CLEAN
COAL
TECHNOLOGY

DOE/FE-0351

Clean Coal Technology Demonstration Program

Project Fact Sheets

September 1996

U.S. Department of Energy
Assistant Secretary for Fossil Energy
Washington, DC 20585

The United States Department of Energy's Clean Coal Technology Demonstration Program

Summary

The Clean Coal Technology Demonstration Program is a unique partnership between the United States Department of Energy (DOE) and industry that has as its primary goal the successful demonstration of a new generation of advanced coal-based technologies, with the most promising technologies being moved into the domestic and international marketplace.

Begun in 1985 and expanded in 1987 to meet the recommendations of the United States and Canadian Special Envoys on Acid Rain, the program has resulted in a capital investment of nearly $6 billion in 40 competitively selected projects. Of the 40 projects, 20 have completed operations, 7 are in operation, 5 are in construction, 7 are in design, and 1 is in negotiation. The demonstrations are at a scale large enough to generate data needed to enable potential domestic and international users to make judgments about the commercial viability of a particular process. These demonstrations will improve the global environment and enhance global energy security through the use of technologies and services provided by United States industry.

The 40 projects are directed toward satisfying the energy and environmental needs of four application categories:

- Advanced electric power generation
- Environmental control devices
- Coal processing for clean fuels
- Industrial applications

Advanced Electric Power Generation

The growing concern over global climate change is being addressed through the demonstration of high-efficiency advanced electric power generating technologies. Nearly 900 megawatts-electric (MWe) of new capacity and more than 800 MWe of repowered capacity are represented by 12 projects valued at nearly $3.4 billion. These projects include five fluidized-bed combustion systems, four integrated gasification combined-cycle systems, and three advanced combustion/heat engine systems. These projects not only will provide environmentally sound electric power generation in the mid- to late 1990s, but also will provide the demonstrated technology base necessary to meet new capacity requirements in the 21st century.

Environmental Control Devices

There are 19 environmental control devices projects valued at nearly $704 million. These include seven NO_x emissions control systems installed on more than 1,700 MWe of utility generating capacity, five SO_2 emissions control systems installed on approximately 770 MWe, and seven combined SO_2/NO_x emissions control systems installed on approximately 800 MWe of capacity. Most of these environmental control devices will have their operating experience documented by the end of 1996.

Coal Processing for Clean Fuels

Valued at more than $519 million, the five projects in the coal processing for clean fuels application category represent a diversified portfolio of technologies. Three projects involve the production of high-energy-density solid compliance fuels for utility or industrial boilers; one of these projects also produces a liquid for use as a chemical or transportation fuel feedstock. A fourth project is demonstrating a new methanol production process. The fifth project has demonstrated an expert computer software system that enables a utility to predict operating performance of coals being considered but not previously burned in the utility's boiler.

Industrial Applications

The four projects in the industrial applications category have a combined value of nearly $1.3 billion. Projects encompass substitution of coal for 40 percent of the coke in iron making, integration of a direct iron-making process with the production of electricity, reduction of cement kiln emissions and solid waste generation, and demonstration of an industrial-scale combustor.

International Activities

Internationally, clean coal technologies are increasingly important in the export market, creating major opportunities for U.S. business. Recognizing the importance of this export market, a number of efforts are under way to define market opportunities to promote U.S. technology and to support U.S. project development work. International activities have concentrated on providing technical support to U.S. trade agencies, organizing trade missions, conducting education and training, developing financial and market analysis in response to Section 1331 of the Energy Policy Act of 1992, and developing an international technology transfer program as directed by Section 1332 of that act.

The Energy Policy Act provided the Secretary of Energy with the responsibility, among others, to "encourage the export of United States clean coal technologies" and to "assist United States firms, especially firms that are in competition with firms in foreign countries, to obtain opportunities to … undertake projects in foreign countries." The Secretary was authorized to "develop policies and programs to encourage export and promotion … to developing countries" of all "domestic energy resource technologies."

Project Fact Sheets

Exhibit 1 provides the project schedules by application category for the 40 projects in the program. The remainder of this report contains fact sheets for all projects. The information provided includes the project participant, team members, location, process flow diagram, significant project features, project objectives, description of the process and its performance attributes, progress and accomplishments, commercial applications, and major milestones.

To prevent the release of project-specific information of a proprietary nature, process flow diagrams contained in the fact sheets are highly simplified and presented only as illustrations of the concepts involved in the demonstrations.

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Key to Milestone Charts in Fact Sheets

Each fact sheet contains a bar chart that highlights major milestones—past and planned. The bar chart shows a project's duration and indicates the time period for three general categories of project activities—preaward, design and construction, and operation. The key provided below explains what is included in each of these categories.

▨ **Preaward**

Includes preaward briefings, negotiations, and other activities conducted during the period between DOE's selection of the project and award of the cooperative agreement.

■ **Design and Construction**

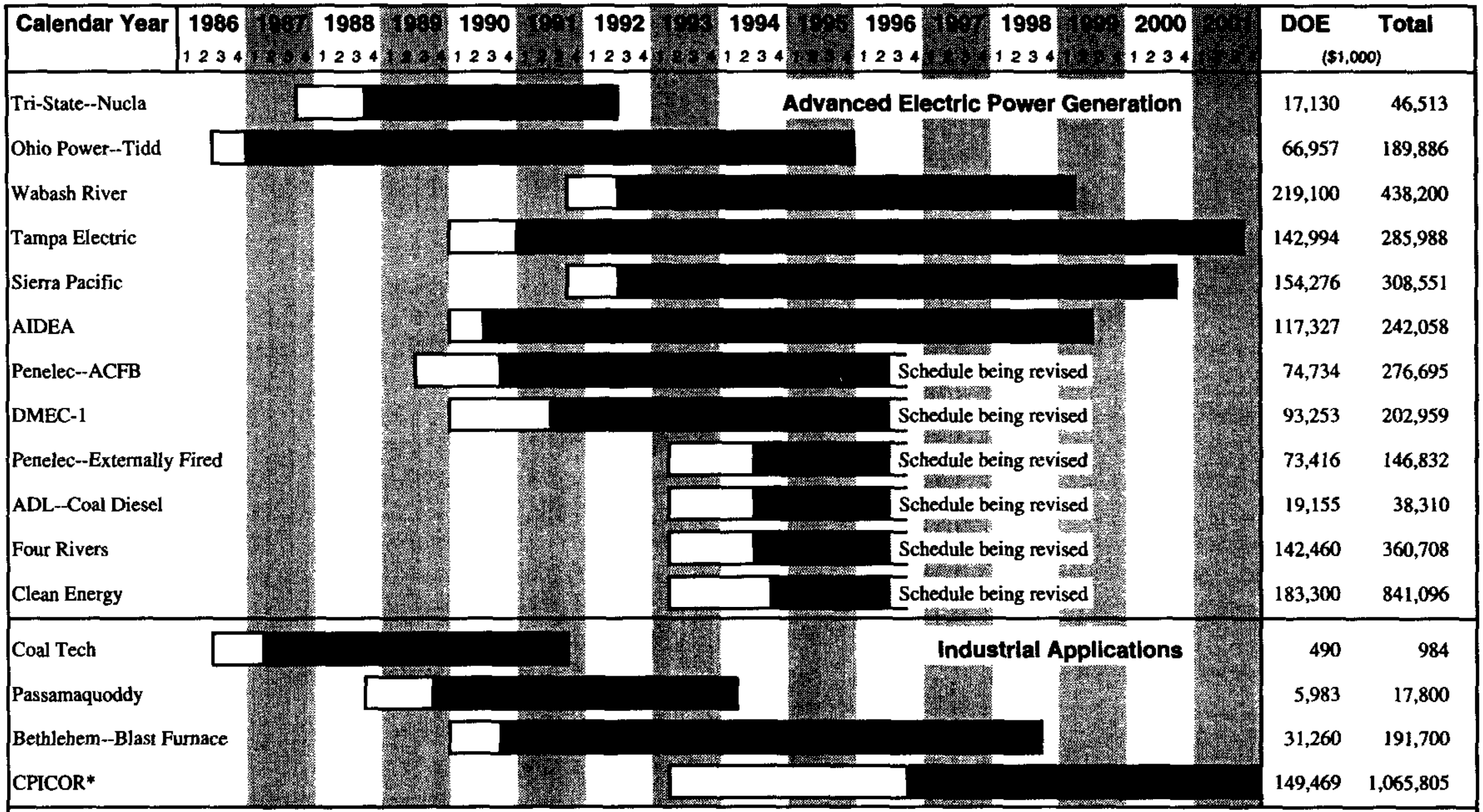
Includes the NEPA process, permitting, design, procurement, construction, preoperational testing, and other activities conducted prior to the beginning of operation of the demonstration.

MTF	Memo-to-file
CX	Categorical exclusion
EA	Environmental assessment
EIS	Environmental impact statement
NEPA	National Environmental Policy Act

■ **Operation**

Begins with start-up of operation and includes operational testing, data collection, analysis, evaluation, reporting, and other activities to complete the demonstration project.

Exhibit 1
Project Schedules and Funding by Application Category

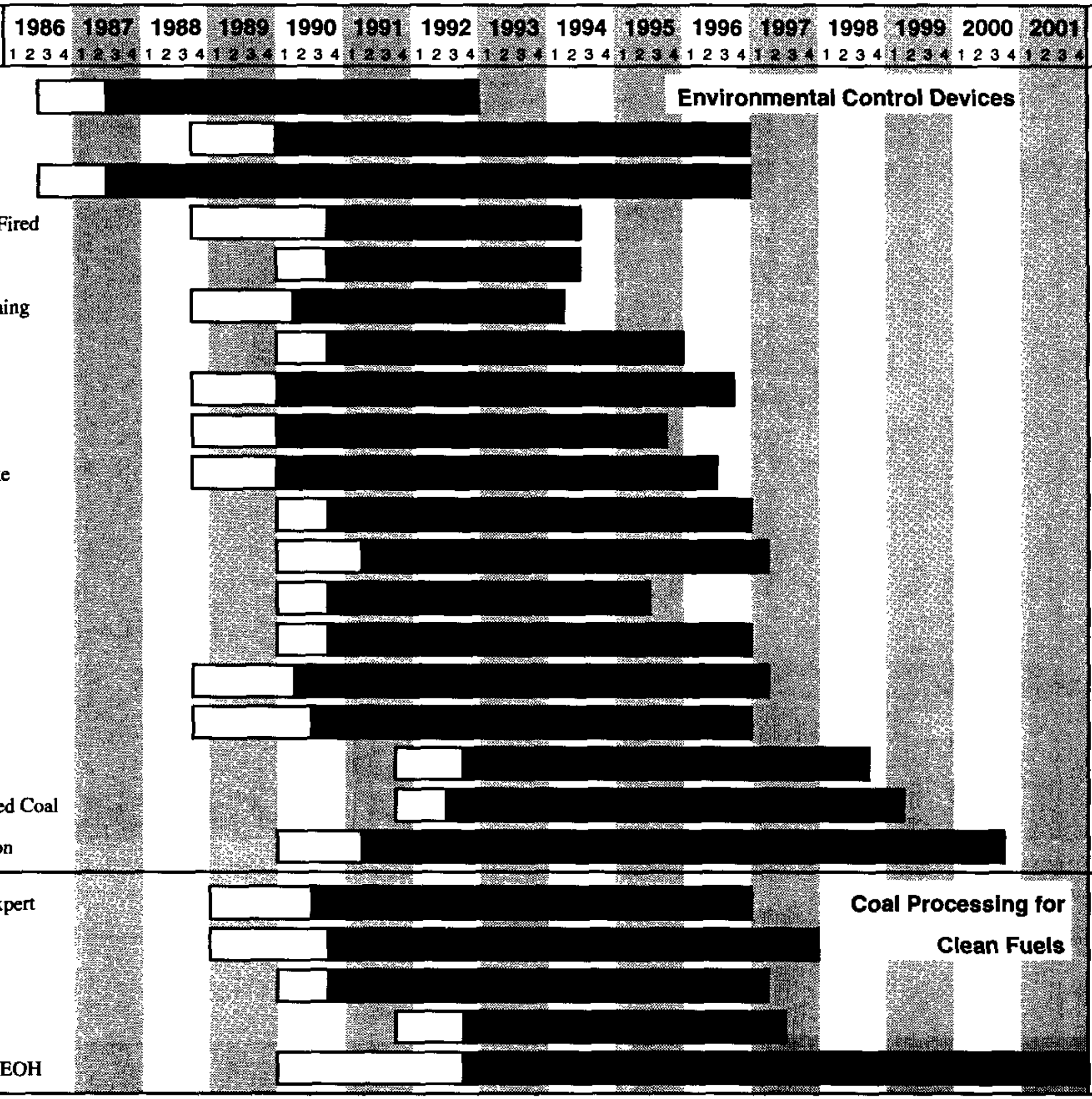


Calendar Year	DOE	Total
	($1,000)	
Tri-State--Nucla	17,130	46,513
Ohio Power--Tidd	66,957	189,886
Wabash River	219,100	438,200
Tampa Electric	142,994	285,988
Sierra Pacific	154,276	308,551
AIDEA	117,327	242,058
Penelec--ACFB	74,734	276,695
DMEC-1	93,253	202,959
Penelec--Externally Fired	73,416	146,832
ADL--Coal Diesel	19,155	38,310
Four Rivers	142,460	360,708
Clean Energy	183,300	841,096
Coal Tech	490	984
Passamaquoddy	5,983	17,800
Bethlehem--Blast Furnace	31,260	191,700
CPICOR*	149,469	1,065,805

* Award of Cooperative Agreement expected in October 1996. Operations are scheduled to end January 2003.

☐ Preaward ■ Design and Construction ■ Operation and Reporting

Exhibit 1 (continued)
Project Schedules and Funding by Application Category



Calendar Year	DOE	Total
	($1,000)	
Environmental Control Devices		
B&W--LIMB	7,597	19,405
SCS--Wall-Fired	6,554	14,711
EER--GR/SI	18,748	37,589
SCS--Tangentially Fired	4,440	9,153
Bechtel--CZD	5,206	10,412
B&W--Coal Reburning	6,341	13,647
B&W--LNCB	5,443	11,233
ABB ES--SNOX	15,719	31,438
B&W--SNRB	6,078	13,272
Pure Air on the Lake	63,913	151,708
LIFAC	10,637	21,394
PSC of Colorado	13,706	27,411
AirPol--GSA	2,315	7,717
EER--GR-LNB	8,896	17,807
SCS--CT-121	21,085	43,075
SCS--SCR	9,407	23,230
NYSEG--Milliken	45,000	158,608
NYSEG--Micronized Coal	2,701	9,096
NOXSO Corporation	41,406	82,812
Coal Processing for Clean Fuels		
ABB CE & CQ--Expert	10,864	21,746
Rosebud SynCoal	43,125	105,700
ENCOAL	45,332	90,664
Custom Coals	37,994	87,386
Air Products--LPMEOH	92,708	213,700

Project Fact Sheets: The United States Department of Energy's Clean Coal Technology Demonstration Program

Project Fact Sheets: The United States Department of Energy's Clean Coal Technology Demonstration Program (continued)

Advanced Electric Power Generation Fact Sheets

Project Results/Accomplishments:

Between August 1988 and January 1991, a total of 72 steady-state performance tests were conducted: 22 tests at 50% load, 6 at 75% load, 2 at 90% load, and 42 at full load (110 MWe). Some key results, as reported by the participant, follow:

- Results indicated strong correlations of absolute CO, SO_2, and NO_x emissions levels with combustor operating temperatures. Although NSPS compliance was maintained, a penalty on limestone feed requirements for sulfur retention was realized at the higher operating temperatures. Below 1,620 °F, 70% sulfur retention was achieved with 1.5 Ca/S, and 95% sulfur retention was achieved with 4.0 Ca/S. At approximately 1,700 °F, Ca/S greater than 5.0 was required to maintain 70% sulfur capture.
- The NO_x emissions for all tests were less than 0.34 lb/million Btu, which was well within the state-regulated emission limit of 0.50 lb/million Btu. The average level of NO_x emissions for all tests was 0.18 lb/million Btu.
- Combustion efficiency, a measure of the quantity of carbon that is fully oxidized to CO_2, ranged from 96.9% to 98.9%. Of the four exit sources of incompletely burned carbon, the largest was carbon contained in the fly ash (93%). The next largest (5%) was carbon contained in the bottom ash stream, and the remaining feed-carbon loss (2%) was incompletely oxidized CO in the flue gas. The fourth possible source, hydrocarbons in the flue gas, was measured and found to be negligible.
- Boiler efficiencies for 68 performance tests varied from 85.6% to 88.6%. The contributions to boiler heat loss were identified as unburned carbon, sensible heat in dry flue gas, fuel and sorbent moisture, latent heat in burning hydrogen, sorbent calcination, radiation and convection, and bottom ash cooling water.

  Net plant heat rate decreased with increasing boiler load, from 12,400 Btu/kWh at 50% of full load to 11,600 Btu/kWh at full load. The lowest value achieved during a full-load steady-state test was 10,980 Btu/kWh. These values were affected by the absence of reheat, the presence of the three older 12.5-MWe turbines in the overall steam cycle, the number of unit restarts, and part-load testing.
- Over the range of operating temperatures at which testing was performed at Nucla, bed temperature was found to be the most influential operating parameter. With the possible exception of coal-feed configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions or efficiencies. Emissions of SO_2 and NO_x were found to increase with increasing combustor temperatures while CO emissions decreased with increasing temperature. Combustion efficiency also improved as the temperature was increased.

An economic evaluation indicated that the final capital costs for the Nucla ACFB system were about $112.3 million, representing a cost of $1,123/net kW. Total power production costs associated with test operations were about $54.7 million, which translates to a normalized power production cost of $63.63/MWh. Fixed costs were less than 62% of the total, and variable costs were more than 38%. Nucla's power production costs proved competitive with pulverized coal units not limiting emissions as significantly.

Commercial Applications:

ACFB technology has good potential in both industrial and utility sectors for new capacity additions or for repowering existing coal-fired plants. Coal of any sulfur content can be used. Because any type or size of boiler can be repowered by ACFB using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment, the life of the plant can be extended. Benefits of ACFB include 90% SO_2 reduction, 60–80% NO_x reduction, and control of pollutants at lower costs than are offered by existing technologies.

As a result of the Nucla demonstration, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of ACFB units. Pyropower's commercial units are now offered under warranty in sizes ranging up to 400 MWe. Under the terms of the project's repayment plan, Tri-State is required to submit to DOE semiannual payments based on a percentage of the net revenues from plant operation. This repayment obligation ends in October 2011 unless DOE's contribution is repaid before that time. Tri-State has made payments of $351,700 under the plan.

Project Schedule:

DOE selected project (CCT-I)	10/7/87
Cooperative agreement awarded	10/3/88
NEPA process completed (MTF)	4/18/88
Environmental monitoring plan completed	2/27/88
Operational testing	8/88–1/91
Project completed	4/92

Final Reports:

Final Technical Report	10/91
Economic Evaluation Report	3/92
Performance Test Summary Reports	3/92
Public Design Report	12/90

Clean Energy Demonstration Project

Participant:

Clean Energy Partners Limited Partnership (a limited partnership consisting of Clean Energy Genco, Inc., an affiliate of Duke Energy Corp.; Makowski Clean Energy Investors, Inc.; British Gas Americas, Inc.; and an affiliate of the General Electric Company)

Additional Team Members:

Duke Engineering & Services, Inc.—engineer and constructor
General Electric Company—power island designer and supplier
British Gas Americas, Inc., affiliate in conjunction with Lurgi Energie and Umwelt GmbH—gasification island designer
Fuel Cell Engineering Corporation—molten carbonate fuel cell designer and supplier; cofunder
Electric Power Research Institute—cofunder
National Rural Electric Cooperative Association—cofunder
Deutsche Aerospace AG—cofunder

Location:

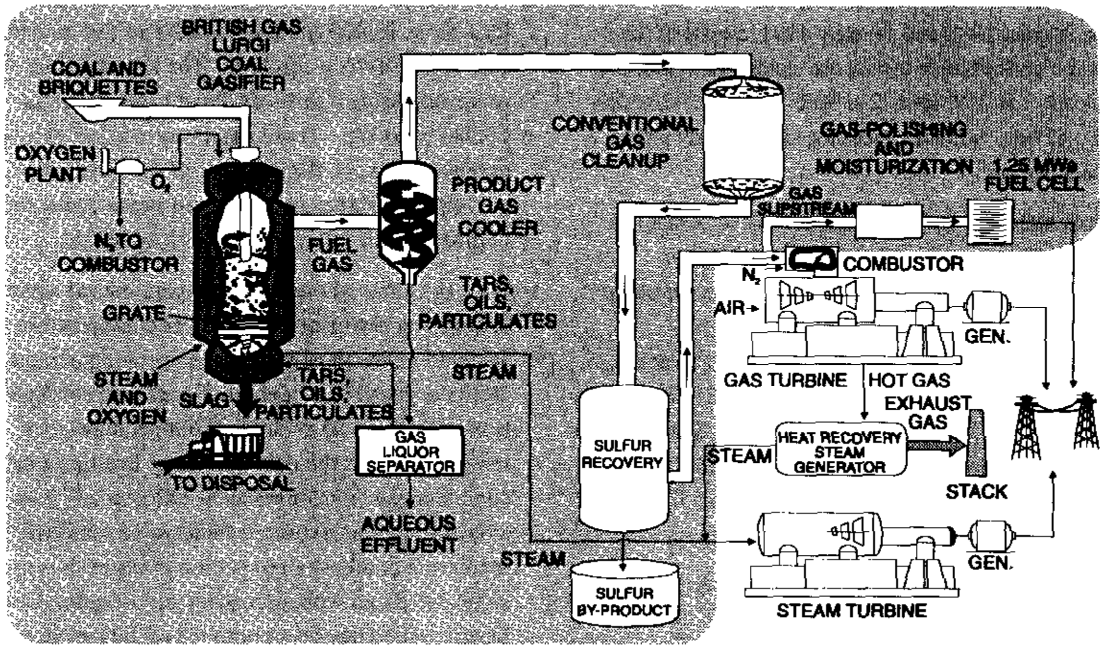
An east coast site

Technology:

Integrated gasification combined-cycle (IGCC) using British Gas/Lurgi (BG/L) slagging fixed-bed gasification system coupled with Fuel Cell Engineering's molten carbonate fuel cell (MCFC)

Plant Capacity/Production:

477-MWe (net) IGCC; 1.25-MWe MCFC



Project Funding:

Total project cost	$841,096,189	100%
DOE	183,300,000	22
Participant	657,796,189	78

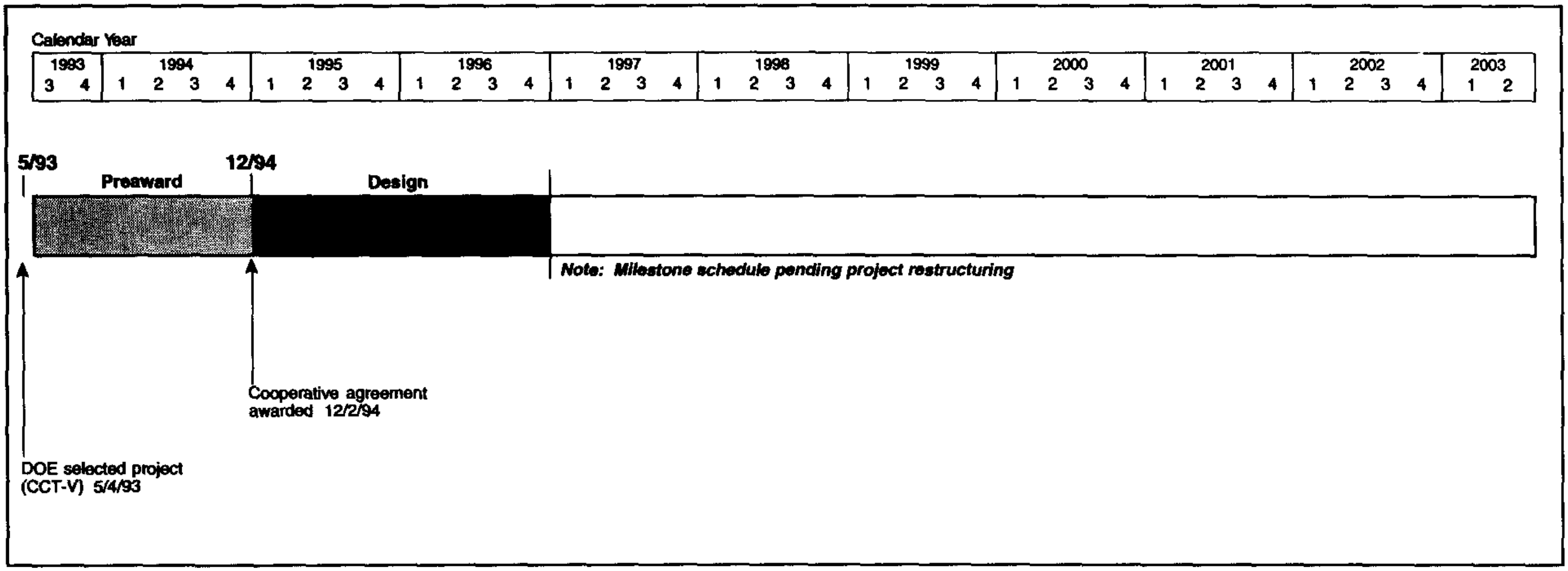
Project Objective:

To demonstrate and assess the reliability, availability, and maintainability of a utility-scale IGCC system using high-sulfur bituminous coal in an oxygen-blown, fixed-bed, slagging gasifier and the operability of a molten carbonate fuel cell fueled by coal gas, by an independent power producer under commercial terms and conditions.

Technology/Project Description:

The BG/L gasifier is supplied with steam, oxygen, limestone flux, and coals having a high fines content. During gasification, the oxygen and steam react with the coal and limestone to produce a raw coal gas rich in hydrogen and carbon monoxide. Raw coal gas exiting the gasifier is washed and cooled. Hydrogen sulfide and other sulfur compounds are removed. Elemental sulfur is reclaimed and disposed of as a by-product. Tars, oils, and dust are recycled to extinction in the gasifier. The resulting clean, medium-Btu fuel gas is used to fuel the gas turbine in the IGCC power island. A small portion of the clean gas is used for the MCFC.

The MCFC is composed of a molten carbonate electrolyte sandwiched between porous anode and cathode plates. Fuel (desulfurized, heated medium-Btu gas) and steam are fed continuously into the cathode. Electrical reactions produce direct electric current which is converted to alternating power in an inverter.



Note: Milestone schedule pending project restructuring

The project is demonstrating the use of eastern U.S. bituminous coal in a commercial-scale IGCC system and integrated MCFC module.

Project Status/Accomplishments:

The cooperative agreement was awarded December 2, 1994. The participant is looking for an east coast site.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for both repowering applications and new power plants. The technology is expected to be adaptable to a wide variety of potential market applications because of several factors. First, the BG/L gasification technology has successfully used a wide variety of U.S. coals. Also, the highly modular approach to system design makes the BG/L-based IGCC and molten carbonate fuel cell competitive in a wide range of plant sizes. In addition, the high efficiency and excellent environmental performance of the system are competitive with or superior to other fossil-fuel-fired power generation technologies.

The heat rate of the IGCC demonstration facility is 8,560 Btu/kWh (40% efficiency) and the commercial embodiment of the system has a projected heat rate of 8,035 Btu/kWh (42.5% efficiency). The commercial version of the molten carbonate fuel cell fueled by a BG/L gasifier is anticipated to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). These efficiencies represent greater than 20% reduction in emissions of CO_2 when compared to a conventional pulverized coal plant equipped with a scrubber. SO_2 emissions from the IGCC system are expected to be less than 0.1 lb/million Btu (99% reduction); NO_x emissions, less than 0.15 lb/million Btu (90% reduction).

Also, the slagging characteristic of the gasifier produces a nonleaching, glass-like slag that can be marketed as a usable by-product.

Piñon Pine IGCC Power Project

Participant:

Sierra Pacific Power Company

Additional Team Members:

Foster Wheeler USA Corporation—architect, engineer, and constructor
The M.W. Kellogg Company—technology supplier

Location:

Reno, Storey County, NV (Sierra Pacific Power Company's Tracy Station)

Technology:

Integrated gasification combined-cycle (IGCC) using the KRW air-blown pressurized fluidized-bed coal gasification system

Plant Capacity/Production:

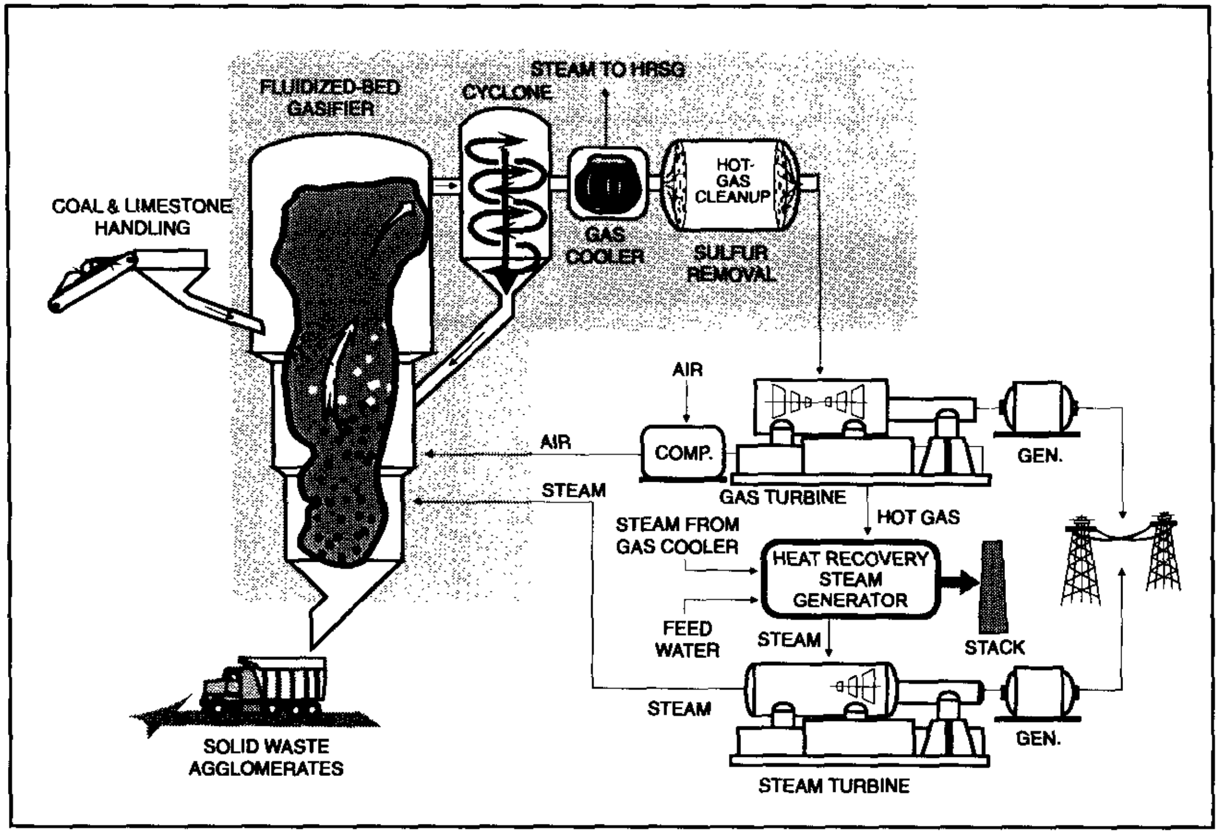
99 MWe (net)

Project Funding:

Total project cost	$308,551,000	100%
DOE	154,275,500	50
Participant	154,275,500	50

Project Objective:

To demonstrate air-blown, pressurized, fluidized-bed IGCC technology incorporating hot gas cleanup; to evaluate a low-Btu gas combustion turbine; and to assess long-term reliability, availability, maintainability, and environmental performance at a scale sufficient to determine commercial potential.



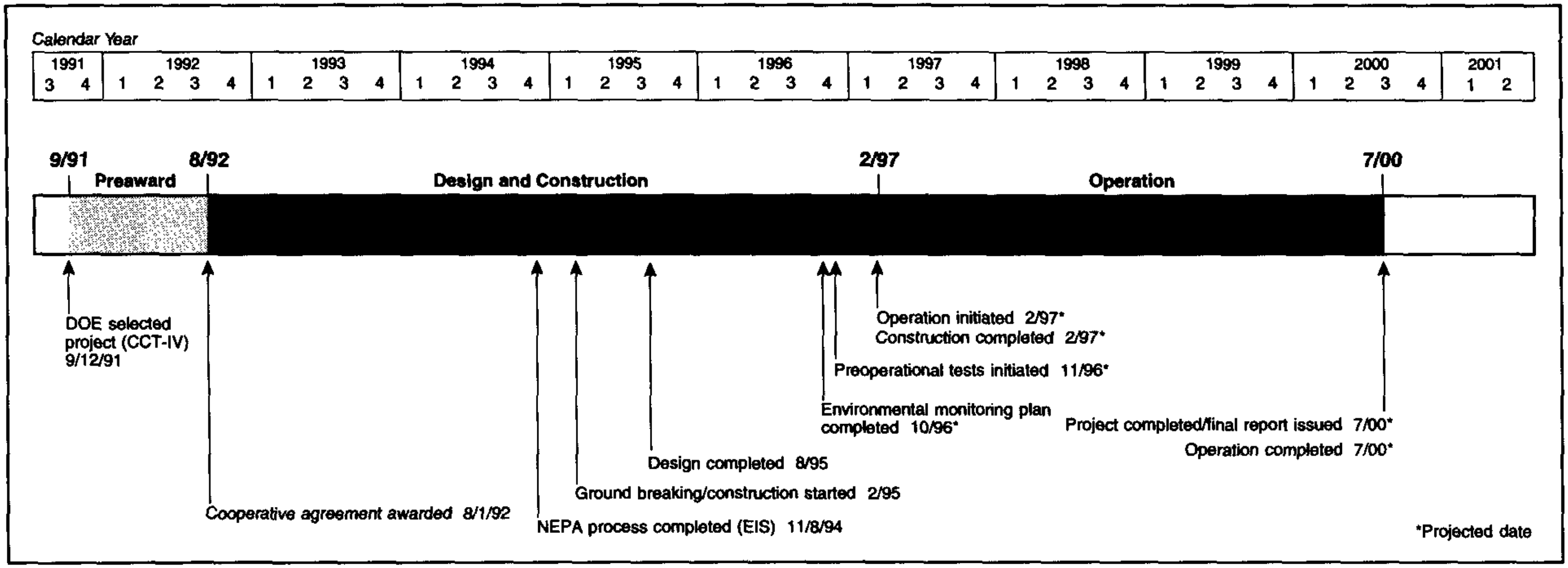
Technology/Project Description:

Dried and crushed coal and limestone are introduced into a pressurized, air-blown, fluidized-bed gasifier. Crushed limestone is used to capture a portion of the sulfur and to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits as calcium sulfate along with the coal ash in the form of agglomerated particles suitable for landfill.

Hot, low-Btu coal gas leaving the gasifier passes through cyclones which return most of the entrained particulate matter to the gasifier. The gas, which leaves the gasifier at about 1,700 °F, is cooled to about 1,100 °F before entering the hot-gas cleanup system. During cleanup, virtually all of the remaining particulates are removed by ceramic candle filters, and final traces of sulfur are removed by reaction with metal oxide sorbent in a transport reactor.

The hot, cleaned gas then enters the combustion turbine which is coupled to a generator designed to produce 61 MWe (gross). Exhaust gas is used to produce steam in a heat recovery steam generator. Superheated high-pressure steam drives a condensing steam turbine-generator designed to produce about 46 MWe (gross).

Due to the relatively low operating temperature of the gasifier and the injection of steam into the combustion fuel stream, the NO_x emissions are 0.069 lb/million Btu (94% reduction). Due to the combination of in-bed sulfur capture and hot gas cleanup, SO_2 emissions are 0.069 lb/million Btu (90% reduction).



In the demonstration project, 880 tons/day of coal are converted into 107 MWe (gross), or 99 MWe (net), for export to the grid. Western bituminous coal (0.5–0.9% sulfur) from Utah is the design coal; tests using eastern bituminous coal containing 2–3% sulfur also are planned. The integrated gasification system is being built at Sierra Pacific Power Company's Tracy Station, near Reno, NV.

Project Status/Accomplishments:

The project is in the final stages of engineering and construction. Steel erection was started in late 1995 and completed in February 1996. Consistent with an environmentally pristine area, all solid feedstocks and products will be unloaded, conveyed, and stored in completely enclosed subsystems. Major pieces of equipment, including the gasifier, syngas coolers, particulate filters, cyclones, and two turbines were vendor-fabricated, shipped to the site, and lifted into place consistent with an overall modular mechanical and erection schedule.

The combustion turbine and steam turbine have been installed, aligned with generators, and made ready for commissioning. Operator training for the combustion turbine has been ongoing since mid-April 1996 in preparation for start-up on natural gas in mid-August. The switch to coal gas will be made as the gasification island becomes operational in the fourth quarter of 1996.

Commercial Applications:

The Piñon Pine IGCC system concept is suitable for new power generation, repowering needs, and cogeneration applications. The net effective heat rate for a proposed greenfield plant using this technology is projected to be 7,800 Btu/kWh (43.7% efficiency), representing a 20% increase in thermal efficiency as compared to a conventional pulverized coal plant with a scrubber and a comparable reduction in CO_2 emissions. The compactness of IGCC systems reduces space requirements per unit of energy generated relative to other coal-based power generation systems, and the advantages provided by modular construction reduce the financial risk associated with new capacity additions.

The KRW IGCC technology is capable of gasifying all types of coals, including high-sulfur and high-swelling coals, as well as bio- or refuse-derived waste, with minimal environmental impact. This versatility provides numerous economic advantages for the depressed mineral extraction and cleanup industries. There are no significant process waste streams that require remediation. The only solid waste from the plant is a mixture of ash and calcium sulfate, a nonhazardous waste.

Tampa Electric Integrated Gasification Combined-Cycle Project

Participant:

Tampa Electric Company

Additional Team Members:

Texaco Development Corporation—gasification technology supplier
General Electric Company—combined-cycle technology supplier
GE Environmental Systems, Inc.—hot-gas cleanup technology supplier
TECO Power Services Corporation—project manager and marketer
Bechtel Power Corporation—architect and engineer

Location:

Mulberry, Polk County, FL (Tampa Electric Company's Polk Power Station, Unit 1)

Technology:

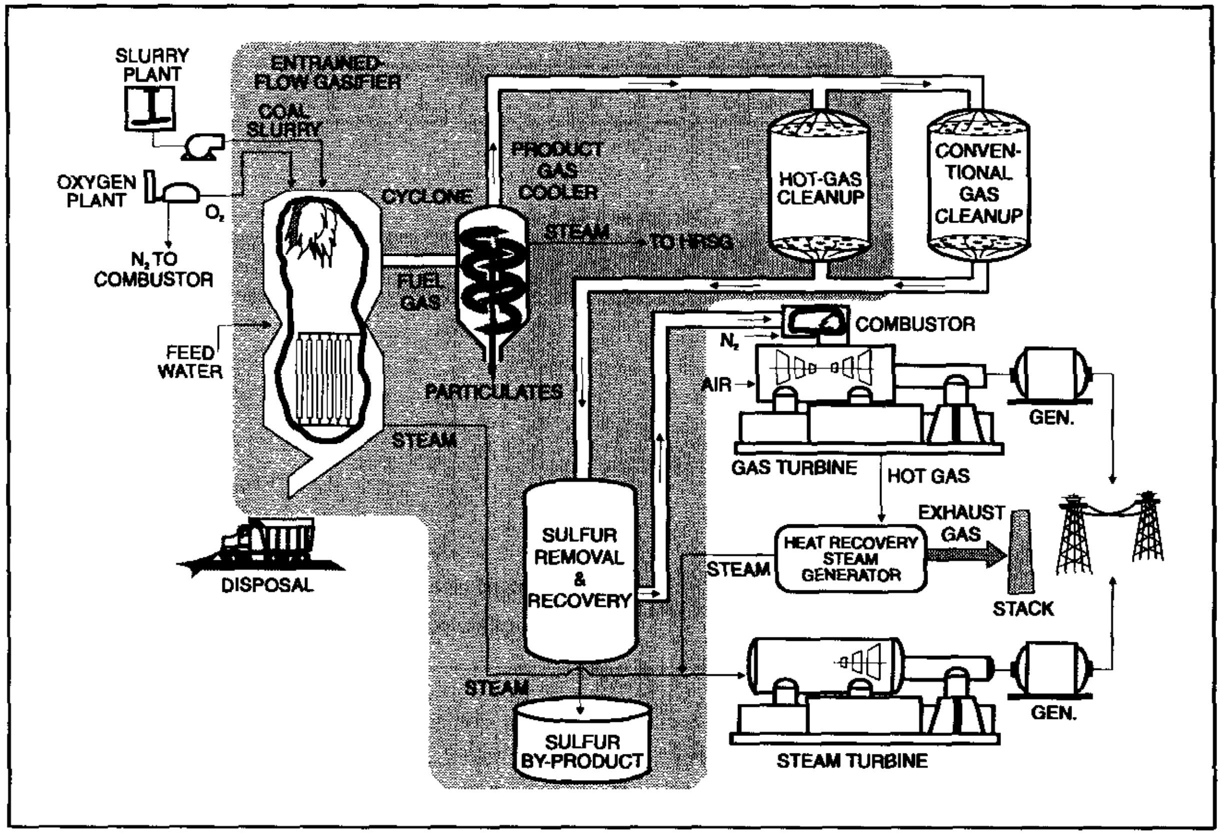
Integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology and incorporating both conventional, low-temperature acid-gas removal and hot-gas moving-bed desulfurization

Plant Capacity/Production:

250 MWe (net)

Project Funding:

Total project cost	$285,988,446	100%
DOE	142,994,223	50
Participant	142,994,223	50



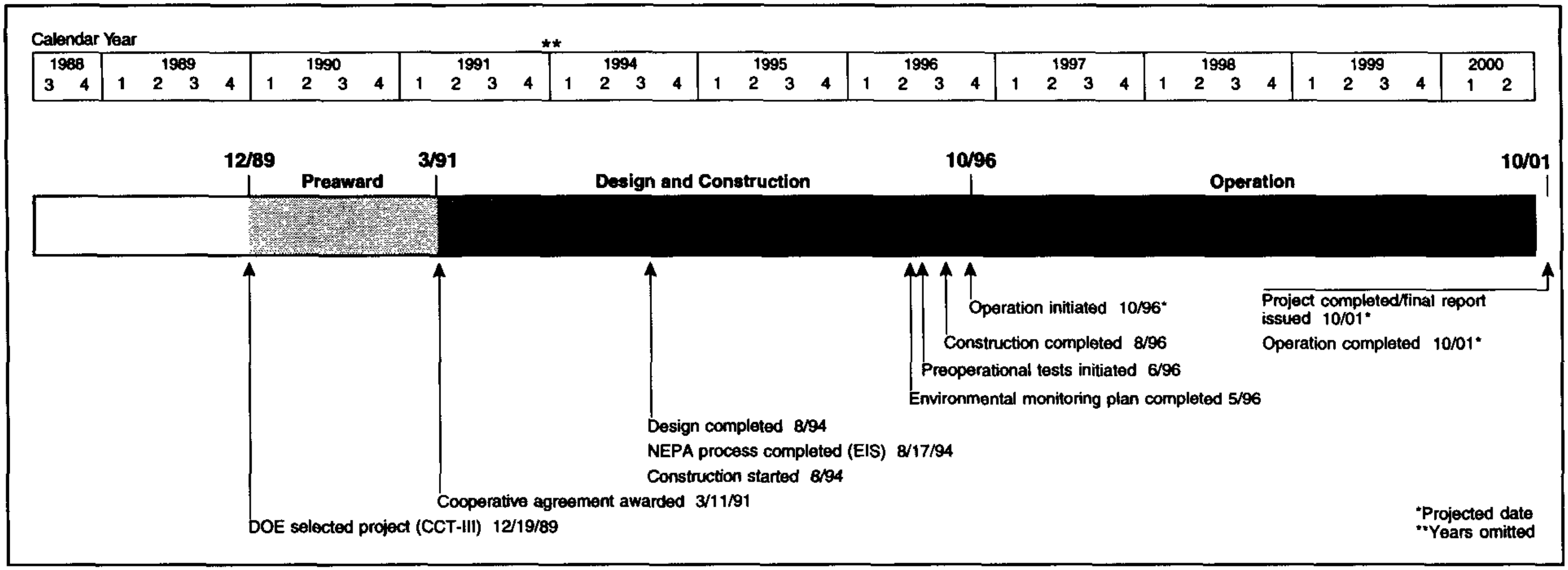
Project Objective:

To demonstrate IGCC technology in a greenfield, commercial, electric utility application at the 250-MWe size with a Texaco gasifier. To demonstrate the integrated performance of a metal oxide hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection (from the air separation plant) for power augmentation and NO_x control.

Technology/Project Description:

Texaco's pressurized, oxygen-blown, entrained-flow gasifier is used to produce a medium-Btu fuel gas. Coal/water slurry and oxygen are reacted at high temperature and pressure to produce a high-temperature syngas. Molten coal-ash flows out of the bottom of the vessel and into a water-filled quench tank where it is turned into a solid slag. The syngas from the gasifier moves to a high-temperature heat-recovery unit which cools the gases.

The cooled gases flow to a particulate-removal section before entering gas-cleanup trains. A portion of the syngas is passed through a moving bed of metal oxide absorbent to remove sulfur. The remaining syngas is further cooled through a series of heat exchangers before entering a conventional gas-cleanup train where sulfur is removed by an acid-gas removal system. Combined, these cleanup systems are expected to maintain sulfur levels below 0.21 lb/million Btu (96% capture). The cleaned gases are then routed to a combined-cycle system for power generation. A gas turbine generates about 192 MWe. Thermally generated NO_x is controlled to below 0.27 lb/million Btu by injecting nitrogen as a dilutent in the turbine's combustion section. A heat-



recovery steam-generator uses heat from the gas-turbine exhaust to produce high-pressure steam. This steam, along with the steam generated in the gasification process, is routed to the steam turbine to generate an additional 120 MWe (gross). The IGCC heat rate for this demonstration is expected to be approximately 8,600 Btu/kWh (40% efficient).

The demonstration project involves only the first 250 MWe (net) of the planned 1,150-MWe Polk Power Station. Being used in the demonstration are Illinois 6 and Pittsburgh 8 bituminous coals having sulfur contents ranging 2.5–3.5%.

By-products from the process—sulfuric acid and slag—can be sold commercially, sulfuric acid by-products as a raw material to make agricultural fertilizer and the nonleachable slag for use in roofing shingles and asphalt roads and as a structural fill in construction projects.

Project Status/Accomplishments:

Tampa Electric held a formal groundbreaking ceremony at the Polk County site on November 2, 1994. Site construction is complete. The combined cycle has generated the first 235 MWe at Polk on fuel oil. The gasifier achieved first light-off on coal on July 19, 1996. The gasifier operated on Pittsburgh No. 8 coal for 20 hours before being shut down to correct minor water leaks downstream of the gasifier. Initiation of integrated tests of the gasifier and combined-cycle plant is planned for September 1996. Operation of the sulfuric acid plant on coal gas is also planned for September.

Reclamation of the area west of Rt. 37 is complete. This area was approved for development of a deep pond fishing and recreational area by the state of Florida.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for new electric power generation, repowering needs, and cogeneration applications. The net effective heat rate for the Texaco-based IGCC is expected to be below 8,500 Btu/kWh, which makes it very attractive for baseload applications. Commercial IGCCs should achieve better than 98% SO_2 capture with a NO_x emissions reduction of 90%.

The Texaco-based system has already been proven capable of handling both subbituminous and bituminous coals. This demonstration project is scaling up the technology from Cool Water's 100-MWe system to the 250-MWe size.

Wabash River Coal Gasification Repowering Project

Participant:

Wabash River Coal Gasification Repowering Project Joint Venture (a joint venture of Destec Energy, Inc., and PSI Energy, Inc.)

Additional Team Members:

PSI Energy, Inc.—host

Destec Energy, Inc.—engineer, gas plant operator, and technology supplier

Location:

West Terre Haute, Vigo County, IN (PSI Energy's Wabash River Generating Station, Unit 1)

Technology:

Integrated gasification combined-cycle (IGCC) using Destec's two-stage, entrained-flow gasification system

Plant Capacity/Production:

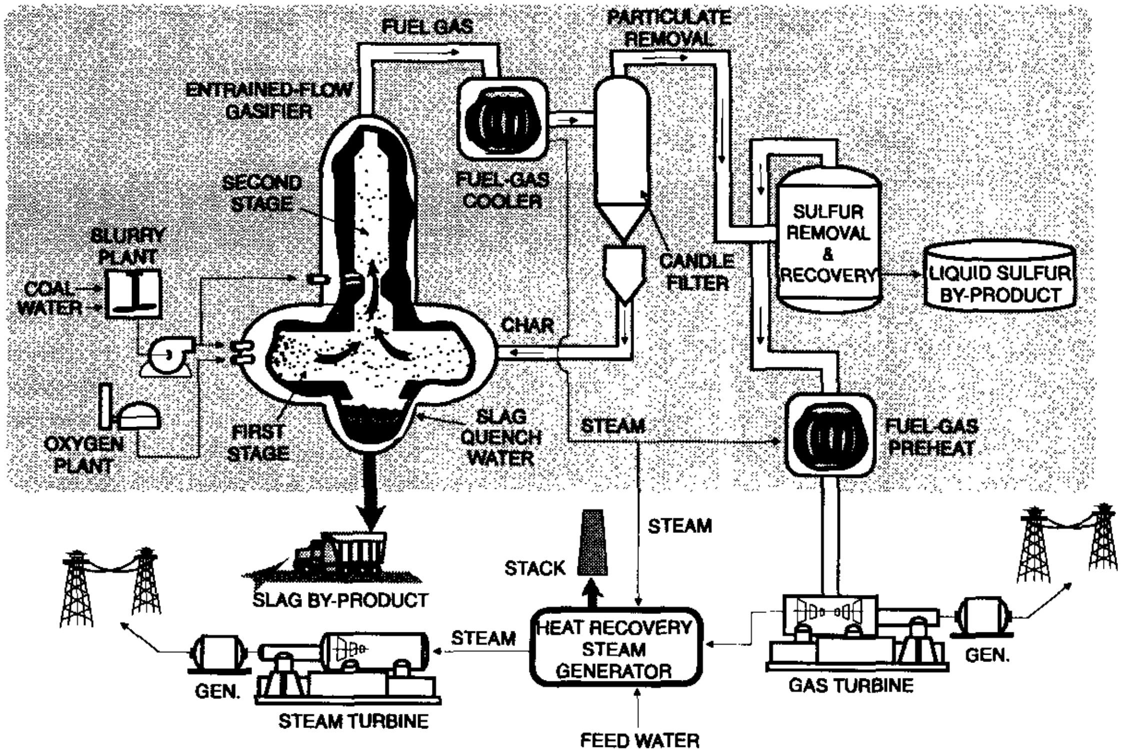
262 MWe (net)

Project Funding:

Total Project cost	$438,200,000	100%
DOE	219,100,000	50
Participant	219,100,000	50

Project Objective:

To demonstrate utility repowering with a two-stage, oxygen-blown IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal, and to assess long-term reliability, availability, and maintainability of the system at a fully commercial scale.

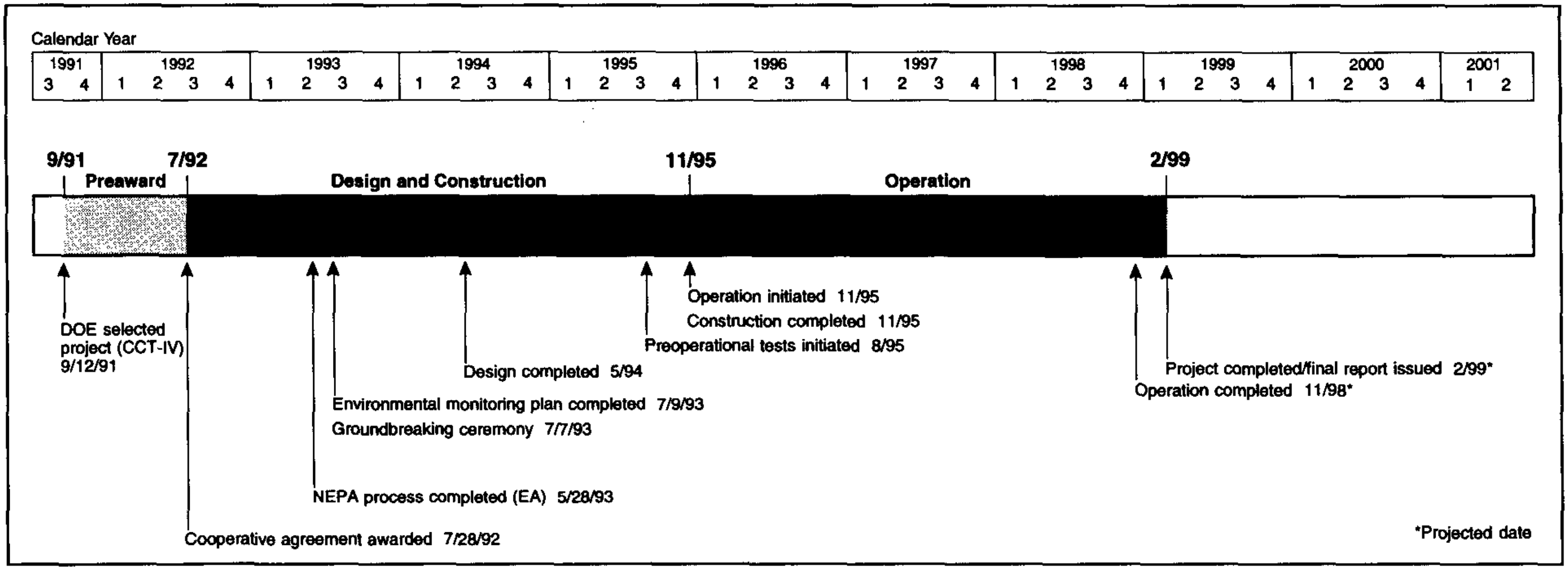


Technology/Project Description:

Coal is ground, slurried with water, and gasified in a pressurized, two-stage (slagging first stage and non-slagging entrained-flow second stage), oxygen-blown, gasifier. The product gas is cooled through heat exchangers and passed through a conventional cold gas cleanup system which removes particulates, ammonia, and sulfur. The clean, medium-Btu gas is then reheated and burned in an advanced 192-MWe (gross) gas turbine. Hot exhaust from the gas turbine is passed through a heat recovery steam generator to produce high-pressure steam. High-pressure steam is also produced from the gasification plant and superheated in the heat recovery steam generator. The combined high-pressure steam flow is supplied to an existing 104-MWe (gross) steam turbine.

The process has the following subsystems: a coal-grinding and slurry system, an entrained-flow coal gasifier, a syngas heat recovery system, a cold gas cleanup system which produces a marketable sulfur by-product, a combustion turbine capable of using coal-derived fuel gas, a heat recovery steam generator, and a repowered steam turbine.

One of six units at PSI Energy's Wabash River Generating Station, located in West Terre Haute, IN, is being repowered. The demonstration unit will be designed to generate 262 MWe (net) using 2,544 tons/day of high-sulfur (2.3–5.9% sulfur), Illinois Basin bituminous coal. The anticipated heat rate for the repowered unit is approximately 9,000 Btu/kWh (38% efficiency). Using high-sulfur bituminous coal, SO_2 emissions are expected to be less than 0.1 lb/million Btu (98% reduc-



tion). NO_x emissions are expected to be less than 0.1 lb/million Btu (90% reduction). The project represents the largest single-train IGCC plant in operation in the world.

Project Status/Accomplishments:

The plant began commercial operation in November 1995. Through July 1996, the plant has operated more than 1,000 hours on syngas in combined-cycle mode and has produced almost 170,000 MWh of electricity on syngas. The combustion turbine has demonstrated 192 MWe (100% of nameplate) and the gasifier has demonstrated 1,825 million Btu/hr, HHV (103% of nameplate). The longest continuous operation on syngas was 151 hours. The primary problem area has been the reliability of the particulate removal system, primarily due to breakage of ceramic candle filters. Further testing and modifications to the particulate removal system are under way to minimize element breakage.

Commercial Applications:

Throughout the United States, particularly in the Midwest and East, there are more than 95,000 MWe of existing coal-fired utility boilers that will be over 30 years old in 1996. Many of these aging plants are without air pollution controls and are candidates for repowering with IGCC technology. Repowering these plants with IGCC systems will improve plant efficiencies and reduce SO_2, NO_x, and CO_2 emissions. The modularity of the gasifier technology will permit a range of units to be considered for repowering, and the relatively short construction schedule for the technology will allow utilities greater flexibility in designing strategies to meet load requirements. Also, the high degree of fuel flexibility inherent in the gasifier design will provide utilities with more choice in selecting fuel supplies to meet increasingly stringent air quality regulations.

Due to the advantages of modularity, rapid and staged on-line generation capability, high efficiency, fuel flexibility, environmental controllability, and reduced land and natural resource needs, the IGCC system is also a strong contender for new electric power generating facilities. Commercial offerings of the technology will be based on a 300-MWe train which is ideally suited to utility-scale power generation applications. The system heat rate for a new power plant based on this technology is expected to realize at least a 20% improvement in efficiency compared to a conventional pulverized-coal-fired plant with flue gas desulfurization. The improved system efficiency also results in a similar decrease in CO_2 emissions.

Healy Clean Coal Project

Participant:

Alaska Industrial Development and Export Authority

Additional Team Members:

Golden Valley Electric Association—host utility
Stone and Webster Engineering Corp.—engineer
TRW, Inc.—technology supplier
Joy Technologies, Inc.—technology supplier

Location:

Healy, Denali Borough, AK (adjacent to Healy Unit #1)

Technology:

TRW's advanced entrained (slagging) combustor
Joy Technologies' spray dryer absorber with sorbent recycle

Plant Capacity/Production:

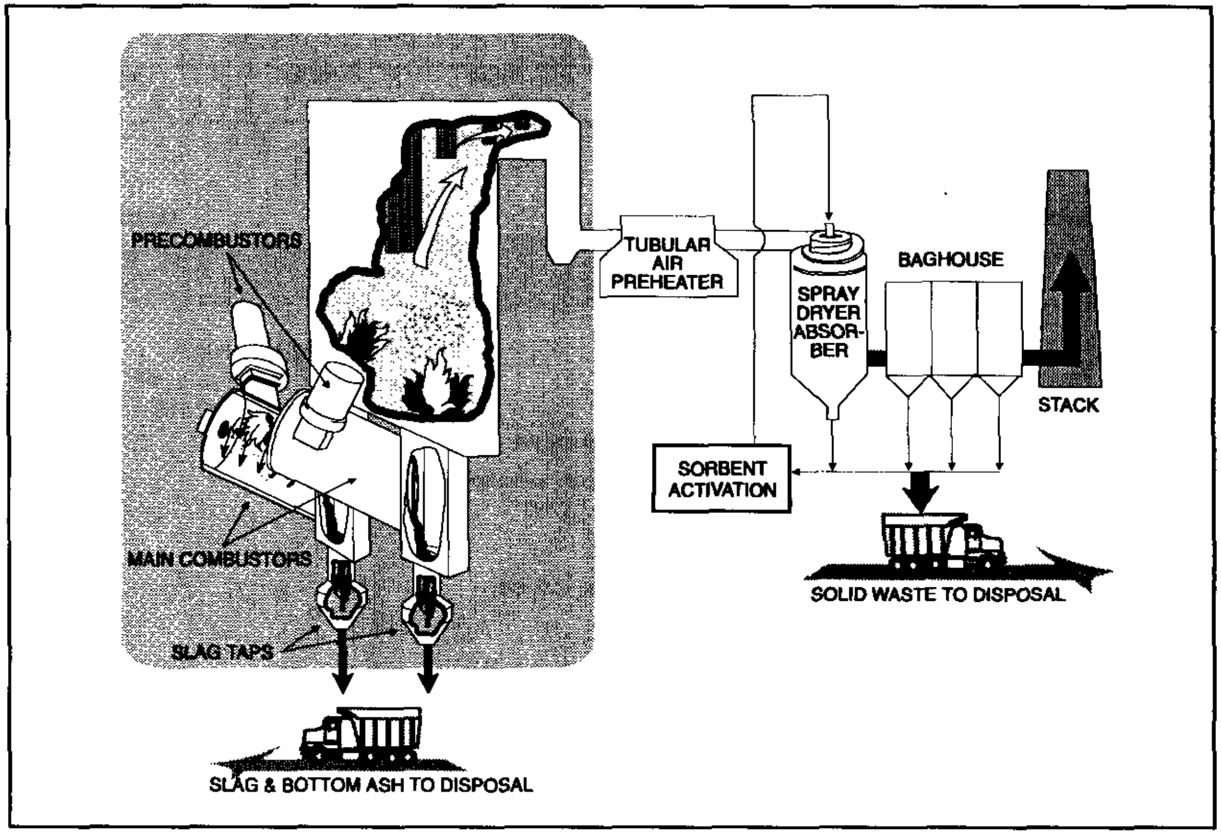
50 MWe (nominal electric output)

Project Funding:

Total project cost	$242,058,000	100%
DOE	117,327,000	48
Participant	124,731,000	52

Project Objective:

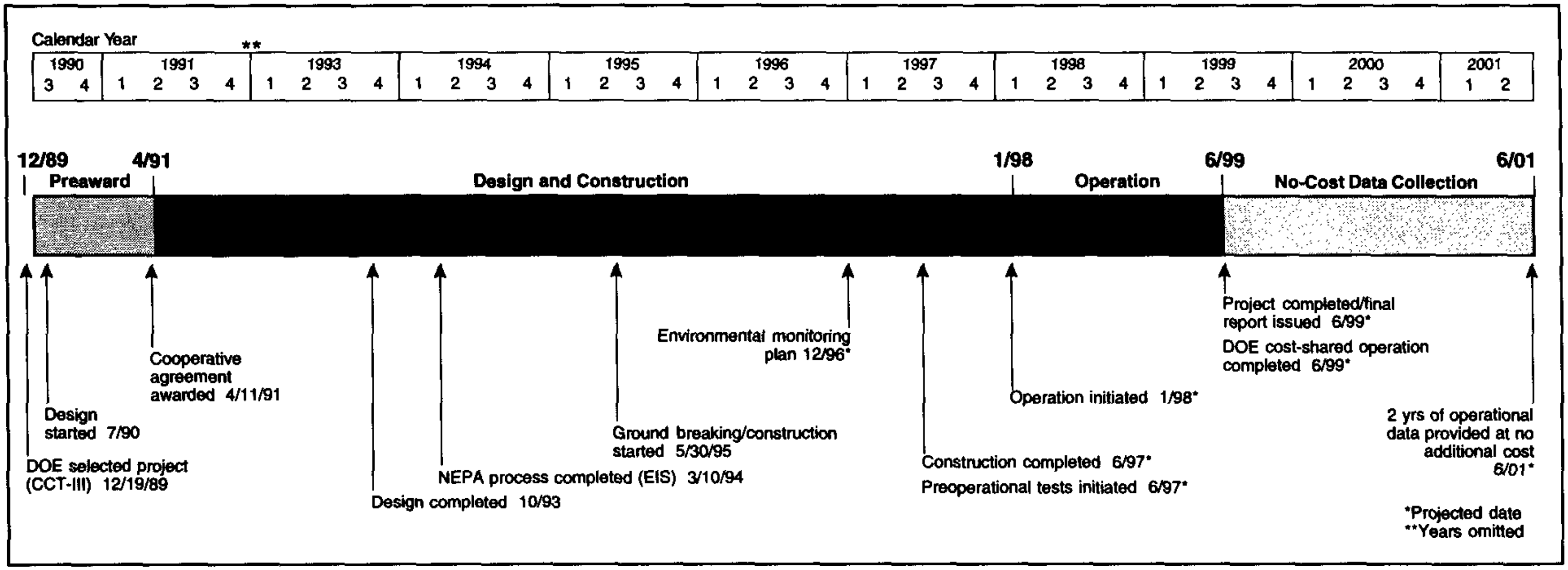
To demonstrate an innovative new power plant design featuring integration of an advanced combustor and heat recovery system coupled with both high- and low-temperature emissions control processes.



Technology/Project Description:

The project is to be a nominal 50-MWe facility consisting of two pulverized-coal-fired combustor systems. Emissions of SO_2 and NO_x will be controlled using TRW's slagging combustion systems with staged fuel and air, a boiler that controls fuel- and thermal-related conditions, and limestone injection. Additional SO_2 will be removed using Joy's activated recycle spray dryer absorber system. Performance goals are NO_x emissions of less than 0.2 lb/million Btu, particulate emissions of 0.015 lb/million Btu, and SO_2 removal greater than 90%. The performance coal consists of 35% run-of-mine and 65% waste coal, with the waste coal having a lower heating value and significantly more ash.

A coal-fired precombustor increases the air inlet temperature for optimum slagging performance. The TRW slagging combustors are bottom-mounted on the boiler hopper. The main slagging combustor consists of a water-cooled cylinder that slopes toward a slag opening. The precombustor burns 25–40% of the total coal input. The remaining coal is injected axially into the combustor, rapidly entrained by the swirling precombustor gases and additional air flow, and burned under substoichiometric (fuel-rich) conditions for NO_x control. The ash forms molten slag which accumulates on the water-cooled walls and is driven by aerodynamic and gravitational forces through a slot into the slag recovery section. About 70–80% of the coal's ash is removed as molten slag. The hot gas is then ducted to the furnace where, to ensure complete combustion, additional air is supplied from the tertiary air windbox to NO_x ports and to final overfire air ports.



*Projected date
**Years omitted

Pulverized limestone ($CaCO_3$) for SO_2 control is fed into the combustor where most is flash calcined. The mixture of this lime (CaO) and the ash not slagged, called flash-calcined material, is removed in the fabric filter (baghouse) system. A small part of the flash-calcined material is disposed of, but most is conveyed to a mixing tank where water is added to form a 45% flash-calcined-material solids slurry. The slurry leaving the mixing tank is pumped to a grinding mill where it is mechanically activated by abrasive grinding. Feed slurry is pumped from the feed tank to the spray dryer absorber where the slurry is atomized using Joy dry scrubbing technology. SO_2 in the flue gas reacts with the slurry droplets as water is simultaneously evaporated. SO_2 is further removed from the flue gas by reacting with the dry flash-calcined material on the baghouse filter bags.

The project site is adjacent to the existing Healy Unit #1 near Healy, AK. Power will go to the Golden Valley Electric Association (GVEA). The plant will use a nominal 900 tons/day of subbituminous coal containing a nominal 0.2% sulfur and waste coal. The project will collect performance data for 3 years, with 2 years of data being provided at no cost to DOE. A hazardous air pollutant monitoring program will also be implemented.

To address concerns about potential impact to the nearby Denali National Park and Preserve, DOE, the National Park Service, GVEA, and the project participant entered into an agreement to reduce the emissions from Unit #1 so that the combined emissions from the two units will be only slightly greater than those currently emitted from Unit #1 alone. Total site emissions will be further reduced to current levels if necessary to protect the park.

Project Status/Accomplishments:

Erection of structural steel is virtually complete. On-site fabrication of the spray dryer absorber system is complete as is the erection of the stack. Installation of the coal-handling, slagging combustor, boiler systems, and mechanical and electrical tie-ins to Unit No. 1 are proceeding on schedule.

Commercial Applications:

This technology has a wide range of applications. It is appropriate for any size utility or industrial boiler in new and retrofit uses. It can be used in coal-fired boilers as well as in oil- and gas-fired boilers because of its high ash removal capability. However, cyclone boilers may be the most amenable type to retrofit with the slagging combustor because of the limited supply of high-Btu, low-sulfur, low-ash-fusion-temperature coal that cyclone boilers require. The commercial availability of cost-effective and reliable systems for SO_2, NO_x, and particulate control is important to potential users planning new capacity, repowering, or retrofits to existing capacity in order to comply with CAAA of 1990 requirements.

Coal Diesel Project

Participant:
Arthur D. Little, Inc.

Additional Team Members:
University of Alaska at Fairbanks—host and cofunder

Cooper Energy Services (Cooper-Bessemer Reciprocating Products Division is a division of Cooper Energy Services which is owned by Cooper Industries.)—engine supplier and commercializer

CQ Inc.—coal-slurry supplier

PSI—cleanup system designer

AMBAC International—coal-water fuel injection system components supplier

Usibelli Coal Company—coal supplier

Location:
Fairbanks, Alaska (University of Alaska facility)
(Pending DOE approval)

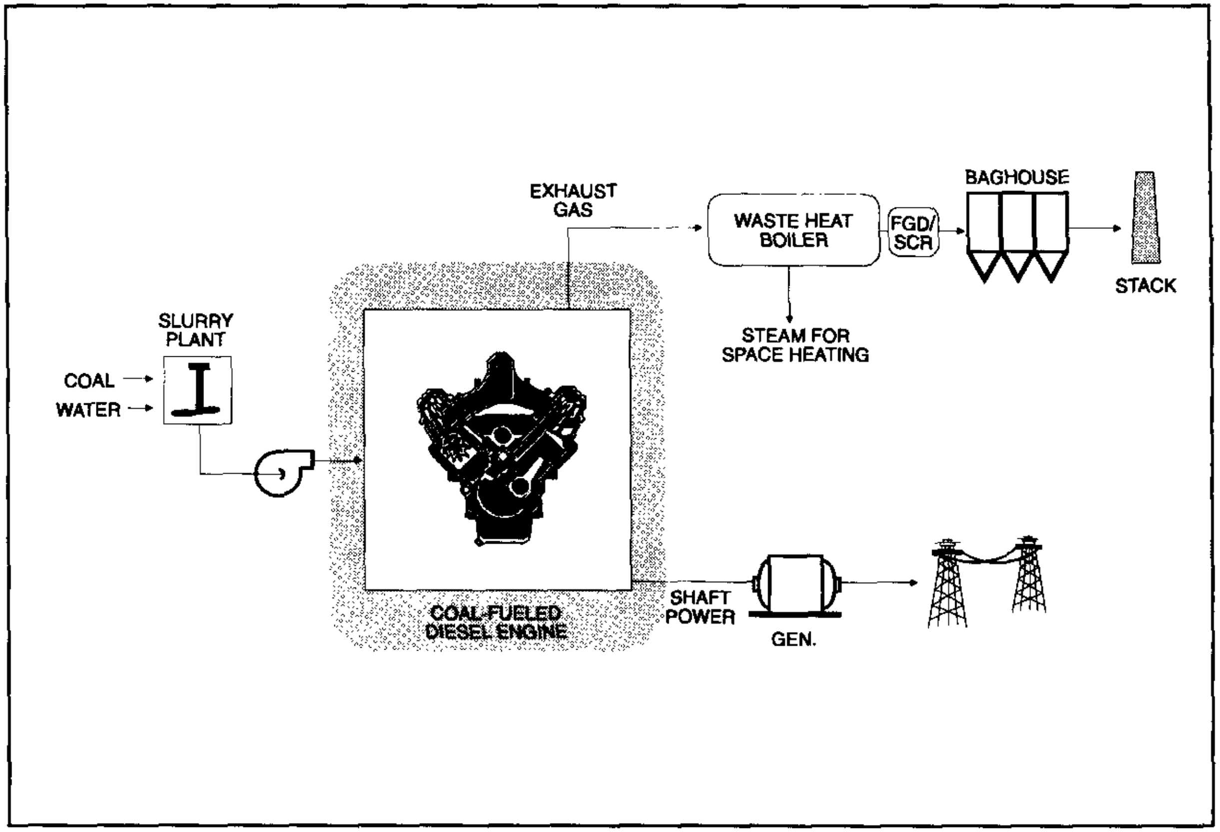
Technology:
Cooper-Bessemer's coal-fueled diesel engine

Plant Capacity/Production:
6.3 MWe (net)

Project Funding:

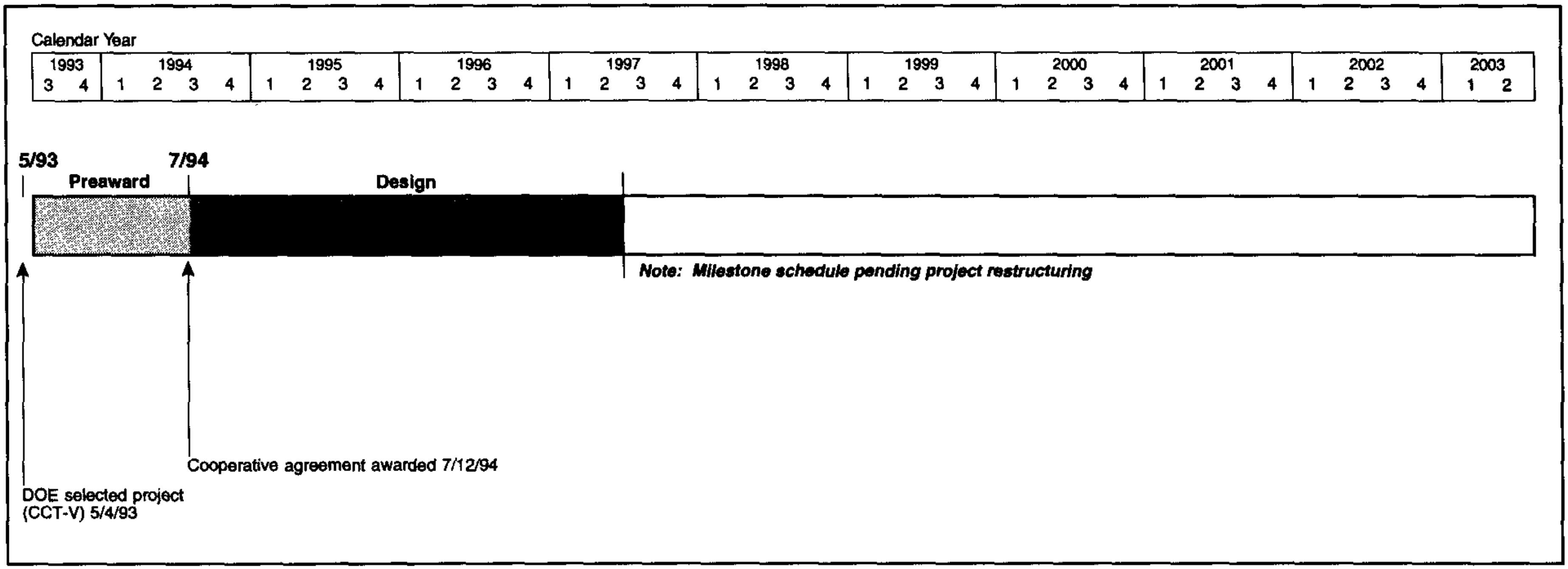
Total project cost	$38,309,516	100%
DOE	19,154,758	50
Participant	19,154,758	50

Project Objective:
To demonstrate an advanced, coal-fueled diesel engine system based on Cooper-Bessemer's LSB/LSVB diesel engine series. To provide critical data on the performance, reliability, and wear information of all major subsystems.



Technology/Project Description:
The project involves modifying a Cooper-Bessemer medium-speed (400 rpm) diesel engine to operate on coal-water fuel. Engine modifications include a larger camshaft and fuel cams, modified engine block, hardened piston rings and liners, and hardened turbocharger blades. The system utilizes a coal-water fuel having a nominal 50% solids loading with a 2.5% ash cleaned-coal. The subbituminous Alaskan coal is ground and dried using an advanced hot-water drying process. The dried product is further ground and slurried with water and then injected into each of the engine's 20 cylinders. The exhaust gases from the engine pass through an integrated emission-control system capable of reducing pollutants while protecting the engine's turbocharger and maintaining high engine and overall system efficiency. The exhaust gases pass through a waste heat boiler to supply steam for space heating. Critical data on performance, reliability, and wear are being collected for all major subsystems including the coal-water fuel metering and injection system, medium-speed diesel, lube oil protection system, exhaust cyclone, turbocharger, waste heat boiler, and exhaust emission cleanup system.

The exhaust emission cleanup system incorporates cyclones to remove the larger particulates, a selective catalytic recovery system for NO_x control, a duct sorbent injection system for SO_2 control, and baghouse for final collection of ash particulates and spent sorbent.



Project Status/Accomplishments:

Easton Utilities, the original host, withdrew from the project after reevaluating its long-term need for power. The participant plans to resite the project at the University of Alaska in Fairbanks, where the engine would operate on subbituminous Alaskan coals. An extension until June 30, 1997, has been granted to complete restructuring activities, obtain firm financial commitments, and establish the schedule and milestones for the project.

Design activities are ongoing. In addition, full-scale single-cylinder coal fuel evaluation testing and component durability testing will continue at Cooper's research engine facility in Mount Vernon, OH.

Commercial Applications:

The coal-fueled diesel engine is particularly suited for small (below 50 MWe) electric power generation markets. Projected markets include small nonutility generators and repowering applications for small coal-fired boilers. The net effective heat rate for the mature diesel system is expected to be 6,830 Btu/kWh (48%), which makes it very competitive with similarly sized coal- and fuel-oil-fired installations. Environmental emissions from commercial diesel systems should be reduced to levels between 50% and 70% below NSPS.

The diesel system has already achieved more than 200 hours of operation using coal-water fuel in a 6-cylinder engine at Cooper's test facilities in Ohio. Over 6,000 hours of coal-water fuel operation in the 20-cylinder engine are planned for this project. Demonstration of the long-term reliability of the critical components in the diesel system will provide power producers with an efficient and environmentally superior option for future power.

Externally Fired Combined-Cycle Demonstration Project

Participant:
Pennsylvania Electric Company

Additional Team Members:
Hague International—technology developer and supplier
Black & Veatch—engineer and construction manager

Location:
Site under negotiation

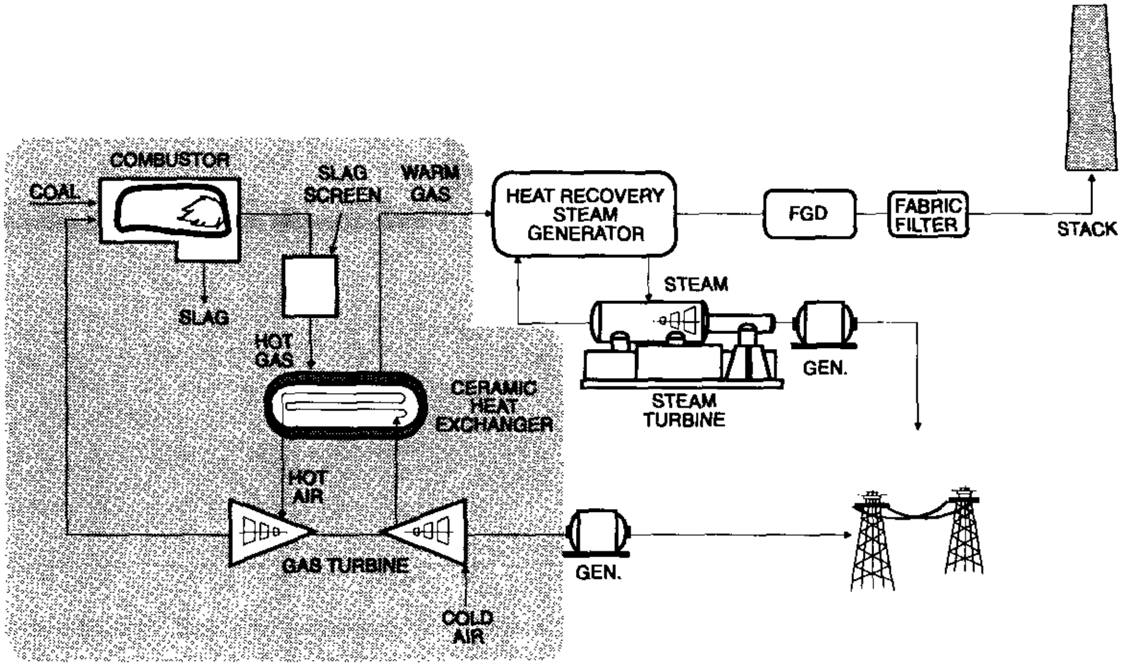
Technology:
Hague International's externally fired combined-cycle (EFCC) system using a novel, high-temperature, ceramic gas-to-air heat exchanger

Plant Capacity/Production:
5 MWe slipstream

Project Funding:

Total project cost	$146,832,000	100%
DOE	73,416,000	50
Participant	73,416,000	50

Project Objective:
To demonstrate an externally fired combined-cycle system through the use of a novel ceramic heat exchanger and to assess the system's environmental and economic performance for meeting future energy needs.



Technology/Project Description:
In this project, an existing coal-fueled steam plant is being repowered by adding an externally fired gas turbine to form a combined-cycle system. The central feature of the EFCC is a ceramic air heater or heat exchanger (CerHx®) and an atmospheric combustor which together replace a conventional combustion system in an open-cycle gas turbine.

Coal is first combusted in a staged combustor for NO_x control. Particulate-laden gases exit the combustor and enter the slag screen where all particles larger than about 10 microns are collected. Air from the turbine compressor is heated by exchange with the hot product gas in the CerHx®. The product gas is then passed through a heat recovery steam generator, where more heat is extracted to drive a steam turbine generator and produce electricity. The product gas is finally passed through a gas cleanup system consisting of a flue gas desulfurizer and a fabric filter before exiting to the atmosphere through the stack. The hot air from the CerHx® is passed through a gas turbine to produce additional electricity before being fed to the combustor.

The attractiveness of the EFCC lies in its ability to eliminate the need for a hot gas cleanup system to protect the costly gas turbine gas-path components from the corrosive and abrasive elements in the combustion product gas. Instead, the gas turbine operates on indirectly heated clean air and the gas path is never exposed to the corrosive elements in the fuel or product gas. The CerHx® raises the temperature of the air to the turbine

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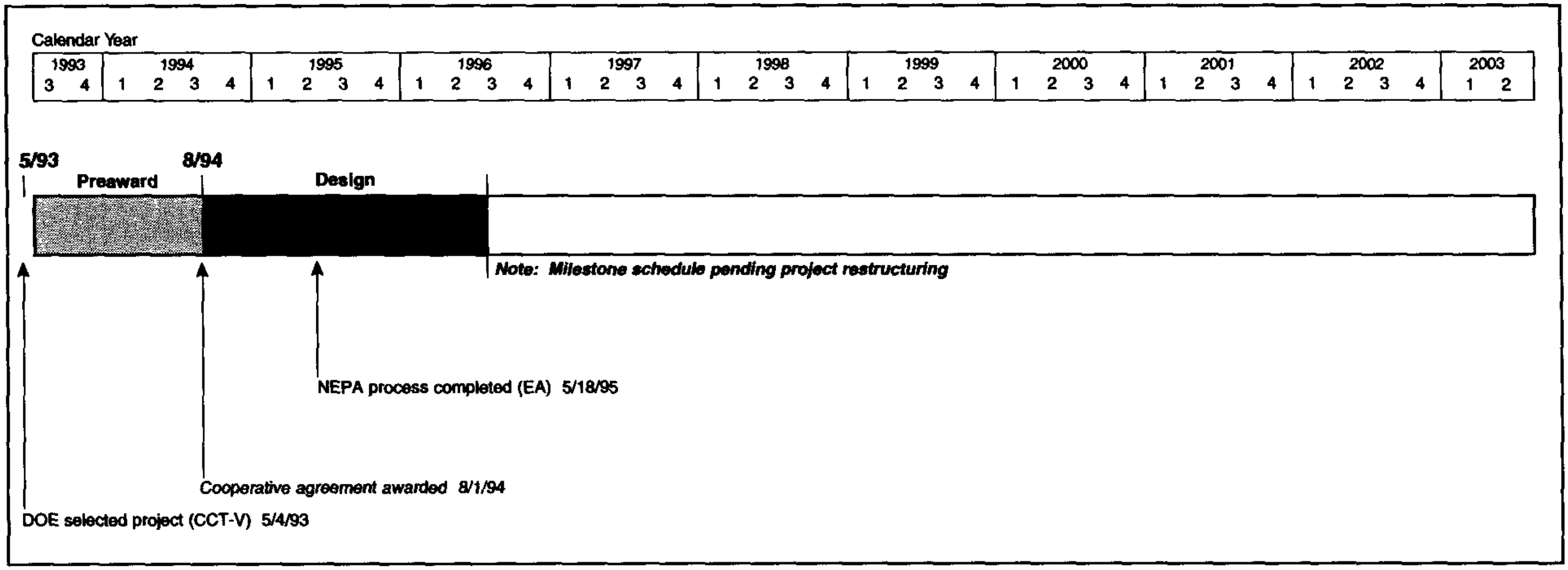
CerHx is a registered trademark of Hague International.



inlet conditions using tube elements that are manufactured from corrosion resistant, toughened, ceramic materials.

Potential SO_x release is reduced by more than 90% through capture in the flue gas desulfurization system. NO_x emissions are expected to be less than 0.13 lb/million Btu.

Project Status/Accomplishments:

In May 1995, Pennsylvania Electric stopped all project activity due to lack of progress in resolving technical issues relating to the ceramic heat exchanger. The utility has announced it will not pursue the full-scale EFCC at Warren Station. However, the utility has proposed demonstration of a scaled-down EFCC in a slipstream at its Seward Station. Hague International is seeking non-federal funds to continue developmental testing of the ceramic heat exchanger at the Kennebunk facility.

Commercial Applications:

The EFCC system concept is suitable for new electric power generation, repowering needs, and cogeneration applications. The potential commercial market for EFCC systems is expected to be about 24 GWe by 2010. The net effective heat rate for a 300-MWe greenfield plant using this technology is projected to be 7,790 Btu/kWh. This represents a 20% increase in thermal efficiency compared to a conventional pulverized coal plant with a scrubber.

SO_2 emissions are expected to be less than 0.081 lb/million Btu, which is a reduction of more than 90% for most coals. NO_x emissions are expected to be less than 0.15 lb/million Btu, and particulate emissions are expected to be less than 0.015 lb/million Btu.

Environmental Control Devices Fact Sheets

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Project completed.

Participant:
The Babcock & Wilcox Company

Additional Team Members:
Wisconsin Power and Light Company—cofunder and host
Sargent and Lundy—engineer for coal handler
Electric Power Research Institute—cofunder
State of Illinois, Department of Energy and Natural Resources—cofunder
Utility companies (14 cyclone boiler operators)—cofunders

Location:
Cassville, Grant County, WI (Wisconsin Power and Light Company's Nelson Dewey Station, Unit No. 2)

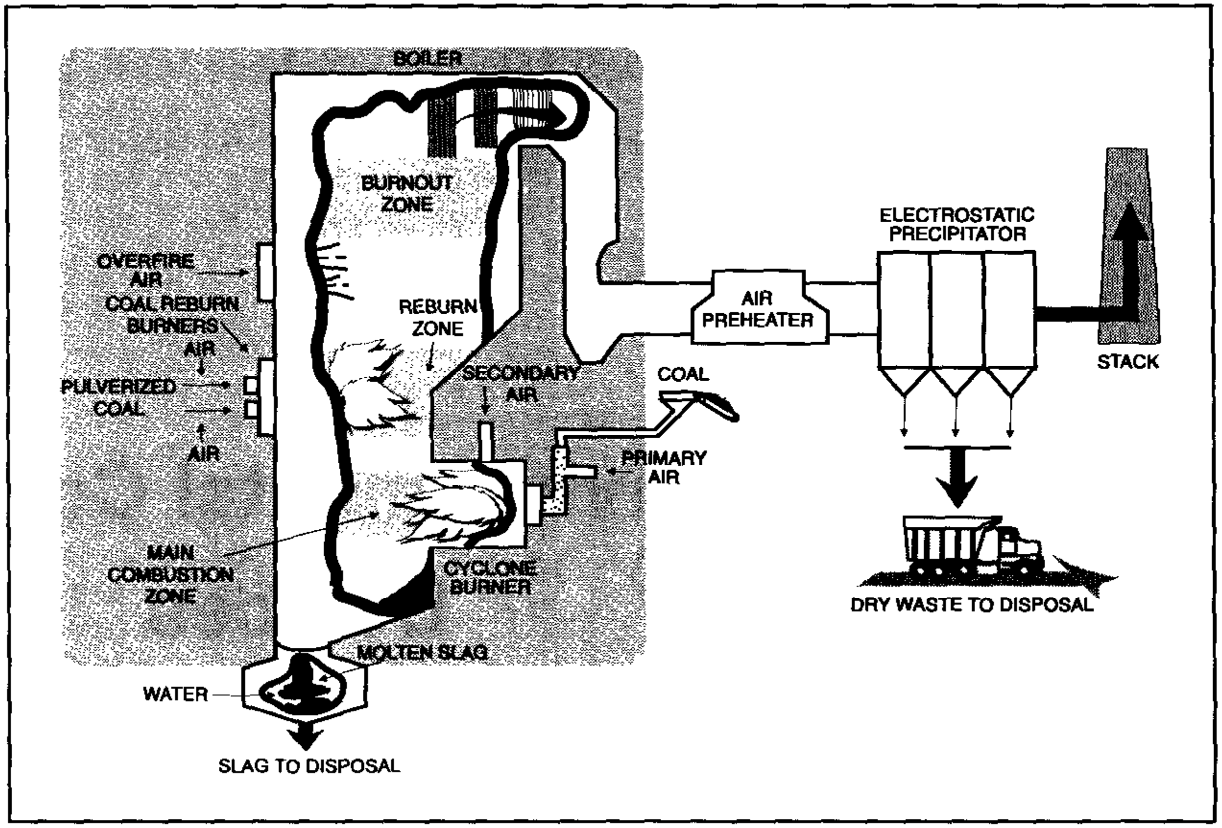
Technology:
The Babcock & Wilcox Company's coal-reburning system

Plant Capacity/Production:
100 MWe

Project Funding:

Total project cost	$13,646,609	100%
DOE	6,340,788	46
Participant	7,305,821	54

Project Objective:
To evaluate the applicability of reburning technology for reducing NO_x emissions from a full-scale coal-fired cyclone boiler, pulverizing a portion of the primary coal fuel to use as the secondary, "reburning" fuel; and to achieve greater than 50% reduction in NO_x emissions with no serious impact on cyclone combustor operation, boiler efficiency, boiler fireside performance (corrosion and deposition), or ash removal system performance.



Technology/Project Description:
The coal-reburning process reduces NO_x in the furnace through the use of multiple combustion zones. The main combustion zone uses 70–80% of the total heat equivalent fuel input to the boiler and slightly less than normal combustion air input. The balance of the coal (20–30%), along with significantly less than the theoretically determined requirement of air, is fed to the reburning zone above the cyclones to create an oxygen-deficient condition. The NO_x formed in the cyclone burners reacts with the resultant reducing flue gas and is converted into nitrogen in this zone. The completion of the combustion process occurs in the third zone, called the burnout zone, where the balance of the combustion air is introduced. The combined production of boiler slag and dry waste from the electrostatic precipitator remains unchanged with coal reburning because the required coal input for the same boiler load is the same.

The coal-reburning technology can be applied with the cyclone burners operating within their normal, non-corrosive, oxidizing conditions, thereby minimizing any adverse effects of reburn on the cyclone combustor and boiler performance.

This project involved retrofitting an existing 100-MWe cyclone boiler that is representative of a large population of cyclone units. The boiler is located at Wisconsin Power and Light's Nelson Dewey Station in Cassville, WI.

Project Results/Accomplishments:

Coal-reburn tests were conducted to determine the reduction in NO_x emissions for the coal-reburning technology over a range of boiler loads varying from 37 MWe to 118 MWe (nominal maximum boiler load is 110 MWe). Two coals were tested, namely, the design Illinois Basin bituminous coal (Lamar, 1.8% sulfur avg) and a western subbituminous coal (Powder River Basin, 0.6% sulfur avg). The bituminous coal tests evaluated a fuel typical of the coals fired by utilities operating cyclones. The subbituminous coal tests evaluated coal switching for SO_2 reduction.

As a part of the test program, several parameters were optimized over the load range to achieve the optimum NO_x reduction while keeping other variables, such as unburned carbon and carbon monoxide emissions, within reasonable limits. The optimized parameters included the split of boiler fuel between the reburn system and the cyclone burners, the reburn burner and the reburn zone stoichiometries, the reburn burner pulverized coal fineness, flue gas recirculation, and economizer outlet O_2 content. Also, adjustments were made to the reburn burners and the over-fire air ports during the tests.

With the Lamar coal, the boiler NO_x emissions were reduced as follows:

- 52% (to 290 ppm or 0.394 lb/million Btu) at 110 MWe
- 47% (to 285 ppm or 0.387 lb/million Btu) at 82 MWe
- 36% (325 ppm or 0.442 lb/million Btu) at 60 MWe

With Powder River Basin coal, the NO_x emissions were reduced as follows:

- 62% (to 208 ppm or 0.278 lb/million Btu) at 110 MWe
- 55% (to 215 ppm or 0.287 lb/million Btu) at 82 MWe
- 53% (to 220 ppm or 0.294 lb/million Btu) at 60 MWe

Reburn testing with both coals indicated that varying reburn zone stoichiometry is the most critical factor in controlling NO_x. Reburn zone stoichiometry can be varied by altering air flow quantities to the reburn burners, percent reburn heat input, flue gas recirculation flow rate, or cyclone stoichiometry.

Burning subbituminous coal produced lower overall NO_x emissions levels and higher NO_x emissions reductions. This result is probably due to the coal's higher volatile content, which generates higher concentrations of hydrocarbon radicals in the reburn zone. With the reburn system contributing additional burning capacity for the cyclone boiler, the lower Btu content western fuel could be fired up to the full boiler load rating.

Additional effects of coal reburning on the retrofitted boiler follow:

- Loss of combustion efficiency, due to increased unburned carbon, amounted to 1.5% at full load with bituminous coal and 0.3% with subbituminous coal.
- The performance of the ESP remained constant even though its ash loading doubled. The increased ash consisted of larger sized particulates.
- The furnace exit gas temperature decreased by more than 100 °F at full load, contrary to expectations, and thus improved the boiler heat absorption efficiency correspondingly.
- Slagging and fouling were significantly reduced with bituminous coal reburning. The subbituminous reburn operations were too short in duration to make a reasonable observation.
- No furnace corrosion was observed over the 1-year test period.

Hazardous air pollutants (HAP) testing was performed using Lamar test coal. HAP emissions were generally well within expected levels and emissions with reburn comparable to baseline operations.

Commercial Applications:

The current reburn market is nearly 26,000 MWe and consists of about 120 units ranging from 100 MWe to 1,150 MWe, with most in the 100–300-MWe range. Coal reburning is a retrofit technology applicable across the size range of utility and industrial cyclone boilers.

The principal environmental benefit is reduced NO_x emissions. A secondary benefit may be reduced SO_2 emissions by enabling greater use of lower sulfur western coal; due to its lower Btu content, western coals limit cyclone capacity. With the additional firing capacity of the reburn system, full-load performance on western coal may be possible for some cyclone units.

For cyclone boilers, coal reburning offers a NO_x reduction alternative at a cost expected to be in the range of $65/kW for 100-MWe units to $40/kW for a larger 600-MWe unit. This includes costs for coal handling and pulverizers/coal piping. Coal's cost differential and dependability of supply give it the long-run advantage over natural gas. Another advantage of the reburn system is its ability to utilize different coals.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	4/2/90
NEPA process completed (EA)	2/12/91
Environmental monitoring plan completed	11/18/91
Construction	11/90–11/91
Operational testing	11/91–12/92
Project completed	3/94

Final Reports:

Final Technical Report (includes economic information)	2/94
Public Design Report	8/91

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

Project completed.

Participant:

The Babcock & Wilcox Company

Additional Team Members:

The Dayton Power and Light Company—cofunder and host
Electric Power Research Institute—cofunder
Ohio Coal Development Office—cofunder
Tennessee Valley Authority—cofunder
New England Power Company—cofunder
Duke Power Company—cofunder
Allegheny Power System—cofunder
Centerior Energy Corporation—cofunder

Location:

Aberdeen, Adams County, OH (Dayton Power and Light Company's J.M. Stuart Plant, Unit No. 4)

Technology:

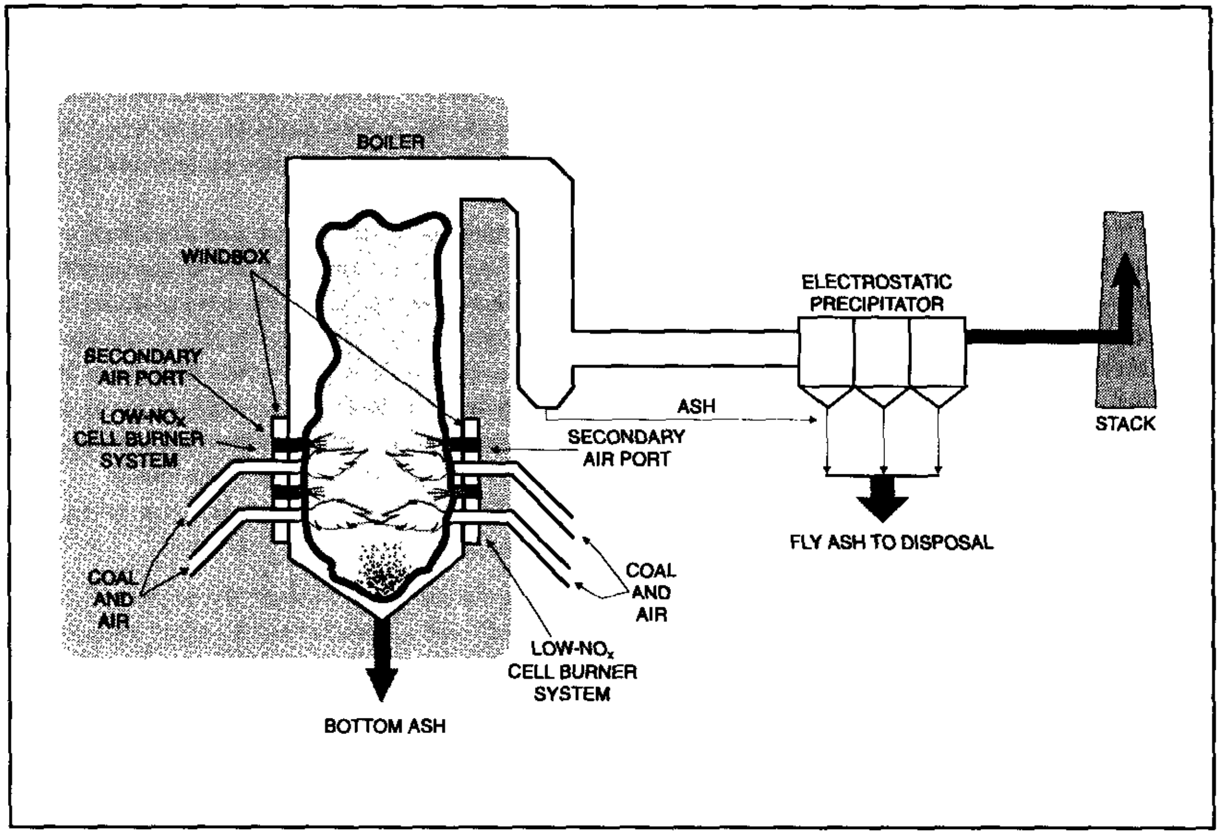
The Babcock & Wilcox Company's low-NO_x cell burner (LNCB®) system

Plant Capacity/Production:

605 MWe

Project Funding:

Total project cost	$11,233,392	100%
DOE	5,442,800	48
Participant	5,790,592	52



Project Objective:

To demonstrate through the first commercial-scale full burner retrofit the cost-effective reduction of NO_x from a large base-load coal-fired utility boiler with LNCB® technology; and to achieve at least a 50% NO_x reduction without degradation of boiler performance at less cost than conventional low-NO_x burners.

Technology/Project Description:

The LNCB® technology replaces the upper coal nozzle of the standard two-nozzle cell burner with a secondary-air port. The lower burner coal nozzle is enlarged to the same fuel input capacity as the two standard coal nozzles. The LNCB® operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70% of the total air (primary, secondary, and excess air) is supplied through or around the coal-feed nozzle. The remainder of the air is directed to the upper port of each cell to complete the combustion process. The fuel-bound nitrogen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO_x.

The net effect of this technology is greater than 50% reduction in NO_x formation with no boiler pressure part changes and no impact on boiler operation or performance. In addition, the technology is compatible with most commercial and emerging SO_2 control technologies, including confined zone dispersion, gas suspension absorption, duct injection, and advanced wet scrubbers.

The demonstration was conducted at a large-scale power plant operated by The Dayton Power and Light Company and jointly owned with the Cincinnati Gas and

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LNCB is a registered trademark of The Babcock & Wilcox Company.

Electric Company and the Columbus Southern Power Company. The boiler unit is a Babcock & Wilcox-designed, supercritical, once-through boiler equipped with an electrostatic precipitator. This unit contained 24 two-nozzle cell burners arranged in an opposed-firing configuration. Twelve burners (arranged in two rows of six burners each) were mounted on each of two opposing walls of the boiler. All 24 standard cell burners were removed, and 24 new LNCB® were installed. Alternate LNCB® on the bottom rows were inverted, with the air port then being on the bottom to insure complete combustion in the lower furnace.

Project Results/Accomplishments:

The initial test results on the LNCB® were disappointing. Reducing gases containing high concentrations of carbon monoxide and hydrogen sulfide accumulated in the lower furnace below the burners, and the NO_x emissions reduction was only about 35%. By numerically modelling several possible burner configurations, Babcock & Wilcox was able to select an optimum new burner arrangement. On the lower row of burners, alternate LNCB® were inverted so that the air ports integral to these burners directed air into the lower furnace. Also, a design change for the burners' coal impellers increased the NO_x reduction to above the design goal.

The LNCB® demonstration emphasized evaluation of boiler performance, boiler life, and environmental impact. Key boiler performance parameters included boiler output (steam temperatures); flue gas temperatures at the furnace, economizer, and air heat exits; the slagging tendencies of the unit; and unburned carbon losses. Boiler life potentials (corrosion tendencies) were measured by gas sampling for high H_2S concentrations in the furnace, ultrasonic testing of lower furnace tube walls, and destructive examination of a corrosion test panel. Environmentally, NO_x, CO, CO_2, total hydrocarbons, and particulate matter were measured at varying test conditions.

At full load (605 MWe) with all mills in service, average NO_x emissions were 0.53 lb/million Btu, a 54.4% reduction from the baseline. CO emissions ranged from 28 to 55 ppm. Flyash unburned carbon averaged 1.12%, for a 0.2% loss unburned carbon efficiency. This is a 56% improvement over baseline unburned carbon losses, probably resulting from improved air flow distribution achieved by the LNCB® retrofit. At reduced loads of 460 MWe and 350 MWe, the NO_x emissions reductions were 54% and 48% respectively, and CO emissions and unburned carbon values were comparable with baseline emissions.

Long-term NO_x emissions data were accumulated using a third-party continuous emissions monitor over an 8-month test period that followed the parametric and optimization test periods. On days when the boiler was operating at 590 MWe or above, and with all mills in service, NO_x emissions averaged 0.49 lb/million Btu, a 58% reduction from baseline emissions. This data set covered 79 days.

Overall unit efficiency remained essentially unchanged from baseline to optimized LNCB® burner operation. The demonstration boiler is operating at a lower overall excess air since the optimization testing, which has reduced the dry gas loss and increased the boiler efficiency slightly.

A corrosion test panel was installed when the LNCB® burner were installed. The panel consisted of SA-213T2 bare tube material with some of this material aluminized, some stainless weld overlaid, and some chromized. The level of corrosion is roughly equivalent to the boiler's corrosion prior to the retrofit. The coated materials had no loss.

The LNCB® project received the 1994 R&D 100 Award for technical excellence in a new commercial product.

Commercial Applications:

The low cost and short outage time for retrofit make the LNCB® design attractive. Typically, the retrofit capital-cost will be $5.50–$8.00/kW in 1993 dollars, based upon DOE's 500-MWe reference unit. The outage time can be as short as 5 weeks because of the "plug-in" design. The LNCB® system can be installed at about half the cost and outage time for other commercial low-NO_x burner installations.

Dayton Power & Light has retained the LNCB® burners for use in commercial operation at the unit. There have been eight commercial sales of LNCB® burners.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/11/90
NEPA process completed (MTF)	8/10/90
Environmental monitoring plan completed	8/9/91
Construction	9/91–11/91
Operational testing	12/91–4/93
Project completed	12/95

Final Reports:

Final Technical Report (includes economic information and corrosion test results)	12/95
Public Design Report	8/91

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler

Project completed.

Participant:

Energy and Environmental Research Corporation

Additional Team Members:

Public Service Company of Colorado—cofunder and host
Gas Research Institute—cofunder
Colorado Interstate Gas Company—cofunder
Electric Power Research Institute—cofunder

Location:

Denver, Adams County, CO (Public Service Company of Colorado's Cherokee Station, Unit No. 3)

Technology:

Energy and Environmental Research Corporation's gas reburning (GR) system
Foster Wheeler's low-NO_x burners (LNB)

Plant Capacity/Production:

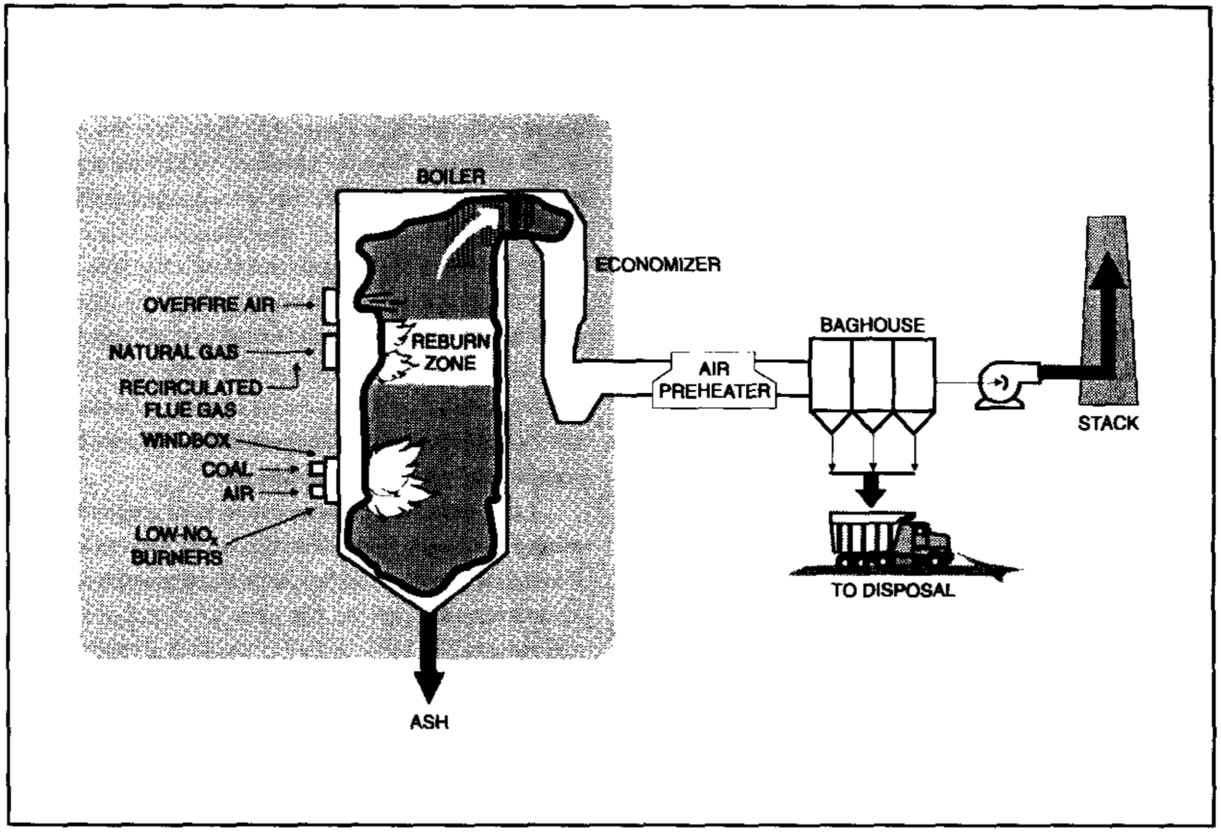
172 MWe

Project Funding:

Total project cost	$17,807,258	100%
DOE	8,895,790	50
Participant	8,911,468	50

Project Objective:

To attain up to a 70% decrease in the emissions of NO_x from an existing wall-fired utility boiler firing low-sulfur coal using both gas reburning and low-NO_x burners (GR–LNB).



Technology/Project Description:

Gas reburning involves firing natural gas (up to 20% of total fuel input) above the main coal combustion zone in a boiler. This upper-level firing creates a slightly fuel-rich zone. NO_x drifting upward from the lower region of the furnace is "reburned" in this zone and converted to molecular nitrogen. Low-NO_x burners positioned in the coal combustion zone retard the production of NO_x by staging the burning process so that the coal-air mixture can be carefully controlled at each stage. The synergistic effect of adding a reburning stage to wall-fired boilers equipped with low-NO_x burners lowers NO_x emissions by up to 70%. Gas reburning was demonstrated with and without the use of recirculated flue gas, on a gas/gas firing mode and with optimized overfire air.

The project site is Public Service Company of Colorado's Cherokee Station, Unit No. 3, in Denver, CO. This project combines gas reburning and low-NO_x burners on a 172-MWe wall-fired utility boiler. Western bituminous coals containing 0.35–0.66% sulfur were used in this demonstration.

Project Results/Accomplishments:

Parametric and long-term testing was conducted from October 1992 to January 1994 during more than 4,000 hours of operation. The results showed that for the first generation GR–LNB, average NO_x reductions of 37% (0.46 lb/million Btu) was achieved with the LNB alone and 65% (0.26 lb/million Btu) with GR–LNB at an average gas input of 18% of total heat input. The second generation system showed average NO_x reductions of 37% for LNB and 64% for GR–LNB at an average gas heat input of 13%. The boiler efficiency decreased by approximately 1% during gas reburning due to moisture in the fuel and an increase in heat loss due to moisture formed in combustion. There was no measurable boiler tube wear resulting from GR–LNB operation and, in general, the tubes were free from slagging.

Based on the demonstration and the data collected, the technology can be applied to utility and industrial units. The participant expects that most GR–LNB installations will achieve 60% NO_x reductions when firing 10–15% gas. The capital cost for units of 100 MWe or larger is approximately $15/kW plus the cost of a gas pipeline. Operating costs are almost entirely related to the differential cost of gas over coal as reduced by the value of SO_2 emissions credits.

The Public Service Company of Colorado retained the gas-reburning system and associated controls. The low-NO_x burners were also retained and repaired to reduce carbon-in-ash levels and thus improve the economic performance of the unit. The flue gas recirculation system was removed.

Commercial Applications:

Gas reburning in combination with low-NO_x burners is applicable to wall-fired utility and industrial boilers. The technology can be used in new and pre-NSPS wall-fired boilers.

Specific features of this technology that increase its potential for commercialization are that it can be retrofitted to existing units, reduces NO_x emissions by 70% or more, is suitable for use with a wide range of coals, has the potential to improve boiler operability and reduce the cost of electricity, consists of commercially available components, and requires minimal space.

Current estimates indicate that about 35 existing wall-fired utility installations, plus industrial boilers, could make immediate use of this technology. The technology would apply to retrofit, repowering, or new, greenfield installations. There is no known limit to the size or scope of the application of this technology combination. Presently, the largest existing utility boiler is estimated at about 1,300 MWe. The GR–LNB combination could be applied directly to this size boiler because the equipment is an integral part of the unit. For this reason, GR–LNB is expected to be less capital intensive, or less costly, than a scrubber, selective catalytic reduction, or other technology approaches. GR–LNB functions equally well with any kind of coal. NO_x emissions are reduced with internally staged low-NO_x burners, followed by gas reburning. As a side benefit, SO_2 is decreased in direct proportion to the amount of natural gas that is substituted for coal.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/31/90
NEPA process completed (MTF)	9/6/90
Environmental monitoring plan completed	7/26/90
Construction	6/91–6/92
Operational testing	10/92–1/95
Restoration completed	11/95
Project completed	12/96

Final Reports:

Final Technical Report (includes economic information)	12/96
Public Design Report	9/96

Micronized Coal Reburning Demonstration for NO_x Control

Participants:

New York State Electric & Gas Corporation

Additional Team Members:

Eastman Kodak Company—host and cofunder
Consol— tester
D.B. Riley—technology supplier
Fuller Company—technology supplier
Energy and Environmental Research Corporation—reburn system designer

Locations:

Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station, Unit 1)
Rochester, Monroe County, NY (Eastman Kodak Company's Utility Power House, Unit 15)

Technology:

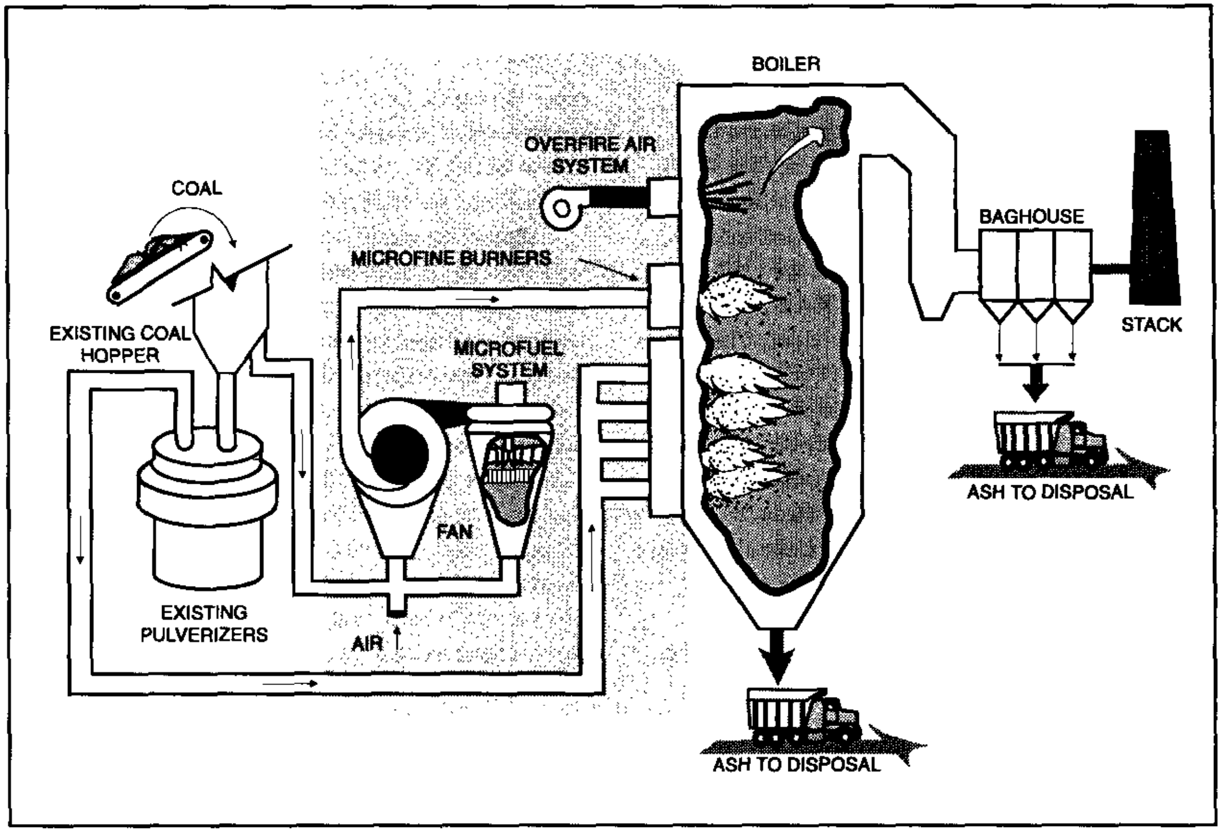
Advanced NO_x control using D.B. Riley's MPS mill and Fuller's MicroMill™ technologies for producing micronized coal

Plant Capacity/Production:

148 MWe (Milliken Station); 50 MWe (Eastman Kodak Company)

Project Funding:

Total project cost	$9,096,486	100%
DOE	2,701,011	30
Participant	6,395,475	70



Project Objective:

To reduce NO_x emissions by 50–60% using micronized coal as the reburning fuel combined with advanced coal-reburning technology.

Technology/Project Description:

The reburning coal, which can comprise up to 30% of the total fuel, is micronized (80% below 325 mesh) and injected into a pulverized-coal-fired furnace above the main burner, the region where NO_x formation occurs.

Micronized coal has the surface area and combustion characteristics of an atomized oil flame, which allows carbon conversion within milliseconds and release of volatiles at a more even rate. This uniform, compact combustion envelope allows for complete combustion of the coal/air mixture in a smaller furnace volume than conventional pulverized coal because heat rate, carbon loss, boiler efficiency, and NO_x formation are affected by coal fineness.

The combination of micronized coal, supplying 30% of the total furnace fuel requirements, and advanced reburning, utilizing that requirement in conjunction with fuel/air staging, provides flexible options for significant combustion operations and environmental improvements. These options can prevent higher operating costs or furnace performance derating often associated with conventional environmental controls.

New York State Electric & Gas Milliken Station, Unit 1, a 148-MWe tangentially fired boiler, is one host site, and Eastman Kodak Utility Power House, Unit 15, a 50-MWe cyclone boiler, is the other host site. The Milliken site will use the D.B. Riley MPS mill with dy-

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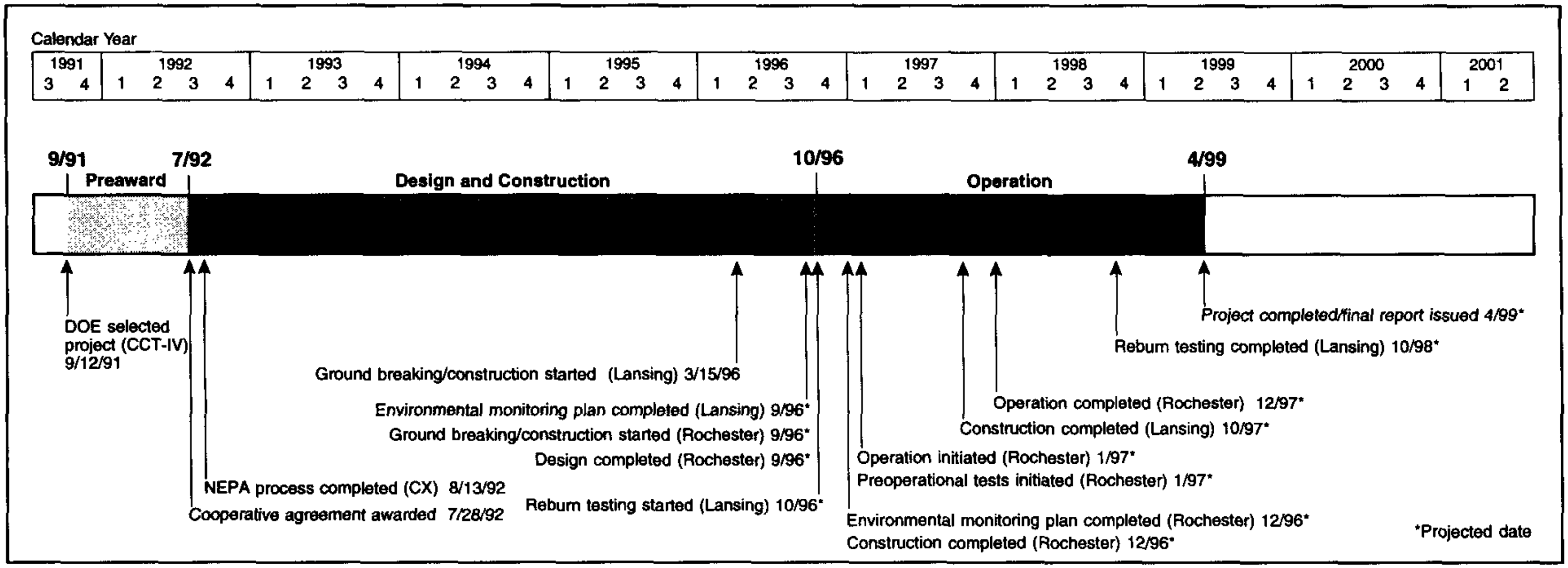
MicroMill is a trademark of the Fuller Company.



namic classifiers to produce the micronized coal. The coal will be reburned for NO_x control using two methods. One method is close-coupled overfire air (CCOFA) reburning in which the top burner of the existing Low-NO_x Concentric Firing System (LNCFS™) burners are used for burning the micronized coal and the remaining burners are re-aimed. A second method being considered is to use the burners in a deep stage combustion mode and re-aim them to create burn and reburn zones. The third method is more standard and will use injectors to input micronized coal into the boiler. At the Eastman Kodak site, the Fuller MicroMill™ will be used to produce the micronized coal, and injectors or burners, depending on boiler characteristics, will be used for the reburning. Overfire air also will be installed. Both the injectors/burners and the overfire air will be installed at the optimum point downstream of the cyclone burners.

Project Status/Accomplishments:

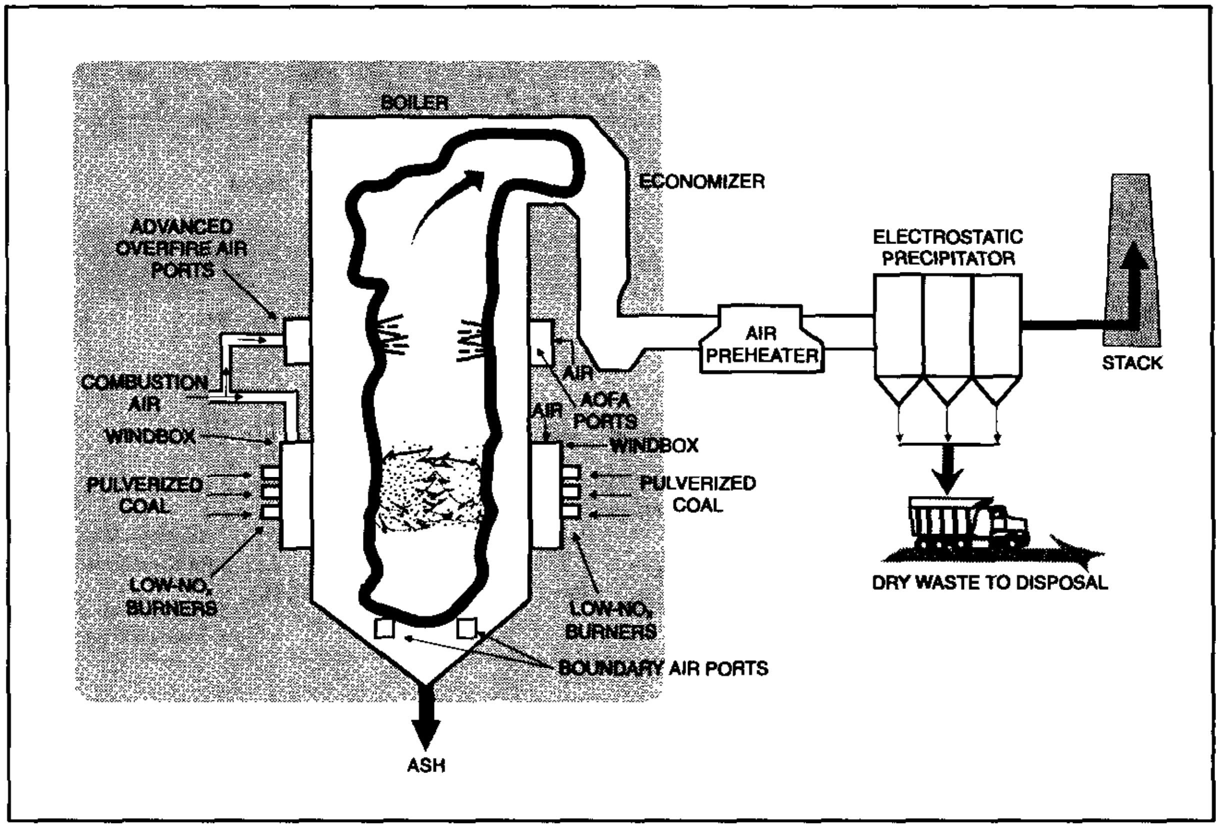
New York State Electric & Gas is in the process of beginning preliminary design to perform close-coupled reburn at Milliken Station. Eastman Kodak and Fuller are working on preliminary design for the MicroMill™ installation at Kodak's Rochester facility. Fuller is starting to place long-lead-time orders for parts to assemble the MicroMill™. Boiler characterization tests are being run on the Kodak boiler.

Commercial Applications:

Micronized-coal-reburning technology can be applied to existing and greenfield cyclone-fired, wall-fired, and tangential-fired pulverized coal units. The technology reduces NO_x emissions by 50–60% with minimal furnace modifications for existing units. For greenfield units, the technology can be designed as an integral part of the system. Either way, the technology enhances boiler performance with the improved burning characteristics of micronized coal. About 25% of the more than 1,000 existing units could benefit from use of this technology.

The availability of a coal-reburning fuel, as an additional fuel to the furnace, solves several problems concurrently. Existing units unable to switch fuels because of limited mill capacity would be able to reach their maximum continuous rating. NO_x emissions reductions will enable lost capacity to be restored, creating a very economic source of generation. For both retrofit and greenfield facilities, reburn burners also can serve as low-load burners, and commercial units can achieve a turndown of 8:1 on nights and weekends without consuming expensive auxiliary fuel. Existing pulverizers can be operated on a variety of coals with improved performance. The combination of micronized-coal-reburning fuel and better pulverizer performance will increase overall pulverized-fuel surface area for better carbon burnout.

This demonstration will provide methods for NO_x control at a low capital cost for utilities and industrial users to meet the current and upcoming NO_x regulations. Utilities that install low-NO_x burners to meet CAAA Title I requirements and must also meet Title IV requirements will have a low-cost option to choose. Industrial users being pressured by states to reduce NO_x also will be provided a low-cost option, particularly cyclone users who are without low-NO_x burners.



Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Participant:

Southern Company Services, Inc.

Additional Team Members:

Electric Power Research Institute—cofunder
Foster Wheeler Energy Corporation—technology supplier
Georgia Power Company—host

Location:

Coosa, Floyd County, GA (Georgia Power Company's Plant Hammond, Unit No. 4)

Technology:

Foster Wheeler's low-NO_x burner (LNB) with advanced overfire air (AOFA)
EPRI's Generic NO_x Control Intelligence System (GNOCIS) for plant optimization

Plant Capacity/Production:

500 MWe

Project Funding:

Total project cost	$14,710,909	100%
DOE	6,553,526	45
Participant	8,157,383	55

(Of the total project cost, $523,680 are for toxics testing.)

Project Objective:

To achieve 50% NO_x reduction with the AOFA/LNB system; to determine the contributions of AOFA and the LNB to NO_x reduction and the parameters determining optimum AOFA/LNB system performance; and to assess the long-term effects of AOFA, LNB, and combined AOFA/LNB and advanced digital controls on NO_x reduction and boiler performance.

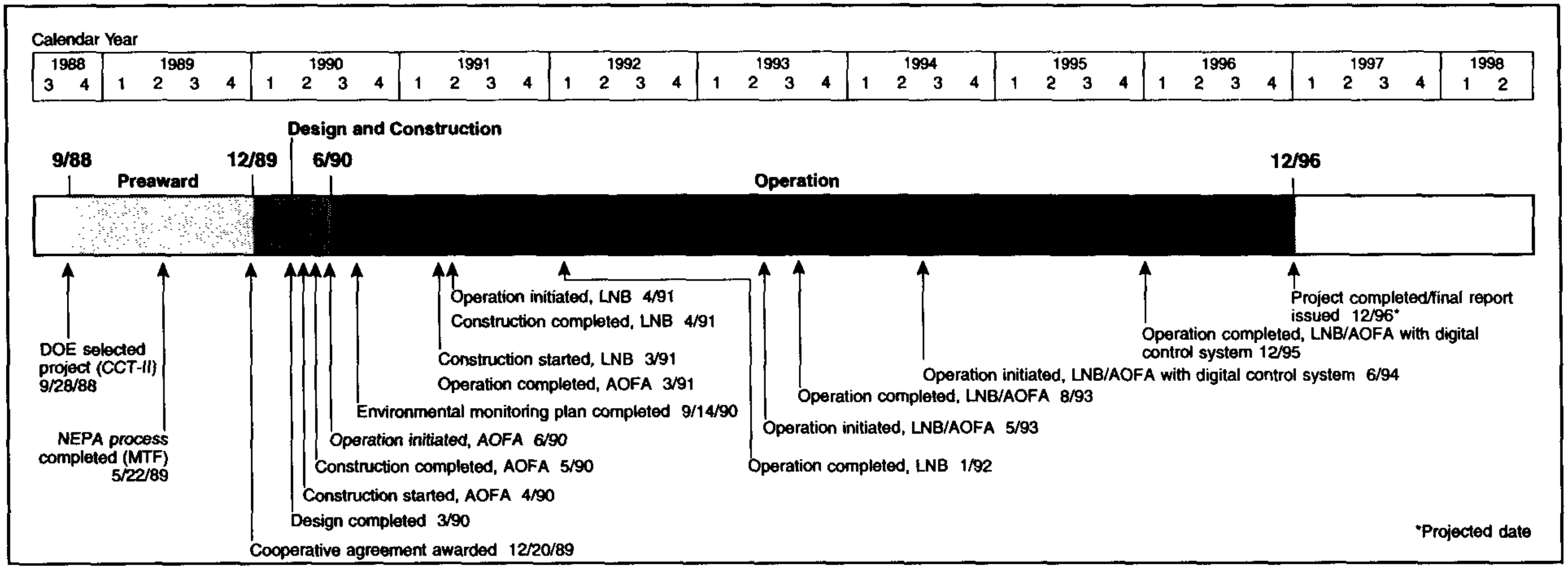
Technology/Project Description:

AOFA involves (1) improving the mixing of overfire air with the furnace gases to achieve complete combustion, (2) depleting the air from the burner zone to minimize NO_x formation, and (3) supplying air over furnace wall tube surfaces to prevent slagging and furnace corrosion. The AOFA technique was expected to reduce NO_x emissions by about 35%.

In an LNB, fuel and air mixing is controlled to preclude the formation of NO_x. This is accomplished by regulating the initial fuel-air mixture, velocities, and turbulence to create a fuel-rich flame core and by controlling the rate at which additional air required to complete combustion is mixed with the flame solids and gases so as to maintain a deficiency of oxygen. Typical results for utilities indicate that LNB technology is capable of reducing NO_x emissions by about 45%.

Based on earlier experience, the use of AOFA in conjunction with LNB can reduce NO_x emissions by as much as 65% compared with conventional burners.

The demonstration is located at the Georgia Power Company's Plant Hammond, Unit No. 4. The boiler is a nominal 500-MWe pulverized coal, opposed wall-fired unit, which is representative of many existing pre-NSPS wall-fired utility boilers in the United States. The project also includes installation and testing of an advanced digital control system that optimizes LNB/AOFA performance using artificial intelligence techniques. The project is using bituminous coal containing 3% sulfur.



Project Status/Accomplishments:

Baseline, AOFA, LNB, and LNB/AOFA test segments have been completed. Analysis of more than 80 days of AOFA operating data has provided statistically reliable results indicating that, depending upon load, NO_x reductions of 24% are achievable under normal long-term operation. Analysis of the 94 days of LNB long-term data collected show the full-load NO_x emission levels to be approximately 0.65 lb/million Btu. This NO_x level represents a 48% reduction when compared to the baseline, full-load value of 1.23 lb/million Btu. These reductions were sustainable over the long-term test period and were consistent over the entire load range. Full-load, flyash loss-on-ignition values in the LNB configuration were near 8%, compared to 5% for baseline. Results from the LNB/AOFA testing indicate that full-load NO_x emissions were approximately 0.41 lb/million Btu with a corresponding flyash loss-on-ignition value of nearly 8%. Full-load, long-term NO_x emission reductions in the LNB/AOFA configuration were about 63%. However, analysis of emissions data showed that the incremental NO_x reduction effectiveness of the AOFA system (beyond the use of the LNB) was approximately 17% with additional reductions resulting from other operational changes.

The new digital control system became operational in mid-1994, and testing of the GNOCIS for optimizing NO_x reduction and boiler efficiency began in February 1996. Although narrow parameters were placed on the recommendations that GNOCIS could provide, preliminary data analysis is encouraging, with an observed efficiency gain of 0.5%, a reduction in loss-on-ignition levels of 1–3%, and a reduction in NO_x emissions by 10–15% at full load.

Short-term testing of the GNOCIS, in both open- and closed-loop configurations, and long-term closed-loop testing will be conducted through fall 1996. The final project report and a report on testing of several on-line carbon-in-ash monitors are being prepared.

Pre-retrofit LNB air toxics testing was performed to establish a baseline. Additional air toxics testing with the combined LNB/AOFA configuration has been completed. A report on this work was issued in December 1993.

Commercial Applications:

The technology is applicable in the United States for retrofitting the 422 existing pre-NSPS wall-fired boilers; these boilers burn a variety of coals, including bituminous, subbituminous, and lignite. The GNOCIS technology is applicable to all fossil-fuel-fired boilers.

Commercialization of the technology will be aided by the following characteristics: reduced NO_x emissions by as much as 65%; competitive capital and operating costs; relatively easy retrofit; little or no derating of the boiler; use of commercially available components; and automatic control of boiler efficiency and maximum pollution abatement through use of artificial intelligence technology in conjunction with a digital control system.

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

Project completed.

Participant:

Southern Company Services, Inc.

Additional Team Members:

Electric Power Research Institute—cofunder
Ontario Hydro—cofunder
Gulf Power Company—host

Location:

Pensacola, Escambia County, FL (Gulf Power Company's Plant Crist, Unit 4)

Technology:

Selective catalytic reduction (SCR)

Plant Capacity/Production:

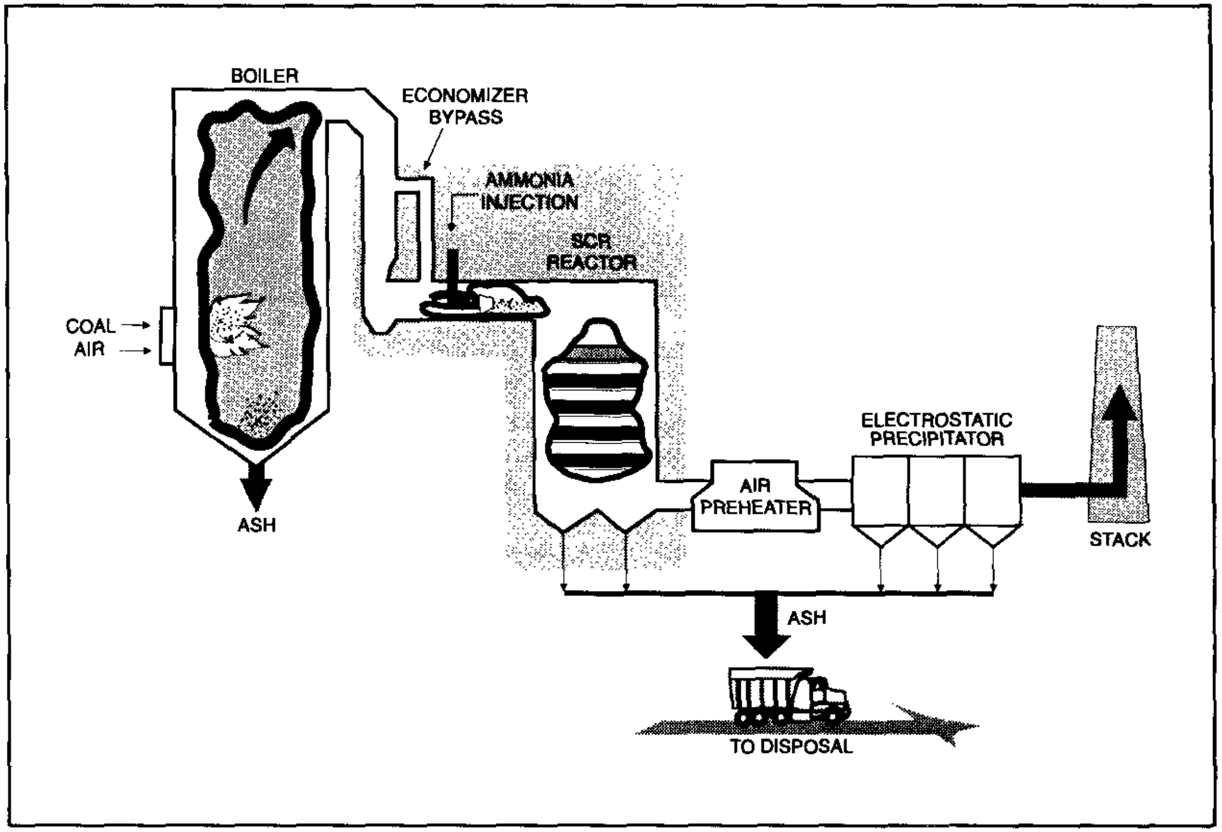
8.7-MWe equivalent (three 2.5-MWe and six 0.2-MWe equivalent SCR reactor plants)

Project Funding:

Total project cost	$23,229,729	100%
DOE	9,406,673	40
Participant	13,823,056	60

Project Objective:

To evaluate the performance of commercially available SCR catalysts when applied to operating conditions found in U.S. pulverized coal-fired utility boilers using high-sulfur U.S. coal under various operating conditions while achieving as much as 80% NO_x removal.



Technology/Project Description:

The SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor.

In this demonstration project, the SCR facility consisted of three 2.5-MWe-equivalent SCR reactors, supplied by separate 5,000 std ft^3/min flue gas slipstreams, and six 0.20-MWe-equivalent SCR reactors. These reactors were calculated to be large enough to produce design data that will allow the SCR process to be scaled up to commercial size. Catalyst suppliers (two U.S., two European, and two Japanese) provided eight catalysts with various shapes and chemical compositions for evaluation of process chemistry and economics of operation during the operation.

The project demonstrated, at high- and low-dust loadings of flue gas, the applicability of SCR technology to provide a cost-effective means of reducing NO_x emissions from power plants burning high-sulfur U.S. coal.

The demonstration plant, which was located at Gulf Power Company's Plant Crist near Pensacola, FL, utilized flue gas from the burning of principally Illinois No. 5 coal with approximately 3% sulfur under various NO_x and particulate levels.

Project Results/Accomplishments:

Preliminary design engineering for the SCR test facility was concluded at the end of February 1991. Construction began in late March 1992; a dedication ceremony was held on July 1, 1992. Detailed engineering was completed in December 1992. Flue gas was first passed through the SCR facility during equipment checkout on January 10, 1993. Construction was completed in February 1993. Commissioning tests without catalysts began the first week of March 1993, and the 2-year-long operations phase began on July 1, 1993. The test period included parametric testing of each catalyst every 4–6 months. The final report has been drafted, and the test facility has been dismantled.

Upon completion of the initial parametric testing in December 1993, baseline measurements were obtained. These tests were completed during December 1993 and all catalysts performed well at the targeted NO_x removal rates with slip less than 2 ppm under baseline conditions (80% NO_x removal) and in many cases the measured slip was below the 1 ppm detection limit.

Project results indicate that all eight catalysts performed well in both parametric and long-term testing and that NO_x removal rates of 80% or better, with acceptable ammonia slips, were achieved for all catalysts.

Commercial Applications:

SCR technology can be applied to existing and new utility applications for removal of NO_x from flue gas for virtually any size boiler. There are approximately 1,041 coal-fired utility boilers in active commercial service in the United States; these boilers represent a total generating capacity of 296,000 MWe. Assuming that SCR technology is installed on dry-bottom boilers that are not equipped with low-NO_x combustion technologies (i.e., low-NO_x burners, overfire air, and atmospheric fluidized-bed combustion), the potential total retrofit market for SCR technology is 154,560 MWe (642 boilers). In addition, SCR technology could be applicable to 34,700 MWe (70 boilers) of new firm (i.e., announced, sited, and committed in terms of service date or under construction) and 144,500 MWe (290 boilers) of planned dry-bottom electric generating capacity in the United States.

A number of successful commercial SCR installations that utilize catalysts demonstrated in this CCT project are now operational in the United States. As a result of this demonstration, utilities have a flue gas NO_x removal technology that has the flexibility and removal capabilities to assist in meeting both Title IV as well as Title I (ozone nonattainment) provisions of the CAAA of 1990.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	6/14/90
NEPA process completed (MTF)	8/16/89
Environmental monitoring plan completed	3/11/93
Construction	3/92–2/93
Operational testing	7/93–7/95
Project completed	12/96

Final Reports:

Final Technical Report (includes economic evaluation)	12/96
Public Design Report	12/96

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

Project completed.

Participant:

Southern Company Services, Inc.

Additional Team Members:

Gulf Power Company—cofunder and host
Electric Power Research Institute—cofunder
ABB Combustion Engineering, Inc.—cofunder and technology supplier

Location:

Lynn Haven, Bay County, FL (Gulf Power Company's Plant Lansing Smith, Unit No. 2)

Technology:

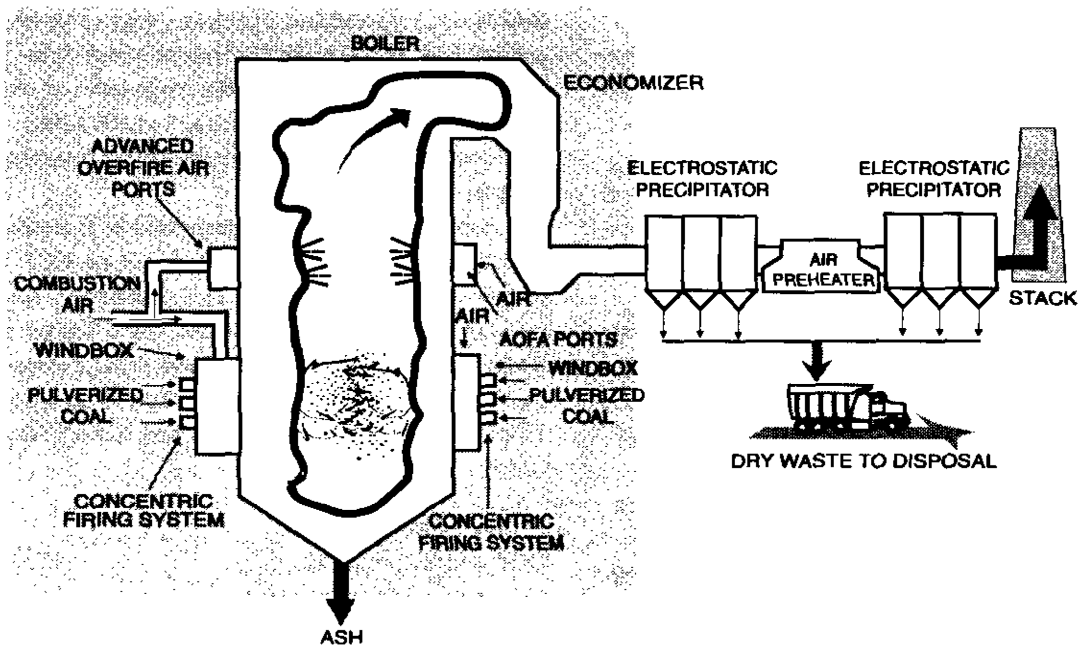
ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) with advanced overfire air (AOFA), clustered coal nozzles, and offset air

Plant Capacity/Production:

180 MWe

Project Funding:

Total project cost	$9,153,383	100%
DOE	4,440,184	49
Participant	4,713,199	51



Project Objective:

To demonstrate in a stepwise fashion the short- and long-term NO_x reduction capabilities of Low-NO_x Concentric Firing System Levels I, II, and III on a single reference boiler under typical dynamic operating conditions, and evaluate the cost effectiveness of each low-NO_x combustion technique.

Technology/Project Description:

Three different low-NO_x combustion technologies for tangentially fired boilers were demonstrated. The concept of overfire air was demonstrated in all of these systems. In LNCFS Level I, a close-coupled overfire air (CCOFA) system is integrated directly into the windbox of the boiler. Compared to the baseline windbox configuration, LNCFS Level I is arranged by exchanging the highest coal nozzle with an air nozzle immediately below it. This configuration provides the NO_x reducing advantages of an overfire air system without pressure part modifications to the boiler.

In LNCFS Level II, a separated overfire air (SOFA) system is used. This advanced overfire air system has backpressuring and flow measurement capabilities. The air supply ductwork for the SOFA is taken off from the secondary air duct and routed to the corners of the furnace above the existing windbox. The inlet pressure to the SOFA system can be increased above windbox pressure using dampers downstream of the takeoff in the secondary air duct. Operating at a higher pressure increases the quantity and injection velocity of the overfire air into the furnace. A multicell venturi is used to

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LNCFS is a trademark of ABB Combustion Engineering, Inc.

measure the amount of air through the SOFA system. LNCFS Level III utilizes both CCOFA and SOFA.

In addition to overfire air, the LNCFS™ incorporates other NO_x reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The majority of the coal is contained in the fuel-rich inner region. This region is surrounded by a fuel-lean zone containing combustion air. The size of this outer circle of combustion air can be varied using adjustable offset air nozzles. Separation of air and coal at the burner level further reduces production of NO_x.

The names of the technologies described above have been changed from those originally considered for this project to reflect the most recent knowledge. However, the basic concepts for the reduction of NO_x emissions have remained constant. These technologies provide a stepwise reduction in NO_x emissions, with LNCFS Level III expected to provide the greatest reduction.

Eastern bituminous coals from Kentucky, Illinois, and West Virginia, with an average sulfur content of 2.5–3.0%, were used.

Project Results/Accomplishments:

The results from the demonstration showed that, at full load, the NO_x emissions using LNCFS I, II, and III were 0.39, 0.39, and 0.34 lb/million Btu respectively; these levels represented emission reductions of 37%, 37%, and 45%, respectively, from the baseline. These emissions are within the annual average emission limit of 0.45 lb/million Btu established for tangentially fired boilers. Simulated load profiles showed that only LNCFS™ III could marginally meet the emission regulations at peaking loads because of the significant increase in NO_x emission for LNCFS technology below 100 MWe.

Testing to investigate the effects of low-NO_x combustion on the emissions of air toxics was also completed. These tests showed that the LNCFS™ had little or no impact on the emissions of air toxics.

Unit performance observations included increased CO emissions, reduced furnace slagging but increased back-pass fouling, and minimally impacted efficiency and heat rate. Further, unit operations were not significantly affected; however, operating flexibility of the unit was reduced at low loads with LNCFS II and III.

The capital cost estimate for LNCFS I is \$5–15/kW and for LNCFS II and III, \$15–25/kW. The cost effectiveness for LNCFS I was \$103/ton of NO_x removed; LNCFS II, \$444/ton; and LNCFS III, \$400/ton.

Commercial Applications:

Commercial applications of this technology include a wide range of tangentially fired utility and industrial boilers throughout the United States and abroad. There are nearly 600 U.S. pulverized coal tangentially fired utility units. These units range in electric generating capacity from 25 MWe to 950 MWe. A wide range of coals, from low-volatile bituminous through lignite, are being fired in these units. LNCFS™ technologies can be used in retrofit as well as new boiler applications. Boiler operation with these in-furnace technologies does not require intensive retraining.

Environmental benefits to be realized with these in-furnace emission control technologies are primarily based upon reducing NO_x emissions from fossil-fuel-fired power plants. Potential exists for significant NO_x emission reductions, depending on the unit load scenario and the level of technology selected.

Gulf Power has retained the LNCFS™ at its Plant Lansing Smith Unit No. 2. The technology also is being used by other utilities, including the Tennessee Valley Authority, Illinois Power, Public Service Company of Colorado, Indianapolis Power and Light, Cincinnati Gas and Electric, Virginia Power, Union Electric, and New York State Electric & Gas Corporation.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	9/20/90
NEPA process completed (MTF)	7/21/89
Environmental monitoring plan completed	12/27/90
Construction	11/90–5/91
Operational testing	5/91–12/92
Project completed	6/94

Final Reports:

Final Report and Key Project Findings (includes economic information)	2/94
Measurement of Chemical Emissions Report	10/93
ESP Performance Analysis Report	9/93

10-MWe Demonstration of Gas Suspension Absorption

Project completed.

Participant:

AirPol, Inc.

Additional Team Members:

FLS miljo a/s (parent company of AirPol, Inc.)—technology owner

Tennessee Valley Authority—cofunder and site owner

Location:

West Paducah, McCracken County, KY (Tennessee Valley Authority's Center for Emissions Research)

Technology:

FLS miljo a/s' Gas Suspension Absorption (GSA) system for flue gas desulfurization (FGD)

Plant Capacity/Production:

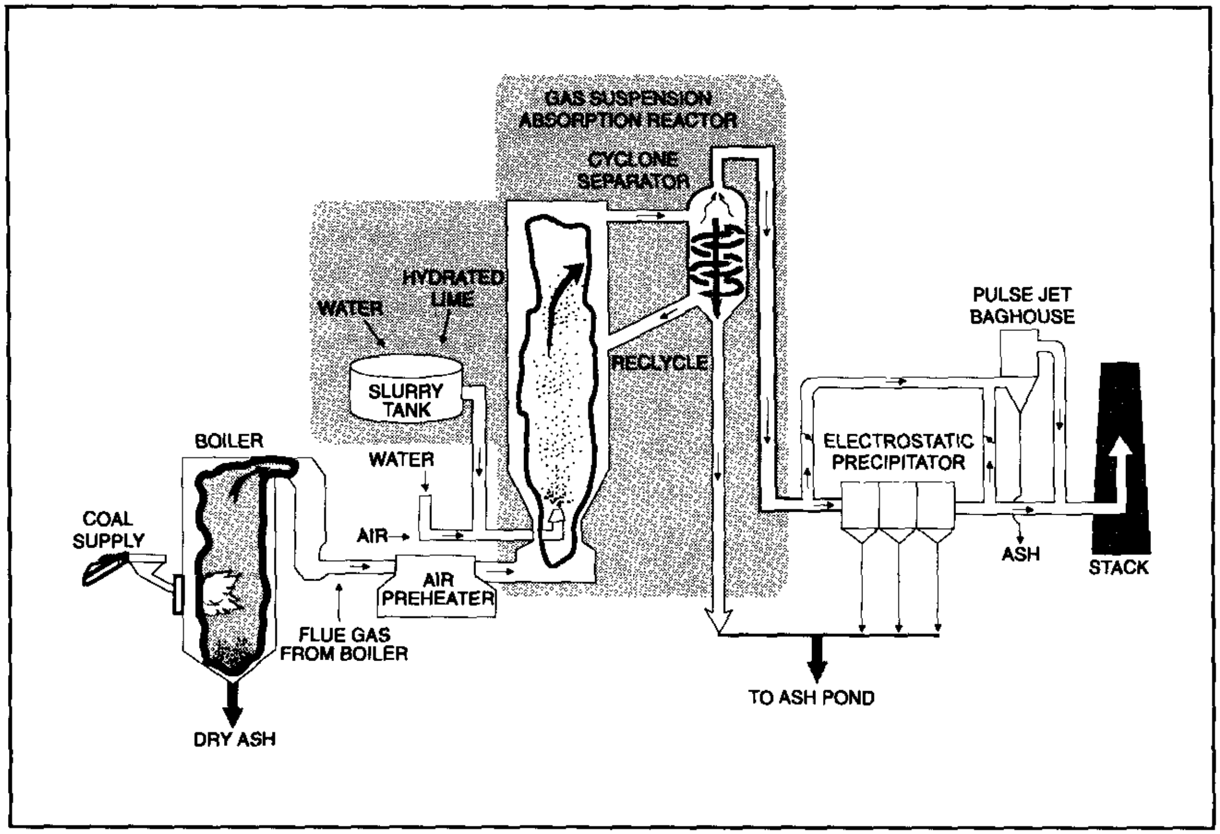
10-MWe equivalent slipstream of flue gas from a 150-MWe boiler

Project Funding:

Total project cost	$7,717,189	100%
DOE	2,315,259	30
Participant	5,401,930	70

Project Objective:

To demonstrate the applicability of Gas Suspension Absorption for flue gas desulfurization using high-sulfur U.S. coals by installing and testing a 10-MWe GSA demonstration system.



Technology/Project Description:

The GSA system consists of a vertical reactor in which flue gas comes into contact with suspended solids consisting of lime, reaction products, and fly ash. About 99% of the solids are recycled to the reactor via a cyclone while the exit gas stream passes through an electrostatic precipitator (ESP) before being released to the atmosphere. The lime slurry, prepared from hydrated lime, is injected through a spray nozzle at the bottom of the reactor. The volume of lime slurry is regulated with a variable-speed pump controlled by the measurement of the acid content in the inlet and outlet gas streams. The dilution water added to the lime slurry is controlled by on-line measurements of the flue gas exit temperature. Solids collected from the cyclone and particulate control device are combined and disposed of in an existing site disposal area.

GSA can remove in excess of 90% of the SO_2 as well as increase lime utilization efficiency with solids recycle.

This project was located at the Center for Emissions Research, utilizing a 10-MWe slipstream of flue gas from a 150-MWe coal-fired boiler at the Tennessee Valley Authority's Shawnee Fossil Plant in West Paducah, KY. A western Kentucky coal containing about 3% sulfur was used.

Project Results/Accomplishments:

Optimization testing was conducted to determine the effect of the process design variables on the SO_2 removal efficiency in the reactor/cyclone and the ESP. The testing indicated that the order of importance of the key variables is (1) Ca/S, (2) approach-to-adiabatic-saturation temperature, and (3) coal chloride content.

The SO_2 removal efficiency for the overall system ranged from slightly more than 60% to nearly 95%, depending on the specific test conditions. The lower SO_2 removal efficiency levels were achieved at the higher approach-to-saturation temperature (28 °F), the lower lime stoichiometry level (Ca/S of 1.00), and lower coal chloride level (0.02–0.04%). The higher SO_2 removal efficiency levels were achieved at the closer approach-to-saturation temperatures (8 and 18 °F), the higher lime stoichiometry level (Ca/S of 1.30), and higher coal chloride level (0.12%). Most of the SO_2 removal in the GSA system occurred in the reactor/cyclone, with only about 2–5% of the overall removal occurring in the ESP.

Results of a 4-week around-the-clock demonstration run of the GSA system with the ESP indicated that the GSA/ESP is capable of consistently maintaining 90% or better SO_2 removal at a moderate lime requirement. A 14-day pulse jet baghouse (PJBH) run was successfully completed in March 1994. SO_2 removal efficiency in the GSA/PJBH system averaged more than 95% during the demonstration; this was typically about 3–5 percentage points higher than that achieved in the GSA/ESP system at the same test conditions.

The project demonstrated a number of key technical attributes, including a simple and direct method of lime/solid recirculation, high acid gas adsorption, low lime consumption with minimal waste by-product residue, low maintenance operation, no internal buildup, and reduced space requirement. In addition, the project demonstrated that a pulse jet baghouse system improved SO_2 removal efficiency by about 3–5 percentage points. Also, air toxics testing showed that a removal rate of more than 95% could be achieved by the GSA.

The relative process economics for the GSA system were evaluated for a moderately difficult retrofit to a 300-MWe boiler burning a coal containing 2.6% sulfur. The design SO_2 removal efficiency was 90%. The resulting capital cost estimate (in 1990 $) is $149/kW for GSA as compared to $216/kW for a wet limestone, forced-oxidation (WLFO) scrubbing system. The levelized annual revenue requirement for the GSA process is lower than that for the WLFO system, but the difference is only about 20% (which is not considered to be significant given the limitations on the accuracy of estimates used in the analysis). The principal annual operating cost for the GSA process is the cost of the pebble lime. The 15-year levelized costs in mills/kWh for the two systems are listed below:

	GSA	WLFO
Fixed costs	2.3	2.81
Variable costs	3.1	2.93
Capital costs	5.0	7.30
Total	10.4	13.04

Commercial Applications:

The GSA process offers several advantages over conventional FGD technologies: (1) GSA is 30% cheaper than wet FGD and 20% cheaper than spray drying; (2) GSA is much simpler to build and operate than wet FGD and regenerable processes and requires much less space; (3) space requirements, operability, and ease of installation are comparable to spray dryers and duct injection; and (4) the SO_2 removal capability (90%) compares to that of wet FGD and regenerable processes. This high removal rate makes the GSA process suitable for use with high-sulfur coal.

Successful testing of the AirPol demonstration project has resulted in a commercial application in Ohio. The city of Hamilton, OH, received a $5-million grant from the Ohio Coal Development Office to install the GSA technology to control emissions from a 50-MWe coal-fired boiler at the city's municipal power plant. The new system is scheduled to be operational in August 1996 and will be the first full-scale commercial GSA unit in the United States as well as the world's first GSA unit for a coal-fired boiler. The GSA technology was identified as the least-cost alternative for the city to meet CAAA compliance requirements for 1997.

In addition, FLS miljo has been awarded a major project in Sweden for a high-performance GSA system to remove sulfur from the flue gas of a 4-million-ton/year iron ore sinter plant. Sweden's stringent standards require an SO_2 removal efficiency of 90–95%.

The GSA should fulfill the need of the utility industry to meet the new SO_2 emission standard as set forth by the CAAA of 1990. Based on a comparison of GSA capital and operating costs with other FGD processes, the GSA is especially suited for 50–250-MWe utility plants. Simplicity in GSA design and operation plus modest space requirements make GSA ideal for retrofitting to existing plants as well as for greenfield plants. One major advantage of the GSA, as compared to other semi-dry scrubbing processes, is that operation of the GSA will not result in excessive dust loading to the gas stream, thus minimizing the cost for upgrading the existing dust collector. The potential market for the GSA is estimated at $300 million within the next 20 years.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/11/90
NEPA process completed (MTF)	9/21/90
Environmental monitoring plan completed	10/2/92
Construction	5/92–9/92
Operational testing	10/92–3/94
Project completed	6/95

Final Reports:

Final Project Performance and Economic Report	1/95
Air Toxics Characterization Final Report	3/95
Public Design Report	6/95

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Project completed.

Participant:

Bechtel Corporation

Additional Team Members:

Pennsylvania Electric Company—cofunder and host
Pennsylvania Energy Development Authority—cofunder
New York State Electric & Gas Corporation—cofunder
Rockwell Lime Company—cofunder

Location:

Seward, Indiana County, PA (Pennsylvania Electric Company's Seward Station, Unit No. 5)

Technology:

Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process

Plant Capacity/Production:

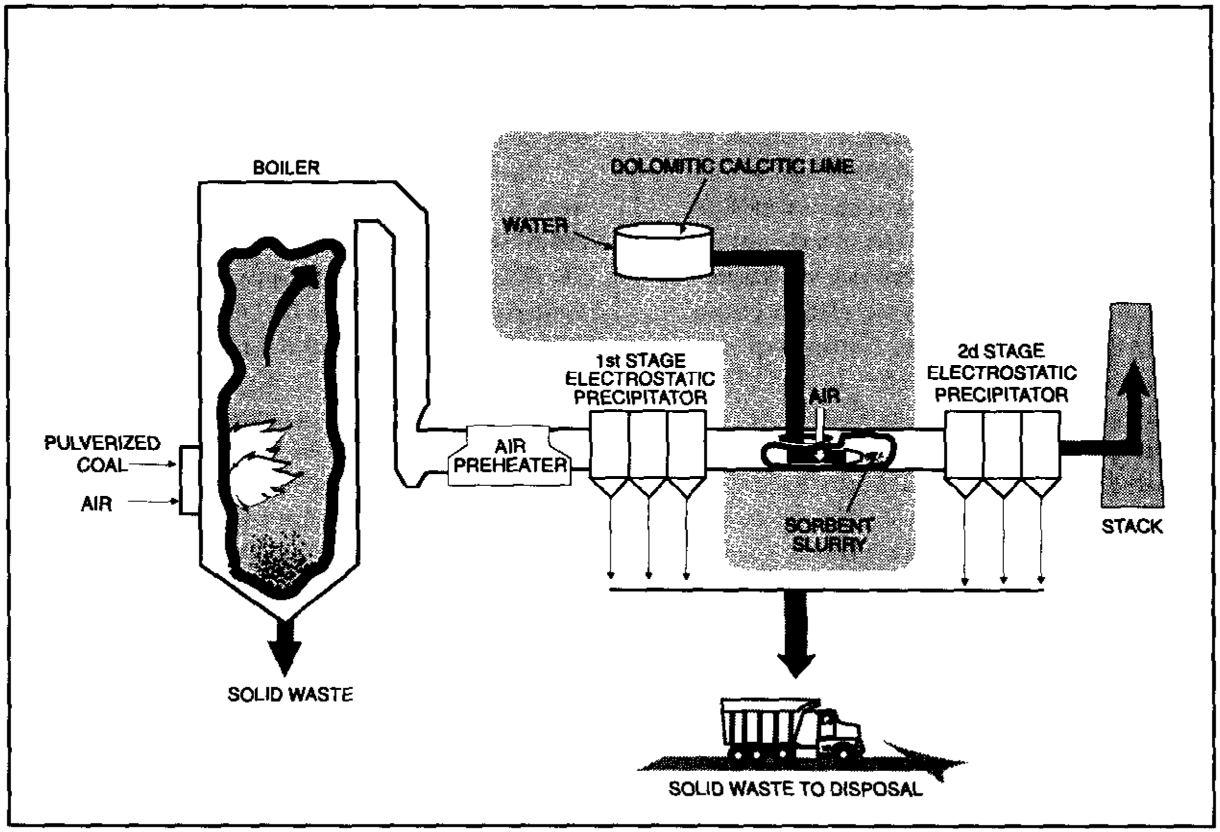
73.5 MWe

Project Funding:

Total project cost*	$10,411,600	100%
DOE	5,205,800	50
Participant	5,205,800	50

Project Objective:

To demonstrate SO_2 removal capabilities of in-duct CZD/FGD technology; specifically, to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations and emissions.



Technology/Project Description:

In Bechtel's CZD/FGD process, a finely atomized slurry of reactive lime is sprayed into the flue gas stream between the boiler air heater and the electrostatic precipitator (ESP). The lime slurry is injected into the center of the duct by spray nozzles designed to produce a cone of fine spray. As the spray moves downstream and expands, the gas within the cone cools and the SO_2 is rapidly absorbed in the liquid droplets. The droplets mix with the hot flue gas, and the water evaporates rapidly. Fast drying precludes wet particle buildup in the duct and aids the flue gas in carrying the dry reaction products and the unreacted lime to the ESP.

This project included injection of different types of sorbents (dolomitic and calcitic limes) with several atomizer designs using low- and high-sulfur coals to verify the effects on SO_2 removal and the capability of the ESP to control particulates. The demonstration was conducted at Pennsylvania Electric Company's Seward Station in Seward, PA. One-half of the flue gas capacity of the 147-MWe Unit No. 5 was routed through a modified, longer duct between the first- and second-stage ESPs. Pennsylvania bituminous coal (approximately 1.2–2.5% sulfur) was used in the project.

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*Additional project overrun costs were funded 100% by the participant for a final total project cost of $12,173,000.

Project Results/Accomplishments:

Bechtel began its 18-month, two-part test program for the CZD process in July 1991. The first 12 months of the test program consisted primarily of parametric testing. The latter 6 months involved continuous operational testing with the system being operated under fully automatic control by host utility boiler operators. The new atomizing nozzles were thoroughly tested both outside and inside the duct prior to testing. The lime slurry injection parametric test program, which began in October 1991, was completed in August 1992.

In summary, the demonstration showed the following:

- A 50% SO_2 removal efficiency with CZD/FGD is possible, and continuous operation at removal rates lower than 50% can be maintained over long periods without significant process problems.
- The process requires that drying and SO_2 absorption take place within 2 seconds. A long and straight horizontal gas duct of about 100 feet is required to assure residence time of 2 seconds.
- During normal operations, no deposits of fly ash or reaction products took place in the flue gas duct.
- The fully automated system, fully integrated with power plant operation, demonstrated that the CZD/FGD process responded well to automated control operation.
- Availability of the system was very good.
- At Seward Station, stack opacity was not detrimentally affected by the CZD/FGD system.
- Results of the demonstration indicated that the CZD/FGD process can achieve costs of $300/ton of SO_2 removed when operating a 500-MWe unit burning 4% sulfur coal. Based on a 500-MWe plant retrofitted with CZD/FGD for a 50% rate of SO_2 removal, the total capital cost is estimated to be less than $30/kW.

Bechtel notified DOE on June 30, 1993, that it was discontinuing the demonstration project effective July 1, 1993.

Commercial Applications:

CZD can be used for retrofit of existing and installation in new utility boiler flue gas facilities to remove SO_2 derived from a wide variety of sulfur-containing coals.

A CZD system can be added to a utility boiler with a capital investment of about $25–50/kW of installed capacity, or approximately one-fourth the cost of building a conventional wet scrubber. In addition to low capital cost, other advantages include small space requirements, ease of retrofit, low energy requirements, fully automated operation, and production of only nontoxic, disposable waste. The CZD technology is particularly well suited for retrofitting existing boilers, independent of type, age, or size. The CZD installation does not require major power station alterations and can be easily and economically integrated into existing power plants.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	10/13/90
NEPA process completed (MTF)	9/25/90
Environmental monitoring plan completed	6/12/91
Construction	3/91–6/91
Operational testing	7/91–6/93
Project discontinued	7/93

Final Reports:

Final Technical Report	6/94
Public Design Report	10/93

LIFAC Sorbent Injection Desulfurization Demonstration Project

Project completed.

Participant:

LIFAC–North America (a joint venture partnership between Tampella Power Corporation and ICF Kaiser Engineers, Inc.)

Additional Team Members:

ICF Kaiser Engineers, Inc.—cofunder and project manager
Tampella Power Corporation—cofunder
Tampella, Ltd.—technology owner
Richmond Power & Light—cofunder and host
Electric Power Research Institute—cofunder
Black Beauty Coal Company—cofunder
State of Indiana—cofunder

Location:

Richmond, Wayne County, IN (Richmond Power & Light's Whitewater Valley Station, Unit No. 2)

Technology:

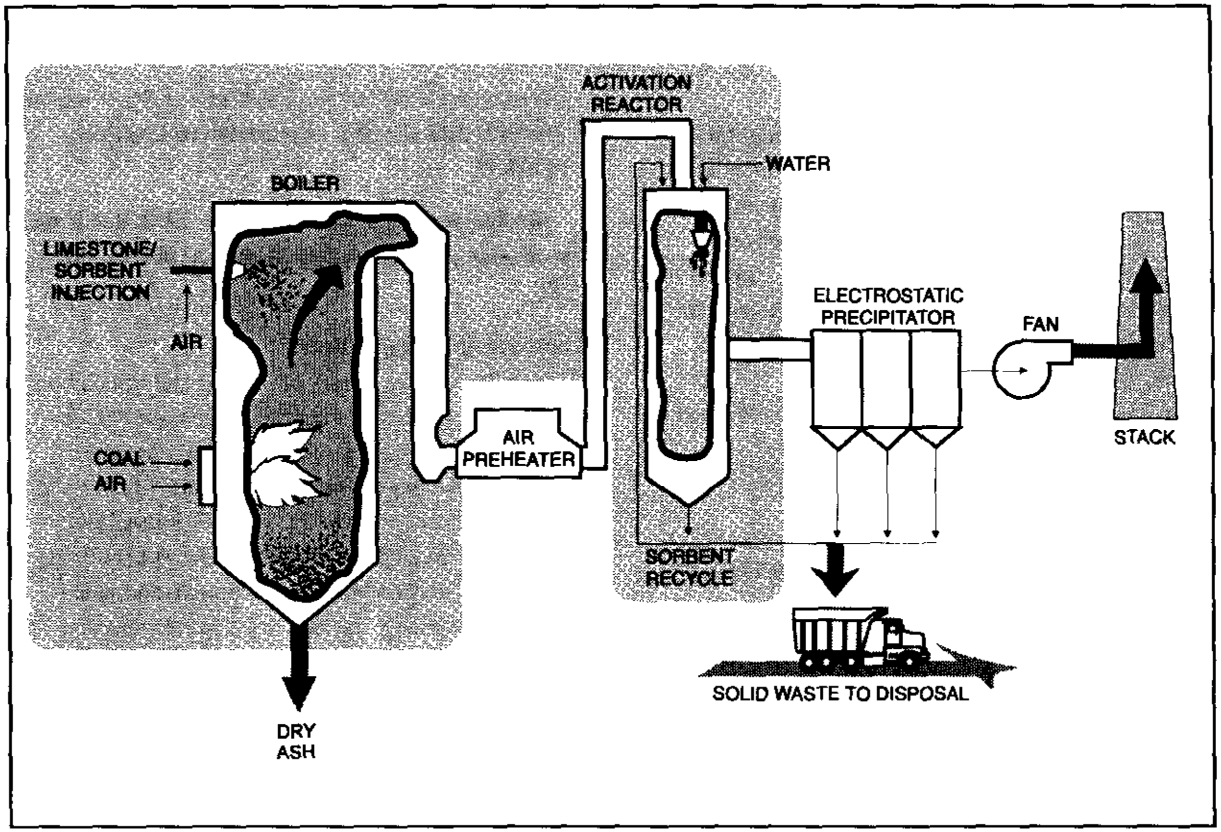
LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor

Plant Capacity/Production:

60 MWe

Project Funding:

Total project cost	$21,393,772	100%
DOE	10,636,864	50
Participant	10,756,908	50



Project Objective:

To demonstrate that electric power plants—especially those with space limitations—burning high-sulfur coals can be retrofitted successfully with the LIFAC limestone injection process to remove 75–85% of the SO_2 from flue gas and produce a dry solid waste product for disposal in a landfill.

Technology/Project Description:

Pulverized limestone is pneumatically blown into the upper part of the boiler near the superheater where it absorbs some of the SO_2 in the boiler flue gas. The limestone is calcined into calcium oxide and is available for capture of additional SO_2 downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions leading to SO_2 capture. After leaving the chamber, the sorbent is easily separated from the flue gas along with the fly ash in the electrostatic precipitator (ESP). The sorbent material from the reactor and ESP is recirculated back through the reactor for increased efficiency. The waste is dry, making it easier to handle than the wet scrubber sludge produced by conventional wet limestone scrubber systems.

The technology enables power plants with space limitations to use high-sulfur midwestern coals by providing an injection process that removes 75–85% of the SO_2 from flue gas and produces a dry solid waste product suitable for disposal in a landfill.

The process was demonstrated at the Whitewater Valley Station, 60-MWe Unit No. 2. This coal-fired unit is owned and operated by Richmond Power & Light and is located in Richmond, IN. Bituminous coal containing 2.0–2.9% sulfur was used for the majority of system testing.

Project Results/Accomplishments:

The total duration of the project was 2,800 hours of operation over a 2-year period.

LIFAC process variables and their effects on sulfur removal efficiency were evaluated during parametric testing. The four major parameters having the greatest influence on sulfur removal efficiency were limestone quality, Ca/S ratio, reactor bottom temperature (approach-to-saturation), and ESP ash recycling rate. Total SO_2 capture was about 15 percentage points better when injecting fine limestone (80% minus 325 mesh) than it was with coarse limestone (80% minus 200 mesh).

Parametric tests indicated that a 70% SO_2 reduction was achievable with a Ca/S ratio of 2.0. ESP ash containing unreacted sorbent and fly ash was recycled from the ESP hoppers back into the reactor inlet duct work. Ash recycling is essential for efficient SO_2 capture. The large quantity of ash removed from the LIFAC reactor bottom, and the small size of the ESP hoppers limited the ESP ash recycling rate. As a result, the amount of material recycled from the ESP was approximately 70% less than had been anticipated. However, this low recycling rate contributed an additional 15 percentage points to total SO_2 capture. During a brief test, it was found that increasing the recycle rate by 50% resulted in a 5 percentage point increase in SO_2 removal efficiency. It is anticipated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5 °F above saturation temperature, an SO_2 reduction of 85% could be maintained.

Optimization testing began in March 1994 and was followed by long-term testing in June 1994. The boiler was operated at an average load of 60 MWe during long-term testing, although it fluctuated according to power demand. The LIFAC process automatically adjusted to boiler load changes. A Ca/S ratio of 2.0 was selected to attain SO_2 reductions above 70%. Reactor bottom temperature was about 5 °F higher than optimum to avoid ash buildup on the steam reheaters. Atomized water droplet size was smaller than optimum for the same reason. Other key process parameters held constant during long-term tests included degree of humidification, grind size of the high-calcium-content limestone, and recycle ratio of spent sorbent from the ESP.

Long-term testing showed that SO_2 reductions of 70% or more can be maintained under normal boiler operating ranges. Stack opacity was low (about 10%) and ESP efficiency was high (99.2%). The solid waste generated was a mixture of fly ash and calcium compounds and was readily disposed of at a local landfill.

The LIFAC system has few moving parts and is simple to operate. The process can be easily shutdown and restarted. The process is automated by a programmable logic system, which regulates process control loops, interlocking, start-up, shut downs, and data collection. The entire LIFAC process was easily managed via two personal computers located in the host utility's control room.

The economic evaluation indicated that the capital cost of a LIFAC installation is lower than for either spray dryers or wet scrubbers. Capital costs for LIFAC technology vary depending on unit size and the quantity of reactors needed:

- $99/kW for one LIFAC reactor at Whitewater Valley Station (65 MWe)
- $76/kW for one LIFAC reactor at Shand Station (150 MWe)
- $66/kW for two LIFAC reactors at Shand Station (300 MWe)

Commercial Applications:

This process is suitable for application to all coal-fired utility or industrial boilers, especially those with tight space limitations. The LIFAC process is less expensive to install than conventional wet flue gas desulfurization processes; uses dry limestone instead of more costly lime; is relatively simple to operate; produces a dry, readily disposable waste; and can handle all types of coal.

The benign waste material can be disposed of in a landfill along with the fly ash. Commercial use of the LIFAC by-product in the manufacture of construction materials is currently being investigated in Finland.

There are 10 full-scale LIFAC units in operation or under construction in Canada, China, Finland, Russia, and the United States. The LIFAC system at Richmond Power & Light is being retained and is the first to be applied to a power plant using high-sulfur (2.0–2.9%) coal. The other LIFAC installations are on power plants using low-sulfur (0.6–1.5%) coals.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	11/20/90
NEPA process completed (MTF)	10/2/90
Environmental monitoring plan completed	6/12/92
Construction	5/91–6/92
Operational testing	9/92–6/94
Project completed	12/96

Final Reports:

Final Technical Report	12/96
Economic Evaluation Report	12/96
Public Design Report	12/96

Advanced Flue Gas Desulfurization Demonstration Project

Project completed.

Participant:

Pure Air on the Lake, L.P. (a project company of Pure Air which is a general partnership between Air Products and Chemicals, Inc., and Mitsubishi Heavy Industries America, Inc.)

Additional Team Members:

Northern Indiana Public Service Company—cofunder and host
Mitsubishi Heavy Industries, Ltd.—process designer
United Engineers and Constructors (Stearns-Roger Division)—facility designer
Air Products and Chemicals, Inc.—constructor and operator

Location:

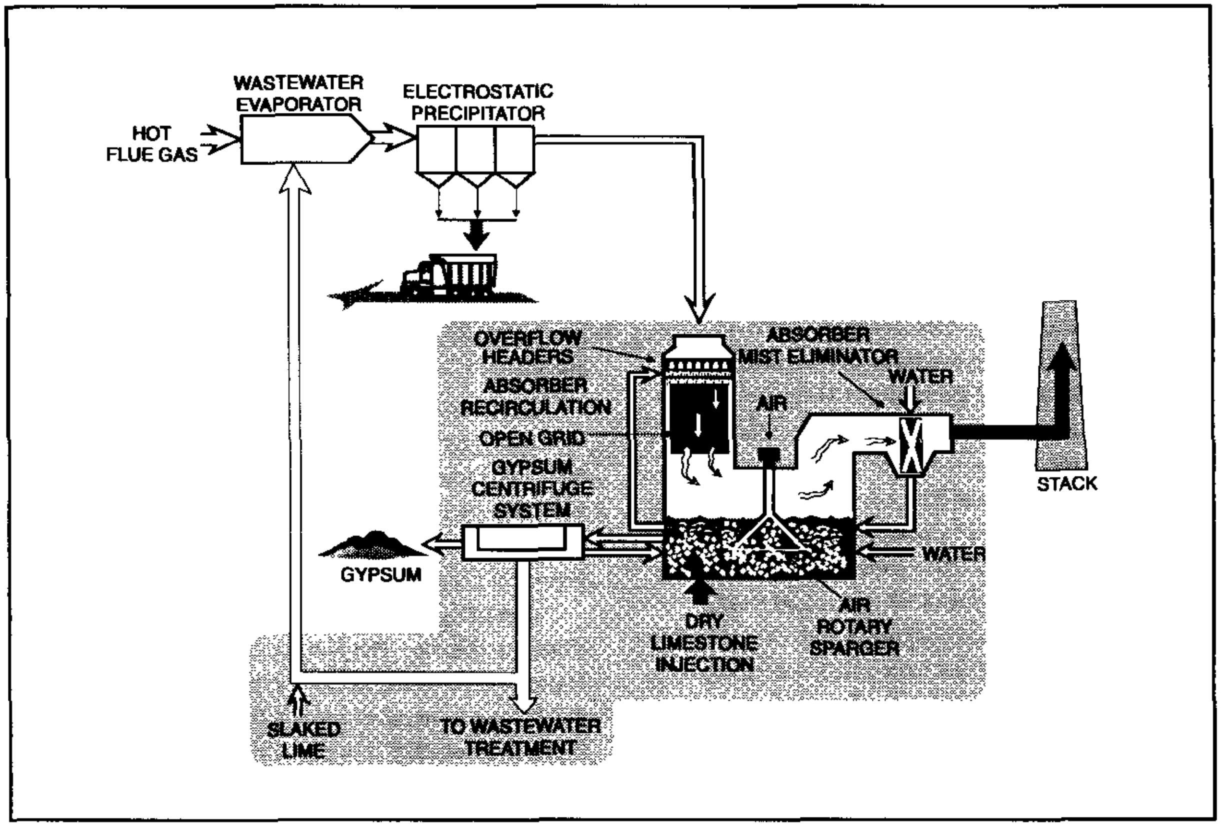
Chesterton, Porter County, IN (Northern Indiana Public Service Company's Bailly Generating Station, Units 7 and 8)

Technology:

Pure Air's advanced flue gas desulfurization (AFGD) process

Plant Capacity/Production:

528 MWe



Project Funding:

Total project cost	$151,707,898	100%
DOE	63,913,200	42
Participant	87,794,698	58

Project Objective:

To demonstrate removal of 90–95% or more of the SO_2 at approximately one-half the cost of conventional scrubbing technology; and to demonstrate significant reduction of space requirements.

Technology/Project Description:

In this project, Pure Air has built a single SO_2 absorber for a 528-MWe power plant. Although this is the largest capacity absorber module in the United States, it has relatively modest space requirements because no spare or backup absorber modules are required. The absorber performs three functions in a single vessel: prequencher, absorber, and oxidation of sludge to gypsum. Additionally, the absorber is of a co-current design, in which the flue gas and scrubbing slurry move in the same direction and at a relatively high velocity compared to conventional scrubbers. These features all combine to yield a state-of-the-art SO_2 absorber that is more compact and less expensive than conventional scrubbers.

Technical features include the injection of pulverized limestone directly into the absorber, a device called an air rotary sparger located within the base of the absorber, and a novel wastewater evaporation system. The air rotary sparger combines the functions of agitation and air distribution into one piece of equipment to facilitate the oxidation of calcium sulfite to gypsum.

PowerChip is a registered trademark of Pure Air on the Lake, L.P.

Pure Air also demonstrated a unique gypsum agglomeration process that produces PowerChip® gypsum.

Bituminous coals primarily from the Indiana-Illinois coal basin containing 2.25–4.7% sulfur were tested.

Project Results/Accomplishments:

The 528-MWe demonstration accumulated approximately 26,280 hours of operation over a 3-year period and achieved an availability of 99.79%. Construction began in April 1990, and in June 1992 the AFGD system began to process flue gas, thus becoming the first commercial scrubber to meet the requirements of the CAAA of 1990. Tests were on coals ranging from 2.0% to 4.5% sulfur. During the 3-year operation, SO_2 removal efficiency averaged 94.71% with a maximum of 98+% or 0.382 lb/million Btu. Twenty-four-hour average power consumption was 5,275 kW, or 61% of expected consumption, and water consumption was 1,560 gallons/minute, or 52% of expected consumption. The production rate of the PowerChip® facility was 7 tons/hr. During the 3-year demonstration, an average of 207,623 tons/yr of dry gypsum were produced, with an average purity of 97.56%.

In 1993, *Power Magazine* presented the Powerplant of the Year Award to the generating station for demonstrating advanced wet limestone FGD technology with innovations in wastewater treatment and gypsum production. In 1992, the National Society of Professional Engineers presented its Outstanding Engineering Achievement Award to the project.

Commercial Applications:

The AFGD process is attractive for both new and retrofit utility applications. The demonstration project is using bituminous coals primarily from the Indiana-Illinois coal basin, with sulfur content ranging from 2.0% to 4.5%.

The AFGD unit at Bailly Station will continue to operate for an additional 17 years under a novel business concept whereby Pure Air is the owner of the unit and Air Products and Chemicals, Inc., is the operator. This AFGD facility will reduce SO_2 emissions by approximately 75,000 tons/yr. Further, the gypsum by-product and wastewater evaporation will demonstrate that SO_2 control can occur without increased solid waste or wastewater production.

All this can be accomplished with costs (and space requirements) that are roughly one-half of those associated with a conventional scrubber.

In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO_2 scrubbing capability at Florida Power & Light Company's Manatee power plant on the same own-and-operate basis. The Manatee scrubber will feature two 800-MWe absorber vessels, PowerChip® gypsum recycling, and wastewater evaporation.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	12/20/89
NEPA process completed (EA)	4/16/90
Environmental monitoring plan completed	1/31/91
Construction	4/90–9/92
Operational testing	6/92–6/95
Project completed	6/96

Final Reports:

Final Technical Report (includes economics)	6/96
Public Design Report	3/90

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process

Project completed.

Participant:

Southern Company Services, Inc.

Additional Team Members:

Georgia Power Company—host
Electric Power Research Institute—cofunder
Radian Corporation—environmental and analytical consultant
Ershigs, Inc.—fiberglass fabricator
Composite Construction and Equipment—fiberglass sustainment consultant
Acentech—flow modeling consultant
Ardaman—gypsum stacking consultant
University of Georgia Research Foundation—by-product utilization studies consultant

Location:

Newnan, Coweta County, GA (Georgia Power Company's Plant Yates, Unit No. 1)

Technology:

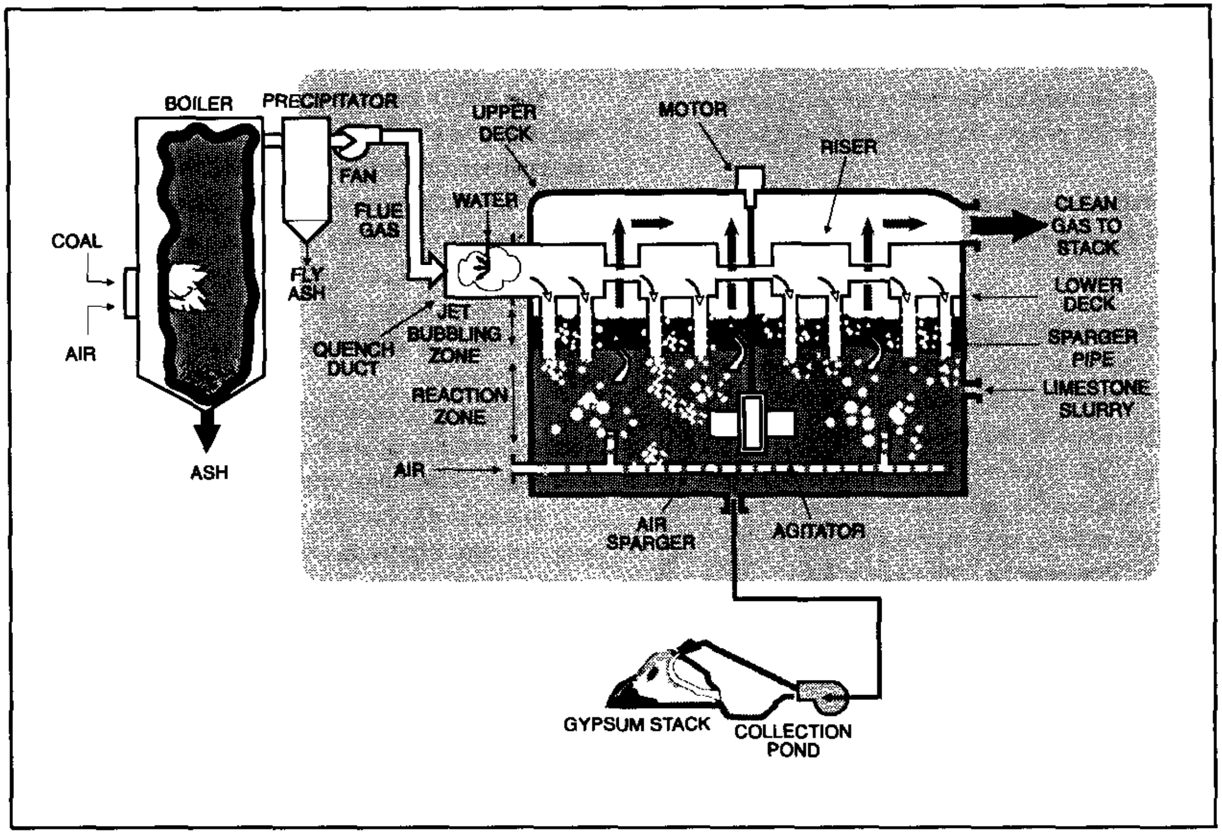
Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process

Plant Capacity/Production:

100 MWe

Project Funding:

Total project cost	$43,074,996	100%
DOE	21,085,211	49
Participant	21,989,785	51



Project Objective:

To demonstrate the CT-121 flue gas desulfurization system, including several design innovations, at the 100-MWe scale; more specifically, to demonstrate 90% SO_2 control at high reliability with and without simultaneous particulate control with possible additional reductions in operating costs.

Technology/Project Description:

The project is demonstrating the CT-121 FGD process, which uses a unique absorber design known as the jet-bubbling reactor (JBR). The process combines limestone FGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically and chemically simpler than conventional FGD processes and can be expected to exhibit lower cost characteristics.

The flue gas enters underneath the scrubbing solution in the jet-bubbling reactor. The SO_2 in the flue gas is absorbed and forms calcium sulfite ($CaSO_3$). Air is bubbled into the bottom of the solution to oxidize the calcium sulfite to form gypsum. The slurry is dewatered in a gypsum stack, which involves filling a dyked area with gypsum slurry. Gypsum solids settle in the dyked area by gravity, and clear water flows to a retention pond. The clear water from the pond is returned to the process.

The project also evaluated process innovations to determine if costs can be reduced further by using fiberglass-reinforced plastic (FRP) vessels, eliminating flue gas reheat and spare absorber modules, and stacking gypsum to reduce waste management costs. The ability of this technology to capture SO_2 and particulates simultaneously also was evaluated.

Bituminous coals containing 1.2–4.3% sulfur were used to demonstrate 90% SO_2 control with high reliability, with and without simultaneous particulate control.

Project Results/Accomplishments:

Parametric testing was completed in March 1993, and long-term testing began in May 1993. DOE-sponsored air-toxics testing was done in June 1993.

During the 19,000 hours or 27 months available for the demonstration, the scrubber operated for 14,000 hours. The coal burned during the demonstration was a blend of Illinois No. 5 and 6 that averaged 2.4% sulfur. Other tests were conducted on coals varying from 1.2% to 4.3% sulfur. The system demonstrated the ability to exceed 98% SO_2 removal efficiency with high-sulfur coal while at maximum boiler load and limestone utilization of 97%. Using FRP fabrication of key components, with its high resistance to corrosion, enabled elimination of a rescrubber to remove chlorides and flue gas reheat to prevent corrosive condensation in the chimney (constructed of FRP). The structural and chemical durability of FRP construction combined with the simplicity of design afforded by the unique JBR resulted in high availability (97% at low ash levels and 95% at elevated ash levels) and elimination of the need for a spare reactor module. The CT-121 system demonstrated high particulate capture efficiency (97.7–99.3%) at flyash levels reflective of marginal ESP performance (up to 1.14 lbs/million Btu). Testing also showed the CT-121 to be highly efficient in the capture of hazardous air pollutants (HAPs) which are largely borne by particulates.

In April 1996, an internal inspection of the JBR revealed no noticeable problems after extended operations.

In February 1996, the project won the Society of Plastics Industries' Design Award for the mist eliminator. The project received two awards in 1994: *Power Magazine's* 1994 Powerplant of the Year Award and an Outstanding Achievement Award from the Georgia chapter of the Air and Waste Management Association for using an innovative technology for air quality control. In 1993, Plant Yates received an environmental award from the Georgia Chamber of Commerce, based on the success of the CT-121 scrubber.

Commercial Applications:

The CT-121 FGD system is applicable to both new and pre-NSPS utility and industrial boilers.

Specific features of this technology that will enhance its potential for commercialization follow: (1) fiberglass construction can be used, eliminating the need for rubber-lined carbon steel or costly alloys; (2) no spare absorber is required because the system is at least 97% reliable; (3) reheating of the flue gas is not necessary; (4) both SO_2 and particulates are removed from flue gas; (5) more than 99% of the calcium in the limestone reagent is used; (6) the gypsum by-product can be stored safely and easily or used in commercial applications; (7) the CT-121 operating costs are the lowest for state-of-the-art FGD systems; (8) there is no known size limit for this technology; (9) utilities and industrial concerns could make immediate use of this technology; and (10) the system is not sensitive to the type of coal used, its sulfur content, or the limestone utilized.

Involvement of Southern Company (which owns Southern Company Services, Inc.), with its utility system that has more than 20,000 MWe of coal-fired generating capacity, is expected to enhance the confidence of other large, high-sulfur coal boiler users in the CT-121 process. This process will be applicable to 370,000 MWe of new and existing generating capacity by the year 2010. A 90% reduction in SO_2 emissions from only the retrofit portion of this capacity represents more than 10,500,000 tons/yr of potential SO_2 control.

In 1994 a tar sands oil extraction facility in Murray, Canada, purchased the CT-121 scrubber.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	4/2/90
NEPA process completed (EA)	8/10/90
Environmental monitoring plan completed	12/18/90
Construction	8/90–10/92
Operational testing	10/92–12/94
Project completed	1/97

Final Reports:

Final Technical Report	12/96
Economic Evaluation Report	12/96
Public Design Report	12/96
Final Report on Gypsum Stacking	1/97

SNOX™ Flue Gas Cleaning Demonstration Project

Project completed.

Participant:

ABB Environmental Systems

Additional Team Members:

Ohio Coal Development Office—cofunder
Ohio Edison Company—cofunder and host
Haldor Topsoe a/s—patent owner for process technology, catalysts, and WSA Tower
Snamprogetti, U.S.A.—cofunder and process designer

Location:

Niles, Trumbull County, OH (Ohio Edison's Niles Station, Unit No. 2)

Technology:

Haldor Topsoe's SNOX™ catalytic advanced flue gas cleanup system

Plant Capacity/Production:

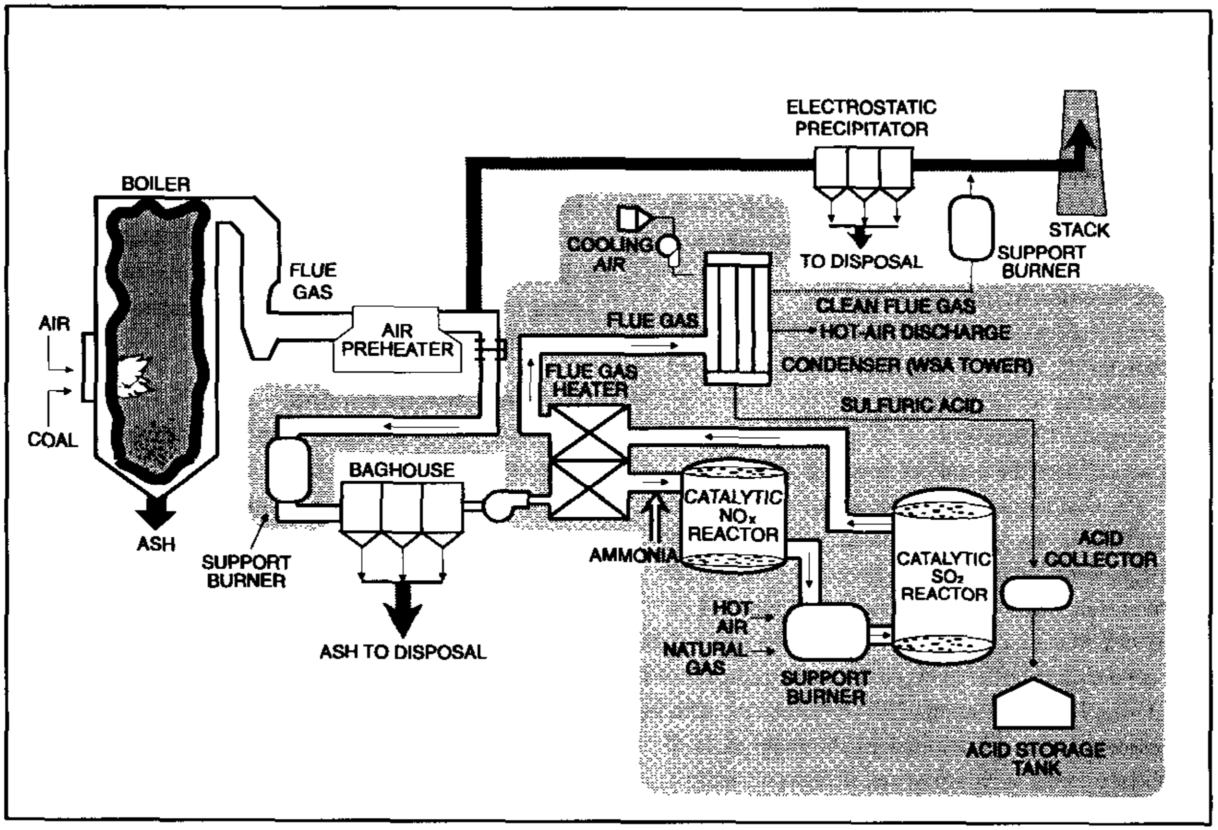
35-MWe equivalent slipstream from a 108-MWe boiler

Project Funding:

Total project cost	$31,438,408	100%
DOE	15,719,200	50
Participant	15,719,208	50

Project Objective:

To demonstrate at an electric power plant using U.S. coals that SNOX™ technology will catalytically remove 95% of SO_2 and more than 90% of NO_x from flue gas and produce a salable by-product of concentrated sulfuric acid.



Technology/Project Description:

In the SNOX™ process, the stack gas leaving the boiler is cleaned of fly ash in a high-efficiency fabric filter baghouse to minimize the cleaning frequency of the sulfuric acid catalyst in the downstream SO_2 converter. The ash-free gas is reheated, and NO_x is reacted with small quantities of ammonia in the first of two catalytic reactors where the NO_x is converted to harmless nitrogen and water vapor. The SO_2 is oxidized to SO_3 in a second catalytic converter. The gas then passes through a novel glass-tube condenser which allows SO_3 to hydrolyze to concentrated sulfuric acid.

The technology, while using U.S. coals, is designed to remove 95% of the SO_2 and more than 90% of the NO_x from flue gas and produce a salable sulfuric acid by-product. This is accomplished without using sorbents and without creating waste by-products.

The demonstration was conducted at Ohio Edison's Niles Station in Niles, OH. The demonstration unit treated a 35-MWe equivalent slipstream of flue gas from the 108-MWe Unit No. 2 boiler which burned a 3.4% sulfur Ohio coal. The process steps were virtually the same as for a commercial full-scale plant, and commercial-scale components were installed and operated.

SNOX is a trademark of Haldor Topsoe a/s.

Project Results/Accomplishments:

Operational testing was initiated in March 1992 and completed in December 1994. The system operated for more than 8,000 hours and produced more than 5,600 tons of commercial-grade sulfuric acid. The facility has routinely operated at full capacity, achieving removal efficiencies of 96% for SO_2, 94% for NO_x, and 99.9% for particulates.

Many tests for the SNOX™ system were designed to be conducted at 75%, 100%, and 110% of design capacity. During the test program, SO_2 removal efficiencies were normally in excess of 95% for inlet concentrations which averaged about 2,000 ppm. System NO_x reduction efficiencies averaged 94% with inlet NO_x levels of approximately 500–700 ppm.

Sulfuric acid concentrations and composition have met or exceeded federal specifications for class I acid. The acid from the plant has been sold to the agriculture industry for the production of diammonium phosphate fertilizer and to the steel industry for pickling. Ohio Edison has used a significant amount in its boiler water demineralizer system throughout its plants.

Air toxics testing at the plant indicated that, for the majority of the species examined, especially those that exit primarily as particulates at the SNOX™ fabric filter or SNOX™ outlet, removal is very high. Because of the mechanism of sulfuric acid condensation in the WSA condenser, any particulates remaining at this point act as nuclei for H_2SO_4 and are captured in the acid. For volatile species, the WSA condenser outlet temperature is lower than conventional boiler outlet temperatures and should condense and capture more of the volatile species than a plant with only an ESP or fabric filter.

The economic evaluation of the SNOX™ process showed a capital cost of approximately $250/kW and a total operating cost of approximately 1.3 mills/kWh.

Commercial Applications:

The SNOX™ technology is applicable to all electric power plants and industrial/institutional boilers firing coal, oil, or gas. The high removal efficiency for NO_x and SO_2 will make the process attractive in many applications. Elimination of additional solid waste (except ash) enhances the marketability in urban and other areas where solid waste disposal is a significant problem.

The host utility, Ohio Edison, is retaining the SNOX™ technology as a permanent part of the pollution control system at Niles Station to help Ohio Edison meet its overall SO_2/NO_x reduction goals.

Commercial SNOX™ plants also are operating in Denmark and Sicily. In Denmark, a 305-MWe plant has operated since August 1991. The boiler at this plant burns coals from various suppliers around the world, including the United States; the coals contain 0.5–3.0% sulfur. The plant in Sicily, operating since March 1991, has a capacity of about 30 MWe and fires petroleum coke.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	12/20/89
NEPA process completed (MTF)	1/31/90
Environmental monitoring plan completed	10/31/91
Construction	1/91–12/91
Operational testing	3/92–12/94
Project completed	7/96

Final Reports:

Final Technical Report (includes economic information)	7/96
Public Design Report	7/96

LIMB Demonstration Project Extension and Coolside Demonstration

Project completed.

Participant:

The Babcock & Wilcox Company

Additional Team Members:

Ohio Coal Development Office—cofunder
Consolidation Coal Company—cofunder and technology supplier
Ohio Edison Company—host

Location:

Lorain, OH (Ohio Edison's Edgewater Station, Unit 4)

Technology:

The Babcock & Wilcox Company's limestone injection multistage burner (LIMB) system; Babcock & Wilcox DRB-XCL® low-NO_x burners
Consolidation Coal Company's Coolside duct injection of lime sorbents

Plant Capacity/Production:

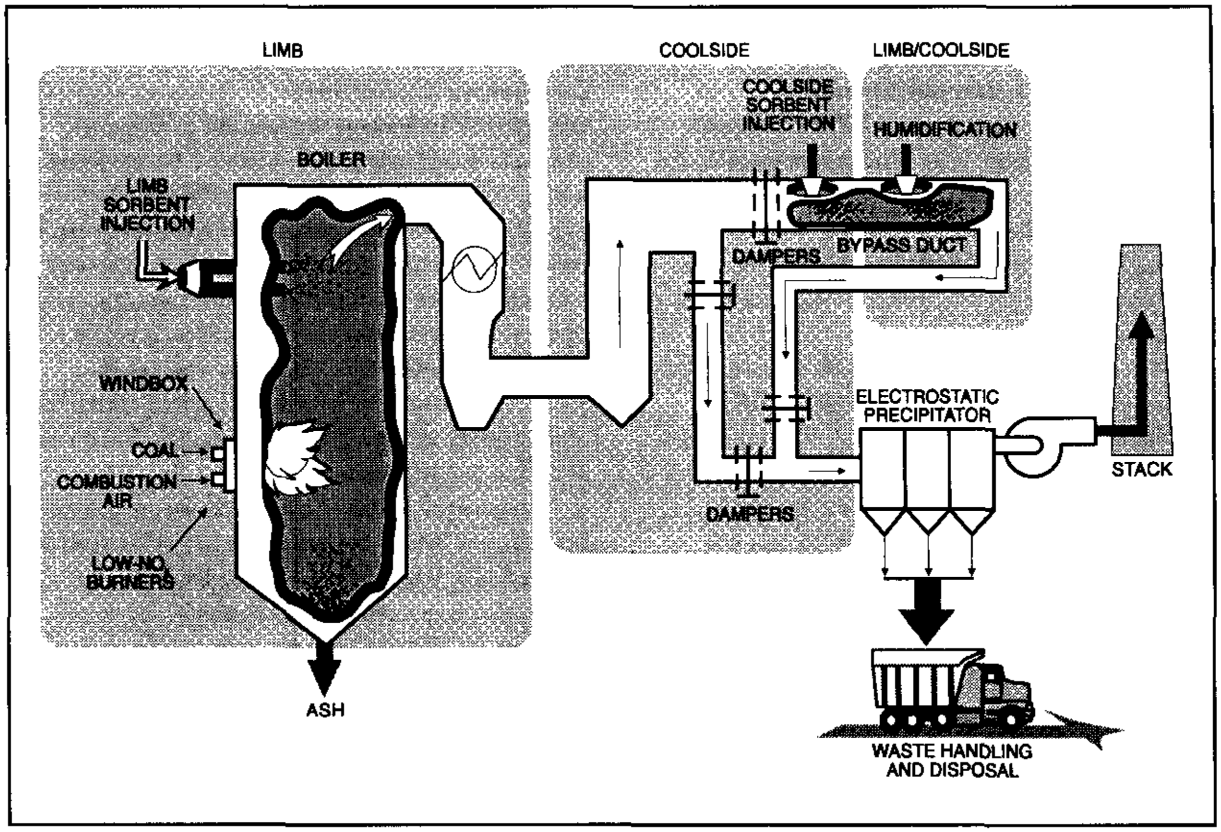
105 MWe

Project Funding:

Total project cost	$19,404,940	100%
DOE	7,597,026	39
Participant	11,807,914	61

Project Objective:

To demonstrate, with a variety of coals and sorbents, the LIMB process as a retrofit system for simultaneous control of NO_x and SO_2 in the combustion process, and that LIMB can achieve up to 70% NO_x and SO_2 reductions; to test alternate sorbent and coal combinations, using the Coolside process, to demonstrate in-duct sorbent injection upstream of the humidifier and precipitator and to show SO_2 removal of up to 70%.



Technology/Project Description:

The LIMB process reduces SO_2 by injecting dry sorbent into the boiler at a point above the burners. The sorbent then travels through the boiler and is removed along with fly ash in an electrostatic precipitator (ESP) or baghouse. Humidification of the flue gas before it enters an ESP is necessary to maintain normal ESP operation and to enhance SO_2 removal. Combinations of three eastern bituminous coals (1.6%, 3.0%, and 3.8% sulfur) and four sorbents were tested. Other variables examined were stoichiometry, humidifier outlet temperature, and injection level.

In the Coolside process, dry sorbent is injected into the flue gas downstream of the air preheater, followed by flue gas humidification. Humidification enhances ESP performance and SO_2 absorption. SO_2 absorption is improved by dissolving NaOH or Na_2CO_3 in the humidification water. The spent sorbent is collected with the fly ash, as in the LIMB process. An eastern bituminous coal with 3.0% sulfur was used in testing.

The same low-NO_x burners (Babcock & Wilcox DRB-XCL® low-NO_x burners), which control NO_x through staged combustion, were used in demonstrating both LIMB and Coolside technologies.

DRB-XCL is a registered trademark of The Babcock & Wilcox Company.

This project was conducted at Ohio Edison's Edgewater Plant in Lorain, OH, on a commercial, Babcock & Wilcox Carolina-design, wall-fired 105-MWe boiler.

Project Results/Accomplishments:

LIMB tests were conducted over a range of Ca/S ratios and humidification conditions. Each of four sorbents (calcitic limestone, type-N atmospherically hydrated dolomitic lime, calcitic hydrated lime, and calcitic hydrated lime with added calcium lignosulfonate) was injected while burning each of three coals (Ohio bituminous, 1.6%, 3.0%, and 3.8% sulfur). Tests were conducted under minimal humidification, defined as operation at a humidifier outlet temperature sufficient to maintain ESP performance. That temperature was typically 250–275 °F. Tests were also conducted at a 20 °F approach to the adiabatic saturation temperature of the flue gas to enhance SO_2 removal of the LIMB system. Close-approach operation typically meant controlling the flue gas temperature at the humidifier outlet (ESP inlet) to about 145 °F. Other variables were stoichiometry and injection level. Highlights of reported test results follow:

- The coal's sulfur content, as reflected in the SO_2 concentration in the flue gas, affected SO_2 removal efficiency—the higher the sulfur content, the greater the SO_2 removal for a given sorbent at a comparable stoichiometry. A 5–7% increase in removal occurred when switching to 3.8% from 1.6% sulfur coal and injecting at a stoichiometry of 2.0.
- The highest sulfur removal efficiencies, without humidification to close approach, were attained using the ligno lime—61% SO_2 removal was achieved while burning 3.8% sulfur coal. All sorbents tested were capable of removing SO_2 although calcium utilization of even finely pulverized limestone was not nearly as high as those of the limes.
- While injecting commercial limestone with 80% of the particles less than 44 microns in size, removal efficiencies of about 22% were obtained at a stoichiometry of 2.0 while burning 1.6% sulfur coal. However, removal efficiencies of about 32% were achieved at a stoichiometry of 2.0 when using a limestone with all particles less than 44 microns. For a third limestone with essentially all particles less than 10 microns, the removal efficiency was about 5–7% higher than that obtained at similar conditions for limestone with all particles less than 44 microns.
- Sorbent injection at the 181-ft plant elevation level inside the boiler, just above the boiler's nose, yielded the highest SO_2 removal rates. Here, the sorbent was injected at close to the optimum furnace temperature of 2,300 °F.
- SO_2 removal efficiencies were enhanced by about 10% over the range of stoichiometries tested when humidification down to a 20 °F approach to saturation was used.

During the Coolside demonstration, compliance (1.2–1.6% sulfur) and noncompliance (3.0% sulfur) coals were burned. Key process variables—Ca/S, Na/Ca, and approach to adiabatic saturation—were evaluated in short-term (6–8-hr) parametric tests and longer term (1–11-day) process operability tests.

The Coolside process routinely achieved 70% SO_2 removal at design conditions (2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to adiabatic saturation temperature) using commercial hydrated lime. SO_2 removal depended on Ca/S, Na/Ca, approach to adiabatic saturation, and the physical properties of the hydrated lime. Sorbent recycle showed significant potential to improve sorbent utilization. Observed SO_2 removal with recycle sorbent alone was 22% at 0.5 available Ca/S and 18 °F approach to adiabatic saturation. Observed SO_2 removal with simultaneous recycle and fresh sorbent feed was 40% at 0.8 fresh Ca/S, 0.2 fresh Na/Ca, 0.5 available recycle, and 18 °F approach to adiabatic saturation.

NO_x removal was in the 40–50% range throughout both LIMB and Coolside testing.

Commercial Applications:

Both LIMB and Coolside technologies are applicable to most utility and industrial coal-fired units and provide alternatives to conventional wet flue gas desulfurization (FGD) processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. Depending on the plant capacity factor and the coal's sulfur content, they can be economically competitive with FGD systems. For example, using 2.5% sulfur coal at a 65% plant capacity factor, LIMB can be cost competitive with conventional wet FGD up to 450 MWe and Coolside up to 220 MWe. The environmental benefits for LIMB are 40–50% lower NO_x and more than 20% lower SO_2 emissions, and for Coolside up to 70% lower SO_2 emissions. The waste from each of these processes is dry, easily handled, and contains unreacted lime that has potential commercial application. Both processes can handle all coal types, especially low- to medium-sulfur coals.

Project Schedule:

DOE selected project (CCT-I)	7/24/86
Cooperative agreement awarded	6/25/87
NEPA process completed (MTF)	6/2/87
Environmental monitoring plan completed	10/19/88
Construction	8/87–9/89
Coolside operational testing	7/89–2/90
LIMB extension operational testing	4/90–8/91
Project completed	11/92

Final Reports:

Final Report (LIMB/Coolside)	11/92
Topical Report (Coolside)	2/92
Topical Report (LIMB/Coolside)	9/90
Public Design Report	12/88

SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project

Project completed.

Participant:
The Babcock & Wilcox Company

Additional Team Members:
Ohio Edison Company—cofunder and host
Ohio Coal Development Office—cofunder
Electric Power Research Institute—cofunder
Norton Company—cofunder and SCR catalyst supplier
3M Company—cofunder and filter bag supplier
Owens Corning Fiberglas Corporation—cofunder and filter bag supplier

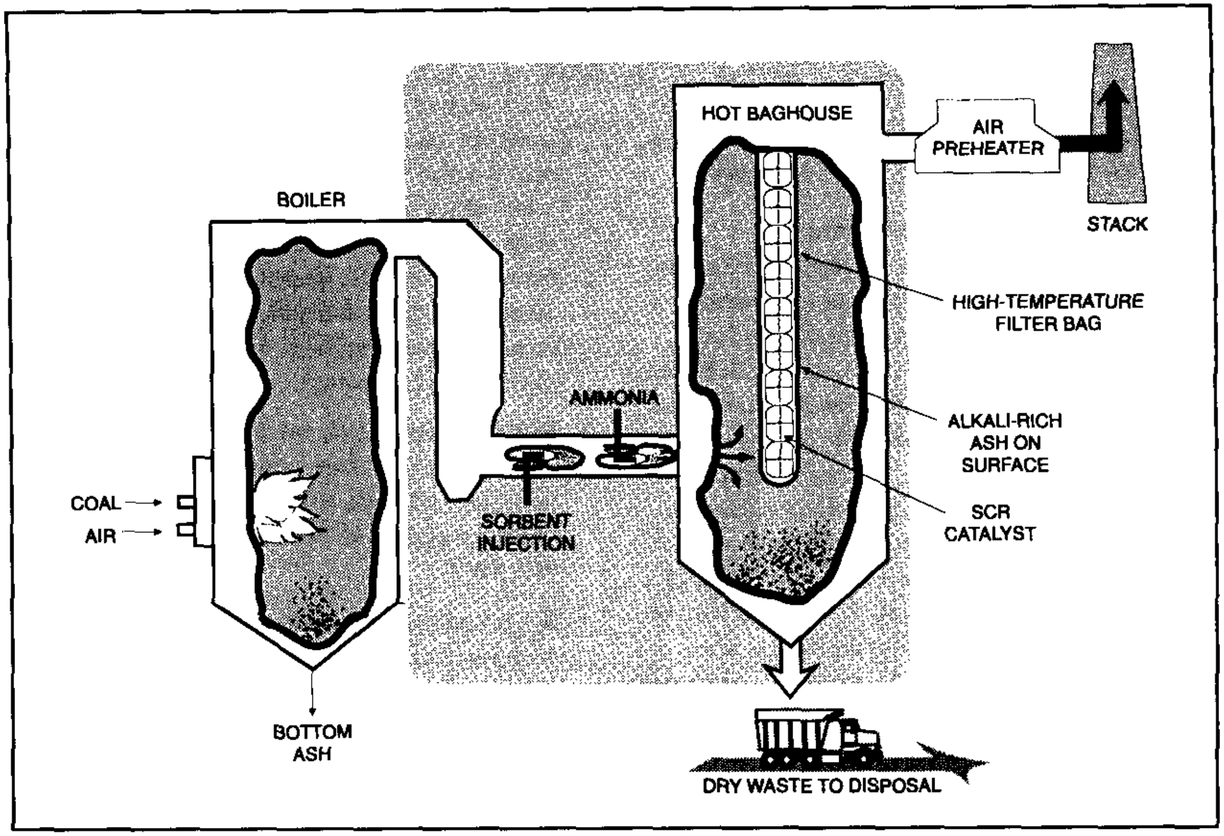
Location:
Dilles Bottom, Belmont County, OH (Ohio Edison Company's R.E. Burger Plant, Unit No. 5)

Technology:
The Babcock & Wilcox Company's SO_x-NO_x-Rox Box™ (SNRB™) process

Plant Capacity/Production:
5-MWe equivalent slipstream from a 156-MWe boiler

Project Funding:

Total project cost	$13,271,620	100%
DOE	6,078,402	46
Participant	7,193,218	54



Project Objective:
To demonstrate that the SNRB™ process, used in retrofitting a high-sulfur-coal-fired power plant, can remove high levels of all three pollutants (NO_x, SO_2, and particulates) using a single processing unit for treating flue gas, thereby lessening on-site space requirements and capital costs.

Technology/Project Description:
The SNRB™ process combines the removal of SO_2, NO_x, and particulates in one unit—a high-temperature baghouse. SO_2 removal is accomplished using either calcium- or sodium-based sorbent injected into the flue gas. NO_x removal is accomplished by injecting ammonia to selectively reduce NO_x in the presence of a selective catalytic reduction, or SCR, catalyst. Particulate removal is accomplished by high-temperature fiber bag filters.

The 5-MWe SNRB™ demonstration unit is large enough to demonstrate commercial-scale components while minimizing the demonstration cost. Operation at this scale also permitted cost-effective control of the flue gas temperature which allowed for evaluation of performance over a wide range of sorbent injection and baghouse operating temperatures. Thus several different arrangements for potential commercial installations could be simulated.

The project demonstrated the technical and economic feasibility of achieving greater than 80% SO_2 removal, above 90% NO_x removal, and 99% particulate removal at lower capital, operating, and maintenance costs than a combination of conventional systems. The demonstration was conducted at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles

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SO_x-NO_x-Rox Box and SNRB are trademarks of The Babcock & Wilcox Company.

Bottom, OH. Bituminous coal with an average sulfur content of 3.4% was burned at this site during the demonstration.

Project Results/Accomplishments:

SNRB™ demonstration tests were conducted for emissions control of SO_2, NO_x, and particulates. Four different sorbents were tested for SO_2 capture. Calcium-based sorbents included commercial-grade hydrated lime, sugar hydrated lime, and lignosulfonate hydrated lime. In addition, sodium bicarbonate was tested. The optimum location for injecting the sorbent into the flue gas was immediately upstream of the baghouse. Effectively, the SO_2 was captured by the sorbent while the sorbent was in the form of a filter cake on the filter bags (along with fly ash). To capture NO_x, ammonia was injected between the sorbent injection point and the baghouse. The ammonia and NO_x reacted to form nitrogen and water in the presence of Norton Company's NC-300 series zeolite SCR catalyst. Because the catalyst was located inside the filter bags, it was well protected from potential particulate erosion or fouling. The sorbent reaction products, unreacted lime, and fly ash were collected on the filter bags and thus removed from the flue gas.

With commercial-grade lime, at a Ca/S ratio of 2, and with the baghouse temperature between 800 and 850 °F, sulfur capture was well above 80%. With the modified hydrated limes, at the same operating temperature range, sulfur capture approached 90%. With an NH_3/NO_x ratio of 0.9, the reduction in NO_x emissions was consistently above 90% and the ammonia slip was consistently below 5 ppm. Particulate emissions were always below 0.03 lb/million Btu, the NSPS for particulates. Particulate emissions averaged 0.018 lb/million Btu (0.009 grains/std ft^3), corresponding to a collection efficiency of 99.89%.

High SO_2 removal efficiency was demonstrated in a brief test program with sodium bicarbonate injection. Removal efficiency increased from 80% to 98% and the ratio of Na_2/S was increased from 1 to 2.

All of the demonstration tests were conducted using 3M's Nextel ceramic fiber filter bags or Owens Corning Fiberglas's S-Glass filter bags. All of the test work was carried out at air-to-cloth ratios of 3–4 ft/min. No excessive wear or failures occurred in more than 2,000 hours of elevated temperature operation.

A preliminary evaluation has been made of the projected capital cost of the SNRB™ system for various utility boilers. For a 250-MWe boiler fired with 3.5% sulfur coal and generating NO_x emissions of 1.2 lbs/million Btu, the projected cost of a SNRB™ system is approximately $260/kW including various standard technology and project contingency factors. The cost of *competitive technology, consisting of a combination of* fabric filter, SCR, and wet scrubber for achieving comparable emissions control, has been estimated at $360–400/kW.

Commercial Applications:

Commercial application of the technology offers the potential for significant reductions of multiple pollutants from fossil-fired plants with the potential for increasing thermal efficiency. SNRB™ offers the potential for lower capital and operating costs and smaller space requirements than a combination of conventional, high-efficiency control technologies. SNRB™ is capable of reducing emissions from plants burning high- or low-sulfur coal. In retrofit applications, SNRB™ provides a means of improving particulate emissions control with the addition of SO_2 and NO_x emissions control capacity.

Commercialization of the technology is expected to develop with an initial larger scale application equivalent to 50–100 MWe. The focus of marketing efforts will be tailored to match the specific needs of potential industrial, utility, and independent power producers for both retrofit and new plant construction. SNRB™ is a flexible technology which can be tailored to maximize control of SO_2, NO_x, or combined emissions to meet current performance requirements while providing flexibility to address future needs.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	12/20/89
NEPA process completed (MTF)	9/22/89
Environmental monitoring plan completed	12/31/91
Construction	5/91–12/91
Operational testing	5/92–5/93
Project completed	9/95

Final Reports:

Final Technical Report (includes economic information)	9/95
Detailed Design Report	11/92

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Project completed.

Participant:

Energy and Environmental Research Corporation

Additional Team Members:

Gas Research Institute—cofunder
State of Illinois, Department of Energy and Natural Resources—cofunder
Illinois Power Company—host
City Water, Light and Power—host

Locations:

Hennepin, Putnam County, IL (Illinois Power Company's Hennepin Plant, Unit 1)
Springfield, Sangamon County, IL (City Water, Light and Power's Lakeside Station, Unit 7)

Technology:

Energy and Environmental Research Corporation's gas reburning and sorbent injection (GR–SI) process

Plant Capacity/Production:

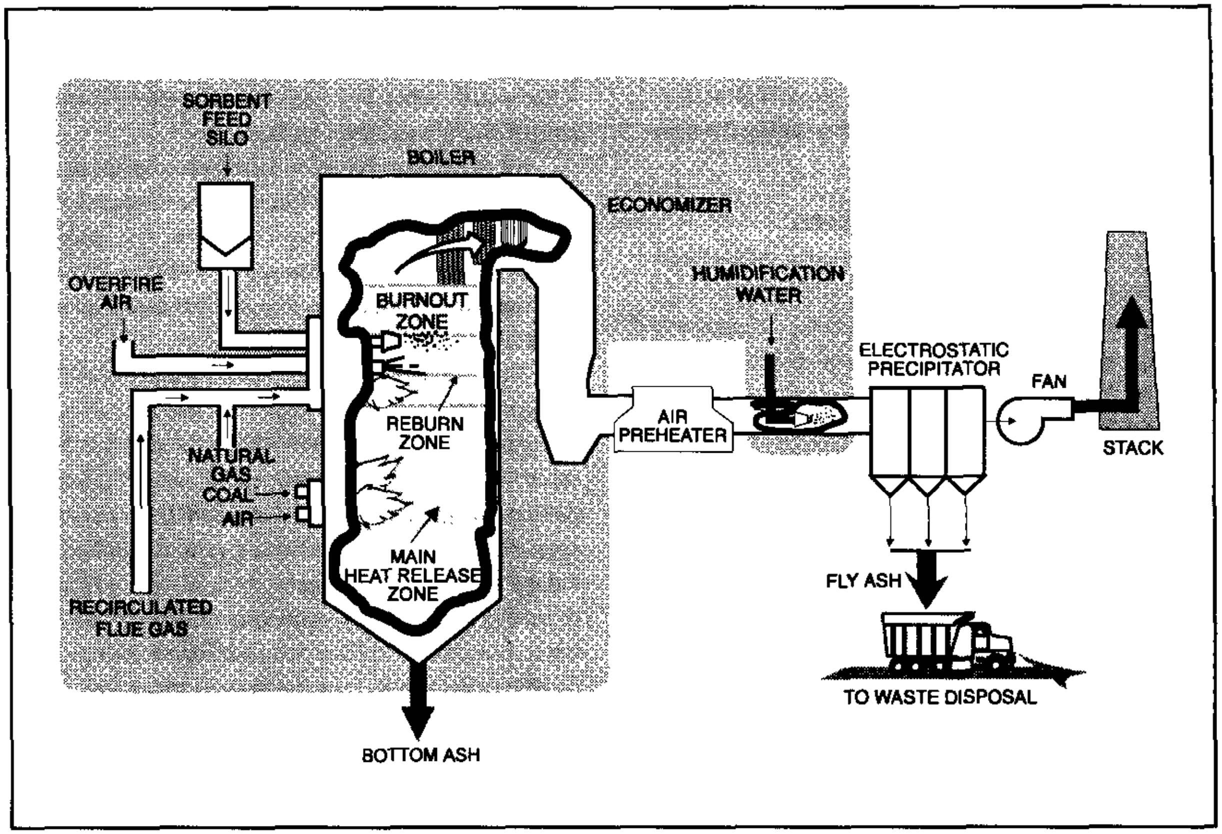
Hennepin: tangential-fired 80 MWe (gross), 71 MWe (net)
Lakeside: cyclone-fired 40 MWe (gross), 33 MWe (net)

Project Funding:

Total project cost	$37,588,955	100%
DOE	18,747,816	50
Participant	18,841,139	50

Project Objective:

To demonstrate gas reburning to attain at least 60% NO_x reduction along with sorbent injection to capture at least 50% of the SO_2 on two different boiler configurations—tangentially fired and cyclone-fired—while burning high-sulfur midwestern coal.



Technology/Project Description:

In this process, 80–85% of the fuel is coal and is supplied to the main combustion zone. The remaining 15–20% of the fuel, generally natural gas or other hydrocarbon, bypasses the main combustion zone and is injected above the main burners to form a reducing (reburn) zone in which NO_x is converted to nitrogen. A calcium compound (sorbent) is injected in the form of dry, fine particulates above the reburning zone in the boiler or even further downstream. The calcium compound tested is $Ca(OH)_2$ (lime). This project demonstrated the GR–SI process on two separate boilers representing two different firing configurations—a tangentially fired, 80-MWe (gross) boiler at Illinois Power Company's Hennepin Plant in Hennepin, IL, and a cyclone-fired, 40-MWe (gross) boiler at City Water, Light and Power's Lakeside Station in Springfield, IL. Illinois bituminous coal containing 3% sulfur was the test coal for both Hennepin and Lakeside.

Project Results/Accomplishments:

A matrix of 32 gas reburn tests were completed on the tangentially fired boiler at the Hennepin Plant. NO_x reductions of up to 77% were achieved, with 65% being routine—exceeding the project objective of 60%. Evaluation of 20 overfire air tests indicated substantial NO_x reduction was achievable at low power generation loads, with lesser reductions as load increased. Sorbent injection reduced SO_2 emissions as much as 62%, with 52% reduction being routine—also exceeding the project objective of 50%. The Ca/S was about 1.75.

Three proprietary sorbents (including PromiSorb A, PromiSorb B, and high surface area hydrated lime) were also tested at Hennepin. The sorbents showed higher SO_2 capture and higher calcium utilization than the regular hydrated lime.

The GR–SI process reduced CO_2, HCl, and HF emissions as well as NO_x and SO_2. During sorbent injection, particulate emissions were reduced by flue gas humidification upstream of the ESP.

The system installed at Hennepin operated for more than 2,100 hours, of which about 400 hours were gas reburning; 115 hours, sorbent injection; and nearly 760 hours, combined operation (the remainder was baseline testing).

After reviewing the operational performance, boiler impact, and economics, Illinois Power retained the gas burning portion of the GR–SI system for possible use for NO_x control.

Parametric testing on the cyclone boiler at the Lakeside Station was conducted in three series: gas reburning parametric testing, sorbent injection parametric testing, and GR–SI optimization tests. The goal of the parametric test series was to define the optimum GR–SI operating conditions with minimal degradation of the thermal performance of the boiler and to evaluate the GR–SI process over a wide range of representative operating conditions.

A total of 100 gas reburning parametric tests were conducted at boiler loads of 33 MWe, 25 MWe, and 20 MWe. The reburn parametric tests achieved NO_x reduction levels either at or just marginally above the 60% reduction goal. Additional flow modeling and computer modeling studies indicated that smaller reburning fuel jet nozzles could increase reburning fuel mixing and improve NO_x reduction performance.

A total of 25 sorbent injection parametric tests to isolate the effects of the sorbent on boiler performance and operability were completed. Tests indicated that SO_2 reduction level varied with load because of the effect of temperature on the sulfurization reaction. At a Ca/S of 2.0, full load (33 MWe) achieved a 44% SO_2 reduction; mid-load (25 MWe), 38% reduction; and low load (20 MWe), 32% reduction at Lakeside.

In the GR–SI optimization tests, the two technologies were integrated. Modifications were made to the reburning fuel injection nozzles based on the results of the initial gas reburning parametric tests. Tests did not indicate any adverse effect from changing the thermal profile. SO_2 reductions of more than 50% could be achieved with Ca/S greater than 1.25 along with gas heat inputs of 22–25%. The total SO_2 reduction from the combined effect of fuel replacement and sorbent injection exceeded the project goal of 50% reduction.

The primary goal of the long-term testing was to operate GR-SI during the normal operating cycle of the Lakeside unit. The unit typically operated in cycling service with a very low capacity factor, so testing was conducted whenever the unit was operated. The average NO_x reduction after 249 hours of gas reburning operation was 67%. The average SO_2 reduction after 221 hours of GR–SI operation was 58%. During GR–SI operation there was a 0.8% drop in thermal efficiency due to the fuel switch and a small increase in the exit flue gas temperature.

During extended tests that included a 38-hr GR–SI continuous run, a 115-hr GR-only continuous run, and a 66-hr continuous GR–SI run, process operation with variable load met the project goals of 60% NO_x reduction and 50% SO_2 reduction. No significant boiler or ESP impacts were observed. Compliance test results for particulate emissions averaged 0.016 lb/million Btu, well below the limit of 0.1 lb/million Btu.

City Water, Light and Power is retaining the equipment for possible future use. Restoration involves preparing the system for long-term storage.

Commercial Applications:

Gas reburning and sorbent injection is a unique combination of two separate technologies. The commercial applications for these technologies, both separately and combined, extend to both utility companies and industry in the United States and abroad. In the United States alone, these two technologies can be applied to more than 900 pre-NSPS utility boilers; the technologies also can be applied to new utility boilers. With NO_x and SO_2 removal exceeding 60% and 50%, respectively, these technologies have the potential to extend the life of a boiler or power plant and also provide a way to use higher sulfur coals.

Project Schedule:

DOE selected project (CCT-I)	7/24/86
Cooperative agreement awarded	7/14/87
NEPA process completed, Hennepin (MTF)	5/9/88
Environmental monitoring plan completed,	
Hennepin	10/15/89
Lakeside	11/15/89
Construction, Hennepin	5/89–8/91
Operational testing, Hennepin	1/91–1/93
Restoration completed, Hennepin	12/93
NEPA process completed, Lakeside (EA)	6/25/89
Construction, Lakeside	6/90–5/92
Operational testing, Lakeside	5/93–10/94
Restoration completed, Lakeside	12/95
Project completed	12/96

Final Reports:

Final Technical Report, Hennepin	10/94
Final Technical Report, Edwards	10/94
Final Technical Report, Lakeside	12/96
Economic Evaluation Report	12/96
Public Design Report	12/96

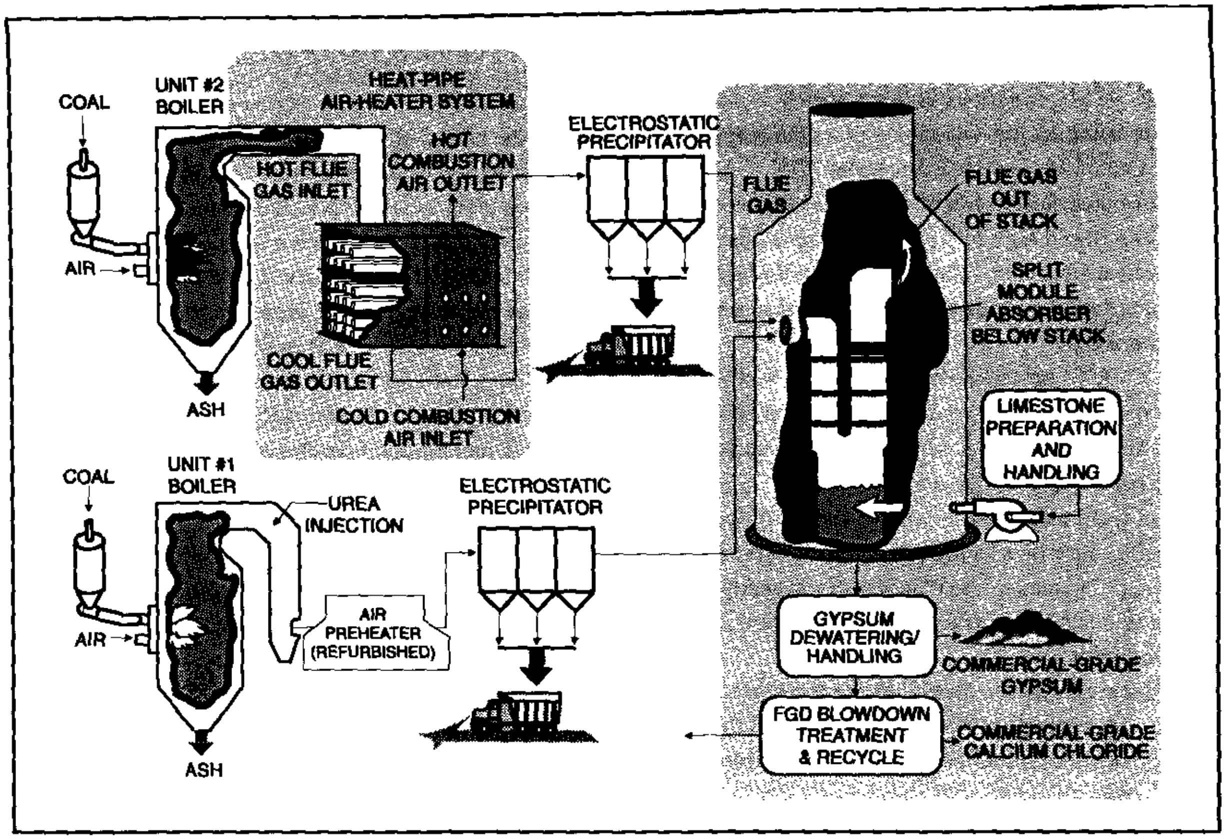
Milliken Clean Coal Technology Demonstration Project

Participant:

New York State Electric & Gas Corporation

Additional Team Members:

New York State Energy Research and Development Administration—cofunder
Empire State Electric Energy Research Corporation—cofunder
Consolidation Coal Company—technical consultant
Saarberg-Hölter-Umwelttechnik, GmbH—technology supplier
The Stebbins Engineering and Manufacturing Company—technology supplier
Nalco Fuel Tech—technology supplier
ABB Air Preheater, Inc.—technology supplier
DHR Technologies, Inc.—operator of advisor system



Location:

Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station, Units 1 and 2)

Technology:

Flue gas cleanup using Saarberg-Hölter-Umwelttechnik's (S-H-U) formic-acid-enhanced, wet limestone scrubber technology; ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) Level III; Nalco Fuel Tech's NO_xOUT® urea injection system; Stebbins' tile-lined split-module absorber; and ABB Air Preheater's heat-pipe air-heater system

Plant Capacity/Production:

300 MWe

Project Funding:

Total Project Cost	$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

Project Objective:

To demonstrate at a 300-MWe utility-scale a combination of cost-effective and innovative emission reduction and efficiency improvement technologies, including the S-H-U wet scrubber system enhanced with formic acid to increase SO_2 removal in a Stebbins tile-lined scrubber, low-NO_x burner, urea injection for NO_x removal, and a heat-pipe air preheater.

Technology/Project Description:

The S-H-U wet flue gas desulfurization process is a formic-acid-enhanced, wet limestone process which results in very high SO_2 removal with low energy consumption and the production of commercial-grade gypsum.

The flue gas desulfurization absorber is a Stebbins tile-lined split-module vessel which has superior corrosion and abrasion resistance, leading to decreased life-cycle costs and reduced maintenance. The split-module design is constructed below the stack to save space and provide operational flexibility.

The Nalco Fuel Tech NO_xOUT® system is used to remove NO_x by injecting urea into the boiler flue gas. This facet of the project, in conjunction with other com-

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NO_xOUT is a registered trademark of Nalco Fuel Tech.
LNCFS is a trademark of ABB Combustion Engineering, Inc.
PEOA is a trademark of DHR Technologies, Inc.

rado coal, with a short test using low-sulfur (0.35%) subbituminous Wyoming coal.

Project Results/Accomplishments:

Operational testing of the boiler with low-NO_x burners and overfire air started in early August 1992. While firing western bituminous coal, NO_x was reduced from an original baseline of 1.15 lbs/million Btu to about 0.4 lb/million Btu—a 65% reduction—with no operating problems. In-furnace urea injection resulted in a 44% NO_x reduction at full load with a 10-ppm ammonia slip, but at low load, only 11% NO_x reduction was obtained. New retractable injection lances were installed in April 1995, and NO_x reduction at low load was improved to 35% at 10-ppm slip. Sodium-bicarbonate injection achieved more than 70% SO_2 removal at a stoichiometric ratio of approximately 1.0. Sodium sesquicarbonate injection after the air heater also obtained a 70% SO_2 removal but at a stoichiometric ratio of approximately 1.8. Calcium-based dry reagent injection achieved a maximum of 40% SO_2 removal and caused some operational concerns. Overall NO_x reduction of 80% has been demonstrated at full load with the integrated sodium and urea injection system.

A 2-week test burn of Power River Basin coal was completed during November 1995. SO_2 emissions were reduced about 20% due to the lower sulfur content of the coal. NO_x emissions decreased by 25–30% at both 60 and 80 MWe.

Testing of the integrated system was completed in March 1996. The system worked as expected and significantly decreased NO_2 emissions that occur due to sodium injection and the ammonia emissions that occur due to urea injection. The project goal of obtaining 70% SO_2 and NO_x reductions was demonstrated. The combination of sodium and urea injection allowed much higher urea injection while maintaining stack ammonia concentrations of 10 ppm or less. The control system was adjusted to allow a maximum of 5 ppm ammonia concentration at the stack, and the ammonia concentration in the flyash unloading area was greatly reduced. The project has been extended through February 1997 to test and evaluate an improved urea lance design.

Four series of air toxics testing have been completed. Results indicate that the baghouse successfully removes nearly all trace metal emissions and nearly 80% of the mercury emissions. Radionuclides, semi-volatile organic compounds, and dioxins/furans were below or very near their detection limits.

Arapahoe 4 has operated more than 33,700 hours since combustion modifications were completed in May 1992. The availability factor during this period was over 91%.

Due to the successful application of the system, the Public Service Company of Colorado plans to continue operation of the combustion modifications and the sodium-based dry sorbent injection system. A final decision on the selective noncatalytic reduction system will be made after the test program is completed.

Commercial Applications:

Either the entire integrated dry NO_x/SO_2 emissions control system or the individual technologies are applicable to most utility and industrial coal-fired units. They provide a lower capital-cost alternative to conventional wet flue gas desulfurization processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. They can be applied to any unit size but are mostly applicable to the older, small- to mid-size units.

Project Schedule:

DOE selected project (CCT-III)	12/19/89
Cooperative agreement awarded	3/11/91
NEPA process completed (MTF)	9/27/90
Environmental monitoring plan completed	8/5/93
Construction	5/91–8/92
Operational testing	8/92–3/96
Project completed	2/97

Final Reports:

Final Technical Report	2/97
Economic Evaluation Report	2/97
Public Design Report	2/97

Coal Processing
for Clean Fuels
Fact Sheets

Development of the Coal Quality Expert

Project completed.

Participants:

ABB Combustion Engineering, Inc.
CQ Inc.

Additional Team Members:

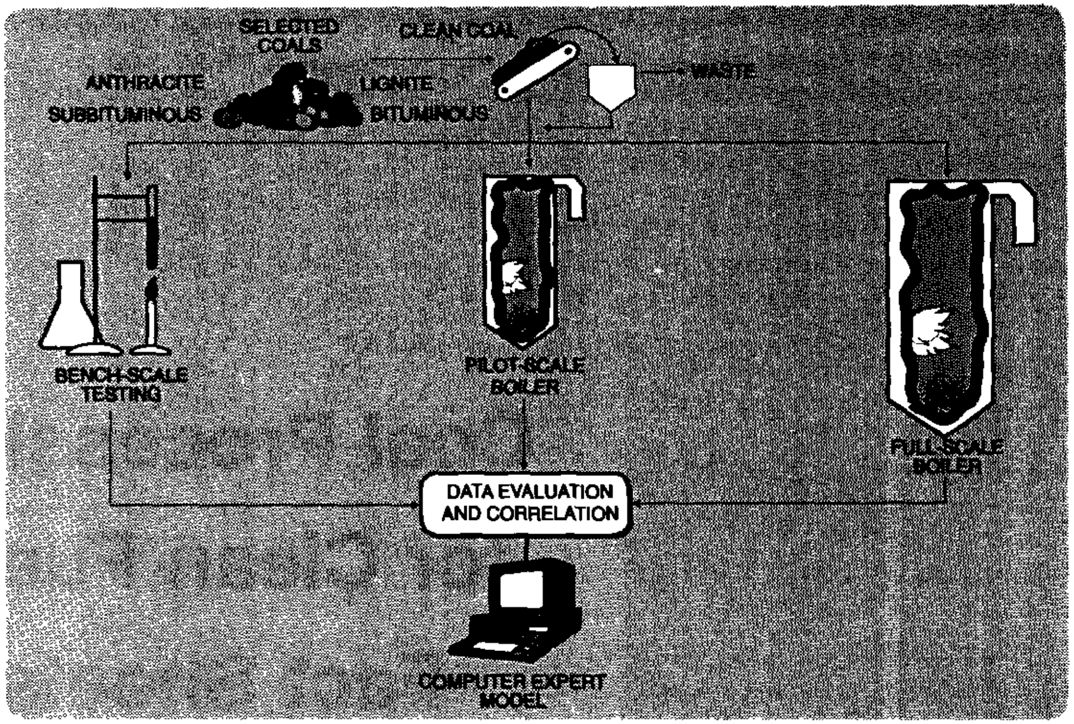
Black and Veatch—cofunder and software developer
Electric Power Research Institute—cofunder
The Babcock & Wilcox Company—cofunder and pilot-scale tester
Electric Power Technologies, Inc.—field tester
University of North Dakota, Energy and Environmental Research Center—bench-scale tester
Alabama Power Company—host
Mississippi Power Company—host
New England Power Company—host
Northern States Power Company—host
Public Service Company of Oklahoma—host

Locations:

Alliance, Columbiana County, OH (pilot-scale tests)
Windsor, Hartford County, CT (pilot-scale tests)
Grand Forks, Grand Forks County, ND (bench tests)
Wilsonville, Shelby County, AL (Gatson, Unit 5)
Gulfport, Harrison County, MS (Watson, Unit 4)
Somerset, Bristol County, MA (Brayton Point, Units 2 and 3)
Bayport, Washington County, MN (King Station)
Oologah, Rogers County, OK (Northeastern, Unit 4)

Technology:

CQ Inc.'s EPRI Coal Quality Expert (CQE) computer software



Plant Capacity/Production:

Full-scale testing took place at six utility sites ranging in size from 250 to 880 MWe.

Project Funding:

Total project cost	$21,746,004	100%
DOE	10,863,911	50
Participants	10,882,093	50

Project Objective:

To develop and demonstrate a personal computer software package that will serve as a predictive tool to assist coal-burning utilities in the selection of optimum quality coal for a specific boiler based on operational efficiency, cost, and environmental emissions.

Technology/Project Description:

Data derived from bench-, pilot-, and full-scale testing were used to develop algorithms for inclusion into a state-of-the-art software package, the Coal Quality Expert, that can be run on a personal computer. Utilities may use CQE to predict the operating performance and cost of coals not previously burned at a particular facility.

Six large-scale field tests consisted of burning a baseline coal and an alternate coal over a 2-month period. The baseline coal was used to characterize the operating performance of the boiler. The alternate coal, a blended or cleaned coal of improved quality, was burned in the boiler for the remaining test period.

The baseline and alternate coals for each test site also were burned in bench- and pilot-scale facilities under similar conditions. The alternate coal was cleaned at CQ Inc. to determine what quality levels of clean coal can be produced economically and then transported to the bench- and pilot-scale facilities for testing. All data from bench-, pilot-, and full-scale facilities were evaluated and correlated to formulate algorithms being used to develop the model.

Bench-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, CT, and the University of North Dakota's Energy and Environmental Research Center in Grand Forks, ND; pilot-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, CT, and Alliance, OH. The six field test sites were Gatson, Unit 5 (880 MWe), Wilsonville, AL; Watson, Unit 4 (250 MWe), Gulfport, MS; Brayton Point, Unit 2 (285 MWe) and Unit 3 (615 MWe), Somerset, MA; King Station (560 MWe), Bayport, MN; and Northeastern, Unit 4 (445 MWe), Oologah, OK.

Project Results/Accomplishments:

More than 100 algorithms based on data generated from six full-scale field tests have been developed. Acid Rain Advisor software became available in 1992, with two commercial sales made (one in 1993 and one in 1995).

Debugging of the CQE software proceeded through the end of the project. A CQE beta version was released in May 1995 and evaluated by several utilities by July 1995. The initial commercial version of CQE was released in December 1995. CQE has been distributed to about 35 U.S. utilities and 1 U.K. utility through their memberships in EPRI.

A CQE home page has been created on the World Wide Web to promote CQE, facilitate communications with and among CQE users, and distribute an easily updated electronic user's manual.

An update of CQE, version 1.1, is planned for late 1996, and the software may be migrated from OS/2 to Windows 95 or NT.

The final report is being prepared.

Commercial Applications:

The software will enable coal-fired utilities to select the *optimum quality coals for their specific boilers to reduce* SO_2, NO_x, and particulate emissions and to achieve the lowest operating costs.

The CQE system is applicable to all electric power plants and industrial/institutional boilers that burn pulverized coal. The system can predict the operational benefits of using alternative or cleaned coals.

CQ Inc. and Black and Veatch have signed a commercialization agreement which gives Black and Veatch nonexclusive worldwide rights to sell users' licenses and to offer consulting services that include the use of CQE software.

Project Schedule:

DOE selected project (CCT-I)	12/9/88
Cooperative agreement awarded	6/14/90
NEPA process completed (MTF)	4/27/90
Environmental monitoring plan completed	7/31/90
Operational testing	8/90–1/96
Project completed	12/96

Final Reports:

Final Technical Report	12/96
CQE Software	
Final version released	9/96
First commercial version released	12/95

Self-Scrubbing Coal™: An Integrated Approach to Clean Air

Participant:

Custom Coals International (a joint venture between Genesis Coals Limited Partnership and Genesis Research Corporation)

Additional Team Members:

Pennsylvania Power & Light Company—host
Richmond Power & Light—host
Centerior Service Company—host

Locations:

Central City, Somerset County, PA (advanced coal-cleaning plant)
Lower Mt. Bethel Township, Northampton County, PA (combustion tests at Pennsylvania Power & Light's Martin's Creek Power Station, Unit 2)
Richmond, Wayne County, IN (combustion tests at Richmond Power & Light's Whitewater Valley Generating Station, Unit No. 2)
Ashtabula, Trumbull County, OH (combustion tests at Centerior Energy's Ashtabula C)

Technology:

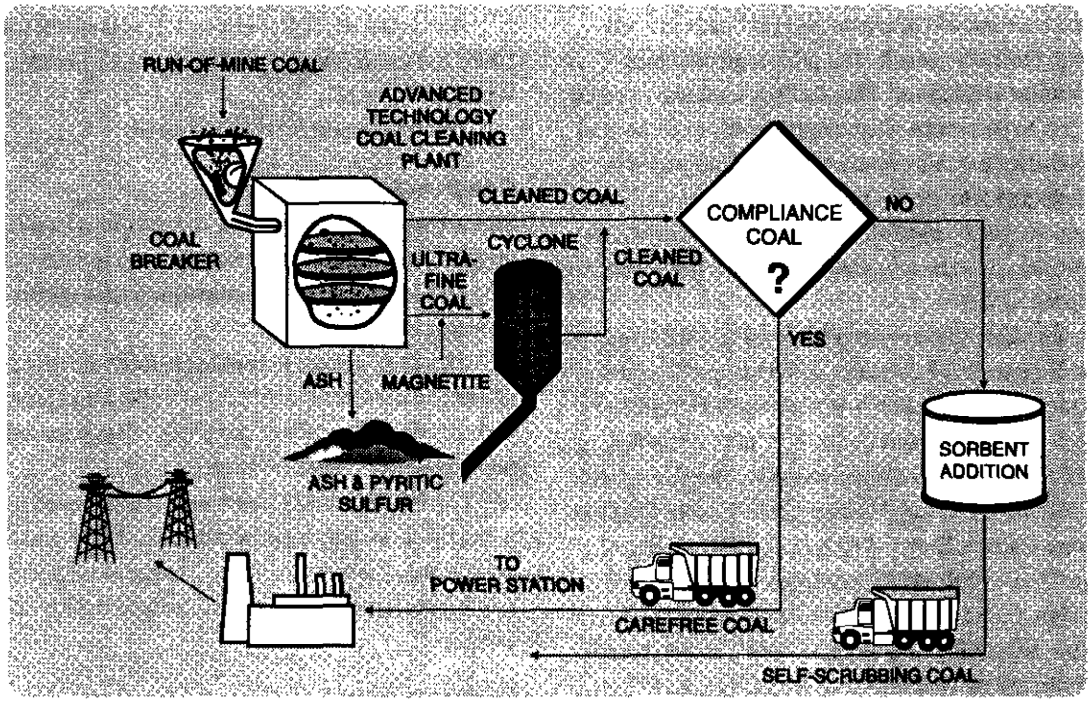
Coal preparation using Custom Coals' advanced physical coal-cleaning and fine magnetite separation technology plus sorbent addition technology

Plant Capacity/Production:

500 tons/hr

Project Funding:

Total project cost	$87,386,102	100%
DOE	37,994,437	43
Participant	49,391,665	57



Project Objective:

To demonstrate advanced coal-cleaning unit processes to produce low-cost compliance coals that can meet full requirements for commercial-scale utility power plants to satisfy CAAA of 1990 provisions.

Technology/Project Description:

An advanced coal-cleaning plant has been designed, blending existing and new processes, to produce, from high-sulfur bituminous feedstocks, two types of compliance coals—Carefree Coal™ and Self-Scrubbing Coal™.

Carefree Coal™ is produced by breaking and screening run-of-mine coal and by using innovative dense-media cyclones and finely sized magnetite to remove up to 90% of the *pyritic* sulfur and most of the ash. Carefree Coal™ is designed to be a competitively priced, high-Btu fuel that can be used without major plant modifications or additional capital expenditures. While many utilities can use Carefree Coal™ to comply with SO_2 emissions limits, others cannot due to the high content of *organic* sulfur in their coal feedstocks. When compliance coal cannot be produced by reducing pyritic sulfur, Self-Scrubbing Coal™ can be produced to achieve compliance.

Self-Scrubbing Coal™ is produced by taking Carefree Coal™, with its reduced pyritic sulfur and ash content, and adding to it sorbents, promoters, and catalysts. Self-Scrubbing Coal™ is expected to achieve compliance with virtually any U.S. coal feedstock through in-boiler absorption of SO_2 emissions. The reduced ash content of the Self-Scrubbing Coal™ permits the addition of relatively large amounts of sorbent without exceeding the ash specifica-

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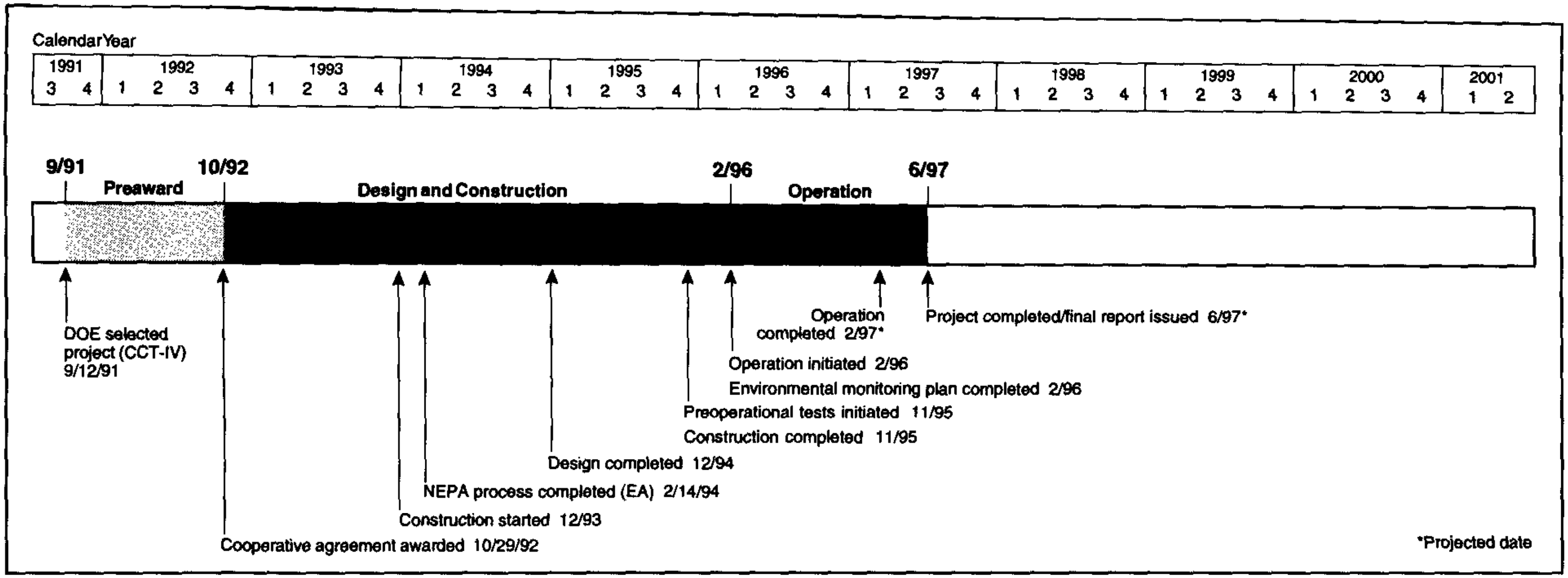
Self-Scrubbing Coal and Carefree Coal are trademarks of Custom Coals International.



tions of the boiler or overloading the electrostatic precipitator.

A 500-ton/hr advanced coal-cleaning plant is located at a site near Central City, PA. Two medium- to high-sulfur coals—Illinois No. 5 (2.7% sulfur) and Lower Freeport Seam coal (3.9% sulfur)—are being used to produce Self-Scrubbing Coal™. Carefree Coal™ is being made using Lower Kittanning Seam coal (1.8% sulfur). The Lower Kittanning coal is being tested at Martin's Creek Power Station; the Illinois No. 5 coal is being tested at Whitewater Valley Generating Station; and the Lower Freeport Seam coal is being tested at Ashtabula C.

Project Status/Accomplishments:

Since February 1996, the facility has operated 900 hours, received 301,000 tons of raw coal, processed 289,000 tons of raw coal, and produced 208,000 tons of clean coal. Clean coal quality has averaged 8.5% ash and 1% or less sulfur (SO_2 content of 1.2 lbs/million Btu). CoalScan continues to make adjustments to the analyzer and calibrated the unit during July 1996. Approximately 36,000 tons of compliance steam coal were shipped to Homer City in July. Four unit trains (approximately 28,800 tons) were shipped to PEPCO during June 1996 and another unit train (7,200 tons) was shipped in July. The first unit train (7,200 ton) of metallurigical coal was shipped May 29, 1996.

Bank performance testing began in June 1996 and is nearly completed.

Commercial Applications:

Commercialization of Self-Scrubbing Coal™ has the potential of bringing into compliance about 164 million tons/yr of bituminous coal that cannot meet emissions limits through conventional coal cleaning. This represents more than 38% of the bituminous coal burned in 50-MWe or larger U.S. generating stations.

The technology produces coal products that can be used to reduce a utility or industrial power plant's total sulfur emissions 80–90%.

In August 1994, a U.S.-led consortium with Custom Coals Corporation as the principal partner signed a cooperative agreement with the People's Republic of China to build a coal-cleaning plant, a 500-mile underground slurry pipeline, and port facility. The pipeline will bring coal from the ShanXi province in northwest China to the coastal province of Shandong. The work included under the agreement is valued at $888.6 million.

Custom Coals is aggressively marketing the technology in Eastern Europe and has received letters of intent from three Polish power plants that wish to produce 7.5 million tons/yr of cleaned coal.

Custom Coals also has a proposed agreement with domestic coal-marketing companies for 1 million tons of compliance coal annually.

Advanced Coal Conversion Process Demonstration

Participant:

Rosebud SynCoal Partnership (a partnership between Western Energy Company and the NRG Group, a nonregulated subsidiary of Northern States Power Company)

Additional Team Member:

None

Location:

Colstrip, Rosebud County, MT (adjacent to Western Energy Company's Rosebud Mine)

Technology:

Rosebud SynCoal Partnership's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals

Plant Capacity/Production:

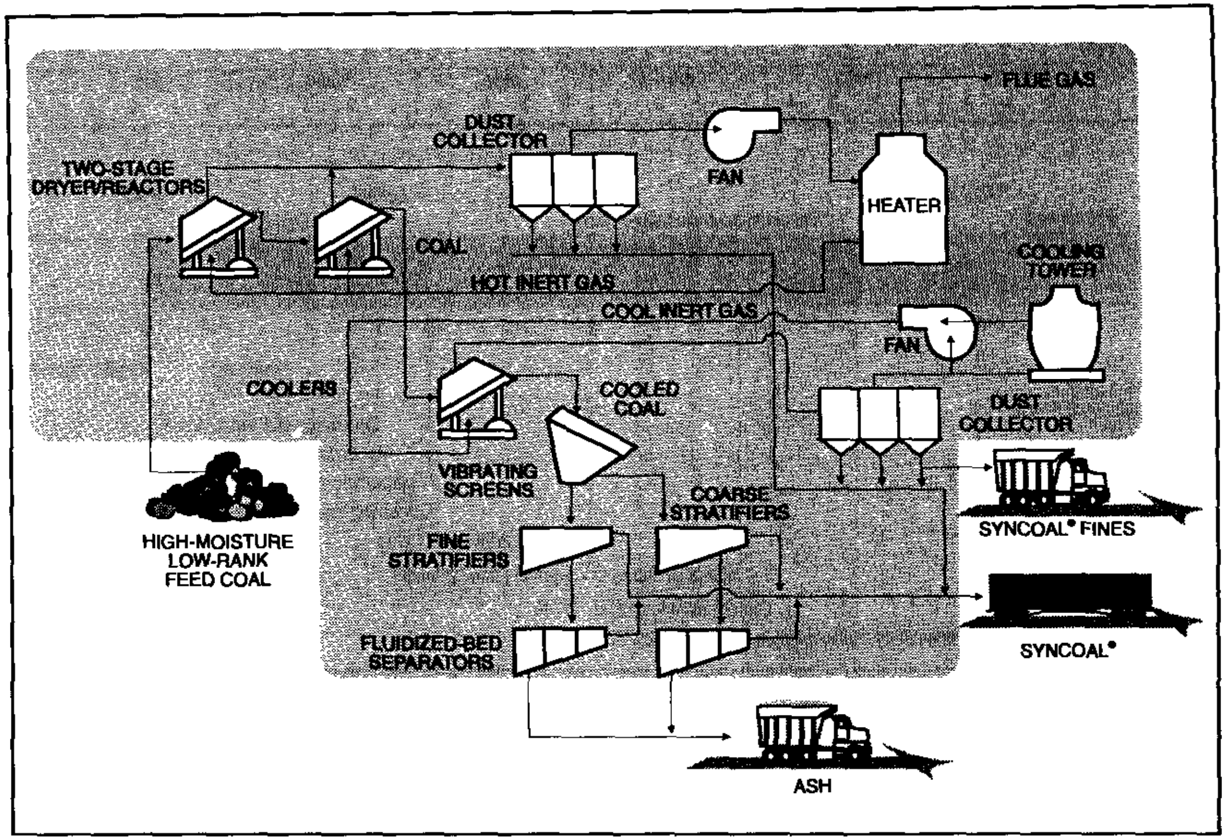
45 tons/hr of SynCoal® product (300,000 tons/yr)

Project Funding:

Total project cost	$105,700,000	100%
DOE	43,125,000	41
Participant	62,575,000	59

Project Objective:

To demonstrate Rosebud SynCoal's advanced coal conversion process to produce SynCoal®, a stable coal product having a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.



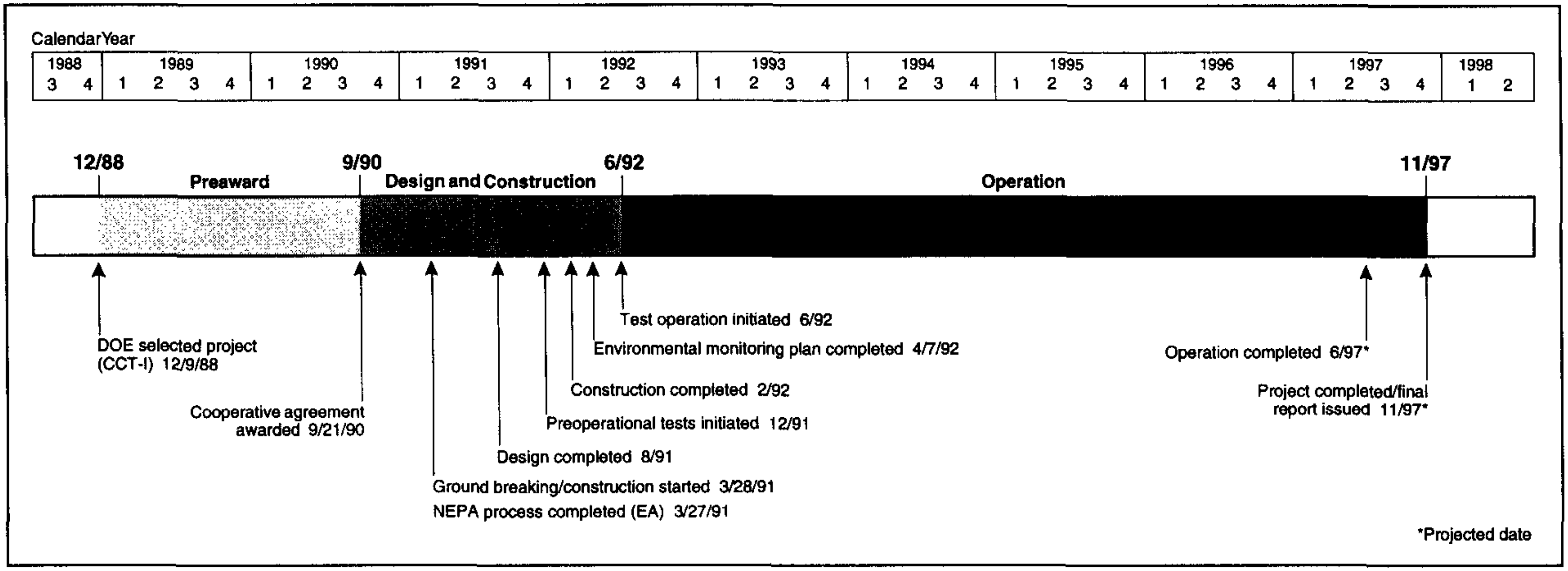
Technology/Project Description:

Being demonstrated is an advanced thermal coal conversion process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel. The coal is processed through two fluidized-bed dryer/reactors that remove loosely held water and then chemically bound water, carboxyl groups, and volatile sulfur compounds. After conversion, the coal is put through a deep-bed stratifier cleaning process to effect separation of the ash.

The technology enhances low-rank western coals, usually with a moisture content of 25–40%, sulfur content of 0.5–1.5%, and heating value of 5,500–9,000 Btu/lb, by producing an upgraded SynCoal® product with a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.

The 45-ton/hr unit is located adjacent to a unit train loadout facility at Western Energy Company's Rosebud coal mine in Colstrip, MT. The demonstration plant is one-tenth the size of a commercial facility. However, the process equipment is at 1/3–1/2 commercial scale because a full-sized commercial plant will have multiple process trains.

SynCoal is a registered trademark of the Rosebud SynCoal Partnership.



Project Status/Accomplishments:

The demonstration facility continues reliable operation. It has processed more than one million tons of coal and produced nearly 825,000 tons of SynCoal® products through July 1996. Rosebud continues to supply different products to a range of customers, including industrial, institutional, and utility users. Total sales of SynCoal® product have exceeded 720,000 tons.

SynCoal® products have been delivered to several industrial and utility customers, including Ash Grove Cement, Bentonite Corporation, Wyoming Lime, Continental Lime, Empire Sand and Gravel, Montana Power, Minnkota Power, and the University of North Dakota. The participant has negotiated a contract with Colstrip Units 1 and 2 to take excess production of SynCoal® after Colstrip Units 3 and 4 were switched to a Wyoming coal supplier.

Extended kiln testing is continuing at Wyoming Lime.

Commercial Applications:

Rosebud SynCoal's advanced coal conversion process has the potential to enhance the use of low-rank western subbituminous and lignite coals. Many of the power plants located throughout the upper Midwest have cyclone boilers, which burn low-ash-fusion-temperature coals. Presently, most of these plants burn Illinois Basin high-sulfur coal. SynCoal® is an ideal low-sulfur coal substitute for these and other plants because it allows operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. The advanced coal conversion process produces SynCoal® which has a consistently low moisture content, a low sulfur content, a high heating value, and a high volatile content. Because of these characteristics, SynCoal® could have significant impact on SO_2 reduction and provide a clean, economical alternative fuel to many regional industrial facilities and small utilities being forced to use fuel oil and natural gas. Rosebud SynCoal's process, therefore, will be attractive to industry and utilities because the upgraded fuel will be less costly to use than would the construction and use of flue gas desulfurization equipment. This will allow plants that would otherwise be closed to remain in operation.

Rosebud SynCoal Partnership conducted a $2-million study for Minnkota Power Cooperative to examine the merits of applying the coal-processing technology to a commercial plant integrated into an existing power plant site. The study's results have been positive, but market commitments are still necessary. The partnership is working on plans for two semi-commercial projects, one each in Wyoming and Montana.

ENCOAL Mild Coal Gasification Project

Participant:

ENCOAL Corporation (a subsidiary of SMC Mining Company, which is a unit of Zeigler Coal Holding Company)

Additional Team Members:

SMC Mining Company—cofunder
TEK-KOL (partnership between SMC Mining Company and SGI International)—technology owner, supplier, and licenser
SGI International—technology developer
Triton Coal Company (subsidiary of SMC Mining Company)—host and coal supplier
The M.W. Kellogg Company—engineer and constructor

Location:

Near Gillette, Campbell County, WY (Triton Coal Company's Buckskin Mine)

Technology:

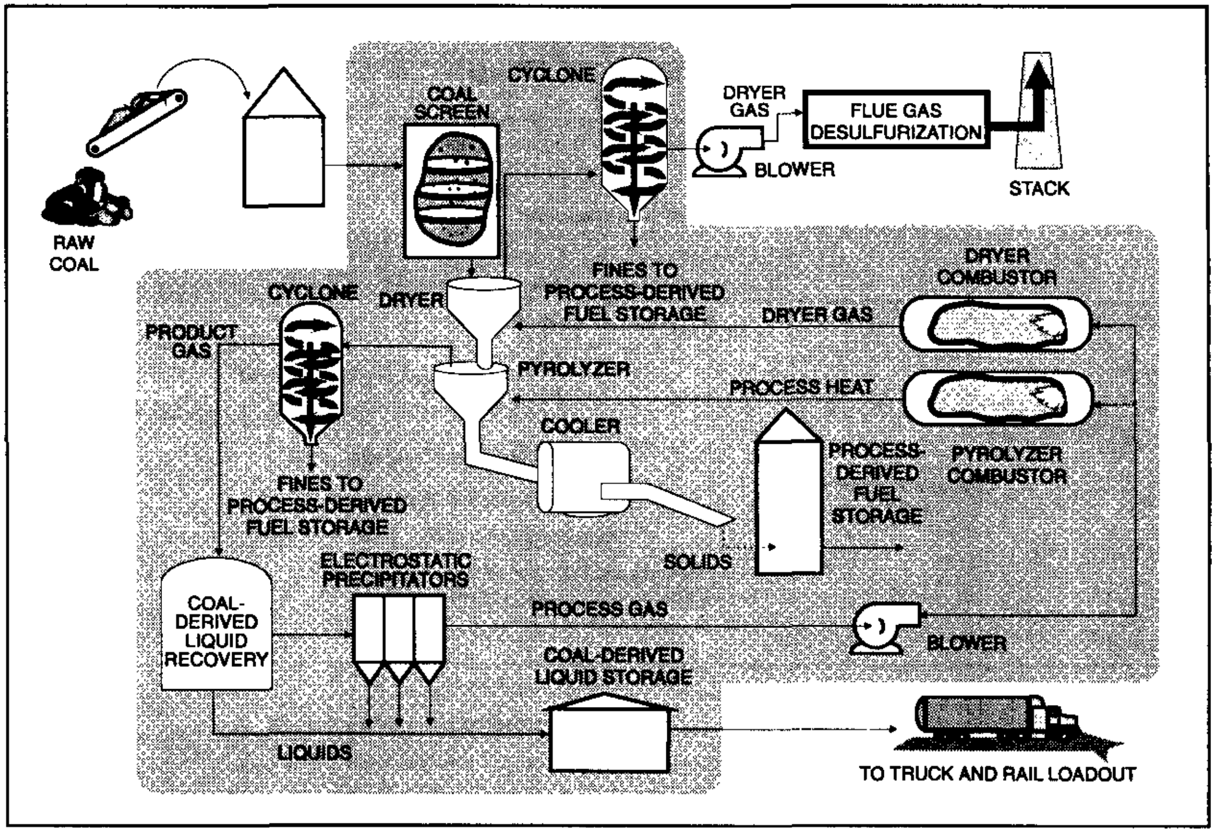
SGI International's liquids from coal process

Plant Capacity/Production:

1,000 tons/day of subbituminous coal feed

Project Funding:

Total project cost	$90,664,000	100%
DOE	45,332,000	50
Participant	45,332,000	50



Project Objective:

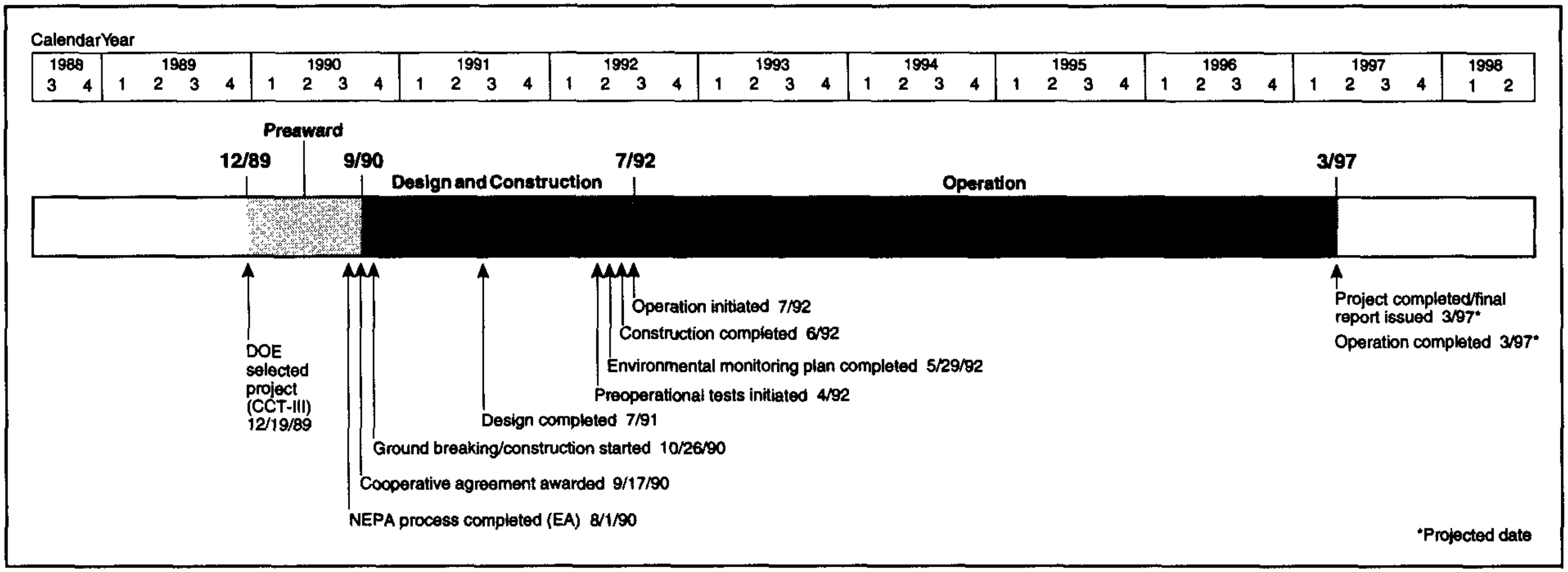
To demonstrate the integrated operation of a number of novel processing steps to produce two higher value fuel forms from mild gasification of low-sulfur subbituminous coal; and to provide sufficient products for potential end users to conduct burn tests.

Technology/Project Description:

The ENCOAL mild coal gasification process involves heating coal under carefully controlled conditions. Coal is fed into a rotary grate dryer where it is heated by a hot gas stream to reduce the coal's moisture content. The solid bulk temperature is controlled so that no significant amounts of methane, CO, or CO_2 are released from the coal. The solids from the dryer are conveyed to the pyrolyzer where the rate of heating of the solids and residence time are controlled to achieve desired properties of the fuel products. During processing in the pyrolyzer, all remaining free water is removed, and a chemical reaction occurs that results in the release of volatile gaseous material. Solids exiting the pyrolyzer are cooled and transferred to a process-derived fuel (PDF) storage bin.

The gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled to condense the liquid-fuel products, or coal-derived liquids (CDL). Most of the gas from the condensation unit is recycled to the pyrolyzer. The rest of the gas is burned in combustors to provide heat for the pyrolyzer and the dryer. NO_x emissions are controlled by staged air injection.

The offgas from the dryer is treated in a wet venturi scrubber to remove particulates and a horizontal scrubber to remove SO_2, both using a sodium carbonate solution. The treated gas is vented to a stack, and the spent solution is discharged into a pond for evaporation.



The ENCOAL project is located within Campbell County, WY, at Triton Coal Company's Buckskin Mine, 10 miles north of Gillette. The plant makes use of the present coal-handling facilities at the mine. Subbituminous coal with 0.4–0.9% sulfur content is being used.

Project Status/Accomplishments:

The plant officially entered the production mode in June 1994; operation has been at a coal feed rate of 500 tons/day. By mid-1996 the plant had logged more than 9,200 hours of operation on coal. By the end of July 1996, more than 63,000 tons of solid product and more than 2.5 million gallons of liquid product had been shipped to industrial and utility customers.

As a result of the very successful PDF combustion test in a pulverized-coal boiler by the American Electric Power Company, a unit train of pure PDF was shipped to a major Missouri utility where it was successfully handled and burned.

U.S. Steel successfully tested two tank cars of CDL as an injectant fuel in a Gary, IN, blast furnace. ENCOAL also shipped 12 tank cars of CDL to Michigan and Maine and another 13 tank cars of CDL to a Louisiana refinery.

ENCOAL has negotiated the sale of 10,000 tons of PDF to Bethlehem Steel for use as a blast furnace fuel injectant. ENCOAL is also negotiating a similar sale to another major steel producer.

Design has begun on a large commercial "grain dryer" for full-scale passivation of PDF.

ENCOAL also has begun construction of a permanent wastewater disposal pond.

Commercial Applications:

The liquid products from mild coal gasification can be *used in existing markets in place of No. 6 fuel oil.* The solid product can be used in most industrial or utility boilers and also shows promise for iron ore reduction applications. The feedstock for mild gasification is being limited to high-moisture, low-heating-value coals.

The potential benefits of this mild gasification technology in its commercial configuration are attributable to the increased heating value (about 12,000 Btu/lb) and lower sulfur content (per unit of fuel value) of the new solid-fuel product compared to the low-rank coal feedstock, and the production of low-sulfur liquid products requiring no further treatment for the fuel oil market. The product fuels are expected to be used economically in commercial boilers and furnaces and to reduce significantly *SO_2 emissions at industrial and utility facilities* currently burning high-sulfur bituminous coals or fuel oils.

Numerous feasibility studies have been performed for both domestic and international clients who are primarily interested in upgrading their low-rank coal reserves. TEK-KOL and Mitsubishi Heavy Industries are performing advanced feasibility studies regarding joint engineering, design, and construction of commercial plants in Indonesia, China, and Russia. TEK-KOL is also negotiating with Japanese trading companies to *market both liquid and solid products in Southeast Asia.*

Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process

Participant:

Air Products Liquid Phase Conversion Company, L.P. (a limited partnership between Air Products and Chemicals, Inc., the general partner, and Eastman Chemical Company)

Additional Team Members:

Air Products and Chemicals, Inc.—technology supplier and cofunder

Eastman Chemical Company—host; operator; synthesis gas and services provider

Acurex Environmental Corporation—fuel methanol tester and cofunder

Electric Power Research Institute—fuel methanol test advisor

Location:

Kingsport, Sullivan County, TN (Eastman Chemical Company's Integrated Coal Gasification Facility)

Technology:

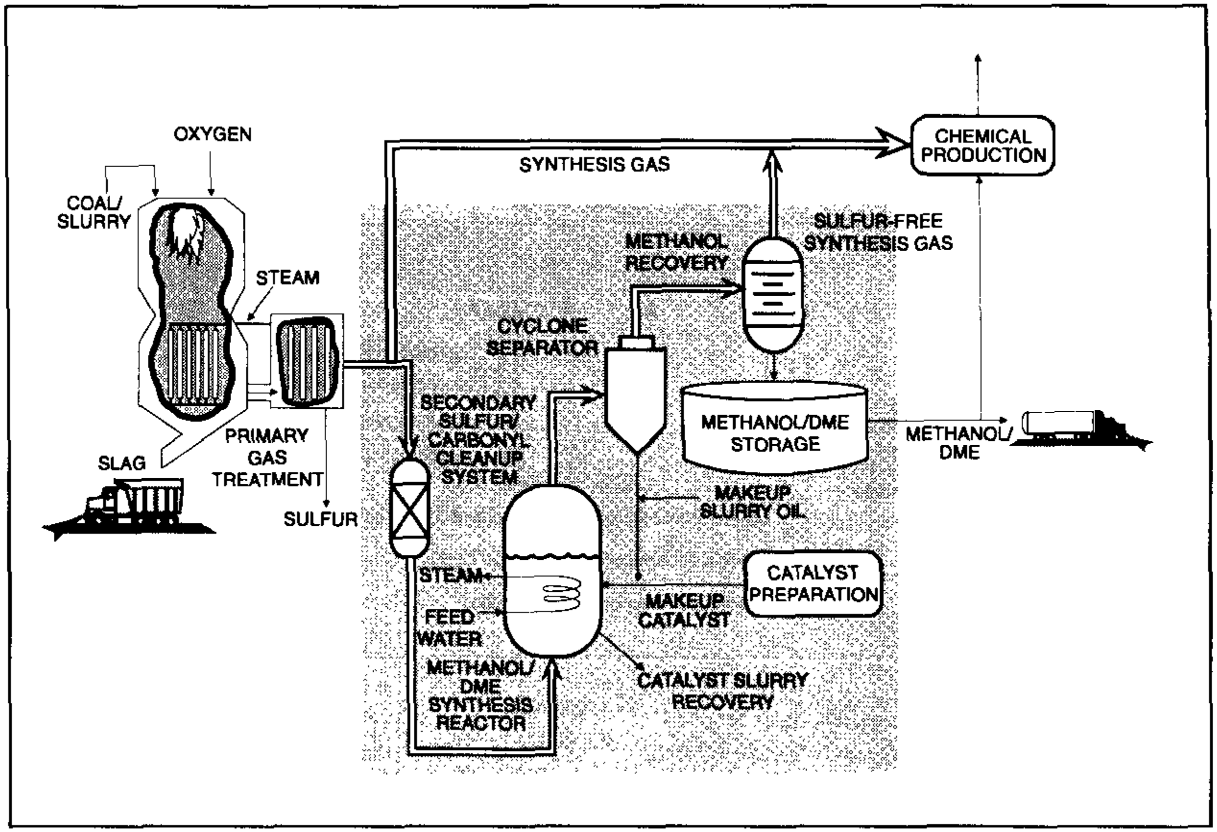
Air Products and Chemicals' liquid-phase methanol (LPMEOH™) process

Plant Capacity/Production:

80,000 gallons/day of methanol (nominal)

Project Funding:

Total project cost	$213,700,000	100%
DOE	92,708,370	43
Participant	120,991,630	57



Project Objective:

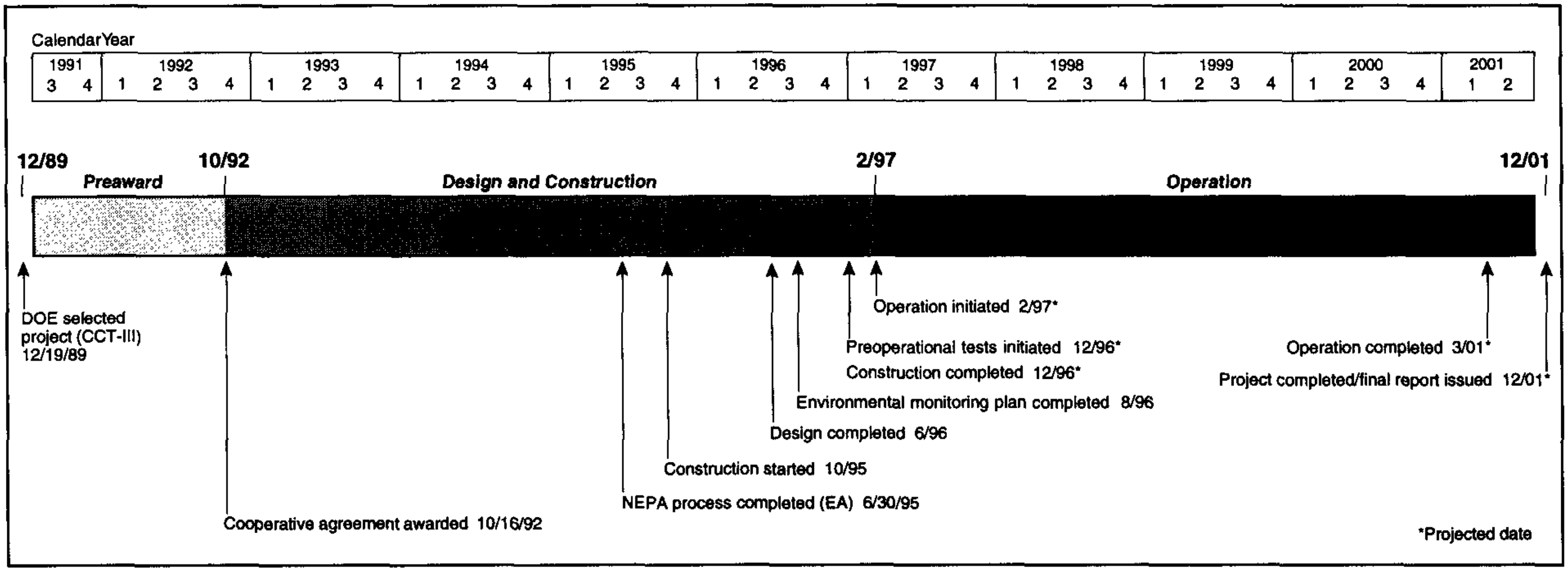
To demonstrate on a commercial scale the production of methanol from coal-derived synthesis gas using the LPMEOH™ process; and to determine the suitability of methanol produced during this demonstration for use as a chemical feedstock or as a low-SO_x, low-NO_x alternative fuel in stationary and transportation applications. If practical, the production of dimethyl ether (DME) as a mixed coproduct with methanol also will be demonstrated.

Technology/Project Description:

This project is demonstrating, at commercial scale, the LPMEOH™ process to produce methanol from coal-derived synthesis gas. The combined reactor and heat removal system is different from other commercial methanol processes. The liquid phase not only suspends the catalyst but functions as an efficient means to remove the heat of reaction away from the catalyst surface. This feature permits the direct use of synthesis gas streams as feed to the reactor without the need for shift conversion.

The Eastman Chemical Company's integrated coal gasification facility at Kingsport, TN, has operated commercially since 1983. At this site, it will be possible to ramp up and down to demonstrate the unique load-following flexibility of the LPMEOH™ unit for application to coal-based electric power generation facilities. Methanol fuel testing will be conducted in off-site stationary and mobile applications, such as fuel cells, buses, and distributed electric power generation. Design verification testing for the production of DME

LPMEOH is a trademark of Air Products and Chemicals, Inc.



as a mixed coproduct with methanol for use as a storable fuel is planned, and a decision on whether or not to demonstrate will be made. Eastern high-sulfur bituminous coal (Mason seam) containing 3% sulfur (5% maximum) and 10% ash will be used.

Project Status/Accomplishments:

Construction activities are at their peak. The liquid-phase reactor was installed on July 2, 1996. All other major process equipment has been installed, and the installation of structural and pipe rack steel, process piping, and electrical and instrumentation equipment is continuing on schedule. Construction is scheduled to be completed in late December 1996, with start-up expected to begin in early 1997.

Commercial Applications:

The LPMEOH™ process has been developed to enhance integrated gasification combined-cycle (IGCC) power generation by producing a clean burning, storable liquid fuel—methanol—from the clean coal-derived gas. Methanol also has a broad range of commercial applications, can be substituted for conventional fuels in stationary and mobile combustion applications, is an excellent fuel for utility peaking units, contains no sulfur, and has exceptionally low-NO_x characteristics when burned. Methanol can be produced from coal as a coproduct in an IGCC facility.

DME has several commercial uses. In a storable blend with methanol, the mixture can be used as peaking fuel in IGCC electric power generating facilities. Blends of methanol and DME can also be used as a chemical feedstock for the synthesis of chemicals or new, oxygenate fuel additives. Pure DME has been gaining acceptance as an environmentally friendly aerosol in personal products.

Typical commercial-scale LPMEOH™ units are expected to range in size from 150 to 1,000 tons/day of methanol produced when associated with commercial IGCC power generation trains of 200–350 MWe. Air Products and Chemicals expects to market the LPMEOH™ technology through licensing, owning/operating, and tolling arrangements.

Industrial Applications
Fact Sheets

Blast Furnace Granulated-Coal Injection System Demonstration Project

Participant:

Bethlehem Steel Corporation

Additional Team Members:

British Steel Consultants Overseas Services, Inc.
(marketing arm of British Steel Corporation)—technology owner
Simon-Macawber, Ltd.—equipment supplier
Fluor Daniel, Inc.—architect and engineer
ATSI, Inc.—injection equipment engineer
(U.S. technology licensee)

Location:

Burns Harbor, Porter County, IN (Bethlehem Steel's Burns Harbor Plant, Blast Furnace Units C and D)

Technology:

British Steel's blast furnace granulated-coal injection (BFGCI) process

Plant Capacity/Production:

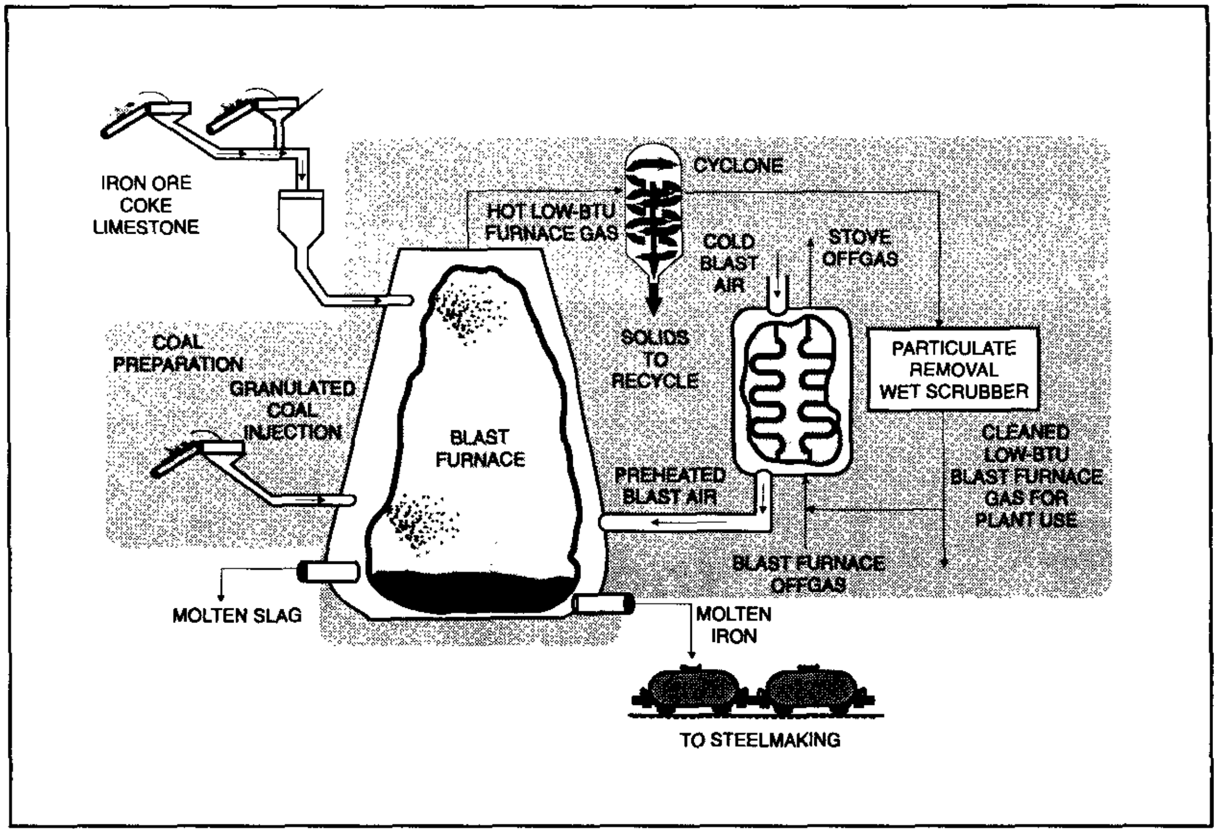
7,000 net tons/day of hot metal (each blast furnace)

Project Funding:

Total project cost	$191,700,000	100%
DOE	31,259,530	16
Participant	160,440,470	84

Project Objective:

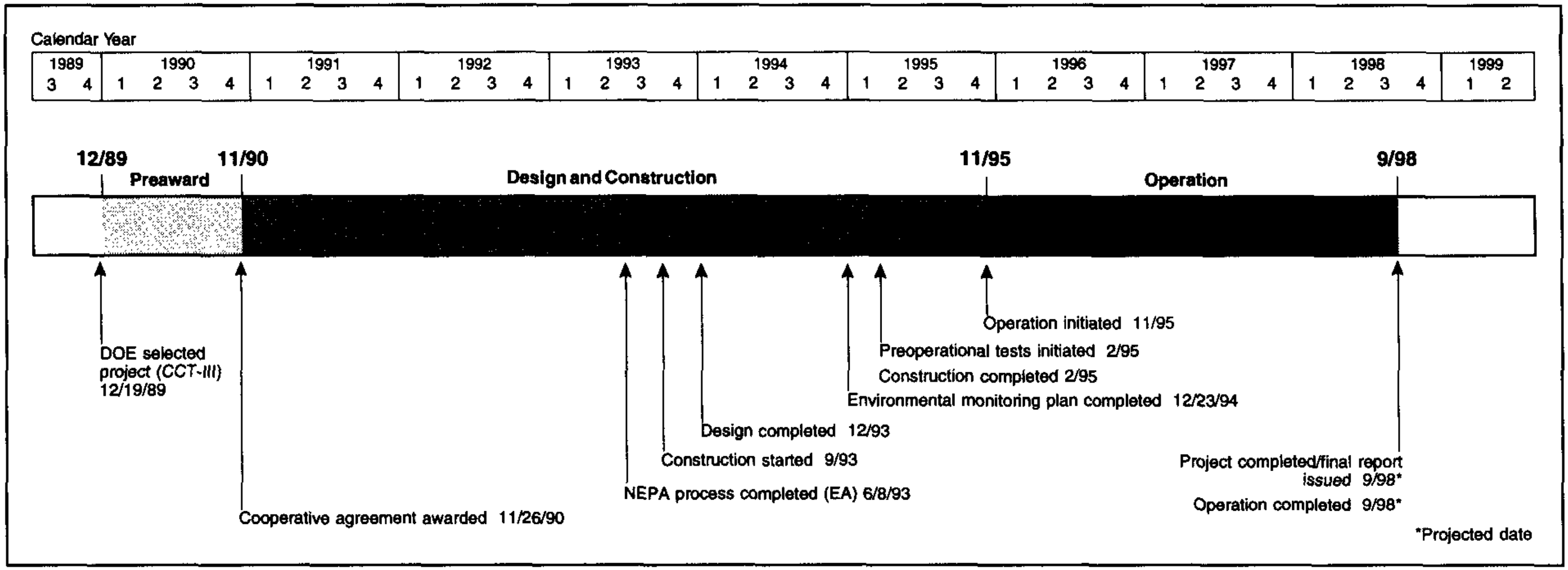
To demonstrate that existing iron-making blast furnaces can be retrofitted with blast furnace granulated-coal injection technology; and to demonstrate sustained operation with a variety of coal particle sizes, coal injection rates, and coal types, and to assess the interactive nature of these parameters.



Technology/Project Description:

In the BFGCI process, both granulated and pulverized coal is injected into the blast furnace in place of natural gas (or oil) as a blast furnace fuel supplement. The coal along with heated air is blown into the barrel-shaped section in the lower part of the blast furnace through passages called tuyeres, which creates swept zones in the furnace called raceways. The size of a raceway is important and is dependent upon many factors including temperature. Lowering of a raceway temperature, which can occur with gas injection, reduces blast furnace production rates. Coal, with a lower hydrogen content than either gas or oil, does not cause as severe a reduction in raceway temperatures. In addition to displacing injected natural gas, the coal injected through the tuyeres displaces coke, the primary blast furnace fuel and reductant (reducing agent), on approximately a pound-for-pound basis. Because coke production results in significant emissions of NO_x, SO_2, and air toxics and coal could replace up to 40% of the coke requirement, BFGCI technology has significant potential to reduce emissions and enhance blast furnace production.

Emissions generated by the blast furnace itself remain virtually unchanged by the injected coal; the gas exiting the blast furnace is clean, containing no measurable SO_2 or NO_x. Sulfur from the coal is removed by the limestone flux and bound up in the slag, which is a salable by-product. In addition to the net emissions reduction realized by coke displacement, blast furnace production is increased by maintaining high raceway temperatures.



Two high-capacity blast furnaces, Units C and D at Bethlehem Steel Corporation's Burns Harbor Plant, are being retrofitted with BFGCI technology. Each unit has a production capacity of 7,000 net tons/day of hot metal. The two units will use about 2,800 tons/day of coal during full operation. Bituminous coals with sulfur content ranging from 0.8% to 2.8% from West Virginia, Pennsylvania, Illinois, and Kentucky are to be used. A western subbituminous coal having 0.4–0.9% sulfur might be tested also.

Project Status/Accomplishments:

Construction was completed in February 1995. Bethlehem Steel submitted a public design report in March 1995. Start-up testing has been completed, and the plant is fully commissioned. Operational testing began in November 1995.

Furnace C has been operated with an average coal injection rate of 275 lbs/net ton of hot metal, using low-volatile bituminous coals. Bethlehem Steel has determined that this injection rate will be the new operating baseline for Furnace C for all future test coal comparisons. Furnace C also has been operated with a coke rate of approximately 650 lbs/net ton of hot metal without coal injection, down from 770 lbs/net ton. Furnace D has been operated with a coal injection rate of approximately 190 lbs/net ton of hot metal, which is above its design point of 180 lbs/net ton. Bethlehem Steel has completed repairs to a coal preparation plant necessitated by tramp organics in recent coal supplies.

Bethlehem Steel plans to increase substantially the coal feed rate through all 52 tuyeres for comparison with the baseline standard of 275 lbs/net ton of hot metal on Furnace C. In addition, the purchase of 10,000 tons of ENCOAL's process derived fuel is being negotiated for a future test.

Commercial Applications:

BFGCI technology can be applied to essentially all U.S. blast furnaces. The technology should be applicable to any rank coal commercially available in the United States that has a moisture content no higher than 12%. The environmental impacts of commercial application are primarily indirect and consist of a significant reduction of emissions resulting from diminished coke-making requirements.

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

Project completed.

Participant:
Coal Tech Corporation

Additional Team Members:
Commonwealth of Pennsylvania Energy Development Authority—cofunder
Pennsylvania Power and Light Company—supplier of test coals
Tampella Power Corporation—host

Location:
Williamsport, Lycoming County, PA (Tampella Power Corporation's boiler manufacturing plant)

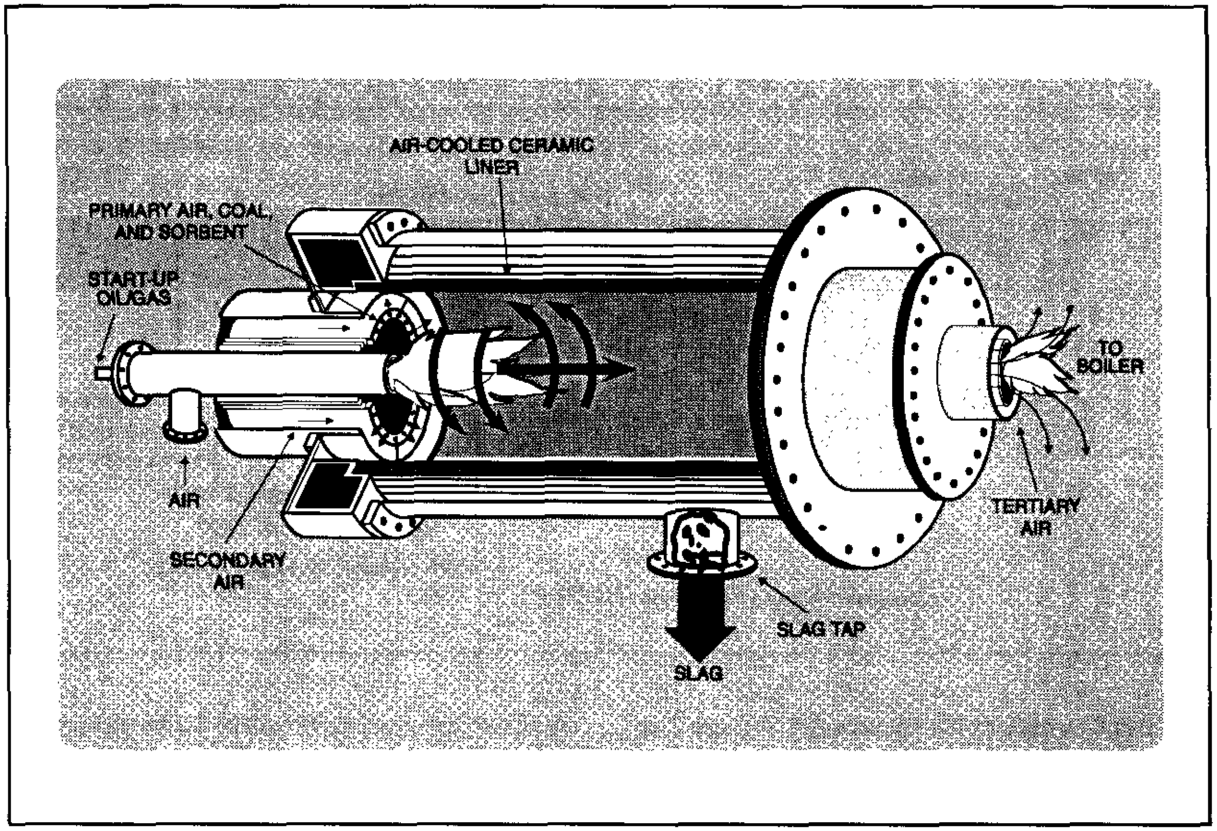
Technology:
Coal Tech's advanced, air-cooled, slagging combustor

Plant Capacity/Production:
23 million Btu/hr

Project Funding:

Total project cost	$984,394	100%
DOE	490,149	50
Participant	494,245	50

Project Objective:
To demonstrate that an advanced cyclone combustor can be retrofitted to an industrial boiler and that it can simultaneously remove up to 90% of the SO_2 and 90–95% of the ash within the combustor and reduce NO_x by up to 100 ppm.



Technology/Project Description:
Coal Tech's horizontal cyclone combustor is internally lined with ceramic that is air-cooled. Pulverized coal, air, and sorbent are injected tangentially toward the wall through tubes in the annular region of the combustor to cause cyclonic action. In this manner, coal-particle combustion takes place in a swirling flame in a region favorable to particle retention in the combustor. Secondary air is used to adjust the overall combustor stoichiometry. The ceramic liner is cooled by the secondary air and maintained at a temperature high enough to keep the slag in a liquid, free-flowing state. The secondary air is preheated by the combustor walls to attain efficient combustion of the coal particles in the fuel-rich cumbustor. Fine coal pulverization allows combustion of most of the coal particles near the cyclone wall, with the balance burned on or near the wall. This improves combustion in the fuel-rich chamber, as well as slag retention. The slag contains more than 80% of the ash and sorbent fed to the combustor. For NO_x control, the combustor is operated fuel rich, with final combustion taking place in the boiler furnace to which the combustor is attached.

In Coal Tech's demonstration, an advanced, air-cooled, cyclone coal combustor was retrofitted to a 23-million-Btu/hr, oil-designed package boiler located at the Tampella Power Corporation boiler factory in Williamsport, PA. Air cooling in this combustor takes place in a very compact combustor which can be retrofitted to a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. NO_x reduction is achieved by staged combustion, and SO_2 is captured by injection of limestone into the combustor. The cyclonic action inside the combustor forces the coal ash and sorbent to the walls where it can be collected as liquid slag. Under optimum operating conditions, the slag contains a significant fraction of vitrified coal sulfur. Downstream sorbent injection into the boiler provides additional sulfur removal capacity.

Project Results/Accomplishments:

The test effort consisted of 800 hours of operation which included five individual tests, each of 4 days duration, plus another 100 hours of operation as part of separate ash vitrification tests. Eight Pennsylvania bituminous coals with sulfur contents ranging from 1% to 3.3% and volatile matter ranging from 19% to 37% were tested.

Under fuel-rich conditions, combustion efficiencies exceeded 99% after proper operating procedures were achieved. Turndown to 6 million Btu/hr from a peak of 19 million Btu/hr was achieved. Due to facility limits on water availability for the boiler and for cooling the combustor, the maximum heat input during the tests was approximately 20 million Btu/hr even though the combustor was designed for 30 million Btu/hr and the boiler was thermally rated at around 25 million Btu/hr.

Coal Tech reported the following test results:

- With fuel-rich operation of the combustor, a 75% reduction in boiler-outlet-stack NO_x was obtained, corresponding to 0.3 lb/million Btu (184 ppmv). An additional 5–10% NO_x reduction was obtained by the action of the wet particulate scrubber, resulting in atmospheric NO_x emissions as low as 0.26 lb/million Btu (160 ppmv).
- Over 80% SO_2 reduction measured at the boiler outlet stack was achieved using sorbent injection in the furnace at various Ca/S molar ratios. A maximum SO_2 reduction of 58% was measured at the stack with limestone injection into the combustor at a Ca/S of 2. A maximum of 33% of the coal sulfur was retained in the dry ash removed from the combustor and furnace hearths, and a high of 11% of the coal sulfur was retained in the slag rejected through the slag tap.
- Local stack particulate emission standards were met with the wet venturi particulate scrubber.
- Total slag/sorbent retention in the combustor, under efficient combustion operating conditions, averaged 72% and ranged from 55% to 90%. Under more fuel-lean conditions, the slag retention averaged 80%. In post-CCT-project tests on flyash vitrification in the combustor, modifications to the solids injection method and increases in the slag flow rate produced substantial increases in the slag retention rate.
- All slag removed from the combustor produced trace metal leachates well below the EPA drinking water standard.
- Different sections of the combustor had different materials requirements. Suitable materials for each section were identified. Also, the test effort showed that operational procedures were closely coupled with materials durability. By implementing certain procedures, such as changing the combustor wall temperature, it was possible to replenish the combustor refractory wall thickness with slag.
- Procedures for properly operating an air-cooled combustor were developed, and the entire operating database was incorporated into a computer-controlled system for automatic combustor operation.

Commercial Applications:

At the end of this demonstration, Coal Tech had concluded that, while the combustor was not at that time fully ready for sale with commercial guarantees, it was ready to be further scaled up for commercial applications (100 million Btu/hr), such as combustion of waste solid fuels, limited sulfur control in coal-fired boilers, and conversion of ash to slag. Since the CCT demonstration, a modified and improved version of the air-cooled combustor has been built and is currently being tested. Results so far indicate improvements in performance, and Coal Tech officials indicate that the technology is now commercially ready.

Coal Tech's advanced, air-cooled, slagging combustor can use a wide range of U.S. coals and can be retrofitted to existing or new units. The target market is industrial and utility boilers sized 20–100 million Btu/hr or more; multiple combustors can be attached to larger boilers. The near-term focus is on using the combustor in combined-cycle industrial and small utility power plants in the 10–50-MWe range. The combustor is capable of using pulverized coal, coal-water slurry, cofired pulverized coal, and refuse-derived fuels (e.g., industrial sludge and coal-mine waste).

Project Schedule:

DOE selected project (CCT-I)	7/24/86
Cooperative agreement awarded	3/20/87
NEPA process completed (MTF)	3/26/87
Environmental monitoring plan completed	9/22/87
Construction	7/87–11/87
Operational testing	11/87–5/90
Project completed	9/91

Final Reports:

Final Technical Report	8/91
DOE Assessment	5/93

Clean Power from Integrated Coal/Ore Reduction (COREX®)

Participant:

CPICOR™ Management Company, L.L.C. (a limited liability company composed of subsidiaries of Centerior Energy Corporation, Air Products and Chemicals, Inc., and the Geneva Steel Company)

Additional Team Members:

Geneva Steel Company—cofunder; site owner; constructor and operator of COREX® unit
Centerior Energy Corporation—cofunder
Air Products and Chemicals, Inc.—cofunder; designer, engineer, constructor, and operator of air separation and combined-cycle units
Deutsche Voest-Alpine Industrieanlagenbau GmbH—COREX® developer/supplier; designer and engineer of COREX® unit

Location:

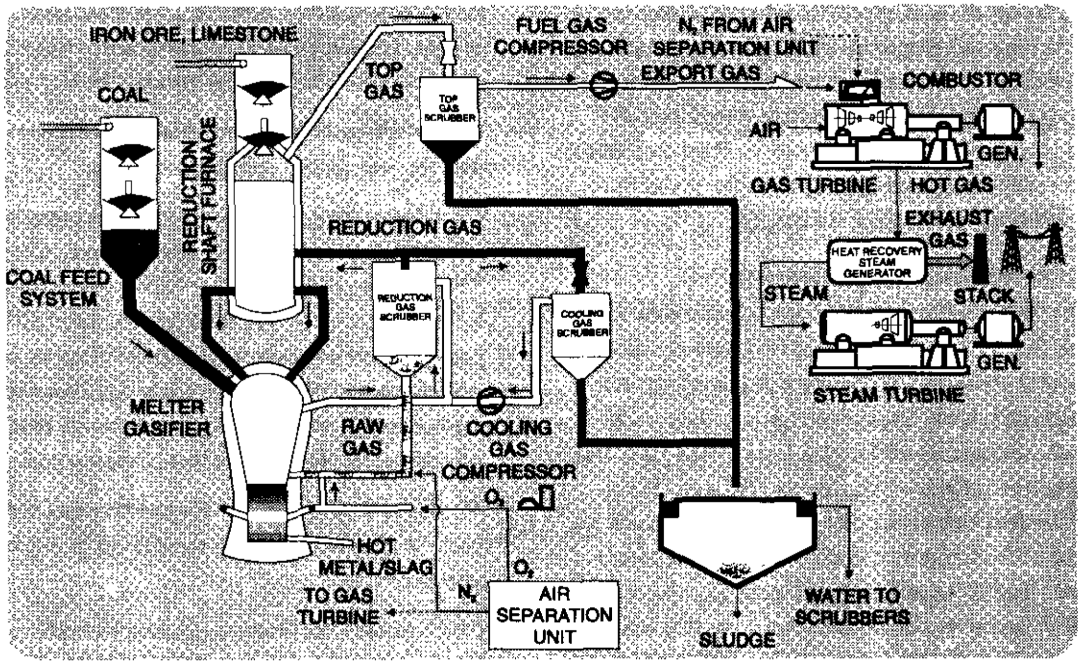
Vineyard, Utah County, UT (Geneva Steel Company's mill)

Technology:

Integration of Deutsche Voest-Alpine Industrieanlagenbau's COREX® iron-making process with a combined-cycle power generation system

Plant Capacity/Production:

195 MWe (net) and 3,300 tons/day of hot metal (liquid iron)



Project Funding:

Total project cost	$1,065,805,000	100%
DOE	149,469,242	14
Participant	916,335,758	86

(Funding amounts are preliminary and subject to negotiation, pending award of a cooperative agreement.)

Project Objective:

To demonstrate the integration of a direct iron-making process (COREX®) with the co-production of electricity using various U.S. coals in an efficient and environmentally responsible manner.

Technology/Project Description:

The clean power from integrated coal/ore reduction (CPICOR™) process integrates two historically distinct processes—iron-making and electric power generation. COREX® is a novel iron-making technology which eliminates the need for coke production. The key innovative features of the COREX® process include the reduction shaft furnace, which is used to reduce the iron ore to iron, and the melter-gasifier, located beneath the reduction furnace, which gasifies the coal and melts the iron. The gasification process generates the reducing gas for use in the reduction furnace as well as sufficient heat to melt the resulting iron in the melter-gasifier.

Excess reducing gas exiting the reduction furnace is cooled, cleaned, compressed, mixed with air, and burned in a gas turbine generator system capable of combusting low-Btu gas to make electric power. The hot exhaust from the turbine is then delivered to a heat recovery steam generator where process steam is made for utiliza-

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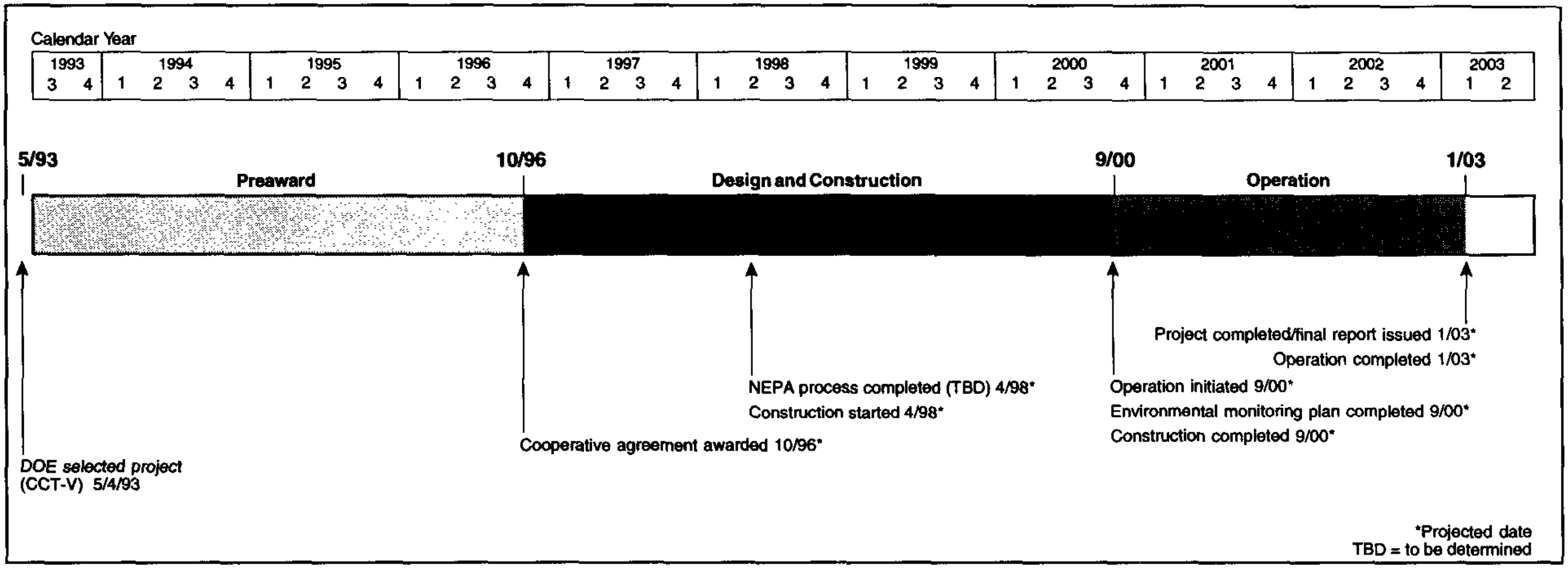
COREX is a registered trademark of Deutsche Voest-Alpine Industrieanlagenbau GmbH.

CPICOR is a trademark of the CPICOR Management Company, L.L.C.



tion in a steam turbine generator system to produce additional electric power.

During the demonstration, approximately 3,400 tons/day of a western bituminous coal blend containing about 0.5% sulfur will be utilized. The project will produce 3,300 tons/day of hot metal and 195 MWe.

CPICOR™ technology is less complex and environmentally superior than competing iron-making and power-generating technologies. Criteria air pollutants are reduced substantially largely due to (1) the inherent desulfurizing capability of the COREX® process in which limestone fed to the reduction furnace captures the sulfur present in the coal and (2) the efficient control systems within the combined-cycle power generation process. Because coke is not used, coke plants and their associated pollutants can be eliminated.

The energy efficiency of the CPICOR™ technology is much greater than competing commercial technology. This efficiency advantage is gained by more effective use of both the sensible heat in the process and the volatile matter in the coal, as well as by incorporation of the combined-cycle power generation system.

Project Status/Accomplishments:

DOE has completed negotiations with the participant and approved the project. Award of the cooperative agreement is subject to congressional approval.

Commercial Applications:

The CPICOR™ technology is a direct replacement for existing blast furnace and coke-making capacity with the additional benefit of combined-cycle power generation. A full-scale commercial plant based on the CPICOR™ demonstration project will produce nearly 200 MWe (net exportable) and 1,200,000 tons/yr of hot metal while expanding the type of coals that can be used to produce hot metal into the much larger noncoking range.

The total emissions of NO_x from a future commercial plant are expected to be 0.012 lb/million Btu of coal, which is a reduction of more than 97% from the combination of a comparably sized blast furnace, associated coke-making facilities, and a comparably sized pulverized coal power plant with flue gas desulfurization. Similarly, the total emissions of SO_2 from the commercial facility are expected to be 0.024 lb/million Btu, a reduction of more than 90%. The net electrical generating efficiency of the commercial facility is estimated to be 47% (a net effective heat rate of 7,262 Btu/kWh on an LHV basis). This compares to a net efficiency of 32% for comparably sized conventional facilities.

Overall, a CPICOR™ commercial plant would produce minimal solid or liquid impacts to the environment, especially when compared to existing competing facilities. All solid wastes are expected to be exempt from Resource Conservation and Recovery Act requirements. The majority of solid wastes are beneficially reused, which increases the economic benefit of the technology and avoids burdening landfills. Most of the solid waste is slag from the iron-making process, which is usable in applications such as ballast for road construction and foundations.

Cement Kiln Flue Gas Recovery Scrubber

Project completed.

Participant:

Passamaquoddy Tribe

Additional Team Members:

Dragon Products Company—project manager and host

HPD, Incorporated—designer and fabricator of tanks and heat exchanger

Cianbro Corporation—constructor

Location:

Thomaston, Knox County, ME (Dragon Products Company's coal-fired cement kiln)

Technology:

Passamaquoddy Technology Recovery Scrubber™

Plant Capacity/Production:

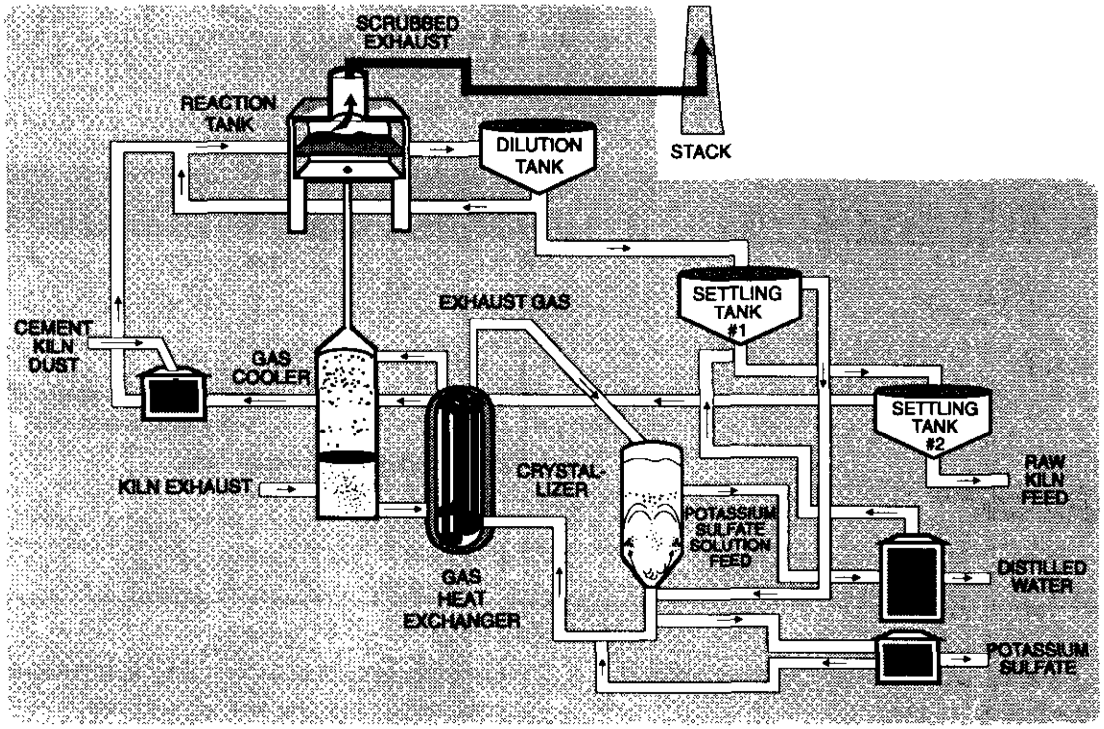
1,450 tons/day of cement; 250,000 std ft^3/min of kiln gas; and up to 274 tons/day of coal

Project Funding:

Total project cost	$17,800,000	100%
DOE	5,982,592	34
Participant	11,817,408	66

Project Objective:

To retrofit and demonstrate a full-scale industrial scrubber and waste recovery system for a coal-burning wet process cement kiln using waste dust as the reagent to accomplish 90–95% SO_2 reduction using high-sulfur eastern coals and to produce a commercial by-product, potassium-based fertilizer.



Technology/Project Description:

The Passamaquoddy Technology Recovery Scrubber™ uses a water solution/slurry containing potassium-rich dust recovered from the kiln flue gas, which serves as the scrubbing medium. No other chemicals are required for the process. After scrubbing the gas, the slurry is separated into liquid and solid fractions. The solid fraction is returned to the cement plant as renovated and usable raw feed material. The liquid fraction is passed to a crystallizer that uses waste heat in the exhaust gas to evaporate the water and recover dissolved alkali metal salts.

The Passamaquoddy Tribe's recovery scrubber was constructed at the Dragon Products Company's cement plant in Thomaston, ME, a plant that processes approximately 470,000 tons/yr of cement. The process was developed by the Passamaquoddy Indian Tribe while it was seeking ways to solve landfill problems, which resulted from the need to dispose of waste kiln dust from the cement-making process.

The kiln burns Pennsylvania bituminous coal containing approximately 3% sulfur.

Passamaquoddy Technology Recovery Scrubber is a trademark of the Passamaquoddy Tribe.

Project Results/Accomplishments:

The recovery scrubber began operations in August 1991 and has continued operations with several temporary shutdowns for normal kiln repairs and maintenance and a more lengthy shutdown from January to May 1992 due to poor economic conditions in the area. In a 5-month period from May to September 1992, the plant produced approximately 140,000 tons of cement while the scrubber removed 70 tons of SO_2 and treated 6,000 tons of kiln dust for return to the kiln as raw feed. Initial testing of the scrubbing system achieved the project objective of 90–95% SO_2 emission reduction, with a maximum reduction of 98%. The effect on NO_x emissions also was determined during the demonstration. NO_x emission reductions averaged 18.8% for the entire operating period. Operations have totaled 5,316 hours. Capital costs are approximately $10 million for a 450,000-ton/yr plant, with a simple payback in about 3–4 years. Project operations continued through September 1993 when the scrubber became a permanent part of the Dragon Products facility.

Commercial Applications:

The recovery scrubber permits the use of high-sulfur coal in cement kilns using available waste dust as the reagent, without requiring the purchase of other materials as scrubber reactant.

There are more than 250 cement kiln installations in the United States and along the St. Lawrence River in Canada emitting approximately 230,000 tons/yr of SO_2. Based on the technology's characteristics, the applicable market would include approximately 75% of these installations. If the technology were installed in the applicable market facilities, SO_2 emissions could be reduced by approximately 150,000 tons/yr. Commercialization of the technology may be spurred when EPA issues emissions limits on cement kilns under the CAAA of 1990. The technology may also have broader applications in paper production and municipal waste incineration in the United States and abroad.

Water usage might or might not increase depending on the configuration of the existing kiln facility. However, the quality of wastewater would be improved and the amount reduced because the technology produces distilled water either for sale or discharge.

The waste dust that previously would have been sent to a landfill would be recovered for recycling to the kiln and to produce by-product fertilizer. Essentially, the solid waste stream would be eliminated through recovery.

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	12/20/89
NEPA process completed (EA)	2/16/90
Environmental monitoring plan completed	3/26/90
Construction	4/90–5/91
Operational testing	8/91–9/93
Project completed	2/94

Final Reports:

Final Technical Report (including economic assessment)	2/94
Topical Report	3/92
Public Design Report	10/93

Appendix A: CCT Project Contacts

Listed below are contacts for obtaining further information about specific CCT Program demonstration projects. Each listing provides the name, title, phone number, and mailing address of the contact person. In those instances where the project participant consists of more than one company, a partnership, or joint venture, the mailing address listed is that of the contact person.

Advanced Electric Power Generation/ Fluidized-Bed Combustion

PCFB Demonstration Project

Participant:
DMEC-1 Limited Partnership

Contacts:
Gary E. Kruempel, Project Manager
(515) 281-2459
(515) 281-2355 (fax)

Midwest Power Systems, Inc.
907 Walnut
P.O. Box 657
Des Moines, IA 50303

Jeffrey Summers, DOE/HQ, (301) 903-4412
Gary A. Nelkin, METC, (304) 285-4216

Four Rivers Energy Modernization Project

Participant:
Four Rivers Energy Partners, L.P.

Contacts:
Edward Holley, Senior Project Manager
(610) 481-8568
(610) 481-3228 (fax)

Air Products and Chemicals, Inc.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Jeffrey Summers, DOE/HQ, (301) 903-4412
Donald W. Geiling, METC, (304) 285-4784

Tidd PFBC Demonstration Project

Participant:
American Electric Power Service Corporation as agent for The Ohio Power Company

Contacts:
Mario Marrocco, Manager, PFBC Programs
(614) 223-1740
(614) 223-2466 (fax)

American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

Jeffrey Summers, DOE/HQ, (301) 903-4412
Donald W. Geiling, METC, (304) 285-4784

ACFB Demonstration Project

Participant:
Pennsylvania Electric Company

Contacts:
Kenneth Gray, Project Manager
(814) 533-8044
(814) 533-8108 (fax)

Pennsylvania Electric Company
1001 Broad Street
Johnstown, PA 15907

Jeffrey Summers, DOE/HQ, (301) 903-4412
Nelson F. Rekos, METC, (304) 285-4066

Nucla CFB Demonstration Project

Participant:
Tri-State Generation and Transmission Association, Inc.

Contacts:
Marshall L. Pendergrass, Assistant General Manager
(303) 249-4501

Tri-State Generation and Transmission
Association, Inc.
P.O. Box 1149
Montrose, CO 81402

Jeffrey Summers, DOE/HQ, (301) 903-4412
Nelson F. Rekos, METC, (304) 285-4066

Advanced Electric Power Generation/ Integrated Gasification Combined Cycle

Clean Energy Demonstration Project

Participant:
Clean Energy Partners Limited Partnership

Contacts:
Victor Shellhorse, Vice President
(704) 373-2474
(704) 382-9325 (fax)

Duke Energy Corp.
400 S. Tryon Street
Charlotte, NC 28202

Jeffrey Summers, DOE/HQ, (301) 903-4412
Donald W. Geiling, METC, (304) 285-4784

Piñon Pine IGCC Power Project

Participant:
Sierra Pacific Power Company

Contacts:
John W. (Jack) Motter, Project Manager
(702) 689-4013
(702) 689-3047 (fax)

Sierra Pacific Power Company
6100 Neil Road
P.O. Box 10100
Reno, NV 89520-0400

Lawrence Saroff, DOE/HQ, (301) 903-9483
Douglas M. Jewell, METC, (304) 285-4720

Tampa Electric Integrated Gasification Combined-Cycle Project

Participant:
Tampa Electric Company

Contacts:
Donald E. Pless, Director, Advanced Technology
(813) 228-1332
(813) 228-1308 (fax)

TECO Power Services Corporation
P.O. Box 111
Tampa, FL 33601-0111

William Fernald, DOE/HQ, (301) 903-9448
Nelson F. Rekos, METC, (304) 285-4066

Wabash River Coal Gasification Repowering Project

Participant:
Wabash River Coal Gasification Repowering Project Joint Venture

Contacts:
Michael R. Woodruff
(713) 735-4131
(713) 735-4169 (fax)

Destec Energy, Inc.
2500 City West Boulevard, Suite 1500
Houston, TX 77042

Jeffrey Summers, DOE/HQ, (301) 903-4412
Gary A. Nelkin, METC, (304) 285-4216

Advanced Electric Power Generation/ Advanced Combustion/Heat Engines

Healy Clean Coal Project

Participant:
Alaska Industrial Development and Export Authority

Contacts:
John B. Olson, Project Manager
(907) 269-3000

Alaska Industrial Development and Export Authority
480 West Tudor Road
Anchorage, AK 99503-6690

Jeffrey Summers, DOE/HQ, (301) 903-4412
Robert M. Kornosky, PETC, (412) 892-4521

Coal Diesel Project

Participant:
Arthur D. Little, Inc.

Contacts:
Robert P. Wilson, Vice President
(617) 498-5806
(617) 498-7206 (fax)

Arthur D. Little, Inc.
200 Acorn Park
Cambridge, MA 02140

Jeffrey Summers, DOE/HQ, (301) 903-4412
Nelson F. Rekos, METC, (304) 285-4066

Externally Fired Combined-Cycle Demonstration Project

Participant:
Pennsylvania Electric Company

Contacts:
Kenneth Gray, Project Manager
(814) 533-8044
(814) 533-8108 (fax)

Pennsylvania Electric Company
1001 Broad Street
Johnstown, PA 15907

Douglas Archer, DOE/HQ, (301) 903-9443
Donald W. Geiling, METC, (304) 285-4784

Environmental Control Devices/NO_x Control Technologies

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Participant:
The Babcock & Wilcox Company

Contacts:
Tony Yagiela
(330) 829-7403

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

Jeffrey Summers, DOE/HQ, (301) 903-4412
John C. McDowell, PETC, (412) 892-6237

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

Participant:
The Babcock & Wilcox Company

Contacts:
Tony Yagiela
(330) 829-7403

The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601

Jeffrey Summers, DOE/HQ, (301) 903-4412
Ronald W. Corbett, PETC, (412) 892-6141

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler

Participant:
Energy and Environmental Research Corporation

Contacts:
Blair A. Folsom, Senior Vice President
(714) 859-8851

Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718

William Fernald, DOE/HQ, (301) 903-9448
Jerry L. Hebb, PETC, (412) 892-6079

Micronized Coal Reburning Demonstration of NO_x Control

Participant:
New York State Electric & Gas Corporation

Contacts:
Dennis O'Dea, Project Manager
(607) 729-2551

New York State Electric & Gas Corporation
120 Chenango Street
Binghamton, NY 13902

Lawrence Saroff, DOE/HQ, (301) 903-9483
James U. Watts, PETC, (412) 892-5991

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Participant:
Southern Company Services, Inc.

Contacts:
John N. Sorge, ICCT Project Manager
(205) 877-7426

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Scott M. Smouse, PETC, (412) 892-5725

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

Participant:
Southern Company Services, Inc.

Contacts:
J.D. (Doug) Maxwell, Project Manager
(205) 877-7614

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Arthur L. Baldwin, PETC, (412) 892-6011

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

Participant:
Southern Company Services, Inc.

Contacts:
Robert R. Hardman, Project Manager
(205) 877-7772

Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625

William Fernald, DOE/HQ, (301) 903-9448
Scott M. Smouse, PETC, (412) 892-5725

Environmental Control Devices/SO_2 Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

Participant:
AirPol, Inc.

Contacts:
Frank E. Hsu,Vice President, Operations
(201) 490-6400

AirPol, Inc.
3 Century Drive
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Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

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Coal Processing for Clean Fuels/Coal Preparation Technologies

Development of the Coal Quality Expert

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Advanced Coal Conversion Process Demonstration

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ENCOAL Mild Coal Gasification Project

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Coal Processing for Clean Fuels/Indirect Liquefaction

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Industrial Applications

Blast Furnace Granulated-Coal Injection System Demonstration Project

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Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

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Clean Power from Integrated Coal/Ore Reduction (COREX®)

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Cement Kiln Flue Gas Recovery Scrubber

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Appendix B: Acronyms and Abbreviations

Acronyms

ABB CE	ABB Combustion Engineering, Inc.
ABB ES	ABB Environmental Systems
ADL	Arthur D. Little, Inc.
ACFB	atmospheric circulating fluidized bed
AFBC	atmospheric fluidized-bed combustion
AFGD	advanced flue gas desulfurization
AIDEA	Alaska Industrial Development and Export Authority
AOFA	advanced overfire air
BFGCI	blast furnace granulated-coal injection
BG/L	British Gas/Lurgi
B&W	The Babcock & Wilcox Company
CAAA	Clean Air Act Amendments of 1990
CCOFA	close-coupled overfire air
CCT	clean coal technology
CCT Program	Clean Coal Technology Demonstration Program
CDL	coal-derived *liquid*
CFB	circulating fluidized bed
CQE	Coal Quality Expert
CX	categorical exclusion
CZD	confined zone dispersion
DME	dimethyl ether
DOE	U.S. Department of Energy
DOE/HQ	U.S. Department of Energy Headquarters
EA	*environmental assessment*
EER	Energy and Environmental Research Corporation
EFCC	externally fired combined cycle
EIS	environmental impact statement
EMP	environmental monitoring plan
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator
FBC	fluidized-bed combustion
FGD	flue gas desulfurization
FRP	fiberglass-reinforced plastic
FY	*fiscal year*
GE	General Electric
GNOCIS	Generic NO_x Control Intelligence System
GR	gas reburning
GR–LNB	gas reburning and low-NO_x burner
GR–SI	gas reburning and sorbent injection
GSA	*gas suspension absorption*
HAP, HAPs	hazardous air pollutant(s)
HHV	high heating value
HRSG	heat recovery steam generator
IGCC	integrated gasification combined cycle
JBR	jet-bubbling reactor
LHV	low heating value
LIMB	limestone injection multistage burner
LNB	low-NO_x burner
LNCFS	*low-NO_x concentric-firing system*
LSFO	limestone forced oxidation
MCFC	molten carbonate fuel cell
METC	Morgantown Energy Technology Center
MTF	memorandum (memoranda)-to-file
NEPA	National Environmental Policy Act
NSPS	New Source Performance Standards
NYSEG	New York State Electric & Gas Corporation
PCFB	pressurized circulating fluidized bed
PDF	process-derived fuel
PENELEC	Pennsylvania Electric Company
PEPCO	Potomac Electric Power Company
PETC	Pittsburgh Energy Technology Center
PFBC	pressurized fluidized-bed combustion
PJBH	pulse jet baghouse
PSCC	Public Service Company of Colorado
SCR	*selective catalytic reduction*
SCS	Southern Company Services, Inc.
S-H-U	Saarberg-Hölter-Umwelttechnik, GmbH
SI	sorbent injection
SNCR	selective noncatalytic reduction
SOFA	separated over-fire air
TVA	Tennessee Valley Authority
UBCL	unburned carbon boiler efficiency losses
U.K.	United Kingdom

U.S.	United States
VOC	volatile organic compound
WLFO	wet limestone, forced oxidation

Abbreviations

States are abbreviated using two-letter postal codes.

atm	atmosphere(s)
avg	average
Btu	British thermal unit
C/H	molar ratio of carbon to hydrogen
$CaCO_3$	calcium carbonate (calcitic limestone)
CaO	calcium oxide (lime)
$Ca(OH)_2$	calcium hydroxide (calcitic hydrated lime)
$Ca(OH)_2 \cdot MgO$	dolomitic hydrated lime
Ca/S	molar ratio of calcium to sulfur
$CaSO_3$	calcium sulfite
$CaSO_4$	calcium sulfate
CO	carbon monoxide
CO_2	carbon dioxide
°F	degrees Fahrenheit
ft, ft^2, ft^3	foot (feet), square feet, cubic feet
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HCl	hydrogen chloride
HF	hydrogen fluoride
hr, hrs	hour, hours
in, in^2, in^3	inch(es), square inches, cubic inches
KCl	potassium chloride
K_2SO_4	potassium sulfate
kW	kilowatt
kWh	kilowatt-hour
lb, lbs	pound, pounds
mo, mos	month, months
$MgCO_3$	magnesium carbonate
MgO	magnesium oxide
MWe	megawatt(s)-electric
N_2	atmospheric nitrogen
Na/Ca	molar ratio of sodium to calcium
Na_2/S	molar ratio of sodium to sulfur
NaOH	sodium hydroxide
Na_2CO_3	sodium carbonate
NH_3	ammonia
NO_x	nitrogen oxides
ppm	parts per million (mass)
ppmv	parts per million by volume
psi	pound(s) per square inch
rpm	revolutions per minute
SO_2	sulfur dioxide
std ft^3	standard cubic feet
yr, yrs	year, years