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Tidd PFBC Demonstration Project

A DOE Assessment

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Contents

List of Tables and Figures

Executive Summary

This document serves as a U.S. Department of Energy (DOE) post-project assessment of the Tidd Clean Coal demonstration project. The project at Ohio Power Company's Tidd plant represented the first large-scale operational demonstration of pressurized fluidized-bed combustion (PFBC) in the United States. The Ohio Power Company, a wholly owned subsidiary of American Electric Power Company, Inc. (AEP), provided the host site. Additional participants were Babcock & Wilcox, the Ohio Coal Development Office, and DOE. DOE provided $67.0 million (35 percent) of the total project cost of $189.9 million. The participants provided the remaining $122.9 million.

The Tidd facility is a bubbling fluidized-bed combustion process operating at 12 atm (175 psi). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed. Off gases are expanded through a gas turbine with a steam turbine bottoming cycle. A low-bed-temperature of 1,580 EF limits NO_X formation.

The specific technical objectives of the project were the following:

C Prove survivability of the in-bed tube bundle and gas turbine.
C Achieve greater than 90% sulfur capture at calcium-to-sulfur molar ratio less than 2.0 and NO_X emissions less than 0.25 lb/10^6 Btu.
C Investigate commercial application of PFBC ash.
C Demonstrate overall system reliability and availability consistent with commercialization.
C Prove economic competitiveness with pulverized-coal (PC)-fired plants with flue gas desulfurization (FGD) and other advanced coal-based systems.

All objectives were met or exceeded in 4.5 years of testing at Tidd. The PFBC boiler showed a lack of erosion in the in-bed tube bundle and sustained operation at targeted performance levels. The gas turbine operated in the PFBC flue gas environment but failed to meet performance requirements for reasons unrelated to the PFBC technology. Tests showed the SO_2 removal efficiencies of 90 and 95 percent were achievable at full load and temperature of 1,580 EF with Ca/S ratios of 1.14 and 1.5, respectively. NO_X emissions ranged from 0.15-0.33 lb/10^6 Btu but were typically around 0.20 lb/10^6 Btu during test periods. The Tidd unit logged 11,444 h of coal-fired operation over a 4-year period. Table 1 shows yearly operating statistics for October 1990 through March 1995; these statistics include availability, number of runs, and unit output. During the demonstration, AEP conducted a comparative cost analysis between PFBC, PC/FGD, and other advanced coal-based technologies, and concluded that PFBC was the lowest-cost option on a cost-of-electricity (COE) basis.

Table 1. Key Operating Statistics

Key Operating Statistics October 1990 through March 1995						
Yearly Data	1990 3 Months	1991	1992	1993	1994	1995 3 Months
G.T. Operating Hours	457	1,482	2,914	2,544	5,035	1,301
Coal Fire Hours	61	795	2,367	2,310	4,766	1,145
Unit Availability	4.1%	9.6%	28.7%	26.6%	54.7%	54.5%
Gross Capacity Factor @ 70 MWG	0.4%	3.6%	17%	15.5%	37%	38.9%
Number of Runs	9	43	29	16	18	10
Gross Unit Output Factor @ 70 MWG	10.7%	37.3%	59.2%	58.2%	67.6%	71.4%
Maximum Gross Unit Load Achieved	N/A	53 MW	71 MW	64 MW	68 MW	72 MW

I Introduction

The Clean Coal Technology (CCT) Demonstration Program is a government and industry co-funded technology development effort to demonstrate a new generation of innovative coal utilization processes. One goal of the program is to furnish the energy marketplace with a variety of energy efficient, environmentally superior coal-based technologies. Demonstration projects seek to establish the commercial feasibility of the most promising coal technologies that have proceeded beyond the proof-of-concept stage. This report is a post-project assessment of the DOE CCT Demonstration Program, the Tidd PFBC Demonstration Project.

A major objective of the CCT Program is to provide the technical data necessary for the private sector to proceed confidently with the commercial replication of the demonstrated technologies. An essential element of meeting this goal is the dissemination of results from the demonstration projects. This post-project assessment (PPA) report is an independent DOE appraisal of the successes that the completed project had in achieving its objectives and aiding in the commercialization of the demonstrated technology. The report also provides an assessment of the expected technical, environmental, and economic performance of the commercial version of the technology, as well as an analysis of the commercial market.

Plant-scale investigation of PFBC began in the late 1960s with the completion of a combustor rig at the now National Coal Board (NCB) coal utilization research laboratory (CURL) in Leatherhead, England. Later expanded facilities, including gas turbine blade cascade, were added at CURL. In the mid-1970s to early 1980s, a number of PFBC test facilities were built and tested. These were built by Exxon, Curtiss-Wright, General Electric, New York University, Argonne National Laboratory, National Aeronautics and Space Administration (NASA) Lewis Laboratory, NCB (IEA Grimethorpe and CURL) and ASEA Brown Boveri (ABB) (then ASEA Component Test Facility).

In late 1976, following theoretical studies and review of available PFBC test results, American Electric Power Service Corporation (AEPSC) and ABB Carbon (then STAL-LAVAL) of Sweden signed an agreement to perform a joint feasibility study to evaluate the merits of PFBC technology and the technical challenges to be overcome in proceeding with a development program. A conceptual design of a 170 MWe demonstration plant was prepared by utilizing the deactivated Tidd Plant steam turbine.

The feasibility study addressed many technical issues which had to be resolved prior to embarking on a demonstration project. Combustion tests began in 1977 at the CURL, using Ohio coal and dolomite. The advantages of a tapered bed and the environmental advances of the PFBC process, including high sulfur removal and low NO_X emissions, were demonstrated.

Encouraged by these developments, AEPSC and ABB Carbon agreed to proceed with the next phase of development in 1978. The development work continued with an extensive cold and hot physical model test program and analytical modeling to quantify crucial design items. Cold flow models were constructed primarily to further study the fluidization process. The primary effort in the hot test work was AEPSC and ABB carbon participation in the DOE-sponsored 1,000-h test program at CURL. Major objectives were to determine the operating life of gas turbine blades exposed to hot PFBC gases and in-bed tube erosion/corrosion potential. Results verified the extended life for both the gas turbine blades and steam generator tubes.

These test facilities, while providing valuable process and hardware data, have not operated in a true combined-cycle mode (i.e., generation of electricity from both steam and gas turbines). Combined-cycle operation can only be technologically and economically demonstrated on a utility plant scale, such as Tidd.

Over 2,000 h of tests were completed at CURL, resulting in considerable evolution of combustor and other component designs. The technical readiness of the process for major generation was proven, and the economic evaluation indicated a clear advantage for PFBC. At that time, ASEA Carbon (then ASEA PFBC) decided to erect an integrated pilot plant to conduct more extensive tests on the PFBC process and PFBC-related systems.

The 15 MWt component test facility (CTF), which incorporated all PFBC-related auxiliary systems and components required for operation in a commercial power station, was designed in 1980. Key design parameters (temperatures, pressures, velocities, bed geometry, tube arrangements, etc.) at the CTF were identical to the PFBC demonstration plant design.

In 1982, financial constraints dictated that the demonstration plant be scaled down from 170 to 70 MWe. The 15 MWe ABB STAL gas turbine (GT)-35P was substituted for the 75 MWe GT-120P. This scale-down allowed for the commercial viability of PFBC to be proven at reduced cost. The preliminary design and cost estimate for the 70 MWe plant were completed in 1984. In 1984, Babcock & Wilcox became involved in the PFBC demonstration plant project. After a careful review of the design and concept by Babcock & Wilcox, a partnership, ASEA Babcock was formed in October 1985. ABB Carbon and Babcock & Wilcox were to pursue the project and the ultimate commercialization of PFBC.

In May 1986, AEPSC and ASEA Babcock began detailed design of the 70-MWe demonstration plant. In February 1987, Ohio Power Company, a subsidiary of AEP, entered into an agreement with DOE for up to $60.2 million in federal cost-sharing under the CCT and with the Ohio Coal Development Office for $10 million in state cost-sharing.

While the test program was proceeding, a preliminary engineering and design of both the 170-MWe Tidd commercial demonstration plant and a future larger commercial plant were performed. Part of this effort consisted of cost estimates for both plants and a comparison of the economics of a commercial PFBC plant with a conventional PC plant using an FGD system.

II Technical and Environmental Assessment

II.A Description of the Technology

The PFBC system is composed of a fluidized-bed boiler enclosed in a pressure vessel with dual hot cyclones on the exhaust leg. Exhaust gas is burned in a gas turbine to produce electric power. Steam generated in the boiler tubes is used by a steam turbine to produce electric power. Figure 1 is a flow diagram showing the major components of the Tidd plant, unit no. 1, located at Brilliant, Jefferson County, Ohio.

The combustor assembly, which is the heart of the combined cycle system, generates the hot gases to fuel the gas turbine and the steam to drive the steam turbine. The combustor assembly contains the boiler, cyclones, cyclone ash coolers, and bed ash reinjection vessels, all contained within a single, cylindrical pressure vessel. This arrangement allows the working components to be designed for relatively low differential pressures, even though the process pressure is relatively high in absolute terms.

The externally insulated pressure vessel is designed for internal operating conditions of 572 EF at 168 psig, about 12.4 atm. It consists of a vertical cylindrical shell approximately 44 ft in diameter with elliptical heads. The overall vessel height is approximately 70 ft. The heads include service openings which allow for the removal of internal components. In addition, service platforms, lifting devices, and access doors are provided to permit maintenance and service of both internal and external systems.

The PFBC boiler contains the combustion process and absorbs the heat necessary to generate steam and control bed temperature, while maintaining the required gas temperature to the gas turbine. The boiler is designed with membrane water wall construction and is composed of three major sections: the boiler bottom, the bed zone, and the freeboard.

The gas leaving the boiler passes through two stages of cyclone separation to reduce particulate erosion in the gas turbine. The cyclones are arranged in seven parallel strings, each with two stages. The gas is conveyed from the upper part of the boiler into the first-stage cyclones through connecting flues, then flows from the first to the second-stage cyclones and out, through a common gas collecting pipe which discharges into the center portion of the coaxial pipe to the gas turbine. All cyclones and lines are insulated to maximize gas temperature retention.

Bed level is the primary load-controlling parameter in the PFBC boiler. The bed ash reinjection system permits rapid unit load change by transferring bed material to and from a pair of reinjection vessels located inside the combustor pressure vessel. To increase load, bed material is moved from the reinjection vessels into the bed by means of an L-valve. To decrease load, bed material is pneumatically transported to the reinjection vessels with air from the combustor pressure vessel serving as the transport medium. Reinjection vessels are normally at the same pressure as the boiler.

A bed preheating system is necessary during startup to bring the bed material to 1,200 EF, the minimum temperature for sustained coal combustion. This is accomplished by directing air flow from the gas turbine compressor through the bed preheating combustor. The air flow ranges from 260,000 lb/h to 300,000 lb/h. The bed preheating combustor is designed to burn No. 2 fuel oil with this air to generate combustion gases at 1,560 EF.

The gas turbine/generator set is modified for PFBC application. The set is closely matched thermally to the combustor. The major gas turbine mechanical components are two compressors, with an intercooler between them, and two gas turbines. The compressor intercooling maintains combustion air temperature within required limit and increases overall cycle efficiency. The gas turbine/generator set functions mechanically as a PFBC system and thermodynamically by contributing to the high efficiency of a PFBC combined-cycle system.

Optimization of the cycle and cycle efficiency is enhanced by the two-shaft design. The quantity of excess air can be held constant over the entire ambient air temperature range. At partial loads, excess air levels can be optimized. Fluidizing velocity is held constant over the operating range of the unit.

The existing steam turbine at the Tidd Plant is a 110,000 kW, 1800 rpm condensing turbine/generator. The turbine is contained in a single casing directly connected to a 0.9 pf, 111,111 kVa, 3-phase, 60-cycle, 13,800-volt generator. Some high-pressure feedwater heater extractions will be blanked off, since most of the high pressure feedwater will be heated by the waste heat available in the gas turbine exhaust. This modification will result in a slight reduction in steam turbine flow to ensure that interstage differential pressures are within limits.

The turbine is designed to have a maximum output of 110,000 kW, 1300 psia, 925 EF steam, and a vacuum of .0 in. Hg, and regenerative feedwater heating. The design allows for a maximum pressure of no more than 105 percent of normal, but in an emergency it can withstand up to 115 percent of normal pressure for a short period. The turbine will operate at approximately 50-percent turndown.

II.B Benefits of the Technology

Benefits of the PFBC technology can be divided into three areas: operational, environmental, and economic:

Operational Benefits

C The higher pressure exhaust gases of the PFBC contain sufficient energy to drive a gas turbine, while the steam generated in the in-bed boiler tubes drives a steam turbine.
C The deep bed combustion results in a long residence time, yielding high combustion efficiency.

Environmental Benefits

- The long residence time allows 90% sulfur removal with a calcium-to-sulfur molar ratio of 1.6.
- The relatively low combustion temperatures result in low NO_X emissions.
- All ash produced is dry, benign, and manageable.

Economic Benefits

- The high PFBC efficiencies allow a reduction in plant size with corresponding material savings.
- The PFBC process permits burning a wide range of coals in an environmentally compatible manner.

III Results of the Demonstration

The objective of the first 3 years of the Tidd PFBC 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 as follows:

- To demonstrate that a gas turbine could operate in a PFBC in CC mode with acceptable availability, durability, and controllability.
- 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/MBtu.
- To investigate the commercial potential of PFBC ash.
- To demonstrate the viability of the equipment and systems required to apply PFBC technology to utility electric power generation.
- To demonstrate PFBC as an economic alternative to pulverized coal-fired plants with flue gas desulfurization.

These goals were pursued through performance tests, equipment inspections, and studies.

A total of 47 unit performance tests were conducted during the first 3 years of the test program. Tests were conducted to evaluate sorbent utilization, combustor performance, gas turbine and compressor performance, SO_X and NO_X emissions. During the later portion of the test program, the emphasis was on sorbent optimization by evaluating unit performance with various sorbent types, sizes, feed methods, and bed distributions.

The initial performance tests (tests 1, 2, and 3) were conducted prior to adding boiler tube surface during the fall 1991 outage. Initially, full bed height was 126 in.; with the additional tube surface, full height is 142 in. Unit acceptance tests (tests 6 and 7) were conducted in June 1992 to confirm contractual guarantees.

All baseline and unit acceptance tests were conducted with the design coal and sorbent (Pittsburgh #8 coal, Plum Run Greenfield dolomite). Variations to the baseline data included tests with National Lime Carey and Plum Run Peebles dolomite, Ohio No. 6A coal, coarse sorbent in paste, sorbent fines in paste, and increased sorbent feed points. Attempts were made to test limestone as a sorbent, but these tests were aborted because of sintering.

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 SO_2 emission levels were set by controlling the sorbent flow. After the unit reached steady-state operating conditions, data collection and material sampling were initiated.

Typical data collection and materials sampling lasted for a period of 12 to 24 h. The interval of steadiest operation within the collection period was selected for evaluation. The evaluation period was usually 4 to 12 h in length.

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. Because of the lead and lag times of the materials handling systems, the sorbent sampling period was typically 12 h ahead of the data collection period, coal sampling was 2 h ahead of data collection, and bed ash sampling was 12 h behind data collection. All other material 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.

The unit was operated from June 9, 1992, through July 10, 1992, to complete the contractually required 30-d reliability run. During the period, the unit operated at a 69.4-percent capacity factor, including a 100-h full load endurance run. After successful completion of the run, the unit was removed from service for inspections.

ASTM coal samples were obtained every 2 h during the test periods. Sorbent samples were obtained in 12-h composites, starting 24 h before the test periods began. Moisture analysis was determined every 2 h on a grab sample of coal paste. Bed ash samples were obtained in 2-h composites between 8 and 12 h after the test periods. A cyclone ash sample was obtained from the rotary unloader just following the test periods.

IV Post-Project Achievements

IV.A Post-Project Results

If a utility were to build a new coal-fired power plant today of over 200 MWe capacity that utilized commercially available technology to meet current New Source Performance Standards (NSPS) for emissions, the only option would be a pressurized circulating fluid-bed (PCF) plant with a wet lime/limestone FGD system. However, it is not certain whether such a plant can be operated at high availability and reasonable reliability using high-sulfur coal. Furthermore, the cost of operating such a system is directly related to the sulfur content; i.e., the higher the sulfur, the higher the variable operating cost and, hence, the higher the cost of electricity.

The Tidd PFBC, during the test and demonstration period, provided confidence in design and the necessary data and experience to utilize PFBC technology for commercial power plants. Tidd also provided the possibility to operate as a test base to develop further refinements and test new technologies.

AEP wanted to see PFBC technology commercialized for use in future electric generation, along with competition among suppliers of PFBC-related equipment. Therefore, AEP expected to share the operational information gained from Tidd with other electric utilities and industries. The successful operation of the Tidd unit generated interest from many U.S. manufacturers in providing equipment applicable to PFBC technology, including fuel preparation and feeding, ash removal, and hot gas cleanup. AEP intends to disseminate information to a wide audience interested in PFBC combined-cycle technology.

The PFBC demonstration plant was a necessary step to the ultimate commercialization of PFBC technology. Therefore, scaling up critical parameters has been carefully evaluated in the design of both the CTF and Tidd. Comparisons have been made of critical design parameters between the CTF (15 MWt), Tidd (200 MWt), and the commercial plant (800 MWt). Three major parameters in process performance must be evaluated in scaleup considerations: temperature, pressure, and residence time.

Bed temperature has a strong influence on process results. The CTF, Tidd, and a commercial plant will all operate at a bed temperature of 1,580 EF. Operating pressure does not significantly influence process results in the 10 to 20 atm range as indicated from tests at the CTF and other pilot plants. Residence time, a function of fluidizing velocity and bed depth has a strong influence on sulfur removal and combustion efficiency. The fluidizing velocity of 3 ft/s and the bed height are similar for the plants; hence, scaleup is not expected to be a problem.

For sulfur capture, the calcium-to-sulfur molar ratio (Ca/S) is the controllable variable to compensate for variations of sulfur content in the coal. Because of the limited effect of this parameter with scaleup, a Ca/S ratio of 1.6 for 90-percent sulfur retention when burning 4-percent sulfur coal is anticipated to provide excellent sulfur removal.

Increasing bed area is not expected to be a problem, especially since a larger bed area minimizes wall cooling effects. Experience at the CTF has shown that boiler tube geometry and proper air distribution are the most significant parameters.

The GT-35P and GT-120P gas turbines are of similar design, both with two shafts and intercooling. Both gas turbines can be used in commercial plants. Tidd was the first PFBC plant to operate in a true combined-cycle mode, with the gas turbine driving a generator and steam generated in the PFBC combustor driving a steam turbine. Essential gas conditions to the gas turbine, including gas velocity and temperature, will be the same for Tidd and commercial plants.

The cyclones will be the same size as those at Tidd for the larger commercial plants, with seven parallel strings in the former and 20 parallel strings in the latter. Both the original three-stage cyclones and the modified two-stage cyclones have design efficiencies in excess of 99 percent.

IV.A.1 Post-Bed Combustion

The most significant consideration regarding post-bed combustion is proper coal paste preparation. Every effort should be made to make preparation more reliable. Another critical aspect is adequate distribution of the paste. Even with proper coal, low freeboard oxygen measurements still exist above the fuel nozzle outlets. This indicates the continued existence of localized combustion, which undoubtedly makes the unit more susceptible to variations in 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.

IV.A.2 Bed Sintering

Excessive "egg sinter" formation was not resolved at Tidd. The increased propensity to sinter at higher firing rates associated with high bed heights and higher bed temperatures offers a clue for resolving the "egg sinter" problem. In light of this, the highly localized fuel release associated with the limited number of fuel feed points is speculated to be a key factor in the formation of the sinters. Investigations into improved fuel distribution through additional fuel nozzles or the splitting of the existing six fuel nozzles would be necessary to test this theory.

Changing the fuel supply will not resolve the sintering problem since fuel flexibility is a must for any coal-burning technology to be competitive. Testing at the NCB (CURL) PFBC pilot facility produced similar "egg sinters" when using limestone as the sorbent with Pittsburgh No. 8 coal paste. These sinters were eliminated when the fluidization velocity was increased from 3 to 4 ft/s.

IV.A.3 Sorbent Utilization

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 has shown improvements in the order of 10 to 15 percent from the "baseline" test results at a 115-in. bed level. No obvious improvements have been seen at full-bed level while operating with four-point sorbent injection and fines in the paste.

The greatest potential for additional improvements in sorbent utilization is by further optimizing sorbent particle size. Tests at the 115-in. bed level with finer sorbent yielded 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 reduced bed levels. Further tests should be conducted to investigate the improved sorbent utilization noted while operating with sorbent fines in the paste. Relative to sorbent type, the most reactive sorbent tested was the Plum Run Greenfield dolomite. It is believed 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 delivered cost as well as reactivity.

IV.A.4 Boiler Heat-Transfer Surface

Operating experience revealed that the unit could be run for extended periods with little or no post-bed combustion. In light of this, it should be possible to raise the mean bed temperature to the original design value of 1,580 EF, which would increase the tube bundle heat absorption thereby compensating for some of the shortfall. However, excessive "egg sinter" formation prevented extended operation at any temperature above 1,540 EF. If the sintering problem is resolved without inducing additional post-bed combustion, it may be possible to operate the unit in such a manner.

A finer bed will possibly result in increased particle activity which might reduce the magnitude of bed sintering. Minimization of sintering would likely improve heat transfer because of reduced fouling. In addition, if the finer bed does result in increased bed particle activity, this may itself improve heat transfer.

IV.A.5 Gas Turbine Compressor Air Flow Capacity Shortfall

The Tidd PFBC unit was expected to be capable of achieving a full-load firing rate of approximately 208 MWt at ambient temperatures up to 85 EF. Although the full-load firing rate at that time was only 93 percent of the original design because of continued below-design tube bundle heat absorption, unit load was further limited because of insufficient air at ambient temperatures above 60 EF. 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.

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. Test data revealed that leakages were much higher that 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. It should be noted that decreased LP compressor efficiency results in excessive temperature rise throughout that component, which necessitates more intercooling.

IV.A.6 Cyclone Ash Removal

The current secondary ash removal system design appears to be acceptable. The system has operated with greater than 99-percent 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. This system should be redesigned with an all-welded type design, and each ash line would penetrate the combustor vessel wall. Provisions should be made to clear an ash line if it plugged while in service.

Aside from the need to redesign the primary ash removal system, one other significant 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.

IV.A.7 Coal Preparation System

The reliability of the coal crusher because of changes in coal quality remains a significant problem. Whenever the coal changes, the crusher is still prone to tripping out because of 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 reliable, producing the required size consistently needed for good pumpability and combustion. All of this is achievable at a low energy-consumption.

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 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-percent 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.

IV.B Expected Performance of a Future Reference Commercial Plant

The reference plant design is based on the technology utilized in the Tidd plant repowering, scaled up to a nominal 415 MWe, net, and configured as a new “green-field” installation. The steam cycle is matched to the PFBC island utilizing current utility practice and design parameters. The reference PFBC plant is described in this section.

IV.B.1 Design Basis

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

C Location is the Ohio River Valley
- 300 acres within 15 miles of a medium-sized metropolitan area
- Railroad suitable for unit trains passes within 2-1/2 miles of the site
- Well-trained laborers are available within a 50-mile radius

C Plant performance based on Pittsburgh coal and Greer limestome
C 442.7 MWe gross capacity
C 30-year plant life
C Mature technology application; no first-of-a-kind considerations
C Steam conditions: main steam — 2,400 psig/1,000 EF; reheat steam — 475 psig/1,000 EF
C Insulation and lagging are provided on pressure vessels, piping, and other plant components that are potentially a significant heat-loss source
C The plant is designed for base-load operation; 65% capacity factor

C No. 2 oil-fired startup burners will provide preheat startup
C An integrated plant-wide distributed control system (DCS) is included

IV.B.2 Heat and Mass Balance

The PFBC reference power plant described here utilizes a combined cycle for conversion of thermal energy from the fluid bed to electric power. An open Brayton cycle using air and combustion products as working fluid is used in conjunction with a conventional subcritical steam Rankine cycle. The two cycles are coupled in the PFBC bed and by recovery of exhaust heat from the Brayton cycle compressor intercooler and from the exhaust gases prior to final particulate removal and discharge to the atmosphere.

The net plant output power, after plant auxiliary power requirements are deducted, is nominally 415 MWe. The overall net plant efficiency is 40.4 percent.

In summary, the major features of the steam turbine cycle for this PFBC plant include the following:

C Subcritical steam conditions and single reheat (2,400 psig/1,000 EF/1,000 EF)
C Boiler feed pumps are steam turbine driven
C Turbine configuration is a 3,600 rpm tandem compound, two flow exhaust
C Five stages of closed feedwater heaters plus a deaerator
C Heat recovery from the gas path by the condensate/feedwater stream

IV.B.3 Environmental Standards

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

The plant pollution emission requirements under the NSPS, prior to the Clean Air Act Amendments (CAAA) of 1990, were as follows:

• SO_X	90% removal
• Particulate	0.03 lb/MBtu
• NO_X	0.6 lb/MBtu
• Visibility	20% opacity

The 1990, the CAAA imposed a two-phase capping of SO_2 emissions on a nationwide basis. For a new green fields plant, the reduction of SO_2 emissions required would depend on possession or availability of SO_2 allowances by the utility, and on local site conditions. In many cases, prevention of significant deterioration (PSD) regulations will apply, requiring that best available control technology (BACT) be used. BACT is applied separately for each site, and results indifferent values for different sites. In general, the emission limits set by BACT will be significantly lower than NSPS limits.

The following ranges will generally cover most cases:

- SO_X 92 to 95%
- NO_X 0.2 to 0.45 lb/MBtu
- Particulate 0.015 to 0.03 lb/MBtu
- Opacity 10 to 20%

For this study, plant emissions are capped at the values listed in Table 2. The nominal design basis SO_2 removal rate is set at 95 percent with a Ca/S ratio of 2.0 for the PFBC unit described in this study.

Table 2. PFBC Reference Plant Emissions

Emission	lb/MBtu	tons/year@415 MWe 65% capacity factor
SO_2	0.232	2,410
NO_X	0.30	3,120

BACT is not applied to the plant described in this report, since it is a site- and time-dependent issue. Selected adjustments for additional SO_2 and/or NO_X reduction may be applied by users of this report by applying specific technology increments that suit each case.

Air quality regulations concerning other compounds such as CO, CO_2, and air toxics are under evaluation by the U.S. Environmental Protection Agency (EPA) at the present time and may have an effect on the design of plants in the time frame being considered here. However, impacts from these considerations are not included in this report.

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

Bed ash, cyclone ash, and precipitator ash, and sludge produced from water treatment will be disposed of according to the nonhazardous waste disposal guidelines of Sections 1008 and 4004 of the Resource Conservation and Recovery Act (RCRA), and applicable state standards, appropriate for the actual plant's location.

In-plant equipment will be designed to meet the noise exposure regulations of the Occupational Safety and Health Administration (OSHA). Noise levels from major noise sources (e.g., fans, motors, gas turbines, valves, pumps, and piping) will not exceed 95 dBA at 3 ft. Outdoor noise criteria for onsite sources of noise will be an integrated equivalent level (Leq) of 55 dBA at the property boundary. The minimum distance to the property line will be assumed to be 1,000 ft.

IV.C Description of PFBC Island Systems

The following sections describe the components and their functions in a reference PFBC plant design sized at a nominal net output of 415 MWe.

IV.C.1 Combustor Pressure Vessel

The combustor assembly consists of the pressure vessel together with the installed internals. The main internal systems are described separately. The function of the combustor assembly is to provide the main pressure containment for the boiler, cyclones, bed reinjection, ash coolers, and bed preheating systems. The combustor assembly also prevents heat losses from the process to the environment, facilitates a good arrangement, and provides support for the internals.

The PFBC pressure vessel is fabricated of 3.75-in.-thick SA-533 Gr. B steel plate and has a 50 ft, 10-in. outside diameter and 164-ft overall height. The vessel is designed, fabricated, and stamped in accordance with the American Society of Mechanical Engineers (ASME) boiler and pressure vessel code, section VIII, division 2. The vessel has a design pressure and temperature of 245 psig and 700 EF, respectively.

Air from the compressor side of the gas turbine is supplied to the combustor vessel through the outer portion of a coaxial pipe. The air in the vessel flows through the cyclone ash coolers adding about 45 EF to the air temperature before it enters the boiler through the lower half of the combustor. The boiler enclosure contains the bed, the in-bed heat transfer surface, and the freeboard above the bed. The hot gas from the freeboard flows to the cyclones, and then through the inner portion of the coaxial pipe to the gas turbine.

The boiler feedwater is fed from the economizer, which is located outside the pressure vessel. Steam generated in the boiler is used to power the steam turbine.

A design feature of PFBC units is their modularized components. Modularity tends to reduce project costs and site erection span time. The degree of modularity can be tailored to suit each PFBC plant site. The combustor internal equipment, such as platforms, boiler, cyclones, and bed reinjection vessels, are prefabricated and shop assembled into modules for field installation into the pressure vessel to the maximum extent practical. Other components, such as instrumentation and insulation, may be partially shop assembled, with the remaining assembly performed at the site. Service openings and manholes are provided for access during inspection, repair, or replacement of equipment, which must be carried out during normal maintenance.

IV.C.2 PFBC Boiler

The purpose of the PFBC boiler is to contain the combustion process and absorb the heat necessary to control bed temperature while providing steam to the steam turbine and hot gases to the gas turbine.

The boiler is a once-through design consisting of a water-cooled membrane wall enclosure and in-bed heat transfer surface. The water-cooled enclosure contains the combustion process, within a specified gas path geometry, and is designed to withstand the expected pressure differential across the membrane tube wall. The enclosure is sized to provide (1) the bed area set by gas velocity and flow, (2) a 14.75-ft-deep bed to achieve the desired residence time affecting combustion efficiency and sulfur capture, and (3) sufficient freeboard height to provide residence time and allow maintenance of the in-bed platens without requiring removal from the enclosure. The tube bundle inside the boiler is completely submerged in the fluidized bed at full load. The in-bed surface is designed to evaporate, superheat, and reheat the steam at a required flow, temperature, and pressure for delivery to the steam turbine. This heat extraction also helps regulate the gas temperature to the gas turbine.

Load reduction is accomplished by lowering the bed level and lowering fuel input. By lowering the bed level, less steam is produced and also the gas temperature to the gas turbine is reduced because some of the tube bundle is now above the bed level. Bed level is rapidly raised and lowered by using reinjection vessels. When a load reduction is called for, bed material is withdrawn and stored in the reinjection vessels. If load is increased, the stored bed material is reinjected back into the bed. A load change rate of 4 %/min is possible with this system. More gradual changes are accomplished by changes in coal feed and ash withdrawal rates.

The in-bed heat transfer surface is fabricated of SA-213 (various types) alloy tubes and is designed and stamped in accordance with the ASME Boiler and Pressure Vessel Code, Section I. Tube diameters vary from 1.125 to 2 in.

IV.C.3 Fuel Preparation

The fuel preparation system crushes coal to the required size distribution and dries it to an appropriate moisture level from the as-received condition. Each crusher/dryer subsystem is rated at 50 tons/h of coal, but handles 70 tons/h of combined coal and limestone mixture. At this capacity, the four crushing/drying subsystems operate about 16 h/d to crush and dry the coal required for continuous plant operation.

Each crusher/dryer subsystem is composed of a roller mill type crusher, a main mill fan, a cyclone collector, an exhaust fan, and a baghouse filter. The rough sized (1 in. x 0) coal is crushed to a nominal 1/8-in. size. The crushed coal/limestone mixture is exhausted from the mill, which contains internal classifiers to separate out oversize particles, and conveyed to the cyclone separator. The sized particles are disentrained from the air stream in the cyclone collector and discharged through a rotary valve to a day bin.

IV.C.4 Fuel and Limestone Injection System

The day bins containing the sized coal/limestone mixture discharge through slide gate valves into the injection trains, four of which are provided for each of the four day bins, for a total of 16 injection trains. Each train includes a lockhopper, an injection vessel, and four rotary feeders. The coal/limestone mixture is metered into the PFBC at 64 discrete injection points.

The oxygen reduction units are membrane type units, which reduce the oxygen concentration in the product discharge stream to less than 10 percent. The reduced oxygen content enables the product gas stream to serve as a transport media for the coal/limestone mixture with minimal risk of premature combustion, fire, or explosion.

The system operates with the full complement of injection trains and feed points in service over the entire load range. At reduced loads, the feed rate is reduced across the entire complement of feed points. The system has sufficient excess capacity to maintain 100-percent load if 25 percent of the feed points must be taken out of service.

IV.C.5 Hot Gas Cleaning System

The hot flue gas coming from the freeboard is cleaned of particulate with two stages of cyclone separators. There are 18 trains of primary and secondary cyclones. Approximately 98 percent of the ash in the coal is removed before the gas enters the gas turbine. The ash that remains in the gas stream is between 1 and 10 Fm in size with the average particle size in the 2 to 3 Fm range, all the larger particles having been removed with the bed ash and in the cyclones. A small amount of flue gas is removed with the separated ash for pneumatic transport of the ash to a storage silo. Before the ash is transported outside the pressure vessel, it travels through a cooler where it exchanges heat with the combustor air. This cools the ash to approximately 605 EF before exiting the combustor vessel. The ash and gas are then depressurized and cooled and the ash is stored in the storage silo and the gas is vented to a bag filter. A summary showing the total run period and longest run for the hot gas cleanup unit (HGCU) is given in Table 3.

Table 3. Tidd HGCU Test Period

Test Period	I	II	III	IV	V
Date	10/92-12/92	6/93-9/93	1/94-4/94	7/94-10/94	1/95-3/95
Run No.	1-4	5-11	12-18	19-24	25-34
Test Period Total Hours	464	1,295	1,279	1,706	1,110
Longest Run, Hours	286	597	444	691	427

IV.C.6 Bed Ash Removal System

The bed ash is removed through the boiler bottom by gravity to L-valves where it is transported to a complement of 12 cycling lockhoppers. When a lockhopper is full, the air to the associated L-valve is turned off, an isolation valve to the lockhopper is closed, and the hopper is depressurized and emptied to a conveyor for transport to storage. Cooling of the ash takes place in the boiler bottom hopper before entry into the L-valve. Cooling air is injected into the hopper concurrent to the downward flow of the ash. The velocity of the air is kept below the fluidization velocity of the bed material so that the ash can maintain its downward flow direction. This direct contact between the ash and air cools the ash to approximately 350 EF. The heated air flows up into the fluidized bed where it is mixed with the combustion air in the bed.

IV.C.7 Bed Ash Reinjection System

Load changes are accomplished by raising or lowering the bed level. At maximum load, the tube bundle is completely submersed in the fluidized bed. At this condition, the maximum steam production is obtained as well as the maximum gas temperature and flow to the gas turbine. When the bed level is lowered, the steam production is also lowered, and because part of the tube bundle is now exposed in the gas stream, the gas temperature is also lowered to the gas turbine.

The ability to raise or lower bed level is accomplished by storing or injecting hot bed material. Reinjection vessels are located inside the combustor vessel. These vessels are internally lined to minimize heat loss from stored material. When a load reduction is called for, the reinjection vessels depressurize and allow bed material to flow upward through a transport line into the vessel.

The level of material in the vessels is monitored by change in weight of the vessels detected by load cells. The reinjection vessel hopper is open to an L-valve. When a load increase is called for, high-pressure nitrogen is pulsed into the L-valve to begin sending material back into the fluidized bed. A load changing rate of 4 %/min can be obtained with this system.

IV.C.8 Gas Turbine

The gas turbine operates at 1,525 EF, and a pressure ratio of approximately 9.2 to 1. It 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. With this design combustion gas temperatures fall when unit load is decreased because the lower bed height exposes more steam generator tubes. As the gas temperature drops, the low-pressure shaft slows, decreasing the pressure and flow to the high-pressure compressor. Thus, the free-spinning low-pressure shaft allows the air flow to vary with unit load. The low-pressure and high-pressure compressors supply air to the combustion process. The outlet air temperature is held to 572 EF by an intercooler between the low-pressure and high-pressure compressors. The air in the intercooler is cooled by condensate and is in a parallel stream with number one and two low-pressure heaters and the first-stage economizer.

IV.C.9 Economizer

The economizer is a finned-tube, three-stage unit designed to meet the required performance throughout the load range. The unit is arranged in downflow/upflow configuration on the gas side. The downflow section houses the third-stage economizer and heats the entire feedwater flow to 533 EF. The upflow section houses the second-stage economizer. The second stage is in parallel with the three top feedwater heaters. A partial flow of feedwater will be heated from 300 to 472 EF.

The first stage is located in a horizontal run of duct and is used as the final stage heating in the condensate system. This stage will heat condensate from 215 EF to approximately 258 EF. The final gas temperature leaving the economizer will be 280 EF.

IV.C.10 Particulate Collection

The flue gas discharged from the PFBC economizer is directed through a baghouse filter to remove the fine particulate remaining in the gas stream. The baghouse is composed of multiple, cylindrical bags which are open at one end and arranged vertically in the baghouse structure. Dirty gas is directed to the outside of the bag, where the particulate builds a filter cake as the gas passes through the fabric. When the pressure differential across the bag becomes high, a pulse of air is injected into the bag to dislodge the particulate buildup, which, in turn, falls into the hopper below. The dust, or fly ash, is periodically removed from the hopper for disposal. The baghouse is provided with the appropriate accessories, such as air piping, inlet and outlet nozzles, and expansion joints.

Bag type filters have been used on PFBC units in Europe and are a viable option for the PFBC plant presented herein. Electrostatic precipitators also have a long and successful application history on medium- to high-sulfur coal, and also provide high (up to 99.9 percent) collection efficiencies with a modest electric power consumption and minimal flue gas pressure drop.

IV.C.11 Coal Handling System

The 6-in. x 0 bituminous coal will be delivered to the site by unit trains of 100-ton rail cars. The choice of delivery system is site-dependent and may involve other means, such as trucks or barges. Each unit train consists of 100, 100-ton rail cars. The unloading will be done by a rotary car dumper with a hydraulic car positioner. The rotary car dumper will unload the coal to four receiving hoppers. Coal from each hopper is fed by a vibratory feeder onto a belt conveyor. The 6-in. x 0 coal is conveyed into a transfer building where a sample of coal is taken from each consignment by a coal sampling system. The main stream of coal feeds onto the coal stacker conveyor.

The active pile boom conveyor discharges the coal onto the active coal storage pile and is reclaimed via three reclaim hoppers. The coal is then discharged onto a belt conveyor. The coal is conveyed from the reclaim hoppers to the crusher building and is fed into a two-compartment surge bin provided with a vent filter to reduce dust emissions. Each compartment of the surge bin supplies coal to a full-size vibratory feeder. At the inlet of each primary crusher, a bypass flop gate allows coal to be fed to either the primary crusher, or to a crusher bypass when presized coal is being used. The primary crusher is a ring granulator type crusher while the secondary reduction of the coal is performed by an impactor type crusher. Coal taken from the crusher discharge is sampled by a two-strand, swing-hammer type sampling system before entering the boiler building.

IV.C.12 Limestone Handling and Preparation System

Limestone will be delivered to the plant by 25-ton trucks. The limestone is conveyed to and stored in an enclosed A-frame building. A portal scraper/reclaimer loads limestone onto a belt conveyor for transport to two 100-percent capacity, equipment trains for crushing. Each 120-ton capacity surge bin supplies one rod mill of 45 ton/h capacity each. The rod mills discharge onto airslide conveyors and then move on to bucket elevators, which transport the pulverized material to four-day bins of 125-ton capacity each. The day bins discharge the material to the sorbent injection system.

IV.C.13 Ash Handling System

The function of the ash handling system is to provide the equipment required for conveying, storing, and disposing the cyclone ash and bed ash produced by the PFBC boiler, the ash removed by sootblowers from the economizer sections, and the fly ash captured by the fabric filter baghouse. The scope of the system is from the baghouse hoppers, economizer hopper collectors, cyclone ash storage hoppers, and bottom ash lockhoppers to the ash pond (for bottom ash) and truck filling stations (for fly ash).

The fly ash collected in the baghouse and the economizer sections is conveyed to the fly ash storage silo. A pneumatic transport system using low-pressure air from a blower provides the transport mechanism for the fly ash. Fly ash is discharged through a wet unloader, which conditions the fly ash and conveys it through a telescopic unloading chute into a truck for disposal.

The cyclone ash is conveyed pneumatically from the two storage hoppers to the storage silo. The cyclone ash is discharged by gravity to a truck for transport offsite and disposal. The bed ash is conveyed from the lockhopper discharge connections (12) onto two conveyors. These convey the ash to either of two bucket elevators, which elevate the ash to a second pair of conveyors. The second pair transports the ash to a storage silo, which discharges to a truck for disposal on or offsite.

IV.C.14 Steam Turbine-Generator and Auxiliaries

The steam turbine consists of a high-pressure (HP) section, intermediate-pressure (IP) section, and one double flow low-pressure (LP) section, all connected to the generator by a common shaft. Main steam from the PFBC boiler passes through the stop valves and control valves and enters the turbine at 2,400 psig/1,000 EF.

The steam initially enters the turbine near the middle of the high-pressure span, flows through the turbine, and returns to the PFBC boiler for reheating. The reheat steam flows through the reheat stop valves and intercept valves and enters the IP section at 475 psig/1000 EF. After passing through the IP section, the steam enters a cross-over pipe, which transports the steam to the LP section. The steam divides into two paths and flows through the LP section, exhausting downward into the condenser.

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

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

IV.C.15 Condensate and Feedwater Systems

The function of the condensate system is to pump condensate from the condenser hotwell to the deaerator. The system consists of one main condenser; three 50-percent capacity, motor-driven vertical condensate pumps; one gland steam exhauster; two stages of feedwater; three gas-to-condensate shell and tube heat exchangers, one deaerator with storage tank; three 50-percent capacity, vacuum pumps; two 100-percent capacity, heater drain pumps; and one 250,000-gallon condensate storage tank.

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

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

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

The function of the feedwater system is to pump feedwater from the deaerator storage tank through two parallel circuits: Approximately 59 percent of the flow passes three stages of HP feedwater heaters to the third-stage economizer inlet; the balance of the flow passes through the second-stage economizer, and then combines with the flow exiting the last-stage feedwater heater prior to entering the third-stage economizer.

The system consists of two 60-percent capacity, turbine-driven, boiler feed pumps; one 25-percent capacity, motor-driven, startup boiler feed pump, three stages of partial capacity HP feedwater heaters, and two economizer stages.

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

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

IV.C.16 Circulating Water System

The function of the circulating water system is to supply cooling water to condense the main turbine exhaust steam. The system consists of one counterflow, mechanical draft cooling tower composed of six cells; two 50-percent capacity, vertical, circulating water pumps; and carbon steel cement-lined interconnecting piping. The cooling tower structure is concrete, with PVC fill and fiberglass fan stacks.

The condenser is a single-shell type with divided water boxes arranged for single pass flow of the circulating water. There are two separate circulating water circuits in the condenser. The water splits prior to entering the condenser and reconnects in the discharge prior to returning to the cooling tower. One half of the condenser can be removed from service for cleaning or plugging tubes. This can be done during normal operation at reduced load.

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

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

Each pump has a motor-operated discharge butterfly valve. The pump discharge valve is interlocked with the pump motor starting circuit so that the valve is first opened approximately 15E. The motor starts automatically when the valve reaches that position. After the pump is up to speed, the system is full and stable flow is established, the valve is opened to 90E. On shutdown, the valve closes fully and, as it passes the 15E open position, automatically trips the pump. The valve closes automatically on loss of power to avoid hydraulic surges.

IV.C.17 Liquid Waste Treatment

Industrial wastewater from station operations will be collected, treated in an onsite treatment system, and discharged to an adjacent stream. The treated effluent will meet U.S. Environmental Protection Agency standards for total suspended solids, oil and grease, pH, and miscellaneous metals. The coal pile runoff basin, the raw waste sump, and the lime storage and feed system are located outdoors. The remaining treatment system components are located in a heated building.

IV.C.18 Auxiliary Boiler Steam System

The auxiliary boiler supplies steam to all plant components normally requiring steam during periods of unit or station shutdown, startup, or in certain cases, normal plant operation. The major interfacing components and systems with the auxiliary boiler are the feed pumps, deaerator, fuel oil storage and supply, and stack.

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

IV.C.19 Fuel Oil Supply System

A fuel oil storage and supply system sized to accommodate the boiler startup burners and auxiliary boiler was included in the estimate. No. 2 grade fuel oil was selected for use because of anticipated usage and cost considerations, as well as providing future fuel flexibility benefits.

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

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

IV.C.20 Station Air Service

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

IV.C.21 Station Service Water

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

Two service water pumps at 100-percent capacity each provide the general cooling water requirements for the station. Cooling water is supplied from this system to equipment such as generator hydrogen and turbine lube oil coolers, compressors, mills, boiler feed pumps, etc. Service water is also used to cool the closed-cycle cooling-water system loop. The system services loads not served by the circulating water system branch, which may require cooling when the main circulating water pumps are shutdown. A separate header takes water to the ash and dust unloading systems, and car dumper house.

A closed-cycle cooling-water system is used to cool smaller cooling loads that require a higher pressure, such as coolers located higher in the plant. Condensate quality water is used as the cooling fluid.

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

Two pumps (100-percent capacity each) are installed to supply river water for makeup to the circulating water system, filtered water, service water, and condensate.

Two filtered water pumps take water from the clearwell and supply the filtered water tank and the demineralizers. The pumps are centrifugal pumps constructed with single suction, cast iron vertically split casings.

A filtered and sterile water storage tank is provided and has a capacity of 15,000 gallons. All water except that flowing to the demineralizers is taken directly to the storage tank to provide a constant head on the system and to prevent stagnation of water in the tank.

IV.C.22 Plant Control and Monitoring Systems

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

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

IV.C.23 Automation and Operation

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

The design of the combustion control systems will be a joint, integrated process involving the boiler supplier, plant designer, operator/user, and DCS supplier. Conventional logic and control strategies will be used for the majority of the control loops.

IV.C.24 Continuous Emission Monitoring System

The continuous emissions monitoring system (CEMS) consists of four major parts: the flue gas emission analyzers, opacity monitor, flue gas flow rate monitor, and data acquisition and reporting system (DAS). The CEMS provides the plant with the ability to monitor and report emissions in compliance with the EPA CAAA. CEMS continuously monitors the emissions of sulfur dioxide (SO_2), nitrogen oxides (NO_X), and carbon dioxide (CO_2) in the flue gas as well as a measurement of the flue gas opacity and flow. In addition to providing emissions monitoring capabilities, the system will provide emissions and system calibration reports for submittal to the regulatory agency as required by the Clean Air Act.

IV.D Reference PFBC Plant Economics

Capital cost projections for large PFBC (100-200 MWe) for power generation have been estimated to range from $1,200 to $1,550/kW. The PFBC power plant cost can be up to 20 percent less expensive than PC power plants with wet scrubbers. PFBC power plants provide other advantages compared to PC power plants with scrubbers: fuel flexibility, modularity, and suitability for retrofit. The Tidd plant was a relatively small-scale facility, and as such, detailed economics were not prepared as part of this project. A recent cost estimate performed on Japan's 360-MWe PFBC Karita Plant projected a capital cost of $1,263/kW (1997 dollars).

Capital cost estimates for mature PFBC technology were prepared by Gilbert Commonwealth, Inc. For the U.S. Department of Energy, Office of Fossil Energy, Morgantown Energy Technology Center (now the National Energy Technology Laboratory). The cost estimates were for new baseload power plants and are given in December 1994 dollars. Site-specific conditions were not considered. Cost summaries are presented in Table 4 for 110- and 250-MWe mature PFBC power plants.

Although the estimate is intended to represent a complete power plant, several exclusions remain:

- Sales tax is not included (considered to be exempt).
- Onsite fuel transportation equipment (such as barge tug, barges, yard locomotive, bulldozers) is not included.
- Allowances for unusual site conditions (such as piling, extensive site access, excessive dewatering, extensive inclement weather) are not included.
- Switchyard (transmission plant) is not included. The costed scope terminates at the high side of the main power transformer.
- Ash disposal facility is excluded, other than the storage in the ash storage silos. (The ash disposal cost is accounted for in the ash disposal charge as part of consumable costs.)
- Royalties are not included.

Table 4. PFBC Cost Summaries

Cost Parameters	**110 MWe**	**250 MWe**
Heat Rate	8,484 Btu/kWh	8,247
Primary Fuel	Pittsburgh #8	Pittsburgh #8
Book Life	30 years	30 years
Capacity Factor	65%	65%
Capital Cost Summary $/kW		
Process Capital and Facilities	$1,495	$875
Engineering and Contingencies	$100	$200
AFDC	$135	$115
Total Plant Investment	$1,630	$1,190
Owner Costs	$90	$70
Total Capital Requirements	$1,720	$1,260
Levelized O&M Costs $/kWyr		
Fixed O&M	16.4	9.4
Variable O&M	8.8	5.1
Consumables	5.5	5.2
Fuel	27.8	27.3
Capital Carrying Charge	49.8	36.5
Total Busbar COE	108.4	83.4

O&M = operating and maintenance

V Commercial Applications

The successful operation of the Tidd PFBC Demonstration Project has established the viability of the process. Plants throughout the world continue to demonstrate the viability of PFBC technology. Table 5 lists PFBC commercial size plants worldwide. Worldwide, coal-fired systems are expected to provide a significant portion of future base-load generation capacity. PFBC operational, environmental, and economic performance should place it in a strong position to capture a significant share of the base-load market.

Table 5. PFBC Commercial Scale Plants

Plant	Bed Type	Size	Location	Vendor	Status
Vartan	Bubbling (two units)	135 MWe +225 MWth	Sweden	ABB Carbon	Operational 1989
Escatron	Bubbling	70 MWe	Spain	ABB Carbon	Operational 1990
Wakamatsu	Bubbling	70 MWe	Japan	IHI*	Operational 1993
Tidd	Bubbling	70 MWe	U.S.	B&W*	Test Completed Shut Down
Karita	Bubbling	360 MWe	Japan	IHI*	Operational 1999
Cottbus	Bubbling	74 Mwe +120 MWe	Germany	ABB Carbon	Operational 1999

* Under license from ABB Carbon

A review of public information concludes there are a number of markets which PFBC ash may be able to penetrate. Ash from both high-sulfur and low-sulfur coal-fired units may have a market. Potential markets include the following:
- Supplementary cementing materials in concrete and cement production
- Structural fill and embankment material
- Soil stabilizing agent
- Synthetic aggregate production
- Soil amendment

Unfortunately, the value of the market products and the availability of competing materials is restricted by transportation distances. Competing materials already established in these markets have substantial technical performance records.

VI Acronyms and Abbreviations

ABB	ASEA Brown Boveri
AEP	American Electric Power
AEPSC	American Electric Power Service Corporation
AFDC	allowance for funds used during construction
ASME	American Society of Mechanical Engineers
BACT	best available control technology
CAAA	Clean Air Act Amendments
CC	combined-cycle
CCT	Clean Coal Technology
CEMS	continuous emission monitoring system
COE	cost of electricity
CTF	component test facility
CURL	coal utilization research laboratory
DAS	data acquisition and reporting system
DCS	distributed control system
DOE	U.S. Department of Energy
EPA	Environmental Protection Agency
FGD	flue gas desulfurization
GT	gas turbine
HGCU	hot gas cleanup unit
HP	high pressure
IP	intermediate pressure
NASA	National Aeronautics and Space Administration
NCB	National Coal Board
NFPA	National Fire Protection Agency
NSPS	New Source Performance Standards
O&M	operating and maintenance
OSHA	Occupational Safety and Health Administration
PC	pulverized coal
PCF	pressurized circulating fluid bed plant
PFBC	pressurized fluidized-bed combustion
PPA	post-project assessment
PSD	prevention of significant deterioration
RCRA	Resource Conservation and Recovery Act

VII Bibliography

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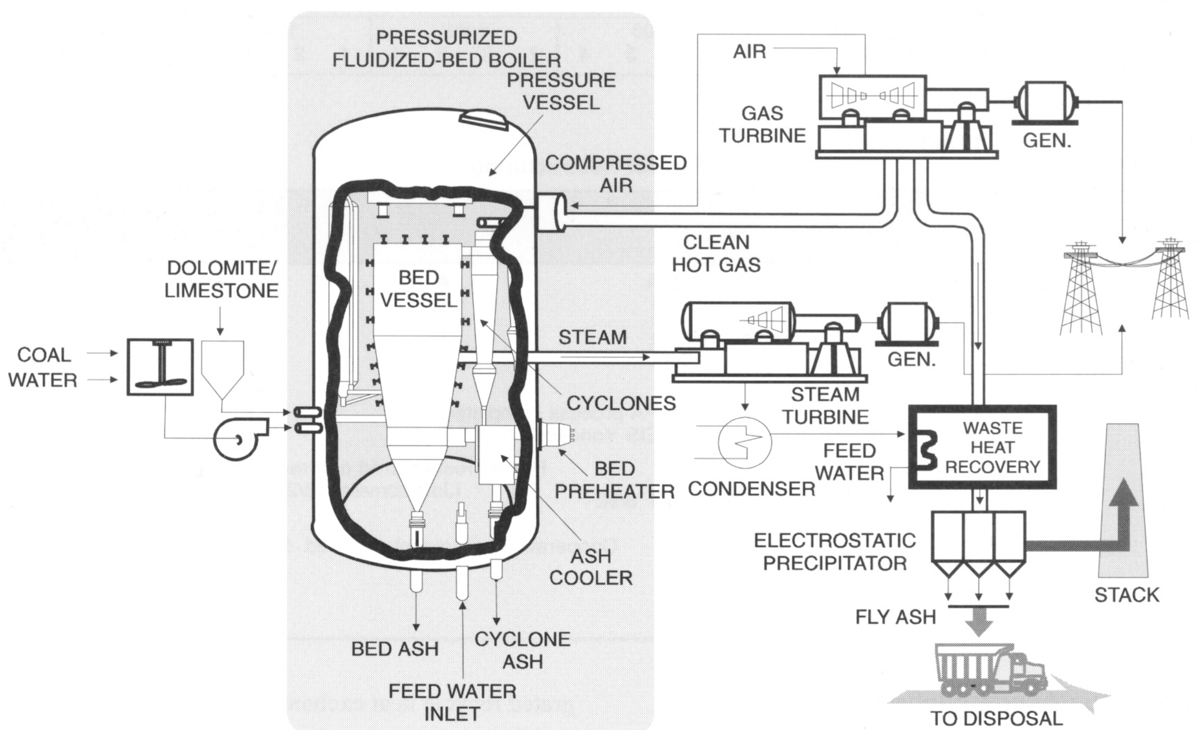

Figure 1. Diagram of Typical PFBC Composite Cycle

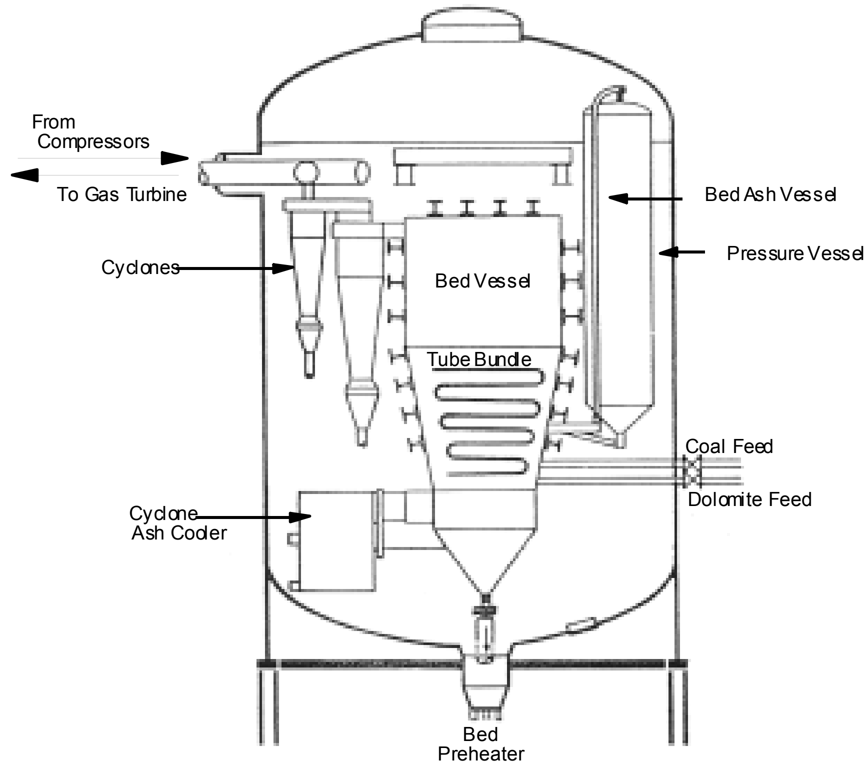

Figure 2. Tidd Demonstration Plant Combustor Vessel Assembly

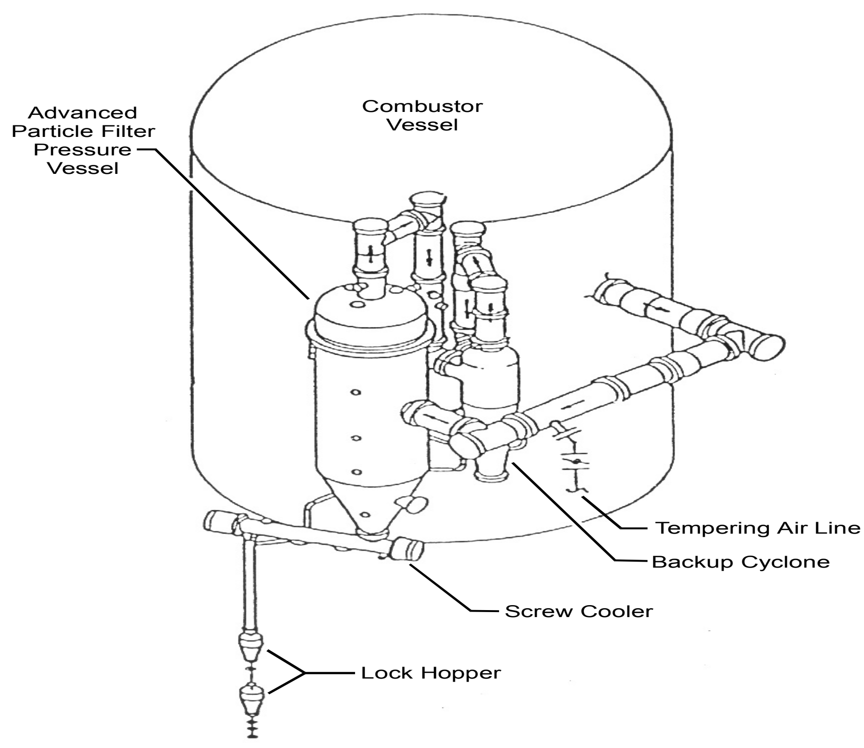

Figure 3. Isometric View of HGCU System