CLEAN
COAL
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DOE/FE-0402

Clean Coal Technology Demonstration Program

Project Fact Sheets

Status as of March 31, 1999

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

June 1999

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The Clean Coal Technology Demonstration Program

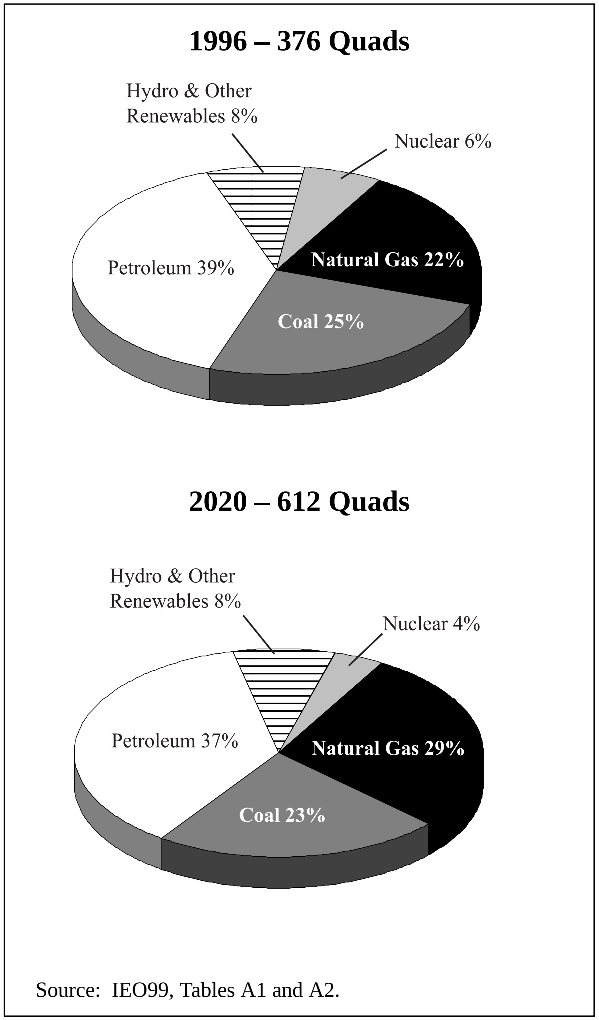
Introduction

The Clean Coal Technology Demonstration Program (CCT Program), a model of government and industry cooperation, responds to the Department of Energy's (DOE) mission to foster a secure and reliable energy system that is environmentally and economically sustainable. The CCT Program represents an investment of over \$5.6 billion in advanced coal-based technology, with industry and state governments providing an unprecedented 66 percent of the funding. With 23 of the 40 active projects having completed operations, the CCT Program has yielded clean coal technologies (CCTs) that are capable of meeting existing and emerging environmental regulations and competing in a deregulated electric power marketplace.

The CCT Program is providing a portfolio of technologies that will assure the U.S. recoverable coal reserves of 274 billion tons can continue to supply the nation's energy needs economically and in an environmentally sound manner. As the new millennium approaches, many of the clean coal technologies have realized commercial application. Industry stands ready to respond to the energy and environmental demands of the 21st century, both domestically and internationally. For existing power plants, there are cost effective environmental control devices to control sulfur dioxide (SO_2), nitrogen oxides (NO_x), and particulate matter (PM). Also ready are a new generation of technologies that can produce electricity and other commodities, such as steam and synthetic gas, and provide the efficiencies and environmental performance responsive to global climate change concerns. The CCT Program took a pollution prevention approach as well, demonstrating technologies that remove pollutants or their precursors from coal-based fuels before combustion. Lastly, new technologies were introduced into the major coal-using industries, such as steel production, to enhance environmental performance. Thanks in part to the CCT Program, coal—abundant, secure, and economical—can continue in its role as a key component in the U.S. and world energy markets.

The CCT Program also has global importance in providing clean, efficient coal-based technology to a burgeoning energy market in developing countries, largely dependent on coal. World energy consumption is expected to increase 63 percent by 2020, with almost half of the energy increment occurring in developing Asia (including China and India). By 2020, energy consumption in developing Asia is projected to surpass consumption in North America. The energy form contributing most to the growth is electricity, as developing Asia establishes its energy infrastructure. Coal, the predominant indigenous fuel, will be the fuel of choice in electricity production. CCTs offer a means to mitigate potential environmental problems associated with unprecedented energy growth and to enhance the U.S. economy through equipment sales and engineering services.

▼ World Energy Consumption by Fuel Type, 1996 and 2020.



Source: IEO99, Tables A1 and A2.

Evolution of the Coal Technology Portfolio

The CCT Program has been implemented through a series of five nationwide competitive solicitations. The first solicitation was directed towards demonstrating the feasibility of future commercial application of clean coal technology, which would balance the goals of expanding coal use and minimizing environmental impact. The next two solicitations sought technologies that could mitigate the potential impacts of acid rain from existing coal-fired power plants in response to the recommendations of the Special Envoys on Acid Rain. The fourth and fifth solicitations addressed the post-2000 energy supply and demand situation with SO_2 emissions capped under the CAAA, increased need for electric power, and the need to alleviate concerns over global climate change—a situation requiring technologies with very high efficiencies and extremely low emissions.

CCT Program demonstrations provide a portfolio of technologies that will enable coal to continue to provide low-cost, secure energy vital to the nation's economy while satisfying energy and environmental goals well into the 21st century. This is being carried out by addressing four basic market sectors: (1) environmental control devices for existing and new power plants, (2) advanced electric power generation for repowering existing facilities and providing new generating capacity, (3) coal processing for clean fuels to convert the nation's vast coal resources to clean fuels, and (4) industrial applications dependent upon coal use.

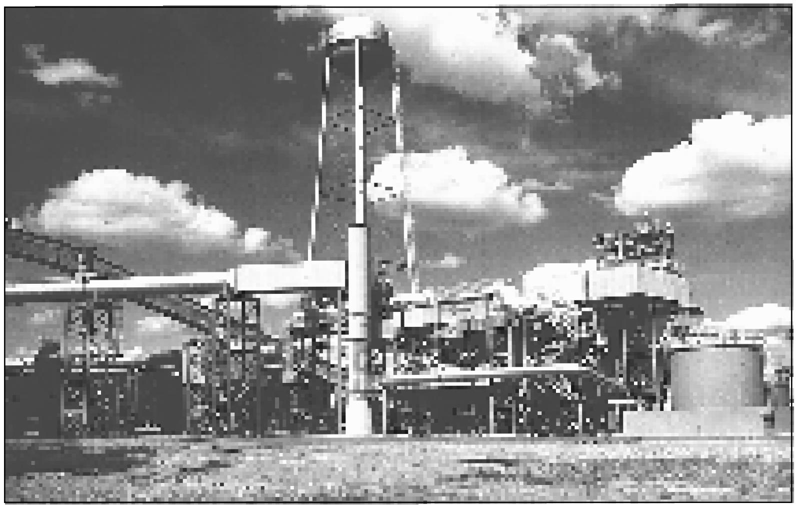
In response to the initial thrust of the program, operations have been completed for 17 of 19 projects that address SO_2 and NO_x control for coal-fired boilers. The resultant technologies provide a suite of cost-effective control options for the full range of boiler types. The 19 environmental control device projects are valued at more than $704 million. These include seven NO_x emission control systems installed on more than 1,750 MWe of utility generating capacity, five SO_2 emissions systems installed on approximately 770 MWe, of capacity and seven combined SO_2/NO_x emission control systems installed or planned on more than 665 MWe of capacity.

To respond to load growth as well as growing environmental concerns, the program provides a range of advanced electric power generation options for both repowering and new power generation. These advanced options offer greater than 20 percent reductions in greenhouse gas emissions; SO_2, NO_x, and PM emissions far below New Source Performance Standards (NSPS); and salable solid and liquid by-products in lieu of solid wastes. Over 1,800 MWe of capacity are represented by 11 projects valued at more than $3.1 billion. These projects include five fluidized-bed combustion (FBC) systems, four integrated gasification combined-cycle (IGCC) systems, and two advanced combustion/heat engine systems. These projects will not only provide environmentally sound electric generation now, but also will provide the demonstrated technology base necessary to meet new capacity requirements in the 21st century.

Also addressed are approaches to converting raw, run-of-mine coals to high-energy-density, low-sulfur products. These products have application domestically for compliance with the Clean Air Act Amendments of 1990 (CAAA). Internationally, both the products and processes have excellent market potential. Valued at more than $519 million, the five projects in the coal processing for clean fuels category represent a diversified portfolio of technologies. Three projects involve the production of high-energy-density solid fuels, one of which also produces a liquid product equivalent to No. 6 fuel oil. A fourth project is demonstrating a new methanol production process. A fifth effort complements the process demonstrations by providing an expert computer software system that enables a utility to assess the environmental, operational, and cost impact of utilizing coals not previously burned at a facility, including upgraded coals and coal blends.

Projects were undertaken to address pollution problems associated with coal use in the industrial

▼ The SNOX™ demonstration at Ohio Edison's Niles Station Unit No. 2 achieved SO_2 removal efficiencies exceeding 95% and NO_x reduction effectiveness averaging 94%. Ohio Edison is retaining the SNOX™ technology as part of its environmental control system.



sector. These problems included dependence of the steel industry on coke and the inherent pollutant emissions in coke-making; reliance of the cement industry on low-cost indigenous, and often high-sulfur, coal fuels; and the need for many industrial boiler operators to consider switching to coal fuels to reduce operating costs. The five industrial applications projects have a combined value of nearly $1.3 billion. Projects encompass substitution of coal for 40 percent of 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 demonstrations of an industrial-scale slagging combustor and a pulse combustor system.

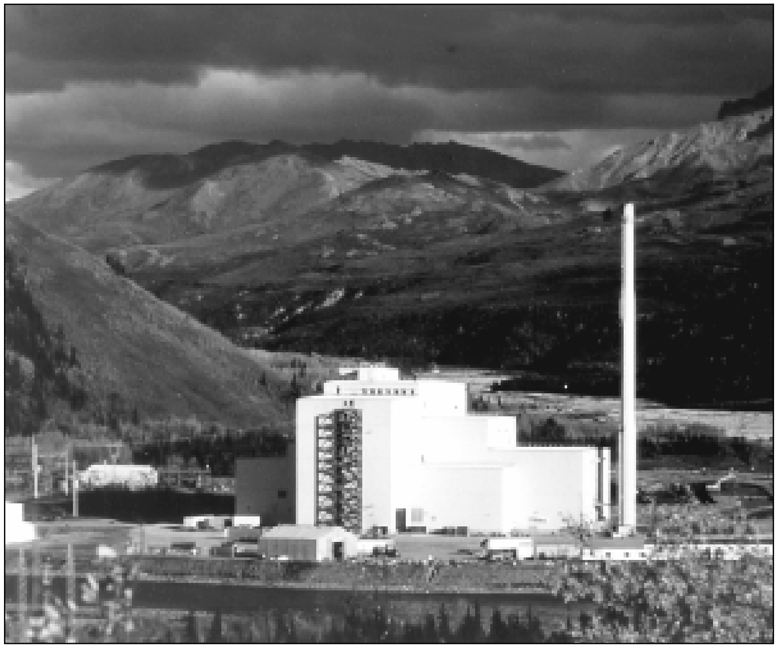
Program Status

The CCT Program has extended the technical, economic, and environmental performance envelope of a broad portfolio of advanced coal technologies. As of March 31, 1999, a total of 23 CCT demonstration projects have completed operation, 9 are in operation, 2 projects are in construction, and 6 are in design. Exhibit 1 shows the number of projects having completed operations by application category. Exhibit 2 provides a schedule for the 40 projects as of March 31, 1999.

▲ NO_x emissions at Georgia Power's Plant Hammond were reduced by 63 percent with Foster Wheeler's low-NO_x burners, shown here, and advanced overfire air.

Exhibit 1
Completed Projects by Application Category

Application Category	Number of Projects Completed Operations	Total
Environmental Control Devices		
SO_2 Control Technology	5	5
NO_x Control Technology	6	7
Combined SO_2/NO_x Control Technology	6	7
Advanced Electric Power Generation		
Fluidized-Bed Combustion	2	5
Integrated Gasification Combined Cycle	0	4
Advanced Combustion/Heat Engines	0	2
Coal Processing for Clean Fuels	2	5
Industrial Applications	2	5
Total	**23**	**40**



▲ Golden Valley Electric Association is adding capacity to its 25 MWe Healy Unit No. 1 with a 50-MWe slagging combustor unit using 65 percent waste coal.

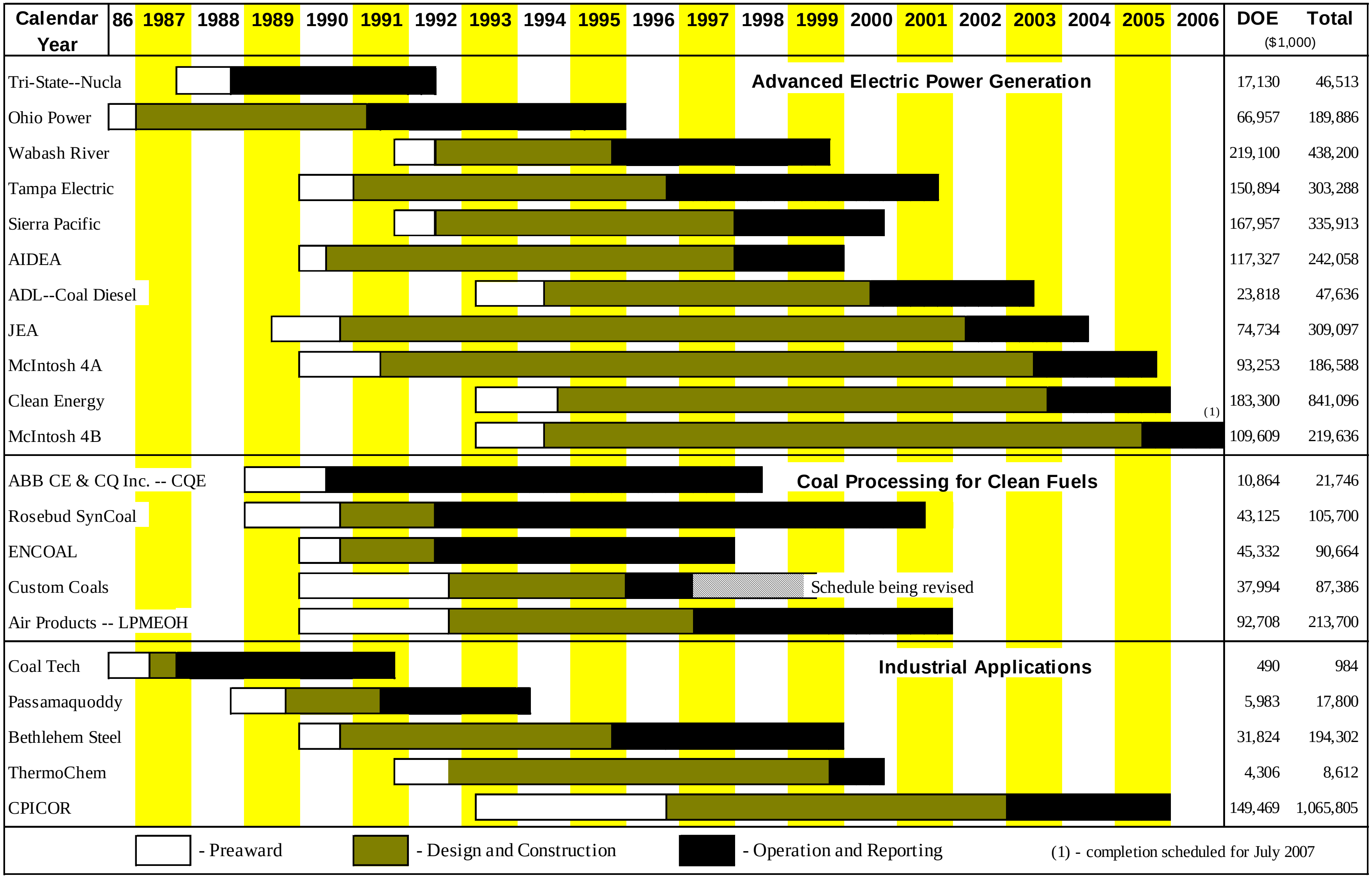
Program Accomplishments

Some of the accomplishments of the CCT Program to date are summarized below.

- The Clean Coal Technology (CCT) Program enabled the utility industry to respond cost effectively to the first wave of NO_x control requirements using low-NO_x burners) and has positioned the utility industry to respond to NO_x control requirements in the 21st century. The CCT Program also provided valuable input to the regulatory process by furnishing real-time NO_x control data. To date, over one-third of the coal-fired generating capacity in the United States has low-NO_x burners, worth a value exceeding $1.5 billion.
- The CCT Program has also provided a portfolio of SO_2 control technologies that enable utilities to respond cost effectively to year 2000 CAAA requirements. Technologies are available for the full range of units from old space-constrained boilers to relatively-new large boilers. The two advanced wet flue gas desulfurization technologies demonstrated under the CCT Program redefined the state-of-the-art for sorbent-based scrubbers by: (1) halving operating costs and significantly reducing capital costs; (2) producing by-products instead of waste; and (3) mitigating plant efficiency loses by using high-capture-efficiency devices.
- The CCT Program was instrumental in commercializing atmospheric circulating fluidized-bed combustion (ACFB) technology through the Tri-State Generation and Transmission Association, Inc. project in Nucla, Colorado. An industry consortium joined with DOE to fully evaluate the potential of the technology for utility application. The results and the attendant comprehensive database served to establish ACFB as a commercial offering, with an estimated 9.5 gigawatts of capacity installation worldwide.
- Pressurized Fluidized-bed Combustion (PFBC) technology is also beginning to make market penetration as a result of work performed at The Ohio Power Company's Tidd Plant. The CCT Program demonstration and associated development work have resulted in several commercial sales, including a 360 MW unit in Japan and a 220 MW unit in Germany. The technology represents a new generation of advanced power systems, with efficiencies far higher than conventional coal-fired systems and pollutant emissions far below new source performance standards, without the need of add-on emission controls. The work at Tidd also provided the basis for second generation PFBC demonstrations to be conducted in Lakeland, Florida.
- Four IGCC demonstration projects, representing a diversity of gasifier types and cleanup systems, are pioneering the introduction of a new approach to power generation. Two of the technologies are currently operating in a commercial dispatch mode, providing valuable performance data. The units are attracting worldwide interest because of their potential to significantly improve efficiency, reduce pollutant emissions, and serve as building blocks for even more advanced systems.
- ENCOAL has completed the successful demonstration of a coal processing technology that produces a high-energy-density solid fuel and a liquid product from low-rank coal. The solid fuel is low enough in sulfur to be considered a compliance fuel, i.e., capable of meeting CAAA standards for 2000. Also, the solid product has demonstrated combustion characteristics that enable reduced NO_x emissions. The liquid product has most potential as a chemical feedstock and can be used as a low-sulfur boiler fuel.
- The Liquid Phase Methanol process (LPMEOH™) at the Eastman Chemical Company in Kingsport, Tennessee is demonstrating a cost effective means of coproducing electricity and methanol. Continued stable production of methanol at or beyond design rates from high-sulfur bituminous coal suggests that IGCC with LPMEOH™ offers a very clean, highly efficient means of using high-sulfur coal in chemical and electricity production.
- Demonstration of granular-coal injection at Bethlehem Steel's Burns Harbor blast furnace operations is proving that coal can replace up to 40 percent of the coke requirement in ironmaking. This has significant environmental and cost ramifications because of the magnitude and extent of pollutant emissions from coke production. Emissions from granular-coal injection are controlled in the blast furnace.

Exhibit 2

Project Schedules and Funding by Application Category

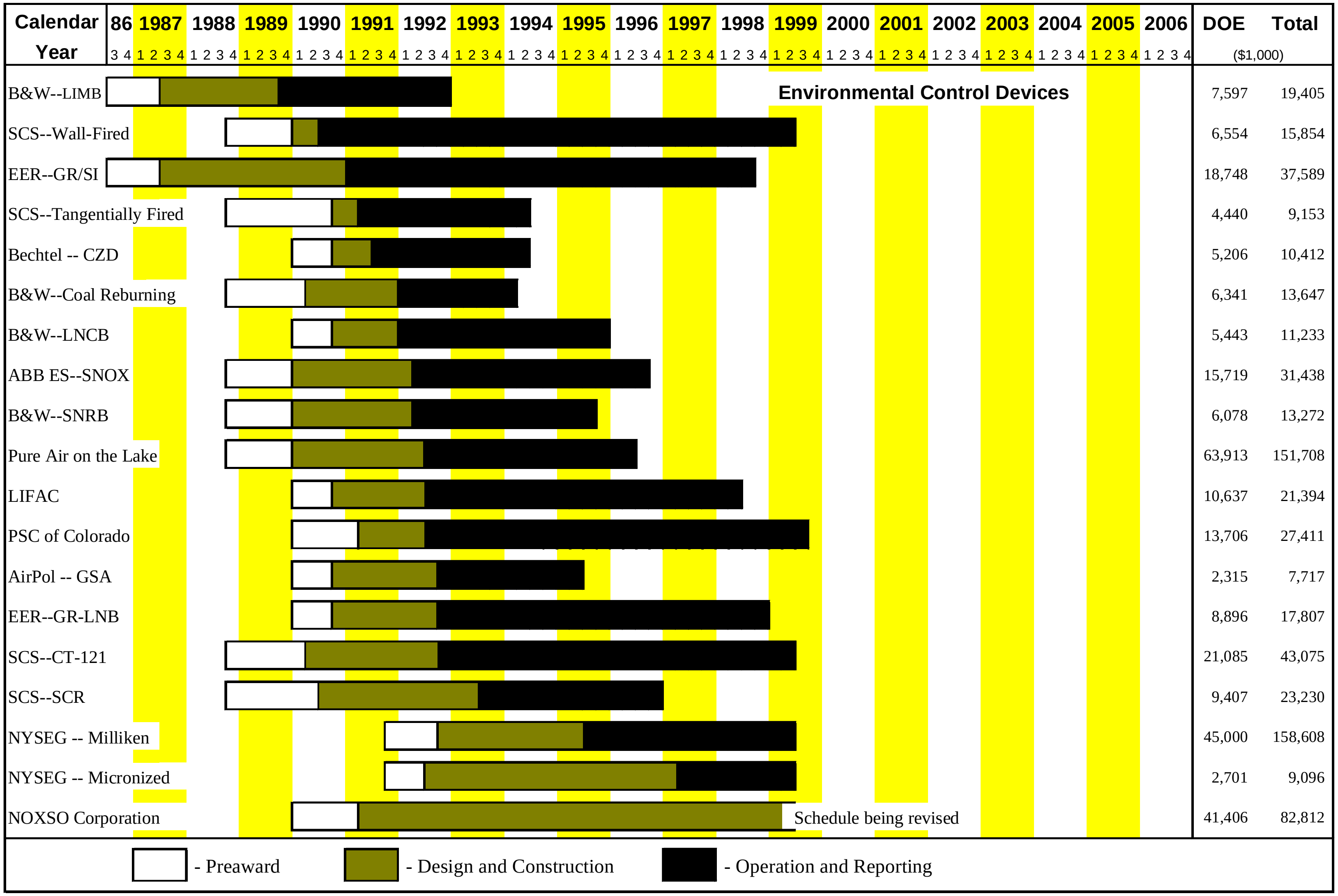


Project	DOE ($1,000)	Total ($1,000)
Advanced Electric Power Generation		
Tri-State--Nucla	17,130	46,513
Ohio Power	66,957	189,886
Wabash River	219,100	438,200
Tampa Electric	150,894	303,288
Sierra Pacific	167,957	335,913
AIDEA	117,327	242,058
ADL--Coal Diesel	23,818	47,636
JEA	74,734	309,097
McIntosh 4A	93,253	186,588
Clean Energy (1)	183,300	841,096
McIntosh 4B	109,609	219,636
Coal Processing for Clean Fuels		
ABB CE & CQ Inc. -- CQE	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
Industrial Applications		
Coal Tech	490	984
Passamaquoddy	5,983	17,800
Bethlehem Steel	31,824	194,302
ThermoChem	4,306	8,612
CPICOR	149,469	1,065,805

(1) - completion scheduled for July 2007

Exhibit 2 (continued)

Project Schedules and Funding by Application Category



Calendar Year	DOE ($1,000)	Total ($1,000)
B&W--LIMB	7,597	19,405
SCS--Wall-Fired	6,554	15,854
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	2,701	9,096
NOXSO Corporation	41,406	82,812

Technology Overview

Environmental Control Devices

Environmental control devices are those technologies retrofitted to existing facilities or installed on new facilities for the purpose of controlling SO_2 and NO_x emissions. Although boilers may be modified and combustion affected, the basic boiler configuration and function remains unchanged with these technologies.

SO_2 Control Technology. Sulfur dioxide is an acid gas formed during coal combustion, which oxidizes the inorganic, pyritic sulfur (Fe_2S), and organically bound sulfur in the coal. Identified as a precursor to formation of acid rain, SO_2 was targeted in Title IV of the CAAA. Phase I of Title IV, effective in 1995, affected 261 coal-fired units nationwide. The required SO_2 reduction was moderate and largely met by switching to low-sulfur fuels. In year 2000, Phase II of Title IV will come into effect, impacting all fossil-fuel-fired units, but most of all, the approximately 900 pre-NSPS coal-fired units. Under the stricter Phase II requirements, compliance by fuel switching alone is unlikely. The CAAA provides utilities flexibility in control strategies through SO_2 allowance trading. This permits a range of control options to be applied by a utility, as well as allowance purchasing. Recognizing this, the CCT Program has sought to provide a portfolio of SO_2 control technologies.

Sulfur dioxide control devices embody those technologies that condition and act upon the flue gas resulting from combustion, not the combustion itself, for the purpose of removing only SO_2. Three basic approaches evolved, driven primarily by different conditions that exist within the pre-NSPS boiler population impacted by the CAAA. There is a tremendous range in critical factors, e.g., size, type, age, and space availability.

On one end of the spectrum are the smaller, older boilers with limited space for adding equipment. For these, sorbent injection techniques hold promise. Sorbent is injected into the boiler or the ductwork, and humidification is incorporated in some fashion to properly condition the flue gas for efficient SO_2 capture. Equipment size and complexity are held to a minimum to keep capital costs and space requirements low. Both limestone and lime sorbents are used. Limestone costs are about one-third that of hydrated lime; but, limestone must be conditioned (calcined), and even then, it is less effective in SO_2 capture (under simple sorbent injection conditions) than hydrated lime. Where limestone is used, it is injected in the boiler to produce calcium oxide, which reacts with SO_2 to form solid compounds of calcium sulfite and calcium sulfate. Both limestone and lime injection require the presence of water (humidification) and a calcium-to-sulfur (Ca/S) molar ratio of about 2.0 for sulfur capture efficiencies of 50 to 70 percent.

In the mid-range of the spectrum are 100 to 300 MWe boilers less than 30 years old and somewhat space constrained. For many of these, an increase in higher equipment cost is justified by enhanced performance. The approach involves introduction of a reactor vessel in the flue gas stream to create conditions to enhance SO_2 capture beyond that achievable with the simpler sorbent injection systems. Lime, as opposed to limestone, is used and sulfur capture efficiencies up to 90 percent can be achieved at a Ca/S molar ratio of 1.3 to 2.0. This category of control device is called a spray dryer (because the solid by-product from the reaction is dry).

▲ Unique CT-121 SO_2 scrubber at Plant Yates combined a number of functions and eliminated process steps.

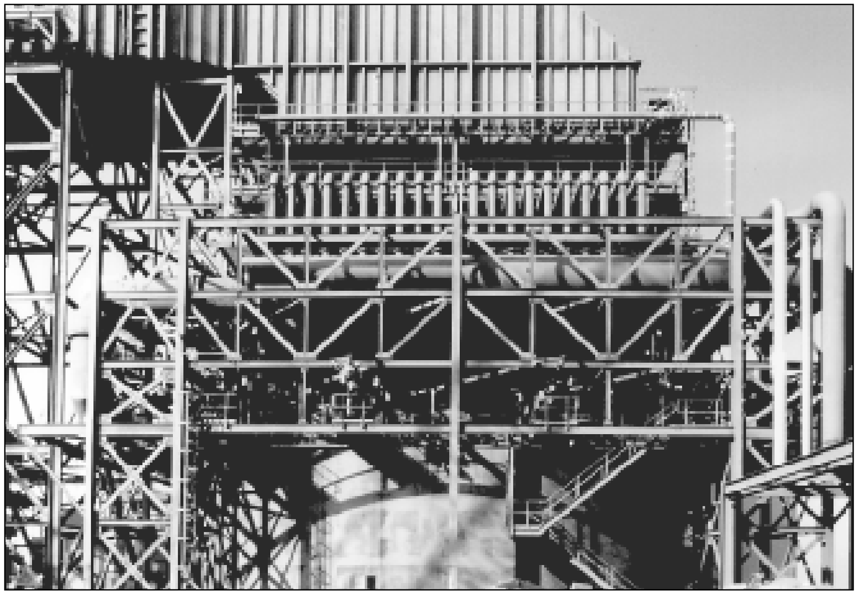
At the other end of the spectrum are the larger (300 MWe and more) boilers with some latitude in space availability, as well as new capacity additions. For these boilers, advanced flue gas desulfurization (AFGD) wet scrubbers, with higher capital cost, but higher sulfur capture efficiency than other approaches, become cost effective. These systems apply larger and somewhat more complex reactors that drive up the capital cost. However, the sorbent is limestone and SO_2 removal efficiencies greater than 90 percent are achieved at a Ca/S molar ratio of about 1.0, making operating costs significantly lower than those of the other two approaches. Furthermore, although the initial AFGD solid by-product is in slurry form, it is dewatered to produce gypsum—a salable product.

Under the CCT Program, two sorbent injection systems, one spray dryer, and two AFGD processes were successfully demonstrated. All have completed testing. Exhibit 3 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

Exhibit 3
CCT Program SO_2 Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO_2 Reduction	Fact Sheet
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Sorbent injection—in-duct lime sorbent injection and humidification	1.5–2.5%	50%	32
LIFAC Sorbent Injection Desulfurization Demonstration Project	Sorbent injection—furnace sorbent injection (limestone) with vertical humidification vessel and sorbent recycle	2.0–2.9%	70%	36
10-MWe Demonstration of Gas Suspension Absorption	Spray dryer—vertical, single-nozzle reactor with integrated sorbent particulate recycle (lime sorbent)	2.7–3.5%	60–90%	28
Advanced Flue Gas Desulfurization Demonstration Project	AFGD—co-current flow, integrated quench absorber tower and reaction tank with combined agitation/oxidation (gypsum by-product)	2.25–4.7%	94%	40
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	AFGD—forced flue gas injection into reaction tank (Jet Bubbling Reactor®) for combined SO_2 and particulate capture (gypsum by-product)	1.2–3%	90+%	44

▼ This side view of Pure Air's advanced flue gas desulfurization absorber module shows air inlet ducts and sorbent injection piping.



▼ This view shows the sorbent (top) and water (bottom) inlet connections to the Pure Air absorber module.

NO_x Control Technology. Nitrogen oxides (NO_x) are formed from oxidation of nitrogen contained within the coal (fuel-bound NO_x) and oxidation of the nitrogen in the air at high temperatures of combustion (thermal NO_x). Rapid formation of NO_x at the flame front can occur; but usually, this reaction of hydrocarbon fragments with atmospheric nitrogen represents a small fraction of total NO_x emissions. To control fuel-bound NO_x formation, it is important to limit oxygen at the early stages of combustion. To control thermal-NO_x, it is important to limit peak temperatures.

Nitrogen oxides were identified both as a precursor to acid rain (targeted under Title IV of the CAAA) and as a contributor to ozone formation (targeted under Title I). Phase I of Title IV, effective in 1995, required 169 wall- and tangentially-fired coal units to reduce emissions to 0.50 and 0.45 lb/10^6 Btu, respectively. In 2000, Phase II of Title IV will come into effect, impacting all fossil-fueled units, but most of all, the balance of the pre-NSPS coal-fired units (see Exhibit 4). Ozone nonattainment prompted the U.S. Environmental Protection Agency (EPA) to issue a NO_x transport State Implementation Plan (SIP) call for 22 states and the District of Columbia to cut NO_x emissions 85 percent below 1990 rates or achieve a 0.15 lb/10^6 Btu emission rate by May 2003.

The CCT Program has sought to provide a number of NO_x control options to cover the range of boiler types and emission reduction requirements.

Control of NO_x emissions can be accomplished by either modifying the combustion process or acting upon the products of combustion (or combinations thereof). Combustion modification technologies include low-NO_x burners (LNBs), advanced overfire air (AOFA), and reburning processes using either gas or coal. Processes used to act upon flue gas include selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR).

LNBs regulate the initial fuel-air mixture, velocities, and turbulence to create a fuel-rich flame core and control the rate at which additional air required to complete combustion is mixed. This staging of combustion avoids a highly oxidized environment and hot spots conducive to fuel-bound NO_x and thermal NO_x formation. LNBs alone typically can achieve 40 to 50 percent NO_x reduction.

Exhibit 4
Group I and 2 Boiler Statistics and Phase II NO_x Emission Limits

Boiler Types	No. of Boilers	Phase II NO_x Emission Limits (lb/10^6 Btu)
Group 1		
Tangentially-fired	299	0.40
Dry-bottom, wall-fired	308	0.46
Group 2		
Cell burner	36	0.68
Cyclone >155 MWe	55	0.86
Wet-bottom, wall-fired >65 MWe	26	0.84
Vertically fired	28	0.80

Source: Environmental Protection Agency, Nitrogen Oxides Emission Reduction Program, Final Rule for Phase II, Group 1 and Group 2 Boilers (downloaded from http://www.epa.gov/docs/acidrain/noxfs3.html).

▲ A portion of ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) is shown being installed on a tangentially-fired boiler.

AOFA involves injection of air above the primary combustion zone to allow the primary combustion to occur without the amount of oxygen needed for complete combustion. This oxygen deficiency mitigates fuel-bound NO_x formation. AOFA injected at high velocity creates turbulent mixing to complete the combustion in a gradual fashion at lower temperatures to mitigate thermal NO_x formation. Usually, AOFA is used in combination with LNBs; but alone, AOFA can achieve 10 to 25 percent NO_x emission reductions. The LNB/AOFA systems generally can achieve NO_x emission reductions of 60 to 67 percent.

Advanced control systems using artificial intelligence are also becoming an integral part of NO_x control systems. These systems can handle the numerous parameters and optimize performance to reduce NO_x while enhancing boiler performance.

Exhibit 5
CCT Program NO_x Control Technology Characteristics

Project	Process	Boiler Size/ Type	NO_x Reduction	Fact Sheet
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	Coal reburning—30% heat input	100-MWe/cyclone	52–62%	52
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	LNB/gas reburning/AOFA—13–18% gas heat input	172-MWe/wall	37–65%	60
Micronized Coal Reburning Demonstration for NO_x Control	Coal reburning—30% heat input	148-MWe/tangential 50-MWe/cyclone	50–60% (goal)	50
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	LNB—separation of coal and air ports on plug-in unit	605-MWe/cell burner	48–58%	56
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	LNB/AOFA—advanced LNB with separated AOFA and artificial intelligence controls	500-MWe/wall	68%	72
180 MWe Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	LNB/AOFA—advanced LNB with close-coupled and separated overfire air	180-MWe/tangential	37–45%	68
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers	SCR—eight catalysts with different shapes and chemical compositions	8.7-MWe/various	80%	64

In reburning, a percentage of the fuel input to the boiler is diverted to injection ports above the primary combustion zone. Either gas or coal is typically used as the reburning fuel to provide 10 to 30 percent of the heat input to the boiler. The reburning fuel is injected to create a fuel-rich zone deficient in oxygen (a reducing rather than oxidizing zone). NO_x entering this zone is stripped of oxygen, resulting in elemental nitrogen. Combustion is completed in a burnout zone where air is injected by an AOFA system. Reburning has application to all boiler types, including cyclone boilers, and can achieve NO_x emission reductions of 50 to 67 percent.

SCR and SNCR can be used alone or in combination with combustion modification. These processes use ammonia or urea in a reducing reaction with NO_x to form elemental nitrogen and water. SNCR can only be used at high temperatures (1,600 to 2,200 ºF) where a catalyst is not needed. SCR is typically applied at temperatures between 600 to 800 ºF. Generally, SNCR and SCR systems alone can achieve NO_x emission reductions of 30 to 50 percent and 80 to 90+ percent, respectively.

Under the CCT Program, seven NO_x control technologies were assessed encompassing LNBs, AOFA, reburning, SNCR, SCR, and combinations thereof. Six of the projects have completed operations and the remaining project is in the operations phase. Exhibit 5 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

Combined SO_2/NO_x Control Technology. Combined SO_2/NO_x control systems encompass those technologies that combine previously described control methods and those that apply other, synergistic techniques. Three of the projects combine either LNBs or gas reburning with sorbent injection. In one of these, SNCR is used with LNBs to enhance performance. Another project combines a number of techniques to improve overall system performance, such as LNBs with SNCR, unique space-saving and durable wet-scrubber design, sorbent additive, and artificial intelligence controls. The balance of the seven projects use synergistic methods not previously described.

SO_x-NO_x-Rox Box™ incorporates an SCR catalyst in a high-temperature filter bag for NO_x control and applies sorbent injection for SO_2 control. The high-temperature filter bag, operated in a standard pulsed-jet baghouse, protects the SCR catalyst, allows operation at optimal NO_x control temperatures, forms a sorbent cake on the surface to enhance SO_2 capture, and provides high-efficiency particulate capture.

SNOX™ uses SCR followed by catalytic oxidation of SO_2 to SO_3 with condensation of the SO_3 in the presence of water to produce sulfuric acid. Following the SCR with the catalytic oxidation allows the SCR to operate at optimal ammonia concentration without worry of ammonia slip (ammonia passing to the second catalyst is broken down into water vapor, nitrogen, and a small amount of NO_x). Furthermore, most particulates passing through the upstream baghouse are captured in the sulfuric acid condensing unit. The system produces no solid waste.

NOXSO uses a single, regenerable adsorber (spherical alumina beads impregnated with sodium carbonate) to capture both SO_2 and NO_x. The adsorber is used in a fluidized bed to achieve effective mixing with the flue gas. The adsorber is then processed through a regenerator system to release the NO_x and SO_2 before return to the fluidized bed. The flue gas passes through a baghouse to remove particulates.

Six of the seven combined SO_2/NO_x control technology projects have completed operations and one is in the project definition and design phase. Exhibit 6 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

▲ New York State Electric & Gas Corporation's Milliken Station is hosting the demonstration of a combination of unique SO_2 and NO_x control technologies.

Exhibit 6

CCT Program Combined SO_2/NO_x Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO_2/NO_x Reduction	Fact Sheet
LIMB Demonstration Project Extension and Coolside Demonstration	LNB/sorbent injection—furnace and duct injection, calcium-based sorbents	1.6–3.8%	60–70%/40–50%	88
Integrated Dry NO_x/SO_2 Emissions Control System	LNB/SNCR/sorbent injection—calcium- and sodium-based sorbents used in duct injection	0.4%	70%/62–80%	100
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Gas reburning/sorbent injection—calcium-based sorbents used in duct injection	3.0%	50–60%/67%	96
Milliken Clean Coal Technology Demonstration Project	LNB/SNCR/wet scrubber—sorbent additive and space-saving, durable scrubber design	1.5–4.0%	98%/53–58%	78
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	SCR/high temperature baghouse/sorbent injection—SCR in high-temperature filter bag and calcium-based sorbent injection	3.4%	80–90%/90%	92
SNOX™ Flue Gas Cleaning Demonstration Project	SCR/oxidation catalyst/sulfuric acid condenser—synergistic catalyst effect and no solid waste	3.4%	95%/94%	84
Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System	Regenerable adsorbent—spherical alumina beads impregnated with sodium carbonate in fluidized-bed adsorber	3.4% (planned)	98% (goal)/75% (goal)	82

Advanced Electric Power Generation Technology

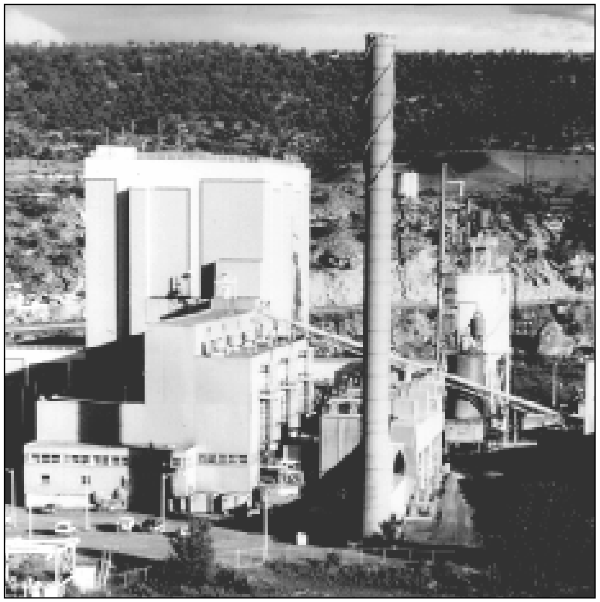
Advanced electric power generation technologies enable the efficient and environmentally superior generation of electricity. The advanced electric power generation projects selected under the CCT Program are responsive to the capacity expansion needs requisite to meeting long-term demand, off setting nuclear retirements, and meeting stringent CAAA emission limits effective in 2000. These technologies are characterized by high thermal efficiency, very low pollutant emissions, reduced CO_2 emissions, few solid waste problems, and enhanced economics. Advanced electric power generation technologies may be deployed in modules, allowing phased construction to better match demand growth, and to meet the smaller capacity requirements of municipal, rural, and nonutility generators.

There are five generic advanced electric power generation technologies demonstrated in the CCT Program. The characteristics of these five technologies are outlined here, and the specific projects and technologies are presented in more detail in the fact sheets.

Fluidized-Bed Combustion. Fluidized-bed combustion (FBC) reduces emissions of SO_2 and NO_x by controlling combustion parameters and by injecting a sorbent (such as crushed limestone) into the combustion chamber along with the coal. Pulverized coal mixed with the limestone is fluidized on jets of air in the combustion chamber. Sulfur released from the coal as SO_2 is captured by the sorbent in the bed to form a solid calcium compound that is removed with the ash. The resultant waste is a dry, benign solid that can be disposed of easily or used in agricultural and construction applications. More than 90 percent of the SO_2 can be captured this way.

At combustion temperatures of 1,400 to 1,600 ºF, the fluidized mixing of the fuel and sorbent enhances both combustion and sulfur capture. The operating temperature range is about half that of a conventional pulverized-coal boiler and below the temperature at which thermal NO_x is formed. In fact, fluidized-bed NO_x emissions are about 70 to 80 percent lower than those for conventional pulverized-coal boilers. Thus, fluidized-bed combustors substantially reduce both SO_2 and NO_x emissions. Also, fluidized-bed combustion has the capability of using high-ash coal, whereas conventional pulverized-coal units must limit ash content in the coal to relatively low levels.

Two parallel paths were pursued in fluidized-bed development—bubbling and circulating beds. Bubbling beds use a dense fluid bed and low fluidization velocity to effect good heat transfer and mitigate erosion of an in-bed heat exchanger. Circulating fluidized beds use a relatively high fluidization velocity, which entrains the bed material, in conjunction with hot cyclones to separate and recirculate the bed material from the flue gas before it passes to a heat exchanger. Hybrid systems have also evolved from these two basic approaches.



▲ Tri-State Generation and Transmission Association's Nucla Station was host to demonstration of the world's first utility-scale AFBC.

Fluidized-bed combustion can be either atmospheric (AFBC) or pressurized (PFBC). AFBC operates at atmospheric pressure while PFBC operates at pressure 6 to 16 times higher. PFBC offers potentially higher efficiency, and consequently, reduced operating costs and waste relative to AFBC, as well as smaller size per unit of power output.

Second-generation PFBC integrates the combustor with a pyrolyzer (coal gasifier) to fuel a gas turbine (topping cycle), the waste heat from which is used to generate steam for a steam turbine (bottoming cycle). The inherent efficiency of the gas turbine and waste heat recovery in this combined-cycle mode significantly increases overall efficiency. Such advanced PFBC systems have the potential for efficiencies over 50 percent.

Of the five fluidized-bed combustion projects, two have successfully completed demonstration (one PFBC and one AFBC), and the other three are in the project definition and design phase.

Integrated Gasification Combined Cycle. The integrated coal gasification combined-cycle process has four basic steps: (1) fuel gas is generated from coal reacting with high-temperature steam and an oxidant (oxygen or air) in a reducing atmosphere; (2) the fuel gas is either passed directly to a hot-gas cleanup system to remove particulates, sulfur, and nitrogen compounds or first cooled to produce steam and then cleaned conventionally; (3) the clean fuel gas is combusted in a gas turbine generator to produce electricity; and (4) the residual heat in the hot exhaust gas from the gas turbine is recovered in a heat recovery steam generator, and the steam is used to produce additional electricity in a steam turbine generator.

Integrated gasification combined-cycle systems are among the cleanest and most efficient of the emerging clean coal technologies. Sulfur, nitrogen compounds, and particulates are removed before the fuel is burned in the gas turbine, that is, before combustion air is added. For this reason, there is a much lower volume of gas to be treated than in a postcombustion scrubber. The chemical composition of the gas requires that the gas stream must be cleaned to a high degree, not only to achieve low emissions, but to protect downstream components, such as the gas turbine, from erosion and corrosion.

In a coal gasifier, the sulfur in the coal is released in the form of hydrogen sulfide (H_2S) rather than as SO_2. In some IGCC systems, much of the sulfur-containing gas is captured by a sorbent injected into the gasifier. Others use existing proven commercial hydrogen sulfide removal processes, which remove up to 99+ percent of the sulfur, but require the fuel to be cooled, which is an efficiency penalty. Therefore, hot-gas cleanup systems are now being demonstrated. In these cleanup systems, the hot coal gas is passed through a bed of metal oxide particles, such as zinc oxides. Zinc oxide can absorb sulfur contaminants at temperatures in excess of 1,000 °F, and the compound can be regenerated and reused with little loss of effectiveness. Produced during the regeneration stage are salable sulfur, sulfuric acid, or sulfur-containing compounds that may be used to produce useful by-products. The technique is capable of removing more than 99.9 percent of the sulfur in the gas stream. With hot-gas cleanup, IGCC systems have the potential for efficiencies of over 50 percent.

High levels of nitrogen removal are also possible. Some of the coal's nitrogen is converted to ammonia, which can be almost totally removed by commercially available chemical processes. NO_x formed in the gas turbine can be held to well within allowable levels by staged combustion in the gas turbine or by adding moisture to control flame temperature.

Integrated Gasification Fuel Cell. A typical fuel cell system using coal as fuel includes a coal gasifier with a gas cleanup system, a fuel cell to use the coal gas to generate electricity (direct current) and heat, an inverter to convert direct current to alternating current, and a heat-recovery system. The heat-recovery system would be used to produce additional electric power in a bottoming steam cycle.

▲ Tampa Electric Company's Polk Power Station Unit 1, a 250-MWe IGCC greenfield installation, is currently in operation. It is one of the world's cleanest and most advanced coal power plants.

Energy conversion in fuel cells is more efficient (up to 60 percent, depending on fuel and type of fuel cell) than traditional energy conversion devices. Fuel cells directly transform the chemical energy of a fuel and an oxidant (air or oxygen) into electrical energy instead of going through an intermediate step, i.e., burner, boiler, turbines, and generators. Each fuel cell includes an anode and a cathode separated by an electrolyte layer. In a coal gasification/fuel cell application, coal gas is supplied to the anode and air is supplied to the cathode to produce electricity and heat.

Of the four IGCC projects, three are in operation and one is in the project definition and design phase.

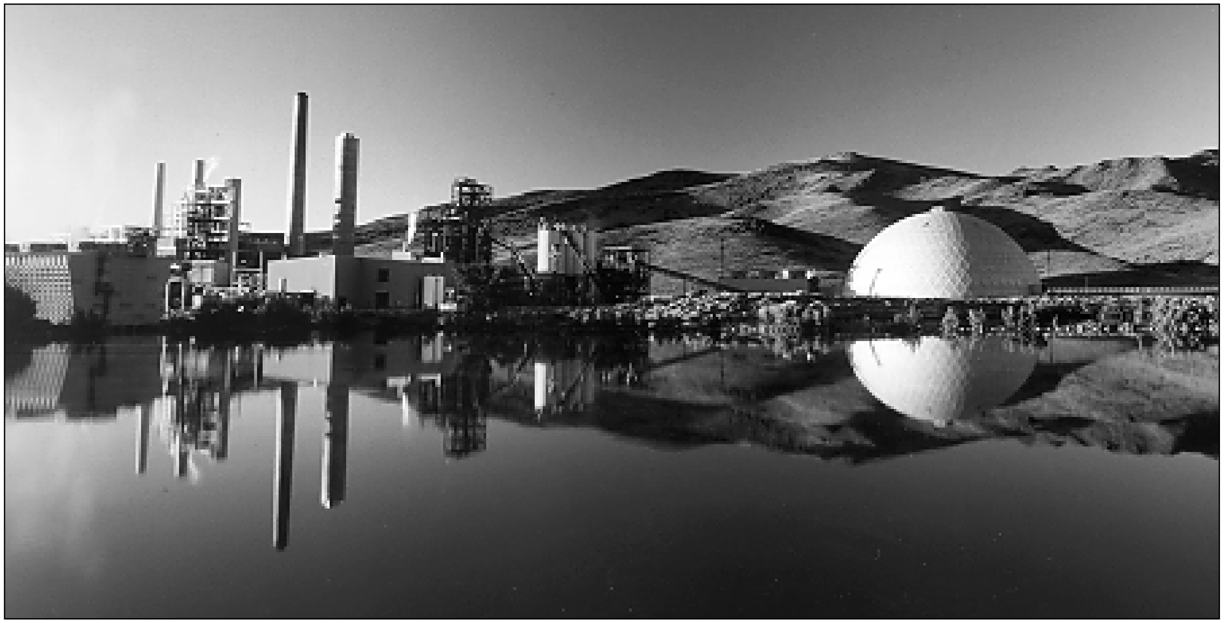
Coal-Fired Diesel. Coal-fired diesels use either a coal-oil or coal-water slurry fuel drive an electric generation system. The hot exhaust from the diesel engine is routed through a heat-recovery unit to produce steam for a steam-turbine electric generating system (combined cycle). Environmental control systems for SO_2, NO_x, and particulate removal treat the cooled exhaust before release to the atmosphere. The diesel system is expected to achieve 41 to 48 percent thermal efficiencies. The 5–20 MWe capacity range of the technology would be most amenable to distributed power applications. The CCT coal-fired diesel project is in construction.

Slagging Combustor. Many new coal-burning technologies are designed to remove the coal ash as molten slag in the combustor rather than the furnace. Most of these slagging combustors are based on a cyclone combustor concept. In a cyclone combustor, coal is burned in a separate chamber outside the furnace cavity. The hot combustion gases then pass into the boiler where the actual heat exchange takes place.

The advantage of a cyclone combustor is that the ash is kept out of the furnace cavity where it could collect on boiler tubes and lower heat transfer efficiency. To keep ash from being blown into the furnace, the combustion temperature is kept so hot that mineral impurities melt and form slag, hence the name slagging combustor. A vortex of air (the cyclone) forces the slag to the outer walls of the combustor where it can be removed as waste.

Results to date show that by positioning air injection ports so that coal is combusted in stages, NO_x emissions can be reduced by 70 to 80 percent. Injecting limestone into the combustion chamber has the potential to reduce sulfur emissions by 90 percent in combination with a spray-dryer absorber. Advanced slagging combustors could replace oil-fired units in both utility and industrial applications or be used to retrofit older, conventional cyclone boilers. The CCT advanced slagging combustor project is in operation.

Exhibit 7 summarizes the process characteristics and size of the advanced electric power generating technologies presented in more detail in the project fact sheets.



▲ SPPC's Piñon Pine project demonstrates air-blown, fluidized-bed IGCC technology using hot gas cleanup, and evaluates a low-Btu gas combustion turbine.

Exhibit 7
CCT Program Advanced Electric Power Generation Technology Characteristics

Project	Process	Size	Fact Sheet
Fluidized-Bed Combustion			
McIntosh Unit 4A PCFB Demonstration Project	Pressurized circulating fluidized-bed combustion	137-MWe (net)	106
McIntosh Unit 4B Topped PCFB Demonstration Project	McIntosh 4A with pyrolyzer and topping combustor	157-MWe + 103-MWe (net)	108
Tidd PFBC Demonstration Project	Pressurized bubbling fluidized-bed combustion	70-MWe (net)	112
JEA Large-Scale CFB Combustion Demonstration Project	Atmospheric circulating fluidized-bed combustion	297.5-MWe (gross); 265-MWe (net)	110
Nucla CFB Demonstration Project	Atmospheric circulating fluidized-bed combustion	100-MWe (net)	116
Integrated Gasification Combined Cycle			
Clean Energy Demonstration Project	Oxygen-blown, slagging fixed-bed gasifier with cold gas cleanup	477-MWe (net); 1.25 MWe MCFC	122
Piñon Pine IGCC Power Project	Air-blown, fluidized-bed gasifier with hot gas cleanup	107 MWe (gross); 99-MWe (net)	124
Tampa Electric Integrated Gasification Combined-Cycle Project	Oxygen-blown, entrained-flow gasifier with hot and cold gas cleanup	313 MWe (gross); 250-MWe (net)	126
Wabash River Coal Gasification Repowering Project	Oxygen-blown, two-stage entrained-flow gasifier with cold gas cleanup	296-MWe (gross); 262-MWe (net)	128
Advanced Combustion/Heat Engines			
Healy Clean Coal Project	Advanced slagging combustor, spray dryer with sorbent recycle	50-MWe (nominal)	132
Clean Coal Diesel Demonstration Project	Coal-fueled diesel engine	6.4-MWe (net)	134

Coal Processing for Clean Fuels Technology

The coal processing category includes a range of technologies designed to produce high-energy-density, low-sulfur solid and clean liquid fuels, as well as systems to assist users in evaluating impacts of coal quality on boiler performance.

In the case of the Custom Coals International project, advanced physical-cleaning techniques are applied to bituminous coal with an already high Btu content to remove the ash, which contains sulfur in the form of pyrite, an inorganic iron compound. A dense-medium cyclone using finely sized magnetite effectively separates 90 percent of the pyritic sulfur. But, because physical methods cannot remove the organically bound sulfur, dense-medium-cyclone processed coals can only be considered compliance coals (meeting CAAA SO_2 requirements) if the organic sulfur content is very low. This processed compliance coal is called Carefree Coal™. For coals with significant organic sulfur content, sorbents and other additives must be added to capture the sulfur released upon combustion and bring the coal into compliance. This second product is called Self-Scrubbing Coal™. The project is on hold pending resolution of financial matters.

The Rosebud SynCoal Partnership’s advanced coal conversion project applies mostly physical-cleaning methods to low-Btu, low-sulfur subbituminous coals, primarily to remove moisture and secondarily to remove ash. The objective is to enhance the energy density of the already low-sulfur coal. Some conversion of the properties of the coal is required, however, to provide stability (prevent spontaneous combustion) in transport and handling. In the process, coal with 5,500 to 9,000 Btu/lb, 25 to 40 percent moisture content, and 0.5 to 1.5 percent sulfur is converted to a 12,000 Btu/lb product with 1.0 percent moisture and as low as 0.3 percent sulfur. The SynCoal® product is used at utility and industrial facilities.

The ENCOAL project, which completed operational testing in July 1997, used mild gasification to convert low-Btu, low-sulfur subbituminous coal to a high-energy-density, low-sulfur solid product and a clean liquid fuel comparable to No. 6 fuel oil. Mild gasification is a pyrolysis process (heating in the absence of oxygen) performed at moderate temperatures and pressures. It produces condensable volatile hydrocarbons in addition to solids and gas. The condensable fraction is drawn off as a liquid product. Most of the gas is used to provide on-site energy requirements. The process solid is significantly beneficiated to produce a 11,000-Btu/lb low-sulfur solid fuel. The demonstration plant processed 500 tons per day of subbituminous coal and produced 250 tons per day of solid Process-Derived Fuel (PDF®) and 250 barrels per day of Coal-Derived Liquids (CDL®). Both the solid and liquid fuels have undergone test burns at utility and industrial sites. The project was successfully completed.

The liquid-phase methanol (LPMEOH™) process being demonstrated is an 80,000 gallon/day indirect liquefaction process using synthesis gas from a coal gasifier. The unique aspect of the process is the use of an inert liquid to suspend the conversion catalyst. This removes the heat of reaction and eliminates the need for an intermediate water-gas shift conversion. Also addressed in the project are the load-following capability of the process by simulating application in an IGCC system and fuel characteristics of the unrefined product. Plant operations began in April 1997.

CQ Inc. has developed a personal computer software package that will serve as a predictive tool to assist utilities in selecting optimal quality coal for a specific boiler based on operational efficiency, cost, and environmental considerations. Algorithms were developed and verified through comparative testing at bench, pilot, and utility scale. Six large-scale field tests were conducted at five separate utilities. The software has been released for use.

Exhibit 8 summarizes the process characteristics and size of the coal processing for clean fuels technologies presented in more detail in the project fact sheets.

Exhibit 8
CCT Program Coal Processing for Clean Fuels Technology Characteristics

Project	Process	Size	Fact Sheet
Development of the Coal Quality Expert™	Coal Quality Expert™ computer software	Tested at 250–880-MWe	144
Advanced Coal Conversion Process Demonstration	Advanced coal conversion process for upgrading low-rank coals	45 tons/hr	142
ENCOAL® Mild Coal Gasification Project	Liquids-from-coal (LFC®) mild gasification to produce solid and liquid fuels	1,000 tons/day*	148
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Liquid phase process for methanol production from coal-derived syngas	80,000 gal/day	138
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Dense-medium cyclones with finely sized magnetic and sorbent addition for bituminous coals	500 tons/hr	140

*Operated at 500 tons/day

▼ Rosebud SynCoal Partnership's advanced coal conversion process plant in Colstrip, MT, has produced over 1.4 million tons of SynCoal® products.

▼ The ENCOAL mild gasification plant near Gillette, WY, has operated 12,800 hours and processed approximately 260,000 tons of raw coal and produced over 120,000 tons of PDF® and 121,000 barrels of CDL®.

▼ The LPMEOH™ process produces over 80,000 gal/day of methanol, all of which is used by the Eastman Chemical Company in Kingsport, TN.

Industrial Applications Technology

Technologies applicable to the industrial sector address significant environmental issues and barriers associated with coal use in industrial processes. These technologies are directed at both continued coal use and introduction of coal use in various industrial sectors.

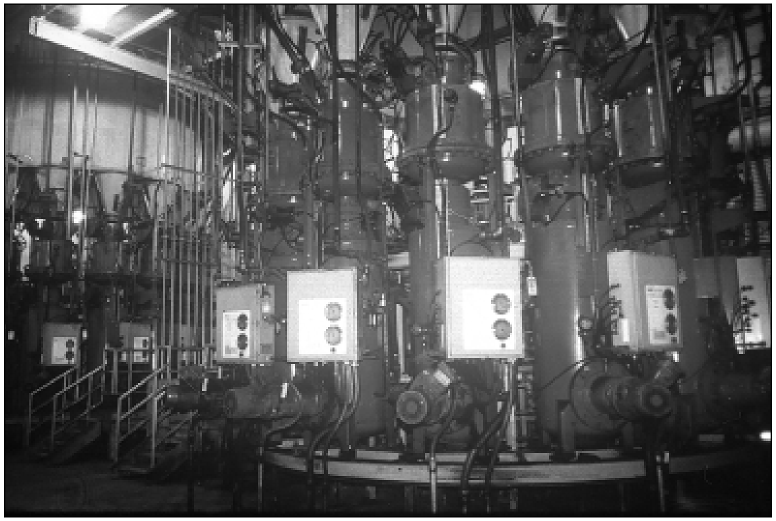
One of the critical environmental concerns has to do with pollutant emissions resulting from producing coke from coal for use in steelmaking. Two approaches to mitigate or eliminate this problem are being demonstrated. In one, about 40 percent of the coke is displaced through direct injection of granular coal into a blast furnace system. The coal is essentially burned in the blast furnace where the pollutant emissions are readily controlled (as opposed to first coking the coal). The other approach eliminates the need for coke making by using a direct iron-making process. In this process, raw coal is introduced into a reactor to produce reducing gas and heat for a unique reduction furnace; no coke is required. Excess reducing gas is cleaned and used to fuel a boiler for electric power generation.

Because production costs are largely driven by fuel cost, coal is often the fuel of choice in cement production. Faced with the need to control SO_2 emissions and also to address growing solid waste management problems, industry sponsored the demonstration of an innovative SO_2 scrubber. The successfully demonstrated Passamaquoddy Technology Recovery Scrubber™ uses cement kiln dust, otherwise discarded as waste, to control SO_2 emissions, convert the sulfur and chloride acid gases to fertilizer, return the solid byproduct as cement kiln feedstock, and produce distilled water. No new wastes are generated and cement kiln dust waste is converted to feedstock. This technology also has application for controlling pollutant emissions in paper production and waste-to-energy applications.

In many industrial boiler applications, the relatively low, stable price of coal makes it an attractive substitute for oil and gas feedstock. However, drawbacks to conversion of oil- and gas-fired units to coal include addition of SO_2 and NO_x controls, tube fouling, and the need for a coolant water circuit for the combustor. Oil- and gas-fired units are not high SO_2 or NO_x emitters, use relatively tight tube spacing in the absence of the potential for ash fouling, and the flow of oil or gas cools the combustor, precluding the need for water cooling. For these reasons, the CCT Program demonstrated an advanced air-cooled, slagging combustor that could avoid these potential problems. The cyclone combustor stages introduction of air to control NO_x, injects sorbent to control SO_2, slags the ash in the combustor to prevent tube fouling, and uses air cooling to preclude the need for water circuitry.

A pulse combustor being demonstrated by ThermoChem has a wide range of applications. The technology can be used in many coal processes, including coal gasification and waste-to-energy applications.

▲ Shown here is the completed Bethlehem Steel Corporation facility to demonstrate the injection of granulated coal directly into two blast furnaces at Burns Harbor, IN.



▲ Shown here is the granular-coal injection system.

Exhibit 9

CCT Program Industrial Applications Technology Characteristics

Project	Process	Size	Fact Sheet
Blast Furnace Granular-Coal Injection System Demonstration Project	Blast furnace granular-coal injection for reduction of coke use	7,000 net tons/day of hot metal/furnace per day	154
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Advanced slagging combustor with staged combustion and sorbent injection	23 x 10^6 Btu/hr	158
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Direct reduction iron-making process to eliminate coke; combined-cycle power generation	170-MWe 3,300 tons/day of hot metal	156
Cement Kiln Flue Gas Recovery Scrubber	Cement kiln dust used to capture SO_2; dust converted to feedstock; and fertilizer and distilled water produced	1,450 tons/day of cement	162
Pulse Combustor Design Qualification Test	Advanced combustion using Manufacturing and Technology Conversion International's pulse combustor/gasifier	To be determined	166

The cement kiln and slagging combustor projects are completed. The project demonstrating granular-coal injection into a blast furnace is in operation. The CPICOR and the ThermoChem projects are in the project definition and design phase and construction phase, respectively.

Exhibit 9 summarizes process characteristics and size for the industrial applications technologies presented in more detail in the project fact sheets.

The Clean Coal Technology Projects

Project Fact Sheets

The remainder of this document contains fact sheets for all 40 projects. Two types of facts sheets are provided: (1) a brief, two page overview for ongoing projects and (2) an expanded four page summary for projects that have successfully completed operational testing. The expanded fact sheets for completed projects contain a summary of the major results from the demonstration as well as sources for obtaining further information, specifically, contact persons and key references. Information provided in the fact sheets includes the project participant and team members, project objectives, significant project features, process description, major milestones, progress (if ongoing) or summary of results (if completed), and commercial applications. A key to interpreting the milestone charts is provided on the right. 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. The portion of the process or facility central to the demonstration is demarcated by the shaded area.

An index to project fact sheets is provided in Exhibit 10. Projects are listed by application category. Ongoing projects in each category appear first followed by projects having completed operations. A shaded area distinguishes projects having completed operations from ongoing projects. Within these breakdowns, projects are listed alphabetically by participant. In addition, Exhibit 10 indicates the solicitation under which the project was selected; its status as of March 31, 1999; and the page number for each Fact Sheet. Exhibit 11 lists the projects alphabetically by participant and provides project location and page numbers.

An appendix containing contact information for all of the projects is provided as Appendix A. A list of acronyms used in this document is provided as Appendix B.

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

▓ **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 10

Project Fact Sheets by Application Category

Project	Participant	Solicitation/Status	Page
Environmental Control Devices			
SO_2 Control Technologies			
10-MWe Demonstration of Gas Suspension Absorption	AirPol, Inc.	CCT-III/completed 3/94	28
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Bechtel Corporation	CCT-III/completed 6/93	32
LIFAC Sorbent Injection Desulfurization Demonstration Project	LIFAC–North America	CCT-III/completed 6/94	36
Advanced Flue Gas Desulfurization Demonstration Project	Pure Air on the Lake, L.P.	CCT-II/completed 6/95	40
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Southern Company Services, Inc.	CCT-II/completed 12/94	44
NO_x Control Technologies			
Micronized Coal Reburning Demonstration for NO_x Control	New York State Electric & Gas Corporation	CCT-IV/operational	50
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	The Babcock & Wilcox Company	CCT-II/completed 12/92	52
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	The Babcock & Wilcox Company	CCT-III/completed 4/93	56
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	Energy and Environmental Research Corporation	CCT-III/completed 1/95	60
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers	Southern Company Services, Inc.	CCT-II/completed 7/95	64
180-MWe Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	Southern Company Services, Inc.	CCT-II/completed 12/92	68
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Southern Company Services, Inc.	CCT-II/completed 5/98	72
Combined SO_2/NO_x Control Technologies			
Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System	NOXSO Corporation	CCT-III/design	82
SNOX™ Flue Gas Cleaning Demonstration Project	ABB Environmental Systems	CCT-II/completed 12/94	84
LIMB Demonstration Project Extension and Coolside Demonstration	The Babcock & Wilcox Company	CCT-I/completed 8/91	88
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	The Babcock & Wilcox Company	CCT-II/completed 5/93	92
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Energy and Environmental Research Corporation	CCT-I/completed 10/94	96
Milliken Clean Coal Technology Demonstration Project	New York State Electric & Gas Corporation	CCT-IV/completed 6/98	78
Integrated Dry NO_x/SO_2 Emissions Control System	Public Service Company of Colorado	CCT-III/completed 12/96	100
Advanced Electric Power Generation			
Fluidized-Bed Combustion			
McIntosh Unit 4A PCFB Demonstration Project	City of Lakeland, Lakeland Electric	CCT-III/design	106
McIntosh Unit 4B Topped PCFB Demonstration Project	City of Lakeland, Lakeland Electric	CCT-V/design	108
JEA Large Scale CFB Combustion Demonstration Project	JEA	CCT-I/design	110

▨ Shaded area indicates projects having completed operations.

Exhibit 10 (continued)

Project Fact Sheets by Application Category

Project	Participant	Solicitation/Status	Page
Tidd PFBC Demonstration Project	The Ohio Power Company	CCT-I/completed 3/95	112
Nucla CFB Demonstration Project	Tri-State Generation and Transmission Association, Inc.	CCT-I/completed 1/91	116
Integrated Gasification Combined Cycle			
Clean Energy Demonstration Project	Clean Energy Partners Limited Partnership	CCT-V/design	122
Piñon Pine IGCC Power Project	Sierra Pacific Power Company	CCT-IV/operational	124
Tampa Electric Integrated Gasification Combined-Cycle Project	Tampa Electric Company	CCT-III/operational	126
Wabash River Coal Gasification Repowering Project	Wabash River Coal Gasification Repowering Project Joint Venture	CCT-IV/operational	128
Advanced Combustion/Heat Engines			
Healy Clean Coal Project	Alaska Industrial Development and Export Authority	CCT-III/operational	132
Clean Coal Diesel Demonstration Project	Arthur D. Little, Inc.	CCT-V/construction	134
Coal Processing for Clean Fuels			
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Air Products Liquid Phase Conversion Company, L.P.	CCT-III/operational	138
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Custom Coals International	CCT-IV/operational	140
Advanced Coal Conversion Process Demonstration	Rosebud SynCoal Partnership	CCT-I/operational	142
Development of the Coal Quality Expert™	ABB Combustion Engineering, Inc., and CQ Inc.	CCT-I/completed 12/95	144
ENCOAL® Mild Coal Gasification Project	ENCOAL Corporation	CCT-III/completed 7/97	148
Industrial Applications			
Blast Furnace Granular-Coal Injection System Demonstration Project	Bethlehem Steel Corporation	CCT-III/operational	154
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	CPICOR™ Management Company, L.L.C.	CCT-V/design	156
Pulse Combustor Design Qualification Test	ThermoChem, Inc.	CCT-IV/construction	166
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Coal Tech Corporation	CCT-I/completed 5/90	158
Cement Kiln Flue Gas Recovery Scrubber	Passamaquoddy Tribe	CCT-II/completed 9/93	162

▨ Shaded area indicates projects having completed operations.

Exhibit 11

Project Fact Sheets by Participant

Participant	Project	Location	Page
ABB Combustion Engineering, Inc., and CQ Inc.	Development of the Coal Quality Expert™	Homer City, PA	144
ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	Niles, OH	84
Air Products Liquid Phase Conversion Company, L.P.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Kingsport, TN	138
AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	West Paducah, KY	28
Alaska Industrial Development and Export Authority	Healy Clean Coal Project	Healy, AK	132
Arthur D. Little, Inc.	Clean Coal Diesel Demonstration Project	Fairbanks, AK	134
The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	Cassville, WI	52
The Babcock & Wilcox Company	Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	Aberdeen, OH	56
The Babcock & Wilcox Company	LIMB Demonstration Project Extension and Coolside Demonstration	Lorain, OH	88
The Babcock & Wilcox Company	SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	Dilles Bottom, OH	92
Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Seward, PA	32
Bethlehem Steel Corporation	Blast Furnace Granular-Coal Injection System Demonstration Project	Burns Harbor, IN	154
City of Lakeland, Lakeland Electric	McIntosh Unit 4A PCFB Demonstration Project	Lakeland, FL	106
City of Lakeland, Lakeland Electric	McIntosh Unit 4B Topped PCFB Demonstration Project	Lakeland, FL	108
Clean Energy Partners Limited Partnership	Clean Energy Demonstration Project	Grand Tower, IL	122
Coal Tech Corporation	Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Williamsport, PA	158
CPICOR™ Management Company, L.L.C.	Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Vineyard, UT	156
Custom Coals International	Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Central City, PA	140
ENCOAL Corporation	ENCOAL® Mild Coal Gasification Project	Gillette, WY	148
Energy and Environmental Research Corporation	Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Hennepin, IL Springfield, IL	96
Energy and Environmental Research Corporation	Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	Denver, CO	60
JEA	JEA Large-Scale CFB Combustion Demonstration Project	Jacksonville, FL	110
LIFAC–North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	Richmond, IN	36
New York State Electric & Gas Corporation	Micronized Coal Reburning Demonstration for NO_x Control	Lansing, NY	50

Exhibit 11 (continued)
Project Fact Sheets by Participant

Participant	Project	Location	Page
New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	Lansing, NY	78
NOXSO Corporation	Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System	To be determined	82
The Ohio Power Company	Tidd PFBC Demonstration Project	Brilliant, OH	112
Passamaquoddy Tribe	Cement Kiln Flue Gas Recovery Scrubber	Thomaston, ME	162
Public Service Company of Colorado	Integrated Dry NO_x/SO_2 Emissions Control System	Denver, CO	100
Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	Chesterton, IN	40
Rosebud SynCoal Partnership	Advanced Coal Conversion Process Demonstration	Colstrip, MT	142
Sierra Pacific Power Company	Piñon Pine IGCC Power Project	Reno, NV	124
Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Coosa, GA	72
Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Newnan, GA	44
Southern Company Services, Inc.	Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers	Pensacola, FL	64
Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	Lynn Haven, FL	68
Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	Mulberry, FL	126
ThermoChem, Inc.	Pulse Combustor Design Qualification Test	Baltimore, MD	166
Tri-State Generation and Transmission Association, Inc.	Nucla CFB Demonstration Project	Nucla, CO	116
Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	West Terre Haute, IN	128

Environmental Control Devices
SO_2 Control Technology

10-MWe Demonstration of Gas Suspension Absorption

Project completed.

Participant

AirPol, Inc.

Additional Team Members

FLS miljo, Inc. (FLS) —technology owner
Tennessee Valley Authority—cofunder and site owner

Location

West Paducah, McCracken County, KY

Technology

FLS' Gas Suspension Absorption (GSA) system for flue gas desulfurization (FGD)

Plant Capacity/Production

10-MWe equivalent slipstream of flue gas from a 175-MWe wall-fired boiler

Coal

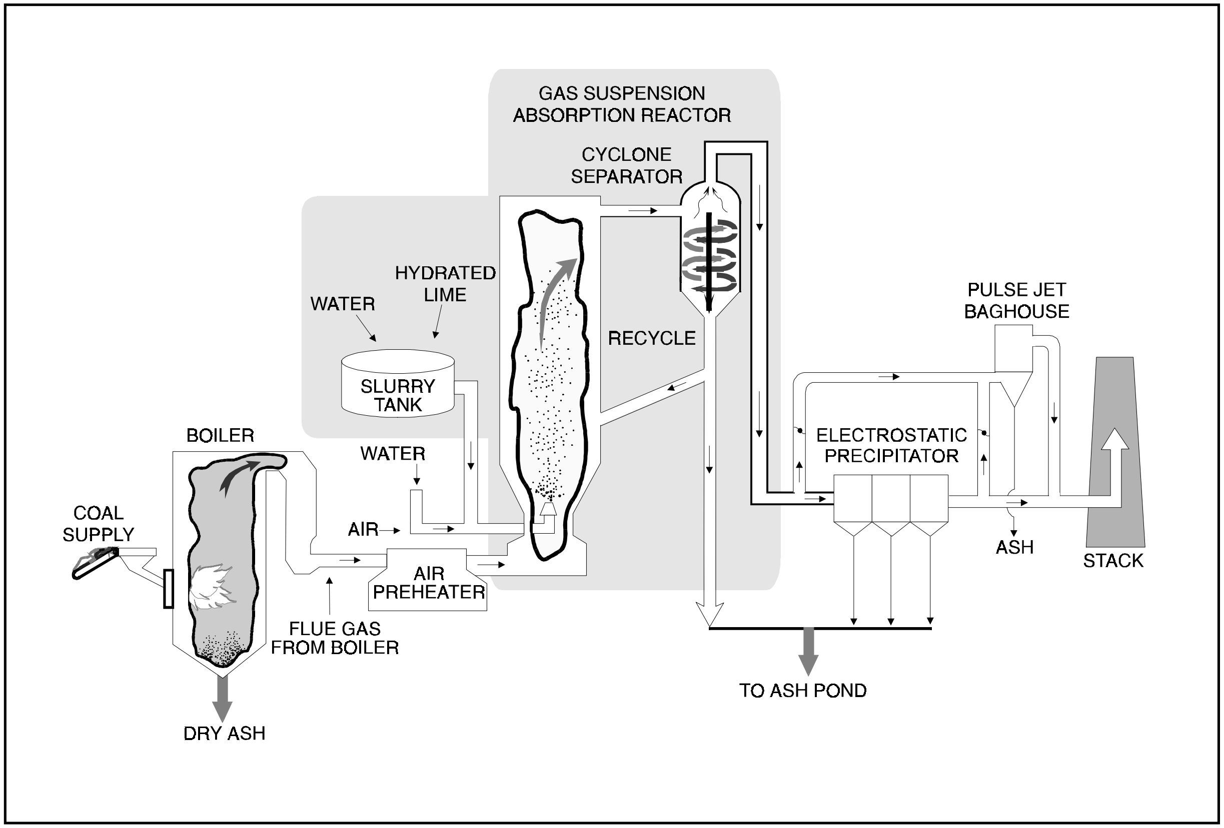
Western Kentucky bituminous—
  Peabody Martwick, 3.05% sulfur
  Emerald Energy, 2.61% sulfur
  Andalax, 3.06% sulfur
Warrior Basin, 3.5% sulfur (used intermittently)

Project Funding

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

Project Objective

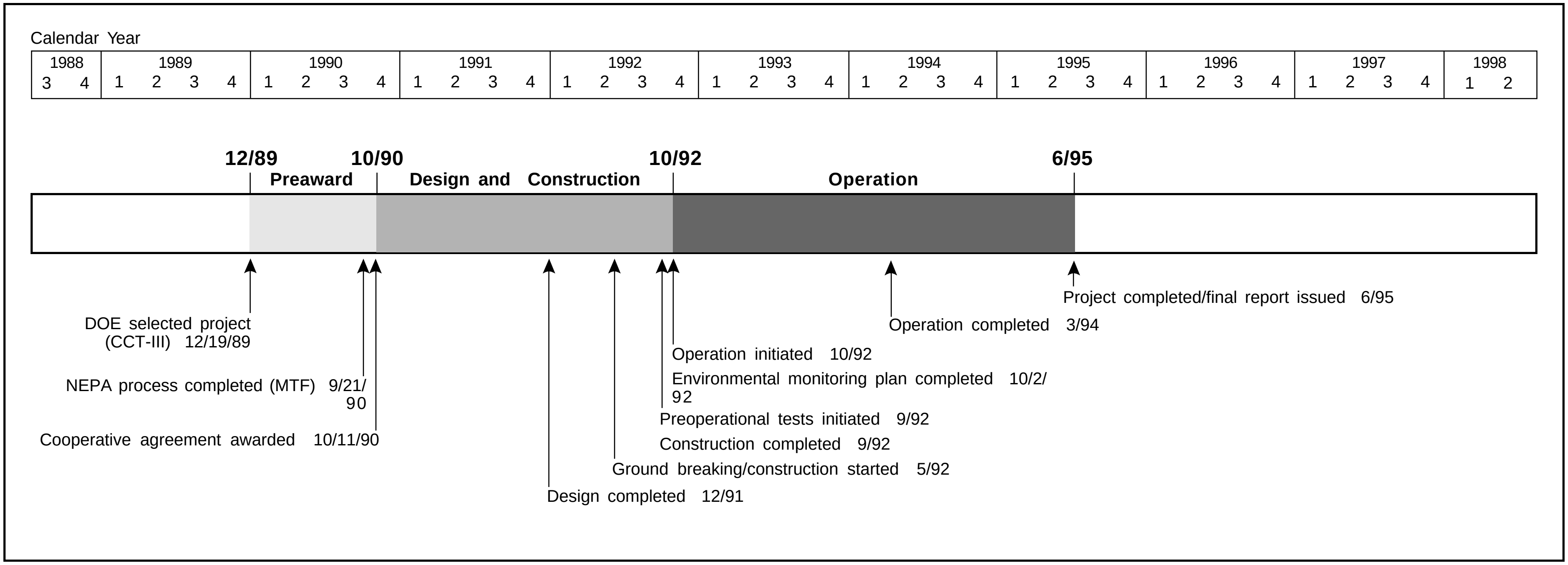
To demonstrate the applicability of Gas Suspension Absorption as an economic option for achieving Phase II CAAA SO_2 compliance on pulverized coal-fired boilers using high-sulfur coal.



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) or pulse jet baghouse (PJBH) 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.

A test program was structured to (1) optimize design of the GSA reactor for reduction of SO_2 emissions from boilers using high-sulfur coal and (2) evaluate the environmental control capability, economic potential, and mechanical performance of GSA. A statistically designed parametric (factorial) test plan was developed involving six variables. Beyond evaluation of the basic GSA unit to control SO_2, air toxic control tests were conducted, and the effectiveness of a GSA/ESP and GSA/PJBH to control both SO_2 and particulate were tested. Factorial tests were followed by continuous runs to verify consistency of performance over



time.

Results Summary

Environmental

- Ca/S molar ratio had the greatest effect on SO_2 removal, with approach-to-saturation temperature next, followed closely by chloride content.
- GSA/ESP achieved
  - 90% sulfur capture at a Ca/S molar ratio of 1.3 with 8 ºF approach-to-saturation and 0.04% chloride,
  - 90% sulfur capture at a Ca/S molar ratio of 1.4 with 18 ºF approach-to-saturation and 0.12% chloride, and
  - 99.9+% average particulate removal efficiency.
- GSA/PJBH achieved
  - 96% sulfur capture at a Ca/S molar ratio of 1.4 with 18 ºF approach-to-saturation and 0.12% chloride,
  - 3–5% increase in SO_2 reduction relative to GSA/ESP, and
  - 99.99+% average particulate removal efficiency.
- GSA/ESP and GSA/PJBH removed 98% of the hydrogen chloride (HCl), 96% of the hydrogen fluoride (HF), and 99% on more of most trace metals, except cadmium, antimony, mercury, and selenium. (GSA/PJBH removed 99+% of the selenium.)
- The solid by-product was usable as low-grade cement.

Operational

- GSA/ESP lime utilization averaged 66.1% and GSA/PJBH averaged 70.5%.
- The reactor achieved the same performance as a conventional spray dryer, but at one-quarter to one-third the size.
- GSA generated lower particulate loading than a conventional spray dryer, enabling compliance with a lower ESP efficiency.
- Special steels were not required in construction, and only a single spray nozzle is needed.
- High availability and reliability similar to other commercial applications were demonstrated, reflecting simple design.

Economic

- Capital and levelized (15-year) costs for GSA in-

	Capital Cost (1990 $/kW)	**Levelized Cost (mills/kWh)**
GSA—3 units at 50% capacity	149	10.35
WLFO	216	13.04

stalled in a 300-MWe plant using 2.6% sulfur coal are compared below to costs for a wet limestone scrubber with forced oxidation (WLFO scrubber). EPRI's TAG™ cost method was used. Based on EPRI cost studies of FGD processes, the capital cost (1990$) for a conventional spray dryer was $172/kW.

Project Summary

The GSA capability of suspending a high concentration of solids, effectively drying the solids, and recirculating the solids at a high rate with precise control results in SO_2 control comparable to that of wet scrubbers and high lime utilization. The high concentration of solids provides the sorbent/SO_2 contact area. The drying enables low approach-to-saturation temperature and chloride usage. The rapid, precise, integral recycle system sustains the high solids concentration. The high lime utilization mitigates the largest operating cost (lime) and further reduces costs by reducing the amount of by-product generated. The GSA is distinguished from the average spray dryer by its modest size, simple means of introducing reagent to the reactor, direct means of recirculating unused lime, and low reagent consumption. Also, injected slurry coats recycled solids, not the walls, avoiding corrosion and enabling use of carbon steel in fabrication.

Environmental Performance

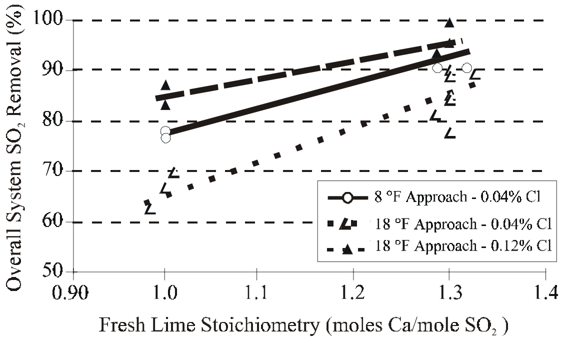
Exhibit 12 lists the six variables used in the factorial tests and the levels at which they were applied. Inlet flue gas temperature was held constant at 320 °F. Factorial testing showed that lime stoichiometry had the greatest effect on SO_2 removal. Approach-to-saturation temperature was the next most important factor, followed closely by chloride levels. Although an approach-to-saturation temperature of 8 °F was achieved without plugging the system, the test was conducted at a very low chloride level (0.04%). Because water evaporation rates decrease as chloride levels increase, an 18 °F approach-to-saturation temperature was chosen for the higher 0.12% coal chloride level. Exhibit 13 summarizes key results from factorial testing.

Exhibit 12
Variables and Levels Used in GSA Factorial Testing

Variable	Level
Approach-to-saturation temperature (°F)	8*, 18, 28
Ca/S (moles $Ca(OH)_2$/mole inlet SO_2)	1.00 and 1.30
Flyash loading (gr/ft^3, actual)	0.50 and 2.0
Coal chloride level (%)	0.04 and 0.12
Flue gas flow rate (10^3 scfm)	14 and 20
Recycle screw speed (rpm)	30 and 45

*8 °F was only run at the low coal chloride level.

Exhibit 13
GSA Factorial Testing Results



Note: All tests were conducted at a 320 °F inlet flue gas temperature.

A 28-day continuous run to evaluate the GSA/ESP configuration was made with bituminous coals averaging 2.7% sulfur, 0.12% chloride levels, and 18 °F approach-to-saturation temperature. A subsequent 14-day continuous run to evaluate the GSA/PJBH configuration was performed under the same conditions as those of the 28-day run, except for adjustments in flyash injection rate from 1.5–1.0 gr/ft^3 (actual).

The 28-day run on the GSA/ESP system showed that the overall SO_2 removal efficiency averaged slightly more than 90%, very close to the set point of 91%, at an average Ca/S molar ratio of 1.40–1.45 moles $Ca(OH)_2$/mole inlet SO_2. The system was able to adjust rapidly to the surge in inlet SO_2 caused by switching to 3.5% sulfur Warrior Basin coal for a week. Lime utilization averaged 66.1%. The particulate removal efficiency averaged 99.9+% and emission rates were maintained below 0.015 lb/10^6 Btu. The 14-day run on the GSA/PJBH system showed that the SO_2 removal efficiency averaged more than 96% at an average Ca/S molar ratio of 1.34–1.43 moles $Ca(OH)_2$/mole inlet SO_2. Lime utilization averaged 70.5%. The particulate removal efficiency averaged 99.99+% and emission rates ranged from 0.001–0.003 lb/10^6 Btu.

All air toxic tests were conducted with 2.7% sulfur, low-chloride coal with a 12 °F approach-to-saturation temperature and a high flyash loading of 2.0 gr/ft^3 (actual). The GSA/ESP arrangement indicated average removal efficiencies of greater than 99% for arsenic, barium, chromium, lead, and vanadium; somewhat less for manganese; and less than 99% for antimony, cadmium, mercury, and selenium. The GSA/PJBH configuration showed 99+% removal efficiencies for arsenic, barium, chromium, lead, manganese, selenium, and vanadium; with cadmium removal much lower and mercury removal lower than that of the GSA/ESP system. The removal of HCl and HF was dependent upon the utilization of lime slurry and was relatively independent of particulate control configuration. Removal efficiencies were greater than 98% for HCl and 96% for HF.

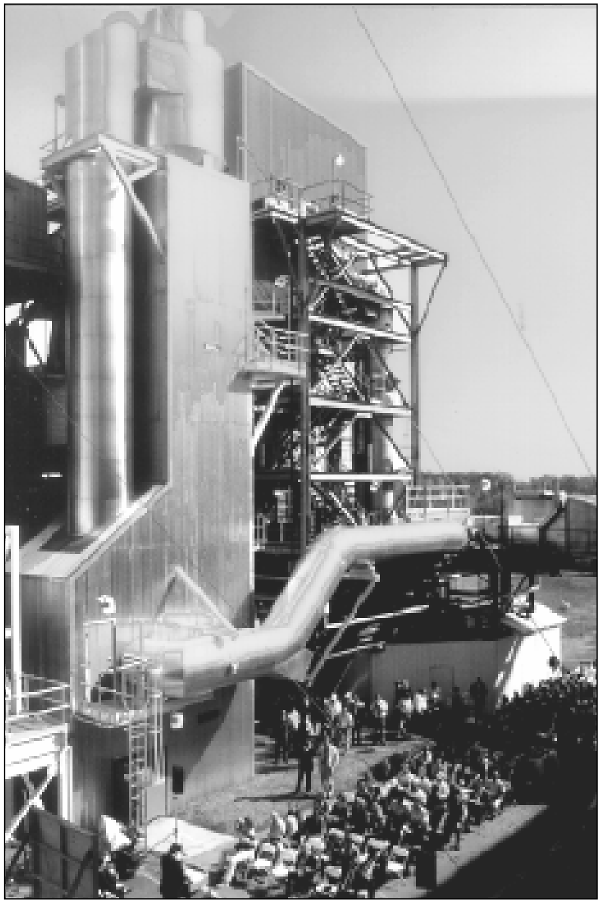
Operational Performance

Because the GSA system has suspended recycle solids to provide a contact area for SO_2 capture, multiple high-pressure atomizer nozzles or high-speed rotary nozzles to achieve uniform, fine droplet size are not required. Also, recycle of solids is direct and avoids recycling material in the feed slurry, which would necessitate expensive abrasion-resistant materials in the atomizer(s).

The high heat and mass transfer characteristics of the GSA enable the GSA system to be significantly smaller than a conventional spray dryer for the same capacity—one-quarter to one-third the size. This makes retrofit feasible for space-confined plants and reduces installation cost. The GSA system slurry is sprayed on the recycled solids, not the reactor walls, avoiding direct wall contact and the need for corrosion-resistant alloy steels. Furthermore, the high concentration of rapidly moving solids scours the reactor walls and mitigates scaling. The GSA system generates a significantly lower grain loading than a conventional spray dryer—2–5 gr/ft^3 for GSA versus 6–10 gr/ft^3 for a spray dryer—enabling compliance even with lower ESP particulate removal efficiency. The GSA system produces a solid by-product containing very low moisture. This material contains both fly ash and unreacted lime. With the addition of water, the by-product undergoes a pozzolanic reaction, essentially providing the characteristics of a low-grade cement.

Economic Performance

Using the EPRI costing methodology applied to 30 to 35 other FGD processes, economics were estimated for a moderately difficult retrofit of a 300-MWe boiler burning 2.6% sulfur coal. The design SO_2 removal efficiency was 90% at a lime feed rate equivalent to 1.30 moles of Ca/mole inlet SO_2. Lime was assumed to be 2.8 times the cost of limestone. It was determined that (1) capital cost (1990$) was $149/kW with three units at 50% capacity and (2) levelized cost (15-year) was 10.35 mills/kWh with three units at 50% capacity.



▲ AirPol, Inc. successfully demonstrated the GSA system at TVA's Center for Emissions Research.

A cost comparison run for a WLFO scrubber showed the capital and levelized costs to be $216/kW and 13.04 mills/kWh, respectively. The capital cost listed in EPRI cost tables for a conventional spray dryer at 300-MWe and 2.6% sulfur coal was $172/kW (1990$). Also, because the GSA requires less power and has better lime utilization than a spray dryer, the GSA will have a lower operating cost.

Commercial Applications

The low capital cost, moderate operating cost, and high SO_2 capture efficiency make the GSA system particularly attractive as a CAAA compliance option for boilers in the 50–250-MWe range. Other major advantages include the modest space requirements comparable to duct injection systems, high availability/reliability owing to design simplicity, and low dust loading, minimizing particulate upgrade costs.

GSA market entry was significantly enhanced with the sale of a 50-MWe unit, worth $10 million, to the city of Hamilton, OH, subsidized by the Ohio Coal Development Office. A sale worth $1.3 million has been made to the U.S. Army for hazardous waste disposal. A GSA system has been sold to a Swedish iron ore sinter plant. Sales to Taiwan and India have a combined value of $5.5 million.

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- *10-MW Demonstration of the Gas Suspension Absorption Final Public Design Report*. Report No. DOE/PC/90542-T10. AirPol, Inc. June 1995. (Available from

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 equivalent

Coal

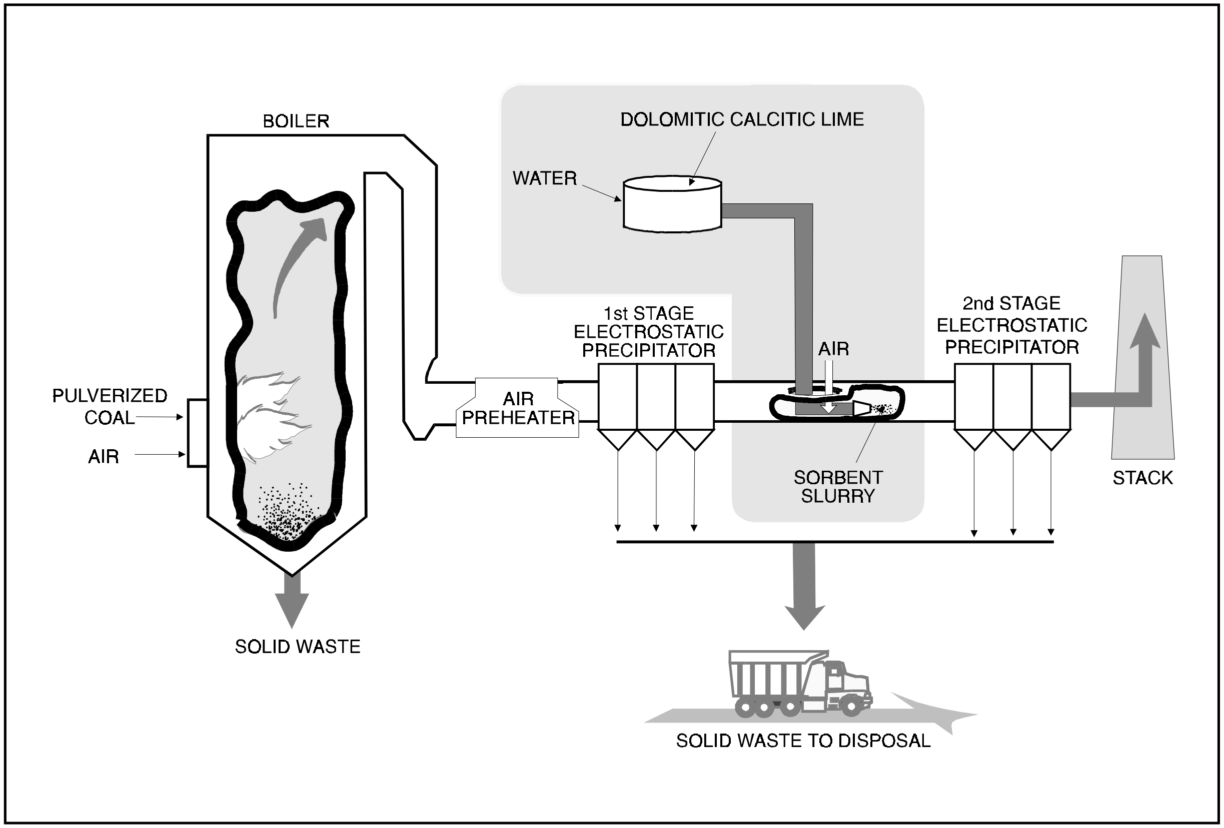
Pennsylvania bituminous, 1.2–2.5% sulfur

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 quickly 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

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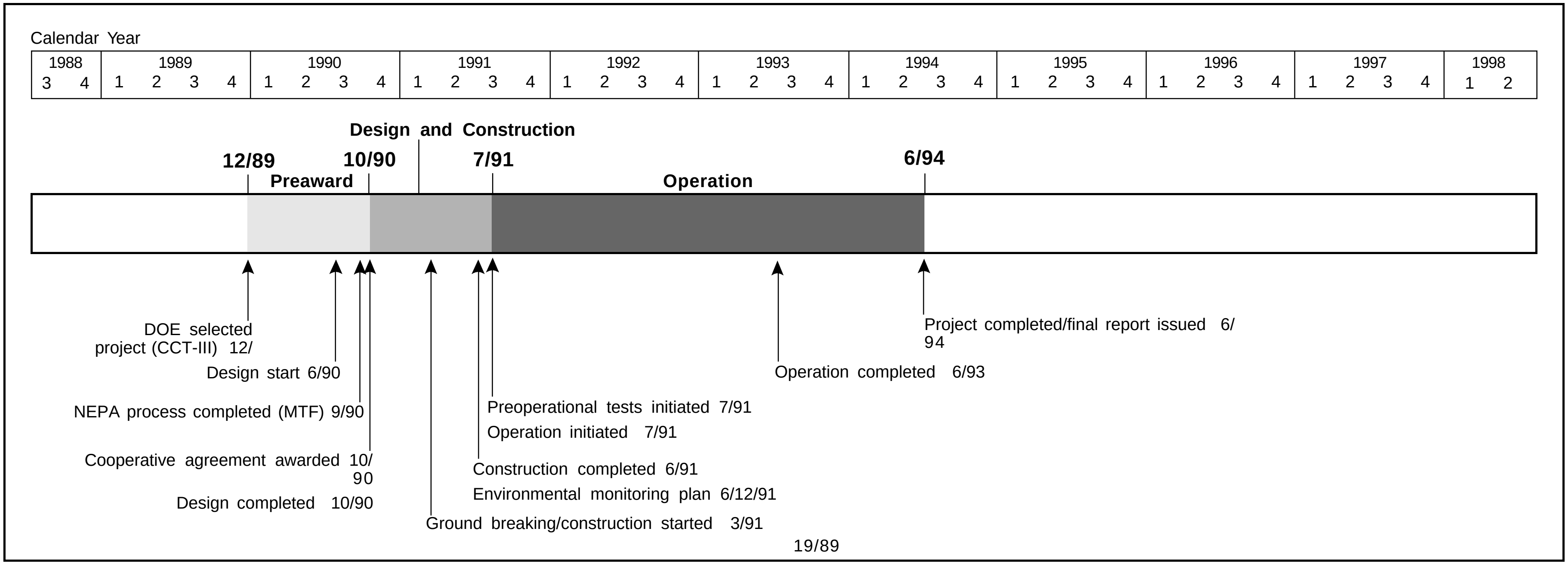
*Additional project overrun costs were funded 100% by the participant for a final total project cost of $12,173,000.



capacity of the 147-MWe Unit No. 5 was routed through a modified, longer duct between the first- and second-stage ESPs.

Results Summary

Environmental

- Pressure-hydrated dolomitic lime proved to be a more effective sorbent than either dry hydrated calcitic lime or freshly slaked calcitic lime.
- Sorbent injection rate was the most influential parameter on SO_2 capture. Flue gas temperature was the limiting factor on injection rate. For SO_2 capture efficiency of 50% or more, a flue gas temperature of 300 ºF or more was needed.
- Slurry concentration for a given sorbent did not increase SO_2 removal efficiency beyond a certain threshold concentration.
- Testing indicated that SO_2 removal efficiencies of 50% or more were achievable with flue gas temperatures of 300–310 ºF (full load), sorbent injection rate of 52–57 gal/min, residence time of 2 seconds, and a pressure-hydrated dolomitic-lime concentration of about 9%.
- For operating conditions at Seward Station, data indicated that for 40–50% SO_2 removal, a 6–8% lime or dolomitic lime slurry concentration, and a stoichiometric ratio of 2–2.5 resulted in a 40–50% lime utilization rate. That is, 2–2.5 moles of CaO or CaO•MgO were required for every mole of SO_2 removed.
- Assuming 92% lime purity, 1.9–2.4 tons of lime was required for every ton of SO_2 removed.

Operational

- About 100 ft of straight duct was required to assure the 2-second residence time needed for effective CZD/FGD operation.
- At Seward Station, stack opacity was not detrimentally affected by CZD/FGD.
- Availability of CZD/FGD was very good.
- Some CZD/FGD modification will be necessary to assure consistent SO_2 removal and avoid deposition of solids within the ductwork during upsets.

Economic

- Capital cost of a 500-MWe system operating on 4%

sulfur coal and achieving 50% SO_2 reduction was estimated at less than $30/kW and operating cost at $300/ton of SO_2 removed (1994$).

Project Summary

The principle of the CZD/FGD is to form a wet zone of slurry droplets in the middle of a duct confined in an envelope of hot gas between the wet zone and the hot gas. The lime slurry reacts with part of the SO_2 in the gas and the reaction products dry to form solid particles. An ESP, downstream from the point of injection, captures the reaction products along with the fly ash entrained in the flue gas.

CZD/FGD did not require a special reactor, simply a modification to the ductwork. Use of the commercially available Type S pressure-hydrated dolomitic lime reduced residence time requirements for CZD/FGD and enhanced sorbent utilization. The increased humidity of CZD/FGD processed flue gas enhanced ESP performance, eliminating the need for upgrades to handle the increased particulate load.

Bechtel began its 18-month, two-part test program for the CZD process in July 1991, with the first 12 months of the test program consisting primarily of parametric testing and the last 6 months consisting of continuous operational testing. During the continuous operational test period, the system was operated under fully automatic control by the host utility boiler operators. The new atomizing nozzles were thoroughly tested both outside and inside the duct prior to testing. The SO_2 removal parametric test program, which began in October 1991, was completed in August 1992.

Specific objectives were as follows:

- Achieve projected SO_2 removal of 50%
- Realize SO_2 removal costs of less than $300/ton
- Eliminate negative effects on normal boiler operations without increasing particulate emissions and opacity

▲ Bechtel's demonstration showed that 50% SO_2 removal efficiency was possible using CZD/FGD technology. The extended duct into which lime slurry was injected is in the foreground.

The parametric tests included duct injection of atomized lime slurry made of dry hydrated calcitic lime, freshly slaked calcitic lime, and pressure-hydrated dolomitic lime. All three reagents remove SO_2 from the flue gas but require different feed concentrations of lime slurry for the same percentage of SO_2 removed. The most efficient removals and easiest to operate system were obtained using pressure-hydrated dolomitic lime.

Environmental Performance

Sorbent injection rate proved to be the most influential factor on SO_2 capture. The rate of injection possible was limited by the flue gas temperature. This impacted a portion of the demonstration when air leakage caused flue gas temperature to drop from 300–310 ºF to 260–280 ºF. At 300–310 ºF, injection rates of 52–57 gal/min were possible and SO_2 reductions greater than 50% were achieved. At 260–280 ºF, injection rates had to be dropped to 30–40 gal/min, resulting in a 15–30% drop in SO_2 removal efficiency. Slurry concentration for a given sorbent did not increase SO_2 removal efficiency beyond a certain threshold concentration. For example, with pressure-hydrated dolomitic lime, slurry concentrations above 9% did not increase SO_2 capture efficiency.

Parametric tests indicated that SO_2 removals above 50% are possible under the following conditions: flue gas temperature of 300–310 ºF; boiler load of 145–147-MWe; residence time in the duct of 2 seconds; and lime slurry injection rate of 52–57 gal/min.

Operational Performance

The percentage of lime utilization in the CZD/FGD significantly affected the total cost of SO_2 removal. An analysis of the continuous operational data indicated that the percentage of lime utilization was directly dependent on two key factors:

- Percentage of SO_2 removed
- Lime slurry feed concentration

For operating conditions at Seward Station, data indicated that for 40–50% SO_2 removal, a 6–8% lime or dolomitic lime slurry concentration, and a stoichiometric ratio of 2–2.5 resulted in a 40–50% lime utilization rate. That is, 2–2.5 moles of CaO or CaO•MgO were required for every mole of SO_2 removed; or assuming 92% lime purity, 1.9–2.4 tons of lime were required for every ton of SO_2 removed. In summary, the demonstration showed the following results:

- A 50% SO_2 removal efficiency with CZD/FGD was possible.
- Drying and SO_2 absorption required a residence time of 2 seconds, which required a long and straight horizontal gas duct of about 100 feet.
- The fully automated system integrated with the

power plant operation demonstrated that the CZD/FGD process responded well to automated control operation. However, modifications to the CZD/FGD were required to assure consistent SO_2 removal and avoid deposition of solids within the gas duct during upsets.

- Availability of the system was very good.
- At Seward Station, stack opacity was not detrimentally affected by the CZD/FGD system.

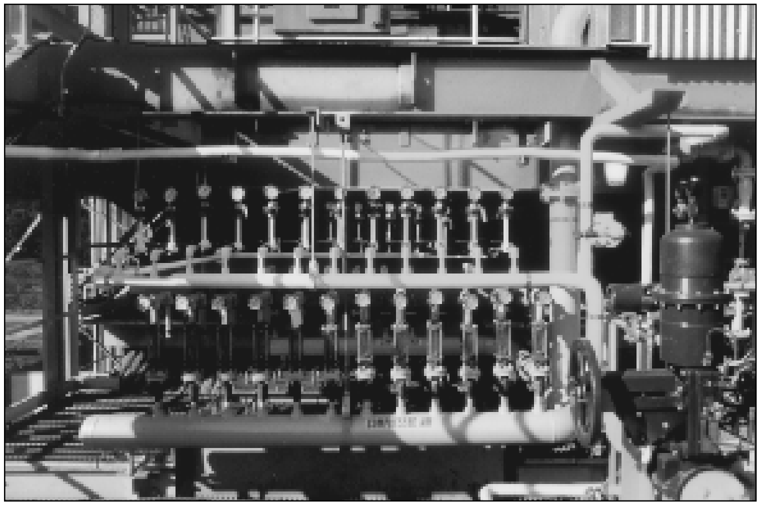
Economic Performance

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 50% SO_2 removal, the total capital cost is estimated to be less than $30/kW (1994$).

Commercial Applications

After the conclusion of the DOE-funded CZD/FGD demonstration project at Seward Station, the CZD/FGD system was modified to improve SO_2 removal during continuous operation while following daily load cycles. Bechtel and the host utility, Pennsylvania Electric Company, continued the CZD/FGD demonstration for an additional year. Results showed that CZD/FGD operation at SO_2 removal rates lower than 50% could be sustained over long periods without significant process problems.

CZD/FGD can be used for retrofit of existing plants and installation in new utility boiler flue gas facilities to remove SO_2 from a wide variety of sulfur-containing coals. A CZD/FGD 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/FGD technology is particularly well suited for retrofitting existing boilers, independent of type, age, or size. The CZD/FGD installation does not require major power station alterations and can be easily and economically integrated into existing power plants.



▲ This photo shows the CZD/FGD lime slurry injector control system.

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- *Comprehensive Report to Congress on the Clean Coal Technology Program: Confined Zone Dispersion Flue Gas Desulfurization Demonstration.* Bechtel Corporation. Report No. DOE/FE-0203P. U.S. Department of Energy. September 1990. (Available from NTIS as DE91002564.)

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 and Light—cofunder and host utility
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

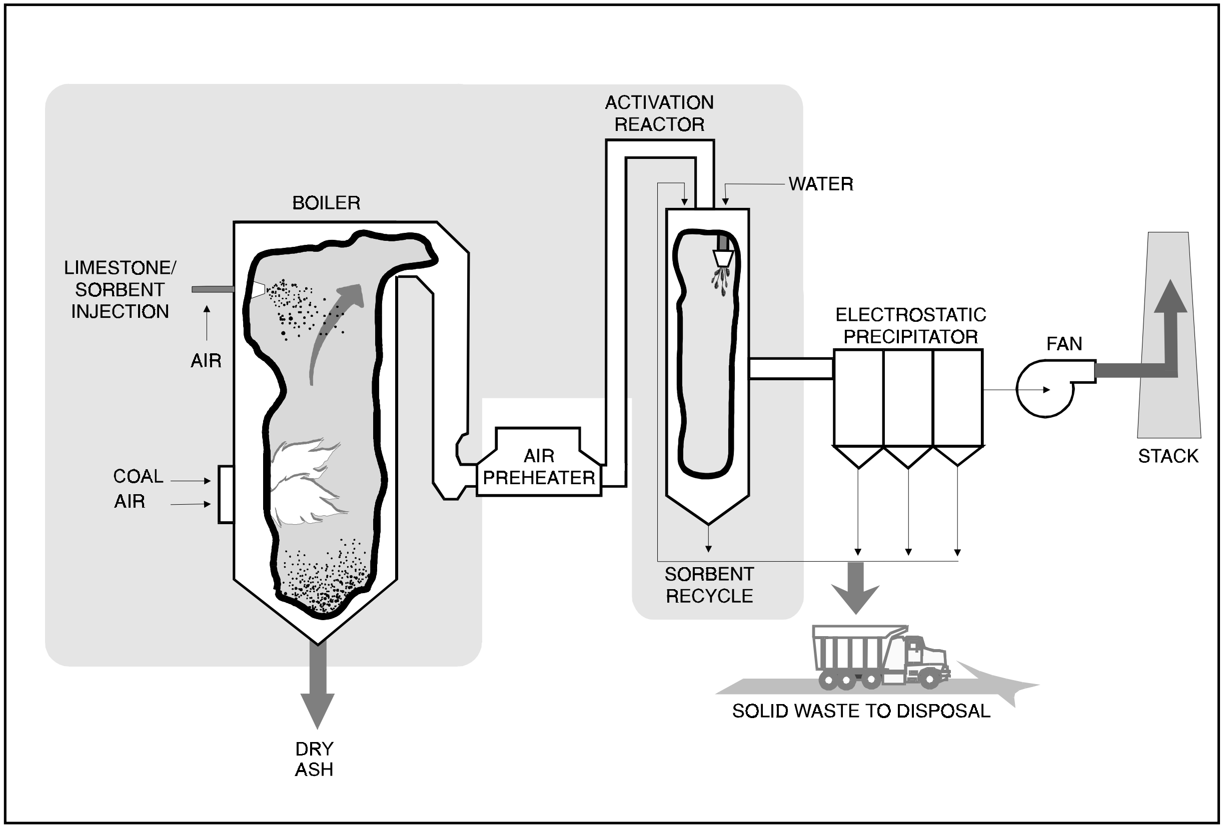
60-MWe

Coal

Bituminous, 2.0–2.8% sulfur

Project Funding

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



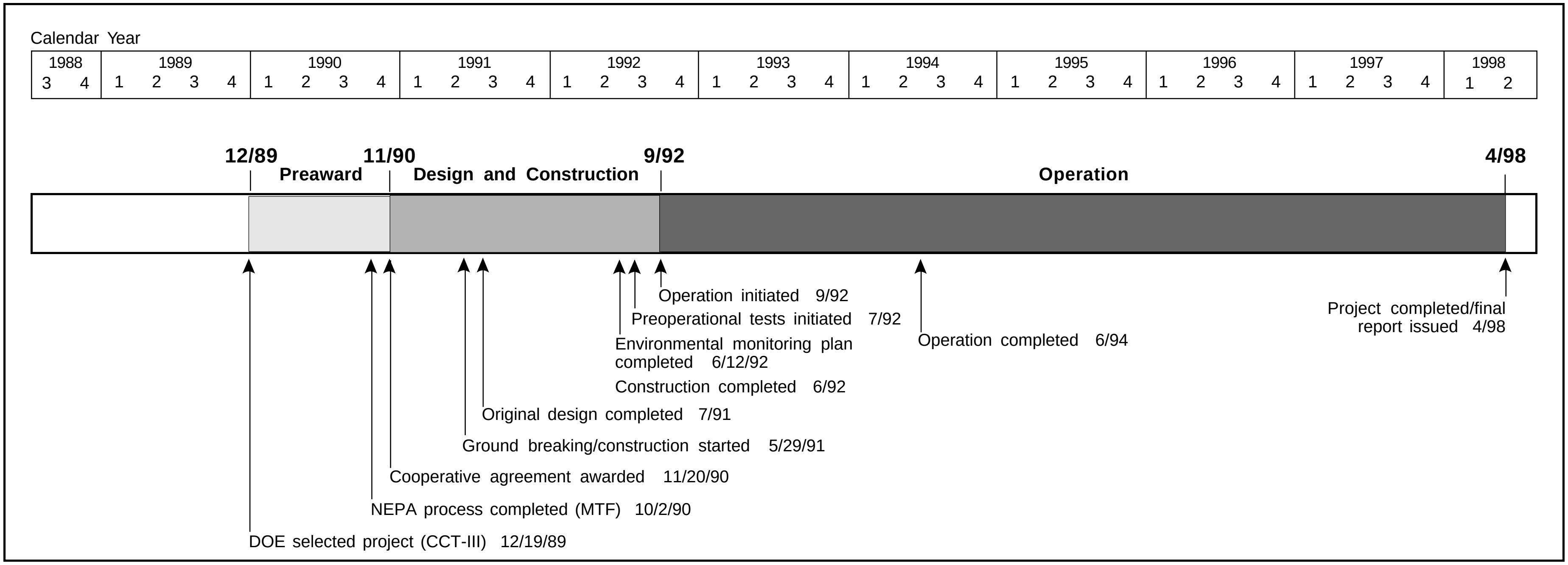
Project Objective

To demonstrate that electric power plants—especially those with space limitations and 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 electrostatic precipitator are 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.



Results Summary

Environmental

- SO_2 removal efficiency was 70% at a calcium-to-sulfur (Ca/S) molar ratio of 2.0, approach-to-saturation temperature of 7–12 ºF, and limestone fineness of 80% minus 325 mesh.
- SO_2 removal efficiency with limestone fineness of 80% minus 200 mesh was 15% lower at a Ca/S molar ratio of 2.0 and 7–12 ºF approach to saturation.
- The four parameters having the greatest influence on sulfur removal efficiency were limestone fineness, Ca/S molar ratio, approach-to-saturation temperature, and ESP ash recycle rate.
- ESP ash recycle rate was limited in the demonstration system configuration. Increasing the recycle rate and sustaining a 5 ºF approach-to-saturation temperature was projected to increase SO_2 removal efficiency to 85% at a Ca/S molar ratio of 2.0 (fine limestone).
- ESP efficiency and operating levels were essentially unaffected by LIFAC operation during steady-state operation.
- Fly and bottom ash were dry and readily disposed of at a local landfill. The quantity of additional solid waste can be determined by assuming that approximately 4.3 tons of limestone is required to remove 1.0 ton of SO_2.

Operational

- When operating with fine limestone (80% minus 325 mesh), the soot-blowing cycle had to be reduced from 6.0 to 4.5 hours.
- Automated programmable logic and simple design make the LIFAC system easy to operate in start-up, shutdown, or normal duty cycles.
- The amount of bottom ash increased slightly, but there was no negative impact on the ash-handling system.

Economic

- Capital cost—$66/kW for two LIFAC reactors (300-MWe); $76/kW for one LIFAC reactor (150-MWe); $99/kW for one LIFAC reactor (65-MWe) (1994$).

- Operating cost—$65/ton of SO_2 removal, assuming 75% SO_2 capture, Ca/S molar ratio of 2.0, limestone composed of 95% $CaCO_3$, and $15/ton.

Project Summary

The LIFAC technology was designed to enhance the effectiveness of dry sorbent injection systems for SO_2 control and to maintain the desirable aspects of low capital cost and compactness for ease of retrofit. Furthermore, limestone was used as the sorbent (about 1/3 of the cost of lime) and a sorbent recycle system was incorporated to reduce operating costs.

The process evaluation test plan was composed of five distinct phases each having its own objectives. These tests were as follows:

- Baseline tests characterized the operation of the host boiler and associated subsystems prior to LIFAC operations.
- Parametric tests were designed to evaluate the many possible combinations of LIFAC process parameters and their effect on SO_2 removal.
- Optimization tests were performed after the parametric tests to evaluate the reliability and operability of the LIFAC process over short, continuous operating periods.
- Long-term tests were performed to demonstrate LIFAC’s performance under commercial operating conditions.
- Post-LIFAC tests involved repeating the baseline test to identify any changes caused by the LIFAC system.

The coals used during the demonstration varied in sulfur content from 1.4–2.8%. However, most of the testing was conducted with the higher sulfur coals (2.0–2.8% sulfur).

Environmental Performance

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

While injecting the fine limestone, the soot blowing frequency had to be increased from 6-hour to 4.5-hour cycle periods. The coarse-quality limestone did not affect soot blowing but was found to be more abrasive on the feed and transport hoses.

Parametric tests indicated that a 70% SO_2 reduction was achievable with a Ca/S molar ratio of 2.0. ESP ash containing unspent 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 was found to affect SO_2 capture. During a brief test, it was found that increasing the recycle rate by 50% resulted in a 5% increase in SO_2 removal efficiency. It was estimated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5 ºF above saturation temperature, an SO_2 reduction of 85% could be maintained.

Operational Performance

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 molar ratio of 2.0 was selected to attain SO_2 reductions above 70%. Reactor bottom temperature was about 5 ºF 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 the long-term tests included the degree of humidification, grind size of the high-calcium-

▲ The LIFAC system successfully demonstrated at Whitewater Valley Station Unit No. 2 is being retained by Richmond Power & Light for commercial use with high-sulfur coal. There are 10 full-scale LIFAC units in Canada, China, Finland, Russia, and the United States.

▲ The top of the LIFAC reactor is shown being lifted into place. During 2,800 hours of operation, long-term testing showed that SO_2 reductions of 70% or more could be sustained under normal boiler operation.

content limestone, and recycle 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 amount of boiler bottom ash increased slightly during testing, but there was no negative impact on the power plant's bottom and flyash removal system. 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 proved to be highly operable because it has few moving parts and is simple to operate. The process can be easily shut down and restarted. The process is automated by a programmable logic system, which regulates process control loops, interlocking, start-up, shutdowns, and data collection. The entire LIFAC process was easily managed via two personal computers located in the host utility's control room.

Economic Performance

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

- $99/kW for one LIFAC reactor at Whitewater Valley Station (65-MWe) (1994$)
- $76/kW for one LIFAC reactor at Shand Station (150-MWe)
- $66/kW for two LIFAC reactors at Shand Station (300-MWe)

Crushed limestone accounts for about one half of LIFAC's operating costs. LIFAC requires 4.3 tons of limestone to remove 1.0 ton of SO_2, assuming 75% SO_2 capture, a Ca/S molar ratio of 2.0, and limestone containing 95% $CaCO_3$. Assuming limestone costs of $15/ton, LIFAC's operating cost would be $65/ton of SO_2 removed.

Commercial Applications

There are 10 full-scale LIFAC units in operation in Canada, China, Finland, Russia, and the United States. The LIFAC system at Richmond Power & Light is the first to be applied to a power plant using high-sulfur (2.0–2.9%) coal. The LIFAC system is being retained by Richmond Power & Light at Whitewater Valley Station, Unit No. 2. The other LIFAC installations on power plants are using bituminous and lignite coals having lower sulfur contents (0.6–1.5%).

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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, Unit Nos. 7 and 8)

Technology

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

Plant Capacity/Production

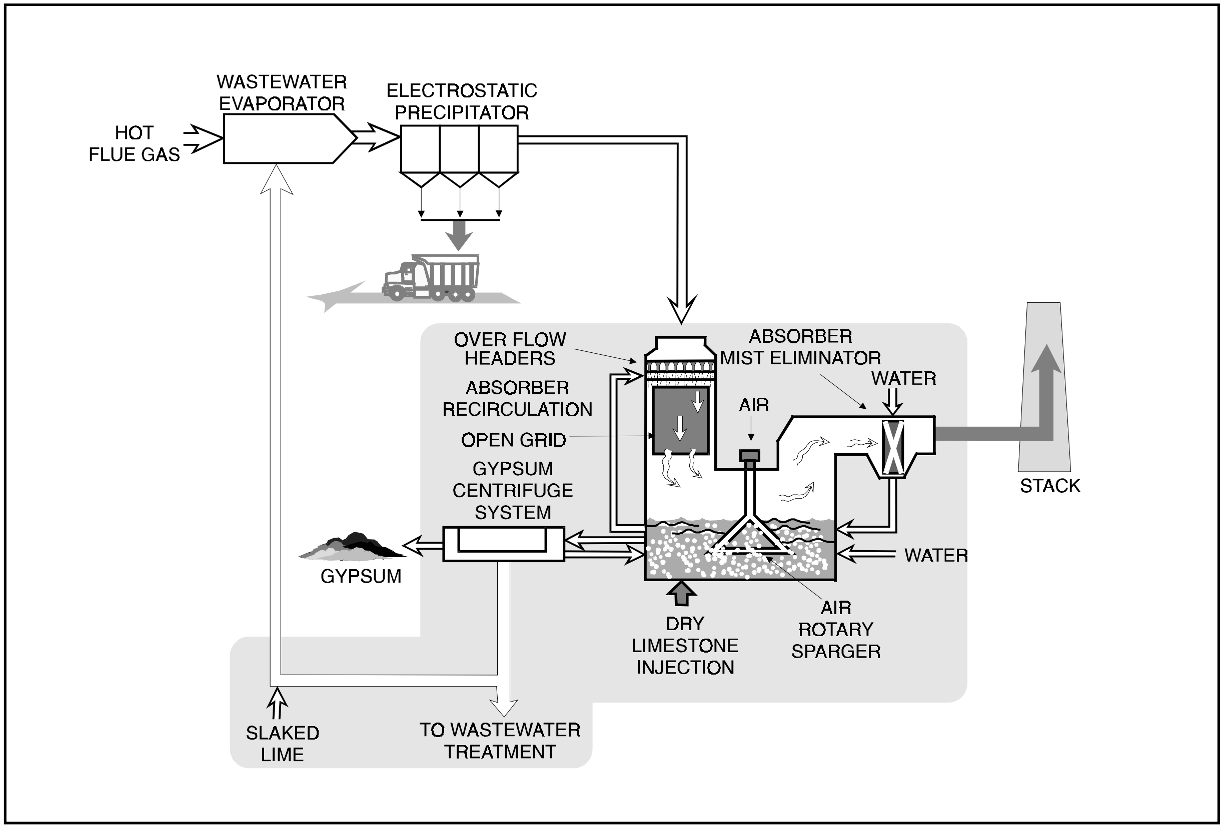
528-MWe

Coal

Bituminous, 2.0–4.5% sulfur

Project Funding

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



Project Objective

To reduce SO_2 emissions by 95% or more at approximately one-half the cost of conventional scrubbing technology, significantly reduce space requirements, and create no new waste streams.

Technology/Project Description

Pure Air built a single SO_2 absorber for a 528-MWe power plant. Although the largest capacity absorber module of its time in the United States, space requirements were modest because no spare or backup absorber modules were required. The absorber performed three functions in a single vessel: prequenching, absorbering, and oxidation of sludge to gypsum. Additionally, the absorber was 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 that in conventional scrubbers. These features all combined to yield a state-of-the-art SO_2 absorber that was more compact and less expensive than contemporary conventional scrubbers.

Other technical features included 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 combined the functions of agitation and air distribution into one piece of equipment to facilitate the oxidation of calcium sulfite to gypsum.

Pure Air also demonstrated a unique gypsum agglomeration process, PowerChip®, to significantly enhance handling characteristics of adsorbed flue gas

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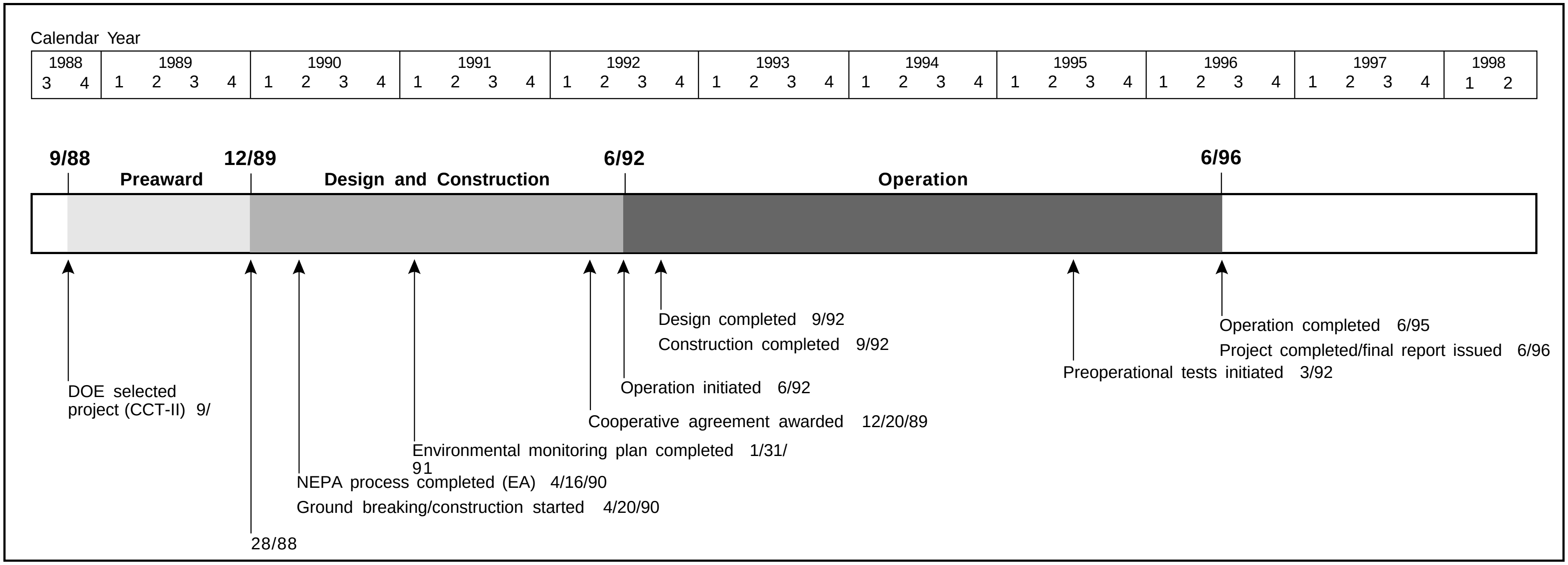
PowerChip is a registered trademark of Pure Air on the Lake, L.P.



desulfurization (AFGD)-derived gypsum.

Results Summary

Environmental

- AFGD design enabled a single 600-MWe absorber module without spares to remove 95% or more SO_2 at availabilities of 99.5% when operating with high-sulfur coals.
- Wallboard-grade gypsum was produced in lieu of solid waste, and all gypsum produced was sold commercially.
- The wastewater evaporation system (WES) mitigated expected increases in wastewater generation associated with gypsum production and showed the potential for achieving zero wastewater discharge (only a partial- capacity WES was installed).
- PowerChip® increased the market potential for AFGD- derived gypsum by cost effectively converting it to a product with the handling characteristics of natural rock gypsum.
- Air toxics testing established that all acid gases were effectively captured and neutralized by the AFGD. Trace elements largely became constituents of the solids streams (bottom ash, fly ash, gypsum product). Some boron, selenium, and mercury passed to the stack gas in a vapor state.

Operational

- AFGD use of co-current, high-velocity flow; integration of functions; and a unique air rotary sparger proved to be highly efficient, reliable (to the exclusion of requiring a spare module), and compact. The compactness, combined with no need for a spare module, significantly reduced space requirements.
- The own-and-operate contractual arrangement whereby Pure Air took on the turnkey, financing, operating and maintenance risks through performance guarantees was successful.

Economic

- Capital costs and space requirements for AFGD were about half those of contemporary systems.

Project Summary

The project proved that single absorber modules of advanced design could process large volumes of flue gas and provide the required availability and reliability without the usual spares. The major performance objectives were met.

Over the 3-year demonstration, the AFGD unit accumulated 26,280 hours of operation with an availability of 99.5%. Approximately 237,000 tons of SO_2 were removed, with capture efficiencies of 95% or more, and over 210,000 tons of salable gypsum were produced. The AFGD continues commercial service, which includes sale of all by-product gypsum to U.S. Gypsum's East Chicago, IN, wallboard production plant.

Environmental Performance

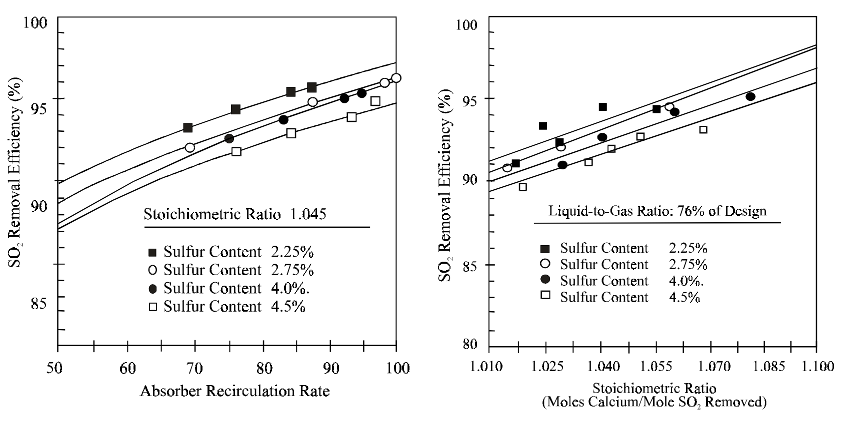
Testing over the 3-year period clearly established that AFGD operating within its design parameters (without additives) could consistently achieve 95% SO_2 reduction or more with 2.0–4.5% sulfur coals. The design range for the calcium-to-sulfur stoichiometric ratio was 1.01–1.07, with the upper value set by gypsum purity requirements (i.e., amount of unreacted reagent allowed in the gypsum). Another key control parameter was the ratio L/G, which is the amount of reagent slurry injected into the absorber grid (L) to the volume of flue gas (G). The design L/G range was 50–128 gal/10^3 ft^3. The lower end was determined by solids settling rates in the slurry and the requirement for full wetting of the grid packing. The high end was determined by where performance leveled out.

Five coals with differing sulfur contents were selected for parametric testing to examine SO_2 removal efficiency as a function of load, sulfur content, stoichiometric ratio, and L/G. Loads tested were 33%, 67%, and 100%. High removal efficiencies, well above 95%, at loads of 33% and 67% were possible with low to moderate stoichiometric ratio and L/G settings, even for 4.5% sulfur coal. Exhibit 14 summarizes the results of parametric testing at full load.

Exhibit 14

SO_2 Removal Performance

(100% Boiler Load)



In the AFGD process, chlorides that would have been released to the air are captured and potentially become a wastewater problem. This was mitigated by the addition of the WES which takes a portion of the wastewater stream with high chloride and sulfate levels and injects it into the ductwork upstream of the ESP. The hot flue gas evaporated the water and the dissolved solids were captured in the ESP. Problems were experienced early on, with the WES nozzles failing to provide adequate atomization and plugging as well. This was resolved by replacing the original single-fluid nozzles with dual fluid systems employing air as the second fluid.

Commercial-grade gypsum quality (95.6–99.7%) was maintained throughout testing, even at the lower sulfur concentrations where the ratio of fly ash to gypsum increases due to lower sulfate availability. The primary importance of producing a commercial-grade gypsum is avoidance of the environmental and economic consequences of disposal. The marketability of the gypsum is dependent upon whether users are in range of economic transport and whether they can handle the gypsum by-product. For these reasons, PowerChip® technology was demonstrated as part of the project. This technology uses a compression mill to convert the highly cohesive AFGD gypsum cake into a flaked product with handling characteristics equivalent to natural rock gypsum. The process avoids use of binders, pre-drying or pre-calcining normally associated with briquetting and is 30–55% cheaper at $2.50–$4.10/ton.

Air toxics testing established that all acid gases are effectively captured and neutralized by the AFGD. Trace elements largely become constituents of the solids streams (bottom ash, fly ash, gypsum product). Some boron, selenium, and mercury pass to the stack gas in a vapor state.

Operational Performance

Availability over the 3-year operating period averaged 99.5% while maintaining an average SO_2 removal efficiency of 94%. This was attributable to the simple, effective design and an effective operating/maintenance philosophy. Modifications were also made to the AFGD system. An example was the implementation of new alloy technology, C-276 alloy over carbon steel clad material, to replace alloy wallpaper construction within the absorber tower wet/dry interface. Also, use of co-current rather than conventional counter-current flow resulted in lower pressure drops across the absorber and afforded the flexibility to increase gas flow without an abrupt drop in removal efficiency. AFGD SO_2 capture efficiency with limestone was comparable to that in wet scrubbers using lime, which is far more expensive. Twenty-four-hour power consumption was 5,275 kW, or 61% of expected consumption, and water consumption was 1,560 gal/min, or 52% of expected consumption.

Economic Performance

Exhibit 15 summarizes capital and levelized current dollar cost estimates for nine cases with varying plant capacity and coal sulfur content. A capacity factor of 65% and a sulfur removal efficiency of 90% were assumed. The calculation of levelized cost followed guidelines established in the Electric Power Research

Institute's Technical Assessment Guide.

The incremental benefits of the own-and-operate arrangement, by-product utilization, and emission allowances were also evaluated. Exhibit 16 depicts the relative costs of a hypothetical 500-MWe generating unit in the Midwest burning 4.3% sulfur coal with a base case conventional FGD system and four incremental cases. The horizontal lines in Exhibit 16 show the range of costs for a fuel-switching option. The lower bar is the cost of fuel delivered to the hypothetical midwest unit and the upper bar allows for some plant modifications to accommodate the compliance fuel.

Commercial Applications

AFGD is positioned well to compete in the pollution control arena of 2000 and beyond. AFGD has markedly reduced cost and demonstrated the ability to compete with fuel switching under certain circumstances even with a first-generation system. Advances in technology, e.g., in materials and components, should improve costs for AFGD. The own-and-operate business approach has done much to mitigate risk on the part of prospective users. High SO_2-capture efficiency places an AFGD user in the possible position of trading allowances or applying credits to other units within the utility. WES and PowerChip® mitigate or eliminate otherwise serious environmental concerns. AFGD effectively deals with hazardous air pollutants.

The project received *Power* magazine's 1993 Powerplant Award and the National Society of Professional Engineer's 1992 Outstanding Engineering Achievement Award.

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- *Advanced Flue Gas Desulfurization Project: Public Design Report.* Pure Air on the Lake, L.P. March 1990.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Flue Gas Desulfurization (AFGD) Demonstration Project.* (Pure Air on the Lake, L.P.) DOE/FE Report No. 0150. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004460.)

Exhibit 15

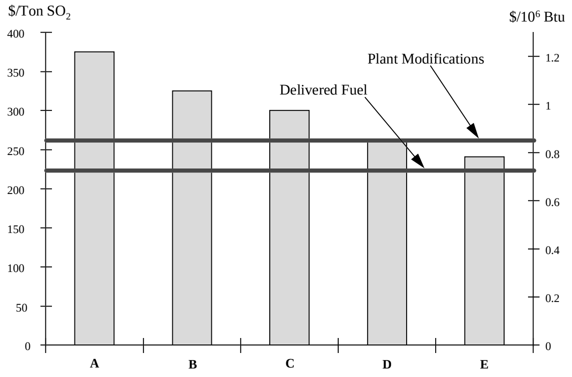
Estimated Costs for an AFGD System

(1995 Current Dollars)

Cases:	1	2	3	4	5	6	7	8	9
Plant size (MWe)	100	100	100	300	300	300	500	500	500
Coal sulfur content (%)	1.5	3.0	4.5	1.5	3.0	4.5	1.5	3.0	4.5
Capital cost ($/kW)	193	210	227	111	121	131	86	94	101
Levelized cost ($/ton SO_2)									
15-year life	1,518	840	603	720	401	294	536	302	223
20-year life	1,527	846	607	716	399	294	531	300	223
Levelized cost (mills/kWh)									
15-year life	16.39	18.15	19.55	7.78	8.65	9.54	5.79	6.52	7.24
20-year life	16.49	18.28	19.68	7.73	8.62	9.52	5.74	6.48	7.21

Exhibit 16

Flue Gas Desulfurization Economics



500-MWe plant, 30-yr levelized costs, allowance value of $300/ton

Incremental cases:

A—Conventional FGD (EPRI model)

B—AFGD, own-and-operate arrangement

C—Adds gypsum sales

D—Adds emission allowance credits at $300/ton, for 90% SO_2 removal

E—Increases SO_2 removal to 95%

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

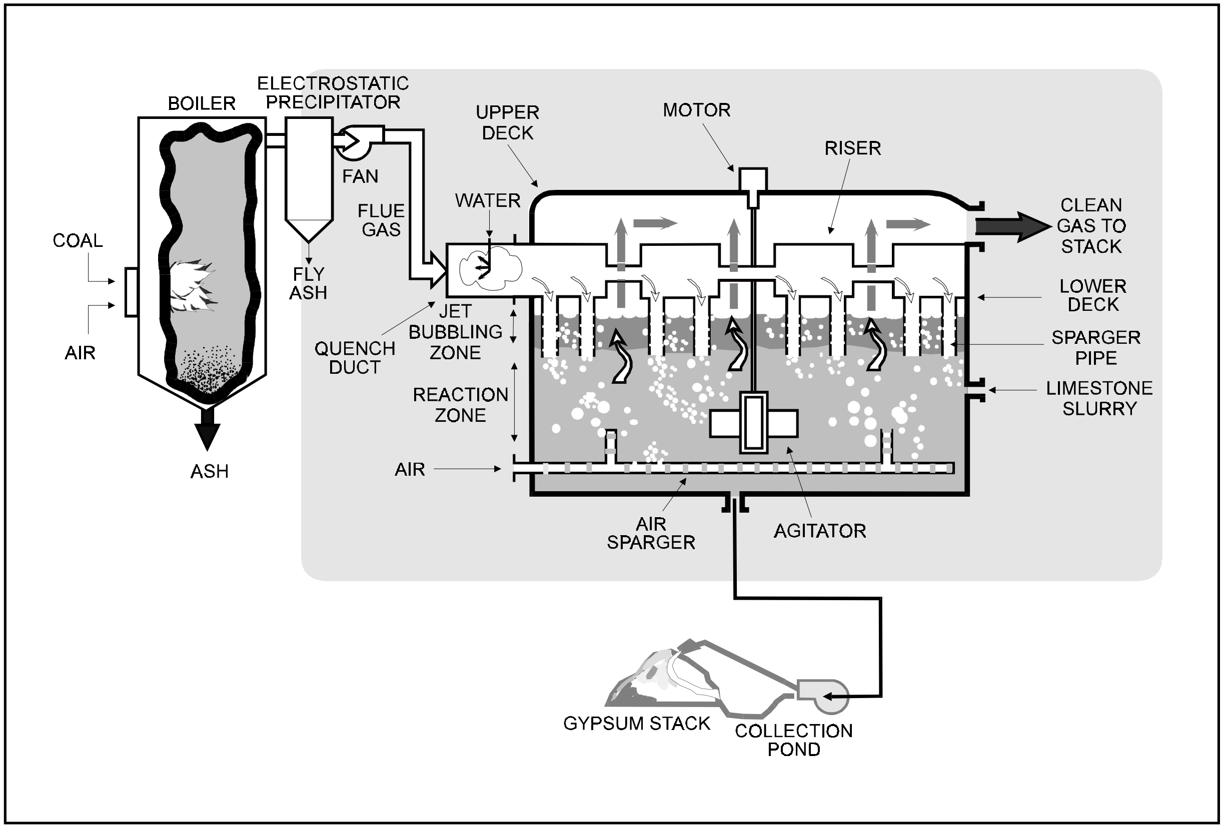
Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process

Plant Capacity/Production

100-MWe

Coal

Illinois No. 5 & No. 6 blend, 2.4% sulfur
Compliance, 1.2% sulfur



Project Funding

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

Project Objective

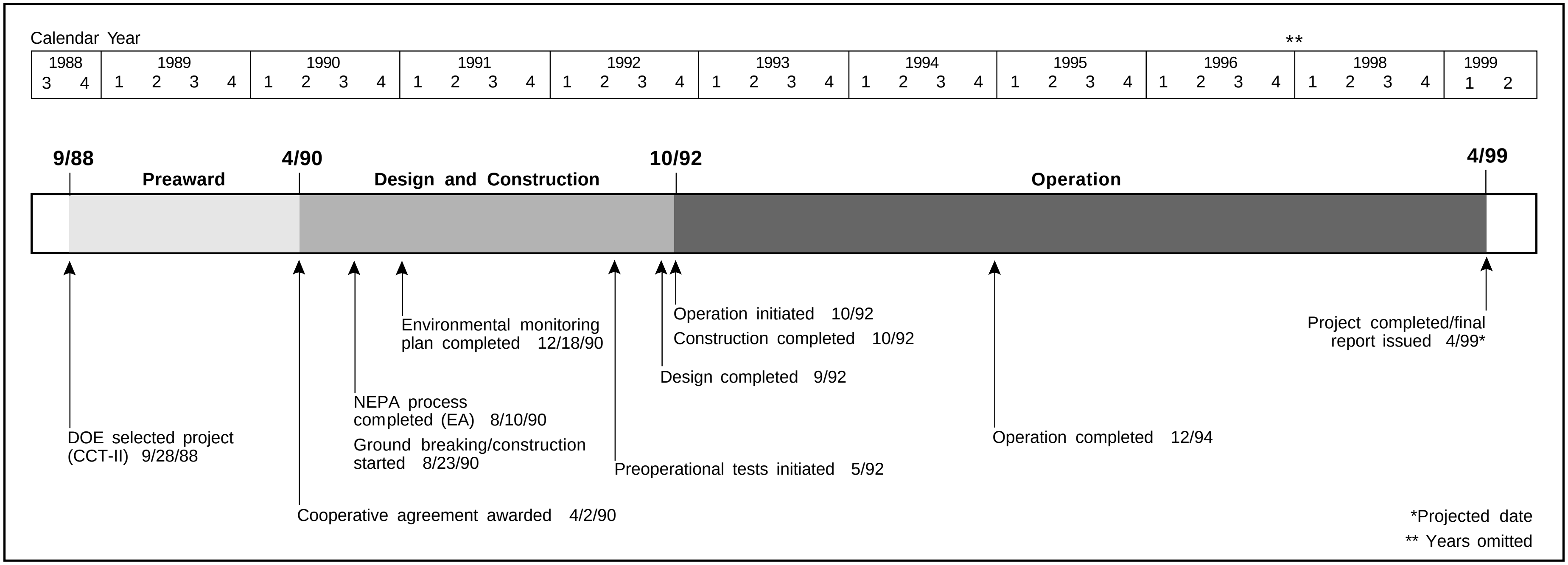
To demonstrate 90% SO_2 control at high reliability with and without simultaneous particulate control; to evaluate use of fiberglass-reinforced-plastic (FRP) vessels to eliminate flue gas reheat and spare absorber modules; and to evaluate use of gypsum to reduce waste management costs.

Technology/Project Description

The project demonstrated 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 diked area with gypsum slurry. Gypsum solids settle in the diked area by gravity, and clear water flows to a retention pond. The clear water from the pond is returned to the process.

Jet Bubbling Reactor is a registered trademark of the Chiyoda



Results Summary

Environmental

- Over 90% SO_2 removal efficiency was achieved at SO_2 inlet concentrations of 1,000–3,500 ppm with limestone utilization over 97%.
- JBR achieved particulate removal efficiencies of 97.7–99.3% for inlet mass loadings of 0.303–1.392 lb/10^6 Btu over a load range of 50–100-MWe.
- Capture efficiency was a function of particle size:
  - >10 microns—99% capture
  - 1–10 microns—90% capture
  - 0.5–1 micron—negligible capture
  - <0.5 micron—90% capture
- Hazardous air pollutant (HAP) testing showed greater than 95% capture of hydrogen chloride (HCl) and hydrogen fluoride (HF) gases, 80–98% capture of most trace metals, less than 50% capture of mercury and cadmium, and less than 70% capture of selenium.
- Gypsum stacking proved effective for producing wallboard/cement-grade gypsum.

Operational

- FRP-fabricated equipment proved durable both structurally and chemically, eliminating the need for a flue gas prescrubber and reheat.
- FRP construction combined with simplicity of design resulted in 97% availability at low ash loadings and 95% at high ash loadings, precluding the need for a spare reactor module.
- Simultaneous SO_2 and particulate control were achieved at flyash loadings reflective of an electrostatic (ESP) with marginal performance.

Economic

- Final results are not yet available. However, elimination of the need for flue gas prescrubbing, reheat, and spare module requirement should result in capital requirements far below those of contemporary conventional FGD systems.

Project Summary

The CT-121 process differs from the more common spray tower type of flue gas desulfurization systems in that a single process vessel is used in place of the usual spray tower/reaction tank/thickener arrangement. Pumping of reacted slurry to a gypsum transfer tank is intermittent. This allows crystal growth to proceed essentially uninterrupted resulting in large, easily dewatered gypsum crystals (conventional systems employ large centrifugal pumps to move reacted slurry causing crystal attrition and secondary nucleation).

The demonstration spanned 27 months, including start-up and shakedown, during which approximately 19,000 hours were logged. Exhibit 17 summarizes operating statistics. Elevated particulate loading included a short test with the electrostatic precipitator (ESP) completely deenergized, but the long-term testing was conducted with the ESP partially deenergized to simulate a more realistic scenario, i.e., a CT-121 retrofit to a

boiler with a marginally performing particulate collection device. The SO_2 removal efficiency was measured under five different inlet concentrations with coals averaging 2.4% sulfur and ranging from 1.2– 4.3% sulfur
(as burned).

Operating Performance

Use of FRP construction proved very successful. Because their large size precluded shipment, the JBR and limestone slurry storage tanks were constructed on site. Except for some erosion experienced at the JBR inlet transition duct, the FRP-fabricated equipment proved to be durable both structurally and chemically. Because of the high corrosion resistance, the need for a flue gas prescrubber to remove chlorides was eliminated. Similarly, the FRP-constructed chimney proved resistant to the corrosive condensates in wet flue gas, precluding the need for flue gas reheat.

Availability of the CT-121 scrubber during the low-ash test phase was 97%. Availability dropped to 95% under the elevated ash-loading conditions due largely to sparger tube plugging problems precipitated by flyash agglomeration on the sparger tube walls during high ash loading when the ESP was deenergized. The high reliability demonstrated verified that a spare JBR is not required in a commercial design offering.

Environmental Performance

Exhibit 18 shows SO_2 removal efficiency as a function of pressure drop across the JBR for five different inlet concentrations. The greater the pressure drop, the greater the depth of slurry traversed by the flue gas. As the SO_2 concentration increased, removal efficiency decreased, but adjustments in JBR fluid level could maintain the efficiency above 90% and, at lower SO_2 concentration levels, above 98%. Limestone utilization remained above 97% throughout the demonstration.

Long-term particulate capture performance was tested with a partially deenergized ESP (approximately 90% efficiency) and is summarized in Exhibit 19.

Analysis indicated that a large percentage of the outlet particulate matter is sulfate,

Exhibit 18
SO_2 Removal Efficiency

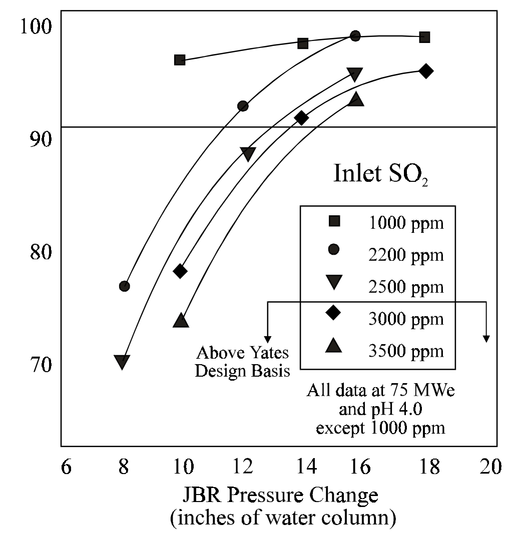


Exhibit 17
Operation of CT-121 Scrubber

	Low-Ash Phase	Elevated-Ash Phase	Cumulative for Project
Total test period (hr)	11,750	7,250	19,000
Scrubber available (hr)	11,430	6,310	18,340
Scrubber operating (hr)	8,600	5,210	13,810
Scrubber called upon (hr)	8,800	5,490	14,290
Reliability[a]	0.98	0.95	0.96
Availability[b]	0.97	0.95	0.97
Utilization[c]	0.73	0.72	0.75

[a] Reliability = hours scrubber operated divided by the hours called upon to operate
[b] Availability = hours scrubber available divided by the total hours in the period
[c] Utilization = hours scrubber operated divided by the total hours in the period

Exhibit 19
Particulate Capture Performance
(ESP Marginally Operating)

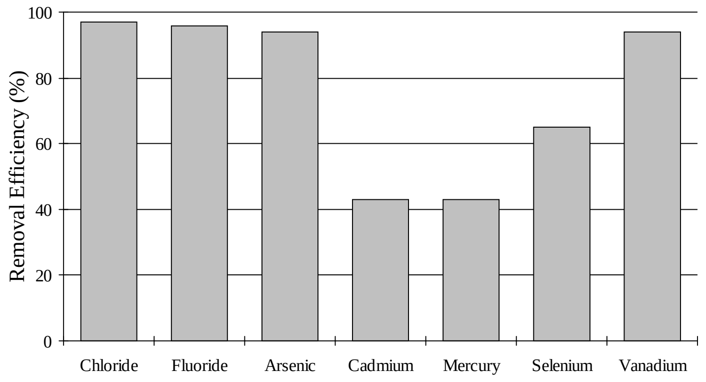
JBR Pressure Change (inches of water column)	Boiler Load (MWe)	Inlet Mass Loading ($lb/10^6$ Btu)	Outlet Mass Loading* ($lb/10^6$ Btu)	Removal Efficiency (%)
18	100	1.288	0.02	97.7
10	100	1.392	0.010	99.3
18	50	0.325	0.005	98.5
10	50	0.303	0.006	98.0

*Federal NSPS is 0.03 $lb/10^6$ Btu for units constructed after September 18, 1978. Plant Yates permit limit is 0.24 $lb/10^6$ Btu as an existing unit.

likely a result of acid mist and gypsum carryover. This reduces the estimate of ash mass loading at the outlet to approximately 70% of the measured outlet particulates.

For particulate sizes greater than 10 microns, capture efficiency was consistently greater than 99%. In the 1–10 micron range, capture efficiency was over 90%. Between 0.5 and 1 micron, the particulate removal dropped at times to negligible values possibly due to acid mist carryover entraining particulates in this size range. Below 0.5 micron, the capture efficiency increased to over 90%. Calculated HAP removals across the CT-121 JBR, based on the measurements taken during the demonstration, are shown in Exhibit 20.

Exhibit 20
CT-121 Air Toxics Removal
(JBR Components Only)



As to solids handling, the gypsum stacking method proved effective in the long term. Although chloride content was initially high in the stack due to the closed loop nature of the process (with concentrations often exceeding 35,000 ppm), a year later the chloride concentration in the gypsum dropped to less than 50 ppm, suitable for wallboard and cement applications. The reduction in chloride content was attributed to rainwater washing the stack.

▲ The unique Jet Bubbling Reactor® (center) was constructed from fiberglass-reinforced plastic.

Economic Performance

Although the final economic analyses are not yet available, it appears as though CT-121 technology offers significant economic advantages. FRP construction eliminates the need for prescrubbing and reheating flue gas. High system availability eliminates the need for a spare absorber module. Particulate removal capability precludes the need for expensive (capital-intensive) ESP upgrades to meet increasingly tough environmental regulations.

Commercial Applications

Involvement of Southern Company (which owns Southern Company Services, Inc.), with more than 20,000-MWe of coal-fired generating capacity, is expected to enhance confidence in the CT-121 process among other large high-sulfur-coal boiler users. 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.

Plant Yates continues to operate with the CT-121 scrubber as an integral part of the site's CAAA compliance strategy. Since the CCT Program demonstration, over 8,200 MWe equivalent of CT-121 FGD Capacity has been sold to 16 customers in seven countries.

The project received *Power* magazine's 1994 Powerplant Award. Other awards include the Society of Plastics Industries' 1995 Design Award for the mist eliminator, the Georgia Chapter of the Air and Waste Management Association's 1994 Outstanding Achievement Award, and the Georgia Chamber of Commerce's 1993 Environmental Award.

Contacts

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James U. Watts, DOE/FETC, (412) 892-5991

References

- *A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing an ESP while Demonstrating the CCT CT-121 FGD Project. Final Report.* Report No. DOE/PC/93253-T1. Radian Corporation. June 1994. (Available from NTIS as DE94016053.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Innovative Applications of Technology for the CT-121 FGD Process.* Southern Company Services, Inc. Report No. DOE/FE-0158. U.S. Department of Energy. February 1990. (Available from NTIS as DE9008116.)

Environmental Control Devices
NO_x Control Technology

Micronized Coal Reburning Demonstration for NO_x Control

Participant

New York State Electric & Gas Corporation

Additional Team Members

Eastman Kodak Company—host and cofunder
Consolidation Coal Company— tester
D.B. Riley—technology supplier
Fuller Company—technology supplier
Energy and Environmental Research Corporation—reburn system designer
New York State Energy Research and Development Authority—cofunder
Empire State Electric Energy Research Corporation—cofunder

Locations

Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station, Unit No. 1)
Rochester, Monroe County, NY (Eastman Kodak Company's Kodak Park Power Plant, Unit No. 15)

Technology

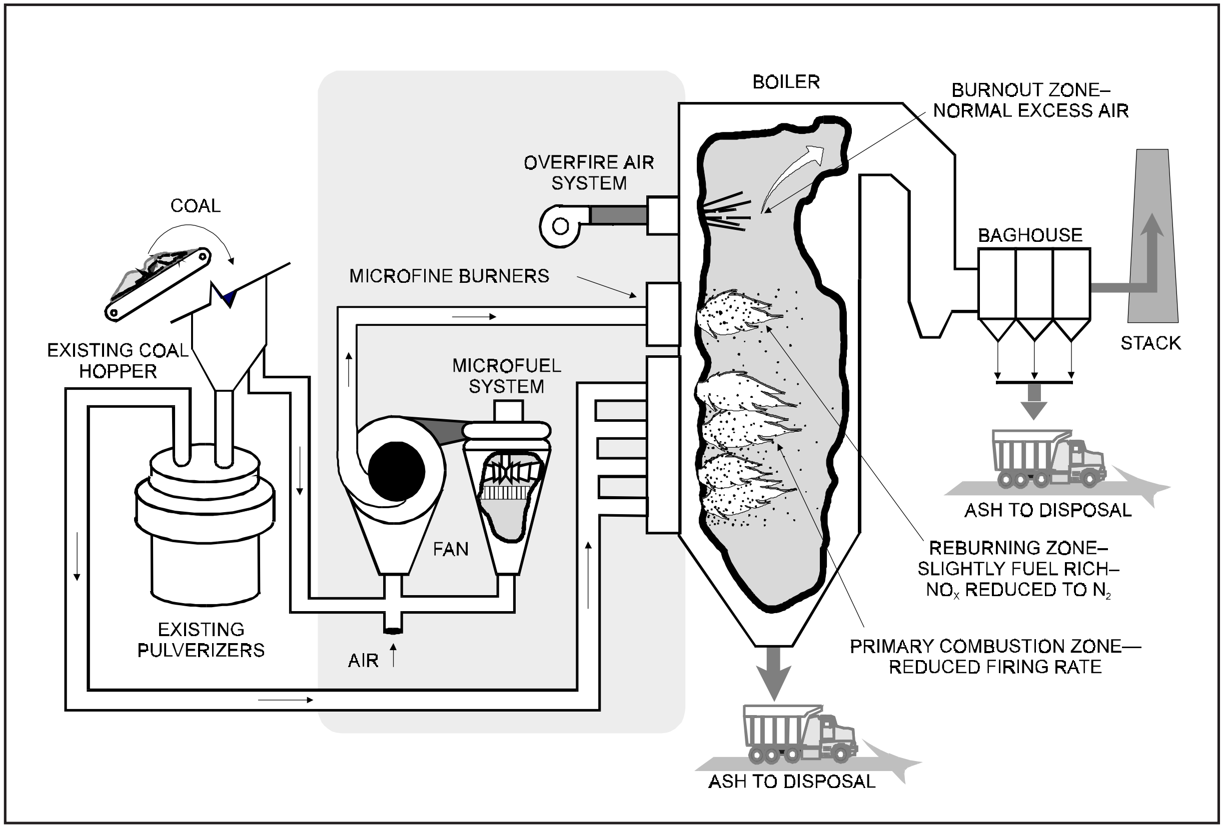
D.B. Riley's MPS mill (at Milliken Station) and Fuller's MicroMill™ (at Eastman Kodak) technologies for producing micronized coal

Plant Capacity/Production

Milliken Station: 148-MWe tangentially-fired boiler
Eastman Kodak Company: 50-MWe cyclone boiler

Coal

Pittsburgh seam bituminous, medium- to high-sulfur



Project Funding

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

Project Objective

To achieve at least 50% NO_x reduction with micronized coal reburning technology on a cyclone boiler; to achieve 25-35% NO_x reduction with micronized coal reburning technology in conjunction with low-NO_x burners on a tangentially-fired boiler; and to determine the effects of coal micronization on electrostatic precipitator (EPS) performance.

Technology/Project Description

The reburning coal, which can comprise up to 30% of the total fuel, is micronized (pulverized to achieve 80% below 325 mesh) and injected into a pulverized-coal-fired furnace above the primary combustion zone. Typical particle size generated in micronization is 20 microns, whereas normal pulverized coal particles are about 60 microns. This similar size increases surface area by nine fold.

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 of the coal fineness.

The combination of micronized coal, supplying up to 30% of the total furnace fuel requirements, advanced reburning, and fuel/air staging provides flexible options

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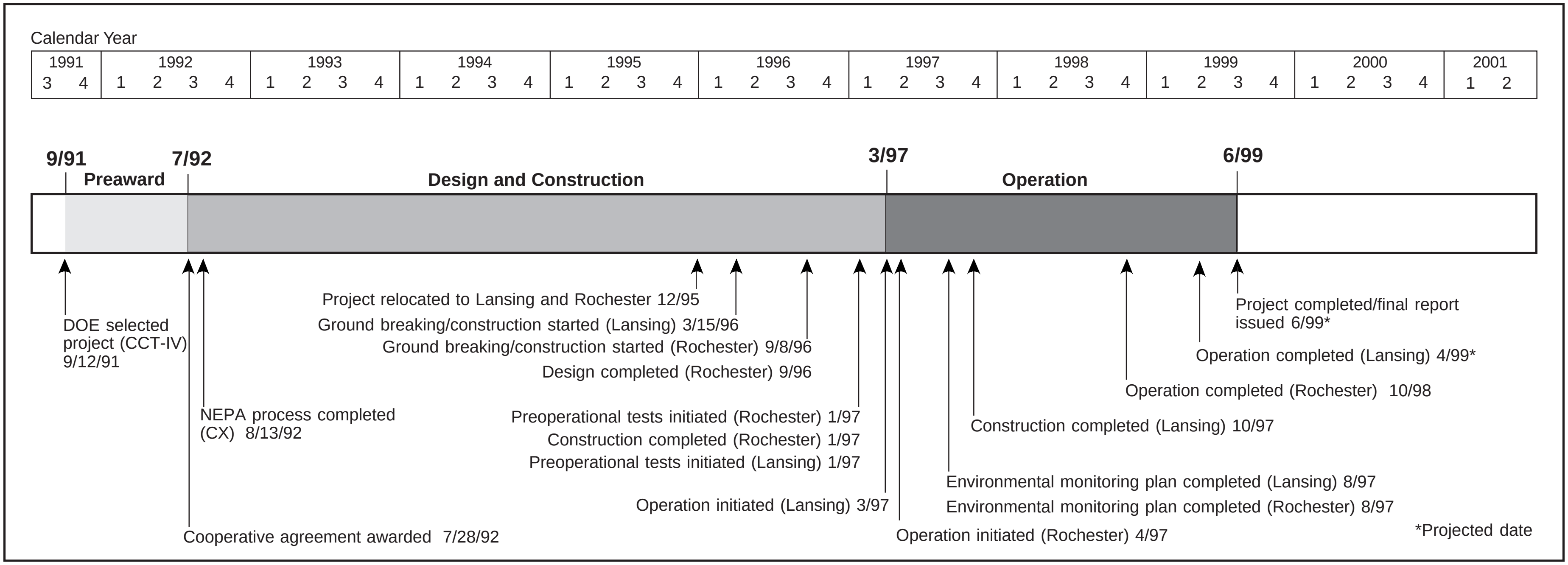
MicroMill is a trademark of the Fuller Company.



for significant combustion modification and environmental improvements. These options can prevent higher operating costs or furnace performance derating often associated with conventional environmental controls.

At the Milliken site, coal is reburned for NO_x control using the following methods: (1) close-coupled overfire air (CCOFA) reburning in which the top burner of the LNCFS III™ burners are used for burning the micronized coal and the remaining burners are re-aimed and (2) adjustment of the remaining burners for deep stage combustion and re-aiming them to create primary combustion and reburn zones. At the Eastman Kodak site, the Fuller MicroMill™ is used to produce the micronized coal, reburn fuel is introduced above the cyclone combustor, and overfire air is employed to complete the combustion.

Project Status/Accomplishments

Parametric testing conducted at the Kodak site examined the relationships that exist between controlling parameters (micronized coal flow rate, coal fineness, flue gas recirculation (FGR) flow rate, overfire air flow rate, coal flow biasing, and soot blowing frequency) and boiler outputs. The parametric testing established the range of control settings for optimum performance that were then used for long-term testing. Testing showed that the target NO_x emission rate of 0.60 lb/10^6 Btu was achieved with as low as 17% reburn fuel heat input, which represented a 59% NO_x reduction. Stoichiometric ratios needed in the reburn zone and cyclone burner zone to achieve the targeted NO_x reduction were 0.9 and 1.05–1.15, respectively. The test program at the Kodak site is complete and data are being evaluated in preparation for issuance of the final technical report.

Parametric testing at the Milliken site examined conditions that will achieve NO_x emissions without exceeding 4.5% loss-on-ignition (LOI) to maintain marketability of the fly ash. Burner tilt, reburn fuel fineness, reburn fuel flow rate, and primary air flow showed little impact on NO_x emissions, but significant impact on LOI. Only excess air had a significant impact on both NO_x emissions and LOI. Long-term testing ensued, exploring optimum conditions for sustained NO_x control at low LOI. Data are being evaluated in preparation for issuance of the final technical report.

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.

The availability of a coal-reburning fuel, as an additional fuel to the furnace, enables switching to lower heating value coals without boiler derating. 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.

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 handling
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, Coal Reburn

Plant Capacity/Production

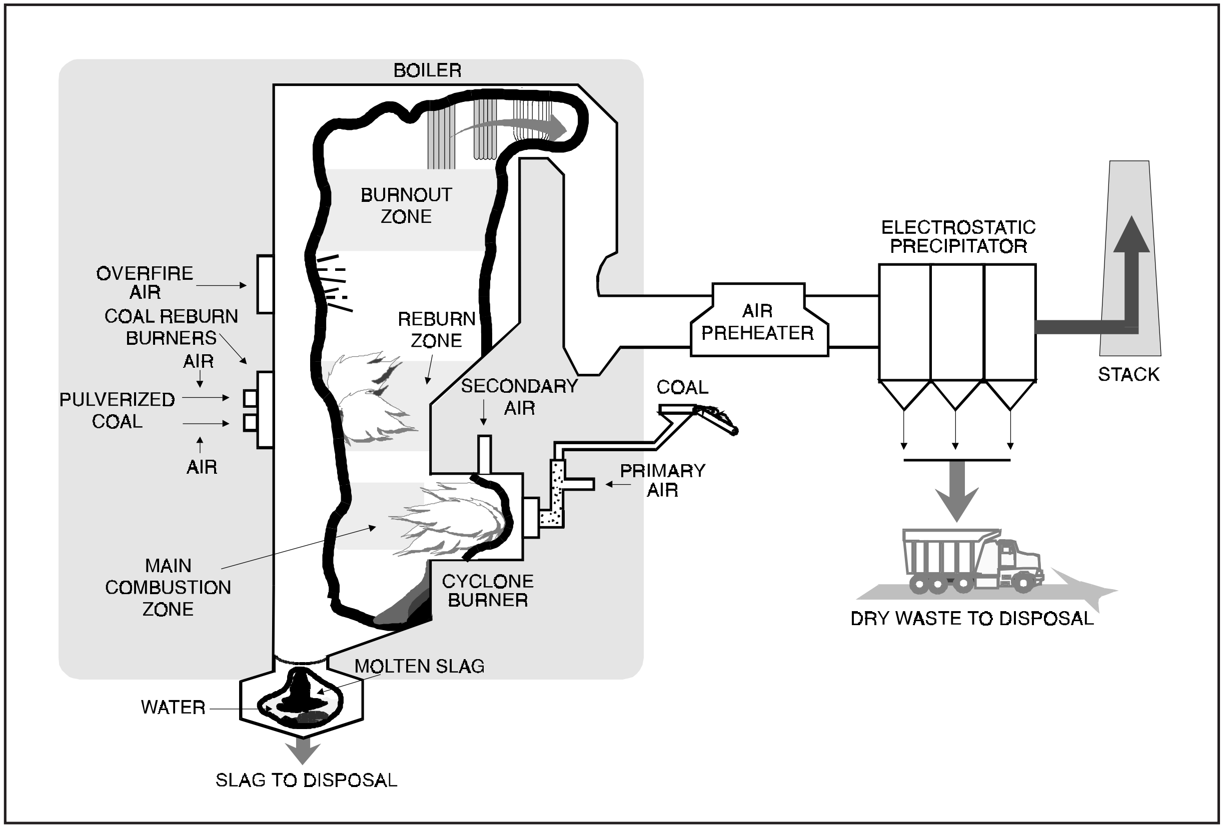
100-MWe

Coal

Illinois Basin bituminous (Lamar), 1.15% sulfur, 1.24% nitrogen
Powder River Basin (PRB) subbituminous, 0.27% sulfur, 0.55% nitrogen

Project Funding

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



Project Objective

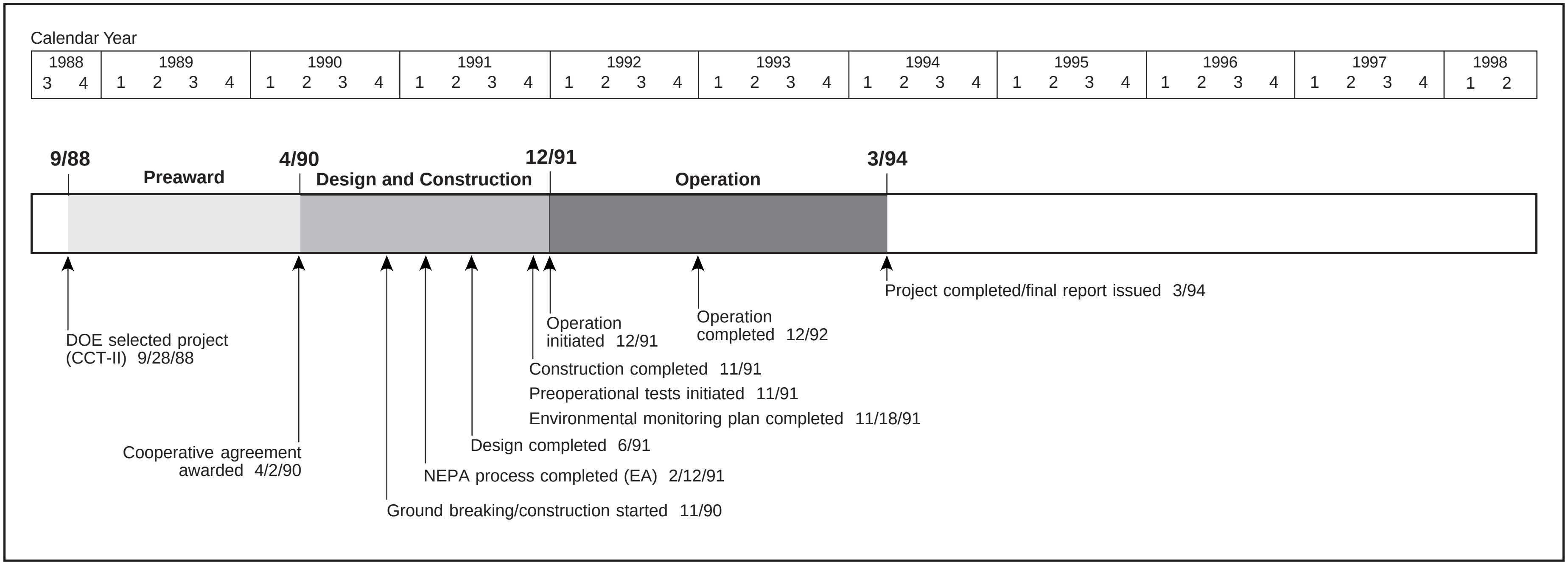
To demonstrate the technical and economic feasibility of achieving greater than 50% reduction in NO_x emissions with no serious impact on cyclone combustor operation, boiler performance, or other emission streams.

Technology/Project Description

Babcock & Wilcox Coal Reburn 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.

Coal Reburn can be applied with the cyclone burners operating within their normal, noncorrosive, 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.



Results Summary

Environmental

- Coal Reburn achieved greater than 50% NO_x reduction at full load with Lamar bituminous and PRB subbituminous coals.
- Reburn-zone stoichiometry had the greatest effect on NO_x control.
- Gas recirculation was vital to maintaining reburn-zone stoichometry while providing necessary burner cooling, flame penetration, and mixing.
- Opacity levels and electrostatic precipitator (ESP) performance were not affected by Coal Reburn with either coal tested.
- Optimal Coal Reburn heat input was 29–30% at full load and 33–35% at half to moderate loads.

Operational

- No major boiler performance problems were experienced with Coal Reburn operations.
- Boiler turndown capability was 66%, exceeding the 50% goal.
- ESP efficiency improved slightly during Lamar coal testing and did not change with PRB coal.
- Coal fineness levels above the nominal 90% through 200 mesh were maintained, reducing unburned carbon losses (UBCL).
- UBCL was the only major contributor to boiler efficiency loss, which was 0.1, 0.25, and 1.5% at loads of 110-, 82-, and 60-MWe, respectively, when using Lamar coal. With PRB coal, the efficiency loss ranged from zero at full load to 0.3% at 60-MWe.
- Superior flame stability was realized with PRB coal, contributing to better NO_x control than with Lamar coal.
- Expanded volumetric fuel delivery with reburn burners enabled switching to PRB low-rank coal without boiler derating.

Economic

- Capital costs for 110- and 605-MWe plants were $66/kW and $43/kW, respectively.
- Levelized 10- and 30-year busbar power costs for a 110-MWe plant were 2.4 and 2.3 mills/kWh, respectively.
- Levelized 10- and 30-year busbar power costs for a 605-MWe plant were 1.6 and 1.5 mills/kWh, respectively. (Costs are in 1990 constant dollars.)

Project Summary

Although cyclone boilers represent only 15% of the pre-NSPS coal-fired generating capacity, they contribute 21% of the NO_x formed by pre-NSPS coal-fired units. This is due to the cyclone combustor's inherent turbulent, high-temperature combustion process. Consequently, cyclone boilers are targeted for NO_x reduction under the CAAA and state implementation plans. However, at the time of this demonstration, there was no cost-effective combustion modification available for cyclone boiler NO_x control.

Babcock & Wilcox Coal Reburn offers an economic and operationally sound response to the environmental impetus. This technology avoids cyclone combustor modification and associated performance complications and provides an alternative to post-combustion NO_x control options, such as SCR, having relatively higher capital and/or operating costs.

The majority of the testing was performed firing Illinois Basin bituminous coal (Lamar), as it is typical of the coal used by many utilities operating cyclones. Subbituminous PRB coal tests were performed to evaluate the effect of coal switching on reburn operation. Wisconsin Power and Light's strategy to meet Wisconsin's sulfur emission limitations as of January 1, 1993, was to fire low-sulfur coal.

Environmental Performance

Three sequences of testing of Coal Reburn used Lamar coal. Parametric optimization testing was used to set up the automatic controls. Performance testing was run with the unit in full automatic control at set load points. Long-term testing was performed with reburn in operation while the unit followed system load demand requirements. PRB coal was tested by parametric optimization and performance modes. Exhibit 21 shows changes in NO_x emissions and boiler efficiency using the reburn system for various load conditions and coal types.

Coal Reburn tests on both the Lamar and PRB coals indicated that variation of reburn-zone stoichiometry was the most critical factor in changing NO_x emissions levels. The reburn-zone stoichiometry can be varied by alternating the air flow quantities (oxygen availability) to the reburn burners, the percent reburn heat input, the gas recirculation flow rate, or the cyclone stoichiometry.

Hazardous air pollutant (HAP) testing was performed using Lamar test coal. HAP emissions were generally well within expected levels, and emissions with Coal Reburn were comparable to baseline operation. No major effect of reburn on trace-metals partitioning was discernible. None of the 16 targeted polynuclear aromatic semi-volatile organics (controlled under Title III of CAAA) was present in detectable concentrations, at a detection limit of 1.2 parts per billion.

▲ Wisconsin Power and Light Company's Nelson Dewey Station hosted the successful demonstration of Coal Reburn.

Operational Performance

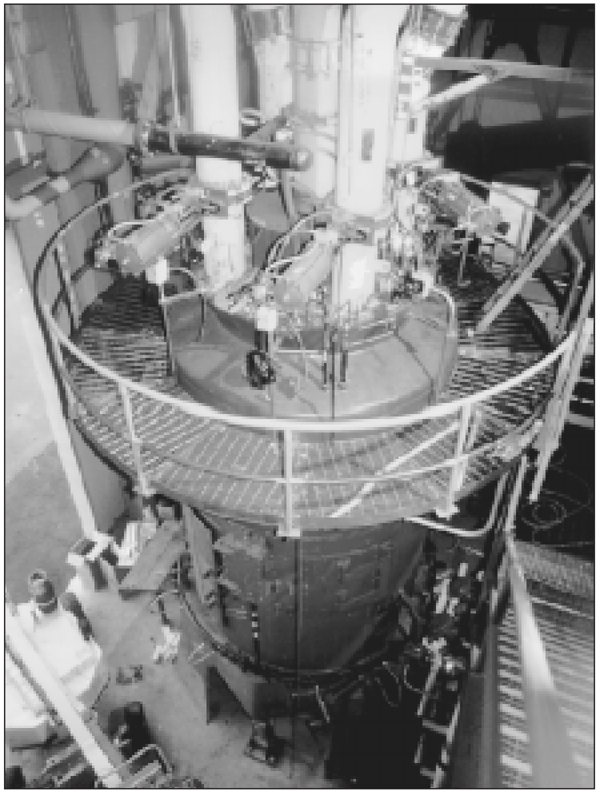
For Lamar coal, the full-, medium-, and low-load efficiency losses, due to unburned carbon, were 0.1, 0.25, and 1.5% higher, respectively, than the baseline. Full-, medium-, and low-load efficiency losses with PRB coal were 0.0, 0.2, and 0.3%, respectively. Coal Reburn burner flame stability improved with PRB coal.

During Coal Reburn operation with Lamar coal, the operators continually monitored boiler internals for increased ash deposition and the on-line performance monitoring system for heat transfer changes. At no time throughout the system optimization or long-term operation period were any slagging or fouling problems observed. In fact, during scheduled outages, internal boiler inspections revealed that boiler cleanliness had actually improved. Extensive ultrasonic thickness measurements were taken of the furnace wall tubes. No observable decrease in wall tube thickness was measured.

Another significant finding was that Coal Reburn minimizes and possibly eliminated a 0–25% derating normally associated with switching to subbituminous coal in a cyclone unit.

Exhibit 21
Coal Reburn Test Results

	Boiler Load		
	110-MWe	**82-MWe**	**60-MWe**
Lamar coal			
NO_x (lb/10^6 Btu/% reduction)	0.39/52	0.36/50	0.44/36
Boiler efficiency losses due to unburned carbon (%)	0.1	0.25	1.5
Powder River Basin coal			
NO_x (lb/10^6 Btu/% reduction)	0.34/55	0.31/52	0.30/53
Boiler efficiency losses due to unburned carbon (%)	0.0	0.2	0.3



▲ The coal pulverizer is part of Babcock & Wilcox Coal Reburn. This system has been retained by Wisconsin Power and Light for NO_x emission control at the Nelson Dewey Station.

This derating results from using a lower Btu fuel in a cyclone combustor, which has a limited coal feed capacity. The Coal Reburn system transferred about 30% of the coal feed out of the cyclone to the reburn burners, bringing the cyclone feed rate down to a manageable level, while maintaining full-load heat input to the unit.

Economic Performance

An economic analysis of total capital and levelized revenue requirements was conducted using the "Electric Power Research Institute Economic Premises" for retrofit of 110- and 605-MWe plants. In addition, annualized costs per ton of NO_x removed were developed for 110- and 605-MWe plants over both 10 and 30 years. The results of these analyses are shown in Exhibit 22. These values assumed typical retrofit conditions and did not take into account any fuel savings from use of low-rank coal. The pulverizers and associated coal handling were taken into account. Site-specific parameters that can significantly impact these retrofit costs included the state of the existing control system, availability of flue gas recirculation, space for coal pulverizers, space for reburn burners and overfire air ports within the boiler, scope of coal-handling modification, sootblowing capacity, ESP capacity, steam temperature control capacity, and boiler circulation considerations.

Commercial Applications

Coal Reburn is a retrofit technology applicable to a wide range of utility and industrial cyclone boilers. The current U.S. Coal Reburn market is estimated to be approximately 26,000-MWe and to consist of about 120 units ranging from 100- to 1,150-MWe with most in the 100–300-MWe range.

The project technology has been retained by Wisconsin Power and Light for commercial use.

Contacts

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Exhibit 22
Coal Reburn Economics
(1990 Constant Dollars)

Costs	Plant Size 110-MWe	605-MWe
Total capital cost ($/kW)	66	43
Levelized busbar power cost (mills/kWh)		
10-year life	2.4	1.6
30-year life	2.3	1.5
Annualized cost ($/ton of NO_x removed)		
10-year life	1,075	408
30-year life	692	263

References

- *Demonstration of Coal Reburning for Cyclone Boiler NO_x Control: Final Project Report.* Report No. DOE/PC/89659-T16. The Babcock & Wilcox Company. February 1994. (Available from NTIS as DE94013052, Appendix 1 as DE94013053, Appendix 2 as DE94013054.)
- *Public Design Report: Coal Reburning for Cyclone Boiler NO_x Control.* The Babcock & Wilcox Company. August 1991. (Available from NTIS as DE92012554.)
- *Comprehensive Report to Congress on the Clean Coal Program: Demonstration of Coal Reburning for Cyclone Boiler NO_x Control.* (The Babcock & Wilcox Company). Report No. DOE/FE-0157. U.S. Department of Energy. February 1990. (Available from NTIS as DE90008111.)

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

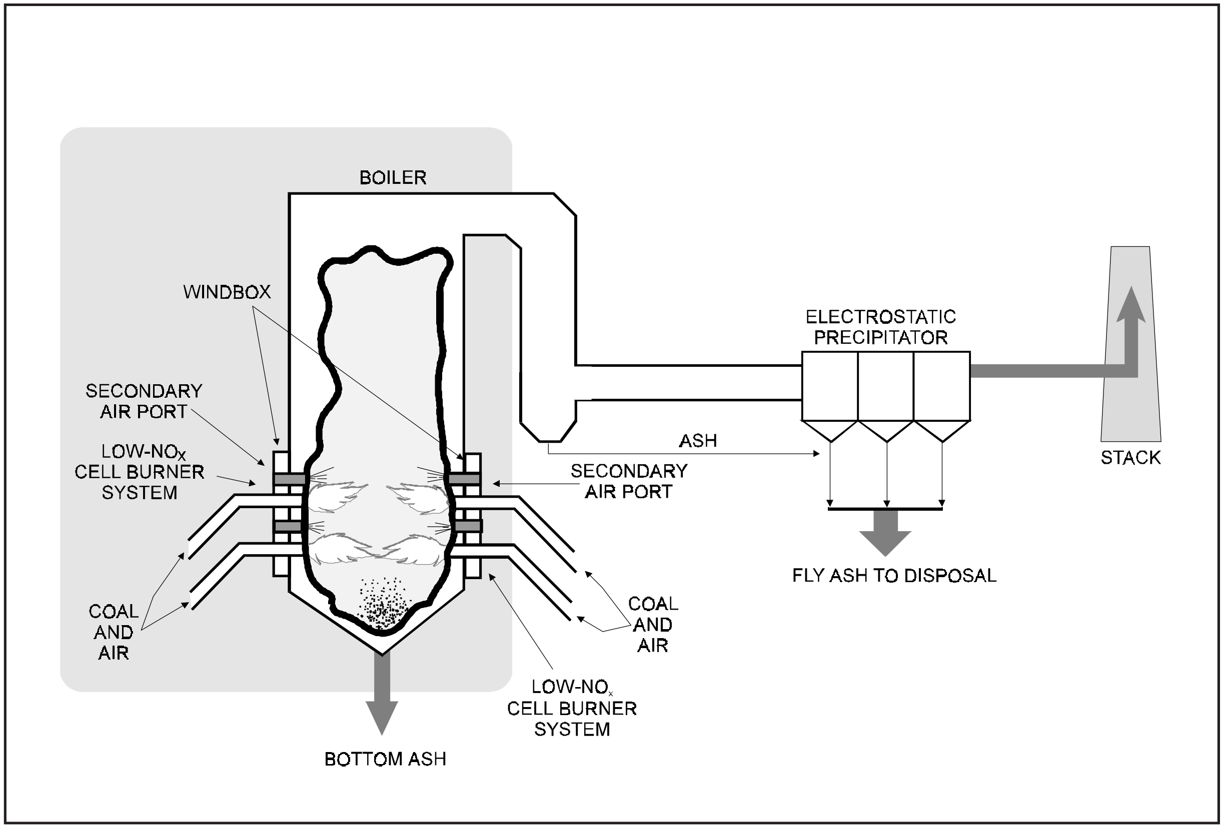
605-MWe

Coal

Bituminous, medium sulfur

Project Funding

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



Project Objective

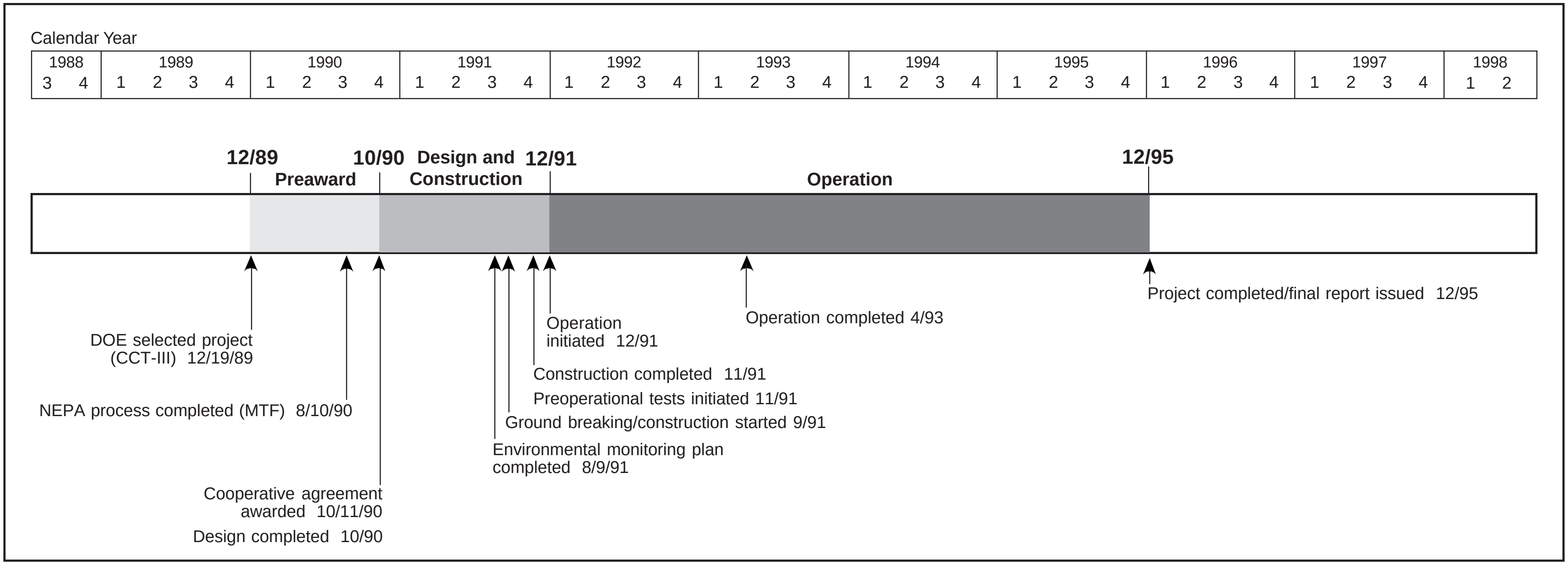
To demonstrate, through the first commercial-scale full burner retrofit, the cost-effective reduction of NO_x from a large baseload coal-fired utility boiler with LNCB® technology; to achieve at least a 50% NO_x reduction without degradation of boiler performance at less cost than that of conventional 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 demonstration was conducted on a Babcock & Wilcox-designed, supercritical, once-through boiler equipped with an electrostatic precipitator (ESP). This unit, which is typical of cell burner boilers, 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 ensure complete combustion in the lower furnace.

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



Results Summary

Environmental

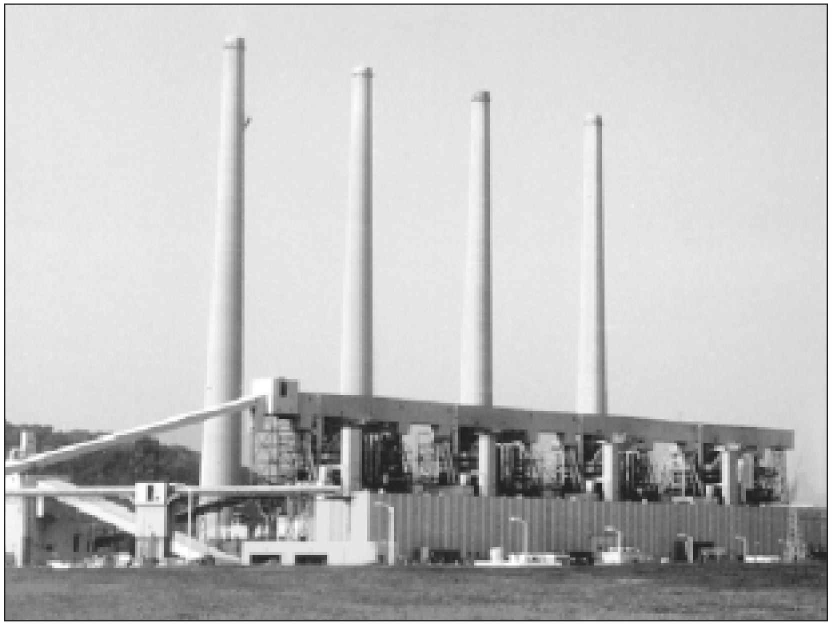
- Short-term optimization testing (all mills in service) showed NO_x reductions in the range of 53.0–55.5%, 52.5–54.7%, and 46.9–47.9% at loads of 605-MWe, 460-MWe, and 350-MWe, respectively.
- Long-term testing at full load (all mills in service) showed an average NO_x reduction of 58% (over 8 months).
- Long-term testing at full load (one mill out of service) showed an average NO_x reduction of 60% (over 8 months).
- CO emissions averaged 28–55 ppm at full load with LNCB® in service.
- Fly ash increased, but ESP performance remained virtually unchanged.

Operational

- Unit efficiency remained essentially unchanged.
- Unburned carbon losses (UBCL) increased by approximately 28% for all tests, but boiler efficiency loss was offset by a decrease in dry gas loss due to a lower boiler economizer outlet gas temperature.
- Boiler corrosion with LNCB® was roughly equivalent to boiler corrosion rates prior to retrofit.

Economic

- Capital cost for a 600-MWe plant was $9/kW (1994$).
- Levelized cost for a 600-MWe plant was estimated at 0.284 mills/kWh and $96.48/ton of NO_x removed.



▲ Dayton Power and Light Company's J.M. Stuart Plant hosted the successful demonstration of LNCB® technology.

Project Summary

Utility boilers equipped with cell burners currently comprise 13% or approximately 23,000-MWe of pre-NSPS coal-fired generating capacity. Cell burners are designed for rapid mixing of the fuel and air. The tight burner spacing and rapid mixing minimize the flame size while maximizing the heat release rate and unit efficiency. Combustion efficiency is good, but the rapid heat release produces relatively large quantities of NO_x.

To reduce NO_x emissions, the LNCB® has been designed to stage mixing of the fuel and combustion air. A key design criterion was accomplishing delayed fuel-air mixing with no modifications to waterwall panels. A plug-in design reduces material costs and outage time required to complete the retrofit, compared to installing conventional, internally staged low-NO_x burners. LNCB® provides a lower cost alternative to address NO_x reduction requirements for cell burners.

Environmental Performance

The initial LNCB® configuration resulted in excessive CO and H_2S emissions. Through modeling, a revised configuration was developed to address the problem without compromising boiler performance. The modification was incorporated and validated model capabilities.

Following parametric testing to establish optimal operating modes, a series of optimization tests were conducted on the LNCB® to assess environmental and operational performance. Two sets of measurements were taken, one by Babcock & Wilcox and the other by an independent company, to validate data accuracy. Consequently, the data provided is a range reflecting the two measurements.

The average NO_x emissions reduction achieved at full load with all mills in service ranged from 53.0–55.5%. With one mill out of service at full load, the average NO_x reduction ranged from 53.3–54.5%. Average NO_x reduction at intermediate load (about 460-MWe) ranged from 52.5–54.7%. At low loads (about 350-MWe), average NO_x reduction ranged from 46.9–47.9%. NO_x emissions were monitored over the long-term at full load for all mills in service and one mill out of service. Each test spanned an 8-month period. NO_x emission reductions realized were 58% for all mills in service and about 60% for one mill out of service.

Complications arose in assessing CO emissions relative to baseline because baseline calibration was not refined enough. However, accurate measurements were made with LNCB® in service. Carbon monoxide emissions were corrected for 3.0% O_2 and measured at full, intermediate, and low loads. The range of CO emissions at full load with all mills in service was 28–55 ppm and 20-38 ppm with one mill out of service. At intermediate loads (about 460-MWe), CO emissions were 28–45 ppm and at low loads (about 350-MWe), 5–27 ppm.

▲ The LNCB® is viewed from within the boiler.

Particulate emissions were minimally impacted. The LNCB® had little effect on flyash resistivity, largely due to SO_3 injection, and therefore ESP removal efficiency remained very high. Baseline ESP collection efficiencies for full load with all mills in service, full load with one mill in service, and intermediate load with one mill out of service were 99.50, 99.49, and 99.81%, respectively. For the same conditions, in the same sequence with LNCB®

in operation, ESP collection efficiencies were 99.43, 99.12, and 99.35%, respectively.

Operational Performance

Furnace exit gas temperature, or secondary superheater inlet temperature, initially decreased by 100 ºF but eventually rose to within 10 ºF of baseline conditions.

The UBCL increased by approximately 28% for all tests. The most significant increase from baseline data occurred for a test with one mill out of service. A 52% increase in UBCL resulted in an efficiency loss of 0.69%.

Boiler efficiency showed very little change from baseline. The average for all mills in service increased by 0.16%. The higher post-retrofit efficiency was attributed to a decrease in dry gas loss with lower economizer gas outlet temperature (and subsequent lower air heater gas outlet temperature), offsetting UBCL and CO emission losses. Also, increased coal fineness mitigated UBCL.

Because sulfidation is the primary corrosion mechanism in substoichiometric combustion of sulfur-containing coal, H_2S levels were monitored in the boiler. After optimizing LNCB® operation, levels were largely at the lower detection limit. There were some higher local readings, but corrosion panel tests established that corrosion rates with LNCB® were roughly equivalent to pre-retrofit rates.

Ash sample analyses indicated that ash deposition would not be a problem. The LNCB® ash was little different from baseline ash. Furthermore, the small variations observed in furnace exit gas temperature between baseline and LNCB® indicated little change in furnace slagging. Start-up and turndown of the unit were unaffected by conversion to LNCB®.

Economic Performance

The economic analyses were performed for a 600-MWe nominal unit size and typical location in the midwest United States. A medium-sulfur, medium-volatile bituminous coal was chosen as the typical fuel. For a baseline NO_x emission level of 1.2 lb/10^6 Btu and a 50% reduction target, the estimated capital cost was $9/kW (1994 $). The levelized cost of electricity was estimated at 0.284 mills/kWh or $96.48/ton of NO_x removed.

Commercial Applications

The low cost and short outage time for retrofit make the LNCB® design the most cost-effective NO_x control technology available today for cell burner boilers. The LNCB® system can be installed at about half the cost and time of other commercial low-NO_x burners.

Dayton Power & Light has retained the LNCB® for use in commercial service. Seven commercial contracts have been awarded for 172 burners, valued at $24 million. LNCB® have already been installed on more than 4,600-MWe of capacity.

The demonstration project received *R&D* magazine's 1994 R&D Award.

▲ The connections to the LNCB® are viewed from outside the boiler.

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- *Comprehensive Report to Congress on the Clean Coal Technology Program: Full-Scale Demonstration of Low-NO_x Cell-Burner Retrofit.* The Babcock & Wilcox Company. Report No. DOE/FE-0197P. U.S. Department of Energy. July 1990. (Available from NTIS as DE90018026.)

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
Foster Wheeler Energy Corp.—technology supplier

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 Energy Corp.'s Low-NO$_x$ burners (LNB)

Plant Capacity/Production

172-MWe (gross), 158-MWe (net)

Coal

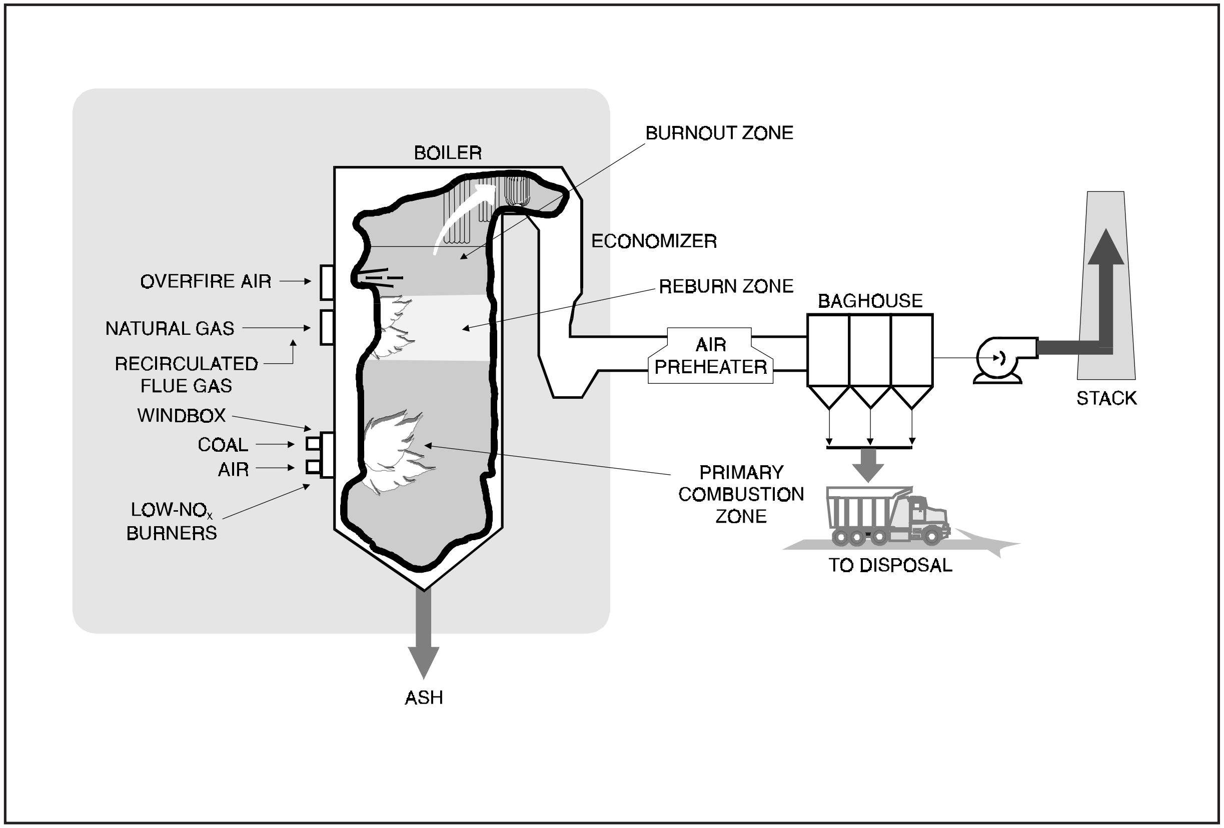
Colorado bituminous, 0.40% sulfur, 10% ash

Project Funding

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

Project Objective

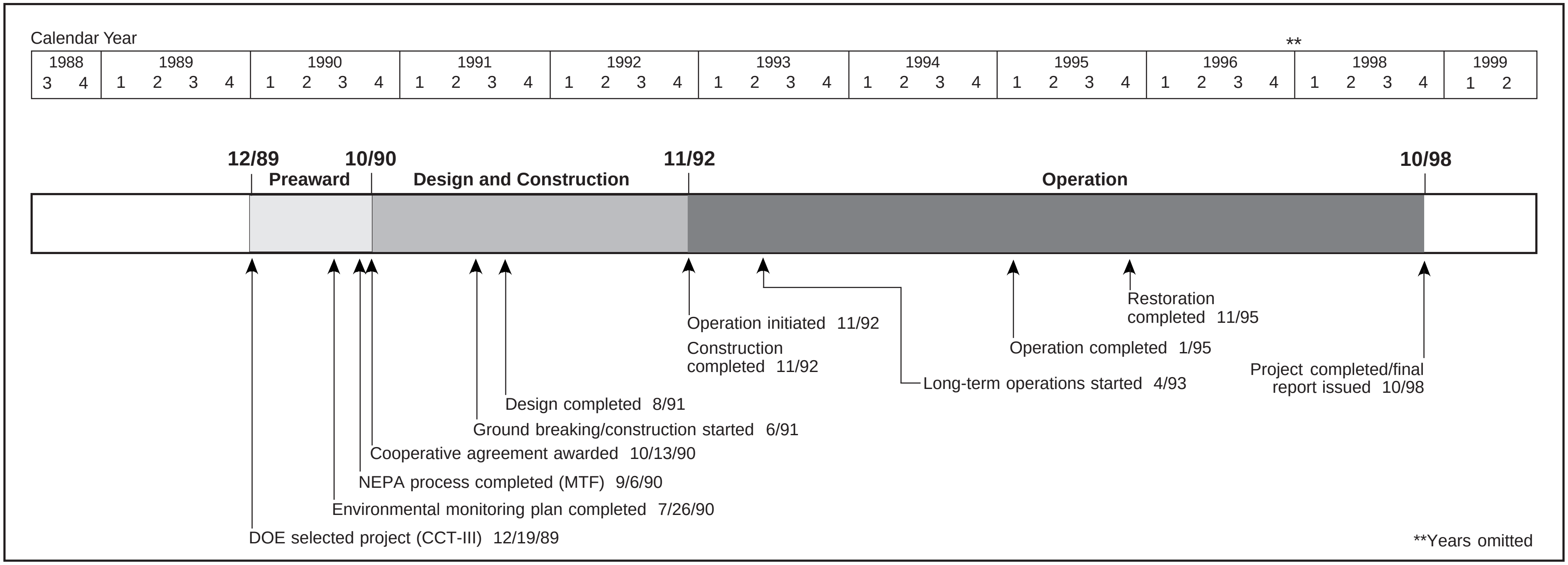
To attain up to a 70% decrease in the emissions of NO$_x$ from an existing wall-fired utility boiler firing low-sulfur coal using both gas reburning and low-NO$_x$ burners (GR–LNB); and to assess the impact of GR–LNB on boiler performance.



Technology/Project Description

Gas reburning involves firing natural gas (up to 25% of total heat 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 stripped of oxygen as the reburn fuel is combusted 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 was intended to lower NO$_x$ emissions by up to 70%. Gas reburning was demonstrated with and without the use of recirculated flue gas and with optimized overfire air.

A series of parametric tests were performed on the gas reburning system, varying operational control parameters, and assessing the effect on boiler emissions, completeness of combustion (carbon-in-ash), thermal efficiency, and heat rate. A one-year, long-term testing program was performed in order to judge the consistency of system outputs, assess the impact of long-term operation on the boiler equipment, gain experience in operating GR–LNB in a normal load-following environment, and develop a database for use in subsequent GR–LNB applications. Both first- and second-generation gas-reburning tests were performed.



Results Summary

Environmental

- LNB alone reduced NO_x emissions from a pre-construction baseline of 0.73 lb/10^6 Btu to 0.46 lb/10^6 Btu (at 3.5% O_2), a 37% NO_x reduction.
- First-generation GR, which incorporated flue gas recirculation, in combination with LNB, reduced NO_x emissions to an average 0.25 lb/10^6 Btu (at 3.25% O_2), a 66% NO_x reduction at an 18% gas heat input rate.
- Second-generation GR, without flue gas recirculation, in combination with LNB reduced NO_x emissions to an average 0.26 lb/10^6 Btu, a 64% NO_x reduction with only 12.5% gas heat input.
- Both first- and second-generation GR with LNB were capable of reducing NO_x emissions by up to 70% for short periods of time, the average was approximately 65%.
- After modifying the overfire air system to enhance penetration and turbulence (as part of second-generation GR), CO emissions were controlled to acceptable levels at low gas heat input rates.
- SO_2 emissions and particulate loadings were reduced by the percentage heat input supplied by GR.

Operational

- Boiler efficiency decreased ≤ 1.0%.
- There was no measurable boiler tube wear and only a small amount of slagging.
- Carbon-in-ash and CO levels were acceptable for first- and second-generation GR with LNB, but not with LNB alone.

Economic

- Capital cost for a GR–LNB retrofit of a 300-MWe plant is $26.01/kW (1996$) plus the gas pipeline cost, if not in place ($12.14/kW for GR only and $13.87/kW for LNB only).
- Operating costs were related to the gas/coal cost differential and the value of SO_2 emission allowances because GR reduces SO_2 emissions when displacing coal.

Project Summary

The demonstration established that GR–LNB offers a cost-effective option for deep NO_x reduction on wall-fired boilers. GR–LNB NO_x control performance approached that of selective catalytic reduction (SCR) but at significantly lower cost. The importance of cost-effective technology for deep NO_x reduction is the need for NO_x reduction in ozone nonattainment areas beyond what is currently projected in Title IV of the CAAA. Title I of the CAAA deals with ozone nonattainment and is currently the driving force for deep NO_x reduction in many regions of the country.

The GR–LNB was installed and evaluated on a 172-MWe (gross) wall-fired boiler—a Babcock & Wilcox balanced-draft pulverized-coal unit. The GR system, including an overfire air system, was designed and installed by Energy and Environmental Research Corporation. The LNBs were designed and installed by Foster Wheeler Energy Corp.

Parametric testing began in October 1992 and was completed in April 1993. The parametric tests examined the effect of process variables (such as zone stoichiometric ratio, percent gas heat input, percent overfire air, and load) on NO_x reduction, SO_2 reduction, CO emissions, carbon-in-ash, and heat rates. The baseline performance of the LNB was also established.

Environmental Performance

At a constant load (150-MWe) and a constant oxygen level at the boiler exit, NO_x emissions were reduced with increasing gas heat input. At gas heat inputs greater than 10%, NO_x emissions were reduced marginally as gas heat input increased. Natural gas also reduced SO_2 emissions in proportion to the gas heat input. At the Cherokee Station, low-sulfur (0.40%) coal is used, and typical SO_2 emissions are 0.65 lb/10^6 Btu. With a gas heat input of 20%, SO_2 emissions decreased by 20% to 0.52 lb/10^6 Btu.

▲ A worker inspects the support ring for the Foster Wheeler low-NO_x burner installed in the boiler wall.

The CO_2 emissions were also reduced as a result of using natural gas because it has a lower carbon-to-hydrogen ratio than coal. At a gas heat input of 20%, the CO_2 emissions were reduced by 8%.

Long-term testing was initiated in April 1993 and completed in January 1995. The objectives of the test were to obtain operating data over an extended period when the unit was under routine commercial service, determine the effect of GR–LNB operation on the unit, and obtain incremental maintenance and operating costs with GR. During long-term testing, it was determined that flue gas recirculation had minimal effect on NO_x emissions.

A second series of tests were added to the demonstration to evaluate a modified or second-generation system. Modifications are summarized below.

- The flue gas recirculation system, originally designed to provide momentum to the natural gas, was removed. (This change significantly reduced capital costs.)
- Natural gas injection was optimized at 10% gas heat input compared to the initial design value of 18%. The removal of the flue gas recirculation system required installation of high-velocity injectors, which made greater use of available natural gas pressure. (This modification reduced natural gas usage and thus operating costs.)
- Overfire air ports were modified to provide higher jet momentum, especially at low total flows.

Exhibit 23
NO_x Data from Cherokee Station, Unit No. 3

	GR Generation	
	First	Second
Baseline (lb/10^6 Btu)	0.73	0.73
Avg NO_x reduction (%)		
LNB	37	44
GR–LNB	66	64
Avg gas heat input (%)	18	12.5

Over 4,000 hours of operation were achieved, with the results as shown in Exhibit 23. Although the 37% NO_x reduction performance of LNB was less than the expected 45%, the overall objectives of the demonstration were met. Boiler efficiency decreased by only 1% during gas reburning due to increased moisture in the fuel resulting from natural gas use. Further, there was no measurable tube wear, and only small amounts of slagging occurred during the GR–LNB demonstration. However, with LNB alone, carbon-in-ash and CO could not be maintained at acceptable levels.

Economic Performance

GR–LNB is a retrofit technology in which the economic benefits are dependent on the following site-specific factors:

- Gas availability at the site
- Gas/coal cost differential
- Boiler efficiency
- SO_2 removal requirements
- Value of SO_2 emission credits

Based on the demonstration, GR–LNB is expected to achieve at least a 64% NO_x reduction with a gas heat input of 12.5%. The capital cost estimate for a 300-MWe wall-fired installation is $26.01/kW (1996 $) plus gas pipeline costs, if required. This cost includes both equipment and installation costs and a 15% contingency. The

GR and LNB system capital costs can be easily separated from one another because they are independent systems. The capital cost for the GR system only is estimated at \$12.14/kW. The LNB system capital cost is \$13.87/kW.

Operating costs are almost entirely related to the differential cost of natural gas and coal and reduced by the value of the SO_2 emission credits received due to absence of sulfur in the gas. A fuel differential of \$1.00/10^6 Btu was used because gas costs more than coal on a heating value basis. Boiler efficiency was estimated to decline by 0.80%; the cost of this decline was calculated using a composite fuel cost of \$1.67/10^6 Btu. Over-fire air booster and cooling fan auxiliary loads will be partially offset by lower loads on the pulverizers. No additional operating labor is required, but there is an increase in maintenance costs. Allowances were also made for overhead, taxes, and insurance. Based on these assumptions and assuming an SO_2 credit allowance of \$95/ton (Feb. 1996), the net operating cost is \$2.14 million per year and the NO_x removal cost is \$786/ton (constant 1996\$).

Commercial Applications

Current estimates indicate that about 35 existing wall-fired utility installations, plus industrial boilers, could make immediate use of this technology. The technology can be used in retrofit, repowering, or greenfield installations. There is no known limit to the size or scope of the application of this technology combination.

GR–LNB is expected to be less capital intensive, or less costly, than selective catalytic reduction. GR–LNB functions equally well with any kind of coal.

Public Service Company of Colorado, the host utility, decided to retain the low-NO_x burners and the gas-reburning system for immediate use; however, a restoration was required to remove the flue gas recirculation system.

Energy and Environmental Research Corporation has been awarded two contracts to provide gas-reburning systems for five cyclone coal-fired boilers: TVA's Allen Unit No. 1, with options for Unit Nos. 2 and 3 (identical 330-MWe Units); Baltimore Gas & Electric's C.P. Crane, Unit No. 2, with an option for Unit No. 1 (similar 200-MWe Units). Use of the technology also extends to overseas markets. One of the first installations of the technology took place at the Ladyzkin State Power Station in Ladyzkin, Ukraine.

This demonstration project was one of two that received the Air and Waste Management Association's 1997 J. Deanne Sensenbaugh Award.

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- *Evaluation of Gas Reburning and Low NO_x Burners on a Wall-Fired Boiler (Optimization Testing, November 1992–April 1993).* Report No. DOE/PC/90547-T19. Energy and Environmental Research Corporation. June 1995. (Available from NTIS as DE95017754.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler.* Energy and Environmental Research Corporation. Report No. DOE/FE-0204P. U.S. Department of Energy. September 1990. (Available from NTIS as DE9100253.)

▲ The Public Service Company of Colorado has retained the gas-reburning and low-NO_x burner system for commercial use.

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 No. 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)

Coal

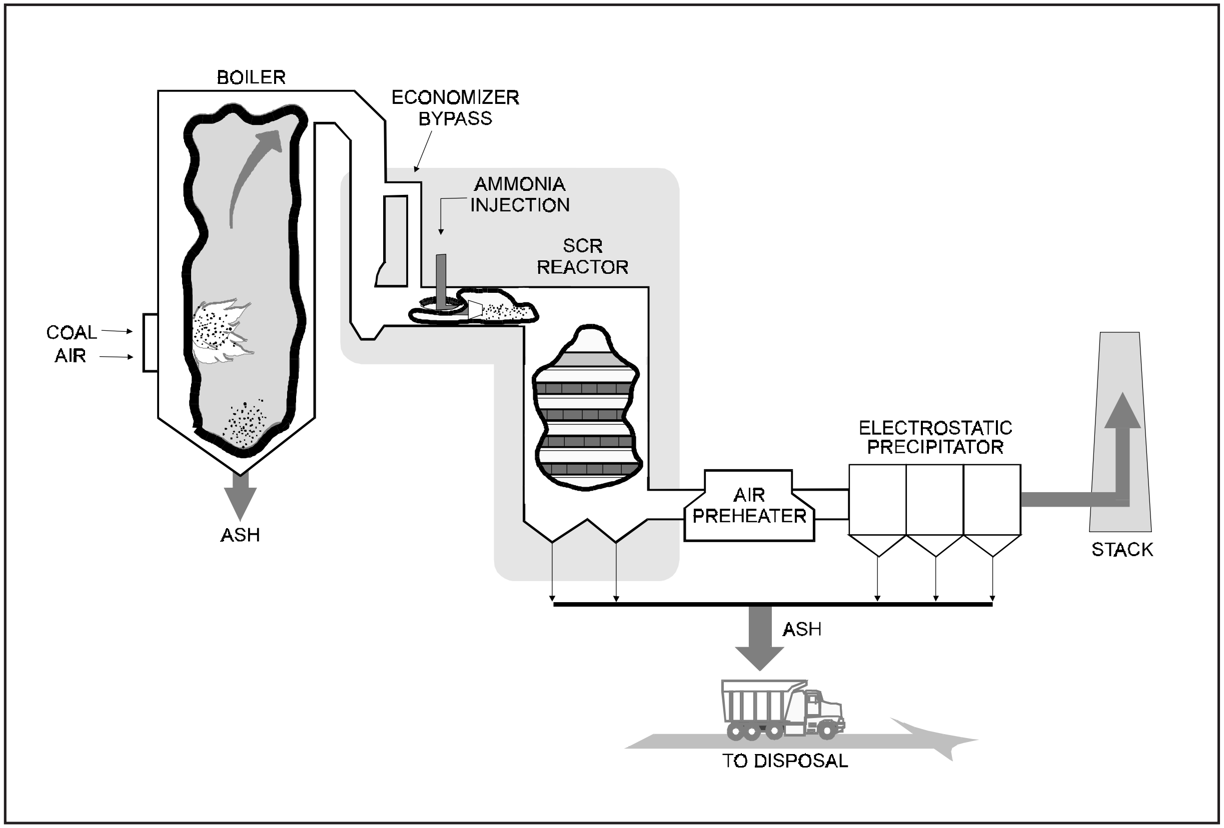
Illinois bituminous, 2.7% sulfur

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 scfm 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 demonstration.

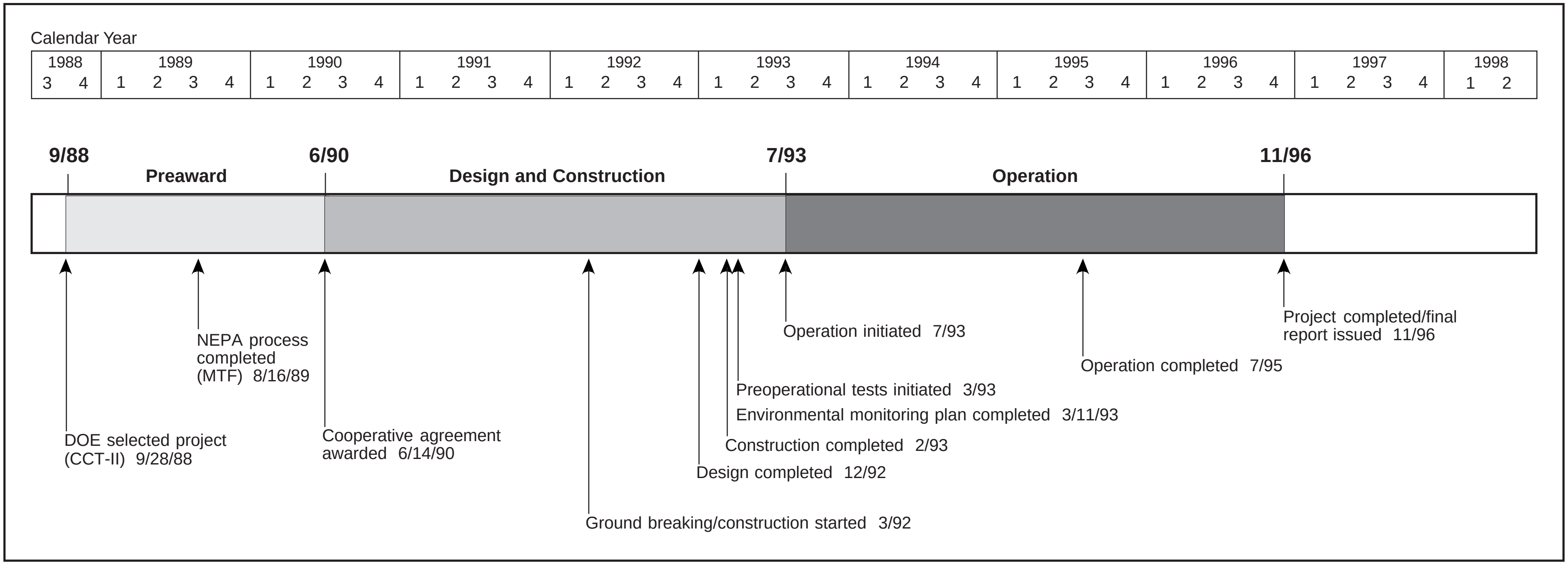
The project demonstrated, at high- and low-dust loadings of flue gas, the applicability of SCR technology to provide a cost-effective means of reducing NO_x emissions from power plants burning high-sulfur U.S. coal.

The demonstration plant, which was located at Gulf Power Company's Plant Crist near Pensacola, FL, used flue gas from the burning of 2.7% sulfur coal.

Results Summary

Environmental

- NO_x reductions of over 80% were achieved at an ammonia slip well under the 5 ppm deemed acceptable for commercial operation.
- Flow rates could be increased to 150% of design without exceeding the ammonia slip design level of 5 ppm at 80% NO_x reduction.



- While catalyst performance increased above 700 ºF, the benefit did not outweigh the heat rate penalties.
- Increases in ammonia slip, a sign of catalyst deactivation, went from less than 1 ppm to approximately 3 ppm over the nearly 12,000 hours of operation, thus demonstrating deactivation in coal-fired units was in line with worldwide experience.
- Long-term testing showed that SO_2 oxidation was within or below the design limits necessary to protect downstream equipment.

Operational

- Fouling of catalysts was controlled by adequate sootblowing procedures.
- Long-term testing showed that catalyst erosion was not a problem.
- Air preheater performance was degraded because of ammonia slip and subsequent by-product formation; however, solutions were identified.
- The SCR process did not significantly affect the results of Toxicity Characteristic Leaching Procedure analysis of the fly ash.

Economic

Levelized costs for various NO_x removal levels for a 250-MWe unit at 0.35 lb/10^6 Btu inlet follow:

	40%	**60%**	**80%**
1996 levelized cost (mills/kWh)	2.39	2.57	2.79
1996 levelized cost ($/ton)	3,502	2,500	2,036

Project Summary

The demonstration tests were designed to address several uncertainties, including potential catalyst deactivation due to poisoning by trace metals species in U.S. coals, performance of technology and effects on the balance-of-plant equipment in the presence of high amounts of SO_2 and SO_3, and performance of the SCR catalyst under typical U.S. high-sulfur coal-fired utility operating conditions. Catalyst suppliers were required to design the catalyst baskets to match predetermined reactor dimensions, provide a maximum of four catalyst layers, and meet the following reactor baseline conditions:

Parameter	**Minimum**	**Baseline**	**Maximum**
Temperature (ºF)	620	700	750
NH_3/NO_x molar ratio	0.6	0.8	1.0
Space velocity (1% design flow)	60	100	150
Flow rate (scfm)			
Large reactor	3,000	5,000	7,500
Small reactor	240	400	600

The catalysts tested are listed in Exhibit 24. Catalyst suppliers were given great latitude in providing the amount of catalyst for this demonstration.

Environmental Results

Ammonia slip, the controlling factor in the long-term operation of commercial SCR, was usually ≤5 ppm be-

Exhibit 24
Catalysts Tested

Catalyst	Reactor Size*	Catalyst Configuration
Nippon/Shokubai	Large	Honeycomb
Siemens AG	Large	Plate
W.R. Grace/Noxeram	Large	Honeycomb
W.R. Grace/Synox	Small	Honeycomb
Haldor Topsoe	Small	Plate
Hitachi/Zosen	Small	Plate
Cormetech/High dust	Small	Honeycomb
Cormetech/Low dust	Small	Honeycomb

* Large = 2.5-MWe; 5,000 scfm   Small = 0.2-MWe; 400 scfm

cause of plant and operational considerations. Ammonia slip was dependent on catalyst exposure time, flow rate, temperature, NH_3/NO_x distribution, and NH_3/NO_x ratio (NO_x reduction). Changes in NH_3/NO_x ratio and consequently NO_x reduction generally produced the most significant changes in ammonia slip. The ammonia slip at 60% NO_x reduction was at or near the detection limit of 1 ppm. As NO_x reduction was increased above 80%, ammonia slip also increased and remained at reasonable levels up to NO_x reductions of 90%. Over 90%, the ammonia slip levels increased dramatically.

The flow rate and temperature effects on NO_x reduction were also measured. In general, flows could be increased to 150% of design without the ammonia slip exceeding 5 ppm at 80% NO_x reduction and design temperature. With respect to temperature, most catalysts exhibited fairly significant improvements in overall performance as temperatures increased from 620 °F to 700 °F but relatively little improvement as temperature increased from 700 °F to 750 °F. The conclusion was that the benefits of high-temperature operation probably do not outweigh the heat rate penalties involved in operating SCR at the higher temperatures.

Catalyst deactivation was generally observed by an increase in ammonia slip over time, assuming the NO_x reduction efficiency was held constant. Over the 12,000 hours of the demonstration tests, the ammonia slip did, in fact, increase from less than 1 ppm to approximately 3 ppm. These results demonstrated the maturity of catalyst design and that deactivation was in line with prior worldwide experience.

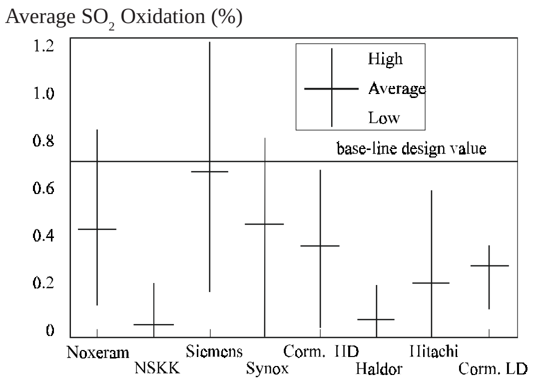
It has been observed that the catalytic active species that results in NO_x reduction often contributed to SO_2 oxidation (i.e., SO_3 formation), which can be detrimental to downstream equipment. In general, NO_x reduction can be increased as the tolerance for SO_3 is also increased. The upper bound for SO_2 oxidation for the demonstration catalyst was set at 0.75% at baseline conditions. The average SO_2 oxidation rate for each of the catalysts is shown in Exhibit 25. These data reflect baseline conditions over the life of the demonstration. All of the catalysts were within design limits, with most exhibiting oxidation rates below the design limit. Other factors affecting SO_2 oxidations are listed below:

- **Flow Rate.** Most of the catalysts exhibited fairly constant SO_2 oxidation with respect to flow rate (i.e., space velocity). In theory, SO_2 oxidation should be inversely proportional to flow rate.
- **Temperature.** Theoretically, the relationship between SO_2 oxidation and temperature should be exponential as temperature increases; however, measurements showed the relationship to be linear with little difference in SO_2 oxidation between 620 ºF and 700 ºF. On the other hand, between 700 °F and 750 °F, the SO_2 oxidation increased more significantly.

Other findings from the demonstration can be summarized as follows:

- **Pressure Drop.** Overall reactor pressure drop was a function of the catalyst geometry and volume, but tests to determine which one was controlling were inconclusive.
- **Fouling.** The fouling characteristics of the catalyst were important to long-term operation. During the demonstration, measurements showed relatively level pressure drop over time, indicating that sootblowing procedures were effective. The plate-type configurations had somewhat less fouling potential than did the honeycomb configuration, but both were acceptable for application.
- **Erosion.** Catalyst erosion was not considered to be a significant problem because most of the erosion was attributed to aggressive sootblowing.
- **Air Preheater Performance.** The demonstration showed that the SCR process exacerbated performance degradation of the air preheaters mainly due to ammo-

Exhibit 25
Average SO_2 Oxidation Rate
(Baseline)



NH_3/NO_x = 0.8, 700 ºF, design flow

nia slip and subsequent by-product formation. Regenerator-type air heaters outperformed recuperators in SCR applications in terms of both thermal performance and fouling.

- **Ammonia Volatilization.** The ammonia volatilized from the SCR flyash when a significant amount of water was absorbed by the ash. This was caused by the formation of a moist layer on the ash with a pH high enough to convert the ammonia compounds in the ash to gas-phase ammonia.
- **Toxicity Characteristic Leaching Procedure (TCLP) Analysis.** TCLP analyses were performed on flyash samples. The SCR process did not significantly affect the toxics leachability of the fly ash.

Economic Results

An economic evaluation was performed for full-scale applications of SCR technology to a new 250-MWe pulverized coal-fired plant located in a rural area with minimal space limitations. The fuel considered was high-sulfur Illinois No. 6 coal. Other key base case design criteria are shown in Exhibit 26.

Results of the economic analysis of capital, operating and maintenance (O&M), and levelized cost based on a 30-year project life for various unit sizes for an SCR system with a NO_x removal efficiency of 60% follow:

	125-MWe	**250-MWe**	**700-MWe**
Capital cost ($/kW)	61	54	45
Operating cost ($)	580,000	1,045,000	2,667,000
1996 levelized cost			
mills/kWh	2.89	2.57	2.22
$/ton	2,811	2,500	2,165

Results of the economic analysis of capital, O&M, and levelized cost for various NO_x removal efficiencies for a 250-MWe unit with 0.35 lb/10^6 Btu of inlet NO_x are as follows:

	40%	**60%**	**80%**
Capital cost ($/kW)	52	54	57
Operating costs ($)	926,000	1,045,000	1,181,000
1996 levelized cost			
mill/kWh	2.39	2.57	2.79
$/ton	3,502	2,500	2,036

For retrofit applications, the estimated capital costs were $59–112/kW, depending on the size of the installation and the difficulty and scope of the retrofit. The levelized costs for the retrofit applications were $1,850–5,100/ton (current 1996 $).

Exhibit 26
Design Criteria

Parameter	Specification
Type of SCR	Hot side
Number of reactors	One
Reactor configuration	3 catalyst support layers
Initial catalyst load	2 of 3 layers loaded
Range of operation	35–100% boiler load
NO_x inlet concentration	0.35 lb/10^6 Btu
Design NO_x reduction	60%
Design ammonia slip	5 ppm
Catalyst life	16,000 hr
Ammonia cost	$250/ton
SCR cost	$400/ft^3

Commercial Applications

As a result of this demonstration, SCR technology has been shown to be applicable to existing and new utility generating capacity for removal of NO_x from the flue gas of virtually any size boiler. There are over 1,000 coal-fired utility boilers in active commercial service in the United States; these boilers represent a total generating capacity of approximately 300,000-MWe.

Contacts

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James U. Watts, FETC, (412) 892-5991

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- *Control of Nitrogen Oxide Emissions: Selective Catalytic Reduction (SCR).* Topical Report No. 9. U.S. Department of Energy and Southern Company Services, Inc. July 1997.
- Maxwell, J. D., et al. "Demonstration of SCR Technology for the Control of NO_x Emissions from High-Sulfur Coal-Fired Utility Boilers." *Fifth Annual Clean Coal Technology Conference: Technical Papers,* January 1997.
- *Demonstration of SCR Technology for the Control of NO_x Emissions from High-Sulfur Coal-Fired Utility Boilers: Final Report.* Vol. 1. Southern Company Services, Inc. October 1996. (Available from NTIS, Vol. 1 as DE97050873, Vol. 2: Appendixes A–N as DE97050874, and Vol. 3: Appendixes O–T as DE97050875.)
- *Economic Evaluation of Commercial-Scale SCR Applications for Utility Boilers.* Southern Company Services, Inc. September 1996. (Available from NTIS as DE97051156.)

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

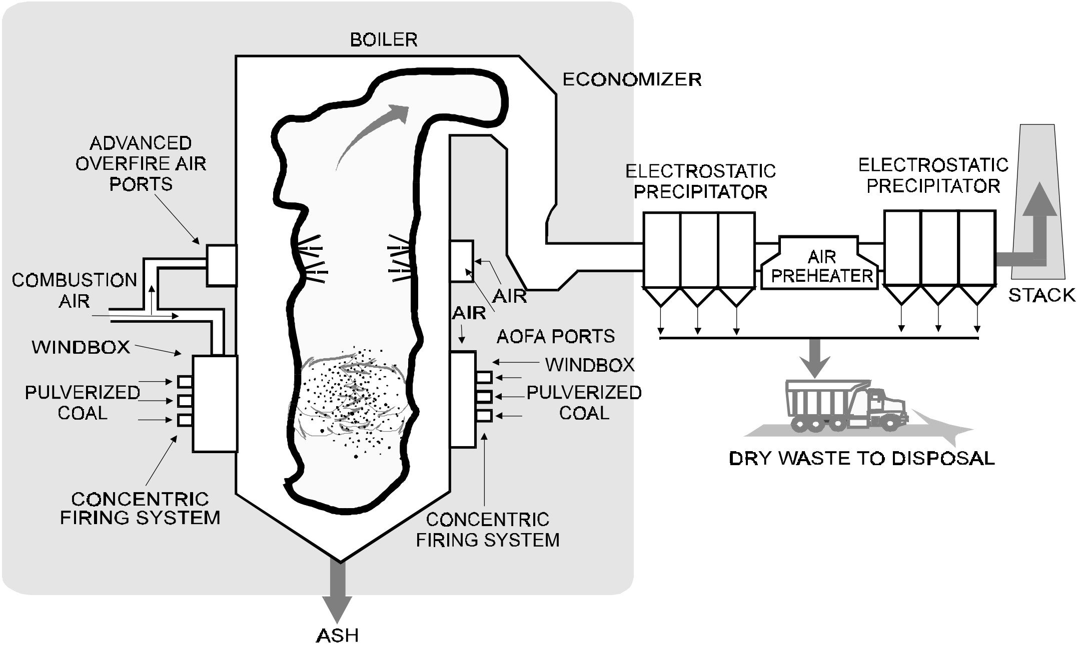
180-MWe

Coal

Eastern bituminous, high reactivity

Project Funding

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



Project Objective

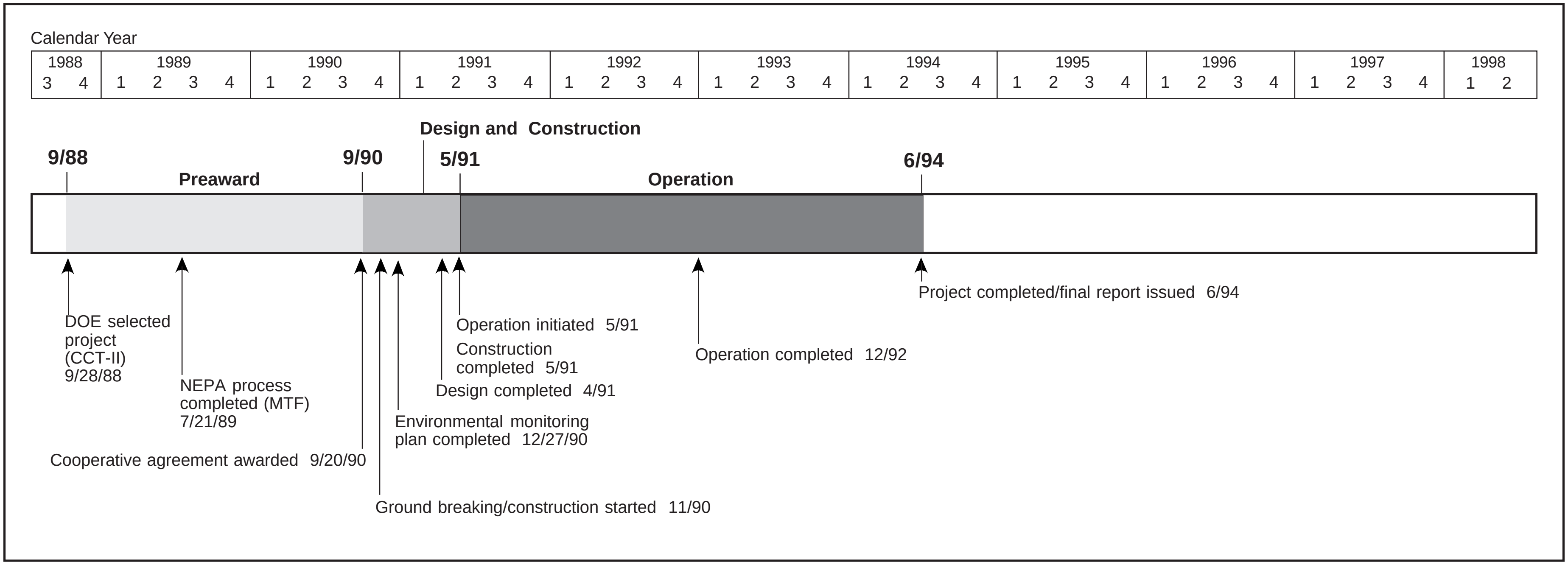
To demonstrate in a stepwise fashion the short- and long-term NO_x reduction capabilities of LNCFS™ levels I, II, and III on a single reference boiler.

Technology/Project Description

Technologies demonstrated included the LNCFS™ levels I, II, and III. Each level of the LNCFS™ used different combinations of overfire air and clustered coal nozzle positioning to achieve NO_x reductions. With the LNCFS™, primary air and coal are surrounded by oxygen-rich secondary air that blankets the outer regions of the combustion zone. LNCFS™ I used a close-coupled overfire air (CCOFA) system integrated directly into the windbox of the boiler. A separated overfire air (SOFA) system located above the combustion zone was featured in the LNCFS™ II system. This was an advanced overfire air system that incorporates back pressuring and flow measurement capabilities. CCOFA and SOFA were both used in the LNCFS™ III tangential-firing approach.

Carefully controlled short-term tests were conducted followed by long-term testing under normal load dispatch conditions. Long-term tests, which typically lasted 2–3 months for each phase, best represent the true emissions characteristics of each technology. Results presented are based on long-term test data.

LNCFS is a trademark of ABB Combustion Engineering, Inc.



Results Summary

Environmental

- At full load, the NO_x emissions using LNCFS™ I, II, and III were 0.39, 0.39, and 0.34 lb/10^6 Btu, respectively, which represent reductions of 37, 37, and 45% from the baseline emissions.
- Emissions with LNCFS™ were not sensitive to power outputs between 100- and 200-MWe, but emissions increased significantly below 100-MWe, reaching baseline emission levels at 70-MWe.
- Because of reduced effectiveness at low loads, LNCFS™ proved marginal as a compliance option for peaking load conditions.
- Average CO emissions increased at full load.
- Air toxics testing found LNCFS™ to have no clear-cut effect on the emissions of trace metals or acid gases. Volatile organic compounds (VOCs) appeared to be reduced and semi-volatile compounds increased.

Operational

- Loss-on-ignition (LOI) was not sensitive to the LNCFS™ retrofits but very sensitive to coal fineness.
- Furnace slagging was reduced but back-pass fouling was increased for LNCFS™ II and III.
- Boiler efficiency and unit heat rate were impacted minimally.
- Unit operation was not significantly affected, but operating flexibility of the unit was reduced at low loads with LNCFS™ II and III.

Economic

- The capital cost estimate for LNCFS™ I was $5–15/kW and for LNCFS™ II and III, $15–25/kW (1993$).
- The cost effectiveness for LNCFS™ I was $103/ton of NO_x removed; LNCFS™ II, $444/ton; and LNCFS™ III, $400/ton (1993$).

Project Summary

At the time of the demonstration, specific NO_x emission regulations were being formulated under the CAAA. The data developed over the course of this project provided needed real-time input to regulation development.

LNCFS™ technology was designed for tangentially-fired boilers, which represent a large percentage of the pre-NSPS coal-fired generating capacity. The technology reduces NO_x by staging combustion in the boiler vertically by separating coal and air injectors and horizontally by creating fuel-rich and lean zones with offset air nozzles. The objective was to determine NO_x emission reductions and impact on boiler performance over the long-term under normal dispatch and operating conditions. By using the same boiler, the demonstration provided direct comparative performance analysis of the three configurations. Short-term parametric testing enabled extrapolation of results to other tangentially-fired units by evaluating the relationship between NO_x emissions and key operating parameters.

Exhibit 27
LNCFS™ Configurations

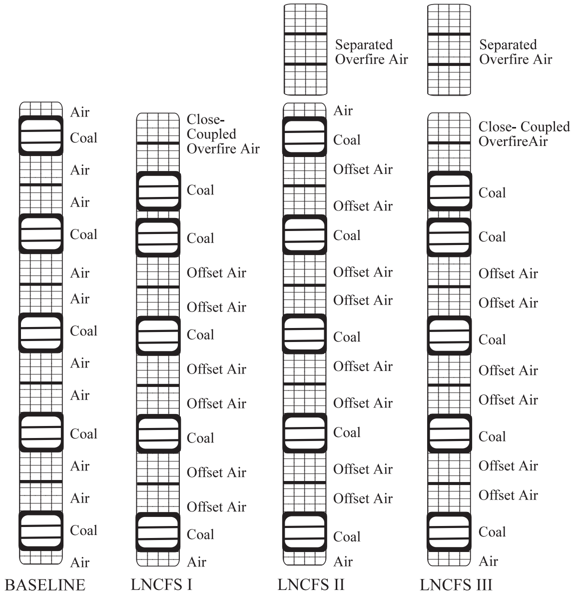
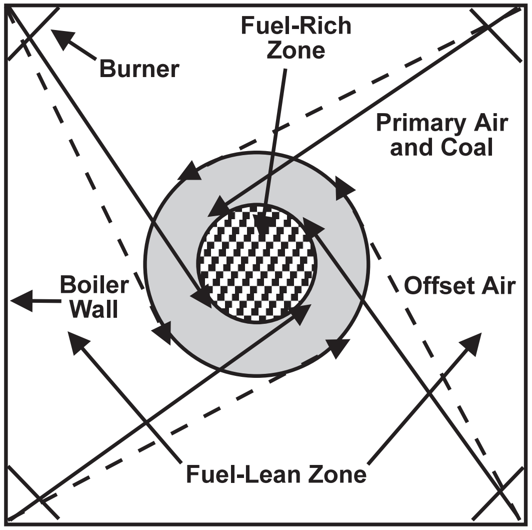


Exhibit 27 shows the various LNCFS™ configurations used to achieve staged combustion. In addition to overfire air, as shown in Exhibit 28, the LNCFS™ incorporates other NO_x-reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The majority 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 annulus of combustion air can be varied using adjustable offset air nozzles.

Operational Performance

Exhibit 29 summarizes the impacts of LNCFS™ on unit performance.

Exhibit 28
Concentric Firing Concept



Environmental Performance

At full load, LNCFS™ I, II, and III reduced NO_x emissions by 37, 37, and 45%, respectively. Exhibit 30 presents the NO_x emission estimates obtained in the assessment of the average annual NO_x emissions for three dispatch scenarios.

Air toxics testing found LNCFS™ to have no clear-cut effect on the emission of trace metals or acid gases. The data provided marginal evidence for a decreased emission of chromium. The effect on aldehydes/ketones could not be assessed because baseline data were compromised. VOCs appeared to be reduced and semi-volatile compounds increased. The increase in semi-volatile compounds was deemed to be consistent with increases in the amount of unburned carbon in the ash.

Economic Performance

LNCFS™ II was the only complete retrofit (LNCFS™ I and III were modifications of LNCFS™ II), and therefore capital cost estimates were based on the Lansing Smith Unit No. 2 retrofit as well as other tangentially-fired LNCFS™ retrofits. The capital cost ranges in 1993 constant dollars follow:

- LNCFS™ I—$5–15/kW
- LNCFS™ II—$15–25/kW
- LNCFS™ III—$15–25/kW

Site-specific considerations have a significant effect on capital costs; however, the above ranges reflect actual experience and are planning estimates. The actual capital cost for LNCFS™ II at Lansing Smith Unit No. 2 was $3 million, or $17/kW, which falls within the projected range.

The cost effectiveness of the LNCFS™ technologies is based on the capital and operating and maintenance costs and the NO_x removal efficiency of the technologies. The cost effectiveness of the LNCFS™ technologies is listed below (based on a levelization factor of 0.144 in 1993 constant dollars):

- LNCFS™ I—$103/ton of NO_x removed
- LNCFS™ II—$444/ton of NO_x removed
- LNCFS™ III—$400/ton of NO_x removed

Commercial Applications

LNCFS™ technology has potential commercial application to all the nearly 600 U.S. pulverized coal, tangentially-fired utility units. These units range from 25-MWe to 950-MWe in size and fire a wide range of coals, from low-volatile bituminous through lignite.

LNCFS™ has been retained at the host site for commercial use. ABB Combustion Engineering has modified 116 tangentially-fired boilers, representing over 25,000 MWe, with LNCFS™ and derivative TFS 2000™ burners.

Exhibit 29
Unit Performance Impacts Based on Long-Term Testing

	Baseline	LNCFS™ I	LNCFS™ II	LNCFS™ III
Avg CO at full load (ppm)	10	12	22	33
Avg excess O_2 at full load (%)	3.7	3.2	4.5	4.3
LOI at full load (%) O_2 (%)	4.8 4.0	4.6 3.9	4.2 5.3	5.9 4.7
Steam outlet conditions	Satisfactory at full load; low temperpatures at low loads	Full load: 5–10 ºF lower than baseline Low loads: 10–30 ºF lower than baseline	Same as baseline	160–200-MWe: OK 80-MWe: 15–35 ºF lower than baseline
Furnace slagging and backpass fouling	Medium	Medium	Reduced slagging, but increased fouling	Reduced slagging, but increased fouling
Operating flexibility	Normal	Same as baseline	More care required at low loads	More difficult to operate than other systems
Boiler efficiency (%) Efficiency change	90 N/A	90.2 +0.2	89.7 -0.3	89.85 -0.15
Turbine heat rate (Btu/kWh)	9,000	9,011	9,000	9,000
Unit net heat rate (Btu/kWh) Change (%)	9,995 N/A	9,986 -0.1	10,031 +0.36	10,013 +0.18

Exhibit 30
Average Annual NO_x Emissions and Percent Reduction

Boiler Duty Cycle	Units	Baseline	LNCFS™ I	LNCFS™ II	LNCFS™ III
Baseload (161.8-MWe avg)	Avg NO_x emissions (lb/10^6 Btu) Avg reduction (%)	0.62	0.41 38.7	0.41 38.7	0.36 42.2
Intermediate load (146.6-MWe avg)	Avg NO_x emissions (lb/10^6 Btu) Avg reduction (%)	0.62	0.40 39.2	0.41 35.9	0.34 45.3
Peaking load (101.8-MWe avg)	Avg NO_x emissions (lb/10^6 Btu) Avg reduction (%)	0.59	0.45 36.1	0.47 20.3	0.43 28.0

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References

- *180-MWe Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Final Report and Key Project Findings*. Report No. DOE/PC/89653-T14. Southern Company Services, Inc. February 1994. (Available from NTIS as DE94011174.)
- *180-MWe Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers—Plant Lansing Smith—Phase III and Final Environmental Monitoring Program Report.* Southern Company Services, Inc. December 1993.
- *Measurement of Chemical Emissions under the Influence of Low-NO_x Combustion Modifications*. Report No. DOE/PC/89653-T12. Southern Company Services, Inc. October 1993. (Available from NTIS as DE94005038.)
- *180-MW Demonstration of Advanced Tangentially-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Public Design Report.* Report No. DOE/PC/89652-T13. Southern Company Services, Inc. September 1993. (Available from NTIS as DE94000218.)

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Project completed.

Participant

Southern Company Services, Inc. (SCS)

Additional Team Members

Electric Power Research Institute (EPRI)—cofunder
Foster Wheeler Energy Corporation (Foster Wheeler)—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) and EPRI's Generic NO$_x$ Control Intelligence System (GNOCIS) computer software.

Plant Capacity/Production

500-MWe

Coal

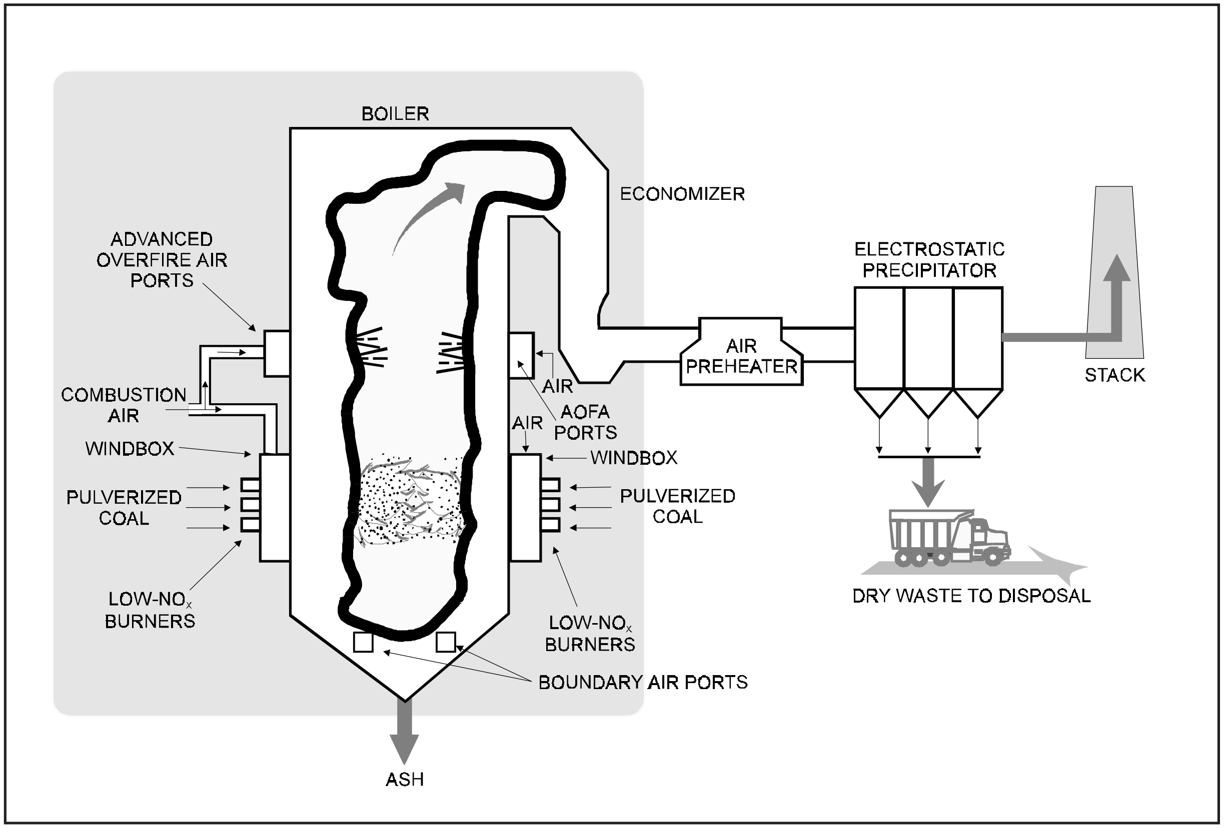
Eastern bituminous coals, 1.7% sulfur

Project Funding

Total project cost	$15,853,900	100%
DOE	6,553,526	41
Participant	9,300,374	59

Project Objective

To achieve 50% NO$_x$ reduction with the LNB/AOFA system; to determine the contributions of AOFA and LNB to NO$_x$ reduction and the parameters for optimal LNB/AOFA performance; and to assess the long-term effects of LNB, AOFA, combined LNB/AOFA, and the Generic NO$_x$ Control Intelligence System advanced digital controls on NO$_x$ reduction and boiler performance.

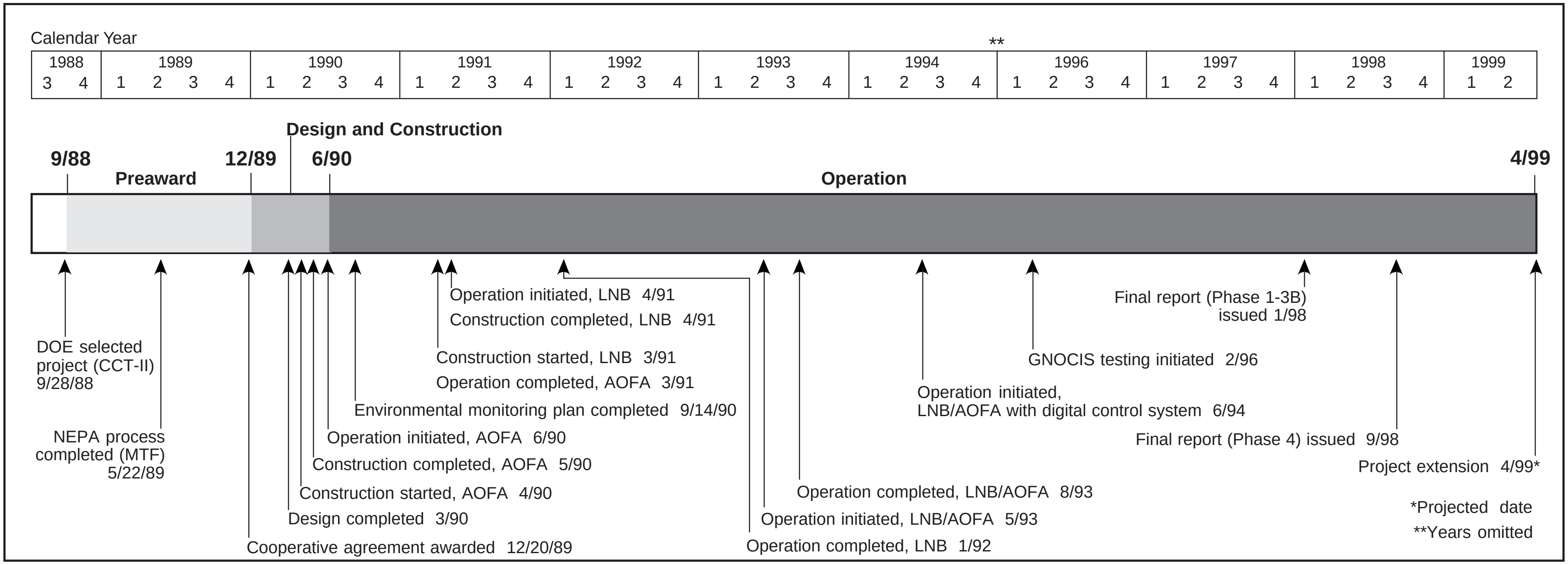


Technology/Project Description

AOFA involves (1) improving overfire air (OFA) mixing to lower overall stoichiometry (less total excess air) while still avoiding high unburned combustible losses, (2) allowing deeper staging (sub-stoichiometric conditions in the flame zone, i.e., reducing atmosphere) without increasing combustible losses, and (3) introducing "boundary air" at the boiler walls to prevent corrosion caused by the reducing atmosphere.

In the Foster Wheeler Controlled Flow/Split Flame (CFSF) LNB, fuel and air mixing (staged combustion) is controlled for localized, individual burner flames, rather than on a gross furnace-wide basis, by regulating the primary air/fuel mixture, velocities, and turbulence to create a fuel-rich core with sufficient air to sustain combustion at a severely sub-stoichiometric air/fuel ratio. The burner also controls the rate at which additional air necessary to complete combustion is mixed with the flame solids and gases so as to maintain a deficiency of oxygen until the remaining combustibles fall below the peak NO$_x$ producing temperature (around 2800 °F). The final excess air can then be allowed to mix with the unburned products so that combustion is completed at a relatively low temperature.

The demonstration was conducted at Plant Hammond Unit No. 4, which is a nominal 500-MWe Foster Wheeler pulverized coal opposed wall-fired unit that typifies many existing pre-NSPS wall-fired boilers in the United States. To accomplish the project objective,



the project was partitioned into the following test phases: (1) Baseline, (2) AOFA, (3A) LNB, (3B) LNB/AOFA, and (4) GNOCIS. Each phase involved three distinct testing periods—short-term characterization (diagnostic, performance, and chemical emission tests), long-term characterization (50-80 continuous days), and short-term verification. Furthermore, air toxics testing was conducted during test phases 2 and 3A and a demonstration of on-line carbon-in-ash monitors was conducted during several of the test phases.

Results Summary

Operational

- At full load, fly ash loss-on-ignition (LOI) was near 8% (compared to a baseline of 5%) for LNB alone and LNB/AOFA combined.
- AOFA accounted for an incremental NO_x reduction beyond the use of LNB of approximately 17%, with additional reductions resulting from other operational changes.
- GNOCIS achieved a boiler efficiency gain of 0.5 percentage points, a reduction in fly ash LOI levels of 1-3 percentage points, and a reduction in NO_x emissions of 10-15% at full load.

Environmental

- Using LNB alone, long-term NO_x emissions were 0.65 lb/10^6 Btu, representing a 48% reduction from baseline conditions (1.24 lb/10^6 Btu).
- Using AOFA only, long-term NO_x emissions were 0.94 lb/10^6 Btu, representing a 24% reduction from baseline conditions.
- Using LNB/AOFA, long-term NO_x emissions were 0.40 lb/10^6 Btu, which represents a 68% reduction from baseline conditions.
- There was not a significant difference in emissions of trace metals, acid gases, and volatile organic compounds between AOFA and LNB operations. But, there was a slight downward trend in emissions during LNB/AOFA operation.

Economic

- Capital cost for a 500 MWe wall-fired unit is $8.8/kW for AOFA alone, $10.0/kW for LNB alone, $18.8/kW for LNB/AOFA, and $0.5/kW for GNOCIS.
- Estimated cost of NO_x removal is $86/ton using LNB/AOFA.

Project Summary

Operational

SCS conducted baseline characterization of the unit in an “as-found” condition from August 1989 to April 1990. The AOFA system was tested from August 1990 to March 1991. Following installation of the LNBs in the second quarter of 1991, the LNBs were tested from July 1991 to January 1992, excluding a three-month delay when the plant ran at reduced capacity. Post-LNB increases in fly ash LOI, along with increases in combustion air requirements and fly ash loading to the electrostatic precipitator (ESP), adversely affected the unit’s stack particulate emissions. The LNB/AOFA testing was conducted from

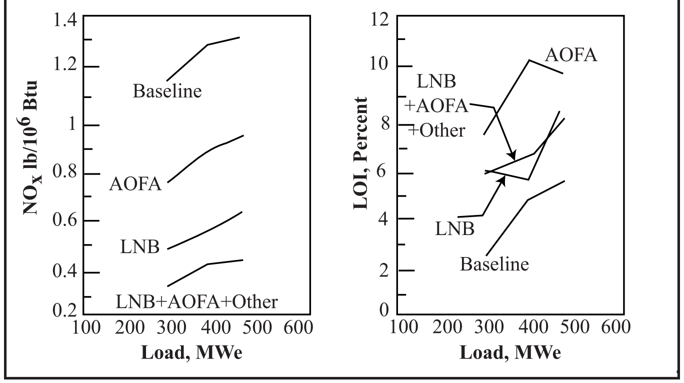
January 1992 to August 1993, excluding downtime for a scheduled outage and for portions of the test period due to excessive particulate emissions. However, an ammonia flue gas conditioning system was added to improve ESP performance, which enabled the unit to operate at full load and testing to continue.

LOI increased significantly for the AOFA, LNB, and LNB/AOFA phases as seen in Exhibit 31, despite improved mill performance due to the replacement of the mills. Increased LOI was a concern not only because of the associated efficiency loss, but a potential loss of fly ash sales. The increased carbon in the fly ash renders the material unsuitable for use in making concrete.

During October 1992, SCS conducted parametric testing to determine the relationship between NO_x and LOI emissions. The parameters tested were: excess oxygen, mill coal flow bias, burner sliding tip position, burner outer register position, and burner inner register position. Nitrogen oxide emissions and LOI levels varied from 0.44–0.57 lb/10^6 Btu and 3–10%, respectively. As expected, excess oxygen level had considerable effect on both NO_x and LOI. The results showed that there is some flexibility in selecting the optimum operating point and making tradeoffs between NO_x emissions and fly ash LOI; however, much of the variation was the result of changes in excess oxygen. This can be more clearly seen in Exhibit 32 in which all sensitivities are plotted. This exhibit shows that for excess oxygen, mill bias, inner register, and sliding tip, any adjustments to reduce NO_x emissions are at the expense of increased fly ash LOI. In contrast, the slope of the outer register characteristic suggests improvement in both NO_x emissions and LOI can be achieved by adjustment of this damper. However, due to the relatively small impact of the outer register adjustment on both NO_x and LOI, it is likely the positive NO_x/LOI slope is an artifact of process noise.

Exhibit 31

LOI Performance Test Results



A subsidiary goal of the project was to evaluate advanced instrumentation and controls (I&C) as applied to combustion control. The need for more sophisticated I&C equipment is illustrated in Exhibit 33. There are tradeoffs in boiler operation, e.g., as excess air increases, NO_x increases, LOI decreases, and boiler losses increase. The goal is to find and maintain an optimal operating condition. The I&C systems tested included GNOCIS and carbon-in-ash analyzers.

The GNOCIS software applies an optimizing procedure to identify the best set points for the plant, which are implemented automatically without operator intervention (closed-loop), or conveyed to the plant operators for implementation (open-loop). The major elements of GNOCIS are shown in Exhibit 34. The GNOCIS system has provided advice that reduced NO_x emissions by 10-15% at full load, reduced fly ash LOI by 1-3 percentage points, and improved boiler efficiency by 0.5 percentage points.

Three carbon-in-ash monitors were installed: Applied Synergistics FOCUS, CAMRAC Corporation CAM, and Clyde-Sturtevant SEKAM. The monitors seemed to represent LOI trends well by responding in the correct direction and provided important and timely information on combustion performance.

Exhibit 32

NO_x vs. LOI Tests–All Sensitivities

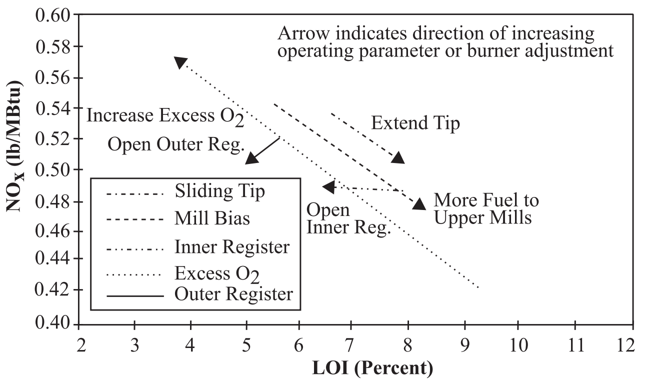
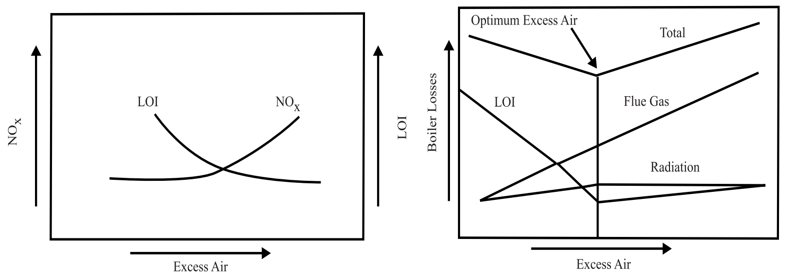


Exhibit 33

Typical Trade-Offs in Boiler Optimization



Environmental

Long-term testing showed that the AOFA, LNBs, and LNB/AOFA provide full load NO_x reductions of 24, 48, and 68%, respectively. The load-weighted average of NO_x emission reductions were 14, 48, and 63%, respectively, for AOFA, LNB, LNB/AOFA. Although the long-term LNB/AOFA NO_x level represents a 68% reduction from baseline levels, a substantial portion of the incremental change in NO_x emissions between the LNB and the LNB/AOFA configurations is the result of operational changes and is not the result of adding AOFA.

A total of 63 days of valid long-term NO_x emissions data were collected during the LNB/AOFA test phase. Based on this data set, the full-load, long-term NO_x emissions were 0.40 lb/10^6 Btu, which was consistent with earlier short-term test data. Earlier long-term testing had resulted in NO_x emissions of 0.94 lb/10^6 Btu and 0.65 lb/10^6 Btu for AOFA only and LNB only, respectively. For reference, long-term baseline testing revealed an initial NO_x emission rate of 1.4 lb/10^6 Btu.

Air toxic testing was conducted for AOFA and LNB/AOFA operation. There was not a significant difference in emissions of trace metals, acid gases, and volatile organic compounds for the two tests. There was a slight downward trend, however, in emissions during LNB/AOFA operation. For elements associated with particulate matter, ten (barium, beryllium, chromium, cobalt, copper, lead, manganese, nickel, phosphorus, and vanadium) show lower mean emissions during LNB/AOFA operation; only two (arsenic and cadmium) show higher mean emissions during LNB/AOFA operation. Total particulate matter emissions were also lower during LNB/AOFA operation; however, this was more an indication of ESP performance rather than burner configuration.

Economic

Estimated capital costs for a commercial 500 MWe wall-fired installation are: AOFA—$8.8/kW, LNB—$10.0/kW, LNB/AOFA—$18.8/kW, and GNOCIS—$0.5/kW. Annual O&M costs and NO_x reductions depend on the assumed load profile. Based on the actual load profile observed in the testing, the estimated annual O&M cost increase for LNB and AOFA is $333,351. Efficiency is decreased by 1.3 percent, and the NO_x reduction is 68 percent of baseline, or 11,615 tons/year. The capital cost is $8,300,000 and the calculated cost of NO_x removed is $86/ton.

The addition of GNOCIS to the LNB/AOFA, using the actual load profile observed in the testing, results in a range of costs depending on whether the unit is operated to maximize NO_x removal efficiency, or LOI. For the maximum NO_x removal case, the efficiency is improved by 0.6 percent, the annual O&M cost is decreased by $228,058, the incremental NO_x reduction is 11 percent (834 tons/year), and the capital cost is $250,000. The calculated cost per ton of NO_x removed is -$299 (net gain due to increased efficiency).

Commercial Applications

The technology is applicable to the 422 existing pre-NSPS wall-fired boilers in the United States, which burn a variety of coals. The GNOCIS technology is applicable to all fossil fuel-fired boilers, including units fired with natural gas and units co-firing coal and natural gas.

The host has retained the technologies for commercial use. Foster Wheeler has equipped 86 boilers with low-NO_x burner technology (51 domestic and 35 international)—1,800 burners for over 30,000 MWe capacity. Some 19 GNOCIS neural-network control projects are underway and another 17 projects are expected in 1999.

Contacts

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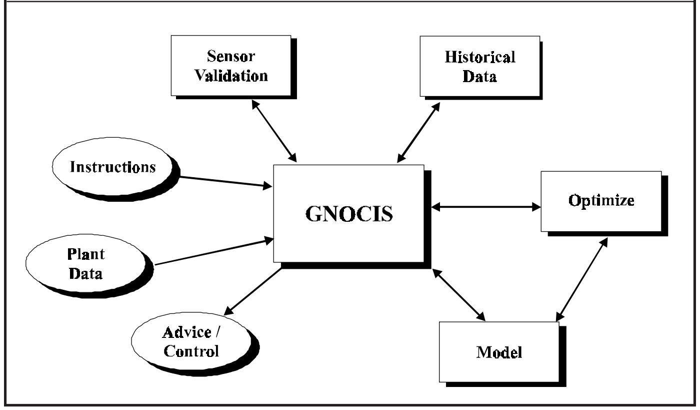
Exhibit 34

Major Elements of GNOCIS



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- *500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers*–Final Report—Phases 1-3. Southern Company Services, Inc. January 1998.
- 500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers–Public Design Report (Preliminary and Final). Southern Company Services, Inc. Submitted to DOE on May 24, 1996.

Environmental Control Devices
Combined SO_2/NO_x Control Technology

Milliken Clean Coal Technology Demonstration Project

Project completed.

Participant

New York State Electric & Gas Corporation

Additional Team Members

New York State Energy Research and Development Authority—cofunder
Empire State Electric Energy Research Corporation—cofunder
Consolidation Coal Company—technical consultant
Saarberg-Hölter-Umwelttechnik, GmbH (S-H-U)—technology supplier
The Stebbins Engineering and Manufacturing Company—technology supplier
ABB Air Preheater, Inc.—technology supplier
DHR Technologies, Inc. (DHR)—operator of advisor control system

Location

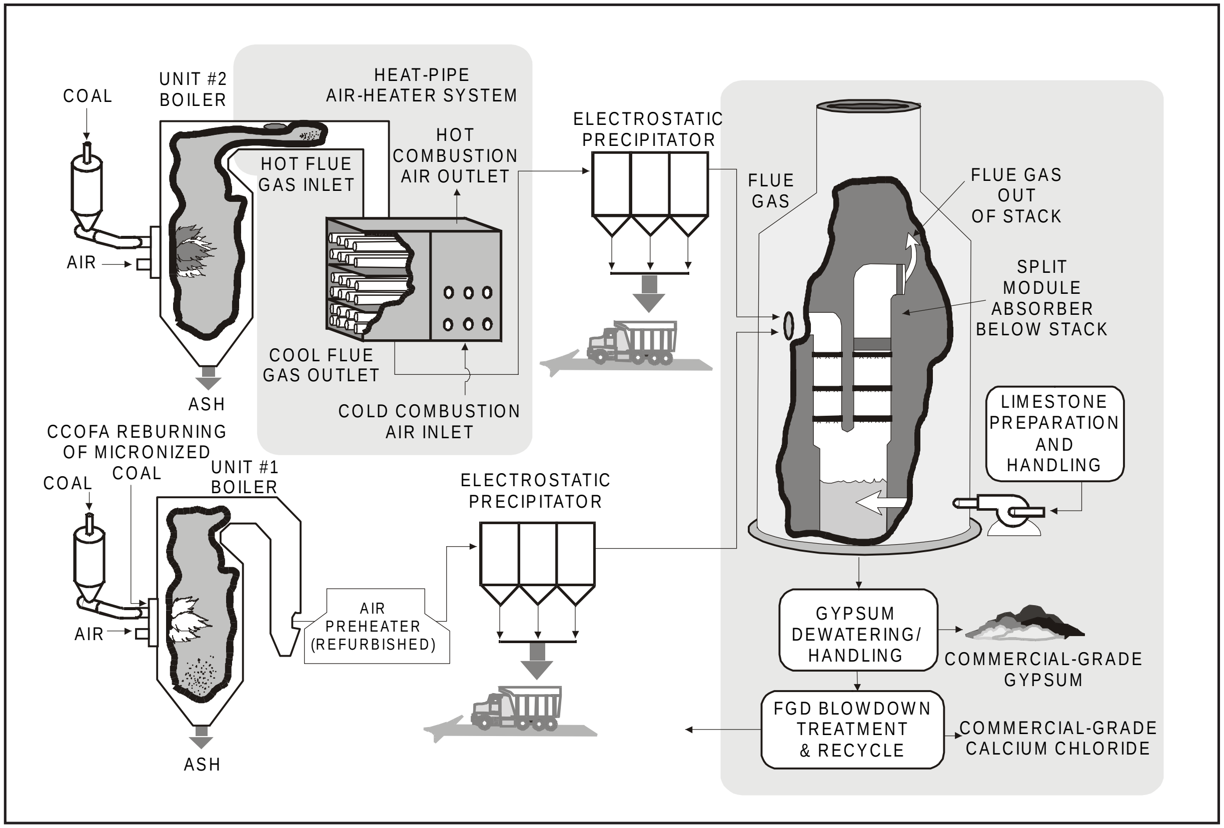
Lansing, Tompkins County, NY (New York State Electric & Gas Corporation's Milliken Station, Unit Nos. 1 and 2)

Technology

Flue gas cleanup using S-H-U formic-acid-enhanced, wet limestone scrubber technology; ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) Level III; Stebbins' tile-lined split-module absorber; ABB Air Preheater's heat-pipe air preheater; and DHR's PEOA™ Control System.

Plant Capacity/Production

300-MWe



Coal

Pittsburgh, Freeport, and Kittanning Coals; 1.5, 2.9 and 4.0% sulfur, respectively.

Project Funding

Total project cost	$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

Project Objective

To demonstrate high sulfur capture efficiency and NO_x and particulate control at minimum power requirements, zero waste water discharge, and the production of by-products in lieu of wastes.

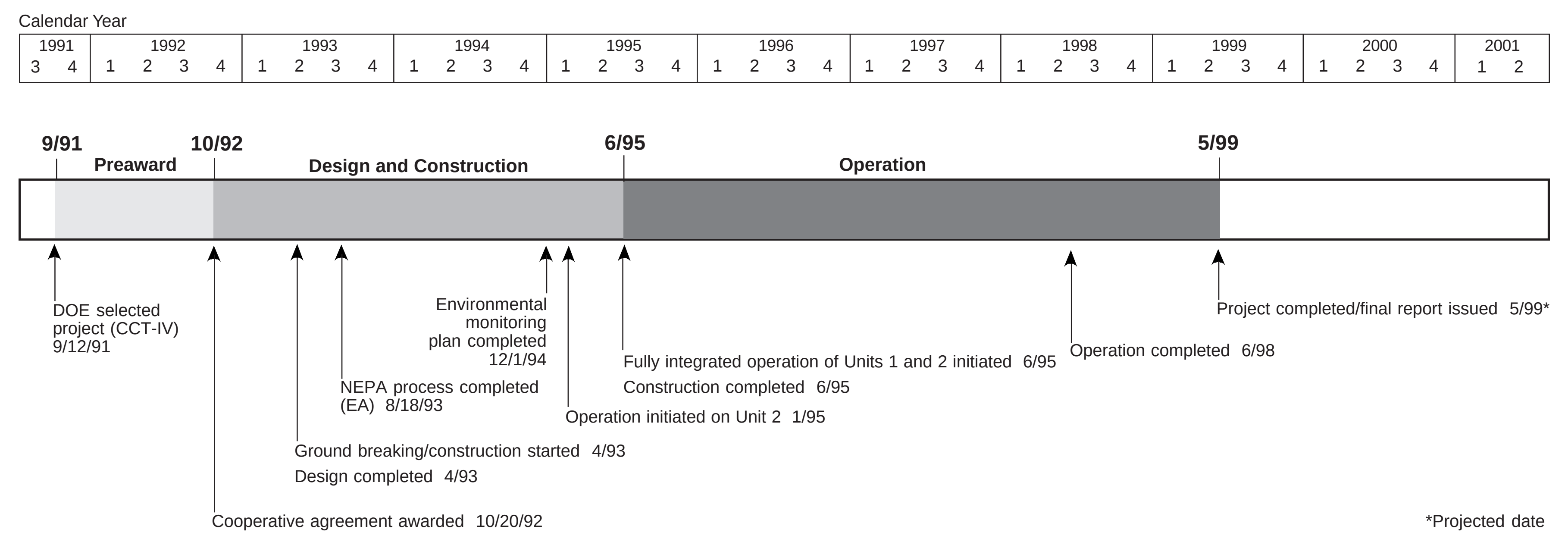
Technology/Project Description

The formic acid enhanced S-H-U process is designed to remove up to 98% SO_2 at high sorbent utilization rates. The Stebbins tile-line, split-module reinforced concrete absorber vessel provides superior corrosion and abrasion resistance. Placement below the stack saves space and provides operational flexibility.

NO_x emissions are controlled by LNCFS III™ low-NO_x burners and by micronized coal reburning. The LNCFS III™ low-NO_x burners are integrated into the Milliken units. (See Micronized Coal Reburning Demonstration for NO_x Control for another CCT Program project at this unit.)

A heat-pipe air preheater is integrated to increase boiler efficiency by reducing both air leakage and the air preheater's flue gas exit temperature. To enhance boiler efficiency and emissions reductions, DHR's Plant Emission Optimization Advisor (PEOA™) provides state-of-the-art artificial-intelligence-based control of key boiler and plant operating parameters.

LNCFS is a trademark of ABB Combustion Engineering, Inc.
PEOA is a trademark of DHR Technologies, Inc.



Results Summary

Environmental

- The maximum SO_2 removal demonstrated has been 98% with all seven recycle pumps operating and using formic acid. The maximum SO_2 removal without formic acid has been 95%.
- The difference in SO_2 removal between the two limestone grind sizes tested (90%–325 mesh and 90%–170 mesh) while using low sulfur coal was a minimum of 2.6 percentage points.
- The SO_2 removal efficiency was greater than the design efficiency during the high velocity test of the cocurrent scrubber section up to a liquid-to-gas ratio (L/G) of 110 gallons per 1,000 actual cubic feet of gas.
- The cocurrent pumps had no measurable effect on pressure drop, whereas the countercurrent pumps significantly increased the scrubber pressure drop. The average effect of each countercurrent header was to increase pressure drop by 0.45 inches water column (WC) in the design flow tests and 0.64 inches WC in the high velocity tests.
- At full load, LNCFS™ III lowered NO_x emissions to 0.39 lb/10^6 Btu (compared to 0.64 lb/10^6 Btu for the original burners).
- During diagnostic tests, LOI was above 4% at full boiler load. During the validation tests (when overfire air limitations were relaxed), the LOI dropped by 0.7 to 1.7 percentage points, with a minor effect on NO_x emissions.

Operational

- Performance of a modified ESP with wider plate spacing and reduced plate area exceeded that of the original ESPs at lower power consumption.
- Boiler efficiency was 88.3–88.5% for LNCFS™ III, compared to a baseline of 89.3–89.6%.
- Air infiltration is low for both heat pipes. Some unaccounted for air leakage occurred at full load, ranging between 2.0–2.4%.
- The flue gas side pressure loss for both heat pipes was less than the design maximum of 3.65 inches WC. The primary side pressure drops for both heat pipes were less than the design maximum of 3.6 inches WC. The secondary air side pressure drops for both heat pipes were less than the design maximum of 5.35 inches WC.

Economic

- Economic data is not yet available.

Project Summary

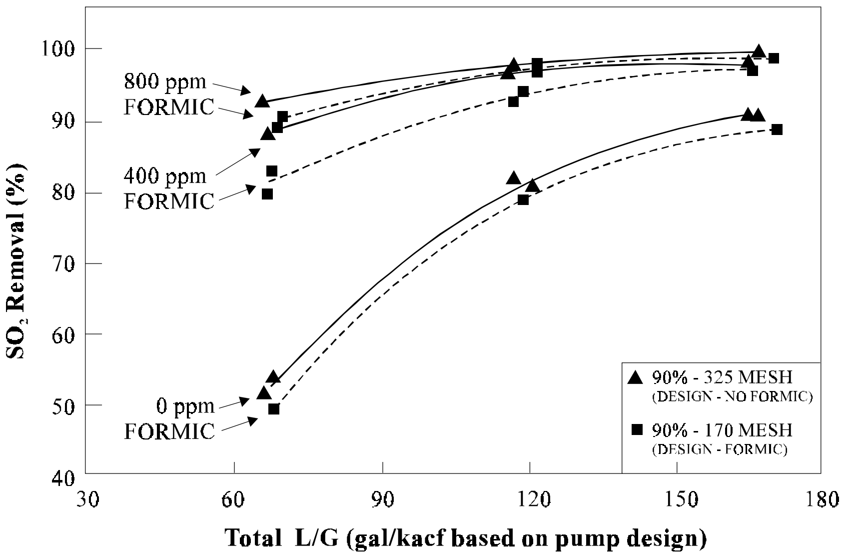
The test plan was developed to cover all of the new technologies used in the project. In addition to the technologies tested, the project demonstrated that existing technologies can be used in conjunction with new processes to produce saleable by-products. Supplemental monitoring has provided operation and performance data illustrating the success of these processes under a variety of operating conditions. Generally, each test program was divided into four independent subtests: diagnostic, performance, long-term, and validation.

Environmental Performance

The S-H-U FGD system was tested over a 36 month period. Typical evaluations included SO_2 removal efficiency, power consumption, process economics, load following capability, reagent utilization, by-product quality, and additive effects. Parametric testing included formic acid concentration, L/G ratio, mass transfer, coal sulfur content, and flue gas velocity. The maximum SO_2 removal demonstrated was 98% with all seven recycle pumps operating and using formic acid and the maximum SO_2 removal without formic acid was 95%. The difference in SO_2 removal between the two limestone grind sizes tested (90%–325 mesh and 90%–170 mesh), while using low sulfur coal was a minimum of 2.6 percentage points as shown in Exhibit 35. The SO_2 removal efficiency was greater than the design efficiency during the high velocity test of the cocurrent scrubber section up to a liquid-to-gas ratio of 110. The cocurrent pumps had no measurable effect on pressure drop, whereas the countercurrent pumps significantly increased the scrubber pressure drop. As seen in Exhibit 36, the average effect of each countercurrent header was to increase pressure drop by 0.45 inches water column (WC) in the design flow tests and 0.64 inches WC in the high velocity tests.

Exhibit 35

Effect of Limestone Grind



Performance of modified ESP with wider plate spacing and reduced plate area exceeded that of the original ESPs at lower power consumption. The average particulate matter penetration before the ESP modification was 0.22% and decreased to 0.12% after the modifications.

At full boiler load (145–150 MWe) and 3.0–3.5% economizer O_2, the LNCFS™ III lowered NO_x emissions from a baseline of 0.64 lb/10^6 Btu to 0.39 lb/10^6 Btu (39% reduction). At 80-90 MWe boiler load and 4.3–5.0% economizer O_2, the LNCFS™ III lowered NO_x emissions from a baseline of 0.58 lb/10^6 Btu to 0.41 lb/10^6 Btu (29% reduction). With LNCFS™ III, LOI was maintained below 4% and CO emissions did not increase.

Operational Performance

The S-H-U FGD system performance goal of 98% SO_2 removal efficiency was achieved. Similarly, the objective of producing a marketable gypsum by-product from the FGD system was achieved. The test results indicate that the gypsum produced can be maintained at a purity level exceeding 95% with a chloride level less than 100 ppm. However, the goal of producing a marketable calcium chloride solution from the FGD blowdown stream was not achieved. FGD availability for the test period was 99.9%.

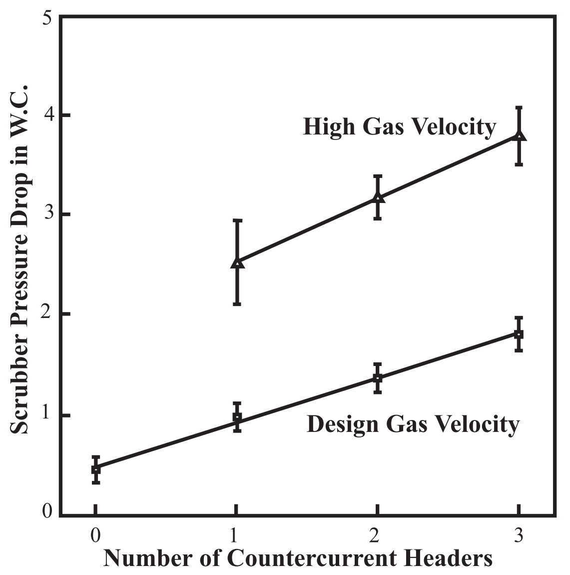
The modified ESP has performed better than the original ESP at a lower power use. The total voltage• current product (V•I) for ESPs is directly proportional to the total power requirement. The modified ESP 75% of the V•I demand of the original ESPs. The modified ESP has a smaller plant footprint with fewer internals and a smaller SCA. Total internal plate area is less than one-half that of the original ESPs, tending to lower capital costs.

Boiler efficiency was 88.3–88.5% for LNCFS™ III, compared to a baseline of 89.3–89.6%. The lower efficiency was attributed to higher post retrofit flue gas O_2 and higher stack temperatures which accompanied the air heater retrofit. When LNCFS™ III and baseline conditions are compared, boiler efficiency with LNCFS™ III was 0.2 percentage points higher than baseline.

The heat pipe were tested in accordance with ASME Power Test Code for Air Heaters 4.3. Air infiltration is low for both heat pipes. Unaccounted for air leakage occurred at full load, ranging between 2.0–2.4%. The tests showed that the flue gas side pressure loss for both heat pipes was less than the design maximum of 3.65 inches WC. The primary side pressure drops for both heat pipes were less than the design maximum of 3.6

Exhibit 36

Pressure Drop vs. Countercurrent Headers



inches WC. The secondary air side pressure drops for both heat pipes were less than the design maximum of 5.35 inches WC.

Economic Performance

Economic data is not yet available.

Commercial Applications

The S-H-U process, stebbins absorber module and heat-pipe air preheater are applicable to virtually all power plants. The space-saving design features of the technologies, combined with the production of marketable byproducts, offer significant incentives to generating stations with limited space. There have been four commercial sales of the PEOA™ system.

Contacts

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- *Milliken Clean Coal Technology Demonstration Project.* Harvilla, James et al. *Sixth Clean Coal Technology Conference: Clean Coal for the 21st Century — What Will It Take? Volume II - Technical Papers.* CONF-980410— VOL II. April 28-May 1, 1998.

Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System

Participant

NOXSO Corporation

Additional Team Members

Olin Corporation—cofunder
Gas Research Institute—cofunder
Electric Power Research Institute—cofunder
W.R. Grace and Company—cofunder
M.K. Ferguson—engineer
Richmond Power & Light (RP&L)—host

Location

To be determined

Technology

NOXSO Corporation's dry, regenerable flue gas cleanup process

Plant Capacity/Production

To be determined

Coal

Medium- to high-sulfur coals

Project Funding

Total project cost	$82,812,120	100%
DOE	41,406,060	50
Participant	41,406,060	50

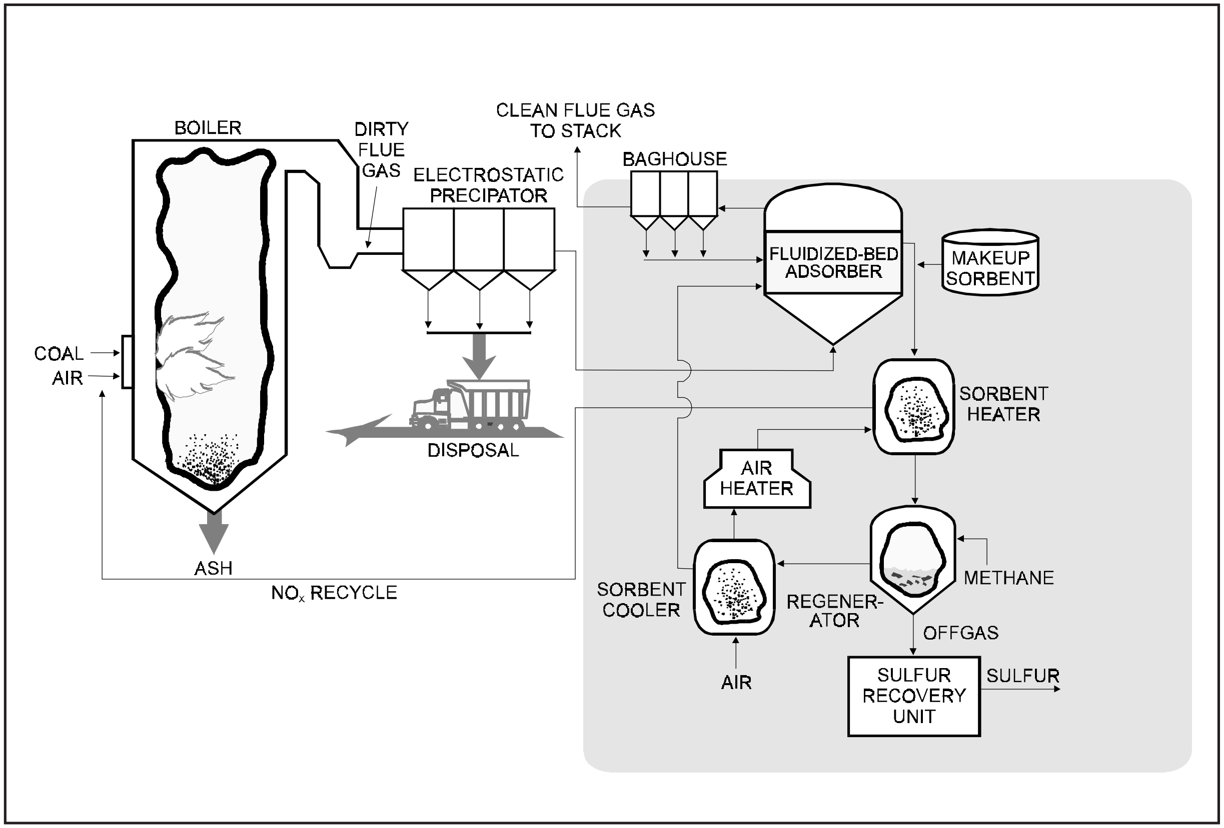
Project Objective

To demonstrate removal of 98% of the SO_2 and 75% of the NO_x from a coal-fired boiler's flue gas using the NOXSO process.

Technology/Project Description

The NOXSO process is a dry, regenerable system capable of removing both SO_2 and NO_x in flue gas from coal-fired utility boilers burning medium- to high-sulfur coals. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; SO_2 and NO_x are adsorbed by the sorbent, which consists of spherical beads of high-surface-area alumina impregnated with sodium carbonate. Cleaned flue gas then passes through a baghouse to the stack.

The NO_x is desorbed from the NOXSO sorbent when heated by a stream of hot air. Hot air containing the desorbed NO_x is recycled to the boiler where equilibrium processes cause destruction of the NO_x. The adsorbed sulfur is recovered from the sorbent in a regenerator where it reacts with methane at high temperature to produce an offgas with high concentrations of SO_2 and hydrogen sulfide (H_2S). This offgas is processed to produce elemental sulfur, which can be further processed to produce liquid SO_2, a higher valued by-product.

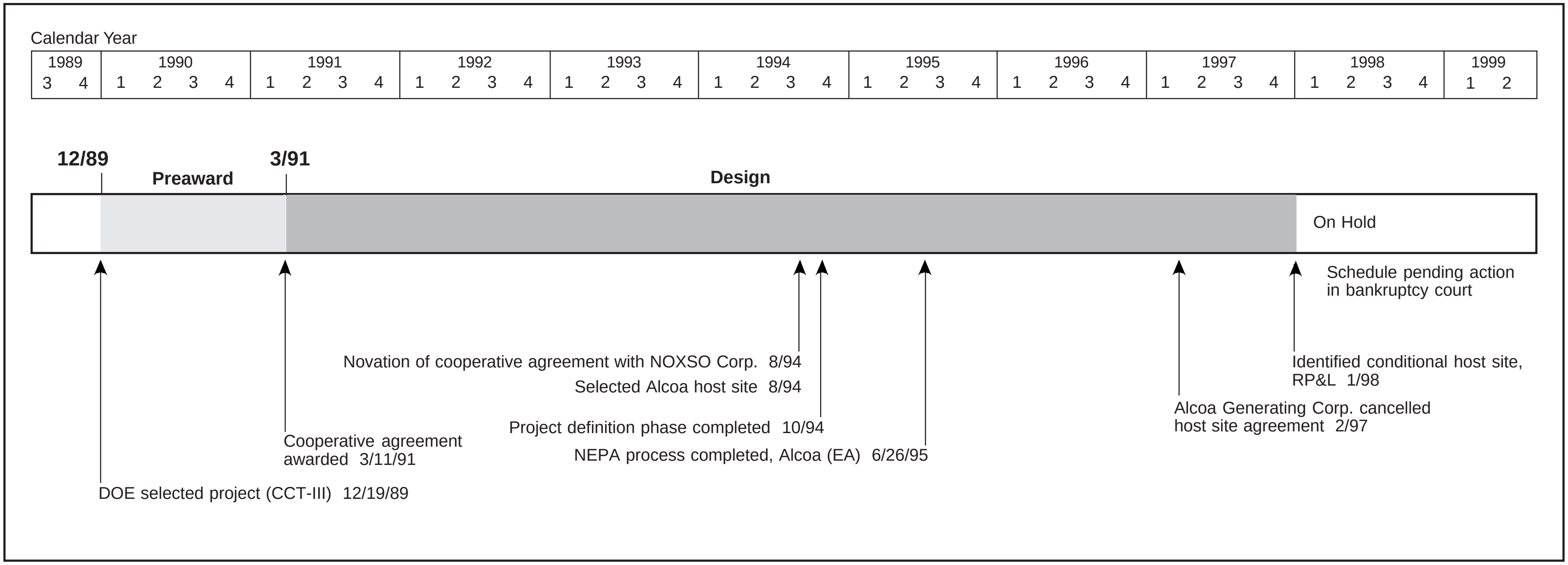


The process is expected to achieve SO_2 reductions of 98% and NO_x reductions of 75%.

Project Status/Accomplishments

Alcoa Generating Corporation chose to cancel a host site agreement when NOXSO was unable to obtain full project financing by January 31, 1997, as specified in the agreement. NOXSO signed a conditional Host Site Agreement with RP&L in January 1998.

NOXSO filed for bankruptcy under Chapter 11 - Reorganization. The Chapter 11 plan was approved by the Bankruptcy Court on September 2, 1998, but NOXSO was unable to raise sufficient funds. NOXSO closed its office in October 1998. An auction of NOXSO's assets is scheduled for May 27, 1999.



Commercial Applications

The NOXSO process is applicable to existing or new facilities. The process is suitable for utility and industrial coal-fired boilers. The process is adaptable to coals with medium- to high-sulfur content.

The process produces one of the following as a salable by-product: elemental sulfur, sulfuric acid, or liquid SO_2. A readily available market exists for these products.

The technology is expected to be especially attractive to utilities that require high removal efficiencies for both SO_2 and NO_x, need to eliminate solid wastes, and/or have inadequate water supply for a wet scrubber.

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

Coal

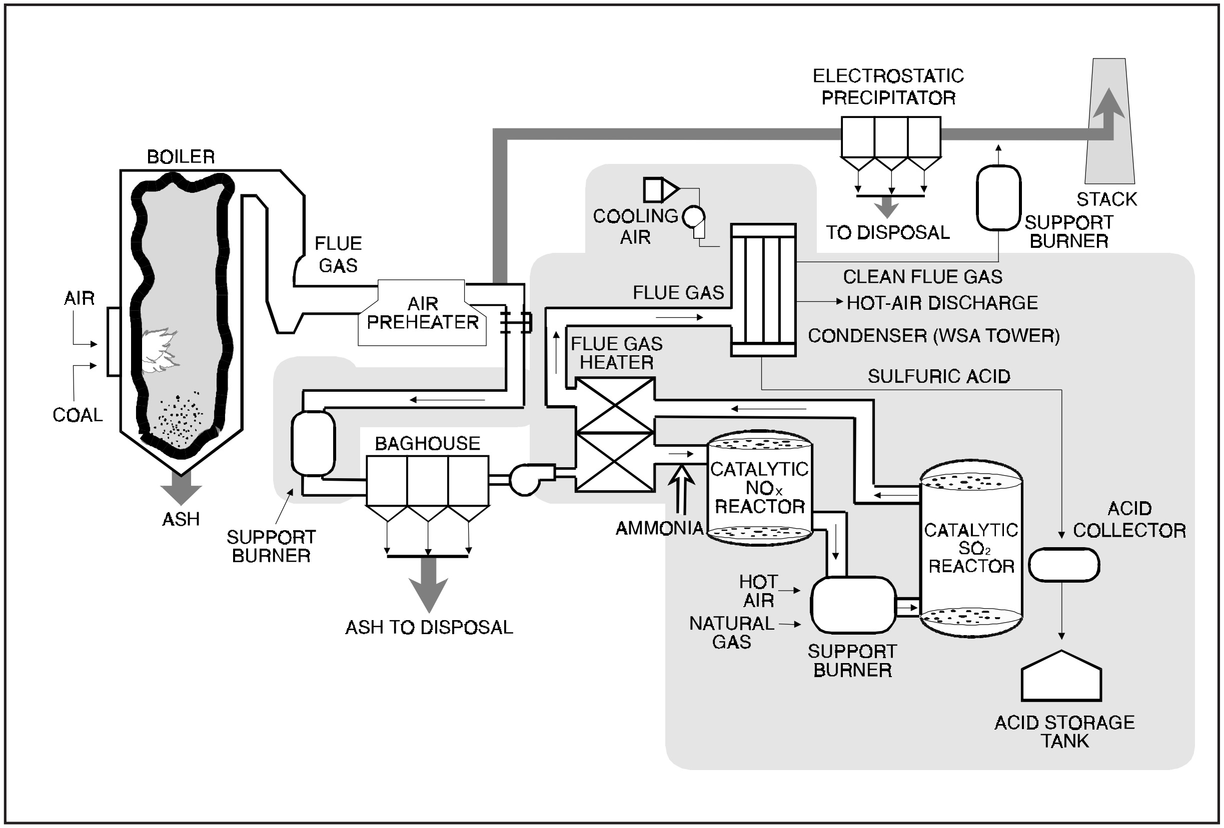
Ohio bituminous, 3.4% sulfur

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. high-sulfur 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.



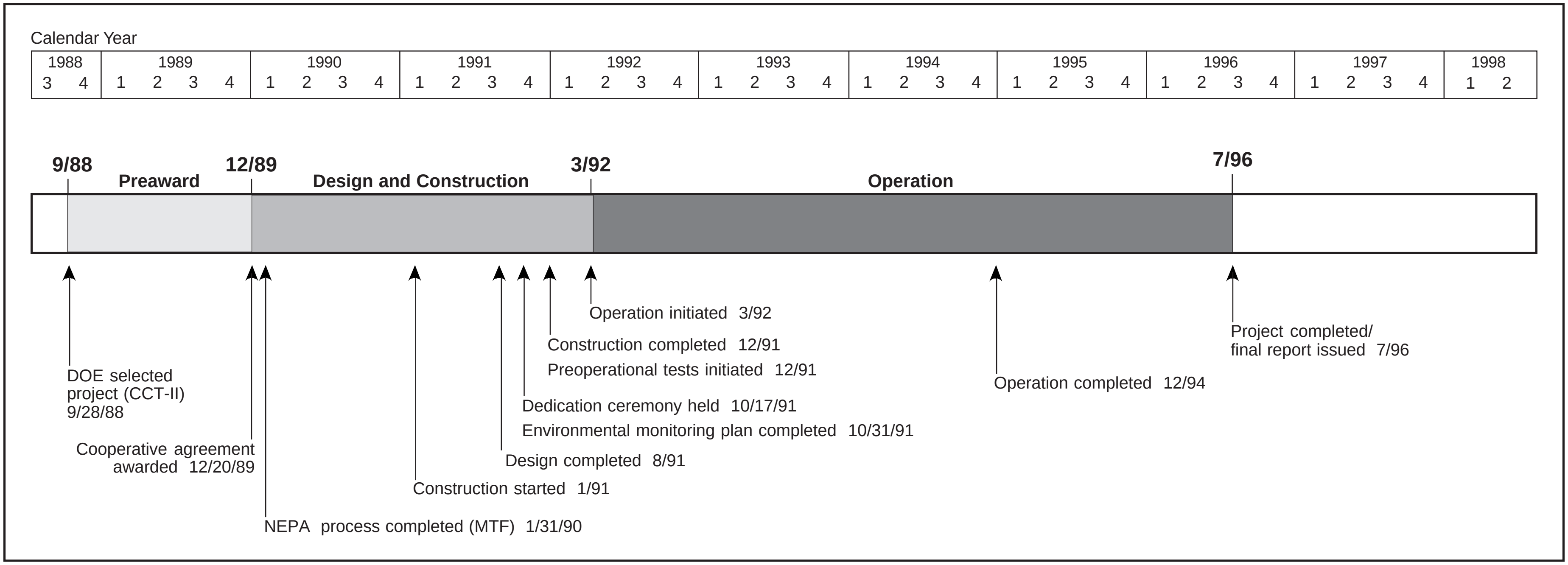
Technology/Project Description

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 that allows SO_3 to hydrolyze to concentrated sulfuric acid.

The technology, while using U.S. coals, was 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 was accomplished without using sorbents and without creating waste streams.

The demonstration was conducted at Ohio Edison's Niles Station in Niles, Ohio. 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.



Results Summary

Environmental

- SO_2 removal efficiency was normally in excess of 95% for inlet concentrations averaging about 2,000 ppm.
- NO_x reduction averaged 94% for inlet concentrations of approximately 500–700 ppm.
- Particulate removal efficiency for the high-efficiency fabric filter baghouse with SNOX™ system was greater than 99%.
- Sulfuric acid purity exceeded federal specifications for Class I acid.
- Air toxics testing showed high capture efficiency of most trace elements in the baghouse. A significant portion of the boron and almost all of the mercury escaped to the stack. But selenium and cadmium, normally a problem, were effectively captured in the acid drain, as were organic compounds.
- Absence of an alkali reagent contributed to having no secondary pollution streams or increases in CO_2 emissions.
- Presence of the SO_2 catalyst virtually eliminated CO and hydrocarbon emissions.

Operational

- Having the SO_2 catalyst downstream of the NO_x catalyst eliminated ammonia slip and allowed the SCR to function more efficiently.
- Heat developed in the SNOX™ process was used to enhance thermal efficiency.

Economic

- Capital cost was estimated at $305/kW for a 500-MWe unit firing 3.2% sulfur coal. The levelized incremental cost was estimated at 6.1 mills/kWh or $219/ton of SO_2 removal on a constant 1995 dollar basis. Comparable current dollar costs were 7.8 mills/kWh and $284/ton of SO_2.

Project Summary

No reagent was required for the SO_2 removal step because the SNOX™ process utilized an oxidation catalyst to convert SO_2 to SO_3 and ultimately to sulfuric acid. As a result, the process produced no other waste streams.

In order to demonstrate and evaluate the performance of the SNOX™ process, general operating data were collected and parametric tests conducted to characterize the process and equipment. The system operated for approximately 8,000 hours and produced more than 5,600 tons of commercial-grade sulfuric acid. Many of the tests for the SNOX™ system were conducted at three loads—75, 100, and 110% of design capacity.

Environmental Performance

Particulate emissions from the process were very low (<1 mg/Nm^3) due to the characteristics of the SO_2 catalyst and the sulfuric acid condenser (WSA Condenser). The Niles SNOX™ plant was fitted with a baghouse (rather than an ESP) on its inlet. This was not necessary for low particulate emissions, but rather was needed to maintain an acceptable cleaning frequency for the SO_2 catalyst. At operating temperature, the SO_2 catalyst, because of its sticky surface, retained about 90% of the dust that entered the catalyst vessel. Dust that passed through was subsequently removed in the WSA Condenser, which acted as a condensing particulate removal device (utilizing the dust particulates as nuclei).

Minimal or no increase in CO_2 emissions by the process was tied to two features—the lack of a carbonate-based alkali reagent that releases CO_2 and the fact that the process recovered additional heat from the flue gas to offset its parasitic energy requirements. This heat recovery, under most design conditions, results in the net heat rate of the boiler being the same or better after addition of the SNOX™ process, and consequently no increase in CO_2 generation per unit of power.

With respect to CO and hydrocarbons, the SO_2 catalyst acted to virtually eliminate these compounds as well. This aspect also positively affected the interaction of the NO_x and SO_2 catalysts. Because the SO_2 catalyst followed the NO_x catalyst, any unreacted ammonia (slip) was oxidized in the SO_2 catalyst to nitrogen, water vapor, and a small amount of NO_x. As a result, downstream fouling by ammonia compounds was eliminated and the SCR was operated at slightly higher than typical ammonia stoichiometries. These higher stoichiometries allowed smaller SCR catalyst volumes and permitted the attainment of very high reduction efficiencies (>95%).

Sulfur dioxide removal in the SNOX™ process was controlled by the efficiency of the SO_2-to-SO_3 oxidation, which occurred as the flue gas passes through the oxidation catalyst beds. The efficiency was controlled by two factors—space velocity and bed temperature. Space velocity governed the amount of catalyst necessary at design flue gas flow conditions, and gas and bed temperature had to be high enough to activate the SO_2 oxidation, reaction. During the test program, SO_2 removal efficiency was normally in excess of 95% for inlet concentrations averaging about 2,000 ppm.

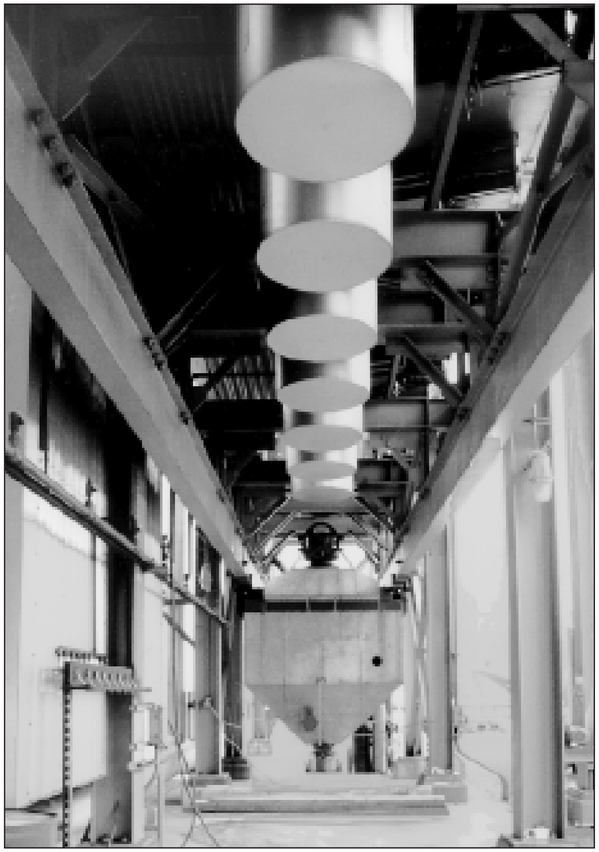
The SCR portion of the SNOX™ process was able to operate at higher than typical ammonia stoichiometries due to its location ahead of the SO_2 catalyst beds. Normal operating stoichiometries for the SCR system were in the range of 1.02–1.05 and system reduction efficiencies averaged 94% with inlet NO_x levels of approximately 500–700 ppm.

Sulfuric acid concentration and composition has met or exceeded the requirements of the federal specifications for Class I acid. During the design and construction of the SNOX™ demonstration, arrangements were made with a sulfuric acid supplier to purchase and distribute the acid from the plant. The acid has been sold to the agriculture industry for the production of diammonium phosphate fertilizer and to the steel industry for pickling. Ohio Edison has also used a significant amount in boiler water demineralizer systems throughout its plants.

Air toxic testing conducted at the Niles SNOX™ plant measured the following substances:

- Five major and 16 trace elements including mercury, chromium, cadmium, lead, selenium, arsenic, beryllium, and nickel
- Acids and corresponding anions (hydrogen chloride, hydrogen fluoride, chloride, fluoride, phosphate, sulfate)
- Ammonia and cyanide
- Elemental carbon
- Radionuclides
- Volatile organic compounds
- Semi-volatile compounds including polynuclear aromatic hydrocarbons
- Aldehydes

Most trace elements were captured in the baghouse along with the particulate. A significant portion of the boron and almost all of the mercury escaped to the stack. But selenium and cadmium, normally a problem, were effectively captured in the acid drain, as were organic compounds.



▲ The bottom portion of the SO_2 converter catalyst, with the catalyst dust collector hopper mounted on steel rails (center), is shown.

Operational Performance

Heat recovery was accomplished by the SNOX™ process. In a commercial configuration, it can be utilized in the thermal cycle of the boiler. The process generated recoverable heat in several ways. All of the reactions that took place with respect to NO_x and SO_2 removal were exothermic and increased the temperature of the flue gas. This heat plus fuel-fired support heat added in the high-temperature SCR/SO_2 catalyst loop was recovered in the WSA Condenser cooling air discharge for use in the furnace as combustion air. Because the WSA Condenser lowered the temperature of the flue gas to about 210 ºF, compared to approximately 300 ºF for a typical power plant, additional thermal energy was recovered along with that from the heats of reaction.

Economic Performance

The economic evaluation of the SNOX™ process showed a capital cost of approximately $305/kW for a 500-MWe unit firing 3.2% sulfur coal. The levelized incremental cost was 6.1 mills/kWh on a constant 1995 dollar basis and 7.8 mills/kWh on a current dollar basis. The equivalent costs per ton of SO_2 removed were $219/ton (constant 1995 dollars) and $384 (current dollars).

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 makes 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.

Contacts

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➤ The SNOX™ demonstration at Ohio Edison’s Niles Station Unit No. 2 achieved SO_2 removal efficiencies exceeding 95% and NO_x reduction effectiveness averaging 94%. Ohio Edison is retaining the SNOX™ technology as part of its environmental control system.

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, Lorain County, OH (Ohio Edison's Edgewater Station, Unit No. 4)

Technology

The Babcock & Wilcox Company's (B&W) 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

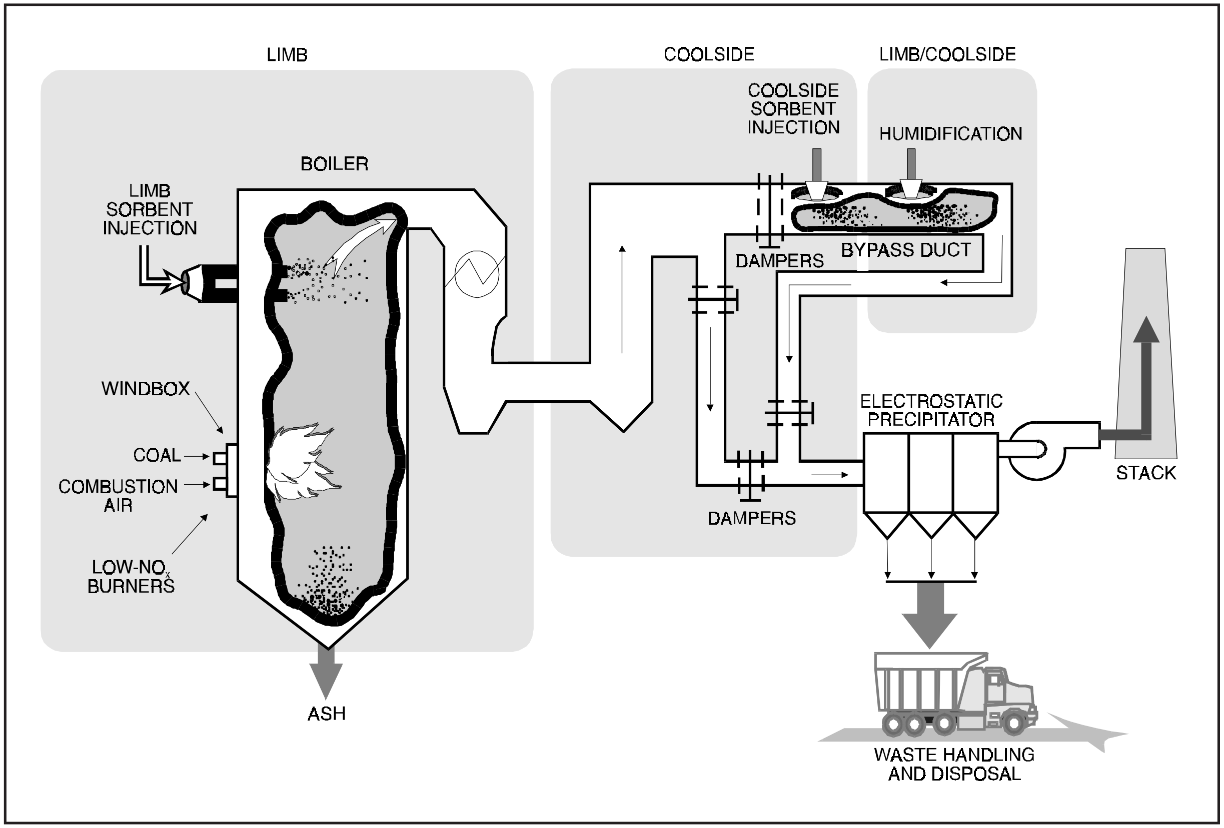
105-MWe

Coal

Ohio bituminous, 1.6, 3.0, and 3.8% sulfur

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, that the LIMB process can achieve up to 50% NO_x and SO_2 reductions and to demonstrate that the Coolside process can achieve SO_2 removal up to 70%.

Technology/Project Description

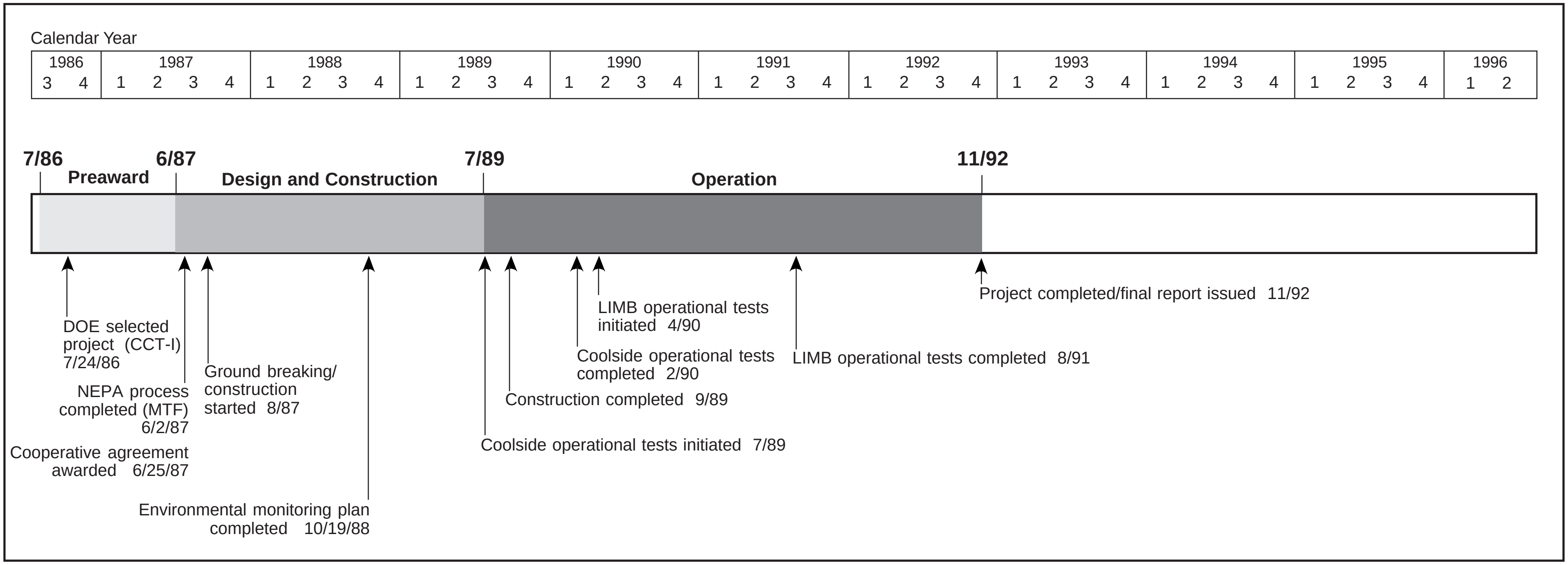
The LIMB process reduces SO_2 by injecting dry sorbent into the boiler at a point above the burners. The sorbent then travels through the boiler and is removed along with fly ash in an electrostatic precipitator (ESP) or baghouse. Humidification of the flue gas before it enters an ESP is necessary to maintain normal ESP operation and to enhance SO_2 removal. Combinations of three 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 boiler.

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 sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) in the humidification water. The spent sorbent is collected with the fly ash, as in the LIMB process. Bituminous coal with 3.0% sulfur was used in testing.

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.

TAG is a trademark of the Electric Power Research Institute.



Results Summary

Environmental

- LIMB SO_2 removal efficiencies at a calcium-to-sulfur (Ca/S) molar ratio of 2.0 and minimal humidification across the range of coal sulfur contents were 53–61% for ligno lime, 51–58% for calcitic lime, 45–52% for dolomitic lime, and 22–25% for limestone ground to 80% less than 44 microns (325 mesh).
- LIMB SO_2 removal efficiency increased to 32% using limestone ground to 100% minus 325 mesh and increased an additional 5–7% when ground to 100% less than 10 microns.
- LIMB SO_2 removal efficiencies were enhanced by about 10% when humidification down to 20 ºF approach-to-saturation temperature was used.
- LIMB, which incorporated Babcock & Wilcox DRB-XCL® low-NO_x burners, achieved 40–50% NO_x reduction.
- Coolside SO_2 removal efficiency was 70% at a Ca/S molar ratio of 2.0, a sodium-to-calcium (Na/Ca) ratio of 0.2, and 20 ºF approach-to-adiabatic-saturation temperature using commercial hydrated lime and 2.8–3.0% sulfur coal.
- Sorbent recycle tests demonstrated the potential to improve sorbent utilization.

Operational

- Humidification enhanced ESP performance, which enabled opacity levels to be kept well within limits.
- LIMB availability was 95%. Coolside did not undergo testing of sufficient length to establish availability.
- Humidifier performance indicated that operation in a vertical rather than horizontal mode would be better.

Economic

- LIMB capital costs were $31–102/kW for plants ranging from 100–500-MWe and coals with 1.5–3.5% sulfur, with a target SO_2 reduction of 60% (1992$). Annual levelized costs (15-year) for this range of conditions were $392–791/ton of SO_2 removed.
- Coolside capital costs were $69–160/kW for plants ranging from 100–500-MWe and coals with 1.5–3.5% sulfur, with a target SO_2 reduction of 70% (1992$). Annualized levelized costs (15-year) for this range of conditions were $482–943/ton of SO_2 removed.

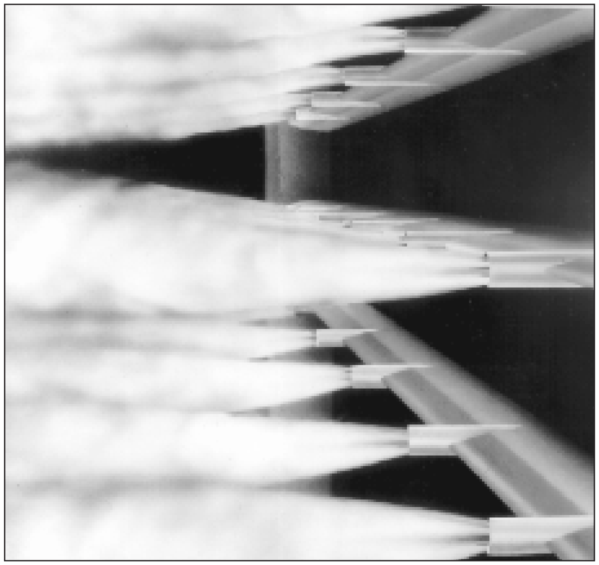
Project Summary

The initial expectation with LIMB technology was that limestone calcined by injection into the furnace would achieve adequate SO_2 capture. Use of limestone in lieu of the significantly more expensive lime would keep operating costs relatively low. However, the demonstration showed that even with fine grinding of the limestone and deep humidification, performance with limestone was marginal. As a result, a variety of hydrated limes were evaluated in the LIMB configuration, demonstrating enhanced performance. Although LIMB performance was enhanced by applying humidification to the point of approaching adiabatic saturation temperatures, performance did not rely on this deep humidification.

Coolside design was dependent upon deep humidification to improve sorbent reactivity and use of hydrated lime. Sorbent injection was downstream of the furnace. In addition, sorbent activity was enhanced by dissolving sodium hydroxide (NaOH) or sodium carbonate (Na_2CO_3) in the humidification water.

Environmental Performance (LIMB)

LIMB tests were conducted over a range of Ca/S molar ratios and humidification conditions while burning Ohio coals with nominal sulfur contents of 1.6, 3.0, and 3.8% by weight. Each of four different sorbents was injected while burning each of the three different coals. Other variables examined were stoichiometry, humidifier outlet temperature, and injection level in the boiler. Exhibit 37 summarizes SO_2 removal efficiencies for the range of sorbents and coals tested.



▲ Water mist, sprayed into the flue gas, enhanced sulfur capture by the sorbent by approximately 10% in the LIMB process when 20 ºF approach-to-saturation was used.

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 a smaller particle size (i.e., all particles were less than 44 microns). A third limestone with essentially all particles less than 10 microns was used to determine what might be the removal efficiency limit. The removal efficiency for this very fine limestone was approximately 5–7% higher than that obtained at similar conditions for limestone with particles all sized less than 44 microns.

During the design phase, it was expected that injection at the 181-foot plant elevation level inside the boiler would permit the introduction of the limestone at close to the optimum furnace temperature of 2,300 ºF. Testing confirmed that injection at this level, just above the nose of the boiler, yielded the highest SO_2 removal. Injection was also performed at the 187-foot level and similar removals were observed. Removal efficiencies while injecting at these levels were about 5% higher than while injecting sorbent at the 191-foot level.

Removal efficiencies were enhanced by approximately 10% over the range of stoichiometries tested when humidification down to a 20 ºF approach-to-saturation temperature was used. The continued use of the low-NO_x burners resulted in an overall average NO_x emissions level of 0.43 lb/10^6 Btu, which is about a 45% reduction.

Operational Performance (LIMB)

Long-term test data showed that the LIMB system was available about 95% of the time it was called upon to operate. Even with minimal humidification, ESP performance was adequately enhanced to keep opacity levels well below the permitted limit. Opacity was generally in the 2–5% range while the limit was 20%.

Exhibit 37

LIMB SO_2 Removal Efficiencies

(Percent)

	Nominal Coal Sulfur Content		
Sorbent	**3.8%**	**3.0%**	**1.6%**
Ligno lime	61	63	53
Commercial calcitic lime	58	55	51
Dolomitic lime	52	48	45
Limestone (80% <44 microns)	NT	25	22

NT = Not tested

Test conditions: injection at 181 ft, Ca/S molar ratio of 2.0, minimal humidification.

Environmental Performance (Coolside)

The Coolside process was tested while burning compliance (1.2–1.6% sulfur) and noncompliance (2.8–3.2% sulfur) coals. Objectives of the full-scale test program were to verify short-term process operability and to develop a design performance database to establish process economics for Coolside. Key process variables—Ca/S molar ratio, Na/Ca molar ratio, and approach-to-adiabatic-saturation—were evaluated in short-term (6–8 hour) parametric tests and longer term (1–11 day) process operability tests.

The test program demonstrated that the Coolside process routinely achieved 70% SO_2 removal at design conditions of 2.0 Ca/S molar ratio, 0.2 Na/Ca molar ratio, and 20 ºF approach-to-adiabatic-saturation temperature using commercially available hydrated lime. Coolside SO_2 removal depended on Ca/S molar ratio, Na/Ca molar ratio, approach-to-adiabatic-saturation, and the physical properties of the hydrated lime. Sorbent recycle showed significant potential to improve sorbent utilization. The observed SO_2 removal with recycled sorbent alone was

Exhibit 38
Capital Cost Comparison
(1992 $/kW)

Coal (%S)	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	100-MWe			**150-MWe**		
1.5	93	150	413	66	116	312
2.5	95	154	421	71	122	316
3.5	102	160	425	73	127	324
	250-MWe			**500-MWe**		
1.5	46	96	228	31	69	163
2.5	50	101	235	36	76	169
3.5	54	105	240	40	81	174

Exhibit 39
Annual Levelized Cost Comparison
(1992 $/Ton of SO_2 Removed)

Coal (%S)	LIMB	Coolside	LSFO	LIMB	Coolside	LSFO
	100-MWe			**150-MWe**		
1.5	791	943	1418	653	797	1098
2.5	595	706	895	520	624	692
3.5	525	629	665	461	570	527
	250-MWe			**500-MWe**		
1.5	549	704	831	480	589	623
2.5	456	567	539	416	502	411
3.5	419	526	413	392	482	321

22% at 0.5 available Ca/S molar ratio and 18 °F approach-to-adiabatic-saturation. The observed SO_2 removal with simultaneous recycle and fresh sorbent feed was 40% at 0.8 fresh Ca/S molar ratio, 0.2 fresh Na/Ca molar ratio, 0.5 available recycle, and 18 °F approach-to-adiabatic-saturation.

Operational Performance (Coolside)

Floor deposits experienced in the ductwork with the horizontal humidification led designers to consider a vertical unit in a commercial configuration. Short-term testing did not permit evaluation of Coolside system availability.

Economic Performance (LIMB & Coolside)

Economic comparisons were made between LIMB, Coolside, and a wet scrubber with limestone injection and forced oxidation (LSFO). Assumptions on performance were SO_2 removal efficiencies of 60, 70, and 95% for LIMB, Coolside, and LSFO, respectively. The EPRI TAG™ methods were used for the economics, which are summarized in Exhibits 38 and 39.

Commercial Application

Both LIMB and Coolside technologies are applicable to most utility and industrial coal-fired units and provide alternatives to conventional wet flue gas desulfurization processes. LIMB and Coolside can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less than for conventional flue gas desulfurization processes.

LIMB has been sold to an independent power plant in Canada. Babcock & Wilcox has signed 85 contracts (61 domestic, 24 foreign) for DLB-XCL® low-NO$_x$ burners, representing 1,515 burners for 20,396-MWe of capacity.

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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

Coal

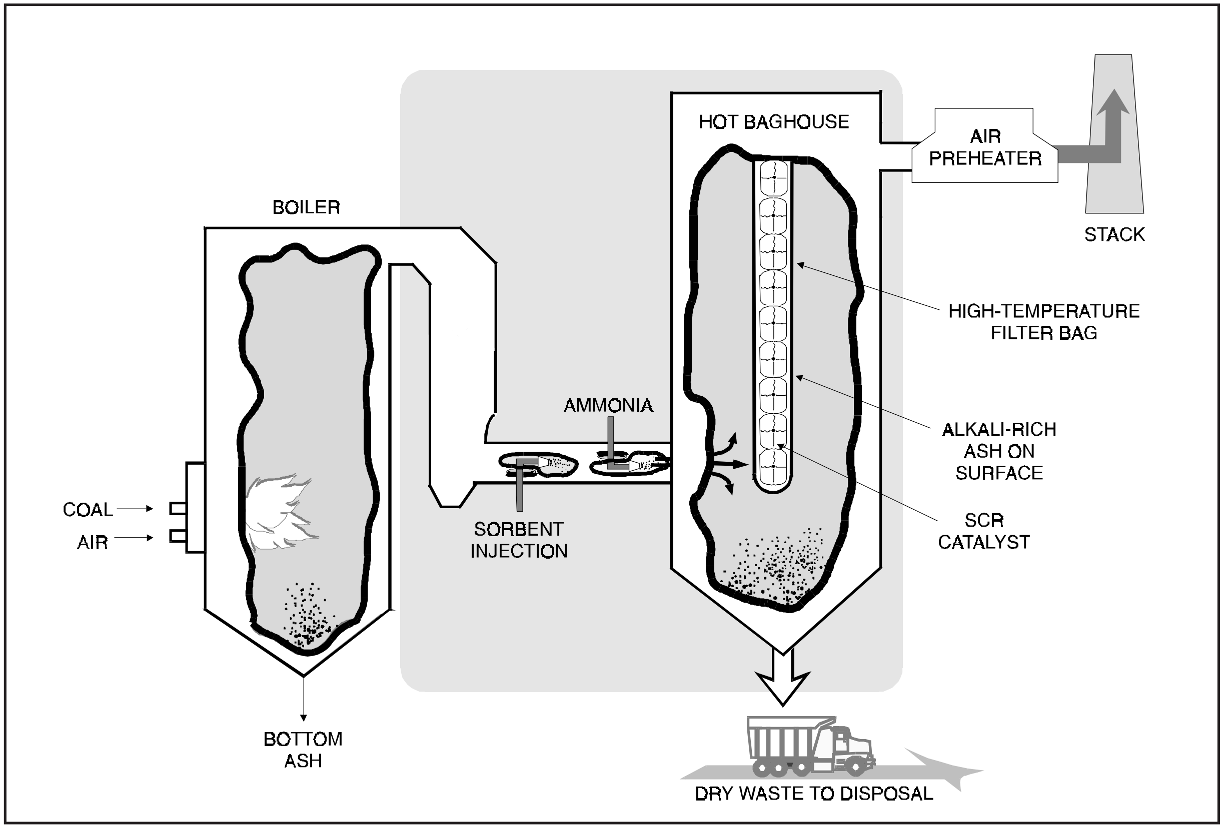
Bituminous coal blend, 3.7% sulfur average

Project Funding

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

Project Objective

To achieve greater than 70% SO_2 removal and 90% or higher reduction in NO_x emissions while maintaining particulate emissions below 0.03 lb/10^6 Btu.



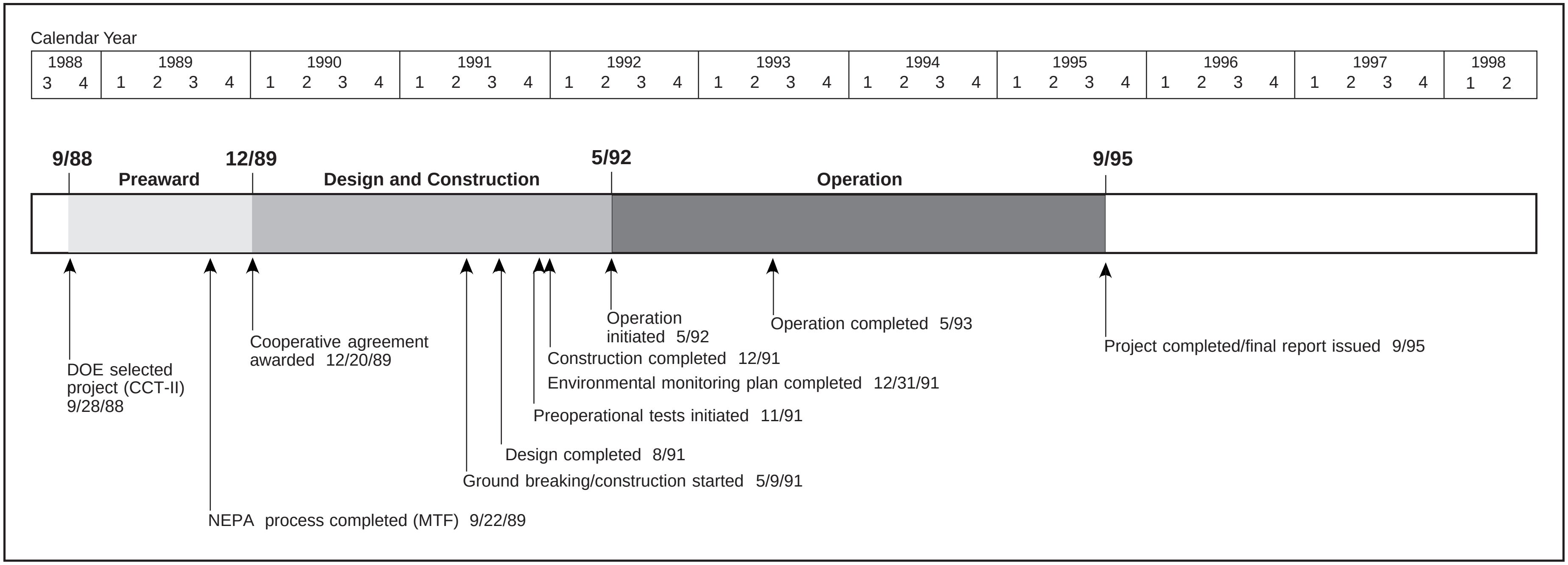
Technology/Project Description

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 (NH_3) to selectively reduce NO_x in the presence of a selective catalytic reduction (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 SNRB™ process was operated for approximately 2,300 hours. Through this effort, SNRB™ demonstrated the technical and economic feasibility of achieving more than 80% SO_2 removal, more than 90% NO_x removal, and 99% particulate removal at lower capital, operating, and maintenance costs than those for a combination of conventional systems. The demonstration was conducted at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles Bottom, Ohio.

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



Results Summary

Environmental

- SO_2 removal efficiency of 80% was achieved with commercial-grade lime at a calcium-to-sulfur (Ca/S) molar ratio of 2.0 and temperature of 800–850 ºF.
- SO_2 removal efficiency of 90% was achieved with sugar hydrated and lignosulfonate hydrated lime at a Ca/S molar ratio of 2.0 and temperature of 800–850 ºF.
- SO_2 removal efficiency of 80% was achieved with sodium bicarbonate at a sodium-to-sulfur (Na_2/S) molar ratio of 1.0 and temperature of 425 ºF.
- SO_2 emissions were reduced to less than 1.2 lb/10^6 Btu with 3–4% sulfur coal with a Ca/S molar ratio as low as 1.5 and Na_2/S molar ratio of 1.0.
- Injection of calcium-based sorbents directly upstream of the baghouse at 825–900 ºF resulted in higher overall SO_2 removal than injection further upstream at temperatures up to 1,200 ºF.
- NO_x reduction of 90% was achieved with an NH_3/NO_x molar ratio of 0.9 and temperature of 800–850 ºF.
- Air toxic removal efficiency was comparable to that of an electrostatic precipitator (ESP), except that hydrogen fluoride (HF) was reduced by 84% and hydrogen chloride (HCl) by 95%.

Operational

- Calcium utilization was 40–45% for SO_2 removals of 85–90%.
- Norton Company’s NC-300 zeolite SCR catalyst showed no appreciable physical degradation or change in catalyst activity over the course of the demonstration.
- No excessive wear or failures occurred with the filter bags tested: 3M’s Nextel ceramic fiber filter bag and Owens Corning Fiberglas’s S-Glass filter bag.

Economic

- Capital cost in 1994 constant dollars for a 250-MWe retrofit was $233/kW, assuming 3.5% sulfur coal and baseline NO_x emissions of 1.2 lb/10^6 Btu.

Project Summary

SNRB™ incorporates two successful technology development efforts that offer distinct advantages over other control technologies. High-temperature filter bags and circular monolith catalyst developments enabled multiple emission control in a single component with a low plan-area space requirement. As a postcombustion control system, it is simple to operate. The high-temperature bag provides a clean, high-temperature environment compatible with effective SCR operation and a surface for enhanced SO_2/sorbent contact (creates a sorbent cake on the surface). Particulate control, which is receiving increasing attention, is typical of the superior performance offered by pulsed jet baghouses.

Environmental Performance

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 optimal location for injecting the sorbent into the flue gas was immediately upstream of the baghouse. Essentially, the SO_2 was captured by the sorbent in the form of a filter cake on the filter bags (along with fly ash).

With the baghouse operating above 830 ºF, injection of commercial-grade hydrated lime at Ca/S molar ratios of 1.8 and above resulted in SO_2 removals of over 80%. At a Ca/S molar ratio of 2.0, performance of the sugar-hydrated lime and lignosulfonate-hydrated lime increased performance by approximately 8%, for overall removal of approximately 90%. SO_2 removal of 85–90% was obtained with calcium utilization in the of 40–45%. Injection of the calcium-based sorbents directly upstream of the baghouse at 825–900 ºF resulted in higher overall SO_2 removal than injection further upstream at temperatures up to 1,200 ºF.

SO_2 removal using sodium bicarbonate was 80% at an Na_2/S molar ratio of 1.0 and 98% at an Na_2/S molar ratio of 2.0 at a significantly reduced baghouse temperature of 450–460 ºF. SO_2 emissions while burning a 3–4% sulfur coal were reduced to less than 1.2 lb/10^6 Btu with a Ca/S molar ratio as low as 1.5 and Na_2/S molar ratio less than 1.0.

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. With the catalyst being 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.

▲ The demonstration baghouse is installed on the back side of the power plant. Workers stand by the catalyst holder tube prior to lifting it into the penthouse.

A NO_x emission reduction of 90% was readily achieved with ammonia slip limited to less than 5 ppm. This performance reduced NO_x emissions to less than 0.10 lb/10^6 Btu. NO_x reduction was insensitive to temperatures over the catalyst design temperature range of 700–900 ºF. Catalyst space velocity (volumetric gas flow/catalyst volume) had a minimal effect on NO_x removal over the range evaluated.

Turndown capability for tailoring the degree of NO_x reduction by varying the rate of ammonia injection was demonstrated for a range of 50–95% NO_x reduction. No appreciable physical degradation or change in the catalyst activity was observed over the duration of the test program. The degree of oxidation of SO_2 to SO_3 over the zeolite catalyst appeared to be less than 0.5%. (SO_2 oxidation is a concern for SCR catalysts containing vanadium.) Leach potential analysis of the catalyst after completion of the field test showed that the catalyst remained nonhazardous for disposal.

Particulate emissions were consistently below NSPS standards of 0.03 lb/10^6 Btu, with an average over 30 baghouse particulate emission measurements of 0.018 lb/10^6 Btu, which corresponds to a collective efficiency of 99.89%. Hydrated lime injection increased the baghouse inlet particulate loading from 5.6 to 16.5 lb/10^6 Btu. Emissions testing with and without the SCR catalyst installed revealed no apparent differences in collection efficiency. On-line cleaning with a pulse air pressure of 30–40 lb/in^2 was sufficient for cleaning the bag/catalyst assemblies. Typically, one of five baghouse modules in service was cleaned every 30–150 minutes.

A comprehensive air toxics emissions monitoring test was performed at the end of the SNRB™ demonstration test program. The targeted emissions monitored included trace metals, volatile organic compounds, semi-volatile organic compounds, aldehydes, halides, and radionuclides. These species were a subset of the 189 hazardous substances identified in the CAAA. Measurements of mercury speciation, dioxins, and furans were unique features of this test program. The emissions control efficiencies achieved for various air toxics by the SNRB™ system were generally comparable to those of the conventional ESP at the power plant. However, the SNRB™ system did reduce HCl by an average of 95% and HF emissions by an average of 84%, whereas the ESP had no effect on these constituents.

Operation of the SNRB™ demonstration resulted in the production of approximately 830 tons of fly ash and by-product solids. An evaluation of potential uses for the by-product showed that the material might be used for agricultural liming (if pelletized). Also, the solids potentially could be used as a partial cement replacement to lower the cost of concrete.

Operational Performance

A 3,800-hour durability test of three fabric filters was completed at the Filter Fabric Development Test Facility in Colorado Springs in December 1992. No signs of failure were observed. All of the demonstration tests were conducted using the 3M Company Nextel ceramic fiber filter bags or the Owens Corning Fiberglas S-Glass filter bags. No excessive wear or failures occurred in over 2,000 hours of elevated temperature operation.

Economic Performance

For a 250-MWe boiler fired with 3.5% sulfur coal and NO_x emissions of 1.2 lb/10^6 Btu, the projected capital cost of a SNRB™ system is approximately $233/kW (1994$), including various technology and project contingency factors. A combination of fabric filter, SCR, and wet scrubber for achieving comparable emissions control has been estimated at $360–400/kW. Variable operating costs are dominated by the cost of the SO_2 sorbent for a system designed for 85–90% SO_2 removal. Fixed operating costs primarily consist of system operating labor and projected labor and material for the hot baghouse and ash-handling systems.

Commercial Applications

Commercialization of the technology is expected to develop with an initial larger scale application equivalent to 50–100-MWe. The focus of marketing efforts is being 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 that 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.

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▲ Workers lower one of the catalyst holder tubes into a mounting plate in the penthouse of the high-temperature baghouse.

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 Commerce & Community Affairs—cofunder
Illinois Power Company—host
City Water, Light and Power—host

Locations

Hennepin, Putnam County, IL (Illinois Power Company's Hennepin Plant, Unit No. 1)
Springfield, Sangamon County, IL (City Water, Light and Power's Lakeside Station, Unit No. 7)

Technology

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

Plant Capacity/Production

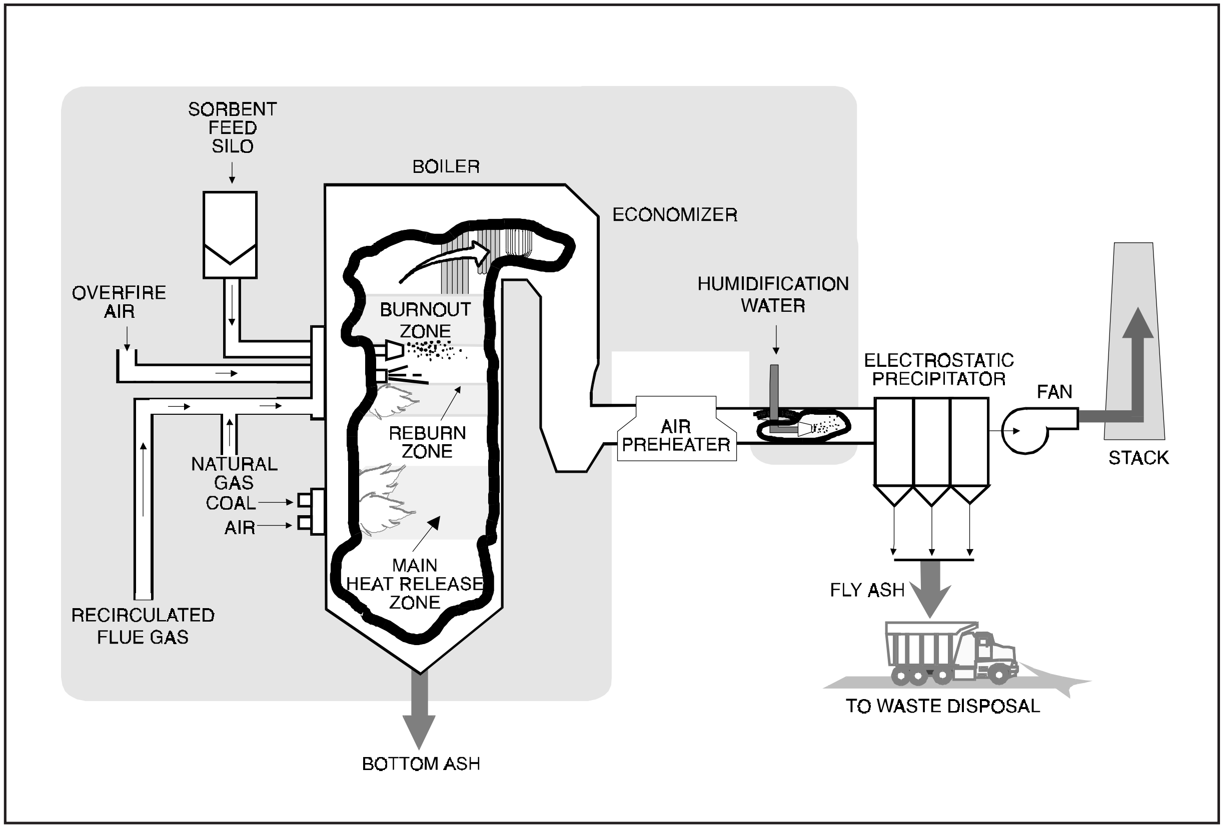
Hennepin: tangentially-fired 80-MWe (gross), 71-MWe (net)
Lakeside: cyclone-fired 40-MWe (gross), 33-MWe (net)

Coal

Illinois bituminous, 3.0% sulfur

Project Funding

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



Project Objective

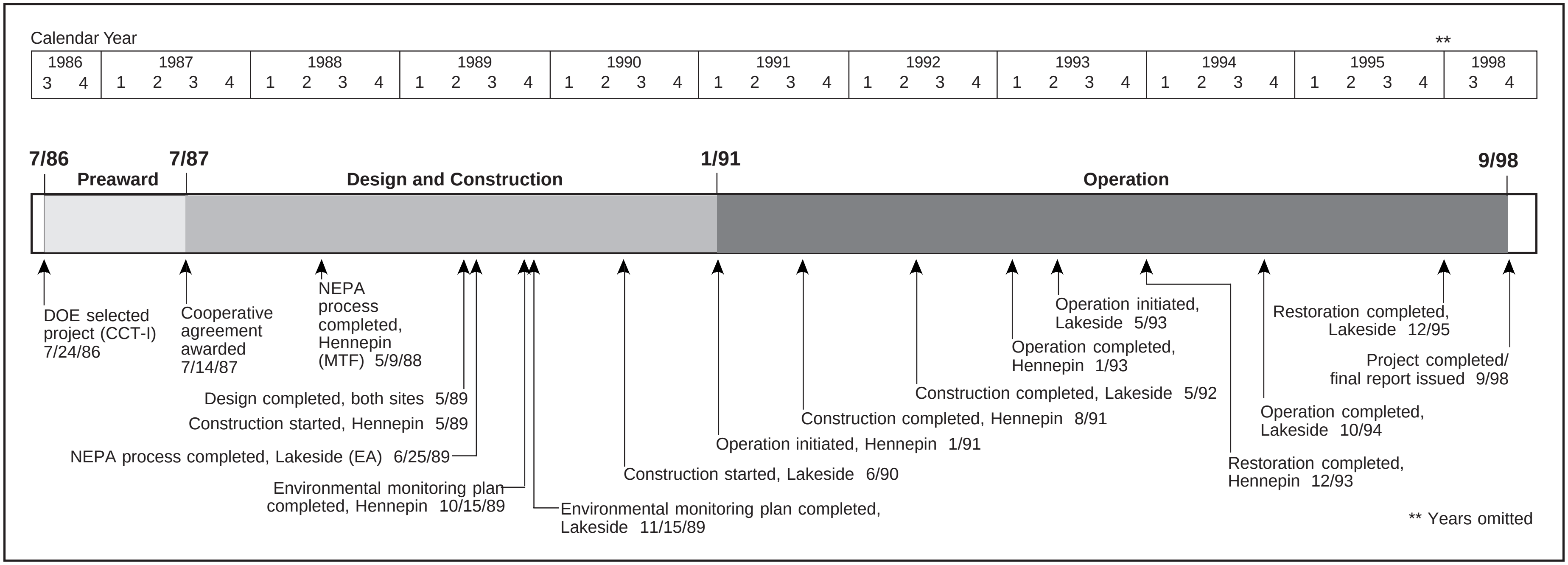
To demonstrate gas reburning to attain at least 60% NO_x reduction along with sorbent injection to capture at least 50% of the SO_2 on two different boiler configurations—tangentially-fired and cyclone-fired—while burning high-sulfur midwestern coal.

Technology/Project Description

In this process, 80–85% of the fuel was coal and was supplied to the main combustion zone. The remaining 15–20% of the fuel, provided by natural gas, bypassed the main combustion zone and was injected above the main burners to form a reducing (reburning) zone in which NO_x was converted to nitrogen. A calcium compound (sorbent) was injected in the form of dry, fine particulates above the reburning zone in the boiler. Lime ($Ca(OH)_2$) was the sorbent tested at both sites. 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.

A comprehensive test program was conducted at each of the two sites, operating the equipment over a wide range of boiler conditions. Over 1,500 hours of operation was achieved, enabling a substantial amount of data to be obtained. Intensive measurements were taken to quantify the reductions in NO_x and SO_2 emissions, the impact on boiler equipment and operability, and all factors influencing costs.

PromiSORB is a trademark of Energy and Environmental Research Corporation.



Results Summary

Environmental

- On the tangentially-fired boiler, GR–SI NO_x reductions of up to 75% were achieved, and an average 67% reduction was realized at an average gas heat input of 18%.
- GR–SI SO_2 removal efficiency on the tangentially-fired boiler averaged 53% with hydrated lime at a calcium-to-sulfur (Ca/S) molar ratio of 1.75 (corresponding to a sorbent utilization of 24%).
- On the cyclone-fired boiler, GR–SI NO_x reductions of up to 74% were achieved, and an average 66% reduction was realized at an average gas heat input of 22%.
- GR–SI SO_2 removal efficiency on the cyclone-fired boiler averaged 58% with hydrated lime at a Ca/S molar ratio of 1.8 (corresponding to a sorbent utilization of 24%).
- Particulate emissions were not a problem on either unit undergoing demonstration, but humidification had to be introduced at Hennepin to enhance ESP performance.
- Three advanced sorbents tested achieved higher SO_2 capture efficiencies than the baseline Linwood hydrated lime. PromiSORB™ A achieved 53% SO_2 capture efficiency and 31% utilization without GR at a Ca/S molar ratio of 1.75. Under the same conditions, PromiSORB™ B achieved 66% SO_2 reduction and 38% utilization, and High-Surface-Area Hydrated Lime achieved 60% SO_2 reduction and 34% utilization.

Operational

- Boiler efficiency decreased by approximately 1% as a result of increased moisture formed in combustion from natural gas use.
- There was no change in boiler tube wastage, tube metallurgy, or projected boiler life.

Economic

- Capital cost for gas reburning (GR) was approximately \$15/kW plus the gas pipeline cost, if not in place (1996\$).
- Operating costs for GR were related to the gas/coal cost differential and the value of SO_2 emission allowances (because GR replaces some coal with gas, it also reduces SO_2 emissions).
- Capital cost for sorbent injection (SI) was approximately \$50/kW.
- Operating costs for SI were dominated by the cost of sorbent and sorbent/ash disposal costs. SI was estimated to be competitive at \$300/ton of SO_2 removed.

Project Summary

The GR–SI project demonstrated the success of gas reburning and sorbent injection technologies in reducing NO_x and SO_2 emissions. The process design conducted early in the project combined with the vast amount of data collected during the testing created a database capable of applying the technology to all major coal-firing configurations (tangential-, cyclone-, and wall-fired) on both utility and industrial units. The emissions control and performance can be accurately projected as can the capital and operating costs.

Environmental Performance (Hennepin)

Operational testing, which included optimization testing and long-term testing, was conducted between January 1991 and January 1993. The GR–SI long-term demonstration tests were carried out from January 1992 to October 1992 to verify the system performance over an extended period. The unit was operated at constant loads and with the system under dispatch operation where load was varied to meet plant power output requirements. With the system under dispatch, the load fluctuated over a wide range from 40-MWe to a maximum load of 75-MWe. Over the long-term demonstration period, the average gross power output was 62-MWe.

For long-term demonstration testing, the average NO_x reduction was approximately 67%. The average SO_2 removal efficiency was over 53% at a Ca/S molar ratio of 1.75. (Linwood hydrated lime was used throughout these tests except for a few days when Marblehead lime was used.) CO emissions were below 50 ppm in most cases but were higher during operation at low load.

A significant reduction in CO_2 was also realized. This was due to partial replacement of coal with natural gas having a lower carbon-to-hydrogen ratio. This cofiring with 18% natural gas resulted in a theoretical CO_2 emissions reduction of nearly 8% from the coal-fired baseline level. With flue gas humidification, electrostatic precipitator (ESP) collection efficiencies greater than 99.8% and particulate emissions less than 0.025 lb/10^6 Btu were measured even with an increase in inlet particulate loading resulting from sorbent injection. These levels were comparable to measured baseline emissions of 0.035 lb/10^6 Btu and a collection efficiency greater than 99.5%.

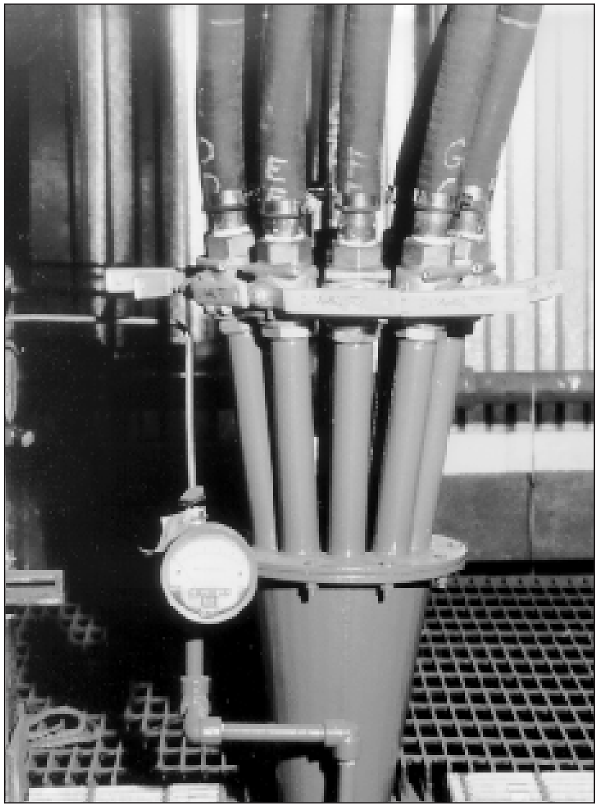
Following the completion of the long-term tests, three specially prepared sorbents were tested. Two were manufactured by the participant and contained proprietary additives to increase their reactivity toward SO_2 and were referred to as PromiSORB™ A and B. The Illinois State Geological Survey developed the other sorbent—High-Surface-Area Hydrated Lime in which alcohol is used to form a material that gives rise to a much higher surface area than that of conventionally hydrated limes.

The SO_2 capture without GR, at a nominal 1.75 Ca/S molar ratio, was 53% for PromiSORB™ A, 66% for PromiSORB™ B, 60% for High-Surface-Area Hydrated Lime, and 42% for Linwood lime. At a 2.6 Ca/S molar ratio, the PromiSORB™ B yielded 81% SO_2 removal efficiency.

Environmental Performance (Lakeside)

Parametric tests were conducted in three series: GR parametric tests, SI parametric tests, and GR–SI optimization tests. A total of 100 GR parametric tests were conducted at boiler loads of 33-, 25-, and 20-MWe. Gas heat input varied from 5-26%. The GR parametric tests achieved a NO_x reduction of approximately 60% at a gas heat input of 22–23%. Additional flow modeling and computer modeling studies indicated that smaller reburning fuel jet nozzles could increase reburning fuel mixing and thus improve the NO_x reduction performance.

A total of 25 SI parametric tests were conducted to isolate the effects of sorbent on boiler performance and operability. Results showed that SO_2 reduction level varied with load because of the effect of temperature on the sulfation reaction. At a Ca/S molar ratio of 2.0, 44% SO_2 reduction was achieved at full load (33-MWe); 38% SO_2 reduction was achieved at mid load (25-MWe); and 32% SO_2 reduction was achieved at low load (20-MWe).

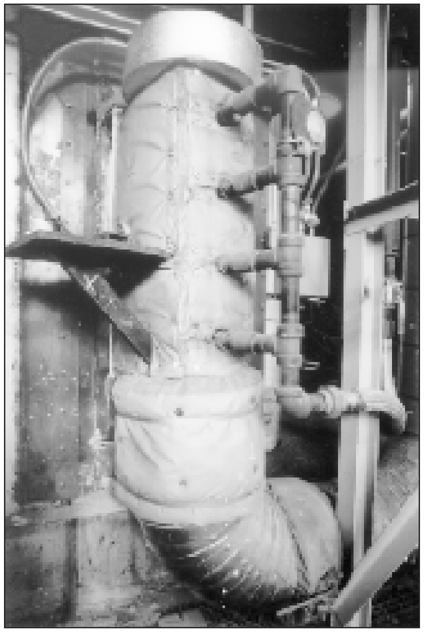


▲ The flexible lime-sorbent distribution lines lead from the sorbent splitter to the top of the cyclone-fired boiler at Lakeside Station.

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 GR parametric tests and flow modeling studies. The total cross-sectional area of the reburning jets was decreased by 32% to increase the reburning jet's penetration characteristics. The decrease in nozzle diameter increased NO_x reduction by an additional 3–5% compared to the initial parametric tests. With GR–SI, total SO_2 reductions resulted from partial replacement of coal with natural gas and sorbent injection. At a gas heat input of 22% and Ca/S molar ratio of 1.8, average NO_x reduction during the long-term testing of GR–SI was 66% and the average SO_2 reduction was 58%.

Operational Performance (Hennepin/Lakeside)

Sorbent injection increased the frequency of sootblower operation but did not adversely affect boiler efficiency or equipment performance. Gas reburning decreased boiler efficiency by approximately 1.0% because of the increase in moisture formed with combustion of natural gas. Examination of the boiler before and after testing showed no measurable change in tube wear or metallurgy. Essentially, the scheduled life of the boiler was not compromised.



The natural gas injector was installed on the corner of Hennepin Station's tangentially-fired boiler.

The ESPs adequately accommodated the changes in ash loading and resistivity with the presence of sorbent in the ash. No adverse conditions were found to exist. But as mentioned, humidification had to be added at Hennepin to achieve acceptable ESP performance with GR–SI.

Economic Performance (Hennepin/Lakeside)

Capital and operating costs depend largely on site-specific factors, such as gas availability at the site, coal/gas cost differential, SO_2 removal requirements, and value of SO_2 allowances. It was estimated that for most installation, a 15% gas heat input will achieve 60% NO_x reduction. The capital cost for such a GR installation was estimated at $15/kW for 100-MWe and larger plants plus the cost of the gas pipeline (if required) (1996$). Operating costs were almost entirely related to the differential cost of the gas over the coal as reduced by the value of SO_2 emission allowances.

The capital cost estimate for SI was $50/kW. Operating costs for SI were dominated by the cost of the sorbent and sorbent/ash disposal costs. SI was projected to be cost competitive at $300/ton of SO_2 removed.

Commercial Applications

The GR–SI process 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.

Illinois Power has retained the gas-reburning system and City Water, Light & Power has retained the full technology for commercial use. The project was one of two receiving the Air and Waste Management Association's 1997 J. Deanne Sensenbaugh Award.

Contacts

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Integrated Dry NO_x/SO_2 Emissions Control System

Project completed.

Participant

Public Service Company of Colorado

Additional Team Members

Electric Power Research Institute—cofunder
Stone and Webster Engineering Corp.—engineer
The Babcock & Wilcox Company—burner developer
Fossil Energy Research Corporation—operational tester
Western Research Institute—flyash evaluator
Colorado School of Mines—bench-scale engineering researcher and tester
NOELL, Inc.—urea-injection system provider

Location

Denver, Denver County, CO (Public Service Company of Colorado's Arapahoe Station, Unit No. 4)

Technology

The Babcock & Wilcox Company's DRB-XCL® low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection

Plant Capacity/Production

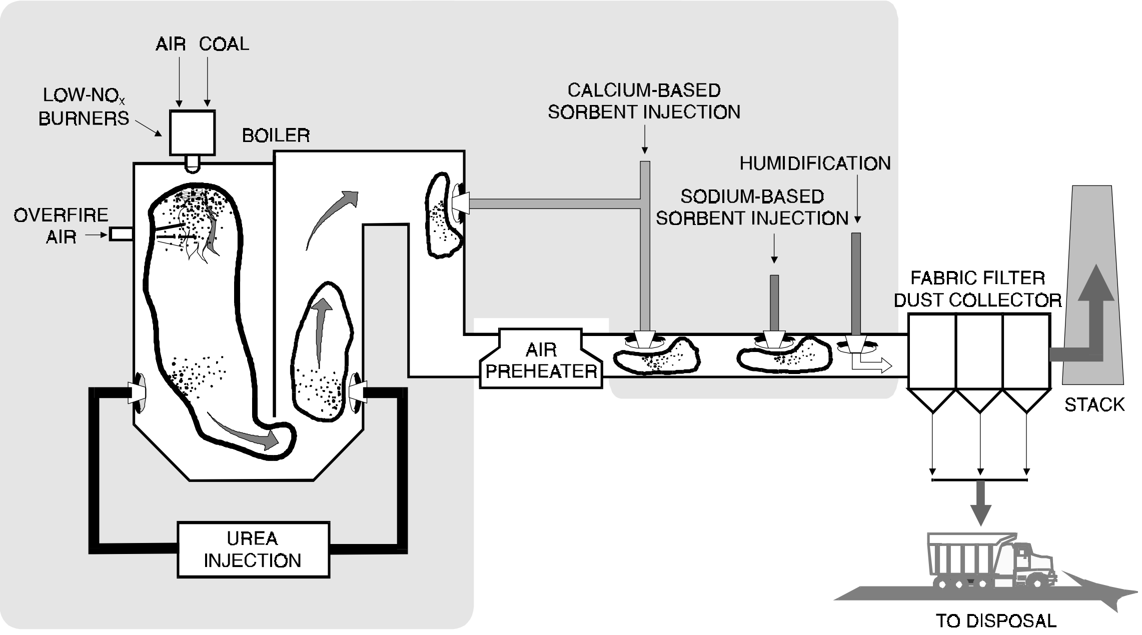
100-MWe

Coal

Colorado bituminous, 0.4% sulfur
Wyoming subbituminous (short test), 0.35% sulfur

Project Funding

Total project cost	$27,411,462	100%
DOE	13,705,731	50
Participant	13,705,731	50



Project Objective

To demonstrate the integration of five technologies to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection with humidification for SO_2 removal.

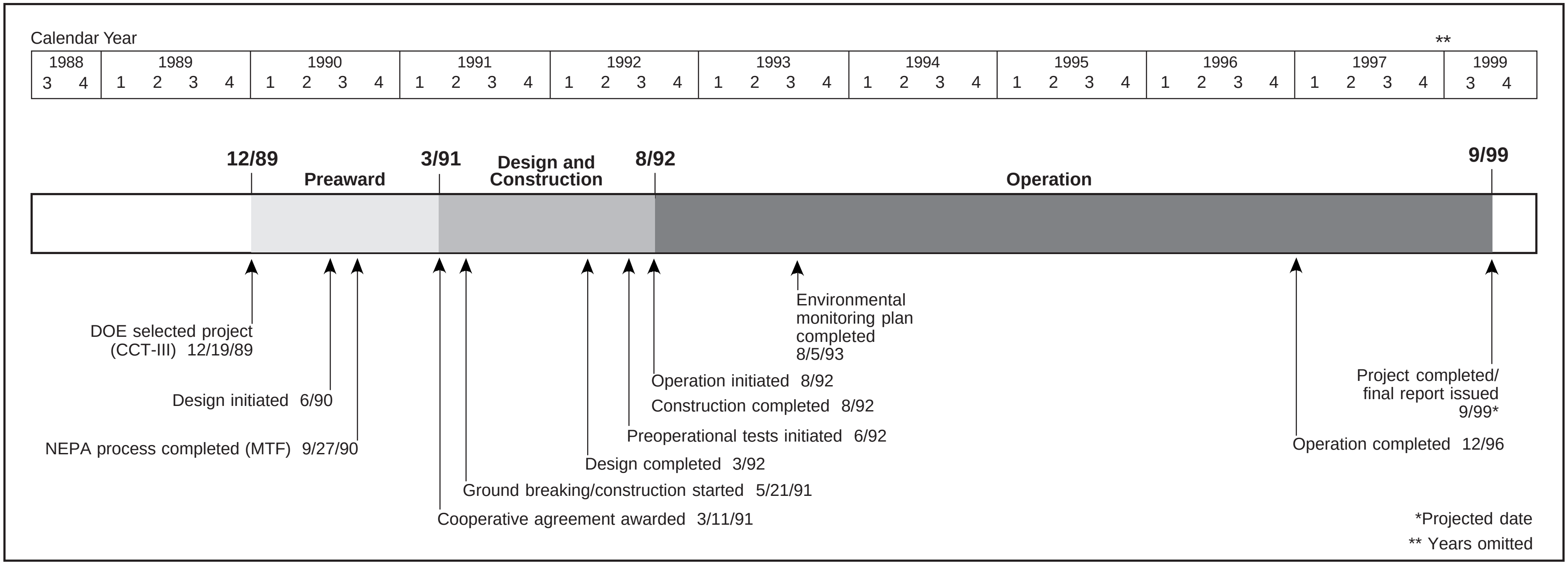
Technology/Project Description

All of the testing used Babcock & Wilcox's low-NO_x DRB-XCL® down-fired burners with overfire air. These burners control NO_x by injecting the coal and the combustion air in an oxygen-deficient environment. Additional air was introduced via overfire air ports to complete the combustion process and further enhance NO_x removal. A urea-based selective noncatalytic reduction (SNCR) system was tested to determine how much additional NO_x can be removed from the combustion gas.

Two types of dry sorbents were injected into the ductwork downstream of the boiler to reduce SO_2 emissions. Either calcium-based sorbent was injected upstream of the boiler economizer or sodium-based sorbent downstream of the air heater. Humidification downstream of the dry sorbent injection was incorporated to aid SO_2 capture and lower flue gas temperature and gas flow before entering the fabric filter dust collector.

The systems were installed on Public Service Company of Colorado's Arapahoe Station Unit No. 4, a 100-MWe down-fired, pulverized-coal boiler with roof-mounted burners.

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



Results Summary

Environmental

- DRB-XCL® burners with minimum overfire air reduced NO_x emissions by more than 63% under steady state conditions.
- With maximum overfire air (24% of total combustion air), a NO_x reduction of 62–69% was achieved across the 50–110-MWe load range.
- NO_x reduction capability decreased by 10–25% under load-following conditions.
- The SNCR system, using both stationary and retractable injection lances in the furnace, provided NO_x removal of 30–50% at an ammonia (NH_3) slip of 10 ppm, thus increasing performance of the total NO_x control system to greater than 80% NO_x reduction.
- SO_2 removal with dry calcium hydroxide injection into the boiler economizer at approximately 1,000 ºF was less than 10%; and with injection into the fabric filter duct, SO_2 removal was less than 40% at a calcium/sulfur (Ca/S) molar ratio of 2.0.
- Sodium bicarbonate injection before the air heater demonstrated a long-term SO_2 removal of approximately 70% at a normalized stoichiometric ratio (NSR) of 1.0.
- Sodium sesquicarbonate injection ahead of the fabric filter achieved 70% SO_2 removal at an NSR of 2.0.
- NO_2 emissions were generally higher when using sodium biocarbonate than when using sodium sesquicarbonate.
- Integrated SNCR and dry sodium-based sorbent injection tests showed reduced NH_3 and NO_2 emissions.
- During four series of air toxics tests, the fabric filter successfully removed nearly all trace metal emissions and 80% of the mercury.

Operational

- Arapahoe Unit No. 4 operated more than 34,000 hours with the combustion modifications in place. Availability factor was over 91%.
- Control system modifications and additional operator training may be necessary to improve NO_x control under load-following conditions.
- Buildup of a hard ash cake on the fabric filter occurred during operation with injection of calcium hydroxide and use of humidification.
- Temperature differential between the top and bottom surfaces of the Advanced Retractable Injection Lances (ARIL) caused the lances to bend downwards 12–18 inches. Alternative designs corrected the problem.
- Concurrent operation of SNCR and the dry sodium-based sorbent injection system caused an NH_3 odor problem around the ash silo, which appeared to be related to the rapid change in pH due to the sodium in the ash.

Economic

- Economic data is not yet available.

Project Summary

The Integrated Dry NO_x/SO_x Emissions Control System combines five major control technologies to form an integrated system to control both NO_x and SO_2. The low-NO_x combustion system consists of 12 Babcock & Wilcox DRB-XCL® low-NO_x burners installed on the boiler roof. The low-NO_x combustion system also incorporates three Babcock & Wilcox dual-zone NO_x ports added to each side of the furnace approximately 20 feet below the boiler roof. These ports inject up to 25% of the total combustion air through the furnace sidewalls.

Additional NO_x control was achieved with the urea-based SNCR system. The SNCR when used with the low-NO_x combustion system allowed the goal of 70% NO_x reduction to be reached. Further, the SNCR system was an important part of the integrated system, interacting synergistically with the dry sorbent injection (DSI) system to reduce NO_2 formation and ammonia slip.

Initially, the SNCR was designed and installed to incorporate two levels of injectors with 10 injectors at each level. Levels were determined by temperature profiles that existed with the original combustion system. However, the retrofit low-NO_x combustion system resulted in a decrease in furnace exit gas temperature by approximately 200 ºF, thus moving one injector level out of the temperature regime needed for effective SNCR operation. With only one operational injector level, load-following performance was compromised.

In order to achieve the desirable NO_x reduction at low loads, two alternatives were explored. The first approach was to substitute ammonia for urea. It was shown that ammonia was more effective than urea at low-loads. An on-line urea-to-ammonia conversion system was installed and resulted in improved low-load performance, but the improvement was not as large as desired for the lowest load (60-MWe). The second approach was to install injectors in the higher temperature regions of the furnace. This was achieved by installing two NOELL ARIL lances into the furnace through two unused sootblower ports. Each lance was nominally 4 inches in diameter and approximately 20 feet in length with a single row of nine injection nozzles. Each injection nozzle consisted of a fixed air orifice and a replaceable liquid orifice. The ability to change orifices allowed not only for removal and cleaning but adjustment of the injection pattern along the length of the lance in order to compensate for any significant maldistributions of flue gas velocity, temperature, or baseline NO_x concentration. One of the key features of the ARIL system was its ability to rotate, thus providing a high degree of flexibility in optimizing SNCR performance.

▲ Public Service Company of Colorado demonstrated low-NO_x burners, in-duct sorbent injection, and SNCR at Arapahoe Station near Denver.

The SO_2 control system was a direct sorbent injection system that could inject either calcium- or sodium-based reagents into the flue gas upstream of the fabric filter. Sorbent was injected into three locations: (1) air heater exit where the temperature was approximately 260 ºF, (2) air heater entrance where the temperature was approximately 600 ºF, or (3) the boiler economizer region where the flue gas temperature was approximately 1,000 ºF. To improve SO_2 removal with calcium hydroxide, a humidification system capable of achieving 20 ºF approach-to-saturation was installed approximately 100 feet ahead of the fabric filter. The system designed by Babcock & Wilcox included 84 I-Jet nozzles that can inject up to 80 gal/min into the flue gas duct work.

Environmental Performance

The combined DRB-XCL® burner and minimum overfire air reduced NO_x emissions by over 63% under steady-state conditions and with carefully supervised operations. Under load-following conditions, NO_x emissions were about 10–25% higher. At maximum overfire air (4% of total combustion air), the low-NO_x combustion system reduced NO_x emissions by 62–69% across the load range (60–110-MWe). The results verified that the low-NO_x burners were responsible for most of the NO_x reduction.

The original design of two rows of injector nozzles proved relatively ineffective because one row of injectors was in a region where the flue gas temperature was too low for effective operation. At full load, the original design achieved NO_x reduction of 45%. However, the performance decreased significantly as load decreased; at 60-MWe, NO_x removal was limited to about 11% with an ammonia slip of 10 ppm. The addition of the retractable lances improved low-load performance of the urea-based SNCR injection system. The ability to follow the temperature window by rotating the ARIL lances proved to be an important feature in optimizing performance. As a result, the SNCR system achieved NO_x removal in the range of 30–50%, (at a NH_3 slip limited to 10 ppm at the fabric filter inlet), increasing total NO_x reduction to greater than 80%, significantly exceeding the goal of 70%.

Testing of calcium hydroxide injection at the economizer without humidification resulted in SO_2 removal in the range of 5–8% at a Ca/S molar ratio of 2.0. Higher SO_2 removal was achieved with duct injection of calcium hydroxide and humidification, with SO_2 removals approaching 40% at a Ca/S molar ratio of 2.0 and within 20–30 ºF approach-to-saturation. Sodium-based reagents were found to be much more effective than calcium-based sorbents and achieved significantly higher SO_2 removals during dry injection. Sodium bicarbonate injection before the air heater demonstrated short-time SO_2 removals of 80%. Long-term reductions of 70% were achieved with an NSR of 1.0. Sodium sesquicarbonate achieved 70% removal at an NSR of 2.0 when injected ahead of the fabric filter. A disadvantage of the sodium-based process was that it converted some existing NO to NO_2. Even though 5–10% of the NO_x was reduced during the conversion process, the net NO_2 exiting at the stack was increased. While NO is colorless, small quantities of brown/orange NO_2 caused a visible plume.

A major objective was the demonstration of the integrated performance of the NO_x emissions control systems and the SO_2 removal technologies. The results showed that a synergistic benefit occurred during the simultaneous operation of the SNCR and the sodium DSI system in that the NH_3 slip from the SNCR process suppressed the NO_2 emissions associated with NO to NO_2 oxidation by dry sodium injection.

Four series of air toxic tests were completed. Results indicated that the fabric filter successfully removed 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 detectable limits.

Operating Performance

The Arapahoe Unit No. 4 operated more than 34,000 hours with the combustion modifications in place. The availability factor during the period was over 91%.

The operational test objectives were met or exceeded. However, there were operational lessons learned during the demonstration that will be useful in future deployment of the technologies. These “lessons learned” are summarized below.

It was found that control system modifications and additional operator training may be necessary to more accurately control NO_x reductions using low-NO_x burners under load-following conditions.

During the operation of the duct injection of calcium hydroxide and humidification under load-following conditions, fabric filter pressure-drop significantly increased. This was caused by the buildup of a hard ash cake on the fabric filter bags that could not be cleaned under normal reverse-air cleaning. The heavy ash cake was caused by the humidification system, but it was not determined whether the problem was due to operation at 30 ºF approach-to-saturation temperature or an excursion caused by a rapid decrease in load.

The performance of the ARIL lances in NO_x removal was good; however, the location created some operational problems. A large differential heating pattern between the top and bottom of the lance caused a significant amount of thermal expansion along the upper surface of the lance. This caused the lance to bend downwards approximately 12–18 inches after 30 minutes of exposure. Eventually the lances become permanently bent, thus making insertion and retraction difficult. The problem was partially resolved by adding cooling slots at the end of the lance. An alternative lance design provided by Diamond Power Specialty Company (a division of Babcock & Wilcox) was tested and found to have less bending due to evaporative cooling, even though its NO_x reduction and NH_3 slip performance were slightly less than for the ARIL lance.

When the SNCR and dry sodium systems were operated concurrently, an NH_3 odor problem was encountered around the ash silo. Reducing the NH_3 slip set points to the range of 4–5 ppm reduced the ammonia concentration in the fly ash to the 100–200 ppm range but the odor persisted. It was found that the problem was related to the rapid change in pH due to the presence of sodium in the ash. The rapid development of the high pH level and the attendant release of the ammonia vapor appear to be related to the wetting of the fly ash necessary to minimize fugitive dust emissions during transportation and handling. Handling ash in dry transport trucks solved this problem.

Economic Performance

Economic analysis is under way.

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 and provide lower capital-cost alternatives 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.

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Advanced Electric Power Generation
Fluidized-Bed Combustion

McIntosh Unit 4A PCFB Demonstration Project

Participant

City of Lakeland, Lakeland Electric

Additional Team Members

Foster Wheeler Corporation—supplier of pressurized circulating fluidized-bed (PCFB) combustor and heat exchanger and engineer

Siemens Westinghouse Power Corporation—supplier of hot gas filter, gas turbine, and steam turbine

Location

Lakeland, Polk County, FL (Lakeland Electric's McIntosh Power Station, Unit No. 4)

Technology

Foster Wheeler's PCFB technology integrated with Siemens Westinghouse's hot gas particulate filter system (HGPFS) and power generation technologies

Plant Capacity/Production

137-MWe (net)

Coal

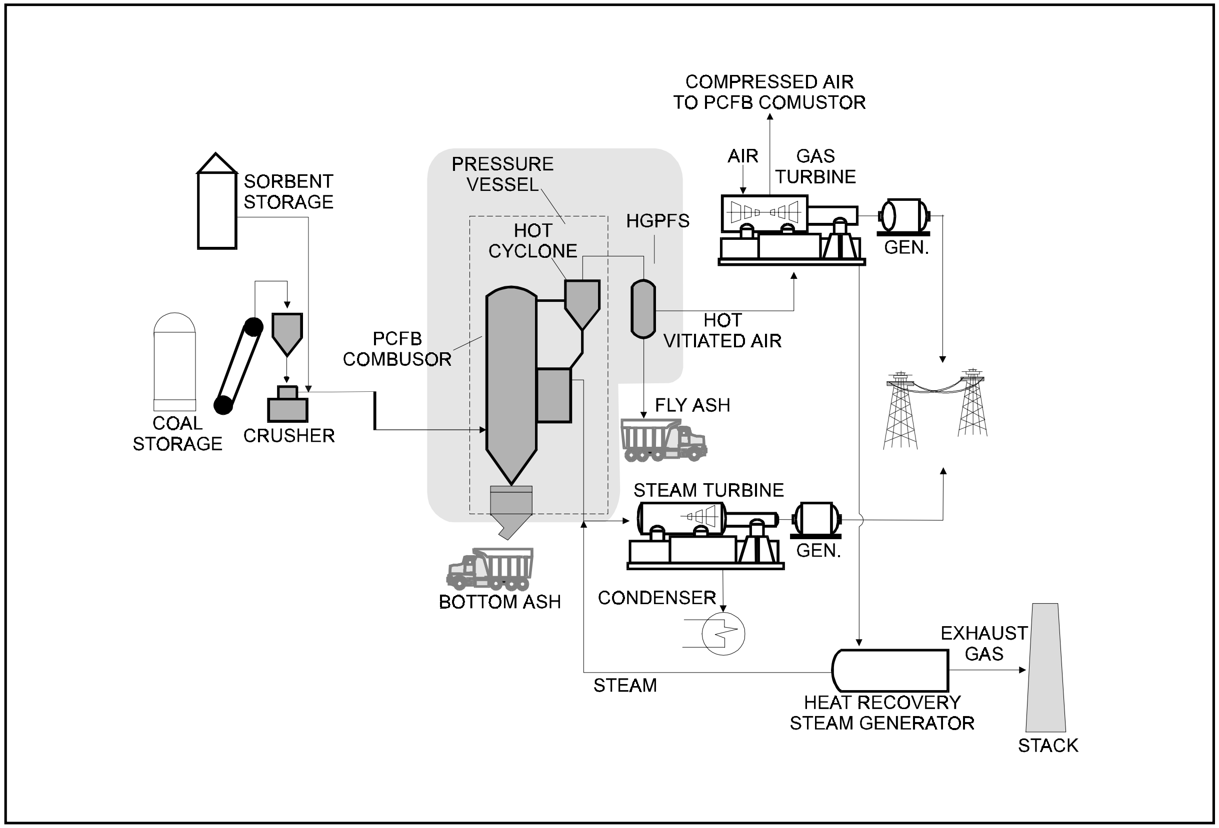
Eastern Kentucky and high ash, high sulfur bituminous coals

Project Funding

Total project cost	$186,588,000	100%
DOE	93,252,864	50
Participant	93,335,136	50

Project Objective

To demonstrate Foster Wheeler's PCFB technology coupled with Siemens Westinghouse's ceramic candle type HGPFS and power generation technologies, which represent a cost-effective, high-efficiency, low-emissions means of adding generating capacity at greenfield sites or in repowering applications.

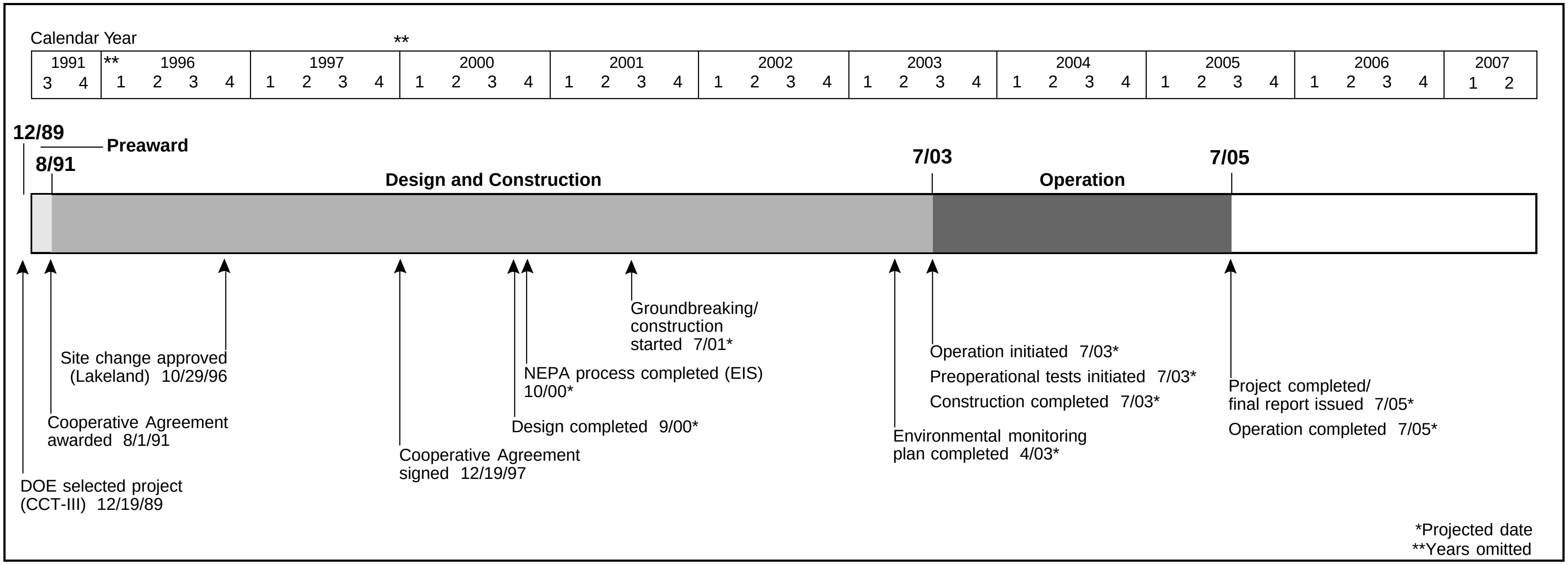


Technology/Project Description

The project resulted from a restructuring of the DMEC-1 PCFB Demonstration Project awarded under the third solicitation. In the first of the two Lakeland Electric projects, McIntosh Unit No. 4A is being constructed with a PCFB combustor adjacent to the existing Unit No. 3 (see also McIntosh Unit 4B Topped PCFB Demonstration Project).

Coal and limestone are mixed and fed into the combustion chamber. Combustion takes place at a temperature of approximately 1,560–1,600 °F and a pressure of about 200 psig. The resulting flue gas and fly ash leaving the combustor pass through a cyclone and ceramic candle type HGPFS where the particulates are removed. The hot gas leaving the HGPFS is expanded through a Siemens V64.3 gas turbine. The gas inlet temperature of less than 1,650 °F allows for a simplified turbine shaft and blade-cooling system. The hot gas leaving the gas turbine passes through a heat recovery steam generator (HRSG). Heat recovered from both the combustor and HRSG is used to generate steam to power a reheat steam turbine. Approximately 5–10% of the gross power is derived from the gas turbine, with the steam turbine contributing the balance.

The project also includes an atmospheric fluidized-bed unit that can be fired on coal or char from the carbonizer and will replace the PCFB unit during times of PCFB unavailability, allowing various modes of operation.



Project Status/Accomplishments

On December 19, 1997, a Cooperative Agreement modification was signed implementing the project restructuring from DMEC-1 to the City of Lakeland. The Lakeland City Council gave approval for the 10 year plan of Lakeland Electric (formerly Department of Electric & Water Utilities), which included this project, in April 1998. The project schedule anticipates the start of commercial operation of the PCFB (McIntosh 4A) in 2003. In parallel with the first two years of operation of the PCFB, the design, fabrication, and construction of the topped PCFB technology (McIntosh 4B) will occur, with a planned start of operation in 2005.

Negotiations continue between Lakeland and Foster Wheeler on the Engineer-Procure-Construct (EPC) proposal for the technology island.

Recent efforts focused on testing of the HGPFS, which is critical to system performance. Silicon carbide candle filters proved effective under conditions simulating those of the demonstration unit. At both 1,550 °F and 1,400 °F, the candle filters performed for over 1,000 hours at design levels without evidence of ash bridging or structural failure. Three new oxide-based candle filters showed promise as well and will undergo further testing because of the potential for reduced cost and operation at higher temperatures.

Commercial Applications

The project serves to demonstrate the PCFB technology to readiness for widespread commercial deployment in post-2000. The project will include the first commercial application of hot gas particulate cleanup and one of the first to use a non-ruggedized gas turbine in a pressurized fluidized-bed application.

The combined-cycle PCFB system permits the combustion of a wide range of coals, including high-sulfur coals, and would compete with the pressurized bubbling-bed fluidized-bed system. PCFB can be used to repower or replace conventional power plants. Because of modular construction capability, PCFB generating plants permit utilities to add economical increments of capacity to match load growth or to repower plants using existing coal- and waste-handling equipment and steam turbines. Another advantage for repowering applications is the compactness of the process due to pressurized operation, which reduces space requirements per unit of energy generated.

The projected net heat rate for the system is approximately 9,480 Btu/kWh (HHV), which equates to an efficiency greater than 36%. Environmental attributes include in-situ sulfur removal of 95%, NO_x emissions less than 0.3 lb/10^6 Btu, and particulate matter discharge less than 0.03 lb/10^6 Btu. Solid waste will increase slightly as compared to conventional systems, but the dry material is readily disposable or potentially usable.

McIntosh Unit 4B Topped PCFB Demonstration Project

Participant

City of Lakeland, Lakeland Electric

Additional Team Members

Foster Wheeler Corporation—supplier of carbonizer; engineer

Siemens Westinghouse Power Corporation—supplier of topping combustor and high-temperature filter

Location

Lakeland, Polk County, FL (Lakeland Electric's McIntosh Power Station, Unit No. 4)

Technology

Fully integrated second-generation PCFB technology with the addition of a carbonizer island that includes Siemens Westinghouse's multi-annular swirl-burner (MASB) topping combustor

Plant Capacity/Production

103-MWe (net) addition to the 137-MWe (net) McIntosh 4A project

Coal

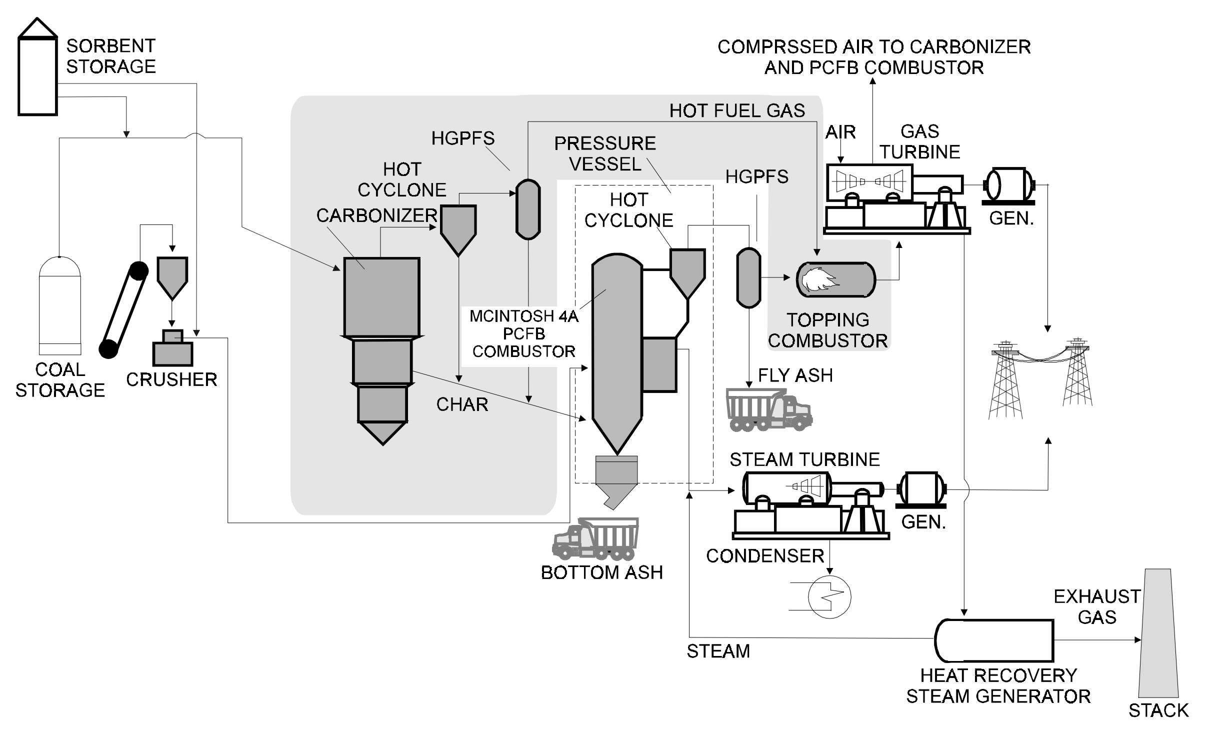
Eastern Kentucky and high ash, high sulfur bituminous coals

Project Funding

Total project cost	$219,635,546	100%
DOE	109,608,507	50
Participant	110,027,039	50

Project Objective

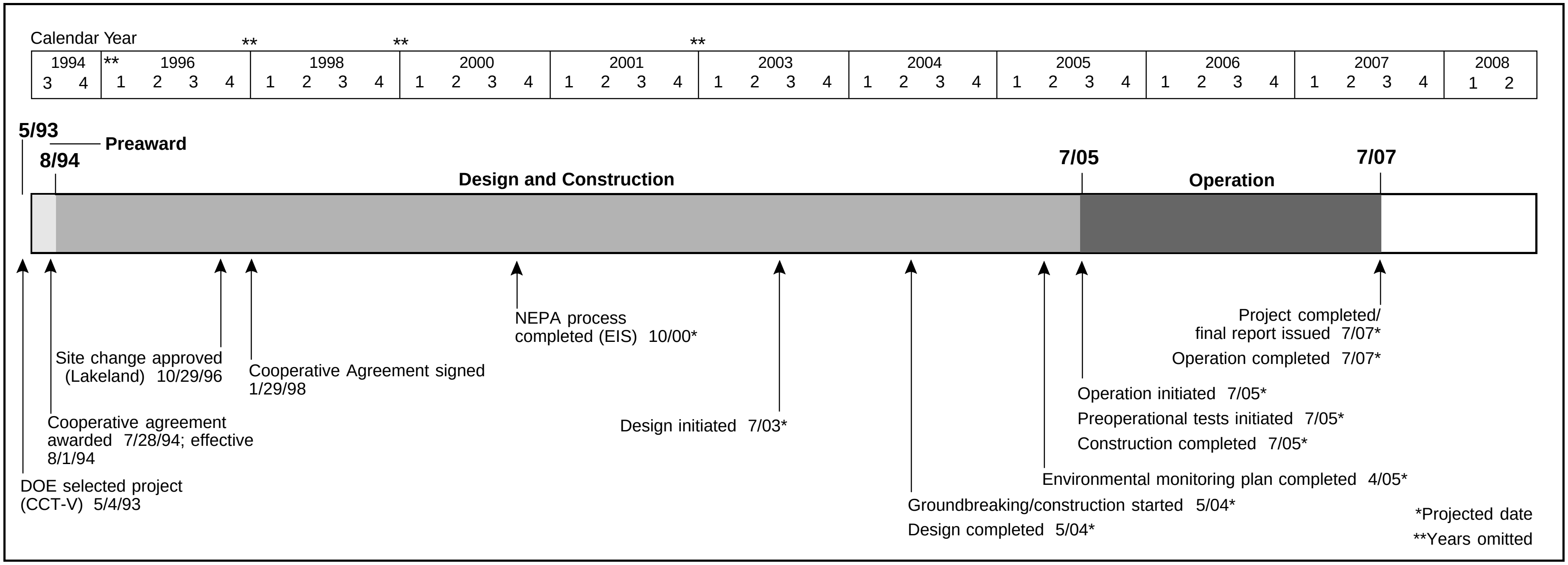
To demonstrate topped PCFB technology in a fully commercial power generation setting, thereby advancing the technology for future plants that will operate at higher gas turbine inlet temperatures and are expected to achieve cycle efficiencies in excess of 45%.



Technology/Project Description

The project resulted from a restructuring of the Four Rivers Energy Modernization Project awarded under the fifth solicitation. The Four Rivers project was to demonstrate the integration of a carbonizer (gasifier) and topping combustor (topping cycle) with the PCFB technology. By using a phased approach, Lakeland Electric will be able to demonstrate both PCFB (McIntosh 4A) and topped PCFB (McIntosh 4B) technologies at one plant site.

The project involves the addition of a carbonizer island to the PCFB demonstrated in the McIntosh 4A project. Dried coal and limestone are fed via a lock hopper system to the carbonizer with part of the gas turbine discharge air. The coal is partially gasified at about 1,750–1,800 °F to produce syngas and char solids streams. The limestone is used to absorb sulfur compounds generated during the mild gasification process. After cooling the syngas to about 1,200 °F, the char and limestone entrained with the syngas are removed by a hot gas particulate filter system (HGPFS). The char and limestone are then transferred to the PCFB combustor for complete carbon combustion and limestone utilization. The hot, cleaned, filtered syngas is then fired in the MASB topping combustor to raise the turbine inlet temperature to approximately 2,350 °F. The gas is expanded through the turbine, cooled in a heat recovery steam generator, and exhausted to the stack. The net impact of the addition of the topping cycle is an increase in both power output and efficiency. The coal and limestone used in McIntosh 4B are the same as those used in McIntosh 4A.



The 240-MWe (net) plant is expected to have a heat rate of 8,776 Btu/kWh (40.6% efficiency; HHV). The design SO_2 capture efficiency rate is 95%. Particulate and NO_x emissions are expected to be 0.02 lb/10^6 Btu and 0.17 lb/10^6 Btu, respectively. In the final configuration, the gas turbine will produce 58-MWe and the steam turbine will produce 207-MWe, while plant auxiliaries will consume about 25 MWe.

Project Status/Accomplishments

On January 29, 1998, a Cooperative Agreement modification was signed implementing the project restructuring from Four Rivers Energy Partners to the City of Lakeland. The Lakeland City Council gave approval for the 10 year plan of Lakeland Electric (formerly Department of Electric & Water Utilities), which included this project, in April 1998. In parallel with the first two years of operation of the PCFB (McIntosh 4A), the design, fabrication, and construction of the topped PCFB technology will take place. Start of operation is planned for late 2005. Negotiations continue between Lakeland and Foster Wheeler on the Engineer-Procure-Construct (EPC) proposal for the technology island.

Recent efforts focused on testing of the HGPFS, which is critical to system performance. Silicon carbide and alumina/mullite candle filters proved effective under conditions simulating those of the demonstration unit. At both 1,550 °F and 1,400 °F, the candle filters performed for over 1,000 hours at design levels without evidence of ash bridging or structural failure. Three new oxide-based candle filters showed promise as well. These will undergo further testing because of the potential for reduced cost and operation at higher temperatures.

Commercial Applications

The commercial version of the topped PCFB technology will have a greenfield net plant efficiency of 45% (which equates to a heat rate approaching 7,500 Btu/kWh, HHV). In addition to higher plant efficiencies, the plant will (1) have a cost of electricity that is projected to be 20% lower than that of a conventional pulverized-coal-fired plant with flue gas desulfurization, (2) meet emission limits that are half those allowed by New Source Performance Standard (NSPS), (3) operate economically on a wide range of coals, and (4) be amenable to shop fabrication. The benefits of improved efficiency include reduced cost for fuels and a reduction in CO_2 emissions.

The commercial version of the topped PCFB technology has other environmental attributes, which include in-situ sulfur retention that can meet 95% removal, NO_x emission that will be lower than 0.3 lb/10^6 Btu, and particulate matter discharge of approximately 0.03 lb/10^6 Btu. Although the system will generate a slight increase in solid waste as compared to conventional systems, the material is a dry, readily disposable, and potentially usable material.

JEA Large-Scale CFB Combustion Demonstration Project

Participant

JEA (formerly Jacksonville Electric Authority)

Additional Team Member

Foster Wheeler Energy Corporation—co-owner and technology supplier

Location

Jacksonville, Duval County, FL (JEA's Northside Station, Unit No. 2)

Technology

Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustor

Plant Capacity/Production

297.5-MWe (gross), 265-MWe (net)

Coal

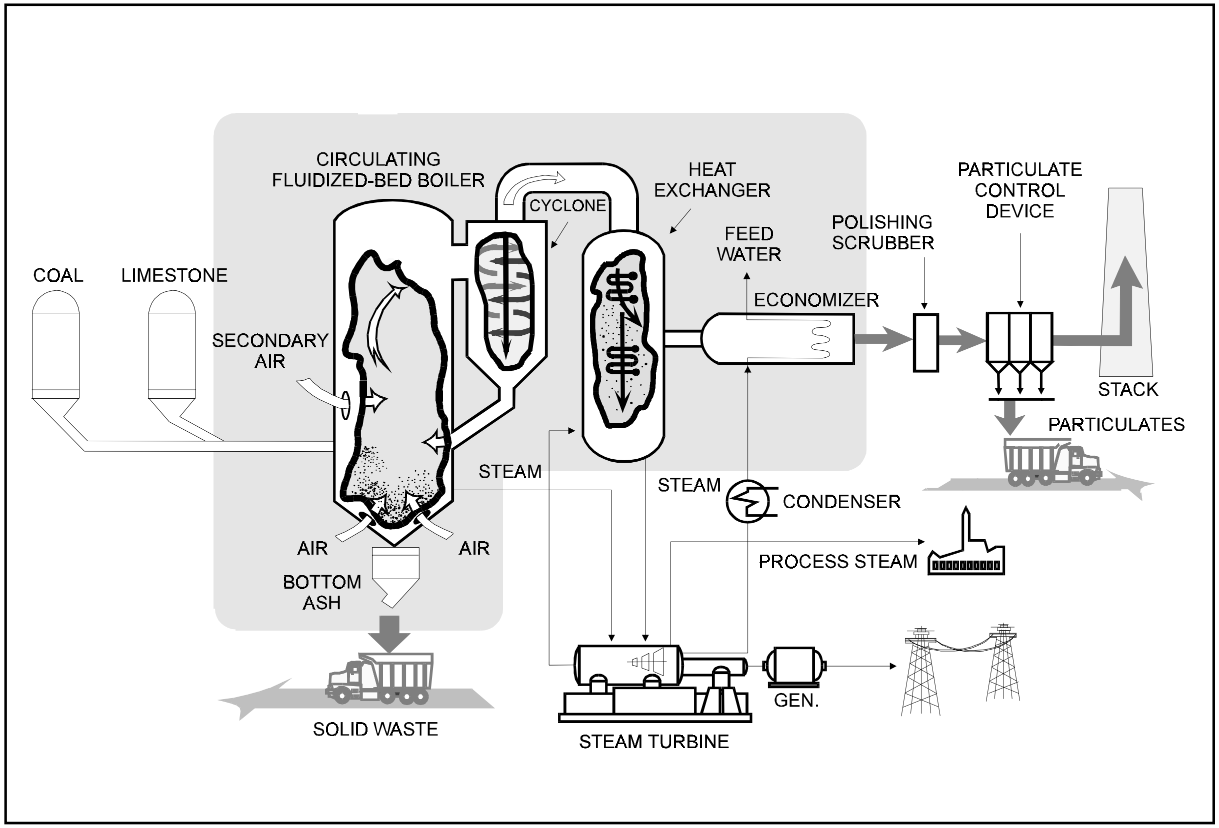
Eastern bituminous, 0.7% sulfur (design)

Project Funding

Total project cost	$309,096,512	100%
DOE	74,733,633	24
Participant	234,362,679	76

Project Objective

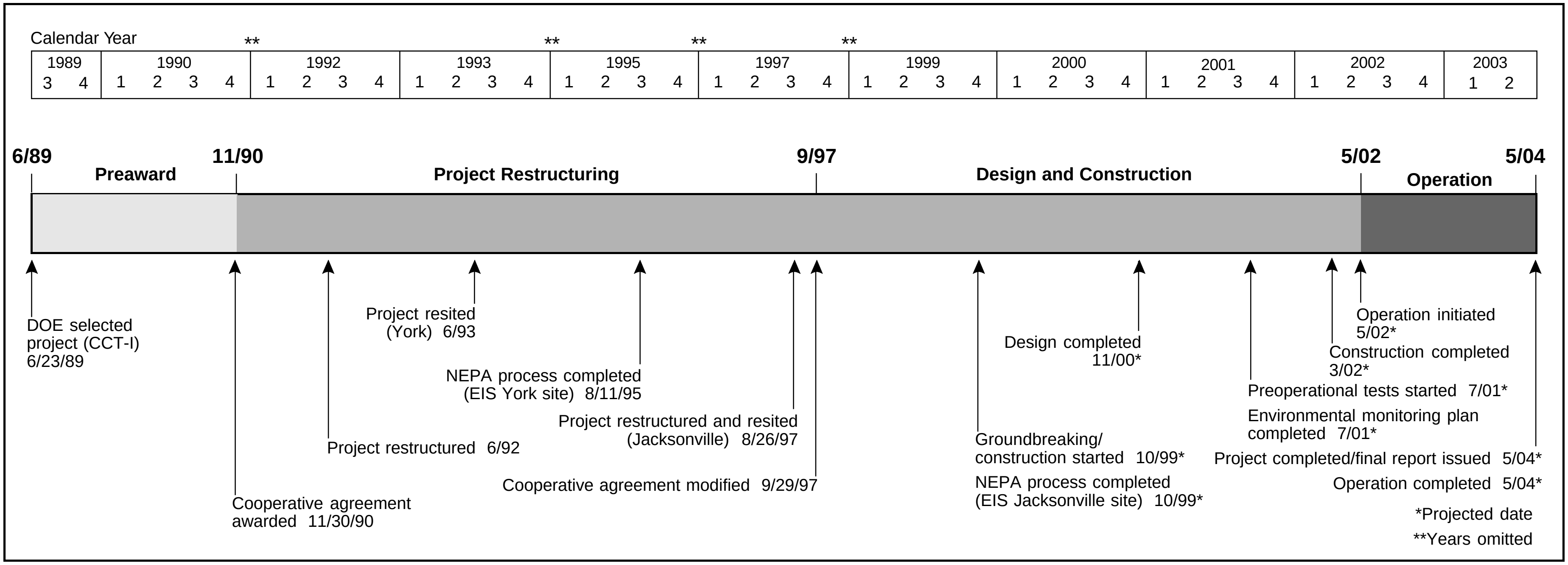
To demonstrate ACFB at 297.5-MWe gross (265-MWe net) representing a scale-up from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance to provide potential users with the data necessary for evaluating a large-scale ACFB as a commercial alternative; to accomplish greater than 90% SO_2 removal; and to reduce NO_x emissions by 60% when compared with conventional technology.



Technology/Project Description

A circulating fluidized-bed combustor, operating at atmospheric pressure, will be retrofitted into Unit No. 2 of the Northside Station. Coal or the secondary fuel (petroleum coke), primary air, and a solid sorbent (such as limestone), are introduced into the lower part of the combustor where initial combustion occurs. As the coal particles decrease in size due to combustion, they are carried higher in the combustor when secondary air is introduced. As the coal particles continue to be reduced in size, the coal, along with some of the sorbent, is carried out of the combustor, collected in a cyclone separator, and recycled to the lower portion of the combustor. Primary sulfur capture is achieved by the sorbent in the bed. However, additional SO_2 capture is achieved through the use of a polishing scrubber to be installed ahead of the particulate control equipment.

Steam is generated in tubes placed along the combustor's walls and superheated in tube bundles placed downstream of the particulate separator to protect against erosion. The system will produce approximately 2 x10^6 lb/hr of main steam at about 2,400 psig and 1,005 ºF and 1.73 x 10^6 lb/hr of reheat steam at 600 psig and 1,005 ºF. The steam will be used in an existing 297.5-MWe (nameplate) steam turbine. The heat rate for the retrofit plant is expected to be approximately 9,950 Btu/kWh (34% efficiency; HHV).



Project Status/Accomplishments

The project was successfully resited to Jacksonville, Florida after York County Energy partners and Metropolitan Edison Company terminated activities on the ACFB in September 1996. On August 26, 1997, DOE approved the transfer of the ACFB clean coal project from York, Pennsylvania, to Jacksonville. On September 29, 1997, DOE signed a modified cooperative agreement with JEA to cost-share refurbishment of the first (Unit No. 2) of two units at Northside Generating Station.

A Public Scoping Meeting on the Environmental Impact Statement (EIS) was held on December 3, 1997 at the Northside Station. The draft EIS is being prepared and was submitted for review in March 1999.

The project, currently in design, moves atmospheric fluidized-bed combustion technology to the larger sizes of utility boilers typically considered in capacity additions and replacements. The nominal 300-MWe demonstration unit in the JEA project will be more than double the size of the Nucla unit (110-MWe). Features include an integrated recycle heat exchanger (INTREX™) in the furnace, steam-cooled cyclones, a parallel pass reheat control, an SO_2 polishing scrubber, and a fabric filter for particulate control. Expected environmental performance is 0.17 lb/10^6 Btu for SO_2 (98% reduction), 0.11 lb/10^6 Btu for NO_x, and 0.017 lb/10^6 Btu for total particulates (0.013 lb/10^6 Btu for PM_{10}).

Commercial Applications

ACFB technology has good potential for application in both the industrial and utility sectors, whether for use in repowering existing plants or in new facilities. ACFB is attractive for both baseload and dispatchable power applications because it can be efficiently turned down to 25% of full load. Coal of any sulfur or ash content can be used, and any type or size of a unit can be repowered. In repowering applications, an existing plant area is used, and coal- and waste-handling equipment as well as steam turbine equipment are retained, thereby extending the life of a plant.

In its commercial configuration, ACFB technology offers several potential benefits when compared to conventional pulverized coal-fired systems: lower capital costs; reduced SO_2 and NO_x emissions at lower costs; higher combustion efficiency; and dry, granular solid material that is easily disposed of or potentially salable.

Tidd PFBC Demonstration Project

Project completed.

Participant

The Ohio Power Company

Additional Team Members

American Electric Power Service Corporation—designer, constructor, and manager
The Babcock & Wilcox Company—technology supplier
Ohio Coal Development Office—cofunder

Location

Brilliant, Jefferson County, OH (Ohio Power Company's Tidd Plant, Unit No. 1)

Technology

The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon)

Plant Capacity/Production

70-MWe (net)

Coal

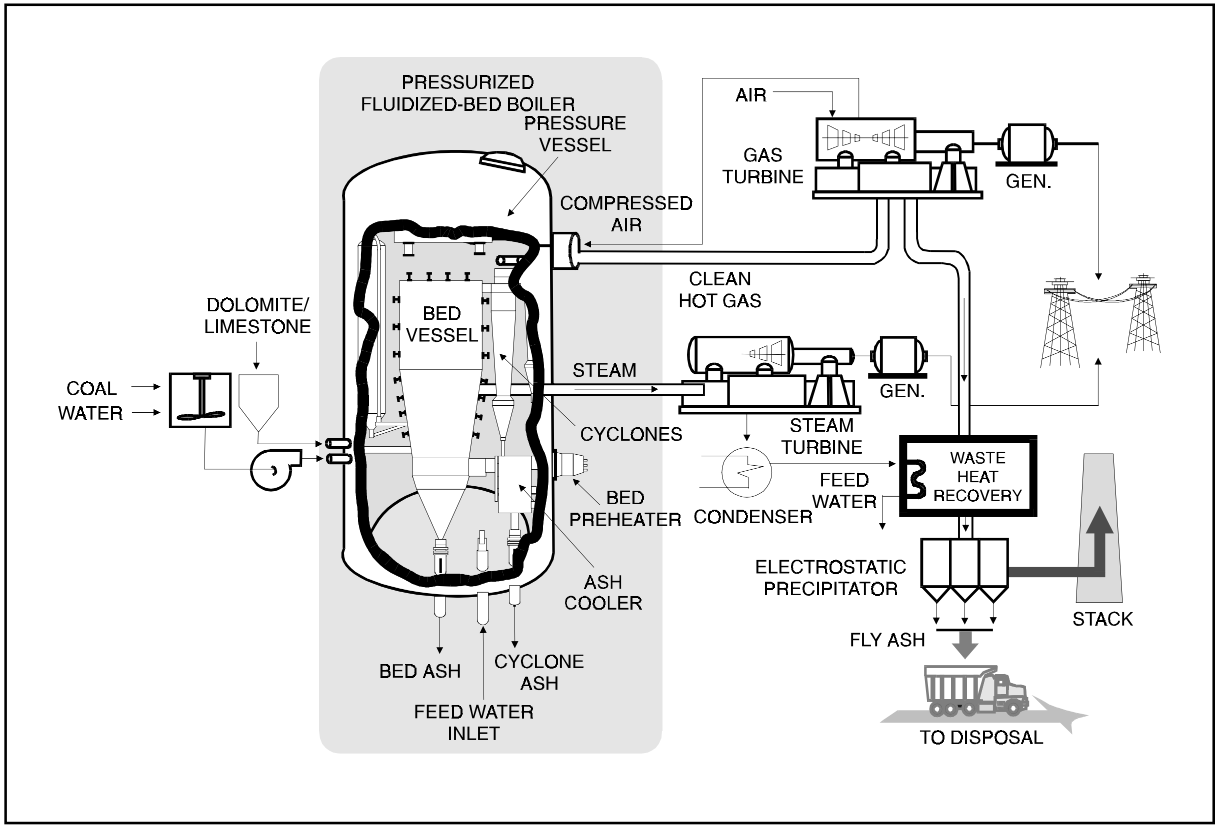
Ohio bituminous, 2–4% sulfur

Project Funding

Total project cost	$189,886,339	100%
DOE	66,956,993	35
Participant	122,929,346	65

Project Objective

To verify expectations of PFBC economic, environmental, and technical performance in a combined-cycle repowering application at utility scale; and to accomplish greater than 90% SO_2 removal and NO_x emission level of 0.2 lb/10^6 Btu at full load.



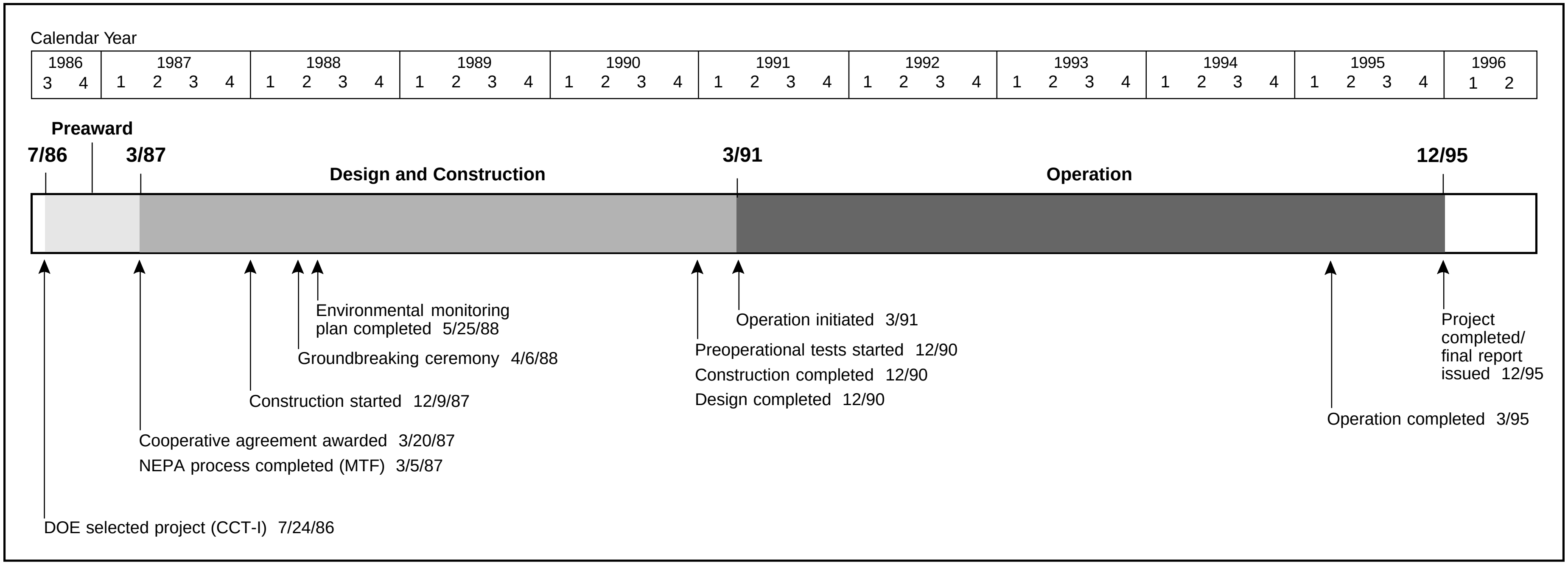
Technology/Project Description

Tidd was the first large-scale operational demonstration of PFBC in the United States. The project represented a 13:1 scaleup from the pilot facility.

The boiler, cyclones, bed reinjection vessels, and associated hardware were encapsulated in a pressure vessel 45 feet in diameter and 70 feet high. The facility was designed so that one-seventh of the hot gases produced could be routed to an Advanced Particulate Filter (APF).

The Tidd facility is a bubbling fluidized-bed combustion process operating at 12 atm (175 psi). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material, which consists of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent. Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material, which is easily disposed of or is usable as a by-product. A low bed-temperature of about 1,600 ºF limits NO_x formation.

The hot combustion gases exit the bed vessel with entrained ash particles, 98% of which are removed when the gases pass through cyclones. The cleaned gases are then expanded through a 15-MWe gas turbine. Heat from the gases exiting the turbine, combined with heat from a tube bundle in the fluid bed, generates steam to drive an existing 55-MWe steam turbine.



Results Summary

Environmental

- Sorbent size had the greatest effect on SO_2 removal efficiency as well as stabilization and heat transfer characteristics of the fluidized-bed.
- SO_2 removal efficiency of 90% was achieved at full load with a calcium-to-sulfur (Ca/S) molar ratio of 1.14 and temperature of 1,580 ºF.
- SO_2 removal efficiency of 95% was achieved at full load with a Ca/S molar ratio of 1.5 and temperature of 1,580 ºF.
- NO_x emissions were 0.15–0.33 lb/10^6 Btu.
- CO emissions were less than 0.01 lb/10^6 Btu.
- Particulate emissions were less than 0.02 lb/10^6 Btu.

Operational

- Combustion efficiency ranged from an average 99.3% at low bed levels to an average 99.5% at moderate to full bed levels.
- Heat rate was 10,280 Btu/kWh (HHV-gross output) (33.2% efficiency) because the unit was small and no attempt was made to optimize heat recovery.
- An Advanced Particulate Filter (APF), using a silicon carbide candle filter array, achieved 99.99% filtration efficiency on a mass basis.
- PFBC boiler demonstrated commercial readiness.
- ASEA Stal GT-35P gas turbine proved capable of operating commercially in a PFBC flue gas environment.

Economic

- The Tidd plant was a relatively small-scale facility, as such, detailed economics were not prepared as part of this project.
- A recent cost estimate performed on Japan's 360-MWe PFBC Karita Plant, due to commence operation in 1999, projected a capital cost of $1,263/kW (1997$).

Project Summary

The Tidd PFBC technology is a bubbling fluidized-bed combustion process operating at 12 atmospheres (175 psi). Fluidized combustion is inherently efficient. A pressurized environment further enhances combustion efficiency, allowing very low temperatures that mitigate thermal NO_x generation, flue gas/sorbent reactions that increase sorbent utilization, and flue gas energy that is used to drive a gas turbine. The latter contributed significantly to system efficiency because of the high efficiency of gas turbines and the availability of gas turbine exhaust heat that can be applied to the steam cycle. A bed design temperature of 1,580 ºF was established because it was the maximum allowable temperature at the gas turbine inlet and was well below temperatures for coal ash fusion, thermal NO_x formation, and alkali vaporization.

Coal crushed to ¼ inch or less was injected into the combustor as a coal/water paste containing 25% water by weight. Crushed sorbent, either dolomite or limestone, was injected into the fluidized bed via two pneumatic feed lines, supplied from two lock hoppers. The sorbent feed system initially used two injector nozzles but was modified to add two more for nozzles to enhance distribution.

In 1992, a 10-MWe equivalent APF was installed and commissioned as part of a research and development program and not part of the CCT demonstration. This system used ceramic candle filters to clean one-seventh of the exhaust gases from the PFBC system. The hot gas cleanup system unit replaced one of the seven secondary cyclones.

The Tidd PFBC demonstration plant accumulated 11,444 hours of coal-fired operations during its 54 months of operation. The unit completed 95 parametric tests, including continuous coal-fired runs of 28, 29, 30, 31, and 45 days. Ohio bituminous coals having sulfur contents of 2–4% were used in the demonstration.

Environmental Performance

Testing showed that 90% SO_2 capture was achievable with a Ca/S molar ratio of 1.14 and that 95% SO_2 capture was possible with a Ca/S molar ratio of 1.5, provided the size gradation of the sorbent being utilized was optimized. This sulfur retention was achieved at a bed temperature of 1,580 °F and full bed height. Limestone induced deterioration of the fluidized-bed, and as a result, testing focused on dolomite. The testing showed that sulfur capture as well as sintering was sensitive to the fineness of the dolomite sorbent (Plum Run Greenfield dolomite was the design sorbent). Sintering of fluidized-bed materials, a fusing of the materials rather than effective reaction, had become a serious problem that required operation at bed temperatures below the optimum for effective boiler operation. Tests were conducted with sorbent size reduced from minus 6 mesh to a minus 12 mesh. The result with the finer material was a major, positive impact on process performance without the expected excessive elutriation of sorbent. The finer material increased the fluidization activity as evidenced by a 10% improvement in heat transfer rate and an approximately 30% increase in sorbent utilization. In addition, the process was much more stable as indicated by reductions in temperature variations in both the bed and the evaporator tubes. Further, sintering was effectively eliminated.

NO_x emissions ranged from 0.15–0.33 lb/10^6 Btu, but were typically 0.2 lb/10^6 Btu during the demonstration. These emissions were inherent to the process, which was operating at approximately 1,580 °F. No NO_x control enhancements, such as ammonia injection, were required. Emissions of carbon monoxide and particulates were less than 0.01 and 0.02 lb/10^6 Btu, respectively.

Operational Performance

Except for localized erosion of the in-bed tube bundle and the more general erosion of the water walls, the Tidd boiler performed extremely well and was considered a commercially viable design. The in-bed tube bundle experienced no widespread erosion that would require significant maintenance. While the tube bundle experienced little wear, a significant amount of erosion on each of the four water walls was observed. This erosion posed no problem, however, because the area affected is not critical to heat transfer and could be protected by refractory.

The prototype gas turbine experienced structural problems and was the leading cause of unit unavailability during the first 3 years of operation. However, design changes instituted over the course of the demonstration proved effective in addressing the problem. The Tidd demonstration showed that a gas turbine could operate in a PFBC flue gas environment.

Efficiency of the PFBC combustion process was calculated during testing from the amount of unburned carbon in cyclone and bed ash, together with measurements of the amount of carbon monoxide in the flue gas. Combustion efficiencies averaged 99.5% at moderate to full bed heights, surpassing the design or expected efficiency of 99.0%.

▲ The PFBC demonstration at the repowered 70-MWe unit at Ohio Power's Tidd Plant led to significant refinements and understanding of the technology.

Using data for typical full-load operation, a heat rate of 10,280 Btu/kWh (HHV basis) was calculated. This corresponds to a cycle thermodynamic efficiency of 33.2% at a point where the cycle produced 70-MWe of gross electrical power while burning Pittsburgh No. 8 coal. Because the Tidd plant was a repowering application at a comparatively small scale, the measured efficiency does not represent what would be expected for a larger utility-scale plant using Tidd technology. Studies conducted under the PFBC Utility Demonstration Project showed that efficiencies of over 40% are likely for a larger utility-scale PFBC plant.

In summary, the Tidd project showed that the PFBC system could be applied to electric power generation. Further, the demonstration project led to significant refinements and understanding of the technology in the areas of turbine design, sorbent utilization, sintering, post-bed combustion, ash removal, and boiler materials.

Testing of the APF for over 5,800 hours of coal-fired operation showed that the APF vessel was structurally adequate; the clay-bonded silicon carbide candle filters were structurally adequate unless subjected to side loads from ash bridging or build-up in the vessel; bridging was precluded with larger particulates included in the particulate matter; and filtration efficiency (mass basis) was 99.99%.

Economic Performance

The Tidd plant was a relatively small-scale demonstration facility, so detailed economics were not prepared as part of this project. However, a recent cost estimate performed on Japan's 360-MWe PFBC Karita Plant, due to commence operation in 1999, projected a capital cost of $1,263/kW (1997$).

Commercial Applications

Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. The compactness of bubbling-bed PFBC technology allows utilities to significantly increase capacity at existing sites. Compactness of the process due to pressurized operation reduces space requirements per unit of energy generated. PFBC technology appears to be best suited for applications of 50-MWe or larger. Capable of being constructed modularly, PFBC generating plants permit utilities to add increments of capacity economically to match load growth. Plant life can be extended by repowering with PFBC using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment.

The 360-MWe Karita Plant in Japan, which will use ABB Carbon P800 technology, represents a major move toward commercialization of PFBC bubbling-bed technology. A second generation P200 PFBC is under construction in Germany. Other PFBC projects are under consideration in China, South Korea, the United Kingdom, Italy, and Israel.

The Tidd project received *Power* magazine's 1991 Powerplant Award. In 1992, the project received the National Energy Resource Organization award for demonstrating energy-efficient technology.

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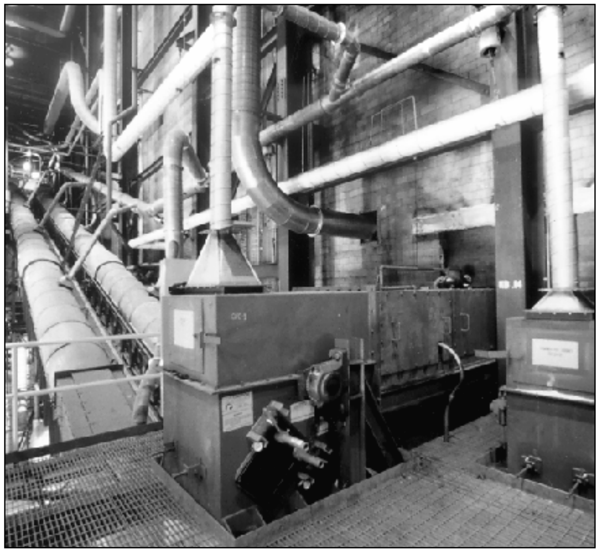


▲ Coal and sorbent conveyors can be seen just after entering the Tidd Plant.

Nucla CFB Demonstration Project

Project completed.

Participant

Tri-State Generation and Transmission Association, Inc. (formerly Colorado-Ute Electric Association, Inc.)

Additional Team Members

Foster Wheeler Energy Corporation*—technology supplier
Technical Advisory Group (potential users)—cofunder
Electric Power Research Institute—technical consultant

Location

Nucla, Montrose County, CO (Nucla Station)

Technology

Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustion system

Plant Capacity/Production

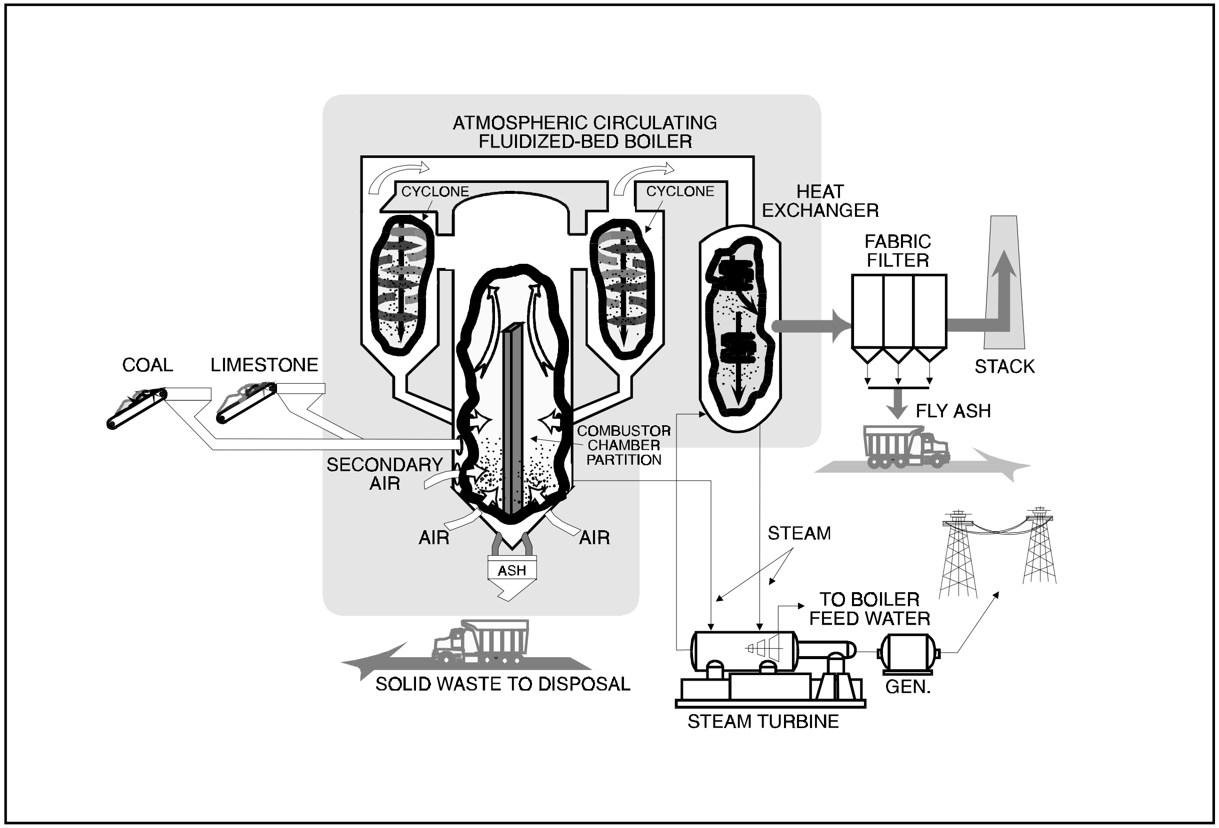
100-MWe (net)

Coal

Western bituminous—
  Salt Creek, 0.5% sulfur, 17% ash
  Peabody, 0.7% sulfur, 18% ash
  Dorchester, 1.5% sulfur, 23% ash

Project Funding

Total project cost	$46,512,678	100%
DOE	17,130,411	37
Participant	29,382,267	63



Project Objective

To demonstrate the feasibility of ACFB technology at utility scale and to evaluate the economic, environmental, and operational performance at that scale.

Technology/Project Description

Nucla's circulating fluidized-bed system operates at atmospheric pressure. In the combustion chamber, a stream of air fluidizes and entrains a bed of coal, coal ash, and sorbent (e.g., limestone). Relatively low combustion temperatures limit NO_x formation. Calcium in the sorbent combines with SO_2 gas to form calcium sulfite and sulfate solids, and solids exit the combustion chamber and flow into a hot cyclone. The cyclone separates the solids from the gases, and the solids are recycled for combustor temperature control. Continuous circulation of coal and sorbent improves mixing and extends the contact time of solids and gases, thus promoting high utilization of the coal and high-sulfur-capture efficiency. Heat in the flue gas exiting the hot cyclone is recovered in the economizer. Flue gas passes through a baghouse where particulate matter is removed. Steam generated in the ACFB is used to produce electric power.

Three small, coal-fired, stoker-type boilers at Nucla Station were replaced with a new 925,000-lb/hr ACFB steam generator capable of driving a new 74-MWe turbine generator. Extraction steam from this turbine generator powers three existing turbine generators (12-MWe each).

In 1992, Colorado-Ute Electric Association, Inc., the owner of Nucla Station, was purchased by Tri-State Generation and Transmission Association, Inc.

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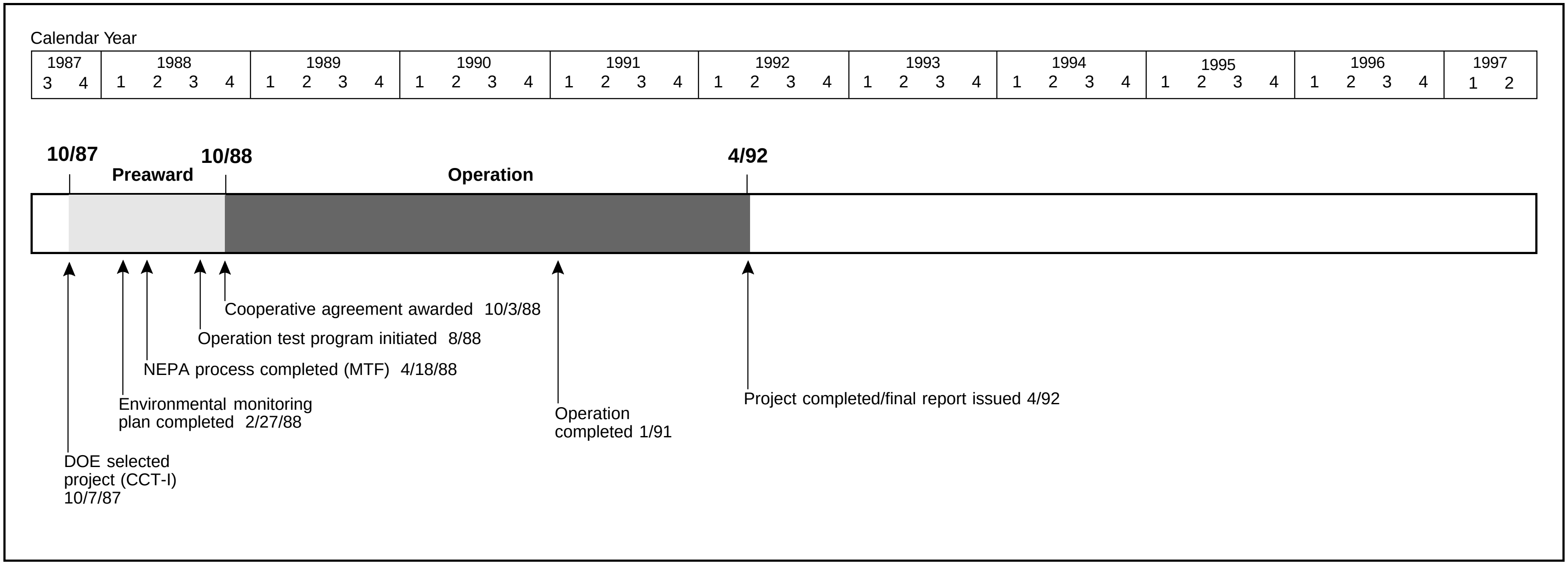
*Pyropower Corporation, the original technology developer and supplier, was acquired by Foster Wheeler Energy Corp.



Results Summary

Environmental

- Bed temperature had the greatest effect on pollutant emissions and boiler efficiency.
- At bed temperatures below 1,620 ºF, sulfur capture efficiencies of 70 and 95% were achieved at calcium-to-sulfur (Ca/S) molar ratios of 1.5 and 4.0, respectively.
- During all tests, NO_x emissions averaged 0.18 lb/10^6 Btu and did not exceed 0.34 lb/10^6 Btu.
- CO emissions ranged from 70–140 ppmv.
- Particulate emissions ranged from 0.0072–0.0125 lb/10^6 Btu, corresponding to a removal efficiency of 99.9%.
- Solid waste was essentially benign and showed potential as an agricultural soil amendment, soil/road bed stabilizer, or landfill cap.

Operational

- Boiler efficiency ranged from 85.6–88.6% and combustion efficiency ranged from 96.9–98.9%.
- A 3:1 boiler turndown capability was demonstrated.
- Heat rate at full load was 11,600 Btu/kWh and was 12,400 Btu/kWh at half load.

Economic

- Capital cost for the Nucla retrofit was $1,123/kW and a normalized power production cost was 64 mills/kWh.

Project Summary

Fluidized-bed combustion evolved from efforts to find a combustion process conducive to controlling pollutant emissions without external controls. Fluidized-bed combustion enables efficient combustion at temperatures of 1,400–1,700 ºF, well below the thermal-NO_x formation temperature (2,500 ºF), and high SO_2-capture efficiency through effective sorbent/flue gas contact. ACFB differs from the more traditional fluid-bed combustion. Rather than submerging a heat exchanger in the fluid bed, which dictates a low-fluidization velocity, ACFB uses a relatively high fluidization velocity, which entrains the bed material. Hot cyclones capture and return the solids emerging from the turbulent bed to control temperature and extend the gas/solid contact time and to protect a downstream heat exchanger.

Interest and participation of the Department of Energy, Electric Power Research Institute, and Technical Advisory Group (potential users) resulted in the evaluation of ACFB potential for broad utility application through a comprehensive test program. Over a 2½-year period, 72 steady-state performance tests were conducted and 15,700 hours logged. The result was a database that remains the most comprehensive, available resource on ACFB technology.

Operational Performance

Between July 1988 and January 1991, the plant operated with an average availability of 58% and an average capacity factor of 40%. However, toward the end of the demonstration, most of the technical problems had been overcome. During the last three months of the demonstration, average availability was 97% and the capacity factor was 66.5%.

Over the range of operating temperature at which testing was performed, bed temperature was found to be the most influential operating parameter. With the exception of coal-fired configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions and efficiency.

Combustion efficiency, a measure of the quantity of carbon that is fully oxidized to CO_2, ranged from 96.9–98.9%. 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 85.6–88.6%. 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.

Environmental Performance

As indicated above, bed temperature had the greatest impact on ACFB performance, including pollutant emissions. Exhibit 40 shows the effect of bed temperatures on the Ca/S molar ratio requirement for 70% sulfur retention. The Ca/S molar ratios were calculated based on the calcium content of the sorbent only and do not account for the calcium content of the coal. While a Ca/S molar ratio of about 1.5 was sufficient to achieve 70% sulfur retention in the 1,500–1,620 °F range, the Ca/S molar ratio requirement jumped to 5.0 or more at 1,700 °F or greater.

Exhibit 41 shows the effect of Ca/S molar ratio on sulfur retention at average bed temperatures below 1,620 ºF. Salt Creek and Peabody coals contain 0.5% and 0.7% sulfur, respectively. To achieve 70% SO_2 reduction, or the 0.4 lb/10^6 Btu emission rate required by the licensing agreement, a Ca/S molar ratio of approximately 1.5 is required. To achieve an SO_2 reduction of 95%, a Ca/S molar ratio of approximately 4.0 is necessary. Dorchester coal, averaging 1.5% sulfur content, required a somewhat lower Ca/S molar ratio for a given retention.

NO_x emissions measured throughout the demonstration were less than 0.34 lb/10^6 Btu, which is well below the regulated value of 0.5 lb/10^6 Btu. The average level of NO_x emissions for all tests was 0.18 lb/10^6 Btu. NO_x emissions indicate a relatively strong correlation with temperature, increasing from 40 ppmv (0.06 lb/10^6 Btu) at 1,425 ºF to 240 ppmv (0.34 lb/10^6 Btu) at 1,700 °F. Limestone feed rate was also identified as a variable affecting NO_x emissions, i.e., somewhat higher NO_x emissions resulted from increasing calcium-to-nitrogen (Ca/N) molar ratios. The mechanism was believed to be oxidation of volatile nitrogen in the form of ammonia (NH_3) catalyzed by calcium oxide. CO emissions decrease as temperature increases, from 140 ppmv at 1,425 ºF to 70 ppmv at 1,700 ºF.

At full load, the hot cyclones removed 99.8% of the particulates. With the addition of baghouses, removal efficiencies achieved on Peabody and Salt Creek Coals were 99.905% and 99.959%, respectively. This equated to emission levels of 0.0125 lb/10^6 Btu for Peabody coal and 0.0072 lb/10^6 Btu for Salt Creek coal, well below the required 0.03 lb/10^6 Btu.

Exhibit 40
Effect of Bed Temperature on Ca/S Requirement

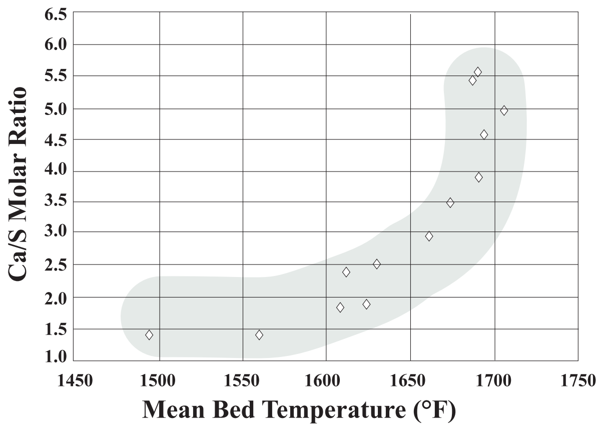
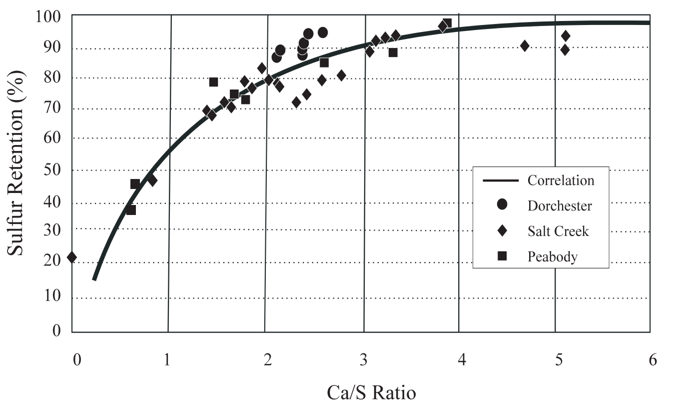


Exhibit 41
Calcium Requirements and Sulfur Retentions for Various Fuels



Economic Performance

The final capital costs associated with the engineering, construction, and start-up of the Nucla ACFB system were $112.3 million. This represents a cost of $1,123/kW (net). Total power costs associated with plant operations between September 1988 and January 1991 were approximately $54.7 million, resulting in a normalized cost of power production of 64 mills/kWh. The average monthly operating cost over this period was about $1,888,000. Fixed costs represent about 62% of the total and include interest (47%), taxes (4.8%), depreciation (6.9%), and insurance (2.7%). Variable costs represent more than 38% of the power production costs and include fuel expenses (26.2%), non-fuel expenses (6.8%), and maintenance expenses (5.5%).

▲ The 110-MWe Nucla ACFB demonstration enabled Pyropower Corporation (now owned by Foster Wheeler) to save almost 3 years in establishing a commercial line of ACFB units.

Commercial Applications

The Nucla project represented the first repowering of a U.S. utility plant with ACFB technology and showed the technology's effectiveness to burn a wide variety of coals cleanly and efficiently. The comprehensive database resulting from the Nucla project enabled the resultant technology to be replicated in numerous commercial plants throughout the world. Nucla continues in commercial service.

Today, every major boiler manufacturer offers an ACFB system in its product line. There are now more than 120 fluidized-bed combustion boilers of varying capacity operating in the U.S. and the technology has made significant market penetration abroad. The fuel flexibility and ease of operation make it a particularly attractive power generation option for the burgeoning power market in developing countries.

Contacts

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Nelson F. Rekos, FETC, (304) 285-4066

References

- *Colorado-Ute Nucla Station Circulating Fluidized-Bed (CFB) Demonstration—Volume 2: Test Program Results.* EPRI Report No. GS-7483. October 1991.
- *Demonstration Program Performance Test: Summary Reports.* Report No. DOE/MC/25137-3104. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE92001299.)
- *Economic Evaluation Report: Topical Report.* Report No. DOE/MC/25137-3127. Colorado-Ute Electric Association, Inc., March 1992. (Available from NTIS as DE93000212.)
- *Nucla CFB Demonstration Project: Detailed Public Design Report.* Report No. DOE/MC/25137-2999. Colorado-Ute Electric Association, Inc., December 1990. (Available from NTIS as DE91002081.)

Advanced Electric Power Generation
Integrated Gasification Combined Cycle

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.; AMEREN Corporation; and Energy Research Corporation)

Additional Team Members

Duke Engineering & Services, Inc.—engineer and constructor

General Electric Company—power island designer and supplier

British Gas Americas, Inc., in conjunction with Lurgi Energie and Umwelt GmbH—gasification island designer

Energy Research Corporation—molten carbonate fuel cell designer and supplier; cofunder

AMEREN Corporation—cofunder

Location

Carbondale, Jackson County, IL (Central Illinois Public Service Company's Grand Tower Station)

Technology

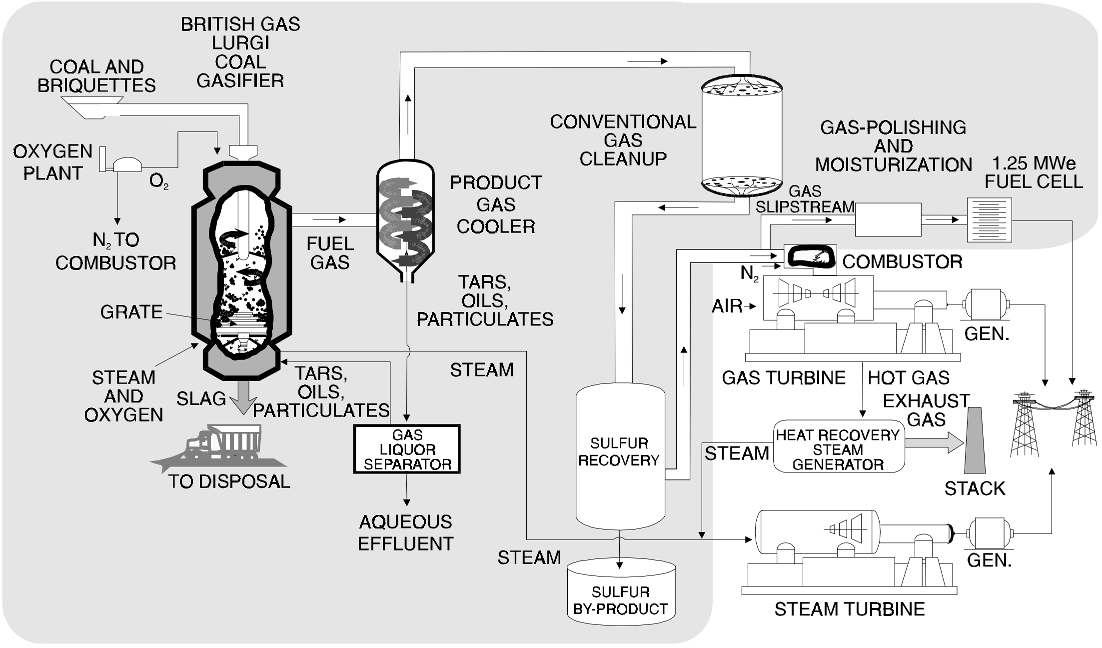
Integrated gasification combined-cycle (IGCC) using British Gas/Lurgi (BG/L) slagging fixed-bed gasification system coupled with Energy Research Corporation's molten carbonate fuel cell (MCFC)

Plant Capacity/Production

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

Coal

Illinois basin bituminous coal



Project Funding

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

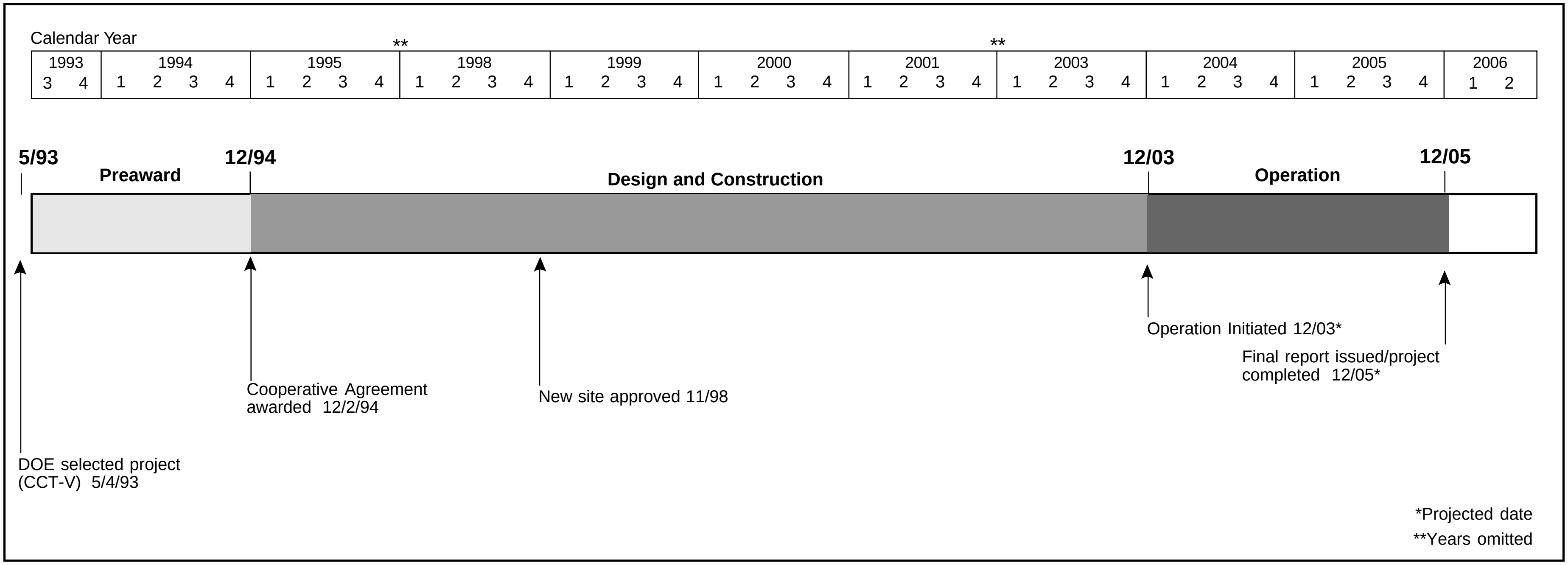
Project Objective

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.

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 flux to produce a raw coal-derived fuel gas rich in hydrogen and carbon monoxide. Raw fuel gas exiting the gasifier is washed and cooled. Hydrogen sulfide and other sulfur compounds are removed. Elemental sulfur is reclaimed and sold as a by-product. Tars, oils, and dust are recycled to the gasifier. The resulting clean, medium-Btu fuel gas fires the gas turbine. A small portion of the clean fuel 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 fuel gas) and steam are fed continuously into the anode; carbon dioxide enriched air is fed into the cathode. Electrical reactions produce direct electric current, which is converted to alternating power in an inverter.



Project Status/Accomplishments

The cooperative agreement was awarded December 2, 1994. Subsequent to award, a new site had to be found. The Central Illinois Public Service Company's Grand Tower Station was proposed by the Participant and approved by DOE on November 10, 1998. The initial scoping meeting for the NEPA process was held in January 1999.

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 projected to be 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/10^6 Btu (99% reduction); NO_x emissions, less than 0.15 lb/10^6 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
Bechtel Corporation—startup engineer

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

107-MWe (gross), 99-MWe (net)

Coal

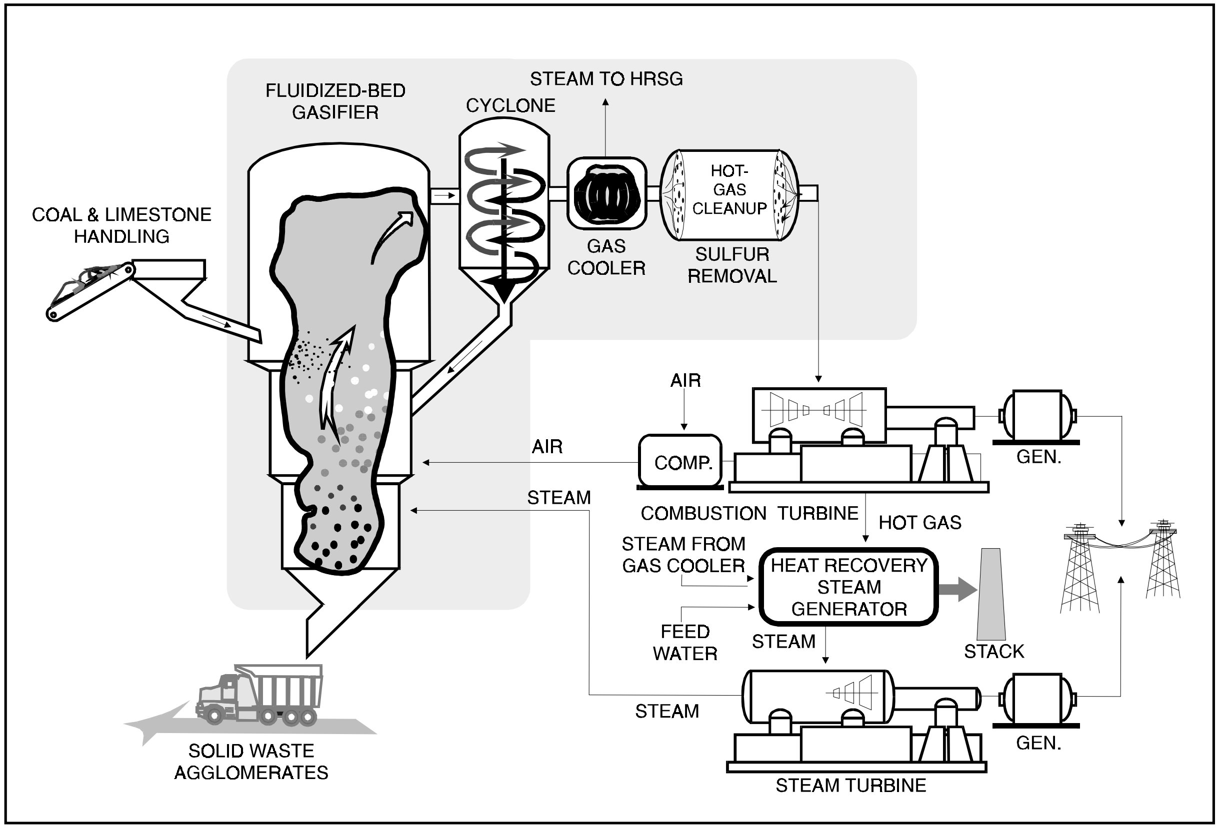
Southern Utah bituminous, 0.5–0.9% sulfur (design coal); eastern bituminous, 2–3% sulfur (planned test)

Project Funding

Total project cost	$335,913,000	100%
DOE	167,956,500	50
Participant	167,956,500	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.



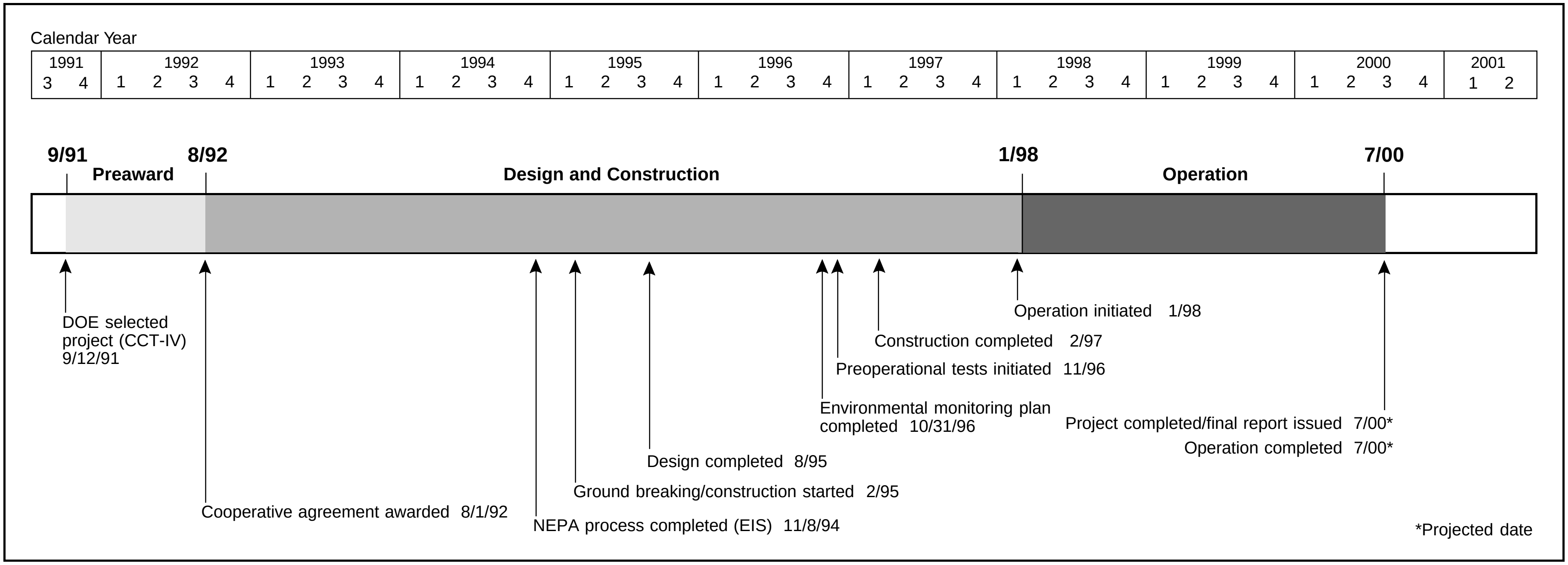
Technology/Project Description

Dried and crushed coal and limestone are introduced into an air-blown pressurized fluidized-bed gasifier. Crushed limestone is used to capture a portion of the sulfur. 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.

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 ºF, is cooled to about 1,100 ºF 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 a metal oxide sorbent in a transport reactor.

The cleaned gas then enters the General Electric MS6001FA (Frame 6FA) combustion turbine, which is coupled to a generator designed to produce 61-MWe (gross). Exhaust gas from the combustion turbine is used to produce steam in a heat recovery steam generator (HRSG). Superheated high-pressure steam drives a condensing steam turbine-generator designed to produce about 46-MWe (gross).

The IGCC plant will remove 95+% of the sulfur in the coal. 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 expected to be 70% less than a conventional coal-fired plant. The IGCC will produce 20% less CO_2 (a greenhouse gas) than conventional plants.



In the demonstration project, 880 tons/day of coal are converted into 99 MWe (net) for export to the grid. Southern Utah bituminous coal (0.5–0.9% sulfur) is the design coal; tests using midwestern or eastern high-sulfur bituminous coal (2–3% sulfur) also are planned. The IGCC system is located at Sierra Pacific Power Company's Tracy Station, near Reno, NV.

Project Status/Accomplishments

The system has initiated test-plan operations and continues to experience start-up problems. The station began operation on natural gas in November 1996. Pre-operational testing and shakedown of the coal gasification combined-cycle system continued through 1997 with syngas produced in January 1998. The plant was dedicated in April 1998.

The GE Frame 6FA combustion turbine, the first of its kind in the world, has performed well since commencing operation in August 1996 on natural gas. Other portions of the plant have undergone design modification to improve performance, including the start-up logic for the gasifier and the sorbent used for the transport desulfurizer.

This project continues to make progress achieving integrated operation of all systems. Some earlier problems (related to measuring solids levels) in the fines handling system have been resolved; however, other non-gasifier problems, such as fines bridging in vessels, have occurred that prevent feeding coal for more than 6-8 hours continuously. The gasifier continues to operate smoothly through numerous startup-turndown cycles, with reproducible production of specification-quality syngas. Sierra Pacific continues to operate the plant on natural gas in the combined cycle mode.

Commercial Applications

The Piñon Pine IGCC system concept is suitable for new power generation, repowering needs, and cogeneration applications. The net 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 an IGCC system reduces space requirements per unit of energy generated relative to other coal-based power generation systems. The advantages provided by phased 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, high-ash, low-rank, and high-swelling coals, as well as bio- or refuse-derived waste, with minimal environmental impact. 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 Corporation—combined-cycle technology supplier

GE Environmental Services, 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 No. 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

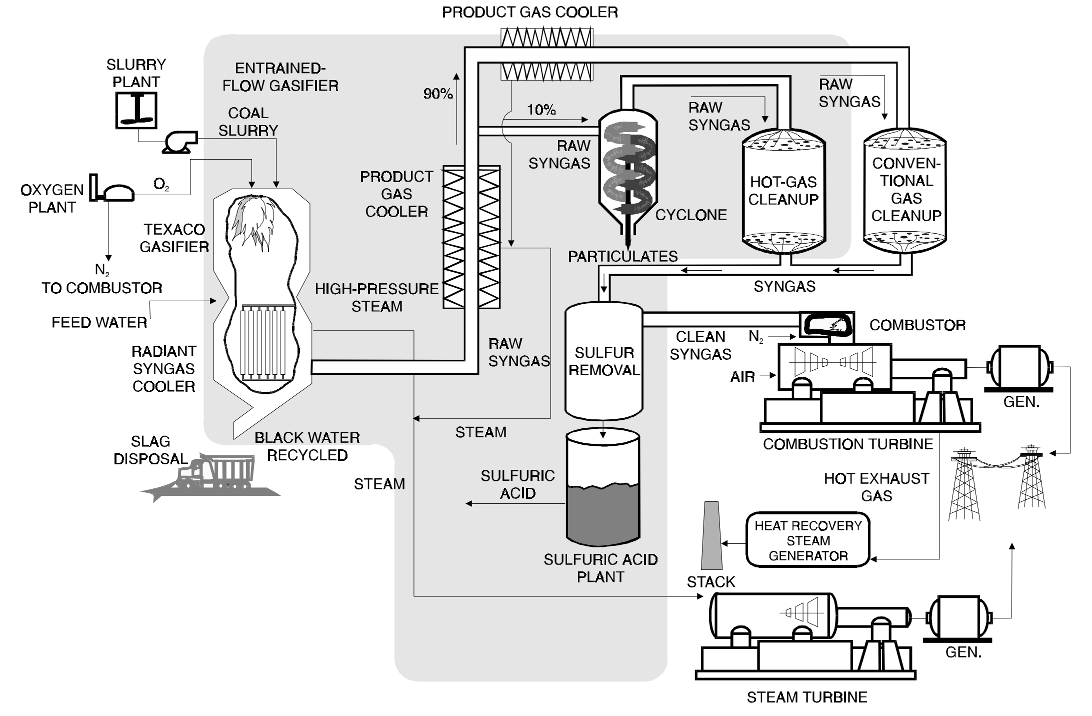
313-MWe (gross), 250-MWe (net)

Coal

Illinois #6, Pittsburgh #8, and Kentucky #11; 2.5–3.5% sulfur

Project Funding

Total project cost	$303,288,446	100%
DOE	150,894,223	49
Participant	152,394,223	51



Project Objective

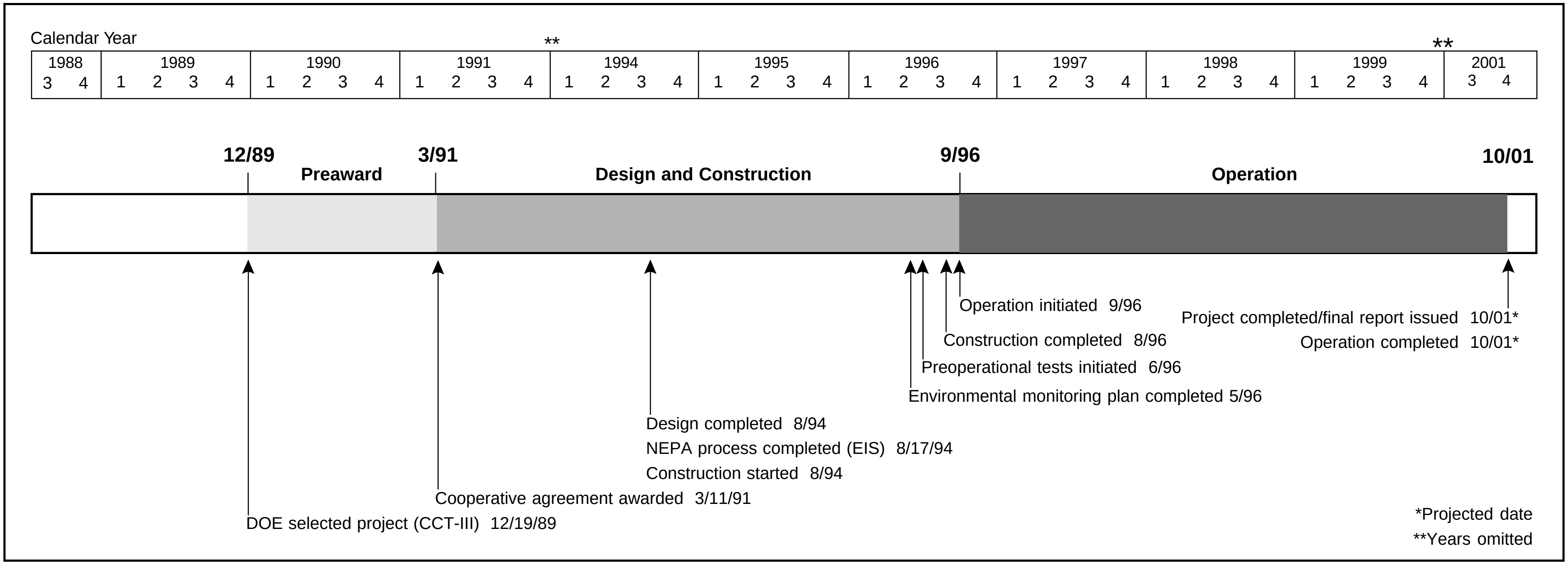
To demonstrate IGCC technology in a greenfield, commercial, electric utility application at the 250-MWe size with a Texaco gasifier; to demonstrate the integrated performance of a metal oxide hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection (from 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. A coal/water slurry and oxygen are reacted at high temperature and pressure to produce a high-temperature syngas. The syngas moves from the gasifier to a high-temperature heat-recovery unit, which cools the gases. Molten coal-ash flows out of the bottom of the gasifier vessel and into a water-filled quench tank where it is forms a solid slag.

The cooled gases flow to a particulate-removal section before entering gas-cleanup trains. A portion of the syngas (10%) is passed through a moving bed of metal oxide absorbent to remove sulfur. The remaining syngas is further cooled through a series of convective 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/10^6 Btu (96% capture). The cleaned gases are then routed to a combined-cycle system for power generation. Sulfuric acid and slag are salable by-products.

A GE MS 7001F combustion turbine generates about 192 MWe (gross). Thermal-NO_x is controlled to below



0.27 lb/10^6 Btu by injecting nitrogen as a dilutent in the turbine's combustion section. A steam turbine, which uses steam produced by the heat recovery steam-generator, produces an additional 121-MWe (gross). Polk's 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. Illinois #6, Pittsburgh #8, and Kentucky #11 bituminous coals (2.5–3.5% sulfur) are being used.

Project Status/Accomplishments

The plant began commercial operation in September 1996 and continues to successfully accumulate run time. IGCC operation had exceeded 11,000 hours by December 1998. The unit has produced over 2,944,278 MWh on syngas. The gasifier on-stream factor was over 70% for 1998. Overall combined-cycle availability has remained above 90% since the second quarter of 1997. Improved gasifier availability was largely due to removal of the raw gas/clean gas heat exchanger, a source of particulate contamination, and installation of a larger filter to prevent leakage of particulate matter to the turbine. Also contributing to improved availability are new operating procedures to deal with radiant syngas cooler dome seal leaks and hot restarts of the gasifier.

Tests included evaluation of various coal types on system performance. Kentucky #11, Illinois #6, and three Pittsburgh #8 coals were tested for their: (1) ability to be processed into a high concentration slurry, (2) carbon conversion efficiency, (3) aggressiveness of the slag in regard to refractory wear, and (4) tendency toward fouling of the syngas coolers. Kentucky #11 coal proved to have the best overall characteristics and supplanted Pittsburgh #8 as the base coal. Illinois #6 placed second and prompted further testing because of some promising aspects of its performance. The unit is currently running on a blend of Ohio #11/Powder River Basin coals. The gasifier and combustion turbine set continuous operating records of over 49 and 51 days, respectively.

Commercial Applications

This demonstration project is scaling up the technology from Cool Water demonstration unit (100-MWe) tested without full system integration. The Texaco-based IGCC is suitable for new electric power generation, repowering needs, and cogeneration applications. Commercial IGCCs should achieve better than 98% SO_2 capture with a NO_x emissions reduction of 90% relative to a conventional pulverized coal-fired plant.

Texaco and ASEA Brown Boveri have signed an agreement forming an alliance to market IGCC technology in Europe.

The project was presented the 1997 Powerplant Award by *Power* magazine. In 1996 the project received the Association of Builders and Contractors Award for construction quality. Several awards were presented for using an innovative siting process: 1993 Ecological Society of America Corporate Award and 1993 Timer Powers Conflict Resolution Award from the State of Florida, and the 1991 Florida Audubon Society Corporate Award.

Wabash River Coal Gasification Repowering Project

Participant

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

Additional Team Members

PSI Energy, Inc.—host

Dynegy (formerly Destec Energy, Inc.; a subsidiary of Natural Gas Clearinghouse)—engineer, gas plant operator, and technology supplier

Location

West Terre Haute, Vigo County, IN (PSI Energy's Wabash River Generating Station, Unit No. 1)

Technology

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

Plant Capacity/Production

296-MWe (gross), 262-MWe (net)

Coal

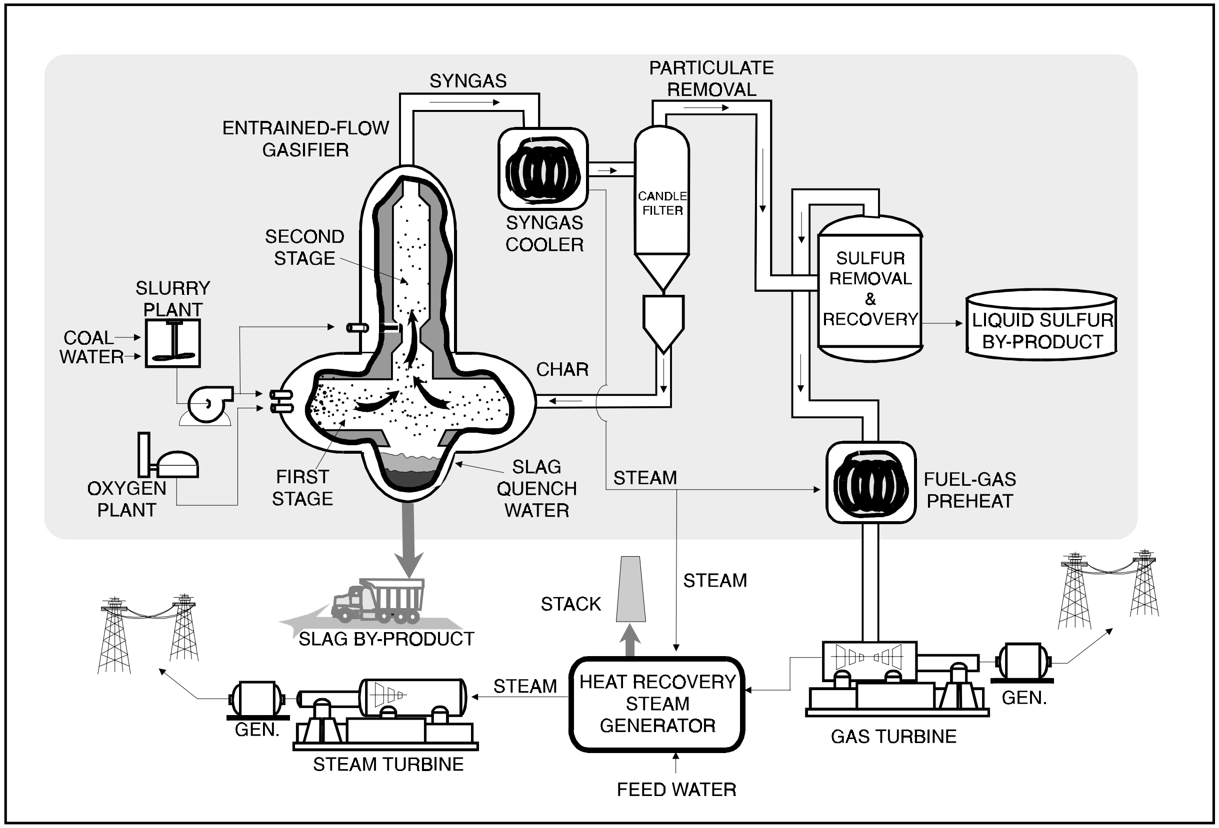
Illinois Basin bituminous

Project Funding

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

Project Objective

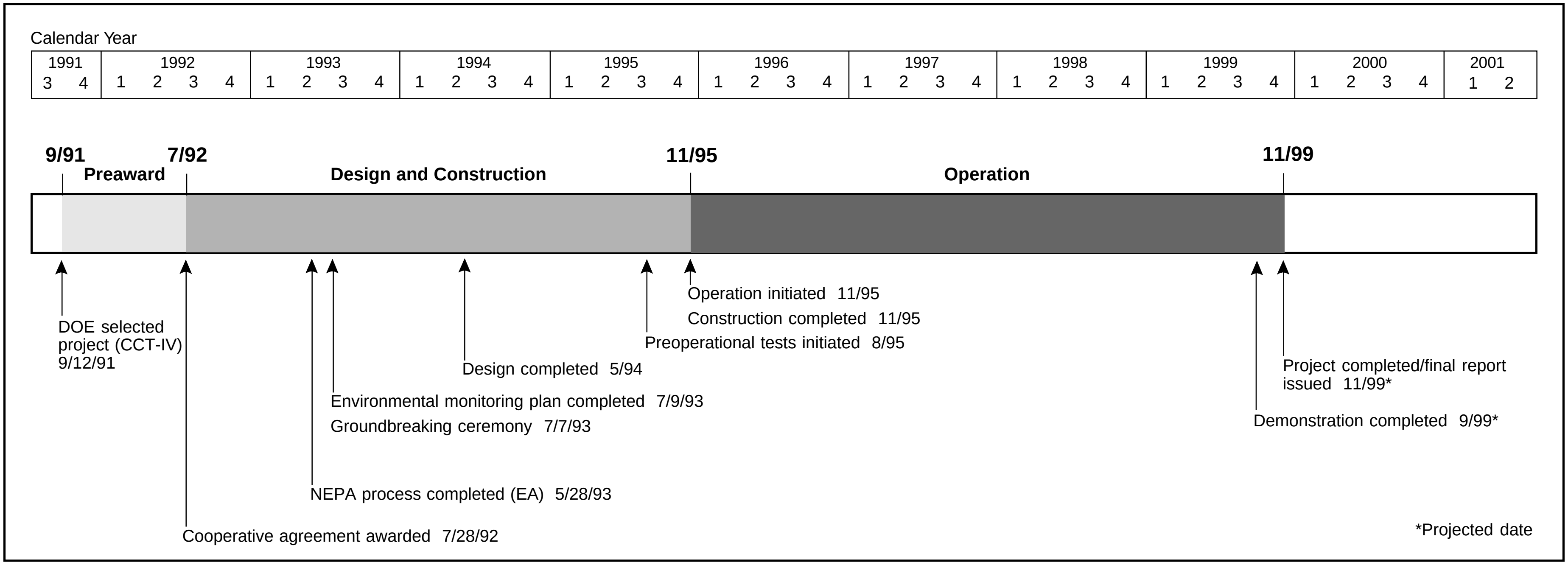
To demonstrate utility repowering with a two-stage pressurized oxygen-blown entrained-flow IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal and to assess long-term reliability, availability, and maintainability of the system at a fully commercial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



Technology/Project Description

The Destec coal gasification process features an oxygen-blown, continuous-slagging, two-stage, entrained flow gasifier. Coal is slurried, combined with oxygen in mixer nozzles, and injected into the first stage of the gasifier, which operates at 2600 °F and 400 psig. Oxygen of 95% purity is supplied by an Air Liquide 2,060-ton/day low-pressure cryogenic distillation facility (Air Separation Unit or ASU), which is owned and operated by Destec. In the first stage, the coal slurry undergoes a partial oxidation reaction at temperatures high enough to bring the coal's ash above its melting point. The fluid ash falls through a tap hole at the bottom of the first stage into a water quench, forming an inert vitreous slag. The syngas flows to the second stage, where additional coal slurry is injected. This coal is pyrolyzed in an endothermic reaction with the hot syngas to enhance syngas heating value and to improve overall efficiency. A Claus unit is used to produce elemental sulfur as a salable by-product.

The syngas then flows to the high-temperature heat-recovery unit (HTHRU), essentially a firetube steam generator, to produce high-pressure saturated steam. After cooling in the HTHRU, particulates in the syngas are removed in a hot/dry filter and recycled to the gasifier. The syngas is further cooled in a series of heat exchangers. The syngas is water scrubbed to remove chlorides and passed through a catalyst that hydrolyzes carbonyl sulfide (COS) into hydrogen sulfide. Hydrogen sulfide is removed in the acid gas removal system using MDEA-based absorber/stripper columns. The "sweet" gas is then moisturized, preheated, and piped to the power block.



The power block consists of a single 192-MWe General Electric MS 7001FA combustion turbine/generator (CT), a Foster Wheeler single-drum heat recovery steam generator with reheat, and a 1952 vintage Westinghouse reheat steam turbine. Steam injection is used for NO_x control in the CT, but the steam flow is minimal because the syngas is moisturized in the gasification process. Existing coal handling facilities, interconnections, and other auxiliaries were reused.

Project Status/Accomplishments

The project began operations in December 1995 and continues in its fourth year of commercial service. CINergy, PSI's post-merger parent company, preferentially dispatches the unit second behind its hydroelectric facilities on the basis of environmental emissions and efficiency, with a demonstrated heat rate of better than 9,000 Btu/kWh (HHV). In 1998, the facility operated for 5,281 hours processing over 560,000 tons of coal and producing over 8.8 trillion Btus of syngas. Since beginning operation, the facility has operated on coal for over 10,000 hours and processed more than one million tons of coal. The unit has achieved monthly production levels of one trillion Btus on four occasions. The 1998 operating data show a capacity factor of 68% and an availability of over 72%. Refinements to the design are continuing, including replacement of ceramic candle particulate filters with a metallic filter (operating temperature 800 ºF) and installation of a chloride scrubber and new COS hydrolysis catalyst for SO_2 control.

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 over 30 years old. 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.

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.

Destec Energy and CINergy Corp./PSI Energy received the 1996 Powerplant Award from *Power* magazine. Sargent & Lundy, engineer for the combined-cycle facility, won the American Consulting Engineers Council's 1996 Engineering Excellence Award.

Advanced Electric Power Generation
Advanced Combustion/Heat Engines

Healy Clean Coal Project

Participant

Alaska Industrial Development and Export Authority

Additional Team Members

Golden Valley Electric Association—host and operator
Stone and Webster Engineering Corp.—engineer
TRW Inc., Space & Technology Division—combustor technology supplier
The Babcock & Wilcox Company (which has acquired assets of Joy Environmental Technologies, Inc.)—spray-dryer absorber technology supplier
Usibelli Coal Mine, Inc.—coal supplier

Location

Healy, Denali Borough, AK (adjacent to Healy Unit No. 1)

Technology

TRW's advanced entrained (slagging) combustor
Babcock & Wilcox's spray-dryer absorber with sorbent recycle

Plant Capacity/Production

50-MWe (nominal)

Coal

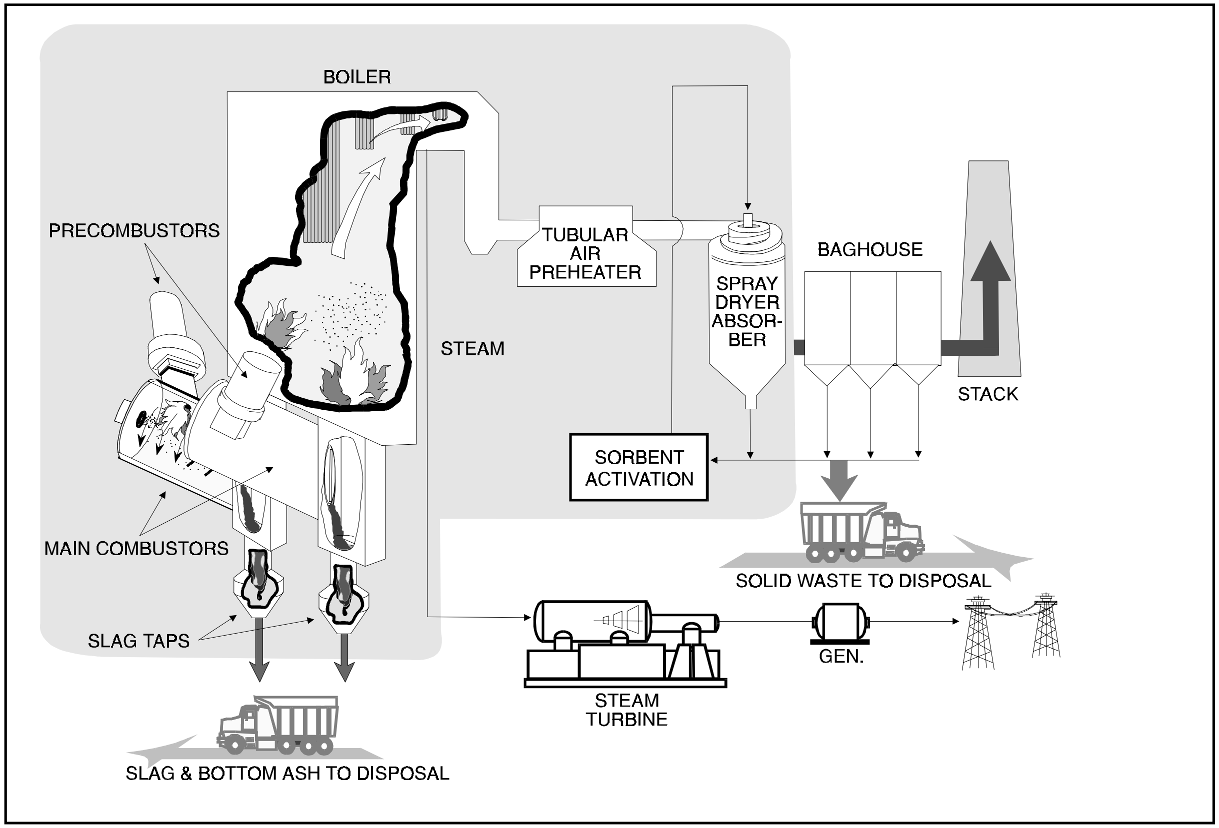
Usibelli subbituminous 35% run-of-mine (ROM) (0.2% sulfur) and 65% waste coal (design)

Project Funding

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

Project Objective

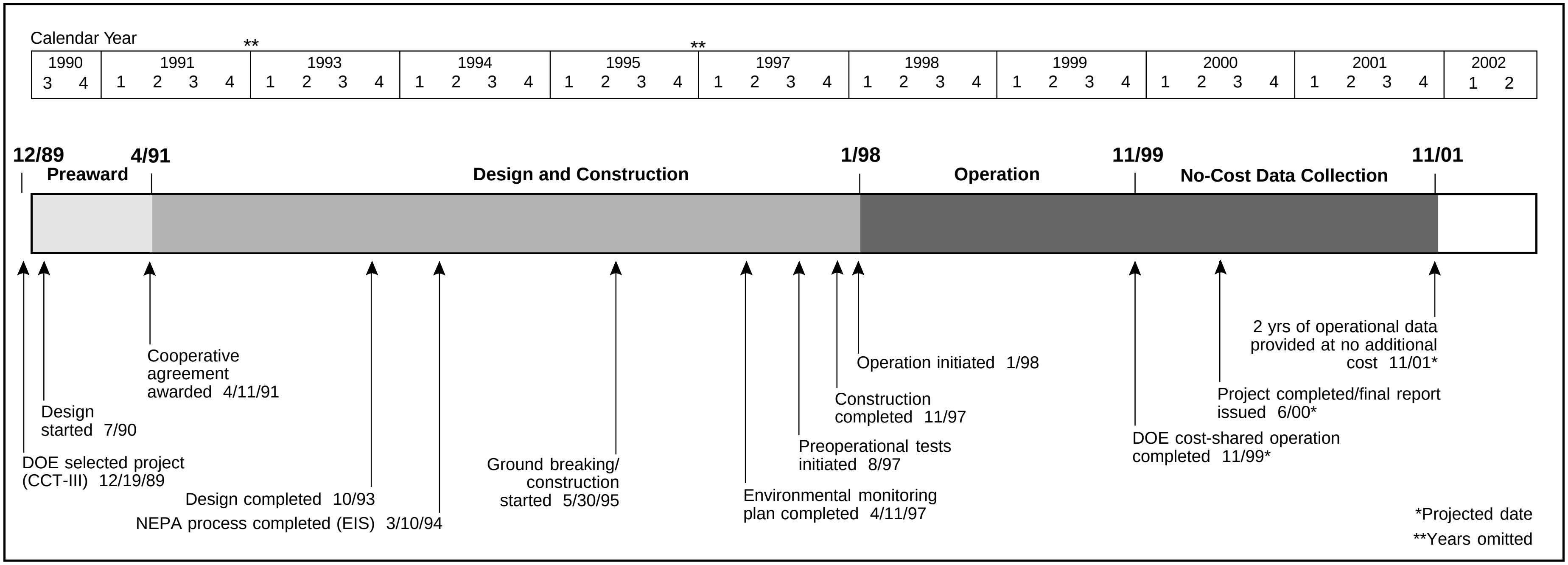
To demonstrate an innovative new power plant design featuring integration of an advanced combustor and heat recovery system coupled with both high- and low-temperature emissions control processes.



Technology/Project Description

The project involves two unique slagging combustors generating a nominal 50 MWe. Emissions of SO_2 and NO_x are controlled using TRW's slagging combustion systems with staged fuel and air, a boiler that controls NO_x related conditions, and limestone injection. Additional SO_2 is removed using Babcock & Wilcox's activated recycle spray-dryer absorber system. Performance goals are NO_x emissions of less than 0.2 lb/10^6 Btu, particulate emissions of 0.015 lb/10^6 Btu, and SO_2 removal greater than 90%. The design fuel blend performance testing of coal consists of 35% ROM and 65% waste coal.

A coal-fired precombustor increases the air inlet temperature for optimum slagging performance. The TRW slagging combustors are side mounted, injecting the combustion products vertically into the boiler. 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.



Pulverized limestone ($CaCO_3$) for SO_2 control is fed into the combustor where it is flash calcined (converting $CaCO_3$ to CaO). The mixture of this lime (CaO) and ash not slagged, called flash-calcined material, is removed in the fabric filter (baghouse) system. Most of the flash-calcined material is used to form a 45% flash-calcined-material solids slurry. 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 No. 1 near Healy, Alaska, and to the Usibelli coal mine. Power will go to the Golden Valley Electric Association (GVEA). The plant will use 900 tons/day of subbituminous and waste coal. Following the completion of cost-shared demonstration operations, the project will collect an additional 2 years of performance data being provided at no cost to DOE. A HAP 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 No. 1 so that the combined emissions from the two units will be only slightly greater than those currently emitted from Unit No. 1 alone. Total site emissions will be further reduced to current levels if necessary to protect the park.

Project Status/Accomplishments

The initial firing of the entrained slagging combustion system on coal began in January 1998. During a record-setting 18-day period of continuous operation, initial NO_x and SO_2 environmental compliance testing was completed. The preliminary results showed that NO_x emissions of 0.25 lb/10^6 Btu and SO_2 emissions of 0.08 lb/10^6 Btu were achieved. The permit requires emissions to be less than 0.35 lb/10^6 Btu for NO_x and less than 0.10 lb/10^6 Btu for SO_2. The stringent SO_2 emission level required by the permit is significantly lower than the 1.2 lb/10^6 Btu NSPS limit. By the end of the first year of operation, the plant had logged over 4,900 hours of operation and converted 156,000 tons of coal/waste coal blend into 231 gigawatts of electricity (average capacity factor 44%). The following minor modifications were made on Combustor “A” during a routine outage completed in January 1999: combustor improvements to minimize slag buildup in the precombustor/combustor, acoustical silencer added to the ID fan area, and a flow distribution device was inserted prior to the baghouse to minimize bag wear. Operations are currently focused on blending ROM coal with up to 65% waste coal. In March 1999, compliance particulate emissions tests were conducted.

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 requirements.

The combustion technology supplier, TRW, is offering licensing of its technology worldwide and already has a licensing agreement in place in China.

Clean Coal Diesel Demonstration Project

Participant
Arthur D. Little, Inc.

Additional Team Members
University of Alaska at Fairbanks—host and cofunder
Alaskan Science & Technology Foundation—cofunder
Coltec Industries Inc.—diesel engine technology vendor
Energy and Environmental Research Center, University of North Dakota—fuel preparation technology vendor
R.W. Beck, Inc.—architect/engineer, designer, constructor
Usibelli Coal Mine, Inc.—coal supplier

Location
Fairbanks, AK (University of Alaska facility)

Technology
Coltec's coal-fueled diesel engine

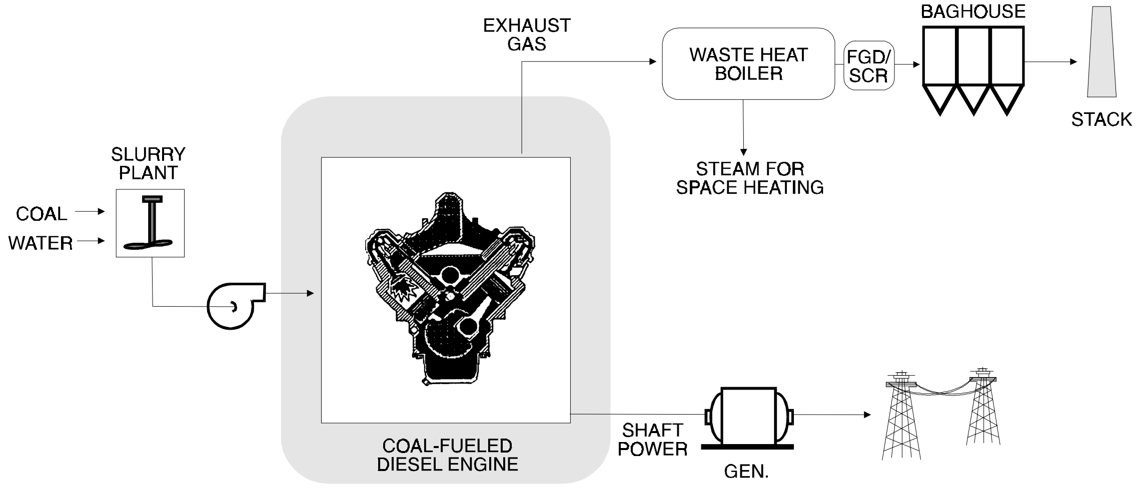
Plant Capacity/Production
6.4-MWe (net)

Coal
Usibelli Alaskan subbituminous

Project Funding

Total project cost	$47,636,000	100%
DOE	23,818,000	50
Participant	23,818,000	50

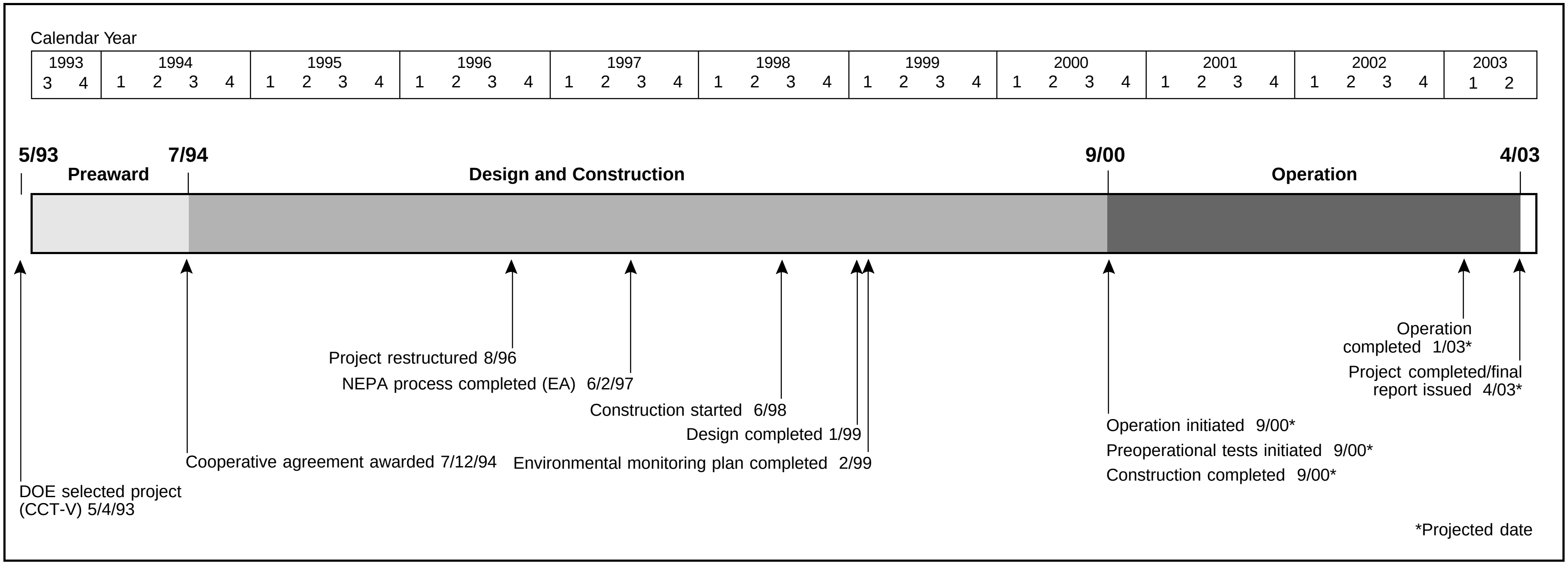
Project Objective
To prove the design, operability, and durability of the coal diesel engine during 6,000 hours of operation; verify the design and operation of an advanced drying/slurrying process for subbituminous Alaskan coals; and test the coal slurry in the diesel and a retrofitted oil-fired boiler.



Technology/Project Description
The project is based on the demonstration of an 18-cylinder, heavy duty engine (6.4-MWe) modified to operate on Alaskan subbituminous coal. The clean coal diesel technology, which uses a low-rank coal-water-fuel (LRCWF), is expected to have very low NO_x and SO_2 emission levels (50–70% below current New Source Performance Standards). In addition, the demonstration plant is expected to achieve 41% efficiency, while future plant designs are expected to reach 48% efficiency. This will result in a 25% reduction in CO_2 emissions compared to conventional coal-fired plants.

The LRCWF is prepared using an advanced coal drying process that allows dried coal to be slurried in water. The University of Alaska will assemble and operate a 5-ton/hr LRCWF processing plant that will use local coal brought by truck from Usibelli's mine in Healy, Alaska. In addition to its use in the coal-fueled diesel engine, the LRCWF is expected to be an alternative to fuel oil in conventional oil-fired industrial boilers.

Project Status/Accomplishments
The project has passed several milestones. A 95% design review was conducted in January 1999 at the University of Alaska, Fairbanks (UAF). Representatives from Coltec, A.D. Little, UAF, DOE, and GHEMM (construction contractor) were in attendance. The latest design eliminates the need for a sorbent injection system because Usibelli was able to locate a very clean coal seam with less than 0.2% sulfur in the ash. The sorbent injection system originally proposed for the coal diesel was designed for use with bituminous coals with greater than



2.0% sulfur levels. Coltec worked with the diesel engine manufacturer to design new injectors with sapphire orifices sized for the volume of LRCWF required to operate the engine at full load. Earlier designs were based on higher energy density bituminous coals.

The 18-cylinder diesel engine arrived in January 1999, but extremely cold weather prevented movement into facilities building until the end of February 1999. Construction activities, which started at the Fairbanks site on June 15, 1998, are over 60% complete.

Samples of the Usibelli coal were sent to CQ Inc., for washability tests; to ADL for wear tests; and to EERC for preliminary hot water drying tests and bench wear tests. Several plant design changes were made in order to keep the project within budget. Notably, only a small oil-fired boiler will be converted for coal slurry tests instead of a utility-scale boiler, and several of the slurry holding tanks will be located closer to the diesel engine to reduce underground piping.

Final design of the low-rank coal-water-fuel (LRCWF) processing plant has been delayed. Construction of the LRCWF is not expected to start until May 2000. A revised schedule for the demonstration test of the diesel or coal is being developed.

Commercial Applications

The U.S. diesel market is projected to exceed 60,000-MWe (over 7,000 engines) through 2020. The worldwide market is 70 times the U.S. market. The technology is particularly applicable to dispersed power generation in the 5–20-MWe range, using indigenous coal in developing countries.

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 estimated installation cost of a mature commercial unit is approximately $1,300/kW.

Coal Processing for Clean Fuels

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

ARCADIS Geraghty & Miller—fuel methanol tester and cofunder

Electric Power Research Institute—utility 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

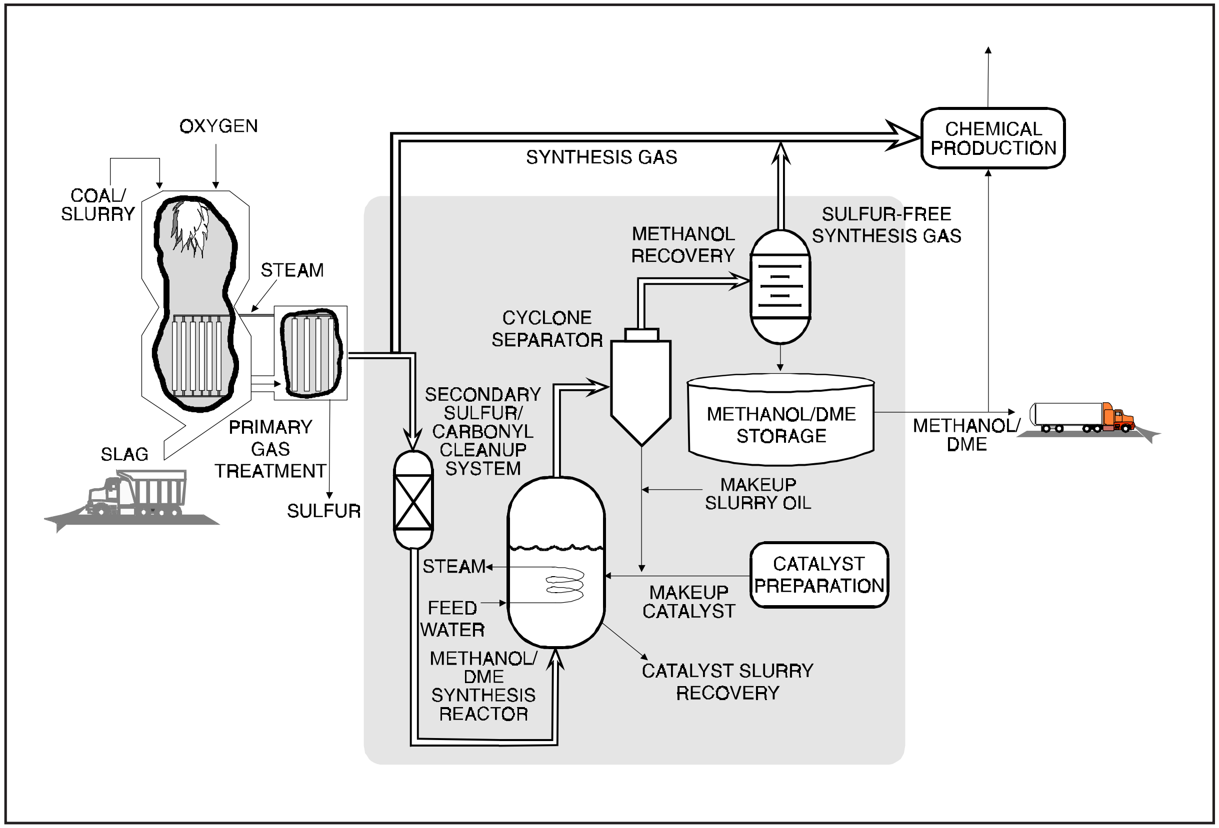
80,000 gallons/day of methanol (nominal)

Coal

Eastern high-sulfur bituminous, 3–5% sulfur

Project Funding

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



Project Objective

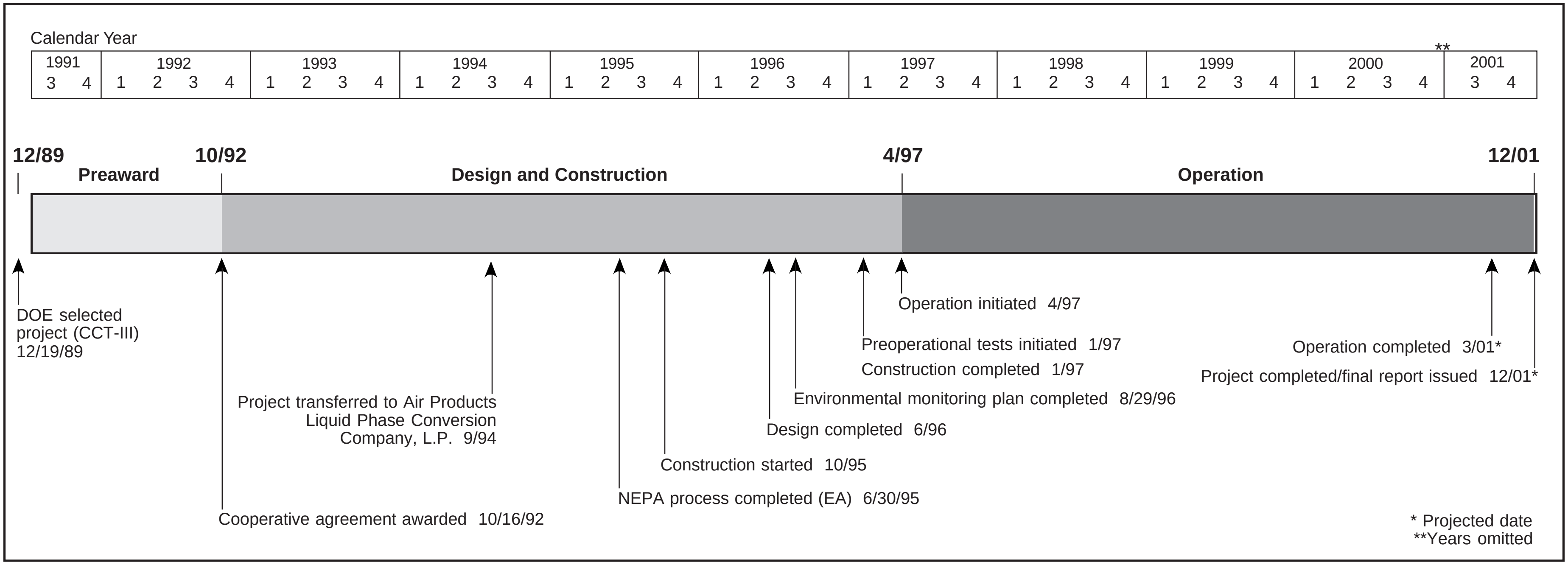
To demonstrate on a commercial scale the production of methanol from coal-derived synthesis gas using the LPMEOH™ process; to determine the suitability of methanol produced during this demonstration for use as a chemical feedstock or as a low-SO_x emitting, low-NO_x emitting alternative fuel in stationary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

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 water-gas shift conversion.

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 as a mixed coproduct with methanol for use as a storable fuel is planned for Fall 1999, 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 is being used.

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



Project Status/Accomplishments

Construction was completed in January of 1997. Following commissioning and shakedown activities, the first production of methanol from the 80,000 gal/day unit occurred on April 2, 1997. The first stable operation of the process demonstration unit at nameplate capacity occurred on April 6, 1998. A stable test period at over 92,000 gal/day revealed no system limitations. The startup also proceeded without injury or environmental incidents.

The hydrogen to carbon monoxide (H_2/CO) ratio in the reactor feed stream was varied from 0.4 to 5.6 with no negative effects on catalyst performance. The operation of the demonstration unit confirmed the engineering methods used in the design of the LPMEOH™ Reactor, and several parameters (such as the overall heat transfer coefficient of the internal heat exchanger) were demonstrated at greater than 115% of design levels.

Operation during 1998 has resulted in significant accomplishments. During 1998, the demonstration unit operated at an availability of over 99%. Since operations began in April 1997, the unit has had an availability of over 96% as of the end of 1998. The design catalyst loading in the LPMEOH™ Reactor has been exceeded to over 150% without indications of mass transfer limitations. Catalyst life has met or exceeded the design target for operation in the environment of trace poisons present in coal-derived synthesis gas. Process variable studies to maximize the reactor volumetric productivity and determine the long-term catalyst performance are on-going. A code inspection of all pressure vessels in the LPMEOH™ Demonstration unit was completed in March 1999. All vessels inspected showed no evidence of erosion, pitting, or fouling. Since startup, the demonstration facility has produced over 35 million gallons of methanol, all of which has been accepted by Eastman Chemical Company for use in downstream chemical processes.

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 clean coal-derived gas. Methanol also has a broad range of commercial applications; it can be substituted for conventional fuels in stationary and mobile combustion applications and is an excellent fuel for utility peaking units. Methanol 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 is an environmentally friendly aerosol for personal products.

Typical commercial-scale LPMEOH™ units are expected to range in size from 50,000–300,000 gal/day of methanol produced when associated with commercial IGCC power generation trains of 200–500 MWe.

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

Participant

Custom Coals International

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 No. 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

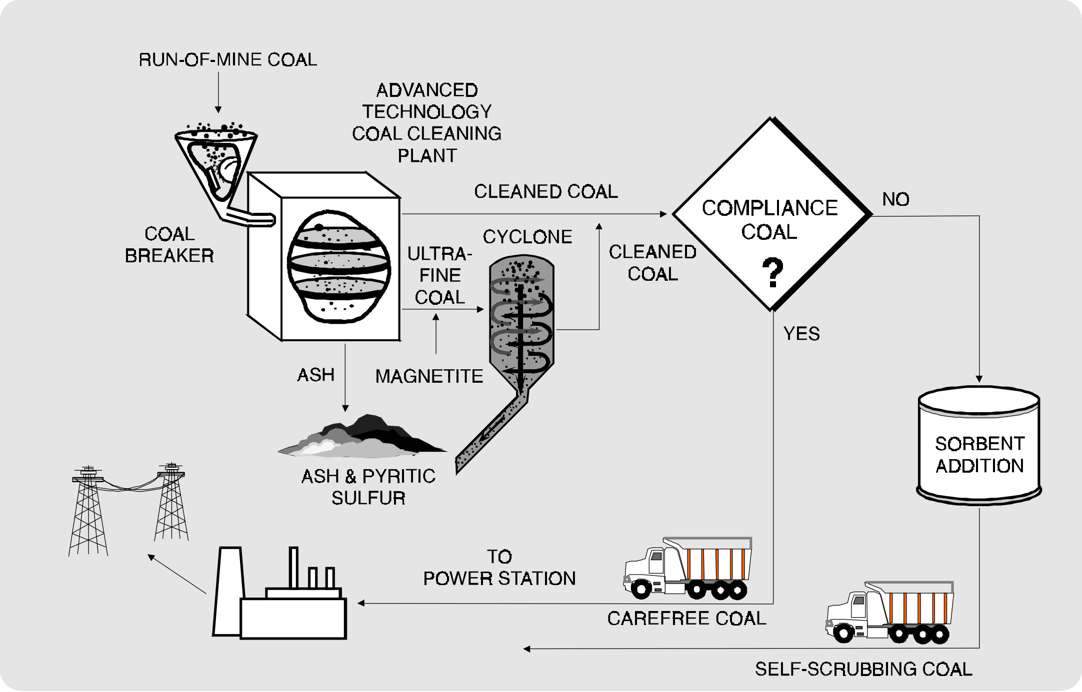
Coal preparation using Custom Coals' advanced physical coal-cleaning and fine magnetite separation technology plus sorbent addition technology

Plant Capacity/Production

500 tons/hr

Coal

Medium and high-sulfur bituminous coals (Lower Kittanning, Illinois No. 5, and Lower Freeport Seam)



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 the requirements for commercial-scale utility power plants to satisfy provisions of the CAAA.

Technology/Project Description

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

Carefree Coal™ is produced by breaking and screening run-of-mine coal and by using innovative dense-medium 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

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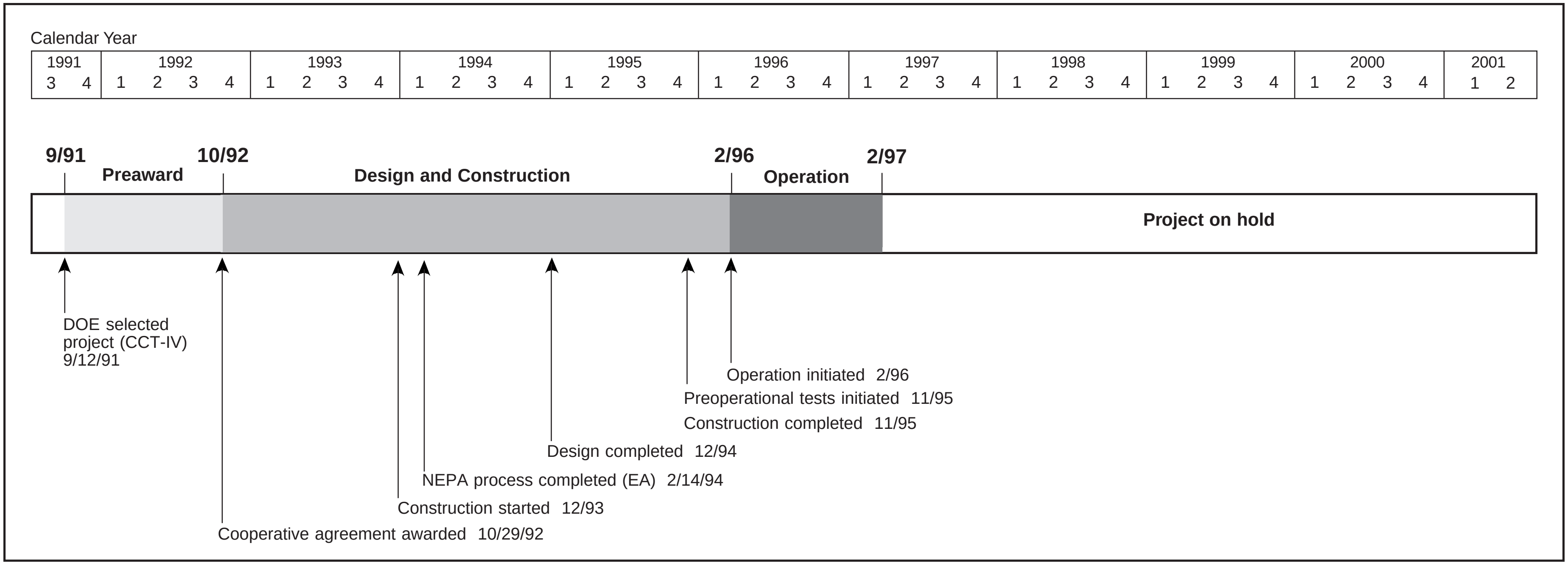
Self-Scrubbing Coal and Carefree Coal are trademarks of Custom Coals International.



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 addition of relatively large amounts of sorbent without exceeding ash specifications of boilers or overloading electrostatic precipitators.

Two medium- to high-sulfur coals—Illinois No. 5 (2.7% sulfur) and Lower Freeport (3.9% sulfur)—are being used to produce Self-Scrubbing Coal™. Carefree Coal™ is being made using Lower Kittanning (1.8% sulfur). Plans called for Lower Kittanning coal to be tested at Martin's Creek Power Station; Illinois No. 5 coal to be tested at Whitewater Valley Generating Station; and Lower Freeport Seam coal to be tested at Ashtabula C.

Project Status/Accomplishments

Start-up began in late December 1995, and the first coal was processed in February 1996. In May 1996, the facility reached its design capacity. Equipment and circuit optimization testing began immediately thereafter and continued throughout 1996.

A Carefree Coal™ test burn (cleaned Lower Kittanning coal) at Martin's Creek Power Station was conducted in mid-November 1996. Although plant optimization was not completed, the overall product made for the test was consistent with the current quality of the plant feed coal. The unit experienced some opacity problems due to the low sulfur in the coal and a marginal electrostatic precipitator.

High organic sulfur in the raw coal created problems with the ability to produce compliance quality clean coal. Further, difficulties with the plant resulted in an excessive amount of material going to the refuse pond, and plant operation was suspended in February 1997. Financial problems ensued and, despite efforts to resolve the matter, the project was placed in Chapter 11. Due to Custom Coals inability to find a buyer for the facility, the Custom Coals Laurel facility was sold at auction on December 16, 1998 to C.J. Betters Enterprises of Monaca, Pennsylvania. C.J. Betters has met with DOE to discuss continuation of the project.

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.

Advanced Coal Conversion Process Demonstration

Participant

Rosebud SynCoal Partnership (a partnership of Western Energy Company and Western SynCoal Company [a subsidiary of Montana Power Company's Energy Supply Division])

Additional Team Members

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

Coal

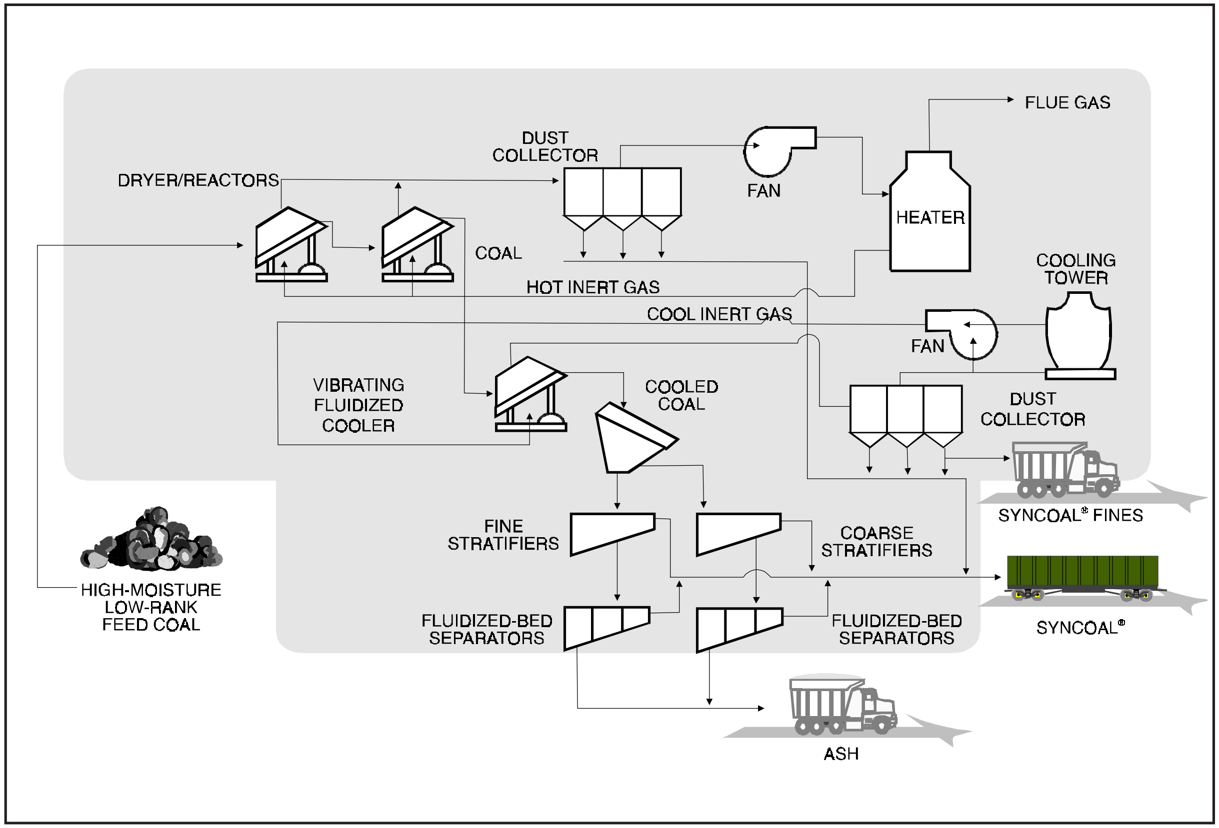
Powder River Basin subbituminous (Rosebud Mine), 0.5-1.5% sulfur, plus tests of other subbituminous coals and lignites

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 Partnership's Advanced Coal Conversion Process (ACCP) 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.



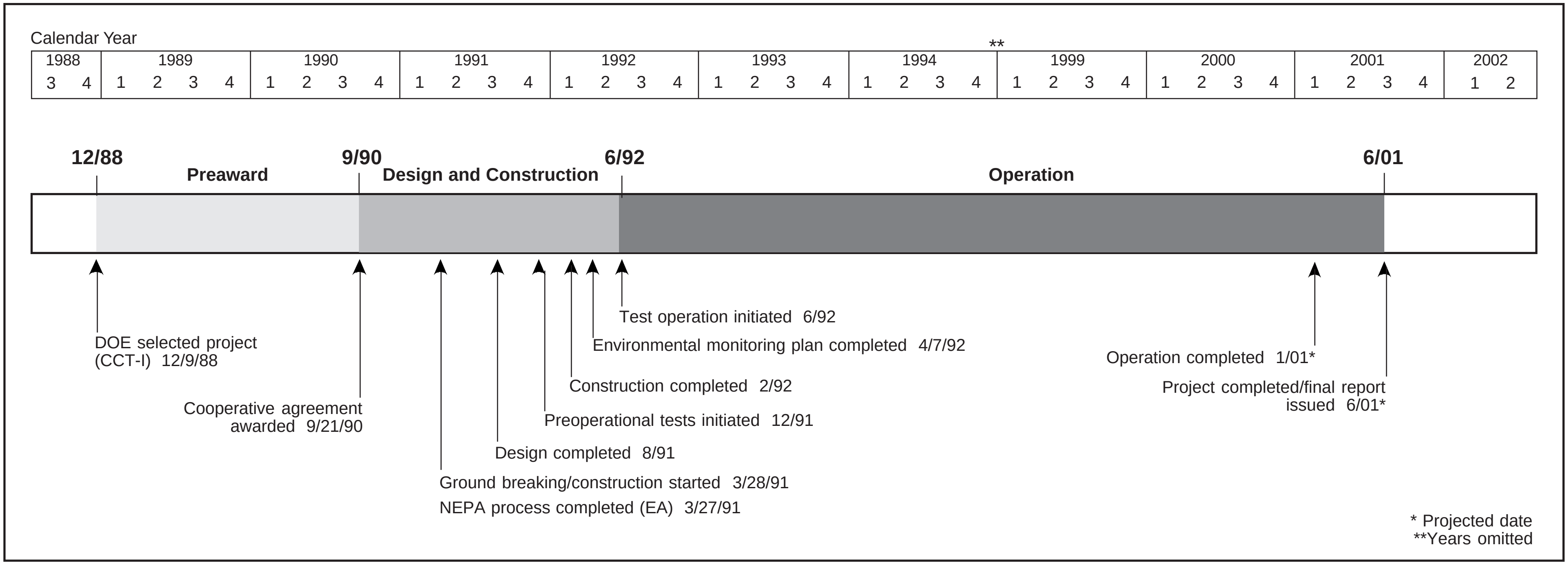
Technology/Project Description

The process 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 raw coal is screened and fed to a vibratory fluidized-bed reactor where surface moisture is removed by heating with hot combustion gas. Coal exists this reactor at a temperature slightly higher than that required to evaporate water and flows to a second vibratory reactor where the coal is heated to nearly 600 °F. This temperature is sufficient to remove chemically-bound water, carboxyl groups, and volatile sulfur compounds. In addition, a small amount of tar is released, partially sealing the dried product. Particle shrinkage causes fracturing, destroys moisture reaction sites, and liberates the ash-forming mineral matter.

The coal is then cooled to less than 150 °F by contact with an inert gas in a vibrating fluidized-bed cooler. The cooled coal is sized and fed to deep bed stratifiers where air pressure and vibration separate mineral matter, including much of the pyrite, from the coal and thereby reducing the sulfur content of the product. The low specific gravity fractions are sent to a product conveyor while heavier fractions go to fluidized-bed separators for additional ash removal.

The fines handling system consolidates the coal fines that are produced throughout the ACCP facility. The fines are gathered by screw conveyors and transported by drag conveyors to a bulk cooling system. The cooled fines are blended with the coarse product, stored in a 250-ton capacity bin until loaded into pneumatic trucks for off-site sales, or returned to the mine pit.

SynCoal is a registered trademark of the Rosebud SynCoal Partnership.



Project Status/Accomplishments

The ACCP facility was scheduled to complete demonstration operations in January 1999, but was granted a two-year no-cost extension. The ACCP facility continues to operate using a dedicated pneumatic feed system to supply SynCoal® to Montana Power's 330 MWe Colstrip No. 2 under an 8-year contract. The ACCP facility has processed 2.0 million tons of raw coal to produce over 1.4 million tons of SynCoal®. The SynCoal® is used by electric utilities and industrial facilities (primarily cement and lime plants).

The demonstration unit can process 1,000 tons per day of SynCoal® and is one-tenth the size of a commercial facility. The ACCP facility takes advantage of existing mine infrastructure. Over a four-year period, 321,528 tons of SynCoal® was burned at the 160-MWe J.E. Corette plant in Billings, Montana. The testing involved both handling and combustion tests of dust stabilization enhancement (DSE; a dilute water-based suppressant) treated SynCoal® in a variety of blends. These blends ranged from 15–85% SynCoal® with raw coal. Overall, the results indicate that 50/50 blend of SynCoal®/raw coal provides improved plant performance, including reduced SO_2 emissions. The use of SynCoal® permitted deslagging the boiler at full load, thereby eliminating costly ash shedding operations. The result was reduced gas flow resistance in the boiler and convection passage, which reduced fan horsepower and improved heat transfer in the boiler, leading to a net increase in generation of approximately 3 MWe.

Three different feedstocks were tested at the ACCP facility—North Dakota lignite, Knife River lignite, and Amax subbituminous coal. Approximately 190 tons of the SynCoal® product produced with the North Dakota lignite was burned at the 250-MWe cyclone-fired Milton R. Young Power Plant Unit No. 1 located near Center, North Dakota. This testing showed dramatic improvement in cyclone combustion, improved slag tapping, and a 13% reduction in boiler air flow requirement, which reduced the auxiliary load from the forced draft and induced draft fans. In addition, boiler efficiency increased from 82% to over 86% and the total gross heat rate improved by 123 Btu/kWh.

Commercial Applications

Western SynCoal Company owns the ACCP technology and has exclusively licensed it to the Rosebud SynCoal Partnership. The Rosebud SynCoal Partnership, a general partnership between Western SynCoal Company is responsible for all activities related to commercialization.

The Rosebud SynCoal Partnership ACCP has the potential to enhance the utility and industrial use of low-rank western subbituminous and lignite coals. The low-moisture, low-sulfur, high-Btu, and high-volatile SynCoal® is a viable compliance option for meeting SO_2 emission reduction requirements. SynCoal® is an ideal supplemental fuel for plants seeking to burn western low-rank coals because the ACCP allows a wider range of low-sulfur raw coals without derating the units.

The ACCP has the potential to convert inexpensive low-sulfur, low-rank coals into valuable carbon-based reducing agents for many metallurgical applications. Furthermore, SynCoal® enhances cement and lime production and provides a value-added bentonite product.

Development of the Coal Quality Expert™

Project completed.

Participants

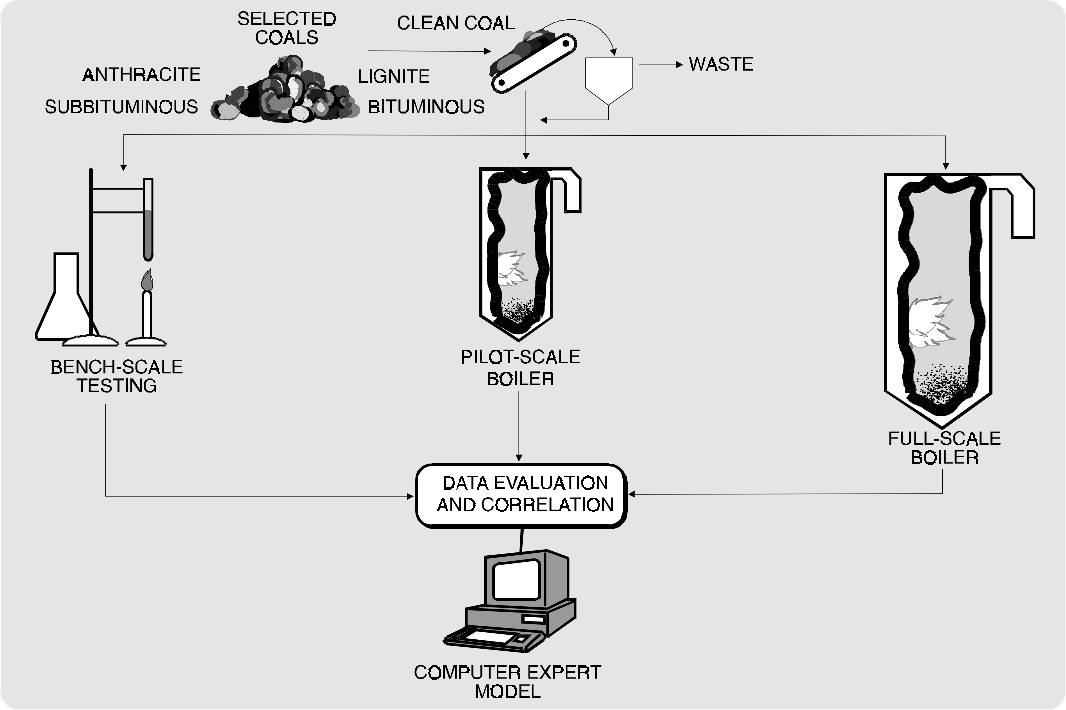
ABB Combustion Engineering, Inc. and
CQ Inc.

Additional Team Members

Black & 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

Grand Forks, Grand Forks County, ND (bench tests)
Windsor, Hartford County, CT (bench- and pilot-scale tests)
Alliance, Columbiana County, OH (pilot-scale tests)
Wilsonville, Shelby County, AL (Gatson, Unit No. 5)
Gulfport, Harrison County, MS (Watson, Unit No. 4)
Somerset, Bristol County, MA (Brayton Point, Unit Nos. 2 and 3)
Bayport, Washington County, MN (King Station)
Oologah, Rogers County, OK (Northeastern, Unit No. 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 250–880-MWe.

Coal

Wide variety of coal blends

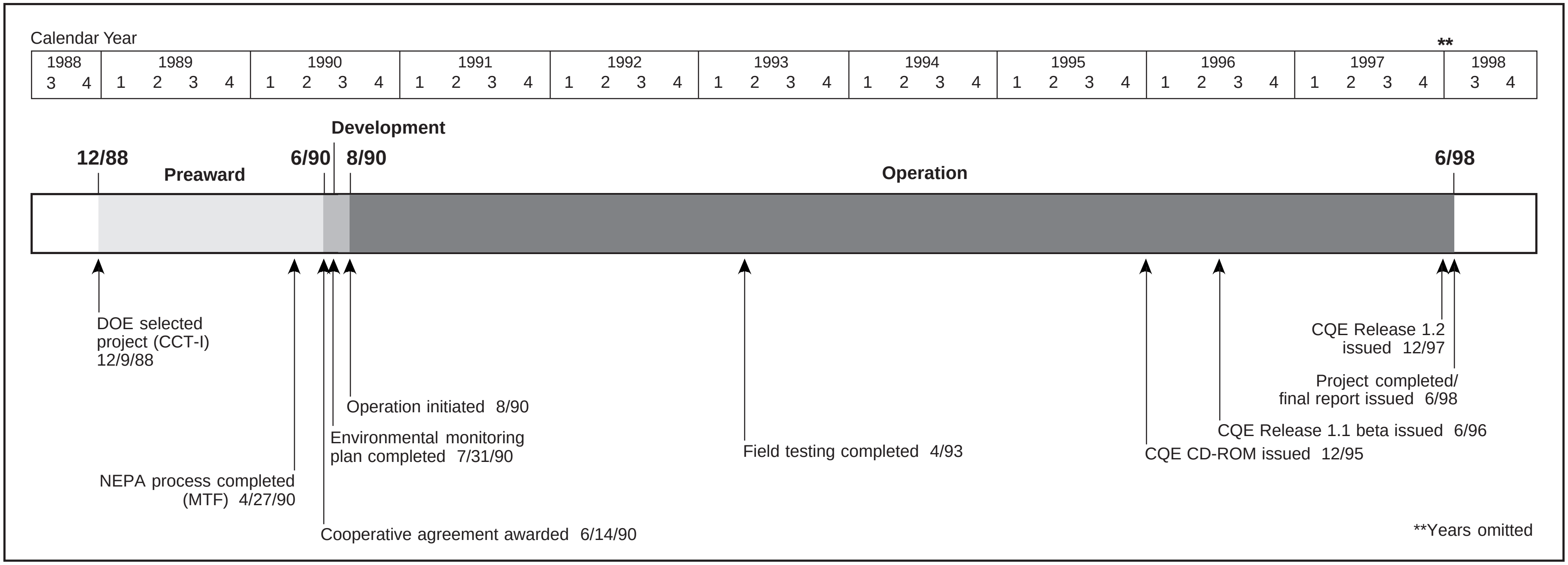
Project Funding

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

Project Objective

The objective of the project was to provide the utility industry with a PC software program to confidently and inexpensively evaluate the potential for coal-cleaning, blending, and switching options to reduce emissions while producing the lowest cost electricity. Specifically the project was to (1) enhance the existing Coal Quality Information System (CQIS™) database and Coal Quality Impact Model (CQIM™) to allow assessment of the effects of coal-cleaning on specific boiler costs and performance and (2) develop and validate CQE™, a model that allows accurate and detailed prediction of coal quality impacts on total power plant operating cost and performance.

Coal Quality Expert, CQE, CQIS, and CQIM are trademarks of the Electric Power Research Institute.



Technology/Project Description

The CQE™ is a software tool that brings a new level of sophistication to fuel decisions by integrating the system-wide impact of fuel purchase decisions on coal-fired power plant performance, emissions, and power generation costs. CQE™ can be used on a stand-alone computer or as a network application for utilities, coal producers, and equipment manufacturers to perform detailed coal impact analyses. The impacts of coal quality; capital improvements; operational changes; and environmental compliance alternatives on power plant emissions, performance, and production costs can be evaluated using CQE™. CQE™ can be used to systematically evaluate all such impacts or it may be used in modules with some default data to perform more strategic or comparative studies.

Project Summary

Background

CQE™ began with EPRI's CQIM™, developed for EPRI by Black & Veatch and introduced in 1989. CQIM™ was endowed with a variety of capabilities, including evaluating Clean Air Act compliance strategies, evaluating bids on coal contracts, conducting test-burn planning and analysis, and providing technical and economic analyses of plant operating strategies. CQE™, which combines CQIM™ with other existing software and databases, extends the art of model-based fuel evaluation established by CQIM™ in three dimensions: new flexibility and application, advanced technical models and performance correlations, and advanced user interface and network awareness.

Algorithm Development

Data derived from bench-, pilot-, and full-scale testing were used to develop the CQE™ algorithms. Bench-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, Connecticut, and the University of North Dakota's Energy and Environmental Research Center in Grand Forks, North Dakota. Pilot-scale testing was performed at ABB Combustion Engineering's facilities in Windsor, Connecticut, and Alliance, Ohio. The six field test sites were Alabama Power's Gatson, Unit No. 5 (880-MWe), Wilsonville, Alabama; Mississippi Power's Watson, Unit No. 4 (250-MWe), Gulfport, Mississippi; New England Power's Brayton Point, Unit No. 2 (285-MWe) and Unit No. 3 (615-MWe), Somerset, Massachusetts; Northern States Power's King Station (560-MWe), Bayport, Minnesota; and Public Service Company of Oklahoma's Northeastern, Unit No. 4 (445-MWe), Oologah, Oklahoma.

The 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 used to develop the model.

CQE™ Capability

The PC-based program evaluates coal quality, transportation system options, performance issues, and alternative emissions control strategies for utility power plants. CQE™ is composed of technical tools to evaluate performance issues, environmental models to evaluate emissions and regulatory issues, and economic models to determine production cost components, including consumables (e.g., fuel, scrubber additives), waste disposal, operation and maintenance, replacement energy costs, and operational and maintenance costs for coal-cleaning processes, power production equipment, and emissions control systems. CQE™ has four main features:

- Fuel Evaluator—Performs system-, plant-, or unit-level fuel quality, economic, and technical assessments.
- Plant Engineer—Provides in-depth performance evaluations with a more focused scope than provided in the Fuel Evaluator.
- Environmental Planner—Provides access to evaluation and presentation capabilities of the Acid Rain Advisor.
- Coal-Cleaning Expert—Establishes the feasibility of cleaning a coal, determines cleaning processes, and predicts associated costs.

Software Description

CQE™ includes more than 100 algorithms based on the data generated in the six full-scale field test.

CQE™'s design philosophy underscores the importance of flexibility by modeling all important power plant equipment and systems and their performance in real-world situations. This level of sophistication allows new applications to be added by assembling a model of how objects interact. Updated information records can be readily shared among all affected users because CQE™ is network-aware, enabling users throughout an organization to share data and results. The CQE™ object-oriented design, coupled with an object database management system, allows different views into the same data. As a result, staff efficiency is enhanced when decisions are made.

CQE™ also can be expanded without major revisions to the system. Object-oriented programming allows new objects to be added and old objects to be deleted or enhanced easily. For example, if modeling advancements are made with respect to predicting boiler ash deposition (i.e., slagging and fouling), the internal calculations of the object that provides these predictions can be replaced or augmented. Other objects affected by ash deposition (e.g., ash collection and disposal systems, soot blower systems) do not need to be altered; thus, the integrity of the underlying system is maintained.

System Requirements

CQE™ currently uses the OS/2 operating system, but the developers are planning to migrate to a Windows-based platform. CQE™ can operate in stand-alone mode on a single computer or on a network. The system requirements for stand-alone operation are listed in Exhibit 42. Technical support is available from Black & Veatch for licensed users.

Commercial Applications

The CQE™ system is applicable to all electric power generation plants and large industrial/institutional boilers that burn pulverized coal. Potential users include fuel suppliers, environmental organizations, government and regulatory institutions, and engineering firms. International markets for CQE™ are being explored by both CQ Inc. and Black & Veatch.

EPRI owns the software and distributes CQE™ to EPRI members for their use. CQE™ is available to others in the form of three types of licenses: user, consultant, and commercializer. CQ Inc. and Black & Veatch have each signed commercialization agreements, which give both companies non-exclusive worldwide rights to sell user's licenses and to offer consulting services that include the use of CQE™ software. Two U.S. utilities have been licensed to use copies of CQE™'s stand-alone Acid Rain Advisor. Over 30 U.S. utilities and one U.K. utility have CQE™ through their EPRI membership. Proposals are pending with several non-EPRI-member U.S. and foreign utilities to license their software.

Exhibit 42

CQE™ Stand-Alone System Requirements

Item	Minimum	Preferred
Hardware speed	486 PC, 33 Mhz	Pentium PC, market stock
RAM	16 MB	32 MB
Disk space	200 MB	1 GB
Monitor	SVGA color	SVGA color
Graphics card	Capable of 1024x768 mode	Capable of 1024x768 mode
External drives	1.44 MB 3.5-inch; CD-ROM	1.44 MB 3.5-inch; CD-ROM
Mouse	Required	Required
Keyboard	Required	Required
Printer	Access to high-speed printer	Access to laser printer
Operating system	OS/2 Version 2.0	OS/2 WARP (3.0)

The CQE™ team has a Home Page on the World Wide Web (http://www.fuels.bv.com:80/cqe/cqe.htm) and the EPRI Fuels Web Server to promote CQE™, facilitate communications between CQE™ developers and users, and eventually allow software updates to be distributed over the Internet. It also was developed to provide an on-line updatable user's manual. The Home Page also helps attract the interest of international utilities and consulting firms.

CQE™ was recognized by former Energy Secretary Hazel O'Leary and EPRI President Richard Balzhiser in 1996 as the best of nine DOE/EPRI cost-shared utility research and development projects under the "Sustainable Electric Partnership" program.

Contacts

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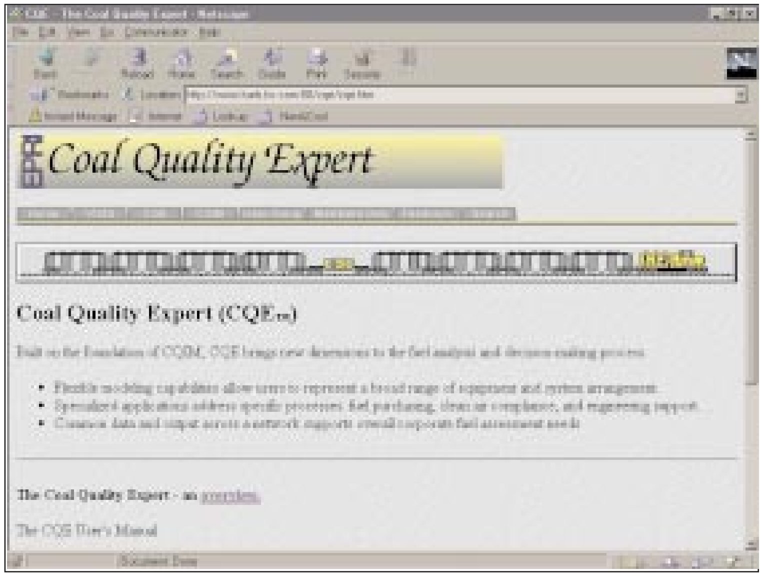


Coal Quality Expert

Coal Quality Expert (CQE™)

The Coal Quality Expert - an overview.

The CQE User's Manual

▲ CQE™, a PC-based software tool, can be used to determine the complete costs of various fuel options by seamlessly integrating the effects of fuel purchase decisions on power plant performance, emissions, and power generation costs. Portions of the CQE™ User's Manual are available on the Internet.

ENCOAL® Mild Coal Gasification Project

Project completed.

Participant

ENCOAL Corporation (a wholly owned subsidiary of Bluegrass Coal Development Company)

Additional Team Members

Bluegrass Coal Development Company (a wholly owned subsidiary of AEI Resources, Inc.)—cofunder

SGI International—technology developer, owner, licensor

Triton Coal Company (a wholly owned subsidiary of Vulcan Coal Company)— host

Location

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

Technology

SGI International's Liquids-From-Coal (LFC®) process

Coal

Low-sulfur Powder River Basin (PRB) subbituminous coal, 0.45% sulfur

Plant Capacity/Production

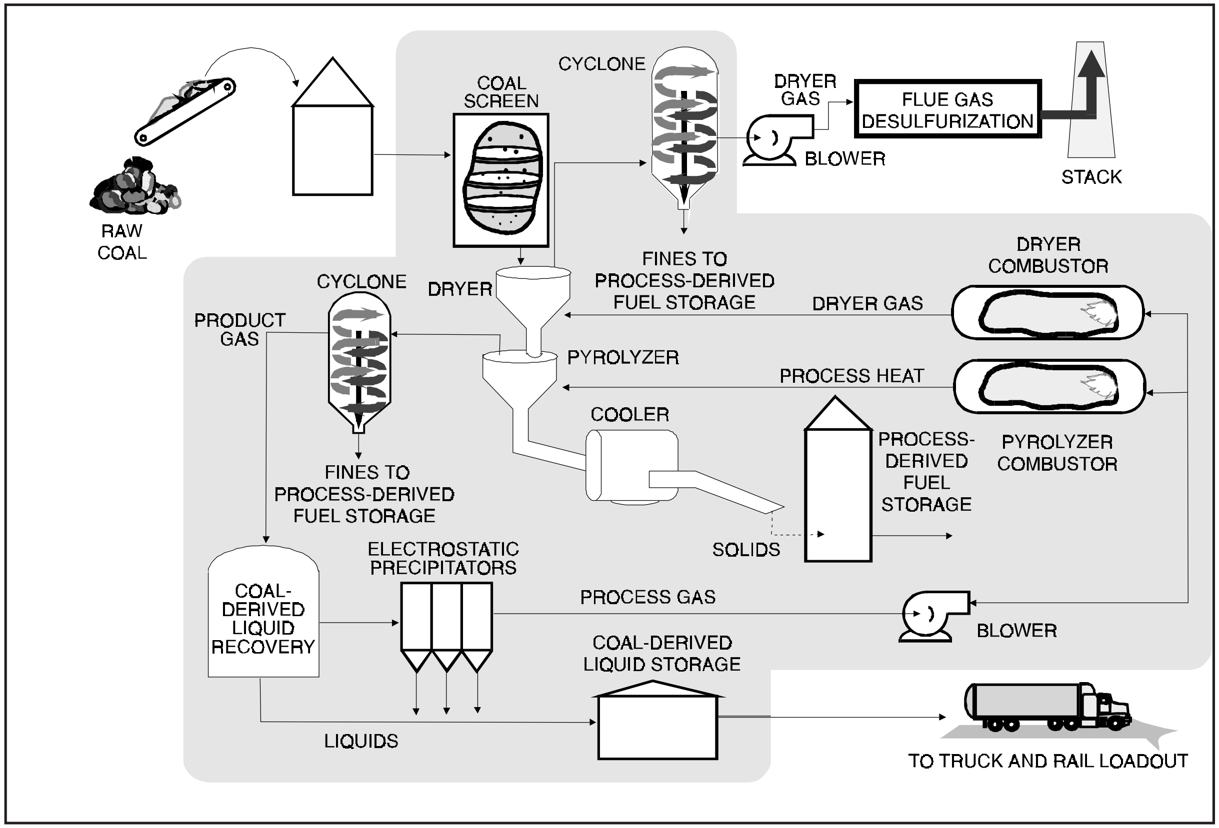
1,000 tons/day of subbituminous coal feed

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.



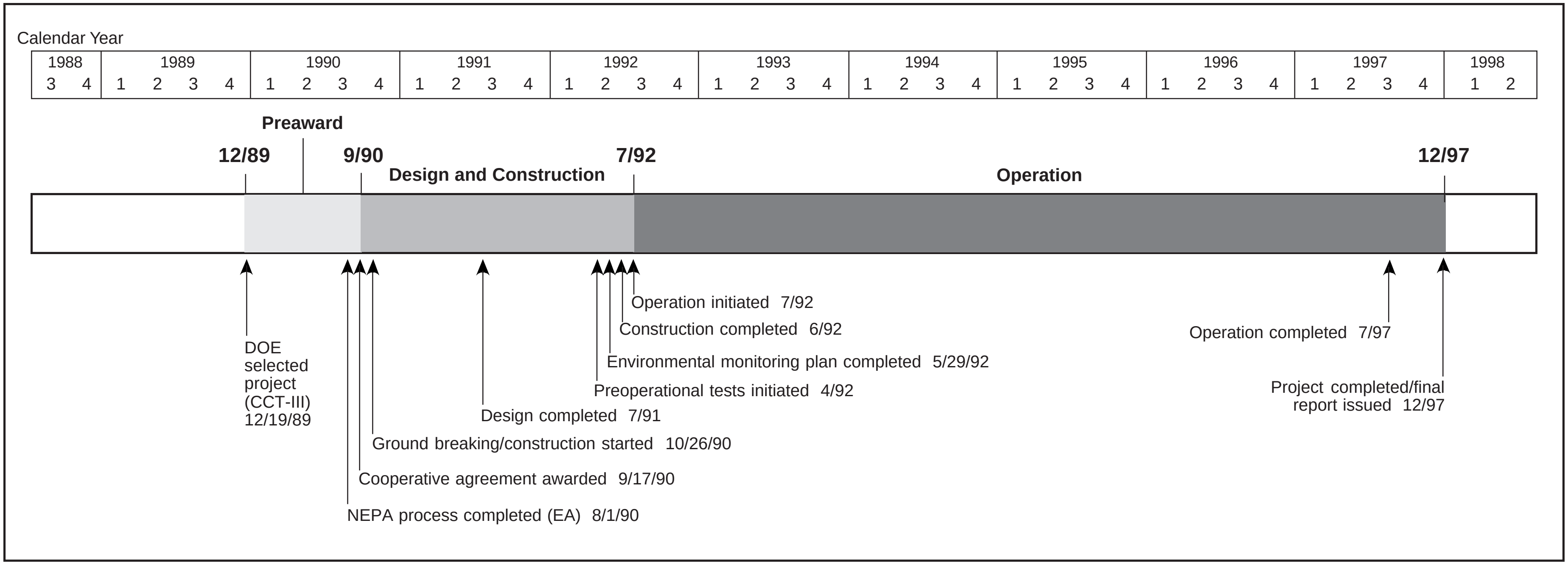
Technology/Project Description

Coal is fed into a rotary grate dryer where it is heated to reduce moisture. The temperature is controlled so that no significant amounts of methane, CO_2, or CO are released. The solids are then fed to the pyrolyzer, where the temperature is about 1,000 °F, and all remaining water is removed. A chemical reaction releases the volatile gaseous material. Solids exiting the pyrolyzer are quenched to stop the pyrolysis reactions.

In the original process, the quench table solids were further cooled in a rotary cooler and transferred to a surge bin. A single 50% flow rate vibrating fluidized-bed (VFB) was added to stabilize the Process-Derived Fuel (PDF®) with respect to oxygen and water. In the VFB, the partially-cooled, pyrolyzed solids contact a gas stream containing a controlled amount of oxygen. Termed "oxidative deactivation," a reaction occurs at active surface sites in the particles reducing the tendency for spontaneous ignition.

Following the VFB, the solids are cooled to near atmospheric temperature in an indirect rotary cooler where water is added to rehydrate the PDF®. A patented dust suppressant is added as the PDF® leaves the surge bin. The hot gas produced in the pyrolyzer is sent through a cyclone for removal of the particulates and then cooled in a quench column to stop any additional pyrolysis reactions and to condense the Coal-Derived Liquid (CDL®).

ENCOAL, LFC, CDL, and PDF are registered trademarks of SGI and Bluegrass.



Results Summary

Environmental

- The PDF® contains 0.36% sulfur with a heat content of 11,100 Btu/lb (compared to 0.45% sulfur and 8,300 Btu/lb for the feed coal).
- The CDL® contains 0.6% sulfur and 140,000 Btu/gal (compared to 0.8% sulfur and 150,000 Btu/gal for No. 6 fuel oil).
- In utility applications, PDF® enabled reduction in SO_2 emissions, reduction in NO_x emissions (through flame stabilization), and maintenance of boiler rated capacity with fewer mills in service.
- LFC® products contained no toxins in concentrations anywhere close to federal limits.

Operational

- Steady state operation exceeding 90% availability was achieved for extended periods for the entire plant (numerous runs exceeded 120 days duration).
- The LFC® process consistently produced 250 tons/day of PDF® and 250 barrels/day of CDL® from 500 tons/day of run-of-mine PRB coal.
- Integrated operation of the LFC® process components over five years has provided a comprehensive database for evaluation and design of a commercial unit.
- Over 83,500 tons of PDF® were shipped via 17 unit trains and one truck shipment to seven customers in six states. Shipments included 100% PDF® and blends from 14–94% PDF®.
- PDF®, alone and in blends, demonstrated excellent combustion characteristics in utility applications, providing heating values comparable to bituminous coal, more reactivity than bituminous coal, and a stable flame.
- The low-volatile PDF® also showed promise as a reductant in direct iron reducing testing and also as a blast furnace injectant in place of coke.
- Nearly 5 million gallons of CDL® were produced and shipped to eight customers in seven states.
- CDL® demonstrated fuel properties similar to a low sulfur No. 6 fuel oil but with the added benefit of lower sulfur content. High aromatic hydrocarbon content, however, may make CDL® more valuable as a chemical feedstock.

Economic

- A commercial plant designed to process 15,000-metric-ton/day would cost an estimated $475,000,000 (2001 year dollars) to construct, with annual operating and maintenance costs of $52,000,000 per year.

Project Summary

Operational Performance

The LFC® facility operated for more than 15,000 hours over a five year period. Steady-state operation was maintained for much of the demonstration with availabilities of 90 percent for extended periods. The length of operation and volume of production proved the soundness and durability of the process.

Exhibit 43 summarizes ENCOAL's production history. By the end of the demonstration, over 83,500 tons of PDF® were shipped via 17 unit trains and one truck shipment to seven customers in six states. Shipments included 100% PDF® and blends from 14–94 percent PDF®. Over 5 million gallons of CDL® were produced and shipped to eight customers in seven states.

PDF® Product. As with most demonstrations, however, success required overcoming many challenges. The most difficult challenge had to do with stability of the PDF® product, which had to be overcome to achieve market acceptance.

In June 1993, efforts ceased in trying to correct persistent PDF® stability problems within the bounds of the original plant design. The rotary cooler failed to provide the deactivation necessary to quell spontaneous ignition of PDF®. It was concluded that a separate, sealed vessel was needed for product deactivation. A search for a suitable design led to adoption of a vibrating fluidized-bed (VFB). A 500 ton/day VFB was installed between the quench table and rotary cooler. (Installation of a second 500 ton/day VFB was planned but never implemented.)

Although the VFB enhanced deactivation, the PDF still required "finishing" to achieve stabilization. Extensive study revealed that more oxygen was needed for deactivation. Two courses of action were pursued: (1) development of interim measures to finish deactivation external to the plant, enabling immediate PDF® shipment for test burns; and (2) development of an in-plant process for finishing, eliminating product quality and labor penalties for external finishing.

"Pile layering" was the primary external PDF® finishing measure adopted. However, PDF® quality becomes somewhat impaired by impacting size, moisture and ash content.

Pursuit of a finishing process step resulted in establishment of a stabilization task force composed of private sector and government engineers and scientists. The outcome was construction and testing of a Pilot Air Stabilization System (PASS) to complete the oxidative deactivation of PDF®. PASS controls temperature and humidity during forced oxidation. The data obtained were used to develop specifications and design requirements for a full-scale, in-plant PDF® finishing unit based upon a commercial (Aeroglide) tower dryer design.

CDL® Product. The first shipment of ENCOAL's liquid product experienced unloading problems. The use of heat tracing and tank heating coils solved the unloading problems for subsequent customers. The CDL® also contained more solids and water than had been hoped for, but was considered usable as a lower grade oil.

Following VFB installation, CDL® quality improved. The pour point ranged from 75º to 95 ºF, and the flash point averaged 230 ºF, both within the design range. Water content was down to 1–2 percent, and solids content was 2–4 percent. Improvements resulted from more consistent operation and lower pyrolysis temperatures and higher pyrolysis flow rates enabled by a new pyrolyzer water seal.

Environmental Performance

PDF® Product. PDF® offers the advantages of low-sulfur Powder River Basin coal without a heating value penalty. In fact, the LFC® process removes organically-bound sulfur, making the PDF® product lower in sulfur than the parent coal on a Btu basis. Because the ROM coal is low in ash, PDF® ash levels remain reasonable after processing, even though the ash level is essentially doubled (ash from one ton of ROM coal goes into ½ ton of PDF®).

Dust emissions were not a problem with PDF®. A dust suppressant (MK) was sprayed on the PDF® to coat the surface as it leaves the storage bin. Also, PDF® has a narrower particle size distribution than ROM coal, having

Exhibit 43
ENCOAL Production

	Pre-VFB		Post-VFB				
	1992	1993	1994	1995	1996	1997[1]	Sum
Raw Coal Feed (tons)	5,200	12,400	67,500	65,800	68,000	39,340	**258,300**
PDF® Produced (tons)	2,200	4,900	31,700	28,600	33,300	19,300	**120,500**
PDF® Sold (tons)	0	0	23,700	19,100	32,700	7,400	**82,900**
CDL® Produced (bbl)	2,600	6,600	28,000	31,700	32,500	20,300	**121,700**
Hours on Line	314	980	4,300	3,400	3,600	2,603	**15,197**
Average Length of Runs (Days)	2	8	26	38	44	75	

[1] Through June 1997.

a larger fines content but fewer particles in the fugitive dust range than ROM coal.

ENCOAL's test burn shipments became international when Japan's Electric Power Development Company (EPDC) evaluated six metric tons of PDF® in 1994. The EPDC, which must approve all fuels being considered for electric power generation in Japan, found PDF® acceptable for use in Japanese utility boilers.

In October 1996, instrumented combustion testing was conducted at the Indiana-Kentucky Electric Cooperative's (IKEC) Clifty Creek Station, Unit #3. Important findings included the following:

- Full generating capacity using PDF® was possible with one mill out of service, which was not possible on the baseline fuel and a source of concern. Operation on PDF® afforded time to perform mill maintenance and calibration without losing capacity or revenues, increasing capacity factor and availability and decreasing operating and maintenance costs.
- NO_x emissions were reduced by 20 percent due to high PDF® reactivity, resulting in almost immediate ignition upon leaving the burner coal nozzle. Furthermore, PDF® sustained effective combustion (maintaining low loss on ignition) with very low excess oxygen, which is conducive to low NO_x emissions.
- PDF® use precipitated increased ash deposits in the convective pass that were wetter than those resulting from baseline coal use, requiring increased sootblowing to control build-up.

CDL® Product. The CDL® liquid product is a low-sulfur, highly aromatic, heavy liquid hydrocarbon. CDL® fuel characteristics are similar to a low-sulfur No. 6 fuel oil, except that the sulfur content is significantly less. Its market potential as a straight industrial residual fuel, however, appears limited. The market for CDL® as a fuel never materialized and CDL® has limited application as a blend for high sulfur residual fuels due to incompatibility of the aromatic CDL® with many straight-chain hydrocarbon distillates.

A determination was made that a centrifuge was needed to reduce solids retention (tests validated a 90 percent removal capability); and an optimum slate of upgraded products was identified. The upgraded products were: (1) crude cresylic acid (2) pitch, (3) refinery feedstock (low-oxygen middle distillate), and (4) oxygenated middle distillate (industrial fuel).

Economic

The "base case" for economics of a commercial plant is the 15,000-metric-ton/day, three-unit North Rochelle LFC® plant, the commercial scale plant proposed by ENCOAL, with an independent 80-MW cogeneration unit, and no synthetic fuel tax credit (29c tax credit). It is assumed that the cogeneration unit is owned and operated by an independent third-party. The capital cost for a full scale three module LFC® plant is $475 million.

Economic benefits from an LFC® commercial plant are derived from the margin in value between a raw, unprocessed coal and the upgraded products, making an LFC® plant dependent on the cost of feed coal. In fact, this is the largest single operating cost item. The total estimated operating cost is $9.00/ton of feed coal including the cost of feed coal, chemical supplies, maintenance, and labor.

Commercial Applications

In a commercial application, CDL® would be upgraded to cresylic acid, pitch, refinery feedstock, and oxygenated middle distillate. Oxygenated middle distillate, the lowest value byproduct, would be used in lieu of natural gas as a make-up fuel for the process (30 percent of the process heat input). PDF® would be marketed not only as a boiler fuel but as a supplement or substitute for coke in the steel industry. PDF® characteristics make it attractive to the metallurgical market as a coke supplement in pulverized coal injection and granular coal injection methods and as a reductant in direct reduced iron processes.

Partners in the ENCOAL® project completed five detailed commercial feasibility studies over the course of the demonstration and shortly thereafter—two Indonesian, one Russian, and two U.S. projects. A U.S. project has received an Industrial Siting Permit and an Air Quality Construction Permit.

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Douglas M. Jewell, FETC, (304) 285-4720

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Industrial Applications

Blast Furnace Granular-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

CPC-Macawber, Ltd. (formerly named Simon-Macawber, Ltd.)—equipment supplier (world rights to sublicense technology)

Fluor Daniel, Inc.—architect and engineer

ATSI, Inc.—injection equipment engineer (North America technology licensee)

Location

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

Coal

Eastern bituminous, 0.8–2.8% sulfur; and western subbituminous, 0.4–0.9% sulfur

Technology

British Steel and CPC-Macawber blast furnace granular-coal injection (BFGCI) process

Plant Capacity/Production

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

Project Funding

Total project cost	$194,301,790	100%
DOE	31,824,118	16
Participant	162,477,672	84

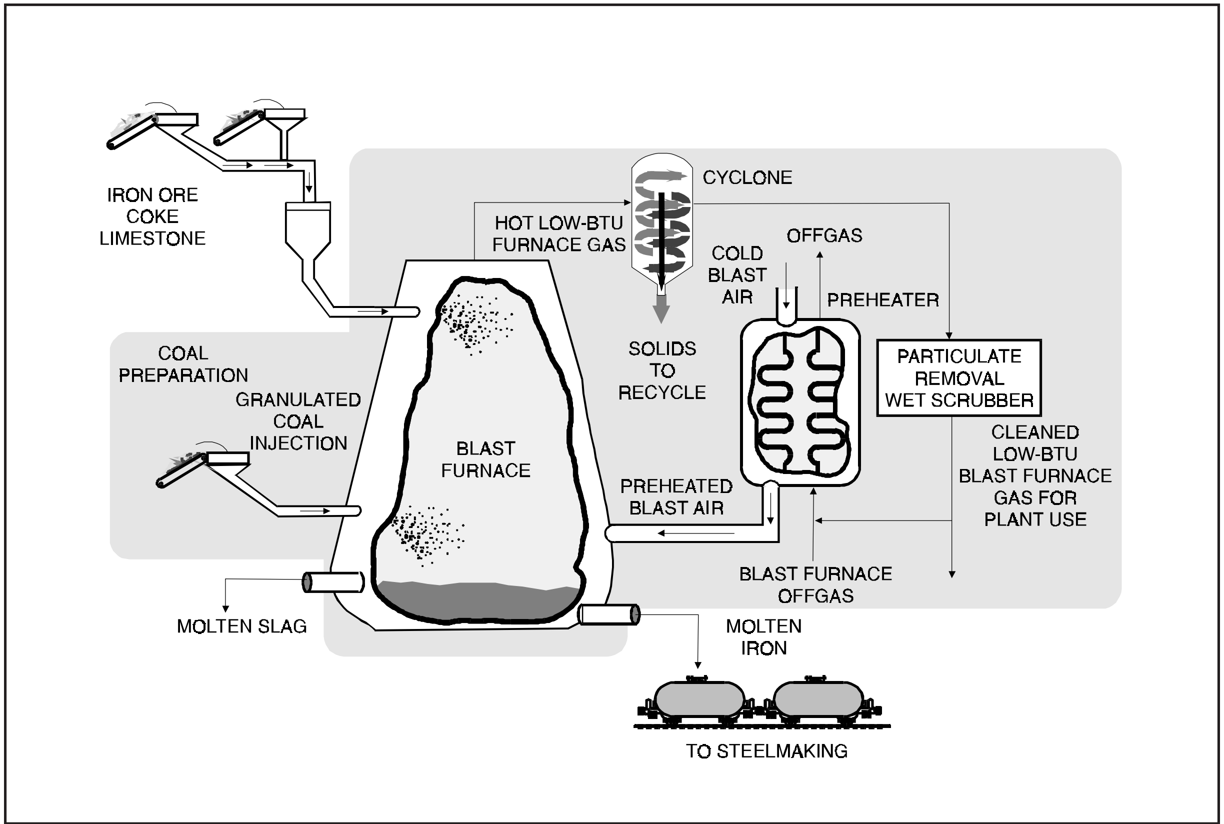
Project Objective

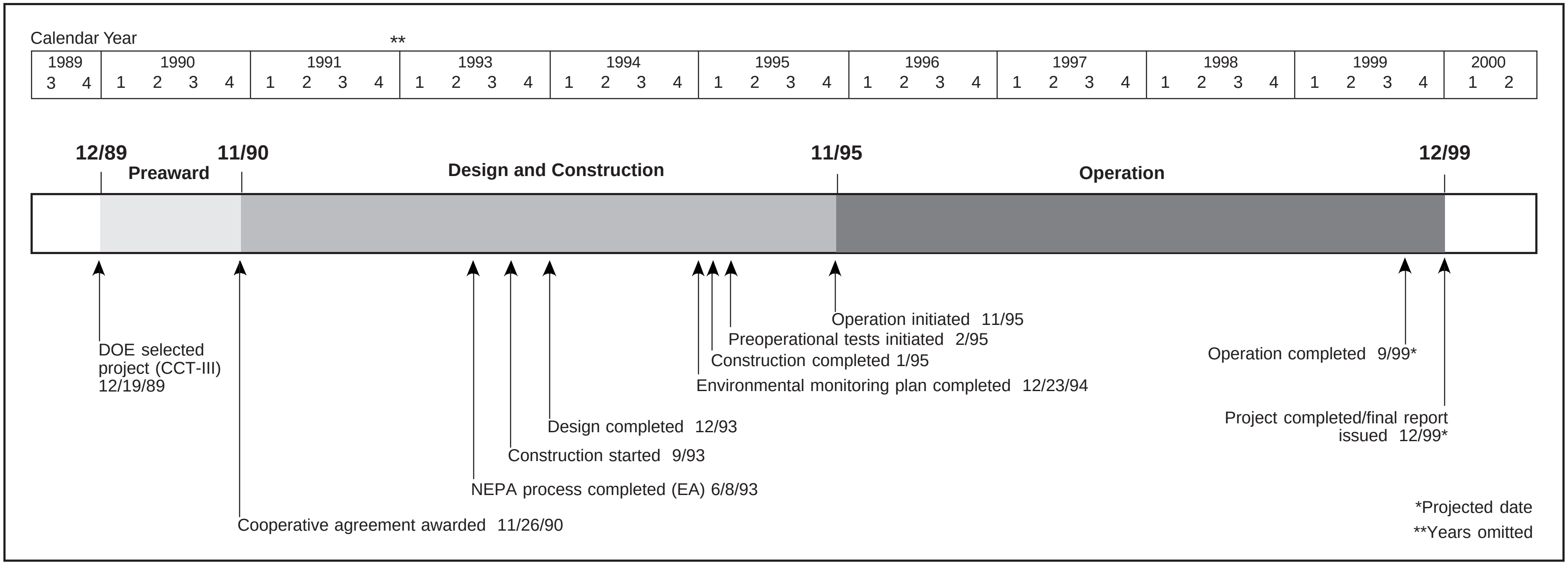
To demonstrate that existing iron-making blast furnaces can be retrofitted with blast furnace granular-coal injection technology; to demonstrate sustained operation with a variety of coal particle sizes, coal injection rates, and coal types; and to assess the interactive nature of these parameters.

Technology/Project Description

In the BFGCI process, either granular or 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 natural gas injection, reduces blast furnace production rates. Coal, with a lower hydrogen content than either natural gas or oil, does not cause as severe a reduction in raceway temperatures. In addition to displacing 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. BFGCI technology has significant potential to reduce pollutant emissions and enhance blast furnace production because coke production results in significant emissions of NO_x, SO_2, and air toxics. Coal could replace up to 40% of the coke requirement.

Emissions generated by the blast furnace itself remain virtually unchanged by the injected coal; the gas exiting the blast furnace is cleaned and used in the mill. Sulfur from the coal is removed by the limestone flux and bound up in the slag, which is a salable by-product.





Two high-capacity blast furnaces, Units C and D at Bethlehem Steel's Burns Harbor Plant, were retrofitted with BFGCI technology. Each unit has a production capacity of 7,000 NTHM/day. The two units use about 2,800 tons/day of coal during full operation. Tests will include eastern bituminous coals with sulfur content of 0.8–2.8% and a western subbituminous coal having 0.4–0.9%.

Project Status/Accomplishments

Early trials comparing high- and low-volatile coals as injectant showed that low-volatile coal replaces more coke and results in better blast furnace operation than high-volatile coal. The replacement ratio was 0.96 pounds of coke replaced for every pound of low-volatile coal used. A major conclusion of the early trials was that granular-coal injection performs very well on large blast furnaces. The low-volatile coals used were Buchanan and Virginia Pocahantas coals (different mines, but same seam and similar properties).

Further trials were conducted on the effect of higher coal ash content on the furnace operation. The baseline coal was the Virginia Pocahantas coal with high carbon and relatively low ash content. Three trials were run varying the ash content while keeping all other parameters constant.

The high ash trials revealed that (1) furnace permeability was not changed and no deleterious effect was experienced in the raceway, (2) furnace blast pressure and wind volume were maintained at the base conditions during the trial, (3) furnace production rates were up as delay periods declined during the trial, and (4) hot metal silicon and sulfur content and variability were about the same during all three periods. Corrected coke rates calculated from the trial results reveal that there is a coke rate disadvantage of 3 lb/NTHM for each 1% increase of ash in the injection coal at an injection rate of 260 lb/NTHM.

Western coal trials were completed using Colorado Oxbow high-volatile granular and pulverized coal. Trials validated that low-volatile coal replaces more coke than high-volatile coal. The high-volatile coal required 31.4 kWh/ton to pulverize and 19.6 kWh/ton to granulate, showing a 40% reduction in power costs for granulation versus pulverization.

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 10%. The environmental impacts of commercial application are primarily indirect and consist of a significant reduction of emissions resulting from diminished coke-making requirements.

The BFGCI technology was developed jointly by British Steel and CPC-Macawber. British Steel has granted exclusive rights to market BFGCI technology worldwide to CPC-Macawber. CPC-Macawber also has the right to sublicense BFGCI rights to other organizations through-out the world. British Steel and CPC-Macawber have recently installed a similar facility at U.S. Steel's Fairfield blast furnace.

Clean Power from Integrated Coal/Ore Reduction (CPICOR™)

Participant

CPICOR™ Management Company, L.L.C. (a limited liability company composed of subsidiaries of the Geneva Steel Company)

Additional Team Members

Geneva Steel Company—cofunder and host; constructor and operator of unit

Location

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

Technology

HIsmelt® direct ironmaking process

Plant Capacity/Production

3,300 tons/day liquid iron production

Coal

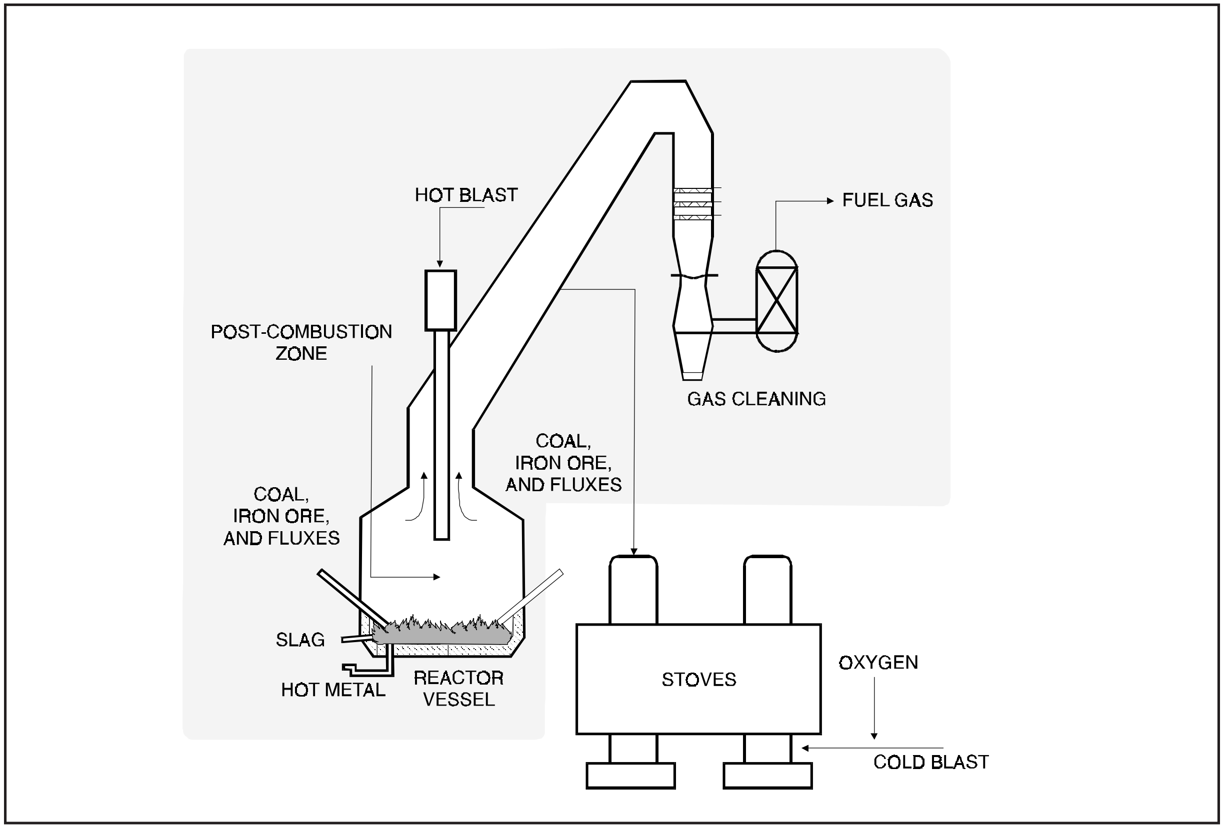
Bituminous, 0.5% sulfur

Project Funding

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

Project Objective

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



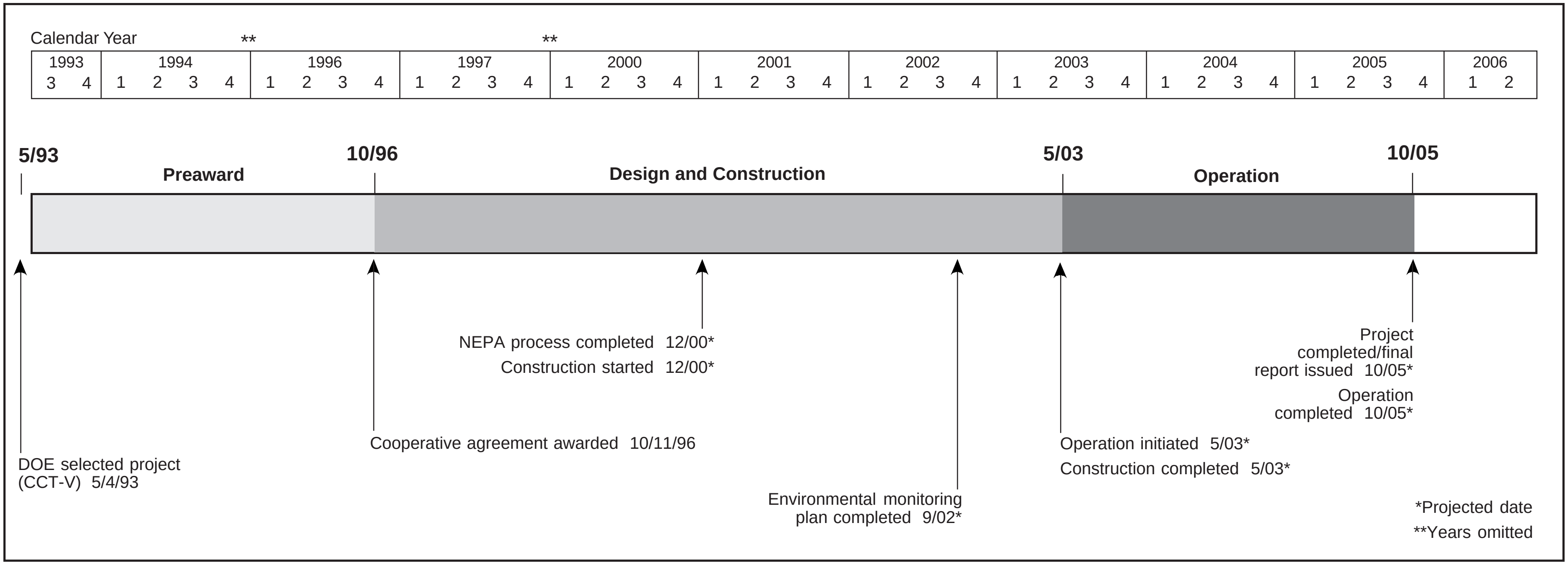
Technology/Project Description

The HIsmelt® process is based on producing hot metal and slag from iron ore fines and non-coking coals. The heart of the process is producing sufficient heat and maintaining high heat transfer efficiency in the post combustion zone above the reaction zone to reduce and smelt iron oxides. Tests have consistently demonstrated 60% post-combustion levels (degree of post combustion attained) with 90% heat transfer efficiency.

The HIsmelt® process uses a vertical smelt reduction reactor, which is a closed molten bath vessel, into which iron ore fines, coal, and fluxes are injected. The coal, which can have a wide range of composition, is injected into the bath where carbon is rapidly dissolved. The dissolved carbon reacts with oxygen (from the injected iron ore) to form CO and metallic iron. Injection gases and evolved CO entrain and propel droplets of slag and molten iron upward into the post combustion zone.

The iron reduction reaction in the molten bath is endothermic; therefore, additional heat must be generated and returned to the bath to sustain the reduction process and maintain an acceptable hot metal temperature. This additional heat is generated by post-combusting the CO and hydrogen from the bath with oxygen-enriched hot air blast entering through the central top lance. The heat is absorbed by the metal and slag droplets and returned to the bath as the droplets descend under the gravity. Droplets in contact with the gas in the post-combustion zone absorb heat, but are shrouded during the descent by ascending reducing gases (CO), which together with bath carbon, prevent unacceptable levels of FeO in the slag.

HIsmelt is a registered trademark of HIsmelt Corporation Pty Limited.
CPICOR is a trademark of the CPICOR™ Management Company, L.L.C.



The molten iron collects in the bottom of the bath and is continuously tapped from the reactor through a fore-hearth, which maintains a constant level of iron in the reactor. Slag, which is periodically tapped through a conventional blast furnace-type tap hole, is used to coat and control the internal cooling system and reduce the heat loss.

Reacted gases, mainly N_2, CO_2, CO, H_2, and water vapor, exit the vessel. After scrubbing the reacted gases, the cleaned gases will be combusted to produce 170-MWe of power. The cleaned gases can also be used to pre-heat and partially reduce the incoming iron ore.

Project Status/Accomplishments

The cooperative agreement was awarded on October 11, 1996. CPICOR™ analyzed the global assortment of new direct ironmaking technologies to determine which technology would be most adaptable to western U.S. coals and raw materials. Originally, the COREX® process appeared suitable for using Geneva's local raw materials; however, lack of COREX® plant data on 100% raw coals and ores prevented its application in this demonstration. Thus, CPICOR™ chose to examine alternatives. The processes evaluated included: AISI direct ironmaking, DIOS, Romelt, Tecnored, Cyclonic Smelter, and HIsmelt®. The HIsmelt® process appears to offer good economic and operational potential, as well as the prospect of rapid commercialization. CPICOR™ has completed testing of two U.S. coals at the HIsmelt® pilot plant near Perth, Australia.

On February 1, 1999, Geneva Steel Company (CPICOR™ Management Company's parent corporation) filed a voluntary petition for bankruptcy under Chapter 11 of the United States Bankruptcy Code in the U.S. Bankruptcy Court for the District of Utah. Geneva Steel intends to emerge from Chapter 11 with a restructured balance sheet that will enable full participation in this demonstration project. Other developments include the following: DOE is reviewing final drafts of license and marketing agreements between HIsmelt® and CPICOR™; DOE has established a NEPA Team to review the Environmental Information Volume and begin the NEPA scoping process; baseline air monitoring is in progress.

Commercial Applications

The HIsmelt® technology is a direct replacement for existing blast furnace and coke-making facilities with additional potential to produce steam for power production. Of the existing 79 coke oven batteries, half are 30 years of age or older and are due for replacement or major rebuilds. There are about 60 U.S. blast furnaces, all of which have been operating for more than 10 years, with some originally installed up to 90 years ago. HIsmelt® represents a viable option as a substitute for conventional ironmaking technology.

The HIsmelt® process is ready for demonstration. Two pilot plants have been built, one in Germany in 1984 and one in Kwinana, Western Australia in 1991. Through test work in Australia, the process has been proven—operational control parameters have been identified and complete computer models have been successfully developed and proven. The goal is to have a fully operational commercial plant by early the next decade.

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 x 10^6 Btu/hr of steam

Coal

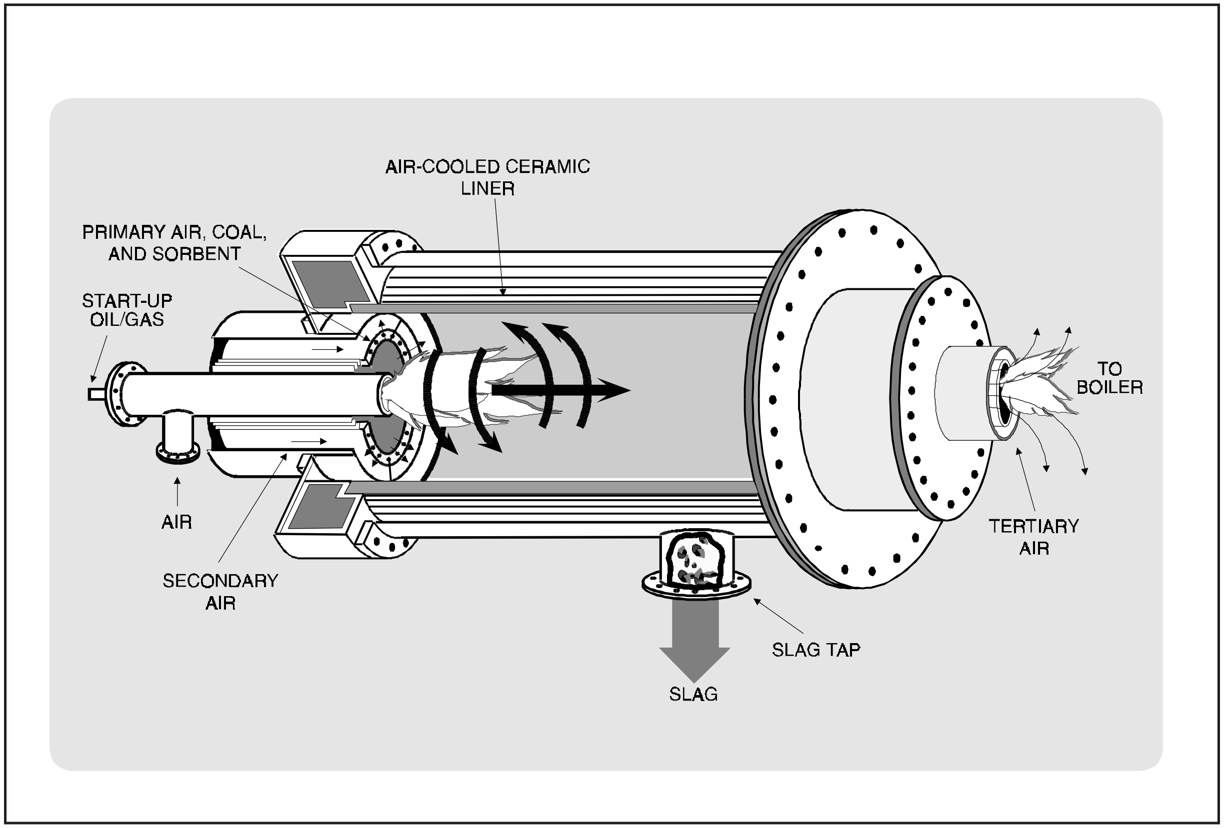
Pennsylvania bituminous, 1.0–3.3% sulfur

Project Funding

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

Project Objective

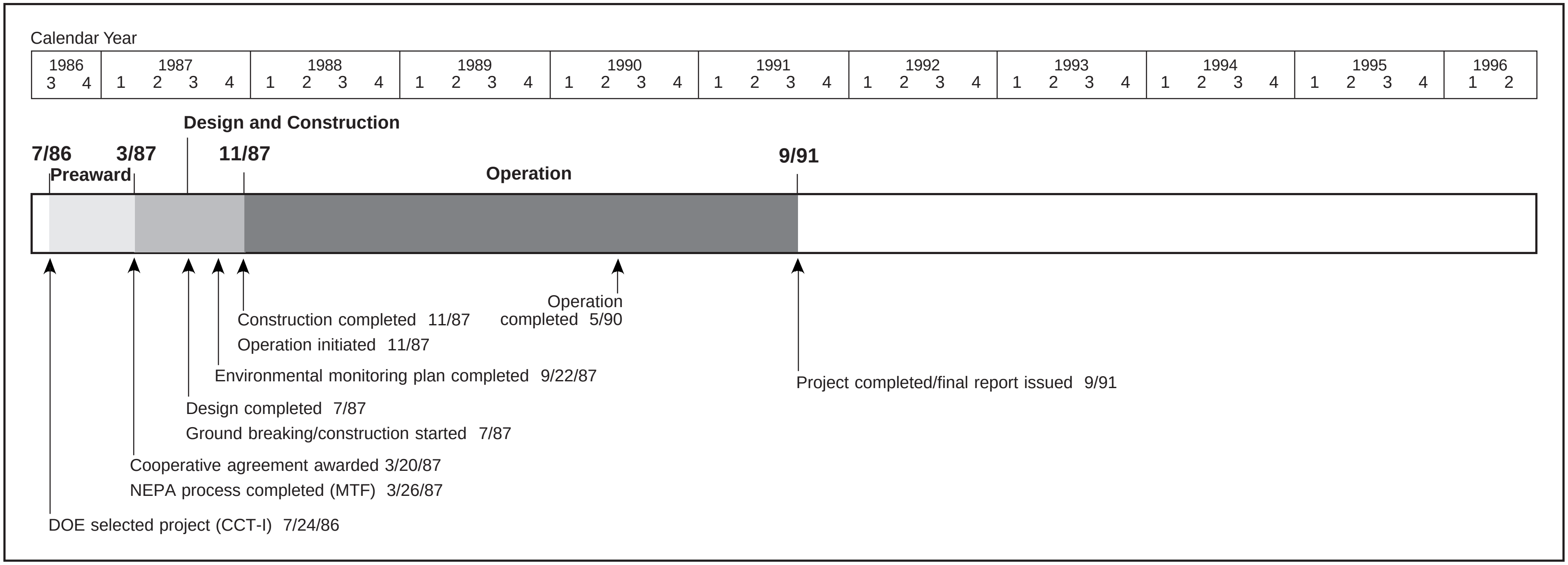
To demonstrate that an advanced cyclone combustor can be retrofitted to an industrial boiler and that it can simultaneously remove up to 90% of the SO_2 and 90–95% of the ash within the combustor and reduce NO_x to 100 ppm.



Technology/Project Description

Coal Tech's horizontal cyclone combustor is internally lined with an air-cooled 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. Tertiary air is injected at the combustor/boiler interface. 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 combustor. Fine coal pulverization allows combustion of most of the coal particles near the cyclone wall. The combustor was designed to retain a high percentage of the ash and sorbent fed to the combustor as slag. 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. 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.

In Coal Tech's demonstration, an advanced, air-cooled, cyclone coal combustor was retrofitted to a 23 x 10^6 Btu/hr, oil-designed package boiler located at the Tampella Power Corporation boiler factory in Williamsport, Pennsylvania.



Results Summary

Environmental

- SO_2 removal efficiencies of over 80% were achieved with sorbent injection in the furnace at various calcium-to-sulfur (Ca/S) molar ratios.
- SO_2 removal efficiencies up to 58% were achieved with sorbent injection in the combustor at a Ca/S molar ratio of 2.0.
- A maximum of 1/3 of the coal's sulfur was retained in the dry ash removed from the combustor (as slag) and furnace hearth.
- At most, 11% of the coal's sulfur was retained in the slag rejected through the combustor's slag tap.
- NO_x emissions were reduced to 184 ppm by the combustor and furnace and to 160 ppm with the addition of a wet particulate scrubber.
- Combustor slag was essentially inert.
- Ash/sorbent retention in the combustor as slag averaged 72% and ranged from 55–90%. Under more fuel lean conditions, retention averaged 80%.
- Meeting local particulate emissions standards required the addition of a wet venturi scrubber.

Operational

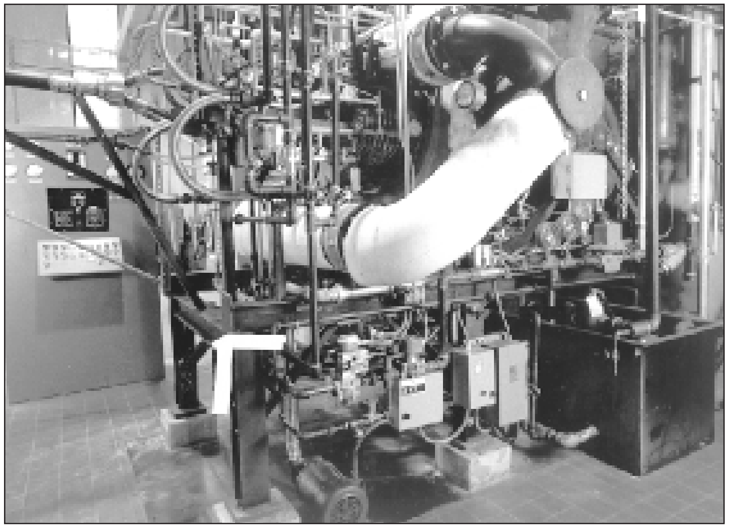
- Combustion efficiencies of over 99% were achieved.
- A 3-to-1 combustor turndown capability was demonstrated. Protection of combustor refractory with slag was shown to be possible.
- A computer-controlled system for automatic combustor operation was developed and demonstrated.

Economic

- Because the technology failed to meet commercialization criteria, economics were not developed during the demonstration. However, subsequent efforts indicate that incremental capital costs for installing the coal combustor in lieu of oil or gas systems are \$100–\$200/kW.

Project Summary

The novel features of Coal Tech's patented ceramic-lined, slagging cyclone combustor included its air-cooled walls and environmental control of NO_x, SO_2, and solid waste emissions. Air cooling took place in a very compact combustor, which could be retrofitted to a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. In this technology, NO_x reduction was achieved by staged combustion, and SO_2 was captured by injection of limestone into the combustor and/or boiler. Critical to combustor performance was removal of ash, as slag, which would otherwise erode boiler tubes. This was particularly important in oil furnace retrofits where tube spacing is tight (made possible by the low-ash content of oil-based fuels).



▲ The slagging combustor, associated piping, and control panel for Coal Tech's advanced ceramic-lined slagging combustor are shown.

The test effort consisted of 800 hours of operation, including five individual tests, each of four days duration. An additional 100 hours of testing was performed as part of a separate ash vitrification test. Test results obtained during operation of the combustor indicated that Coal Tech attained most of the objectives contained in the cooperative agreement. About eight different Pennsylvania bituminous coals with sulfur contents ranging from 1.0–3.3% and volatile matter contents ranging from 19–37% were tested.

Environmental Performance

A maximum of 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 molar ratio of 2. A maximum of 1/3 of the coal's sulfur was retained in the dry ash removed from the combustor and furnace hearths, and as much as 11% of the coal's sulfur was retained in the slag rejected through the slag tap. Additional sulfur retention in the slag is possible by increasing the slag flow rate and further improving fuel-rich combustion and sorbent-gas mixing.

With fuel-rich operation of the combustor, a three-fourths reduction in measured boiler outlet stack NO_x was obtained, corresponding to 184 ppm. An additional 5–10% reduction was obtained by the action of the wet particulate scrubber, resulting in atmospheric NO_x emissions as low as 160 ppm.

All the slag removed from the combustor produced trace metal leachates well below EPA's Drinking Water Standard.

Total ash/sorbent retention as slag in the combustor under efficient combustion operating conditions averaged 72% and ranged from 55–90%. 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 system and increases in the slag flow rate produced substantial increases in the slag retention rate. To meet local stack particulate emission standards, a wet venturi particulate scrubber was installed at the boiler outlet.

Operational Performance

Combustion efficiencies exceeded 99% after proper operating procedures were achieved. Combustor turndown to 6 x 10^6 Btu/hr from a peak of 19 x 10^6 Btu/hr (or a 3-to-1 turndown) was achieved. The maximum heat input during the tests was around 20 x 10^6 Btu/hr, even though the combustor was designed for 30 x 10^6 Btu/hr and the boiler was thermally rated at around 25 x 10^6 Btu/hr. This situation resulted from facility limits on water availability for the boiler. In fact, due to the lack of sufficient water cooling, even 20 x 10^6 Btu/hr was borderline, so that most of the testing was conducted at lower rates.

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. As an example, by implementing certain procedures, such as changing the combustor wall temperature, it was possible to replenish the combustor refractory wall thickness with slag produced during combustion rather than by adding ceramic to the combustor walls.

The combustor's total operating time during the life of the CCT project was about 900 hours. This included approximately 100 hours of operation in two other flyash vitrification tests projects. Of the total time, about one-third was with coal; about 125 tons of coal were consumed.

Developing proper combustor operating procedures was also an objective. Not only were procedures for properly operating an air-cooled combustor developed, but the entire operating data base was incorporated into a computer-controlled system for automatic combustor operation.

Commercial Applications

In conclusion, the goal of this project was to validate the performance of the air-cooled combustor at a commercial scale. While the combustor was not yet fully ready for sale with commercial guarantees, it was believed to have commercial potential. Subsequent work was undertaken, which has brought the technology close to commercial introduction.

Contacts

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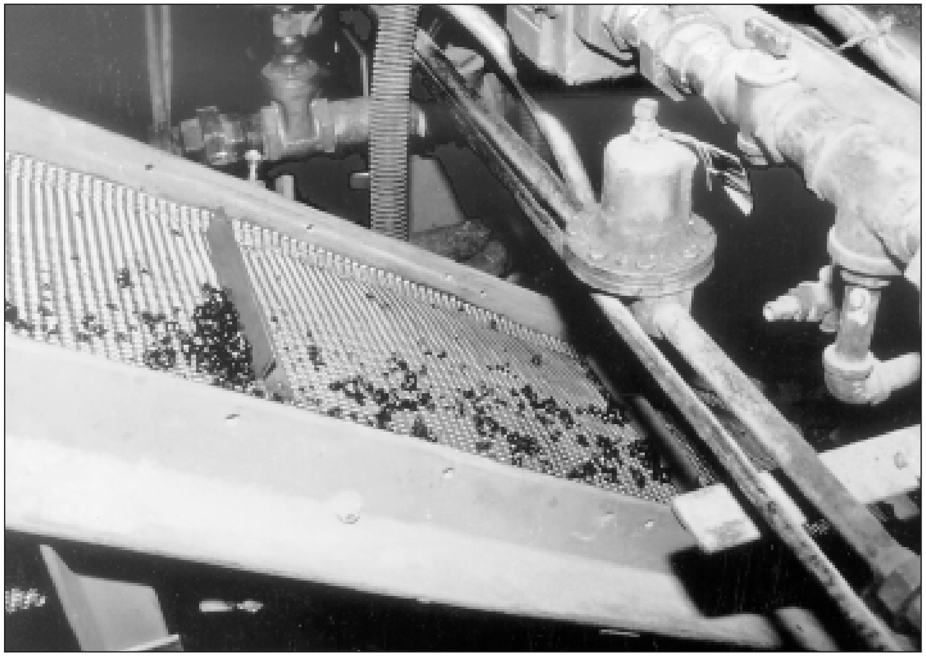
References

- *The Coal Tech Advanced Cyclone Combustor Demonstration Project—A DOE Assessment.* Report No. DOE/PC/79799-T1. U.S. Department of Energy. May 1993. (Available from NTIS as DE93017043.)
- *The Demonstration of an Advanced Cyclone Coal Combustor, with Internal Sulfur, Nitrogen, and Ash Control for the Conversion of a 23 MMBtu/Hour Oil Fired Boiler to Pulverized Coal; Vol. 1: Final Technical Report; Vol. 2: Appendixes I–V; Vol. 3: Appendix VI.* Coal Tech Corporation. August 1991. (Available from NTIS as DE92002587 and DE92002588.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control.* Coal Tech Corporation. Report No. DOE/FE-0077. U.S. Department of Energy. February 1987. (Available from NTIS as DE87005804.)



▲ Coal Tech's slagging combustor demonstrated the capability to retain, as slag, a high percentage of the non-fuel components injected into the combustor. The slag, shown on the conveyor, is essentially an inert glassy by-product with value in the construction industry as aggregate or in the manufacture of abrasives.

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 scfm of kiln gas; and up to 274 tons/day of coal

Coal

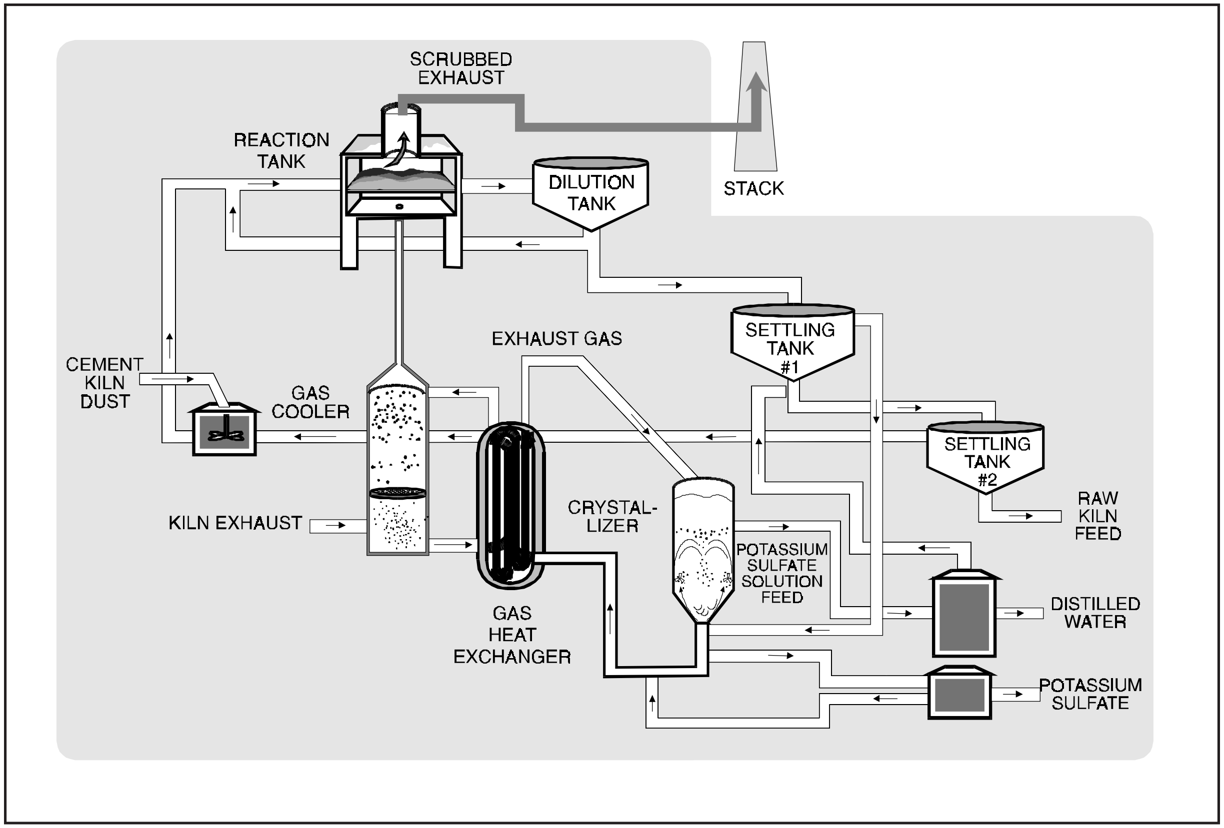
Pennsylvania bituminous, 2.5–3.0% sulfur

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 by-products.

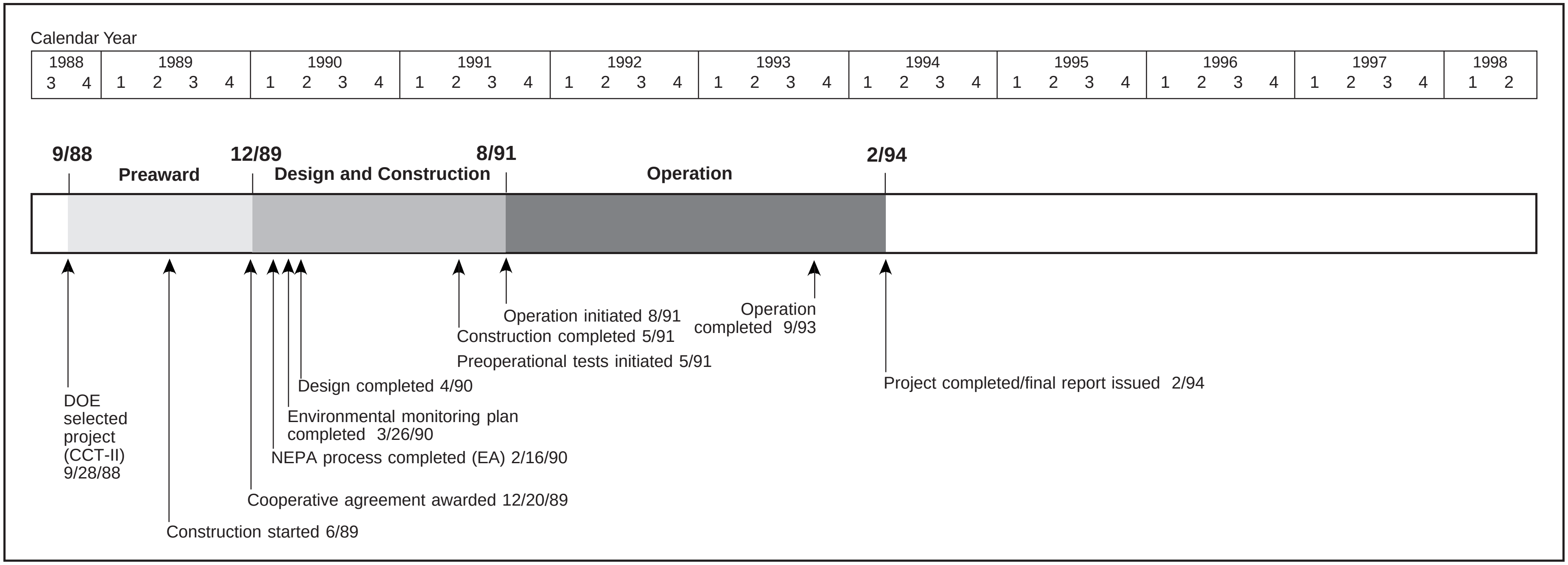


Technology/Project Description

The Passamaquoddy Technology Recovery Scrubber™ uses cement kiln dust (CKD), an alkaline-rich (potassium) waste, to react with the acidic flue gas. This CKD, representing about 10% of the cement feedstock otherwise lost as waste, is formed into a water-based slurry and mixed with the flue gas as the slurry passes over a perforated tray that enables the flue gas to percolate through the slurry. The SO_2 in the flue gas reacts with the potassium to form potassium sulfate, which stays in solution and remains in the liquid as the slurry undergoes separation into liquid and solid fractions. The solid fraction, in thickened slurry form and freed of the potassium and other alkali constituents, is returned to the kiln as feedstock (it is the alkali content that makes the CKD unusable as feedstock). No dewatering is necessary for the wet process used at the Dragon Products Plant. The liquid fraction is passed to a crystallizer that uses waste heat in the flue gas to evaporate the water and recover dissolved alkali metal salts. A recuperator lowers the incoming flue gas temperature to prevent slurry evaporation, enables the use of low-cost fiberglass construction material, and provides much of the process water through condensation of exhaust gas moisture.

The Passamaquoddy Technology Recovery Scrubber™ was constructed at the Dragon Products Company's cement plant in Thomaston, ME, a plant that can process approximately 450,000 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 CKD from the cement-making process.

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



Results Summary

Environmental

- The SO_2 removal efficiency averaged 94.6% during the last several months of operation and 89.2% for the entire operating period.
- The NO_x removal efficiency averaged nearly 25% during the last several months of operation and 18.8% for the entire operating period.
- All of the 250-ton/day CKD waste produced by the plant was renovated and reused as feedstock. This resulted in reducing the raw feedstock requirement by 10% and eliminating solid waste disposal costs.
- Particulate emission rates of 0.005–0.007 gr/scf, about 1/10 that allowed for cement kilns, were achieved with dust loadings of approximately 0.04 gr/scf.
- Pilot testing conducted at U.S. Environmental Protection Agency laboratories under Passamaquoddy Technology, L.P. sponsorship showed 98% HCl removal.
- On three different runs, VOC (as represented by alpha-pinene) removal efficiencies of 72.3, 83.1, and 74.5% were achieved.
- A reduction of approximately 2% in CO_2 emissions was realized through recycling of the CKD.

Operational

- During the last operating interval, April to September 1993, recovery scrubber availability (discounting host site downtime) steadily increased from 65% in April 1993 to 99.5% in July 1993.

Economic

- Capital costs are approximately $10,090,000 (1990 $) for a recovery scrubber to control emissions from a 450,000-ton/yr wet process plant, with a simple payback estimated in 3.1 years. Operating and maintenance costs, estimated at $500,000/yr, plus capital and interest costs, are generally offset by avoided costs associated with fuel, feedstock, and waste disposal and with revenues from the sale of fertilizer.

Project Summary

The Passamaquoddy Technology Recovery Scrubber™ is a unique process that achieves efficient acid gas and particulate control through effective contact between flue gas and a potassium-rich slurry composed of waste kiln dust. Flue gas passes through the slurry as it moves over a special sieve tray. This results in high SO_2 and particulate capture, some NO_x reduction, and sufficient uptake of the potassium (an unwanted constituent in cement) to allow the slurry to be recycled as feedstock. Waste cement kiln dust, exhaust gases (including waste heat), and wastewater are the only inputs to the process. Renovated cement kiln dust, potassium-based fertilizer, scrubbed exhaust gas, and distilled water are the only proven outputs. There is no waste.

The scrubber was evaluated over three basic operating intervals dictated by winter shutdowns for maintenance and inventory and 14 separate operating periods (within these basic intervals) largely determined by unforeseen host-plant maintenance and repairs and a depressed cement market. Over the period August 1991 to September 1993, more than 5,300 hours was logged, 1,400 hours in the first operating interval, 1,300 hours in the second interval, and 2,600 hours in the third interval. Sulfur loadings varied significantly over the operating periods due to variations in feedstock and operating conditions.

Operational Performance

Several design problems were discovered and corrected during start-up. No further problems were experienced in these areas during actual operation.

Two problems persisted into the demonstration period. The mesh-type mist eliminator, which was installed to prevent slurry entrainment in the flue gas, experienced plugging. Attempts to design a more efficient water spray for cleaning failed. However, replacement with a chevron-type mist eliminator prior to the third operating interval was effective. Potassium sulfate pelletization proved to be a more difficult problem. The cause was eventually isolated and found to be excessive water entrainment due to carry-over of gypsum and syngenite. Hydroclones were installed in the crystallizer circuit to separate the very fine gypsum and syngenite crystals from the much coarser potassium sulfate crystals. Although the correction was made, it was not in time to realize pellet production during the demonstration period. After all modifications were completed, the recovery scrubber entered into the third and final operating interval—April to September 1993. During this interval, recovery scrubber availability (discounting host site downtime) steadily increased from 65% in April to 99.5% in July.

Environmental Performance

An average 250 tons/day of CKD waste generated by the Dragon Products plant was used as the sole reagent in the recovery scrubber to treat approximately 250,000 scfm of flue gas. All the CKD, or approximately 10 tons/hr, were renovated and returned to the plant as feedstock and mixed with about 90 tons/hr of fresh feed to make up the required 100 tons/hr. The alkali in the CKD was converted to potassium-based fertilizer, eliminating all solid waste. Exhibit 44 lists the number of hours per operating period, SO_2 and NO_x inlet and outlet readings in pounds per hour, and removal efficiency as a percentage for each operating period.

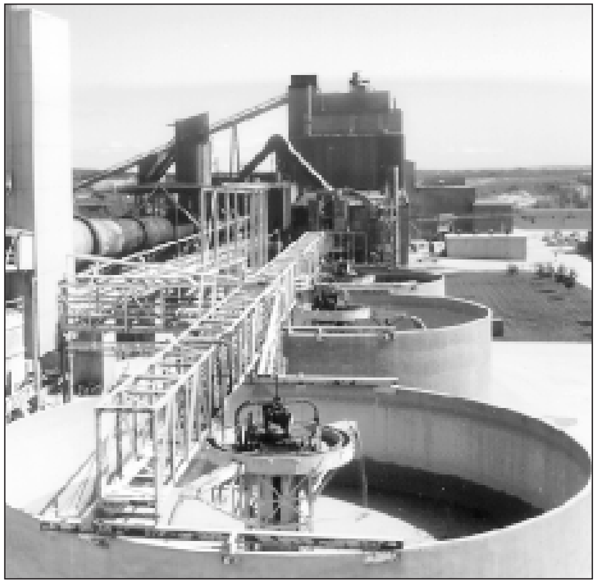
Average removal efficiencies during the demonstration period were 89.2% for SO_2 and 18.8% for NO_x emissions. No definitive explanation for the NO_x control mechanics was available at the conclusion of the demonstration.

Aside from the operating period emissions data, an assessment was made of inlet SO_2 load impact on removal efficiency. For SO_2 inlet loads in the range of 100 lb/hr or less, recovery scrubber removal efficiency averaged 82.0%. For SO_2 inlet loads in the range of 100–200 lb/hr, removal efficiency increased to 94.1% and up to 98.5% for loads greater than 200 lb/hr.

In compliance testing for the State of Maine's Department of Environmental Quality, the recovery scrubber was subjected to dust loadings of approximately 0.04 gr/scf and demonstrated particulate emission rates of 0.005–0.007 gr/scf—less than 1/10 the current allowable limit.

Exhibit 44
Summary of Emissions and Removal Efficiencies

Operating Period	Operating Time (hr)	Inlet (lb/hr)		Outlet (lb/hr)		Removal Efficiency (%)	
		SO_2	NO_x	SO_2	NO_x	SO_2	NO_x
1	211	73	320	10	279	87.0	12.8
2	476	71	284	11	260	84.6	08.6
3	464	87	292	13	251	85.4	14.0
4	259	131	252	16	165	87.6	34.5
5	304	245	293	28	243	88.7	17.1
6	379	222	265	28	208	87.4	21.3
7	328	281	345	28	244	90.1	29.3
8	301	124	278	10	188	91.8	32.4
9	314	47	240	7	194	85.7	19.0
10	402	41	244	6	218	86.1	10.5
11	460	36	315	6	267	83.4	15.0
12	549	57	333	2	291	95.9	12.4
13	464	86	288	4	223	95.0	22.6
14	405	124	274	9	199	92.4	27.4
Total operating time	5,316						
Weighted Average		**109**	**289**	**12**	**234**	**89.2**	**18.8**



The Passamaquoddy Technology Recovery Scrubber™ was successfully demonstrated at Dragon Products Company's cement plant in Thomaston, ME.

Economic Performance

The estimated "as-built" capital cost to reconstruct the Dragon Products prototype, absent the modifications, is $10,090,000 in 1990 dollars.

Annual operating and maintenance costs are estimated at $500,000. Long-term annual maintenance costs are estimated at $150,000. Power costs, estimated at $350,000/yr, are the only significant operating costs. There are no costs for reagents or disposal, and no dedicated staffing or maintenance equipment are required.

Considering various revenues and avoided costs that may be realized by installing a recovery scrubber similar in size to the one used at Dragon Products, simple payback on the investment is projected in as little as 3.1 years. In making this projection, $6,000,000 was added to the "as-built" capital costs to allow for contingency, design/permitting, construction interest, and licensing fees.

Commercial Applications

Of the approximately 2,000 Portland cement kilns in the world, about 250 are in the United States and Canada. These 250 kilns emit an estimated 230,000 tons/yr of SO_2 (only three plants have SO_2 controls, one of which is the Passamaquoddy Technology Recovery Scrubber™). The applicable market for SO_2 control is estimated at 75% of the 250 installations. If full penetration of this estimated market were realized, approximately 150,000 tons/yr of SO_2 reduction could be achieved.

The scrubber became a permanent part of the cement plant at the end of the demonstration. A feasibility study has been completed for a Taiwanese cement plant.

Contacts

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John C. McDowell, FETC, (412) 892-6237

References

- *Passamaquoddy Technology Recovery Scrubber™: Final Report.* Volumes 1 and 2 (Appendices A–M. Passamaquoddy Tribe. February 1994. (Vol. 1 available from NTIS as DE94011175, Vol. 2 as DE94011176.)
- *Passamaquoddy Technology Recovery Scrubber™: Public Design Report.* Report No. DOE/PC/89657-T2. Passamaquoddy Tribe. October 1993. (Available from NTIS as DE94008316.)
- *Passamaquoddy Technology Recovery Scrubber™: Topical Report.* Report No. DOE/PC/89657-T1. Passamaquoddy Tribe. March 1992. (Available from NTIS as DE92019868.)
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Cement Kiln Flue Gas Recovery Scrubber.* (Passamaquoddy Tribe). Report No. DOE/FE-0152. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004462.)

The Passamaquoddy Technology Recovery Scrubber™ became a permanent part of the Dragon Products facility at the project's end.

Pulse Combustor Design Qualification Test

Participant
ThermoChem, Inc.

Additional Team Member
Manufacturing and Technology Conversion International, Inc. (MTCI)—technology supplier

Location
Baltimore, MD (MTCI Test Facility)

Technology
MTCI's Pulsed Enhanced™ Steam Reforming using a multiple resonance tube pulse combustor.

Plant Capacity/Production
30 million Btu/hr (steam reformer)

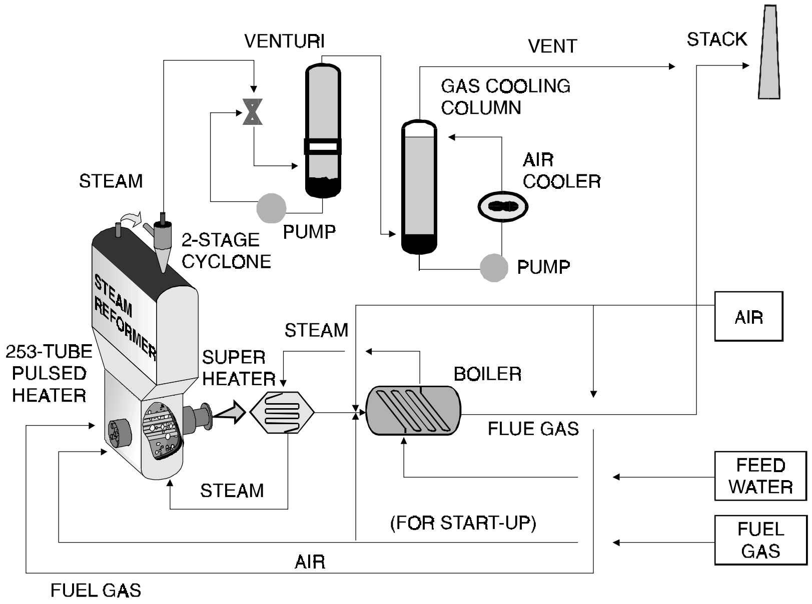
Coal
Black Thunder (Powder River Basin) subbituminous

Project Funding

Total project cost	$8,612,054	100%
DOE	4,306,027	50
Participants	4,306,027	50

Project Objective
To demonstrate the operational/commercial viability of a single 253-resonance-tube pulse combustor unit and evaluate characteristics of coal-derived fuel gas generated by an existing Process Development Unit.

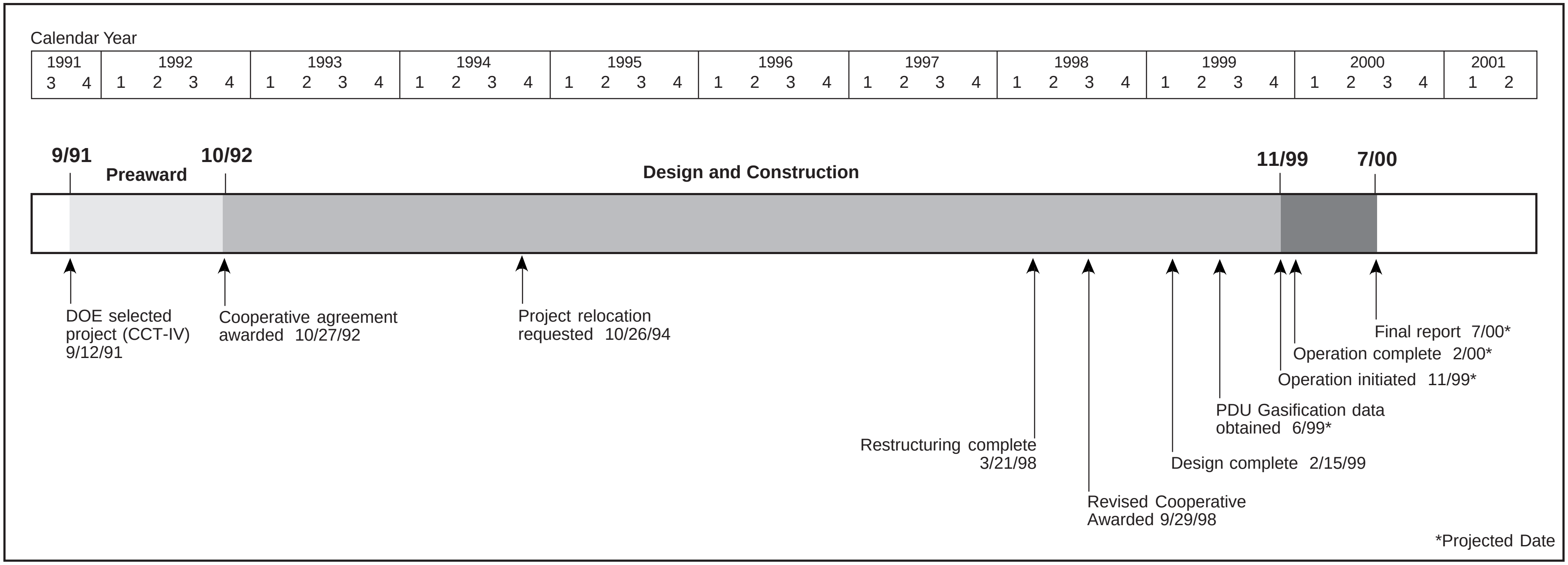
Technology/Project Description
MTCI's PulsedEnhanced™ Steam Reforming process incorporates an indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu content fuel gas without the need for an oxygen plant. Indirect heat transfer is provided by immersing multiple resonance-tube pulse combustors in a fluidized-bed steam gasification reactor. Pulse combustion increases heat transfer rate by a factor of 3 to 5, thus greatly reducing the heat transfer area required in the gasifier.



The pulse combustor represents the core of the PulsedEnhanced™ Steam Reforming process because it provides a highly efficient and cost-effective heat source. Demonstration of the combustor at the 253-resonance-tube commercial scale is critical to market entry. The 253-resonance-tube unit represents a 3.5 scale-up from previous tests. Testing will seek to verify scale-up criteria and appropriateness of controls and instrumentation. Also, an existing Process Development Unit (PDU) will be used to gasify coal feedstock to provide fuel gas data, including energy content, species concentration, and yield. Char from the PDU will be evaluated as well.

The facility will also have a product gas cleanup train that includes two stages of cyclones, a venturi scrubber with a scrubber tank, and a gas quench column. An air-cooled heat exchanger will be used to reject heat from the condensation of excess steam (unreacted fluidization steam) quenched in the venturi scrubber and gas quench column. All project testing will be performed at the MTCI test facility in Baltimore, Maryland.

Project Status/Accomplishments
On September 10, 1998, DOE approved revision of ThermoChem, Inc.'s Cooperative Agreement for a scaled-down project. The original project, awarded in October 1992, was a commercial demonstration facility that would employ 10 identical 253-resonance-tube pulse combustor units. After fabrication of the first combustor



unit, the project went through restructuring. The revised project will demonstrate a single 253-resonance-tube pulse combustor. NEPA requirements were satisfied on November 30, 1998 with a Categorical Exclusion. The first major milestone was completion of the design on February 15, 1999.

The next major milestone is completion of the coal mild gasification data in June 1999 using the existing PDU. Construction of the combustor unit is scheduled to be completed in October or November 1999, with operations beginning in November 1999.

Commercial Applications

PulsedEnhanced™ Steam Reforming has application in many different processes. Coal, with the world production on the order of four billion tons per year, constitutes the largest potential feed stock for steam reforming. Other potential feedstocks include spent liquor from pulp and paper mills, refused-derived fuel, municipal solid waste, sewage sludge, biomass, and other wastes.

Although the project will demonstrate mild gasification only, the following coal-based applications are envisioned:

- Coal processing for combined-cycle power generation,
- Coal processing for fuel cell power generation,
- Coal pond waste and coal rejects processing to produce a hydrogen-rich gas from the steam reformer for use in overfiring or reburning to reduce NO_x emissions,
- Coal processing for production of gas or liquid fuel and char for the steel industry for use in direct reduction of iron ore,
- Coal processing for producing compliance fuels,
- Mild gasification of coal,
- Co-processing of coal and wastes, and
- Coal drying.

In addition, the technology has application for black liquor processing and chemical recovery and for hazardous, low-level radioactive, and low-level mixed waste volume reduction and destruction.

Appendix A: CCT Project Contacts

Project Contacts

Listed below are contacts for obtaining further information about specific CCT Program demonstration projects. Listed are the name, title, phone number, fax number, mailing address, and e-mail address, if available, for the participant's 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. In addition, the names, phone numbers, and e-mail addresses for contact persons at DOE Headquarters and the Federal Energy Technology Center are provided.

Environmental Control Devices

SO_2 Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

Participant:
AirPol, Inc.

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lawrence.saroff@hq.doe.gov
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watts@fetc.doe.gov

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Participant:
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lawrence.saroff@hq.doe.gov
James U. Watts, FETC, (412) 892-5991
watts@fetc.doe.gov

LIFAC Sorbent Injection Desulfurization Demonstration Project

Participant:
LIFAC–North America

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James U. Watts, FETC, (412) 892-5991
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Advanced Flue Gas Desulfurization Demonstration Project

Participant:
Pure Air on the Lake, L.P.

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NO_x Control Technologies

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Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

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

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

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

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Combined SO_2/NO_x Control Technologies

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Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

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Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System

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Appendix B: Acronyms, Abbreviations, and Symbols

Acronyms, Abbreviations, and Symbols

°C	degrees Celsius
°F	degrees Fahrenheit
$	dollars (U.S.)
$/kw	dollars per kilowatt
$/ton	dollars per ton
%	percent
®	registered trademark
™	trademark
ABB CE	ABB Combustion Engineering, Inc.
ABB ES	ABB Environmental Systems
ACFB	atmospheric circulating fluidized-bed
ADL	Arthur D. Little, Inc.
AFBC	atmospheric fluidized-bed combustion
AFGD	advanced flue gas desulfurization
AIDEA	Alaska Industrial Development and Export Authority
AOFA	advanced overfire air
APF	advanced particulate filter
ASME	American Society of Mechanical Engineers
Ass'n.	Association
ATCF	after tax cash flows
atm	atmosphere(s)
avg.	average
BFGCI	blast furnace granular-coal injection
BG	British Gas
BG/L	British Gas/Lurgi
Btu	British thermal unit(s)
Btu/kWh	British thermal units per kilowatt-hour
B&W	The Babcock & Wilcox Company
CAAA	Clean Air Act Amendments of 1990
$CaCO_3$	calcium carbonate (calcitic limestone)
CaO	calcium oxide (lime)
$Ca(OH)_2$	calcium hydroxide (calcitic hydrated lime)
$Ca(OH)_2$•MgO	dolomitic hydrated lime
Ca/N	calcium/nitrogen
CAPI	Clean Air Power Initiative
Ca/S	calcium/sulfur
$CaSO_3$	calcium sulfite
$CaSO_4$	calcium sulfate
CCOFA	close-coupled overfire air
CCT	clean coal technology
CCT I	First CCT Program solicitation
CCT II	Second CCT Program solicitation
CCT III	Third CCT Program solicitation
CCT IV	Fourth CCT Program solicitation
CCT V	Fifth CCT Program solicitation
CCT Program	Clean Coal Technology Demonstration Program
CDL®	Coal-Derived Liquid®
CEQ	Council on Environmental Quality
CFB	circulating fluidized bed
C/H	carbon/hydrogen
CKD	cement kiln dust
CO	carbon monoxide
CO_2	carbon dioxide
COP	Conference of Parties
CT-121	Chiyoda Thoroughbred-121
CQE™	Coal Quality Expert™
CQIM™	Coal Quality Impact Model™
CX	categorical exclusion
CZD	confined zone dispersion
DER	discrete emissions reduction
DME	dimethyl ether
DOE	U.S. Department of Energy
DOE/HQ	U.S. Department of Energy Headquarters
DSE	dust stabilization enhancement
DSI	dry sorbent injection
EA	environmental assessment
EER	Energy and Environmental Research Corporation
EFCC	externally fired combined cycle
EIA	Energy Information Administration
EIS	environmental impact statement
EIV	Environmental Information Volume
EMP	environmental monitoring plan
EPA	U.S. Environmental Protection Agency
EPAct	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ESP	electrostatic precipitator

EWG	exempt wholesale generator
ext.	extension
FBC	fluidized-bed combustion
FCCC	Framework Convention on Climate Change
Fe$_2$S	pyritic sulfur
FERC	Federal Energy Regulatory Commission
FETC	Federal Energy Technology Center
FGD	flue gas desulfurization
FONSI	finding of no significant impact
FRP	fiberglass-reinforced plastic
ft, ft^2, ft^3	foot (feet), square feet, cubic feet
FY	fiscal year
gal.	gallon(s)
gal/ft^3	gallons per cubic feet
GB	gigabyte(s)
GE	General Electric
GHG	greenhouse gases
GNOCIS	Generic NO$_x$ Control Intelligence System
gpm	gallons per minute
GR	gas reburning
GR–LNB	gas reburning and low-NO$_x$ burner
GR–SI	gas reburning and sorbent injection
GSA	gas suspension absorption
GVEA	Golden Valley Electric Association
GW	gigawatt(s)
GWe	gigawatt(s)-electric
H$_2$S	hydrogen sulfide
H$_2$SO$_4$	sulfuric acid
HAP	hazardous air pollutant
HCl	hydrogen chloride
HF	hydrogen fluoride
HGPFS	hot gas particulate filter system
HHV	high heating value
hr.	hour(s)
HRSG	heat recovery steam generator
ID	Induced Draft
IEA	International Energy Agency
IGCC	integrated gasification combined cycle
in, in^2, in^3	inch(es), square inches, cubic inches
JBR	Jet Bubbling Reactor®
KCl	potassium chloride
K$_2$SO$_4$	potassium sulfate
kW	kilowatt(s)
kWh	kilowatt-hour(s)
lb.	pound(s)
L/G	liqud to gas ratio
LHV	low heating value
LIMB	limestone injection multistage burner
LNB	low-NO$_x$ burner
LNCB®	low-NO$_x$ cell burner
LNCFS	Low-NO$_x$ Concentric-Firing System
LOI	loss on ignition
LPMEOH™	Liquid phase methanol™
LRCWF	low-rank coal-water-fuel
LSFO	limestone forced oxidation
MASB	multi-annular swirl burner
MB	megabyte(s)
MCFC	molten carbonate fuel cell
MgCO$_3$	magnesium carbonate
MgO	magnesium oxide
Mhz	megahertz
mills/kWh	mills per kilowatt hour
min.	minute(s)
mo.	month(s)
MTCI	Manufacturing and Technology Conversion International
MTF	memorandum (memoranda)-to-file
MW	megawatt(s)
MWe	megawatt(s)-electric
MWt	megawatt(s)-thermal
N$_2$	atmospheric nitrogen
Na/Ca	sodium/calcium
Na$_2$/S	sodium/sulfur
NaOH	sodium hydroxide
Na$_2$CO$_3$	sodium carbonate
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NH$_3$	ammonia
Nm^3	Normal cubic meter
NO$_2$	nitrogen dioxide
NOPR	Notice of Proposed Rulemaking
NO$_x$	nitrogen oxides
NSPS	New Source Performance Standards
NTHM	net tons of hot metal
NTIS	National Technical Information Service
NYSEG	New York State Electric & Gas Corporation
OC&PS	Office of Coal & Power Systems
O&M	operating and maintenance
O$_2$	oxygen
OTAG	Ozone Transport Assessment Group
OTC	Ozone Transport Commission
PC	personal computer
PCAST	Presidential Committee of Advisors on Science and Technology
PCFB	pressurized circulating fluidized bed
PDF®	Process-Derived Fuel®
PEIA	programmatic environmental impact assessment
PEIS	programmatic environmental impact statement

PEOA™	Plant Emission Optimization Advisor™
PENELEC	Pennsylvania Electric Company
PEP	progress evaluation plan
PFBC	pressurized fluidized-bed combustion
PJBH	pulse jet baghouse
PM	particulate matter
PM_{10}	particulate matter less than 10 microns in diameter
$PM_{2.5}$	particulate matter less than 2.5 microns in diameter
PON	program opportunity notice
PRB	Powder River Basin
ppm	parts per million (mass)
ppmv	parts per million by volume
PSCC	Public Service Company of Colorado
PSD	Prevention of Significant Deterioration
psi	pound(s) per square inch
PUHCA	Public Utility Holding Company Act of 1935
PURPA	Public Utility Regulatory Policies Act of 1978
QF	qualifying facility
RAM	random access memory
R&D	research and development
RD&D	research, development, and demonstration
REA	Rural Electrification Administration
RP&L	Richmmond Power & Light
ROD	Record of Decision
ROM	run-of-mine
rpm	revolutions per minute
RUS	Rural Utility Service
S	sulfur
SBIR	Small Business Innovation Research
scf	standard cubic feet
scfm	standard cubic feet per minute
SCR	selective catalytic reduction
SCS	Southern Company Services, Inc.
SFC	Synthetic Fuels Corporation
S-H-U	Saarberg-Hölter-Umwelttechnik
SI	sorbent injection
SIP	state implementation plan
SM	service mark
SNCR	selective noncatalytic reduction
SNRB™	SO_x-NO_x-Rox Box™
SO_2	sulfur dioxide
SO_3	sulfur trioxide
std ft^3	standard cubic feet
SOFA	separated overfire air
STTR	Small Business Technology Transfer Program
SVGA	super video graphics adapter
TAG™	Technical Assessment Guide™
TCLP	toxicity characteristics leaching procedure
TVA	Tennessee Valley Authority
UAF	University of Alaska, Fairbanks
UARG	Utility Air Regulatory Group
UBCL	unburned carbon
U.K.	United Kingdom
U.S.	United States
VFB	vibrating fluidized-bed
VOC	volatile organic compound
WC	water column
WES	wastewater evaporation system
WLFO	wet limestone, forced oxidation
wt.	weight
yr.	year(s)

State Abbreviations

States within the United States are abbreviated using two-letter postal codes.

Index of CCT Projects and Participants