DOE/FE-0437

CLEAN COAL TECHNOLOGY

Clean Coal Technology Demonstration Program: Program Update 2000

As of September 2000

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

April 2001

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Executive Summary: CCT Program Update 2000

Introduction

CCT Program. The Clean Coal Technology Demonstration Program (CCT Program), a model of government and industry cooperation, advances the Department of Energy's (DOE) mission to foster a secure and reliable energy system that is environmentally and economically sustainable. With 26 of the 38 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 that 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. At the dawn of the 21st century, many of the clean coal technologies have realized commercial application. Industry now stands ready to respond to the energy and environmental demands of the new 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. The CCT Program took a pollution prevention approach as well, demonstrating technologies that produce clean coal-based solid and liquid fuels by removing pollutants or their precursors before being burned. Lastly, new technologies were introduced into the major coal-using industries 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.

Fiscal Year 2000 Major Accomplishments. Early in fiscal year 2000, the Wabash River Coal Gasification Repowering Project successfully completed demonstration operations. The final report was issued and the project was closed out by the end of the year. Beyond the integration of an advanced integrated gasification combined-cycle system with a 1950s vintage pulverized coal-fired plant, the project incorporated other features that resulted in a 40 percent efficient unit. These include: (1) hot/dry particulate removal to enable gas cleanup without heat loss, (2) integration of the gasifier and high-temperature heat recovery steam generator to ensure optimum steam conditions for the steam turbine, (3) use of a carbonyl sulfide hydrolysis process to enable high-percentage sulfur removal, (4) recycle of slag fines for additional carbon recovery, (5) use of 95 percent pure oxygen to lower power requirements for the oxygen plant, and (6) fuel gas moisturization to reduce steam injection requirements for NO_x control.

The Healy Clean Coal Project successfully completed demonstration operations early in fiscal year 2000. The project was the first utility-scale demonstration of the TRW advanced entrained (slagging) combustor. The project eclipsed extremely strict environmental operating permit emission limits, which were required because of the project's proximity to the environmentally sensitive Denali National Park and Preserve, with typical emissions of 30 percent, 56 percent, and 77

Tidd PFBC Demonstration Project (The Ohio Power Company)—1991 Powerplant Award presented by *Power* magazine.

Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)—1997 Powerplant Award presented by *Power* magazine.

percent below permit emission limits for NO_x (0.350 lb/10^6 Btu), SO_2 (0.086 lb/10^6 Btu), and PM (0.02 lb/10^6 Btu), respectively. The project is now in the reporting phase.

Final reports were issued and the following projects closed out:

- Micronized Coal Reburning Demonstration for NO_x Control,
- Milliken Clean Coal Technology Demonstration Project,
- Integrated Dry NO_x/SO_2 Emissions Control System, and
- Blast Furnace Granular-Coal Injection System Demonstration Project.

The cooperative agreement was novated and a new site approved for the Kentucky Pioneer Energy IGCC Demonstration Project. The National Environmental Policy Act (NEPA) process, which includes preparing an Environmental Impact Statement (EIS), was started for the project.

Throughout the year, the CCT Program staff participated in over a dozen domestic and international events involving users and vendors of clean coal technologies, regulators, financiers, environmental groups, and other public and private institutions. Four issues of the *Clean Coal Today* newsletter were published in the same period, along with the fifth annual edition of the *Clean Coal Today Index,* which cross-references all articles published in the newsletter. A 12-page *Project Performance Summary* document was issued for the ENCOAL® Mild Coal Gasification Project. An updated *The Investment Pays Off* document, capturing the latest contributions of the CCT Program to advancing coal technologies, was published. *Clean Coal Technology Topical Reports* were issued during the fiscal year for the Tampa Electric Integrated Gasification Combined-Cycle Project and the Blast Furnace Granular Coal Injection System Demonstration Project. Also, DOE continued coverage of the program by publishing the *Clean Coal Technology Demonstration Program: Program Update 1999,* and the mid-year update of project fact sheets, *Clean Coal Technology Demonstration Program: Project Fact Sheets 2000.*

In fiscal year 2000, the cooperative agreements for two demonstration projects expired—NOXSO Corporation's Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System and Custom Coals International's Self-Scrubbing Coal™: An Integrated Approach—and are not discussed herein.

These accomplishments and more are described in further detail in this *Clean Coal Technology Demonstration Program: Program Update 2000.* In sum, the CCT Program is continuing to yield advances in coal technologies and thus ensures that the nation's most abundant fossil energy resource will serve the energy needs of the United States while satisfying national environmental objectives.

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process Project (Southern Company Services, Inc.)—1994 Powerplant Award presented by *Power* magazine.

Role of the CCT Program

CCT Program Evolution. Coal accounts for over 94 percent of the proven fossil energy reserves in the United States and supplies the bulk of the low-cost, reliable electricity vital to the nation's economy and global competitiveness. In 1999, over half of the nation's electricity was produced with coal, and projections by the U.S. Energy Information Agency (EIA) predict that coal will continue to dominate electric power production well into the first quarter of the 21st century. However, there is a need to use U.S. coal resources in an environmentally responsible manner.

The CCT Program was established to demonstrate the commercial feasibility of CCTs to respond to a growing demand for a new generation of advanced coal-based technologies characterized by enhanced operational, economic, and environmental performance. The first solicitation (CCT-I) for clean coal projects resulted in a broad range of projects being selected in four major product markets—environmental control devices, advanced electric power generation, coal processing for clean fuels, and industrial applications.

The second solicitation (CCT-II) became the centerpiece for satisfying the recommendations contained in the Joint Report of the Special Envoys on Acid Rain (1986). The goal was to demonstrate technologies that could achieve significant reductions in the emissions of precursors of acid rain, namely SO_2 and NO_x. The third solicitation (CCT-III) furthered the goal of CCT-II and added technologies that could produce clean fuel from run-of-mine coal.

The fourth and fifth solicitations (CCT-IV and CCT-V, respectively) recognized emerging energy and environmental issues, such as global climate change and capping SO_2 emissions, and thus focused on technologies that were capable of addressing these issues. CCT-IV called for energy efficient, economically competitive technologies capable of retrofitting, repowering, or replacing existing facilities, while at the same time significantly reducing SO_2 and NO_x emissions. CCT-V focused on technologies applicable to new or existing facilities that could significantly improve efficiency and environmental performance.

Environmental Impetus. Even before enactment of the Clean Air Act Amendments of 1990 (CAAA), the CCT Program was cognizant of the changes in electric power generation that would likely be caused by the statute. Several projects in the CCT Program were implemented at units designated as Phase I units in Title IV of the CAAA, which were required to meet SO_2 reductions by January 1, 1995. The CCT Program projects at Phase I units successfully reduced SO_2 emissions using advanced flue gas desulfurization (AFGD) and repowering with integrated gasification combined-cycle. With the January 1, 2000, Phase II Title IV CAAA provisions in effect, the CCT Program's portfolio of technologies helped industry meet the more stringent SO_2 emission limits. While SO_2 credits are being used to meet short-term goals, EIA predicts 11 GWe of capacity will be retrofitted with scrubbers to meet Phase II goals. Furthermore, these SO_2 reduction technologies may be important in meeting new requirements for $PM_{2.5}$ (particulate matter 2.5 microns and smaller in diameter) because some sulfur species are in this size range.

In addition to SO_2 reductions, Title IV also called for reductions in NO_x emissions. Phase I of the NO_x provisions of Title IV requires reductions from the so-called Group 1 boilers—tangentially fired and dry-bottom wall-fired boilers. The U.S. Environmental Protection Agency (EPA) used data developed during the CCT Program in establishing the NO_x emission standards. Under Phase II, EPA established NO_x emission limitations for Group 2 boilers and reduced the emission limits for Group 1 boilers. Group 2 boilers include cell-burner, cyclone, wet-bottom wall-fired, and vertically fired boilers. The CCT Program has demonstrated NO_x emission control techniques that are applicable to all of these boiler types. Furthermore, these technologies are not only applicable to Phase I and II NO_x emission reductions, but can be used in ozone nonattainment areas to make deeper cuts in NO_x emissions, which are a precursor to ozone.

Although the deadline has been stayed pending appeal, the EPA has issued a "SIP Call" to 22 states and the District of Columbia to take action to reduce regional transport of pollutants that contribute to ozone nonattainment in the Northeast. The SIP Call requires the 23 affected jurisdictions to revise their state implementation plans (SIPs) to reduce NO_x emissions 85 percent below 1990 rates or achieve a 0.15 lb/10^6 Btu emission rate by May 2003. In addition, EPA has tightened the New Source Performance Standard (NSPS) for electric and industrial boilers built or modified after July 9, 1997. The CCT Program has demonstrated several advanced electric power generation technologies that can be used to meet the new requirements or exceed the requirements to produce NO_x credits that could be sold to unit operators unable to meet the requirements. Furthermore, an environmental controls database has been developed that provides a foundation for developing technologies to meet the increasingly stringent standards for existing units.

Air toxics is another important area of environmental concern addressed by the CCT Program. Under Title I of the CAAA, EPA is responsible for determining the hazards to public health posed by 189 identified hazardous air pollutants (HAPs). The CCT Program made a significant contribution to a better understanding of potential HAPs from power plant emissions by monitoring HAPs from CCT Program project sites.

Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)—1993 Powerplant Award presented by *Power* magazine.

The results of these and other studies have significantly mitigated concerns about HAP emissions from coal-fired power plants and focused attention on mercury emissions. In December 2000, EPA decided to develop regulations for mercury emissions over the next three years.

The CCT Program is also cognizant of concerns about global climate change. Clean coal technologies (such as IGCC) being demonstrated in the CCT Program offer utilities an option to reduce greenhouse gases (GHG) by as much as 25 percent with first-generation systems through enhanced efficiency. Commercialization of atmospheric fluidized-bed combustion (AFBC) and pressurized fluidized-bed combustion (PFBC) will also serve to reduce GHGs.

Market Considerations. As the electric generation market moves from a regulated industry to a free market, the CCT Program has kept pace with the changes. Whether the changes are brought about by the federal government through existing or new legislation or by state governments, the CCT Program is demonstrating the first generation of many technologies that will be needed in a competitive power generation market. These new technologies will be far more efficient than existing plants and environmentally benign.

Ensuring Sustainable Economic Growth. It is in the nation's interest to maintain a diverse energy mix to sustain domestic economic growth. The CCT Program is contributing to this interest by developing and deploying a technology portfolio that enhances the efficient use of the United States' abundant coal resource while simultaneously achieving important environmental goals. The advancements in coal use technology resulting from the CCT Program will reduce dependence on foreign energy resources and create an international market for these new technologies. The worldwide market for power generation technologies could be as high as $80 billion between 1995 and 2020.

Coal Technology for the Future. The investment in the CCT Program is forming a solid foundation upon which to build a responsible future for fossil energy while addressing growing global and regional environmental concerns and providing low-cost energy. Two programs are of particular relevance to advancing the clean coal technologies demonstrated in the CCT Program. First is the Power Plant Improvement Initiative and second is Vision 21.

For the near term, the Office of Coal and Power Systems (OCPS) has embarked upon the Power Plant Improvement Initiative. The rapid growth in power demand, especially peak demand, coupled with the ongoing restructuring of the electric power industry, has resulted in a real and growing concern over the reliability of the nation's electricity grid. This concern prompted Congress to add $95 million to the Office of Fossil Energy budget for fiscal year 2001. The Power Plant Improvement Initiative approved by Congress will have a near-term focus on improving the efficiency and environmental performance of coal-fired power generation. New technologies will be demonstrated that can boost the efficiency of a power plant—increasing the amount of electricity it can generate, reducing air emissions, or perhaps a combination of both. The initial program will apply to existing and new coal-based, central power plants. Later, the program could include a wider span of more flexible generation technologies such as fuel cells and turbines that can operate on natural gas as well as coal.

For the long-term, OC&PS will build upon the solid foundation established by the CCT Program toward meeting Vision 21 goals. Vision 21 is a long-term strategic concept that integrates OC&PS program goals to develop the full potential of the nation's abundant fossil fuel resources while addressing regional and global environmental concerns. Vision 21 plants would comprise a portfolio of fuel-flexible systems and modules capable of producing a varied slate of high-value commodities, such as clean fuels, chemicals, and electricity, tailored to meet market demands in the 2010-2015 time frame. The OC&PS program areas, which include Central Power Systems, Distributed Generation, Fuels, CO_2 Sequestration, and Advanced Research, were developed to align with and directly support the goals and objectives of Vision 21 and the Comprehensive National Energy Strategy. The OC&PS program addresses key domestic and global environmental concerns, while being responsive to DOE strategies to enhance scientific understanding and promote secure, efficient, and comprehensive energy systems.

Program Implementation

Implementation Principles. There are 10 guiding principles that have been instrumental in the success of the CCT Program. These principles are:

- Strong and stable financial commitment for the life of the project, including full funding of the government's share of the costs;
- Multiple solicitations spread over a number of years, enabling the CCT Program to address a broad range of national needs with a portfolio of evolving technologies;
- Demonstrations conducted at commercial scale in actual user environments, allowing clear assessment of the technology's commercial potential;
- A technical agenda established by industry, not the government, enhancing commercialization potential;
- Clearly defined roles of government and industry, reflecting the degree of cost-sharing required;
- A requirement for at least 50 percent cost-sharing throughout all project phases, enhancing participant's commitment;
- An allowance for cost growth, but with a ceiling and cost-sharing, recognizing demonstration risk and providing an important check-and-balance to the program;
- Industry retention of real and intellectual property rights, enhancing commercialization potential;
- A requirement for industry to commit to commercialize the technology, reflecting commercialization goals; and

- A requirement for repayment up to the government's cost-share upon successful commercialization of the technology being demonstrated.

Implementation Process. Public and private sector involvement is integral to the CCT Program process and has been crucial to the program's success. Environmental concerns are publicly addressed through the process instituted under the National Environmental Policy Act (NEPA). Through programmatic environmental assessments (PEAs) and environmental impact statements (PEISs), project specific environmental assessments (EAs) and environmental impact statements (EISs), and other NEPA documents, the public is able to comment and have its comments addressed before the projects proceed to implementation. In addition, environmental monitoring programs are required for all projects to address non-regulated pollutant emissions.

As to the solicitation process, Congress set the goals for each solicitation. The Department of Energy translated the congressional guidance into performance-based criteria and developed approaches to address "lessons learned" from previous solicitations. The criteria and solicitation procedures were offered for public comment and presented at pre-proposal conferences. The solicitations were objectively evaluated against the pre-established criteria.

Projects are managed by the participants, not the government. However, to protect the public interest, safeguards are implemented to track and monitor project progress and direction. The Department of Energy interacts with the project at key negotiated decision points (budget periods) to approve or disapprove continuance of the project. Also, any changes to cost or other major project changes require DOE approval. In addition to formal project reporting requirements, an outreach program was instituted to make project information available to customers and stakeholders. This *Program Update 2000* is only one of the many public reports made available through the outreach program.

Commitment to Commercial Realization. The CCT Program has focused on achieving commercial realization since the program's inception. All five solicitations required the potential participants to address the commercial plans and approaches to be used by the participants to achieve full commercialization of the proposed technology. The cooperative agreements contain balanced provisions that provide protection for intellectual property but require the participants to make the technology available under license on a nondiscriminatory basis.

Solicitation Results. Each solicitation was issued as a Program Opportunity Notice (PON)—a solicitation mechanism for cooperative agreements where the program goals and objectives are defined, but the technology is not defined. The procurements followed specific statutory requirements that eventually led to a cooperative agreement between DOE and the participant. The result was a broad spectrum of technologies involving customers and stakeholders from all market segments. In sum, 211 proposals were submitted and 60 of those were selected. As of September 2000, a total of 38 projects have been completed or are currently active. These 38 projects are spread across the nation in 18 states.

Future Implementation Direction. The future direction of the CCT Program focuses on completing the existing projects as promptly as possible and assuring the collection, analyses, and reporting of the operational, economic, and environmental performance results that are needed to effect commercialization. In FY2001, four projects are scheduled to complete operations.

The body of knowledge obtained as a result of the CCT Program is being used in decision making relative to regulatory compliance, forging plans for meeting future energy and environmental demands, and developing the next generation of technologies responsive to ever increasing demands on environmental performance at competitive costs.

Funding and Costs

Program Funding. Congress has appropriated a federal budget of $1.8 billion for the CCT Program. For the 38 completed and active projects, the participants have contributed almost $3.5 billion dollars for a combined commitment of more than $5.2 billion. By law, DOE's contribution cannot exceed 50 percent of the total cost of any project. However, industry has stepped forward and cost shared an unprecedented 66 percent of the project funding.

Congress has provided CCT Program funding for all five solicitations through appropriation acts and adjustments. Additional activities funded by the CCT Program are the Small Business Innovation Research Program and the Small Business Technology Transfer Program. Funding is also provided for administration and management of the CCT Program. Use of appropriated funds is controlled and monitored using a variety of financial management techniques. The full government cost-share specified in the cooperative agreement is considered committed to each project; however, DOE obligates funds for the project in increments by budget period. This procedure reduces the government's financial exposure and assures that DOE fully participates in the decision to proceed with each major phase of project implementation.

Cost Sharing. As stated above, DOE's contribution cannot exceed 50 percent of the total cost of any project. Participant cost-sharing is required for all phases of the project. The federal government may share in project cost growth (which is likely to happen for any demonstration project) up to 25 percent of the original project cost. The participant's contributions must occur as expenses are incurred and cannot be delayed based on forecasted revenues, proceeds, or royalties. Also, prior investments in facilities by participants cannot count toward the participant's share.

Recovery of Government Outlays (Recoupment). The policy objective of DOE is to recover an amount of the federal government's financial contribution to each project when a technology is successfully commercialized. A recoupment agreement accompanies each demonstration agreement and stipulates the repayment provisions.

CCT Program Accomplishments

Marketplace Commitment. The success of the CCT Program ultimately will be measured by the contribution the technologies make to the resolution of energy, economic, and environmental issues. These contributions can only be achieved if the public and private sectors understand that clean coal technologies can increase the efficiency of energy use and enhance environmental performance at costs that are competitive with alternative energy options. The demonstrations, in conjunction with an aggressive outreach effort, are designed to impart that understanding. Also, the CCT Program is organized from a market perspective with projects placed in four major product lines—environmental control devices, advanced electric power generation, coal processing for clean fuels, and industrial applications. A summary of the number of projects having completed operations by category is shown in Exhibit ES-1.

The first major product line, environmental control devices, is subdivided into three groups—SO_2 control technologies, NO_x control technologies, and combined SO_2/NO_x control technologies. Both wet and dry lime- and limestone-based systems were demonstrated to achieve a range of SO_2 capture efficiencies from 50 to 99 percent. All five of the SO_2 control technology demonstrations have successfully completed operations.

For NO_x control technologies, two basic approaches were used: (1) combustion modification techniques including low-NO_x burners, overfire air, advanced controls, and reburning systems; and (2) post-combustion techniques using selective catalytic reduction (SCR) and selective non-catalytic reduction (SNCR) systems. These NO_x control techniques were applied in a variety of combinations on a diverse group of boilers, which are representative of 99 percent of the pre-NSPS boilers, *i.e.*, those boilers built before instituting NSPS under the Clean Air Act of 1970. The result of the NO_x control technology demonstrations is a portfolio of technologies that can be applied to the full range of boiler types and used to address today's pressing environmental concerns, *e.g.*, ozone. Six of the seven NO_x control technology demonstrations have successfully completed operations. For the seventh project, several final reports were issued on key facets of the project, but the project was extended for additional demonstration activities.

All six of the combined SO_2/NO_x control technology demonstrations have successfully completed operations. The demonstrations tested a multiplicity of complementary and synergistic control methods to achieve cost-effective SO_2 and NO_x emission reductions.

A summary of the results of the completed and extended environmental control device projects can be found in exhibit ES-2. The commercial successes of the environmental control devices can be seen in Exhibit ES-3.

Exhibit ES-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	6
Advanced Electric Power Generation		
Fluidized-Bed Combustion	2	5
Integrated Gasification Combined-Cycle	1	4
Advanced Combustion/Heat Engines	1	2
Coal Processing for Clean Fuels	3	4
Industrial Applications	2	5
Total	**26**	**38**

Exhibit ES-2
Summary of Results of Completed Environmental Control Technology Projects

Project and Participant	Key Results	Capital Cost
SO_2 Control Technology		
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Gas suspension absorption (GSA)/electrostatic precipitator (ESP)—SO_2 removal efficiency of 90% at Ca/S molar ratio of 1.4, 18 °F approach to saturation, and 0.12% chloride (3.0% sulfur bituminous coal) GSA/pulse jet baghouse—SO_2 removal efficiency 3–5% greater than GSA/ESP (3.0% sulfur bituminous coal)	\$149/kW for GSA (2.6% sulfur coal) vs. \$216/kW for conventional wet limestone forced oxidation (1990\$)
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	SO_2 reduction of 50% (1.2–2.5% sulfur bituminous coal)	Less than \$30/kW at 500 MWe (4% sulfur coal) (1994\$)
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	SO_2 removal efficiency of 70% at 2.0 Ca/S molar ratio (2.0–2.8% sulfur bituminous coal)	\$66/kW for two reactors (300 MWe); \$76/kW for one reactor (150 MWe); \$99/kW for one reactor (65 MWe) (1994\$)
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	SO_2 removal efficiency of 95% or more at availabilities of 99.5% when operating on 2.0–4.5% sulfur bituminous coal Maximum SO_2 removal efficiency of 98% Over 3-year demonstration, 237,000 tons of SO_2 removed while producing 210,000 tons of gypsum Gypsum purity—97.2% Power consumption—5,275 kW (61% of expected) Water consumption—1,560 gal/min (52% of expected)	\$210/kW at 100 MWe; \$121/kW at 300 MWe; \$94/kW at 500 MWe (3.0% sulfur coal) (1995\$)
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	SO_2 removal efficiency of over 95% at SO_2 inlet concentrations of 1,000–3,500 ppm using 3% sulfur coal Particulate removal efficiency of 97.7–99.3% at inlet mass loadings of 0.303–1.392 lb/10^6 Btu Agricultural-grade gypsum as a by-product Fiberglass-reinforced-plastic construction—chemically and structurally durable; eliminated the need for a flue gas prescrubber and reheat	\$313/kW or \$408/ton SO_2 for 100 MWe \$131/kW or \$171/ton SO_2 for 300 MWe \$104/kW or \$136/ton SO_2 for 500 MWe (Costs based on limestone at \$20/ton delivered)

Exhibit ES-2 (continued)
Summary of Results of Completed Environmental Control Technology Projects

Project and Participant	Key Results	Capital Cost
NO_x Control Technology		
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Using LNB alone, NO_x emissions were 0.65 lb/10^6 Btu at full load, representing a 48% reduction from baseline conditions (1.24 lb/10^6 Btu)	Capital cost for a 500-MWe wall-fired unit is $18.80/kW for LNB/AOFA, $8.80/kW for AOFA alone, $10.00/kW for LNB alone, and $0.50/kW for GNOCIS
	Using AOFA only, NO_x reductions of 24% below baseline conditions were achieved under normal long-term operation, depending upon load	Estimated cost of NO_x removal is $86/ton
	Using LNB/AOFA, full load NO_x emissions were approximately 0.40 lb/10^6 Btu, which represents a 68% reduction from baseline conditions	
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)	NO_x reductions of 52% using bituminous coal and 55% using subbituminous coal at full load (110 MWe); 36% and 53%, respectively, at 60 MWe	$66/kW at 110 MWe; $43/kW at 605 MWe (1990$)
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	NO_x reductions of 58% using bituminous coal at full load (605 MWe); 48% at 350 MWe	$9/kW at 600 MWe (1994$)
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	LNB alone (second generation)—37% NO_x reduction; GR-LNB (second generation)—64% NO_x reduction (13% gas heat input)	GR-LNB $26/kW at 300MWe; GR alone $12/kW, plus gas pipeline cost (1996$)
Micronized Coal Reburning Demonstration for NO_x Control (New York State Electric & Gas Corporation)	Using a 14% reburn fuel heat input on the Milliken Station tangentially fired (T-fired) boiler resulted in a NO_x emission rate of 0.25 lb/10^6 Btu, which represents a 28% NO_x reduction	$14/kW at 300 MWe (1999$)
	Using a 17% reburn fuel heat input on the Kodak Park cyclone boiler resulted in a NO_x emission rate of 0.60 lb/10^6 Btu, which represents a 59% NO_x reduction	
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers (Southern Company Services, Inc.)	NO_x reductions of over 80% at ammonia slip well under 5 ppm	Levelized cost at 80% NO_x reduction—2.79 mills/kWh or $2,036/ton of NO_x removed (1996$)
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	NO_x reductions of 37% for LNCFS™ I and II, and 45% for LNCFS™ III, which includes both separated overfire air and close-coupled overfire air	LNCFS I—$5–15/kW (1993$) LNCFS II/III—$15–25/kW (1993$)

Exhibit ES-2 (continued)
Summary of Results of Completed Environmental Control Technology Projects

Project and Participant	Key Results	Capital Cost
Combined SO_2/NO_x Control Technology		
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	NO_x reduction with SCR over 94% at inlet concentrations of 500–700 ppm SO_2 removal efficiency over 95% at inlet concentrations of 2,000 ppm Produced salable sulfuric acid by-product in lieu of waste	\$305/kW at 500 MWe (3.2% sulfur coal) (1995\$)
LIMB Demonstration Project Extension and Coolside Demonstration (McDermott Technology, Inc.)	SO_2 removal efficiency (3.8% sulfur coal, Ca/S molar ratio of 2.0): – LIMB—53–61% for ligno lime, 51–58% for calcitic lime – Coolside—70% for hydrated lime NO_x reduction of 40–50%	LIMB—\$31–102/kW (100–500 MWe) (1992\$) Coolside—\$69–160/kW (100–500 MWe) (1992\$)
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	SO_2 reductions of 80–90% using 3–4% sulfur bituminous coal, depending on sorbent and conditions NO_x reduction of 90% with 0.9 NH_3/NO_x ratio	\$233/kW at 250 MWe (3.5% sulfur coal and inlet NO_x level of 1.2 lb/10^6 Btu) (1994\$)
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	Hennepin—Average NO_x reduction of 67% with 18% gas heat input; SO_2 removal efficiency of 53% at 1.75 Ca/S molar ratio Lakeside—Average NO_x reduction of 66% and SO_2 reductions of 58% during extended continuous combined (GR-SI) runs at 29 MWe, about 22% gas heat input, and 1.8 Ca/S molar ratio	\$15/kW for gas reburning, plus gas pipeline cost (1996\$) \$50/kW for sorbent injection
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	The maximum SO_2 removal demonstrated was 98% with all seven recycle pumps operating and using formic acid. The maximum SO_2 removal without formic acid was 95% Testing of the LNCFS™ III indicated NO_x emissions of 0.39 lb/10^6 Btu (compared to 0.64 lb/10^6 Btu for the original burners), a 36% reduction	\$300/kW at 300 MWe (1998\$) for total capital requirements \$217/kW at 300 MWe for total plant costs and \$83/kW for other related costs \$4,620,000/yr for O&M costs

Exhibit ES-2 (continued)
Summary of Results of Completed Environmental Control Technology Projects

Project and Participant	Key Results	Capital Cost
Combined SO_2/NO_x Control Technology (continued)		
Integrated Dry NO_x/SO_2 Emissions Control System (Public Service Company of Colorado)	NO_x reduction of 62–69% with low-NO_x burners and maximum overfire air (50–110 MWe) NO_x reduction of 63% with low-NO_x burners and minimum overfire air; steady state conditions NO_x reduction decreased by 10–25% under load following SNCR obtained NO_x reduction of 30–50%, thereby increasing total NO_x control system reduction to more than 80% SO_2 removal efficiency of 70% with sodium bicarbonate at normalized stoichiometric ratio of 1.0	\$125/kW at 300 MWe for total capital requirements \$281/kW at 50 MWe for total capital requirements

Exhibit ES-3
Commercial Successes—Environmental Control Technologies

Project	Commercial Use
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	**Sold domestically and internationally.** GSA market entry was significantly enhanced with the sale of a 50-MWe unit, worth $12.5 million, to the city of Hamilton, Ohio, 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. Two GSA systems valued at $1.8 million have been sold to Taiwan Sugar Corporation for their oil-fired cogeneration plant. Furthermore, Taiwan contracted for technical assistance and proprietary equipment valued at $1.0 million. AirPol sold a GSA system valued at $1.5 million to a petroleum coke calciner in India. Negotiations are under way for a GSA system for a waste incinerator in Holland.
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corp.)	**No sales reported.** CZD/FGD can be used to retrofit existing plants or for new installations at a cost of about one-fourth the cost of a commercial wet scrubber.
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	**Sold domestically and internationally.** There are 10 LIFAC units in operation in Canada, China, Finland, Japan, Russia, and the United States, including 5 projects started before the CCT Program. 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 has been retained for commercial use by Richmond Power & Light at Whitewater Valley Station, Unit No. 2.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	**No sales reported.** The AFGD continues in commercial service at Northern Indiana Public Service Company's Bailly Generating Station. Gypsum produced by the PowerChip® process is being sold commercially.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	**Sold internationally.** 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 are operating at 17 plants in 8 countries. Another 5 projects are either in design or construction.
Micronized Coal Reburning Demonstration for NO_x Control (New York State Electric & Gas Corp.)	**No sales reported.** Technology retained for commercial use at Kodak Power Plant.
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)	**No sales reported.** Technology retained for commercial use at Wisconsin Power and Light Company's Nelson Dewy Station
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	**Sold domestically.** Dayton Power & Light has retained the LNCB® for use in commercial service. Seven commercial contracts have been awarded for 172 burners, valued at $27 million. The LNCB® technology has already been installed on more than 4,900 MWe of capacity.
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corp.)	**Sold domestically and internationally.** 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 cyclone coal-fired boilers: TVA's Allen Unit 1 (a 330-MWe unit) as well as Baltimore Gas & Electric's C. P. Crane Units 1 and 2 (similar 200-MWe units). The technology is also installed at Ladyzkin State Power Station in Ladyzkin, Ukraine.

Exhibit ES-3 (continued)
Commercial Successes—Environmental Control Technologies

Project	Commercial Use
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers (Southern Company Services, Inc.)	**Sold domestically and internationally.** Since the project was initiated, revenues from sales achieved \$2.7 billion through 2000, with projected revenues for 2001 and 2002 expected to be \$1.4 billion and \$1.3 billion, respectively.
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	**Sold domestically and internationally.** LNCFS™ has been retained at the host site for commercial use. ABB Combustion Engineering has sold about 56 GWe of LNCFS™ burners. Of this amount, about 23 GWe are equipped with overfire air and 33 GWe are without overfire air. Total sales are estimated at \$1 billion.
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	**Sold domestically and internationally.** The host has retained the technologies for commercial use. Foster Wheeler has equipped 86 boilers (51 domestic and 35 international) with low-NO_x burner technology—a total of over 1,800 burners representing over 30,000 MWe of capacity valued at \$55 million. Twenty-six commercial installations of GNOCIS, the associated AI control system, are underway or planned. This represents over 12,000 MWe of capacity. In a strict sense, this project has not been completed; it has been extended to apply GNOCIS to other pieces of plant equipment, which may increase its commercial potential.
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	**International use.** The host utility, Ohio Edison, is retaining the SNOX™ technology as a permanent part of the pollution control system at Niles Station to help meet its overall SO_2 and NO_x reduction goals. Commercial SNOX™ plants are also 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, in operation since March 1991, has a capacity of about 30 MWe and fires petroleum coke.
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	**Sold domestically and internationally.** LIMB has been sold to an independent power plant in Canada. Babcock & Wilcox has sales of 2,585 burners for 35,310 MWe of capacity for the DRB-XCL® low-NO_x burners. The low-NO_x burners have an estimated value of \$320 million.
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	**No sales reported.** 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, particulate, or combined emissions to meet current performance requirements while providing flexibility to address future needs.
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corp.)	**No sales reported.** Illinois Power has retained the gas-reburning system and City Water, Light & Power has retained the full technology for commercial use. (See Evaluation of Gas Reburning and Low-NO_x Burner on a Wall-Fired Boiler project for a complete understanding of commercial success of the technology.)

Exhibit ES-3 (continued)
Commercial Successes—Environmental Control Technologies

Project	Commercial Use
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corp.)	**Sold domestically.** Eight modules of DHR Technologies' Plant Emissions Optimization Advisor, with an estimated value of $210,000, have been sold. A U.S. company, SHN, has been established to market the S-H-U scrubber. SHN is pursuing an advanced flue gas desulfurization bid for a Pennsylvania site. ABB Combustion Engineering has modified 116 units representing over 25,000 MWe with LNCFS™ or its derivative TFS 2000™.
Integrated Dry NO_x/SO_2 Emissions Control System (Public Service Company of Colorado)	**Sold domestically.** The technology was retained by Public Service Company of Colorado for commercial service at its Arapahoe Station. The Babcock & Wilcox DRB-XCL® burner that was demonstrated has realized sales of 2,428 burners, representing 31,467 MWe. The burners are valued at $240 million.

The second major product line, advanced electric power generation, is subdivided into three groups—(1) fluidized-bed combustion, (2) integrated gasification combined-cycle, and (3) advanced combustion/heat engines. These technologies can be used for repowering existing plants and for new plants.

For fluidized-bed combustion, two approaches were used: atmospheric fluidized-bed combustion and pressurized fluidized-bed combustion. The two AFBC projects use a circulating-bed, as opposed to a bubbling-bed, operating at atmospheric pressure to generate steam for electricity production. One project is complete and the other project is ongoing. There are three PFBC projects in the CCT Program. The completed PFBC project used a bubbling-bed operating at 16 atmospheres to generate steam and drive a gas turbine in a combined-cycle mode. Two interrelated PFBC projects, which are now on hold pending further analysis for generation needs by the participant, will use a circulating-bed operating at 13 atmospheres, in a combined-cycle mode.

The PC-based software tool CQE™ can be used to determine the complete costs of various fuel options by integrating the effects of fuel purchase decisions on power plant performance, emissions, and power generation costs.

During fiscal year 2000, one integrated gasification combined-cycle (IGCC) project successfully completed operations, two IGCC projects were in operation, and a fourth IGCC project was in the design stage. The IGCC projects represent a diversity of gasifier types, cleanup systems, and applications.

Two projects are demonstrating advanced combustion/heat engine technology. One uses an entrained (slagging) combustor, and the other uses a heavy duty diesel fired on a coal-water fuel. One project completed operations in fiscal year 2000 and the other project is ongoing.

A summary of the results of the completed advanced electric power generation projects can be found in Exhibit ES-4. The commercial successes of these projects can be seen in Exhibit ES-5.

For the third major product line, coal processing for clean fuels, there are four projects. Two projects are using chemical and physical processes to transform raw coal into high-energy-density environmentally compliant fuels. Another project is converting coal to methanol from coal-derived synthesis gas. A fourth project in this product line is a software program used to assess the environmental and operational performance of and determine the least-cost option for available coals. Two of the four coal processing for clean fuels projects are complete.

A summary of the results of the completed coal processing for clean fuels projects can be found in Exhibit ES-6. The commercial successes of the coal processing for clean fuels projects can be seen in Exhibit ES-7.

The fourth and final major product line is industrial applications. This product line is addressing the environmental issues and barriers associated with coal use in industry. There are five diverse projects in this category; three are completed and two are ongoing.

A summary of the results of the industrial application projects can be found in Exhibit ES-8. Commercial successes of these projects can be seen in Exhibit ES-9.

Market Communications—Outreach. Outreach has been a hallmark of the CCT Program since it's inception. Commercialization of new technologies requires

Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)—1996 Powerplant Award presented by *Power* magazine.

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit Project (The Babcock & Wilcox Company)—1994 R&D 100 Award presented by *R&D* magazine.

Exhibit ES-4
Summary of Results of Completed Advanced Electric Power Generation Projects

Project and Participant	Key Results	Capital Cost
Tidd PFBC Demonstration Project (The Ohio Power Company)	SO_2 reduction of 90–95% (Ohio bituminous coal, 2–4% sulfur) at 1.1–1.5 Ca/S molar ratio NO_x emissions of 0.15–0.33 lb/10^6 Btu Particulate emissions of 0.02 lb/10^6 Btu Heat rate—10,280 Btu/kWh Combustion efficiency—99.6% Commercially viable design Gas turbine operable in PFBC environment	$1,263/kW at 360 MWe (1997$)
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	SO_2 reduction of 70–95% (up to 1.8% sulfur coal), depending on Ca/S molar ratio NO_x emissions of 0.18 lb/10^6 Btu Particulate emissions of 0.0072–0.0125 lb/10^6 Btu Heat rate—11,600 Btu/kWh Combustion efficiency—96.9–98.9% Commercial viability established	Approximately $1,123/net kW (repowering cost) (1990$)
Healy Clean Coal Project (Arthur D. Little, Inc.)	SO_2 reduction in excess of 90% (Usibelli subbituminous 50% run-of-mine and 50% waste coal) at 1.4–1.8 Ca/S molar ratio NO_x emissions of 0.208–0.278 lb/10^6 Btu Particulate emissions of 0.0047 lb/10^6 Btu Greater than 99% carbon burnout at 100% maximum continuous rating	Economic data are not yet available

Exhibit ES-5
Commercial Successes—Advanced Electric Power Generation Technologies

Project	Commercial Use
Tidd PFBC Demonstration Project (The Ohio Power Company)	**Sold internationally.** Success of the project has led Babcock & Wilcox to invest in the technology and acquire domestic licensing rights. Commercial ventures abroad include the following: – Vartan Sweden is operating two P200 units to produce 135 MWe and 224 MWth – Escatron in Spain is operating one P200 unit producing 80 MWe – Wakamatsu in Japan is operating one P200 unit to produce 71 MWe – Cottbus in Germany is operating one P200 unit to produce 71 MWe and 40 MWth – Karita in Japan operates one P800 unit to produce 360 MWe – Other projects under construction are in China, South Korea, U.K., and Israel
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	**Sold domestically and internationally.** Since the demonstration, Foster Wheeler Energy Corporation, the technology supplier for the demonstration effort, has achieved sales of $7.9 billion through 2000, with another $2.7 billion in sales projected for 2001 through 2003. Twenty-one percent of the sales through 2000 were domestic, while the remaining sales through 2000 were foreign.
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	**Sold domestically and internationally.** First greenfield IGCC unit in commercial service. Texaco, Inc., and ASEA Brown Boveri signed an agreement forming an alliance to market IGCC technology in Europe. There are currently 10 projects using a Texaco gasifier that are either planned or under construction.
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	**No sales reported.** First repowered IGCC unit in commercial service and world's largest single train IGCC in commercial service. Preferentially dispatched over other coal-fired units in PSI Energy's system because of high efficiency.
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	**No sales reported.** TRW offering licensing of combustor worldwide (China agreement in place).

Exhibit ES-6
Summary of Results of Completed Coal Processing for Clean Fuels Projects

Project and Participant	Key Results	Capital Cost
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ Inc.)	CQE™ features: - Fuel evaluator—performs system-, plant-, and/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	CQE™ package sells for between $75,000 and $100,000
ENCOAL® Mild Gasification Project (ENCOAL Corporation)	The liquid (CDL®) and solid (PDF®) product fuels have been used economically in commercial boilers and furnaces and have reduced SO_2 and NO_x emissions significantly at utility and industrial facilities currently burning high-sulfur bituminous coal or fuel oils Almost five years of operating data have been collected for use as a basis for the evaluation and design of a commercial plant About 260,000 tons of coal had been processed into 120,000 tons of PDF® and 5,101,000 gallons of CDL®	A commercial plant designed to process 15,000 metric-ton/day would cost $475 million (2001$) to construct with annual operating and maintenance costs of $52 million per year

Exhibit ES-7
Commercial Successes—Coal Processing for Clean Fuels Technologies

Project	Commercial Use
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ Inc.)	**Sold domestically and internationally.** The Electric Power Research Institute (EPRI) owns the software and distributes it to EPRI members for their use. CQ Inc. and Black and Veatch have signed commercialization agreements that give both companies nonexclusive worldwide rights to sell user licenses and offer consulting services that include use of CQE®. More than 22 U.S. utilities, two United Kingdom utilities, and one French utility have received CQE® through EPRI membership. Two modules of the Acid Rain Advisor valued at $6,000 have been sold. EPRI estimated that the Acid Rain Advisor saved one U.S. utility about $26 million, more than the total cost of the demonstration project. There have been two sales of the Windows version of the software at an estimated value of $180,000.
ENCOAL® Mild Coal Gasification Project (ENCOAL Corporation)	**Domestic and international sales pending.** In order to determine the viability of potential LFC® plants, five detailed commercial feasibility studies—two Indonesian, one Russian, and two U.S. projects—have been completed. Permitting of a 15,000 metric-ton/day commercial plant in Wyoming is nearly complete.
Advanced Coal Conversion Process Demonstration (Western SynCoal LLC)	**No sales reported.** Total sales of SynCoal® product exceed 1.5 million tons. Six long-term agreements are in place to purchase the product. One domestic and five international projects have been investigated. Western SynCoal LLC has a joint marketing agreement with Ube Industries of Japan providing Ube non-exclusive marketing rights outside of the United States. Ube is pursuing several projects in Asia. Western SynCoal is also discussing a potential marketing and development agreement with a U.S. engineering firm.
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company , L.P.)	**No sales reported.** Nominal 80,000 gallon/day methanol production being used by Eastman Chemical Company

Exhibit ES-8
Summary of Results of Completed Industrial Application Projects

Project and Participant	Key Results	Capital Cost
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	SO_2 reduction of 58% with limestone injection in the combustor at 2.0 Ca/S molar ratio NO_x emissions of 160–184 ppm (75% reduction) Slag/sorbent retention of 55–90% in combustor; inert slag	Not available
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	SO_2 reduction of 90–95% (2.5–3% sulfur bituminous coal); 98% maximum reduction NO_x reduction of 18.8% avg Particulate emissions of 0.005–0.007 gr/std ft^3 with loading of 0.04 gr/std ft^3	\$10 million for 450,000 ton/yr wet-process plant (1990\$)
Blast Furnace Granular-Coal Injection Demonstration Project (Bethlehem Steel Corporation)	The low-volatile, low-ash coal displaced up to 0.96 pounds of coke for every pound of coal No increase in sulfur emissions Sulfur levels in product remained within specified limits	\$15 million for a single blast furnace producing 7,200 net tons of hot metal per day

Exhibit ES-9
Commercial Successes—Industrial Application Technologies

Project	Commercial Use
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	**No sales reported.** 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.
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	**No sales reported.** 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.
Blast Furnace Granular-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	**Domestic sale.** British Steel's Blast Furnace Granular Coal Injection System was sold and installed on a facility owned by United States Steel Corporation.

acceptance by a wide range of interests—customers, manufacturers, suppliers, financiers, government, and public interest groups. The CCT Program has aggressively sought to disseminate key information to this full range of customers and stakeholders and to obtain feedback on changing needs. This dissemination of information takes the form of printed media, exhibits, and electronic media. Printed media consist of newsletters, proceedings, technical papers, fact sheets, program updates, and bibliographies. The CCT Program currently uses four traveling exhibits of varying sizes and complexity that can be updated and tailored to specific forums. A fifth exhibit is being developed to replace an older exhibit that will be retired. Electronic media are available through the World Wide Web.

Feedback is another important part of the outreach effort. From public meetings during the PON process to open houses at demonstration sites, the CCT Program stays in contact with customers and stakeholders. Executive seminars, stakeholder meetings, conferences, workshops, and trade missions are used by the CCT Program to disseminate information and obtain feedback.

Several domestic and international conferences and workshops were attended or sponsored in fiscal year 2000. The forums for conferences varied from Slovakia to Japan. Trade missions during fiscal year 2000 included South Africa and India. The Department of Energy also provided support for the Foreign Service Training Course. All of these events were used to endorse and promote the technologies demonstrated in the CCT Program.

CCT Projects

Technology Overview. The 38 CCT Program projects 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.

Environmental Control Devices. The environmental control technologies provide a suite of cost-effective control options for the full range of boiler types. The 17 environmental control device projects are valued at $620 million. These include seven NO_x emission control systems installed in more than 1,750 MWe of utility generating capacity, five SO_2 emission control systems installed on approximately 770 MWe, and six combined SO_2/NO_x emission control systems installed or planned for installation on more than 665 MWe of capacity.

Advanced Electric Power Generation. To respond to load growth, as well as growing environmental concerns, the CCT 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 particulate emissions far below 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 $2.8 billion. 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.

Coal Processing for Clean Fuels. Also addressed are approaches to converting run-of-mine coals to high-energy-density, low-sulfur products. These products have application domestically for compliance with the CAAA. Internationally, both the products and processes have excellent market potential. Valued at almost $432 million, the four projects in the coal processing for clean fuels category represent a diversified portfolio of technologies.

Industrial Processes. Projects were undertaken as well to address pollution problems associated with coal use in the industrial sector. The problems addressed include dependence of the steel industry on coke and the pollutant emissions inherent 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. The 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; demonstration of an industrial-scale slagging combustor; and demonstration of a pulse combustor system.

Project Fact Sheets. The core of this *Program Update 2000* is the project fact sheets. Two types of fact 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 latter contains a summary of the major results from the demonstrations, as well as sources for obtaining further information. Technology descriptions, costs, and schedules are provided for all projects. A list of the projects with the participant, solicitation, and status is shown in Exhibit ES-10. A list of the award-winning CCT Program projects is shown in Exhibit ES-11.

Exhibit ES-10
Project Fact Sheets by Application Category

Shaded area indicates projects having completed operations.

Exhibit ES-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	5-106
Nucla CFB Demonstration Project	Tri-State Generation and Transmission Association, Inc.	CCT-I/completed 1/91	5-110
Integrated Gasification Combined-Cycle			
Kentucky Pioneer Energy IGCC Demonstration Project	Kentucky Pioneer Energy, LLC	CCT-V/design	5-116
Piñon Pine IGCC Power Project	Sierra Pacific Power Company	CCT-IV/operational	5-118
Tampa Electric Integrated Gasification Combined-Cycle Project	Tampa Electric Company	CCT-III/operational	5-120
Wabash River Coal Gasification Repowering Project	Wabash River Coal Gasification Repowering Project Joint Venture	CCT-IV/completed 12/99	5-122
Advanced Combustion/Heat Engines			
Clean Coal Diesel Demonstration Project	Arthur D. Little, Inc.	CCT-V/construction	5-128
Healy Clean Coal Project	Alaska Industrial Development and Export Authority	CCT-III/completed 12/99	5-130
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	5-136
Advanced Coal Conversion Process Demonstration	Western SynCoal LLC	CCT-I/operational	5-138
Development of the Coal Quality Expert™	ABB Combustion Engineering, Inc. and CQ Inc.	CCT-I/completed 12/95	5-140
ENCOAL® Mild Coal Gasification Project	ENCOAL Corporation	CCT-III/completed 7/97	5-144
Industrial Applications			
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	CPICOR™ Management Company LLC	CCT-V/design	5-150
Pulse Combustor Design Qualification Test	ThermoChem, Inc.	CCT-IV/construction	5-152
Blast Furnace Granular-Coal Injection System Demonstration Project	Bethlehem Steel Corporation	CCT-III/completed 11/98	5-154
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Coal Tech Corporation	CCT-I/completed 5/90	5-158
Cement Kiln Flue Gas Recovery Scrubber	Passamaquoddy Tribe	CCT-II/completed 9/93	5-162

Shaded area indicates projects having completed operations.

Exhibit ES-11
Award-Winning CCT Projects

Project and Participant	Award
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	1994 R&D 100 Award presented by *R&D* magazine to the U.S. Department of Energy for development of the low-NO_x cell burner.
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler; Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	1997 J. Deanne Sensenbaugh Award presented by the Air and Waste Management Association to the U.S. Department of Energy, Gas Research Institute, and U.S. Environmental Protection Agency for the development and commercialization of gas-reburning technology.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	1993 Powerplant Award presented by *Power* magazine to Northern Indiana Public Service Company's Bailly Generating Station.
	1992 Outstanding Engineering Achievement Award presented by the National Society of Professional Engineers.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	1995 Design Award presented by the Society of Plastics Industries in recognition of the mist eliminator.
	1994 Powerplant Award presented by *Power* magazine to Georgia Power's Plant Yates. Co-recipient was the U.S. Department of Energy.
	1994 Outstanding Achievement Award presented by the Georgia Chapter of the Air and Waste Management Association.
	1993 Environmental Award presented by the Georgia Chamber of Commerce.
Tidd PFBC Demonstration Project (The Ohio Power Company)	1992 National Energy Resource Organization award for demonstration of energy-efficient technology.
	1991 Powerplant Award presented by *Power* magazine to American Electric Power Company's Tidd project. Co-recipient was The Babcock & Wilcox Company.
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	1997 Powerplant Award presented by *Power* magazine to Tampa Electric's Polk Power Station.
	1996 Association of Builders and Contractors Award presented to Tampa Electric for quality of construction.
	1993 Ecological Society of America Corporate Award presented to Tampa Electric for its innovative siting process.
	1993 Timer Powers Conflict Resolution Award presented to Tampa Electric by the state of Florida for the innovative siting process.
	1991 Florida Audubon Society Corporate Award presented to Tampa Electric for the innovative siting process.
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	1996 Powerplant Award presented by *Power* magazine to CINergy Corp./PSI Energy, Inc.
	1996 Engineering Excellence Award presented to Sargent & Lundy upon winning the 1996 American Consulting Engineers Council competition.
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ Inc.)	In 1996 recognized by then Secretary of Energy Hazel O'Leary and EPRI President Richard Balzhiser as the best of nine DOE/EPRI cost-shared utility R&D projects under the Sustainable Electric Partnership Program.

Benefits Legacy

The CCT Program, in conjunction with other government-sponsored coal research, development, and demonstration (RD&D) projects and partnerships, has resulted in a broad range of environmental and economic benefits. DOE efforts to advance coal technologies prior to the CCT Program, through the CCT Program, and via ongoing RD&D programs have been highly complementary and successful. Close-working relationships between government and industry have accelerated market entry of the advanced technologies emerging from these collaborative efforts, as well as the realization of the related benefits. Exhibit ES-12 summarizes some of the benefits derived from the CCT Program, associated RD&D partnerships, and the resultant technologies.

Exhibit ES-12
Benefits Legacy from CCT Program and Associated RD&D

NO_x Control Technologies

- 75% of existing U.S. coal-fired units have been or currently are being retrofitted with low-NO_x burners.
- $1.3 billion in commercial foreign and domestic sales of low-NO_x burners have been realized.
- A 50% reduction in SCR costs has resulted since 1980.
- An estimated 30% of U.S. coal-fired generating capacity will incorporate SCR technology by 2004.
- Over 60 million tons of NO_x emissions have been avoided since 1970 based on average fleet emissions.

SO_2 Control Technologies

- A 30% reduction in FGD costs has resulted since the early 1990s.
- An estimated 30% of U.S. coal-fired generating capacity will incorporate FGD technology by 2002.
- 127 million tons of SO_2 emissions have been avoided since 1970 as a result of FGD installations.

Fluidized-Bed Combustion Technologies

- Well over 100 domestic and more than 400 overseas industrial and utility FBCs are in operation.
- Since the CCT demonstrations, at least 29 units greater than 100 MWe have been sold, representing over 6,000 MWe of capacity valued at over $6 billion.
- FBCs offer inherently low NO_x emissions, high combustion and SO_2 capture efficiency, and extreme fuel flexibility—e.g., six FBCs in Pennsylvania are using coal waste as fuel, eliminating an environmental problem, saving $1 billion in fuel costs, and avoiding 1.8 million tons of NO_x emissions over their life.

Integrated Gasification Combined Cycle Technologies

- Over 5,600 MWe of IGCC, designed for a multiplicity of fuels, is in operation or in design, 1,500 MWe of which is coal-fired and in operation.
- 16,500 MWe of IGCC is expected to be operating in the United States by 2020.
- The more than 1,100 MWe of CCT demonstration unit capacity will avoid an estimated 224,000 tons of SO_2 and 312,000 tons of NO_x over the life of the units.

Life-Cycle Cost Savings to Industry and the Public for Near-Term Deployment

- Lower capital and operating costs for advanced power plants and NO_x and SO_2 pollution control systems equate to $23 billion.
- Lower compliance costs for air toxics and solid waste, through technology development, is estimated at $70 billion.
- Market value of SO_2 and NO_x reduction is estimated at $10 billion.
- Improved waste characterization and advances in waste recovery are estimated to result in a $25 billion cost benefit.

1. Role of the CCT Program

Introduction

Over the past quarter century, both nationally and internationally the energy picture has been one of dynamic change. These include the oil embargoes of the 1970s and the environmental debates of the 1980s. The 1990s brought about more changes in response to required emission reductions for acid rain precursors, initiation of more stringent NO_x standards for ozone nonattainment areas, tighter standards on fine particulates, the beginning of electric utility restructuring, and concern about global warming.

Upon entering the 21st century, the immediate challenge is to meet escalating domestic demands for electric power and to assuage associated electricity delivery reliability concerns. This challenge comes at a time when natural gas prices are extremely volatile and environmental regulations are increasingly stringent.

The Clean Coal Technology Demonstration Program (CCT Program), begun in fiscal year 1985, has largely responded to the dynamic changes experienced through the 1990s. Adjustments were enabled by spacing a series of five competitive solicitations from 1986 to 1992. The CCT Program has provided a strong foundation for responding to the challenges now emerging in the energy market.

The CCT Program is implemented through a unique cost-shared government/industry partnership that allows each party to best apply their expertise and carry out appropriate roles. The magnitude of the projects and extent of industry participation in the CCT Program is unprecedented. More than $5.2 billion is being expended, with industry and state governments investing two dollars for every federal government dollar invested. With 66 percent of the projects having completed operations by the end of fiscal year 2000, the technological successes have manifested themselves in the marketplace. New technologies to reduce the emissions of acid rain precursors, namely sulfur dioxide (SO_2) and nitrogen oxides (NO_x), are now in the marketplace and are being used by electric power producers and heavy industry. Advanced electric power generation systems that generate electricity with greater efficiency and fewer environmental consequences are now operating with the nation's most plentiful fossil energy resource—coal. Coal, which accounts for over 94 percent of the proven fossil energy reserves in the United States, supplies the bulk of the low-cost, reliable electricity vital to the nation's economy and global competitiveness. According to the U.S. Department of Energy's (DOE) Energy Information Administration (EIA) *Annual Energy Review 1999* (July 2000) (*AER1999*), 944 million tons of coal were used to produce over 1,890 billion kilowatt-hours or 51 percent of the nation's electricity in 1999. EIA projections count on coal continuing to dominate electric power production, at least through 2020 (the end of the forecast period). In the *Annual Energy Outlook 2001* (December 2000) (*AEO2001*), EIA estimates 1,186 million tons of coal will generate an estimated 2,350 billion kilowatt-hours or 44 percent of all electricity generated in 2020.

The ability of coal and coal technologies to respond to the nation's need for low-cost, reliable electricity hinges on the ability to meet two central requirements: (1) environmental performance requirements established in current and emerging laws and regulations, and (2) operational and economic performance requirements consistent with competition in the era of utility restructuring. The CCT Program is responding to these requirements by producing a portfolio of advanced coal-based technologies that will enable coal to retain its prominent role in the nation's power generation future. Furthermore, advanced technologies emerging from the CCT Program will also enhance coal's competitive position in the industrial sector. For example, technology advances in steel making, involving direct use of coal, will reduce the cost of production while greatly improving environmental performance. Also, coal could increase its market share in the industrial sector through cogeneration (steam and electricity) and coproduction of products (clean fuels and chemicals).

While the CCT Program responds to domestic needs for competitive and clean coal-based technology, it also positions U.S. industry to compete in a burgeoning power market abroad. Electricity continues to be the most rapidly growing form of energy consumption in the world. Projections from EIA's *International Energy Outlook 2000* (March 2000) (*IEO2000*) show electricity demand rising from 12 trillion kilowatt-hours in 1997 to 22 trillion kilowatt-hours in 2020. The strongest growth is projected for the coal-dependent developing countries of Asia. This growth not only represents a tremendous market opportunity, but an opportunity to make a reduction in global carbon emissions through the application of highly efficient clean coal technologies.

CCT Program Evolution

The environmentally sound and competitive performance of modern coal technologies has evolved through many years of industry and government research, development, and demonstration (RD&D). The programs were pursued to assure that the U.S. recoverable coal reserves of 274 billion tons, which represent a secure, low-cost energy source, could continue to supply the nation's energy needs economically and in an environmentally acceptable manner.

During the 1970s and early 1980s, many of the government-sponsored technology demonstrations focused on synthetic fuels production technology. Under the Energy Security Act of 1980, the Synthetic Fuels Corporation (SFC) was established for the purpose of reducing the U.S. vulnerability to disruptions of crude oil imports.

The SFC's purpose was accomplished by encouraging the private sector to build and operate synthetic fuel production facilities that would use abundant domestic energy resources, primarily coal and oil shale. The strategy was for the SFC to be primarily a financier of pioneer commercial and near-commercial scale facilities. The goal of the SFC was to achieve production capacities of 500,000 barrels per day of synthetic fuels by 1987 and 2 million barrels per day by 1992, at an estimated cost of $8.8 billion.

By 1985, the market drivers for synthetic fuels dissolved as oil prices declined, world oil supplies stabilized, and a short-term supply buffer was provided by the Strategic Petroleum Reserve. In 1986, Congress responded to the decline of private-sector interest in the production of synthetic fuels in light of these market conditions. Public Law 99-190, Department of the Interior and Related Agencies Appropriations Act for Fiscal Year 1986, abolished the SFC and transferred project management to the Treasury Department.

The CCT Program was initiated in October 1984. Public Law 98-473, Joint Resolution Making Continuing Appropriation for Fiscal Year 1985 and Other Purposes, provided $750 million from the Energy Security Reserve to be deposited in a separate account in the U.S. Treasury entitled The Clean Coal Technology Reserve. The nation moved from an energy policy based on synthetic fuels production to a more balanced policy. This policy established that the nation should have an adequate supply of energy, maintained at a reasonable cost, and consistent with environmental, health, and safety objectives. Energy stability, security, and strength were the foundations for this policy. Coal was recognized as an essential element in this energy policy for the foreseeable future because of the following:

- The location, magnitude, and characteristics of the coal resource base are well understood.
- The technology and skilled labor base to safely and economically extract, transport, and use coal are available.
- A multi-billion dollar infrastructure is in place to gather, transport, and deliver this valuable energy commodity to serve the domestic and international marketplace.
- Coal is used to produce over half of the nation's electric power and is vital to industrial processes, such as steel and cement production, as well as industrial power.
- This abundant fossil energy resource is secure within the nation's borders and relatively invulnerable to disruptions because the coal industry's production is dispersed and flexible, the delivery network is vast, and the stockpiling capability is great.
- Coal is the fuel of necessity in many lesser developed economies, which provides export opportunities for U.S.-developed, coal-based technologies.

Congress recognized that the continued viability of coal as a source of energy was dependent on the demonstration and commercial application of a new generation of advanced coal-based technologies characterized by enhanced operational, economic, and environmental performance. The CCT Program was established to demonstrate the commercial feasibility of clean coal technology applications in response to that need. In 1986, DOE issued the first solicitation (CCT-I) for clean coal technology projects. The CCT-I solicitation resulted in a broad range of projects being selected in four major product markets—environmental control devices, advanced electric power generation, coal processing for clean fuels, and industrial applications.

In 1987, the CCT Program became the centerpiece for satisfying the recommendations contained in the *Joint Report of the Special Envoys on Acid Rain* (1986). A Presidential initiative launched a five-year, $5-billion U.S. government/industry effort to curb precursors to acid rain formation—SO_2 and NO_x. Thus, the second solicitation (CCT-II), issued in February 1988, provided for the demonstration of technologies that were capable of achieving significant emission reductions in SO_2, NO_x, or both, from existing power plants. These technologies were to be more cost-effective than current technologies and capable of commercial deployment in the 1990s. In May 1989, DOE issued a third solicitation (CCT-III) with essentially the same objective as the second, but additionally encouraged technologies that would produce clean fuels from run-of-mine coal.

The next two solicitations recognized emerging energy and environmental issues, such as global climate change and capping of SO_2 emissions, and thus focused on seeking highly efficient, economically competitive, and low-emission technologies. Specifically, the fourth solicitation (CCT-IV), released in January 1991, had as its objective the demonstration of energy-efficient, economically competitive technologies capable of retrofitting, repowering, or replacing existing facilities while achieving significant reductions in SO_2 and NO_x emissions. In July 1992, DOE issued the fifth and final solicitation (CCT-V) to provide for demonstration projects that significantly advanced the efficiency and environmental performance of technologies applicable to new or existing facilities. As a result of these five solicitations, a total of 60 government/industry cost-shared projects were selected, of which 38, valued at more than $5.2 billion, have either been successfully completed or remain active in the CCT Program.

The success of the government/industry CCT Program is directly attributable to the CCT Program's responsiveness to public and private sector needs to reduce environmental emissions and maximize economic and efficient energy production. The CCT Program is strengthening the economy, enhancing energy security, and reducing the vulnerability of the economy to global energy market shocks.

Environmental Impetus

SO_2 Regulation

Acid Rain Mitigation. During the late 1980s, work began on drafting what was to become the Clean Air Act Amendments of 1990 (CAAA). On November 15, 1990, Congress enacted the CAAA as Public Law 101-549. Title IV, Acid Deposition Control, established emissions-reduction targets for SO_2 and capped SO_2 emission in the post-2000 time frame. Title IV is the first large-scale approach to regulating overall emissions levels by using marketable allowances. The utilities can adopt a control strategy that is most cost-effective for their given systems and plants rather than having to apply a "command-and-control" approach wherein the emission-reduction method is specified.

The emission-reduction requirements for SO_2 were instituted in two phases. Phase I provided for the initial increment of SO_2 reduction, beginning on January 1, 1995. Phase II began on January 1, 2000. Title IV identified 261 generating units (designated as "affected units") that were required to comply with Phase I. Most of these are coal-fired units with fairly high emission rates. Exhibit 1-1 summarizes the compliance methods used by the 261 affected units listed in Title IV to satisfy Phase I requirements. An additional 174 units participated in Phase I based on U.S. Environmental Protection Agency (EPA) rules that allow a utility to designate substitution or compensating units as part of Phase I compliance strategies. Therefore, 435 units are considered Phase I units. Under Phase II, the remaining 2,500 boilers at 1,000 plants are affected.

As a result of Phase I, SO_2 emissions at electric utilities declined from 15.6 million tons per year in 1990 to 12.5 million tons per year in 1997, a 20 percent decline. As shown in Exhibit 1-1, switching to low-sulfur coal was the option chosen by more than half of the owners of Phase I-affected units.

Exhibit 1-1
Phase I SO_2 Compliance Methods

Method	No. of Units	% of Units	% SO_2 Reduction from 1985 Baseline	% of Total SO_2 Reduction
Fuel switching/blending	136	52	60	59
Additional SO_2 allowances	83	32	16	9[a]
Scrubbers	27	10	83	28
Retirements	7	3	100	2
Other[b]	8	3	86	2
Total	261	100	345	100

[a] Includes reduced coal consumption of 2.5 million tons and 16% reduction in sulfur content.
[b] Includes 1 repowered unit, 2 switched to natural gas, and 5 switched to No. 6 fuel oil. Source: *The Effects of Title IV of the Clean Air Act Amendments of 1990 on Electric Utilities: An Update*, Energy Information Administration, March 1997.

In Phase II, all existing boilers must meet SO_2 emission levels of 1.2 lb/10^6 Btu and a sliding-scale percent reduction of 70 to 90 percent, depending upon the input sulfur content. The resultant SO_2 emission levels are generally 0.3 lb/10^6 Btu for low-sulfur coals and 0.6 lb/10^6 Btu for high-sulfur coals. Moreover, the CAAA calls for SO_2 emissions to be limited to 9.48 million tons per year between 2000 and 2009 and 8.95 million tons per year thereafter. EIA predicts that 11 GWe of capacity will be retrofitted with scrubbers to meet the Phase II goals.

Several projects within the CCT Program, listed below, were designated affected units and were required to achieve compliance with Phase I requirements:

- Northern Indiana Public Service Company's Bailly Generating Station, 528-MWe Units Nos. 7 and 8 (Pure Air advanced flue gas desulfurization scrubber);
- Georgia Power Company's Plant Yates, 100-MWe Unit No. 1 (Chiyoda Thoroughbred-121 advanced flue gas desulfurization scrubber);
- New York State Electric & Gas Corporation's Milliken Station, 300-MWe Unit Nos. 1 and 2 (S-H-U formic-acid-enhanced wet limestone scrubber); and
- PSI Energy's Wabash River Station, 262-MWe Unit No. 1 (repowered with Destec integrated gasification combined-cycle unit).

The three Phase I scrubber projects served to redefine the state-of-the-art in wet limestone scrubber technology and the other was the first to introduce integrated gasification combined-cycle as a repowering technology. The advanced scrubbers essentially halved the cost of conventional scrubbers of the time. The repowering project represented an option provided under the CAAA that allows a four-year extension (to December 31, 2003) for compliance with Phase II requirements when advanced electric power generation technology is applied. Together with the other projects, the CCT Program has afforded a portfolio of SO_2 compliance options for the diverse fleet of existing coal-fired electric generating units and the means to meet future energy and environmental demands. These include advanced scrubbers, low-capital-cost sorbent injection systems, clean high-energy-density fuels from both eastern and western coals, and a range of advanced electric power generation systems.

NO_x Regulation

Acid Rain Mitigation. In Title IV of the CAAA, Congress also required the EPA to establish annual allowable emissions limitations for NO_x in two phases. Phase I required NO_x reductions from tangentially fired and dry-bottom wall-fired boilers. These boilers are referred to as Group 1 boilers. In March 1994, EPA promulgated a rule establishing NO_x emission limitations of 0.45 lb/10^6 Btu for tangentially fired units and 0.50 lb/10^6 Btu for wall-fired units. Ultimately, a compliance date of January 1, 1996, was established.

On December 19, 1996, EPA issued a rule to implement Phase II. The rule established NO_x emission limitations for additional coal-fired boilers (Group 2) and reduced the NO_x emissions limitations on Group 1 boilers. The types of Group 1 and 2 boilers and the Phase I and II NO_x emission limits are shown in Exhibit 1-2.

In response to the need to formulate NO_x emission reductions that were realistic and achievable for Group 1, EPA was able to use data developed during the Southern Company Services' evaluation of NO_x control technologies on wall-fired and tangentially fired boilers. Furthermore, NO_x controls were developed under the CCT Program for all five major boiler types (wall-fired, tangentially fired, cyclone-fired, cell-burner, and vertically fired), which constitute over 99

Exhibit 1-2
CAAA NO_x Emission Limits

Group 1 Boiler Type	Group 2 Boiler Type	Phase I NO_x Emission Limits[a] (lb/10^6Btu)	Phase II NO_x Emission Limits[a] (lb/10^6 Btu)
Tangentially fired boilers		0.45	0.40
Dry-bottom wall-fired boilers[b]		0.50	0.46
	Cell-burner boilers		0.68
	Cyclone boiler >155 MWe		0.86
	Wet-bottom wall-fired boilers >65 MWe		0.84
	Vertically fired boilers		0.80

[a]Emission limits are lb/10^6Btu of heat input on an annual average basis.

[b]Other than units applying cell-burner technology.

percent of the pre-New Source Performance Standard (NSPS) boiler types. Low-NO_x burners were developed for all boiler types amenable to burner modification. As a result, nearly half of the pre-NSPS boilers are equipped with low-NO_x burners (LNB). The CCT Program also demonstrated a range of NO_x control techniques to address boilers where burner modification is not practical and to provide methods to enhance NO_x control beyond low-NO_x burner capability. These options included coal and gas reburning, selective noncatalytic reduction (SNCR), and selective catalytic reduction (SCR). This portfolio of NO_x controls not only will assure that Phase I and II emission reductions are achievable, but will provide the technology base necessary to achieve even greater NO_x reductions required to meet new National Ambient Air Quality Standards (NAAQS) for ozone and fine particulate matter under Title I of the CAAA.

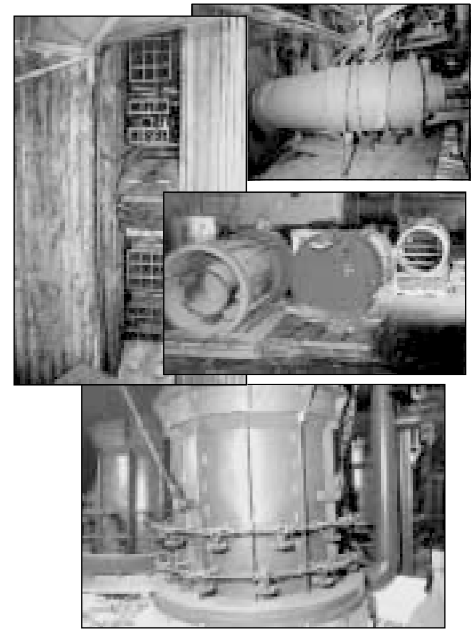
Soot and Smog. In July 1997, under Title I of the CAAA, EPA issued final rules revising the primary and secondary NAAQS for particulate matter (PM) and ozone (O_3) (commonly referred to as "soot and smog" regulations).

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.

The soot provisions addressed ambient air concentrations of particulate matter in the respirable range of 2.5 micrometers (microns) in diameter or less ($PM_{2.5}$). Previous fine particulate standards dealt with airborne material in the inhalable range of 10 microns in diameter or less (PM_{10}). The $PM_{2.5}$ standard affects primary sources such as fly ash, carbon soot, and acid mists (aerosols) and secondary sources such as ammonium sulfates and nitrates from precursor SO_2 and NO_x gases. Monitoring to ascertain $PM_{2.5}$ attainment is ongoing, with designations of non-attainment expected by 2003–2004. State Implementation Plans (SIPs) for compliance are expected by 2007–2008, with compliance by 2013–2014.

The ozone standards in turn impact NO_x emissions because NO_x is a precursor to ozone formation. As an interim measure, EPA issued a rulemaking in response to recommendations of a 37-state Ozone Transport Assessment Group (OTAG). The rulemaking, in the form of a "SIP Call," requires 22 eastern states and the District of Columbia to reduce NO_x emissions according to specified amounts (budgets) by May 2003. The expected emission limits for power plants is 0.15 lb/10^6 Btu, which generally requires relatively expensive selective catalytic reduction (SCR) technology. Under the general provisions of the ozone NAAQS provisions, SIPs are expected by 2003, with compliance ranging from 2003–2018 depending on the air quality in a particular area.

The EPA is also formulating a plan for utilities and industries to trade allowances for NO_x emissions. The "cap and trade" program would apply to the 23 jurisdictions affected by the SIP Call. Under the plan, the affected jurisdictions would establish a cap on NO_x emissions and then give power plants and industries the flexibility to cut NO_x emissions in the most cost-effective manner. Power plants and industries that cut NO_x emissions below the caps could sell credits to facilities that could not cut emissions as quickly or cost-effectively. The NO_x trading program, similar to the existing SO_2 trading program, allows sources to pursue various compliance strategies, such as fuel switching; installing pollution control devices, like the devices demonstrated in the CCT Program; or buying allowances from sources that over-complied.

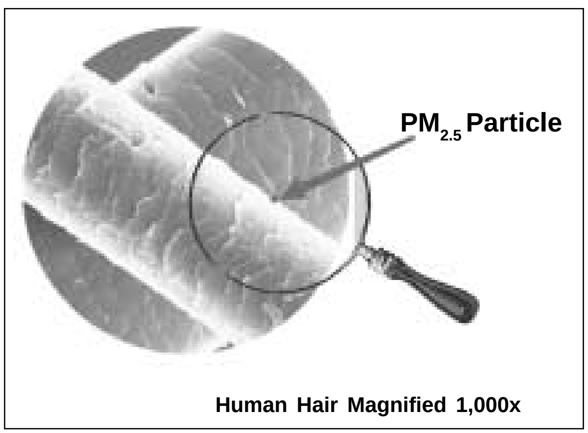


Low-NO_x burner technologies: ABB Combustion Engineering's LNCFS™ for tangentially fired boilers (top left), Foster Wheeler's low-NO_x burner for wall-fired boilers (top right), Babcock & Wilcox's LNCB® for cell-burner boilers (center), and Babcock & Wilcox's DRB-XCL® for down-fired boilers (bottom).

New Source Performance Standards. On the national level, the EPA has tightened its NO_x emission standards for new electric utility boilers and has changed its rules so that all generation fuels are treated the same. Under the revised New Source Performance Standard (NSPS), electric utility and industrial steam generating units built or modified after July 9, 1997, must meet an emission limit of 1.6 lb/MWh regardless of fuel type. However, under EPA's so-called "WEPCO Rule" existing units may be subject to NSPS as a result of certain modifications. By basing the standard on electricity output, there is an economic incentive to use more efficient systems.

Hazardous Air Pollutants

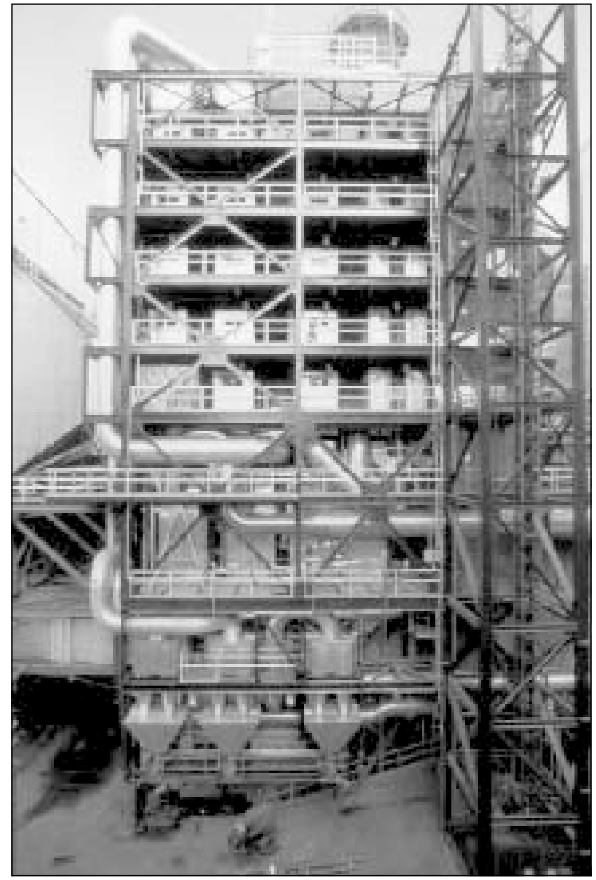
Hazardous Air Pollutant Monitoring. Under Title III of the CAAA, EPA is responsible for determining the hazards to public health posed by 189 hazardous air pollutants (HAPs), and is required to perform a study of HAPs to determine the public health risks that are likely to occur as a result of power plant emissions. To address this issue, DOE implemented a program with industry to monitor HAPs emissions at CCT Program project sites. Objectives of the HAPs monitoring are to (1) improve the quality of HAPs data being gathered, and (2) monitor a broader range of plant configurations and emissions control equipment. As a result of this program, 20 CCT projects are monitoring HAPs, with 13 having completed monitoring by September 2000 (see Appendix C, Exhibit C-7).



This picture illustrates how minute $PM_{2.5}$ particles are when compared to a human hair.

In a parallel effort begun in January 1993, EPA, with the participation of DOE under the Coal Research and Development Program, the Electric Power Research Institute (EPRI), and the Utility Air Regulatory Group (UARG), began an emissions data collection program using state-of-the-art sampling and analysis techniques. Emissions data were collected from eight utilities representing nine process configurations, several of which were sites for CCT projects. These utilities represented different coal types, process configurations, furnace types, and pollution control methods. The report, *A Comprehensive Assessment of Toxic Emissions from Coal-Fired Power Plants: Phase I Results from the U.S. Department of Energy Study*, was released in September 1996 and provided the raw data from the emissions testing. The second phase of the DOE/EPRI effort involves sampling at other sites, including the CCT Program's Wabash River, Tampa Electric, and Sierra Pacific integrated gasification combined-cycle (IGCC) projects.

In another DOE study, HAPs data were collected from 16 power plants and reported in *Summary of Air Toxics Emissions Testing at Sixteen Utility Plants*. The report, issued in July 1996, provides an assessment of HAPs measured in the coal, across the major pollution control devices, and emitted from the stack. The results of the HAPs program have significantly mitigated concerns about a broad range of HAPs emissions from coal-fired power generation, and focused attention on mercury.


Eight SCR catalysts with various shapes and compositions were evaluated side-by-side at Gulf Power's Plant Crist using high-sulfur coal. NO_x reductions of 80 percent were achieved.

Mercury. Following up on the October 1996 EPA report to Congress, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units—Interim Final Report* (final report was issued February 1998). The *Mercury Study Report to Congress*, issued December 1997, estimates that U.S. industrial sources were responsible for releasing 158 tons of mercury into the atmosphere in 1994 and 1995. The EPA estimates that 87 percent of those emissions originate from combustion sources such as waste and fossil fuel facilities, 10 percent from manufacturing facilities, 2 percent from area sources, and 1 percent from other sources. The EPA also identified four specific categories that account for about 80 percent of the total anthropogenic sources: coal-fired power plants, 33 percent; municipal waste incinerators, 18 percent; commercial and industrial boilers, 18 percent; and medical waste incinerators, 10 percent.

In December 2000, EPA decided to develop regulations for mercury emissions. The schedule calls for EPA to issue proposed regulations for comment by 2003 and issue final regulations by 2004.

Global Climate Change

The CCT Program had its roots in the reduction of acid rain precursors and was responsive to the recommendations contained in the *Joint Report of the Special Envoys on Acid Rain,* as discussed earlier. Moreover, as concerns over global climate change emerged, the CCT Program began to emphasize demonstration of advanced electric power generation technology capable of achieving significantly higher efficiency than conventional systems, thus reducing carbon emissions.

For example, pressurized fluidized-bed combustion (PFBC) technology has efficiencies up to 25 percent higher than conventional coal-fired systems, which results in a like reduction in carbon emissions. Also, the PFBC technology reduces pollutant emissions far below NSPS, without expensive add-on emission controls. As a result of the CCT Program's Tidd PFBC Demonstration Project and associated development work, this technology is achieving market penetration, including several commercial sales of this new generation of advanced power system in Japan and Germany. The work at Tidd is also providing the basis for the second-generation PFBC demonstrations to be conducted in Lakeland, Florida with funding from the CCT Program.

Another very efficient advanced power system is integrated gasification combined-cycle (IGCC). There are four IGCC demonstration projects in the CCT Program, representing a diversity of gasifier types and cleanup systems. These projects are pioneering this environmentally friendly technology, which in addition to lower carbon emissions, boasts very low SO_2 and NO_x emissions. The IGCC technology offers flexibility in that new plants can be constructed in modules as demand dictates. Current worldwide market penetration of this technology is approximately 5 gigawatts (GW), and demand is growing.

Regional Haze

In July 1999, EPA published a new rule calling for long-term protection of and improvement in visibility for 156 national parks and wilderness areas across the country. Many environmental groups believe coal-fired power plants are a source of regional haze in the national parks and wilderness areas.

During the period 2003-2008, states are required to establish goals for improving visibility in each of these 156 areas and adopt emission-reduction strategies for the period extending to 2018. States have flexibility to set these goals based upon certain factors, but as part of the process, they must consider the rate of progress needed to reach natural visibility conditions in 60 years. Coal-fired power plants are likely targets for new controls to reduce regional haze.

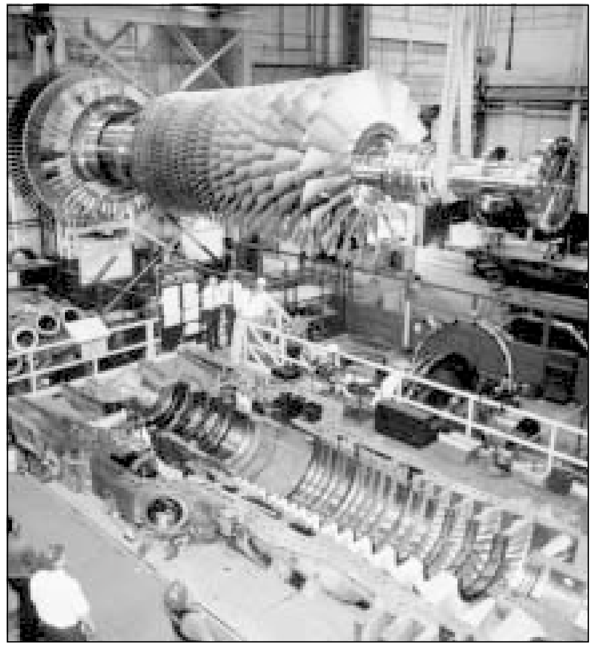
Solid Waste

The CCT Program also addresses the issue of solid waste. For example, several projects redefined the state-of-the-art in wet flue gas desulfurization. Included in this significant technology improvement was production of commercial-grade gypsum in lieu of the scrubber sludge associated with conventional scrubbers of the early 1990s. Scrubber sludge had been projected to require over 4,500 acres per year for disposal by 2015. Advances under the CCT Program precluded that need. The balance of technologies in the CCT Program also address solid waste concerns by producing salable by-products instead of wastes (e.g., sulfur, sulfuric acid, or fertilizer) or dry, environmentally benign materials. These dry materials can be used as construction materials (e.g., for use in soil and roadbed stabilization, or as a cement ingredient), agricultural supplements, a means to mitigate mine subsidence and acid mine drainage, or can be readily disposed of in landfills.

Hazardous air pollutants were measured at the Babcock & Wilcox Company's Demonstration of Coal Reburning for Cyclone Boiler NO_x Control at Nelson Dewey Station.

Toxics Release Inventory

Section 313 of the Emergency Planning and Community Right-To-Know Act (EPCRA) and Section 6607 of the Pollution Prevention Act (PPA) mandate establishment of a publicly accessible database containing information on the release of toxic chemicals by facilities that manufacture, process, or otherwise use them. This database is known as the Toxics Release Inventory (TRI). Starting in 2000, electric utilities are required to report on releases of toxic chemicals into the air, water, and land. EPA compiles this data in an online TRI that gives the public access to detailed information about releases of toxic chemicals in their communities. It is expected that electric utilities will exceed chemical manufacturers as the largest emitters of toxic chemicals into the environment. Although the emission rates are low for electric utilities, the volume of emissions will likely bring pressure for further reductions.



Aero-derivative gas turbines, like the one shown during installation at the Tampa IGCC plant, will account for most new generation capacity.

Market Considerations

When the CCT Program started in 1985, the electric utility industry was highly regulated. The major uncertainty was the breadth and depth of environmental regulatory requirements that would be imposed on the industry. Even this uncertainty was mitigated by the fact that the environmental control costs could be passed through to the consumer if approved by the state regulatory commission. As long as the utility made prudent investments in plant and equipment, their economic future was fairly stable and predictable. Most industry observers assumed that coal and nuclear energy would carry the burden of baseload generation, oil would be phased out, and natural gas would be used for meeting peak load requirements.

By mid-1997, the picture was entirely different—the utility industry was in the midst of a major restructuring to accommodate a competitive marketplace. Under utility restructuring, power generators must assume the risk for new capacity additions. The relatively low capital cost and short lead times for natural gas-based systems makes them the preferred option for the foreseeable future. As a result, projections now call for natural gas to be the fuel of choice for new capacity additions through 2020. During the same period, nuclear-based capacity will decline and coal-based capacity will increase moderately.

Consumers became a major factor in pushing for competition and regulatory reform even though regulators provide the oversight necessary to assure that consumers were paying a fair price. Consumer pressures for access to lower priced power have been successful in bringing about competition in retail as well as wholesale power markets. Deregulation of retail markets is occurring at the state level. (The Federal Energy Regulatory Commission (FERC) is prohibited from ordering retail wheeling.) Under the Energy Policy Act of 1992 (EPAct), states continue to have responsibility for regulating (1) any electric company operating within their jurisdiction, (2) any electric wholesale generator (EWG) selling electricity wholesale to such a utility, and (3) any holding company that was an associate or affiliate of an EWG selling power to a regulated utility. By the end of fiscal year 2000, twenty-three states and the District of Columbia had enacted legislation to allow competition in the retail electricity market in one form or another. In one other state, a comprehensive regulatory order was issued. Eighteen states are currently investigating deregulation options. In eight states, there is no significant deregulation activity. Under retail deregulation, end users are not required to purchase power from their local utility company, but instead may purchase power from generators or marketers located in other states and regions of the country. In this competitive market environment, power is priced according to market conditions, not necessarily according to generation costs.

Advancement in the technology of electricity production is another factor that has had an impact on restructuring. Nonutility generators have taken advantage of these advances, such as aero-derived gas turbines, to generate electricity cheaper than can be achieved using conventional fossil steam or nuclear generators. The new technologies are often more efficient, less environmentally obtrusive, and can be installed in a very short period of time in capacity modules closely matching the load growth curves.

These factors have had a pronounced effect on the utility market for coal and clean coal technology. A comparison of 1985 and 1999 energy projections for coal, natural gas, and oil, which is shown in Exhibit 1-3, illustrates the magnitude of the change that restructuring is playing, as well as environmental regulation discussed previously. According to EIA's *AEO2001,* coal is projected to maintain its lead in the production of electricity in 2010 at 50 percent; however, that is down from 60 percent when the CCT Program started. The differential has been, for the most part, made up by the growth in natural gas power generation. Nuclear power's contribution to the nation's electric power generation in 2010 is expected to drop by almost 30 percent between the 1985 and 2000 projections.

Industry restructuring and competition will impact coal and coal technologies for the foreseeable future. Utilities are expected to improve their operating efficiencies by using existing plants at higher capacity factors. Contributing to increased capacity factors is a projected drop in generating capacity not only from nuclear plant retirements but capacity losses where stranded costs are not recovered. The EIA has projected that the capacity factor for coal-fired power plants will increase from 68 percent in 1998 to 83 percent in 2020. EIA further predicts that nearly 22 GW of new coal-fired capacity is expected to come on line between 1999 and 2020, accounting for almost 6 percent of capacity expansion. During this time, new highly efficient low-emissions power systems will enter the power production markets. New concepts to reduce delivered electricity prices will likely be employed. Examples include minemouth plants that reduce or eliminate the coal transportation cost component in power production. Also, cogeneration and coproduction systems will be available, which allow the consumer's cost of electricity to be offset by the profitability of coproducts.

Ensuring Sustainable Economic Growth

It is in the national interest to maintain a multi-fuel energy mix to sustain national economic growth. Coal is a key component of national energy security because of its affordability, availability, and abundance within the nation's borders. The CCT Program's strategy leads to the development and deployment of a technology portfolio that enhances the efficient use of this coal resource while assuring that national and global environmental goals are achieved. The domestic coal resources are large enough to supply U.S. needs for more than 250 years at current rates of production.

The United States is increasingly dependent on imported oil as low prices have resulted in decreased domestic oil production for 13 years. That trend was

Exhibit 1-3
Comparison of Energy Projections for Electric Generators

	Electricity Sales (10^9 kWh/yr)			Coal Consumption (10^6 tons/yr)			Gas Consumption[a] (10^{12} ft³/yr)			Oil Consumption[a] (10^6 barrels/yr)		
	NEPP 1985	AEO 2001	% dif	NEPP 1985	AEO 2001	% dif	NEPP 1985	AEO 2001	% dif	NEPP 1985	AEO 2001	% dif
1995	3,018	3,026[b]	0.3	924	958[b]	3.7	3.0	3.37[b]	12	73	110	51
2010	4,176	4,147	-0.7	1,355	1,122	-17.2	1.7	6.94	308	146	26	-82

NEPP 1985: *National Energy Policy Plan Projections to 2010,* U.S. Department of Energy, December 1985.

AEO 2001: *Annual Energy Outlook 2001 with Projections to 2020,* Energy Information Agency, December 2000.

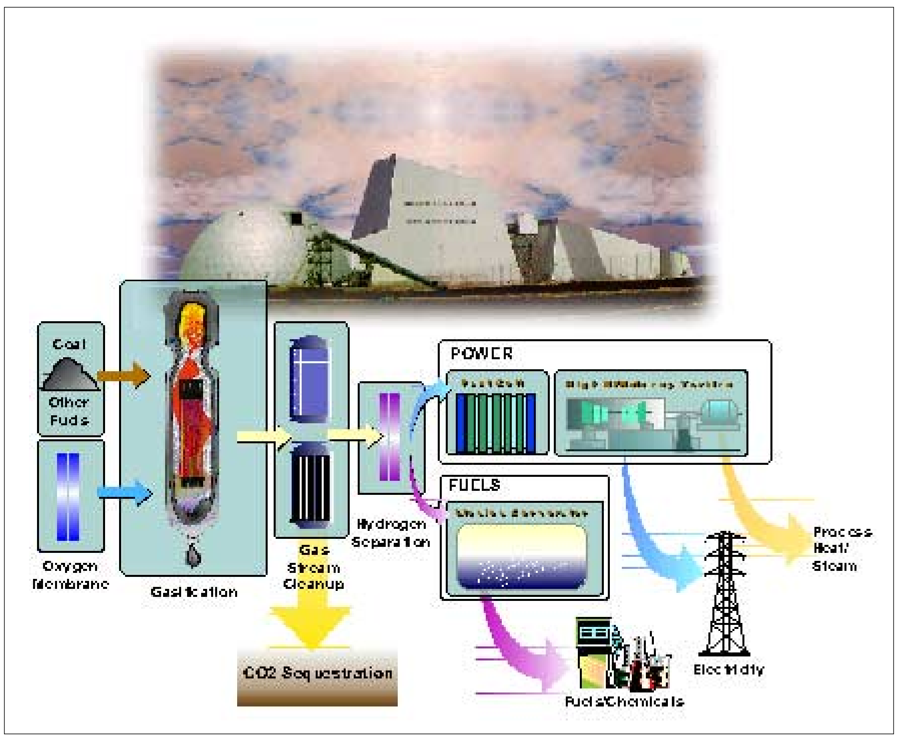
% dif = percent difference between the two projections.

[a]Consumptions by electric generators excluding cogenerators.

[b]Actuals from *Annual Energy Outlook 1998,* December 1997.

broken in 1995 by an oil production capacity increase of 0.4 million barrels per day. In 1998, net petroleum imports were 9.8 million barrels per day, or 51 percent of domestic consumption. The *AEO2001* reference case for 2020 calls for net imports of 12.14 million barrels per day, which is over 70 percent of the total crude supply. Also, natural gas imports are expected to grow from 14.0 percent of total gas consumption in 1998 to 16.7 percent in 2020. These imports are primarily from Canada, which does not represent a supply stability problem, but does represent a drain on balance of payments.

United States coal consumption is equivalent to approximately 3.6 billion barrels of oil per day, which would equate to $44 billion per year. The CCT Program will provide the technologies that will enable coal to continue as a major component in the nation's economy while achieving the environmental quality that society demands. The domestic and export value of 1998 coal production approaches $60 billion in the U.S. economy. Coal-related jobs are dispersed through the mining, transportation, manufacturing, utility, and supporting industries.



Vision 21 modules can be combined in a variety of configurations. One example, shown above, incorporates modules to produce a variety of energy products.

A U.S. coal conversion industry could directly reduce the nation's dependency on imported oil. The economic impact of adding to domestic oil production or reducing the cost of imported oil is very significant. The CCT Program is responding to this opportunity through development and demonstration of mild gasification and liquid-phase methanol production technologies.

According to EIA's *AER1999*, the U.S. exported 78 million tons of coal in 1998. Coal exports to foreign destinations contributed $2.91 billion to the U.S. balance of trade in 1998. Worldwide demand for energy is expected to reach 608 quadrillion Btu by 2020, approximately 1.6 times the current level. According to the EIA, worldwide coal use in 1997 accounted for about 24 percent of total energy consumption and 36 percent of the energy consumed worldwide for electricity generation. Those market shares are not projected to change substantially through 2020.

According to the latest DOE projections, the worldwide market for power generation technologies could be as high as $80 billion between 1995 and 2020. Most of the investment will be in developing countries. This market provides opportunities for U.S. technology suppliers, developers, architect/engineers, and other U.S. firms to capitalize on the advantages gained through experiences in the CCT Program. However, aggressive action is needed, as other governments are recognizing the enormous economic benefits that their economies can enjoy if their manufacturers capture a greater share of this market.

Beyond the CCT Program, DOE activities are aimed at creating a favorable export climate for U.S. coal and coal technology. These efforts include: (1) improving the visibility of U.S. firms and their products by establishing an information clearinghouse and closer liaison with U.S. representatives in other countries, (2) strengthening interagency coordination of federal programs pertinent to these exports, and (3) improving current programs and policies for facilitating the financing of coal-related projects abroad.

Looking to the Future

Power Plant Improvement Initiative

The rapid growth in power demand, especially peak demand, coupled with the ongoing restructuring of the electric power industry, has resulted in a real and growing concern over the reliability of the nation's electricity grid. This concern prompted Congress to

Exhibit 1-4
Vision 21 Objectives

Efficiency—Electricity Generation	Coal-based systems 60% (HHV); natural gas-based systems 75% (LHV) with no credit for cogenerated steam.[a]
Efficiency—Combined Heat & Power	Overall thermal efficiency above 85% (HHV); also meets efficiency goals for electricity.[a]
Efficiency—Fuels Plant Only	Fuel utilization efficiency of 75% (LHV) when producing coal derived fuels.[a]
Environmental	Near-zero emissions of sulfur, nitrogen oxides, particulate matter, trace elements, and organic compounds; 40-50% reduction in CO_2 emissions by efficiency improvement; 100% reduction with sequestration.
Costs	Cost of electricity 10% lower than conventional systems; products of Vision 21 plants must be cost-competitive with market clearing prices.
Timing	Major spinoffs such as improved gasifiers, advanced combustors, high-temperature filters and heat exchangers, and gas separation membranes begin by 2004; designs for most Vision 21 subsystems and modules available by 2012; Vision 21 commercial plant designs available by 2015.

[a]The efficiency goal for a plant co-feeding coal and natural gas will be calculated on a pro-rata basis. Likewise, the efficiency goal for a plant producing both electricity and fuels will be calculated on a pro-rata basis

add $95 million to the Office of Fossil Energy budget for fiscal year 2001.

Coal power plants are a significant part of the nation's generating capacity, currently accounting for more than 51 percent of the country's electricity production. The Power Plant Improvement Initiative, approved by Congress in the Department of the Interior and Related Agencies Appropriations Act for FY 2001, will have a near-term focus on improving the efficiency and environmental performance of coal-fired power generation. New technologies will be demonstrated that can boost the efficiency of a power plant, increasing the amount of electricity it can generate; reduce air emissions; or perhaps a combination of both.

The initial program will apply to existing and new coal-based, central power plants. Later, the program could include a wider span of more flexible generation technologies such as fuel cells and turbines that can operate on natural gas as well as coal.

The initiative will be a cost-shared, public-private partnership that will retain the guidelines of the CCT Program. For example, projects will be chosen competitively and must be supported by at least 50 percent funding from the private sector. Repayment provisions will be incorporated to return proceeds to the government from both domestic and international technology sales. The government's share of funding will be directed at the higher risk aspects of a demonstration project.

There will also be additional guidelines that limit the maximum amount the government will fund in any particular project. Current plans are for the government to cost-share multiple projects from the initial solicitation. The department is also examining the feasibility of additional solicitations, subject to future congressional appropriations.

Congressional guidelines for the initial competition specify that technologies should be supported that enable power plants to operate in a fashion that reduces environmental impacts, achieves greater efficiency in operation, reduces carbon dioxide and other emissions, remains cost-competitive, and responds quickly to changing customer demands. The technologies could apply to existing and new power plants including co-production plants, for example, plants that produce heat, electric power, and liquid fuels, and new technologies such as the introduction of coal fines into the fuel streams of power plants.

The Department of Energy issued a draft of the initial solicitation December 7, 2000 for public comment. The first projects are expected to be selected after September 30, 2001.

Vision 21

The CCT Program is providing the foundation needed to build a future generation of fossil energy-based power systems capable of meeting the energy and environmental demands of the 21st century. The hardware and attendant databases serve as platforms for power, environmental, and fuels systems that together can meet the long-term goals of the Office of Fossil Energy's Coal & Power Systems Program. These "Vision 21" goals are delineated in Exhibit 1-4. The expected result is a suite of technology modules capable of using a broad range of fuels (coal; biomass; and forestry, agricultural, municipal, and refinery wastes) to produce a varied slate of high-value commodities (electricity, steam, clean fuels, and chemicals) at greater than 60 percent efficiency and near-zero emissions.

First-generation systems emerging from the CCT Program provide: (1) the knowledge base from which to launch commercial systems, which will experience increasingly improved cost and performance over time through design refinement; and (2) platforms on which to test new components, which will result in jumps in cost and performance. Examples of new components include advanced hot gas particulate filtration, hot gas sulfur and alkali removal, air separation membranes, high-temperature heat exchangers, artificially intelligent controls and sensors, and CO_2 and hydrogen separation technologies. A strategy of the Vision 21 effort is to develop and spin off such key components to mitigate the risk and cost of integrating the technologies into power, environmental, and fuel system modules.

2. Program Implementation

Introduction

The CCT Program founding principles and implementing process resulted in one of the most successful cost-shared government/industry partnerships forged to respond to critical national needs. Through five nationwide competitions, a total of 60 government/industry cost-shared projects were selected, of which 38, valued at more than $5.2 billion either have been completed or remain active at the end of fiscal year 2000. For the 38 projects, the industry cost-share is an unprecedented 66 percent. Sixty-eight percent (26) of the projects have successfully completed operations. The balance are moving forward, with operational testing under way for five projects.

Over the nine-year period of soliciting and awarding projects, the thrust of the environmental concerns relative to coal use have changed. Nevertheless, the implementing process allowed the program to remain responsive to the changing needs. The result is a portfolio of technologies and a database of technical and cost information that will enable coal to remain a major contributor to the U.S. energy mix without being a threat to the environment. This result will ensure secure, low-cost energy requisite to a healthy economy well into the 21st century.

Success of the CCT Program is measured by the degree to which the operational, environmental, and economic performance of a technology can be projected for commercial applications. Decision makers must have a sufficient database to project performance and assess risk for commercial introduction and deployment of new technologies. This need for information was a driving force in establishing the principles that created the foundation for the implementation process. The government role is nontraditional, moving away from a command-and-control approach to a performance-based approach, where the government sets performance objectives and industry responds with its ideas and is allowed broad latitude in technical management of the projects. This approach encourages technology innovation and cost-sharing. Industry and the public play major roles in the process, reflecting their respective roles in moving technologies into the marketplace.

Implementation Principles

The principles underlying the CCT Program were developed after much study of previous government demonstration programs, assessing both positive and negative results. The principles represent a composite of incentives and checks and balances that allows all participants to best apply their expertise and resources. These guiding principles are outlined below.

- **A strong and stable financial commitment exists for the life of the projects.** Full funding for the government's share of selected projects was appropriated by Congress at the start of the program. This up-front commitment has been vital to getting industry's response in terms of quantity and quality of proposals received and the achievement of 66 percent cost-sharing.
- **Multiple solicitations spread over a number of years enabled the program to address a broad range of national needs with a portfolio of evolving technologies.** Allowing time between solicitations enabled Congress to adjust the goals of the program to meet changing national needs; provided DOE time to revise the implementation process based on lessons learned in prior solicitations; and provided industry the opportunity to develop better projects and more confidently propose evolving technologies.
- **Demonstrations are conducted at commercial scale in actual user environments.** Typically, a technology is constructed at commercial scale with full system integration, reflective of its intended commercial configuration, and operated as a commercial facility or installed on an existing commercial facility. This enables the technology's performance potential to be judged in the intended commercial environment.
- **The technical agenda is determined by industry and not the government.** Based on goals established by Congress and policy guidance received, DOE set definitive performance objectives and performance-based evaluation criteria against which proposals would be judged. Industry was given the flexibility to use their expertise and innovation to define the technology and proposed project in response to the objectives and criteria. The Department of Energy selected the projects that best met the evaluation criteria.

- **Roles of the government and industry are clearly defined and reflect the degree of cost-sharing required.** The government plays a significant role up front in structuring the cooperative agreements to protect public interests. This includes negotiating definitive performance milestones and decision points throughout the project. Once the project begins, the industrial participant is responsible for technical management, while the government oversees the project through aggressive monitoring and engages in implementation only at decision points. Continued government support is assured as long as project milestones and the terms and conditions of the original cooperative agreement continue to be met.
- **At least 50 percent cost-sharing by industry is required throughout all project phases.** Industry's cost-share was required to be tangible and directly related to the project, with no credit for previous work. By sharing essentially in each dollar expended along the way, on at least an equal basis, industry's commitment to fulfilling project objectives was strengthened.
- **Allowance for cost growth provides an important check-and-balance feature to the program.** Statutory provisions allow for additional financial assistance beyond the original agreement in an amount up to 25 percent of DOE's original contribution. Such financial assistance, if provided, must be cost-shared by the industrial participant at no less than the cost-share ratio of the original cooperative agreement. This statutory provision recognizes the risk involved in first-of-a-kind demonstrations by allowing for cost growth. At the same time, it recognizes the need for the industrial participant's commitment to share cost growth and limits the government's exposure.
- **Industry retains real and intellectual property rights.** The level of cost-sharing warrants the industrial participant retaining intellectual and real property rights and removes potential constraints to commercialization. Industry would otherwise be reluctant to come forward with technologies they have developed to the point of demonstration, relinquishing their competitive position.
- **Industry must make a commitment to commercialize the technology.** Consistent with program goals, the industrial participant is required to make the technology available on a nondiscriminatory basis, under reasonable terms and conditions, to all U.S. companies that seek to use the technology. While the technology owner is not forced to divulge know-how to a competitor, the technology must be made available to potential domestic users on reasonable commercial terms.
- **Upon successful commercialization of the technology, repayment up to the government's cost-share is required.** The repayment obligation occurs only upon successful commercialization of the technology. It is limited to the government's level of cost-sharing and the 20-year period following the demonstration.

In summary, these principles provide built-in checks and balances to ensure that the industry and government roles are appropriate and that the government serves as a risk-sharing partner without impeding industry from using its expertise and getting the technology into the marketplace.

Implementation Process

Significant public and private sector involvement was integral to the process leading to technology demonstration and critical to program success. Even before engaging in a solicitation, a public process was instituted under the National Environmental Policy Act (NEPA) to review the environmental impacts. A programmatic environmental impact assessment (PEIA), followed by a programmatic environmental impact statement (PEIS), was prepared prior to initiating solicitations. Public comment and resolution of comments were required prior to proceeding with the program.

As to the solicitation process, Congress set the goals for each solicitation in the enabling legislation and report language (see Appendix A for legislative history and Appendix B for program implementation history). The Department of Energy translated the congressional guidance and direction into performance-based criteria, and developed approaches to address lessons learned from previous solicitations. Before proceeding with a solicitation, however, an outline of the impending solicitation and attendant issues and options was presented in a series of regional public meetings to obtain feedback. The public meetings were structured along the lines of workshops to facilitate discussion and obtain comments from the broadest range of interests. Comments from the public meetings then were used in preparing a draft solicitation, which in turn was issued for public comment. Comments received were formally resolved prior to solicitation issuance.

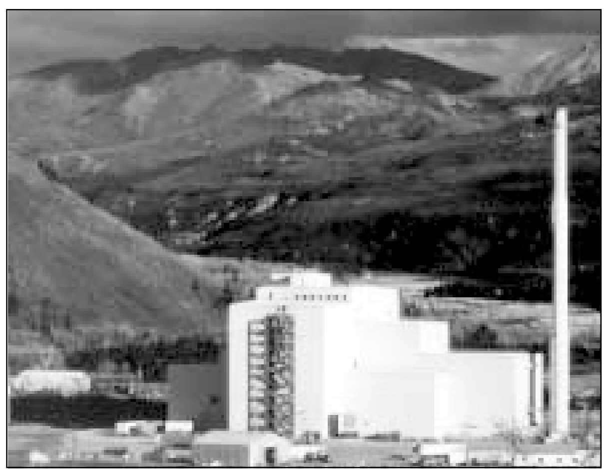
To aid proposers, preproposal conferences were held for the purpose of clarifying any aspects of the solicitation. Further, every attempt was made in the solicitation to impart a clear understanding of what was being sought, how it would be evaluated, and what contractual terms and conditions would apply. A section of the solicitation was devoted to helping potential proposers determine technology eligibility, and numerical quantification of the evaluation criteria was provided. The solicitation also contained a model cooperative agreement with the key relevant contractual terms and conditions.

Project selection and negotiation leading to award were conducted under stringent rules carrying criminal penalties for noncompliance. Proposals were evaluated and projects negotiated strictly against and within the criteria and terms and conditions established in the solicitation. In the spirit of NEPA, information required and evaluated included project-specific environmental, health, safety, and socioeconomic aspects of project implementation.

Upon project award, another public process was engaged to ensure that all site-specific environmental concerns were addressed. The National Environmental Policy Act requires that a rigorous environmental assessment be conducted to address all potential environmental, health, safety, and socioeconomic impacts associated with the project. The findings can precipitate a more formal environmental impact statement (EIS) process, or the findings can remain as an environmental assessment (EA) along with a finding of no significant impact (FONSI). During the EIS process, public meetings are held for the purpose of disclosing the intended project activities, with emphasis on potential environmental, health, safety, and socioeconomic impacts, and planned mitigating measures. Comments are sought and must be resolved before the project can proceed. This process has led to additional actions taken by the industrial participants beyond the original project scope. To facilitate the NEPA process, DOE encouraged environmental data collection through cost-sharing during the negotiation period contingent upon project award.

Because of the environmental nature of the CCT Program, DOE took a proactive posture in following the principles of NEPA. Environmental concerns were aggressively addressed and the public engaged prior to major expenditure of public funds. Furthermore, DOE required that an in-depth environmental monitoring plan (EMP) be prepared, fully assessing potential pollutant emissions, both regulated and unregulated, and defining the data to be collected and the methods for collection. All cooperative agreements required preparation of environmental monitoring reports that provide results of the monitoring activities. As environmental issues emerged, every effort was made to address them directly with the understanding that commercial technology acceptance hinged on satisfying users and the public as to acceptable environmental performance. Appendix C reviews the proactive environmental stance taken by the program, further delineates the NEPA process, and provides the status of key actions.

The NEPA process assured environmental acceptability of the Healy Clean Coal Project on the border of Denali National Park in Alaska.



Projects are managed by the participants, not the government. However, public interests are protected by requiring defined periods of performance referred to as budget periods, throughout the project. Budget periods are keyed to major decision points. A set amount of funds is allotted to each budget period, along with performance criteria to be met before receiving funds for the next budget period. These criteria are contained in project evaluation plans (PEPs). Progress reports and meetings during budget periods serve to keep the government informed. At the decision points, progress against PEPs is formally evaluated, as is the PEP for the next budget period. Financial data is also examined to ensure the participants' capability to continue required cost-sharing. Failure to perform as expected results in greater government involvement in the decision making process. Proposal of major project changes precipitates not only in-depth programmatic assessment, but legal and procurement review as well. Decisions regarding continuance into succeeding budget periods, any increase in funding, or major project changes require the approval of DOE's Assistant Secretary of Fossil Energy.

Beyond the formal process associated with the solicitations, parallel efforts were conducted to inform stakeholders of ongoing events, results, and issues and to engage them in discussion on matters pertinent to ensuring that the program remained responsive to needs. A continuing dialog was facilitated by direct involvement in the projects of a large number of utilities, technology suppliers, and states, as well as key industry-based research organizations (*e.g.*, the Electric Power Research Institute and Gas Research Institute). This was accompanied by executive seminars designed to enhance communications with the utility, independent power producer, regulatory, insurance underwriter, and financial sectors. The approach was to identify those sectors where inputs were missing and then structure seminars to provide information on the program and obtain the executives' perspectives and suggestions for enhancing program performance. Furthermore, a periodic CCT Conference was instituted to serve as a forum for reporting project progress and results and discussing issues affecting the outcome of the CCT Program. And, an outreach program was put in place to ensure that needed information was prepared and disseminated in the most efficient manner, leveraging a variety of domestic and international conferences, symposia, and workshops. These activities are discussed in further detail in Section 4.

During implementation of the CCT Program, many precedent-setting actions were taken and many innovations were used by both the public and private sectors to overcome procedural problems, create new management systems and controls, and move toward accomplishment of shared objectives. The experience developed in dealing with complex business arrangements of multimillion dollar CCT projects is a significant asset that has contributed greatly to the CCT Program's success—an asset of value to other programs seeking to forge government/industry partnerships. To document lessons learned, *Clean Coal Technology Program Lessons Learned* was published in July 1994. This report documents the knowledge acquired over the course of the CCT Program through the completion of five solicitations. The report was based on the belief that it is of mutual advantage to the private and public sectors to identify those factors thought to contribute to the program's success and to point out pitfalls encountered and corrective actions taken.

Commitment to Commercial Realization

The CCT Program has been committed to commercial realization since its inception. The significant environmental, operational, and economic benefits of the technologies being demonstrated in the program will be realized when the technologies achieve widespread commercial success. The importance attached to commercial realization of clean coal technologies is highlighted in Senate Report 99-82, which contains the following recommendation for project evaluation criteria: "[t]he project must demonstrate commercial feasibility of the technology or process and be of commercial scale or of such size as to permit rapid commercial scale-up."

The commitment to commercial realization recognizes the complementary but distinctive roles of the technology owner and the government. It is the technology owner's role to retain and use the information and experience gained during the demonstration and to promote the use of the technology in the domestic and international marketplaces. The detailed operational, economic, and environmental data and the experience gained during the demonstration are vital to efforts to commercialize the technology. The government's role is to capture, assess, and transfer operational, economic, and environmental information to a broad spectrum of the private sector and international community. The information must be sufficient to allow potential commercial users to confidently screen the technologies and to identify those meeting operational requirements. The importance of commercial realization is confirmed by the requirement in the solicitations and cooperative agreements that the project participant must pursue commercialization of the technology after successful demonstration.

Each of the five solicitations contained requirements for the project proposals to include a discussion of the commercialization plans and approaches to be used by the participants. The proposer was required to discuss the following topics:

- The critical factors required to achieve commercial deployment, such as financing, licensing, engineering, manufacturing, and marketing;
- A timetable identifying major commercialization goals and schedule for completion;

Pressurized fluidized-bed combustion, like that demonstrated at Ohio Power Company's Tidd Plant, is starting to see global commercialization.

- Additional requirements for demonstration of the technology at other operational scales, as well as significant planned parallel efforts to the demonstration project, that may affect the commercialization approach or schedule; and
- The priority placed by senior management on accomplishing the commercialization effort and how the project fits into the various corporations' business, marketing, or energy utilization strategies.

The cooperative agreement contains three mechanisms to ensure that the demonstrated technology can be replicated by responsible firms while protecting the proprietary commercial position of the technology owner. These three mechanisms are:

- The commercialization clause requires the technology owner to meet U.S. market demands for the technology on a nondiscriminatory basis (this clause "flows down" from the project participant to the project team members and contractors);
- The clauses concerning rights to technical data deal with the treatment of data developed jointly in the project as well as data brought into the project; and
- The patent clause affords protection for new inventions developed in the project.

In addition to ensuring implementation of the above project-specific mechanisms, the government role also includes disseminating the operational, environmental, and economic performance information on the technologies to potential customers and stakeholders. To carry out this role, a CCT Outreach Program was established to perform the following functions:

- Make the public and local, state, and federal government policy makers aware of the CCTs and their operational, economic, and environmental benefits;
- Provide potential domestic and foreign users of the technologies with the information needed for decision making;
- Inform financial institutions and insurance underwriters about the advancements in technology and associated risk mitigation to increase confidence; and
- Provide customers and stakeholders opportunities for feedback on program direction and information requirements.

Specific accomplishments of the CCT Outreach Program are discussed in Section 4.

Solicitation Results

Each solicitation was issued as a Program Opportunity Notice (PON)—a solicitation mechanism for cooperative agreements where the program goals and objectives are defined but the technology is not. Proposals for demonstration projects consistent with the objectives of the PON were submitted to DOE by specific deadlines. DOE evaluated, selected, and negotiated projects strictly within the bounds of the PON provisions. Award was made only after Congress was allowed 30 in-session days to consider the projects as outlined in a *Comprehensive Report to Congress* issued after each solicitation.

Exhibit 2-1 summarizes the results of solicitations. Exhibit 2-2 identifies the projects currently in the CCT Program and the solicitation under which the projects were selected. Appendix B provides a summary of the procurement history and a chronology of project selection, negotiation, restructuring, and completion or termination. Project sites are mapped in Exhibits 2-3 through 2-6, which indicate the geographic locations of projects by application category.

The resultant projects have achieved broad-based support. Team members for the projects include more than 50 utilities; more than 45 technology suppliers; and more than 20 engineering, construction, or consulting firms. Other team members include the Electric Power Research Institute, the Gas Research Institute, numerous state and local agencies and authorities, industrial manufacturers, and one Native American tribe.

Exhibit 2-1
CCT Program Selection Process Summary

Solicitation	PON Issued	Proposals Submitted	Projects Selected	Projects in CCT Program as of Sept. 30, 2000
CCT-I	February 17, 1986	51	17	8
CCT-II	February 22, 1988	55	16	9
CCT-III	May 1, 1989	48	13	12
CCT-IV	January 17, 1991	33	9	5
CCT-V	July 6, 1992	24	5	4
		211	60	38

Exhibit 2-2
Clean Coal Technology Demonstration Projects by Solicitation

Project and Participant	Location
CCT-I	
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ Inc.)	Homer City, PA
LIMB Demonstration Project Extension and Coolside Demonstration (McDermott Technology, Inc.)	Lorain, OH
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	Williamsport, PA
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	Hennepin and Springfield, IL
Tidd PFBC Demonstration Project (The Ohio Power Company)	Brilliant, OH
Advanced Coal Conversion Process Demonstration (Western SynCoal LLC)	Colstrip, MT
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	Nucla, CO
JEA Large Scale CFB Combustion Demonstration Project (JEA)	Jacksonville, FL
CCT-II	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Niles, OH
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)	Cassville, WI
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	Dilles Bottom, OH
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	Thomaston, ME
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	Chesterton, IN
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Coosa, GA
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	Newnan, GA
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers (Southern Company Services, Inc.)	Pensacola, FL
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	Lynn Haven, FL
CCT-III	
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	Kingsport, TN
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	West Paducah, KY
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Healy, AK
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	Aberdeen, OH

Exhibit 2-2 (continued)
Clean Coal Technology Demonstration Projects by Solicitation

Project and Participant	Location
CCT-III (continued)	
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	Seward, PA
Blast Furnace Granular-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Burns Harbor, IN
McIntosh Unit 4A PCFB Demonstration Project (City of Lakeland, Lakeland Electric)	Lakeland, FL
ENCOAL® Mild Coal Gasification Project (ENCOAL Corporation)	Gillette, WY
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	Denver, CO
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	Richmond, IN
Integrated Dry NO_x/SO_2 Emissions Control System (Public Service Company of Colorado)	Denver, CO
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	Mulberry, FL
CCT-IV	
Micronized Coal Reburning Demonstration for NO_x Control (New York State Electric & Gas Corporation)	Lansing and Rochester, NY
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	Lansing, NY
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	Reno, NV
Pulse Combustor Design Qualification Test (ThermoChem, Inc.)	Baltimore, MD
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	West Terre Haute, IN
CCT-V	
Clean Coal Diesel Demonstration Project (Arthur D. Little, Inc.)	Fairbanks, AK
Clean Power from Integrated Coal/Ore Reduction (CPICOR™) (CPICOR™ Management Company LLC)	Vineyard, UT
Kentucky Pioneer Energy IGCC Demonstration Project (Kentucky Pioneer Energy, LLC)	Trapp, KY
McIntosh Unit 4B Topped PCFB Demonstration Project (City of Lakeland, Lakeland Electric)	Lakeland, FL

Exhibit 2-3
Geographic Locations of CCT Projects—Environmental Control Devices

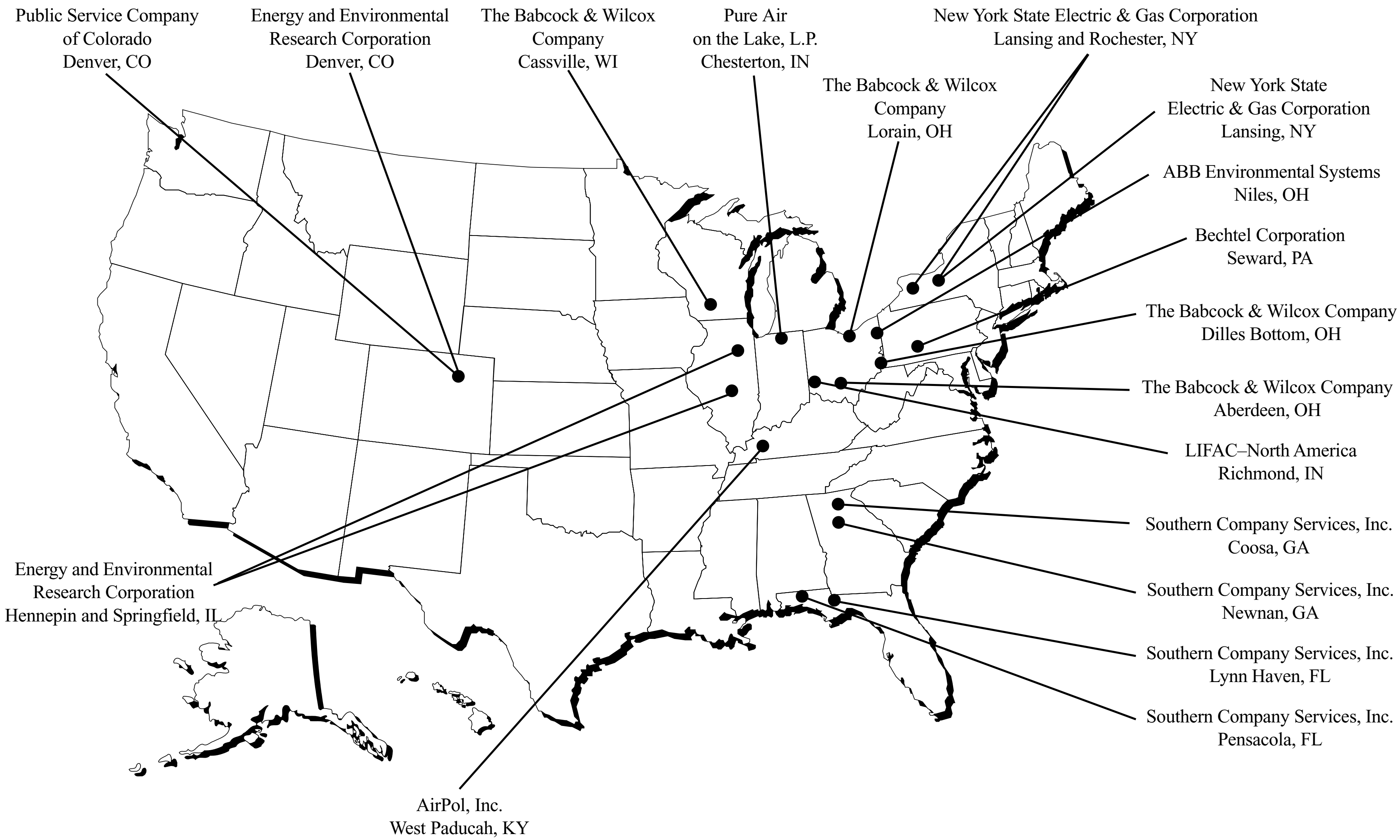


Exhibit 2-4

Geographic Locations of CCT Projects—Advanced Electric Power Generation

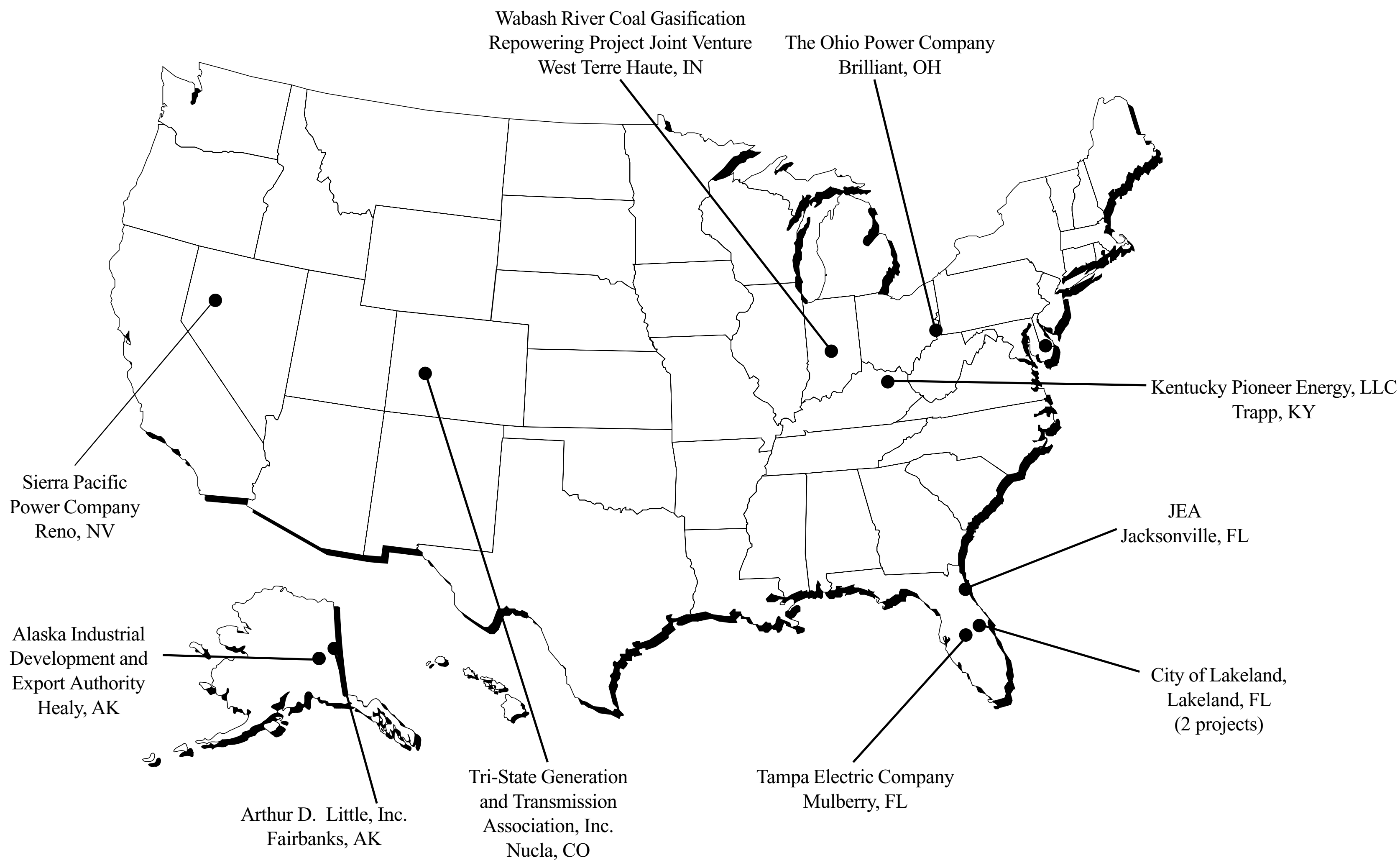


Exhibit 2-5
Geographic Locations of CCT Projects—Coal Processing for Clean Fuels

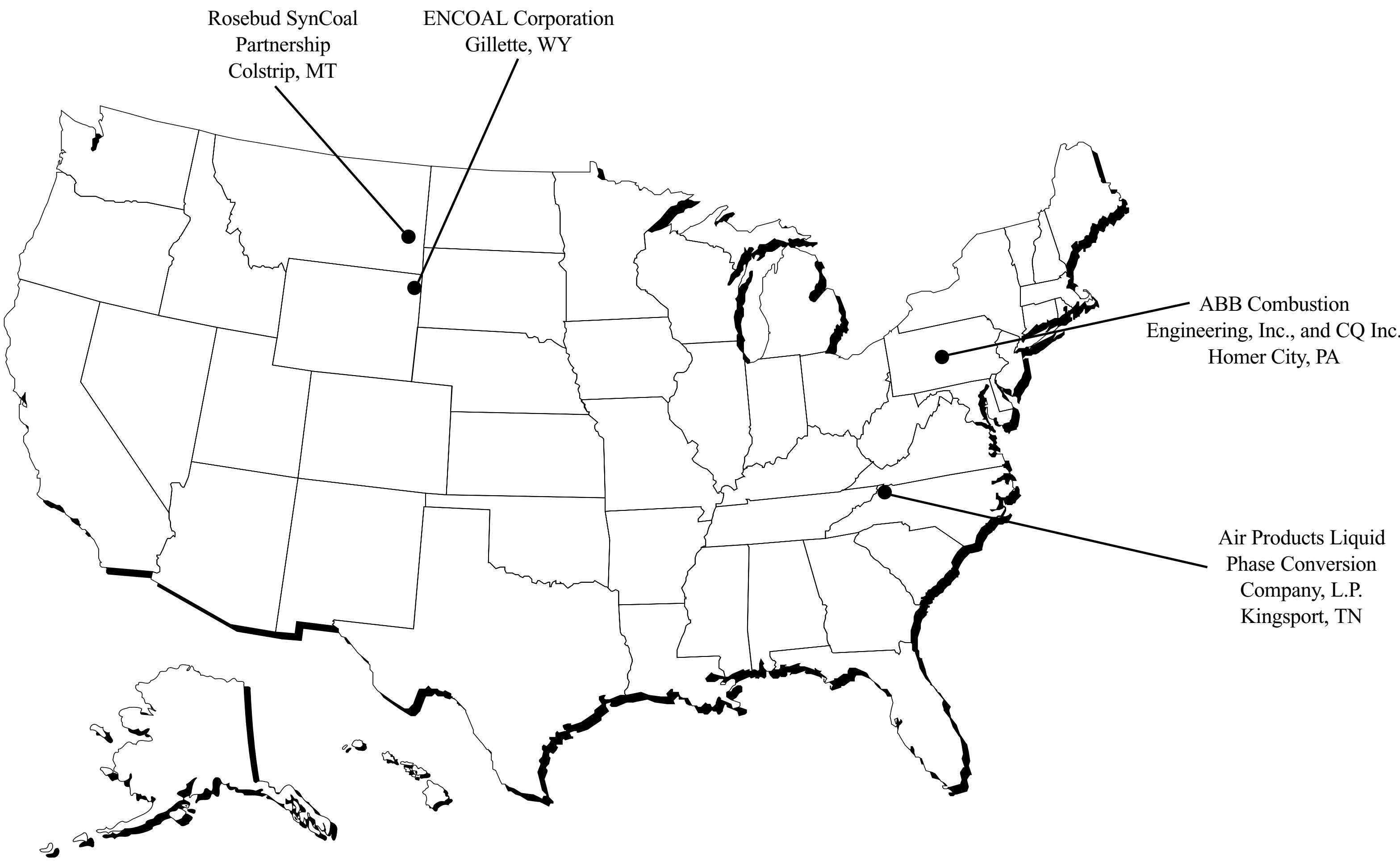


Exhibit 2-6
Geographic Locations of CCT Projects—Industrial Applications

The contributions of the selected projects to domestic and international energy and environmental needs are significant. These contributions include:

- Completing demonstration and proving commercial viability of a suite of cost-effective SO_2 and NO_x control options capable of achieving moderate (50 percent) to deep (70–95 percent) emission reduction for the full range of coal-fired boiler types;
- Providing the database and operating experience requisite to making atmospheric fluidized-bed combustion a commercial technology at utility scale;
- Completing demonstration of a number of coal processes to produce high-energy-density, low-sulfur solid fuels and clean liquids from a range of coal types;

Comprehensive Report to Congress was issued after each solicitation for each selected project.

- Laying the foundation for the next generation of technologies to meet the energy and environmental demands of the 21st century—three IGCC plants are in operation or have completed operations at three separate utilities; and successful demonstration of pressurized fluidized-bed combustion at 70 MWe and two larger scale demonstrations are in progress; and
- Demonstrating significant efficiency and pollutant emission reduction enhancements in steel making, advanced combustion for combined SO_2/NO_x/PM control for industrial and small utility boilers, and innovative SO_2 control for waste elimination in cement production.

Future Implementation Direction

The future implementation direction of the CCT Program focuses on completing the existing projects as promptly as possible and assuring the collection, analysis, and reporting of the operational, economic, and environmental performance results that are needed to promote commercialization.

In fiscal year 2001, the following projects are forecasted to complete operations:

- Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler,
- Piñon Pine IGCC Power Project,
- Advanced Coal Conversion Process Demonstration, and
- Pulse Combustor Design Qualification Test.

The body of knowledge obtained as a result of the CCT Program demonstrations is being used in immediate decision making relative to regulatory compliance, forging plans for meeting future energy and environmental demands, and developing the next generation of technology responsive to ever-increasing demands on environmental performance at competitive costs. An expanded portfolio of information will be forthcoming to make it easier for stakeholders and customers to sift through the already enormous amount of data resulting from the demonstrations.

Efforts will continue toward refining the effectiveness in responding to customer and stakeholder needs. Toward that end, as needs change, forums will be sought to obtain feedback particularly in view of utility restructuring, continued environmental concerns, and a burgeoning foreign market. Objectives are to ensure that CCT Program efforts are fully leveraged and that follow-on efforts under the OC&PS Research, Development, and Demonstration Program are appropriate.

3. Funding and Costs

Introduction

Congress has appropriated a federal budget of $2.2 billion for the CCT Program. These funds have been committed to demonstration projects selected through five competitive solicitations. As of September 30, 2000, the program consisted of 38 active or completed projects. These 38 projects have resulted in a combined commitment by the federal government and the private sector of $5.2 billion. DOE's cost-share for these projects exceeds $1.7 billion, or approximately 34 percent of the total. The project participants (*i.e.*, the non-federal-government participants) are providing the remaining $3.4 billion, or 66 percent of the total. Exhibit 3-1 summarizes the total costs of CCT projects as well as cost-sharing by DOE and project participants. The data used to prepare Chapter 3 is based on the 38 projects that were active in the CCT Program as of September 30, 2000.

Exhibit 3-1
CCT Project Costs and Cost-Sharing
(Dollars in Thousands)

	Total Project Costs	%	Cost-Share Dollars DOE[b]	Cost-Share Dollars Participants	Cost-Share Percent DOE	Cost-Share Percent Participants
Subprogram						
CCT-I	844,363	16	239,640	604,723	28	72
CCT-II	318,577	6	139,229	179,348	44	56
CCT-III	1,325,329	26	576,918	748,411	44	56
CCT-IV	950,429	18	439,063	511,366	46	54
CCT-V	1,765,009	34	360,982	1,404,027	20	80
Total[a]	5,203,707	100	1,755,832	3,447,875	34	66
Application Category						
Advanced Electric Power Generation	2,864,284	55	1,118,865	1,745,419	39	61
Environmental Control Devices	620,110	12	252,866	367,244	41	59
Coal Processing for Clean Fuels	431,810	8	192,029	239,781	44	56
Industrial Applications	1,287,503	25	192,072	1,095,431	15	85
Total[a]	5,203,707	100	1,755,832	3,447,875	34	66

[a]Totals may not add due to rounding.

[b]DOE share does not include $99,581,000 obligated for withdrawn projects and audit expenses.

Program Funding

General Provisions

In the CCT Program, the federal government's contribution cannot exceed 50 percent of the total cost of any individual project. The federal government's funding commitments and other terms of federal assistance are represented in a cooperative agreement negotiated for each project in the program. Terms of the cooperative agreement also include a plan for the federal government to recoup up to the full amount of the federal government's contribution. This approach enables taxpayers to benefit from commercially successful projects. This is in addition to the benefits derived from the demonstration and commercial deployment of technologies that improve environmental quality and promote the efficient use of the nation's coal resources.

The project participant has primary responsibility for the project. The federal government monitors project activities, provides technical advice, and assesses progress by periodically reviewing project performance with the participant. The federal government also participates in decision making at major project junctures negotiated into the cooperative agreement.

Through these activities, the federal government ensures the efficient use of public funds in the achievement of individual project and overall program objectives.

Congress has provided program funding through appropriation acts and adjustments. (See Appendix A for legislative history and excerpts from the relevant funding legislation.)

Exhibit 3-2 presents the allocation of appropriated CCT Program funds (after adjustment) and the amount available for each CCT solicitation. Additional activities funded by CCT Program appropriations are the Small Business Innovation Research (SBIR) Program, the Small Business Technology Transfer (STTR) Program, and CCT Program direction. The SBIR Program implements the Small Business Innovation Development Act of 1982 and provides a role for small, innovative firms in selected research and development (R&D) areas. The STTR Program implements the Small Business Technology Transfer Act of 1992 that establishes a pilot program and funding for small business concerns performing cooperative R&D efforts.

The CCT program direction budget provides for the management and administrative costs of the program and includes federal employees' salaries, benefits, and travel, site support services, and services provided by national laboratories and private firms.

Exhibit 3-2
Relationship Between Appropriations and Subprogram Budgets for the CCT Program
(Dollars in Thousands)

Appropriation Enacted	Subprogram	Adjusted Appropriations	SBIR & STTR Budgets[a]	Program Direction Budget	Projects Budget
P.L. 99-190	CCT-I	380,600	4,902	115,767	259,931
P.L. 100-202	CCT-II	473,959	6,781	32,512	434,666
P.L. 100-446	CCT-III	574,998	6,906	22,548	545,544
P.L. 101-121[b]	CCT-IV	332,000	7,065	25,000	299,935
P.L. 101-121[b]	CCT-V	450,000	5,427	25,000	419,573
Total		2,211,557	31,081	220,827	1,959,649

[a]Small Business Innovation Research (SBIR) and Small Business Technology Transfer (STTR) Programs.

[b]P.L. 101-121 was revised by P.L. 101-512, 102-154, 102-381, 103-138, 103-332, 104-6, 104-208, 105-18, 105-83, 105-277, 106-113, and 106-291.

Availability of Funding

Although all funds necessary to implement the entire CCT Program were appropriated by Congress prior to FY1990, the legislation also directed that these funds be made available (*i.e.*, apportioned) to DOE on a time-phased basis. Exhibit 3-3 depicts this apportionment of funding to DOE. Exhibit 3-3 also shows the program's yearly funding profile by appropriations act and by subprogram. Funds can be transferred among subprogram budgets to meet project and program needs.

Use of Appropriated Funds

There are five key financial terms used by the government to track the status and use of appropriated funds: (1) budget authority, (2) commitments, (3) obligations, (4) costs, and (5) expenditures. The definition of each of these terms is given below.

- **Budget Authority.** This is the legal authorization created by legislation (*i.e.*, an appropriations act) that permits the federal government to obligate funds.

Exhibit 3-3
Annual CCT Program Funding by Appropriations and Subprogram Budgets
(Dollars in Thousands)

Fiscal Year	1986–91	1992[e]	1994[e]	1995	1996	1997	1998	1999	2000	2001	2002	Total[d]
Adjusted Appropriations[a]												
P.L. 99-190	397,600					(17,000)						380,600
P.L. 100-202	574,997						(101,000)	(40,000)	9,962	15,000	15,000	473,959
P.L. 100-446	574,998								(156,000)	156,000		574,998
P.L. 101-121[b]	35,000	315,000	100,000	18,000	50,000	(91,000)				(162,000)	67,000	332,000
P.L. 101-121[b]		100,000	125,000	19,121	100,000	105,879						450,000
Total	1,582,595	415,000	225,000	37,121	150,000	(2,121)	(101,000)	(40,000)	(146,038)	9,000	82,000	2,211,557
Subprogram Budgets												
CCT-I Projects	387,231			(18,000)	(18,000)	(33,000)	(15,000)	(14,900)	(14,400)	(14,000)		259,931
CCT-II Projects	535,704						(101,000)	(40,000)	9,962	15,000	15,000	434,666
CCT-III Projects	545,544								(156,000)	156,000		545,544
CCT-IV Projects	9,875	311,063	98,450	17,622	48,925	(91,000)				(162,000)	67,000	299,935
CCT-V Projects		74,062	123,063	18,719	97,850	105,879						419,573
Projects Subtotal	1,478,354	385,125	221,513	18,341	128,775	(18,121)	(116,000)	(54,900)	(160,438)	(5,000)	82,000	1,959,649
Program Direction	85,527	25,000		18,000	18,000	16,000	15,000	14,900	14,400	14,000		220,827
Fossil Energy Subtotal	1,563,881	410,125	221,513	36,341	146,775	(2,121)	(101,000)	(40,000)	(146,038)	9,000	82,000	2,180,476
SBIR & STTR[c]	18,714	4,875	3,487	779	3,225							31,081
Total[d]	1,582,595	415,000	225,000	37,121	150,000	(2,121)	(101,000)	(40,000)	(146,038)	9,000	82,000	2,211,557

[a]Shown are appropriations less amounts sequestered under the Gramm-Rudman-Hollings Deficit Reduction Act.

[b]Shown is the fiscal year apportionment schedule of P.L. 101-121 as revised by P.L. 101-512, 102-154, 102-381, 103-138, 103-332, 104-6, 104-208, 105-18, 105-83, 105-277, 106-113, and 106-291.

[c]Small Business Innovation Research (SBIR) and Small Business Technology Transfer (STTR) Programs.

[d]Totals may not appear to add due to rounding.

[e]No changes were made to funding amounts in 1993.

- **Commitments.** Within the context of the CCT Program, a commitment is established when DOE selects a project for negotiation. The commitment amount is equal to DOE's share of the project costs contained in the cooperative agreement.
- **Obligations.** The cooperative agreement for each project establishes funding increments, referred to as budget periods. The cooperative agreement defines the tasks to be performed in each budget period. An obligation occurs in the beginning of each budget period and establishes the incremental amount of federal funds available to the participant for use in performing tasks as defined in the cooperative agreement.
- **Costs.** A request for payment submitted by the project participant to the federal government for reimbursement of tasks performed under the terms of the cooperative agreement is considered a cost. Costs are equivalent to a bill for payment or invoice.
- **Expenditures.** Expenditures represent payment amounts to the project participant from checks drawn upon the U.S. Treasury.

The full government cost-share specified in the cooperative agreement is considered committed to each project. However, DOE obligates funds for the project in increments. Most projects are subdivided into several time and funding intervals, or budget periods. The number of budget periods is determined during negotiations and is incorporated into the cooperative agreement. DOE obligates sufficient funds at the beginning of each budget period to cover the government's cost-share for that period. This procedure limits the government's financial exposure and assures that DOE fully participates in the decision to proceed with each major phase of project implementation.

The overall financial profile for the CCT Program is presented in Exhibit 3-4. The graph shows actual performance for FY1986 through FY1999 and DOE estimates for FY2000 through program completion. Excluded from the graph are SBIR and STTR funds, as these are used and tracked separately from the CCT Program. The financial projections presented in Exhibit 3-4 are based on individual project schedules and budget periods as defined in the cooperative agreements and modifications. The negative Budget Authority values shown in Exhibit 3-4 result from rescission of $101 million in FY1998, the deferral of $40 million in FY1999, and the deferral of $146 million in FY2000.

The financial status of the program through September 30, 2000, is presented by subprogram in Exhibit 3-5. SBIR and STTR funds are included in this exhibit to account for all funding. Exhibit 3-5 also indicates the apportionment sequence as modified by Public Law 106-291. These values represent the amount of budget authority available for the CCT Program.

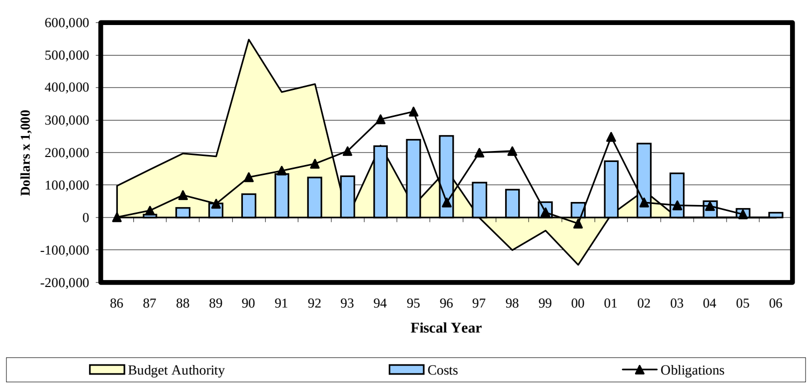
Project Funding, Costs, and Schedules

Information for individual CCT projects, including funding and the status of key milestones, is provided in Section 5. An overview of project schedules and funding is presented in Exhibits 3-6 and 3-7.

Cost-Sharing

A characteristic feature of the CCT Program is the cooperative funding agreement between the participant and the federal government referred to as cost-sharing. This cost-sharing approach, as implemented in the CCT Program, was introduced in Public Law 99-190, An Act Making Appropriations for the Department of the Interior and Related Agencies for the Fiscal Year Ending September 30, 1986, and for Other Purposes. General concepts and requirements

Exhibit 3-4
CCT Financial Projections[a]
as of September 30, 2000



[a]Includes changes resulting from P.L. 106-291.

Exhibit 3-5
Financial Status of the CCT Program as of September 30, 2000[c]
(Dollars in Thousands)

Subprogram	Appropriations Allocated to Subprogram[b]	Apportioned to Date	Committed to Date	Obligated to Date	Cost to Date
CCT-I	259,931	259,931	257,126	257,126	193,291
CCT-II	434,666	419,666	165,370	165,370	164,944
CCT-III	545,544	545,544	592,307	592,307	479,495
CCT-IV	299,935	232,935	477,428	477,428	472,337
CCT-V	419,573	419,573	363,182	148,331	19,521
Projects Subtotal	1,959,649	1,877,649	1,855,413	1,640,562	1,329,588
SBIR & STTR[a]	31,081	31,081	31,081	31,081	31,081
Program Direction	220,827	220,827	220,827	205,837	203,281
Total	2,211,557	2,129,557	2,107,321	1,877,480	1,563,950

[a]Small Business Innovation Research (SBIR) and Small Business Technology Transfer (STTR) Programs
[b]Totals may not appear to add due to rounding
[c]Includes changes from P.L. 106-291

Apportionment Sequence

FY	Annual	Cumulative
1986	99,400	99,400
1987	149,100	248,500
1988	199,100	447,600
1989	190,000	637,600
1990	554,000	1,191,600
1991	390,995	1,582,595
1992	415,000	1,997,595
1993	0	1,997,595
1994	225,000	2,222,595
1995	37,121	2,259,716
1996	150,000	2,409,716
1997	(2,121)	2,407,595
1998	(101,000)	2,306,595
1999	(40,000)	2,266,595
2000	(146,038)	2,120,557
2001	9,000	2,129,557
2002	82,000	2,211,557

Exhibit 3-6
CCT Project Schedules by Application Category

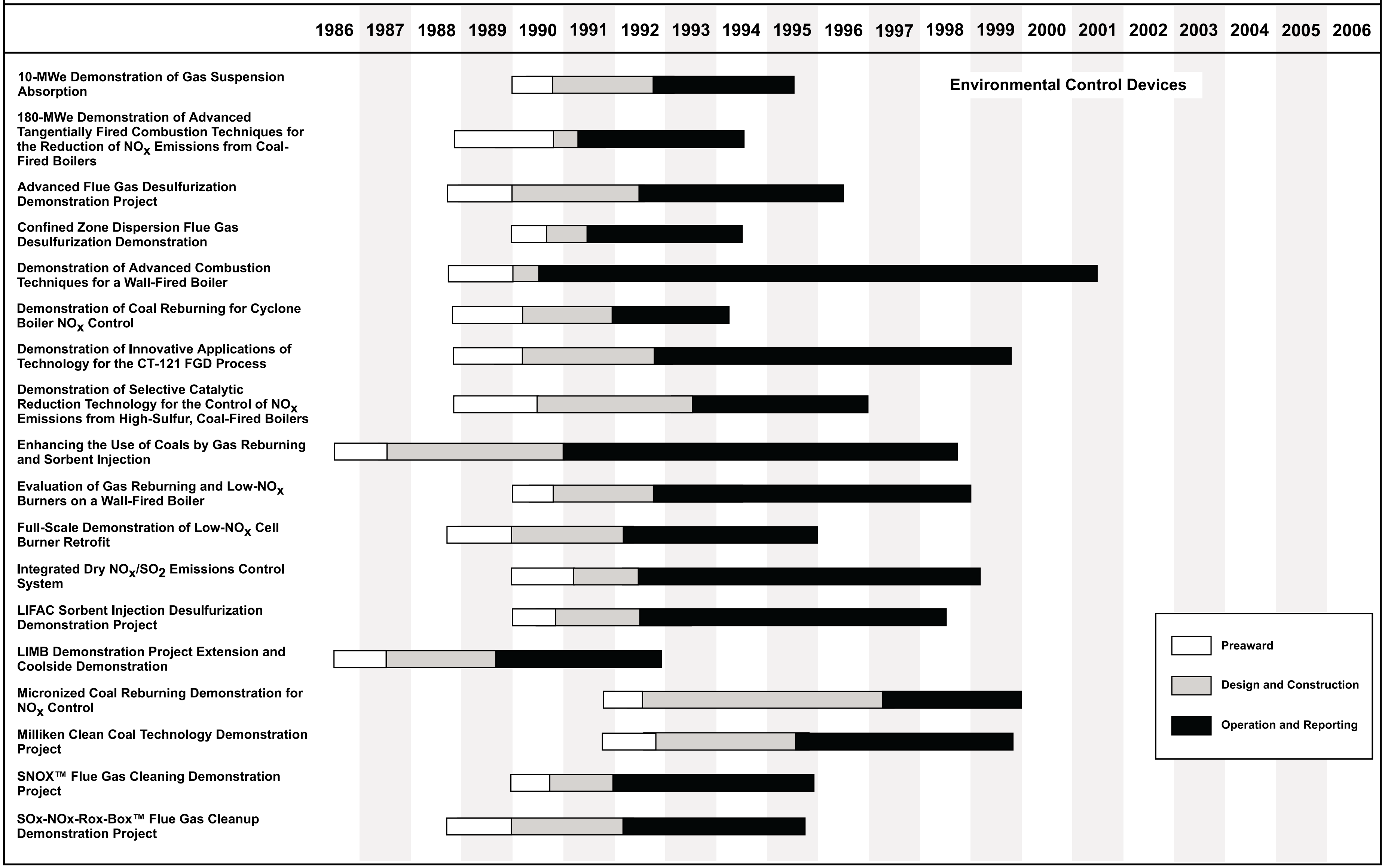


Exhibit 3-6 (continued)
CCT Project Schedules by Application Category

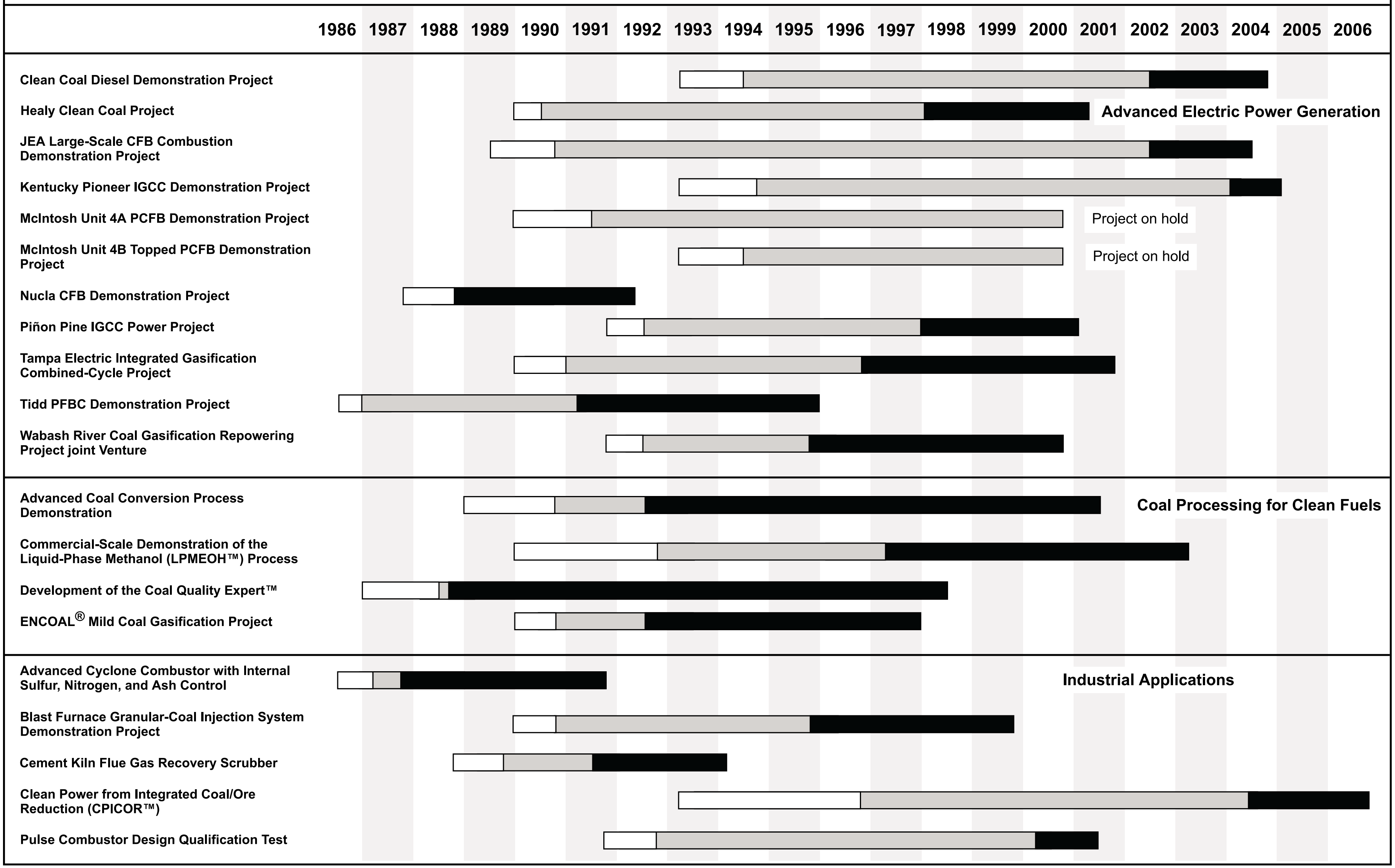


Exhibit 3-7
CCT Project Funding by Application Category

Project	DOE	%	Participant	%	Total
Environmental Control Devices					
SO_2 Control Technologies					
10-MWe Demonstration of Gas Suspension Absorption	2,315,259	30.0	5,401,930	70.0	7,717,189
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	5,205,800	50.0	5,205,800	50.0	10,411,600
LIFAC Sorbent Injection Desulfurization Demonstration Project	10,636,864	49.7	10,756,908	50.3	21,393,772
Advanced Flue Gas Desulfurization Demonstration Project	63,913,200	42.1	87,794,698	57.9	151,707,898
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	21,085,211	49.0	21,989,785	51.0	43,074,996
Subtotal SO_2 Control Technology	**103,156,334**	**44.0**	**131,149,121**	**56.0**	**234,305,455**
NO_x Control Technologies					
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	6,553,526	41.3	9,300,374	58.7	15,853,900
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	6,340,787	46.5	7,305,822	53.5	13,646,609
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	5,442,800	48.5	5,790,592	51.5	11,233,392
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	8,895,790	50.0	8,911,468	50.0	17,807,258
Micronized Coal Reburning Demonstration for NO_x Control	2,701,011	29.7	6,395,475	70.3	9,096,486
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers	9,406,673	40.5	13,823,056	59.5	23,229,729
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	4,149,383	48.5	4,404,282	51.5	8,553,665
Subtotal NO_x Control Technology	**43,489,970**	**43.7**	**55,931,069**	**56.3**	**99,421,039**
Combined SO_2/NO_x Control Technologies					
SNOX™ Flue Gas Cleaning Demonstration Project	15,719,200	50.0	15,719,208	50.0	31,438,408
LIMB Demonstration Project Extension and Coolside Demonstration	7,591,655	39.3	11,719,378	60.7	19,311,033
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	6,078,402	45.8	7,193,219	54.2	13,271,621
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	18,747,816	49.9	18,841,139	50.1	37,588,955
Milliken Clean Coal Technology Demonstration Project	45,000,000	28.4	113,607,807	71.6	158,607,807
Integrated Dry NO_x/SO_2 Emissions Control System	13,082,653	50.0	13,082,653	50.0	26,165,306
Subtotal Combined SO_2/NO_x Control Technologies	**106,219,726**	**37.1**	**180,163,404**	**62.9**	**286,383,130**
Total Environmental Controls	**252,866,030**	**40.8**	**367,243,594**	**59.2**	**620,109,624**

Exhibit 3-7 (continued)
CCT Project Funding by Application Category

Project	DOE	%	Participant	%	Total
Advanced Electric Power Generation					
Fluidized-Bed Combustion					
McIntosh Unit 4A PCFB Demonstration Project	93,252,864	50.0	93,335,136	50.0	186,588,000
McIntosh Unit 4B Topped PCFB Demonstration Project	109,608,507	49.9	110,027,039	50.1	219,635,546
JEA Large-Scale CFB Combustion Demonstration Project	74,733,833	24.2	234,362,679	75.8	309,096,512
Tidd PFBC Demonstration Project	66,956,993	35.3	122,929,346	64.7	189,886,339
Nucla CFB Demonstration Project	17,130,411	10.7	142,919,538	89.3	160,049,949
Subtotal Fluidized-Bed Combustion	**361,682,608**	**34.0**	**703,573,738**	**66.0**	**1,065,256,346**
Integrated Gasification Combined-Cycle					
Kentucky Pioneer Energy IGCC Demonstration Project	78,086,357	18.1	353,846,225	81.9	431,932,582
Piñon Pine IGCC Power Project	167,956,500	50.0	167,956,500	50.0	335,913,000
Tampa Electric Integrated Gasification Combined-Cycle Project	150,894,223	49.8	152,394,223	50.2	303,288,446
Wabash River Coal Gasification Repowering Project	219,100,000	50.0	219,100,000	50.0	438,200,000
Subtotal Integrated Gasification Combined-Cycle	**616,037,080**	**40.8**	**893,296,948**	**59.2**	**1,509,334,028**
Advanced Combustion/Heat Engines					
Clean Coal Diesel Demonstration Project	23,818,000	50.0	23,818,000	50.0	47,636,000
Healy Clean Coal Project	117,327,000	48.5	124,731,000	51.5	242,058,000
Subtotal Advanced Combustion/Heat Engines	**141,145,000**	**48.7**	**148,549,000**	**51.3**	**289,694,000**
Total Advanced Electric Power Generation	**1,118,864,688**	**39.1**	**1,745,419,686**	**60.9**	**2,864,284,374**
Coal Processing for Clean Fuels					
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process	92,708,370	43.4	120,991,630	56.6	213,700,000
Advanced Coal Conversion Process Demonstration	43,125,000	40.8	62,575,000	59.2	105,700,000
Development of the Coal Quality Expert™	10,863,911	50.0	10,882,093	50.0	21,746,004
ENCOAL® Mild Coal Gasification Project	45,332,000	50.0	45,332,000	50.0	90,664,000
Total Coal Processing for Clean Fuels	**192,029,281**	**44.5**	**239,780,723**	**55.5**	**431,810,004**
Industrial Applications					
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	149,469,242	14.0	916,335,758	86.0	1,065,805,000
Pulse Combustor Design Qualification Test	4,306,027	50.0	4,306,027	50.0	8,612,054
Blast Furnace Granular-Coal Injection System Demonstration Project	31,824,118	16.4	162,477,672	83.6	194,301,790
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	490,122	49.8	494,272	50.2	984,394
Cement Kiln Flue Gas Recovery Scrubber	5,982,592	33.6	11,817,408	66.4	17,800,000
Total Industrial Applications	**192,072,101**	**14.9**	**1,095,431,137**	**85.1**	**1,287,503,238**
Grand Total	**1,755,832,100**	**33.7**	**3,447,875,140**	**66.3**	**5,203,707,240**

of the cost-sharing principle as applied to the CCT Program include the following elements:

- The federal government may not finance more than 50 percent of the total costs of a project;
- Cost-sharing by the project participants is required throughout the project (design, construction, and operation);
- The federal government may share in project cost growth (within the scope of work defined in the original cooperative agreement) up to 25 percent of the originally negotiated government share of the project;
- The participant's cost-sharing contribution must occur as project expenses are incurred and cannot be offset or delayed based on prospective project revenues, proceeds, or royalties; and
- Investment in existing facilities, equipment, or previously expended R&D funds are not allowed for the purpose of cost-sharing.

As previously discussed, Exhibit 3-1 summarizes the cost-sharing status by subprogram and by application category for the 38 active or completed projects. In the advanced electric power generation category, which accounts for 55 percent of total project costs, participants are contributing 61 percent of the funds. Cost-sharing by participants for environmental control devices, coal processing for clean fuels, and industrial applications categories is 59 percent, 56 percent, and 85 percent, respectively. For the overall program, participants are contributing 66 percent of the total funding, or nearly $1.7 billion more than the federal government.

Recovery of Government Outlays (Recoupment)

The policy objective of DOE is to recover an amount up to the government's financial contribution to each project. Participants are required to submit a plan outlining a proposed schedule for recovering the government's financial contribution. The solicitations have featured different sets of recoupment rules.

Under the first solicitation, CCT-I, repayment was derived from revenue streams that include net revenue from operation of the demonstration plant beyond the demonstration phase and the commercial sale, lease, manufacture, licensing, or use of the demonstrated technology. In CCT-II, repayment was limited to revenues realized from the future commercialization of the demonstrated technology. The government's share would be 2 percent of gross equipment sales and 3 percent of the royalties realized on the technology subsequent to the demonstration.

The CCT-III repayment formula was adjusted to 0.5 percent of equipment sales and 5 percent of royalties. Limited grace periods were allowed on a project-by-project basis. A waiver on repayment may be sought from the Secretary of Energy if the project participant determines that a competitive disadvantage would result in either the domestic or international marketplace. The recoupment provisions for CCT-IV and CCT-V were identical to those in CCT-III.

As of September 30, 2000, six projects have made repayments to the federal government: Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.); Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company); Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ Inc.); 10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.); the Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.); and the Wabash River Coal Gasification Repowering Project.

In September 1997, the CCT Program office issued a report entitled *Recoupment Lessons Learned—Clean Coal Technology Demonstration Program*. The report: (1) reviewed the lessons learned on recoupment during the implementation of the CCT Program; (2) addressed recommended actions set forth in General Accounting Office (GAO) Report RCED-92-17, GAO Report RCED-96-141, and Inspector General Audit Report IG-0391 relative to recoupment; and (3) provided input into DOE deliberations on recoupment policy.

4. CCT Program Accomplishments

Introduction

The CCT Program's continued success is exemplified by the following demonstrations completing operation in fiscal year 2000:

- Wabash River Coal Gasification Repowering Project, and
- Healy Clean Coal Project.

These completed projects, along with the other 36 active and completed projects, are producing a wealth of knowledge on clean coal technologies.

The success of the CCT Program ultimately will be measured by the contribution the technologies make to the resolution of energy, economic, and environmental issues. These contributions can only be achieved if the public and private sectors understand that clean coal technologies can increase the efficiency of energy use and enhance environmental quality at costs that are competitive with other energy options.

The CCT Program has continued efforts to define and understand the potential domestic and international markets for clean coal technologies. Domestically, this activity requires a continuing dialogue with electric utility executives, public utility commissioners, and financial institutions. Also required are analyses of the effect that regional electric capacity requirements, environmental compliance strategies, and electric utility restructuring have on the demand for clean coal technologies. Internationally, activities include participating in international conferences and workshops, furnishing information on clean coal technologies, and providing technical support to trade agencies, trade missions, and financial organizations.

Throughout the 2000 fiscal year, the CCT Program staff participated in over a dozen domestic and international events involving users and vendors of clean coal technologies, regulators, financiers, environmental groups, and other public and private institutions. Four issues of the *Clean Coal Today* newsletter were published in the same period, along with the fifth annual edition of the *Clean Coal Today Index,* which cross-references all articles published in the newsletter. A 12-page *Project Performance Summary* document was issued for the ENCOAL® Mild Coal Gasification Project. An updated *The Investment Pays Off* document, capturing the latest contributions of the CCT program to advancing coal technologies, was published. Also, two *Clean Coal Technology Topical Reports* were issued during the fiscal year for the Tampa Electric Integrated Gasification Combined-Cycle Project and the Blast Furnace Granular Coal Injection System Demonstration Project. The Department of Energy also continued coverage of the program by publishing the *Clean Coal Technology Demonstration Program: Update 1999,* and the mid-year update of project fact sheets, *Clean Coal Technology Demonstration Program: Project Fact Sheets 2000.*

Marketplace Commitment

Reflecting CCT Program commercialization goals, the majority of the projects involve demonstrations at

Some new publications produced during fiscal year 2000.

commercial scale, providing the opportunity for the participants to continue operation of the demonstrated technologies as part of their strategy to comply with the CAAA.

With government serving as a risk-sharing partner, industry funding has been leveraged to:

- Create jobs,
- Improve the environment,
- Reduce the cost of compliance with environmental regulations,
- Reduce the cost of electricity generation,
- Improve power generation efficiencies, and
- Position U.S.-based industry to export innovative services and equipment.

Reflecting the marketplace commitment, the CCT projects are organized within four major product lines —environmental control devices, advanced electric power generation, coal processing for clean fuels, and industrial applications. Thus, the CCT Program can be viewed from a market perspective. This section of the *Program Update* looks at the domestic market for these technologies and then highlights, by market sector, some of the program and project accomplishments to date along with commercialization successes.

Factors Impacting Domestic Commercialization

The domestic market for advanced SO_2 control technology is not yet fully developed. Domestic utilities are investing in SO_2 control technology by fuel switching, and procuring and banking SO_2 allowances, rather than making capital investments on SO_2 control technologies. Also, the utilities are awaiting the outcome of $PM_{2.5}$ and other regulatory actions that may significantly impact SO_2 compliance requirements. Similarly, there has been no domestic market for advanced technologies that combine high capture efficiency for SO_2, NO_x, and particulate matter.

After being proven as a viable technology in early CCT Program projects, low-NO_x burners enabled utilities to meet the January 2000, Clean Air Act Amendment emission requirements for NO_x. The more advanced coal and gas reburning, and SCR technologies have been applied only sparingly, but will likely come into play as utilities are forced to comply with new, more stringent requirements. Beginning as early as 2003, new NAAQS for $PM_{2.5}$ and ozone, and the associated EPA "SIP Call" will require advanced SO_2, NO_x, and particulate controls like those emerging from the CCT Program. The EIA estimates that 11 gigawatts of scrubber capacity will be in place by 2020.

The domestic market has not been conducive to the introduction of advanced coal-based power generation technologies. Uncertainty in the domestic power markets due to utility restructuring and increasingly stringent emission standards, combined with relatively low natural gas prices to discourage investments in coal plants. Successfully demonstrated technologies like IGCC and PFBC have realized commercial sales but only overseas.

The market is changing. Increasing demand for electric power generation and rising natural gas prices are placing a premium on retaining existing coal-fired electric capacity and making coal-based power generation a solid option for capacity additions. For the existing plants, investments will likely be made in the control measures needed to meet emissions compliance requirements.

For capacity additions, only advanced coal-based power generation systems such as IGCC and PFBC can meet projected emission standards and address concerns over global climate change.

SO_2 control technologies: AirPol (left), CT-121 (center), and LIFAC (right).

Environmental Control Devices

All but 1 of the 19 environmental control device projects have now completed operations. The completed demonstrations proved commercial viability of a suite of cost-effective SO_2 and NO_x control options for the full range of coal-fired boiler types. Risk was significantly mitigated in successfully applying the technologies commercially, because of the extensive databases and attendant predictive models developed through the demonstrations. Also, projects were leveraged to provide input in formulating NO_x control requirements under the CAAA and to evaluate the impact of emerging issues, such as air toxics, on the existing boiler population and control options. Extensive air toxics testing was performed in conjunction with 10 of the environmental control projects. To a great extent, the technologies were retained for commercial service at the demonstration sites and many technology suppliers have realized commercial sales.

SO_2 Control Technologies. All five SO_2 control technology demonstrations have completed operations, evaluating three basic approaches to address the diverse coal-fired boiler population: (1) sorbent injection, (2) gas-suspension absorption, and (3) advanced flue gas desulfurization.

- Two low-capital-cost sorbent injection systems, sponsored by LIFAC–North America and Bechtel Corporation, demonstrated SO_2 capture efficiencies in the range of 50 to 70 percent. These systems hold particular promise for the older, smaller units, particularly those with space constraints.
- A moderate-capital-cost gas-suspension-absorption system, sponsored by AirPol, Inc., demonstrated SO_2 capture efficiencies in the range of 60 to 90 percent. The system has particular applicability to the small- to mid-range units with some space limitations.
- Two advanced flue gas desulfurization (AFGD) systems, sponsored by Pure Air on the Lake, L.P. and Southern Company Services, having somewhat higher capital costs than the other approaches, demonstrated SO_2 capture efficiencies in the range of 90 to 95 percent. These systems are primarily applicable to the larger, newer units that have space available.

The AFGD projects redefined the state-of-the-art in scrubber technology by proving that a single absorber module of advanced design could process large volumes of flue gas and provide the required availability and reliability. This single module design, without the usual spares, combined with integration of functions within the absorber module and use of high throughput designs, nearly halved capital cost and space requirements. The AFGD testing also established that wallboard-grade gypsum could be produced in lieu of solid waste; wastewater discharge could be eliminated; and, by mitigating corrosion, fiberglass-reinforced-plastic fabrication could eliminate process steps (*e.g.*, prequenching for chloride removal and flue gas reheat).

The AFGD demonstration by Southern Company Services using Chiyoda CT-121 showed that the system could significantly enhance particulate control. Pure Air on the Lake, L.P., introduced an innovative business concept whereby the company builds, owns, and operates scrubbers as a contracted service to a utility. The arrangement relieves utilities of the burden of ownership and operation.

Commercialization successes to date for the SO_2 control technologies are summarized in Exhibit 4-1.

NO_x Control Technology. Six of the seven NO_x control technology demonstrations have successfully completed operations. Testing was conducted on the four major boiler types (wall-fired, tangentially fired, cyclone-fired, and cell-burner boilers), representing over 90 percent of the coal-fired boiler population; however, applicability extends to all boiler types.

Typically, NO_x emission reductions achieved for the various approaches were:

- Low-NO_x burners and OFA: 45 to 68 percent
- Reburning systems: 50 to 67 percent
- SNCR systems: 30 to 50 percent
- SCR systems: 80 to 90+ percent
- Advanced controls: 10 to 15 percent

The database developed during Southern Company Services' evaluation of NO_x control on wall-fired and tangentially fired boilers at Plant Smith and Plant Hammond, respectively, was used by EPA in formulating NO_x provisions under the CAAA. ABB Combustion Engineering's LNCFS™ proved effective for tangentially fired boilers and realized commercial acceptance, as did Foster Wheeler's Controlled Flow/Split Flame and Babcock & Wilcox's DRB-XCL® low-NO_x burners for wall-fired boilers. The Babcock & Wilcox Company's low-NO_x cell burner, LNCB®, provided an effective low-cost plug-in NO_x control system for cell-burner boilers, which are known for their inherently high NO_x emissions.

Integration of neural-network systems into digital boiler controls, such as the Generic NO_x Control Intelligent System (GNOCIS) installed at Plant Hammond, demonstrated effective optimization of parameters for NO_x control and boiler performance under load-following operations.

The Babcock & Wilcox Company's coal reburning technology proved not only to be an effective way to control NO_x on cyclone boilers, but a means to avoid derating cyclone boilers when switching to low-sulfur, low-rank western coals. Energy and Environmental Research Corporation's use of gas reburning, applicable to all boiler types, introduced an alternative to SCR for high NO_x emission reduction, particularly when used with low-NO_x burners.

In another project, comparative analyses were conducted on a range of SCR catalysts using high-sulfur U.S. coals, providing needed insight on the environmental and economic performance potential of SCR. Other SCR systems and selective non-catalytic reduc-

Exhibit 4-1
Commercial Successes—SO_2 Control Technology

Project	Commercial Use
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	**Sold domestically and internationally.** GSA market entry was significantly enhanced with the sale of a 50-MWe unit, worth $12.5 million, to the city of Hamilton, Ohio, 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. Two GSA systems valued at $1.8 million have been sold to Taiwan Sugar Corporation for their oil-fired cogeneration plant. Furthermore, Taiwan contracted for technical assistance and proprietary equipment valued at $1.0 million. Airpol sold a GSA system valued at $1.5 million to a petroleum coke calciner in India. Negotiations are under way for a GSA system for a waste incinerator in Holland.
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	**No sales reported.** CZD/FGD can be used to retrofit existing plants or for new installations at a cost of about one-tenth that of a commercial wet scrubber.
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	**Sold domestically and internationally.** There are 10 full-scale LIFAC units in operation in Canada, China, Finland, Russia, Japan, and the United States, including 5 projects started before the CCT Program. 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 has been retained for commercial use by Richmond Power & Light at Whitewater Valley Station, Unit No. 2.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	**No sales reported.** The AFGD continues in commercial service at Northern Indiana Public Service Company's Bailly Generating Station. Gypsum produced by the PowerChip® process is being sold commercially.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	**Sold internationally.** 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 are operating at 17 plants in 8 countries. Another 5 projects are either in design or construction.

tion (SNCR) systems were demonstrated in conjunction with combined SO_2/NO_x control technologies.

Commercialization successes to date for the NO_x control technologies are summarized in Exhibit 4-2.

Combined SO_2/NO_x Control Technologies. All seven of the combined SO_2/NO_x control technology demonstrations have successfully completed operations. The demonstrations evaluated a multiplicity of complementary and synergistic control methods to achieve cost-effective SO_2 and NO_x emissions reductions.

A catalytic process developed by Haldor Topsoe a/s, SNOX™, consistently achieved 95 and 94 percent SO_2 and NO_x reductions, respectively. The process also demonstrated excellent particulate control, while producing a salable by-product in lieu of a solid waste.

In a project sponsored by Public Service Company of Colorado, the complementary use of low-NO_x burners with SNCR resulted in NO_x emission reductions of greater than 80 percent. The SNCR process interacted synergistically with sorbent injection to reduce ammonia slip and lower NO_x emissions. Sodium-based sorbent injection achieved 70 percent SO_2 removal at high sorbent utilization rates.

New York State Electric & Gas Corporation (NYSEG) evaluated an advanced flue gas desulfurization system, the S-H-U scrubber process. The S-H-U process, an advanced formic acid-enhanced wet limestone scrubbing process, demonstrated a 98 percent SO_2 capture efficiency. In conjunction with the S-H-U- process, NYSEG also evaluated micronized coal as a reburn fuel using close-coupled reburning techniques and deep staged combustion incorporated into ABB Combustion Engineering, Inc.'s LNCFS™ burners. DHR Technologies supplied a plant optimization control system known as the Plant Emission Optimization Advisor or PEOA™, which has been sold to a number of users in the power industry.

Milliken Station served as the host for two CCT Program projects demonstrating advanced environmental controls.

The Babcock & Wilcox Company's SO_x-NO_x-Rox Box™, an integration of a newly developed high-temperature fabric-filter bag (for baghouse installations) with SCR and sorbent injection, proved to be an easily installed, highly efficient control system for SO_2, NO_x, and particulates. Typical performance was 80 percent SO_2 removal, 90 percent NO_x removal, and 99.9 percent particulate removal.

Limestone injection multistage burner (LIMB) and coolside demonstrations proved that sorbent injection methods could achieve up to 70 percent SO_2 reduction. The Babcock & Wilcox DRB-XCL® advanced low-NO_x burners reduced NO_x emissions by 45 percent.

Energy and Environmental Research Corporation's demonstration of gas reburning and sorbent injection showed that: (1) NO_x reductions greater than 60 percent could be achieved with only 13 percent natural gas heat input, and (2) SO_2 removal of over 55 percent could be achieved by using special sorbents.

Commercialization successes to date for the combined SO_2 and NO_x control technologies are summarized in Exhibit 4-3.

Advanced Electric Power Generation

Pollution control was the priority early in the CCT Program. This program emphasis included technologies that could effectively repower aging plants faced with the need to both control emissions and respond to growing power demands. Repowering is an important option because existing power generation sites have significant value and warrant investment because the infrastructure is in place, and siting new plants represents a major undertaking. This recognition led to award early on of three key repowering projects—two ACFB projects and a PFBC project.

As the CCT Program unfolded, a number of energy and environmental issues combined to change the emphasis toward seeking high-efficiency, low-emission power generation technologies for both repowering and new power generation. This emphasis was deemed essential to enable coal to fulfill its projected contribution to the nation's energy mix well into the 21st century. Environmental issues included a growing concern over greenhouse gas emissions, capping of SO_2 emissions, increasing attention to NO_x in ozone nonattainment areas, and recognizing fine particulate emissions (respirable particulates) as a significant health threat. These issues prompted follow-on projects in PFBC, initiation of projects in IGCC, and projects in advanced combustion and heat engines.

Fluidized-Bed Combustion. The Tri-State Generation and Transmission Association, Inc.'s Nucla Station repowering project provided the database and operating experience requisite to making ACFB a commercial technology option at utility scale. At 110 MWe, the Nucla ACFB unit was more than 40 percent larger than any other ACFB at that time. Up to 95 percent SO_2 removal was achieved during the 15,700 hours of demonstration, and NO_x emissions averaged a very low 0.18 lb/10^6 Btu. The thrust of this effort was to fully evaluate the environmental, operational, and economic performance of ACFB. As a result, the most comprehensive database on ACFB technology available to date was developed. Based on this knowledge, commercial units were offered and built.

Exhibit 4-2
Commercial Successes—NO_x Control Technology

Project	Commercial Use
Micronized Coal Reburning Demonstration for NO_x Control (New York State Electric & Gas Corporation)	**No sales reported.** Technology retained for commercial use at Kodak Power Plant.
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)	**No sales reported.** Technology retained for commercial use at Wisconsin Power and Light Company's Nelson Dewy Station.
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	**Sold domestically.** Dayton Power & Light has retained the LNCB® for use in commercial service. Seven commercial contracts have been awarded for 172 burners, valued at $27 million. The LNCB® technology has already been installed on more than 4,900 MWe of capacity.
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	**Sold domestically and internationally.** 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 cyclone coal-fired boilers: TVA's Allen Unit 1 (a 330-MWe unit) as well as Baltimore Gas & Electric's C. P. Crane Unit Nos. 1 and 2 (similar 200-MWe units). The technology is also installed at Ladyzkin State Power Station in Ladyzkin, Ukraine.
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers (Southern Company Services, Inc.)	**Sold domestically and internationally.** Since the project was initiated, revenues from sales achieved $2.7 billion through 2000, with projected revenues for 2001 and 2002 expected to be $1.4 billion and $1.3 billion, respectively.
180-MWe Demonstration of Advanced *Tangentially Fired* Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	**Sold domestically and internationally.** LNCFS™ has been retained at the host site for commercial use. ABB Combustion Engineering has sold about 56 GWe of LNCFS™ burners. Of this amount, about 23 GWe are equipped with overfire air and 33 GWe are without overfire air. Total sales are estimated at $1 billion.
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	**Sold domestically and internationally.** The host has retained the technologies for commercial use. Foster Wheeler has equipped 86 boilers (51 domestic and 35 international) with low-NO_x burner technology—a total of over 1,800 burners representing over 30,000 MWe capacity valued at $55 million. Twenty-six commercial installations of GNOCIS, the associated AI control system, are underway or planned. This represents over 12,000 MWe of capacity. In a strict sense, this project has not been completed; it has been extended to apply GNOCIS to other pieces of plant equipment, which may increase its commercial potential.

Exhibit 4-3
Commercial Successes—Combined SO_2/NO_x Control Technology

Project	Commercial Use
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	**International use.** The host utility, Ohio Edison, is retaining the SNOX™ technology as a permanent part of the pollution control system at Niles Station to help meet its overall SO_2 and NO_x reduction goals. Commercial SNOX™ plants are also 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, in operation since March 1991, has a capacity of about 30 MWe and fires petroleum coke.
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	**Sold domestically and internationally.** LIMB has been sold to an independent power plant in Canada. Babcock & Wilcox has sales of 2,585 burners for 35,310 MWe of capacity for the DRB-XCL® low-NO_x burners. The low-NO_x burners have an estimated value of $240 million.
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	**No sales reported.** 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, particulate, or combined emissions to meet current performance requirements while providing flexibility to address future needs.
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	**No sales reported.** Illinois Power has retained the gas-reburning system and City Water, Light & Power has retained the full technology for commercial use. (See Evaluation of Gas Reburning and Low-NO_x Burner on a Wall-Fired Boiler project for a complete understanding of commercial success of the technology.)
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	**Sold domestically.** Eight modules of DHR Technologies' Plant Emissions Optimization Advisor, with an estimated value of $210,000, have been sold. A U.S. company, SHN, has been established to market the S-H-U scrubber. SHN is pursuing an advanced flue gas desulfurization bid for a Pennsylvania site. ABB Combustion Engineering has modified 116 units representing over 25,000 MWe with LNCFS™ or its derivative TFS 2000™.
Integrated Dry NO_x/SO_2 Emissions Control System (Public Service Company of Colorado)	**Sold domestically.** The technology was retained by Public Service Company of Colorado for commercial service at its Arapahoe Station. The Babcock & Wilcox DRB-XCL® burner that was demonstrated has realized sales of 2,428 burners, representing 31,467 MWe. The burners are valued at $320 million.

While the Nucla project established commercial acceptance of ACFB at moderate utility capacities, a second CCT demonstration project, located in Jacksonville, Florida, is carrying on where Nucla left off. JEA (formerly Jacksonville Electric Authority) will build a 300-MWe plant, which will have the distinction of being the largest ACFB in the world, as well as one of the cleanest.

Today, every major U.S. boiler manufacturer offers an ACFB in its product line. There are now more than 120 fluidized-bed combustion boilers of varying capacities operating in the United States, and the technology has made significant market penetration abroad.

Through the Ohio Power Company's repowering of the Tidd Plant (70 MWe), the potential of PFBC as a high-efficiency, low-emission technology was established, and the foundation was laid for commercialization. This was the first utility-scale PFBC system in the United States. Efforts were focused on fully evaluating the performance potential. Over 11,400 hours of operation, the technology successfully demonstrated SO_2 removal efficiencies up to 95 percent with very high sorbent utilization (calcium-to-sulfur molar ratio of 1.5), and NO_x emissions in the range of 0.15 to 0.33 lb/10^6 Btu.

The Tidd Plant PFBC was one of the first generation 70-MWe P200 units installed in the early 1990s. Others were built and operated in Sweden, Spain, and Japan. ABB Stal, the technology supplier, uses a "bubbling" fluidized-bed design, which is characterized by low fluidization velocities and use of an in-bed heat exchanger. The first 360-MWe P800 PFBC is being built in Japan and started operations in 1999. And, a "second generation" P200 PFBC with free-board-firing is operating in Cottbus, Germany. A number of other ABB Carbon PFBC projects are under consideration in China, South Korea, the United Kingdom, Italy, and Israel.

Two ongoing interrelated projects, McIntosh 4A and McIntosh 4B, will demonstrate PCFB at utility scale. PCFB uses a higher fluidization velocity than bubbling-bed systems, which entrains the bed material. Bed material is separated from the flue gas by cyclones and recirculated to the combustor. The economizer, which captures heat from the flue gas, is downstream of the cyclones. McIntosh 4A will evaluate a 137-MWe first generation PCFB configuration using Foster Wheeler technology. McIntosh 4B will demonstrate a second-generation system by integrating a small coal gasifier (pyrolyzer) to fuel the gas turbine "topping cycle," thereby adding 103 MWe capacity. The second-generation PCFB has the potential to significantly improve the efficiency of pressurized fluidized-bed systems by increasing power generation from the gas turbine, which is more efficient than the steam bottom cycle.

Integrated Gasification Combined-Cycle. Three of four IGCC projects are in operation or have completed operations under the CCT Program. They represent a diversity of gasifier types, cleanup systems, and applications. PSI Energy's 262-MWe Wabash River Coal Gasification Repowering Project began operation in November 1995, ceased demonstration operations in December 1999, and now operates in commercial service. The unit, which is the world's largest single-train IGCC, has operated on coal for over 12,400 hours and processed more than one million tons of coal. The unit has achieved monthly production levels of one trillion Btu of syngas on several occasions.

The 250-MWe Tampa Electric Integrated Gasification Combined-Cycle Project began commercial operation in September 1996 and continues to accumulate run time. The gasifier has accumulated over 15,000 hours of operation and produced over 3,500,000 MWh of electricity on syngas. Tests have included evaluation of various coal types on system performance.

The Sierra Pacific Power Company (SPPC) continues to make progress on its IGCC system. The 99-MWe Piñon Pine IGCC Power Project at SPPC's Tracy Station began operation on natural gas in November 1996. The GE Frame 6FA, the first of its kind in the world, performed well. The plant has undergone shakedown, and design modifications have been made. The system has achieved steady-state gasifier operation for short periods, but continued to experience difficulty with sustained operations.

The Kentucky Pioneer Energy IGCC Demonstration Project, which is in the design stage, will offer yet another gasifier design and include the testing of a fuel cell operated on syngas from the coal gasifier. This will provide valuable data for design of an integrated

IGCC plants operating or having completed operations: Tampa Electric (top), Piñon Pine (middle), and Wabash River (bottom).

gasification fuel cell (IGFC) system. IGFC has the potential to achieve efficiencies greater than 60 percent.

Commercial configurations resulting from the current IGCC and PFBC demonstrations will typically have efficiencies at least 20 percent greater than conventional coal-fired systems (with like CO_2 emission reductions), remove 95 to 99 percent of the SO_2, reduce NO_x emissions to levels well within NSPS, reduce particulate emissions by one-third to one-tenth that currently allowed under the CAAA, and produce salable by-products from solid residues as opposed to waste.

Advanced Combustion/Heat Engines. Two projects are demonstrating advanced combustion/heat engine technology. The Healy Clean Coal Project is demonstrating TRW's entrained (slagging) combustor combined with Babcock & Wilcox's spray-dryer absorber using sorbent recycle. Operations were completed in December 2000. Results from environmental compliance testing showed very low emissions—0.26 lb/10^6 Btu for NO_x, 0.01 lb/10^6 Btu for SO_2, and 0.0047 lb/10^6 Btu for particulates. Permit levels are 0.35 lb/10^6 Btu for NO_x, 0.086 lb/10^6 Btu for SO_2, and 0.03 lb/10^6 Btu for particulates because of the plant's proximity to a national park. NSPS allows 1.2 lb/10^6 Btu for SO_2.

The Clean Coal Diesel Demonstration Project is evaluating a heavy duty diesel engine operating on a low-rank coal-water fuel. The demonstration plant is expected to achieve 41 percent efficiency and future commercial designs are expected to reach 48 percent efficiency. As of September 2000, the unit had operated on diesel, with plans for operating on coal in 2002.

Commercialization successes for the advanced electric power generation systems to date are summarized in Exhibit 4-4.

Coal Processing for Clean Fuels

Two of five projects in the coal processing for clean fuels category completed operations and submitted final reports. Projects in this category include physical and chemical processes that can be used to transform the abundant U.S. coal reserves into economic, environmentally compliant solid and liquid fuels and feedstocks. The solid products from coal processing are largely designed to be readily transportable; high in energy density; and low in sulfur, ash, and moisture. The liquid products are designed to be suitable as transportation and stationary power generation fuels, or as chemical feedstocks. Both solid and liquid products, and the processes that produce them, have substantial market potential both domestically and internationally.

The ENCOAL and Western SynCoal LLC projects are breaking down the barrier to using the nation's vast low-sulfur but low-energy-density western coal resources. The resultant fuels have particular application domestically for CAAA compliance and internationally for Pacific Rim energy markets.

ENCOAL's solid fuel product has an energy density of about 11,000 Btu per pound, and the sulfur content averages 0.36 percent. ENCOAL's liquid fuel product can substitute for No. 6 fuel oil or serve as a chemical feedstock. During the demonstration, over 83,500 tons of solid fuel was shipped to seven customers in six states, as well as 203 tank cars of liquid product to eight customers in seven states. Five commercial feasibility studies have been completed—two for Indonesia, one for Russia, and two for U.S. projects. Permitting of a 15,000 metric ton/day commercial plant in Wyoming is nearly complete.

The Western SynCoal LLC project is demonstrating another route to producing high-quality fuel from low-rank coals. The advanced coal conversion process (ACCP) upgrades low-rank coal to produce a low-sulfur (as low as 0.3 percent sulfur) SynCoal® product having a heating value of about 12,000 Btu per pound. Western SynCoal LLC has signed a letter of agreement to supply fuel to Montana Power's 330-MWe Colstrip Unit No. 2. Five other agreements have been signed.

Air Products Liquid Phase Conversion Company, L.P., is demonstrating the LPMEOH™ process to produce methanol from coal-derived synthesis gas. The LPMEOH™ process has been developed to enhance integrated gasification combined-cycle power generation facilities by coproducing a clean-burning storable liquid fuel from coal-derived synthesis gas. The production of dimethyl ether (DME) as a mixed coproduct with methanol will also be demonstrated. Methanol and DME may be used as a low-SO_2, low-NO_x alternative liquid fuel, a feedstock for the synthesis of chemicals, or as a new oxygenate fuel additive. Since startup, the LPMEOH™ demonstration unit has produced over 60 million gallons of methanol, all of which was accepted by Eastman Chemical Company for use in downstream chemical processing. Since restart of the unit with fresh catalyst in December 1997, availability of the unit has been greater than 99 percent and catalyst activity decline has approached 0.4 percent/day.

ABB Combustion Engineering, Inc. and CQ Inc. developed PC-based software, CQE™, to assist utilities in assessing the environmental and operational performance of their systems for the available range of coal fuels to determine the least-cost option. The CQE™ software has been distributed to over 35 utility members of EPRI and is being marketed commercially worldwide. Two U.S. utilities also have been licensed to use copies of the CQE™ stand-alone Acid Rain Advisor.

Commercialization successes for the coal processing technologies to date are summarized in Exhibit 4-5.

Exhibit 4-4
Commercial Successes—Advanced Electric Power Generation

Project	Commercial Use
Tidd PFBC Demonstration Project (The Ohio Power Company)	**Sold internationally.** The project's success has led Babcock & Wilcox to invest in the technology and acquire domestic licensing rights. Commercial ventures abroad include the following: – Vartan in Sweden is operating two P200 units to produce 135 MWe and 224 MWt; – Escatron in Spain is operating one P200 unit producing 80 MWe; – Wakamatsu in Japan is operating one P200 unit to produce 71 MWe; – Cottbus in Germany is operating one P200 unit to produce 71 MWe and 40 MWt; – Karita in Japan operates one P800 unit to produce 360 MWe; and – Other projects under construction are in China, South Korea, U.K., and Israel.
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	**Sold domestically and internationally.** Since the demonstration, Foster Wheeler Energy Corporation, the technology supplier for the demonstration effort, has achieved sales of $7.9 billion through 2000, with another $2.7 billion in sales projected for 2001 through 2003. Twenty-one percent of the sales through 2000 were domestic, while the remaining sales through 2000 were foreign.
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	**Sold domestically and internationally.** First greenfield IGCC unit in commercial service. Texaco, Inc., and ASEA Brown Boveri signed an agreement forming an alliance to market IGCC technology in Europe. There are currently 10 IGCC projects using a Texaco gasifier that are either planned or under construction.
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	**No sales reported.** First repowered IGCC unit in commercial service and is the world's largest single-train IGCC in commercial service. The unit is preferentially dispatched over other coal-fired units in PSI Energy's system because of the unit's high efficiency.
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	**No sales reported.** Unit in initial operation preparatory to commercial service.
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	**No sales reported.** TRW offering licensing of combustor worldwide (China agreement in place). Commercial operation tests are ongoing.

Exhibit 4-5
Commercial Successes—Coal Processing for Clean Fuels

Project	Commercial Use
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ, Inc.)	**Sold domestically and internationally.** The Electric Power Research Institute (EPRI) owns the software and distributes it to EPRI members for their use. CQ Inc. and Black and Veatch have signed commercialization agreements that give both companies nonexclusive worldwide rights to sell user licenses and offer consulting services that include use of CQE®. More than 22 U.S. utilities, two United Kingdom utilities, and one utility in France have received CQE® through EPRI membership. Two modules of the Acid Rain Advisor valued at $6,000 have been sold. EPRI estimated that the Acid Rain Advisor has saved one U.S. utility about $26 million—more than the total cost of the demonstration project. There have also been two sales of the Windows version of the software at an estimated value of $180,000.
ENCOAL® Mild Coal Gasification Project (ENCOAL Corporation)	**Domestic and international sales pending.** In order to determine the viability of potential LFC® plants, five detailed commercial feasibility studies—two Indonesian, one Russian, and two U.S. projects—have been completed. Permitting of a 15,000 metric-ton/day commercial plant in Wyoming is nearly complete.
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	**No sales reported.** Nominal 80,000 gallon/day methanol production being used by Eastman Chemical Company.
Advanced Coal Conversion Process Demonstration (Western SynCoal LLC)	**No sales reported.** Total sales of SynCoal® product exceed 1.5 million tons. Six long-term agreements are in place to purchase the product. One domestic and five international projects have been investigated. Western SynCoal LLC has a joint marketing agreement with Ube Industries of Japan providing Ube non-exclusive marketing rights outside of the United States. Ube is pursuing several projects in Asia. Western SynCoal is also discussing a potential marketing and development agreement with a U.S. engineering firm.

Industrial Applications

The CCT Program is addressing the environmental issues and barriers associated with coal use in industrial applications. Three of five projects have completed operations in this area.

Historically, production of steel has been dependent upon coke. Coke making, however, is an inherently large producer of hazardous air pollutants. Also, cement production often relies on coal fuel because production costs are largely driven by fuel costs. Because of its low stable price, coal is an attractive substitute for oil and gas in industrial boilers, but concerns over increased SO_2 and NO_x emissions and boiler tube fouling have impeded coal use.

Under a project with Bethlehem Steel Corporation, British Steel's blast furnace granular-coal injection (BFGCI) technology demonstrated that 40 percent of the coke can be replaced with coal injected directly into a blast furnace where emissions from coal combustion are effectively controlled in the process.

CPICOR™ Management Company LLC is in the design stage of demonstrating direct iron ore reduction and smelting of iron oxides using coal in lieu of coke. This would reduce the need for coke, which results in large amounts of pollutants during its production.

The Passamaquoddy Tribe successfully demonstrated a unique recovery scrubber that uses cement kiln dust, otherwise disposed of as waste, to remove 90 percent of the SO_2, produce fertilizer and distilled water, and convert the kiln dust to feedstock with no waste generated.

Coal Tech Corporation moved closer to commercializing a combustor for industrial boilers that slags the ash in the combustor to prevent boiler tube fouling, controls NO_x (70 to 80 percent reduction) through staged combustion, and controls SO_2 (90 percent) with sorbent injection.

ThermoChem, Inc. has completed restructuring of its project and is in the construction phase of the demonstration of a multiple resonance tube pulse combustor.

Commercialization successes for the industrial applications technologies to date are summarized in Exhibit 4-6.

The Burns Harbor plant was the site of the BFGCI demonstration.

Awards

The projects in the CCT Program have won numerous awards from news, professional, and non-profit organizations. A listing of those awards is contained in Exhibit 4-7.

Exhibit 4-6
Commercial Successes—Industrial Applications

Project	Commercial Use
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	**No sales reported.** 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.
Blast Furnace Granular-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	**Domestic sale.** British Steel's Blast Furnace Granular-Coal Injection System was sold and installed on a facility owned by United States Steel Corporation.
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	**No sales reported.** While the combustor is not yet fully ready for sale with commercial guarantees, it is believed to have commercial potential. Follow-on work to the CCT Program demonstration was undertaken, which has brought the technology close to commercial introduction.

Exhibit 4-7
Award-Winning CCT Projects

Project and Participant	Award
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	1994 R&D 100 Award presented by *R&D* magazine to the U.S. Department of Energy for development of the low-NO_x cell burner.
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler; Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	1997 J. Deanne Sensenbaugh Award presented by the Air and Waste Management Association to the U.S. Department of Energy, Gas Research Institute, and U.S. Environmental Protection Agency for the development and commercialization of gas-reburning technology.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	1993 Powerplant Award presented by *Power* magazine to Northern Indiana Public Service Company's Bailly Generating Station.
	1992 Outstanding Engineering Achievement Award presented by the National Society of Professional Engineers.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	1995 Design Award presented by the Society of Plastics Industries in recognition of the mist eliminator.
	1994 Powerplant Award presented by *Power* magazine to Georgia Power's Plant Yates. Co-recipient was the U.S. Department of Energy.
	1994 Outstanding Achievement Award presented by the Georgia Chapter of the Air and Waste Management Association.
	1993 Environmental Award presented by the Georgia Chamber of Commerce.
Tidd PFBC Demonstration Project (The Ohio Power Company)	1992 National Energy Resource Organization award for demonstration of energy-efficient technology.
	1991 Powerplant Award presented by *Power* magazine to American Electric Power Company's Tidd project. Co-recipient was The Babcock & Wilcox Company.
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	1997 Powerplant Award presented by *Power* magazine to Tampa Electric's Polk Power Station.
	1996 Association of Builders and Contractors Award presented to Tampa Electric for quality of construction.
	1993 Ecological Society of America Corporate Award presented to Tampa Electric for its innovative siting process.
	1993 Timer Powers Conflict Resolution Award presented to Tampa Electric by the state of Florida for the innovative siting process.
	1991 Florida Audubon Society Corporate Award presented to Tampa Electric for the innovative siting process.
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	1996 Powerplant Award presented by *Power* magazine to CINergy Corp./PSI Energy, Inc.
	1996 Engineering Excellence Award presented to Sargent & Lundy upon winning the 1996 American Consulting Engineers Council competition.
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ Inc.)	In 1996 recognized by then Secretary of Energy Hazel O'Leary and EPRI President Richard Balzhiser as the best of nine DOE/EPRI cost-shared utility R&D projects under the Sustainable Electric Partnership Program.

Market Communications—Outreach

Outreach has been a hallmark of the CCT Program since its inception. The Department of Energy recognized early on that commercialization of technology requires acceptance by a range of interests including: technology users; equipment manufacturers; suppliers and users of raw materials and products; financial institutions and insurance underwriters; government policy makers, legislators, and regulators; and public interest groups. Requisite to acceptance is an outreach program to provide these customers and stakeholders with both program and project information and to seek, on a continuing basis, feedback on program direction and information requirements. An ongoing outreach program has aggressively sought to disseminate key information to the full range of customers and stakeholders and to obtain feedback on changing needs. The effort has recognized the need to highlight environmental, operational, and economic performance characteristics of clean coal technologies and to redesign information packages as customers and stakeholders, and their respective needs, change with the market. Specific objectives of the outreach program include the following:

- Achieving public and government awareness of advanced coal-using technologies as viable energy options;
- Providing potential technology users, both foreign and domestic, with information that is timely and relevant to their decision making process;
- Providing policy makers, legislators, and regulators with information about the advantages of clean coal technologies;
- Convincing financial institutions and insurance underwriters that clean coal technologies are viable options; and
- Providing forums and opportunities for feedback on program direction and information requirements.

Information Sources

A portfolio of publications and information access media exist and are being improved upon as program and marketplace events unfold. Information is currently distributed to over 4,000 customers and stakeholders. The following provides a brief synopsis of the publications and information transfer mechanisms currently in place.

Clean Coal Technology Demonstration Program: Program Update provides an annual summary of program and project progress, accomplishments, and financial status along with a historical backdrop and program role relative to current policy.

The CCT Compendium is a new source of information on the CCT Program.

Clean Coal Technology Demonstration Program: Project Fact Sheets provides a mid-year update on each project.

Clean Coal Technology Conference Proceedings serves as an update on issues impacting the program, feedback on program information requirements, and a

Exhibit 4-8
How to Obtain CCT Program Information

Media	**Description and Action**
Clean Coal Today	Subscription to quarterly newsletter—Send name and address to U.S. Department of Energy, FE-24, Washington, DC 20585.
Fossil Energy Home Page	Primary gateway to extensive information on DOE's Fossil Energy Program and to relevant Web links—On the Internet, access http://www.fe.doe.gov and use menu and/or search options.
CCT Compendium	On the Internet, access http://www.lanl.gov/projects/cctc/.
CCT Program Update and other publications	Send name and address to U.S. Department of Energy, FE-20, Washington, DC 20585.
National Technical Information Service	U.S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161.

periodic snapshot of how each of the active projects is progressing with some degree of technical depth.

Clean Coal Today newsletter offers its readers a quarterly look at the CCT Program and related issues, highlighting key events, updating project status, and listing the latest publications and upcoming events.

Project Performance Summary documents provide a 12-page synopsis of a completed project, highlighting its operational, environmental, and economic performance. Eleven have been published so far, with another one expected in early fiscal year 2001.

Clean Coal Technology Topical Reports capture projects at critical junctures and highlight particular technological advantages, project plans, and expected outcomes. Fifteen have been published so far, with another two expected in early fiscal year 2001.

National Technical Information Service (NTIS) serves as the federal government's central source for the sale of scientific, technical, engineering, and related business information produced by or for the U.S. government. The NTIS has most of CCT Program technical reports.

CCT Program Bibliography of Publications, Papers, and Presentations periodically updates the key materials available on the technologies demonstrated under the CCT Program.

The Investment Pays Off periodically takes a market-based view of the success of the CCT Program by virtue of commercial sales and relevance of ongoing activities to projected market need.

CCT Program—Lessons Learned documents the lessons learned in soliciting, selecting, and awarding projects and implementing the program.

CCT Compendium provides an electronic database incorporating the CCT Program publications that can be accessed on the Internet (http://www.lanl.gov/projects/cctc/).

Exhibits provide a means through graphics, photos, broadcast videos, and interactive videos to convey program messages at a variety of forums, and serve as focal points for distribution of literature and discussion of the program and information needs. There are currently four exhibits of varying sizes and complexity that are updated and modified, as necessary, to convey the appropriate message for specific forums. A fifth exhibit is in development to replace an older exhibit that will be retired.

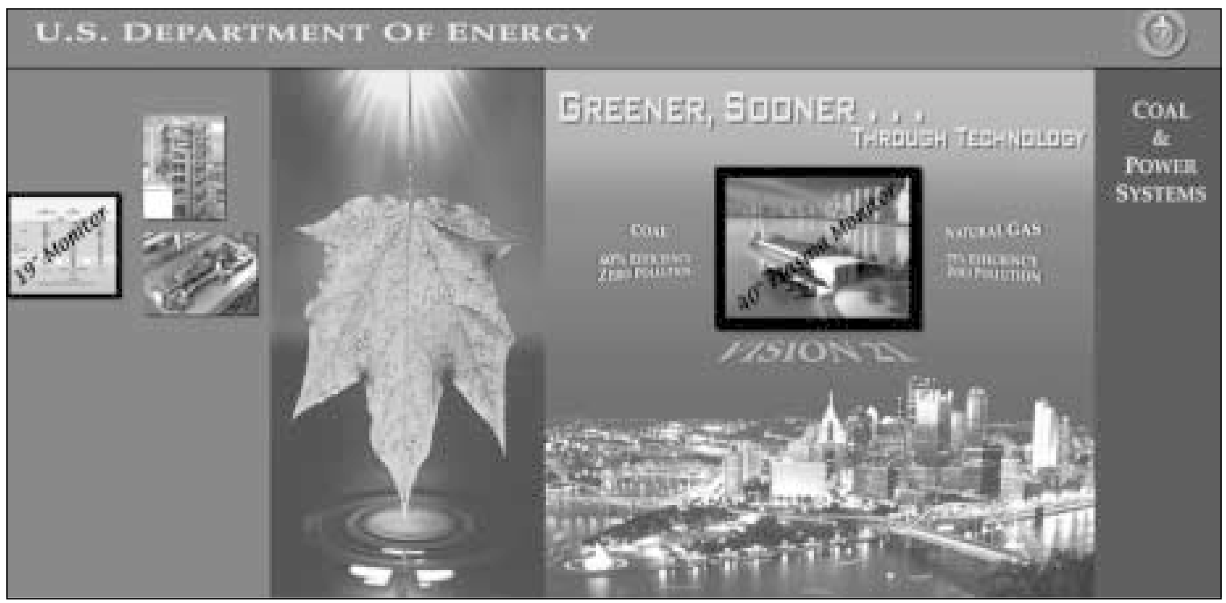
Fossil Energy Home Page provides the primary Internet gateway to extensive information on DOE's Fossil Energy Program and to relevant World Wide Web links (http://www.fe.doe.gov).

Exhibit 4-8 summarizes how the above publications can be obtained and information sources can be accessed.

Publications Issued in FY2000

The following publications were issued in fiscal year 2000 by the CCT Program. Similar publications can be expected in fiscal year 2001.

- *Clean Coal Technology Demonstration Program: Program Update 1999*
- *Clean Coal Technology Demonstration Program: Project Fact Sheets 2000*
- *Clean Coal Today: Winter 1999, Spring 2000, Summer 2000, Fall 2000*
- *Clean Coal Today Index*
- *Project Performance Summary—ENCOAL® Mild Coal Gasification Project*
- *Clean Coal Technology: The Investment Pays Off*
- *Topical Report—Blast Furnace Granular Coal Injection System Demonstration Project.*



A new exhibit is in development for the Outreach Program. Shown is the conceptual design of the exhibit.

- *Topical Report—Tampa Electric Integrated Gasification Combined-Cycle Project: An Update*

Information Access

The Department of Energy continues to expand its website to provide information on federal fossil energy programs and serve as a gateway to other related information throughout the United States and the world. Once into the DOE website, users can obtain general information and follow links to increasingly detailed information, ultimately accessing specific data on individual projects and facilities. Hyperlinks allow users to move seamlessly between headquarters and field sites. Users can also access technical abstracts and reports maintained by DOE's Office of Scientific and Technical Information (OSTI) at Oak Ridge, Tennessee. The gateways link to more than a hundred energy-related websites operated by private companies, trade associations, and other agencies worldwide.

Furthermore, the Fossil Energy International Activities site on the World Wide Web has been expanded with the addition of new country pages in the Western Hemisphere region (Mexico, Ecuador and Canada). Many of the existing country pages have also been upgraded, with new hyperlinks to business- or energy-related information sources. An innovation at the Fossil Energy International Activities website is a series of newly created Country Energy Overviews. Each overview, individualized for a particular country, includes a status summary of that country's energy infrastructure, energy and environmental policies, and privatization efforts. Fifteen country pages are now available. The Uniform Resource Locator (URL) for the Fossil Energy International main page is http://www.fe.doe.gov/international and can be accessed via the "International" hyperlink in the Fossil Energy Home Page (http://www.fe.doe.gov).

In February 1998, DOE established a new information resource on the Internet. The Clean Coal Technology Compendium, sponsored by the Office of Fossil Energy and the National Energy Technology Laboratory (NETL), is dedicated to making the maximum use of information derived from the CCT Program. The compendium is designed to emphasize ease of use, and contains a broad collection of different types of data and information, making it applicable to the needs of both managers and engineers. For example, one can access the latest *Clean Coal Technology Demonstration Program: Program Update* and *Topical Reports* published periodically on individual CCT projects. The CCT Compendium is accessible via the Internet at http://www.lanl.gov/projects/cctc/.

Information Dissemination and Feedback

A number of mechanisms are used to disseminate program information to customers and stakeholders and obtain feedback from them on specific issues, program direction, and information requirements. The following provides a brief outline of the mechanisms.

Public Meetings were routinely held over the course of the acquisition phase of the CCT Program to solicit input on procurement actions. Subsequently, project participants have been holding open houses for the public, providing tours of demonstration facilities, and publicizing projects through groundbreaking and dedication ceremonies.

Executive Seminars involve program officials meeting with key industry officials at their places of business to facilitate discussion. Discussions seek to: obtain a better understanding of the dynamics of the decision making process for adopting new power generating technologies, determine how the program could best support the process and achieve a positive outcome, and gain insights on the future direction of the power industry. Over 50 meetings have been held since 1992 with influential leaders in the utility, independent power, regulatory, and financial communities.

Stakeholder Meetings bring together key stakeholder organizations for the purpose of coordinating programs, where appropriate, and discussing pertinent issues and implementation strategies to address the issues and outreach needs. Such stakeholder organizations include the Electric Power Research Institute (EPRI), Gas Research Institute (GRI), Coal Utilization Research Council, Center for Energy & Economic Development (CEED), Council of Industrial Boiler Owners (CIBO), Clean Coal Technology Coalition, and National Mining Association (NMA).

Conferences and Workshops bring together targeted audiences to review and discuss topics of interest, document discussions and findings, and provide recommendations, as appropriate. *Trade Missions* are a subset of these and differ only in that the thrust is international in character with the purpose of promoting the export of U.S. technology and services. The outreach program has participated in over 230 technical conferences, workshops, and trade missions since 1991.

Conferences and Workshops Held in FY2000

Indonesia. The National Energy Technology Laboratory, along with Indonesia's Energy Research Lab, co-sponsored the highly successful CoalTech '99 conference in Jakarta, Indonesia on November 1-2, 1999. The conference, designed to develop and foster knowledge of clean coal technologies in Indonesia's coal mining and power generation sectors, drew 175 attendees from a variety of countries. A highlight of the meeting was the formation of the Indonesian Coal Society to facilitate technical dialog and better understanding of Indonesian coal properties and clean coal technologies' performance characteristics. Indonesia mines approximately 60 million tons of coal per year, of which 40 million tons are high quality and targeted for export. The remaining 20 million tons of lower quality coal are used in domestic power plants. These power plants are slated to reduce SO_2 emissions by up to 50 percent, and clean coal technologies are seen as a way to achieve that end. During the opening ceremonies for the conference, NETL and Laboratorium Sumderdaya Energi (LSDE) signed a Joint Statement to discuss potential cooperation on clean coal and other advanced power technologies. As a first sign of cooperation, LSDE requested that NETL co-sponsor the second CoalTech Conference during October 23-24, 2000 in Jakarta.

Slovakia. Under a cooperative research agreement between NETL and the Slovak Academy of Sciences, NETL researchers have recently completed a study of the application of triboelectrostatic separation to Slovakian brown coal. The brown coal, a significant resource for power production in Slovakia, contains elevated levels of ash, sulphur, and arsenic. The study concluded that using triboelectrostatic separation reduced ash levels in the coal significantly. The results were presented at the 10th International Conference on Coal Science on September 13, 1999, in Taiyuan, China, as well as at the 16th Pittsburgh Coal Conference on October 14, 1999, in Pittsburgh, Pennsylvania.

Japan. At the request of the Japanese Institute of Applied Energy and the New Energy Development Organization (NEDO), the Office of Fossil Energy hosted a one-day workshop held in Washington, D.C., in January 2000 on municipal solid waste (MSW) treatment options designed to address Japan's landfill shortage and, secondarily, to produce power. Japan's plans are aimed at developing high-temperature processes to transform MSW into vitrified ash and additional power-generation capacity. Particular interest was expressed in the high-temperature gasification systems under FE's Coal & Power Systems programs.

Japan generated 51 million tons of waste in 1996, and the average annual increase since 1992 has been 225,000 tons, making development of effective recycling and disposal methods imperative and making MSW a major power generation fuel option. Currently, Japan has 1,800 small, low-efficiency incineration facilities, only nine percent of which generate a total of 890 MWe.

Japan's goal is to convert or establish new MSW process facilities to generate 5,000 MWe of power by 2010, representing an increase of almost 800 facilities that coproduce power. Currently, Japan relies on a pyrolysis furnace to produce pyrolytic gas from MSW, which in turn fuels a melting furnace to transform the remaining waste from the pyrolysis unit into "molten slag." Heat from the combustion melting furnace raises steam to drive a steam turbine for power generation at an efficiency of about 30 percent. On the other hand, high-temperature gasification systems under development in the United States use the synthetic gas produced in the gasifier to generate power in a combined-cycle, which results in efficiencies of over 40 percent and a vitrified slag usable in construction applications.

The workshop agenda included a presentation to Japan on high-efficiency waste power generation, and discussions of representative R&D, Clean Coal Technology projects, and Vision 21 research program goals as all three address Japan's current need. Various gasification projects were discussed, along with FE's gasification database, and power/fuels coproduction. Japanese attendees were particularly interested in Global Energy's presentation on the latest CCT Program project, the Kentucky Pioneer IGCC facility, which will gasify a briquetted mixture of coal fines and MSW to produce power with gas and steam turbines in combined-cycle, and a molten carbonate fuel cell. One product of FE's R&D effort, a demonstration plant to make slurry fuels from either MSW or municipal sewage sludge for cofiring in a conventional pulverized coal power plant (the "E Fuels from Slurry Carb" process), is already in use on a small scale in Japan using MSW.

In all, U.S. workshop participants presented a strong case to their Japanese counterparts that gasification is a cost-effective option for solid waste and sewage sludge elimination, while simultaneously recycling incinerator organic emissions into usable solid waste products that do not require landfilling.

India. An Office of Fossil Energy representative and several contractors played a major role in an international conference entitled "Power Plant Operation, Efficiency and Environmental Protection," held in February in New Delhi, India. The conference was organized by the National Thermal Power Corporation (India) and the USAID in association with the NETL, Electric Power Research Institute, and Tennessee Valley Authority (TVA). The conference attracted some 350 attendees, including senior officials from the government of India, and private sector representatives. Approximately 25 American public and private sector presenters shared experiences with their Indian counterparts. As part of this conference, TVA, under a Cooperative Agreement with NETL, provided attendees with a two-volume study entitled "Guidelines for Heat Rate Improvements at Coal-Fired Power Plants in India," prepared under the Greenhouse Gas Pollution Prevention Project with funding from the USAID. This report culminates an in-depth study of the Indian power industry, and focuses on identifying critical issues and opportunities for improving overall heat rates and efficiencies of currently operating coal-fired plants. Both DOE and USAID share the long-range hope that many of the recommendations will be incorporated by the Indian power industry.

As part of this conference, FE also helped to organize a workshop entitled "Identification of Barriers and Utilization Options: Large Volume Applications of Fly Ash in India." Some 90 attendees from the Indian power industry discussed areas such as policies and standards, geomaterials and agricultural applications, and construction applications/technologies. The Office of Fossil Energy supported these sessions with consultants and speakers from the U.S. coal and power research community.

APEC. Asia Pacific Economic Cooperation's (APEC) Sixth Coal Flow Seminar was held in the Spring of 2000 in Kyongju, Korea. The Asia Pacific Economic Cooperation was formed in 1989 to address issues of regional interdependence, and its members include 18 countries bordering the Pacific Ocean. The seminar, where policymakers discuss the flow of coal imports and exports among APEC nations, is funded by DOE, along with Japan's Ministry of International Trade and Industry, and Korea's Ministry of Commerce, Industry, and Energy. The Office of Fossil Energy is the main U.S. government presence at the seminar and every year has provided technical speakers.

There were 120 participants from nine APEC economies at this year's conference, the theme of which was "Coal in the New Millennium." With economies rebounding from the Asian economic crisis, APEC is looking for new coal demand projections. Seminar participants believe that a shared view of future coal supply and demand, as well as pricing and environmental concerns, can contribute to greater market stability in the region.

Speakers addressed broad challenges affecting coal in APEC nations, such as excess capacity as a result of lower growth rates during the recent economic crisis, environmental concerns, and insufficient infrastructure. However, on the positive side, the economic crisis resulted in liberalization/privatization reforms so that the energy sector is expected to become more competitive.

The Chairman of APEC's Experts Group on Clean Fossil Energy gave one of the opening addresses and noted that APEC is the fastest growing region in the world in energy terms. Clean coal technologies can help achieve sustainable development in the region, and support the strategic importance of the region's indigenous coal in the context of a vulnerable oil market.

Another keynote address focused on the overriding issue of greenhouse gas constraints and the competitive position of coal in Asia. The speaker noted that local and regional environmental restrictions for SO_2 and particulates, as well as increased competitiveness of natural gas, pose a greater threat to coal expansion than does the Kyoto Protocol. According to the speaker, most economies are following a gradual approach to carbon emission reductions, which should allow time for introduction of clean coal technologies. Under likely scenarios, some experts expect coal consumption to double within the next 25 years.

A number of seminar speakers provided the individual country perspective. Among them were representatives from FE, who noted that the U.S. coal industry has successfully responded to major challenges since the 1960s. They explained that the new slate of near zero-polluting clean coal technologies to be developed under the Vision 21 program can provide new markets for coal in the 21st century. Representatives from Korea noted the country's desire to diversify import sources and develop overseas coal mines; but government assistance may be required for overseas investment. Chinese representatives spoke of a rise in exports, with government infrastructure investments. A representative from the Russian research community addressed problems of industry restructuring, while Australian representatives discussed productivity improvements. A Japanese representative stated that Japan expects to continue importing coal but at lower rates.

Trade Mission Activities in FY2000

South Africa. South Africa's national utility, ESKOM, is considering repowering a 125-MWe unit at the mothballed 1,000-MWe Komati Power Station with circulating fluidized-bed combustion (CFB) technology. The plan is to burn "discard" coal, the high-ash residue from coal washing. Located near Middelburg, South Africa, the project would be the first utility-scale clean coal technology installation in South Africa. The Komati project represents up to $25 million in potential U.S. goods and services exports.

The Office of Fossil Energy's involvement with ESKOM began in 1998, when its representatives facilitated meetings with U.S. engineering firms and technology vendors, arranged CCT Program project site visits, and encouraged attendance at DOE coal-related conferences. ESKOM has visited a number of U.S. power plants, including JEA's Northside Station in Jacksonville, Florida, where the Large-Scale CFB Combustion Demonstration Project is being conducted. ESKOM has also visited the three major vendors of CFB technology in the United States: ABB-Ahlstom, Babcock & Wilcox, and Foster Wheeler.

In recent years, South Africa has produced 250 million tons of coal annually, and currently is the world's second largest exporter with 62 million tons exported in 1999. Discard coal is the country's largest volume industrial waste, with 55 million tons of fresh discards generated annually, 20 percent of the total mined product. By 2002, it is estimated that the inventories of accumulated discard coal in South Africa will reach 1 billion tons.

Long-term planning for ESKOM calls for adding 1,000–2,000 MWe of new generation capacity annually starting in 2007. Clean coal technologies like CFB would allow that power demand to be met with state-of-the-art technology. In addition, CFB plants could use the vast quantities of discard coal that otherwise would have to be landfilled.

A preliminary investigation has indicated that sufficient discard coal inventories exist within a 10-km radius of the Komati power station, in terms of both accumulated product and future streams, to support 400–500 MWe of capacity for 30 years. The Komati demonstration would prove CFB in South Africa and could lead to repowering of additional mothballed conventional pulverized-coal units. If all 3,800 MWe of ESKOM's mothballed units are repowered, the U.S. export potential could be as high as $800 million. Large deposits of discard coal could also make CFB green-field units more attractive.

In August 1999, as a commitment under the U.S.-South Africa Binational Commission, the U.S. Trade Development Agency approved $500,000 for a repowering feasibility study of ESKOM. With results of the feasibility study in hand, ESKOM will assess joint venture possibilities with technology vendors and local investors. To meet the projected demand for new power, ESKOM will likely need to commit to the Komati demonstration project within the next year.

India. In March 2000, President Clinton spent a week in India and Pakistan addressing environmental, economic, health, and other issues of joint concern. During his stay in India, the President announced several initiatives to protect the environment, develop clean energy sources, and combat climate change, some of which could have potential for clean coal technology applications.

One initiative was a Joint Statement on Energy and the Environment, signed by the U.S. Secretary of State and India's Minister of External Affairs. Of particular relevance to the Office of Fossil Energy is a provision for improvements in power plant efficiency, an area on which the efforts of FE in India have long been focused. The goals are a 15 percent improvement in generating efficiency by 2008, along with a 10 percent increase in use of biomass and other renewables by 2012. Since most of India's power is supplied by low-grade coal burned in aging and inefficient facilities, it is likely that much of the improvement will have to come from modification of existing coal-fired plants or installation of new ones. The agreement notes that India is making fossil fuel energy use cleaner and more efficient, and intends to further improve energy efficiency in the electric power sector by focusing on renovation and modernization to include repowering of older plants to improve plant load factors, upgrading, and strengthening transmission and distribution systems as well as to reduce transmission and distribution losses. The agreement expands upon an earlier Joint Statement of October 1999. A Joint Consultative Group on Clean Energy and Environment will be created to promote collaborative projects and cooperation.

While in India, the President announced a $45 million energy efficiency/clean energy package that includes a second, five-year phase of the Greenhouse Gas Pollution Prevention Project headed by the U.S. Agency for International Development (USAID) with technical support from FE, the result of a Participating Agency Service Agreement with USAID-India. Current activities are directed toward reducing the amount of greenhouse gas emissions produced per unit of electricity generated.

Over the past five years, more than a dozen teams led by FE have provided technical assistance to India's power stations and training to power plant engineers. In 1994, FE also helped the National Thermal Power Corporation (NTPC), the sixth largest utility in the world, to establish the national Centre for Power Efficiency and Environmental Protection (CenPEEP) in Noida, near New Delhi. The Centre has an independent, power industry-funded group of coal/power plant experts who manage various activities for the Indian power industry, including plant design and improvement, R&D, and training. It has been serving as a resource for technical knowledge and demonstration in support of improved power sector management, increasing operating efficiencies, and strengthening environmental protection.

In the second phase, termed the Climate Change Supplement, FE will assist in building local capacity to sustain greenhouse gas reduction in existing plants. FE will also introduce more efficient and lower cost greenhouse gas technologies for new power plants and improve the utilization of existing assets.

Three months after the President's visit to India, a regional CenPEEP was opened in June 2000 in Lucknow in the state of Uttar Pradesh, with support from FE and USAID. The CenPEEP in Uttar Pradesh, and another planned for Patna, Bihar, will act to expedite training throughout India.

Department of Energy team members have been instrumental in demonstrating the value of efficiency and environmental improvements at selected NTPC and State Electricity Board plants, and in developing "Heat Rate Improvement Guidelines for Indian Power Plants." During 2001, FE and USAID will provide training in power plant efficiency such as improved operating and maintenance practices, as well as environmental monitoring. Efficiency improvements in Indian plants will help meet the 15 percent improvement goal established in March 2000 by the U.S. and Indian governments.

On September 13, 2000, DOE, USAID, India's Ministry of Power, and the NTPC signed a Protocol of Intent to conduct a detailed technical and economic feasibility study for setting up a commercial-scale integrated gasification combined-cycle demonstration plant in India. The study will seek to establish the most suitable IGCC technology for India's coal and environmental conditions, explore possible financing structures competitive in India, and develop an implementation plan for IGCC technology demonstration in India. The agreement was signed for by the DOE Deputy Secretary, the USAID Deputy Administrator, India's Secretary of Power, and the NTPC Director. This follows the signing of a Joint Statement on Cooperation in Energy and Environment in New Delhi on March 22, 2000, which articulated both countries' desire to increase their energy and environment cooperation. Both USAID and NETL are discussing possible IGCC activities to be conducted under the ongoing Greenhouse Gas Pollution Prevention Project.

Foreign Service Officer Training Course. In cooperation with the U.S. Department of State's Foreign Service Institute and Bureau of Economic and Business Affairs, the Department of Energy hosted the first week-long Coal and Power Sector Training Course in the Pittsburgh, Pennsylvania, area during July 24-28, 2000. The 22 participants were given several extensive site tours to learn about various technologies. They also attended lectures and discussions on timely issues in the international energy arena, such as electricity deregulation, climate change, and emergence of new technologies for clean coal, distributed generation, greenhouse gas reduction and other pollution controls, and ultra-clean fuels.

The Foreign Service Institute was established in 1947 to furnish Foreign Service Officers (FSOs) with training throughout their careers. The FSOs explain U.S. policies and interests to foreign nationals and their governments, and also have a function in promoting exports and negotiating international agreements. Increasingly, FSOs are involved in energy matters. The Foreign Service promotes free-market economies and works with international institutions toward progress in meeting global concerns regarding the environment and other international interests. The Foreign Service also acts as an advocate for U.S. business interests and to protect intellectual property rights. According to the State Department, efforts by FSOs resulted in U.S. exports totaling $934 billion in 1998, or 12 percent of the U.S. gross domestic product.

The training course provided participants an overview of the fundamentals of the coal and power sectors worldwide, and provided a forum for discussion among energy specialists from the U.S. government and private industry. Emphasis was placed on technological changes in the coal and power industry specifically related to developing countries. During the week of training, participants made a number of field trips to sites including Ebensburg Power Company's 50-MWe waste coal-fired cogeneration plant; Edison Mission Energy's 2,012-MWe pulverized coal-fired Homer City Plant and on-site coal preparation plant; First Energy/Penn Power's 2,742-MWe Bruce Mansfield Power Plant with its large wet SO_2 scrubber, and National Gypsum Company's adjacent wallboard manufacturing plant; Allegheny Energy's 88-MWe gas turbine Springdale plant; and the Siemens Westinghouse Solid Oxide Fuel Cell pilot manufacturing facility.

Implementation of the FSO training between FE and numerous private companies is a prime example of successful government-industry collaboration. The Coal and Power Sector training preceded an FE-supported Oil and Gas Industry course, held in Houston, Texas, the following week. The Foreign Service Institute intends to offer both training courses annually in the future.

5. CCT Projects

Introduction

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.

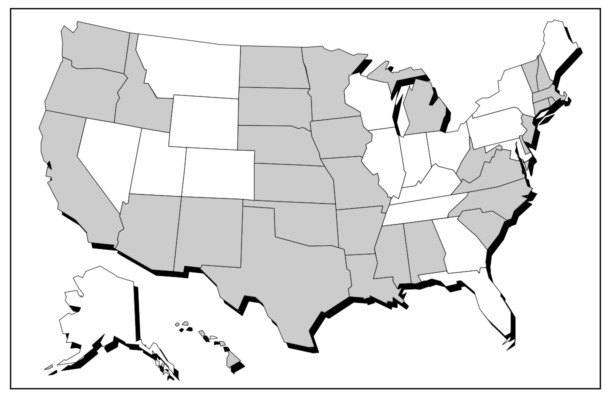
In response to the initial thrust of the CCT Program, operations have been completed for 18 of 19 projects that address SO_2 and NO_x control for coal-fired boilers. The resultant technologies provide a suite of cost-effective control options for the full range of boiler types. The 19 environmental control device projects are valued at more than $702 million. These include seven NO_x emission control systems installed in more than 1,750 MWe of utility generating capacity, five SO_2 emission control systems installed on approximately 770 MWe, 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 particulate 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 $2.8 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 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 also were undertaken to address pollution problems associated with coal use in the industrial sector. These 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.

The remainder of this section contains a discussion of the technologies being demonstrated and fact sheets for each project.



The CCT projects are spread across the nation in 18 states, indicated in white.

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 remain 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 the 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. This year, Phase II of Title IV became effective, impacting all fossil fuel-fired units, but most of all, the approximately 700 pre-NSPS coal-fired facilities. 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 sole purpose of removing SO_2. Three basic approaches, discussed below, have evolved and are 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, such as size, type, age, and space availability for these boilers.

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 into 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 50–70 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 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 is used, as opposed to limestone, and sulfur capture efficiencies up to 90 percent can be achieved at Ca/S molar ratios of 1.3–2.0. This category of control device is called a spray dryer because the solid by-product from the reaction is dry.

At the other end of the spectrum are the larger (300-MWe and larger) existing boilers, with some latitude in space availability, and new plants. 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 the lower cost limestone, which reduces operating costs. In addition, new technologies reduce capital costs, improve reliability, and increase overall plant efficiency. The AFGD achieved SO_2 removal efficiencies of greater than 90 percent 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.

The CCT Program successfully demonstrated two sorbent injection systems, one spray dryer system, and two AFGD systems. All have completed testing. Exhibit 5-1 briefly summarizes the characteristics and performance of the SO_2 control technologies that are described in the project fact sheets in this section.

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

Exhibit 5-1
CCT Program SO_2 Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO_2 Reduction	Page
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%	5-22
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Sorbent injection—in-duct lime sorbent injection and humidification	1.5–2.5%	50%	5-26
LIFAC Sorbent Injection Desulfurization Demonstration Project	Sorbent injection—furnace sorbent injection (limestone) with vertical humidification vessel and sorbent recycle	2.0–2.9%	70%	5-30
Advanced Flue Gas Desulfurization Demonstration Project	AFGD—cocurrent flow, integrated quench absorber tower, and reaction tank with combined agitation/oxidation (gypsum by-product)	2.25–4.7%	94%	5-34
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+%	5-38

The 10-MWe AirPol gas suspension absorption demonstration unit.

LIFAC reactor being installed in Richmond, Indiana.

Pure Air absorber module used in the Advanced Flue Gas Desulfurization Demonstration Project.

The Confined Zone Dispersion FGD technology achieved 50% SO_2 removal efficiency. The extended ductwork, where the lime slurry was injected, is shown on the left.

NO_x Control Technology. Nitrogen oxides 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). 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 265 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 impacted all fossil-fueled units, but most notably, the balance of the pre-NSPS coal-fired units (see Exhibit 5-2). 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 to 85 percent below 1990 rates or achieve a 0.15 lb/10^6 Btu emission rate by May 2003. The fate of the SIP call is uncertain as litigation proceeds.

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 either by modifying the combustion process or by 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 natural gas or coal. Postcombustion processes for treating flue gas include selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR). Advanced controls can also help in NO_x reductions.

The 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 formation of fuel-bound NO_x and thermal NO_x. Alone, LNBs typically can achieve 40–50 percent NO_x reduction.

The AOFA technology 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. The 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 10–25 percent NO_x emission reductions. The LNB/AOFA systems generally can achieve NO_x emission reductions of 37 to 68 percent, depending upon boiler type.

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 10–30 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). The 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

Exhibit 5-2
Group 1 and 2 Boiler Statistics and Phase II NO_x Emission Limits

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

cyclone boilers, and can achieve NO_x emission reductions of 50–67 percent.

The SCR and SNCR technologies 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. The SNCR system can only be used at high temperatures (1,600–2,200 ºF) where a catalyst is not needed. The SCR system is typically applied at temperatures between 600–800 ºF. Generally, SNCR and SCR systems alone can achieve NO_x emission reductions of 30–50 percent and 80–90+ percent, respectively.

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.

Under the CCT Program, seven NO_x control technologies were assessed encompassing LNBs, AOFA, reburning, SNCR, SCR, and combinations thereof. Six of the seven projects have completed operations. One project has been extended. Exhibit 5-3 briefly summarizes the characteristics and performance of the technologies that are described in more detail in the project fact sheets.

Kodak Park was one of two sites demonstrating micronized coal reburning.

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 six 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.

All six of the combined SO_2/NO_x control technology projects have completed operations. Exhibit 5-4 briefly summarizes the characteristics and performance of the technologies that are described in the project fact sheets.

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 capacity expansion needs requisite to meeting long-term demand, offsetting 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.

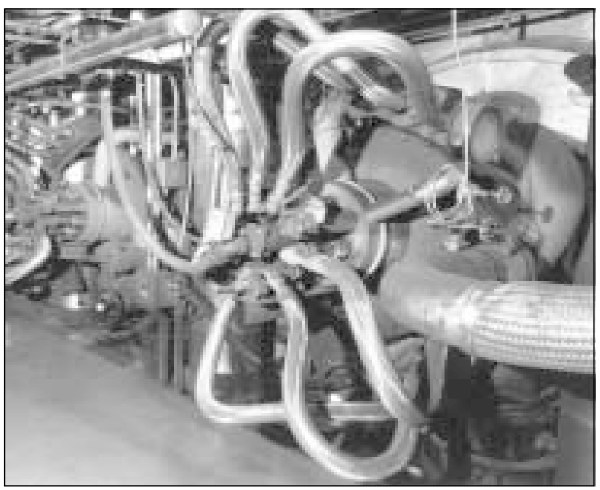
There are five generic advanced electric power generation technologies demonstrated in the CCT Program. The characteristics of these five technologies are outlined here, and the specific projects and technologies are presented in more detail in the fact sheets.

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

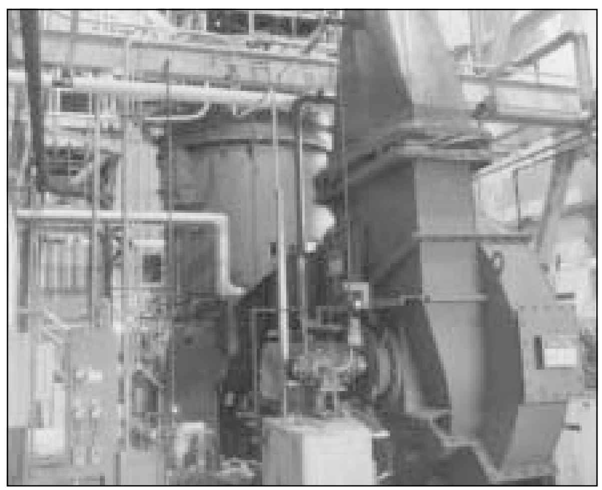
Exhibit 5-3
CCT Program NO_x Control Technology Characteristics

Project	Process	Boiler Size/ Type	NO_x Reduction	Page
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%	5-44
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	Coal reburning—30% heat input	100-MWe/cyclone	52–62%	5-48
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%	5-52
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%	5-56
Micronized Coal Reburning Demonstration for NO_x Control	Coal reburning—14% heat input (tangentially fired) and 17% heat input (cyclone)	148-MWe/tangential 50-MWe/cyclone	28% 59%	5-60
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%	5-64
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%	5-68

Foster Wheeler's LNBs used at Cherokee Station for the GR-LNB demonstration.



New air fan in the foreground and new pulverizer in the background for the micronized coal reburning project.



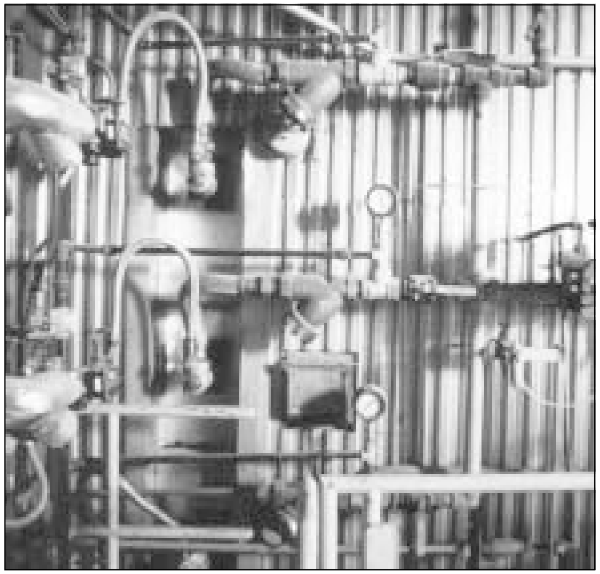
The SCR demonstration facility at Southern Company's Plant Crist.

Exhibit 5-4
CCT Program Combined SO_2/NO_x Control Technology Characteristics

Project	Process	Coal Sulfur Content	SO_2/NO_x Reduction	Page
SNOX™ Flue Gas Cleaning Demonstration Project	SCR/oxidation catalyst/sulfuric acid condenser—synergistic catalyst effect and no solid waste	3.4%	95%/94%	5-74
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%	5-78
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%	5-82
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Gas reburning/sorbent injection (GR-SI)—calcium-based sorbents used in duct injection	3.0%	50–60%/67%	5-86
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%	5-90
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%	5-94

Coolside process sorbent distribution bottle and feed lines on top of bypass duct.

Humidification panels and controls on the side of duct work where water is injected into the flue gas for GR-SI.



The SO_x-NO_x-Rox Box™ baghouse, silos, duct work, and tie-in.

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 in this manner.

At combustion temperatures of 1,400–1,600 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 that thermal NO_x is formed. In fact, FBC NO_x emissions are about 70–80 percent lower than those for conventional pulverized-coal boilers. Thus, fluidized-bed combustors substantially reduce both SO_2 and NO_x emissions. Also, FBC has the capability of using high-ash coal, whereas conventional pulverized-coal units must limit ash content in the coal to relatively low levels.

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

Two parallel paths were pursued in FBC development—bubbling and circulating beds. Bubbling fluidized-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 that 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 evolved from these two basic approaches.

Fluidized-bed combustion can be either atmospheric (AFBC) or pressurized (PFBC). The AFBC systems operate at atmospheric pressure while PFBC operates at pressure 6 to 16 times higher. The PFBC systems offer higher efficiency by using both a gas turbine and steam turbine. Consequently, operating costs and waste are reduced relative to AFBC, as well as boiler size per unit of power output.

Second-generation PFBC integrates the combustor with a pyrolyzer (coal gasifier) to fuel a gas turbine (topping cycle), and the waste heat 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 as of the end of fiscal year 2000.

Integrated Gasification Combined-Cycle. The IGCC 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 the gas is 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 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 and catalysts, 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 more than 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 considered. In these hot 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 ºF, 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. Nitrogen oxides 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.

Energy conversion in fuel cells is more efficient than traditional energy conversion devices (up to 60 percent, depending on fuel and type of fuel cell). Fuel cells directly transform the chemical energy of a fuel and an oxidant (air or oxygen) into electrical energy instead of going through intermediate steps—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, one has completed operations, two are in operation, and one is in the project definition and design phase as of the end of fiscal year 2000. The project in the design phase plans to incorporate a molten carbonate fuel cell (MCFC).

Coal-Fired Diesel. Coal-fired diesels use either a coal-oil or coal-water slurry fuel to 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 a 41–48 percent thermal efficiency. The 5- to 20-MWe capacity range of the technology is 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 from the combustor rather than the furnace. Most of these slagging combustors are based on a cyclone 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.

An 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 high 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 show that by positioning air injection ports so that coal is combusted in stages, NO_x emissions can be reduced by 70–80 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.

Exhibit 5-5 summarizes the process characteristics and size of the advanced electric power generating technologies presented in the project fact sheets.

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.

Western SynCoal LLC's advanced coal conversion process 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 5,500–9,000 Btu/lb, 25–40 percent moisture content, and 0.5–1.5 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. Project operation was extended through 2001.

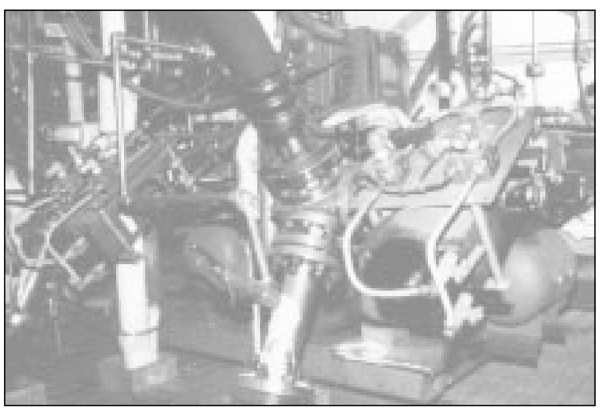
The ENCOAL project, which completed operational testing in July 1997, used mild gasification to convert low-Btu, low-sulfur subbituminous coal to a high-energy-density, low-sulfur solid product and a clean liquid fuel comparable to No. 6 fuel oil. Mild gasification is a pyrolysis process (heating in the absence of oxygen) performed at moderate temperatures and

Exhibit 5-5
CCT Program Advanced Electric Power Generation Technology Characteristics

Project	Process	Size	Page
Fluidized-Bed Combustion			
McIntosh Unit 4A PCFB Demonstration Project	Pressurized circulating fluidized-bed combustion	137 MWe (net)	5- 100
McIntosh Unit 4B Topped PCFB Demonstration Project	McIntosh 4A with pyrolyzer and topping combustor	240 MWe (net)	5-102
JEA Large-Scale CFB Combustion Demonstration Project	Atmospheric circulating fluidized-bed combustion	297.5 MWe (gross); 265 MWe (net)	5-104
Tidd PFBC Demonstration Project	Pressurized bubbling fluidized-bed combustion	70 MWe	5-106
Nucla CFB Demonstration Project	Atmospheric circulating fluidized-bed combustion	100 MWe	5-110
Integrated Gasification Combined Cycle			
Kentucky Pioneer Energy IGCC Demonstration Project	Oxygen-blown, slagging fixed-bed gasifier with cold gas cleanup	580 MWe (gross); 540 MWe (net)[a]	5-116
Piñon Pine IGCC Power Project	Air-blown, fluidized-bed gasifier with hot gas cleanup	107 MWe (gross); 99 MWe (net)	5-118
Tampa Electric Integrated Gasification Combined-Cycle Project	Oxygen-blown, entrained-flow gasifier with hot and cold gas cleanup	313 MWe (gross); 250 MWe (net)	5-120
Wabash River Coal Gasification Repowering Project	Oxygen-blown, two-stage entrained-flow gasifier with cold gas cleanup	296 MWe (gross); 262 MWe (net)	5-122
Advanced Combustion/Heat Engines			
Clean Coal Diesel Demonstration Project	Coal-fueled diesel engine	6.4 MWe (net)	5-128
Healy Clean Coal Project	Advanced slagging combustor, spray dryer with sorbent recycle	50 MWe (nominal)	5-130

[a] Plus a 2.0 MWe molton carbonate fuel cell.

The coal slurry and sorbent injectors for the Tidd PFBC demonstration.



The Wabash IGCC gas cleanup system.

The TRW slagging combustor for the Healy Station.

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 an 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 the fuel characteristics of the unrefined product.

Shown is the Coltec coal-fired diesel being installed at the University of Alaska in Fairbanks.

ABB Combustion Engineering, Inc., and CQ Inc., have developed a personal computer software package, CQE®, that will serve as a predictive tool to assist utilities in selecting optimal quality coal for a specific boiler based on operational, economic, 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 commercial use. More than 35 U.S. utilities and one U.K. utility have received CQE® through Electric Power Research Institute (EPRI) membership. It is estimated that CQE® saves U.S. utilities about $26 million annually.

Exhibit 5-6 summarizes the process characteristics and size of the coal processing for clean fuels technologies presented in the project fact sheets.

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 continuing coal use and introducing 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 steel making. 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.

Coal is often the fuel of choice in cement production because production costs are largely driven by fuel cost. Faced with the need to control SO_2 emissions and 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 by-product 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 potential 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

Exhibit 5-6
CCT Program Coal Processing for Clean Fuels Technology Characteristics

Project	Process	Size	Page
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process	Liquid phase process for methanol production from coal-derived syngas	80,000 gal/day	5-136
Advanced Coal Conversion Process Demonstration	Advanced coal conversion process for upgrading low-rank coals	45 tons/hr	5-138
Development of the Coal Quality Expert™	Coal Quality Expert™ computer software	Tested at 250–880 MWe	5-140
ENCOAL® Mild Coal Gasification Project	Liquids-from-coal (LFC®) mild gasification to produce solid and liquid fuels	1,000 tons/day*	5-144

*Operated at 500 tons/day

Western SynCoal Partnership's advanced coal conversion process plant in Colstrip, Montana, has produced over 1.5 million tons of SynCoal® products.

The ENCOAL mild gasification plant near Gillette, Wyoming, 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, Tennessee.

to prevent tube fouling, and uses air cooling to eliminate the need for water circuitry.

The pulse combustor to be 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.

The cement kiln, slagging combustor, and blast furnace granular-coal injection projects are completed. The CPICOR™ and the ThermoChem projects are in the design phase and the construction phase, respectively, as of the end of fiscal year 2000.

Exhibit 5-7 summarizes process characteristics and size for the industrial applications technologies presented in more detail in the project fact sheets.

Project Fact Sheets

The remainder of this document contains fact sheets for all 38 projects. Two types of fact 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 participants and team members, project objectives, significant project features, process description, major milestones, progress (if ongoing) or summary of results (if completed), and commercial applications. 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 by application category is provided in Exhibit 5-8. An index by participant is provided in Exhibit 5-9. 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 5-8 indicates the solicitation under which the project was selected; its status as of June 30, 2000; and the page number for each fact sheet. Exhibit 5-9 lists the projects alphabetically by participant and provides project location and page numbers. A key to interpreting the milestone charts is provided in Exhibit 5-10.

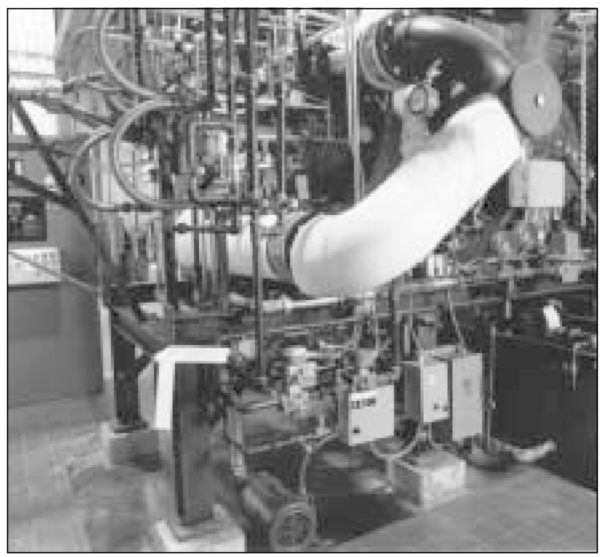
An appendix containing contact information for all of the projects is provided as Appendix D. A list of acronyms used in this document is provided as Appendix E.

Exhibit 5-7
CCT Program Industrial Applications Technology Characteristics

Project	Process	Size	Page
Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Direct reduction iron-making process to eliminate coke; combined-cycle electric power generation	3,300 tons/day of hot metal 170 MWe	5-150
Pulse Combustor Design Qualification Test	Advanced combustion using Manufacturing and Technology Conversion International's pulse combustor/gasifier	30x10^6 Btu/hr	5-152
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	5-154
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	5-158
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	5-162

The Bethlehem Steel Corporation facility, which demonstrated the injection of granulated coal directly into two blast furnaces at Burns Harbor, Indiana.

Front view of Coal Tech's advanced cyclone combustor



The Cement Kiln Flue Gas Recovery Scrubber project's crystallizer and condenser in foreground and flue gas condenser in background.

Exhibit 5-8
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	5-22
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Bechtel Corporation	CCT-III/completed 6/93	5-26
LIFAC Sorbent Injection Desulfurization Demonstration Project	LIFAC–North America	CCT-III/completed 6/94	5-30
Advanced Flue Gas Desulfurization Demonstration Project	Pure Air on the Lake, L.P.	CCT-II/completed 6/95	5-34
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Southern Company Services, Inc.	CCT-II/completed 12/94	5-38
NO_x Control Technologies			
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Southern Company Services, Inc.	CCT-II/extended	5-44
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	The Babcock & Wilcox Company	CCT-II/completed 12/92	5-48
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	The Babcock & Wilcox Company	CCT-III/completed 4/93	5-52
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	Energy and Environmental Research Corporation	CCT-III/completed 1/95	5-56
Micronized Coal Reburning Demonstration for NO_x Control	New York State Electric & Gas Corporation	CCT-IV/completed 4/99	5-60
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	5-64
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	5-68
Combined SO_2/NO_x Control Technologies			
SNOX™ Flue Gas Cleaning Demonstration Project	ABB Environmental Systems	CCT-II/completed 12/94	5-74
LIMB Demonstration Project Extension and Coolside Demonstration	The Babcock & Wilcox Company	CCT-I/completed 8/91	5-78
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	The Babcock & Wilcox Company	CCT-II/completed 5/93	5-82
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Energy and Environmental Research Corporation	CCT-I/completed 10/94	5-86
Milliken Clean Coal Technology Demonstration Project	New York State Electric & Gas Corporation	CCT-IV/completed 6/98	5-90
Integrated Dry NO_x/SO_2 Emissions Control System	Public Service Company of Colorado	CCT-III/completed 12/96	5-94
Advanced Electric Power Generation			
Fluidized-Bed Combustion			
McIntosh Unit 4A PCFB Demonstration Project	City of Lakeland, Lakeland Electric	CCT-III/design	5-100
McIntosh Unit 4B Topped PCFB Demonstration Project	City of Lakeland, Lakeland Electric	CCT-V/design	5-102
JEA Large-Scale CFB Combustion Demonstration Project	JEA	CCT-I/design	5-104

Shaded area indicates projects having completed operations.

Exhibit 5-8 (continued)
Project Fact Sheets by Application Category

Shaded area indicates projects having completed operations.

Exhibit 5-9
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	5-140
ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	Niles, OH	5-74
Air Products Liquid Phase Conversion Company, L.P.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Kingsport, TN	5-136
AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	West Paducah, KY	5-22
Alaska Industrial Development and Export Authority	Healy Clean Coal Project	Healy, AK	5-130
Arthur D. Little, Inc.	Clean Coal Diesel Demonstration Project	Fairbanks, AK	5-128
Babcock & Wilcox Company, The	Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	Cassville, WI	5-48
Babcock & Wilcox Company, The	Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit	Aberdeen, OH	5-52
Babcock & Wilcox Company, The	LIMB Demonstration Project Extension and Coolside Demonstration	Loraine, OH	5-78
Babcock & Wilcox Company, The	SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	Dilles Bottom, OH	5-82
Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Seward, PA	5-26
Bethlehem Steel Corporation	Blast Furnace Granular-Coal Injection System Demonstration Project	Burns Harbor, IN	5-154
Coal Tech Corporation	Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Williamsport, PA	5-158
CPICOR™ Management Company LLC	Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Vineyard, UT	5-150
CQ Inc. (see ABB Combustion Engineering and CQ Inc.)			
ENCOAL Corporation	ENCOAL® Mild Coal Gasification Project	Gillette, WY	5-144
Energy and Environmental Research Corporation	Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Hennepin, IL Springfield, IL	5-86
Energy and Environmental Research Corporation	Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler	Denver, CO	5-56
JEA	JEA Large-Scale CFB Combustion Demonstration Project	Jacksonville, FL	5-104
Kentucky Pioneer Energy, LLC	Kentucky Pioneer Energy IGCC Demonstration Project	Trapp, KY	5-116
Lakeland, City of, Lakeland Electric	McIntosh Unit 4A PCFB Demonstration Project	Lakeland, FL	5-100
Lakeland, City of, Lakeland Electric	McIntosh Unit 4B Topped PCFB Demonstration Project	Lakeland, FL	5-102
LIFAC–North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	Richmond, IN	5-30
New York State Electric & Gas Corporation	Micronized Coal Reburning Demonstration for NO_x Control	Lansing, NY	5-60

Exhibit 5-9 (continued)
Project Fact Sheets by Participant

Exhibit 5-10
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 and reporting. 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 and Reporting

Begins with startup and includes operational testing, data collection, analysis, evaluation, reporting, and other activities to complete the demonstration project.

Environmental Control Devices
SO_2 Control Technologies

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)

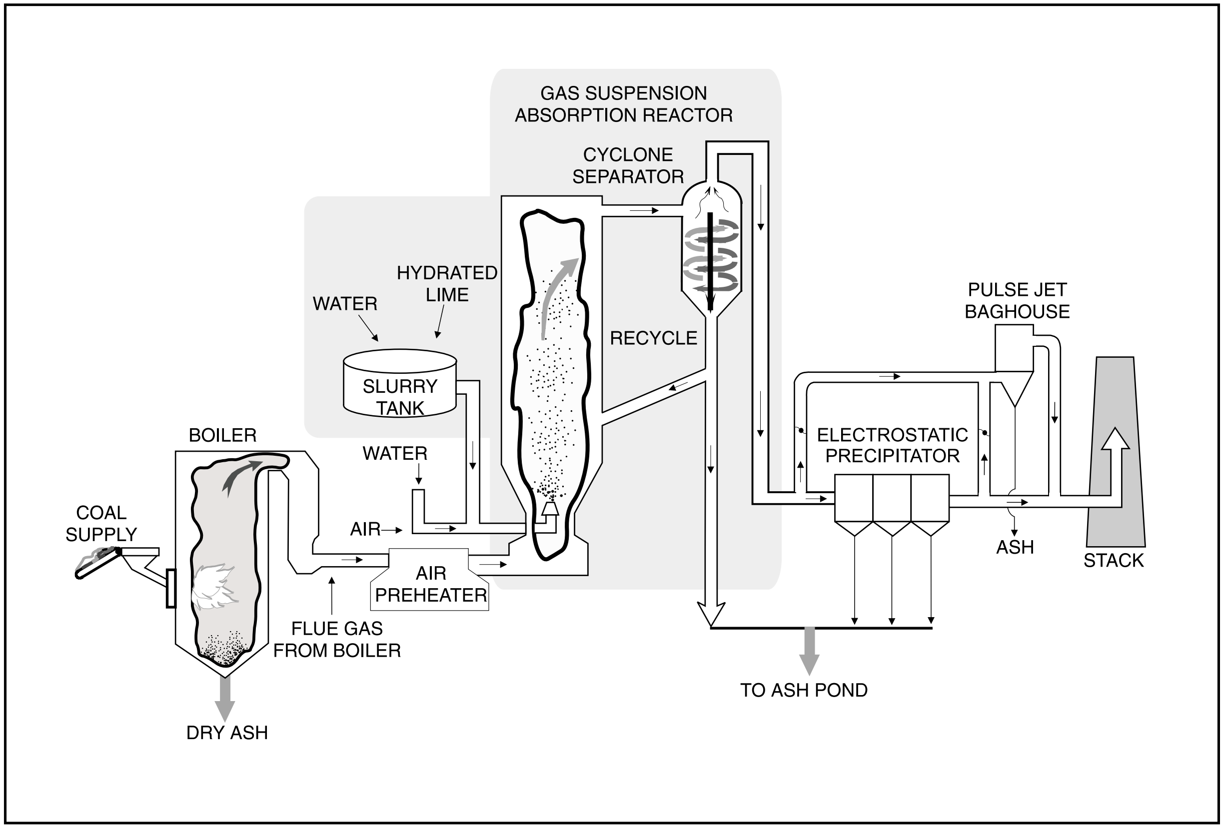
Plant Capacity/Production
10-MWe equivalent slipstream of flue gas from a 175-MWe wall-fired boiler

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

Project Funding

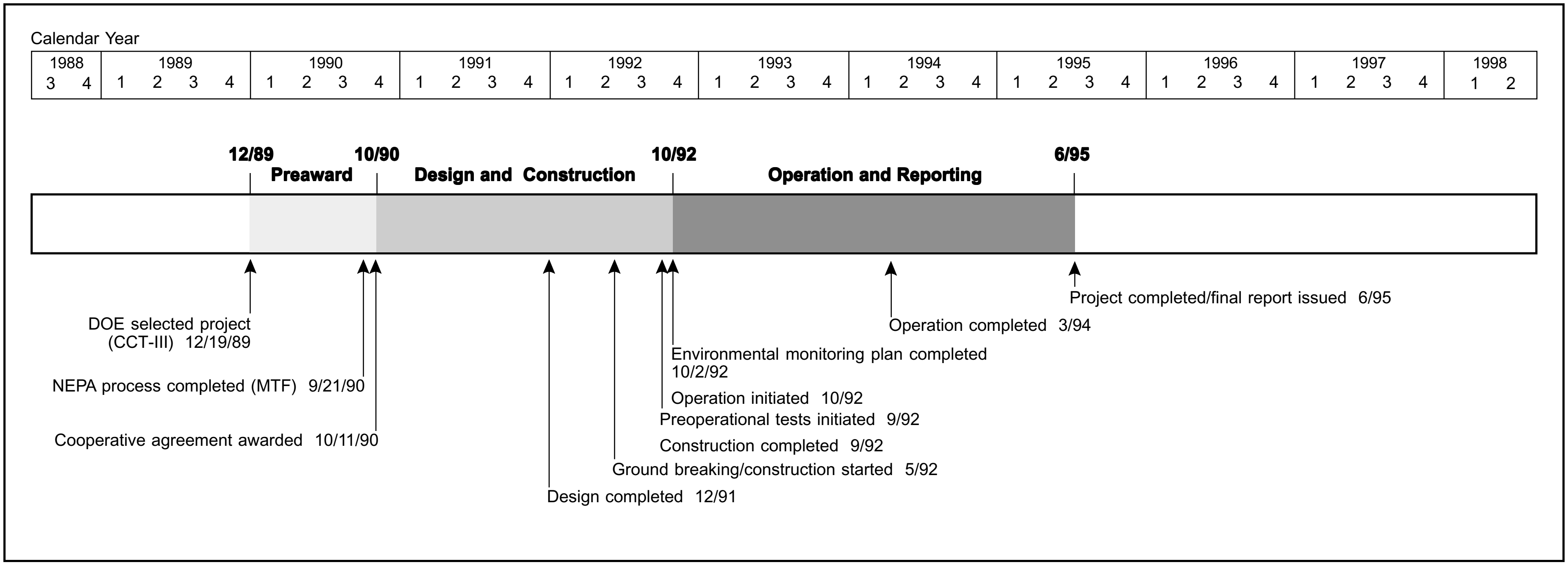
Total project cost	$7,717,189	100%
DOE	2,315,259	30
Participant	5,401,930	70

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 toxics control tests were conducted, and the effectiveness of GSA/ESP and GSA/PJBH combinations to control both SO_2 and particulates 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% or 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 constant 1990$) costs for GSA installed in a 300-MWe plant using 2.6% sulfur coal are compared below to costs for a wet limestone scrubber with forced oxidation (WLFO scrubber). EPRI's TAG™ cost method was used. Based on EPRI cost studies of FGD processes, the capital cost (1990$) for a conventional spray dryer was $172/kW.

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

Project Summary

The GSA has a capability of suspending a high concentration of solids, effectively drying the solids, and recirculating the solids at a high rate with precise control. This 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 5-11 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 ºF. 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 ºF 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 ºF approach-to-saturation temperature was chosen for the higher 0.12% coal chloride level. Exhibit 5-12 summarizes key results from factorial testing.

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 ºF 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 fly ash 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.

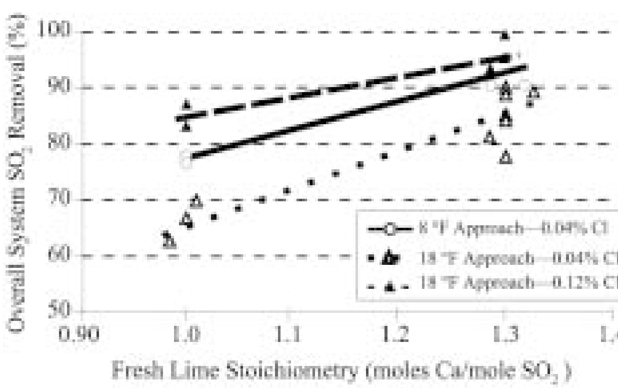
All air toxics tests were conducted with 2.7% sulfur, low-chloride coal with a 12 ºF approach-to-saturation temperature and a high fly ash loading of 2.0 gr/ft^3 (actual). The GSA/ESP arrangement indicated average removal efficiencies of greater than 99% for arsenic, barium, chromium, lead, and vanadium; 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.

Exhibit 5-11
Variables and Levels Used in GSA Factorial Testing

Variable	Level
Approach-to-saturation temperature (°F)	8*, 18, and 28
Ca/S (moles $Ca(OH)_2$/mole inlet SO_2)	1.00 and 1.30
Fly ash 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 5-12
GSA Factorial Testing Results



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

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 are not required to achieve uniform, fine droplet size. 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 dust loading than a conventional spray dryer, 2–5 gr/ft^3 for GSA versus 6–10 gr/ft^3 for a spray dryer, thereby easing the burden on particulate controls. 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 pozzuolanic reaction, essentially providing the characteristics of a low-grade cement.

Economic Performance

Using EPRI costing methods, which have been 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 per mole of inlet SO_2. Lime was assumed to be 2.8 times the cost of limestone. It was estimated that (1) the capital cost was $149/kW (1990$) with three units at 50% capacity, and (2) the levelized cost (15-year constant 1990$) was 10.35 mills/kWh with three units at 50% capacity.

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.

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

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- to 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, Ohio, 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. Another GSA system has been sold to a Swedish iron ore sinter plant. Sales to Taiwan, Indonesia, and India have a combined value of $20 million. Furthermore, Taiwan contracted for technical assistance and proprietary equipment valued at $1.0 million.

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- *10-MWe Demonstration of the Gas Suspension Absorption Process at TVA's Center for Emissions Research: Final Report.* Report No. DOE/PC/90542-T10. Tennessee Valley Authority. March 1995. (Available from NTIS as DE96000327.)

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

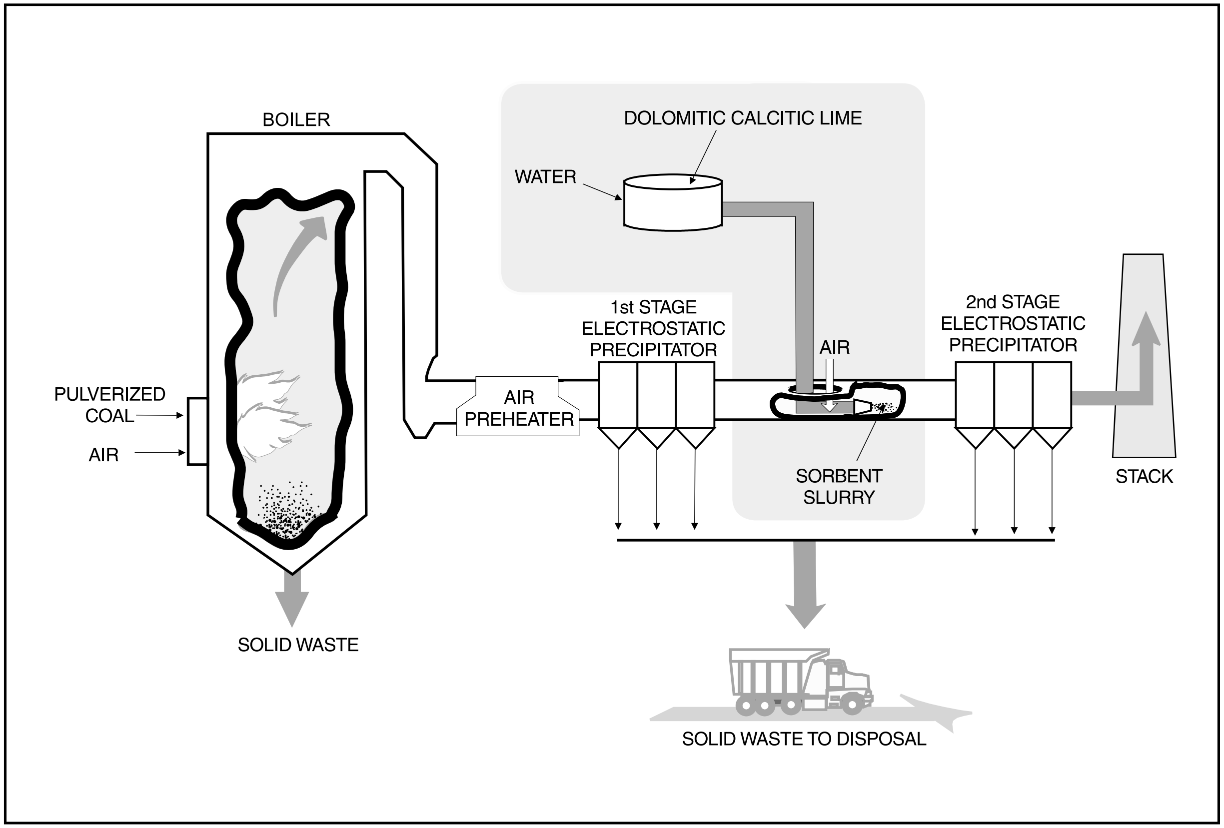
Plant Capacity/Production
73.5 MWe equivalent

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

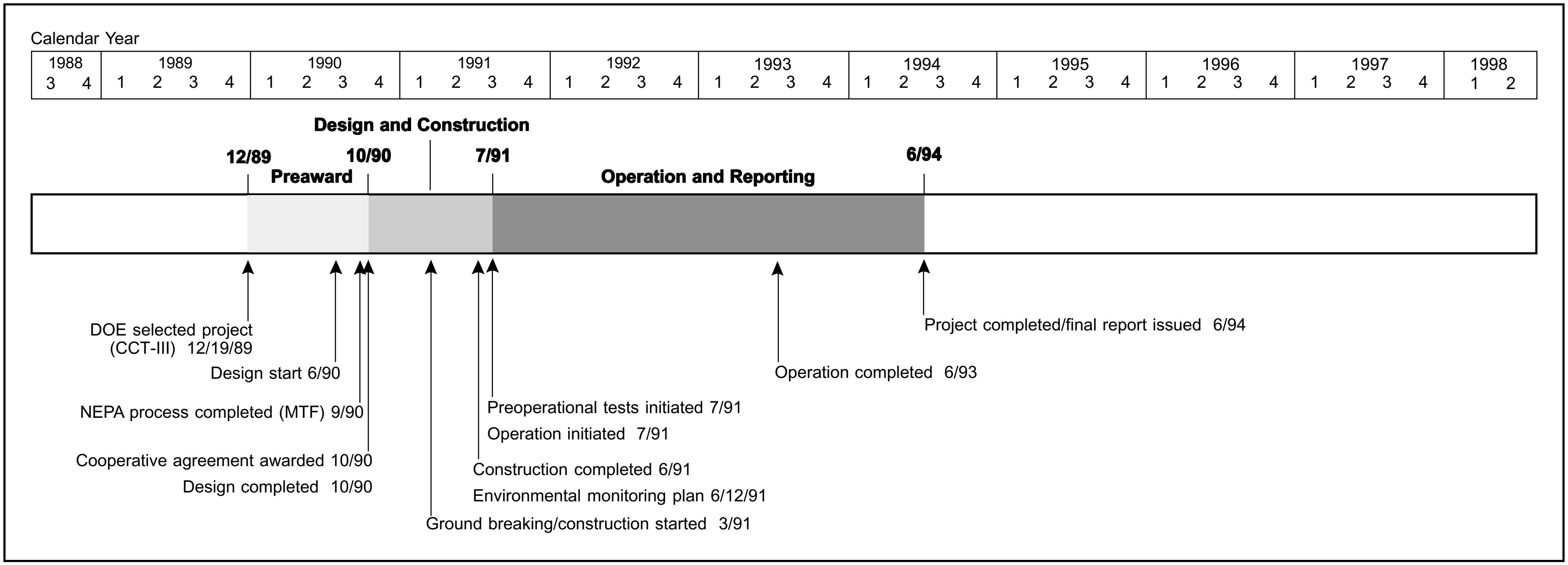
Project Objective
To demonstrate SO_2 removal capabilities of in-duct CZD/FGD technology; specifically, to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations and emissions.



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 on 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 evaluate the effects on SO_2 removal and ESP performance. The demonstration was conducted at Pennsylvania Electric Company's Seward Station in Seward, PA. One-half of the flue gas capacity of the 147-MWe Unit No. 5 was routed through a modified, extended straight section of duct between the first- and second-stage ESPs.

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



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 duct walls. 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'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.

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 system 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; and
- Eliminate negative effects on normal boiler operations without increasing particulate emissions and opacity.

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 operation were achieved 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.

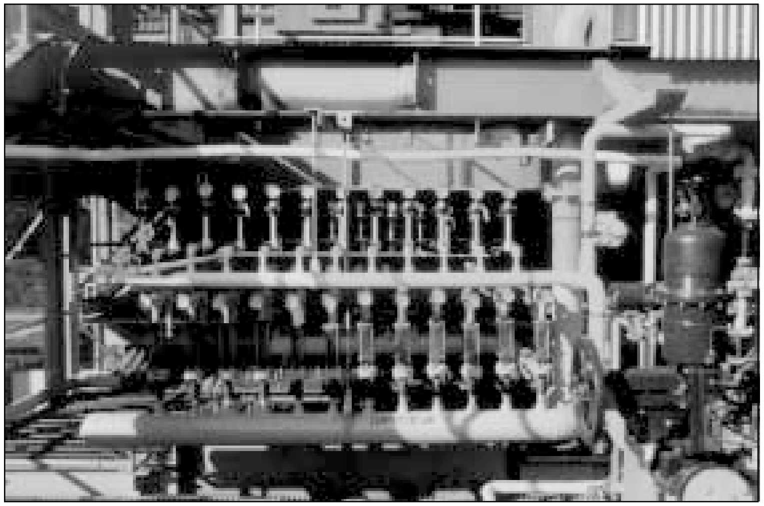
Parametric tests indicated that SO_2 removals above 50% are possible under the following conditions: flue gas temperature of 300–310 ºF; boiler load of 145–147 MWe; residence time in the duct of 2 seconds; and lime slurry injection rate of 52–57 gal/min.

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: (1) percentage of SO_2 removed, and (2) 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.


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

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.

Economic Performance

Estimates show that the CZD/FGD process can achieve costs of $300/ton of SO_2 removed (1994$) 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 retrofitting 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

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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)

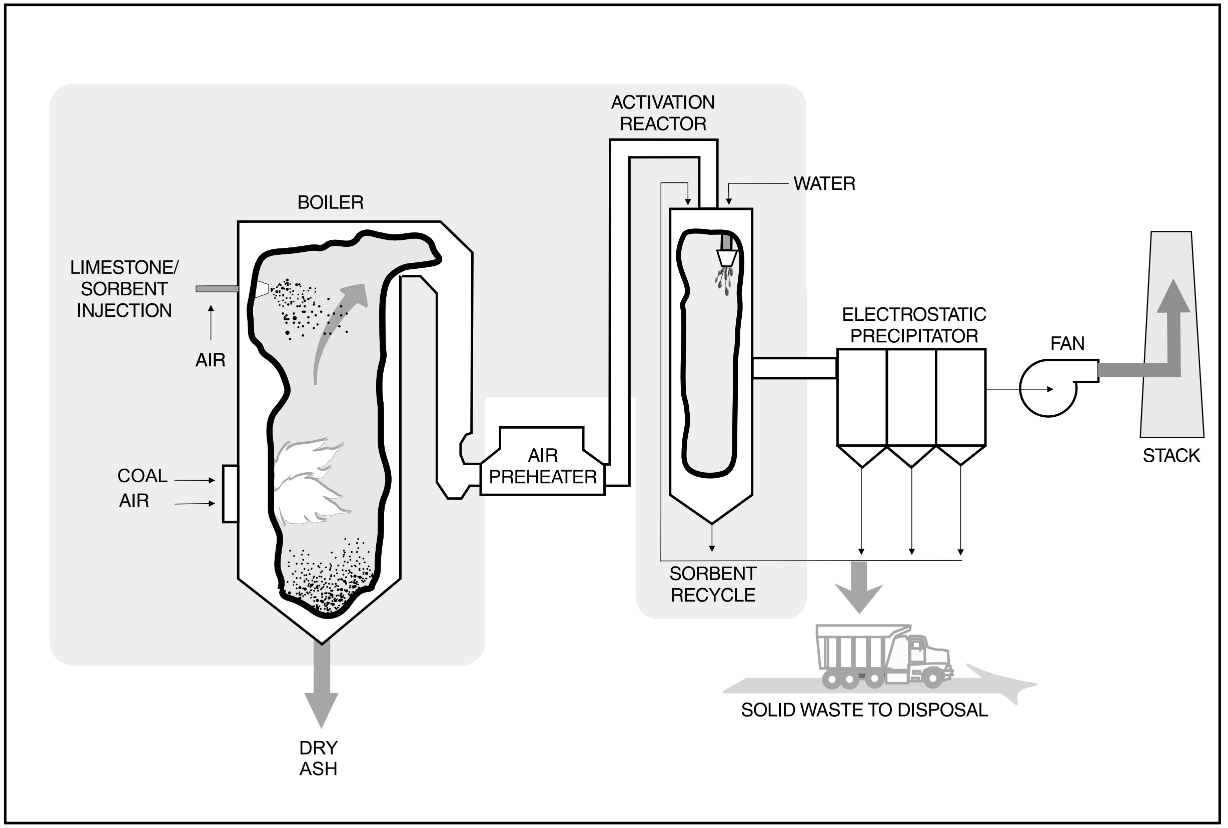
Technology
LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor

Plant Capacity/Production
60 MWe

Coal
Bituminous, 2.0–2.8% sulfur

Project Funding

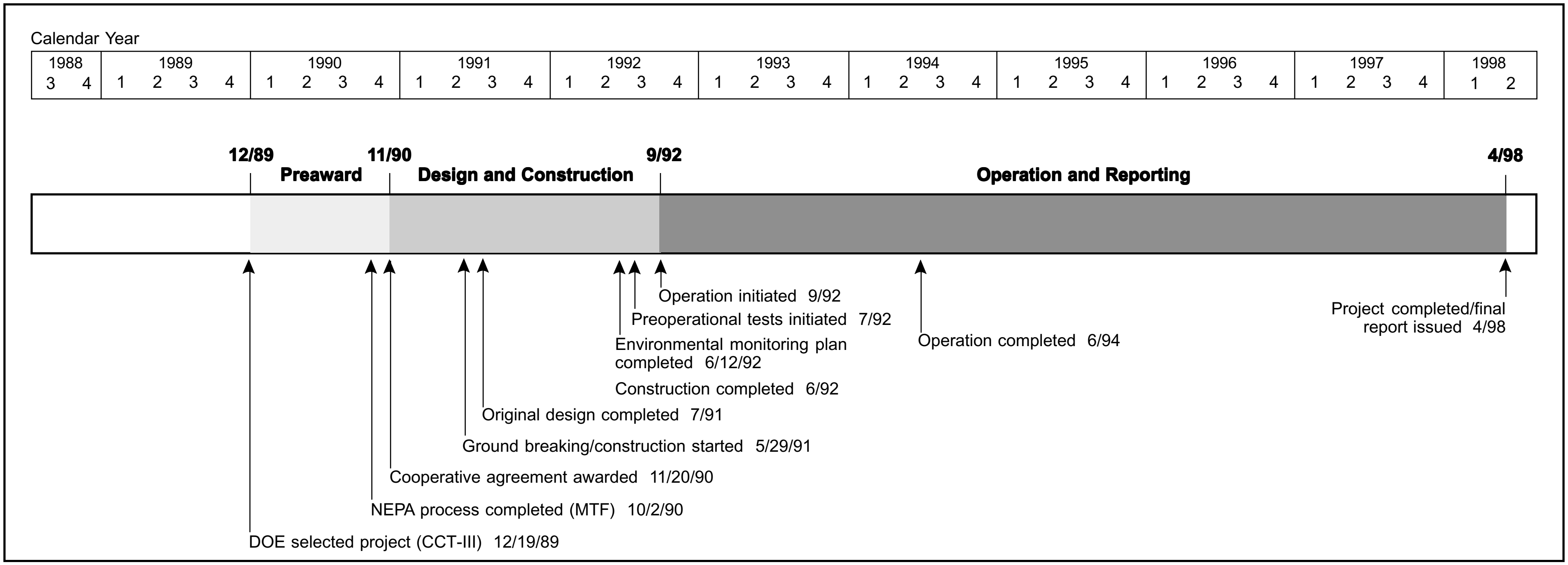
Total project cost	$21,393,772	100%
DOE	10,636,864	50
Participants	10,756,908	50



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 injected 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 was reduced an additional 15% by increasing limestone fineness to 80% minus 200 mesh and maintaining a Ca/S molar ratio of 2.0 and 7–12 ºF approach-to-saturation temperature.
- 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 were projected to increase SO_2 removal efficiency to 85% at a Ca/S molar ratio of 2.0 and limestone fineness of 80% minus 325 mesh.
- ESP efficiency and operating levels were essentially unaffected by LIFAC 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 sootblowing cycle had to be reduced from 6.0–4.5 hours.
- Automated programmable logic and simple design make the LIFAC system easy to operate in startup, 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 (1994\$)—\$66/kW for two LIFAC reactors (300 MWe); \$76/kW for one LIFAC reactor (150 MWe); \$99/kW for one LIFAC reactor (65 MWe).
- Operating cost (1994\$)—\$65/ton of SO_2 removed, assuming 75% SO_2 capture, Ca/S molar ratio of 2.0, limestone composed of 95% $CaCO_3$, and costing \$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:

- 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 designed 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 (2.0–2.8%) sulfur coals.

Environmental Performance

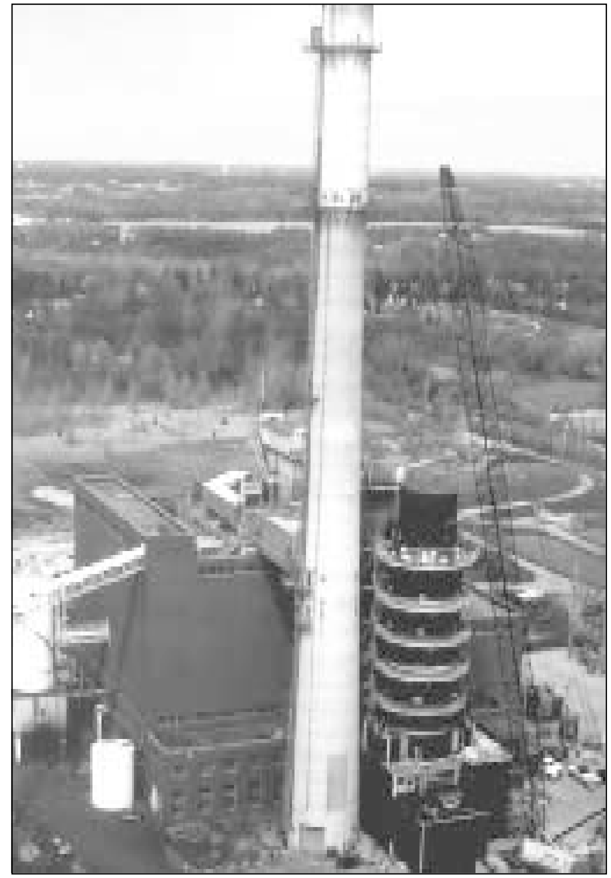
During the parametric testing phase, the numerous LIFAC process values and their effects on sulfur removal efficiency were evaluated. The four major parameters having the greatest influence on sulfur removal efficiency were limestone fineness, Ca/S molar ratio, reactor bottom temperature (approach-to-saturation), 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 sootblowing frequency had to be increased from 6-hour to 4.5-hour cycles. The coarse-quality limestone did not affect sootblowing 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 was found to be essential for efficient SO_2 capture. However, 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, but even 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-content limestone, and recycle of spent sorbent from the ESP.



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.

Long-term testing showed that SO_2 reductions of 70% or more can be maintained under normal boiler operating conditions. 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 fly ash 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 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.

The LIFAC system proved to be highly practical 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 that regulates process control loops, interlocking, startup, shutdown, 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), and
- $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%).

Contacts

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References

- *LIFAC Sorbent Injection Desulfurization Demonstration Project. Final Report, Vol. II: Project Performance and Economics.* LIFAC-North America. February 1998. (Available from NTIS as DE96004421.)
- "LIFAC Nearing Marketability." *Clean Coal Today.* Report No. DOE/FE-0215P-21. Spring 1996.
- Viiala, J., *et al.* "Commercialization of the LIFAC Sorbent Injection Process in North America." *Third Annual Clean Coal Technology Conference: Technical Papers.* September 1994.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: LIFAC Sorbent Injection Desulfurization Demonstration Project.* LIFAC-North America. Report No. DOE/FE-0207P. U.S. Department of Energy, October 1990. (Available from NTIS as DE91001077.)

Advanced Flue Gas Desulfurization Demonstration Project

Project completed.

Participant

Pure Air on the Lake, L.P. (a subsidiary 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
Stearns-Roger Division of United Engineers and Constructors—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 and PowerChip® agglomeration process

Plant Capacity/Production

528 MWe

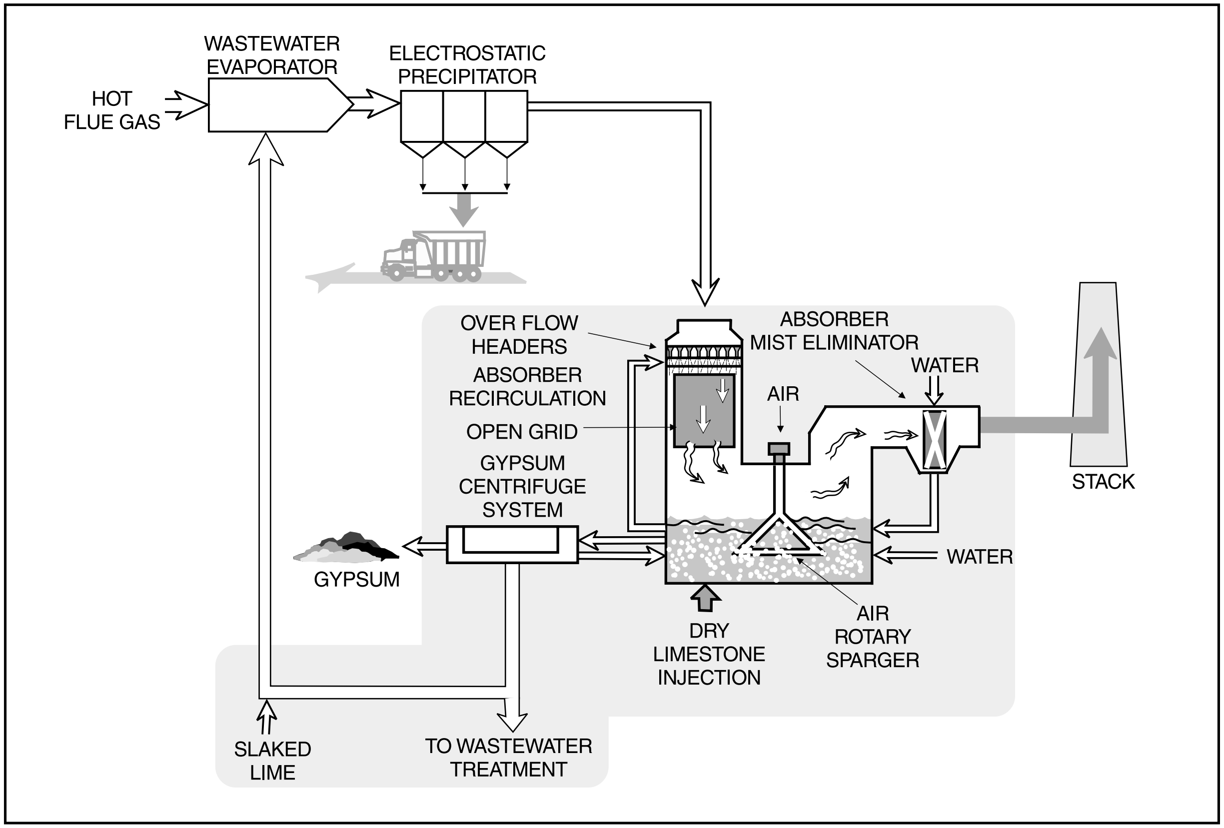
Coal

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

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



Project Objective

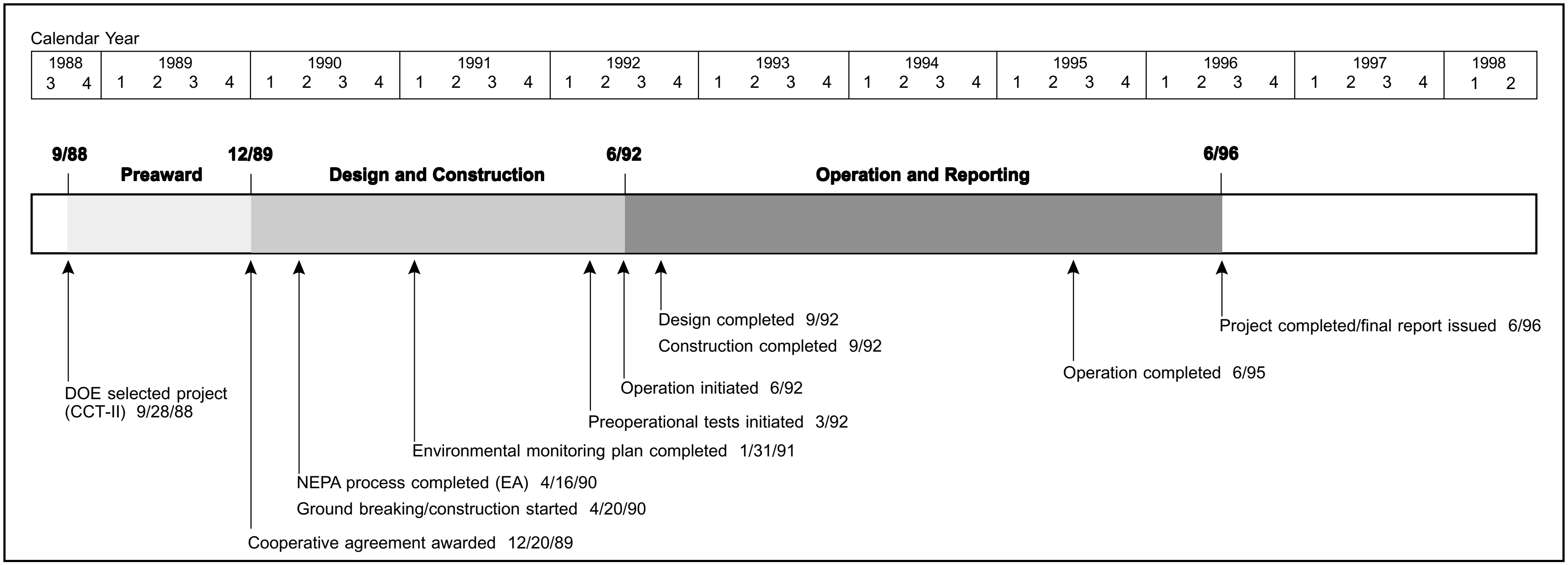
To reduce SO_2 emissions by 95% or more at approximately one-half the cost of conventional scrubbing technology, significantly reduce space requirements, and create no new waste streams.

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, absorbing, 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 AFGD-derived gypsum.



Results Summary

Environmental

- The 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, and 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—Pure Air took on the turnkey, financing, operating, and maintenance risks through performance guarantees—was successful.

Economic

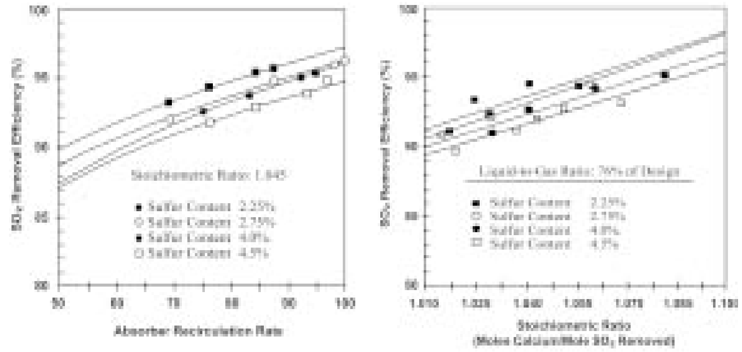
- Capital costs and space requirements for AFGD were about half those of conventional systems.

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 spare absorber modules. The major performance objectives were met.

Over the three-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 in commercial service, which includes sale of all by-product gypsum to U.S. Gypsum's East Chicago, Indiana wallboard production plant.

Exhibit 5-13
Pure Air SO_2 Removal Performance
(100% Boiler Load)



Environmental Performance

Testing over the three-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/1,000 ft^3. The lower end of the L/G ratio was determined by solids settling rates in the slurry and the requirement for full wetting of the grid packing. The high end of the L/G ratio 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%, were possible at loads of 33% and 67% with low to moderate stoichiometric ratio and L/G settings, even for 4.5% sulfur coal. Exhibit 5-13 summarizes the results of parametric testing at full load.

In the AFGD process, chlorides that would have been released to the air are captured, but 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 evaporates the water and the dissolved solids are 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. 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 contributed to the high availability. 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. The 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. The AFGD SO_2 capture efficiency with limestone was comparable to that in wet scrubbers using lime, which is far more expensive. The 24-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.

Exhibit 5-14
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

Economic Performance

Exhibit 5-14 summarizes capital and levelized 1995 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 EPRI's Technical Assessment Guide™.

The incremental benefits of the own-and-operate arrangement, by-product utilization, and emission allowances were also evaluated. Exhibit 5-15 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 5-15 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

The AFGD technology is positioned well to compete in the pollution control arena of 2000 and beyond. The AFGD technology 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 lower 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 offers the AFGD user the possibility of generating 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 Engineers' 1992 Outstanding Engineering Achievement Award.

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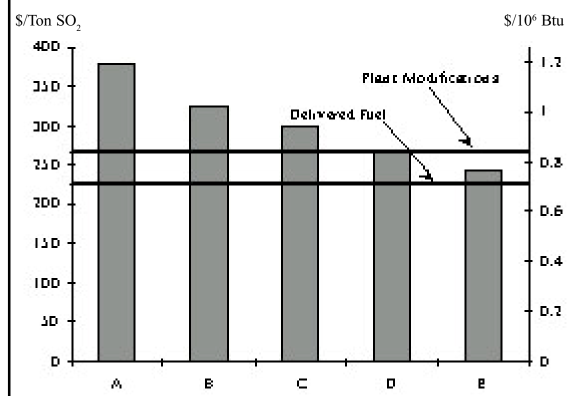
Exhibit 5-15
Flue Gas Desulfurization Economics



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%

References

- *Advanced Flue Gas Desulfurization (AFGD) Demonstration Project. Final Technical Report, Vol. II: Project Performance and Economics.* Pure Air on the Lake, L.P. April 1996. (Available from NTIS as DE96050313.)
- *Advanced Flue Gas Desulfurization Project: Public Design Report.* Pure Air on the Lake, L.P. March 1990.
- *Summary of Air Toxics Emissions Testing at Sixteen Utility Power Plants.* Prepared by Burns and Roe Services Corporation for U.S. Department of Energy, Pittsburgh Energy Technology Center. July 1996.

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

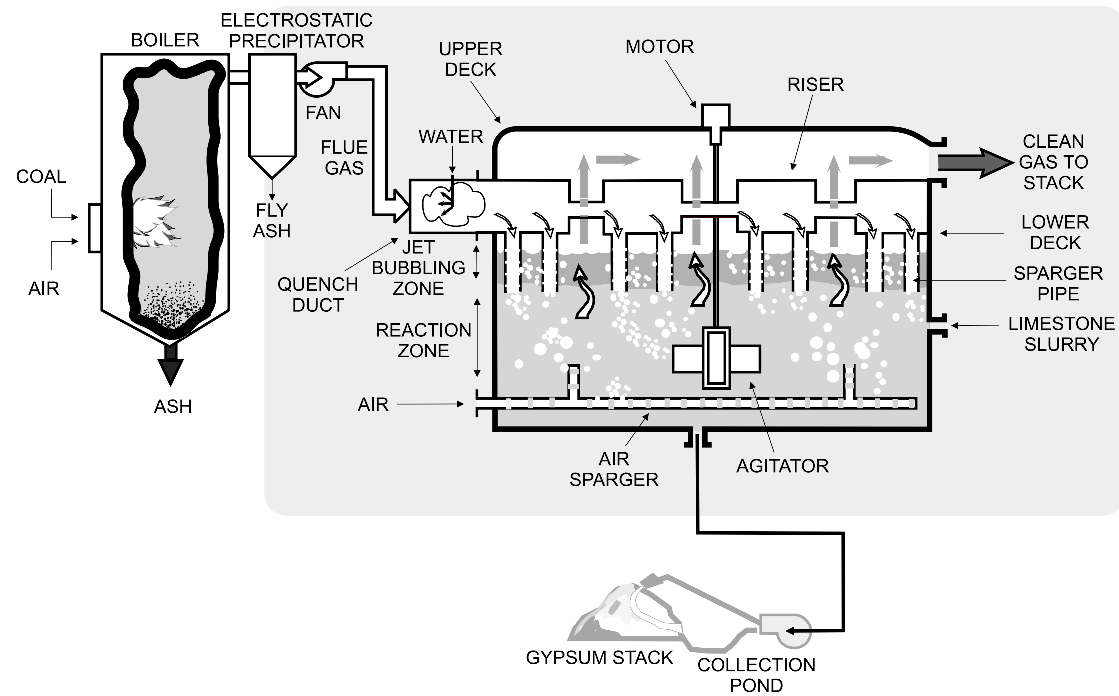
Location
Newnan, Coweta County, GA (Georgia Power Company's Plant Yates, Unit No. 1)

Technology
Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (AFGD) process using the Jet Bubbling Reactor®

Plant Capacity/Production
100 MWe

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

Jet Bubbling Reactor is a registered trademark of the Chiyoda Corp.



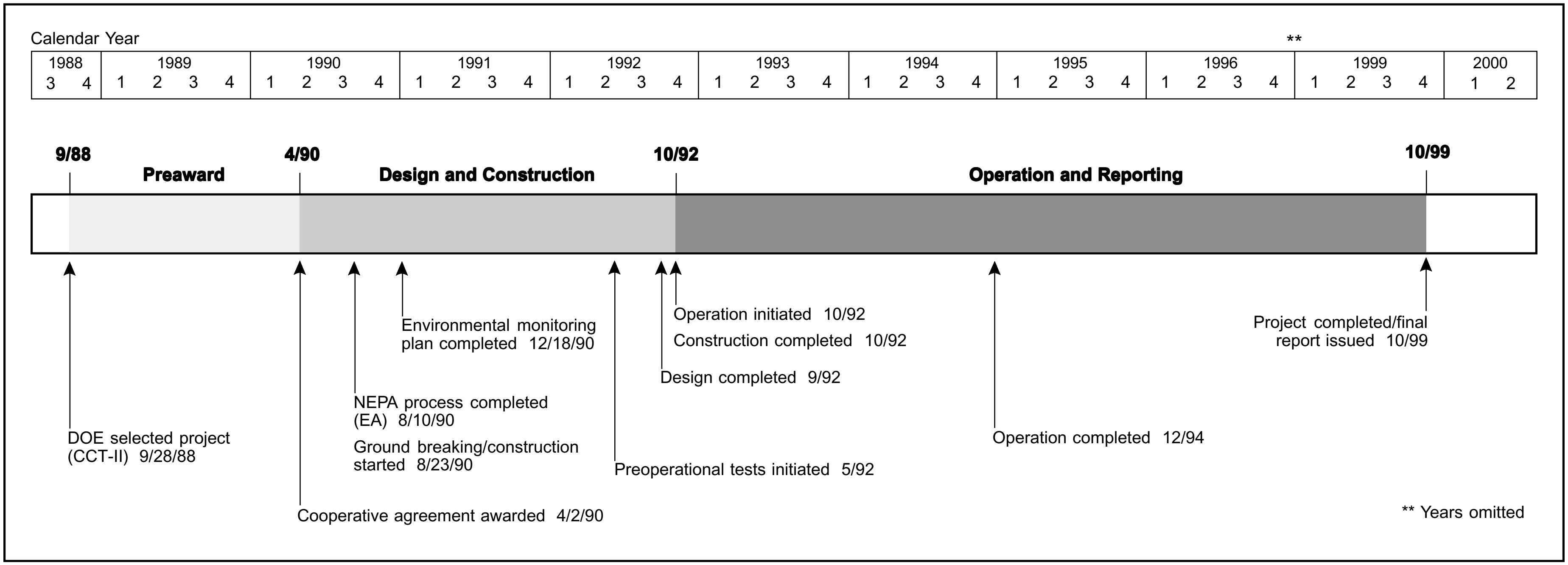
Project Funding

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 requisite to eliminating spare absorber modules; to evaluate use of fiberglass-reinforced plastic (FRP) vessels to eliminate flue gas prescrubbing and reheat, and to enhance reliability; and to evaluate use of gypsum to reduce waste management costs.

Technology/Project Description
The project demonstrated the CT-121 AFGD process, which uses a unique absorber design known as the Jet Bubbling Reactor® (JBR). The process combines limestone AFGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically and chemically simpler than conventional AFGD processes and can be expected to exhibit lower cost characteristics.

The flue gas enters underneath the scrubbing solution in the JBR. 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.



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, eliminating the need for a spare reactor module.
- Simultaneous SO_2 and particulate control were achieved at fly ash loadings similar to those of an electrostatic precipitator (ESP) that has marginal performance.

Economic

- Capital costs for project equipment, process, and startup were $29 million, or $293/kW at Plant Yates.
- Fixed O&M costs were $357,000/yr (1994$), and variable operating costs were $34–64/ton of SO_2 removed, depending on specific test conditions.
- Generic plant costs were not estimated; however, elimination of the need for flue gas prescrubbing, reheat, and a spare module should result in capital requirements far below those of contemporary conventional flue gas desulfurization (FGD) systems.

Project Summary

The CT-121 AFGD 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 startup and shakedown, during which approximately 19,000 hours were logged. Exhibit 5-16 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).

Exhibit 5-16
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

Operating Performance

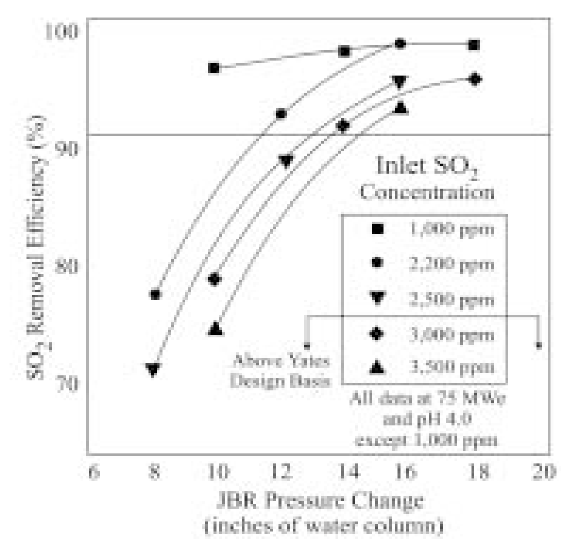
Use of FRP construction proved very successful. Because their large size precluded shipment, the JBR and limestone slurry storage tanks were constructed on site. Except for some erosion experienced at the JBR inlet transition duct, the FRP-fabricated equipment proved to be durable both structurally and 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, eliminating 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 fly ash 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 5-17 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 5-18.

Exhibit 5-17
SO_2 Removal Efficiency



Analysis indicated that a large percentage of the outlet particulate matter is sulfate, 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 air toxics removals across the CT-121 JBR, based on the measurements taken during the demonstration, are shown in Exhibit 5-19.

Exhibit 5-18
CT-121 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.

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.

Economic Performance

The capital cost of the Plant Yates CT-121 project was \$29,335,979, or \$293/kW, which includes equipment, process, and start-up costs. The annual fixed O&M cost was \$354,000/yr. (1994\$). Variable operating cost was \$34–64/ton of SO_2 removed (1994\$), depending on specific test conditions.

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 eliminates the need for expensive (capital-intensive) ESP upgrades to meet increasingly strict 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 AFGD capacity has been sold to 16 customers in seven countries.

The project received *Power* magazine's 1994 Powerplant Award. Other awards include the Georgia Chapter of the Air and Waste Management Association's 1994 Outstanding Achievement Award, the Georgia Chamber of Commerce's 1993 Air Quality Citizen of the Year Award, and the Composites Institute (Society of Plastics Industries) 1996 Design Award of Excellence.

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James U. Watts, DOE/NETL, (412) 386-5991

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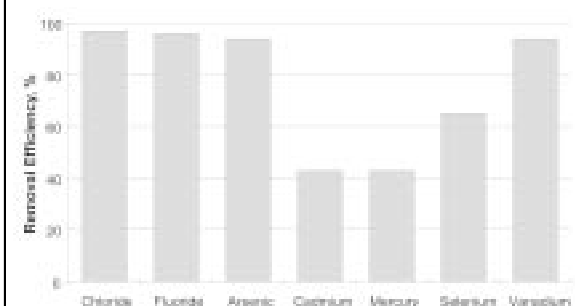
- Southern Company Services, Inc. *Demonstration of Innovative Applications of Technology for Cost Reductions to the CT-121 FGD Process. Final Report. Volumes 1-6.* January 1997.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Innovative Applications of Technology 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 DE9008110.)

Exhibit 5-19
CT-121 Air Toxics Removal
(JBR Components Only)



Environmental Control Devices
NO_x Control Technologies

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Project extended.

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
PowerGen—cofunder
U.K. Department of Trade and Industry—cofunder
EnTEC—technology supplier
Radian—technology supplier
Tennessee Technological University—technology supplier
Southern Company—cofunder

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 Intelligent System (GNOCIS) computer software.

Plant Capacity/Production

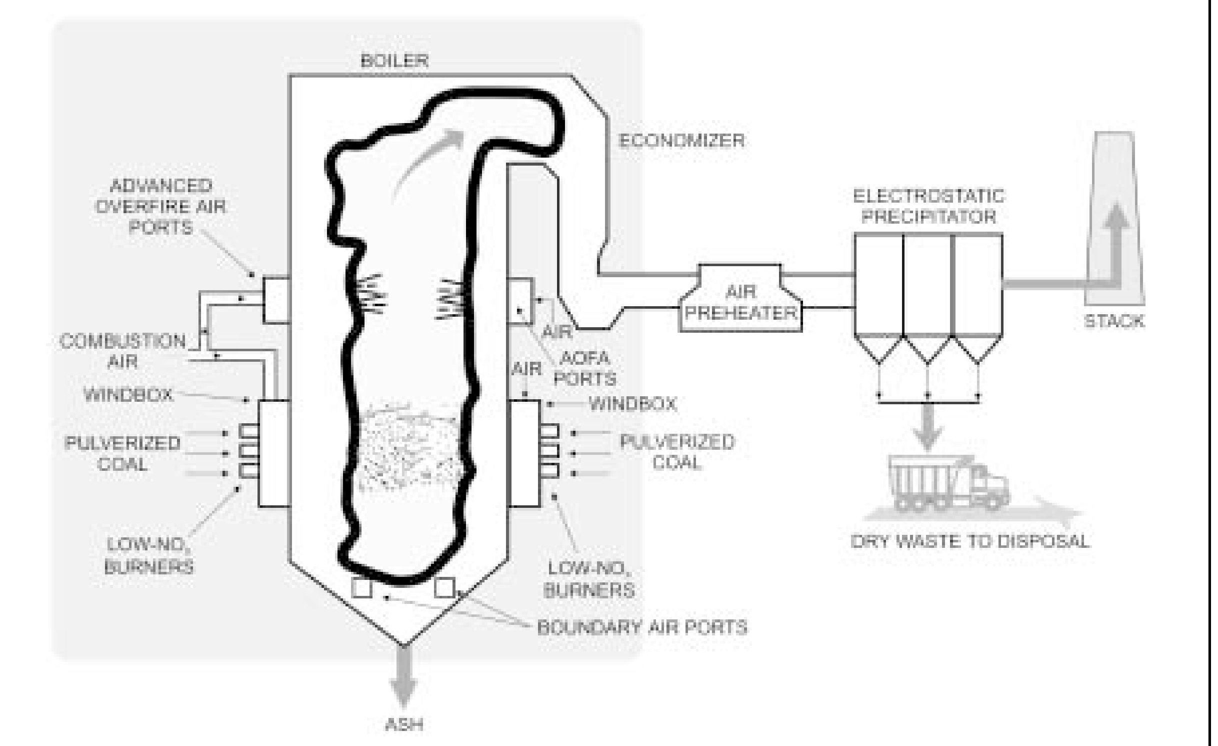
500 MWe

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



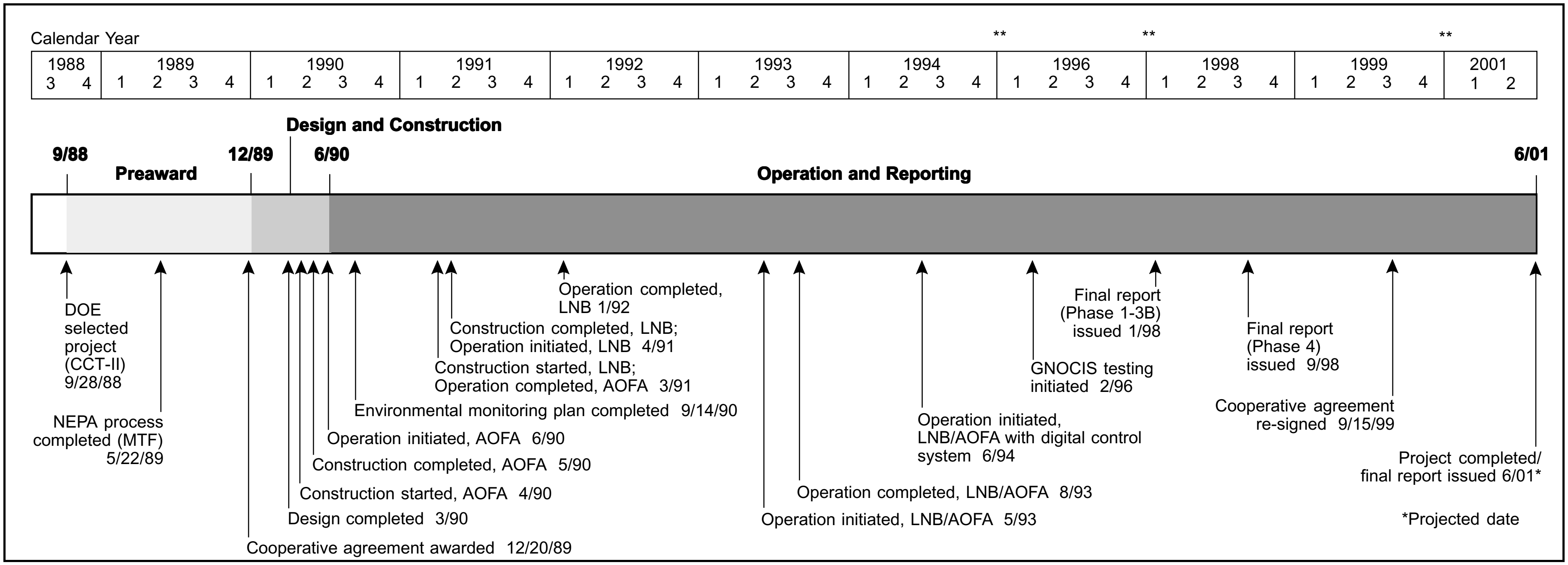
Project Objective

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 GNOCIS advanced digital controls on NO_x reduction, boiler performance, and peripheral equipment performance. The project has been reopened and extended to demonstrate an overall unit optimization system.

Technology/Project Description

AOFA involves: (1) improving OFA mixing to enable operation of the burners below the air/fuel ratio theoretically required to complete combustion (sub-stoichiometric), without increasing combustible losses; and (2) 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 is staged 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 2,800 °F). The final excess air then can be allowed to mix with the unburned products so that combustion is completed at a relatively low temperature. The CFSF LNB splits the coal/air mixture into four streams, which minimizes coal and air mixing and combustion staging.



Results Summary

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, representing a 68% reduction from baseline conditions.
- Chemical emissions testing showed no evidence of organic compound emissions resulting from the combustion modifications installed for NO_x control. Trace element control, except for mercury and selenium, proved to be a function of electrostatic precipitator (ESP) performance.

Operational

- 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 loss-on-ignition (LOI) levels of 1–3 percentage points, and a reduction in NO_x emissions of 10–15% at full load.
- Fly ash LOI increased from a baseline of 7% (corrected to representative excess oxygen conditions) to 10% with AOFA and 8% with LNB and LNB/AOFA, despite significant improvements in coal fineness.

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 \$79/ton using LNB/AOFA in a baseload dispatch scenario experienced at Plant Hammond.

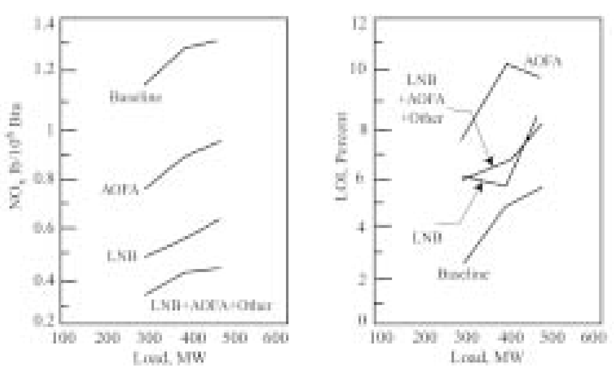
Project Summary

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 allowed testing to continue.

Operational Performance

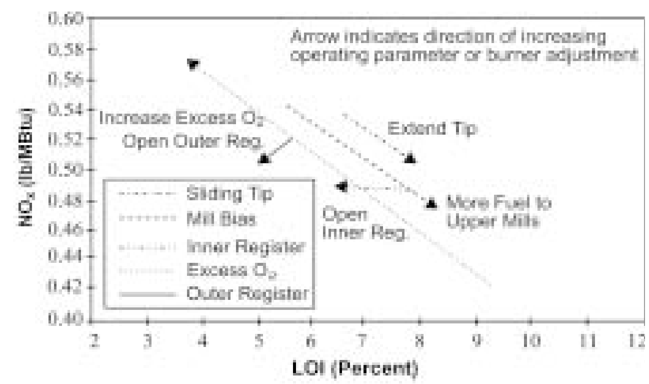
LOI increased for the AOFA, LNB, and LNB/AOFA phases, as shown in Exhibit 5-20, despite improved mill performance due to the replacement of the mills. Increased LOI was a concern not only because of the associated efficiency loss, but also due to a potential loss of fly ash sales. The increased carbon in the fly ash renders the material unsuitable for use in making concrete.

Exhibit 5-20
LOI Performance Test Results



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 levels 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 trade-offs 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 5-21 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 adjustment suggests that 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 5-21
NO_x vs. LOI Tests—All Sensitivities



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 5-22. There are trade-offs 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

Exhibit 5-22
Typical Trade-Offs in Boiler Optimization

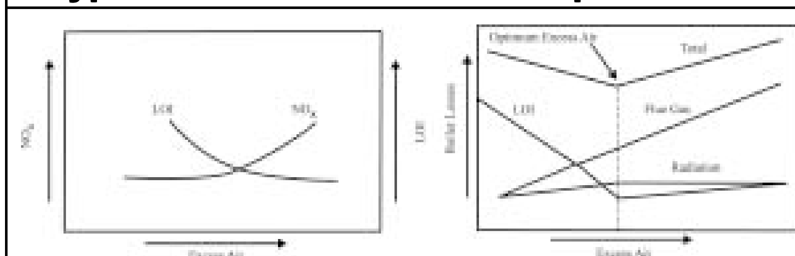
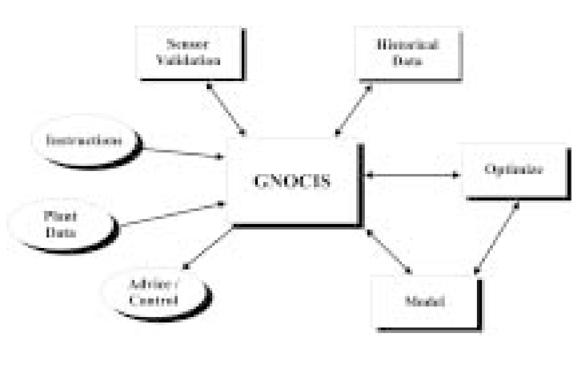


Exhibit 5-23
Major Elements of GNOCIS



GNOCIS are shown in Exhibit 5-23. The GNOCIS system provided advice that reduced NO_x emissions by 10–15% at full load, while improving the heat rate or reducing fly ash LOI by 1–3 percentage points.

Environmental Performance

Long-term testing showed that the AOFA, LNBs, and LNB/AOFA provide full-load NO_x reductions of 24, 48, and 68%, respectively. 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.

During the LNB/AOFA test phase a total of 63 days of valid long-term NO_x emissions data was collected. 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 for AOFA only and 0.65 lb/10^6 Btu for LNB only.

Chemical emissions testing showed no evidence of organic compound emissions resulting from the combustion modifications installed for NO_x control. Trace element control, except for mercury and selenium, proved to be a function of electrostatic precipitator (ESP) performance. Only a small portion of the mercury and selenium, which adopt a vapor phase, and none of the vapor-phase chlorine (as hydrochloric acid) and fluorine (as hydrofluoric acid) were captured.

Economic Performance

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/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 at full load. The capital cost is $8,300,000 and the calculated cost of NO_x removed is $79/ton for the Hammond baseload dispatch scenario.

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 (696 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).

Project Extension

On September 15, 1999, the cooperative agreement was extended and work began on the design and installation of an overall unit optimization system. The work will be carried out as part of Phase 4 of the project. The overall goal of Phase 4 is to demonstrate on-line optimization techniques, which includes a real-time heat rate monitor, for power plant processes and for the unit as a whole. The major tasks include unit optimization, boiler optimization, automated sootblowing, and precipitator modeling/optimization. To date, the total plant optimization study is complete, and the designs for the optimization packages are in progress.

Commercial Applications

The technology is applicable to the 411 existing pre-NSPS dry-bottom 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 cofiring 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.

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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. Phase 4—Digital Control System and Optimization.* Southern Company Services, Inc. September 1998.
- *500-MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers. Phases 1-3B, Final Report.* Southern Company Services, Inc. January 1998.

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)

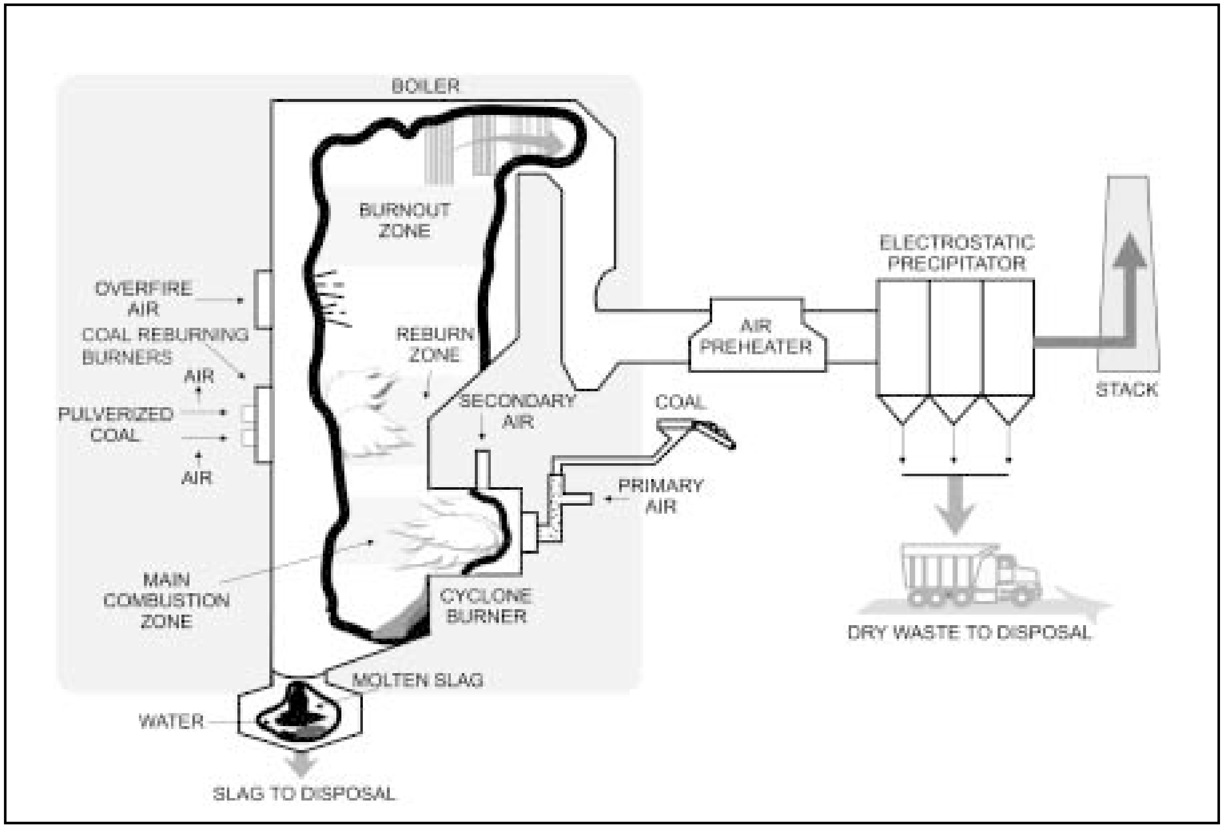
Technology
The Babcock & Wilcox Company's Coal Reburning System (Coal Reburning)

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

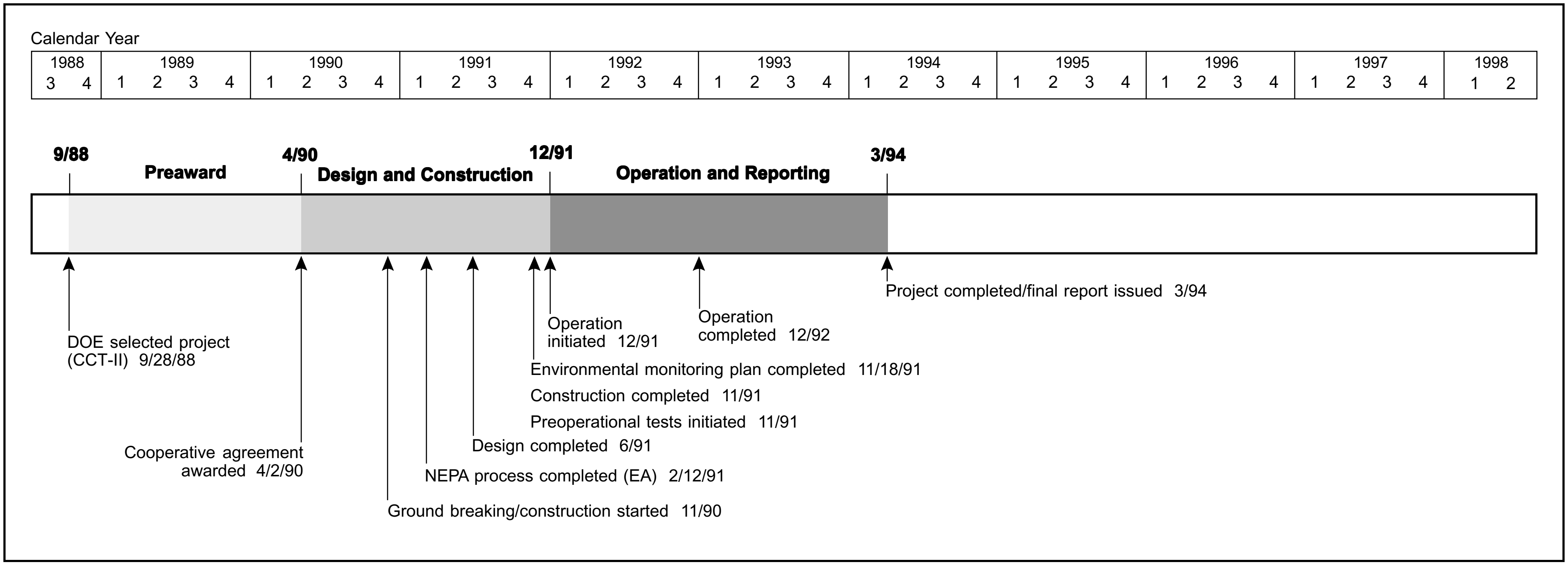
Project Funding

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 Coal Reburning to achieve 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 Reburning 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. Completion of the combustion process occurs in the third zone, called the burnout zone, where the balance of the combustion air is introduced.



Results Summary

Environmental

- Coal Reburning achieved greater than 50% NO_x reduction at full load with Lamar bituminous and PRB subbituminous coals.
- Reburning-zone stoichiometry had the greatest effect on NO_x control.
- Gas recirculation was vital to maintaining reburning-zone stoichiometry while providing necessary burner cooling, flame penetration, and mixing.
- Opacity levels and electrostatic precipitator (ESP) performance were not affected by Coal Reburning with either coal tested.
- Optimal Coal Reburning 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 Reburning 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 percentage points 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 percentage points 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 reburning burners enabled switching to PRB low-rank coal without boiler derating.

Economic

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

Project Summary

Although cyclone boilers represent only 8.5% of the pre-NSPS coal-fired generating capacity, they contribute 12% 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. However, at the time of this demonstration, there was no cost-effective combustion modification available for cyclone boiler NO_x control.

Babcock & Wilcox Coal Reburning offers an economic and operationally sound response to the environmental requirements. This technology avoids cyclone combustor modification and associated performance complications, and provides an alternative to postcombustion NO_x control options, such as SCR, which have relatively high capital and/or operating costs.

The majority of the testing was performed firing Illinois Basin bituminous coal (Lamar), because 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 reburning 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.

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

Exhibit 5-24
Coal Reburning 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

Environmental Performance

Three sequential tests of Coal Reburning used Lamar coal. Parametric optimization testing set up the automatic controls. Performance testing evaluated the unit in full automatic control at set load points. Long-term testing assessed performance in a load-following mode. PRB coal was used for parametric optimization and performance modes. Exhibit 5-24 shows changes in NO_x emissions and boiler efficiency using the reburning system for various load conditions and coal types.

Coal Reburning tests on both the Lamar and PRB coals indicated that variation of reburning-zone stoichiometry was the most critical factor in changing NO_x emissions levels. The reburning-zone stoichiometry can be varied by alternating the air flow quantities (oxygen availability) to the reburning burners, the percent reburning 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 Reburning were comparable to baseline operation. No major effect of reburning on trace-metals partitioning was discernible. None of the 16 targeted polynuclear aromatic semi-volatile organics (controlled under Title III of CAAA) were present in detectable concentrations, at a detection limit of 1.2 parts per billion.

Operational Performance

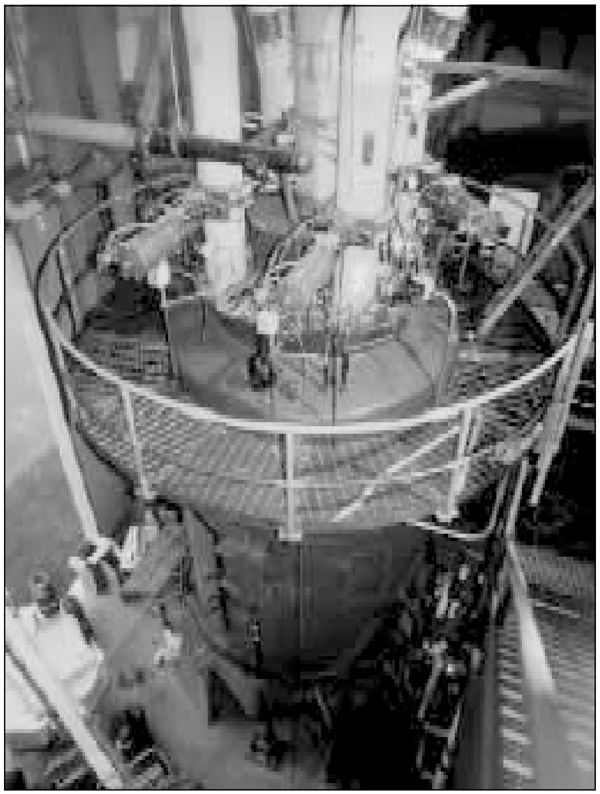
For Lamar coal, the full-, medium-, and low-load efficiency losses due to unburned carbon were higher than the baseline by 0.1, 0.25, and 1.5 percentage points, respectively. Full-, medium-, and low-load efficiency losses with PRB coal were 0.0, 0.2, and 0.3 percentage points, respectively. Coal Reburning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

During Coal Reburning 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 Reburning minimizes and possibly eliminates a 0–25% derating normally associated with switching to subbituminous coal in a cyclone unit. This derating results from using a lower Btu fuel in a cyclone combustor, which has a limited coal feed capacity. Coal Reburning transferred about 30% of the coal feed out of the cyclone to the reburning 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 5-25. 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 reburning 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.



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

Commercial Applications

Coal Reburning is a retrofit technology applicable to a wide range of utility and industrial cyclone boilers. The current U.S. coal reburning market is estimated to be approximately 27,000 MWe and consists of about 89 units ranging from 100–1,150 MWe with most in the 100- to 300-MWe range.

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

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- *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.* Report No. DOE/FE-0157. U.S. Department of Energy. February 1990. (Available from NTIS as DE90008111.)

Exhibit 5-25
Coal Reburning Economics
(1990 Constant Dollars)

Costs	Plant Size: 110 MWe	Plant Size: 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

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

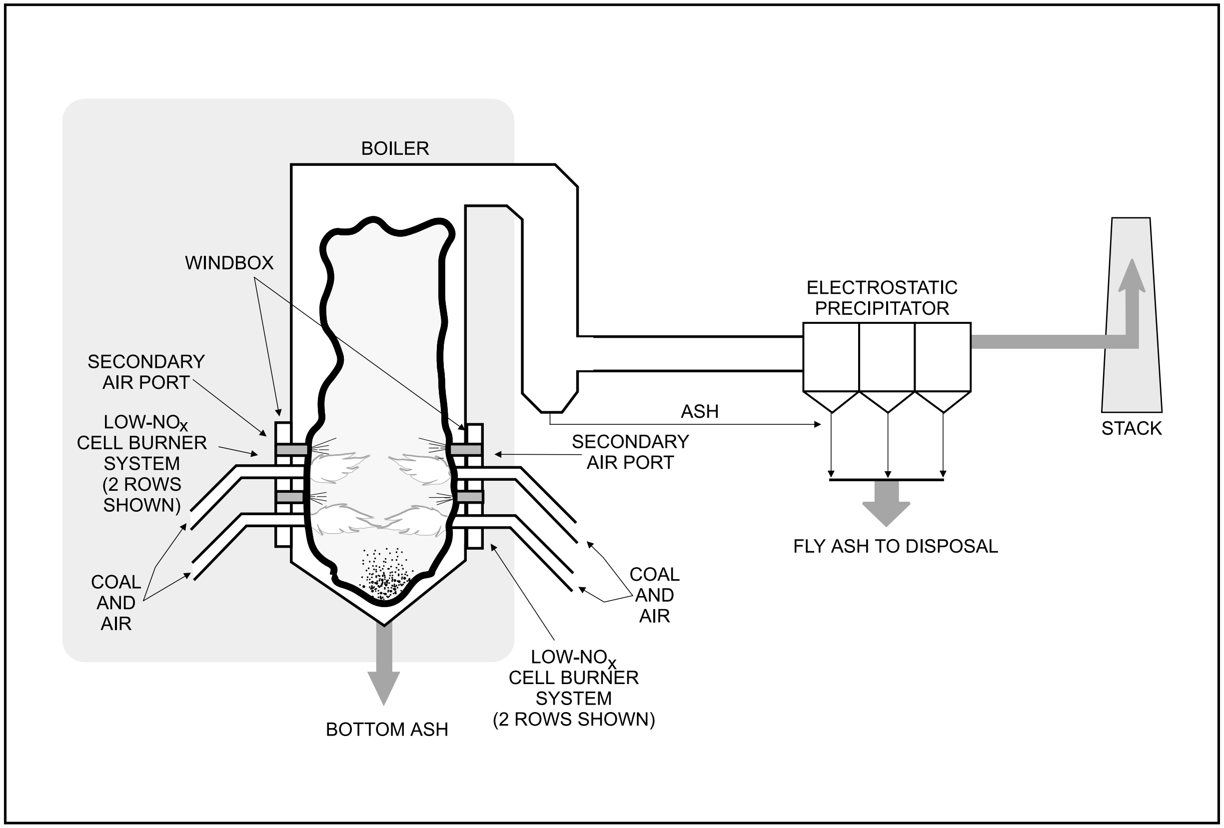
Coal

Bituminous, medium sulfur

Project Funding

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

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



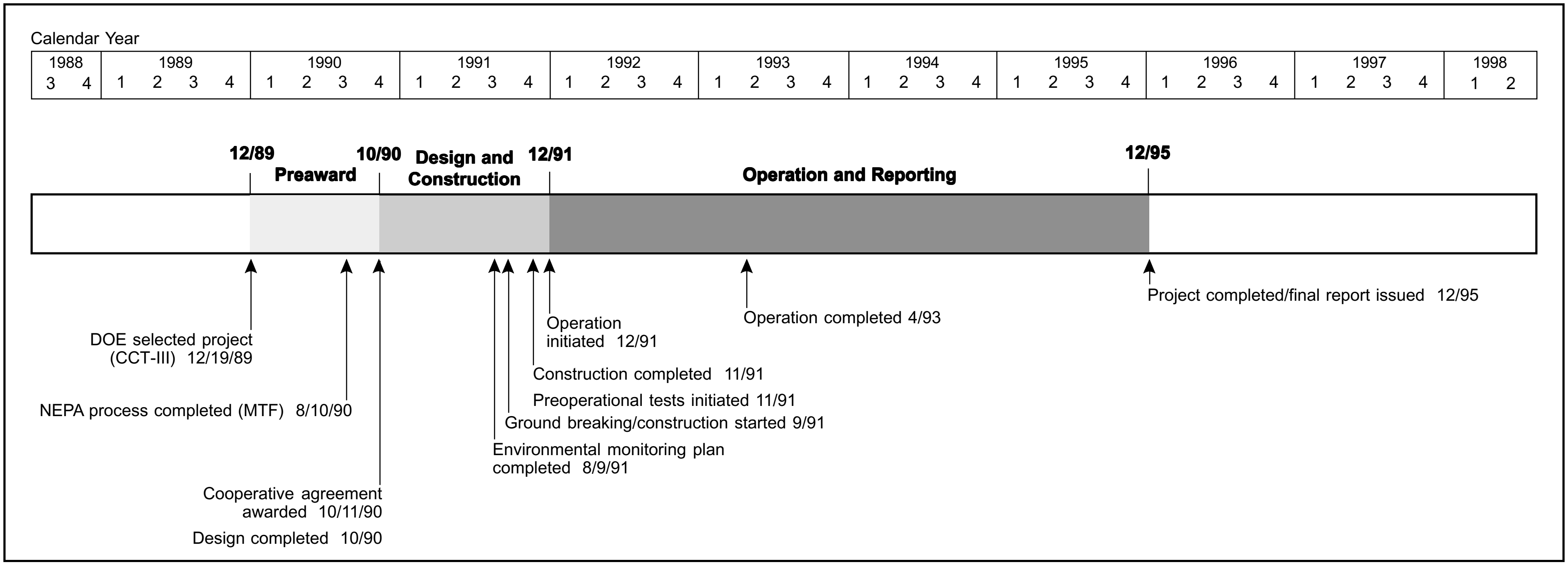
Project Objective

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 and 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. Combustion is staged by providing only about 58% of the air theoretically required for complete combustion through the lower burner and the balance of the air through the secondary air port (NO_x port).

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 LNCBs® were installed. Alternate LNCBs® on the bottom rows were inverted, with the air port then being on the bottom to ensure complete combustion in the lower furnace.



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).
- Carbon monoxide (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 in the Midwest, with a 1.2 lb/10^6 Btu initial NOx emission rate and 65% capacity factor, was $9/kW (1994$).
- Levelized cost (15-year) for the same 600-MWe plant was estimated at 0.284 mills/kWh and $96.48/ton of NO_x removed (constant 1994$).

Project Summary

Utility boilers equipped with cell burners currently represent 7.4% or approximately 24,000 MWe of pre-NSPS coal-fired generating capacity. Cell burners are designed for rapid mixing of fuel and air. The tight burner spacing and rapid mixing minimize 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 fuel and combustion air. A key design criterion was accomplishing delayed fuel-air mixing with no modifications to boiler walls. The plug-in LNCB® design reduces material costs and outage time required to complete the retrofit, compared to installing conventional, internally staged low-NO_x burners, thereby providing 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 (inverting alternate burners on the lower rows), which addressed the problem without compromising boiler performance. The modification served to validate 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. The NO_x emission reductions realized were 58% for all mills in service and about 60% for one mill out of service.

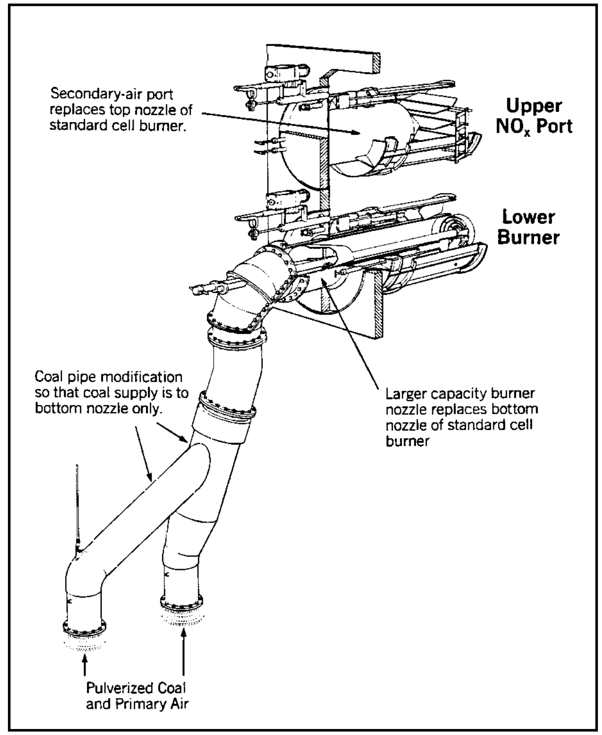
Complications arose in assessing CO emissions relative to baseline because baseline calibration was not sufficiently refined. However, accurate measurements were made with LNCB® in service. Carbon monoxide emissions were corrected for 3.0% O_2 and measured at full, intermediate, and low loads. The range 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.

Particulate emissions were minimally impacted. The LNCB® had little effect on fly ash 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, 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.



Single LNCB® retrofit.

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 differed little from baseline ash. Furthermore, the small variations observed in furnace exit gas temperature between baseline and LNCB® indicated little change in furnace slagging. Startup 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, 65% capacity factor, and a 50% reduction target, the estimated capital cost was $9/kW (1994$). The 15-year levelized cost of electricity was estimated at 0.284 mills/kWh, or $96.48/ton of NO_x removed in constant 1994 dollars.

The LNCB® viewed from within the boiler.

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. LNCBs® have already been installed on more than 4,900 MWe of capacity.

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

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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.)

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

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 and Foster Wheeler Energy Corp.'s low-NO_x burners (LNB)

Plant Capacity/Production

172 MWe (gross), 158 MWe (net)

Coal

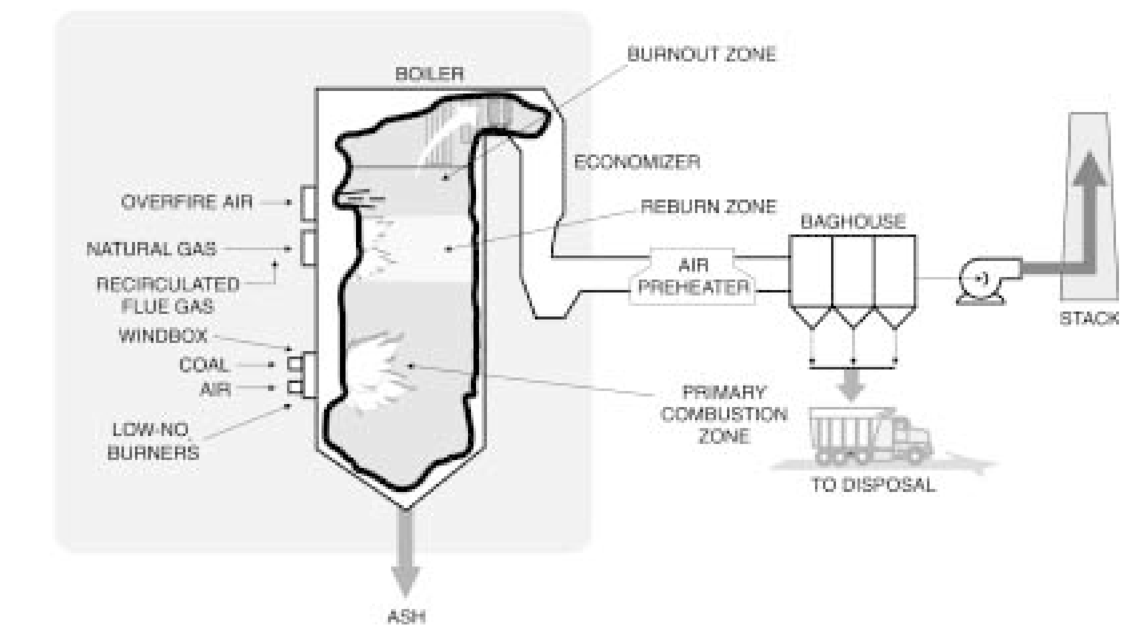
Colorado bituminous, 0.40% sulfur, 10% ash

Project Funding

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

Project Objective

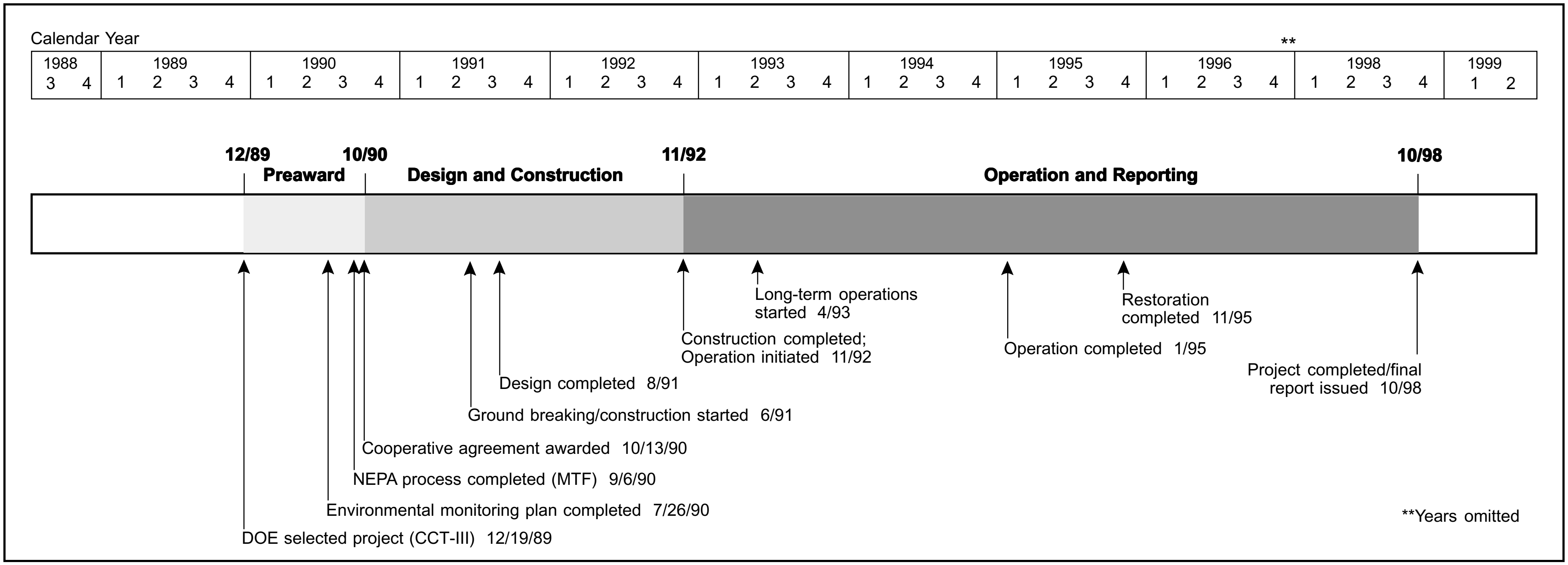
To attain up to a 70% decrease in NO_x emissions from an existing wall-fired utility boiler, firing low-sulfur coal using both gas reburning and low-NO_x burners (GR-LNB); and to assess the impact of GR-LNB on boiler performance.



Technology/Project Description

Gas reburning involves injecting natural gas (up to 25% of total heat input) above the main coal combustion zone in a boiler. This upper-level injection and partial combustion by limiting available oxygen creates a fuel-rich zone. NO_x moving upward from coal combustion in the lower furnace is stripped of oxygen as the reburn fuel is partially combusted in the reburn zone and converted to molecular nitrogen. Overfire air ports above the reburn zone provide for complete combustion in a relatively cooler region of the boiler. Reburning allows the low-NO_x burners to operate at excess air levels far below that needed for complete combustion, thus enhancing their effectiveness. 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.

A series of parametric tests was performed on the gas reburning system, varying operational control parameters and assessing the effect on boiler emissions, completeness of combustion (carbon-in-ash or loss-on-ignition), 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 and 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.

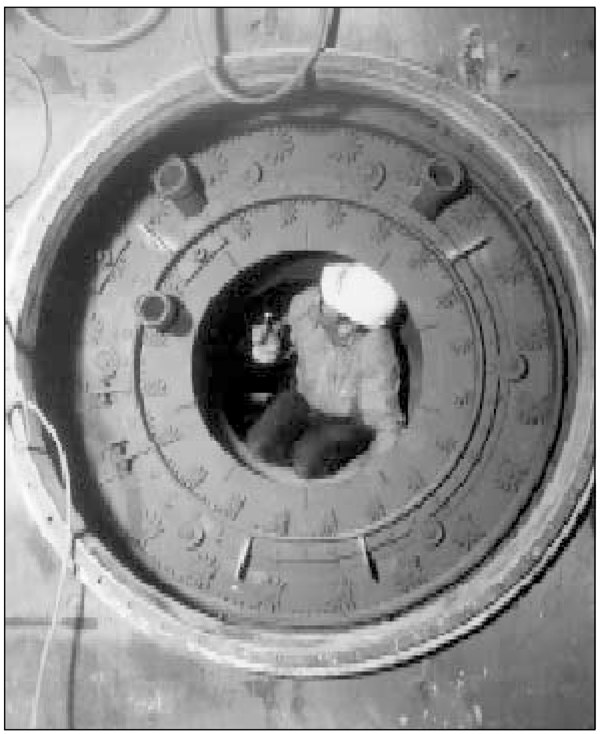
Economic

- Capital cost for a GR-LNB retrofit of a 300-MWe plant is $26.01/kW (1996$) plus the gas pipeline cost, if not already existing ($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 reductions 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 reductions is that it meets 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-fired 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.



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

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. 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 in 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 was added to the demonstration to evaluate a modified or second-generation system. Modifications included the following:

- 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%. 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, particularly at low total flows.

Over 4,000 hours of operation were achieved, with the results shown in Exhibit 5-26. 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:

Exhibit 5-26
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

- Gas availability at the site,
- Gas/coal cost differential,
- Boiler efficiency,
- SO_2 removal requirements, and
- 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. Overfire 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 also were 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

The technology can be used in retrofit, repowering, or greenfield installations of wall-fired boilers. 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); and 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.)

Micronized Coal Reburning Demonstration for NO_x Control

Project completed.

Participant

New York State Electric & Gas Corporation

Additional Team Members

Eastman Kodak Company—host and cofunder
CONSOL (formerly Consolidation Coal Company)—coal sample tester
D.B. Riley—technology supplier
Fuller Company—technology supplier
Energy and Environmental Research Corporation (EER)—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)

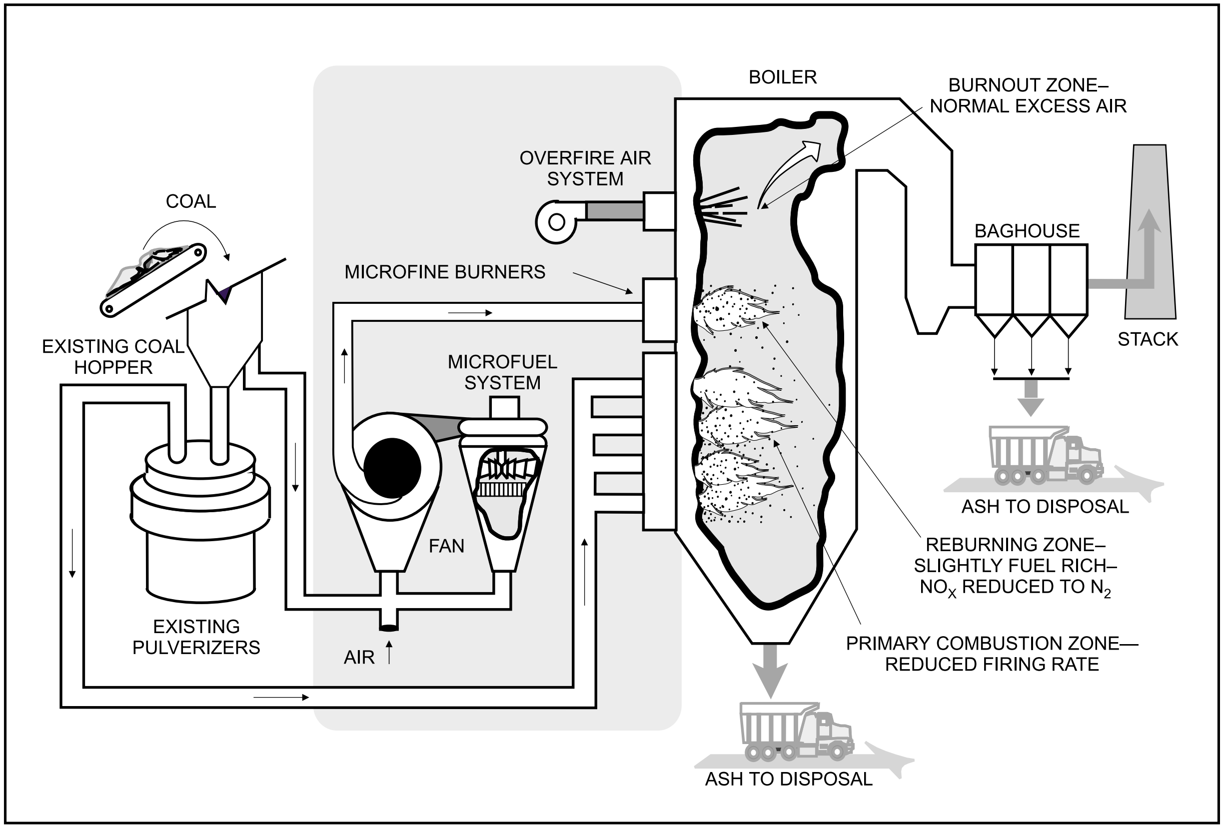
Technology

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
Kodak Park: 60-MWe cyclone boiler

MicroMill is a trademark of the Fuller Company.
LNCFS is a trademark of ABB Combustion Engineering, Inc.



Coal

Pittsburgh seam bituminous, medium- to high-sulfur (3.2% sulfur and 1.5% nitrogen at Milliken and 2.2% sulfur and 1.6% nitrogen at Kodak Park)

Project Funding

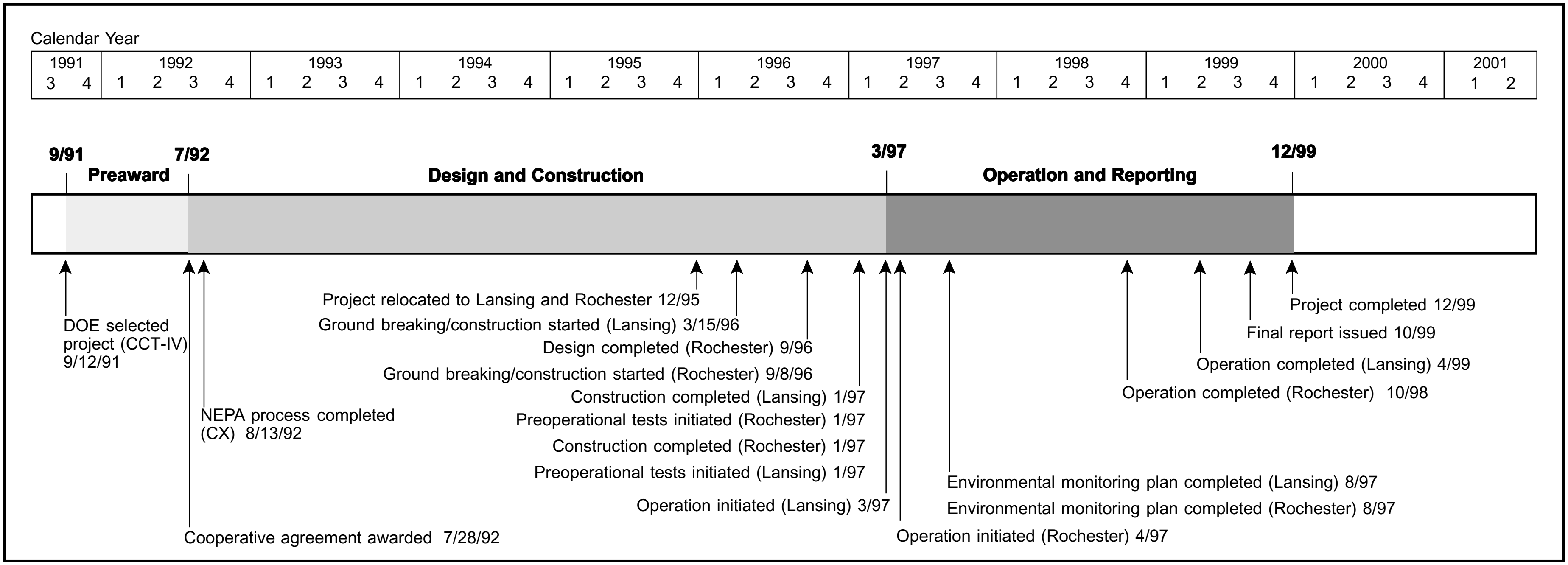
Total project cost	$9,096,486	100%
DOE	2,701,011	30
Participant	6,395,475	70

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 reburn coal, which can constitute up to 30% of the total fuel, is micronized (pulverized to achieve 85% below 325 mesh) and injected into a pulverized coal-fired furnace above the primary combustion zone. At the Milliken tangentially fired boiler site, NO_x control is achieved by: (1) close-coupled overfire air (CCOFA) reburning in which the top coal injector of the LNCFS III™ burner is used for injecting the micronized coal, and the separated overfire air system completes combustion; and (2) the remaining burners and air ports are adjusted for deep-stage combustion by re-aiming them to create a fuel-rich inner zone and fuel-lean outer zone providing combustion air. At the Kodak Park cyclone boiler 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.



Results Summary

Environmental

- Using a 14.4% reburn fuel heat input on the Milliken Station tangentially fired boiler at full load resulted in a NO_x emission rate of 0.25 lb/10^6 Btu, which represents a 29% NO_x reduction from the 0.35 lb/10^6 Btu achieved with the LNCFS III™ burner alone (baseline).
- Using a 17.3% reburn fuel heat input (reburn stoichiometry of 0.89) on the Kodak Park cyclone boiler resulted in a NO_x emission rate of 0.59 lb/10^6 Btu, which represents a 59% NO_x reduction from 1.36 lb/10^6 Btu (baseline). Higher reburn rates (estimated at 18.4% reburn or stoichiometry of 0.87) would be required for long-term compliance with 0.60 lb/10^6 Btu NO_x emission limits.

Operational

- Reburning was successfully applied at Milliken Station using the top coal feed of the LNCFS III™ burner for the reburn fuel and reducing the top burner level air flows. This eliminated the need for a separate reburn system. Testing on the tangentially fired boiler at Milliken Station showed:
  – Unburned carbon-in-ash, also referred to as loss-on-ignition (LOI), was maintained under 5%;
  – Increasing the economizer O_2 generated the classical response of higher NO_x emissions and lower LOI—the sensitivity was estimated at 0.1 lb/10^6 Btu per 1% change in O_2 and was relatively independent of coal fineness;
  – Increasing coal fineness reduced both NO_x emissions and LOI—the effect on NO_x was significant only for large variations in coal fineness; and
  – Pulverizing the reburn coal to the micronized level (greater than 80% passing 325 mesh) was not a requirement for the successful application of reburning, but significantly impacted LOI.
- Testing on the cyclone boiler at Kodak Park showed:
  – The reburn stoichiometry had a significant effect on NO_x emissions and a significant effect on LOI—lower reburn stoichiometries reduced NO_x emissions and increased LOI to 40–45% compared with a LOI baseline of 10–15%.
  – Short-term testing indicated that LOI could be maintained at levels similar to baseline levels without significantly affecting NO_x emissions by maintaining a baseline cyclone heat input.

Economic

- The estimated capital cost for retrofitting a generic 300-MWe tangentially fired boiler with micronized coal reburning is $4.3 million, or approximately $14/kW (1999$). The corresponding O&M costs are estimated at $0.30 million per year (1999$). The resulting total 15-year levelized cost is $1,329/ton of NO_x removed (current 1999$) or $1,023 (constant 1999$).
- The estimated capital cost for retrofitting a generic 300-MWe cyclone boiler with micronized coal reburning is $16.9 million, or approximately $56/kW (1999$). The corresponding O&M costs are estimated at $0.80 million per year (1999$). The total 15-year levelized cost is $741/ton of NO_x removed (current 1999$) or $571 (constant 1999$).

Project Summary

NYSEG demonstrated the micronized coal reburning technology in both tangentially fired and cyclone boilers. The tangentially fired boiler was NYSEG's Milliken Station 148-MWe tangentially fired Unit No. 1 (also the host for another CCT Program demonstration). The cyclone boiler was Eastman Kodak Company's Kodak Park Power Plant 60-MWe cyclone Unit No. 15.

The challenge with this coal reburning demonstration was to achieve adequate combustion of the reburn coal in the oxygen-deficient, short-residence-time reburn zone to reduce NO_x emissions without detrimentally increasing the unburned carbon in the ash, *i.e.*, loss-on-ignition. The primary objective of this two-site project was to demonstrate improvements in coal reburning for NO_x emission control by reducing the particle size of the reburn coal. In this demonstration, the coal was finely ground to 80% or more passing 325 mesh and injected into the boilers above the primary combustion zone. The resulting typical particle size is 20 microns compared to 60 microns for normal pulverized coal particles. This smaller size increases surface area ninefold.

With this increased surface area and coal fineness (micronized coal has the combustion characteristics of atomized oil), carbon combustion occurs in milliseconds and volatiles are released at an even rate.

Operating Performance

At the Milliken Station, the existing ABB Low-NO_x Concentric Firing System™ (LNCFS-III), which includes both close coupled and separated overfire air (SOFA) ports, was used for the reburn demonstration. Four D.B. Riley MPS 150 mills with dynamic classifiers provided the pulverized coal. With LNCFS-III, there are four levels of burners. To simulate and test the coal reburning application, the top-level coal injection nozzles fed micronized coal to the upper part of the furnace for this demonstration. The coal injection nozzles at the three lower elevations were biased to carry approximately 80% of the fuel required for full load. The speed of the dynamic classifier serving the mill feeding the top burners was increased to produce the micronized coal (greater than 80% passing 325 mesh).

During the evaluation, several conclusions were reached on how operating variables affected performance. While maintaining a constant economizer O_2 level, no single operating variable had a dominant effect on reburning performance. A combination of operating settings determined from short-term testing were selected for long-term operation to achieve the lowest NO_x emissions and reliable operation. Operating settings for long-term operation were 14–16% reburn coal, 105 rpm top mill classifier speed (corresponds to 70–72% passing 325 mesh), –5 degrees main burner tilt and 2.8% economizer O_2. No additional improvement in LOI was observed at top mill classifier speeds above 105 rpm.

At Kodak Park, EER designed the micronized coal reburn system using a combination of analytical and empirical techniques. The reburn fuel and OFA injection components were designed with a high degree of flexibility to allow for field optimization to accommodate the complex furnace flow patterns in the cyclone boiler. Two Fuller MicroMills™ were installed in parallel on Kodak Park Unit No. 15 to provide the capacity necessary for high reburn rates, with the second mill serving as a spare at lower reburn rates. The mills produced the micronized coal reburn fuel at greater than 90% passing 325 mesh. Eight injectors, six on the rear wall and one on each of the side walls, introduced the micronized coal into the reburn zone. The optimization variables included the number of injectors, swirl, and velocity. Four ports on the front wall provided OFA using EER's second-generation, dual-concentric overfire air design, which has variable injection velocity and swirl. To maximize NO_x reduction, the reburn fuel was injected with flue gas rather than air. The flue gas was extracted downstream of the electrostatic precipitator and was boosted by a single fan. A new boiler control system was also installed on Unit No. 15.

Environmental Performance

At the Milliken Station, micronized coal reburning with 14.4% reburn fuel at full load reduced NO_x emissions from the 0.35 lb/10^6 Btu baseline level to 0.25 lb/10^6 Btu, a 29% reduction. This reduction represents an addition to the 39% reduction achieved with the LNCFS III™ low-NO_x burner alone. Boiler efficiency was maintained at 88.4–88.8%. Furthermore, concentrating the overfire air through fewer and higher ports and using finer grind reburn coal maintained LOI below 5%. Based on long-term testing consisting of 23 days of continuous measurements, the achievable annual NO_x emissions using 15.1% coal reburn heat input were estimated at 0.245 ± 0.011 lb/10^6 Btu (95% confidence), and the estimated average fly ash LOI was 4.4 ± 0.4%. Based on replicated performance tests and a 95% confidence level, variations in NO_x emissions less than 0.006 lb/10^6 Btu and in fly ash LOI less than 1.5 percentage points were assumed to be of no statistical significance. There were large uncertainties with respect to the effects on LOI, possibly because LOI generally varied within a relatively narrow range (between 3% and 5%) in response to changing operating variables.

With regard to reburn coal fineness and reburn coal quantity, using a finer grind reburn coal (top mill) reduced both NO_x emissions and LOI. The effect on NO_x was significant (relative to the uncertainty level of 0.006 lb/10^6 Btu) only for relatively large variations in the top mill classifier speed (and hence coal fineness). Using a finer grind coal (all mills) reduced both NO_x emissions and LOI. Decreasing the reburn coal fraction from 25% to 14% decreased NO_x emissions from 0.25 to 0.23 lb/10^6 Btu and had a minor effect on LOI (generally less than 1.5 percentage points). The decrease in NO_x from decreasing the coal reburn fraction was attributed to lower excess air levels in the primary combustion zone as more coal was diverted to the lower burners.

Reducing the boiler load reduced NO_x emissions, and the effect was greater when the second mill was taken out of service. Thus, reducing the boiler load by taking the second mill out of service is a recommended option. Taking the second mill out of service while maintaining the same boiler load reduced NO_x emissions at both high (140 MW) and low (110 MW) boiler loads, possibly due to longer residence times in the primary combustion zone.

Changes in air flow resulted in measurable changes in both NO_x reduction and LOI. An increase in the reburn coal transport air (top burner primary air), corresponding to a 20% increase in the air-to-fuel ratio from 2.05 to 2.45, increased NO_x emissions from 0.28–0.31 lb/10^6 Btu. This increase in NO_x was attributed to less reducing reburn zones with the additional introduction of an oxidant with the reburn fuel. Increasing the top level auxiliary airflow increased both NO_x emissions and LOI. This increase in NO_x was attributed to less reducing reburn zones as more oxidant was introduced through the auxiliary air nozzle situated directly below the reburn coal nozzle. The increase in LOI from increasing the top level auxiliary airflow was attributed to lower excess air levels in the primary combustion zone as more air was diverted away from the lower burners. Increasing the economizer O_2 generated the classical response of higher NO_x emissions and lower or stable LOI. The economizer O_2 sensitivity was estimated at 0.1 lb NO_x/10^6 Btu per 1% change in O_2 and was relatively independent of the reburn coal fineness.

The SOFA and main burner tilts had minimal effects on performance. Variations in the SOFA tilt between 0 and 15 degrees (above horizontal) had minor effects on both NO_x emissions and LOI in both LNCFS III™ and reburn configurations. Operating the main burner tilt slightly below the horizontal (about -5 degrees) improved the reburning performance (lower LOI without increasing NO_x), relative to the horizontal setting, which was attributed to longer residence times in the furnace prior to overfire air introduction. Overall, the effect was difficult to quantify due to the limited number of tests.

At Kodak Park, the application of micronized coal reburning reduced NO_x emissions and increased LOI, as expected. Micronized coal reburning with 17.3% reburn fuel at a reburn stoichometry of 0.89, reduced NO_x emissions to 0.59 lb/10^6 Btu from a baseline of 1.36 lb/10^6 Btu, a 59% reduction, and reduced the boiler efficiency from 87.8% to 87.3%. At greater reburn rates, further NO_x reduction was achieved to a degree comparable with gas reburning systems. At full load, LOI was 40–45%, compared with a baseline level of 10–12%.

Based on long-term testing, the achievable annual NO_x emissions (at 15.6% reburn or stoichiometry of 0.90) were 0.69 ± 0.03 lb/10^6 Btu (95% confidence), corresponding to an LOI of 38% ± 2%. Higher reburn feeds (estimated at 18.4% reburn or stoichiometry of 0.87) would be required for long-term compliance with the 0.6 lb/10^6 Btu NO_x emissions limit.

The reburn stoichiometry had a significant effect on NO_x emissions and a significant effect on the LOI. Lower reburn stoichiometries reduced NO_x emissions and increased the LOI, typically dropping below 0.6 lb/10^6 Btu at reburn stoichiometries below 0.9 and corresponding to 40–45% LOI. The increase in the LOI relative to baseline was partially due to a lower cyclone heat input, which resulted in lower temperatures in the primary combustion zone. The lower temperatures produced less thermal NO_x formation and less efficient char burnout. The LOI increase was also partially due to the staged combustion resulting in shorter residence times under oxidizing conditions. At constant heat input levels, the LOI was not significantly different with or without reburning, suggesting that in reburn applications, the LOI could be maintained at levels similar to baseline by maintaining a high cyclone heat input. The contribution of reburning alone (assuming no change in the cyclone heat input) to the increase in the LOI was estimated at 0–12% (absolute).

Economic Performance

Estimates were prepared for retrofitting micronized coal reburning on generic 300-MWe tangentially fired and cyclone boilers. For the tangentially fired boiler, the capital costs were estimated at $4.3 million, or approximately $14/kW (1999$). The O&M costs were estimated at $0.30 million per year (1999$). Costs were levelized both on a current dollar and constant dollar basis. The 15-year levelized cost for the 300-MWe unit is $1,329/ton of NO_x removed on a current dollar basis, and $1,023/ton of NO_x removed on a constant dollar basis (1999$).

For the cyclone boiler, the estimated capital cost is $16.9 million, or approximately $56/kW (1999$). The estimated O&M costs are $0.80 million per year (1999$). The total 15-year levelized cost is $741/ton of NO_x removed on a current dollar basis or $571 on a constant dollar basis (1999$).

Commercial Applications

Micronized coal reburning technology can be applied to existing and greenfield cyclone-fired, wall-fired, and tangentially fired pulverized coal units. The technology reduces NO_x emissions by 20–59% 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. Commercial units can achieve a turndown of 8:1 on nights and weekends without consuming expensive auxiliary fuel.

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References

- *Micronized Coal Reburning Demonstration for NO_x Control. Final Report.* New York State Electric & Gas Corporation and CONSOL, Inc. October 1999.
- *Reburning Technologies for the Control of Nitrogen Oxides from Coal-Fired Boilers.* U.S. Department of Energy, Babcock & Wilcox, EER Corp., and NYSEG Topical Report No. 14. May 1999.
- Savichky *et al.* "Micronized Coal Reburning Demonstration of NO_x Control." *Sixth Clean Coal Technology Conference: Technical Papers.* April–May 1998.

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)

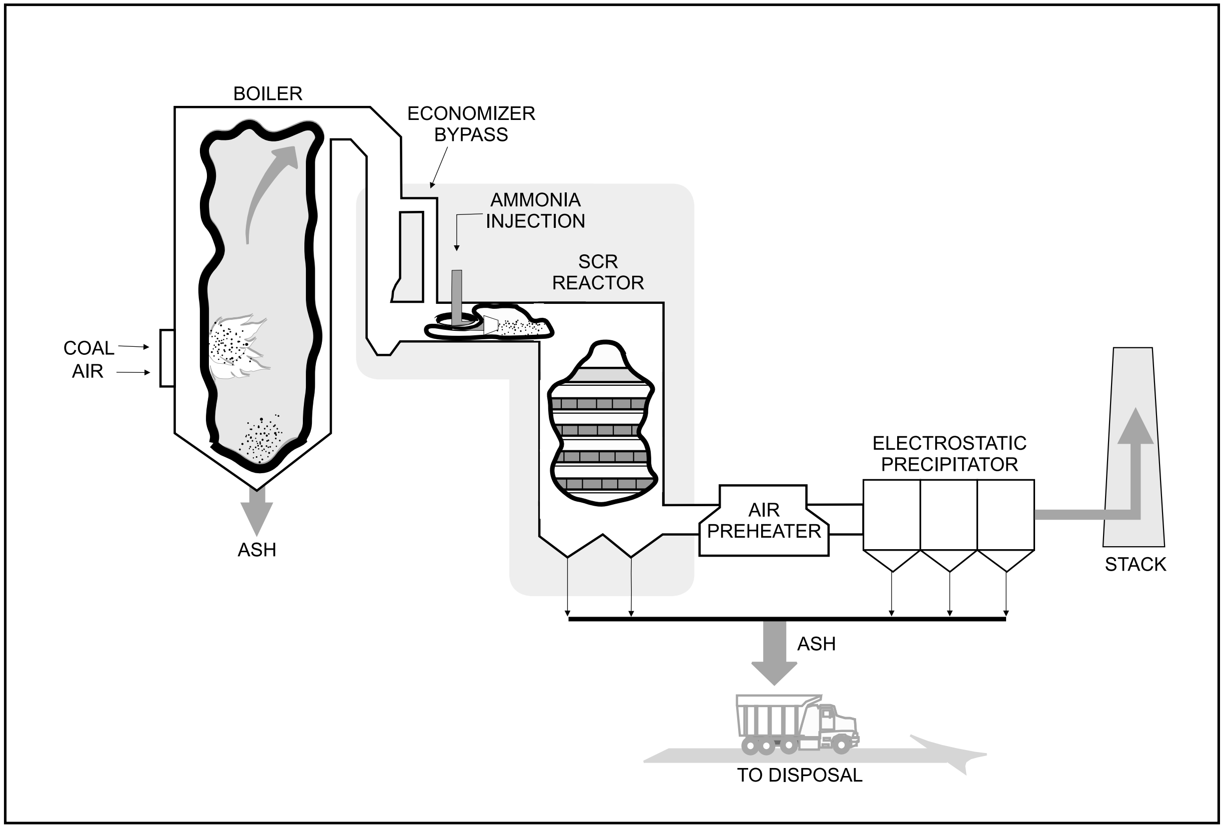
Plant Capacity/Production
8.7-MWe equivalent (three 2.5-MWe and six 0.2-MWe equivalent SCR reactor plants)

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.

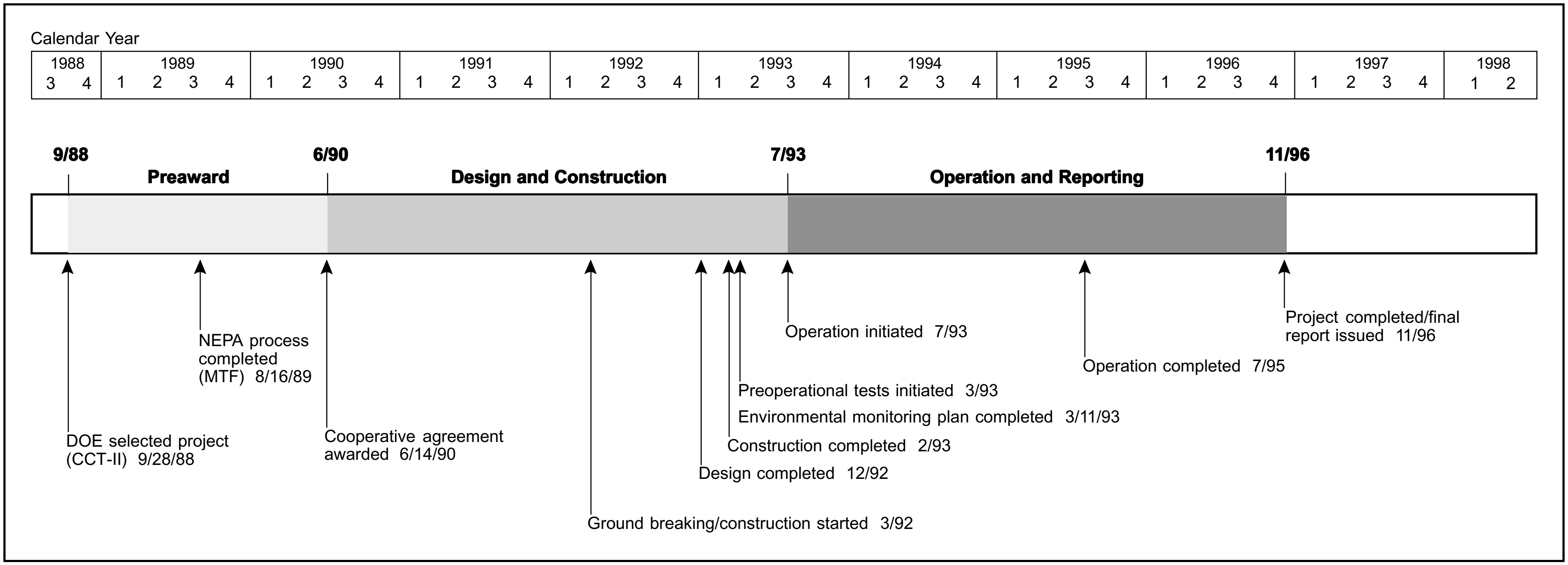


Technology/Project Description
The SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor.

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, Florida, 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 (TCLP) analysis of the fly ash.

Economic

- Levelized costs on a 30-year basis for a 250-MWe unit at a 0.35 lb/10^6 Btu NO_x emission rate were 2.39, 2.57, and 2.79 mills/kWh (Constant 1996$) for 40, 60, and 80 percent removal efficiency, respectively, which equates to 3,502; 2,500; and 2,036 $/ton (constant 1996$), respectively.

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 the technology and its 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 conditions shown in Exhibit 5-27.

Exhibit 5-27
Reactor Baseline Conditions

Parameter	Minimum	Baseline	Maximum
Temperature (°F)	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			
Large reactor (scfm)	3,000	5,000	7,500
Small reactor (scfm)	240	400	600

The catalysts tested are listed in Exhibit 5-28. Catalyst suppliers were given great latitude in providing the amount of catalyst for this demonstration.

Exhibit 5-28
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

Environmental Results

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

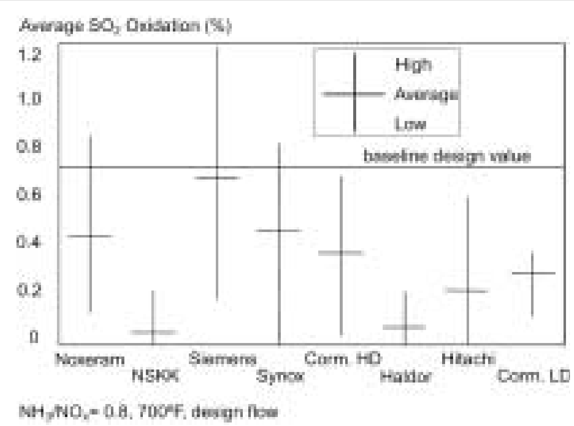
The flow rate and temperature effects on NO_x reduction were also measured. In general, flows could be increased to 150% of design without the ammonia slip exceeding 5 ppm, at 80% NO_x reduction and at the design temperature. With respect to temperature, most catalysts exhibited fairly significant improvements 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 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 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.

Experience has shown that the catalytic active species that result 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 5-29. 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 were flow rate and temperature. 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. 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.

Exhibit 5-29
Average SO_2 Oxidation Rate
(Baseline)



Other findings from the demonstration deal with pressure drop, fouling, erosion, air preheater performance, ammonia volatilization, and TCLP analysis. Overall reactor pressure drop was a function of the catalyst geometry and volume, but tests were inconclusive in determining which parameter was controlling. The fouling characteristics of the catalyst were important to long-term operation. During the demonstration, measurements showed a relatively level pressure drop over time, indicating that sootblowing procedures were effective. The plate-type configuration had somewhat less fouling potential than did the honeycomb configuration, but both were acceptable. Catalyst erosion was not considered to be a significant problem because most of the erosion was attributed to aggressive sootblowing. With regard to air preheater performance, the demonstration showed that the SCR process exacerbated performance degradation of the air preheaters mainly due to ammonia slip and subsequent by-product formation. Regenerator-type air heaters outperformed recuperators in SCR applications in terms of both thermal performance and fouling. The ammonia volatilized from the SCR fly ash when a significant amount of water was absorbed by the ash. This was caused by formation of a moist layer on the ash with a pH high enough to convert ammonia compounds in the ash to gas-phase ammonia. TCLP analyses were performed on fly ash 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 5-30.

The economic analysis of capital, operating and maintenance (O&M), and levelized cost for various unit sizes for an SCR system are shown in Exhibit 5-31. Results of the economic analysis of capital, O&M, and levelized cost for various NO_x removal efficiencies for a 250-MWe unit are shown in Exhibit 5-32. 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 (1996\$).

Exhibit 5-30
SCR 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.

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References

- 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.)

Exhibit 5-31
SCR Economics by Unit Size

	125 MWe	250 MWe	700 MWe
Capital cost (\$/kW)	61	54	45
Operating cost (\$/yr)	580,000	1,045,000	2,667,000
Constant 1996\$ levelized cost			
Mills/kWh	2.89	2.57	2.22
\$/ton NO_x removed	2,811	2,500	2,165

Note: 30 year life; 60% NO_x removal

Exhibit 5-32
SCR Economics by NO_x Removal

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

Note: 250MWe; 0.35 lb/10^6 Btu of inlet NO_x

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

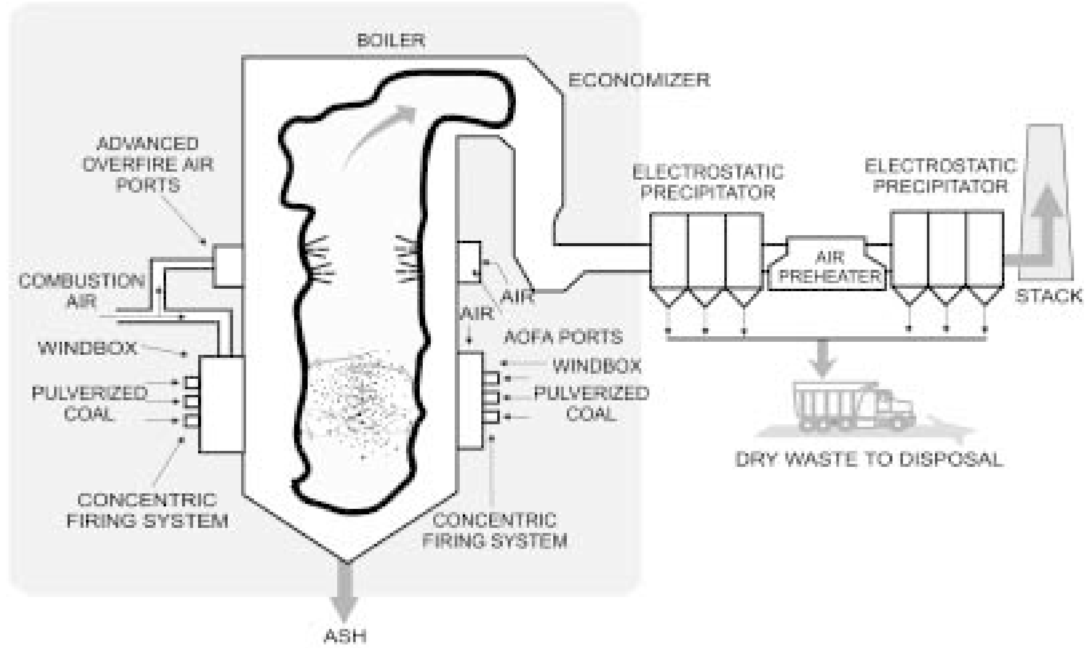
Plant Capacity/Production
180 MWe

Coal
Eastern bituminous, high reactivity

Project Funding

Total project cost	$8,553,665	100%
DOE	4,149,382	49
Participant	4,404,283	51

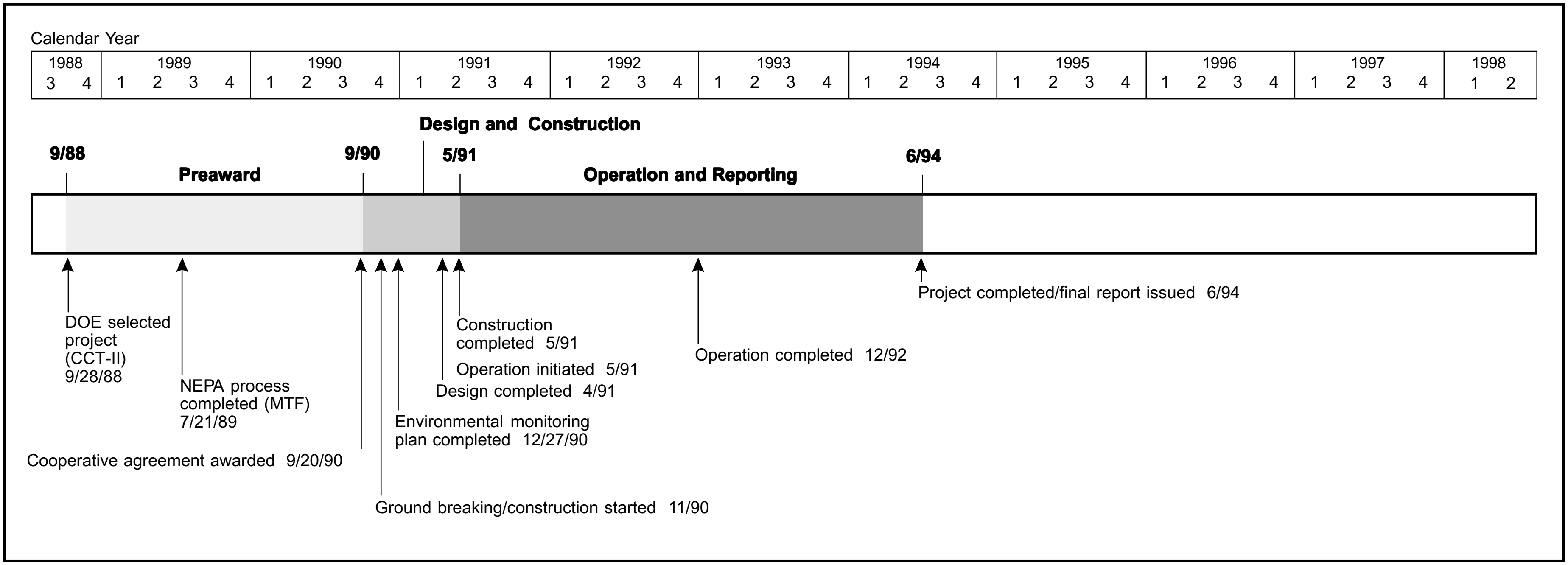
LNCFS is a trademark of ABB Combustion Engineering, Inc.



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 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.



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 MWe 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 backpass 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

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 vertically in the boiler with separate 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 under normal dispatch and operating conditions over the long-term. 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.

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.

Exhibit 5-33 shows the various LNCFS™ configurations used to achieve staged combustion. In addition to overfire air, the LNCFS™ incorporates other NO_x-reducing techniques into the combustion process as shown in Exhibit 5-34. Using offset air, two concentric circular combustion regions are formed. The majority of the coal is contained in the fuel-rich zone. 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.

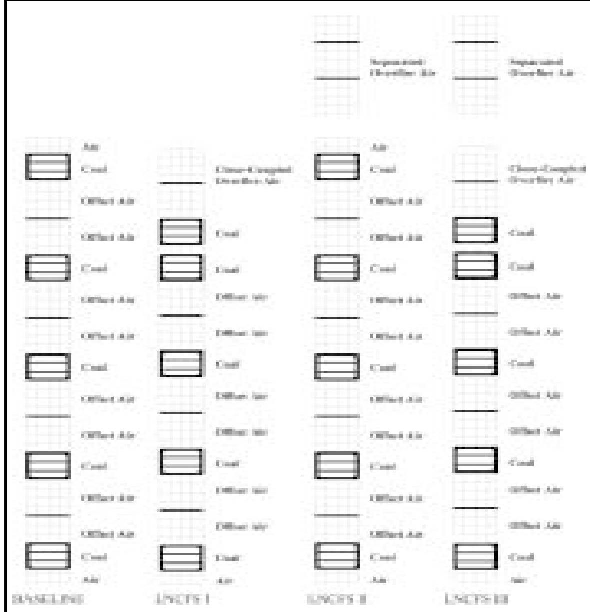
Operational Performance

Exhibit 5-35 summarizes the impacts of LNCFS™ on unit performance.

Environmental Performance

At full load, LNCFS™ I, II, and III reduced NO_x emissions by 37, 37, and 45%, respectively. Exhibit 5-36 presents the NO_x emission estimates obtained from the assessment of the average annual NO_x emissions for three dispatch scenarios.

Exhibit 5-33
LNCFS™ Configurations

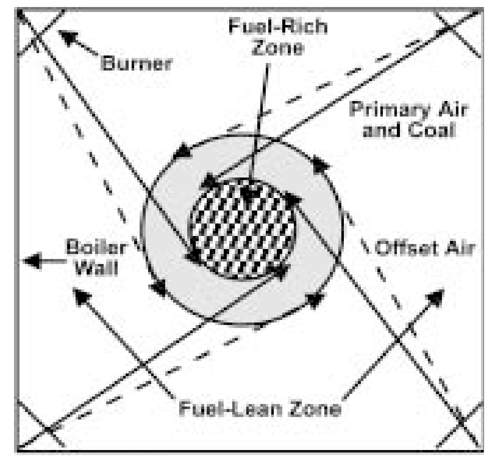


Air toxics testing found LNCFS™ to have no clear-cut effect on the emission of trace metals or acid gases. The data provided marginal evidence for a decreased emission of chromium. The effect on aldehydes/ketones could not be assessed because baseline data were compromised. VOCs appeared to be reduced 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 dollars follow:

Exhibit 5-34
Concentric Firing Concept



Source: Reference 5

- 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 follows (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

The LNCFS™ technology has potential commercial application to all the 423 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.

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

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References

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- *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.

Exhibit 5-35
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 temperatures 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: satisfactory 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 (points)	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 5-36
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

Environmental Control Devices
Combined SO_2/NO_x Control Technologies

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 Condenser
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

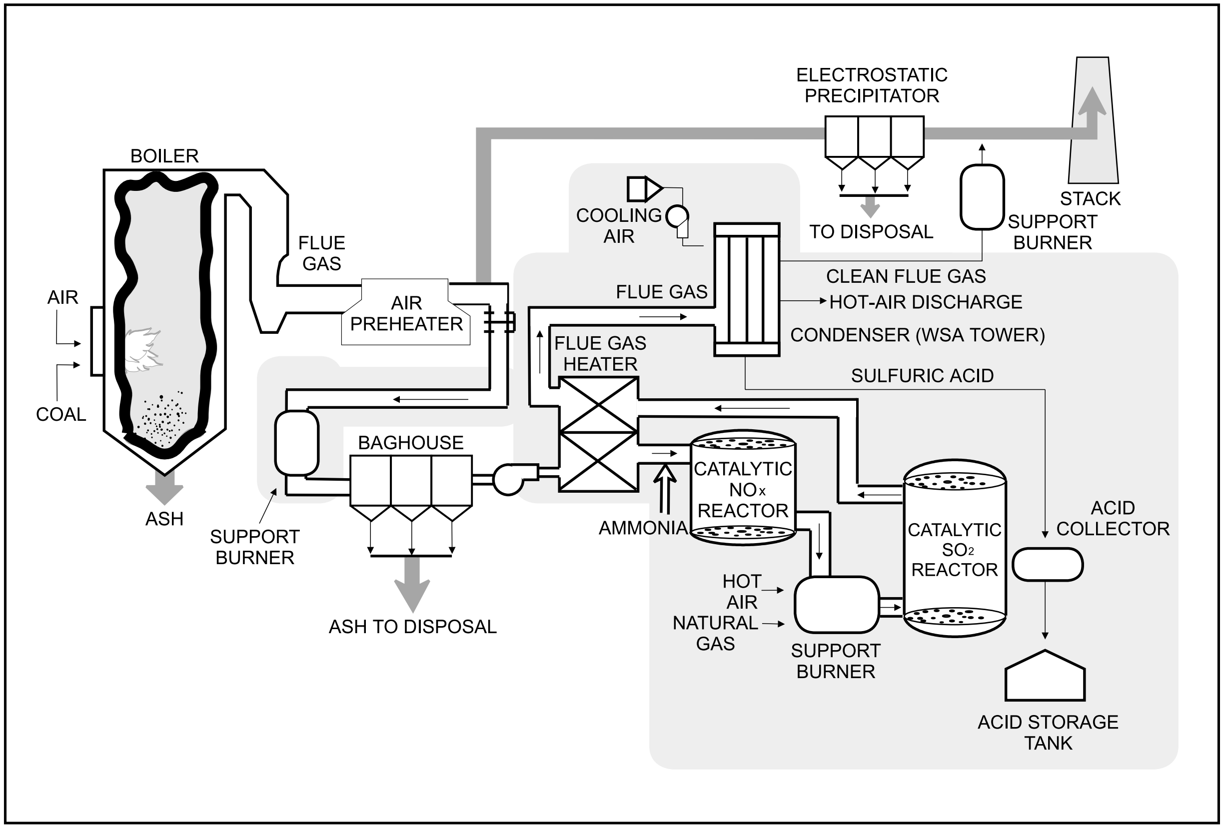
Plant Capacity/Production
35-MWe equivalent slipstream from a 108-MWe boiler

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 SNOX™ technology at an electric power plant using U.S. high-sulfur coals in which it 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.



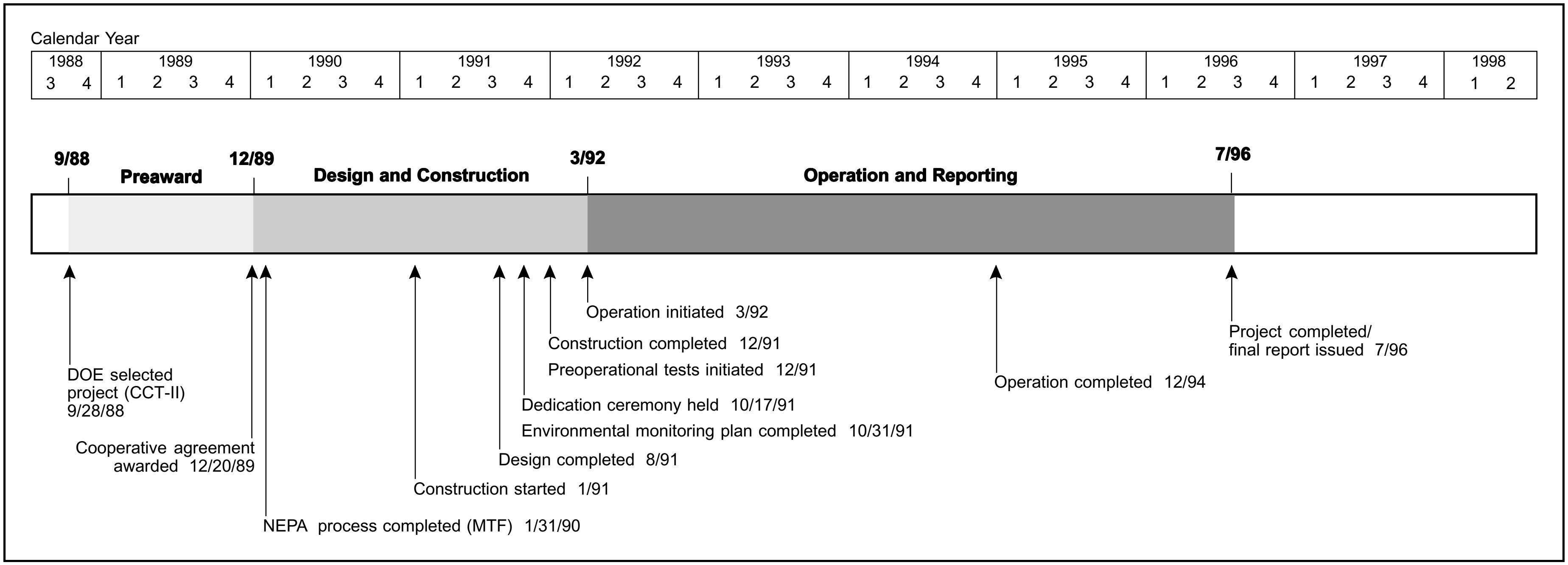
Technology/Project Description
In the SNOX™ process, the stack gas leaving the boiler is cleaned of fly ash in a high-efficiency fabric filter baghouse to minimize the cleaning frequency of the sulfuric acid catalyst in the downstream SO_2 converter. The ash-free gas is reheated, and NO_x is reacted 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.

Because the SO_2 catalyst follows the NO_x catalyst, any unreacted ammonia (slip) is oxidized in the SO_2 catalyst largely to nitrogen and water vapor. Downstream fouling by ammonia compounds is eliminated, permitting operation at higher than normal stoichiometries. These higher stoichiometries allow smaller catalyst volumes and high reduction efficiencies.

The technology 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 using U.S. coals. 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 full-scale commercial 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 ranging from 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 elimination of secondary pollution streams and 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 15-year levelized incremental cost was estimated at 6.1 mills/kWh, \$219/ton of SO_2 removed, and \$198/ton of SO_2 and NO_x removed on a constant 1995 dollar basis.

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 retained about 90% of the dust that entered the catalyst vessel because of its sticky surface. 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 resulted from 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. Under most design conditions this heat recovery results in the net heat rate of the boiler remaining the same or increasing after addition of the SNOX™ process, and consequently no increase occurs in CO_2 generation.

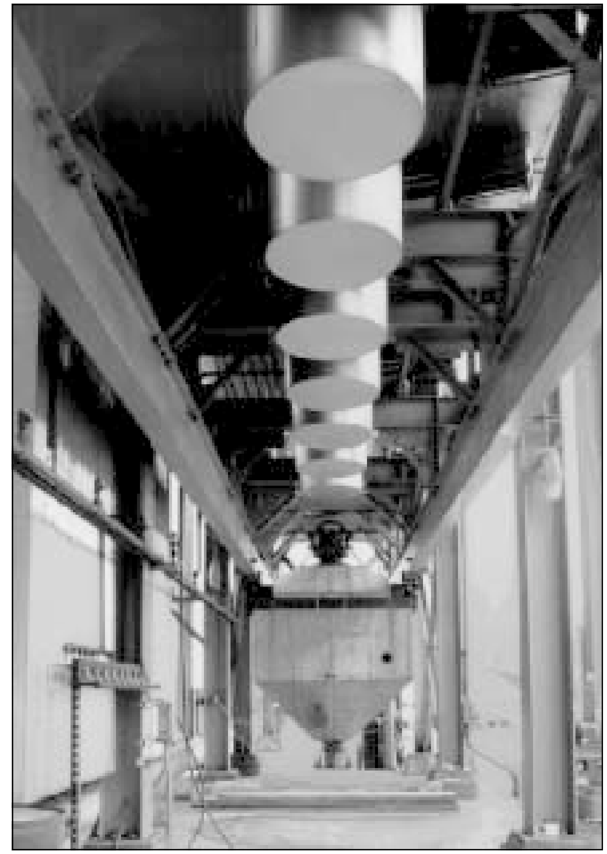
With respect to CO and hydrocarbons, the SO_2 catalyst acted to virtually eliminate these compounds as well. This aspect also positively affected the interaction of the NO_x and SO_2 catalysts. Because the SO_2 catalyst followed the NO_x catalyst, any unreacted ammonia (slip) was oxidized in the SO_2 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. 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.

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 passed 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.

Sulfuric acid concentration and composition have 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 production of diammonium phosphate fertilizer and to the steel industry for pickling. Ohio Edison also has used a significant amount in boiler water demineralizer systems throughout its plants.

Air toxics 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;



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

- 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; and
- Aldehydes.

Most trace elements were captured in the baghouse along with the particulates. 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.

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 with 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 $305/kW for a 500-MWe unit firing 3.2% sulfur coal. The 15-year levelized incremental cost was 6.1 mills/kWh on a constant dollar basis (1995$). The equivalent costs of pollutant removed were $219/ton of SO_2, and $198/ton of SO_2 and NO_x.

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 its 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.

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.

Contacts

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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)

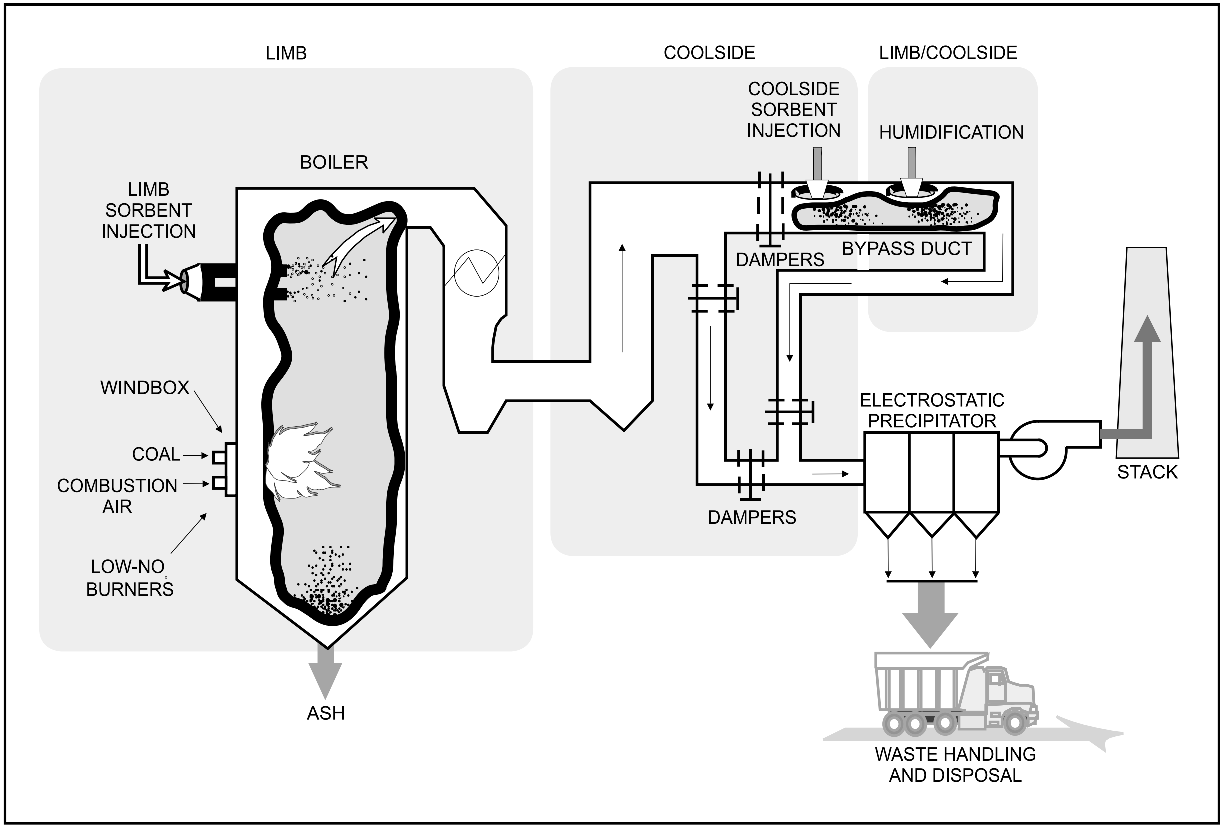
Technology
The Babcock & Wilcox Company's (B&W) limestone injection multistage burner (LIMB) system; Babcock & Wilcox DRB-XCL® low-NO_x burners; Consolidation Coal Company's Coolside duct injection of lime sorbents

Plant Capacity/Production
105 MWe

Coal
Ohio bituminous, 1.6, 3.0, and 3.8% sulfur

Project Funding

Total project cost	$19,311,033	100%
DOE	7,591,655	39
Participant	11,719,378	61



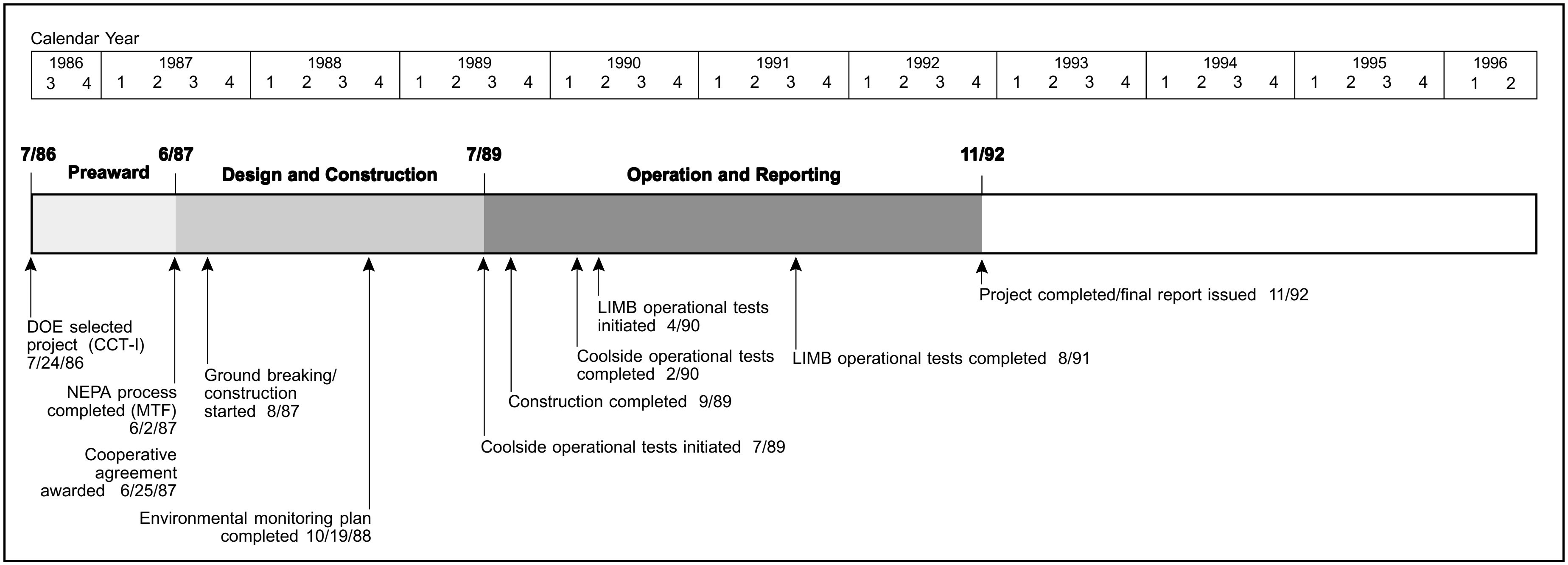
Project Objective
To demonstrate, with a variety of coals and sorbents, that the LIMB process can achieve up to 50% NO_x and SO_2 reductions, and to demonstrate that the Coolside process can achieve SO_2 removal of up to 70%.

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

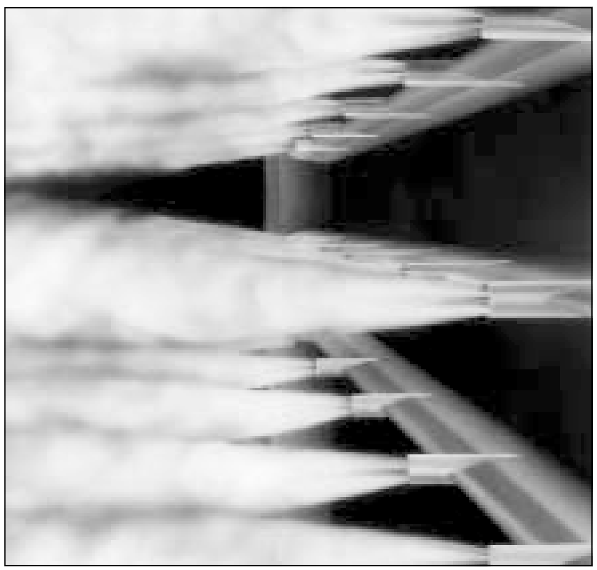
Economic

- LIMB capital costs were \$31–102/kW (1992\$) for plants ranging from 100–500 MWe and coals with 1.5–3.5% sulfur, with a target SO_2 reduction of 60%. 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 (1992\$) for plants ranging from 100–500 MWe and coals with 1.5–3.5% sulfur, with a target SO_2 reduction of 70%. 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 the 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.



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

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 elevation level in the boiler. Exhibit 5-37 summarizes SO_2 removal efficiencies for the range of sorbents and coals tested.

Exhibit 5-37
LIMB SO_2 Removal Efficiencies (Percent)

Sorbent	Nominal Coal Sulfur Content 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.

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 the removal efficiency limit. The removal efficiency for this very fine limestone was approximately 5–7% higher than that obtained under 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 using humidification down to a 20 ºF approach-to-saturation temperature. 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 (limit was 20%).

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-saturation temperatures—were evaluated in short-term (6–8 hours) parametric tests and longer term (1–11 days) process operability tests.

Exhibit 5-38
LIMB 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 5-39
LIMB 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

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-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 22% at 0.5 available Ca/S molar ratio and 18 ºF 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 ºF 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 5-38 and 5-39.

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 124 contracts for DLB-XCL® low-NO_x burners, representing 2,428 burners for 31,467 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

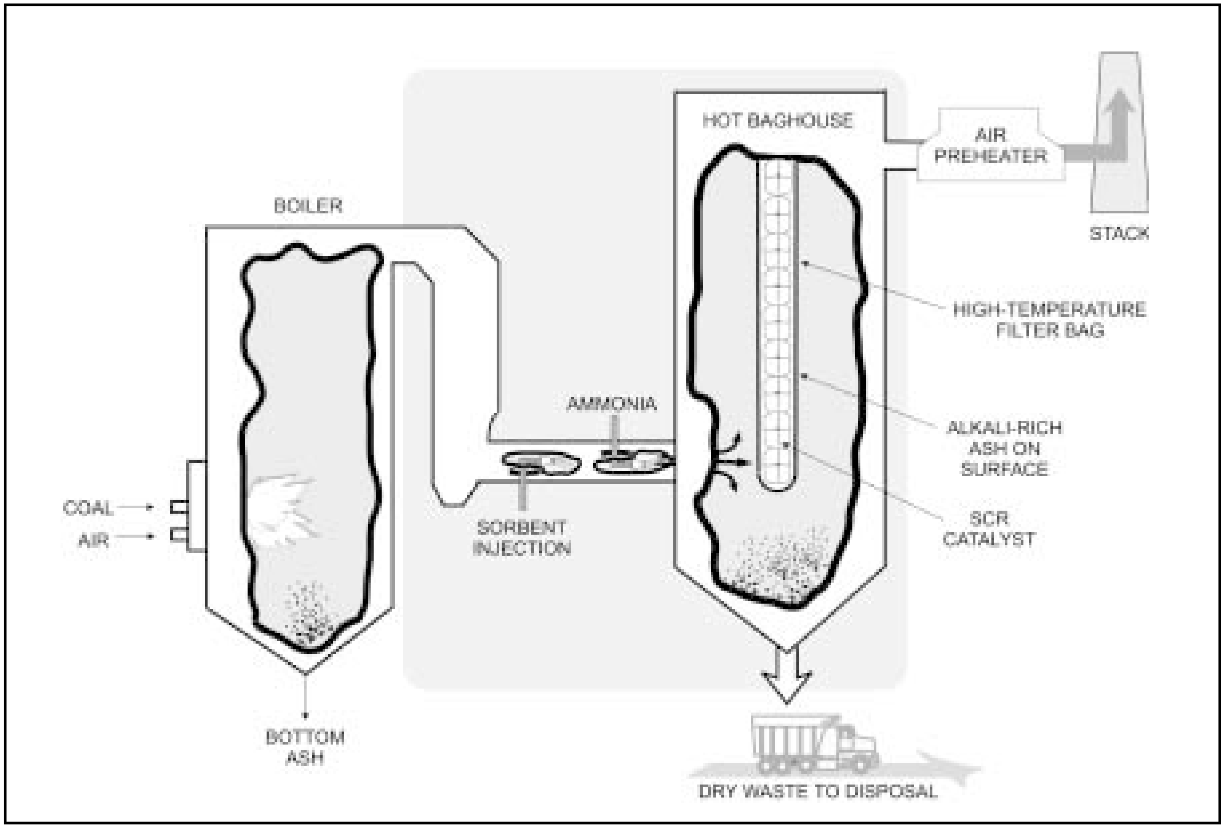
Coal

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

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



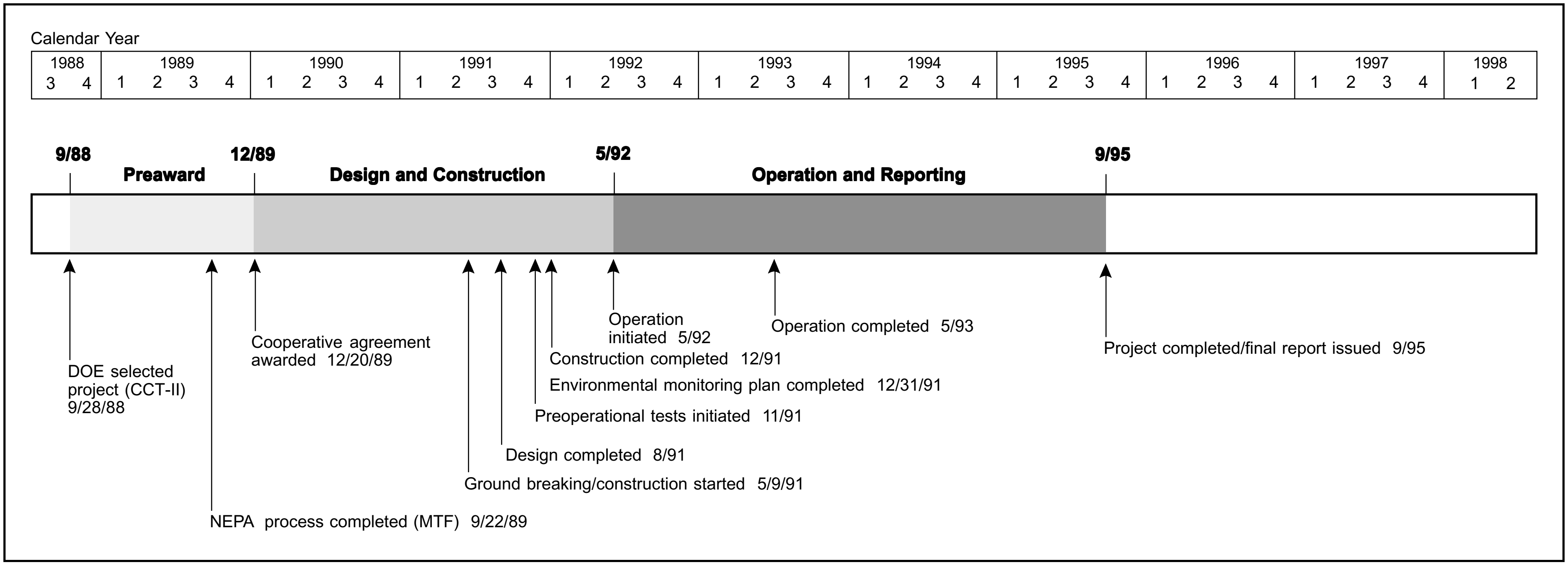
Project Objective

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. The 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.



Results Summary

Environmental

- The 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.
- The SO_2 removal efficiency of 90% was achieved with sugar-hydrated lime and lignosulfonate-hydrated lime at a Ca/S molar ratio of 2.0 and temperature of 800–850 ºF.
- The 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.
- The 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.
- The 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 toxics 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-Glass filter bag.

Economic

- Capital cost in 1994 dollars for a 150-MWe retrofit was \$253/kW, assuming 3.5% sulfur coal, baseline NO_x emissions of 1.2 lb/10^6 Btu, 65% capacity factor, and 85% SO_2 and 90% NO_x removal.
- Levelized cost over 15 years in constant 1994 dollars was \$553/ton of SO_2 and NO_x removed.

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 controls 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).

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, 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 range 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.

The 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.

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.

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.

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 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, Colorado 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 150-MWe boiler fired with 3.5% sulfur coal and NO_x emissions of 1.2 lb/10^6 Btu, 65% capacity factor, and 85% SO_2 and 90% NO_x removal, the projected capital cost of a SNRB™ system is approximately $253/kW (1994$), 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. Levelized costs over 15 years in constant 1994 dollars are estimated at $553/ton of SO_2 and NO_x removed.

Commercial Applications

Commercialization of the technology is expected to develop with an initial 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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- *5-MWe SNRB™ Demonstration Facility: Detailed Design Report.* The Babcock & Wilcox Company. November 1992.
- *Comprehensive Report to Congress on the Clean Coal Technology Program: SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project.* The Babcock & Wilcox Company. Report No. DOE/FE-0145. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004458.)

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

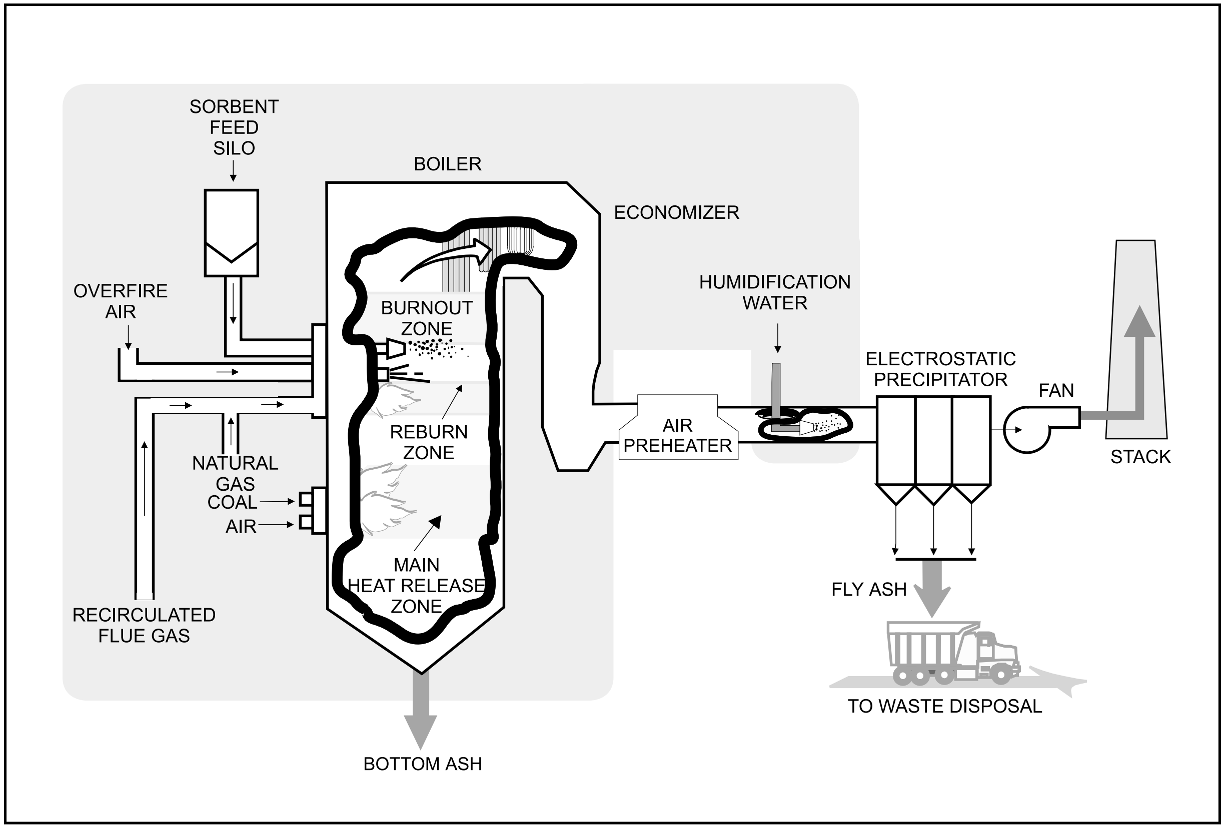
Plant Capacity/Production
Hennepin: tangentially fired 80 MWe (gross), 71 MWe (net)
Lakeside: cyclone-fired 40 MWe (gross), 33 MWe (net)

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

PromiSORB is a trademark of Energy and Environmental Research Corporation.

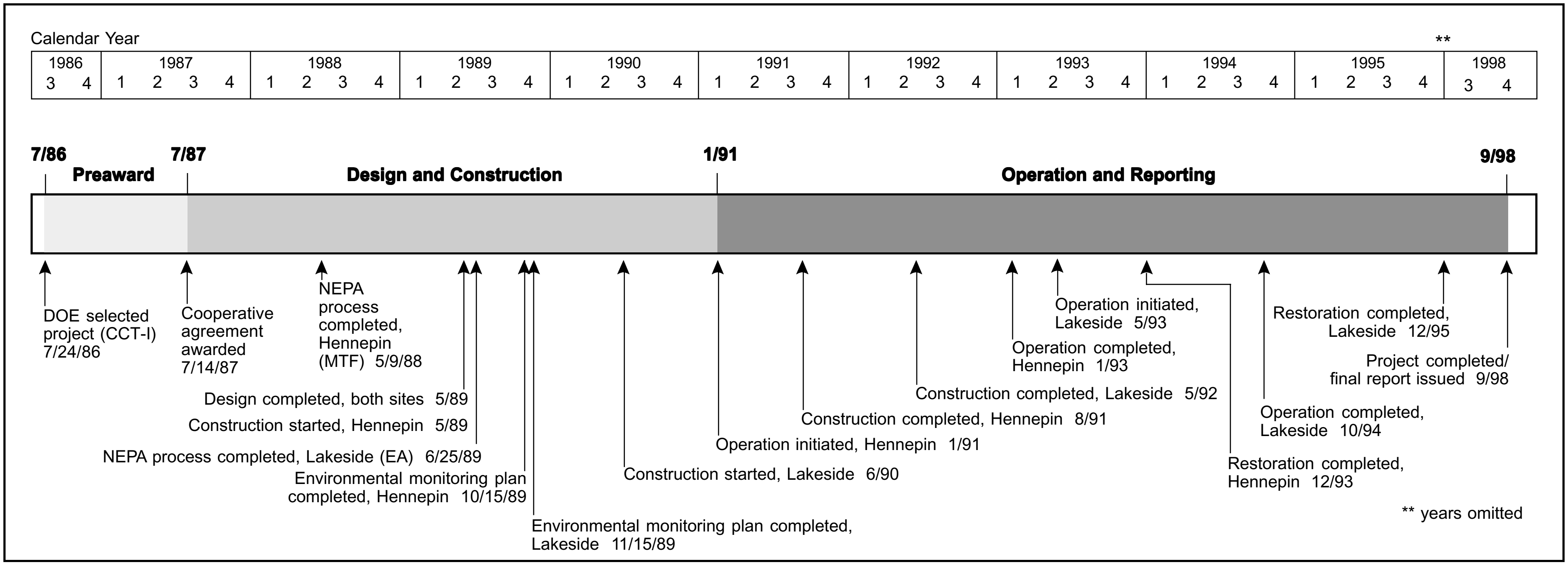


Project Objective
To demonstrate 60% NO_x reduction with gas reburning and at least 50% SO_2 removal with sorbent injection on two different boiler configurations—tangentially fired and cyclone-fired—while burning high-sulfur midwestern coal.

Technology/Project Description
In this process, 80–85% of the fuel as coal is supplied to the main combustion zone. The remaining 15–20% of the fuel, provided as natural gas, bypasses the main combustion zone and is injected above the main burners to form a reducing (reburning) zone in which NO_x is converted to nitrogen. A calcium compound (sorbent) is injected in the form of dry, fine particulates above the reburning zone in the boiler. Hydrated lime ($Ca(OH)_2$) serves as the baseline sorbent.

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, Illinois, and a cyclone-fired, 40-MWe (gross) boiler at City Water, Light and Power's Lakeside Station in Springfield, Illinois. 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 were 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.



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 enabling effective design for any site-specific utility or industrial application.

Environmental Performance (Hennepin)

Following optimization testing throughout 1991, the GR-SI long-term demonstration tests spanned 1992. The unit was operated at constant loads and with the system under dispatch load following. 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 compared favorably to baseline emissions of 0.035 lb/10^6 Btu and a collection efficiency greater than 99.5%.

Following 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 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 levels 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).

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

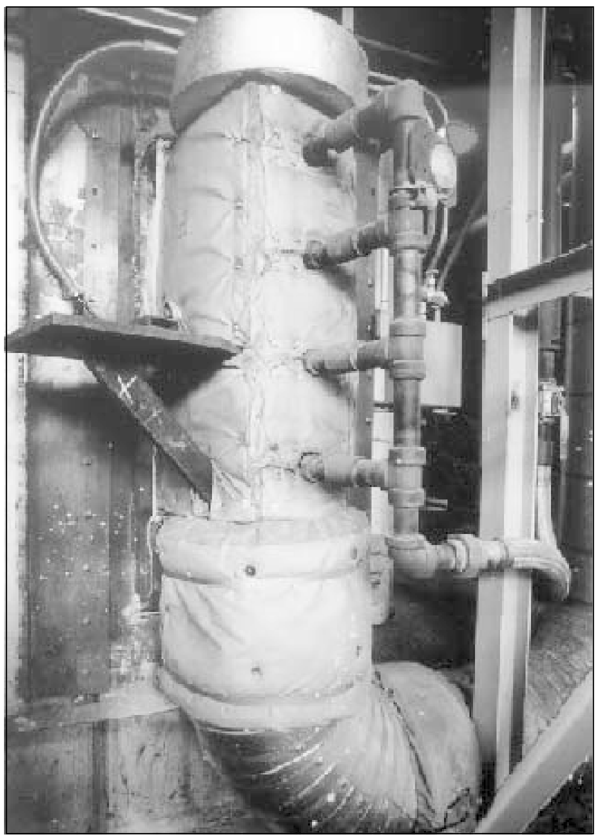
The flexible lime-sorbent distribution lines lead from the sorbent splitter to the top of the cyclone-fired boiler at Lakeside Station.

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 with 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 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 was added at Hennepin to achieve acceptable ESP performance with GR-SI.



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

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.

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Milliken Clean Coal Technology Demonstration Project

Project completed.

Participant

New York State Electric & Gas Corporation (NYSEG)

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

Location

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

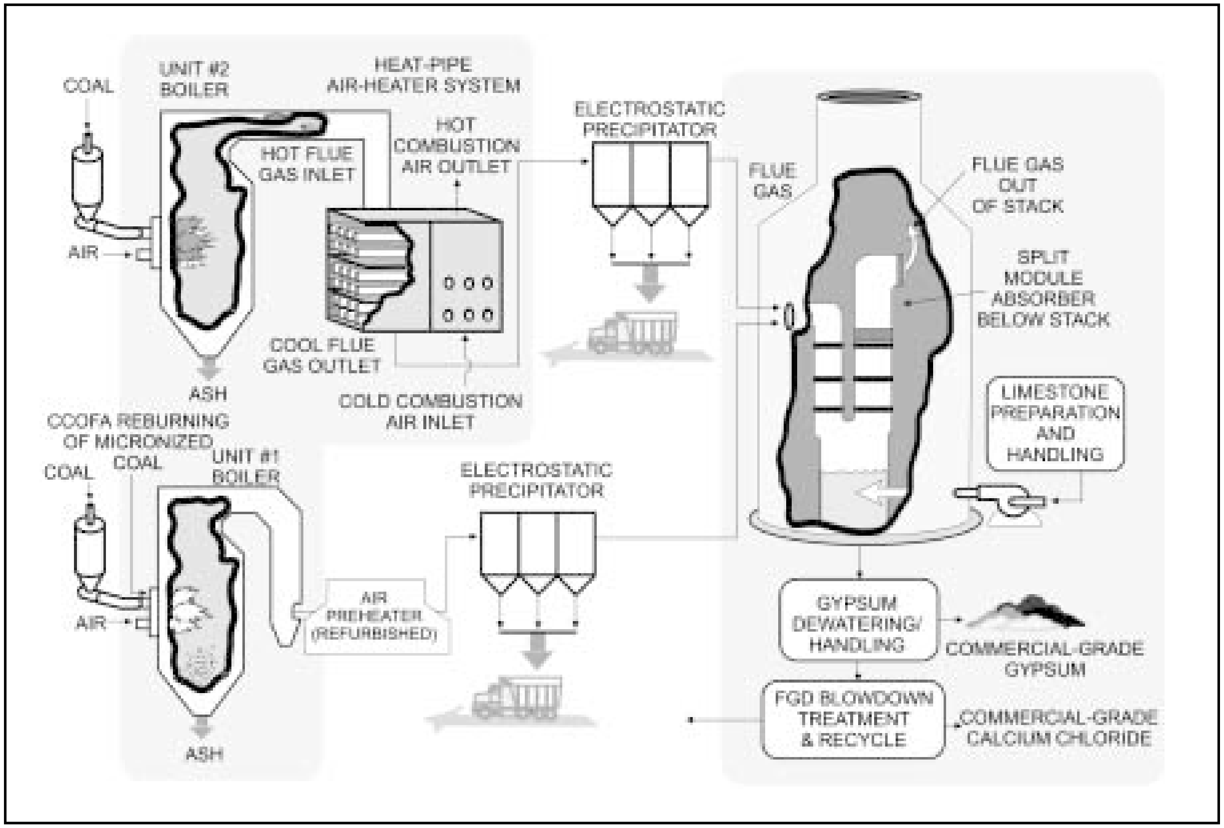
Technology

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 NYSEG's PEOA Control System.

Plant Capacity/Production

300 MWe

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



Coal

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

Project Funding

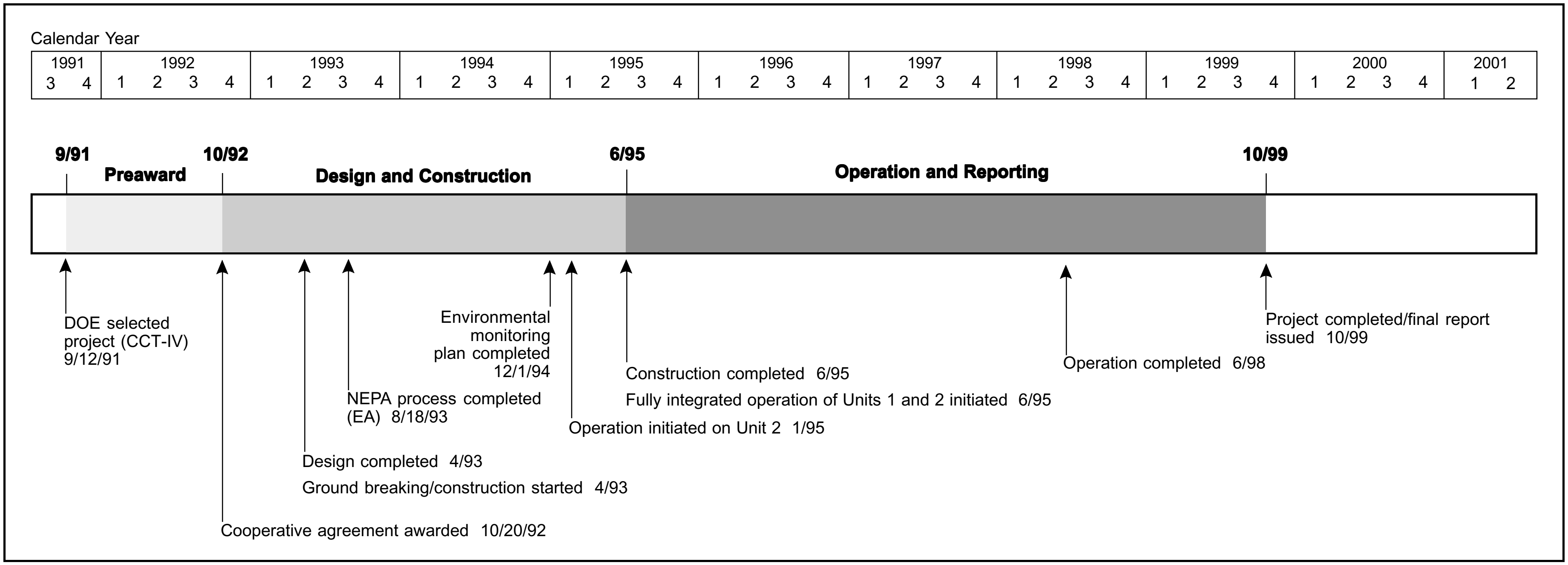
Total project cost	$158,607,807	100%
DOE	45,000,000	28
Participant	113,607,807	72

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-lined, 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. 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, a Plant Emission Optimization Advisor (PEOA) provides state-of-the-art artificial-intelligence-based control of key boiler and plant operating parameters.



Results Summary

Environmental

- The maximum SO_2 removal demonstrated was 98% with all seven recycle pumps operating and using formic acid. 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 an average of 2.6 percentage points.
- The SO_2 removal efficiency was greater than the design efficiency during the high-velocity test of the concurrent scrubber section up to a liquid-to-gas ratio (L/G) of 110 gallons per 1,000 actual cubic feet of gas.
- 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)—a 39% reduction.
- 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

- 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.
- 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 was 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

- The capital cost (1998$) of the FGD system is estimated at $300 /kW for a 300-MWe unit with a 65% capacity factor, 3.2% sulfur coal, and 95% sulfur removal.
- The annual operating cost is estimated at $4.62 million (1998$); and the 15-year levelized cost is estimated at $412/ton of SO_2 removed (constant 1998$).

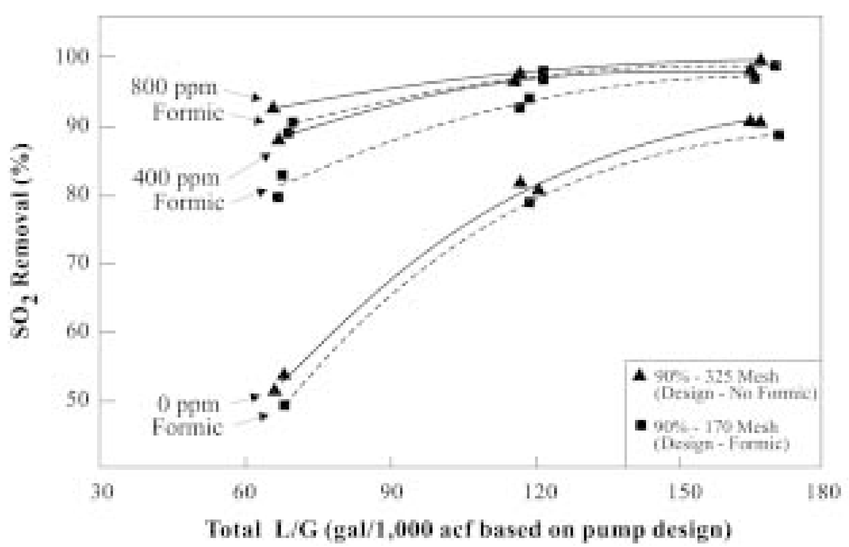
Project Summary

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 salable 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. (See Micronized Coal Reburning Demonstration for NO_x Control for another CCT Program project at this unit.)

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 an average of 2.6 percentage points, as shown in Exhibit 5-40. 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 5-41, the average effect of each countercurrent header was to increase pressure drop by 0.45 inches water column (W.C.) in the design flow tests, and 0.64 inches W.C. in the high velocity tests.

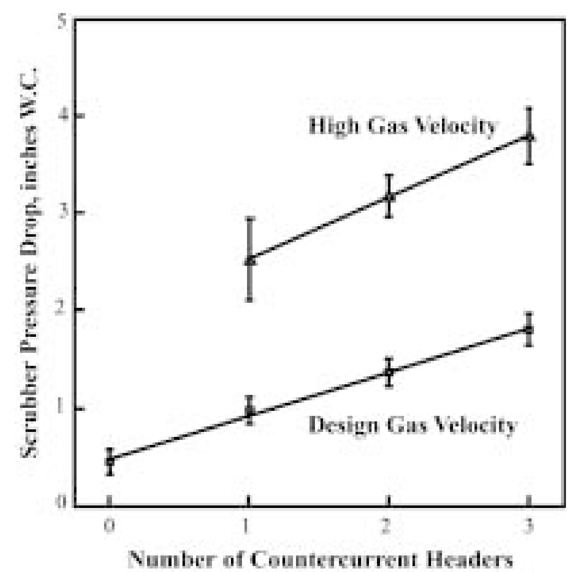
Exhibit 5-40
Effect of Limestone Grind



Performance of a modified ESP with wider plate spacing, reduced plate area, and reduced power consumption exceeded that of the original ESP. 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- to 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.

Exhibit 5-41
Pressure Drop vs. Countercurrent Headers



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 required only 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 excess O_2 requirement and higher stack temperatures which accompanied the air heater retrofit.

The heat pipe was tested in accordance with ASME Power Test Code for Air Heaters 4.3. Air infiltration was 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 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

The capital cost of the total FGD system in 1998 dollars is estimated at $300/kW for a 300-MWe unit with a 65% capacity factor using 3.2% sulfur coal and achieving 95% sulfur removal. The annual operating cost is estimated at $4.62 million. The 15-year levelized cost is estimated at $412/ton of SO_2 removed in 1998 constant dollars.

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 by-products, offer significant incentives to generating stations with limited space. Six modules of DHR Technologies' PEOA™ system have been sold, with an estimated value of $210,000.

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—fly ash 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

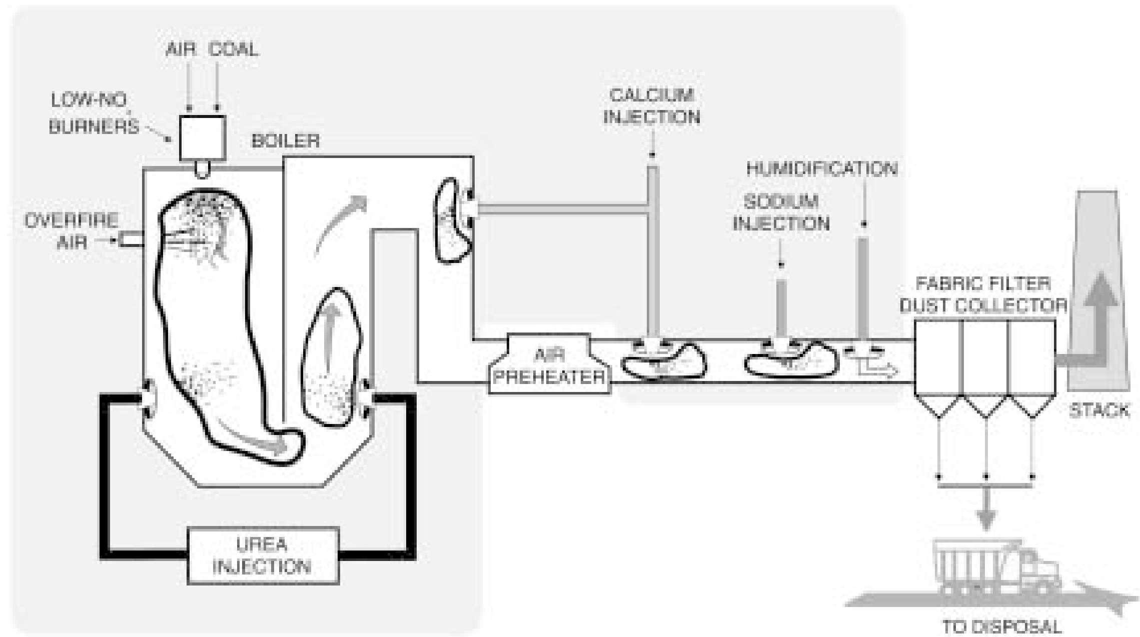
Plant Capacity/Production
100 MWe

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

Project Funding

Total project cost	$26,165,306	100%
DOE	13,082,653	50
Participant	13,082,653	50

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

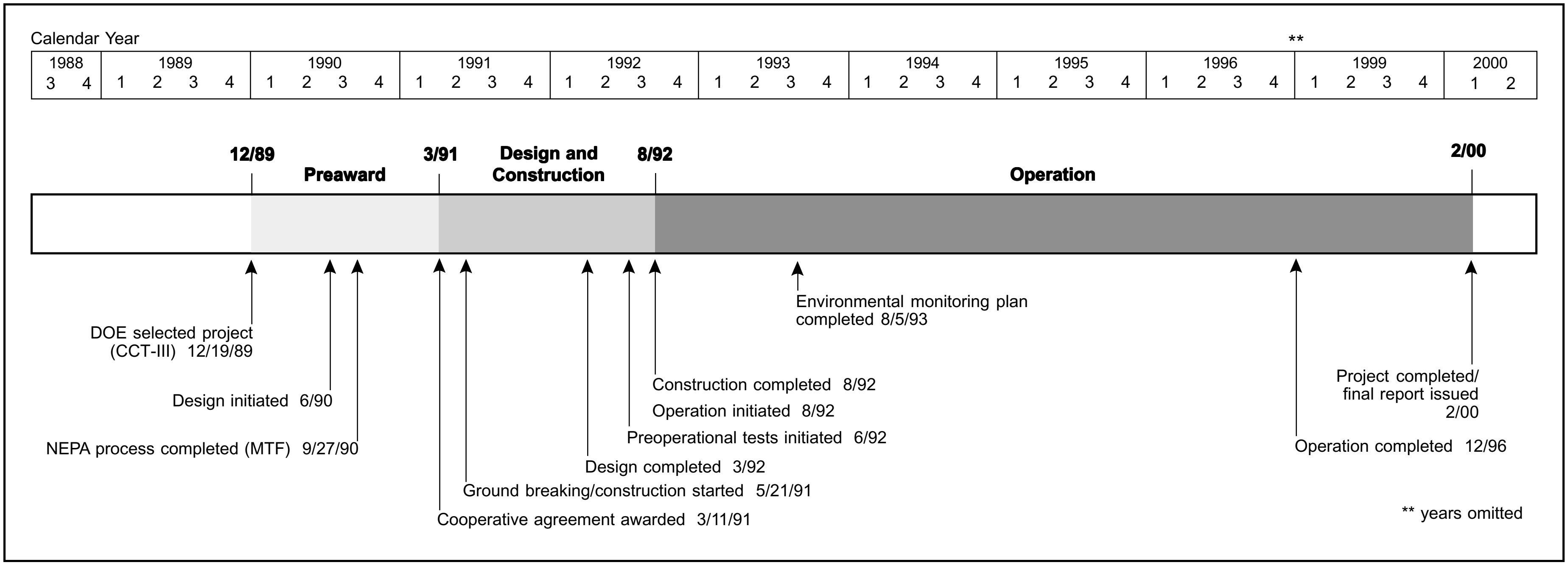


Project Objective
To demonstrate the integration of five technologies to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection with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



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- to 110-MWe load range.
- 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 bicarbonate 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.
- Temperature differential between the top and bottom surfaces of the Advanced Retractable Injection Lances (ARIL) initially caused the lances to bend downward 12–18 inches. Alternative designs corrected the problem.

Economic

- When used on units burning low-sulfur coal, the technology offers SO_2 and NO_x removals comparable to a wet scrubber and SCR, but at a lower cost.
- Total capital costs for the technology ranges from \$125/kW to \$281/kW for 300-MWe to 50-MWe plants, respectively. Levelized costs range from 12.43–7.03 mills/kWh or 1746–987 \$/ton of SO_2 and NO_x removed for 300-MWe to 50-MWe plants, respectively.

Project Summary

The Integrated Dry NO_x/SO_2 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 24% of the total combustion air through the furnace sidewalls.

Additional NO_x control was achieved using 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 of 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 for not only removal and cleaning but also adjustment of the injection pattern along the length of the lance 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, Colorado.

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 (24% of total combustion air), the low-NO_x combustion system reduced NO_x emissions by 62–69% across the load range (60- to 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 SNCR 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 a 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 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 removals 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.

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.

During the operation of the duct injection of calcium hydroxide and humidification under load-following conditions, the 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 downward 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 dropped relative to 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

The technology is an economical method of obtaining SO_2 and NO_x reduction on low-sulfur coal units. Total estimated capital costs range from 125–281 $/kW for capacities ranging from 300–50 MWe. Comparably, wet scrubber and SCR capital costs range from 270–474 $/kW for the same unit size range. On a levelized cost basis, the demonstrated system costs vary from 12.43–7.03 mills/kWh (1,746–987 $/ton of SO_2 and NO_x removed) compared to wet scrubber and SCR levelized costs of 23.34–12.67 mills/kWh (4,974–2,701 $/ton of SO_2 and NO_x removed) based on 0.4% sulfur coal. The integrated system is most efficient on smaller low-sulfur coal units. As size and sulfur content increase, the cost advantages decrease.

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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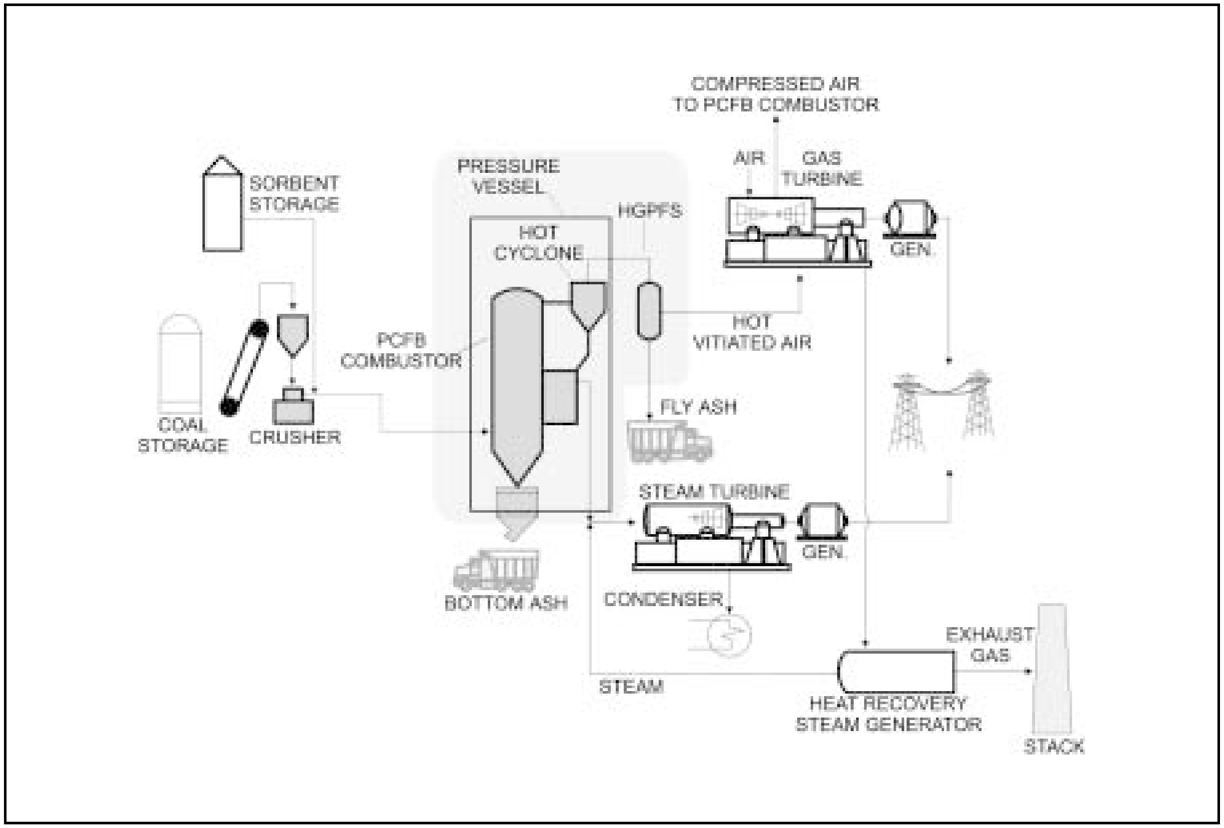
Advanced Electric Power Generation
Fluidized-Bed Combustion

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; 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

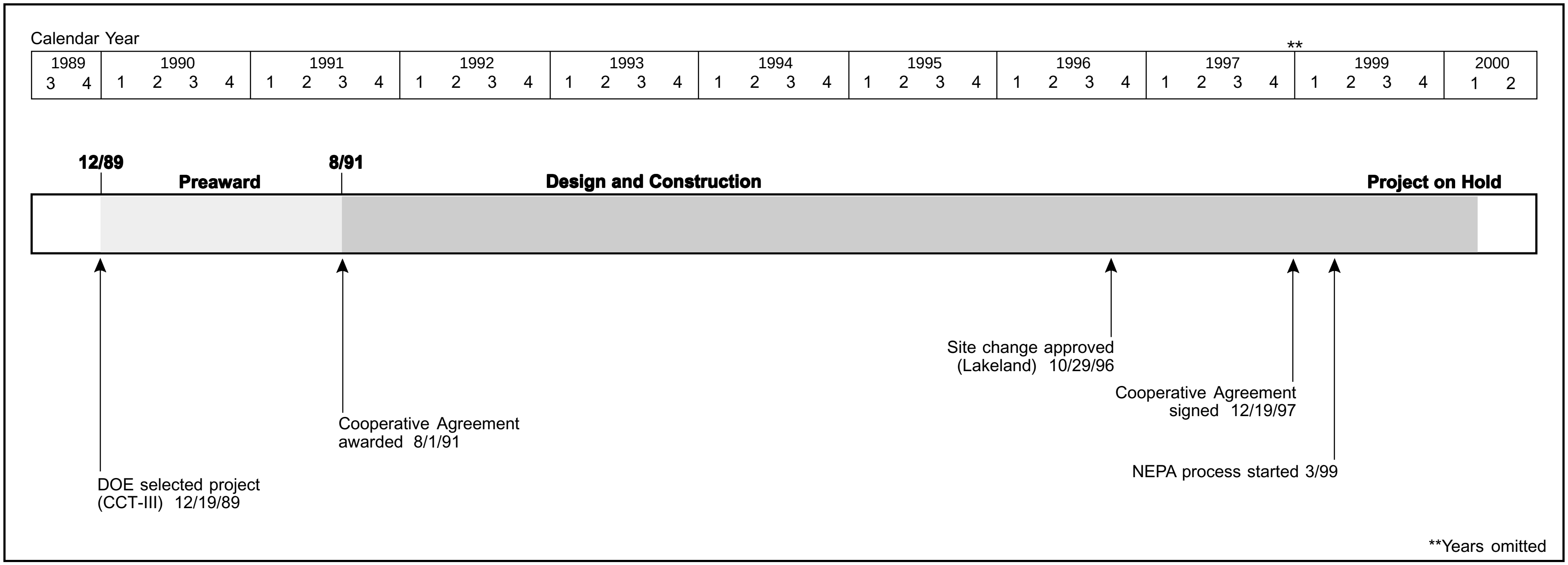
Project Objective
To demonstrate Foster Wheeler's PCFB technology coupled with Siemens Westinghouse's ceramic candle type HGPFS and power generation technologies, which represent a cost-effective, high-efficiency, low-emissions means of adding generating capacity at greenfield sites or in repowering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

Technology/Project Description
In the first of the two Lakeland Electric projects, McIntosh Unit No. 4A will be 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 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.

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.



Project Status/Accomplishments

The project resulted from a restructuring of the DMEC-1 PCFB Demonstration Project awarded under CCT-III. 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 in April 1998 for the 10-year plan of Lakeland Electric (formerly Department of Electric & Water Utilities), which included this project. However, the project is on hold while technical and economic issues are resolved.

Efforts have been focused on testing 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 ºF and 1,400 ºF, 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 for widespread commercial deployment and will include the first commercial application of hot gas particulate cleanup and will be 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. The PCFB technology 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 equipment due to pressurized operation, which reduces space requirements per unit of energy generated.

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

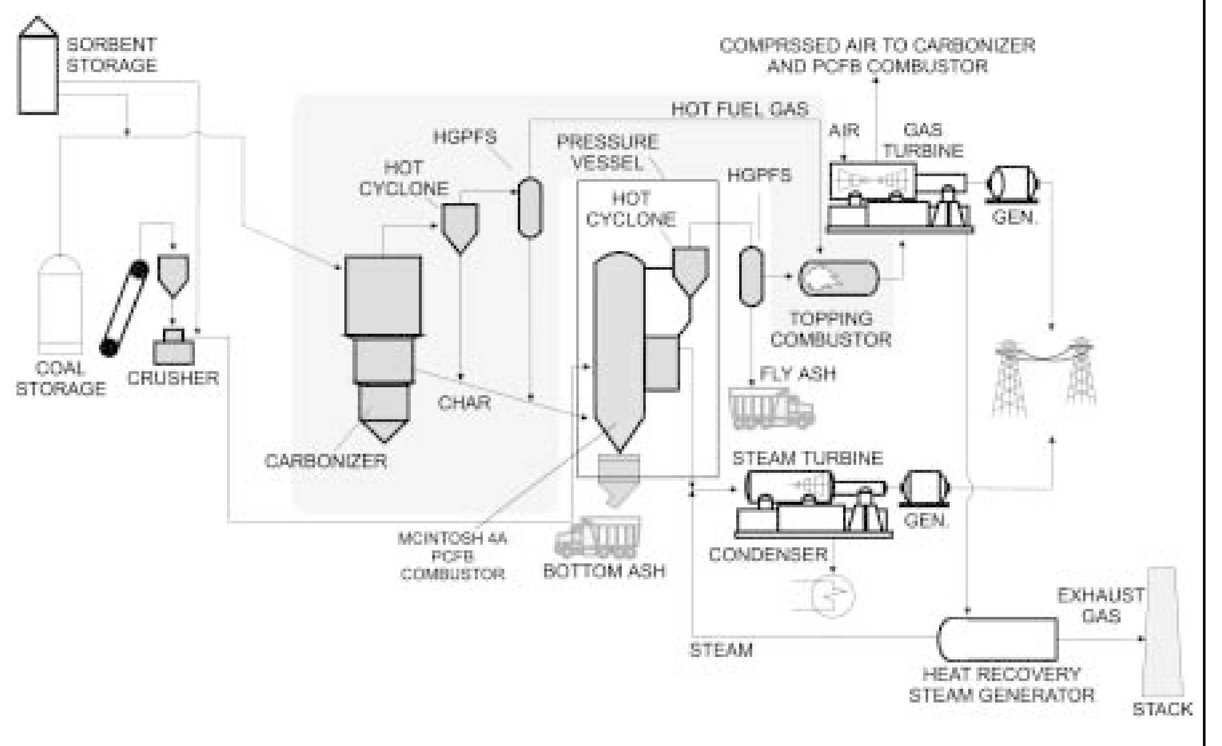
Plant Capacity/Production
103-MWe (net) addition to the 137-MWe (net) McIntosh 4A project

Coal
Eastern Kentucky and high-ash, high-sulfur bituminous coals

Project Funding

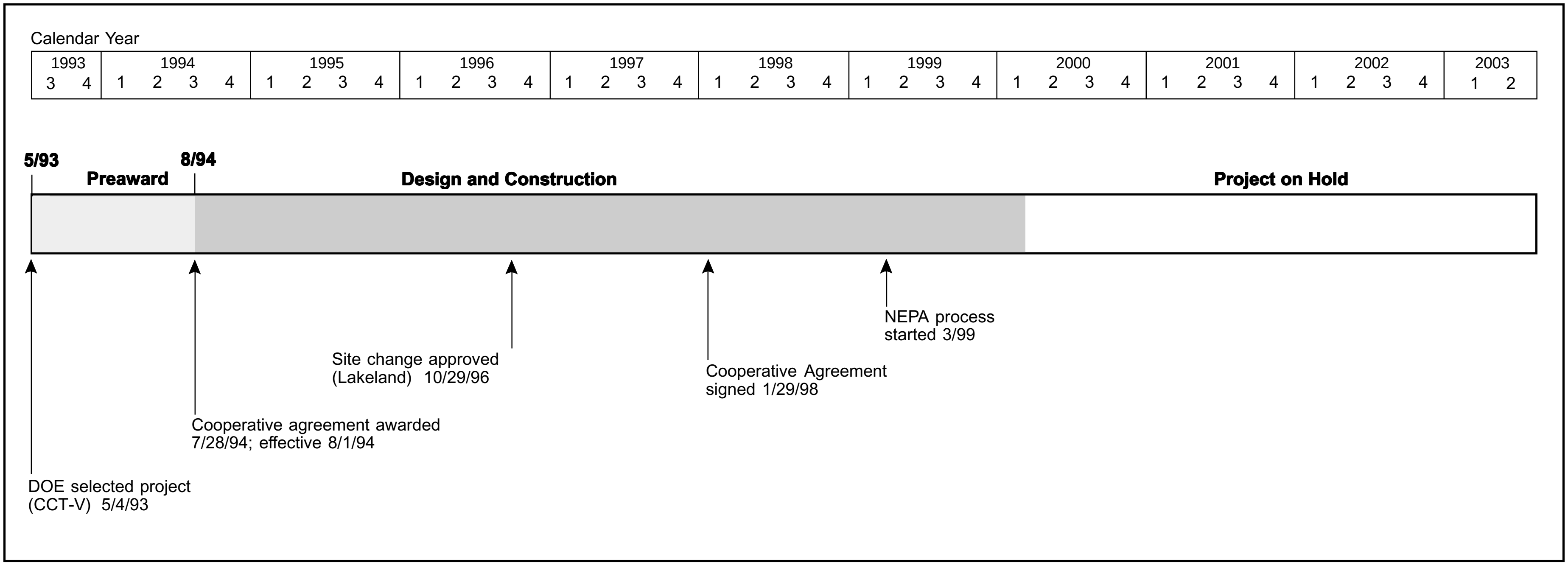
Total project cost	$219,635,546	100%
DOE	109,608,507	50
Participant	110,027,039	50

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 will be expected to achieve cycle efficiencies in excess of 45%.



Technology/Project Description
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 ºF 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 ºF, 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 8,406 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

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.

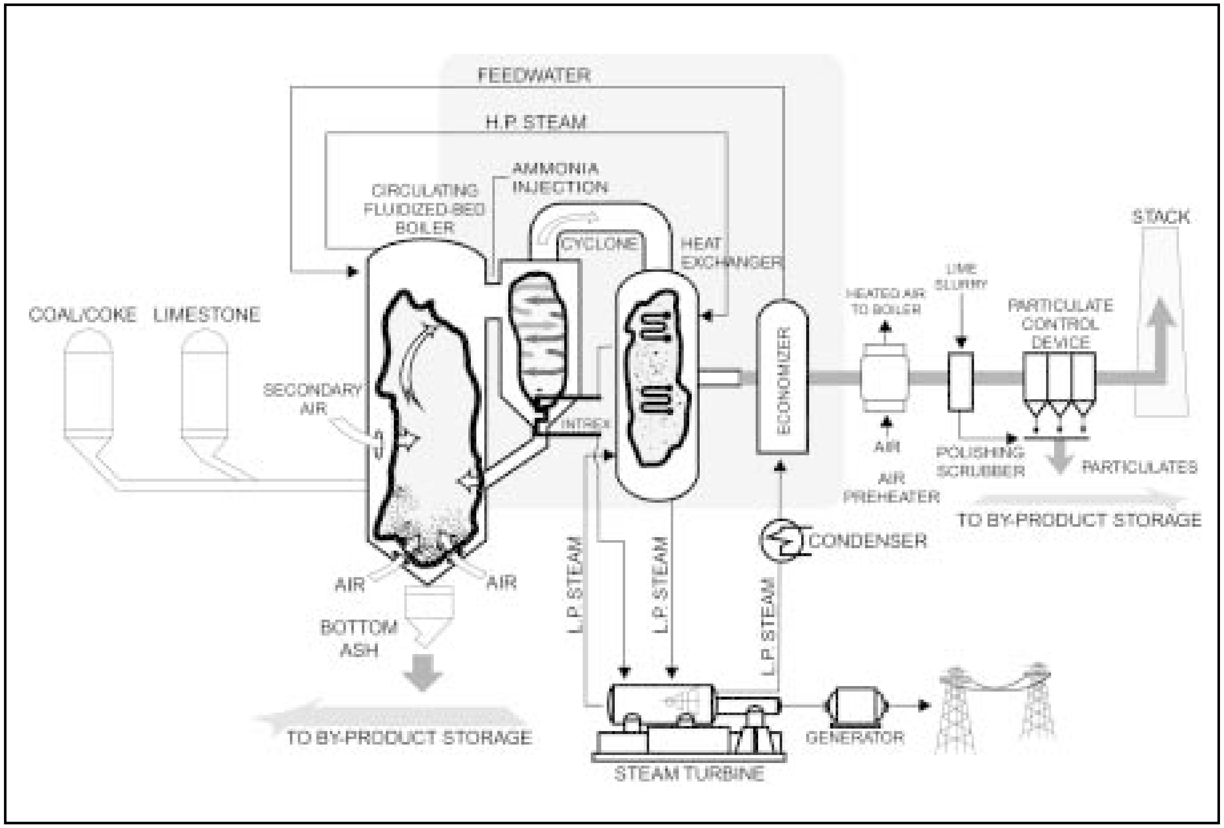
On January 29, 1998, a Cooperative Agreement modification was signed implementing the project restructuring from Four Rivers Energy Partners to the City of Lakeland. The Lakeland City Council gave approval in April 1998 for the 10-year plan of Lakeland Electric (formerly Department of Electric & Water Utilities), which included this project. However, the project is on hold while technical and economic issues are resolved.

Recent efforts focused on testing 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 ºF and 1,400 ºF, 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 allowed by the 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 requirements, NO_x emissions that will meet or exceed NSPS, and particulate matter discharge of approximately 0.03 lb/10^6 Btu. Although the system will generate a slight increase in solid waste 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—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, 0.3.39% sulfur (design)

Project Funding

Total project cost	$309,096,512	100%
DOE	74,733,833	24
Participant	234,362,679	76

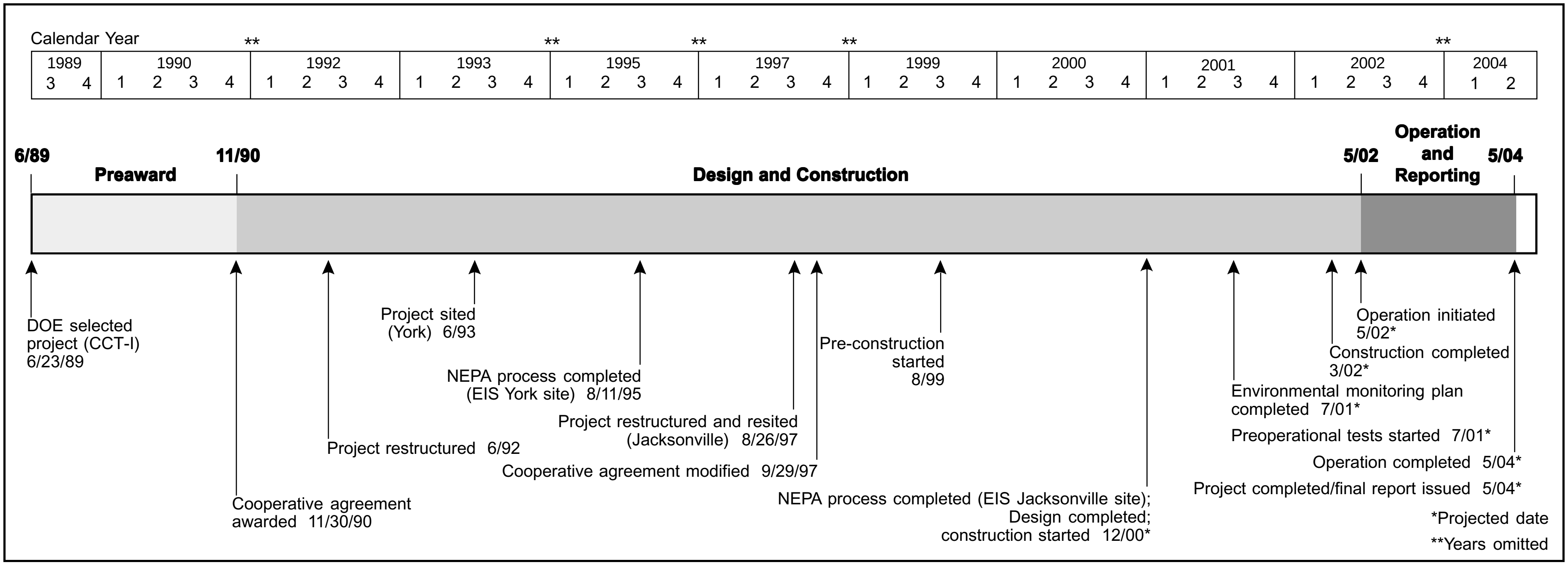
Project Objective
To demonstrate ACFB at 297.5 MWe gross (265 MWe net) representing a scaleup from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance; to provide potential users with the data necessary for evaluating a large-scale 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.

INTREX is a trademark of Foster Wheeler Energy Corp.

Technology/Project Description
A circulating fluidized-bed combustor, operating at atmospheric pressure, will be retrofitted into Unit No. 2 of the Northside Station. In this process 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 x 10^6 lb/hr of main steam at about 2,500 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). Expected environmental performance is 0.15 lb/10^6 Btu for SO_2 (98% reduction), 0.09 lb/10^6 Btu for NO_x, and 0.011 lb/10^6 Btu for total particulates (0.011 lb/10^6 Btu for PM_{10}).



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 project in September 1996. On August 26, 1997, DOE approved the transfer of the ACFB Clean Coal Project from York, Pennsylvania to Jacksonville, Florida. 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.

The Environmental Impact Statement (EIS) process was initiated on December 3, 1997 with the Public Scoping Meeting. Following the NEPA process of public comment and review, the final draft EIS was prepared and approved by DOE. After incorporating comments and obtaining formal approval, the EIS was issued on June 30, 2000. Public comments were addressed and the Record of Decision was issued December 7, 2000.

The project, currently in construction, 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.

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 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 the plant.

In its commercial configuration, ACFB technology offers several potential benefits when compared with conventional pulverized coal-fired systems: lower capital costs; reduced SO_2 and NO_x emissions at lower costs; higher combustion efficiency; a high degree of fuel flexibility (including use of renewable fuels); and dry, granular solid by-product 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, Ohio (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)

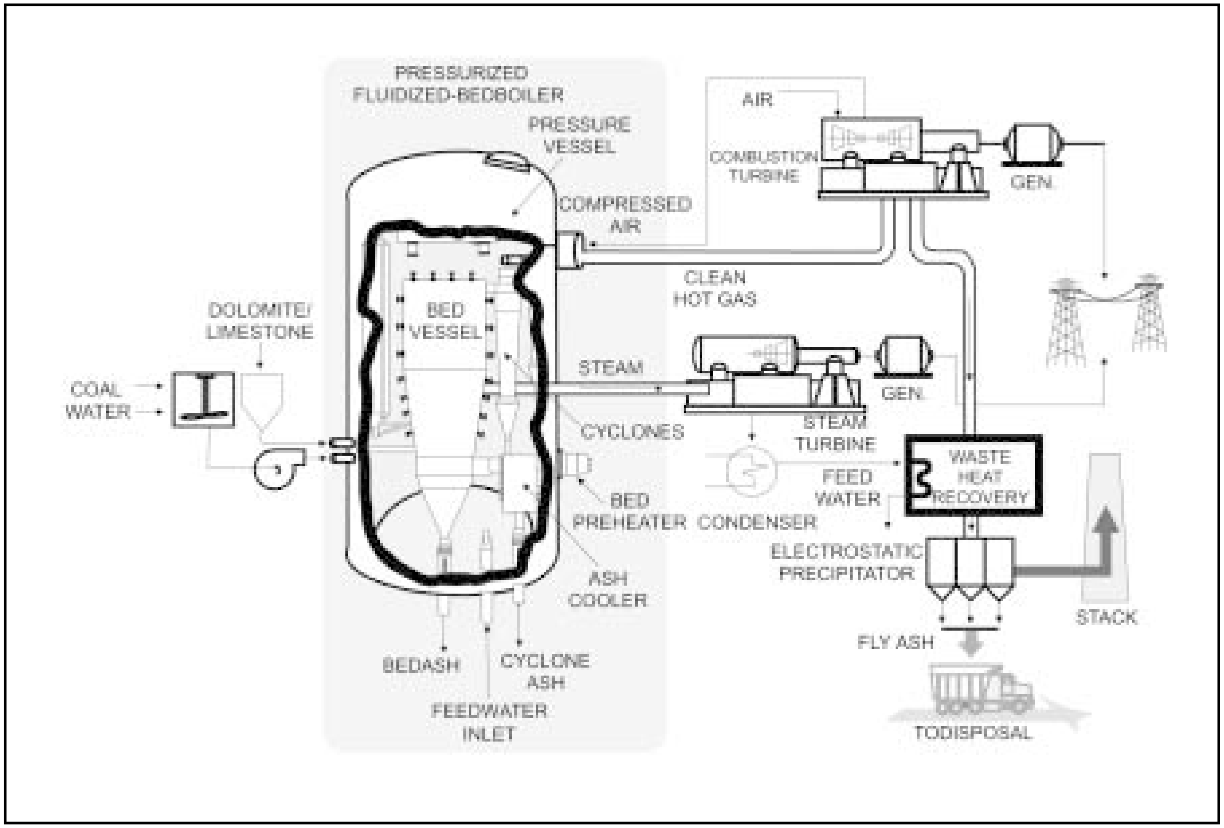
Plant Capacity/Production
70 MWe (net)

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.

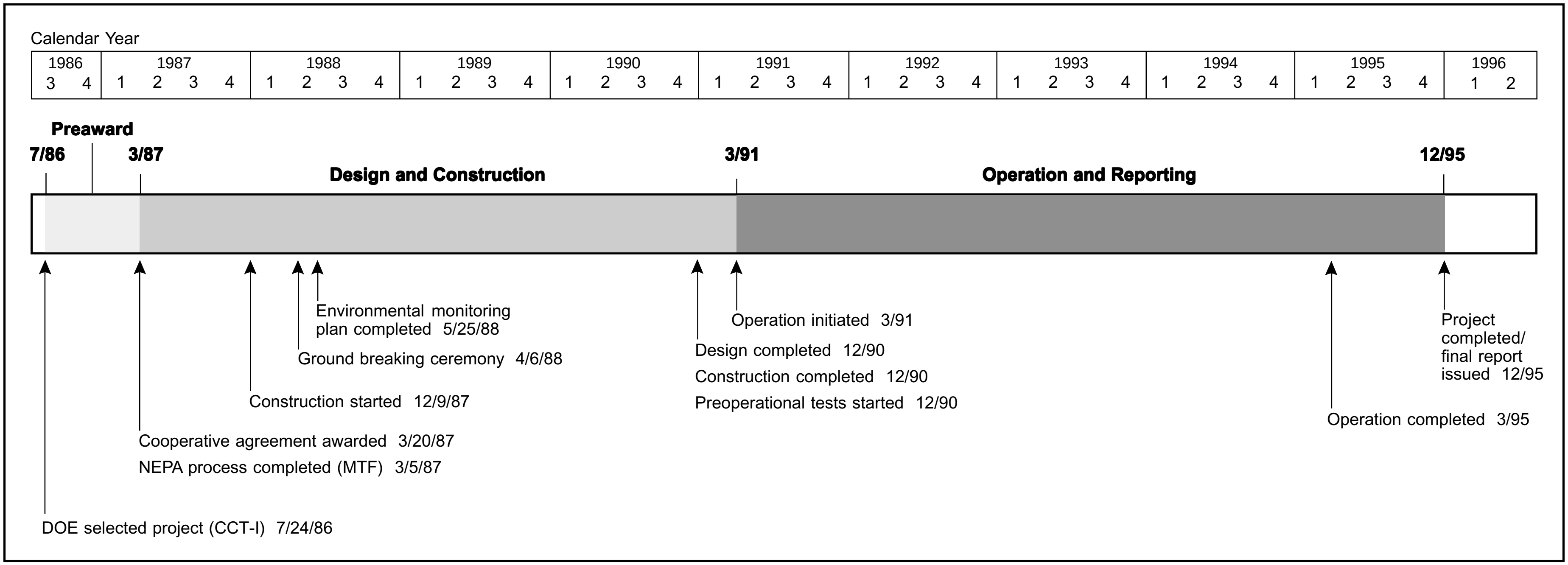


Technology/Project Description
Tidd was the first large-scale operational demonstration of PFBC in the United States. The project represented a 13:1 scaleup from the pilot facility.

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 used 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, and as such, detailed economics were not prepared as part of this project.
- A recent cost estimate performed on Japan's 360-MWe PFBC Karita Plant projected a capital cost of $1,263/kW (1997$).

Project Summary

The Tidd PFBC technology is a bubbling fluidized-bed combustion process operating at 12 atmospheres (175 psi). Fluidized-bed combustion is inherently efficient because the pressurized environment enhances combustion efficiency, allows very low temperatures that mitigate thermal NO_x generation, promotes flue gas/sorbent reactions that increase sorbent utilization, and produces 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 one-quarter 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 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 Program 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 ºF 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. Furthermore, 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 in the process, which was operating at approximately 1,580 ºF. 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 PFBC demonstration at the repowered 70-MWe unit at Ohio Power's Tidd Plant led to significant refinements and understanding of the technology.

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%.

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 buildup in the vessel; bridging was precluded with larger particulates included in the particulate matter; and filtration efficiency (mass basis) was 99.99%.

Economic Performance

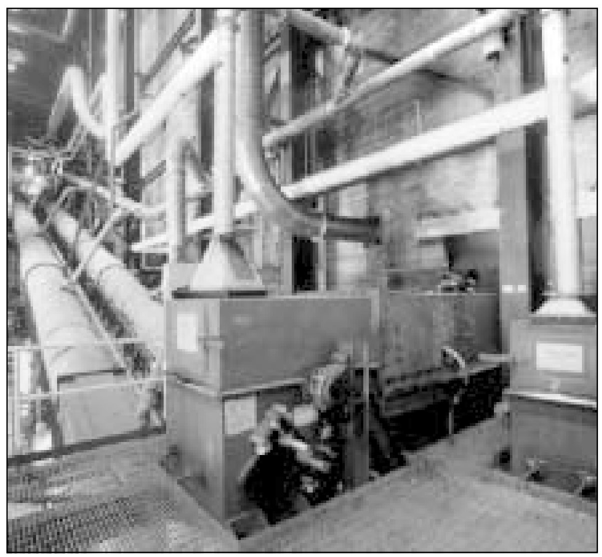
The Tidd plant was a relatively small-scale demonstration facility, so detailed economics were not prepared as part of this project. However, a recent cost estimate performed on Japan's 360-MWe PFBC Karita Plant projected a capital cost of $1,263/kW (1997$).

Commercial Applications

Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. The compactness of bubbling-bed PFBC equipment allows utilities to significantly increase capacity at existing sites. Compactness 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 uses 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.



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

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Nucla CFB Demonstration Project

Project completed.

Participant
Tri-State Generation and Transmission 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
110 MWe (gross), 100 MWe (net)

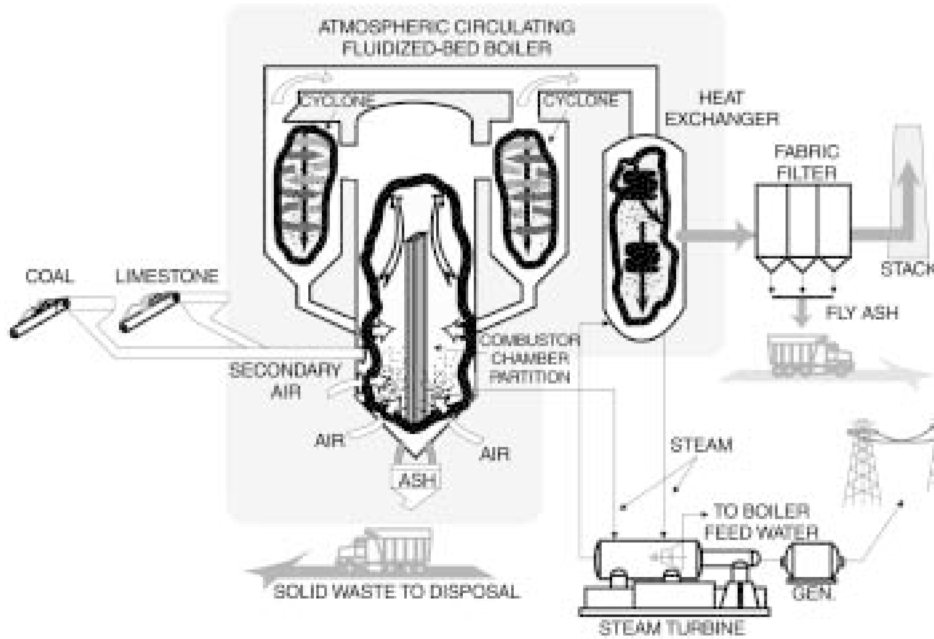
Coal
Western bituminous—
Salt Creek, 0.5% sulfur, 17% ash
Peabody, 0.7% sulfur, 18% ash
Dorchester, 1.5% sulfur, 23% ash

Project Funding

Total project cost	$160,049,949	100%
DOE	17,130,411	11
Participant	142,919,538	89

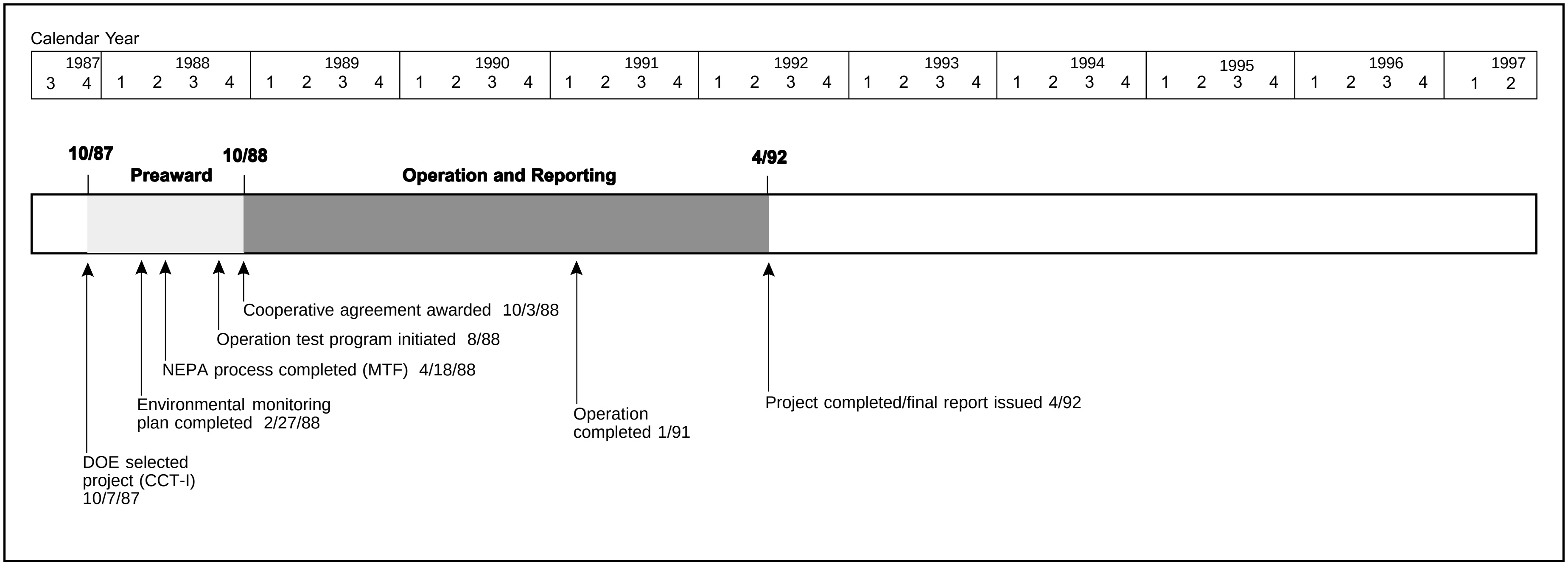
Project Objective
To demonstrate the feasibility of ACFB technology at utility scale and to evaluate the economic, environmental, and operational performance at that scale.

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



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 (gross) turbine generator. Extraction steam from this turbine generator powers three existing turbine generators (12.5 MWe [gross] each).



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/roadbed 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 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 enables 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, extend the gas/solid contact time, and protect a downstream heat exchanger.

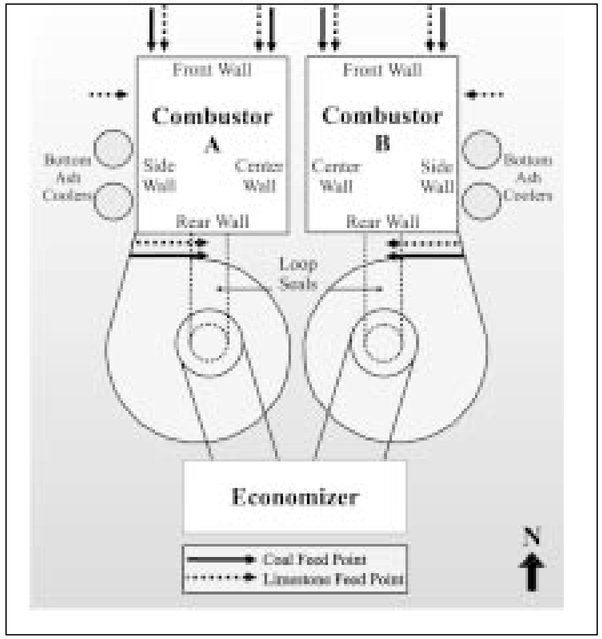
Interest and participation of DOE, EPRI, and the Technical Advisory Group (potential users) resulted in the evaluation of ACFB potential for broad utility application through a comprehensive test program. Over a two-and-a-half-year period, 72 steady-state performance tests were conducted and 15,700 hours 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.

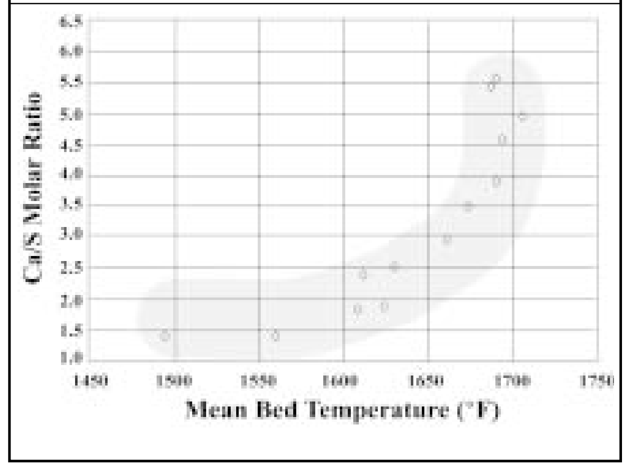
Plant layout with coal and limestone feed locations.



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.

Exhibit 5-42
Effect of Bed Temperature on Ca/S Requirement

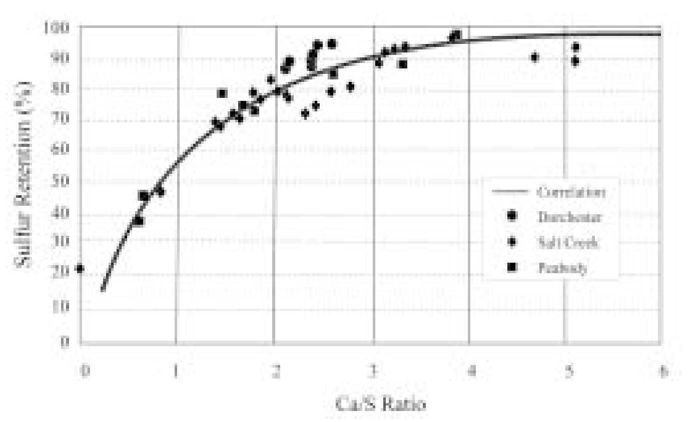


Environmental Performance

As indicated above, bed temperature had the greatest impact on ACFB performance, including pollutant emissions. Exhibit 5-42 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 5-43 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

Exhibit 5-43
Calcium Requirements and Sulfur Retentions for Various Fuels



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 reduction.

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 decreased as temperature increased, 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.

Economic Performance

The final capital costs associated with the engineering, construction, and startup of the Nucla ACFB system were $112.3 million. This represents a cost of $1,123/kW (net). The total power cost associated with plant operations between September 1988 and January 1991 was 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%).

Commercial Applications

The Nucla project represented the first repowering of a U.S. utility plant with ACFB technology and showed the technology's ability 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 170 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.

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Advanced Electric Power Generation
Integrated Gasification Combined-Cycle

Kentucky Pioneer Energy IGCC Demonstration Project

Participant
Kentucky Pioneer Energy, LLC

Additional Team Members
Fuel Cell Energy, Inc. (formerly Energy Research Corporation)—molten carbonate fuel cell designer and supplier, and cofunder

Location
Trapp, Clark County, KY (East Kentucky Power Cooperative's Smith site)

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

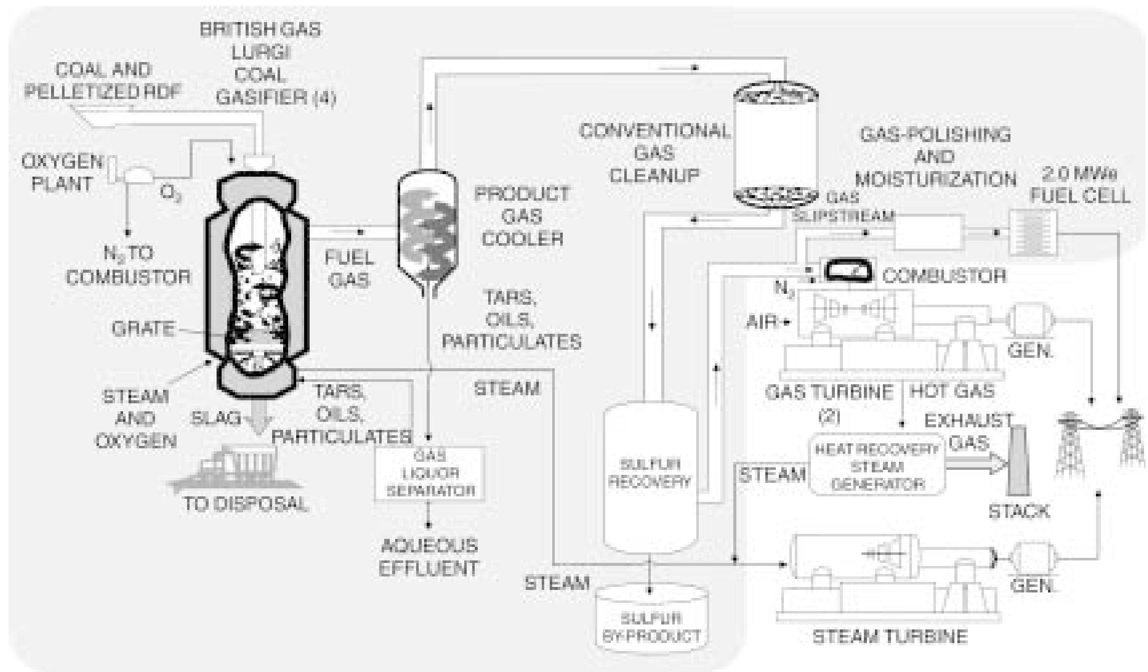
Plant Capacity/Production
580 (gross); 540 MWe (net) IGCC; 2.0 MWe MCFC

Coal
High-sulfur Kentucky bituminous coal and pelletized refuse-derived fuel (RDF)

Project Funding

Total project cost	$431,932,714	100%
DOE	78,086,357	18
Participant	353,846,225	82

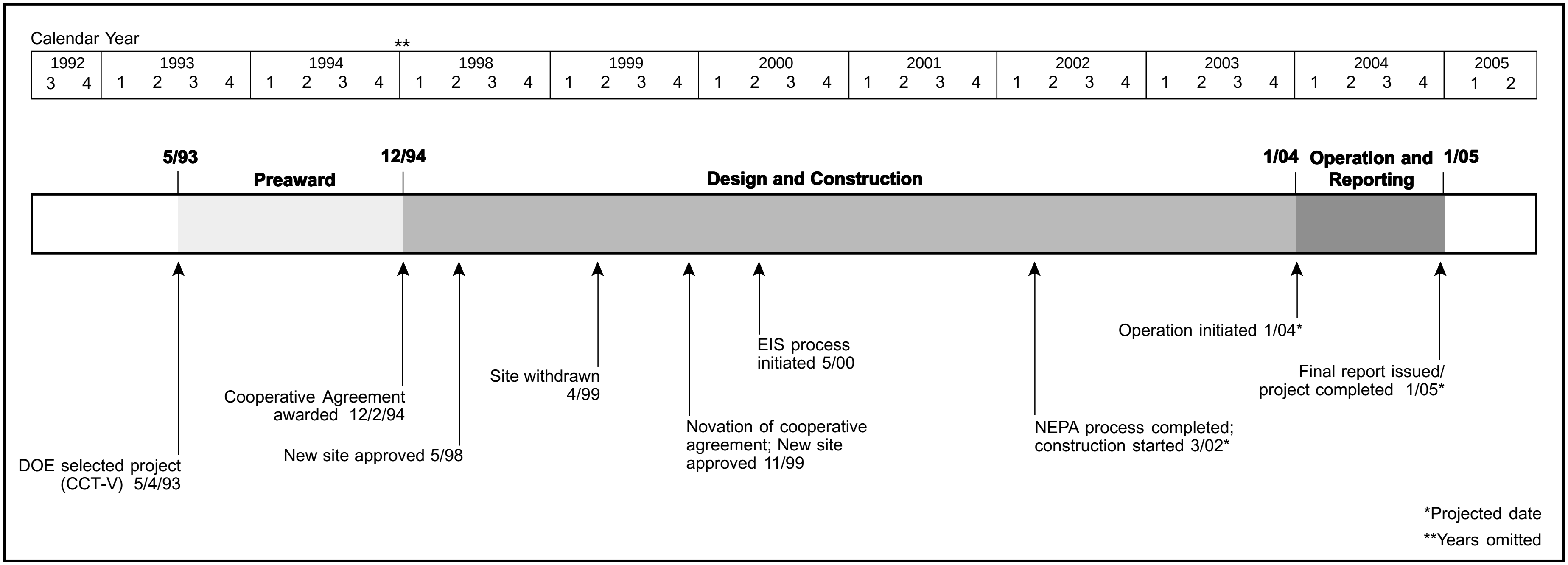
Project Objective
To demonstrate and assess the reliability, availability, and maintainability of a utility-scale IGCC system using a high-sulfur bituminous coal and municipal solid waste blend in an oxygen-blown, fixed-bed, slagging gasifier and the operability of a molten carbonate fuel cell fueled by coal gas.



Technology/Project Description
The four BG/L gasifiers are supplied with steam, oxygen, limestone flux, and a coal and pelletized RDF. During gasification, the oxygen and steam react with the coal and limestone flux to produce a 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 two gas turbines. 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; CO_2-enriched air is fed into the cathode. Chemical reactions produce direct electric current, which is converted to alternating current with an inverter.

Operation will commence on 100% coal with slowly increasing levels of RDF throughout the demonstration. This method will allow the development of a database of plant performance at various levels of RDF feed.



Project Status/Accomplishments

On May 8, 1998, DOE conditionally approved Ameren Services Company (merger of Union Electric Co. and Central Illinois Public Service Co.) as an equity partner and host site provider subject to completing specific business and teaming milestones. The new project site to be provided by Ameren was at its Venice Station Plant in Venice, Illinois. On April 30, 1999, Ameren Services Company withdrew from the project for economic and business reasons.

In May 1999, Global Energy USA Limited (Global), sole owner of Kentucky Pioneer Energy, LLC (KPE), expressed interest in acquiring the project and providing a host site at East Kentucky Power Cooperative's Smith Site in Clark County, Kentucky. Subsequently, Global negotiated all the necessary documents with DOE and Clean Energy Partners, L.P. (CEP) to acquire the project. In November 1999, the cooperative agreement was novated and the new site was approved.

The NEPA process was initiated with the public scoping meeting on May 4, 2000.

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 MCFC 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 BGL gasifier is anticipated to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). These efficiencies represent a greater than 20% reduction in emissions of CO_2 when compared with 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); and 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—start-up 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

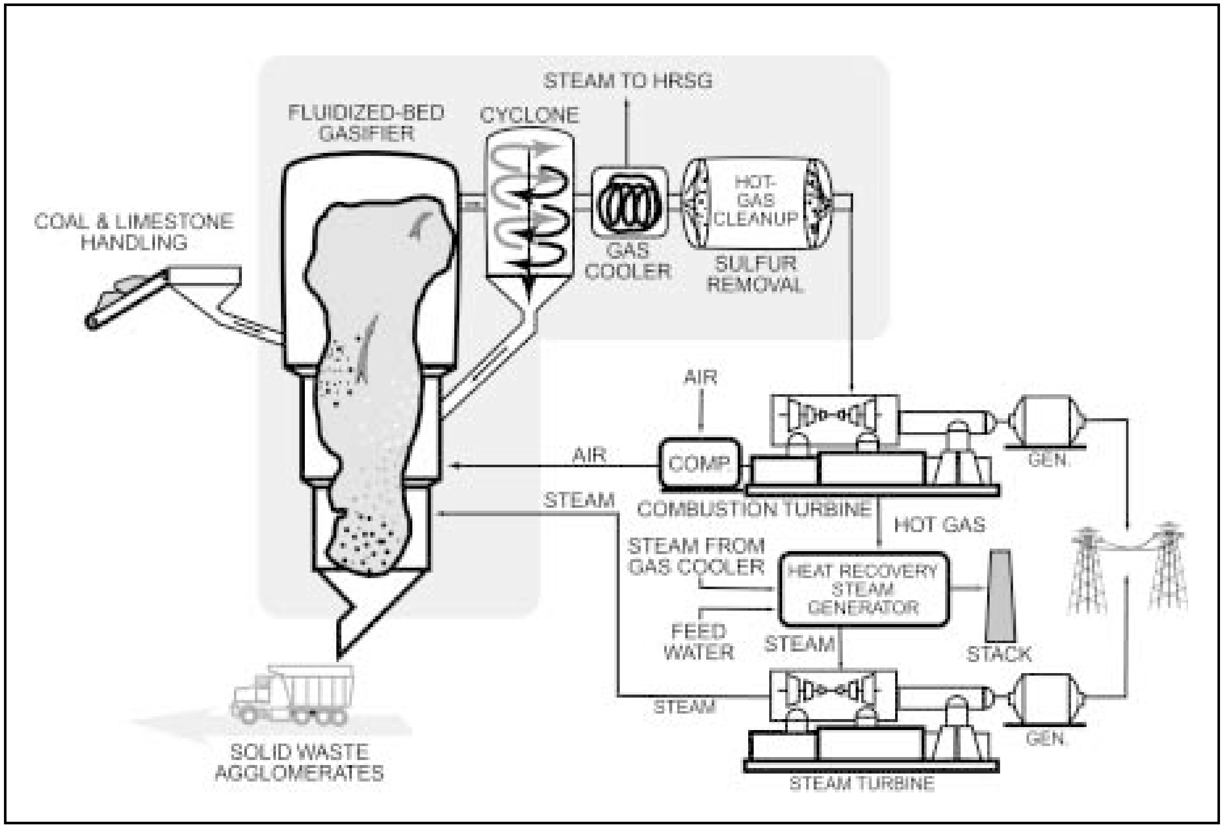
Plant Capacity/Production
107 MWe (gross), 99 MWe (net)

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 (HGCU); to evaluate a low-Btu gas combustion turbine; and to assess long-term reliability, availability, maintainability, and environmental performance at a scale sufficient to determine commercial potential.

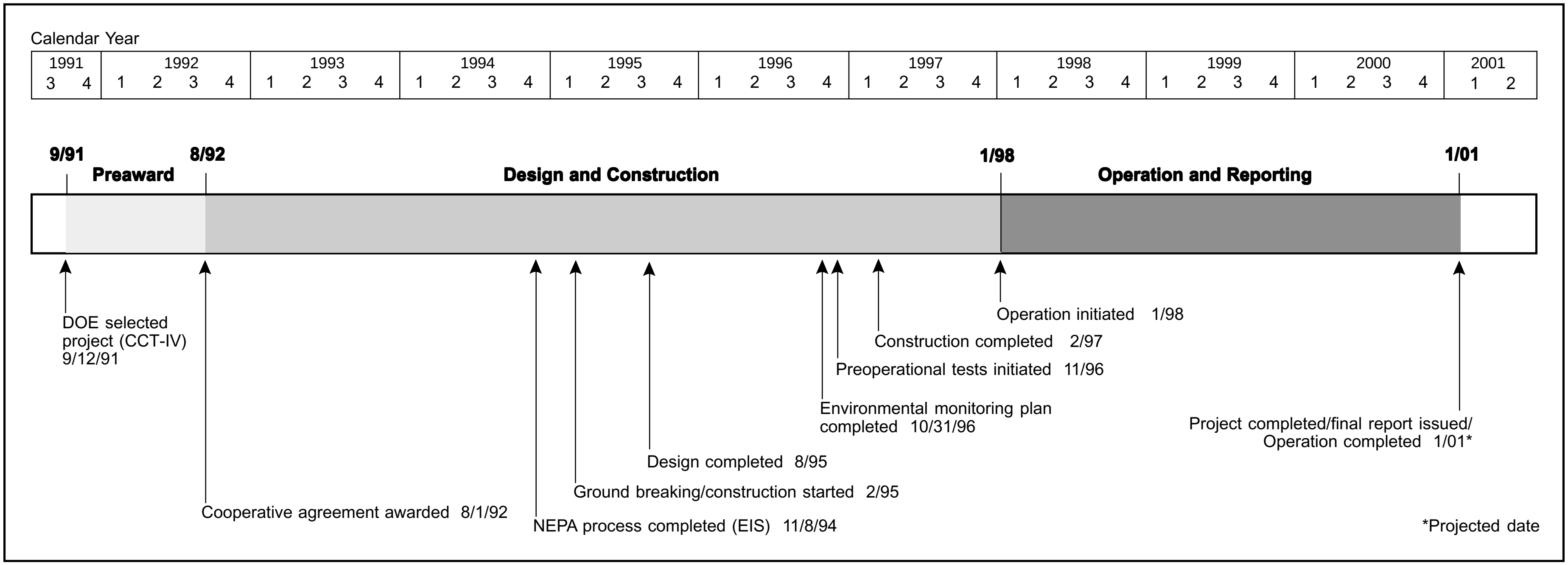


Technology/Project Description
Dried and crushed coal and limestone are introduced into a KRW air-blown pressurized fluidized-bed gasifier. Crushed limestone is used to capture a portion of the sulfur. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation, exits as calcium 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 GE MS6001FA (Frame 6FA) combustion turbine, which is coupled to a 61-MWe (gross) generator. 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 than conventional plants.



Project Status/Accomplishments

The system has initiated demonstration operations but continues to experience operational difficulties. The station began operation on natural gas in November 1996. Preoperational 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 project continues to suffer from a number of design issues, many of which have been solved, but others remain. Problems have been attributed to the high degree of new technology, high scale-up factors on auxiliary components, and some design and engineering deficiencies. Nevertheless, Sierra Pacific is confident that no fatal flaws exist that will preclude successful demonstration and subsequent commercialization of the KRW gasification technology.

In the first quarter of 2000, Sierra Pacific began to make additional repairs and improvements so that sustained operation of the gasifier can be achieved. Improvements include increasing the diameter to the annulus section of the gasifier to address the problem of high temperatures of the limestone and ash leaving the gasifier. Also, the refractory in the gasifier grid area and 18 feet into the fluid bed region will be replaced with a single castable layer in a revised anchoring pattern, to provide improved resistance to low cycle fatigue of the refractory lining.

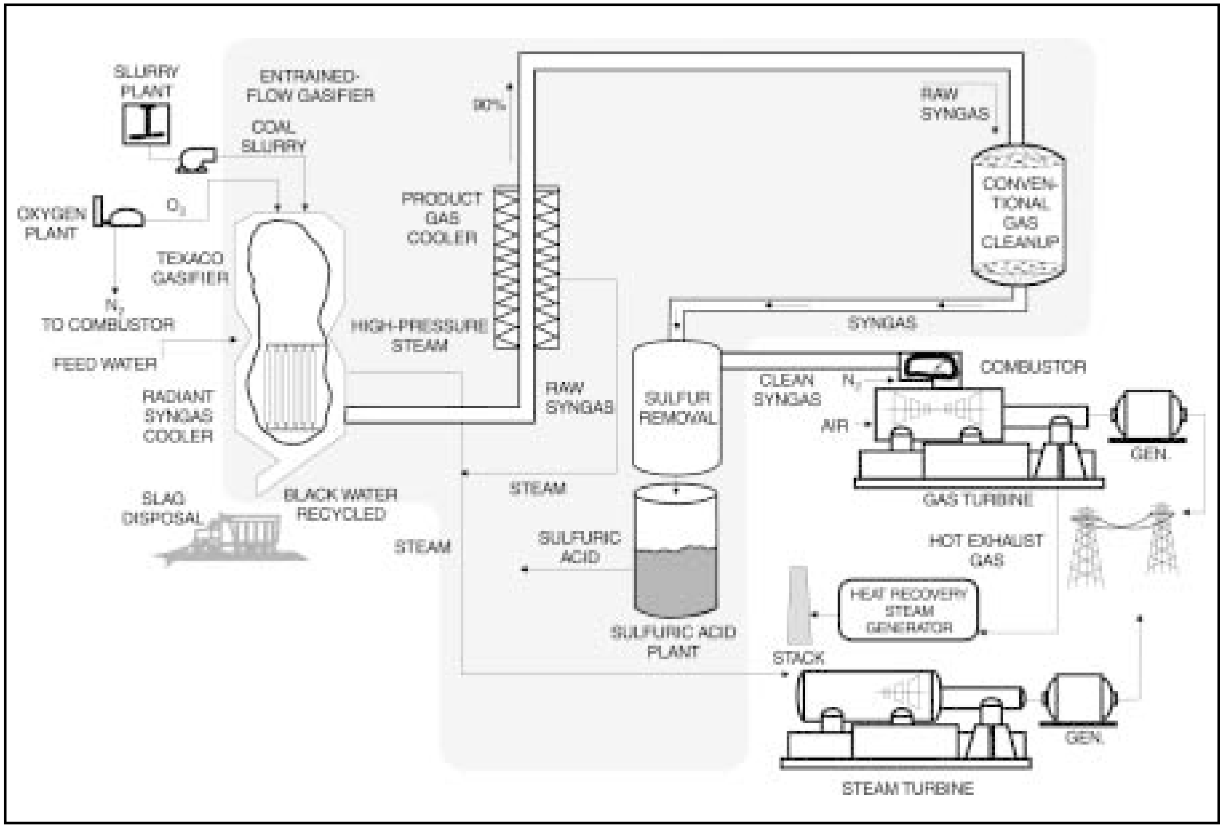
The project suffered a setback in August 2000 when char fines from the desulfurizer caught fire in the filter vessel during a start-up attempt, breaking candles, and melting filter holders. It will take six to eight months to make repairs, which have been delayed until the sale of the plant is complete. The final terms and conditions of the sale will not be known until mid-year 2001.

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 compared with 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. Further, this project is the only project demonstrating HGCU, which is important not only to IGCC technology, but also to pressurized fluidized-bed combustion.

With the exception of the recently awarded Kentucky Pioneer Energy IGCC Demonstration Project, 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 biowaste 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
Air Products and Chemicals, Inc.—air separation unit supplier
Monsanto Enviro-Chem Systems, Inc.—sulfuric acid plant 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

Advanced integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown entrained-flow gasifier technology

Plant Capacity/Production

316 MWe (gross), 250 MWe (net)

Coal

Illinois #6, Pittsburgh #8, Kentucky #11, and Kentucky #9; 2.5-3.5% sulfur

Project Funding

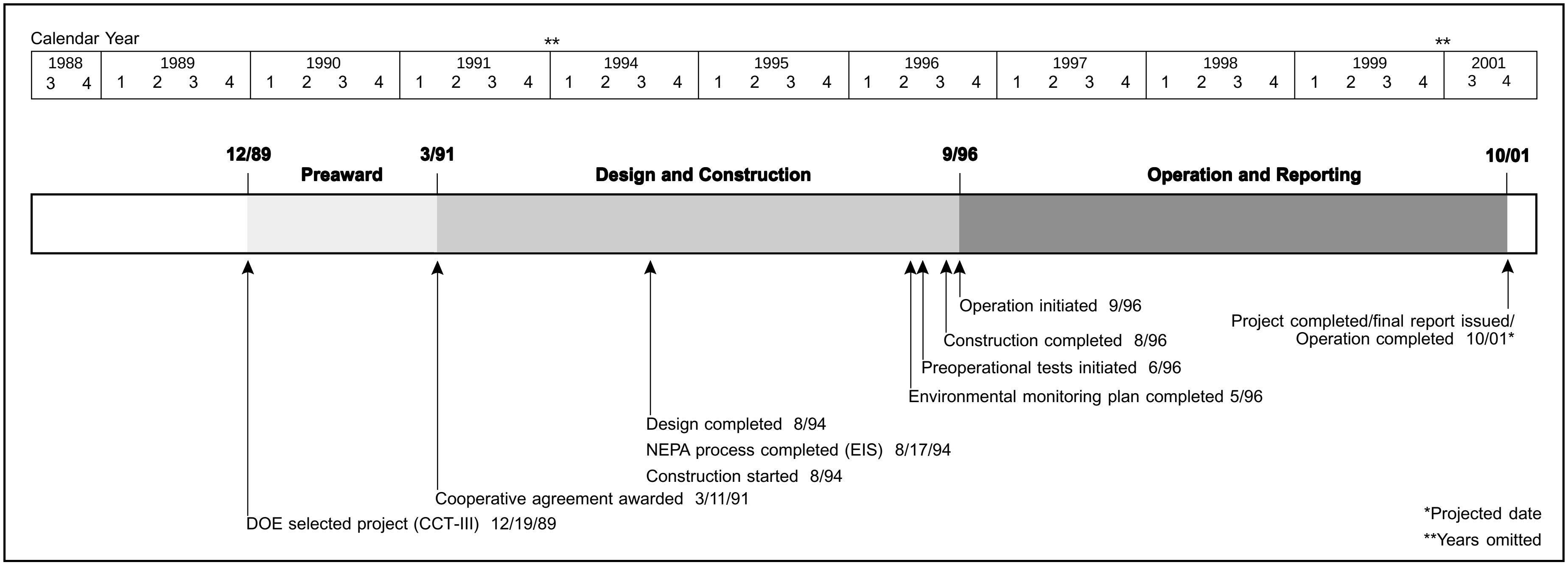
Total project cost	$303,288,446	100%
DOE	150,894,223	49
Participant	152,394,223	51

Project Objective

To demonstrate IGCC technology in a greenfield commercial electric utility application at the 250-MWe size using an entrained-flow, oxygen-blown, gasifier with full heat recovery, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection for power augmentation and NO_x control.

Technology/Project Description

Coal/water slurry and oxygen are reacted at high temperature and pressure to produce a medium-Btu syngas in a Texaco gasifier. Molten ash flows out of the bottom of the gasifier into a water-filled sump where it forms a solid slag. The syngas moves from the gasifier to a high temperature heat-recovery unit, which cools the syngas while generating high pressure steam. The cooled gases flow to a water wash for particulate removal. Next, a COS hydrolysis reactor converts one of the sulfur species in the gas to a form that is more easily removed. The syngas is then further cooled before entering a conventional amine sulfur removal system. The amine system keeps SO_2 emissions below 0.15 lb/10^6 Btu (97% capture). The cleaned gases are then reheated and routed to a combined-cycle system for power generation. A GE MS 7001FA gas turbine generates 192 MWe. Thermal NO_x is controlled to below 0.27 lb/ 10^6 Btu by injecting nitrogen. A steam turbine uses steam produced by cooling the syngas and superheated with the gas turbine exhaust gases in the HRSG to produce an additional 124 MWe. The plant heat rate is 9,350 Btu/kWh (HHV).



Project Status/Accomplishments

Since Polk Power Station's first gasifier run in July 1996, the gasifier has operated over 21,000 hours. The station generated more than 6 million MWh of electricity from syngas it produced through March 2000. During one six-month period, the gasifier had an 83.5% on-stream factor and the combined-cycle availability was 94%.

Several modifications to the original design and procedures were required to achieve the recent high availability, including: (1) removing or modifying some of the heat exchangers in the high-temperature heat recovery system and making compensating adjustments in the balance of the system to resolve ash plugging problems, (2) additional solid particle erosion protection for the combustion turbine to protect the machine from ash, (3) implementing hot restart procedures to reduce gasifier restart time by 18 hours, (4) adding a duplicate fines handling system to deal with increased fines loading resulting from lower than expected carbon conversion, (5) revising operating procedures to deal with high shell temperatures in the dome of the radiant syngas cooler, and (6) making various piping changes to correct for erosion and corrosion in the process and coal/water slurry systems. A COS hydrolysis unit was installed in 1999 to further reduce SO_2 emissions, enabling the station to meet recent, more stringent emissions restrictions.

In March and April 2000, Tampa Electric tested several coal/petroleum coke blends. Preliminary test results from 60/40 and 40/60 blends of Pittsburgh #8 and petroleum coke (petcoke) looked promising. Both tests were successful and provide data that show continued operation on a blend of coal/petcoke is possible. One further test is planned using a 20/80 blend.

Commercial Applications

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, 1993 Timer Powers Conflict Resolution Award from the State of Florida, and the 1991 Florida Audubon Society Corporate Award.

As a result of the Polk Power Station demonstration, Texaco-based IGCC can be considered commercially and environmentally suitable for electric power generation utilizing a wide variety of feedstocks. Sulfur capture for the project is greater than 98%, while NO_x emissions reductions are 90% those of a conventional pulverized coal-fired power plant. The integration and control approaches utilized at Polk can also be applied in IGCC projects using different gasification technologies.

TECO Energy is not only actively working with Texaco to commercialize the technology in the United States, but has been contacted by European power producers to discuss possible technical assistance on using the gasifier technology.

Wabash River Coal Gasification Repowering Project

Project completed.

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 and gas plant operator

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

Technology
Integrated gasification combined-cycle (IGCC) using Global Energy's two-stage pressurized, oxygen-blown, entrained-flow gasification system—E-Gas Technology™

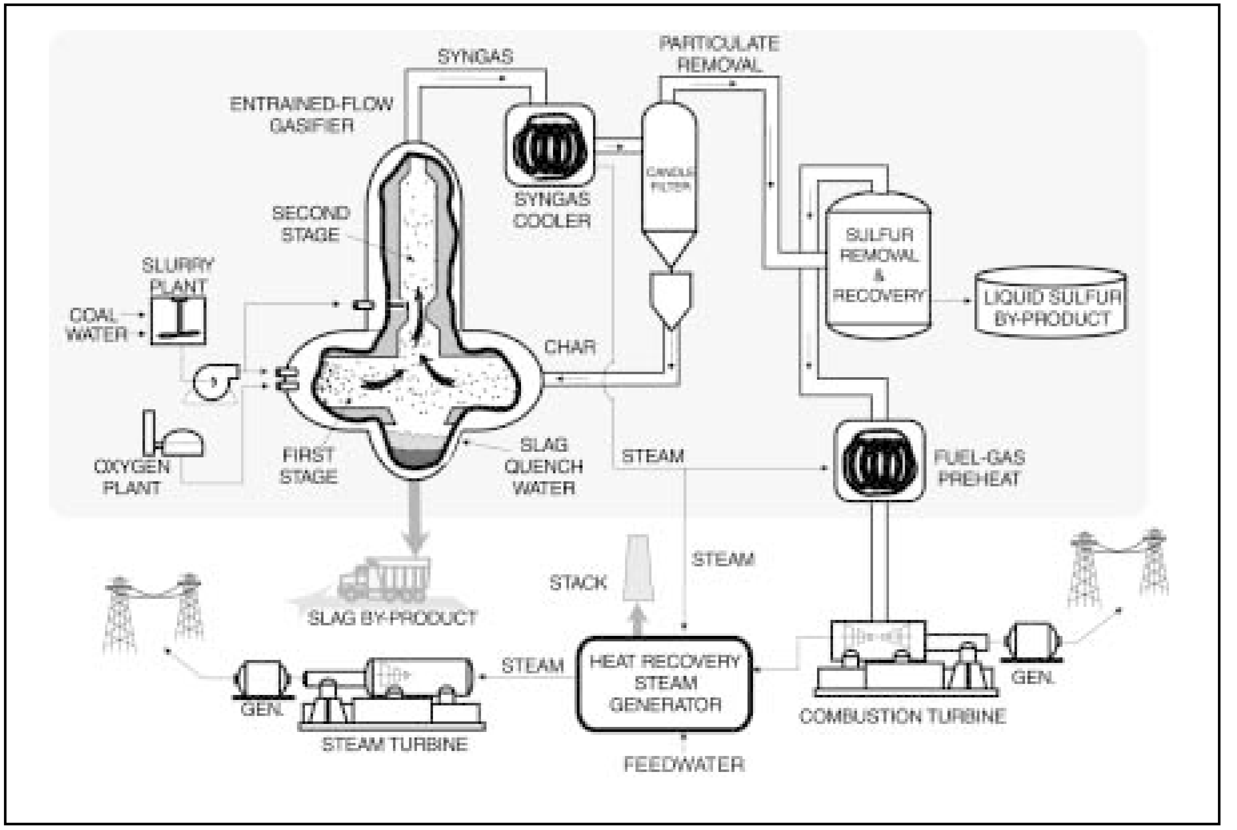
Plant Capacity/Production
296 MWe (gross), 262 MWe (net)

Coal
Illinois Basin bituminous

Project Funding

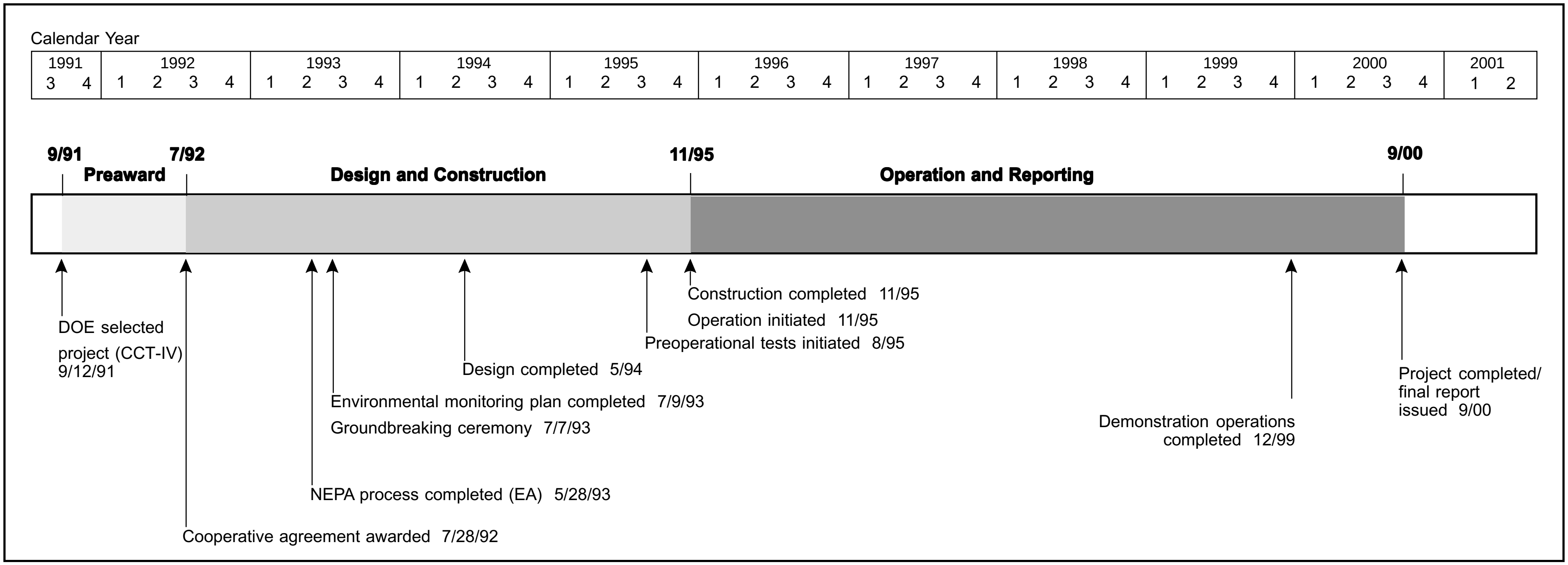
Total project cost	$438,200,000	100%
DOE	219,100,000	50
Participant	219,100,000	50

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 process features an oxygen-blown, continuous-slagging, two-stage, entrained flow gasifier. Coal is slurried, combined with 95% pure oxygen, and injected into the first stage of the gasifier, which operates at 2,600 °F/400 psig. 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 improve efficiency.

The syngas then flows to the syngas cooler, essentially a fire tube steam generator, to produce high-pressure saturated steam. After cooling in the syngas cooler, particulates 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 into hydrogen sulfide. Hydrogen sulfide is removed in the acid gas removal system using MDEA-based absorber/stripper columns. A Claus unit is used to produce elemental sulfur as a salable by-product. The "sweet" gas is then moisturized, preheated, and piped to the power block. The power block consists of a single 192-MWe GE MS 7001FA (Frame 7 FA) gas turbine, a Foster Wheeler single-drum heat recovery steam generator with reheat, and a 1952-vintage Westinghouse reheat steam turbine.



Results Summary

Environmental

- The SO_2 capture efficiency was greater than 99%, keeping SO_2 emissions consistently below 0.1 lb/10^6 Btu and reaching as low as 0.03 lb/10^6 Btu; and SO_2 was transformed into 99.99% pure sulfur, a highly valued by-product.
- The NO_x emissions were controlled by steam injection down to 0.15 lb/10^6 Btu.
- Coal ash was converted to a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as grit for abrasives and roofing materials; and trace metals from petroleum coke were also encased in an inert vitreous slag.

Operational Performance

- The first year problems encountered included:
  - Ash deposition at the fire tube boiler inlet, which was corrected by a change to the flow path geometry;
  - Particulate breakthrough in the hot gas filter, which was largely solved by changing to improved metallic candle filters.
  - Chloride and metals poisoning of the COS catalyst, which was eliminated by installation of a wet chloride scrubber and a COS catalyst less prone to poisoning.
- The second year identified cracking in the gas turbine combustion liners and tube leaks in the heat recovery steam generator (HRSG). Resolution involved replacement of the gas turbine fuel nozzles and liners and modifications to the HRSG to allow for more tube expansion.
- The third year was essentially trouble free and the IGCC unit underwent fuel flexibility tests, which showed that the unit operated trouble free, without modification, on a second coal feedstock, a blend of two different Illinois #6 coals, and petroleum coke.
- Overall thermal performance actually improved during petroleum coke operation.
- In the fourth year, the gas turbine incurred damage to rows 14 through 17 of the compressor causing a 3-month outage. But over the four years of operation, availability of the gasification plant steadily improved reaching 79.1% in 1999.

Economic Performance

- Overall cost of the gasification and power generation facilities was $417 million, including engineering and environmental studies, equipment procurement, construction, pre-operations management, and startup.
- Preliminary estimates for a future dual-train facility are $1,200/kW. Costs could fall to under $1,000/kW for a greenfield plant with advances in turbine technology.

Project Summary

The Wabash River Coal Gasification Repowering Project repowered a 1950s vintage pulverized coal-fired plant, transforming the plant from a nominally 33% efficient, 90-MWe unit into a nominally 40% efficient, 262-MWe (net) unit. Cinergy, PSI's parent company, dispatches power from the project, with a demonstrated heat rate of 8,910 Btu/kWh (HHV), second only to their hydroelectric facilities on the basis of environmental emissions and efficiency.

Beyond the integration of an advanced gasification system, a number of other advanced features contributed to the high energy efficiency. These included: (1) hot/dry particulate removal to enable gas cleanup without heat loss, (2) integration of the gasifier high-temperature heat recovery steam generator with the gas turbine-connected HRSG to ensure optimum steam conditions for the steam turbine, (3) use of a carbonyl sulfide (COS) hydrolysis process to enable high-percentage sulfur removal, (4) recycle of slag fines for additional carbon recovery, (5) use of 95% pure oxygen to lower power requirements for the oxygen plant, and (6) fuel gas moisturization to reduce steam injection requirements for NO_x control.

Over the four-year demonstration period starting in November 1995, the facility operated approximately 15,000 hours and processed approximately 1.5 million tons of coal to produce about 23 x 10^{12} Btu of syngas. For several of the months, syngas production exceeded one trillion Btu. By the beginning of the final year of operation under the demonstration, the 262-MWe IGCC unit had captured over 100 million pounds equivalent of SO_2.

Operational Performance

The first year of operation was plagued by problems primarily with: (1) ash deposition at the inlet to the fire tube boiler, (2) particulate breakthrough in the hot gas filter system, and (3) chloride and metals poisoning of the COS catalyst. A modification to the hot gas path flow geometry corrected the ash deposition problem. Replacement of the ceramic candle filters with metallic candles proved to be largely successful. A follow-on metallic candle filter development effort ensued using a hot gas slipstream, which resulted in improved candle filter metallurgy, blinding rates, and cleaning techniques. The combined effort all but eliminated downtime associated with the filter system by the close of 1998. Installation of a wet chloride scrubber eliminated the chloride problem by September 1996 and use of an alternate COS catalyst less prone to trace metal poisoning provided the final cure for the COS system by October 1997.

The second year of operation identified cracking problems with the gas turbine combustion liners and tube leaks in the HRSG. Replacement of the fuel nozzles and liners solved the cracking problem. Resolution of the HRSG problem required modification to the tube support and HRSG roof/penthouse floor to allow for more expansion.

By the third year, downtime was reduced to nuisance items such as instrumentation-induced trips in the oxygen plant and high-maintenance items such as replacement of high-pressure slurry burners every 40–50 days. In the third year, the IGCC unit underwent fuel flexibility tests. The unit operated effectively, without modification or incident, on a second coal feedstock, a blend of two different Illinois #6 coals, and petroleum coke (petcoke). These tests added to the fuel flexibility portfolio of the gasifier, which had previously processed both lignite and subbituminous coals during its earlier development. The overall thermal performance of the IGCC unit actually improved during petcoke operation. The unit processed over 18,000 tons of high-sulfur petcoke and produced 350,000 x 10^6 Btu of syngas. There was a negligible amount of tar production and no problems were encountered in removing the dry char particulate despite a higher dust loading. Exhibit 5-44 provides a summary of the thermal performance of the unit on both coal and petcoke. Exhibit 5-45 compares the coal and petcoke fuel characteristics and Exhibit 5-46 compares the syngas products.

The fourth year of operation was marred by a 3-month outage due to damage incurred to rows 14 through 17 of the gas turbine air compressor. However, over the four years of operation, availability of the gasification plant steadily improved, reaching 79.1% in 1999.

Environmental Performance

The IGCC unit operates with an SO_2 capture efficiency greater than 99%. As a result, SO_2 emissions are consistently below 0.1 lb/10^6 Btu of coal input, reaching as low as 0.03 lb/10^6 Btu. Moreover, the process transforms the SO_2 pollutant into 99.99% pure sulfur, a highly valued by-product, rather than a solid waste.

Steam injection controls NO_x emissions down to 0.15 lb/10^6 Btu. This is the emission limit being sought under the EPA SIP call related to ozone nonattainment areas. Also, particulate emissions are below detection limits.

The ash component of the coal results in a low-carbon vitreous slag, impervious to leaching and valued as an aggregate in construction or as grit for abrasives and roofing materials. Also, the trace metal constituents in the petcoke were effectively captured in the slag produced.

Economic Performance

The economic performance of the IGCC unit will be forthcoming in the Final Technical Report currently in preparation. Some preliminary information presented here was drawn from technical papers prepared over the course of the demonstration.

The overall combined cost of the gasification and power generation facilities was $417 million at completion. This cost includes engineering and environmental studies, equipment procurement, construction, pre-operations management (including operator training), and startup. Escalation during the project is included. Startup includes the costs of construction and operations, excluding coal and power, up to the date of commercial operation in December 1995. Soft costs such as legal and financing fees and interest during construction are not included.

Project participants project future costs of $1,200/kW for dual-train repowered facilities, and greenfield costs under $1,000/kW, with advances in turbine technology.

Commercial Applications

At the end of the demonstration in December 1999, Global Energy, Inc. purchased Dynegy's gasification assets and technology. Global Energy plans to market the technology under the name "E-Gas Technology™." The project is continuing to operate as Wabash River Energy, Ltd., a subsidiary of Global Energy.

The immediate future for E-Gas Technology™ appears to lie with both foreign and domestic applications where low-cost feedstocks such as petcoke can be used and co-production options are afforded such as bundled production of steam, fuels/chemicals, and electricity. Integration or association with refinery operations are examples.

In the longer term, the technology has application to the repowering of the 95,000 MWe of existing U.S. coal-fired boilers over 30 years old, and new foreign and domestic coal-fired capacity additions. Over time, the economics and performance of the technology will continue to improve, coal and gas price differentials will increase, and displacement of petroleum in chemicals and fuels production will increase in importance.

Contacts

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(713) 374-7279 (fax)
George Lynch, DOE/HQ, (301) 903-9434
Leo E. Makovsky, NETL, (412) 386-5814

References

- Steven L. Douglas. "Wabash River in Its Fourth Year of Commercial Operation." *7th Clean Coal Technology Conference: Volume II Technical Papers.* June 1999.

Exhibit 5-44
Wabash Thermal Performance Summary

	Design	Actual	
	Coal	Coal	Petcoke
Nominal Throughput, tons/day	2,550	2,450	2,000
Syngas Capacity, 10^6 Btu/hr	1,780	1,690	1,690
Combustion Turbine, MW	192	192	192
Steam Turbine, MW	105	96	96
Auxiliary Power, MW	35	36	36
Net Generation, MW	262	261	261
Plant Efficiency, % (HHV)	37.8	39.7	40.2
Sulfur Removal Efficiency, %	>98	>99	>99

Exhibit 5-45
Wabash Fuel Analysis

	Typical Coal	Petcoke
Moisture, % by wt.	15.2	7.0
Ash, % by wt.	12.0	0.3
Volatile, % by wt.	32.8	12.4
Fixed Carbon, % by wt.	39.9	80.4
Sulfur, % by wt.	1.9	5.2
Heating Value, as Rec'd, Btu/lb	10,536	14,282

Exhibit 5-46
Wabash Product Syngas Analysis

	Typical Coal	Petcoke
Nitrogen, % by vol.	1.9	1.9
Argon, % by vol.	0.6	0.6
Carbon Dioxide, % by vol.	15.8	15.4
Carbon Monoxide, % by vol.	45.3	48.6
Hydrogen, % by vol.	34.4	33.2
Methane, % by vol.	1.9	0.5
Total Sulfur, ppmv	68	69
Higher Heating Value, Btu/scf	277	268

Advanced Electric Power Generation
Advanced Combustion/Heat Engines

Clean Coal Diesel Demonstration Project

Participant
Arthur D. Little, Inc. (ADL)

Additional Team Members
University of Alaska at Fairbanks—host and cofunder
Coltec Industries Inc.—diesel engine technology vendor
Usibelli Coal Mine, Inc.—coal supplier
CQ Inc.
Fairbanks Morse
AMBAC, Inc.

Location
Fairbanks, AK (University of Alaska facility)

Technology
Coltec's coal-fueled diesel engine

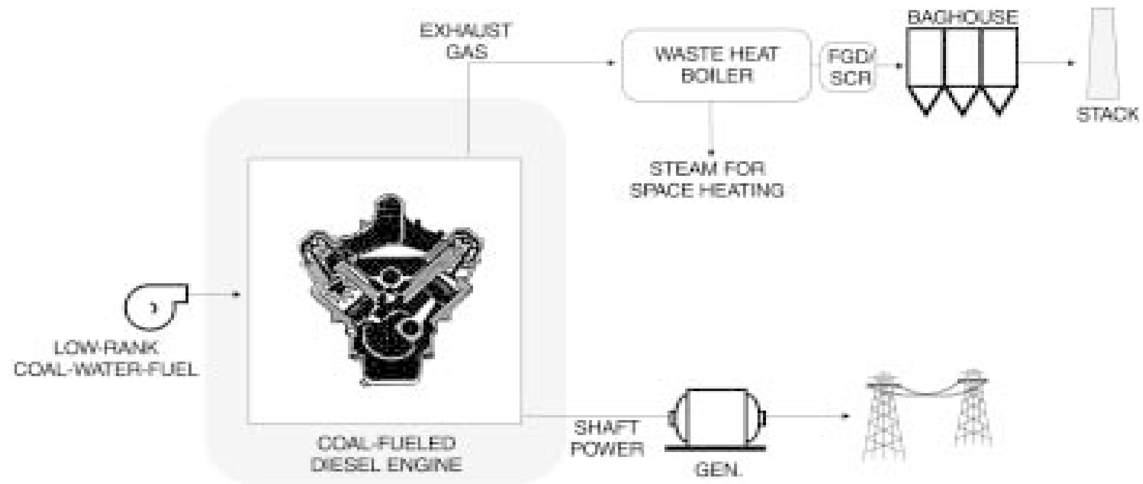
Plant Capacity/Production
6.4 MWe (net)

Coal
Usibelli Alaskan subbituminous

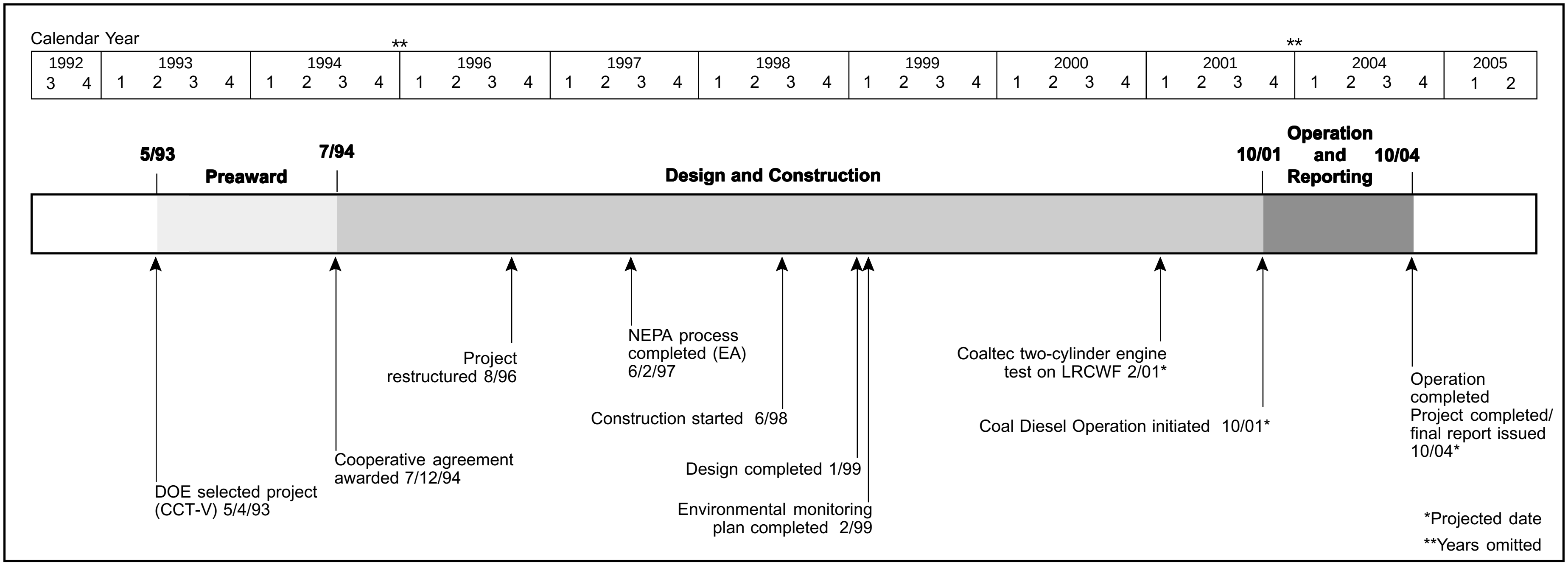
Project Funding

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 4,000 hours of operation and test the coal slurry in the diesel.



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, and future plant designs are expected to reach 48% efficiency. This will result in a 25% reduction in CO_2 emissions compared with conventional coal-fired plants. The engine will use selective catalytic reduction (SCR) for NO_x control.



Project Status/Accomplishments

Overall project system design was completed in early 1999. The 18-cylinder diesel engine arrived on site at UAF in January 1999 and was mounted in the engine house in late February. In October 1999, the engine, after being connected to the generator, was operated on diesel fuel to ensure it would function coupled with the generator. In May 2000, total system startup was attempted on diesel fuel. Minor problems with system integration and tie-in with the existing electrical bus system were encountered. The SCR system for the diesel was tested in August 2000 and achieved 90% reduction in NO_x emissions, which was within contract specifications. Since August 15, 2000, the diesel has been supplying all of the university's power requirements on fuel oil. Upon completion of system checkout, the diesel engine will be modified to use the LRCWF. Design of the hardened engine parts, coal fuel preparation and testing, and completion of the baghouse and SNCR system are in progress.

With the change of site from Easton, Maryland to UAF, Alaskan subbituminous coal will now be used to manufacture the LRCWF. Usibelli Coal Mine, Inc. will supply the coal. Samples of the coal have been sent to CQ Inc. for analysis and washability tests. ADL and EERC will also perform various analyses of the coal. Upon completion of the tests, a design formula will be devised to produce the LRCWF. The LRCWF will first be tested in a Coltec two-cylinder test engine. These tests are scheduled for the Fall 2000. The tests on the test engine will provide information and data on how to optimize the operational settings, verify the coal fuel performance, and finalize the requirements for hardened coatings for critical components.

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 distributed power generation in the 5- to 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.

Healy Clean Coal Project

Project completed.

Participant

Alaska Industrial Development and Export Authority

Additional Team Members

Golden Valley Electric Association, Inc.—host and operator
Stone and Webster Engineering Corp.—engineer
TRW, Inc., Space & Technology Division—combustor technology supplier
The Babcock & Wilcox Company (B&W)—spray dryer absorber technology supplier
Usibelli Coal Mine, Inc.—coal supplier
Steigers Corporation—environmental and permitting support

Location

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

Technology

TRW's Clean Coal Combustion System; Babcock & Wilcox's spray dryer absorber (SDA) with sorbent recycle

Plant Capacity/Production

50 MWe (nominal)

Coal

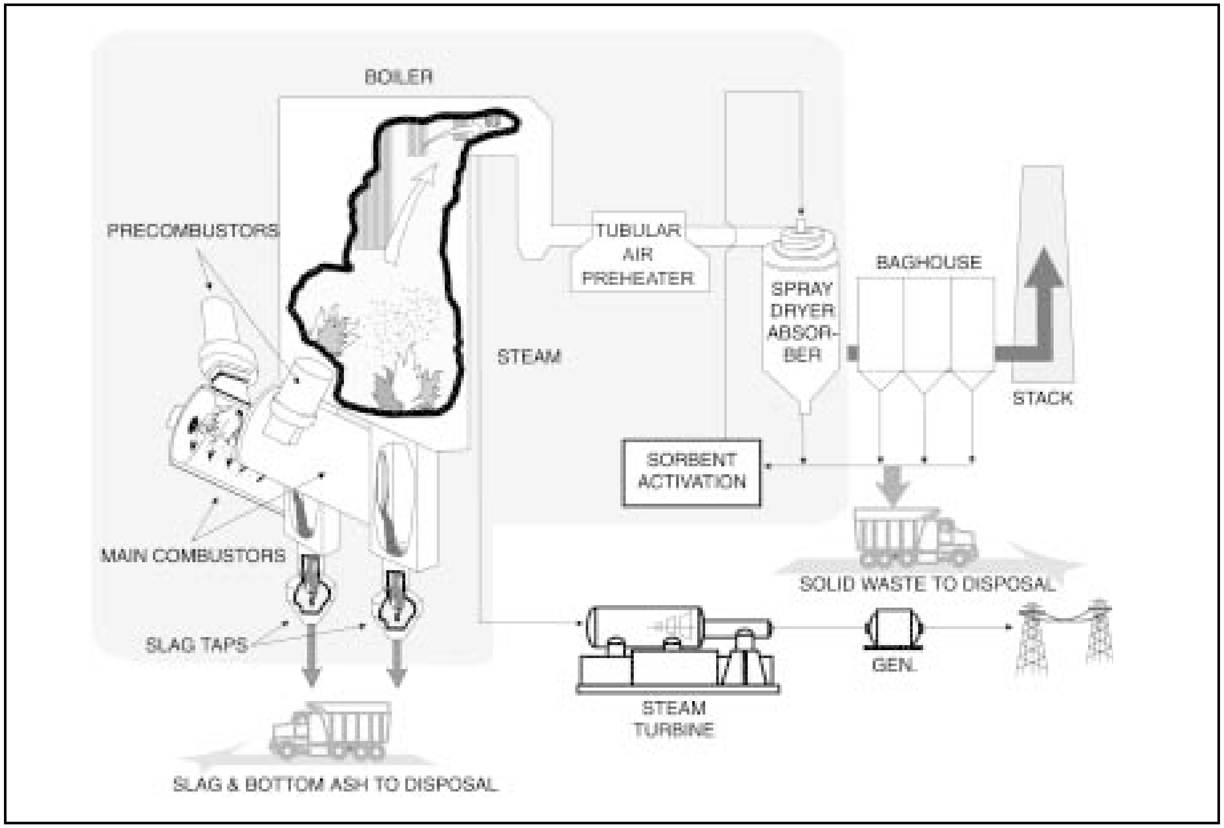
Usibelli subbituminous 50% run-of-mine (ROM) and 50% waste coal

Project Funding

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

Project Objective

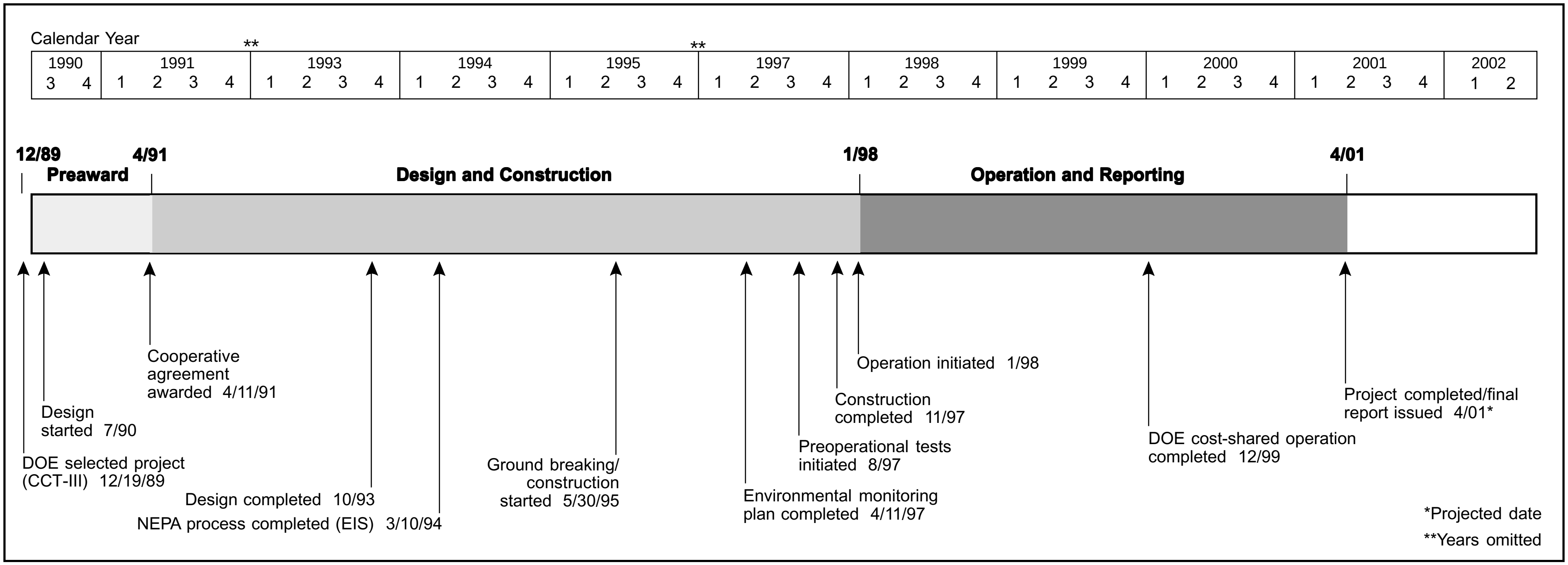
To demonstrate an innovative new power plant design featuring integration of an advanced combustor coupled with both high- and low-temperature emissions control processes.



Technology/Project Description

Emissions are controlled using TRW's clean coal combustion system, an advanced entrained/slagging combustors through staged fuel and air injection for NO_x control and limestone injection for SO_2 control. Additional SO_2 is removed using B&W's activated recycle SDA.

A coal-fired precombustor increases the air inlet temperature for optimum slagging performance. The slagging combustors are bottom mounted, injecting the combustion products 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 conditions for NO_x control. The ash forms molten slag, which flows along 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 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 a 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 combustors where it is flash calcined (converting $CaCO_3$ to lime (CaO). The mixture of this CaO and ash that was not removed in the combustor, called flash-calcined material, is removed in the fabric filter system. Most of the flash-calcined material is used to form a 45% solids slurry, which is injected into the spray dryer. The SO_2 in the flue gas reacts with the slurry droplets as water is simultaneously evaporated. The SO_2 is further removed from the flue gas by reacting with the dry flash-calcined-material on the baghouse filter bags.



Results Summary

Environmental

- NO_x emissions ranged from 0.208–0.278 lb/10^6 Btu, with typical emissions of 0.245 lb/10^6 Btu on a 30-day rolling average, which is well below the permit limit of 0.350 lb/10^6 Btu on a rolling day average.
- SO_2 emissions were consistently less than 0.09 lb/10^6 Btu, with typical emissions of 0.038 lb/10^6 Btu, which are below the permit limit of 0.10 lb/10^6 Btu (3-hour average).
- High SO_2 removal efficiencies in excess of 90% were achieved with low-sulfur coal and Ca/S molar ratios of 1.4–1.8.
- Particulate matter (PM) emissions were 0.0047 lb/10^6 Btu, which is well below the permit limit of 0.02 lb/10^6 Btu.
- CO emissions were less than 130 ppm at 3.0% O_2, with typical emissions of 30–40 ppm at 3.0% O_2, which is well below the permit limit of 202 ppm at 3.0% O_2.
- Tests showed that the SDA system SO_2 emissions, PM emissions, and opacity were well within guarantees.

Operational

- Carbon burnout contract goals were achieved—greater than 99% carbon burnout at 100% maximum continuous rating (MCR) for the ROM, 50/50 blend of ROM/waste coal, and 55/45 blend. The carbon burnout was typically 99.7%.
- The contract goal for slag recovery greater than 70% at 100% MCR for all coals was also achieved. Slag recovery ranged from 78–87%, with a typical recovery of 83%.
- During a 90-day test in the second half of 1999, the plant availability was 97% at a capacity factor of 95%.
- The SDA pressure drops and power consumption were well below guarantee levels.

Economic

- Economic data are not yet available.

Project Summary

The Healy Clean Coal Project is the first utility-scale demonstration of the TRW clean coal combustion system. The project site is adjacent to the existing Healy Unit No. 1 near Healy, Alaska and the Usibelli coal mine. Power is supplied to the Golden Valley Electric Association (GVEA).

Environmental Performance

The entrained/slagging combustor is designed to minimize NO_x emissions, achieve high carbon burnout, and remove the majority of fly ash from the flue gas prior to the boiler. The slagging combustor is also the first step of a three-step process for controlling SO_2 by first converting limestone to flash-calcined lime. Second, the flash calcined-lime absorbs SO_2 within the boiler. Third, the majority of the SO_2 is removed with B&W's SDA system, which uses the flash-calcined lime and fly ash captured in the baghouse. Because most of the coal ash is removed by the slagging combustors, the recycled material is rich enough in calcium content that the SDA can be operated solely on the recycled solids, eliminating the need to purchase or manufacture lime for the back end scrubbing system.

During a cumulative six-month combustion system characterization test, a series of tests were performed to establish baseline performance of the combustion system while burning ROM and ROM/waste coal blends, to map combustor performance characteristics over a broad range of operating conditions and hardware configurations, and to determine the best configuration and operating conditions for long-term operation. Throughout the testing period, the NO_x, SO_2, PM, opacity, and CO emission goals were met with the exception of short-term SO_2 and opacity exceedences during startup and repairs. The emissions, as well as permit and NSPS requirements, are presented in Exhibit 5-47.

Performance testing of the SDA system conducted in June 1999 showed that the technology performed well. Measurements of the SDA inlet, SDA outlet, stack, limestone feed, coal feed, air preheater hopper ash, surge bin ash, electrical power consumption, and stack opacity, as well as normal plant data from the plant distributed control system, showed that the technology exceeds the guar-

Exhibit 5-47
Healy Performance Goals and Combustion System Characterization
Testing Results (June–December 1998)

Parameter	NSPS	Permit	Goal	Actual Range	Actual Typical
NO_x	0.5 lb/10^6 Btu (before 7/97) 0.15 lb/10^6 Btu (modified after 7/97) 0.5 lb/10^6 Btu (new plant after 7/97)	0.350 lb/10^6 Btu (30-day rolling avg)	<0.35 lb/10^6 Btu	0.208–0.278 lb/10^6 Btu (30-day rolling avg)	0.245 lb/10^6 Btu (30-day rolling avg)
SO_2	90% removal and less than 1.2 lb/10^6 Btu 70% removal when emissions < 0.60 lb/10^6 Btu	0.086 lb/10^6 Btu (annual avg) 0.10 lb/10^6 Btu (3-hour avg) 65.8 lb/hr max (3-hour avg)	70% removal (min) 79.6 lb/hr max	<0.09 lb/10^6 Btu (<35 ppm @ 3% O_2)	0.038 lb/10^6 Btu (15 ppm @ 3% O_2) 25 lb/hr
PM	0.03 lb/10^6 Btu	0.02 lb/10^6 Btu (hourly avg)	0.015 lb/10^6 Btu	NA	0.0047 lb/10^6 Btu[a]
Opacity	20% Opacity (6-minute avg)	20% Opacity (3-minute avg) 27% Opacity (one 6-minute period per hour)	20% Opacity (3-minute avg)	<10% Opacity (30-min avg.)	2.3% Opacity[a]
CO	Dependent on ambient CO levels in the local region	0.20 lb/10^6 Btu (hourly avg) (202 ppm CO @ 3.0% O_2)	<200 ppm (dry basis) at 3.5% O_2 (dry basis) (<206 ppm CO @ 3.0% O_2)	<130 ppm @ 3.0% O_2	30–40 ppm @ 3.0% O_2 0.036 lb/10^6 Btu

[a] After correction of problems with premature filter bag failures in the baghouse.

antees. The results of the tests and the performance guarantees are shown in Exhibit 5-48.

Operational Performance

The slagging stage of the combustor performed extremely well and continuously demonstrated the capability to burn both ROM and ROM/waste coal blends over a broad range of operating conditions. The precombustor performed very well with ROM coal, but exhibited more variable performance, in terms of slagging behavior, during the initial tests with ROM/waste coal blends.

Localized slag freezing was observed in the precombustor during early testing. A combination of hardware configuration and operational configuration changes were made that successfully minimized slag freezing. These changes included relocating the secondary air from the precombustor mix annulus to the head end of the slagging stage and completely transferring the precombustor mill air to the boiler NO_x ports following boiler warmup. These changes eliminated the mixing of excess air downstream of the precombustor chamber to minimize local slag freezing and increased the precombustor operating temperature to provide additional temperature margin. The mill air change had the added benefit of simplifying combustor operation by eliminating the need to monitor and control coal-laden mill air flow to the precombustor mill air ports during steady-state operation.

Testing of the slagging combustor also showed that the contract goals were achieved, which included greater than 99% carbon burnout at 100% MCR for the performance, ROM, 50/50 blend of ROM/waste coal, and 55/45 blend; and greater than 98% carbon burnout at 100% MCR for waste coal. The carbon burnout was typically 99.7%. Slag recovery ranged from 78–87%, with a typical reading of 83%, easily meeting the contract goal for slag recovery of greater than 70% at 100% MCR for all coals.

The SDA system also performed well. During performance testing in June 1999, system pressure drops were well below the 13 in. WG guarantee. The range was 9.6–10.0 in. WG as can be seen in Exhibit 5-48. Power consumption was approximately 38–41% less than the guaranteed level. Based on these results, Stone & Webster concluded that the SDA system met all performance guarantees.

Economic Performance

Economic data are not yet available.

Exhibit 5-48
Healy SDA Performance Test Results and Performance Guarantees

Operating Parameter	Guarantee	Range of Parameter Values
SO_2	79.6 lb/hr (max)	<2.15
PM	0.015 lb/10^6 Btu	0.0014-0.0052
Opacity	20% Opacity (3-minute avg) 27% Opacity for 3 minutes per hour	1.0-2.0
System Pressure Drop	13 inches WG	9.6-10.0
System Power Consumption	550.5 kW	324-340

Commercial Applications

This technology is appropriate for any size utility or industrial boiler in new or 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 entrained/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.

Continued use of the combustors is on hold for at least one year while GVEA evaluates the technical, economic, and regulatory feasibility of a "full retrofit" to conventional low-NOx burner technology and a "limited retrofit" that repairs and improves the existing entrained/slagging combustor. Preliminary results indicate the "limited retrofit" option is the most desirable option; however, the commercial viability of that option is under evaluation.

Contacts

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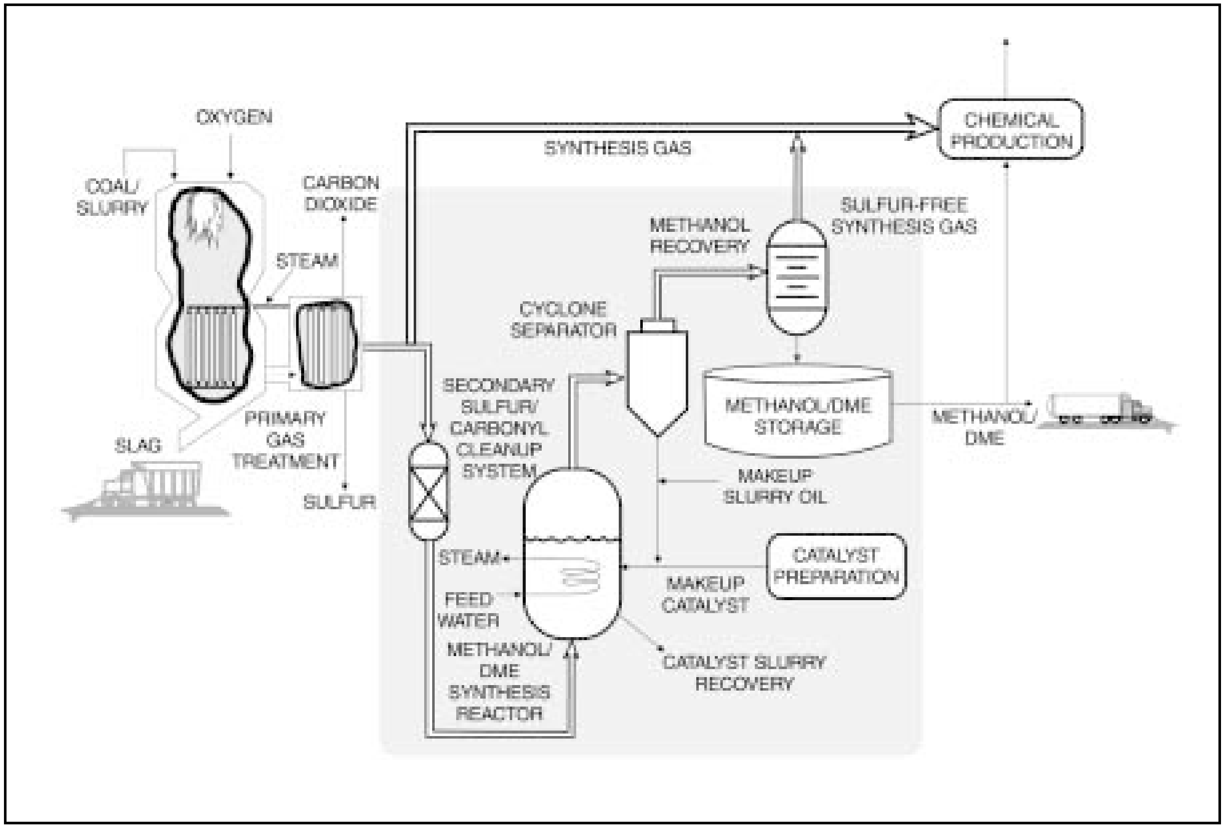
Robert M. Kornosky, NETL, (412) 386-4521

References

- TRW, Inc. *Healy Clean Coal Project (HCCP) Demonstration Program Topical Report: Combustion System Operation Final Report.* March 31, 2000.
- Stone & Webster Engineering Corporation. *Spray Dryer Absorber System Performance Test Report: June 7-11, 1999.* February 2000.

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 Chemicals-from-Coal Complex)

Technology

Air Products and Chemicals, Inc.'s liquid phase methanol 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

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

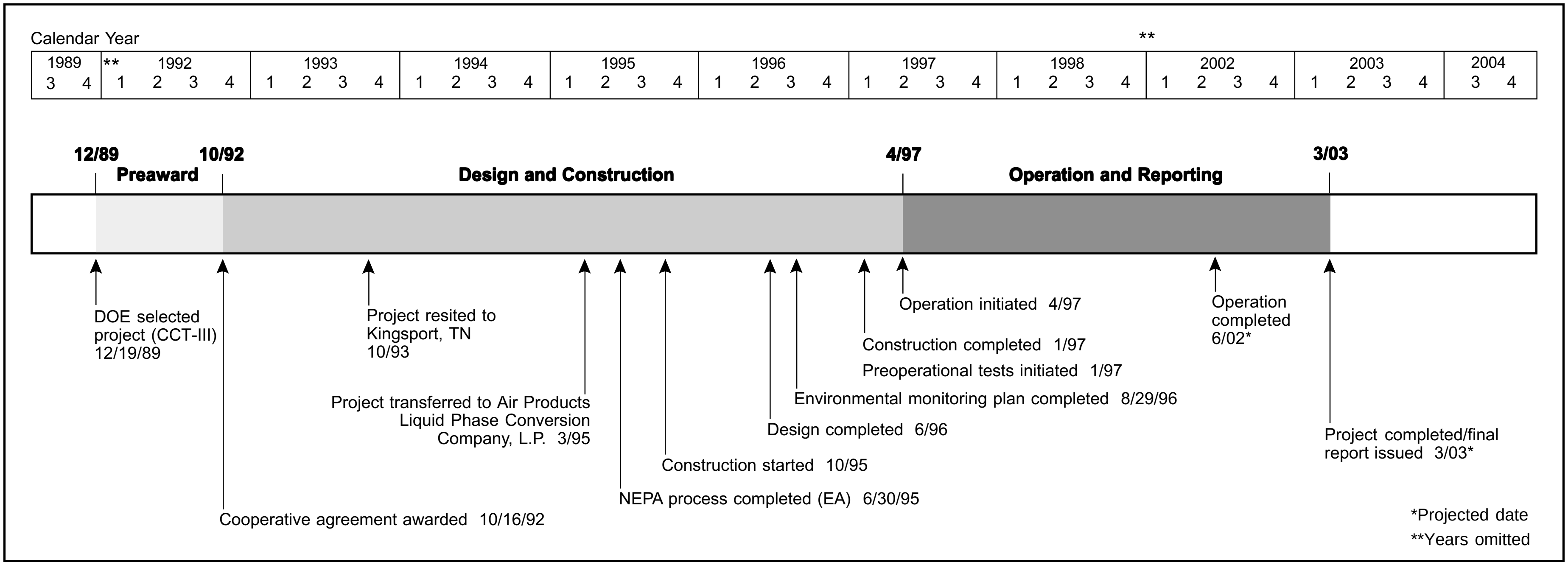
Project Objective

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 is being conducted in off-site stationary and mobile applications, such as fuel cells, buses, and distributed electric power generation. Stabilized methanol from the project is being made available to several test locations to study the feasibility of using the product as a feedstock in transportation and power generation applications. Eastern high-sulfur bituminous coal (Mason seam) containing 3% sulfur (5% maximum) and 10% ash is being used.



Project Status/Accomplishments

The first production of methanol from the 80,000 gal/day unit occurred on April 2, 1997 with the first stable operation at nameplate capacity occurring on April 6, 1997. A stable test period at over 92,000 gal/day revealed no system limitations.

The LPMEOH™ process demonstration unit continues to exceed expectations. Tests have given increased confidence in the use of the LPMEOH™ process for IGCC applications. This confidence level will increase with additional testing of the LPMEOH™ process.

Since startup in April 1997, about 66 million gallons of methanol have been produced and plant availability has exceeded 97.7%. Availability in 1998 through 2000 was in excess of 99.1%. As a result of the successes achieved, the demonstration operations were extended an additional 15 months (through June 30, 2002) to allow for the opportunity to perform new tests that are considered to be of significant commercial interest.

Methods for the removal and control of potential catalyst poisons continue to be an important part of the ongoing plant operation. To support this effort, the catalyst guard bed will incorporate an improved adsorbent material, which is expected to reduce significant poisons such as arsine. The new adsorbent material is a copper oxide impregnated activated carbon that is commercially available. The guard bed and new adsorbent will be placed in service after the implementation of some plant equipment modifications to allow for the adsorbent change.

Engineering for the plant modifications to support *in situ* catalyst activation in the LPMEOH™ reactor has been completed. Currently, catalyst is activated in small batches in a separate vessel and transferred into the LPMEOH™ reactor. *In situ* activation of the methanol catalyst is of commercial significance as it has the potential to simplify equipment and to reduce capital requirements. It is expected that the *in situ* activation demonstration will occur prior to mid-2001.

Commercial Applications

The LPMEOH™ process has been developed to enhance 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.

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 also can 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.

Advanced Coal Conversion Process Demonstration

Participant
Western SynCoal LLC (formerly Rosebud SynCoal Partnership; 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
Western SynCoal LLC's Advanced Coal Conversion Process for upgrading low-rank subbituminous and lignite coals

Plant Capacity/Production
45 tons/hr of SynCoal® product

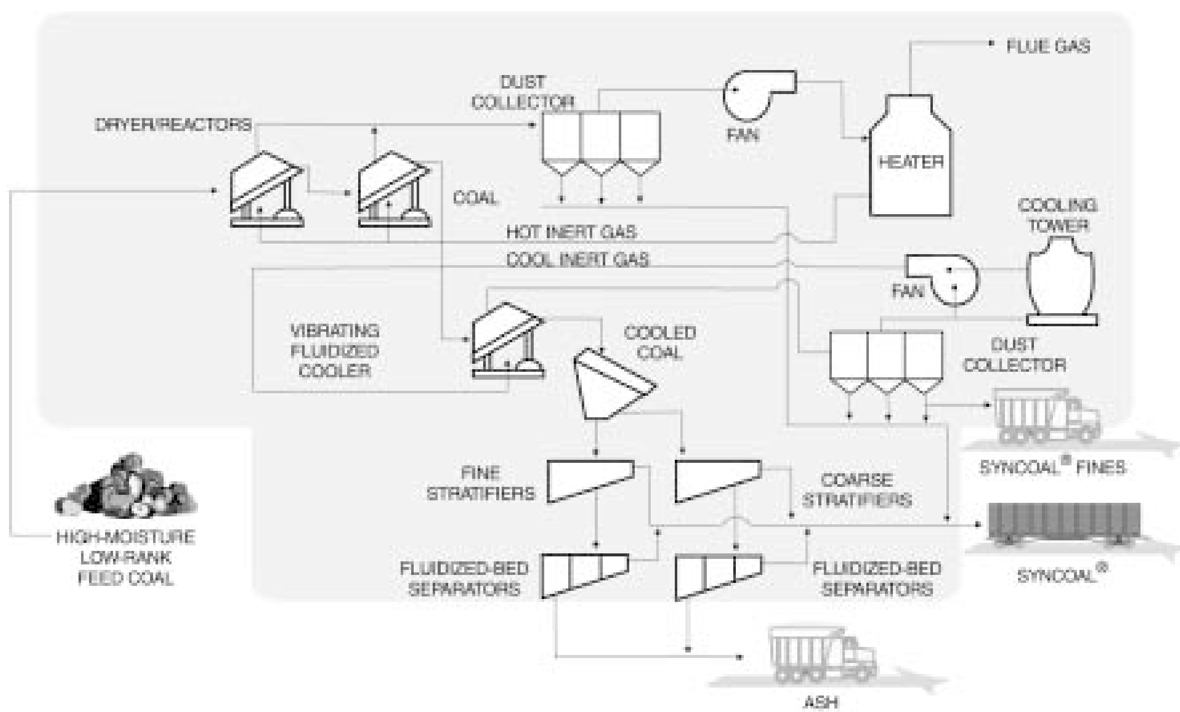
Coal
Powder River Basin subbituminous (Rosebud Mine), 0.5–1.5% sulfur, plus tests of other subbituminous coals and lignites

Project Funding

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

Project Objective
To demonstrate Western SynCoal LLC'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.

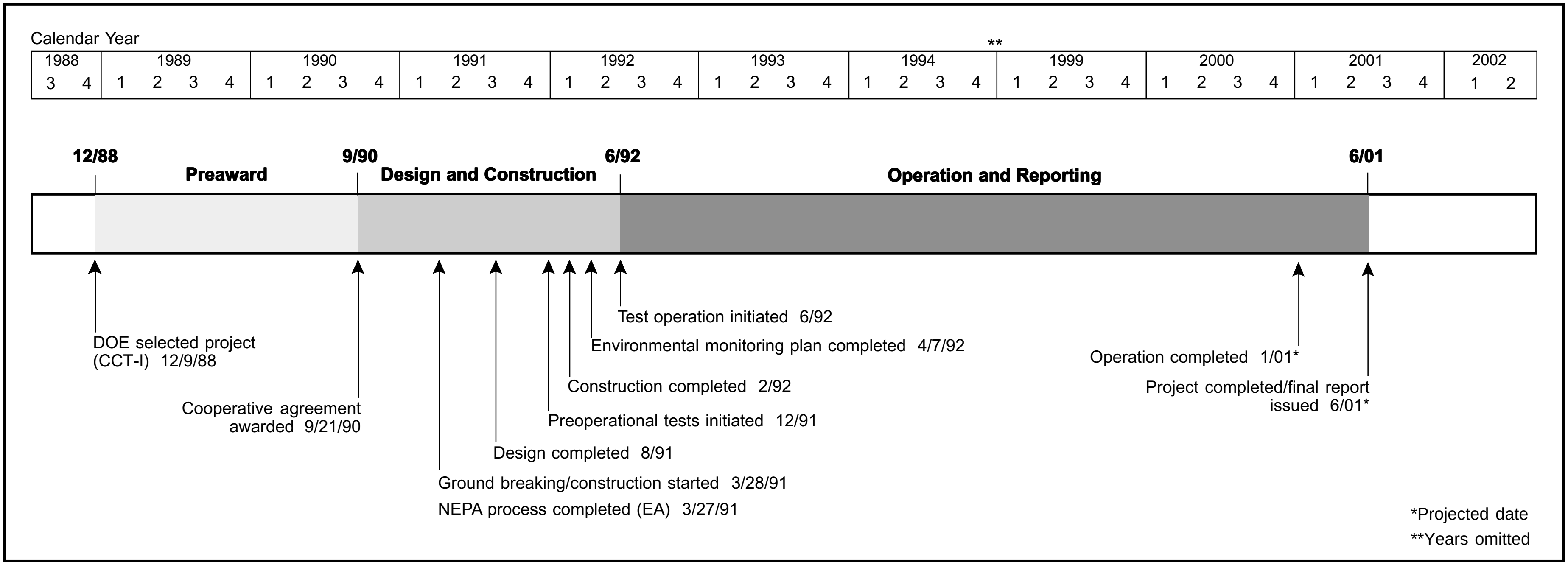
SynCoal is a registered trademark of the Rosebud SynCoal Partnership.



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 exits 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, 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.



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 has processed over 2.6 million tons of raw coal to produce over 1.7 million tons of SynCoal. The SynCoal is used by electric utilities and industrial facilities (primarily cement and lime plants). The ACCP facility continues to supply six commercial customers including the 330-MWe Colstrip Unit No. 2. SynCoal is trucked to Colstrip Unit No. 2 and fed to three of the five pulverizers using a dedicated pneumatic feed system.

The demonstration of SynCoal as a supplemental fuel for Unit No. 2 started in February 1999. About 131,000 tons of SynCoal were used during 1999, or approximately 11.6% of the total thermal input on an annual basis. On days that SynCoal was used as a supplemental fuel, Unit No. 2 produced an average of 3.7%, or 10.5 MWe (net), of additional generation. The gross unit heat rate for Unit No. 2 improved by 85 Btu/kWh when firing SynCoal (auxiliary power demand decreased about 1.9 MWe). When the demonstration started, baseline testing indicated that Unit No. 2 was typically producing 2.9 MWe (net) less than Unit No. 1, a sister unit of comparable capacity. In late Spring 1999, Unit No. 1 was overhauled, resulting in an increase in its average output of 7 MWe (net). With this increase in output, the overhauled Unit No. 1 would have produced 5.4 MWe more than Unit No. 2. However, for the days that SynCoal was used, Unit No. 2 out-produced the overhauled Unit No. 1 by an average of 7.3 MWe—285.7 MWe versus 278.4 MWe (net)—with 15.0% of the total heat input coming from SynCoal. Furthermore, SynCoal can be credited for actual 1999 SO_2 emissions reductions for Unit No. 2 of approximately 430 tons, or an 8% reduction, and NO_x emissions reductions of approximately 826 tons, or a 19% reduction, when compared with Unit No. 1 emissions.

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. Testing showed dramatic improvement in cyclone combustion, improved slag tapping, and a 13% reduction in boiler air flow requirements. In addition, boiler efficiency increased from 82% to over 86% and the total gross heat rate improved by 123 Btu/kWh.

Commercial Applications

ACCP has the potential to enhance the use of low-rank western subbituminous and lignite coals. The 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 participant has six long-term agreements in place to provide SynCoal® to industrial and utility customers.

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
Utility Companies—(5 hosts)

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)
Five utility host sites

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 coals and blends

Coal Quality Expert, CQE, CQIS, and CQIM are trademarks of the Electric Power Research Institute.
Pentium is a registered trademark of Intel.
OS/2 Warp is a registered trademark of IBM.
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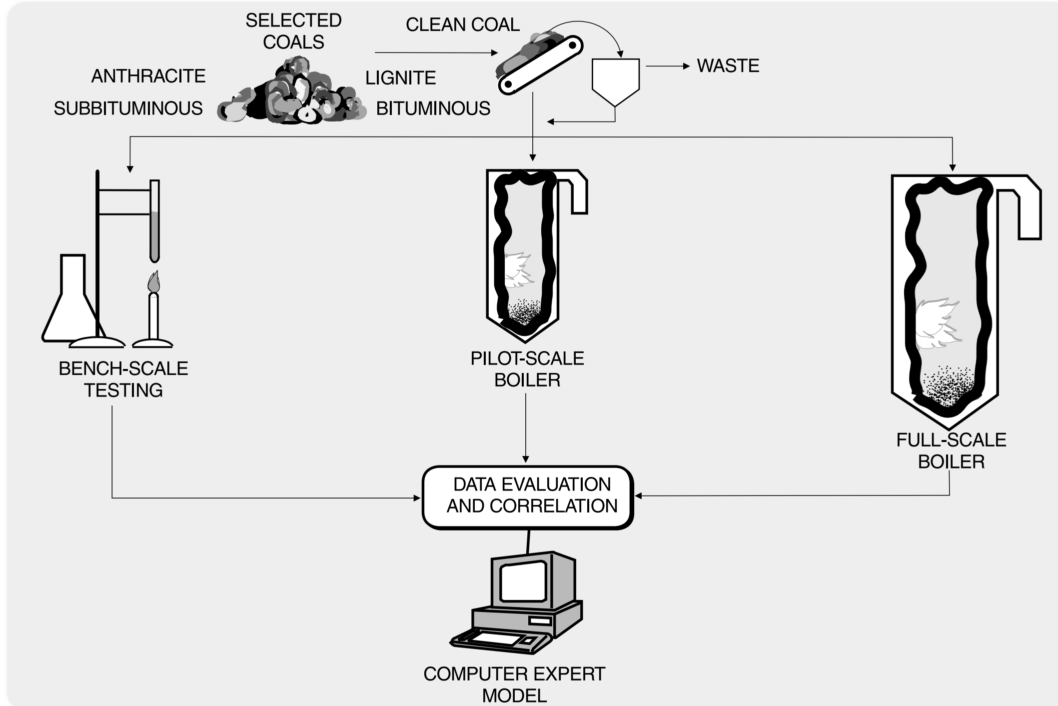
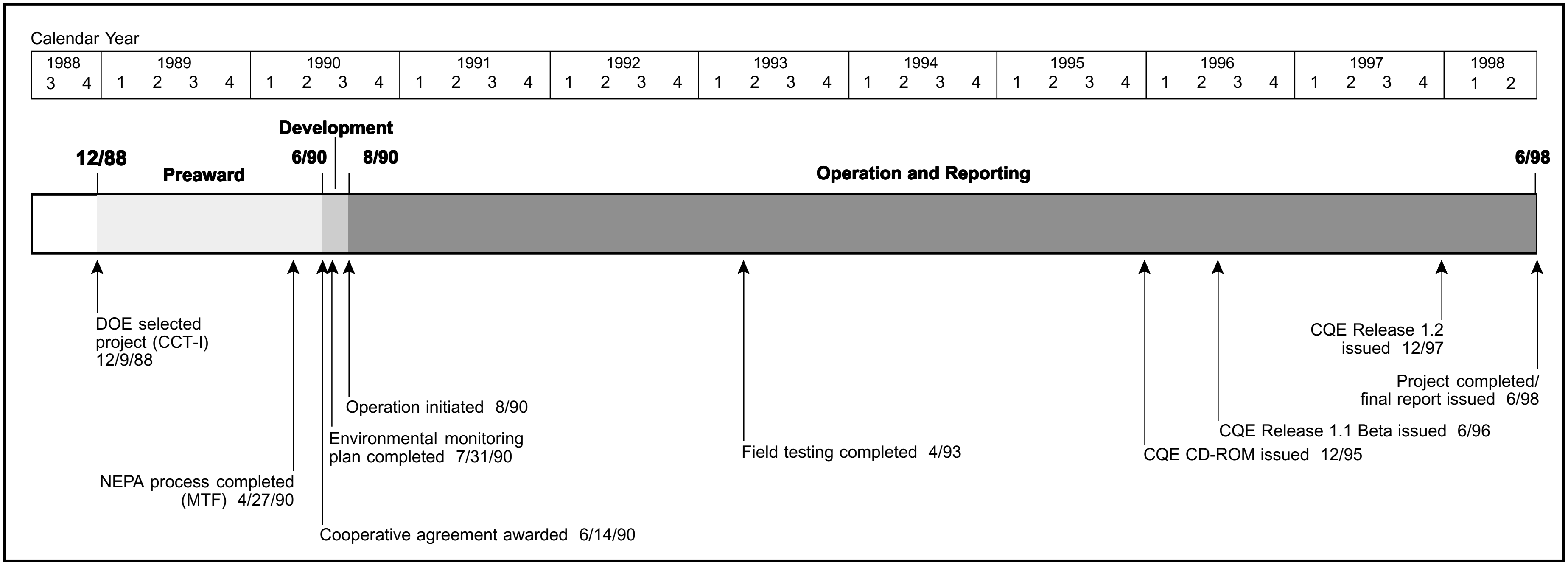


Project Funding

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 it could use 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.

Technology/Project Description
The CQE™ is a software tool that brings a new level of sophistication to fueling decisions by integrating the system-wide impact of fuel purchase decisions on coal-fired power plant performance, emissions, and power generation costs. 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.



Results Summary

Environmental

- CQE™ includes models to evaluate emission and regulatory issues.

Operational

- 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.
- Four features included in the CQE™ program are:
  - Fuel Evaluator,
  - Plant Engineer,
  - Environmental Planner, and
  - Coal-Cleaning Expert.
- CQE™ can be used to evaluate:
  - Coal quality,
  - Transportation system options,
  - Performance issues, and
  - Alternative emissions control strategies.
- CQE™ operates on an OS/2 Warp® (Version 3 or later) operating system with preferred hardware requirements of a Pentium®-equipped personal computer, 1 gigabyte hard disk space, 32 megabytes RAM, 1024x768 SVGA, and CD-ROM.

Economic

- CQE™ includes economic models to determine production cost components for coal-cleaning processes, power production equipment, and emissions control systems.

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: (1) new flexibility and application, (2) advanced technical models and performance correlations, and (3) 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 five 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 two-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 OS/2®-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 operation 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

The CQE™ includes more than 100 algorithms based on the data generated in the six full-scale field tests. The CQE™ 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 of 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, sootblower 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. 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.

Five utilities acted as hosts for field tests of CQE™.

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. Over 100 utilities and coal companies are now using CQE™. Proposals are pending with several non-EPRI-member U.S. and foreign utilities to license their software.

The CQE™ team has a Home Page on the World Wide Web (http://www.fuels.bv.com:80/cqe/cqe.htm) and uses 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 makes available 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 the Secretary of Energy and the President of EPRI in 1996 as the best of nine DOE/EPRI cost-shared utility research and development projects under the "Sustainable Electric Partnership" program.

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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

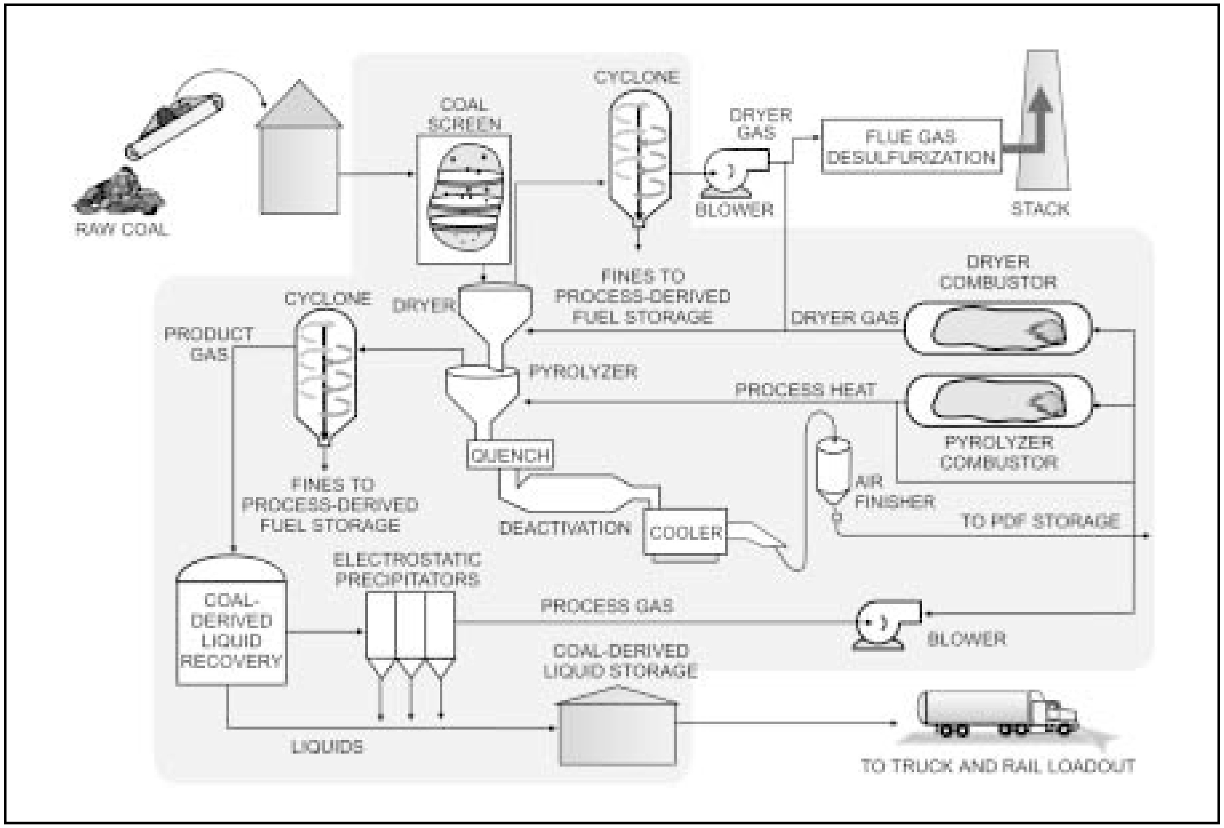
Coal
Low-sulfur Powder River Basin (PRB) subbituminous coal, 0.45% sulfur

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-heating value fuel forms from mild gasification of low-sulfur subbituminous coal, and to provide sufficient products for potential end users to conduct burn tests.

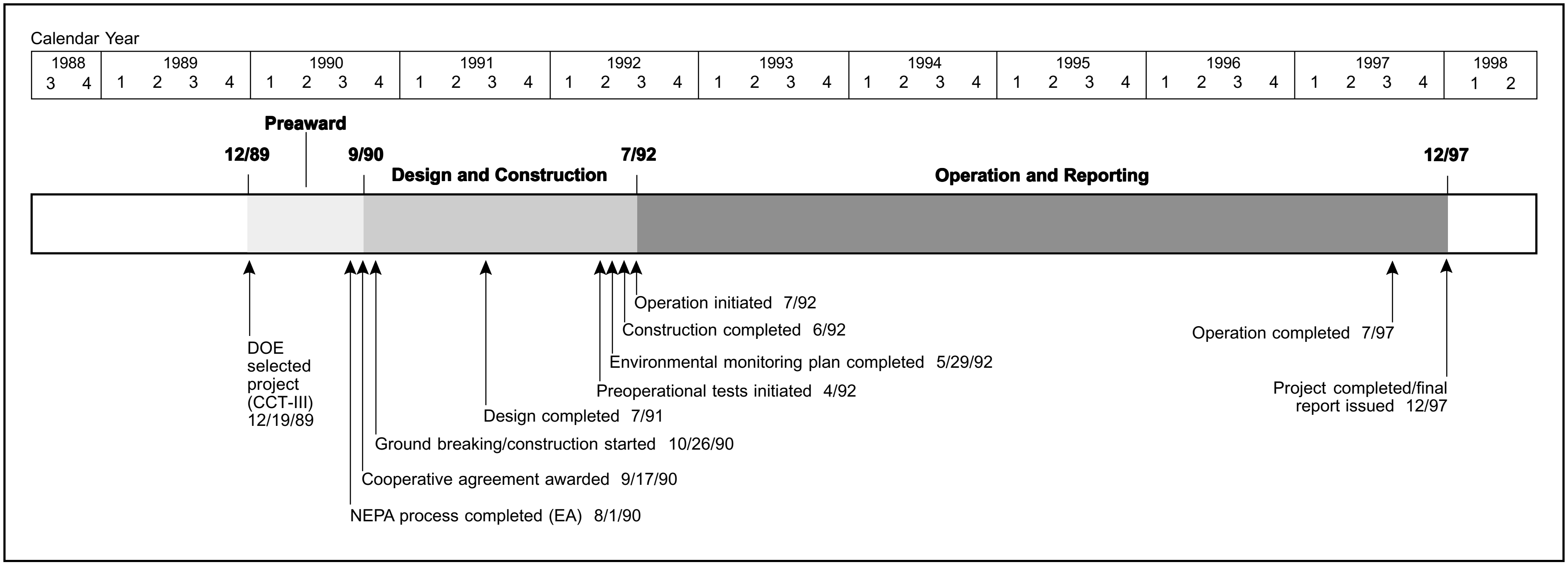


Technology/Project Description
Coal is fed into a rotary grate dryer where it is heated to reduce moisture. The temperature is controlled so that no significant amounts of methane, CO_2, or CO are released. The solids are then fed to the pyrolyzer where the temperature is about 1,000 °F, and all remaining 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 on 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 International and Bluegrass Coal Development Company.



Results Summary

Environmental

- The PDF® contains 0.36% sulfur with a heat content of 11,100 Btu/lb (compared with 0.45% sulfur and 8,300 Btu/lb for the feed coal).
- The CDL® contains 0.6% sulfur and 140,000 Btu/gal (compared with 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 tons per day would cost an estimated $475 million (2,001$) to construct, with annual operating and maintenance costs of $52 million 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% for extended periods. The length of operation and volume of production proved the soundness and durability of the process.

Exhibit 5-49 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% 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 was achieving stability of the PDF® product, which had to be resolved in order 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®. ENCOAL concluded that a separate, sealed vessel was needed for product deactivation. A search for a suitable design led to adoption of a VFB. A 500-ton/day VFB was installed between the quench table and rotary cooler. (Plans were made for installation of a second 500 ton/day VFB but were 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 due to changes in 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®. The 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 75–95 ºF, and the flash point averaged 230 ºF, both within the design range. Water content was down to 1–2%, and solids content was 2–4%. 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 one-half 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 a larger fines content but fewer particles in the fugitive dust range than ROM coal.

Exhibit 5-49
ENCOAL Production

	Pre-VFB		Post-VFB				
	1992	1993	1994	1995	1996	1997[1]	Total
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	**N/A**

[1]Through June 1997.

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 using the baseline fuel. Operation using PDF® afforded time to perform mill maintenance and calibration without losing capacity or revenues, increasing capacity factor and availability, and decreasing operation and maintenance costs.
- NO_x emissions were reduced by 20% 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 those of a low-sulfur No. 6 fuel oil, except that the sulfur content is significantly lower. CDL®'s 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.

ENCOAL determined that a centrifuge was needed to reduce solids retention and improve marketability of CDL® (tests validated a 90% 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-MWe 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 by-product, would be used in lieu of natural gas as a make-up fuel for the process (30% of the process heat input). PDF® would be marketed not only as a boiler fuel but as a supplement to 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, but the project is on hold due to lack of funding.

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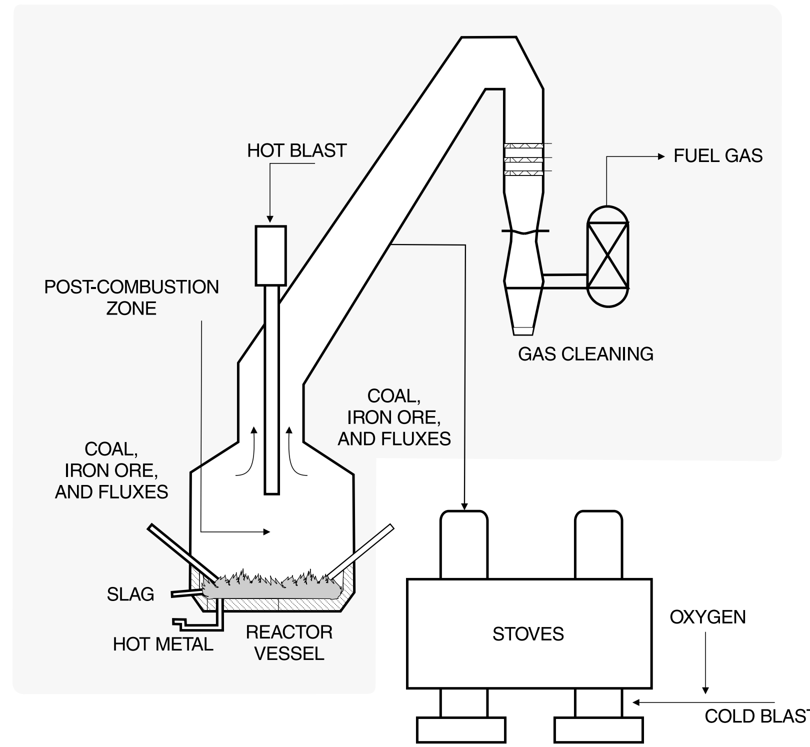
Industrial Applications

Clean Power from Integrated Coal/Ore Reduction (CPICOR™)



Participant

CPICOR™ Management Company LLC (a limited liability company composed of subsidiaries of the Geneva Steel Company)

Additional Team Members

Geneva Steel Company—cofunder, constructor, host, and operator of unit

Location

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

Technology

HIsmelt® direct iron-making process

Plant Capacity/Production

3,300 ton/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

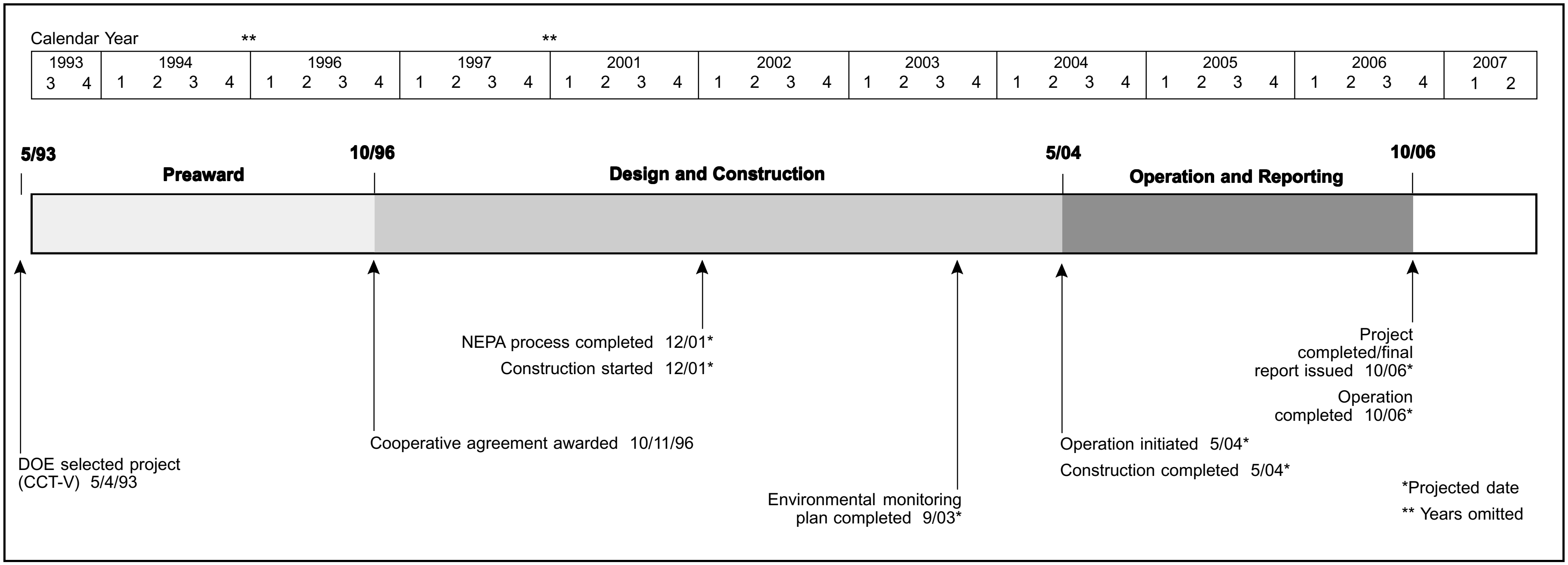
To demonstrate the integration of direct iron making with the coproduction of electricity using various U.S. coals in an efficient and environmentally responsible manner.

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. 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 is injected into the bath where carbon is dissolved rapidly. The carbon reacts with O_2 (from the 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 is needed to sustain the process and maintain hot metal temperature. This heat is generated by post-combusting the CO and hydrogen from the bath with an O_2-enriched hot air blast from the central top lance. The heat is absorbed by the slag and molten iron droplets, which are returned to the bath by gravity. Droplets in contact with the gas in the post-combustion zone absorb heat, but are shrouded during the descent by ascending reducing gases, which, together with bath carbon, prevent unacceptable levels of FeO in the slag. 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 H_2O, exit the vessel. After scrubbing the reacted gases, the cleaned gases will be combusted to produce 170 MWe of power and can be used to pre-heat and partially reduce the incoming iron ore.

HIsmelt is a registered trademark of HIsmelt Corporation Pty Limited.
CPICOR is a trademark of the CPICOR™ Management Company, LLC.



Project Status/Accomplishments

The cooperative agreement was awarded on October 11, 1996. CPICOR™ analyzed the global assortment of new direct iron-making 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 iron-making, 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.

Project definition, preliminary design, and environmental permitting are ongoing. On July 28, 1999, DOE issued a Notice of Intent to prepare an Environmental Impact Statement for the project. A NEPA public scoping meeting was held in Provo, Utah on July 15, 1999.

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 is expected to emerge from Chapter 11 bankruptcy in early 2001 with a restructured balance sheet that enables full participation in this demonstration project.

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 iron-making technology.

The HIsmelt® process is ready for demonstration. Two pilot plants have been built, one in Germany in 1984 and one in Kwinana, 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.

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 process using a multiple resonance-tube pulse combustor.

Plant Capacity/Production
30 million Btu/hr (steam reformer)

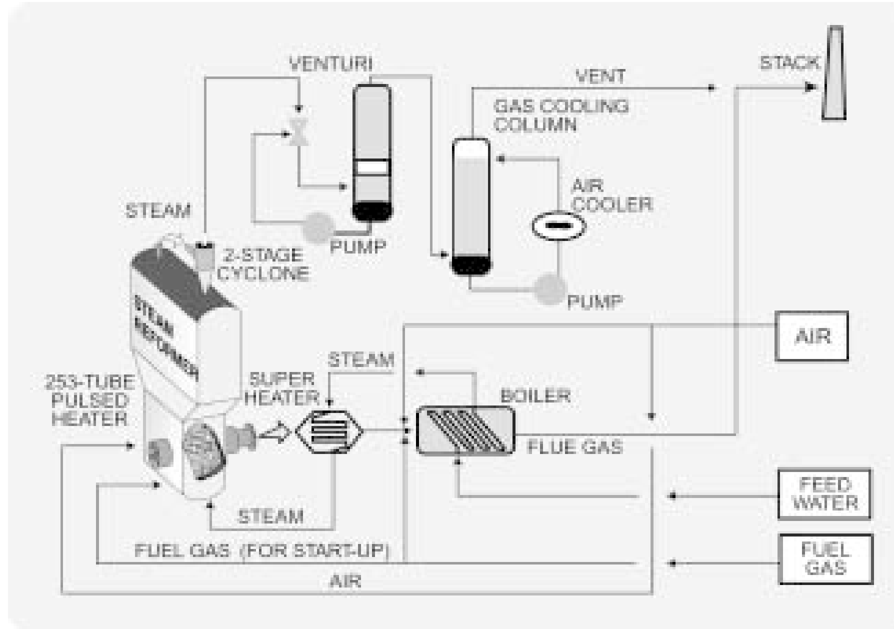
Coal
Black Thunder (Powder River Basin) subbituminous

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 Data Unit.

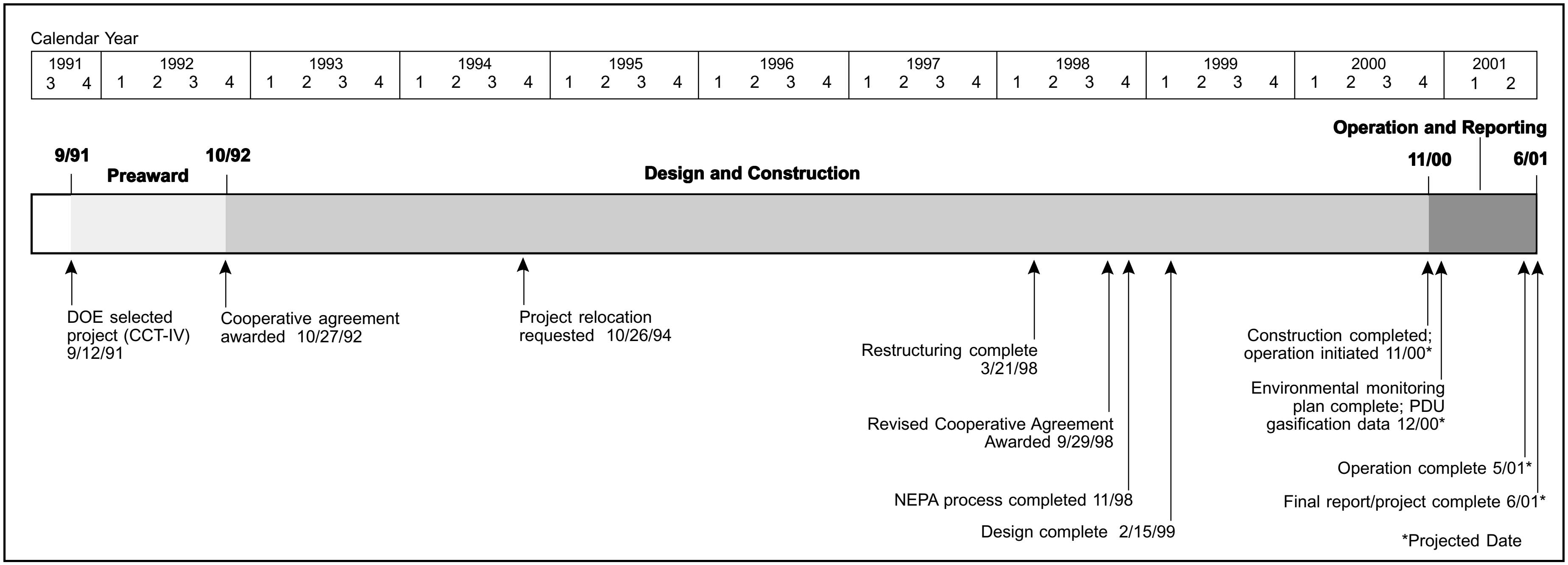
Technology/Project Description
MTCI's Pulsed Enhanced™ Steam Reforming process incorporates an indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu content fuel gas without the need for an oxygen plant. Indirect heat transfer is provided by immersing a multiple resonance-tube pulse combustor in a fluidized-bed steam gasification reactor. Pulse combustion increases the 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 Pulsed Enhanced™ 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 3.5:1 scale-up from previous tests. Testing will seek to verify scale-up criteria and appropriateness of controls and instrumentation. Also, an existing process data unit will be used to gasify coal feedstock to provide fuel gas data, including energy content, species concentration, and yield. Char from the process data unit 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.

Pulsed Enhanced is a trademark of MTCI.



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.

Construction of the 253-resonance-tube combustor unit is continuing. Operation is expected to begin in November 2000. Shakedown tests of the process data unit were conducted in April 2000. Following modifications to improve operability, PDU tests with Black Thunder subbituminous coal are expected to be completed in December 2000.

Commercial Applications

PulsedEnhanced™ Steam Reforming has application in many different processes. Coal, with world production on the order of four billion tons per year, constitutes the largest potential feedstock for steam reforming. Other potential feedstocks include spent liquor from pulp and paper mills, refuse-derived fuel, municipal solid waste, sewage sludge, biomass, and other wastes.

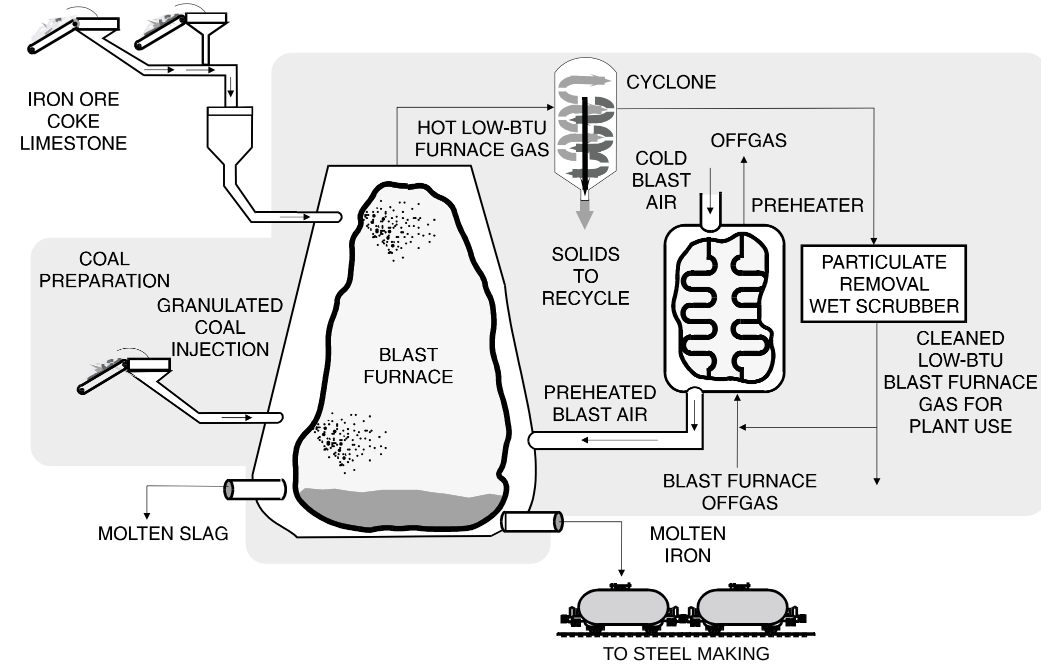
Although the project will demonstrate mild gasification only, the following coal-based applications are envisioned:

- 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,
- Coprocessing 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.

Blast Furnace Granular-Coal Injection System Demonstration Project

Project completed.



Participant

Bethlehem Steel Corporation

Additional Team Members

British Steel Consultants Overseas Services, Inc. (marketing arm of British Steel Corporation)—technology owner

Clyde Pneumatic (formerly named Simon-Macawber, Ltd.)—equipment supplier

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)

Technology

British Steel and Clyde Pneumatic blast furnace granular-coal injection (BFGCI) process

Plant Capacity/Production

7,000 net tons of hot metal (NTHM)/day requiring 2,800 tons/day of coal (each blast furnace)

Coal

Virginia Pocahontas/Buchanan; 0.76% S, 86.39% C
Oxbow; 0.76% S, 73.2% C

Project Funding

Total project cost	$194,301,790	100%
DOE	31,824,118	16
Participant	162,477,672	84

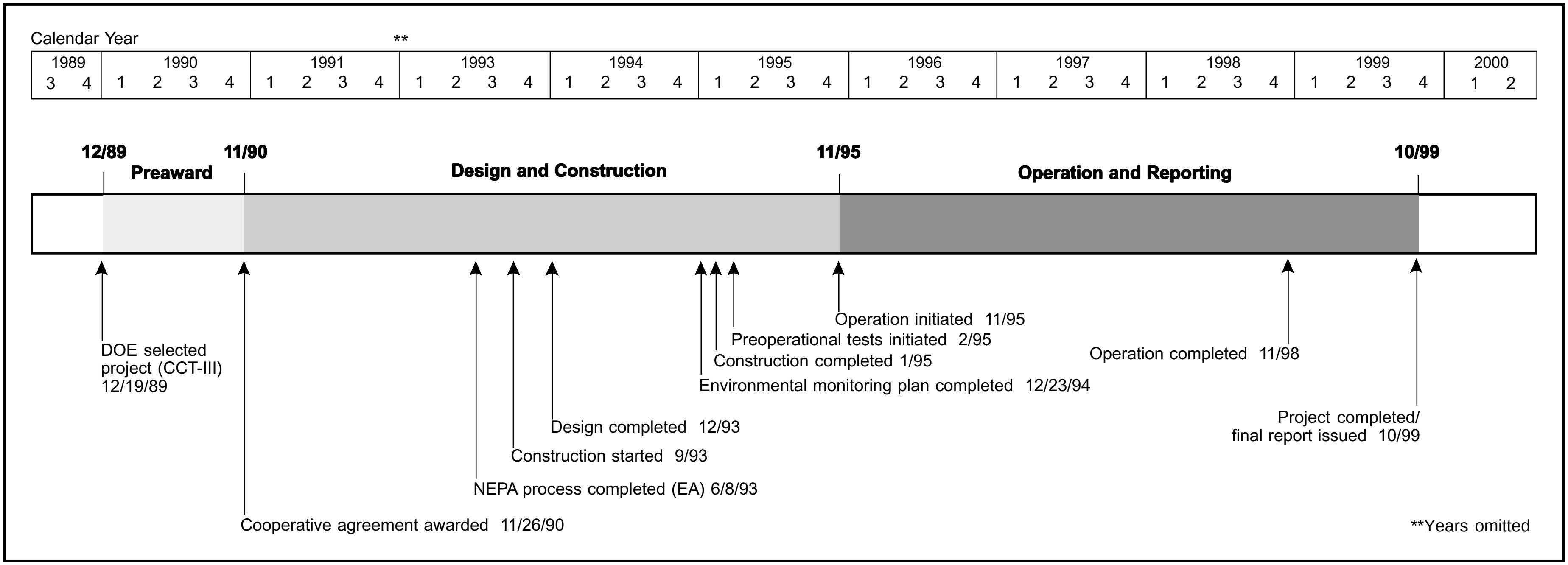
Project Objective

To demonstrate that granular coal could effectively displace coke and maintain established blast furnace production rates and quality specifications; to determine the effect of coal chemistry, such as ash content (quantity and sulfur levels) and volatile levels, on blast furnace performance; and to evaluate the economics of granular coal injection relative to natural gas injection.

Technology/Project Description

The BFGCI process uses granular coal, which requires significantly less grinding energy than pulverized coal to produce. The coal, along with heated air, is blown into the lower part of the blast furnace through passages called tuyeres, which create swept zones in the furnace called raceways. This preheated blast air provides partial oxidation of the coke introduced along with the iron ore and limestone at the top of the furnace. The coke serves as the primary fuel and reducing agent for the process. The carbon reacts with the air and the iron oxide ore to produce heat, iron, and carbon monoxide. The limestone acts as a fluxing agent, creating a slag to capture mineral constituents such as sulfur and silicon not wanted in the product. The low-Btu gas leaving the furnace is essentially free of sulfur and is used to preheat blast air and fire a boiler for on-site power.

Bethlehem Steel introduced coal injection primarily to reduce the amount of coke needed in the blast furnace, which also replaced the natural gas normally injected in the tuyeres for supplemental fuel. High levels of air toxics emissions result from coke production requiring extensive, expensive control systems. Bethlehem Steel retrofitted Units C and D at its Burns Harbor facility, both rated at 7,000 NTHM/day. The project sought to determine the effect of coal size and chemical composition on process performance and economics.



Results Summary

Environmental

- BFGCI technology, using low-volatile, low-ash coal, displaced up to 0.96 pounds of coke for every pound of coal, which avoids the air toxics emissions associated with comparable coke production. By adjusting blast furnace slag, no additional sulfur emissions resulted from the coal injection, and sulfur levels in the product remained within the specified range.

Operational

- Granular coal performed as well as pulverized coal on the large blast furnaces and proved easier to handle than pulverized coal, which tended to plug when using low-volatile coals. Direct comparative testing on a specific coal showed that 60% less energy is consumed in granulating coal than in pulverizing coal.
- Coal injection decreased furnace permeability, which can adversely affect hot blast flow rate and furnace productivity, but increasing oxygen enrichment and moisture content returned permeability and productivity to acceptable levels. Low-volatile coal replaced significantly more coke than lower carbon content, high-volatile coal, which was a major objective and also a measure of the quality of the overall operation. Using low-volatile Virginia Pocahontas coal, the coke rate was reduced from approximately 740 lb/NTHM to 661 lb/NTHM.
- There is a coke rate disadvantage of 3 lb/NTHM for each one percent increase in ash content at an injection rate of 260 lb/NTHM. Higher ash coal had no adverse effect on furnace permeability, productivity, or product quality, but the slag volume increased.

Economic

- The capital cost for one complete injection system at Burns Harbor was $15,073,106 (1990$) for the 7,200 NTHM/day blast furnace. The total fixed costs (labor and repair costs) at Burns Harbor were $6.25/ton of coal. The total variable costs (water, electricity, natural gas, and nitrogen) were $3.56/ton of coal. Coal costs were $50-60/ton. At a total cost of $60/ton and a natural gas cost of $2.80/10^6 Btu, the iron cost savings would be about $6.50/ton of iron produced. Based on the Burns Harbor production of 5.2 million tons of iron per year, the annual savings is about $34 million.

Project Summary

Bethlehem Steel retrofitted two high-capacity blast furnaces with BFGCI technology, Units C and D, at their Burns Harbor facility in a successful attempt to reduce coke use and become a self-sufficient supplier. The questions posed in applying the technology went to the effect of coal grind (size) and coal chemistry on coke displacement and furnace performance. A coal pulverizer in lieu of a less energy- and capital-intensive hammer mill, was used to provide a range of coal grinds from granular (30% passing 200 mesh) to pulverized (80% passing 200 mesh). Each 7,000-NTHM/day furnace required approximately 2,800 tons/day of coal. Each BFGCI unit included a raw coal reclaim area and two 240-ton enclosed storage bins, a 500-Hp Williams variable speed coal-grinding mill and integrated dryer, two 180-ton product coal silos designed to exclude oxygen, two distribution bins each with 14 conical pant leg distributors, 28 injectors with lock hoppers and metered screw feeders, and a high-pressure air system transporting the coal 600 feet to injection lances mounted on 28 separate tuyeres.

Operational Performance

Initial steady-state testing involved operation on granulated (15% passing 200 mesh) Virginia Pocahontas low-ash, low-volatile, high-carbon coal in the Unit C furnace. This coal was selected as the baseline coal after a series of trials on different coal types. An average coal injection rate of 264 lb/NTHM was achieved over the baseline October 1996 performance period. The furnace coke rate during the period was 661 lb/NTHM, down from 740 lb/NTHM when operating on natural gas.

Increasing slag volume in the furnace controlled the additional sulfur and silicon loading from the coal injection to specified levels in the hot metal product. The slag also captured sufficient sulfur to prevent any additional sulfur in the furnace gas output. An adverse downturn in furnace permeability resulting from coal injection was moderately increased and compensated for by increasing the oxygen enrichment from 24.4–27.3% and increasing steam input from 3.7 grains/scf to 19.8 grains/scf. The permeability adjustments enabled furnace productivity to be maintained.

To determine the coal/coke replacement ratio, all factors impacting on coke rate other than coal injection had to be removed from the equation. After doing so, the adjusted furnace coke rate shows that one pound of Virginia Pocahontas baseline coal displaces 0.96 pounds of coke. The next test addressed the impact of ash volume on coke displacement and furnace performance. To do so, only the percentage of ash was increased, not the coal or ash chemistry. This was done by eliminating a coal cleaning step on the Pocahontas Seam coal (obtained from the Buchanan Mine), which increased the ash content from 5.3–7.7%. Tests showed that there is a coke rate disadvantage of 3 lb/NTHM for each one percentage point increase in coal ash content at an injection rate of 260 lb/NTHM; and the higher ash coal had no adverse impact on furnace permeability, productivity, or product quality.

Comparative testing followed to evaluate the effect of coal grind size (granular versus pulverized) on coke displacement and furnace performance as well as the effects of coal chemistry. Furnace D was used because of some temporary operating difficulties on Furnace C. A high-volatile, low-carbon Oxbow western coal was used in lieu of the baseline coal because of plugging problems experienced when pulverizing the baseline low-volatile coal and because there was the need to evaluate the impact of high-volatile coal on furnace performance. The Oxbow coal averaged 73.2% carbon and 11.2% ash versus 86.3% carbon and 5.3% ash for the baseline coal. The granular Oxbow coal grind was 15% passing 200 mesh and the pulverized Oxbow coal grind was 74% passing 200 mesh. Granular coal production required 60% less energy (19.6 kWh/ton) than pulverized coal production (31.4 kWh/ton). The grinding mill production rate for pulverizing the coal limited the coal injection rate to 183 lb/NTHM. After adjusting for the lower coal injection rate and other factors, it was determined that the coke rate when using the Oxbow coal was 46 lb/NTHM higher than when using the low-volatile baseline coal during tests—a substantial disadvantage. The blast furnace performance was unaffected by whether the coal was pulverized or granular at the coal injection rate of 183 lb/NTHM.

Environmental Performance

Data collected over each test period show that the use of injected coal in the blast furnace does not cause an increase in the sulfur content of the gas for coals averaging 0.76% sulfur. Evidence suggests that adjustments to slag volume and chemistry could effectively handle higher sulfur coals. However, the greatest benefit derived from application of the BFGCI technology is the reduction in coke usage. Coke production is air toxics intensive and to be avoided if at all possible. With the application of the BFGCI technology, Bethlehem Steel can maintain steel production with the limited coke production currently on site.

Economic Summary

Capital cost for one complete injection system at Burns Harbor was approximately \$15 million (1990\$). This does not include infrastructure improvements, which cost \$87 million at Burns Harbor. The fixed operating cost, which includes labor and repair costs, was \$6.25/ton of coal. The variable operating cost, which includes water, electricity, natural gas, and nitrogen, was \$3.56/ton of coal. Coal costs were \$50–60/ton. This brought the total operating costs to \$59.81–69.81/ton of coal. Using \$60/ton of coal and a natural gas cost of \$2.80/10^6 Btu, the cost savings would be about \$6.50/ton of iron produced. At Burns Harbor, which produces 5.2 million tons of iron per year, the annual savings would be about \$34 million and the payback period 3.44 years, using a simple rate of return calculation.

Commercial Applications

There are 35 operating blast furnaces in the United States. Seventeen of them are already using some type of coal injection. An extensive market analysis conducted by Bethlehem Steel showed that 18 of the 35 blast furnaces have the potential to utilize a BFGCI system. In August 1994, U.S. Steel Group contracted with ATSI and Clyde Pneumatic for the installation of a BFGCI unit at their Fairfield Works in Alabama, Blast Furnace #8. The unit, which began operating in 1995, is similar to Bethlehem's except that no added coal grinding facility was needed to meet the granular coal sizing requirements. Fairfield Works Blast Furnace #8 produces 6,300 NTHM/day. The BFGCI installation cost at Fairfield was $20.2 million, with an additional $5.5 million required to build a coal load-out facility.

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- Hill, D.G. *et al.* "Blast Furnace Granular-Coal Injection System Demonstration Project." *Sixth Clean Coal Conference Proceedings: Volume II—Technical Papers.* April–May, 1998.

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

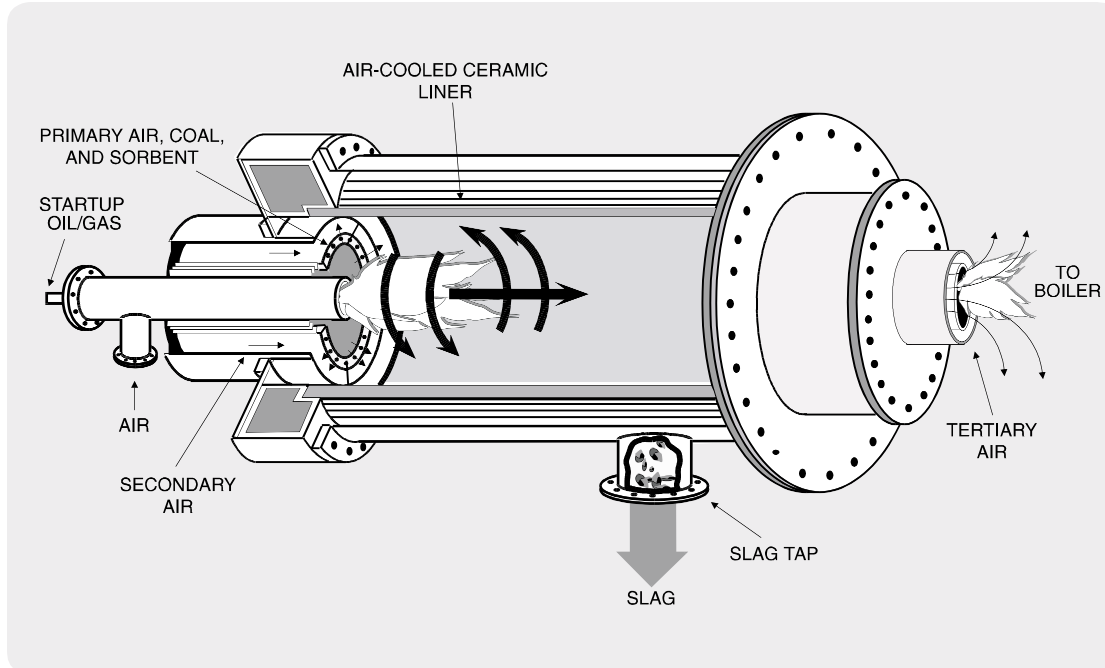
Plant Capacity/Production
23 x 10^6 Btu/hr of steam

Coal
Pennsylvania bituminous, 1.0–3.3% sulfur

Project Funding

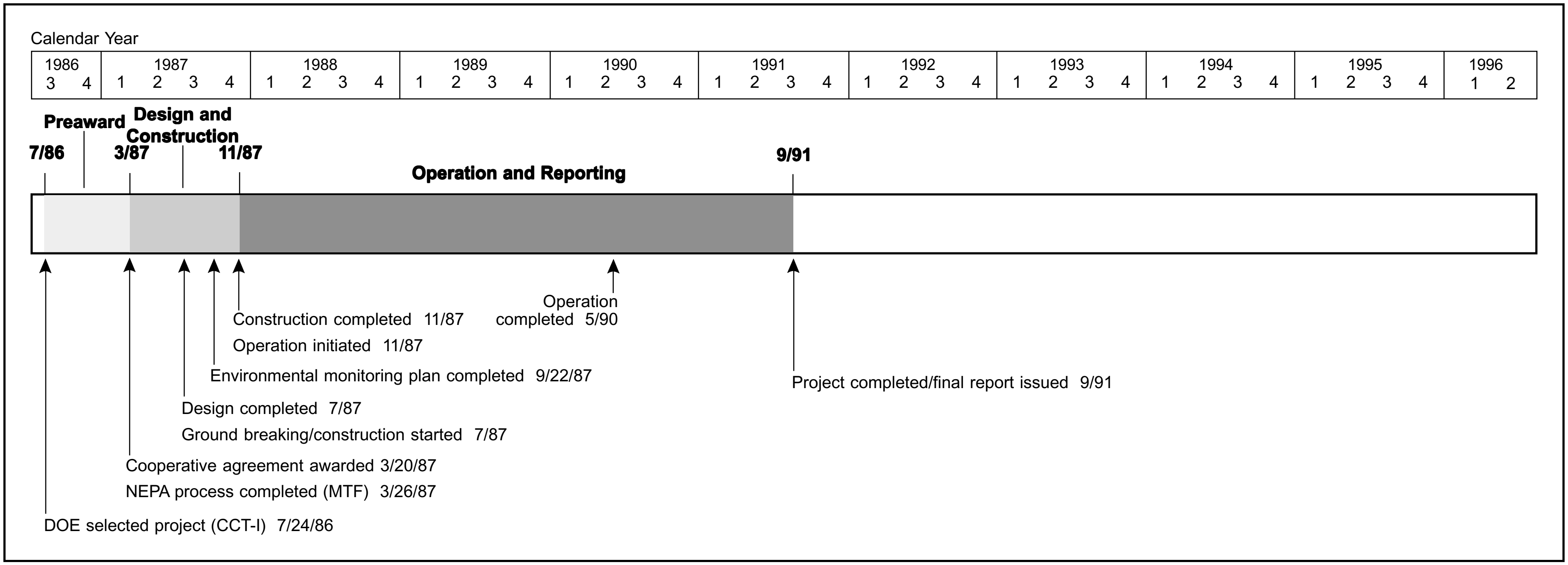
Total project cost	$984,394	100%
DOE	490,149	50
Participant	494,245	50

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 lined with an air-cooled ceramic. 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 so that a high percentage of the ash and sorbent fed to the combustor is retained 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 optimal 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-fired 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 one-third 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

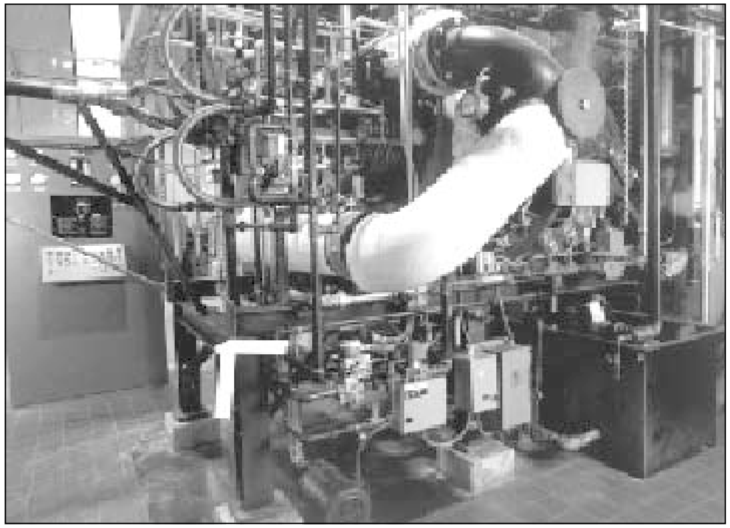
- Combustion efficiencies of over 99% were achieved.
- A 3-to-1 combustor turndown capability was demonstrated. Protection of combustor refractory with slag was shown to be possible.
- A computer-controlled system for automatic combustor operation was developed and demonstrated.

Economic

- Because the technology failed to meet commercialization criteria, economics were not developed during the demonstration. However, subsequent efforts indicate that the incremental capital cost for installing the coal combustor in lieu of oil or gas systems is $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 one-third 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%. After the CCT project, tests on fly ash 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 6×10^6 Btu/hr from a peak of 19×10^6 Btu/hr (or a 3-to-1 turndown) was achieved. The maximum heat input during the tests was around 20×10^6 Btu/hr, even though the combustor was designed for 30×10^6 Btu/hr and the boiler was thermally rated at around 25×10^6 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 20×10^6 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 fly ash vitrification test 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 a project objective. Not only were procedures for properly operating an air-cooled combustor developed, but the entire operating database was incorporated into a computer-controlled system for automatic combustor operation.

Commercial Applications

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.

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- *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 an aggregate and 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 ton/day of cement; 250,000 scfm of kiln gas; and up to 274 ton/day of coal

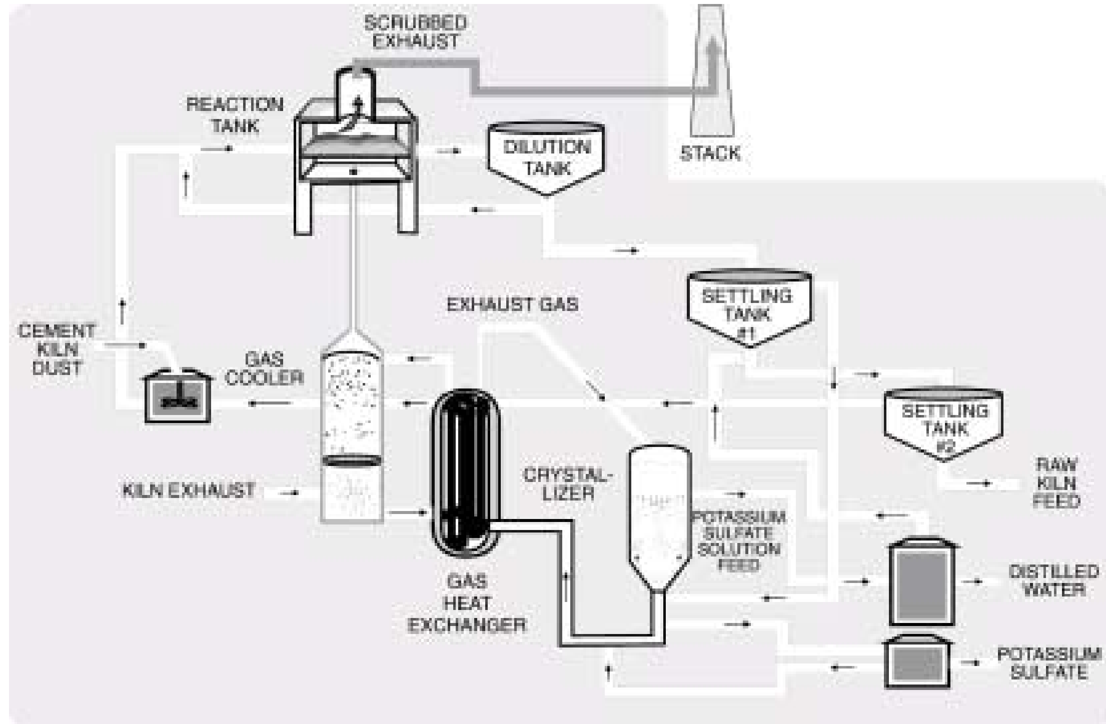
Coal
Pennsylvania bituminous, 2.5–3.0% sulfur

Project Funding

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

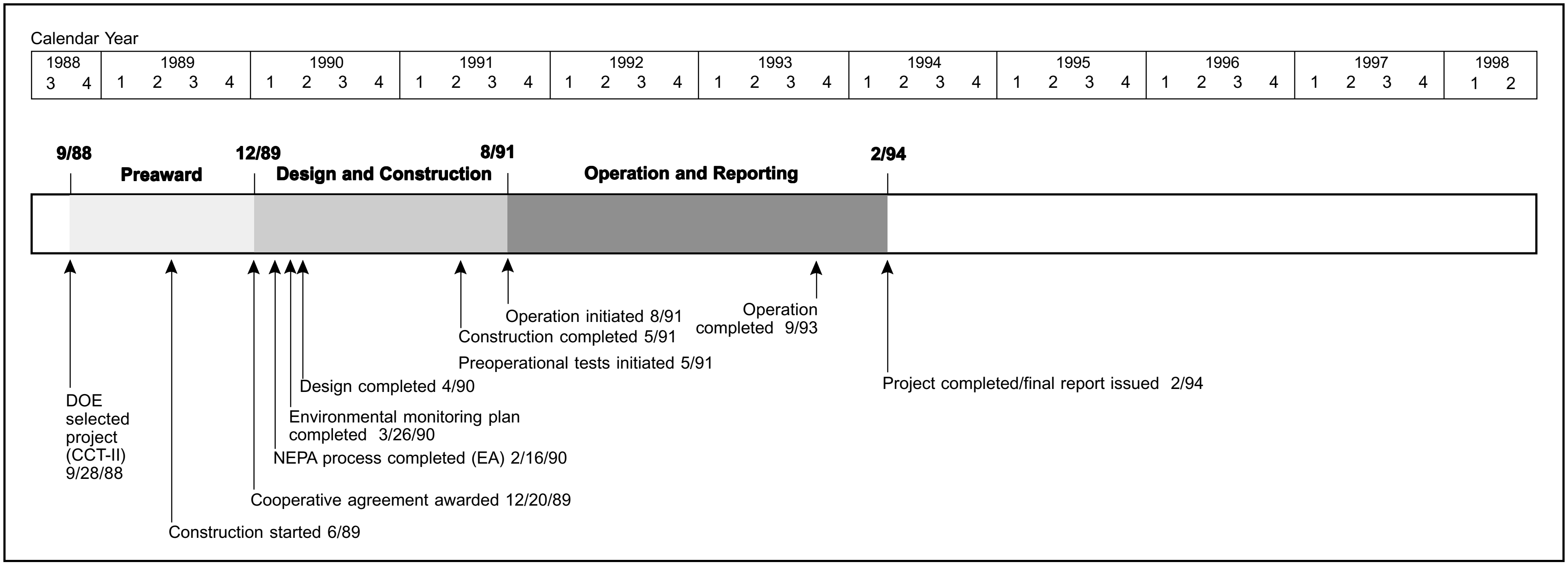
Project Objective
To retrofit and demonstrate a full-scale industrial scrubber and waste recovery system for a coal-burning wet process cement kiln using waste dust as the reagent to accomplish 90–95% SO_2 reduction using high-sulfur eastern coals; and to produce a commercial by-product, potassium-based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

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



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 Company cement 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 plant in Thomaston, Maine, a plant that can process approximately 450,000 ton/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.



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, which 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 one-tenth 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.
- Operation 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 were 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 startup. 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 completed 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 ton/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 ton/hr, was renovated and returned to the plant as feedstock and mixed with about 90 ton/hr of fresh feed to make up the required 100 ton/hr. The alkali in the CKD was converted to potassium-based fertilizer, eliminating all solid waste. Exhibit 5-50 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.

Exhibit 5-50
Summary of Emissions and Removal Efficiencies

Operating Period	Operating Time (hr)	Inlet (lb/hr) SO_2	Inlet (lb/hr) NO_x	Outlet (lb/hr) SO_2	Outlet (lb/hr) NO_x	Removal Efficiency (%) SO_2	Removal Efficiency (%) 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, Maine.

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 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 one-tenth the current allowable limit.

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 is required.

The simple payback on the investment is projected in as little as 3.1 years 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. 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 ton/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 ton/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.

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Appendix A: Historical Perspective and Legislative History

Historical Perspective

There were a number of key events that prompted creation of the CCT Program and impacted its focus over the course of the five solicitations. The roots of the CCT Program can be traced to the acid rain debates of the early 1980s, culminating in U.S. and Canadian envoys recommending a five-year, $5 billion U.S. effort to curb precursors to acid rain formation—SO_2 and NO_x. This recommendation was adopted and became a Presidential initiative in March 1987.

As a part of the response to the recommendations of the *Special Envoys on Acid Rain* in April 1987, the President directed the Secretary of Energy to establish a panel to advise the President on innovative clean coal technology activities. This panel was the Innovative Control Technology Advisory Panel. As a part of the panel's activities, the state and federal incentive subcommittee prepared a report, *Report to the Secretary of Energy Concerning Commercialization Incentives,* that addressed actions that states could take to provide incentives for demonstrating and deploying clean coal technologies. The panel determined that demonstration and deployment should be managed through both state and federal initiatives.

In the same time frame, the Vice President's Task Force on Regulatory Relief (later referred to as the Presidential Task Force on Regulatory Relief) was established. Among other things, the task force was asked to examine incentives and disincentives to the commercial realization of new clean coal technologies. The task force also examined cost-effective emissions reduction measures that might be inhibited by various federal, state, and local regulations. The task force recommended that preference be given to projects located in states that offer certain regulatory incentives to encourage such technologies. This recommendation was accepted and became part of the project selection considerations beginning with CCT-II.

Initial CCT Program emphasis was on controlling SO_2 and NO_x emissions from existing coal-based power generators. Approaches demonstrated through the program were coal processing to produce clean fuels, combustion modification to control emissions, postcombustion cleanup of flue gas, and repowering with advanced power generation systems. These early efforts (projects resulting from the first three solicitations) produced a suite of cost-effective compliance options available today to address acid rain concerns.

As the CCT Program evolved, work began on drafting what was to become the Clean Air Act Amendments of 1990. Through a dialog with EPA and Congress, the program was able to remain responsive to shifts in environmental emphasis. Also, projects in place enabled CAAA architects to have access to real-time data on emission control capabilities while structuring proposed acid rain regulations under Title IV of the CAAA.

Aside from acid rain, there was an emerging issue in the area of hazardous air pollutants (HAPs), also referred to as air toxics. Title III of the CAAA listed 189 airborne compounds subject to control, including trace elements and volatile and semi-volatile compounds. To assess the impacts on coal-based power generation, CCT Program projects were leveraged to obtain data through an integrated effort among DOE, EPA, EPRI, and the Utility Air Regulatory Group. Through this effort, concerns about HAPs relative to coal-based power generation have been significantly mitigated, enabling focus on but a few flue gas constituents. Also, because NO_x is a precursor to ozone formation, the presence of NO_x in ozone nonattainment areas, even at low levels, became an issue. This precipitated action in the CCT Program to include technologies capable of deep NO_x reduction in the portfolio of technologies sought.

In the course of the last two solicitations of the CCT Program, a number of energy and environmental considerations combined to change the emphasis toward seeking high-efficiency, very-low-emission power generation technology. Energy demand projections in the United States showed the need for continued reliance on coal-based power generation, with significant growth required into the 21st century. The CAAA, however, capped SO_2 emissions at year 2000 levels, and NO_x continued to receive increased attention relative to ozone nonattainment. Furthermore, particulate emissions were coming under increased scrutiny because of correlations with lung disorders and the tendency for toxic compounds to adhere to particulate matter. Added to these concerns was the growing concern over global warming, and more specifically, the CO_2 produced from burning fossil fuels. Coal became a primary target because of the high carbon-to-hydrogen ratio relative to natural gas, resulting in somewhat higher CO_2 emissions per unit of energy produced. However, coal is the fuel of choice (if not necessity) for many developing countries where projected growth in electric power generation is the greatest. The path chosen to respond to these considerations was to pursue advanced power generation systems that could provide major enhancements in efficiency and control SO_2, NO_x, and particulates without introducing external parasitic control devices. (Increased efficiency translates to less coal consumption per unit of energy produced.) As a result, a number of advanced power generation projects were undertaken, representing pioneer efforts recognized throughout the world.

Legislative History

The legislation authorizing the CCT Program is found in Public Law 98-473, Joint Resolution Making Continuing Appropriations for Fiscal Year 1985 and for Other Purposes. Title I set aside $750 million of the congressionally rescinded $5.375 billion of the Synthetic Fuels Corporation into a special U.S. Treasury account entitled the "Clean Coal Technology Reserve." This account was dedicated to "conducting cost-shared clean coal technology projects for the construction and operation of facilities to demonstrate the feasibility of future commercial applications of such technology." Title III of this act directed the Secretary of Energy to solicit statements of interest in and proposals for clean coal projects. In keeping with this mandate, DOE issued a program announcement, which resulted in the receipt of 176 proposals representing both domestic and international projects with a total estimated cost in excess of $8 billion.

After this significant initial expression of interest in clean coal demonstration projects, Public Law 99-190, enacted December 1985, appropriated $400 million to conduct cost-shared demonstration projects. Of the total appropriated funds, approximately $387 million was made available for cost-shared projects to be selected through a competitive solicitation, or Program Opportunity Notice (PON), referred to as CCT-I. (The remaining funds were required for program direction and the legislatively mandated Small Business Innovation Research Program [SBIR] and Small Business Technology Transfer Program [STTR].)

In a manner similar to the initiation of CCT-I, Congress again directed DOE to solicit information from the private sector in the Department of the Interior and Related Agencies Appropriations Act for FY1987 (Public Law 99-591), enacted October 30, 1986). The information received was to be used to establish the level of potential industrial interest in another solicitation, this time involving clean coal technologies capable of retrofitting, repowering, or modernizing existing facilities. Projects were to be cost-shared, with industry sharing at least 50 percent of the cost. As a result of the solicitation, a total of 39 expressions of interest were received by DOE in January 1987.

On March 18, 1987, the President announced the endorsement of the recommendations of the Special Envoys on Acid Rain, including a $2.5 billion government share of funding for industry/government demonstrations of innovative control technology over a five-year period. The Secretary of Energy stated that the department would ask Congress for an additional $350 million in FY1988 and an advanced appropriation of $500 million in FY1989. Additional appropriations of $500 million would be requested in fiscal years 1990, 1991, and 1992. This request was made by the President on April 4, 1987.

Public Law 100-202, enacted December 22, 1987, as amended by Public Law 100-446, appropriated a total of $575 million to conduct CCT-II. About $536 million was for projects, with the remainder for program direction and the SBIR and STTR Programs.

The Department of the Interior and Related Agencies Appropriations Act for FY1989 (Public Law 100-446, enacted September 27, 1988) provided $575 million for necessary expenses associated with clean coal technology demonstrations in the CCT-III solicitation. Of the total funding, about $546 million was made available for cost-sharing projects, with the remainder for program direction and the SBIR and STTR Programs. The act continued the requirement that proposals must demonstrate technologies capable of retrofitting or repowering existing facilities. The statute also authorized the use of Tennessee Valley Authority power program funds as a source of nonfederal cost-sharing, except if provided by annual appropriations acts. In addition, funds borrowed by Rural Electrification Administration (now Rural Utilities Service) electric cooperatives from the Federal Financing Bank became eligible as cost-sharing in the CCT-III solicitation, except if provided by annual appropriations.

In the Department of the Interior and Related Agencies Appropriations Act of 1990 (Public Law 101-121, enacted October 23, 1989), Congress provided $600 million for the CCT-IV solicitation. CCT-IV, according to the act, "shall demonstrate technologies capable of replacing, retrofitting, or repowering existing facilities and shall be subject to all provisos contained under this head in Public Laws 99-190, 100-202 and 100-446 as amended by this Act." About $563 million was made available for federal cofunding of projects selected in CCT-IV, with the remainder for program direction and the SBIR and STTR Programs.

In Public Law 101-121, enacted October 23, 1989, Congress also provided $600 million for the CCT-V solicitation. CCT-V, according to the act, "shall be subject to all provisos contained under this head in Public Laws 99-190, 100-202 and 100-446 as amended by this Act." Approximately $568 million was made available for federal cofunding of projects to be selected in this solicitation, with the remainder again for program direction and the SBIR and STTR Programs.

Subsequent acts (Public Laws 101-164, 101-302, 101-512, and 102-154) modified the schedule for issuing CCT-IV and/or CCT-V PONs and selecting projects. In Public Law 101-512, Congress directed DOE to issue the PON for CCT-IV not later than February 1, 1991, with selections to be made within 8 months. In Public Law 102-154, Congress directed DOE to issue CCT-V PON not later than July 6, 1992, with selections to be made within 10 months. This later act also directed that CCT-V proposals should advance significantly the efficiency and environmental performance of coal-using technologies and be applicable to either new or existing facilities.

Public Laws 101-164, 101-302, 101-512, 103-138, and 103-332 adjusted the rate at which funds were to be made available to the program.

CCT Program funds have been further adjusted through sequestering requirements of the Gramm-Rudman-Hollings Deficit Reduction Act as well as rescissions. Sequestering reduced CCT Program appropriations as follows:

- $2.4 million was sequestered from the $400 million appropriated by Public Law 99-190.
- $2,600 was sequestered from the $575 million appropriated by Public Law 100-202, as amended by Public Law 100-446.
- $2,028 was sequestered from the $575 million appropriated by Public Law 100-446, as amended by Public Law 101-164.
- $455 was sequestered from the $1.2 billion appropriated by Public Law 101-121, as amended by Public Laws 101-512, 102-154, 102-381, 103-138, 103-332, 104-6, 104-208, and 105-18.

Rescissions have reduced CCT Program appropriations as follows:

- $200 million was rescinded by Public Law 104-6.
- $123 million was rescinded by Public Law 104-208.
- $17 million was rescinded by Public Law 105-18.
- $101 million was rescinded by Public Law 105-83.
- $38,000 was rescinded by Public Law 106-113 (general reduction).

In 1998, $40 million of the CCT program funds were deferred by Public Law 105-277. Funds will be restored over a three-year period beginning October 1, 1999. Again in 1999, Congress deferred program funds. In Public Law 106-113, Congress deferred $156,000,000 until October 1, 2000. And again in 2000, Congress deferred $67,000,000 until October 1, 2001.

Exhibit A-1 lists all the key legislation relating to the CCT Program and provides a summary of provisions relating to program funding as well as program implementation. Following this exhibit are funding provisions excerpted from appropriations and other relevant funding-related acts.

Exhibit A-1
CCT Program Legislative History

Public Law	Date Enacted	CCT Round	Program Funding	Implementation Provisions
98-473	10/12/84	Initiation of CCT Program; informational solicitation	Rescinded $750 million of $5.375 billion from the Energy Security Reserve (Synthetic Fuels Corporation) to be deposited in a U.S. Treasury Department account entitled "Clean Coal Technology Reserve" for conducting cost-shared CCT projects for the construction and operation of facilities to demonstrate the feasibility for future commercial application of such technology, without fiscal year limitation, subject to subsequent annual appropriation.	Title III required publication of a notice soliciting statements of interest in and proposals for projects employing emerging CCTs. A report to Congress was required no later than 4/15/85.
99-88	8/15/85		Deferred $1.6 million for obligation until 10/1/85.	Conference Report (H. Rep. 99-236) concurred with CCT project guidelines contained in Senate Report 99-82, with certain modifications.
99-190	12/19/85	CCT-I	Conference Report (H. Rep. 99-450) agreed to a $400-million CCT Program as described under the U.S. Treasury Department Energy Security Reserve, with the request for proposals to be for the full $400 million.	Required a PON (CCT-I) to be issued and projects to be selected no later than 8/1/86. Project cost-sharing provisions were detailed.
99-591	10/30/86	Second informational solicitation	(Contained no funding provisions for CCT Program)	Title II required publication of a notice soliciting statements of interest in, and informational proposals for projects employing emerging CCTs capable of retrofitting, repowering, or modernizing existing facilities. A report to Congress was required no later than 3/6/87.
100-202	12/22/87	CCT-II	Appropriated $50 million for FY beginning 10/1/87 until expended and $525 million for FY beginning 10/1/88 until expended.	Required a request for proposals (CCT-II) to be issued no later than 60 days following enactment, for emerging CCTs capable of retrofitting or repowering existing facilities. Extended project selection from 120 days to 160 days after receipt of proposals. Provided for cost-sharing of pre-award costs for preparation and submission of environmental data upon signing of the cooperative agreement. Conference Report (H. Rep. 100-498) provided that project cost-sharing funds be made available to nonutility as well as utility applications. No funds were made available for new, stand-alone applications. House Report 100-171 and Senate Report 100-165 outlined provisions for participants to repay government contributions.

Exhibit A-1 (continued)
CCT Program Legislative History

Public Law	Date Enacted	CCT Round	Program Funding	Implementation Provisions
100-446	9/27/88	CCT-III	Made available $575 million on 10/1/89 until expended. Pub. L. 100-202 was amended by striking $525 million and inserting $190 million for FY beginning 10/1/88 until expended, $135 million for fiscal year beginning 10/1/89 until expended, and $200 million for FY beginning 10/1/90 until expended, provided that outlays for FY89 resulting from use of funds appropriated under Pub. L. 100-202, as amended, did not exceed $15.5 million.	Request for proposals (CCT-III) to be issued by 5/1/89 for emerging CCTs capable of retrofitting or repowering existing facilities. Proposals were to be due 120 days after issuance of the PON; projects were to be selected no later than 120 days after receipt of proposals. Funds borrowed by REA electric cooperatives from the Federal Financing Bank were made eligible as cost-sharing. Funds derived by the Tennessee Valley Authority from its power program were deemed allowable as cost-sharing except if provided by annual appropriations acts.
101-45	6/30/89	CCT-III	Funds appropriated for FY1989 were made available for a third solicitation.	Project selections for the third solicitation were to be made not later than 1/1/90.
101-121	10/23/89	CCT-IV and CCT-V	Made available $600 million on 10/1/90 until expended and $600 million on 10/1/91 until expended. Pub. L. 100-446 was amended by striking $575 million and inserting $450 million to be made available on 10/1/89 until expended and $125 million to be made available on 10/1/90. Unobligated balances excess to the needs of the procurement for which they originally were made available may be applied to other procurements for which requests for proposals had not yet been issued, except that no supplemental, backup, or contingent selection of projects could be made over and above the projects originally selected.	Two solicitations (CCT-IV and CCT-V) to be issued, one for each appropriation, to demonstrate technologies capable of replacing, retrofitting, or repowering existing facilities, subject to all provisos contained in Pub. L. 99-190, 100-202, and 100-446 as amended. The PON (CCT-IV) using funds becoming available on 10/1/90 was to be issued by 6/1/90, with selections made by 2/1/91. The PON (CCT-V) using funds becoming available on 10/1/91 was to be issued no later than 9/1/91, with selections made by 5/1/92.
101-164	11/21/89	CCT-IV and CCT-V	Appropriation for FY1990 was amended by striking $450 million and inserting $419 million and by striking $125 million and inserting $156 million.	Solicitations could not be conducted prior to ability to obligate funds. Repayment provisions for CCT-IV and CCT-V were to be the same as for CCT-III.
101-302	5/25/90	CCT-IV and CCT-V	Obligation of funds previously appropriated for CCT-IV and CCT-V was deferred until 9/1/91.	

Exhibit A-1 (continued)
CCT Program Legislative History

Public Law	Date Enacted	CCT Round	Program Funding	Implementation Provisions
101-512	11/5/90	CCT-IV and CCT-V	Pub. L. 101-121 was amended by striking $600 million made available on 10/1/90 until expended and $600 million made available on 10/1/91 until expended and inserting $600 million made available as follows: $35 million on 9/1/91, $315 million on 10/1/91, and $250 million on 10/1/92, all sums remaining until expended, for use in conjunction with a separate general request for proposals, and $600 million made available as follows: $150 million on 10/1/91, $225 million on 10/1/92, and $225 million on 10/1/93, all sums remaining until expended, for use with a separate general request for proposals.	The CCT-IV solicitation was to be issued not later than 2/1/91. The CCT-V PON was to be issued not later than 3/1/92. Project selections were to be made within eight months of PON's issuance. Repayment provisions were to be the same as for CCT-III. Provisions were included to provide protections for trade secrets and proprietary information. Conference Report (H. Rep. 101-971) recommends changes to program policy factors.
102-154	11/13/91	CCT-V	Pub. L. 102-512 was amended by striking $150 million on 10/1/91 and $225 million on 10/1/92 and inserting $100 million on 10/1/91 and $275 million on 10/1/92.	The CCT-V PON was delayed to not later than 7/6/92, with selection to be made within 10 months (extended by two months). The PON was to be for projects that advance significantly the efficiency and environmental performance of coal-using technologies and would be applicable to either new or existing facilities. Conference Report (H. Rep. 102-256) stated expectations that the CCT-V solicitation would be conducted under the same general types of criteria as CCT-IV, principally modified only to (1) include the wider range of eligible technologies or applications; (2) adjust technical criteria to consider allowable development activities, strengthen criteria for nonutility demonstrations, and adjust commercial performance criteria for additional facilities and technologies with regard to aspects of general energy efficiency and environmental performance; and (3) clarify and strengthen cost and finance criteria, particularly with regard to development activities. Funding was allowed for project-specific development activities for process performance definition, component design verification, materials selection, and evaluation of alternative designs on a cost-shared basis up to a limit of 10 percent of the government share of project cost.

Exhibit A-1 (continued)
CCT Program Legislative History

Public Law	Date Enacted	CCT Round	Program Funding	Implementation Provisions
102-154 (continued)				Development activities eligible for cost-sharing included limited modifications to existing facilities for project-related testing but not construction of new facilities.
102-381	10/5/92		Pub. L. 101-512 was amended by striking $250 million on 10/1/92 and inserting $150 million on 10/1/93 and $100 million on 10/1/94; and by striking $275 million on 10/1/92 and $225 million on 10/1/93 and inserting $250 million on 10/1/93 and $250 million on 10/1/94.	
102-486	10/24/92		(Contained no funding provisions for CCT Program)	Section 1301—Coal RD&D and Commercial Applications Programs (Title XIII; Subtitle A) authorized DOE to conduct programs for RD&D and commercial applications of coal-based technologies. Secretary of Energy was directed to submit to Congress (1) a report that included, among other things, recommendations regarding the manner in which the cost-sharing demonstrations conducted pursuant to the Clean Coal Program (Pub. L. 98-473) might be modified and extended in order to ensure the timely demonstration of advanced coal-based technologies and (2) periodic status reports on the development of advanced coal-based technologies and RD&D and commercial application attributes.
103-138	11/11/93		Pub. L. 101-512 was amended by striking $150 million on 10/1/93 and $100 million on 10/1/94 and inserting $100 million on 10/1/93, $100 million on 10/1/94, and $50 million on 10/1/95; and by striking $250 million on 10/1/93 and $250 million on 10/1/94 and inserting $125 million on 10/1/93, $275 million on 10/1/94, and $100 million on 10/1/95.	
103-332	9/30/94		Pub. L. 101-512 was amended by striking $100 million on 10/1/94 and $50 million on 10/1/95 and inserting $18 million on 10/1/94, $100 million on 10/1/95, and $32 million on 10/1/96; and by striking $275 million on 10/1/94 and $100 million on 10/1/95 and inserting $19.121 million on 10/1/94, $100 million on 10/1/95, and $255.879 million on 10/1/96.	An amount not to exceed $18 million available in FY1995 may be used for administrative oversight of the CCT Program.

Exhibit A-1 (continued)
CCT Program Legislative History

Public Law	Date Enacted	CCT Round	Program Funding	Implementation Provisions
104-6	4/10/95		Of funds available for obligation in FY1996, $50 million was rescinded. Of the funds to be made available for obligation in FY1997, $150 million was rescinded.	
104-134[a]	4/26/96			Conference Report (H. Rep. 104-402 to accompany H.R. 1977) allowed for the use of up to $18 million in CCT Program funds for program administration.
104-208[b]	9/30/96		Conference Report (H. Rep. 104-863 to accompany H.R. 3610) noted rescission of $123 million for FY1997 or prior years.	House and Senate committees did not object to use of up to $16 million in available funds for administration of the CCT Program in FY1997 (H. Rep. 104-625 and Senate 104-319 to accompany H.R. 3662).
105-18	6/12/97		Of funds made available for obligation in FY1997 or prior years, $17 million was rescinded.	
105-83	11/14/97		Of funds made available for obligation in FY1997 or prior years, $101 million was rescinded.	
105-277	10/21/98		Of funds made available for obligation in prior years, $40 million was deferred.	Conference Report (H. Rep. 105–825) allowed $14.9 million in CCT Program funds for program administration.
106-113	11/29/99		Of funds made available for obligation in prior years, $156 million was deferred. Also, $38,000 was rescinded as a result of the general reduction.	
106-291	10/11/00		Of funds made available for obligation in prior years, $67 million was deferred.	Conference Report (H. Rep. 106–406) did not object to the use of up to $14.4 million in CCT Program funds for program administration.

[a] H.R. 3019, which became Pub. L. 104-134, replaced H.R. 1977.

[b] H.R. 3610, which became Pub. L. 104-208, replaced H.R. 3662.

Public Law 99-190

Public Law 99-190, 99 Stat. 1251 (1985)

Clean Coal Technology

Within 60 days following enactment of this Act [Dec. 19, 1985] the Secretary of Energy shall, pursuant to the Federal Nonnuclear Energy Research and Development Act of 1974 *(42 U.S.C. 5901,* et seq.), issue a general request for proposals for clean coal technology projects for which the Secretary of Energy upon review may provide financial assistance awards. Proposals for clean coal technology projects under this section shall be submitted to the Department of Energy within 60 days after issuance of the general request for proposals. The Secretary of Energy shall make any project selections no later than August 1, 1986: Provided, That the Secretary may vest fee title or other property interests acquired under cost-shared clean coal technology agreements in any entity, including the United States: Provided further, That the Secretary shall not finance more than 50 per centum of the total costs of a project as estimated by the Secretary as of the date of award of financial assistance: Provided further, That cost-sharing by project sponsors is required in each of the design, construction, and operating phases proposed to be included in a project: Provided further, That financial assistance for costs in excess of those estimated as of the date of award of original financial assistance may not be provided in excess of the proportion of costs borne by the Government in the original agreement and only up to 25 per centum of the original financial assistance: Provided further, That revenues or royalties from prospective operation of projects beyond the time considered in the award of financial assistance, or proceeds from prospective sale of the assets of the project, or revenues or royalties from replication of technology in future projects or plants are not cost-sharing for the purposes of this appropriation: Provided further, That other appropriated Federal funds are not cost-sharing for the purposes of this appropriation: Provided further, That existing facilities, equipment, and supplies, or previously expended research or development funds are not cost-sharing for the purposes of this appropriation, except as amortized, depreciated, or expensed in normal business practice.

Conference Report (H.R. Conf. Rep. No. 450, 99th Cong., 1st Sess. [1985])

Clean Coal Technology

The managers have agreed to a $400,000,000 Clean Coal Technology program as described under the Department of the Treasury, Energy Security Reserve. Bill language is included which provides for the selection of projects no later than August 1, 1986. Within that period, a general request for proposals must be issued within 60 days and proposals must be submitted to the Department within 60 days after issuance of the general request for proposals. Language is also included allowing the Secretary of Energy to vest title in interests acquired under agreements in any entity, including the United States, and delineating cost-sharing requirements. Funds for these activities and projects are made available to the Clean Coal Technology program in the Energy Security program.

It is the intent of the managers that contributions in the form of facilities and equipment be considered only to the extent that they would be amortized, depreciated or expensed in normal business practice. Normal business practice shall be determined by the Secretary and is not necessarily the practice of any single proposer. Property which has been fully depreciated would not receive nay cost-sharing value except to the extent that it has been in continuous use by the proposer during the calendar year immediately preceding the enactment of this Act. For this property, a fair use value for the life of the project may be assigned. Property offered as a cost-share by the proposer that is currently being depreciated would be limited in its cost-share value to the depreciation claimed during the life of the demonstration project. Furthermore, in determining normal business practice, the Secretary should not accept valuation for property sold, transferred, exchanged, or otherwise manipulated to acquire a new basis for depreciation purposes or to establish a rental value in circumstances which would amount to a transaction for the mere purpose of participating in this program.

The managers agree that, with respect to cost-sharing, tax implications of proposals and tax advantages available to individual proposers should not be considered in determining the percentage of Federal cost-sharing. This is consistent with current and historical practices in Department of Energy procurements.

It is the intent of the managers that there be full and open competition and that the solicitation be open to all markets utilizing the entire coal resource base. However, projects should be limited to the use of United States mined coal as the feedstock and demonstration sites should be located within the United States.

The managers agree that no more than $1,500,000 shall be available in FY1986 and $2,000,000 each year thereafter for contracting, travel and ancillary costs of the program, and that manpower costs are to be funded under the fossil energy research and development program.

The managers direct the Department, after projects are selected, to provide a comprehensive report to the Congress on proposals received.

The managers also expect the request for proposals to be or the full $400,000,000 program, and not only for the first $100,000,000 available in fiscal year 1986.

Public Law 100-202

Public Law 100-202, 101 Stat. 1329-1 (1987)

Clean Coal Technology

For necessary expenses of, and associated with, Clean Coal Technology demonstrations pursuant to 42 U.S.C. 5901 et seq., $50,000,000 are appropriated for the fiscal year beginning October 1, 1987, and shall remain available until expended, and $525,000,000 are appropriated for the fiscal year beginning October 1, 1988, and shall remain available until expended.

No later than sixty days following enactment of this Act, the Secretary of Energy shall, pursuant to the Federal Nonnuclear Energy Research and Development Act of 1974 (42 U.S.C. 5901 et seq.), issue a general request for proposals for emerging clean coal technologies which are capable of retrofitting or repowering existing facilities, for which the Secretary of Energy upon review may provide financial assistance awards. Proposals under this section shall be submitted to the Department of Energy no later than ninety days after issuance of the general request for proposals required herein, and the Secretary of Energy shall make any project selections no later than one hundred and sixty days after receipt of proposal: *Provided*, That projects selected are subject to all provisos contained under this head in Public Law 99-190: *Provided further*, That pre-award costs incurred by project sponsors after selection and before signing an agreement are allowable to the extent that they are related to (1) the preparation of material requested by the Department of Energy and identified as required for the negotiation; or (2) the preparation and submission of environmental data requested by the Department of Energy to complete National Environmental Policy Act requirements for the projects: *Provided further*, That pre-award costs are to be reimbursed only upon signing of the project agreement and only in the same ratio as the cost-sharing for the total project: *Provided further*, That reports on projects selected by the Secretary of Energy pursuant to authority granted under the heading “Clean coal technology” in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, which are received by the Speaker of the House of Representatives and the President of the Senate prior to the end of the first session of the 100th Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading “Administrative provision, Department of Energy” in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate.

Conference Report (H.R. Conf. Rep. No. 498, 100th Cong., 1st Sess. [1987])

Clean Coal Technology

Appropriates $575,000,000 for clean coal technology instead of $350,000,000 as proposed by the House and $850,000,000 as proposed by the Senate. The comparison by year is as follows:

	House	Senate	Conference
Fiscal year:			
1988	$50,000,000	$350,000,000	$50,000,000
1989	200,000,000	500,000,000	525,000,000
1990	100,000,000	—	—
Total	**350,000,000**	**850,000,000**	**575,000,000**

Bill language, proposed by the House, which would have prohibited using grants has been deleted. The managers agree that project funding is expected to be based on cooperative agreements, but that grants might be applicable to support work also funded from this account.

The managers agree to deleted Senate language providing personnel floors for Clean Coal Technology. The managers further agree that the budget estimates for personnel and contract support are to be followed. The agreement included 58 new positions above current employment floors for the fossil energy organization and 30 positions within the floors. Out of clean coal technology funds, up to $3,980,000 is for fiscal year 1988 personnel-related costs and up to $16,520,000 is for all contract costs needed to make project selections and complete negotiations for both clean coal procurements. Contract costs necessary to monitor approved projects should be requested in the fiscal year 1989 budget. Increases above those amounts are subject to reprogramming procedures. No funds other than personnel related costs for the 30 positions included in the program direction are to be provided from the fossil energy research and development account.

The length of time for selection of projects by the Secretary of Energy has been extended from 120 days to 160 days based on experience from the original clean coal procurement. Once projects have been selected the Secretary should establish project milestones and guidelines for project negotiations in order to expedite the negotiation process to the extent feasible.

The managers agree that the funds provided are available for nonutility applications as well as for utility applications.

The managers agree that no funds are provided for the demonstration of clean coal technologies which are intended solely for new, stand alone, applications. The Senate had proposed up to 25% of the funds be available for this purpose.

Bill language has been included which provides that reports on projects selected in the first round of clean coal procurements that are received before the end of the first session of the 100th Congress will satisfy reporting requirements 30 calendar days after receipt by Congress. This provision applies to a maximum of two project reports.

Public Law 100-446

Public Law 100-446, 102 Stat. 1774 (1988)

Clean Coal Technology

For necessary expenses of, and associated with, Clean Coal Technology demonstrations pursuant to 42 U.S.C. 5901 et seq., $575,000,000 shall be made available on October 1, 1989, and shall remain available until expended: *Provided*, That projects selected pursuant to a general request for proposals issued pursuant to this appropriation shall demonstrate technologies capable of retrofitting or repowering existing facilities and shall be subject to all provisions contained under this head in Public Laws 99-190 and 100-202 as amended by this Act.

The first paragraph under this head in Public Law 100-202 is amended by striking “and $525,000,000 are appropriated for the fiscal year beginning October 1, 1988” and inserting “$190,000,000 are appropriated for the fiscal year beginning October 1, 1988, and shall remain available until expended, $135,000,000 are appropriated for the fiscal year beginning October 1, 1989, and shall remain available until expended, and $200,000,000 are appropriated for the fiscal year beginning October 1, 1990”: *Provided*, That outlays in fiscal year 1989 resulting from the use of funds appropriated under this head in Public Law 100-202, as amended by this Act, may not exceed $15,500,000: *Provided further;* That these actions are taken pursuant to section 202(b)(1) of Public law 100-119 (2 U.S.C. 909).

For the purposes of the sixth proviso under this head in Public Laws 99-190, funds derived by the Tennessee Valley Authority from its power program are hereafter not to be precluded from qualifying as all or part of any cost-sharing requirement, except to the extent that such funds are provided by annual appropriations Acts: *Provided*, That unexpended balances of funds made available in the “Energy Security Reserve” account in the Treasury for the Clean Coal Technology Program by the Department of the Interior and Related Agencies Appropriations Acts, 1986, as contained in section 101(d) of Public Law 99-190, shall be merged with this account: *Provided further*, That for the purposes of the sixth proviso in Public Law 99-190 under this heading, funds provided under section 306 of Public Law 93-32 shall be considered non-Federal: *Provided further*, That reports on projects selected by the Secretary of Energy pursuant to authority granted under the heading “Clean coal technology” in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, which are received by the Speaker of the House of Representatives and the President of the Senate prior to the end of the second session of the 100th Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading “Administrative provisions, Department of Energy” in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate.

Conference Report (H.R. Conf. Rep. No. 862, 100th Cong., 2nd Sess. [1988])

Clean Coal Technology

Amendment No. 131: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

In lieu of the matter proposed by said amendment insert the following: *For necessary expenses of, and associated with, Clean Coal Technology demonstrations pursuant to 42 U.S.C. 5901 et seq., $575,000,000 shall be made available on October 1, 1989, and shall remain available until expended: Provided, That projects selected pursuant to a general request for proposals issued pursuant to this appropriation shall demonstrate technologies capable of retrofitting or repowering existing facilities and shall be subject to all provisos contained under this head in Public Laws 99-190 and 100-202 as amended by this Act.*

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate. The amendment provides $575,000,000 in fiscal year 1990 for a third Clean Coal Technology procurement as proposed by the Senate, and clarifies that the procurement is for retrofit and repowering technologies and is subject to the cost-sharing provisions of the previous two procurements.

The managers agree that a request for proposals should be issued by May 1, 1989, with proposals due no later than 120 days after issuance of the request for proposals, and that the Secretary of Energy should make project selections no later than 120 days after receipt of proposals.

Amendment No. 132: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

Restore the matter stricken by said amendment, amended to read as follows: *The first paragraph under this head in Public Law 100-202 is amended by striking "and $525,000,000 are appropriated for the fiscal year beginning October 1, 1988" and inserting "$190,000,000 are appropriated for the fiscal year beginning October 1, 1988, and shall remain available until expended, $135,000,000 are appropriated for the fiscal year beginning October 1, 1989, and shall remain available until expended, and $200,000,000 are appropriated for the fiscal year beginning October 1, 1990": Provided, That outlays in fiscal year 1989 resulting from the use of funds appropriated under this head in Public Law 100-202, as amended by this Act, may not exceed $15,500,000: Provided further, That these actions are taken pursuant to section 202(b)(1) of Public Law 100-119 (2 U.S.C. 909).*

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate. The amendment changes the availability of $525,000,000 originally made available for fiscal year 1989 in Public Law 100-202 by making $190,000,000 available in 1989, $135,000,000 available in 1990, and $200,000,000 available in 1991 and also provides an outlay ceiling in fiscal year 1989. The House had proposed $100,000,000 in fiscal year 1989, $225,000,000 in fiscal year 1990, and $200,000,000 in fiscal year 1989, $225,000,000 in fiscal year 1990, and $200,000,000 in fiscal year 1991, and the Senate struck the House language.

Both of these changes are necessary because of budget allocation constraints, but neither action has an effect on the execution of the Clean Coal program, or on the Congress' overall support for the program, as is evidenced by additional appropriations provided for a third procurement of technologies.

The managers agree that administrative contract expenses may be incurred up to the budget level of $9,820,000, but caution that close control of such expenditures is necessary to assure that the outlay ceiling provided will be sufficient to cover project costs.

Amendment No. 133: Modifies public law citation as proposed by the Senate.

Amendment No. 134: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which clarifies that funds borrowed by REA Electric Cooperatives from the Federal Financing Bank are eligible as cost-sharing in the clean coal technology program.

Amendment No. 135: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which specifies clean coal projects may proceed 30 calendar days after receipt by Congress of required reports, provided the reports are received prior to the end of the 100th Congress.

Public Law 101-45

Public Law 101-45, 103 Stat. 97 (1989)

Clean Coal Technology

Notwithstanding any other provision of law, funds originally appropriated under this head in the Department of the Interior and Related Agencies Appropriations Act, 1989, shall be available for a third solicitation of clean coal technology demonstration projects, which projects are to be selected by the Department not later than January 1, 1990.

Public Law 101-121

Public Law 101-121, 103 Stat. 701 (1989)

Clean Coal Technology

For necessary expenses of, and associated with, Clean Coal Technology demonstrations pursuant to 42 U.S.C. 5901 et seq., $600,000,000 shall be made available on October 1, 1990, and shall remain available until expended, and $600,000,000 shall be made available on October 1, 1991, and shall remain available until expended: Provided, That projects selected pursuant to a separate general request for proposals issued pursuant to each of these appropriations shall demonstrate technologies capable of replacing, retrofitting or repowering existing facilities and shall be subject to all provisos contained under this head in Public Laws 99-190, 100-202, and 100-446 as amended by this Act: Provided further, That the general request for proposals using funds becoming available on October 1, 1990, under this paragraph shall be issued no later than June 1, 1990, and projects resulting from such a solicitation must be selected no later than February 1, 1991: Provided further, That the general request for proposals using funds becoming available on October 1, 1991, under this paragraph shall be issued no later than September 1, 1991, and projects resulting from such a solicitation must be selected no later than May 1, 1992.

The first paragraph under this head in Public Law 100-446 is amended by striking "$575,000,000 shall be made available on October 1, 1989" and inserting "$450,000,000 shall be made available on October 1, 1989, and shall remain available until expended, and $125,000,000 shall be made available on October 1, 1990": Provided, That these actions are taken pursuant to section 202(b)(1) of Public Law 100-119 (2 U.S.C. 909).

With regard to funds made available under this head in this and previous appropriations Acts, unobligated balances excess to the needs of the procurement for which they originally were made available may be applied to other procurements for which requests for proposals have not yet been issued: Provided, That for all procurements for which project selections have not been made as of the date of enactment of this Act no supplemental, backup, or contingent selection of projects shall be made over and above projects originally selected for negotiation and utilization of available funds: Provided further, That reports on projects selected by the Secretary of Energy pursuant to authority granted under this heading which are received by the Speaker of the House of Representatives and the President of the Senate less than 30 legislative days prior to the end of the first session of the 101st Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading "Administrative provisions, Department of Energy" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate or at the end of the session, whichever occurs later.

Conference Report (H.R. Conf. Rep. No. 264, 101st Cong., 1st Sess. [1987])

Clean Coal Technology

Amendment No. 112: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of he Senate which adds the word "replacing" to the definition of clean coal technology. The managers agree that the inclusion of "replacing" for clean coal IV and V is intended to cover the complete replacement of an existing facility if because of design or site specific limitations, repowering or retrofitting of the plant is not a desirable option.

Amendment No,. 113: Appropriates $450,000,000 for fiscal year 1990 for clean coal technology instead of $500,000,000 as proposed by the House and $325,000,000 as proposed by he Senate. This appropriation along with $125,000,000 provided for fiscal year 1991 in Amendment 114 fully funds the third round of clean coal technology projects. The managers agree that additional manpower is required, particularly at the Department's Energy Technology Centers, in order to manage adequately the increased workload from the accumulation of active clean coal technology projects and the inclusion of additional procurements in this bill. Although a legislative floor is not included, the managers agree that at least eighty personnel will be required in addition to the approximately thirty FTE's now included in the fossil energy research and development appropriation. The managers agree further that funds from the fossil energy research and development appropriation should not be used to pay the cost of more than the equivalent FTE's paid under that account in fiscal year 1989.

Amendment No. 114: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

In lieu of the matter stricken and inserted by said amendment, insert: *and shall remain available until expended, and $125,000,000*

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate. The amendment provides $125,000,000 in fiscal year 1991 for the third clean coal technology procurement instead of $75,000,000 as proposed by the House and $100,000,000 as proposed by the Senate.

Amendment No 115: Deletes Senate proposed appropriation of $150,000,000 for fiscal year 1992 for clean coal technology. The House proposed no such appropriation.

Amendment No. 116: Restores House language stricken by the Senate which prohibits the use of supplemental, backup, or contingent project selections in clean coal technology procurements.

Amendment No. 117: Restores the word "further" stricken by the Senate.

Public Law 101-164

Public Law 101-164, 103 Stat. 1069 (1989)

Clean Coal Technology

The second paragraph under this head contained in the Act making appropriations for the Department of the Interior and Related Agencies for the fiscal year ending September 30, 1990, is amended by striking "$450,000,000" and inserting "$419,000,000" and by striking "$125,000,000" and inserting "$156,000,000".

Conference Report (H.R. Conf. Rep. No. 315, 101st Cong., 1st Sess. [1989])

The managers have agreed to reduce the funds appropriated by the Energy and Water Development Appropriations Act for Fiscal Year 1990 (Public Law 101-101) for the "Nuclear Waste Disposal Fund" by $46,000,000. This reduction will make funds available for the drug prevention effort.

The managers have agreed to reductions to the Interior and Related Agencies Appropriations Act for Fiscal Year 1990 (Public Law 101-121) in order to accommodate additional drug related appropriations.

The reductions are in three areas. The new budget authority for Clean Coal Technology of $450,000,000 for fiscal year 1990 is reduced by $31,000,000 with this same amount added to the advance appropriation for fiscal year 1991. With this change the new amount for fiscal year 1990 is $419,000,000 while fiscal year 1991 increases to $156,000,000. The second area of change is the imposition of an outlay ceiling on Strategic Petroleum Reserve oil acquisition. Outlays will be reduced from an estimated $169,945,000 to $147,125,000 and will decrease the fill rate from approximately 50,000 barrels per day to approximately 46,000 or 47,000 barrels per day. The third reduction relates to the Pennsylvania Avenue Development Corporation. The borrowing authority is reduced from $5,000,000 to $100,000.

The conference agreement includes bill language reducing the amount of funds transferred from trust funds to the Health Care Financing Administration Program Management account by $32,000,000 from $1,917,172,000 to $18,851,712,000. This reduction, along with the outlays reserved from the regular 1990 Labor, Health and Human Services, and Education appropriations bill, will be sufficient to support the Subcommittee's share of the cost of anti-drug abuse funding. The conferees intend that the reduction in trust fund transfers be associated with activities to implement catastrophic health insurance, where funding needs may be diminished.

Public Law 101-302

Public Law 101-302, 104 Stat. 213 (1990)

Clean Coal Technology

Funds previously appropriated under this head for clean coal technology solicitations to be issued no later than June 1, 1990, and no later than September 1, 1991, respectively, shall not be obligated until September 1, 1991: Provided, That the aforementioned solicitations shall not be conducted prior to the ability to obligate these funds: Provided further, That pursuant to section 202(b) of the Balanced Budget and Emergency Deficit Control Reaffirmation Act of 1987, this action is a necessary (but secondary) result of a significant policy change: Provided further, That for the clean coal solicitations identified herein, provisions included for the repayment of government contributions to individual projects shall be identical to those included in the Program Opportunity Notice (PON) for Clean Coal Technology III (CCT-III) Demonstration Projects (solicitation number DE-PSO1-89 FE 61825), issued by the Department of Energy on May 1, 1989.

Conference Report (H.R. Conf. Rep. No. 493, 101st Cong., 2nd Sess. [1990])

Clean Coal Technology

Amendment No. 89. Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the senate with an amendment as follows:

In lieu of the matter proposed by said amendment insert:

Department of Energy
Clean Coal Technology

Funds previously appropriated under this head for clean coal technology solicitations to be issued no later than June 1, 1990, and no later than September 1, 1991, respectively, shall not be obligated until September 1, 1991: Provided, That the aforementioned solicitations shall not be conducted prior to the ability to obligate these funds: Provided further, That pursuant to section 202 (b) of the Balanced Budget and Emergency Deficit Control reaffirmation /Act of 1987 this action is a necessary (but secondary) result of a significant policy change: Provided further, That for the clean coal solicitations identified herein, provisions included for the repayment of government contributions to individual projects shall be identical to those included in the Program Opportunity Notice (PON) for Clean Coal Technology III (CCT-III) Demonstration Projects (solicitation number DE-PS01-89 FE 61825), issued by the Department of Energy on May 1, 1989.

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate.

The amendment delays the fourth and fifth clean coal technology solicitations as proposed by the Senate and specifies that, when issued, these solicitations must use repayment provisions used successfully in the third solicitation. This provision was included in the House introduced bill (H.R. 4828) and modifies a Senate amendment to the original Dire Emergency Supplemental.

The managers agree that changes to the clean air bill, proposed by a House authorizing committee, that would modify the clean coal technology program must be resolved before a reasonable solicitation can be issued. The proposed delay will allow such resolution.

The managers have added language to ensure that provisions dealing with the repayment of government provided funds will remain the same as the third round of procurements. These provisions were developed over a four year period based on experience of previous procurements and negotiations, and input from industrial participants, Congress, and the managers of the program. They appear to be working well.

Based on the long-term experience, and the clear fact that implementation of this type of technology will become even more important with passage of clean air legislation, the managers reject proposals put forth by the Department of Energy to increase rates substantially. Such proposals, while they might increase the recovery of government-provided funds over periods of up to 20 years, might also act as a deterrent to industrial participation in the program, which is already over 50 percent cost-shared by industry. The purpose of the program is to accelerate the introduction of clean uses of coal in a more efficient manner in compliance with stringent new air quality standards, not the provision of investment returns to the Government at the expense of nascent markets.

Public Law 101-512

Public Law 101-512, 104 Stat. 1915 (1990)

Clean Coal Technology

The first paragraph under this head in Public Law 101-121 is amended by striking "$600,000,000 shall be made available on October 1, 1990, and shall remain available until expended, and $600,000,000 shall be made available on October 1, 1991, and shall remain available until expended" and inserting "$600,000,000 shall be made available as follows: $35,000,000 on September 1, 1991, $315,000,000 on October 1, 1991, and $250,000,000 on October 1, 1992, all such sums to remain available until expended for use in conjunction with a separate general request for proposals, and $600,000,000 shall be made available as follows: $150,000,000 on October 1, 1991, $225,000,000 on October 1, 1992, and $225,000,000 on October 1, 1993, all such sums to remain available until expended for use in conjunction with a separate general request for proposals": Provided, That these actions are taken pursuant to section 202(b)(1) of Public Law 100-119 *(2 U.S.C. 909):* Provided further, That a fourth general request for proposals shall be issued not later than February 1, 1991, and a fifth general request for proposals shall be issued not later than March 1, 1992: Provided further, That project proposals resulting from such solicitations shall be selected not later than eight months after the date of the general request for proposals: Provided further, That for clean coal solicitations required herein, provisions included for the repayment of government contributions to individual projects shall be identical to those included in the Program Opportunity Notice (PON) for Clean Coal Technology III (CCT-III) Demonstration Projects (solicitation number DE-PS01-89 FE 61825), issued by the Department of Energy on May 1, 1989: Provided further, That funds provided under this head in this or any other appropriations Act shall be expended only in accordance with the provisions governing the use of such funds contained under this head in this or any other appropriations Act.

With regard to funds made available under this head in this and previous appropriations Acts, unobligated balances excess to the needs of the procurement for which they originally were made available may be applied to other procurements for use on projects for which cooperative agreements are in place, within the limitations and proportions of Government financing increases currently allowed by law: Provided, That the Department of Energy, for a period of up to five (5) years after completion of the operations phase of a cooperative agreement may provide appropriate protections, including exemptions from subchapter II of chapter 5 of title 5, United States Code, against the dissemination of information that results from demonstration activities conducted under the Clean Coal Technology Program and that would be a trade secret or commercial or financial information that is privileged or confidential if the information had been obtained from and first produced by a non-Federal party participating in a Clean Coal Technology project: Provided further, That, in addition to the full-time permanent Federal employees specified in section 303 of Public Law 97-257, as amended, no less than 90 full-time Federal employees shall be assigned to the Assistant Secretary for Fossil Energy for carrying out the programs under this head using funds available under this head in this and any other appropriations Act and of which 35 shall be for PETC and 30 shall be for METC: Provided further, That reports on projects selected by the Secretary of Energy pursuant to authority granted under this heading which are received by the Speaker of the House of Representatives and the President of the Senate less than 30 legislative days prior to the end of the second session of the 101st Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading "Administrative provisions, Department of Energy" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate or at the end of the session, whichever occurs later.

Conference Report (H.R. Conf. Rep. No. 971, 101st Cong., 2nd Sess. [1990])

Clean Coal Technology

Amendment No. 142: Provides $35,000,000 for clean coal technology on September 1, 1991 as proposed by the House instead of $100,000,000 as proposed by the Senate. This amendment and Amendment No. 143 shift the availability of $65,000,000 from fiscal year 1991 to fiscal year 1992.

Amendment No. 143: Provides $315,000,000 for clean coal technology on October 1, 1991 as proposed by the House instead of $250,000,000 as proposed by the Senate. This amendment and Amendment No. 142 shift the availability of $65,000,000 from fiscal year 1991 to fiscal year 1992.

Amendment No. 144: Provides dates for two solicitations for clean coal technology as proposed by the Senate. The date for CCT-IV is amended to February 1, 1991 from January 1, 1991. The date for CCT-V is not changed from the Senate date of March 1, 1992.

The managers have agreed to a February 1, 1991 date for the next solicitation to enable the Department to publish a draft solicitation for comment by interested parties. It is expected that there will be changes to evaluation criteria and other factors that make it imperative that potential proposers have an opportunity to comment on the content of the solicitation.

The managers urge the Department to include potential benefits to remote, import-dependent sites as a program policy factor in evaluating proposals. The Department should also consider projects which can provide multiple fuel resource options for regions which are more than seventy-five percent dependent on one fuel form for total energy requirements.

Amendment No. 145: Requires selection of projects within eight months of the requests for proposals required by Amendment No. 144 as proposed by the Senate. The House had no such provision.

Amendment No. 146: Requires repayment of government contributions to projects under conditions identical to the most recent clean coal solicitation as proposed by the Senate. The House had no such provision.

Amendment No. 147: Provides that funds for clean coal technology may be expended only under conditions contained in appropriations Acts. The Senate language had prohibited geographic restrictions on the expenditure of funds. The House had no such provision. The managers direct that no preferential consideration be given to any project referenced explicitly or implicitly in other legislation.

The managers agree to delete bill language dealing with geographic restrictions based on such restrictions being deleted from clean air legislation.

Amendment No. 148: Earmarks employees to two fossil energy technology centers as proposed by the Senate. The House had no such provision. The managers agree that the earmarks for PETC and METC are minimum levels and may be increased as necessary.

The managers agree that no more than the current 30 full-time equivalent positions from fossil energy research and development may be used in the clean coal program in fiscal year 1991.

Public Law 102-154

Public Law 102-154, 105 Stat. 990 (1991)

Clean Coal Technology

The first paragraph under this head in Public Law 101-512 is amended by striking the phrase "$150,000,000 on October 1, 1991, $225,000,000 on October 1, 1992" and inserting "$100,000,000 on October 1, 1991, $275,000,000 on October 1, 1992".

Notwithstanding the issuance date for the fifth general request for proposals under this head in Public Law 101-512, such request for proposals shall be issued not later than July 6, 1992, and notwithstanding the proviso under this head in Public Law 101-512 regarding the time interval for selection of proposals resulting from such solicitation, project proposals resulting from the fifth general request for proposals shall be selected not later than ten months after the issuance date of the fifth general request for proposals: Provided, That hereafter the fifth general request for proposals shall be subject to all provisos contained under this head in previous appropriations Acts unless amended by this Act.

Notwithstanding the provisos under this head in previous appropriations Acts, projects selected pursuant to the fifth general request for proposals shall advance significantly the efficiency and environmental performance of coal-using technologies and be applicable to either new or existing facilities: Provided, That budget periods may be used in lieu of design, construction, and operating phases for cost-sharing calculations: Provided further, That the Secretary shall not finance more than 50 per centum of the total costs of any budget period: Provided further, That project specific development activities for process performance definition, component design verification, materials selection, and evaluation of alternative designs may be funded on a cost-shared basis up to a limit of 10 per centum of the Government's share of project cost: Provided further, That development activities eligible for cost-sharing may include limited modifications to existing facilities for project related testing but do not include construction of new facilities.

With regard to funds made available under this head in this and previous appropriations Acts, unobligated balances excess to the needs of the procurement for which they originally were made available may be applied to other procurements for use on projects for which cooperative agreements are in place, within the limitations and proportions of Government financing increases currently allowed by law: Provided, That hereafter, the Department of Energy, for a period of up to five years after completion of the operations phase of a cooperative agreement may provide appropriate protections, including exemptions from subchapter II of chapter 5 of title 5, United States Code, against the dissemination of information that results from demonstration activities conducted under the Clean Coal Technology Program and that would be a trade secret or commercial or financial information that is privileged or confidential if the information had been obtained from and first produced by a non-Federal party participating in a Clean Coal Technology project: Provided further, That hereafter, in addition to the full-time permanent Federal employees specified in section 303 of Public Law 97-257, as amended, no less than 90 full-time Federal employees shall be assigned to the Assistant Secretary for Fossil Energy for carrying out the programs under this head using funds available under this head in this and any other appropriations Act and of which not less than 35 shall be for PETC and not less than 30 shall be for METC: Provided further, That hereafter reports on projects selected by the Secretary of Energy pursuant to authority granted under this heading which are received by the Speaker of the House of Representatives and the President of the Senate less than 30 legislative days prior to the end of each session of Congress shall be deemed to have met the criteria in the third proviso of the fourth paragraph under the heading "Administrative provisions, Department of Energy" in the Department of the Interior and Related Agencies Appropriations Act, 1986, as contained in Public Law 99-190, upon expiration of 30 calendar days from receipt of the report by the Speaker of the House of Representatives and the President of the Senate or at the end of the session, whichever occurs later.

Conference Report (H.R. Conf. Rep. No. 256, 102nd Cong., 1st Sess. [1991])

Clean Coal Technology

Amendment No. 165: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate with an amendment as follows:

In lieu of the matter stricken and inserted by said amendment insert:

Notwithstanding the issuance date for the fifth general request for proposals under this head in Public Law 101-512, such request for proposals shall be issued not later than July 6, 1992, and notwithstanding the proviso under this head in Public Law 101-512 regarding the time interval for selection of proposals resulting from such solicitation, project proposals resulting from the fifth general request for proposals shall be selected not later than ten months after the issuance date of the fifth general request for proposals: Provided, That hereafter the fifth general request for proposals

The managers on the part of the Senate will move to concur in the amendment of the House to the amendment of the Senate.

The amendment changes the issuance date for the fifth general request for proposals to July 6, 1992 instead of March 1, 1992 as proposed by the House and August 10, 1992 as proposed by the Senate and the allowable length of time from issuance of the request for proposals to selection of projects to ten months. The amendment also deletes Senate proposed bill language pertaining to a sixth general request for proposals as discussed below.

The managers agree that the additional two months in the procurement process for the fifth round of proposals should include an additional month to allow for the preparation of proposals by the private sector, and up to an additional month for Department of Energy review and evaluation of proposals when compared to the process for the fourth round.

The managers have agreed to delete bill language regarding a sixth round of proposals, but agree that funding will be provided for a sixth round based on unobligated and unneeded amounts that may become available from the first five rounds. The report from the Secretary on available funds, which was originally in the Senate amendment, is still a requirement and such report should be submitted to the House and Senate Committees on Appropriations not later than May 1, 1994. Based on that report, the funding, dates and conditions for the sixth round will be included in the fiscal year 1995 appropriation.

The managers expect that the fifth solicitation will be conducted under the same general types of criteria as the fourth solicitation principally modified only (1) to include the wider range of eligible technologies or applications; (2) to adjust technical criteria to consider allowable development activities, to strengthen criteria for nonutility demonstrations, and to adjust commercial performance criteria for additional facilities and technologies with regard to aspects of general energy efficiency and environmental performance; and (3) to clarify and strengthen cost and finance criteria particularly with regard to development activities.

Amendment No. 166: Restores House language deleted by the Senate which refers to a fifth general request for proposals. The Senate proposed language dealing with both a fifth and a sixth round.

Amendment No. 167: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which directs the Secretary of Energy to reobligate up to $44,000,000 from the fourth round of Clean Coal Technology proposals to a proposal ranked highest in its specific technology category by the Source Evaluation Board if other than the highest ranking project in that category was selected originally by the Secretary, and if such funds become unobligated and are sufficient to fund such projects. This amendment would earmark such funds, if they become available, to a specific project not chosen in the Department of Energy selection process for the fourth round of Clean Coal Technology.

Amendment No. 168: Technical amendment which deletes House proposed punctuation and numbering as proposed by the Senate.

Amendment No. 169: Deletes House proposed language which made unobligated funds available for procurements for which requests for proposals have not been issued.

Amendment No. 170: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which adds “not less than” to employment floor language for PETC as proposed by the Senate. The House had no such language.

Amendment No. 171: Reported in technical disagreement. The managers on the part of the House will offer a motion to recede and concur in the amendment of the Senate which adds “not less than” to employment floor language for METC as proposed by the Senate. The House had no such language.

Public Law 102-381

Public Law 102-381, 106 Stat. 1374 (1992)

Clean Coal Technology

The first paragraph under this head in Public Law 101-512, as amended, is further amended by striking the phrase "and $250,000,000 on October 1, 1992" and inserting "$150,000,000 on October 1, 1993, and $100,000,000 on October 1, 1994" and by striking the phrase "$275,000,000 on October 1, 1992, and $225,000,000 on October 1, 1993" and inserting "$250,000,000 on October 1, 1993, and $250,000,000 on October 1, 1994".

Public Law 103-138

Public Law 103-138, 107 Stat. 1379 (1993)

Clean Coal Technology

The first paragraph under this head in Public Law 101-512, as amended, is further amended by striking the phrase "$150,000,000 on October 1, 1993, and $100,000,000 on October 1, 1994" and inserting "$100,000,000 on October 1, 1993, $100,000,000 on October 1, 1994, and $50,000,000 on October 1, 1995" and by striking the phrase "$250,000,000 on October 1, 1993, and $250,000,000 on October 1, 1994" and inserting "$125,000,000 on October 1, 1993, $275,000,000 on October 1, 1994, and $100,000,000 on October 1, 1995".

Public Law 103-332

Public Law 103-332, 108 Stat. 2499 (1994)

Clean Coal Technology

The first paragraph under this head in Public Law 101-512, as amended, is further amended by striking the phrase "$100,000,000 on October 1, 1994, and $50,000,000 on October 1, 1995" and inserting "$18,000,000 on October 1, 1994, $100,000,000 on October 1, 1995, and $32,000,000 on October 1, 1996"; and by striking the phrase "$275,000,000 on October 1, 1994, and $100,000,000 on October 1, 1995" and inserting "$19,121,000 on October 1, 1994, $100,000,000 on October 1, 1995, and $255,879,000 on October 1, 1996": Provided, That not to exceed $18,000,000 available in fiscal year 1995 may be used for administrative oversight of the Clean Coal Technology program.

Public Law 104-6

Public Law 104-6, 109 Stat. 73 (1995)

Clean Coal Technology (Rescission)

Of the funds made available under this heading for obligation in fiscal year 1996, $50,000,000 are rescinded and of the funds made available under this heading for obligation in fiscal year 1997, $150,000,000 are rescinded: Provided, That funds made available in previous appropriations Acts shall be available for any ongoing project regardless of the separate request for proposal under which the project was selected.

Public Law 104-134

Conference Report (H.R. Conf. Rep. No. 402, 104th Cong., 1st Sess. [1995])

The managers do not object to the use of up to $18,000,000 in clean coal technology program funds for administration of the clean coal program.

Public Law 104-208

Public Law 104-208, 110 Stat. 3009 (1996)

Clean Coal Technology (Rescission)

Of the funds made available under this heading for obligation in fiscal year 1997 or prior years, $123,000,000 are rescinded: *Provided*, That funds made available in previous appropriations Acts shall be available for any ongoing project regardless of the separate request for proposal under which the project was selected.

Conference Report (H.R. Conf. Rep. No. 863, 104th Cong., 2nd Sess., [1996])

CLEAN COAL TECHNOLOGY
(RESCISSION)

Of the funds made available under this heading for obligation in fiscal year 1997 or prior years, $123,000,000 are rescinded: Provided, That funds made available in previous appropriations Acts shall be available for any ongoing project regardless of the separate request for proposal under which the project was selected.

Senate Report (S. Rep. No. 319, 104th Cong., 2nd Sess. [1996])

The Committee does not object to the use of up to $16,000,000 in available funds for administration of the clean coal program in fiscal year 1997.

House Report (H.R. Rep. No. 625, 104th Cong., 2nd Sess. [1996])

The Committee does not object to the use of up to $16,000,000 in available funds for administration of the clean coal program in fiscal year 1997.

Public Law 105-18

Public Law 105-18, 111 Stat. 158 (1997)

CLEAN COAL TECHNOLOGY
(RESCISSION)

Of the funds made available under this heading for obligation in fiscal year 1997 or prior years, $17,000,000 are rescinded: *Provided*, That funds made available in previous appropriations Acts shall be available for any ongoing project regardless of the separate request for proposal under which the project was selected.

Public Law 105-83

Public Law 105-83, 111 Stat. 37 (1997)

Of the funds made available under this heading for obligation in fiscal year 1997 or prior years, $101,000,000 are rescinded: *Provided*, That funds made available in previous appropriations Acts shall be available for any ongoing project regardless of the separate request for proposal under which the project was selected.

Public Law 105-277

Public Law 105-277, 112 Stat. 2681 (1998)

CLEAN COAL TECHNOLOGY
(DEFERRAL)

Of the funds made available under this heading for obligation in prior years, $10,000,000 of such funds shall not be available until October 1, 1999; $15,000,000 shall not be available until October 1, 2000; and $15,000,000 shall not be available until October 1, 2001: Provided, That funds made available in previous appropriations Acts shall be available for any ongoing project regardless of the separate request for proposal under which the project was selected.

Conference Report (H.R. Conf. Rep. No. 825, 105th Cong. 2nd Sess. [1998])

CLEAN COAL TECHNOLOGY

The conference agreement provides for the deferral of $40,000,000 in previously appropriated funds for the clean coal technology program as proposed by the Senate. The House did not propose to defer funding. The Committees agree that $14,900,000 may be used for administration of the clean coal technology program.

Public Law 106-113

Public Law 106-113, ___ Stat. ___ (1999)

Clean Coal Technology (Deferral)

Of the funds made available under this heading for obligation in prior years, $156,000,000 shall not be available until October 1, 2000: *Provided*, That funds made available in previous appropriations Acts shall be available for any ongoing project regardless of the separate request for proposal under which the project was selected.

Conference Report (H.R. Rep. No. 406, 106th Cong., 1st Sess. [1999])

Clean Coal Technology (Deferral)

The conference agreement provides for the deferral of $156,000,000 in previously appropriated funds for the clean coal technology program as proposed by the Senate instead of a deferral of $256,000,000 as proposed by the House. The managers agree that up to $14,400,00 may be used for program direction.

Public Law 106-291

Public Law 106-291, __ Stat. __ (2000)

Clean Coal Technology (Deferral)

Of the funds made available under this heading for obligation in prior years, $67,000,000 shall not be available until October 1, 2001: Provided, That funds made available in previous appropriations Acts shall be available for any ongoing project regardless of the separate request for proposal under which the project was selected.

Appendix B: Program History

Solicitation History

The objective of the CCT-I solicitation, issued February 17, 1986, was to seek cost-shared projects to demonstrate the feasibility of clean coal technologies for commercial applications. The Program Opportunity Notice (PON) elicited 51 proposals. Nine projects were selected and 14 projects were placed on a list of alternatives in the event negotiations on the original 9 projects were unsuccessful; 8 alternate projects were eventually selected as replacement projects. Projects were selected from the list of alternates on three separate occasions.

The CCT-II PON, issued February 22, 1988, solicited cost-shared, innovative clean coal technology projects to demonstrate technologies that were capable of being commercialized in the 1990s, more cost-effective than current technologies, and capable of achieving significant reductions in SO_2 and/or NO_x emissions from existing coal-burning facilities, particularly those that contribute to transboundary air pollution. The CCT-II PON was the first solicitation implementing the recommendations of the U.S. and Canadian Special Envoys' report on acid rain. DOE received 55 proposals and selected 16 as best furthering the goals and objectives of the PON (no alternates were selected).

The objective of the CCT-III PON, issued May 1, 1989, was to solicit cost-shared clean coal technology projects to demonstrate innovative, energy-efficient technologies capable of being commercialized in the 1990s. These technologies were to be capable of (1) achieving significant reductions in emissions of SO_2 and/or NO_x from existing facilities to minimize environmental impacts, such as transboundary and interstate air pollution; and/or (2) providing for future energy needs in an environmentally acceptable manner. DOE received 48 proposals and selected 13 projects as best furthering the goals and objectives of the PON.

The CCT-IV PON, issued January 17, 1991, solicited proposals to conduct cost-shared clean coal technology projects to demonstrate innovative, energy-efficient, economically competitive technologies. These technologies were to be capable of (1) retrofitting, repowering, or replacing existing facilities while achieving significant reductions in the emissions of SO_2, NO_x, or both, and/or (2) providing for future energy needs in an environmentally acceptable manner. A total of 33 proposals were submitted in response to the PON. Nine projects were selected.

The objective of the CCT-V PON, issued July 6, 1992, was to solicit proposals to conduct cost-shared demonstration projects that significantly advance the efficiency and environmental performance of coal-using technologies and are applicable to either new or existing facilities. In response to the solicitation, DOE received proposals for 24 projects and selected 5 projects.

Selection and Negotiation History

The following is a history of the selection and negotiations for the CCT Program Projects. Data are provided through September 2000.

July 1986

Nine projects were selected under CCT-I (14 alternate projects selected to replace any selected projects if negotiations were unsuccessful).

March 1987

DOE signed cooperative agreements with two CCT-I participants, Coal Tech Corporation (Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control) and The Ohio Power Company (Tidd PFBC Demonstration Project).

June 1987

DOE signed a cooperative agreement with CCT-I participant, The Babcock & Wilcox Company (now McDermott Technology, Inc.) LIMB Demonstration Project Extension and Coolside Demonstration.

July 1987

DOE signed a cooperative agreement with CCT-I participant, Energy and Environmental Research Corporation (Enhancing the Use of Coals by Gas Reburning and Sorbent Injection).

September 1987

General Electric Company withdrew its proposal (Integrated Coal Gasification Steam Injection Gas Turbine Demonstration Plants with Hot Gas Cleanup).

October 1987

Weirton Steel Corporation withdrew its proposal, Direct Iron Ore Reduction to Replace Coke Oven/Blast Furnace for Steelmaking, from further consideration.

Four more CCT-I projects were selected: Colorado-Ute Electric Association, Inc. (Nucla CFB Demonstration Project); TRW, Inc. (Advanced Slagging Coal Combustor Utility Demonstration Project); Minnesota Department of Natural Resources (COREX Ironmaking Demonstration Project); and Foster Wheeler Power Systems, Inc. (Clean Energy IGCC Demonstration Project).

December 1987

DOE signed cooperative agreements with two more CCT-I participants, Ohio Ontario Clean Fuels, Inc., (Prototype Commercial Coal/Oil Coprocessing Project) and Energy International, Inc. (Underground Coal Gasification Demonstration Project).

January 1988

DOE signed a cooperative agreement with The M.W. Kellogg Company and Bechtel Development Company for a CCT-I project, The Appalachian IGCC Demonstration Project.

September 1988

Sixteen projects were selected under CCT-II.

November 1988

DOE signed a cooperative agreement with CCT-I participant, TRW, Inc. (Advanced Slagging Coal Combustor Utility Demonstration Project).

December 1988

Negotiations were terminated with Minnesota Department of Natural Resources (COREX Ironmaking Demonstration Project) under CCT-I.

DOE selected three more CCT-I projects: ABB Combustion Engineering, Inc. and CQ Inc. (Development of the Coal Quality Expert™); Western Energy Company (formerly Rosebud SynCoal Partnership, now Western SynCoal LLC; Advanced Coal Conversion Process Demonstration); and United Coal Company (Coal Waste Recovery Advanced Technology Demonstration).

June 1989

The City of Tallahassee CCT-I project, ACFB Repowering, was selected from the alternate list.

The M.W. Kellogg Company and Bechtel Development Company withdrew their CCT-I project, Clean Energy IGCC Demonstration Project.

September 1989

United Coal Company withdrew its CCT-I project, Coal Waste Recovery Advanced Technology Demonstration.

November 1989

DOE signed a cooperative agreement with CCT-II participant, Bethlehem Steel Corporation (Innovative Coke Oven Gas Cleaning System for Retrofit Applications).

Combustion Engineering, Inc., (CCT-II) withdrew its Postcombustion Sorbent Injection Demonstration Project.

December 1989

Thirteen projects were selected under CCT-III.

DOE signed cooperative agreements with five CCT-II participants: ABB Combustion Engineering, Inc. (SNOX™ Flue Gas Cleaning Demonstration Project); The Babcock & Wilcox Company (SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project); Passamaquoddy Tribe (Cement Kiln Flue Gas Recovery Scrubber); Pure Air on the Lake, L.P. (Advanced Flue Gas Desulfurization Demonstration Project); and Southern Company Services, Inc. (Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler).

Energy International, Inc., withdrew its CCT-I project, Underground Coal Gasification Demonstration Project.

February 1990

Foster Wheeler Power Systems, Inc., withdrew its CCT-I proposal, Clean Energy IGCC Demonstration Project.

April 1990

DOE signed cooperative agreements with three CCT-II participants: The Appalachian Power Company (PFBC Utility Demonstration Project); The Babcock & Wilcox Company (Demonstration of Coal Reburning for Cyclone Boiler NO_x Control); and Southern Company Services, Inc. (Demonstration of Innovative Applications of Technology for the CT-121 FGD Process).

June 1990

DOE signed cooperative agreements with the co-participants of one CCT-I project, ABB Combustion Engineering, Inc. and CQ Inc. (Development of the Coal Quality Expert™), and with two CCT-II participants: Southern Company Services, Inc. (Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers) and TransAlta Resources Investment

Corporation (LNS Burner for Cyclone-Fired Boilers Demonstration Project).

September 1990

DOE signed cooperative agreements with one CCT-I participant, Western Energy Company (formerly Rosebud SynCoal Partnership, now Western SynCoal LLC); Advanced Coal Conversion Process Demonstration); one CCT-II participant, Southern Company Services, Inc. (180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers); and one CCT-III participant, ENCOAL Corporation (ENCOAL® Mild Coal Gasification Project).

Negotiations were terminated with CCT-II participant, Southwestern Public Service Company (Nichols CFB Repowering Project).

October 1990

DOE signed cooperative agreements with four CCT-III participants: AirPol, Inc. (10-MWe Demonstration of Gas Suspension Absorption); The Babcock & Wilcox Company (Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit); Bechtel Corporation (Confined Zone Dispersion Flue Gas Desulfurization Demonstration); and Energy and Environmental Research Corporation (Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler).

November 1990

DOE signed cooperative agreements with one CCT-I participant, The City of Tallahassee (Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project; now JEA and the JEA Large-Scale CFB Combustion Demonstration Project); one CCT-II participant, ABB Combustion Engineering, Inc. (Combustion Engineering IGCC Repowering Project); and two CCT-III participants, Bethlehem Steel Corporation (Blast Furnace Granular-Coal Injection System Demonstration Project) and LIFAC–North America (LIFAC Sorbent Injection Desulfurization Demonstration Project).

December 1990

Negotiations terminated with CCT-II participant, Otisca Industries, Ltd. (Otisca Fuel Demonstration Project) and CPICOR™.

March 1991

DOE signed cooperative agreements with three CCT-III participants: MK-Ferguson Company (now NOXSO Corporation (Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System); Public Service Company of Colorado (Integrated Dry NO_x/SO_2 Emissions Control System); and Tampa Electric Company (formerly Clean Power Cogeneration Limited Partnership; now Tampa Electric Integrated Gasification Combined-Cycle Project).

TRW, Inc., withdrew its CCT-I project (Advanced Slagging Coal Combustion Utility Demonstration Project).

April 1991

DOE signed a cooperative agreement with CCT-III participant, Alaska Industrial Development and Export Authority (Healy Clean Coal Project).

June 1991

DOE withdrew its sponsorship of the Ohio Ontario Clean Fuels, Inc., CCT-I project, Prototype Commercial Coal/Oil Coprocessing Plant.

August 1991

DOE signed a cooperative agreement with CCT-III participant, DMEC-1 Limited Partnership (formerly Dairyland Power Cooperative; PCFB Demonstration Project).

TransAlta Resources Investment Corporation withdrew its CCT-II project, LNS Burner for Cyclone-Fired Boilers Demonstration Project.

September 1991

Nine projects were selected under CCT-IV.

Coal Tech Corporation's CCT-I project, Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control, final reports issued and project completed.

April 1992

Tri-State Generation and Transmission Association, Inc.'s (formerly Colorado-Ute Electric Association, Inc.) CCT-I project, Nucla CFB Demonstration Project, final reports issued and project completed.

June 1992

The City of Tallahassee project (CCT-I) was restructured and transferred to York County Energy Partners, L.P. (York County Energy Partners Cogeneration Project).

July 1992

DOE signed cooperative agreements with two CCT-IV participants: Tennessee Valley Authority (now New York State Electric & Gas Corporation; Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit), and the Wabash River Coal Gasification Repowering Project Joint Venture (Wabash River Coal Gasification Repowering Project).

August 1992

DOE signed a cooperative agreement with CCT-IV participant, Sierra Pacific Power Company (Piñon Pine IGCC Power Project).

Cordero Mining Company withdrew from negotiations for its CCT-IV project, Cordero Coal-Upgrading Demonstration Project.

At the participant's request, Union Carbide Chemicals and Plastics Company, Inc. (CCT-IV) was granted an extension of one year to the DOE deadline for completing negotiations of its Demonstration of the Union Carbide CANSOLV™ System at the Alcoa Generating Corporation Warrick Power Plant.

October 1992

DOE signed cooperative agreements with one CCT-III participant, Air Products and Chemicals, Inc. (Commercial-Scale Demonstration of the Liquid Phase Methanol [LPMEOH™] Process) and with four CCT-IV participants: Custom Coals International (Self-Scrubbing Coal™: An Integrated Approach to Clean Air); New York State Electric & Gas Corporation (Milliken Clean Coal Technology Demonstration Project); TAMCO Power Partners (Toms Creek IGCC Demonstration Project); and ThermoChem, Inc. (Pulse Combustor Design Qualification Test).

November 1992

The Babcock & Wilcox Company's (now McDermott Technology, Inc.) CCT-I project, LIMB Demonstration Project Extension and Coolside Demonstration, final reports issued and project completed.

May 1993

Five projects were selected under CCT-V: Four Rivers Energy Partners, L.P. (Four Rivers Energy Modernization Project (formerly Calvert City Advanced Energy Project, now McIntosh Unit 4B Topped PCFB Demonstration Project); Duke Energy Corporation (Camden Clean Energy Demonstration Project); Centerior Energy Corporation, on behalf of CPICOR™ Management Company LLC (Clean Power from Integrated Coal/Ore Reduction [CPICOR™]); Arthur D. Little, Inc. (Clean Coal Combined-Cycle Project; formerly Demonstration of Coal Diesel Technology at Easton Utilities; now Clean Coal Diesel Demonstration Project); and Pennsylvania Electric Company (Warren Station Externally Fired Combined-Cycle Demonstration Project).

July 1993

Union Carbide Chemicals and Plastics Company, Inc., withdrew its CCT-IV proposal, Demonstration of the Union Carbide CANSOLV™ System at the Alcoa Generating Corporation Warrick Power Plant.

February 1994

The Passamaquoddy Tribe's CCT-III project, Cement Kiln Flue Gas Recovery Scrubber, final reports issued and project completed.

March 1994

The Babcock & Wilcox Company's CCT-II project, Demonstration of Coal Reburning for Cyclone Boiler NO_x Control, final reports issued and project completed.

June 1994

DOE signed a cooperative agreement with CCT-V participant, Arthur D. Little, Inc. (Coal Diesel Combined-Cycle Project).

Southern Company Services' CCT-III project, 180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers, final reports issued and project completed.

Bechtel Corporation's CCT-III project, Confined Zone Dispersion Flue Gas Desulfurization Demonstration, final reports issued and project completed.

August 1994

DOE signed cooperative agreements with two CCT-V participants, Four Rivers Energy Partners, L.P. (Four Rivers Energy Modernization Project); and Pennsylvania Electric Company (Warren Station Externally-Fired Combined-Cycle Demonstration Project).

The CCT-III project, Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System, was relocated and transferred to NOXSO Corporation.

September 1994

The Air Products and Chemicals CCT-III project, Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process, was transferred to Air Products Liquid Phase Conversion Company, L.P.

December 1994

DOE signed a cooperative agreement with CCT-V participant, Clean Energy Partners Limited Partnership (formerly Duke Energy Corporation; Clean Energy Demonstration Project; now Kentucky Pioneer IGCC Demonstration Project).

March 1995

TAMCO Power Partner's CCT-IV project, Toms Creek IGCC Demonstration Project, was not granted a further extension and the project was concluded.

April 1995

Bethlehem Steel Corporation's CCT-II project, Innovative Coke Oven Gas Cleaning System for Retrofit Applications, was terminated by mutual agreement with DOE because coke production was suspended at the demonstration facility.

June 1995

AirPol, Inc.'s CCT-II project, 10-MWe Demonstration of Gas Suspension Absorption, final reports issued and project completed.

September 1995

The Babcock & Wilcox Company's CCT-II project, SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project, final reports issued and project completed.

December 1995

The Tennessee Valley Authority and New York State Electric & Gas Corporation finalized an agreement to allow the project, Micronized Coal Reburning Demonstration for NO_x Control, to be conducted at both Milliken Station in Lansing, NY and Eastman Kodak Company in Rochester, NY.

The Babcock & Wilcox Company's CCT-II project, Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit, final reports issued and project completed.

The Ohio Power Company's CCT-I project, Tidd PFBC Demonstration Project, final reports issued and project completed.

May 1996

The ABB Combustion Engineering, Inc. CCT-II project, Combustion Engineering IGCC Repowering Project, was concluded.

June 1996

Pure Air on the Lake's CCT-II project, Advanced Flue Gas Desulfurization Project, final reports issued and project completed.

August 1996

The Arthur D. Little, Inc., CCT-V project was restructured and retitled as the Clean Coal Diesel Demonstration Project.

September 1996

The Appalachia Power Company CCT-II project, PFBC Utility Demonstration Project, was concluded.

October 1996

DOE signed a cooperative agreement with CCT-V participant, CPICOR™ Management Company LLC (Clean Power from Integrated Coal/Ore Reduction [CPICOR™]).

November 1996

Southern Company Services' CCT-II project, Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers, final reports issued and project completed.

December 1996

ABB Environmental Systems' CCT-II project, SNOX™ Flue Gas Cleaning Demonstration Project, final reports issued and project completed.

May 1997

The Pennsylvania Electric Company CCT-V project, Externally Fired Combined-Cycle Demonstration Project, was concluded.

September 1997

DOE modified the cooperative agreement for JEA's (formerly Jacksonville Electric Authority) CCT-I project, JEA Large-Scale CFB Combustion Project (formerly The City of Tallahassee project, then the York County Energy Partners project).

December 1997

ENCOAL Corporation's CCT-III project, ENCOAL® Mild Coal Gasification Project, final reports issued and project completed.

DOE signed a new cooperative agreement for the restructured City of Lakeland's CCT-III project, McIntosh Unit 4A PCFB Demonstration Project (formerly the DMEC-1 Limited Partnership project).

January 1998

DOE signed a new cooperative agreement for the restructured City of Lakeland's CCT-III project, McIntosh Unit 4B Topped PCFB Demonstration Project (formerly the Four Rivers Energy Partners, L.P. project).

April 1998

LIFAC–North America's CCT-III project, LIFAC Sorbent Injection Desulfurization Demonstration Project, final reports issued and project completed.

June 1998

Southern Company Services' CCT-II project, Demonstration of Innovative Applications of Technology for the CT-121 FGD Process, final reports issued and project completed.

The ABB Combustion Engineering, Inc. and CQ Inc.'s CCT-I project, Development of the Coal Quality Expert™, final reports issued and project completed.

September 1998

Energy and Environmental Research Corporation's CCT-I project, Enhancing the Use of Coals by Gas Reburning and Sorbent Injection, final reports issued and project completed.

DOE signed a revised cooperative agreement for the restructured ThermoChem Inc.'s CCT-IV project, Pulse Combustor Design Qualification test.

October 1998

Energy and Environmental Research Corporation's CCT-III project, Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler, final reports issued and project completed.

September 1999

Energy and Environmental Research Corp.'s CCT-I project, Enhancing the Use of Coals by Gas Reburning and Sorbent Injection, final report issued and project completed.

DOE signed a revised cooperative agreement for Southern Company Services, Inc.'s CCT-II project, Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler, extending the project.

October 1999

Southern Company Services, Inc.'s CCT-II project, Demonstration of Innovative Applications of Technology for the CT-121 FGD Process, final report issued and project completed.

New York State Electric & Gas Corporation's CCT-IV project, Milliken Clean Coal Technology Demonstration Project, final report issued and project completed.

Bethlehem Steel Corporation's CCT-III project, Blast Furnace Granular-Coal Injection System Demonstration Project, final report issued and project completed.

December 1999

New York State Electric & Gas Corporation's CCT-IV project, Micronized Coal Reburning Demonstration for NO_x Control, final report issued and project completed.

NOXSO Corporation's project, Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System, was terminated.

January 2000

Custom Coal International's CCT-IV project, Self-Scrubbing Coal™ : An Integrated Approach to Clean Air, was terminated.

February 2000

Public Service Company of Colorado's CCT-III project, Integrated Dry NO_x/SO_2 Emissions Control System, final report issued and project completed.

September 2000

Wabash River Coal Gasification Repowering Project Joint Venture's CCT-IV project, Wabash River Coal Gasification Repowering Project, final report issued and project completed.

Appendix C: Environmental Aspects

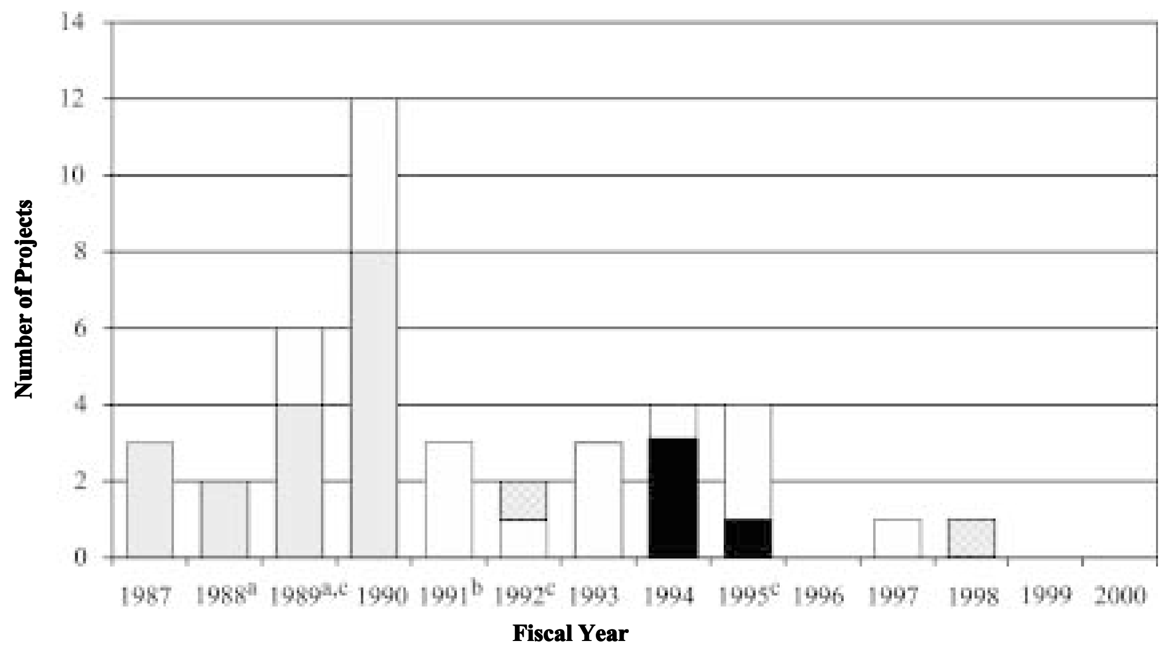
Introduction

The U.S. Department of Energy employs a three-step process to ensure that the CCT Program and its projects comply with the procedural requirements of the National Environmental Policy Act (NEPA), and the regulations for NEPA compliance promulgated by the Council on Environmental Quality (CEQ) (40 CFR Parts 1500–1508) and by DOE (10 CFR Part 1021). This process includes (1) preparation of a programmatic environmental impact statement (PEIS) in 1989; (2) preparation of preselection, project-specific environmental reviews; and (3) preparation of postselection, site-specific NEPA documentation. Several types of NEPA documents have been used in the CCT Program, including memoranda-to-file (MTF; discontinued as of September 30, 1990), environmental assessments (EA), and environmental impact statements (EIS). The Department of Energy's NEPA regulations also provide for categorical exclusions (CX) for certain classes of actions.

Exhibit C-1 shows the progress made through September 30, 2000, to complete NEPA reviews of projects in the CCT Program. By September 30, 2000, NEPA reviews were completed for 34 of the 38 CCT projects remaining in the program (two NEPA reviews were completed for one project, Enhancing the Use of Coals by Gas Reburning and Sorbent Injection—an MTF was completed for the Hennepin site and an EA for the Lakeside site). From 1987 through September 30, 2000, NEPA requirements were satisfied with a CX for 1 project, MTFs for 17 projects, EAs for 18 projects and EISs for 4 projects (actions exceed 35 because of project terminations, withdrawals, and restructuring).

For each project cofunded by DOE under the CCT Program, the industrial participant is required to develop an environmental monitoring plan (EMP) that will ensure operational compliance and that significant technical and environmental data are collected and disseminated. Data to be collected include compliance data to meet federal, state, and local requirements and performance data to aid in future commercialization of the technology.

Exhibit C-1
NEPA Reviews Completed as of September 30, 2000



[a] Includes an MTF (1988) and an EA (1989) required for one project

[b] Includes an EA for a project that was withdrawn

[c] Includes an EA for a project that was terminated

Memoranda-to-file
Environmental assessments
Categorical exclusions
Environmental impact statements

The Role of NEPA in the CCT Program

NEPA was initially enacted in 1969 as Public Law 91-190 and is codified at 42 U.S.C. §4321 *et seq.* The applicability of NEPA to the CCT Program is encapsulated in the following provision (Section 102):

[A]ll agencies of the Federal Government shall—. . .

(C) include in every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the quality of the human environment, a detailed statement by the responsible official on—

i. the environmental impact of the proposed action,

ii. any adverse environmental effects which cannot be avoided should the proposal be implemented,

iii. alternatives to the proposed action,

iv. the relationship between local short-term uses of man's environment and the maintenance and enhancement of long-term productivity, and

v. any irreversible and irretrievable commitments of resources which would be involved in the proposed action should it be implemented. . . .

(E) study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources[.]

Through NEPA, Congress created the CEQ, which has promulgated regulations that ensure compliance with the Act.

Compliance with NEPA

In November 1989, a PEIS was completed for the CCT Program. This PEIS addressed issues such as potential global climatic modification and the ecological and socioeconomic impacts of the CCT Program. The PEIS evaluated the following two alternatives:

- "No action," which assumed that conventional coal-fired technologies with conventional flue gas desulfurization controls would continue to be used, and
- "Proposed action," which assumed that successfully demonstrated clean coal technologies would undergo widespread commercialization by the year 2010.

In preselection project-specific environmental reviews, DOE evaluates the environmental aspects of each proposed demonstration project. Reviews are provided to the Source Selection Official for consideration in the project selection process. The site-specific environmental, health, safety, and socioeconomic issues associated with each proposed project are examined during the NEPA review. As part of the comprehensive evaluation prior to selecting projects, the strengths and weaknesses of each proposal are compared with the environmental evaluation criteria. To the maximum extent possible, the environmental impacts of each proposed project and practical mitigating measures are considered. Also, a list of necessary permits is prepared, to the extent known; these are permits that would need to be obtained in implementing the proposed project.

Upon selection, project participants are required to prepare and submit additional environmental information. This detailed site- and project-specific information is used, along with independent information gathered by DOE, as the basis for site-specific NEPA documents that are prepared by DOE for each selected project. These NEPA documents are prepared, considered, and published in full conformance with CEQ and DOE regulations for NEPA compliance.

Categorical Exclusions

"Subpart D—Typical Classes of Actions" of the DOE NEPA regulations provides for categorical exclusions as a class of actions that DOE has determined do not individually or cumulatively have a significant effect on the human environment. Two projects, Micronized Coal Reburning Demonstration for NO_x Control and Pulse Combustor Design Qualification Test, were determined to be covered by a categorical exclusion in August 1992 and November 1998, respectively.

Memoranda-to-File

The MTF was established when DOE's NEPA guidelines were first issued in 1980. The MTF was intended for circumstances when the expected impacts of the proposed action were clearly insignificant, yet the action had not been specified as a categorical exclusion from NEPA documentation. The use of the MTF was terminated as of September 30, 1990. Exhibit C-2 lists the 17 projects for which an MTF was prepared.

Environmental Assessments

An EA has the following three functions:

1. To provide sufficient evidence and analysis for determining whether a proposed action requires preparation of an EIS or a finding of no significant impact (FONSI);

Exhibit C-2
Memoranda-to-File Completed

Project and Participant	Completed
CCT-I	
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ Inc.)	4/27/90
LIMB Demonstration Project Extension and Coolside Demonstration (McDermott Technology, Inc.)	6/2/87
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	3/26/87
Nucla CFB Demonstration Project (Colorado-Ute Electric Association, Inc.; now Tri-State Generation and Transmission Association, Inc.)	4/18/88
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Hennepin site) (Energy and Environmental Research Corporation)	5/9/88
Tidd PFBC Demonstration Project (The Ohio Power Company)	3/5/87
CCT-II	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	1/31/90
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	9/22/89
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	5/22/89
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur, Coal-Fired Boilers (Southern Company Services, Inc.)	8/16/89
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	7/21/89
CCT-III	
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	9/21/90
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	8/10/90
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	9/25/90
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	9/6/90
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	10/2/90
Integrated Dry NO_x/SO_2 Emissions Control System (Public Service Company of Colorado)	9/27/90

2. To aid an agency's compliance with NEPA when no EIS is necessary, *i.e.*, to provide an interdisciplinary review of proposed actions, assess potential impacts, and identify better alternatives and mitigation measures; and
3. To facilitate preparation of an EIS when one is necessary.

An EA's contents are determined on a case-by-case basis and depend on the nature of the action. If appropriate, a DOE EA also includes any floodplain or wetlands assessment that has been prepared, and may include analyses needed for other environmental determinations.

If an agency determines on the basis of an EA that it is not necessary to prepare an EIS, a FONSI is issued. Council on Environmental Quality regulations describe the FONSI as a document that briefly presents the reasons why an action will not have a significant effect on the human environment and for which an EIS therefore will not be prepared. The FONSI includes the EA, or a summary of it, and notes any other related environmental documents. The CEQ and DOE regulations also provide for notification of the public that a FONSI has been issued. Also, DOE provides copies of the EA and FONSI to the public on request.

Exhibit C-3 lists the 18 projects for which an EA has been prepared. The exhibit includes EAs for one project that was subsequently withdrawn from the program—TransAlta Resources Investment Corporation's Low-NO_x/SO_2 Burner Retrofit for Utility Cyclone Boilers project—and three that were terminated—ABB Combustion Engineering's Combustion Engineering IGCC Repowering Project, Bethlehem Steel Corporation's Innovative Coke Oven Gas Cleaning System for Retrofit Applications, and Pennsylvania Electric's Warren Station Externally-Fired Combined-Cycle Demonstration Project.

Exhibit C-3
Environmental Assessments Completed as of September 30, 2000

Project and Participant	Completed
CCT-I	
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Lakeside site) (Energy and Environmental Research Corporation)	6/25/89
Advanced Coal Conversion Process Demonstration (Western SynCoal LLC)	3/27/91
CCT-II	
Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.) (project terminated)	3/27/92
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)	2/12/91
Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation) (project terminated)	12/22/89
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	2/16/90
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	4/16/90
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	8/10/90
Low-NO_x/SO_2 Burner Retrofit for Utility Cyclone Boilers (TransAlta Resources Investment Corporation) (project withdrawn)	3/21/91
CCT-III	
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	6/30/95
Blast Furnace Granular-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	6/8/93
ENCOAL® Mild Coal Gasification Project (ENCOAL Corporation)	8/1/90
Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System (NOXSO Corporation)	6/26/95
CCT-IV	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	2/14/94
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	8/18/93
Warren Station Externally-Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company) (Warren Station site) (project terminated)	5/18/95
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	5/28/93
CCT-V	
Clean Coal Diesel Demonstration Project (Arthur D. Little, Inc.)	6/2/97

Environmental Impact Statements

The primary purpose of an EIS is to serve as an action-forcing device to ensure that the policies and goals defined in NEPA are infused into the programs and actions of the federal government. An EIS contains a full and fair discussion of all significant environmental impacts. The EIS should inform decision makers and the public of reasonable alternatives that would avoid or minimize adverse impacts or enhance the quality of the human environment.

The CEQ regulations state that an EIS is to be more than a disclosure document; it is to be used by federal officials in conjunction with other relevant material to plan actions and make decisions. Analysis of alternatives is to encompass those alternatives to be considered by the ultimate decision maker, including a complete description of the proposed action. In short, the EIS is a means of assessing the environmental impacts of a proposed DOE action (rather than justifying decisions already made), prior to making a decision to proceed with the proposed action. Consequently, before a record of decision (ROD) is issued, DOE may not take any action that would have an adverse environmental effect or limit the choice of reasonable alternatives. As seen in Exhibit C-4, the EISs for three projects were completed in 1994. In 1995, DOE issued a ROD on the EIS prepared for the York County Energy Partners project located in York County, Pennsylvania. This project has been restructured, and a new NEPA compliance document for the JEA project site was completed in 2000, but the ROD had not been issued by the end of the fiscal year.

NEPA Actions in Progress

Exhibit C-5 lists the status of projects for which the NEPA process has not yet been completed.

Exhibit C-4
Environmental Impact Statements Completed as of September 30, 2000

Project and Participant	Completed*
CCT-I	
York County Energy Partners Cogeneration Project (York County, PA site) (York County Energy Partners, L.P.) (project relocated)	8/11/95
CCT-III	
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	3/10/94
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	8/17/94
CCT-IV	
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	11/8/94

* Completion is the date DOE issued a record of decision.

Exhibit C-5
NEPA Reviews in Progress as of September 30, 2000

Project and Participant	Status
CCT-I	
JEA Large-Scale CFB Combustion Demonstration Project (JEA)[a]	EIS planned (12/00)
CCT-III	
McIntosh Unit 4A PCFB Demonstration Project (Lakeland, City of, Lakeland Electric)	On hold
CCT-V	
McIntosh Unit 4B Topped PCFB Demonstration Project (Lakeland, City of, Lakeland Electric)	On hold
Clean Power from Integrated Coal/Ore Reduction (CPICOR™) (CPICOR™ Management Company LLC)	EIS planned (12/01)
Kentucky Pioneer Energy IGCC Demonstration Project (Kentucky Pioneer Energy, LLC)	EIS planned (8/01)

[a] EIS completed in June 2000.

Environmental Monitoring

CCT project participants are required to develop and implement an EMP that addresses both compliance and supplemental monitoring. Exhibit C-6 lists the status of EMPs for all 38 projects in the CCT Program. The EMP is intended to ensure collection and dissemination of the significant technology-, project-, and site-specific environmental data necessary for evaluation of impacts upon health, safety, and the environment. Further, the data are used to characterize and quantify the environmental performance of the technology in order to evaluate its commercialization and deployment potential. In addition to regulatory compliance data, further monitoring is required to fulfill the following:

- Ensure that emissions, ambient levels of pollutants, and environmental impacts do not exceed expectations projected in the NEPA documents,
- Identify any need for corrective action,
- Verify the implementation of any mitigative measure that may have been identified in a mitigation action plan pursuant to the provisions of an EA or EIS, and
- Provide the essential data on the environmental performance of the technology needed to evaluate the potential impact of future commercialization, including the ability of the technology to meet requirements of the Clean Air Act and the 1990 amendments.

The objective of the CCT Program's environmental monitoring efforts is to ensure that, when commercially available, clean coal technologies will be capable of responding fully to air toxics regulations that emerge from the CAAA, and to the maximum extent possible, are in the vanguard of cost-effective solutions to concerns about public health and safety related to coal use.

Air Toxics

Title III of the CAAA lists known hazardous air pollutants (HAPs) and, among other things, calls for the EPA to establish categories of sources that emit these pollutants. Exploratory analyses suggest that HAPs may be released by conventional coal-fired power plants and, presumably, by plants using clean coal technologies. It is expected that emissions standards will be proposed for the electric-power-production-source categories. However, there are many uncertainties as to which HAPs will be regulated, their prevalence in various types and sources of coal, and their nature and fate as functions of combustion characteristics and the particular clean coal technology used.

The CCT Program recognizes the importance of monitoring HAPs in achieving widespread commercialization in the late 1990s and beyond. For all projects with existing cooperative agreements, DOE sought to include HAPs monitoring. A total of 20 projects contain provisions for monitoring HAPs.

The CCT-V Program Opportunity Notice (PON) acknowledged the importance of HAPs throughout the solicitation, including them as an aspect of proposal evaluation. The PON addressed the control of air toxics as an environmental performance criterion. Also, in the instructions on proposal preparation, the PON directed proposers as follows:

> With respect to emission of air toxics, Proposers should consider . . . the particular elements and compounds [listed in Table 5-1 of the PON, "Specific Air Toxics to be Monitored"]. Proposers should present any information known concerning the reduction of emissions of these toxics by [the proposed] technology. Some of the toxics for which the proposed technology may offer control are likely unregulated in the target market at present. The significance and importance of the additional control afforded by the proposed technology for the continued use of coal should be explained. An example of this kind would be one or more particular air toxic compounds controlled by a technology meant for use in power generation.

The CCT-V PON also stipulates that information on air toxics be presented in the environmental information required by DOE. Exhibit C-7 lists the 20 projects that provide for HAPs monitoring. Eleven of these projects have completed the HAPs monitoring requirements. The objective of the HAPs monitoring program is to improve the quality of HAPs data being gathered and to monitor a broader range of plant configurations and emissions control equipment.

The CCT Program is coordinating with organizations such as the Electric Power Research Institute (EPRI) and the Ohio Coal Development Office in activities focused on HAPs monitoring and analysis. Further, under the DOE Coal R&D Program, two reports summarizing the source, distribution, and fate of HAPs from coal-fired power plants were published in 1996. A report released in July 1996, *Summary of Air Toxics Emissions Testing at Sixteen Utility Plants,* provided assessment of HAPs measured in the coal, across the major pollution control devices, and the HAPs emitted from the stack. A second report, *A Comprehensive Assessment of Toxics Emissions from Coal-Fired*

Exhibit C-6
Status of Environmental Monitoring Plans for CCT Projects as of September 30, 2000

Project and Participant	Status
CCT-I	
Development of the Coal Quality Expert™ (ABB Combustion Engineering, Inc. and CQ Inc.)	Completed 7/31/90
LIMB Demonstration Project Extension and Coolside Demonstration (McDermott Technology, Inc.)	Completed 10/19/88
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	Completed 9/22/87
Nucla CFB Demonstration Project (Colorado-Ute Electric Association, Inc.; now Tri-State Generation and Transmission Association, Inc.)	Completed 2/27/88
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	Completed 10/15/89 (Hennepin) Completed 11/15/89 (Lakeside)
Tidd PFBC Demonstration Project (The Ohio Power Company)	Completed 5/25/88
Advanced Coal Conversion Process Demonstration (Western SynCoal LLC)	Completed 4/7/92
JEA Large-Scale CFB Combustion Demonstration Project (JEA)	Projected 7/01
CCT-II	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Completed 10/31/91
Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)	Completed 11/18/91
SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	Completed 12/31/91
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	Completed 3/26/90
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	Completed 1/31/91
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Completed 9/14/90
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	Completed 12/18/90
Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	Completed 3/11/93
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	Completed 12/27/90

Exhibit C-6 (continued)
Status of Environmental Monitoring Plans for CCT Projects as of September 30, 2000

Project and Participant	Status
CCT-III	
Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	Completed 8/29/96
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Completed 10/2/92
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Completed 4/11/97
Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)	Completed 8/9/91
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	Completed 6/12/91
Blast Furnace Granular-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Completed 12/23/94
McIntosh Unit 4A PCFB Demonstration Project (Lakeland, City of, Lakeland Electric)	On hold
ENCOAL® Mild Coal Gasification Project (ENCOAL Corporation)	Completed 5/29/92
Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	Completed 7/26/90
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC–North America)	Completed 6/12/92
Integrated Dry NO_x/SO_2 Emissions Control System (Public Service Company of Colorado)	Completed 8/5/93
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	Completed 5/96
CCT-IV	
Micronized Coal Reburning Demonstration for NO_x Control (New York State Electric & Gas Corporation)	Completed 8/97
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	Completed 12/1/94
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	Completed 10/31/96
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	Completed 7/9/93
Pulse Combustor Design Qualification Test (ThermoChem, Inc.)	Completed 12/00
CCT-V	
Clean Coal Diesel Demonstration Project (Arthur D. Little, Inc.)	Completed 2/99
Clean Power from Integrated Coal/Ore Reduction (CPICOR™) (CPICOR™ Management Company LLC)	Projected 9/03
Kentucky Pioneer Energy IGCC Demonstration Project (Kentucky Pioneer Energy, LLC)	To be determined
McIntosh Unit 4B Topped PCFB Demonstration Project (Lakeland, City of, Lakeland Electric)	On hold

Exhibit C-7
Status of CCT Projects Monitoring Hazardous Air Pollutants as of September 30, 2000

Application Category	Participant	Project	Status
Advanced Electric Power Generation	Arthur D. Little, Inc.	Clean Coal Diesel Demonstration Project	Planned
	Kentucky Pioneer Energy, LLC	Kentucky Pioneer Energy IGCC Demonstration Project	Planned
	Lakeland, City of, Lakeland Electric	McIntosh Unit 4B Topped PCFB Demonstration Project	On hold
	The Ohio Power Company	Tidd PFBC Demonstration Project	Completed
	Sierra Pacific Power Company	Piñon Pine IGCC Power Project	In progress
	Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	In progress
	Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	Completed
	JEA	JEA Large-Scale CFB Combustion Demonstration Project	Planned
Environmental Control Devices	ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	Completed
	AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	Completed
	The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO_x Control	Completed
	The Babcock & Wilcox Company	SO_x-NO_x-Rox Box™ Flue Gas Cleanup Demonstration Project	Completed
	New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	Completed
	Public Service Company of Colorado	Integrated Dry NO_x/SO_2 Emissions Control System	Completed
	Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	Completed
	Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Completed
	Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Completed
	Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers	Completed
Coal Processing for Clean Fuels	ENCOAL Corporation	ENCOAL® Mild Coal Gasification Project	Completed
Industrial Applications	CPICOR™ Management Company LLC	Clean Power from Integrated Coal/Ore Reduction (CPICOR™)	Planned

Power Plants: Phase I Results from the U.S. Department of Energy Study, was released in September 1996 and provided the raw data from the emissions testing. Emissions data were collected from 16 power plants, representing nine process configurations, operated by eight different utilities; several power plants were sites for CCT Program projects. The power plants represented a range of different coal types, process configurations, furnace types, and pollution control methods.

The second phase of the DOE/EPRI effort currently in progress is sampling at other sites, including the CCT Program's Wabash River IGCC project. Further, the results from the first phase will be used to determine what configuration and coal types require further assessment.

In October 1996, EPA submitted to Congress an interim version of its technical assessment of toxic air pollutant emissions from power plants, *Study of Hazardous Air Pollutant Emissions from Electric Utility Steam Generating Units, Interim Final Report.* EPA plans to continue evaluating the potential exposures and potential public health concerns from mercury emissions from utilities. In addition, the agency will evaluate information on various potential control technologies for mercury. If EPA decides that HAPs pose a risk, then the agency must propose air toxic emissions controls by November 15, 1998, and make them final two years later.

Following up on the October 1996 report to Congress, a report was released by EPA focusing on Mercury emissions. The December 1997 report, *Mercury Study Report to Congress*, estimates that U.S. industrial sources were responsible for releasing 158 tons of Mercury into the atmosphere in 1994 and 1995. The EPA estimates that 87 percent of those emissions originate from combustion sources such as waste and fossil fuel facilities, 10 percent from manufacturing facilities, 2 percent from area sources, and 1 percent from other sources. The EPA also identified four specific categories that account for about 80 percent of the total anthropogenic sources: coal-fired power plants, 33 percent; municipal waste incinerators, 18 percent; commercial and industrial boilers, 18 percent; and medical waste incinerators, 10 percent. The next step for EPA is to assess the need for enhanced research on health effects and on new pollution control technologies, community "right-to-know" approaches, and regulatory actions.

Most recently, the National Academy of Sciences released a report in June 2000 reinforcing the importance, especially for women in their child-bearing years, of heeding consumption advisories on noncommercial fish to avoid methylmercury. As a result of the study, EPA has announced it will regulate mercury emissions from power plants. The Environmental Protection Agency will propose regulations by December 2003.

The results of the HAPs program have significantly mitigated concerns about HAPs emission from coal-fired generation and focused attention on but a few flue gas constituents. The results have the potential to make the forthcoming EPA regulations less strict, which could avoid unnecessary control costs and thus save consumers money on electricity bills.

Appendix D: 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 project participant 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 National Energy Technology Laboratory (NETL) are provided.

Environmental Control Devices

SO_2 Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

Participant:

AirPol, Inc.

Contacts:

Niels H. Kastrup
(281) 539-3400
(281) 539-3411 (fax)
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NO_x Control Technologies

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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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Coal Processing for Clean Fuels

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Appendix E: Acronyms, Abbreviations, and Symbols

¢	cent
°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.
AEO2000	*Annual Energy Outlook 2000*
AER99	*Annual Energy Review 1999*
AFBC	atmospheric fluidized-bed combustion
AFGD	advanced flue gas desulfurization
AIDEA	Alaska Industrial Development and Export Authority
AOFA	advanced overfire air
APEC	Asia Pacific Economic Cooperation
APF	advanced particulate filter
ARIL	Advanced Retractable Injection Lances
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
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-to-nitrogen
CAPI	Clean Air Power Initiative
Ca/S	calcium-to-sulfur
$CaSO_3$	calcium sulfite
$CaSO_4$	calcium sulfate
CCOFA	close-coupled overfire air
CCT	clean coal technology
CCTDP	Clean Coal Technology Demonstration Program
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
CD-ROM	Compact disk-read only memory
CDL®	Coal-Derived Liquid®
CenPEEP	Center for Power Efficiency and Environmental Protection
CEQ	Council on Environmental Quality
CFB	circulating fluidized-bed
C/H	carbon-to-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
EERC	Energy and Environmental Research Center, University of North Dakota
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
EPDC	Japan's Electric Power Development Company
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	Office of Fossil Energy
FeO	iron oxide
Fe_2S	pyritic sulfur
FERC	Federal Energy Regulatory Commission
FETC	Federal Energy Technology Center (now NETL)
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 foot
GB	gigabyte(s)
GE	General Electric
GHG	greenhouse gases
GNOCIS	Generic NO_x Control Intelligent System
gpm	gallons per minute
gr	grains
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	elemental hydrogen
H_2	molecular hydrogen
H_2S	hydrogen sulfide
H_2SO_4	sulfuric acid
HAP	hazardous air pollutant
HCl	hydrogen chloride
HF	hydrogen fluoride
HGPFS	hot gas particulate filter system
HHV	higher heating value
hr.	hour(s)
HRSG	heat recovery steam generator
ID	Induced Draft
IEA	International Energy Agency
IEO2000	*International Energy Outlook 2000*
IGCC	integrated gasification combined-cycle
in, in^2, in^3	inch(es), square inch(es), cubic inch(es)
JBR	Jet Bubbling Reactor®
KCl	potassium chloride
K_2SO_4	potassium sulfate
kW	kilowatt(s)
kWh	kilowatt-hour(s)
lb.	pound(s)
L/G	liquid-to-gas ratio
LHV	lower 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
LSDE	Laboratorium Sumderdaya Energi
LSFO	limestone forced oxidation
MASB	multi-annular swirl burner
MB	megabyte(s)
MCFC	molten carbonate fuel cell
MCR	Maximum Continuous Rating
MDEA	methyldiethanolamine
$MgCO_3$	magnesium carbonate
MgO	magnesium oxide
MHz	megahertz
mills/kWh	mills per kilowatt hour
min.	minute(s)
mo.	month(s)
MSW	municipal solid waste
MTCI	Manufacturing and Technology Conversion International
MTF	memorandum (memoranda)-to-file
MW	megawatt(s)
MWe	megawatt(s)-electric
MWt	megawatt(s)-thermal
N	elemental nitrogen
N_2	molecular nitrogen
n.d.	not dated
N/A	not applicable
Na/Ca	sodium-to-calcium
Na_2/S	sodium-to-sulfur
NaOH	sodium hydroxide
Na_2CO_3	sodium carbonate
NAAQS	National Ambient Air Quality Standards

NEDO	New Energy Development Organization
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory (formerly FETC)
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
NSR	normalized stoichiometric ratio
NTHM	net tons of hot metal
NTIS	National Technical Information Service
NTPC	National Thermal Power Corporation
NYSEG	New York State Electric & Gas Corporation
O	elemental oxygen
O_2	molecular oxygen
O&M	operation and maintenance
OC&PS	Office of Coal & Power Systems
OTAG	Ozone Transport Assessment Group
OTC	Ozone Transport Commission
PASS	Pilot Air Stabilization System
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
psia	pound(s) per square inch absolute
psig	pound(s) per square inch gauge
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	Richmond 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.
SDA	spray dryer absorber
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 losses
U.K.	United Kingdom
UNESCO	United Nations Educational, Scientific and Cultural Organization
URL	Uniform Resource Locator
U.S.	United States
USAID	U.S. Agency for International Development

VFB	vibrating fluidized bed
VOC	volatile organic compound
WC	water column
WES	wastewater evaporation system
W.G.	water gage
WLFO	wet limestone, forced oxidation
wt.	weight
yr.	year(s)

State Abbreviations

AK	Alaska
AL	Alabama
AR	Arkansas
AZ	Arizona
CA	California
CO	Colorado
CT	Connecticut
DC	District of Columbia
DE	Delaware
FL	Florida
GA	Georgia
HI	Hawaii
IA	Iowa
ID	Idaho
IL	Illinois
IN	Indiana
KS	Kansas
KY	Kentucky
LA	Louisiana
MA	Massachusetts
MD	Maryland
ME	Maine
MI	Michigan
MN	Minnesota
MO	Missouri
MS	Mississippi
MT	Montana
NC	North Carolina
ND	North Dakota
NE	Nebraska
NH	New Hampshire
NJ	New Jersey
NM	New Mexico
NV	Nevada
NY	New York
OH	Ohio
OK	Oklahoma
OR	Oregon
PA	Pennsylvania
PR	Puerto Rico
RI	Rhode Island
SC	South Carolina
SD	South Dakota
TN	Tennessee
TX	Texas
UT	Utah
VA	Virginia
VI	Virgin Islands
VT	Vermont
WA	Washington
WI	Wisconsin
WV	West Virginia
WY	Wyoming

Other

Some companies have adopted an acronym as their corporate names. The following corporate names reflect the former name of the company.

BG/L	British Gas Lurgi
JEA	Jacksonville Electric Authority
KRW	Kellogg Rust Westinghouse

Index of CCT Projects and Participants