two groups to be developing the control program and performing simulation tests while two groups test and verify inputs and outputs. Three engineering workstations, two management command consoles and one additional CIU were added. This equipment became a permanent part of the system.

Availability of the two original MCSs was unacceptable. One additional MCS with two screens and two keyboards was added to the control room. The third MCS is used by operation and management personnel for monitoring. It is used as a backup in case one of the original two units fail. One additional CRT screen was installed on the original two MCS consoles.

Four Computer Interface Units were added for data acquisition. Hot Gas Clean Up added one PCU with two MFPs and two relay/ termination cabinets and an Operator Interface System, or "OIS". Three MFPs were added to accommodate expanding logic programs. Ground detection alarm circuits with test switches were added to all 125-volt d.c. power supplies. Special double-wide relays were added so that critical control valves could be controlled from two different PCUs.

6.19.3 Operating Experience Overview

Overall, the Network-90 control system has operated satisfactorily. Size and complexity was increased by 75% with few problems. PCU reliability has been good. All problems were eventually resolved.

The biggest shortfall of the system is data storage. Trend data can be stored in the MCSs for up to three days. Thereafter it is dumped to reel-to-reel storage tape. The storage tape was not user friendly, and required the use of a MCS to retrieve data. Trend data is also stored in the control program before being reported to the Plant Loop. The resolution was poor and would not allow adequate interpretation of transient responses. A multi-tasking Encore computer to support a "Plant Operations and Performance System called "POPS" was added for the purpose of trending and data storage. The POPS system accesses data directly from the plant loop through two Computer Interface Units. Trend data storage in the control program is not needed by POPS. Network-90 Trends were reduced to a minimum and the original reel-to-reel tape drive is now used strictly for environmental data storage.

Power supplies have had the worst failure rate of all Network-90 equipment. During the first six months following power-up, 25% of the Module Power Supplies failed. Since then the failure rates dropped to less than 10% per year. Most recent failures have been heat/dirt-related. The PCUs need to be cleaned frequently to prevent dirt from reducing cooling capacities.

During initial checkout and startup the Management Command System would crash repeatedly. The units would then need reset, which took 17 minutes. A control room humidifier was added to reduce the static electricity. Bailey Controls finally added anti-static kits to each MCS. This reduced the number of MCS crashes to an acceptable level.

MCS software was continually being upgraded by Bailey. The system was purchased with Rev K.1 software. Tidd then became the test site for Rev L.4. Several more upgrades were installed until we finally settled on Rev Q1.1. MCS software revisions were difficult and time-consuming to load, and usually caused other system problems. Software revisions sometimes required firmware changes in other equipment. In one case, the firmware revision was not compatible with the rest of the system, and the upgrade was scrapped.

Network-90 controls are sensitive to RF. Radio transmissions in close proximity to MCS consoles or PCU cabinets cause abnormal operations. Control rooms were posted: "NO RADIOS". Control room radios were replaced with remote units and the transmitters were moved to a different location.

The computer interface units ("CIUs") have been a source of system problems. A defective CIU can cause the plant loop to stop communicating. MCS screens may display incorrect or old data. This is confusing to the operators. Poor decisions can be made as a result. Extreme caution must be taken when starting equipment connected to the plant loop.

The panel-mounted digital control stations were removed from the system and abandoned in place. On several occasions this equipment caused erratic and uncontrollable operation of critical devices. The exact cause was never found. It is suspected to be in the card edge connectors and PCU daisy chain cable connectors. MCS operation is adequate now only because the operators have gained experience.

Operator interface screens received a generally favorable acceptance by operations. The screen of choice became the "Mimic". The most useful screens developed into the ones with the most information on them. A most recent Gas Turbine Mimic screen is shown in figure 6.19.7.

The capacity of the system does have its limits. Overloading the loop has been a concern. Loop interface equipment startup causes a surge in loop data traffic. If the traffic reaches some unknown level, the loop will "crash" and the operators will be left with no ability to interface with the system.

6.19.4 Summary and Conclusions

The Bailey Network-90 control system has served the PFBC combined cycle very well. Its flexibility and ease of control and protection logic programming has been an asset. After earlier failures the equipment reliability has been acceptable for a demonstration unit. The system must be kept clean. Future installations should include a more dirt-free environment with reliable heating, venting, and air conditioning equipment. Software and firmware compatibility must be maintained. Improved loop- communications equipment is now available.

6.20 System 741 - Boiler Ventilation

6.20.1 System Description

System Purpose and Function

The boiler ventilation system serves multiple functions as follows:

The system filters and collects the particulate matter from the depressurization air streams from the bed ash and sorbent injection lockhoppers and the oxygen analyzer slipstream vent line clean-out gas/air stream before emitting these flows to atmosphere.

The system, in conjunction with the process air system provides a closed combustion gas circulation loop for bed cool down after a gas turbine trip.

The system, in conjunction with the process air system provides open-loop cooling of the boiler setting.

The system, in conjunction with the process air system provides for warmup of the combustor and boiler settings during unit startups prior to gas turbine roll.

The system serves to provide ventilation to and dust evacuation from the boiler setting for improved personnel atmosphere conditions, during unit outages.

The boiler ventilation system interfaces with the following systems:

The boiler enclosure, from which it evacuates air and/or combustion gases when the combustor is depressurized.

The sorbent injection system, from which it evacuates the sorbent injection vessel depressurization flows.

The bed ash reinjection system, from which it evacuates the ash lockhopper depressurization flows.

The oxygen analyzer system, from which it evacuates the gas/air flow when the slipstream vent lines are cleaned with high-velocity air flow.

The process air system, to which it delivers air and/or combustion gases.

The compressed air system, which supplies the normal bag filter back-pulse medium.

The low pressure nitrogen system which supplies the bag filter back-pulse medium when in gas circulation mode following a gas turbine trip.

The closed cycle cooling system which supplies cooling/warming water to the boiler ventilation cooler.

General Description

Figure 6.20.1 depicts the original configuration of the boiler ventilation system, whereas Figure 6.20.2 depicts the system configuration at the end of the original three-year test program. All of the major equipment in this system is located outside atop the combustor building roof.

Normal Operation Mode

The boiler ventilation system is in continuous operation whenever the unit is in service, providing a means of cleaning particulates from dusty intermittent PFBC process vent streams. The system fan maintains a vacuum on the vent collection header and a weighted check valve, located on the vent collection header, allows a continuous stream of air to be drawn from the combustor building basement. When venting occurs, the amount of air drawn from the basement decreases; however, air continues to be drawn in thereby diluting the vent stream. A separate weighted check valve is used for overpressure relief in the event that the flow streams from the venting systems overwhelm the evacuation capability of the system. The system has sufficient capacity to handle simultaneous venting from both a sorbent injection vessel and a bed ash lockhopper. The air/diluted vent flow is drawn from the vent collection header through a bag filter for particulate collection through the boiler ventilation fan and exhausted to atmosphere. Dust collected in the bag filter is pulse cleaned from the filter bags with compressed air. The dust particles collect in the bag filter hopper and fall by gravity into a collection hopper. The collection hopper is periodically vacuumed out.

Combustor Warming Mode

This mode of operation is used to warm the combustor when the combustor vessel is depressurized prior to gas turbine roll. Air is drawn from the boiler enclosure through the boiler ventilation cooler, the bag filter, and the system fan to the process air system which returns the air to the boiler via the combustor vessel. Since the "cooling" water to the system heat exchanger is relatively hot water from the closed cycle cooling system, the heat exchanger warms the air passing through it.

Air Cooling Mode

In this mode of operation, the system is used to evacuate air from the boiler. Warm air is evacuated from the bed via the heat exchanger, bag filter and fan, and discharged to atmosphere. Cooling provided by the heat exchanger serves to protect the filter bags from high temperatures.

Gas Circulation Mode

This mode of operation is used to cool the bed material after a gas turbine trip with the combustor vessel depressurized. The system draws the hot gases from the boiler freeboard, cools them in the heat exchanger, cleans them of particulate matter in the bag filter, and delivers them to the process air system which returns the gases to the boiler. This mode is used after a gas turbine trip when the slumped bed temperature is in excess of 1176 F. The recirculation of combustion products and other inert gases by operation of the boiler ventilation and process air system achieves the needed cooling without admitting fresh air. The bag filter hopper is large enough to store the dust collected until the slumped bed is sufficiently cool to transfer operation to the Air Cooling Mode.

Boiler Ventilation/ Dust Evacuation Mode

This mode of operation is used when the combustor vessel is depressurized and open for personnel access, in order to provide ventilation of and airborne dust removal from the boiler enclosure. The operation is the same as in the Air Cooling Mode (See above); however, the process air system is not in service. The evacuated air is drawn into the combustor vessel through open manways, and into the boiler via the normal air passages, as well as through any open boiler man doors. Since no heating or cooling is required, the water supplies to and from the heat exchanger are isolated.

Key Instrumentation and Controls

Differential pressure measurement across the bag filter is used to initiate the bag cleaning sequence on high measured differential.

Pressure measurement at the fan inlet is used to trip the fan on high vacuum and high positive pressure. This measurement is also used to run back the process air system flow demand (slumped bed differential pressure based flow) in the Gas Circulation mode on high vacuum.

Temperature measurement at the bag filter inlet shuts down the fan on high temperature to protect the filter bags.

Temperature measurement on the line from the boiler upstream of the first isolation provides high-temperature alarm if piping material temperature limits are approached.

System Control Overview

The only control in the system is accomplished through fixed positioning of the boiler ventilation fan inlet guide vanes. In all modes, the guide vanes ramp open at system startup to a fixed open position which varies depending on the mode. In Gas Circulation Mode, the demanded fixed open position varies dependent on slumped bed height.

Photo 6.20.1 is a picture of the boiler ventilation fan, baghouse, and cooler located on the combustor building roof.

6.20.2 System Modifications Completed

The operators on the system's two combustor isolation valves were replaced with larger size operators due to problems experienced with closing of the valves.

A blind flanged connection was added on the vent line from the bed ash lockhoppers. This connection is used to connect the temporary hose used to evacuate the ash/sand transport air when filling the bed ash reinjection vessels.

The atmospheric vent line on the collection hopper, into which the bag filter discharges, was closed off, causing the hopper to run under vacuum. Prior to this modification, air was being drawn up into the bag filter and fluidizing the collected dust particles in the filter hopper. This inhibited hopper draining.

The oxygen analyzer gas slipstream vent lines to atmosphere were experiencing plugging, so high-velocity air purging was employed to periodically clean out the vent lines. This line cleaning resulted in excessive dust emissions to atmosphere. In order to preclude such fugitive dust emissions, the seven oxygen analyzer vent lines were tied into a common vent line that normally discharged to atmosphere, but was connected to a line to the boiler ventilation system vent collection header for dust evacuation during line cleaning. A valve in that line was then opened during the line cleaning process to collect the dust in the air/gas before exiting to atmosphere. Normal venting continued directly to atmosphere, since the oxygen analyzer system would have been adversely impacted by the vacuum induced on the slipstream vent lines by the boiler ventilation system.

6.20.3 Operating Experience Overview

The boiler ventilation system has functioned very reliably with very few operational problems.

6.20.4 Summary and Conclusions

The boiler ventilation system design used at Tidd is sufficiently reliable for use in a commercial PFBC facility.

6.21 System 755 - Nitrogen Gas

6.21.1 System Description

System Purpose and Function

Nitrogen is required to support the PFBC process in several ways:

It is required to inert the fluidized bed of coal and sorbent upon a gas turbine trip (when fluidizing air flow was interrupted) to prevent the bed from sintering into one massive clinker.

It is injected into the bed ash reinjection system L-valves and reinjection vessels during load reductions to prevent sinter formation in the reinjection vessels and into the L-valves if no load increase occurred for three hours.

It is used to clean and purge the bag filter in the boiler ventilation system during gas recirculation.

Nitrogen is used as a backup to splitting air supply for gas turbine trips, loss of splitting air events, and coal paste pump reversing.

Nitrogen is used to pressurize two closed cycle cooling water systems, purge instrument lines, and blow out fuel injection lines when necessary.

Nitrogen is used during extended outages to blanket the coal hoppers as a fire protection measure and boiler and economizer water and steam circuits for corrosion protection.

A separate high-pressure nitrogen system was installed to inject nitrogen into the feedwater injection tank to displace water from the tank during a 45- to 120-second period in the event of loss of all power (black plant) or simultaneous loss of all feed pumps. This was to protect the boiler tubes from overheating until the boiler circulation pump (powered by a diesel generator) could be placed in service.

General Description

The nitrogen system is shown on the simplified schematic diagram in Figure 6.21.1. The original and final system configurations are the same. The only significant change made to the system was to replace the vaporizer on the liquid system with another of triple the original capacity. Two independent nitrogen systems were installed, a high-pressure gaseous system and a medium-pressure cryogenic liquid system. The primary elements in the systems included seven high-pressure storage cylinders, a liquid nitrogen storage tank, vaporizer, fill pump, buffer tank, and piping and valves. The capacity of the liquid system is 3000 gallons or 282,000 standard cubic feet. The buffer tank volume is 1,925 cubic feet. The total capacity of the high-pressure storage system is 37,400 standard cubic feet at 3,300 psig.

Key Instrumentation and Controls

The high-pressure nitrogen system is equipped with a low-pressure alarm. The medium-pressure system is equipped with level alarms on the liquid tank, and high- and low-pressure alarms on the buffer tank. A temperature control valve is installed between the vaporizer and the buffer tank, which closed if the nitrogen temperature falls below -40 F. Various pressure-regulating valves are also installed in the system. The buffer tank is equipped with a 5kw heater to maintain the stored nitrogen at 104 F. The reason for this is to prevent the nitrogen temperature from dropping below -40 F during rapid depressurization since that is the buffer tank minimum design temperature. The high-pressure storage cylinders are heat traced and insulated to maintain a minimum temperature of 60 F, which ensures that the pressure in the tanks does not fall below the minimum required.

System Control Overview

During either blackout condition or loss of feed pumps, control valves at the injection tank open automatically and admit nitrogen from the high-pressure nitrogen storage to the injection tank. A pressure controller on the injection tank modulates a control valve to control injection tank pressure to 1850 psig for a two-minute injection period. After the feedwater injection is completed, the control valves close.

During injection of the nitrogen, the storage tank pressure decreases to approximately 1900 psig and the nitrogen temperature drops approximately 80 F. However, due to the heat stored in the piping between the storage tank and injection tank, the temperature of the nitrogen entering the injection tank is no lower than 40 F.

Since the high-pressure nitrogen storage tanks have only enough capacity for one feedwater injection, it is necessary to refill the storage tanks following such an event.

Liquid nitrogen was stored in a double-walled tank with the space between the tank walls insulated and maintained under vacuum to minimize heat leakage into the inner container. Liquid nitrogen drawn from the tank is passed through a vaporizer which absorbs heat from the surroundings to convert the liquid nitrogen into gaseous nitrogen. The system is equipped with an economizer circuit which automatically withdraws gaseous nitrogen from the tank during periods of low nitrogen demand before liquid nitrogen is withdrawn. This circuit provides the system with gas that would otherwise be vented to atmosphere. The system was also equipped with a pressurizing circuit which automatically controls tank pressure. When tank pressure falls to a predetermined setpoint, liquid nitrogen automatically flows from the bottom of the tank through a pressure building coil where it is changed into gas. The gas then flows into the top of the tank to rebuild pressure. Pressure relief devices protect both the inner and outer vessels from over-pressure.

When the nitrogen supply in the liquid tank becomes depleted, it is necessary to refill the tank from a liquid nitrogen tank truck. Since the maximum pressure of the nitrogen tank truck is 300 psig, it is necessary to use a fill pump to refill the storage tank which is maintained at 350 psig. The pump is manually started and stopped from a local control switch. The liquid nitrogen tank is filled from top and bottom inlet lines.

In the event that an extreme demand of nitrogen and the vaporizer outlet temperature drops to -40 F, a temperature control valve closes to protect the downstream equipment. If the temperature control valve fails, an orifice downstream of the control valve limits the flow to maintain a temperature above -40 F.

As nitrogen is withdrawn from the buffer tank, the pressure decreases and a pressure control valve in the supply line from the liquid nitrogen supply system reacts to a decrease in buffer tank pressure, opens, and admits nitrogen to the buffer tank until the pressure increases to the set point of 325 psig.

6.21.2 System Modifications

The only significant modification to the nitrogen systems was to replace the original vaporizer with one of triple the capacity (33,000 versus 10,000 standard cubic feet per hour). The original vaporizer proved to be inadequate during periods of high system demand and would cause the buffer tank pressure to drop below 280 psig during load decreases. Under load reductions, the bed ash reinjection system nitrogen consumption proved higher than expected.

A removable spool piece was added to the nitrogen supply line from the buffer tank for safety isolation during plant outages.

6.21.3 Operating Experience Overview

The nitrogen systems performed their functions very well. Although the high-pressure system was never called into duty for a loss-of-feedwater event, it was successfully demonstrated during a test of the boiler injection system on May 18, 1991. The high-pressure cylinders required topping off about twice a month. The tank pressure dropped below the minimum during outages when the system was isolated from the injection tank and the line to the injection tank was vented.

The liquid system also functioned as designed following enlargement of the vaporizer. The liquid system required refilling about three times a month.

6.21.4 Summary and Conclusions

The nitrogen systems were silent support systems which did not receive much attention, but did their jobs when necessary. The systems required only one modification from the initial design.

6.22 System 758 - Process Air

6.22.1 System Description

System Purpose and Function

The process air system serves multiple functions as follows:

The system provides a supply of relatively cool air (<200 F) at a pressure slightly more than the PFBC process for direct contact bed ash cooling in the boiler bottom hoppers, pressurization of the bed ash and APF ash lockhoppers, sealing of boiler ventilation system and bed ash removal system isolation valves, and purging/cooling of the bed preheater burners.

The system provides for initial pressurization of the combustor to approximately seven psig during unit start ups.

The system, in conjunction with the boiler ventilation system, provides a closed combustion gas recirculation loop with cooling for bed cool down after a gas turbine trip.

The system, in conjunction with the boiler ventilation system, provides open-loop cooling of the boiler.

The system, in conjunction with the boiler ventilation system, provides for initial warm-up of the combustor and boiler.

The process air system interfaces with the following systems:

The boiler ventilation system, from which it receives cool combustion gases.

The bed preheating oil system, to which it delivers cool air for burner cooling and purge.

The bed ash removal system, to which it delivers cool air for lockhopper pressurization and valve sealing.

The combustor vessel and boiler, to which it supplies air for initial pressurization of the combustor vessel.

The combustor vessel, to which it provides warm air for initial warming of the combustor.

The boiler bottom, from which it draws air, cools it, then raises it in pressure for delivery back to the boiler bottom for direct-contact bed ash cooling.

The APF system, to which it delivers cool air for ash lockhopper pressurization.

The low-pressure service water system which supplies cooling water to the process air cooler.

The boiler ventilation system, to which it provides cool pressurized air for valve sealing.

General Description

Figure 6.22.1 depicts the original configuration of the process air system, whereas Figure 6.22.2 depicts the system configuration at the end of the original three-year test program.

Normal Operation Mode

The process air system is in the "Normal Operation" mode when the unit is in service. In this mode the combustor vessel is at the normal PFBC process operating pressure. The process air system provides relatively cool air at a pressure slightly more than that of the PFBC process for bed ash cooling, bed ash lockhopper pressurizing, bed preheater burner cooling/ purge, and boiler ventilation system isolation valve sealing. Air is drawn off the boiler windbox to the process air cooler where it is cooled from approximately 600 F to less than 200 F. It is then boosted in pressure by the process air fan for delivery to the consuming systems.

Combustor Pressurization Mode

Two startup fans arranged in series draw suction from the combustor building, boost the air in pressure and deliver it to the combustor vessel for initial pressurization of the combustor and boiler. This mode of operation results in a gradual rise in pressure in the pressure vessel until a pressure of approximately seven psig is attained. At that point the gas turbine air and gas bypass/ isolation valves are aligned to the combustor vessel after which the startup fans are tripped.

Combustor Warming Mode

This mode of operation is used to warm the combustor with the combustor vessel depressurized prior to gas turbine roll. In this mode, air is recirculated and heated by combined operation of the process air system and boiler ventilation systems. The boiler ventilation system draws the air off from the boiler, warms it in a heat exchanger, then delivers it to a line which feeds an alternate suction to the startup fans. From the fans, the process air system is aligned to deliver the warm air into the combustor vessel. The warm air then flows up through the vessel and into the boiler via the normal combustion air ducts, completing the recirculation loop.

Air Cooling Mode

This mode of operation is used to cool the boiler and bed material at slumped bed temperatures below 660 F with the combustor vessel depressurized. In this mode, the process air system draws cool air from the combustor building and delivers it into the boiler. The air is then evacuated from the boiler to the outside atmosphere by the boiler ventilation system.

Gas Circulation Mode

This mode of operation is used to cool the slumped bed material after a gas turbine trip with the combustor vessel depressurized. In this mode, combustion gases are recirculated and cooled by combined operation of the boiler ventilation and process air systems.

Photo 6.22.1 is a picture of the startup and process air fans located in the basement.

Key Instrumentation and Controls

The main instrument in this system is the flow transmitter. This measurement is used as feedback in the regulation of flow control valve, and as input for setting of the startup fan guide vane positions. The system also has temperature measurements after the cooler, and pressure measurements after the fans.

System Control Overview

In the "Normal Operation" mode, the top elevation bed ash cooling flow rate is an automatic demand based on combustor vessel pressure. The flow rate is regulated by the flow control valve with flow feedback provided by flow transmitter. The bed ash cooling air flow to the lower two elevations of the bed bottom hoppers is not actively controlled, but is controlled by fixed set positions of manual regulating valves. Automatic isolation valves in the supply lines to each of these lower elevations are cycled closed whenever the bed ash removal L-valves are pulsed, otherwise they remain open at all times when in this mode.

In the "Combustor Pressurization" and "Air Cooling" modes, the startup fan inlet guide vanes are set to a fixed position and the mass flow rate is controlled to a fixed value by the flow control valve with the flow transmitter providing the flow feedback signal. In the latter stages of pressurization, the flow control valve goes wide open and the startup fan delivered flow then follows the fan curve.

In the "Gas Circulation" mode, the flow control valve is regulated to provide a flow rate necessary to achieve a certain differential pressure across the slumped bed. In this mode, the flow control valve is regulated in response to differential pressure feedback from the wide range bed differential pressure measurements. Excessive vacuum at the boiler ventilation system acts as a flow rate control override in this mode. The inlet guide vanes of the startup fans are set in position in response to the flow rate indicated by the flow transmitter.

In the "Combustor Warming" mode, the operators adjust the flow control valve manually, and the startup fan inlet guide vanes respond automatically to the indicated flow.

6.22.2 System Modifications Completed

A number of changes were made to the process air system. These modifications included:

Bed ash cooling air lines were added to supply additional cooling air to two additional lower elevations in the boiler bottom hoppers.

A moisture separator was installed downstream of the process air cooler.

The seals on the guide vanes of the startup fans were replaced with a lower leakage design.

A duct was added inside the combustor vessel to extend the combustor vessel air space system interface pipe down into the bottom of the combustor vessel. This line was installed to direct warm air down to the bottom of the vessel for the "Combustor Warming" mode of operation, which was a new mode added to help heat up the combustor and thereby minimize gas turbine air preheating operation.

A tie-in was installed in the process air system's combustor air space interface pipe between the combustor and that line's combustor isolation valve in order to supply air at combustor vessel pressure to the APF system for ash transport. This tie point was used later to supply tempering air to the APF's inlet gas pipe.

A tie-in was installed at the bed ash lockhopper pressurization line to provide pressurization air to the APF ash removal lockhoppers.

6.22.3 Operating Experience Overview

This system functioned very reliably throughout the three-year test period. The only system issue of note was startup fan surging in the "Combustor Pressurization" mode. If gas turbine alignment to the combustor vessel took too long, the pressure vessel pressure would reach too high a level and the startup fan package would surge as it ran back on its operating curve at low delivered flow. This problem was much worse on hot restarts. It was combatted at times through manual positioning of the combustor cooling system's discharge isolation valve. Partial opening of this valve induced a vent flow from the combustor, which then limited the combustor vessel pressure attained and kept the fan operating further out on its characteristic curve.

6.22.4 Summary and Conclusions

The process air system design used at Tidd is sufficiently reliable for use in a commercial PFBC facility.

6.23 System 759 - Combustor Cooling

6.23.1 System Description

System Purpose and Function

The function of the combustor cooling system is to cool the combustor internal setting to permit personnel access at the start of unit outages. Once the combustor is cooled, the system was also intended to deliver ventilation air to the combustor; however, it was not used for this function due to high noise levels associated with fan operation.

General Description

Figure 6.23.1 depicts the original configuration of the combustor cooling system, whereas Figure 6.23.2 depicts the configuration at the end of the original three-year test program.

The system consists of a high-volume fan (28,000 scfm) which takes suction from the combustor building basement and delivers air to the combustor vessel via a 24-inch diameter penetration in the lower head. The air flows up through the open space in the combustor, and is vented by discharge piping which connects to a 24-inch diameter penetration in the combustor vessel's upper head. Once outside the combustor, the air is directed through the combustor building roof to atmosphere.

Adjustable inlet guide vanes incorporated into the fan design were intended to allow the system to provide a lower flow rate of air for outage ventilation of the combustor.

Key Instrumentation and Controls

The only instrumentation on the system are temperature measurements on the inlet and outlet pipes. These are used to generate high-temperature alarms when the unit is in service, which indicates system isolation valve leakage from the combustor vessel to atmosphere.

System Control Overview

There are no automatic controls associated with this system. Opening of isolation valves and starting of the fan are all manual actions, as is the fan guide vane adjustment.

6.23.2 System Modifications Completed

Due to the large volume of hot pressurized air stored in the combustor vessel, concerns were raised about inadvertent opening of the lone combustor inlet isolation valve while the unit was in service. Such inadvertent valve opening would present personnel danger in the combustor building basement. Therefore, a second isolation valve was installed on the combustor inlet line. No second valve was installed on the combustor outlet line, since hot air exiting the combustor through inadvertent opening of the outlet valve would pass safely to the outside atmosphere through the discharge piping which exhausts through the combustor building roof.

6.23.3 Operating Experience Overview

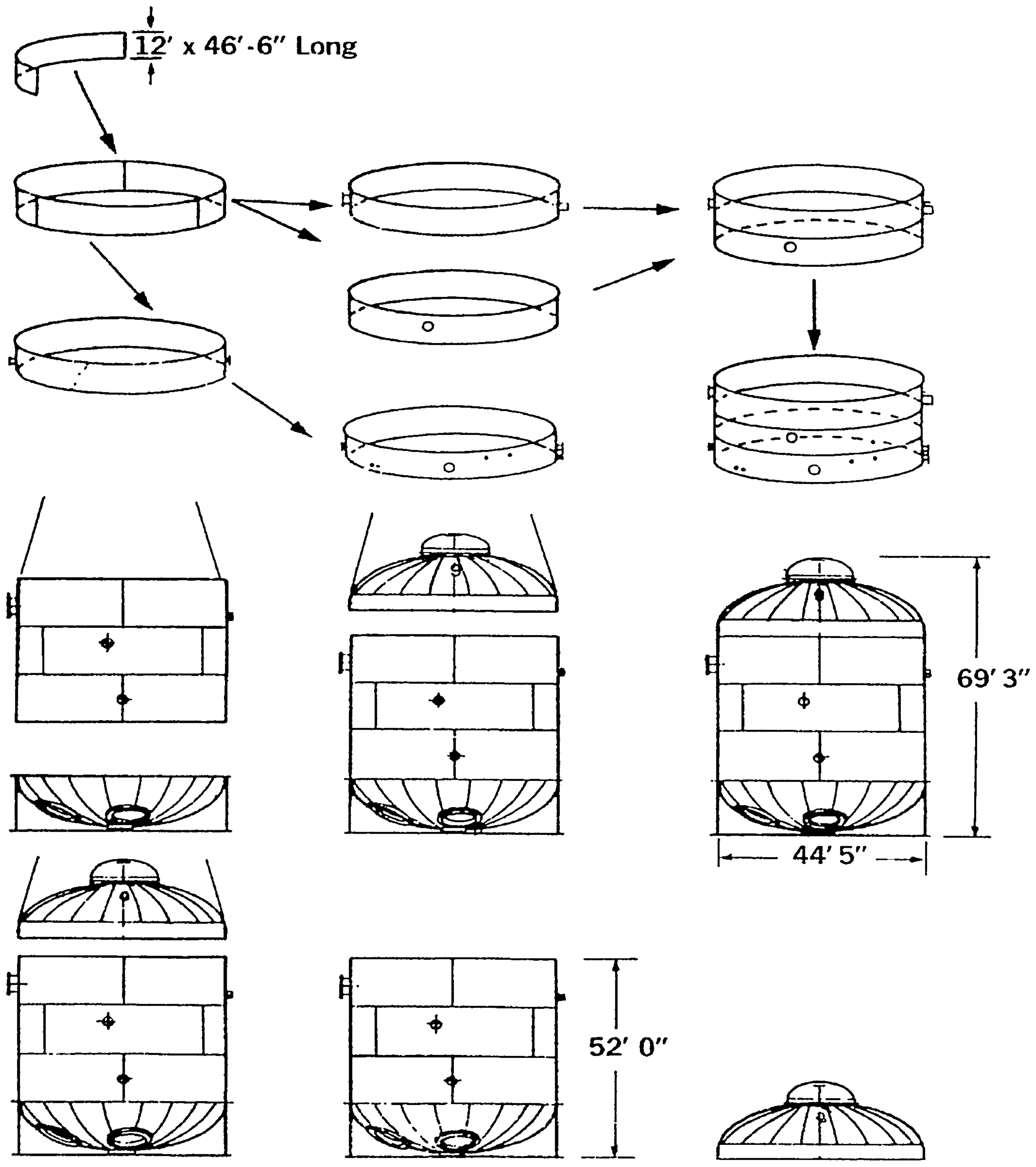
The system generally cooled the combustor vessel to personnel access temperature levels within 1-1/2 to 2-1/2 days depending on ambient air temperature. Initial personnel access to the lower and middle regions of the vessel was quicker than at the vessel top, which remained hot much longer. The overall time frame is a little longer than expected, which is believed to be due to channeling of the cooling air. There is no distribution ducting for the cooling air, thus it takes the path of least resistance up through the vessel air space.

It was found that in order to achieve sufficient combustor ventilation, the fan had to be run at fairly high volumetric flow rates. Such flow rates resulted in excessive noise in the combustor and excessive air heating due to fan compression. The use of the combustor cooling fan for ventilation purposes was therefore abandoned. In its place, temporary tube axial fans were installed at various combustor penetrations during each outage to induce a flow of air through the vessel. In addition, operation of the boiler ventilation system was found to produce a good ventilation air flow into the combustor vessel and boiler enclosure.

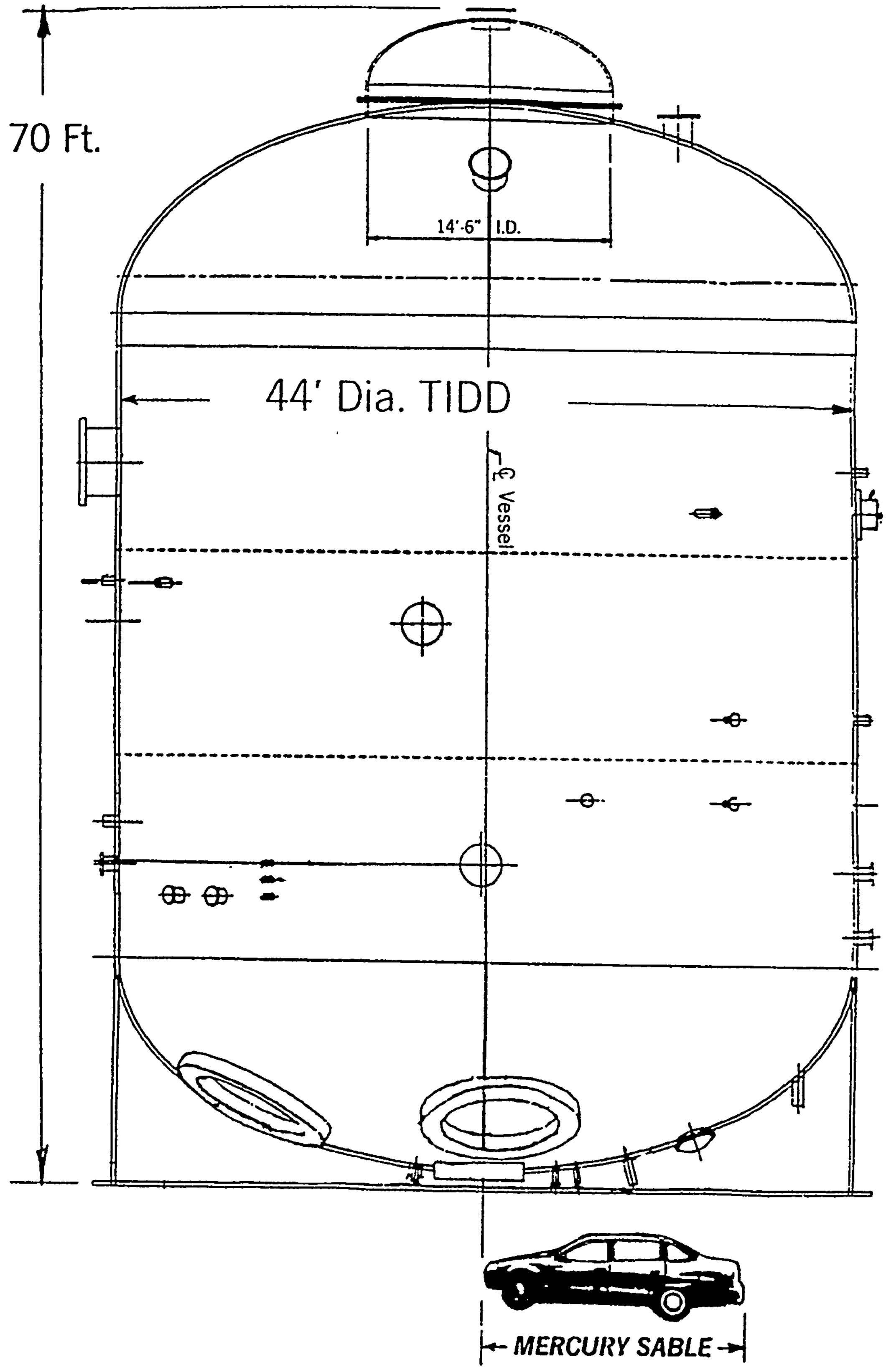
6.23.4 Summary and Recommendations

The system functioned adequately with respect to combustor cool down. The long cool down time experienced at Tidd; however, will likely not be acceptable for a commercial PFBC facility. Increased cooling air flow rates along with improved distribution inside the combustor vessel will likely be necessary. In addition some means to cool the ambient air (i.e. cooled by well water or river water) will likely be needed to avoid extended cool down times in the summer months.

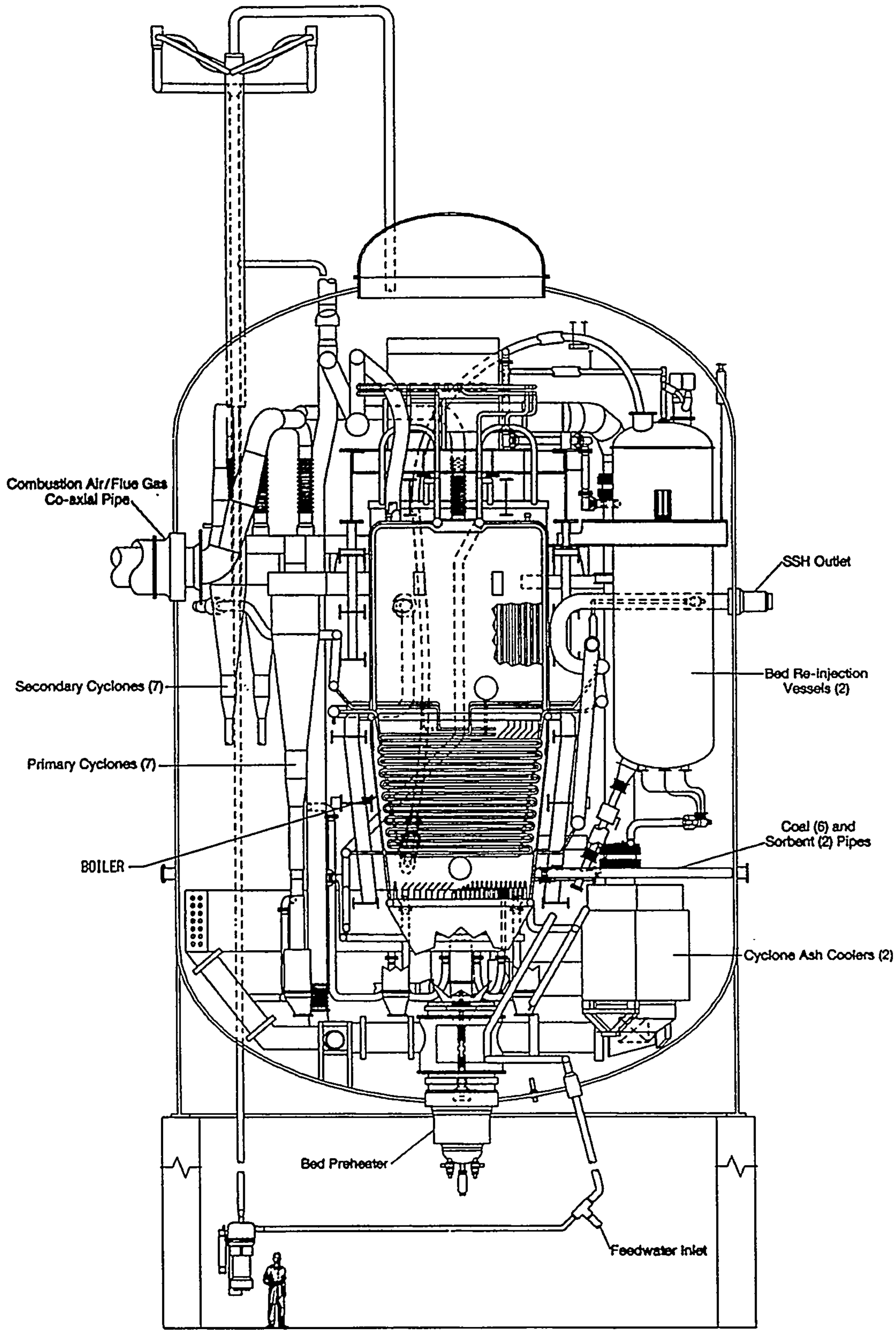
The combustor cooling system did not function in a satisfactory manner with respect to combustor ventilation. For a commercial facility, a combination of sufficient flow of relatively cool ventilation air along with proper distribution of that air will likely be needed to insure that the combustor vessel work environment is adequately cool to achieve reasonable outage activity productivity.



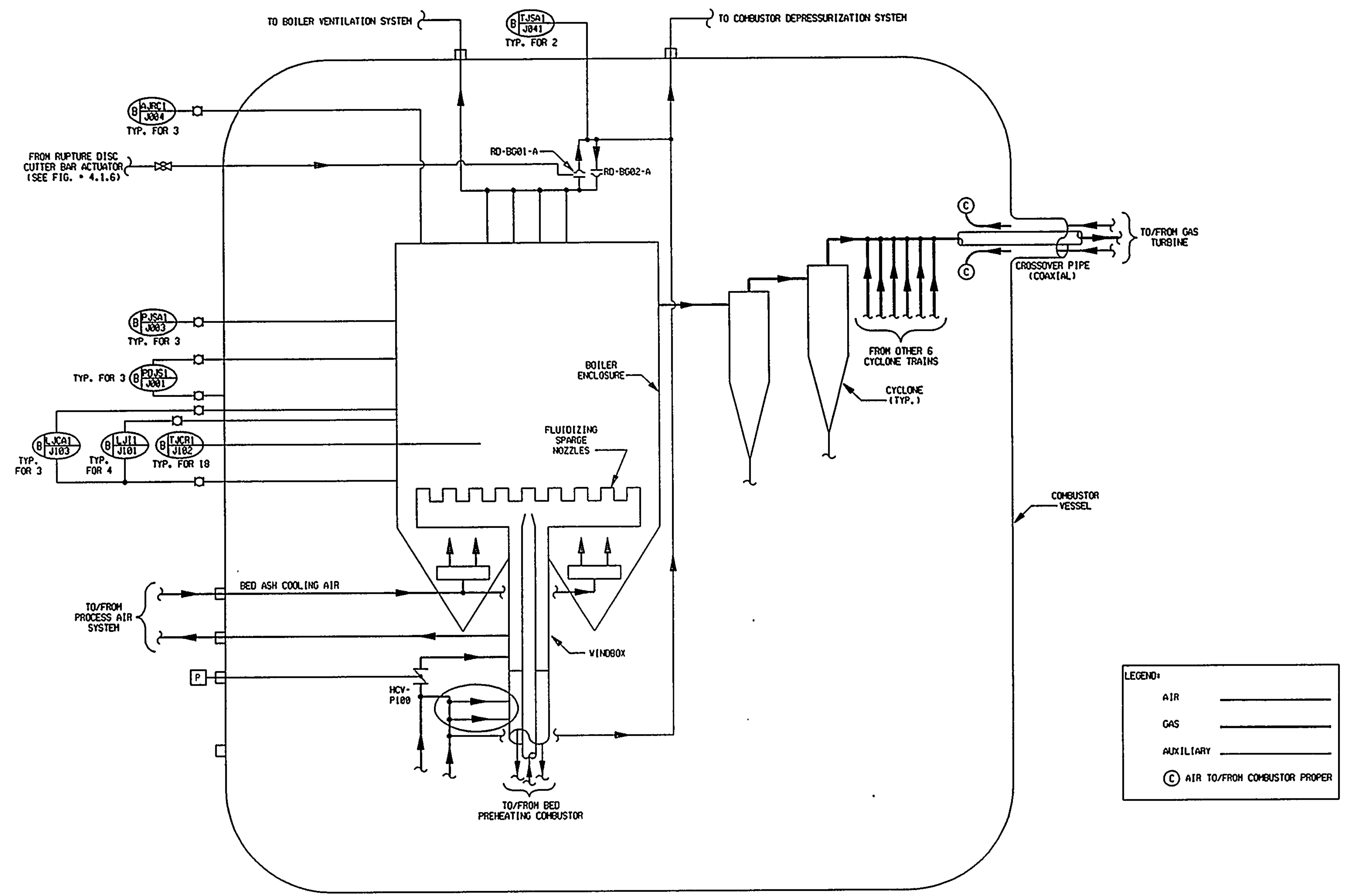
PRESSURE VESSEL FABRICATION
ASSEMBLY PROCEDURE
FIGURE 6.1.1



COMBUSTOR VESSEL
OUTSIDE SIDEVIEW
FIGURE 6.1.2



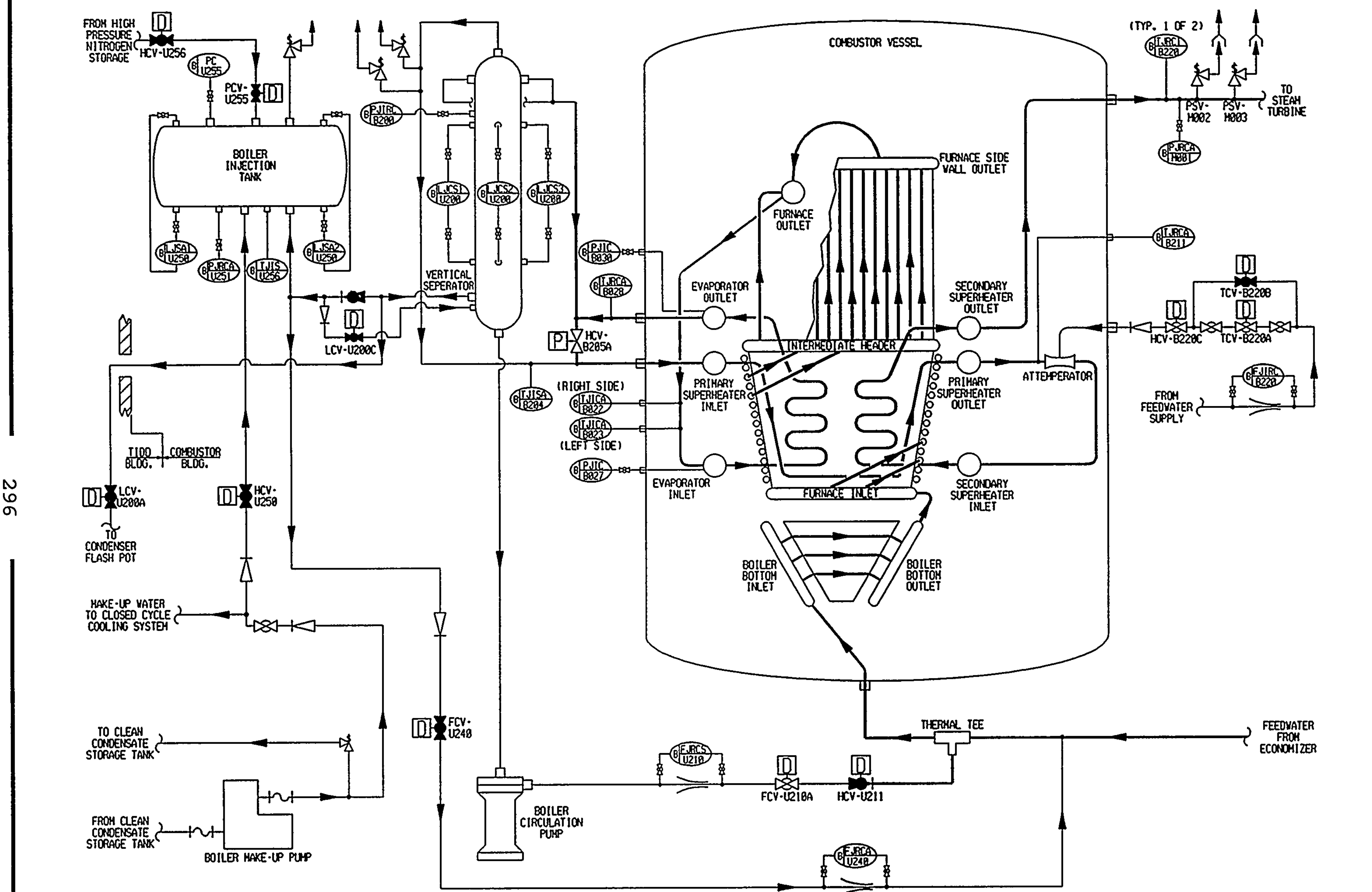
COMBUSTOR ARRANGEMENT
FIGURE 6.2.1



BOILER AIR /GAS SIMPLIFIED FLOW DIAGRAM

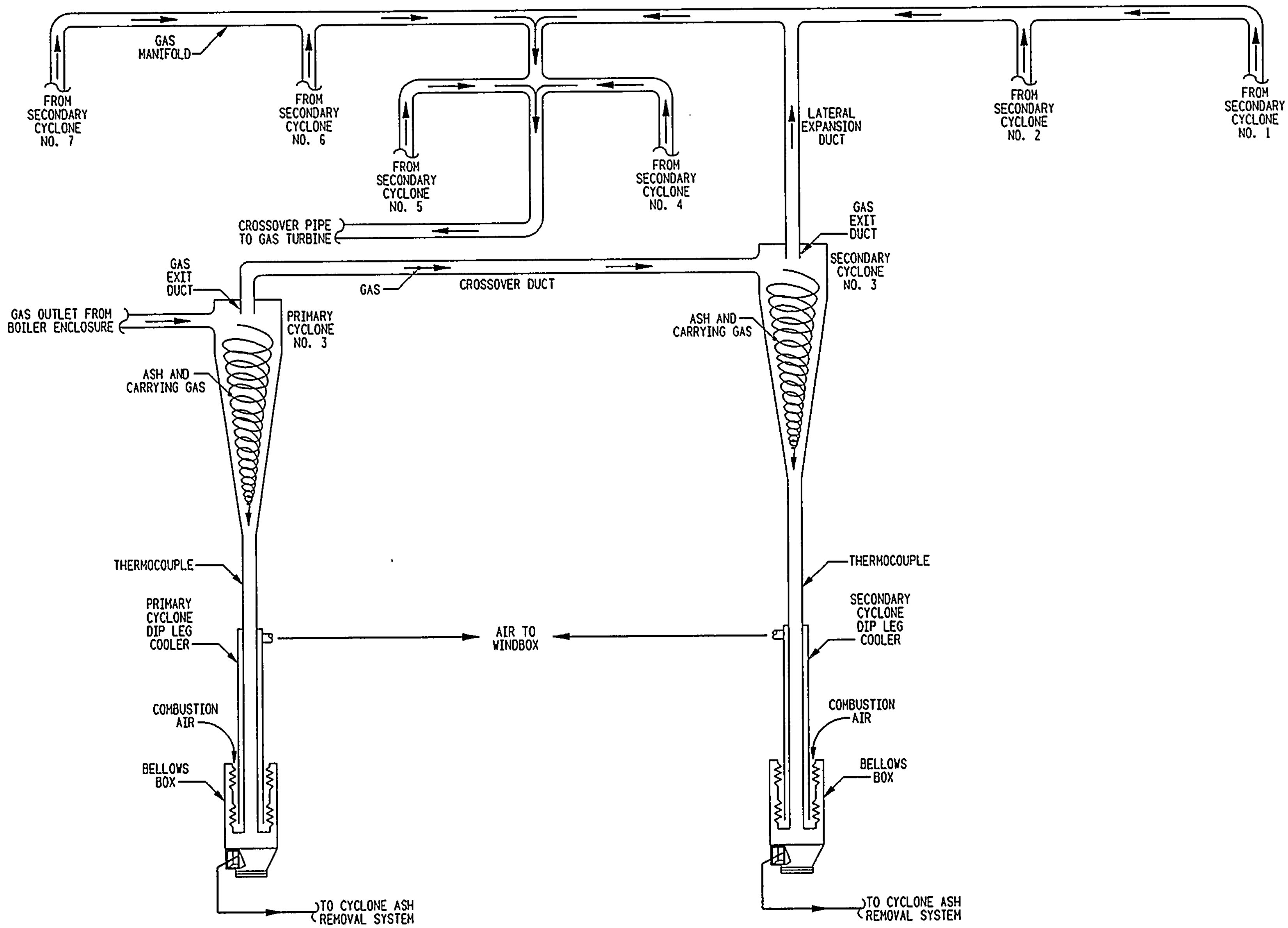
FIGURE 6.2.2

/usr6/mech/tidd/u doe/figure.shl

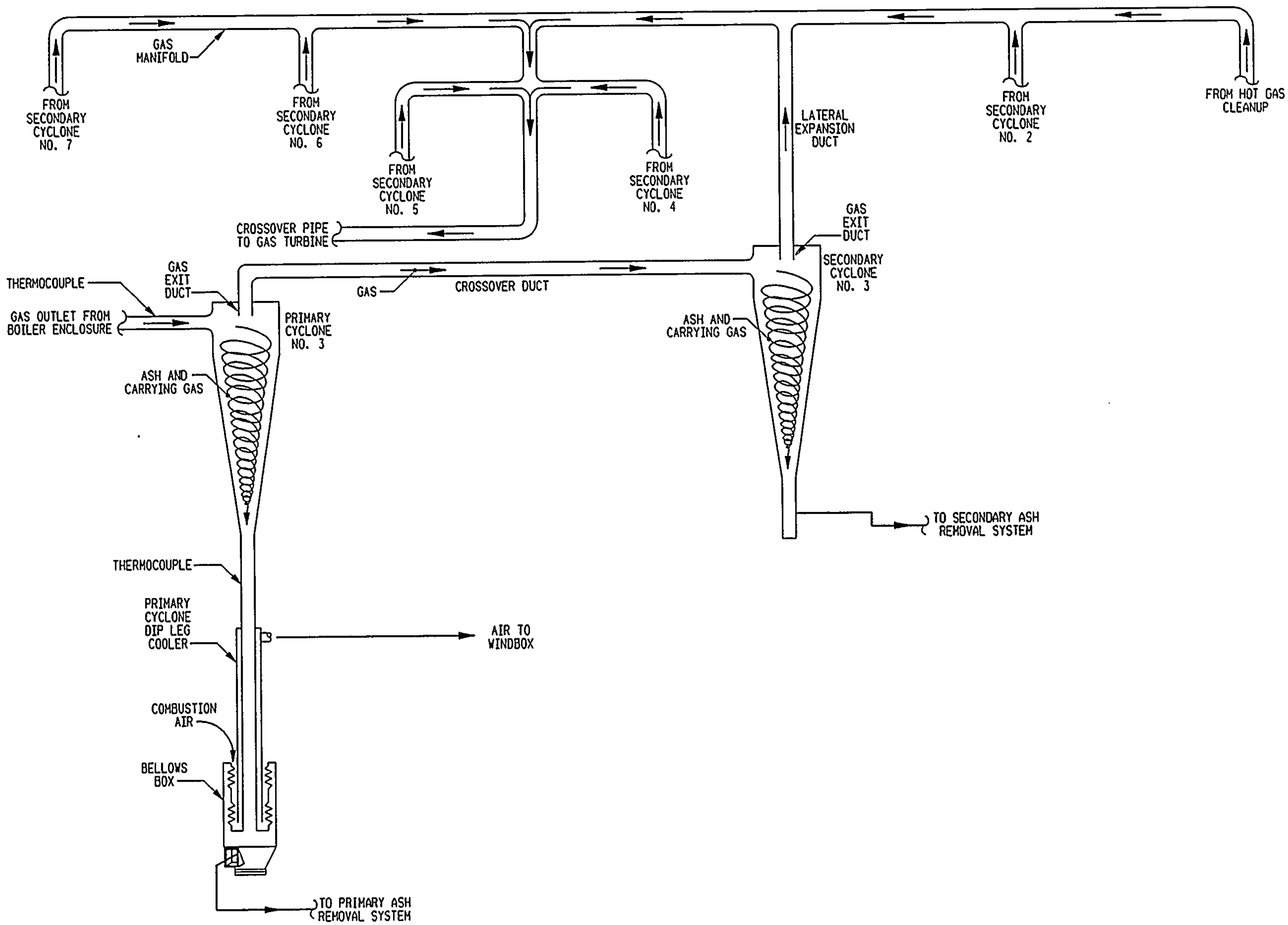


BOILER WATER / STEAM SIMPLIFIED FLOW DIAGRAM
FIGURE 6.2.3

/usr/mech/tidd/u doc/figure.shl

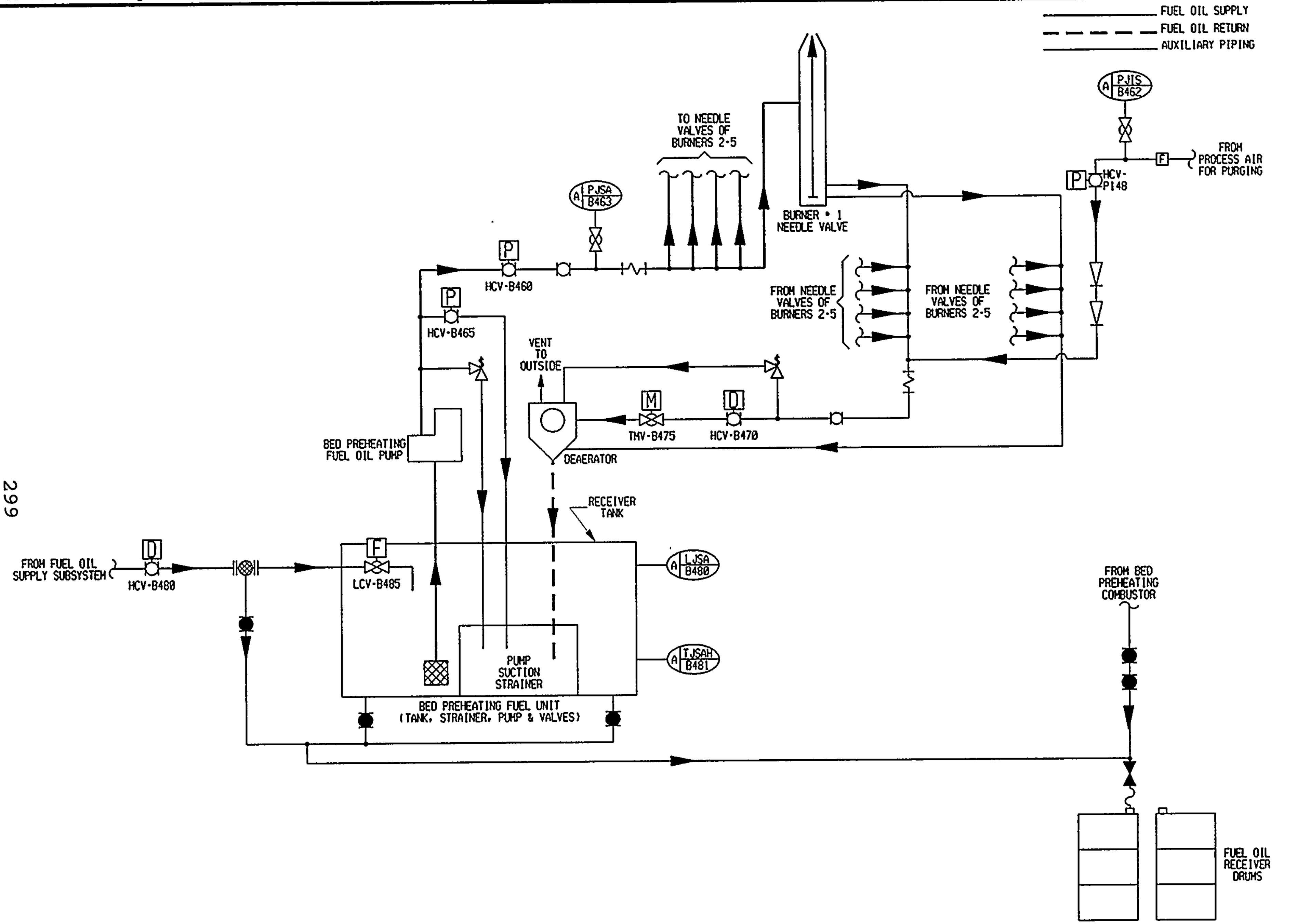


GAS CLEANING SYSTEM SIMPLIFIED FLOW DIAGRAM
ORIGINAL CONFIGURATION
FIGURE 6.3.1



GAS CLEANING SYSTEM SIMPLIFIED FLOW DIAGRAM
FINAL CONFIGURATION
FIGURE 6.3.2

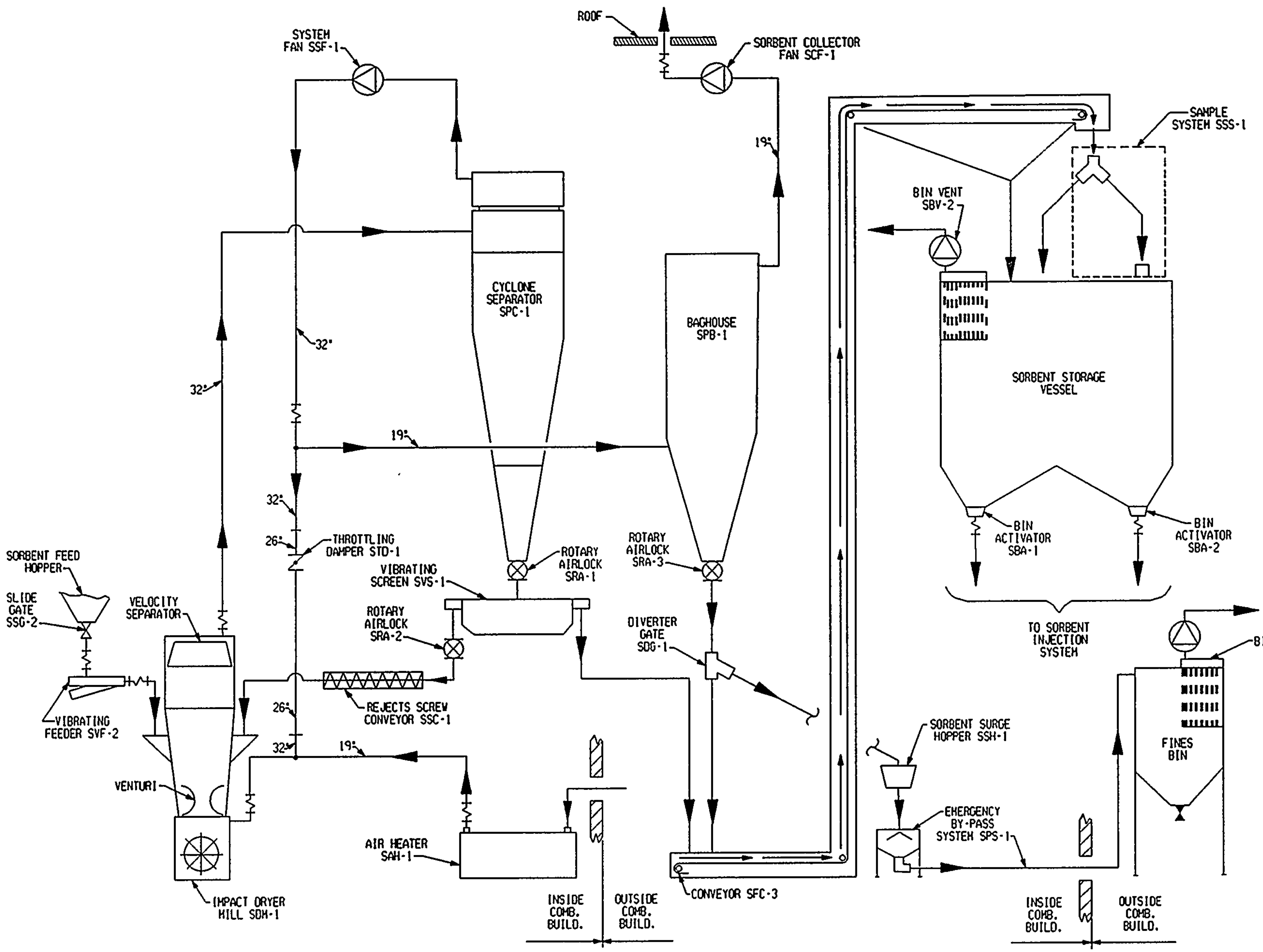
usr/ /mech tidd/u doe/figure.shl



BED PREHEATING FUEL OIL SUBSYSTEM SIMPLIFIED FLOW DIAGRAM

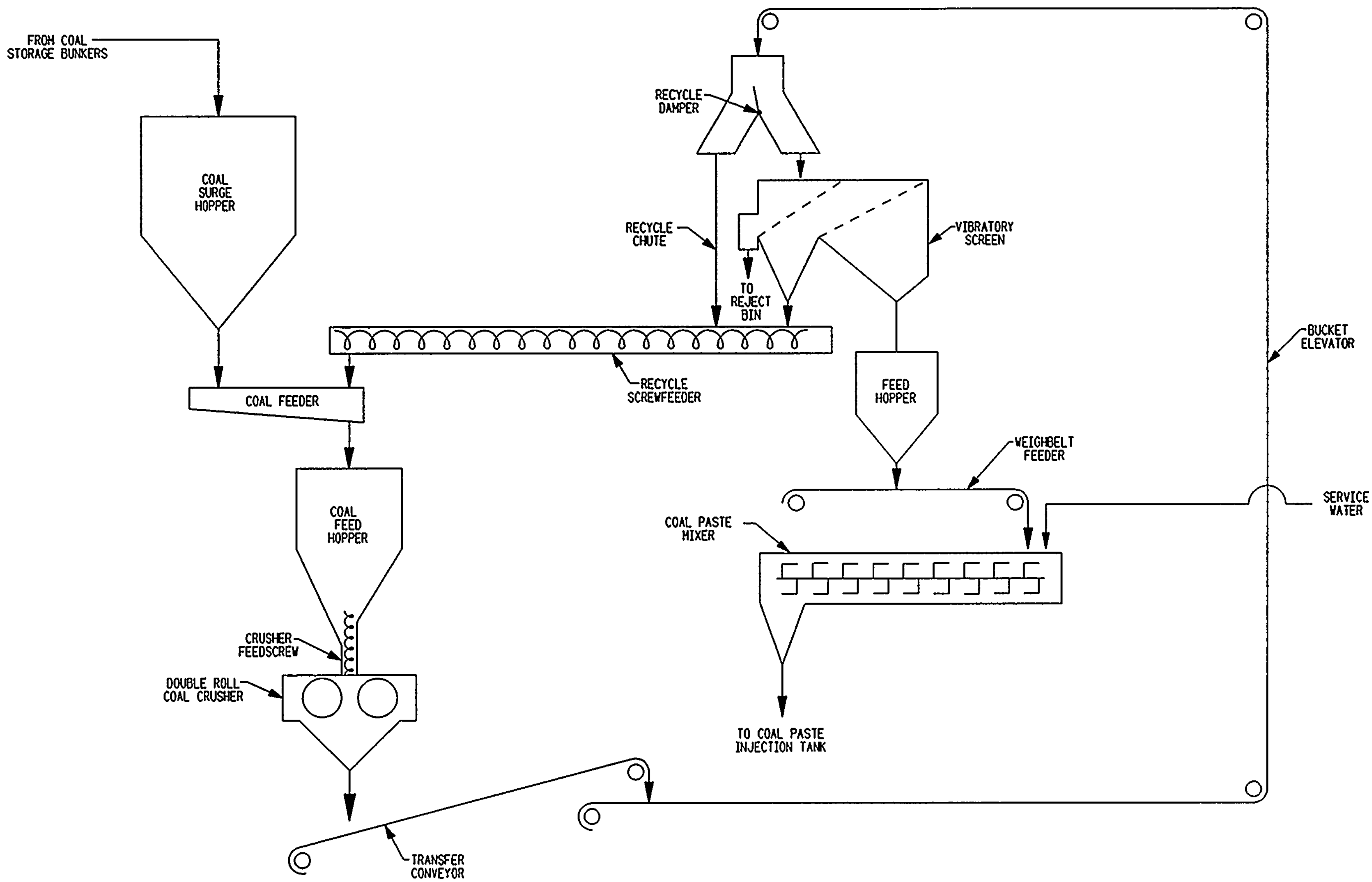
FIGURE 6.5.1

u:\ mech\tidd\u doe figure.shl

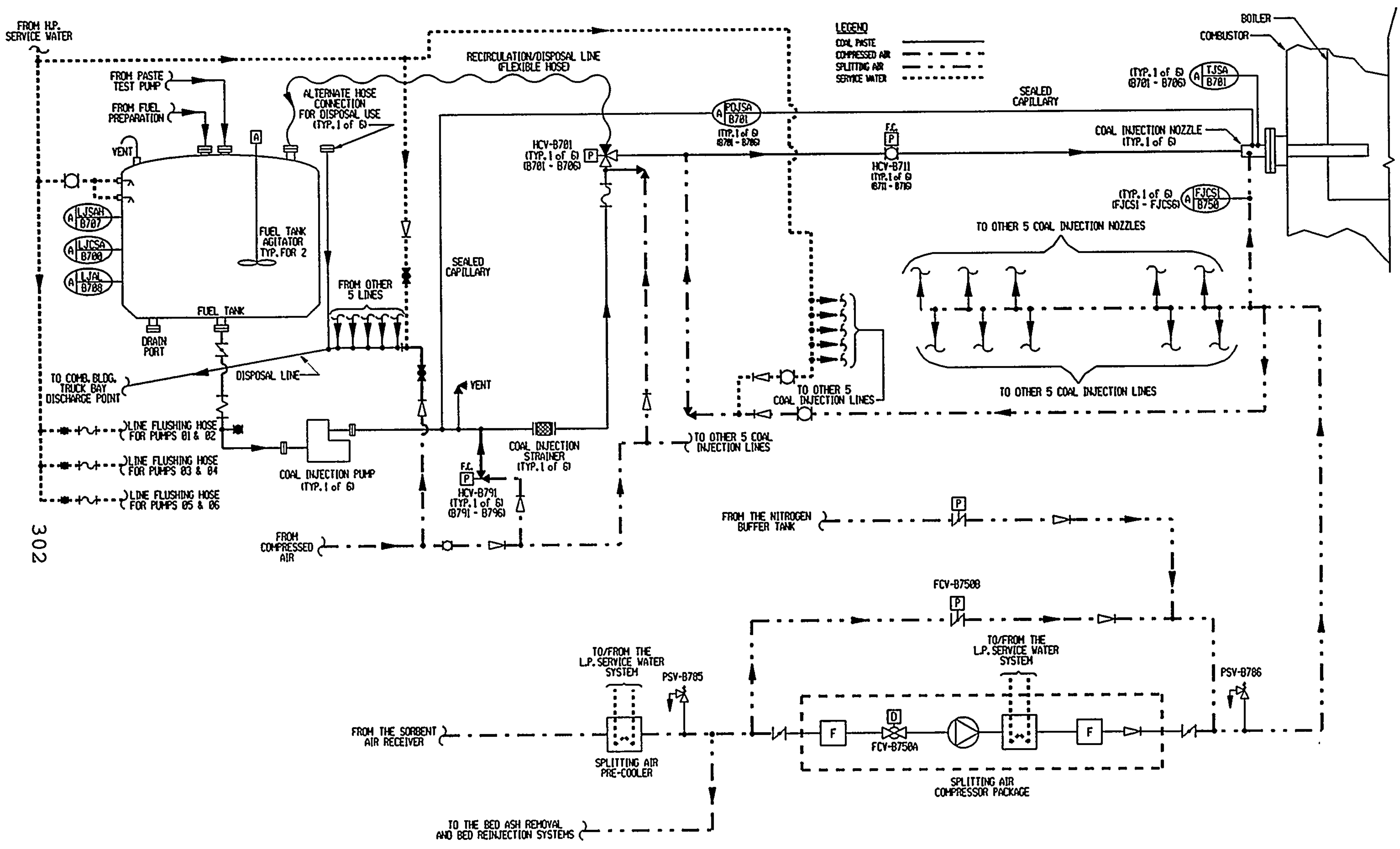


SORBENT PREPARATION SYSTEM
SIMPLIFIED FLOW DIAGRAM
FIGURE 6.6.1

/usr6 mech/tidd u doe figure.shl

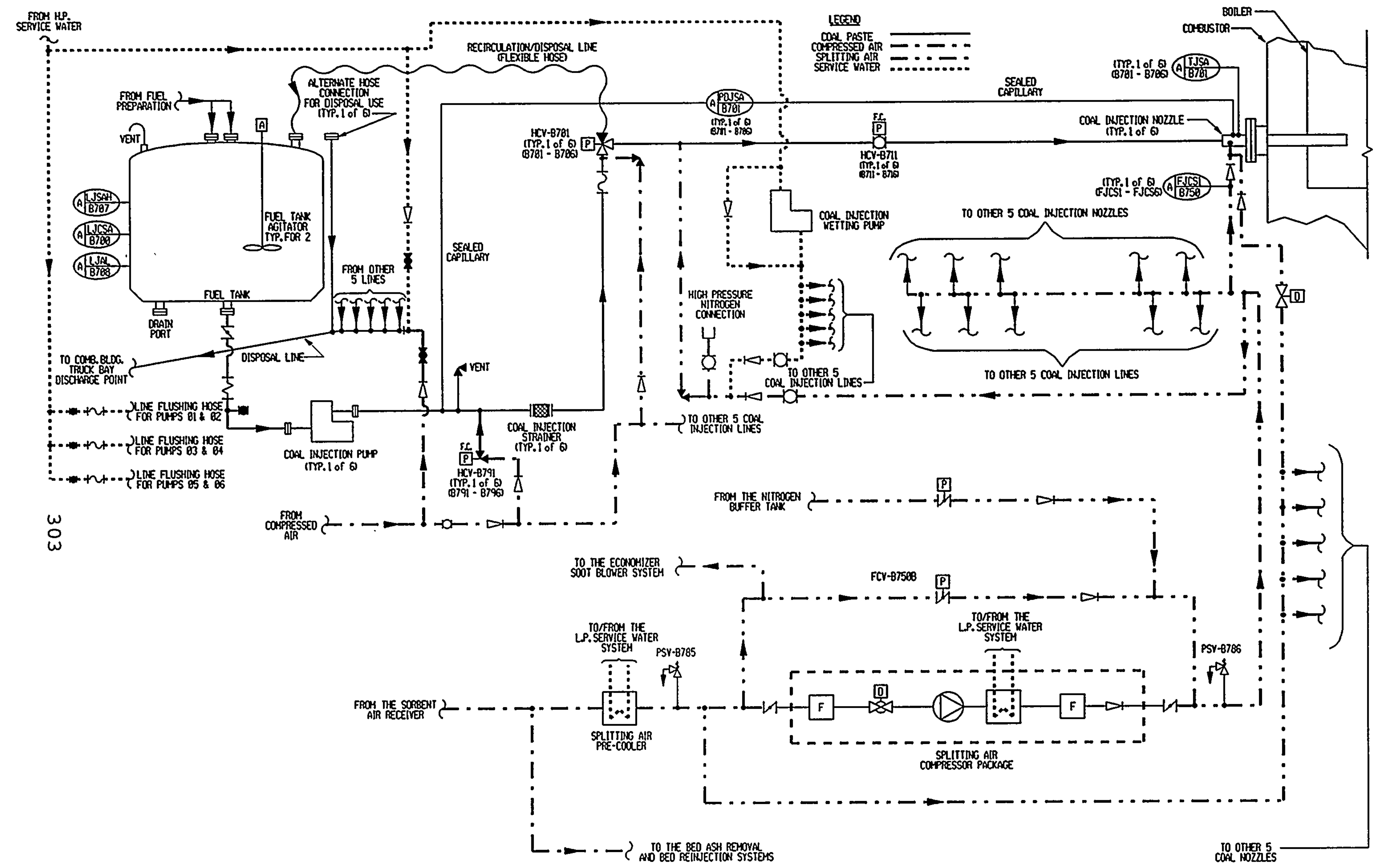


COAL PREPARATION SYSTEM
SIMPLIFIED FLOW DIAGRAM
FIGURE 6.7.1



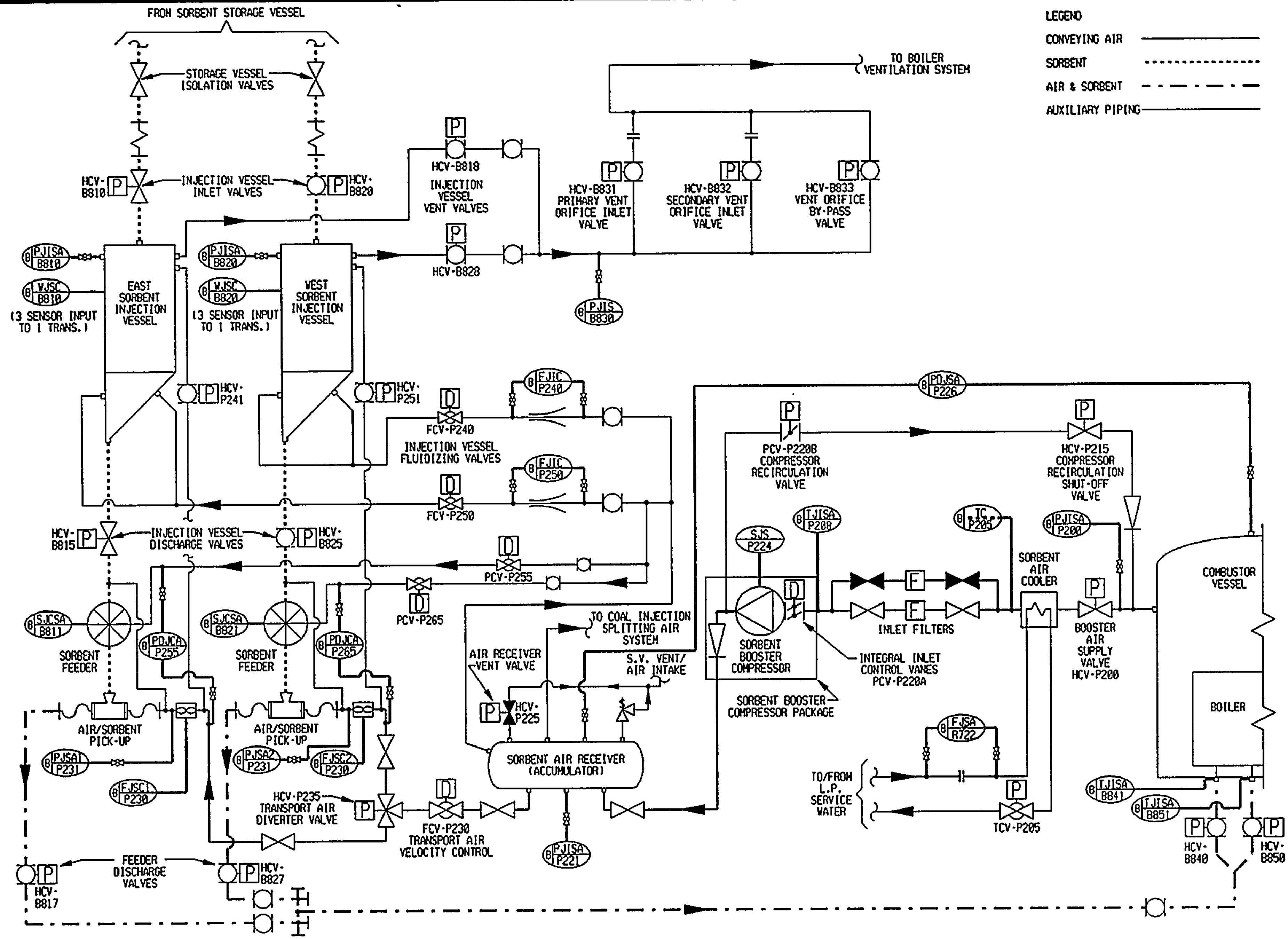
COAL INJECTION SIMPLIFIED FLOW DIAGRAM
ORIGINAL CONFIGURATION FIGURE 6.8.1

/usr6/mech/tidd/u doe/figure.shl



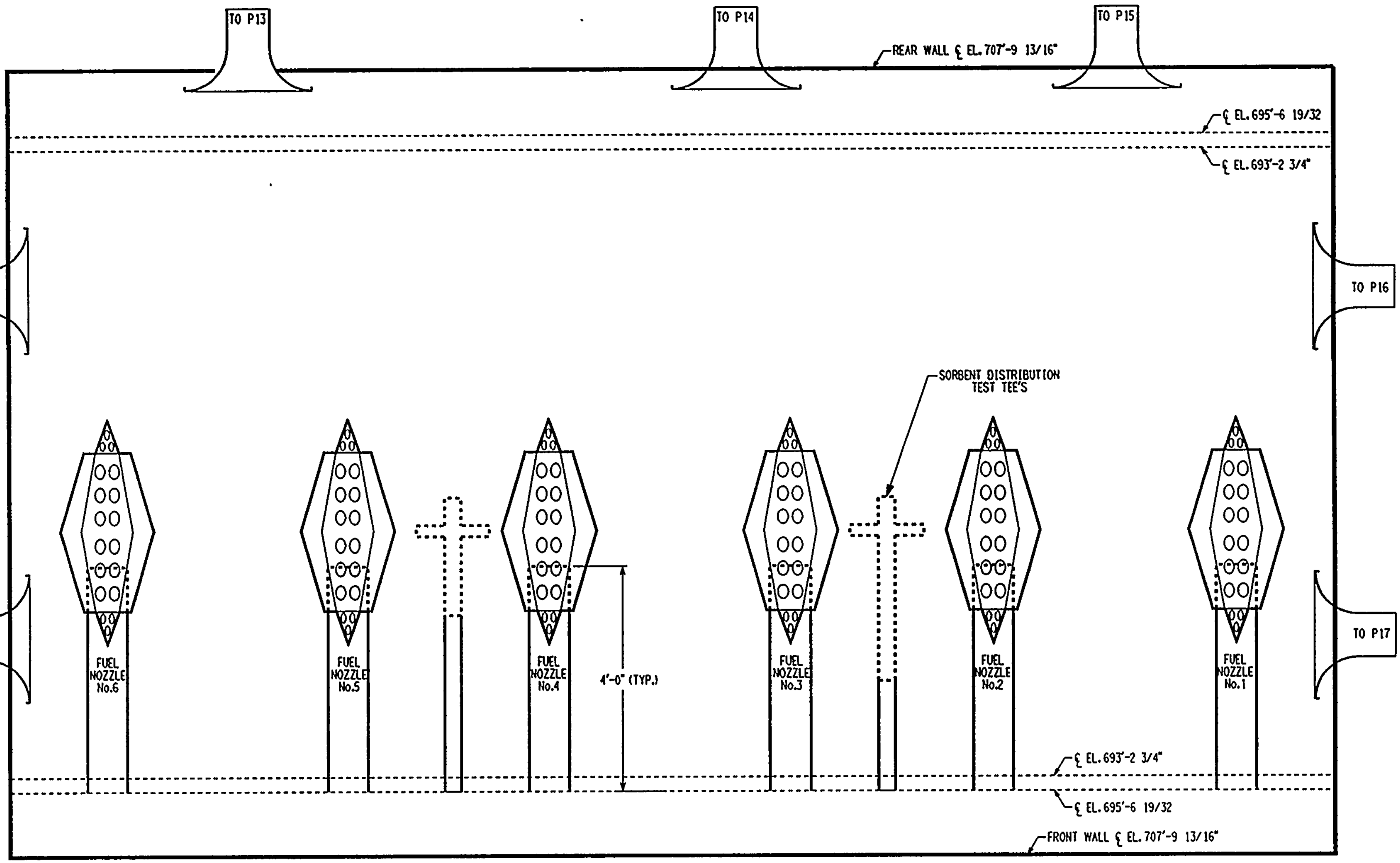
COAL INJECTION SIMPLIFIED FLOW DIAGRAM
FINAL CONFIGURATION FIGURE 6.8.2

/usr6/mech/tidd/u doe/figure.shl



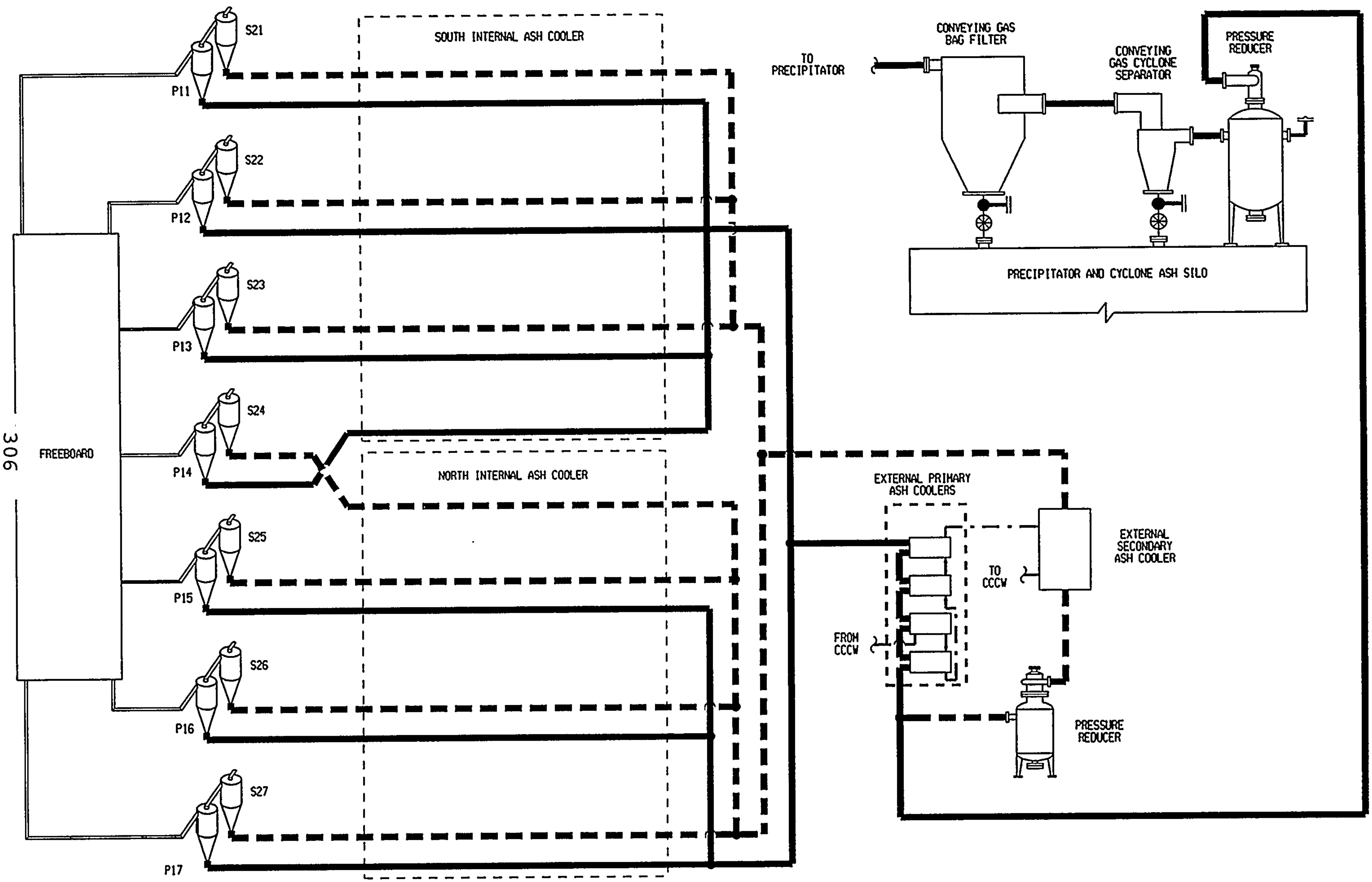
SORBENT INJECTION SIMPLIFIED FLOW DIAGRAM
FIGURE 6.9.1

/usr6/mech/tidd/u doe/figure.shl

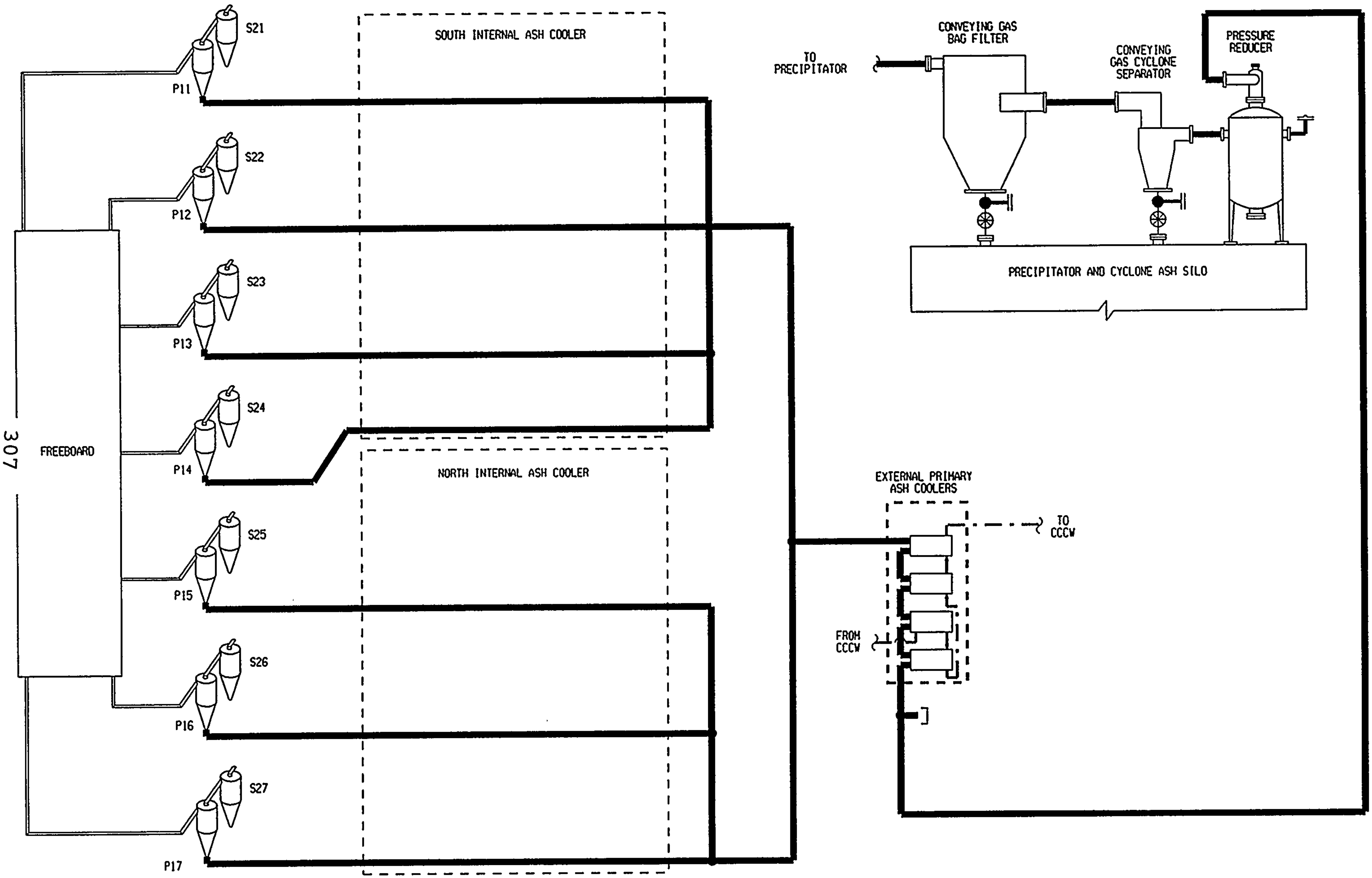


LOCATION OF FUEL AND SORBENT
NOZZLES IN FLUIDIZED BED
FIGURE 6.9.2

/usr6/mech/tidd/u doe/figure.shl

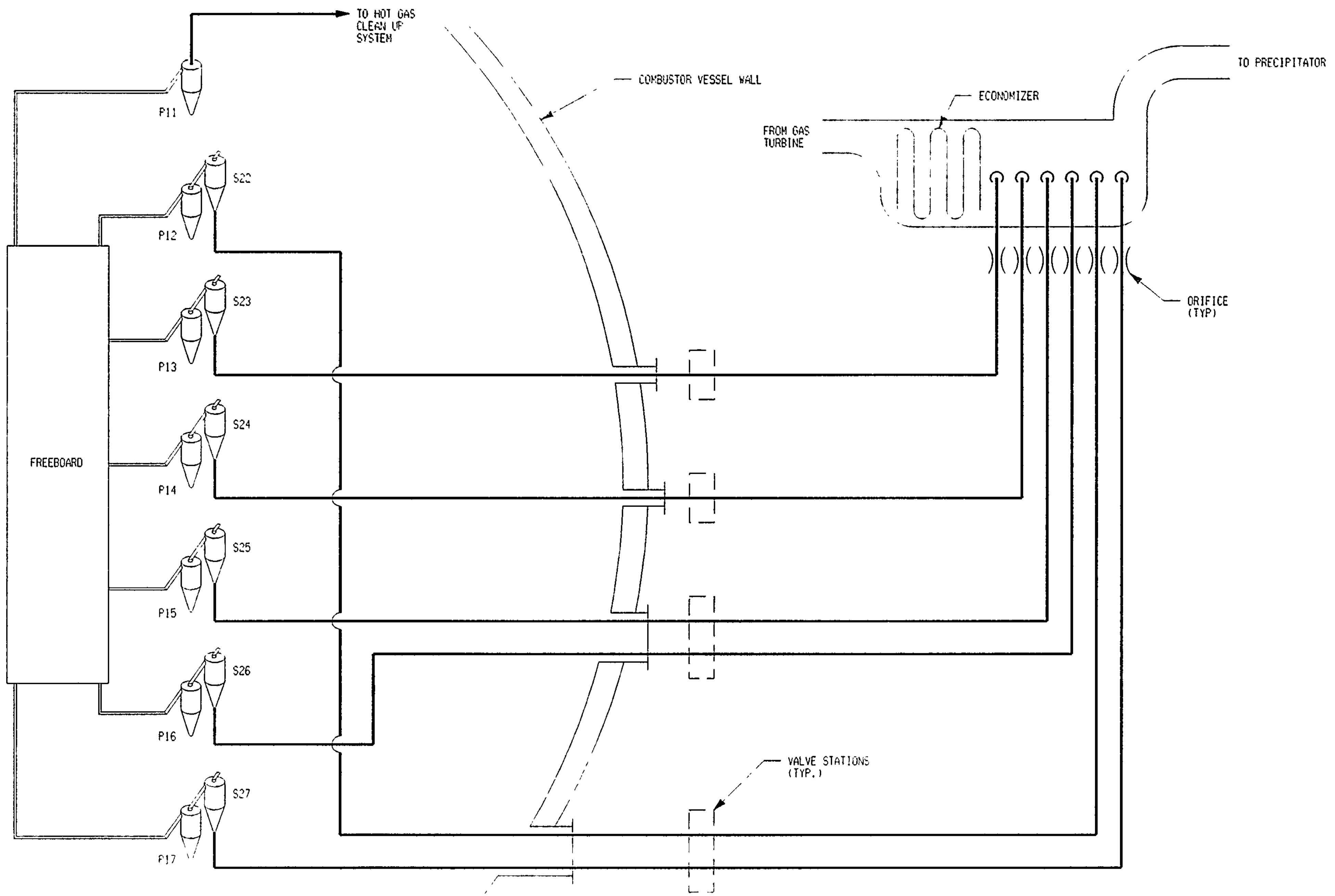


ORIGINAL CYCLONE ASH REMOVAL SYSTEM
FIGURE 6.10.1



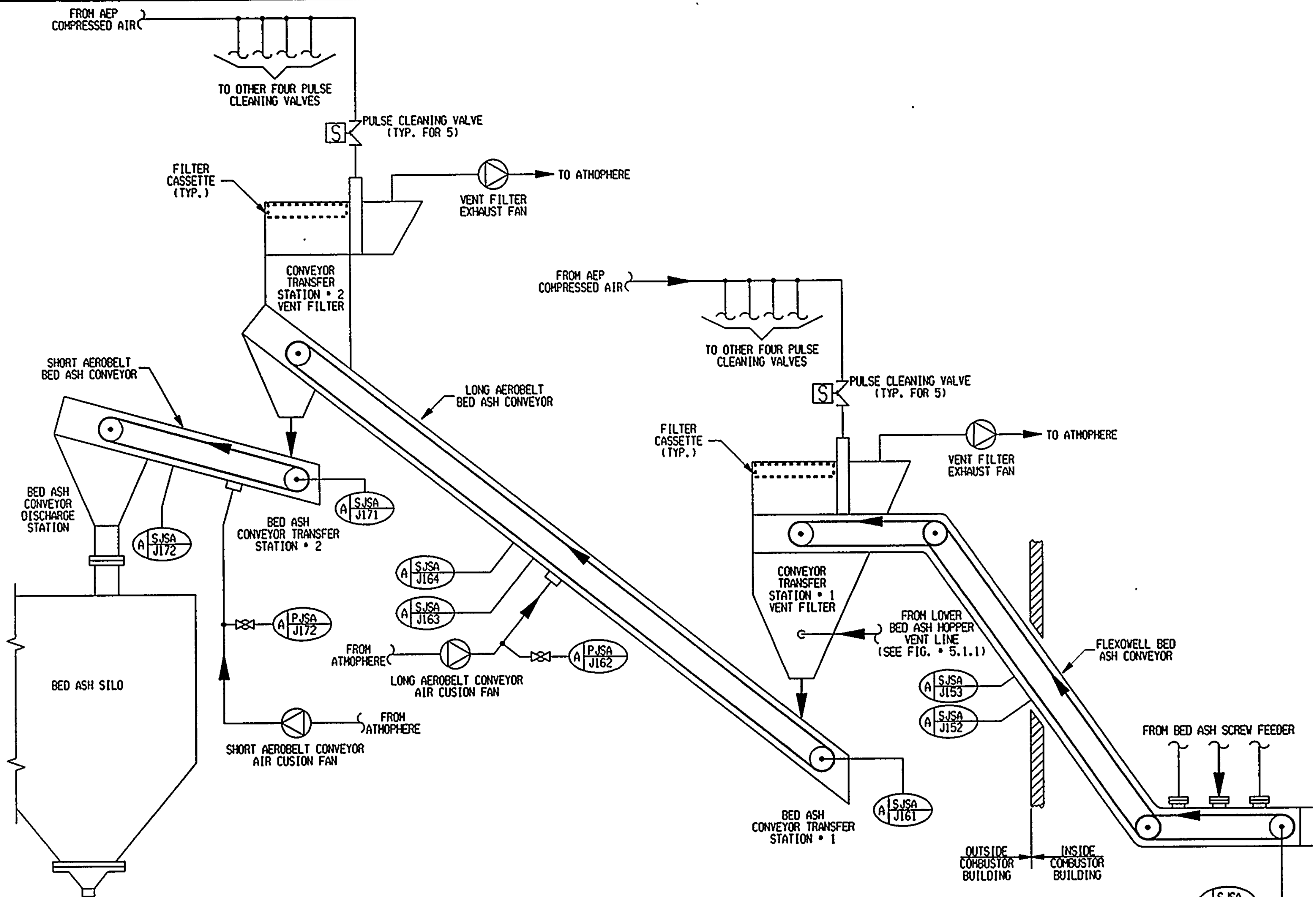
FINAL PRIMARY CYCLONE ASH REMOVAL SYSTEM
FIGURE 6.10.2

/usrf/mech/tidd/u doe/figure2.dgn



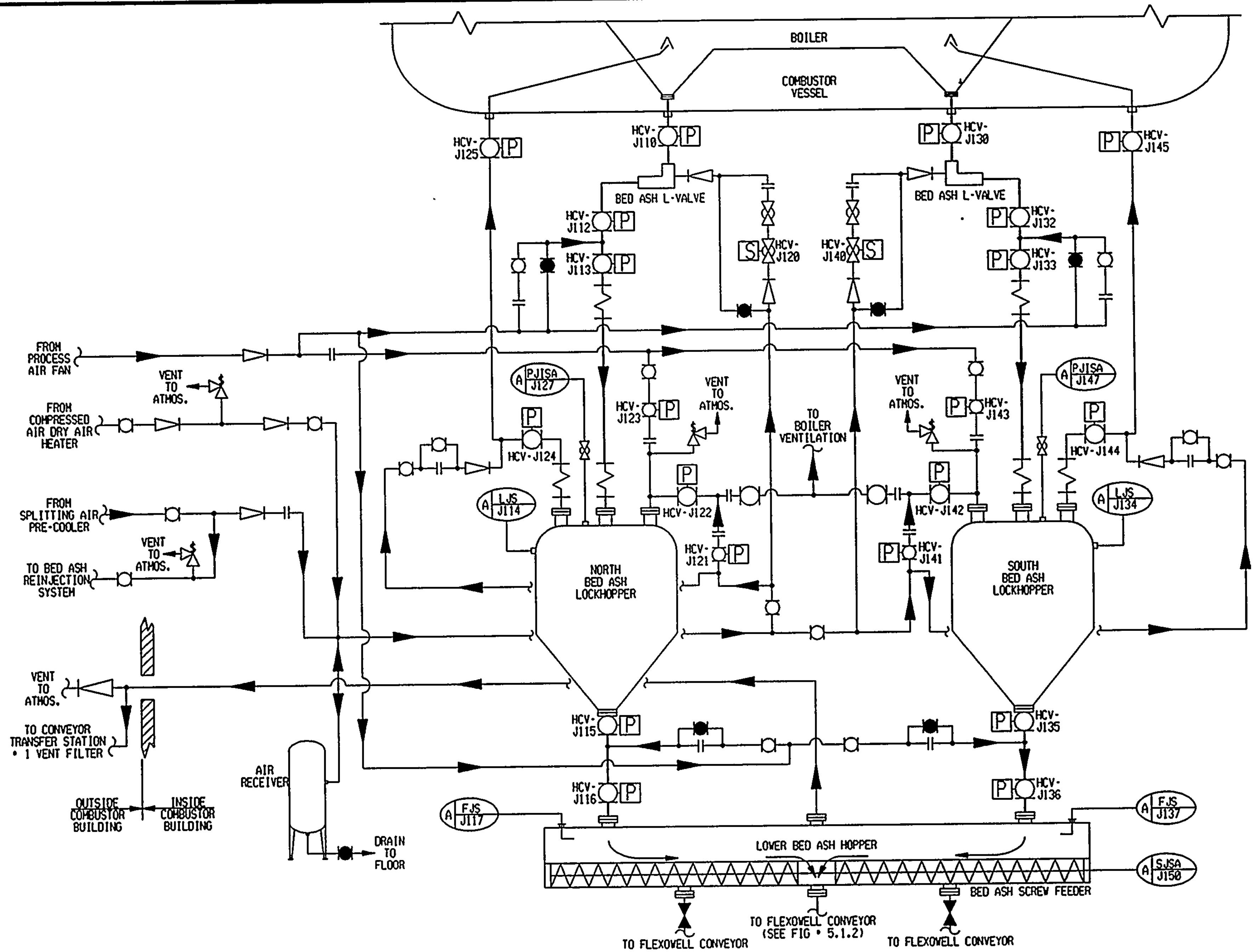
FINAL SECONDARY CYCLONE ASH REMOVAL SYSTEM
FIGURE 6.10.3

/usr6/mech/tidd/u doe/figure.shl



BED ASH REMOVAL SYSTEM – SCREW FEEDER TO SILO

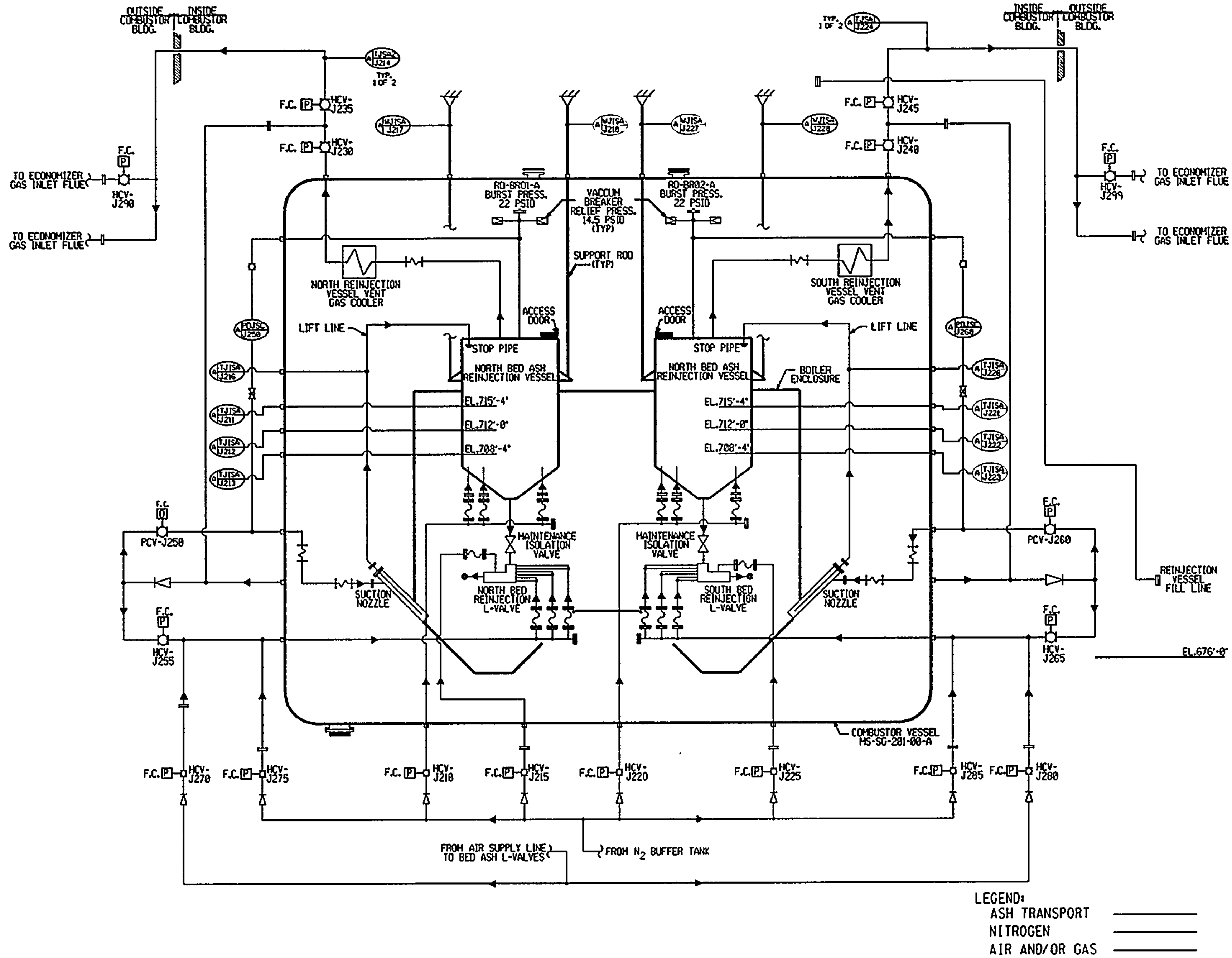
FIGURE 6.11.1



BED ASH REMOVAL SYSTEM TO SCREW FEEDER

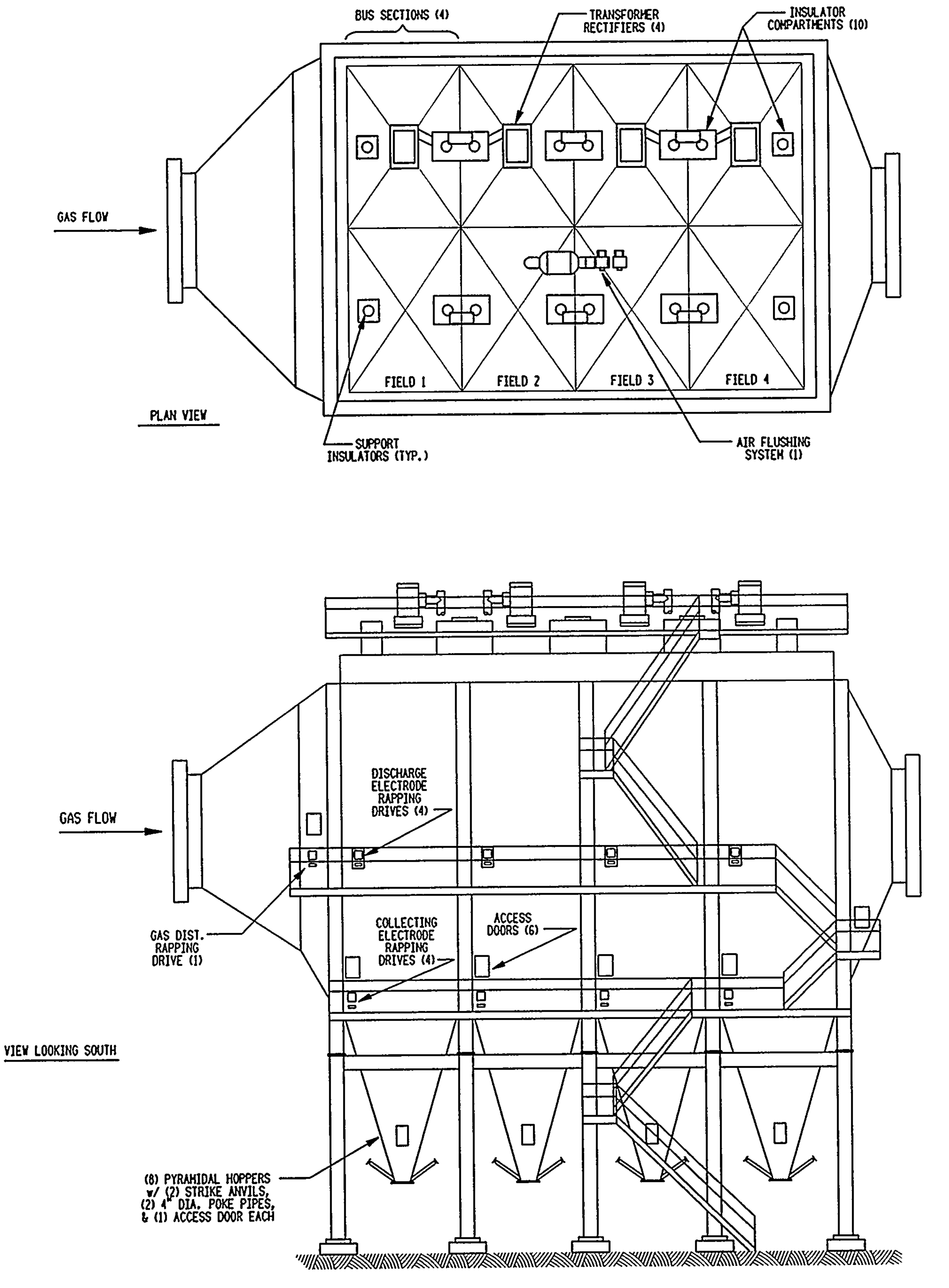
FIGURE 6.11.2

/usr6/mech/tidd u doe figure.shl



BED ASH REINJECTION SIMPLIFIED FLOW DIAGRAM

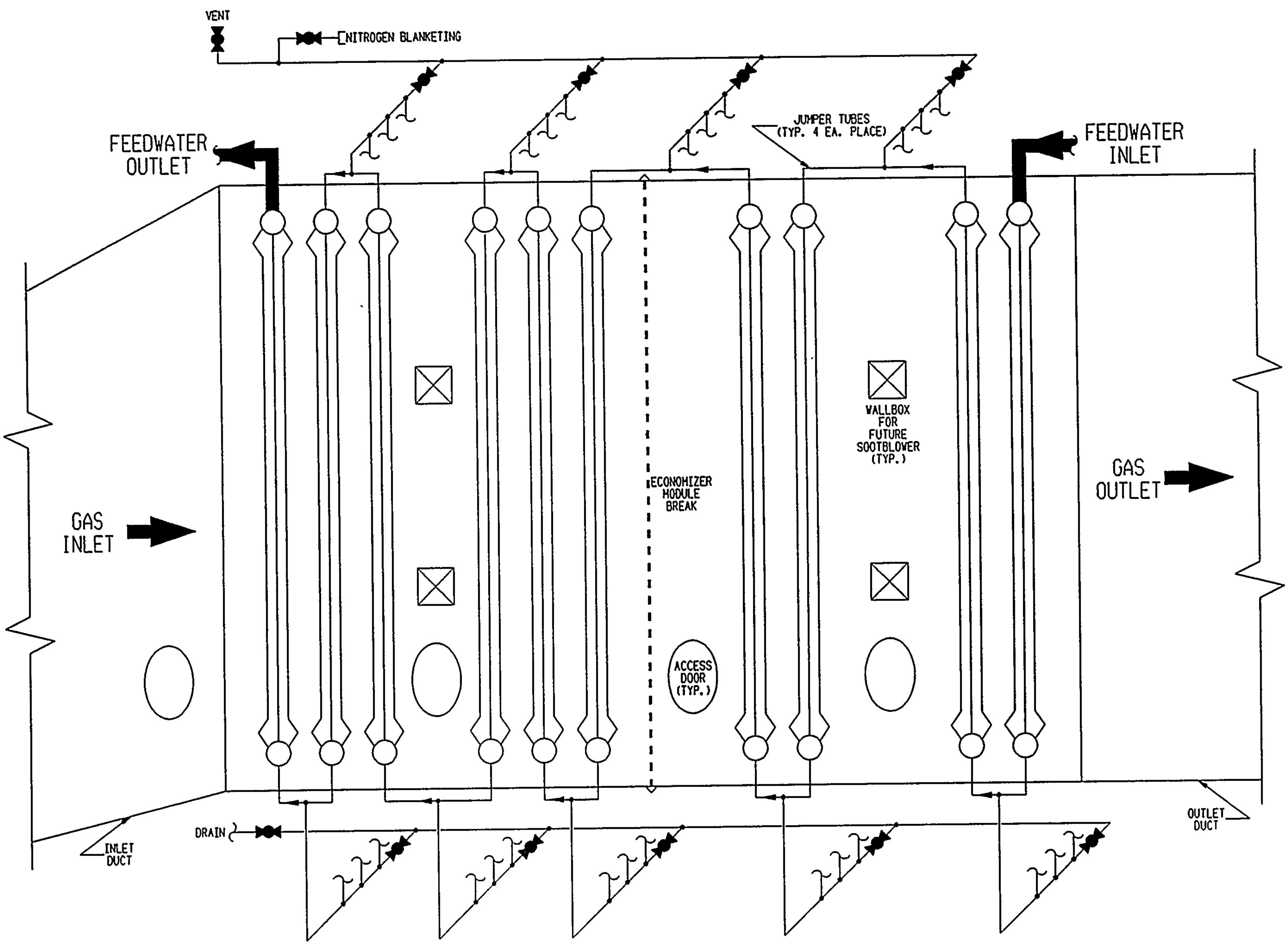
FIGURE 6.12.1



ELECTROSTATIC PRECIPITATOR

FIGURE 6.15.1

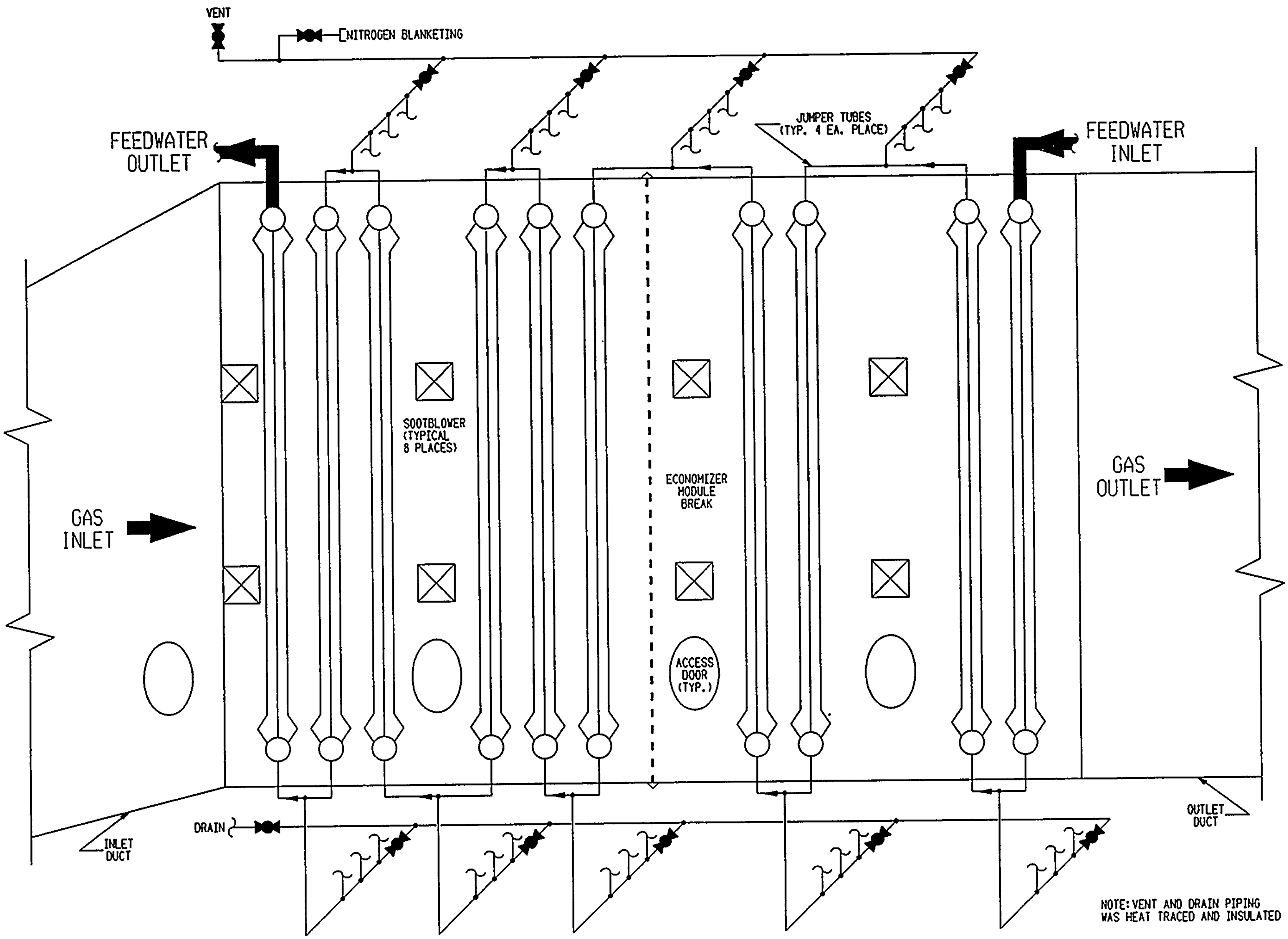
/usr3 mech/tldd/u doe/figure.shl & figure1.tg4



ECONOMIZER SIDE VIEW SCHEMATIC (INITIAL CONFIGURATION)
FIGURE 6.16.1

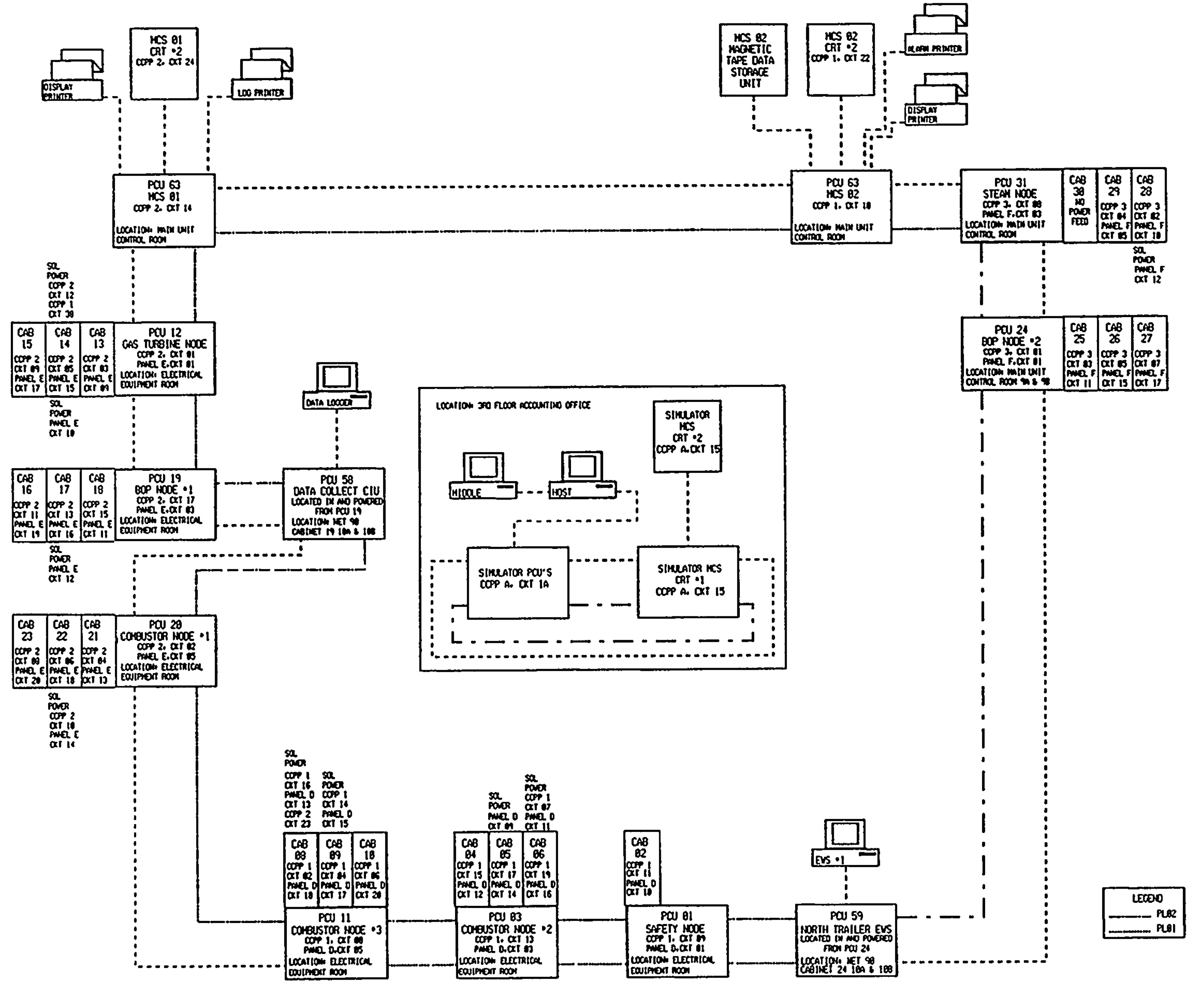
usr6/mech/tidd/u doe/figure.sh1

/usr 6/mech. tidc u doe. figure. shl



ECONOMIZER SIDE VIEW SCHEMATIC (FINAL CONFIGURATION)
FIGURE 6.16.2

/usr6/mech/tuc.../dce/figure2.dgn



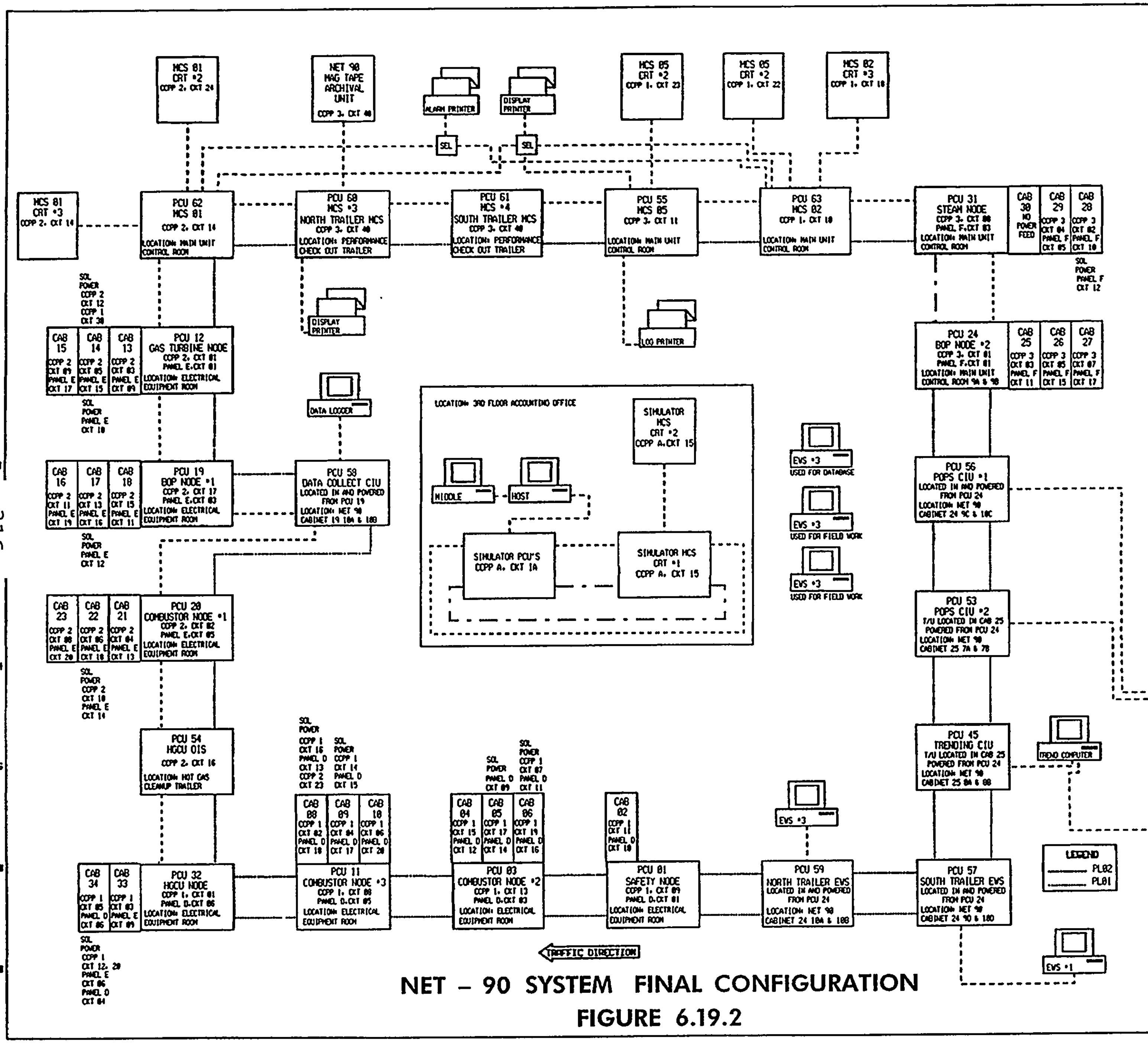
PCU	MASTERS	MODULE TYPE	NO OF SLAVES
PCU01	00104	MFC04	10
	00110	AMM02	6
PCU03	00304	MFC04	11
	00306	MFC04	19
	00310	AMM02	7
PCU11	01104	MFC04	19
	01106	MFC04	13
	01110	AMM02	6
PCU12	01204	MFC04	15
	01206	MFC04	7
	01210	AMM02	6
PCU19	01904	MFC03	1
	01906	MFC04	9
	01908	MFC04	21
PCU20	02004	MFC04	13
	02006	MFC04	12
	02010	AMM02	8
	02012	AMM02	7
	02014	AMM02	8
PCU24	02404	MFC04	10
	02406	MFC04	9
PCU31	03104	MFC04	10
	03106	MFC04	16
	03110	AMM02	4
	03102	AMM02	8

NET – 90 SYSTEM ORIGINAL CONFIGURATION

FIGURE 6.19.1

TITLE:
BAILEY NET 90 PLANT LOOP & PERIPHERALS
(120 VAC CRITICAL & NONCRITICAL POWER)

COMPILED BY: R. B. GRIN | REVISION: 3
DRAWING NO: 1-9551002-M | DATE: 07-07-93

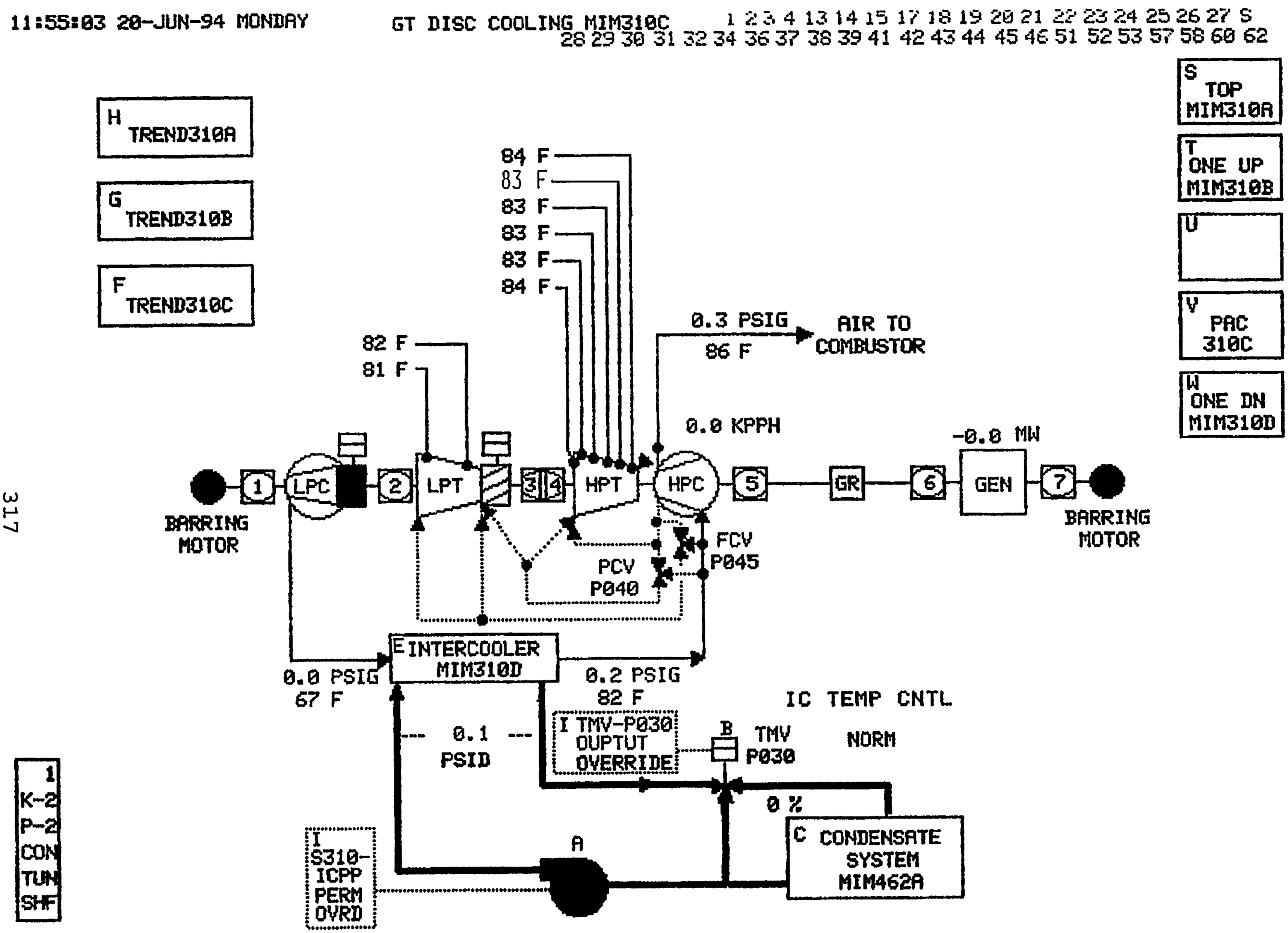


PCU	MASTER	TYPE OF MODULE	NO OF SLAVES
PCU01	00104	MFP01	10
	00110	AMM02	7
PCU03	00304	MFP01	11
	00306	MFP01	7
	00308	MFP01	13
	00310	AMM02	8
PCU11	01104	MFP01	16
	01106	MFP01	17
	01108	MFP01	0
	01110	AMM02	7
PCU12	01204	MFP01	15
	01206	MFP01	7
	01210	AMM02	6
PCU19	01904	MFP01	6
	01906	MFP01	9
	01908	MFP01	23
PCU20	02004	MFP01	13
	02006	MFP01	12
	02008	MFP01	0
	02010	AMM02	8
	02012	AMM02	7
	02014	AMM02	8
PCU24	02404	MFP01	1
PCU31	03104	MFP01	10
	03106	MFP01	18
	03110	AMM02	6
	03112	AMM02	8
PCU32	03204	MFP01	11
	03206	MFP01	11
	03210	AMM02	8
	03212	AMM02	6

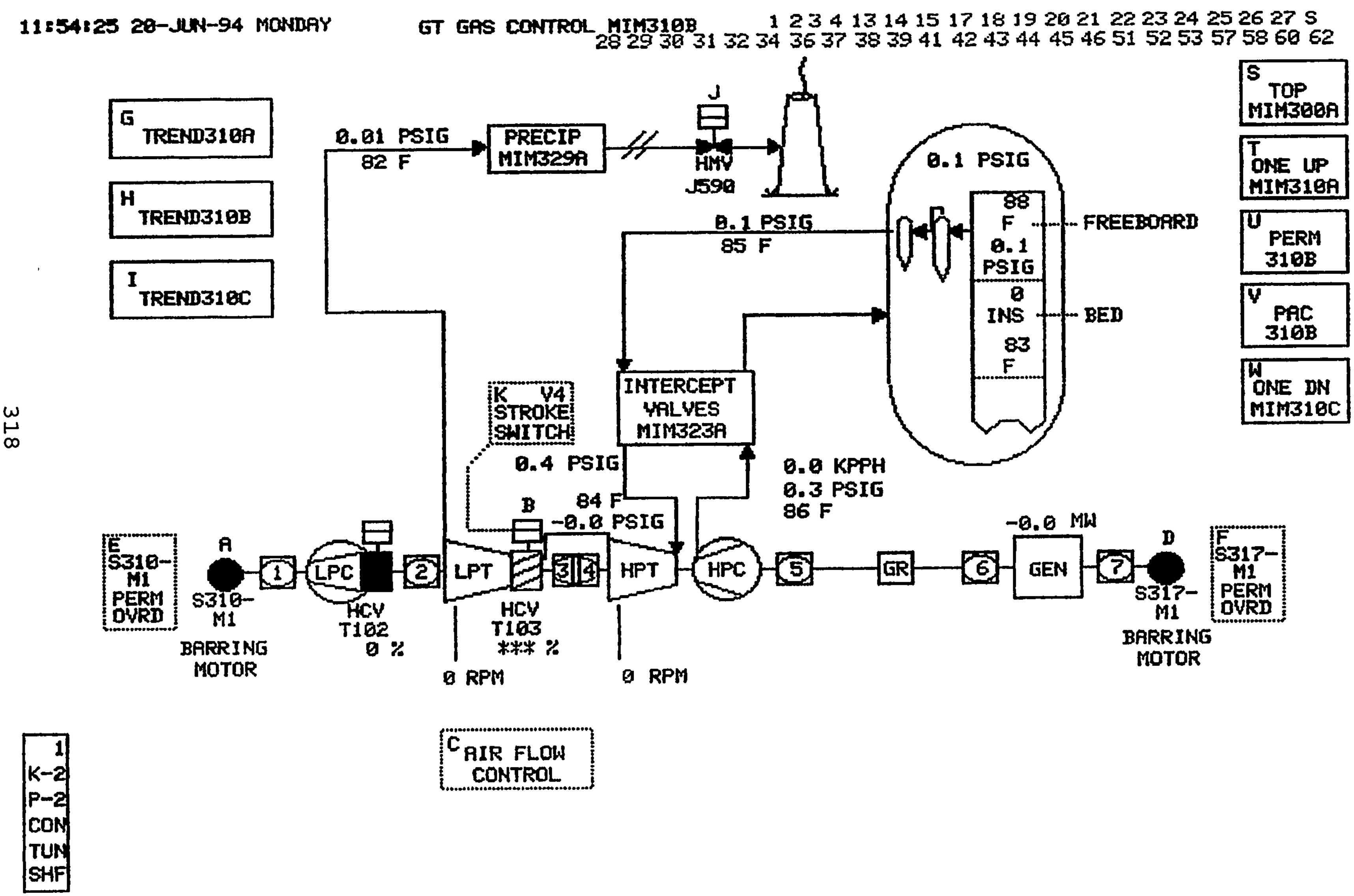
NET – 90 SYSTEM FINAL CONFIGURATION

FIGURE 6.19.2

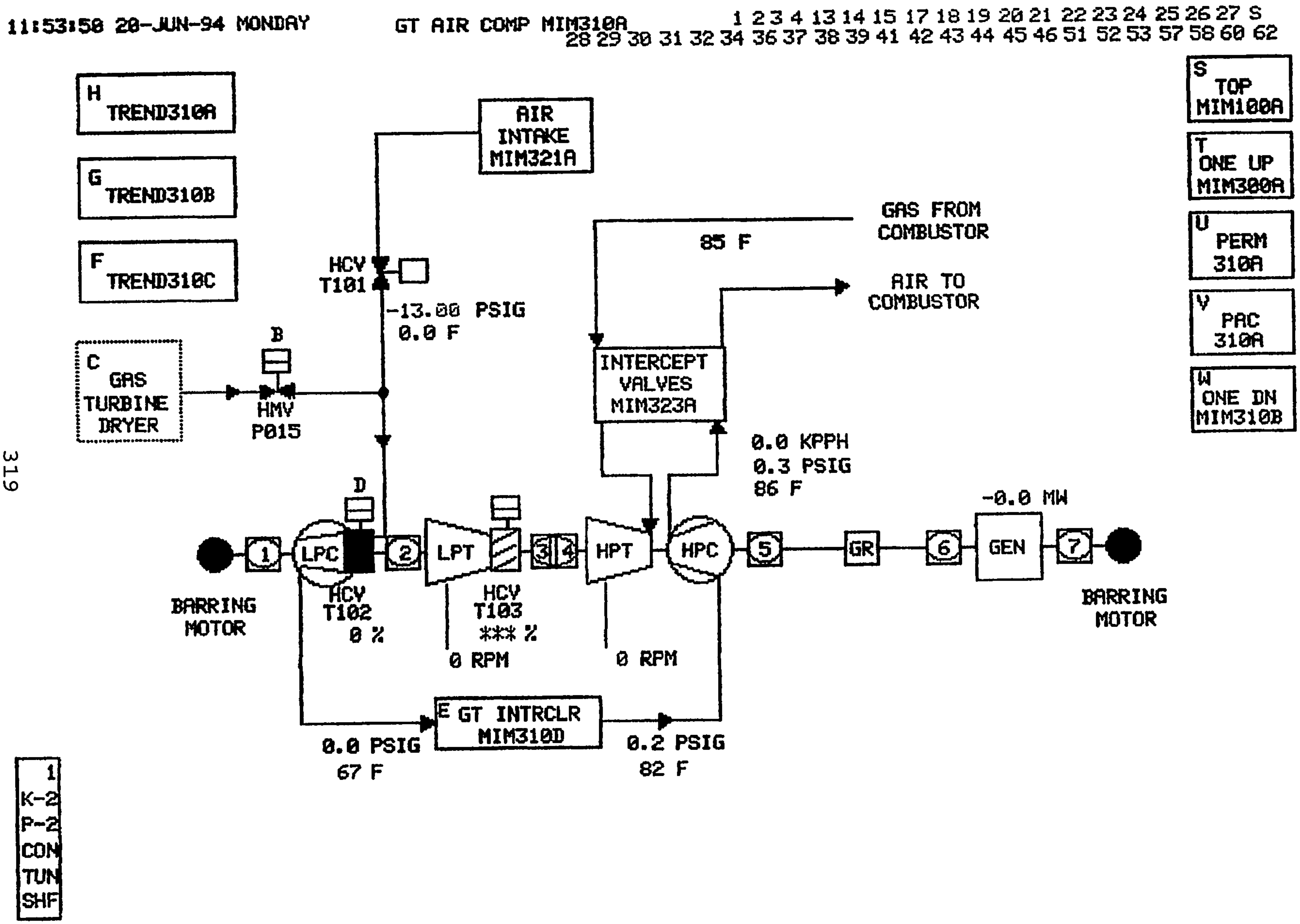
usr6 mech tidd/u doe/figure2.dgn



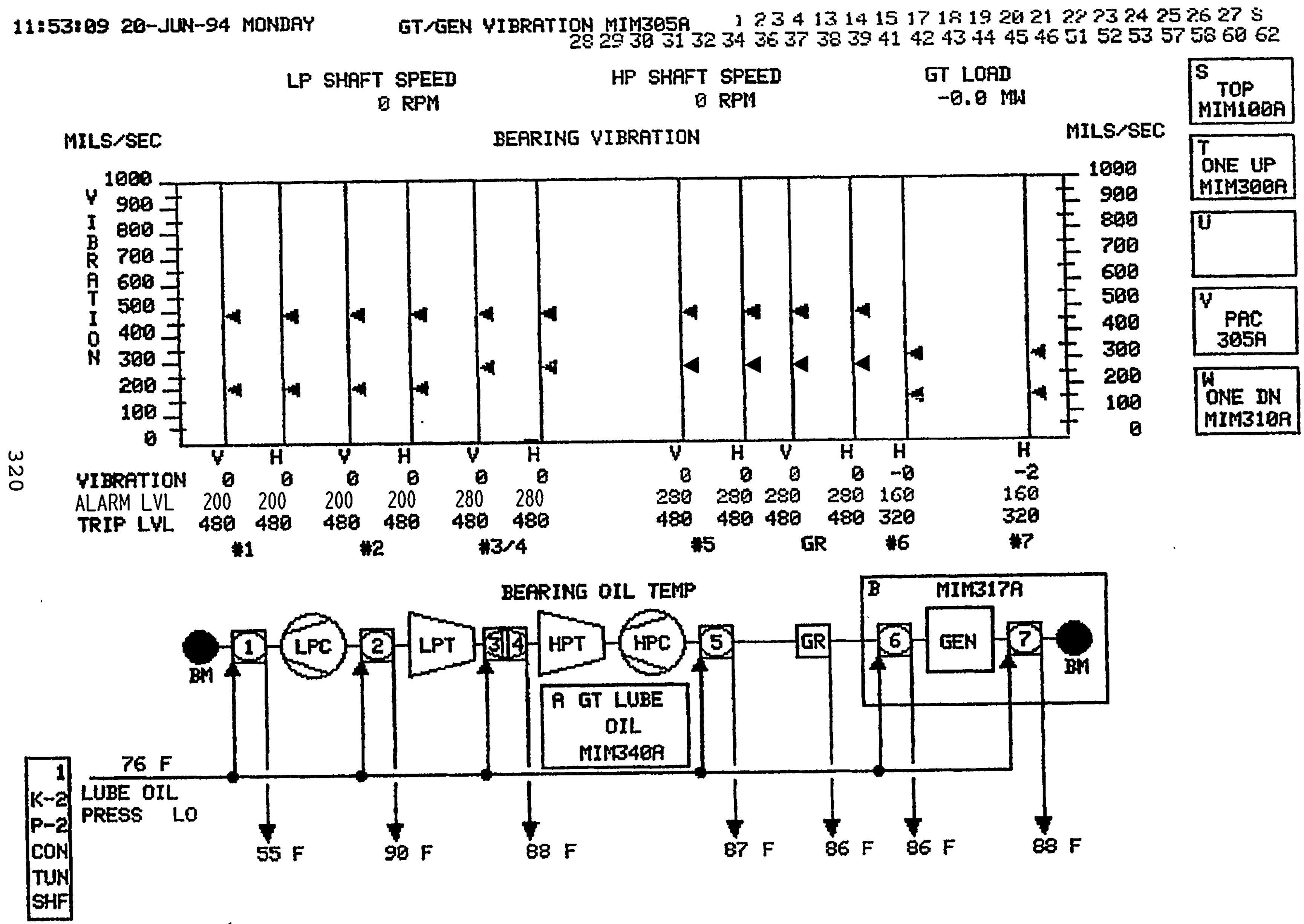
TYPICAL NET – 90 GAS TURBINE MIMIC SCREEN
FIGURE 6.19.3



TYPICAL NET – 90 GAS TURBINE MIMIC SCREEN
FIGURE 6.19.4

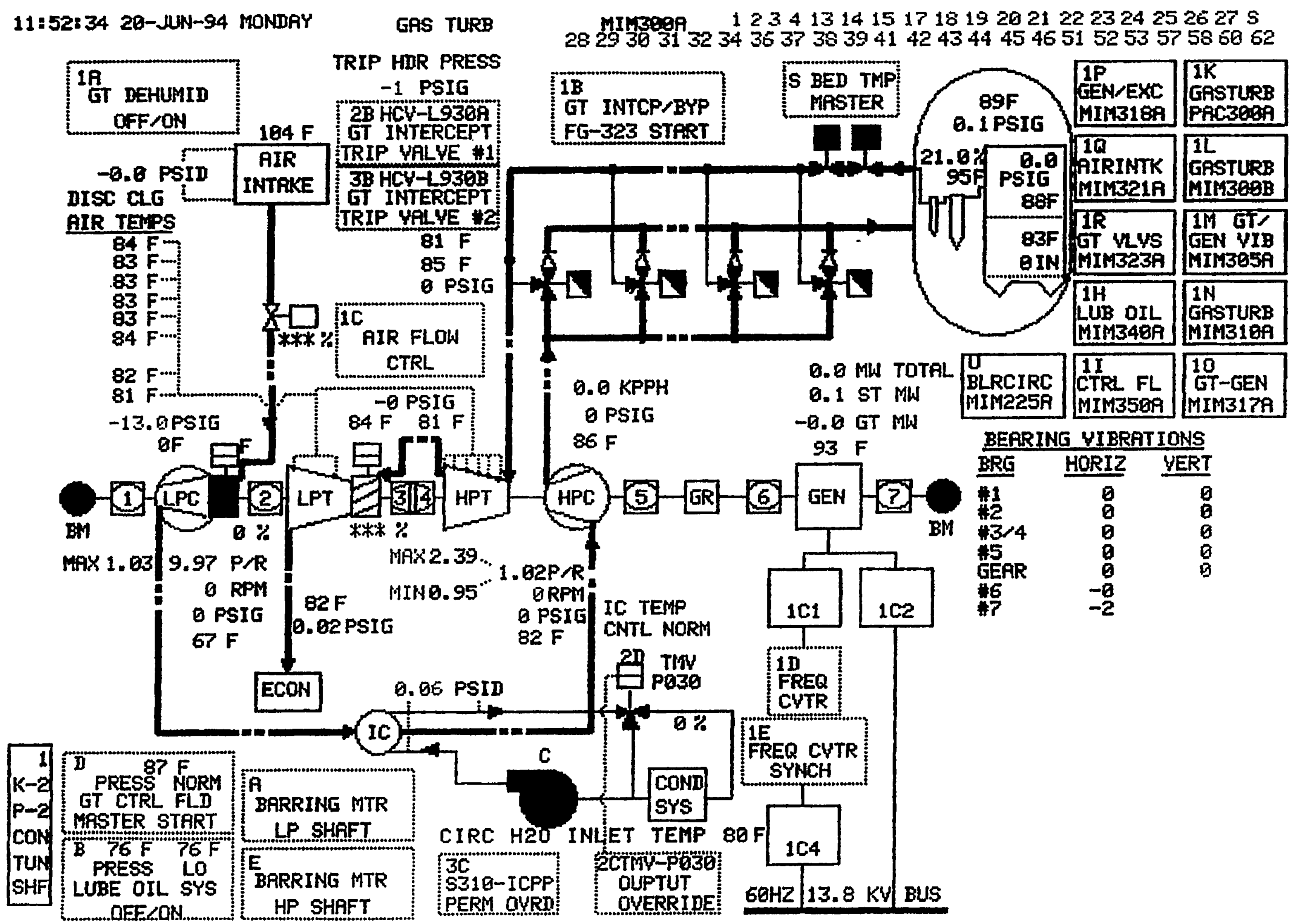


TYPICAL NET – 90 GAS TURBINE MIMIC SCREEN
FIGURE 6.19.5



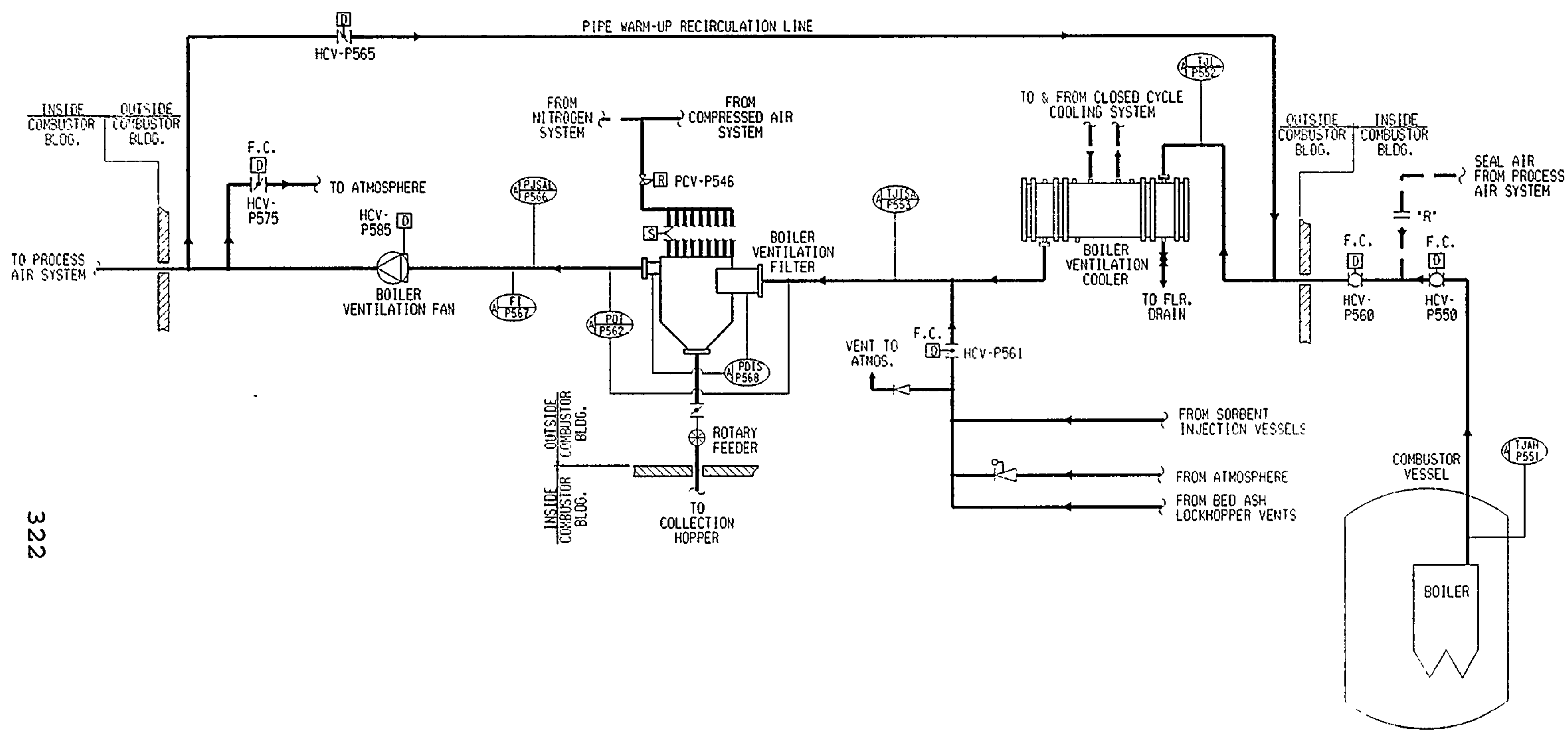
TYPICAL NET – 90 GAS TURBINE MIMIC SCREEN

FIGURE 6.19.6



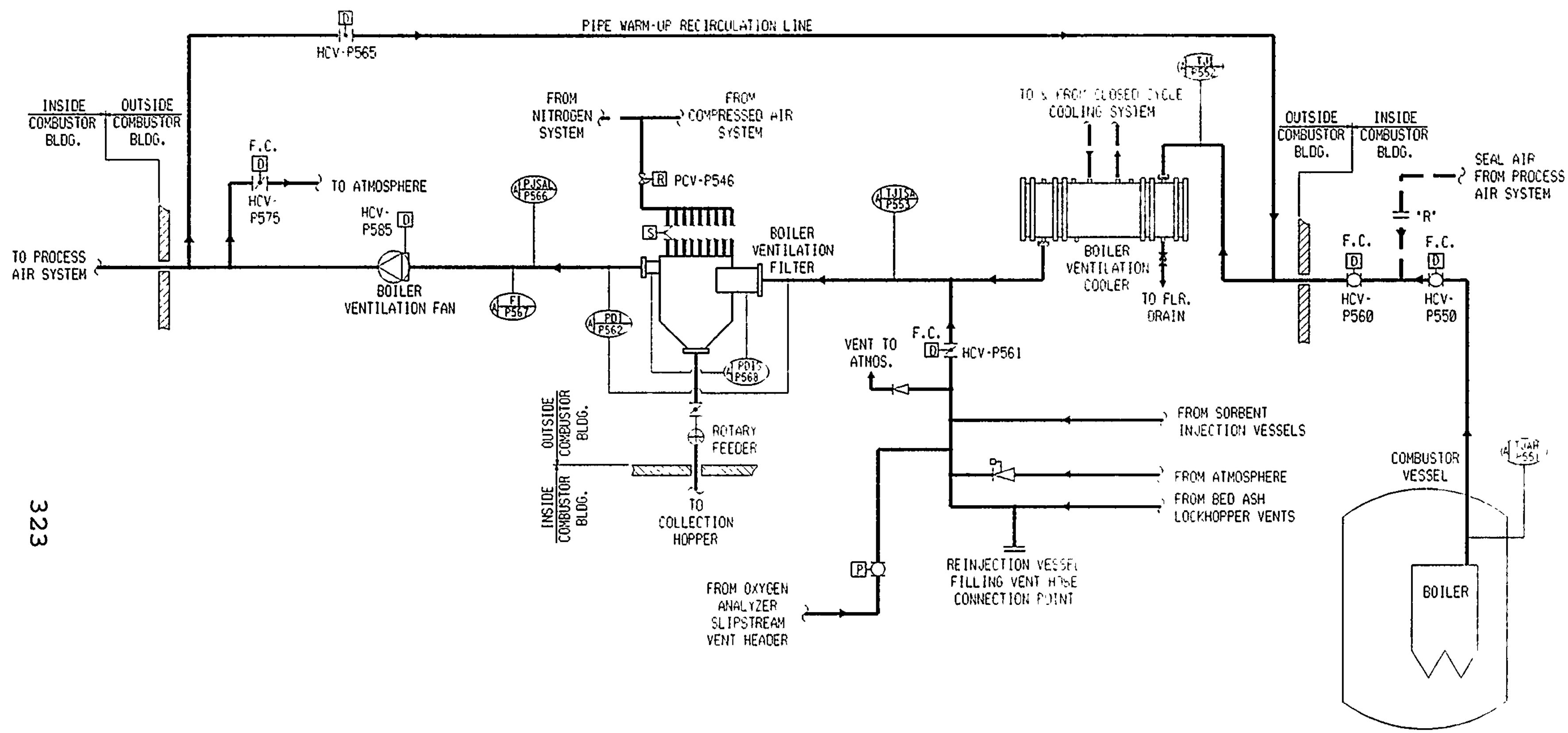
TYPICAL NET – 90 GAS TURBINE MIMIC SCREEN

FIGURE 6.19.7

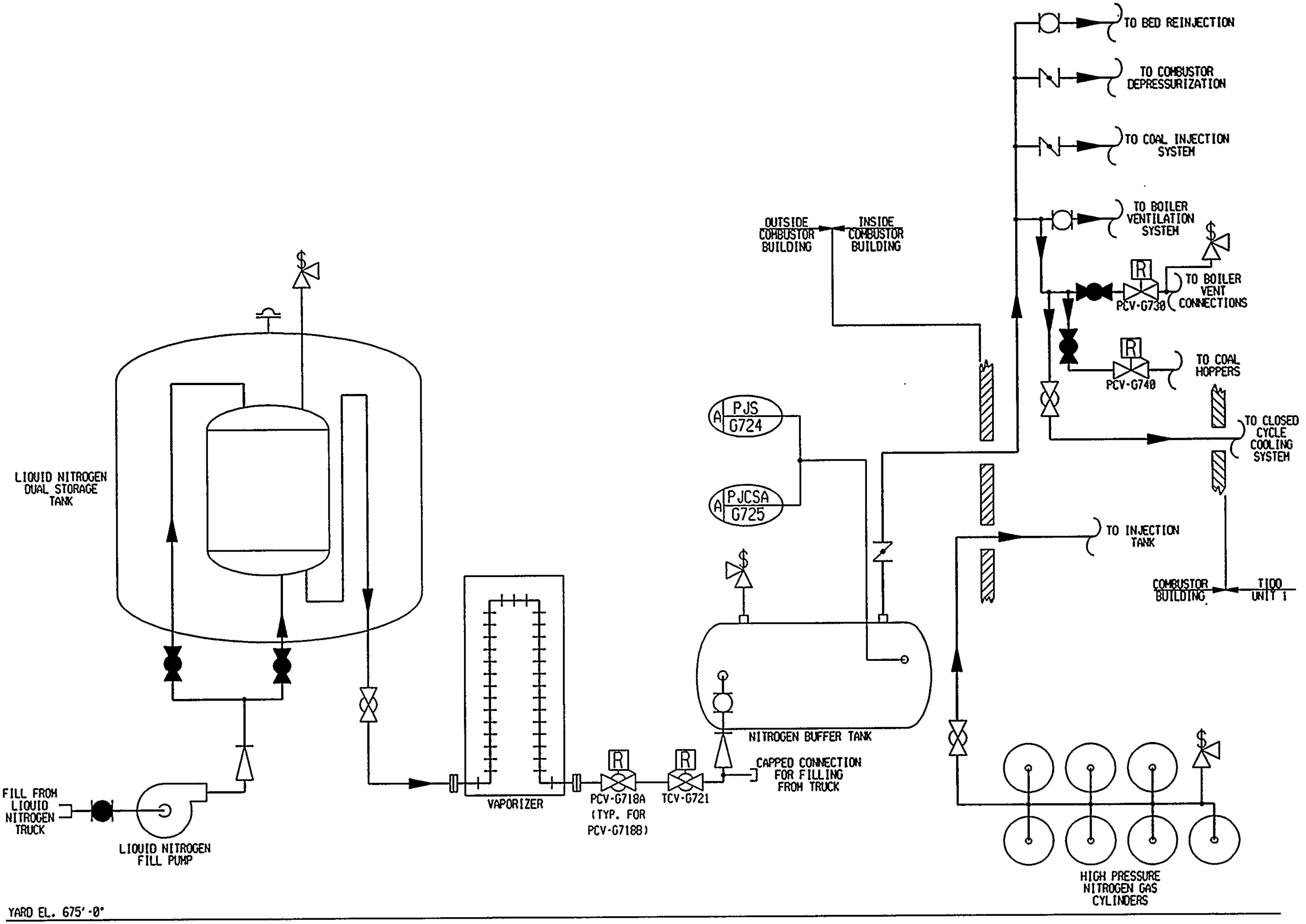


BOILER VENTILATION SYSTEM SIMPLIFIED FLOW DIAGRAM
ORIGINAL CONFIGURATION
FIGURE 6.20.1

usr6/mech/tidd/u doe/figure2.dgn

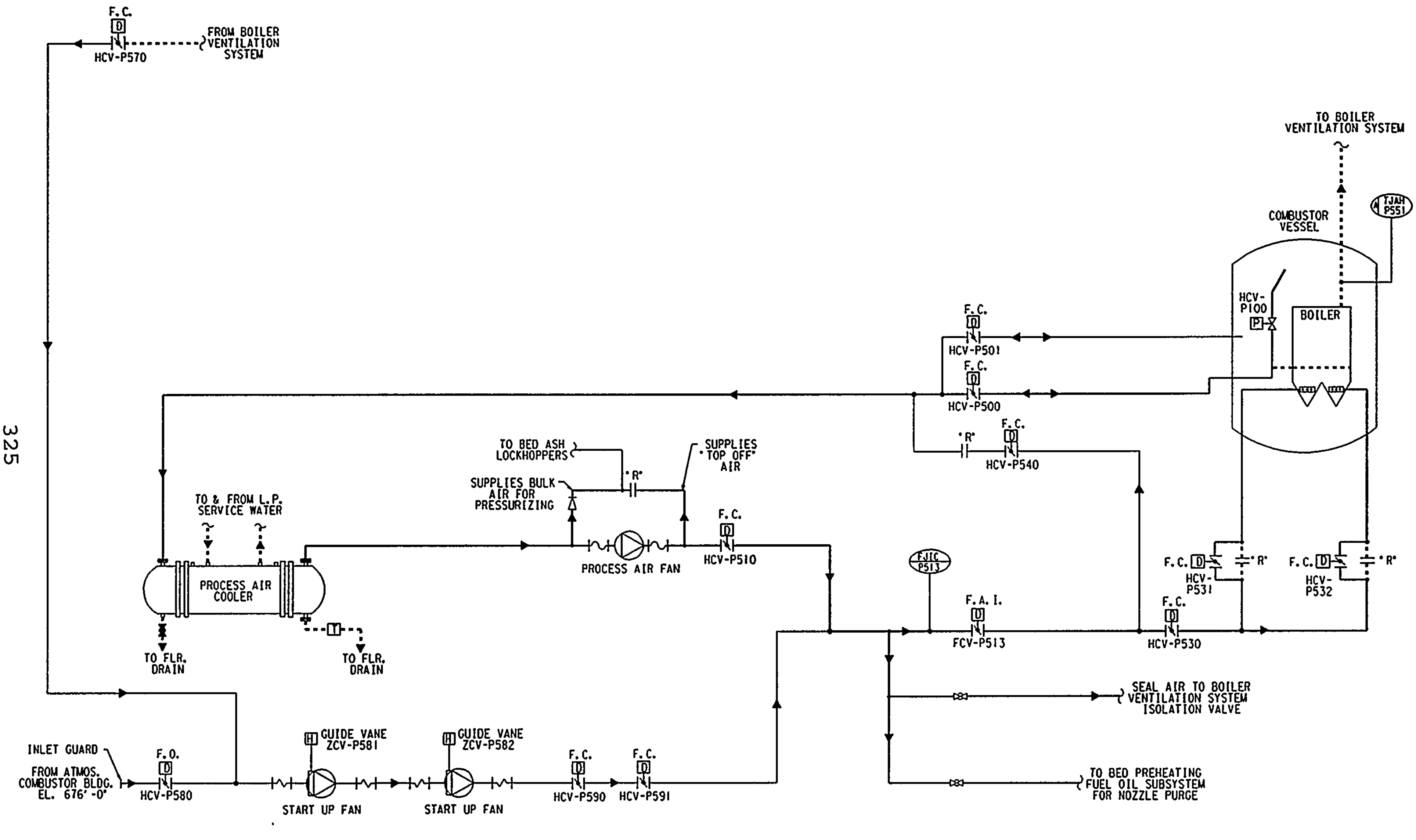


BOILER VENTILATION SYSTEM SIMPLIFIED FLOW DIAGRAM
FINAL CONFIGURATION
FIGURE 6.20.2

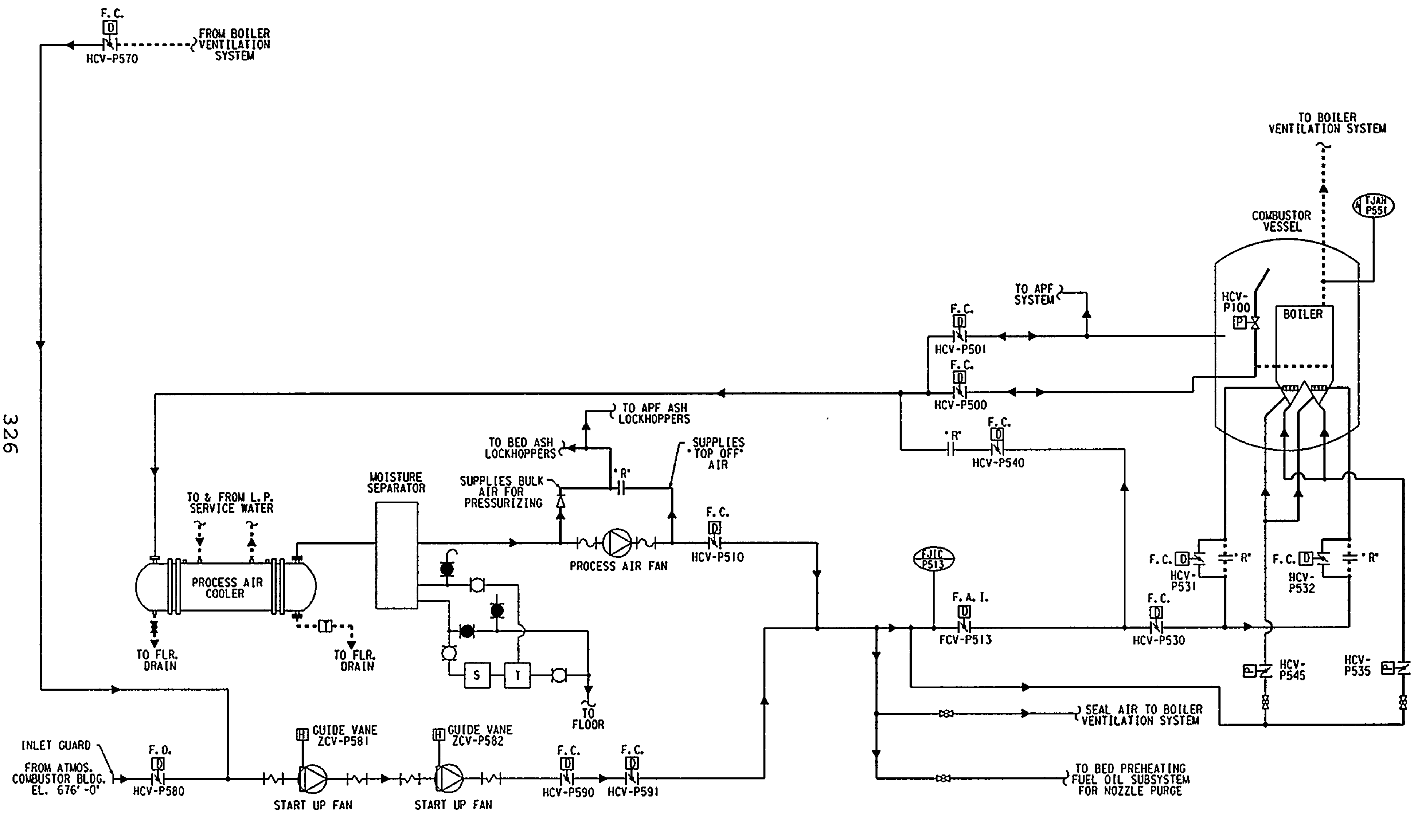


NITROGEN SIMPLIFIED FLOW DIAGRAM

FIGURE 6.21.1



PROCESS AIR SYSTEM SIMPLIFIED FLOW DIAGRAM
INITIAL CONFIGURATION
FIGURE 6.22.1

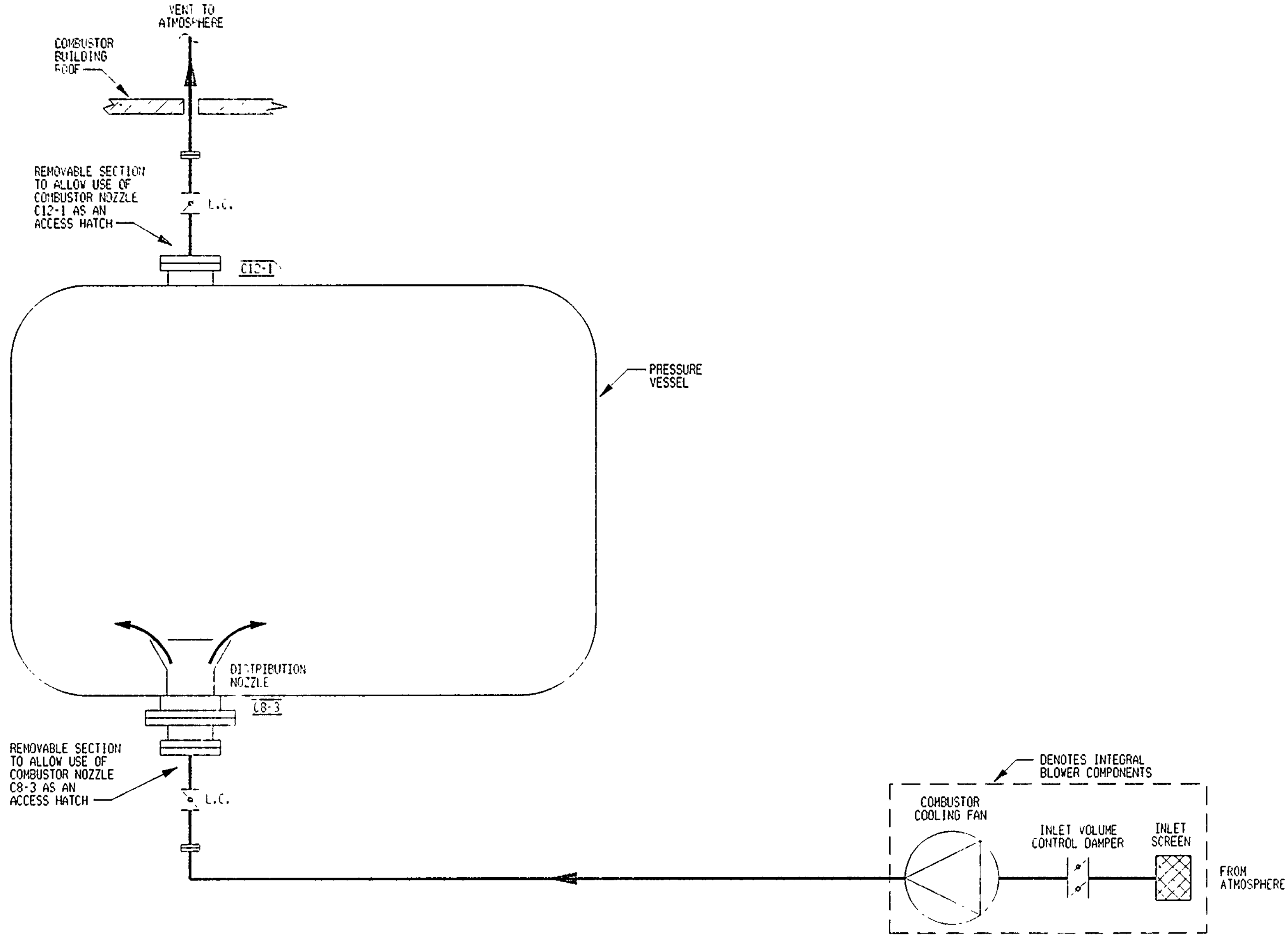


PROCESS AIR SYSTEM SIMPLIFIED FLOW DIAGRAM

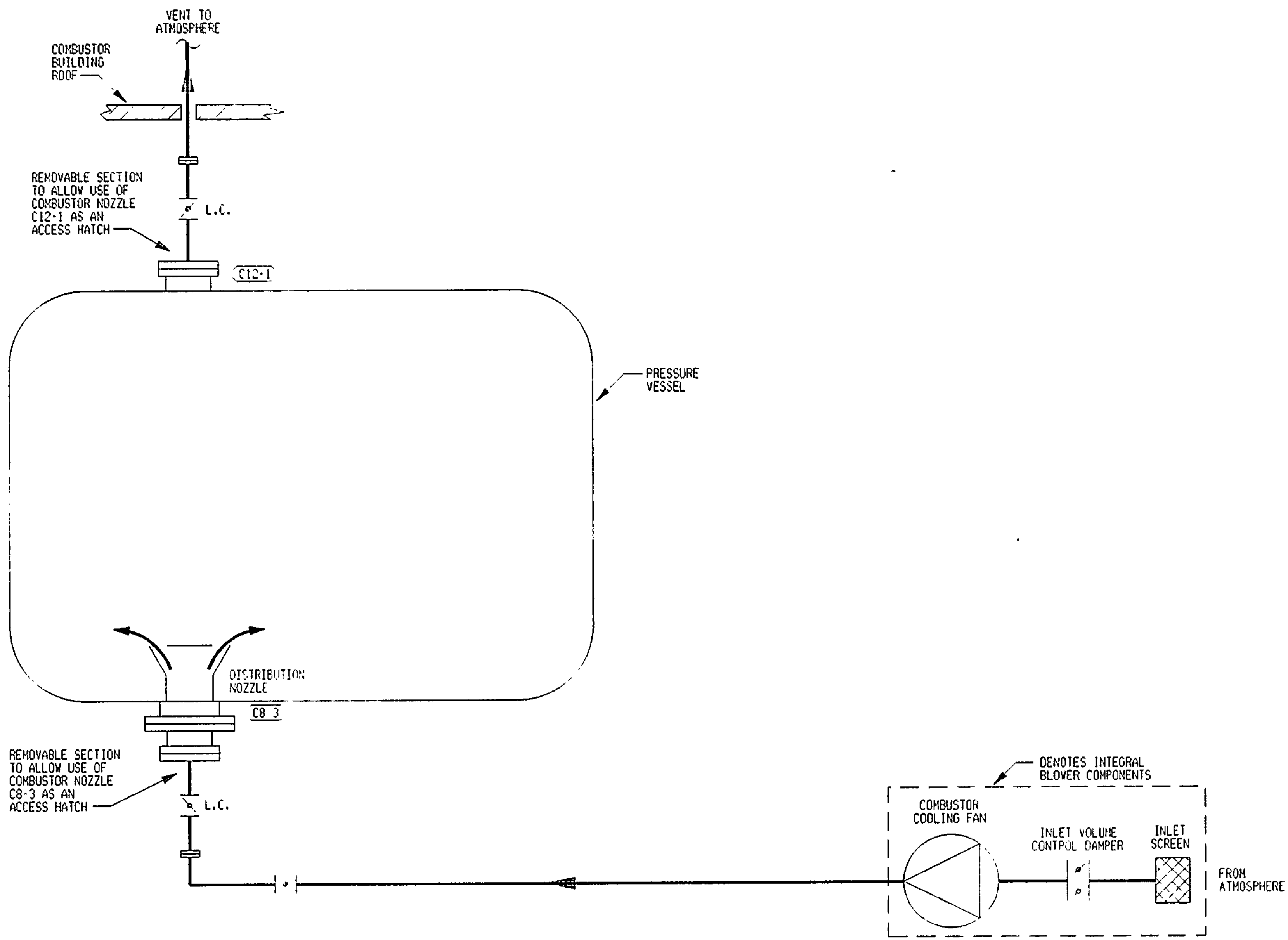
FINAL CONFIGURATION

FIGURE 6.22.2

usrt mech. tldd u doe/figure2.dgn



COMBUSTOR COOLING SYSTEM SIMPLIFIED FLOW DIAGRAM
ORIGINAL CONFIGURATION
FIGURE 6.23.1



COMBUSTOR COOLING SYSTEM SIMPLIFIED FLOW DIAGRAM
FINAL CONFIGURATION
FIGURE 6.23.2

Photo 6.1.1 - Photo of combustor vessel being shipped to Tidd on the Ohio River.

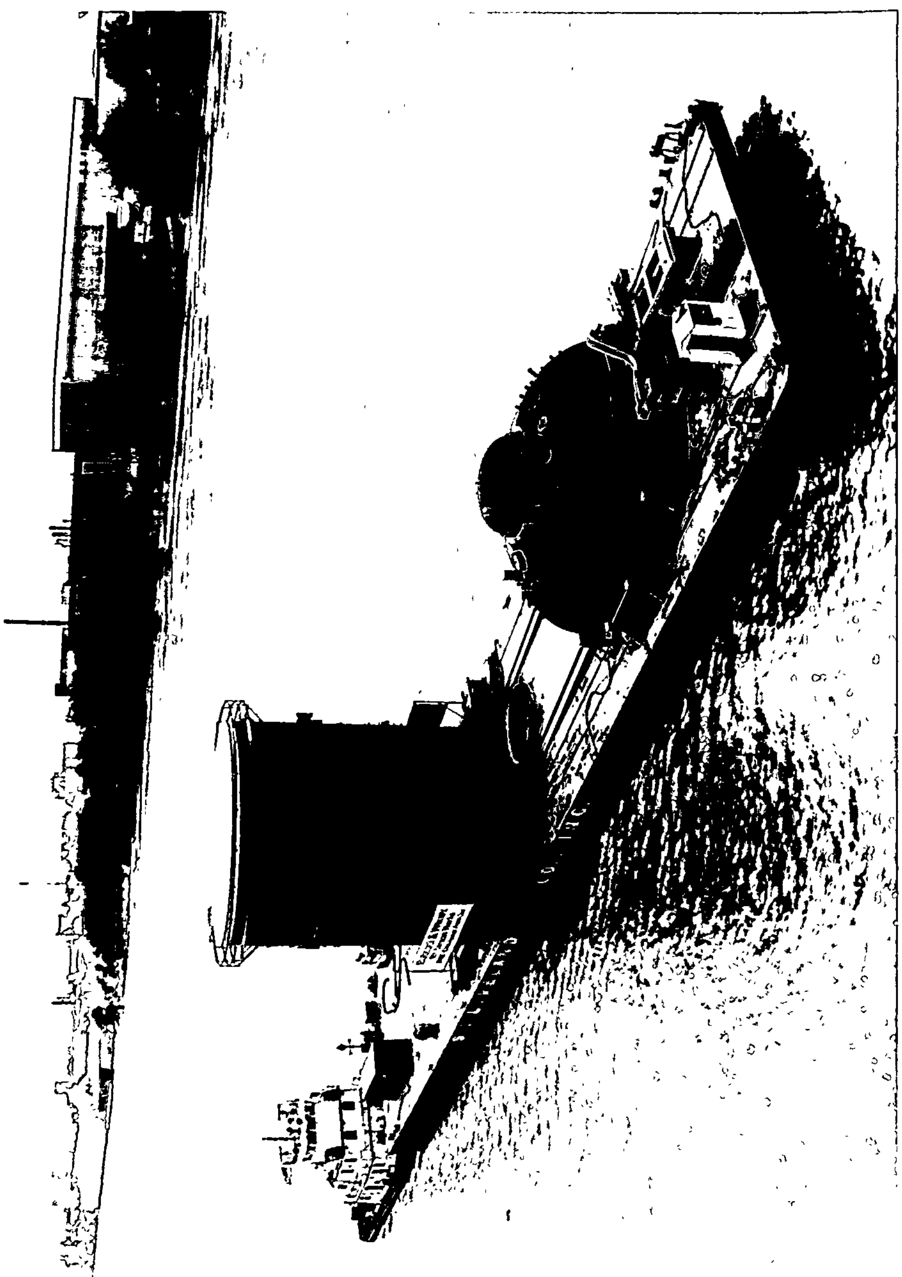


Photo 6.1.2 - Photo of combustor vessel being off loaded at Tidd Plant.

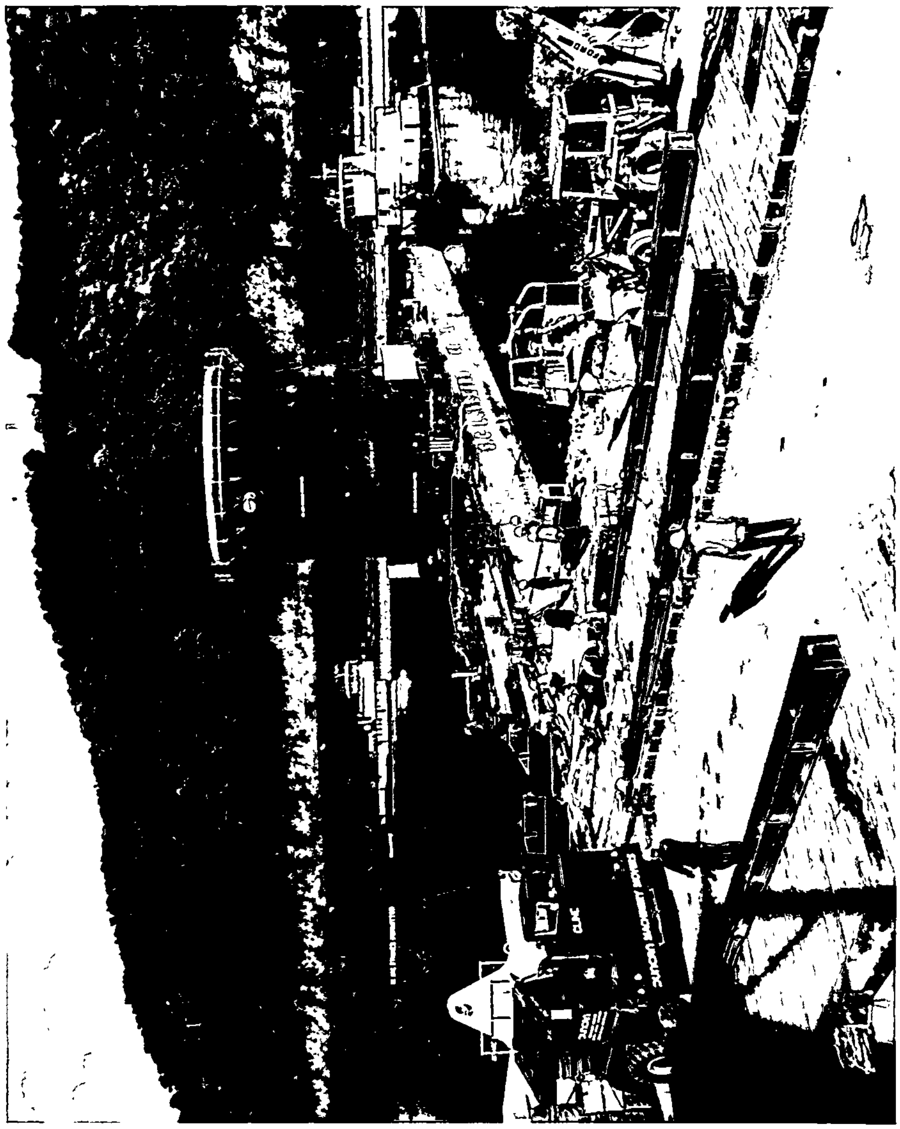


Photo 6.1.3 - Photo of completed combustor vessel at Tidd Plant.

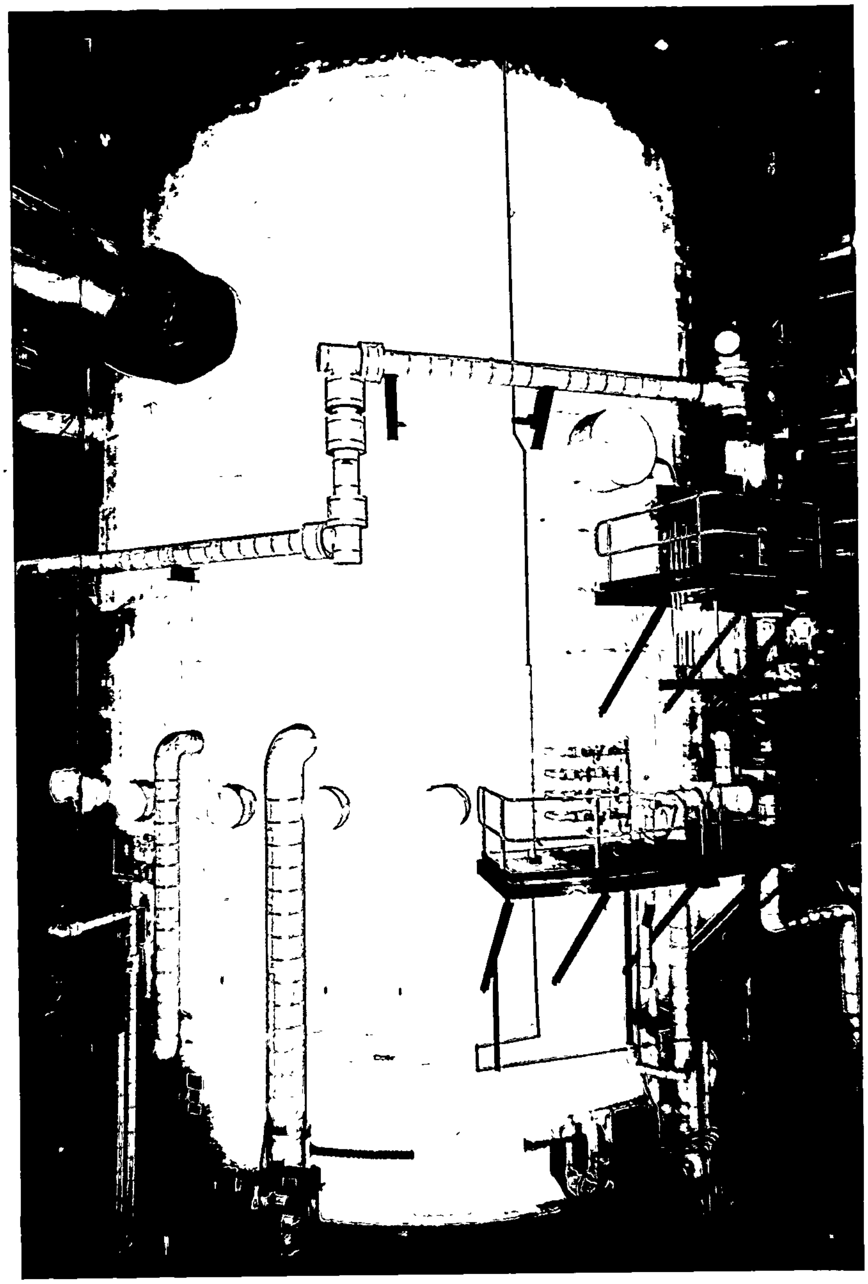


Photo 6.1.4 - Photo of top of combustor showing oxygen analyzer equipment.

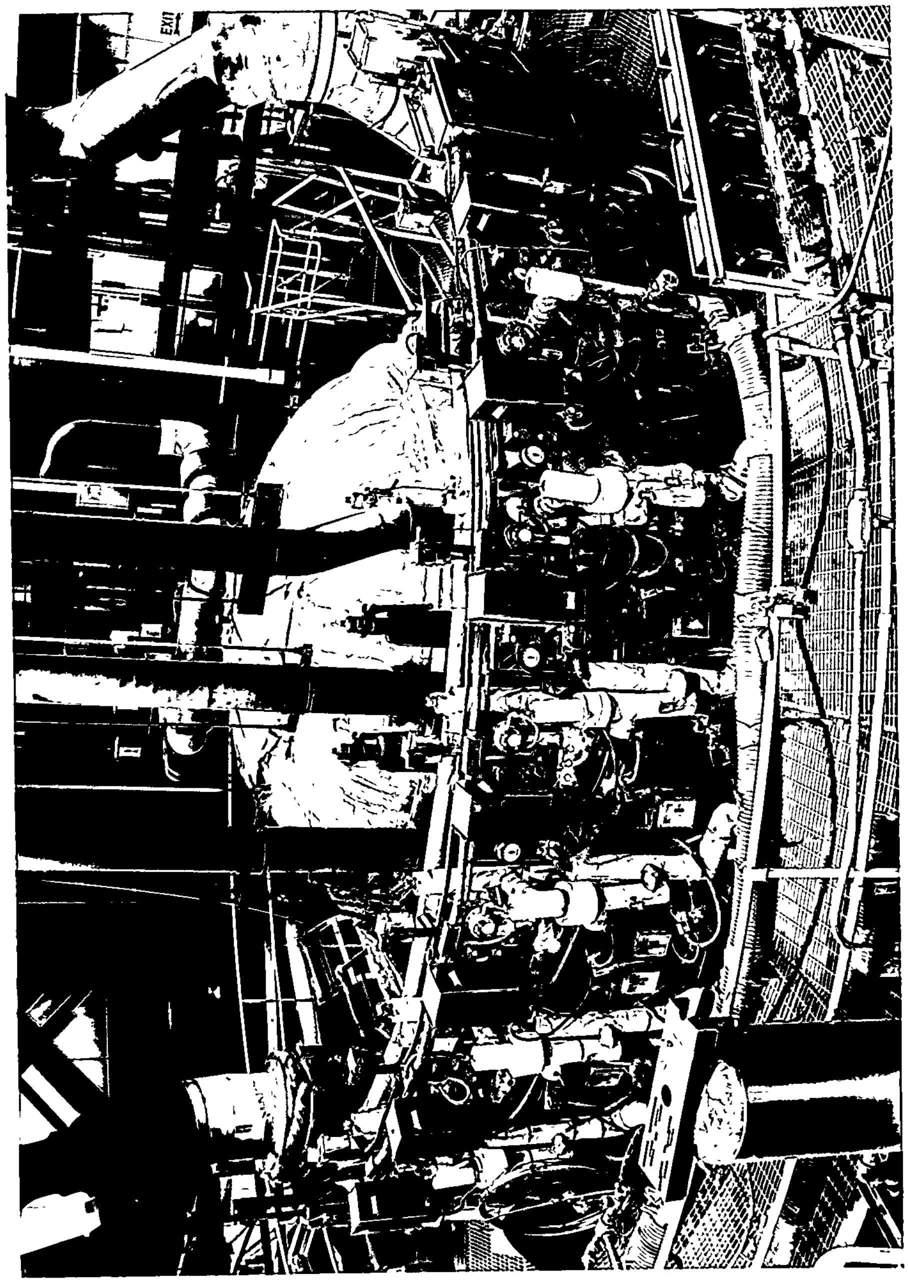


Photo 6.2.1 - Photo of boiler vertical separator sideview.

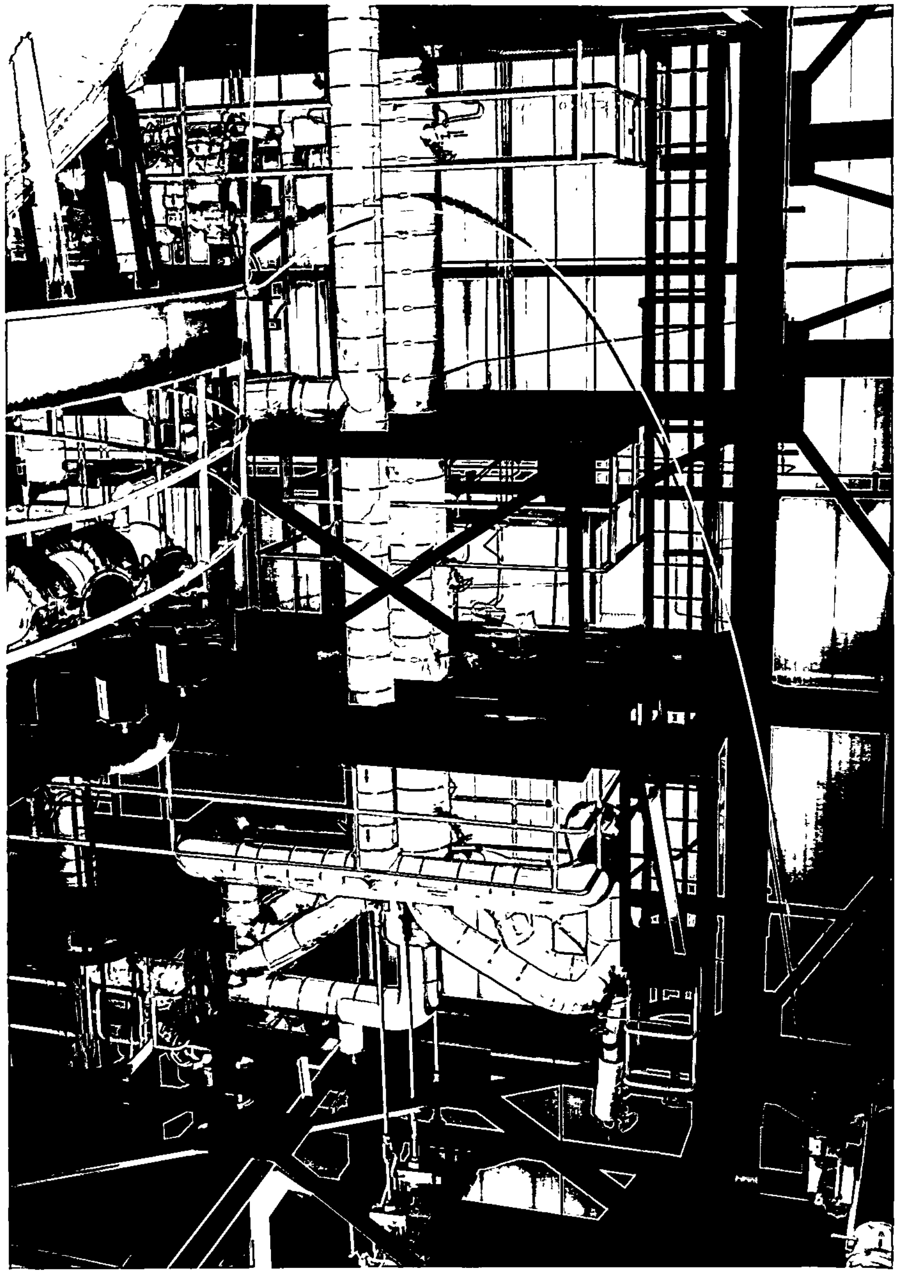


Photo 6.2.2 - Photo of steam turbine.

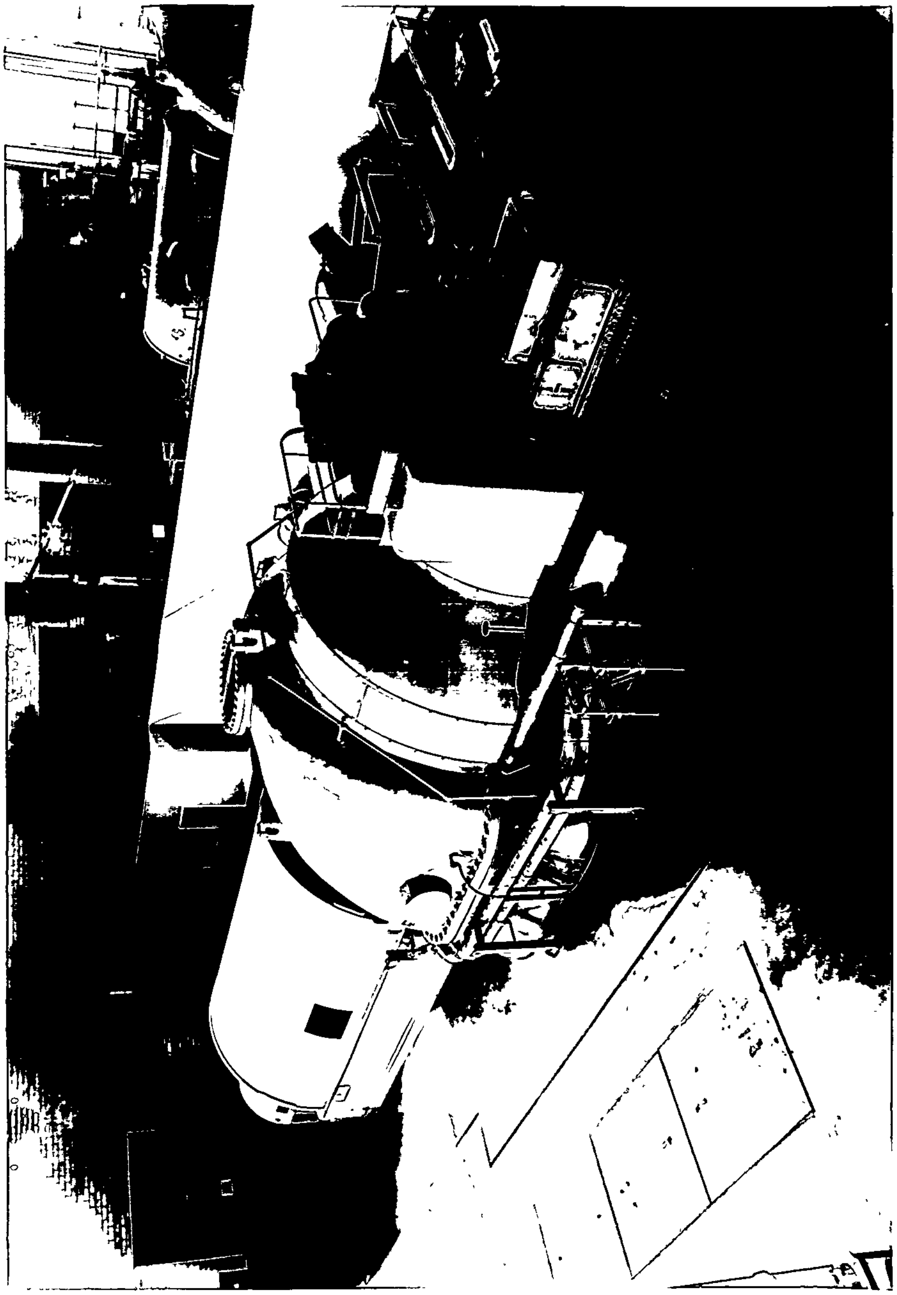


Photo 6.4.1 - Photo of combustor depressurization valves.

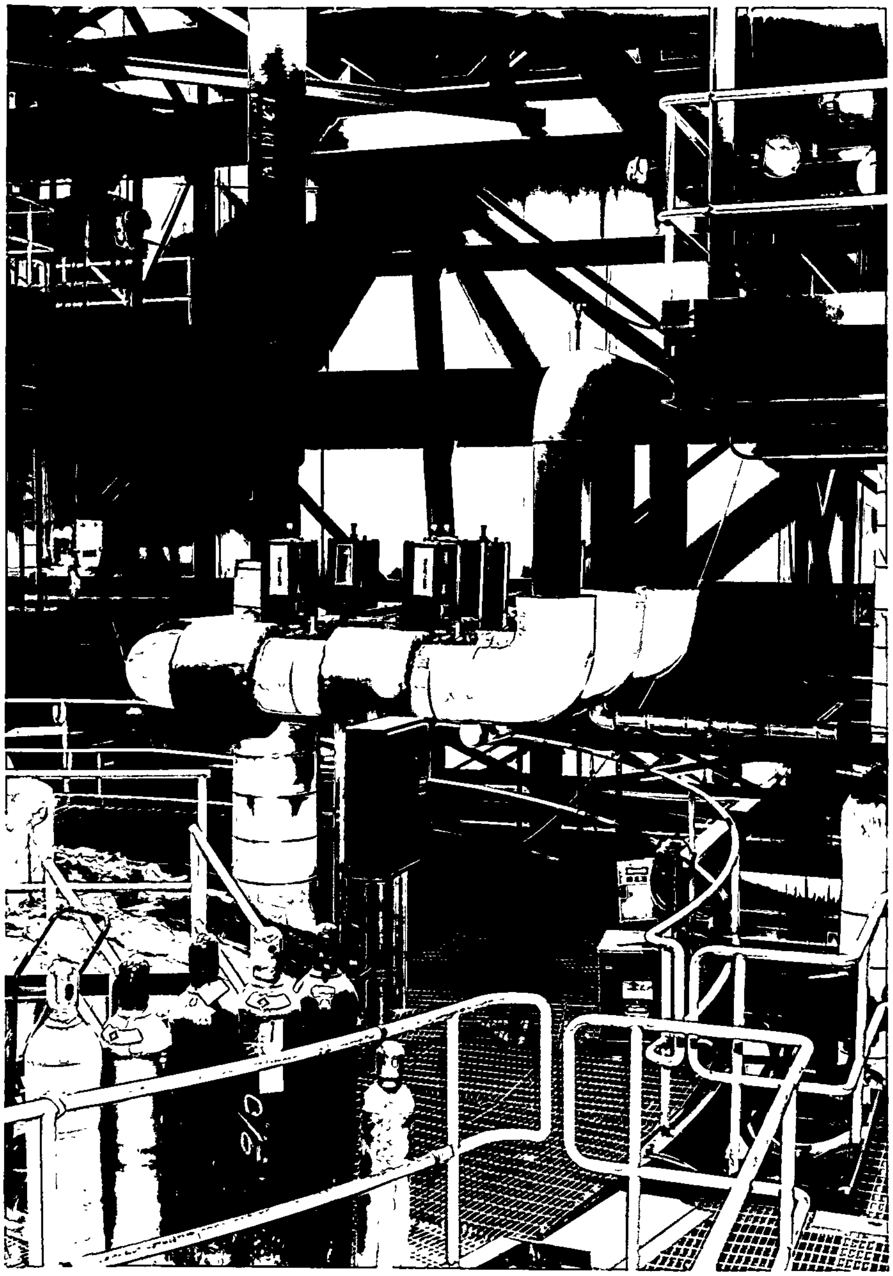


Photo 6.5.1 - Photo of bed preheater module.

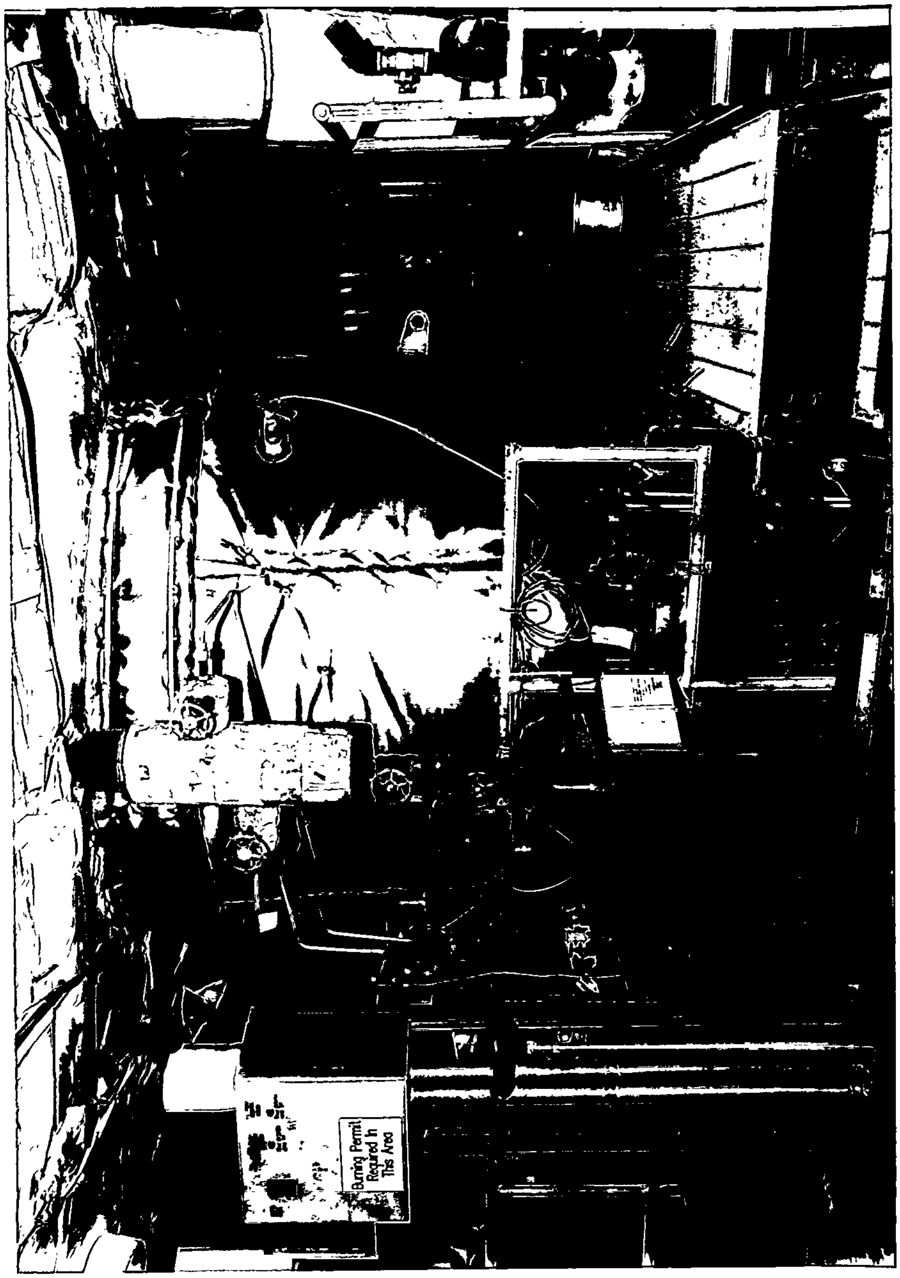


Photo 6.6.1 - Photo of sorbent preparation crusher.

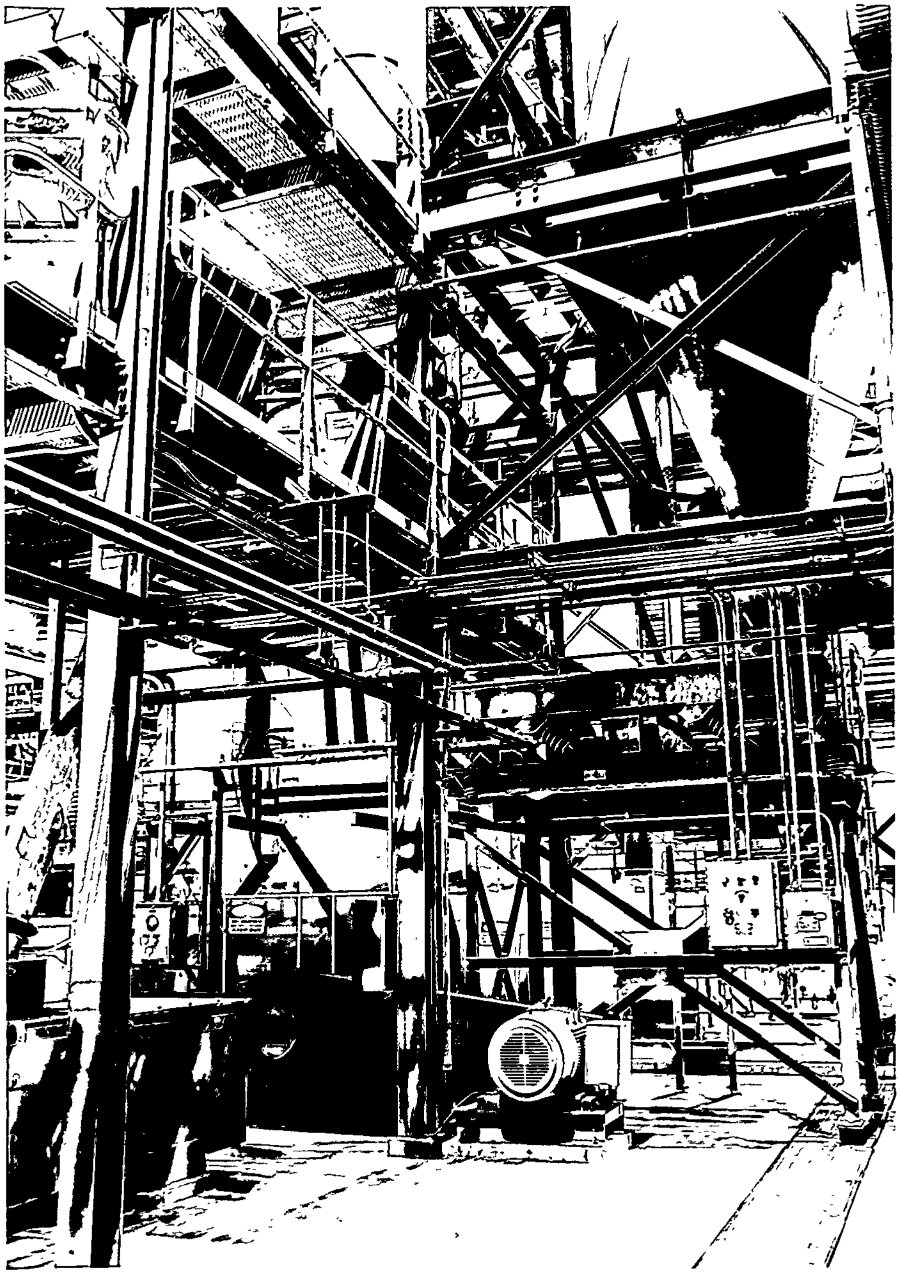


Photo 6.7.1 - Photo of coal crusher.

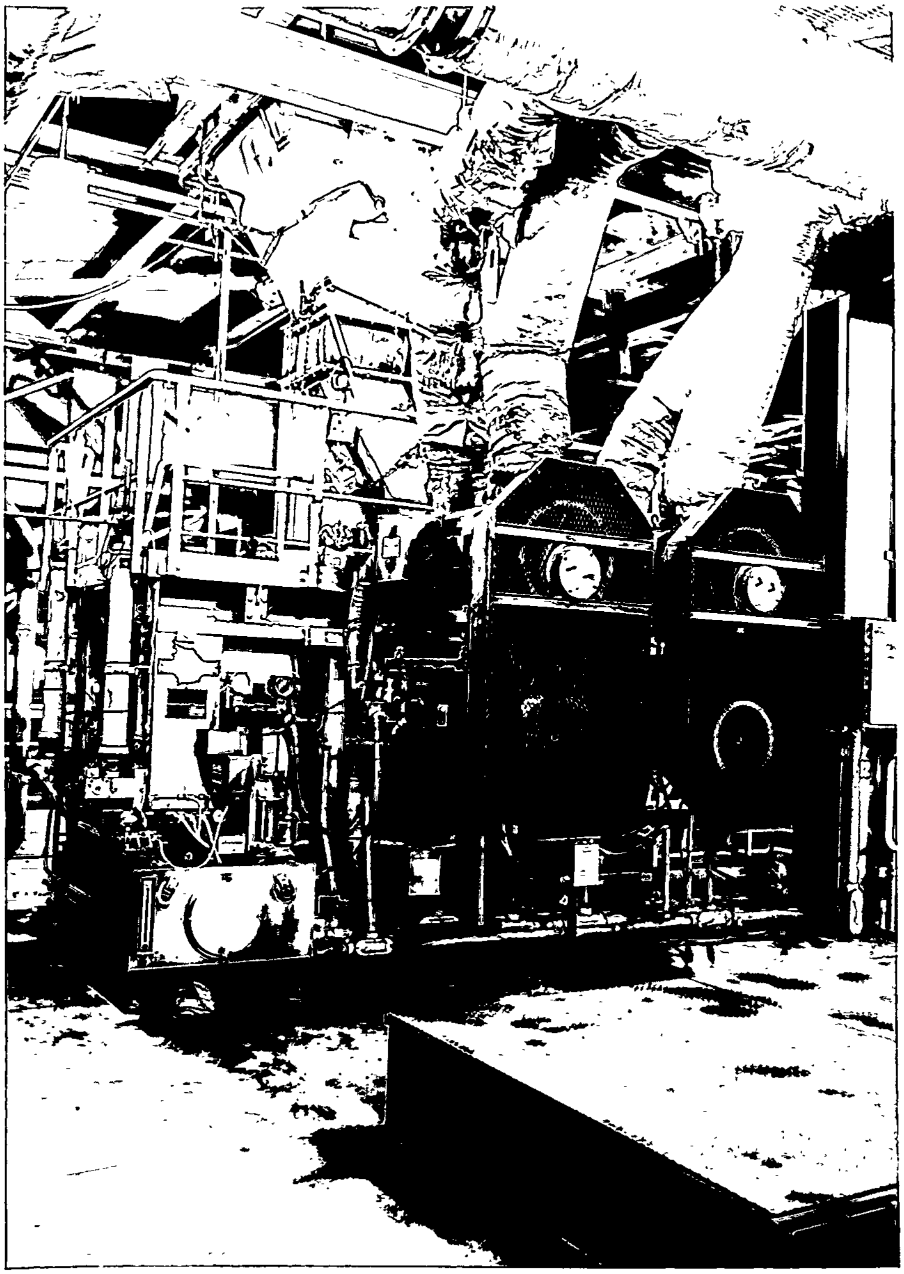


Photo 6.7.2 - Photo of coal paste mixer discharge and paste slump testing station.

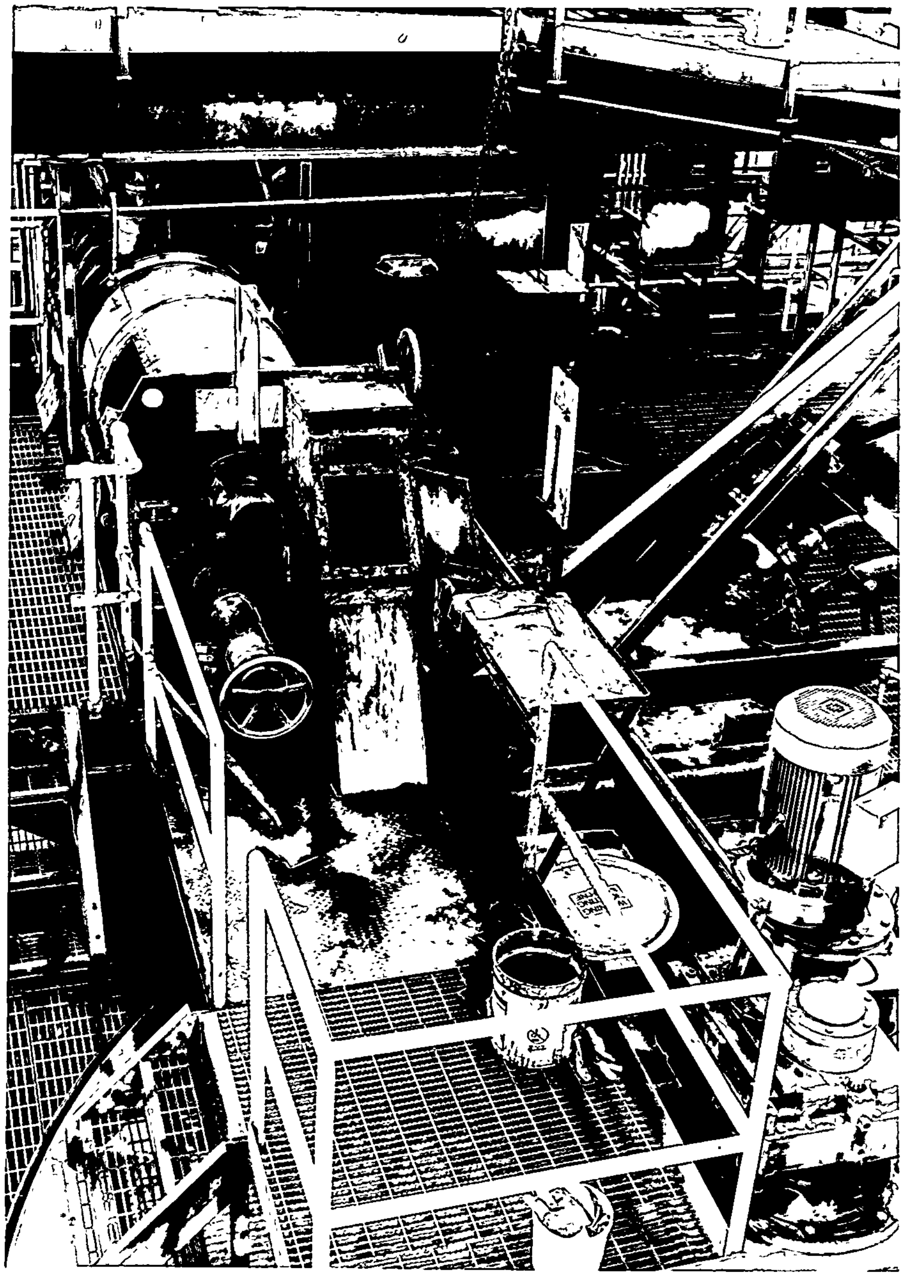


Photo 6.7.3 - Photo of paste mixing train showing feeder and mixer.

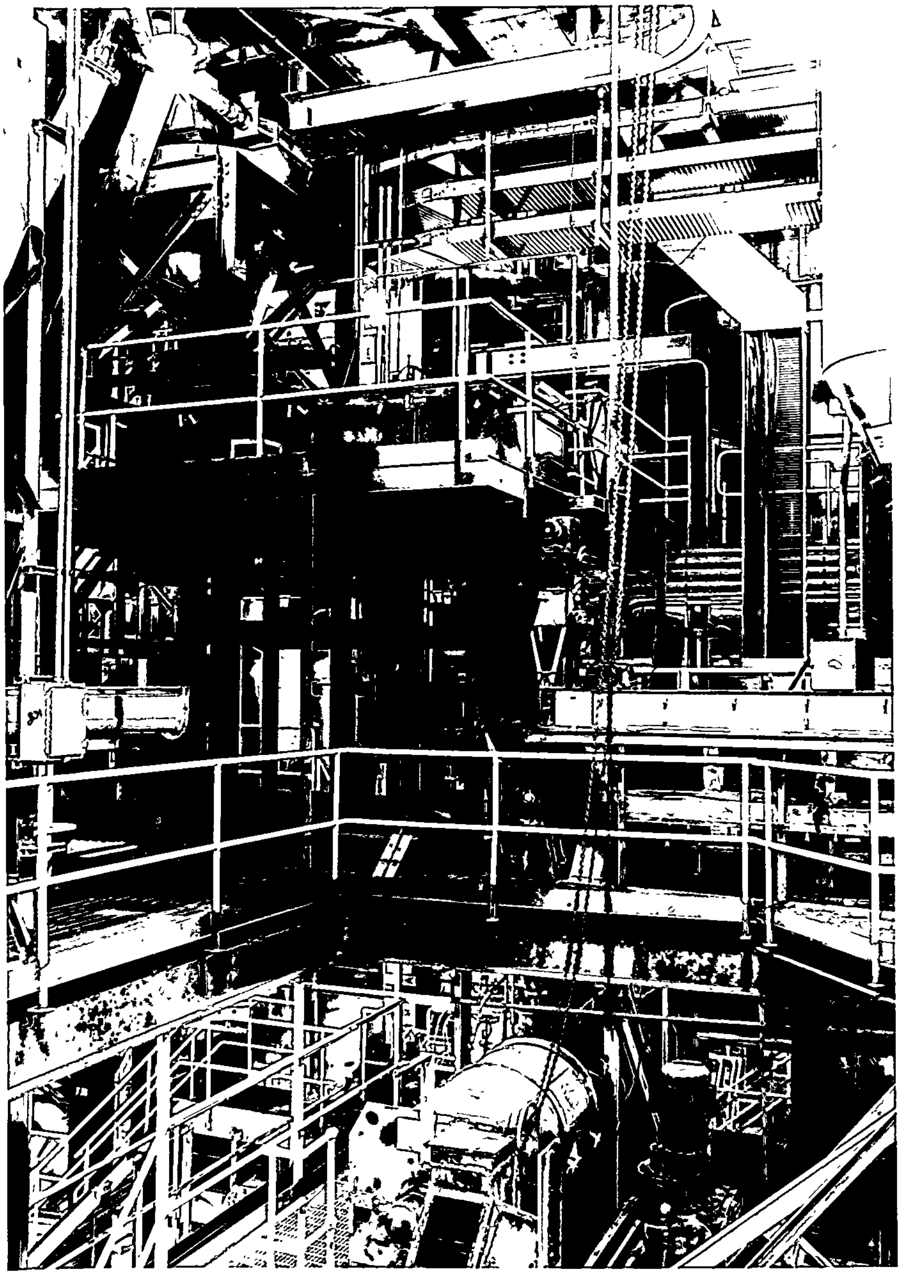


Photo 6.8.1 - Photo of coal paste tank and paste pumps.

Photo 6.8.2 - Photo of discharge end of paste pumps.

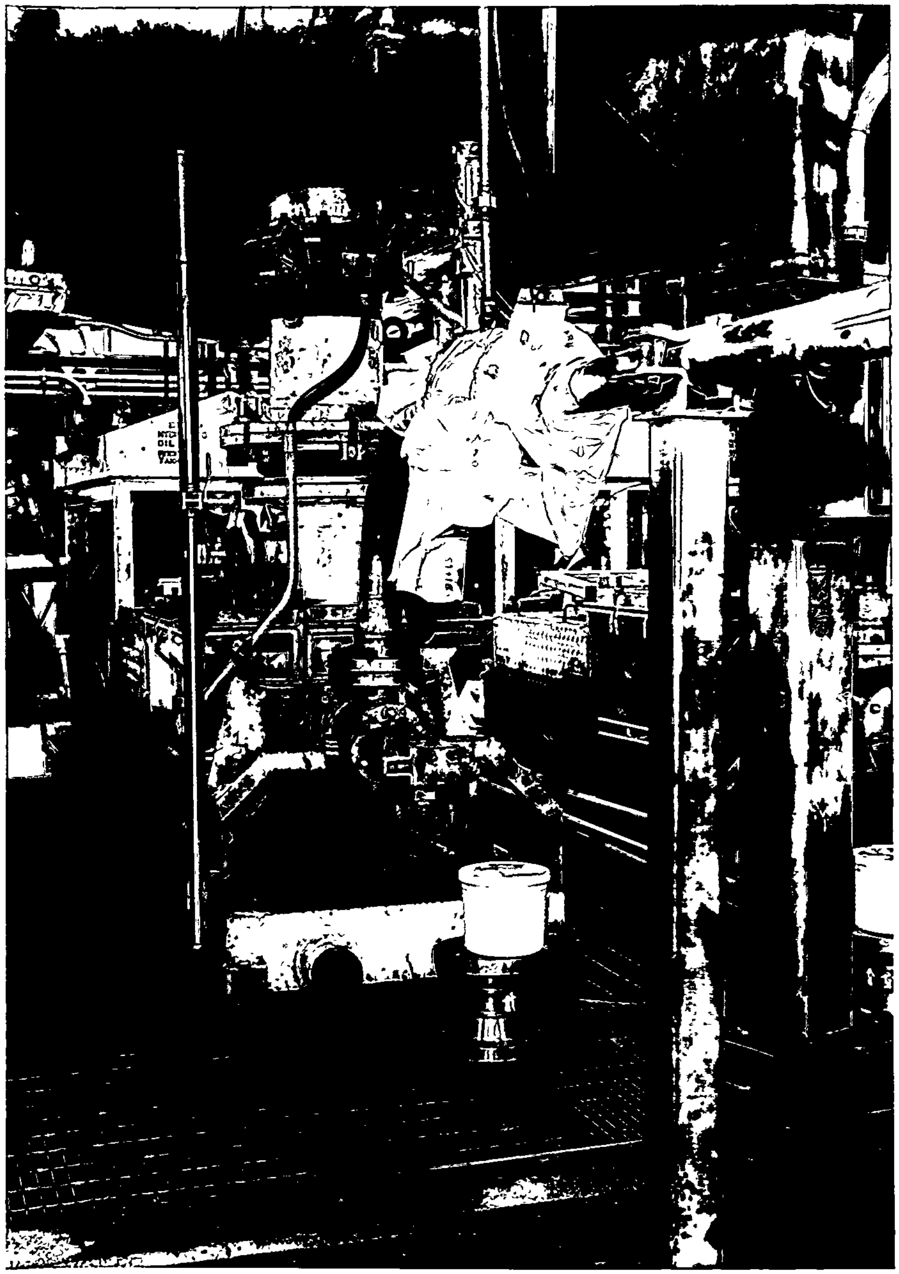


Photo 6.8.3 - Photo of the coal and sorbent injection burner deck.

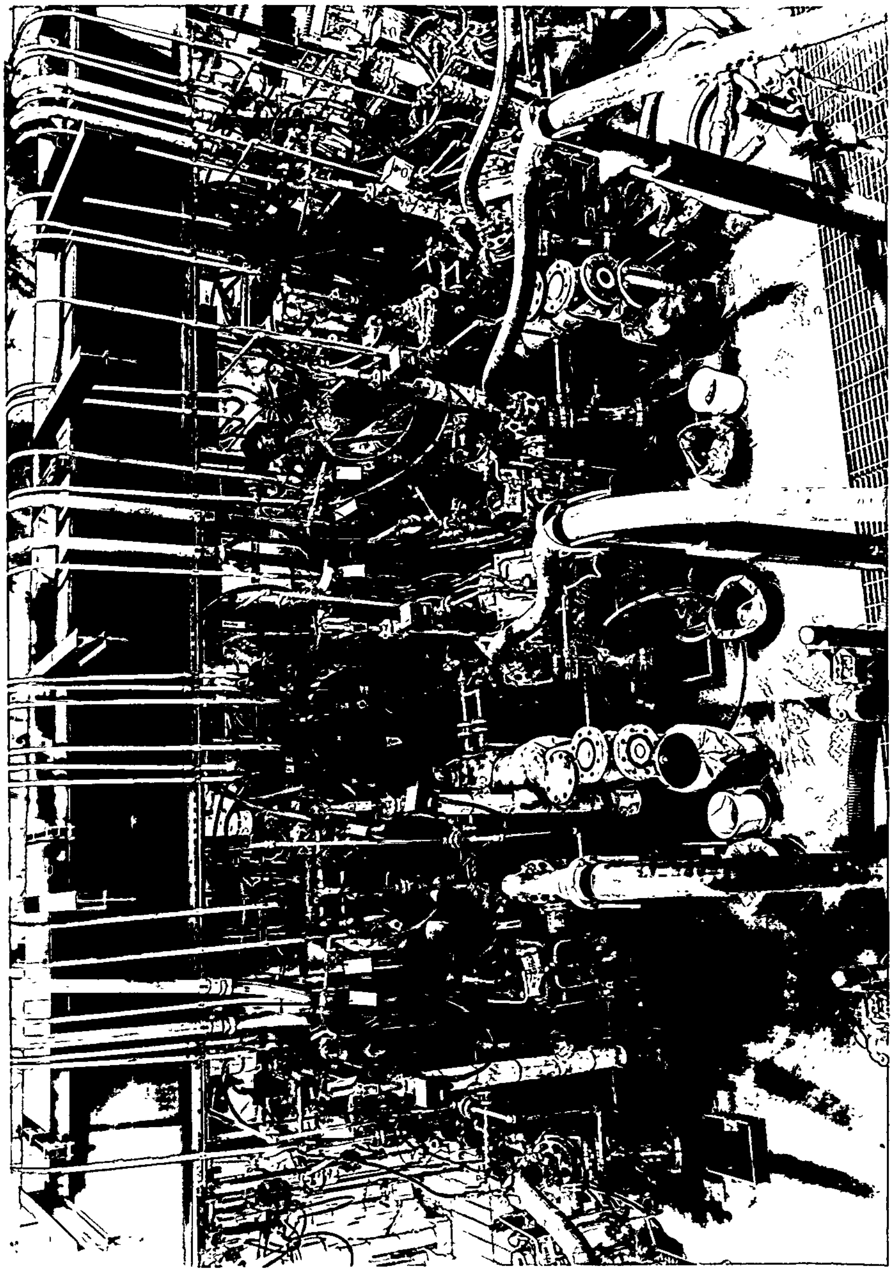


Photo 6.8.4 - Photo of coal injection splitting air compressor.

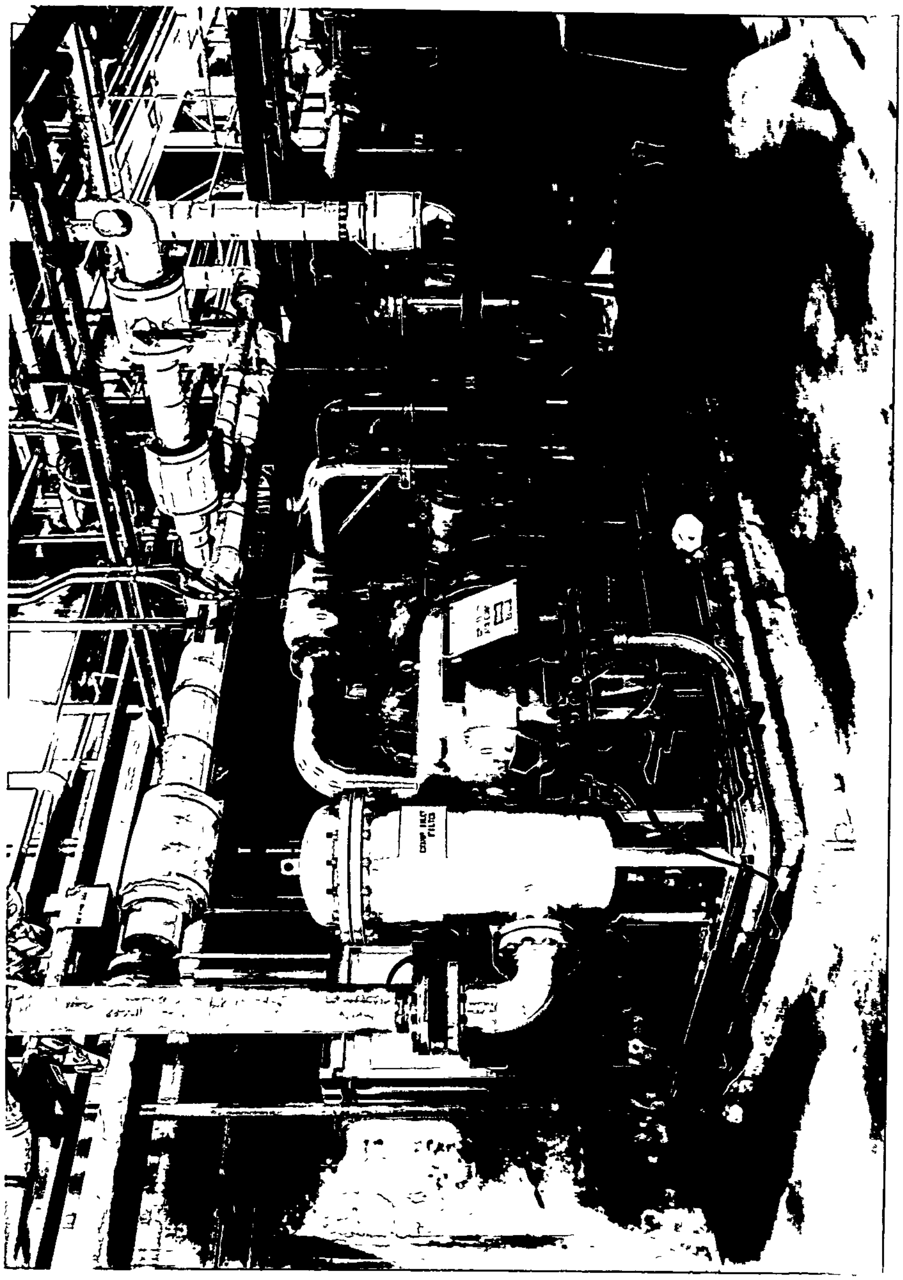


Photo 6.9.1 - Photo of sorbent injection lockhopper bottom, feeder and transport line.

Photo 6.10.1 - Photo of primary cyclone ash external ash coolers.

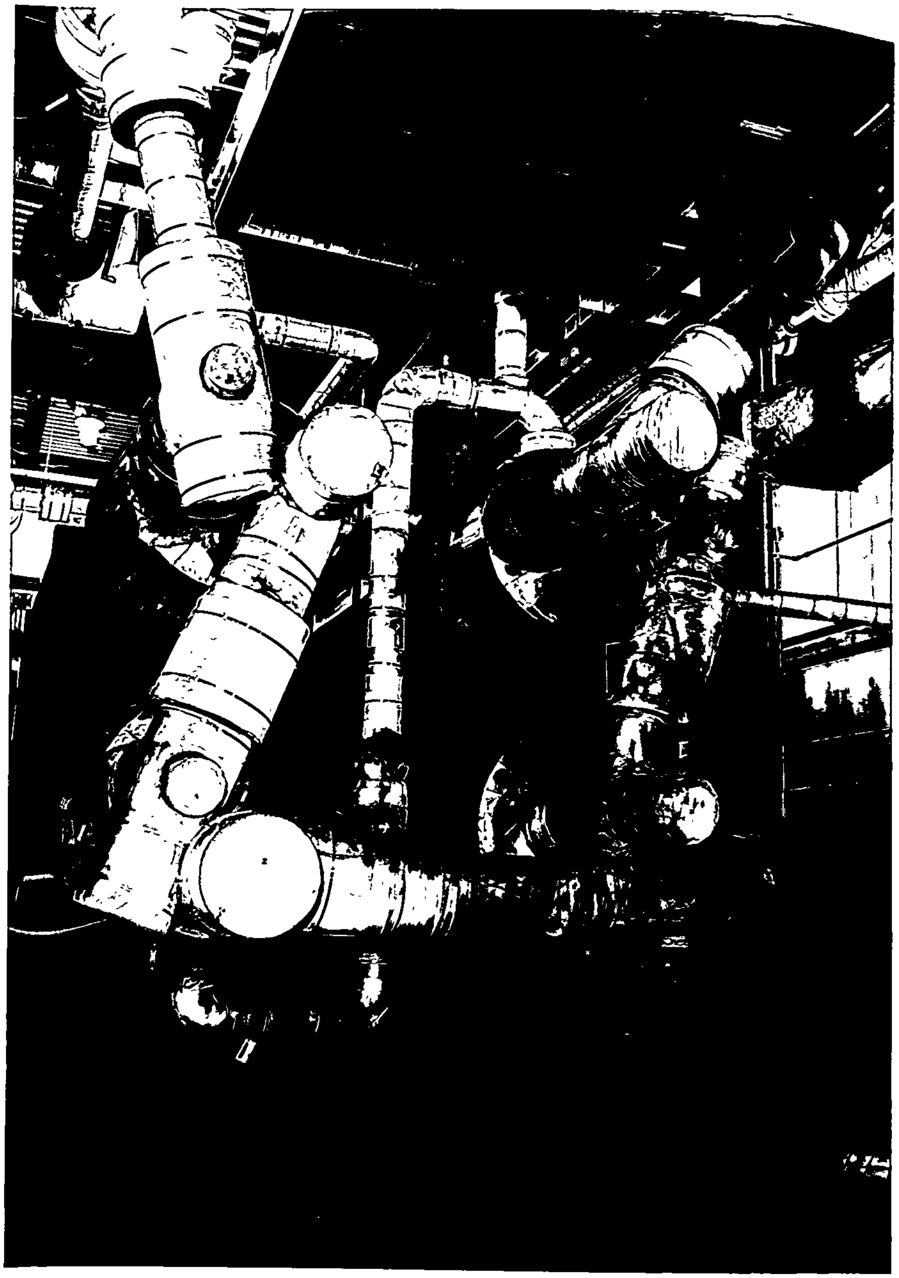


Photo 6.10.2 - Photo of primary cyclone dis-entrainment equipment atop ash silo.

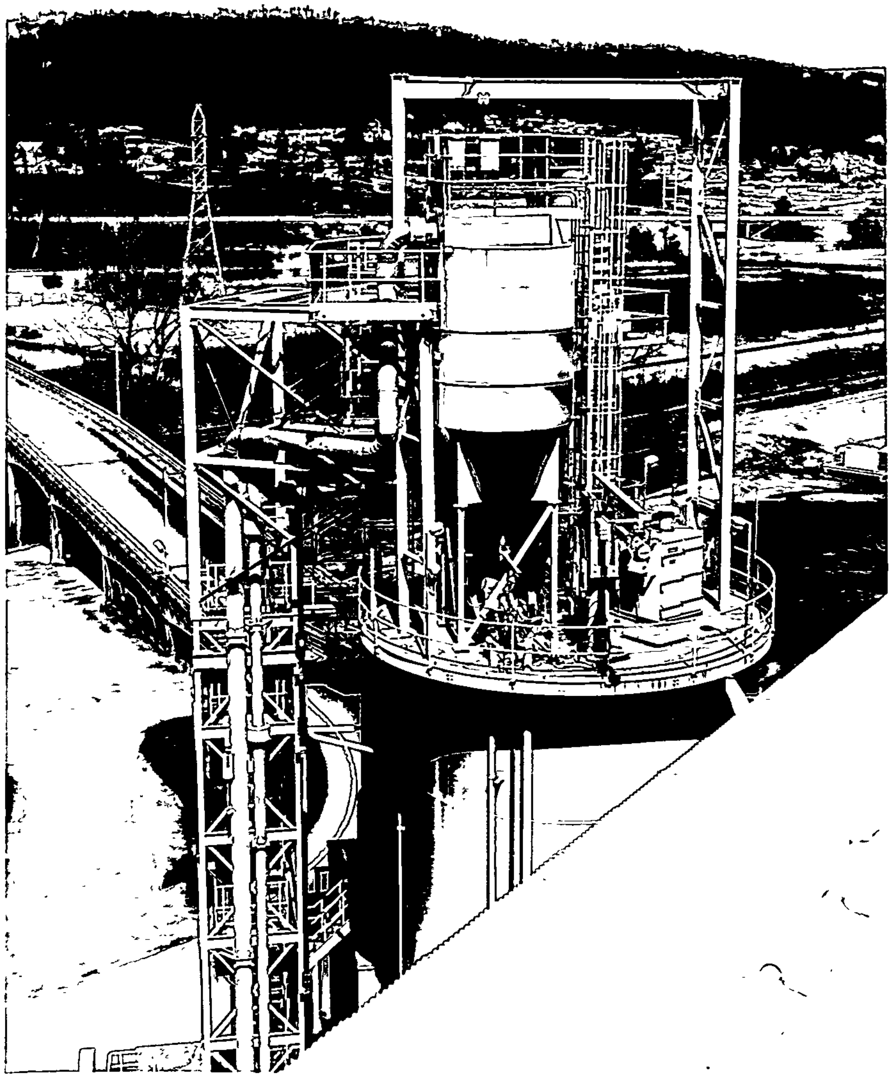


Photo 6.11.1 - Photo of bed ash removal lockhoppers.

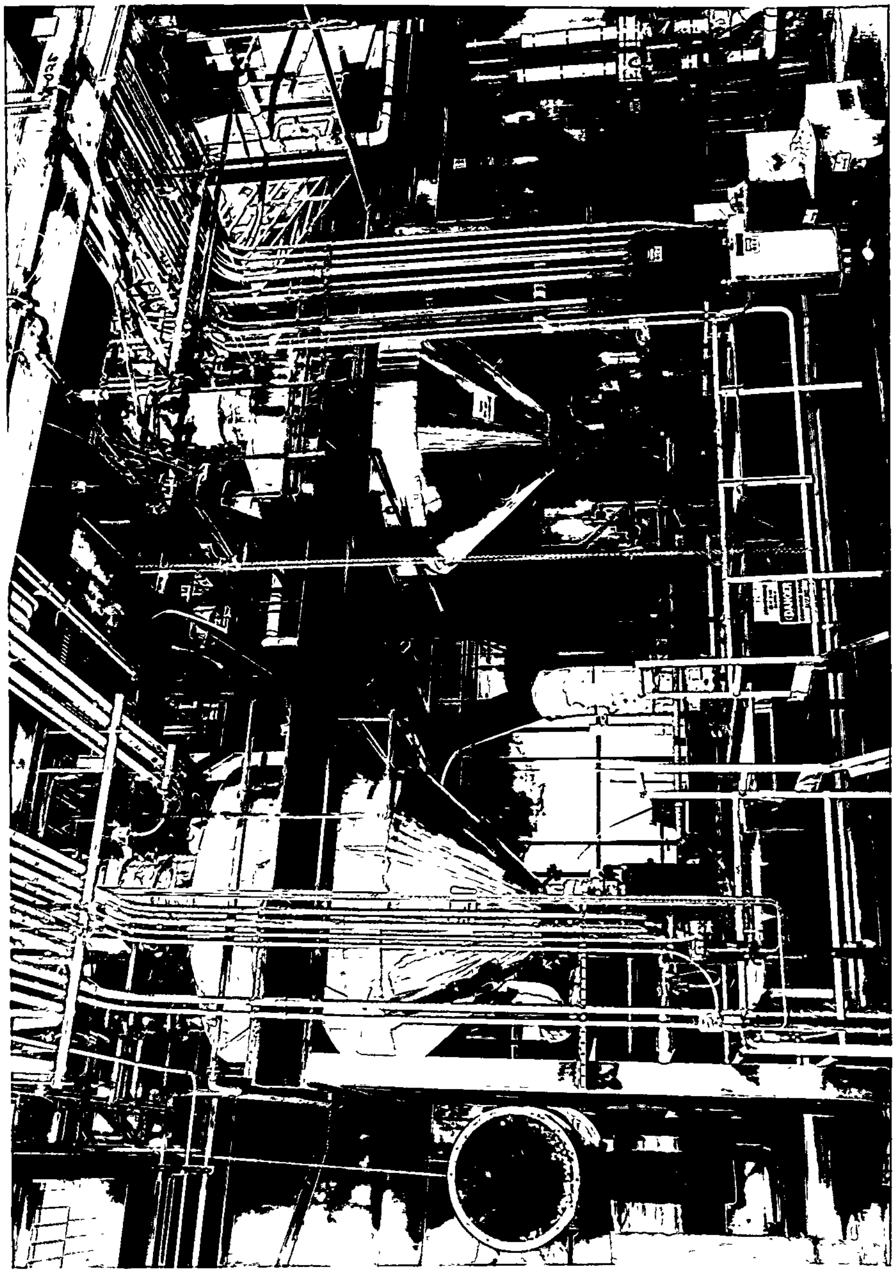


Photo 6.13.1 - Photo of gas turbine overhead view.

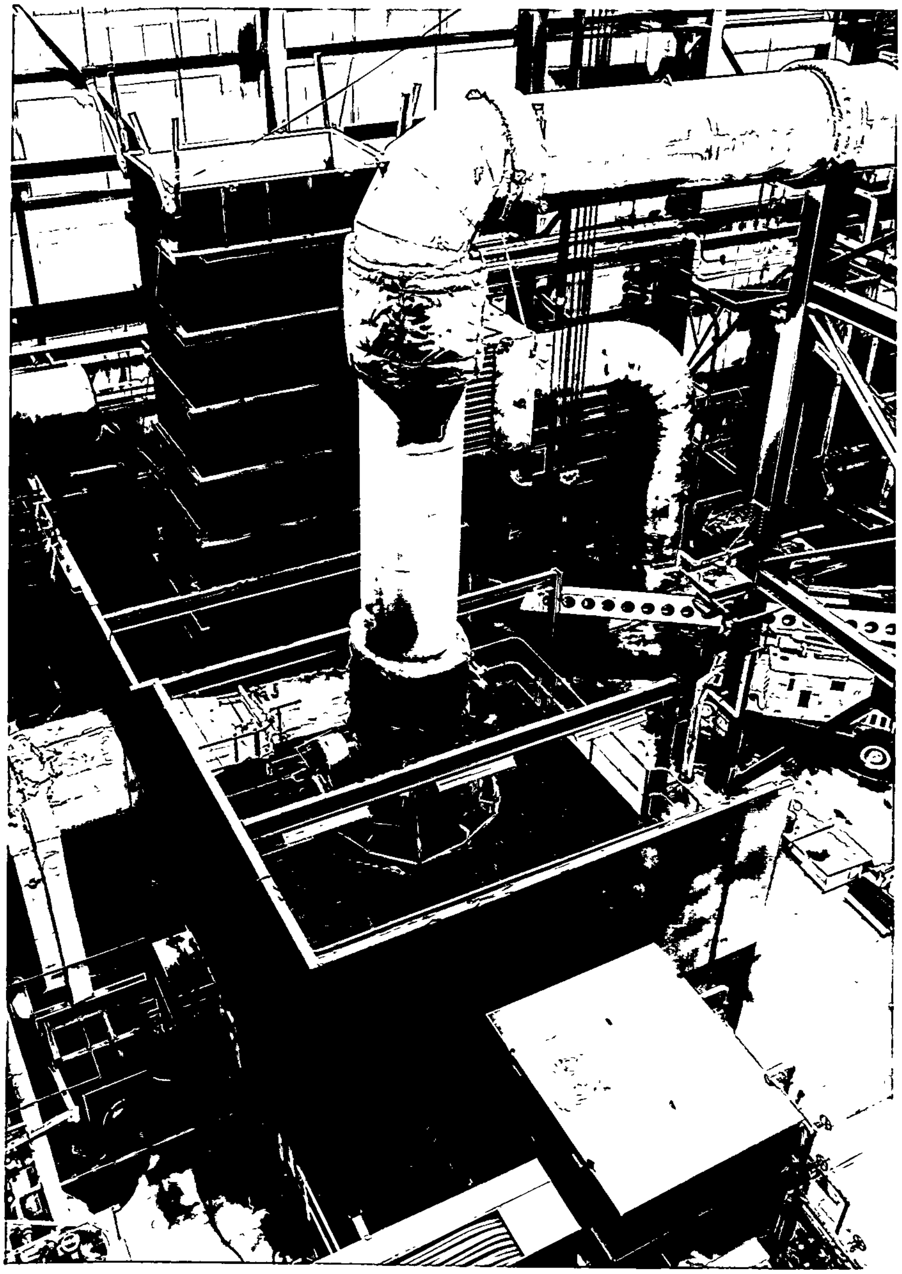


Photo 6.13.2 - Photo of gas turbine sideview.

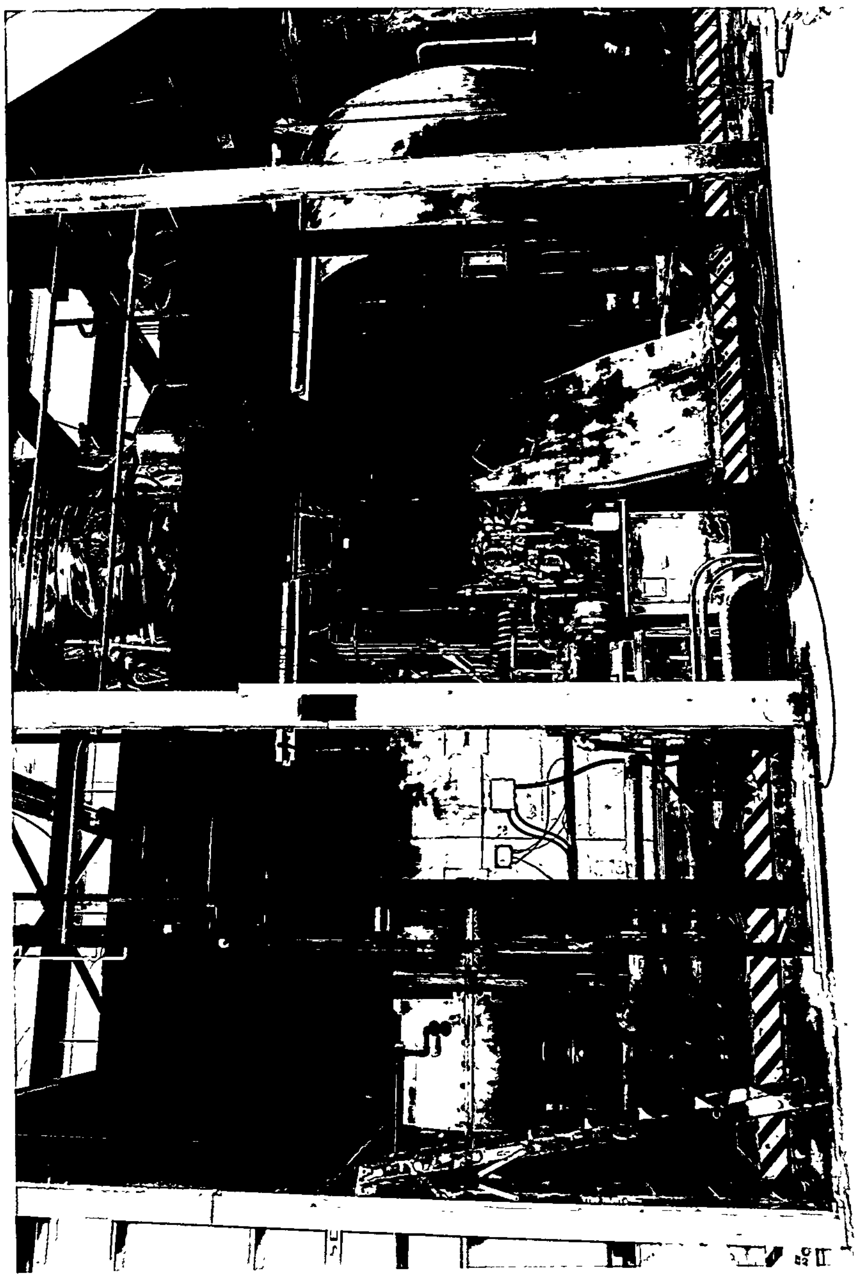


Photo 6.15.1 - Photo of precipitator and nitrogen buffer tank.

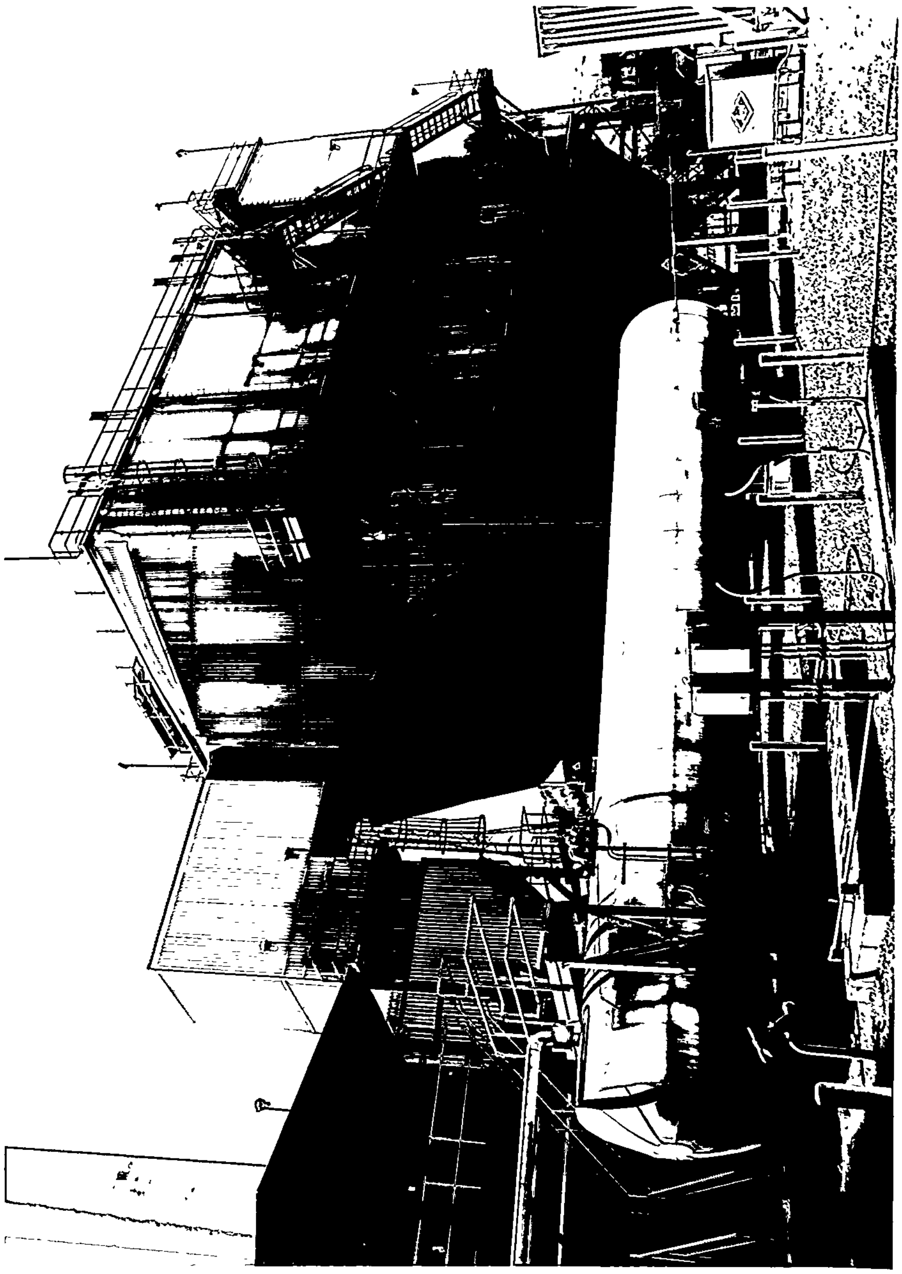


Photo 6.16.1 - Photo of economizer, sootblowers, and secondary ash lines entering ductwork.

Photo 6.19.1 - Photo of Network-90 MCS in control room.

Photo 6.20.1 - Photo of boiler ventilation fan, baghouse, and cooler.

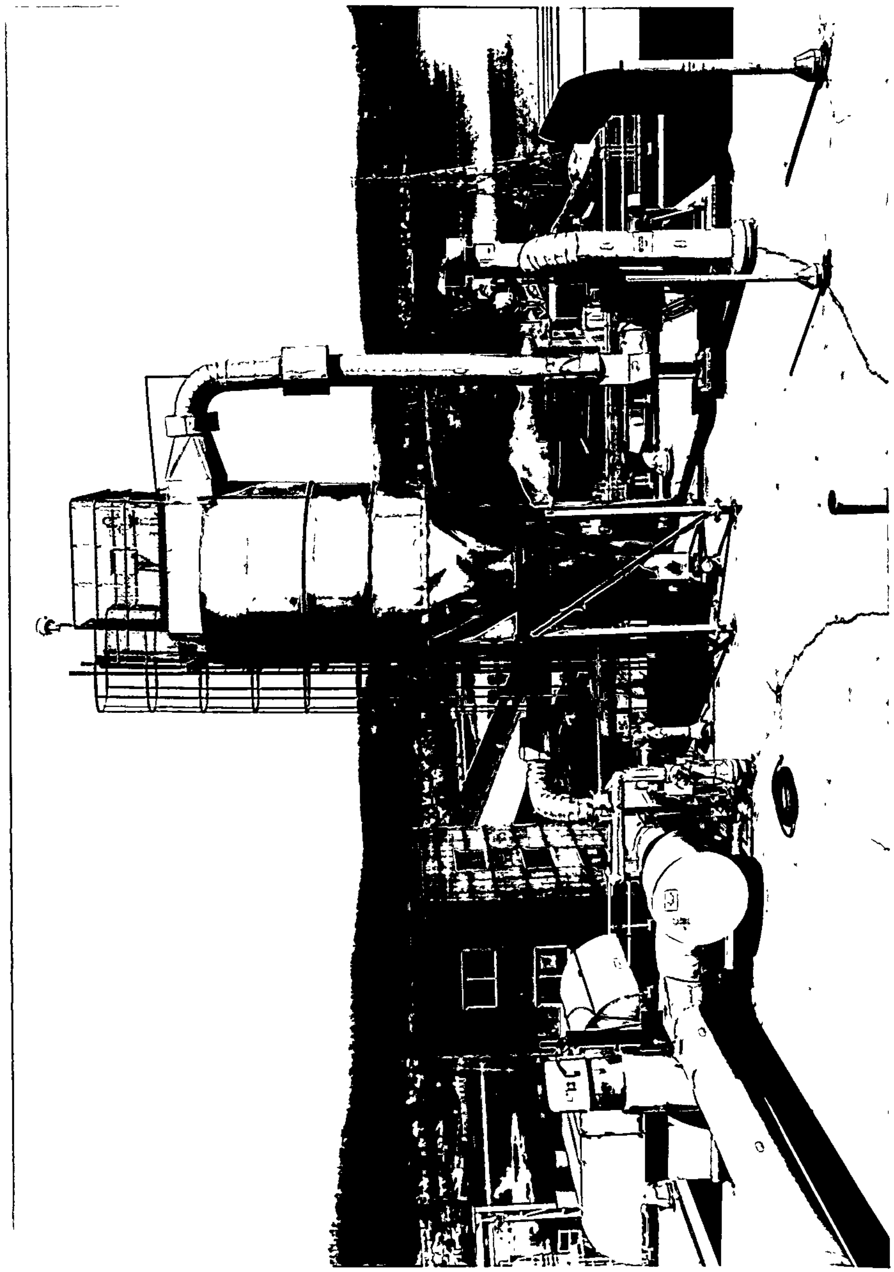


Photo 6.22.1 - Photo of startup and process air fans.