Session 3

Advanced IGCC Systems

Integrated Gasification Combined Cycle - A View to the Future

Dale K. Schmidt
Morgantown Energy Technology Center

INTRODUCTION

DOE is involved in research, development, and demonstration (RD&D) of Integrated Gasification Combined Cycle (IGCC) because of a strong belief that it will result in widespread commercialization that will be of great benefit to this Nation. METC's long-range vision comprises (1) product goals that require improvements to known technical advantages, and (2) market goals that are based on expectations of market pull.

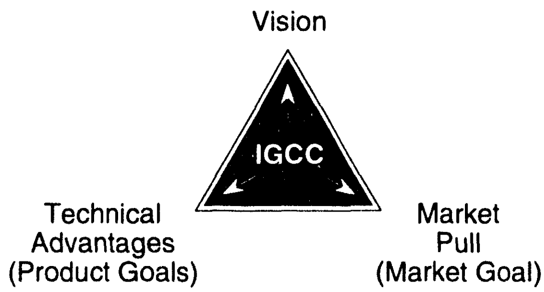

Figure 1. Vision and Goals for IGCC

The first IGCC plant in the United States was build for about $3,000 per kilowatt (kW) in the mid 1980s and operated at an efficiency comparable to conventional coal-fired plants. The six IGCC clean coal projects scheduled for startup from the mid to late 1990s will demonstrate significant reductions in capital cost ranging from $1,500 to $2,000 per kilowatt and impressive increases in efficiency of around 40 percent, based on higher heating value (HHV). The METC vision for IGCC is that over the next 20 years R&D-based technology advances and plant learning curve cost reductions will yield even more dramatic improvements resulting in plant efficiencies of over 50 percent and cost reductions to nearly $1,000 per kilowatt.

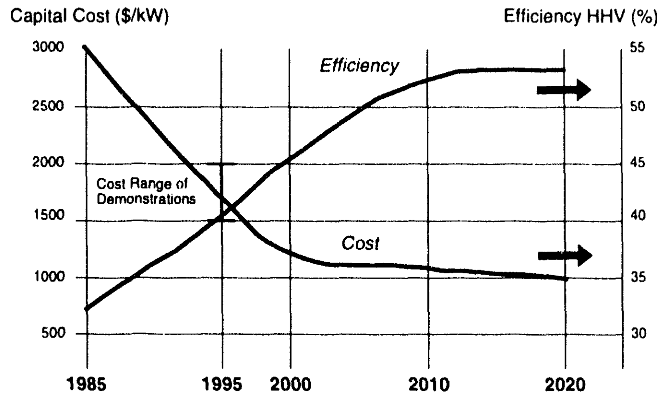

Figure 2. IGCC Vision: Cost versus Efficiency

Specific goals (Table 1) are that by the year 2010, capital cost as low as $1,050/kW and efficiencies as high as 52 percent HHV are viable along with superior coal-based environmental performance, resulting in possibly the lowest cost electricity option. Commercial-scale demonstration of multiple IGCC technologies that will result in healthy competition is critical to this goal.

Fossil Energy research and development (R&D) is interactively supporting the IGCC product goals. The year 2000 goal of 45 percent efficient IGCC plants is aided by over 50 METC contracted and in-house projects that are topics of these conference proceedings. Major initiatives are underway in advanced gasifier systems and advanced turbine systems toward achievement of the more ambitious year 2010 goal of 52 percent efficiency.

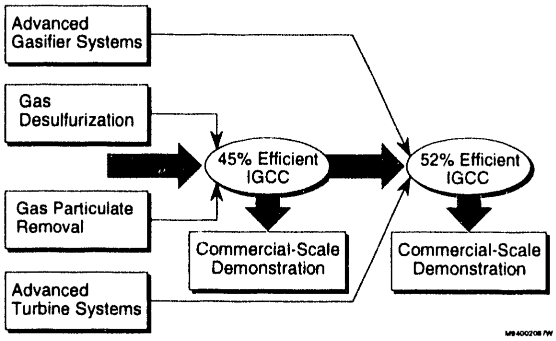

Figure 3. Interaction of IGCC Product Improvements

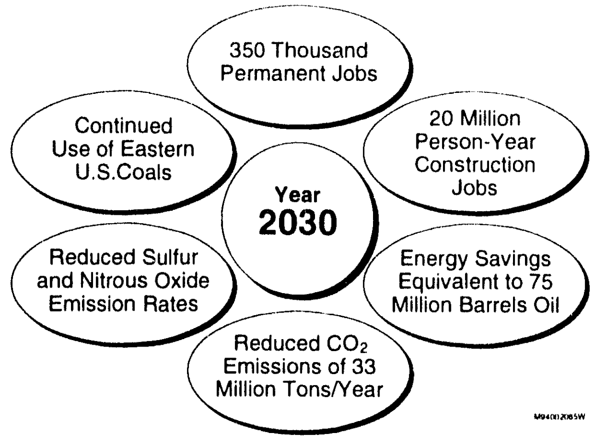

Figure 4. National Benefits of IGCC

DOE projections of our Nation's electricity needs are provided by the Energy Information Administration-Annual Energy Outlook (AEO). (See Table 2.) Considering the AEO-1994 projection for coal-based and gas turbine-based electricity production, modest assumptions about the IGCC market share of three market segments are made. These market segments are: (1) coal plant additions, (2) coal plant repowerings, and (3) staged addition of gasifiers to natural gas combined cycle plants. It is expected that the IGCC investment could exceed $150 billion by the year 2030.

The combination of these IGCC technology goals and market goals suggest great benefit to our Nation. The IGCC dollar investment, as projected through the year 2000, has the potential of millions of person/year construction jobs, thousands of permanent operating jobs related to domestic projects, and thousands of U.S. jobs related to overseas projects.

Six IGCC commercial-scale demonstration projects costing nearly $3 billion are underway in DOE's Clean Coal Technology (CCT) program. The Government is cost sharing about one-third of these CCT demonstrations. METC's strategy is to link RD&D via a product improvement concept so that (a) the CCT projects will benefit from the latest R&D results, and (b) R&D will be focused toward technical breakthroughs that shortcut achievement of the longer range IGCC goals.

The IGCC R&D budget (Table 3) necessary to accomplish these purposes projects a modest growth for FY 1995 to about $28.2 million. Additionally, there is about $2 million of IGCC-related funding in two other budget categories: advanced research and environmental technology (AR&ET), and advanced research and technology development (AR&TD).

Within the IGCC budget (Table 4), about 40 percent is allocated to the Power Systems Development Facility, about 25 percent to Gasifier Product Improvement, about 20 percent to two large-scale hot gas cleanup systems test facilities, one at General Electric and one at METC, and the balance of about 15 percent to other hot gas cleanup (HGCU) activities. Essentially, all of these projects are described in these conference proceedings.

Table 1. IGCC Product Goals by Year 2010

Capital Cost: $1,050 per kW to build	**NO_x Emissions:** 0.06 lb. per million Btu
Efficiency: Operating at 52 percent efficiency	**SO_2 Emissions:** 0.06 lb. per million Btu
Commercial-Scale Demonstrations: Six U.S. technologies	

Table 2. IGCC Market Goals

Market Area	By 2010	By 2030	By 2050
Added or Replaced Plants IGCC Share	1%	20%	30%
Aged Plants > 30 IGCC Repowered	0.5%	20%	80%
Nat. Gas CC Plants Conversions to IGCC	0%	10%	50%
Cumulative IGCC Capacity (Thousand Megawatts)	6	155	450

Table 3. R&D Budget - IGCC Related

Budget Category	FY93	FY94	FY95*	
AR&ET	5.3	3.7	2.9	~ $2 Million per Year is IGCC Related
AR&TD	3.6	2.5	2.7	
IGCC	19.5	27.2	28.2	

Dollars in Millions

* *Proposed to Congress*

Table 4. IGCC R&D Budget

	FY 93	FY 94	FY 95*
Power Systems Development Facility	6.8	10.2	12.9
Gasifier Product Improvement Facility	4.2	6.0	7.8
GE/METC PDUs	3.4	5.9	5.2
Other HGCU	5.1	5.1	2.3
IGCC Total	19.5	27.2	28.2

* *Proposed to Congress* *Dollars in Millions*

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3.1 IGCC System Studies

Lawrence K. Rath
George T. Lee
Patrick H. Le
Morgantown Energy Technology Center

OBJECTIVE

Systems studies are performed on both the currently available, but not fully demonstrated, integrated gasification combined-cycle (IGCC) technologies and the future technologies. The objective of these studies is to support and guide the Morgantown Energy Technology Center's (METC) Strategic Product Planning efforts. Through these efforts, the research, development and demonstration (RD&D) needs of various alternative gasification and power island components can be quantified and factored into the overall planning processes.

BACKGROUND

IGCC product plans have established the following RD&D goals:

- Net system efficiency of 45% by 2000 and 52% by 2010.
- Capital costs in 1990 dollars of $1,200/kilowatt (kW) in 2000 and $1,050/kW in 2010.
- Cost of electricity (COE) 80% of conventional pulverized coal (PC) plant with flue gas desulfurization in 2000; COE 75% of PC plant by 2010.
- Nitrogen oxide (NO_X) and oxides of sulfur emission values of 0.06 pound per million British thermal unit in 2000 and less than 0.06 by the year 2010.

Ideally a number of IGCC systems will be able to meet these goals in the noted time periods. Results of system studies conducted by METC are discussed in this paper relating to these goals.

IGCC STUDIES BASED ON CURRENT GAS TURBINE TECHNOLOGY

Two U.S. organizations are currently offering gas turbines that feature 2,300°F to 2,350°F turbine inlet temperatures. Each organization also has sufficient experience or data to guarantee performance on fuel gas supplied via coal gasification. This guarantee allows these "F-technology offerings" to be a basis for METC's current view of nominal 250-megawatt (MW) IGCC modules representing a spectrum of gasification technologies, as shown in Table 1. The predicted exhaust gas temperatures exiting the turbine of approximately 1,100°F would readily allow a heat recovery steam generator with 1,450 pounds force per square inch, absolute (psia), 1,000°F generation and 1,000°F reheat for the steam turbine portion of a combined cycle.

An IGCC based on a fluidized-bed gasifier would operate at 1,850 to 1,900°F and 400 psia with air supplied from the gas turbine and a booster compressor as the oxygen source. Limestone added to the coal inlet stream would calcine and provide in-bed sulfur capture of hydrogen sulfide as it is released from the coal. Carbon conversion in the gasifier is 96.5% with residual carbon present primarily in overhead fines. Fuel gas from the gasifier passes through

Table 1. Today's View

IGCC Efficiency Using F-Type Technology
1,450 P/1,000/1,000°F Steam Cycle

Gasifier Type	Fluidized Bed	2-Stage Entrained Flow	Fixed-Bed Slagging	Slurry Feed Entrained Flow
Oxidant	Air	Air	Oxygen (Partial Integrated ASU)	Oxygen (Partial Integrated ASU)
Gasifier C-Conv.	96.5%	98.7%	99.2%	98.9%
Gasifier Pressure	400 psia	325 psia	395 psia	615 psia
Type of Gas Cleanup	1,210°F ZnTi, HGCU, Fixed Bed	1,250°F ZnTi, HGCU, Fluid Bed	100°F Selexol, Claus/ Scot, CGCU	1,250°F ZnTi, HGCU, Moving Bed
Sulfur Recovery or Conversion	Atmospheric Sulfation (Disposal)	Sulfuric Acid	Elemental Sulfur	Sulfuric Acid
Net Power	275 MW	260 MW	248 MW	268 MW
Overall Efficiency, % of HHV	43.3%	43.9%	41.8%	42.8%
Cost of Electricity, mills/ kW, Constant $	55.6	53.9	64.4	58.5

cyclones and is cooled to 1,210°F, where it is filtered of all particulates and chlorine is removed. The fuel gas is then desulfurized to less than 20 parts per million by volume (ppmv) in a fixed bed of a regenerable zinc-based sorbent. The clean gas can then be directed to the combustors of the gas turbine. Sulfur dioxide (SO_2) generated in the regeneration process along with the calcium sulfide underflow from the gasifier is converted to calcium sulfate. Any residual carbon from the gasifier is burned to produce additional steam in an atmospheric sulfation unit. All residue from this unit is disposed by landfill.

The steam turbine contribution to the combined cycle is increased by the steam generated from the atmospheric sulfation unit. The overall net efficiency on an higher heating value (HHV) basis for this 275-MW net IGCC is 43.3%. The COE in constant 1992 dollars is 55.6 mills per kW/hr.

An alternative air-blown, gasification concept is a two-stage entrained flow unit, where the dried coal feed and some limestone is split 85/15 between a slagging bottom stage at 2,800 to 3,000°F (partial combustion gases flow upward) and the second stage, where steam is added to promote carbon conversion at 2,000°F and 325 psia. Fuel gas and fines carried over from the second stage are cooled to 1,250°F. Fines are separated and recycled to the bottom stage. With the higher operating temperatures, carbon conversion is predicted to be 98.7% A ceramic filter removes the last traces of fines prior to a chloride removal guard bed. A fluidized-bed desulfurization process reduces the hydrogen sulfide level to less than 50 ppmv, and sorbent regeneration produces an SO_2 stream that is converted into byproduct sulfuric acid.

Without the steam generated from sulfation in the previous IGCC system, the overall net power generation from this IGCC system is 260 MW. The higher carbon conversion of the gasifier contributes to a net efficiency on a HHV basis of 43.9%. COE in constant 1992 dollars is 53.9 mills per kW/hr.

Overall coal gasification efficiency is enhanced by counterflow of coal against the rising product gases generated in fixed-bed gasification of the oxygen-blown, slagging type. Partial integration of the air separation unit (ASU) with the gas turbine is utilized to enhance overall plant efficiency. A substantial portion of the coal sulfur is released in the form of coal tars in the uppermost region of the gasifier. To achieve overall sulfur capture in gasification of 99% as a common basis for all of the system studies discussed in this paper, the coal tars in the product gas had to be quenched to facilitate recycle to extinction in the slagging zone of the gasifier. The overall carbon conversion of the gasifier was 99.2%. With tars in the raw gas, no heat recovery of raw gas is considered feasible. Cold gas cleanup of the product gas at 100°F was utilized with a Selexol System, followed by elemental sulfur recovery using the Claus with a SCOT tail gas treatment.

The overall power production of this IGCC system was only 248 MW for two reasons: inability to utilize raw-gas heat recovery, and higher miscellaneous power usage of the partial ASU supplying oxygen and cold gas cleanup. As a result, the IGCC efficiency was 41.8% on a HHV basis, and COE was substantially higher at 64.4 mill per kW/hr than other cases studied.

The final IGCC case simulated with the current version of gas turbine technology is a slurry-feed, entrained-flow, slagging gasifier operated in excess of 2,400°F and 615 psia, followed by heat recovery/chloride removal and moving-bed, hot-gas cleanup at 1,250°F using zinc-based sorbents. The overall power requirements for oxygen supply to the gasifier are reduced via partial integration of the ASU with the gas turbine air compressor. Power is recovered in an expander on the fuel gas between the chloride guard and the moving-bed desulfurizer. Gasifier carbon conversion is 98.9%. The moving-bed desulfurization system produces an enriched SO_2 stream that can be integrated to a sulfuric acid plant. A final cyclone after the moving-bed system provides particulate removal before the combined cycle.

The steam generated from the raw-gas heat recovery adds substantially to the steam turbine portion of power generation and helps to compensate for the high oxygen plant power requirements. The result is a net power output of 268 MW and a net efficiency of 42.8% on an HHV basis. The resulting COE of 58.5 mills per kW/hr on a constant 1992 dollar basis reflects a 10% or more higher capital cost of this case over the first two cases.

ENHANCED IGCC EFFICIENCIES WITH ADVANCED TURBINE SYSTEMS

DOE/METC is currently managing an Advanced Turbine Systems (ATS) Program to develop a new generation of gas turbines that, on natural gas, are expected to achieve efficiencies of greater than 60% on a lower heating value (LHV) basis in a combined cycle. These gas turbines will likely incorporate improved cooling of the first stator airfoils in addition to rotor stage cooling enhancements. Closed cycle cooling is being considered to reduce parasitic air cooling requirements. For the IGCC performance simulations performed by METC, closed-loop steam cooling of the stator and nozzles other than the first is utilized to minimize total parasitic airflow. With fuel gas supplied from the gasifier, the gas turbine pressure ratio of 18:1 with a turbine inlet temperature of 2,600°F yielded an exhaust temperature of 1,215°F.

The higher exhaust temperature permitted selection of a 2,465-psig, 1,140°-F steam turbine inlet conditions with a reheat temperature of 1,110°F for the intermediate pressure section. European pulverized-coal plants under development now are utilizing similar steam temperatures at higher pressures. The gasifier heat recovery was also used to produce the high-pressure superheated steam; this is not currently being practiced in all worldwide IGCC demonstrations (most demos produce saturated stream in the gasifier heat recovery) and may require metallurgy developments over the next 10 years.

As shown in Table 2, the fluidized-bed gasifier system previously discussed, when adapted to the future ATS cycle, will produce a net power output of 441 MW at an efficiency of 51.2% on an HHV basis. The calculation of the simple cycle efficiency of the gas turbine on an LHV basis is 45.3%. The two-stage, entrained-flow slagging gasifier previously presented, but adapted to the advanced turbine systems IGCC configuration, yielded an efficiency of 52.2% HHV for a 423-MW plant. With a capital cost per MW that is 12% lower than current technology with hot gas cleanup and the higher operating efficiencies, the COE for this configuration in constant 1992 dollars is 14% lower. Therefore, a substantial benefit to IGCC will be obtained from the ATS Program.

The fixed-bed slagging gasifier with ATS cycle gave an efficiency of 48.1% HHV for a 378-MW IGCC plant.

IMPACTS OF IMPROVED GASIFICATION CONCEPTS

METC is exploring ways in which improved concepts for gasification can improve the overall COE for IGCC applications while still maintaining excellent environmental performance. One concept is the PYGAS concept of CRS Sirrine Engineers, Inc., which currently is the focus of a preliminary engineering design effort for testing in a Gasification Product Improvement Facility. As soon as the conceptual design phase of this project was completed, METC attempted to model the PYGAS reaction zones utilizing ASPEN. The most optimistic of the simulations is presented to illustrate the potential of the gasification reactor if all the combined processes work together synergistically.

The METC ASPEN simulation assumed a pyrolyzer exit temperature of 1,650°F at 600 psig and 86% capture of coal sulfur by the limestone feed simultaneously with the coal. Carbon conversion in the pyrolyzer was assumed to be 68% of incoming carbon. An upper combustion zone above the pyrolyzer elevates the products of pyrolysis to 2,300°F. The gases and char then flow downward in a packed column, and gasification occurs until the char reaches 1,500°F or until the char reaches a larger fixed-bed gasifier zone. The remaining carbon is consumed by the gasification reactions above the fixed-bed air/steam rotating grate. The products of gasification from both the upper and the lower bed exit the gasifier at 1,500°F. The coal

Table 2. Tomorrow's View

IGCC Efficiency Using ATS Technology
2465 P/1142/1100°F Steam Cycle

Gasifier Type	Fluidized Bed	2-Stage Entrained Flow	Fixed-Bed Slagging
Oxidant	Air	Air	Oxygen
Gasifier C-Conv.	96.5%	99.0%	99.2%
Gas Cleanup/ Sulfur Recovery	HGCU, Sulfation	HGCU, Sulfuric Acid	CGCU, Elemental Sulfur
Net Power	441 MW	423	378
Overall Efficiency, % of HHV	51.2%	52.2%	48.1%

sulfur picked up by the limestone in the pyrolyzer is assumed to remain as calcium sulfide as it passes through the ash grate region and exits the gasifier at 700°F. The reactor is constructed with metal internals that must be cooled to maintain structural strength. If the cooling of the internals of the gasifier can be substantially converted into steam for power generation, the net loss of reactor input heat can be kept to less than 2.5% of total coal heating value.

The exit gas from the gasifier passes through a cyclone at 1,500°F and is expanded down to 255 psia to generate power prior to the final desulfurization of the product gas. A fluidized-bed desulfurization system is used at 1,270°F to increase the overall sulfur capture to 99%, and regeneration of the sorbent produces SO_2 that is converted to sulfuric acid.

As shown in Table 3, the net power production of the PYGAS-based IGCC with current gas turbine technology is 278 MW and yields an efficiency of 45.1% on an HHV basis. The 1.0 to 1.5% increased efficiency of this best case PYGAS IGCC simulation does not translate into a lower COE, since the number of gasifier trains is doubled from those of other IGCC systems. The COE for this case is 61 mills per kW/hr based on capital costs that are 10 to 12% higher than the cases with the next highest efficiencies. This gasifier throughput per train may be less significant in repowering applications on the COE, where the repowering is of the type in which the exhaust from a smaller gas turbine (40 to 80 MW) is used to repower an existing coal-fired boiler and its associated steam turbine. In this way, 30% more capacity can be added to a nominal 100-MW boiler with an overall 20 to 25% efficiency improvement for minimum dollars per kW.

Another promising study case of future gasification technology shown in the table is a transport gasifier that operates at potentially 1,600°F with coal and limestone pulverized to less than 100 micrometers in size. The gasifier operates at substantial velocities with high recirculation of char and calcined limestone. The possibility of a single moderate temperature gasifier supplying a 420-MW IGCC plant is plausible, but two gasifiers were considered as

Table 3. Improving Gasification Concepts Impacts IGCC Efficiency

	With Current Technology		With ATS Technology		
	Fluid Bed	PyGas	Fluid Bed	Transport w/Ext. Desulf.	Transport w/o Ext. Desulf.
Oxidant	Air	Air	Air	Air	Air
Sulfur Capture, In Gasifier	86.5%	86.0%	86.5%	96.0%	96.0%
With Ext. Desulf.	99.0%	99.0%	99.0%	99.0%	-
Carbon Conversion	96.5%	98.5%	96.5%	98.2%	98.2%
Sulfur Recovery or Conversion	Atmospheric Sulfation	Atmospheric Sulfation	Atmospheric Sulfation	Pressurized Sulfation	Pressurized Sulfation
Overall Efficiency, % of HHV	43.3%	45.1%	51.2%	52.5%	52.5%
Cost of Electricity, mills/kW, Constant $	55.6	61.0	48.0	46.9	43.3

part of this analysis. Claims of 96.0% sulfur capture and 98.2% carbon conversion will be confirmed in testing at the Wilsonville Power Systems Development Facility. The overall IGCC concept as viewed by METC is shown in Figure 1 for the gasifier concept integrated with the gas turbine, and in Figure 2 for the heat-recovery steam generator/steam turbine integration. Fixed-bed desulfurization increases overall sulfur capture to 99% with regeneration gases recycled to the gasifier. Final sulfation and carbon burnout of the gasifier underflow material is performed in a pressurized sulfator, the exhaust gas of which provides some of the oxidant requirements for gasification.

With the ATS power module, this IGCC concept is projected to have an efficiency of 52.5% on an HHV basis. Equally important to the higher efficiency is a 47 mills per kW/hr COE for a system that has excellent environmental performance. Since the in-bed desulfurization performance is already 96% with a low calcium to sulfur ratio, tests at Wilsonville could prove that 97% plus sulfur capture is possible. This could eliminate the need for external desulfurization, lowering the capital cost and COE to $1,100/kW and COE to the 43 mills per kW/hr range on a constant dollar basis. Alternately, lower capital cost, external desulfurization systems can be explored in DOE's RD&D program to lower overall capital costs to the $1,050/kW goal.

CONCLUSIONS

The following conclusions can be made when one reviews METC's projected performance with current gas turbine combined cycles and the suite of gasifiers currently included in planned demonstrations in the U.S. DOE Clean Coal Technology Demonstration Program or undergoing demonstration elsewhere in the world.

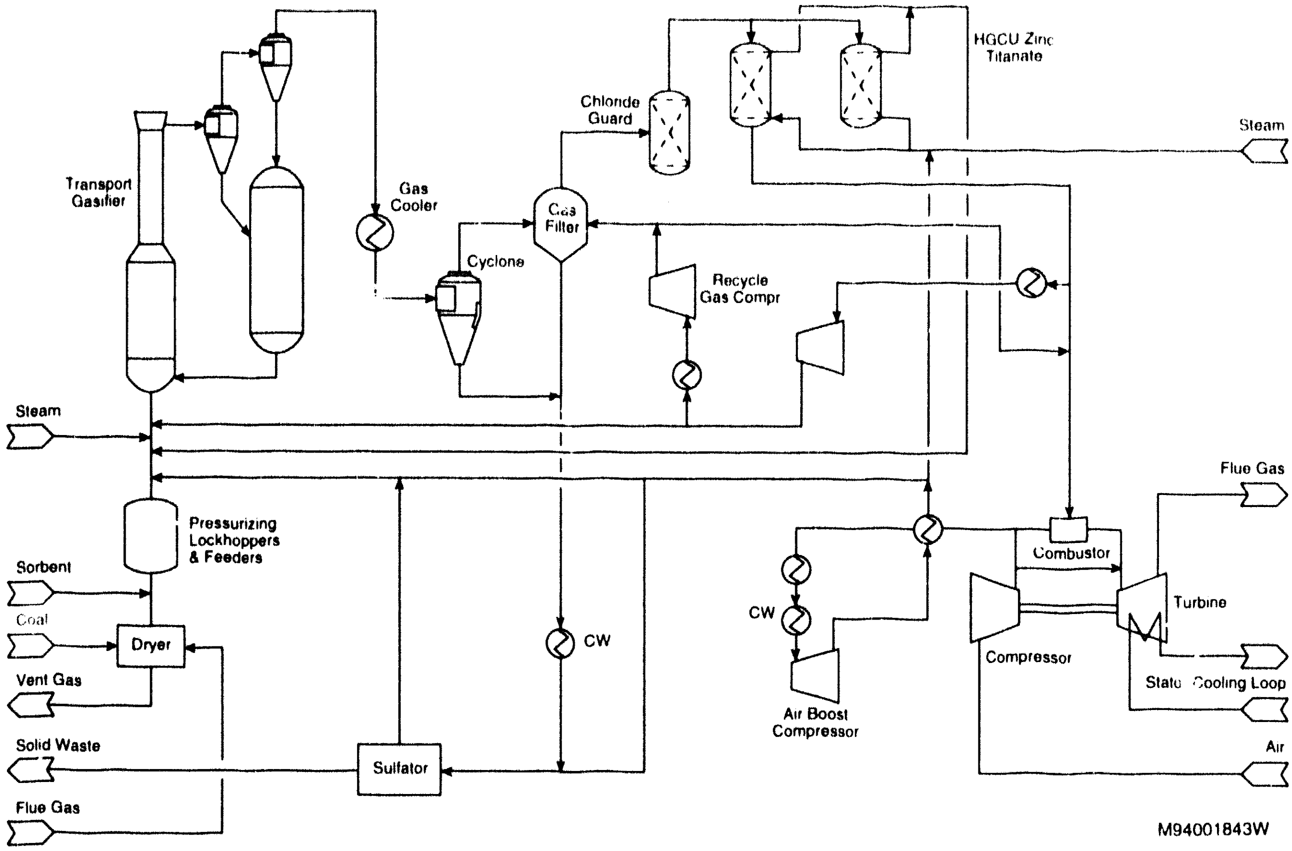

Figure 1. Transport Gasifier Advanced IGCC - Gasifier Island and Gas Turbine

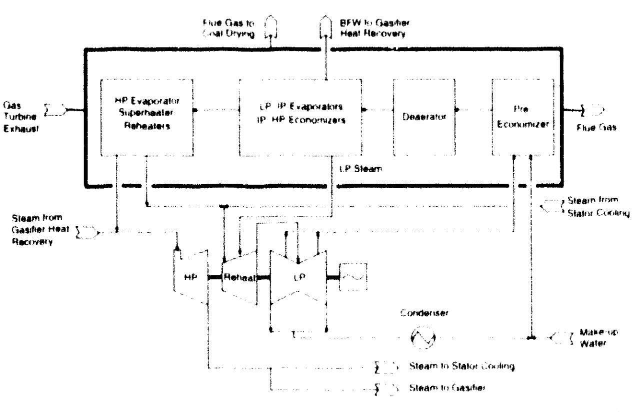

Figure 2. Transport Gasifier Advanced IGCC Heat Recovery and Steam Turbine

- All of today's gasifier type when coupled with hot gas cleanup technology should be able to achieve an efficiency of 43 plus/minus 1% on an HHV basis and give excellent environmental performance relative to a PC plant with low NO_x burners and scrubbers.
- When coupled to cold gas cleanup technology, the IGCC efficiency range of 41 plus/minus 1.5% (HHV basis) is predicted with environmental performance close to or equal to a natural gas combined cycle (without carbon dioxide externalities).

With the results of DOE's Clean Coal Technology Demonstration Program and demonstrations of utility-size ATS machinery likely in place shortly after the turn of the century, the following conclusions about the future of IGCC can be made.

- The goal of an IGCC with an efficiency of 52% on an HHV basis for the year 2010 appears achievable with initial demonstration projects of the initial high efficiency IGCC systems occurring around 2005.
- The 27% gain in efficiency over those IGCC systems undergoing demonstration today translates into 28% COE reductions.

Additional gains of 3.2 efficiency points over today's best IGCC system with cold gas cleanup (2.0 efficiency points over today's demonstration with hot gas cleanup) are plausible if the advanced gasification PYGAS process is proven capable of high pyrolysis yields at moderate temperatures. However, the COE for a grassroots IGCC application of this gasifier can only be reduced to those of alternate gasification concepts if capacity gains per unit gasifier volume are doubled over the current basis.

The transport gasifier concept integrated with an ATS cycle has the greatest potential to achieve simultaneously a 52% efficiency goal along with a 33% COE savings over the IGCC systems currently planned or undergoing demonstrations.

METC goals for the year 2000 and 2010 in the IGCC product area are demanding but clearly achievable with diligent research, focused engineering development, and prudent and cost effective demonstrations.

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3.2 Transport Reactor Development Status

CONTRACT INFORMATION

Cooperative Agreement	DE-FC21-MC25140
Contractor	Southern Company Services, Inc.
Subcontractor	The M.W.Kellogg Company 601 Jefferson Avenue P.O.Box 4557 Houston, Tx 77210
Contractor Project Director	Randall E. Rush
Subcontractor Project Manager	Martin O. Fankhanel
Subcontractor Development Manager	William M. Campbell
METC Project Manager	James R. Longanbach
Period of Performance	November 1990 to March 1996

OBJECTIVES

This project is part of METC's Power Systems Development Facility (PSDF) located at Wilsonville, Alabama. The prime contractor for the program is Southern Company Services, Inc. The M.W.Kellogg Company will supply the technology for the Advanced Gasifier module. This module includes Kellogg's Transport reactor technology for combustion and gasification of coal.

The primary objective of the Advanced Gasifier module is to produce vitiated gases for intermediate-term testing of Particulate Control Devices (PCDs). The Transport reactor potentially allows particle size distribution, solids loading, and particulate characteristics in the off-gas stream to be varied in a number of ways. Particulates in the hot gases from the Transport reactor will be removed in the PCDs. Two PCDs will be initially installed in the module; one a ceramic candle filter, the other a granular bed filter. After testing of the initial PCDs they will be removed and replaced with PCDs supplied by other vendors.

A secondary objective is to verify the performance of a Transport reactor for use in advanced Integrated Gasification Combined Cycle (IGCC), Integrated Gasification Fuel Cell (IG-FC), and Pressurized Combustion Combined Cycle (PCCC) power generation units.

This paper discusses the development of the Transport reactor design from bench-scale testing through pilot-scale testing to design of the Process Development Unit (PDU-scale) facility at Wilsonville.

BACKGROUND

In the PSDF, Kellogg's Transport reactor will produce either an oxidizing or reducing gas for parametric testing of the PCDs. The Transport reactor was selected as the gas generator due to its flexibility for producing particulate-containing test gases. The reactor operates at pressure in either the gasification or combustion mode over a wide range of temperatures and particle residence times. The feed coal to the reactor consists of fine particles similar to entrained reactor gasification systems while the reactor operates at temperatures characteristic of fluidized bed systems.

The Transport reactor concept is modelled on the Fluid Catalytic Cracking (FCC) process which has been used for about 50 years in petroleum refineries to upgrade heavy oils to transportation fuels. Kellogg built a one ton per day (TPD) Transport combustor at its Technology Development Center in Houston, Texas, and operated it on bituminous coal and petroleum coke under a wide variety of test conditions. Subsequently, a bench-scale Transport Reactor Test Unit (TRTU) was built to develop the kinetic data required for design of coal gasification units.

An intermediate-size Transport Reactor Development Unit (TRDU) was built at the University of North Dakota, Energy and Environmental Research Center (UND/EERC) in Grand Forks, ND, to verify the scale-up factors that were being used in the design of the Wilsonville facility. The UND/EERC unit is designed to process 2.4 TPD of coal in the gasification mode and 1.8 TPD in the combustion mode. To date, the TRDU has operated only on Wyodak coal.

PROJECT DESCRIPTION

The Wilsonville Transport Reactor

The Wilsonville Transport reactor is sized to process 38 TPD of coal in the gasification mode and 27 TPD in the combustion mode, delivering 1000 ACFM of particulate-laden gas to the PCD units over a temperature range of 1000-1800^{o}F at 300 psig. The design coal for the facility is Illinois No. 6 bituminous coal with a Powder River subbituminous coal as an alternate feed. Longview limestone, available locally, has been chosed as the sulfur sorbent.

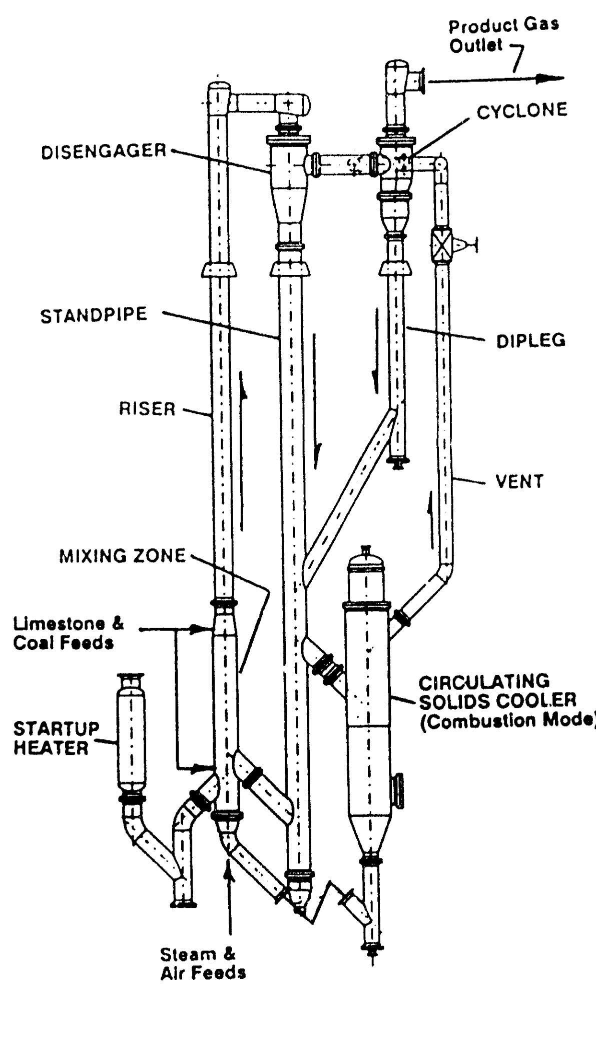

Figure 1.
Wilsonville Transport Reactor

In gasification mode, pulverized coal and limestone are fed into the top of the mixing zone of the reactor where they mix with a much larger quantity of hot circulating char. See Figure 1. The coal immediately devolatilizes and, in the presence of steam, the volatiles pyrolyze and the char gasifies in the Riser section of the reactor. The velocity in the Riser is about 35 feet per second (fps) providing 1-2 seconds of contact time for each pass of the solids through the system.

The product fuel gas passes through a disengager and a cyclone where the bulk of the solids are removed and become part of the circulating inventory of the system. The disengaged solids build up in the downcomer providing the hydraulic head to recirculate the solids through the reactor. Air injected into the bottom of the mixing zone substoichiometrically combusts a small portion of the char in the circulating solids providing the heat for the pyrolysis and gasification reactions.

Product fuel gas coolers are provided to accomodate whatever temperature is desired for the PCD being tested. The expected amount of particulate matter in the gas is about 4000 ppm and can be increased, if desired, by online spoiling in the cyclone.

In combustion mode, the coal is fed to the bottom of the mixing zone and the combustion air is staged to reduce the formation of NOX. Circulation of solids is substantially higher in combustion mode to control the temperature rise of the solids. Heat is removed from a slipstream of the circulating solids in an external bayonet-type heat exchanger. Circulating solids temperature is affected by controlling the amount of solids flowing through the heat exchanger.

The design of the Wilsonville Transport reactor is based upon data developed in bench-scale and pilot-scale facilities which are briefly described below.

The CFBC, TRTU and TRDU Reactors

In 1985 Kellogg built a 1-TPD Circulating Fluid Bed Combustor (CFBC) to verify the performance predicted by the model that had been developed during previous studies. The design of this atmospheric pressure reactor included a mixing zone with staged combustion, and a Riser designed to operate at velocities up to 60 fps. See Figure 2. The physical design is very similar to the design for the Wilsonville facility.

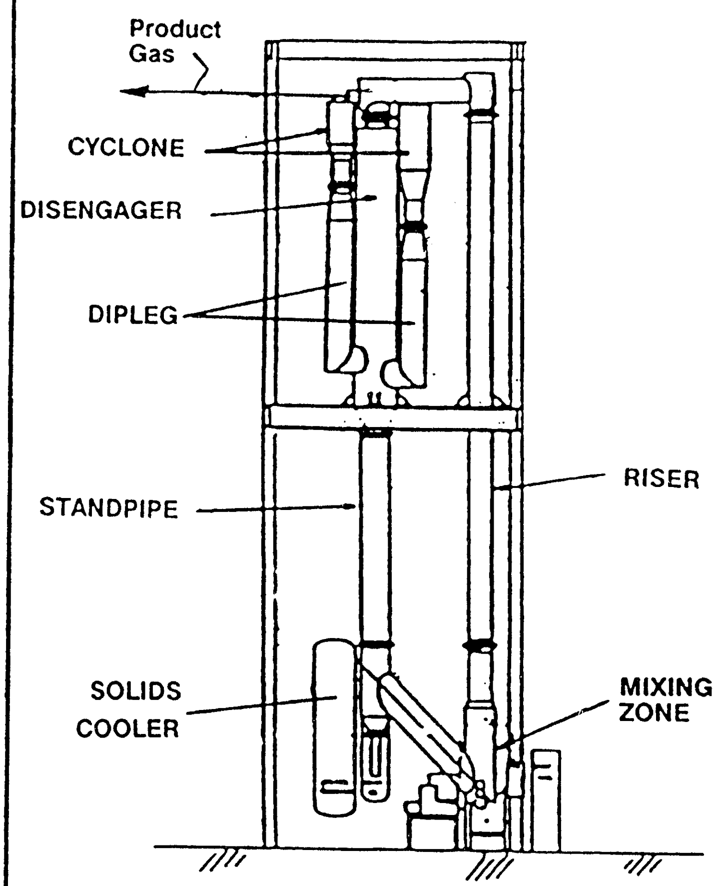

Figure 2.
Circulating Fluid Bed Combustor

In 1990 Kellogg built a bench-scale Transport Reactor Test Unit (TRTU) to verify the performance predicted by the Transport gasification model which had been developed. Gasification tests at small scale require a reactor system in which heat leak is essentially nil, so that actual commercial oxidant/coal ratios can be tested. The TRTU is a 0.6 inch diameter, 30 feet high reactor totally enclosed in a multi-section clam-shell heater. See Figure 3. This heater assures that there is no data bias caused by system heat leak.

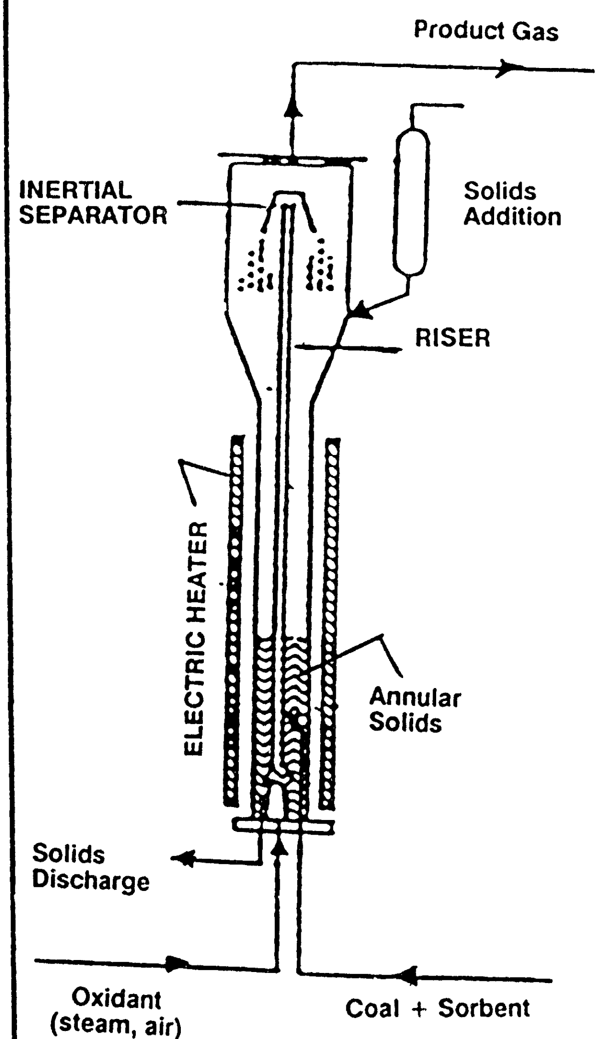

Figure 3.
Bench-Scale Transport Reactor

The TRTU processes up to 10 pounds per hour of coal feed and is capable of operation at high pressure in combustion, pyrolysis or gasification modes. For accurate modelling, reaction rates associated with the three stages of Transport gasification; i.e., substoichiometric combustion, pyrolysis and steam gasification, need to be separately measured.

In 1992 Kellogg designed a pilot-scale Transport Reactor Development Unit (TRDU) which was installed at UND/EERC. See Figure 4, overleaf. This reactor was designed to process 2.4 TPD of coal feed and special care was taken to assure that the reactor heat leak was minimized. This required addition of substantially greater refractory thicknesses than are required in a commercial unit. Although this extra refractory is needed to assure minimum heat leak and proper oxidant/coal ratios are achieved during testing, it does add substantially to the size of the reactor and the heat-up time whenever the unit is started.

An overview of the results of testing in the CFBC, TRTU and TRDU is presented next along with some comments on the applicability of the data to the Wilsonville reactor design.

RESULTS

The development of the Transport reactor concept which is incorporated in the Wilsonville PSDF has been a protracted process, influenced by the background and experience of many participants and by data produced in a number of test facilities. The application of this test data to the design of the Advanced Gasifier module is now discussed.

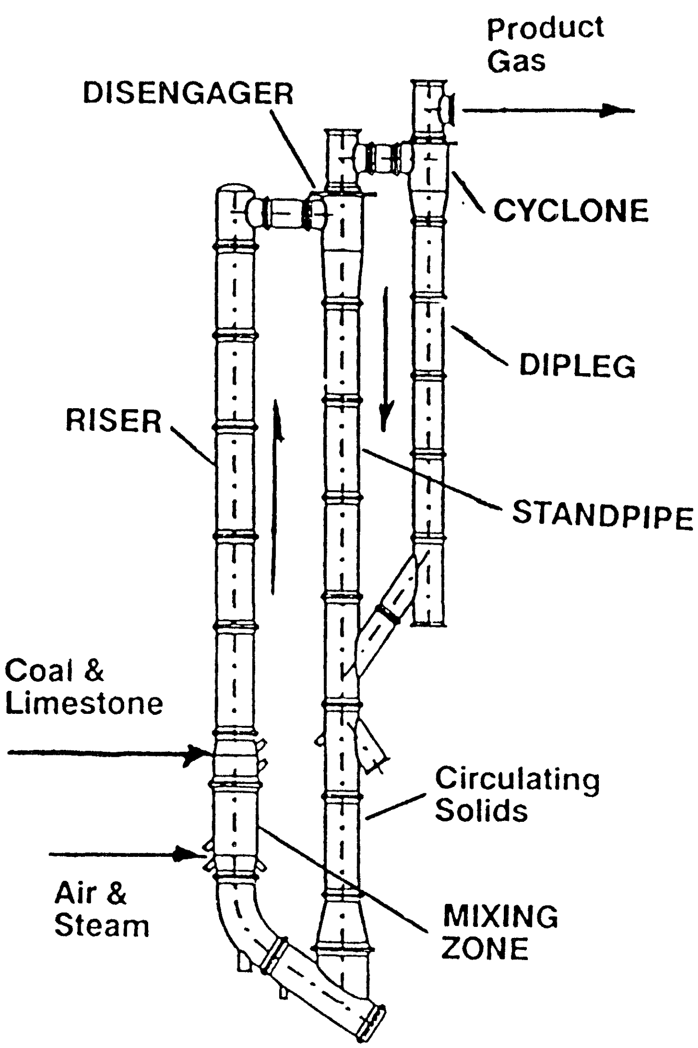

Figure 4.
Transport Reactor Development Unit

The Conceptual Design Models

The Transport combustion and gasification models were initially based on literature data available from a wide variety of reactor designs, none of which represented the Transport concept very closely. The prototype for the concept was the ubiquitous Fluid Catalytic Cracking (FCC) unit which is a combination of a Transport gasifier and a fluid bed combustor processing heavy oils. Reaction rates in fluid beds are substantially different from those in Transport reactors. Typically, the particle size in fluid beds is much larger and superficial gas velocities are lower. The oxidants and product gases are imperfectly mixed with the reacting solids in the emulsion phase in the bed.

In the Transport reactor the particles are much smaller and are totally surrounded by the gas phase. The combination of high surface area, high turbulence and lower gas diffusion resistances results in substantially higher reaction rates and requires a smaller reactor volume. The gas residence in these reactors is 1-2 seconds but the high solid recirculation rate increases the residence time of the reacting solids many fold.

Kellogg's models predict that in gasification the particle size and solid recirculation rate has a very substantial effect on carbon conversion and sulfur capture. Staging introduction of coal and oxidants was expected to affect both carbon conversion and sulfur removal. In combustion, the models predict that staging the oxidant addition affects NOX, CO and SO_2 emissions. Each of these predictions needs to be verified for a range of operating conditions and for several types of coal.

Testing in the Circulating Fluid Bed Combustor (CFBC)

Testing was carried out in the CFBC in 1986. Table 1 shows the range of variables in the test program and Table 2 indicates the range of results. Some 56 runs were carried out. It is apparent that the combustion reaction rate at about $1600^{\circ}F$ is more than adequate to complete carbon conversion, even with the relatively refractory petroleum coke. No uncontrolled reactor exotherms were experienced, indicating that it is possible to circulate adequate quantities of solids in a 40-50 feet tall reactor. No apparent difference was noted between the two coal particle sizes tested.

Table 1. Circulating Fluid Bed Combustor Design Basis	
Feed Rate	1.0 TPD
Temperature	1550-1650oF
Pressure	atmospheric
Velocity	20-60 Ft/sec
Contact Time	1-3 Seconds
Riser Dia.	6 inches
Rxr Height	64 feet

Table 2. Circulating Fluid Bed Combustor Test Results		
Feeds	West Kentucky #6 Petroleum Coke	
Limestone	Greer	
Riser Velocity	36-60 ft/sec	
Riser Temperature	Coal: Petcoke:	1550oF 1650oF
Carbon Conversion	Coal: Petcoke:	99.5 % 99.2 %
Calcium/Sulfur Ratio	1.3 - 1.6	
Sulfur Capture	Coal: Petcoke:	96 - 99% 93 - 97%
NOx Emission	0.04 - 0.07 #/MM Btu	

Sulfur capture was substantially higher than reported in the literature on fluid bed combustors. Sulfur capture is affected by Riser velocity and by solid recirculation rate, indicating that the sulfur/sorbent reaction rate is relatively slow and particle and pore surface dependent. Sorbent utilization, or the amount of excess sorbent available, did not seem to affect the sulfur leakage within the range tested. It is apparent that the Transport reactor is an effective combustion device.

Testing in the Transport Reactor Test Unit (TRTU)

As a result of the successful combustion tests Kellogg decided to proceed with the development of a Transport gasifier model. Subsequent economic studies also indicated that substantial capital cost savings could be realized compared to fluid bed gasifier designs if results of testing verified the model predictions.

Testing was carried out in the TRTU in 1991. Table 3 indicates the range of variables in the test program and Table 4 shows the test results. Western Kentucky #6 and Illinois #6 bituminous coals and Wyodak subbituminous coal were tested. Transport gasification is a staged reaction. Circulating char is first combusted substoichiometrically to supply reaction heat, then coal is introduced, devolatilizes, the volatiles pyrolyze and, finally, the residual char is steam gasified. This staging forces the air to react with char rather than volatiles, as is characteristic in fluid bed gasifiers. If staging is effective, then the amount of char to be gasified by the very slow reaction with steam is reduced substantially.

A typical staged test sequence in the TRTU is as follows: (1) coal is fed into the circulating solids (which are alumina or ash initially) in a steam/nitrogen atmosphere. The coal pyrolyzes and the volatiles crack, laying down carbon on the circulating solids. The solids are allowed to build up to 20-30 wt% carbon; (2) the coal feed is stopped and air is introduced into the reactor, simulating substoichiometric combustion of char; and (3) before the char is completely oxidized, the air is replaced by steam and gasification rates are measured.

Table 3.
TRTU - Bench-Scale Gasification
Test Variables

Coals	Wyodak, subbit. West Kentucky #6, bit. Illinois #6, bit.
Limestones	Greer, Longview
Riser Velocity	28 - 38 fps
Riser Temp.	1600 -1850°F *
Pressure	85 psig
Ca/S Ratio	1.5

* Temperature range depended upon actual coal tested

In this test sequence the rates of devolatilization/pyrolysis, substoichiometric combustion and steam gasification are each separately measured. By raising or lowering the reactor temperature (via the external clam shell heaters) during steps (2) and (3), the effect of temperature on reaction rates can be determined. Figure 5 presents an Arrhenius-type plot of carbon conversion rate against operating temperature for the coals examined.

Tests were also carried out in which all three reactions occur simultaneously as in a commercial reactor system. Coal was fed continuously and the char level in the recirculating solids was monitored to permit establishing operating conditions where the char level remained constant. In practice this is not easy to achieve in the TRTU and in a number of cases the carbon level increased or decreased during the testing.

The TRTU testing indicated that both bituminous and subbituminous coals could be effectively gasified without agglomerating in the reactor and that acceptable sulfur emission levels could be expected.

Table 4.
TRTU - Bench-Scale Gasification
Test Results

Riser Temp.	Subbit: Bit:	1600-1750°F 1600-1850°F
Carbon Conv.	Subbit: Bit:	95+ % 90+ %
Sulfur Capture	Subbit: Bit:	70 - 80% 70 - 95%

Referring to Arrhenius-type plot in Figure 5. it can be seen that in the operating range of interest, the rate of conversion for the subbituminous coal is 2 - 3 times higher than for the bituminous coal at the same temperature. Expressed another way, there is about 150°F lower operating temperature for the subbituminous coal equivalent gasification rate.

Testing in the Transport Reactor Development Unit (TRDU)

The Wilsonville project team proposed building a Transport reactor at a size somewhere between the TRTU bench scale and the Wilsonville plant size. It was determined that such a reactor could be readily inserted into the existing infrastructure at UND/EERC. After reviewing the facility at UND/EERC it was decided to build the 2.4 TPD unit previously described. The reactor was designed in multiple sections to facilitate installation into the existing high bay structure. The design basis for this unit is given in Table 5.

Initial shakedown of the TRDU was started in October 1993. Cold circulation of solids was established for about 70 hours while operators familiarized themselves with the unit and checked out instrumentation. The unit was initially heated with natural gas and then gradually switched over to coal feed.

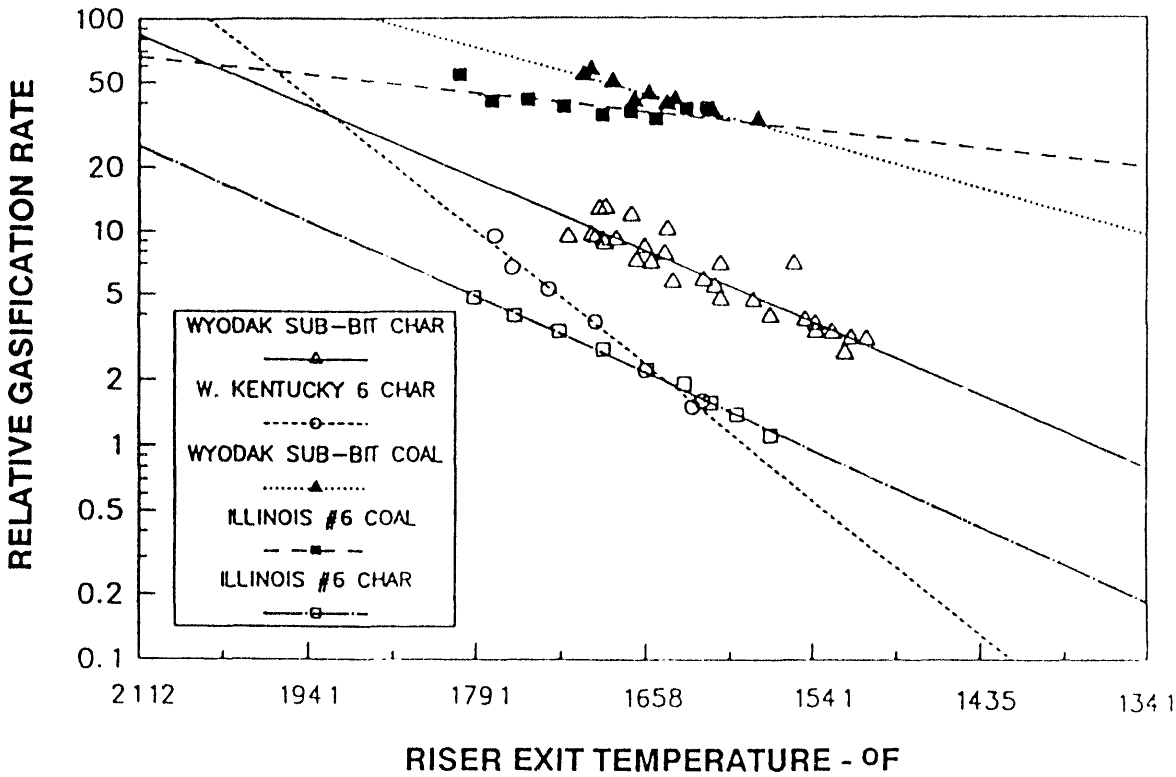

Figure 5.
Arrhenius-type Plot - Gasification Transients

Table 5.
TRDU - Pilot-Scale Gasification
Design Basis

Coal	Wyodak subbituminous
Limestone	Longview
Riser Velocity	28 - 30 fps
Pressure	120 psig
Ca/S Ratio	1.5

Table 6.
TRDU - Pilot-Scale Gasification
Test Results

Riser Temperature	1520 - 1565°F
Carbon Conversion	92 - 97%
Sulfur in Outlet Gas	100-300 ppmv
Product gas HHV*	83 - 104 Btu/Scf

* Adjusted to reflect corrections for heat leak, excess water in coal feed and miscellaneous purges.

There were some problems with the ash removal augers and solids were purged batchwise from the unit. Operation was not sufficiently stable and solids carryover to the gas recovery system forced shutdown of the unit before gasification was initiated.

Repairs to the unit were made and a second shakedown was started in early December. During this test campaign the TRDU operated for over 250 hours in hot circulation mode, for 46 hours in combustion mode, and for 34 hours in gasification mode during which two steady-state periods of about eight hours each were analyzed in detail. Selected steady state test data is presented in Table 6. The test successfully met pre-set conditions for capacity, operating pressure, carbon conversion and heating value of the product gas. Reactor heat losses were essentially as predicted in the design calculations.

Table 7.
Design Basis for Wilsonville Transport Reactor

	Gasification	Combustion
Coal Feed, TPD	38.0	19.3
Limestone, TPD	5.2	2.7
Mean Particle Size, microns	100	100
Riser Vel., fps	36	30
Pressure, psig	295	295
Riser Temp., ^{o}F	1770	1600

Application of the Test Data to the Wilsonville Design

The design bases for the Wilsonville Transport reactor in gasification and combustion modes are given in Table 7. Figure 1 is a sketch of the Wilsonville reactor. The disengager on the design is a cyclone with the gas inlet and outlet positions reversed to permit higher dust loadings in the product gas to the PCDs. Spoiling gas is available on the cyclone to permit varying the quantity of dust for the PCD testing.

There are a number of significant differences between Transport and fluid bed reactors that the development program described above was designed to address and verify.

Common to both Transport gasification and combustion is the need to circulate large quantities of solids to assure effective mixing of reactants and to dissipate the large amount of heat evolved within a small reactor volume. The Transport concept is based upon maintaining the temperature of the reactants below the point where ash melting is detrimental. This is done by avoiding a hot gas jet and by circulating large quantities of "dry" solids compared to the coal feed rate.

The ashes and chars circulated in the CFBC, the TRTU and the TRDU gave no indication that there was a problem in circulating these materials. There were no hot spots detected in operation and no indication of significant ash agglomeration during processing. TRTU testing indicated that high conversion of bituminous coals could be achieved at moderate operating temperature. Bituminous coal has not been tested in the TRDU yet.

Product gas desulfurization is expected to be very efficient in the Transport reactor because of the high sorbent surface area and continuous contact of the product gas with the sorbent until it leaves the reactor.

Testing in the CFBC and the TRTU confirmed high sulfur removal and calcium utilization. Sulfur emission with subbituminous coal in the TRDU gasification testing was low but the the Wyodak coal contains only 0.5 %S.

The full advantage of staged gasification has not been tested in the TRDU since the carbon conversion on Wyodak coal was very high and the carbon level in the circulating solids did not build up to the desired level to prove the concept. The advantage of staging will not be demonstrasted until bituminous coal is tested in the unit.

Although the TRDU was designed for pressurized combustion operation, the circulating solids cooler required to remove the exothermic heat of combustion was not initially installed. Coal combustion did take place during each startup of the TRDU in the reactor heat up cycle. There was no indication that ash agglomeration took place during this operation. The TRDU operates at only 120 psig pressure and requires use of enriched air to simulate the effect of higher pressure and prove that excessive temperature exotherms do not occur. Enriched air tests are planned but have not yet been carried out.

There was no indication of refractory damage during the CFBC testing at KTDC. During the two short test campaigns carried out at UND/EERC there was no indication of excessive refractory wear in any section of the reactor.

Kellogg is confident that the design of the Wilsonville Transport reactor will meet the design criteria established for the facility. Sufficient flexibility has been built into the unit to permit operation of the reactor with a variety of coals and over a wide range of operating conditions.

ACKNOWLEDGEMENTS

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3.3 Gasification Product Improvement Facility Status

CONTRACT INFORMATION

Contract Number	DE-RP21-91MC28202
Contractor	CRS Sirrine Engineers, Inc. 1041 East Butler Road P. O. Box 5456 Greenville, South Carolina 29606-5456 (803) 676-5082
Contractor Project Managers	R. Don Carson, CRS Sirrine Engineers, Inc. Vijay B. Dixit, Riley Stoker Corporation
Principal Investigators	Richard S. Sadowski, CRS Sirrine Engineers, Inc. William H. Skinner, CRS Sirrine Engineers, Inc. Robert A. Lisauskas, Riley Stoker Corporation Stephen A. Johnson, PSI PowerServ
METC Project Manager	Richard A. Johnson
Period of Performance	October 1, 1992 to March 31, 1996
Schedule and Milestones	**FY94 Program Schedule**

	S	O	N	D	J	F	M	A	M	J	J	A	S
Conceptual Design	—	—	—	—	—	—	—	—	—	—			
Bench-Scale Testing											—	—	—
Detailed Design											—	—	—
Construction (1995)													

OBJECTIVE

The objective of the Gasification Product Improvement Facility (GPIF) project is to provide a test site to support early commercialization of the Integrated Gasification Combined Cycle (IGCC) technology. The design of this facility will be based on PyGas™, a patented air blown fixed bed gasification process. The GPIF will be capable of processing run of mine high swelling coals that comprise 87% of all Eastern U.S. coals. A team consisting of CRS Sirrine Engineers, Inc., Riley Stoker Corporation and PSI PowerServ has been formed to execute the program.

BACKGROUND INFORMATION

Success of any technology hinges on its cost competitiveness in the market place. The GPIF project is expected to deliver a gasifier design that will satisfy the criteria for good process performance and cost effectiveness. For utility applications, IGCC offers the potential benefits of achieving higher efficiencies than those possible in conventional coal-fired systems. IGCC systems are also capable of meeting the stringent environmental regulations which will be promulgated in the early part of the next century.

The PyGas™ process was conceived to handle high swelling coals, crack tars, and reduce ammonia and trace metal emissions. The GPIF program will generate useful scale up data.

Initially, the PyGas™-IGCC systems will be offered as modular units for the repowering markets which will reduce the financial burden on utilities in comparison to large plants. In addition, modular designs will also reduce the plant construction schedules.

PyGas™ Process

Sticky coal agglomerates can form during the heating process in a fixed bed gasifier using highly swelling coals. The PyGas™ process deals with this situation by carrying out the devolatilization by rapid heating and gasification at two separate locations in a single vessel.

Figure 1 schematically describes different steps in the PyGas™ process. Coal is pneumatically injected into the pyrolyzer section of the gasifier vessel. Steam can also be added to the pyrolyzer bottom if needed. The temperature in the pyrolyzer is maintained between 1500-1800°F. The intent is to decake the coal and maximize devolatilization in this region with some tar cracking.

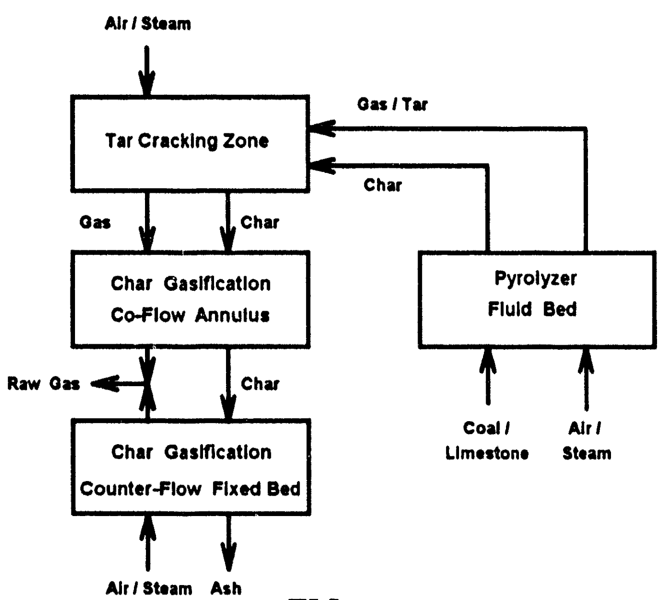

Figure 1. PyGas™ Process Schematic

The remaining tars are cracked in the tar cracking zone down stream of the pyrolyzer. The gases and char then move down a co-flow annular section and to the top of the fixed bed where the final gasification of char takes place.

The combined gasification products from the fixed bed and the co-flow region exit the gasifier at approximately 1150°F and enter a cyclone for removal of particulates. The clean gases go through pressure reduction and enter the combustion chamber of a Heat Recovery Steam Generator (HRSG) to produce steam for the process.

In a fully implemented IGCC system, the gas generated will be combusted in a combustion turbine to generate power and the HRSG will be located down stream of the combustion turbine.

The Fort Martin Project Site

Selection process of a site for the GPIF project was based on the following criteria:

- An existing utility site to reduce permitting requirements
- A utility with interest in the IGCC technology
- Close vicinity to Morgantown Energy Technology Center (METC) to reduce operating costs
- Infrastructure for steam and other utility tie-ins with the GPIF

Near perfect conditions exist at Monongahela Power's Ft. Martin (subsidiary of Allegheny Power System) project site. This 1100 MW_e pulverized coal-fired electric utility facility is providing several key utility interfaces which would otherwise become added project costs.

The following utilities have been combined with the main site to minimize both the capital and operating costs:

- High and medium voltage power interconnects
- 600± psig backup steam for startup
- No. 2 oil interconnect for preheat

- Coal dryer and coal gas combustion sustaining flame use
- Cooling water
- Wastewater treatment
- Potable water supply
- Flue gas breeching tie to the existing electrostatic precipitator
- Coal sourcing
- Permitted ash disposal site
- Electricity production from the steam byproduct

The integration of the PyGas™ process at Fort Martin has alleviated several process and environmentally related concerns, which has led to an approval of the required National Environmental Protection Act (NEPA) permit.

PROJECT DESCRIPTION

Team

The project team consists of CRS Sirrine Engineers, Inc., Riley Stoker Corp. and PSI PowerServ.

This partnering arrangement has added significant advanced gasifier and control system technology engineering, design, fabrication, and field construction expertise as well as an in-place marketing capability to commercialize PyGas™.

The Multi Phase Project

The GPIF project will be executed in two phases. Phase I consists of design and construction of a fixed bed gasifier based on the PyGas™ process. The plant will operate at 600 psi and will be capable of processing 150 tons/day of high swelling Eastern coals. During Phase I, Cooperative Research And Development Agreement (CRADA) work will be performed to support the gasifier design. Another CRADA related to the testing on the GPIF plant will be executed at the conclusion of Phase I.

The Phase I work will address process and coal based issues associated with fixed bed gasification. These include the handling of high swelling coals, pressure scaleup and system integration.

Phase II consists of the design, construction and operation of a hot gas cleanup unit integrated with the gasifier. Provisions for the major peripheral equipment such as storage, piping, material handling, electricals, interconnects, control room, building, and foundations will be made in the Phase I - General Arrangement.

GPIF Schematic

The following major sub-systems comprise the GPIF as shown in Figure 2:

- Air Compressor
- Day Silo/Coal Dryer/Crusher
- Coal Pressure Lock
- PyGas™ Coal Gasifier
- Hot Gas Cyclone
- Pressure Reducing Station
- Emergency Flare Stack
- Fixed Heat Recovery Steam Generator (HRSG)
- Ash Depressurization Lock
- Wet Sulfation Tank/Pumps/Vacuum Filter
- Enclosed Ash Temporary Storage Slab
- Tarpaulin Covered Test Coal Pile Slab
- Limestone Storage Silo
- Administration Buildings/Facilities

RESULTS

Conceptual Design

The "Conceptual Design" task, which was the major effort in the past year, can be broken into what we term process and mechanical areas.

Process Design

The major focus of the conceptual design effort was to develop a thorough understanding of the processes occurring in different parts of the gasifier. To examine these parts independently, the gasifier was divided into four major sections as shown previously. This allowed us to study how individual parameters operate within these blocks to influence the overall performance.

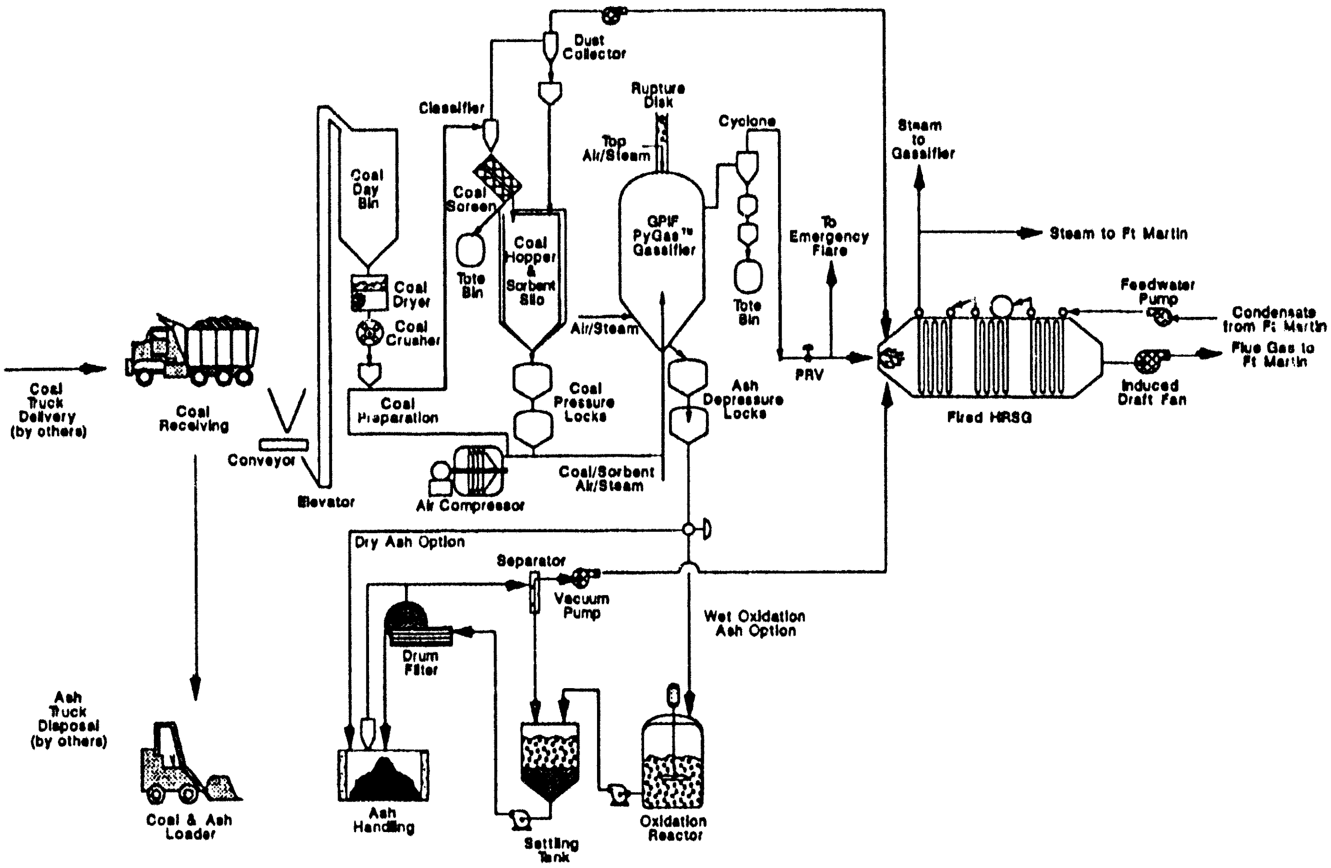

Figure 2. GPIF System Schematic

The sections down stream of the pyrolyzer are strongly influenced by the exit conditions of the pyrolyzer. Therefore, during the conceptual design stage considerable effort was spent on analyzing the pyrolyzer design. A wide range of process and mechanical parameters were selected to predict fluid dynamics in the pyrolyzer. Pressure, particle sizing, local/superficial velocities, fuel injection nozzle design, air distribution were among the variables studied.

The design approach employed for the gasifier also focused on building sufficient mechanical flexibility to carry out development work in support of current and future IGCC systems. The gasifier is equipped with a reversing/rotating type grate. Also, the pyrolyzer bottom was arranged outside of the gasifier vessel for ease of accessibility.

Heat and mass balance calculations were performed for the design case in which all the conversion outside of the pyrolyzer was carried out in the fixed bed gasifier. Figure 3 shows the major flows for this case. The coal analysis used for this design is shown in Table 1.

Table 1. COAL ANALYSIS: FORT MARTIN STATION

Ultimate Analysis	Wt%	Proximate Analysis	Wt%
Carbon	68.7	VR Matter	30.0
Hydrogen	4.6	Fixed Carbon	52.0
Nitrogen	1.2	Moisture	3.0
Oxygen	4.7	Ash	15.0
Sulfur	2.8		100.0
Ash	15.0		
Moisture	3.0		
	100.0		
HHV (Btu/lb) 12,500			

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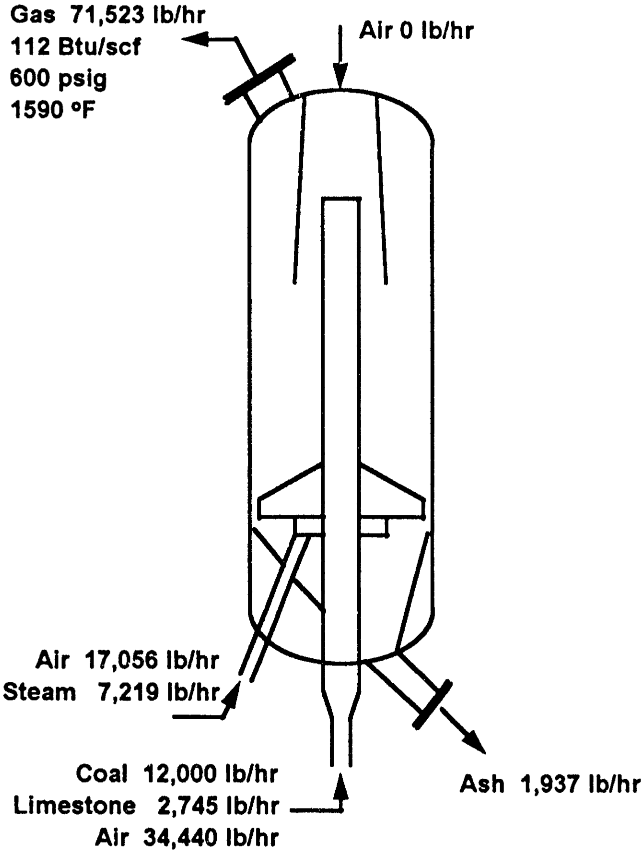

Figure 3. PyGas™ Gasifier Process Flows

It is important that the devolatilized coal particles be well dispersed in the pyrolyzer to avoid agglomeration due to the caking characteristics of the coal. Maintaining a good jet penetration length in the bed facilitates this process. Using jet penetration correlations that incorporate pressure effects, jet lengths were estimated for the 600 psi and 200 psi operations. To avoid any stagnation of solids as they move down the walls of the pyrolyzer, fluidizing air was included on the conical sections of the pyrolyzer. Earlier gasifier designs have employed such an arrangement to improve the down flow of solids.

The amount of fines leaving the pyrolyzer and how it would impact the total throughput was an issue that received tremendous attention during the conceptual design task. Another critical issue related to the estimated superficial gas velocities at different locations, especially in the fixed bed and the outer annulus of the gasifier. It is very important that the particle size in the bed should be coarse enough to maintain a fixed bed. Also, if considerable amount of carbon is elutriated from the gasifier due to high velocities in the outer annulus, recycling of the fines to improve efficiency would be necessary. Different ideas for internal and external recycling of fines were considered during the conceptual design. A strong focus on these issues will be maintained during the final design phase.

Mechanical Design

The conceptual gasifier arrangement is shown in Figure 4. The pressure vessel has flanged construction which will permit mechanical modifications to different parts of the gasifier without affecting other parts. It is equipped with a reversing/ rotating type grate with provision for breaking large agglomerates. It also has a water cooled ledge at the bottom that restricts the uncontrolled flow of fine ash from the gasifier. The outer jacket is cooled with an evaporative circuit. The pyrolyzer has membrane wall construction cooled with an economizer circuit. Because of reducing conditions in the pyrolyzer, its walls are lined with refractory to protect them against corrosion and abrasion.

The pneumatically conveyed solids are injected at the bottom of the pyrolyzer. The fuel nozzle is designed with an annular space around it to provide additional air to meet the process needs of the pyrolyzer. The same annular space will be used for draining ash from the pyrolyzer on an intermittent basis. The pyrolyzer bottom is arranged outside of the main gasifier vessel to provide additional access. The conical section has fluidizing air streams at three levels to help avoid any stagnation of solids at the bottom of the pyrolyzer. To maintain proper fluidization and jet penetration in the pyrolyzer at 600 and 200 psi, the two operating pressures for the gasifier, separate sets of removable nozzles have been designed.

Preliminary stress analysis was performed to start work on selecting material thickness for the inner and outer walls of the water jacket and the flanges.

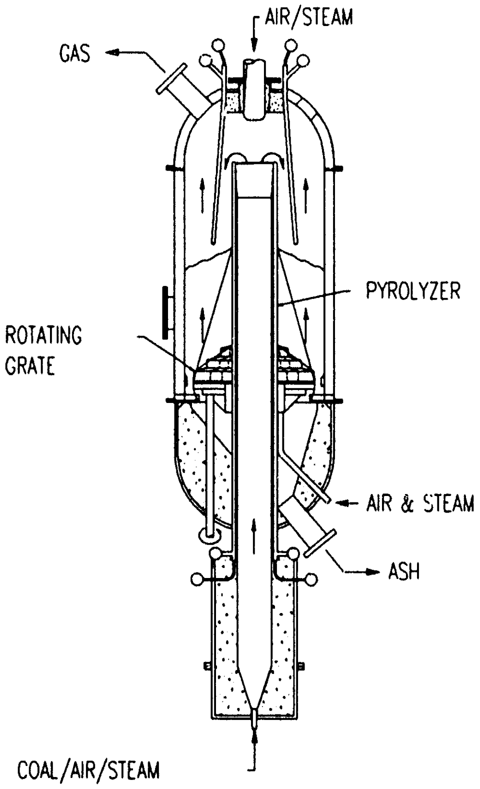

Figure 4. PyGasTM Gasifier Arrangement

Work was also initiated on detailing the control philosophy for operating the plant and instrumentation needs for monitoring temperatures and pressures at strategic locations. More work is ongoing in that area.

In the GPIF the low BTU gas will be combusted in a Heat Recovery Steam Generator (HRSG) to produce steam using a multi nozzle burner. The performance of the HRSG is presented in Table 2.

Other Results

An important milestone was reached with the formal NEPA approval for the project by the government. Without this we could not perform any site specific plant design work. Preliminary site work activities were also initiated. Among them was soil testing for plant foundations and other site construction.

Table 2. GPIF HRSG PREDICTED PERFORMANCE

Coal Gas Fuel:	112 BTU/dscf
Supplemental Fuel:	No. 2 Oil
Steam Generation (lb/hr)	96,473
Temp. of water ent. econ., °F	227
Water press. drop thru econ., psi	20
Temp. of air entering FD fan, °F	80
Steam temp. at SH outlet, °F	700
Steam press. at SH outlet, psig	900
Steam press. drop thru SH, psi	30
Boiler drum press., psig	730

FUTURE WORK

GPIF Tasks

The next step in the project is to proceed to the final design phase for the GPIF. Data available on other similar systems will be evaluated to refine the process issues related to the PyGas design. The CRSS/Riley team will also participate in a number of CRADA activities at METC to generate information to understand fluidization characteristics and pressure scaling issues facing the PyGas technology.

Immediate attention will be given to the pressure vessel design along with the control philosophy. This will require a thorough examination of all the process issues related to the technology.

Work on the design for the balance of plant and on the preparation of specifications for the auxiliary systems will be started. This will proceed along with the site work.

Operating CRADA

An operating CRADA will be executed to generate data to optimize process conditions and to provide scale up data for the commercialization of the PyGas™ technology.

Commercialization

A commercialization plan was also conceived during the conceptual design phase to identify markets that would initially benefit from this technology. The CRSS/Riley strategy calls for taking a step approach, starting with the repowering markets that are expected to open up in late nineties. This would be followed by greenfield installations in the first decade of the next century. Initially, in the repowering area, partial repowering options will be considered where existing utility site infrastructure and major power generating equipment will be used to enhance the efficiency and generation capacity at the site. The technical challenge forcing this approach will be the successful integration of new and existing equipment based on economics, efficiency, reliability and emission criteria. Hot windbox, partial fuel substitution, feed water heating were among the repowering options considered.

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Session 4

Advanced PFBC Systems

4.1 PFBC System Studies

Michael E. Reed
Morgantown Energy Technology Center

ABSTRACT

The U.S. Department of Energy (DOE) has been involved in research, development and demonstration (RD&D) of pressurized fluidized-bed combustion (PFBC) systems since the 1970's. PFBC's success in the Clean Coal Program is the start of the demonstration phase of PFBC's life cycle. Because the DOE's emphasis has shifted to the commercialization of systems, the focus of PFBC system studies at the Morgantown Energy Technology Center (METC) has changed from the evaluation of new systems to the improvement of present commercial concepts.

Thermal efficiency is a key factor in the commercialization of power generation systems. Studies are being conducted to assess the impact of the Advanced Turbine Systems (ATS) Program and the use of advanced bottoming cycles in second-generation PFBC systems. Preliminary results show that systems using these advanced technologies will have efficiencies of 2-7 percent (%) higher than the baseline efficiency. The baseline of 46.5% higher heating value (HHV) is based on a Foster Wheeler system using a Westinghouse 501F gas turbine and a conventional 2,400-pound steam cycle.

Environmental performance is another key factor in defining the commercial potential of a system. Quantitative assessments are limited to the quality of data available on a system. Tools are being developed and used at METC that will perform quantitative studies on the environmental performance of a system taking into account the uncertainty associated with preliminary data. These studies will provide the guidance for targeted efforts to improve the environmental performance of PFBC systems. Specific studies addressing nitrous-oxide production, hazardous air pollutants (HAP's), co-firing of wastes, and very low sulfur emissions systems will be discussed.

Efforts are underway to develop operating philosophies for utility-sized systems. Dynamic models are under development to simulate systems and test control strategies. These efforts will also suggest changes to the system to enhance the operability of the system without detrimental effects to the rest of the system.

INTRODUCTION

METC's Process and Project Engineering Branch is responsible for performing systems analysis of the products under development by METC. A major portion of the systems studies are designed to support the METC Product Managers as they decide budget priorities and perform marketing functions in behalf of their specific system. These studies range from economic analysis of competing filter technologies to a technical assessment of selected nitrogen oxide (NO_X) control technologies. This paper gives a summary of the major PFBC systems studies performed during the past year and analysis that will be done during the next year. The topics covered are thermal efficiency, stochastic analysis of NO_X formation and control, dynamic modeling, HAP's, co-firing of wastes, systems with very low sulfur emissions, and future work.

THERMAL EFFICIENCY

Improvements to the thermal efficiency are an important area of study involving PFBC systems. A recent study addressed the effect of the ATS Program and the use of supercritical steam cycles in second-generation PFBC systems.

Baseline System

The baseline system used to test the effect of changing the gas turbine and the steam cycle is a Foster Wheeler second-generation PFBC system. A process diagram of the system is shown in Figure 1. Coal, steam, air, and limestone are fed using a dry, pneumatic system to a pressurized carbonizer. The carbonizer operates at a temperature of 1,700°F, and a portion of the coal is turned into a fuel gas. The limestone captures sulfur compounds that are evolved in this reducing environment. The solids left, after the fuel gas is produced, are sent to a pressurized, circulating, fluidized combustor. More air is added to create an oxidizing environment in the combustor, where the remaining combustible solids are burned. The limestone captures sulfur compounds that are created during the combustion process. The bed is operated at a temperature of 1,600°F. This temperature is maintained by generating steam in heat exchange tubes imbedded in a fluidized-bed heat exchanger. The non-combusted solids are withdrawn from the combustor as an ash and disposed. The ash has been shown to have beneficial uses as a roadbed filler, a strip mine reclamation material and other uses. This is an area of continuing research.

The fuel gas produced in the carbonizer and the flue gas from the combustor are combined in a topping combustor and burned. The outlet temperature of the topping combustor is 2,300°F. This is the inlet temperature of the Westinghouse 501F gas turbine. The gas turbine expander drives the compressor, providing the pressurized air for the combustor and carbonizer and a generator set producing electricity.

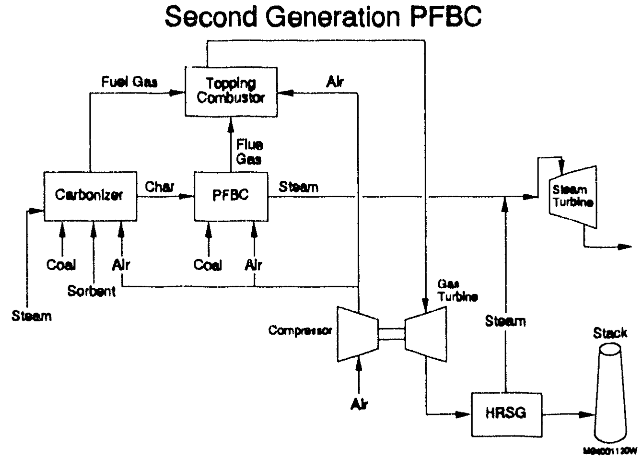

Figure 1. Second-Generation PFBC System

The gas exiting the gas turbine is fed to a heat recovery steam generator providing heat to the steam cycle. The steam cycle is a conventional 2,400 pounds force per square inch, absolute (psia)/1,000°F/1,000°F/2.5 millimeters of mercury single reheat steam cycle.

A summary of the performance of this system is in Table 1. The items to note in this table are the net power of 269.3 megawatt electrical (MWe) and the HHV efficiency of 46.5%.

ATS Gas Turbine

Starting in 1992, the Office of Fossil Energy and the Office of Energy Efficiency and Renewable Energy have been working with industry and academia in an 8-year program to develop the next generation of gas turbines. The turbines developed in this RD&D program are to have efficiencies such that a natural gas-fired combined cycle utility system will have a lower heating value efficiency greater than 60% (Webb 1994). In order to simulate an ATS turbine,

Table 1. Performance of Base System

Gas Turbine	139.4 MWe
Steam Turbine	138.3 MWe
Miscellaneous	-3.5 MWe
Auxilary	-5.0 MWe
Total Net Power	269.3 MWe
Net Efficiency (HHV)	46.5%

assumptions had to be made concerning the performance of the ATS-like turbine to change the natural gas-fired goals to coal-based performance. The assumption was made that advances in materials and air cooling schemes would allow a turbine inlet temperature of 2,450°F while using the same amount of cooling air as used in the present 501F machine. The efficiency of the expander and compressor sections are kept the same in the ATS-alike turbine as the present efficiencies in the 501F machine. These are conservative assumptions.

The ATS Program has a goal to produce inlet temperatures of 2,600°F+. However, these advances are expected to translate into coal-based systems only after development as a natural gas-fired system. As the ATS Program progresses, the gas turbine models will be updated and incorporated into future studies.

Supercritical Steam Cycles

During the 1950's and 1960's, development work was done in the U.S. on supercritical steam cycles. Because there was no economic need for efficient power and some technology problems with materials, the systems were shelved. However, steam system improvements have been shown to result in improved PFBC systems (Rubow et al. 1992). Supercritical steam cycles are an attractive way to boost the efficiency of coal-based power plants. The steam systems used in this study are based on two EPRI reports (EPRI CS-2555, EPRI CS-2223). Performance parameters are listed in Table 2. The cycle efficiencies listed in Table 2 are calculated using the Advanced System for Process Engineering (ASPEN™) System. The 3,500 psia and 4,500 psia dual reheat cycles are very efficient and capable of enhancing the electricity production of a second-generation PFBC system.

Efficiency Results

The results of different combinations of gas turbine and steam cycle are presented in Table 3. The top efficiency of 53.4% produced with an ATS turbine and a 4,500-psia steam cycle serves as a target for systems to reach for in the 21st century.

NO_X STOCHASTIC ANALYSIS

Because the systems under development at METC have not been fully commercialized, there are uncertainties associated with the performance and economic characteristics of the systems. In order to assess the technical and economic performance of the systems, this uncertainty must be accounted for in the analysis. It is difficult for a deterministic analysis to account for the uncertainty, so new tools must be developed. Stochastic analysis methods are the tools implemented at METC to analyze systems under uncertainty of technical and economic parameters (Dawes 1988). These tools were used to study the effect of uncertainty on NO_X production and control in a second-generation PFBC system (Reed 1994).

System Definition

The system studied is the same 46.5 efficient cycle used as the base case for the

Table 2. Supercritical Steam Cycle Performance

Throttle Pressure	2400 psi	3500 psi	4500 psi
Throttle Temperature	1000°F	1050°F	1100°F
Reheat 1 Temperature	1000°F	1050°F	1100°F
Reheat 2 Temperature	N/A	1050°F	1100°F
Cycle Efficiency (HHV)	38.67%	47.16%	48.54%

Table 3. Advanced Systems Power Breakout

GT	ST	GT Power (MWe)	ST Power (MWe)	Aux. (MWe)	Misc. (MWe)	Net Power (MWe)	Net Eff. (HHV)
W501F	2400	139.42	138.32	-3.48	-5.00	269.26	46.5%
ATS	2400	156.02	131.39	-3.35	-5.17	278.89	48.2%
W501F	3500	138.83	167.78	-4.84	-5.52	296.25	51.2%
W501F	4500	139.49	173.36	-5.89	-5.63	301.33	52.1%
ATS	3500	155.46	159.48	-4.63	-5.67	304.64	52.6%
ATS	4500	155.46	165.04	-5.64	-5.77	309.09	53.4%

ATS/supercritical steam study discussed above. The NO_X control technologies considered in this study were selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). The flow diagram of the system containing the NO_X control technologies is given as Figure 2.

SNCR is based upon the Exxon™ thermal de-NO_X™ process. Ammonia (NH_3) is injected into the freeboard or cyclone of the solids combustor where the NO_X is converted into nitrogen and water. SCR is based upon the same chemical principle as SNCR, but the entire flue gas stream is passed over a catalyst that enhances the conversion of the NH_3 + NO_X reaction at a lower temperature to yield better conversion of NO_X.

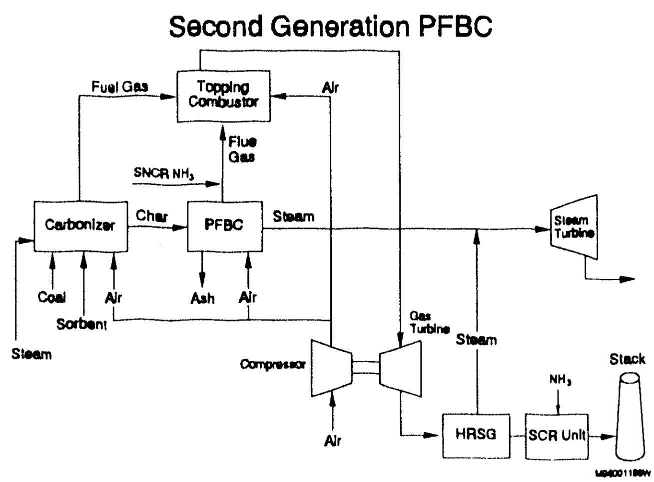

Figure 2. NO_X Controls Flow Diagram

Methodology

Stochastic analysis involves four steps. First, the parameters that will contain uncertainty must be chosen and the distributions modeling the uncertainty must be assigned. Second, a statistically sound method must be used to generate the samples from the distributions assigned in step 1. Third, the generated samples are used as input parameters to the model being studied and the output results are calculated. Finally, the output results are processed to obtain cumulative frequency diagrams and output coefficients.

In order to have a study that yields meaningful results, the parameters assigned uncertainty must be chosen with great care. Also, the distributions placed on the parameters must be carefully considered. The results of the simulation are totally dependent upon these choices. If any variable is added or deleted, or if any of the distributions are changed, the results under the old conditions do not apply. The calculations must start from the beginning in order to be relevant.

The parameters chosen and their distributions are given in Table 4. The first five parameters concern NO_X production within the PFBC system. The first of these parameters is the fraction of coal bound nitrogen converted to NH_3 in the carbonizer. This NH_3 can be turned into NO_X in the topping combustor. The second parameter is an error factor associated with a correlation used to predict the amount of NH_3 converted to NO_X in the topping combustor. This NO_X is called fuel-NO_X because the nitrogen starts in the coal. The third parameter is the ratio of NO to NO_2 formed in the PFBC. This has an effect on the chemistry of the PFBC and was of interest in the study. The fourth parameter is the amount of NO_X created in the PFBC. The fifth parameter of this group is the amount of thermal-NO_X created in the topping combustor. The next four parameters are related to the performance of the SNCR system. The sixth parameter determines the efficiency of NO_X reduction in the SNCR. The next three are related to operational characteristics of the SNCR system and are included to check the amount of NH_3 in the stack gas and the possible efficiency changes related to the SNCR system.

The final three parameters deal with the performance of the SCR system. The first parameter in this group is the efficiency of the SCR system. The other two are operational parameters of the SCR system and are included to check the amount of NH_3 in the stack gas and the possible efficiency changes related to the SCR system.

Latin Hypercube Sampling is the method used to generate random samples from the probability distributions selected. Details of this methodology can be found elsewhere (Iman 1984). The result of the selection process is a set of input vectors used as starting points by the PFBC system.

The PFBC power plant is modeled using the ASPEN™ computer software. This is the software that performs the energy and material balances of the PFBC system. The results of these calculations are further processed into forms used to assess the quantitative effect of uncertainty on the system.

The output results are used to create cumulative frequency diagrams such as Figure 3. The mean and confidence intervals calculated from these diagrams provides insight into the quantitative effect of uncertainty on the system.

The output results are also used to calculate regression coefficients or correlation coefficients, as shown in Figure 4. The coefficients give a

Table 4. Listing of Distributions of Uncertain Variables

Variable	Units	Low	Most Likely	High	Distribution
Coal N to NH_3 in Carbonizer	mole fraction	.1	.3184	.7684	Triangle
NH_3 to NO_X in Topping Combustor Noise	N/A	.9	1.0	1.1	Triangle
NO/NO_2 in PFBC	mole %	.37	.38	.44	Triangle
NO_X in PFBC	lb/MM BTU	.2	.6	1.2	Triangle
Thermal NO_X in Topping Combustor	ppm	24	25	30	Triangle
SNCR outlet NO_X	ppm	35	55	65	Triangle
NH_3 slip in SNCR	ppm	5	10	20	Triangle
NH_3 feed ratio in SNCR	mole %	.75	.85	1.0	Triangle
% carrier air for SNCR NH_3	%	1.0	1.2	2.0	Triangle
SCR NO_X % reduction	%	80	85	87	Triangle
NH_3 feed ratio in SCR	mole %	.71		.89	Uniform
SCR pressure drop	psia	8	8	12	Triangle

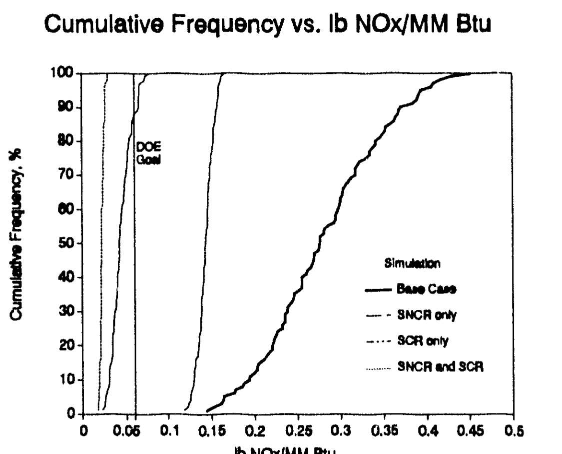

Figure 3. Cumulative Frequency Diagram for NO_X Emissions

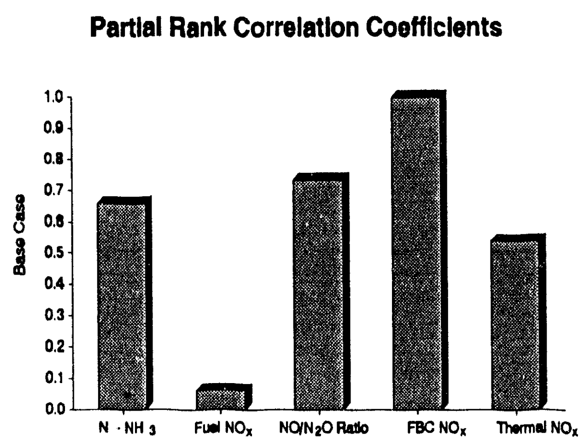

Figure 4. Partial Rank Correlation Coefficients for Base Case System

quantitative comparison of the importance of the input variables effect on the output of interest. Details on the calculation and use of these coefficients can be found elsewhere (Iman 1985).

NO_X Stochastic Study Results

The results of the study are presented in Figures 3 and 4, and in Table 5. Table 5 lists the NO_X emissions under different control schemes. Inspection of this table shows that SCR and SNCR have a significant effect on the total NO_X emissions of the plant.

Figure 3 shows the uncertainty associated with the calculations. The large range presented in the base case curve demonstrates that more work needs to be done to accurately quantify NO_X emissions from this system. Figure 4 shows the importance of the variables under study. These coefficients only apply to the base case configuration. A different set of coefficients must be calculated for each of the four cases because the parameter's given uncertainty changes for each of the different configurations.

NO_X Stochastic Study Conclusions

The largest absolute value in the set of coefficients corresponds to the most important parameter. In this case, NO_X production in the PFBC is the critical parameter. The conclusion from this information is that research should focus on controlling NO_X production in the PFBC first.

This study demonstrates the stochastic simulation methodology that has been implemented into the ASPEN™ simulator at METC. This tool is powerful and will provide input into the evaluation and budget process as METC moves into the 21st century. If research is focused on reducing NO_X production in the PFBC solids combustor, it is possible that the curves in Figure 3 will be shifted to the left and the DOE's goal can be met with only the use of SNCR. This type of advancement in NO_X control technology would make the addition of an extra downstream cleanup system, and the associated capital cost, unnecessary.

DYNAMIC MODELING

Historically, studies done at METC have concentrated on steady-state analysis. Because PFBC technologies are entering the commercialization phase, more emphasis is being placed on the operability of the systems. Operations studies require dynamic analysis.

Starting last summer, Gilbert/Commonwealth and Foster Wheeler have been working under a DOE/METC contract to develop a dynamic model of a second-generation PFBC system to develop an operations control strategy. The objectives of the study are as follows:

- Develop a working dynamic model of the Foster Wheeler second-generation PFBC process.
- Develop a control strategy for the fully integrated system.
- Develop operating strategies for turn-down from 100 to 90% and 90 to 50% power.
- Suggest changes to the system that will improve operating characteristics without an adverse impact on system efficiency.

At this time, the model has been developed using PC Trax™ software. The model has been tested under steady-state and some dynamic conditions. The final report for this task will be delivered in September 1994. This software and modeling knowledge will be used to evaluate other systems and eventually become a part of the technology evaluation process at METC.

HAP's STUDIES

Part of the Clean Air Act Amendments of 1990 is designed to address the emissions of

Table 5. Statistics for Cumulative Frequency Curves

Case	Mean (lb/MM BTU)	90% Low (lb/MM BTU)	90% High (lb/MM BTU)
Base Case	.28	.19	.37
SNCR	.14	.128	.157
SCR	.05	.03	.065
SNCR+SCR	.02	.019	.026

HAP's. Coal-based power plants have the potential to be regulated under this law. In order to assess the potential problems PFBC systems may have with HAP's emissions, a modeling study was performed.

This study was based upon the configuration and operating parameters of the Tidd PFBC plant operating in Brilliant, Ohio. A Lotus 1-2-3™ spreadsheet was developed using basic thermodynamic models. The purpose of the model was to partition HAP's into the flue gas and various solid waste streams leaving the system. A sensitivity study assessed the effects of temperature and pressure in different unit operations.

The sensitivity study shows the potential to reduce HAP's emissions by using lower operating temperatures in particulate cleanup devices such as barrier filters. As shown in Figure 5, the amount of HAP's emissions can be reduced by over 80% if the temperature of the barrier filter is lowered to 600°C (1,112°F). This model will be enhanced and validated as data is obtained from Tidd and other Clean Coal development projects.

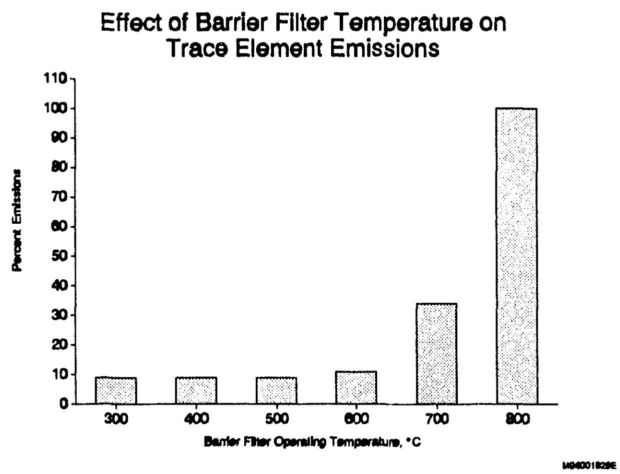

Figure 5. PRCCs for Base Case System

SCOPING STUDIES

Waste Co-Firing

A study assessed the effect of co-firing on the performance of PFBC systems (Bonk et al. 1994) to provide industry with an assessment of PFBC's ability to be as fuel flexible as atmospheric fluidized-bed technology. Results indicate that up to 20% waste by weight can be burned without dramatically changing the performance of first-generation PFBC systems. The additional cost of waste handling has been studied and was shown not to be prohibitive to the development of these systems.

Low Sulfur Emissions Study

The Clean Air Act Amendments of 1990 place strict requirements on sulfur emissions from future coal-based power plants. In response to the regulations, DOE sponsored a study to determine if second-generation PFBC systems could operate under very strict sulfur (99% capture) requirements (Horazak et al. 1993). Results indicate that a system could be configured to meet this requirement. However, using limestone to capture sulfur compounds in the carbonizer and PFBC as the only sulfur capture method is not sufficient to reach 99% capture. Additional sulfur clean-up methods, such as Zinc Titinate, must be used.

FUTURE ACTIVITIES

Optimization and Process Synthesis

Work is continuing that will add new capabilities to the ASPEN™ simulator at METC. A contract with Carnegie Mellon University will add optimization and process synthesis sections to the simulator software. By the end of fiscal year (FY) 94 these advanced programming techniques will be installed. Plans for FY 95 include testing and implementation of these enhancements on PFBC systems.

With the optimization capability, we plan to perform an economic optimization on the NO_X control study discussed above. SCR is expensive and SNCR is less costly. The optimization capability allows for an objective function to be used as the basis for optimizing the system. In this case, the cost of electricity will be the objective function. This technique could also be used to explore how the compressor air should be used. The amount of air heated in the solids combustor instead of by-passed to the topping combustor is one option that could be optimized for efficiency or cost.

The process synthesis techniques will be used to address the problem of NO_X control. Several techniques are available to reduce the amount of NO_X emitted from a PFBC system. The process synthesis capability will consider all of these techniques at the same time, and determine which techniques should be used and where they should be placed in the system. An optimization algorithm based on an objective function is used to determine the optimum system. This technique could be used for other studies where unit operations need to be moved within the system as part of the study.

Advanced Bottoming Cycles

Supercritical steam cycles are one way to improve the efficiency of bottoming cycles. METC is also active in analyzing other bottoming cycles to take advantage of the unique heat characteristics of the second-generation PFBC cycle. The two sources of heat for a bottoming cycle may make alternative cycles, such as the Kalina ammonia-water cycle, very attractive. This cycle and alternate configurations of steam cycles are being investigated.

Economic Modeling

Most of the analysis at METC is focused on the technical side of problems. As commercialization becomes a larger issue, the economics of the system become more important to decision makers. We are addressing this by developing an economic data base that will cost the advanced coal systems METC is commercializing. Then economic factors can be directly integrated into calculations with the ASPEN™

simulation system. The economics will be involved in optimization and synthesis criteria. Also economic uncertainty for advanced processes can be accounted for when calculating cost associated with these systems.

CONCLUSIONS

System studies of PFBC systems are summarized in this paper. These studies are being used for various reasons: to validate the economic and environmental benefits that this technology offers the country, to identify issues associated with the commercialization of PFBC technology, and to help the DOE and its industrial partners focus on those RD&D activities which produce the "biggest bang for the buck," an increasingly important goal in the present climate of increasingly tight Federal and corporate budgets.

This year, the conclusion that NO_X generation in the solids combustor is the most important factor in determining NO_X production in an uncontrolled system was of particular significance. The initial assessment of HAP's, showing a possible reduction in HAPs emissions if the barrier filter is operated below 600°C in a first-generation PFBC, was the first time this type of data was produced on the ability of PFBC systems to be a low HAP's emission technology. Work will continue to improve these analytical tools used in these system studies useful for both DOE and its industrial partners.

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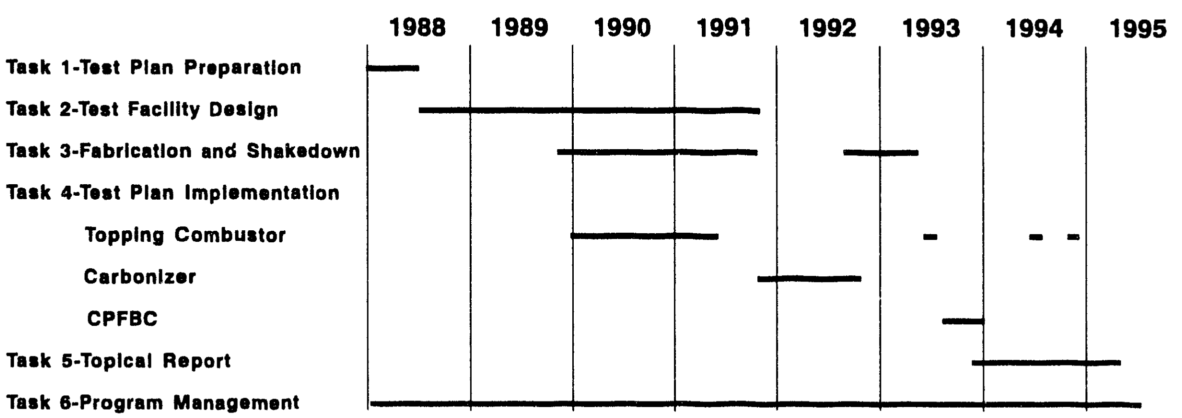
4.2

Second-Generation PFBC Systems Research and Development—Phase 2
Circulating PFBC Test Results

CONTRACT INFORMATION:

Contract Number:	DE-AC21-86MC21023
Contractor:	Foster Wheeler Development Corporation 12 Peach Tree Hill Road Livingston, NJ 07039 (201) 535-2328
Contractor Program/Project Manager:	Archie Robertson
Contractor Project Engineer:	James Van Hook
Principal Investigators:	Frank Burkhard, Giovanni Carli, Rich Conn, Paul Crooker, Dave Kulcsar, Chongqing Lu, Anthony Mack, Aydemir Nehrozoglu, Mark Torpey, Frank Zoldak
METC Project Manager:	Donald Bonk
Phase 2 Period of Performance:	April 1988 through May 1995

Schedule and Milestones:



OBJECTIVES—PHASE 2

Three major objectives of Phase 2 are: ■ Separately test key components [the carbonizer, circulating pressurized fluidized bed combustor (CPFBC), particle-capturing ceramic barrier filter, and topping combustor] of second-generation PFB combustion plants at laboratory scale to ascertain their performance characteristics ■ Revise the commercial plant performance and economic predictions where necessary ■ Prepare for a 1.2-MWe equivalent Phase 3 integrated subsystem test of the key components.

BACKGROUND INFORMATION

Second-generation pressurized fluidized bed (PFB) combustion plants that generate electricity offer utilities the potential for significantly increased efficiencies with reduced costs of electricity and lower emissions, while burning the Nation's abundant supply of high-sulfur coal. Figure 1 is a simplified process block diagram of a second-generation PFB combustion plant.

In the plant, coal is fed to a pressurized carbonizer that produces a low-Btu fuel gas and char. After passing through a cyclone and ceramic barrier filter to remove gas-entrained particulates, the fuel gas is burned in a topping combustor to produce the energy required to drive a gas turbine. The gas turbine drives a generator and a compressor that feeds air to the carbonizer, a CPFBC, and a fluidized bed heat exchanger (FBHE). The carbonizer char is burned in the CPFBC with high excess air. The vitiated air from the CPFBC supports combustion of the fuel gas in the topping combustor. Steam generated in a heat-recovery steam generator (HRSG) downstream of the gas turbine and in the FBHE associated with the CPFBC drives the steam turbine generator that furnishes the balance of electric power delivered by the plant.

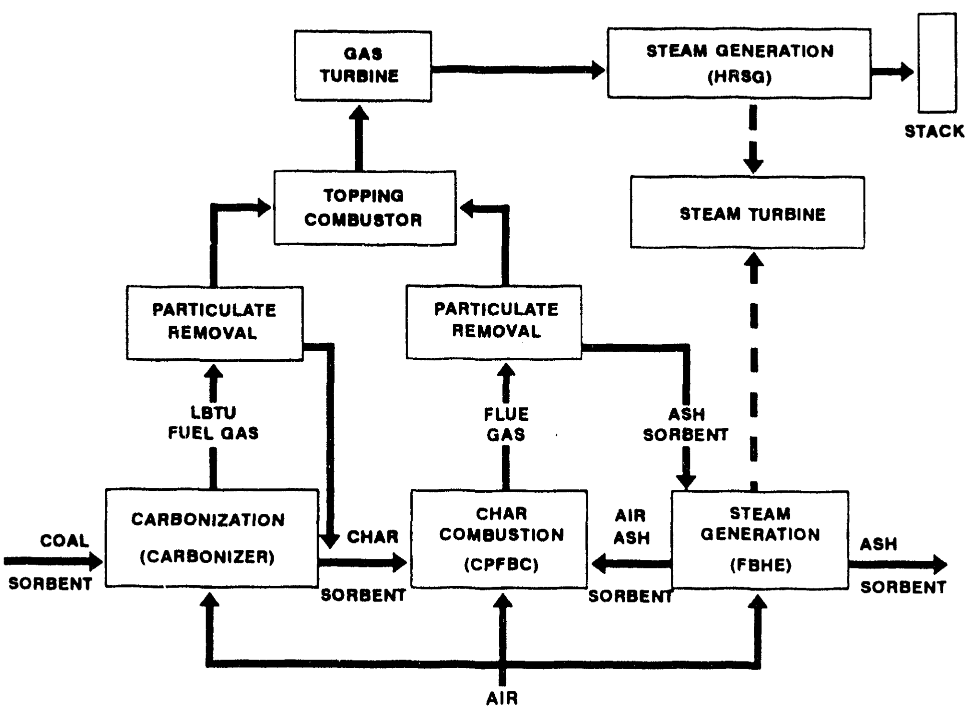


Figure 1. Simplified Process Block Diagram—Second-Generation PFB Combustion Plant

The low-Btu gas is produced in the carbonizer by pyrolysis/mild devolatilization of coal in a fluidized bed reactor. Because this unit operates at temperatures much lower than gasifiers currently under development, it also produces a char residue. Left untreated, the fuel gas will contain hydrogen sulfide and sulfur-containing tar/light oil vapors; therefore, lime-based sorbents are injected into the carbonizer to catalytically enhance tar cracking and to capture sulfur as calcium sulfide. Sulfur is captured in situ, and the raw fuel gas is fired hot. Thus the expensive, complex, fuel gas heat exchangers and chemical or sulfur-capturing bed cleanup systems that are part of the coal gasification combined-cycle plants now being developed are eliminated.

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

In the CPFBC, the burning char heats the high-excess-air flue gas to 1600°F; any surplus heat is transferred to the FBHE by the recirculation of solids (sorbent and coal fly ash) between the two units. Controlled recirculation is accomplished with cyclone separators and nonmechanical valves. The FBHE contains tube surfaces that cool the circulating solids. Because of the low fluidizing velocity in the FBHE ($\leq 1/2$ ft/s), the risk of tube erosion is virtually eliminated.

The exhaust gases leaving the carbonizer and the CPFBC contain sorbent and fly ash particles—both of which can erode and foul downstream equipment. A hot gas cleanup (HGCU) system, consisting of ceramic cross-flow filters preceded by cyclone separators, cleans these gases to <20 ppm solids loading before they enter the fuel gas topping combustor and the gas turbine and cause erosion and fouling. Ceramic candle filters, screenless granular-bed filters, and others, are candidate alternatives for the cross-flow filter should their performance and economics be found superior. All these devices are currently under development for first-generation PFB combustion cycles. They should also be applicable to the second-generation plant.

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

A team of companies led by Foster Wheeler Development Corporation (FWDC)—with ■ Foster Wheeler Energy Corporation and Foster Wheeler USA ■ Gilbert/Commonwealth, Inc. ■ Institute of Gas Technology ■ Westinghouse Power Generation Business Unit (PGBU) and Science & Technology Center (STC)—has embarked upon a DOE-funded three-phase program to develop the technology for this new type of plant. A conceptual design of a 3-percent-sulfur Pittsburgh

No. 8 coal-fired second-generation PFB plant with a conventional 2400 psig/1000°F/1000°F/ 2-1/2 in. Hg steam cycle was prepared, and its economics were determined [1]. In 1987 we estimated that, when operated with a 14-atm/ 1600°F carbonizer, the plant efficiency would be 44.9 percent (based on the higher heating value of the coal) and its cost of electricity would be 21.8 percent lower than that of a conventional pulverized coal-fired plant. Tests conducted in our pilot-scale carbonizer (described later) yielded performance superior to that estimated in 1987. As a result, we now expect a more energetic fuel gas and a plant efficiency of 46.2 percent with a 1600°F carbonizer [2].

PROJECT DESCRIPTION

The second-generation PFB combustion plant development effort is divided into three phases, the first of which has already been completed and documented in a series of reports available through the National Technical Information Service [3-4].

The first phase of the DOE program was aimed at plant conceptualization and optimization and identification of plant R&D needs. The second phase, involving laboratory-scale tests of the key plant components, is under way.

The R&D needs of this new type plant were presented in the Phase 1 Task 2 Report issued under this contract [3]; an integrated program plan for meeting these needs was presented in the Task 3 Report [4]. In accordance with that plan, the key components of this new plant are being tested separately in Phase 2 of this contract to ascertain their individual performance characteristics. A series of topping combustor tests has already been conducted at the University of Tennessee Space Institute (UTSI) under the direction of Westinghouse PGBU [5-7]. These tests were successful, proving the combustor concept.

CARBONIZER TEST PROGRAM

In November 1991 FWDC began operating a PFB pilot plant at its John Blizard Research Center in Livingston, New Jersey. The facility had a multipurpose reactor and a ceramic barrier filter. The reactor was designed to test a second-generation plant carbonizer and then, after modification, a CPFBC/FBHE. Ceramic barrier filters provided by Westinghouse STC were used with both of these units to demonstrate particulate control capabilities.

Because a new facility and a new process (carbonization) were involved, the pilot plant began operation with a two-cyclone HGCU system. After completing the planned carbonizer test matrix and ascertaining that the carbonizer fuel gas composition was compatible with a ceramic barrier filter (no tars or oil vapors in the gas), the second-stage cyclone was replaced by a ceramic cross-flow filter.

The carbonizer was a 30-in.-OD × 34 ft-6 in.-tall refractory-lined pressure vessel. It had a 19-ft-deep jetting fluidized bed and a 9 ft 5-3/4 in.-tall freeboard (Figure 2). The carbonizer ID increased from the bottom to the top in three steps to enhance solids circulation and limit slugging and elutriation. The ID was 10 in. for the first 3 ft-7 in. of bed height, 12 in. to the top of the bed, and 14 in. in the freeboard. Air, coal, and lime-based sorbent were injected into the unit at a 40- to 60-ft/s jet velocity through a central, vertical, 1-in., Sch 80, stainless steel feed pipe at the bottom of the unit. Low-Btu fuel gas left through a 3-in. ID radial nozzle at the top. Spent bed material and char drained through the annulus that surrounded the feed pipe, entered the packed

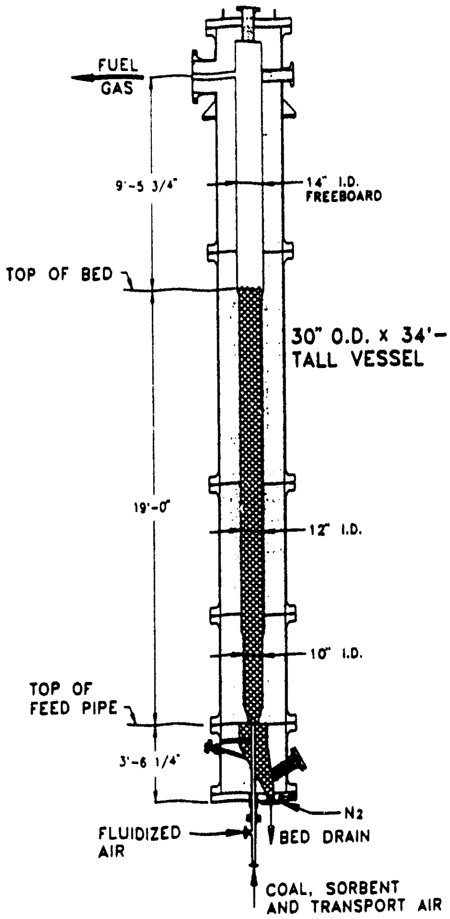


Figure 2. 10-in. Carbonizer Test Unit

bed, and were cooled to 300°F by counter-flowing nitrogen before leaving through a 4-in. drain. A pressurized screw feeder in the drain line controlled the material drain rate/bed height and discharged to a lock hopper for depressuring and ultimate drum disposal.

The first carbonizer test program consisted of eight bubbling fluidized bed test runs. It encompassed 37 setpoints/533 hours of operation. Portions of the collected data have been discussed in other publications [8-10]. Although highly caking Pittsburgh No. 8 coal and Ohio Plum Run dolomite were most frequently used, Illinois No. 6 and Wyoming Eagle Butte coals and Alabama Longview limestone were also tested. The Pittsburgh coal typically had a 3.5-percent sulfur content and a Free Swelling Index of 6.5; the Eagle Butte coal contained 0.7-percent sulfur and 27-percent moisture.

The bubbling bed carbonizer shown in Figure 2 was operated at approximately 3 ft/s superficial gas velocity (measured in the 10-in. ID section). Pressures, temperatures, and steam injection rates ranged from 10 to 14 atm, 1500 to 1800°F, and 0 to 0.4 lb steam/lb coal respectively.

From the standpoint of fluidized bed combustors, circulating bed performance (e.g., combustion efficiency, sulfur-capture efficiency, NO_x emissions) is generally accepted to be superior to bubbling bed performance. Although the bubbling bed carbonizer demonstrated excellent performance, an exploratory test run was made with a circulating bed carbonizer to determine whether it also offered improved performance. To achieve the higher gas velocity required for circulating bed operation, ceramic inserts were installed in the carbonizer, reducing its cross section to a constant top-to-bottom 8-in. ID, as shown in Figure 3. Four circulating bed carbonizer test points were completed at a nominal velocity of 10 ft/s at 5 to 9 atm pressure, with Pittsburgh No. 8 coal and limestone. Because a comparison of the circulating and bubbling bed data showed little difference in performance, no further circulating bed tests were completed.

At no point in the program have any tar or oil vapors been found/condensed from the fuel gas. This finding is very important because their presence might jeopardize barrier filter operation by causing filter blinding and blocking. The high carbonizer operating temperature, relatively long in-bed gas residence time (approximately 8 seconds), high pressure, exposure to lime-based sorbents, and method

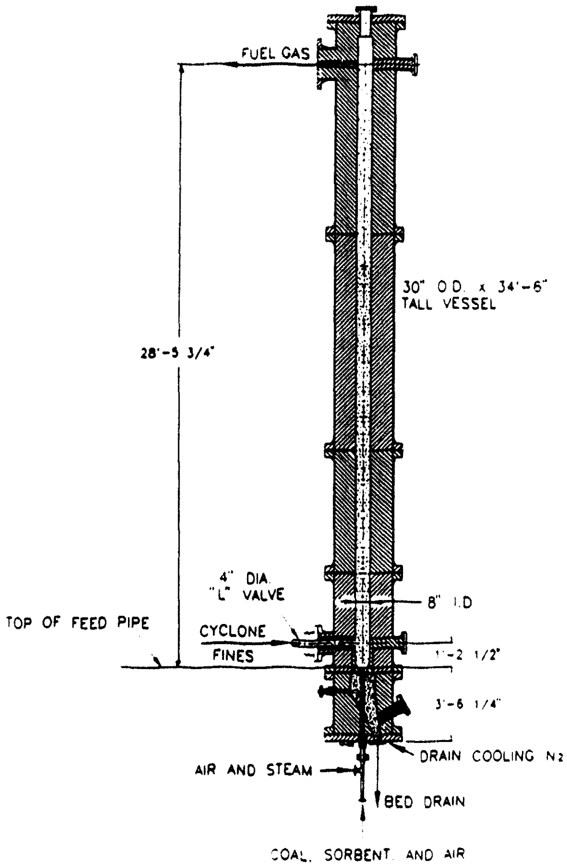


Figure 3. 8-in. Circulating Bed Carbonizer Test Unit

of coal/air feed (coal and air injected at the same point) destroy all tar and oil vapors in the bed.

The solids residue from the process is a char/sorbent mixture containing fine carbon particles. The residue is free flowing and not sticky, except possibly at very low sorbent-to-coal ratios with highly caking coals. It is captured by the primary cyclone and returned hot to the base of the carbonizer via the refractory-lined L-valve arrangement shown in Figure 4.

Ceramic cross-flow and ceramic candle filters were used in the bubbling bed and circulating bed carbonizer tests respectively. All four program fuels and two program sorbents were used, and the cross-flow filter inlet temperature reached a high of about 1500°F. Filter test results were discussed by R. Newby, et al. [11]. Briefly, residue from the four different fuels posed no problem to the barrier filter; the filter cakes were easily cleaned, there was little change in filter permeability, and there were no indications of significant particle reentrainment during pulse cleaning.

In summary, the carbonizer test program has been very successful. It has demonstrated that carbonizer operation is smooth and controlled, emissions are lower than were previously estimated for a commercial plant, and the char/sorbent residue and fuel gas from the process appear compatible with the particle-capturing ceramic barrier filters.

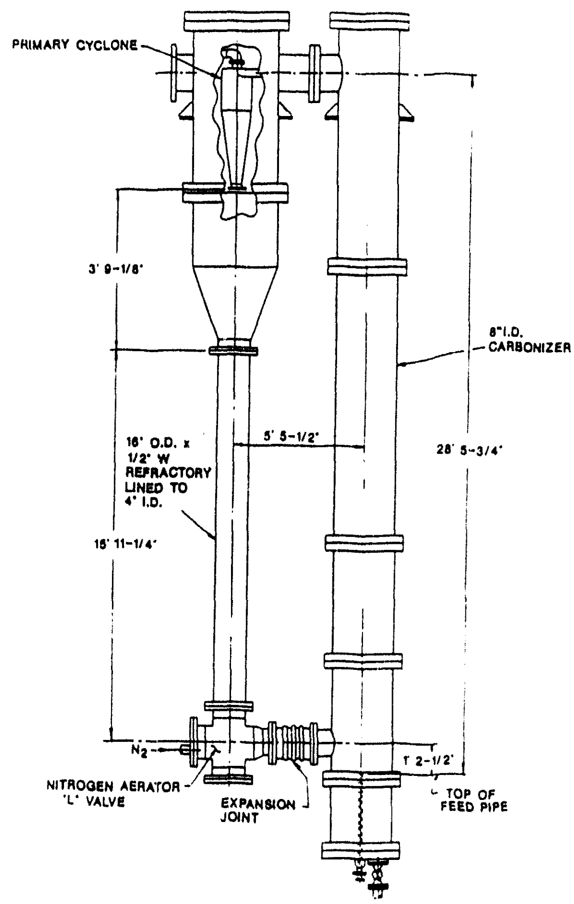


Figure 4. Circulating Bed Carbonizer General Arrangement

CPFBC PILOT PLANT

Having successfully completed the carbonizer test program, the pilot plant was modified for CPFBC operation.

A schematic of the CPFBC pilot plant is shown in Figure 5. Crushed coal and sorbent are loaded into and stored in separate 10-ton silos adjacent to the outside wall of the laboratory. A series of bucket elevators, vibrating feeders, belt conveyors, etc., load and transfer these materials into the building into separate lock hopper systems that are pressurized to approximately 200 psig with 70°F nitrogen. From the pressurized hoppers, the coal and sorbent are fed into a pneumatic transport line via screw feeders and injected into the CPFBC.

The CPFBC is a vertical, 30-in.-OD, 34 ft-6 in.-tall pressure vessel, shown in Figure 6. The CPFBC primary zone is 12 ft-6 in. tall, and the secondary zone is 16 ft tall. The vessel is refractory lined to an 8-in. diameter. Coal, sorbent, and pneumatic transport air are injected at the bottom of the unit at a 40- to 60-ft/s jet velocity through a central, vertical 1-in. Sch 80 stainless steel pipe. At a point 10-3/4 in. below the feed pipe discharge, an outer, concentric, 2-in. Sch 40 pipe injects fluidized air around and at the base of the feed pipe. A nitrogen-aerated packed-bed cooler at the bottom of the CPFBC cools spent bed material to 300°F before lock-hopper depressuring and disposal. Two diametrically opposed secondary air injection ports are provided 12 ft-6 in. above the point of fluidized air entry.

The heat released during the combustion process is absorbed by a sorbent/fly ash mixture continuously circulated between the CPFBC and the FBHE. A cyclone separator atop the FBHE and a nonmechanical L-valve at the bottom control the circulation of solids entering the CPFBC 14-3/8 in. above the fluidizing air.

The FBHE, also shown in Figure 6, is a 42-in.-OD by 34 ft-6 in.-tall pressure vessel, refractory lined to yield a 18-in. square bed and freeboard section. A 39-in.-tall (bottom-to-top tube centerline height) water-cooled tube bundle in the bed consists of eight 1-in.-OD Incoloy 800H tubes. City water is used as the coolant, and its flow rate is adjusted as required to keep the water outlet temperature below 140°F. An air-sparger pipe injects fluidized air at the bottom of the bed and allows solids to flow downward into the L-valve or through the bed-drain cooling section. A screw feeder immediately below the FBHE controls the bed drain rate and bed height. Raising and lowering the bed height controls the amount of tube surface immersed in the bed and hence the bed and CPFBC solids return temperature. The fluidized air leaves the top of the FBHE and enters the CPFBC as secondary air.

The combustion gas/solids mixture exits the combustor and passes through a 3-in. connecting pipe into the cyclone atop the FBHE. The hot solids are separated from the gas and fall by gravity into the 6-in. Sch 40 standpipe. At the end of the standpipe, an aerated J-valve provides a gas seal between the FBHE and cyclone separator. After passing through the J-valve, the solids fall into the FBHE bed, containing tube bundles, where part of the secondary air fluidizes the solids. After passing over the heat exchanger coils, the solids are recycled to the combustor via the nitrogen-aerated L-valve. Pressure, temperature, and pressure differential ports are provided on the standpipe, J-valve, heat exchanger, and L-valve. The cyclone exhaust gas exits the FBHE and enters a ceramic barrier candle filter for final particulate cleanup.

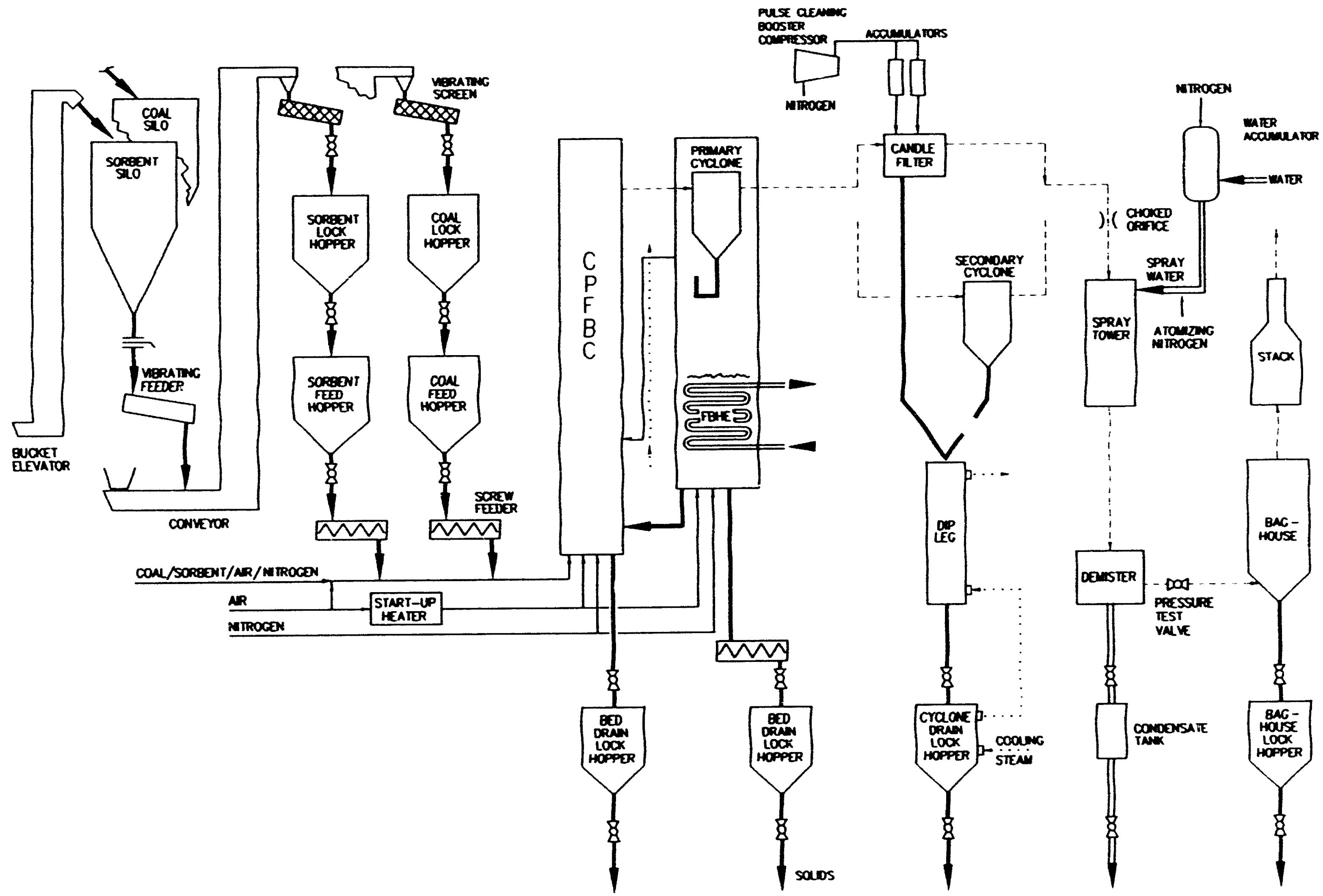


Figure 5. CPFBC Pilot Plant Schematic

filter and is then discharged to the atmosphere via an elevated stack.

Flue gas is sampled both periodically and continuously. The periodic samples are taken from the CPFBC freeboard and from a point downstream of the demister; the continuous measurements are made at the stack via continuous emissions monitors.

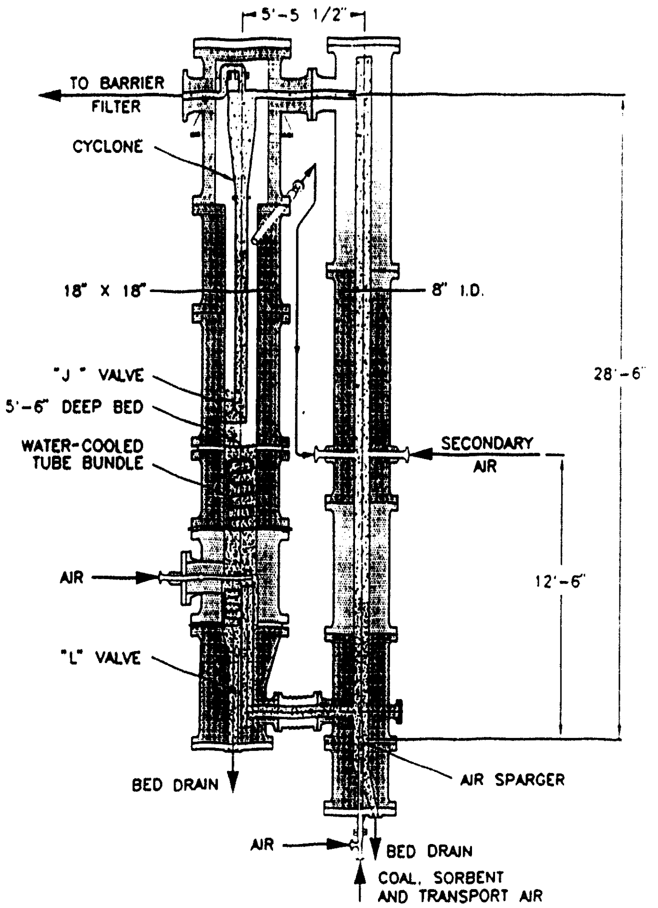


Figure 6. Integrated CPFBC/FBHE Unit—Phase 2

The gas exhausting from the ceramic-candle filter is lowered to atmospheric pressure as it passes through a choked-flow orifice. The high-velocity orifice jet discharges into an Incoloy-shrouded refractory-lined chamber, where a nitrogen-atomized nozzle injects spray water to cool the gas to approximately 350°F. Although the cooling is accomplished by a dry quench, a wire mesh demister is provided at the base of the spray tower to remove any water droplets that may be present in the gas. The cooled gas passes through a baghouse

CPFBC TEST RESULTS

A total of 23 steady-state setpoint periods were obtained from over 300 hours of operation while firing the test fuels. The coals tested in the pilot plant included Pittsburgh No. 8, Illinois No. 6, and Kentucky Andalex, all high-volatile bituminous and Eagle Butte subbituminous. A setpoint period was also conducted with petroleum coke, which served as the pilot plant start-up fuel. Char-sorbent residues from the carbonizer test program were also tested; they included Eagle Butte with limestone, three Illinois No. 6 blends with limestone, and a Pittsburgh No. 8 with dolomite. Proximate and ultimate analyses of the test fuels are shown in Tables 1 and 2.

Sulfur contents ranged from 0.5 to 3.53 percent for the Eagle Butte subbituminous and Kentucky Andalex coals respectively. All of the coals were relatively low in ash content, with the Kentucky Andalex having the highest ash content (11.66 percent). The low ash content of some of these fuels was important from a bed maintenance standpoint; consequently, sorbent feed was often dictated by CPFBC system inventory requirements.

All of the chars contained Longview limestone sorbent, except for the Pittsburgh No. 8 which contained Plum Run dolomite. As shown in Table 2, all of the chars were relatively low in volatile content (less

Table 1. Fuels Tested in CPFBC

Description	Petroleum Coke	Pittsburgh No. 8 (HVB)	Illinois No. 6 (HVB)	Kentucky (HVB)	Eagle Butte
Proximate Analysis, wt%					
Fixed Carbon	86.34	51.30	47.37	46.65	34.11
Volatile Matter	11.85	35.96	33.13	35.71	30.92
Ash	1.30	10.16	11.14	11.66	4.86
Moisture	0.51	2.58	8.36	5.98	30.11
Ultimate Analysis, wt%					
Carbon	90.34	71.48	62.37	66.49	47.21
Hydrogen	3.72	4.74	3.80	3.98	3.37
Oxygen	0.77	5.60	9.84	6.77	13.04
Nitrogen	1.32	1.92	1.35	1.59	0.90
Sulfur	2.04	3.52	2.84	3.53	0.51
Ash	1.30	10.16	11.14	11.66	4.86
Moisture	0.51	2.58	8.36	5.98	30.11
HHV, Btu/lb	15,382	12,799	11,532	12,216	8,245

Table 2. Char Proximate and Ultimate Analysis

Description	Eagle Butte Limestone	Pittsburgh No. 8/ Dolomite	Illinois No. 6/ Limestone Blend 2	Illinois No. 6/ Limestone Blend 3	Illinois No. 6/ Limestone Blend 10
Proximate Analysis, wt%					
Fixed Carbon	60.16	46.39	35.98	46.91	45.75
Volatile Matter	8.08	5.55	10.73	7.76	14.86
Ash	28.64	47.15	53.06	44.67	34.74
Moisture	3.12	0.91	0.23	0.66	4.65
Ultimate Analysis, wt%					
Carbon	63.54	45.97	39.33	48.31	51.25
Hydrogen	0.52	0.50	0.65	0.54	0.65
Oxygen	1.78	0	0.32	0	4.36
Nitrogen	0.90	0.96	0.70	0.81	0.89
Sulfur	1.50	4.51	5.71	5.01	3.46
Ash	28.64	47.15	53.06	44.67	34.74
Moisture	3.12	0.91	0.23	0.66	4.65
HHV, Btu/lb	9,407	8,156	5,961	8,364	8,527
Sulfide S, %	0.80	3.03	4.30	4.19	1.80

than 15 percent). The higher heating values of the chars ranged from 5961 Btu/lb for an Illinois No. 6 char to 9407 Btu/lb for the Eagle Butte char. The sulfide sulfur content of the chars ranged from 0.80 percent for the Eagle Butte to 4.30 percent for an Illinois No. 6 blend.

The major operating variables evaluated in the test program included combustor bed temperature, combustor pressure, primary air stoichiometry, and excess air. The range of these operating variables is shown below:

Combustor temperature, °F	1600 to 1700
Combustor pressure, psig	90 to 190
Primary air stoichiometry, %	60 to 90
Excess air, %	30 to 80

The target sulfur capture for all test points was 92 percent or greater. Sorbent feed rate was often dictated by system inventory requirements, not the desired level of sulfur capture.

Heat and material balances were performed for all setpoint periods to ensure the validity of efficiency and emissions calculations. Material balances were calculated based on measured and calculated input and output streams from the combustor. Input streams included measured air and nitrogen input flows and calculated fuel and sorbent rates. Output streams included measured stack gas flow and calculated ash drain rates. Both total mass flow and elemental rates (C, H, O, and N) generally showed excellent closure of less than 5 percent.

Carbon conversion efficiencies were in excess of 99.5 percent for the diverse types of fuels tested. Carbon conversions were determined by measuring the organic carbon content of the ash drains and calculating the ash drain rates. The organic carbon content of all ash drains was very low and never exceeded 0.5 percent.

A plot of carbon conversion vs. combustor bed temperature is shown in Figure 7 for the coals and chars. As shown in this figure, there appeared to be little effect from bed temperature on carbon conversion since conversions were all in excess of 99.5 percent. These data are consistent with those from the literature for other pressurized CFB pilot plants [12, 13]. Extremely high carbon conversion in the CPFBC was probably a result of the high oxygen partial pressure compared with atmospheric CFBs.

Average CO, SO_2, and NO_x emissions were determined for the steady-state test periods. These emissions were calculated from averages of 1-minute data over a setpoint period of between 2 and 4 hours.

Carbon monoxide emissions were very low for all the fuels tested and generally ranged between 0.01 and 0.02 lb/10^6 Btu. Low CO emissions are usually an indication of high carbon combustion efficiency. A plot of CO emissions vs. combustor bed temperature is shown in Figure 8. CO emissions decreased by a factor of two as the bed temperature was increased from 1500 to 1600°F. These data are consistent with atmospheric CFBC experience, which also shows a strong temperature dependence on CO emissions.

The sorbents utilized in this test program included two limestones (Genstar and Three Rivers) and one dolomite (Plum Run). Important chemical and physical properties of these sorbents are summarized in Table 3. At the beginning of each test run, the bed was sulfated by a nitrogen-SO_2 gas mixture for a

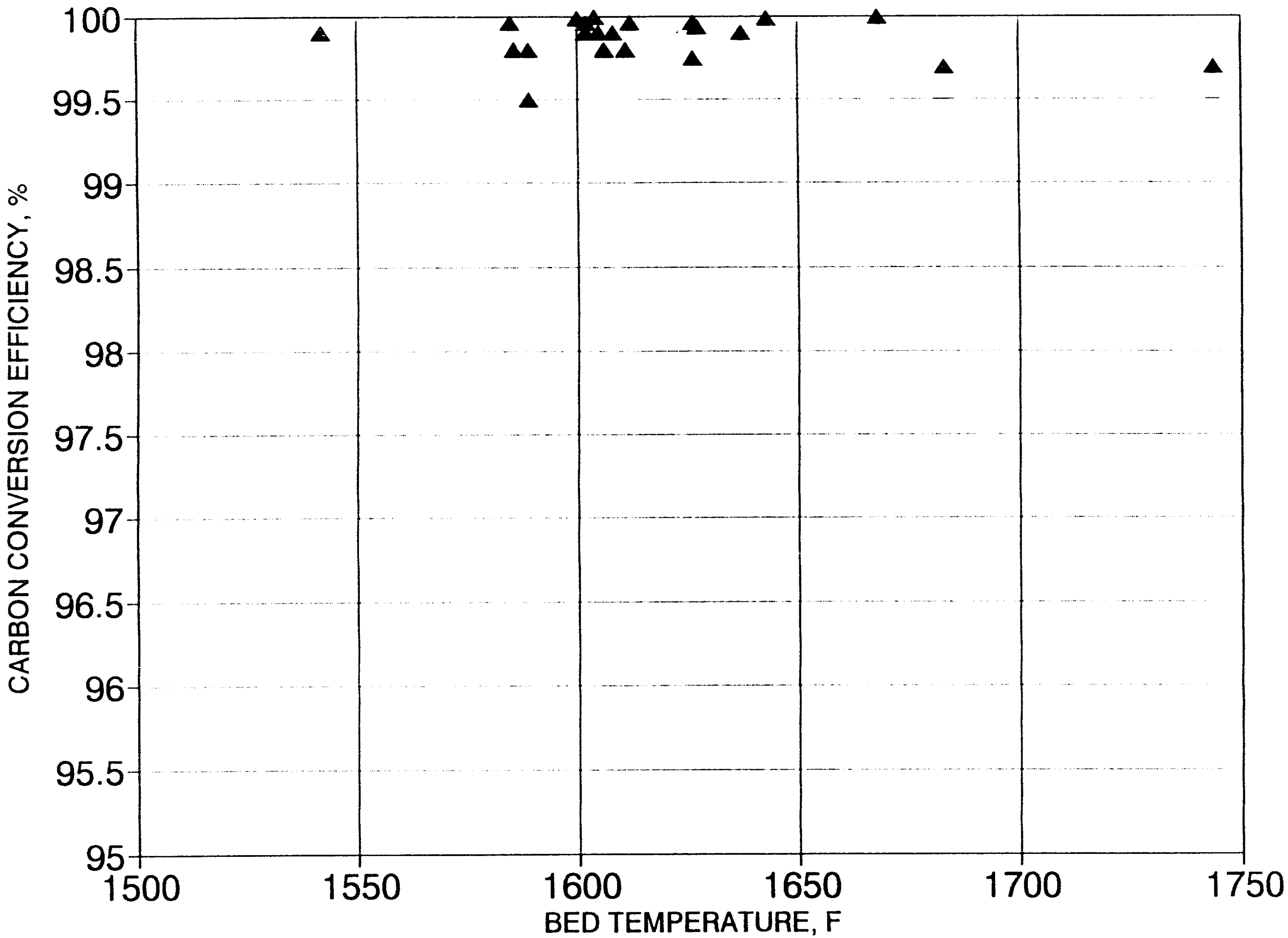


Figure 7. Carbon Combustion Efficiency Vs. Combustor Bed Temperature

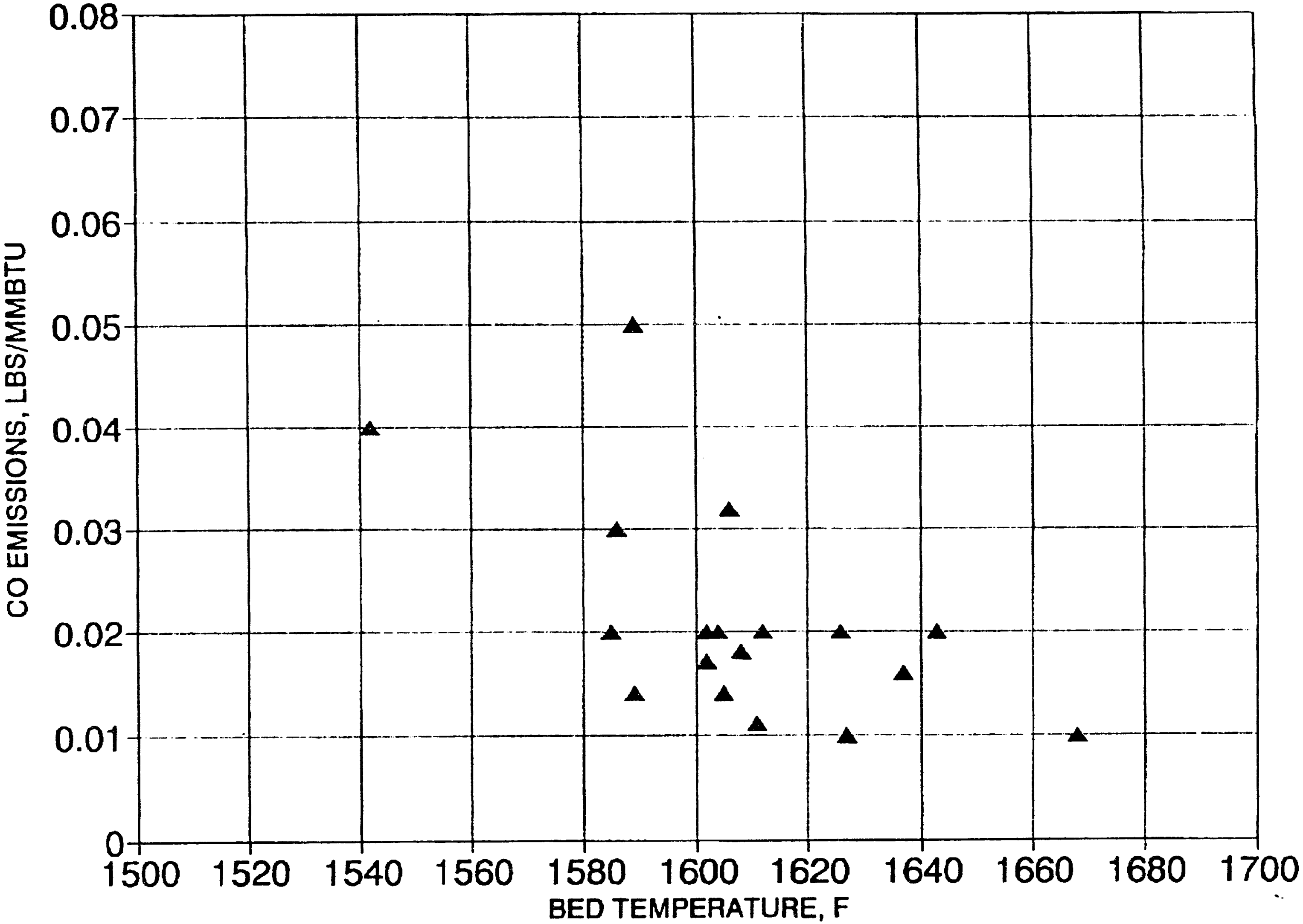


Figure 8. Carbon Monoxide Emission as a Function of Combustor Bed Temperature

Table 3. Sorbents Tested in CPFBC

Analyses	Genstar Limestone	Three Rivers Limestone	Plum Run Dolomite
Chemical Analysis, wt%			
$CaCO_3$	98.1	98.0	55.5
$MgCO_3$	0.7	1.1	42.7
Inerts	1.2	0.9	1.8
Hardgrove Index	53	49	91
TGA Ca Utilization, %	49	40	88

period of up to 20 hours to mature the bed and provide reasonable sulfur-capture data.

Sulfur-capture data for all of the test points are shown in Figure 9 as sulfur-capture efficiency vs. feed Ca/S ratio. A sulfur-capture efficiency greater than 96 percent was usually achieved with Ca/S ratios ranging from 1:1 to 2:1. In some cases system inventory maintenance dictated sorbent feed rate instead of targeted sulfur capture. This was particularly true for very low ash fuels such as petroleum coke and Eagle Butte subbituminous coal. The carbonizer chars all revealed very high sulfur capture from inherent calcium and did not require additional sorbent.

NO_x emissions generally ranged from 0.3 to 0.6 lb/10^6 Btu for the test fuels. Of all the operating parameters, primary zone stoichiometry appeared to have the greatest impact on NO_x emissions. Over the range of operating temperatures and excess air levels, no strong dependence was observed. Some of the test chars showed exceptionally high conversions of fuel nitrogen to NO_x. This phenomenon has been observed in atmospheric CFBC systems and has been attributed to the inability to control NO_x formation from nonvolatile nitrogen by air staging.

The effect of primary-zone stoichiometry on NO_x emissions is shown in Figure 10. Although there is considerable scatter in the data, NO_x emissions did reveal a moderate dependence on primary air stoichiometry, particularly for the Illinois No. 6 coal tests. Most of the other fuels did not show a strong dependence of primary air stoichiometry on NO_x. However, the range of primary air stoichiometries was not very great for these tests (65 to 75 percent).

To discern the effect of fuel type, the same emissions data are shown in Figure 11 as the percentage of fuel nitrogen converted to NO_x. These data show similar trends with primary zone stoichiometry, with the exception of the test chars. In particular, the Pittsburgh No. 8 and Eagle Butte chars showed much higher conversions of nitrogen to NO_x than the parent coals. This trend was also observed for the Illinois No. 6 chars, but was not quite as pronounced.

As mentioned earlier, there was considerable scatter in the NO_x data correlation with primary zone stoichiometry. This scatter may be because of the variation of other operating parameters, particularly excess air level. Because of the intricate coupling of the FBHE with the combustor, difficulty was often encountered in varying one operating parameter at a time while holding all others constant. However, from some limited data, excess air level did not appear to have a significant effect on NO_x emissions. Figure 12 shows the effect of excess air on NO_x emissions for Illinois No. 6 coal over a narrow range of primary air stoichiometries. NO_x emissions remained fairly constant even though excess air was increased by over a factor of three (25 to 83 percent).

A major issue involving the performance of the CPFBC is the extent of char calcium sulfide conversion. Conversion of sulfide was evaluated for four different char blends (Pittsburgh No.8/dolomite and three Illinois No. 6/limestones). The sulfide sulfur contents of the chars varied from 1.8 to 4.3 percent, as shown in Table 4. The sulfide conversion ranged from 68 to 82 percent, with the high-sulfide Illinois No. 6 char having the highest conversion. As expected, the candle filter drains had the lowest concentrations of sulfide (about 1 percent). The sulfide sulfur levels were considerably higher in the FBHE and combustor drains, with the latter having the highest.

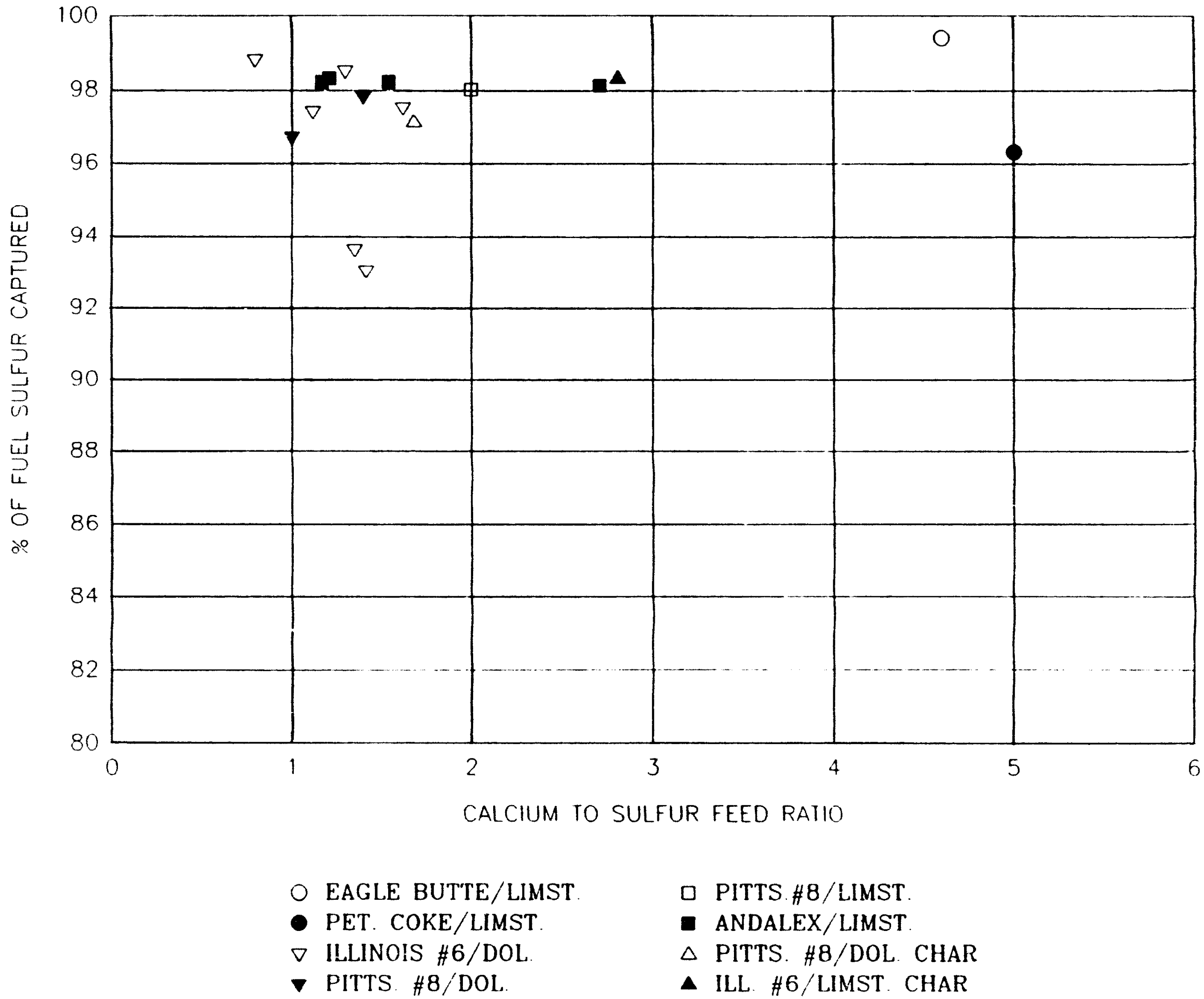


Figure 9. Sulfur Capture Vs. Ca/S Ratio

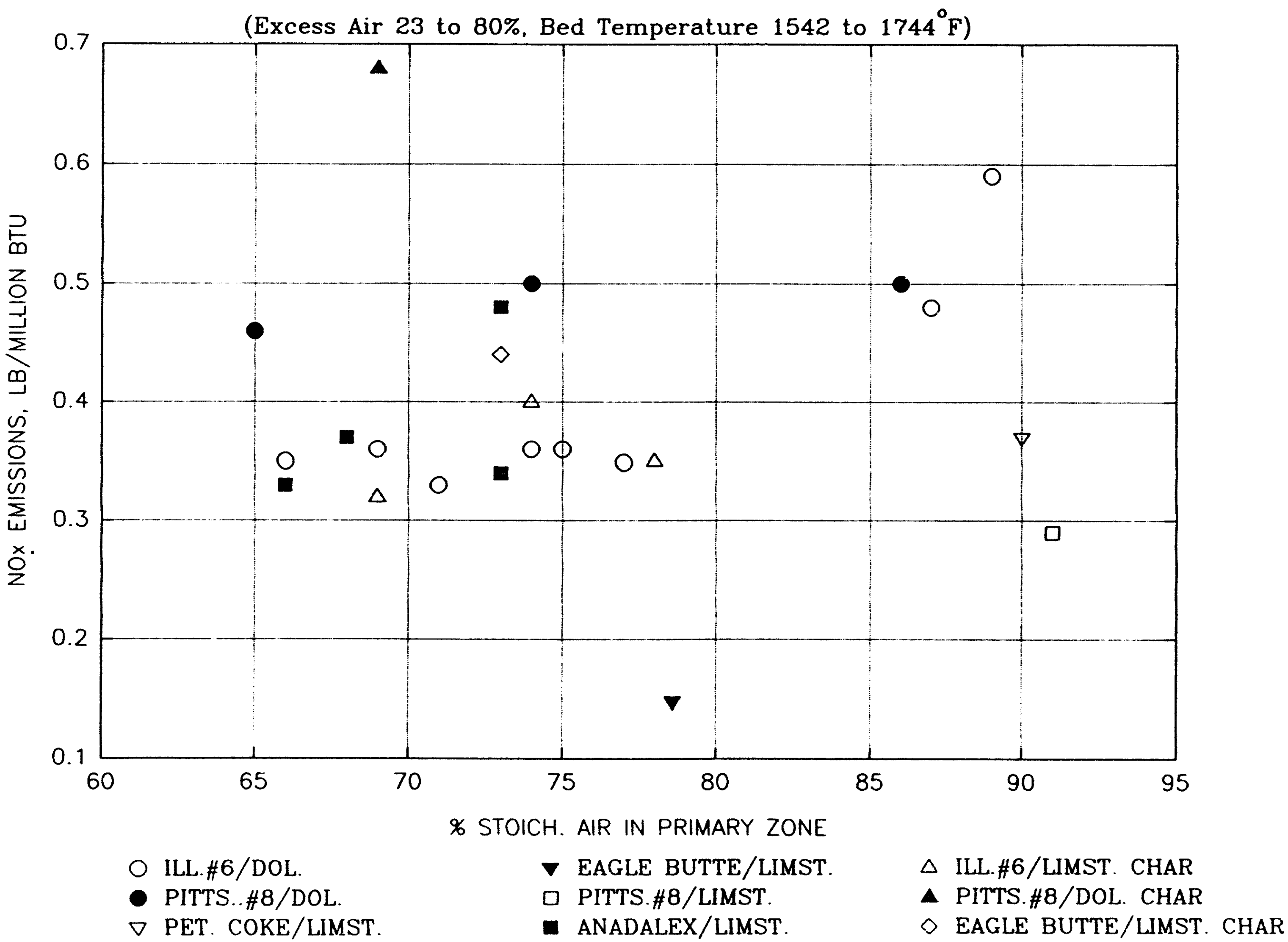


Figure 10. NO_x Emissions Vs. Primary Zone Stoichiometry

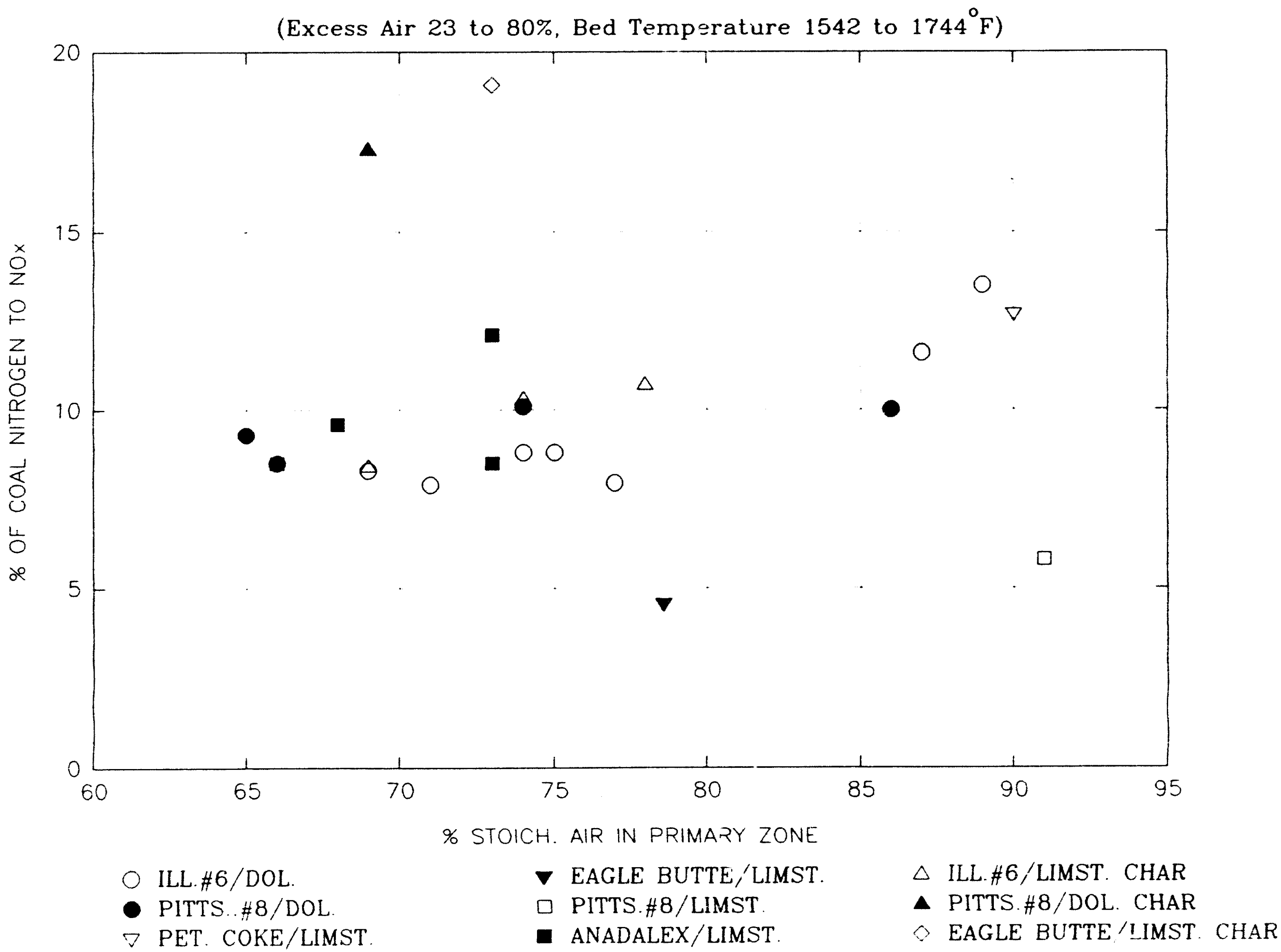


Figure 11. Nitrogen in Fuel Conversion to NO_x Vs. Primary Zone Stoichiometry

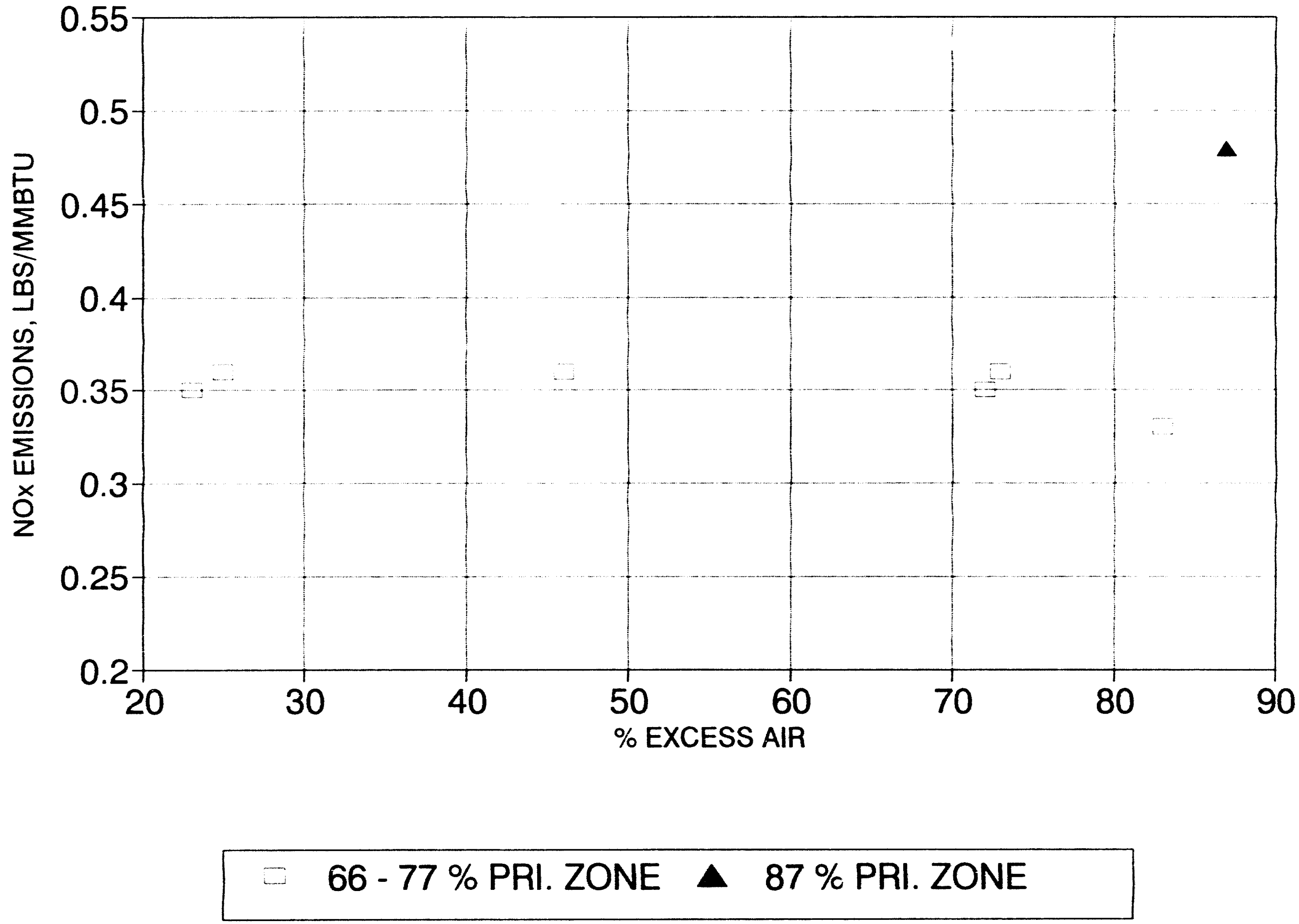


Figure 12. Effect of Excess Air on NO_x Emissions for Illinois No. 6

Table 4. PFB Char Sulfide Conversion Data—Run TRC-5

Description	Pittsburgh No. 8 (Dolomite)	Illinois No. 6 (Limestone)		
Char Rate, lb/h	200	190	195	165
Sulfide S, %	2.68	4.19	4.3	1.8
Sulfide S (in), lb/h	5.36	7.96	8.39	2.97
Filter Drain, lb/h	43	29	21	18
Sulfide S, %	1	1	1	1
Sulfide S, lb/h	0.43	0.29	0.21	0.18
Bed Drain, lb/h	21	12	8	8
Sulfide S %	1.82	1.96	2.88	1.71
Sulfide S, lb/h	0.38	0.23	0.23	0.14
Heat Exchanger Drain, lb/h	30	55	73	57
Sulfide S, %	1.7	1.61	1.62	1.89
Sulfide S, lb/h	0.51	0.89	1.91	1.08
Sulfide S (out), lb/h	1.32	1.41	2.35	1.4
Sulfide Conversion, %	75.4	82.3	72	52.9
Bed Temperature, °F	1627	1612	1626	1626
Primary Air Stoichiometry, %	69	78	74	69
Excess Air, %	51	68	39	41

Some of the major operating parameters affecting the level of sulfide in the system inventory include temperature, excess air, and solids circulation rate. In all the char tests, relatively low firing rates and solids circulation rates (< 10,000 lb/h) were used because of the limited supply of carbonizer chars. Higher circulation rates may have resulted in higher sulfide conversions for two major reasons. First, higher circulation rates increase the inventory residence time in the oxidizing region of the combustor secondary zone. Second, increased circulation also promotes particle attrition, which can break down the calcium sulfate shell of spent sorbent particles and allow further reaction of the exposed calcium sulfide layer. Higher solids circulation rates will be utilized in Phase 3 testing of the CPFBC to assess their effect on sulfide conversion.

The CPFBC tests were conducted in the multipurpose reactor vessel. Since this vessel was primarily designed to support the carbonizer test program, its short height resulted in a relatively short secondary/oxidizing zone. With secondary gas residence times being only approximately 1 second, NO_x and sulfide conversion levels were less than optimum. In Phase 3, a larger CPFBC will be used, and we expect both reduced NO_x levels and increased sulfide conversion levels.

PHASE 3 TEST PROGRAM

The carbonizer and CPFBC have been tested separately to ascertain their individual performance characteristics. In Phase 3, the multipurpose reactor will be returned to the bubbling bed carbonizer configuration, and a larger CPFBC will be installed to facilitate integrated performance tests. The CPFBC will have a 13-in. ID and, being 38 ft-3 in. tall, should exhibit improved NO_x and sulfide conversion performance. In addition, the dry lock-hopper pneumatic transport feed systems will be supplemented with a coal/water paste feed system to study the effect of a coal/water paste feed on carbonizer performance.

Construction of the Phase 3 pilot plant began on January 3, 1994, and shakedown/ commissioning is expected to begin in July 1994.

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4.3 Status of the Advanced PFBC at the Power Systems Development Facility

CONTRACT INFORMATION

Cooperative Agreement DE-FC21-90MC25140

Contractor Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625
(205) 870-6011

Contractor Project Manager Randall E. Rush

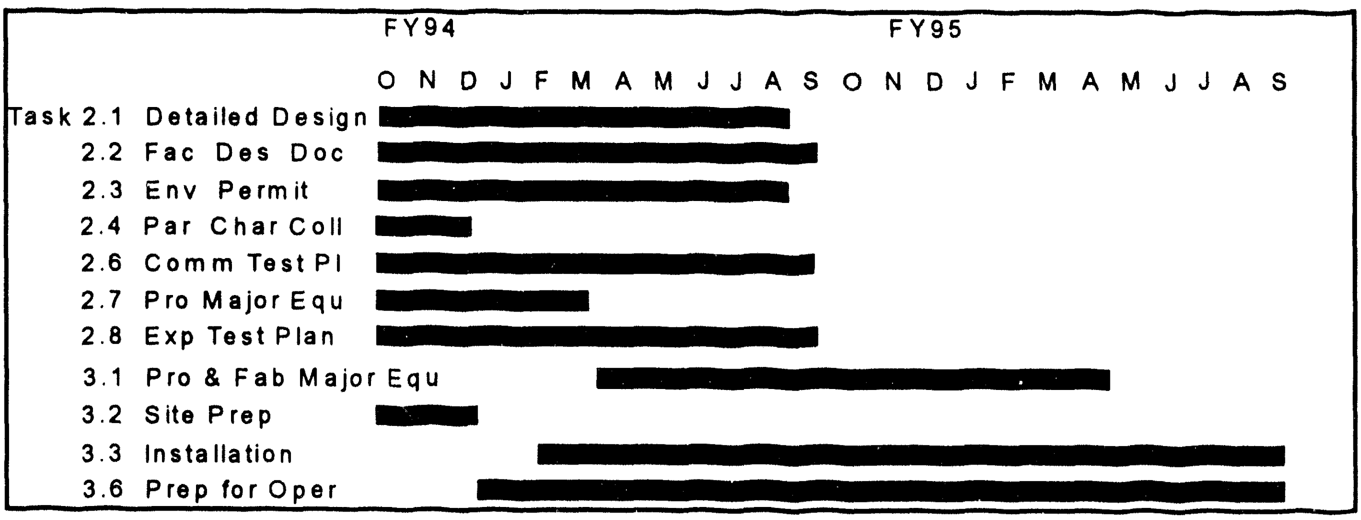
Principal Investigators Darrell L. Moore, Zia Haq, Timothy E. Pinkston, and P. Vimalchand, SCS
James D. McClung, FWDC
Michael T. Quandt, FWEC

METC Project Manager James R. Longanbach

Period of Performance June 16, 1993 to June 6, 1994

Schedule and Milestones

FY '94 & '95 Program Schedule



OBJECTIVES

The objectives of the Power Systems Development Facility (PSDF) are to develop advanced coal-fired power generation technologies through the testing and evaluation of hot gas cleanup systems and other major components at the pilot scale and to assess and demonstrate the performance of the components in an integrated mode of operation and at a component size easily scaled to commercial systems. This will entail the design, construction, installation, and use of a flexible test facility, which can operate under realistic gasification and combustion conditions. The major particulate control device issues to be addressed include the integration of the particulate control devices (PCDs) into coal utilization systems, on-line cleaning techniques, chemical and thermal degradation of components, fatigue or structural failures, blinding, collection efficiency as a function of particle size, and scale-up of particulate control systems to commercial size.

BACKGROUND INFORMATION

Coal is the primary fuel source for the generation of electricity in the United States. Due to The Southern Company's commitment to be a major supplier of electricity and the continued use of coal as a primary fuel source throughout the Southern electric system, Southern Company Services (SCS) has entered into a cooperative effort with the U. S. Department of Energy (DOE) Morgantown Energy Technology Center (METC) to develop a facility where component and system integration tests can be carried out for advanced coal-based power plants. The PSDF is being designed to be a flexible facility that will address the development of the PCDs and an advanced second-generation pressurized fluidized-bed combustion technology. A key element of the program is the testing and assessment of the technical issues for PCDs in an integrated test facility that directly supports DOE's Clean Coal program. Test conditions - such as gas pressure, temperature, and particulate loading - are variable over a range of values to facilitate the assessment of the PCDs.

PROJECT DESCRIPTION

The Power Systems Development Facility will be located 40 miles southeast of Birmingham, Alabama, at the Southern Company's Clean Coal Research Center in Wilsonville, Alabama. The PSDF location is adjacent to Alabama Power Company's 1,900 MW Plant Gaston. The PSDF utilizes the site of the decommissioned Selective Oil Agglomeration Facility in addition to a greenfield area west of the agglomeration site.

A simplified diagram of the PSDF is shown in Figure 1. The facility is divided into two trains, an advanced gasifier train for parametric testing of the PCDs and an Advanced Pressurized Fluidized Bed Combustion (APFBC) train for integration of the PCDs into a power generation system for longer term testing. The PSDF will be sized to feed 104 tons/day of Illinois No. 6 bituminous coal with a Powder River subbituminous coal as an alternate coal. Longview Limestone, which is obtained locally near Wilsonville, has been chosen as the sorbent for sulfur removal during the initial testing. The estimated project value is $150 million with 80 percent of the funding being provided by DOE and 20 percent being cost shared by industry.

The project team for the PSDF is comprised of DOE/METC, SCS, the Electric Power Research Institute (EPRI), The M. W. Kellogg Company (MWK), Foster Wheeler USA (FW), Westinghouse, Southern Research Institute (SRI), Industrial Filter & Pump, Combustion Power Company and Nolan Multimedia. SCS Research

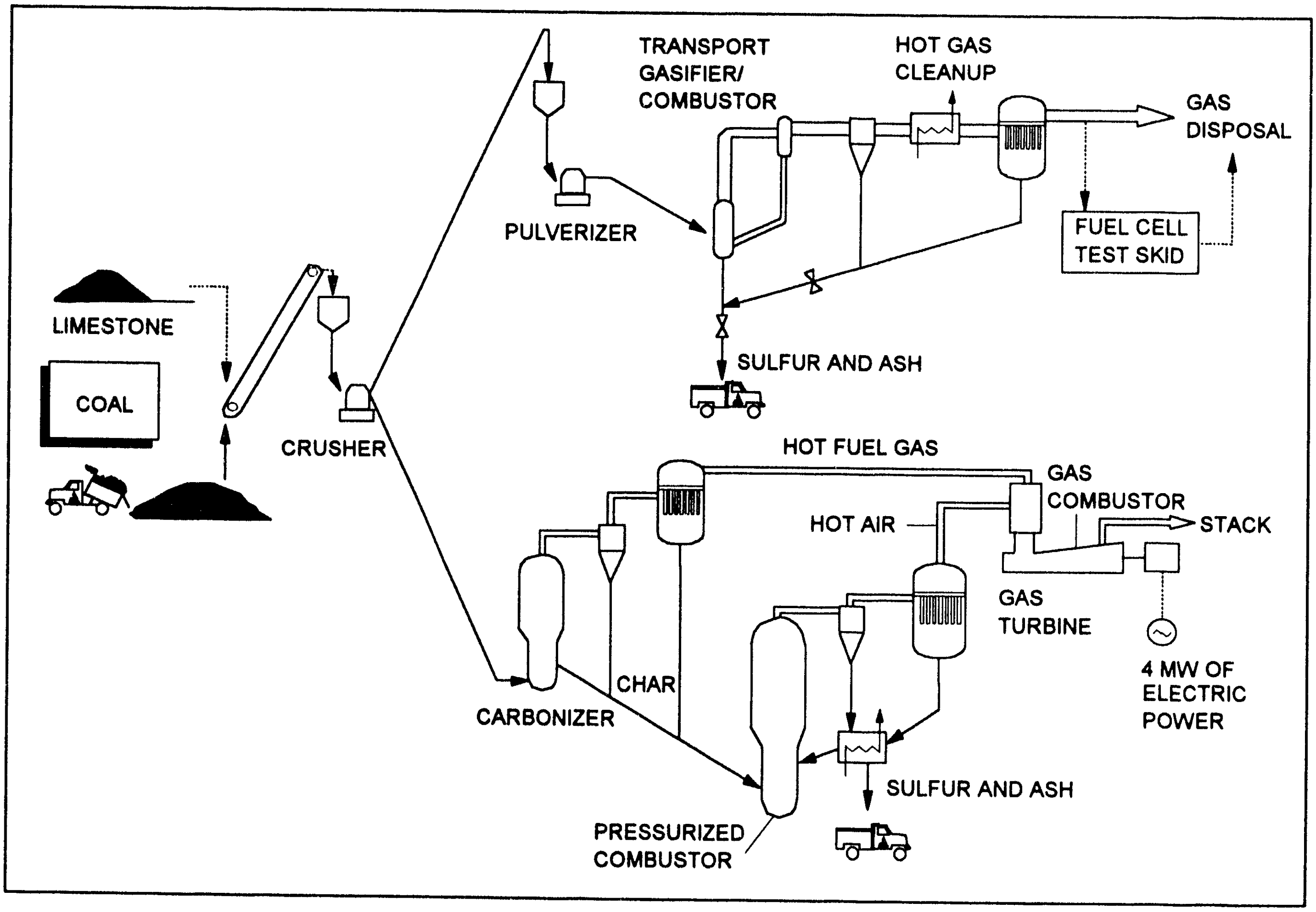


Figure 1. Simplified Diagram of the Power Systems Development Facility

and Environmental Affairs is responsible for overall project management and procurement of the PCDs. SCS Engineering is responsible for coordinating the design of the facility as well as plant layout and balance-of-plant design. SCS will provide construction management through the construction and installation phases of the project and will also be the facility operator, with a site staff of approximately 90.

The process engineering and detail design for the APFBC train is being done by FW. The APFBC system is designed to accommodate long-term testing of the PCDs and other system components, as well as evaluation of turbine

The process engineering and detail design for the APFBC train is being done by FW. The APFBC system is designed to accommodate long-term testing of the PCDs and other system components, as well as evaluation of turbine system configurations. FW also has the lead in integrating a carbonizer and a circulating pressurized fluidized-bed combustor (CPFBC) with the topping combustor (supplied by Westinghouse Electric Corporation) and the gas turbine/air compressor (supplied by Allison Engine Company). MWK is providing the process engineering and detail design for the Advanced Gasifier train, which includes a transport reactor unit. The MWK transport train is designed to accommodate parametric testing of the PCDs and other system components. Southern Research Institute will conduct particulate and alkali sampling to evaluate PCD performance. In addition to providing cost sharing, EPRI is also providing technical guidance for the project.

FOSTER WHEELER'S APFBC SYSTEM

In the Foster Wheeler Second-Generation PFBC concept, coal is fed to a pressurized carbonizer, where it is converted to a low-Btu fuel gas and char. The relatively low carbon conversion in the carbonizer results in a simpler sulfur-removal process than is typically required in coal gasification processes. The char produced in the carbonizer is transferred to a CPFBC where it is subsequently burned. The carbonizer fuel gas and CPFBC flue gas are cleaned of particulates in separate ceramic filters, after which the fuel gas is fired in a specially designed topping combustor outside a high-temperature gas turbine using the CPFBC flue gas as the oxidant. Steam is raised and superheated in the fluidized bed heat exchanger (FBHE) with heat extracted from the CPFBC.

Most of the Second-Generation PFBC components will be tested in the Wilsonville configuration as an integrated system. An exception is that a steam turbine is not incorporated in the design. Instead, heat from the CPFBC will be rejected to condensate supplied by and returned to the balance of plant areas. A major component to be evaluated will be the pressurized FBHE integral to the CPFBC, to prove the use of an integrated heat exchanger to remove heat from the CPFBC under pressurized conditions. The APFBC plant will also provide the first full integration of the gas side of the power island, allowing operation of a gas turbine topping combustor with hot pressurized fuel gas from the carbonizer and hot pressurized flue gas from the CPFBC. Periodic examination of the gas turbine will demonstrate the merits of hot gas cleanup for the APFBC systems.

APFBC PROCESS DESIGN

A process flow diagram of the APFBC plant is shown in Figure 2. Dry coal and sorbent with steam are fed to the pressurized carbonizer, where the coal is converted to a low-Btu fuel gas and char. The design coal and sorbent are Illinois No. 6 and Longview limestone. Eagle Butte subbituminous coal is an alternate fuel. The plant is designed for a coal feed rate of about 5500 lb/hr, and a sorbent feed rate of about 1050 lb/hr. Provision has been made in the design to test the CPFBC under low excess-air conditions, feeding coal (either paste or dry) and sorbent directly to the CPFBC. Low-Btu fuel gas exits the top of the carbonizer and is cleaned of particulates in a single-stage cyclone and PCD (ceramic filter), and of alkalies in an alkali getter in series with the cyclone and PCD. Solids collected in the carbonizer cyclone and PCD combine in a surge hopper with char and reacted/unreacted sorbent exiting the side of the carbonizer, and are fed by gravity with pneumatic assist through an N-valve to the CPFBC, where the balance of carbon conversion occurs.

The flue gas from the CPFBC is also cleaned of particulates and alkali in a single-stage cyclone, PCD (ceramic filter), and alkali getter. Solids captured by the cyclone are fed to the FBHE via a J-valve for heat removal and returned to the CPFBC. Ash collected by the CPFBC PCD is cooled via a screw cooler and discharged through lock hoppers. Solids are removed from the CPFBC bottoms by an oxidizer/cooler, which fluidizes and cools the ash from 1600 to about 400°F, discharging bed ash to a depressurizing hopper, which operates at system pressure during charging and at atmospheric pressure during

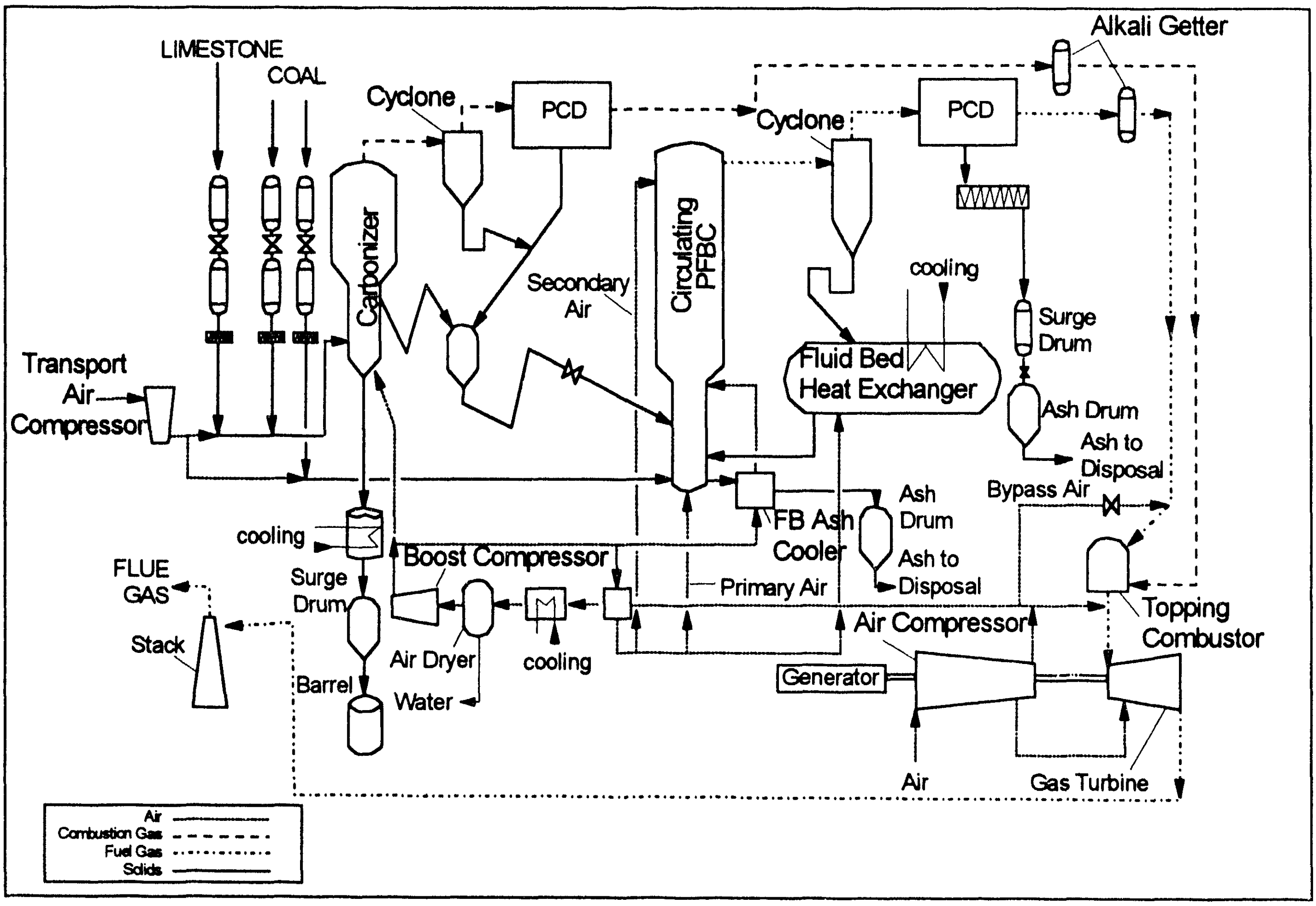


Figure 2. Advanced Pressurized Fluidized-Bed Combustion

discharge. The cleaned fuel gas from the carbonizer is burned in a topping combustor, utilizing clean flue gas from the CPFBC as the oxidant. The hot topping combustor exhaust is expanded in the gas turbine driving the air compressor and generator, and discharged to atmosphere via a stack.

Carbonizer

The carbonizer is a spouting fluidized bed without heat-transfer surface. The 175 psia/1700°F carbonizer is a vertical, approximately 48 ft. in height, refractory-lined vessel comprising the bed section (lower part - I.D. approximately 3 ft.) and a disengagement section (upper part - I.D. approximately 4 ft.). Coal and sorbent are fed into the carbonizer pneumatically under pressure, entering axially through the bottom. The carbonizer has been provided with additional nozzles to allow for alternately feeding coal and sorbent radially at varied in-bed and above-bed elevations. Provision has also been made in the design to feed a coal/water paste. Bed temperature is maintained by the air-to-coal ratio.

Circulating Pressurized Fluidized Bed Combustor (CPFBC)

The CPFBC, shown in Figure 3, is a refractory-lined vessel with a 33 in. I.D. upper section. The vessel is lined with two-layer refractory, 4 in. of light castable refractory and 4.8 in. of hard-face refractory for erosion resistance. The main functions of the CPFBC are char combustion and conversion of CaS in the char to $CaSO_4$, while combining effective capture of SO_2 to achieve >95 percent sulfur removal with reduced NO_x formation through staged combustion. The major operating parameters controlling these functions are:

- Bed Temperature - Based on bubbling bed PFBC technology, bed temperature is limited to about 1600°F. A higher bed temperature improves carbon conversion, but also results in higher alkali release, which increases the potential for bed agglomeration and corrosion of downstream components.

- Ca/S Molar Ratio - A Ca/S molar ratio of 2 is assumed to attain 95 percent sulfur capture with Illinois No. 6 coal and Longview limestone. This assumption will be verified during operation.

- Bed Stoichiometry - To control NO_x formation, the combustion process is staged. The lower part of the CPFBC operates in a reducing mode with approximately 70 percent stoichiometry, while the upper portion operates in an oxidizing mode.

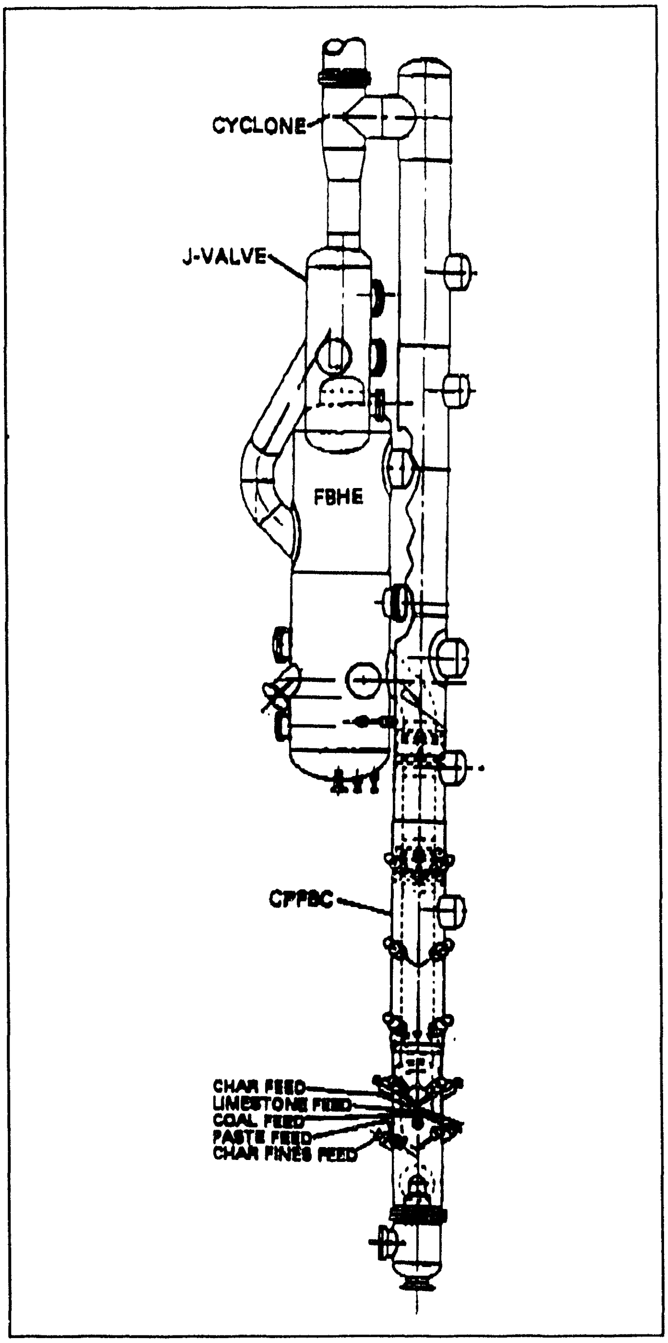


Figure 3. Circulating Pressurized Fluidized-Bed Combustor (CPFBC)

The CPFBC bed temperature is controlled by the amount of heat-transfer surface in the unit, and the load to the gas turbine is controlled by the fuel feed rate. The unit has been designed so it can operate between 20 and 300 percent excess air to test both first-generation and advanced PFBC concepts. Primary air is fed into the CPFBC from the plenum below the grid. Nozzles distribute the air flow evenly for optimum air/solids mixing in the CPFBC. Secondary air to the CPFBC can be fed above the grid at four different elevations, and can be adjusted between the elevations to determine the best emissions control and carbon burnup. Hot flue gas exits at the top of the vessel.

Oxidizer/Cooler

Solids are withdrawn from the CPFBC bottoms via an oxidizer/cooler, which assures sulfation of the CPFBC bottoms ash and cools the ash from 1500 to 400°F. Drawoff from this system may be either on a batch basis or a continuous basis. The design also provides for two bed ash drain locations, with the higher elevation drain for continuous operation.

Fluidized Bed Heat Exchanger (FBHE)

The FBHE is a refractory-lined vessel containing four cells - an inlet, an outlet, and two heat exchanger cells. The FBHE receives recycled ash from the CPFBC cyclone/J-valve. The flow of recycled material to the FBHE will be dependent on the load of the unit (fuel flow). Material enters the inlet cell, underfeeds to the heat exchanger cells, and discharges through the outlet cell back to the CPFBC. Heat is removed from the FBHE by a once-through condensate system. The FBHE is designed to allow the heat duty to be changed for different case studies in the test plan. This FBHE design has been tested and commercially accepted in CFB designs.

High-Temperature Gas Cleaning (HTGC)

The carbonizer and CPFBC have independent HTGC systems consisting of three cleaning stages in series - a cyclone, PCD, and alkali-removal system. The cyclone design is based on the use of a single, standard cyclone stage to remove the bulk of the relatively coarse particles from the gas streams and protect the downstream PCD from process upsets.

The PCDs are used for final particulate removal. An Industrial Filter & Pump Mfg. Co. low-density fiber ceramic candle design will be used as the initial carbonizer PCD. The refractory-lined filter vessel has a 60 in. diameter and contains 78 candles arranged in six groups of 13 each for jet pulse cleaning. The 54 mm O.D. x 1.5 m long candles are of an aluminosilicate fiber construction (with binders of silica and alumina). The monolithic flared flange and end cap of the candle are of densified ceramic fiber construction, as are the tubesheet and the candle retainer plate. The six pie-shaped jet pulse plenums are constructed of a high-alumina castable material for maximum strength. For effective cleaning, individual jet pulse nozzles are provided to each candle. An Enhancer™ consisting of an orifice-type device at the outlet of the candle increases jet pulse intensity and also serves as a fail-safe plug in case of a candle failure. A back-pulse tank, designed for 1500 psig, will provide back-pulse gas to the filter.

The CPFBC PCD will be a Westinghouse ceramic candle filter consisting of a refractory-lined 10.2 ft. O.D. pressure vessel containing six arrays ("clusters") of 60 mm O.D. x 1.5 m long candle elements. The individual clusters are supported from a common high-alloy tubesheet and expansion assembly that spans the pressure vessel and divides it into the "clean" and "dirty" gas sides. The Westinghouse cluster arrays are formed by attaching individual filter elements to a common plenum and discharge pipe. The arrays are cleaned from a single pulse nozzle source. For efficient packaging, several of the individual plenum assemblies are arranged vertically from a common support structure forming a filter cluster. The cluster concept permits maintenance and replacement of individual filter elements and provides a modular approach to scale-up.

The last stage, alkali removal, captures sodium and potassium vapor-phase species. The alkali-removal systems are simple, packed beds of emathlite pellets contained in vertical, refractory-lined pressure vessels. The emathlite material reacts irreversibly with sodium and potassium vapor-phase compounds at high temperature. Nozzles are provided for gas inlet and outlet at the top and bottom of the vessels, respectively, as well as for pellet loading and unloading. The alkali getter in the CPFBC flue gas stream is being installed as a safety measure since the alkali content expected in the CPFBC flue gas is lower than the turbine tolerance. Following particulate and alkali removal, fuel gas and flue gas are conveyed to the topping combustor by refractory-lined piping. A metallic lining between the alkali getters and topping combustor isolates the refractory and prevents any spalled refractory from entering the cleaned gas streams.

The HTGC systems are designed to achieve sufficient levels of particle and alkali removal to protect the gas turbine from erosion, deposition, and corrosion damage as well as satisfy plant emissions standards. The HTGC systems must meet the following performance levels:

- Achieve particle-removal efficiency to meet both environmental and turbine protection standards.
- Meet performance standards - outlet particulate loadings less than 20 ppm(w) with no more than 1 wt% particles exceeding 10 μm and no more than 10 wt% exceeding 5 μm.
- Control alkali content (total sodium plus potassium vapor) to less than 50 ppb(w).
- Limit the maximum pressure drop across each HTGC train to 10 psi.
- Limit the temperature drop to less than 100°F across the carbonizer HTGC train and to less than 10°F across the CPFBC train.

Topping Combustor

The topping combustor assembly consists of carbon steel spools which form the pressure vessel. A concentric, stainless steel cylinder inside each steel spool piece provides the temperature boundary. A layer of insulation fills the void between the concentric cylinders. The multiannular swirl burner (MASB) is constructed from an Inconel or Hastelloy-type alloy with a diameter of about 18 in., which is a commercial size. Flue gas from the CPFBC enters the topping combustor at approximately 150 psia and 1400°F. About 11,600 lb/hr of carbonizer fuel gas, entering at approximately 1650°F, is burned in the MASB to produce an exhaust gas temperature of 2350°F, which is the optimum firing temperature for a commercial plant at this carbonizer temperature. The gas is cooled to about 1975°F with compressor bypass air before entering the gas turbine.

Gas Turbine

The gas turbine generator set is a modified Allison 501-KB5 gas turbine, which drives a synchronous generator through a speed-reducing gearbox. The hot exhaust gas from the topping combustor is expanded through the gas turbine, powering both the electric generator and the air compressor. Exhaust gases from the gas turbine are discharged hot through a stack. Air from the compressor supplies all APFBC plant process air requirements. Approximately 8 percent of the air flow is used for gas turbine blade cooling and approximately 22 percent for tempering the topping combustor exhaust gas from 2350 to 1975°F before it enters the turbine. Most of the compressed air, approximately 63 percent, is used in the CPFBC system for fluidizing the FBHE and as primary and secondary air. The remaining 7 percent provides air to the carbonizer.

CHANGES IN PSDF APFBC DESIGN

Carbonizer Operation and Char Flow

The carbonizer train design has been reviewed to ensure that operation up to 1800°F is possible. The PSDF design originally removed char from the bottom of the carbonizer, cooling the char via a screw cooler, and reducing oversized particles with a delumper. Particles were then dumped into a holding vessel and pneumatically conveyed to the CPFBC. This design has been replaced with a system which withdraws char from a bed overflow nozzle from the side of the carbonizer, instead of withdrawing from the bottom, so hot char will feed directly to the PFBC by gravity and differential pressure. In addition, the carbonizer bottoms has been modified to allow occasional batchwise rejection of oversized char through a double pipe heat exchanger, where cooling is effected by the heating of low pressure steam, to a lock hopper for discharge. Nitrogen is introduced below the heat exchanger to keep the exchanger clear and sweep fuel gas from the discharged solids. These changes should improve reliability of the plant, reduce heat loss and maintenance, and decrease capital equipment costs.

CPFBC Solids Withdrawal

Earlier PSDF design provided for ash removal from the CPFBC primarily from the FBHE and from overhead (PCD) fly ash with incidental removal from the bottom of the CPFBC. Alternate operating lock hoppers with combined feeds from both the FBHE and the CPFBC PCD were provided for continuous removal of the ash. Because the design required multiple, relatively expensive and potentially problematic ash coolers and other factors, this design was abandoned in favor of a more simplified design. Bed ash removal from the FBHE was deleted, and bed ash removal and cooling is now accomplished at the bottom of the CPFBC. Continuous flyash removal and cooling below the PCD using a screw cooler, surge drum and lock hopper was retained. Solids are withdrawn from the CPFBC bottoms via an oxidizer/cooler, which has been added to assure sulfation of the CPFBC bottoms ash and cool the ash from 1600 to 400°F. In addition, there is an increase in fuel burnup efficiency and limestone utilization, as well as classifying of the ash particles, which results in longer residence time for small particles and removal of very coarse particles from the system.

Full-stream Booster Compressor

A full-stream booster compressor has been incorporated into the PSDF design to increase the air pressure to both the carbonizer and the CPFBC. This was effected due to the thrust bearing limitation of the Allison gas turbine. Due to the type (aircraft derivative) and size of the gas turbine employed in the APFBC plant, the turbomachinery was not sufficiently robust to accommodate the pressure drop of the plant without significant rework. Conversely, a more "rugged" gas turbine would reduce the turbine efficiency in the simple cycle mode (propane firing). Consequently, it was decided to boost the air pressure in the CPFBC process flow stream in addition to the carbonzier process flow stream to reduce the overall system pressure drop. Another advantage of the full-stream booster compressor is that it can be used for a more rapid cool down and heat up of the CPFBC. Heat exchange between the hot air flowing to the booster compressor suction and the booster compressor discharge gas feed to the CPFBC was provided to minimize the effect on the heat and material balance of the unit.

Transport Air Compressor

Pneumatic feed systems are pressure sensitive and with minimum pressure drop through the feed system, minor surges in pressure have a significant effect on the operation of the system. Review of pilot plant operation indicated multiple cases where pressure surges led to feed system upsets which in turn led to thermal excursions and in some cases to plant shutdown. As a result, the Wilsonville APFBC design was revised to provide more conventional solid to gas loading rates and respectively higher pressure drop, necessitating the need for a transport air compressor. Since pneumatic transport systems prefer dry air it was decided to use plant instrument air as the source of transport air. The instrument air will be boosted by the transport air compressor to desired pressures, a less expensive option than boosting some of the flow from the full-stream booster compressor.

Burners

An additional startup burner was added to the Combustor because the original single burner resulted in an excessive pressure differential across the grate in the Combustor which would have required a redesign of the grid floor. Also, the above Grid Burner will help the Combustor and cyclone heat up evenly during startup. In addition, a startup burner has been added to the oxidizer cooler.

Other Design Changes Under Consideration

A simplified char transfer system is being evaluated, which consists of separate down legs from the carbonizer, carbonizer cyclone, and carbonizer PCD feeding a common up leg, and final down leg to the CPFBC. Aeration gas would be supplied to the bottom of the up leg as well as to various alternative positions on each down leg.

Deletion of the fugitive dust baghouse and blower is being reviewed. This system currently services the coal and limestone surge and pressurization drums, the ash depressurization drums, and the oversized char drum. If the system is deleted, the fugitive dust collection system would be revised to vent the coal and sorbent surge and feed drums to their respective feed hoppers, which are equipped with filters. The ash depressurization drums would vent to the ash transfer system, and ultimately to the balance-of-plant storage silo. A new filter would be installed on the oversized char drum.

Particulate Sampling

Past hot particulate removal demonstration projects have shown that particulate size distribution and morphology determine particle penetration and energy loss (pressure drop), and play an important role in the durability of filtration devices. Particle mass loading, size distribution, morphology, and levels of alkali metals, both in particulates and in the vapor phase, play distinct roles in subjecting turbine components to erosion and corrosion. Characterization of alkali vapor is also needed to quantify turbine exposure and to assess the performance of the alkali getter beds that will be installed to protect the topping combustor and gas turbine. Therefore, on-line sampling for both particulates and alkali species will be conducted at the PSDF. Particulate sampling will be done at the inlet and outlet of the PCDs. Alkali sampling will be done at the inlet and outlet of the alkali getter beds for the APFBC system.

Project Status

Currently, the PSDF schedule consists of a 22 month design period overlapping with a 24 month installation period to better accommodate the design and construction of the facility.

Detailed design for the base facility commenced in July 1992 and construction began in September 1993. At present, the FW APFBC system design and the PCD designs are nominally 50% complete. Procurement of long-lead equipment is in progress. Site grading and preparation are complete and steel erection will start in July. The construction phase will be followed by three months of shakedown and an additional three months of characterization test runs. The commissioning of the test facility will be completed by the third quarter of 1995 and will be followed by a two year operations period.

Summary

The Power Systems Development Facility offers a unique opportunity for government and the utility industry to focus on the developmental needs of advanced coal-based power generation systems. The critical need in advanced power generation processes is to improve the reliability and performance of hot particulate removal systems. This continues to be the primary focus for the PSDF. The testing and operation of the second-generation APFBC system at the PSDF will generate data and operational experience that will be helpful in the evaluation of newer process and equipment design and concepts. The facility will be instrumental in testing and advancing the PFBC technology. The PSDF is an investment in the development of more efficient, cost effective, and environmentally sound advanced coal-based power plants. The results should be a reduction or stabilization in the cost of electricity and a reduction in environmental emissions for new coal-based power plants.

ACKNOWLEDGEMENTS

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