DEMONSTRATION OF SELECTIVE CATALYTIC REDUCTION TECHNOLOGY FOR THE CONTROL OF NITROGEN OXIDE EMISSIONS FROM HIGH-SULFUR, COAL-FIRED BOILERS

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ABSTRACT

This paper describes the status of the Innovative Clean Coal Technology project to demonstrate SCR technology for reduction of NOx emissions from flue gas of utility boilers burning U.S. high-sulfur coal. The funding participants are the U.S. Department of Energy (DOE), Southern Company Services, Inc. (SCS), on behalf of the entire Southern Company, Electric Power Research Institute (EPRI), and Ontario Hydro. SCS is the participant responsible for managing all aspects of the project. The project is being conducted on Gulf Power Company's Plant Crist Unit 5 (75-MW nominal capacity), located near Pensacola, Florida, on U.S. coals that have a sulfur content near 3.0%. The SCR facility treats a 17,400 scfm slip-stream of flue gas and consists of three 2.5-MW (5000 scfm) and six 0.2-MW (400 scfm) SCR reactors. The reactors operate in parallel with commercially available SCR catalysts obtained from vendors throughout the world. The design engineering and construction have been completed, and the start-up/shakedown was completed in June 1993. Long-term performance testing began in July 1993 and will be conducted for two years. Test facility description and test plans, as well as start-up issues and preliminary commissioning test results are reported in this paper.

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INTRODUCTION

The need within the utility industry for detailed information on selective catalytic reduction (SCR) technology has never been greater. The 1990 Clean Air Act Amendments (CAAA) create two new nitrogen oxide (NO_x) control requirements on fossil fuel-fired utility boilers. First, Title IV of the CAAA regarding acid rain requires that emission limits be placed on all coal-fired utility boilers in two phases, one beginning in 1995 and the other in the year 2000. SCR, in which ammonia is added to the flue gas to reduce NO_x to nitrogen over a catalyst, is not as prominently mentioned as low NO_x burner technology for meeting the Title IV provisions. However, the final EPA emission limitations for each of the two phases remain to be established, and SCR is still very much under consideration in utilities' compliance strategies. Second, Title I of the CAAA addresses attainment of the ambient air quality standards. Regarding ozone, Title I calls for certain areas presently not in attainment to consider NO_x controls to achieve attainment. As a result, renewed focus has been placed on NO_x controls, including advanced NO_x control technologies such as SCR, which may be required to meet compliance requirements for ozone non-attainment areas.

SCR technology involves the injection of ammonia into flue gas and then passing the gases through one or more catalyst layers where NO_x and ammonia react to form nitrogen and water vapor. A simplified, typical SCR process installation for a utility boiler is depicted in Figure 1. Hot flue gas leaving the economizer section of the boiler is ducted to the SCR reactor. Prior to entering the reactor, ammonia (NH_3) is injected into the flue gas at a sufficient distance upstream of the SCR reactor to provide for complete mixing of the NH_3 and flue gas. The quantity of NH_3 is adjusted to achieve the desired NO_x removal efficiency. The reactions between NH_3 and NO_x occur as the flue gas passes through the catalytic layers of the SCR reactor. Ductwork is installed to bypass some flue gas around the economizer during periods when the boiler is operating at reduced load. This is done, especially on retrofits, to maintain the temperature of the flue gas entering the catalytic reactor at the proper reaction temperature of about 700^{o}F.

SCR technology is in commercial use in Japan and Western Europe on gas-, oil-, and low-sulfur, coal-fired power plants. There are now over 36,000 MW of fossil-fuel-fired SCR capacity in

Japan, including 6,200 MW on coal. There are over 33,000 MW of fossil-fuel-fired SCR capacity in Western Europe, including 30,500 MW of coal-fired capacity.[1]

SCR DEMONSTRATION GOALS

Although SCR is widely practiced in Japan and Western Europe, numerous technical uncertainties are associated with applying SCR to U.S. coals. These uncertainties include:

(1) potential catalyst deactivation due to poisoning by trace metal species present in U.S. coals but not present, or present at much lower concentrations, in fuels from other countries;
(2) performance of the technology and effects on the balance-of-plant equipment in the presence of high amounts of SO_2 and SO_3 (e.g., plugging of downstream equipment with ammonia-sulfur compounds); and
(3) performance of a wide variety of SCR catalyst compositions, geometries and manufacturing methods at typical high-sulfur coal-fired utility operating conditions.

These uncertainties are being explored by constructing and operating a series of small-scale SCR reactors and simultaneously exposing different SCR catalysts to flue gas derived from the combustion of high-sulfur U.S. coal. The first uncertainty will be handled by evaluating SCR catalyst performance for two years under realistic operating conditions found in U.S. pulverized-coal-fired utility boilers. Deactivation rates for the catalysts exposed to flue gas of high-sulfur U.S. coal will be documented to determine catalyst life and associated process economics. The second uncertainty will be explored by performing parametric tests, during which SCR operating conditions will be adjusted above and below design values to observe deNO_x performance and ammonia slip. The performance of air preheaters installed downstream of the larger SCR reactors will be observed to evaluate the effects of SCR operating conditions upon heat transfer and boiler efficiency. The third uncertainty is being addressed by using honeycomb- and plate-type SCR catalysts of various commercial compositions from the U.S., Japan, and Europe. Tests with these catalysts will expand knowledge of the performance of SCR catalysts under U.S. utility operating conditions with high-sulfur coal.

The intent of this project is to demonstrate commercial catalyst performance and to determine optimum operating conditions and catalyst life for the SCR process. This project will also demonstrate the technical and economic viability of SCR while reducing NO_x emissions by at least 80%.

SCR DEMONSTRATION FACILITY DESCRIPTION

The SCR demonstration facility is located at Gulf Power Company's Plant Crist in Pensacola, Florida. The facility will treat a flue gas slip-stream from Unit 5, a commercially operating 75-MW unit, firing U.S. coals with a sulfur content near 3.0%. Unit 5 is a tangentially-fired, dry bottom boiler with hot- and cold-side electrostatic precipitators (ESPs) for particulate control. The SCR test facility consists of nine reactors operating in parallel for side-by-side comparisons of commercially available SCR catalysts obtained from vendors throughout the world. With all reactors in operation, the amount of combustion flue gas that can be treated is 17,400 scfm or 12% of Unit 5's capacity (about 8.7 MWe).

The process flow diagram for the SCR test facility is shown in Figure 2. There are three large SCR reactors (2.5 MW, 5000 scfm) and six smaller SCR reactors (0.2 MW, 400 scfm). Eight of the nine reactors will operate with flue gas containing full particulate loading (high dust) extracted from the inlet duct of the hot-side ESP, while one small reactor will use flue gas fed from the ESP outlet (low dust).

Each reactor train has electric duct heaters to control the temperature of the flue gas entering the reactor and a venturi flow meter to measure the flue gas flow. An economizer bypass line to the SCR test facility maintains a minimum temperature of 620°F for flue gas supplied to the test facility. Anhydrous ammonia is independently metered to a stream of dilution air that injects the ammonia via nozzles into the flue gas stream prior to each SCR reactor. The flue gas and ammonia pass through the SCR reactors, which have the capacity to contain up to four catalyst layers.

For the large reactor trains, the flue gas exits the reactor and enters a pilot-scale air preheater (APH). The APHs are incorporated in the project to evaluate the effects of SCR reaction chemistry on APH deposit formation and the effects of the deposits on APH performance and operations. All reactor trains, except the low-dust train, have a cyclone downstream of the SCR reactor to protect the induced draft (ID) fan from particulates. The exhaust for all the SCR reactors is combined into a single manifold and reinjected into the host boiler's flue gas stream ahead of the cold-side ESP. The preheated air from the APH on the large reactors is also combined into a single manifold and returned to the host boiler draft system at the air outlet of the existing APH. All of the particulates that are removed from the flue gas with the cyclones are combined and sent to an ash disposal area.

CATALYST TESTING PLANS

Seven catalyst suppliers are participating in this project, providing nine different catalysts. The two suppliers from Europe and two from Japan provide one catalyst each. The three U.S. firms are supplying five of the catalysts. The catalysts being evaluated represent the wide variety of SCR catalysts being offered commercially and possess different chemical compositions and physical shapes. Of these nine catalysts, six have a honeycomb geometry while the remaining three are plate-type catalysts. The suppliers, corresponding reactor size, and catalyst configuration are listed in Table 1.

After start-up, the baseline performance of each catalyst will be determined at design conditions which will be maintained for the two year test period. Once baseline performance has been established, each reactor will be sequenced through a test matrix (parametric tests) that varies the following variables around the SCR process design point: ammonia-to-NO_x ratio, temperature, and space velocity. Space velocity is the ratio of flue gas volumetric flow rate to catalyst volume. With a fixed catalyst volume, variations in flue gas flow rates will alter the space velocity around the design point.

DeNO_x efficiency, pressure drop, SO_2 oxidation, and ammonia slip will be determined at each parametric test condition. Once a parametric test matrix has been completed, each reactor will be returned to baseline design conditions. This allows for steady-state operation over a three month period between parametric tests for aging of the catalyst. The parametric test matrix will be repeated every three months for each reactor train. Only one reactor train will be undergoing parametric testing at any one time. The remaining reactors will be either in steady-state operation or off-line. The APH is bypassed during parametric testing so that long-term deposit formation is not affected.

The operating parameter ranges to be examined during the parametric tests and the long-term design condition (baseline) are as follows:

	Minimum	Baseline	Maximum
Temperature,°F	620	700	750
NH_3/NO_x molar ratio	0.6	0.8	1.0
Space velocity,			
• % of design flow	60	100	150
• Flow rate, scfm			
-large reactor	3000	5000	7500
-small reactor	240	400	600

PROJECT SCHEDULE AND STATUS

The demonstration project is organized into three phases. Phase I consisted of permitting, preparing the Environmental Monitoring Plan and preliminary engineering. Phase II included detailed design engineering, construction, and start-up/shakedown. Detailed design engineering began in early 1991 and concluded in December, 1992. Construction began at the end of March 1992 and was completed by the end of February 1993. Start-up/shakedown concluded in June 1993. Baseline commissioning tests without catalysts were conducted through June. The loading of all catalysts was completed at the end of June.

The operations phase for process evaluation, Phase III, commenced in July 1993. The process evaluation will last for two years and will be followed by preparation of a final report, which will include process economic projections. The major milestones on the schedule are shown in Table 2.

START-UP ISSUES

As may be normally expected, there have been several problems encountered upon start-up, some of which are not associated with the SCR process per se. The major experiences are highlighted below:

Dilution/Extraction Gas Sampling/Monitoring System

The SCR test facility uses a dilution/extraction sampling system for measurement of NO_X, SO_2, CO_2, and CO in the flue gas. This sampling method uses dry air as a dilution medium, with typical air/sample dilution ratios ranging from 100 to 250, to minimize the difficulties associated with the transport and measurement of these gases as compared to other available methods. Problems experienced with this system include accurate measurement of NO_X when ammonia is injected, coordination of the shared analyzers, and communications with the test facility data collection system.

Although the inlet NOx readings are not affected, there have been problems with NO_X measurements at intermediate reactor levels in the presence of ammonia. Apparently catalytic reactions are proceeding in the sampling system, resulting in reduced NO_X values. There has been a series of traps and filters installed in sample lines to capture the ash, water vapor and acid condensate in order to improve the accuracy of the analyzer system. Work is underway to investigate the use of alternate materials of construction for the sampling probes.

For the nine reactors, there are three NO_X analyzers for the reactor outlet measurements. Each of these analyzers operate on a time-shared basis serving three specific reactors. These systems use a complex system of pumps and valves to direct the sample that is continuously extracted to the analyzer. While one of the three reactor sampling points is active, the other two points are expected to hold their previous values. However, erroneous data is being transmitted for the two points which are supposedly inactive.

The gas analyzer system has a dedicated programmable controller that collects the data from all the analyzers and then sends them to the test facility's control and data collection system. Because these are different systems, the communication protocol had to be worked out during start-up. Although many of the communication problems were solved during the start-up of the test facility, there are still some communication failures occurring. All of these problems with the gas sampling/analysis systems are being addressed.

Ammonia Injection Flow Control

The ammonia vapor flow rates for injection into the reactors are being controlled by precision mass flow control valves. These controllers are affected by liquid in the flow stream, pressure variations, trash in the line, and also the orientation of the controller itself. These controllers were calibrated on nitrogen and scaled to read ammonia flow. Although initial results indicated accurate flow control, subsequent measurements have indicated that actual ammonia flow has been 10 to 25 percent higher than the controllers are indicating. Actions taken to correct this situation include installing coalescent filters on the ammonia supply lines to each control valve, reorienting the controllers, replacing the ammonia header pressure regulator, cleaning each controller, and recalibrating and verifying with other instruments.

Sulfate Deposition

There have been problems with plugging in ductwork where continuous flow is not maintained. These areas provide condensation sites which is exacerbated by the high sulfur concentrations in the fuel and the flue gas. While the ammonia injection system was being completed and flue gas was being passed through the system for startup, the installed injectors presented one such low flow area that sulfates diffused into and precipitated out, plugging almost every injection system.

The nozzles and injection header were cleaned and some portions of the feed piping had to be replaced. The air fan for ammonia dilution has since been placed in service and will be used to supply a continuous air flow to act as a purge to prevent recurrence of the plugging. The horizontal sections of the large reactor bypass lines accumulated a large amount of sulfate formation that blocked operation of several dampers. These dampers are being exercised on a weekly basis to prevent the blockage from binding the dampers again.

Low Dust Reactor Fouling

After only a few hours of operation during its first start-up after catalyst loading, the low-dust reactor experienced severe plugging of the first catalyst layer. While the large reactor bypass lines may be used to flush any ash accumulations associated with the main extraction scoop, the low dust reactor ductwork was not provided with any bypass capability. Also, the isolation damper for that line is approximately 100 feet downstream of the scoop allowing a deadleg for sulfate formation when the reactor is off-line. So during start-up an unusually large amount of solid material may have been introduced to the low-dust reactor. The first layer catalyst element has been returned to the catalyst vendor for examination and a study is underway to evaluate solutions to prevent recurrence of this problem.

Bypass Heat Exchangers

The bypass heat exchangers, which were included for use during the parametric testing on the large reactors to minimize effects of high ammonia slip upon the long-term evaluation of the air preheaters, have been easily plugged by ash and sulfate deposits. Cleaning with either air or water has not been a satisfactory solution. Work is underway to develop another means to cool the flue gas while bypassing the air preheaters.

Ash Accumulation

During start-up, especially during low flows, ash build-up was found in several areas of the ductwork including the main scoop area, the electric flue gas heaters, and the bypass heat exchangers. Extra access ports for soot blowing were added to clean these areas.

Reactor and Air Preheater Soot blowing

Steam soot blowers are used in the large reactor trains for both the catalyst baskets as well as the air preheaters. Much effort has been expended to eliminate the condensate from the soot blowing steam supply piping before the soot blowers extend into the reactors. An extra steam isolation valve has been added on each soot blower and a process steam condensate trap is used on each reactor's steam supply header. Warm-up vents have been added to assure the piping is hot enough to prevent condensation. Follow up inspections reveal that the soot blowers are effective in dislodging any ash build-up on either the reactor baskets or on the air preheater baskets.

Reactor Fans

Due to the small flow, high head requirements of the test facility, the reactor fans are custom designed and not "off the shelf" models. Because of the head requirement, the fan wheels are narrow, large diameter with relatively high inertial moments that made bearing selection difficult. On the small reactor fans, the bearings were replaced twice before changing the design to ball bearings.

Because of the possibility of ammonia slip in the flue gas, materials used in fan construction had to be compatible with ammonia. Ammonia will attack any copper-based alloy. The original vane support bushings were pressed carbon and very brittle; several were broken in shipment and more broke during installation. The first replacements fabricated were brass, and they were rejected due to the ammonia attack of copper alloys. The next offering was stainless steel, which galled as soon as it was installed. The latest solution is a silicon alloyed cast iron, which has performed well over the last three months. The vane bearings have been extended off of the fan housing and new seals have also been installed.

TEST RESULTS

The facility test plan is divided into two main sections, 1) start-up and commissioning tests, and 2) long term testing and parametric evaluation. The start-up and commissioning tests were designed to insure the quality of data obtained from the facility. These tests include base-line evaluations as well as measurements insuring comparability between the reactors. The majority of the tests have been completed and data evaluation is currently underway. The following list describes some of the start-up and commissioning tests that were performed during this section of testing.

(1) Instrument calibration and gas analysis system verification.
(2) Base-line particulate concentration, size distribution, and metals concentrations from host unit.
(3) Base-line chemical composition of host unit slip stream.
(4) Comparative particulate loading to each reactor.
(5) SO_2 oxidation characteristics of the system.
(6) Determination of inherent system ammonia oxidation characteristics.
(7) Verification of ammonia mass flow control.
(8) Measurement of catalyst SO_2 oxidation characteristics.
(9) Determination of velocity and particulate profiles at reactor exits.

The following tables and discussions describe some of the most important start-up and commissioning test results that are available at this time. All of the data presented here is of a preliminary nature. Several analyses such as particle size distributions and metals analysis are not available at this time due to the long analytical times required for these measurements.

Table 3 shows the base-line flue gas composition measured in the host unit duct at high (84 MW) and low (43 MW) boiler load. This data compares favorably with data taken several years ago during initial site selection.

Particulate loading in the process stream is a critical design consideration in the development of SCR catalysts. Initial particulate measurements showed that the small reactors were receiving a higher particulate loading than the large reactors under all boiler conditions. After reviewing the design of the splitting section of the main flue gas scoop at the point of the small reactor take-off, the splitting section was mechanically improved to give proper isokinetics, which corrected the particulate loading discrepancies between the reactors. Table 4 gives the particulate loading to each of the eight high dust test facility reactors at high and low boiler load. This data was taken using isokinetic particulate sampling performed as a traverse across the cross-section of the reactor exits. This data compared favorably with the base-line particulate data taken from the host unit duct work.

The data in Table 4 show that the particulate loading to each reactor is fairly consistent and that the loading does not vary more than 10% from the average in most cases. Some of the differences in loading are likely due to boiler variations since individual measurements were taken over a very short period of time with the overall tests taking several weeks. More particulate data will be obtained as the testing program continues. This should allow long term loading characteristics to be established for each reactor.

Tests have also been performed to determine how evenly the particulates are distributed within the individual reactors. These tests were performed at the reactor exits. Preliminary results indicate that the mass loading is evenly distributed in the cross-sections of the reactors. These measurements were made as six point traverses over the cross-section of the large reactors and three point traverses over the cross-section of the small reactors. Velocity distribution measurements across the reactors at the same sampling locations also indicate a very even velocity distribution.

Sulfur trioxide in the flue gas stream is an extremely important consideration for balance of plant equipment in SCR applications. This is primarily due to the side reaction of SO_3 with ammonia. This reaction forms ammonium bisulfate and sulfate which occur at relatively low temperatures downstream of the SCR reactor, e.g., at the air preheater. SCR catalysts have the potential to oxidize SO_2 to SO_3 thereby exacerbating the ammonium bisulfate/sulfate formation problem as well as contributing to acid deposition problems.

To characterize this oxidation, two series of start-up and commissioning test were performed. The first series of tests characterized the inherent SO_2 oxidation within the test facility system. This included oxidation across the test facility flue gas heaters, as well as oxidation across the reactors themselves (without catalyst). These tests were performed on one large reactor and one small reactor. The results are shown in Table 5. The heater inlet SO_3 values compare favorably with the base line values at low load. However, the high load values for SO_3 appear to be considerably lower than base line. This may be due to changes in boiler operation between testing periods (several months). The data show that no net increase in SO_3 was taking place across the SCR reactors. In fact, a slight decrease in SO_3 was noted, which was probably due to deposition in cool spots on the reactor between measurement points. Some oxidation was noted across the flue gas heaters, which was expected. The absolute increase in SO_3 over the heaters was greatest at low load. This may be due to the higher heat flux required from the heaters at low unit load to maintain temperature to the SCR reactors. However, the percent increase in SO_3 across the heater at both high and low load is roughly equivalent. The second series of SO_2 oxidation tests will determine the oxidative characteristics of the SCR catalysts themselves. These tests will be performed as part of the preliminary parametric sequence. This data is not available at this time.

Upon completion of commissioning tests without catalyst, catalyst loading was completed in late June 1993. Long-term testing and parametric evaluations are underway. Immediately after catalyst loading, all reactors were operated briefly to obtain fly ash samples for the Toxicity Characteristics Leaching Procedure (TCLP) analysis. The TCLP results indicated no detectable amounts or change in constituents between baseline ash samples and ash samples from the SCR process outlet.

The first parametric testing is underway. Based upon the results of this first test, a parametric test plan will be finalized for the remainder of the two year operation of this test facility.

SUMMARY

During this ICCT demonstration, performance data will be developed to evaluate SCR capabilities and costs that are applicable to boilers using high-sulfur U.S. coals. The SCR demonstration facility construction has been completed and start-up/shakedown was finished in early June 1993. Long-term performance testing began in July 1993 and will be completed in 1995.

Operation issues which have been successfully addressed include resolving sulfate deposition in the ammonia injection header system, adding extra soot blower ports to clean areas of ash accumulation, improvements on steam soot blowing of large reactors and air preheaters, and resolving several fan operational issues. Problem areas still being addressed include operation of sampling/monitoring systems, low dust reactor fouling and bypass duct exchanger operation.

In general, the start-up and commissioning tests have demonstrated that each of the SCR reactors is operating on the same basis in terms of process gas feed. Distribution measurements on the individual reactors are in good agreement with the original design requirements. The results of these tests validate the test facility and should guarantee the quality of data obtained in long-term operation and parametric testing.

REFERENCES

1. A. L. Baldwin, J. D. Maxwell, U.S. Department Of Energy's and Southern Company Services's August 24 -September 1, 1991, Visit to European SCR Catalyst Suppliers, U.S. DOE, Pittsburgh, PA, 1991, p 41-3.

Table 1. SCR Project Catalyst Suppliers.

Catalyst Vendor	Reactor Size	Catalyst Configuration
Nippon Shokubai	Large	Honeycomb
Siemens AG	Large	Plate
W. R. Grace	Large	Honeycomb
W. R. Grace	Small	Honeycomb
Haldor Topsoe	Small	Plate
Hitachi Zosen	Small	Plate
Cormetech	Small	Honeycomb
Engelhard	Small	Honeycomb (high dust)
Engelhard	Small	Honeycomb (low dust)

Table 2. Project Schedule

Detailed Engineering	1/92 - 12/92
Construction	3/92 - 2/93
Start-up/Shakedown	1/93 - 6/93
Process Evaluation	7/93 - 6/95
Disposition/Final Report	7/95 - 10/95

Table 3. Test Facility Inlet Flue Gas Composition

Constituent	ESP Inlet		ESP Outlet	
	84 MW	43 MW	84 MW	43 MW
NO_x	325	401	332	Not Available
SO_2 (ppm)	2340	1780	2030	1510
SO_3 (ppm)	32	42	14	20
HCl (ppm)	104	89	115	101
NH_3 (ppm)	<0.4	<0.4	<0.4	<0.4
Particulate (gr/dscf)	3.76	2.43	0.0018	BDL*

* Below detection limits

Table 4. Particulate Loading to Reactors

Reactor	Ash Loading (84 MW) (gr/dscf)	Ash Loading (43 MW) (gr/dscf)
A	3.65	3.08
B	4.18	3.04
C	3.96	3.16
D	2.83	2.70
E	3.96	3.22
F	4.01	3.04
G	3.60	2.71
H	3.52	2.75

Table 5. SO2 Oxidation Across Test Facility Without Catalyst

		SO3 (ppm)		
		Heater Inlet	Heater Exit	Reactor Exit
Large Reactor	84 MW	12	15	10
	43 MW	31	40	32
Small Reactor	84 MW	8	11	7
	43 MW	28	35	23

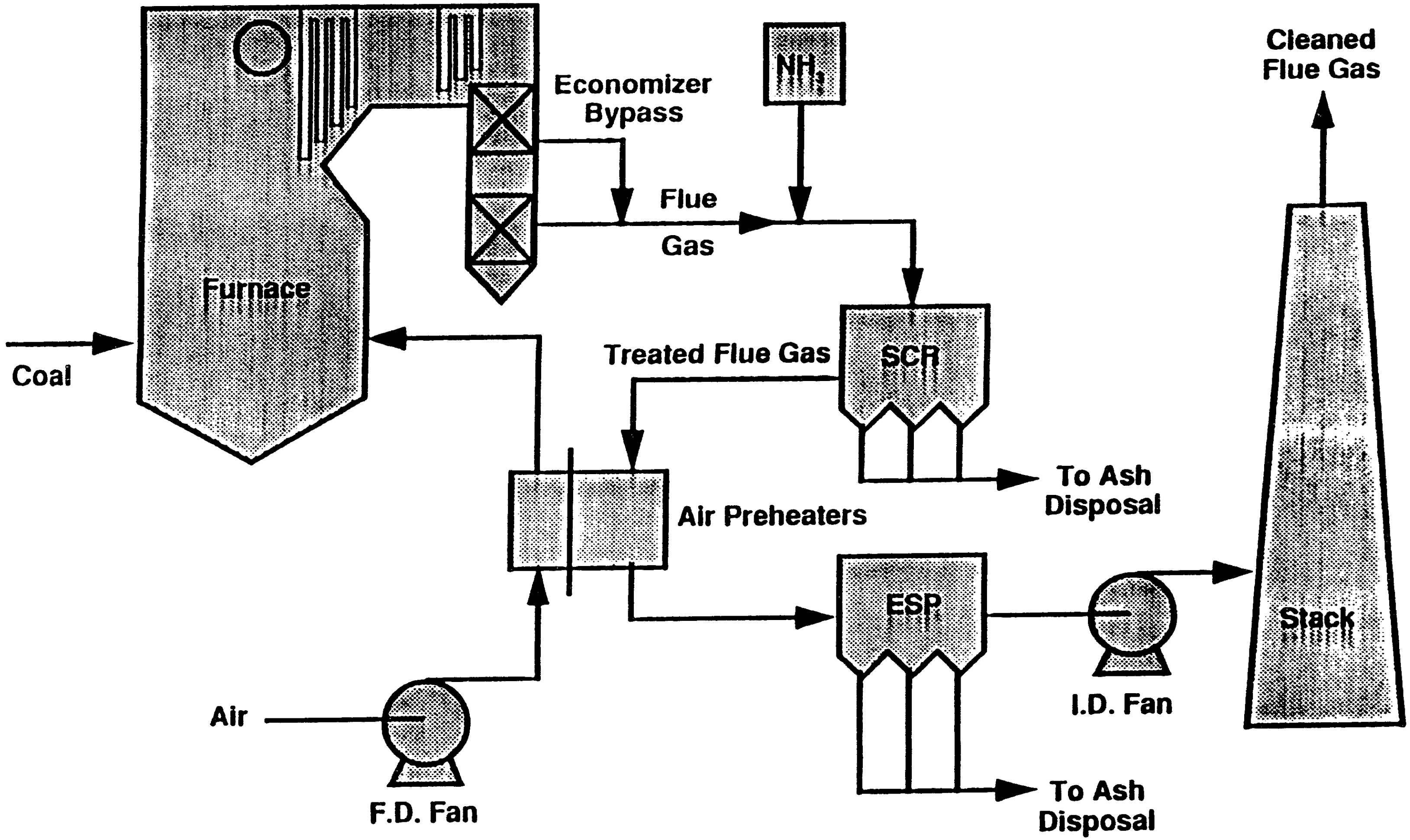

Figure 1. Flow Diagram of a Typical SCR Installation.

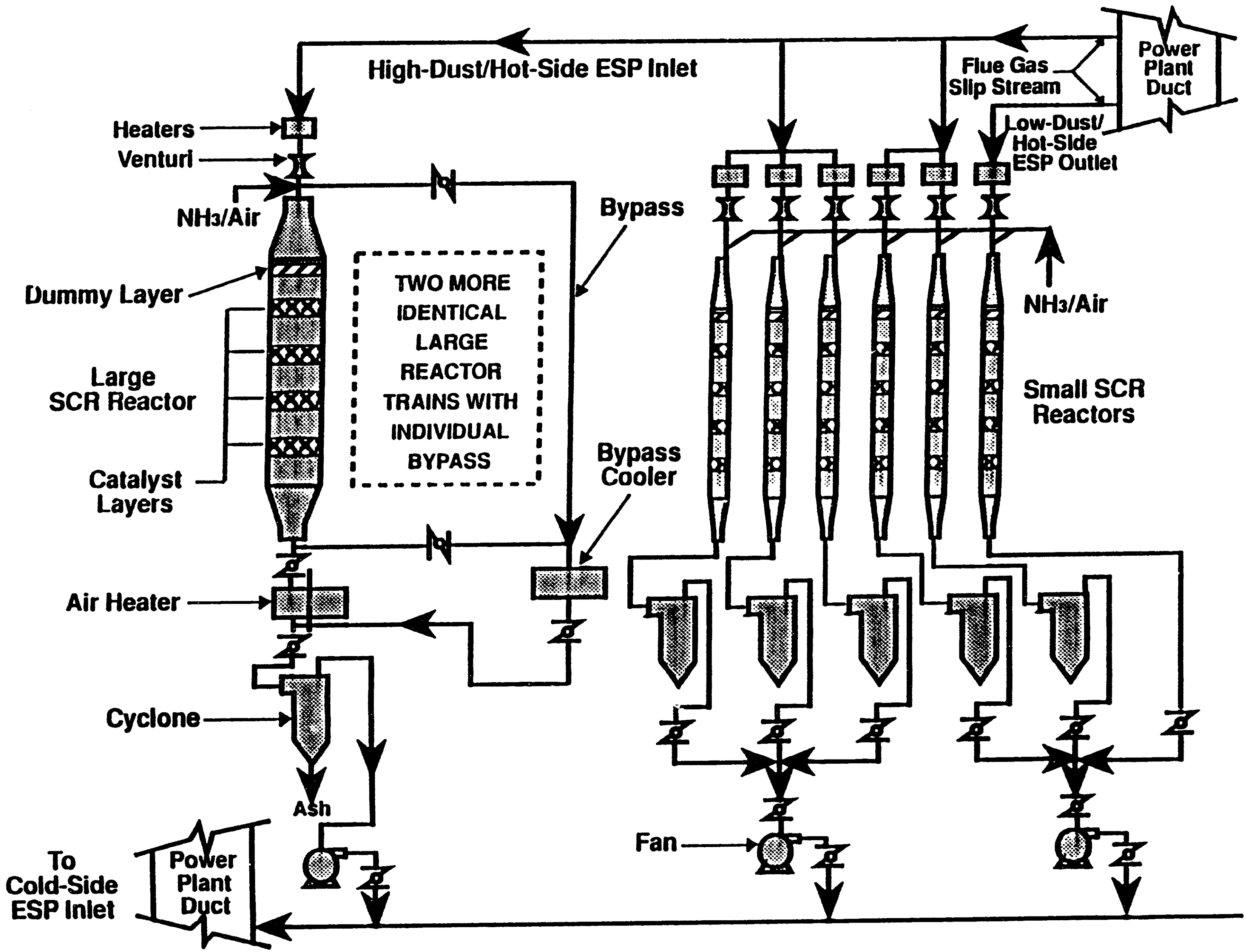

Figure 2. Prototype SCR Demonstration Facility-Process Flow Diagram.

Design Methodology for a Micronized Coal Reburn System Using Modeling

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ABSTRACT

The Tennessee Valley Authority (TVA) has been selected by the Department of Energy's Clean Coal Technology IV program to demonstrate micronized coal reburn technology for control of nitrogen oxide (NO_x) emissions. The demonstration will be done at full scale on a 175 MWe wall-fired steam generator at the Shawnee Fossil Plant. The micronization technology of the Fuller Corporation makes this demonstration feasible, hence, TVA has selected Fuller as the prime contractor for the project and partner in the commercialization of the technology. Radian Corporation has been selected to define the combustion and mixing aspects of the demonstration. Radian Corporation will thus define the design of the reburn injection and OFA system to be installed. This retrofit demonstration is expected to decrease NO_x emissions by 50 to 60 percent. Up to 30 percent of the total fuel fired in the furnace will be micronized coal injected in the upper furnace creating a fuel-rich reburn zone. Overfire air will be injected at conditions that will attain good furnace gas mixing above the reburn zone to insure complete combustion. This paper outlines the efforts to be conducted in defining the key parameters associated with injection and mixing of the micronized coal reburning media and the overfire air (OFA). Shawnee Station is indicative of a large portion of boilers in TVA's and the nation's utility operating base. Micronized coal reburn technology compares favorably with other NO_x control technologies and yet offers additional performance benefits.

INTRODUCTION AND PROGRAM OVERVIEW

The reburn NO_x control process is essentially a post combustion cleanup technology that occurs within the boiler furnace. In reburning, NO_x is chemically reduced back to nitrogen and oxygen. Micronized coal reburn technology has application to cyclone-fired, turbo-fired, wall-fired and tangentially-fired pulverized coal units. A key advantage of micronized coal reburn, of course, is the fact that the technology uses the in-place fuel (coal) and does not require additional fuels to be brought into the plant. Research has shown that micronized fuel can function with very nearly the same effectiveness as natural gas in a reburning situation. The high effectiveness is due to the high surface area of the fuel which is conducive to the liberation of hydrocarbons and the formation of carbon monoxide; key species involved in the reburning process.

Additionally, the high burning rate of micronized coal in reburning indicates that a low tendency for carbon carryover exists; thereby creating a reduced possibility of increases in deposition in the upper radiant sections or the initial convective sections of the boiler. A major aspect of this program is to demonstrate this high effectiveness of micronized coal reburning on a full scale basis.

The reburn/OFA system can also be easily adapted to incorporate in-furnace sorbent injection for SO_2 control.

One key area of application of micronized coal reburning is for older units. Older fossil plants typically have the following operating characteristics, and many of these conditions lead to high NO_x production.

- High excess air.
- Deteriorating coal fineness.
- Poor control of secondary air.
- Mill limited from coal switching.
- Poor turn-down ratio.
- Cyclic duty operation.

TVA and many other utilities have a high population of boilers which fall into this category; yet demand upon this existing generating capacity continues. Therefore, means of reducing NO_x, which are now required under new Amendments of the Clean Air Act, while improving overall boiler performance and operability are required.

In-situ combustion modification/tuning and many types of modern low NO_x burners are suitable technologies for reducing NO_x on this class of boilers. In many cases, however, the use of these techniques will require significant upgrades of pulverization equipment, means of air distribution, and improved control systems to attain the benefits of these technologies. This significantly increases the effective cost of the technology. One key goal of this program is to demonstrate the effectiveness of micronized coal (80 percent less than 325 mesh) combined with an advanced coal returning technology to reduce NO_x without significant changes to the current firing and control equipment.

Up to 30 percent of the total fuel fired in the furnace will be micronized coal. This fuel will be injected into the upper furnace, creating a fuel-rich zone at a stoichiometry of 0.8 to 0.9. The program will examine the use of either air or recirculated flue gas as the micronized coal transport media. Overfire air will be injected at conditions for good furnace gas mixing above the reburn zone creating an overall furnace stoichiometry of 1.15 (excess air of 15 percent) and therefore change of overall boiler combustion efficiency. Cold flow modeling and numerical modeling will be used to define the parameters associated with the "best" mixing scheme for the micronized coal reburn media and the OFA.

The availability of the reburn fuel presents the potential to solve several additional problems associated with older boilers. Firstly, these units are called into deep cycling operation as they move further down the loading hierarchy. Attainment of significantly low loads (high turndown) has been restricted by low steam temperatures. With operation of the reburn injectors as true burners at low loads, steam temperatures can be better controlled. Thus, one further goal is to demonstrate the technology of operating the reburn injectors (operation at minimal air flow) as true burners (15% excess air flow) at low boiler loads for improvement of steam temperatures.

Additionally, the use of high moisture low sulfur fuels on this class of older boilers can obviate the need for installing expensive flue gas desulfurization equipment. With use of these fuels, many units will likely be faced with mill throughput limitations due to the reduced heating value of these fuels and will incur significant generation reductions. The use of micronized coal reburning can provide the additional mill capacity needed to regain potentially lost generation capability without upgrading of the entire current mill system. Increased fuel flexibility is accomplished while, at the same time, controlling NO_x which is now a requirement for nearly all boilers.

SITE DESCRIPTION

Boilers

The host site will be one of Units 1-9 at TVA's Shawnee Fossil Plant which was built to help meet the huge electric power requirements of a nearby DOE facility. Construction began in January 1951 and was completed in 1956.

Units 1-9 are 175 MWe (gross) front wall-fired, dry-bottom furnaces burning East Appalachian lower-sulfur coal. The plant was originally designed to burn high-sulfur coal; but in the 1970's, the plant was modified to burn low-sulfur coal in order to meet an emission limit of 1.2 lbs $SO_2/10^6$ Btu of heat input without the use of any sulfur dioxide control technology. Each unit has been equipped with a baghouse to control particulate emissions. Flue gas from each unit discharges to one of two 800-foot stacks, also constructed in the 1970's. The nine existing pulverized coal units are representative of a large number of wall-fired units in the industry which will be required to reduce NO_x emissions in response to the 1990 Clear Air Act Amendments. Unit #6 has been selected as the demonstration unit. This unit is identical to the others with the exception that different burner air registers have been installed.

Coal Acquisition

TVA has contracts in place to supply Shawnee with low-sulfur bituminous coals from Kentucky and West Virginia. These coals will be used as the primary fuels for the project. TVA has test burned western coals such as Powder River Basin (PRB) at a number of sites, including Shawnee, since the late 1970's. PRB coal will be obtained for testing during this demonstration.

MICRONIZED COAL TECHNOLOGY

Technology Description

The technology to be utilized is a combination of a technology that produces micro-fine coal reliably and economically, with new applications of a relatively well known NO_x control technology (fuel reburning). When micronized coal is fired at a stoichiometry of 0.8 to 1.2, devolatilization and carbon conversion occur rapidly.

Micronized coal is defined as a coal ground to a particle size of 80 percent 43 microns or smaller. The MicroFuel® system, consisting of the MicroMill and an external classifier, micronizes coal to a particle range of 10 to 20 microns.

The combined surface area of just one gram of micronized coal particles is 31 square meters, contrasted to a surface area of 25 square meters per gram for pulverized coal.

The MicroMill system is a patented centrifugal-pneumatic mill with the replacement rotating impeller as the only moving part. Size reduction is accomplished by the particles themselves striking against one another as they whirl in a tornado-like column of air inside the MicroMill. Centrifugal force retains material in the cone and rotational impact zone (RIZ) as the particles reduce in size prior to being conveyed by the air stream entering the center of the rotating impeller.

The net result of micronized coal as a reburn fuel is a uniform compact combustion envelope allowing for complete combustion of the coal/air mixture in a smaller volume than conventional pulverized coal. Heat rate, heat flux, carbon loss, and NO_x formation are all impacted by coal fineness.

DESIGN OF THE MICRONIZED COAL REBURN/OFA SYSTEM

Design Parameters

The success of this demonstration hinges on designing a reburn system that will rapidly mix the micronized fuel with crossflowing flue gas rapidly and as completely as possible. The key parameters to mixing in this situation are fuel inlet velocity, inlet area and number of inlets. With a properly designed mixing system most or all of the flue gases will pass through a region of controlled fuel rich stoichiometry. Generally, a region of less than 0.9 of stoichiometric is required. Gases not exposed to the reburn media or hydrocarbons liberated from the reburn media will remain untreated. Thus, with incomplete mixing, NO_x reduction effectiveness is compromised. A design criteria of >70% of the main combustion zone flue gas mass flow through the fuel rich environment will be employed.

Additionally, with incomplete mixing of the reburn media super-fuel rich region can be generated wherein the hydrocarbon products are not utilized by the NO_x in the flue gas. In this situation, hydrocarbon emissions can increase, particles can coke and become very difficult to burn and tendencies for increased tube deposition are possible. The OFA system can compensate for fuel unmixedness in some cases but not likely for extreme situations. Thus, an additional goal is to not have large super-fuel rich regions.

In addition to mixing, establishing sufficient residence time for the NO_x reduction reactions to occur is necessary. Conversion effectiveness varies with residence time. A design criteria for residence time to be >0.4 seconds for high reduction will be employed. The residence time requirement dictates the vertical location of the fuel inlets. Flue gas temperature also plays a role in reburn residence time requirements and reburn fuel injector location.

Similarly, the attainment of high mixedness in the OFA system is important. The OFA system completes the oxidation of the fuel rich flue gases. Increases in unburnt carbon and increasing tendency for slag deposition can occur as a result of OFA unmixedness. A design criteria of 99% mixing is required to satisfactorily complete combustion in this zone. Note also that mixing must be controlled so as to avoid creation of high temperatures and air rich regions which can regenerate NO_x.

The same degree of importance is placed on residence time in this zone. A design criteria of residence time >.3 seconds will be employed in the post reburn zone.

Boiler performance factors such as furnace exit temperature, the distribution of furnace exit temperature, and boiler heat flux profiles are other criteria of importance to be considered in the design of the reburn/OFA system.

The key design parameters to be established are:

Reburn Injection
- total quantity
- location
- velocity
- number
- transport media (air or FGR)

OFA Injection
- total quantity
- location
- velocity
- number

Boiler Performance
- peak heat flux
- vertical heat flux profile
- furnace exit temperature
- spatial furnace exit temperature variation

Boiler Reliability
- avoid fuel rich regions on walls
- avoid fuel rich regions at exit

Design Process

The combustion process in a coal fired boiler is a complex process. High quantities of chemical energy are converted into heat in a relatively small volume (short time). The generation, transfer, and transport of this heat involves high intensity turbulent processes. As a result, the velocities, temperatures, and gas compositions exiting the furnace region of a boiler deviate significantly from a simple plug flow scenario. To account for the interactions between a complex ill defined flow and provide the required confidence of mixing first fuel then air very nearly completely, requires several approaches.

To meet the target design criteria and establish high degree of confidence in the performance of the reburn/OFA design several resources will be employed. These include:

numerical modeling of the flow and mixing processes
physical flow modeling
good boiler test data with furnace probing
experience in mixing and fluid mechanics
experience in fundamental combustion processes
research and full scale data from other similar programs

Physical flow modeling will be conducted utilizing dynamic similarity in plastic models. Smoke and other chemical tracers will be used to assess mixing profiles and establish velocities.

QA comprehensive boiler and furnace test program will be conducted. Furnace temperatures will be established at different locations for a range of boiler conditions. These will be used to verify the numerical model. This data will be used in addition to develop preliminary designs that will be evaluated in more detail and refined by the physical and numerical modeling efforts.

Numerical modeling will be carried out by adapting the Radian Furnace Simulation Model (FSM) to the Shawnee #6 configuration and incorporating reburn and OFA inlets.

USE OF NUMERICAL MODELING IN THE DESIGN PROCESS

The Radian FSM

The Furnace Simulation Model (FSM) was developed to provide assistance in determining how a particular burner and/or burner overfire air system will perform in a given boiler. It is a complete model of the combustion, fluid mechanics, and heat transfer processes occurring in the boiler. The model provides the ability to analytically change burner designs, add OFA ports, and move burners around. The model predicts NO_x levels but more importantly provides an evaluation of the potential for operational problems (i.e., slagging, corrosion, performance, heat transfer maldistribution) for a particular burner type and/or burner overfire air system configuration. The model provides the ability to "look" inside a boiler with the purpose of diagnosing problems where measurements are difficult or impossible. Trained application of the model permits evaluation of complex tradeoffs between NO_x control techniques and operational benefits and penalties.

The FSM model is a complete two-phase simulation of the combustion, fluid mechanics, and heat transfer process occurring in a boiler furnace. It is designed to run within the PHOENICS Navier-Stokes equation solver and is capable of incorporating the detailed geometry of each burner. In addition, a complete description of the walls and heat absorbing surfaces within the boiler is used by the model to incorporate the flow resistance and heat transfer effects of the walls. Operation specific fuel properties are also used. Thermal and fuel nitrogen chemical kinetics are included on a simplified basis that incorporates experience factors.

The model includes fuel devolatilization, gas phase combustion, heterogeneous combustion, and interphase transport processes of heat, mass, and momentum. Radiant heat transfer between particles, gas, and walls is included using a six flux relationship for each phase. Convective heat transfer is included based upon relationships known to be useful in furnace design. Turbulence at the microscale, eddy scale, and in large recirculation zones is also included.

The model is run using a unique three pass approach which saves computer costs and time. The first pass is a coarse combustion analysis which solves for the major combustion species along with fluid mechanics and heat transfer. In the second pass, the fluid mechanics and heat transfer are fixed and dissociation of species to form free radicals such as O and N atoms are included based upon chemical equilibrium calculations. These calculations are performed at each grid point and a Gibbs free energy minimization approach is utilized to adjust species concentrations and consider dissociation. The NO_x kinetics are evaluated in the third pass, again with the fluid mechanics fixed. This approach reduces the number of solved parameters (and subsequent computer time) in terms of the number of species for the main run, where their influence on the fluid mechanics solution is minimal.

The furnace geometry is divided into grids in three dimensions. A fine grid is used in the burner region where gradients of concentration, temperature, and velocity are high while a much coarser grid is used in regions of the furnace outside the main combustion region. The current model solves for 18 field variables and incorporates about 18,000 grid points for the initial geometric configuration.

Adaptation of the Numerical Model

Initial work in adapting the model involves the gathering of information necessary for input and verification of the model. Primary data include the current burner/boiler geometry information in the form of drawings and sketches. The model requires details of the burners sufficient to determine the flow areas and velocities in each region (primary, secondary, and tertiary). Estimations are made of tangential (swirl) velocities based upon drawings and flame observation. These estimations are used for initial runs, and are parameters that can be varied during the course of the project. Also required is the shape of the water tubes around the throat.

For the boiler, the required data includes the general geometric arrangement and design values for the water wall conditions (i.e., temperature versus height or depth) for each plane or surface. The location and design temperatures of division walls, partial water walls, and any other surface extensions are also required.

Typical fuel analyses (ultimate and proximate) are required. Ash fusion temperature data is also desirable, as are results from any recent pulverization tests and any recent data on fuel/air balancing tests.

Any good NO_x data relating NO_x to load, excess oxygen, and fuel types is also required for verification. Available information on the occurrence of operational problems such as slagging, tube corrosion, heat rate, etc., is also be collected from operating plant personnel to assist in the verification work. In this demonstration program comprehensive tests of furnace conditions will be performed to assist in the verification.

In the initial runs of the model work is performed to optimize the grid size and grid size distribution to be the coarsest that will give good results, and yet have acceptable run times (and corresponding computer run time costs). Key to the description of combustion/NO_x processes is having a sufficiently fine grid in the near burner region where the gradients of temperatures, velocities, and compositions are the highest. In the bulk furnace regions of the model, the grid can be much coarser and still describe heat transfer and mixing processes adequately. Simply developing the entire grid as fine as that required in the burner region would result in extremely long run times. (e.g., perhaps as long as a week on a high speed 486 PC for a single run.) The results of this task are examined for tradeoffs relative to a baseline set of data.

In the actual model verification runs the objective is to verify that the model accurately describes the NO_x formation rates and operational characteristics of the current boiler configuration. This work is divided into the following three areas.

With a uniform "ideal" firing pattern for each burner, the model is run at conditions of load, excess oxygen, mills-out-of-service, etc., for which good NO_x and operational data exist. Once a good comparison in trends and levels is achieved, work proceeds. Key process constants are then adjusted on an as needed basis to improve the predictability of the model. These results are also examined for trends consistent with frequently encountered operating problems.

In this work any suspected fuel or air imbalances are incorporated into the model. Maldistribution of fuel and primary air are simple changes in input variables to the model. In addition, any broken registers, bad pipes, or other combustion anomalies are also included.

Cases are then run to compare the "real world" operation with the NO_x and operational problems documented previously. Parametric variations are then made around these initial values to determine the sensitivity of NO_x and operational characteristics to firing anomalies. Comparisons are also made with the previously developed process constants to determine if any additional adjustments are necessary.

With a well calibrated model, the design of the reburn\OFA system proceeds. Additional fuel injectors are incorporated into the model as are OFA ports. Parametric variations are made of injection flow, location, velocity, number in inlets, and the benefits of tilt, yaw, and swirl.

SYSTEMS EVALUATION USING THE FSM

A key use of the model will be to evaluate in extensive detail the performance of the overall system once the critical design parameters have been established. The model will be used to:

Evaluate Low Load / Peak Load Burner Performance

Examining Potential Critical Localized Problems

- Coal Pipe Temperatures
- Burner Component Temperatures
- Slag Deposition in Reburn or OFA Regions

Determining Critical Control Measurements and Ranges of Values

- Excess Oxygen Levels
- Main Fuel Flows
- Reburn Fuel Flows

Firing Procedures During Micronizer Outages

Firing Procedures for Alternate Coal (L.S. PRB)

A UNIQUE FUEL INJECTOR/BURNER IS REQUIRED

Much attention in this program will be given to the design of the reburn injector\burner. The functions of this burner are unique to most of the common requirements of the burner industry.

In the reburn mode, the burner will be designed to utilize as little as possible secondary air. Any significant amounts of secondary air increase the amount of reburn media required. The secondary air flow will be only that required for cooling of the burner mechanism. In the reburn mode, consideration will be given to the use of recirculated flue gas as the transport media for the micronized coal. This will further reduce the required amount of reburn media.

In low load operation of the boiler, however, the fuel injector will be designed to function as a stand alone burner. This requires about 9:1 lbs air/lb coal. Thus the secondary air will be required to modulate over an order of magnitude range.

With use of low sulfur PRB coals, it is likely that the main pulverizers of the unit will encounter a significant throughput derate. In this situation the micronized coal system will be required to carry a significant percentage of the boiler fuel input. Perhaps, as high as 30 percent. Thus, significant fuel modulation over about a 10:1 range is also required for the specially designed injector/burner.

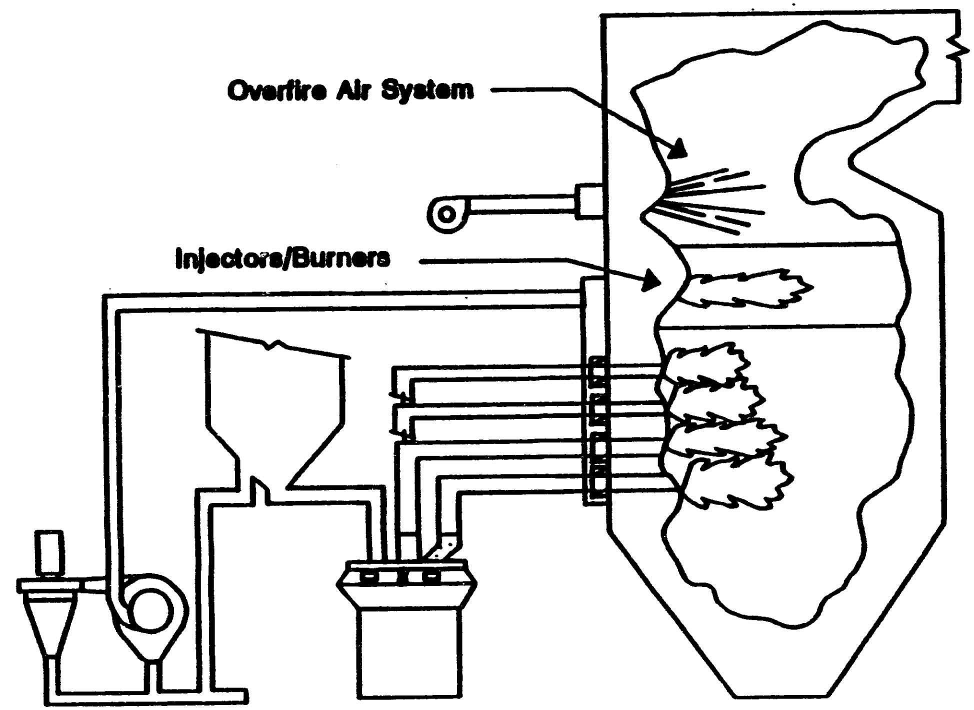
The design of a modulating burner that will vary both fuel flow and air flow over a wide range of values presents a unique design challenge in this program.

PROGRAM SCHEDULE

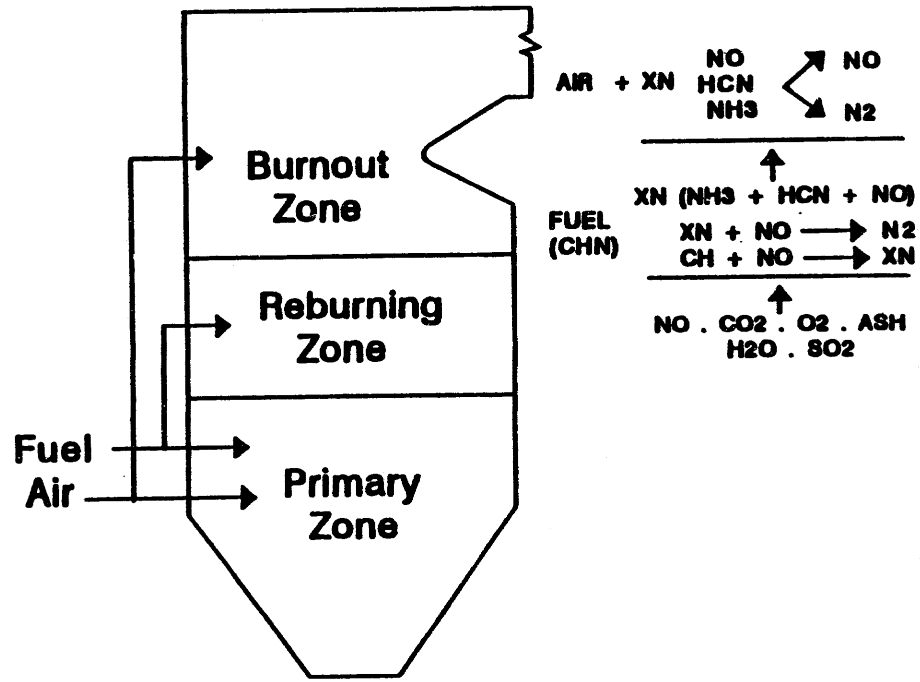
The program schedule is outlined as followed:

Detailed Testing	Completed December 1993
Modeling	Completed February 1994
Final Design	Completed May 1994
Installation of Reburn/OFA	Completed March 1995
Final Testing and Report	Completed July 1995

MICRO FUEL



Schematic of Reburn Process



Chemistry of Reburning Process

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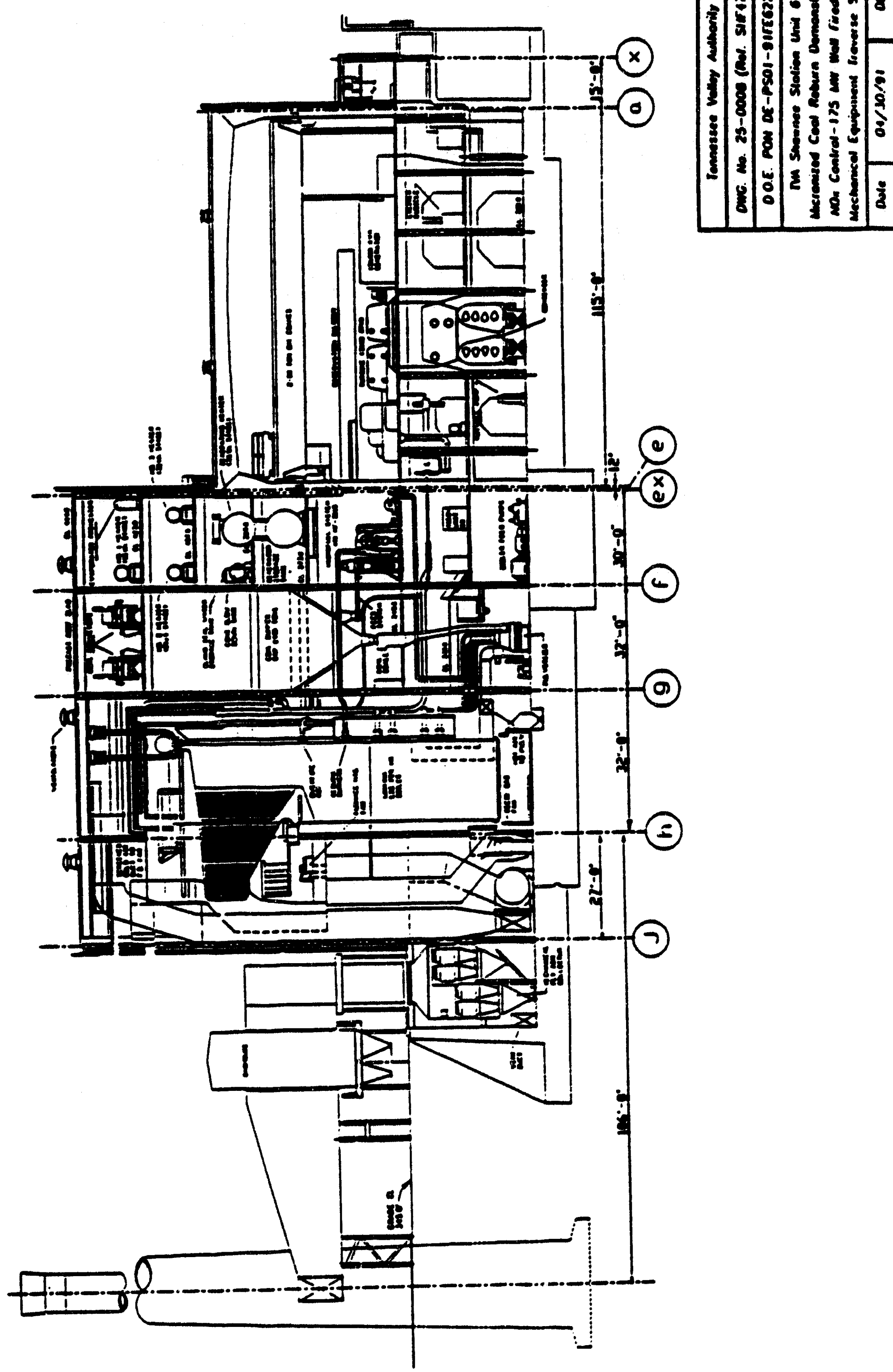
PROGRAM BACKGROUND

- Micronized Coal Reburn High Candidate System
  - Cyclone Fired Systems
  - Turbofire Fired System
  - PC Systems

- Micronized Coal Reburn Attractive Alternative for Older Boilers
  - Imprecise Control of Air Flow and Distribution
  - Deteriorating Fineness and Flow Maldistribution
  - Marginal Milling Capacity for Low Sulfur Fuels

- Micronized Coal Reburn Attractive for Deep-Cycling Boilers
  - Raise Low Load Steam Temperatures
  - Provide Peaking

Presented at Power-Gen '91



Page 5

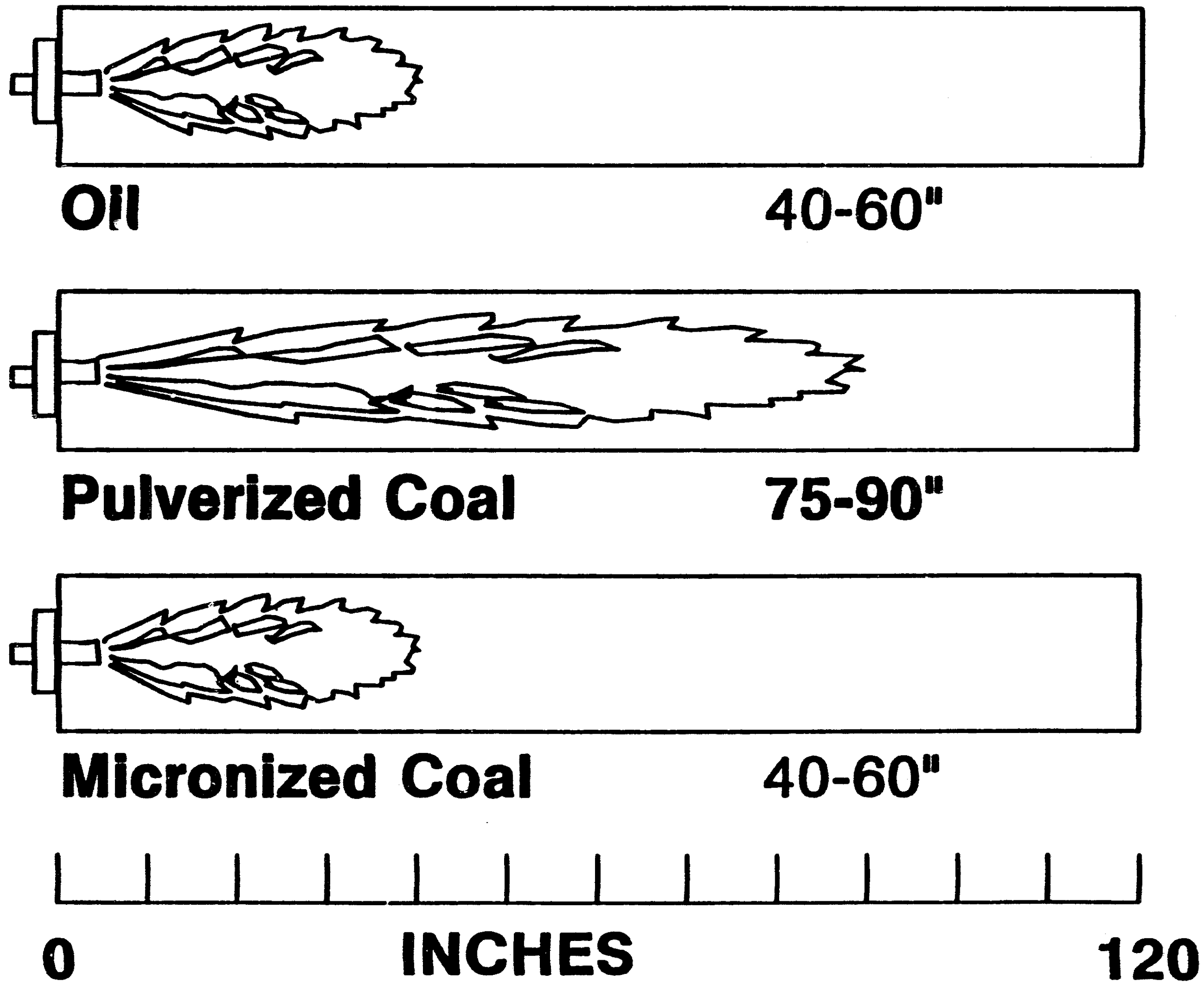
Figure 3

MICRONIZED COAL AS REBURN MEDIA

- Use Same Fuel as Main Combustion Zone
- High Surface Area Liberates Hydrocarbons
- Rapid Burnout to Avoid Convective Pass Deposits
- With Good Mixing Can Require Less Reburn Media

MICRO FUEL — COAL WORKING FOR YOU

Micronized Coal Flame Characteristics



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GOALS OF DEMONSTRATION PROJECT

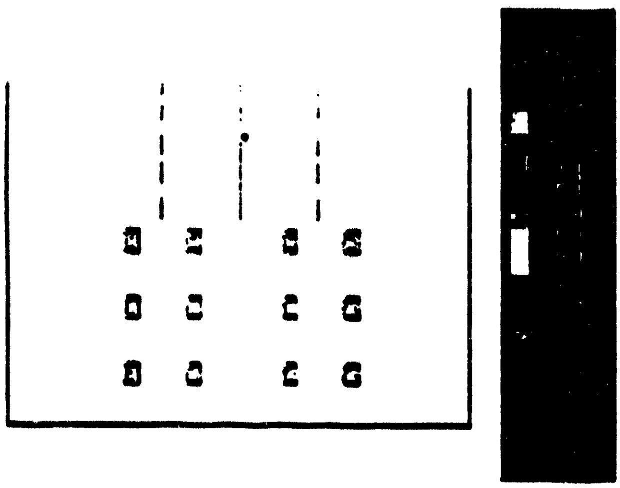
- Full Scale Demonstration of Micronized Coal Reburn
- Use of Micronized Coal Reburn to Improve Turndown / Peaking Capabilities
- Show Improved / Non-Undegraded Boiler Performance
- Demonstrate Micronized Coal Reburn Injectors Operate As Burners
- Use Micronized Coal Reburn to Increase Fuel Flexibility

RESOURCES EMPLOYED IN REBURN / OF A SYSTEM DESIGN

- Numerical Modeling
- Cold Flow Modeling
- Burner / Mixing / Fluid Mechanics Experience
- Combustion Expertise
- Review of Other Projects

RADIAN FURNACE SIMULATION MODEL

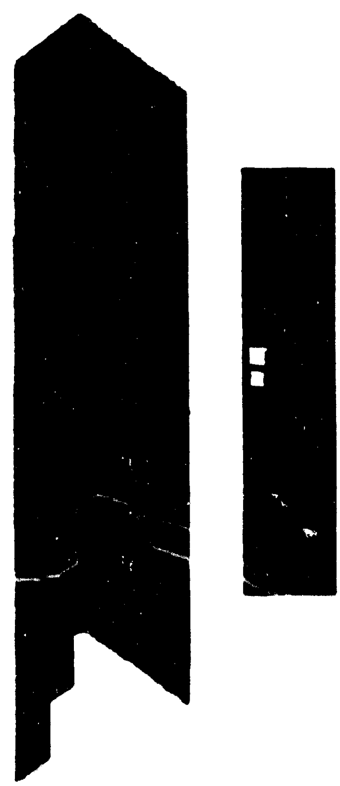
- Computational Fluid Dynamics
- Full 3-Dimensional
- Two Phase Flow
- Radiant and Convective Heat Transfer
- Interphase Transport
- Well Calibrated



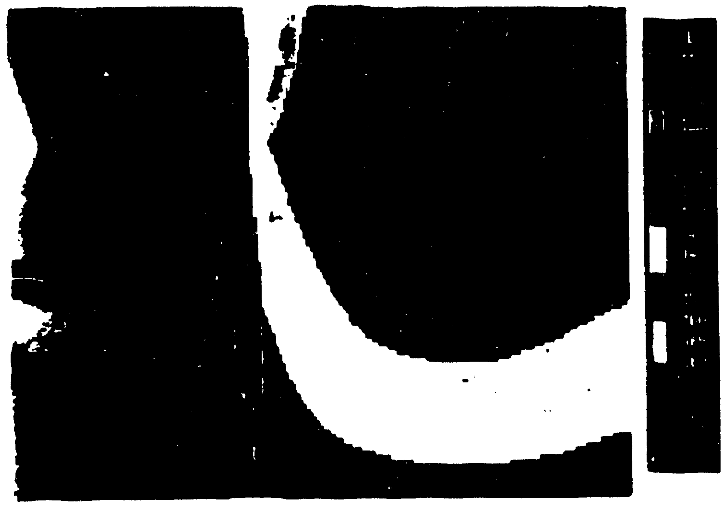
Burner Configuration

Gas Temperature in Burner Region

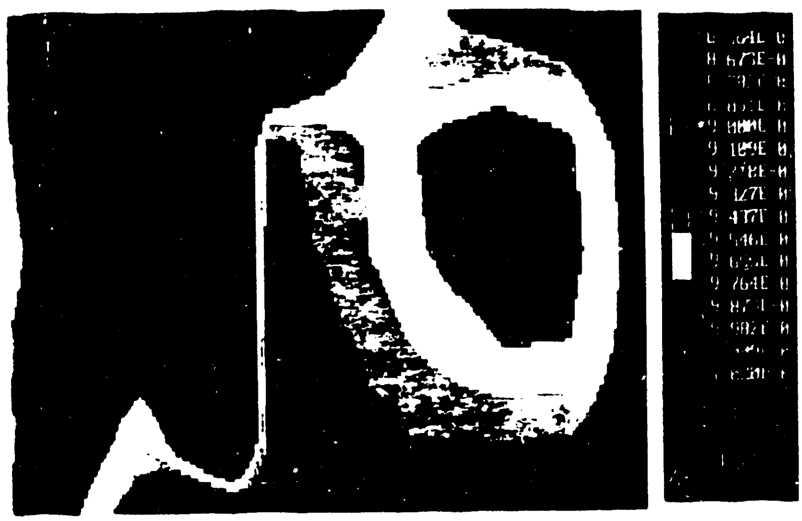
Gas Temperature Near Sidewall and Firing Face



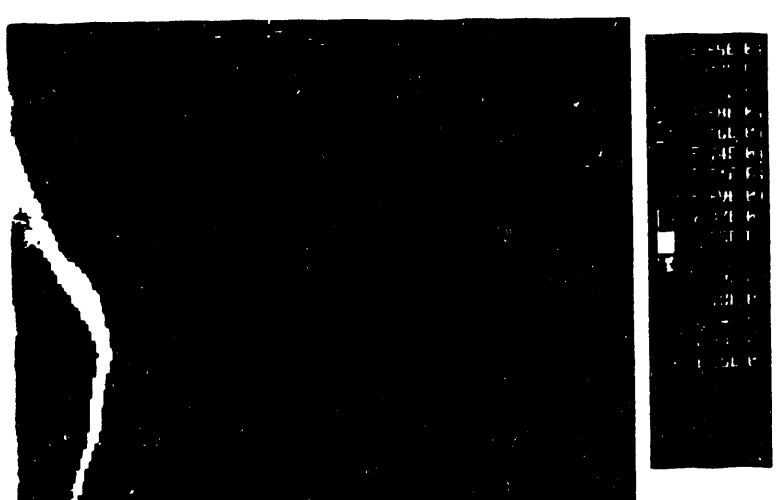
Equivalence Ratios Near Sidewall and [illegible]



Exit Plane Gas Temperatures

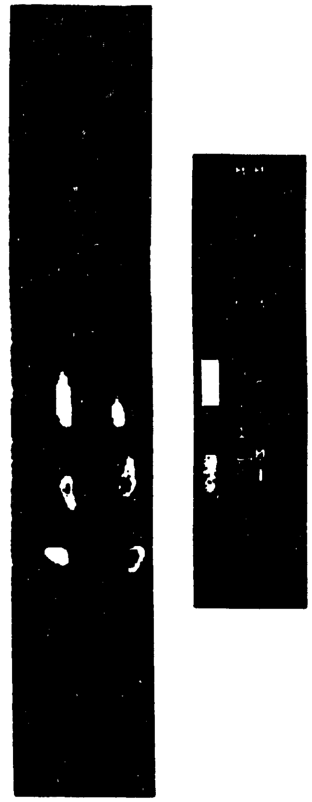


Exit Plane Equivalence Ratio



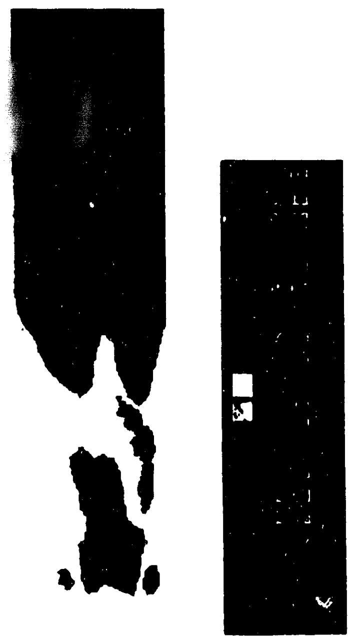
NOx Concentrations at Exit

Large Overfire Air Ports



Poor Mixing from Large Overfire Air Ports

Small Overfire Air Ports



Good Mixing from Small Overfire Air Ports

MODELLING IN REBURN SYSTEM DESIGN

- Design "Best" Reburn / OFA System

- Set Reburn System Parameters

  - Fuel Quantity
  - Injection Velocity
  - Location of Inlets
  - Number of Inlets
  - Evaluation Benefits of Tilt, Yaw, Swirl
  - Use of FGR as Coal Transport

- Set OFA System Parameters

  - Air Quantity
  - Injection Velocity
  - Number of Inlets
  - Evaluate Benefits of Tilt, Yaw, Swirl

COMBUSTION / NO_x CRITERIA OF 'BEST' DESIGN

- Reburn Mixed Mass (Mass of Flue Gas $<$ 0.9 stoich)

- Residence Time Criteria (Mass of Flue Gas $<$ 0.9 stoich with $T > T_{REQ.}$)

- OFA Mixed Mass

- OFA Residence Time

BOILER PERFORMANCE CRITERIA OF "BEST" DESIGN

- No Change from Baseline

  - Average Furnace Exit Temperature
  - Spatial Distribution of Furnace Exit Temperature
  - Wall Vertical Heat Flux Profile
  - Peak Wall Heat Flux
  - Mass Flow Velocity Distribution
  - Carbon Burnout

- Avoid Large Fuel Rich Regions on Walls

- Avoid Large Fuel Rich Regions at Exit Plane

MODEL ADAPTATION TO SHAWNEE #6

- Incorporate Boiler / Burner Geometry

- Incorporate Current and Planned Fuel Properties

- Boiler Characterization Testing Program

  - Gas Temperatures
  - Gas Velocities
  - Species Concentrations

- Review / Correlate Unit Operational Data

  - Carbon Burnout
  - Steam / Metal Temperatures
  - Tube Wastage
  - Unknown or Suspected Fuel / Air Imbalances

- Review Correlate Unit Emissions Data

  - NO_x
  - CO
  - Excess Oxygen Levels

- Verification of Model with Tests / Operational Data

  - Perform Verification Runs
  - Correlate Results

USE OF MODEL IN SYSTEM PERFORMANCE EVALUATIONS

- Evaluate Low Load / Peak Load Burner Performance

- Examining Potential Critical Localized Problems

    - Coal Pipe Temperatures
    - Burner Component Temperatures
    - Slag Deposition in Reburn or OFA Regions

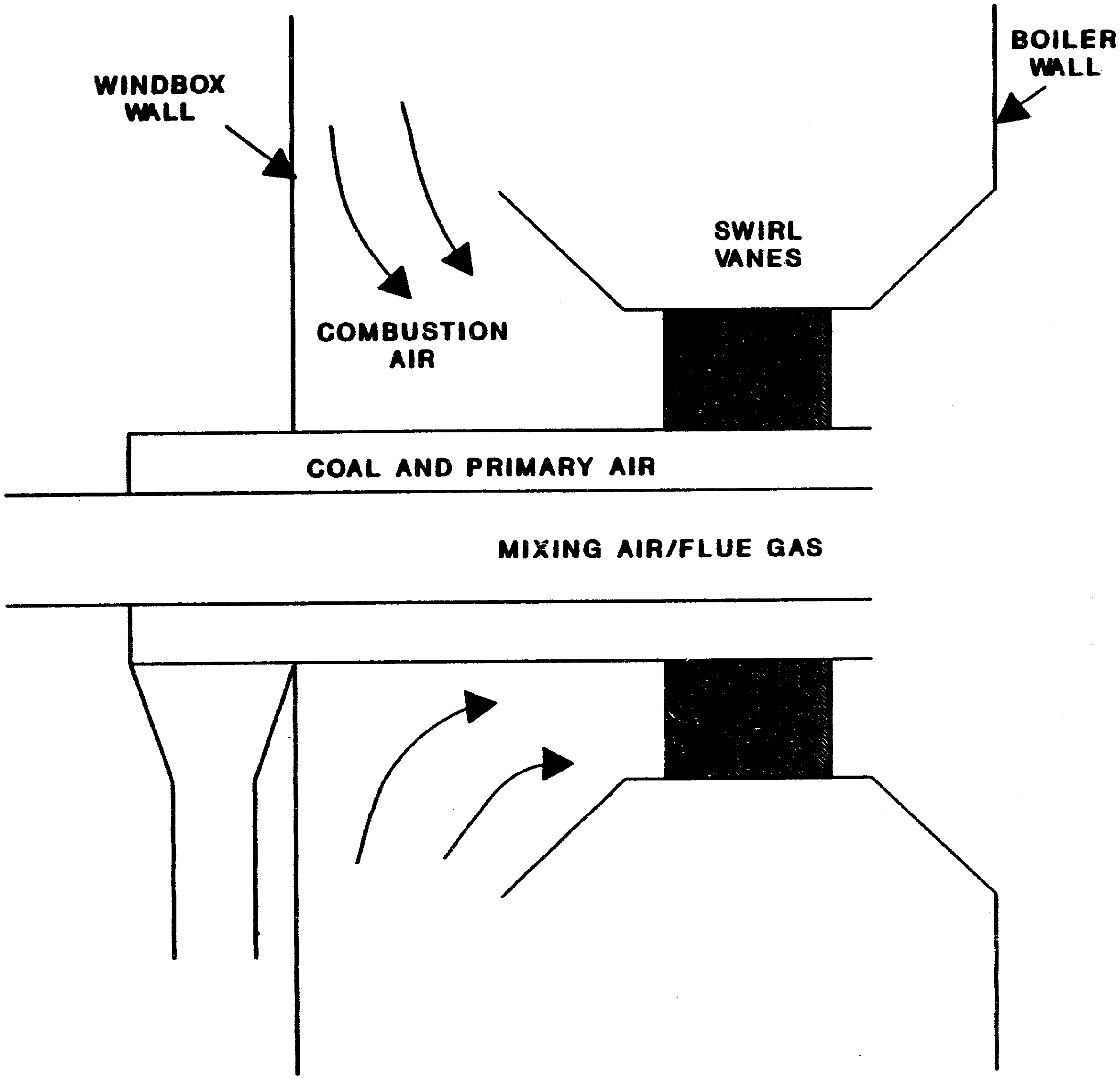
- Determining Critical Control Measurements and Ranges of Values

    - Excess Oxygen Levels
    - Main Fuel Flows
    - Reburn Fuel Flows

- Firing Procedures During Mill Outages

- Firing Procedures During Micronizer Outages

- Firing Procedures for Alternate Coal (L.S. PRB)



CONCEPTUAL DESIGN FOR COMBINED REBURN INJECTORS/BURNERS

Session 2
Advanced Electric Power Generation Systems

Co-Chairs:
Larry K. Carpenter,
Morgantown Energy Technology Center/
U.S. Department of Energy
George Lynch,
Office of Clean Coal Technology/
U.S. Department of Energy

YORK COUNTY ENERGY PARTNERS ACFB DEMONSTRATION PROJECT STATUS

S. I. Wang and F. T. Bolinsky
Environmental and Energy Systems
Air Products & Chemicals, Inc.
Allentown, Pennsylvania

ABSTRACT

The York County Energy Partner, L.P. project, to be located in York County, Pennsylvania, will demonstrate the world's largest atmospheric circulating fluidized bed (ACFB) boiler under sponsorship of the U.S. Department of Energy's Clean Coal Technology I Program. The single ACFB boiler, designed by Foster Wheeler Energy Corporation, will supply 227 MWe of net electrical power and export up to 400,000 lb/hr of steam to an adjacent paper mill. This paper outlines the project summary, process description, changes due to site relocation, the value improvement of boiler island and current status of the project.

INTRODUCTION

The York County Energy Partners cogeneration project located in York County, PA will demonstrate the largest single ACFB boiler in the U.S. under sponsorship of the U.S. Department of Energy's (DOE) Clean Coal Technology I Program. The goal of the DOE program is to demonstrate the technical and economic feasibility of applying circulating fluidized bed combustion technology at the 250 MW scale for producing electrical power and steam in an environmentally acceptable manner while efficiently utilizing our nation's coal resources. The single-train ACFB boiler, designed by Foster Wheeler Energy Corporation (FWEC), will supply 227 MWe of electrical power to the Metropolitan Edison Company (Met-Ed) and export approximately 400,000 lb/hr of

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steam to the P.H. Glatfelter Company, a manufacturer of printing and specialty papers. The ACFB combustor will be fueled with low sulfur (less than 2 percent) bituminous coal available locally in Western PA, MD, and W. VA. The scaled-up single ACFB boiler will generate 2,100,000 lb/hr of main steam at 2500 psig and 1005°F and 1,325,000 lb/hr of reheat steam at 495 psig and 1005°F. Commercial operation is scheduled to begin by January 1998.

FACILITY DESCRIPTION

Figure 1 provides a process flow diagram for the YCEP ACFB facility. The heart of the process is a circulating fluidized bed combustor in which the fuel is combusted while simultaneously capturing SO_2. Solid particles entrained by the upflowing gas in the combustor exit the top of the combustor into four cyclones which efficiently separate the flue gas from the entrained particles. Selective non-catalytic reduction of NOx emissions is accomplished through injection of aqueous ammonia at the inlet to the cyclones. The flue gas discharged from the cyclone is directed to the downstream convective section of the boiler and the captured solids are recycled to the base of the ACFB by means of standpipes, J-valves, and a fluidized bed Integrated Recycle Heat Exchanger (INTREX™) unit. The J-valves provide a seal between the positive pressure in the lower furnace where the recycle solids are fed and the near ambient pressure in the cyclones.

Coarse bed ash material accumulating in the ACFB is removed from the bed using a specially designed directional grid and a fluidized bed stripper cooler. The bed ash is cooled by the fluidizing air flow to the stripper cooler. This heated air stream flows to the combustor along with the fines that are stripped out. The cooled bed ash is conveyed to a bed ash silo. Fly ash collected in the air heaters, economizer, and baghouse hoppers is pneumatically conveyed to the fly ash storage silo.

To support the development of the YCEP ACFB project, Foster Wheeler Development Corporation will conduct tests with a 1 MW_{th} combustor at Livingston, New Jersey. The ACFB hot model is constructed of MONOWALL® and consists of a 1'x2'x48' combustion chamber, MONOWALL®-enclosed cyclone separator and downflow heat recovery section. It is equipped with instrumentation to measure temperature, pressure, and gas compositions to assess combustion and emission characteristics. The test results will be used to characterize the performance of candidate coals and limestones in the commercial unit. The tests will provide data on fuel and sorbent characteristics, such as reactivity, friability, and composition that will directly impact both the design and performance of the ACFB combustor and the feed and ash handling equipment.

The key design information to be obtained from the hot model includes combustion efficiency, optimal temperature for sulfur capture, estimated Ca/S molar ratio for 92% sulfur removal, NOx removal efficiency by SNCR with ammonia injection, emissions, and fly/bed ash ratio. In addition, ashes collected during the hot model tests will be used in various tests required by environmental permit applications as well as in ash conveying and conditioning tests for the selection of proper ash handling equipment. To date, tests were completed for one coal and two sorbents.

The hot model tests will not address the effects of combustor scale. Since the YCEP ACFB will be considerably larger than any existing ACFB, this project carries scale-up risks. To minimize these risks an evaluation of the scale-up issues impacting the performance of the 250 MW YCEP ACFB was made. The proposed design was reviewed, potential problems were identified, and innovative design changes were made as a result of a team effort between Air Products and Foster Wheeler Development Corporation.

SITE RELOCATION

The original site of the York County Energy Partners ACFB demonstration project was West Manchester Township, York County, PA. As a result of seeking air emissions offsets that include SOx, NOx and particulates, the project was relocated to a site adjacent to Glatfelter's paper mill in North Codorus Township (York County). This site is about 5 miles southwest of the original site (Figure 2). By providing Glatfelter 400,000 lbs/hr of 600 psig steam, Glatfelter can shut down their No. 4 boiler (except to back-up the YCEP facility when it is shutdown for maintenance) and provide YCEP significant emission offsets. An additional significant site change item is the water supply. The YCEP facility will use treated wastewater from Glatfelter's secondary water treatment facility (3 million gpd). This largely eliminates the facility's needs for fresh water as compared to the previous site. Most significantly, this project will result in a decrease in SO_2 emissions of approximately 50%. Table 1 compares the scope differences between the old site and new site.

BOILER MODIFICATIONS

As a result of increasing export steam from 40,000 lbs/hr (15 psig) to 400,000 lbs/hr (600 psig, 680°F), the boiler steaming rate will increase from 1,725,000 lbs/hr to 2,100,000 lbs/hr. The combustor size increases proportionally. Table 2 compares the key boiler parameter differences between the two sites. As more pilot plant data becomes available from Foster Wheeler's pilot plant testing, Foster Wheeler is confident that they can reduce the cyclone diameter from 21 ft. to 20 ft. in I.D. and reduce the front coal feeders from 8 to 6, without sacrificing the combustion efficiency and emissions performance. The boiler configuration is shown in Figure 3.

VALUE IMPROVEMENT

The pilot p[illegible] test results conducted by Foster Wheeler suggested that the SNCR process (NH_3 thermal deNOx) can further reduce NOx emission from 0.15 to 0.10 lb/MM BTU. Furthermore, the SOx removal efficiency can maintain at 92% at a lower Ca/S ratio. These data are presented in Tables 3 and 4. More pilot plant testings are scheduled to further optimize the thermal deNOx process using different reagents.

PROJECT STATUS

The commercial activity and status is shown in Table 5. The Public Utility Commission approved the power contract in May 1993. In June 1993, YCEP and DOE executed a

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modification to the Cooperatiave Agreement for the North Codorus site. An Agreement for steam supply to P. H. Glatfelter is currently being negotiated. Other commercial agreements, such as the coal contract, limestone contract, and NOx offset agreement, and ash byproduct utilization agreements, are in progress. By October local land development approvals are expected to be in hand.

As far as project schedule is concerned, we are continuing to work on environmental permitting, equipment procurement and preliminary engineering site work. Construction is expected to start in January 1995. Boiler erection will start in September 1995 and the boiler island and turbine generator erection will be completed in September 1997. The first fire is scheduled in September 1997 and the commercial operation is scheduled for December 1997. This is shown in Tables 6 and 7.

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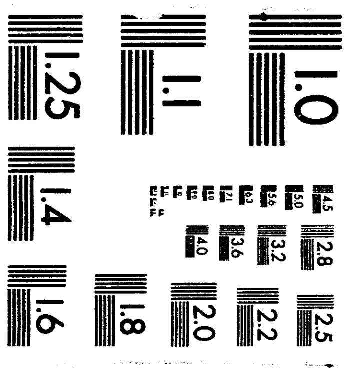
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YCEP Project Summary

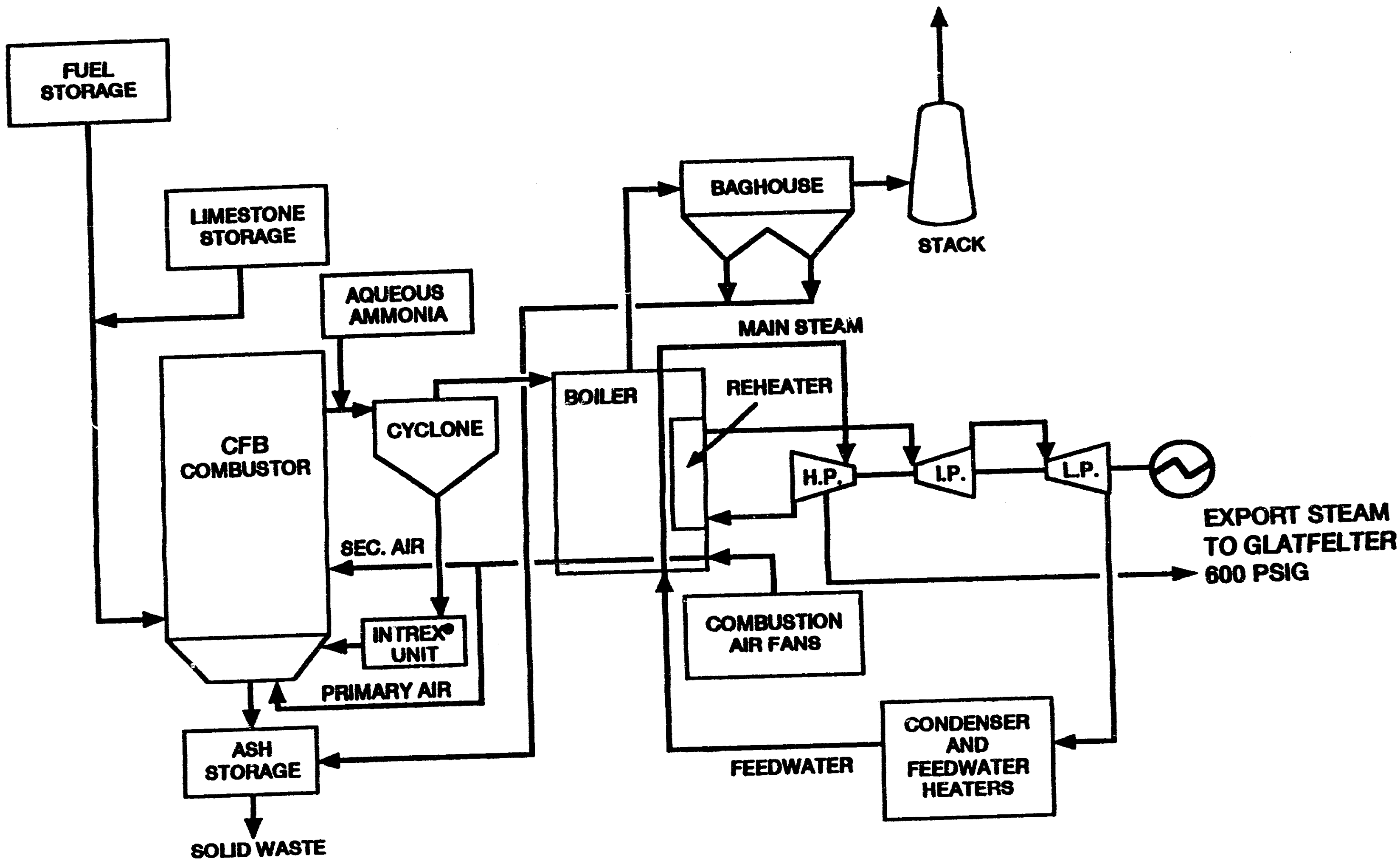
Title:	York County Energy Partners Clean Coal Technology Round I Cogeneration Project
Proposer:	York County Energy Partners, L.P., a Project Company of Air Products and Chemicals, Inc.
Location:	York County, PA
Technology:	Atmospheric Circulating Fluidized Bed Combustion
Applications:	Utility and Industrial Electric Power/Steam Generation, Repowering Existing Boilers or New Plants

YCEP Project Summary

Fuel:	Less than 2% Sulfur Bituminous Coal
Size:	227 MWe net to Met-Ed 2,100,000 PPH/2500 psig/1005°F Main Steam, 1,325,000 PPH/495 psig/1005°F Reheat Steam
Steam Host:	P.H. Glatfelter Co., Spring Grove, PA 400,000 PPH Steam
Project Cost:	Greater than $380 Million
DOE Funding:	$75 Million

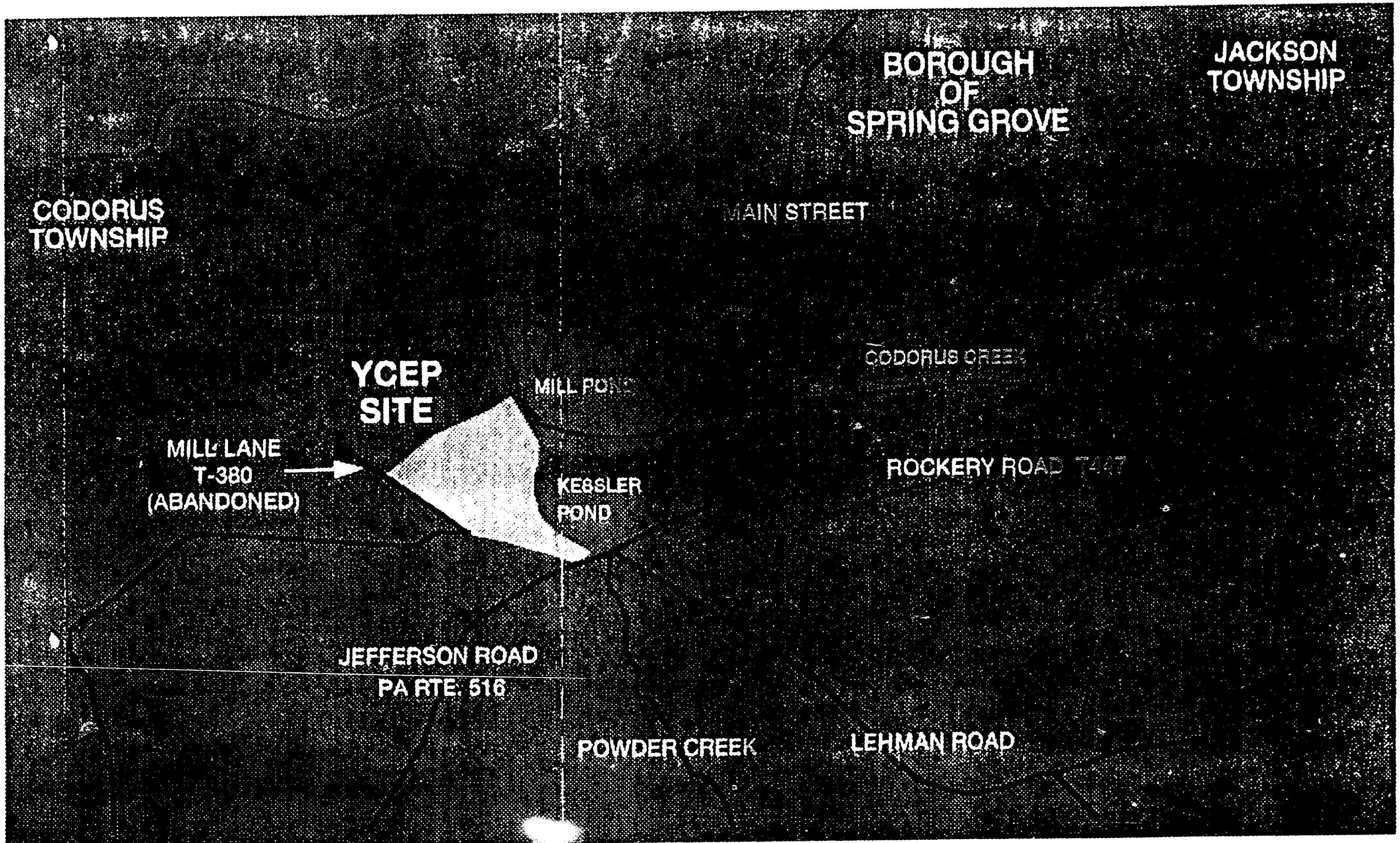
5361P 25

PROCESS FLOW DIAGRAM FOR YCEP COGEN PLANT



6920PP 30

YCEP ACFB DEMONSTRATION PROJECT SITE



6820PP 28

PROJECT SCOPE COMPARISON FOR YORK COUNTY ENERGY PARTNER ACFB DEMONSTRATION PROJECT

Old Site	Project Scope	New Site
West Manchester Twp.	Site Location	North Codorus Twp.
J. E. Baker, Refractory Brick Manufacturer	Steam Host	P. H. Glatfelter Paper Manufacturer
45	Site Size (Acres)	25
227	Electricity (MW) to Met-Ed	227
1,725,000	Total Steam Made (lbs/hr) 2,500 psig, 1005°F	2,100,000
1,400,000	Reheat Steam (lbs/hr) 1005°F	1,400,000
40,000 (15 psig)	Export Steam (lbs/hr)	400,000 (600 psig, 680°F)
Yes	New Auxiliary Boiler	No
City Water	Cooling Water Supply	P.H.G. Co. Secondary Effluent From Mills
High Bearing Capacity 15 ft Deep Over Burden	Soil Conditions	Low Bearing Capacity 60-100 ft Deep Over Burden
Double Circuit 230 KV 1.25 Mile to Jackson Substation	Electric Interconnection	• Double Circuit 115 KV 0.5 mile on P.H.G. Property • Single 115 KV, Nearby Met-Ed Interconnection Point

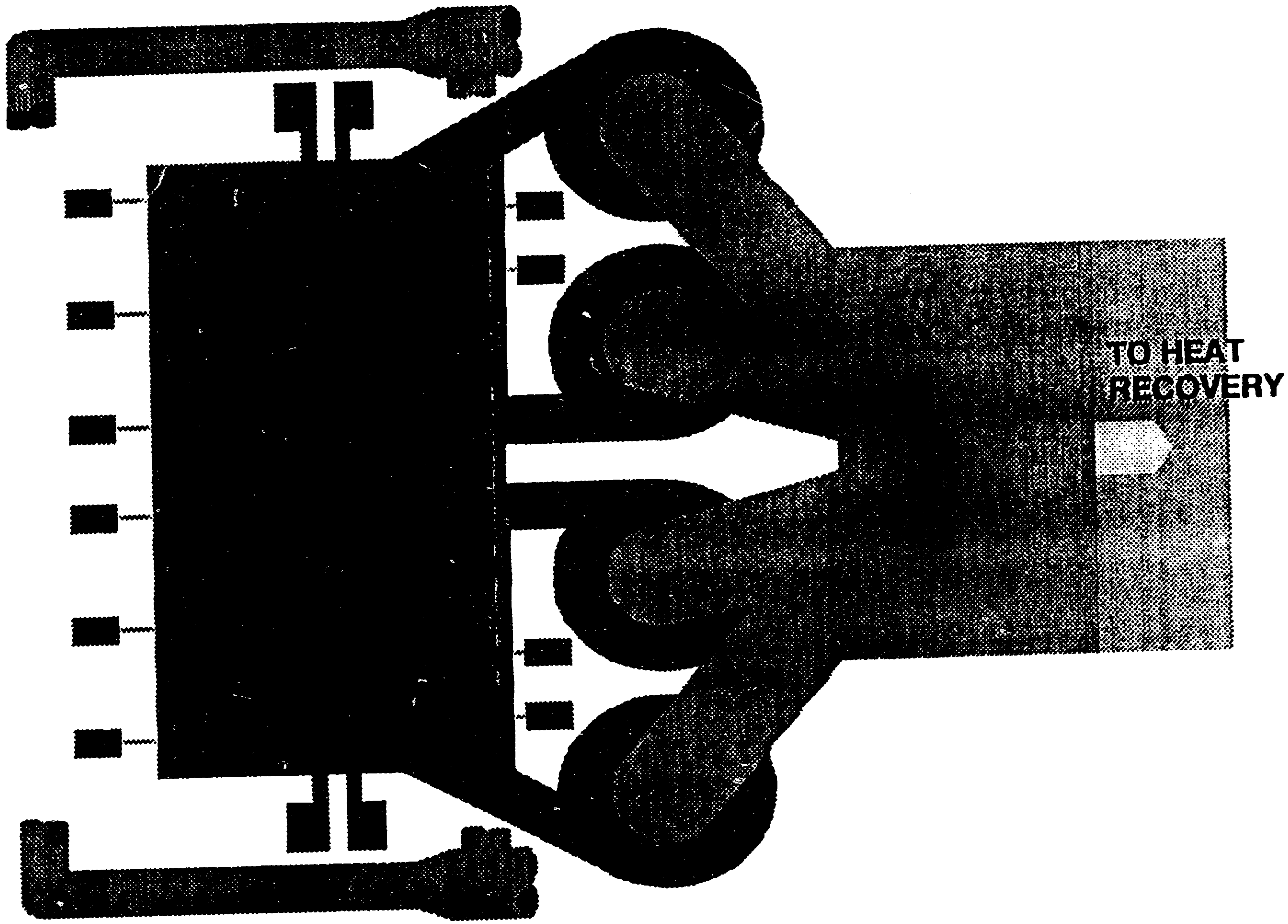
5920PP 28

KEY BOILER PARAMETERS

New Site		Old Site
2,100,000	Main Stream, lb/hr	1,725,000
1,400,000	Reheat Steam, lb/hr	1,400,000
21	Depth, ft	20
84	Width, ft	78
105	Height, ft	112
20	Cyclone Diameter, ft	21
4	No. of Cyclones	4
	Coal Feeders:	
6	– Front	8
4	– Back	4

5820PP 23

YCEP ACFB BOILER CONFIGURATION



5920PP 29

EMISSIONS IMPROVEMENT

New Design		Old Design
0.10	NOx, lb/MMBtu (SNCR)	0.15
92%	SO_2 Removal Efficiency	92%
0.15	CO, lb/MMBtu	0.15
0.004	VOC, lb/MMBtu	0.004

5620PP 24

EFFICIENCY IMPROVEMENT

Revised Design		Old Design
2,290	Steam Duty, MMBtu/hr	1,952
2,299,300	Total Combustion Air, lb/hr	1,988,700
2,486,000	Total Flue Gas, lb/hr	2,152,000
89.21	Overall Efficiency, %	88.19
197,076	Fuel Flow, lb/hr	170,296
92	Percent S Removal	92
2.3	Ca/S Ratio	2.5
32,940	Limestone Flow, lb/hr	28,788

5920PP 25

YORK COUNTY ENERGY PARTNERS COMMERCIAL STATUS

- Met-Ed Power Contract
- P. H. Glatfelter Steam Agreement
- Ash Byproduct Beneficial Use Agreement
- Coal Contracts
- Limestone Procurement
- NOx Offset Agreement
- Local Land Development Approvals

5920PP 21

YCEP ACFB DEMONSTRATION PROJECT SCHEDULE

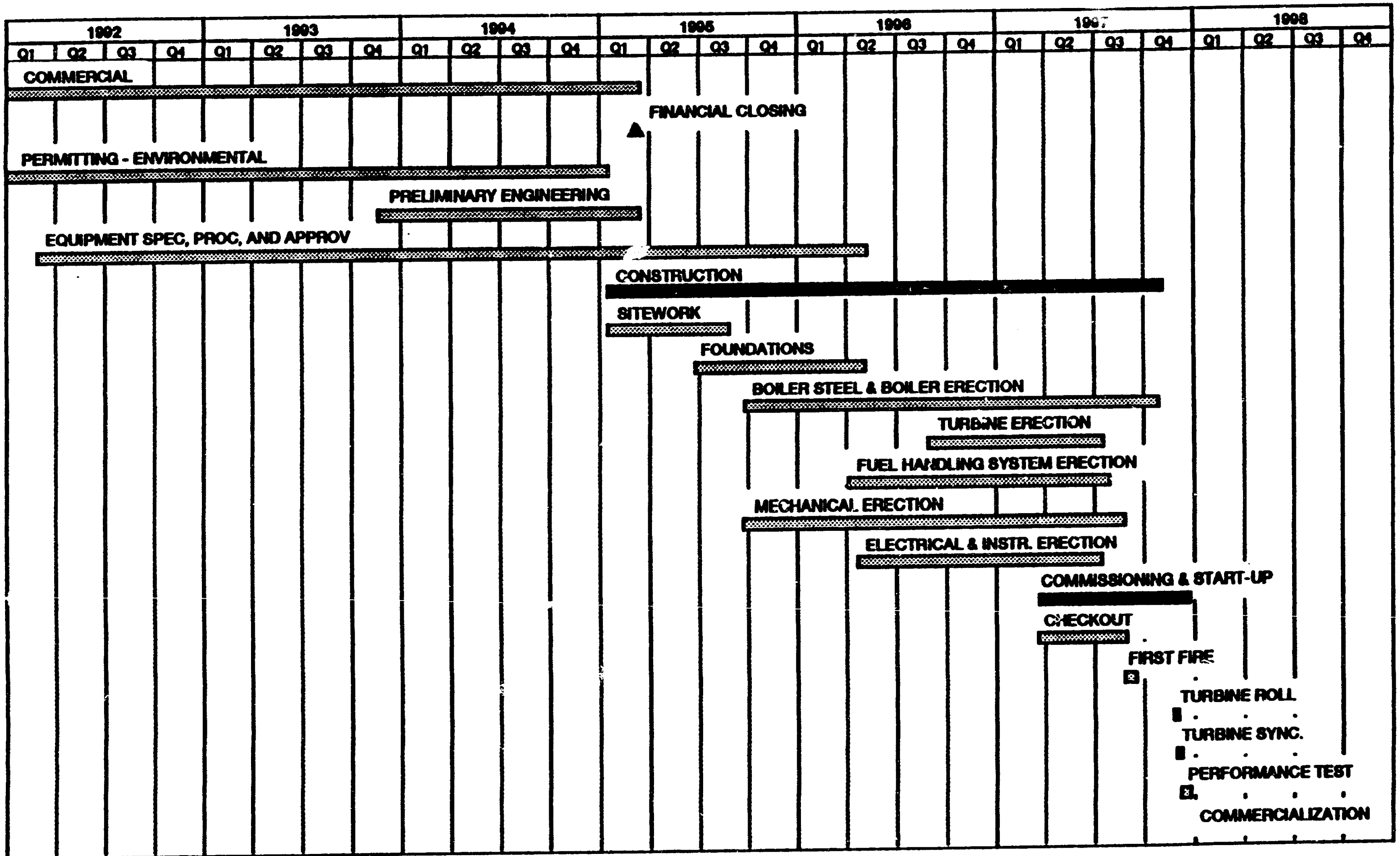
P. H. GLATFELTER SITE

NEPA Process Complete	Jan. 95
PA DER Review Complete	Jan. 95
Begin Boiler Steel Erection	Sept. 95
Hydro Boiler	May 97
Erect Turbine/Generator	Sept. 96 - Sept. 97
Commision DCS	Aug. 97
First Fire	Sept. 97
T/G Load/Sync	Dec. 97
Commercialization	Dec. 97

5920PP 22

YORK COUNTY ENERGY PARTNERS COGENERATION PROJECT

Overview Schedule: 6 July 1993, 12:25p.m.; S. J. McKitish, P.E.



5920PP 27

DMEC-1 Pressurized Circulating Fluidized Bed Demonstration Project

Gary Kruempel and Steve Ambrose
Midwest Power
Des Moines, Iowa

Steve Provol
Pyropower Corporation
San Diego, California

Mitch Bjeldanes
Black & Veatch
Kansas City, Missouri

Second Annual Clean Coal
Technology Conference

Sponsored by
DOE
Southern States Energy Board
Atlanta, Georgia

September 7-9, 1993

DMEC-1 Pressurized Circulating Fluidized Bed Demonstration Project

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INTRODUCTION

The Des Moines Energy Center (DMEC) Project will be the first commercial scale demonstration of Pyropower Corporation's PYROFLOW® Pressurized Circulating Fluidized Bed (PCFB) technology. The project will be a repowering of an existing steam turbine at the DMEC site. The design incorporates a hot (1,600° F) particulate removal system and operates in a combined cycle configuration for increased plant efficiency.

The DMEC-1 limited partnership, with Dairyland Power as the limited partner and Midwest Power, formerly Iowa Power, as the general partner, will be the participant for the project. The project was selected in the Clean Coal Technology Round 3 solicitation. The partnership signed the Cooperative Agreement with the DOE in May 1991.

In August 1991, Midwest Power, Dairyland Power Cooperative, Pyropower Corporation, and Black & Veatch initiated the preliminary design of the PCFB Repowering Project. During the preliminary design process, plant and system layouts have been completed, subsystem specifications have been prepared, and cost and schedule baselines have been updated. Process verification testing for hot gas filter equipment, gas turbine materials, and fuel selection has continued at the Ahlstrom PCFB Testing Facility in Karhula, Finland. Testing results have shown the need to continue this testing prior to finalization of the ceramic filter system selection.

PROJECT GOALS

The goals of the project are to demonstrate the following advantages of the PCFB technology:

- Lower capital cost compared to atmospheric CFB or pulverized coal plant with scrubbers.
- High efficiency and reduced CO_2 emissions.
- Reduced space requirements.
- Hot gas cleanup technology.
- No exposed surfaces in the lower combustor.
- Control of NO_x, SO_x, and CO.
- Simplified load following.
- Erosion prevention.

DMEC-1 PROJECT SITE DESCRIPTION

The Des Moines Energy Center (DMEC) is located southeast of the City of Des Moines, Iowa, in the City of Pleasant Hill. The plant is located adjacent to the Des Moines River on Highway 46.

DMEC was first constructed in 1925 with the installation of two steam turbines and six stoker fired boilers. Between 1925 and 1964, five steam turbine generators and five pulverized coal fired boilers were added. The units operated in baseload mode up to the late 1970s when their operation was reduced due to the addition of more efficient generating units to the Midwest Power system. Steam Turbine Number 6, which will be repowered in the DMEC-1 Project, was mothballed in 1985.

The DMEC-1 Project will require refurbishment or replacement of some major plant equipment. The existing turbine generator is expected to be refurbished. It is rated at a nominal 65 MWe and is a nonreheat unit designed to operate at 1,250 psig and 950° F with a steam flow of approximately 561,000 lb/h. In addition, the existing coal handling facilities, structure, and some of the major auxiliaries, such as the boiler feed pumps, condensate pumps, circulating water pumps, fuel oil, condensate and surge tanks, deaerator, feedwater heaters, auxiliary heat exchangers, etc., will most likely be refurbished with some components being replaced. New equipment is expected to include the main step-up transformer, main auxiliary and reserve auxiliary transformers, digital control system, gas turbine, electrical distribution system and switchgear, and demineralizer.

An artist's rendering of the reconstructed plant structure is shown as Figure 1.

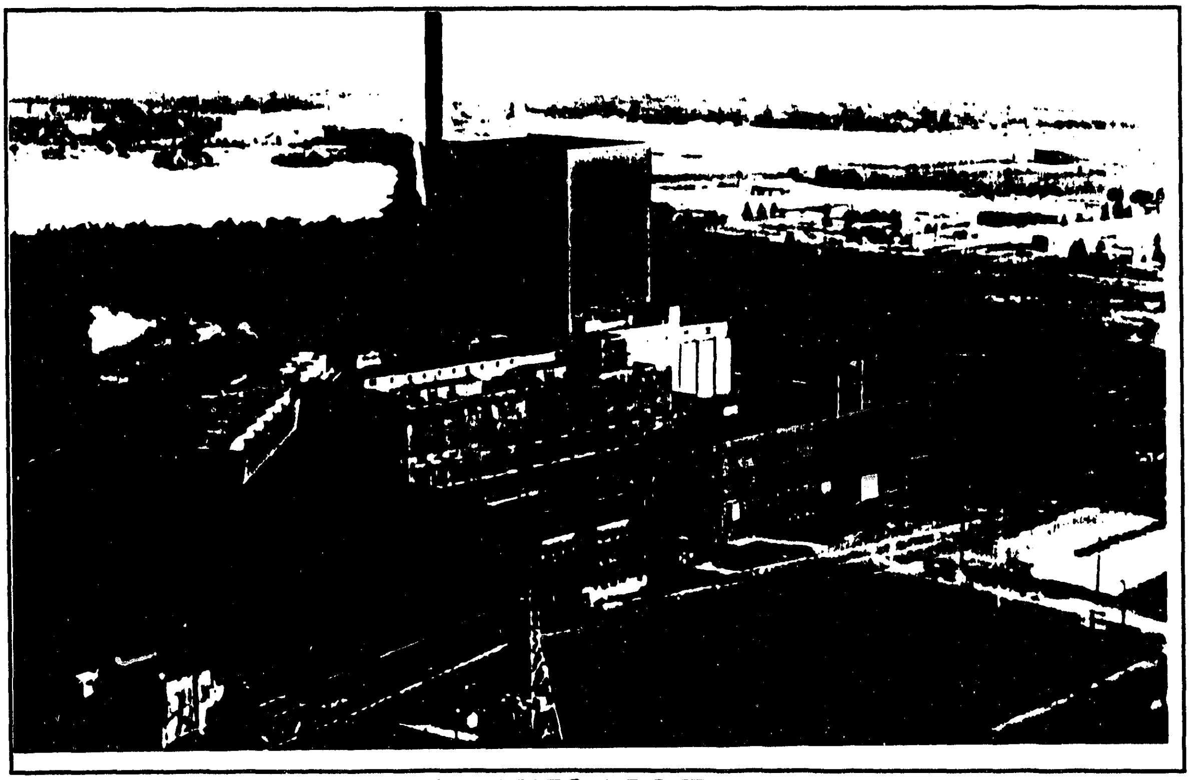


Figure 1. Artist's Rendering DMEC-1 PCFB Repowering Demonstration

TECHNOLOGY DESCRIPTION

The PCFB process uses a combined cycle which employs a combination of a gas turbine and a steam turbine to generate electrical power. The pressurized combustion chamber is used to burn coal to produce steam for the steam turbine which produces approximately 75 percent of the total plant output. The hot flue gases are filtered and expanded through a turbine to generate the remaining 25 percent of the plant output and to drive the compressor that supplies air to the PCFB combustor. A schematic process flow diagram of the Pyroflow PCFB process and subsystems is shown on Figure 2.

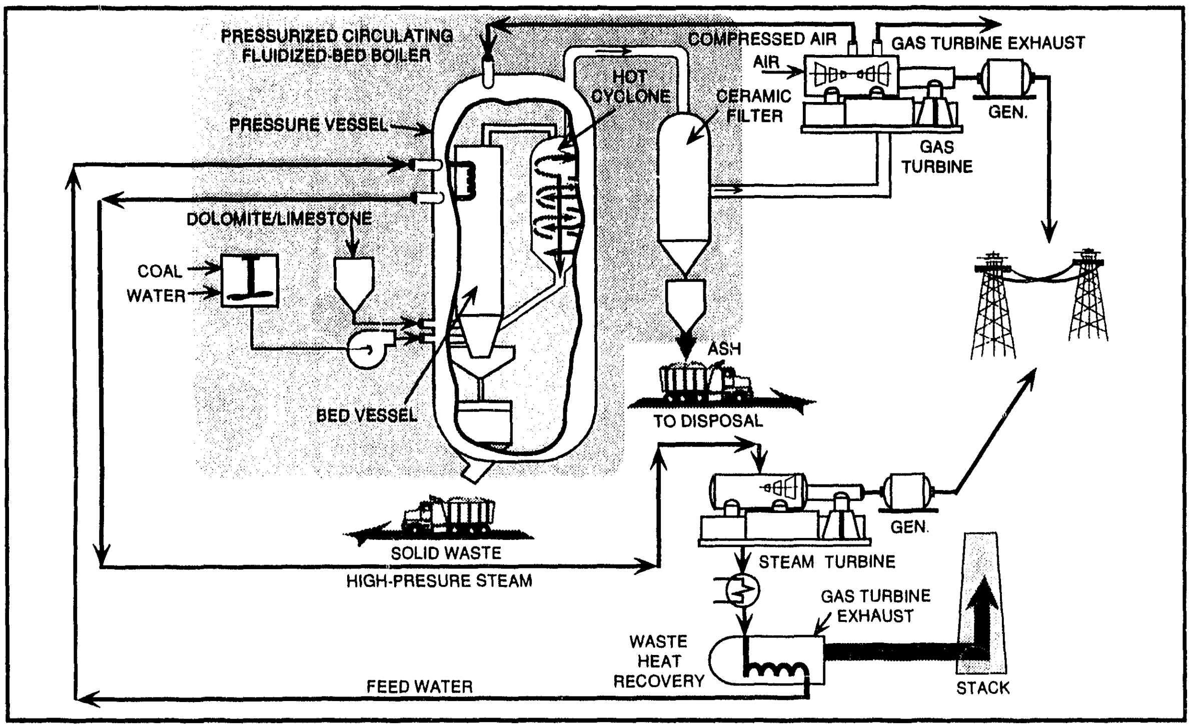


Figure 2. PCFB Process Flow Diagram

Coal and sorbent are fed to the combustor as a paste, applying existing technology as used in the pumping of concrete, and atomized with steam to distribute the materials in the PCFB. The compressor section of the gas turbine provides air to the PCFB vessel. The air flows from the top to the bottom of the vessel, and cools the vessel and internal components. The fuel and sorbent are mixed with the air in the combustor chamber where combustion occurs at about 1,600° F. Heat is recovered from the hot flue gases in a similar way as conventional boilers to generate steam to power the steam turbine.

As particles are burned and sulfur is absorbed in the furnace by the sorbent, the finer particles of coal and sorbent become entrained with the flue gas and enter the hot cyclone. Here, the majority of the particles are collected and returned to the combustor through the loop seal. The finer ash particles continue with the hot gases to the ceramic filter where final removal of particulates is achieved.

Once cleaned, the hot pressurized flue gases are expanded through the gas turbine. The resulting mechanical power drives the compressor and the gas turbine's generator. The remaining useful heat exhausted from the gas turbine is recovered in a conventional heat recovery unit to preheat process water in route to the PCFB boiler. Clean exhaust is then released to the stack.

TECHNOLOGY DEVELOPMENT HISTORY

The Karhula PCFB Testing Facility was built in Karhula, Finland, to support the design and operation of commercial first generation and advanced PCFB units. In 1989, Ahlstrom, the parent company of Pyropower, initiated operation of the Karhula PCFB facility. It is an integrated PCFB unit, including all of the key components and incorporating the same mechanical design features which will be utilized in commercial plants. These include fuel handling and preparation systems, sorbent injection systems, pressurized furnace with radiant heat transfer surfaces, hot cyclone, ceramic filter, ash cooling and depressurization systems, and testing of materials and coatings for gas turbine blades.

The main objectives of the Karhula PCFB Filter testing program are the following:

- To generate process data for the design of commercial size PCFB units.
- To develop engineering data for design of PCFB systems and plant auxiliaries including fuel feeding and ash handling.
- To generate database information for auxiliary equipment performance which can be used for other advanced coal utilization technologies.

- To demonstrate a commercial scale high-pressure high-temperature filter under PCFB conditions.

PILOT PLANT TESTING RESULTS

The facility has operated for over 3,000 hours with various sorbents and coals. The PCFB combustor has performed well in terms of process characteristics such as combustion efficiency, gaseous emissions, and response to load changes. The following are the results observed for key performance parameters.

Combustion Efficiency

Testing results have shown a carbon conversion in the range of 99.8 to 100 percent with excess air levels as low as 10 percent. Very low CO levels have been observed as well.

Sulfur Retention

It has been observed that sulfur absorption in the PCFB occurs in a different manner than that in an atmospheric circulation fluidized bed (ACFB) boiler. This can result in nearly complete utilization of the sorbent. In the pilot plant testing, sulfur removal efficiencies in the range of 95 to 99.5 percent have been achieved at calcium to sulfur ratios 30 to 70 percent below what is required in an ACFB. For high sulfur coals with a Ca/S ration of less than 2, a sulfur retention of about 95 percent has been recorded.

NO_x Formation

In the pilot plant, NO_x emissions below 200 ppmvd at oxygen levels of less than 3 percent have been measured. Further reduction is possible if required by using ammonia injection. Levels below 30 ppm have been achieved with ammonia slip levels of less than 5 ppmvd.

N_2O Emissions

N_2O emissions from the pilot plant have been measured at less than 30 ppmvd at 3 percent O_2. It is expected to be lower in large size combustors where gas residence times are increased.

Hot Gas Cleanup

A key feature of the pilot plant testing has been and will continue to be the testing of ceramic barrier filter technologies. Testing was first done on an Asahi Advanced Ceramic Tube Filter and then subsequently on a Westinghouse Candle Filter. Both configurations were successful in reducing the outlet dust loading to levels required by gas turbine manufacturers, but premature ceramic element failures occurred. Evaluation of various filter modifications and additional filter designs continues.

PROJECT SCHEDULE

Budget Period 1, the preliminary engineering phase, was originally scheduled to be completed on June 30, 1993. The DOE and the project participants are currently reviewing options to reschedule the project to allow time for additional component testing. Budget Period 1 has been extended to September 30, 1993, to allow for development of these plans.

SUMMARY

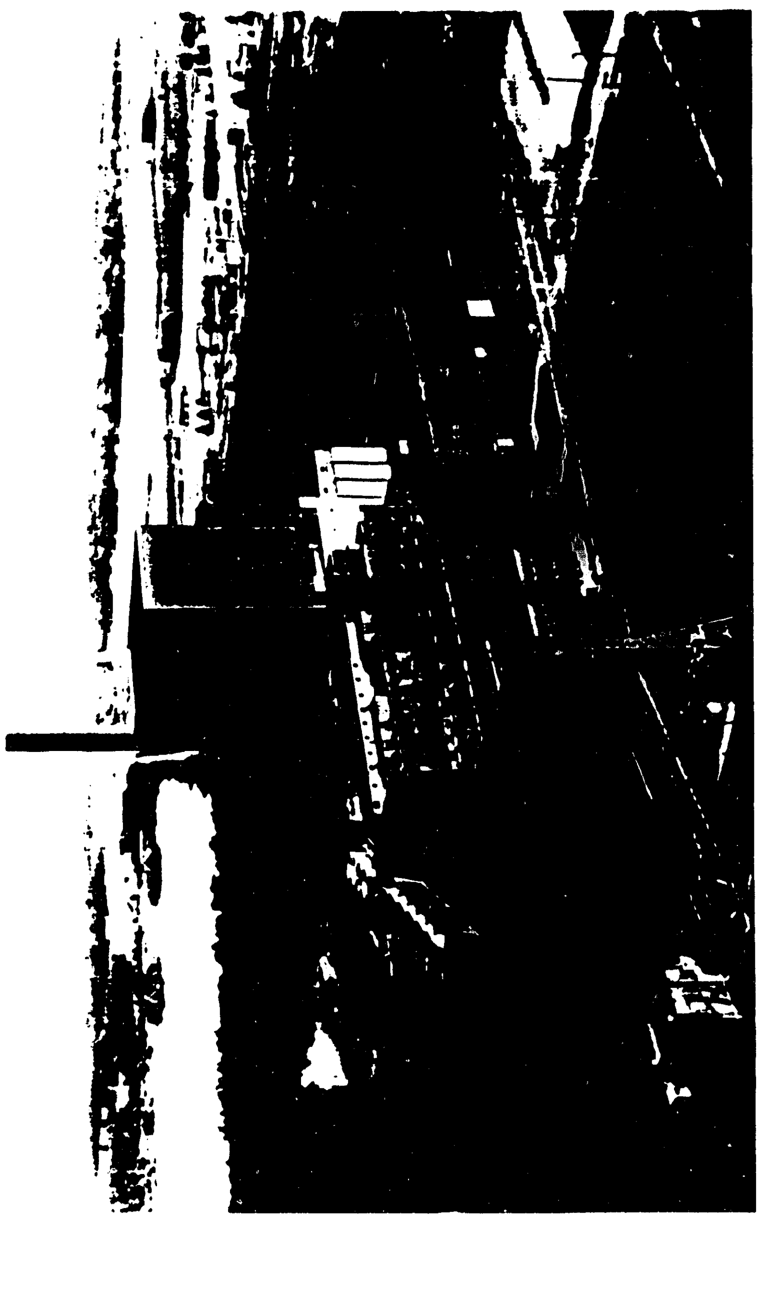
The DMEC-1 Project will demonstrate the use of Pyropower's PYROFLOW pressurized circulating fluidized bed technology to repower an existing coal fired generating station. The project continues in Budget Period 1, the preliminary design phase.

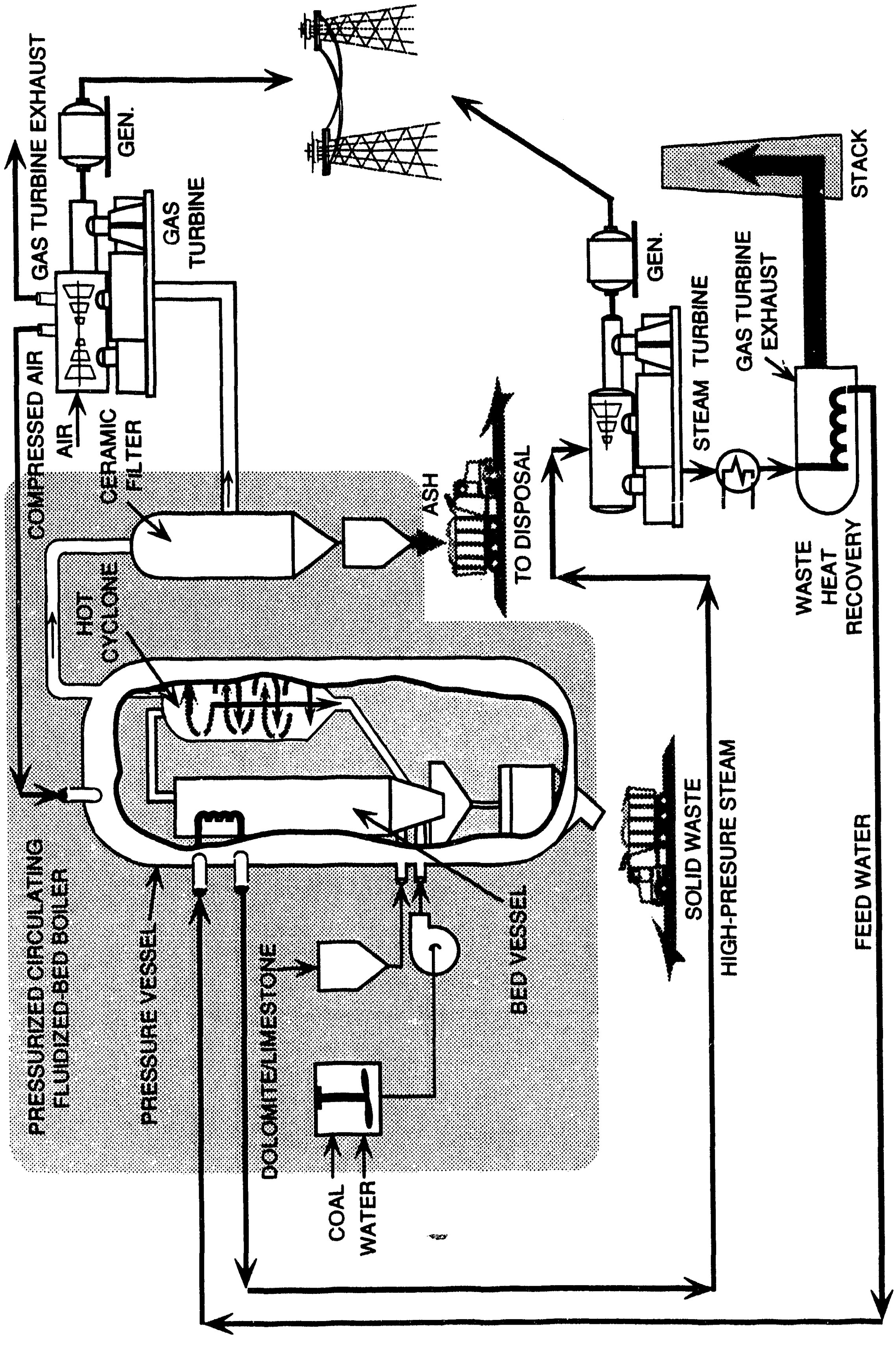
SOURCES

1. G.E. Kruempel, S.J. Ambrose, and S.J. Provol, "DMEC-1 Pressurized Circulating Fluidized Bed Demonstration Project," Paper presented at *1st Annual Clean Coal Technology Conference*, Cleveland, Ohio, Sept. 22-24, 1992.

2. "PCFB Repowering Project Annual Report August 1991 to December 1992," DMEC-1 Limited Partnership for US Doe, No. DE-FC21-91MC27364, April 1993.

3. K.M. Sellakumar, and J. Isaksson, "Process Performance of Ahlstrom Pyroflow® PCFB Pilot Plant," Paper presented at *12th International Conference on Fluidized Bed Combustion*, San Diego, California, May 9-13, 1993.





PRESSURIZED CIRCULATING FLUIDIZED-BED BOILER
PRESSURE VESSEL
DOLOMITE/LIMESTONE
COAL
WATER
BED VESSEL
HOT CYCLONE
CERAMIC FILTER
COMPRESSED AIR
AIR
GAS TURBINE EXHAUST
GAS TURBINE
GEN.
ASH
TO DISPOSAL
SOLID WASTE
HIGH-PRESURE STEAM
FEED WATER
STEAM TURBINE
GEN.
GAS TURBINE EXHAUST
WASTE HEAT RECOVERY
STACK

AMERICAN ELECTRIC POWER PRESSURIZED FLUIDIZED BED COMBUSTION TECHNOLOGY STATUS

M. M. Marrocco
American Electric Power
Service Corporation
1 Riverside Plaza
Columbus, Ohio 43215

ABSTRACT

The American Electric Power Pressurized Fluidized Bed Combustion (PFBC) Program is the only ongoing PFBC and Hot Gas Clean Up (HGCU) Program in the United States. The 70 MWe Tidd PFBC Demonstration Plant is a Round 1 Clean Coal Technology Project that was constructed to demonstrate the viability of PFBC combined cycle technology. The addition of a Hot Gas Clean Up (HGCU) stream at Tidd, separately funded by the U.S. Department of Energy as an R&D project, is intended to demonstrate that Advanced Particle Filters (APF) can operate reliably in a PFBC gas stream. The experience gained from these programs is expected to hasten the commercial deployment of the technology and provide a viable power generation option in a time frame consistent with the growing baseload generation needs which are expected to develop early in the next decade.

This paper reviews PFBC technology and HGCU and discusses the status of project goals and milestones. Special emphasis is placed on the operation of the Tidd PFBC and HGCU Programs.

INTRODUCTION

The onset of the next century is expected to bring a resurgence of electric load growth. This projected increase in growth is expected to coincide with the need to replace or repower large blocks of existing capacity which will have reached the end of its useful life. The net impact will be the creation of a substantial market for Clean Coal Technologies for both new and repowering generating capacity (Figure 1.).

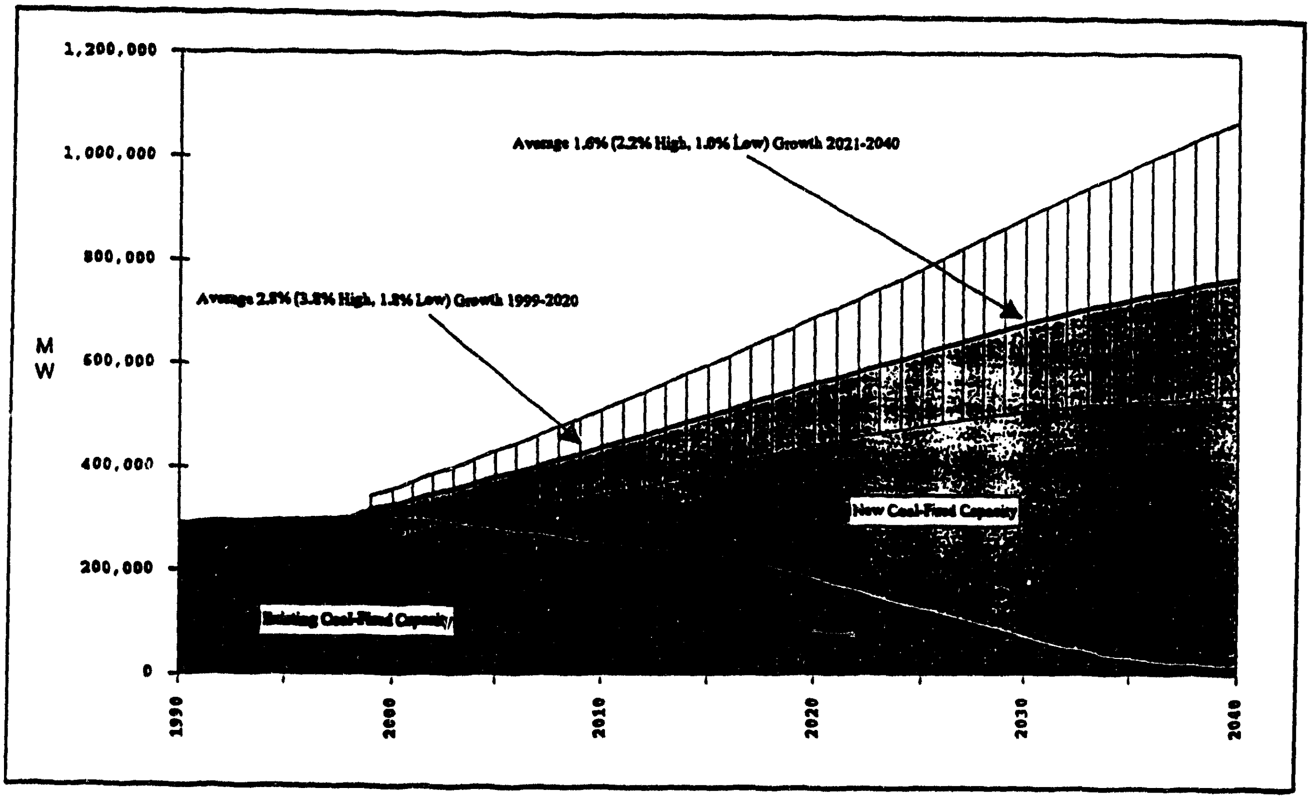


Figure 1 Potential Market for Advanced Coal-Based Technologies

This required capacity addition is expected to be met by a variety of generating options. However, coal is expected to be a dominant fuel and Clean Coal

Technologies the dominent technologies. The innovative clean coal technologies being developed and demonstrated in this decade will play an important role in meeting these power needs in an efficient and environmentally responsible manner.

TECHNOLOGY DESCRIPTION

PFBC technology is one of the advanced coal power generation options being developed. First generation PFBC technology has made significant advances over the last five years and represents an option which is ready for full scale deployment.

PFBC technology consists of a fluidized bed made up of a mass of granular particles which are maintained in a highly turbulent suspended state by an upward air flow. This fluidized state permits excellent surface contact between the air and the solid particles which permits almost isothermal conditions and efficient combustion. The temperature in the bed is established between the combustion temperature and the ash fusion temperature of the fuel – for the Tidd PFBC, this temperature is between 1520°F - 1580°F. During combustion, the SO_2 generated is removed by the addition of a sorbent such as dolomite or limestone to the bed. This process has been demonstrated to remove 90 - 95 percent of the sulfur from high sulfur coals. In addition to SO_2 removal, the process mitigates the formation of NO_x, due to its relatively low combustion temperature. The high operating pressure (approximately 175 psia) of a PFBC unit provides exhaust gases with sufficient energy to drive a gas turbine, allowing a combined cycle configuration.

TIDD PFBC DEMONSTRATION PLANT

The Tidd PFBC Demonstration Plant, a 70 MWe electric generating station in Brilliant, Ohio, is the first pressurized fluidized bed combustor to operate in combined cycle mode in the United States. Funding for the $193-million project is being provided by Ohio Power Company, the U.S. Department of Energy ($60.2-million) and the Ohio Coal Development Office ($10-million).

The Tidd PFBC Demonstration involves the repowering of a 1940's vintage coal-fired power plant with PFBC components. The original Tidd Plant, consisting of two 110 MWe conventional coal-fired units, was decommissioned in 1976. The units were preserved in anticipation of a PFBC repower.

Major balance of plant equipment from the original units is utilized at Tidd. Major plant additions include the combustor building, economizer, electrostatic precipitator, and coal and sorbent storage areas.

The PFBC power island, which has been incorporated into the existing steam cycle, provides a nominal steam flow of 440,000 pounds per hour at 1300 psia and 925°F, and has a gross electrical output of 70 MW. Figure 2. depicts the Tidd cycle.

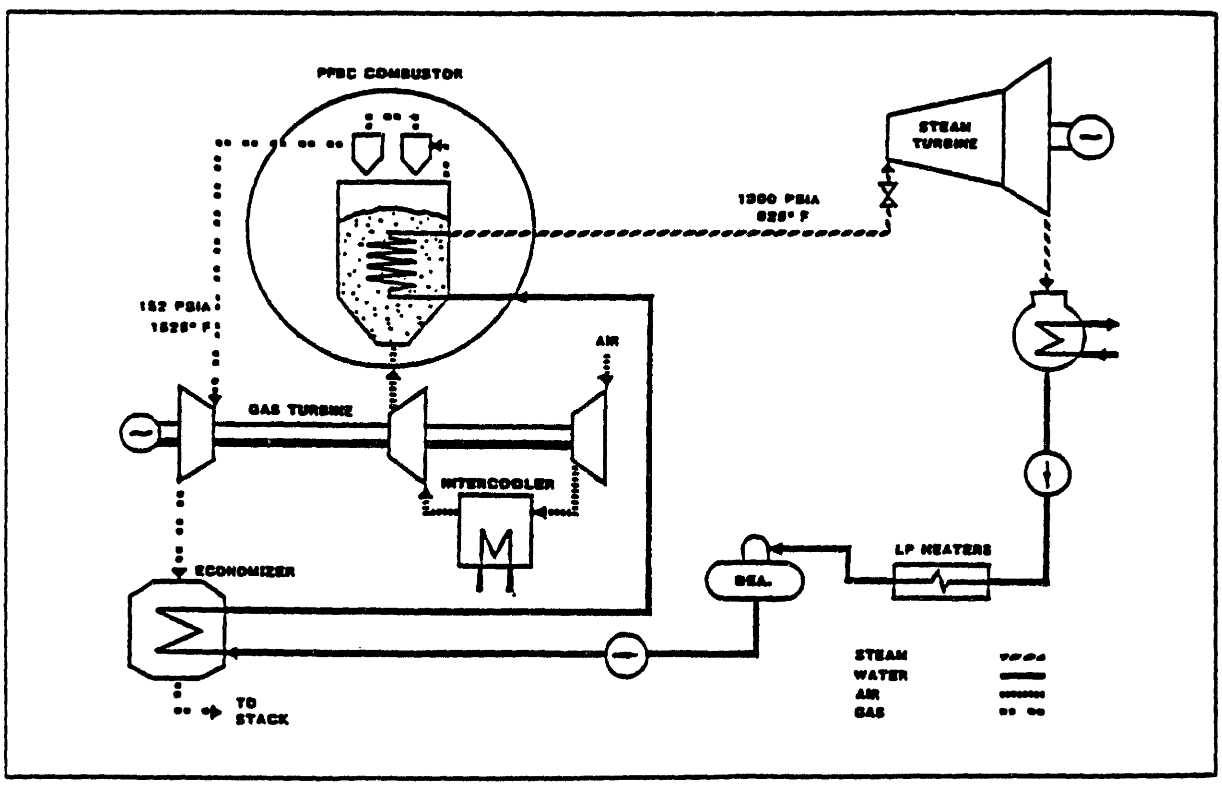


Figure 2. Tidd PFBC Demonstration Plant Cycle

Combustion air at about 175 pisa is provided by the gas turbine compressor to the combustor pressure vessel through the outer annulus of a coaxial pipe. The combustion air fluidizes and entrains bed material consisting of fuel (coal/water paste), coal ash, and sorbent (dolomite).

Seven strings of two-stage cyclones, located in the combustor vessel, remove about 98 percent of the entrained ash from the fluidized bed exhaust gases. The clean, hot gases leave the pressure vessel via the inner cavity of the coaxial pipe and are expanded through an ASEA Stal GT-35P gas turbine. The gases are exhausted through the turbine exhaust gas economizer. An electrostatic precipitator cleans the gas of particulate prior to exhausting to atmosphere.

The steam cycle is a typical Rankine Cycle with a once-through boiler. Condensate is heated in three stages of low pressure heaters and the gas turbine intercooler as it is pumped to the deaerator. A single high pressure heater and an economizer raise the final feedwater temperature to approximately 480°F. The feedwater flows through the boiler bottom zone and into the in-bed evaporator surface. Steam generated there is conveyed to a vertical separator outside the pressure vessel; flow to the separator is two-phase up to about 40 percent load and slightly superheated at full load. Saturated or slightly superheated steam from the vertical separator is routed back to the in-bed tube bundle where it passes through primary and secondary superheater sections. Final steam temperature is controlled by spray attemperation between the primary and secondary superheaters.

Coal is injected into the combustor as a coal water paste nominally containing 25 percent water by weight. Paste preparation begins by reducing the 3/4" x 0" feedstock to - 1/4" in a double roll crusher. A crushed coal recirculation system provides the ability to recirculate crushed coal to ensure correct fines content. The crushed coal is conveyed to a vibratory screen, which controls coal top size, and then into the coal water paste mixer where the appropriate amount of water is added.

The mixer discharges to two interconnected surge tanks which feed six hydraulically driven piston pumps, each of which feeds an individual in-bed full nozzle.

Sorbent feed stock sized to 3/4" x 0" is reduced to 1/8" x 0" by a hammer mill crusher. A vibratory recycle screen controls the top size of the prepared sorbent. Crushed sorbent is injected into the fluidized bed via two pneumatic feed lines supplied from dual lock hopper strings.

An alternate sorbent feed system, which provides the capability of injecting sorbent of various size directly into the coal/water paste feed system, was added in early 1993. This system provides the means to assess a wet feed sorbent system, while also providing the opportunity for better control of sorbent size consist.

Bed ash, which comprises about 50 percent of total ash generation, is removed from below the bed via a lock hopper system. Elutriated ash collected by the cyclones is removed via a pressurized pneumatic transport system which depressurizes and cools the ash without using valves or lock hoppers.

HOT GAS CLEAN UP SYSTEM

In 1992, the 10 MW (equivalent) Tidd Hot Gas Clean Up System was commissioned. This system uses ceramic candle filters to clean a portion of the exhaust gases from an operating PFBC unit. The Advanced Particle Filter (APF) is installed in a slipstream which takes one-seventh of the Tidd exhaust gases and directs these through the APF and back to the process. The HGCU slipstream replaces one of the seven secondary cyclones which is normally used for final process gas cleaning.

The HGCU slipstream is comprised of an advanced particle filter located adjacent to the PFBC combustor vessel, a back-up cyclone, a bypass cyclone, and the ancillary systems required for ash removal and ceramic filter cleaning. A schematic of the HGCU system cycle is presented in Figure 3.

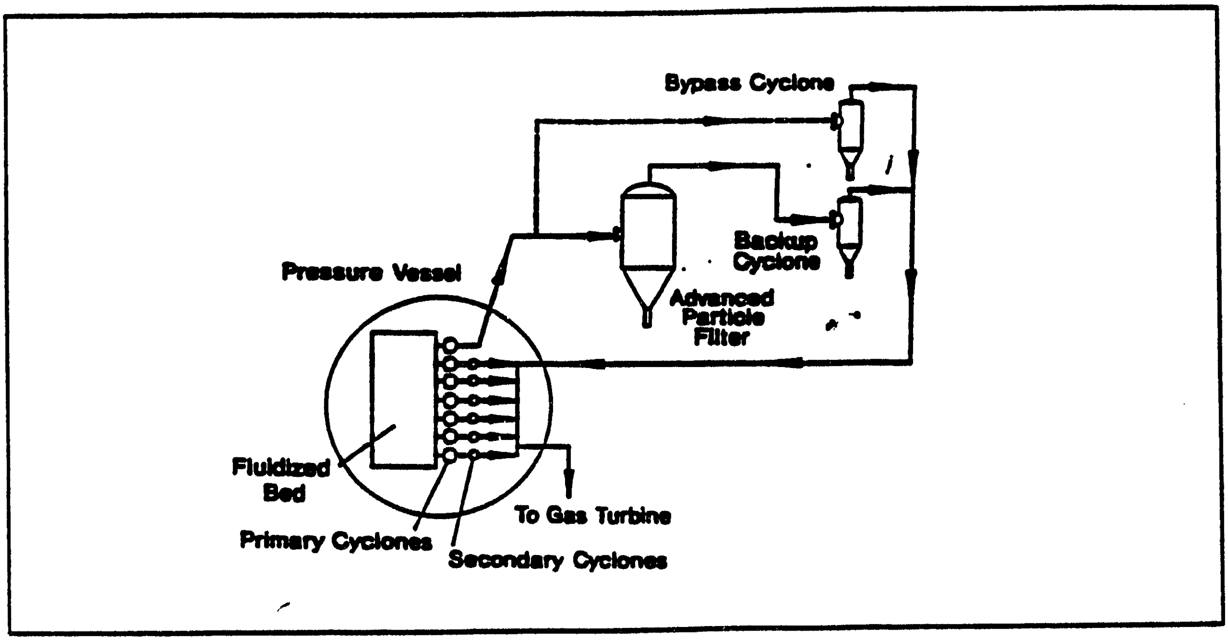


Figure 3. Tidd HGCU Test Facility Arrangement

Hot combustion gases are routed from the discharge of the primary cyclone out of the combustor vessel into the filter. The gases are then routed through the back-up cyclone and returned to the secondary cyclones' collection header located in the combustor vessel. The gases flow from this collection header to the gas turbine. A bypass cyclone is provided in the event that the APF filter is removed from service.

At full load, approximately 7600 ACFM of combustion gases at 150 psig, 1550°F, flow through the HGCU system. Normal dust loading through the filter is approximately 600 ppmw. Clean gases from the ceramic filter contain less than 15 ppmw dust loading. The back-up cyclone downstream of the filter protects the gas turbine in the event of a filter malfunction.

The design basis for the APF system is listed in Table 1.

AFP Design Basis

Maximum Temperature (°F)	1670
Operating Temperature (°F)	1550
Maximum Pressure (PSIG)	185
Operating Pressure (PSIG)	150
Design Gas Flow Rate (LB/HR)	100,700
Inlet Dust Loading (PPM)	500-5000
Outlet Dust Loading (PPM)	<15
Average Particle Size (MICRONS)	1.5
Filter Temperature Drop (°F)	5
Pressure Drop (PSI)	3

Table 1.

The Advanced Particle Filter, shown in Figure 4., is a 10 foot diameter by 44 foot high vessel. The vessel is internally insulated with alumina-silica ceramic insulation and lined with a 310 stainless steel liner for erosion protection. The hot gas enters at the side of the vessel and is channeled through the filter elements. Clean gas exists through the top of the vessel.

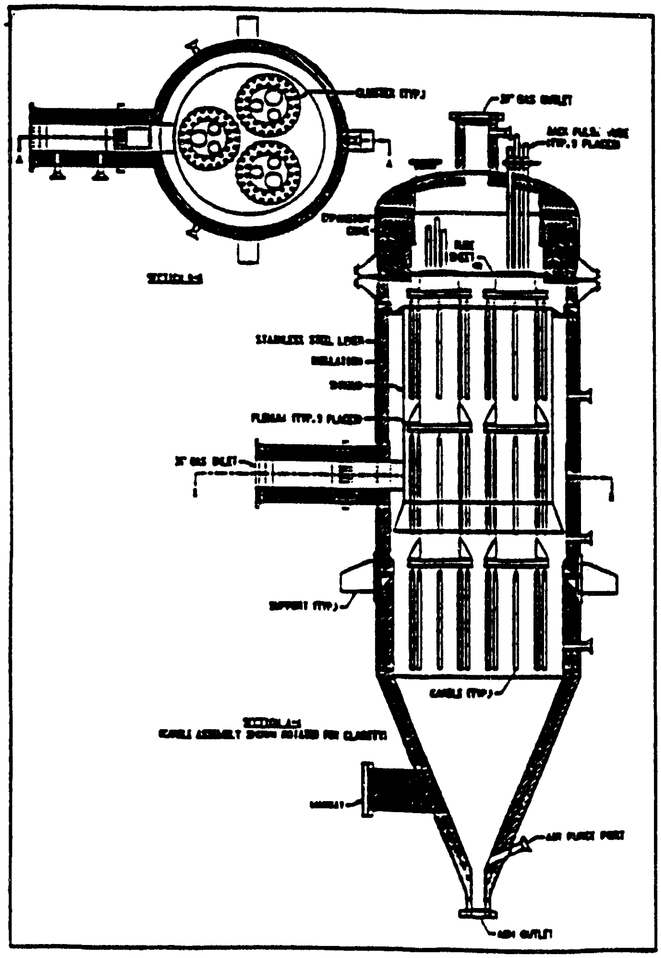


Figure 4. Tidd Advanced Particle Filter

The APF filter contains 384 ceramic candle filter elements, arranged in three clusters spaced 120 degrees apart. Each cluster holds three plenums arranged vertically, with 38 candles in each upper and middle cluster, and 52 candles in each lower cluster.

The candles are Schumacher Dia-Schumalith F40 candles consisting of a clay-bonded sintered silicon carbide support matrix coated by an aluminum silicate fibrous membrane. Each candle is 2.36 inches in outside diameter and 4.92 feet in length. The candles are attached to the tube sheet in each plenum by bolted collars and sealed by high temperature gaskets. The plenums are attached to a two inch thick, RA-333 alloy tube sheet. The tube sheet is supported from an inverted "V" expansion cone.

Candle cleaning is achieved by an air backpulse system which serves to dislodge the filter cake from the elements.

The Backpulse System is shown in Figure 5. Backpulse air is available at pressures up to 1500 psig. However, the normal backpulse pressure has been set at 800 psig.

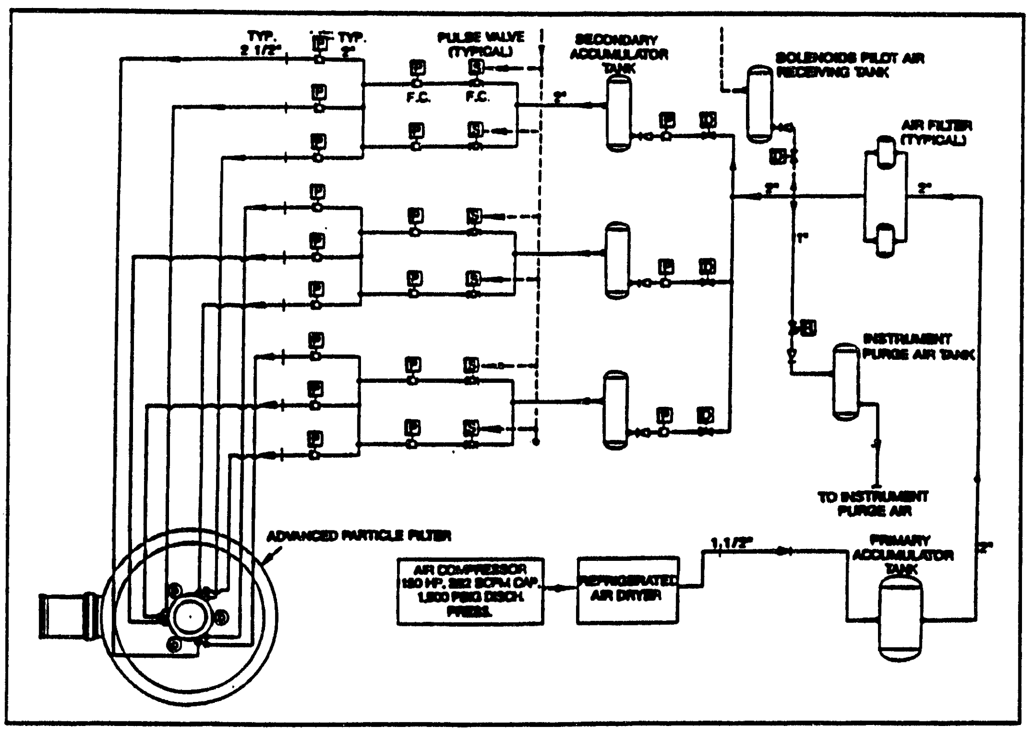


Figure 5. APF Backpulse System

Ash collected in the AFP is discharged through a pressurized screw cooler into depressurizing lock hoppers which feed a pneumatic transport system. The transport system conveys the ash from the lock hopper to the economizer outlet.

TIDD PFBC OPERATIONAL SUMMARY

The Tidd PFBC Plant achieved its first coal fire in November 1990. The details of operation through June 1992 were previously reported at the First Annual Clean Coal Technology Conference. The operating statistics for that period are summarized in Table 2.

Tidd Operating Statistics
Through June, 1992

Initial Combined Cycle Operation	1/29/90
Total Operation in Coal (Hours)	2100
Longest Continuous Run (Hours)	740
Highest Bed Level Achieved (Inches)	142
Highest Gross Generation (MWe)	70

Table 2.

The Tidd Plant was removed from service in July 1992, following a successful 31-day run, for equipment repair and general maintenance. Three test runs in late July and early August 1992 ended prematurely, due to a variety of system problems. The unit was returned to service on August 8 and ran on coal for approximately 422 hours before being shutdown on August 27 for inspections. Testing focused on the feasibility of feeding sorbent with the coal-water paste.

The unit ran for four short periods during September 1992, but coal-water paste problems and bed sintering, particularly when injecting limestone as the sorbent, prevented meaningful testing.

The unit was removed from service in early October 1992 to repair a damaged coupling on the low pressure gas turbine and to tie in the HGCU loop.

Four test runs totalling 464 hours of operation on coal were conducted from late October to early December 1992. The unit was subsequently removed from service for inspection. A number of broken ceramic candles were discovered along with a pinhole leak in one of the HGCU piping expansion joints.

The PFBC was reconfigured to six cyclone operation, thereby eliminating the HGCU system from the circuit, and the unit resumed operation in late December 1992. Baseline testing was completed utilizing Pittsburgh No. 8 and Ohio No. 6 coals with Plum Run dolomite as the sorbent.

The unit experienced a catastrophic failure of a low pressure turbine blade on February 9, 1993 and was removed from service for a complete gas turbine overhaul. A modified Hot Gas Clean Up System was reconnected during this period.

The unit returned to service in early July 1993. Gas turbine vibration problems have limited unit load, but the plant has logged approximately 500 hours on coal, operating at reduced load. Table 3 provides a summary of operating statistics through July 1993.

Tidd Operating Statistics Through July, 1993	
Initial Combined Cycle Operation	11/29/90
Total Operation in Coal (Hours)	4000
Longest Continuous Run (Hours)	740
Highest Bed Level Achieved (Inches)	142
Highest Gross Generation (MWe)	70

Table 3.

The bar charts presented as Figure 6, 7, and 8 show a graphical depiction of Tidd operating history.

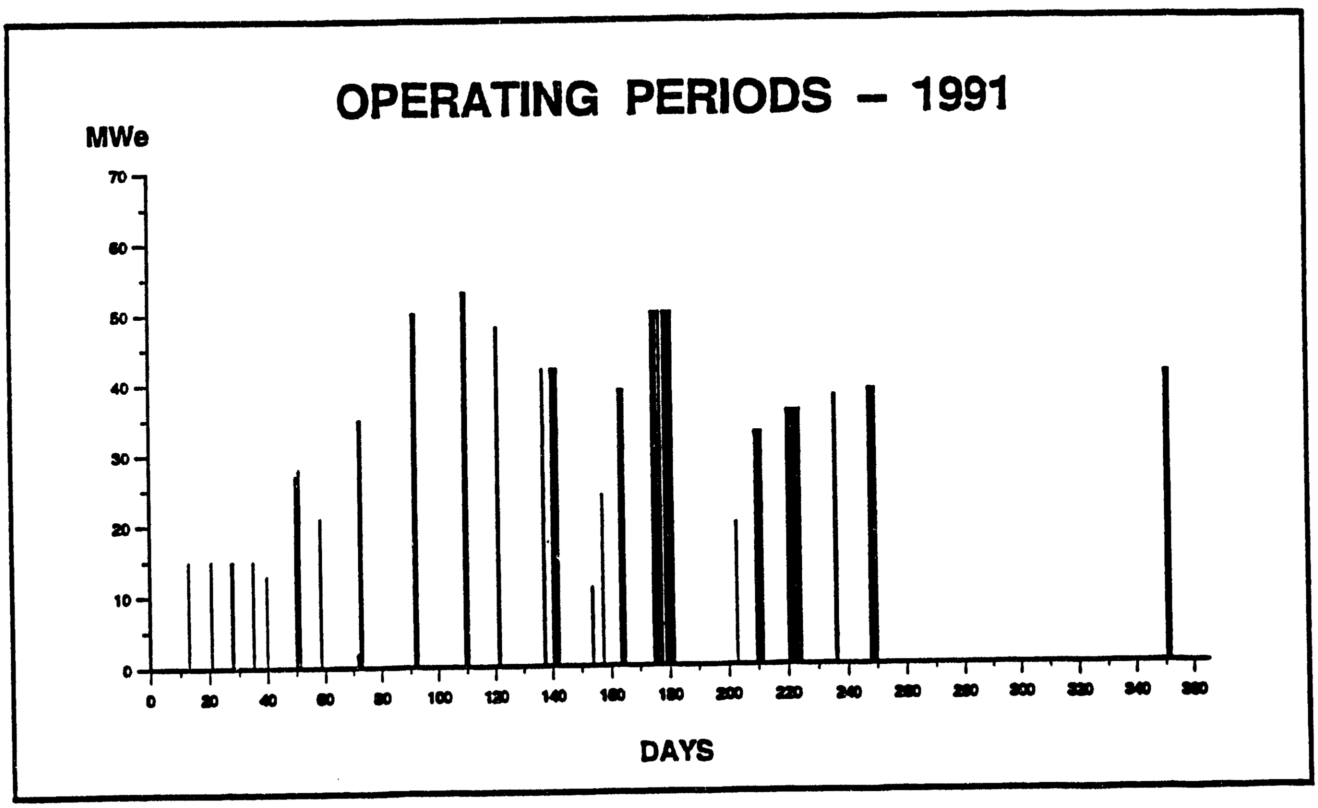


Figure 6.

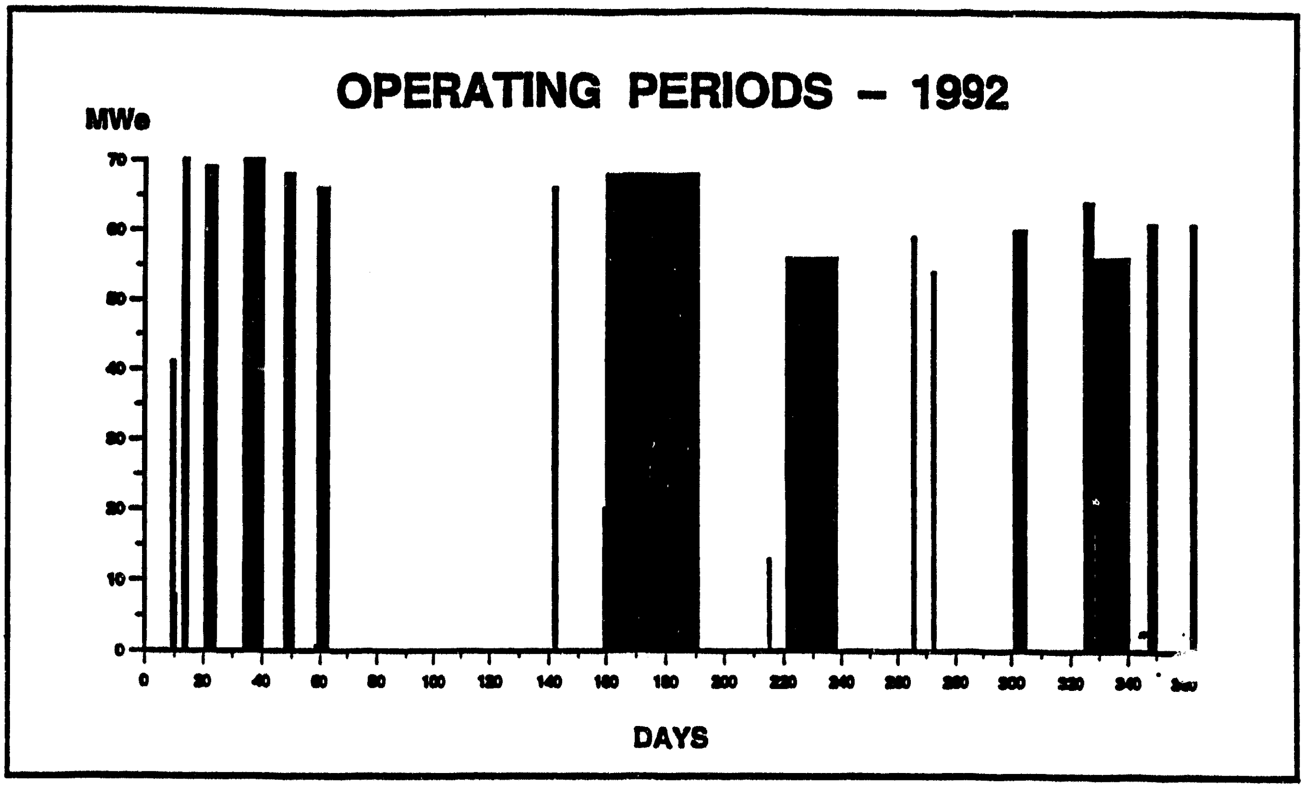


Figure 7.

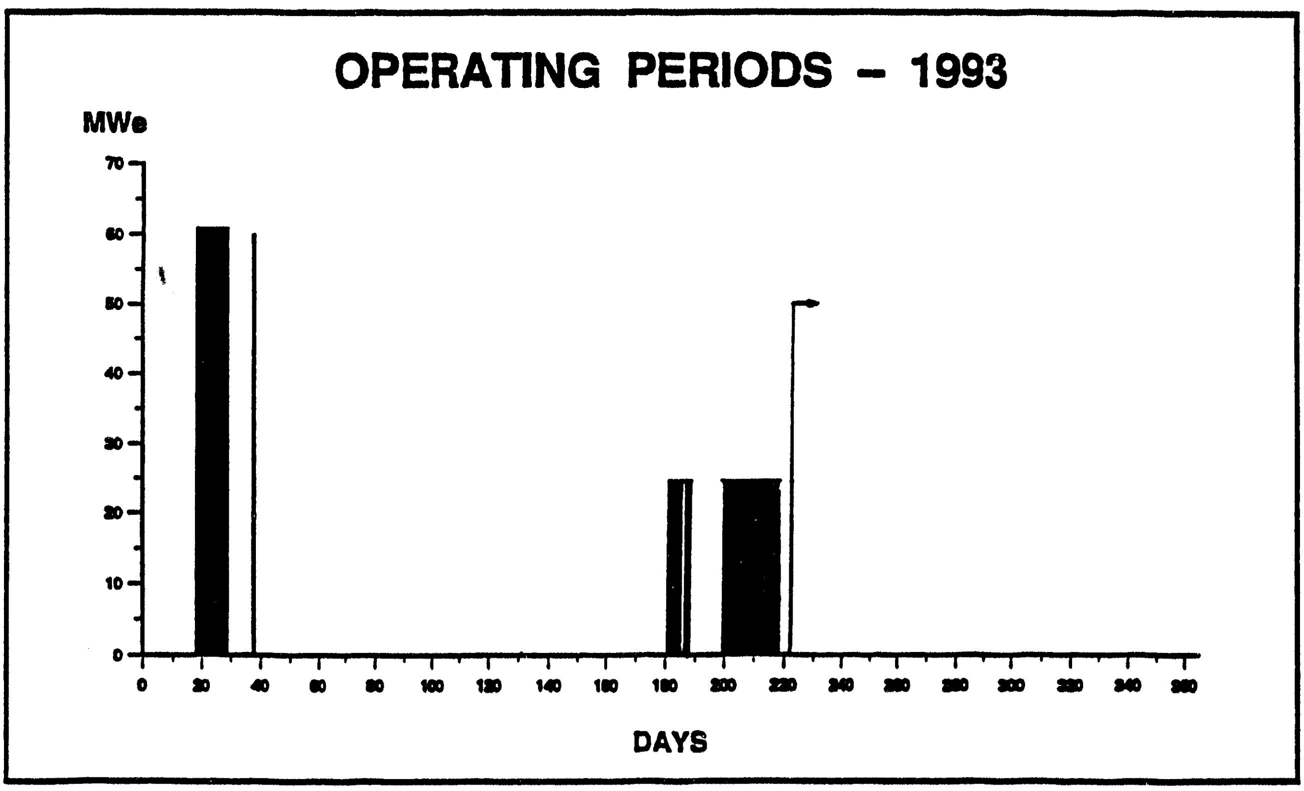


Figure 8.

The Tidd PFBC Demonstration Plant has completed over 4000 hours of coal-fired operation and has met its original environmental performance objectives and most of its performance guarantees. A review of plant operating history shows that in the sixty-five runs, which constitute the first thirty months of operation, mechanical difficulties accounted for 85 percent of forced shutdowns. Approximately 30 percent of these shutdowns were a direct result of either primary or secondary cyclone ash removal system outages. Another 20 percent of the shutdowns was attributed to coal/water paste feed system problems. Gas turbine problems caused approximately 15 percent of the forced shutdowns, but clearly represented the largest contributors to unit downtime. The remainder of shutdowns were caused by various mechanical equipment control and process problems, which each individually accounted for 5 - 10 percent of the shutdowns.

HOT GAS CLEAN UP SYSTEM OPERATIONAL SUMMARY

The advanced particle filter was first commissioned on October 25, 1992. Through the end of 1992, the APF system logged 464 hours of coal-fired operation, with a longest run of 286 hours. The system remained out of service during the first half of 1993 for repairs to both the APF system and the Tidd PFBC Plant.

The plant returned to service in July 1993. The APF system has operated for approximately 400 hours as of the end of July.

The initial operation of the Hot Gas Filter System identified a number of difficulties. These generally can be grouped into two areas – mechanical problems and process problems. The mechanical problems included hot spots in various areas of the HGCU system components, failure of the backpulse compressor, and of system expansion joints. Process difficulties included the inability to remove ash from the bottom of the filter vessel and ash pluggage in the lock hopper system. These difficulties have been discussed in detail in a previous paper presented at the International Conference on Fluidized Bed Combustion.

The problems identified during initial operation of the HGCU system were generally addressed during the PFBC gas turbine outage, which began in February 1993. The system was returned to service in early July 1993. The APF system has operated for approximately 400 hours since that time. All of the problems previously identified appear to have been solved. Operation during the 400 hours run was uneventful; all of the APF system functioned as designed. Filter conditions were stable and filter pressure drop was relatively consistent. The backpulse system performed well in cleaning the candle elements of filter cake. However, difficulties are still being encountered with ash buildup on the APF hopper walls.

CONCLUSION

The Tidd PFBC Demonstration Plant has completed over 4000 hours of coal-fired operation and has generally met all performance, environmental, and reliability goals established for the demonstration. A review of the unit's operating history reveals that mechanical equipment problems accounted for the majority of system shutdowns. The first thirty months of operation have clearly demonstrated the need for a demonstration unit and have provided a clear basis for a commercial plant design. Significant strides have been made in cyclone ash removal system design and in coal preparation/coal-water paste feed system design. A clear picture is beginning to emerge with respect to system operating parameters and their impact on PFBC performance. Continued operation of the Tidd PFBC unit will continue to provide significant input to a commercial design, which will compete effectively in the repower and base load generation market.

The Tidd HGCU system has achieved almost 1000 hours of operation. Lessons learned to date emphasize the importance of auxiliary systems, especially external piping systems and ash handling systems. The design basis for such systems are being developed, applied, and refined at Tidd. Continued operation of the APF should provide an in-depth understanding of ceramic candle filter operation and limitations. This will provide the basis for development of commercial ceramic filters capable of contributing to numerous clean coal technologies.

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Session 3
SO_2 Control Technologies

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