

CLEAN GOAL

T E C H N O L O G Y



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

DOE/FE-0346

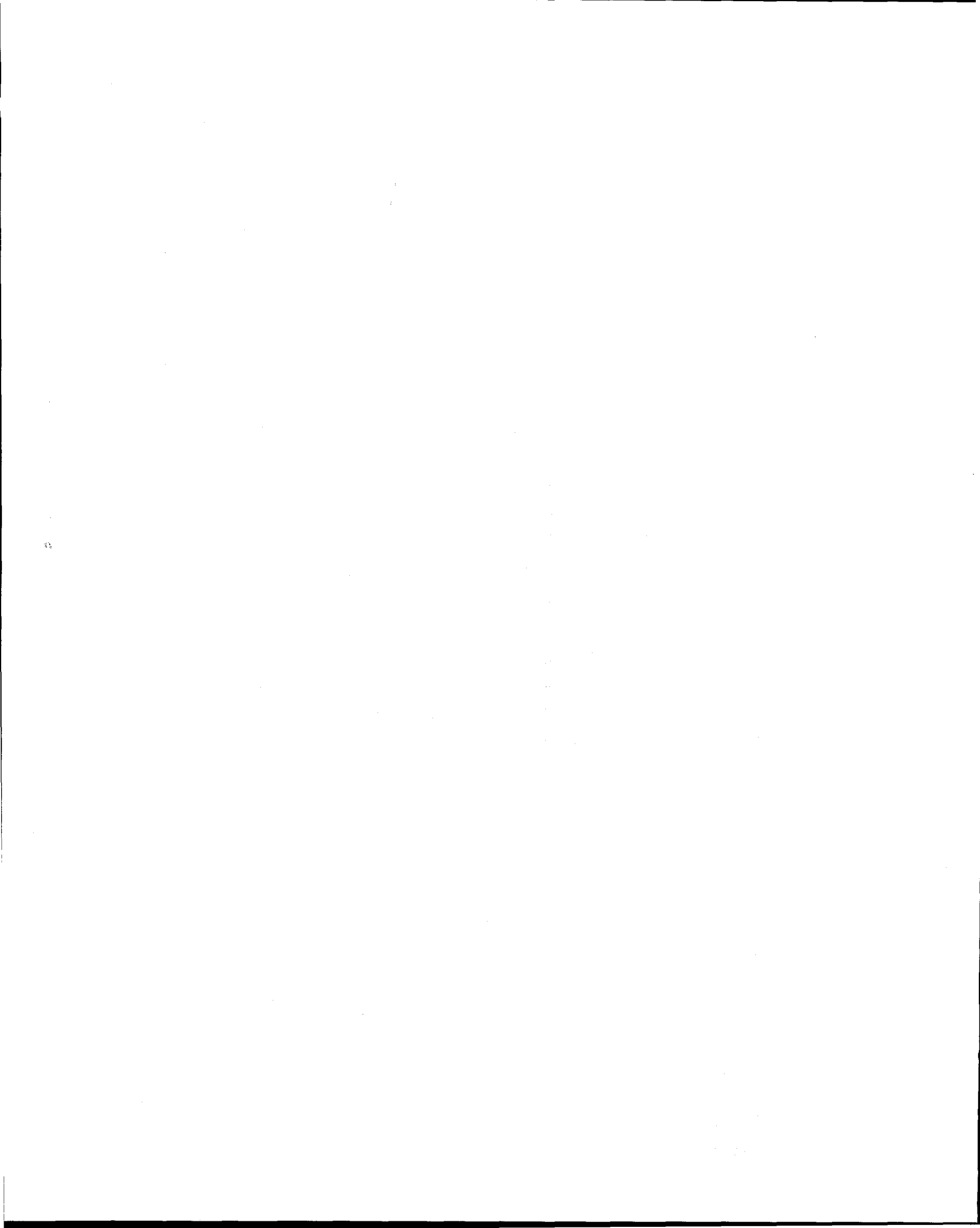
Clean Coal Technology Demonstration Program

Program Update 1995

April 1996

MASTER

de
DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED



Portions of this document may be illegible
in electronic image products. Images are
produced from the best available original
document.

DISCLAIMER



Contents

Executive Summary: The Clean Coal Technology Demonstration Program—10 Years of Progress

Introduction	ES-1
The Coal Technology Portfolio	ES-2
Technical, Economic, and Environmental Performance	ES-2
Marketplace Credibility	ES-3
Model Government/Industry Partnership for Technology Advancement and Job Creation	ES-8

Section 1: Role of the Program

National Perspective	1-1
Maximizing Energy Productivity	1-2
Preventing Pollution to Reduce Adverse Environmental Impact	1-7
Acid Rain Mitigation	1-7
Hazardous Air Pollutants	1-10
Value-Added Solid Wastes	1-10
Global Climate Change Protection	1-10
Keeping America Secure	1-11
Coal Technology Perspective	1-12
Role of the Technologies	1-13
Advanced Electric Power Generation	1-13
Environmental Control Devices	1-18
Coal Processing for Clean Fuels	1-21
Industrial Applications	1-24
Introduction	2-1
The Legislation	2-1
Implementation Principles	2-2
Solicitation Results	2-3

Section 2: Program Implementation

Future Implementation Direction 2-12
Environmental Aspects 2-15

The Role of NEPA in the CCT Program 2-15

Compliance with NEPA 2-16

Categorical Exclusions 2-16

Memoranda-to-File 2-17

Environmental Assessments 2-17

Environmental Impact Statements 2-19

NEPA Actions in Progress 2-19

Environmental Monitoring 2-19

Air Toxics 2-20

Summary 3-1

Program Funding 3-1

Availability of Funding 3-2

Use of Appropriated Funds 3-2

Project Funding, Costs, and Schedules 3-4

Cost Sharing 3-4

Recovery of Government Outlays (Recoupment) 3-5

Summary 4-1

Commitment to Commercial Realization 4-2

Understanding the Domestic Market 4-10

An Emerging International Market 4-12

Market Communications 4-14

Summary 5-1

Tidd PFBC Demonstration Project 5-1

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler 5-1

Section 3: Funding and Costs

Section 4: The Road to Commercial Realization

Section 5: Results of Completed Projects

Demonstration of Selective Catalytic Reduction Technology for Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers 5-2

Advanced Flue Gas Desulfurization Demonstration Project 5-2

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process 5-3

Results Summaries 5-3

Advanced Electric Power Generation 5-5

Environmental Control Devices 5-13

Industrial Applications 5-53

Introduction 6-1

Advanced Electric Power Generation 6-2

Environmental Control Devices 6-6

Coal Processing for Clean Fuels 6-9

Industrial Applications 6-14

Summary 7-1

Advanced Electric Power Generation 7-7

Environmental Control Devices 7-37

Coal Processing for Clean Fuels 7-77

Industrial Applications 7-89

Relevant Legislation A-1

Selection and Negotiation History B-1

CCT Program Publications C-1

Papers and Presentations on the CCT Program D-1

CCT Project Contacts E-1

Acronyms and Abbreviations F-1

Index G-1

Section 6: Results and Accomplishments from Ongoing Projects

Section 7: Project Fact Sheets

Appendix A

Appendix B

Appendix C

Appendix D

Appendix E

Appendix F

Index

Exhibits

Executive Summary

- ES-1 Completed Projects by Application Category ES-3
- ES-2 Summary of Results of Completed CCT Projects ES-4

Section 1: Role of the Program

- 1-1 Service Areas of Utilities Participating in the CCT Program 1-4
- 1-2 CCT Demonstration Projects, by Application Category 1-5
- 1-3 NO_x Emission Limits for Coal-Fired Units 1-9
- 1-4 R&D Goals of Advanced Power Systems 1-13
- 1-5 CCT Program IGCC Project Characteristics 1-16
- 1-6 CCT Program NO_x Control Technology Characteristics 1-19
- 1-7 CCT Program SO₂ Control Technology Characteristics 1-20
- 1-8 CCT Program Combined SO_x/NO_x Control Technology 1-21

Section 2: Program Implementation

- 2-1 CCT Program Selection Process Summary 2-4
- 2-2 Clean Coal Technology Demonstration Projects, by Solicitation 2-5
- 2-3 Geographic Locations of CCT Projects—Advanced Electric Power Generation 2-8
- 2-4 Geographic Locations of CCT Projects—Environmental Control Devices 2-9
- 2-5 Geographic Locations of CCT Projects—Coal Processing for Clean Fuels 2-10
- 2-6 Geographic Locations of CCT Projects—Industrial Applications 2-11
- 2-7 NEPA Reviews Completed 2-16
- 2-8 Memoranda-to-File Completed 2-17
- 2-9 Environmental Assessments Completed 2-18
- 2-10 Environmental Impact Statements Completed 2-19
- 2-11 NEPA Reviews in Progress 2-20

Section 3: Funding and Costs

- 3-1 Relationship between Appropriations and Subprogram Budgets for the CCT Program 3-2
- 3-2 Annual CCT Program Funding, by Appropriations and Subprogram Budgets 3-3
- 3-3 CCT Financial Projections as of December 31, 1995 3-4
- 3-4 Financial Status of the CCT Program as of December 31, 1995 3-5
- 3-5 CCT Project Schedules and Funding, by Application Category 3-6
- 3-6 Cost Sharing of Active CCT Projects 3-8
- 4-1 CCT Program: Commercialization Successes 4-4
- 4-2 Award-Winning CCT Projects 4-11

Section 4: The Road to Commercial Realization

Section 5: Results of Completed Projects

- 5-1 Completed Projects 5-3
- 5-2 Completed Projects, by Application Category 5-4
- 5-3 Coal Reburning System Test Results 5-15
- 5-4 LNCB® Test Results 5-18
- 5-5 NO_x Data from Cherokee Station, Unit 3 5-20
- 5-6 Tangential Burner Configurations 5-21
- 5-7 Catalysts Tested 5-24
- 5-8 Test Parameters 5-34
- 5-9 Operating Results 5-34
- 5-10 SO₂ Removal Performance 5-35
- 5-11 Operation of CT-121 Scrubber 5-38
- 5-12 SO₂ Removal Efficiency 5-39
- 5-13 Particulate Capture Performance 5-40

Section 6: Results and Accomplishments from Ongoing Projects

- 6-1 Highlighted CCT Projects, by Application Category 6-1
- 6-2 Status of CCT Demonstration Projects at Year-End 1995—Advanced Electric Power Generation 6-15
- 6-3 Status of CCT Demonstration Projects at Year-End 1995—Environmental Control Devices 6-17
- 6-4 Status of CCT Demonstration Projects at Year-End 1995—Coal Processing for Clean Fuels 6-20
- 6-5 Status of CCT Demonstration Projects at Year-End 1995—Industrial Applications 6-21

Section 7: Project Fact Sheets

7-1	Project Fact Sheets, by Application Category	7-2
7-2	Project Fact Sheets, by Participant	7-4

Executive Summary: The Clean Coal Technology Demonstration Program—10 Years of Progress

Introduction

The year 1995 marked the 10th anniversary of the Clean Coal Technology Demonstration Program (known as the CCT Program): an anniversary of progress toward assuring that technologies being demonstrated will enable coal to continue as the major contributor to the nation's energy supply mix, provide the base for the nation's leadership in world energy production, and assist the country in achieving environmental objectives.

In the framing of the CCT Program, the congressional, executive branch, and private-sector participants recognized and understood the fundamental realities of coal and its contribution to the national and global energy future. These included the facts that (1) the location, magnitude, and characteristics of the coal resource base were well understood, thus minimizing costs and risks associated with resource exploration; (2) the technology and skilled labor base of nearly 1.1 million workers were available to safely and economically extract, transport, and use coal in a manner that protected the environment; (3) a multi-billion dollar infrastructure was in place to gather, transport, and deliver this valuable energy commodity to serve the domestic and international marketplace; (4) coal was used to produce over 55 percent of the nation's electric power and was vital to industrial processes such as steel and cement production as well

as industrial power; (5) the most abundant fossil energy resource was secure within the nation's borders and relatively invulnerable to natural or human disruptions because of the coal industry's production responsiveness and stockpiling capability; and (6) coal was the fuel of necessity in many lesser developed countries. The program framers recognized that the continued viability of coal as a source of energy was dependent on demonstration and commercial application of a new generation of advanced coal-based technology characterized by enhanced technical, economic, and environmental performance. This vision was extended to encompass the recommendations of the U.S. and Canadian Special Envoys on Acid Rain and broadened the range of technological solutions available to eliminate acid rain concerns associated with coal use.

The participants in the framing of the CCT Program made use of the lessons learned from previous U.S. Department of Energy (DOE) demonstration programs and the operation of the Synthetic Fuels Corporation to craft a unique, cost-shared technology development effort which relied on the strengths of the private industry and government participants working in partnership. The pioneering process implemented under the CCT Program proved that an industry/government partnership to advance energy technology can produce exceptional results in a relatively short time frame.

With over 40 percent of the projects completed, the CCT Program has achieved several significant accomplishments that will have lasting impact on the continued use of coal. These accomplishments are as follows:

1. Demonstration of a portfolio of technologies that expand coal utilization capabilities, improve economics of coal use, and achieve strict environmental compliance goals for acid rain and other global environmental concerns
2. Extension of the technical, economic, and environmental performance envelope of coal technologies
3. Establishment of commercial credibility of advanced coal technologies in the domestic and international marketplaces
4. Demonstration of a model program for government/industry cooperation in technology development

The Coal Technology Portfolio

The CCT Program has been implemented through a series of five nationwide competitive solicitations conducted over a 9-year period. The first solicitation was directed towards demonstrating the feasibility of future commercial application of clean coal technology, which would balance the goals of expanding coal use and minimizing environmental impact. The next two solicitations were aimed primarily at the technologies that could mitigate the potential impacts of acid rain from existing coal-fired power plants. The fourth and fifth solicitations addressed the post-2000 energy supply and demand situations with sulfur dioxide (SO₂) emissions capped under the Clean Air Act Amendments (CAAA) of 1990, increased need for electric power, and the need to alleviate concerns over global climate change—a situation that translates into a need for technologies with very high efficiencies and extremely low emissions.

The portfolio of clean coal technologies being demonstrated under the CCT Program is creating a technology base that allows the nation to meet its energy and environmental goals efficiently and reliably. The fact that most of the demonstrations are being conducted at commercial scale, in actual user environments and under conditions typical of commercial operations allows the potential of the technologies to be evaluated in their intended commercial applications.

The technologies are categorized in four market sectors:

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

Approximately 75 percent, or about \$5.4 billion, of the total CCT Program costs are directed toward enhancing efficiency, environmental performance, and reliability of electric power production by the demonstration of advanced electric power generation systems and environmental control devices.

Over 1,200 megawatts (MWe) of new capacity and over 900 MWe of repowered capacity are represented by 14 advanced electric power generation projects with an estimated cost of nearly \$4.7 billion. Projects include 5 integrated gasification combined-cycle systems, 6 fluidized-bed combustion systems, and 3 advanced combustion/heat engine systems. These projects will provide environmentally sound, more efficient, and less costly electric power generation in the mid- to late-1990s and also will provide the demonstrated technology base necessary to meet new capacity requirements in the 21st century.

There are 19 environmental control devices projects valued at nearly \$704 million. These projects include 7 nitrogen oxide (NO_x) emissions control systems installed on over 1,700 MWe of utility generating capacity, 5 SO₂ emissions control systems installed on about 770 MWe, and 7 combined SO₂/NO_x emissions control systems installed on about 800 MWe of capacity. Most of these environmental control devices will have their operating experience documented by the end of 1996.

The five projects in the coal processing for clean fuels application category, valued at over \$519 million, represent a diversified portfolio of technologies. These projects involve the production of high-energy-density solid compliance fuels for utility or industrial boilers. One of these projects also produces a liquid for use as a chemical or transportation fuel feedstock. One project will demonstrate a new methanol production process. The other project is developing an expert computer software system that will enable a utility to predict operating performance of coals being considered but not previously burned in the utility's boiler.

The five projects in the industrial applications category have a combined value of over \$1.3 billion. Projects encompass the substitution of coal for 40 percent of the coke used 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 the demonstration of two efficient industrial-scale combustors.

Technical, Economic, and Environmental Performance

The CCT Program has extended the technical, economic, and environmental performance envelope of a broad portfolio of advanced coal technologies. As of the 10th anniversary of the CCT Program, 18 projects have completed operation, 8 projects are in operation, 5 projects are in construction, 11 projects are in project definition, and 1 project is in negotiation. Exhibit ES-1 shows the number of completed

projects by application category. Exhibit ES-2 provides a summary of the key technical and environmental results from the 18 completed demonstration projects and the capital cost, where available.

Marketplace Credibility

The CCT Program is establishing marketplace credibility as the technologies demonstrated during the 10 years of program implementation are entering the commercial marketplace. Today, demonstrated technologies used to reduce NO_x emissions are being retrofitted on a significant percentage (i.e., over 25 percent) of the nation's coal-fired capacity and provide the capability of achieving not only existing

regulated levels, but those proposed by the Environmental Protection Agency (EPA) for 2000. In fact, EPA has used the results from the NO_x technology demonstrations to guide its efforts in establishing NO_x control regulations. Circulating fluidized-bed technology has become a commercial success in the utility sector worldwide due largely to the data generated from a CCT project that was one of the first utility-scale circulating fluidized-bed projects in the world. The electric power generation technologies for the next century are being demonstrated in the form of the pressurized fluidized-bed combustion (PFBC) systems and integrated gasification combined-cycle (IGCC) systems. The CCT Program has also shown that several advanced technologies have led to significant improvements in the economic and environmental performance of SO₂ controls. Further,

technologies are being used to transform low-rank and non-compliance coals to useful, environmentally superior coal-based fuels for use by domestic utility and industrial coal users and are being considered for major projects abroad. Finally, coal-based industrial processes are benefiting, environmentally and economically, from the demonstration of advanced coal technologies.

Over the past 10 years, market credibility has been enhanced by the following project successes:

- The Tidd demonstration was the first utility-scale PFBC system in the United States and confirmed that the system could be applied to electric power generation. The plant represented a 13:1 scale-up from the pilot facility and led to significant refinements and understanding of the technology. The unit accumulated over 11,400 hours of operation and established the commercial viability of the design.
- As a result of the Tri-State Generation and Transmission Association's Nucla CFB Demonstration Project, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of atmospheric circulating fluidized-bed units. Pyropower's commercial units are now offered under warranty in sizes up to 400 MWe.
- The Wabash River project is the world's largest single train IGCC power plant to be operated in a fully commercial environment. This repowered 262-MWe unit has the ability to produce some of the lowest cost electricity in PSI Energy's system. The unit's net heat

Exhibit ES-1

Completed Projects by Application Category

Application Category	Number Completed
Advanced Electric Power Generation	2
Atmospheric fluidized bed combustion	1
Pressurized fluidized bed combustion	1
Environmental Control Devices	14
NO _x control technology	5
SO ₂ control technology	5
Combined SO ₂ /NO _x control technology	4
Industrial Applications	2
Industrial cyclone combustor	1
Cement kiln flue gas recovery scrubber	1

Exhibit ES-2 Summary of Results of Completed CCT Projects

Project and Participant	Key Results	Capital Cost
Advanced Electric Power Generation		
Tidd PFBC Demonstration Project (The Ohio Power Company)	<p>SO₂ reduction of 90-95% (Ohio bituminous coal) at 1.1-1.5 Ca/S ratio</p> <p>Heat rate 10,280 Btu/kWh</p> <p>Combustion efficiency 99.9%</p> <p>Commercially viable design</p> <p>Gas turbine operable in PFBC environment</p>	Not yet available
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	<p>SO₂ reduction of 70-95% (up to 1.8% sulfur coal), depending on Ca/S ratio</p> <p>NO_x emissions average 0.18 lb/million Btu</p> <p>Heat rate 11,600 Btu/kWh</p> <p>Combustion efficiency 96.9-98.9%</p>	Approximately \$1,123/net kW (tepower cost)
Environmental Control Devices		
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company)	<p>NO_x reductions of 52% using bituminous coal and 62% using subbituminous coal at full load (110 MWe), ranging to 36% and 53%, respectively, at 60 MWe</p> <p>NO_x reductions of 54-58% using bituminous coal at full load (605 MWe); 48% at 350 MWe</p>	<p>Ranges from \$64/kW at 100 MWe to \$40/kW at 600 MWe</p> <p>\$5.50-8.00/kW at 500 MWe</p>
Full-Scale Demonstration of Low-NO _x Cell Burner Retrofit (The Babcock & Wilcox Company)	<p>Approximately 37% NO_x reduction; LNB alone (second generation) — 64% NO_x reduction (13% gas heat input)</p>	Approximately \$15/kW plus gas pipeline cost
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	<p>NO_x reductions of up to 48% at full load (180 MWe) for Low-NO_x Concentric Firing System (LNCFS™) Level III, which includes both separated overfire air and close-coupled overfire air</p>	LNCFS I—\$8-10/kW LNCFS II/III—\$15-20/kW
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for Reduction of NO _x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	<p>Available in 1996</p>	Not yet available
Demonstration of Selective Catalytic Reduction Technology for Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)		

Exhibit ES-2 (continued) Summary of Results of Completed CCT Projects

Project and Participant	Key Results	Capital Cost
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Gas suspension absorption (GSA)/electrostatic precipitator SO ₂ removal efficiency 60-91%; GSA/pulse jet baghouse, 96%	\$149/kW for GSA (\$216/kW for conventional wet limestone forced oxidation)
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	SO ₂ reduction of 50% (1.5-2.5% sulfur bituminous coal)	Less than \$30/kW at 500 MWe
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)	SO ₂ removal efficiency 70+% at Ca/S ratio 2.0	\$66/kW for two reactors (300 MWe); \$76/kW for one reactor (150 MWe)
Advanced Flue Gas Desulfurization Project (Pure Air on the Lake, L.P.)	Average SO ₂ removal efficiency—94% over 3 years Maximum SO ₂ removal efficiency 98%	Not yet available
	Gypsum production 210,000 tons	
	Gypsum purity—97.2%	
	Availability—99.4%	
	Power consumption—5,275 kW (61% of expected)	
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	Over 90% SO ₂ removal efficiency 97.7-99.3% particulate removal efficiency Produced wallboard-grade gypsum as a by-product	Not yet available
	Fiberglass reinforced plastic equipment—chemically and structurally durable	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	NO _x reduction with SCR over 94%; SO ₂ removal efficiency over 95%; produced salable sulfuric acid by-product	\$250/kW
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	SO ₂ removal efficiency: LIMB—61% (3.8% sulfur coal; ligno lime) Coolside—70% (hydrated lime)	LIMB—\$31-102/kW Coolside—\$69-160/kW
SOx-NOx-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	\$260/kW at 250 MWe

Exhibit ES-2 (continued) Summary of Results of Completed CCT Projects

Project and Participant	Key Results	Capital Cost
<p>Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)</p>	<p>Hennepin—NO_x reduction averaged 67% with 18% gas input, SO₂ removal efficiency 52% at Ca/S ratio 1.76</p> <p>Lakeside—NO_x reductions of 64–66% and SO₂ reductions of 60–63% during extended continuous combined (GR–SI) runs at 29 MWe, about 22% gas input, and Ca/S of 1.67–1.75</p> <p>NO_x reduction averaged 67% during long-term testing of gas reburn only</p>	<p>\$979–1,318/ton of NO_x removed</p> <p>\$425–514/ton of SO₂ removed</p>
Industrial Applications		
<p>Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)</p>	<p>SO₂ reduction of over 80% with sorbent injection; 58% maximum with limestone injection at 2.0 Ca/S</p> <p>NO_x emissions of 160–184 ppm (75% reduction)</p> <p>Slag/sorbent retention of 55–90% in combustor; inert slag</p>	<p>Not available</p>
<p>Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)</p>	<p>SO₂ reduction of 90–95% (3% sulfur bituminous coal); 98% maximum reduction</p> <p>NO_x reductions of 5–15%</p>	<p>\$25/ton of annual cement capacity</p>

rate of about 9,000 Btu per kilowatt-hour (38 percent efficiency) is roughly 20 percent better than that of the original plant. The project is expected to continue to operate as part of PSI Energy's baseload capacity for a period of at least 25 years including the 3-year demonstration.

- Babcock & Wilcox's coal-reburning technology has been successfully demonstrated as a NO_x emissions reduction technology for cyclone boilers. The system is being retained

by Wisconsin Power and Light for commercial use at Nelson Dewey Station, Unit No. 2.

- Foster Wheeler's commercial sale of its low-NO_x burners has an estimated value of \$20 million and an estimated employment impact of 240 person-years. For example, Georgia Power is retaining the low-NO_x burners installed at Plant Hammond for use in complying with emission regulations. Further, the project also demonstrated the ability of the

Generic NO_x Control Intelligence System to optimize plant performance in terms of NO_x emissions, unburned carbon in the fly ash, and overall plant efficiency.

- The Low-NO_x Concentric Firing System (LNCFS™) supplied by ABB Combustion Engineering, Inc., is being retained by Gulf Power at its Plant Lansing Smith. The technology also is being used at a number of other utilities including Tennessee Valley Authority, Illinois Power, Public Service

Company of Colorado, Indianapolis Power and Light, Cincinnati Gas and Electric, Virginia Power, Union Electric, and New York State Electric & Gas Corporation.

- Successful testing of the AirPol technology resulted in the city of Hamilton, Ohio, receiving a \$5-million grant from the Ohio Coal Development Office to install the gas suspension absorption technology to control SO₂ emissions from a 50-MWe coal-fired boiler at the municipal power plant. This project has an estimated employment impact of 70 person-years.
- Pure Air on the Lake, L.P., will continue to operate the advanced flue gas desulfurization unit at the Northern Indiana Public Service Company's Bailly Generating Station for 17 years beyond the 3-year demonstration which was completed in 1995. In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO₂ scrubbing capacity at Florida Power & Light's Manatee power plant. The estimated value of the sale is \$200 million with an estimated employment benefit of 1,400 person-years.
- Georgia Power is retaining the CT-121 flue gas desulfurization system at its Plant Yates, Unit No. 1, for use in commercial operation. In 1994, a tar sands oil extraction facility in Murray, Canada, purchased a CT-121 scrubber.
- Ohio Edison is retaining the SNOX™ technology as a permanent part of the

emissions control system at Niles Station to help the utility meet its overall SO₂ and NO_x reduction goals. Commercial SNOX™ plants are operational in Denmark and Sicily.

- A software package developed as part of the Milliken project to assist the utility in optimizing project operation has become a commercial product. Six modules of the Plant Environmental and Economic Optimization Advisor have been sold, and another five sales are pending.
- The Babcock & Wilcox DRB-XCL® low-NO_x burner demonstrated in Public Service Company of Colorado's integrated dry NO_x/SO₂ emissions control system has been a commercial success. Sales have involved 1,829 burners, or approximately 23,664 MWe of capacity, at an estimated value of over \$240 million and an employment benefit of over 1,670 person-years.
- The first commercial sale of the Coal Quality Expert (CQE) Acid Rain Advisor software package, developed as part of CQE to assist utilities in making CAAA compliance decisions, was made in 1993. The final CQE software was released in December 1995 and is being offered commercially. Over 40 U.S. utilities have access to CQE through their membership in the Electric Power Research Institute.
- The Self-Scrubbing Coal™ demonstration has resulted in (1) proposed agreements with domestic coal-marketing companies to purchase 1 million tons of compliance coal

annually, (2) a proposed agreement with China to build a coal-cleaning plant, together with a 500-mile underground slurry pipeline and port facility at an estimated value of \$888 million, and (3) signed letters of intent from three Polish power plants that wish to produce 7.5 million tons per year of cleaned coal with an estimated value of \$75 million.

- Rosebud SynCoal Partnership is working on two potential semi-commercial projects located in Wyoming and Montana, ranging in size from 0.5 to 5 million tons per year. The Wyoming project is a stand-alone mine-mouth design. The Montana project is designed to expand the existing demonstration facility.
- The ENCOAL Mild Coal Gasification project has operated successfully for 4 years, accruing over 8,200 hot operating hours. More than 43,000 tons of process-derived fuel have been shipped to utility and metallurgical customers. Unit train quantities have been successfully burned as a compliance fuel in commercial boilers for over 2 years. Additionally, 2.2 million gallons of coal-derived fuel have been shipped to industrial and metallurgical clients. Letters of intent for engineering and economic assessments of full-scale commercial plants are currently in place with two Indonesian companies. A letter of intent is also in place with a company that controls large reserves of subbituminous and lignite coals in Russia.

Model Government/Industry Partnership for Technology Advancement and Job Creation

The successful implementation of the CCT

Program over the past 10 years is based on a number of principles that evolved as a result of the dedicated effort of industry and DOE to cement a partnership to advance clean coal technologies. Highlights of some of these principles are as follows:

- Strong and stable financial commitments for the life of the project were put into place by Congress.
- 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.
- The technology agenda was determined by industry, not government.
- Demonstrations were conducted at commercial scale in actual user environments.
- The respective roles of government and industry were clearly defined.
- Cost sharing was required through all project phases.
- Allowance for cost growth, but with a statutory limit, provided an important check-and-balance feature of the program.
- Repayment of funds to the government was required of successful industrial participants.

- Real and intellectual property rights were retained by industry.
- Technology developed is made available on a non-discriminatory basis to all U.S. companies that seek, under reasonable terms and conditions, to use the technology.

These principles, in large measure, led to wide private industry and non-federal government participation in the program. Non-DOE funds of nearly \$4.9 billion have come from a wide variety of sources. Approximately 55 investor-owned utilities, nonutility power generators, municipalities and cooperatives have invested over \$3.5 billion into projects. These electric power generators represent approximately 50 percent of the coal-fired capacity in the United States and almost 70 percent of the units affected by Phase I under Title IV of the CAAA of 1990. Further, over 60 industry participants, including technology owners and equipment vendors, have committed over \$850 million of cost sharing to the projects. Finally, 7 state agencies and 8 industry and academic research and development organizations have provided over \$225 million as their portion of cost sharing.

This broad-based cost-shared participation in the program has translated into jobs over the past 10 years. The projects supported by industry are a source of over 29,000 jobs in many trades and professions. Over 2,000 people are employed as facility operators and 500 in coal mining and related industries. Each emissions control project provides 100-200 jobs and each advanced power generating project provides over 1,000 construction jobs.

In summary, the joint effort between industry and the government in the CCT Program is a success. The number of complex, capital intensive projects put into place by the CCT Program partnership is unprecedented, as is the degree of cost sharing. The partnership is important not only for the end objectives it is achieving but for the benefits, tangible and intangible, created by continuing association of the partners. Ten years have shown that, with the government serving as a risk-sharing partner, industry funding can be leveraged to improve the environment, reduce the cost of electricity, create jobs, and assure technology is available that will enable coal to continue as the major contributor to the nation's and the world's energy future.

1. Role of the Program

National Perspective

Coal is the nation's most plentiful fossil fuel, accounting for over 94 percent of the proven fossil energy reserves in the United States. Deposits of coal can be found in 38 of the 50 states, with production contributing to the economies of 26 states; coal is used in all 50 states and the District of Columbia. It is a major contributor to the energy well-being of the United States, accounting for almost one-quarter of the primary energy consumed. Nearly 52 percent of all electricity generated in 1994 came from coal; of the 3,271 billion kilowatt-hours generated by utilities, nonutility generators, and cogenerators, 1,694 billion kilowatt-hours were generated from coal. The Energy Information Administration (EIA) forecasts that coal will continue to dominate as a fuel for electric power production at least through 2015 (the end of the forecast period) when generation by coal technologies is projected to increase to 2,146 billion kilowatt-hours and account for approximately 50 percent of all electricity generated. Although EIA forecasts show that coal-fired utility generation is expected to grow at only 1.1 percent annually and coal-fired cogeneration at 0.7 percent annually through 2015, nonutility generators are expected to increase their coal-fired generation at an annual rate of approximately 5.5 percent.

In the EIA forecast, average capacity factors for coal-fired power plants increase from 62 percent to 74

percent. Utilities have reported plans to construct 16 gigawatts of new coal-fired capacity, while retiring approximately 19 gigawatts of coal-fired capacity.

Cogenerators and nonutility generators significantly increase their share of the market by 2015, accounting for 43 percent of the new capacity construction and capturing 18 percent of the total capacity by 2015. Cogeneration and nonutility coal-fired generation are expected to grow from 59 billion kilowatt-hours in 1994 to approximately 92 billion kilowatt-hours in 2015.

In the non-electric sectors, an increase of 11 million tons of industrial steam coal consumption is forecasted between 1994 and 2015 (0.6 percent annual growth). Increasing consumption of industrial steam coal results primarily from the increased use of coal in the chemical and food processing industries.

A projected decrease of 14 million tons in coking coal consumption is caused by the displacement of raw steel production from integrated steel mills, which use coke as an energy and raw material input, by increased production from mini mills using electric arc furnaces, and by increased import of semi-finished steels.

Further, the amount of coke required per ton of iron produced will decline because of improved energy efficiency and increased use of pulverized coal injection into blast furnaces. Finally, coal consumption in the residential and commercial sectors will remain constant, accounting for less than 1 percent of total U.S. coal demand.

The environmental improvements in the use of coal for the generation of electric power has been

significant over the past 25 years. With the promulgation of the National Ambient Air Quality Standards (NAAQS) for sulfur dioxide (SO₂) and the New Source Performance Standard (NSPS) for new coal-fired power plants in 1971, a steady reduction in SO₂ emissions per unit of electricity output has been witnessed. Since 1970, SO₂ emissions declined 8 percent from coal-fired plants; this contrasts with a 150 percent increase in coal consumed to produce electricity. This improved environmental trend is continuing with the implementation of the Clean Air Act Amendments (CAAA) of 1990. SO₂ emissions from electric power generating sources are expected to decrease over 24 percent between 1994 and 2000 and an additional 16 percent by 2010. These decreases will be achieved through a number of approaches including fuel-switching, use of SO₂ allowance credits, and advanced technologies demonstrated under the CCT Program for the control of emissions and production of electric power. Emissions from industrial and other sources declined by over 40 percent between 1970 and 1994, due in part to the decrease in coal burning by the industrial and commercial sectors. Further, during the period 1970–1994, emissions from metal processing industry declined by 86 percent due to increased use of emissions control devices and reduced coal use.

Coal production is a vital contributor to the U.S. economy. According to a 1994 Pennsylvania State University study commissioned by the National Coal Association, the direct and indirect benefits of coal to the U.S. economy are as follows:

- The coal industry is responsible for more than \$88 billion of total sales, nearly 1.1 million workers, and for personal income of nearly \$50 billion.
- Coal production results in almost \$14 billion in personal income, wages, benefits, interest, and dividends.
- Each \$1 billion of U.S. coal production stimulates \$3.1 billion of production throughout the U.S. economy.
- For every direct job sustained in the coal industry, 11 indirect jobs are supported.

Coal also exerts a positive influence on the nation's trade deficit. U.S. coal consumption displaces almost 10 million barrels of oil equivalent per day. The nation's reliance on coal increases energy security and reduces the balance of trade deficit by over \$50 billion per year. Further, the export of coal to approximately 40 nations is valued at about \$4 billion per year. Clean coal technology (CCT) has a vital role in ensuring that coal will continue to serve U.S. energy interests, enhancing opportunities for economic growth and employment while meeting the national commitment to a clean and healthy global environment. These technologies are being advanced through the U.S. Department of Energy (DOE) Clean Coal Technology Demonstration Program (also referred to as the CCT Program).

The CCT Program is a government and industry cost-shared partnership to demonstrate a new generation of advanced coal-based technologies so that the most promising technologies can be moved into the marketplace.

The demonstrations, for the most part, are at a scale large enough to generate data needed to enable stakeholders to make judgments about the commercial potential of particular processes. The importance given to the commercial deployment of these technologies reflects the strategic importance of coal to the U.S. economy and the commitment to sound environmental policies.

The CCT Program plays a major role in advancing the DOE's policy of a sustainable energy future, which is grounded in three fundamental facts: (1) energy fuels a competitive economy; (2) energy affects the quality of the environment; and (3) energy affects national security. The CCT Program has a key role in achieving three strategic goals contained in the national energy policy articulated in *Sustainable Energy Structure: Clean and Secure Energy for a Competitive Economy*.

These three goals are as follows:

- Maximize energy productivity to strengthen the economy and improve living standards.
- Prevent pollution to reduce adverse environmental impacts associated with energy production, delivery, and use.
- Keep America secure by reducing vulnerability to global energy market shocks.

Maximizing Energy Productivity

The CCT Program is fostering the demonstration of a portfolio of advanced coal-based technologies

that will meet the diverse requirements of the competitive marketplace for energy technologies well into the next century. These technologies make use of the most secure and abundant fossil energy resource base in the United States and will play a major role in strengthening the economy and improving living standards by making use of secure energy resources at reasonable costs. The CCT Program addresses the diversity of the energy marketplace by demonstrating technologies in four market sectors:

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

Clean coal technologies being demonstrated under the CCT Program are establishing the technology data base that allows the nation to meet its energy and environmental goals efficiently and reliably. Because most of the demonstrations are being conducted at commercial scale, in actual user environments, and under conditions typical of commercial operations, the performance potential of the technologies can be meaningfully evaluated in their intended commercial applications.

Approximately 75 percent, or about \$5.4 billion, of the total CCT Program funds are directed toward enhancing energy productivity and reliability of utility advanced electric power generation systems and environmental control devices.

There are over 55 investor-owned utilities, non-utility generators, municipalities, and cooperatives participating in the CCT Program. These generators account for approximately 50 percent of the coal-fired

capacity in the United States and have almost 70 percent of the Phase-I-affected units under Title IV of the CAAA of 1990. Exhibit 1-1 illustrates the extent of the geographic area served by utilities participating in the CCT Program.

The U.S. market for efficient and reliable electric power consists of retrofitting existing power plants with environmental control devices, repowering existing plants with advanced electric power generation systems, and constructing new power plants using advanced electric power generation systems or conventional power generation technology with environmental control devices. The EIA forecasted 0.9 percent overall annual growth in electric utility generation between 1994 and 2015 while projecting growth in utility generation from coal at 1.1 percent annually.

Increases in coal-fired generation are expected to come from a combination of increased utilization of existing generating capacity and additions of new capacity. The average utilization rate for existing coal-fired units is expected to increase by nearly 20 percent by 2015. Together, utilities, nonutilities, and cogenerators are expected to increase net coal-fired capacity by 10 gigawatts over the forecast period. There are, however, uncertainties that affect the projected need for new capacity, such as follows:

- The electric utility industry is in transition from a highly regulated industry to one where competition is promoted. The Energy Policy Act of 1992 provided the broad policy consensus to promote competition in wholesale power markets. On March 29, 1995, the Federal Energy Regulatory Commission (FERC) issued a Notice of Proposed Rulemaking (NOPR) entitled "Promoting

Wholesale Competition through Open Access: Non-Discriminatory Transmission Service by Public Utilities" (RM 95-8-000) and a supplemental NOPR entitled "Recovery of Stranded Costs by Public Utilities and Transmitting Utilities" (RM 95-7-000). Referred to together as the mega-NOPR, it addresses the key issues in moving toward a competitive bulk power market. Deregulation and greater competition in the electric utility industry will most likely have an impact on the projected need for new capacity and the commercial deployment of conventional and advanced coal technologies; however, the magnitude is unknown.

- Increased competition from natural gas will reduce the growth of coal generation particularly in nonutility generation, where natural gas is estimated to provide over 300 billion kilowatt-hours in 2015 compared to 37 billion kilowatt-hours from coal.

- The existing inventory of nuclear units, which accounts for about 20 percent of the electric power generation in the United States, starts to come up for relicensing in about 10 years. It is doubtful that life extension for all these nuclear units will take place. Further, a recent study by DOE indicated that several nuclear units may retire before their licenses come up for renewal. The EIA is projecting a decrease of 207 billion kilowatt-hours per year in nuclear generation between 1994 and 2015 with 37 gigawatts of nuclear capacity expected to be retired during this time period.

- Considerable uncertainty exists about the projected savings from demand-side management and whether these savings will have a significant impact on reduction of power generation needs.

CCT Program demonstrations provide a portfolio of technologies to satisfy markets for coal conversion and utilization while satisfying energy and environmental goals in a highly efficient manner.

Over 1,200 megawatts (MWe) of new capacity and over 900 MWe of repowered capacity are represented by 14 advanced electric power generation projects, valued at nearly \$4.7 billion, which have been selected and are being developed under the CCT Program. The projects are listed in Exhibit 1-2.

These projects include six fluidized-bed combustion systems, five integrated gasification combined-cycle systems, and three advanced combustion/heat engine systems. The participants in the projects include seven investor-owned utilities, two cooperative utilities, one municipal utility, two independent power producers, and two industrial sponsors. These projects, when completed, will use over 4 million tons of coal per year. Because of their superior environmental performance and increased efficiency, these units are projected to produce 42 percent less SO₂, 83 percent less nitrogen oxide (NO_x), and 1.5 percent less carbon dioxide (CO₂) than 2,100 MWe of conventional pulverized coal-fired capacity with flue gas desulfurization units capable of meeting NSPS. Based on a 3 percent sulfur coal, this represents a total reduction of approximately 68,000 tons per year of acid rain precursor emissions.

These units not only will provide environmentally sound electric power generation starting in the mid-

Exhibit 1-1
Service Areas of Utilities Participating in the CCT Program

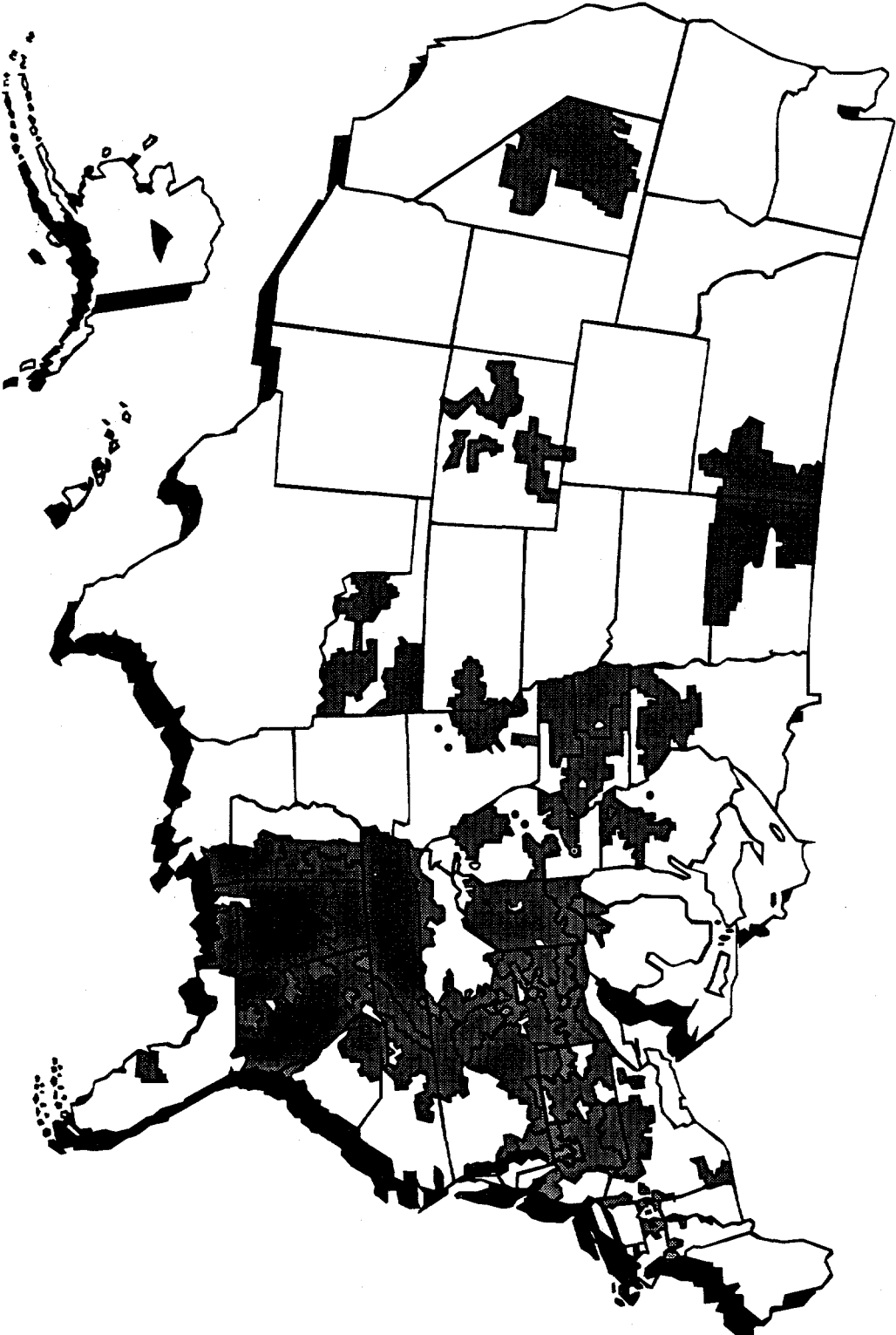


Exhibit 1-2 CCT Demonstration Projects, by Application Category

Application Category	Participant	Project	Solicitation	
Advanced Electric Power Generation	ABB Combustion Engineering, Inc.	Combustion Engineering IGCC Repowering Project	CCT-II	
	Alaska Industrial Development and Export Authority	Healy Clean Coal Project	CCT-III	
	The Appalachian Power Company	PFBC Utility Demonstration Project	CCT-II	
	Arthur D. Little, Inc.	Coal Diesel Combined-Cycle Project	CCT-V	
	DMEC-1 Limited Partnership	PCFB Demonstration Project	CCT-III	
	Clean Energy Partners Limited Partnership	Clean Energy Demonstration Project	CCT-V	
	Four Rivers Energy Partners, L.P.	Four Rivers Energy Modernization Project	CCT-V	
	The Ohio Power Company	Tidd PFBC Demonstration Project	CCT-I	
	Pennsylvania Electric Company	Warren Station Externally Fired Combined-Cycle Demonstration Project	CCT-V	
	Sierra Pacific Power Company	Pinon Pine IGCC Power Project	CCT-IV	
	Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	CCT-III	
	Tri-State Generation and Transmission Association, Inc.	Nuclea CFB Demonstration Project	CCT-I	
	Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	CCT-IV	
	York County Energy Partners, L.P.	ACFB Demonstration Project	CCT-I	
	Environmental Control Devices	ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	CCT-II
		AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	CCT-III
		The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO _x Control	CCT-II
The Babcock & Wilcox Company		Full-Scale Demonstration of Low-NO _x Cell Burner Retrofit	CCT-III	
The Babcock & Wilcox Company		LIMB Demonstration Project Extension and Coolside Demonstration	CCT-I	
The Babcock & Wilcox Company		SO _x -NO _x -Rox Box™ Flue Gas Cleanup Demonstration Project	CCT-II	
Bechtel Corporation		Confined Zone Dispersion Flue Gas Desulfurization Demonstration	CCT-III	
Energy and Environmental Research Corporation		Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	CCT-I	
Energy and Environmental Research Corporation		Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler	CCT-III	

Exhibit 1-2 (continued) CCT Demonstration Projects, by Application Category

Application Category	Participant	Project	Solicitation
Environmental Control Devices (continued)	LIFAC-North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	CCT-III
	New York State Electric & Gas Corporation	Micronized Coal Reburning Demonstration for NO _x Control	CCT-IV
	New York State Electric & Gas Corporation	Milliken Clean Coal Technology Demonstration Project	CCT-IV
	NOXSO Corporation	Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System	CCT-III
	Public Service Company of Colorado	Integrated Dry NO _x /SO ₂ Emissions Control System	CCT-III
	Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	CCT-II
	Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	CCT-II
	Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	CCT-II
	Southern Company Services, Inc.	Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers	CCT-II
	Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers	CCT-II
Coal Processing for Clean Fuels	ABB Combustion Engineering, Inc., and CQ, Inc.	Development of the Coal Quality Expert	CCT-I
	Air Products Liquid Phase Conversion Company, L.P.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	CCT-III
	Custom Coals International	Self-Scrubbing Coal™: An Integrated Approach to Clean Air	CCT-IV
	ENCOAL Corporation	ENCOAL Mild Coal Gasification Project	CCT-III
	Rosebud SynCoal Partnership	Advanced Coal Conversion Process Demonstration	CCT-I
Industrial Applications	Bethlehem Steel Corporation	Blast Furnace Granulated-Coal Injection System Demonstration Project	CCT-III
	Centerior Energy Corporation	Clean Power from Integrated Coal/Ore Reduction (COREX®)	CCT-V
	Coal Tech Corporation	Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	CCT-I
	Passamaquoddy Tribe	Cement Kiln Flue Gas Recovery Scrubber	CCT-II
	ThermoChem, Inc.	Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	CCT-IV

late 1990s but also will provide the demonstrated technology base required to carry the nation into the 21st century with a suite of highly efficient, reliable, environmentally superior clean coal technologies to meet new capacity and repowering requirements. Decisions on technology options to meet these requirements would occur early in the next century. By that time, there will be sufficient technical, environmental, economic, and operational performance data available from the CCT Program to enable potential users to make informed decisions from the technology options.

In summary, it will be critical to bring new technology options into the marketplace during the next 5 years in order to satisfy environmental goals and to meet longer range capacity growth requirements both domestically and abroad. These technologies must be able to meet the stringent performance requirements of the traditional utility industry, independent power producers, and cogenerators.

The portfolio of technology options available to existing coal-fired utilities to comply efficiently and reliably with the CAAA of 1990 requirements is large and diverse. There are 19 environmental control devices projects, valued at more than \$703 million, which can be used to retrofit existing power plants (see Exhibit 1-2). These include seven NO_x emission control systems installed on over 1,700 MWe of utility plant capacity, five SO₂ emission control projects installed on about 770 MWe of capacity, and seven combined SO₂/NO_x emission control systems installed on about 800 MWe of capacity. In addition to establishing a sound base of technical, environmental, and economic information to enable commercial deployment, these demonstrations are having an

immediate and significant environmental benefit by reducing SO₂ and NO_x emissions from the uncontrolled host plants by approximately 40 percent. This represents approximately 244,000 tons per year of SO₂ and NO_x that otherwise would have been emitted into the atmosphere, assuming the use of 3 percent sulfur coal. These technologies also can be used in new plants to satisfy increased capacity requirements.

Most of these environmental control devices projects have their operating experience documented. By the end of 1995, all five of the SO₂ control technology projects had been completed, five of the seven NO_x control projects had completed testing, and four of the seven combined SO₂/NO_x control technologies had finished operational demonstration.

The technical, environmental, and economic performance results will be available for users and vendors to evaluate commercial deployment potential in time to develop Phase II compliance strategies and the decision-making process regarding which technologies to use.

There are five coal processing for clean fuels projects, valued at over \$519 million (see Exhibit 1-2). These projects produce solid, high-energy-density compliance fuel; coal-derived liquid that can be used as a chemical or transportation fuel feedstock; and a method to allow optimum matching of boilers to coal. Over 4 million tons per year of solid and liquid products will be produced from these projects. These solid and liquid compliance fuels are being tested by industrial and utility customers.

There are five industrial application projects, valued at over \$1.3 billion, encompassing steel and cement industries and industrial boilers (see Exhibit 1-2). Coke oven emissions are a major concern of the

steel industry. One project is to substitute coal for at least 40 percent of the coke used in iron ore reduction, and another steel industry project is directed toward eliminating the need for coke altogether. In another project, cement kiln waste was used to achieve 90 percent or more reduction in SO₂. Cement, municipal waste, and paper production industries in the United States and abroad are actively considering adoption of this technology. Two advanced combustors that have broad industrial application also are being demonstrated

Preventing Pollution to Reduce Adverse Environmental Impact

The CCT Program is pursuing the goal of reducing adverse environmental impacts. This goal is being pursued through the demonstration of technologies that reduce emissions of SO₂, NO_x, hazardous air pollutants (HAPs), and solid and liquid wastes through significant improvements in pre-utilization, in-situ, and post-utilization emissions control technologies. High-efficiency technologies that result not only in efficient and cost-effective use of resources, but also in reduction of greenhouse gas emissions, are being demonstrated.

Acid Rain Mitigation

The CCT Program had its roots in the acid rain programmatic initiatives of the 1980s. It became the centerpiece for satisfying the recommendations contained in the January 1986 *Joint Report of the Special Envoys on Acid Rain*. The first three solicitations of the CCT Program (CCT-I-III) were aimed

primarily at mitigating the potential impacts of acid rain. The resulting CCT projects are providing a pool of technologies for industry to draw upon to meet specific needs in developing compliance strategies.

On November 15, 1990, Congress enacted the CAAA of 1990. Title IV, Acid Deposition Control, established emissions reduction targets for SO₂, including the capping of SO₂ emissions in the post-2000 time frame, and directed the establishment of allowable emissions limitations for NO_x. This, along with concerns over global warming and air toxics, prompted thrusts in the last two solicitations (CCT-IV-V) toward advanced electric power generation systems characterized by very high efficiency and negligible pollutant emissions compatible with the 21st century.

The acid rain provision of the CAAA of 1990 sets emission reduction requirements on SO₂ to be met in two phases. Phase I affected 110 coal- and oil-fired generating plants, a total of 261 units nationwide, beginning in January 1995. By the end of 1995, 145 units had switched to lower sulfur fuels with the majority of the coal switching/blending activities involving the use of lower sulfur western and eastern coals and a reduced use of higher sulfur interior or midwestern coals. Twenty-seven units were installing or had installed flue-gas desulfurization units. Seven of these units are part of the CCT Program. The single repowered Phase I unit was the Wabash River IGCC project being conducted under the CCT Program. Other compliance strategies included natural gas cofiring, retirement of seven plants with 1,120 MWe of capacity, and the allowances purchased from other utilities that generated "offsets" by reducing emissions below compliance levels.

In Phase II, beginning in 2000, emission levels on Phase I plants will be further reduced and restrictions set for the remaining 2,500 boilers at 1000 plants. This will reduce SO₂ emissions by another 3 million tons. Because SO₂ allowance prices are expected to increase significantly after 2000, EIA is projecting that almost 32 gigawatts of capacity will be retrofitted with scrubbers to achieve Phase II goals, with the bulk being installed between 2005 and 2010. A provision of the CAAA of 1990 allows a 4-year extension (to December 31, 2003) to comply with the requirements of Title IV if one or more units is repowered with a qualifying clean coal technology.

The CAAA of 1990 required the U.S. Environmental Protection Agency (EPA) to establish annual allowable emissions limitations for NO_x in two phases. Phase I limitations were to be effective January 1, 1995, and address allowable emissions for tangentially fired and dry-bottom wall-fired boilers. Phase II limits will require wet-bottom wall-fired boilers, cyclone burners, cell burners, and all other types of utility boilers to reduce their NO_x emissions starting in 2000. Proposed Phase II limits also further restrict tangentially fired and dry-bottom wall-fired boilers.

Phase I limitations were published in the *Federal Register* on March 22, 1994. Emission limitations for NO_x have been set at 0.45 pound per million British thermal units (Btu) for tangentially fired units and 0.50 pound per million Btu for wall-fired boilers. The Phase I NO_x limitations involve 169 boilers. An option for NO_x control is available for an owner or operator of two or more units subject to NO_x emission limitations. The option allows the owner or operator to average emissions among its units in lieu of complying on a unit-specific basis. The actual Btu-

weighted annual emissions rate averaged over the units must be no greater than the Btu-weighted annual emissions rate for the same units had they been operated in compliance with the applicable emission limitation. Another 580 tangentially fired and wall-fired boilers must meet the applicable NO_x emission limits by January 1, 2000.

In the published Phase I rule, EPA included overfire air systems in its definition of low-NO_x burner technology. A lawsuit was filed in the U.S. Court of Appeals for the District of Columbia arguing that the CAAA of 1990 prevents EPA from requiring installation of any equipment in addition to low-NO_x burners. On November 29, 1994, the court agreed with industry and vacated the rule upon finding that EPA had overstepped its statutory authority.

In April 1995, EPA announced that it would reissue the NO_x emissions rule and extend the Phase I compliance date to January 1, 1996, and include new definitions of "low-NO_x burner" and "low-NO_x burner technology." These new definitions expressly exclude "overfire air" as a low-NO_x burner technology. The new rules also drop EPA's original interpretation of the law's emissions averaging requirements, which could have left individual units at a plant vulnerable to enforcement even if the annual emissions average of all the plant's units comply with the emissions limit specified in its permit. Instead, the rule clarifies that if a plant that averages its emissions is in compliance with its emissions limits, then the plant's individual units are deemed to be in compliance.

In addition, on August 3, 1995, EPA issued a proposed regulation that included a provision for "open market" emissions trading. Under this rule, utilities would not need state and federal approval for

Exhibit 1-3 NO_x Emission Limits for Coal-Fired Units

Group 1 Unit Type	Group 2 Unit Type	Number of Boilers Phase I Phase II	Phase I NO _x Emission Limits ^a	Proposed Phase II NO _x Emission Limits ^a	Proposed Emission Control Technology
Tangentially fired boilers	}	296	0.45 lb/million Btu	0.38 lb/million Btu	Plug-in combustion controls or non-plug-in combustion controls
Dry bottom wall-fired boilers ^b		169	0.50 lb/million Btu	0.45 lb/million Btu	
	Cell burner boilers	35		0.68 lb/million Btu	Coal reburning, natural gas reburning, or selective catalytic reduction
	Cyclone boilers	88		0.94 lb/million Btu	Combustion controls
	Wet-bottom boilers	38		0.86 lb/million Btu	Combustion controls
	Vertically fired boilers	29		0.80 lb/million Btu	Fluidized-bed combustion controls
	Fluidized-bed combustor boilers	5		0.29 lb/million Btu	

^a Emission limits are lb/million Btu of heat input on an annual average basis.

^b Other than units applying cell burner technology

transactions of NO_x and volatile organic compounds (VOCs). Instead, utilities would be able to comply with air pollution mandates by buying and using an appropriate number of tons of "discrete emissions reductions."

In January 1996, EPA issued its proposed rule for implementing Phase II CAAA NO_x reduction provisions, extending NO_x control requirements to cell burners, cyclone boilers, wet-bottom boilers, vertically fired boilers, and fluidized-bed combustor boilers and tightening requirements for tangentially fired and wet-bottom wall-fired boilers. The NO_x emission limits for coal-fired units for both Phase I and Phase II are shown in Exhibit 1-3.

In establishing the Phase I emissions limitations, EPA used the data from tangentially fired and wall-fired boiler demonstrations conducted under the CCT Program by Southern Company Services, Inc. Further, NO_x controls for cell burners, cyclone boilers, vertically fired boilers, and fluidized-bed boilers have been demonstrated under the CCT Program, thus establishing the technology base to achieve Phase II emission levels. Techniques such as coal reburning, selective catalytic reduction, and low-NO_x burners will have baseline technical, environmental, and economic results by the end of 1996.

The NO_x reduction program is also driven by concern about ground-level ozone. Title I of the CAAA of 1990 requires each state with ozone non-

attainment areas to adopt regulations for controlling NO_x and VOCs emissions in these areas.

The Northeast Ozone Transport Commission approved a memorandum of understanding in September 1994 to reduce power plant emissions of NO_x by as much as 70 percent. An EPA-sponsored initiative, the Ozone Transport Assessment Group, may expand the geographic boundaries for these NO_x controls to a 37-state region extending eastward from North and South Dakota. It is also likely that state regulations pertaining to emissions of ozone precursors and other air pollutants will be modified and made more stringent. Stricter regulations would affect both existing and new power generation facilities.

EPA also is considering a new particulate standard that could affect power plant emissions. EPA must issue a new rule on particulate matter no later than January 31, 1997. This new standard undoubtedly will be more stringent than the existing particulate standard, which addresses particulate matter of 10 microns in diameter and smaller (referred to as PM10).

Hazardous Air Pollutants

Title III of the CAAA of 1990 required that EPA conduct specific studies to establish if public health criteria warrant further control of utility emissions of HAPs and expanded the list of HAPs to 189. EPA specifically included a requirement for the analysis of mercury emissions in its HAPs report.

Electric utilities are the third leading source of mercury emissions. Mandated by the CAAA, EPA's study is to provide Congress with information on which to make a decision on the control of mercury emissions.

DOE recognized the importance of detecting the presence of and measuring the level of HAPs in stack gases. A program was implemented to monitor HAPs emissions at CCT project sites, under both baseline and demonstration operating conditions. A further objective was to quantify the removal of HAPs in the gaseous streams of various emissions control systems. For the five CCT-V projects, DOE requires that HAPs monitoring be included in environmental monitoring plans (see Section 2). For CCT-I-IV projects, DOE has sought to include a HAPs monitoring requirement. A total of 24 CCT projects are monitoring HAPs, and HAPs monitoring has been completed for 10 projects. Two objectives of HAPs

monitoring, which have been met, were to improve the quality of HAPs data being gathered and to monitor a broader range of plant configurations and emissions control equipment.

A parallel effort under DOE's Coal Research and Development Program (referred to as the Coal R&D Program) is being undertaken to collect HAPs data from 16 coal-fired power plants representing a cross section of technical configurations; seven of these plants are sites of CCT demonstration projects. Beyond monitoring stack gas emission levels, the Coal R&D Program is seeking to determine the fate of HAPs as they move through the plant, i.e., what waste stream and what form they ultimately take. Data collected at nine of the plants have been shared with EPA so that the agency will have the benefit of actual data in formulating air toxics control regulations required under Title III of the CAAA of 1990.

Two reports summarizing source, distribution, and facts from these 16 plants will be available in the spring of 1996. The first report provides a comprehensive assessment of HAPs measured in the coal, across all the major pollution control devices for the flue gas produced, and the HAPs emitted from the stacks. The second report is a summary of HAP emissions from nine power plants characterized under the first phase of the Coal R&D Program. During the second phase, the Louisiana Gasification Technology, Inc., coal gasification plant was fully characterized. The HAPs measured provided data for the Wabash River IGCC project. In addition, four other coal-fired plants are being characterized for 16 trace elements including mercury.

Value-Added Solid Wastes

Current SO₂ emissions control technologies typically result in conversion of an air emission to an emission of a "solid" waste, in most cases a scrubber sludge that must be carefully handled and disposed of in sludge ponds. Estimates are that by 2015 over 4,500 acres per year would be required to dispose of flue gas desulfurization (FGD) sludge if wet FGD systems were used. Most of the clean coal technologies being demonstrated under the CCT Program produce a dry solid waste that significantly reduces the disposal problem. For example, nine projects produce dry, solid compounds or composites that can be used as building material, agriculture supplements, neutralizing agents for use with acid mine drainage, and for other purposes; five CCT projects produce commercial-grade gypsum; and eight projects produce a salable by-product in the form of commercial-grade sulfur or sulfuric acid.

Global Climate Change Protection

It is U.S. policy to embark upon an action plan that returns U.S. greenhouse gas emissions to 1990 levels by the year 2000. Voluntary programs have been implemented as a means for addressing environmental issues without regulations. For example, CO₂ is the most significant greenhouse gas but is not subject to regulation. *The Climate Change Action Plan* published in October 1993 initiated a number of voluntary programs, including Climate Challenge and Climate Wise, to reduce greenhouse gas emissions.

Under the voluntary Climate Challenge Program, developed jointly by DOE and the electric utility industry, utilities pledge to reduce, avoid, or sequester greenhouse gas emissions using flexible, individual-

ized plans to achieve reductions in the most cost-effective way. The utility-specific plan contains specific commitments to one or more of the following actions:

- Make a specified contribution to particular industry initiatives
- Reduce greenhouse gas emissions by a specified amount below the utility's 1990 baseline level by the year 2000
- Reduce greenhouse gas emissions to the utility's 1990 baseline level by the year 2000
- Reduce greenhouse gas emissions to some other specified level
- Reduce or limit the rate of greenhouse gas emissions to a particular level, expressed in terms of emissions per kilowatt-hour generated or sold
- Undertake specific projects or actions, or make specific expenditures on projects or actions to reduce greenhouse gas emissions

Approximately 450 utilities are participating in the Climate Challenge Program, pledging to reduce greenhouse gas emissions substantially by 2000.

The Climate Wise Program is being carried out by EPA and DOE. It is designed to stimulate industrial emissions reductions. Companies representing almost 4 percent of U.S. industrial energy use are participating in the program.

Reduction of greenhouse gas emissions is achieved through increased efficiency in energy use. In more efficient energy systems, less CO₂ is produced per unit of power generated.

For example, pressurized fluidized-bed and gasification combined-cycle technologies boost generating efficiencies into the 40–45 percent range, as compared to conventional technology efficiencies of approximately 33 percent. This can reduce CO₂ emissions by 17–27 percent. Clean coal technologies yet to be demonstrated, such as gasifier/fuel cell combinations and advanced turbines, could lower CO₂ emissions by up to 55 percent.

The *Climate Change Action Plan* includes a joint implementation pilot program to gain experience in evaluating investments in other countries for emissions reduction benefit. A central purpose of the joint implementation initiative is to "encourage the rapid development and implementation of cooperative, mutually voluntary projects between the U.S. and foreign partners aimed at reducing net emissions of greenhouse gases, particularly projects promoting technology cooperation with and sustainable development in developing countries and countries with economies in transition to market economies."

Further, in Senate Report 103-294, Congress directed DOE to make the dissemination of CCTs overseas an integral part of its policy to reduce greenhouse gas emissions in developing countries.

Utilization of highly efficient clean coal technologies being developed under the CCT Program offers a major opportunity to contribute to this initiative. The benefits would be significant from the stand point of reduction of "global" CO₂ emissions in view of the fact that the major energy growth is in the targeted economies. Further, significant benefits to the U.S. economy would accrue from improvement of U.S. balance of trade and creation of U.S. jobs in the engineering, manufacturing, and service sectors.

Keeping America Secure

It is in the national interest to maintain a multi-fuel energy mix to sustain national economic growth. The CCT Program strategy is to pursue technology development and deployment that increases productivity and enhances the efficient use of the United States' major energy resource, coal, while assuring national and global environmental goals are achieved. The domestic coal resources are large enough to sustain economic production at high levels for several hundred years. In terms of market price for delivered energy, coal is the least expensive energy source providing economical energy for electric power and industrial needs.

The United States is highly dependent on imported oil, importing about 8.5 million barrels per day or over half the total consumed. Today, U.S. coal consumption displaces the equivalent of approximately 10 million barrels per day. This large utilization of coal increases energy security and reduces the nation's balance of payments by over \$50 billion per year.

Clean coal technologies can provide the utilization and conversion technologies that will enable the coal fuel cycle to remain a major component of the nation's economy while achieving the environmental quality that society demands. The domestic and export value of annual coal production is \$21 billion in the U.S. economy. There are over 1.1 million workers whose jobs directly depend on the coal industry. These jobs are dispersed through the mining, transportation, manufacturing, utility, and supporting industries. Clean coal technologies will enable the coal fuel cycle to respond to these energy

markets, ensuring the continued need for these jobs and their economic benefit. In addition to domestic opportunities, the international marketplace also holds enormous potential for U.S. industry. Conservative estimates conclude that by 2010, today's annual worldwide coal consumption of 4.3 billion short tons should increase by almost 800 million short tons. Of this projected growth, almost 250 million short tons will be for electric power generation.

The worldwide market for power generation technologies could be as high as \$1 trillion by 2015. Of this, the U.S. share could be \$200 billion. If this level of penetration is achieved, the export of clean coal technologies could result in 200,000 high-quality U.S. jobs over this period. 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, other governments are recognizing the enormous economic benefits that their economies can enjoy if their manufacturers capture a greater share of this market.

Other DOE activities are aimed at creating a favorable export climate for U.S. coal and coal technology. These efforts will (1) improve 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) strengthen interagency coordination of federal programs pertinent to these exports, and (3) improve current programs and policies for facilitating the financing of coal-related projects abroad.

Coal Technology Perspective

DOE has structured an integrated coal technology development program that will pursue, in partnership with industry, three major technology product lines:

- Power systems
- Coal fuels and industrial systems
- Environmental systems

The thrust of the coal technology development program is to accelerate the progress of clean coal technologies from the laboratory to the marketplace and is focused on the development of new technologies that will help fill the energy needs of the post-2000 world.

The power systems product line research, development, and demonstration (RD&D) program is shaped by three challenges:

- The possibility that the U.S. will lose a substantial share of the global power technology market if it does not sustain the same type of government/industry partnership forged in recent years and that the nation's competitors are now creating

- The realization that utility deregulation and promotion of competition will have a profound affect on the utility sector's approach to R&D resulting in a sharply reduced private R&D funding and shifting the emphasis to projects with almost immediate payoff

- The virtual disappearance of private sector funding for long-term public good benefits, such as lower cost environmental protection

The power systems program will focus on the

completion of the 12 remaining CCT Program advanced power system projects and the dissemination of the technical, economic, and environmental results into the domestic and international marketplace. Further, the power systems program will pursue an evolving portfolio of more advanced power systems directed toward acceleration of the commercial realization of affordable, high-efficiency, low-emission, coal-fired electricity generating technologies. The specific goals for these advanced power systems are outlined in Exhibit 1-4.

The coal fuels and industrial systems product line program is directed toward keeping the option available to refine coal into a variety of liquid fuels and chemicals that might be needed as substitutes for petroleum-based products. Coal preparation technologies will emphasize advanced methods for removing the organic and inorganic matter that causes air toxics and other air pollutants. The industrial system technologies will assure that the industrial steam coal users and other users, such as the steel industry, will have available advanced high-efficiency and low-emission technologies that will keep the energy contribution to final product cost low and the product cost competitive in the global market.

The coal fuels and industrial systems program includes the completion of the CCT Program's five industrial application projects and the five coal processing for clean fuels projects. Moreover, advanced technologies will be pursued for the production of coal-derived fuels, chemicals, cleaned coal, and other products for the utility, industrial, transportation, commercial, and residential sectors.

Advanced Electric Power Generation

Advanced electric power generating systems employ the technologies that enable the efficient and environmentally superior generation of electric power. These systems, which initially come on-line in the mid- to late 1990s, will form the basis for responding to the energy and environmental demands of the early 21st century. The 14 advanced electric power generation projects selected under the CCT Program will provide the technical, environmental, and economic performance data in a time frame consistent with most utility expansion plans and the stringent CAAA of 1990 Phase II emission limits effective in 2000.

These technologies are characterized by high thermal efficiencies, very low pollutant emissions, reduced CO₂, fewer solid waste problems, and enhanced economics. The advanced electric power generation systems may be deployed in modules, thus allowing phased construction to match demand growth more predictably and to meet the requirements of smaller municipal utilities and nonutility generators.

There are seven generic advanced electric power system technology approaches being demonstrated in the 14 projects selected in this area under the CCT Program. Detailed descriptions of each project can be found in Section 7 project fact sheets. The results from the two completed advanced electric power system projects, Tidd PFBC Demonstration Project and Nucla CFB Demonstration Project, can be found on pages 7-14 and 7-16, respectively.

The following subsections present a discussion of the generic characteristics of the seven advanced electric power system technologies being demonstrated in the CCT Program.

Exhibit 1-4 R&D Goals of Advanced Power Systems

	2000	2005	2010	2015
Efficiency	42-45%	48-55%	55%	60%
SO ₂ , NO _x , particulates	33% of NSPS	25% of NSPS	10% of NSPS	10% of NSPS
CO ₂ reduction	29%	42%	42%	47%
Cost of energy			10-20% lower	

NSPS = New Source Performance Standards

The goal is to develop proof-of-concept technology by 2005 for producing premium-grade liquid fuels from coal at \$25 per barrel-of-oil equivalent or less in 1990 dollars. In the area of coal preparation, the goal is to develop, in coordination with EPA and the utility industry, a sound data base of coal preparation technologies for reducing air toxics from power generation.

The environmental systems product line program is directed toward the control of HAPs and particulate matter which will be the subject of future EPA rulings and regulations. This will require working with EPA and the utility industry to develop a sound data base on the effectiveness of existing and advanced control technologies in reducing HAPs and particulate matter from power generation. Further, the remaining five CCT Program environmental control device projects will be completed and the technical, environmental, and economic results disseminated to the domestic and international marketplace. The results from the 24 CCT Program HAPs monitoring projects will be analyzed and disseminated.

The above product line programs are undergirded by advanced research and technology development (AR&TD) that provides the fundamental science and engineering basis for future fossil energy concepts.

This program includes coal utilization science, bioprocessing of coal, and multiple fossil energy technology crosscutting research, such as materials, components, instrumentation, and diagnosis. Another element of AR&TD is university coal research that is focused on improving the knowledge base in fundamental and innovative coal science and technology research and on training fossil fuel scientists and engineers in relevant disciplines.

Role of the Technologies

Because the ultimate level of success of the CCT Program will be measured by the degree of deployment of certain technologies in the energy marketplace, it is most appropriate to discuss the technologies and processes from a market perspective.

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 crushed limestone is suspended on jets of air (fluidized) in the combustion chamber. Sulfur released from the burning coal is captured by the limestone before it can escape from the boiler. The sulfur chemically combines with the limestone to form a new solid waste product, a mixture of calcium sulfite and calcium sulfate. Some of the solid waste is removed with the bed ash through the bottom of the boiler. Small ash particles, or fly ash, that escape the boiler are captured with dust collectors (cyclones, baghouses, electrostatic precipitators, or ceramic filters). More than 90 percent of the sulfur released from coal can be captured this way.

At combustion temperatures of 1,400–1,600 °F, the fluidized mixing of the fuel and sorbent enhances both coal combustion and sulfur capture. The operating temperature range is almost half that of a conventional boiler and is below the threshold where thermally induced NO_x is formed. Thus, fluidized-bed combustors substantially reduce both SO_2 and NO_x emissions. Fluidized-bed combustion has the capability of utilizing high-ash coal, whereas conventional pulverized coal units must limit ash to relatively low levels.

Fluidized-bed combustion can be either atmospheric (AFBC) or pressurized (PFBC). The atmospheric type operates at normal atmospheric pressure while the pressurized type operates at pressure 6–16 times higher than normal atmospheric pressure. The pressurized fluidized-bed boiler offers potentially

higher efficiency, reduced operating costs, and less waste product than does the atmospheric fluidized-bed boiler. Initially, fluidized-bed combustion systems were either bubbling-bed or circulating-bed configurations. System improvements have modified these earlier classifications so that current designs are designated as bubbling beds with solid recirculation, fluid beds with internal circulation, hybrid designs combining several fluidization concepts, and full-fledged circulating (entrained) fuel flow.

A second-generation pressurized fluidized-bed concept is being developed and demonstrated. This concept integrates a pressurized circulating fluidized-bed combustor and a pyrolyzer to fuel a gas-turbine topping cycle and a steam-turbine bottoming cycle. The integration of the pyrolyzer and turbine topping cycle improves the efficiency when compared to first-generation PFBC systems by introducing the high efficiency inherent in gas turbines and recovery of heat from the gas turbine exhaust in a steam generator.

Fluidized-bed combustion attributes follow:

- No special coal handling is needed other than the addition of limestone or other sorbent to the coal feed.
- The fluid-like motion of the solids in the combustion chamber promotes turbulent mixing that improves combustion efficiency and the capture of SO_2 .
- The superior mixing also permits combustion at substantially lower and more evenly distributed temperatures, thus reducing formation of NO_x .

- Combustion occurs at temperatures below the ash melting point so that solids accumulation and boiler tube erosion and corrosion are minimized.

- All types of coals or coal wastes can be used, including high-ash coals, because FBC is nonsensitive to feedstock.

- The waste generated is a dry, benign solid that can be disposed of easily or usefully employed (e.g., as material for road or building construction).

- Combined-cycle plants, in addition to increasing the efficiency of energy production, can be composed of standardized modules. This leads to ease of installation and a generally lower cost without the usual economy-of-scale penalties.

In the case of repowering, any type or size of boiler can be repowered by a fluidized-bed combustor using the existing plant area, coal and waste handling equipment, and steam turbine equipment. This repowering extends the life of the plant. In many cases, such as where the capacity of the boiler has been reduced because of aging or the turbine generator has greater capacity than the boiler, or both, FBC can be used to repower an existing boiler and, in addition to controlling SO_2 and NO_x emissions, can increase the boiler's capacity as much as 50 percent with the use of PFBC. The costs of the additional capacity are low compared to the cost of a new plant.

There are six fluidized-bed combustion demonstration projects in the CCT Program; two are atmospheric and four are pressurized. One project, the Nucla CFB Demonstration Project (110 MWe), in



▲ The Ohio Power Company completed the demonstration of the first utility-scale PFBC in the United States at the Tidd Plant. The 70-MW_e unit represented a 13:1 scale-up from the pilot facility and used the Babcock & Wilcox technology under license from ASEA Brown Boveri Carbon. The Tidd PFBC technology is a bubbling-bed process operating at 12 atmospheres. The unit produced 55 MWe from a steam turbine and 15 MWe from a gas turbine.

Nucla, Colorado, completed operations in 1991 and final project documentation in 1992 (see Section 5). The Tidd PFBC Demonstration Project (70 MWe) in Brilliant, Ohio, shown in the photo above, completed operations in 1995 (see Section 5). The four ongoing fluidized-bed combustion projects are in project definition and design; new sites are under negotiation.

Integrated Gasification Combined Cycle. The coal gasification combined-cycle process basically has

four steps: (1) a fuel gas is generated by coal reacting with high-temperature steam and an oxidant (oxygen or air) in a reducing atmosphere; (2) the gas is cooled, producing steam, and then purified to further remove particulates and sulfur and nitrogen compounds; (3) the clean fuel gas is combusted in a gas turbine generator to produce electricity; (4) the residual heat in the hot exhaust gas from the turbine is recovered in a heat recovery steam generator, and the steam is used to produce additional electricity in a steam turbine generator.

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 gas stream must be cleaned to a high level, not only to achieve low emissions, but to protect downstream components, such as the gas turbine, from erosion and corrosion. In a coal gasifier, the sulfur in coal is released in the form of hydrogen sulfide rather than as SO₂, which is the case in coal combustion. In some integrated gasification combined-cycle (IGCC) systems, as in the case of clean combustion, much of the sulfur-containing gas is captured by a sorbent injected into the gasifier. In addition, several commercial processes are capable of removing hydrogen sulfide, whereby more than 99 percent of the sulfur is removed from the gas, making it as clean as natural gas.

The existing commercial hydrogen sulfide removal processes require the fuel gas to be cooled, with some efficiency penalty. Therefore, hot-gas cleanup systems are being demonstrated. In these cleanup

systems, the hot coal gas is passed through a bed of metal oxide particles such as zinc ferrite. Zinc ferrite can absorb sulfur contaminants at temperatures in excess of 1,000 °F, and the compound can be regenerated and reused with little loss of effectiveness.

During the regeneration stage, salable sulfur is produced. The technique is capable of removing more than 99.9 percent of the sulfur in the gas stream.

High levels of nitrogen removal are also possible. Some of the coal's nitrogen is converted to ammonia, which can be almost totally removed by commercially available chemical processes. NO_x formed from the combustion air can be held to well within allowable levels by staging the combustion process at the turbine or by adding moisture to hold down flame temperature.

In repowering with IGCC, a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added; in most cases, these replace the existing coal boiler. The remaining equipment is left in place, including the coal-handling equipment, the steam turbine, and electrical generator. The result is an extension of plant life to essentially that of a new plant, an increase in efficiency from a nominal 35 percent to over 40 percent, and an increase in overall plant output of 50–150 percent with significantly reduced overall emissions. The incremental costs of the additional capacity are low compared to the cost of a new conventional pulverized coal plant.

The attributes of the IGCC are summarized as follows:

- Sulfur removal levels of over 99 percent have been demonstrated. These emissions levels are well below the existing NSPS emission standard of 90 percent removal for new plants.

Exhibit 1-5 CCT Program IGCC Project Characteristics

Project	Size	Gasifier	Reactant	Gas Cleanup	Fact Sheet
Combustion Engineering IGCC Repowering Project	65 MWe	Two-stage entrained-flow	Air	Hot gas	7-20
Clean Energy Demonstration Project	477 MWe	Slagging fixed-bed	Oxygen	Cold	7-22
Pifion Pine IGCC Power Project	99 MWe	Fluidized-bed	Air	Hot	7-24
Tampa Electric Integrated Gasification Combined-Cycle Project	250 MWe	Entrained-flow	Oxygen	Hot & cold	7-26
Wabash River Coal Gasification Repowering Project	262 MWe	Two-stage entrained-flow	Oxygen	Cold	7-28

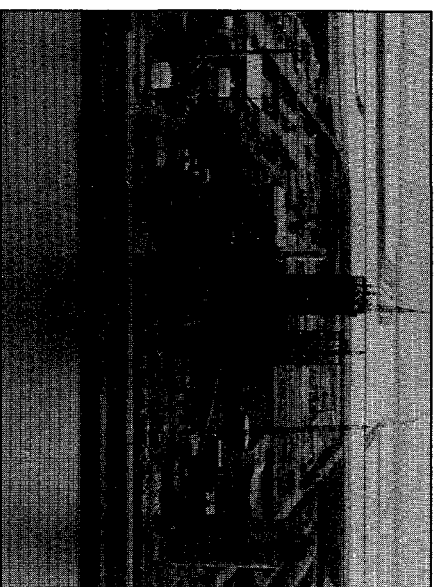
- NO_x reductions of over 90 percent have been demonstrated.
- Salable by-products are produced, such as elemental sulfur or material for road or building construction.
- Zero wastewater discharge criteria can be met easily.
- CO₂ emissions are reduced compared to pulverized-coal-fired plants.
- A wide variety of carbonaceous feedstock can be used.
- Potentially high levels of plant availability (up to 85 percent) are achievable.
- Efficiency of energy production can be increased, while using standardized modules sized for large and small utilities.

- No special coal-handling is needed other than the potential to add limestone to the coal feed.

Five different approaches to the highly efficient and environmentally clean IGCC technology are in various stages in the path toward full-scale commercialization. The projects cover a broad spectrum of gasifier types, coal feedstocks, gas cleanup systems, and operating conditions to satisfy various market situations. Exhibit 1-5 provides a summary of the major characteristics of the five IGCC projects. One project, the Wabash River Coal Gasification Repowering Project (262 MWe) in West Terre Haute, Indiana, began commercial operations in November 1995. Two projects are in construction. A formal groundbreaking ceremony for the Tampa Electric Integrated Gasification Combined-Cycle Project (250 MWe) in Lakeland, Florida, shown in the photo on this page, was held on November 2, 1994; operations are expected to begin in late 1996. Construction at the

Piñon Pine IGCC Power Project (99 MWe) near Reno, Nevada, began in February 1995 and by year-end was approximately 50 percent complete. Operation is expected to begin in early 1997. The two other IGCC projects are in the project definition and design phase.

Indirect Fired Cycle. In an indirect-fired cycle, the products of coal combustion do not come in contact with the working components of a gas turbine. Coal, biomass, or other ash-bearing fuel is burned in a combustor. Hot combustion gases flow on the shell side of a tube-type metallic or ceramic air heater. On the tube side of the air heater, compressed gas from a gas turbine compressor is heated as it passes through the air heater and enters the turbine section of the gas turbine. Exhausted flue gas from the air heater passes through a heat recovery generator where steam is



▲ The IGCC system produces power with efficiencies approaching 40%, SO₂ reductions over 95%, and NO_x reductions of over 90%. The 250-MWe Tampa Electric IGCC project, shown here, was about 70% complete on December 31, 1995, and construction will be completed in the fall of 1996.

generated to power a steam turbine. Flue gas is treated to remove SO_2 and particulates while NO_x is controlled during the combustion process. An overall conversion efficiency of 50–55 percent can be obtained in an indirect-fired cycle.

The 62.5-MWe Warren Station Externally Fired Combined-Cycle Demonstration Project described on page 7-34 was selected to demonstrate this technology. The project will use a novel, high-temperature ceramic gas-to-air heat exchanger. The project was undergoing restructuring as of the end of 1995.

Integrated Gasification Fuel Cell. A typical fuel cell system using coal as fuel would include 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 capture rejected thermal energy to produce additional electrical power in a bottoming steam cycle.

Energy conversion in fuel cells is potentially more efficient (40–60 percent, depending on fuel and type of fuel cell) than traditional energy conversion devices. This is because electricity is generated directly in the fuel cell instead of going through an intermediate conversion step (i.e., burner, boiler, turbines, and generators). Fuel cells directly transform the chemical energy of a fuel and an oxidant (oxygen) into electrical energy. Each fuel cell includes an anode and a cathode separated by an electrolyte layer. In a typical fuel cell, coal gas is supplied to the anode and air is supplied to the cathode to produce electricity and heat.

This advanced electric power generation system technology will be demonstrated as part of the Clean

Energy Demonstration Project described on page 7-22. As structured at the end of 1995, the project would demonstrate a 1.25-MWe molten carbonate fuel cell as part of a 477-MWe IGCC demonstration.

Coal-Fired Diesel. This technology involves firing a diesel-engine-driven electric generating system with a coal-oil or coal-water slurry. The hot exhaust from the diesel engine is routed through a heat-recovery steam generator 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 45–48 percent thermal efficiencies. The 10–100-MWe capacity range of the technology would be most applicable to small utility (municipal) and industrial cogeneration applications.

This technology was selected to be demonstrated in the Coal Diesel Combined-Cycle Project (see description, page 7-32). The 14-MWe project was being restructured at the end of 1995.

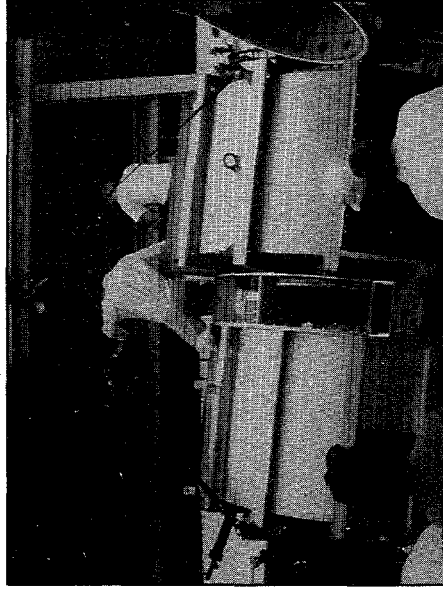
Slagging Combustor. Most of these new coal-burning technologies are based on the cyclone combustor concept. In a cyclone combustor, coal is burned in a separate chamber outside the furnace cavity. The hot combustion gases then pass into the boiler where the actual heat exchange takes place.

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

where it can be removed as waste. Because ash removal efficiency is high, there is no degradation of boiler tube surfaces to reduce boiler efficiency over time.

Results to date show that by positioning air injection ports so that coal is combusted in stages, NO_x emissions can be reduced by 70–80 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 combustors could replace oil-fired units in both utility and industrial applications or be used to retrofit older, conventional cyclone boilers. The technology is being demonstrated in a nominal 50-MWe facility in Alaska under the Healy Clean Coal Project described on page 7-30. The unit is scheduled to go into operation in early 1998. Shown below is the precombustion module for the unit.



▲ The advanced TRW slagging combustor with staged fuel and air will be used in the Healy Clean Coal Project under construction in Alaska. Shown here is the precombustion module being lowered into place at TRW's San Juan Capistrano test facility.

Environmental Control Devices

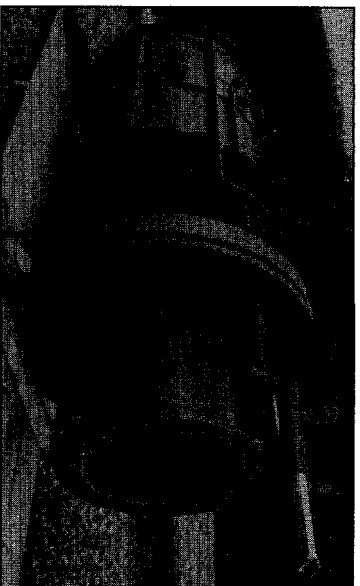
Environmental control devices must respond to the need for efficient, effective, and economic means whereby existing coal-fired boilers can comply with the CAAA of 1990 and, at the same time, mitigate broader environmental concerns such as solid waste disposal. Optimal performance for these retrofit devices is characterized by highly efficient pollutant capture, low capital and operating costs, high operating efficiency and availability, and no waste products (pollutants being either recycled or converted into salable by-products). The targeted boiler population is the 929 pre-NSPS boilers, many of which will continue operation through the first quarter of the 21st century to meet electricity demands.

Technologies that would find application in this market include advanced NO_x control technology, advanced SO_2 control technology, and advanced combined SO_2 , NO_x , and particulate control technology.

The CCT Program includes 19 projects that are demonstrating environmental control device technologies. These projects are providing technical, environmental, and economic performance data on NO_x and SO_2 emissions control and for combined SO_2/NO_x controls.

Fourteen of these projects have completed the operational phase and have provided technical and environmental performance data. A summary of the results of the completed environmental control device projects can be found in Section 5, pages 5-14-5-52. Descriptions of all 19 projects is provided in Section 7, beginning on page 7-37.

The following subsections present summaries of the generic characteristics of NO_x , SO_2 , and combined



▲ Babcock & Wilcox's low- NO_x cell burner (LNCB®) technology was one of seven demonstrated under the CCT Program and is summarized in Exhibit 1-6.

SO_2/NO_x emissions control technologies demonstrated under the CCT Program.

NO_x Control Technology. Control of NO_x emissions can be accomplished by modifying the combustion process or by postcombustion noncatalytic or catalytic selective reduction processes, or combinations of the two approaches.

Modified combustion processes include the use of specially designed advanced low- NO_x burners, alone or in conjunction with advanced overfire air (AOFA) ports, AOFA ports without low- NO_x burners, or natural gas and coal-fired reburning processes. All of these technologies utilize staged combustion whereby the primary combustion zone is maintained deficient in oxygen and the combustion process is completed in stages. The more gradual mixing of fuel and air results in lower flame temperatures and reducing-atmosphere combustion conditions before the combustion process is completed, which reduces the oxidation of nitrogen to NO_x . Emissions reductions for NO_x of 50-70 percent are achievable with these systems.

The use of air ports alone, which are installed in the furnace wall above the top row of burners, permits creation of a fuel-rich primary combustion zone with minimal hardware changes. However, NO_x emissions reductions, which average 15-30 percent, are lower than when air ports are used in combination with low- NO_x burners.

Natural gas or coal-reburning technologies for NO_x control also are being demonstrated in the CCT Program. About 10-30 percent of the total fuel input to the boiler is injected above the normal combustion zone, creating the fuel-rich combustion zone. NO_x rising from the lower region of the furnace is "reburned" in the zone where the secondary fuel enters and is converted to nitrogen. NO_x emissions reductions in the 50-65 percent range are achievable with this modified system. Reburning technology can be applied in conjunction with low- NO_x burners.

Postcombustion selective catalytic reduction processes are characterized by high NO_x emissions reductions of 80-90 percent or more. Selective catalytic reduction (SCR) involves injecting ammonia into the boiler flue gas and passing the gases through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor. Noncatalytic processes utilize ammonia and/or urea injection into the boiler after combustion is complete to chemically reduce NO_x to nitrogen. NO_x emission reductions are less than with catalytic processes. However, when noncatalytic technologies are combined with low- NO_x burners, NO_x emissions reductions of 60-70 percent are predicted.

The CCT Program contains seven NO_x emissions control projects; of these, five have been completed, one is near completion, and one is under construction.

Exhibit 1-6

CCT Program NO_x Control Technology Characteristics

Project	Size	Boiler Firing Type	NO _x Reduction	Fact Sheet
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control	100 MWe	Cyclone	52-62%	7-38
Full-Scale Demonstration of Low-NO _x Cell Burner Retrofit	605 MWe	Cell burner	48-58%	7-40
Evaluation of Gas Reburning and Low-NO _x Burner on a Wall-Fired Boiler	172 MWe	Wall fired	37-65%	7-42
Micronized Coal Reburning Demonstration for NO _x Control	148 MWe 50 MWe	Tangentially fired Cyclone	50-60% (goal)	7-44
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	500 MWe	Wall fired	50% (goal)	7-46
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers	8.7 MWe	Various	80% (goal)	7-48
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers	180 MWe	Tangentially fired	37-45%	7-50

The project characteristics, including size, boiler-firing type, and NO_x reduction, are summarized in Exhibit 1-6. As can be seen, the NO_x control technologies are being demonstrated for the full range of boiler firing types, and thus the technologies provide the capability of achieving existing and future regulated levels as proposed by EPA for various boiler firing types. It should be noted that EPA has used the results from the NO_x technology demonstrations to guide its efforts in establishing NO_x emissions control regulations.

SO₂ Control Technology. Advanced combustion or postcombustion flue gas cleaning techniques

are approaches for removal of sulfur and particulates from flue gas. Examples of advanced combustion techniques are discussed in the previous subsection, Advanced Electric Power Generation. These techniques (e.g., fluidized-bed combustion, slagging combustors, and some coal gasification processes) involve injection of calcium sorbents (lime or limestone) into the combustion zones.

Postcombustion cleanup involves removal of SO₂ from the downstream flue gas after it exits the boiler. There are three basic approaches: (1) advanced flue gas desulfurization using lime or limestone (wet scrubbers) to capture 90 percent or more of the SO₂ in

the flue gas before it exits the stack, (2) in-duct injection of sorbents utilizing the existing flue gas ductwork, and (3) insertion of one or more separate vessels into the downstream ductwork where the sorbents are added.

Advanced flue gas desulfurization has significantly improved the reliability of wet scrubbers through improvements to eliminate corrosion problems and designs that simplify the process. Markets (such as wallboard manufacture) have been found for the waste gypsum sludge. The improved reliability has reduced the requirement for spare (backup) scrubber systems, contributing to significant reductions in capital costs of modern scrubbers compared to earlier systems. The advanced flue gas desulfurization systems can consistently remove more than 90 percent of the SO₂ at half the cost of conventional systems.

In-duct sorbent injection involves spraying sulfur absorbents, such as hydrated lime with water, into the center of the existing ductwork. By controlling the humidity of the flue gas and the spray pattern for the sorbent, SO₂ removal approaches 70 percent. Selective additives, such as adipic acid, may improve removal levels to around 90 percent. Advantages of this technology include an easily handled and readily disposable dry, granular waste and minimal construction because the plant's existing ductwork is used. This makes in-duct sorbent injection an attractive option for retrofitting smaller, older plants where space availability might be limited.

When separate vessels are used, one or more process chambers are inserted in the flue gas ductwork, and various sorbents are injected to remove the pollutants. Generally the separate vessels provide a longer residence time for the sorbent to react with the

Exhibit 1-7 CCT Program SO₂ Control Technology Characteristics

Project	Size	Process	Coal Sulfur Content	SO ₂ Reduction	Fact Sheet
10-MW _e Demonstration of Gas Suspension Absorption	10 MW _e	Gas suspension absorption	2.7-3.5%	60-95%	7-52
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	73.5 MW _e	In-duct confined	1.5-2.5%	50%	7-54
LIFAC Sorbent Injection Desulfurization Demonstration Project	60 MW _e	Sorbent injection	2.0-2.9%	70%	7-56
Advanced Flue Gas Desulfurization Demonstration Project	528 MW _e	Advanced limestone	2.25-4.7%	94%	7-58
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	100 MW _e	Limestone, forced oxidation	1.2-4.3%	90%+	7-60

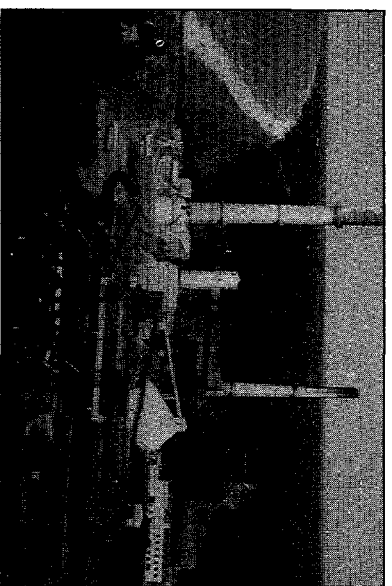
gas, and pollutant capture is greater. Although more costly than in-duct injection, this approach has the potential of capturing more than 90 percent of the pollutants. Due to the cost and added size requirements, the use of separate vessels tends to be more suitable to new plant applications or to plants that can accommodate the additional size requirements.

Depending upon process selection, advanced postcombustion cleaning technologies offer several advantages over the old conventional scrubber systems, including the following:

- High reliability and availability preclude the need for standby spare capacity.
- Physical plant size requirements are reduced.
- Increased residence time or reactivity with the sulfur sorbent leads to high levels of SO₂ removal.

- Regeneration of the sulfur-absorbing chemical reduces operating costs.
- Waste generation is reduced through production of dry, benign waste products or marketable by-products.
- Systems can be designed to remove more than one pollutant.

The CCT Program is demonstrating five SO₂ control technologies, all of which were completed by the end of 1995. The important characteristics and performance of these demonstration projects is summarized in Exhibit 1-7. Several of these technologies, including the advanced flue gas desulfurization process pictured on this page, are currently being used by utilities to comply with the CAAA of 1990 Phase I SO₂ emissions requirements and will be available for



▲ Pure Air on the Lake, L.P., completed a 3-year demonstration of an advanced flue gas desulfurization process at Northern Indiana Public Service Company's 528-MW Bailly Generating Station. SO₂ removal efficiency averaged 94% with a maximum of 98%. This is one of five SO₂ control projects conducted under the CCT Program.

meeting Phase II requirements in 2000. Further, these technologies have an added benefit in that scrubber wastes normally associated with the conventional wet flue gas desulfurization process have been replaced with salable by-products, such as gypsum.

Combined SO₂/NO_x Control Technology.

Many of the technologies discussed above can be successfully combined with particulate removal systems to reduce emissions of SO₂, NO_x, and particulates. Examples of this approach being utilized in the CCT Program include the following processes and systems:

- Selective catalytic reduction; catalytic oxidation of SO₂ to SO₃ with condensation of the SO₃ in the presence of water to produce salable sulfuric acid; baghouse particulate removal

- Low-NO_x burners with sorbent injection into the boiler or in-duct injection; conventional electrostatic precipitator (ESP)
- In-duct sorbent injection and selective catalytic reduction in a baghouse where the catalyst is suspended in the bags
- Gas reburning with in-duct sorbent injection; conventional ESP
- Regenerable dry sorbent for both SO₂ and NO_x control
- Low-NO_x burners supplemented with in-boiler urea injection; noncatalytic selective reduction for NO_x control; in-duct sorbent injection for SO₂; conventional ESP
- Formic-acid-enhanced wet limestone technology with an advanced tile-lined scrubber for SO₂ control, including recovery of marketable gypsum and calcium chloride; in-boiler urea injection for NO_x control; conventional ESP

Seven combined SO₂/NO_x emission control technologies are part of the CCT Program. Four of the projects have been completed, and the results are summarized in Section 5; a fifth project is nearing completion. One project is in operational testing, and the remaining project was in the project definition and design phase at the end of 1995. The characteristics of the projects and the achieved or expected emission reductions are shown in Exhibit 1-8.

Coal Processing for Clean Fuels

Physical and chemical processes can be applied to abundant U.S. coal reserves to transform them to an economic, energy-option fuel for at least a portion of

Exhibit 1-8 CCT Program Combined SO₂/NO_x Control Technology

Project	Size	Coal Sulfur Content	SO ₂ Reduction	NO _x Reduction	Fact Sheet
SNOX™ Flue Gas Cleaning Demonstration Project	35 MWe	3.4%	95%	94%	7-62
LIMB Demonstration Project Extension and Coolside Demonstration	105 MWe	1.6-3.8%	60-70%	40-50%	7-64
SOx-NOx-Rox Box™ Flue Gas Cleanup Demonstration Project	5 MWe	3.4%	80-90%	90%	7-66
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	80 MWe (tangential) 40 MWe (cyclone)	3.0% 3.0%	52% 50-60%	67% 67%	7-68
Milliken Clean Coal Technology Demonstration Project*	150 MWe	1.5-4.0%	95% (goal)	62-75% (goal)	7-70
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System*	150 MWe	3.4%	98% (goal)	75% (goal)	7-72
Integrated Dry NO _x /SO ₂ Emissions Control System*	100 MWe	0.4%	70% (goal)	70% (goal)	7-74

* Ongoing projects

the existing coal-fired boilers enabling them to comply with the CAAA of 1990. In addition, coal processing creates the capability to generate substitute liquid fuels from coal that can replace petroleum and petroleum-derived fuels in a wide range of applications, thus enhancing the nation's energy security. The solid products are easily transportable fuels high in energy density and low in sulfur, ash, and moisture. The liquid fuels are low in sulfur and suitable for the transportation sector, stationary power generation, or as chemical feedstocks.

There are five CCT projects in the coal processing for clean fuels application category. Two projects involve technologies for cleaning and upgrading coals to produce higher-energy-density compliance fuels; one project produces a solid product fuel, which has been used by utilities and industry, and a liquid product for use in industrial boilers. Another project will demonstrate a new synthesis technology for methanol. The fifth project involves the development of software to predict operating performance of coals not previously burned at the facility in question.

The clean coal technologies generating products for this market include physical and chemical coal cleaning, mild gasification, coal gasification, and direct and indirect liquefaction.

Coal Cleaning. About 40 percent of the coal used in U.S. utility boilers today receives some cleaning before it is burned. Most commercial coal cleaning is done on eastern and midwestern U.S. bituminous coals at more than 500 preparation plants. With wider use of conventional coal-cleaning processes, total nationwide SO₂ emissions from burning coal could be reduced by 10–15 percent. To achieve greater reductions, however, significant improvements will have to be made to coal-cleaning technology.

Traditionally, research to improve precombustion cleaning has been concentrated on two major categories of cleaning technology: physical and chemical cleaning. Recently a new category, biological cleaning, has attracted interest as advances have been made in microbial and enzymatic techniques for liberating sulfur and ash from coal.

Virtually all coal cleaning today is done with physical techniques, some of which have been used for more than a century. Physical cleaning typically separates undesirable matter from coal by relying on differences in densities or variations in surface properties. When coal from the mine is crushed and then washed, the heavier impurities are separated.

Physical cleaning can remove only matter that is physically distinct from the coal, such as small dirt particles, rocks, and pyritic sulfur (sulfur combined with iron particles). Physical cleaning cannot remove organic sulfur that is chemically bound with the coal, nor can it remove nitrogen, another source of pollution, from the coal. Currently, physical cleaning of

domestic coals can remove 30–50 percent of the pyritic sulfur and about 60 percent of the ash-forming minerals.

Conventional physical coal-cleaning methods include froth flotation and gravity separation techniques. Advanced physical cleaning techniques are expected to be significantly more effective than older techniques. An example would be electrostatic coal cleaning, which utilizes opposite polarity charges on coal and mineral matter particles to accomplish separation. Increased effectiveness is achieved by first grinding the coal into much smaller sizes at which the coal releases more of the ash and pyrite. New coal-cleaning processes can remove more than 90 percent of the pyritic sulfur and undesirable minerals from the coal.

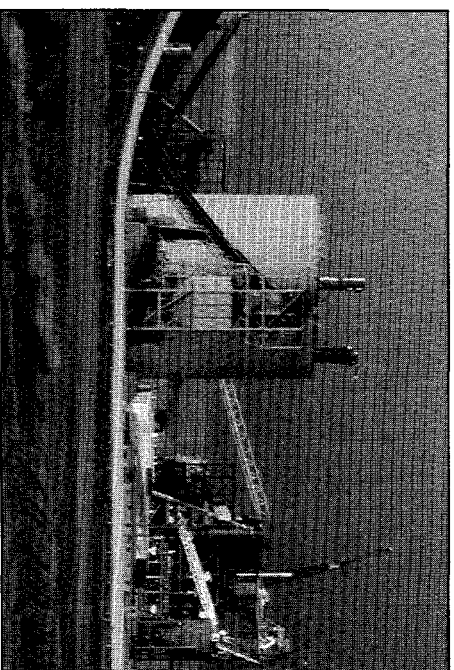
Removing organic sulfur that is chemically bound to the coal is a far greater challenge than removing pyritic sulfur through physical means. Currently, chemical and biological processes that react with the coal are being used to remove organic sulfur. One chemical technique that has shown promise is molten caustic leaching. This technique exposes coal to a hot sodium- or potassium-based chemical. The chemical leaches sulfur and mineral matter from the coal. Other chemical techniques modify the chemical characteristics of coal in a way that makes the coal more receptive to cleaning.

Biological cleaning represents some of the most exotic techniques in coal cleaning. A potential advantage of biological techniques over chemical cleaning is that biological cleaning requires less severe operating conditions. Researchers have identified naturally occurring bacteria that can digest the organic sulfur in

coal. Other approaches involve using fungi, rather than bacteria, and injecting sulfur-digesting enzymes directly into the coal.

Chemical or biological coal cleaning appears to be capable of removing as much as 90 percent of the total sulfur (pyritic and organic) in coal. Some chemical techniques also can remove 99 percent of the ash.

The CCT Program has two projects that employ coal-cleaning technologies. The Advanced Coal Conversion Process Demonstration conducted by the Rosebud SynCoal Partnership converts, at a rate of 45 tons per hour, low-energy, high-moisture subbituminous coal to a stable coal product having a moisture content as low as 1 percent, a sulfur content as low as 0.3 percent, and a heating value of up to 12,000 Btu per pound. The facility, shown in the photo on this page, has been producing product since March 1994 for testing in utility boilers. The other project is being



▲ The Rosebud SynCoal Partnership is demonstrating an advanced thermal coal process coupled with physical cleaning techniques to upgrade low-rank subbituminous and lignite coals. The 45-ton/hr unit is located in Colstrip, MT, and produces an upgraded SynCoal® product for utility and industrial use.

conducted by Custom Coals International to demonstrate an advanced coal-cleaning process that produces two types of compliance coals—Carefree Coal™ and Self-Scrubbing Coal™.

Carefree Coal™ is designed to be a competitively priced high-Btu fuel that can be used without major plant modifications or additional capital expenditures. Self-Scrubbing Coal™ is produced by taking Carefree Coal™ and adding to it sorbent, promoters, and catalysts. The product is expected to achieve compliance with virtually any U.S. coal feedstock through in-boiler absorption of SO₂ emissions.

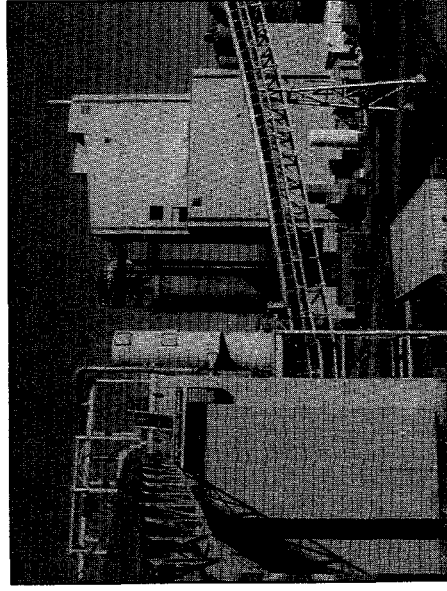
A third project, while not involved in the demonstration of a coal-cleaning technology, is included in the coal processing for clean fuels. The project, Development of the Coal Quality Expert, is directed toward the development and demonstration of a computer software package that will serve as a prediction tool to assist coal-burning utilities in selecting optimum quality coal for a specific boiler based on operational efficiency, cost, and environmental emissions. The CCT Program's coal-cleaning (or preparation) projects are described in fact sheets on pages 7-78-7-83.

Mild Gasification. Mild gasification is a modification of the conventional coal gasification process that produces gaseous, solid, and liquid products by heating coal in an oxygen-free reactor. The process takes an alternative approach to complete gasification of coal by driving off the condensable volatile hydrocarbons and leaving behind carbon, in lieu of converting the entire charge of coal to synthesis gas.

Mild gasification processes generate multiple fuels and chemical feedstocks by medium-temperature treatment of coal. The products generated are charac-

terized as coal-derived liquids, gases, and solids, depending on the operating conditions. The solid product can be further beneficiated to remove both ash and pyritic sulfur. A slurry of coal-derived fuel and beneficiated solid has the potential of being a very versatile fuel that can be burned in both coal- and oil-fired boilers. If the solid product is beneficiated to a high degree, even feedstock coal with a high sulfur content can be used.

The mild gasification technology is being demonstrated in the CCT Program by the ENCOAL project (see photo on this page). The technology produces two products: (1) a solid fuel with higher heating value (about 12,000 Btu per pound) and a lower sulfur content than the coal feedstock and (2) a low-sulfur liquid product that can be directly substituted for No. 6 fuel oil. The project is described in the fact sheet on page 7-84.



▲ The ENCOAL mild gasification plant near Gillette, WY, processes about 500 tons/day of low-sulfur, low-heating-value subbituminous coal. The plant produces a low-sulfur, high-heating-value solid fuel for utility use and a low-sulfur liquid product for industrial use.

Coal Gasification. The basic coal gasification process was previously described in the Advanced Electric Power Generation market subsection (see page 1-13). The technology can be used to produce a low-Btu gas when air is used as the oxidant or a medium-Btu gas when oxygen is used as the oxidant. Low-Btu gas provides a clean fuel gas that can be used locally to fire boilers, gas turbines, industrial furnaces, and other systems. Medium-Btu gas, which is essentially carbon monoxide and hydrogen with some carbon dioxide, can be used as a fuel on site or transported economically by pipeline (100-200 miles) for distribution to an industrial or municipal complex. If the gas is further converted to a highly pure mixture of hydrogen and carbon monoxide, it replaces reformed natural gas as the feedstock for chemical synthesis (e.g., methanol, ammonia, hydrogen).

Besides the five integrated gasification combined-cycle technologies being demonstrated under the CCT Program, the liquid-phase methanol (LPMEOH™) project has its basis in coal gasification. In this project, which could also be classified under indirect coal liquification, methanol is produced from a coal-derived synthesis gas using Air Products and Chemicals' LPMEOH™ process. The fact sheet on page 7-86 describes the 260-ton-per-day methanol production project.

Coal Liquefaction. Liquefaction of coal involves the addition of hydrogen to coal by various techniques so that the fuel's ratio of hydrogen to carbon is increased to a level comparable to petroleum-based fuels.

Coprocessing, a recent development in liquefaction technology, involves the production of liquid fuel from a mixture of coal and heavy petroleum residue,

with the residual oil providing some of the hydrogen needed for the conversion process. Once produced, the coal-derived liquid can be cleaned of its sulfur and ash before being used.

The potential advantages of direct liquefaction include improved thermal efficiency (in the range of 60–70 percent), high product yield, and the potential to make products such as high-quality gasoline.

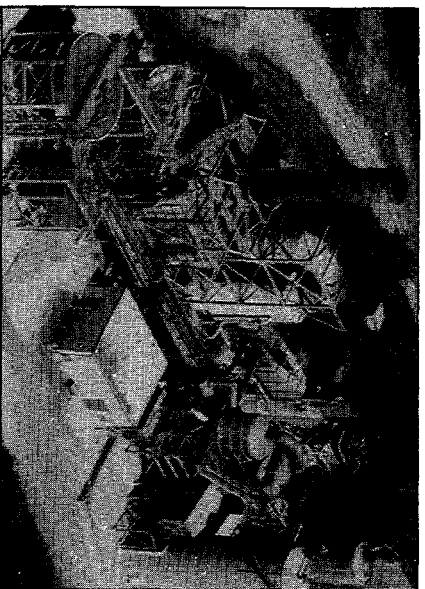
Principal disadvantages stem from the severe operating conditions (temperature and pressure) required and the lack of integration among process steps.

There are no direct coal liquefaction projects under the CCT Program as efforts in this area are still in the pilot-plant stage. However, coal liquids are produced indirectly through the LPMEOHTM process and the ENCOAL mild gasification process.

Industrial Applications

Technologies developed for U.S. industry can improve industry's productivity and efficiency while resolving environmental issues similar to those faced by the electric power generation industry. Many of the technologies principally identified in the other marketplace application categories are applicable to the industrial market. These technologies include advanced combustion, fluidized-bed combustion, coal gasification processes, and a variety of environmental control systems.

Two industrial application projects in the CCT Program have completed operations: Coal Tech Corporation's Advanced Cyclone Combustor with Integral Sulfur, Nitrogen, and Ash Control project completed operations in 1990 and the final report was issued in 1991. The Passamaquoddy Tribe's Cement Kiln Flue Gas Recovery Scrubber project completed



▶ There are five industrial application projects totaling over \$1.31 billion. Above is the Passamaquoddy Tribe's cement kiln flue gas scrubber project that successfully demonstrated greater than 90% sulfur reduction and the production of usable by-products. Shown on the right is the recently completed Bethlehem Steel Corporation facility to demonstrate the injection of granulated coal directly into two blast furnaces at Burns Harbor, IN.

operations and issued the final report at year-end 1993 (see photo this page). This successful cement kiln project may have broader applications in paper production and municipal waste incineration. Cement kiln waste was used to achieve greater than 90 percent SO₂ emissions reductions, produce fertilizer, convert kiln waste to cement feedstocks, and eliminate all waste streams. A discussion of the completed projects is contained in Section 5. Bethlehem Steel Corporation completed construction and start-up for a project to demonstrate the injection of granulated coal directly into two blast furnaces at Burns Harbor, Indiana (see photo on this page). Preoperational testing began in February 1995 and continued until November 1995 when full opera-

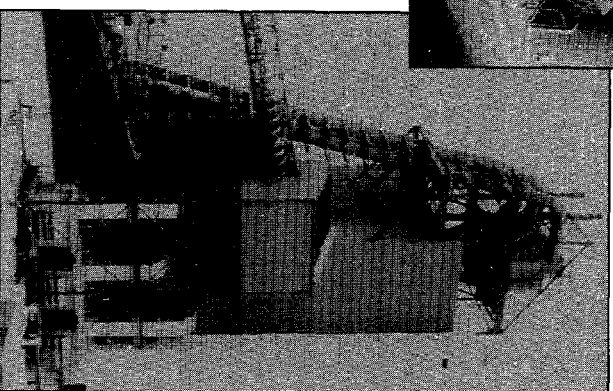
tion began. The coal displaces up to 40 percent of the coke normally used in the steelmaking process, thus reducing coke requirements and the attendant emissions associated with coke making. The reducing environment of the blast furnace enables all of the

sulfur in the coal to be captured by the slag and hot metal. The fact sheet on page 7-90 describes this project.

Another project, Clean Power from Integrated Coal/Ore Reduction, is planned to demonstrate the integration of a direct iron-making process (COREX[®]) with the coproduction of electricity using various U.S. coals. The project, currently in negotiation, will produce 195 MWe

(net) of electricity and 3,300 tons per day of liquid iron and will be sited at Geneva Steel's mill in Vinyard, Utah. The fact sheet on page 7-92 describes this project.

The fifth project is the Demonstration of Pulse Combustion in the Application for Steam Gasification of Coal. The project is planned to produce 161 million Btu per hour or 325 standard cubic feet of medium-Btu fuel gas and 40,000 pounds per hour of export steam. The project, which is undergoing restructuring, is described on page 7-98.



2. Program Implementation

Introduction

The CCT Program has been implemented through selecting projects in a series of five nationwide competitive solicitations conducted over a period of 9 years, with each competition associated with a specific level of government funding and objectives. At the end of 1995, a total of 43 projects, valued at nearly \$7.21 billion and located in 18 states, are either already complete or moving forward. Government funding for the projects is approximately \$2.35 billion; the private sector is providing nearly \$4.86 billion, or 67 percent of the projects' total value—far in excess of the congressionally mandated minimum of 50 percent.

The Legislation

The legislation authorizing the CCT Program is found in Public Law 98-473, Joint Resolution Making Continuing Appropriations for Fiscal Year (FY) 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 were 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 Innovative Research, or SBIR, Program.)

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 FY 1987 (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 139 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 industry/government demonstrations of innovative control technology over a 5-year period. The Secretary of Energy stated that the department would ask Congress for an additional \$350 million in FY 1988 and an advanced appropriation of \$500 million in FY 1989. 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 were for projects, with the remainder for program direction and the SBIR Program.

The Department of the Interior and Related Agencies Appropriations Act for FY 1989 (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 were made available for cost-sharing projects, with the remainder for program direction and the SBIR Program.

The act continued the requirement that proposals demonstrate technologies capable of retrofitting or repowering existing facilities. The statute also authorized the use of Tennessee Valley Authority (TVA) power program funds as a source of nonfederal cost sharing. In addition, funds borrowed by Rural Electrification Administration electric cooperatives from the Federal Financing Bank became eligible as cost sharing in the CCT-III solicitation.

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 were made available for federal cofunding of projects selected in CCT-IV, with the remainder for program direction and the SBIR Program.

The FY 1990 Supplemental Appropriations Act (Public Law 101-302, enacted May 25, 1990) delayed issuance of the CCT-IV solicitation from June 1, 1990, until September 1, 1990. However, the Department of the Interior and Related Agencies Appropriations Act of FY 1991 (Public Law 101-512, enacted November 15, 1990) subsequently directed DOE to issue the PON for CCT-IV on or before February 1, 1991.

In Public Law 101-121, enacted October 23, 1989, Congress 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 were made available for federal cofunding of projects to be selected in this solicitation, with the remainder again for program direction and the SBIR Program. In Public Law 101-512, Congress directed DOE to issue the PON for CCT-V no later than March 1, 1992, and subsequently, in Public Law 102-154, postponed the PON's release to July 6, 1992. This later act also directed that the proposals should advance significantly the efficiency and environmental performance of coal-using technologies and be applicable to either new or existing facilities.

Public Law 103-138, enacted November 11, 1993, and Public Law 103-332, enacted September 30, 1994, adjusted the rate at which funds were to be made available to the program in FY 1994, 1995, and 1996. During FY 1995, a \$200-million rescission was enacted by Public Law 104-6 on April 10, 1995. (See Appendix A for excerpts of relevant legislation.)

Implementation Principles

The programmatic success of the CCT Program is a result, in large measure, of the evolution of a set of principles governing the implementation process that evolved over the past 10 years. 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 result had been the develop-

ment of a model program for government/industry cooperation in technology development. The program principles that were developed under the CCT Program and served to guide its implementation follow:

- **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 outset 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 nearly 67 percent industry 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 set the basic goals of the program to meet changing national needs, provided DOE time to adjust 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 project is constructed as a commercial facility or may be installed at an existing facility and subjected to conditions typical of commercial operations. This enables the technology's performance potential to be judged in the intended commercial environment.

- **The technical agenda is determined by industry, not the government.** DOE solicited proposals seeking projects satisfying broad programmatic areas. Industry defined the specific projects. DOE selected the projects based on those that best met the programmatic criteria.
- **Roles of government and industry are clearly defined.** In the program, the industrial participant is responsible for technical management of the project while the government oversees the project through aggressive monitoring. Continued government support is assured as long as the project continues to meet the terms of the initial cooperative agreement. The agreement identifies key decision points in the project at which mutually agreed upon progress and performance goals are evaluated and expected to be met.
- **Cost sharing is required throughout all project phases.** A minimum of 50 percent cost-sharing is required. It must be tangible and directly related to the demonstration project, with no credit given to prior work. Requiring cost sharing throughout the project ensured industry's commitment of fulfilling project objectives.
- **Industry retains real and intellectual property rights.** Title to all real property rights vests with the industrial participants. Because of the level of cost sharing, the industrial participant also retains the intellectual property rights.

- **Technology that is developed is being made available on a nondiscriminatory basis to all U.S. companies that seek, under reasonable terms and conditions, to use the technology.** While the technology owner is not forced to divulge its know-how to a competitor, the technology must be made available to a potential domestic user on reasonable commercial terms.
- **Repayment of the government funds is required of the industrial participant.** The repayment obligation occurs only upon the successful commercialization of the technology. It is limited to the government's level of cost sharing and can be repaid over a 20-year period following the end of the demonstration.

These principles can serve as a guide for future technology development programs. Although some of these principles cannot be adopted verbatim by other programs, the precepts are transferrable and concepts underlying the CCT Program can be molded to fit. The experience developed in dealing with complex business arrangements of the CCT projects is a significant asset that has contributed greatly to the CCT Program's success—an asset that can be used in other programs as well as guiding the completion of the CCT Program. A report, *The Clean Coal Technology Program Lessons Learned*, published in July 1994, documents the knowledge acquired over the course of the program through the completion of the five solicitations. The report was based on the belief that it is of mutual advantage to the private sector and government to identify those factors thought to contribute to the program's success and to point out what pitfalls were encountered and corrective actions taken.

The 10 years of program implementation have demonstrated that a government/industry partnership can be crafted to engage the major energy, economic, and environmental issues involved with the use of the nation's most significant energy source—coal. With the government serving as a risk-sharing partner, industry funding has been leveraged to improve the environment, reduce the cost of electricity, improve power generation efficiencies, create jobs, and position U.S. industry to successfully compete internationally.

Solicitation Results

The CCT Program has been implemented through five competitive solicitations. Congress set the basic goals for the program and for each solicitation in the enabling legislation and accompanying report language. DOE subsequently translated the guidance into performance-oriented solicitations. For each solicitation, evaluation criteria were defined and weighted to reflect specific congressional guidance and the current CCT Program objectives. This process enabled industry to set the technical agenda by allowing companies to propose their own technologies as qualifying projects. This had the significant benefit of attracting higher levels of private-sector cost-sharing and increasing the likelihood of realizing commercialization objectives.

An important attribute to the solicitation approach used to implement the CCT Program was the use of multiple solicitations spread over a number of years. Allowing time between solicitations made it possible to adjust program implementation. At the end of

each solicitation, Congress provided the flexibility as needed to effectively implement the program.

Each solicitation was issued as a PON. Proposals for demonstration projects consistent with the objectives of the PON were submitted to DOE by a specific deadline. DOE evaluated the proposals and announced those projects selected for negotiation.

Exhibit 2-1 summarizes the results of the solicitation processes. Exhibit 2-2 identifies the projects currently in the CCT Program and the solicitation under which they were selected. (Also see Appendix B.)

The objective of the CCT-I solicitation was to seek cost-shared projects to demonstrate the feasibility of clean coal technologies for commercial applications. The solicitation elicited 51 proposals. Nine projects were selected and 8 alternate projects were eventually selected as replacement projects when negotiations could not be completed on the originally selected projects. Projects were selected from the list of alternates on three separate occasions.

At year-end 1995, there were 8 CCT-I projects in the CCT Program: 5 had completed operations; 2 were in operation; and 1 was in project definition and design. The 8 CCT-I projects included 3 demonstrating advanced electric power generation; 2, environmental control devices; 2, coal processing for clean fuels; and 1, an industrial application.

The CCT-II PON 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 SO₂ and/or NO_x emissions from existing coal-burning facilities, particularly those that contribute to transboundary and interstate 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 select-

ed). At the end of 1995, 11 CCT-II projects remained in the CCT Program: 8 had completed operations; 1 was in operation; 2 were in design; and 5 were withdrawn. The 11 CCT-II projects included 2 demonstrating advanced electric power generation; 8, environmental control devices; and 1, industrial applications.

The objective of the CCT-III PON 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 SO₂ and/or NO_x from existing facilities to minimize environmental impacts, such as transboundary and interstate 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. On December 31, 1995, all 13 projects remained in the CCT Program: 5 had completed operations; 3 were in operation; 3 were in construction; and 2 were in design. These 13 CCT-III projects included 2 demonstrating advanced electric power generation; 7, environmental control devices; 2, coal processing for clean fuels; and 1, industrial applications.

The CCT-IV PON 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 SO₂ and/or NO_x and/or (2) providing for future energy needs in an environmentally acceptable manner. A total of 33 proposals

Exhibit 2-1 CCT Program Selection Process Summary

Solicitation	PON Issued	Proposals Submitted	Projects Selected	Projects in CCT Program as of December 31, 1995
CCT-I	February 17, 1986	51	17	8
CCT-II	February 22, 1988	55	16	11
CCT-III	May 1, 1989	48	13	13
CCT-IV	January 17, 1991	33	9	6
CCT-V	July 6, 1992	24	5	5
		211	60	43

**Exhibit 2-2
Clean Coal Technology Demonstration Projects, by Solicitation**

Project and Participant	Location
<p>CCT-I</p> <p>Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ, Inc.)</p> <p>LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)</p> <p>Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)</p> <p>Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)</p> <p>Tidd PFBC Demonstration Project (The Ohio Power Company)</p> <p>Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)</p> <p>Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)</p> <p>ACFB Demonstration Project (York County Energy Partners, L.P.)</p>	<p>Homer City, PA</p> <p>Lorain, OH</p> <p>Williamsport, PA</p> <p>Hennepin and Springfield, IL</p> <p>Brilliant, OH</p> <p>Colstrip, MT</p> <p>Nucla, CO</p> <p>Under negotiation</p>
<p>CCT-II</p> <p>Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.)</p> <p>SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)</p> <p>PFBC Utility Demonstration Project (The Appalachian Power Company)</p> <p>Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)</p> <p>SOx-NOx-Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)</p> <p>Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)</p> <p>Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)</p> <p>Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)</p> <p>Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)</p> <p>Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)</p> <p>180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)</p>	<p>Under negotiation</p> <p>Niles, OH</p> <p>Under negotiation</p> <p>Cassville, WI</p> <p>Dilles Bottom, OH</p> <p>Thomaston, ME</p> <p>Chesteron, IN</p> <p>Coosa, GA</p> <p>Newnan, GA</p> <p>Pensacola, FL</p> <p>Lynn Haven, FL</p>

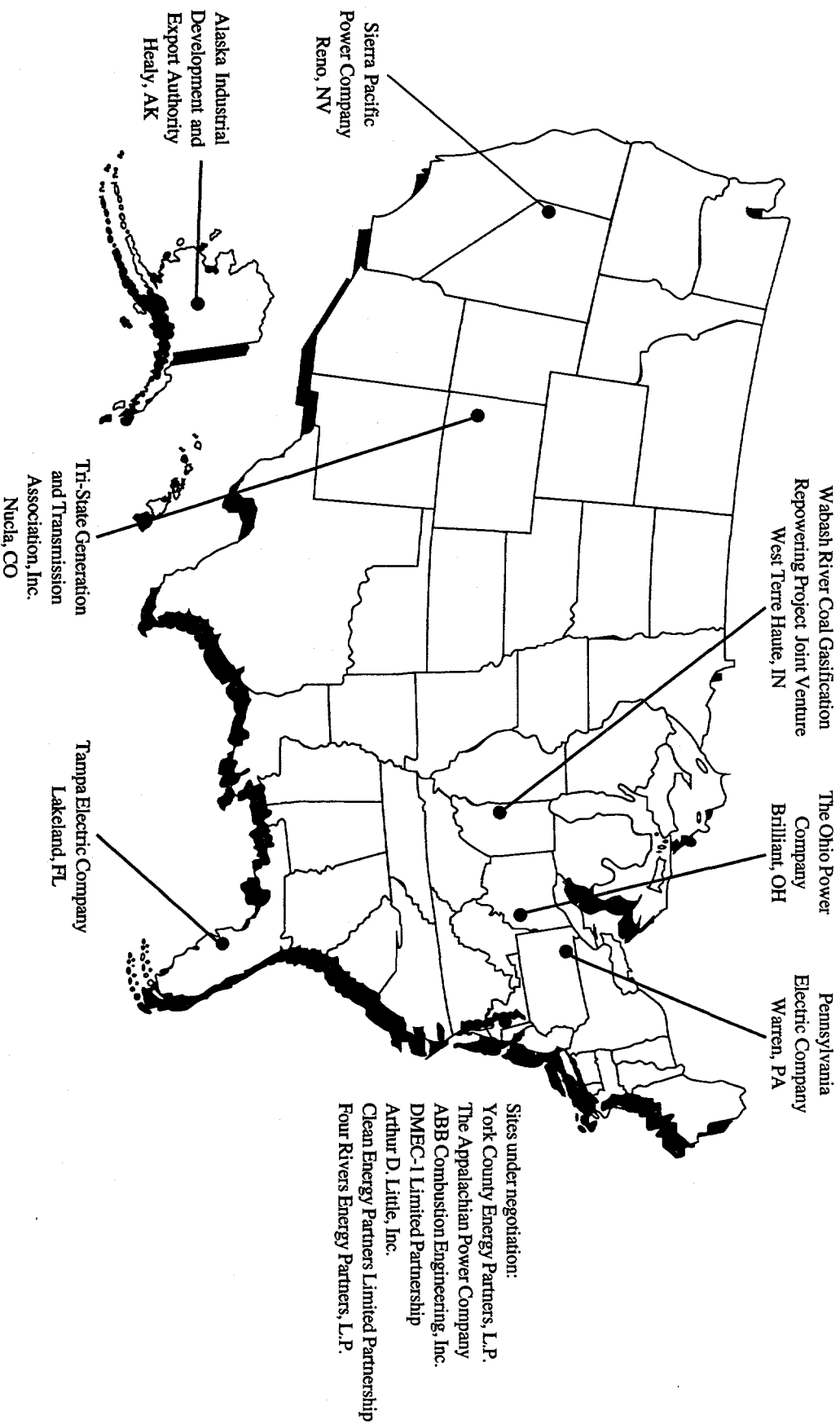
Exhibit 2-2 (continued) Clean Coal Technology Demonstration Projects, by Solicitation

Project and Participant	Location
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
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	Seward, PA
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Burns Harbor, IN
PCFB Demonstration Project (DMEC-1 Limited Partnership)	Under negotiation
ENCCOAL Mild Coal Gasification Project (ENCCOAL 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
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System (NOXSO Corporation)	Newburgh, 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)	Lakeland, FL
CCT-IV	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custon Coals International)	Central City and Lower Mt. Bethel, PA
	Richmond, IN
	Ashabula, OH
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
Piton Pine IGCC Power Project (Sierra Pacific Power Company)	Reno, NV
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	Silver Bay, MN
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	West Terre Haute, IN

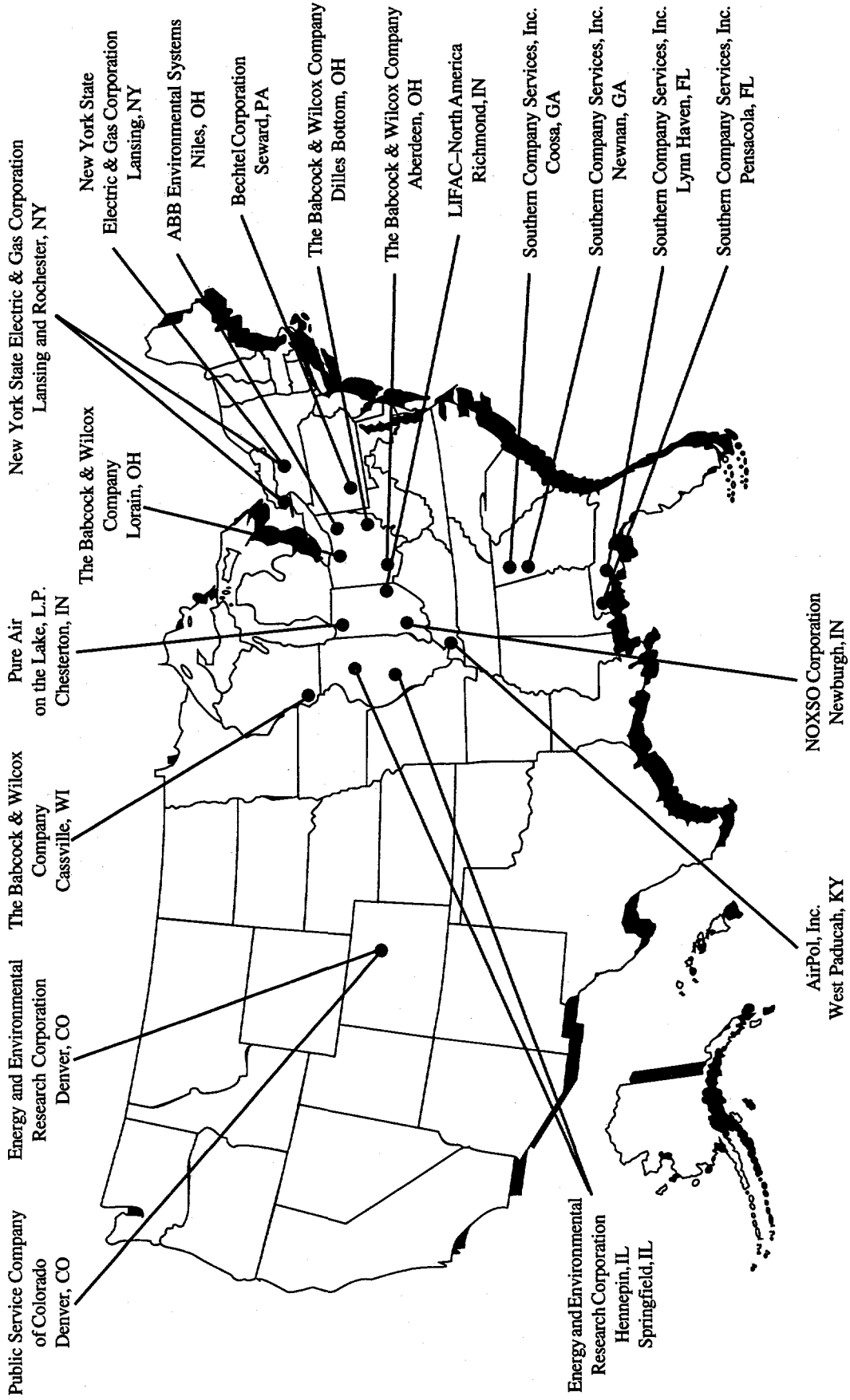
Exhibit 2-2 (continued)
Clean Coal Technology Demonstration Projects, by Solicitation

Project and Participant	Location
CCT-V	
Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.)	Under negotiation
Clean Power from Integrated Coal/Ore Reduction (COREX®) (Centerior Energy Corporation)	Vineyard, UT
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	Eastern U.S.
Four Rivers Energy Modernization Project (Four Rivers Energy Partners, L.P.)	Under negotiation
Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company)	Warren, PA

Exhibit 2-3 Geographic Locations of CCT Projects—Advanced Electric Power Generation



**Exhibit 2-4
Geographic Locations of CCT Projects—Environmental Control Devices**



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

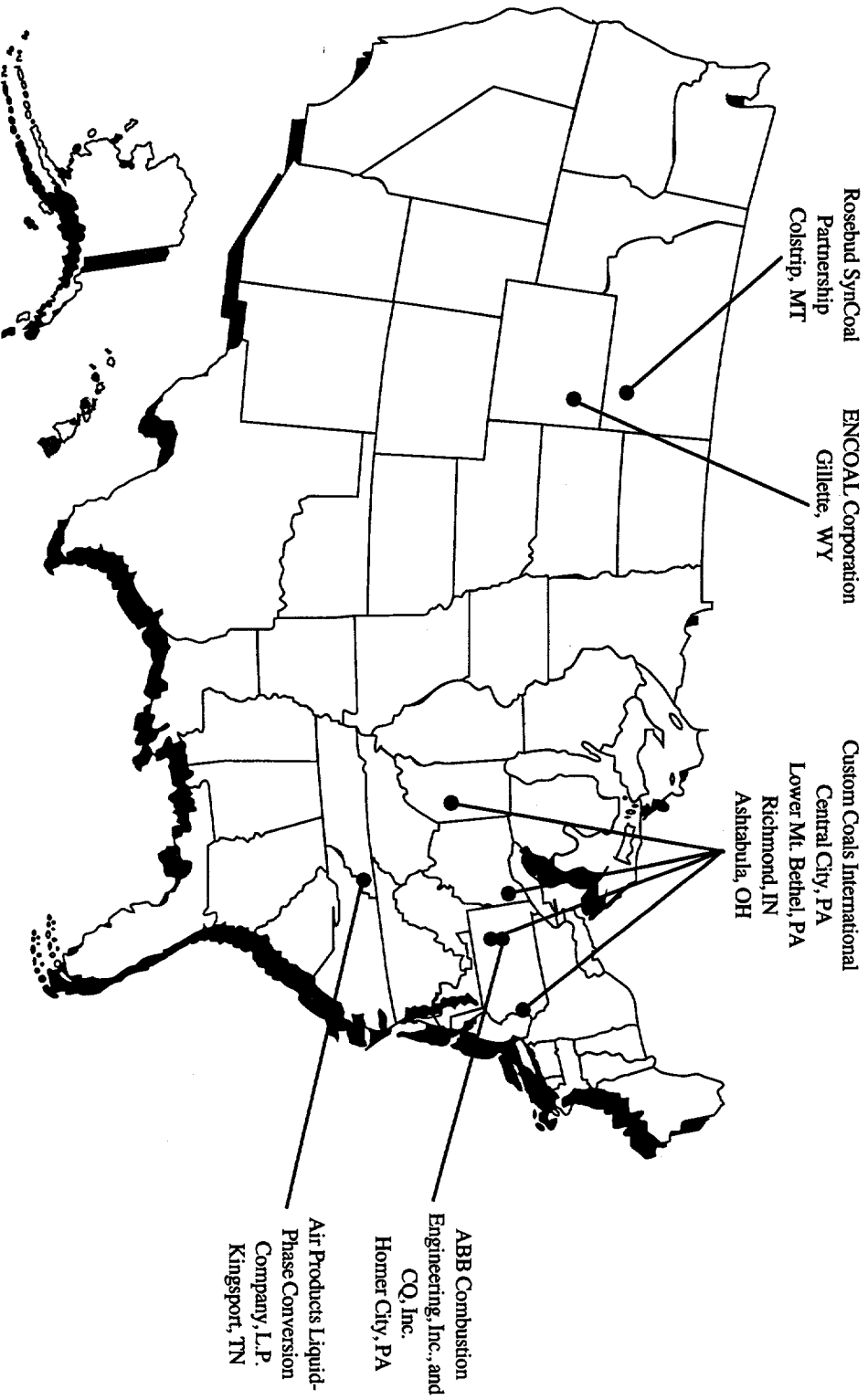
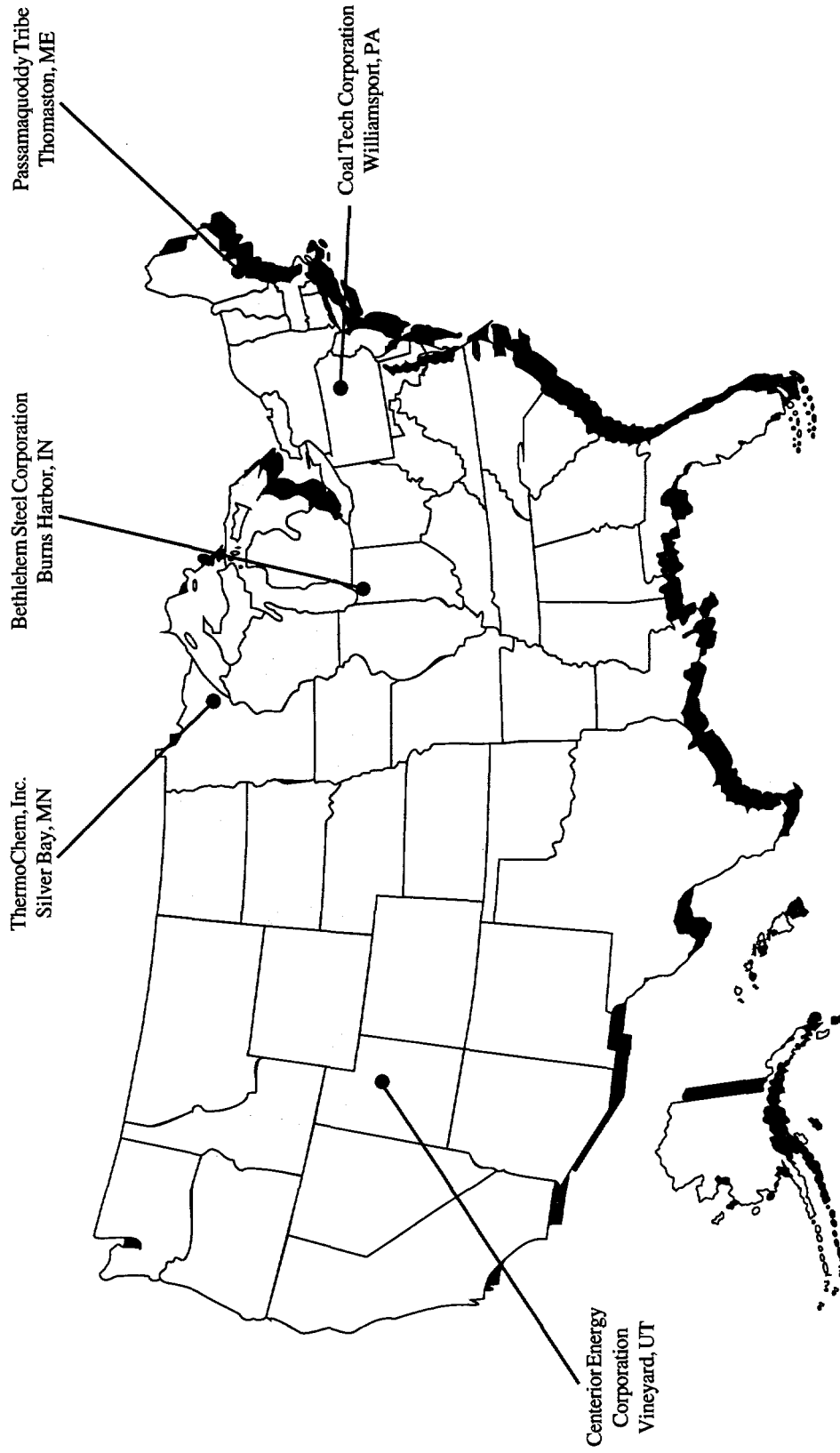


Exhibit 2-6
Geographic Locations of CCT Projects—Industrial Applications



were submitted in response to the PON. Nine projects were selected; however, 3 have been withdrawn. As of December 31, 1995, 2 were in operation; 2 were in construction, and 2 were in design; they included 2 demonstrating advanced electric power generation; 2, environmental control devices; 1, coal processing for clean fuels; and 1, industrial applications.

The objective of the CCT-V PON 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. At year-end 1995, 4 CCT-V projects were in design and 1 was in negotiation. Selected projects included 4 demonstrating advanced electric power generation and 1, industrial applications.

Project sites are mapped in Exhibits 2-3 through 2-6, which indicate the geographic locations of projects by application category.

Future Implementation Direction

The report, *Clean Coal Technology Program*

Completing the Mission, was issued by DOE in May 1994. It contains DOE's response to a congressional request that the Secretary of Energy report on available funds appropriated but not used in CCT-I-V. DOE found that "an expansion of the current demonstration program in the form of an additional round of competition is not recommended." Further, DOE

recommended "that Congress initially establish an International Technology Transfer Program."

In response to these proposals and recommendations, Senate Report 103-294 stated that "the highest priority for this program is to complete the existing projects as promptly as possible, but with reasonable assurance that sufficient data are generated to support subsequent commercialization activity."

During 1995, the goals and objectives of the CCT Program received additional support in the national energy policy developed to guide markets and technologies toward the goals of affordable, clean, reliable, and secure energy. This is articulated in the policy document, *Sustainable Energy Strategy: Clean and Secure Energy for a Competitive Economy*.

The sustainable energy policy pursues all three goals to meet the needs of today without compromising the ability of future generations to satisfy future needs.

The nation's policy for coal and coal technologies is to help industry develop cleaner and more efficient uses for coal as part of the U.S. energy portfolio. Coal policy addresses the primary risk associated with the environmental impacts of coal use. This is pursued through development and deployment of technologies to reduce environmental impacts; such technologies are critical to sustaining coal's contribution to U.S. energy needs. The national energy policy recognizes that technology improvements over the past two decades have reduced significantly the environmental impacts of coal use, and that trend is expected to continue for many of the conventional regulated air pollutants. Further, high-efficiency technologies can cost-effectively reduce carbon dioxide emissions per unit of energy produced.

The national energy policy supports clean coal technology development and recognizes the contribution of the CCT Program and the fact that industry has contributed \$2 for every \$1 of federal money invested.

Commercial realization is being achieved by the emission control technologies demonstrated under the early solicitations, while the advanced power systems selected under the later solicitations will reach commercial status within a decade. DOE is focusing its coal R&D program at advanced electric power technologies so that by 2015 these technologies achieve an efficiency of 58-60 percent and 10-20 percent lower generating costs, making a new generation of power systems available through government/industry cost-shared investments. These new technologies are projected to account for 56 gigawatts of capacity per year in both domestic and export markets. However, as noted in the national energy policy document, recent studies by the National Academy of Sciences and the National Coal Council conclude that continued federal support is needed to ensure that advanced technologies will be available.

The federal government also supports the efforts of U.S. vendors of clean coal technologies to export equipment and services. The use of clean and efficient U.S. generation equipment, including clean coal technology, will help reduce global environmental impacts from expanded coal-fired generation and create U.S. jobs to develop and build these advanced power systems.

The electricity policies to promote competition by restructuring the industry to link competition to national goals and to examine the statutory framework that enables the market to move toward greater competition will affect the commercial realization of

clean coal technologies. The transformation of the industry and its regulatory institutions is being driven by the following factors:

- Statutory changes, such as the Energy Policy Act of 1992, that promote increased competition in bulk power markets
- Large disparities in electric rates from utility to utility, which encourage customers to seek access to lower-cost suppliers
- New low-cost generation technologies, which offer cheaper power and reduce the economic value of existing traditional generation equipment
- Successful experience with reduced regulation in other industries

Many proposals for increasing competition are now being considered at the state level. The FERC is considering changes in federal regulations to accommodate greater competition under the existing statutory framework. In March 1995, FERC issued a notice of proposed rulemaking that addressed key issues involved in moving toward a competitive wholesale electricity marketplace. However, significant issues exist as individual state and federal regulatory reform efforts evolve. These issues include stranded assets and stranded benefits. Stranded assets refer to prudent investments incurred or contracts entered under the existing regulatory framework, the cost of which is unlikely to be recovered under more competitive market conditions. State and federal regulators have solicited suggestions regarding mechanisms for potential recovery of stranded assets. Stranded benefits refer to system and social

objectives currently served by the regulated market that may be vulnerable under more competitive markets. These benefits include end-use efficiency, industry-sponsored electricity R&D, reduction of greenhouse gas emissions, environmental externalities, service to low-income consumers, and others. The impact of deregulation and greater competition in the electricity industry will have an impact on the commercial realization of clean coal technology; however, the magnitude is currently unknown.

During 1994 and 1995, the National Coal Council was commissioned by the Secretary of Energy to perform two studies providing an in-depth review and prioritization of coal-related development activities under way, from research to commercialization. Both studies concluded that DOE plays a key role in clean coal technology deployment and recommended that the government continue its financial and technical support for the development and initial deployment of clean coal technologies that are (1) highly efficient, (2) environmentally sound, and (3) cost competitive.

In February 1994, the National Coal Council released its report entitled *Clean Coal Technology for Sustainable Development*. This report addressed five issues: (1) the current status of industrial acceptance of CCTs, (2) technical gaps in CCT, (3) the desirability of additional federal incentives to overcome market hurdles for CCTs, (4) the merits of confounding further improvements to previously demonstrated CCT projects, and (5) international technology transfer. The National Coal Council made the following recommendations:

1. DOE should not engage in any further solicitations under the existing CCT Program. Where unused funds exist, the continuation of

operating demonstrations should be pursued as a means of facilitating commercial deployment through expanded operating experience.

2. DOE should promote the role of CCTs in the government's environmental technology programs; CCTs can improve the global environment as well as prevent pollution.
3. DOE should establish a new federal Clean Coal Technology Incentive Program of approximately \$1.4 billion over 15 years to stimulate commercial deployment.
4. The DOE market assessment and communications program should continue and be expanded to include all stakeholders in coal.
5. DOE should evaluate the potential of converting old existing, but non-complying plant sites to new sites employing CCTs.
6. DOE should disseminate commercial cost information as it becomes available to facilitate assessment of each technology's economic viability.
7. Unused CCT Program funds should be used to continue selected operating demonstrations to gain more experience, which would facilitate commercial deployment and obtain environmental data necessary to understand air toxics and other related issues.
8. Global deployment of CCTs is a critical ingredient to both sound domestic economic development and worldwide sustainable economic and social development.

In May 1995, the National Coal Council released *A Critical Review of Efficient and Environmentally Sound Coal Utilization Technologies*, which showed that technology can enable coal to continue and perhaps expand its major role in the energy portfolio of the United States. In this study, 46 coal utilization technologies were comprehensively reviewed and evaluated from the perspective of their potential value to industry. In addition, the report covered advanced power systems and examined technologies associated with the conversion of coal into other usable products. The key conclusions of this study are as follows:

1. All new technologies need some form of risk-sharing for first-of-a-kind plants in order to progress quickly from demonstration to commercial use.
2. Many of the promising technologies will be demonstrated under the CCT Program; however, further development to reduce cost is critical to market acceptance.
3. Many of the technologies still require fundamental research and development before their potential applicability for future utilization can be properly evaluated.
4. As federal and state environmental requirements are mandated, the relative importance of many of these technologies change.
5. A wide range of technologies is necessary to assure economically viable and environmentally acceptable coal options in both the short-term and the long-term.

To place the conclusions and recommendations of the National Coal Council within the context of the CCT Program, eight technical demonstration priorities and six technical commercial assistance priorities were identified. The demonstration priorities were identified as follows:

1. The pressurized fluidized-bed demonstration program should be completed.
2. The integrated coal gasification combined-cycle demonstrations should also be completed.
3. Advanced pulverized coal boilers should be completed under the low-emission boiler system program.
4. Hazardous air pollution system controls should be extended to include the characterization of all effluents from demonstration projects in the CCT Program.
5. The indirect-fired cycle demonstration should be completed under the CCT Program.
6. The molten carbonate fuel cell demonstration should be completed.
7. By-product utilization work should concentrate on key solids streams found in the CCT Program.
8. SO_x/NO_x control demonstration projects under the CCT Program should be completed and economics of each control system evaluated separately.

Commercial assistance priorities were as follows:

1. Integrated coal gasification combined-cycle systems will need further government-supported risk-sharing.
2. Advanced pressurized fluidized-bed systems will need further government-supported risk-sharing.
3. Physical coal-cleaning systems need international marketing assistance.
4. Low-rank coal beneficiation systems need international marketing assistance.
5. By-product utilization technologies need to have a national utilization standard as a basis for commercialization.
6. Coal-fired diesel engines need international marketing assistance.

Future implementation direction with respect to international technology transfer was further defined in 1995. Senate Report 103-294 provided the following provision: "The Committee does, however, support efforts by DOE in promoting exports of CCTs, particularly to countries experiencing rapid economic development. . . . Accordingly, DOE is directed to make the dissemination of CCTs overseas an integral part of its policy to reduce greenhouse gas emissions in developing countries." Further, the report directed DOE to conduct an informational solicitation. The request for expressions of interest in commercial projects employing clean coal technologies in foreign countries that project significant growth in greenhouse gas emissions was distributed on November 18, 1994.

Thirty-three organizations responded to DOE's request for Expression of Interests (EOIs) to build CCT projects in developing countries, Eastern Europe, Newly Independent States, and Pacific Rim nations. Seventy-seven EOIs were submitted, with projects proposed in 21 countries. The 77 projects, which represent a total of 58,237 MWe of generating capacity, were valued at \$7.15 billion. The largest number of projects were proposed for China; 20 projects representing 6,537 MWe were valued at \$2.5 billion. Ten projects were proposed for India; these represent 1,110 MWe and were valued at nearly \$2.1 billion.

The respondents' EOIs identified government incentives amounting to \$1.4 billion of federal funds that would be needed to implement the proposed projects. The number of EOIs identifying each type of incentive is listed below:

- Funding of initial project development—33
- Funding of projects—34
- Financial assistance to U.S. business—24
- General support assistance to U.S. business—18
- Technical assistance to host country—32

The document, *Report to Congress: Expressions of Interest in Commercial Clean Coal Technology Projects in Foreign Countries*, was prepared and submitted in June 1995. This document contains an in-depth analysis of the responses to the EOI.

Environmental Aspects

DOE employs a three-step process to ensure that the CCT Program and its projects comply with the environmental 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 in 1989 of a programmatic environmental impact statement (PEIS); (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). In 1992, final NEPA implementation procedures were provided for categorical exclusions (CX) for certain classes of actions.

Exhibit 2-7 shows the progress made through 1995 to complete NEPA reviews of projects in the CCT Program. By year-end 1995, NEPA reviews were completed for 37 projects (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 1995, NEPA requirements were satisfied with a CX for 1 project, MTFs for 17 projects, EAs for 17 projects (including a project which was subsequently withdrawn from the CCT Program), and EISs for 4 proposed projects.

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.

The Role of NEPA in the CCT Program

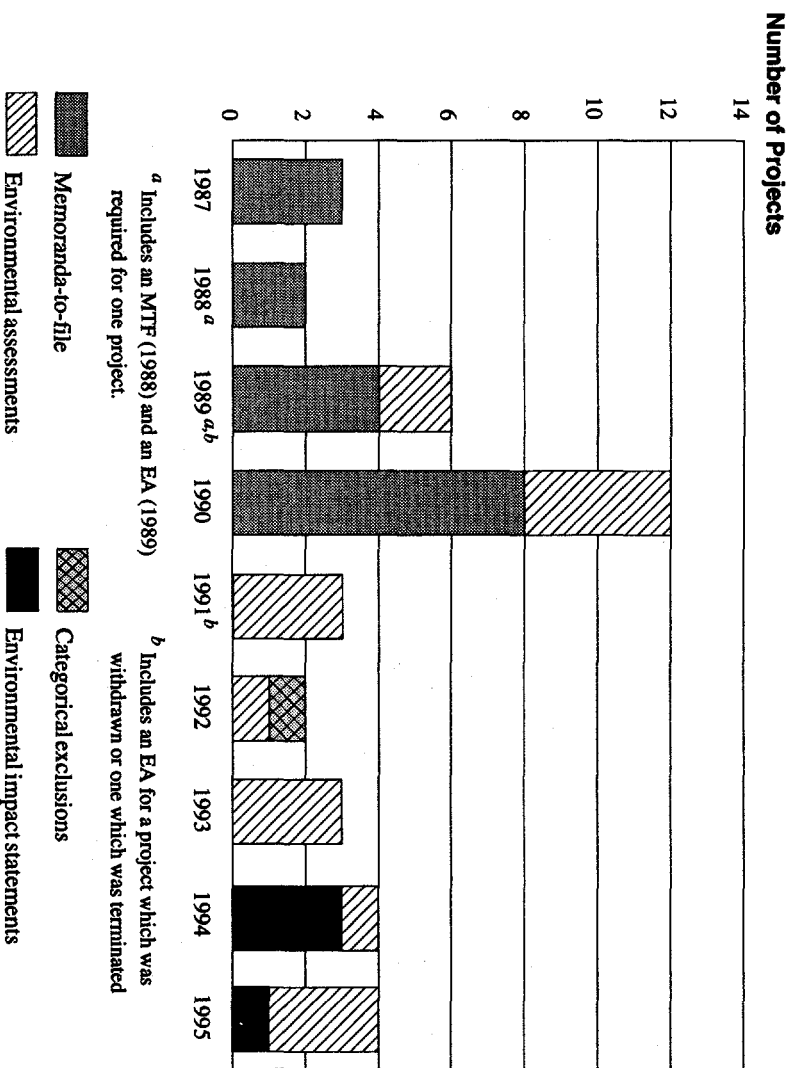
NEPA was initially enacted in 1969 as Public Law 91-190 and has since been amended, most recently by Public Law 94-83 in 1975. The applicability of NEPA to the CCT Program is encapsulated in the following provision (Section 102):

[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.

NEPA created the CEQ, which has promulgated regulations that ensure compliance with the act.

Exhibit 2-7 NEPA Reviews Completed



Compliance with NEPA

In November 1989, a PEIS was completed for the entire 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
- “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 environmental 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 which 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 provide 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. One project, Tennessee Valley Authority’s Micronized

Coal Reburning Demonstration for NO_x Control, was originally covered by a categorical exclusion (NEPA review was completed August 13, 1992); however, a new NEPA determination may be necessary as a result of project restructuring.

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 2-8 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
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 help identify better alternatives and mitigation measures
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

Exhibit 2-8 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 (The Babcock & Wilcox Company)	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
SOx-NOx-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

Exhibit 2-9 Environmental Assessments Completed

Project and Participant	Completed
CCT-I Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Lakeside site) (Energy and Environmental Research Corporation) Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	6/25/89 3/27/91
CCT-II Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.) Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company) Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation) (project terminated) Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe) Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.) Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.) Low-NO _x /SO ₂ Burner Retrofit for Utility Cyclone Boilers (TransAlta Resources Investment Corporation) (project withdrawn)	3/27/92 2/12/91 12/22/89 2/16/90 4/16/90 8/10/90 3/21/91
CCT-III Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.) Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation) ENCOAL Mild Coal Gasification Project (ENCOAL Corporation) Commercial Demonstration of the NOXSO ₂ /NO _x Removal Flue Gas Cleanup System (NOXSO Corporation)	6/30/95 6/8/93 8/1/90 6/26/95
CCT-IV Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International) Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Company) Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company) Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	2/14/94 8/18/93 5/18/95 5/28/93

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 "finding of no significant impact," or FONSI, is issued. CEQ 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. 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 2-9 lists the 17 projects for which an EA has been prepared. The exhibit includes EAs that were completed for one project that was subsequently withdrawn from the program—TransAlta Resources Investment Corporation's Low-NO_x/SO₂ Burner Retrofit for Utility Cyclone Boilers project—and one that was terminated—Bethlehem Steel Corporation's Innovative Coke Oven Gas Cleaning System for Retrofit Applications.

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.

Exhibit 2-10 Environmental Impact Statements Completed

Project and Participant	Completed*
CCT-I York County Energy Partners Cogeneration Project (York County site) (York County Energy Partners, L.P.)	8/11/95
CCT-III Healy Clean Coal Project (Alaska Industrial Development and Export Authority) Tampa Electric Company Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	3/10/94 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.

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 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 is issued, DOE may not take any action that would have an adverse environmental effect or limit the choice of reasonable alternatives. In 1995, DOE issued a record of decision on the EIS prepared for the York County Energy

Partners project located in York county, Pennsylvania, on August 11, 1995. Because this project is being restructured, a new NEPA compliance document will be required. (See Exhibit 2-10).

NEPA Actions in Progress

Exhibit 2-11 lists the status of projects for which the NEPA process has not yet been completed.

Environmental Monitoring

Participants of CCT projects are required to develop and implement an environmental monitoring plan (EMP) which addresses both compliance and supplemental monitoring. Exhibit 2-12 lists the status of EMPs for all 43 projects in the CCT Program. The

Exhibit 2-11 NEPA Reviews in Progress

Project and Participant	Status
CCT-I ACFB Demonstration Project (new site) (York County Energy Partners, L.P.)	To be determined
CCT-II Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.)	To be determined
PFBC Utility Demonstration Project (The Appalachian Power Company)	To be determined
CCT-III PCFB Demonstration Project (DMEC-1 Limited Partnership)	To be determined
CCT-IV Micronized Coal Reburning Demonstration for NO _x Control (New York State Electric & Gas Corporation)	To be determined
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	To be determined
CCT-V Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.)	To be determined
Clean Power from Integrated Coal/Ore Reduction (COREX®) (Centerior Energy Corporation)	To be determined
Four Rivers Energy Modernization Project (Four Rivers Energy Partners, L.P.)	To be determined
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	To be determined

EMEP 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 is 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
- 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 which emerge from the CAAA of 1990, and, to the 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 of 1990 lists known hazardous air pollutants (HAPs) and, among other things, calls for EPA to establish categories of sources that emit these gases. Exploratory analyses suggest that HAPs may be released by conventional coal-fired power plants and, presumably, by plants utilizing 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 utilized.

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 24 projects contain provisions for monitoring HAPs.

The CCT-V 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 2-13 lists the 24 projects that provide for HAPs monitoring. Ten 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 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 16 coal-fired utilities will be available in the spring of 1996. The first report includes the nine sites under the DOE R&D program and seven sites demonstrating CCT projects. This report provides a comprehensive assessment of the HAPs measured in the coal, across all the major pollution control devices for the flue gas produced, and the HAPs emitted from the stacks.

The second report is a summary of HAP emissions from the nine power plants characterized under the first phase of the DOE Coal R&D Program. The report considers the quality of the data relative to sampling and analytical protocols used and the variability of the data due to the different rank of coals, plant configurations, pollution control, and other key variables in the study.

During the second phase of the DOE assessment program, Louisiana Gasification Technology's coal gasification plant, located in Plaquemine, Louisiana, was fully characterized. HAPs were measured to provide data for the Wabash River gasification project. In addition, a power plant having an onsite coal preparation facility, cyclone boiler, ESP, and venturi scrubber was characterized for 16 trace elements including mercury. Planned for the second phase are assessments of trace elements, including elemental and speciated forms of mercury, of three power plants equipped with wet FGD systems.

Exhibit 2-12 Status of Environmental Monitoring Plans for CCT Projects

Project and Participant	Status
CCT-I	
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CO ₂ Inc.)	Completed 7/31/90
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	Completed 10/19/88
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	Completed 9/22/87
Nuclea CFB Demonstration Project (Colorado-Lite 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 (Rosebud SynCoal Partnership)	Completed 4/7/92
ACFB Demonstration Project (York County Energy Partners, L.P.)	To be determined
CCT-II	
Combustion Engineering IGCC Repowering Project (ABB Combustion Engineering, Inc.)	To be determined
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Completed 10/31/91
PFBC Utility Demonstration Project (The Appalachian Power Company)	To be determined
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
Innovative Coke Oven Gas Cleaning System for Retrofit Applications (Bethlehem Steel Corporation) (project terminated)	Completed 7/5/91
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 2-12 (continued) Status of Environmental Monitoring Plans for CCT Projects

Project and Participant	Status
CCT-III	
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	Projected 6/96
10-MW Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Completed 10/2/92
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	Projected 8/96
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 Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Completed 12/23/94
PCFB Demonstration Project (DMEC-1 Limited Partnership)	To be determined
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
LJFAC Sorbent Injection Desulfurization Demonstration Project (LJFAC-North America)	Completed 6/12/92
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System (NOXSO Corporation)	Projected 2/97
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)	Projected 5/96
CCT-IV	
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	Projected 2/96
Micronized Coal Reburning Demonstration for NO _x Control (New York State Electric & Gas Corporation)	To be determined
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)	Projected 6/96
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	To be determined
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	Completed 7/9/93
CCT-V	
Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.)	To be determined
Clean Power from Integrated Coal/Ore Reduction (COREX®) (Centerior Energy Corporation)	To be determined
Clean Energy Demonstration Project (Clean Energy Partners Limited Partnership)	To be determined
Four Rivers Energy Modernization Project (Four Rivers Energy Partners, L.P.)	To be determined
Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company)	To be determined

Exhibit 2-13 CCT Projects Monitoring Hazardous Air Pollutants

Application Category	Participant	Project	Status
Advanced Electric Power Generation	Alaska Industrial Development and Export Authority	Healy Clean Coal Project	Planned
	Arthur D. Little, Inc.	Coal Diesel Combined Cycle Project	Planned
	Clean Energy Partners Limited Partnership	Clean Energy Demonstration Project	Planned
	Four Rivers Energy Partners, L.P.	Four Rivers Energy Modernization Project	Planned
	Pennsylvania Electric Company	Warren Station Externally Fired Combined-Cycle Demonstration Project	Planned
	The Ohio Power Company	Tidd PFBC Demonstration Project	Completed
	Sierra Pacific Power Company	Piñon Pine IGCC Power Project	Planned
	Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	Planned
	Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	In progress
	York County Energy Partners, L.P.	ACFB Demonstration Project	Planned
Environmental Control Devices	ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	Completed
	AirPol, Inc.	10-MW 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	SOX-NOx-Rox Box™ Flue Gas Cleanup Demonstration Project	Completed
	New York State Electric & Gas Corporation	Miliken Clean Coal Technology Demonstration Project	In progress
	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-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers	Completed
Coal Processing for Clean Fuels	Custom Coals International	Self-Scrubbing Coal™: An Integrated Approach to Clean Air	In progress
	ENCOAL Corporation	ENCOAL Mild Coal Gasification Project	In progress
Industrial Applications	Centerior Energy Corporation	Clean Power from Integrated Coal/Ore Reduction (COREX®)	Planned
	ThermoChem, Inc.	Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	Planned

3. Funding and Costs

Summary

Congress has appropriated a federal budget of nearly \$2.55 billion for the CCT Program. These funds have been committed to demonstration projects selected through five competitive solicitations. As of December 31, 1995, the program consisted of 43 active or completed projects, including one project selected under the fifth solicitation that remains in negotiation.

The 43 active or completed projects have resulted in a combined commitment by the federal government and the private sector of about \$7.21 billion. DOE's cost share for these projects is \$2.35 billion, or approximately 33 percent of the total. The project participants (i.e., the non-federal-government participants) are providing the remaining \$4.86 billion.

Program Funding

In the CCT Program, the federal government's contribution can not 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 energy sources.

The participant has primary responsibility for the project. The federal government monitors project activities, provides technical advice, assesses progress by periodically reviewing project performance with the participant, and 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 the following appropriation acts and adjustments due to sequestering requirements of the Gramm-Rudman-Hollings Deficit Reduction Act (see Appendix A for excerpts from the relevant legislation):

- Public Law 99-190, enacted December 19, 1985, appropriated \$400 million to conduct cost-shared demonstration projects; sequestering reduced this amount by \$2.4 million.
- Public Law 100-202, enacted December 22, 1987, as amended by Public Law 100-446, appropriated a total of \$575 million; sequestering reduced this amount by \$2,600.

- Public Law 100-446, enacted September 27, 1988, as amended by Public Law 101-164, provided \$575 million; sequestering reduced this amount by \$2,028.
- Public Law 101-121, enacted October 23, 1989, as amended by Public Laws 101-512, 102-154, 102-381, 103-138, and 103-332 provided the final \$1.2 billion for the program; sequestering reduced this amount by \$455.
- Public Law 104-6, enacted April 10, 1995, rescinded \$200 million of federal funds from the program.

Exhibit 3-1 presents the allocation of appropriated CCT Program funds (after adjustment) and the amount available for each CCT solicitation. The five CCT solicitations are referred to as CCT-I, CCT-II, CCT-III, CCT-IV, and CCT-V. Additional activities funded by CCT Program appropriations are the Small Business Innovative Research (SBIR) Program, the Small Business Technology Transfer Program (STTR), 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 research and development efforts.

Exhibit 3-1 Relationship between Appropriations and Subprogram Budgets for the CCT Program (Dollars in Thousands)

Appropriation Enacted	Subprogram	Appropriation to DOE ^a	SBR & STTR Budgets ^b	Program Direction Budget	Projects Budget
P.L. 99-190	CCT-I	397,600	4,902	41,467	351,231
P.L. 100-202	CCT-II	574,997	6,781	32,512	535,704
P.L. 100-446	CCT-III	574,998	6,906	22,548	545,544
P.L. 101-121 ^c	CCT-IV	550,000	7,913	25,000	517,087
P.L. 101-121 ^c	CCT-V	450,000	8,233	25,000	416,767
Total		2,547,595	34,735	146,527	2,366,333

^a FY 1991 apportionment increments for CCT-II and CCT-III were reduced by \$4,628 total due to Gramm-Rudman-Hollings sequestering requirements; original appropriations were \$575 million each; appropriations for CCT-IV were cut \$455. Previously, sequestering requirements had reduced original CCT-I appropriations of \$400 million by \$2.4 million.

^b Small Business Innovative Research Program (SBR) and Small Business Technology Transfer Program (STTR).

^c P.L. 101-121 was revised by P.L. 101-512, 102-154, 102-381, 103-138, 103-332, and 104-6.

The 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.

Availability of Funding

Although all funds necessary to implement the entire CCT Program were appropriated by Congress prior to FY 1990, the legislation also directs that these funds be made available (i.e., apportioned) to DOE on a time-phased basis. Exhibit 3-2 depicts this

apportionment of funding to DOE from FY 1986, when the program was initiated, through FY 1997, when the final increment of funding is scheduled to become available to DOE. Exhibit 3-2 also shows the program's yearly funding profile by appropriations act and by subprogram. Funds can be transferred between 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 follows:

- **Budget Authority.** This is the legal authorization created by legislation (i.e., an appropriations act) that permits the federal government to obligate funds.
- **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 approved cooperative agreement and the amount of funds needed for projects in negotiation.
- **Obligations.** The negotiated 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.

Exhibit 3-2
Annual CCT Program Funding, by Appropriations and Subprogram Budgets
(Dollars in Thousands)

Fiscal Year	1986-87	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	Total ^d
Adjusted Appropriations^a												
P.L. 99-190	248,500	149,100										397,600
P.L. 100-202		50,000	190,000	135,000	199,997							574,997
P.L. 101-446				419,000	155,998							574,998
P.L. 101-121 ^b					35,000	315,000	0	100,000	18,000	50,000	32,000	550,000
P.L. 101-121 ^b						100,000	0	125,000	19,121	100,000	105,879	450,000
Total	248,500	199,100	190,000	554,000	390,995	415,000	0	225,000	37,121	150,000	137,879	2,547,595
Subprogram Budgets												
CCT-I Projects	241,958	145,273							(18,000)	(18,000)		351,231
CCT-II Projects		31,094	173,800	133,313	197,497							535,704
CCT-III Projects				391,496	154,048							545,544
CCT-IV Projects					9,875	311,063	0	98,450	17,622	48,925	31,152	517,087
CCT-V Projects						74,062	0	123,063	18,719	97,850	103,073	416,767
Projects Subtotal	241,958	176,367	173,800	524,809	361,420	385,125	0	221,513	18,341	128,775	134,225	2,366,333
Program Direction	3,479	20,500	14,000	22,548	25,000	25,000			18,000	18,000		146,527
Fossil Energy Subtotal	245,437	196,867	187,800	547,357	386,420	410,125	0	221,513	36,341	146,775	134,225	2,512,860
SBIR & STTR ^c	3,063	2,233	2,200	6,643	4,575	4,875	0	3,487	779	3,225	3,654	34,735
DOE Total ^d	248,500	199,100	190,000	554,000	390,995	415,000	0	225,000	37,121	150,000	137,879	2,547,595

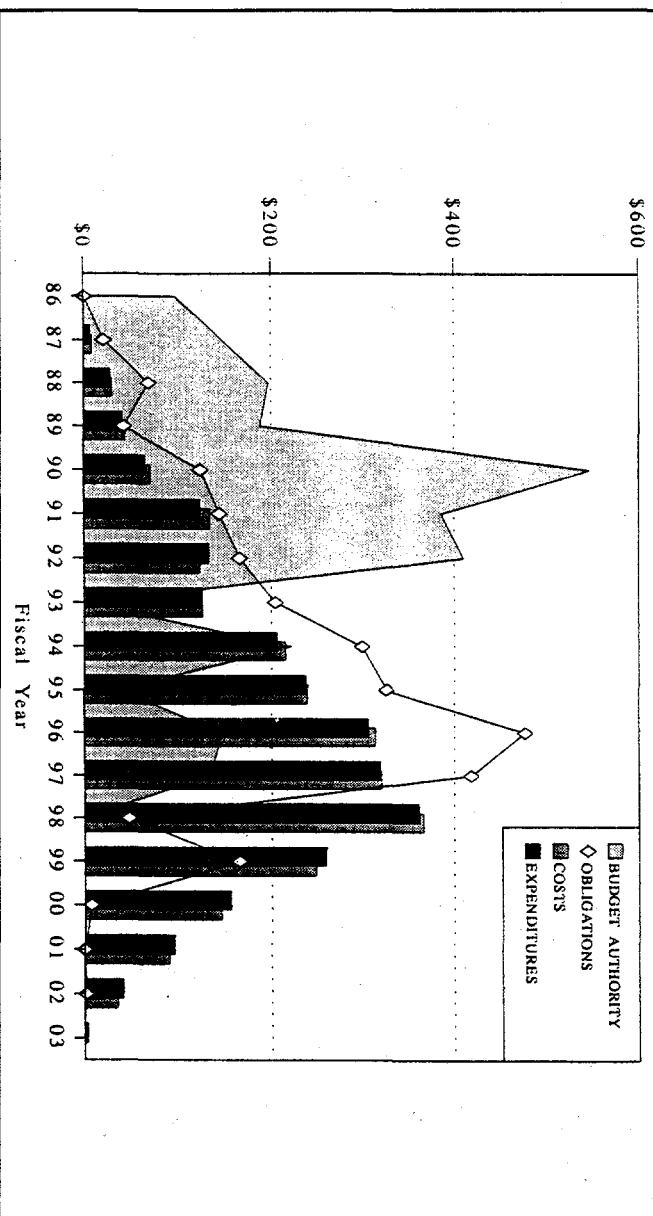
^a Shown are appropriations less amounts sequestered under the Gramm-Rudman-Hollings Deficit Reduction Act.

^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, and 104-6.

^c Small Business Innovative Research Program (SBIR) and Small Business Technology Transfer Program (STTR).

^d Totals may not appear to add due to rounding.

Exhibit 3-3 CCT Financial Projections as of December 31, 1995 (Dollars in Millions)



Expenditures directly affect the government's cash flow.

The full government cost-share is considered committed to each project upon selection for negotiation. 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 3-3. The graph shows actual performance for FY 1986 through FY 1995 and DOE estimates for FY 1996 through program completion. Excluded from the graph are SBIR obligations, costs, and expenditures, as these funds are used and tracked separately from the CCT Program. The financial projections presented in

Exhibit 3-3 are based on individual project schedules and budget periods as defined in the cooperative agreements and modifications. The projections are updated as modifications to the cooperative agreements are approved.

The financial status of the program through December 31, 1995, is presented by subprogram in Exhibit 3-4. SBIR and STTR monies are included in this exhibit to account for all funding. Exhibit 3-4 also indicates the apportionment sequence as modified by Public Law 104-6. 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 the fact sheets in Section 7. An overview of project schedules and funding is presented in Exhibit 3-5.

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

Exhibit 3-4
Financial Status of the CCT Program as of December 31, 1995
(Dollars in Thousands)

Subprogram	Appropriations				Apportionment Sequence	
	Allocated to Subprograms ^a	Apportioned to Date	Committed to Date	Obligated to Date	Cost to Date	FY Annual Cumulative
CCT-I	351,231	351,231	257,157	251,967	183,044	1986 99,400 99,400
CCT-II	535,704	535,704	469,586	172,317	157,914	1987 149,100 248,500
CCT-III	545,544	545,544	610,482	401,816	286,173	1988 199,100 447,600
CCT-IV	517,087	485,935	482,290	427,300	288,405	1989 190,000 637,600
CCT-V	416,767	313,694	567,800	22,140	4,964	1990 554,000 1,191,600
Projects Subtotal	2,366,333	2,232,108	2,387,315	1,275,540	920,500	1991 390,995 1,582,595
SBIR & STTR ^a	34,735	31,081	34,735	31,081	31,081	1992 415,000 1,997,595
Program Direction	146,527	146,527	146,527	126,843	121,956	1993 0 1,997,595
Total	2,547,595	2,409,716	2,568,577	1,433,464	1,073,537	1994 225,000 2,222,595
						1995 37,121 2,259,716
						1996 150,000 2,409,716
						1997 137,879 2,547,595

^a Small Business Innovative Research Program (SBIR) and Small Business Technology Transfer Program (STTR)

^b Sums may not appear to add due to rounding.

- 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 can not be offset or delayed based on prospective project revenues, proceeds, or royalties.
 - Investment in existing facilities, equipment, or previously expended R&D funds are not allowed for the purpose of cost sharing.
- Exhibit 3-6 summarizes the cost-sharing status by subprogram and by application category. The projects in the advanced electric power generation category account for 65 percent of total project costs

and for the overall program, the participant contribution is over twice that of the federal government.

Recovery of Government Outlays (Recoupment)

DOE's policy objective 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

Exhibit 3-5 CCT Project Schedules and Funding, by Application Category

Calendar Year	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	DOE Total (\$1,000)	
	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4		
Tri-State--Nucla	Advanced Electric Power Generation																17,130	46,513
Ohio Power--Tidd	[Bar chart showing funding from 1986 to 2001]																66,957	189,886
Wabash River	[Bar chart showing funding from 1986 to 2001]																219,100	438,200
Tampa Electric	[Bar chart showing funding from 1986 to 2001]																142,994	285,988
Sierra Pacific	[Bar chart showing funding from 1986 to 2001]																154,276	308,551
AIDEA	[Bar chart showing funding from 1986 to 2001]																117,327	242,058
York County Energy	[Bar chart showing funding from 1986 to 2001]																74,734	379,645
Appalachian Power	[Bar chart showing funding from 1986 to 2001]																184,800	917,944
ABB CE-IGCC	[Bar chart showing funding from 1986 to 2001]																129,357	270,700
DMEC-1	[Bar chart showing funding from 1986 to 2001]																93,253	202,959
Pennsylvania Electric	[Bar chart showing funding from 1986 to 2001]																73,416	146,832
ADL--Coal Diesel	[Bar chart showing funding from 1986 to 2001]																19,155	38,310
Four Rivers	[Bar chart showing funding from 1986 to 2001]																142,460	360,708
Clean Energy	[Bar chart showing funding from 1986 to 2001]																183,300	841,096
Coal Tech	[Bar chart showing funding from 1986 to 2001]																490	984
Passamaquoddy	[Bar chart showing funding from 1986 to 2001]																5,983	17,800
Bethlehem--Blast Furnace	[Bar chart showing funding from 1986 to 2001]																31,260	191,700
Centerior Energy*	[Bar chart showing funding from 1986 to 2001]																149,469	1,065,805
ThermoChem	[Bar chart showing funding from 1986 to 2001]																18,667	37,333
Industrial Applications																		

* Schedule and funding are in negotiation.



Preaward



Design and Construction



Operation and Reporting

Exhibit 3-5 (continued)
CCT Project Schedules and Funding, by Application Category

Calendar Year	1986				1987				1988				1989				1990				1991				1992				1993				1994				1995				1996				1997				1998				1999				2000				2001				DOE Total (\$1,000)
	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4																	
B&W--LIMB																																																									7,597	19,405							
SCS--Wall-Fired																																																					6,554	14,711											
EER--GR/SI																																																	18,748	37,589															
SCS--Tangentially Fired																																																	4,440	9,153															
Bechtel -- CZD																																																	5,206	10,412															
B&W--Coal Reburning																																																	6,341	13,647															
B&W--LNCB																																																	5,443	11,233															
ABB ES--SNOX																																																	15,719	31,438															
B&W--SNRB																																																	6,078	13,272															
Pure Air on the Lake																																																	63,913	151,708															
LIFAC																																																	10,637	21,394															
PSC of Colorado																																																	13,706	27,411															
AirPol -- GSA																																																	2,315	7,717															
EER--GR-LNB																																																	8,896	17,807															
SCS--CT-121																																																	21,085	43,075															
SCS--SCR																																																	9,407	23,230															
NYSEG -- Milliken																																																	45,000	158,608															
NYSEG -- Micronized Coal																																																	2,701	9,096															
NOXSO Corporation																																																	41,406	82,812															
ABB CE & CQ--Expert																																																	10,864	21,746															
Rosebud SynCoal																																																	43,125	105,700															
ENCOAL																																																	45,332	90,664															
Custom Coals																																																	37,994	87,386															
Air Products -- LPMEOH																																																	92,708	213,700															

government's financial contribution. The solicitations have featured different sets of recoupment rules.

Under the first solicitation, repayment was derived from revenue streams including 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 1/2 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.

To date, four 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.) and the 10-MW_e Demonstration of Gas Suspension Absorption (AirPol, Inc.). Additionally, recoupment is anticipated from the Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.) based on commercial sales.

Exhibit 3-6 Cost Sharing of Active CCT Projects (Dollars in Thousands)

Subprogram	Total Project Costs	%	Cost Share		Percent	
			DOE ^b	Participants	DOE	Participants
CCT-I	801,469	11	239,645	561,824	30	70
CCT-II	1,506,678	21	453,677	1,053,001	30	70
CCT-III	1,405,856	20	610,482	795,374	43	57
CCT-IV	1,039,175	14	477,738	561,437	46	54
CCT-V	2,452,750	34	567,800	1,884,950	23	77
Total^a	7,205,928	100	2,349,342	4,856,586	33	67

Application Category	Total	%	DOE ^b	Participants	DOE	Participants
Advanced Electric Power Generation	4,669,390	65	1,618,259	3,051,131	35	65
Environmental Control Devices	703,719	10	295,191	408,528	42	58
Coal Processing for Clean Fuels	519,196	7	230,024	289,172	44	56
Industrial Applications	1,313,623	18	205,868	1,107,755	16	84
Total^a	7,205,928	100	2,349,342	4,856,586	33	67

^a Totals may not appear to add due to rounding.
^b DOE share does not include \$37,973,230 obligated for withdrawn and terminated projects.

4. The Road to Commercial Realization

Summary

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

During 1995, efforts to define and understand the potential domestic and international markets for clean coal technologies were expanded. This activity involved interviews with electric utility executives, public utility commissioners, and financiers. Analyses were made of utility integrated resource plans, environmental compliance strategies, state regulations, and legislation that may impact commercial deployment.

A highlight of the continuing CCT Program outreach effort was the Fourth Annual Clean Coal Technology Conference attended by close to 300 persons from over a dozen countries. The theme of the conference was "The Global Opportunity," placing new emphasis on the international scope of the clean coal market and opportunities that are growing as international economies are becoming increasingly competitive and environmental concerns

are moving to the forefront. Highlights included discussions on privatization from a Polish delegation; dialogue on transition to competition in the domestic electric power industry and its impact on clean coal markets; discussions on externalities and environmental regulations and their impact on clean coal technology deployment; reports on international clean coal projects and opportunities; and frank discussions about challenges posed by economic, political, and environmental agendas both domestic and international. Information was shared on conducting business in international markets, from intellectual property to financing opportunities, giving attendees new insights into the expanding clean coal markets.



▲ Pat Godley, Assistant Secretary for Fossil Energy, addresses global opportunities before an international audience at the Fourth Annual Clean Coal Technology Conference.

Throughout the year, the CCT Program staff participated in over 16 domestic and international events involving users and vendors of technologies, regulators, financiers, environmental groups, and other public and private institutions. Three issues of the *Clean Coal Today* newsletter were published, along with the first annual edition of the *Clean Coal Today Index*, which is a cross-reference of all articles published in the newsletter to date, presented by both project title and participant. To meet growing demand for project-specific information, DOE published a mid-year update of project fact sheets in *Clean Coal Technology Demonstration Program: Project Fact Sheets*. A revision of the popular *Investment Pays Off* was also published.

Clean coal technologies are acquiring significantly increased importance in the export market, creating major opportunities for U.S. business. A number of efforts are under way to define international market opportunities to promote U.S. technology and to support U.S. project development work. In 1995, international activities have concentrated on providing technical support to the U.S. trade agencies, organizing trade missions, conducting education and training, developing financial and market analysis, and developing an international technology transfer program.

Also during 1995, DOE completed analysis of responses to the expressions of interest in commercial projects employing clean coal technologies in countries projected to have significant growth in

greenhouse gas emissions. In June 1995, DOE published *Report to Congress: Expressions of Interest in Commercial Clean Coal Technology Projects in Foreign Countries*.

Commitment to Commercial Realization

The CCT Program has been committed to commercial realization since its inception. The significant environmental, efficiency, and economic benefits of the technologies being demonstrated in the program will be realized only if 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: "The project must demonstrate commercial feasibility of the technology or process and be of commercial scale 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 utilization of the technology in the domestic and international marketplace. The detailed technical, economic, and environmental data and experience gained during the demonstration are vital to efforts to commercialize the technology. The government's role is to capture, assess, and transfer sufficient technical, economic, and environmental

information to a broad spectrum of the private sector and international community 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 the cooperative agreement 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
- Additional requirements for demonstration of the technology at other operational scales as well as significant planned parallel efforts to the demonstration project which may affect the commercialization approach or schedule
- The priority placed by senior management on accomplishing the commercialization effort and how the project fits into the various corporation's business, marketing, or energy utilization strategies

The cooperative agreement contains three mechanisms to ensure the demonstrated technology can be replicated by responsible firms while protecting the

proprietary commercial position of the technology owner:

- The commercialization clause requires the technology owner to meet U.S. market demand for the technology on a nondiscriminatory basis. Further, 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.
- The patent clause affords protection for new inventions developed in the project.

In addition to ensuring the implementation of the above project-specific mechanisms, the government role also includes the following functions:

- Developing and disseminating the technical, economic, and environmental knowledge base necessary for federal, state, and local government decisions regarding commercial deployment of clean coal technologies
- Improving the regulatory and institutional climate for deployment of demonstrated clean coal technologies at a pace consistent with domestic and international free market decision-making
- Informing the public of the increased efficiency, enhanced environmental quality, and improved energy security benefits that can be

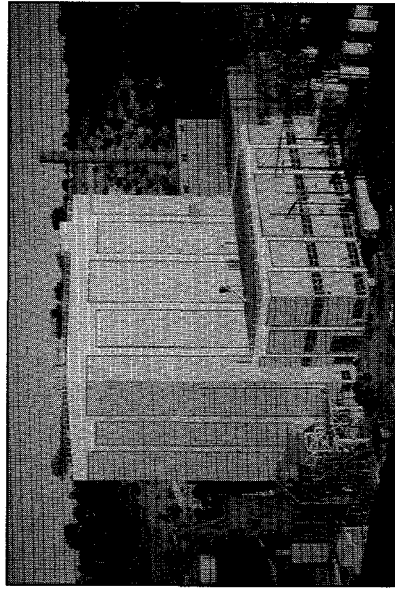
achieved through commercial use of clean coal technologies

With about 42 percent of the projects in the CCT Program completed and another 21 percent in operation, a number of commercialization successes already have been realized. These successes are summarized in Exhibit 4-1. Success stories are highlighted below:

- Demonstration of the first utility-scale PFBC system in the United States has been successfully completed at Ohio Power's Tidd Plant. Representing a 13:1 scale-up from the pilot facility, this project has laid important groundwork for the 340-MWe PFBC Utility Demonstration Project, a clean coal demonstration which is expected to define the capital and operating costs of PFBC technology for large utility-scale applications.
- The Nucla ACFB demonstration proved the viability of scaling up to the 110-MWe size. When the Nucla boiler was first sold, it was 41 percent larger than any other ACFB unit sold in the world. As a result of the demonstration, Pyropower Corporation saved almost 3 years in establishing a commercial line of ACFB units and now offers these units under warranty in sizes ranging up to 400 MWe.
- The world's largest single-train IGCC power plant began operating in a fully commercial setting at PSI Energy's Wabash River Generating Station. The repowered 262-MWe unit has the ability to produce some of the lowest cost electricity on PSI Energy's system and will continue to operate as part of

the utility's baseload capacity for at least 25 years. The Wabash plant is recognized around the world as one of the pioneers in IGCC technology, which is expected to emerge as one of the leading means of generating electric power from coal, both in the United States and international marketplaces.

- Five of the seven NO_x control technology demonstrations have been completed, and in each case, the host utility has decided to retain the system for use in commercial operations. Furthermore, Babcock & Wilcox, Foster Wheeler, and ABB Combustion Engineering have reported successful commercial sales of their respective NO_x control technologies.



- ▲ The 110-MWe Nucla project demonstrated the viability of the ACFB technology for utility operation. The unit continues to be operated by Tri-State Generation and Transmission Association. The ACFB has become the technology of choice by many utilities and independent power producers, particularly when fuel flexibility is an important factor.

- All five SO₂ control technologies demonstrations have been completed. Three demonstration hosts are continuing to use the systems in commercial operations. Four technology owners have reported successful commercial sales of the systems for use in other facilities.
 - Four of the seven combined NO_x/SO₂ control technology demonstrations have been successfully completed, and three sites are retaining the systems for current or future use in commercial operations.
 - Although the five coal processing demonstrations are still in operation or construction, four of the technologies are already being marketed successfully for use in commercial operations.
 - One industrial application also has had commercial success. The Passamaquoddy Technology Recovery Scrubber™ has become a permanent part of the cement kiln. In addition, a Taiwanese cement company is considering installation of the scrubber in a new cement plant.
- Not only have commercial successes been realized from demonstrated technologies, but innovative business concepts have also been developed. The CCT Program's Pure Air on the Lake, L.P., Advanced Flue Gas Desulfurization Demonstration Project is an example. Pure Air on the Lake expects to specialize in pollution control activities relieving electric utilities of the ownership and operation of advanced flue gas desulfurization (AFGD) units. Under the arrangement with Northern Indiana Public Service Company, the Pure Air limited partnership

Exhibit 4-1 CCT Program: Commercialization Successes

Project and Participant

Commercialization Progress

Advanced Electric Power Generation

Fluidized-Bed Combustion

Tidd PFBC Demonstration Project (The Ohio Power Company)

The Tidd demonstration was the first utility-scale PFBC system in the United States. The plant represented a 13:1 scale-up from the pilot facility. The project successfully demonstrated that the PFBC system could be applied to electric power generation and led to significant refinements and understanding of the technology in the areas of turbine erosion, sorbent utilization, sintering, post-bed combustion, and boiler materials. This project has laid important groundwork for the 340-MWe PFBC Utility Demonstration Project, a clean coal project which is expected to define the capital and operating costs of this technology for large utility-scale applications. Future commercial PFBC plants are likely to be 100-200 MWe in size and feature efficiencies over 40%. Compared to conventional technology, PFBC will have superior environmental and economic performance and is a technology which will be used to meet the growing electricity demand worldwide.

Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)

The Nucla ACFB demonstration prompted wide dissemination of the technical progress of ACFB technology and showed the viability of scaling up to the 110-MWe size. When the Nucla ACFB boiler was sold, it was 44% larger than any other ACFB that had been sold in the United States and 41% larger than any other ACFB sold anywhere in the world. It was not until after the Nucla ACFB unit was built and the first coal firing occurred that another ACFB boiler of comparable size was sold. As a result of the project, Pyropower Corporation was able to save almost 3 years in establishing a commercial line of ACFB units. Pyropower's commercial units are now offered under warranty in sizes ranging up to 400 MWe. Presently, 22 ACFB units larger than 100 MWe are being planned, engineered, built, or operated; 11 of these are in the United States. These 22 ACFBs represent about 3,800 MWe of capacity and are estimated to be worth about \$5 billion (in 1994 dollars), assuming an average total capital cost of \$1,400/kW.

Integrated Gasification Combined Cycle

Wabash River Coal Gasification Repowering Project
(Wabash River Coal Gasification Repowering Project Joint Venture)

Wabash River is the world's largest single-train IGCC power plant to be operated in a fully commercial setting. Commercial operation is under way. This repowered 262-MWe unit has the ability to produce some of the lowest cost electricity on PSI Energy's system. The unit's net heat rate of about 9,000 Btu/kWh (38% efficiency) is roughly 20% better than that of the original plant. The project is expected to continue to operate as part of PSI Energy's baseload capacity for a period of at least 25 years, including the 3-year demonstration. The plant is also designed to outperform substantially the emissions standards for the year 2000 required by the CAAA of 1990. CO₂ emissions also will be reduced by about 20% on a per kWh basis by virtue of the increased efficiency, thereby minimizing contributions to possible global climate change. The Wabash plant is a fully commercial operating power plant, recognized around the world as one of the pioneers in IGCC technology. This technology is expected to emerge as one of the leading means of generating electric power from coal, both in the United States and international marketplaces.

Exhibit 4-1 (continued)
CCT Program: Commercialization Successes

Commercialization Progress

Project and Participant

Environmental Control Devices

NO_x Control Technologies

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)

Babcock & Wilcox's coal reburning technology has been successfully demonstrated as a NO_x emissions reduction technology for cyclone boilers. The system is being retained by Wisconsin Power and Light for commercial use at Nelson Dewey Station, Unit No. 2.

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)

Dayton Power & Light is retaining the LNCB® burners for use in commercial operation at the J.M. Stuart Plant. Babcock & Wilcox has sold seven contracts for the LNCB® technology; these contracts, which involve 144 burners, have an estimated value of \$27 million and an employment benefit of 27 person-years.

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)

Public Service Company of Colorado is retaining the low-NO_x burners and the gas-reburning system for immediate use.

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)

Foster Wheeler's commercial sales of its low-NO_x burners have an estimated value of \$20 million and represent an employment impact of 140 person-years. Georgia Power is retaining the low-NO_x burners installed at Plant Hammond, Unit No. 4 for use in commercial operation to comply with emissions regulations. The project also successfully demonstrated the ability of the Generic NO_x Control Intelligence System (GNOCIS) to optimize plant performance in terms of NO_x emissions, unburned carbon in fly ash, and overall plant efficiency. Final testing of GNOCIS in a closed-loop configuration in early 1996 will remove plant operators from direct control of some plant functions. Several U.S. utilities are discussing commercial GNOCIS installations with the project team, including applications to other boiler types and for other fuels, such as natural gas. Organizations have been selected to commercialize GNOCIS domestically and abroad.

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)

The Low-NO_x Concentric Firing System (LNCFS™) is being retained by Gulf Power at its Plant Lansing Smith Unit No. 2. The system also is being used by a number of other utilities, including the Tennessee Valley Authority, Illinois Power, Public Service Company of Colorado, Indianapolis Power and Light, Cincinnati Gas and Electric, Virginia Power, Union Electric, and New York State Electric & Gas Corporation.

Exhibit 4-1 (continued) CCT Program: Commercialization Successes

Project and Participant

Commercialization Progress

SO₂ Control Technologies

10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)

The AirPol project is the first North American demonstration of the GSA system for coal-fired FGD. As a result of this successful project, the city of Hamilton, OH, received a \$5-million grant from the Ohio Coal Development Office to install the GSA technology to control emissions from a 50-MWe coal-fired boiler at the city's municipal power plant. The GSA technology was identified as the least-cost alternative for the city to meet the 1997 CAAA compliance requirements. The estimated value of this sale is \$10 million and involves an employment impact of 70 person-years. In addition, FL S miljo has been awarded a major project in Sweden for a high-performance GSA system to remove sulfur from the flue gas of a 4-million-ton/yr iron ore sinter plant. Sweden's stringent sulfur emission standard requires a 90-95% removal efficiency. In Europe, where GSA was first commercially installed in 1988, there are 10 GSA units installed on municipal solid waste incinerators. Further, AirPol has been awarded contracts for the supply of GSA systems in Taiwan and India; these sales have a combined value of \$33 million and a U.S. employment benefit of 10 person-years.

LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)

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

Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)

In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO₂ scrubbing capacity at Florida Power & Light's Manatee power plant. The estimated value of the sale is \$200 million and the employment impact is about 1,400 person-years. Pure Air on the Lake, L.P., will continue to operate the AFGD unit at Northern Indiana Public Service Company's Bailly Generating Station for 17 years beyond the 3-year demonstration. By-product gypsum sales produce enough wallboard to supply the construction needs of 32,500 new homes annually. Bailly Generating Station with the AFGD unit became the first power plant on the list of CAAA of 1990 Phase-I-affected units to meet the SO₂ standards using FGD technology.

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)

Georgia Power is retaining the CT-121 FGD system installed at its Plant Yates, Unit No. 1, for use in commercial operation. In 1994, a tar sands oil extraction facility in Murray, Canada, purchased a CT-121 scrubber.

Exhibit 4-1 (continued) CCT Program: Commercialization Successes

Commercialization Progress

Project and Participant

Combined SO₂/NO_x Control Technologies

SNOX™ Flue Gas Cleaning Demonstration Project
(ABB Environmental Systems)

Ohio Edison is retaining the SNOX™ technology as a permanent part of the pollution control system at Niles Station to help the utility meet its overall SO₂ and NO_x reduction goals. Commercial SNOX™ plants are operational in Denmark and Sicily. In Denmark, a 305-MWe plant has been designed and constructed; it has operated since August 1991. The boiler at this plant burns coals from numerous suppliers around the world, including the United States; the coals contain up to 3.0% sulfur. The plant in Sicily, operating 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)

A commercial version of LIMB will be used in an independent power production project in Canada.

Enhancing the Use of Coals by Gas Reburning and
Sorbent Injection (Energy and Environmental
Research Corporation)

Illinois Power retained the gas-reburning system for possible use in NO_x control at its Hennepin Plant, Unit 1. City Water, Light and Power retained both the gas-reburning and sorbent injection systems for future use at Lakeside Station, Unit 7.

Milliken Clean Coal Technology Demonstration
Project (New York State Electric & Gas Corpora-
tion)

A software package developed as part of the Milliken project to assist the utility optimize project operations has become a commercial product. There have been six sales of DHR Technologies' Plant Emission Optimization Advisor (PEOA™), and another five bids are pending.

Integrated Dry NO_x/SO₂ Emissions Control System
(Public Service Company of Colorado)

The Colorado utility plans to continue operation of the combustion modifications and the sodium-based dry sorbent injection system. A final decision on the urea injection system will be made after the test program is completed. Furthermore, Babcock & Wilcox has the DRB-XCL® low-NO_x burner for 101 boiler units (46 international and 55 domestic). These sales involve 1,829 burners or 23,664 MWe of capacity. The sales have an estimated value of about \$240 million and an employment benefit of 1,670 person-years.

Exhibit 4-1 (continued) CCT Program: Commercialization Successes

Project and Participant

Commercialization Progress

Coal Processing for Clean Fuels

Coal Preparation Technologies

Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ Inc.)

Intensifying competition among U.S. electric power companies as a result of utility deregulation is forcing utilities to strive for minimal operating expenses. Because fuel constitutes about 70% of total operating and maintenance costs for a coal-fired power plant, the impact of coal quality on plant performance and overall economics takes on special importance. Using COE, utilities can optimize coal selection for specific boilers based on coal cost and quality information, emissions requirements, and power plant design and operational data. CQ Inc. and Black and Veatch have signed a commercialization agreement which gives Black and Veatch nonexclusive worldwide rights to sell users' licenses and to offer consulting services that include the use of COE software. Two commercial sales of the Acid Rain Advisor software package, developed as part of COE to help utilities make CAAA compliance decisions, were made in 1993 and 1995. The final COE software was released in December 1995 and is being offered commercially. Over 40 U.S. utilities and one U.K. utility have COE through their membership in the Electric Power Research Institute. An upgrade is planned for 1996 in response to user comments. Several non-EPRI-member U.S. and foreign utilities have approached CQ Inc. about access to the software. Under consideration are various worldwide marketing and distribution methods for commercializing COE abroad.

Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)

This demonstration has resulted in (1) proposed agreements with domestic coal marketing companies to purchase 1 million tons of compliance coal annually, (2) a proposed agreement with China to build a coal cleaning plant, together with a 500-mile underground slurry pipeline and port facility (estimated value of \$888.6 million), and (3) signed letters of intent from three Polish power plants that wish to produce 7.5 million tons/yr of cleaned coal (estimated value at \$75 million). The China Pipeline Project, for which final Chinese approval is pending, will link coal mines in eastern Shanxi Province, near Shouyang, to Chinese and world markets through the port of Qingdao in Shandong Province. Other markets in the United States include Illinois Basin and Northern Appalachian Basin coal reserves because of the high sulfur content of the coal and the ability of the technology to reduce the pyritic sulfur content, thus reducing SO₂ emissions during combustion.

Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)

The Rosebud SynCoal Partnership is working on two potential semi-commercial projects located in Wyoming and Montana. These projects would range in size from 500,000 to 5 million tons/yr. The Wyoming project is a stand-alone mine-mouth design. The Montana project is designed either to be integrated into a power plant and fuel user or to expand the existing demonstration facility. The partnership conducted a \$2-million study for Minnesota Power Cooperative to examine the merits of applying the coal processing technology to a commercial plant integrated into an existing power plant site. The study's results have been positive, but market commitments are still necessary. Commercial development efforts for the SynCoal® product and fines continue. Current industrial and utility users include Ash Grove Cement, Bentonite Corporation, Empire Sand and Gravel, and Montana Power Company.

Exhibit 4-1 (continued) CCT Program: Commercialization Successes

Project and Participant	Commercialization Progress
<p>Mild Gasification ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)</p>	<p>The demonstration facility has operated successfully for 4 years while accruing over 8,200 hot operating hours. More than 43,000 tons of process-derived fuel (PDF) have been shipped to utility and metallurgical customers. Unit train quantities have been successfully burned as a compliance fuel in commercial boilers for over a 2-year period. Additionally, 2.2 million gallons of coal-derived liquid (CDL) have been shipped to industrial and metallurgical clients. Numerous feasibility studies were also performed for both domestic and international clients who are primarily interested in upgrading their low rank coal reserves. TEK-KOL and Mitsubishi Heavy Industries are performing advanced feasibility studies regarding joint engineering, design, and construction of commercial plants in Indonesia, China, and Russia. TEK-KOL is also negotiating with Japanese trading companies to market both liquid and solid products in Southeast Asia. Letters of intent for engineering and economic assessments of full-scale commercial plants are currently in place with two Indonesian companies, P.T. Berau and P.T.B.A. A letter of intent is also in place with ROSUGOL, which controls large reserves of subbituminous and lignite coals in Russia. The two products, PDF and CDL, are well suited for utility and iron-making markets normally served by low-sulfur bituminous coals, which are expected to be in short supply in the post-2000 period while dependence on low-rank coals is expected to increase.</p>
<p>Industrial Applications Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)</p>	<p>At the end of the project, the scrubber became a permanent part of the Dragon Products facility. In 1994, a Taiwanese cement company engaged Passamaquoddy Technologies, L.P., to do a preliminary study for the installation of the Passamaquoddy Technology Recovery Scrubber™ on a new cement plant in Taiwan.</p>

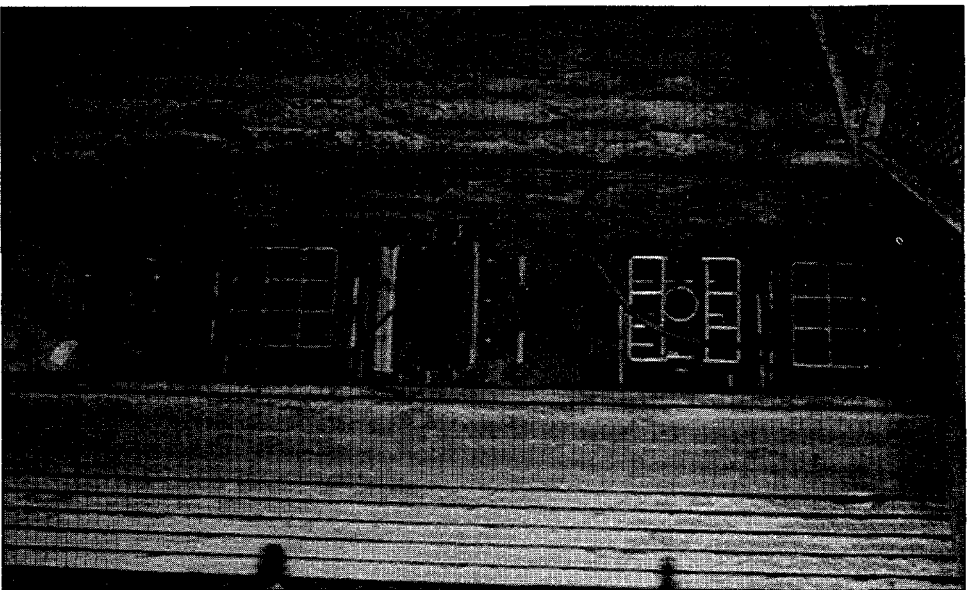
will continue to operate the AFGD unit as a contracted service at the Bailly Station for 17 years after the 3-year demonstration. It should be noted that the Bailly Generating Station with the AFGD unit became the first power plant on the CAAA of 1990 list of Phase-I-affected units to meet the SO₂ standards using flue gas desulfurization. Moreover, Pure Air has a similar own-and-operate contract with Florida Power & Light to provide 1,600 MWe of SO₂ scrubbing capacity at the Manatee power plant.

In two instances, subsystems of the clean coal technology projects have been spun off for commercial

sale. Southern Company Services' Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler at Plant Hammond has included installation and testing of an advanced digital control system that optimizes low-NO_x burner/advanced overfire air performance using artificial intelligence techniques. The Generic NO_x Control Intelligence System is being commercialized domestically and abroad, and discussions are under way with several interested U.S. utilities. The second example is a software package developed as part of the Milliken Clean Coal Technology Demonstration Project to assist the utility

in optimizing, project operations. Six modules of DHR Technologies' Plant Emission Optimization Advisor (PEOA™) have been sold, and another five bids are pending.

Another important use of the technical and environmental data resulting from the projects is to establish a sound basis for making policy and regulatory decisions by all levels of government. For example, Southern Company Services has successfully demonstrated ABB Combustion Engineering's Low-NO_x Concentric Firing System in a tangentially fired boiler in Gulf Power Company's Plant Lansing



▲ The Low-NO_x Concentric Firing System (LNCFS™), which combines overfire air and clustered coal nozzle positioning to achieve NO_x reductions, was successfully demonstrated by Southern Company Services, Inc., at Gulf Power's Plant Lansing Smith Unit 2. The LNCFS™ is being retained by Gulf Power and also is being used by a number of other utilities, including the Tennessee Valley Authority, Illinois Power, Public Service Company of Colorado, Indianapolis Power and Light, Cincinnati Gas and Electric, Virginia Power, Union Electric, and New York State Electric & Gas Corporation.

Smith in Lynn Haven, Florida. In a sister project at Georgia Power Company's Plant Hammond, Southern Company Services is completing a demonstration of Foster Wheeler's low-NO_x burner with overfire air in a wall-fired boiler. The test results from these two CCT Program demonstrations were used by the EPA to develop CAAA of 1990 regulations for NO_x control. Further, the hazardous air pollutant data collected under DOE's CCT Program and the Coal R&D Program are being shared with EPA so that the agency will have the best available data for use in formulating air toxics control regulations under Title III of the CAAA of 1990.

The excellent quality and importance of the CCT projects are well recognized by the business and environmental communities. Numerous industry and environmental awards for excellence and outstanding achievement have been presented to CCT projects since 1991. These award-winning projects and honors earned are highlighted in Exhibit 4-2.

Understanding the Domestic Market

Since the beginning of the program in 1985, there have been a number of activities aimed at developing an understanding of the commercial market for the technologies and enhancing their entry into the commercial marketplace. As a part of the response to the recommendations of the Special Envoys on Acid Rain, the President directed the Secretary of Energy in April 1987 to establish a panel to advise him on innovative clean coal technol-

ogy activities. This panel was entitled the Innovative Control Technology Advisory Panel (ICTAP). As a part of its activities, the state and federal incentive subcommittee of ICTAP prepared a report (*Report to the Secretary of Energy Concerning Commercialization Incentives*) on the actions that states could take to provide incentives for demonstrating and deploying clean coal technologies and their eventual commercial successes and 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 and other cost-effective emissions reduction measures that might be inhibited by various federal, state, and local regulations. An outgrowth of this activity was the recommendation 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 the second CCT solicitation.

The framers of the CAAA of 1990 recognized the environmental benefits of widespread commercial deployment of clean coal technologies. A provision in the act allows a 4-year extension (to December 31, 2003) to comply with the requirements of Title IV if one or more units are repowered with a qualifying clean coal technology.

An effort has been under way to gain greater understanding of the potential domestic market for

Exhibit 4-2 Award-Winning CCT Projects

Project and Participant	Award
Tidd PFBC Demonstration Project (The Ohio Power Company)	1992 National Energy Resource Organization award for demonstration of energy efficient technology.
Full-Scale Demonstration of Low-NO _x Cell Burner Retrofit (The Babcock & Wilcox Company)	1991 Powerplant Award presented by <i>Power Magazine</i> to American Electric Power Company's Tidd project "for demonstrating pressurized fluidized-bed-combustion combined-cycle technology." Co-recipient was The Babcock & Wilcox Company.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	1994 R&D 100 Award presented by <i>R&D Magazine</i> to the U.S. Department of Energy for development of the low-NO _x cell burner, selected as "one of the 100 most technologically significant new products of the year."
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	1993 Powerplant Award presented by <i>Power Magazine</i> to Northern Indiana Public Service Company's Bailly Generating Station "for demonstrating advanced wet limestone FGD technology with innovations in wastewater treatment and gypsum production reuse."
	1992 Outstanding Engineering Achievement Award presented by the National Society of Professional Engineers.
	1995 Design Award presented by the Society of Plastics Industries in recognition of the mist eliminator.
	1994 Powerplant Award presented by <i>Power Magazine</i> to Georgia Power's Plant Yates "for large-scale demonstration of an advanced scrubbing process ... and commercial application of low-NO _x burners." 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 for use of an innovative technology for air quality control.
	1993 Environmental Award presented by the Georgia Chamber of Commerce in recognition of the success of the scrubber.

clean coal technologies and the organizations and factors that will influence what and when facilities get built as well as the technologies that are used. A DOE team has been conducting a series of executive seminars with the CCT Program's key stakeholders. In these meetings, DOE seeks insights from management and planners whose views and decisions will shape the future use of clean coal technologies in power generation. The seminars focus on the power generation market and include discussions with leaders in utilities, independent power producers,

regulatory agencies, financial institutions, investment bankers, insurance carriers, and equipment manufacturers. A total of 47 seminars have been conducted. Priority has been placed on (1) utilities with significant coal utilization, projected load growth, and existing units aged 30 years or more and (2) nonutility generators utilizing coal-based technologies and having plants up to 300 MWe of capacity. Priority also has been placed on states where coal is a major resource, near-term growth is expected, or advanced regulatory issues predominate.

Additionally, a series of regional studies of key utilities and utility systems are under way with the purpose of gaining a better understanding of the markets for clean coal technologies and the regional and state factors that have a bearing on commercial deployment. Regions selected for study account for most of the U.S. coal-fired generating capacity. Detailed data and information have been compiled on (1) regional and state energy use, coal use and resources, and electric power generation; (2) state government agencies (including public utility com-

missions), regulations, legislation, and policies that could have a bearing on clean coal technology commercial realization; and (3) coal-using investor-owned, rural cooperative, and municipal electric entities which are potential users of clean coal technologies. The collected information and data are analyzed for insights into environmental compliance strategies, capacity planning, and other issues facing state and utility stakeholders.

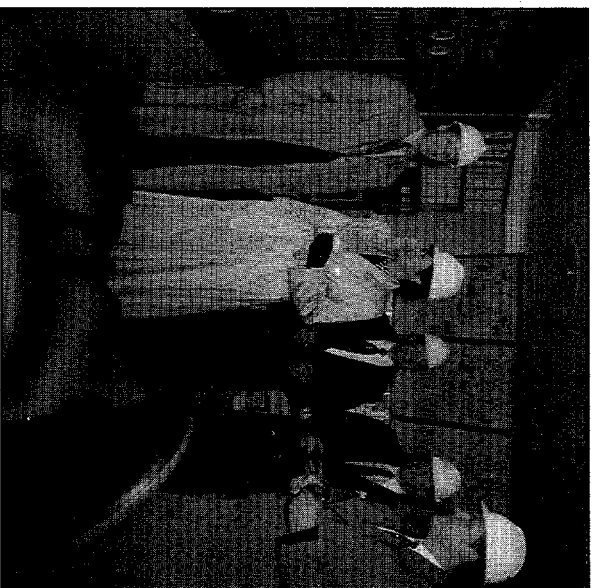
The insights contributed by these continuing efforts identify some of the more significant factors and trends affecting domestic markets for CCTs and relating to the contributions of CCT demonstration projects to these markets, such as issues associated with restructuring the electric industry and new limits on environmental emissions.

An Emerging International Market

Internationally, clean coal technologies are acquiring significant increased importance in the export market, creating major opportunities for U.S. business. The potential CCT market for new facilities and retrofit installations outside the United States for the 1993-2010 period is estimated to be \$571-870 billion. Export of technology to meet this demand would create a reported 69,000-109,000 person-years of employment. Aggressive action by U.S. companies to capture a share of this market with U.S. technologies from the CCT Program could lead to a significant reduction in both the U.S. trade

deficit and unemployment by providing high-technology engineering and manufacturing jobs.

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



▲ Secretary of Energy Hazel O'Leary, at the dedication of the Wabash River Coal Gasification Repowering Project, discusses the magnitude of the payoff that the investment in clean coal technology could have in the 2010 world market.

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

In fulfillment of this congressional direction, the Secretary of Energy led Presidential Missions on Sustainable Energy and Trade Development to the People's Republic of China in February 1995 and to the Republic of South Africa in August 1995. The Office of Clean Coal Technology provided support on both of these missions; the support involved developing forums for project development discussions with industry and government. It is estimated that China will need 100 gigawatts of electric power generation in the next 10 years. The primary source of energy for both China and South Africa is coal. Both countries are facing increased pollution resulting from current and increased coal use. The SO₂ emissions from China constitute 70 percent of the SO₂ emissions in Asia, and 90 percent of China's SO₂ emissions are related to the use of coal. China's NO_x emissions represent over 60 percent of the NO_x emissions in Asia, and coal is the source of 70 percent of China's NO_x emissions. In both countries, the current average efficiency of power plants is approximately 25-30 percent. Clean coal technology is a tremendous prospect for both countries; however, the main barrier to its implementation is capital cost,

even though clean coal technology is advantageous when economic benefits based on life-cycle cost are taken into consideration.

Activities that were conducted during these missions included meetings with the ministers of power, energy, coal, environment, and finance (as appropriate). These meetings provided forums for U.S. industry to understand the plans of the country, advocate technologies or projects, and establish relationships for the future. Technical seminars were conducted during the missions to educate U.S. and foreign leaders regarding technology options, needs, and problems in the country. The missions helped to identify business opportunities for discussion then and in the future.

As a follow up to the 1994 Presidential mission to India, the Secretary of Energy returned there in 1995 to fulfill commitments made during the previous trip. The Office of Clean Coal Technology participated in this mission by providing an exhibit for the ENCON 95 conference.

During 1995, representatives from the Office of Clean Coal Technology continued to participate in a leadership capacity in the Asia Pacific Economic Cooperation Expert Working Group on Clean Coal Technology and in the United Nations Economic Community of Europe Clean Coal Technology Expert Working Group to develop regional multilateral policies for development and implementation of clean coal technology in the respective regions. United Nations activities included a conference on the use of clean coal technology in residential and commercial applications in Eastern Europe and the development of a multilateral program for encouraging the application of clean coal technologies in Eastern Europe.

A computer model was developed by the Office of Clean Coal Technology as a tool for use by project developers in screening technology options for overseas clean coal projects. To date, the model has provided support to five U.S. companies to assist with the development of their projects.

DOE is making international dissemination of clean coal technologies an integral part of its policy to reduce greenhouse gas emissions in developing countries. Pursuant to Conference Report 103-740 to accompany the Department of the Interior and Related Agencies Appropriations Act for FY 1995 (Public Law 103-332) and the guidance contained in corresponding Senate and House Report 103-294 and 103-551, respectively, DOE published an "Announcement to Request Expressions of Interest (EOIs) in Commercial CCT Projects in Foreign Countries" in the *Federal Register* (59 FR 59768) on November 18, 1994. This solicitation was conducted to provide Congress with the information it required to consider the technical, economic, and environmental aspects of various incentives to support CCTs and their merits for potential future support. Potential respondents were advised that DOE had no monies to fund or otherwise provide any incentive in support of the proposed projects.

By the January 13, 1995, closing date, 33 organizations had responded with 77 expressions of interest to build clean coal technology projects in 21 countries. The number of expressions of interest proposed for each type of clean coal technology is listed below:

- Computer software and modeling—16
- Integrated gasification combined cycle—14
- Emissions controls—10

- Pressurized fluidized-bed combustion—8
- Atmospheric fluidized-bed combustion—7
- New fuel forms—6
- Coal preparation—6
- Advanced combustion—4
- Industrial applications—2
- Miscellaneous—4

The 77 projects, which represent a total of 58,237 MWe of generating capacity, were valued at \$7.15 billion. The largest number of projects were proposed for China; 20 projects representing 6,537 MWe were valued at \$2.5 billion. Ten projects were proposed for India; these represented 1,110 MWe and were valued at nearly \$2.1 billion. A total of 35 projects were proposed for Eastern European countries and the Newly Independent States; these projects represented over 47,000 MWe and were valued at approximately \$1.48 billion.

Proposed government incentives included funding of initial project development, funding of projects, financial assistance to U.S. business, general support and assistance to U.S. business, and technical assistance to the host country. The submissions also noted the merits of trade missions and reverse trade missions, such as the recent highly successful DOE mission, and governmental participation in addressing regulatory and other trade impediments encountered in the course of negotiating projects in foreign lands.

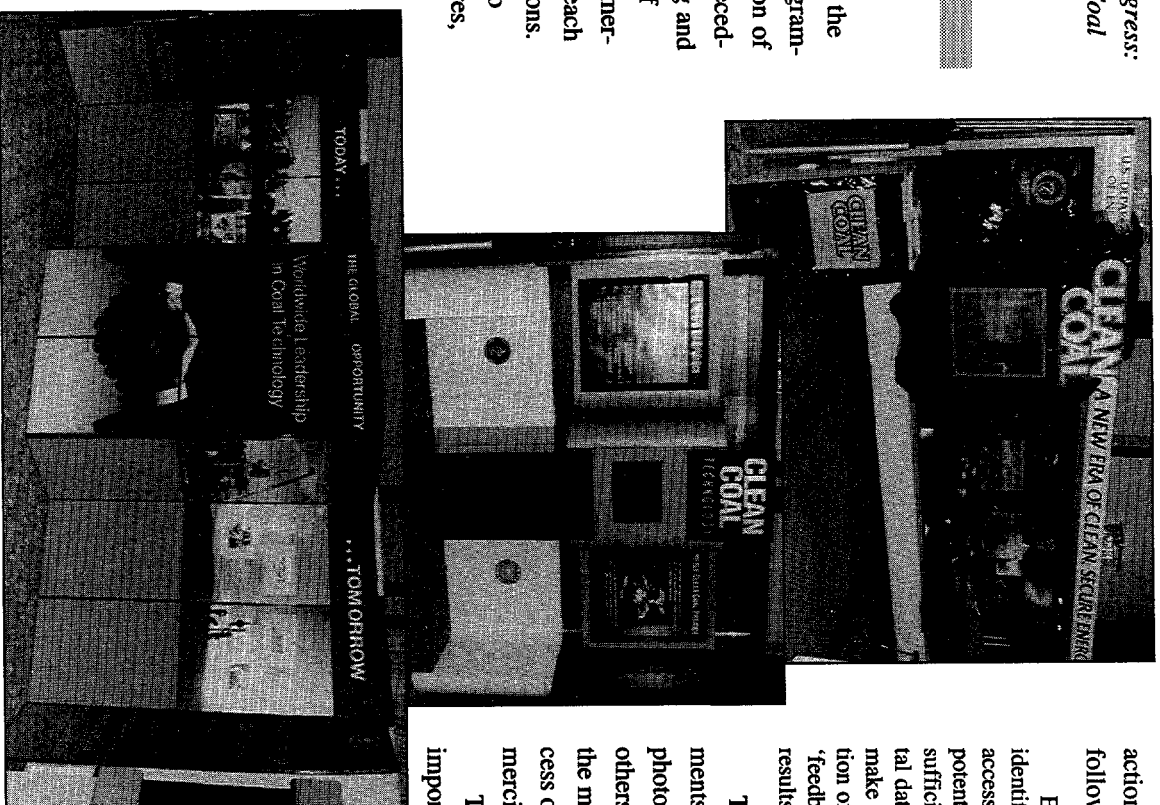
Detailed information about the solicitation, including summaries of each submission, country-specific discussions, and technology assessments, are provided

ed in the June 1995 publication, *Report to Congress: Expressions of Interest in Commercial Clean Coal Technology Projects in Foreign Countries*.

Market Communications

Public involvement has been a hallmark of the CCT Program since its inception in 1984. Programmatic interest was evaluated, first at the direction of Congress, in two informational solicitations preceding the CCT-I and CCT-II solicitations. Strong and broad industry interest covering a wide range of clean coal technologies was found to exist. Numerous public meetings were held prior to issuing each of the CCT-II through CCT-V project solicitations. The 12 public meetings that were held helped to sharpen the solicitation objectives and procedures, enabling industry to propose a technical agenda that met each of the solicitations' broad objectives.

As an outgrowth of ICTAP's *Report to the Secretary of Energy Concerning Commercialization Incentives*, a clean coal technology outreach program was established in 1989 to build a broad constituency for the CCT Program and to identify the needs of that constituency for information and data. The support of outreach was reemphasized in the National Energy Strategy in 1991. As a result, a formal outreach organization was established with DOE's Office of Clean Coal Technology. This outreach organization has received guidance and approval of outreach



▲ The CCT Program makes use of several exhibits to help communicate the progress of the program and the benefits of clean coal technologies.

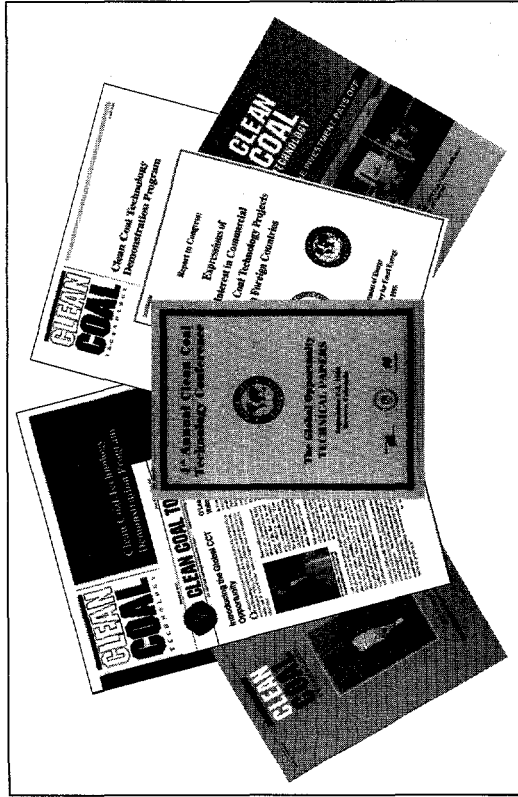
actions from a steering committee, which has the following mission:

Establish a clear understanding of the specific needs of identified priority stakeholders/customers to ensure that full access to information essential to the realization of the full potential of clean coal technology is achieved. Provide sufficient and timely technical, economic, and environmental data to the priority stakeholders/customers so they can make informed decisions affecting the commercial realization of the technologies, and to ensure that the necessary 'feedback loops' exist to R&D so problem definition and results will enter into the technology development process.

The steering committee has undertaken assessments of outreach materials (publications, exhibits, photographs, and electronic information, among others), and is developing long-term plans to import the most effective support to ensure continued success of clean coal technology deployment and commercialization.

The purpose of the outreach program is to import an understanding that clean coal technologies can increase the efficiency of coal use and enhance environmental quality at competitive costs. Further, the outreach program underscores the commitment to commercial realization of the technologies. 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 with information that is timely and relevant to their decision-making process



outreach program has been expanded into the international arena through sponsorship and participation in trade missions, Secretarial visits, and more specifically as part of the Asia Pacific Economic Cooperation initiative.

The outreach activities conducted by DOE have been directed toward reaching targeted audiences, including users and vendors of the technology, regulators, public educators, environmental organizations, and export markets.

Currently there are over 4,000 priority stakeholder/customers in the CCT Program. Stakeholders include approximately 275 participants in the program, about 15 of which interact with the CCT Program to provide

independent and objective program assessments and guidance and/or provide cosponsorship and inputs to the formulation and planning of outreach materials and the annual conferences. Support of this outreach program also comes from well established relationships with major organizations representing the coal industry (e.g., Clean Coal Coalition, Center for Energy and Economic Development, and National Mining Association). The CCT Program mails newsletters, annual program updates, and a variety of other outreach materials to almost 4,000 stakeholder/customers, 80 percent of whom have indicated overall satisfaction with the information and data received from the program. These mailings are made on a periodic basis (quarterly or annually) and as

special publications are available. The outreach program has participated in over 170 technical conferences, professional meetings, and trade missions since 1991.

DOE's outreach program has been implemented through the following mechanisms: publications, annual clean coal technology conferences, presentations and exhibits, and international trade missions. Additionally, project participants have been holding open houses, providing tours of demonstration facilities, and publicizing projects through groundbreaking ceremonies. They also have been presenting technical papers at professional and industry conferences to report progress and results to potential users.

Outreach assets include four traveling exhibits, interactive videos, broadcast videos, printed publications, an extensive photographic library, and a mailing list of stakeholders/customers.

DOE has been disseminating information through the distribution of published material about the program and the projects. These reports include the annual *Program Update*, *Comprehensive Reports to Congress* for each solicitation and successfully negotiated projects, the *New Coal Era*, the *Investment Pays Off*, and a series of project-specific topical reports to highlight project events or to capture progress at particular points driven by project-specific considerations. In 1995, at the program's midpoint, the following key publications were prepared and disseminated:

- *Clean Coal Technology: The Investment Pays Off* was updated; it highlights a number of commercial successes achieved thus far in the program.

▲ The CCT Program reports progress and accomplishments in several publications, including a quarterly newsletter, *Clean Coal Today*, the annual *Program Update*, and other topical reports. Publications are distributed to approximately 4,000 stakeholders/customers.

- Providing policymakers and regulators with information about the advantages of clean coal technologies
- Increasing the confidence of financial institutions that these technologies are viable options

A vigorous outreach program is being pursued in the form of dissemination of program information, publication of materials, including quarterly newsletters and annual program reports, cosponsorship of the Annual Clean Coal Technology Conference, attendance at trade shows and other high-visibility events, conduct of executive seminars, and providing electronic access to project information via the Internet World Wide Web as well as a fax-on-demand system and a computer bulletin board. The

- *Clean Coal Technology Demonstration Program: Project Fact Sheets* provides a mid-year update on each project.
- *Fourth Annual Clean Coal Technology Conference: The Global Opportunity; Technical Papers* contains the technical papers submitted in advance of the 1995 conference.
- *Fourth Annual Clean Coal Technology Conference: The Global Opportunity; Proceedings* contains the papers presented during plenary and panel sessions as well as the luncheon addresses.

Appendix C is a comprehensive listing of CCT Program publications, and Appendix D lists recent papers and presentations on the CCT Program. Three issues of the newsletter, *Clean Coal Today*, were published in 1995, along with the first annual edition of the *Clean Coal Today Index* which cross-references all articles published in the newsletter to date by both project title and participant. The newsletter is distributed to approximately 4,000 domestic and international readers.

Fossil Energy TechLine is a 24-hour fax-on-demand system that can provide a wide variety of information on DOE's fossil energy programs including the CCT Program. The TechLine system offers news announcements on clean coal projects, fact sheets for individual projects, and monthly updated status reports. A computer bulletin board also provides updates.

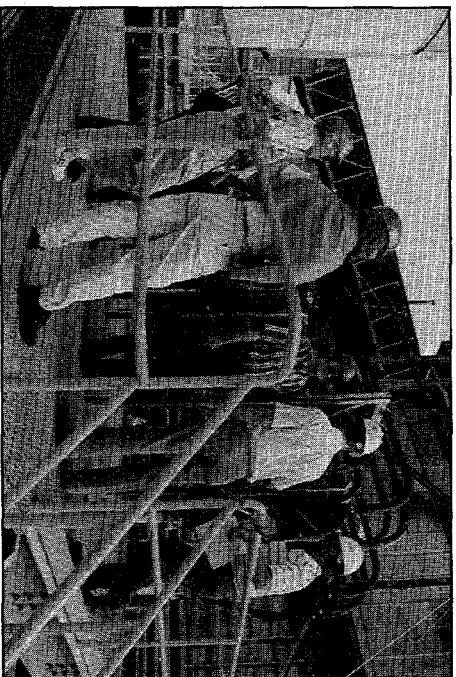
DOE also has put into operation a public computer network accessible through the Internet World Wide Web which provides information on federal fossil energy programs and serves as a "gateway" to other related information throughout the United States and the world. Once into the network, users can obtain general information and follow links to increasingly detailed information, ultimately accessing specific data on individual projects and facilities. Internet's electronic links 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 at Oak Ridge, Tennessee. The gateways link to more than a hundred energy-

related computer servers and networks operated by private companies, trade associations, and other agencies worldwide. (See Appendix C for additional information on how to access CCT Program information electronically.)

The Fourth Annual Clean Coal Technology Conference was held in Denver, Colorado, in September 1995 and was cosponsored by the Center for Energy & Economic Development and the National Mining Association. There were nearly 300 participants, including 34 representatives from more than a dozen countries. The theme, "The Global Opportunity," emphasized international opportunities for clean coal projects. An important goal of this conference was to assess and evaluate promising technologies that will be the benchmark technologies in emissions control for 1996 and into the next century. The conference provided a forum to review the status of CCT projects here and abroad and provided an opportunity to evaluate CCT Program directions.

The conference provided attendees with reviews of the current status of clean coal technologies, descriptions of barriers to commercialization domestically and internationally, explanations of how the changing utility organizations and structure may affect these technologies, and recommendations for support required to ensure the continuing deployment of clean coal technologies.

Modeling the agenda and program after last year's successful conference, the opening day was devoted to an international orientation session, providing an overview of the importance of clean coal technologies internationally and an opportunity for trade development dialogue. This was followed by tours of two Public Service Company of Colorado



- ▲ The Fourth Annual Clean Coal Technology Conference held in Denver, CO, was attended by about 300 persons from more than a dozen countries. Energy and Environmental Research Corporation conducted site tours of the gas reburning and low-NO_x burner demonstration at Cherokee Station, and the Public Service Company of Colorado conducted site tours of the integrated dry NO_x/SO₂ emissions control system at Arapahoe Station.



in the electric power industry, and domestic challenges, such as externalities, emissions regulations, selecting technologies in the competitive era in power generation, alternative power marketing, and utility industry restructuring.

During six technical sessions, presentations were given by 28 industrial participants on results and accomplishments of the projects in three categories—advanced emissions reduction technologies, advanced technologies for power/industrial applications, and advanced NO_x/SO_2 emissions reduction technologies.

▲ The Fourth Annual Clean Coal Technology conference was held in Denver, CO, and focused on the global opportunities within the international market for clean coal technologies.

sites: Arapahoe Station, where an integrated dry NO_x/SO_2 emissions control system is being demonstrated, and Cherokee Station, where gas reburning and low- NO_x burners were evaluated.

In the opening plenary session, "Global Opportunity, Meeting the Diverse Challenges," speakers addressed the world economic and energy outlook, role of clean coal technologies and coal in the expanding world economy, recent National Coal Council studies on clean coal technologies, and technology deployment in emerging markets.

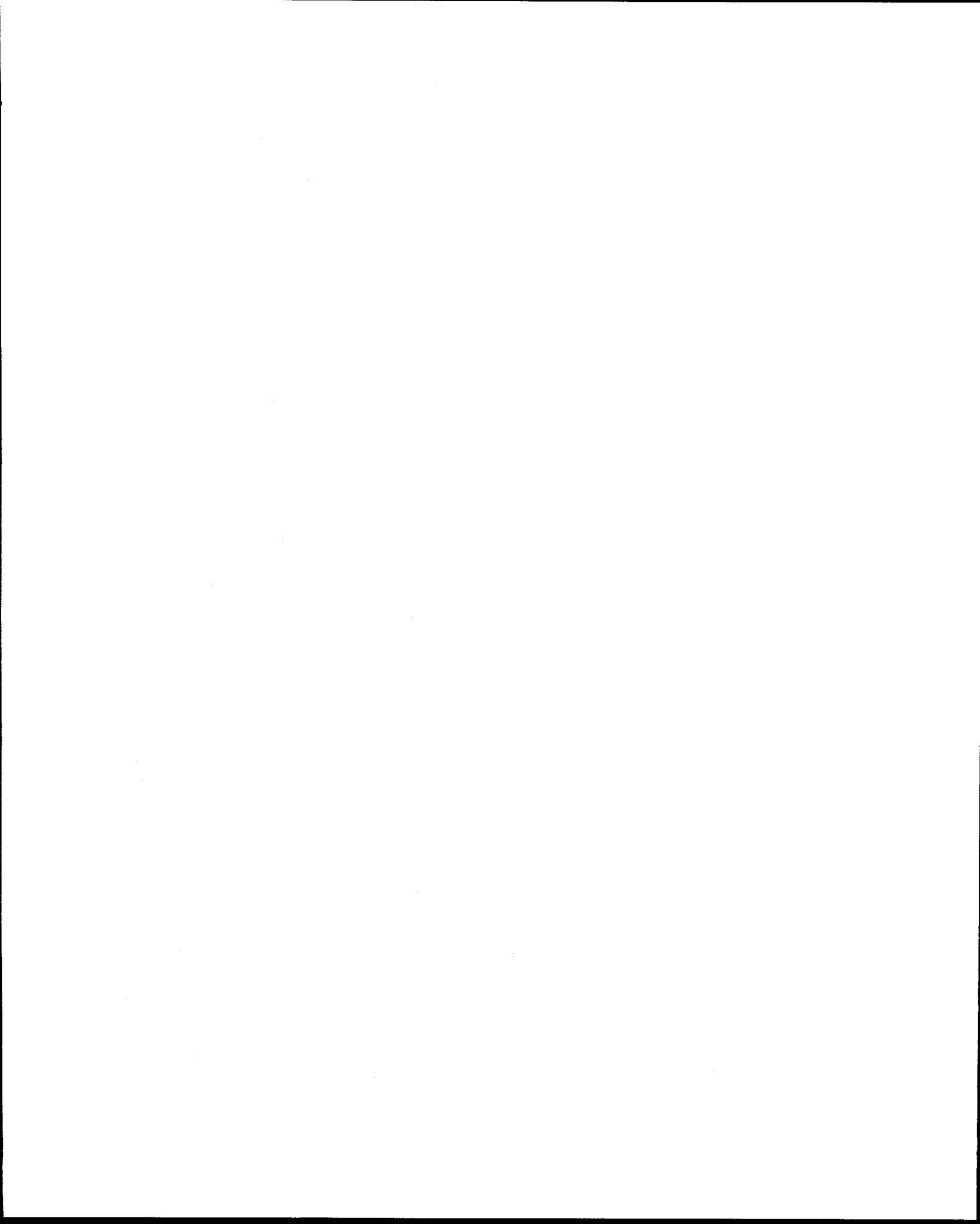
The first of four panel sessions addressed international business from the perspectives of understanding the markets, mechanisms for international commercialization, international intellectual property, and the World Bank Clean Power Technologies Initiative. Other panels covered transitions in the international power sectors, transition to competition

including Virginia Power Electrotechnologies Expo, DOE/EH Annual NEPA Conference, EPRI-EPA-DOE 1995 SO_2 Control Symposium, EPRI/DOE workshop, American Power Conference, Third African/African American Summit, New England Cogeneration Association Conference & Exhibit, PETC School Day and Open House, PowerGen International, Association of Energy Engineers Competitive Power Congress, International Energy & Environmental Congress, Virginia Coal Council Conference & Exposition, NASA Technology 2005, NARUC 107th Annual Convention & Regulatory Symposium, and PowerGen Americas.

The final day provided affirmation that clean coal technologies have a definite place in the global energy environ-

ment. Presentations were given on specific international projects and reports from China, India, Indonesia, Russia, and the Ukraine. Some described joint U.S./international projects, while others explained energy needs, infrastructure developments, economic and environmental factors, and increasing opportunities in their respective countries. Conferees also heard from organizations that are actively pursuing cooperative energy ventures and financing opportunities globally. A lack of infrastructure appeared to be the most common impediment to such projects. It was clear that the potential for international successes remains dependent upon continued domestic successes for clean coal technologies.

During 1995, DOE made use of exhibits and presentations as a means to highlight the activities and benefits of the CCT Program. The exhibits were used in 16 major domestic and international events



5. Results of Completed Projects

Summary

Five projects completed operation in 1995, bringing to 18 the total number of projects for which operations have been completed under the CCT Program. The five projects, which fall into three categories, are as follows:

- Advanced Electric Power Generation Technology
- Tidd pressurized fluidized-bed combustion demonstration project (The Ohio Power Company)
- NO_x Control Technologies
- Gas reburning and low-NO_x burners on a wall-fired boiler (Energy and Environmental Research Corporation)
- Selective catalytic reduction technology (Southern Company Services, Inc.)
- SO₂ Control Technologies
- Advanced flue gas desulfurization technology (Pure Air on the Lake, L.P.)
- CT-121 advanced flue gas desulfurization technology (Southern Company Services, Inc.)

These five projects provide further valuable contributions to a growing CCT Program data base

designed to address energy and environmental issues associated with the use of coal in the U.S. energy portfolio.

Tidd PFBC Demonstration Project

The Ohio Power Company completed the demonstration of the first utility-scale pressurized fluidized-bed combustion (PFBC) unit in the United States at the Tidd Plant in Brilliant, Ohio. The 70-MWe plant represented a 13:1 scale-up from the pilot facility and used The Babcock & Wilcox Company's PFBC technology under license from ASEA Brown Boveri Carbon. The Tidd PFBC technology is a bubbling fluidized-bed combustion process

operating at 12 atmospheres. The PFBC power island was incorporated into the existing steam cycle at Tidd. The unit provided a nominal steam flow of 440,000 pounds per hour at 1,300 pounds per square inch and 925 °F and had an electrical output of 55-MWe from the steam turbine and 15-MWe from an ASEA Stal GT-35P gas turbine. The unit accumulated 11,444 hours of coal-fired operation during its 54 months of operation. The unit completed 95 parametric tests and included continuous coal-fired runs of 28, 29, 30, 31, and 45 days.

Test results showed that 90 percent SO₂ capture was achieved with a Ca/S molar ratio of 1.1 and 95 percent SO₂ capture was possible with a Ca/S molar ratio of 1.5 using both Ohio bituminous coals having a sulfur content of 2-4 percent and Plum Run Greenfield dolomite. The unit demonstrated NO_x emis-

sions in the range of 0.15-0.33 pound per million Btu. These emissions were inherent to the process which had an operating temperature of 1,580 °F.

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 is considered a commercially viable design. While the gas turbine was the leading cause of unit unavailability during the first 3 years of operation, technical improvement and revised designs are addressing the mechanical and erosion problems. The Tidd demonstration showed that a gas turbine could operate in the PFBC flue gas environment and erosion was manageable with a scheduled maintenance program.

As part of a research and development program, advanced ceramic candle filtration elements were tested on one-seventh of the gas stream for 5,854 hours of coal-fired operation between October 1992 and March 1995. Test results showed that the design of the candle-based advanced particulate filter was structurally adequate. However, results also showed that clay-based silicon carbide lost 50 percent of its strength after 1,000-2,000 hours of exposure and that a build-up of ash in the filter vessel would cause breakage of the candles.

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

Energy and Environmental Research Corporation (EER) completed an evaluation of a gas-reburning system combined with low-NO_x burners

(GR-LNB) at Public Service Company of Colorado's 172-MWe wall-fired boiler located at Cherokee Station Unit 3. Parametric and long-term testing was conducted from October 1992 to January 1995. More than 4,000 hours of operation were achieved enabling EER to obtain a substantial amount of data. The results showed that for the first generation system using flue gas recirculation, average NO_x reduction of 37 percent (0.46 pound per million Btu) was achievable with the LNB alone and 65 percent (0.26 pound per million Btu) was achieved with GR-LNB at an average gas input of 18 percent of total boiler heat input. The second generation system without flue gas recirculation showed an average NO_x reductions of 37 percent for LNB and 64 percent for GR-LNB at an average gas heat input of 13 percent. The boiler efficiency decreased by approximately 1 percent during gas reburning due to moisture in the fuel and an increase in heat loss due to moisture formed in combustion. There was no measurable boiler tube wear resulting from GR-LNB operation and, in general, the tubes were free from slagging.

Based on the demonstration and the data collected, the technology can be applied to utility and industrial units. EER expects that most GR-LNB installations will achieve 60 percent NO_x reductions when firing 10-15 percent gas. The capital cost for units of 100-MWe or larger is in the range of \$15 per kilowatt plus the cost of a gas pipeline. Operating costs are almost entirely related to the differential cost of gas over coal as reduced by the value of SO₂ emissions credits.

Public Service Company of Colorado retained the gas reburning system and associated controls. The low-NO_x burners are also to be retained and

repaired to reduce carbon-in-ash levels and, thus, improve the economic performance of the unit.

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

Southern Company Services, Inc., completed a demonstration designed to evaluate the performance of eight commercially offered catalysts of various shapes and composition under U.S. utility operating conditions with high sulfur coal at Gulf Power Company's Plant Crist. Project objectives include assessing the technical and economic viability of the catalysts when applied in U.S. utility application with high-sulfur coal while maintaining at least 80 percent NO_x reduction and acceptable ammonia slip (5 parts per million). Three large selective catalytic reduction (SCR) reactors (2.5 MWe, 5,000 standard cubic feet per minute) and six smaller SCR reactors (0.2 MWe, 400 standard cubic feet per minute) were operated in parallel. Eight of the nine reactors generated with flue gas containing high particulate loading (ESP inlet), and one small reactor received low particulate loading (ESP outlet). Each reactor train had the provision to control and measure temperature and flow.

The larger trains had pilot-scale air preheaters at the SCR exit to evaluate the effect of SCR reaction chemistry on air preheater deposit formation. Each SCR train was operated over the long term at design/baseline conditions with parametric tests interjected every 4 months. Parametric tests varied NH₃/NO_x ratio, temperature, and space velocity while measuring NO_x reduction efficiency, pressure drop, SO₂ oxidation, and ammonia slip.

Detailed results from the SCR demonstration will be available in 1996.

Advanced Flue Gas Desulfurization Demonstration Project

Pure Air on the Lake, a general partnership between Air Products and Chemicals, Inc., and Mitsubishi Heavy Industries America, Inc., completed a 3-year demonstration of an advanced flue gas desulfurization (AFGD) process at Northern Indiana Public Service Company's Bailly Generating Station, Units 7 and 8. The 528-MWe demonstration accumulated approximately 26,280 hours of operation over a 3-year period and achieved an availability of 99.47 percent. Construction began in April 1990, and in June 1992 the AFGD system began to process flue gas, thus becoming the first commercial scrubber to meet the requirements of the CAAA of 1990. Tests were performed on coals ranging from 2.25 percent to greater than 4.5 percent sulfur. During the 3-year operation, SO₂ removal efficiency averaged 94 percent with a maximum of 98+ percent or 0.382 pound per million Btu. Twenty-four hour average power consumption was 5,275 kilowatts or 61 percent of design expectations, and water consumption was 1,560 gallons per minute or 52 percent of design expectations. The project also demonstrated a unique gypsum agglomeration process known as PowerChip™ that converts AFGD gypsum into stable product conducive to transporting and handling. The production rate of the PowerChip™ facility was 7 tons per hour. During the 3-year demonstration, over 210,000 tons of dry gypsum was produced with an average purity of 97.2 percent.

The AFGD will continue to operate for an additional 17 years under a novel business concept whereby Pure Air is the owner of the unit and operates the system on a service contract basis for Northern Indiana Public Service Company. In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO₂ scrubbing capability to Florida Power and Light Company's Manatee Power Plant on the same own-and-operate basis.

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

Southern Company Services, Inc., completed demonstration of Chiyoda Corporation's CT-121 advanced flue gas desulfurization process retrofitted to an existing 100-MWe coal-fired boiler at Georgia

Power Company's Plant Yates. In the 19,000 hours logged over 27 months of operation, the system was able to maintain SO₂ removal efficiencies above 90 percent at all loads with coals ranging from 1.2 to 4.3 percent sulfur, ash levels up to 1.4 pounds per million Btu, and limestone utilization above 97 percent. Use of fiberglass reinforced plastic in fabricating key components, with its high resistance to corrosion, enabled elimination of a pre-rescubber to remove chlorides and flue gas reheat to prevent corrosive condensation in the chimney. The structural and chemical durability of fiberglass reinforced plastic construction combined with the simplicity of design afforded by the unique jet bubbling reactor resulted in high availability (97 percent at low ash levels and 95 percent at elevated ash levels) and elimination of the

need for a spare reactor module. The CT-121 system demonstrated high particulate capture efficiency (97.7-99.3 percent) at flyash levels reflective of marginal ESP performance (up to 1.4 pounds per million Btu). Testing also showed the CT-121 system is highly efficient in the capture of hazardous air pollutants which are largely borne by particulate.

Results Summaries

Exhibit 5-1 shows the number of completed projects for each application category. As can be seen, the technical, environmental, and economic performance results are available for 14 of the 19 projects in the environmental control device category—in time for potential users to have the information necessary to make decisions on how best to satisfy the requirements of the CAAA of 1990 for SO₂ and NO_x reduction.


Results summaries for the 18 completed projects, as reported by the participants, follow for quick reference. More detailed results are discussed in the project summaries provided later in this section.

Exhibit 5-1 Completed Projects

Application Category	Total Projects	Completed Projects
Advanced Electric Power Generation		
Fluidized-bed combustion	6	2
Integrated gasifier combined cycle	5	0
Advanced combustion/heat engines	3	0
Environmental Control Devices		
NO _x control technologies	7	5
SO ₂ control technologies	5	5
Combined SO ₂ /NO _x control technologies	7	4
Coal Processing for Clean Fuels	5	0
Industrial Applications	5	2
	43	18

Exhibit 5-2 Completed Projects, by Application Category

Project and Participant	Page
Advanced Electric Power Generation	
Fluidized-Bed Combustion	
Tidd PFBC Demonstration Project (The Ohio Power Company)	5-6
Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)	5-10
Environmental Control Devices	
NO_x Control Technology	
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company)	5-14
Full-Scale Demonstration of Low-NO _x Cell Burner Retrofit (The Babcock & Wilcox Company)	5-17
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	5-19
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	5-21
Demonstration of Selective Catalytic Reduction Technology for Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	5-23
SO₂ Control Technology	
10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)	5-25
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	5-28
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)	5-30
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	5-33
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	5-37
SO₂/NO_x Control Technology	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	5-41
LMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	5-43
SOx-NOx-ROx Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	5-46
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	5-49
Industrial Applications	
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	5-54
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	5-56



Advanced Electric Power Generation

Tidd PFBC Demonstration Project (The Ohio Power Company)

Technology

Pressurized fluidized-bed combustion combined cycle (12 atm)

Size

70-MW total—(55 MWe steam turbine; 15-MW gas turbine)

Demonstration Duration (10/91-3/95)

11,444 hrs of coal-fired operation

Coal

Ohio bituminous, 2-4% sulfur

Sorbent

- Both limestone and dolomite evaluated
- Plum Run Greenfield dolomite preferred

Environmental Results

- 90% SO₂ removal efficiency at 1.1 Ca/S (1,580 °F)
- 95% SO₂ removal efficiency at 1.5 Ca/S (1,580 °F)
- NO_x emissions of 0.15-0.33 lb/million Btu
- CO emissions less than 0.01 lb/million Btu
- Particulate emissions less than 0.02 lb/million Btu

Technical Results

- Combustion efficiency—99.6%
- Heat rate—10,280 Btu/kWh (33.2% efficiency) based on fuel HHV and gross electrical output
- Candide filter—99.99% filtration efficiency, mass basis
- Boiler design considered commercially viable
- Gas turbine shown to operate in PFBC flue gas environment

Economic Results

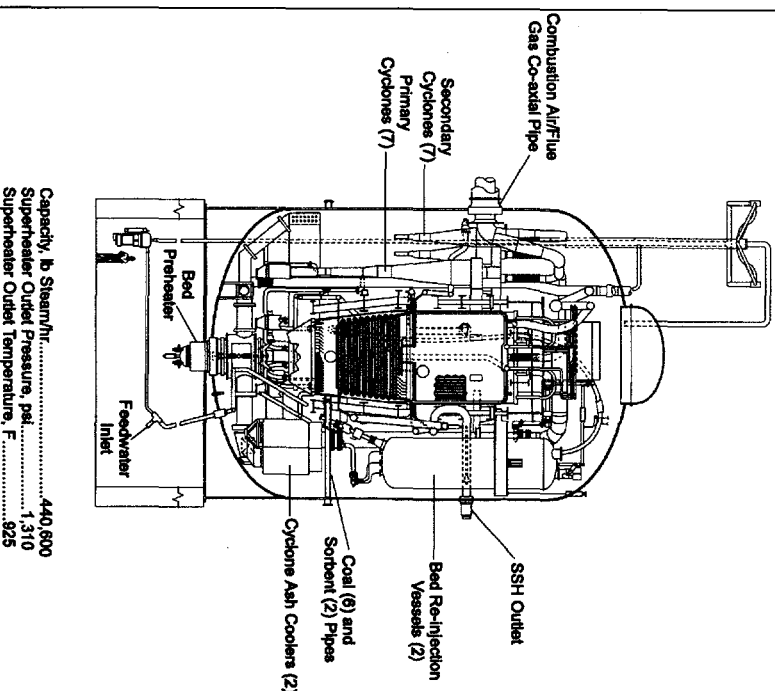
Because the Tidd project produced 70 MWe, economic results would not be applicable to future utility-scale applications of this technology. Economic results from the

340-MW PFBC Utility Demonstration Project (see project fact sheet, page 7-8) will define the capital and operating cost for this technology.

The Ohio Power Company completed demonstration of the first utility-scale pressurized fluidized-bed combustion (PFBC) system in the United States at the Tidd Plant in Brilliant, Ohio. The 70-MW unit used the Babcock & Wilcox Company's PFBC technology under license from ASEA Brown Boveri Carbon. The plant represented a 13:1 scale-up from the pilot facility. The objective of the demonstration was to verify the technology's economic, environmental and technical performance in a combined-cycle repowering application at a utility site. Specific objectives were to achieve 90 percent SO₂ removal, NO_x emissions of 0.2 lb/million Btu and an efficiency of 35 percent in a repowering mode which used the existing steam system.

The Tidd PFBC technology is a bubbling fluidized-bed combustion process operating at 12 atmospheres (175 pounds per square inch). Fluidized combustion is inherently efficient. A pressurized environment further enhances combustion efficiency, allowing very low temperatures that mitigate thermal NO_x generation, flue gas/sorbent reactions increase sorbent utilization, and flue gas energy is used to drive a

Tidd PFBC Combustor Assembly



▲ The Ohio Power Company completed the 54-month demonstration of the first utility-scale PFBC unit in the United States. The unit accumulated over 11,400 hours of operation and generated 55 MWe from the steam turbine and 15 MWe from a gas turbine and is considered a commercially viable design.

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 (such systems are called combined cycles).

The boiler, cyclones, bed injection vessels, and associated hardware are encapsulated in a pressure vessel 45 feet in diameter and 70 feet high. Pressurized combustion air is provided by the gas turbine compressor. The combustion air fluidizes the bed material consisting of fuel (coal/water paste), coal ash and sorbent (dolomite). Seven two-stage cyclones, located in the combustor vessel, remove about 98 percent of the entrained ash from the fluidized bed exhaust gases. The clean hot gases pass from the

pressure vessel and are expanded through an ASEA Stal GT-35P gas turbine. Heat from the turbine exhaust is captured in a waste heat recovery unit for steam generation. The cooled gas is further cleaned in an electrostatic precipitator.

The PFBC power island was incorporated into the existing steam cycle at Tidd. The PFBC provided a nominal steam flow of 440,000 pounds per hour at 1,300 pounds per square inch and 925 °F and had a gross electric output of 70 MWe (55 MWe from the steam turbine generator and 15 MWe from the gas turbine generator).

Coal was injected into the combustor as a coal/water paste containing 25 percent water by weight. The coal was crushed to ¼ inch or less, then conveyed to a vibratory screen, which controlled coal top size and then to the coal-water paste mixer where the appropriate amount of water was added. The coal/water paste was fed into six hydraulically driven pumps, each of which fed an individual in-bed nozzle.

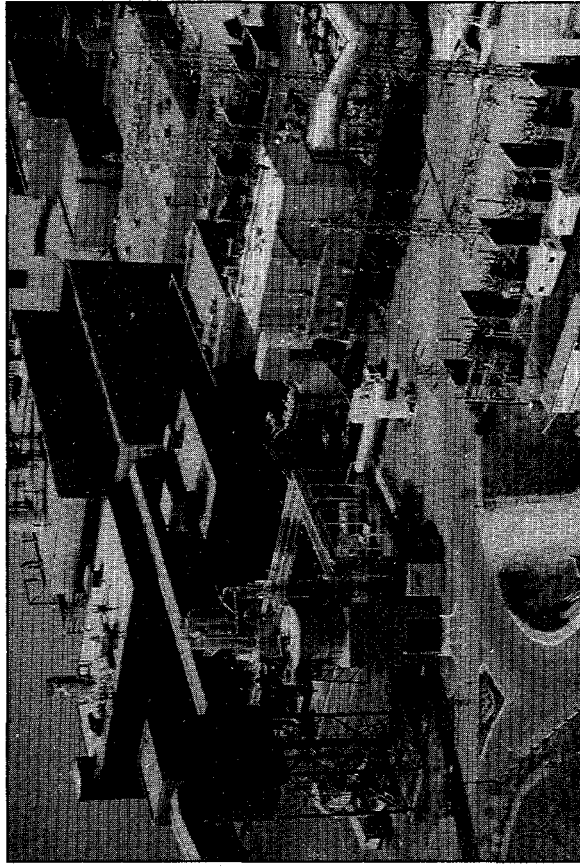
In the process, sorbent, dolomite or limestone, is used to react with the sulfur in the coal to form calcium sulfate, a dry granular bed-ash material which is easily disposed of or used to produce a usable by-product. The crushed sorbent is injected into the fluidized

bed via two pneumatic feed lines, supplied from two lock hoppers. An alternative sorbent feed system was added in 1993 which provided the capability of injecting sorbent of various sizes directly into the coal-water paste feed system. The system provided the means to assess a wet feed sorbent system while providing the opportunity to better control sorbent size.

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

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 and included continuous coal-fired runs of 28, 29, 30, 31 and 45 days. Ohio bituminous coals having sulfur contents of 2–4 percent were used in the demonstration.

Testing indicated that 90 percent SO₂ capture was achievable with a Ca/S molar ratio of 1.1 and 95 percent SO₂ capture with a Ca/S molar ratio of 1.5, provided the size gradation of the sorbent being utilized was optimized. This sulfur retention was achieved at a bed temperature of 1,580 °F and full bed height. Limestone proved ineffective as a sorbent, and as a result, testing focused on use of dolomite. The testing showed that sulfur capture as well as sintering was sensitive to the fineness of the dolomite sorbent (Plum Run Greenfield dolomite). Sintering of fluidized bed materials, a fusing of the



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

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 material to a minus 12 mesh material. 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 percent improvement in heat transfer rate and an approximately 30 percent increase in sorbent utilization. In addition, the process was much more stable as indicated by reductions in temperature variations in both the bed and the evaporator tubes. Further, post-bed combustion and sintering were effectively eliminated.

The process demonstrated NO_x emissions in the range of 0.15–0.33 pound per million Btu. These emissions were inherent to the process which was operating at approximately 1,580 °F. No NO_x control enhancements, such as ammonia injection, were required. Emissions of carbon monoxide and particulates were less than 0.01 and 0.02 pound per million Btu, respectively.

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 is considered a commercially viable design. The in-bed tube bundle experienced no widespread erosion that would require significant maintenance. There was one in-bed bundle tube leak during the first 3 years of operation attributed to erosion. This was caused by a missing access hatch seal. Final inspection revealed some distortion of the superheater uncooled support trusses and loss of a number of

retaining clips. While the tube bundle was in good condition, a significant amount of erosion on each of the four water walls was observed. This occurred approximately 5 feet above the air sparge ducts and extended to about three feet below the top of the tube bundle. While no operational failure occurred during the demonstration, remedial action such as the use of refractory coatings should provide a solution. Such coatings were utilized on two commercial PFBC units and were shown to be effective in precluding water wall erosion.

The gas turbine was the leading cause of unit unavailability during the first 3 years of operation. The low-pressure turbine blades were replaced, once due to cracks and once due to a failure of a blade. During the fourth year, no significant failures occurred. These failures were all related to the turbine mechanical design, not its operation in the PFBC plant. Erosion was a problem throughout the demonstration. While erosion on the turbine blades was relatively minor, it was significant on the variable-pitch inlet guide vanes and the inlet guide vanes' inner and outer rings. However, a revised design, which was not installed at Tidd due to its limited remaining life, was installed at other operating PFBC units and was effective in addressing this problem. The Tidd demonstration showed that a gas turbine could operate in a PFBC flue gas environment and it was concluded that erosion was manageable with a scheduled maintenance program.

The efficiency of the PFBC combustion process was calculated during the testing from the amount of unburned carbon in the cyclone ash and bed ash together with the measurements of the amount of carbon monoxide in the flue gas. Tests conducted in

the fourth year of operation showed combustion efficiencies surpassing the design or expected efficiency of 99.0 percent. The typical efficiency calculated at design operation conditions was about 99.6 percent.

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

Testing of advanced ceramic candle filtration elements on a slipstream of one-seventh of the exhaust gases for over 5,800 hours of coal-fired operation showed that the design of the particulate filter was structurally adequate. However, results also showed that clay-bonded silicon carbide lost 50 percent of its strength after 1,000–2,000 hours of exposure and that a buildup of ash in the filter vessel caused breakage of the candles. The filter operated at a pressure drop on the order of 100 inches of water column and a filtration efficiency (mass basis) of 99.99 percent.

Because the Tidd project produced 70 MWe, economic results would not be characteristic of future utility-scale applications of this technology. Economic results from the 340-MWe PFBC Utility Demonstration Project will define the capital and operating costs for this technology.

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

The Tidd project has received two major awards. In 1992, it received the National Energy Resources Organization award for demonstration of energy efficient technology. In 1992, *Power Magazine* presented the Powerplant of the Year Award to the project for demonstrating PFBC technology.

Available Reports

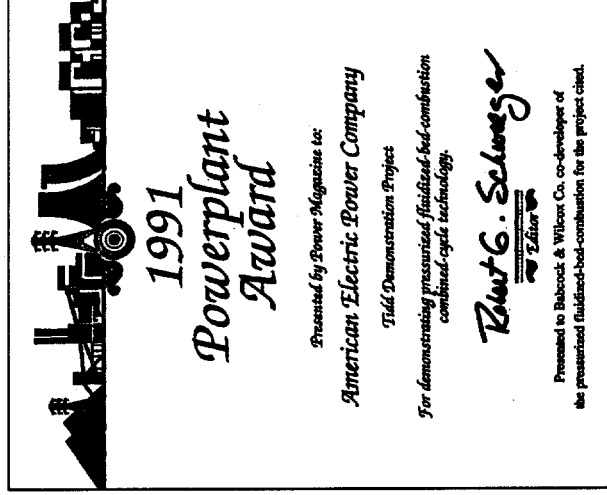
- *Tidd PFBC Hot Gas Clean Up Program Final Report*. Report No. DOE/MC/26042-5130. The Ohio Power Company. October 1995. (Available from NTIS as DE96000650.)
- *Tidd PFBC Demonstration Project Final Report, March 1, 1994-March 30, 1995*. Report No. DOE/MC/24132-T8. The Ohio Power Company. August 1995. (Available from NTIS as DE96004973.)
- *Tidd PFBC Demonstration Project—First Three Years of Operation*. Report No. DOE/MC/34132-5037-vol. 1 and -vol. 2. The Ohio Power Company. April 1995. (Available from NTIS as DE96000559 for vol. 1 and DE96003781 for vol. 2.)
- *A Study of Hazardous Air Pollutants at the Tidd PFBC Demonstration Plant*. Report No. DOE/MC/26042-4083. American Electric

Power Service Corporation. October 1994. (Available from NTIS as DE95009729.)

- *Tidd PFBC Demonstration Project Topical Report—First Eighteen Months of Operation*. Report No. DOE/MC/24132-3746. The Ohio Power Company. March 1994. (Available from NTIS as DE94004120.)
- *Tidd PFBC Demonstration Project: Public Final Design Report*. Report No. DOE/MC/24132-3195. The Ohio Power Company. October 1992. (Available from NTIS as DE93000234.)

Contact

Mario Marrocco, Manager, PFBC Programs
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215
(614) 223-1740
(614) 223-2466 (fax)



American Electric Power Company received *Power Magazine's* 1991 Powerplant Award and in 1992, a National Energy Resource Organization award for demonstration of energy efficient technology.

Nucla CFB Demonstration Project (Tri-State Generation and Transmission Association, Inc.)

Technology

Atmospheric circulating fluidized-bed (ACFB) combustion

Size

110 MWe

Demonstration Duration (6/88-1/91)

15,700 hrs

Coal

Salt Creek & Peabody, 0.4-0.8% sulfur; Dorchester, 1.4-1.8% sulfur

Sorbent

Limestone

Environmental Results

- 70% SO₂ removal efficiency with 1.5 Ca/S (<1,620 °F)
- 95% SO₂ removal efficiency with 4.0 Ca/S (<1,620 °F)
- NO_x emissions less than 0.34 lb/million Btu; avg 0.18 lb/million Btu

Technical Results

- Combustion efficiency—96.9-98.9%
- Heat rate—12,400 Btu/kWh (50% load); 11,600 Btu/kWh (100% load)

Economic Results

Capital cost—approx \$1,123/net kW (repower cost)

The primary objective of the Nucla project was to demonstrate the feasibility of atmospheric circulating fluidized-bed (ACFB) combustion technology at utility scale and to evaluate the economic, environmental, and operational benefits of ACFB steam generators at that scale. At the conclusion of testing in January 1991, this objective had been achieved.

The Nucla CFB Demonstration Project was conducted by Colorado-Use Electric Association, Inc., owner of the project site, Nucla Station. In 1992, Colorado-Use Electric Association was purchased by Tri-State Generation and Transmission Association, Inc.

The original Nucla Station was built in 1959 and included three identical stoker-fired units, each rated at 12.5 MWe. Due to the plant's reduced position in the dispatch order resulting from poor station efficiency and increased maintenance costs, the decision was made to upgrade and repower the station with a new 925,000-pound-per-hour ACFB boiler and a 74-MWe turbine generator. Except for the old stoker-fired units, most of the equipment from the old plant, including the turbine-generator sets, was refurbished and reused, bringing the plant's total electrical output to 110 MWe. The project offered several advantages to the utility, including an improvement of 15 percent in station heat rate, reduced fuel costs due to the inherent fuel flexibility of the ACFB design, lower emissions than required by NSPS, and life extension of 30 years beyond that of the plant's original design.

Construction of the new ACFB boiler began in the spring of 1985 and was completed over a 2-year period. The first turbine roll was initiated in May 1987, followed in June by the first coal firing. Preparation for the test program began in February 1987. Cold-mode shakedown was completed by the third quarter of 1988.

The plant had accumulated more than 15,700 hours of coal-fired operation by the end of the dem-

onstration test program. In July 1988, the data acquisition system and software became fully operational. From August 1988 through January 1991, the plant operated with an average availability of 58.3 percent and a capacity factor of 39.6 percent, which are below national averages. (According to the North American Reliability Council Generating Availability Data System, between 1984 and 1988, non-CFB coal-fired units in the 100-199-MWe size range had average availability and capacity factors of 83.9 percent and 49.7 percent respectively.)

Several factors account for the differences in average availability and capacity factors, including the demonstration nature of the project and requirements for inspection of materials at the facility, equipment modification outages required for some nondesign fuel tests, and outages related to ACFB technology installation.

From April 1988 through June 1990, a total of 45 steady-state performance tests were completed. These tests established the effects of load, excess air, primary-to-secondary air ratio, unit operating temperatures, coal and limestone feed configurations, and coal type and size distributions on emissions performance and combustion and boiler efficiencies. Data were collected from these tests to quantify heat transfer in the combustion chambers, tubular air heat effectiveness, and baghouse collection efficiency.

Between July 1990 and January 1991, an additional 27 steady-state performance tests were conducted. These tests provided new information in areas with limited results during previous tests. As

part of the alternate fuels testing, Dorchester coal was also tested. This coal had a much higher sulfur content (approximately 1.5 percent by weight) compared to Salt Creek coal (about 0.5 percent) and a local Nucla coal used in earlier tests. In addition, dynamic response tests were completed at rates up to 7 MWe per minute.

In summary, a total of 72 steady-state performance tests were completed between 1988 and 1991. Of these tests, 8 were conducted on a local Nucla coal and 2 on a local Dorchester coal as part of alternate fuels testing; 62 were completed on Salt Creek coal, which was the baseline fuel used for the test program. A total of 22 tests were performed at 50 percent of full load (full load being 110 MWe), 6 tests at 75 percent, 2 tests at 90 percent, and 42 tests at full load. Except for limestone sizing tests, which were not possible with existing plant preparation equipment, all independent process variables proposed in the original test matrix were completed.

Some key results obtained during the performance of these tests, as reported by the participant, are as follows:

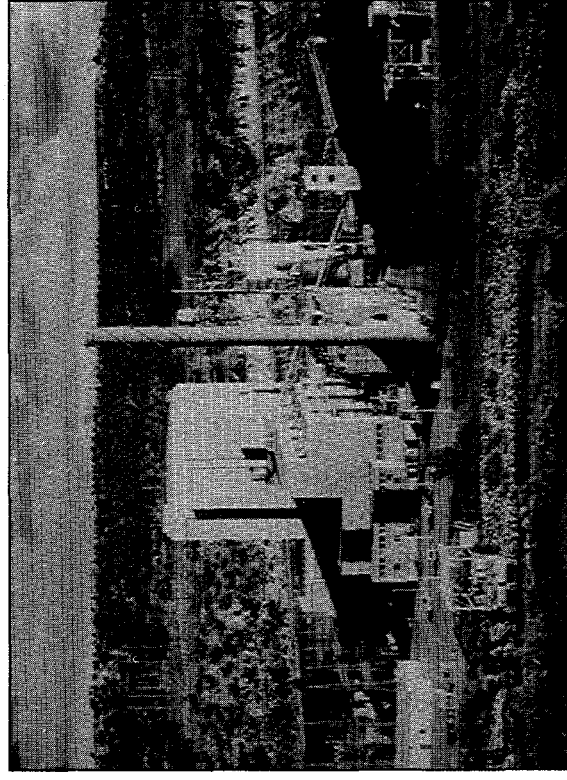
- **Emissions Performance.** Results indicated strong correlations of absolute CO, SO₂, and NO_x emissions levels with combustor operating temperatures. Although compliance was maintained within NSPS for each emission type, a penalty on limestone feed requirements for sulfur retention was realized at the higher operating temperatures. For temperatures below 1,620 °F, 70 percent SO₂ retention was achieved with 1.5 Ca/S and 95 percent retention was achieved with 4.0 Ca/S. At combustor operating temperatures around

1,700 °F, Ca/S greater than 5.0 was required to maintain 70 percent sulfur capture.

The NO_x emissions for all tests completed were less than 0.34 pound per million Btu, which was well within the state-regulated emission limit of 0.5 pound per million Btu. The average level of NO_x emissions for all tests was 0.18 pound per million Btu. For fluidized-bed boilers operating well below the thermal NO_x formation temperature of about 2,500 °F, it is believed that NO_x emissions result from fuel-bound nitrogen being converted to NO_x, followed by the destruction of the NO_x in the combustor.

- **Combustion Efficiency.** The values obtained for combustion efficiency ranged from 96.9 to 98.9 percent. Combustion efficiency is a measure of the quantity of carbon that is fully oxidized to CO₂. Carbon in the fly ash was the largest source of heat loss from incomplete combustion of carbon at Nucla. The flue gas stream accounted for an average of about 93 percent of the incompletely burned carbon leaving the boiler. Another 5 percent was contained in the bottom ash stream. The contribution from CO in the flue gas averaged 2 percent. Hydrocarbons in the flue gas were measured and found to be negligible.

- **Boiler Efficiency.** Efficiencies for 68 performance tests varied from 85.6 to 88.6 percent. 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 per kilowatt-hour at 50 percent of full load to 11,600 Btu per kilowatt-hour at full load. The lowest heat rate achieved during a full-load steady-state test was 10,980 Btu per kilowatt-hour. These values were affected by the absence of reheat, the presence



▲ The 110-MWe Nucla ACFB demonstration enabled Pyropower Corporation to save almost 3 years in establishing a commercial line of ACFB units. Presently 22 ACFB units larger than 100 MWe are planned, under design, or built and operated; 11 of these are in the United States.

of the three older 12.5-MWe turbines in the overall steam cycle, the number of unit restarts, and part-load testing. By October 1991, the Nucla ACFB unit had been restarted almost 175 times following various intervals of unit outage.

- **Operating Temperature.** Over the range of operating temperature at which testing was performed at Nucla, bed temperature was found to be the most influential operating parameter. With the possible exception of coal-fired configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions or efficiencies. Emissions of SO₂ and NO_x were found to increase with increasing combustor temperatures while CO emission decreased with increasing temperature. Combustion efficiency also improved as the temperature was increased.

An economic evaluation indicated that the final capital costs for the Nucla ACFB system were about \$112.3 million. This represents a cost of \$1,123 per net kilowatt. Total power production costs associated with test operations were about \$54.7 million, which results in a normalized power production cost of \$63.63 per megawatt-hour. Fixed costs were about 62 percent of the total, and variable costs were more than 38 percent. Nucla's power production costs proved competitive with pulverized coal units not limiting emissions as significantly.

As a result of the demonstration, Pyropower Corporation was able to save almost 3 years in estab-

lishing a commercial line of ACFB units. Although the demonstration unit was the largest unit of its time at 110 MWe, Pyropower's commercial units are now sold under warranty in sizes ranging up to 400 MWe.

Available Reports

- *Clean Coal Reference Plants: Atmospheric CFB.* Report No. DOE/MC/25177-3307. Gilbert/Commonwealth, Inc. June 1992. (Available from NTIS as DE93000251.)
- *Economic Evaluation Report: Topical Report.* Report No. DOE/MC/25137-3127. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE93000212.)

- *Demonstration Program Performance Test: Summary Reports.* Report No. DOE/MC/25137-3014. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE92001299.)

- *Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: 1990 Annual Report.* Report No. DOE/MC/25137-3089. Colorado-Ute Electric Association, Inc. February 1992. (Available from NTIS as DE92001275.)

- *Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: Final Technical Report for the Period February 1987 through January 1991.* Report No. DOE/MC/25137-3046. Colorado-Ute Electric Association, Inc. October 1991. (Available from NTIS as DE92001122.)

- *Nucla CFB Demonstration Project: Detailed Public Design Report.* Report No. DOE/MC/25137-2999. Colorado-Ute Electric Association, Inc. December 1990. (Available from NTIS as DE91002081.)

Contact

Marshall L. Pendergrass, Assistant General Manager
Tri-State Generation and Transmission Association, Inc.
P.O. Box 1149
Montrose, CO 81402
(303) 249-4501



Environmental Control Devices

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control (The Babcock & Wilcox Company)

Technology

Injection of pulverized coal (20–30% of total boiler heat input) to stage combustion in a cyclone boiler

Size

100 MWe

Demonstration Duration (11/91–12/92)

2,000 hrs

Coal

- Illinois Basin bituminous (Lamar), 1.8% sulfur avg
- Powder River Basin subbituminous, 0.6% sulfur avg

Environmental Results

Coal	Reduction in NO _x		
	Boiler Load 110 MWe	82 MWe	60 MWe
Lamar	52%	47%	36%
Powder River	62%	55%	53%

Technical Results

- Combustion efficiency losses at full load, due to unburned carbon, were 1.5% with bituminous, 0.3% with subbituminous.
- ESP performance was constant even though ash loading doubled (increased ash consisted of larger sized particulates).
- Derating, normally associated with switching to subbituminous coal, was minimized or eliminated.
- Slagging and fouling were significantly reduced with bituminous coal-reburning.
- No furnace corrosion was observed over the 1-yr test.

Economic Results

Capital cost—\$65/kW at 100 MWe to \$40/kW at 600 MWe

The objective of the coal-reburning demonstration was to evaluate the applicability of the technology to full-scale cyclone-fired boilers for the reduction of NO_x emissions. The goals of the project were as follows:

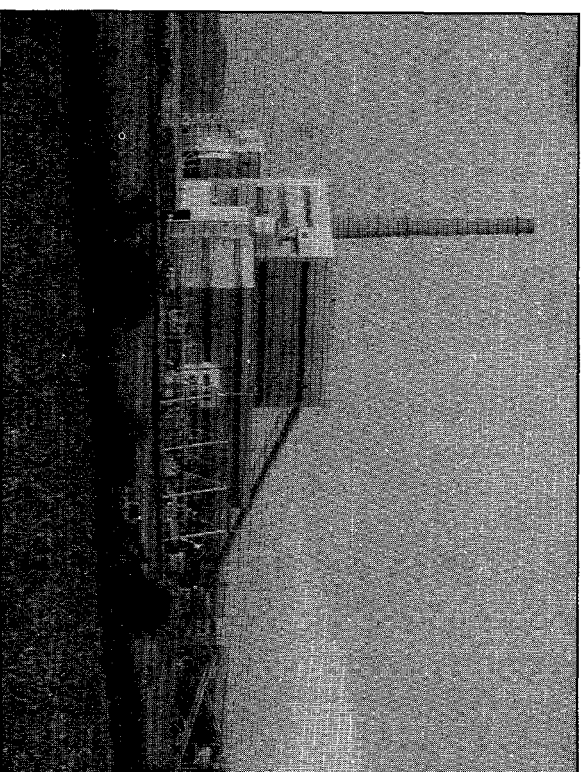
- Achieve a minimum 50 percent reduction in NO_x emissions at full load
- Reduce NO_x emissions without serious impact to cyclone operations, boiler performance, or other emissions streams

- Demonstrate a technically and economically feasible retrofit technology

Cyclone-equipped utility boilers contribute approximately 21 percent of the NO_x emitted by utilities because of the inherent high-temperature, turbulent combustion process which is conducive to NO_x formation. Typically, NO_x levels associated with cyclone-fired boilers range from 1.0 to 1.8 pounds per million Btu input (NO_x as NO₂).

The coal-reburning process for cyclone boilers, demonstrated by The Babcock & Wilcox Company, controls NO_x formation in the main furnace through the use of multiple combustion zones. The main combustion zone uses 70–80 percent of

the total heat equivalent of the fuel input to the boiler and slightly less than normal combustion air input. The balance of the coal (20–30 percent), along with significantly less than the theoretically determined requirement of air, is fed to the boiler above the cyclones in the reburning combustion zone to create an oxygen-deficient (reducing) condition in the flue gas. The NO_x formed in the cyclone burners reacts with the reducing flue gas and is converted into nitrogen and water in this zone. The balance of the combustion air is introduced in the third, or burnout,



▲ Babcock & Wilcox's demonstration of coal reburning at the 100 MWe cyclone boiler of Nelson Dewey Station achieved NO_x reduction in excess of 50% at full load with bituminous coal and over 60% at full load with subbituminous coal with little or no derating.

combustion zone to complete the combustion process. Reburning is the only technology that has been shown to be technically feasible for NO_x control for cyclone boilers.

The demonstration was conducted on an existing 100-MWe cyclone boiler in operation at Wisconsin Power and Light Company's Nelson Dewey Station located at Cassville, Wisconsin.

Operations were initiated in November 1991. Monitoring of air toxics emissions was included as part of the test program and was conducted in November 1992. Reburn testing of western coal and all testing scheduled for Nelson Dewey Station were completed in December 1992.

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

Three sequences of testing of the coal-reburning system were used for Lamar coal. Parametric optimization testing was used to set up the automatic controls. Performance testing was run with the unit in full automatic control at set load points. Long-term testing was performed with reburn in operation while the unit followed system load demand requirements. Powder River Basin coal was tested by parametric optimization and performance modes. Exhibit 5-3 shows changes in NO_x emissions and boiler efficiency using the reburn system for various load conditions and coal types.

Reburning tests on both the Lamar and Powder River Basin coals indicate that varying reburn zone stoichiometry is the most critical factor in changing NO_x emissions levels. The reburn zone stoichiometry can be varied by alternating the air flow quantities (oxygen availability) to the reburn burners, the percent reburn heat input, the gas recirculation flow rate, or the cyclone stoichiometry.

For Lamar coal, the full-, medium-, and low-load unburned carbon boiler efficiency losses (UBCL) were 0.1, 0.25, and 1.5 percent higher, respectively, than the baseline. Full-, medium-, and low-load UBCL with Powder River Basin coal were 0.0, 0.2, and 0.3 percent higher, respectively, than the baseline. Reburn burner flame stability improved with Powder River Basin coal.

During reburn system operation with Lamar coal, the operators continually monitored boiler internals for increased ash deposition and the on-line

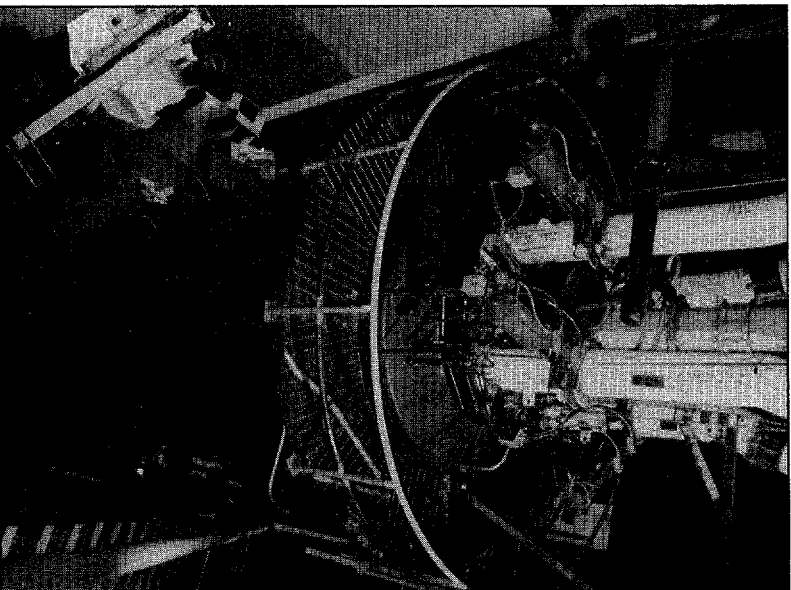
performance monitoring system for heat transfer changes. At no time throughout the system optimization or long-term operation period were any slagging or fouling problems observed. In fact, during scheduled outages, internal boiler inspections revealed that boiler cleanliness had actually improved. Extensive furnace wall tube ultrasonic thickness measurements were taken. No observable decrease in tube wall thickness was measured.

Another significant finding was that coal reburning minimizes and possibly eliminates a 0-25 percent derating normally associated with switching to subbituminous coal in a cyclone unit. This derating is a result of using a lower Btu fuel in a cyclone with a limited coal feed capacity. The reburn system transfers about 30 percent of the coal feed out of the cyclone to the reburn burners, bringing the cyclone feed rate down to a manageable level, while maintaining full-load heat input to the unit.

Exhibit 5-3 Coal Reburning System Test Results

	Boiler Load 110 MWe	82 MWe	60 MWe
Lamar Coal			
NO _x (lb/million Btu/% reduction)	0.394/52	0.387/47	0.442/36
Boiler efficiency losses due to unburned carbon (%)	0.1	0.25	1.5
Powder River Basin Coal			
NO _x (lb/million Btu/% reduction)	0.278/62	0.287/55	0.294/53
Boiler efficiency losses due to unburned carbon (%)	0.0	0.2	0.3

HAP testing was performed using Lamar test coal. HAP emissions were generally well within expected levels, and emissions with reburn 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 (Title III, CAAA of 1990) was present in detectable concentrations, at a detection limit of 1.2 parts per billion.



▲ Shown here is the coal pulverizer installed as part of the Babcock & Wilcox coal-reburning system. This system has been retained by Wisconsin Power and Light for NO_x emission control at the Nelson Dewey Station.

In conclusion, for cyclones, coal reburning offers a NO_x reduction alternative at a cost expected to range from \$65 per kilowatt for a 100-MW unit to \$40 per kilowatt for a larger, 600-MW unit. This includes the costs for coal handling and pulverizers/coal piping. Site-specific factors related to pulverizer location and coal supply can greatly influence overall reburn system costs. However, coal reburning brings with it benefits allowing increased flexibility in coal selection which can yield significant fuel cost savings.

Coal reburning is a retrofit technology applicable to a wide range of utility and industrial cyclone boilers. The current U.S. reburn market is estimated to be approximately 26,000 MWe and to consist of about 120 units ranging from 100 to 1,750 MWe with most in the 100-300 MWe range.

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

Available Reports

- *Demonstration of Coal Reburning for Cyclone Boiler NO_x Control: Final Project Report.* Report No. DOE/PC/89659-T16. The Babcock & Wilcox Company. February 1994. (Available from NTIS as DE94013052, Appendix 1 as DE94013053, Appendix 2 as DE94013054.)
- *Public Design Report: Coal Reburning for Cyclone Boiler NO_x Control.* The Babcock & Wilcox Company. August 1991.

Contact

Tony Yagiela
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
(216) 829-7403

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit (The Babcock & Wilcox Company)

Technology

The Babcock & Wilcox Company low-NO_x cell burner (LNCB™)

Size

605 MWe

Demonstration Duration (12/91–4/93)

Continuous service

Coal

KY, OH, and WV bituminous, 1.1% sulfur avg

Environmental Results

- 54–58% NO_x reduction at 605 MWe (full load)
- 54% NO_x reduction at 460 MWe
- 48% NO_x reduction at 350 MWe

Technical Results

- Unit efficiency essentially unchanged from baseline
- Flyash unburned carbon averaged 1.12% for a 0.2% loss in unburned carbon efficiency
- Boiler corrosion with LNCB™ roughly equivalent to boiler corrosion prior to retrofit

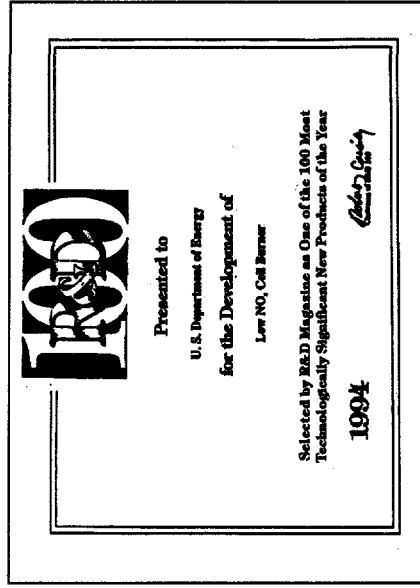
Economic Results

Capital cost—\$5.50–8.00/kW at 500 MWe

The Babcock & Wilcox Company has completed demonstration of its low-NO_x cell burner (LNCB®) technology. The objective was to demonstrate the capability of the LNCB® burner to achieve at least 50 percent NO_x reduction without degradation of boiler performance and at less cost than conventional low-NO_x burners. Cell burners are designed for rapid mixing of fuel and oxidant. The tight burner spacing

and rapid mixing minimizes the flame size while maximizing the heat release rate and unit efficiency. Consequently, the combustion efficiency is good, but the high heat release rate produces relatively large quantities of NO_x. Typically NO_x levels associated with cell burners range from 1.0 to 1.8 pounds per million Btu input (NO_x as NO₂).

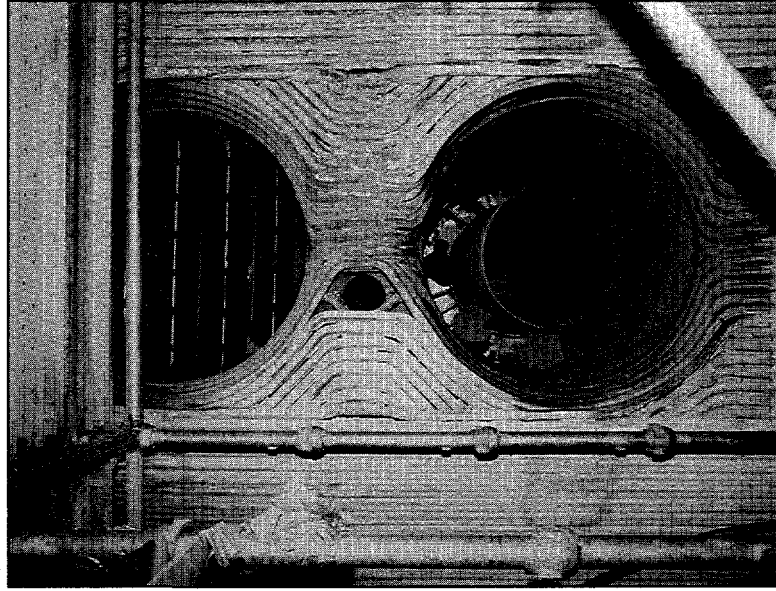
To reduce NO_x emissions, the upper burner of the standard two-burner cell was replaced with a secondary air port, and the lower burner was replaced with a larger burner having the same fuel input capacity as the standard cell. The LNCB® operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70 percent of the total air (primary, secondary, and excess air) is supplied through or around the modified coal feed nozzle.



▲ The LNCB® project received *R&D Magazine's* 1994 R&D 100 Award for technical excellence in a new commercial product.

The remainder of the air is directed to the upper port of each cell to delay and complete the combustion process.

The process was demonstrated at Dayton Power & Light Company's J.M. Stuart Plant located in Aberdeen, Ohio, and jointly owned with Cincinnati Gas & Electric and Columbus Southern Power. All



▲ The Babcock & Wilcox LNCB® burners demonstrated at the 605-MWe J.M. Stuart Plant Unit No. 4 showed 54–58% NO_x reduction with little change in unit efficiency.

24 of the 605-MW unit's two-nozzle cell burners, which were arranged in an opposed-firing configuration with two rows of six cells on each side, were replaced with LNCB® burners.

The LNCB® demonstration emphasized evaluation of boiler performance, boiler life, and environmental impact. Key boiler performance parameters that were measured included boiler output; flue gas temperature at the furnace, economizer, and air heater exits; slagging tendencies of the unit; and unburned carbon loss. Evaluation of H₂S levels, ultrasonic testing of lower furnace tube wall thicknesses, and destruction examination of a corrosion test panel were mechanisms used to predict impact on remaining boiler life. NO_x, CO, CO₂, total hydrocarbons, particulate matter, dust loadings, and precipitator collection efficiency were measured at varying test conditions.

Preretrofit baseline testing was completed in November 1990. During 1991 the 24 new LNCB® burners were fabricated and installed and construction was completed during a scheduled outage that began in September 1991. Operation began in late 1991. During the early testing, high levels of CO were noted in the lower furnace, below the burners, when the unit was operated to achieve high NO_x removals. In May 1992, every other lower burner and NO_x port on the bottom rows were inverted and shallow-angled replacement impellers were installed in all of the coal nozzles to eliminate the

problem. Optimization testing was completed in June 1992, with representative NO_x emissions reductions of 53–55 percent attained. Long-term testing was completed in 1993. Results are summarized in Exhibit 5-4.

A corrosion test panel was installed when the LNCB® burners were installed. The panel consisted of bare tube material with some of the material aluminumized, some stainless weld overlaid, and some chromized. Tube thickness wastage ranged from 2 to 15 mils per year on the bare tubes. Over a 15-month exposure period, this level of corrosion is roughly equivalent to the boiler's corrosion prior to the retrofit. The coated material had no losses. The project is now completing the final reporting requirements of the cooperative agreement.

The low cost and short outage time for an LNCB® retrofit make the option financially attractive. In a typical retrofit installation, the capital cost would include LNCB® hardware, coal-pipe modifications, hangers, support steel, sliding air-damper

Exhibit 5-4 LNCB® Test Results

	Boiler Load		
	604 MWe	460 MWe	350 MWe
NO _x (lb/million Btu/% reduction)	0.53/54.4	0.42/54	0.37/48
CO (ppm)	28–55	28–45	5–27
Unburned carbon in ash (%)	1.12	0.98	3.17
Efficiency loss due to unburned carbon (%)	0.2	0.17	0.59
Test duration (days)	79.02	—	—

drives, and associated electrical equipment. The capital cost would be about \$5.50–8.00 per kilowatt in 1993 dollars for a reference 500-MW plant. The outage time can be as short as 5 weeks because the LNCB® is a plug-in design.

The domestic market potential for the LNCB® consists of about 26,000 MWe of utility boilers equipped with cell burners. This represents about 13 percent of the pre-NSPS coal-fired generating capacity in the United States.

The LNCB® project received *R&D Magazine's* 1994 R&D 100 award for technical excellence in a new commercial product.

Dayton Power & Light is retaining the LNCB® burners for use in commercial operation. By the end of 1995, there have been seven commercial sales of LNCB® burners.

Available Reports

- *Final Report: Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit.* Report No. DOE/PC/90545-2. The Babcock & Wilcox Company. December 1995.
- *Public Design Report: Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit.* Report No. DOE/PC/9545-T4. The Babcock & Wilcox Company. August 1991.

Contact

Tony Yagiela
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
(216) 829-7403

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)

Technology

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

Size

172 MWe

Demonstration Duration (10/92-1/95)

Over 4,000 hrs of operation

Coal

Western bituminous, 0.35-0.66% sulfur

Environmental Results

- LNB alone (first generation with flue gas recirculation)—37% NO_x reduction
- GR-LNB at 18% gas heat input (first generation with flue gas recirculation)—65% NO_x reduction
- LNB alone (second generation without flue gas recirculation)—64% NO_x reduction
- GR-LNB at 13% gas heat input (second generation without flue gas recirculation)—64% NO_x reduction

Technical Results

- Boiler efficiency decreased approximately 1% during gas reburn
- No measurable boiler tube wear or slagging

Economic Results

- Capital cost—approx \$15/kW plus gas pipeline cost
- Operating cost—related to gas/coal cost differential

A gas-reburning system combined with low-NO_x burners (GR-LNB) was installed and evaluated on a 172-MWe (gross) wall-fired boiler. The host boiler was Cherokee Station Unit 3, owned and operated by the Public Service Company of Colorado. The boiler

is a balanced-draft pulverized-coal unit supplied by Babcock & Wilcox. The gas reburn (GR) system including an overfire air system was designed and installed by Energy and Environmental Research Corporation. The low-NO_x burners (LNB) were designed and installed by Foster Wheeler.

The GR-LNB project was selected in the third solicitation and the cooperative agreement was awarded in October 1990. Parametric testing was begun in October 1992 and completed in April 1993. Long-term testing was started in April 1993 and

completed in January 1995. The parametric tests were conducted by changing the process variables (such as zone stoichiometrics, percent gas input, percent overfire air, load) and the effects of these variables on NO_x reduction, SO₂ reduction, CO emissions, carbon in ash, and heat rates were analyzed. The baseline condition of the low-NO_x burners was also established. At a constant load (150 MWe) and a constant oxygen level at the boiler exit, both NO_x and SO₂ emissions decrease when natural gas is introduced in the GR operation.

In general, the NO_x emissions were reduced with increasing gas input. At gas heat inputs greater than 10 percent, NO_x emissions were reduced marginally as gas heat input increased.

Natural gas also reduces SO₂ emissions in proportion to the gas input. At Cherokee Station, low-sulfur (0.4 percent) coal is used, and typical SO₂ emissions are 0.65 pound per million Btu. With a gas heat input of 20 percent, SO₂ emissions are decreased by 20 percent to 0.52 pound per million Btu.

The CO₂ emissions were also reduced as a result of using natural gas because natural gas has a lower carbon-to-hydrogen ratio than coal. At a gas heat input of 20 percent, the CO₂ emissions were reduced by 8 percent.

- ◀ Energy and Environmental Research Corporation completed a 4,000-hour evaluation of a gas-reburning system combined with low-NO_x burners at Public Service Company of Colorado's 172-MWe Cherokee Station Unit 3. A worker inspects the support ring for the Foster Wheeler low-NO_x burner installed in the boiler wall.

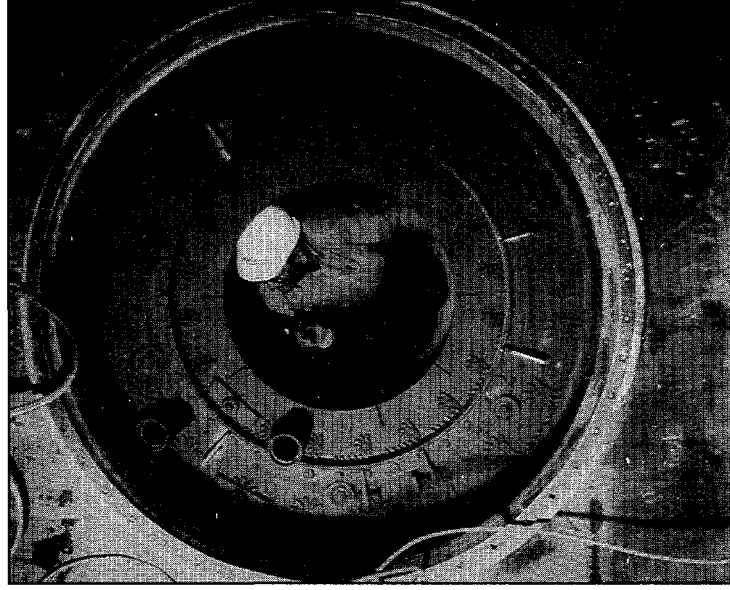


Exhibit 5-5 NO_x Data from Cherokee Station, Unit 3

	Generation	
	First	Second
Baseline (lb/million Btu)	0.73	0.73
Avg NO _x reduction (%)	37	37
LNB	65	64
GR-LNB	18	13
Avg gas input (%)		

Long-term testing was initiated in April 1993 and completed in January 1995. The objectives of the test were to obtain operating data over an extended period when the unit was under routine commercial service, determine the effect of GR-LNB operation on the unit, and obtain incremental maintenance and operating costs with GR.

During long-term testing, it was determined that flue gas recirculation had minimal effect on NO_x emissions. A second series of tests were added to the project to evaluate a modified or second-generation system. This system was as follows:

- The flue gas recirculation system, originally designed to provide momentum to the natural gas, was removed. (This change significantly reduces capital costs.)
- Natural gas injection was optimized at 10 percent gas heat input compared to the initial design value of 18 percent. The removal of the flue gas recirculation system required installation of high velocity injectors which

made greater use of available natural gas pressure. (This modification reduces natural gas usage and thus operating costs.)

- Overfire air ports were modified to provide higher jet momentum, especially at low total flows.
- Over 4,000 hours of operations were achieved with the results as shown in Exhibit 5-5.

The overall objectives of the LNB was less than the expected NO_x reduction of 45 percent, boiler efficiency only decreased by approximately 1 percent during gas reburning due to moisture in the fuel and an increase in heat. Further, it was concluded that there was no measurable tube wear and only small amounts of slagging occurred during the GR-LNB demonstration.

The GR-LNB is a retrofit technology in which the costs are dependent on the following site-specific factors:

- Gas availability at the site
- Coal-gas cost differential
- SO₂ removal requirements
- Value of SO₂ emission credits.

Based on the demonstration, the GR-LNB is expected to achieve at least 60 percent NO_x control with gas heat input of 10-15 percent. The capital cost estimate for a 100-MWe or larger installation is about \$15 per kilowatt plus gas pipeline costs, if required. Operating costs are almost entirely related to the differential cost of gas over coal as reduced by the value of the SO₂ emission credits received due to absence of sulfur in the gas.

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.

Available Reports

- *Evaluation of Gas Reburning and Low NO_x Burners on a Wall-Fired Boiler (Long-Term Testing, April 1993-January 1995).* Report No. DOE/PC90547-T20. Energy and Environmental Research Corporation. June 1995. (Available from NTIS as DE95017755.)
- *Evaluation of Gas Reburning and Low NO_x Burners on a Wall-Fired Boiler (Optimization Testing, November 1992-April 1993).* Report No. DOE/PC90547-T19. Energy and Environmental Research Corporation. June 1995. (Available from NTIS as DE95017754.)
- *Reduction of NO_x and SO₂ Using Gas Reburning, Sorbent Injection and Integrated Technologies.* Topical Report No. 3, Revision 1. Report No. DOE/FE-94007444. U.S. Department of Energy and Energy at Environmental Research Corporation. September 1993. (Available from NTIS as DE94007444.)

The final reports will be available in 1996.

Contact

Blair A. Folsom, Senior Vice President
Energy and Environmental Research Corporation
18 Mason
Irvine CA 92718
(714) 859-8851

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)

Technology

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

Size

180 MWe

Demonstration Duration (5/91-12/92)

Continuous operation

Coal

KY, IL, and WV eastern bituminous, 2.5-3.0% sulfur avg

Environmental Results

- LNCFS Level I incorporating a close-coupled overfire air (CCOFA) system—37% maximum NO_x reduction at full load
- LNCFS Level II incorporating a separated overfire air (SOFA) system—37% maximum NO_x reduction at full load
- LNCFS Level III incorporating both SOFA and CCOFA—45% maximum NO_x reduction at full load

Technical Results

- Increases in coal fineness increased unburned carbon levels; however, there was no effect on NO_x emissions.
- CO emissions with LNCFS Level III were double those with LNCFS Level I, II, or the baseline case.
- Minimal impact on unburned carbon occurred.
- LNCFS Levels II and III required higher excess air levels than baseline or LNCFS Level I.

Economic Results

- Capital costs
 - LNCFS I, \$5-15/kW
 - LNCFS II/III, \$15-25/kW

• Cost effectiveness

- LNCFS I, \$103/ton NO_x removed
- LNCFS II, \$444/ton NO_x removed
- LNCFS III, \$400/ton NO_x removed

Southern Company Services, Inc., has demon-

strated several low-NO_x technologies on the

180-MWe tangentially fired Unit No. 2 coal boiler at Gulf Power Company's Plant Lansing Smith located at Lynn Haven, Florida. Technologies demonstrated included the Low-NO_x Concentric Firing System (LNCFS™), Levels I, II, and III. Each level of the LNCFS™ used various combinations of overfire air and clustered coal nozzle positioning, as shown in

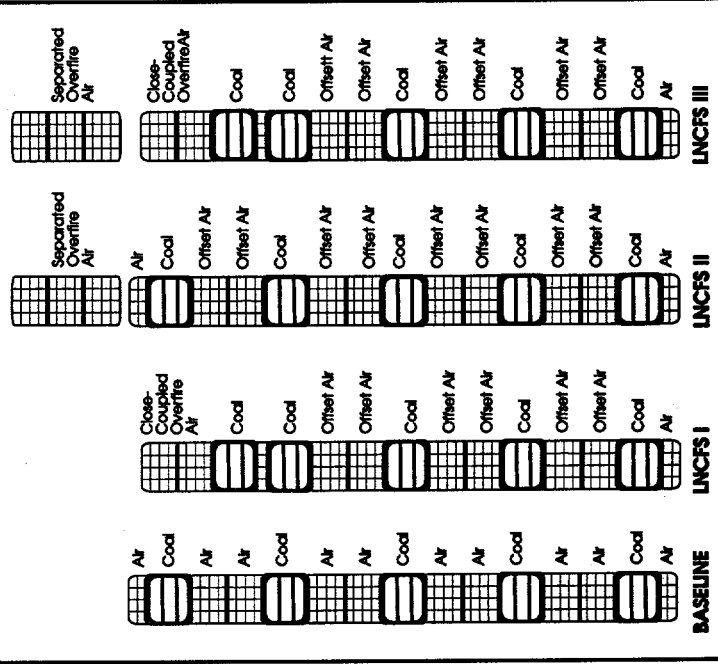
Exhibit 5-6, to achieve NO_x reductions. With the LNCFS™, primary air and coal are surrounded by oxygen-rich secondary air that blankets the outer regions of the combustion zone. LNCFS Level I used a close-coupled overfire air (CCOFA) system integrated directly into the windbox of the boiler. A separated overfire air (SOFA) system located above the combustion zone was featured in the LNCFS Level 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 Level III tangential-firing approach. In addition to conducting carefully controlled short-term tests, long-term testing under normal load dispatch

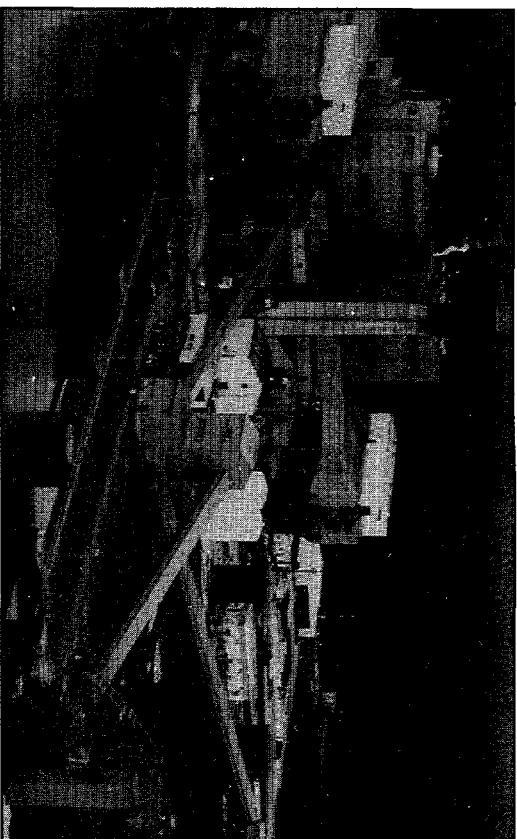
conditions were conducted. Long-term tests, which typically lasted 2-3 months for each phase, best represent the true emissions characteristics of each technology. Results presented are based on long-term test data.

The results from the demonstration showed that, at full load, the NO_x emissions using LNCFS I, II,

Exhibit 5-6

Tangential Burner Configurations





▲ Southern Company Services, Inc., completed a 19-month demonstration of three levels of LNCFS™ at Plant Lansing Smith Unit No. 2. NO_x reductions ranged from 37% for Levels I and II to 45% for Level III, all at full load.

and III were 0.39, 0.39 and 0.34 pound per million Btu respectively; these levels represented emission reductions of 37 percent, 37 percent, and 45 percent from the baseline. These emissions are within the annual average emission limit of 0.45 pound per million Btu set for tangentially fired boilers. Simulated load profiles showed that only LNCFS III could marginally meet the emission regulation at peaking loads because of the significant increase in NO_x emission for LNCFS™ technology below 100 MWE. Unit performance observations included increased CO emissions, reduced furnace slagging but increased back-pass fouling, and minimum impact on efficiency and heat rate. Further, unit operations were not significantly affected; however, operating flexibility of the unit was reduced at low loads with LNCFS II and III.

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

Potential commercial

applications of this technology include a wide range of tangentially fired utility and industrial boilers throughout the United States and abroad. There are nearly 600 U.S. pulverized coal tangentially fired utility units.

These units range from 25 to 950 MWE. A wide range of low-volatile bituminous through lignite coals are being fired in these units. LNCFS™ can be used in retrofitting existing units as well as in new boilers.

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

Available Reports

- *180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Final Report and*

Key Project Findings. Report No. DOE/PC/89653-T14. Southern Company Services, Inc. February 1994. (Available from NTIS as DE94011174.)

- *180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Chemical Emissions Report.* Report No. DOE/PC/89653-T12. Southern Company Services, Inc. October 1993. (Available from NTIS as DE94005038.)

- *180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Public Design Report.* Report No. DOE/PC/89653-T13. Southern Company Services, Inc. September 1993. (Available from NTIS as DE94000218.)

Contact

Robert R. Hardman, Project Manager
Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625
(205) 877-7772

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)

Technology

Selective catalytic reduction (SCR); eight catalysts from six suppliers (two U.S., two European, two Japanese)

Size

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

Demonstration Duration (7/93-7/95)

Available in 1996

Coal

Illinois No. 5, 3% sulfur

Environmental Results

Available in 1996

Technical Results

Available in 1996

Economic Results

Available in 1996

Southern Company Services, Inc., has completed a demonstration designed to evaluate the performance of eight commercially offered catalysts of various shapes and compositions under U.S. utility operating conditions with high sulfur coal at Gulf Power Company's Plant Crist.

With the advent of the CAAA of 1990, there has been increased emphasis on high-capture-efficiency NO_x control. This is driven primarily by the ozone nonattainment provision in Title I that essentially caps NO_x emissions in nonattainment areas, which represent a significant portion of the United States. Selective catalytic reduction (SCR) is a high-capture-

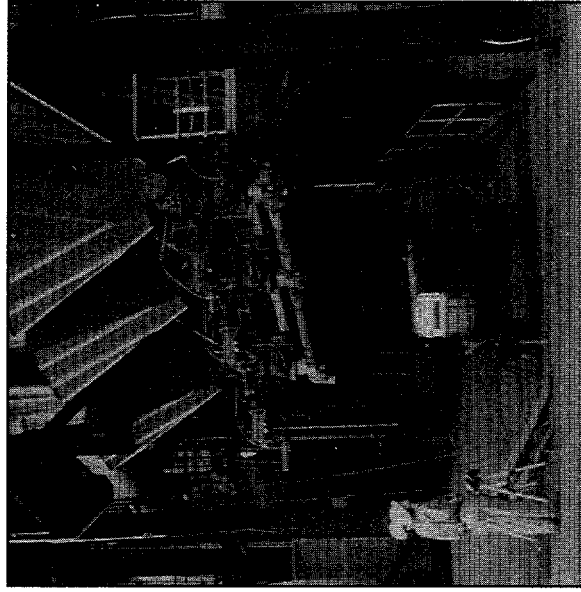
efficiency NO_x control technology option proven in Western Europe and Japan, but not in the United States with its different coals and operating conditions. This demonstration was undertaken with strong utility sponsorship to establish whether or not SCR is a U.S. NO_x control option and under what circumstances.

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

Six catalyst suppliers provided eight different catalysts. The two suppliers from Europe and the two from Japan provided one catalyst each with two U.S. firms providing the balance. The catalysts, listed in Exhibit 5-7, represent the wide variety of commercially available SCR catalysts that were tested.

Project objectives included assessing the technical and economic viability of the catalysts when applied in U.S. utility applications with high-sulfur coal while maintaining at least 80 percent NO_x reduction and acceptable ammonia slip (5 parts per million). Specific uncertainties addressed were as follows:

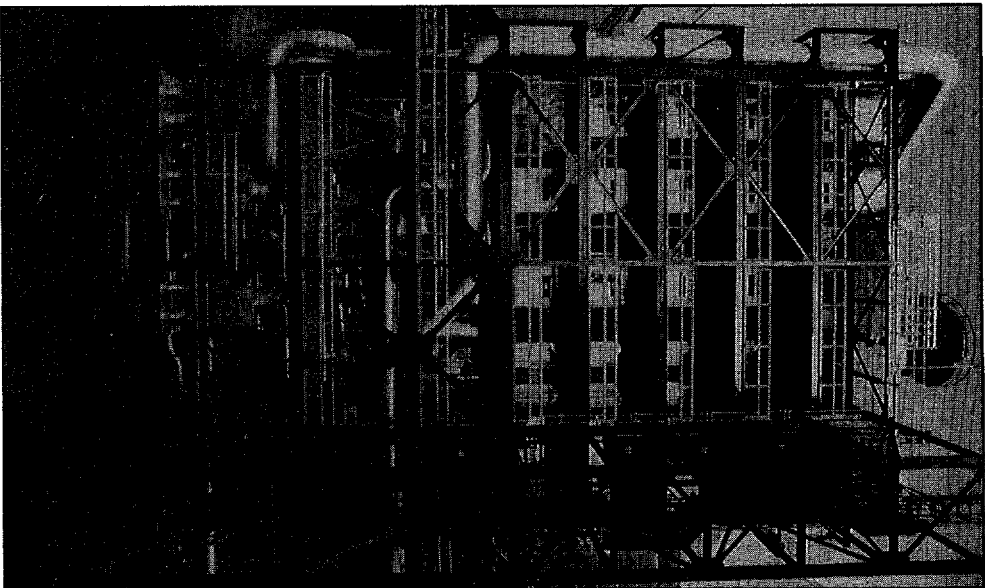
- Potential catalyst deactivation due to poisoning by trace metals species in U.S. coals
- Performance of technology and effects on the balance-of-plant equipment in the presence of high amounts of SO₂ and SO₃



▲ This view shows the three particulate collection cyclones on the system. Final results from the demonstration will be available in 1996.

- Performance of the SCR catalysts at typical U.S. high-sulfur coal-fired utility operating conditions

To accomplish the objectives, a slipstream from Plant Crist, Unit No. 5 (75-MWe tangentially fired, dry bottom boiler) burning Illinois No. 5, 3 percent sulfur coal was provided to three 2.5-MWe, 5,000-standard-cubic-foot-per-minute and six 0.2-MWe, 400-standard-cubic-foot-per-minute SCR reactor trains operating in parallel. These reactor trains were calculated to be large enough to produce design



▲ Eight different SCR catalysts (seven high dust and one low dust) were tested by the Southern Company Services, Inc., during the 2 years ending in July 1995. Results indicate all catalysts were able to achieve the NO_x reduction target of 80% removal. This view shows the large insulated reactors on the top four levels.

data that will allow the SCR processes to be scaled to

Available Reports

commercial size. The three larger trains were equipped with pilot-scale air preheaters to evaluate the effect of SCR reaction chemistry on deposit formation that could impact air preheater performance. Eight of the nine reactors operated with flue gas containing high particulate loading (ESP inlet) and one small reactor receiving low particulate loading (ESP outlet). Temperature and flow could be controlled and measured for each reactor train.

Final reports are scheduled to be available in mid-1996.

Contact

Each SCR train was operated over the long-term at design, or baseline, conditions with parametric tests interjected every four months. Parametric tests varied NH₃/NO_x ratio, temperature, and space velocity while measuring NO_x reduction efficiency, pressure drop, SO₂ oxidation, and ammonia slip. Detailed technical, environmental, and economic results will be available in 1996.

J.D. (Doug) Maxwell, Project Manager
Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625
(205) 877-7614

Exhibit 5-7 Catalysts Tested

Catalyst Supplier	Reactor Size*	Catalyst Configuration
Nippon Shokubai	Large	Honeycomb
Siemens AG	Large	Plate
W.R. Grace	Large	Honeycomb
W.R. Grace	Small	Honeycomb
Haldor Topsoe	Small	Plate
Hitachi Zosen	Small	Plate
Cornetech	Small	Honeycomb
Cornetech	Small	Honeycomb (low dust)

* Large = 2.5 MWe; 5,000 std ft³/min Small = 0.2 MWe; 400 std ft³/min

10-MWe Demonstration of Gas Suspension Absorption (AirPol, Inc.)

Technology

- FLS miljø a/s gas suspension absorption (GSA) system for flue gas desulfurization
- Pulse jet baghouse for particulate control

Size

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

Demonstration Duration (10/92-3/94)

- Air toxic tests—400 hrs (9/93-10/93)
- Factorial tests—2,200 hrs (1/93-9/93)
- Demonstration—672 hrs (10/25/93-11/24/93)
- Pulse jet baghouse test—336 hrs (2/94-3/94)

Coal

- Bituminous, 2.7-3.5% sulfur
- Simulated high-chloride (about 0.3%) coal

Sorbent

Hydrated lime slurry

Environmental Results

- 60% SO₂ removal efficiency at 28 °F approach-to-saturation temperature, lime stoichiometry of 1.00 mole Ca(OH)₂/mole of inlet SO₂, coal chloride of 0.02-0.04%
- 90-91% SO₂ removal efficiency at 18 °F approach-to-saturation temperature, avg 1.40-1.45 moles of Ca(OH)₂/mole of inlet SO₂, coal chloride of 0.12%
- 96% SO₂ removal efficiency achieved with GSA/pulse jet baghouse system
- Particulate removal efficiency—99.9% avg; emission rate—0.015 lb/million Btu avg (NSPS is 0.03 lb/million Btu)
- HCl removal rate across the GSA reactor and cyclone approx 100%
- Trace metals, particulates, and HF removal high

Technical Results

- Demonstrated reliability of technology by remaining on-line for entire 28-day demonstration period
- Demonstrated a number of key technical attributes including
 - Simple and direct method of lime/solid recirculation
 - High acid gas absorption
 - Low lime consumption/minimum waste by-product residue
 - Low maintenance operation
 - No internal buildup
 - Reduced space requirement
- Demonstrated pulse jet baghouse system improved SO₂ removal efficiency by about 3-5 percentage points

Economic Results

- Capital cost (1990 dollars)—\$149/kW for GSA as compared to \$216/kW for wet limestone, forced-oxidation (WLFO) scrubbing system (300 MWe, 2.6% sulfur coal, 90% SO₂ removal efficiency)
- Levelized cost (mills/kWh)

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

The objectives of the gas suspension absorption (GSA) system for flue gas desulfurization demonstration project were as follows:

- Effectively demonstrate SO₂ removal in excess of 90 percent using high-sulfur U.S. coals

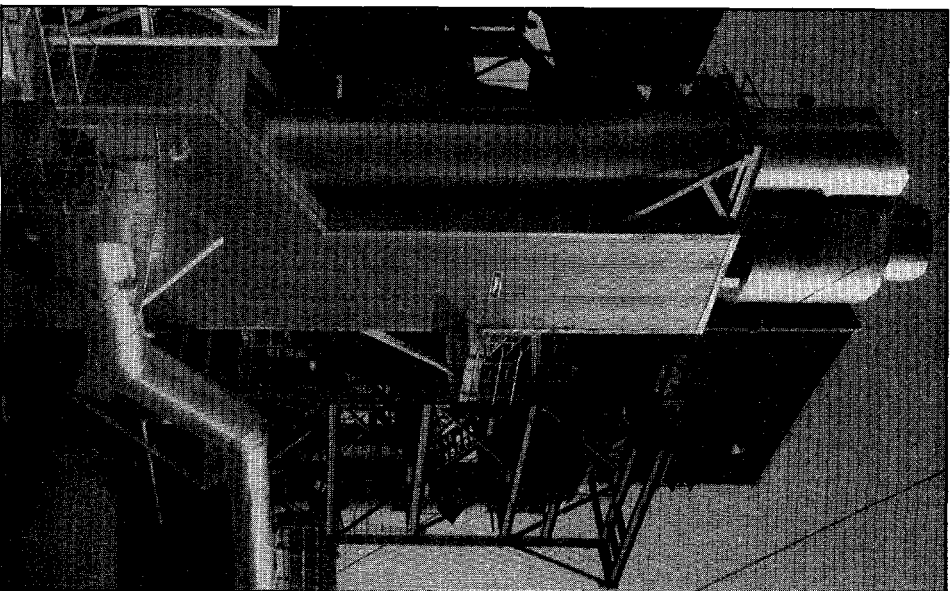
- Optimize design and operating parameters to increase the SO₂ removal efficiency and the lime utilization

- Compare the SO₂ removal efficiency of the GSA technology with existing spray dryer/electrostatic precipitator technology

The GSA process concept was developed by AirPol's parent company, FLS miljø a/s of Copenhagen, Denmark. The process was initially developed as a cyclone preheater system for cement kiln raw material. The system provided both capital and energy savings by reducing the required length of the rotary kiln and by lowering fuel consumption. The GSA system also showed superior heat and mass transfer characteristics. The GSA system for FGD applications was developed later by injecting lime slurry and recycle solids into the bottom of the reactor to function as an acid gas absorber. In 1985, a GSA pilot plant was built in Denmark to establish design parameters for SO₂ and hydrogen chloride absorption for waste incineration applications. The first commercial GSA unit was installed at the KARA waste-to-energy plant at Roskilde, Denmark, in 1988. Currently there are 10 GSA units in Europe, all installed on municipal solid waste incinerators.

The 10-MWe demonstration project was selected under the third solicitation, initiated in October 1990, and completed in December 1994. The project was the first North American demonstration of the GSA system for coal-fired utility FGD. The project was located at the Center for Emissions Research

and used a 10-MWe slipstream of flue gas from a 150-MWe coal-fired boiler at the Tennessee Valley Authority's Shawnee Fossil Plant in West Paducah, Kentucky. A western Kentucky coal with about 3 percent sulfur was used in the demonstration.



▲ AirPol successfully demonstrated the GSA system at TVA's Center for Emissions Research. The world's first full-scale, commercial GSA unit on a coal-fired boiler is being installed on a 50-MWe boiler at the municipal power plant in Hamilton, OH.

Approximately 26 months of operating and testing were conducted during the demonstration. A test plan was prepared to detail the procedures, locations, and analytical methods to be used in all tests. The specific objectives of the tests were as follows:

- Optimization of operating variables
- Determination of Ca/S stoichiometric ratios for various SO₂ removal efficiencies
- Evaluation of erosion and corrosion at various locations in the system
- Demonstration of 90 percent or greater SO₂ removal efficiency when the boiler is fired with high-sulfur coal
- Determination of air toxics removal performance
- Evaluation of pulse jet baghouse performance in conjunction with the GSA process

Several general relationships affecting SO₂ removal efficiency became apparent. A significant positive effect on SO₂ removal efficiency came from increasing the lime stoichiometry and other factors, such as increasing the coal chloride level or decreasing the approach-to-saturation temperature. Increasing the recycle rate resulted in higher SO₂ removal, but the benefit appeared to reach an optimum level above which further increases in the recycle rate did not seem to have a significant effect on SO₂ removal. Increasing the flue gas flow rate had a negative effect on SO₂ removal.

The SO₂ removal efficiency during the tests ranged from about 60 percent to nearly 95 percent, depending on the specific test conditions.

The lower SO₂ removal efficiency levels were achieved at the higher approach-to-saturation temperature (28 °F), lower lime stoichiometry level (Ca/S of 1.00), and lower coal chloride level (0.02–0.04 percent). The higher SO₂ removal efficiency levels were achieved at lower approach-to-saturation temperatures (8 and 18 °F), higher lime stoichiometry level (Ca/S of 1.30), and higher coal chloride level (0.12 percent). Most of the SO₂ removal in the GSA system occurred in the reactor/cyclone, with only about 2–5 percent of the overall removal occurring in the ESP.

An evaluation of ESP performance was also conducted as part of the tests. The results from the particulate testing showed that the emission rate from the ESP was substantially below the New Source Performance Standard for particulates (0.03 pound per million Btu) at all test conditions evaluated. The typical emission rate was 0.010 pound per million Btu. The particulate removal efficiency was above 99.9 percent for nearly all tests and the outlet grain loading was below 0.005 grain per cubic foot.

Although not part of the original GSA demonstration, TVA and EPRI cofunded the installation of a 1-MWe pulse jet baghouse (PJBH) pilot plant to be operated in conjunction with the existing GSA demonstration. Later, AirPol and DOE joined in the operation and testing of the PJBH pilot-plant program. The resulting SO₂ removal efficiency in the GSA reactor/cyclone/PJBH system was typically about 3–5 percent higher than that achieved in the reactor/cyclone/ESP system at the same test conditions. The particulate removal efficiency in the PJBH was 99.9+ percent for all tests completed with full dust loading from the GSA reactor/cyclone.

A total of six air toxic tests were conducted: four with the GSA reactor operating and two with the GSA system not operating. All tests were completed while the boiler was burning high-sulfur (2.7 percent), low-chloride coal and were run at the high flue gas flow rate (20,000 standard cubic feet per minute) and high flyash loading (2.0 grains per cubic foot) test conditions. Preliminary results suggest that the GSA system is capable of removing HCl, particulate, and trace metals. The removal rate of the HCl across the reactor and cyclone appears to be 100 percent. Removal rates for trace metals, particulate, and HF also appear to be high during the six tests.

A continuous 4-week demonstration run of the GSA system in conjunction with only the ESP demonstrated an SO₂ removal efficiency of 90 percent or better using a high-sulfur (2.7 percent), low-chloride coal and a higher sulfur (3.5 percent) coal. The Ca/S ratio averaged 1.40–1.45 moles of Ca(OH)₂ per mole of inlet SO₂ during the demonstration run.

The project demonstrated a number of key technical attributes including a direct and simple method of lime/solid recirculation, high acid gas adsorption, low lime consumption with minimal waste by-product residue, low maintenance operation, no internal buildup, and reduced space requirements.

The relative process economics for the GSA system were evaluated for a moderately difficult retrofit to a 300-MWe boiler burning a coal containing 2.6 percent sulfur. The design SO₂ removal efficiency was 90 percent. The resulting capital cost estimate (in 1990 dollars) is \$149 per kilowatt for GSA as compared to \$216 per kilowatt for the wet limestone, forced-oxidation (WLFO) scrubbing system. The levelized annual revenue requirement

for the GSA process is lower than that for the WLFO system, but the difference is only about 20 percent (which is not considered to be significant given the limitations on the accuracy of estimates used in the analysis). The principal annual operating cost for the GSA process is the cost of the pebble lime. The 15-year levelized costs in mills per kilowatt-hour for the two systems are listed below:

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

The GSA should fulfill the need of the utility industry to meet the new SO₂ emission standards set forth in the CAAA of 1990. There is a particular need for a simple and economic FGD process, such as GSA, by plants in the 50–250-MWe range where wet FGD systems are not feasible.

Successful testing of the AirPol demonstration project has resulted in a commercial application in Ohio. The city of Hamilton, Ohio, has received a \$5-million grant from the Ohio Coal Development Office to install the GSA technology to control emissions from a 50-MWe coal-fired boiler at the city's municipal power plant. The new system is scheduled to be operational in August 1996 and will be the first full-scale commercial GSA unit in the United States as well as the world's first GSA unit for a coal-fired boiler. The GSA technology was identified as the least-cost alternative for the city to meet the 1997 compliance requirements under the CAAA of 1990.

In addition, FLS mijlo has been awarded a major project in Sweden for a high-performance GSA

system to remove sulfur from the flue gas of a 4-million-ton-per-year iron ore sinter plant. Sweden has stringent sulfur emission standards which require a removal efficiency of 90–95 percent.

Available Reports

- *10 MW Demonstration of the Gas Suspension Absorption Final Project Performance and Economics Report*. Report No. DOE/PC/90542-T9. AirPol, Inc. June 1995. (Available from NTIS as DE95016681.)
- *10 MW Demonstration of the Gas Suspension Absorption Final Public Design Report*. Report No. DOE/PC/90542-T10. AirPol, Inc. June 1995.
- *SO₂ Removal Using Gas Suspension Absorption Technology*. Topical Report No. 4. U.S. Department of Energy and AirPol, Inc. April 1995.
- *10-MW 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.)

Contact

Frank E. Hsu, Vice President, Operations
AirPol, Inc.
3 Century Drive
Parsippany, NJ 07054
(201) 490-6400

Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)

Technology

In-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process

Size

73.5 MWe

Demonstration Duration (7/91-6/93)

Approximately 5 months of continuous testing

Coal

Pennsylvania bituminous, 1.5-2.5% sulfur

Sorbent

- Dry hydrated calcitic lime
- Slaked calcitic lime
- Pressure-hydrated dolomitic lime

Environmental Results

50% SO₂ removal efficiency

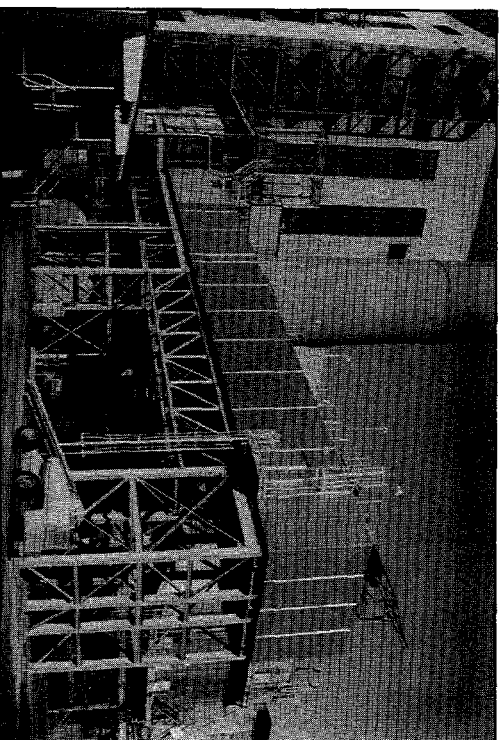
Technical Results

- About 100 ft of straight flue gas duct is required to accommodate the 2 seconds residence time needed to absorb SO₂ and dry the gas before ESP entry.
- Process responded well to automated control operation; some process modifications were required to assure consistent SO₂ capture and avoid solids deposition in ductwork before commercial use can be achieved.
- Very good system availability was demonstrated.

Economic Results

Capital cost—less than \$30/kW at 500 MWe

The objective of Bechtel Corporation's project was to demonstrate SO₂ removal capabilities of in-duct confined zone dispersion flue gas desulfurization (CZD/FGD) technology; specifically to define



▲ Bechtel demonstrated CZD/FGD technology at Pennsylvania Electric's Seward Station Unit No. 5. The demonstration showed that 50% SO₂ removal efficiency was possible. This view pictures the extended duct in which lime slurry was injected.

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.

The CZD/FGD process involves injecting a finely atomized slurry of reactive lime into the flue gas stream. The principle of the confined zone is to form a wet zone of slurry droplets in the middle of the duct confined in an envelope of hot gas between the wet zone and the duct walls. The lime slurry reacts with part of the SO₂ in the gas and the reactive products dry to form solid particles. An electrostatic precipitator, downstream from the point of injection,

captures the reactive products along with the fly ash entrained in the flue gas.

The demonstration was located at Pennsylvania Electric Company's Seward Station in Seward, Pennsylvania. One-half of the flue gas capacity of the 147-MWe Unit No. 5 was routed through a modified, longer duct between the first and second stage electrostatic precipitators. Pennsylvania bituminous coal (approximately 1.2-2.5 percent sulfur) was used in the project.

Bechtel began its 18-month, two-part test program for the CZD process in July 1991, with the first 12 months of the test program consisting primarily of parametric testing and the last 6 months consisting of continuous operational testing. During the continuous operational test period, the system was operated under fully automatic control by the host utility boiler operators. The new atomizing nozzles were thoroughly tested both outside and inside the duct prior to testing. The SO₂ removal parametric test program, which began in October 1991, was completed in August 1992.

Specific objectives were as follows:

- Achieving projected SO₂ removal of 50 percent
- Realizing SO₂ removal costs of less than \$300 per ton

- Eliminating 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 SO₂ from the flue gas but require different feed concentrations of lime slurry for the same percentage of SO₂ removed. The most efficient removals and easiest to operate system were obtained using pressure-hydrated dolomitic lime. These parametric tests indicated that SO₂ removals above 50 percent are possible under the following conditions: flue gas temperature of 300–310 °F; boiler load of 145–147 MWe; residence time in the duct of 2 seconds; and lime slurry injection rate of 52–57 gallons per minute. It was determined that duct injection of slurry does not adversely impact stack opacity provided proper operational procedures are instituted.

The percentage of lime utilization in the CZD/FGD significantly affects the total cost of SO₂ removal. An analysis of the continuous operational data indicates that the percentage of lime utilization is directly dependent on two key factors:

- Percentage of SO₂ removed
- Lime slurry feed concentration

For operating conditions at Seward Station, data indicate that for 40–50 percent SO₂ removal a 6–8 percent lime or dolomitic lime slurry concentration fed at a stoichiometric ratio of 2–2.5 results in a 40–50 percent lime utilization rate. That is, 2–2.5 moles of CaO or CaO•MgO are required for every

mole of SO₂ removed; or assuming 92 percent lime purity, 1.9–2.4 tons of lime are required for every ton of SO₂ removed. In summary, the demonstration showed the following results:

- A 50 percent SO₂ removal efficiency with CZD/FGD is possible.
- Drying and SO₂ absorption require a residence time of 2 seconds. A long and straight horizontal gas duct of about 100 feet is required to assure a residence time of 2 seconds.
- 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 are required to assure consistent SO₂ 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.

- The CZD/FGD process can achieve costs of \$300 per ton of SO₂ removed when operating a 500-MWe unit burning 4 percent sulfur coal. Based on a 500-MWe plant retrofitted with CZD/FGD for 50 percent SO₂ removal, the total capital cost is estimated to be less than \$30 per kilowatt.

After the conclusion of the DOE-funded CZD demonstration project at Seward Station, the CZD/

FGD demonstration was modified to improve SO₂ removal during continuous operation while following daily load cycles. Bechtel and the host utility, Pennsylvania Electric Company, continued the CZD demonstration for an additional year. Results showed that CZD operation at SO₂ removal rates lower than 50 percent could be sustained over long periods without significant process problems.

Available Reports

- *Confined Zone Dispersion Project: Final Technical Report.* Bechtel Corporation. June 1994.
- *Confined Zone Dispersion Project: Public Design Report.* Bechtel Corporation. October 1993.

Contact

Joseph T. Newman, Project Manager
Bechtel Corporation
P.O. Box 193965
San Francisco, CA 94119-3965
(415) 768-1189
(415) 768-3580 (fax)

LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC-North America)

Technology

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

Size

60 MWe

Demonstration Duration (9/92-9/94)

2,800 hrs

Coal

Bituminous, 2.0-2.9% sulfur

Sorbent

- Fine limestone (80% minus 325 mesh)
- Coarse limestone (80% minus 200 mesh)

Environmental Results

- 70% SO₂ removal efficiency at 7-12 °F approach to saturation, 2.0% less with coarse limestone
- Solid waste—mixture of fly ash and calcium compounds; quantity equal to amount of limestone injected (4.3 tons/ton of SO₂ removed, assuming 75% capture with Ca/S of 2.0)
- ESP efficiency 99.2%; stack opacity about 10%

Technical Results

- High operability due to few moving parts
- Ease of start-up and shutdown
- Automated programmable logic system to regulate process control loops, interlocking, start-ups, shutdowns, and data collection
- No negative impact on bottom ash and flyash removal systems

Economic Results

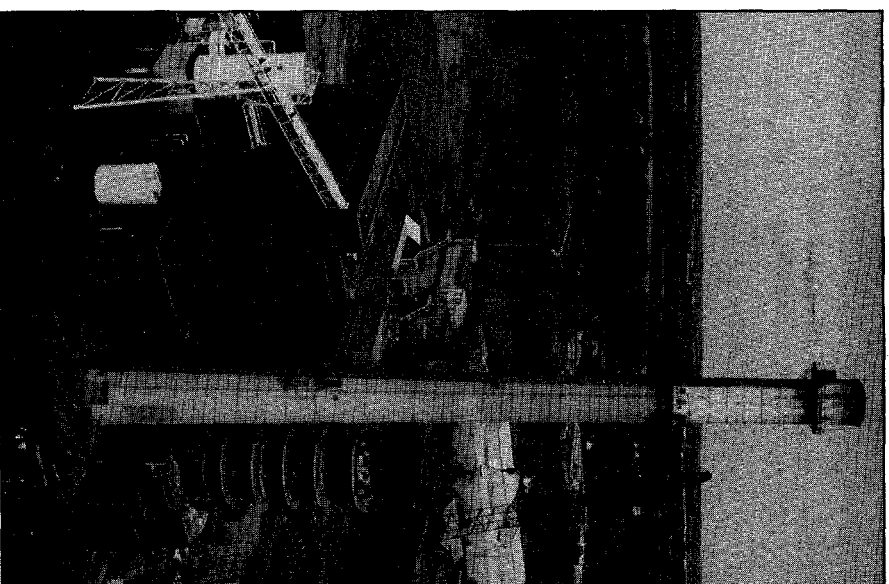
- Capital cost—\$66/kW for two LIFAC reactors (300 MWe); \$76/kW for one LIFAC reactor (150 MWe);

- \$99/kW for one LIFAC reactor (65 MWe) (compare with \$216/kW for 300-MWe wet scrubber)
- Operating cost—\$65/ton of SO₂ removed, assuming 75% SO₂ capture, Ca/S of 2.0, limestone 95% CaCO₃, limestone cost of \$15/ton

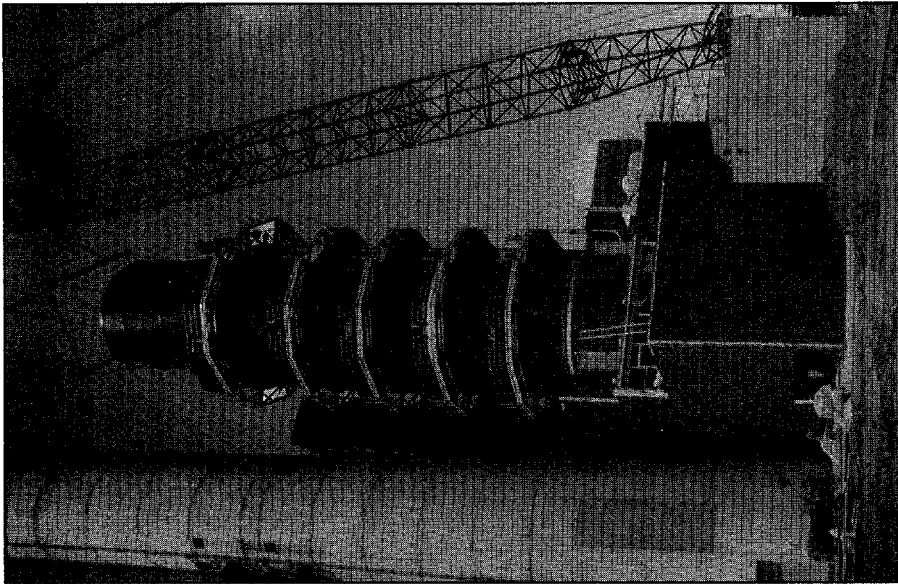
LIFAC-North America, a joint venture partnership between Tampella Power Corporation and ICF Kaiser Engineers, has demonstrated the LIFAC flue gas desulfurization technology developed by Tampella Power. The technology provides SO₂ control for coal-fired power plants, especially where tight space limitations exist. SO₂ emissions are reduced over 75 percent by using limestone as a sorbent.

The LIFAC technology was developed in response to Finland's acid rain legislation which applied limits on SO₂ emissions sufficient to require that FGD systems have the capability to remove approximately 80 percent of the SO₂ from the flue gas. Tampella Power began developing an economical, alternative sorbent injection system. Process development first involved laboratory and pilot-plant tests, followed by full-scale tests of sorbent injection of limestone. Subsequent research and development by Tampella led to the addition of a humidification section after the boiler.

In 1986, the first major full-scale test was performed at Imatron Vainuu's Inkee power plant in Finland using a 70-MWe side-stream from a 250-MWe boiler burning 1.5 percent sulfur coal. A second LIFAC reactor was constructed to treat an additional 125-MWe side-stream. The initial demon-



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



▲ The top of the LIFAC reactor is shown being lifted into place. During 2,800 hours of operation, it was shown that SO₂ reductions of 70% or more could be maintained under normal boiler operation.

stration installations were capable of achieving removal rates of 70–80 percent using Ca/S molar ratios of 2–2.5. In 1988, the first tests with high-sulfur U.S. coals were performed at Tampella's pilot plant. A Pittsburgh No. 8 coal containing 3 percent sulfur was evaluated and an SO₂ removal rate of over 70 percent was achieved at a Ca/S molar ratio of 2.0.

The LIFAC project was selected in the third solicitation and the cooperative agreement was awarded in November 1990. The demonstration was conducted at Whitewater Valley Station Unit No. 2, a 60-MWe coal-fired power plant owned and operated by Richmond Power & Light and located in Richmond, Indiana. Operational testing was begun in September 1992 and completed in August 1994 and consisted of 2,800 hours of operation. The demonstration had the following four objectives:

- Sustained high SO₂ removal efficiency
- Ability to retrofit the LIFAC system under tight construction conditions
- Compatibility of the LIFAC system with existing equipment and operation
- Demonstration of LIFAC's competitiveness on a cost-per-ton of SO₂ removed

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

- **Baseline Tests.** Baseline measurements were taken to characterize the operation of the host boiler and associated subsystems prior to LIFAC operations.

- **Parametric Tests.** Parametric tests were designed to evaluate the many possible combinations of LIFAC process parameters and their effect on SO₂ removal.
- **Optimization Tests.** 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.** Long-term tests were performed to demonstrate LIFAC's performance under commercial operating conditions.
- **Post-LIFAC Tests.** 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 to 2.8 percent. However, most of the testing was conducted with the higher sulfur coals (2.0–2.8 percent sulfur).

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 quality, Ca/S molar ratio, reactor bottom temperature (approach-to-saturation), and ESP ash recycling rate. Total SO₂ capture was about 15 percent better when injecting fine limestone (80 percent minus 325 mesh) than it was with coarse limestone (80 percent minus 200 mesh).

While injecting the fine limestone, the soot blowing frequency had to be increased from 6- to

4.5-hour cycle periods. The coarse-quality limestone did not affect soot blowing but was found to be more abrasive on the feed and transport hoses.

Parametric tests indicated that a 70 percent SO₂ reduction was achievable with a Ca/S molar ratio of 2.0. ESP ash containing unspent sorbent and fly ash was recycled from the ESP hoppers back into the reactor inlet duct work. Ash recycling is essential for efficient SO₂ capture. The large quantity of ash removed from the LIFAC reactor bottom and the small size of the ESP hoppers limited the ESP ash recycling rate. As a result, the amount of material recycled from the ESP was approximately 70 percent less than had been anticipated. However, this low recycling rate was found to affect SO₂ capture. During a brief test, it was found that increasing the recycle rate by 50 percent resulted in a 5 percent increase in SO₂ removal efficiency. It is anticipated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5 °F above saturation temperature, an SO₂ reduction of 85 percent could be maintained.

Optimization testing began in March 1994 and was followed by long-term testing in June 1994. The boiler was operated at an average load of 60 MWe during long-term testing, although it fluctuated according to power demand. The LIFAC process automatically adjusted to boiler load changes. A Ca/S molar ratio of 2.0 was selected to attain SO₂ reductions above 70 percent. Reactor bottom temperature was about 5 °F higher than optimum to avoid ash buildup on the steam reheaters. Atomized water droplet size was smaller than optimum for the same reason. Other key process parameters held constant during the long-term tests included the degree of

humidification, the grind size of the high-calcium content limestone, and recycle of spent sorbent from the ESP.

Long-term testing showed that SO₂ reductions of 70 percent or more can be maintained under normal boiler operating ranges. Stack opacity was low (about 10 percent) and ESP efficiency was high (99.2 percent). The amount of boiler bottom ash increased slightly during testing, but there was no negative impact on the power plant's bottom and flyash removal system. The solid waste generated was a mixture of fly ash and calcium compounds and was readily disposed of at a local landfill.

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

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

- \$99 per kilowatt for one LIFAC reactor at Whitewater Valley Station (65 MWe)
- \$76 per kilowatt for one LIFAC reactor at Shand Station (150 MWe)
- \$66 per kilowatt 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 ton of SO₂, assuming 75 percent SO₂ capture, a Ca/S ratio of 2.0, and limestone containing 95 percent CaCO₃. Assuming limestone costs \$15 per ton, LIFAC's operating cost would be \$65 per ton of SO₂ removed.

There are 10 full-scale LIFAC units in operation or under construction in Canada, China, Finland, Russia, and the United States. The LIFAC system at Richmond Power & Light is the first to be applied to a power plant using high-sulfur (2.0–2.9 percent) 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 percent).

Available Reports

Final reports are scheduled to be available in mid-1996.

Contact

Jim Hervol, Project Manager
ICF Kaiser Engineering, Inc.
4 Gateway Center
Pittsburgh, PA 15222-1207
(412) 497-2235
(412) 497-2298 (fax)

Advanced Flue Gas Desulfurization Project (Pure Air on the Lake, L.P.)

Technology

Advanced flue gas desulfurization process; single SO₂ absorber; PowerChip™ gypsum agglomeration process

Size

528 MWe

Demonstration Duration (6/92-6/95)

26,280 hrs of operation

Coal

Bituminous, 2.25-4.7% sulfur

Environmental Results

- Avg SO₂ removal efficiency—94% over 3 yrs
- Maximum SO₂ removal efficiency—98% (emission of 0.382 lb/million Btu)
- Gypsum production over 210,000 tons
- Gypsum purity—97.2%

Technical Results

- Availability—99.47%
- Power consumption (24 hr avg)—5,275 kW (61% of expected)
- Water consumption—1,560 GPM (avg 52% of expected)

Economic Results

Not yet available

Pure Air on the Lake, a general partnership between Air Products and Chemicals, Inc., and Mitsubishi Heavy Industries America, Inc., completed a 3-year demonstration of an advanced flue gas desulfurization (AFGD) process at Northern Indiana Public Service Company's Bailly Generating Station.

The project objective was to demonstrate an AFGD unit retrofitted on Bailly Station's 183-MWe Unit 7 and 345-MWe Unit 8. The goal was to achieve 90-95 percent or more SO₂ removal at approximately one-half the cost of conventional scrubber technology and production of commercial-grade gypsum.

The AFGD project was selected under the second CCT Program solicitation in September 1988. Construction was started in April 1990, and in June 1992, the AFGD system began to process flue gas, thus becoming the first commercial scrubber to meet the requirements of the CAAA of 1990. The demonstration was conducted over a 3-year period and accumulated almost 26,280 hours of operation with an availability of 99.47 percent. The project will continue to operate for an additional 17 years under a novel business concept whereby Pure Air is the owner of the AFGD unit and operates the system for the utility under a service contract.

The AFGD system consists of one resin-lined absorber module and the required ancillary systems. The absorber is a co-current grid-packed tower with two levels of slurry distribution and an integral reaction tank performing three functions in a single vessel; prequencher, absorber, and oxidation of calcium sulfite to gypsum. Upon entering the absorber module, the flue gas from Units 7 and 8 is saturated by contacting a CO₂-enriched gypsum slurry and passes through an open-faced grid. The absorber grid provides the required surface area for the flue gas and slurry to react. An air rotary sparger in the

reaction tank combines the functions of agitation and air distribution into one piece of equipment to facilitate oxidation of calcium sulfite to gypsum. The cleaned flue gas then passes through a two-stage mist eliminator where liquid and solid droplets are removed prior to exiting the scrubber.

The co-current design, whereby the flue gas and liquid slurry flow in the same direction, allows for higher gas velocities (up to 20 feet per second) and, therefore, higher throughput than conventional systems. A large gas-liquid disengagement zone above the absorber tank is also conducive to high gas velocity. The high gas velocity and simplicity of the AFGD design (making it inherently reliable) allowed a single module design for the 528-MWe Bailly Generating Station, which had very limited space available. In addition to the single module, other space and cost-saving features follow:

- Non-pressurized slurry distribution system, requiring approximately 30 percent less recirculation pump power than conventional counter-current spray towers
- Fountain-like flow that does not generate a fine mist, reducing mist eliminator loading by as much as 95 percent compared to counter-current designs
- Use of a dry pulverized limestone injection system, eliminating the need for ball mills, tanks, pumps, and other equipment associated with on-site wet grinding systems

Chloride buildup in FGD system wastewater is common and poses a disposal problem. To address this problem, the AFGD incorporated a wastewater evaporation system that injects wastewater into the flue gas ductwork upstream of the existing ESP. The hot flue gas evaporates the water enabling the dissolved solids to be captured by the ESP along with the fly ash.

Pure Air also demonstrated a unique gypsum agglomeration process known as PowerChip®. Unprocessed FGD gypsum which has the consistency of wet sand is not conducive to transportation or handling by existing equipment at wallboard or cement plants. This limits its marketability. The Power Chip® process utilizes a compression mill at an optimum compacting force with an exclusive curing time and temperature relationship that reformulates and modifies the physical structure of the by-product gypsum. The process produces stable, semi-dry agglomerated flakes of calcium sulfate dihydrate (gypsum) with a range of 1/8-1/16-inch in thickness and 3/8-1/4-inch in length and width. This particle size distribution more closely resembles that of natural gypsum. This makes PowerChip® gypsum just as easy to transport and handle as natural rock gypsum. The production rate of the PowerChip® demonstration facility at the Bailly Station is 7 tons per hour. During the 3-year demonstration over 210,000 tons of dry gypsum was produced. This synthetic gypsum is used by United States Gypsum Company to produce wallboard.

Environmental Results

Pure Air and Northern Indiana Public Service Company conducted a series of five tests over a

**Exhibit 5-8
Test Parameters**

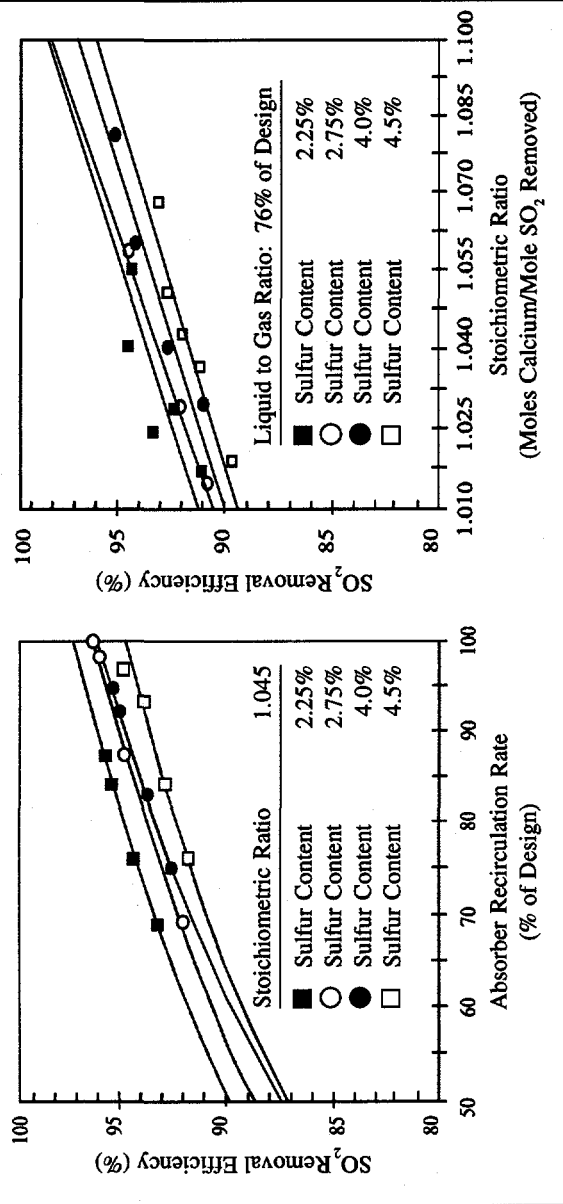
Parameter	Test Year			
	1992	1993	1994/Qt 1	1994/Qt 2 1994/Qt 3
Coal sulfur content (%)	3.2	3.8	4.7	2.25 2.75 (blend)
Boiler load (%)	33, 67, 100	33-100	100	33, 67, 100 33, 67, 100
Stoichiometric ratio	—	1.03-1.00	1.05	1.015-1.056 1.015-1.065
Recirculation rate (%)	75-94	75-93	70-85	—
SO ₂ reduction (%)	90.5-97	95	92-97	94-97.5 —
Gypsum purity (%)	96.7	95.6-99.7	96.7-99.7	96.3-99.4 —

**Exhibit 5-9
Operating Results**

	Expected	Achieved
SO ₂ emissions	90% removal or 0.6 lb/million Btu	Avg 94% (during demonstration tests) up to 98+% or 0.382 lb/million Btu
Power consumption 24-hr avg (KW)	<8,650	5,275
Particulate emissions (g/dry std ft ³)	No net increase	0.04 inlet
Availability (%)	95	99.47
Gypsum moisture (%)	<10	6.64
Gypsum purity (%)	93	97.2
Avg water consumption (GPM)	3,000	1,560
Avg wastewater flow (GPM)	275	81

period of 3 years to demonstrate the operation of the facility using coals with a wide range of sulfur content. Each test lasted approximately 5-6 weeks. In summary, the AFGD demonstration at the Bailly Station has established the technical results of the 3-year demonstration. Exhibit 5-8 summarizes the coal and test parameters

Exhibit 5-10 SO₂ Removal Performance (100% Boiler Load)

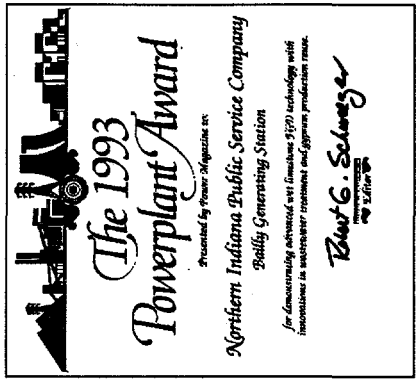


nology as an efficient and reliable means of removing SO₂. The following relationships were established during the demonstration tests:

- At a constant stoichiometric ratio, SO₂ removal efficiency increases with recirculation rate, as shown in Exhibit 5-10 (left graph).
- For a given stoichiometric ratio, boiler load and liquid-to-gas ratio, SO₂ removal efficiency is highest with the lowest sulfur coal (2.25 percent sulfur) and decreases as sulfur content increases (to 4.5 percent), as illustrated in Exhibit 5-10 (right graph)

Operating Performance

The AFGD achieved a 99.47 percent availability at the Bailey Generating Station over the 3 years of operation. The key components of this achievement were the operating/maintenance philosophy coupled with technical modifications. Critical mode analyses were used to identify equipment that, if down, would have the greatest impact on availability. In-line spares were incorporated for those critical pieces of equipment. Productive maintenance techniques, centrally located spare parts inventory, and computerized maintenance systems were also used to assure availability.



▲ The project received *Power Magazine's* 1993 Powerplant Award and in 1992, the National Society of Professional Engineers' Outstanding Engineering Achievement Award.

Modifications were also made to the AFGD system which contributed to the high availability record. An example was the implementation of new alloy technology. The C-276 alloy over carbon-steel-clad material replaced alloy wallpaper construction within the absorber tower wet/dry interface. This resulted in significant reduction in maintenance costs. In another modification, the high pressure nozzles in the original wastewater evaporation system were replaced with two-fluid nozzles which provided better droplet size distribution and more control of liquid being evaporated. This modification eliminated the problem of excessive accumulation of solids in the duct work.

Commercial Applications

The AFGD process is attractive for both new and retrofit applications particularly where space availability is at a premium. The technology has been

shown to be applicable to bituminous coal with sulfur contents ranging from 2.0 to 4.5 percent. The AFGD system will continue to be used, under contract with Pure Air, at the Bailly Generating Station where it is expected to reduce SO₂ emissions by 75,000 tons per year.

The project has received two major awards. In 1993, *Power Magazine* presented the project the Powerplant of the Year Award for demonstrating advanced wet limestone FGD technology with innovations in wastewater treatment and gypsum production reuse. In 1992, the National Society of Professional Engineers presented the project its Outstanding Engineering Achievement Award.

In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600-MWe of SO₂ scrubbing capability to Florida Power and Light Company's Manatee Power Plant on an own-and-operate basis. The Manatee scrubber will feature two 800-MWe absorber vessels, PowerChip® gypsum agglomeration, and wastewater evaporation.

Available Reports

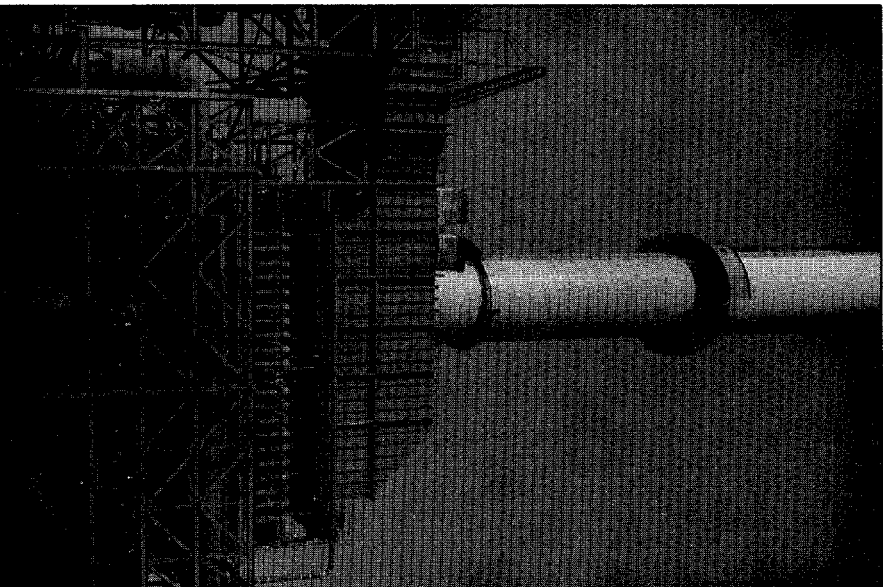
- *Advanced Flue Gas Desulfurization Project: Public Design Report.* Pure Air on the Lake, L.P. March 1990.

The final technical report and economic evaluation report are expected to be available in 1996.

► This side view shows the SO₂ absorber tank and duct work, with the new 480-ft stack in the background. Pure Air on the Lake's absorber module at Bailly Generating Station is the largest module in the United States.

Contact

Don Vymazal, Manager, Contract Administration
Pure Air on the Lake, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501
(610) 481-3687



Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)

Technology

Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) jet-bubbling reactor (JBR) advanced flue gas desulfurization system

Size

100 MWe

Demonstration Duration (10/92-12/94)

Over 14,000 hrs of scrubber operation

Coal

- Blend of Illinois No. 5 and No. 6 bituminous coal, 2.4% sulfur avg
- Bituminous, 3.8-4.3% sulfur
- Compliance, 1.2% sulfur

Sorbent

Limestone

Environmental Results

- Over 90% SO₂ removal efficiency at SO₂ inlet levels of 1,000-3,500 ppm and limestone utilization over 97%
- 97.7-99.3% particulate removal efficiency for inlet mass loadings of 0.303-1.392 lbs/million Btu for a load range of 50-100 MWe
- Capture efficiency as a function of particle size:
 - >10 microns—99%
 - 1-10 microns—90%
 - 0.5-1 microns—negligible
 - <0.5 microns—90%
- High HAPs removal efficiency demonstrated
- Gypsum stack method effective for obtaining wallboard/cement-grade gypsum

Technical Results

- Fiberglass reinforced plastic fabricated equipment proved durable both structurally and chemically, eliminating need for a flue gas prescrubber and reheat.
- Fiberglass reinforced plastic construction, combined with simplicity of design, resulted in 97% availability at low ash loadings and 95% at elevated ash loadings—sufficiently high to preclude the need for a spare reactor module.
- Simultaneous SO₂ and particulate control were achieved at flyash loadings reflective of an ESP with marginal performance.

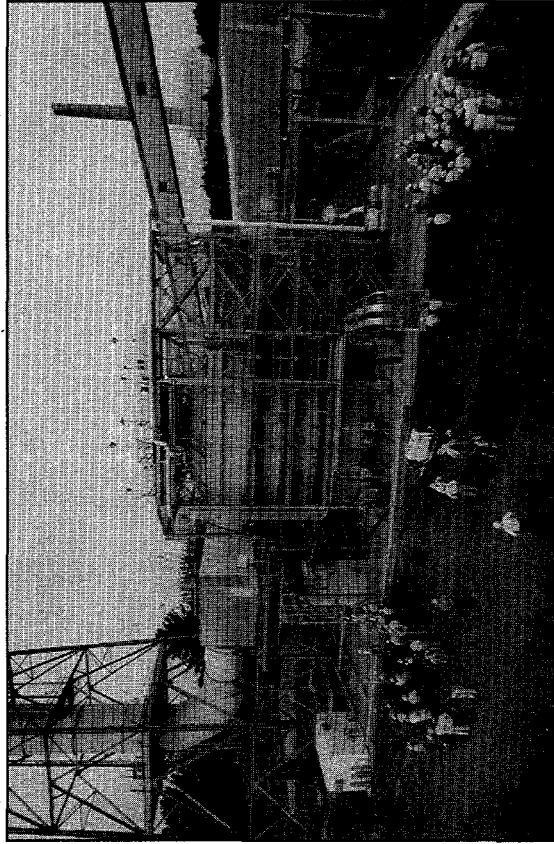
Economic Results

Not yet available but fiberglass reinforced plastic construction and elimination of a flue gas prescrubber, flue gas heat, and spare module should result in capital costs far below conventional FGD systems

Southern Company Services, Inc., completed demonstration of Chiyoda Corporation's CT-121 advanced flue gas desulfurization process retrofitted to an existing 100-MWe pulverized coal-fired boiler at Georgia Power Company's Plant Yates.

The CT-121 process differs from the more common spray tower type of flue gas desulfurization systems in that a single process vessel is used in place of the usual spray tower/ reaction tank/thickener arrangement. The single reactor vessel, called a jet-bubbling reactor (JBR), combines concurrent reactions of SO₂ absorption/neutralization, limestone dissolution, sulfite oxidation, gypsum precipitation, and gypsum crystal growth.

The process is mechanically and chemically simpler than conventional flue gas desulfurization processes. Cooled flue gas, saturated with water and



▲ Southern Company Services, Inc., completed demonstration of the CT-121 scrubber at Georgia Power Company's 100-MWe Plant Yates. The system maintained SO₂ removal efficiencies above 90% at all loads during the 19,000 hours of operation. Shown in the center is the unique jet-bubbling reactor constructed from fiberglass reinforced plastic.

JBR slurry, enters beneath the scrubbing solution.

The SO₂ in the flue gas is absorbed as it rises through the scrubber solution forming calcium sulfite. Air is introduced into the bottom of the reaction tank to oxidize the calcium sulfite and form gypsum. 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). After bubbling through the slurry, flue gas flows upward via large gas riser tubes into a plenum where entrained scrubber solution is released as a consequence of abrupt velocity reduction. Further liquid capture is accomplished with a two-stage mist eliminator before the gas passes to a wet chimney.

The objectives of the project were to demonstrate several cost-saving modifications to the CT-121 process and associated systems, as well as 90 percent SO₂ removal for both high- and low-sulfur coals with and without simultaneous particulate capture. More specifically, the project set out to evaluate the following questions:

- Is fiberglass reinforced plastic (FRP) effective in the construction of the JBR and other associated vessels?
- Can flue gas reheat be eliminated through the use of an FRP wet chimney?
- Will operation be sufficiently reliable to eliminate a spare absorber module?
- Can gypsum product be adequately dewatered through use of a gypsum stack, i.e., slurry

**Exhibit 5-11
Operation of CT-121 Scrubber**

	Low-Ash Phase	Elevated-Ash Phase	Cumulative for Project
Total test period (hrs)	11,750	7,250	19,000
Scrubber available (hrs)	11,430	6,310	18,340
Scrubber operating (hrs)	8,600	5,210	13,810
Scrubber called upon (hrs)	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

deposit into a diked area with separated water returned to the process?

- Can 90 percent SO₂ capture and reliable system performance be maintained at normal and elevated particulate loadings with both high- and low-sulfur coals?

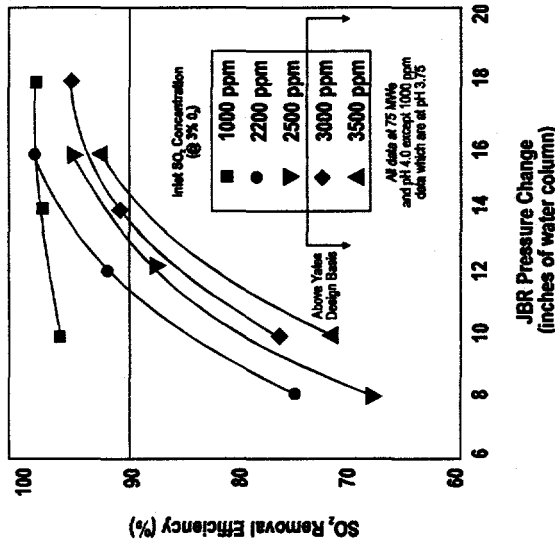
The scope of work was expanded in the latter stages of the project to evaluate air toxics removal across the CT-121 process under elevated ash loading conditions as well as validate or controvert findings of earlier 1993 air toxic tests.

The demonstration spanned 27 months, including startup and shutdown, during which approximately 19,000 hours were logged. Of the approximately 11,750 hours of operation accumulated during the low particulate test phase (including shutdown),

the scrubber operated for 8,600 hours. The remaining 7,250 hours of the demonstration included 5,510 hours of scrubber operation at elevated particulate loading. Exhibit 5-11 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 SO₂ removal efficiency was measured under five different inlet concentrations with coals averaging 2.4 percent and ranging from 1.2 to 4.3 percent sulfur (as burned).

Plant Yates continues to operate with the CT-121 scrubber as an integral part of the site's CAAA 1990 compliance plan.

Exhibit 5-12 SO₂ Removal Efficiency



Operating Performance

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

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

Environmental Performance

Exhibit 5-12 shows SO₂ 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 SO₂ concentration increased, removal efficiency decreased, but adjustments in JBR fluid level could maintain the efficiency above 90 percent and, at lower SO₂ concentration levels, above 98 percent. Limestone utilization remained above 97 percent throughout the demonstration.

Particulate capture performance for long-term testing was tested with a partially deenergized ESP (approximately 90 percent efficiency) and is summarized in Exhibit 5-13.

Analysis indicated that a large percentage of the outlet particulate 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 percent of the measured outlet particulate.

For particulate sizes greater than 10 microns, capture efficiency was consistently greater than 99 percent. In the 1–10 micron range, capture efficiency was over 90 percent. Between 0.5 and 1 micron, the particulate removal dropped at times to negligible

values possibly due to acid mist carryover entraining particulate in this size range. Below 0.5 micron, the capture efficiency increased to over 90 percent.

Overall, better particulate removal efficiency was achieved at 100 MWe than at 50 MWe. This was attributed to higher particulate momentum at the higher load increasing the likelihood of slurry contact as the gas bubble passes through.

Several observations emerged from air toxics (or HAPs) testing:

- The 1993 effort saw significantly more measurement error than the 1994 effort.
- The CT-121 JBR is highly efficient at HAP removal.
- Sampling is very sensitive to any error (e.g., contamination) at these minimum detection levels.
- Source apportionment identifies a significant emission contribution from particulate generated within the wet scrubbing process.

Calculated HAP removals across the CT-121 JBR based on the measurements taken during the demonstration were as follows:

- Antimony—81.1 percent
- Chromium—98.3 percent
- Manganese—94.4 percent
- Nickel—97.9 percent
- Arsenic—91.1 percent
- Lead—95.9 percent
- Vanadium—97.6 percent

As to solids handling, the gypsum stack 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 parts per million), a year later the chloride concentration in the gypsum dropped to less than 50 parts per million, suitable for wallboard and cement applications. The predominant cause was attributed to rainwater washing the stack.

Project Awards

The CT-121 project has received four major awards. In 1995, the Society of Plastics Industries presented the project its Design Award in recognition of the mist eliminator. In 1994 *Power Magazine* presented the Powerplant of the Year Award for large-scale demonstration of an advanced scrubbing process and commercial application of low-NO_x burners. The Georgia chapter of the Air and Waste Management Association presented its 1994 Outstanding Achievement Award to the project for use of an innovative technology for air quality control. In 1993, the Georgia Chamber of Commerce presented the project with an Environmental Award in recognition of the success of the scrubber.

Available Reports

Final technical, economic evaluation, and public design reports are expected to be available in late 1996 and the final report on gypsum stacking in 1997.


Exhibit 5-13
Particulate Capture Performance
(ESP Marginally Operating)

JBR Pressure Change (inches of water column)	Boiler Load (MWe)	Inlet Mass Loading (lb/million Btu)	Outlet Mass Loading* (lb/million 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/million Btu for units constructed after September 18, 1978. Plant Yates permit limit is 0.24 lb/million Btu as an existing unit.

Contact

David P. Burford, Project Manager
Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625
(205) 870-6329



The 1994 Powerplant Award

Presented by Power Magazine to
Georgia Power Co.
Yates Electric Generating Plant

For large scale demonstration of an advanced scrubbing process with features such as regenerative SO₂ construction, ultra-high SO₂ removal efficiency, and simultaneous particulates removal and commercial application of low-NO_x burners.

Rolf G. Schaefer
Executive Director
American Electric Power

Presented to U.S. Department of Energy, a major participant in the project.

▲ The project received *Power Magazine's* 1994 Powerplant Award. The project also received a 1995 Design Award from the society of Plastics Industries and two other awards, one each in 1993 and 1994.

SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)

Technology

- NO_x control—selective catalytic reactor
- SO₂ control—Haldor Topsoe's catalytic SO₂ oxidizer; WSA sulfuric acid condenser
- Particulate control—fabric filter baghouse

Size

35-MWe slipstream from 108-MWe boiler

Demonstration Duration (3/92–12/94)

7,800 hrs

Coal

Ohio bituminous, 3.4% sulfur

Environmental Results

- SO₂ removal efficiency—95%
- NO_x reduction—94%
- Particulate control—99*%
- Sulfuric acid purity—exceeds federal specification for Class I acid
- Air toxics—removal very high for majority of species examined

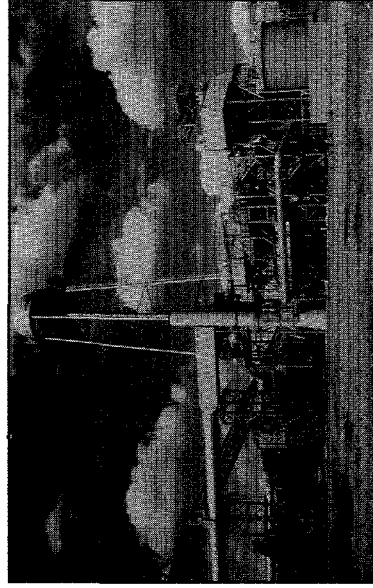
Technical Results

- No alkali reagent required for SO₂ removal
- No generation of secondary pollution streams, e.g., solids, slurries, and liquids
- Minimal or no increase in CO₂ emissions
- Reduction of CO and hydrocarbons in flue gas
- Synergistic coupling of NO_x and SO₂ catalysts
- Furnace integration of recovered heat

Economic Results

- Capital costs—\$250/kWh
- Total operating cost—1.3 mills/kWh

ABB Environmental Systems has demonstrated the SNOX™ process developed by Haldor Topsoe a/s. SNOX™ is a totally catalytic process for the reduction of SO₂ and NO_x in gaseous streams. The SO₂ is converted to commercial grade sulfuric acid and the NO_x is decomposed to elemental nitrogen and water vapor. The objective of the project was to (1) demonstrate the feasibility of the SNOX™ process as applied to coal-fired power plants, (2) achieve 95 percent SO₂ removal and at least 90 percent NO_x reduction at various loads, (3) demonstrate commercial quality of the sulfuric acid produced, (4) satisfy all environmental monitoring plan requirements, and (5) perform a technical and economic characterization of the technology. The demonstration unit is



▲ The SNOX™ demonstration at Ohio Edison's Niles Station Unit No. 2 achieved SO₂ removal efficiencies in excess of 95% and NO_x reduction effectiveness averaging 94%. The demonstration was completed in 1994, and Ohio Edison is retaining the SNOX™ technology as part of its environmental control system.

installed at the Ohio Edison's Niles Station. The process is treating a 35-MWe equivalent slipstream of flue gas from the 108-MWe Unit No. 2 boiler. A high-sulfur (3.4 percent) Ohio coal is used to fire the boiler. The project was selected under the second solicitation and the cooperative agreement was awarded in December 1989. Testing was initiated in March 1992 and completed in December 1994.

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 SO₂ converter. The ash-free gas is reheated through the primary side of a gas/gas heat exchanger. An ammonia and air mixture is then added to the gas prior to the SCR where NO_x is reduced to elemental nitrogen and water. The DNX-932 catalyst used in the SCR is a high activity, titanium-oxide-based monolithic type which operates in a temperature range of 650–800 °F. As the flue gas leaves the SCR, its temperature is raised slightly by an in-line burner, and the flue gas enters the SO₂ converter containing Haldor Topsoe VL-WSA sulfuric acid catalyst which oxidizes SO₂ to sulfur trioxide (SO₃). The SO₃ laden gas is passed through the secondary side of a gas/gas heat exchanger where it is cooled as incoming flue gas is heated.

The processed flue gas is then passed through a falling film condenser (the WSA condenser) where it is further cooled with ambient air to below the sulfuric acid dewpoint. Acid condenses out of the gas phase on the interior of borosilicate glass tubes and is subsequently collected, cooled, and stored. The flue

gas is discharged from the process at about 210 °F and cooling air leaves the WSA condenser at approximately 400 °F. In a full-scale integrated SNOX™ system, the hot air is used for process support and as boiler combustion air after increasing the temperature through the air preheater.

In order to demonstrate and evaluate the performance of the SNOX™ process, general operating data was collected and parametric tests conducted to characterize the process and equipment. The system has operated for over 7,800 hours and produced more than 5,400 tons of commercial-grade sulfuric acid.

Many tests for the SNOX™ system were conducted at three loads—75 percent, 100 percent, and 110 percent of design capacity.

Sulfur dioxide removal in the SNOX™ process is controlled by the efficiency of the SO₂-to-SO₃ oxidation which occurs as the flue gas passes through the oxidation catalyst beds. The efficiency is controlled by two factors—space velocity and bed temperature. Space velocity governs the amount of catalyst which is necessary at design flue gas flow conditions, and gas and bed temperature must be high enough to activate the SO₂ oxidation reaction. During the test program, SO₂ removal efficiency was normally in excess of 95 percent for inlet concentrations averaging about 2,000 parts per million.

The SCR portion of the SNOX™ process can operate at higher than typical ammonia stoichiometries due to its location ahead of the SO₂ catalyst beds. The excess ammonia is oxidized to nitrogen, water vapor, and a small amount of nitrogen oxide. Normal operating stoichiometrics for the SCR system are in the range of 1.02–1.05 and system reduction efficiencies averaged 94 percent with inlet NO_x levels of approximately 500–700 parts per million.

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

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

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

For the majority of the species examined, especially those that exit primarily as particulates at the SNOX™ fabric filter or SNOX™ outlet, removal is very high. Because of the mechanism of sulfuric acid condensation in the WSA condenser, any particulates remaining at this point act as a nuclei for H₂SO₄ and

are captured in the acid. For volatile species, the WSA condenser outlet temperature (200 °F) is lower than conventional boiler outlet temperatures (about 300 °F) and should condense and capture more of the volatile species than a plant with only an ESP or fabric filter.

The economic evaluation of the SNOX™ process shows a capital cost of approximately \$250 per kilowatt and a total operating cost of approximately 1.3 mills per kilowatt-hour.

Ohio Edison is retaining the plant, and funds that were designated for dismantling were reappor- tioned into the operating phase of the program for testing and system modifications in addition to the Niles demonstration.

Commercial SNOX™ plants are in operation in Denmark and Sicily. In Denmark, a 305-MWe plant has been designed and constructed and has been in operation since August 1991. The boilers at this plant burn coals from various suppliers around the world including the United States; the coals contain sulfur varying from 0.5 to 3.0 percent. The plant in Sicily, operating since March 1991, has a capacity of approximately 30 MWe and fires petroleum coke.

Available Reports

Final reports are scheduled to be available in March 1996.

Contact

Bill Kingston, Project Manager
ABB Environmental Systems
P.O. Box 43030
Birmingham, AL 35243
(205) 995-5368

LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)

Technology

- Limestone injection multistage burner (LIMB)
- In-duct sorbent injection (Coolside)
- DRB-XCL[®] low-NO_x burners

Demonstration Duration

- LIMB—3,521 hrs (4/90–8/91)
- Coolside—1,716 hrs (7/89–2/90)

Size

105 MWe

Coal

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

Sorbent

Calclitic limestone; type-N atmospheric hydrated dolomitic lime; calcitic hydrated lime; calcitic hydrated lime with added calcium lignosulfonate (ligno lime)

Environmental Results

- LIMB—61% SO₂ removal efficiency (3.8% sulfur coal; ligno lime)
- Coolside—70% SO₂ removal efficiency (hydrated lime; 2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to saturation)
- 40–50% NO_x removal throughout LIMB and Coolside testing

Technical Results

LIMB and Coolside economically competitive with wet FGD processes—

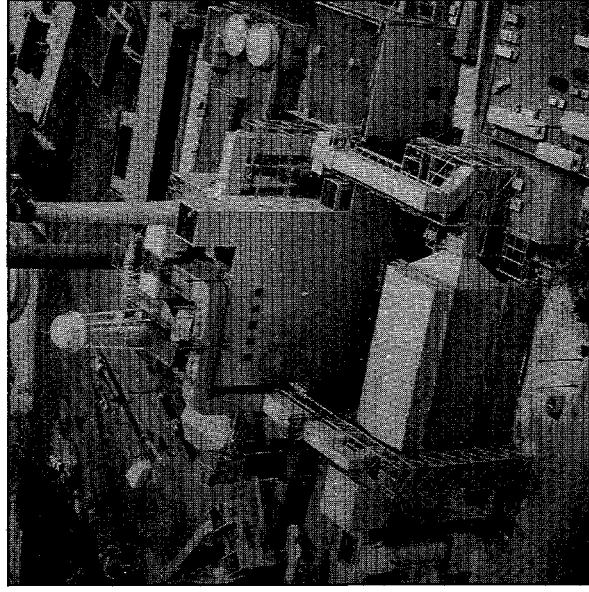
- Up to 1.5% sulfur coal for up to 500 MWe net
- Up to 2.5% sulfur coal for up to 450 MWe net (LIMB), 220 MWe net (Coolside)
- Up to 3.5% sulfur coal for up to 240 MWe net (LIMB), 100 MWe net (Coolside)
- Competitiveness increases with lower plant capacity factor and shorter book life, and as sulfur removal requirements decrease below 70%

Economic Results

- Capital cost—LIMB \$31–102/kW; Coolside \$69–160/kW
- Annual leveled cost—LIMB \$392–791/ton of SO₂ removed; Coolside \$482–943/ton of SO₂ removed

Limestone injection multistage burner (LIMB) technology was the product of a series of bench-scale and pilot-plant projects performed by the U.S. Environmental Protection Agency during the early 1980s. These studies were directed toward the development of relatively low-cost, moderately efficient SO₂ and NO_x emissions control technologies for older fossil fuel-fired utility boilers. At about the same time, the Ohio Edison Company undertook a program to participate in emerging technology development to be in a better position to evaluate the technical, operational, and economic aspects of the newer emissions control technologies being developed. By 1984, the two programs led to the full-scale demonstration of the LIMB process.

In 1987, The Babcock & Wilcox Company, with confunding from the Ohio Coal Development Office, was awarded a cooperative agreement under the CCT Program to extend the full-scale demonstration of the LIMB process. The project also provided for demonstration of the Coolside process, an induct injection technology developed by Consolidation Coal Company (also a cofunder). Both LIMB and Coolside were demonstrated on the 105-MWe coal-fired boiler at Unit No. 4 of Ohio Edison Company's Edgewater Station in Lorain, Ohio.



▲ Babcock & Wilcox demonstrated LIMB and Coolside processes on Ohio Edison's Edgewater Station. LIMB achieved 61% SO₂ removal efficiency and Coolside, 70%. Shown are the humidification water tower and duct work with guillotine dampers on the roof.

During both LIMB and Coolside testing, Babcock & Wilcox's DRB-XCL[®] low-NO_x burners achieved 40–50 percent NO_x removal.

LIMB Extension

The primary purpose of the extension testing under the CCT Program was to demonstrate the generic applicability of LIMB technology. The LIMB process reduces SO₂ 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 the fly ash.

The extended effort, which began in April 1990, characterized the SO₂ removal efficiency for the four sorbents. These tests were conducted over a range of Ca/S and humidification conditions while burning Ohio coals with nominal sulfur contents of 1.6, 3.0, and 3.8 percent by weight. Each of the different sorbents was injected while burning each of the three different coals. Other variables examined were stoichiometry, humidifier outlet temperature, and injection level. The results of these tests follow:

- **Effect of Coal Sulfur Content.** The sulfur content of the coal as reflected in the SO₂ concentration in the flue gas had an effect on SO₂ removal efficiency—the higher the sulfur content, the greater the SO₂ removal for a given sorbent at a comparable stoichiometry. A 5–7 percent increase in removal was noted when switching to 3.8 percent from 1.6 percent sulfur coal and injecting at a stoichiometry of 2.0.
- **Effect of Sorbent Choice.** The highest removal efficiencies, without humidification to close approach, were attained using the ligno lime. Efficiencies on the order of 61 percent were achieved while burning a nominal 3.8 percent sulfur coal. Removal efficiencies for dolomitic lime were about 8 percent less than those for calcitic or ligno lime, at a stoichiometry of 2.0. All sorbents tested were found to be capable of removing SO₂ although calcium utilization of even finely pulverized limestone was not nearly as high as those of the limes.

- **Effect of Limestone Particle Size.** While injecting commercial limestone with 80 percent of the particles less than 44 microns in size, removal efficiencies of about 22 percent were obtained at a stoichiometry of 2.0 while burning 1.6 percent sulfur coal. However, removal efficiencies of about 32 percent were achieved at a stoichiometry of 2.0 when using a limestone with a smaller particle size (i.e., all particles were less than 44 microns). A third limestone with essentially all particles less than 10 microns was used to determine what might be the removal efficiency limit. The removal efficiency for this very fine limestone was approximately 5–7 percent higher than that obtained at similar conditions for limestone with particles all sized less than 44 microns.

- **Effect of Injection Level.** 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 °F. Testing confirmed that injection at this level, just above the nose of the boiler, yielded the highest SO₂ 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 percent higher than while injecting sorbent at the 191-foot level.

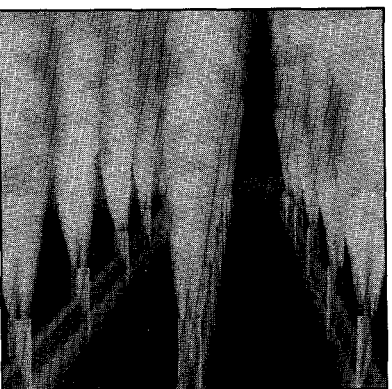
- **Effect on Humidification.** Removal efficiencies were enhanced by approximately 10 percent over the range of stoichiometries tested

when humidification down to a 20 °F approach to saturation was used.

- **NO_x Removal.** The continued use of the low-NO_x burners resulted in an overall average NO_x emissions level of 0.43 pound per million Btu.
- **Costs.** Capital costs of LIMB are estimated to range between \$31 and \$102 per kilowatt and annual levelized costs between \$392 and \$791 per ton of SO₂ removed.

Coolside Process Studies

The generic Coolside desulfurization technology involves injection of dry hydrated lime (sorbent) into the flue gas downstream of the air preheater, followed by flue gas humidification by water sprays. The SO₂ is captured by reaction with the entrained sorbent particles in the humidifier and with the sorbent collected in the particulate removal system. The humidification water serves two purposes. First, it activates the sorbent to enhance SO₂ removal and,



▲ Water mist sprayed into the flue gas enhances sulfur capture by the sorbent by approximately 10%.

second, it conditions the particulate matter to maintain efficient electrostatic precipitator performance. Spent sorbent is removed from the gas along with the fly ash in the existing particulate collector. The sorbent activity can be significantly enhanced by dissolving sodium hydroxide (NaOH) or sodium carbonate (Na₂CO₃) in the humidification water.

Sorbent recycling can be used to improve the sorbent utilization if the particulate collector can handle the resulting increased solids loading.

The demonstration of the Coolside process was conducted from late July 1989 to mid-February 1990. During that period, Boiler 13, Edgewater Unit No. 4, was burning compliance (1.2–1.6 percent sulfur) and noncompliance (2.8–3.2 percent 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, Na/Ca, and approach to adiabatic saturation—were evaluated in short-term (6–8-hour) parametric tests and longer term (1–11-day) process operability tests.

The test program demonstrated that the Coolside process routinely achieved 70 percent SO₂ removal at design conditions of 2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to adiabatic saturation temperature using commercially available hydrated lime. Coolside SO₂ removal depended on Ca/S, Na/Ca, approach to adiabatic saturation, and the physical properties of the hydrated lime. Sorbent recycle showed significant potential to improve sorbent utilization. The observed SO₂ removal with recycled sorbent alone was 22 percent at 0.5 available Ca/S and 18 °F approach to adiabatic saturation. The observed SO₂ removal with simultaneous recycle and fresh sorbent

feed was 40 percent at 0.8 fresh Ca/S, 0.2 fresh Na/Ca, 0.5 available recycle, and 18 °F approach to adiabatic saturation.

The capital cost for the Coolside process is estimated to range between \$69 and \$160 per kilowatt with annual levelized cost ranging \$482–943 per ton of SO₂ removed.

An economic comparison of Coolside and wet limestone FGD processes indicated the Coolside process is economically competitive with a wet limestone forced oxidation (LSFO) FGD process for baseload boiler operations (65 percent capacity factor) under the following conditions:

- 1.5 percent sulfur coal, up to 350 MWe net
- 2.5 percent sulfur coal, up to 130 MWe net

In addition, process sensitivity analyses showed the following factors favor the Coolside process for SO₂ control:

- **Lower Boiler Capacity Factors.** The Coolside process can be characterized as a low capital cost, high operating cost process. When compared to high capital cost, low operating cost processes such as LSFO FGD, the economic attractiveness of the Coolside process increases with decreasing boiler capacity factor.
- **Lower Required SO₂ Percentage Reductions.** The base case SO₂ removals are 70 percent and 95 percent respectively for the Coolside and LSFO process. As the SO₂ removal requirement falls below 70 percent, the Coolside process becomes more economically attractive relative to the LSFO process.

- **Shorter Remaining Boiler Life.** A shorter remaining boiler life favors the low-capital-cost Coolside process.

Available Reports

- T.R. Goots, M.J. DePetro, and P.S. Nolan. *LIMB Demonstration Project Extension and Coolside Demonstration: Final Report.* Report No. DOE/PC/79798-T27. The Babcock & Wilcox Company. November 1992. (Available from NTIS as DE93005979.)
- D.C. McCoy et al. *The Edgewater Coolside Process Demonstration: A Topical Report.* Report No. DOE/PC/79798-T26. CONSOL, Inc. February 1992. (Available from NTIS as DE93001722.)
- *Coolside and LIMB: Sorbent Injection Demonstrations Nearing Completion.* Topical Report No. 2. U.S. Department of Energy and The Babcock & Wilcox Company. September 1990.
- *Public Design Report.* Report No. DOE/PC/79798-T2. The Babcock & Wilcox Company. December 1988. (LIMB/Coolside demonstration.) (Available from NTIS as DE92016131.)

Contact

Paul Nolan
The Babcock & Wilcox Company
P.O. Box 351
Barberton, OH 44203-0351
(216) 860-1074
(216) 860-2045 (fax)

SOx-NOx-Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)

Technology

- SO₂—in-duct sorbent injection
- NO_x—ammonia injection with selective catalytic reduction (SCR) catalyst
- Particulate—high-temperature fabric bag filters

Size

5-MW equivalent slipstream from 156-MW boiler

Demonstration Duration (5/92-5/93)

2,300 hrs

Coal

Ohio bituminous, 3.4% sulfur avg

Sorbent

- Calcium based—commercial-grade hydrated lime; sugar hydrated lime; lignosulfonate hydrated lime
- Sodium based—sodium bicarbonate

Environmental Results

- 80% SO₂ removal efficiency with commercial-grade lime at 2.0 Ca/S (800-850 °F)
- 90% SO₂ removal efficiency with hydrated lime at 2.0 Ca/S (800-850 °F)
- 80% SO₂ removal efficiency with sodium bicarbonate at 1.0 Na₂/S (425 °F)
- 90% NO_x reduction with 0.9 NH₃/NO_x (800-850 °F)
- 99.89% particulate emissions removal efficiency
- Air toxic removal efficiency largely comparable to an ESP but also reduced HCl and HF emissions by over 90%

Technical Results

- Calcium utilization ranged from 40-45% for SO₂ removals of 85-90%
- Norton Company's NC-300 zeolite SCR catalyst located in filter bag to protect against erosion 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 bags and Owens Corning Fiberglas's S-Glass filter bags.

Economic Results

Capital cost—\$260A/W (250 MWe, 3.5% sulfur coal, 1.2 lbs NO_x/million Btu)

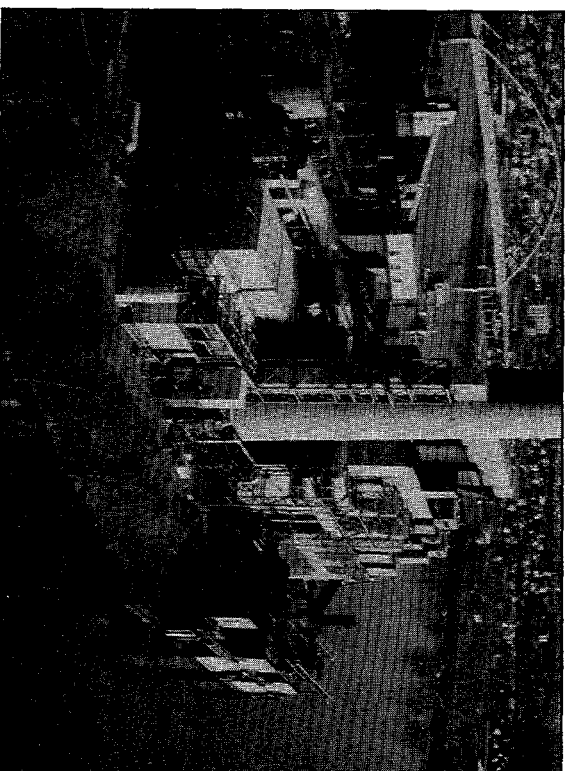
The Babcock & Wilcox Company completed the demonstration of the SOx-NOx-Rox Box™

(SNRB™) process for the combined removal of SO₂, NO_x, and particulates in one piece of the equipment—a high-temperature baghouse. SNRB™ incorporates dry sorbent injection for SO₂ emissions control, selective catalytic reduction (SCR) for reducing NO_x emissions, and a pulse-jet baghouse operating at 450-850 °F for controlling particulate emissions.

The demonstration of the commercial-scale baghouse module was conducted on a 5-MW equivalent slipstream from the 156-MW boiler located at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles Bottom, Ohio. Gas tie-in was between the economizer and the combustion air heater where the flue gas temperature was approximately 600-650 °F.

Construction of the demonstration unit was completed in November 1991 and operations were completed in May 1993. The SNRB™ process was operated for approximately 2,300 hours. The project consisted of four primary test programs:

- Base demonstration project
- Filter fabric assessment
- Alternative bag demonstration
- Air toxics emissions testing



▲ The Babcock & Wilcox Company SNRB™ 5-MW equivalent demonstration at Ohio Edison's R.E. Burger Plant demonstrated the technical and economic feasibility of achieving greater than 80% SO₂ removal, 90% NO_x reduction, and 99% particulate removal.

The overall project objective was to achieve greater than 70 percent SO₂ removal and 90 percent or higher reduction in NO_x emissions while maintaining particulate emissions below 0.03 pound per million Btu.

Four different sorbents were tested for SO₂ capture. Calcium-based sorbents included commercial-grade hydrated lime, sugar hydrated lime, and lignosulfonate hydrated lime. In addition, sodium bicarbonate was tested. The optimum location for injecting the sorbent into the flue gas was immediately upstream of the baghouse. Effectively, the SO₂ was captured by the sorbent while it was in the form of a filter cake on the filter bags (along with fly ash).

A summary of SO₂ removal performance follows:

- With the baghouse operating above 830 °F, injection of commercial-grade hydrated lime at Ca/S ratios of 1.8 and above resulted in SO₂ removals of over 80 percent.
- At a Ca/S of 2.0, performance of the sugar hydrated lime and lignosulfonate hydrated lime increased performance by approximately 8 percent for an overall removal of approximately 90 percent.
- SO₂ removals of 85–90 percent were obtained with calcium utilizations of 40–45 percent.
- Injection of the calcium-based sorbents directly upstream of the baghouse at 825–900 °F resulted in higher overall SO₂ removal than injection further upstream at temperatures up to 1,200 °F.
- SO₂ removal using sodium bicarbonate was 80 percent at 1.0 Na₂/S and 98 percent at 2.0

Na₂/S at a significantly reduced baghouse temperature of 450–460 °F.

- SO₂ emissions were reduced to less than 1.2 pounds per million Btu with a 3–4 percent sulfur coal with Ca/S as low as 1.5 and Na₂/S 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.

Key SNRBTM NO_x reduction observations from the demonstration tests follow:

- 90 percent NO_x emissions reduction was readily achieved with ammonia slip limited to less than 5 parts per million. This performance reduced NO_x emissions to less than 0.10 pound per million Btu.
- NO_x reduction was insensitive to temperatures over the catalyst design temperature range of 700–900 °F.
- Catalyst space velocity (volumetric gas flow/catalyst volume) had a minimal effect on NO_x removal over the range evaluated.
- Turndown capability for tailoring the degree of NO_x reduction by varying the rate of ammonia injection was demonstrated for a range of 50–95 percent 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 SO₂ to SO₃ over the zeolite catalyst appeared to be less than 0.5 percent. (SO₂ 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.

Key observations related to SNRBTM particulate collection follow:

- Emissions were consistently below NSPS standards of 0.03 pound per million Btu, with an average over 30 baghouse particulate emission measurements of 0.018 pound per million Btu, which corresponds to a collective efficiency of 99.89 percent.
- Hydrated lime injection increased the baghouse inlet particulate loading from 5.6 to 16.5 pounds per million Btu.
- Emission 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 pounds per square inch 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 SNRBTM

demonstration test program. Summaries of key program characteristics and test observations follow:

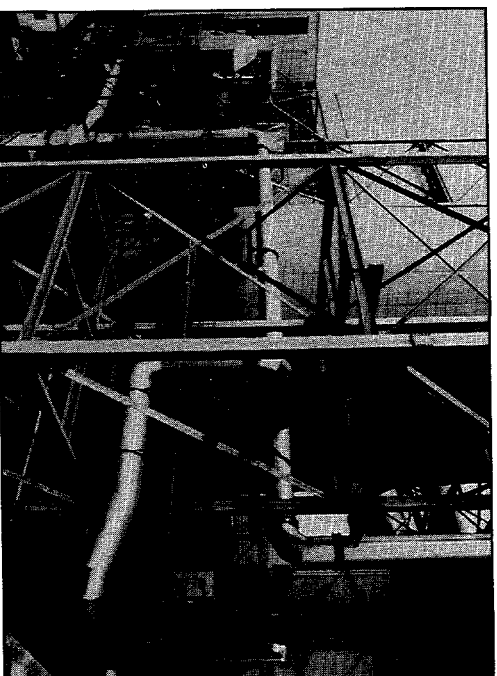
- The targeted emissions monitored included trace metals, volatile organic compounds, semi-volatile organic compounds, aldehydes, halides, and radionuclides. These species were a subset of the 189 substances identified in the CAAA of 1990. Mercury speciation measurements and measurement of dioxins and furans were unique features of this test program.

- The flue gas and solids streams were sampled at 12 locations in the host boiler, SNRRB™ facility, and host plant electrostatic precipitator.

- The emissions control efficiencies achieved for various air toxics by the SNRRB™ system were generally comparable to those of the conventional electrostatic precipitator at the power plant. However, the SNRRB™ system did reduce HCl and HF emissions by over 90 percent, which was significantly higher than that observed for the electrostatic precipitator.

- For some sampling locations, conventional sampling methods were modified to handle higher than normal flue gas temperatures, particulate loading, and acid gas conditions.

Operation of the SNRRB™ 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.



▲ This photo shows the SNRRB™ duct work, propane heater, and structural steel housing.

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

A preliminary evaluation has been made of the projected capital costs of the SNRRB™ system for various utility boiler emissions control applications. For a 250-MWe boiler fired with 3.5 percent sulfur coal and generating 1.2 pounds of NO_x per million Btu, the projected capital cost of a SNRRB™ system is approximately \$260 per kilowatt including various technology and project contingency factors. A combination of a fabric filter, SCR, and wet scrubber for achieving comparable emissions control has been

estimated at \$360–400 per kilowatt. Variable operating costs are dominated by the cost of the SO₂ sorbent for a system designed for 85–90 percent SO₂ removal. Fixed operating costs primarily consist of system operating labor and projected labor and material for the hot bag-house and ash handling systems.

The Babcock & Wilcox Company is pursuing commercial applications of the technology, using the successful 5-MWe demonstration as proof of the technical feasibility of the process. Activity to date has been focused on smaller units where the cost advantages appear to be greatest. Potential applications to waste-to-energy plant emission control are also being investigated.

Available Reports

- *SOX-NOX-Rox Box™ Flue Gas Clean-up Demonstration Final Report*. Report No. DOE/PC/89656-T1. The Babcock & Wilcox Company. September 1995. (Available from NNTS as DE96003839.)
- *5 MWe SNRRB™ Demonstration Facility: Detailed Design Report*. The Babcock & Wilcox Company. November 1992.

Contact

Kevin Redinger
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
(216) 829-7719

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)

Technology

- Gas reburning (GR)
- Sorbent injection (SI)

Hennepin

Size

80 MWe (gross), 71 MWe (net), tangentially fired

Demonstration Duration (1/91-1/93)

- Gas reburning, 400 hrs
- Sorbent injection, 115 hrs
- Combined, 760 hrs
- Baseline, 825 hrs

Coal

Illinois bituminous, 3.0% sulfur

Sorbent

- Linwood hydrated lime
- PromiSORB™ A
- PromiSORB™ B
- High-surface-area hydrated lime

Environmental Results

- 52% avg SO₂ reduction at Ca/S of 1.76
 - 67% avg NO_x reduction with 18% gas input
 - Particulate emissions reduced by flue gas humidification upstream of ESP
 - CO₂, HCl, and HF emissions reduced
- ## Technical Results
- Thermal efficiency—fell 0.3-1.1%; latent heat loss due to hydrogen
 - Carbon-in-ash—increased 0.5-1.7%; minimal impact on boiler efficiency
 - Steam temperature—no change; controlled by attemperation

- Heat distribution—minor changes; within normal range
- No change in tube wastage, tube metallurgy, or projected boiler life

Lakeside

Size

40 MWe (gross), 33 MWe (net), cyclone-fired

Demonstration Duration (5/93-10/94)

- Parametric tests—100 gas reburning tests; 25 sorbent injection tests
- Long-term tests—gas reburning, 249 hrs; combined, 223 hrs
- Extended operating tests (4/94-5/94)—continuous gas reburning, 115 hrs; continuous combined, 38 hrs and 64 hrs

Coal

Illinois bituminous, 3.0% sulfur

Sorbent

- Limestone (CaCO₃)
- Hydrated lime [Ca(OH)₂]

Environmental Results

- 44% SO₂ reduction at 33 MWe; 38% reduction at 25 MWe; 32% at 20 MWe (all at Ca/S of 2.0) (sorbent injection only); 58% avg SO₂ reduction during GR-SI long-term testing
- 50% SO₂ reduction at Ca/S > 1.5 along with gas heat inputs of 22-25% (combined operation)
- Over 60% NO_x reduction with optimum achieved at 22-23% gas input (gas reburn only); 67% avg NO_x reduction during GR long-term testing
- Extended continuous combined runs:
 - 60% SO₂ reduction, 66% NO_x reduction (38 hrs at 29 MWe, gas input 22.4%, Ca/S 1.67)

- 63% SO₂ reduction, 64% NO_x reduction (64 hrs at 29 MWe, gas input 21.6%, Ca/S 1.75)
- Particulate emissions averaged 0.016 lb/million Btu, well below the 0.1 lb/million Btu permitted limit

Technical Results

- Thermal efficiency—fell 0.8% due to higher moisture in methane
- Carbon-in-ash—gas reburn neither increased carbon-in-ash nor impacted boiler efficiency
- Flue gas temperature—increased 6 °F; sorbent deposition on back pass heat transfer surfaces
- Operated consistently and reliably

Combined Economic Results

- SO₂ removal cost effectiveness
 - \$425/ton SO₂ removed (1.0 Ca/S; 29% SO₂ removal)
 - \$514/ton SO₂ removed (2.0 Ca/S; 45% SO₂ removal)
- NO_x reduction cost effectiveness
 - \$979/ton of NO_x removed (14% gas input; 47% NO_x reduction)
 - \$1,318/ton of NO_x removed (24% gas input; 60% NO_x reduction)

The Energy and Environmental Research Corporation (EER) has conducted a demonstration of gas reburning and sorbent injection (GR-SI) at the tangentially fired Illinois Power Hennepin Plant Unit 1 and the cyclone-fired Lakeside Station Unit 7 of City Water, Light and Power. The gas reburning (GR) process consists of injection of natural gas corresponding to 15-25 percent of the heat input at a location above the coal burners to create a fuel-rich zone which will allow the reduction of NO_x formed

in the coal zone to molecular nitrogen. Overfire air is injected at a higher elevation to burn out the fuel combustibles under fuel-lean conditions. In the sorbent injection (SI) process, a calcium-based sorbent such as calcium hydroxide [$\text{Ca}(\text{OH})_2$] is injected into the upper furnace to react with flue gas SO_2 resulting in the formation of calcium sulfate (CaSO_4) and calcium sulfite (CaSO_3). These solids are carried from the boiler and captured with the fly ash in the particulate collection device.

The GR-SI project was selected in the first solicitation and the cooperative agreement was awarded in July 1987. The following summary of results addresses the Hennepin and Lakeside demonstrations separately.

Hennepin Plant Unit 1

Hennepin Plant Unit 1 is a 71-MWe (net) or 80-MWe (gross) tangentially fired unit designed by Combustion Engineering. The unit was retrofitted with a GR-SI system designed by EER. Operational testing, which included optimization testing, and long-term testing were conducted between January 1991 and January 1993. The project goal was a reduction in NO_x emission by 60 percent, from a baseline of 0.75 pound per million Btu, and SO_2 emissions by 50 percent, from a baseline of 5.30 pounds per million Btu.

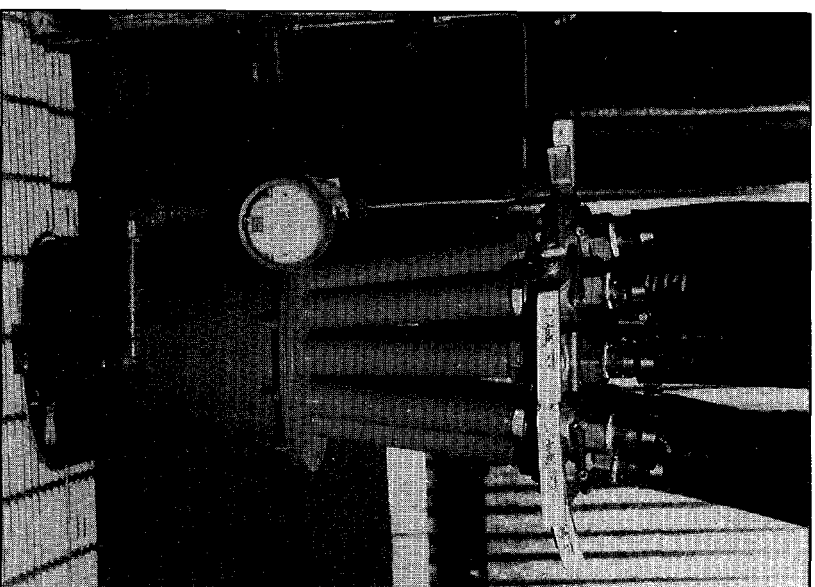
The GR-SI long-term demonstration tests were carried out from January 1992 to October 1992 to verify the system performance over an extended period. The unit was operated at constant loads and with the system under dispatch operation where load was varied to meet plant power output requirements. With the system under dispatch, the load fluctuated

over a wide range from 40 MWe to a maximum load of 75 MWe. Over the long-term demonstration period, the average gross power output was 62 MWe.

For the long-term demonstration testing, the average NO_x reduction was approximately 67 percent. The average SO_2 removal efficiency was over 52 percent at a Ca/S molar ratio of 1.76. (Linwood hydrated lime was used throughout these tests except for a few days when Marblehead lime was used.) CO emissions were below 50 parts per million in many cases but were higher during operation at low load.

A significant reduction in CO_2 was also measured. This was due to partial replacement of coal with natural gas having a lower C/H ratio. This cofiring with 18 percent natural gas results in a theoretical CO_2 emissions reduction of nearly 8 percent from coal-fired baseline level. With flue gas humidification, ESP collection efficiencies greater than 99.8 percent and particulate emissions less than 0.025 pound per million Btu were measured even with an increase in inlet particulate loading resulting from sorbent injection. These are comparable to measured baseline emissions of 0.035 pound per million Btu and a collection efficiency greater than 99.5 percent.

Following the completion of the long-term tests, three specially prepared sorbents were tested. Two were manufactured by EER and contained proprietary additives to increase their reactivity toward SO_2 , and were referred to as PromiSORB™ A and B. The other sorbent was developed by the Illinois State Geological Survey. It was a high-sulfur and hydrated lime which uses alcohol to form a material that gives rise to a much higher than normal surface area per unit rate than the atmospherically hydrated limes.



▲ The GR-SI was demonstrated at Illinois Power's Hennepin Station and City Water, Light and Power's Lakeside Station. SO_2 removal efficiency ranged from about 52% to over 80%, depending on type and amount of sorbent used. Shown here are the flexible lime-sorbent distribution lines that lead from the sorbent splitter to the top of the boiler at Lakeside Station.

tions above the 50 percent reduction goal were achieved with Ca/S molar ratios greater than 1.5 along with gas heat inputs of 22–25 percent.

The primary goal of the long-term testing was to operate the GR-SI during normal operating cycle of the Lakeside unit. The NO_x and SO₂ reduction goals were to be achieved while maintaining the unit's operability and availability during the 9-month test period. The unit typically operated in cycling service with a very low capacity factor. The average NO_x reduction during the long-term testing was 67 percent after a total of 249 hours of GR operation. The average SO₂ reduction after 223 hours of GR-SI operation was 58 percent.

During the demonstration program, loss on ignition (LOI) for fly ash was determined only under GR operations. LOI varied from 7 percent to 14 percent with GR; the baseline LOI was in the range of 3–12 percent in 1991, before this demonstration. LOI varied somewhat with boiler load. Part of the weight loss caused by igniting a sample to determine LOI was due to the burning of carbon; the balance was made up of other materials. The LOI with GR was within the range of the baseline measurement. This indicated that GR most likely did not increase LOI and therefore did not decrease efficiency.

There were two extended GR-SI runs of 38 and 64 hours duration each. The 38-hour run was conducted at 29 MWe with a gas input of 22.4 percent and a Ca/S molar ratio of 1.67. The average NO_x emission was 0.311 pound per million Btu, a 66 percent reduction, and the average SO₂ emission was 2.338 pounds per million Btu, a 60 percent reduction. The 64-hour run was carried out at 29 MWe with a gas input of 21.6 percent and a Ca/S molar

Industrial Applications

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)

Technology

Air-cooled cyclone slagging combustor

Demonstration Duration (11/87-5/90)

900 hrs

Size

23 million Btu/hr

Coal

8 different Pennsylvania bituminous coals, 1-3.3% sulfur

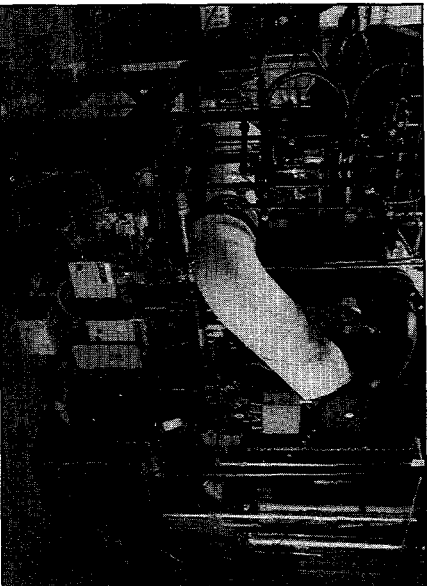
Environmental Results

- SO₂—over 80% reduction with sorbent injection; at combustor outlet, maximum 58% reduction with limestone injection into the combustor at 2.0 Ca/S
- NO_x—160-184 ppm (75% reduction)
- Solid waste—inert slag
- Slag/sorbent retention—55-90% in combustor

Technical Results

- Combustion efficiency—over 99%
- Turndown—3-to-1 achieved
- Materials—slag protection of materials achieved
- Operability—computer-controlled system for automated combustor operation achieved

In Coal Tech's demonstration, an air-cooled cyclone combustor was retrofitted to a 23-million-Btu-per-hour, oil-designed package boiler at the Tampa-La-Keeler boiler factory in Williamsport, Pennsylvania. The novel features of Coal Tech's patented ceramic-lined, slagging cyclone combustor include its air-cooled walls and environmental control of NO_x, SO₂, and solid waste emissions. Air cooling takes place in a very compact combustor which can be retrofitted to



▲ The demonstration of Coal Tech's advanced ceramic-lined slagging combustor was completed in 1991. Shown above are the slagging combustor, associated piping, and control panel.

a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. In this technology, NO_x reduction is achieved by staged combustion, and SO₂ is captured by injection of limestone into the combustor. The cyclonic action inside the combustor forces the coal ash and sorbent to the walls where it can be collected as liquid slag. Under optimum operating conditions, the slag will contain a significant fraction of coal sulfur. Downstream sorbent injection into the boiler provides additional sulfur removal capacity.

The test effort consisted of 800 hours of operation which included five individual tests, each of 4 days duration. An additional 100 hours were performed as part of separate ash vitrification tests. Pennsylvania bituminous coals with 1.1-3.1 percent

sulfur content were used throughout the demonstration. Test results obtained during operation of the combustor indicate that Coal Tech attained most of the objectives contained in the cooperative agreement. The agreement defined 10 objectives. Accomplishments reported for each follow:

- Use Pennsylvania coals with up to 4 percent sulfur content. About eight different Pennsylvania bituminous coals with sulfur contents ranging from 1 to 3.3 percent and volatile matter contents ranging from 19 to 37 percent were tested.
- Achieve 70-90 percent SO₂ reduction at the stack with maximum sulfur encapsulation in the slag. With regard to the first part of the objective, a maximum of over 80 percent SO₂ reduction measured at the boiler outlet stack was achieved using sorbent injection in the furnace at various calcium-to-sulfur molar ratios. A maximum SO₂ reduction of 58 percent was measured at the stack with limestone injection into the combustor at a Ca/S 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 a high of 11 percent of the coal's sulfur was retained in the slag rejected through the slag tap. Further sulfur retention in the slag is possible by increasing the slag flow rate, by further improvements in fuel-rich combustion, and by further improvements in sorbent-gas mixing.

- **Achieve NO_x reductions to 100 parts per million or less.** With fuel-rich operation in the combustor, a three-fourths reduction in measured boiler outlet stack NO_x was obtained, corresponding to 184 parts per million. An additional 5–10 percent reduction was obtained by the action of the wet particulate scrubber, resulting in atmospheric NO_x emissions as low as 160 parts per million.
- **Produce an inert solid waste.** All the slag removed from the combustor produced trace metal leachates well below EPA's Drinking Water Standard.
- **Achieve 90–95 percent slag/sorbent retention in the combustor, while meeting local stack particulate emission standards.** The second part of this objective was met with the wet venturi particulate scrubber. Total slag/sorbent retention under efficient combustion operating conditions averaged 72 percent with a range of 55–90 percent. Under more fuel-lean conditions, the slag retention averaged 80 percent. In post-CCT-project tests on fly ash vitrification in the combustor, modifications to the solids injection method and increases in the slag flow rate produced substantial increases in the slag retention rate.
- **Achieve efficient combustion under fuel-rich conditions.** This objective was met with combustion efficiencies over 99 percent after proper operating procedures were achieved.
- **Achieve a 3-to-1 combustor turnaround.** Turndown to 6 million Btu per hour from a peak of 19 million Btu per hour was achieved.

The maximum heat input during the tests was around 20 million Btu per hour, even through the combustor was designed for 30 million Btu per hour and the boiler was thermally rated at around 25 million Btu per hour. This situation resulted from facility limits on water availability for the boiler and for cooling the combustor. In fact, even 20 million Btu per hour was borderline, so that most of the testing was conducted at lower rates.

- **Evaluate materials compatibility and durability.** Different sections of the combustor have different materials requirements. Suitable materials for each section have been identified. Also, the test effort has shown that operational procedures are closely coupled with materials durability. In other words, by implementing certain procedures, such as changing the combustor wall temperature, it has been possible to replenish the combustor refractory wall thickness with slag.

- **Operate the combustor on coal for approximately 1,000 hours of steady state operations with frequent start-up and shutdown.** The combustor's total operating time during the life of the CCT project was about 900 hours. This included approximately 100 hours of operation in two other flyash vitrification tests projects. Of the total time, about one-third was with coal; about 125 tons of coal were consumed.

- **Develop proper combustor operating procedures.** This was the most important objective. Not only were procedures for

properly operating an air-cooled combustor developed, but the entire operating data base was incorporated into a computer-controlled system for automatic combustor operation.

In conclusion, the goal of this project was to validate the performance of the air-cooled combustor at a commercial scale. While the combustor is not yet fully ready for sale with commercial guarantees, it is believed to be ready for further major scaleup to commercial-scale applications such as combustion of waste solid fuels, limited sulfur control in coal-fired boilers, and conversion of ash to slag.

Available Reports

- *The Coal Tech Advanced Cyclone Combustor Demonstration Project—A DOE Assessment.* Report No. DOE/PC/79799-T1. U.S. Department of Energy. May 1993.
- B. Zauderer and E.S. Fleming. *The Demonstration of an Advanced Cyclone Coal Combustor, with Internal Sulfur, Nitrogen, and Ash Control for the Conversion of a 23 MMBtuw Hour Oil Fired Boiler to Pulverized Coal; Vol. 1: Final Technical Report; Vol. 2: Appendices I–V; Vol. 3: Appendix VI.* Coal Tech Corporation. August 1991. (Available from NTIS as DE92002587 and DE92002588.)

Contact

Bert Zauderer, President
Coal Tech Corporation
P.O. Box 154
Merion, PA 19066
(215) 667-0442

Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)

Technology

Passamaquoddy Technology Recovery Scrubber™

Size

1,450 tons/day of cement; 250,000 std ft³/min of kiln gas; up to 274 tons/day of coal

Demonstration Duration (8/91-9/93)

5,316 hrs

Coal

Pennsylvania bituminous, 3% sulfur

Sorbent

Water solution/slurry containing potassium-rich dust recovered from kiln flue gas

Environmental Results

- SO₂—90-95%, with 98% maximum reduction
- NO_x—18.8% avg reduction
- Particulate—10% of permitted level
- Cement kiln dust waste—all 250 tons/day removed and reused as feedstock
- HCl—98% removal
- VOC—72-83% removal
- CO₂—2% reduction

Technical Results

- In 5-mo period, plant produced 140,000 tons of cement while scrubber removed 70 tons of SO₂ and treated 6,000 tons of kiln dust
- Scrubber became permanent part of commercial plant operation

Economic Results

- Capital cost—\$10 million to control emissions from 450,000-ton/yr plant with single payback in 3.1 yrs from sales of fertilizer and avoided fuel and waste disposal costs

- O&M cost—estimated at \$500,000/yr offset by sale of fertilizer and avoided fuel and waste disposal costs

A scrubbing system that can reduce SO₂ emissions from coal-burning cement kilns by more than 90 percent using waste kiln dust as the scrubbing reagent was demonstrated by the Passamaquoddy Tribe. The project is located in Thomaston, Maine, at Dragon Products' 470,000-ton-per-year cement plant which is owned by CDN U.S.A. The Passamaquoddy Technology Recovery Scrubber™ is a wet flue gas desulfurization process that uses alkaline waste materials as scrubbing reagent. These wastes may include fly ash, waste cement kiln dust, incinerator ash, biomass ash from wood-fired systems, and other similar wastes in solid or liquid form. Useful by-products that minimize or eliminate the need for landfill disposal of wastes are produced by the scrubbing reaction. Tipping fees for consumption of wastes produced by others, sale of useful by-products and emission credits, and "fee for service" pollution control generally allow profitable operation of the scrubbing process.

The scrubbing process was installed with minimum impact on the operating cement plant, being an "end of the pipeline" retrofit process. The only interconnect to the cement plant that could curtail operations is the physical tie-in of the flue gas handling duct. The demonstration project tie-in was made during a routine kiln shutdown with no impact on kiln operations.

The project was initiated as a result of the Dragon Products Company facing increased fuel costs in response to more stringent sulfur emissions regulations, and increased kiln dust disposal costs with the existing landfill capacity nearly exhausted. Fuel sulfur would have had to be reduced by half to meet emission regulations. The payment of premiums associated with the lower sulfur coal were deemed untenable with fuel costs representing 30-40 percent of operating costs. Securing permits for a new landfill were viewed as too expensive and time consuming with cement kiln dust receiving a great deal of attention by permitting agencies. To address these concerns, the project sought to accomplish the following objectives:

- Use the cement kiln dust as the sole reagent to reduce air emissions
 - Accomplish 90-95 percent sulfur control on high sulfur eastern bituminous coals
 - Convert a substantial percentage of the cement kiln dust to kiln feedstock
 - Produce a potentially significant commercial by-product (potassium-based fertilizer)
 - Use waste heat for evaporation and concentration of the potassium-based fertilizer
 - Demonstrate the overall technical, economic, and environmental viability of the technology
- All objectives were met or exceeded. Further testing was conducted to evaluate scrubber effective-

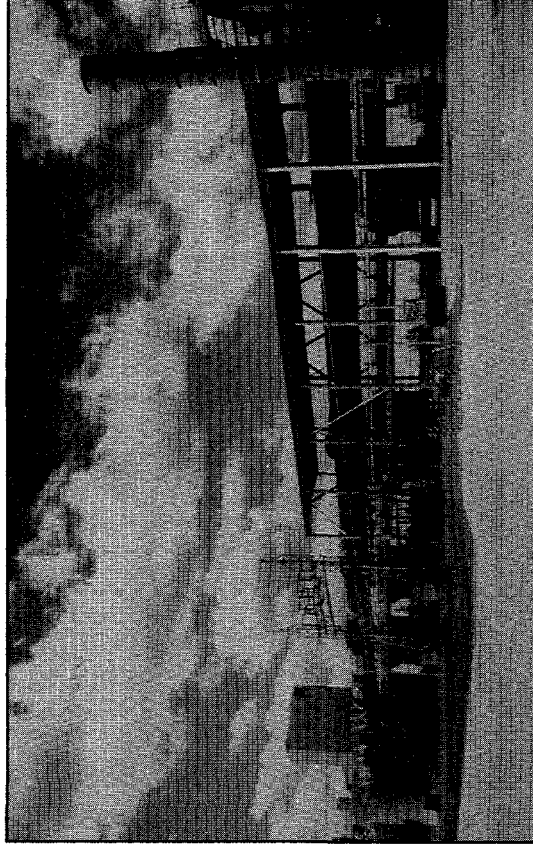
ness in removing NO_x , HCl, VOCs, and particulates. The scrubber was evaluated over three basic operating intervals dictated by winter shutdowns for maintenance and inventory and 14 separate operating periods (within these basic intervals) largely determined by unforeseen host plant maintenance and repairs and a depressed cement market.

Over the period August 1991 to September 1993, a total of 5,316 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.

The technology uses the alkaline (potassium) rich cement kiln dust waste to react with the acidic flue gas. This cement kiln dust, representing about 10 percent 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 potas-



▲ The Passamaquoddy Technology Recovery Scrubber™ was successfully demonstrated at a cement plant in Maine. Kiln dust, once a solid waste problem, is being used in a process to capture more than 90% of the SO_2 . The process also reduces NO_x emissions by 5–15%.

sium and other alkali constituents, is returned to the kiln as feedstock (it is the alkali content which makes the cement kiln dust unusable as feedstock). No dewatering is necessary for wet processes such as that used at the Dragon Products plant. The liquid fraction is passed to a crystallizer that uses waste heat in the flue gas to evaporate the water and recover dissolved alkali metal salts. A recuperator lowers the incoming flue gas temperature to prevent slurry evaporation, enable the use of low-cost fiber glass construction material, and provide much of the process water through condensation of exhaust gas moisture.

Waste cement kiln dust, exhaust gases (including waste heat), and waste water are process inputs. Renovated cement kiln dust, potassium-based fertiliz-

er (either KCl or K_2SO_4), scrubbed exhaust gas, and distilled water are process outputs. There is no waste; nothing goes to a land fill or sewer.

Project results are summarized below:

- The SO_2 removal efficiency averaged 94.6 percent over the last 3-months of operation and 89.2 percent for the entire operating period. Scrubber loading varied from 2 to 10 pounds per hour to over 200 pounds per hour. Removal efficiencies in the ranges of less than 100, 100–200, and greater than 200 pounds per hour were 82.0 percent, 94.1 percent, and 98.5 percent, respectively.
- The NO_x removal efficiency averaged nearly 25 percent over the last several months of operation and 18.8 percent for the entire operating period.
- All of the 250-ton-per-day cement kiln dust waste produced by the plant was renovated and reused as feedstock. This resulted in a 10 percent reduction in raw feedstock requirement and elimination of solid waste disposal costs.
- Particulate emission rates of 0.005–0.007 grains per dry standard cubic feet (about 1/10 that allowed for cement kilns) were achieved with dust loadings of approximately 0.04 grains per dry standard cubic foot.
- Pilot testing conducted at U.S. EPA's laboratories under Passamaquoddy Technology, L.P., sponsorship resulted in 98 percent HCl removal.

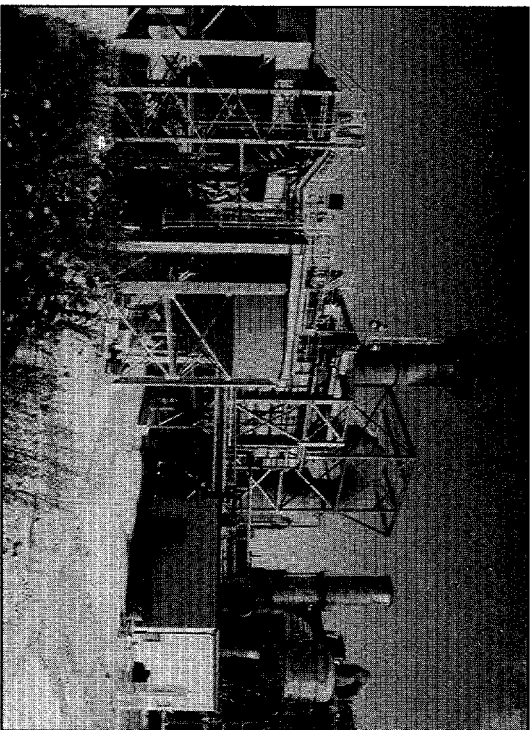
- On three different runs, VOC (as represented by alpha-pinene) removal efficiencies of 72.3 percent, 83.1 percent, and 74.5 percent were achieved.
- A reduction of approximately 2 percent in CO₂ emissions was realized through recycling of the cement kiln dust.
- Capital costs are approximately \$10 million for a recovery scrubber to control emissions from a 450,000-ton per year wet process plant, with a simple payback estimated in 3.1 years. Operating and maintenance costs, estimated at \$500,000 per year, plus capital and interest costs are generally offset by avoided costs associated with fuel, feedstock, and waste disposal as well as revenues from the sale of fertilizer.

Available Reports

- *Passamaquoddy Technology Recovery Scrubber™: Final Report.* Volumes 1 and 2. Passamaquoddy Tribe. February 1994. (Vol. 1 available from NTIS as DE94011175, Vol. 2 as DE94011176.)
- *Passamaquoddy Technology Recovery Scrubber™: Public Design Report.* Report No. DOE/PC/89657-T2. Passamaquoddy Tribe. October 1993. (Available from NTIS as DE94008316.)
- *Passamaquoddy Technology Recovery Scrubber™: Topical Report.* Report No. DOE/PC/89657-T1. Passamaquoddy Tribe. March 1992. (Available from NTIS as DE92019868.)

Contact

Garrett Morrison, Project Manager
 Passamaquoddy Technology, L.P.
 P.O. Box 350
 Thomaston, ME 04861-0350
 (207) 594-5555



▲ The Passamaquoddy Technology Recovery Scrubber™ became a permanent part of the Dragon Products facility at the project's end.

6. Results and Accomplishments from Ongoing Projects

Introduction

By the end of 1995, the CCT Program consisted of 43 projects. A total of 18 projects have successfully completed operations and fulfilled all reporting requirements or are preparing the final project documentation. An additional 8 projects are in operation, 5 are in construction, 11 are in design and project definition, and 1 CCT-V project is in negotiation.

The true measure of the CCT Program's success will be the degree to which the clean coal technologies are adopted in the energy marketplace. The majority of the projects involve demonstrations at full commercial scale, providing the opportunity for the participants to leave the technologies in place and continue operation as part of their strategy to comply with the CAAA of 1990.

The number of complex, capital-intensive projects put in place is unprecedented, as is the degree of cost sharing achieved in this cooperative government and private sector technology development program. 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.

In this section of the *Program Update*, highlights of the results and accomplishments are presented for those projects now in operation or under construction (see Exhibit 6-1). The status of each project is sum-

marized in Exhibits 6-2 through 6-5 at the end of Section 6.

Underlining the premise that success of the CCT Program depends on adoption of the technologies in the energy marketplace, project information is organized within four major product markets—advanced electric power generation, environmental control devices, coal processing for clean fuels, and industrial applications. Thus, the program can be viewed from a market perspective.

Exhibit 6-1

Highlighted CCT Projects, by Application Category

Project and Participant	Page
Piñon Pine IGCC Power Project (Sierra Pacific Power Company)	6-2
Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)	6-3
Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)	6-4
Healy Clean Coal Project (Alaska Industrial Development and Export Authority)	6-5
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	6-6
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	6-7
Integrated Dry NO _x /SO ₂ Emissions Control System (Public Service Company of Colorado)	6-8
Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ Inc.)	6-9
Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)	6-10
Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)	6-11
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)	6-12
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)	6-13
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	6-14

Advanced Electric Power Generation

Piñon Pine IGCC Power Project (Sierra Pacific Power Company)

The Piñon Pine IGCC Power Project is demonstrating the KRW air-blown, pressurized, fluidized-bed IGCC technology and incorporates hot gas cleanup. The project evaluates a low-Btu gas combustion turbine and assesses long-term reliability, availability, maintainability, and environmental performance of the IGCC system at a scale sufficient to determine commercial potential.

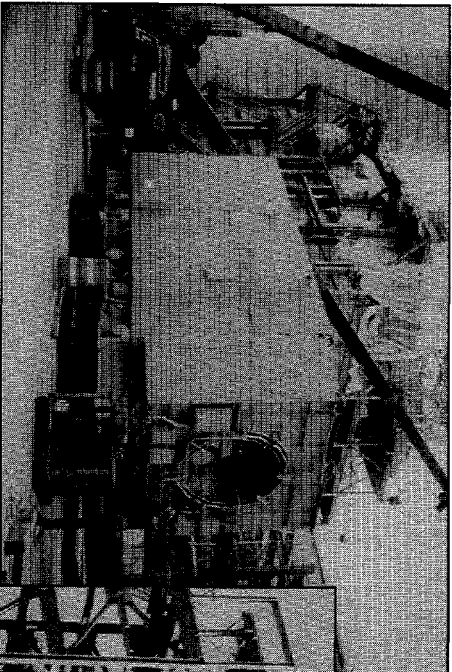
The gasifier is being built at Sierra Pacific Power Company's Tracy Station near Reno, Nevada. The unit will convert 880 tons per day of coal into 107 MWe (gross), or 99 MWe (net), for export to the grid. The design coal is western bituminous coal from Utah, with a sulfur content of 0.5–0.9 percent. Tests using eastern bituminous coal containing 2–3 percent sulfur also are planned.

The anticipated heat rate for this IGCC system is approximately 7,800 Btu per kilowatt-hour (43.7 percent thermal efficiency). Due to the relatively low operating temperature of the gasifier and the injection of steam into the combustion fuel system, the NO_x emissions are expected to be 0.069 pound per million Btu. With the combination of in-bed sulfur capture and hot gas cleanup, SO₂ emissions are expected to be 0.069 pound per million Btu (90 percent reduction).

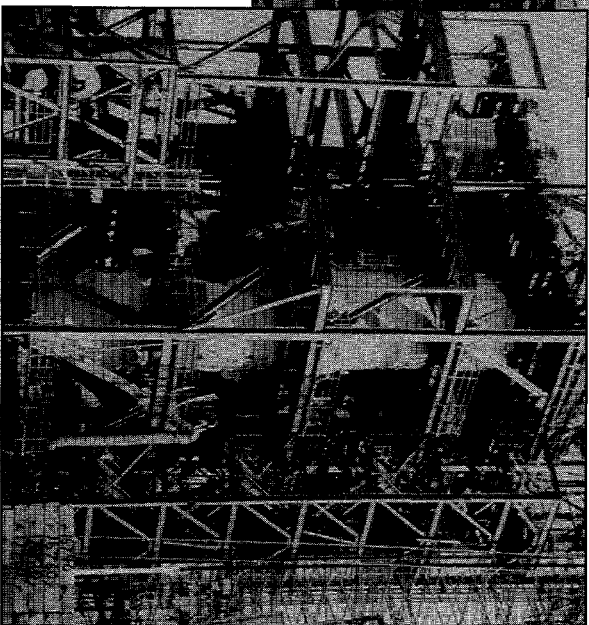
Construction was started in early 1995 and is expected to be completed in early 1997. A 3–4-year demonstration period is planned. All permits needed for plant construction were received by year-end 1994. The NEPA process was completed upon

release of a final environmental impact statement in September and the DOE's issuance of a record of decision on November 8, 1994. By year-end 1995, construction was approximately 50 percent complete. Fabrication of the gasifier was complete, and structural steel has been erected to the 93-foot elevation. Foundations north of the gasifier island as well as

foundations for the coal crusher and solid wastes silo were complete; also, the steam turbine pad has been poured. Further, the 42-inch cooling lines to the steam turbine foundation and in the cooling tower area were complete. The public design report was issued in August 1995.



▲ The General Electric 6FA combustion turbine, shown above, produces 61 MWe (gross) of the 107 MWe (gross) generated by the Piñon Pine IGCC Power Project being built at Sierra Pacific Power Company's Tracy Station near Reno, NV. Operations are planned to begin in early 1997.



▲ This photo shows the 165-ton (without refractory) air blown, pressurized, fluidized-bed KRW gasifier mounted inside the gasifier island.

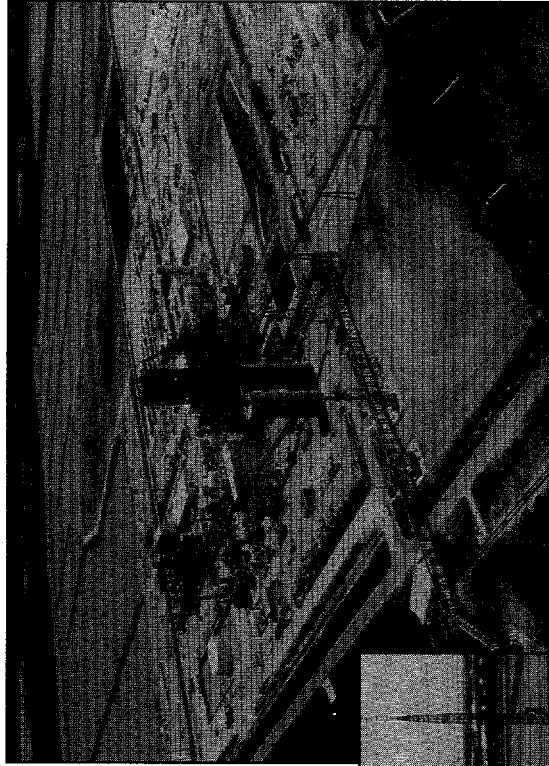
Advanced Electric Power Generation

Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)

The Tampa Electric Integrated Gasification Combined-Cycle Project is demonstrating a utility application of IGCC using Texaco's pressurized, oxygen-blown, entrained-flow gasifier and the integrated performance of a metal oxide hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection for power augmentation and NO_x control. The project involves only the first 250-MWe (net) IGCC portion of the planned 1,150-MWe Polk Power Station in Lakeland, Florida. The gasifier is being designed to use about 2,000 tons per day of bituminous coal containing 2.5-3.5 percent sulfur. The anticipated heat rate for the IGCC system is approximately 8,600 Btu per kilowatt-hour (40 percent thermal efficiency). SO_2 emissions are expected to be below 0.21 pound per million Btu (96 percent reduction). Thermally generated NO_x is expected to be controlled to less than 0.27 pound per million Btu by injecting nitrogen as a diluent in the gas turbine's combustion section.

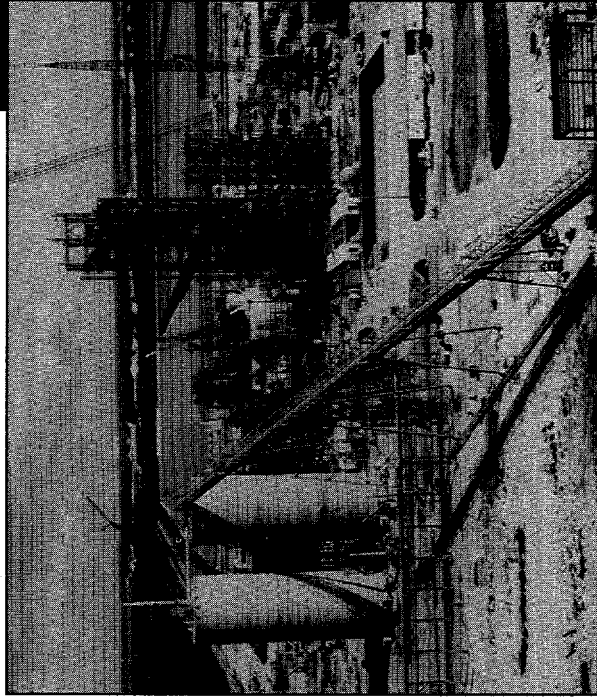
The final EIS was released for public comment on June 10, 1994; DOE issued a favorable record of decision on the demonstration project on August 17, 1994. A groundbreaking ceremony was held on November 2, 1994. Construction was approximately 70 percent complete by year-end 1995. Structural steel was 90 percent in

place. All major vessels have been placed in the structure. The turnkey air separation plant is mechanically complete and undergoing checkout and qualification testing. Construction is expected to be completed in the fall of 1996 and will be followed by a 4-5 year demonstration period. Reclamation of the area west of Rt. 37 has begun. This area was approved for development of a deep pond fishing and recreational area by the state of Florida.



▲ This aerial view shows Tampa Electric's 250-MWe greenfield IGCC unit under construction at the Polk Power Station in Lakeland, FL. The gasifier island is located in the center of the photo behind and to the left of the storage silos; the power island can be seen in the upper right of the photo.

◀ This closer view shows the coal conveyor and storage silos on the right and the Texaco gasifier on the left.



Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)

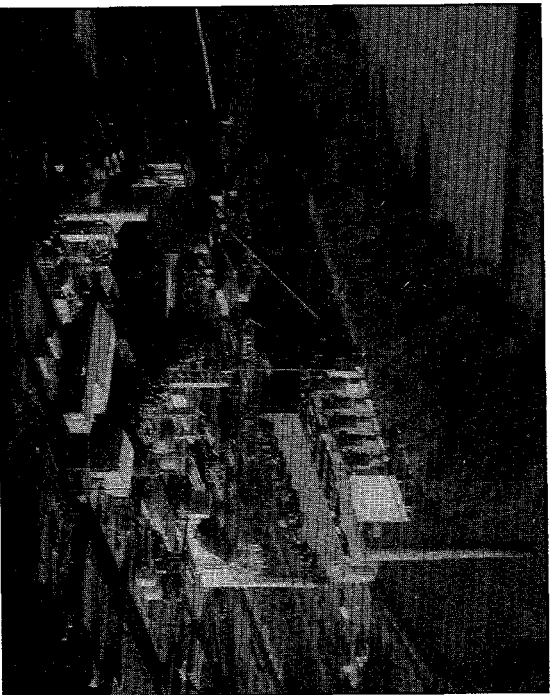
The Wabash River Coal Gasification Repowering Project is demonstrating utility repowering with Destec Energy's two-stage, oxygen-blown IGCC system. The plant is the world's largest single-train IGCC power plant to be operated in a fully commercial setting. One of six units at PSI Energy's Wabash River Generating Station located in West Terre Haute, Indiana, has been repowered with the addition of gasification, cold-gas cleanup, by-product sulfur

recovery, combustion turbine, and associated heat recovery steam generation systems.

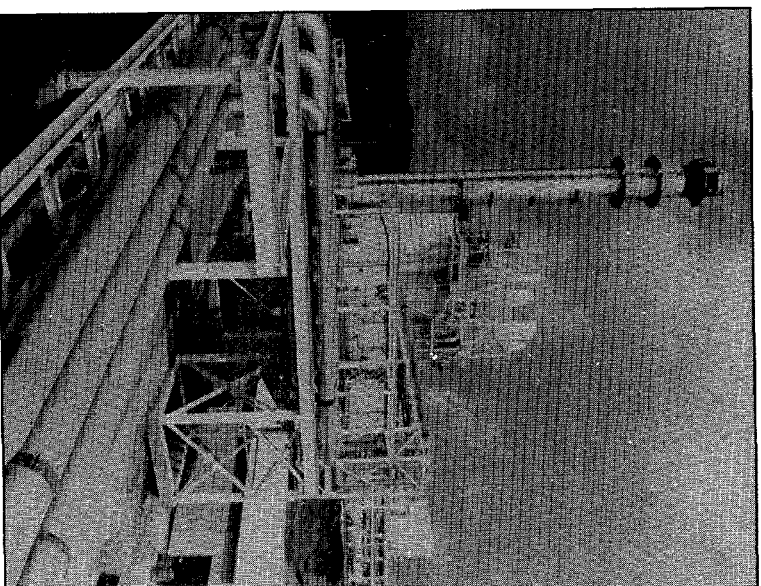
The new combustion turbine will generate 192 MWe and the existing steam turbine will generate an additional 104 MWe (262 MWe net) of electricity using 2,544 tons per day of high-sulfur, Illinois Basin bituminous coal. This is an increase of more than 150 percent in unit capacity. The anticipated heat rate for the repowered unit is approximately 9,000 Btu per kilowatt-hour (38 percent thermal efficiency), or a 21 percent increase in station efficiency.

SO₂ emissions are expected to be less than 0.1 pound per million Btu (98 percent reduction). NO_x emissions are expected to be less than 0.1 pound per million Btu.

Coal was introduced into the gasifier for the first time in August 1995. Plant construction is complete, and all plant systems have been operated. Design specifications for several vessels have been modified to incorporate recent experience from Destec Energy's operating unit located in Plaquemine, Louisiana. Plant acceptance testing has been completed, and commercial operation began in November 1995. A 3-year demonstration period is under way.



▲ Shown is an aerial view of the Wabash River Coal Gasification Repowering Project. This 262-MWe (net) plant is the largest single-train IGCC plant in the world to be operated in a fully commercial setting. The gasifier can be seen in the center, the power island to the right, with the original Wabash River plant in the background.



▲ This photo shows the Wabash River IGCC power island where a clean medium-Btu gas is burned in an advanced 192-MWe (gross) gas turbine and its exhaust is used to produce high-pressure steam in a heat recovery generator. The steam is supplied to an existing 104-MWe (gross) steam turbine.

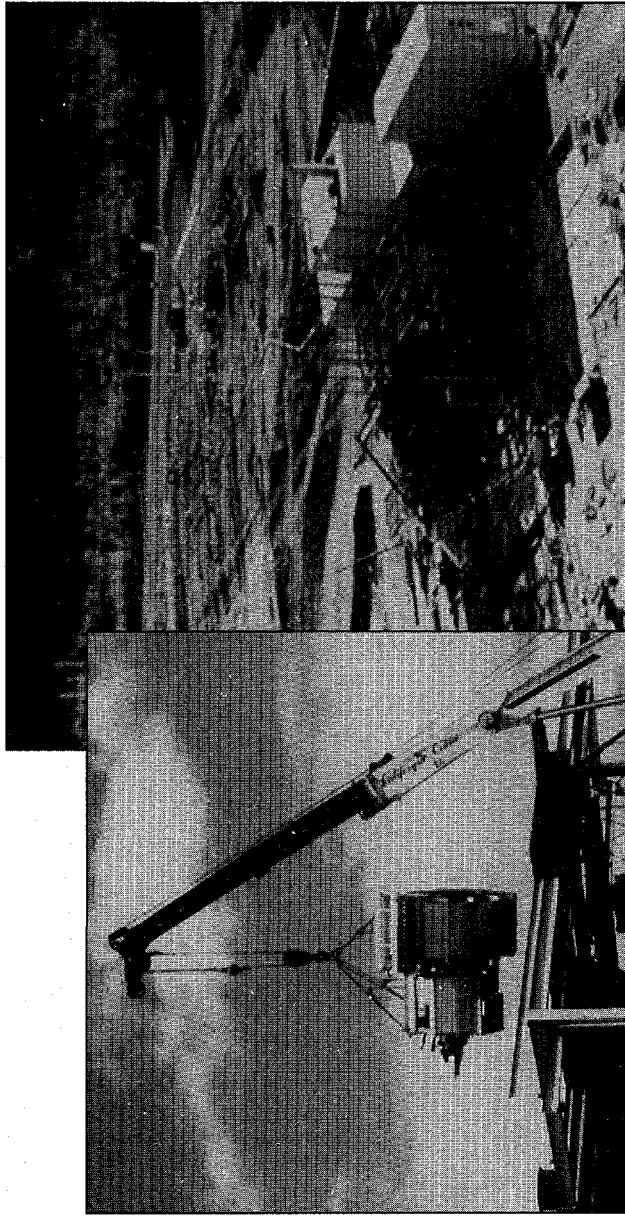
Advanced Electric Power Generation

Healy Clean Coal Project (Alaska Industrial Development and Export Authority)

The Healy Clean Coal Project is demonstrating an innovative power plant design featuring integration of an advanced combustor and heat recovery system coupled with both high- and low-temperature emissions control processes. The 50-MWe facility will consist of two pulverized-coal-fired combustor systems. Emissions of SO_2 and NO_x will be controlled using TRW's advanced entrained (slagging) combustor with staged fuel and air combustion. Further, SO_2 will be removed using Joy Technologies' activated recycle spray dryer absorber system. NO_x emissions are expected to be less than 0.2 pound per million Btu; particulates, 0.015 pound per million Btu; and SO_2 removal, greater than 90 percent.

The project site is adjacent to the existing Healy Unit No. 1 near Healy, Alaska. Power will go to the Golden Valley Electric Association. The plant will use a nominal 900 tons per day of subbituminous coal containing a nominal 0.2 percent sulfur and waste coal. The demonstration will yield 3 years of data, with 2 years of data being provided at no cost to DOE.

On May 30, 1995, a groundbreaking celebration initiated construction activities. By the end of the 1995 construction season, over 30 percent of the structural steel had been erected. Approximately 12,000 cubic yards of concrete had been poured and over 48,000 cubic yards of structural backfill had been hauled. Construction is scheduled to be completed by late-1997, with operation scheduled to start in early 1998.



▲ Construction of the 50-MWe Healy Clean Coal Project began in May 1995. This photograph shows 30% of the structural steel erected at the end of the 1995 construction season. Construction will resume at the site in March 1996.

▲ The full-size precombustion module is being mounted into place at TRW's San Juan Capistrano test facility for design verification testing of the slagging combustor to be used in the 50-MWe Healy Clean Coal Project being built in Alaska.

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)

Southern Company Services is conducting sequential demonstrations of four advanced NO_x control technologies applicable for retrofitting wall-fired, pulverized-coal boilers: (1) advanced overfire air (AOFA), (2) second generation low-NO_x burners (LNB), (3) combined LNB/AOFA, and (4) advanced digital control system that optimizes LNB/AOFA performance using artificial intelligence techniques. The demonstration is being accomplished with a single furnace, which is the 500-MWe Unit No. 4 subcritical, wall-fired boiler at Georgia Power Company's Plant Hammond, located in Coosa, Georgia.

The baseline test segments for AOFA, LNB, and combined LNB/AOFA are complete. More than 80 days of AOFA operating data collected indicated that NO_x reduction of 24 percent is achievable under normal long-term conditions depending upon load. Analysis of the 94 days of LNB long-term data collected showed the full-load NO_x emission levels to be approximately 0.65 pound per million Btu. This NO_x level represents a 48 percent reduction when compared to the baseline, full-load value of 1.23 pounds per million Btu. These reductions were sustainable over the long-term test period and were consistent over the entire load range. Full-load values of flyash loss on ignition in the LNB configuration were near 8 percent, compared to 5 percent for the baseline.

Results from the combined LNB/AOFA testing indicate that full-load NO_x emissions are approximately 0.41 pound per million Btu (63 percent reduction)

with a corresponding value for flyash loss on ignition of near 8 percent.

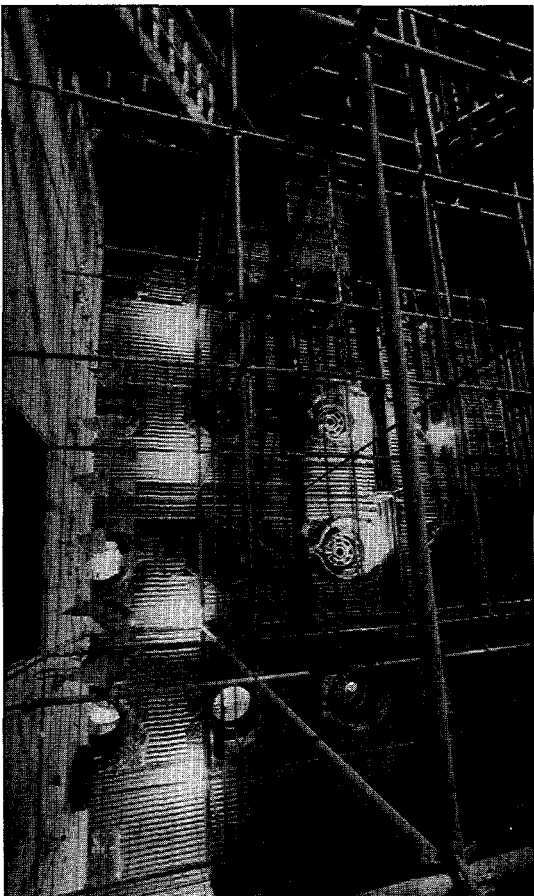
However, preliminary analysis of the emissions data suggests that the incremental NO_x reduction effectiveness of the AOFA system (above LNB alone) was approximately 17 percent, with additional reductions resulting from other operational changes.

The digital control system became operational in mid-1994. Short- and long-term test data are being used to train the neural network combustion models. The artificial intelligence software package for optimizing NO_x reduction and boiler efficiency is nearly

complete. However, low electricity demand has caused the unit to be taken off line for most of October and December 1995. Open- and closed-loop testing will commence upon resumption of unit operation.

A report on the air toxics testing with the combined LNB/AOFA configuration was issued in December 1993.

Completion of the demonstration project and issuance of the final report are scheduled for September 1996.



▲ Shown are the three rows of four low-NO_x burners installed below the AOFA ports on one of two opposing boiler walls. NO_x emissions were reduced by 24% using AOFA, 48% using LNB, and 63% using LNB and AOFA.

Environmental Control Devices

Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)

New York State Electric & Gas Corporation is demonstrating a combination of cost-effective, innovative emissions reduction and efficiency improvement technologies on Units 1 and 2 (150 MWe each) at Milliken Station located in Lansing, New York. Technologies include flue gas cleanup for SO₂ removal using Saarberg-Hölter-Umwelttechnik's formic acid enhanced wet limestone scrubber technology; Nalco Fuel Tech's NO_x OUT[®] urea injection system for NO_x removal, in conjunction with separate combustion modifications, including installation of ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS[™]) Level III; Stebbins' tile-lined split-module absorber for decreased life-cycle costs; a heat-pipe air heater by ABB Air Preheater, Inc., for increased system efficiency; and an operator advisor system developed by DHR Technologies, Inc., for addressing economic and environmental performance.

The project is demonstrating a "total environmental and energy management" concept encompassing low emissions, low energy consumption, improved combustion, upgraded boiler controls, and reduced solid waste. Hazardous air pollutant monitoring is part of the demonstration program.

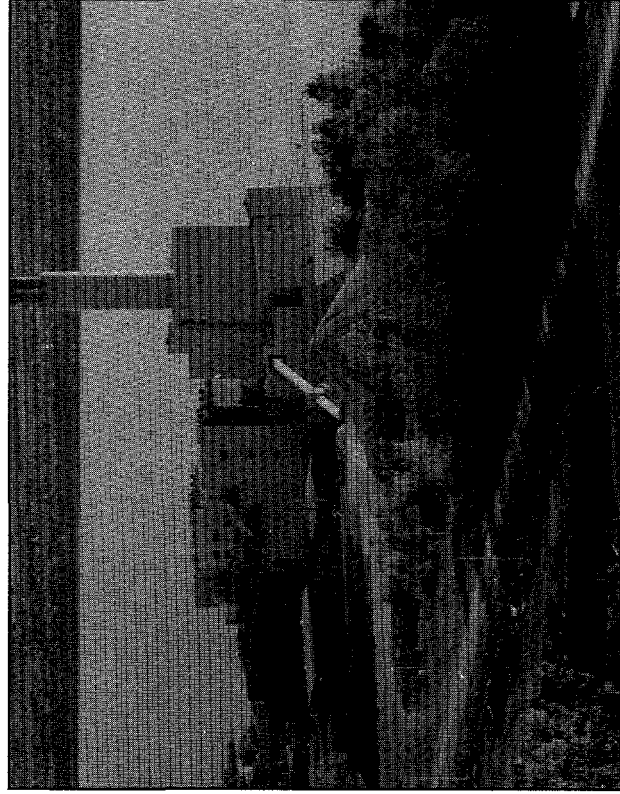
The system is designed to achieve up to 98 percent SO₂ removal efficiency using limestone while burning high-sulfur coal. Pitsburgh, Freeport, and Kittanning coals with sulfur contents ranging from 1.5–4.0 percent are being used.

NO_x emissions have been reduced from 0.65 to 0.40 pound per million Btu (38 percent) by retrofitting the two boilers with low-NO_x burners (LNCFS Level III). NO_x OUT[®] is expected to reduce NO_x emissions from Unit 1 by an additional 15–20 percent.

The split module scrubber began operation for Unit 2 in January 1995. Gypsum production also began in January 1995. Full plant operation with Unit 1 incorporated into the split module scrubber was achieved in June 1995. Low-sulfur performance testing was conducted October–November 1995; evaluation of the data is in progress. Environmental

noise monitoring as required by the state of New York was completed.

A software package developed as part of the Milliken project to assist the utility optimize project operations has become a commercial product. Six modules of DHR Technologies' Plant Emission Optimization Advisor (PEOA[™]) have been sold, and five bids are pending.



▼ The combined SO₂/NO_x environmental control process demonstration at the 300-MW e Milliken Station (two 150-MW e tangentially fired units), was begun in January 1995. The system is designed to achieve 98% SO₂ removal and 38% NO_x reduction. The demonstration is also testing novel automated control system.

Integrated Dry NO_x/SO₂ Emissions Control System (Public Service Company of Colorado)

The integrated dry NO_x/SO₂ emissions control system was installed at Public Service Company of Colorado's Arapahoe 4 in 1992. The 100-MW demonstration combines low-NO_x burners, overfire air, and selective noncatalytic reduction (SNCR) for NO_x control and dry sorbent injection (DSI) with humidification for SO₂ control. The Arapahoe 4 uses top-fired boilers fired with low-sulfur (0.4 percent) Colorado bituminous coal.

The test program involves the individual testing of the low-NO_x burners, overfire air, urea injection, calcium duct injection, calcium economizer injection, sodium injection, and fully integrated system. Four tests were conducted to determine baseline and removal capabilities of the system for many air toxics.

Baseline NO_x emissions before retrofit were nearly uniform across the load range (60–100 MWe) at approximately 1.15 pounds per million Btu. The combination of low-NO_x burners (Babcock & Wilcox Dual-Zone NO_x Ports) and overfire air (Babcock & Wilcox Dual Register Burner–Axially Controlled Low-NO_x or DRB-XCL[®]) greatly reduced NO_x emissions by 63–69 percent across the load range.

The urea-based SNCR supplied by Noell, Inc., reduced NO_x formation by 11–45 percent over the load range. This performance was at urea injection rates that limit NH₃ slip at the

fabric filter inlet to 10 parts per million. Low-load NO_x removal was increased from 11 to 35 percent with the addition of retractable lances that allow urea injection at a higher flue gas temperature. When used with low-NO_x burners, the urea-based SNCR increases total system NO_x reduction to greater than 80 percent at full load, significantly exceeding the project goal of 70 percent. Further, higher NO_x reduction is possible using ammonia as the SNCR chemical at lower loads.

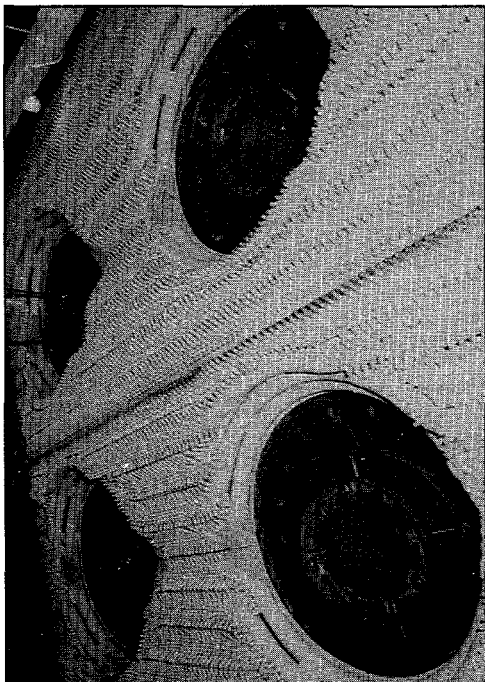
SO₂ removal with the calcium-based [Ca(OH)₂] dry sorbent injected into the boiler without humidifi-

cation was only 5–8 percent at a stoichiometry of 2.0. Operation with the humidification system during economizer injection increased SO₂ removal by only 3–4 percent.

Sodium bicarbonate injection before the air heater was very effective, with short-term SO₂ removal efficiencies of over 80 percent possible. Long-term testing with sodium bicarbonate demonstrated removal efficiency near 70 percent at an approximate stoichiometric ratio of 1.0. Sodium sesquicarbonate injection after the air heater also obtained 70 percent SO₂ removal but at a stoichiometric ratio of approximately 1.8.

The project includes a comprehensive investigation into many potential air toxic emissions. The fabric filter had an overall particulate removal efficiency of over 99.96 percent. Removal efficiency of all trace metals sampled averaged over 96.9 percent. Mercury removal had the lowest capture efficiency of 78 percent.

Due to the successful application of the system, the Public Service Company of Colorado plans to continue operation of the combustion modifications and sodium-based DSI system. A final decision on the SNCR system will be made after the test program is completed. The project has been extended through July 1996. Arapahoe 4 has operated over 2,800 hours with an availability factor of over 91 percent.



▲ The combined dry NO_x/SO₂ emission control system installed at the Public Service Company of Colorado's Arapahoe 4 has achieved NO_x reductions greater than 80% and SO₂ reductions of 70–80%. This photo shows four Babcock & Wilcox low-NO_x DRB-XCL[®] down-fired burners mounted in the roof of the boiler.

Coal Processing for Clean Fuels

Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ Inc.)

ABB Combustion Engineering, Inc., and CQ Inc. are demonstrating a personal computer software package that will serve as a predictive tool to assist coal-burning utilities in the selection of optimum quality coal for a specific boiler based on environmental emissions requirements, operational efficiency, and cost. The software predicts operating performance of coals not previously burned at the facility in question.

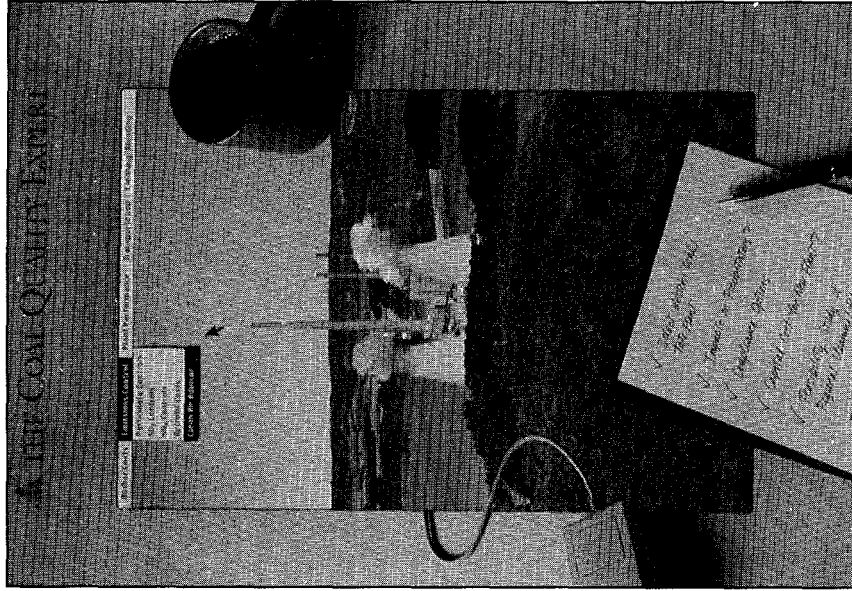
Data have been obtained from bench-, pilot-, and commercial-scale testing of selected coals. The results have been used to develop algorithms for use in a state-of-the-art software package, the Coal Quality Expert (CQE) that can run on a personal computer. In large-scale field tests, a baseline coal (which is the coal currently used as fuel) was burned in the boilers of six utilities over 2-month test periods. An alternate coal, blended or cleaned to improve quality, was also burned in the boiler during the test period. Both the baseline and alternate coals were concurrently tested in bench- and pilot-scale facilities to develop data for correlations and to determine the economics of achieving various quality levels for the cleaned coals.

All of the full-scale field tests with supporting bench and pilot correlation tests were completed by the end of 1993. More than 100 algorithms based on the data generated have been developed. Acid Rain Advisor software became available in 1992, with two commercial sales made in 1993 and 1995.

A CQE prototype was showcased in September 1993. Debugging of the CQE software proceeded

through the end of the project. A CQE beta version was released in May 1995 and evaluated by several utilities by July 1995. The initial commercial version of CQE was released in December 1995. CQE has been distributed to about 40 U.S. utilities and 1 U.K. utility through their membership in EPRI.

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



▲ Software to enable a utility to analyze the effects of coal quality on power plant performance has been developed and tested. The final CQE software, which was received in December 1995, has been evaluated by four U.S. utilities.

Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)

Custom Coals International is demonstrating advanced coal-cleaning unit processes to produce low-cost compliance coals. The project is using Custom Coal's advanced physical coal cleaning and fine magnetite separation technology as well as sorbent addition technology. The 500-ton-per-hour plant is located near Central City, Pennsylvania. The plant will manufacture Self-Scrubbing Coal™ from Illinois No. 5 and Lower Freeport Seam coals and Carefree Coal™ using Lower Kittanning Seam coal. Carefree Coal™ is produced by breaking and screening run-of-mine coal and by using innovative dense-media cyclones and finely sized magnetite to remove up to 90 percent of the pyritic sulfur and most of the ash. When compliance coal cannot be produced by reducing pyritic sulfur, Self-Scrubbing Coal™ can be produced to achieve compliance. This coal is produced by taking Carefree Coal™ and adding to it sorbents, promoters, and catalysts. The coal's reduced ash content permits the addition of relatively large amounts of sorbent without exceeding the ash specifications of the boiler or overloading the electrostatic precipitator.

Construction, initiated in December 1993, was completed in November 1995. Plant start-up procedures were initiated in November. By year-end 1995, all but two conveyors were fully operational. All piping was complete. Electrical work in the plant was 98 percent. All plant units have been turned over by the contractor. All 17 of the planned loop tests have

been completed. Interlock checking was approximately 75 percent complete. Roughly 1,700 tons of coal were received to check out the raw coal truck scales and storage handling system.

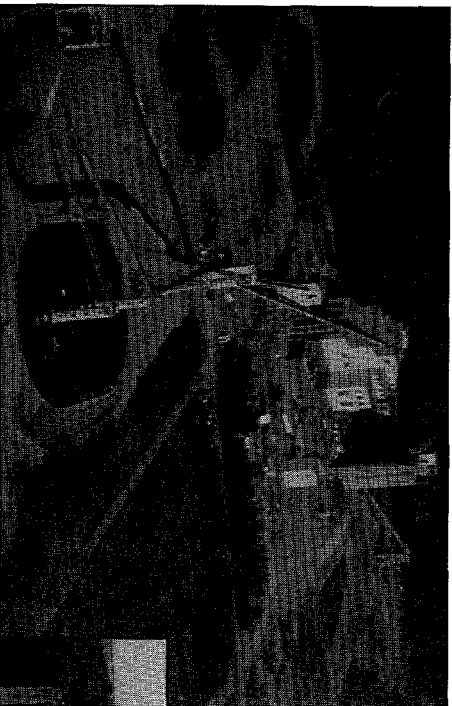
Combustion testing of Kittanning coal is being conducted at Pennsylvania Power and Light's Martin's Creek Power Station; Illinois No. 5 coal is being tested at Richmond Power & Light's Whitewater Valley Generating Station, and Lower Freeport Seam coal at Centenor Energy's Ashabula C Power Plant.

In August 1994, a U.S.-led consortium with Custom Coals International as the principal partner

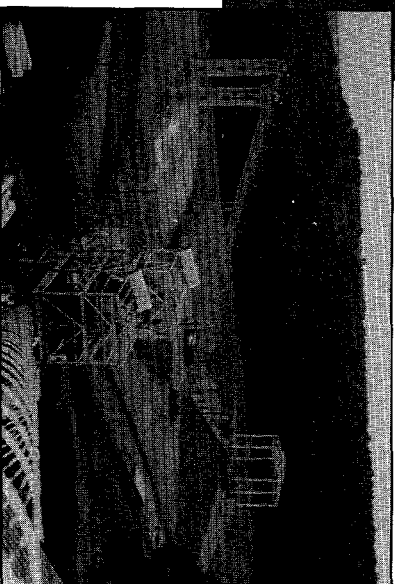
signed a cooperative agreement with the People's Republic of China to build a coal-cleaning plant, a 500-mile underground slurry pipeline, and port facility. The pipeline will bring coal from the Shanxi province in northwest China to the coastal province of Shandong. Final Chinese approval is pending.

Custom Coals has received letters of intent from three Polish power plants that wish to produce 7.5 million tons per year of cleaned coal.

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



▲ Construction of the 500-ton/hr Custom Coal International facility was completed in 1995. The coal preparation plant (upper center) is positioned next to three 5,000-ton clean coal product storage silos. Coal receiving and sizing facilities are left center, and train and truck loadouts are upper right.



▼ This photo shows the coal receiving and sizing facilities, as viewed from the coal preparation plant.

Coal Processing for Clean Fuels

Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)

The Rosebud SynCoal Partnership project is demonstrating an advanced thermal coal-conversion process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, reduced-ash, low-sulfur fuel called SynCoal®. The 1,000-ton-of-SynCoal-per-day demonstration unit is located at the Rosebud Mine in Colstrip, Montana. The project enhances low-rank western coal, which usually has a moisture content of 25-40 percent, sulfur content of 0.5-1.5 percent, and heating value of 5,500-9,000 Btu per pound. Enhancement is achieved by producing a stable, upgraded SynCoal® with a moisture content as low as 1 percent, sulfur content as low as 0.4 percent, ash content of about 9 percent, and heating value of up to 12,000 Btu per pound.

A test program was initiated in March 1994 at Montana Power's J.E. Corette plant using a 50/50 blend of raw subbituminous coal and DSE-conditioned SynCoal®. Preliminary results indicate significantly improved boiler cleanliness, efficiency, and operations output while the SO₂ emissions decreased with no noticeable effect on NO_x. With higher SynCoal® blends, SO₂ emissions decreased by as much as 43 percent and the plant could hold a 170-MWe load, which is well above the normal 160-MWe load. The boiler efficiency increased from 84.9 to 85.7 percent with the 50/50 blend and to 86.2 percent with a 75/25 blend. The corresponding decreases in net unit heat

rate were 130 Btu per kilowatt-hour for the 50/50 blend and 181 Btu per kilowatt-hour for the 75/25 blend.

Project operations have been extended through mid-1997.

Rosebud SynCoal Partnership has conducted a study for Minnkota Power Cooperative to examine the merits of applying the coal processing technology to a commercial plant integrated into an existing power plant site. The study results have been positive, but market commitments are still necessary.

Total sales of SynCoal® product continued strong during 1995 with deliveries made to four industrial customers: Ash Grove Cement, Bentonite Corporation, Empire Sand and Gravel, and Wyoming Lime.

Montana Power's J. E. Corette Plant, Colstrip Units 3 and 4, Minnkota Power, and the University of North Dakota also have received SynCoal® products for testing. A total of 1,037,255 tons of SynCoal® products were made through year-end 1995. Total sales of SynCoal® products during 1995 were 315,687 tons.

The partnership is working on two semi-commercial projects, one each in Wyoming and Montana. These projects would range in size from 500,000 to 5 million tons per year.



◀ The Rosebud SynCoal® facility is an advanced coal-conversion process designed to upgrade low-rank western coal to a low-moisture, low-sulfur, low-ash, enhanced Btu fuel called SynCoal®. During 1995 over 42,000 tons of SynCoal® were delivered to utility and industrial customers.

Coal Processing for Clean Fuels

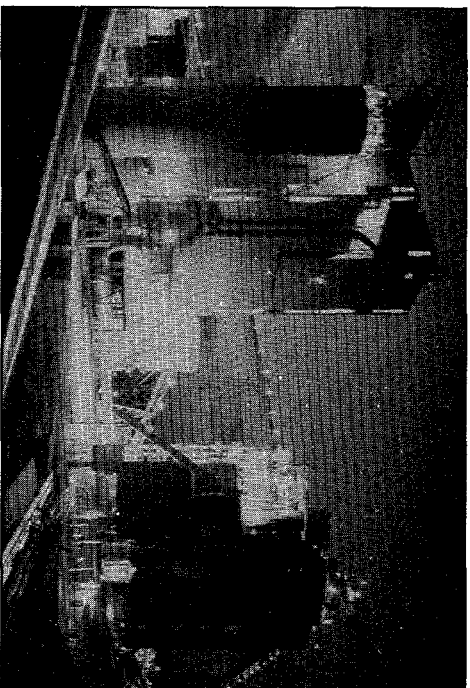
ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)

ENCOAL Corporation is demonstrating the integrated operation of a number of novel process steps which involve heating coal under carefully controlled conditions to produce two higher value fuel forms from mild gasification of low-sulfur, low-heating-value subbituminous coal. The coal is dried and pyrolyzed in two rotary grates arranged in series. The process produces (1) a new solid fuel with higher heating value (about 12,000 Btu per pound) and lower sulfur content than the coal feedstock (on a pound-per-million-Btu basis) and (2) low-sulfur liquid products that can be directly substituted for No. 6 fuel oil. The solid product is usable in any scale industrial or utility boiler.

The site for this plant is Triton Coal Company's Buckskin Mine located about 10 miles north of Gillette, Wyoming.

The plant officially entered the production mode in June 1994; operation has been at a coal feed rate of 500 tons per day. By year-end 1995, the plant had completed test runs representing more than 7,900 hours of operation on coal. More than 43,189 tons of solid product and more than 2.2 million gallons of liquid product have been shipped to industrial and utility customers.

Solid product has been tested by Western Farmers Cooperative's Hugo plant in Oklahoma (15-30 percent blends with Powder River Basin coal), by Muscatine Power and Water in Iowa (40-100 percent product), and by Omaha Public Power District in



► By year-end 1995, the ENCOAL plant had produced more than 43,000 tons of solid product for utility use and 2.2 million gallons of liquid product mainly for industrial use.

Nebraska (92 percent blend). ENCOAL also has contracted with Wisconsin Power & Light for the sale of 30,000 tons of solid product. Test data from the study of initial commercial shipments and utilization of both solid and liquid products show a reduction in sulfur content of over 20 percent on the basis of SO₂ per million Btu.

Tank cars of liquid product are being shipped to several customers in the Midwest for use in industrial boilers. The Dakota Gasification Company tested the liquid products in 1992 and in 1994 purchased an additional 800,000 gallons and continues to use it in the synfuel plant in Beulah, North Dakota.

A topical report on the initial commercial shipment and utilization of both solid and liquid products was released in March 1995. Test data with respect to

sulfur distribution in the products show a reduction of over 20 percent in the SO₂ content per million Btu.

Numerous feasibility studies have been performed for both domestic and international clients who are primarily interested in upgrading their low-rank coal reserves. TEK-KOL and Mitsubishi Heavy Industries are performing advanced feasibility studies regarding joint engineering, design, and construction of commercial plants in Indonesia, China, and Russia. TEK-KOL is also negotiating with Japanese trading companies to market both liquid and solid products in Southeast Asia. The products are well suited for utility and iron-making markets normally served by low-sulfur bituminous coals, which are expected to be in short supply in the post-2000 period when dependence on low-rank coals is expected to increase.

Coal Processing for Clean Fuels

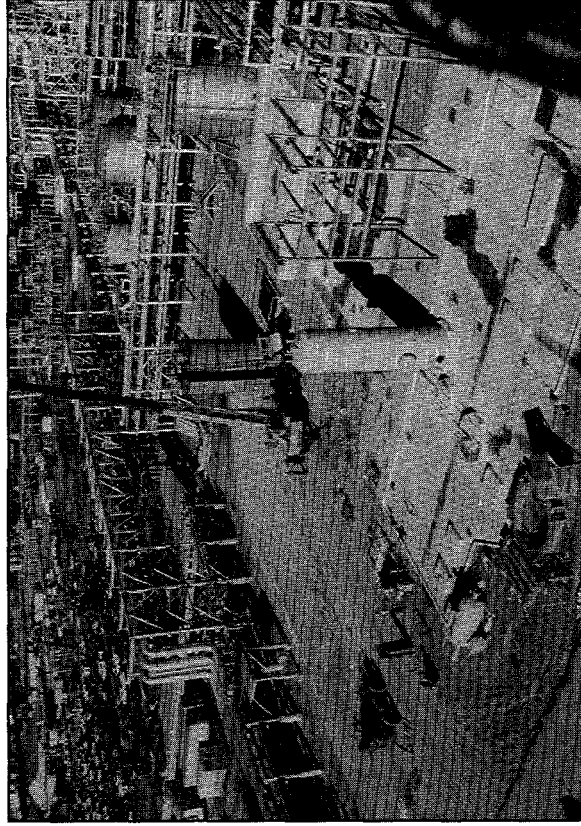
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)

The Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process will demonstrate the production of methanol from coal-derived synthesis gas using Air Products and Chemicals' LPMEOH™ process. The project will determine the suitability of methanol as produced by the demonstration facility for use as a chemical feedstock or as a low-SO₂, low-NO_x alternative fuel in stationary and transportation applications. If practical, the production of dimethyl ether (DME) also will be demonstrated.

The project site is Eastman Chemical Company's integrated coal gasification facility at Kingsport, Tennessee, where it will be possible to ramp up or down to demonstrate the unique load-following flexibility of the LPMEOH™ unit for coal-based power generation applications. Methanol fuel testing will be conducted in off-site stationary and mobile applications, such as boilers, fuel cells, buses, and van pools. Design verification testing for the production of DME as a mixed coproduct with methanol for use as a storable fuel is planned. Based on the results of this testing, a decision to demonstrate the coproduction of DME at a commercial scale will be made. Eastern high-sulfur bituminous coal containing 3 percent sulfur and 10 percent ash will be used.

The NEPA process has been completed. An environmental assessment was prepared, and a finding of no significant impact was approved on June 30, 1995.

Construction activities started in October 1995, and are scheduled to be completed in late-1996. A 4-year demonstration period will follow. By year-end 1995, site preparation was complete and foundation installation was under way. Activities to update the off-site fuel-use test plan were initiated. Revisions also were being made to the environmental monitoring plan. The demonstration test plan is also under development.



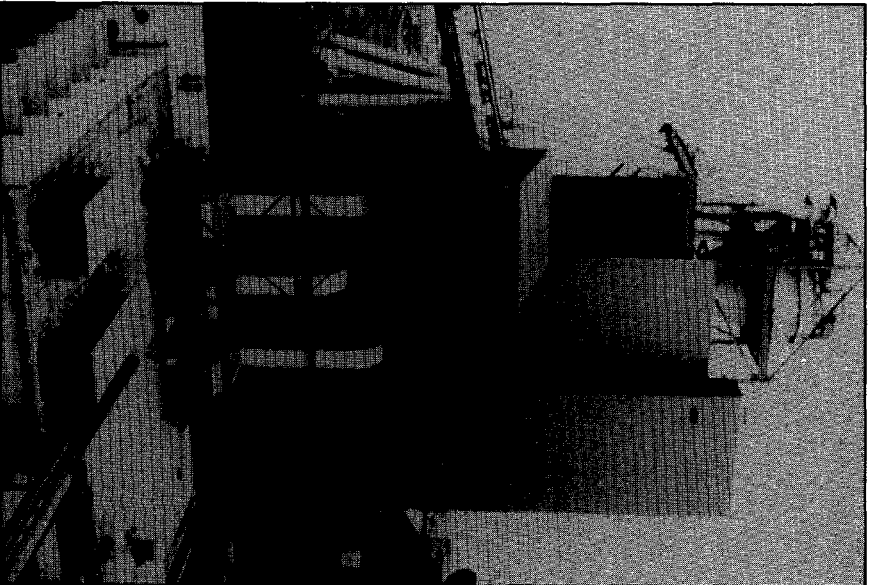
▲ Construction began in October 1995 on the LPMEOH™ demonstration unit at Eastman Chemical Company's coal gasification facility in Kingsport, TN. When completed in late-1996, the demonstration unit will produce 80,000 gallons/day of methanol.

Industrial Applications

Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)

Bethlehem Steel Corporation completed construction and start-up for a project to demonstrate the injection of granulated coal directly into two blast furnaces at Burns Harbor, Indiana. Preoperational testing began in February 1995 and continued until November 1995 when full operation began. The coal displaces up to 40 percent of the coke normally used in the steelmaking process, thus reducing coke requirements and the attendant emissions associated with coke making. The reducing environment of the blast furnace enables all of the sulfur in the coal to be captured by the slag and hot metal.

Granular coal is being injected through 26 inyeses of both the C and D furnaces at average injection rates of 170–225 pounds per net ton of hot metal. (The target rate was 180 pounds per net ton for each furnace during start-up.) Injection rates of 235 pounds per net ton of hot metal have been achieved. Furnace operation has been improving as operators gain experience. Coal is being switched on the fly from a high-volatile Kentucky coal to a low-volatile Virginia coal. Burden and blast conditions are being fine-tuned on both furnaces as injection rate increases.



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

Exhibit 6-2

Status of CCT Demonstration Projects at Year-End 1995—Advanced Electric Power Generation

Project and Participant

Status

Fluidized-Bed Combustion

PFBC Utility Demonstration Project
(The Appalachian Power Company)

The participant has proposed resiting the project at the Jacksonville Electric Authority's Northside Station in Florida.

PCFB Demonstration Project
(DMEC-1 Limited Partnership)

The July 1995 merger between Midwest Resources, Inc., (parent of Midwest Power) and Iowa-Illinois Gas and Electric to form MidAmerican Energy Company has impacted the project structure. A further complication has resulted from the recent acquisition of Ahlstrom Pyropower by Foster Wheeler Energy Corporation. An extension to April 30, 1996, has been issued to provide the participant with additional time to resite the project, restructure activities, and finalize continuation plans.

Four Rivers Energy Modernization Project
(Four Rivers Energy Partners, L.P.)

The participant has been informed that a decision on a power purchase agreement would not be made until the summer of 1996. An extension until April 30, 1996, has been issued so that the participant can consider alternative sites.

Tidd PFBC Demonstration Project
(The Ohio Power Company)

Operational testing was completed on March 30, 1995; the final report is expected to be available in early 1996. During the 54 months of testing, the unit completed 95 parametric tests and accumulated 11,444 hours of coal-fired operations. Test results showed that 90% SO₂ capture was achieved with a Ca/S of 1.1 and 95% SO₂ capture was achieved with a Ca/S of 1.5 using 2-4% sulfur Ohio bituminous coals and dolomite sorbent. Inherent in the process were NO_x emissions in the range of 0.15-0.33 lb/million Btu. CO and particulate emissions were less than 0.01 and 0.02 lb/million Btu respectively.

Nucla CFB Demonstration Project (Tri-State
Generation and Transmission Association, Inc.)

Project reporting is complete. The cooperative agreement ended in April 1992.

ACFB Demonstration Project
(York County Energy Partners, L.P.)

All activities have been put on hold while resiting options are considered. On September 26, 1995, York County Energy Partners and Metropolitan Edison Company announced their joint decision to restructure the power-purchase agreement to allow for development of a natural-gas-fired facility instead of the coal-fired cogeneration plant originally planned. DOE will not participate in the revised natural gas project. Other options for a coal-fired plant are being considered.

Integrated Gasification Combined Cycle

Combustion Engineering IGCC Repowering Project
(ABB Combustion Engineering, Inc.)

An extension to May 31, 1996, has been granted to allow the participant to complete project restructuring activities, including changing the site to TVA's Bellefonte Plant near Scottsboro, AL; increasing the size to 375-400 MWe; changing the technology to the Shell gasification process; and changing the project team, schedule, and total cost. No additional DOE funds will be requested beyond the current DOE share amount.

Clean Energy Demonstration Project
(Clean Energy Partners Limited Partnership)

The cooperative agreement was awarded December 2, 1994. The participant is seeking a suitable project site on the east coast.

**Exhibit 6-2 (continued)
Status of CCT Demonstration Projects at Year-End 1995—Advanced Electric Power Generation**

Project and Participant	Status
<p>Piñon Pine IGCC Power Project (Sierra Pacific Power Company)</p>	<p>Construction began in early 1995 and by year-end was approximately 50% complete. Fabrication of the gasifier is complete. Structural steel has been erected to the 93-ft elevation. Foundations north of the gasifier islands as well as foundations for the coal crusher and solid waste silo are complete; also the steam turbine mat has been poured. Further, the 42-inch cooling lines to the steam turbine foundation and in the cooling tower area are complete. The public design report was issued in August 1995.</p>
<p>Tampa Electric Integrated Gasification Combined-Cycle Project (Tampa Electric Company)</p>	<p>Site construction is approximately 70% complete, and structural steel is 90% in place. All major vessels have been placed in the structure. The turnkey air separation plant is mechanically complete and undergoing checkout and qualification testing. Reclamation of the area west of Rt. 37 has begun. This area was approved for development of a deep pond fishing and recreational area by the state of Florida.</p>
<p>Wabash River Coal Gasification Repowering Project (Wabash River Coal Gasification Repowering Project Joint Venture)</p>	<p>Plant acceptance testing has been completed, and commercial operations began in November 1995. Coal was introduced into the gasifier for the first time in August 1995. Plant construction is complete.</p>
<p>Advanced Combustion/Heat Engines</p>	
<p>Healy Clean Coal Project (Alaska Industrial Development and Export Authority)</p>	<p>Engineering and design activities are complete. A groundbreaking ceremony was held May 30, 1995. By the end of the 1995 construction season, approximately 12,000 cubic yards of concrete had been poured and over 48,000 cubic yards of structural backfill had been hauled. Erection of structural steel, which began in August 1995, is more than 30% complete. Construction will resume in March 1996.</p>
<p>Coal Diesel Combined-Cycle Project (Arthur D. Little, Inc.)</p>	<p>Full-scale single-cylinder fuel evaluation tests have been conducted on Ohio coal-water fuels at Cooper's research energy facility in Mount Vernon, OH. The participant has finalized subcontract agreements with Cooper-Bessemer and CQ Inc., as well as its funding agreement with the Ohio Coal Development Office. Easton Utilities, the original host, has withdrawn from the project. An extension to June 15, 1996, has been granted to the participant to allow completion of activities relating to resiting the project to the University of Alaska in Fairbanks.</p>
<p>Warren Station Externally Fired Combined-Cycle Demonstration Project (Pennsylvania Electric Company)</p>	<p>The cooperative agreement was awarded on August 1, 1994. The design period has been extended because of a lack of sufficient development progress for the externally fired technology. Options for restructuring the project also are under discussion.</p>

Exhibit 6-3

Status of CCT Demonstration Projects at Year-End 1995—Environmental Control Devices

Project and Participant	Status
NO_x Control Technologies	
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control (The Babcock & Wilcox Company)	Results of parametric and optimization testing demonstrated NO _x emissions are reduced by about 52% at 110 MWe (full load), 47% at 82 MWe, and 36% at 60 MWe. For western coal, NO _x emissions were reduced by 62% at 110 MWe, 55% at 82 MWe, and 53% at 60 MWe. The project was completed as of December 31, 1993, and the final report was delivered in March 1994. The technology is being retained by Wisconsin Power and Light for commercial use.
Full-Scale Demonstration of Low-NO _x Cell Burner Retrofit (The Babcock & Wilcox Company)	Operational testing was completed in April 1993. Testing indicated that the NO _x emissions reduction when at full load is 54-58%. The final report has been submitted.
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler (Energy and Environmental Research Corporation)	Operational testing was completed in January 1995; final reports are in preparation. The project demonstrated that, with a gas heat input of 13%, second generation GR-LNB without flue gas recirculation can achieve a NO _x reduction of 64%. Restoration work was completed in November 1995.
Micronized Coal Reburning Demonstration of NO _x Control (New York State Electric & Gas Corporation)	Due to plant problems and operational and environmental strategy changes, the original host site was no longer suitable to demonstrate the technology. TVA and New York State Electric & Gas are finalizing an agreement to allow the project to be conducted at both Milliken Station in Lansing, NY, and Eastman Kodak Company in Rochester, NY. The revised project will accomplish all of the original project objectives (with no increase in the DOE cost) plus bring additional technologies under the repayment umbrella.
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler (Southern Company Services, Inc.)	Long-term testing of advanced overfire air (AOFA), low-NO _x burners (LNB), and LNB+AOFA has been completed. The digital control system has been installed and is operational. Short- and long-term test data are being used to train the neural network combustion models. The Generic NO _x Control Intelligent System software installation is virtually complete; however, low boiler utilization has delayed debugging and testing. Full-load, long-term emission levels for the baseline, AOFA, LNB, and LNB+AOFA configurations were 1.23, 0.94, 0.65, and 0.41 lb/million Btu, respectively.
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers (Southern Company Services, Inc.)	Operational testing was completed in July 1995. Dismantling efforts have been completed. Final reports are in preparation and the results are expected to be available in mid-1996.
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers (Southern Company Services, Inc.)	Long-term test data from operating the LNCFS Level I and II equipment (two of three air/coal-feed test configurations) indicated NO _x reductions of up to 37% at full load, compared to baseline emissions data. For Level III, NO _x reductions were as much as 45%. The project was completed as of June 30, 1994. Gulf Power has retained the LNCFS™ at its Plant Lansing Smith.

Exhibit 6-3 (continued) Status of CCT Demonstration Projects at Year-End 1995—Environmental Control Devices

Project and Participant	Status
SO₂ Control Technologies	
10-MW _e Demonstration of Gas Suspension Absorption (AirPol, Inc.)	Operational testing was completed in March 1994. Test results indicate that the GSA is capable of consistently maintaining 90+-% SO ₂ removal at a moderate lime requirement and at an 18 °F approach-to-adiabatic-saturation temperature. The GSA has also demonstrated high availability during the test period. Air toxics testing conducted during October 1993 showed a removal rate of over 95%. A full-scale unit is being installed at the 50-MW _e municipal power station in Hamilton, OH; this unit is scheduled for operation in August 1996.
Confined Zone Dispersion Flue Gas Desulfurization Demonstration (Bechtel Corporation)	Bechtel notified DOE on June 30, 1993, that it was discontinuing the project effective July 1, 1993. The final report has been submitted.
LIFAC Sorbent Injection Desulfurization Demonstration Project (LIFAC—North America)	LIFAC testing was completed in June 1994; final reports are in preparation. Long-term tests showed that SO ₂ reductions above 70% can be maintained under normal boiler operating ranges. The LIFAC system has been retained by Richmond Power & Light.
Advanced Flue Gas Desulfurization Demonstration Project (Pure Air on the Lake, L.P.)	Operational testing was completed in June 1995. Final reports are in preparation. During the 3-year operation, SO ₂ removal efficiency averaged 94%, with a maximum of 98+-% or 0.382 lb/million Btu. Availability was more than 99%. The AFGD unit will continue to be operated at Bailly Station under an own-and-operate agreement.
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process (Southern Company Services, Inc.)	Operational testing concluded in December 1994; the final report is in preparation. The system was able to maintain SO ₂ removal efficiency above 90% at all loads at SO ₂ inlet levels of 1,000–3,500 ppm and limestone utilization over 97%. Particulate removal efficiency was 97.7–99.3% for inlet mass loadings of 0.303–1.392 lbs/million Btu for a load range of 50–100 MW _e . Operational responsibility for the scrubber was permanently assumed by Georgia Power in January 1995. Reporting and gypsum investigations will continue through 1996.
Combined SO₂/NO_x Control Technologies	
SNOX™ Flue Gas Cleaning Demonstration Project (ABB Environmental Systems)	Operational testing was completed in December 1994; final reports are in preparation. The system has operated for over 8,000 hours and produced more than 5,600 tons of commercial-grade sulfuric acid. The facility has routinely operated at full capacity, achieving removal efficiencies of 95% for SO ₂ , 94% for NO _x , and 99+-% for particulates. The system was retained by Ohio Edison Company as part of its CAAA of 1990 compliance strategy.
LIMB Demonstration Project Extension and Coolside Demonstration (The Babcock & Wilcox Company)	Final reports on Coolside and LIMB extension testing are complete and available to the public through NNTS. The cooperative agreement ended January 1993.
SO _x -NO _x -Rox Box™ Flue Gas Cleanup Demonstration Project (The Babcock & Wilcox Company)	Operational testing was completed in May 1993; the final report was issued in September 1995. SO ₂ removal efficiencies were 80% with commercial-grade lime and 90% with hydrated lime (both at 2.0 Ca/S and 800–850 °F) and 80% with sodium bicarbonate (1.0 Na ₂ S, 425 °F). NO _x reductions consistently exceeded 90%. Particulate removal efficiency was 99.89%.

Exhibit 6-3 (continued)
Status of CCT Demonstration Projects at Year-End 1995—Environmental Control Devices

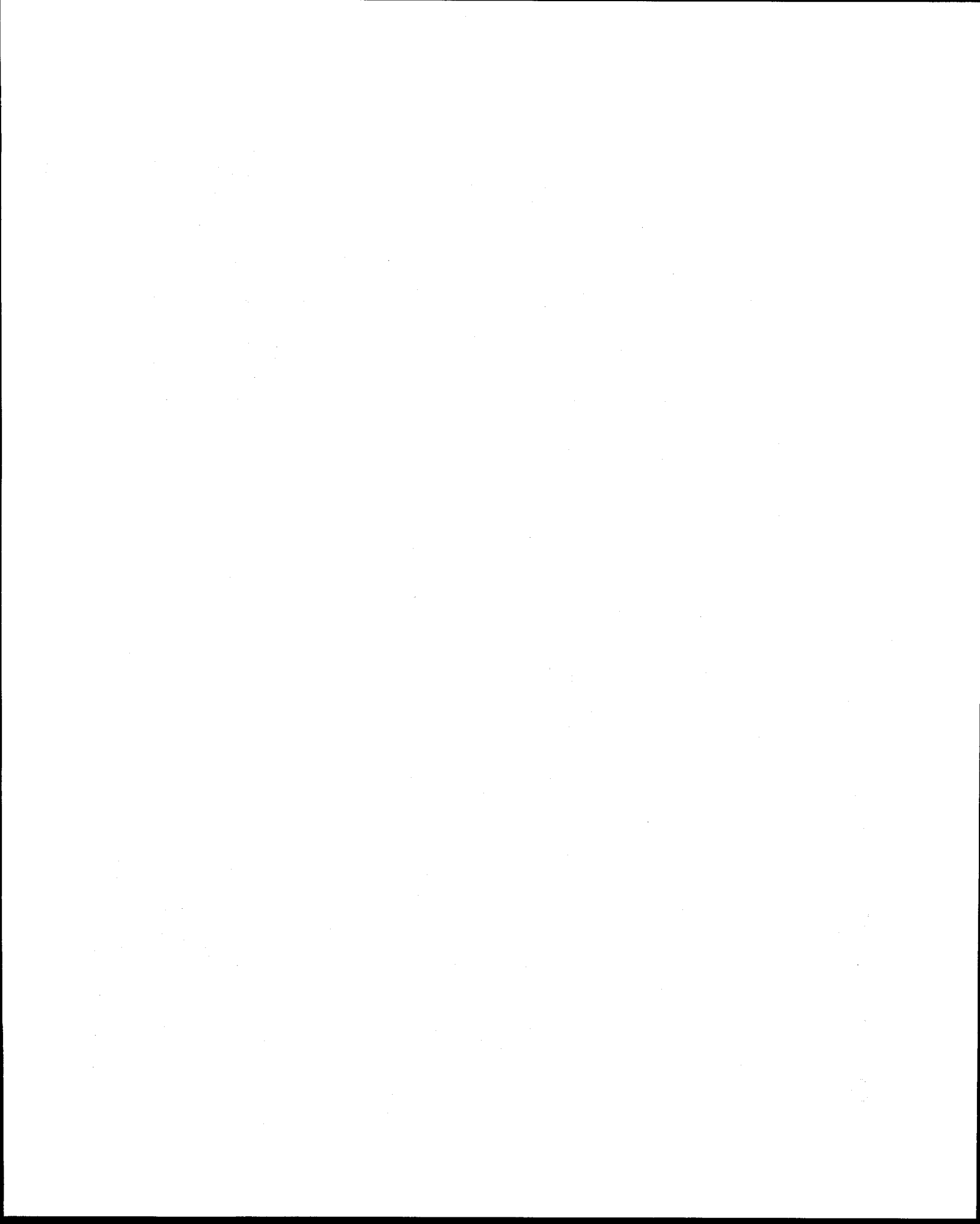
Project and Participant	Status
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection (Energy and Environmental Research Corporation)	<p>Long-term load-following and alternate sorbent testing were completed at Hennepin in January 1993; the final report was issued in October 1994. Average emission reductions of 52% for SO₂ and 67% for NO_x with 18% gas input were achieved. Operational testing at Lakeside was completed in October 1994. During long-term, full-load GR-SI testing at Lakeside, the SO₂ reduction was 58%. During gas-reburn long-term testing, NO_x reduction averaged 67%. Restoration work has been completed at both sites. Illinois Power is retaining the gas-reburning system for possible use in NO_x control at Hennepin Unit 1. City Water, Light and Power is retaining both the gas-reburning and sorbent injection systems at Lakeside Station for use at a later date.</p>
Milliken Clean Coal Technology Demonstration Project (New York State Electric & Gas Corporation)	<p>The split module scrubber began operation for Unit 2 in January 1995. Gypsum production also began in January 1995. Full plant operation with Unit 1 incorporated into the split module scrubber was achieved in June 1995. Low-sulfur performance testing was conducted October–November 1995; evaluation of the data is in progress. Environmental noise monitoring as required by the state of New York was completed.</p>
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System (NOXSO Corporation)	<p>A new site—Alcoa Generating Company's Warrick Power Plant—was identified in 1994. An environmental assessment and finding of no significant impact was approved June 26, 1995. Detailed design activities are under way. Construction is pending final sale of revenue bonds which will provide the balance of NOXSO's cost share. The revenue bonds will be issued and guaranteed by the state of Indiana.</p>
Integrated Dry NO _x /SO ₂ Emissions Control System (Public Service Company of Colorado)	<p>Parametric testing of urea injection was completed in December 1995. The retractable lances showed a marked improvement over the original wall injectors. The best NO_x reduction (50%) was obtained at 60 MWe. A short test of automatic load following was completed. After several control system modifications, the system responded correctly by switching between various injection points as the load varied. A 4-week test of the urea injection and dry sorbent injection system will begin in mid-February 1996.</p>

Exhibit 6-4 Status of CCT Demonstration Projects at Year-End 1995—Coal Processing for Clean Fuels

Project and Participant	Status
<p>Coal Preparation Technologies</p> <p>Development of the Coal Quality Expert (ABB Combustion Engineering, Inc., and CQ Inc.)</p> <p>Self-Scrubbing Coal™: An Integrated Approach to Clean Air (Custom Coals International)</p> <p>Advanced Coal Conversion Process Demonstration (Rosebud SynCoal Partnership)</p>	<p>Over 100 algorithms based on data generated from 6 full-scale field tests have been developed. Acid Rain Advisor software became available in 1992, with two sales made in 1993 and 1995. A COE beta version was released in May 1995 and evaluated by several utilities by July 1995. The initial commercial version of COE was released in December 1995. COE has been distributed to about 40 U.S. utilities and 1 U.K. utility through membership in EPRI.</p> <p>Plant start-up procedures were initiated in November. By year-end 1995, all but two conveyors were fully operational. All piping was complete. Electrical work in the plant was 98%. All plant units have been turned over by the contractor. All 17 of the planned loop tests have been completed. Interlock checking was approximately 75% complete. Approximately 1,700 tons of coal were received to check out the raw-coal truck scales and storage handling system. In addition, preliminary baseline testing of 10,000 tons of low-volatile coal burned at Martin's Creek has been completed.</p> <p>A total of 1,037,255 tons of SynCoal® products were made through year-end 1995. Total sales during 1995 were 315,687 tons. In 1995, a total of 42,177 tons of SynCoal® products were delivered to four industrial customers: Ash Grove Cement of Montana City, MT, has received granular SynCoal® and fines; Bentonite Corporation of Colony, WY, regular SynCoal®, Empire Sand and Gravel of Billings, MT, granular SynCoal®, and Wyoming Lime of Warren, MT, fines and granular SynCoal®. Montana Power's J.E. Corette Plant has received a conditioned SynCoal® and DSE-conditioned SynCoal® blend. Montana Power's Colstrip Units 3 and 4 and Minkota Power have received SynCoal® to continue their testing. The University of North Dakota has received SynCoal® blended with raw coal. "Klinker Killer" testing has been initiated at the Minkota Power Station and the J.E. Corette Plant. Extended kiln testing has begun at Wyoming Lime.</p>
<p>Mild Gasification</p> <p>ENCOAL Mild Coal Gasification Project (ENCOAL Corporation)</p>	<p>By year-end 1995, the plant had logged more than 7,900 hours of operation on coal. More than 43,189 tons of solid product and more than 2.2 million gallons of liquid product have been shipped to industrial and utility customers. A topical report on the initial commercial shipment and utilization of both solid and liquid products was released in March 1995. Test data with respect to sulfur distribution in the products show a reduction of over 20% in the SO₂ content per million Btu.</p>
<p>Indirect Liquefaction</p> <p>Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process (Air Products Liquid Phase Conversion Company, L.P.)</p>	<p>The NEPA process has been completed. An environmental assessment was prepared and a finding of no significant impact was approved June 30, 1995. Construction started in October 1995. By year-end 1995, site preparation was complete and foundation installation was under way. Activities to update the off-site fuel-use test plan were initiated. Revisions also were being made to the environmental monitoring plan.</p>

Exhibit 6-5 Status of CCT Demonstration Projects at Year-End 1995—Industrial Applications

Project and Participant	Status
Blast Furnace Granulated-Coal Injection System Demonstration Project (Bethlehem Steel Corporation)	Construction was completed in February 1995. A public design report was issued in March 1995. Start-up testing has been completed, and the plant is fully commissioned. Operational testing began in November 1995. Granular coal is being injected through 26 tuyeres of both the C and D furnaces at average injection rates of 170–225 lbs/net ton of hot metal. (The target rate was 180 lbs/net ton for each furnace during start-up.) Injection rates of 235 lbs/net ton of hot metal have been achieved. Furnace operation has been improving as operators gain experience. Coal is being switched on the fly from a high-volatile Kentucky coal to a low-volatile Virginia coal. Burden and blast conditions are being fine-tuned on both furnaces as injection rate increases.
Clean Power from Integrated Coal/Ore Reduction (COREX®) (Centerior Energy Corporation)	The project was selected May 4, 1993, and the cooperative agreement is in negotiation. In July 1994, Air Products and Chemicals, Centerior Energy, and Geneva Steel Company signed an agreement to site the project at the Geneva Steel mill in Vineyard, UT.
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control (Coal Tech Corporation)	Project reporting is complete. The cooperative agreement ended September 1991.
Cement Kiln Flue Gas Recovery Scrubber (Passamaquoddy Tribe)	Project reporting is complete. The cooperative agreement ended February 1994.
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal (ThermoChem, Inc.)	The project has been resited to Northshore Mining Company's facility located in Silver Bay, MN, and project restructuring activities are in progress. At the new site, the ThermoChem pulse combustion technology will produce fuel gas and char for use in a proposed direct reduction iron process.



7. Project Fact Sheets

Summary

Included in this chapter is project-specific information for each of the 43 projects selected in the CCT Program's five solicitations. This information includes, for each ongoing project, the participant, team members, location, cost and schedule data, process flow diagram (technology being demonstrated is shaded), significant project features, project objectives, description of the process and its performance attributes, progress and accomplishments, and commercial applications. Fact sheets for completed projects contain a brief overview of the results of the demonstration and sources of more detailed information.

The fact sheets are organized into four application categories:

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

To prevent the release of project-specific information of a proprietary nature, the process flow diagrams contained in the fact sheets are presented only as illustrative of the concepts involved in the demonstration.

For the convenience of the reader, two indexes which cross-reference CCT projects by participants

and application categories are provided as a guide to the fact sheets included in this section.

- Exhibit 7-1 indexes project fact sheets by application category.
- Exhibit 7-2 indexes fact sheets by participant.

Additional project information can be obtained through publications listed in Appendixes C and D or from the project contacts listed in Appendix E. Full references for the final reports listed in abbreviated form in fact sheets for completed projects can be found in Appendix C. Furthermore, progress on the CCT projects and significant events can be tracked through DOE's quarterly newsletter, *Clean Coal Today*. To be included on the newsletter mailing list, send name and address to U.S. Department of Energy, FE-22, Washington, DC 20585.

Key to Milestone Charts in Fact Sheets

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



Preaward

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



Design and Construction

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

MTF Memo-to-file

CX Categorical exclusion

EA Environmental assessment

EIS Environmental impact statement



Operation

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

Exhibit 7-1 Project Fact Sheets, by Application Category

Project	Participant	Page
Advanced Electric Power Generation		
Fluidized-Bed Combustion		
PFBC Utility Demonstration Project	The Appalachian Power Company	7-8
PCFB Demonstration Project	DMEC-1 Limited Partnership	7-10
Four Rivers Energy Modernization Project	Four Rivers Energy Partners, L.P.	7-12
Tidd PFBC Demonstration Project	The Ohio Power Company	7-14
Nucla CFB Demonstration Project	Tri-State Generation and Transmission Association, Inc.	7-16
ACFB Demonstration Project	York County Energy Partners, L.P.	7-18
Integrated Gasification Combined Cycle		
Combustion Engineering IGCC Repowering Project	ABB Combustion Engineering, Inc.	7-20
Clean Energy Demonstration Project	Clean Energy Partners Limited Partnership	7-22
Piñon Pine IGCC Power Project	Sierra Pacific Power Company	7-24
Tampa Electric Integrated Gasification Combined-Cycle Project	Tampa Electric Company	7-26
Wabash River Coal Gasification Repowering Project	Wabash River Coal Gasification Repowering Project Joint Venture	7-28
Advanced Combustion/Heat Engines		
Healy Clean Coal Project	Alaska Industrial Development and Export Authority	7-30
Coal Diesel Combined-Cycle Project	Arthur D. Little, Inc.	7-32
Warren Station Externally Fired Combined-Cycle Demonstration Project	Pennsylvania Electric Company	7-34
Environmental Control Devices		
NO_x Control Technologies		
Demonstration of Coal Reburning for Cyclone Boiler NO _x Control	The Babcock & Wilcox Company	7-38
Full-Scale Demonstration of Low-NO _x Cell Burner Retrofit	The Babcock & Wilcox Company	7-40
Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler	Energy and Environmental Research Corporation	7-42
Micronized Coal Reburning Demonstration for NO _x Control	New York State Electric & Gas Corporation	7-44
Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	Southern Company Services, Inc.	7-46
Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers	Southern Company Services, Inc.	7-48
180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers	Southern Company Services, Inc.	7-50

**Exhibit 7-1 (continued)
Project Fact Sheets, by Application Category**

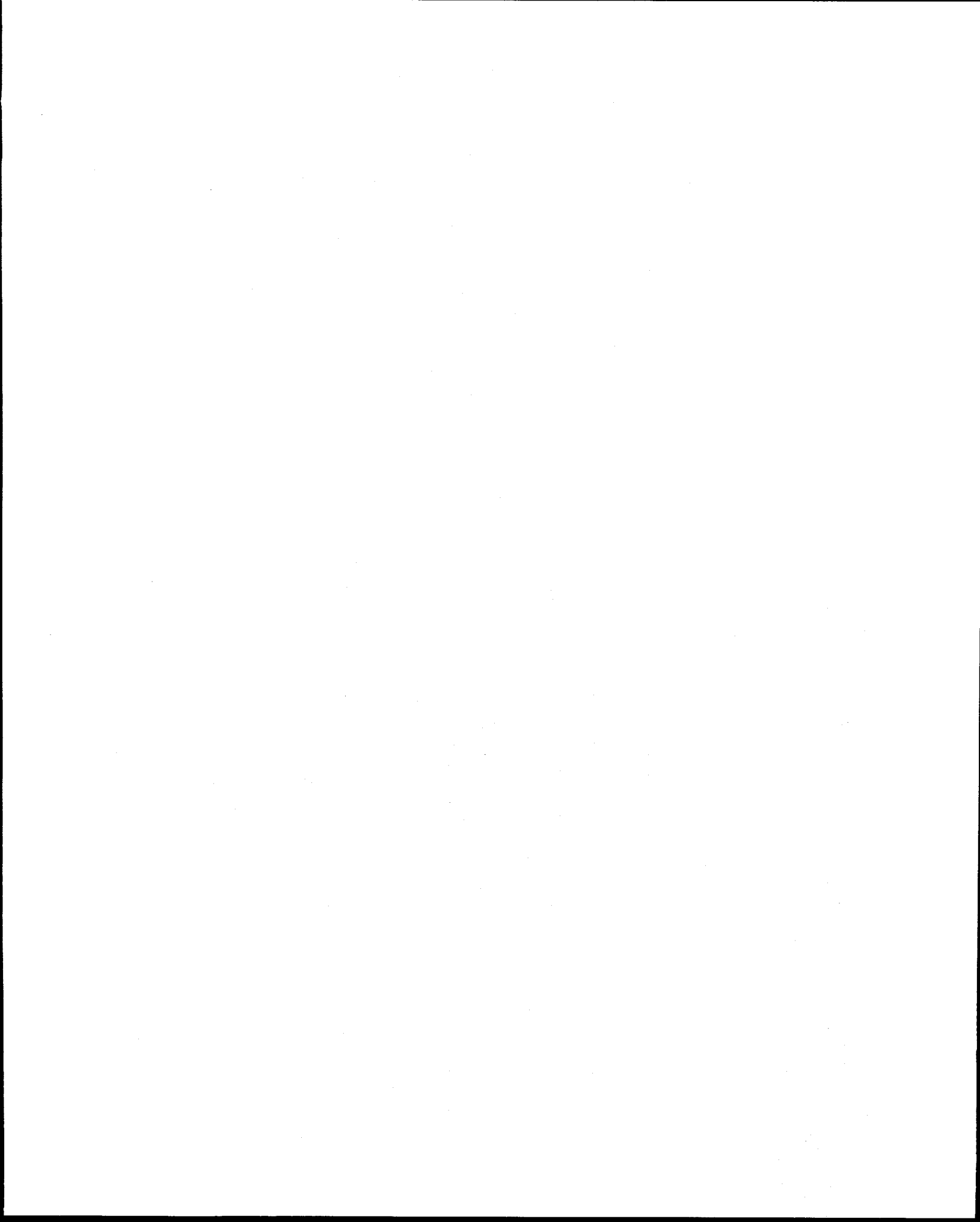
Project	Participant	Page
SO₂ Control Technologies		
10-MWe Demonstration of Gas Suspension Absorption	AirPol, Inc.	7-52
Confined Zone Dispersion Flue Gas Desulfurization Demonstration	Bechtel Corporation	7-54
LIFAC Sorbent Injection Desulfurization Demonstration Project	LIFAC-North America	7-56
Advanced Flue Gas Desulfurization Demonstration Project	Pure Air on the Lake, L.P.	7-58
Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	Southern Company Services, Inc.	7-60
Combined SO₂/NO_x Control Technologies		
SNOX™ Flue Gas Cleaning Demonstration Project	ABB Environmental Systems	7-62
LIMB Demonstration Project Extension and Coolside Demonstration	The Babcock & Wilcox Company	7-64
SOx-NOx-Rox Box™ Flue Gas Cleanup Demonstration Project	The Babcock & Wilcox Company	7-66
Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	Energy and Environmental Research Corporation	7-68
Milliken Clean Coal Technology Demonstration Project	New York State Electric & Gas Corporation	7-70
Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System	NOXSO Corporation	7-72
Integrated Dry NO _x /SO ₂ Emissions Control System	Public Service Company of Colorado	7-74
Coal Processing for Clean Fuels		
Coal Preparation Technologies		
Development of the Coal Quality Expert	ABB Combustion Engineering, Inc., and CQ Inc.	7-78
Self-Scrubbing Coal™: An Integrated Approach to Clean Air	Custom Coals International	7-80
Advanced Coal Conversion Process Demonstration	Rosebud SynCoal Partnership	7-82
Mild Gasification		
ENCOAL Mild Coal Gasification Project	ENCOAL Corporation	7-84
Indirect Liquefaction		
Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	Air Products Liquid Phase Conversion Company, L.P.	7-86
Industrial Applications		
Blast Furnace Granulated-Coal Injection System Demonstration Project	Bethlehem Steel Corporation	7-90
Clean Power from Integrated Coal/Ore Reduction (COREX®)	Centerior Energy Corporation	7-92
Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	Coal Tech Corporation	7-94
Cement Kiln Flue Gas Recovery Scrubber	Passamaquoddy Tribe	7-96
Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	ThermoChem, Inc.	7-98

Exhibit 7-2 Project Fact Sheets, by Participant

Participant	Project	CCT	Page
ABB Combustion Engineering, Inc.	Combustion Engineering IGCC Repowering Project	II	7-20
ABB Combustion Engineering, Inc., and CQ Inc.	Development of the Coal Quality Expert	I	7-78
ABB Environmental Systems	SNOX™ Flue Gas Cleaning Demonstration Project	II/Complete	7-62
Air Products Liquid Phase Conversion Company, L.P.	Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process	III	7-86
AirPol, Inc.	10-MWe Demonstration of Gas Suspension Absorption	III/Complete	7-52
Alaska Industrial Development and Export Authority	Healy Clean Coal Project	III	7-30
The Appalachian Power Company	PFBC Utility Demonstration Project	II	7-8
Arthur D. Little, Inc.	Coal Diesel Combined-Cycle Project	V	7-32
The Babcock & Wilcox Company	Demonstration of Coal Reburning for Cyclone Boiler NO _x Control	II/Complete	7-38
The Babcock & Wilcox Company	Full-Scale Demonstration of Low-NO _x Cell Burner Retrofit	III/Complete	7-40
The Babcock & Wilcox Company	LIMB Demonstration Project Extension and Coolside Demonstration	I/Complete	7-64
The Babcock & Wilcox Company	SO _x -NO _x -Rox Box™ Flue Gas Cleanup Demonstration Project	II/Complete	7-66
Bechtel Corporation	Confined Zone Dispersion Flue Gas Desulfurization Demonstration	III/Complete	7-54
Bethlehem Steel Corporation	Blast Furnace Granulated-Coal Injection System Demonstration Project	III	7-90
Centerior Energy Corporation	Clean Power from Integrated Coal/Ore Reduction (COREX®)	V	7-92
Coal Tech Corporation	Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control	I/Complete	7-94
Custom Coals International	Self-Scrubbing Coal™: An Integrated Approach to Clean Air	IV	7-80
DMEC-1 Limited Partnership	PCFB Demonstration Project	III	7-10
Clean Energy Partners Limited Partnership	Clean Energy Demonstration Project	V	7-22
ENCOAL Corporation	ENCOAL Mild Coal Gasification Project	III	7-84
Energy and Environmental Research Corporation	Enhancing the Use of Coals by Gas Reburning and Sorbent Injection	I/Complete	7-68
Energy and Environmental Research Corporation	Evaluation of Gas Reburning and Low-NO _x Burners on a Wall-Fired Boiler	III/Complete	7-42
Four Rivers Energy Partners, L.P.	Four Rivers Energy Modernization Project	V	7-12
LIFAC-North America	LIFAC Sorbent Injection Desulfurization Demonstration Project	III/Complete	7-56
New York State Electric & Gas Corporation	Micronized Coal Reburning Demonstration for NO _x Control	IV	7-44
New York State Electric & Gas Corporation	Miliken Clean Coal Technology Demonstration Project	IV	7-70

Exhibit 7-2 (continued) Project Fact Sheets, by Participant

Participant	Project	CCT	Page
NOXSO Corporation	Commercial Demonstration of the NOXSO SO ₂ /NO _x Removal Flue Gas Cleanup System	III	7-72
The Ohio Power Company	Tidd PFBC Demonstration Project	I/Complete	7-14
Passamaquoddy Tribe	Cement Kiln Flue Gas Recovery Scrubber	II/Complete	7-96
Pennsylvania Electric Company	Warren Station Externally Fired Combined-Cycle Demonstration Project	V	7-34
Public Service Company of Colorado	Integrated Dry NO _x /SO ₂ Emissions Control System	III	7-74
Pure Air on the Lake, L.P.	Advanced Flue Gas Desulfurization Demonstration Project	II/Complete	7-58
Rosebud SynCoal Partnership	Advanced Coal Conversion Process Demonstration	I	7-82
Sierra Pacific Power Company	Piñon Pine IGCC Power Project	IV	7-24
Southern Company Services, Inc.	Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler	II	7-46
Southern Company Services, Inc.	Demonstration of Innovative Applications of Technology for the CT-121 FGD Process	II/Complete	7-60
Southern Company Services, Inc.	Demonstration of Selective Catalytic Reduction Technology for the Control of NO _x Emissions from High-Sulfur-Coal-Fired Boilers	II/Complete	7-48
Southern Company Services, Inc.	180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO _x Emissions from Coal-Fired Boilers	II/Complete	7-50
Tampa Electric Company	Tampa Electric Integrated Gasification Combined-Cycle Project	III	7-26
ThermoChem, Inc.	Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal	IV	7-98
Tri-State Generation and Transmission Association, Inc.	Nucla CFB Demonstration Project	I/Complete	7-16
Wabash River Coal Gasification Repowering Project Joint Venture	Wabash River Coal Gasification Repowering Project	IV	7-28
York County Energy Partners, L.P.	ACFB Demonstration Project	I	7-18



**Advanced Electric
Power Generation
Fact Sheets**

PFBC Utility Demonstration Project

Participant:
The Appalachian Power Company

Additional Team Members:
American Electric Power Service Corporation—designer, constructor, and manager
The Babcock & Wilcox Company—technology supplier

Location:
Site under negotiation

Technology:
The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) combined-cycle system (under license from ABB Carbon) (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
340 MWe (net)

Project Funding:

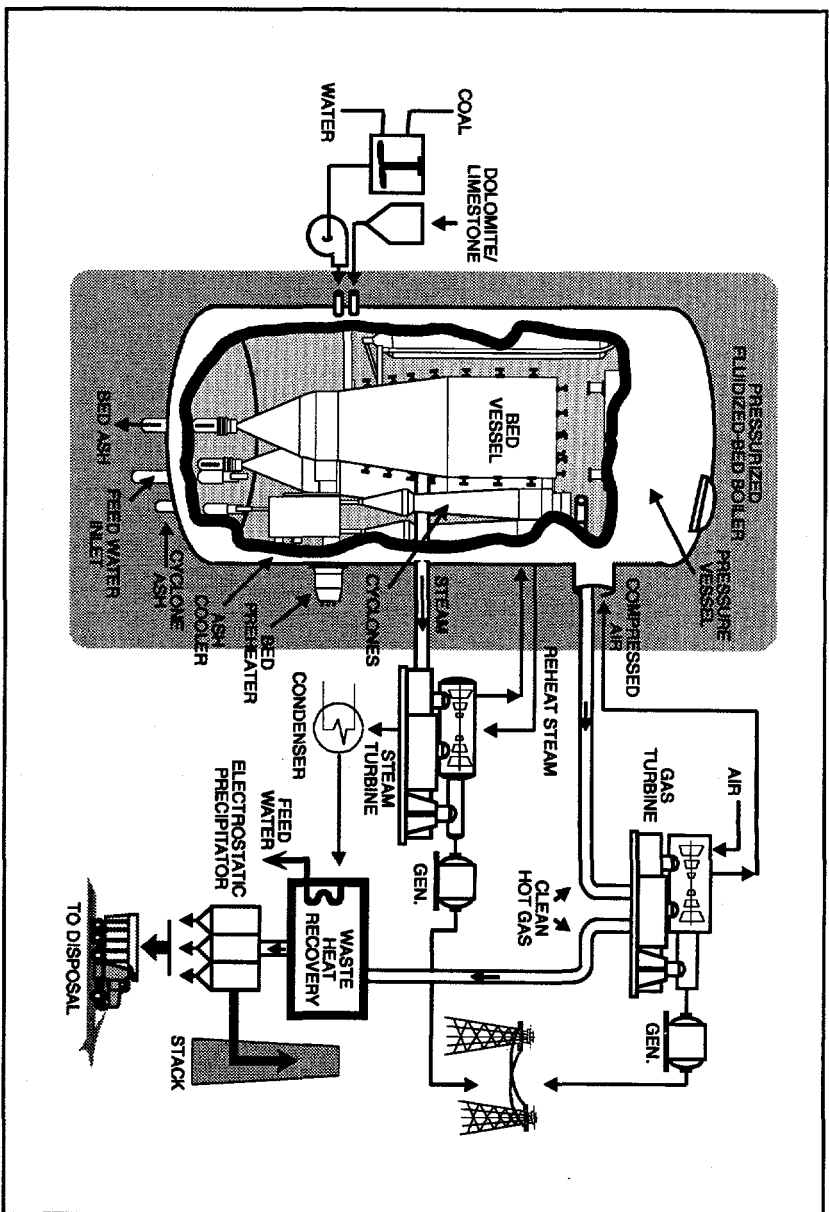
Total project cost	\$917,944,000	100%
DOE	184,800,000	20
Participant	733,144,000	80

Project Objective:
To demonstrate a large utility-scale PFBC at 340 MWe; to assess long-term reliability, availability, and maintainability of PFBC in a commercial operating mode and the integration of a reheat steam cycle.

Technology/Project Description:

This project will be a greenfield facility located adjacent to the existing Mountaineer and Sporn plants. The most noticeable aspect of the unit is that the boiler, cyclones, reinjection vessel, and associated hardware are encapsulated in a pressure vessel 60 ft in diameter and 100 ft high.

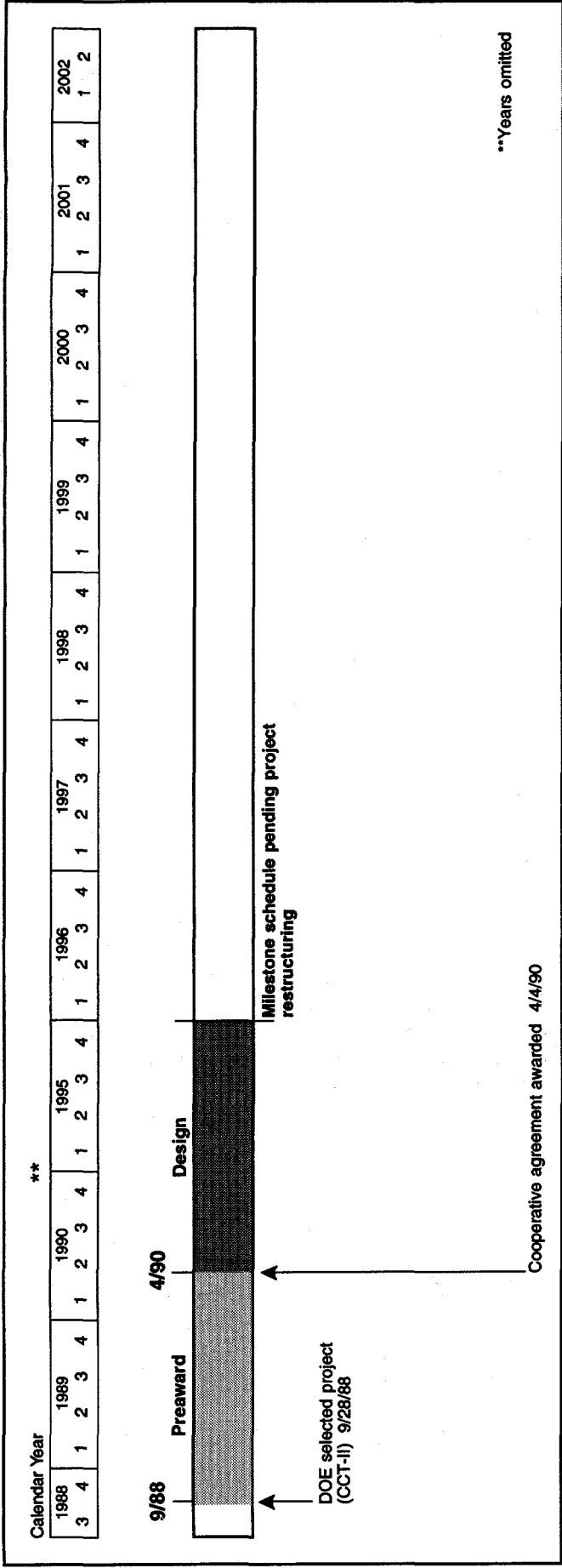
The project incorporates a bubbling fluidized-bed process operating at 16 atm (235 psi). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material (consisting of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent). Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material, which is easily disposed of or used as a by-product. A low bed-temperature of 1,600 °F 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. An option being considered is to employ some advanced filtration devices in the design. The cleaned gases are then expanded through a 75-MWe gas turbine.

The reheat system turbine operates at a state-of-the-art pressure and temperature to produce at least 250 MWe. Superheated steam will be produced from pressurized boiler-feed water in the tubes submerged in the fluidized bed. The projected heat rate for this unit is 8,500 Btu/kWh (40.2% efficiency based on HHV). SO₂ emissions are expected to be reduced by 95% and NO_x emissions by 80%.

The design coal is Pittsburgh 8, high-sulfur (4% maximum), bituminous coal.



Project Status/Accomplishments:

The participant has proposed resiting the project to Jacksonville Electric Authority's Northside Station in Florida.

Commercial Applications:

This project will be the initial version of a commercial plant. Combined-cycle PFBC systems permit the combustion of a wide range of coals, including high-sulfur coals. This technology will compete with circulating PFBC systems to repower or replace conventional power plants with a technology capable of using high-sulfur coals in an environmentally sound manner. PFBC technology appears to be best suited for a wide range of applications beginning at the 50-MWe size. Because of modular construction capability, PFBC generating plants permit utilities to add economical increments of capacity to match load growth and/or to easily repower existing plants using available coal- and waste-handling equipment, and existing steam turbines. Another advantage

for repowering is the compactness of the process because of pressurized operation.

The projected net heat rate for the commercial plant will be 8,500 Btu/kWh (based on HHV) which equates to an efficiency of 40.2%. An advanced cycle that integrates a small gasifier could yield heat rates approaching 7,500 Btu/kWh (45% efficiency). Environmental attributes include in-situ sulfur reduction of 95% and NO_x emissions reduction to 0.1 lb/million Btu. Although the system may generate a slight increase of solid waste as compared to conventional systems, the dry material is either disposable or potentially usable.

PCFB Demonstration Project

Participant:

DMEC-1 Limited Partnership (a partnership among Ahlstrom Pyropower [general partner], MidAmerican Energy [limited partner], and Dairyland Power [limited partner])

Additional Team Members:

Pyropower Corporation—technology supplier
Black and Veatch—architect and engineer

Location:

Site under negotiation

Technology:

Pyropower Corporation's AHLSTROM PYROFLOW® pressurized circulating fluidized-bed combustion (PCFB) combined-cycle system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:

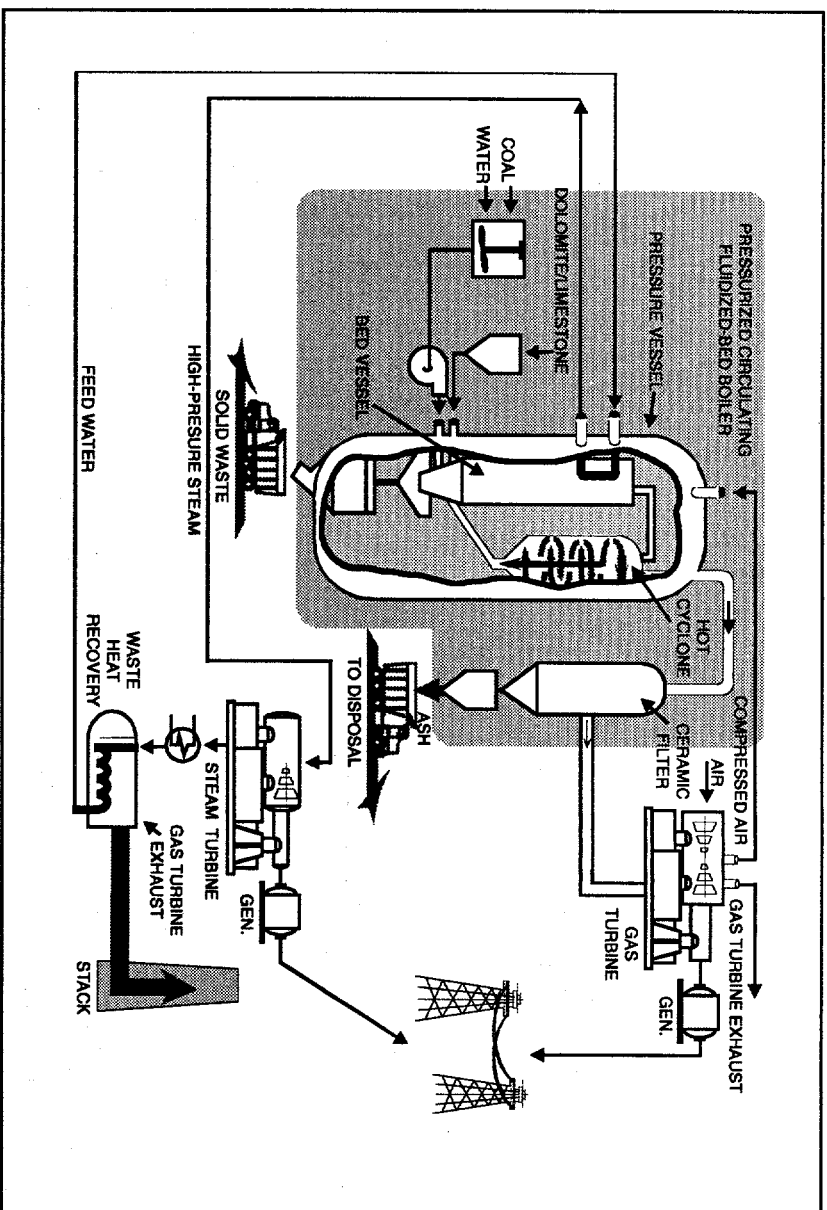
80 MWe

Project Funding:

Total project cost	\$202,959,000	100%
DOE	93,253,000	46
Participant	109,706,000	54

Project Objective:

To demonstrate PCFB at sufficient scale to evaluate environmental, cost, and plant performance and to obtain the technical data required for commercialization of the technology; to assess operating performance of unique features that include an integral ceramic hot-gas filter and slightly modified, commercially available gas turbine.



Technology/Project Description:

In the PCFB process, coal is combusted at about 1,600 °F and 12 atm in a circulating fluidized bed contained within a pressure vessel. Coal is pumped into the PCFB via a water slurry while dolomite or limestone is added to the combustion process to absorb sulfur compounds. Particulates from the hot, pressurized combustion gases are removed by a ceramic filter, and the clean gases are then expanded through a gas turbine. The solid waste (bed and fly ash) from the process is dry, easily disposed of, and potentially usable. Steam generated within the PCFB combustor and the heat recovery system downstream of the gas turbine is used to generate power in an existing steam turbine.

The project would be the world's first large-scale demonstration of PCFB technology. The project also would be the first commercial application of hot gas cleanup and the first use of a nonruggedized gas turbine in a pressurized fluidized-bed application.

AHLSTROM PYROFLOW is a registered trademark of Ahlstrom Pyropower, Inc., which is now owned by Foster Wheeler Energy Corporation.

Tidd PFBC Demonstration Project

Project completed.

Participant:
The Ohio Power Company

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

Location:
Brilliant, Jefferson County, OH (Ohio Power Company's Tidd Plant, Unit 1)

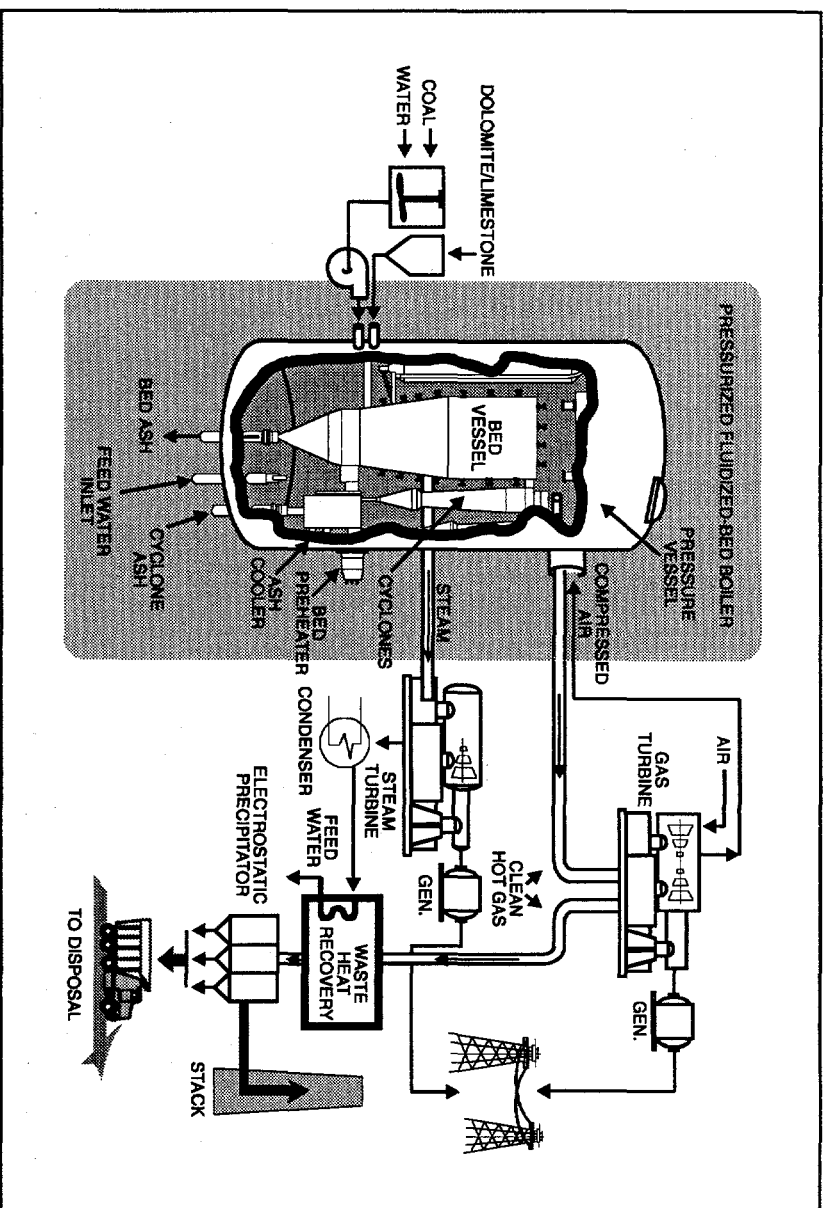
Technology:
The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon) (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
70 MWe

Project Funding:

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

Project Objective:
To demonstrate PFBC at a 70-MWe scale, representing a 13:1 scaleup from the pilot plant facility; to verify expectations of the technology's economic, environmental, and technical performance in a combined-cycle repowering application at a utility site; and to accomplish greater than 90% SO₂ removal, NO_x emission level of 0.2 lb/million Btu, and an efficiency of 35% in a repowering mode using the existing steam system.



Technology/Project Description:
Tidd is the first large-scale operational demonstration of PFBC in the United States and one of only five worldwide. The boiler, cyclones, bed reification vessels, and associated hardware are encapsulated in a pressure vessel 45 ft in diameter and 70 ft high. The facility was designed so that one-seventh of the hot gases produced could be routed to a slipstream to test advanced filtration devices.

The Tidd facility is a bubbling fluidized-bed combustion process operating at 12 atm (175 psi). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material which consists of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent. Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular

bed-ash material which is easily disposed of or is usable as a by-product. A low bed-temperature of 1,600 °F 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 ASEA Stal GT-35P gas turbine. The gases exiting the turbine are cooled via a waste heat economizer and further cleaned in an electrostatic precipitator.

The Tidd steam turbine operates at a pressure of 1,305 psi and a temperature of 925 °F to produce approximately 55 MWe. Superheated steam is produced from pressurized boiler feed water in the in-bed combustor tubes. Steam generated within the combustor and the heat recovery system downstream of the gas turbine is

used to generate power in a previously existing steam turbine. Due to repowering, plant efficiency was improved to a heat rate of 10,280 Btu/kWh (an efficiency of 33.2% based on HHV and gross electrical power output).

Ohio bituminous coals having sulfur contents of 2-4% are being used in the demonstration.

Project Results/Accomplishments:

Operational testing was completed on March 30, 1995. During the 54 months of testing, the unit completed 95 parametric tests and accumulated 11,444 hours of coal-fired operations, including continuous coal-fired runs of 28, 29, 30, 31, and 45 days.

Advanced ceramic hot-gas-filtration elements have undergone approximately 5,800 hours of exposure to one-seventh of the slipstream. Test results showed that the design of the candle-based advanced particulate filter was structurally adequate. However, results also showed that clay-based silicon carbide lost 50% of its strength after 1,000-2,000 hours of exposure and that a build-up of ash in the filter vessel would cause breakage of the candles.

Test results showed that 90% SO₂ capture was achieved with a Ca/S molar ratio of 1.1 and 95% SO₂ capture with a Ca/S molar ratio of 1.5 using Ohio bituminous coals having a sulfur content of 2-4% and Plum Run Greenfield dolomite. The unit demonstrated NO_x emissions in the range of 0.15-0.33 lb/million Btu. These emissions were inherent to the process which had an operating temperature of 1,580 °F. Emissions of carbon monoxide and particulate were less than 0.01 and 0.02 lb/million Btu, respectively.

Except for localized erosion of the in-bed tube bundle and the more general erosion of the waterwalls, the Tidd boiler performed extremely well and is considered a commercially viable design. While the gas turbine was the leading cause of unit unavailability during the first three years of operation, technical improvement

and revised designs are addressing the mechanical and erosion problems. The Tidd demonstration showed that a gas turbine could operate in the PFBC flue gas environment and erosion was manageable with a scheduled maintenance program.

Because the Tidd project produced 70 MWe, economic results would not be characteristic of future utility-scale applications of the technology. Economic results from the 340-MWe PFBC Utility Demonstration Project will define the capital and operating costs for this technology.

The project has received two major awards. In 1992, it received the National Energy Resource Organization's Award for demonstrating energy efficient technology. In 1991, *Power Magazine* presented the Powerplant of the Year Award to the project for demonstrating PFBC technology.

Commercial Applications:

Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. Bubbling PFBC technology, along with other advanced technologies, will compete with circulating PFBC systems to repower or replace conventional power plants. 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. Another advantage for repowering applications is the compactness of the process due to pressurized operation, which reduces space requirements per unit of energy generated.

In a fully mature system, the projected net heat rate is 8,500 Btu/kWh (based on HHV) which equates to 40.2% efficiency. An advanced cycle that integrates a small gasifier could yield heat rates approaching 7,500 Btu/kWh (45% efficiency).

The environmental attributes of a mature system include in-situ sulfur removal of 95% and NO_x emissions reduction levels less than 0.1 lb/million Btu. Although the system generates a slight increase in solid waste as compared to conventional systems, the dry material is either disposable or potentially usable.

Project Schedule:

DOE selected project (CCT-1)	7/24/86
Cooperative agreement awarded	3/20/87
NEPA process completed (MTF)	3/5/87
Environmental monitoring plan completed	5/25/88
Construction	12/87-12/90
Operational testing	3/91-3/95
Project completed	12/95

Final Reports:

Final Technical Report	8/95
Public Design Report	10/92

Nucla CFB Demonstration Project

Project completed.

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

Additional Team Members:
Pyropower Corporation—technology supplier
Technical Advisory Group (potential users)—cofunder
Electric Power Research Institute—technical consultant

Location:
Nucla, Montrose County, CO (Nucla Station)

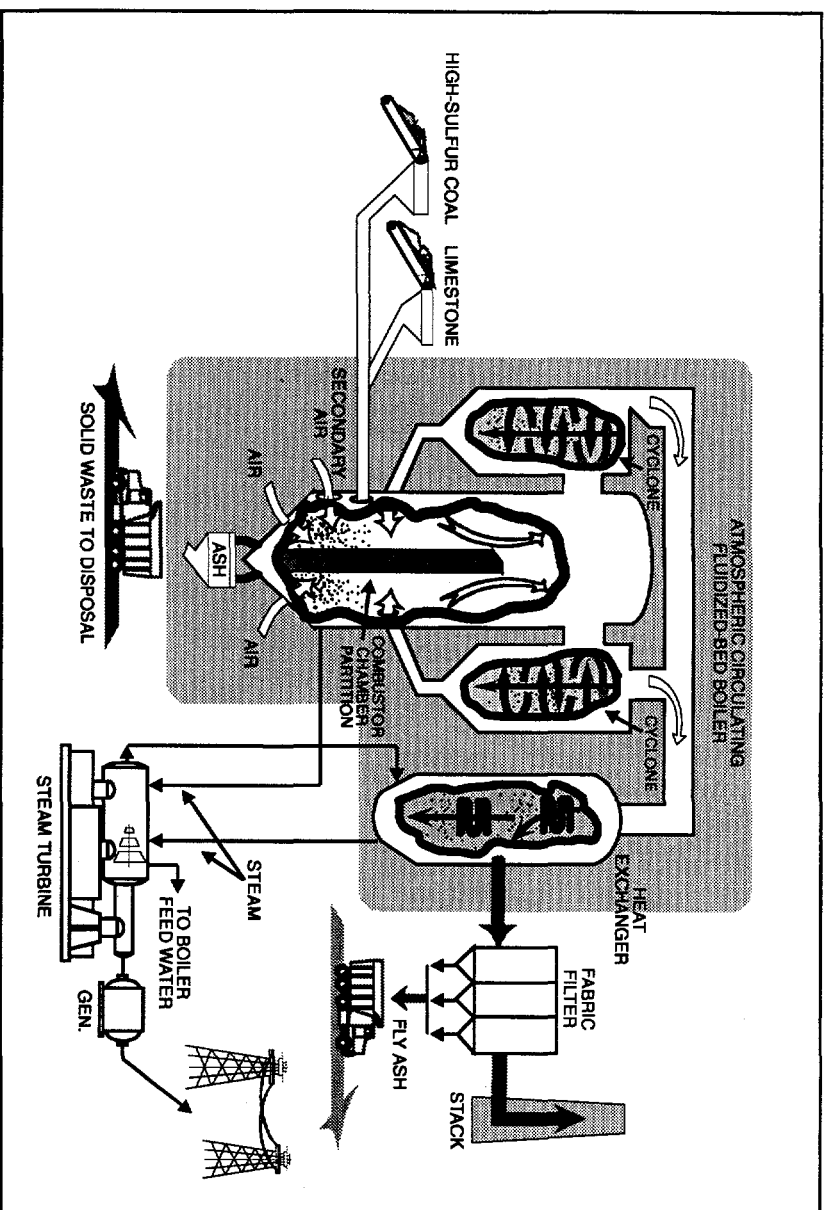
Technology:
Pyropower's atmospheric circulating fluidized-bed combustion (ACFB) system (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:
110 MWe

Project Funding:

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

Project Objective:
To demonstrate ACFB at a scale of 110 MWe, representing a 2.1 scaleup from previously demonstrated capacities; to verify expectations of the technology's economic, environmental, and technical performance in a repowering application at a utility site; to accomplish greater than 90% SO₂ removal; to reduce NO_x emissions by 60%; and to achieve an efficiency of 34% in a repowering mode.



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 SO₂ gases, 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. The flue gas

passes through a baghouse where the particulate matter is removed. The steam generated in the ACFB is used to generate electric power.

Three small, coal-fired, stoker-type boilers at Nucla Station were replaced with a new 925,000-lbs/hr ACFB steam generator capable of driving a new 74-MWe turbine generator. Extraction steam from this turbine generator powers three existing turbine generators (12 MWe each). Three western coals were tested: Peabody coal (0.4-0.8% sulfur), Dorchester coal (1.5% sulfur), and Salt Creek coal (0.5% sulfur).

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

Project Results/Accomplishments:

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

- Results indicated strong correlations of absolute CO₂, SO₂, and NO_x emissions levels with combustor operating temperatures. Although NSPS compliance was maintained, a penalty on limestone feed requirements for sulfur retention was realized at the higher operating temperatures. Below 1,620 °F, 70% sulfur retention was achieved with 1.5 Ca/S, and 95% sulfur retention was achieved with 4.0 Ca/S. Around 1,700 °F, Ca/S greater than 5.0 was required to maintain 70% sulfur capture.
- The NO_x emissions for all tests were less than 0.34 lb/million Btu, which was well within the state-regulated emission limit of 0.50 lb/million Btu. The average level of NO_x emissions for all tests was 0.18 lb/million Btu.
- Combustion efficiency, a measure of the quantity of carbon that is fully oxidized to CO₂, ranged from 96.9% to 98.9%. Of the four exit sources of incompletely burned carbon, the largest was carbon contained in the fly ash (93%). The next largest (5%) was carbon contained in the bottom ash stream, and the remaining feed-carbon loss (2%) was incompletely oxidized CO in the flue gas. The fourth possible source, hydrocarbons in the flue gas, was measured and found to be negligible.
- Boiler efficiencies for 68 performance tests varied from 85.6% to 88.6%. The contributions to boiler heat loss were identified as unburned carbon; sensible heat in dry flue gas; fuel and sorbent moisture; latent heat in burning hydrogen; sorbent calcination; radiation, and convection; and bottom ash cooling water.

Net plant heat rate decreased with increasing boiler load, from 12,400 Btu/kWh at 50% of full load to 11,600 Btu/kWh at full load. The lowest value achieved during a full-load steady-state test was 10,980 Btu/kWh. These values were affected by the absence of reheat, the presence of the three older 12.5-MWe turbines in the overall steam cycle, the number of unit restarts, and part-load testing.

- Over the range of operating temperatures at which testing was performed at Nucla, bed temperature was found to be the most influential operating parameter. With the possible exception of coal-feed configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions or efficiencies. Emissions of SO₂ and NO_x were found to increase with increasing combustor temperatures while CO emissions decreased with increasing temperature. Combustion efficiency also improved as the temperature was increased.

An economic evaluation indicated that the final capital costs for the Nucla ACFB system were about \$112.3 million. This represents a cost of \$1,123/net kW. Total power production costs associated with test operations were about \$54.7 million, which results in a normalized power production cost of 0.064 mills/kWh. Fixed costs were about 62% of the total, and variable costs were more than 38%. Nucla's power production costs proved competitive with pulverized coal units not limiting emissions as significantly.

Commercial Applications:

ACFB technology has good potential in both industrial and utility sectors for new capacity additions or for repowering existing coal-fired plants. Coal of any sulfur content can be used. Because any type or size of boiler can be repowered by ACFB using the existing plant area, coal- and waste-handling equipment, and steam turbine

equipment, the life of the plant can be extended. Benefits of ACFB include 90% SO₂ reduction, 60–80% NO_x reduction, and control of pollutants at lower costs than are offered by existing technologies.

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

Project Schedule:

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

Final Reports:

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

ACFB Demonstration Project

Participant:

York County Energy Partners, L.P. (a limited partnership which includes Air Products and Chemicals, Inc.)

Additional Team Members:

Foster Wheeler Energy Corporation—technology supplier

Location:

Site under negotiation

Technology:

Foster Wheeler's atmospheric circulating fluidized-bed (ACFB) combustor (advanced electric power generation/fluidized-bed combustion)

Plant Capacity/Production:

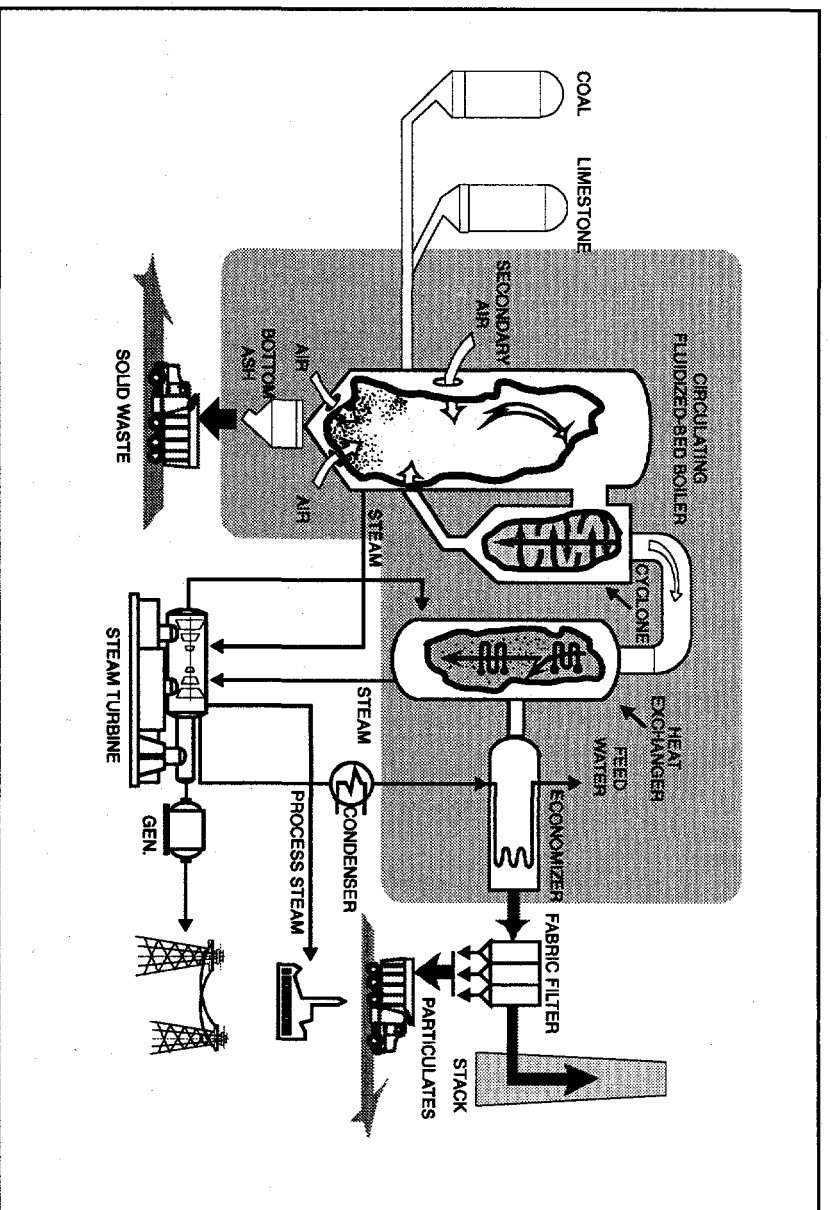
227 MWe (net) and 400,000 lbs/hr steam

Project Funding:

Total project cost	\$379,645,450	100%
DOE	74,733,833	20
Participant	304,911,617	80

Project Objective:

To demonstrate ACFB at 250 MWe, representing a 1.7:1 scaleup from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance in a greenfield cogeneration application; and to provide cogenerators, as well as utility and nonutility power producers, with the data necessary for evaluating a 250-MWe ACFB as a commercial alternative to accomplish greater than 90% SO₂ removal, to reduce NO_x emissions by 60% when compared with conventional technology, and to achieve a steam efficiency of 88%.

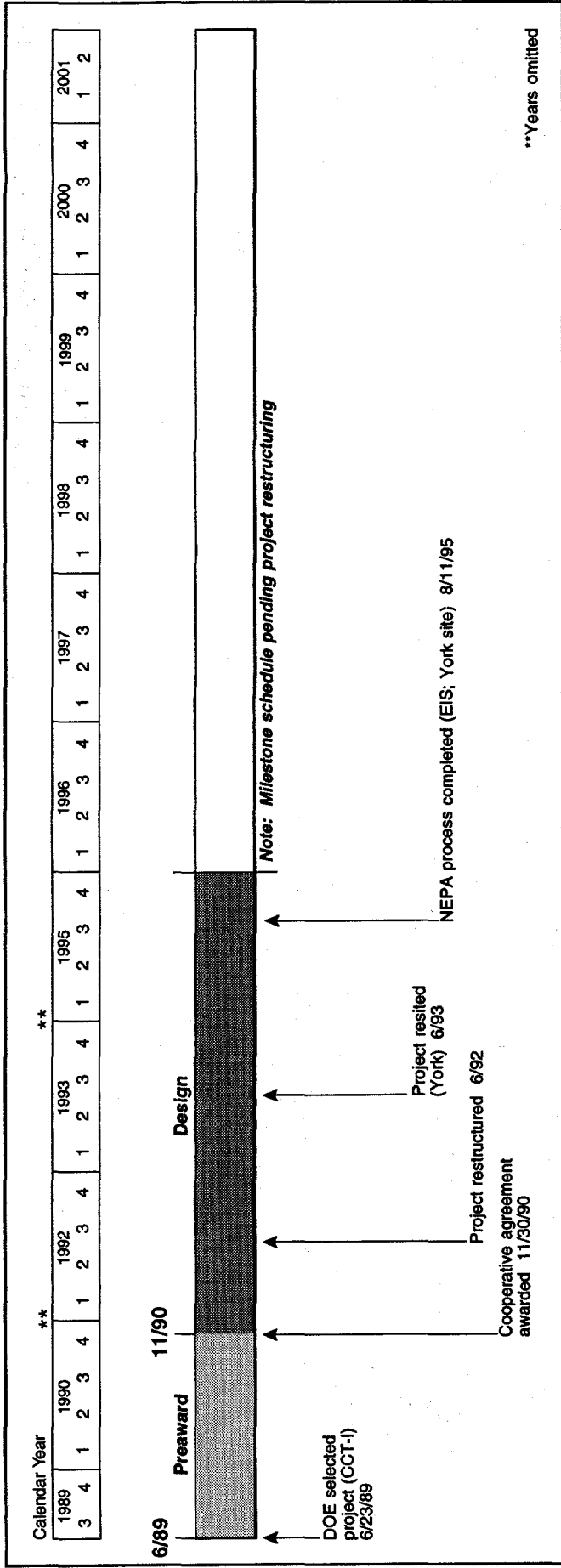


Technology/Project Description:

In this project, the circulating fluidized-bed combustor operates at atmospheric pressure. Coal, primary air, and a solid sorbent, such as limestone, are introduced into the lower portion of the combustor where initial combustion occurs. As coal particles decrease in size due to combustion and breakage, they are carried higher in the combustor to an area where 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 particle separator, and recycled to the lower portion of the combustor. The sorbent in the bed removes sulfur during the combustion process, eliminating the need for scrubbers.

Steam is generated in tubes placed along the combustor's walls and superheated in tube bundles placed in the solids-circulating stream and the flue gas stream. The steam is then used to produce power in a conventional steam cycle.

The heat rate for this cogeneration plant is expected to be 9,200 Btu/kWh (37% efficiency). SO₂ emissions are expected to be below 0.24 lb/million Btu. This technology operates at lower temperatures than conventional boilers, thus reducing NO_x production.



Project Status/Accomplishments:

All activities have been put on hold while resiting options are considered. On September 26, 1995, York County Energy Partners and Metropolitan Edison Company announced their joint decision to restructure the power-purchase agreement to allow for development of a natural-gas-fired facility instead of the coal-fired cogeneration plant originally planned. DOE will not participate in the revised natural gas project. Other options for a coal-fired plant are being considered.

The final EIS for the originally planned coal-fired cogeneration plant at the York County, PA, site was published in June 1995, and a record of decision was approved by DOE on August 11, 1995. Public hearings on the draft EIS were held in York in December 1994 and January 1995. (The NEPA process will need to be repeated for any new site.)

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 content can be used, and any type or size of a coal-fired boiler can be repowered. In repowering applications, an existing plant area is used, and coal- and waste-handling equipment as well as steam turbine equipment are retained, thereby extending the life of a plant.

In its commercial configuration, ACFB technology offers several potential benefits when compared to conventional pulverized coal-fired systems: lower capital costs; reduced SO₂ and NO_x emissions at lower costs; higher combustion efficiency; and dry, granular solid waste which is easily disposed of or which may be a salable by-product.

Combustion Engineering IGCC Repowering Project

Participant:

ABB Combustion Engineering, Inc.

Additional Team Members:

Project is being restructured and will include new team members.

Location:

Site under negotiation

Technology:

ABB Combustion Engineering's integrated gasification combined-cycle (IGCC) system (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:

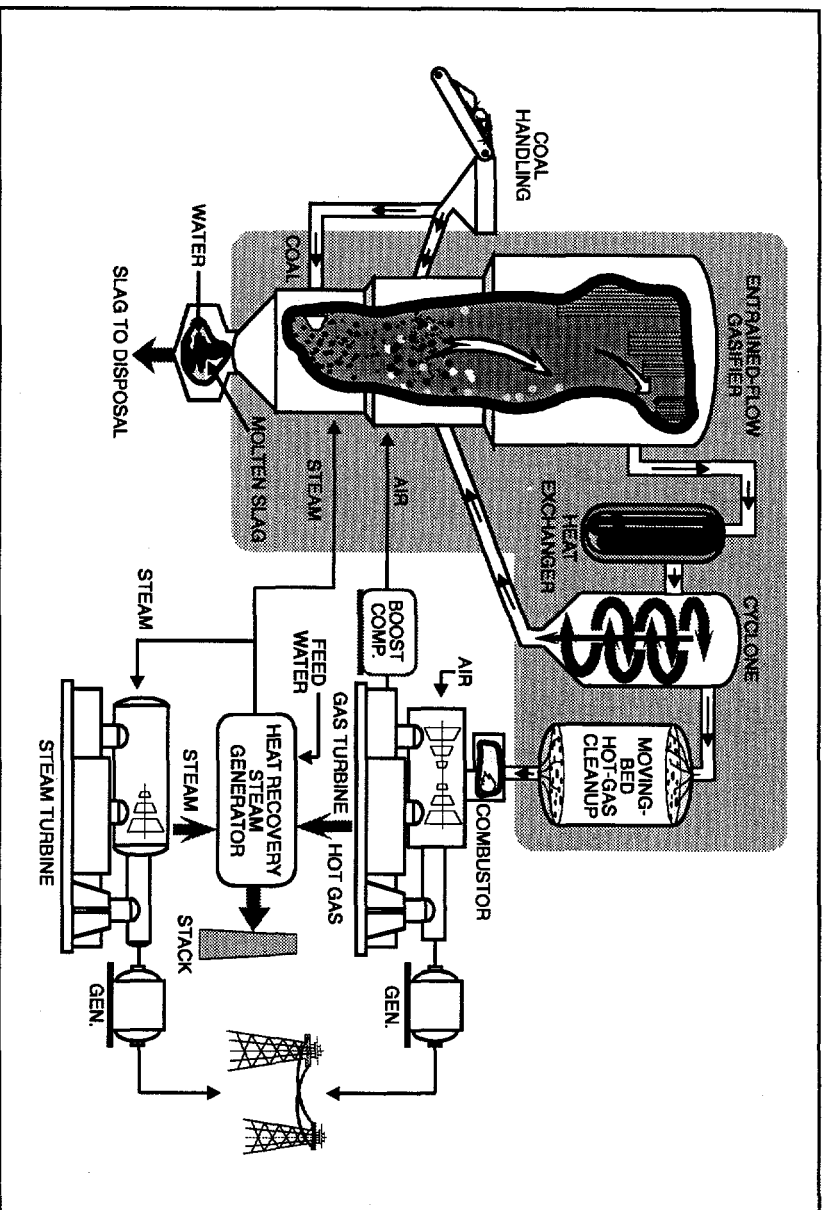
65 MWe (net)

Project Funding:

Total project cost	\$270,700,000	100%
DOE	129,357,204	48
Participant	141,342,796	52

Project Objective:

To demonstrate an advanced dry-feed, air-blown, two-stage, entrained-flow coal gasifier with a moving-bed, zinc titanate, hot-gas cleanup system; to assess long-term reliability and maintainability of the system at a sufficient scale to determine commercial potential.



Technology/Project Description:

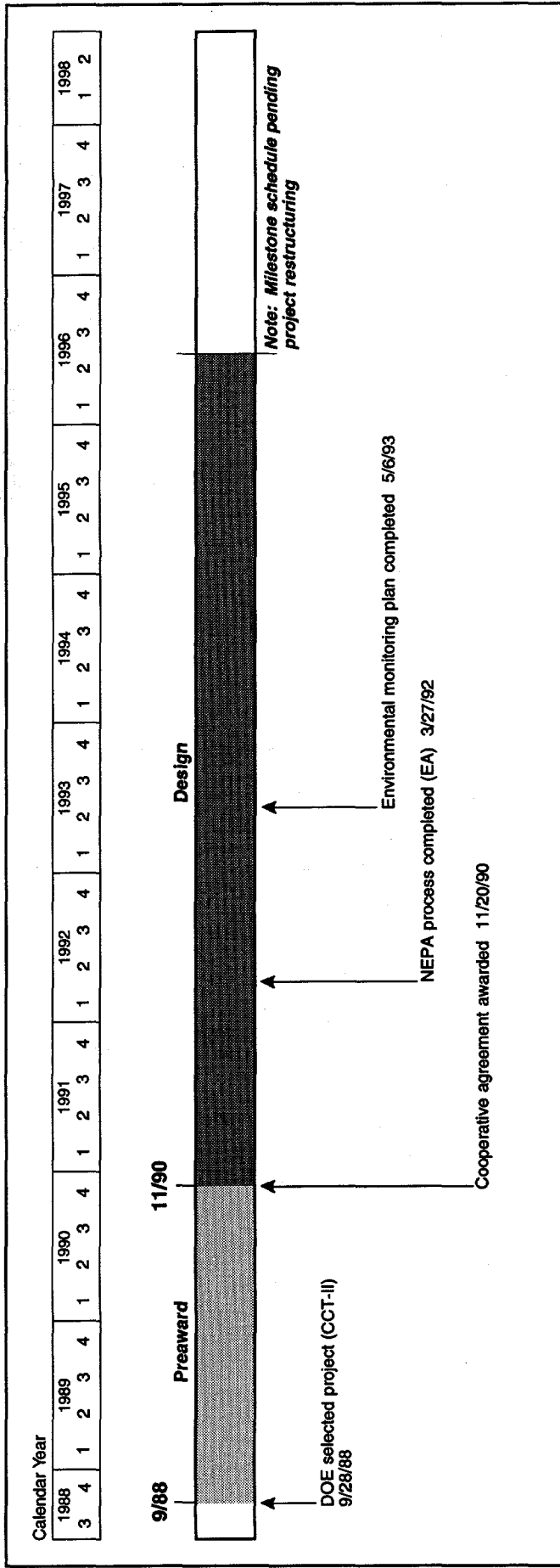
Pulverized coal is pneumatically transported to the pressurized gasifier. The gasifier essentially consists of a bottom combustor section and a top reactor section. Coal is fed into both sections. A slag tap at the bottom of the combustor allows molten slag to flow into a water-filled quench tank.

The raw, low-Btu gas and char leave the gasifier at approximately 2,000 °F and are reduced in temperature to about 1,000 °F in a heat exchanger. Char in the gas stream is captured by a high-efficiency cyclone, as well as by a subsequent fine-particulate removal system, and recycled back to the gasifier.

A newly developed process consisting of a moving bed of zinc titanate sorbent is being used to remove sulfur from the hot gas. Particulate emissions are re-

moved from the coal-handling system and gas stream by a combination of cyclone separators and baghouses, and a high percentage of particulates are fed back to the gasifier for more complete reaction and ultimate removal with the slag.

The cleaned low-Btu gas is routed to a combined-cycle system for electric power production. About 40 MWe (net) are generated by a gas turbine. Extracted air from the gas turbine is used to meet the high-pressure air requirements of the gasifier and the zinc titanate desulfurization system. Exhaust gases from the gas turbine are used to produce steam which is fed to a bottoming cycle to generate an additional 25 MWe (net).



Project Status/Accomplishments:

An extension to May 31, 1996, has been granted to allow the participant to complete project restructuring, including changing the site to TVA's Bellefonte Plant near Scottsboro, AL; increasing the size to 375-400 MWe; changing the gasification technology to Shell; and changing the project team, schedule, and total cost. The participant has indicated that no additional DOE funds will be required beyond the current DOE cost share.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for both repowering and new power plant applications. Repowering aging plants with this technology will improve plant efficiency and reduce emissions of SO₂, NO_x, and CO₂. Also, the modular design of the gasifier will permit a range of units to be considered for repowering.

Due to the advantages of modularity, rapid and staged on-line generation capability, high efficiency, fuel flexibility, environmental controllability, and reduced land

and natural resource needs, the IGCC system is also a strong contender for new electric power generating facilities. Further, without the need for an oxygen plant, the ABB Combustion Engineering technology represents a potentially simpler approach to gasification-based power generation. A single-train IGCC system based on this gasifier is capable of producing more than 150 MWe. A commercial-scale facility based on the ABB Combustion Engineering technology is expected to have a heat rate less than 8,000 Btu/kWh (efficiency greater than 43%). This heat rate is expected to realize at least a 20% improvement in efficiency compared to a conventional pulverized-coal-fired plant with flue gas desulfurization. The improved system efficiency also results in a similar decrease in CO₂ emissions.

Clean Energy Demonstration Project

Participant:

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

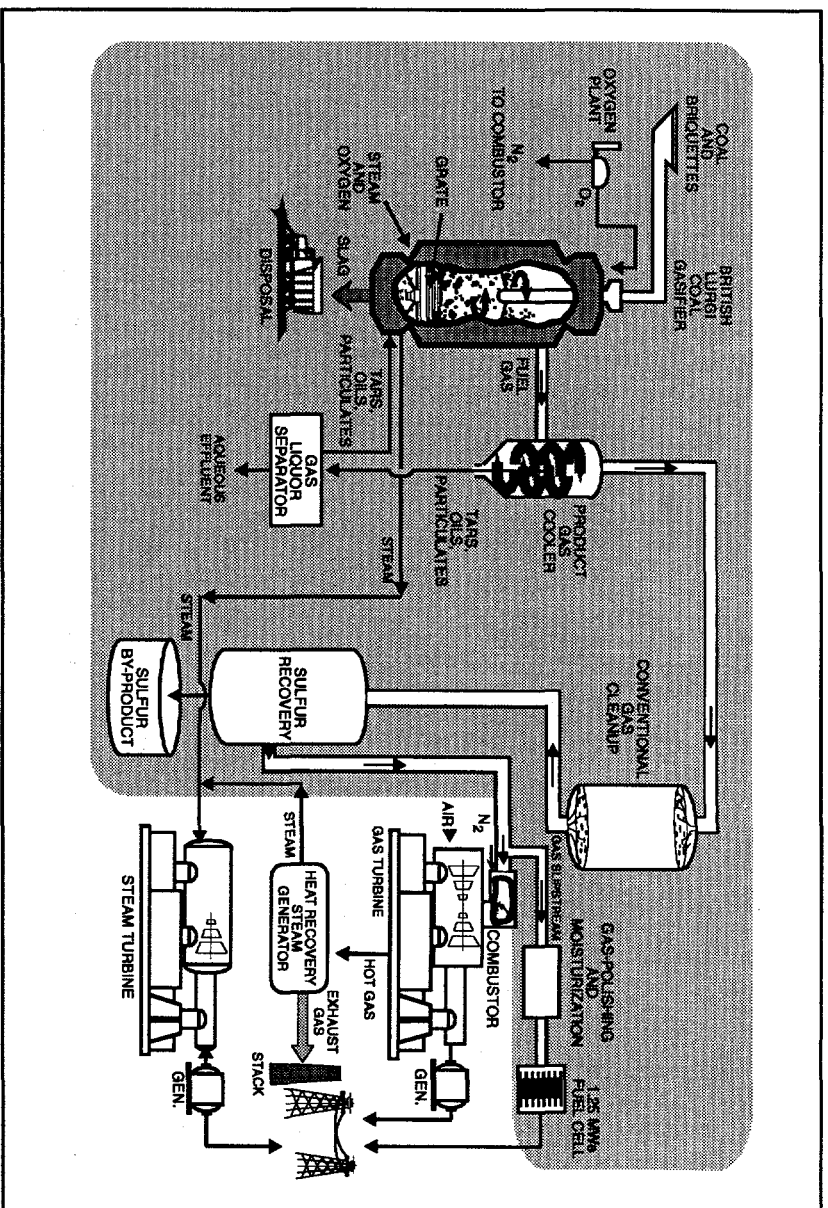
Additional Team Members:

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

Location:
 An east coast site

Technology:
 Integrated gasification combined-cycle (IGCC) using British Gas/Lurgi (BGL) slagging fixed-bed gasification system coupled with Fuel Cell Engineering's molten carbonate fuel cell (MCFC) (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:
 477-MWe (net) IGCC; 1.25-MWe MCFC



Project Funding:

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

Project Objective:

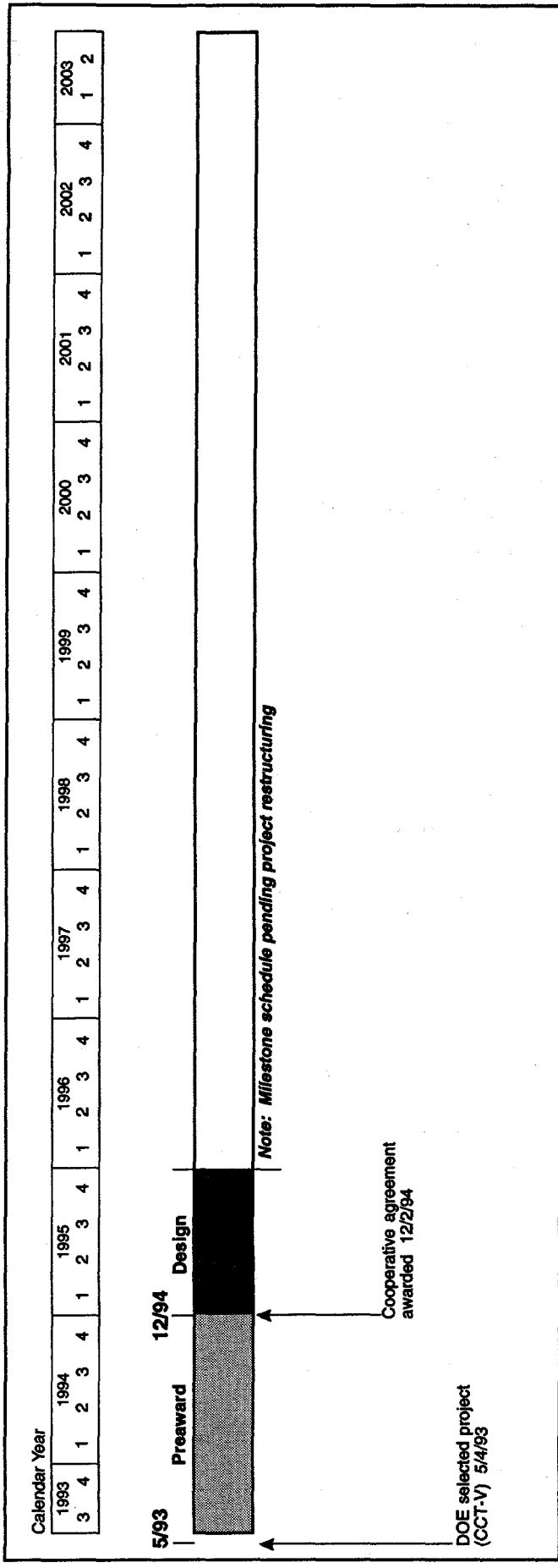
To demonstrate and assess the reliability, availability, and maintainability of a utility-scale IGCC system using high-sulfur bituminous coal in an oxygen-blown, fixed-bed, slagging gasifier and the operability of a molten carbonate fuel cell fueled by coal gas, by an independent power producer under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

Technology/Project Description:

The BGL gasifier is supplied with steam, oxygen, limestone flux, and coals having a high fines content. During gasification, the oxygen and steam react with the coal

and limestone to produce a raw coal gas rich in hydrogen and carbon monoxide. Raw coal gas exiting the gasifier is washed and cooled. Hydrogen sulfide and other sulfur compounds are removed. Elemental sulfur is reclaimed and disposed of as a by-product. Tars, oils, and dust are recycled to extinction in the gasifier. The resulting clean, medium-Btu fuel gas is used to fuel the gas turbine in the IGCC power island. A small portion of the clean gas is used for the MCFC.

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



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

Project Status/Accomplishments:

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

Commercial Applications:

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

The heat rate of the IGCC demonstration facility is 8,560 Btu/kWh (40% efficiency) and the commercial embodiment of the system has a projected heat rate of 8,035 Btu/kWh (42.5% efficiency). The commercial version of the molten carbonate fuel cell fueled by a BG/L gasifier is anticipated to have a heat rate of 7,379 Btu/kWh (46.2% efficiency). These efficiencies represent greater than 20% reduction in emissions of CO₂ when compared to a conventional pulverized coal plant equipped with a scrubber. SO₂ emissions from the IGCC system are expected to be less than 0.1 lb/million Btu (99% reduction); NO_x emissions, less than 0.15 lb/million Btu (90% reduction).

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

Piñon Pine IGCC Power Project

Participant:

Sierra Pacific Power Company

Additional Team Members:

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

Location:

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

Technology:

Integrated gasification combined-cycle (IGCC) using the KRW air-blown pressurized fluidized-bed coal gasification system (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:

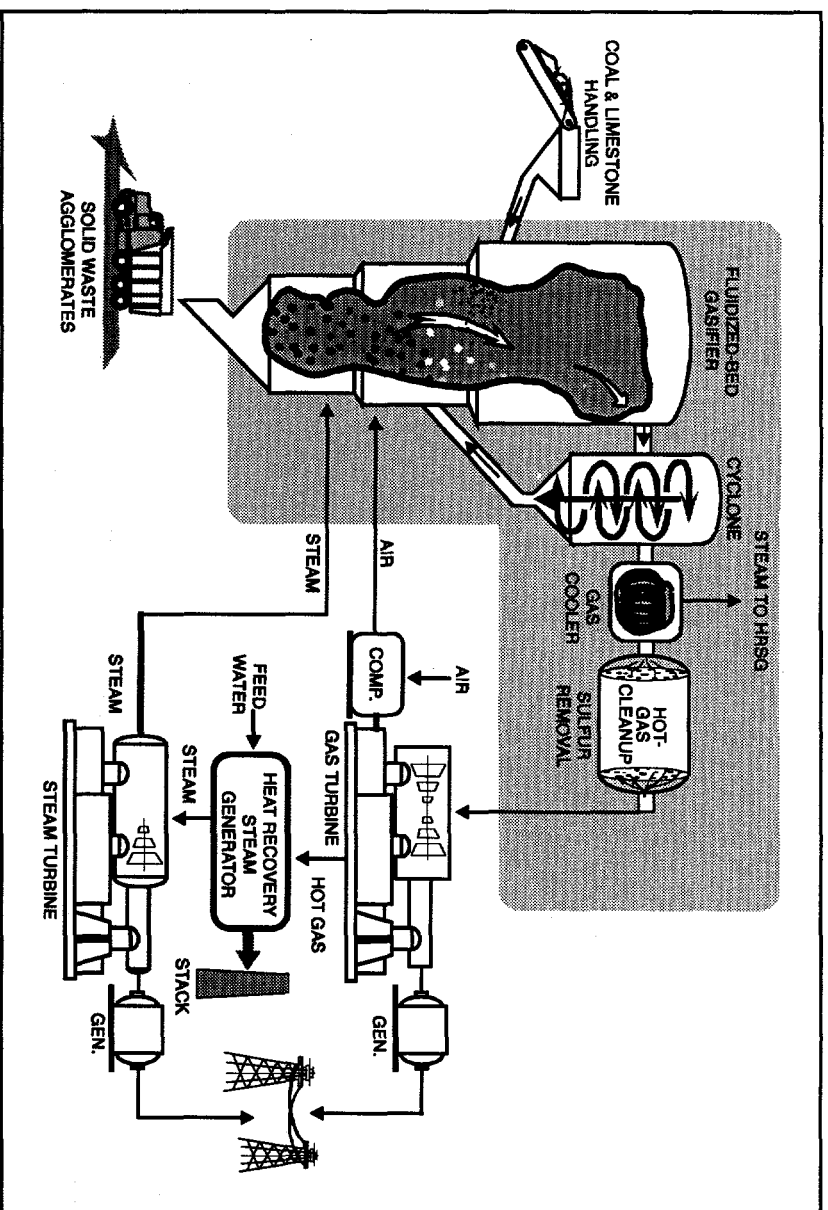
99 MWe (net)

Project Funding:

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

Project Objective:

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



Technology/Project Description:

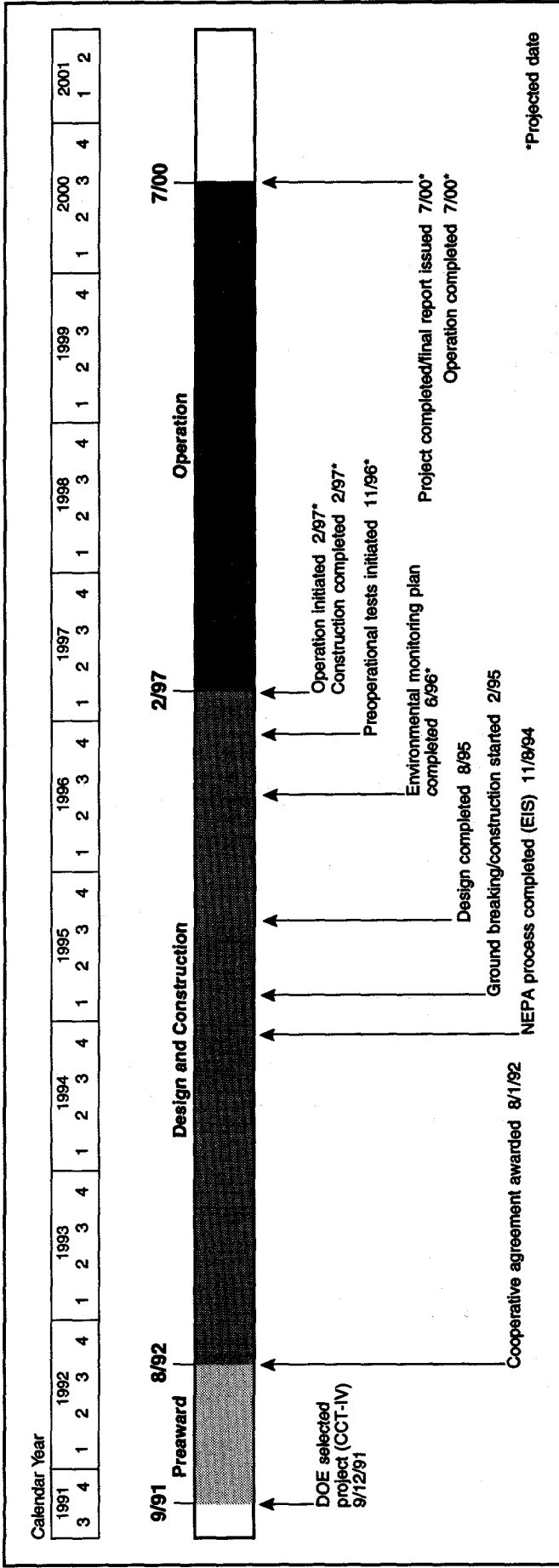
Dried and crushed coal and limestone are introduced into a pressurized, air-blown, fluidized-bed gasifier. Crushed limestone is used to capture a portion of the sulfur and to inhibit conversion of fuel nitrogen to ammonia. The sulfur reacts with the limestone to form calcium sulfide which, after oxidation,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

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

sulfur are removed by reaction with metal oxide sorbent in a transport reactor.

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

Due to the relatively low operating temperature of the gasifier and the injection of steam into the combustion fuel stream, the NO_x emissions are 0.069 lb/million Btu (94% reduction). Due to the combination of in-bed sulfur capture and hot gas cleanup, SO₂ emissions are 0.069 lb/million Btu (90% reduction).



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

Project Status/Accomplishments:

The participant started construction activities in early 1995 and, by year-end 1995, construction was approximately 50% complete. Fabrication of the gasifier island as well as foundations for the coal crusher and solid waste silo are complete; also the steam turbine pad has been poured. Further, the 42-inch cooling lines to the steam turbine foundation and in the cooling tower area are complete. The public design report was issued in August 1995.

Commercial Applications:

The Piñon Pine IGCC system concept is suitable for new power generation, repowering needs, and cogeneration applications. The net effective heat rate for a proposed greenfield plant using this technology is projected to be 7,800 Btu/kWh (43.7% efficiency), representing a 20% increase in thermal efficiency as compared to a conventional pulverized coal plant with a scrubber and a comparable reduction in CO₂ emissions. The compactness of IGCC systems reduces space requirements per unit of energy generated relative to other coal-based power generation systems, and the advantages provided by modular construction reduce the financial risk associated with new capacity additions.

The KRW IGCC technology is capable of gasifying all types of coals, including high-sulfur and high-swelling coals, as well as bio- or refuse-derived waste, with minimal environmental impact. This versatility provides numerous economic advantages for the depressed mineral extraction and cleanup industries. There are no

significant process waste streams that require remediation. The only solid waste from the plant is a mixture of ash and calcium sulfate, a nonhazardous waste.

Tampa Electric Integrated Gasification Combined-Cycle Project

Participant:

Tampa Electric Company

Additional Team Members:

Texaco Development Corporation—gasification technology supplier

General Electric Company—combined-cycle technology supplier

GE Environmental Systems, Inc.—hot-gas cleanup technology supplier

TECO Power Services Corporation—project manager and marketer

Bechtel Power Corporation—architect and engineer

Location:

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

Technology:

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

Plant Capacity/Production:

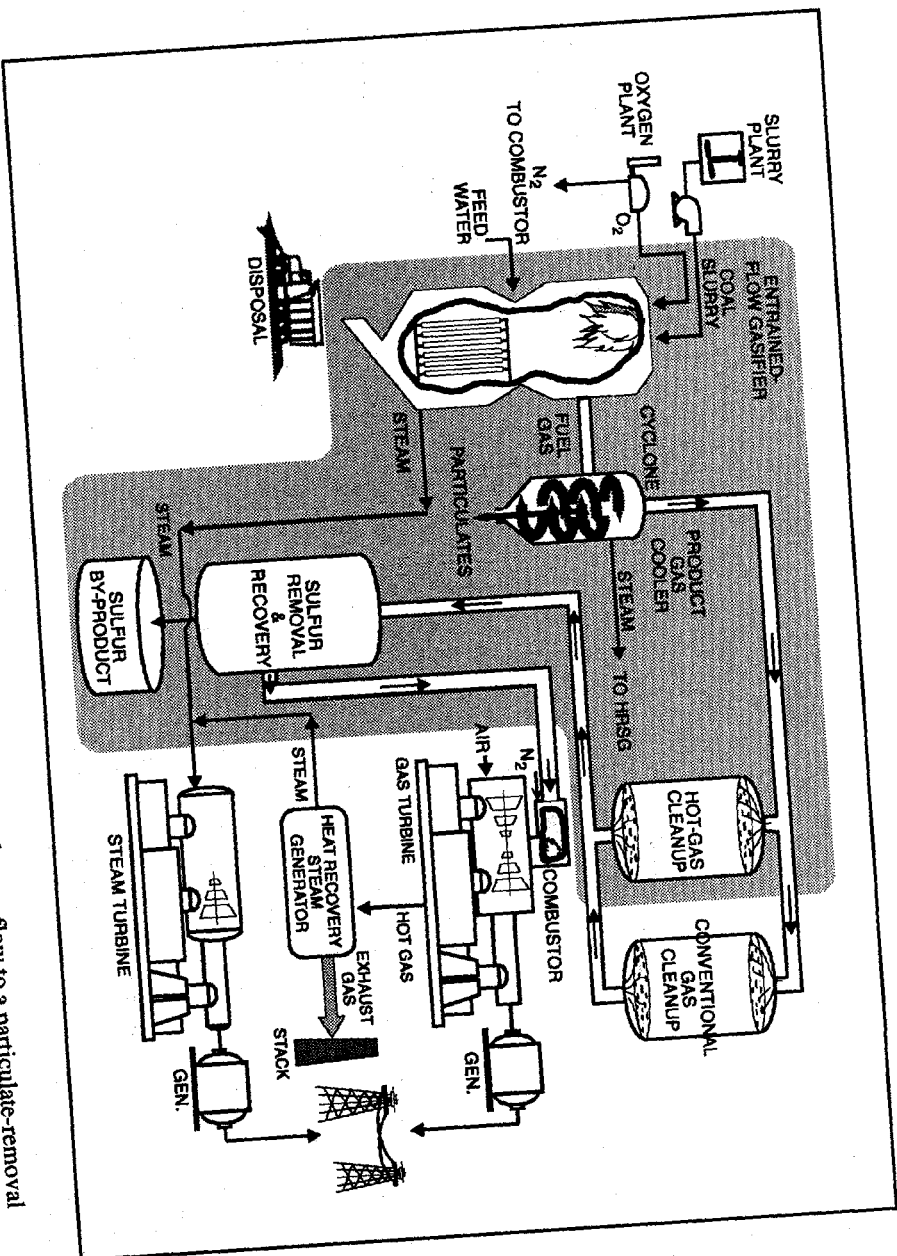
250 MWe (net)

Project Funding:

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

Project Objective:

To demonstrate the IGCC technology in a greenfield, commercial, electric utility application at the 250-MWe

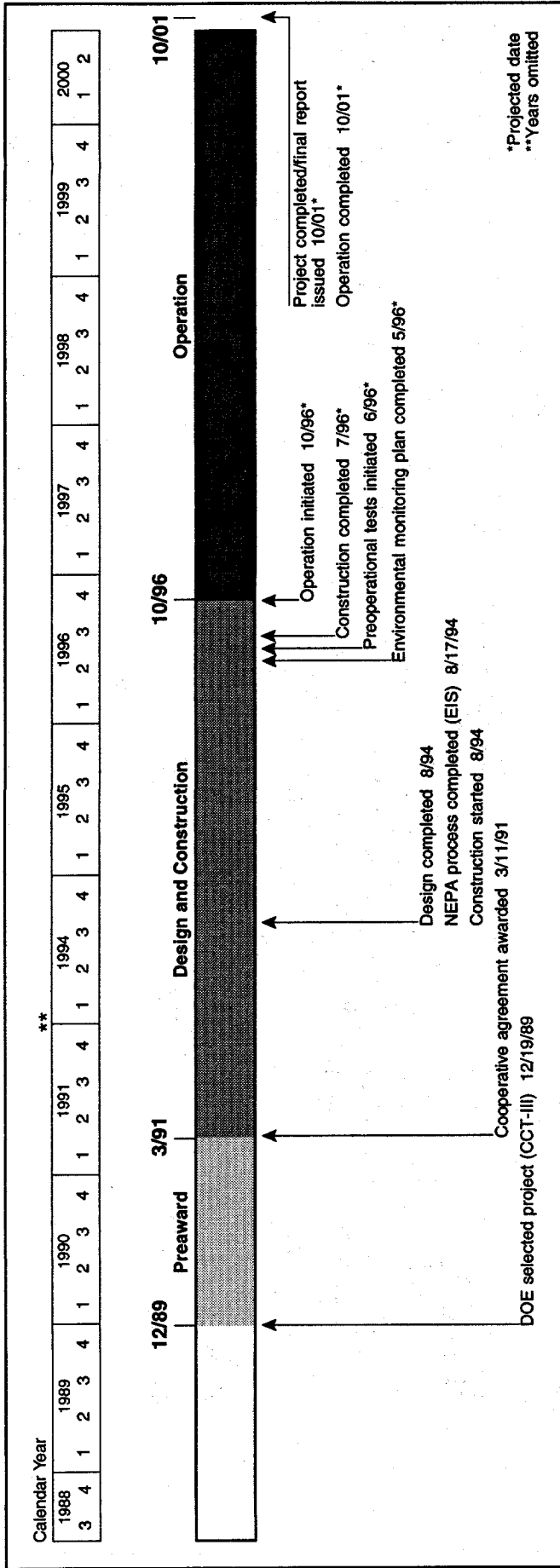


size with a Texaco gasifier. To demonstrate the integrated performance of a metal oxide hot-gas cleanup system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection (from the air separation plant) for power augmentation and NO_x control.

Technology/Project Description:

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

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



along with the steam generated in the gasification process, is routed to the steam turbine to generate an additional 120 MWe (gross). The IGCC heat rate for this demonstration is expected to be approximately 8,600 Btu/kWh (40% efficient).

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

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

Project Status/Accomplishments:

Tampa Electric held a formal groundbreaking ceremony at the Polk County site on November 2, 1994. Construction was approximately 70% complete by year-end 1995. Structural steel is 90% in place. All major vessels have been placed in the structure. The turnkey air separation plant is mechanically complete and undergoing checkout and qualification testing. Construction is expected to be completed by mid-1996 and will be followed by a 4-5-year demonstration period. Reclamation of the area west of Rt. 37 has begun. This area was approved for development of a deep pond fishing and recreational area by the state of Florida.

EPA (the lead agency) released the final EIS for public comment on June 10, 1994. Favorable records of decision were issued by EPA and the U.S. Army Corps of Engineers in July 1994. DOE issued a record of decision on the demonstration portion on August 17, 1994.

In January 1994, all state permits for the plant were approved by the governor.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for new electric power generation, repowering needs, and cogeneration applications. The net effective heat rate for the Texaco-based IGCC is expected to be below 8,500 Btu/kWh, which makes it very attractive for baseload applications. Commercial IGCCs should achieve better than 98% SO₂ capture with NO_x emissions reduced by 90%.

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

Wabash River Coal Gasification Repowering Project

Participant:

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

Additional Team Members:

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

Location:

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

Technology:

Integrated gasification combined-cycle (IGCC) using Destec's two-stage, entrained-flow gasification system (advanced electric power generation/integrated gasification combined cycle)

Plant Capacity/Production:

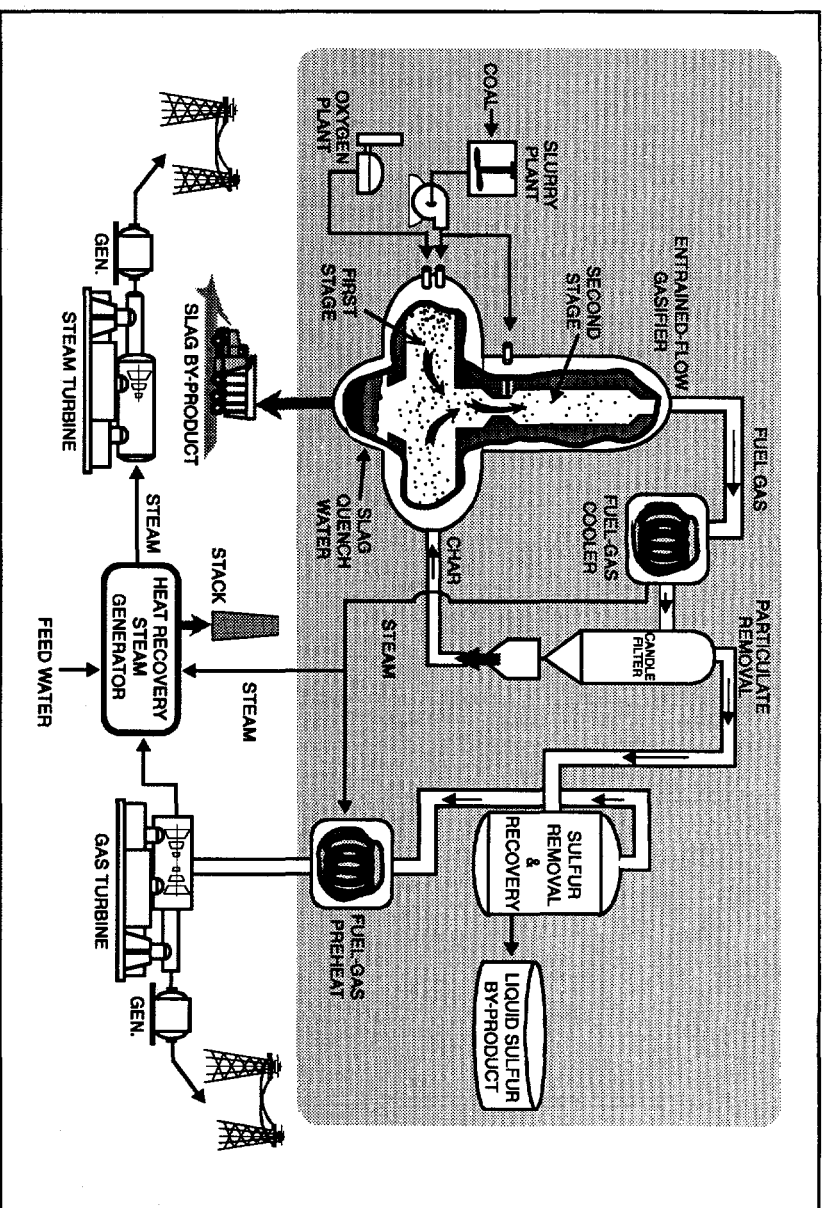
262 MWe (net)

Project Funding:

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

Project Objective:

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

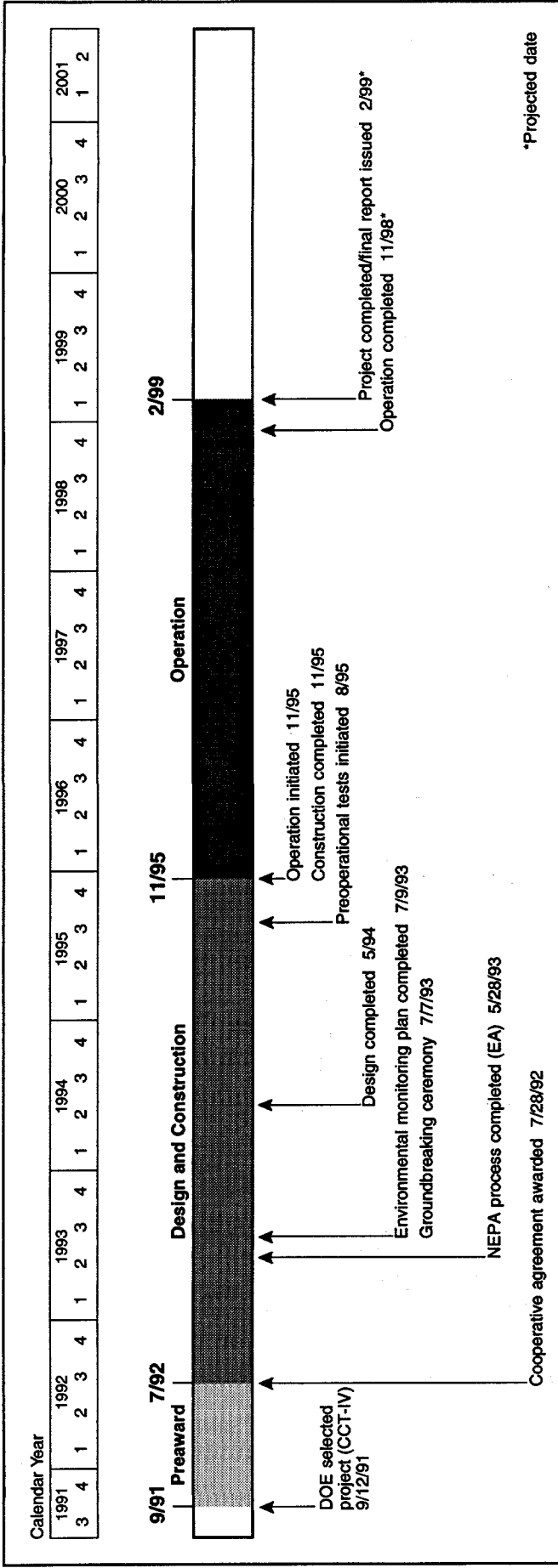


Technology/Project Description:

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

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

One of six units at PSI Energy's Wabash River Generating Station, located in West Terre Haute, IN, is being repowered. The demonstration unit will be designed to generate 262 MWe (net) using 2,544 tons/day of high-sulfur (2.3-5.9% sulfur), Illinois Basin bituminous coal. The anticipated heat rate for the repowered unit is approximately 9,000 Btu/kWh (38% efficiency). Using high-sulfur bituminous coal, SO₂ emissions are



expected to be less than 0.1 lb/million Btu (98% reduction). NO_x emissions are expected to be less than 0.1 lb/million Btu (90% reduction). Upon completion, the project will represent the largest single-train IGCC plant in operation in the United States.

Project Status/Accomplishments:

Plant construction is complete, and all plant systems have been operated. Design specifications for several vessels were modified to incorporate recent experience from Destec Energy's operating unit at the Louisiana Gasification Technology, Inc., facility in Plaquemine, L.A. Coal was introduced into the gasifier for the first time in August 1995. Plant acceptance testing has been completed, and commercial operation began in November 1995.

An environmental assessment was completed, and DOE issued a finding of no significant impact on May 28, 1993. All required environmental permits have been granted.

Commercial Applications:

Throughout the United States, particularly in the Midwest and East, there are more than 95,000 MWe of existing coal-fired utility boilers that will be over 30 years old in 1996. Many of these aging plants are without air pollution controls and are candidates for repowering with IGCC technology. Repowering of these plants with IGCC systems will improve plant efficiencies and reduce SO₂, NO_x, and CO₂ emissions. The modularity of the gasifier technology will permit a range of units to be considered for repowering and the relatively short construction schedule for the technology will allow utilities greater flexibility in designing strategies to meet load requirements. Also, the high degree of fuel flexibility inherent in the gasifier design allows utilities greater choices in fuel supplies to meet increasingly stringent air quality regulations.

Due to the advantages of modularity, rapid and staged on-line generation capability, high efficiency, fuel flexibility, environmental controllability, and reduced

land and natural resource needs, the IGCC system is also a strong contender for new electric power generating facilities. Commercial offerings of the technology will be based on a 300-MWe train which is ideally suited to utility-scale power generation applications. The system heat rate for a new power plant based on this technology is expected to realize at least a 20% improvement in efficiency compared to a conventional pulverized-coal-fired plant with flue gas desulfurization. The improved system efficiency also results in a similar decrease in emissions of CO₂.

Healy Clean Coal Project

Participant:

Alaska Industrial Development and Export Authority

Additional Team Members:

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

Location:

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

Technology:

TRW's advanced entrained (slagging) combustor
 Joy Technologies' spray dryer absorber with sorbent recycle
 advanced electric power generation/advanced combustion/heat engines)

Plant Capacity/Production:

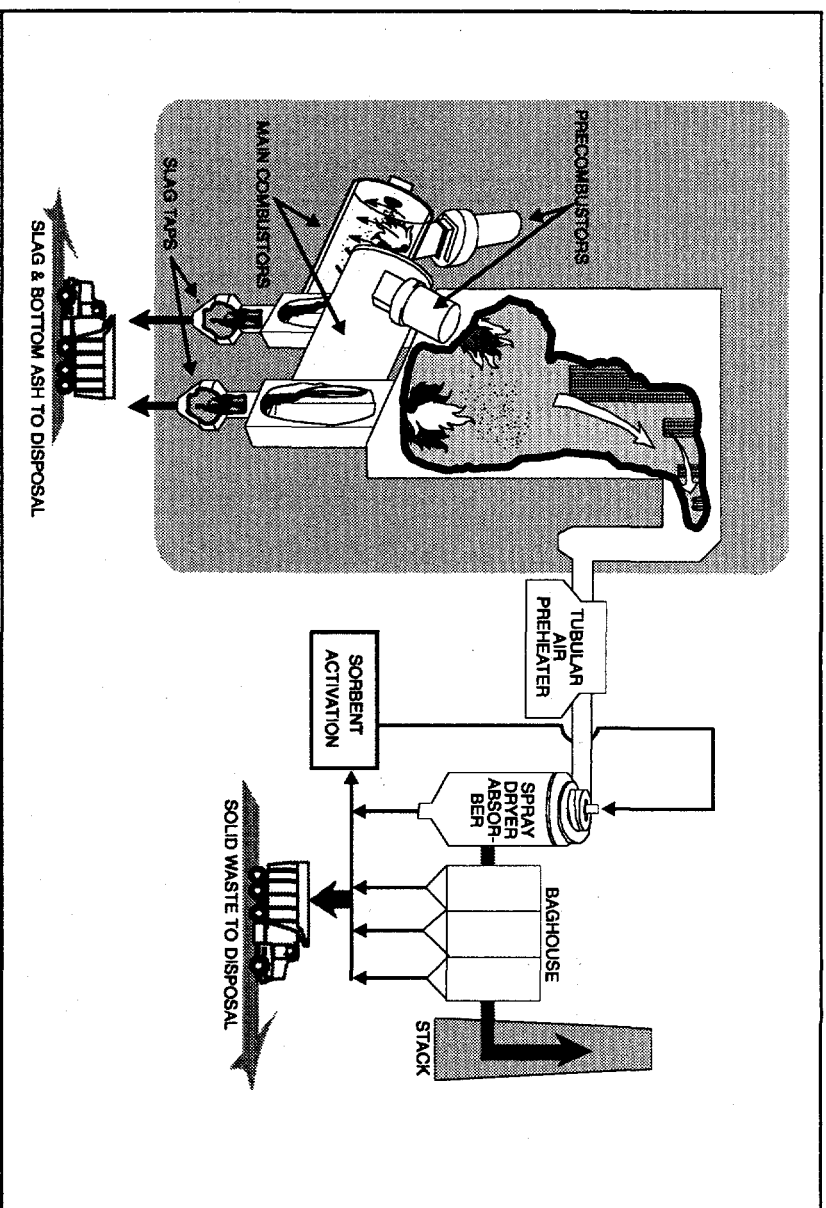
50 MWe (nominal electric output)

Project Funding:

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

Project Objective:

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

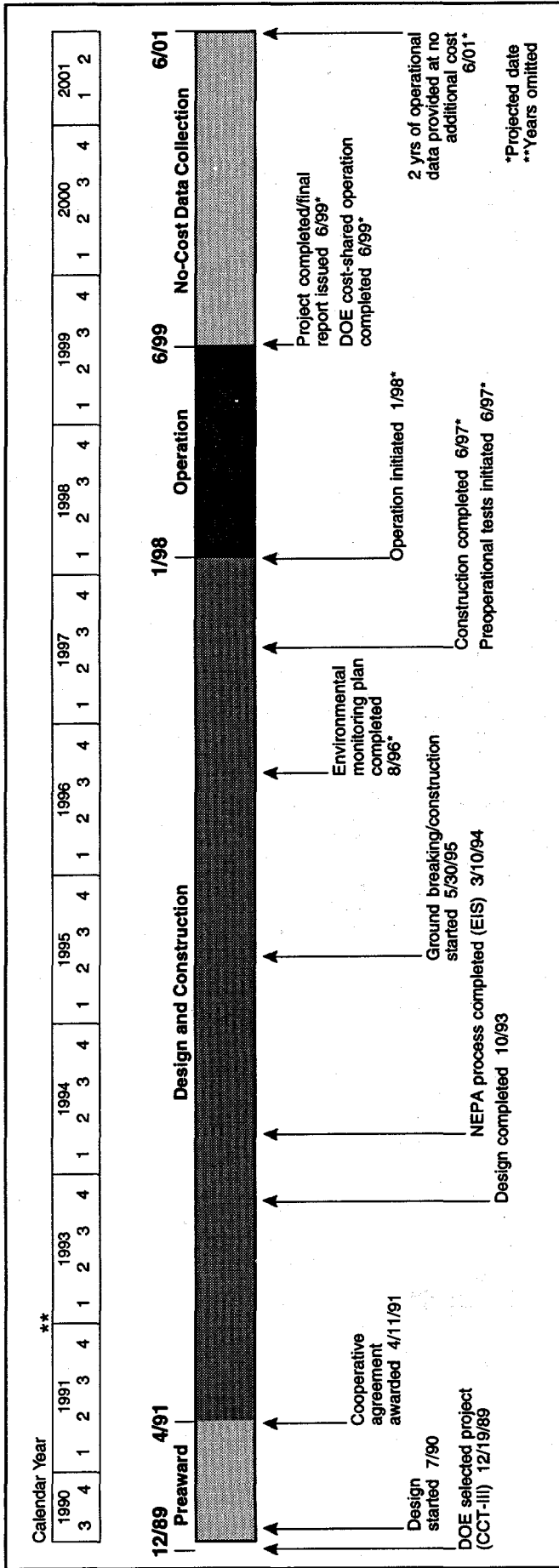


Technology/Project Description:

The project is to be a nominal 50-MWe facility consisting of two pulverized-coal-fired combustor systems. Emissions of SO_2 and NO_x will be controlled using TRW's slagging combustion systems with staged fuel and air, a boiler that controls fuel- and thermal-related conditions, and limestone injection. Additional SO_2 will be removed using Joy's activated recycle spray dryer absorber system. Performance goals are NO_x emissions of less than 0.2 lb/million Btu, particulates of 0.015 lb/million Btu, and SO_2 removal greater than 90%. The performance coal consists of 37% run-of-mine and 65% waste coal, with the waste coal having a lower heating value and significantly more ash.

A coal-fired precombustor increases the air inlet temperature for optimum slagging performance. The

TRW slagging combustors are bottom-mounted on the boiler hopper. The main slagging combustor consists of a water-cooled cylinder which 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 stoichiometric (fuel-rich) conditions for NO_x control. The ash forms molten slag which accumulates on the water-cooled walls and is driven by aerodynamic and gravitational forces through a slot into the slag recovery section. About 70–80% of the coal's ash is removed as molten slag. The hot gas is then ducted to the furnace where, to ensure complete combustion, additional air is supplied from the tertiary air windbox to NO_x ports and to final overfire air ports.



Pulverized limestone (CaCO₃) for SO₂ control is fed into the combustor where most is flash calcined. The mixture of this lime (CaO) and the ash not slagged, called flash-calcined material, is removed in the fabric filter (baghouse) system. A small part of the flash-calcined material is disposed of, but most is conveyed to a mixing tank where water is added to form a 45% flash-calcined-material solids slurry. The slurry leaving the mixing tank is pumped to a grinding mill where it is mechanically activated by abrasive grinding. Feed slurry is pumped from the feed tank to the spray dryer absorber where the slurry is atomized using Joy dry scrubbing technology. SO₂ in the flue gas reacts with the slurry as water is simultaneously evaporated. SO₂ is further removed from the flue gas by reacting with the dry flash-calcined material on the baghouse filter bags.

The project site is adjacent to the existing Healy Unit #1 near Healy, AK. Power will go to the Golden Valley Electric Association (GVEA). The plant will use a nominal 900 tons/day of subbituminous coal containing a nominal 0.2% sulfur and waste coal. The project

will collect performance data for 3 years, with 2 years of data being provided at no cost to DOE. A hazardous air pollutant monitoring program will also be implemented.

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

Project Status/Accomplishments:

Design and engineering is complete; the general construction contractor was issued full notice to proceed, and major equipment suppliers were released to begin fabrication. A groundbreaking celebration was held May 30, 1995. By the end of the 1995 construction season, approximately 12,000 cubic yards of concrete had been poured and over 48,000 cubic yards of structural backfill has been hauled and completed. Erection of structural steel, which began in August 1995, is 30% complete.

A final EIS was signed on December 15, 1993, and a record of decision was signed on March 10, 1994. A final visibility monitoring plan has been submitted to the Alaska Department of Environmental Conservation.

Commercial Applications:

This technology has a wide range of applications. It is appropriate for any size utility or industrial boiler in new and retrofit uses. It can be used in coal-fired boilers as well as in oil- and gas-fired boilers because of its high ash removal capability. However, cyclone boilers may be the most amenable type to retrofit with the slagging combustor because of the limited supply of high-Btu, low-sulfur, low-ash-fusion-temperature coal that cyclone boilers require. The commercial availability of cost-effective and reliable systems for SO₂, NO_x, and particulate control is important to potential users planning new capacity, repowering, or retrofits to existing capacity in order to comply with CAAA of 1990 requirements.

Coal Diesel Combined-Cycle Project

Participant:
Arthur D. Little, Inc.

Additional Team Members:

- Ohio Coal Development Office—cofunder
- Cooper Energy Services (Cooper-Bessemer Reciprocating Products Division is a division of Cooper Energy Services which is owned by Cooper Industries.)—engine supplier and commercializer
- CQ Inc.—coal-slurry supplier
- PSI—cleanup system designer
- AMBAC International—coal-water fuel injection system components supplier

Location:

Site under negotiation

Technology:

Cooper-Bessemer's coal-fueled diesel engine combined-cycle (CDCC) system (advanced electric power generation/advanced combustion/heat engines)

Plant Capacity/Production:

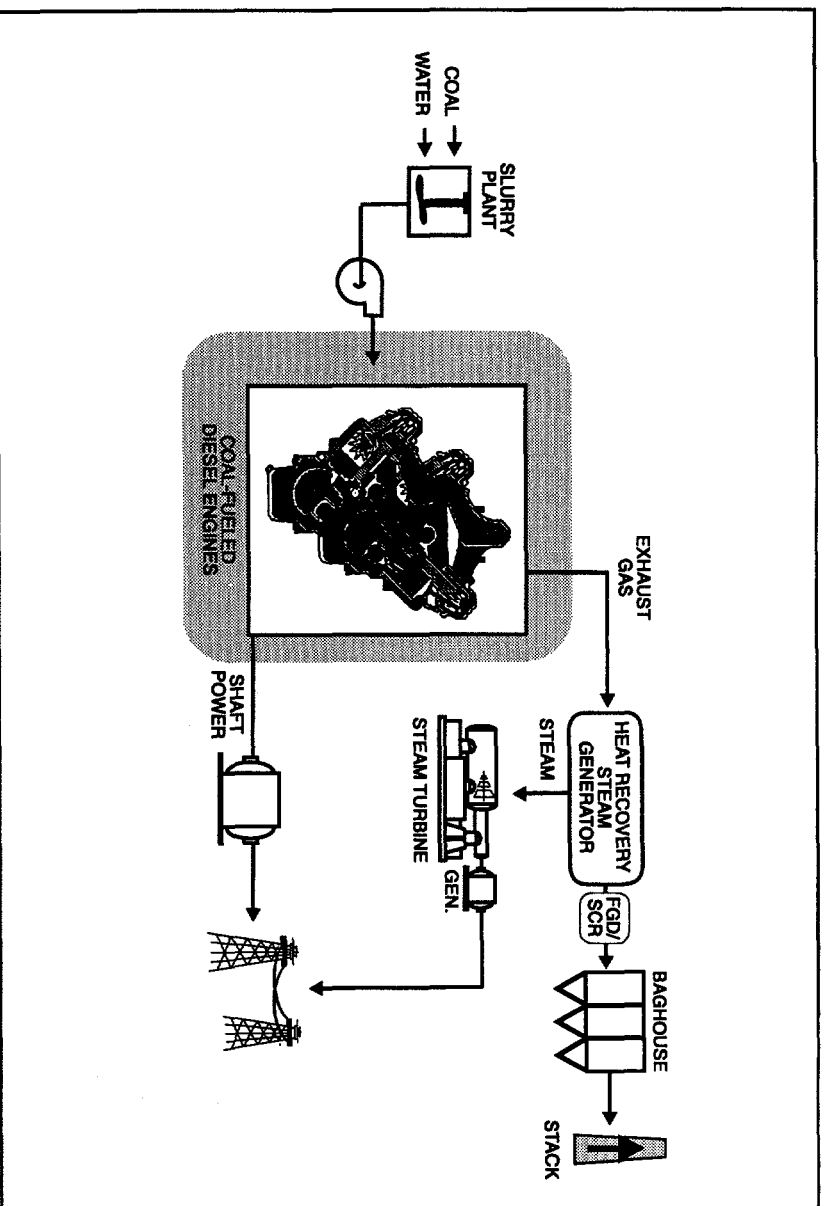
14 MWe (net)

Project Funding:

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

Project Objective:

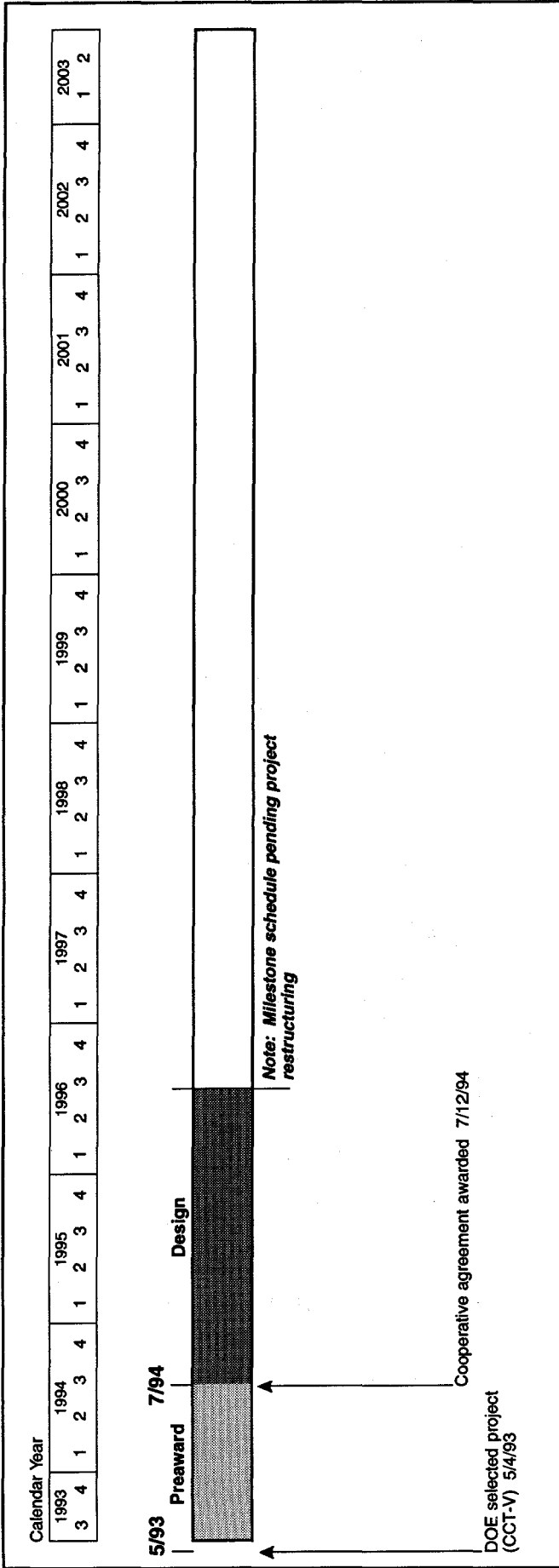
To demonstrate an advanced, coal-fueled diesel engine combined-cycle system based on Cooper-Bessemer's LSBLSVB diesel engine series. To provide critical data on the performance, reliability, and wear information of all major subsystems.



Technology/Project Description:

The project involves modifying two Cooper-Bessemer medium-speed (400 rpm) diesel engines (6.3 MWe each) to operate on coal-water fuel. Engine modifications include a larger camshaft and fuel cams, modified engine block, hardened piston rings and liners, and hardened turbocharger blades. The CDCC system utilizes a coal-water fuel with a nominal 50% solids loading with a 2% ash cleaned coal. The cleaned coal is ground and slurried with water and then injected into each of the engine's 20 cylinders. The exhaust gases from the engine pass through an integrated emission-control system capable of reducing pollutants while protecting the engine's turbo-charger and maintaining high engine and overall system efficiency (45%). The exhaust gases pass through a heat recovery steam boiler coupled to a steam turbine and

generator to supply an additional 1.4 MWe. Critical data on performance, reliability, and wear are being collected for all major subsystems including the coal-water fuel metering and injection system, medium-speed diesel, lube oil protection system, exhaust cyclone, turbo-charger, heat recovery steam boiler, steam turbine, and exhaust emission cleanup system. The exhaust emission cleanup system incorporates cyclones to remove the larger particulates, a selective catalytic recovery system for SO₂ control, a duct sorbent injection system for NO_x control, and baghouse for final collection of ash particulates and spent sorbent.



Project Status/Accomplishments:

The cooperative agreement was awarded July 12, 1994. Design is in progress. Full-scale single-cylinder fuel evaluation tests have been conducted on Ohio coal-water fuels at Cooper's research engine facility in Mount Vernon, OH. The participant has finalized its subcontract arrangements with Cooper-Bessemer and CQ, Inc., as well as its funding agreement with the Ohio Coal Development Office.

Easton Utilities, the original host, has withdrawn from the project after reevaluating its long-term need for power. An extension to June 15, 1996, has been granted to the participants to allow completion of activities relating to resiting the project to the University of Alaska in Fairbanks.

Commercial Applications:

The CDCC system is particularly suited for small (below 50 MWe) electric power generation markets. Projected markets include small nonutility generators and repower-

ing applications for small coal-fired boilers. The net effective heat rate for the mature CDCC 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 CDCCs should be reduced to levels between 50% and 70% below NSPS.

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

Warren Station Externally Fired Combined-Cycle Demonstration Project

Participant:

Pennsylvania Electric Company

Additional Team Members:

Hague International—technology developer and supplier
Black & Veatch—engineer and construction manager

Location:

Warren, Warren County, PA (Pennsylvania Electric Company's Warren Station, Unit 2)

Technology:

Hague International's externally fired combined-cycle (EFCC) system using a novel, high-temperature, ceramic gas-to-air heat exchanger (advanced electric power generation/advanced combustion/heat engines)

Plant Capacity/Production:

62.4 MWe (net)

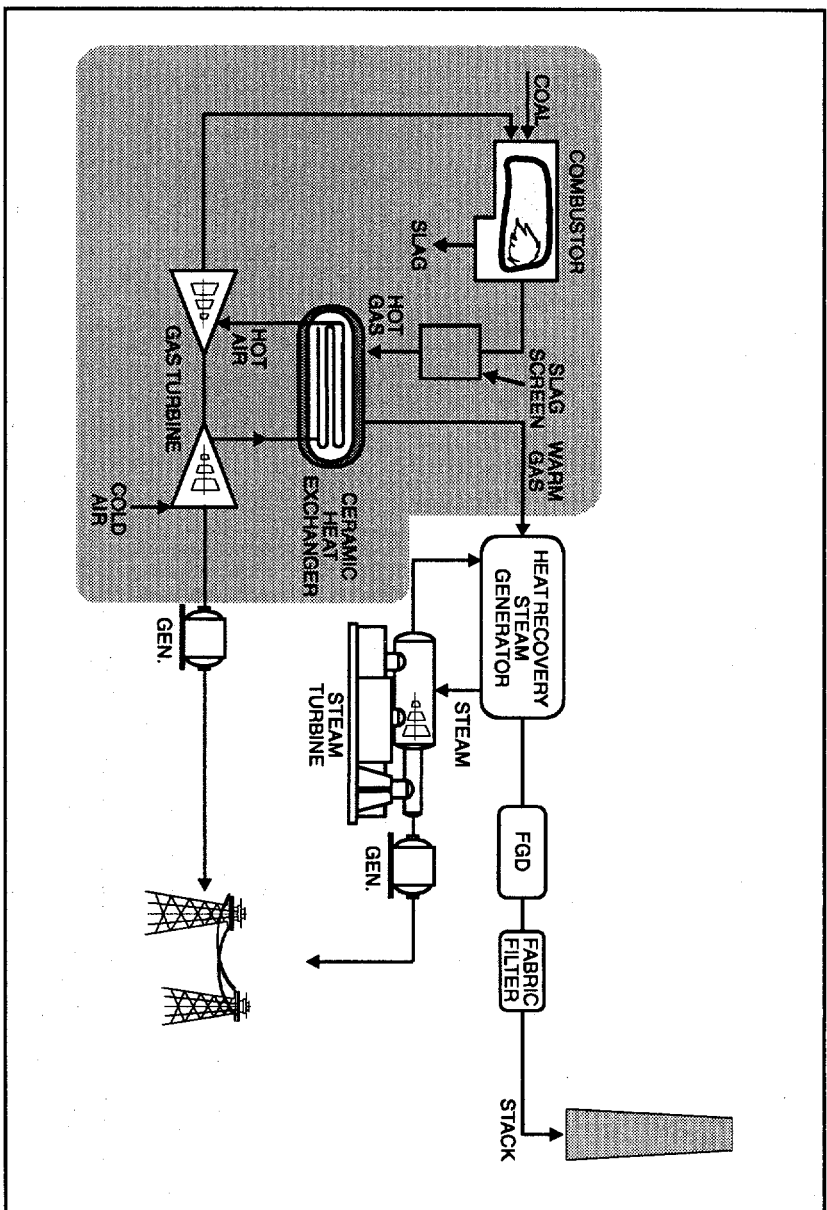
Project Funding:

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

Project Objective:

To demonstrate an externally fired combined-cycle system through the use of a novel ceramic heat exchanger and to assess the system's environmental and economic performance for meeting future energy needs. Along with the heat exchanger, the system will demonstrate a ceramic slag screen for removal of combustion by-products from the product gas prior to entering the heat exchanger; a staged, wet bottom, low- NO_x combustor; and

CerTix is a registered trademark of Hague International.



the integration of the above with a gas turbine and a steam turbine.

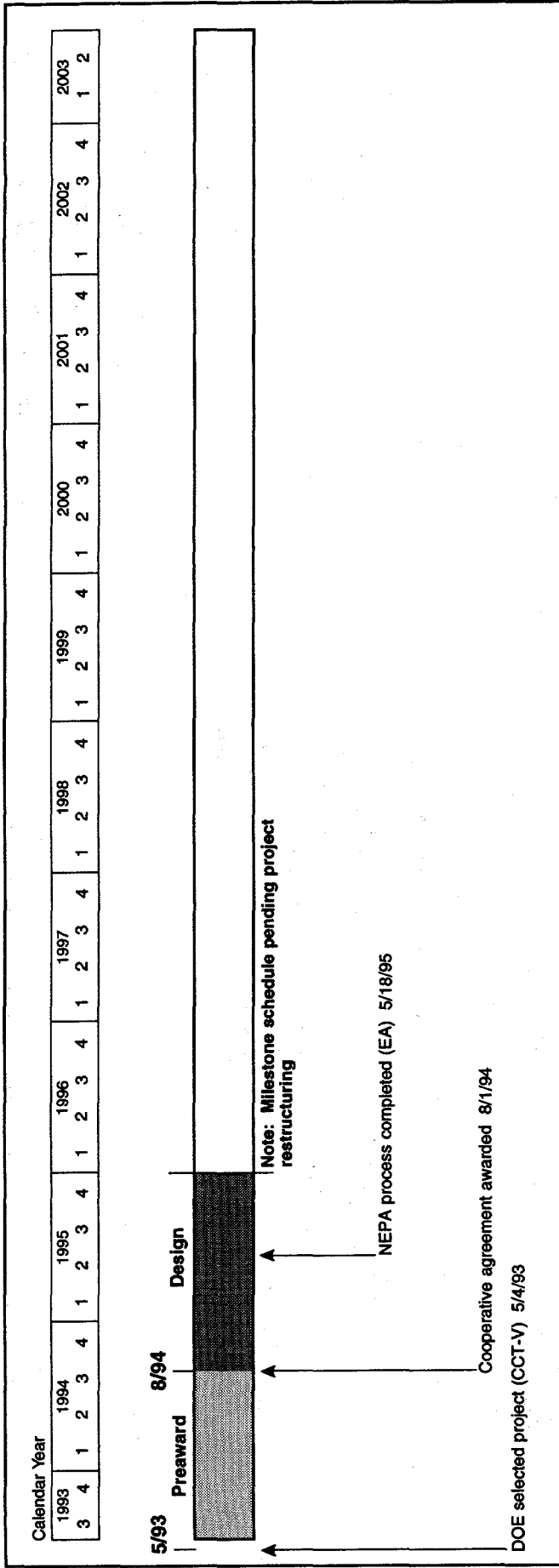
Technology/Project Description:

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

Coal is first combusted in a staged combustor for NO_x control. Particulate-laden gases exit the combustor and enter the slag screen where all particles larger than about 10 microns are collected. Air from the turbine compressor is heated by exchange with the hot product

gas in the CerTix®. The product gas is then passed through a heat recovery steam generator, where more heat is extracted to drive a steam turbine generator and produce electricity. The product gas is finally passed through a gas cleanup system consisting of a flue gas desulfurizer and a fabric filter before exiting to the atmosphere through the stack. The hot air from the CerTix® is passed through a gas turbine to produce additional electricity before firing the combustor.

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



CerFix® raises the temperature of the air to the turbine inlet conditions using tube elements that are manufactured from corrosion resistant, toughened, ceramic materials.

About 225,000 tons/yr of bituminous coal will be combusted to produce 62.4 MWe. The gas turbine will generate 18.3 MWe with a small amount of steam injection and the existing steam turbine will generate 47.7 MWe, for a total gross output of 66 MWe. Approximately 3.6 MWe will be consumed internally. The heat rate of the demonstration facility will be 9,650 Btu/kWh (HHV), which is a 31.3% improvement over the existing Warren Station unit. Potential SO_x release is reduced by over 90% through capture in the flue gas desulfurization system. NO_x emissions are expected to be below 0.13 lb/million Btu.

The facility being repowered is Pennsylvania Electric Company's Warren Station Unit 2 near Warren, PA. The primary coal for the project is Pennsylvania bituminous coal containing either 1.0% or 2.3% sulfur, depend-

ing on the mine. A secondary test coal is Pennsylvania bituminous coal containing 1.6% sulfur.

Project Status/Accomplishments:

The cooperative agreement was awarded on August 1, 1994. Design efforts are in progress. The design period has been extended because of a lack of development progress for the externally fired technology. Options for restructuring the project also are under consideration.

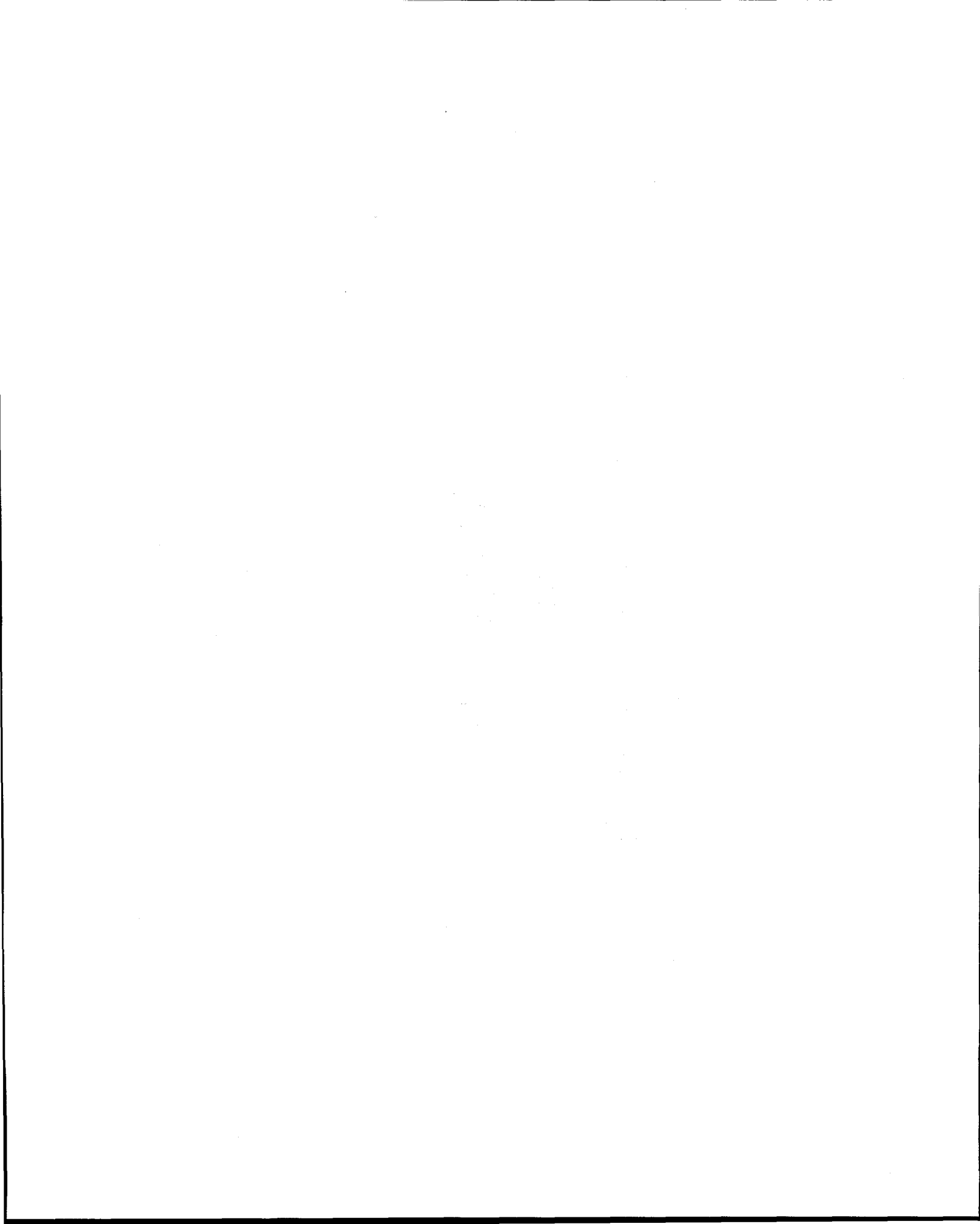
An environmental assessment was completed, and DOE issued a finding of no significant impact on May 18, 1995.

Commercial Applications:

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

mal efficiency compared to a conventional pulverized coal plant with a scrubber.

SO₂ is expected to be below 0.081 lb/million Btu, which is a reduction of over 90% for most coals. NO_x emissions are expected to be less than 0.15 lb/million Btu and particulate emissions (PM10) are expected to be below 0.015 lb/million Btu.



**Environmental Control
Devices
Fact Sheets**

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Project completed.

Participant:

The Babcock & Wilcox Company

Additional Team Members:

Wisconsin Power and Light Company—cofunder and host

Sargent and Lundy—engineer for coal handler

Electric Power Research Institute—cofunder

State of Illinois, Department of Energy and Natural Resources—cofunder

Utility companies (14 cyclone boiler operators)—

cofundors

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 (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

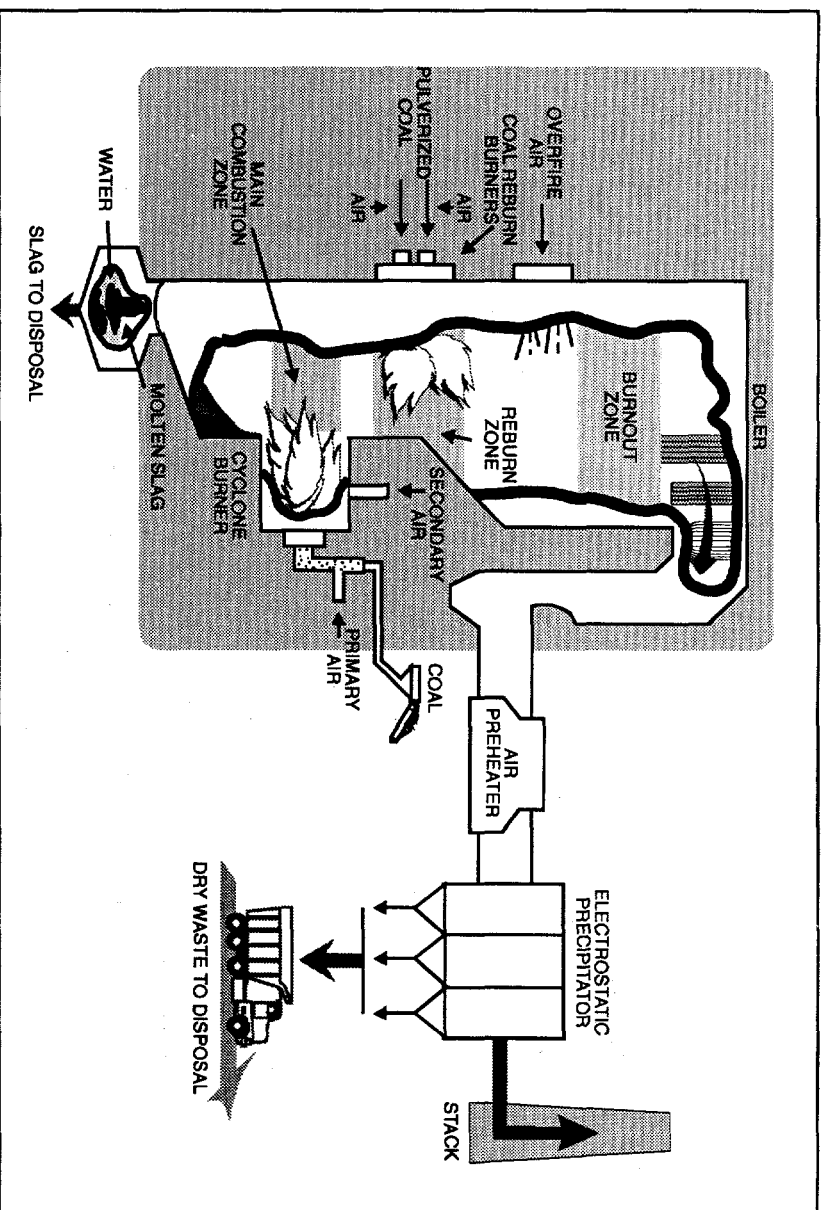
100 MWe

Project Funding:

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

Project Objective:

To evaluate the applicability of reburning technology for reducing NO_x emissions from a full-scale coal-fired cyclone boiler, pulverizing a portion of the primary coal fuel to use as the secondary, "reburning" fuel; and to



achieve greater than 50% reduction in NO_x emissions with no serious impact on cyclone combustor operation, boiler efficiency, boiler fireside performance (corrosion and deposition), or ash removal system performance.

Technology/Project Description:

The coal-reburning process reduces NO_x in the furnace through the use of multiple combustion zones. The main combustion zone uses 70–80% of the total heat equivalent fuel input to the boiler and slightly less than normal combustion air input. The balance of the coal (20–30%), along with significantly less than the theoretically determined requirement of air, is fed to the reburning zone above the cyclones to create an oxygen-deficient condition. The NO_x formed in the cyclone burners reacts with the resultant reducing flue gas and is converted into nitrogen in this zone. The completion of the combustion

process occurs in the third zone, called the burnout zone, where the balance of the combustion air is introduced. The combined production of boiler slag and dry waste from the electrostatic precipitator remains unchanged with coal reburning because the required coal input for the same boiler load is the same.

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

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

Project Results/Accomplishments:

Coal-reburn tests were conducted to determine the reduction in NO_x emissions for the coal-reburning technology over a range of boiler loads varying from 37 MWe to 118 MWe (nominal maximum boiler load is 110 MWe). Two coals were tested, namely, the design Illinois Basin bituminous coal (Lamar, 1.8% sulfur) and a western subbituminous coal (Powder River Basin, 0.5% sulfur). The bituminous coal tests evaluated a fuel typical of the coals fired by utilities operating cyclones. The subbituminous coal tests evaluated coal switching for SO₂ reduction.

As a part of the test program, several parameters were optimized over the load range to achieve the optimum NO_x reduction while keeping other variables, such as unburned carbon and carbon monoxide emissions, within reasonable limits. The optimized parameters included the split of boiler fuel between the reburn system and the cyclone burners, the reburn burner and the reburn zone stoichiometries, the reburn burner pulverized coal fineness, flue gas recirculation, and economizer outlet O₂ content. Also, adjustments were made to the reburn burners and the over-fire air ports during the tests.

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

- 52% (to 290 ppm or 0.394 lb/million Btu) at 110 MWe
 - 47% (to 285 ppm or 0.387 lb/million Btu) at 82 MWe
 - 36% (325 ppm or 0.442 lb/million Btu) at 60 MWe
- With Powder River Basin coal, the NO_x emissions were reduced as follows:
- 62% (to 208 ppm or 0.278 lb/million Btu) at 110 MWe
 - 55% (to 215 ppm or 0.287 lb/million Btu) at 82 MWe
 - 53% (to 220 ppm or 0.294 lb/million Btu) at 60 MWe

Reburn testing with both coals indicated that varying

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

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

Additional effects of coal reburning on the retrofitted boiler follow:

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

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

Commercial Applications:

The current reburn market is nearly 26,000 MWe and consists of about 120 units ranging from 100 MWe to 1,150 MWe, with most in the 100–300-MWe range.

Coal reburning is a retrofit technology applicable across the size range of utility and industrial cyclone boilers. The principal environmental benefit is reduced NO_x emissions. A secondary benefit may be reduced SO₂ emissions by enabling greater use of lower sulfur western coal; due to its lower Btu content, western coals limit cyclone capacity. With the additional firing capacity of the reburn system, full-load performance on western coal may be possible for some cyclone units.

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

Project Schedule:

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

Final Reports:

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

Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit

Project completed.

Participant:
The Babcock & Wilcox Company

Additional Team Members:

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

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

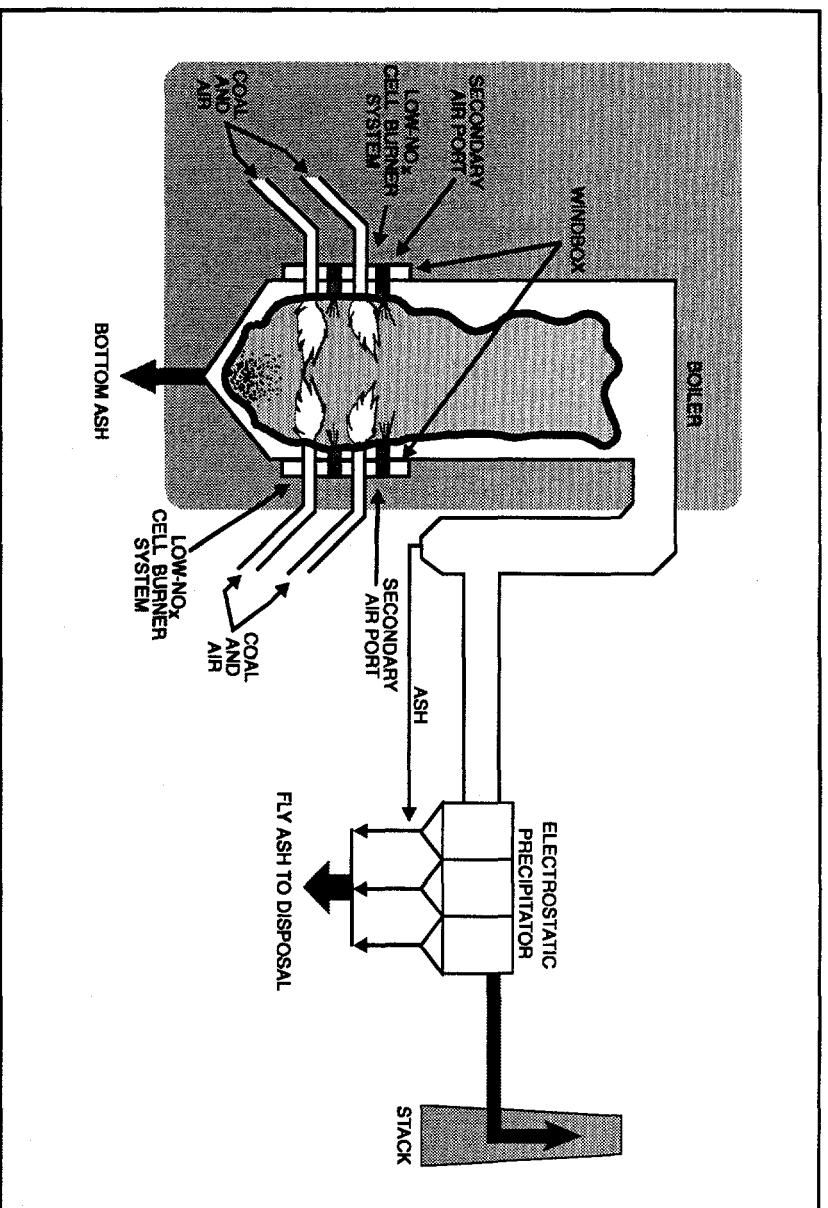
Technology:
The Babcock & Wilcox Company's low-NO_x cell burner (LNCB®) system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
605 MWE

Project Funding:

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

Project Objective:
To demonstrate through the first commercial-scale full burner retrofit the cost-effective reduction of NO_x from a LNCB is a registered trademark of The Babcock & Wilcox Company.



large base-load coal-fired utility boiler with LNCB® technology; and to achieve at least a 50% NO_x reduction without degradation of boiler performance at less cost than conventional low-NO_x burners.

Technology/Project Description:

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

gen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO_x.

The net effect of this technology is greater than 50% reduction in NO_x formation with no boiler pressure part changes and no impact on boiler operation or performance. In addition, the technology is compatible with most commercial and emerging SO₂ control technologies, including confined zone dispersion, gas suspension absorption, duct injection, and advanced wet scrubbers.

The demonstration was conducted at a large-scale power plant operated by The Dayton Power and Light Company and jointly owned with the Cincinnati Gas and Electric Company and the Columbus Southern Power Company. The boiler unit is a Babcock & Wilcox-designed, supercritical, once-through boiler equipped with

an electrostatic precipitator. This unit contained 24 two-nozzle cell burners arranged in an opposed-firing configuration. Twelve burners (arranged in two rows of six burners each) were mounted on each of two opposing walls of the boiler. All 24 standard cell burners were removed, and 24 new LNCB® were installed. Alternate LNCB® on the bottom rows were inverted, with the air port then being on the bottom to insure complete combustion in the lower furnace.

Project Results/Accomplishments:

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

The LNCB® demonstration emphasized evaluation of boiler performance, boiler life, and environmental impact. Key boiler performance parameters included boiler output (steam temperatures); flue gas temperatures at the furnace, economizer, and air heat exits; the slagging tendencies of the unit; and unburned carbon losses. Boiler life potentials (corrosion tendencies) were measured by gas sampling for high H₂S concentrations in the furnace, ultrasonic testing of lower furnace tube walls, and destructive examination of a corrosion test panel. Environmentally, NO_x, CO, CO₂, total hydrocarbons, and particulate matter were measured at varying test conditions.

At full load (605 MWe) with all mills in service, average NO_x emissions were 0.53 lb/million Btu, a 54.4% reduction from the baseline. CO emissions

ranged from 28 to 55 ppm. Flyash unburned carbon averaged 1.12%, for a 0.2% loss unburned carbon efficiency. This is a 56% improvement over baseline unburned carbon losses, probably resulting from improved air flow distribution achieved by the LNCB® retrofit. At reduced loads of 460 MWe and 350 MWe, the NO_x emissions reductions were 54% and 48% respectively, and CO emissions and unburned carbon values were comparable with baseline emissions.

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

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

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

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

Commercial Applications:

The low cost and short outage time for retrofit make the LNCB® design attractive. Typically, the retrofit capital cost will be \$5.50-\$8.00/kW in 1993 dollars, based upon DOE's 500-MWe reference unit. The outage time can be

as short as 5 weeks because of the "plug-in" design. The LNCB® system can be installed at about half the cost and outage time for other commercial low-NO_x burner installations.

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

Project Schedule:

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

Final Reports:

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

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

Project completed.

Participant:
Energy and Environmental Research Corporation

Additional Team Members:
Public Service Company of Colorado—cofunder and host
Gas Research Institute—cofunder
Colorado Interstate Gas Company—cofunder
Electric Power Research Institute—cofunder

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

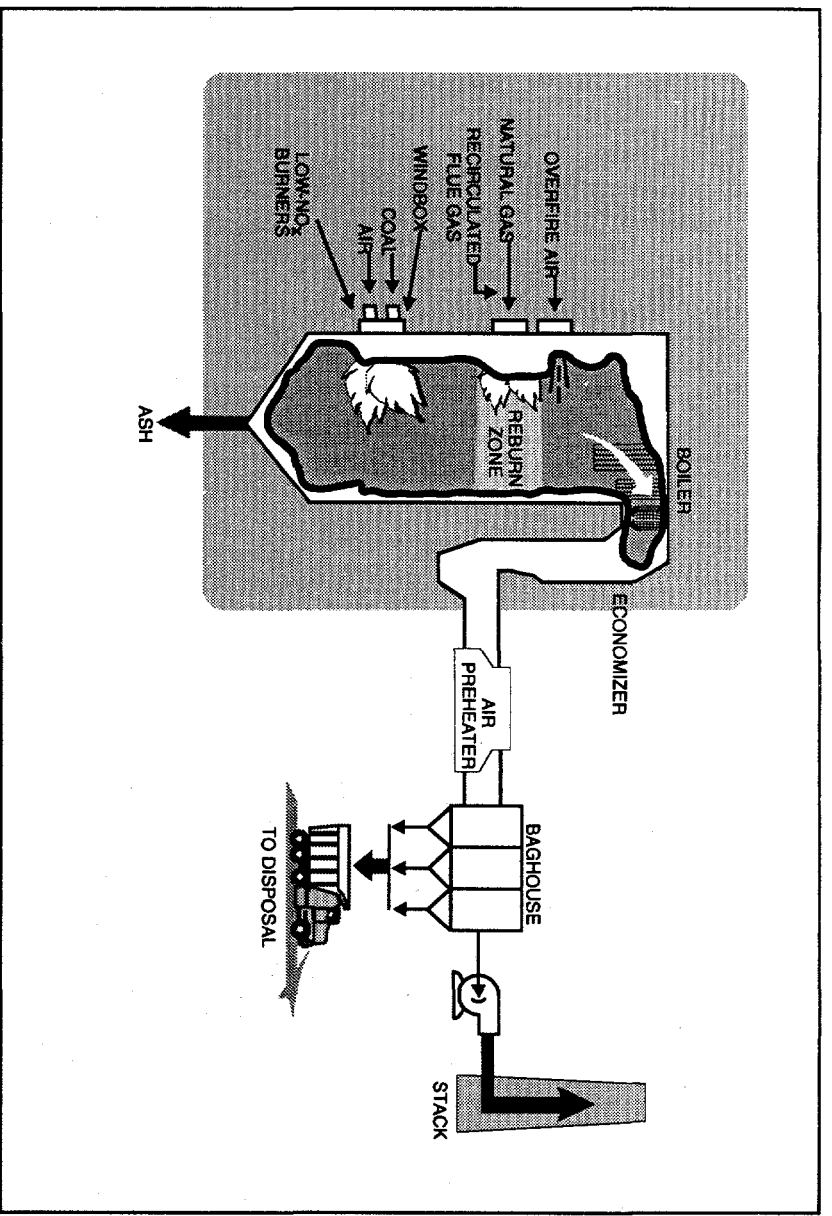
Technology:
Energy and Environmental Research Corporation's gas reburning and low-NO_x burner (GR-LNB) system (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
172 MWe

Project Funding:

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

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



Technology/Project Description:

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

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

Project Results/Accomplishments:

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

Based on the demonstration and the data collected, the technology can be applied to utility and industrial units. The participant expects that most GR-LNB installations will achieve 60% NO_x reductions when firing 10-15% gas. The capital cost for units of 100 MWe or larger is in the range of \$15/kW plus the cost of a gas pipeline. Operating costs are almost entirely related to the differential cost of gas over coal as reduced by the value of SO₂ emissions credits.

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

Commercial Applications:

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

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

Current estimates indicate that about 35 existing wall-fired utility installations, plus industrial boilers, could make immediate use of this technology. The technology would apply to retrofit, repowering or to new, greenfield installations. There is no known limit to the size or scope of the application of this technology combination. Presently, the largest existing utility boiler is estimated at about 1,300 MWe. The GR-LNB combination could be applied directly to this size boiler because the equipment is an integral part of the unit. For this reason, GR-LNB is expected to be less capital intensive, or less costly, than a scrubber, selective catalytic reduction, or other technology approaches. GR-LNB functions equally well with any kind of coal. NO_x emissions are reduced with internally staged low-NO_x burners, followed by gas reburning. As a side benefit, SO₂ is decreased in direct proportion to the amount of natural gas that is substituted for coal.

Project Schedule:

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

Final Reports:

Final Technical Report	2/96
Economic Evaluation Report	4/96
Public Design Report	4/96

Micronized Coal Reburning Demonstration for NO_x Control

Participants:

New York State Electric & Gas Corporation

Additional Team Members:

Eastman Kodak Company—host and cofunder

Consol—tester

D. B. Riley—technology supplier

Fuller Company—technology supplier

Energy and Environmental Research Corporation—reburn system designer

Locations:

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

Rochester, Monroe County, NY (Eastman Kodak Company's Utility Power House, Unit 15)

Technology:

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

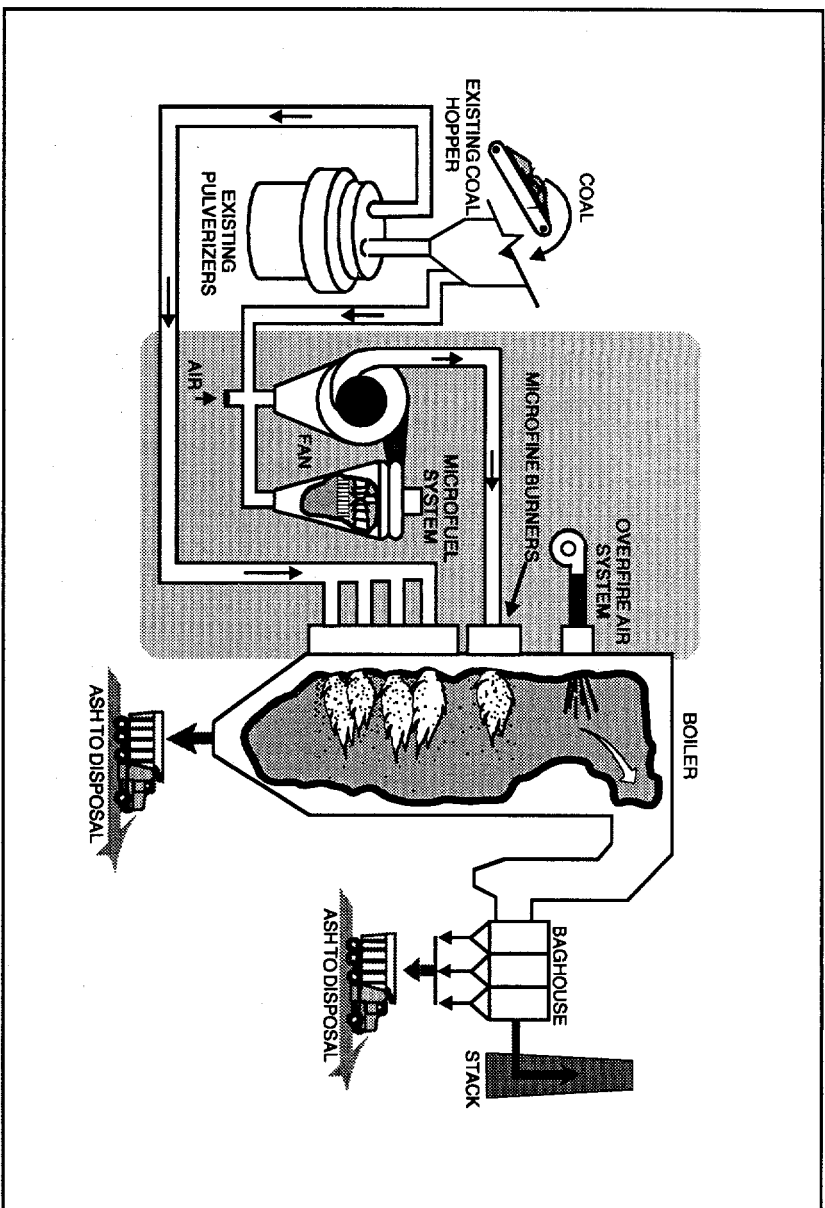
Plant Capacity/Production:

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

Project Funding:

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

MicroMill is a trademark of the Fuller Company.



Project Objective:

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

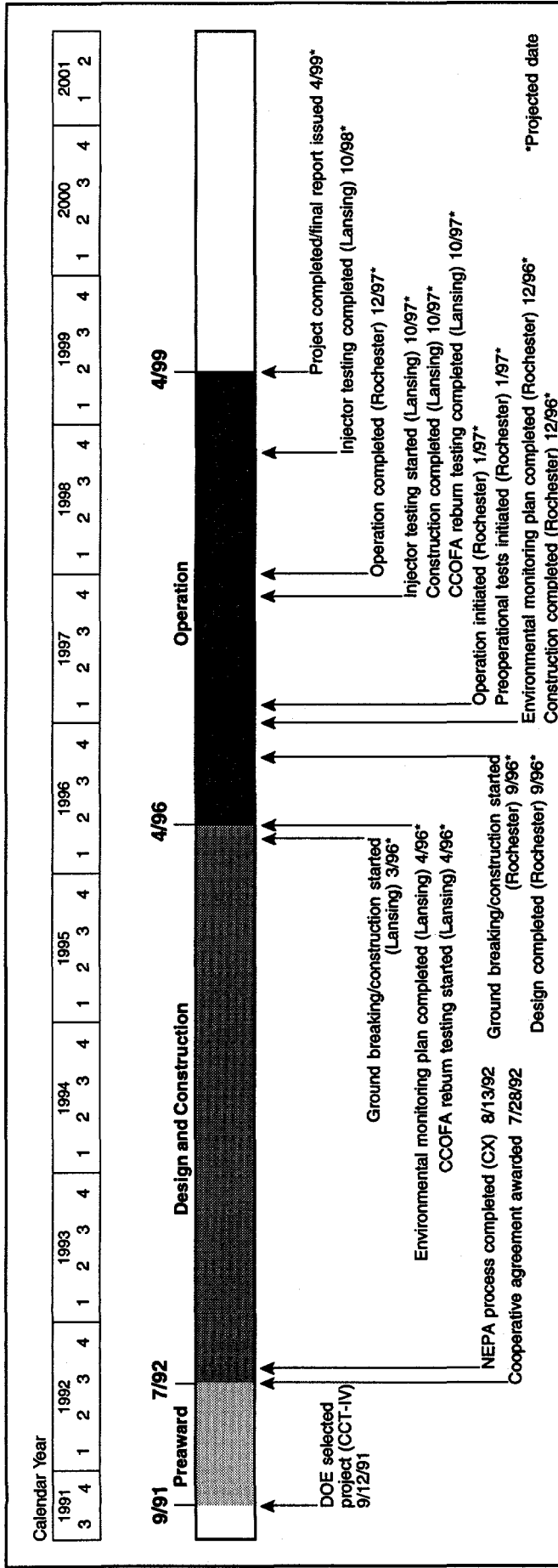
Technology/Project Description:

The reburning coal, which can comprise up to 30% of the total fuel, is micronized (80% below 325 mesh) and injected into a pulverized-coal-fired furnace above the main burner, the region where NO_x formation occurs. Micronized coal has the surface area and combustion characteristics of an atomized oil flame, which allows carbon conversion within milliseconds and release of volatiles at a more even rate. This uniform, compact combustion envelope allows for complete combustion of the coal/air mixture in a smaller furnace volume than

conventional pulverized coal because heat rate, carbon loss, boiler efficiency, and NO_x formation are affected by coal fineness.

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

New York State Electric & Gas Milliken Station, Unit 2, a 148-MWe tangentially fired boiler, is one host site, and Eastman Kodak Utility Power House Unit 15, a 50-MWe cyclone boiler, is the other host site. The Milliken site will use the D. B. Riley MPS mill with dy-



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

Project Status/Accomplishments:

Due to plant problems and operational and environmental strategy changes, the original host site, the Tennessee Valley Authority's Shawnee Fossil Plant, was no longer suitable to demonstrate the technology.

The project has been restructured to include two sites, Milliken Station near Lansing, NY, and Eastman Kodak Company in Rochester, NY. The revised project will accomplish the original project objectives plus bring additional technologies into the project.

Commercial Applications:

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

The availability of a coal-reburning fuel, as an additional fuel to the furnace, solves several problems concurrently. Existing units unable to switch fuels because of limited mill capacity would be able to reach

their maximum continuous rating. NO_x emissions reductions will enable lost capacity to be restored, creating a very economic source of generation. For both retrofit and greenfield facilities, reburn burners also can serve as low-load burners, and commercial units can achieve a turnaround of 8:1 on nights and weekends without consuming expensive auxiliary fuel. Existing pulverizers can be operated on a variety of coals with improved performance. The combination of micronized coal-reburning fuel and better pulverizer performance will increase overall pulverized-fuel surface area for better carbon burnout.

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

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Participant:
Southern Company Services, Inc.

Additional Team Members:
Electric Power Research Institute—cofunder
Foster Wheeler Energy Corporation—technology supplier
Georgia Power Company—host

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

Technology:
Foster Wheeler's low- NO_x burner (LNB) with advanced overfire air (AOFA) (environmental control devices/ NO_x control technologies)

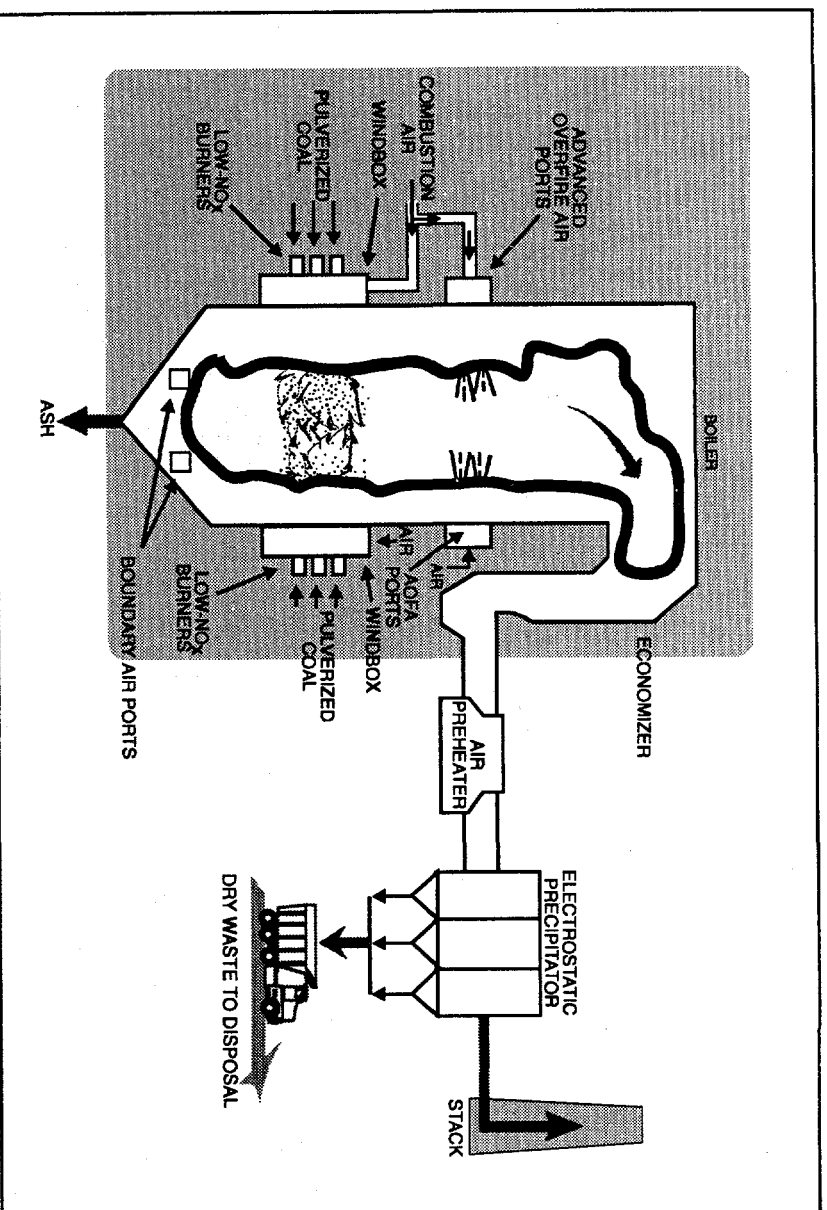
Plant Capacity/Production:
500 MWe

Project Funding:

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

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

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



Technology/Project Description:

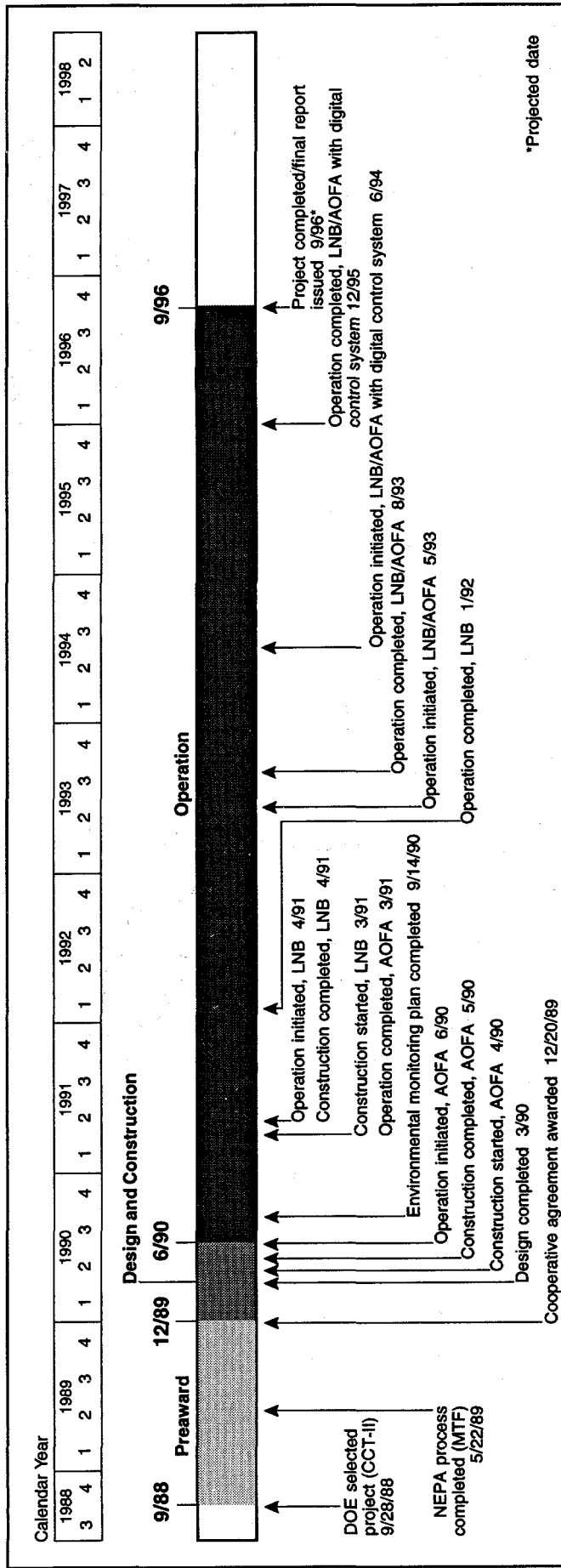
AOFA involves (1) improving the mixing of overfire air with the furnace gases to achieve complete combustion, (2) depleting the air from the burner zone to minimize NO_x formation, and (3) supplying air over furnace wall tube surfaces to prevent slagging and furnace corrosion. The AOFA technique is expected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

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

utilities indicate that LNB technology is capable of reducing NO_x emissions by about 45%.

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

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



Project Status/Accomplishments:

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

ever, preliminary analysis of emissions data suggests that the incremental NO_x reduction effectiveness of the AOFA system (beyond the use of the LNB) was approximately 17% with additional reductions resulting from other operational changes.

The digital control system became operational in mid-1994, and installation of the artificial intelligence software package for optimizing NO_x reduction and boiler efficiency is nearly complete. Short- and long-term test data are being used to train the neural network combustion models. However, the unit was taken off line in the fall of 1995, due to low electricity demand. Testing will commence upon resumption of unit operation.

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

Commercial Applications:

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

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

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

Project completed.

Participant:

Southern Company Services, Inc.

Additional Team Members:

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

Location:

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

Technology:

Selective catalytic reduction (SCR) (environmental control devices/NO_x control technologies)

Plant Capacity/Production:

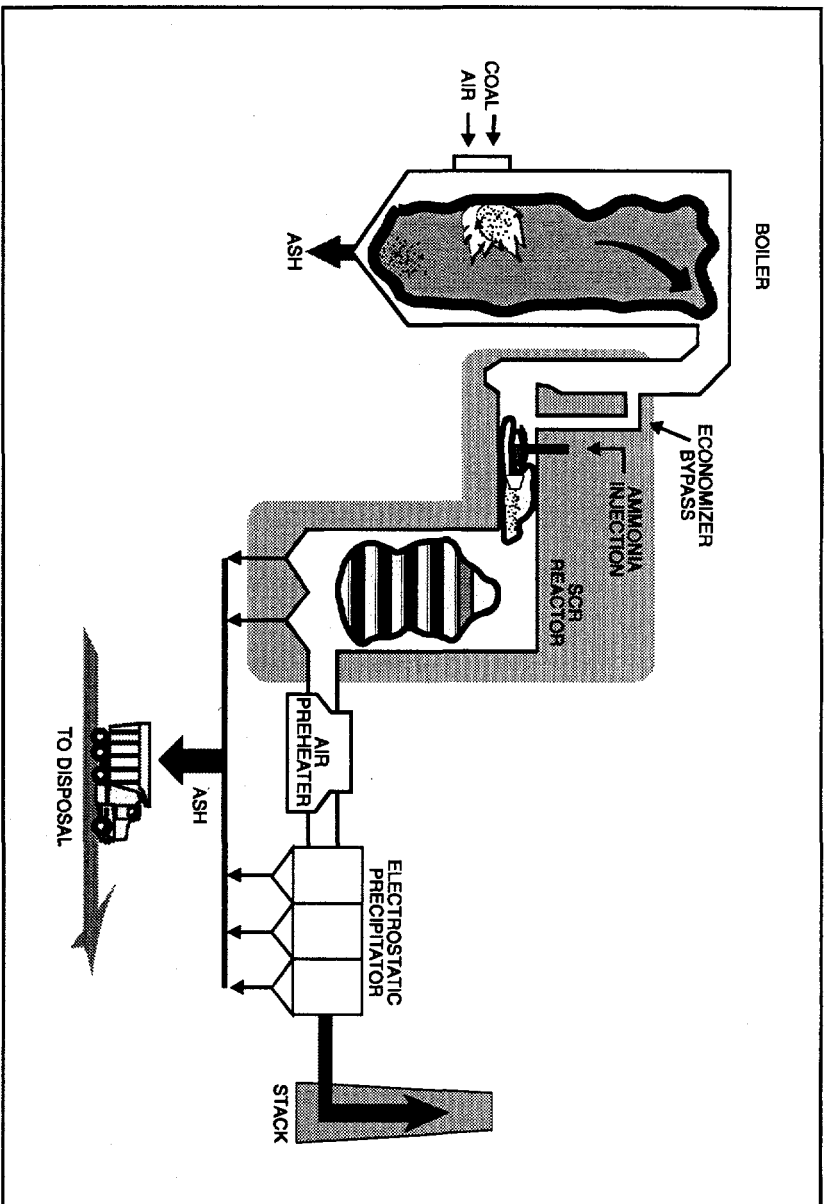
8.7-MWe equivalent (three 2.5-MWe and six 0.2-MWe equivalent SCR reactor plants)

Project Funding:

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

Project Objective:

To evaluate the performance of commercially available SCR catalysts when applied to operating conditions found in U.S. pulverized coal-fired utility boilers using U.S. high-sulfur 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 consists of three 2.5-MWe-equivalent SCR reactors, supplied by separate 5,000 std ft³/min flue gas slipstreams, and six 0.20-MWe-equivalent SCR reactors. These reactors were calculated to be large enough to produce design data that will allow the SCR process to be scaled up to commercial size. Catalyst suppliers (two U.S., two European, and two Japanese) provided eight catalysts with various shapes and chemical compositions for evaluation of process chemistry and economics of operation during the operation.

The project is demonstrating, 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 U.S. high-sulfur coal.

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

Project Results/Accomplishments:

Preliminary design engineering for the SCR test facility was concluded at the end of February 1991. Construction began in late-March 1992; a dedication ceremony was held on July 1, 1992. Detailed engineering was completed in December 1992. Flue gas was first passed through the SCR facility during equipment checkout on January 10, 1993. Construction was completed in February 1993. Commissioning tests without catalysts began the first week of March 1993, and the 2-year-long operations phase began on July 1, 1993.

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

Results of parametric tests through December 1994 indicated that the eight different catalysts (seven high dust and one low dust), supplied by six different companies, performed within or exceeded designed specifications, both with respect to activity and life. However, differences have been noted in NO_x reduction activity, SO_2 oxidation, physical fouling, and pressure drop.

Commercial Applications:

SCR technology can be applied to existing and new utility applications for removal of NO_x from flue gas for virtually any size boiler. There are approximately 1,041 coal-fired utility boilers in active commercial service in the United States; these boilers represent a total generating capacity of 296,000 MWe. Assuming that SCR technology is installed on dry-bottom boilers that are not equipped with low- NO_x combustion technologies (i.e., low- NO_x burners, overfire air, and atmospheric fluidized-bed combustion), the potential total retrofit

market for SCR technology is 154,560 MWe (642 boilers). In addition, SCR technology could be applicable to 34,700 MWe (70 boilers) of new firm (i.e., announced, sited, and committed in terms of service date or under construction) and 144,500 MWe (290 boilers) of planned dry-bottom electric generating capacity in the United States.

Project Schedule:

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

Final Reports:

Final Technical Report	6/96
Economic Evaluation Report	6/96
Public Design Report	6/96

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

Project completed.

Participant:
Southern Company Services, Inc.

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

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

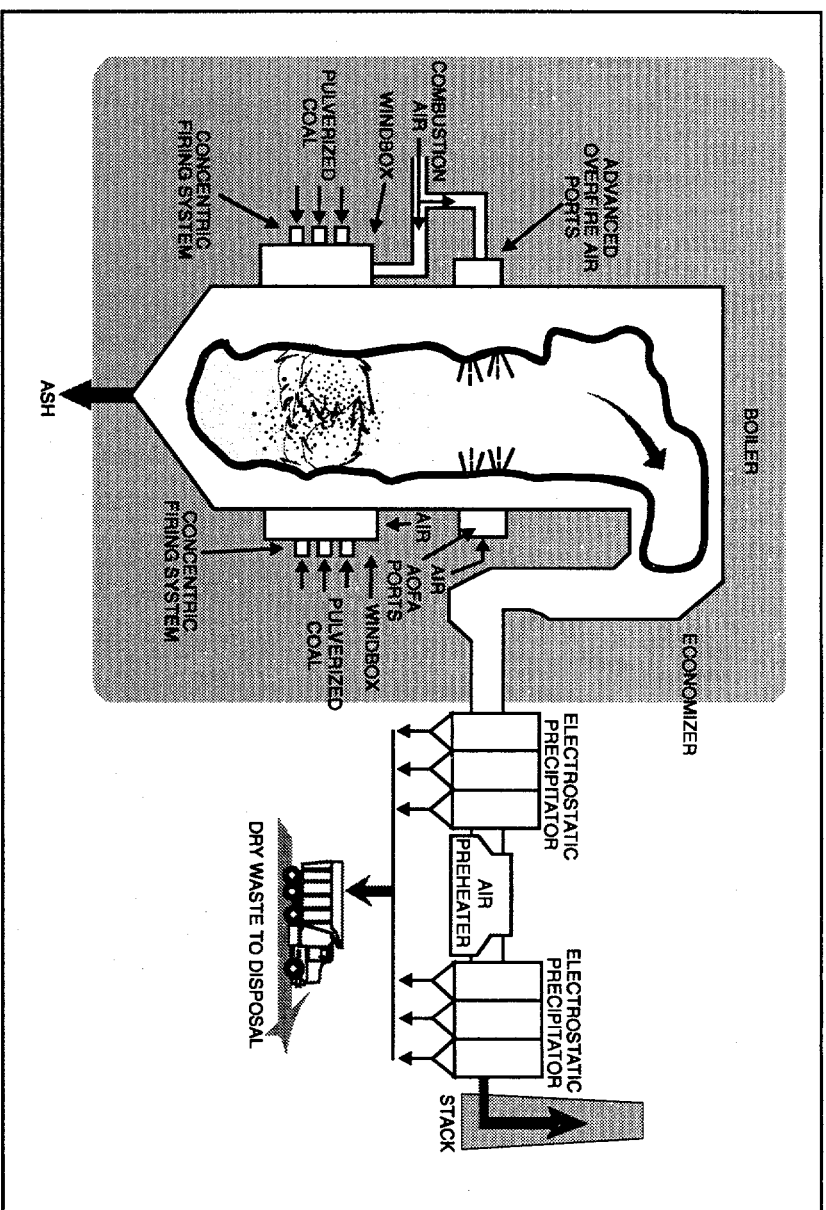
Technology:
ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) with advanced overfire air (AOFA), clustered coal nozzles, and offset air (environmental control devices/NO_x control technologies)

Plant Capacity/Production:
180 MWe

Project Funding:

Total project cost	\$9,153,383	100%
DOE	4,440,184	49
Participant	4,713,199	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 Low-NO_x Concentric Firing System Levels I, II, and III on a single reference boiler under typical dynamic operating conditions, and evaluate the cost effectiveness of each low-NO_x combustion technique.

Technology/Project Description:

Three different low-NO_x combustion technologies for tangentially fired boilers were demonstrated. The concept of overfire air was demonstrated in all of these systems. In LNCFS Level I, a close-coupled overfire air (CCOFA) system is integrated directly into the windbox configuration. Compared to the baseline windbox configuration, LNCFS Level I is arranged by exchanging the

highest coal nozzle with an air nozzle immediately below it. This configuration provides the NO_x reducing advantages of an overfire air system without pressure part modifications to the boiler.

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

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

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

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

Project Results/Accomplishments:

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

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

Unit performance observations included increased CO emissions, reduced furnace slagging but increased

back-pass fouling, and minimally impacted efficiency and heat rate. Further, unit operations were not significantly affected; however, operating flexibility of the unit was reduced at low loads with LNCFS II and III.

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

Commercial Applications:

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

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

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

Project Schedule:

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

Final Reports:

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

10-MWe Demonstration of Gas Suspension Absorption

Project completed.

Participant:
AirPol, Inc.

Additional Team Members:
FLS miljo a/s (parent company of AirPol, Inc.)—
technology owner
Tennessee Valley Authority—cofunder and site owner

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

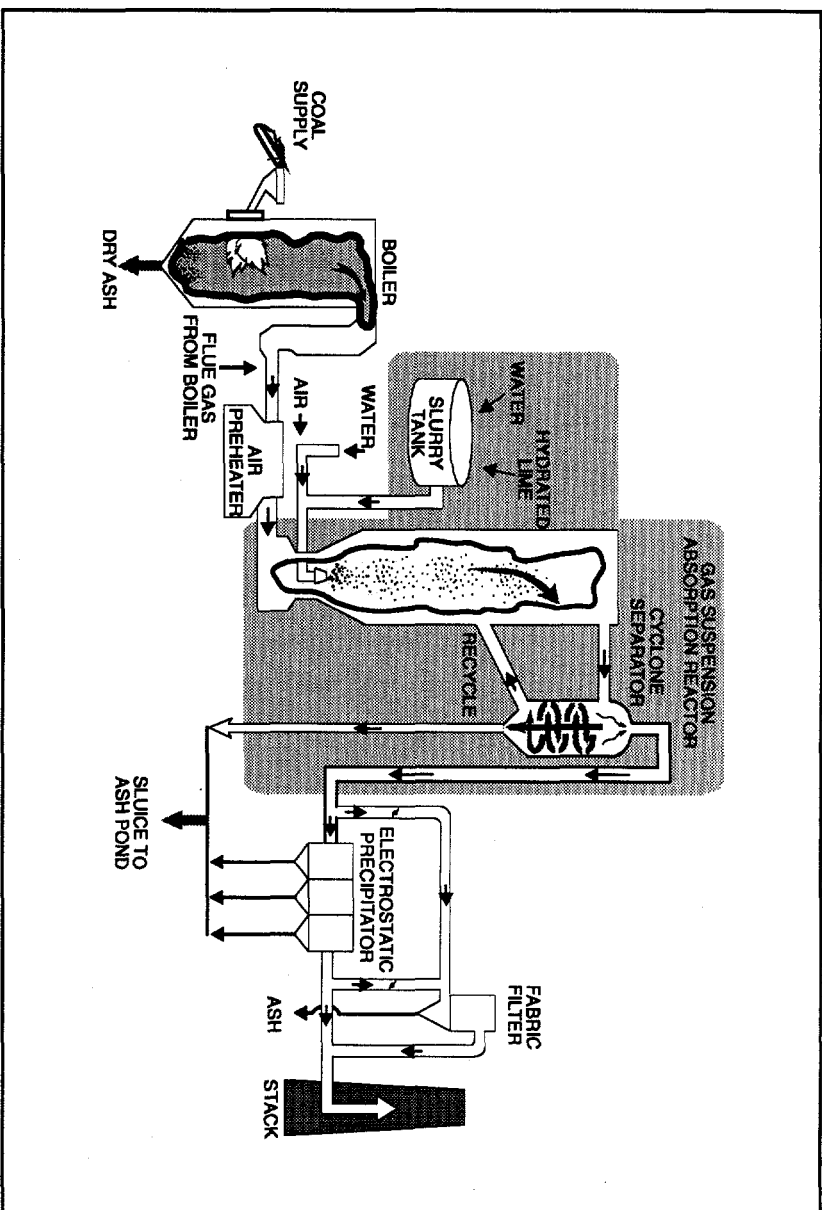
Technology:
FLS miljo a/s' Gas Suspension Absorption (GSA)
system for flue gas desulfurization (FGD) (environmental
control devices/SO₂ control technologies)

Plant Capacity/Production:
10-MWe equivalent slipstream of flue gas from a
150-MWe boiler

Project Funding:

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

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



Technology/Project Description:

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

device are combined and disposed of in an existing site disposal area. GSA can remove in excess of 90% of the SO₂ as well as increase lime utilization efficiency with solids recycle.

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

Project Results/Accomplishments:

Optimization testing was conducted to determine the effect of the process design variables on the SO₂ removal efficiency in the reactor/cyclone and the ESP. The testing

indicated that the order of importance of the key variables is (1) Ca/S, (2) approach-to-adiabatic-saturation temperature, and (3) coal chloride content.

The SO₂ removal efficiency for the overall system ranged from slightly more than 60% to nearly 95%, depending on the specific test conditions. The lower SO₂ removal efficiency levels were achieved at the higher approach-to-saturation temperature (28 °F), the lower lime stoichiometry level (Ca/S of 1.00), and lower coal chloride level (0.02–0.04%). The higher SO₂ removal efficiency levels were achieved at the closer approach-to-saturation temperatures (8 and 18 °F), the higher lime stoichiometry level (Ca/S of 1.30), and higher coal chloride level (0.12%). Most of the SO₂ removal in the GSA system occurred in the reactor/cyclone, with only about 2–5% of the overall removal occurring in the ESP.

Results of a 4-week around-the-clock demonstration run of the GSA system with the ESP indicated that the GSA/ESP is capable of consistently maintaining 90% or better SO₂ removal at a moderate lime requirement. A 14-day pulse jet baghouse (PIBH) run was successfully completed in March 1994. SO₂ removal efficiency in the GSA/PIBH system averaged more than 95% during the demonstration; this was typically about 3–5 percentage points higher than that achieved in the GSA/ESP system at the same test conditions.

The project demonstrated a number of key technical attributes, including a simple and direct method of lime/solid recirculation, high acid gas adsorption, low lime consumption with minimal waste by-product residue, low maintenance operation, no internal buildup, and reduced space requirement. In addition, the project demonstrated that a pulse jet baghouse system improved SO₂ removal efficiency by about 3–5 percentage points. Also, air toxics testing showed that a removal rate of over 95% could be achieved by the GSA.

The relative process economics for the GSA system were evaluated for a moderately difficult retrofit to a

300-MW boiler burning a coal containing 2.6% sulfur. The design SO₂ removal efficiency was 90%. The resulting capital cost estimate (in 1990 \$) is \$149/kW for GSA as compared to \$216/kW for a wet limestone, forced-oxidation (WLFO) scrubbing system. The levelized annual revenue requirement for the GSA process is lower than that for the WLFO system, but the difference is only about 20% (which is not considered to be significant given the limitations on the accuracy of estimates used in the analysis). The principal annual operating cost for the GSA process is the cost of the pebble lime. The 15-year levelized costs in mills/kWh for the two systems are listed below:

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

Commercial Applications:

The GSA process offers several advantages over conventional FGD technologies: (1) GSA is 30% cheaper than wet FGD and 20% cheaper than spray drying; (2) GSA is much simpler to build and operate than wet FGD and regenerable processes and requires much less space; (3) space requirements, operability, and ease of installation are comparable to spray dryers and duct injection; and (4) the SO₂ removal capability (90%) compares to that of wet FGD and the regenerable processes. This high removal rate makes the GSA process suitable for use with high-sulfur coal.

Successful testing of the AirPol demonstration project has resulted in a commercial application in Ohio. The city of Hamilton, OH, received a \$5-million grant from the Ohio Coal Development Office to install the GSA technology to control emissions from a 50-MW coal-fired boiler at the city's municipal power plant. The new system is scheduled to be operational in August 1996 and will be the first full-scale commercial GSA unit

in the United States as well as the world's first GSA unit for a coal-fired boiler. The GSA technology was identified as the least-cost alternative for the city to meet CAAA compliance requirements for 1997.

In addition, FLS miljo has been awarded a major project in Sweden for a high-performance GSA system to remove sulfur from the flue gas of a 4-million-ton/year iron ore sinter plant. Sweden's stringent standards require an SO₂ removal efficiency of 90–95%.

The GSA should fulfill the need of the utility industry to meet the new SO₂ emission standard as set forth by the CAAA of 1990. Based on a comparison of GSA capital and operating costs with other FGD processes, the GSA is especially suited for 50–250-MW utility plants. Simplicity in GSA design and operation plus modest space requirements make GSA ideal for retrofitting to existing plants as well as for greenfield plants. One major advantage of the GSA, as compared to other semi-dry scrubbing processes, is that operation of the GSA will not result in excessive dust loading to the gas stream, thus minimizing the cost for upgrading the existing dust collector. The potential market for the GSA is estimated at \$300 million within the next 20 years.

Project Schedule:

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

Final Reports:

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

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Project completed.

Participant:

Bechtel Corporation

Additional Team Members:

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

Location:

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

Technology:

Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process (environmental control devices/SO₂ control technologies)

Plant Capacity/Production:

73.5 MWe

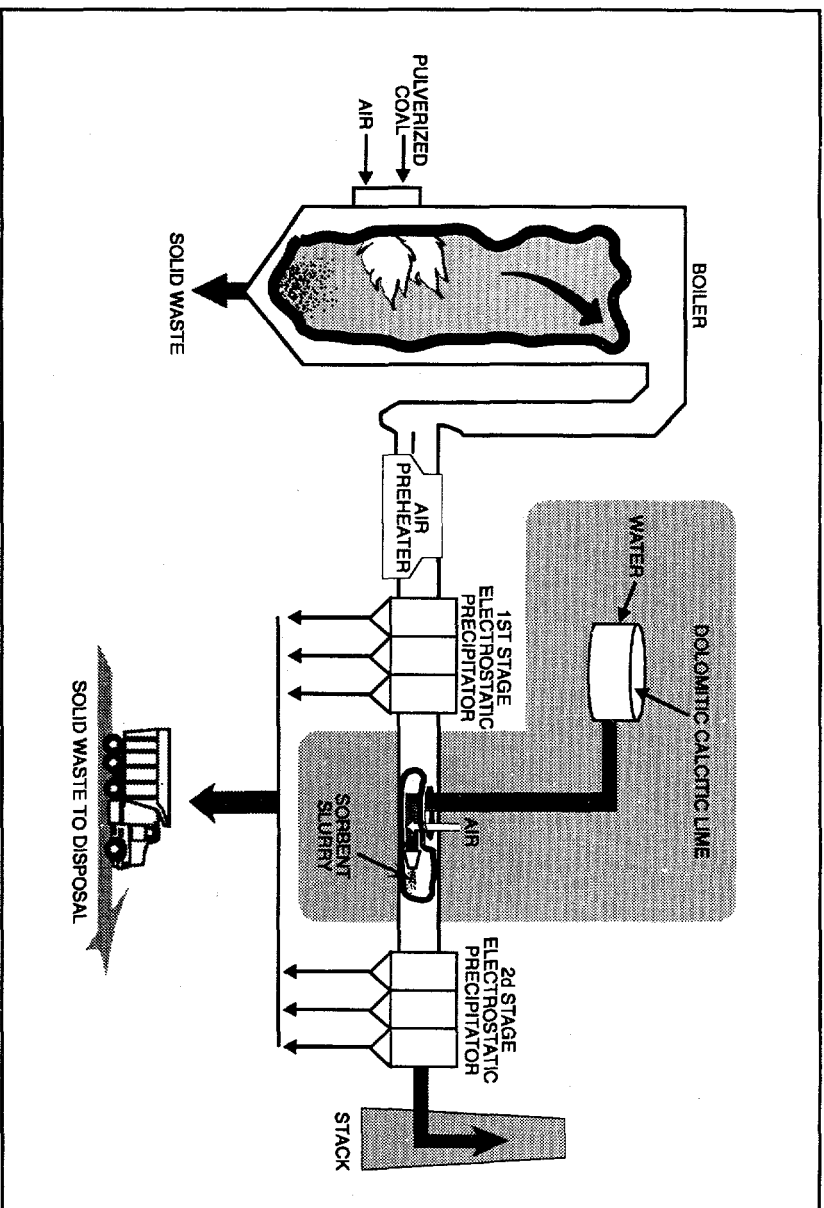
Project Funding:

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

Project Objective:

To demonstrate SO₂ 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.

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



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 SO₂ is rapidly absorbed in the liquid droplets. The droplets mix with the hot flue gas, and the water evaporates rapidly. Fast drying precludes wet particle buildup in the duct and aids the flue gas in carrying the dry reaction products and the unreacted lime to the ESP.

The CZD/FGD process is expected to remove up to 50% of the SO₂ emissions from coal-fired boilers. If successfully demonstrated, this technology would be an

alternative to conventional FGD processes, requiring less physical space and lower capital, operating, and maintenance costs.

This project includes injection of different types of sorbents (dolomitic and calcitic limes) with several atomizer designs using low- and high-sulfur coals to verify the effects on SO₂ removal and the capability of the ESP to control particulates. The demonstration is located at Pennsylvania Electric Company's Seward Station in Seward, PA. One-half of the flue gas capacity of the 147-MWe Unit No. 5 is being routed through a modified, longer duct between the first- and second-stage ESPs. Pennsylvania bituminous coal (approximately 1.2-2.5% sulfur) is being used in the project.

Project Results/Accomplishments:

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

In summary, the demonstration showed the following:

- A 50% SO₂ removal efficiency with CZD/FGD is possible, and continuous operation at removal rates lower than 50% can be maintained over long periods without significant process problems.
- The process requires that drying and SO₂ absorption take place within 2 seconds. A long and straight horizontal gas duct of about 100 feet is required to assure residence time of 2 seconds.
- During normal operations, no deposits of fly ash or reaction products took place in the flue gas duct.
- The fully automated system, fully integrated with power plant operation, demonstrated that the CZD/FGD process responded well to automated control operation.
- Availability of the system was very good.
- At Seward Station, stack opacity was not detrimentally affected by the CZD/FGD system.
- Results of the demonstration indicated that the CZD/FGD process can achieve costs of \$300/ton of SO₂ removed when operating a 500-MWe unit burning 4% sulfur coal. Based on a 500-MWe plant retro-

fitted with CZD/FGD for a 50% rate of SO₂ removal, the total capital cost is estimated to be less than \$30/kW.

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

Commercial Applications:

CZD can be used for retrofit of existing and installation in new utility boiler flue gas facilities to remove SO₂ derived from a wide variety of sulfur-containing coals.

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

Project Schedule:

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

Final Reports:

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

LIFAC Sorbent Injection Desulfurization Demonstration Project

Project completed.

Participant:

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

Additional Team Members:

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

Location:

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

Technology:

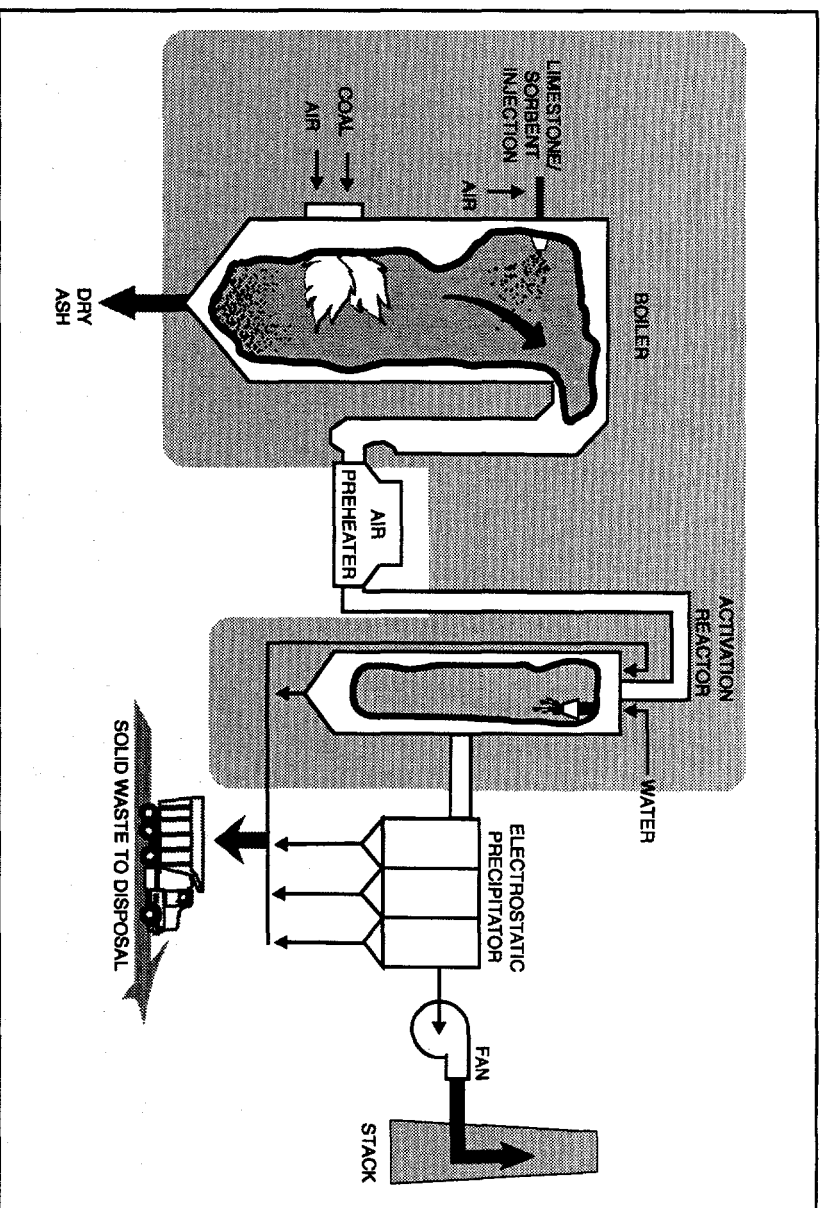
LIFAC's sorbent injection process with sulfur capture in a unique, patented vertical activation reactor (environmental control devices/SO₂ control technologies)

Plant Capacity/Production:

60 MWe

Project Funding:

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



Project Objective:

To demonstrate that electric power plants—especially those with space limitations—burning high-sulfur coals can be retrofitted successfully with the LIFAC limestone injection process to remove 75–85% of the SO₂ from flue gas and produce a dry solid waste product for disposal in a landfill.

Technology/Project Description:

Pulverized limestone is pneumatically blown into the upper part of the boiler near the superheater where it absorbs some of the SO₂ in the boiler flue gas. The limestone is calcined into calcium oxide and is available for capture of additional SO₂ downstream in the activation, or humidification, reactor. In the vertical chamber, water sprays initiate a series of chemical reactions lead-

ing to SO₂ 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 is recirculated back through the reactor for increased efficiency. The waste is dry, making it easier to handle than the wet scrubber sludge produced by conventional wet limestone scrubber systems.

The technology enables power plants with space limitations to use high-sulfur midwestern coals by providing an injection process that removes 75–85% of the SO₂ from flue gas and produces a dry solid waste product suitable for disposal in a landfill.

The process was demonstrated at the Whitewater Valley Station, 60-MWe Unit No. 2. This coal-fired unit is owned and operated by Richmond Power & Light and

is located in Richmond, IN. Bituminous coal containing 2.0-2.8% sulfur was used for the majority of system testing.

Project Results/Accomplishments:

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

LIFAC process values and their effects on sulfur removal efficiency were evaluated during parametric testing. The four major parameters having the greatest influence on sulfur removal efficiency were limestone quality, Ca/S ratio, reactor bottom temperature (approach-to-saturation), and ESP ash recycling rate. Total SO₂ capture was about 15 percentage points better when injecting fine limestone (80% minus 325 mesh) than it was with coarse limestone (80% minus 200 mesh).

Parametric tests indicated that a 70% SO₂ reduction was achievable with a Ca/S ratio of 2.0. ESP ash containing unspent sorbent and fly ash was recycled from the ESP hoppers back into the reactor inlet duct work. Ash recycling is essential for efficient SO₂ capture. The large quantity of ash removed from the LIFAC reactor bottom, and the small size of the ESP hoppers limited the ESP ash recycling rate. As a result, the amount of material recycled from the ESP was approximately 70% less than had been anticipated. However, this low recycling rate contributed an additional 15 percentage points to total SO₂ capture. During a brief test, it was found that increasing the recycle rate by 50% resulted in a 5 percentage point increase in SO₂ removal efficiency. It is anticipated that if the reactor bottom ash is recycled along with ESP ash, while sustaining a reactor temperature of 5 °F above saturation temperature, an SO₂ reduction of 85% could be maintained.

Optimization testing began in March 1994 and was followed by long-term testing in June 1994. The boiler was operated at an average load of 60 MWe during long-term testing, although it fluctuated according to power demand. The LIFAC process automatically adjusted to

boiler load changes. A Ca/S ratio of 2.0 was selected to attain SO₂ reductions above 70%. Reactor bottom temperature was about 5 °F higher than optimum to avoid ash buildup on the steam reheaters. Atomized water droplet size was smaller than optimum for the same reason. Other key process parameters held constant during the long-term tests included the degree of humidification, the grind size of the high-calcium-content limestone, and recycle ratio of spent sorbent from the ESP.

Long-term testing showed that SO₂ reductions of 70% or more can be maintained under normal boiler operating ranges. Stack opacity was low (about 10%) and ESP efficiency was high (99.2%). The solid waste generated was a mixture of fly ash and calcium compounds and was readily disposed of at a local landfill.

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

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

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

Commercial Applications:

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

The benign waste material can be disposed of in a landfill along with the fly ash. Commercial use of the LIFAC by-product in the manufacture of construction materials is currently being investigated in Finland. There are 10 full-scale LIFAC units in operation or under construction in Canada, China, Finland, Russia, and the United States. The LIFAC system at Richmond Power & Light is being retained and is the first to be applied to a power plant using high-sulfur (2.0-2.9%) coal. The other LIFAC installations on power plants use low-sulfur (0.6-1.5%) coals.

Project Schedule:

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

Final Reports:

Final Technical Report	6/96
Economic Evaluation Report	6/96
Public Design Report	6/96

Advanced Flue Gas Desulfurization Demonstration Project

Project completed.

Participant:

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

Additional Team Members:

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

Location:

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

Technology:

Pure Air's advanced flue gas desulfurization (AFGD) process (environmental control devices/SO₂ control technologies)

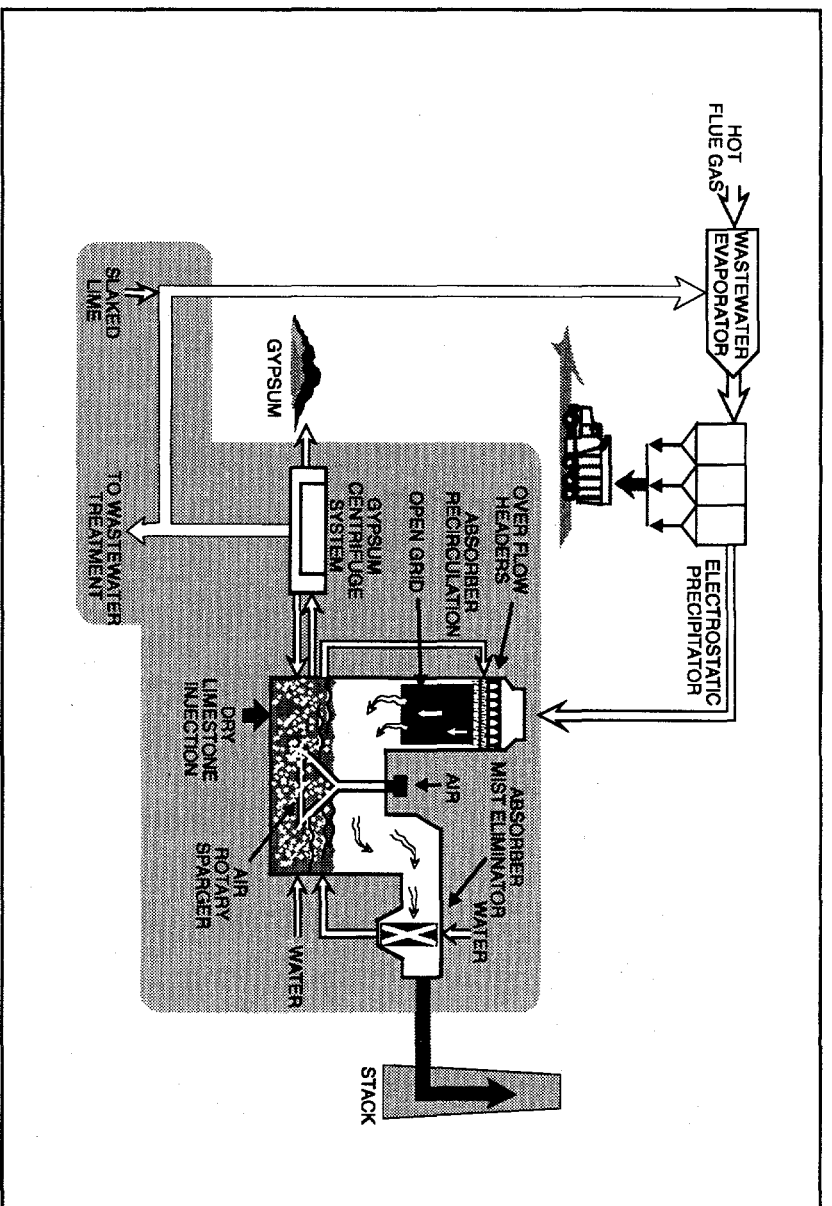
Plant Capacity/Production:

528 MWe

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 demonstrate removal of 90–95% or more of the SO₂ at approximately one-half the cost of conventional scrubbing technology; and to demonstrate significant reduction of space requirements.

Technology/Project Description:

In this project, Pure Air has built a single SO₂ absorber for a 528-MWe power plant. Although this is the largest capacity absorber module in the United States, it has relatively modest space requirements because no spare or backup absorber modules are required. The absorber performs three functions in a single vessel: prequencher, absorber, and oxidation of sludge to gypsum. Additionally, the absorber is of a co-current design, in which the flue gas and scrubbing slurry move in the same direction

and at a relatively high velocity compared to conventional scrubbers. These features all combine to yield a state-of-the-art SO₂ absorber that is more compact and less expensive than conventional scrubbers.

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

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

Project Results/Accomplishments:

The 528-MWe demonstration accumulated approximately 26,280 hours of operation over a 3-year period and achieved an availability of 99.47%. Construction began in April 1990, and in June 1992 the AFGD system began to process flue gas, thus becoming the first commercial scrubber to meet the requirements of the CAAA of 1990. Tests were on coals ranging from 2.25% sulfur to greater than 4.5% sulfur. During the 3-year operation, SO₂ removal efficiency averaged 94% with a maximum of 98+% or 0.382 lb/million Btu. Twenty-four-hour average power consumption was 5,275 kW, or 61% of expected consumption, and water consumption was 1,560 gallons/minute, or 52% of expected consumption. The production rate of the PowerChip® facility was 7 tons/hr. During the 3-year demonstration, over 210,000 tons of dry gypsum were produced, with an average purity of 97.2%.

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

Commercial Applications:

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

The AFGD unit at Bailly Station will continue to operate for an additional 17 years under a novel business concept whereby Pure Air is the owner of the unit and Air Products and Chemicals, Inc., is the operator. This AFGD facility will reduce SO₂ emissions by approximately 75,000 tons/yr. Further, the gypsum by-product and wastewater evaporation will demonstrate that SO₂

control can occur without increased solid waste or wastewater production.

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

In April 1994, Pure Air of Manatee, L.P., entered into a contract to provide 1,600 MWe of SO₂ scrubbing capability at Florida Power & Light Company's Manatee power plant on the same own-and-operate basis. The Manatee scrubber will feature two 800-MWe absorber vessels, PowerChip® gypsum recycling, and wastewater evaporation.

Project Schedule:

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

Final Reports:

Final Technical Report	1996
Economic Evaluation Report	1996
Public Design Report	3/90

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

Project completed.

Participant:
Southern Company Services, Inc.

Additional Team Members:
Georgia Power Company—host
Electric Power Research Institute—cofunder
Radian Corporation—environmental and analytical consultant
Ershugs, Inc.—fiberglass fabricator

Composite Construction and Equipment—fiberglass sustainment consultant

Acentech—flow modeling consultant
Ardaman—gypsum stacking consultant
University of Georgia Research Foundation—by-product utilization studies consultant

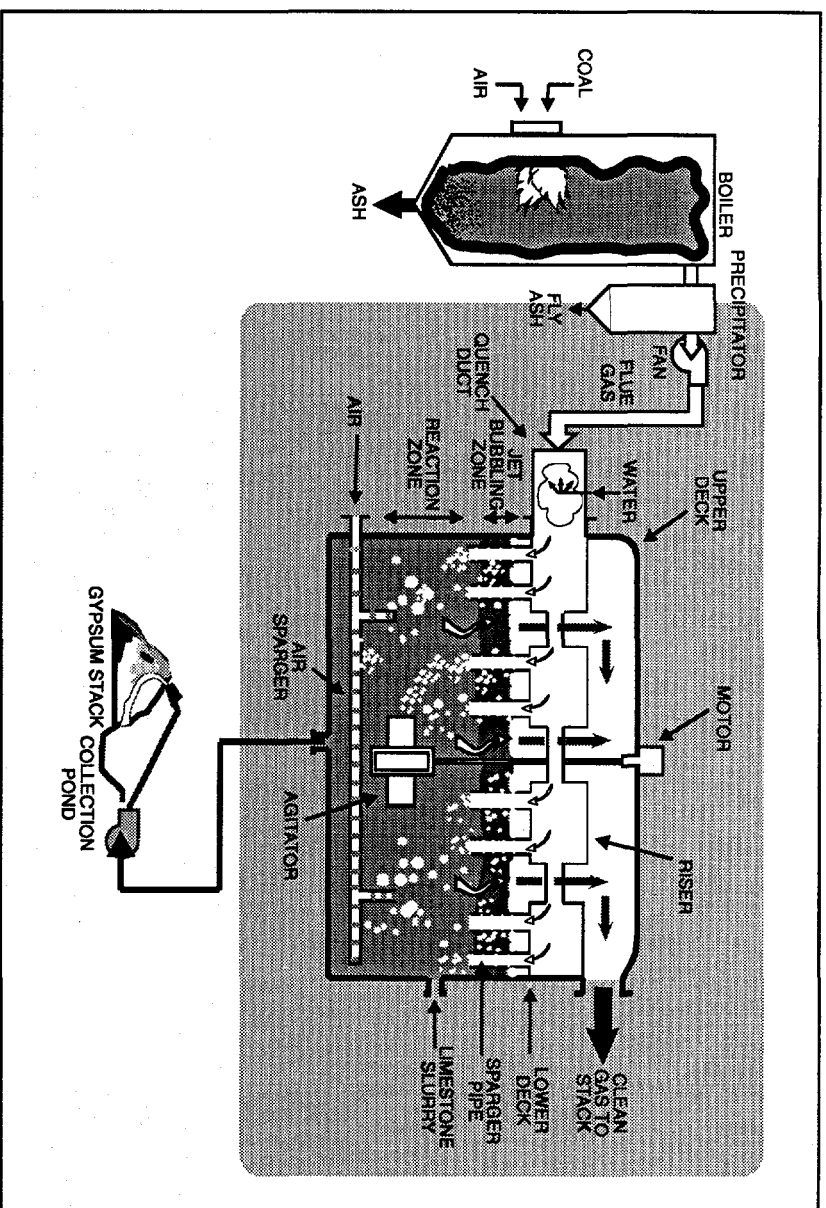
Location:
Newnan, Coweta County, GA (Georgia Power Company's Plant Yates, Unit No. 1)

Technology:
Chiyoda Corporation's Chiyoda Thoroughbred-121 (CT-121) advanced flue gas desulfurization (FGD) process (environmental control devices/SO₂ control technologies)

Plant Capacity/Production:
100 MWe

Project Funding:

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



Project Objective:
To demonstrate the CT-121 flue gas desulfurization system, including several design innovations, at the 100-MWe scale; more specifically, to demonstrate 90% SO₂ control at high reliability with and without simultaneous particulate control with possible additional reductions in operating costs.

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

The flue gas enters underneath the scrubbing solution in the jet-bubbling reactor. The SO₂ in the flue gas is absorbed and forms calcium sulfite (CaSO₃). Air is bubbled into the bottom of the solution to oxidize the calcium sulfite to form gypsum. The slurry is dewatered in a gypsum stack, which involves filling a dyked area with gypsum slurry. Gypsum solids settle in the dyked area by gravity, and clear water flows to a retention pond. The clear water from the pond is returned to the process. The project is also evaluating process innovations to determine whether costs can be reduced further by using fiberglass-reinforced plastic (FRP) vessels, eliminating flue gas reheat and spare absorber modules, and stacking gypsum to reduce waste management costs. The ability of this technology to capture SO₂ and particulates simultaneously is also being evaluated.

Bituminous coals containing 1.2-4.3% sulfur were used to demonstrate 90% SO₂ control with high reliability, with and without simultaneous particulate control.

Project Results/Accomplishments:

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

During the 19,000 hours or 27 months available for the demonstration, the scrubber was operated for 14,000 hours. The coal burned during the demonstration was a blend of Illinois No. 5 and 6 that averaged 2.4% sulfur. Other tests were conducted on coals varying from 1.2% to 4.3% sulfur. The system demonstrated the ability to exceed 98% SO₂ removal efficiency with high-sulfur coal while at maximum boiler load and limestone utilization of 97%. Use of FRP fabrication of key components, with its high resistance to corrosion, enabled elimination of a rescrubber to remove chlorides and flue gas reheat to prevent corrosive condensation in the chimney (constructed of FRP). The structural and chemical durability of FRP construction combined with the simplicity of design afforded by the unique JBR resulted in high availability (97% at low ash levels and 95% at elevated ash levels) and elimination of the need for a spare reactor module. The CT-121 system demonstrated high particulate capture efficiency (97.7-99.3%) at flyash levels reflective of marginal ESP performance (up to 1.14 lbs/million Btu). Testing also showed the CT-121 to be highly efficient in the capture of hazardous air pollutants (HAPs) which are largely borne by particulates.

In 1995, the project won the Society of Plastics Industries' Design Award for the mist eliminator. The project received two awards in 1994: *Power Magazine's* 1994 Powerplant of the Year Award and an Outstanding Achievement Award from the Georgia chapter of the Air

and Waste Management Association for the use of an innovative technology for air quality control. In 1993, Plant Yates received an environmental award from the Georgia Chamber of Commerce, based on the success of the CT-121 scrubber.

Commercial Applications:

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

Specific features of this technology that will enhance its potential for commercialization follow: (1) fiberglass construction can be used, eliminating the need for rubber-lined carbon steel or costly alloys; (2) no spare absorber is required because the system is at least 97% reliable; (3) reheating of the flue gas is not necessary; (4) both SO₂ and particulates are removed from flue gas; (5) more than 99% of the calcium in the limestone reagent is used; (6) the gypsum by-product can be stored safely and easily or used in commercial applications; (7) the CT-121 operating costs are the lowest for state-of-the-art FGD systems; (8) there is no known size limit for this technology; (9) utilities and industrial concerns could make immediate use of this technology; and (10) the system is not sensitive to the type of coal used, its sulfur content, or the limestone utilized.

Involvement of the Southern Company (which owns Southern Company Services, Inc.), with its utility system that has over 20,000 MWe of coal-fired generating capacity, is expected to enhance the confidence of other large, high-sulfur coal boiler users in the CT-121 process. This process will be applicable to 370,000 MWe of new and existing generating capacity by the year 2010. A 90% reduction in SO₂ emissions from only the retrofit portion of this capacity represents over 10,500,000 tons/yr of potential SO₂ control.

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

Project Schedule:

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

Final Reports:

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

SNOX™ Flue Gas Cleaning Demonstration Project

Project completed.

Participant:
ABB Environmental Systems

Additional Team Members:

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

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

Technology:
Haldor Topsoe's SNOX™ catalytic advanced flue gas cleanup system (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

35-MWe equivalent slip-stream from a 108-MWe boiler

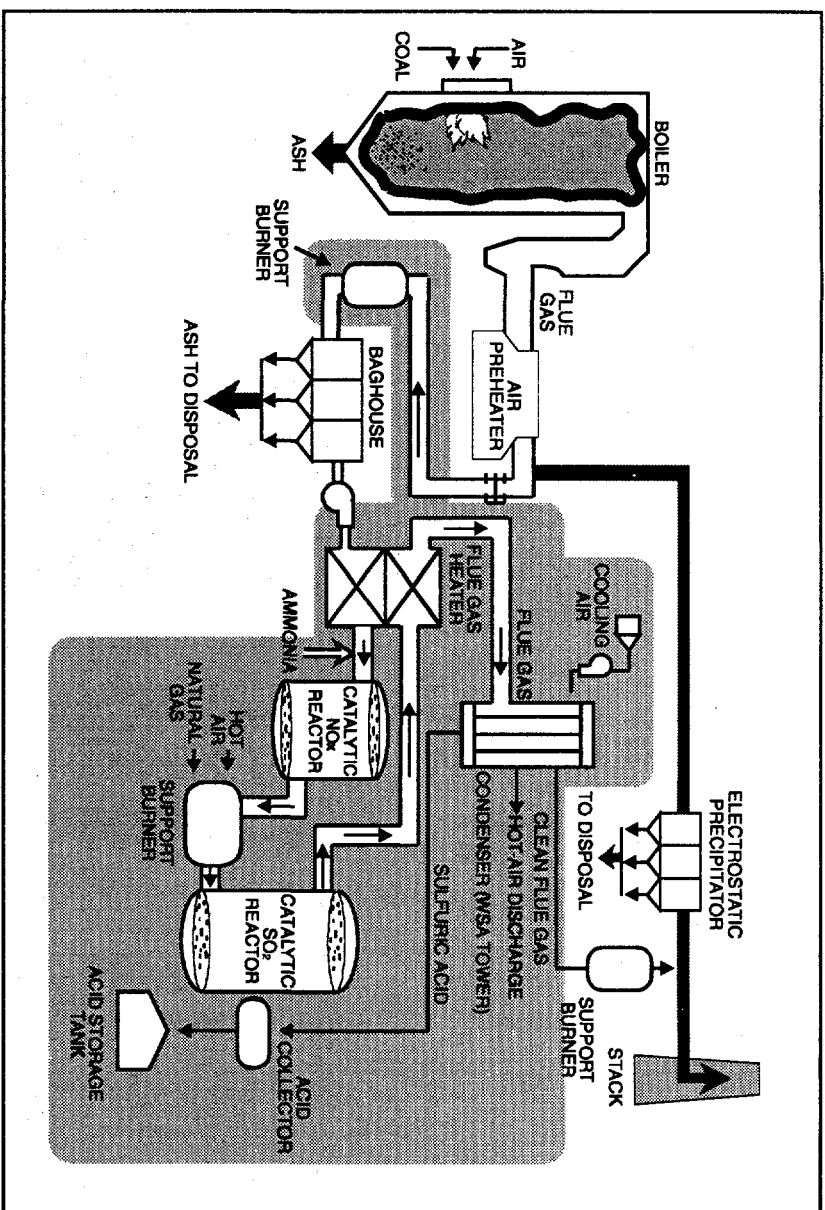
Project Funding:

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

Project Objective:

To demonstrate on U.S. coals at an electric power plant that SNOX™ technology will catalytically remove 95% of SO₂ and more than 90% of NO_x from flue gas and produce a salable by-product of concentrated sulfuric acid.

SNOX is a trademark of Haldor Topsoe a/s.



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 SO₂ 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 SO₂ is oxidized to SO₃ in a second catalytic converter. The gas then passes through a novel glass-tube condenser which allows SO₃ to hydrolyze to concentrated sulfuric acid.

The technology, while using U.S. coals, is designed to remove 95% of the SO₂ and more than 90% of the NO_x from flue gas and produce a salable sulfuric acid

by-product. This is accomplished without using sorbents and without creating waste by-products.

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

Project Results/Accomplishments:

Operational testing was initiated in March 1992 and completed in December 1994. The system has operated for over 8,000 hours and produced more than 5,600 tons of commercial-grade sulfuric acid. The facility has routinely operated at full capacity, achieving removal efficiencies of 96% for SO₂, 94% for NO_x, and 99.9% for particulates.

Many tests for the SNOX™ system were designed to be conducted at 75%, 100%, and 110% of design capacity. During the test program, SO₂ removal efficiencies were normally in excess of 95% for inlet concentrations which averaged about 2,000 ppm. System NO_x reduction efficiencies averaged 94% with inlet NO_x levels of approximately 500–700 ppm.

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

Air toxics testing at the plant indicated that, for the majority of the species examined, especially those that exit primarily as particulates at the SNOX™ fabric filter or SNOX™ outlet, removal is very high. Because of the mechanism of sulfuric acid condensation in the WSA condenser, any particulates remaining at this point act as nuclei for H₂SO₄ and are captured in the acid. For volatile species, the WSA condenser outlet temperature is lower than conventional boiler outlet temperatures and should condense and capture more of the volatile species than a plant with only an ESP or fabric filter.

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

Commercial Applications:

The SNOX™ technology is applicable to all electric power plants and industrial/institutional boilers firing coal, oil, or gas. The high removal efficiency for NO_x and SO₂ will make the process attractive in many applications. Elimination of additional solid waste (except ash) enhances the marketability in urban and other areas where solid waste disposal issues are a significant impediment.

The host utility, Ohio Edison, is retaining the SNOX™ technology as a permanent part of the pollution control system at Niles Station and to help Ohio Edison meet its overall SO₂/NO_x reduction goals.

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

Project Schedule:

DOE selected project (CCT-II)	9/28/88
Cooperative agreement awarded	12/20/89
NEPA process completed (MTF)	1/31/90
Environmental monitoring plan completed	10/31/91
Construction	1/91–12/91
Operational testing	3/92–12/94
Project completed	5/96

Final Reports:

Final Technical Report	5/96
Economic Evaluation Report	5/96
Public Design Report	5/96

LIMB Demonstration Project Extension and Coolside Demonstration

Project completed.

Participant:

The Babcock & Wilcox Company

Additional Team Members:

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

Location:

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

Technology:

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

(environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

105 MWe

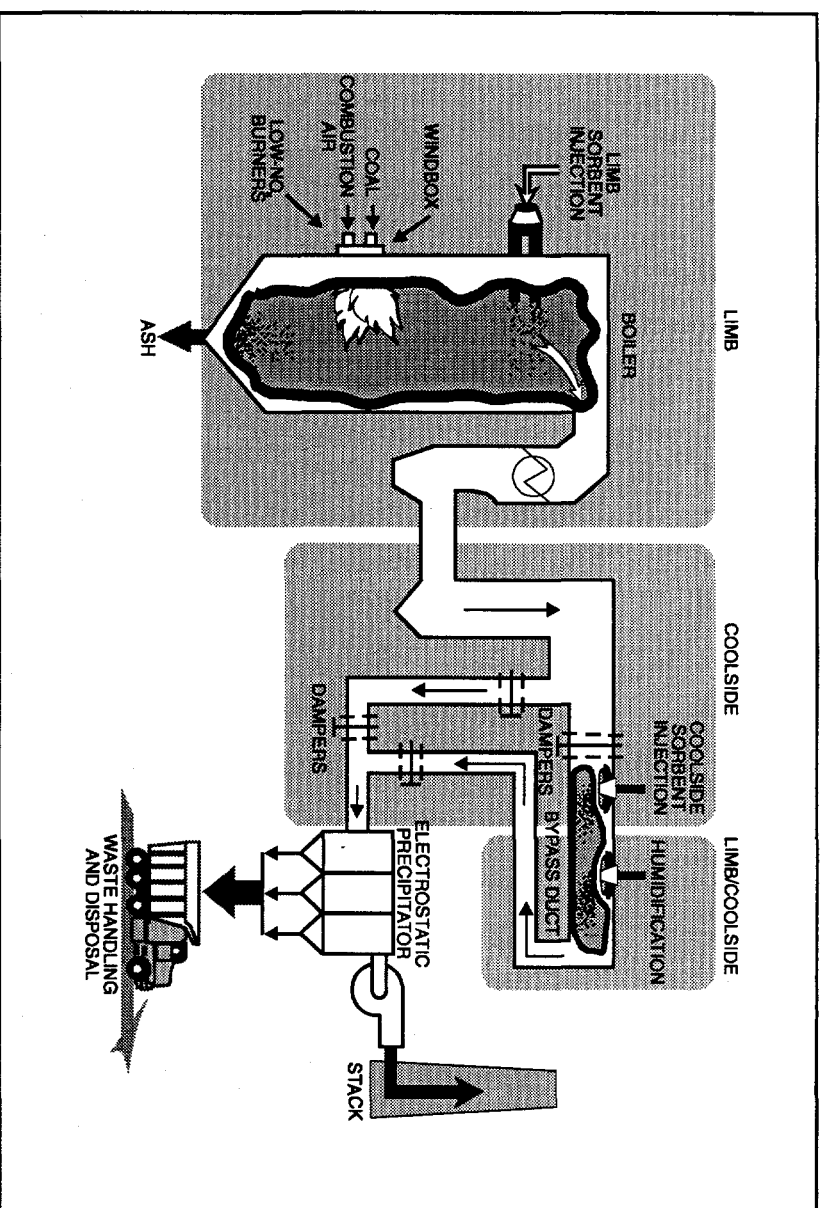
Project Funding:

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

Project Objective:

To demonstrate, with a variety of coals and sorbents, the LIMB process as a retrofit system for simultaneous control of NO_x and SO₂ in the combustion process, and that LIMB can achieve up to 70% NO_x and SO₂ reductions;

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



to test alternate sorbent and coal combinations, using the Coolside process, to demonstrate in-duct sorbent injection upstream of the humidifier and precipitator and to show SO₂ removal of up to 70%.

Technology/Project Description:

The LIMB process reduces SO₂ 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 SO₂ removal. Combinations of three eastern bituminous coals (1.6%, 3.0%, and 3.8% sulfur) and four sorbents were tested. Other variables examined were stoichiometry, humidifier outlet temperature, and injection level.

In the Coolside process, dry sorbent is injected into the flue gas downstream of the air preheater, followed by flue gas humidification. Humidification enhances ESP performance and SO₂ absorption. SO₂ absorption is improved by dissolving NaOH or Na₂CO₃ in the humidification water. The spent sorbent is collected with the fly ash, as in the LIMB process. An eastern bituminous coal with 3.0% sulfur was used in testing.

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

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

Project Results/Accomplishments:

LIMB tests were conducted over a range of Ca/S ratios and humidification conditions. Each of four sorbents (calcitic limestone, type-N atmospherically hydrated dolomitic lime, calcitic hydrated lime, and calcitic hydrated lime with added calcium lignosulfonate) was injected while burning each of three coals (Ohio bituminous, 1.6%, 3.0%, and 3.8% sulfur). Tests were conducted under minimal humidification, defined as operation at a humidifier outlet temperature sufficient to maintain ESP performance. That temperature was typically 250–275 °F. Tests were also conducted at a 20 °F approach to the adiabatic saturation temperature of the flue gas to enhance SO₂ removal of the LIMB system. Close-approach operation typically meant controlling the flue gas temperature at the humidifier outlet (ESP inlet) to about 145 °F. Other variables were stoichiometry and injection level. Highlights of reported test results follow:

- The coal's sulfur content, as reflected in the SO₂ concentration in the flue gas, affected SO₂ removal efficiency—the higher the sulfur content, the greater the SO₂ removal for a given sorbent at a comparable stoichiometry. A 5–7% increase in removal occurred when switching to 3.8% from 1.6% sulfur coal and injecting at a stoichiometry of 2.0.
- The highest sulfur removal efficiencies, without humidification to close approach, were attained using the ligno lime—61% SO₂ removal was achieved while burning 3.8% sulfur coal. All sorbents tested were capable of removing SO₂ although calcium utilization of even finely pulverized limestone was not nearly as high as those of the limes.
- While injecting commercial limestone with 80% of the particles less than 44 microns in size, removal efficiencies of about 22% were obtained at a stoichiometry of 2.0 while burning 1.6% sulfur coal. However, removal efficiencies of about 32% were achieved at a

Commercial Applications:

Both LIMB and Coolside technologies are applicable to most utility and industrial coal-fired units and provide alternatives to conventional wet flue gas desulfurization (FGD) processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. Depending on the plant capacity factor and the coal's sulfur content, they can be economically competitive with FGD systems. For example, using 2.5% sulfur coal at a 65% plant capacity factor, LIMB can be cost competitive with conventional wet FGD up to 450 MWe and Coolside up to 220 MWe. The environmental benefits for LIMB are 40–50% lower NO_x and more than 20% lower SO₂ emissions, and for Coolside up to 70% lower SO₂ emissions. The waste from each of these processes is dry and easily handled and contains unreacted lime that has potential commercial application. Both processes can handle all coal types, especially low- to medium-sulfur coals.

Project Schedule:

DOE selected project (CCT-1)	7/24/86
Cooperative agreement awarded	6/25/87
NEPA process completed (MTF)	6/2/87
Environmental monitoring plan completed	10/19/88
Construction	8/87–9/89
Coolside operational testing	7/89–2/90
LIMB extension operational testing	4/90–8/91
Project completed	11/92

Final Reports:

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

stoichiometry of 2.0 when using a limestone with all particles less than 44 microns. For a third limestone with essentially all particles less than 10 microns, the removal efficiency was about 5–7% higher than that obtained at similar conditions for limestone with all particles less than 44 microns.

- Sorbent injection at the 181-ft plant elevation level inside the boiler, just above the boiler's nose, yielded the highest SO₂ removal rates. Here, the sorbent was injected at close to the optimum furnace temperature of 2,300 °F.
- SO₂ removal efficiencies were enhanced by about 10% over the range of stoichiometries tested when humidification down to a 20 °F approach to saturation was used.

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

The Coolside process routinely achieved 70% SO₂ removal at design conditions (2.0 Ca/S, 0.2 Na/Ca, and 20 °F approach to adiabatic saturation temperature) using commercial hydrated lime. SO₂ removal depended on Ca/S, Na/Ca, approach to adiabatic saturation, and the physical properties of the hydrated lime. Sorbent recycle showed significant potential to improve sorbent utilization. Observed SO₂ removal with recycle sorbent alone was 22% at 0.5 available Ca/S and 18 °F approach to adiabatic saturation. Observed SO₂ removal with simultaneous recycle and fresh sorbent feed was 40% at 0.8 fresh Ca/S, 0.2 fresh Na/Ca, 0.5 available recycle, and 18 °F approach to adiabatic saturation.

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

SOx-NOx-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 Sox-NOx-Rox Box™ (SNRB™) process (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

5-MWe equivalent slipstream from a 156-MWe boiler

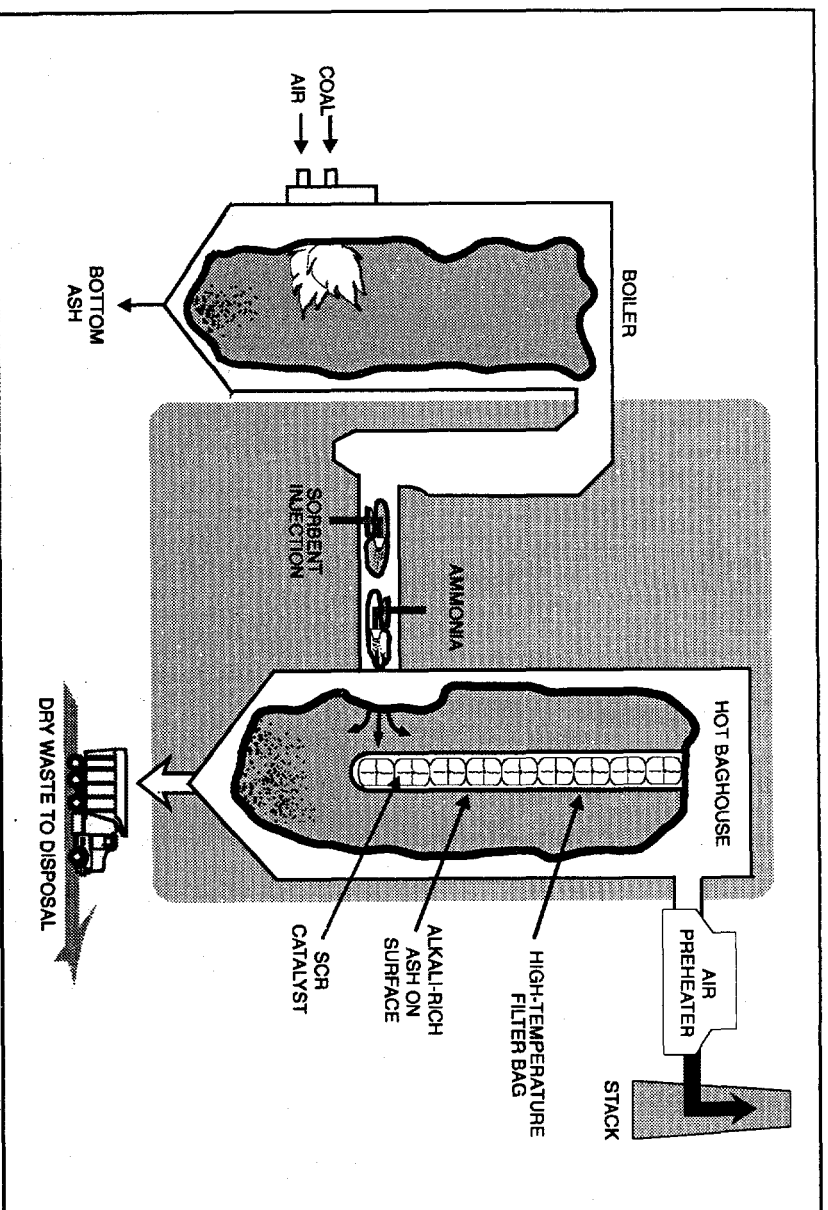
Project Funding:

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

Project Objective:

To demonstrate that the SNRB™ process, used in retrofitting a high-sulfur-coal-fired power plant, can remove high levels of all three pollutants using a single process-

SOx-NOx-Rox Box and SNRB are trademarks of The Babcock & Wilcox Company.



ing unit for treating flue gas, thereby lessening on-site space requirements and capital costs.

Technology/Project Description:

The SNRB™ process combines the removal of SO₂, NO_x, and particulates in one unit—a high-temperature baghouse. SO₂ removal is accomplished using either calcium- or sodium-based sorbent injected into the flue gas. NO_x removal is accomplished by injecting ammonia to selectively reduce NO_x in the presence of a selective catalytic reduction, or SCR, catalyst. Particulate removal is accomplished by high-temperature fiber bag filters.

The 5-MWe SNRB™ demonstration unit is large enough to demonstrate commercial-scale components while minimizing the demonstration cost. Operation at this scale also permitted cost-effective control of the flue

gas temperature which allowed for evaluation of performance over a wide range of sorbent injection and baghouse operating temperatures. Thus several different arrangements for potential commercial installations could be simulated.

The project demonstrated the technical and economic feasibility of achieving greater than 80% SO₂ removal, above 90% NO_x removal, and 99% particulate removal at lower capital, operating, and maintenance costs than a combination of conventional systems. The demonstration was conducted at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles Bottom, OH. Bituminous coal with an average sulfur content of 3.4% was burned at this site during the demonstration.

Project Results/Accomplishments:

SNRBTM demonstration tests were conducted for emissions control of SO₂, NO_x, and particulates. Four different sorbents were tested for SO₂ capture. Calcium-based sorbents included commercial-grade hydrated lime, sugar hydrated lime, and lignosulfonate hydrated lime. In addition, sodium bicarbonate was tested. The optimum location for injecting the sorbent into the flue gas was immediately upstream of the baghouse. Effectively, the SO₂ was captured by the sorbent while the sorbent was in the form of a filter cake on the filter bags (along with fly ash). To capture NO_x, ammonia was injected between the sorbent injection point and the baghouse. The ammonia and NO_x reacted to form nitrogen and water in the presence of Norton Company's NC-300 series zeolite SCR catalyst. 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.

With commercial-grade lime, at a Ca/S ratio of 2, and with the baghouse temperature between 800 and 850 °F, sulfur capture was well above 80%. With the modified hydrated limes, at the same operating temperature range, sulfur capture approached 90%. With an NH₃/NO_x ratio of 0.9, the reduction in NO_x emissions was consistently above 90% and the ammonia slip was consistently below 5 ppm. Particulate emissions were always below 0.03 lb/million Btu, the NSPS for particulates. Particulate emissions averaged 0.018 lb/million Btu (0.009 grains/std ft³), corresponding to a collection efficiency of 99.89%.

High SO₂ removal efficiency was demonstrated in a brief test program with sodium bicarbonate injection. Removal efficiency increased from 80% to 98% and the ratio of Na/S was increased from 1 to 2.

All of the demonstration tests were conducted using 3M's Nextel ceramic fiber filter bags or Owens Corning

Fiberglas's S-Glass filter bags. All of the test work was carried out at air-to-cloth ratios of 3–4 ft/min. No excessive wear or failures occurred in over 2,000 hours of elevated temperature operation.

A preliminary evaluation has been made of the projected capital cost of the SNRBTM system for various utility boilers. For a 250-MWe boiler fired with 3.5% sulfur coal and generating NO_x emissions of 1.2 lbs/million Btu, the projected cost of a SNRBTM system is approximately \$260/kW including various standard 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.

Commercial Applications:

Commercial application of the technology offers the potential for significant reductions of multiple pollutants from fossil-fired plants with the potential for increasing thermal efficiency. SNRBTM offers the potential for lower capital and operating costs and smaller space requirements than a combination of conventional, high-efficiency control technologies. SNRBTM is capable of reducing emissions from plants burning high- or low-sulfur coal. In retrofit applications, SNRBTM provides a means of improving particulate emissions control with the addition of SO₂ and NO_x emissions control capacity.

Commercialization of the technology is expected to develop with an initial larger scale application equivalent to 50–100 MWe. The focus of marketing efforts will be tailored to match the specific needs of potential industrial, utility, and independent power producers for both retrofit and new plant construction. SNRBTM is a flexible technology which can be tailored to maximize control of SO₂, NO_x, or combined emissions to meet current performance requirements while providing flexibility to address future needs.

Project Schedule:

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

Final Reports:

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

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Project completed.

Participant:
Energy and Environmental Research Corporation

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

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

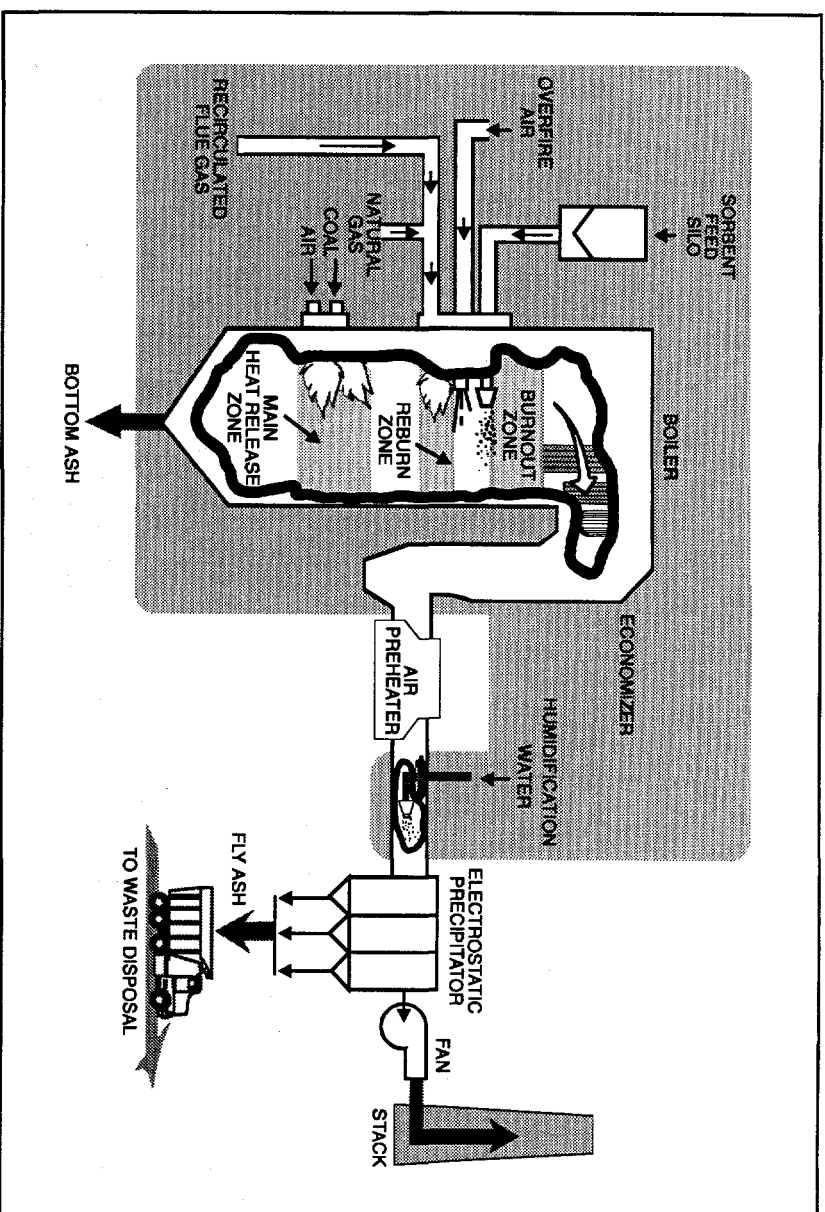
Technology:
Energy and Environmental Research Corporation's gas reburning and sorbent injection process (GR-SI) (environmental control devices/combined SO₂/NO_x control technologies)

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

Project Funding:

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

Project Objective:
To demonstrate gas reburning to attain 60% NO_x reduction along with sorbent injection to capture 50% of the SO₂ on two different boiler configurations: tangentially fired and cyclone-fired.



Technology/Project Description:

In this process, 80–85% of the fuel is coal and is supplied to the main combustion zone. The remaining 15–20% of the fuel, generally natural gas or a hydrocarbon, bypasses the main combustion zone and is injected above the main burners to form a reducing zone in which NO_x is converted to nitrogen. A calcium compound (sorbent) is injected in the form of dry, fine particulates above the reburning zone in the boiler or even further downstream. The calcium compound tested is Ca(OH)₂ (lime). The goal was to achieve at least 60% NO_x reduction and at least 50% SO₂ reduction on different boiler configurations at power plants burning high-sulfur midwestern coal. This project demonstrated the GR-SI process on two separate boilers representing two different firing configurations—a tangentially fired, 80-MWe

(gross) boiler at Illinois Power Company's Hennepin Plant in Hennepin, IL, and a cyclone-fired, 40-MWe (gross) boiler at City Water, Light and Power's Lakeside Station in Springfield, IL. Illinois bituminous coal containing 3% sulfur was the test coal for both Hennepin and Lakeside.

Project Results/Accomplishments:

A matrix of 32 gas reburn tests were completed on the tangentially fired boiler at the Hennepin Plant. NO_x reductions of up to 77% were achieved, with 65% being routine—exceeding the project objective of 60%. Evaluation of 20 over-fire air tests indicated substantial NO_x reduction was achievable at low power generation loads, with lesser reductions as load increased. Sorbent injection reduced SO₂ emissions as much as 62%, with 52%

reduction being routine—also exceeding the project objective of 50%. The Ca/S was about 1.75.

Three proprietary sorbents (including PromiSorb A, PromiSorb B, and high surface area hydrated lime) were also tested at Hennepin. The sorbents showed higher SO₂ capture and higher calcium utilization than the regular hydrated lime.

The GR-SI process reduced CO₂, HCl, and HF emissions as well as NO_x and SO₂. During sorbent injection, particulate emissions were reduced by flue gas humidification upstream of the ESP.

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

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

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

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

A total of 25 sorbent injection parametric tests to isolate the effects of the sorbent on boiler performance

and operability were completed. Tests indicated that SO₂ reduction level varied with load because of the effect of temperature on the sulfurization reaction. At a Ca/S of 2.0, full load (33 MWe) achieved a 44% SO₂ reduction; mid-load (25 MWe), 38% reduction; and low load (20 MWe), 32% reduction at Lakeside.

In the GR-SI optimization tests, the two technologies were integrated. Modifications were made to the reburning fuel injection nozzles based on the results of the initial gas reburning parametric tests. Tests did not indicate any adverse effect of the change in the thermal profile. SO₂ reductions of over 50% could be achieved with Ca/S greater than 1.25 along with gas heat inputs of 22–25%. The total SO₂ reduction from the combined effect of fuel replacement and sorbent injection exceeded the project goal of 50% reduction.

The primary goal of the long-term testing was to operate GR-SI during the normal operating cycle of the Lakeside unit. The unit typically operated in cycling service with a very low capacity factor, so testing was conducted whenever the unit was operated. The average NO_x reduction was 67% after a total of 249 hours of gas reburning operation. The average SO₂ reduction after 221 hours of GR-SI operation was 58%. During GR-SI operation there was a 0.8% drop in thermal efficiency due to the fuel switch and a small increase in the exit flue gas temperature.

During extended tests that included a 38-hr GR-SI continuous run, a 115-hr GR-only continuous run, and a 66-hr continuous GR-SI run, process operation with variable load met the project goals of 60% NO_x reduction and 50% SO₂ reduction. No significant boiler or ESP impacts were observed. Compliance test results for particulate emissions averaged 0.016 lb/million Btu, well below the limit of 0.1 lb/million Btu.

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

Commercial Applications:

Gas reburning and sorbent injection is the 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 over 900 pre-NSPS utility boilers; the technologies also can be applied to new utility boilers. With NO_x and SO₂ removal exceeding 60% and 50%, respectively, these technologies have the potential to extend the life of a boiler or power plant and also provide a way to use higher sulfur coals.

Project Schedule:

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

Final Reports:

Final Technical Report, Hennepin	10/94
Final Technical Report, Edwards	10/94
Final Technical Report, Lakeside	5/96
Economic Evaluation Report	5/96
Public Design Report	5/96

Milliken Clean Coal Technology Demonstration Project

Participant:

New York State Electric & Gas Corporation

Additional Team Members:

New York State Energy Research and Development Administration—cofunder
 Empire State Electric Energy Research Corporation—cofunder

Consolidation Coal Company—technical consultant
 Saarberg-Höller-Umwelttechnik, GmbH—technology supplier

The Stebbins Engineering and Manufacturing Company—technology supplier

Nalco Fuel Tech—technology supplier

ABB Air Preheater, Inc.—technology supplier

DHR Technologies, Inc.—operator of advisor system

Location:

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

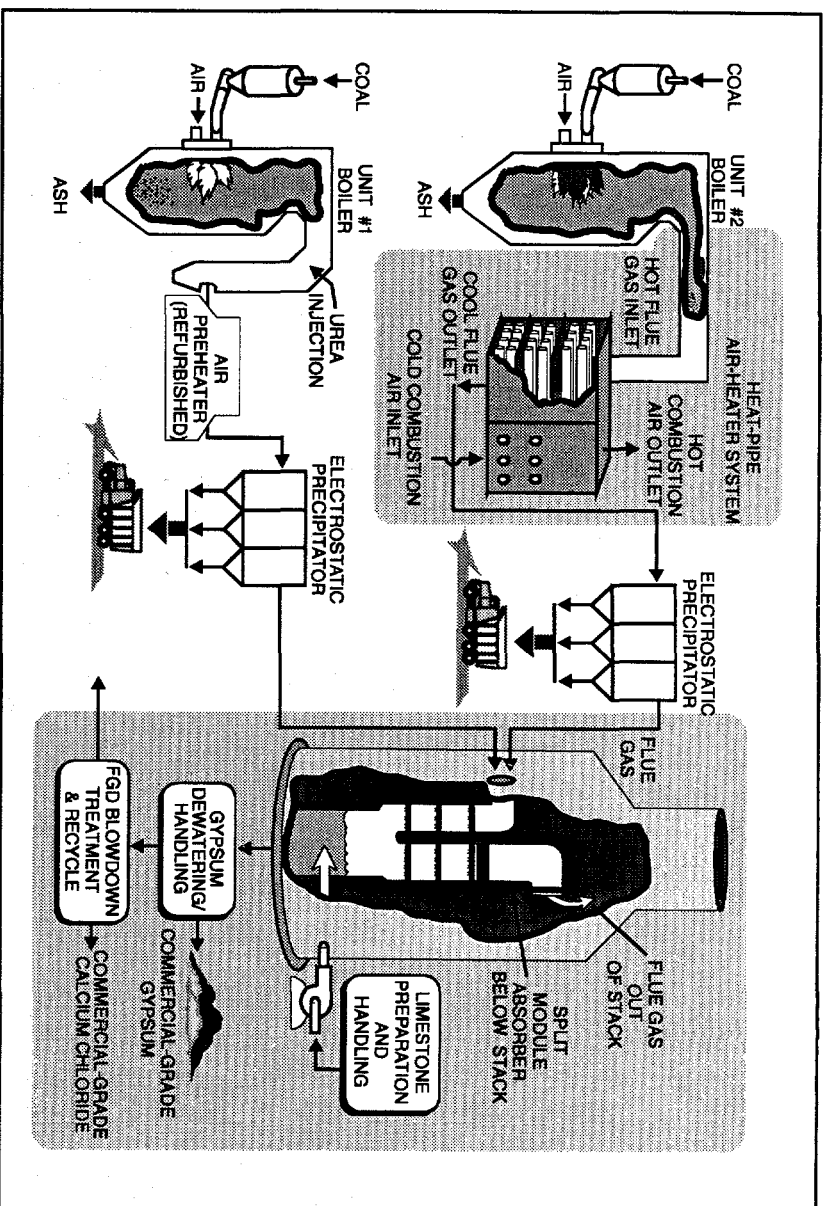
Technology:

Flue gas cleanup using Saarberg-Höller-Umwelttechnik's (S-H-U) formic-acid-enhanced, wet limestone scrubber technology; ABB Combustion Engineering's Low-NO_x Concentric Firing System (LNCFS™) Level III; Nalco Fuel Tech's NO_xOUT™ urea injection system; Stebbins' tile-lined split-module absorber; and ABB Air Preheater's heat-pipe air-heater system (environmental control devices/combined SO₂/NO_x control technologies).

Plant Capacity/Production:

300 MWe

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



Project Funding:

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

Project Objective:

To demonstrate at a 300-MWe utility-scale a combination of cost-effective and innovative emission reduction and efficiency improvement technologies, including the S-H-U wet scrubber system enhanced with formic acid to increase SO₂ removal in a Stebbins tile-lined scrubber, low-NO_x burner, urea injection for NO_x removal, and a heat-pipe air preheater.

Technology/Project Description:

The S-H-U wet flue gas desulfurization process is a formic-acid-enhanced, wet limestone process which

results in very high SO₂ removal with low energy consumption and the production of commercial-grade gypsum.

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

The Nalco Fuel Tech NO_xOUT™ system is being used to remove NO_x by the injection of urea into the boiler gas. This facet of the project, in conjunction with other combustion modifications, including LNCFS Level III (low-NO_x burner system), will reduce NO_x emissions and produce marketable fly ash.

Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System

Participant:
NOXSO Corporation

Additional Team Members:

Alcoa Generating Company—cofounder and host
Southern Indiana Gas and Electric Company—cofounder and operator

W.R. Grace and Company—cofounder
Gas Research Institute—cofounder
Electric Power Research Institute—cofounder

Location:
Newburgh, Warrick County, IN (Alcoa Generating Company's Warrick Power Plant, Unit 2)

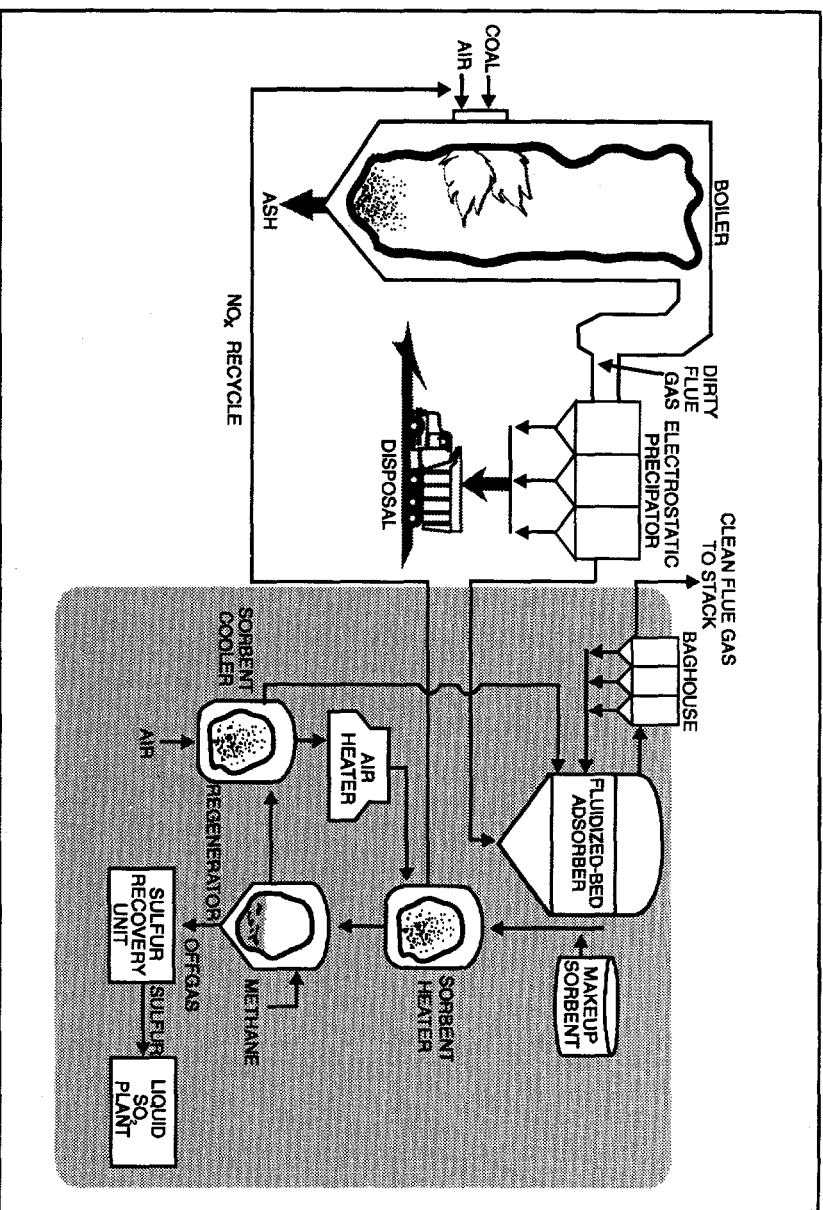
Technology:
NOXSO Corporation's dry, regenerable flue gas cleanup process (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:
150 MWe (net)

Project Funding:

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

Project Objective:
To demonstrate removal of 98% of the SO₂ and 75% of the NO_x from a coal-fired boiler's flue gas using the NOXSO process.



Technology/Project Description:

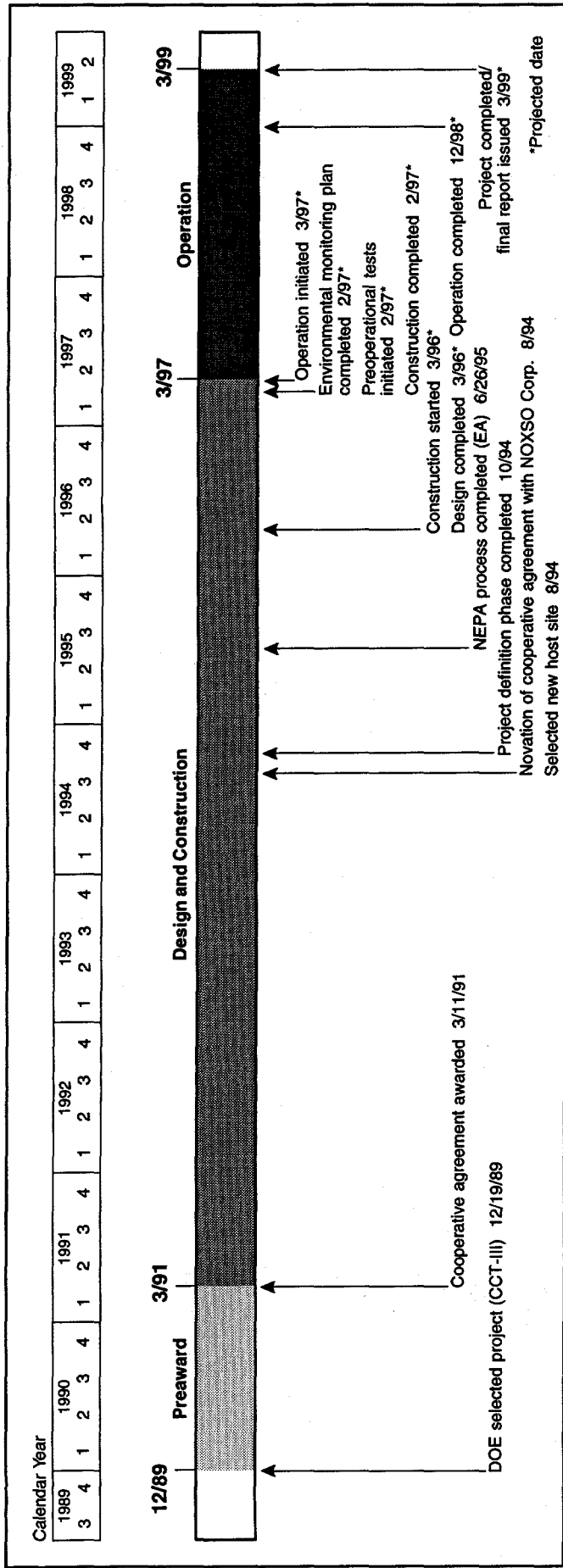
The NOXSO process is a dry, regenerable system capable of removing both SO₂ and NO_x in flue gas from coal-fired utility boilers burning medium- to high-sulfur coals. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; the SO₂ and NO_x are absorbed by the sorbent. The sorbent consists of spherical beads of high-surface-area alumina impregnated with sodium carbonate. The cleaned flue gas then passes through a baghouse to the stack.

The NO_x is desorbed from the NOXSO sorbent when heated by a stream of hot air. The hot air containing the desorbed NO_x is recycled to the boiler where equilibrium processes cause destruction of the NO_x. The absorbed sulfur is recovered from the sorbent in a regen-

erator where it reacts with methane at high temperature to produce an offgas with high concentrations of SO₂ and hydrogen sulfide (H₂S). This offgas is processed to produce elemental sulfur. The elemental sulfur is further processed to produce liquid SO₂, a higher valued by-product.

The process is expected to achieve SO₂ reductions of 98% and NO_x reductions of 75%.

The NOXSO Corporation is demonstrating a full-scale commercial NOXSO unit on a 150-MWe (net) pulverized coal boiler at Alcoa Generating Company's Warrick Power Plant, Unit 2, in Newburgh, IN. The fuel coal is Indiana bituminous coal containing an average of 3.4% sulfur. Data from the proof-of-concept facility at



Ohio Edison Company's Toronto Station is being incorporated into the plant design.

Project Status/Accomplishments:

The NEPA process is complete. An environmental assessment and finding of no significant impact was approved June 26, 1995.

Detailed design activities are continuing. Construction is pending final sale of revenue bonds which will provide the balance of NOXSO's cost share. The revenue bonds will be issued and guaranteed by the state of Indiana.

All front-end engineering and environmental evaluation activities are complete. Detailed design and procurement activities are ongoing.

Commercial Applications:

The NOXSO process is applicable for retrofit or new facilities. The process is suitable for utility and industrial coal-fired boilers of 75 MWe or larger. A high-sulfur

coal is being used in the demonstration; however, the process is adaptable to coals with medium- to high-sulfur content.

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

The technology is expected to be especially attractive to utilities that require high removal efficiencies for both SO₂ and NO_x and/or need to eliminate solid wastes.

Integrated Dry NO_x/SO₂ Emissions Control System

Participant:

Public Service Company of Colorado

Additional Team Members:

Electric Power Research Institute—cofunder
 Stone and Webster Engineering Corp.—engineer
 The Babcock & Wilcox Company—burner developer
 Fossil Energy Research Corporation—operational tester

Western Research Institute—flyash evaluator
 Colorado School of Mines—bench-scale engineering researcher and tester

Noell, Inc.—urea-injection system provider

Location:

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

Technology:

The Babcock & Wilcox Company's DRB-XCL[®] low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection (environmental control devices/combined SO₂/NO_x control technologies)

Plant Capacity/Production:

100 MWe

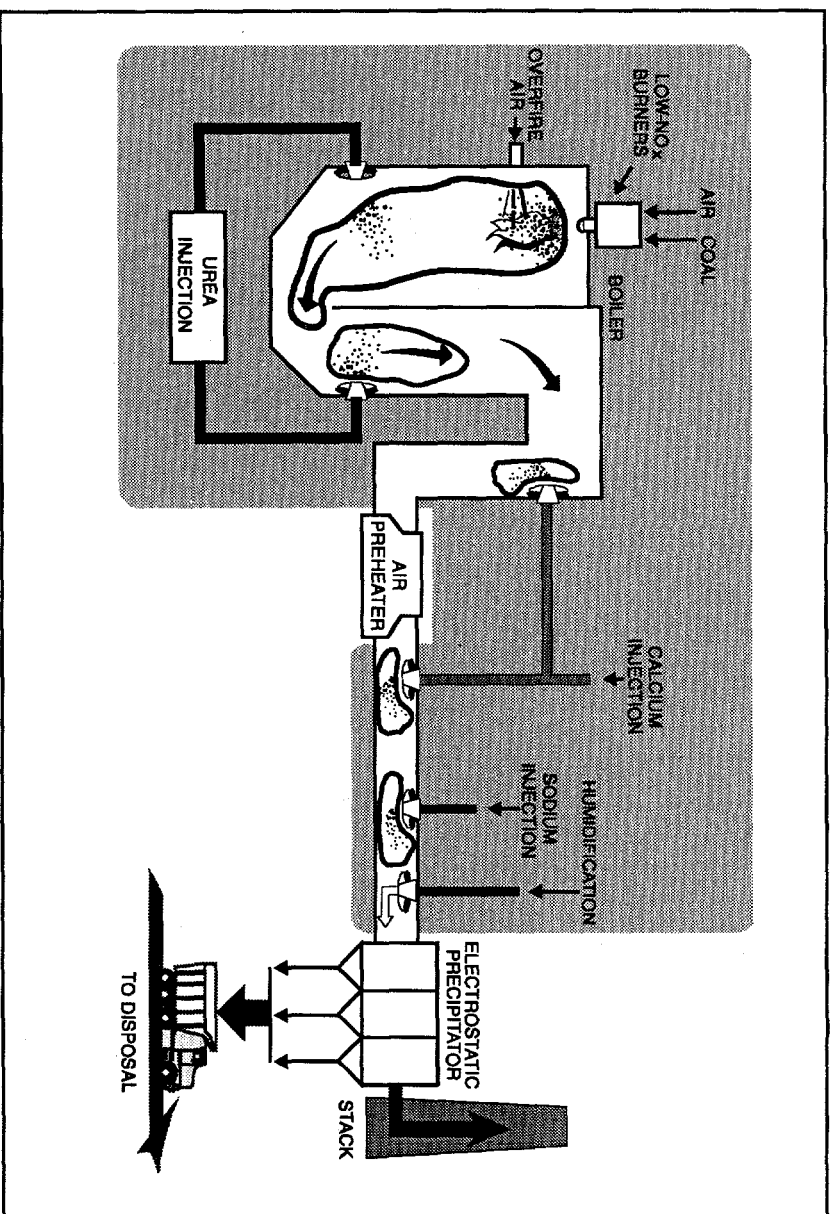
Project Funding:

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

Project Objective:

To demonstrate the integration of three technologies to achieve up to 70% reduction in NO_x and SO₂ emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for

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



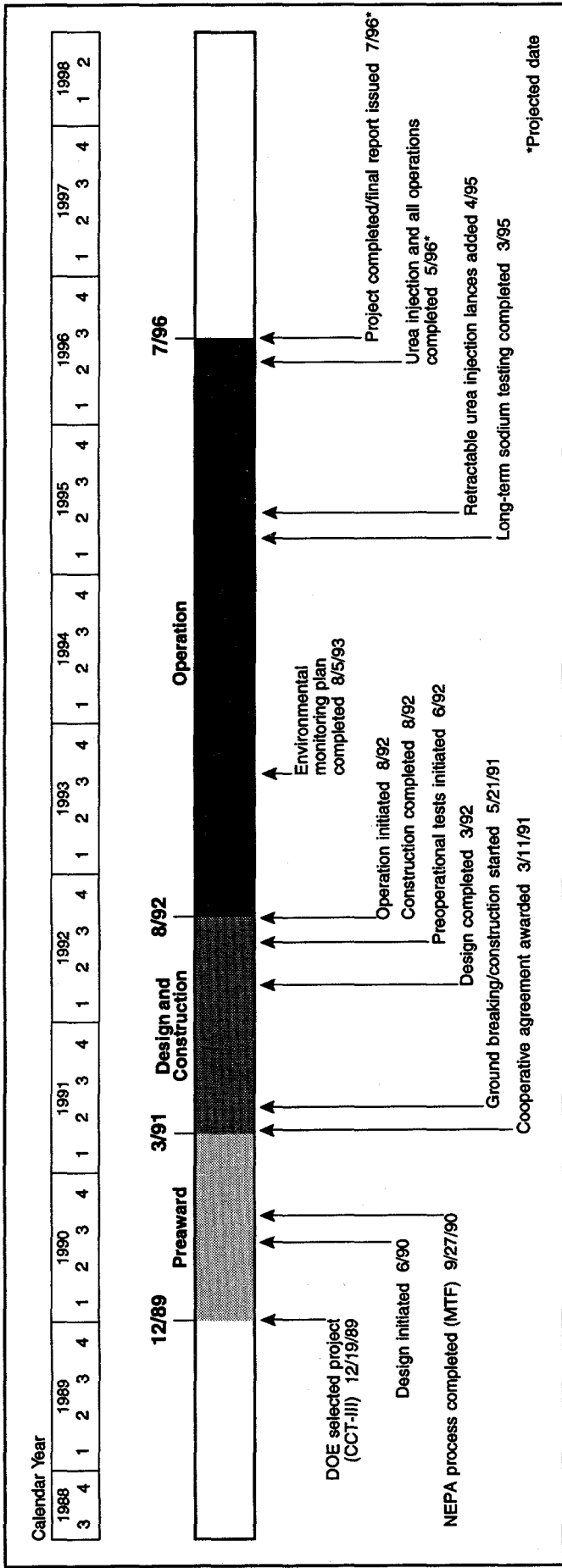
additional NO_x removal and dry sorbent in-duct injection with humidification for SO₂ removal.

Technology/Project Description:

All of the testing is using 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. The low-NO_x burners are expected to reduce NO_x emissions by up to 50%, and, with added air, by up to 70%. Further, in-furnace urea injection is being tested to determine how much additional NO_x can be removed from the combustion gas.

Two types of dry sorbents are being injected into the ductwork downstream of the boiler to reduce SO₂ emissions. Either calcium or sodium is injected downstream of the air heater. Humidification downstream of the dry sorbent injection aids SO₂ capture and lowers flue gas temperature and gas flow, which can decrease pressure drop at the fabric filter dust collector.

The three basic technology systems have been 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. Testing is being conducted using a low-sulfur (0.4%) bituminous Colorado coal, with a short test using low-sulfur (0.35%) subbituminous Wyoming coal.



Project Status/Accomplishments:

Operational testing of the boiler with low-NO_x burners and overfire air started in early August 1992. While firing western bituminous coal, NO_x was reduced from an original baseline of 1.15 lbs/million Btu to about 0.4 lb/million Btu—a 65% reduction—with no operating problems. In-furnace urea injection resulted in a 44% NO_x reduction at full load with a 10-ppm ammonia slip, but at low load, only 11% NO_x reduction was obtained. New retractable injection lances were installed in April 1995, and NO_x reduction at low load was improved to 35% at 10-ppm slip. Sodium-bicarbonate injection achieved over 70% SO₂ removal at a stoichiometric ratio of approximately 1.0. Sodium sesquicarbonate injection after the air heater also obtained a 70% SO₂ removal but at a stoichiometric ratio of approximately 1.8. Calcium-based dry reagent injection achieved a maximum of 40% SO₂ removal and caused some operational concerns. Overall NO_x reduction of 80% has been demonstrated at full load with the integrated sodium and urea injection system.

A 2-week test burn of Power River Basin coal was completed during November 1995. SO₂ emissions were reduced about 20% due to the lower sulfur content of the coal. NO_x emissions decreased by 25–30% at both 60 and 80 MWe. Flyash unburned carbon decreased to less than 1% due to the higher volatility of this coal. Performance of the sodium injection was not affected by the test coal. The coal did increase exit flue gas temperature slightly and thus changed operation of the urea injection system. NO_x removal increased at low loads but decreased slightly at high loads.

The project has been extended through July 1996 to allow for additional modifications and testing of the retractable urea injection lances, additional long-term SO₂ removal testing, and integrated testing of the low-NO_x burners with overfire air, sodium injection, and urea injection with the retractable lances.

Four series of air toxics testing have been completed. Results indicate that the baghouse successfully removes nearly all trace metal emissions and nearly 80% of the mercury emissions. Radionuclides, semi-volatile

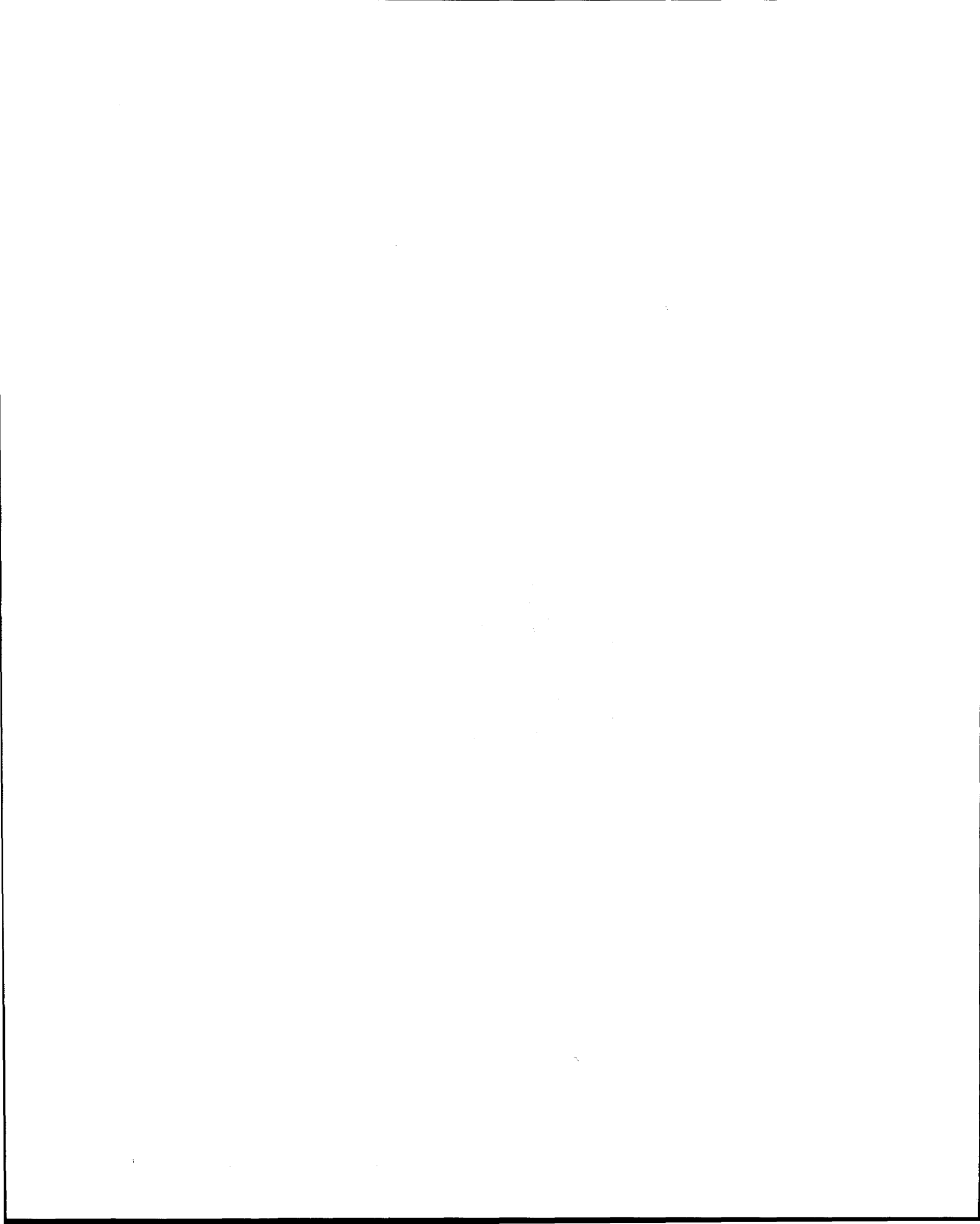
organic compounds, and dioxins/furans were below or very near their detection limit.

Arapahoe 4 has operated over 28,800 hours since combustion modifications were completed in May 1992. The availability factor during this period was over 91%.

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

Commercial Applications:

Either the entire integrated dry NO_x/SO₂ emissions control system or the individual technologies are applicable to most utility and industrial coal-fired units. They provide a lower capital-cost alternative to conventional wet flue gas desulfurization processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. They can be applied to any unit size but are mostly applicable to the older, small- to mid-size units.



**Coal Processing
for Clean Fuels
Fact Sheets**

Development of the Coal Quality Expert

Participants:

ABB Combustion Engineering, Inc.
CQ Inc.

Additional Team Members:

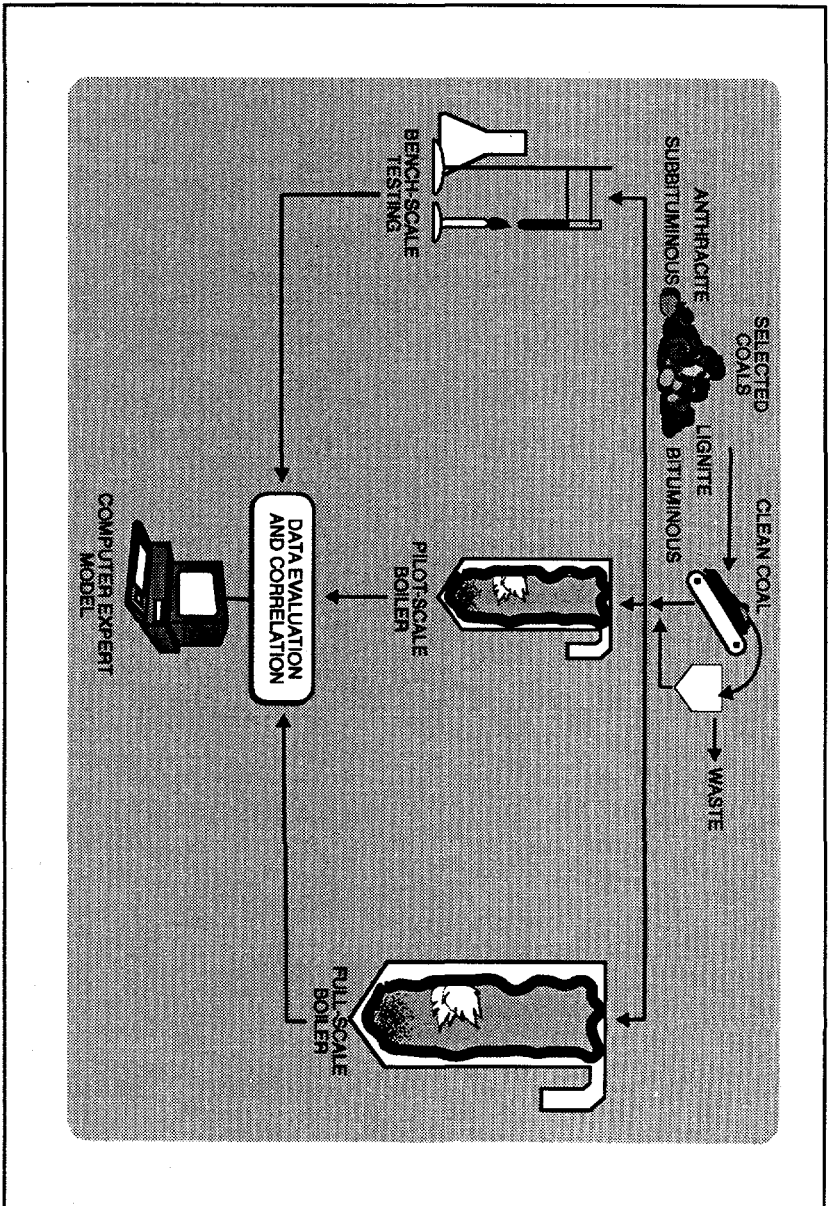
Black and Veatch—cofounder and software developer
Electric Power Research Institute—cofunder
The Babcock & Wilcox Company—cofunder and pilot-scale tester
Electric Power Technologies, Inc.—field tester
University of North Dakota, Energy and Environmental Research Center—bench-scale tester
Alabama Power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

Locations:

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

Technology:

CQ Inc.'s EPRI Coal Quality Expert (CQE) computer software (coal processing for clean fuels/coal preparation technologies)



Plant Capacity/Production:

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

Project Funding:

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

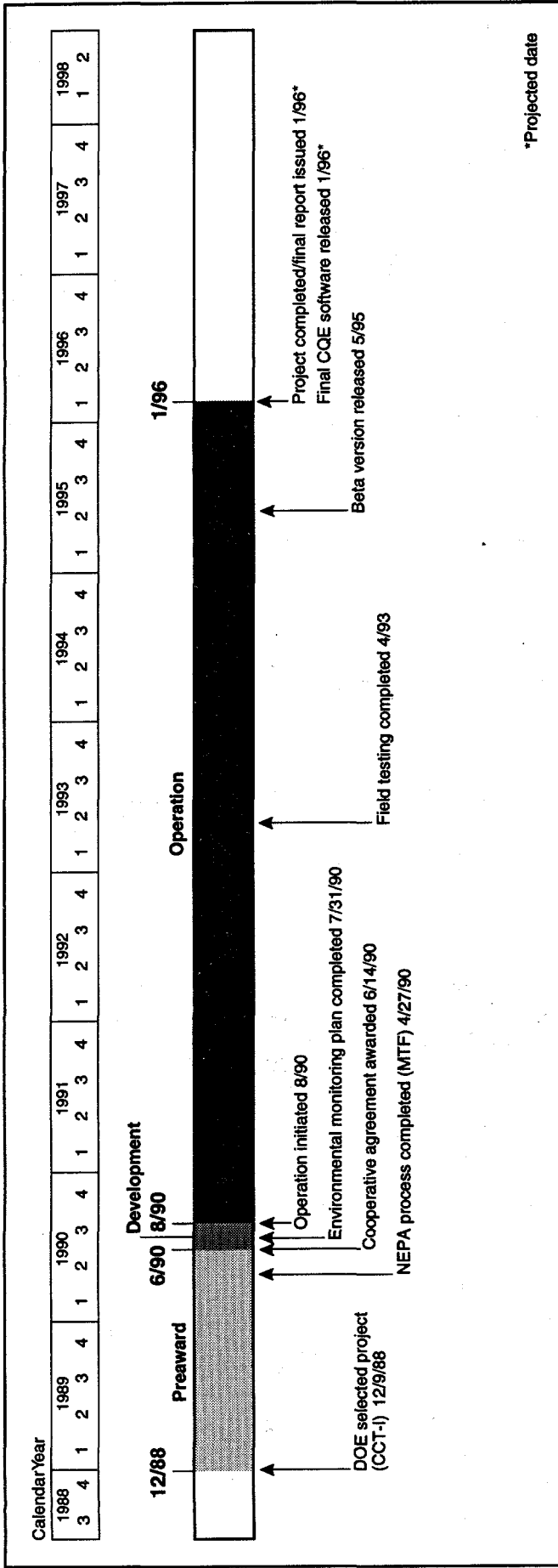
Project Objective:

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

Technology/Project Description:

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

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



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

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

Project Status/Accomplishments:

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

Debugging of the CQE software proceeded through the end of the project. A CQE beta version was released in May 1995 and evaluated by several utilities by July 1995. The initial commercial version of CQE was released in December 1995. CQE has been distributed to about 40 U.S. utilities and 1 U.K. utility through membership in EPRI.

Commercial Applications:

The software will enable coal-fired utilities to select the optimum quality coals for their specific boilers to reduce SO₂, NO_x, and particulate emissions and to achieve the lowest operating costs.

The CQE system is applicable to all electric power plants and industrial/institutional boilers that burn pul-

verized coal. The system can predict the operational benefits of using alternative or cleaned coals.

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

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

Participant:

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

Additional Team Members:

Pennsylvania Power & Light Company—host
 Richmond Power & Light—host
 Centerior Service Company—host
 CQ Inc.—operator

Locations:

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

Technology:

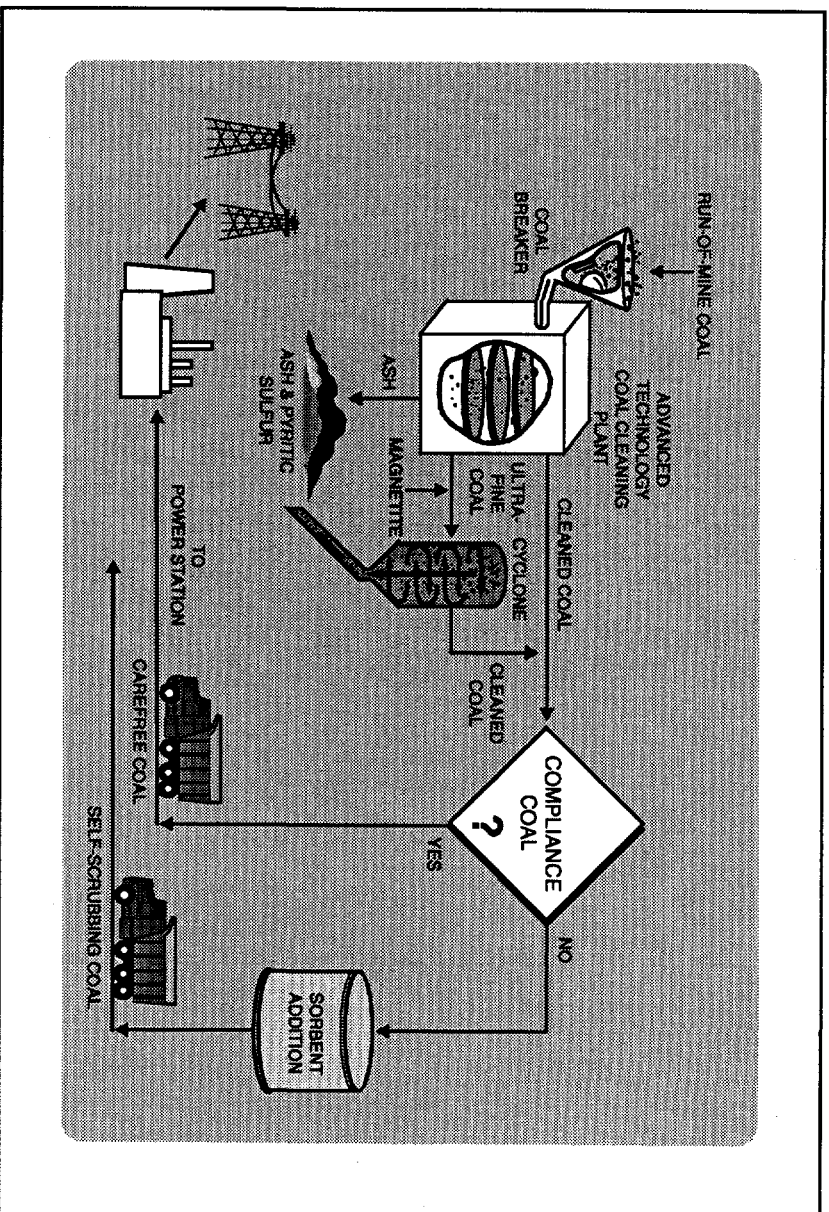
Coal preparation using Custom Coals' advanced physical coal cleaning and fine magnetite separation technology plus sorbent addition technology (coal processing for clean fuels/coal preparation technologies)

Plant Capacity/Production:

500 tons/hr

Project Funding:

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



Project Objective:

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

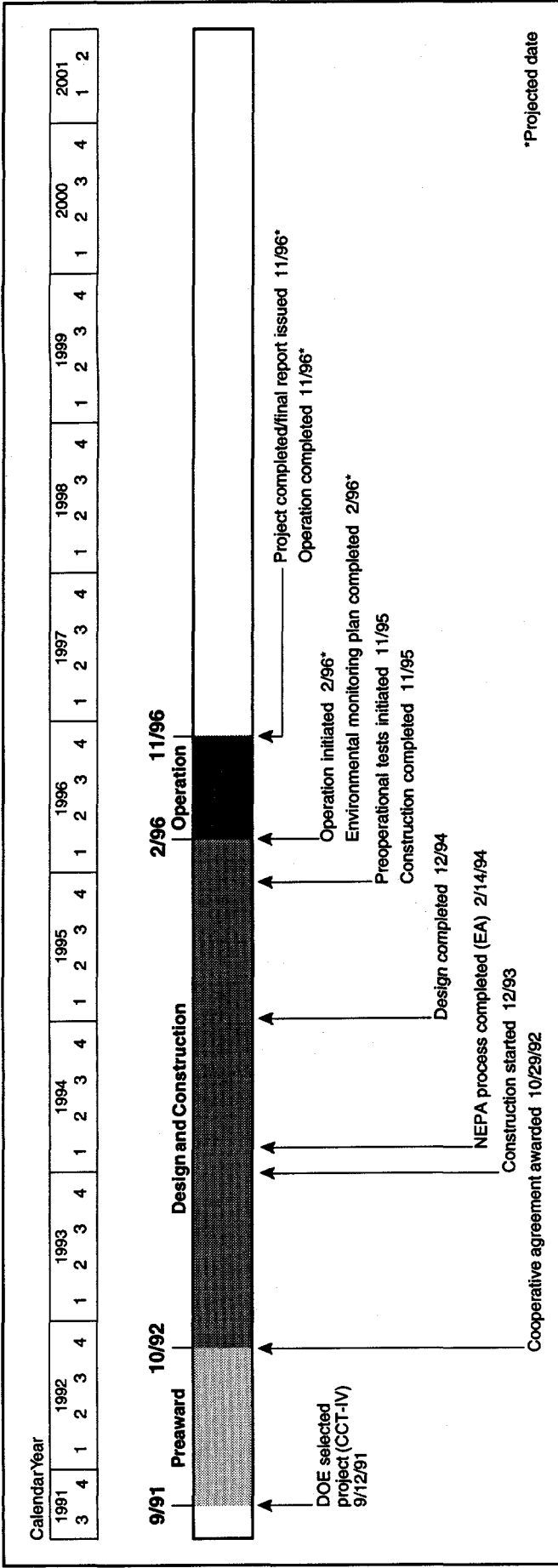
Technology/Project Description:

An advanced coal-cleaning plant will be designed, blending existing and new processes, to produce, from high-sulfur bituminous feedstocks, two types of compliance coals—Carefree Coal™ and Self-Scrubbing Coal™. Carefree Coal™ is produced by breaking and screening run-of-mine coal and by using innovative dense-media cyclones and finely sized magnetite to remove up

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

to 90% of the pyritic sulfur and most of the ash. Carefree Coal™ is designed to be a competitively priced, high-Btu fuel that can be used without major plant modifications or additional capital expenditures. While many utilities can use Carefree Coal™ to comply with SO₂ emissions limits, others cannot due to the high content of organic sulfur in their coal feedstocks. When compliance coal cannot be produced by reducing pyritic sulfur, Self-Scrubbing Coal™ can be produced to achieve compliance.

Self-Scrubbing Coal™ is produced by taking Carefree Coal™, with its reduced pyritic sulfur and ash content, and adding to it sorbents, promoters, and catalysts. Self-Scrubbing Coal™ is expected to achieve compliance with virtually any U.S. coal feedstock through in-boiler absorption of SO₂ emissions. The reduced ash content of



the Self-Scrubbing Coal™ permits the addition of relatively large amounts of sorbent without exceeding the ash specifications of the boiler or overloading the electrostatic precipitator.

A 500-ton/hr advanced coal-cleaning plant is being designed and constructed at a site near Central City, PA. The advanced coal-cleaning plant will manufacture Self-Scrubbing Coal™ and Carefree Coal™. Two medium-to high-sulfur coals—Illinois No. 5 (2.7% sulfur) from Wabash County, IL, and Lower Freeport Seam coal (3.9% sulfur) from Belmont County, OH—will be used to produce Self-Scrubbing Coal™. Carefree Coal™ will be made using Lower Kittanning Seam coal (1.8% sulfur) from Somerset County, PA. The Lower Kittanning coal is being tested at Pennsylvania Power & Light's Martin's Creek Power Station located in Lower Mt. Bethel Township, PA. The Illinois No. 5 coal is being tested at Richmond Power & Light's Whitewater Valley Generating Station Unit No. 2 located in Richmond, IN; and the Lower Freeport Seam coal is being tested at Centrior Energy's Ashtabula C Power Plant near Ashtabula, OH.

Project Status/Accomplishments:

Plant start-up procedures were initiated in November; by month's end, 10% of the units had been started manually through the programmable logic control system, and several analog functions were verified. By year-end 1995, all but two conveyors were fully operational. All piping was complete. Electrical work in the plant was 98%. All plant units have been turned over by the contractor. All 17 of the planned loop tests have been completed. Interlock checking was approximately 75% complete. Roughly 1,700 tons of coal were received to check out the raw coal truck scales and storage handling system. In addition, preliminary baseline testing of 10,000 tons of low-volatile coal burned at Martin's Creek has been completed.

Commercial Applications:

Commercialization of Self-Scrubbing Coal™ has the potential of bringing into compliance about 164 million tons/yr of bituminous coal that cannot meet emissions limits through conventional coal cleaning. This repre-

sents over 38% of the bituminous coal burned in 50-MW or larger U.S. generating stations.

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

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

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

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

Advanced Coal Conversion Process Demonstration

Participant:

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

Additional Team Member:

None

Location:

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

Technology:

Rosebud SynCoal Partnership's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals (clean processing for clean fuels/coal preparation technologies)

Plant Capacity/Production:

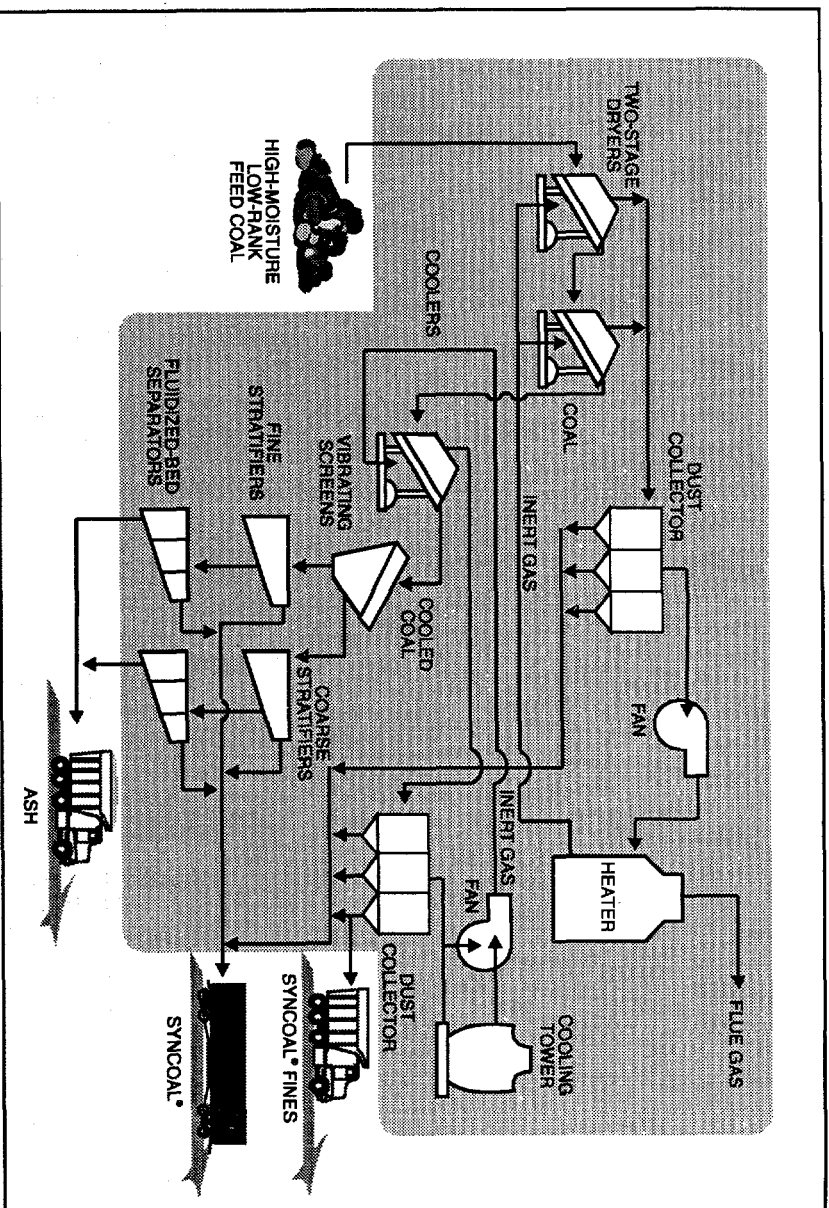
45 tons/hr of SynCoal® product (300,000 tons/yr)

Project Funding:

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

Project Objective:

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



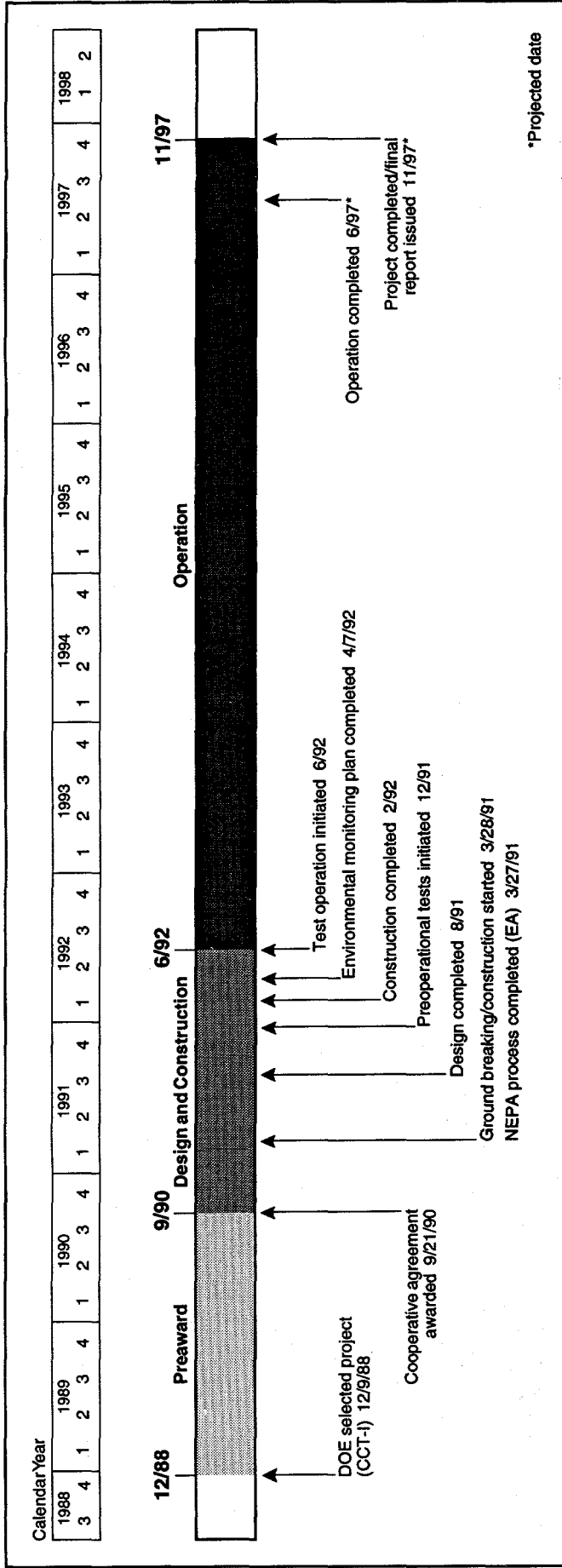
Technology/Project Description:

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

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

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

SynCoal is a registered trademark of the Rosebud SynCoal Partnership.



Project Status/Accomplishments:

The demonstration facility continues reliable operation. It has produced a total of 1,037,255 tons of SynCoal® products through year-end 1995. Rosebud continues to supply different products to a range of customers, including industrial, institutional, and utility users. Total sales of SynCoal® product during 1995 were 315,687 tons.

Two different products have been delivered to four industrial customers. Ash Grove Cement of Montana City, MT, has received granular SynCoal® and fines; Bentonite Corporation of Colony, WY, regular SynCoal®; Empire Sand and Gravel of Billings, MT, granular SynCoal®, and Wyoming Lime of Warren, MT, fines and granular SynCoal®.

Montana Power's J.E. Corette Plant has received a conditioned SynCoal® and DSE-conditioned SynCoal® blend. Montana Power's Colstrip Units 3 and 4 and Minnkota Power have received SynCoal® to continue their testing. The University of North Dakota has received SynCoal® blended with raw coal. "Klinker

"Killer" testing has been initiated at the Minnkota Power Station and Montana Power's J.E. Corette Plant. Extended kiln testing has begun at Wyoming Lime.

Commercial Applications:

Rosebud SynCoal®'s advanced coal conversion process has the potential to enhance the use of low-rank western subbituminous and lignite coals. Many of the power plants located throughout the upper Midwest have cyclone boilers, which burn low-ash-fusion-temperature coals. Presently, most of these plants burn Illinois Basin high-sulfur coal. SynCoal® is an ideal low-sulfur coal substitute for these and other plants because it allows operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. The advanced coal conversion process produces SynCoal® which has a consistently low moisture content, a low sulfur content, a high heating value, and a high volatile content. Because of these characteristics, SynCoal® could have significant

impact on SO₂ reduction and provide an economical clean alternative fuel to many regional industrial facilities and small utilities being forced to use fuel oil and natural gas. Rosebud SynCoal's process, therefore, will be attractive to industry and utilities because the upgraded fuel will be less costly to use than would the construction and use of flue gas desulfurization equipment. This will allow plants that would otherwise be closed to remain in operation.

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

ENCOAL Mild Coal Gasification Project

Participant:

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

Additional Team Members:

SMC Mining Company—cofunder
TEK-KOL (partnership between SMC Mining Company and SGI International)—technology owner, supplier, and licensor

SGI International—technology developer
Triton Coal Company (subsidiary of SMC Mining Company)—host and coal supplier
The M. W. Kellogg Company—engineer and constructor

Location:

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

Technology:

SGI International's liquids from coal process (coal preparation for clean fuels/mild gasification)

Plant Capacity/Production:

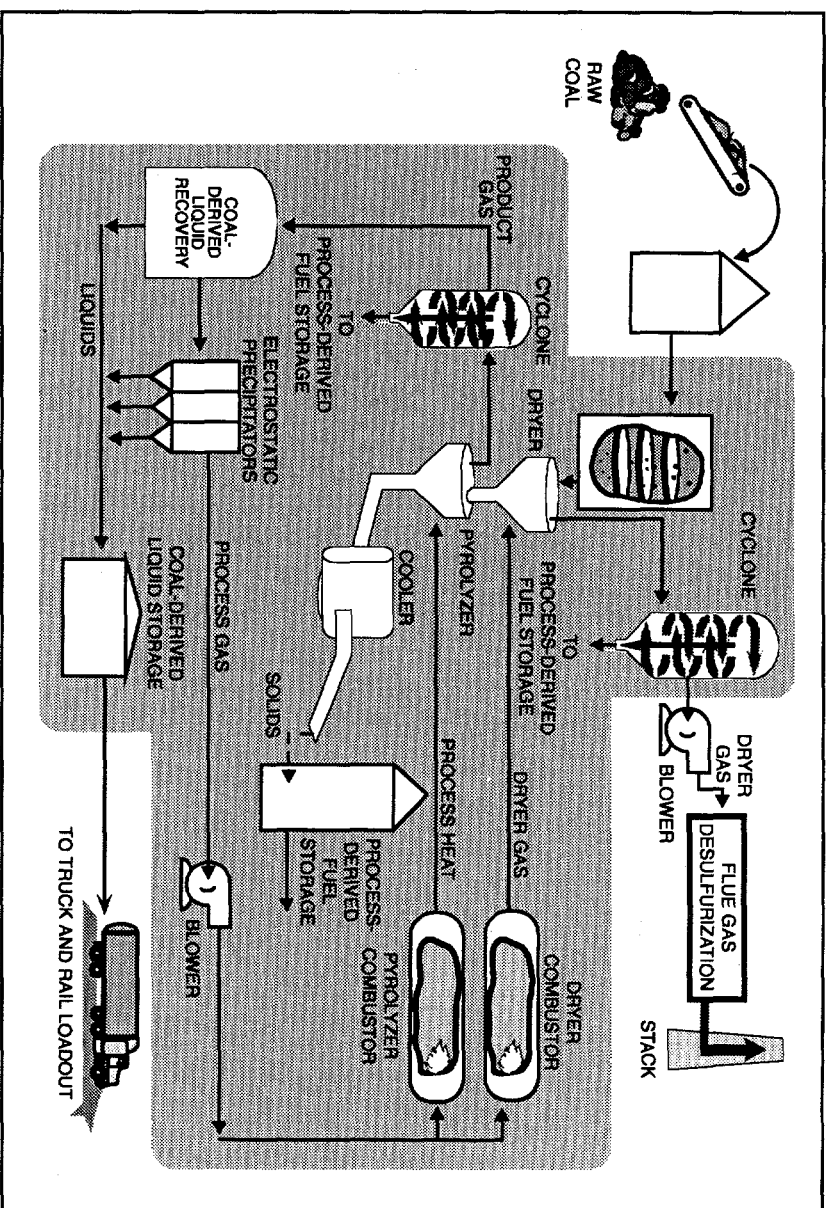
1,000 tons/day of subbituminous coal feed

Project Funding:

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

Project Objective:

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



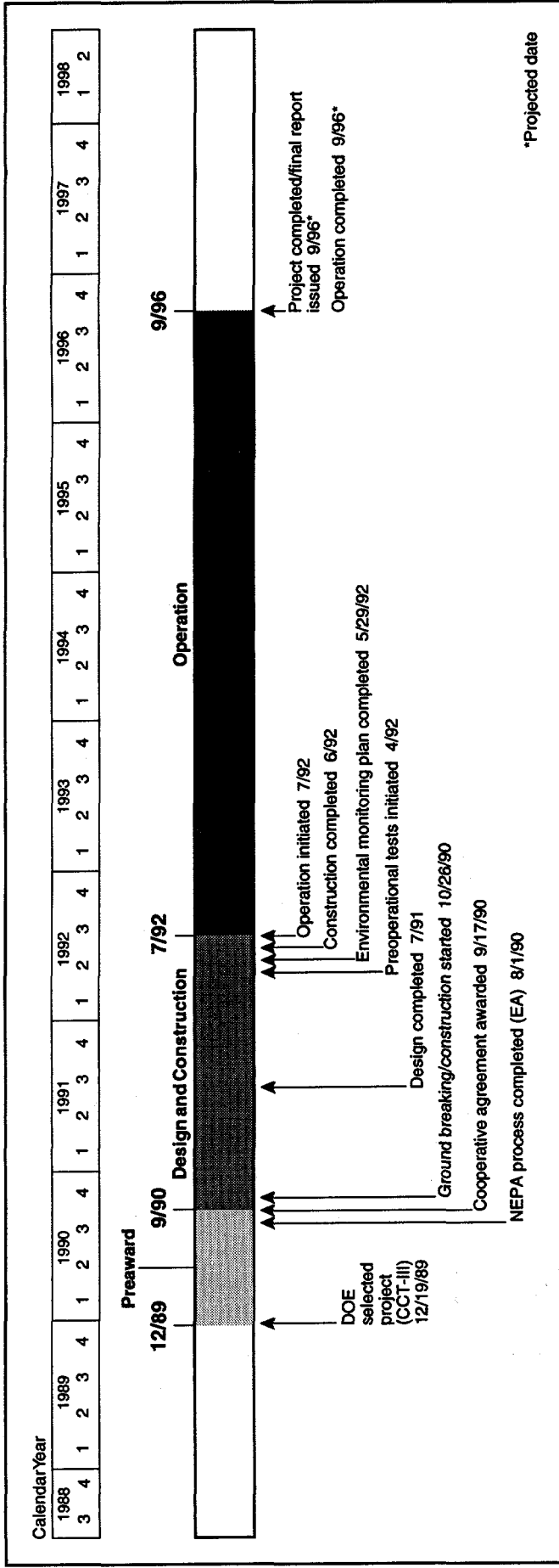
Technology/Project Description:

The ENCOAL mild coal gasification process involves heating coal under carefully controlled conditions. Coal is fed into a rotary grate dryer where it is heated by a hot gas stream to reduce the coal's moisture content. The solid bulk temperature is controlled so that no significant amounts of methane, CO, or CO₂ are released from the coal. The solids from the dryer are conveyed to the pyrolyzer where the rate of heating of the solids and residence time are controlled to achieve desired properties of the fuel products. During processing in the pyrolyzer, all remaining free water is removed, and a chemical reaction occurs that results in the release of volatile gaseous material. Solids exiting the pyrolyzer are quenched, cooled, and transferred to a surge bin.

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

The offgas from the dryer is treated in a wet venturi scrubber to remove particulates and a horizontal scrubber to remove SO₂, both using a sodium carbonate solution. The treated gas is vented to a stack, and the spent solution is discharged into a pond for evaporation.

The ENCOAL project is located within Campbell County, WY, at Triton Coal Company's Buckskin Mine, 10 miles north of Gillette. The plant makes use of the



present coal-handling facilities at the mine. Subbituminous coal with 0.4–0.9% sulfur content is being used.

Project Status/Accomplishments:

The plant officially entered the production mode in June 1994; operation has been at a coal feed rate of 500 tons/day. By year-end 1995, the plant had logged more than 7,900 hours of operation on coal. To date, more than 43,189 tons of solid product and more than 2.2 million gallons of liquid product have been shipped to industrial and utility customers.

Solid product has been tested by Western Farmers Cooperative's Hugo plant in Oklahoma, by Muscatine Power and Water in Iowa, and by the Omaha Public Power District in Nebraska. Wisconsin Power & Light also has contracted for 30,000 tons of pure solid product to test storage stability and to do test burns.

Tank cars of liquid product are being shipped to several customers in the Midwest for use in industrial boilers. The Dakota Gasification Company has pur-

chased 800,000 gallons for use in its synfuel plant in Beulah, ND.

The project has been extended to resolve problems with the in-process stabilization of the solid product and to conduct and analyze utility test burns of solid product.

A topical report on the initial commercial shipment and utilization of both solid and liquid products was released in March 1995. Test data with respect to sulfur distribution in the products show a reduction in SO₂ of over 20% on a lb/million Btu basis.

Commercial Applications:

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

The potential benefits of this mild gasification technology in its commercial configuration are attributable to the increased heating value (about 12,000 Btu/lb) and

lower sulfur content (per unit of fuel value) of the new solid-fuel product compared to the low-rank coal feedstock, and the production of low-sulfur liquid products requiring no further treatment for the fuel oil market. The product fuels are expected to be used economically in commercial boilers and furnaces and to reduce significantly SO₂ emissions at industrial and utility facilities currently burning high-sulfur bituminous coals or fuel oils.

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

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

Participant:

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

Additional Team Members:

Air Products and Chemicals, Inc.—technology supplier and cofunder
 Eastman Chemical Company—host; synthesis gas and services provider
 Acurex Environmental Corporation—fuel methanol tester and cofunder
 Electric Power Research Institute—fuel methanol tester and cofunder

Location:

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

Technology:

Air Products and Chemicals' liquid-phase methanol (LPMEOH™) process (coal processing for clean fuels/indirect liquefaction)

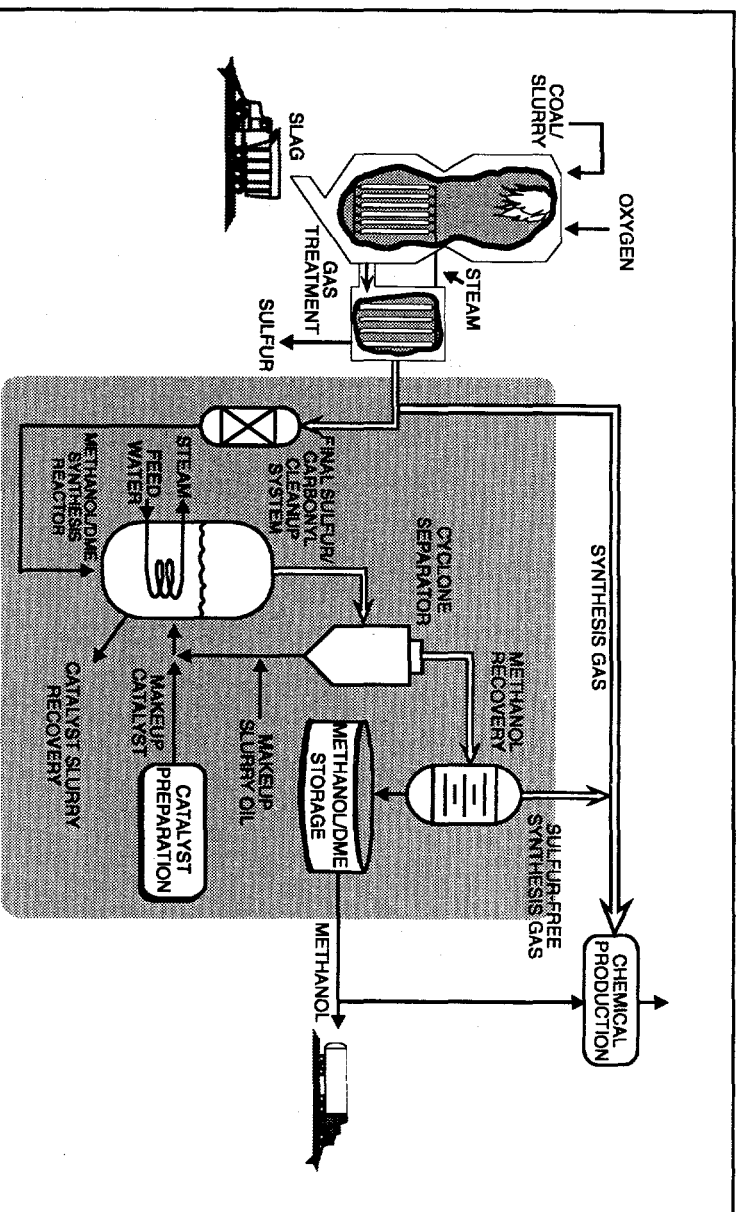
Plant Capacity/Production:

260 tons/day of methanol (nominal)

Project Funding:

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

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



Project Objective:

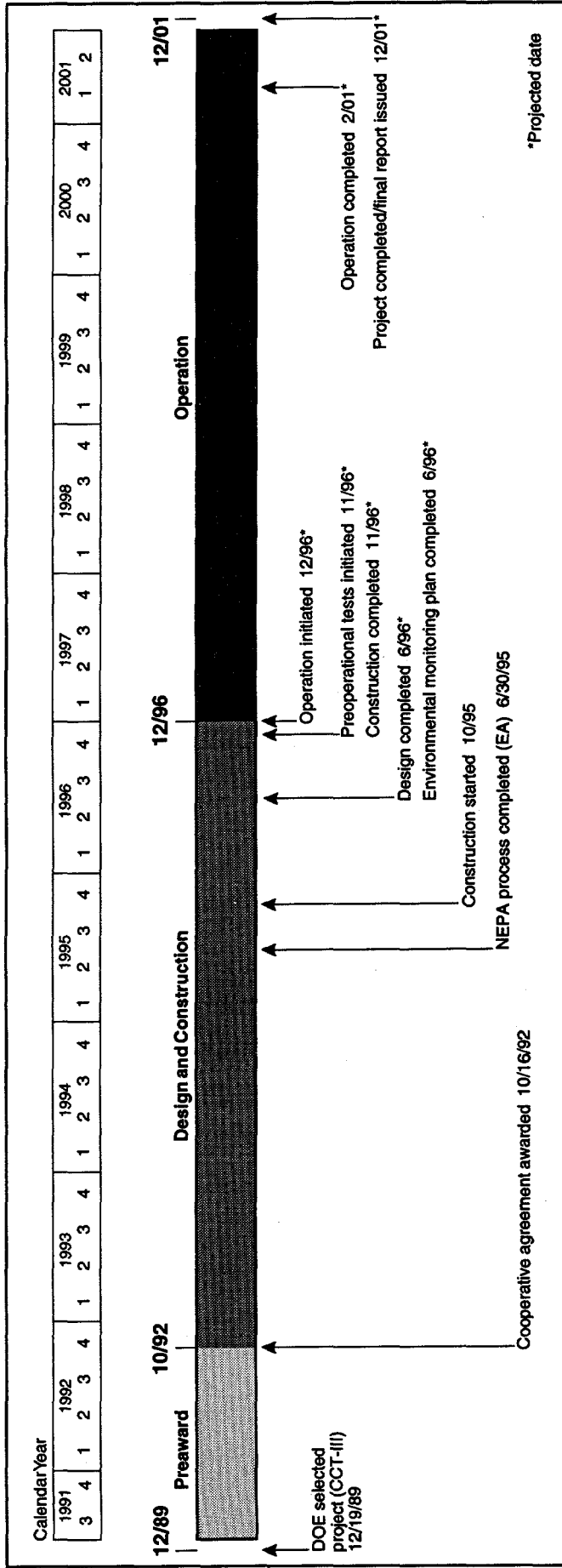
To demonstrate on a commercial scale the production of methanol from coal-derived synthesis gas using the LPMEOH™ process; and to determine the suitability of methanol produced during this demonstration for use as a chemical feedstock or as a low-SO_x, low-NO_x alternative fuel in stationary and transportation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

Technology/Project Description:

This project is demonstrating, at commercial scale, the LPMEOH™ process to produce methanol from coal-derived synthesis gas. The combined reactor and heat removal system is different from other commercial

methanol processes. The liquid phase not only suspends the catalyst but functions as an efficient means to remove the heat of reaction away from the catalyst surface. This feature permits the direct use of synthesis gas streams as feed to the reactor without the need for shift conversion.

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



demonstrate will be made. Eastern high-sulfur bituminous coal (Mason seam) containing 3% sulfur (5% maximum) and 10% ash will be used.

Project Status/Accomplishments:

To provide a contractual basis to manage and execute the LPMEOH™ demonstration project, Air Products and Chemicals and the Eastman Chemicals Company have formed the limited partnership, Air Products Liquid Phase Conversion Company. Project definition activities were completed in September 1994 and design was initiated. The NEPA process has been completed. An environmental assessment was prepared, and a finding of no significant impact was signed June 30, 1995. Construction started in October 1995. By year-end 1995, site preparation was complete and foundation installation was under way. Activities to update the off-site fuel-use test plan were initiated. Revisions also were being made to the environmental monitoring plan. The demonstration test plan is also under development.

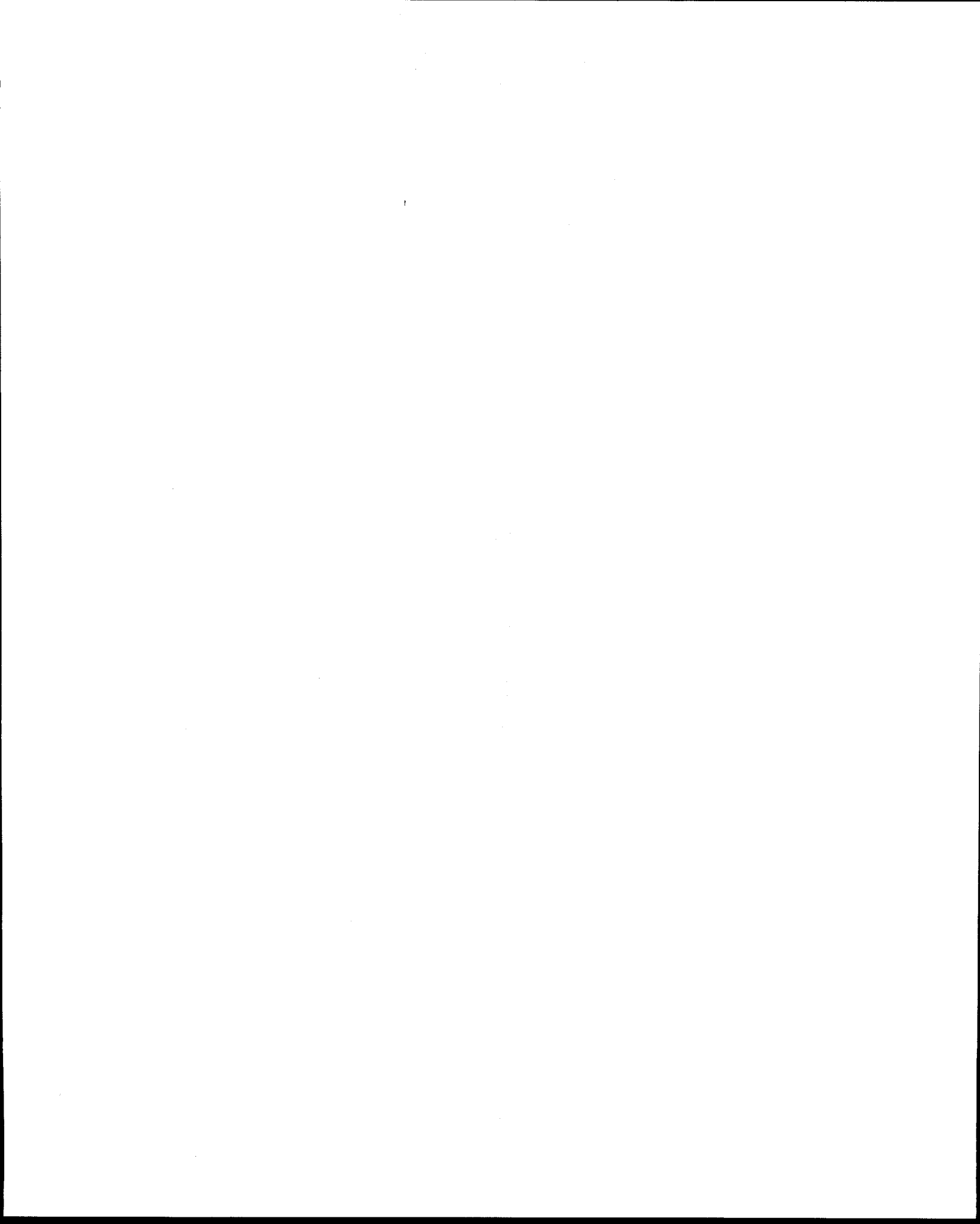
Commercial Applications:

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

DME has several commercial uses. In a storable blend with methanol, the mixture can be used as peaking fuel in IGCC electric power generating facilities. DME can also be used to increase the vapor pressure of a methanol blend. The resulting higher volatility is expected to provide beneficial "cold start" properties to methanol being used as a diesel engine fuel. Blends of methanol and DME can also be used as a chemical feed-

stock for the synthesis of chemicals or new, oxygenate fuel additives. Pure DME has been gaining acceptance as an environmentally friendly aerosol in personal products.

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



Industrial Applications Fact Sheets

Blast Furnace Granulated-Coal Injection System Demonstration Project

Participant:

Bethlehem Steel Corporation

Additional Team Members:

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

Location:

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

Technology:

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

Plant Capacity/Production:

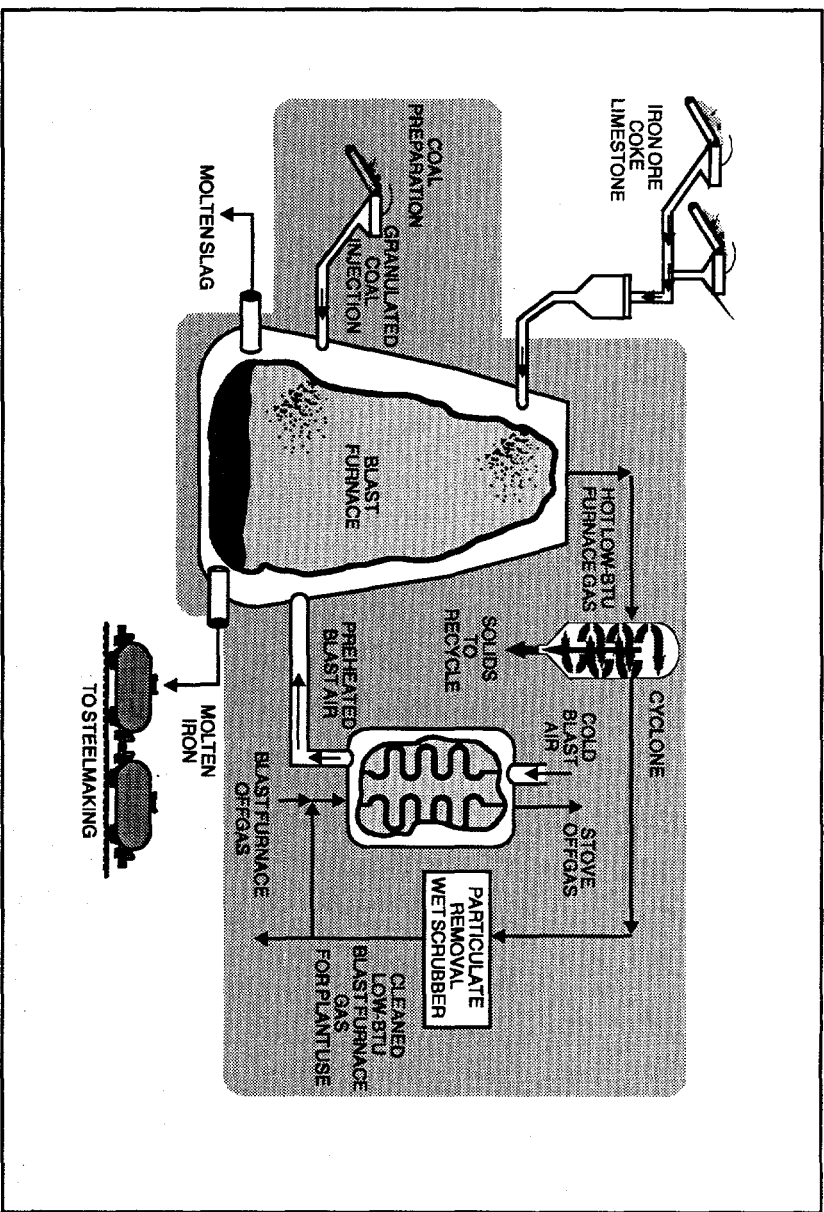
7,000 net tons/day of hot metal (each blast furnace)

Project Funding:

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

Project Objective:

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



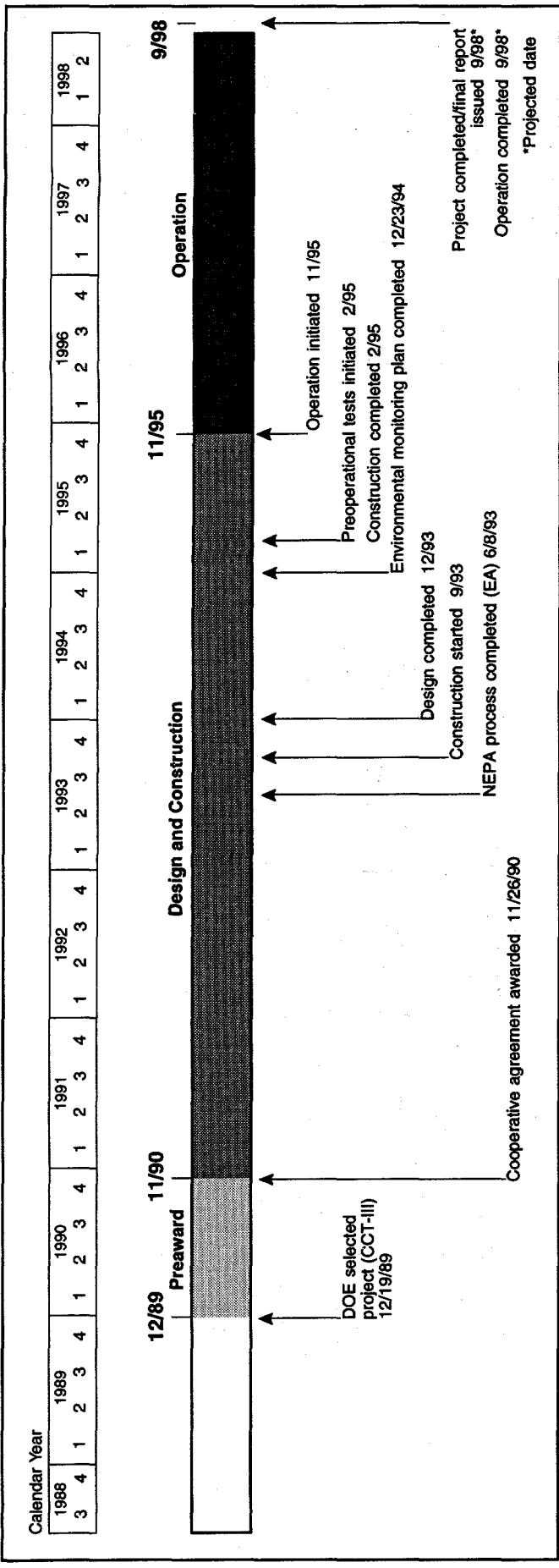
Technology/Project Description:

In the BFGCI process, both granulated and pulverized coal is injected into the blast furnace in place of natural gas (or oil) as a blast furnace fuel supplement. The coal along with heated air is blown into the barrel-shaped section in the lower part of the blast furnace through passages called tuyeres, which creates swept zones in the furnace called raceways. The size of a raceway is

important and is dependent upon many factors including temperature. Lowering of a raceway temperature, which can occur with gas injection, reduces blast furnace production rates. Coal, with a lower hydrogen content than either gas or oil, does not cause as severe a reduction in raceway temperatures. In addition to displacing injected natural gas, the coal injected through the

tuyeres displaces coke, the primary blast furnace fuel and reductant (reducing agent), on approximately a pound-for-pound basis. Because coke production results in significant emissions of NO_x , SO_2 , and air toxics and coal could replace up to 40% of the coke requirement, BFGCI technology has significant potential to reduce emissions and enhance blast furnace production.

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



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

Project Status/Accomplishments:

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

Bethlehem Steel has been injecting granular coal through 26 tuyeres of both the C and D furnaces at average injection rates of 170-225 lbs/net ton of hot metal.

The target rate was 180 lbs/net ton for each furnace during the start-up. Bethlehem Steel has achieved coal injection rates of 235 lbs/net ton of hot metal. Furnace operation has been improving as operators gain experience.

Bethlehem Steel has switched on the fly from a high-volatile Kentucky coal to a low-volatile Virginia coal. Burden and blast conditions are being fine-tuned on both furnaces as injection rate increases.

Commercial Applications:

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

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

Participant:

Centerior Energy Corporation

Additional Team Members:

Geneva Steel Company—site owner; constructor and operator of COREX® unit
 Air Products and Chemicals, Inc.—designer, engineer, constructor, and operator of air separation and combined-cycle units

Deutsche Voest-Alpine Industrieanlagenbau GmbH—COREX® developer/supplier; designer and engineer of COREX® unit

Location:

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

Technology:

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

Plant Capacity/Production:

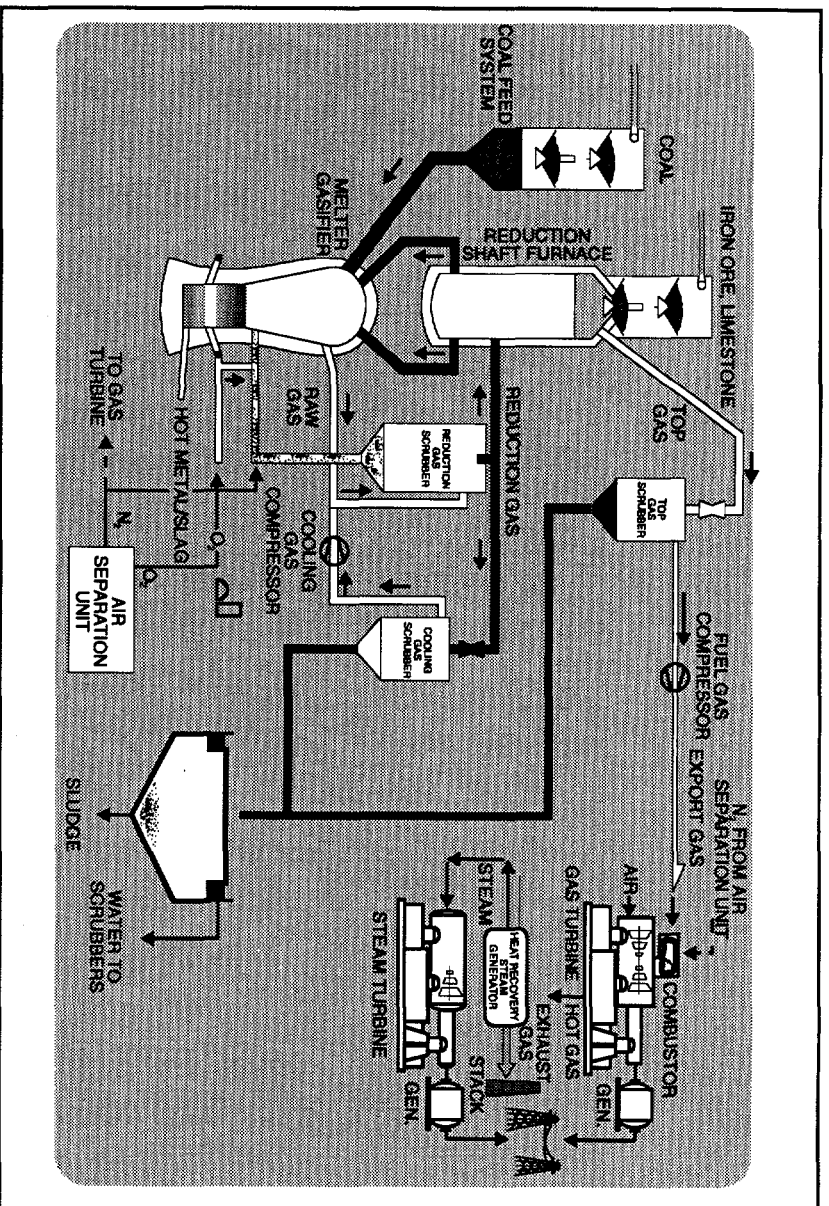
195 MWe (net) and 3,300 tons/day of hot metal (liquid iron)

Project Funding:

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

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

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



Project Objective:

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

Technology/Project Description:

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

iron. The gasification process generates the reducing gas for use in the reduction furnace as well as sufficient heat to melt the resulting iron in the melter-gasifier.

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

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

Calendar Year		1993		1994		1995		1996		1997		1998		1999		2000		2001		2002		2003			
3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4	1	2	3	4

5/93

Preaward



Note: Milestone schedule pending award of cooperative agreement

DOE selected project (CCT-V) 5/4/93

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

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

Project Status/Accomplishments:

The project is in negotiation. In April 1994, LTV Steel elected to withdraw from the proposed project. In

July 1994, Air Products and Chemicals, Centerior Energy, and Geneva Steel Company signed an agreement to develop and site the project at Geneva Steel's mill in Vineyard, UT (near Orem).

Commercial Applications:

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

The total emissions of NO_x from a future commercial plant are expected to be 0.012 lb/million Btu of coal, which is a reduction of more than 97% from the combination of a comparably sized blast furnace, associated coke-making facilities, and a comparably sized pulver-

ized coal power plant with flue gas desulfurization. Similarly, the total emissions of SO₂ from the commercial facility are expected to be 0.024 lb/million Btu, a reduction of more than 90%. The net electrical generating efficiency of the commercial facility is estimated to be 47% (a net effective heat rate of 7,262 Btu/kWh on an LHV basis). This compares to a net efficiency of 32% for comparably sized conventional facilities.

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

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 boiler manufacturing plant)

Technology:

Coal Tech's advanced, air-cooled, slagging combustor (industrial applications)

Plant Capacity/Production:

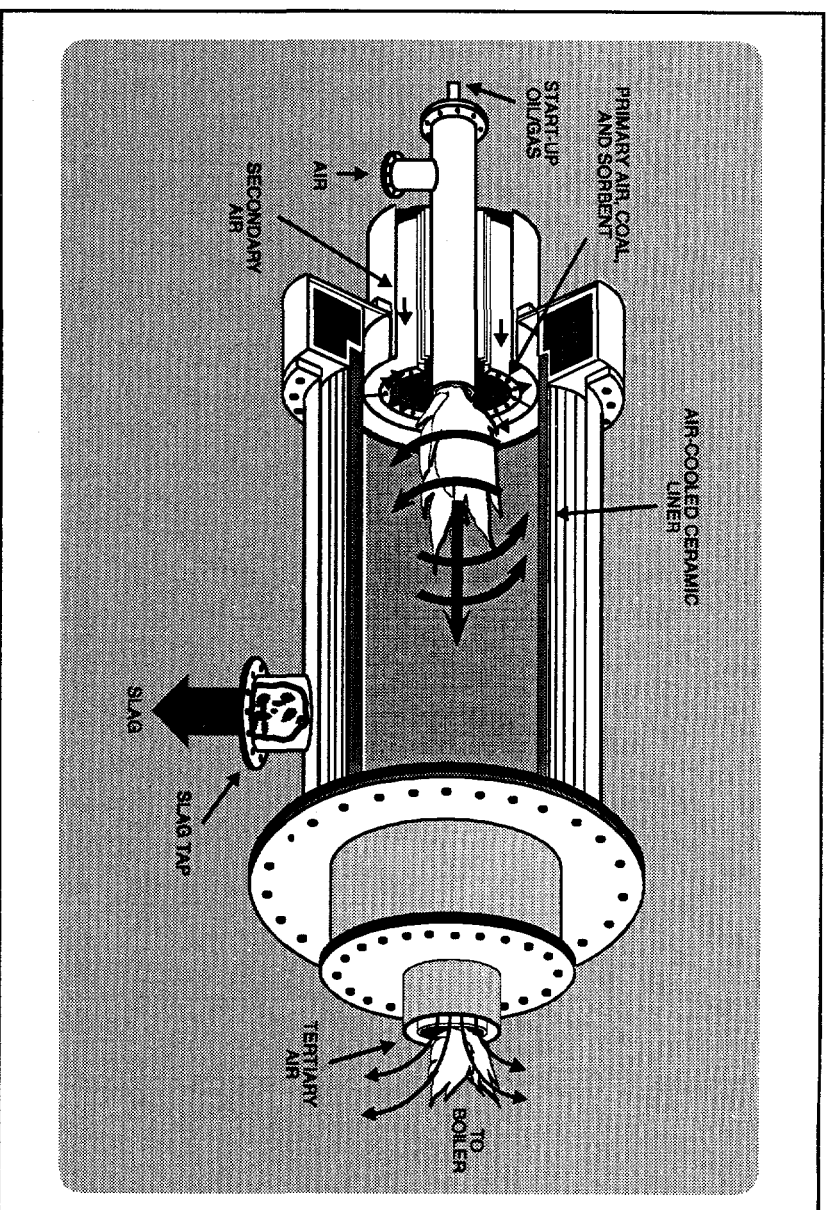
23 million Btu/hr

Project Funding:

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

Project Objective:

To demonstrate that an advanced cyclone combustor can be retrofitted to an industrial boiler and that it can simultaneously remove up to 90% of the SO₂ and 90–95% of the ash within the combustor and reduce NO_x by up to 100 ppm.



Technology/Project Description:

Coal Tech's horizontal cyclone combustor is internally lined with ceramic that is air-cooled. Pulverized coal, air, and sorbent are injected tangentially toward the wall through tubes in the annular region of the combustor to cause cyclonic action. In this manner, coal-particle combustion takes place in a swirling flame in a region favorable to particle retention in the combustor. Secondary air is used to adjust the overall combustor stoichiometry. The ceramic liner is cooled by the secondary air and maintained at a temperature high enough to keep the slag in a liquid, free-flowing state. The secondary air is preheated by the combustor walls to attain efficient combustion of the coal particles in the fuel-rich combustor. Fine coal pulverization allows combustion of most of the coal particles near the cyclone wall, with

the balance burned on or near the wall. This improves combustion in the fuel-rich chamber, as well as slag retention. The slag contains over 80% of the ash and sorbent fed to the combustor. For NO_x control, the combustor is operated fuel rich, with final combustion taking place in the boiler furnace to which the combustor is attached.

In Coal Tech's demonstration, an advanced, air-cooled, cyclone coal combustor was retrofitted to a 23-million-Btu/hr, oil-designed package boiler located at the Tampella Power Corporation boiler factory in Williamsport, PA. Air cooling in this combustor takes place in a very compact combustor which can be retrofitted to a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. NO_x reduction is achieved by staged combustion, and SO₂ is

captured by injection of limestone into the combustor. The cyclonic action inside the combustor forces the coal ash and sorbent to the walls where it can be collected as liquid slag. Under optimum operating conditions, the slag contains a significant fraction of vitrified coal sulfur. Downstream sorbent injection into the boiler provides additional sulfur removal capacity.

Project Results/Accomplishments:

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

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

Coal Tech reported the following test results:

- With fuel-rich operation of the combustor, a 75% reduction in boiler-outlet-stack NO_x was obtained, corresponding to 0.3 lb/million Btu (184 ppmv). An additional 5–10% NO_x reduction was obtained by the action of the wet particulate scrubber, resulting in atmospheric NO_x emissions as low as 0.26 lb/million Btu (160 ppmv).
- Over 80% SO_2 reduction measured at the boiler outlet stack was achieved using sorbent injection in the furnace at various calcium-to-sulfur molar ratios (Ca/S). A maximum SO_2 reduction of 58% was measured at the stack with limestone injection into the combustor at a Ca/S of 2. A maximum of 33% of

the coal sulfur was retained in the dry ash removed from the combustor and furnace hearths, and a high of 11% of the coal sulfur was retained in the slag rejected through the slag tap.

- Local stack particulate emission standards were met with the wet venturi particulate scrubber.
- Total slag/sorbent retention in the combustor, under efficient combustion operating conditions, averaged 72% and ranged from 55% to 90%. Under more fuel-lean conditions, the slag retention averaged 80%. In post-CCT-project tests on flyash vitrification in the combustor, modifications to the solids injection method and increases in the slag flow rate produced substantial increases in the slag retention rate.
- All slag removed from the combustor produced trace metal leachates well below the EPA drinking water standard.
- Different sections of the combustor had different materials requirements. Suitable materials for each section were identified. Also, the test effort showed that operational procedures were closely coupled with materials durability. By implementing certain procedures, such as changing the combustor wall temperature, it was possible to replenish the combustor refractory wall thickness with slag.
- Procedures for properly operating an air-cooled combustor were developed, and the entire operating database was incorporated into a computer-controlled system for automatic combustor operation.

Commercial Applications:

Coal Tech has concluded that, while the combustor is not yet fully ready for sale with commercial guarantees, it is ready to be further scaled up for commercial applications (100 million Btu/hr), such as combustion of waste solid fuels, limited sulfur control in coal-fired boilers, and conversion of ash to slag.

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

Project Schedule:

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

Final Reports:

Final Technical Report	8/91
DOE Assessment	5/93

Cement Kiln Flue Gas Recovery Scrubber

Project completed.

Participant:
Passamaquoddy Tribe

Additional Team Members:

Dragon Products Company—project manager and host
E.C. Jordan Company—engineer for overall scrubber system
HPD, Incorporated—designer and fabricator of tanks and heat exchanger
Ciambro Corporation—constructor

Location:

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

Technology:

Passamaquoddy Technology Recovery Scrubber™ (industrial applications)

Plant Capacity/Production:

1,450 tons/day of cement; 250,000 std ft³/min of kiln gas; and up to 274 tons/day of coal

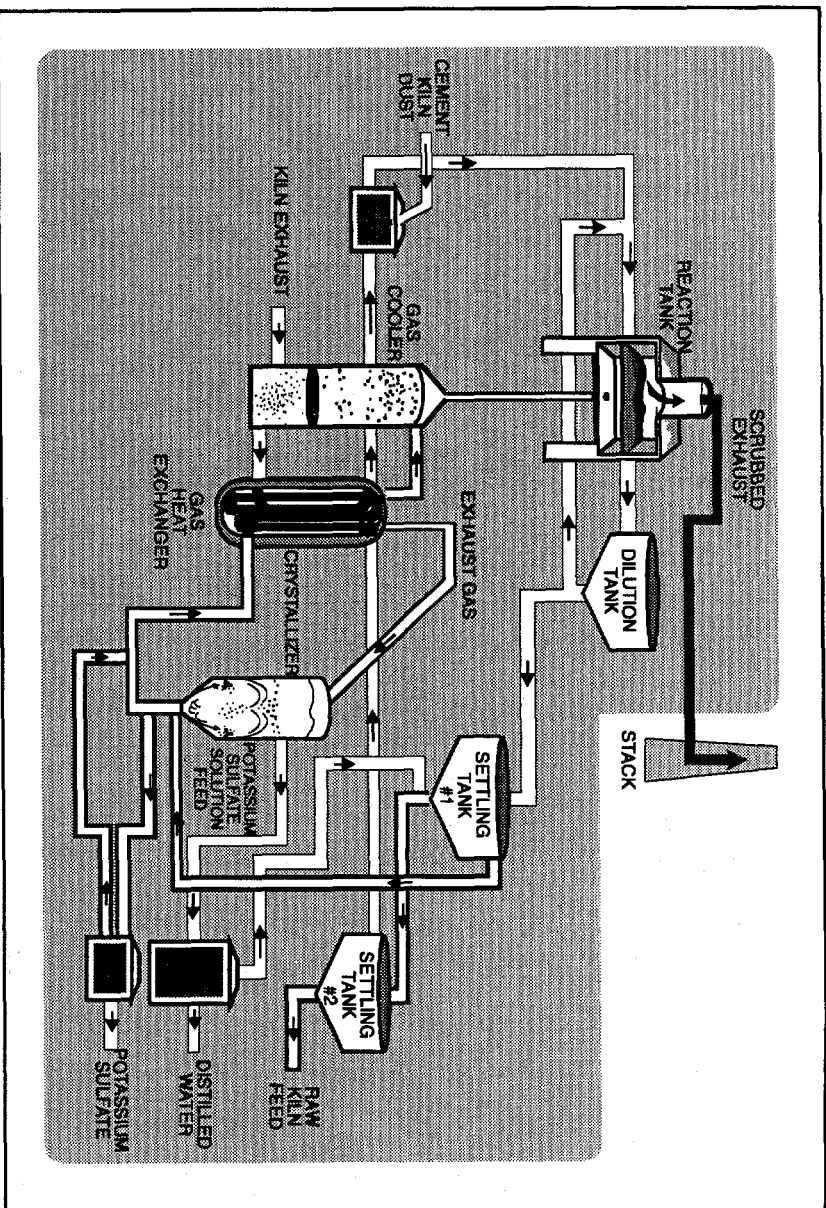
Project Funding:

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

Project Objective:

To retrofit and demonstrate a full-scale industrial scrubber and waste recovery system for a coal-burning wet process cement kiln using waste dust as the reagent to accomplish 90–95% SO₂ reduction using high-sulfur

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



eastern coals and to produce a commercial by-product, potassium-based fertilizer.

Technology/Project Description:

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

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

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

Project Results/Accomplishments:

The recovery scrubber began operations in August 1991 and has continued operations with several temporary shutdowns for normal kiln repairs and maintenance and a more lengthy shutdown from January to May 1992 due to poor economic conditions in the area. In a 5-month period from May to September 1992, the plant produced approximately 140,000 tons of cement while the scrubber removed 70 tons of SO₂ and treated 6,000 tons of kiln dust for return to the kiln as raw feed. Initial testing of the scrubbing system achieved the project objective of 90–95% SO₂ emission reduction, with a maximum reduction of 98%. The effect on NO_x emissions also was determined during the demonstration. NO_x emissions were reduced 5–15%. Operations have totaled 5,316 hours. Capital costs are approximately \$10 million for a 450,000-ton/yr plant, with a simple payback in about 3–4 years. Project operations continued through September 1993 when the scrubber became a permanent part of the Dragon Products facility.

Commercial Applications:

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

There are over 250 cement kiln installations in the United States and along the St. Lawrence River in Canada emitting approximately 230,000 tons/yr of SO₂. Based upon the characteristics of the technology, the applicable market would include approximately 75% of these installations. If the technology were installed in the applicable market facilities, SO₂ emissions could be reduced by approximately 150,000 tons/yr. Commercialization of the technology may be spurred on when EPA issues emissions limits on cement kilns under the CAAA of 1990. The technology may also have broader applications in paper production and municipal waste incineration in the United States and abroad.

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

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

Project Schedule:

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

Final Reports:

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

Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

Participant:
ThermoChem, Inc.

Additional Team Member:
Manufacturing and Technology Conversion International, Inc.—technology supplier

Location:
Silver Bay, Lake County, MN (Northshore Mining Company facility)

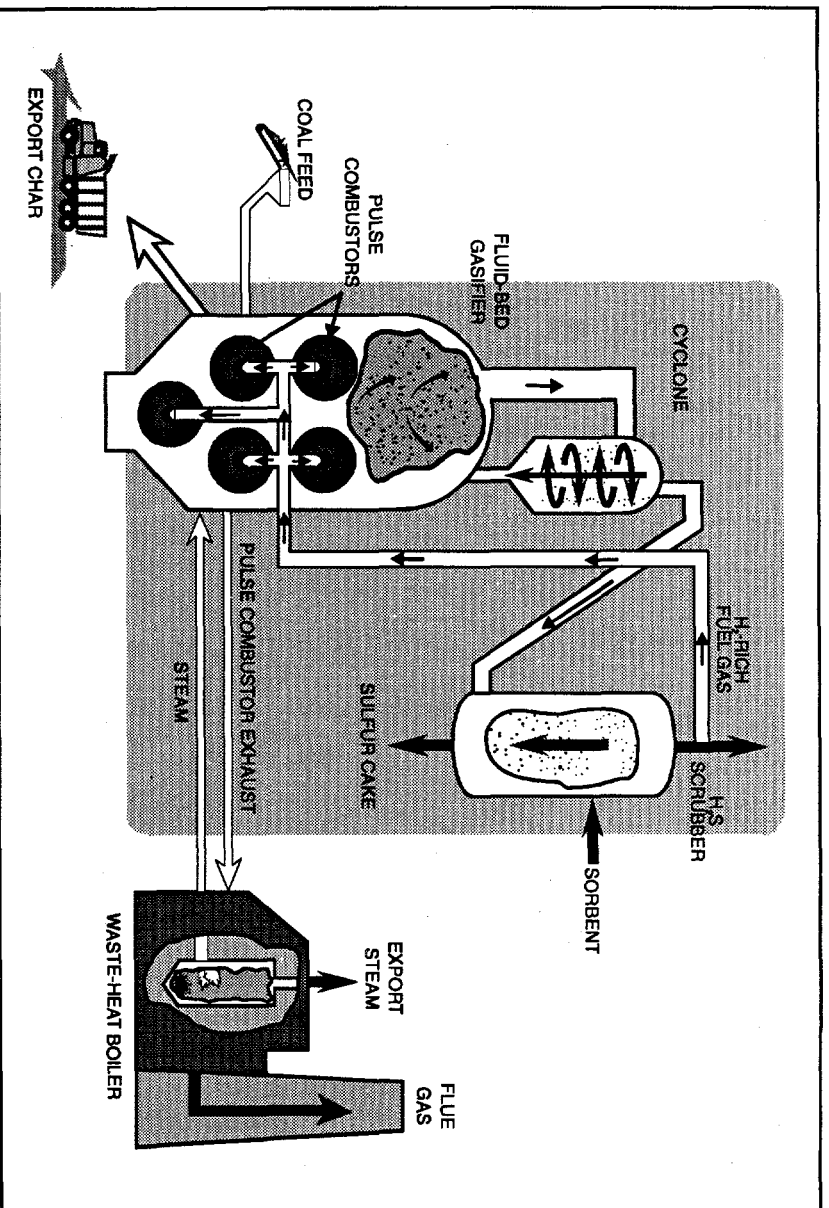
Technology:
Advanced combustion using Manufacturing and Technology Conversion International's (MTCI) pulse combustor/gasifier (industrial applications)

Plant Capacity/Production:
161 million Btu/hr of 325 Btu/std ft³ medium-Btu fuel gas plus 40,000 lb/hr of export steam

Project Funding:

Total project cost	\$37,333,474	100%
DOE	18,666,737	50
Participant	18,666,737	50

Project Objective:
To demonstrate the MTCI pulse combustor in an application for steam gasification of coal to produce a medium-Btu fuel gas from subbituminous coal.

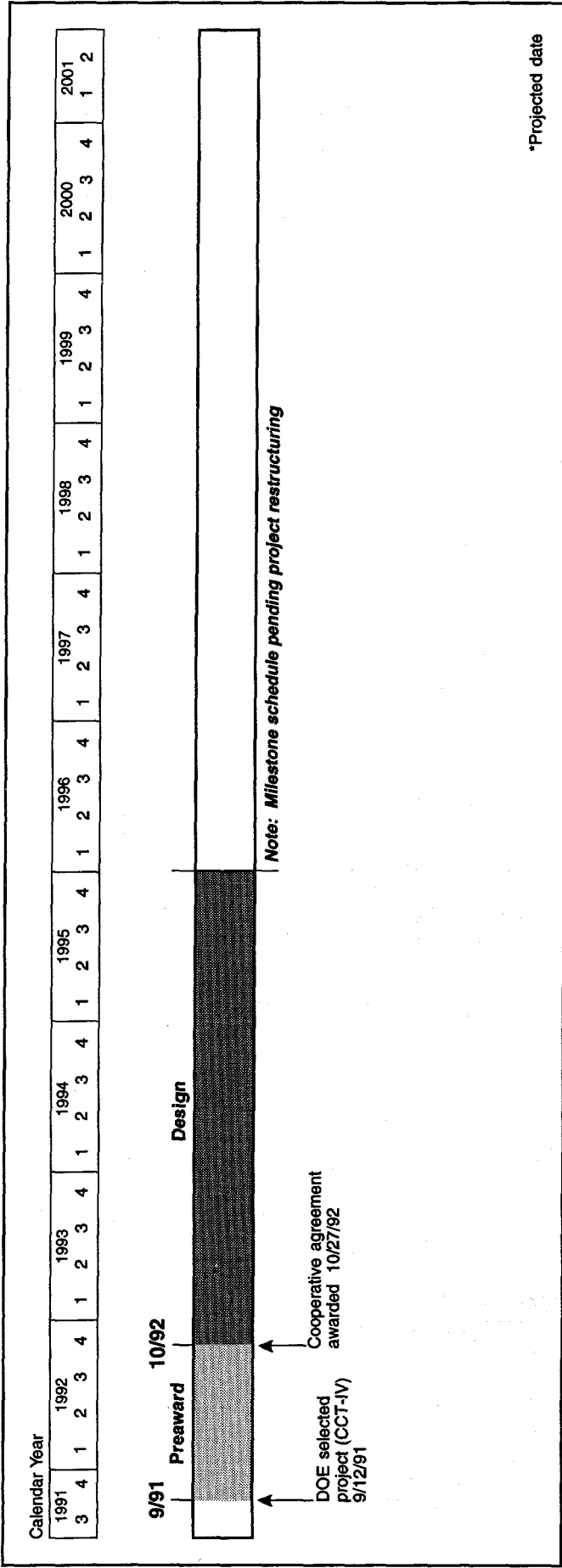


Technology/Project Description:

The MTCI fluidized-bed gasifier incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by MTCI's multiple resonance tube pulse combustor technology with the resonance tubes comprising the heat exchanger immersed in the fluidized-bed reactor. Heat transfer is 3–5 times greater than other indirectly heated gasifier concepts, allowing the heat transfer surface to be minimized.

The demonstration plant's overall efficiency is expected to be 72% or more. In major commercial applications, char combustion and heat recovery operations can be included to enhance overall plant efficiency.

SO₂ emissions are controlled by scrubbing the product gas using commercially available processes. A market for the by-product sulfur is being sought, and disposal methods are being evaluated.



Project Status/Accomplishments:

The cooperative agreement was awarded on October 27, 1992. Design verification tests at MTCI's Baltimore facility are continuing. The design tests include the construction and test firing of one full-size pulse combustor tube bundle. Fabrication of the design-verification-scale 252-tube pulse combustor has been completed. On October 26, 1994, ThermoChem, Inc., requested that DOE consider relocating the project to an alternative host site—Northshore Mining Company's facility in Silver Bay, MN. A planning conference on changing sites was held in December 1994. Project restructuring activities for the Silver Bay site are continuing.

Commercial Applications:

The MTCI fluidized-bed gasifier is expected to provide the exceptional environmental performance exhibited by coal gasification in general. SO₂ emissions are controlled by removing hydrogen sulfide from the product gas prior to combustion; removal efficiencies approach-

ing 99% are possible. Particulate emissions are also controlled in highly efficient scrubbers. Finally, the MTCI pulse combustion technology that provides the required gasifier heat is an inherently low-NO_x combustion process, thereby assuring that NO_x emissions are substantially below acceptable limits.

Because of its potential for reducing emissions while producing a clean-burning, hydrogen-rich fuel gas, the MTCI fluidized-bed gasifier is expected to have considerable commercial potential. Some of the early industrial applications of this technology are expected to be waste-to-energy or waste and coal cofired facilities for power and steam generation. One of the more promising non-coal applications is processing of kraft black liquor.

The processing of pulp results in the production of about 88 million tons of by-product black liquor. The current practice of using black liquor recovery boilers to produce steam and electricity is inefficient. Replacing these boilers with MTCI gasifiers would significantly improve the conversion efficiency. The estimated mar-

ket for MTCI gasifiers in this application alone is 28 units annually.

Another potential application for the technology is in industrial coal gasification because of its modularity and ability to produce a medium-Btu gas without requiring an oxygen plant.



Appendix A: Relevant Legislation

Public Law 99-190

CLEAN COAL TECHNOLOGY

Within 60 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 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 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. Rep. 99-450)

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 any 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 FY 1986 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 for the full \$400,000,000 program, and not only for the first \$100,000,000 available in fiscal year 1986.

Public Law 100-202

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 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 proposals: *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 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. Rep. 100-498)

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:

Fiscal year:	House	Senate	Conference
1988	\$50,000,000	\$350,000,000	\$50,000,000
1989	200,000,000	500,000,000	575,000,000
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 delete 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 includes 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 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 non-utility 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

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 provisos 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 Law 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 Act, 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 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. Rep. 100-862)

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 follow: *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 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

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

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. Rep. 101-264)

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 the 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 the 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

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. Rep. 101-315)

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 \$1,885,172,000. 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

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. Rep. 101-493)

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-PSO1-89 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 in the third round of procurements. These provisions were developed over a four year period based on the 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 this long-term experience, and the clear fact that the implementation of this type of technology will become even more important with the passage of clean air legislation, the managers reject proposals put forth by the Department of Energy to increase repayment rates substantially. Such proposals, while they might increase the recovery of government-provided funds over periods of up to twenty 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

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 (OCT-III) Demonstration Projects (solicitation number DE-PSO1-89 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. Rep. 101-971)

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 fulltime equivalent positions from fossil energy research and development may be used in the clean coal program in fiscal year 1991.

Public Law 102-154

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. Rep. 102-256)

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 changes 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 non-utility 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 project. 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 yet 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

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

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

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

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.



Appendix B: Selection and Negotiation History

July 1986

9 projects were selected under CCT-I (14 alternate projects selected if negotiations for original 9 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 (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.

4 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

16 projects were selected under CCT-II.

October 1988

DOE signed a cooperative agreement with CCT-I participant, Colorado-Ute Electric Association, Inc. (Nucla CFB Demonstration Project).

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 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 (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) on alternate list was selected.

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

13 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 (SOx-NOx-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, Rosebud SynCoal Partnership (formerly Western Energy Company; 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 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); one CCT-II participant, ABB Combustion Engineering, Inc. (Combustion Engineering IGCC Repowering Project); and two CCT-III participants, Bethlehem Steel Corporation (Blast Furnace Granulated-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).

March 1991

DOE signed cooperative agreements with three CCT-III participants: MK-Ferguson Company (Commercial Demonstration of the NOXSO₂/NO_x Removal Flue Gas Cleanup System); Public Service Company of Colorado (Integrated Dry NO_x/SO₂ Emissions Control System); and Tampa Electric Company (formerly Clean Power Cogeneration Limited Partnership; 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

9 projects were selected under CCT-IV. Coal Tech Corporation's CCT-I project, Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control, was completed; final reports have been issued.

April 1992

Tri-State Generation and Transmission Association, Inc., (formerly Colorado-Ute Electric Association, Inc.) completed its CCT-I project, Nucla CFB Demonstration Project; final reports have been issued.

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 (Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit) and 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 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 1-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 [LPMEOHTM] Process) and with four CCT-IV participants: Custom Coals International (Self-Scrubbing CoalTM: 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. (Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal).

November 1992

The Babcock & Wilcox Company's CCT-I project, LMB Demonstration Project Extension and Coolside Demonstration, was completed; final reports have been issued.

May 1993

5 projects were selected under CCT-V: Four Rivers Energy Partners, L.P. (Four Rivers Energy Modernization Project; previously, Calvert City Advanced Energy Project); Duke Energy Corp. (Camden Clean Energy Demonstration Project); Centerior Energy Corporation, on behalf of CPICOR Management Company (Clean Power from Integrated Coal/One Reduction [COREX[®]]); Arthur D. Little, Inc. (Clean Coal Combined-Cycle Project; previously Demonstration of Coal Diesel Technology at Easton Utilities); 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 CANSOLVTM System at the Alcoa Generating Corporation Warrick Power Plant.

December 1993

The Babcock & Wilcox Company's CCT-II project, SOx-NOx-Rox BoxTM Flue Gas Cleanup Demonstration Project, was completed; final reports have been issued.

The Babcock & Wilcox Company's CCT-II project, Demonstration of Coal Reburning for Cyclone Boiler NO_x Control, was completed; the final technical report has been issued.

Bechtel Corporation's CCT-III project, Confined Zone Dispersion Flue Gas Desulfurization Demonstration, was completed; final reports have been issued.

February 1994

The Passamaquoddy Tribe's CCT-III project, Cement Kiln Flue Gas Recovery Scrubber, was completed; final reports have been issued.

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, was completed; final reports have been issued.

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 SO₂/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 (LPMEOHTM) 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 Corp.; Clean Energy Demonstration Project).

The Babcock & Wilcox Company's CCT-II project, Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit, was completed (operational testing was completed April 1993; project was extended to complete the boiler water-wall corrosion examination during the fall 1994 boiler outage); final reports have been issued.

AirPol's CCT-III project, 10-MWe Demonstration of Gas Suspension Absorption, was completed; final reports have been issued.

LIFAC-North America's CCT-III project, LIFAC Sorbent Injection Desulfurization Project, was completed; final reports are in preparation.

ABB Environmental Systems' CCT-II project, SNOX™ Flue Gas Cleaning Demonstration Project, was completed; final reports are in preparation.

Energy and Environmental Research Corporation's CCT-I project, Enhancing the Use of Coal by Gas Reburning and Sorbent Injection, was completed; final reports for Hennepin and Edwards have been issued and the final report for Lakeside is in preparation.

Southern Company Services' CCT-II project, Demonstration of Innovative Applications of Technology for the CT-121 FGD Process, completed operational testing; final reports are in preparation.

January 1995

Energy and Environmental Research Corporation's CCT-III project, Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler, completed operational testing; final reports are in preparation.

March 1995

The Ohio Power Company's CCT-I project, Tidd PFBC Demonstration Project, completed operational testing; final reports have been issued.

TAMCO Power Partner's CCT-IV project, Toms Creek IGCC Demonstration Project, was not granted a further extension and the project was ended.

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

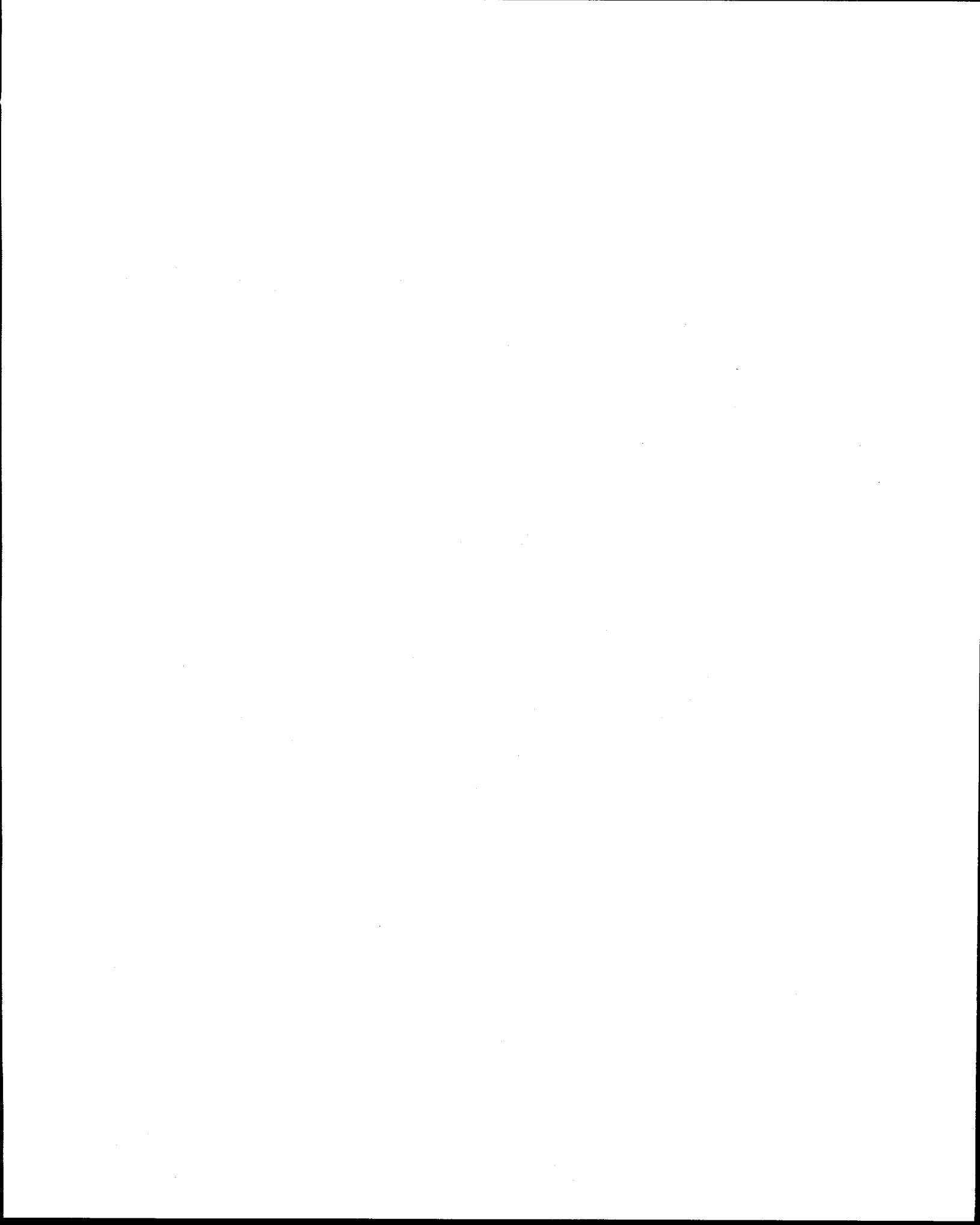
Pure Air on the Lake's CCT-II project, Advanced Flue Gas Desulfurization Project, completed operational testing; final reports are in preparation.

July 1995

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, completed operational testing; final reports are in preparation.

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.



Appendix C: CCT Program Publications

Numerous publications are available on the major activities of the Clean Coal Technology Demonstration Program. The most comprehensive report is the annual *Program Update*. Project status and accomplishments are reported in the quarterly newsletter, *Clean Coal Today*. Detailed information about each project selected for award of a cooperative agreement may be found in the project's *Comprehensive Report to Congress on the Clean Coal Technology Program*. When a project is completed, the technical, environmental, and economic performance as well as other key results are reported and disseminated by the participant and the CCT Program. Key CCT Program publications available at year-end are listed in this appendix. Project-specific reports and newsletter articles are listed by application category and, within each category, by project.

The CCT Program reports are available through the National Technical Information Service (NTIS), U.S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161.

To receive issues of the newsletter, *Clean Coal Today*, send name and address to U.S. Department of Energy, FE-22, Washington, DC 20858.

To receive program-related information via the Fossil Energy TechLine, a fax-on-demand system, call (202) 586-4300 from a tone phone and follow the voice instructions. For additional TechLine information, call (202) 586-6503. A computer bulletin board also provides updates; call (202) 586-6495 via modem.

Access to clean coal technology and other information can be made via the Internet. The Fossil Energy Home Page (<http://www.fe.doe.gov>) offers general information and a gateway to more detailed information about projects in the CCT Program.

Program Updates

Clean Coal Technology Demonstration Program: Project Fact Sheets. Report No. DOE/FE-0339. U.S. Department of Energy. July 1995.

Clean Coal Technology Demonstration Program: Program Update 1994 (As of December 31, 1994). Report No. DOE/FE-0330. U.S. Department of Energy. April 1995. (Available from NTIS as DE95012257.)

Clean Coal Technology Demonstration Program: Program Update 1993 (As of December 31, 1993). Report No. DOE/FE-0299P. U.S. Department of Energy. March 1994. (Available from NTIS as DE94012389.)

Clean Coal Technology Demonstration Program: Program Update 1992 (As of December 31, 1992). Report No. DOE/FE-0272. U.S. Department of Energy. February 1993. (Available from NTIS as DE93011403.)

Clean Coal Technology Demonstration Program: Program Update 1991 (As of December 31, 1991).

Report No. DOE/FE-0247P. U.S. Department of Energy. February 1992. (Available from NTIS as DE92008451.)

Clean Coal Technology Demonstration Program: Project Status (As of June 30, 1991). Report No. DOE/FE-0221P. U.S. Department of Energy. June 1991. (Available from NTIS as DE91018648.)

Clean Coal Technology Demonstration Program: Program Update 1990 (As of December 31, 1990). Report No. DOE/FE-0219P. U.S. Department of Energy. February 1991. (Available from NTIS as DE91008636.)

Clean Coal Technology Demonstration Program: Annual Report to Congress (As of December 31, 1989). Report No. DOE/FE-0195P. U.S. Department of Energy. March 1990. (Available from NTIS as DE90013603.)

Clean Coal Technology Demonstration Program: Annual Report to Congress (As of December 31, 1988). Report No. DOE/FE-0125. U.S. Department of Energy. February 1989. (Available from NTIS as DE89009636.)

Clean Coal Technology Demonstration Program: Annual Report to Congress (As of December 31, 1987). Report No. DOE/FE-0107. U.S. Department of Energy. 1988. (Available from NTIS as 88012672.)

Advanced Electric Power Generation/ Fluidized-Bed Combustion

The Appalachian Power Company—PFBC Utility Demonstration Project

Clean Coal II—PFBC Utility Demonstration Project: 1992 Annual Report. Report No. DOE/MC/26304-3497. The Appalachian Power Company. December 1992. (Available from NTIS as DE94000029.)

PFBC Utility Demonstration Project: 1991 Annual Report. Report No. DOE/MC/26304-3194. The Appalachian Power Company. November 1992. (Available from NTIS as DE93000233.)

Comprehensive Report to Congress on the Clean Coal Technology Program: PFBC Utility Demonstration Project. (The Appalachian Power Company and The Ohio Power Company). Report No. DOE/FE-0159. U.S. Department of Energy. February 1990. (Available from NTIS as DE90008094.)

DMEC-1 Limited Partnership—PCFB Project

Karhula Hot Gas Cleanup Test Results. Report No. DOE/MC/26042-94/C0383. Westinghouse Electric Corporation. June 1994. (Available from NTIS as DE95000652.)

PCFB Repowering Project 80 MW Plant Description. Report No. DOE/MC/27364-3998. Midwest Power Systems, Inc. May 1994. (Available from NTIS as DE95000073.)

Pressurized Circulating Fluidized Bed (PCFB) Repowering Project: Annual Report/January-December 1993. DMEC-1 Limited Partnership. April 1994. (Available from NTIS as DE94014920.)

Pressurized Circulating Fluidized Bed (PCFB) Repowering Project: Annual Report/August 1991-December 1992. Report No. DOE/MC/27364-3468. DMEC-1 Limited Partnership. April 1993. (Available from NTIS as DE94000007.)

“Des Moines, Iowa Greets New Clean Coal Plant.” *Clean Coal Today.* Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Pressurized Circulating Fluidized Bed Demonstration Project. (Dairyland Power Cooperative and Iowa Power Inc.). Report No. DOE/FE-0236P. U.S. Department of Energy. June 1991. (Available from NTIS as DE91018504.)

Four Rivers Energy Partners, L.P.—Four Rivers Energy Modernization Project

Comprehensive Report to Congress on the Clean Coal Technology Program: Four Rivers Energy Modernization Project. (Air Products and Chemicals, Inc.) Report No. DOE/FE-0295P. U.S. Department of Energy. June 1994. (Available from NTIS as DE94017563.)

The Ohio Power Company—Tidd PFBC Demonstration Project

Tidd PFBC Hot Gas Clean Up Program Final Report. Report No. DOE/MC/26042-5130. The Ohio Power Company. October 1995. (Available from NTIS as DE96000650.)

Tidd PFBC Demonstration Project Final Report, March 1, 1994–March 30, 1995. Report No. DOE/MC/24132-T8. The Ohio Power Company. August 1995. Available from NTIS as DE96004973.)

Tidd PFBC Demonstration Project—First Three Years of Operation. Report No. DOE/MC/24132-5037-vol.1 and -vol.2. The Ohio Power Company. April 1995. (Available from NTIS as DE96000559 for vol. 1 and DE96003781 for vol. 2.)

A Study of Hazardous Air Pollutants at the Tidd PFBC Demonstration Plant. Report No. DOE/MC/26042-4083. American Electric Power Service Corporation. October 1994. (Available from NTIS as DE95009729.)

Tidd PFBC Hot Gas Filter Operating Experience: July 1993–April 1994. Report No. DOE/MC/26042-94/C0382. The Ohio Power Company. June 1994. (Available from NTIS as DE95000653.)

“Tidd Concludes Four-Year PFBC Test Program.” *Clean Coal Today.* Report No. DOE/FE-0215P-17. Summer 1995.

- Tidd PFBC Demonstration Project Topical Report—First Eighteen Months of Operation.* Report No. DOE/MC/24132-3746. The Ohio Power Company. March 1994. (Available from NTIS as DE94004120.)
- "Tidd Sets Mark, with Continuous 45-Day Run." *Clean Coal Today.* Report No. DOE/FE-0215P-14. Summer 1994.
- "Tidd Extended Runs Verify Design Basis." *Clean Coal Today.* Report No. DOE/FE-0215P-7. Fall 1992.
- Tidd PFBC Demonstration Project: Public Final Design Report.* Report No. DOE/MC/24132-3195. The Ohio Power Company. October 1992. (Available from NTIS as DE93000234.)
- "Tidd Plant Sets New Technical Operations and Environmental Performance Records." *Clean Coal Today.* Report No. DOE/FE-0215P-6. Summer 1992.
- "Tidd Plant Resumes Operation." *Clean Coal Today.* Report No. DOE/FE-0215P-4. Winter 1991.
- "Tidd Receives 1991 Power Plant Award." *Clean Coal Today.* Report No. DOE/FE-0215P-1. Spring 1991.
- "TIDD Plant Produces Power: Operations Planned Early 1991." *Clean Coal Today.* Report No. DOE/FE-0215P. Winter 1990.
- Tidd: The Nation's First PFBC Combined-Cycle Demonstration.* Topical Report No. 1. U.S. Department of Energy and American Electric Power Service Corporation. March 1990.
- Comprehensive Report to Congress on the Clean Coal Technology Program: Tidd PFBC Demonstration Project.* (The Ohio Power Company). Report No. DOE/FE-0078. U.S. Department of Energy. February 1987. (Available from NTIS as DE87005803.)
- Tri-State Generation and Transmission Association, Inc.—Nucla CFB Demonstration Project**
- Clean Coal Reference Plants: Atmospheric CFB (Topical Report, Task 1).* Report No. DOE/MC/25177-3307. Gilbert/Commonwealth, Inc. June 1992. (Available from NTIS as DE93000251.)
- Demonstration Program Performance Test: Summary Reports.* Report No. DOE/MC/25137-3104. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE92001299.)
- Economic Evaluation Report: Topical Report.* Report No. DOE/MC/25137-3127. Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE93000212.)
- Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: 1990 Annual Report.* Report No. DOE/MC/25137-3089. Colorado-Ute Electric Association, Inc. February 1992. (Available from NTIS as DE92001275.)
- Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: Final Technical Report for the Period February 1987 through January 1991.* Report No. DOE/MC/25137-3046. Colorado-Ute Electric Association, Inc. October 1991. (Available from NTIS as DE92001122.)
- "Colorado Fluid Bed Project Yields Both Power and Data." *Clean Coal Today.* Report No. DOE/FE-0215P. Winter 1990.
- Nucla CFB Demonstration Project: Detailed Public Design Report.* Report No. DOE/MC/25137-2999. Colorado-Ute Electric Association, Inc. December 1990. (Available from NTIS as DE91002081.)
- Comprehensive Report to Congress on the Clean Coal Technology Program: Nucla CFB Demonstration Project.* (Colorado-Ute Electric Association, Inc.). Report No. DOE/FE-0106. U.S. Department of Energy. July 1988.
- York County Energy Partners, L.P.—ACFB Demonstration Project**
- Comprehensive Report to Congress on the Clean Coal Technology Program: Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project.* (The City of Tallahassee). Report No. DOE/FE-0208P. U.S. Department of Energy. October 1990. (Available from NTIS as DE91001076.)
- Advanced Electric Power Generation/Integrated Gasification Combined Cycle**
- IGCC—Integrated Gasification Combined Cycle.* Morgantown Energy Technology Center. June 1994.
- Integrated Gasification Combined-Cycle Research and Development Activities in the U.S.* Report No. DOE/METC/C-95/7193. Morgantown Energy Technology Center. 1994. (Available from NTIS as DE96002566.)

- “Advanced Power Generation Future Bright with Coal Gasification—Combined Cycle—Six Major Projects in DOE’s CCT Program.” *Clean Coal Today*. Report No. DOE/FE-0215P-5. Spring 1992.
- ABB Combustion Engineering, Inc.—Combustion Engineering IGCC Repowering Project**
- CE IGCC Repowering Project; Topical Report: Use of the Lockheed Kinetic Extruder for Coal Feeding.* Report No. DOE/MC/26308-3646. ABB Combustion Engineering, Inc. February 1994. (Available from NTIS as DE94004066.)
- CE IGCC Repowering Project; Topical Report: Controls and Instrumentation.* Report No. DOE/MC/26308-3648. ABB Combustion Engineering, Inc. December 1993. (Available from NTIS as DE94004068.)
- CE IGCC Repowering Project; Annual Report/January–December 1992.* Report No. DOE/MC/26308-3645. ABB Combustion Engineering, Inc. December 1993. (Available from NTIS as DE94004063.)
- CE IGCC Repowering Project; Topical Report: Sulfuric Acid Plant.* Report No. DOE/MC/26308-3640. ABB Combustion Engineering, Inc. December 1993. (Available from NTIS as DE94004061.)
- CE IGCC Repowering Project; Topical Report: Bins and Lockhoppers.* Report No. DOE/MC/26308-3647. ABB Combustion Engineering, Inc. October 1993. (Available from NTIS as DE94004067.)
- CE IGCC Repowering Project; Topical Report: Materials for Coal Gasification Environment.* Report No. DOE/MC/26308-3628. ABB Combustion Engineering, Inc. October 1993. (Available from NTIS as DE94000097.)
- CE IGCC Repowering Project; Topical Report: Hot Gas Clean Up System.* Report No. DOE/MC/26308-3545. ABB Combustion Engineering, Inc. September 1993. (Available from NTIS as DE94000070.)
- CE IGCC Repowering Project; Topical Report: Preliminary Hazard Analysis.* Report No. DOE/MC/26308-3637. ABB Combustion Engineering, Inc. June 1993. (Available from NTIS as DE94004056.)
- CE IGCC Repowering Project; Topical Report: Char Filters.* Report No. DOE/MC/26308-3639. ABB Combustion Engineering, Inc. May 1993. (Available from NTIS as DE94004060.)
- Comprehensive Report to Congress on the Clean Coal Technology Program: Combustion Engineering IGCC Repowering Project.* (ABB Combustion Engineering, Inc.). Report No. DOE/FE-0201P. U.S. Department of Energy. October 1990. (Available from NTIS as DE91001054.)
- Clean Energy Partners Limited Partnership—Clean Energy Demonstration Project**
- Comprehensive Report to Congress on the Clean Coal Technology Program: Clean Energy Demonstration Project.* (Clean Energy Partners, L.P.). Report No. DOE/FE-0319P. U.S. Department of Energy. October 1994.
- Sierra Pacific Power Company—Piñon Pine IGCC Power Project**
- Piñon Pine Power Project; Annual Report, January–December 1994.* Report No. DOE/MC/29309-4054. Sierra Pacific Power Company. January 1995. (Available from NTIS as DE95009707.)
- Tracy Power Station—Unit No. 4, Piñon Pine Power Project Public Design Report.* Report No. DOE/MC/29309-4056. Sierra Pacific Power Company. December 1994. (Available from NTIS as DE95009708.)
- Piñon Pine Power Project; Annual Report, August 1992–December 1993.* Report No. DOE/MC/29309-4063. Sierra Pacific Power Company. November 1994. (Available from NTIS as DE95009709.)
- Comprehensive Report to Congress on the Clean Coal Technology Program: Piñon Pine IGCC Power Project.* (Sierra Pacific Power Company). Report No. DOE/FE-0255P. U.S. Department of Energy. June 1992. (Available from NTIS as DE92015632.)
- Tampa Electric Company—Tampa Electric Integrated Gasification Combined-Cycle Project**
- Integrated Gasification Combined Cycle (IGCC) Demonstration Project, Polk Power Station—Unit No. 1; Annual Report, October 1993–September 1994.* Report No. DOE/MC/27363-5012. Tampa Electric Company. May 1995. (Available from NTIS as DE95009742.)

Tampa Electric Company Polk Power Station Unit No. 1; Annual Report, January-December 1993. Report No. DOE/MC/27363-3870. Tampa Electric Company. August 1994. (Available from NTIS as DE95000042.)

Tampa Electric Company, Polk Power Station Unit No. 1, Preliminary Public Design Report. Report No. DOE/MC/27363-3966. Tampa Electric Company. June 1994. (Available from NTIS as DE95000051.)

Tampa Electric Company Polk Power Station Unit No. 1; Annual Report, January-December 1992. Report No. DOE/MC/27363-3629. Tampa Electric Company. October 1993. (Available from NTIS as DE94000098.)

"Florida Project Demonstrates Key Technologies." *Clean Coal Today.* Report No. DOE/FE-0215P-9. Spring 1993.

Comprehensive Report to Congress on the Clean Coal Technology Program: Air-Blown Integrated Gasification Combined-Cycle Demonstration Project. (Clean Power Cogeneration Limited Partnership). Report No. DOE/FE-0216P. U.S. Department of Energy. January 1991. (Available from NTIS as DE91009355.)

Wabash River Coal Gasification Repowering Project Joint Venture—Wabash River Coal Gasification Repowering Project
Wabash River Coal Gasification Repowering Project: Topical Report, July 1992-December 1993. Report No. DOE/MC/29310-3840. Wabash River

Coal Gasification Repowering Project Joint Venture. January 1994. (Available from NTIS as DE94012272.)

"Largest U.S. Single Train IGCC Facility." *Clean Coal Today.* Report No. DOE/FE-0215P-12. Winter 1993/1994.

"Promise of Coal Gasification Power Draws 400 Representatives to Wabash River Site." *Clean Coal Today.* Report No. DOE/FE-0215P-10. Summer 1993.

Comprehensive Report to Congress on the Clean Coal Technology Program: Wabash River Coal Gasification Repowering Project. (Wabash River Coal Gasification Repowering Project Joint Venture). Report No. DOE/FE-0257P. U.S. Department of Energy. June 1992. (Available from NTIS as DE92015634.)

**Advanced Electric Power Generation/
Advanced Combustion/Heat Engines**
Alaska Industrial Development and Export Authority—Healy Clean Coal Project
"Healy Celebrates a Successful Groundbreaking."
Clean Coal Today. Report No. DOE/FE-0215P-17. Summer 1995.

Healy Clean Coal Project, Design Verification and Cold-Flow Modeling Test Report. Report No. DOE/PC/90544-T9. TRW Space and Technology Group. July 1993. (Available from NTIS as DE94002026.)

Healy Clean Coal Project: Healy FCM Testing at Niro Air Pollution Pilot Facility. Report No. DOE/PC/90544-T6. U.S. Department of Energy. October 1992. (Available from NTIS as DE93014937.)

Healy Clean Coal Project: Healy Coal Firing at TRW Cleveland Test Facility. Report No. DOE/PC/90544-T2. TRW Space and Technology Group, TRW, Inc. August 1991. (Available from NTIS as DE92007602.)

Comprehensive Report to Congress on the Clean Coal Technology Program: Healy Clean Coal Project. (Alaska Industrial Development and Export Authority). Report No. DOE/FE-0211P. U.S. Department of Energy. January 1991. (Available from NTIS as DE91008637.)

Arthur D. Little, Inc.—Coal Diesel Combined-Cycle Project

Comprehensive Report to Congress on the Clean Coal Technology Program: Coal Diesel Combined-Cycle Project. (Arthur D. Little, Inc.). Report No. DOE/FE-0296P. U.S. Department of Energy. May 1994. (Available from NTIS as DE94012984.)

Pennsylvania Electric Company—Warren Station Externally Fired Combined-Cycle Demonstration Project

PETC Review, Issue 9, Fall 1993. (Available from NTIS as DE94005180.)

Public Design Report: Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit. Report No. DOE/PC/9545-T4. The Babcock & Wilcox Company, August 1991. (Available from NTIS as DE92009768.)

Comprehensive Report to Congress on the Clean Coal Technology Program: Warren Station EFCC Demonstration Project. (Pennsylvania Electric Company.) Report No. DOE/FE-0316P. U.S. Department of Energy, June 1994. (Available from NTIS as DE94017288.)

"Coal Reburn Exceeds Expected NO_x Reductions." *Clean Coal Today*. Report No. DOE/FE-0215P-9. Spring 1993.

"B&W Low NO_x Cell Burners Fabricated." *Clean Coal Today*. Report No. DOE/FE-0215P-1. Spring 1991.

Environmental Control Devices/NO_x Control Technologies

"NO_x Reduction by SCR/SNCR." *PETC Review: A Global Role for Energy*. Issue 10, Summer 1994. (Available from NTIS as DE95000411.)

Public Design Report: Coal Reburning for Cyclone Boiler NO_x Control. The Babcock & Wilcox Company, August 1991.

"Clean Coal Program Marks First Commercial Success with Sale of Low NO_x Technology." *Clean Coal Today*. Report No. DOE/FE-0215P-10. Summer 1993.

Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Coal Reburning for Cyclone Boiler NO_x Control. (The Babcock & Wilcox Company). Report No. DOE/FE-0157. U.S. Department of Energy, February 1990. (Available from NTIS as DE90008111.)

The Babcock & Wilcox Company—Demonstration of Coal Reburning for Cyclone Boiler NO_x Control

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control: Final Project Report. Report No. DOE/PC/89659-T16. The Babcock & Wilcox Company, February 1994. (Available from NTIS as DE94013052, Appendix 1 as DE94013053, Appendix 2 as DE94013054.)

The Babcock & Wilcox Company—Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit
Final Report: Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit. Report No. DOE/PC/90545-2. The Babcock & Wilcox Company, December 1995.

"Two CCT Projects 'Get the Word Out'." *Clean Coal Today*. Report No. DOE/FE-0215P-9. Spring 1993.

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.)

"Reburning for NO_x Reduction—Demonstration of Coal Reburning for Cyclone Boiler NO_x Control."

"B&W Low-NO_x Cell Burner Tests under Way." *Clean Coal Today*. Report No. DOE/FE-0215P-6. Summer 1992.

Reduction of NO_x and SO₂ Using Gas Reburning, Sorbent Injection and Integrated Technologies. Topical Report No. 3, Revision 1. Report No. DOE/FE-94007444. U.S. Department of Energy and Energy and Environmental Research Corporation. September 1993. (Available from NTIS as DE94007444.)

"Reburning for NO_x Reduction—Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler." *PETC Review*, Issue 9, Fall 1993. (Available from NTIS as DE94005180.)

"EER's Gas Reburning—Low-NO_x Burner Technologies Reducing NO_x Emissions." *Clean Coal Today*. Report No. DOE/FE-0215P-8. Winter 1992.

"Gas Reburning Emerging as Cost-Effective Nitrogen Oxide Reduction Technique." *Clean Coal Today*. Report No. DOE/FE-0215P-5. Spring 1992.

"Gas Reburning Tests Begin at Illinois Power Plant—Early Tests Exceed Expectations." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

"Wall-Fired Boiler Low NO_x Overfire Air Tests Complete." *Clean Coal Today*. Report No. DOE/FE-0215P-1. Spring 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler. (Energy and Environmental Research Corporation). Report No. DOE/FE-0204P. U.S. Department of Energy. September 1990. (Available from NTIS as DE9100253.)

New York State Electric & Gas Corporation—Micronized Coal Reburning Demonstration for NO_x Control

"Reburning for NO_x Reduction—Micronized Coal Reburning for NO_x Control." *PETC Review*, Issue 9, Fall 1993. (Available from NTIS as DE94005180.)

Comprehensive Report to Congress on the Clean Coal Technology Program: Micronized Coal Reburning Demonstration for NO_x Control on a 175-MW Wall-Fired Unit. (Tennessee Valley Authority). Report No. DOE/FE-0256P. U.S. Department of Energy. June 1992. (Available from NTIS as DE92015633.)

Southern Company Services, Inc.—Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide Emissions from Coal-Fired Boilers [Advanced Digital Control/Optimization Phase]. Report No. DOE/PC/89651-T22. Southern Company Services, Inc. January 1995. (Available from NTIS as DE95017742.)

500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers; Phase 3B LNB AOFATests. Report No. DOE/PC/89651-T17. Woodward Clyde Consultants and Southern Company Services, Inc. December 1993. (Available from NTIS as DE95010619.)

500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers; Phase 3A, Low NO_x Burner Tests. Report No. DOE/PC/89651-T17. Woodward Clyde Consultants and Southern Company Services, Inc. March 1993. (Available from NTIS as DE95002388.)

500-MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers; Field Chemical Emissions Monitoring; Overfire Air and Overfire Air/Low NO_x Burner Operation; Final Report. Report No. DOE/PC/89651-T16. Southern Company Services, Inc. January 1993. (Available from NTIS as DE95006352.)

"Georgia Power's Plant Hammond Previews Clean Air Act's NO_x Challenges—Project Generating Data that will Help Utilities Face New Law's 'Sleeping Giant'." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler. (Southern Company Services, Inc.). Report No. DOE/FE-0146. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004459.)

Southern Company Services, Inc.—Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

"Gulf Power's SCR Test Facility in Operation." *Clean Coal Today*. Report No. DOE/FE-0215P-13. Spring 1994.

"SCR Tests Progress at Gulf's Plant Crist." *Clean Coal Today*. Report No. DOE/FE-0215P-10. Summer 1993.

"SCR Holds Promise for Effective NO_x Control—CCT Projects Address Higher Costs, Limited U.S. Experience." *Clean Coal Today*. Report No. DOE/FE-0215P-6. Summer 1992.

"Catalyst Suppliers Selected in Southern Company's SCR Project." *Clean Coal Today*. Report No. DOE/FE-0215P-2. Summer 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Selective Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxide (NO_x) Emissions from High-Sulfur-Coal-Fired Boilers. (Southern Company Services, Inc.). Report No. DOE/FE-0161P. U.S. Department of Energy. April 1990. (Available from NTIS as DE90010360.)

Southern Company Services, Inc.—180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers: Final Report and Key Project Findings. Report No. DOE/PC/89653-T14. Southern Company Services, Inc. February 1994. (Available from NTIS as DE94011174.)

Measurement of Chemical Emissions under the Influence of Low-NO_x Combustion Modifications. Report No. DOE/PC/89653-T12. Southern Company Services, Inc. October 1993. (Available from NTIS as DE94005038.)

ESP Performance Analysis during the 180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions from Coal-Fired Boilers. Report No. DOE/PC/89653-T13. Southern Company Services, Inc. September 1993. (Available from NTIS as DE94010218.)

Comprehensive Report to Congress on the Clean Coal Technology Program: 180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of Nitrogen Oxide (NO_x) Emissions for Coal-Fired Boilers. (Southern Company Services, Inc.). Report No. DOE/FE-0191P. U.S. Department of Energy. July 1990. (Available from NTIS as DE9001359.)

Environmental Control Devices/SO₂ Control Technologies

AirPol, Inc.—10-MWe Demonstration of Gas Suspension Absorption

Clean Coal Technology III: 10 MW Demonstration of Gas Suspension Absorption Final Project Performance and Economics Report. Report No. DOE/PC/90542-T9. AirPol, Inc. June 1995. (Available from NTIS as DE95016681.)

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

SO₂ Removal Using Gas Suspension Absorption Technology. Topical Report No. 4. U.S. Department of Energy and AirPol, Inc. April 1995.

10-MW 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.)

10 MW Demonstration of the Gas Suspension Absorption Final Project Performance and Economics Report. Report No. DOE/PC/90542-T9. AirPol, Inc. January 1995. (Available from NTIS as DE95016681.)

"AirPol Plant Runs Smoothly." *Clean Coal Today*. Report No. DOE/FE-0215P-8. Winter 1992.

- Comprehensive Report to Congress on the Clean Coal Technology Program: 10-MW Demonstration of Gas Suspension Absorption.* (AirPol, Inc.). Report No. DOE/FE-0198P. U.S. Department of Energy. July 1990. (Available from NTIS as 90016669.)
- Bechtel Corporation—Confined Zone Dispersion Flue Gas Desulfurization Demonstration**
- Confined Zone Dispersion Project: Final Technical Report.* Bechtel Corporation. June 1994.
- Confined Zone Dispersion Project: Public Design Report.* Bechtel Corporation. October 1993.
- Comprehensive Report to Congress on the Clean Coal Technology Program: Confined Zone Dispersion Flue Gas Desulfurization Demonstration.* (Bechtel Corporation). Report No. DOE/FE-0203P. U.S. Department of Energy. September 1990. (Available from NTIS as DE91002564.)
- LIFAC—North America—LIFAC Sorbent Injection Desulfurization Demonstration Project**
- "LIFAC Process Tests Now Underway." Clean Coal Today.* Report No. DOE/FE-0215P-8. Winter 1992.
- 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.)
- Pure Air on the Lake, L.P.—Advanced Flue Gas Desulfurization Demonstration Project**
- Characterizing Toxic Emissions from a Coal-Fired Power Plant Demonstrating the AFGD ICCT Project and a Plant Utilizing a Dry Scrubber/Baghouse System: Bailly Station Units 7 and 8 and AFGD ICCT Project. Final Report.* Report No. DOE/PC/93254-T1. Southern Research Institute. October 1994. (Available from NTIS as DE95005662.)
- "Continued Success with Landmark Pure Air Project." Clean Coal Today.* Report No. DOE/FE-0215P-14. Summer 1994.
- "Clean Coal Project Wins Outstanding Achievement Award." Clean Coal Today.* Report No. DOE/FE-0215P-8. Winter 1992.
- "Pure Air Project Helps Hurricane Relief Efforts." Clean Coal Today.* Report No. DOE/FE-0215P-8. Winter 1992.
- "Pure Air FGD Scrubber Begins Operation—Indiana Utility Leads Nation in Clean Air Act Compliance." Clean Coal Today.* Report No. DOE/FE-0215P-6. Summer 1992.
- "Pure Air Flue Gas Project Construction Well Advanced." Clean Coal Today.* Report No. DOE/FE-0215P-1. Spring 1991.
- Advanced Flue Gas Desulfurization Project: Public Design Report.* Pure on the Lake, L.P. March 1990.
- Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Flue Gas Desulfurization (AFGD) Demonstration Project.*
- (Pure Air on the Lake, L.P.). Report No. DOE/FE-0150. U.S. Department of Energy. November 1989. (Available from NTIS as DE90004460.)
- Southern Company Services, Inc.—Demonstration of Innovative Applications of Technology for the CT-121 FGD Process**
- A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing and ESP while Demonstrating the ICCT CT-121 FGD Project. Final Report.* Report No. DOE/PC/93253-T1. Radian Corporation. June 1994. (Available from NTIS as DE94016053.)
- "CT-121 Advanced Scrubber Moves Ahead at Georgia Site." Clean Coal Today.* Report No. DOE/FE-0215P-10. Summer 1993.
- "Fiberglass Reinforced Plastic Highlights CT-121 'Second Generation' Wet Scrubber." Clean Coal Today.* Report No. DOE/FE-0215P-2. Summer 1991.
- 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 DE90008110.)

Environmental Control Devices/Combined SO₂/NO_x Control Technologies

"NO_x Reduction by SCR/SNCR." *PETC Review: A Global Role for Energy*. Issue 10. Summer 1994. (Available from NTIS as DE95000411.)

ABB Environmental Systems—SNOX™ Flue Gas Cleaning Demonstration Project

A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing the SNOX Innovative Clean Coal Technology Demonstration. Volume 1, Sampling/Results/Special Topics: Final Report. Report No. DOE/PC/93251-T3-Vol. 1. Battelle Columbus Operations. July 1994. (Available from NTIS as DE94018832.)

A Study of Toxic Emissions from a Coal-Fired Power Plant Utilizing the SNOX Innovative Clean Coal Technology Demonstration. Volume 2, Appendices: Final Report. Report No. DOE/PC/93251-T3-Vol. 2. Battelle Columbus Operations. July 1994. (Available from NTIS as DE94018833.)

A Study of Toxic Emissions from a Coal-Fired Power Plant: Niles Station Boiler No. 2. Volume 2, Appendices: Final Report. Report No. DOE/PC/93251-T1-Vol. 2. Battelle Columbus Operations. July 1994. (Available from NTIS as DE94016051.)

"Two CCT Projects 'Get the Word Out'." *Clean Coal Today*. Report No. DOE/FE-0215P-9. Spring 1993.

"SNOX Demonstration on Line." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

"WSA-SNOX Offers Multiple Pollutant Capture, Efficiency, Salable Byproducts." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: WSA-SNOX Flue Gas Cleaning Demonstration Project. (ABB Combustion Engineering, Inc.). Report No. DOE/FE-0151. U.S. Department of Energy. November 1989. (Available from NTIS as DE000446.)

The Babcock & Wilcox Company—LIMB Demonstration Project Extension and Coolside Demonstration

T.R. Goots, M.J. DePetro, and P.S. Nolan. *LIMB Demonstration Project Extension and Coolside Demonstration: Final Report*. Report No. DOE/PC/79798-T27. The Babcock & Wilcox Company. November 1992. (Available from NTIS as DE93005979.)

D.C. McCoy et al. *The Edgewater Coolside Process Demonstration: A Topical Report*. Report No. DOE/PC/79798-T26. CONSOL, Inc. February 1992. (Available from NTIS as DE93001722.)

"B&W's LIMB Operating; Coolside Tests Complete." *Clean Coal Today*. Report No. DOE/FE-0215P. Winter 1990.

Coolside and LIMB: Sorbent Injection Demonstrations Nearing Completion. Topical Report No. 2. U.S. Department of Energy and The Babcock & Wilcox Company. September 1990.

Public Design Report. Report No. DOE/PC/79798-T2. The Babcock & Wilcox Company. December 1988. (LIMB/Coolside.) (Available from NTIS as DE92016131.)

Comprehensive Report to Congress on the Clean Coal Technology Program: LIMB Demonstration Project Extension. (The Babcock & Wilcox Company). Report No. DOE/FE-0085. U.S. Department of Energy. April 1987. (Available from NTIS as DE87009793.)

The Babcock & Wilcox Company—SOx-NOx-Rox Box™ Flue Gas Cleanup Demonstration Project

SOX-NOX-Rox Box™ Flue Gas Clean-up Demonstration Final Report. Report No. DOE/PC/89656-T1. The Babcock & Wilcox Company. September 1995. (Available from NTIS as DE96003839.)

SNRR™ Air Toxics Monitoring. Final Report. Report No. OCDDO-94014782. Battelle Columbus Operations. January 1994. (Available from the Ohio Coal Development Office as TI94014782.)

"Progressive Technology Exceeds Expectations." *Clean Coal Today*. Report No. DOE/FE-0215P-10. Summer 1993.

5 MWe SNRR™ Demonstration Facility: Detailed Design Report. The Babcock & Wilcox Company. November 1992.

"Success is in the Ceramic Bag—B&W's SOx-NOx-Rox Box Starts Up." *Clean Coal Today*. Report No. DOE/FE-0215P-5. Spring 1992.

- Comprehensive Report to Congress on the Clean Coal Technology Program: SOX-NOX-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.)
- Energy and Environmental Research Corporation—Enhancing the Use of Coals by Gas Reburning and Sorbent Injection**
- “Site Tours: Arapahoe Station and Cherokee Station.” *Clean Coal Today*. Report No. DOE/FE-0215P-18. Fall 1995.
- “EER Completes Three Demonstration Tests.” *Clean Coal Today*. Report No. DOE/FE-0215P-17. Summer 1995.
- Enhancing the Use of Coals by Gas Reburning—Sorbent Injection; Long Term Testing Period, September 1, 1991–January 15, 1993.* Report No. DOE/PC/79796-T40. Energy and Environmental Research Corporation. February 1995. (Available from NTIS as DE95011481.)
- Enhancing the Use of Coals by Gas Reburning and Sorbent Injection; Volume 2: Gas Reburning—Sorbent Injection at Hennepin Unit 1, Illinois Power Company.* Report No. DOE/PC/79796-T38-Vol. 2. Energy and Environmental Research Corporation. October 1994. (Available from NTIS as DE95009448.)
- Enhancing the Use of Coals by Gas Reburning and Sorbent Injection; Volume 3: Gas Reburning—Sorbent Injection at Edwards Unit 1, Central Illinois Light Company.* Report No. DOE/PC/79796-T38-Vol. 3. Energy and Environmental Research Corporation. October 1994. (Available from NTIS as DE95009447.)
- Reduction of NO_x and SO₂ Using Gas Reburning, Sorbent Injection and Integrated Technologies.* Topical Report No. 3. U.S. Department of Energy and Environmental Research Corporation. September 1993.
- “Reburning for NO_x Reduction—Enhancing the Use of Coals by Gas Reburning and Sorbent Injection.” *PETC Review*. Issue 9. Fall 1993. (Available from NTIS as DE94005180.)
- Comprehensive Report to Congress on the Clean Coal Technology Program: Enhancing the Use of Coals by Gas Reburning and Sorbent Injection.* (Energy and Environmental Research Corporation). Report No. DOE/FE-0087. U.S. Department of Energy. May 1987. (Available from NTIS as DE87010815.)
- New York State Electric & Gas Corporation—Milliken Clean Coal Technology Demonstration Project**
- “Milliken Project in Final Construction Stage.” *Clean Coal Today*. Report No. DOE/FE-0215P-14. Summer 1994.
- Comprehensive Report to Congress on the Clean Coal Technology Program: Milliken Clean Coal Technology Demonstration Project.* (New York State Electric & Gas Corporation). Report No. DOE/FE-0265P. U.S. Department of Energy. September 1992. (Available from NTIS as DE93001756.)
- NOXSO Corporation—Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System**
- Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System.* Report No. DOE/EA-1080. Pittsburgh Energy Technology Center. June 1995. (Available from NTIS as DE96000179.)
- Comprehensive Report to Congress on the Clean Coal Technology Program: Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System.* (MK-Ferguson Company). Report No. DOE/FE-0213P. U.S. Department of Energy. January 1991. (Available from NTIS as DE91008638.)
- Public Service Company of Colorado—Integrated Dry NO_x/SO₂ Emissions Control System**
- “Site Tours: Arapahoe Station and Cherokee Station.” *Clean Coal Today*. Report No. DOE/FE-0215P-18. Fall 1995.
- Integrated Dry NO_x/SO₂ Emissions Control System Calcium-Based Dry Sorbent Injection; Test Report, April 30–November 2, 1993.* Report No. DOE/PC/90550-T14. Fossil Energy Research Corporation and

Public Service Company of Colorado. December 1994. (Available from NTIS as DE95007932.)

"Second Colorado Project Also Operating." *Clean Coal Today*. Report No. DOE/FE-0215P-8. Winter 1992.

Comprehensive Report to Congress on the Clean Coal Technology Program: Integrated Dry NO_x/SO₂ Emission Control System. (Public Service Company of Colorado). Report No. DOE/FE-0212P. U.S. Department of Energy. January 1991. (Available from NTIS as DE91008624.)

Coal Processing for Clean Fuels/Coal Preparation Technologies

ABB Combustion Engineering, Inc., and CQ Inc.—Development of the Coal Quality Expert

"Clean Coal Project will Develop Expert Computer Software Program." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Development of the Coal Quality Expert. (ABB Combustion Engineering, Inc., and CQ Inc.). Report No. DOE/FE-0174P. U.S. Department of Energy. May 1990. (Available from NTIS as DE9001038.)

Custom Coals International—Self-Scrubbing Coal™: An Integrated Approach to Clean Air

"Custom Coals Nears Completion." *Clean Coal Today*. Report No. DOE/FE-0215P-17. Summer 1995.

Comprehensive Report to Congress on the Clean Coal Technology Program: Self-Scrubbing Coal™: An Integrated Approach to Clean Air. (Custom Coals International). Report No. DOE/FE-0266P. U.S. Department of Energy. October 1992. (Available from NTIS as DE93001270.)

Rosebud SynCoal Partnership—Advanced Coal Conversion Process Demonstration

Advanced Coal Conversion Process Demonstration; Progress Report, January 1, 1992–December 31, 1992. Report No. DOE/PC/89664-T11. Power Environmental Services, Inc. December 1993. (Available from NTIS as DE95017741.)

"SynCoal™ Burn Tests Spawn Commercial Studies." *Clean Coal Today*. Report No. DOE/FE-0215P-12. Winter 1993/1994.

"Montana Plant to Open New Markets for Plentiful Low-Rank Coals." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Coal Conversion Process Demonstration. (Western Energy Company). Report No. DOE/FE-0192P. U.S. Department of Energy. July 1990. (Available from NTIS as DE90013559.)

Coal Processing for Clean Fuels/Mild Gasification

ENCOAL Corporation—ENCOAL Mild Coal Gasification Project

The ENCOAL Project: Initial Commercial Shipment and Utilization of Both Solid and Liquid Products; Topical Report. Report No. DOE/MC/27339-4088. ENCOAL Corporation. March 1995. (Available from NTIS as DE95009735.)

ENCOAL Mild Coal Gasification Demonstration Project; Annual Report, October 1993–September 1994. Report No. DOE/MC/27339-4064. ENCOAL Corporation. March 1995. (Available from NTIS as DE95009710.)

ENCOAL Mild Coal Gasification Demonstration Project Public Design and Construction Report. Report No. DOE/MC/27339-4065. ENCOAL Corporation. December 1994. (Available from NTIS as DE95009711.)

"ENCOAL Plant Enters Production Mode." *Clean Coal Today*. Report No. DOE/FE-0215P-14. Summer 1994.

"ENCOAL Project Resumes Operation." *Clean Coal Today*. Report No. DOE/FE-0215P-12. Winter 1993/1994.

ENCOAL Mild Coal Gasification Demonstration Project; Annual Report. Report No. DOE/MC/27339-3842. ENCOAL Corporation. October 1993. (Available from NTIS as DE94012274.)

"ENCOAL Plant Starting Up." *Clean Coal Today*. Report No. DOE/FE-0215P-6. Summer 1992.

ENCOAL Mild Coal Gasification Project: Annual Report (October 1990-September 1991). Report No. DOE/MC/27339-3087. ENCOAL Corporation. February 1992. (Available from NTIS as DE9200-1273.)

"ENCOAL Project Continues Rapid Pace—Spring 1992 Plant Startup Expected." *Clean Coal Today*. Report No. DOE/FE-0215P-4. Winter 1991.

"ENCOAL Mild Gasification Project Breaks Ground in Many Ways." *Clean Coal Today*. Report No. DOE/FE-0215P-1. Spring 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: ENCOAL Mild Coal Gasification Project. (ENCOAL Corporation). Report No. DOE/FE-0194P. U.S. Department of Energy. June 1990. (Available from NTIS as 91004624.)

Coal Processing for Clean Fuels/Indirect Liquefaction

Air Products Liquid Phase Conversion Company, L.P.—Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process

"Site Chosen for Coal to Methanol Energy Project." *Clean Coal Today*. Report No. DOE/FE-0215P-12. Winter 1993/1994.

Comprehensive Report to Congress on the Clean Coal Technology Program: Commercial-Scale Demonstration of the Liquid Phase Methanol (LPMEOH™) Process.

(Air Products and Chemicals, Inc.). Report No. DOE/FE-0243P. U.S. Department of Energy. August 1992.

Industrial Applications

Bethlehem Steel Corporation—Blast Furnace Granulated-Coal Injection System Demonstration Project

Blast Furnace Granular Coal Injection Project; Annual Report, January-December 1994. Report No. DOE/MC/27362-4089. Bethlehem Steel Corporation. July 1995. (Available from NTIS as DE95009736.)

Blast Furnace Granular Coal Injection System Demonstration Project Public Design Report. Report No. DOE/MC/27362-4073. Bethlehem Steel Corporation. March 1995. (Available from NTIS as DE95009719.)

Blast Furnace Granular Coal Injection Project; Annual Report, January-December 1993. Report No. DOE/MC/27362-3860. Bethlehem Steel Corporation. June 1994. (Available from NTIS as DE94012286.)

"Blast Furnace Coal Facility in Construction." *Clean Coal Today*. Report No. DOE/FE-0215P-13. Spring 1994.

Comprehensive Report to Congress on the Clean Coal Technology Program: Blast Furnace Granulated Coal Injection System Demonstration Project. (Bethlehem Steel Corporation). Report No. DOE/

FE-0206P. U.S. Department of Energy. October 1990. (Available from NTIS as DE91001069.)

Centerior Energy Corporation—Clean Power from Integrated Coal/Ore Reduction (COREX®)

This CCT-V project is in negotiations.

Coal Tech Corporation—Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

The Coal Tech Advanced Cyclone Combustor Demonstration Project—A DOE Assessment. Report No. DOE/PC/79799-T1. U.S. Department of Energy. May 1993.

B. Zauderer and E.S. Fleming. *The Demonstration of an Advanced Cyclone Coal Combustor, with Internal Sulfur, Nitrogen, and Ash Control for the Conversion of a 23 MMBtu/Hour Oil Fired Boiler to Pulverized Coal; Volume 1: Final Technical Report; Volume 2: Appendixes I, II, III, IV, and V; Volume 3: Appendix VI*. Coal Tech Corporation. August 1991. (Available from NTIS as DE92002587 and DE92002588.)

"Coal Tech Completes Combustor Operations." *Clean Coal Today*. Report No. DOE/FE-0215P. Winter 1990.

Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Cyclone Combustor with Integral 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.)

Passamaquoddy Tribe—Cement Kiln Flue Gas Recovery Scrubber

Passamaquoddy Technology Recovery Scrubber™. Final Report. Volumes 1 and 2. Passamaquoddy Tribe. February 1994. (Volume 1 available from NNTS as DE94011175, Volume 2 as DE94011176.)

Passamaquoddy Technology Recovery Scrubber™. Public Design Report. Report No. DOE/PC/89657-T2. Passamaquoddy Tribe. October 1993. (Available from NNTS as DE94008316.)

“Success Continues at Cement Kiln Project.” *Clean Coal Today.* Report No. DOE/FE-0215P-7. Fall 1992.

Passamaquoddy Technology Recovery Scrubber™. Topical Report. Report No. DOE/PC/89657-T1. Passamaquoddy Tribe. March 1992. (Available from NNTS as DE92019868.)

“Passamaquoddy Cement Kiln Project Begins Operations.” *Clean Coal Today.* Report No. DOE/FE-0215P-1. Spring 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Cement Kiln Flue Gas Recovery Scrubber. (Passamaquoddy Tribe). Report No. DOE/FE-0152. U.S. Department of Energy. November 1989. (Available from NNTS as DE90004462.)

ThermoChem, Inc.—Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

Comprehensive Report to Congress on the Clean Coal Technology Program: Demonstration of Pulse

Combustion in an Application for Steam Gasification. (ThermoChem, Inc.). Report No. DOE/FE-0267P. U.S. Department of Energy. October 1992. (Available from NNTS as DE93000959.)

Reports on Withdrawn and Terminated Projects

Comprehensive Report to Congress on the Clean Coal Technology Program: Toms Creek IGCC Demonstration Project. (TAMCO Power Partners). Report No. DOE/FE-0264P. U.S. Department of Energy. September 1992. (Available from NNTS as DE93000960.)

“Bethlehem Steel’s Innovative Cleanup System Nears Completion at Sparrow’s Point—Power Plants Aren’t the Only Facilities Benefiting from New Technologies Emerging from the Clean Coal Technology Program.” *Clean Coal Today.* Report No. DOE/FE-0215P-2. Summer 1991.

Comprehensive Report to Congress on the Clean Coal Technology Program: Low-NO_x/SO₂ Burner Retrofit for Utility Cyclone Boilers. (TransAlta Resources Investment Corporation). Report No. DOE/FE-0160P. U.S. Department of Energy. April 1990. (Available from NNTS as DE90010359.)

Comprehensive Report to Congress on the Clean Coal Technology Program: Innovative Coke Oven Gas Cleaning System for Retrofit Applications. (Bethlehem Steel Corporation). Report No. DOE/FE-0137. U.S. Department of Energy. August 1989. (Available from NNTS as DE90000952.)

Comprehensive Report to Congress on the Clean Coal Technology Program: Advanced Slagging Combustor Utility Demonstration Project. (TRW, Inc.). Report No. DOE/FE-0108. U.S. Department of Energy. October 1988. (Available from NNTS as DE89001276.)

Comprehensive Report to Congress: The Appalachian Project. (The M. W. Kellogg Company). Report No. DOE/FE-0095. U.S. Department of Energy. December 1987. (Available from NNTS as DE88004630.)

Comprehensive Report to Congress on the Clean Coal Technology Program: UCG/Clean Fuels Proof-of-Concept Project. (Energy International, Inc.). Report No. DOE/FE-0093. U.S. Department of Energy. November 1987. (Available from NNTS as DE88002571.)

Comprehensive Report to Congress on the Clean Coal Technology Program: Prototype Commercial Coal/Oil Co-Processing Plant. (Ohio Clean Fuels, Inc.). Report No. DOE/FE-0092. U.S. Department of Energy. October 1987. (Available from NNTS as DE88002370.)

Reports on CCT Solicitations

Informational Solicitations

Report to Congress: Expressions of Interest in Commercial Clean Coal Technology Projects in Foreign Countries. Report No. DOE/FE-0334. U.S. Department of Energy. June 1995. (Available from NNTS as DE95015939.)

Second Report to Congress on Emerging Clean Coal Technologies Capable of Retrofitting, Repowering, or Modernizing Existing Facilities. Report No. DOE/FE-0086. U.S. Department of Energy. May 1987. (Available from NTIS as DE87009348.)

Summary Report to Congress on Emerging Clean Coal Technologies Capable of Retrofitting, Repowering, or Modernizing Existing Facilities. Report No. DOE/FE-0082. U.S. Department of Energy. March 1987. (Available from NTIS as DE87006604.)

Supplemental Report to Congress on Emerging Clean Coal Technologies. Report No. DOE/MC/22121-1. U.S. Department of Energy. August 1985. (Available from NTIS as DE85018356.)

Report to Congress on Emerging Clean Coal Technologies. Report No. DOE/S-0034. U.S. Department of Energy. May 1985.

CCT-I Solicitation

Report to Congress on the Relationships between Projects Selected for the Clean Coal Technology Program and the Recommendations of the Joint Report of the Special Envoys on Acid Rain. Report No. DOE/FE-0072. U.S. Department of Energy. October 1986. (Available from NTIS as DE87000865.)

Comprehensive Report to Congress on Proposals Received in Response to the Clean Coal Technology Program Opportunity Notice. Report No. DOE/FE-0070. U.S. Department of Energy. August 1986. (Available from NTIS as DE87000051.)

CCT-II Solicitation

Comprehensive Report to Congress: Proposals Received in Response to the Innovative Clean Coal Technology Program Opportunity Notice. Report No. DOE/FE-0114. U.S. Department of Energy. October 1988. (Available from NTIS as DE89006384.)

Summary Proceedings: Public Meetings for Views and Comments on the Conduct of the Innovative Clean Coal Technologies Solicitation. Report No. DOE/FE-0094. U.S. Department of Energy. November 1987. (Available from NTIS as DE880032238.)

Background Information: Public Meetings for Views and Comments on the Conduct of the Innovative Clean Coal Technologies Solicitation. Report No. DOE/FE-0090. U.S. Department of Energy. July 1987. (Available from NTIS as DE87013416.)

CCT-III Solicitation

Comprehensive Report to Congress: Proposals Received in Response to the Clean Coal Technology III Program Opportunity Notice. Report No. DOE/FE-0163. U.S. Department of Energy. February 1990. (Available from NTIS as DE90006448.)

Summary Proceedings: Public Meetings for Views and Comments on the Conduct of the 1989 Clean Coal Technology Solicitation. Report No. DOE/FE-0140. U.S. Department of Energy. July 1989. (Available from NTIS as DE89016685.)

Background Information: Public Meetings for Views and Comments on the Conduct of the 1989 Clean Coal Technology Solicitation. Report No. DOE/FE-0112. U.S. Department of Energy. December 1988. (Available from NTIS as DE89005511.)

Summary Proceedings: Public Meetings on Increasing Western Participation in the 1989 Clean Coal Technology Solicitation. Report No. DOE/FE-0113. U.S. Department of Energy. December 1988. (Available from NTIS as DE89005512.)

CCT-IV Solicitation

"Nine New Clean Coal Technology Projects Selected in Fourth Round of Competition." Clean Coal Today. Report No. DOE/FE-0215P-4. Winter 1991.

Comprehensive Report to Congress: Proposals Received in Response to Clean Coal Technology IV Program Opportunity Notice. Report No. DOE/FE-0242P. U.S. Department of Energy. December 1991. (Available from NTIS as DE91018648.)

Summary Proceedings: Public Meetings for Views and Comments on the Conduct of the 1990 Clean Coal Technology Solicitation. Report No. DOE/FE-0171. U.S. Department of Energy. April 1990. (Available from NTIS as DE90008197.)

Background Information: Public Meetings for Views and Comments on the Conduct of the 1990 Clean Coal Technology Solicitation. Report No. DOE/FE-0157. U.S. Department of Energy. February 1990. (Available from NTIS as DE90008111.)

CCT-V Solicitation

Comprehensive Report to Congress: Proposals Received in Response to the Clean Coal Technology V Program Opportunity Notice. Report No. DOE/FE-0277. U.S. Department of Energy. June 1993. (Available from NTIS as DE93016084.)

"Five New Clean Coal Projects." *Clean Coal Today*. Report No. DOE/FE-0215P-9. Spring 1993.

Summary Proceedings: Public Meetings for Views and Comments on the Conduct of the 1992 Clean Coal Technology Solicitation. Report No. DOE/FE-0246P. U.S. Department of Energy. December 1991. (Available from NTIS as DE92006425.)

Background Information Public Meetings for Views and Comments on the Conduct of the 1992 Clean Coal Technology Solicitation. U.S. Department of Energy. October 1991.

Other Reports and Clean Coal Today Articles

"Introducing the Global CCT Opportunity." *Clean Coal Today*. Report No. DOE/FE-0215P-20. Winter 1995.

"CCT Commercialization Challenges." *Clean Coal Today*. Report No. DOE/FE-0215P-20. Winter 1995.

"International CCT Deployment Needs Strong U.S. Support." *Clean Coal Today*. Report No. DOE/FE-0215P-20. Winter 1995.

"Polish Energy Experts Discuss Privatization." *Clean Coal Today*. Report No. DOE/FE-0215P-20. Winter 1995.

"Improving the 'Enabling Environment' for CCTs." *Clean Coal Today*. Report No. DOE/FE-0215P-20. Winter 1995.

"Power Generation Competition Threatens Clean Coal." *Clean Coal Today*. Report No. DOE/FE-0215P-20. Winter 1995.

"Domestic Regulatory Challenges." *Clean Coal Today*. Report No. DOE/FE-0215P-20. Winter 1995.

"Expanding the International Market." *Clean Coal Today*. Report No. DOE/FE-0215P-20. Winter 1995.

Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy and Economic Development, and National Mining Association. September 1995.

Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy and Economic Development, and National Mining Association. September 1995.

"The Global Opportunity: A Message from Pat Godley, Assistant Secretary for Fossil Energy." *Clean Coal Today*. Report No. DOE/FE-0215P-18. Fall 1995.

Clean Coal Technology: The Investment Pays Off. Report No. DOE/FE-0291 (Revised). U.S. Department of Energy. July 1995.

"DOE Report to Congress: CCT Expressions of Interest in Foreign Countries." *Clean Coal Today*. Report No. DOE/FE-0215P-17. Summer 1995.

"Clean Coal Celebrates Earth Day 1994—Exhibits Accent Reducing Greenhouse Gas Emissions." *Clean Coal Today*. Report No. DOE/FE-0215P-13. Spring 1994.

"In Memoriam." *Clean Coal Today*. Report No. DOE/FE-0215P-15. Special Memorial Issue. 1994.

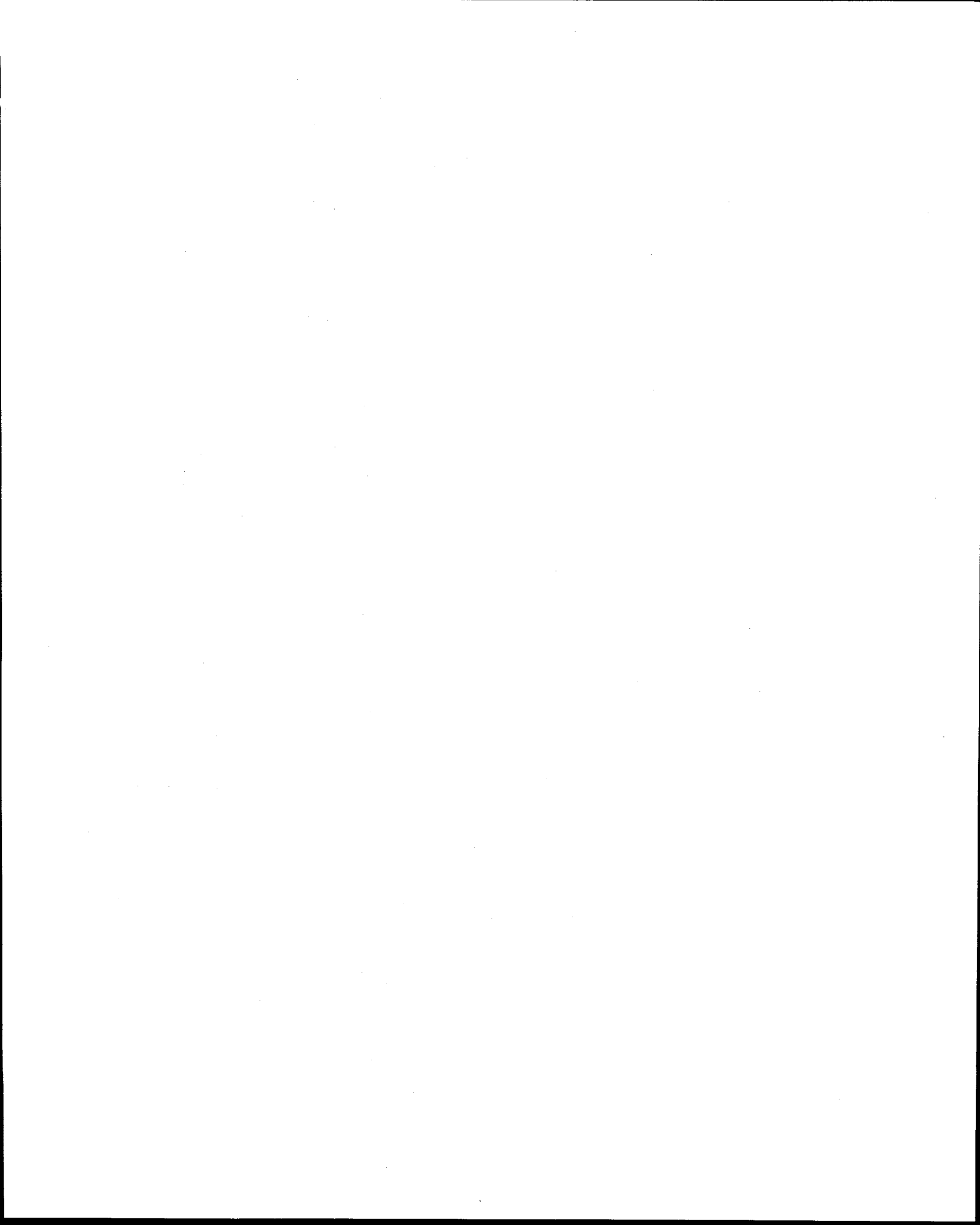
Third Annual Clean Coal Technology Conference: Technical Papers. U.S. Department of Energy and Center for Energy and Economic Development. September 1994.

The Clean Coal Technology Program Lessons Learned. Report No. DOE/FE-0315P. U.S. Department of Energy. July 1994. (Available from NTIS as DE9401777.)

Comprehensive Report to Congress: Clean Coal Technology Program Completing the Mission. Report No. DOE/FE-0309P. U.S. Department of Energy. May 1994. (Available from NTIS as DE94014065.)

Report to the United States Congress: Clean Coal Technology Export Markets and Financing Mechanisms. Report No. DOE/FE-0307P. U.S. Department of Energy. May 1994. (Available from NTIS as DE94014093.)

- Foreign Markets for U.S. Clean Coal Technologies.* Report No. DOE/FE-0317. U.S. Department of Energy. May 1994. (Available from NTIS as DE94018421.)
- Clean Coal Technology for Sustainable Development.* The National Coal Council. February 1994.
- Clean Coal Technology: The Investment Pays Off.* Report No. DOE/FE-0291. U.S. Department of Energy. January 1994. (Available from NTIS as DE94008697.)
- Clean Coal Technology: The New Coal Era.* Report No. DOE/FE-0217P. U.S. Department of Energy. January 1994.
- "Update—Clean Coal Air Toxics Testing Programs." *Clean Coal Today.* Report No. DOE/FE-0215P-12. Winter 1993/1994.
- Clean Coal Technologies: Research, Development, and Demonstration Program Plan.* Report No. DOE/FE-0284. U.S. Department of Energy. November 1993. (Available from NTIS as DE94004382.)
- "2nd Annual CCT Conference Examines Technology Markets." *Clean Coal Today.* Report No. DOE/FE-0215P-11. Fall 1993.
- Second Annual Clean Coal Conference Proceedings, Volumes I and II.* Report No. CONF-9309152. U.S. Department of Energy and Southern States Energy Board. September 1993. (Available from NTIS as DE94004378.)
- Region 3 Market Description Summary—Mid-Atlantic.* Report No. DOE/FE-62046 H-1. U.S. Department of Energy. September 1993. (Available from NTIS as DE94000431.)
- Region 4 Market Description Summary—South Atlantic.* Report No. DOE/FE-62046 H-2. U.S. Department of Energy. September 1993. (Available from NTIS as DE94000430.)
- Export of Coal and Coal Technology.* The National Coal Council. 1993.
- Fossil Energy Review.* Report No. DOE/FE-0223P-4. U.S. Department of Energy. January-June 1992. (Available from NTIS as DE92018656.)
- "Notable First Annual Clean Coal Conference—Technology Developers Linked with Wide Range of Users." *Clean Coal Today.* Report No. DOE/FE-0215P-7. Fall 1992.
- First Annual Clean Coal Conference Proceedings.* Report No. CONF-920979. U.S. Department of Energy. September 1992. (Available from NTIS as DE93004314.)
- "Clean Coal Projects Join Integrated Effort to Obtain Toxic Air Pollution Data." *Clean Coal Today.* Report No. DOE/FE-0215P-4. Winter 1991.
- Final Programmatic Environmental Impact Statement, Clean Coal Technology Demonstration Program.* Report No. DOE/EIS-0146. U.S. Department of Energy. November 1989. (Available from NTIS as DE90001890.)
- Innovative Clean Coal Technology Program: Programmatic Environmental Impact Analysis (PEIA).* Report No. DOE/FEIA-0002. U.S. Department of Energy. September 1988. (Available from NTIS as DE89008582.)
- Innovative Clean Coal Technology Deployment.* The National Coal Council. 1988.
- Clean Coal Technology.* The National Coal Council. 1986.



Appendix D: Papers and Presentations on the CCT Program

As design, construction, and operational data are generated by the various CCT projects, the information is being reported in a number of ways. One of the most available and up-to-date ways is through papers presented at technical conferences held at various locations throughout the United States and abroad.

Several annual conferences at which papers on clean coal technologies are usually presented follow:

- Annual American Power Conference
- Annual Clean Coal Technology Conference (U.S. Department of Energy)
- Annual Conference on Gasification Power Plants
- Annual International Pittsburgh Coal Conference (Pittsburgh Energy Technology Center)
- Annual METC Gasification and Gas Stream Cleanup Contractors Review Meeting (Morgantown Energy Technology Center)
- International Conference on Fluidized-Bed Combustion
- International Joint Power Generation Conference
- Power-Gen: International Conference and Exhibition for the Power Generating Industries

Because conference papers are generally available through the authors and may report data well in advance of the release of a formal project report, selected recent papers are listed below as an additional source of information on the CCT Program. Copies can be obtained from the authors or, in most cases, through the resources of a technical library.

Advanced Electric Power Generation/Fluidized-Bed Combustion

The Appalachian Power Company—PFBC Demonstration Utility Demonstration Project

DMEC-1 Limited Partnership—PCFB Project

Four Rivers Energy Partners, L.P.—Energy Modernization Project

Holley, E.P. (Air Products and Chemicals, Inc.) and J.J. Lewnard et al. (Four Rivers Energy Partners, L.P.). "Four Rivers Second Generation Pressurized Circulating Fluidized-Bed Combustion Project." *13th International Conference on Fluidized-Bed Combustion; Conference Proceedings*. Report No. CONF-950522-3 and DOE/MC/31261-95/C0448. U.S. Department of Energy. May 1995. (Available from NTIS as DE95008946.)

The Ohio Power Company—Tidd PFBC Demonstration Project

Marrocco, M. (American Electric Power Service Corporation). "Tidd Pressurized Fluidized Bed Combustion Demonstration Plant Assessment." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Judkins, R.R., et al. (Oak Ridge National Laboratory). "Development of Ceramic Composite Hot-Gas Filters." *ASME International Gas Turbine and Aeroengine Congress and Exposition: Land, Sea and Air*. Report No. CONF-950629-7. June 1995. (Available from NTIS as DE95010290.)

Roberts, B. (Lincoln Electric Co.). "Monster Pressure Vessel Proves Low-Emission Power Plant Technology." *Welding Journal*; 74: (4): 65-67. April 1995.

Tri-State Generation and Transmission Association, Inc.—Nucla CFB Demonstration Project

Bush, S.A. and M.L. Pendergrass (Tri-State Generation and Transmission Association, Inc.) and M.A. Friedman (Combustion Systems Inc.). "Tri-State's Nucla CFB Demonstrates Benefits of Clean Coal

Technology Program." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

York County Energy Partners, L.P.—ACFB Demonstration Project

Diamond, B.W. (Air Products and Chemicals, Inc.). "Environmental Design Considerations for the York County Energy Partners Circulating Fluid Bed Boiler." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

**Advanced Electric Power Generation/
Integrated Gasification Combined Cycle**

ABB Combustion Engineering, Inc.—Combustion Engineering IGCC Repowering Project

**Clean Energy Partners Limited Partnership—
Clean Energy Demonstration Project**

**Sierra Pacific Power Company—Piñon Pine
IGCC Power Project**

Motter, J.W. (Sierra Pacific Power Company). "The Piñon Pine IGCC Project: Advanced Coal-Fired Power Generation Systems." *Fourth Annual Clean*

Coal Technology Conference: The Global Opportunity. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Tatar, G., M. Gonzalez, and M. Fankhanel (Sierra Pacific Power Company). "An Update on the Piñon Pine IGCC Project." *Proceedings of the 57th American Power Conference: Volume 57-1*. Report No. CONF-950414. Pages 60-64. April 1995.

Swanekamp, R. "Tracy Station Showcases DLN, IGCC Technologies." *Power*; 139 (3): 64, 66, 68. March 1995.

Burrow, J.D., et al. (Sierra Pacific Power Company). "Integration of an Advanced Technology Gas Turbine in an Air Blown Gasifier." *Power Generation Conference*. Report No. CONF-941210-1. U.S. Department of Energy. December 1994. (Available from NTIS as DE95004233.)

**Tampa Electric Company—Tampa Electric
Integrated Gasification Combined-Cycle Project**

Pless, D.E. (TECO Power Services Corporation). "Status Update—Polk Power Station IGCC." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Phillips, J.L. (Radian Corporation), S. Gray, and D. Dekraker (Pittsburgh Energy Technology Center). "High-Efficiency SO₂ Removal in Utility FGD Sys-

tems." *Eleventh Annual Coal Preparation, Utilization, and Environmental Control Contractors Conference: Proceedings*. Report No. CONF-9507159. Pages 221-228. July 1995. (Available from NTIS as DE95017240.)

Jenkins, S.D., and L.A. Schmoie (Tampa Electric Company). "Tampa Electric Company Polk Power Station IGCC Project." *Power Generation Conference*. Report No. CONF-941210-5. U.S. Department of Energy. December 1994. (Available from NTIS as DE95005406.)

**Wabash River Coal Gasification Repowering
Project Joint Venture—Wabash River Coal
Gasification Repowering Project**

Woodruff, M.R. (Destec Energy, Inc.). "Wabash River Project Moves into Commercial Operation." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Cook, J.J., and L.A. Lednicky (PSI Energy, Inc.). "CGCC Repowering Nears Commercial Startup." *Power Engineering*; 99 (6): 26-29. June 1995.

Cook, J.J., and J. Bott (PSI Energy, Inc.). "Wabash River Nears Completion." *Modern Power Systems*; 15 (5): 83, 85, 87. May 1995.

Roll, M. (Destec Energy, Inc.). "Coal Gasification Passes Another Strategic Milestone." *Power*; 139: (4): 81-83. April 1995.

Stultz, J., R.E. Maurer, and C. Troxclair (PSI Energy, Inc.). "Pre-operation Activities Leading to the Start-Up of the Wabash River Repowering Project." *Proceedings of the American Power Conference: Volume 57-1*. Report No. CONF-950414. Pages 54-59. April 1995.

Advanced Electric Power Generation/ Advanced Combustion/Heat Engines

Alaska Industrial Development and Export Authority—Healy Clean Coal Project

Ubhayakar, S.K. (TRW Space & Technology Division). "Healy Clean Coal Project: Fabrication and Construction Status." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Arthur D. Little, Inc.—Coal Diesel Combined-Cycle Demonstration Project

Benedek, K.R., C.E. Benson, and R.P. Wilson (Arthur D. Little, Inc.), J.W. Parkinson (CQ, Inc.), and A.K. Rao (Cooper-Bessemer Reciprocating). "Coal Diesel Combined-Cycle Demonstration Update." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Pennsylvania Electric Company—Warren Station Externally Fired Combined-Cycle Demonstration Project

Stoddard, L.E., et al. (Black and Veatch). "Externally Fired Combined Cycle: An Effective Coal Fueled Technology for Repowering and New Generation." *20th International Technical Conference on Coal Utilization and Fuels Systems*. Report No. CONF-950313-2 and DOE/MC/31327-95/C0451. U.S. Department of Energy. March 1995. (Available from NTIS as DE95012295.)

Environmental Control Devices/ NO_x Control Technologies

"Update on NO_x Control Technologies." *PETC Review*; (11): 28-39. Spring 1995.

The Babcock & Wilcox Company—Demonstration of Coal Repowering for Cyclone Boiler NO_x Control

The Babcock & Wilcox Company—Full-Scale Demonstration of Low- NO_x Cell Burner Retrofit Energy and Environmental Research Corporation—Evaluation of Gas Repowering and Low- NO_x Burners on a Wall-Fired Boiler

Folsom, B., et al. (Energy and Environmental Research Corporation) and A.L. Baldwin (Pittsburgh Energy Technology Center). "Demonstration of Gas Repowering—Low NO_x Burner Technology for Cost Effective NO_x Emission Control." *Fourth Annual*

Clean Coal Technology Conference: The Global Opportunity. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

New York State Electric & Gas Corporation—Micronized Coal Repowering Demonstration for NO_x Control

Southern Company Services, Inc.—Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Sorge, J.N. (Southern Company Services, Inc.), B. Mensies (Radian Corporation), S.M. Smouse (Pittsburgh Energy Technology Center), and J.W. Stallings (Electric Power Research Institute). "500 MW Demonstration of Advanced Wall-Fired Combustion Techniques for the Reduction of Nitrogen Dioxide Emissions from Coal-Fired Boilers." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Southern Company Services, Inc.—Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers

Hinton, W.S., and J.D. Maxwell (Southern Company Services, Inc.) and A.L. Baldwin (Pittsburgh Energy Technology Center). "Demonstration of Selective

Catalytic Reduction (SCR) Technology for the Control of Nitrogen Oxides (NO_x) Emissions from High Sulfur Coal-Fired Utility Boilers at Plant Crist SCR Test Facility." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. *Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Southern Company Services, Inc.—180-MW Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers

Environmental Control Devices/SO₂ Control Technologies

AirPol, Inc.—10-MW Demonstration of Gas Suspension Absorption

Hsu, F.E., and B.B. Bhagat (AirPol, Inc.), S.K. Marchant and G.W. Pukanic (Pittsburgh Energy Technology Center), and V.M. Norwood and T.A. Burnett (Tennessee Valley Authority). "The Clean Coal Technology Program 10 MWe Demonstration of Gas Suspension Absorption for Flue Gas Desulfurization." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. *Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Burnett, T.A. (Tennessee Valley Authority), E.J. Puschaver, and T.M. Little. "Results from the Phase II Testing of the Gas Suspension Absorption Flue Gas Desulfurization Technology at the Center for Emissions Research." *Proceedings: 1995 SO₂ Control Symposium*. Volume 2, Sessions 4a, 4b, 5a, 5b. Report No. EPRI-TR-105258-Vol. 2 and CONF-950332-Vol. 2. Pages 35.1-35.14. June 1995.

Bechtel Corporation—Confined Zone Dispersion Flue Gas Desulfurization Demonstration

LIFAC—North America—LIFAC Sorbent Injection Desulfurization Demonstration Project

Pure Air on the Lake, L.P.—Advanced Flue Gas Desulfurization Demonstration Project

Manavi, G.B., and J.J. Lewnard (Pure Air), D.A. Styf (Northern Indiana Public Service Company), and T.A. Sarkus (Pittsburgh Energy Technology Center). "Bally Station AFGD Demonstration Program." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. *Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Manavi, G.B. (Pure Air), D.A. Styf, and T.A. Sarkus. "First Two Years of Operating Data from Bally Station AFGD Project." *Proceedings: 1995 SO₂ Control Symposium*. Volume 2, Sessions 4a, 4b, 5a, 5b. Report No. EPRI-TR-105258-Vol. 2 and CONF-950332-Vol. 2. Pages 41.2-41.32. June 1995.

Southern Company Services, Inc.—Demonstration of Innovative Applications of Technology for the CT-121 FGD Process

Pearl, I.G. (Radian Corporation). "Chiyoda Thoroughbred 121 Phase II Demonstration Results." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. *Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Burford, D.P. (Southern Company Services, Inc.) and I.G. Pearl. "Operational Highlights of the Chiyoda CT-121 FGD Demonstration at Georgia Power's Plant Yates." *Proceedings: 1995 SO₂ Control Symposium*. Volume 2, Sessions 4a, 4b, 5a, 5b. Report No. EPRI-TR-105258-Vol. 2 and CONF-950332-Vol. 2. Pages 40.1-40.18. June 1995.

Larrimore, L. (Southern Company Services, Inc.) and M. Burford. "Disposal and Utilization of Byproduct Materials from the Chiyoda CT-121 FGD Process." *Proceedings: 1995 SO₂ Control Symposium*. Volume 4, Sessions 8a, 8b. Report No. EPRI-TR-105258-Vol. 4 and CONF-950332-Vol. 4. Pages 87.1-87.15. June 1995.

Vakhtshoorzadeh, K. (Southern Company Services, Inc.), M.P. Burford, and D.P. Burford. "Evaluation of Fiber-Reinforced Plastics for Use in Chiyoda Thoroughbred-121 Flue Gas Desulfurization Process Vessel." *Proceedings: 1995 SO₂ Control Symposium*. Volume 4, Sessions 8a, 8b. Report No. EPRI-TR-105258-Vol. 4 and CONF-950332-Vol. 4. Pages 99.1-99.15. June 1995.

Burford, D.P. (Southern Company Services, Inc.) and I.G. Pearl. "Georgia Power's Plant Yates CT-121 FGD Demonstration Project Results." *American Power Conference: Proceedings. Volume 57-II*. Report No. CONF-950414-2. April 1995.

Environmental Control Devices/Combined SO₂/NO_x Control Technologies

Markussen, C.M. (Pittsburgh Energy Technology Center) and D. Livengood (Argonne National Laboratory). "Alternative Flue Gas Treatment Technologies for Integrated SO₂ and NO_x Control." *American Power Conference: Proceedings. Volume 57-III*. Report No. CONF-950414-3. April 1995. (Available from NTIS as DE95012919.)

ABB Environmental Systems—SNOX™ Flue Gas Cleaning Demonstration Project

Borio, R. (ABB Environmental Systems). "Status of the SNOX Technology and Demonstration." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Borio, D.C. (ABB Environmental Systems) and P.E. Chambers. "SNOX Economics for Multi Pollutant Control Applications." *Proceedings: 1995 SO₂ Control Symposium. Volume 3, Sessions 6a, 6b, 7a, 7b*. Report No. EPRI-TR-105258-Vol. 3 and CONF-950332-Vol. 3. Pages 81.1-81.10. June 1995.

The Babcock & Wilcox Company—LIMB Demonstration Project Extension and Coolside Demonstration

Withum, J.A. (Consol, Inc.), J.T. Maskew, and W.A. Rosenhoover. "Development of the Advanced Coolside Sorbent Injection Process for SO₂ Control." *Proceedings: 1995 SO₂ Control Symposium. Volume 2, Sessions 4a, 4b, 5a, 5b*. Report No. EPRI-TR-105258-Vol. 2 and CONF-950332-Vol. 2. Pages 33.2-33.16. June 1995.

Beeghley, J.H., et al. "Impact of Weathering and Aging on a LIMB Ash Stockpile Material." *Eleventh International Symposium on Use and Management of Coal Combustion By-Products*. Report No. CONF-950106-3. U.S. Department of Energy. January 1995. (Available from NTIS as DE95008365.)

Kim, S.H., S. Nodjomian, and W. Wolfe. "Field Demonstration Project using Clean Coal Technology By-Products." *Eleventh International Symposium on Use and Management of Coal Combustion By-Products*. Report No. CONF-950106-4. U.S. Department of Energy. January 1995. (Available from NTIS as DE95008386.)

The Babcock & Wilcox Company—SO_x-NO_x-Rox™ Flue Gas Cleanup Demonstration Project

Martinelli, R., J.B. Doyle, and K.E. Redinger. (Babcock & Wilcox). "SO_x-NO_x-ROX BOX™ Technology Review and Global Commercial Opportunities." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy &

Economic Development, and National Mining Association. September 1995.

Energy and Environmental Research Corporation—Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Sommer, T. (Energy and Environmental Research Corporation). "Demonstration of Gas Reburning-Sorbent Injection Technology for NO_y/SO_x Emission Control." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

New York State Electric & Gas Corporation—Milliken Clean Coal Technology Demonstration Project

Baron, III, E.S., and G. Gauffillet (New York State Electric & Gas Corporation) and C.E. Jackson (Gilbert/Commonwealth). "Milliken Station Demonstration Project FGD Retrofit Update—1995." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Simonetti, R.K. (Gilbert/Commonwealth, Inc.) and D.T. O'Dea. "Innovative FGD Structures." *American Power Conference: Proceedings. Volume 57-II*. Report No. CONF-950414-2. Pages 853-858. April 1995.

NOXSO Corporation—Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System

Black, J.B., et al. (NOXSO Corporation). "The NOXSO Clean Coal Project." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Public Service Company of Colorado—Integrated Dry NO_x/SO₂ Emissions Control System

Hunt, T. (Public Service Company of Colorado), L.J. Muzio and R. Smith (Fossil Energy Research Corporation), D. Jones (NOELI, Inc.), E. Mali (Babcock & Wilcox), and J. Stallings (Electric Power Research Corporation). "Performance of the Integrated Dry NO_x/SO₂ Emissions Control System." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Hunt, T. (Public Service Company of Colorado), L.J. Muzio, and R. Smith (Fossil Energy Research Corporation). "Integrated Low-NO_x Burners, Overfire Air, and Selective Non-catalytic Reduction on a Utility Coal-Fired Boiler." *Environmental Progress*. 14 (2): 115-120. May 1995.

Coal Processing for Clean Fuels/Coal Preparation Technologies

ABB Combustion Engineering, Inc., and CQ Inc.—Development of the Coal Quality Expert

Harrison, C.D., and D.B. Kehoe (CQ Inc.), D.C. O'Connor (Electric Power Research Institute), and G.S. Stallard (Black & Veatch). "CQE: Integrating Fuel Decisions." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Custom Coals International—Self-Scrubbing Coal™: An Integrated Approach to Clean Air

Harrison, K.E. (Custom Coals Corporation). "Self Scrubbing Coal—A Progress Update." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Rosebud SynCoal Partnership—Advanced Coal Conversion Process Demonstration

Sheldon, R. W. (Rosebud SynCoal Partnership) and R.M. Kornosky, W.J. O'Dowd, and J.B. Renk, III (Pittsburgh Energy Technology Center). "Rosebud SynCoal Partnership SynCoal® Demonstration Technology Development Update." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-

9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Coal Processing for Clean Fuels/Mild Gasification

ENCOAL Corporation—ENCOAL Mild Coal Gasification Project

Frederick, J.P. (ENCOAL Corporation) and S.A. van Hoffen (SGI International). "Commercialization of the Liquids from Coal Process." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Coal Processing for Clean Fuels/Indirect Liquefaction

Air Products Liquid Phase Conversion Company, L.P.—Commercial-Scale Demonstration of Liquid-Phase Methanol (LPMEOH™) Process

Schaub, E.S., et al. (Air Products and Chemicals, Inc.). "An Update on Liquid Phase Methanol (LPMEOH™) Technology and the Kingsport Demonstration Project." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity*. Technical Papers. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Industrial Applications

Bethlehem Steel Corporation—Blast Furnace Granulated-Coal Injection System Demonstration Project

Walter, L.L., R.W. Bouman, and D.G. Hill (Bethlehem Steel Corporation). "Blast Furnace Granular Coal Injection." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Centerior Energy Corporation—Clean Power from Integrated Coal/Ore Reduction (COREX®)

Wintrell, R. (Geneva Steel). "CPICOR™." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

Coal Tech Corporation—Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control

Zauderer, B., et al. (Coal Tech Corporation). "Demonstration of the Air Cooled Slagging Combustor on a 500 kW Coal Fired Power Plant." *Fourth Annual Clean Coal Technology Conference: The Global Opportunity. Technical Papers*. Report No. CONF-9509170. U.S. Department of Energy, Center for Energy & Economic Development, and National Mining Association. September 1995.

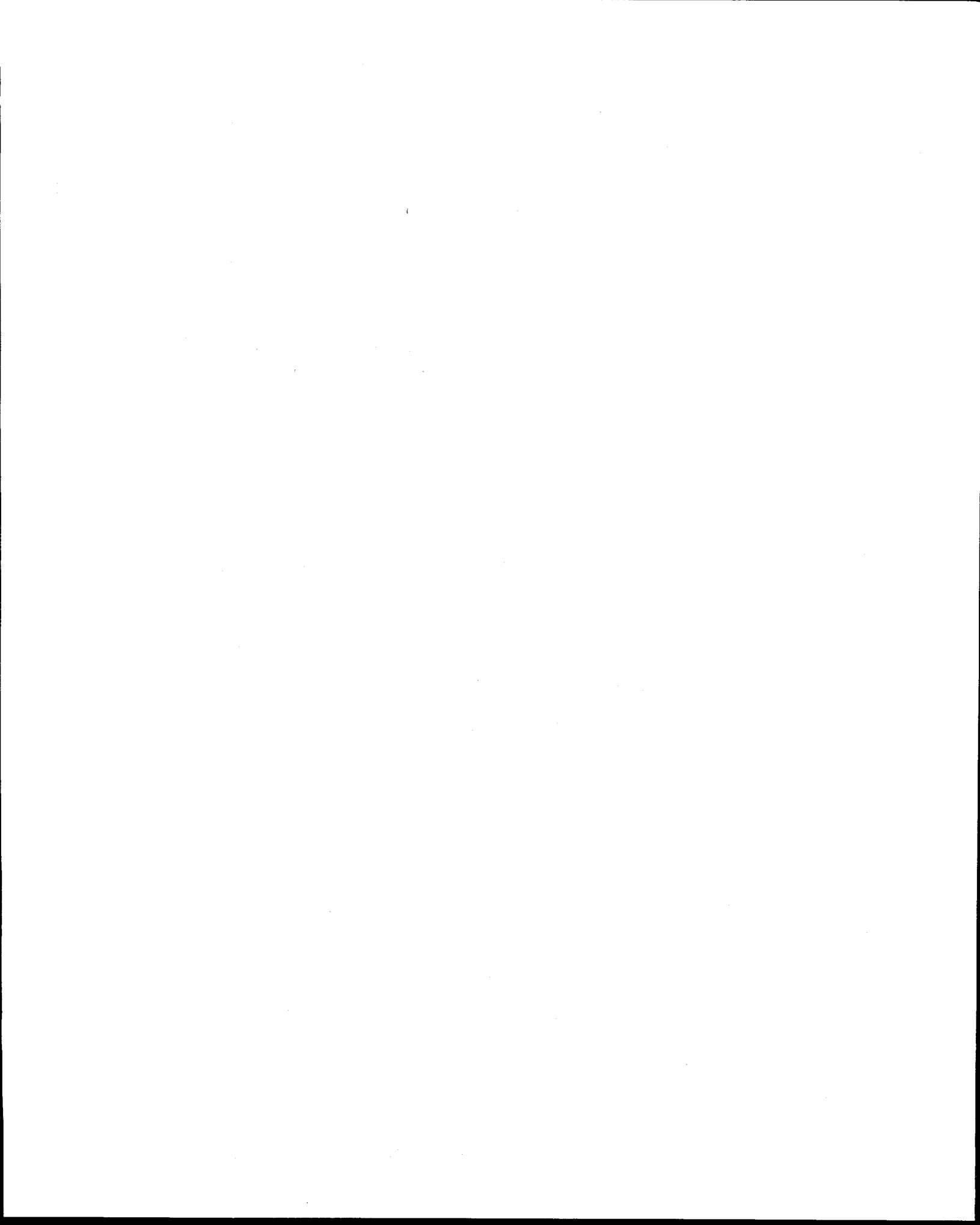
Passamaquoddy Tribe—Cement Kiln Flue Gas Recovery Scrubber

ThermoChem, Inc.—Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

Other

Schmidt, C.E. (Pittsburgh Energy Technology Center), M. Baird, and P. Chu. "Hazardous Air Pollutants (HAPS) Emissions Characterization." *Proceedings: 1995 SO₂ Control Symposium. Volume 3, Sessions 6a, 6b, 7a, 7b*. Report No. EPRI-TR105258-Vol. 3 and CONF-950332-Vol. 3. U.S. Department of Energy and the Electric Power Research Institute. Pages 63.1-63.13. June 1995.

Dennis, R.A., H.M. McDaniel, T.J. McMahon (Morgantown Energy Technology Center). "Hot Gas Particulate Cleanup for Advanced Coal-Based Power Systems." *ASME International Gas Turbine and Aeroengine Congress and Exposition: Land, Sea and Air*. Report No. CONF-950629-4. U.S. Department of Energy. June 1995. (Available from NTIS as DE05010307.)



Appendix E: CCT Project Contacts

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

Advanced Electric Power Generation/ Fluidized-Bed Combustion

PFBC Utility Demonstration Project

Participant:

The Appalachian Power Company

Contacts:

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

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

Jeffrey Summers, DOE/HQ, (301) 903-4412
Douglas M. Jewell, METC, (304) 285-4720

PCFB Demonstration Project

Participant:

DMEC-1 Limited Partnership

Contacts:

Gary E. Kruempel, Project Manager
(515) 281-2459
(515) 281-2355 (fax)
Midwest Power Systems, Inc.
907 Walnut
P.O. Box 657
Des Moines, IA 50303

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

Four Rivers Energy Modernization Project

Participant:

Four Rivers Energy Partners, L.P.

Contacts:

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

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

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

Tidd PFBC Demonstration Project

Participant:

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

Contacts:

Mario Marrocco, Manager, PFBC Programs
(614) 223-1740
(614) 223-2466 (fax)
American Electric Power Service Corporation
1 Riverside Plaza
Columbus, OH 43215

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

Nucla CFB Demonstration Project

Participant:

Tri-State Generation and Transmission Association, Inc.

Contacts:

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

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

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

ACFB Demonstration Project

Participant:
York County Energy Partners, L.P.

Contacts:
Bradley F. Hahn, Project Manager
(610) 481-3955
(610) 481-2393 (fax)

York County Energy Partners, L.P.
25 South Main Street
Spring Grove, PA 17362

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

Clean Energy Demonstration Project

Participant:
Clean Energy Partners Limited Partnership

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

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

Stanley Roberts, DOE/HQ, (301) 903-9431
Donald W. Geiling, METC, (304) 285-4784

Piñon Pine IGCC Power Project

Participant:
Sierra Pacific Power Company

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

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

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

**Tampa Electric Integrated Gasification
Combined-Cycle Project**

Participant:
Tampa Electric Company

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

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

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

**Wabash River Coal Gasification Repowering
Project**

Participant:
Wabash River Coal Gasification Repowering Project
Joint Venture

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

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

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

**Advanced Electric Power Generation/
Integrated Gasification Combined Cycle**

**Combustion Engineering IGCC Repowering
Project**

Participant:
ABB Combustion Engineering, Inc.

Contacts:
Henry H. Vroom, Project Director
(203) 285-9085
(203) 285-3861 (fax)

ABB Combustion Engineering, Inc.
P.O. Box 500
Windsor, CT 06095-0500

Lawrence Saroff, DOE/HQ, (301) 903-9483
Gary A. Nelkin, METC, (304) 285-4216

**Advanced Electric Power Generation/
Advanced Combustion/Heat Engines**

Healy Clean Coal Project
Participant:
Alaska Industrial Development and Export Authority
Contacts:
John B. Olson, Project Manager
(907) 269-3000
Alaska Industrial Development and Export Authority
480 West Tudor Road
Anchorage, AK 99503-6690
Stanley Roberts, DOE/HQ, (301) 903-9431
Robert M. Kornosky, PETC, (412) 892-4521

Coal Diesel Combined-Cycle Project
Participant:
Arthur D. Little, Inc.
Contacts:
Robert P. Wilson, Vice President
(617) 498-5806
(617) 498-7206 (fax)
Arthur D. Little, Inc.
200 Acorn Park
Cambridge, MA 02140
Jeffrey Summers, DOE/HQ, (301) 903-4412
Nelson F. Rekos, METC, (304) 285-4066

**Warren Station Externally Fired Combined-Cycle
Demonstration Project**

Participant:
Pennsylvania Electric Company
Contacts:
Kenneth Gray, Project Manager
(814) 533-8593
(814) 533-8108 (fax)
Pennsylvania Electric Company
1001 Broad Street
Johnsontown, PA 15907
Douglas Archer, DOE/HQ, (301) 903-9443
Donald W. Geiling, METC, (304) 285-4784

**Environmental Control Devices/NO_x Control
Technologies**

**Demonstration of Coal Reburning for Cyclone
Boiler NO_x Control**
Participant:
The Babcock & Wilcox Company
Contacts:
Tony Yagiela
(216) 829-7403
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
Jeffrey Summers, DOE/HQ, (301) 903-4412
John C. McDowell, PETC, (412) 892-6237

**Full-Scale Demonstration of Low-NO_x Cell Burner
Retrofit**

Participant:
The Babcock & Wilcox Company
Contacts:
Tony Yagiela
(216) 829-7403
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
Jeffrey Summers, DOE/HQ, (301) 903-4412
Ronald W. Corbett, PETC, (412) 892-6141

**Evaluation of Gas Reburning and Low-NO_x
Burners on a Wall-Fired Boiler**
Participant:
Energy and Environmental Research Corporation
Contacts:
Blair A. Folsom, Senior Vice President
(714) 859-8851
Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718
William Fernald, DOE/HQ, (301) 903-9448
Jerry L. Hebb, PETC, (412) 892-6079

Micronized Coal Reburning Demonstration of NO_x Control

Participant:

New York State Electric & Gas Corporation

Contacts:

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

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

Stanley Roberts, DOE/HQ, (301) 903-9431
James U. Watts, PETC, (412) 892-5991

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler

Participant:

Southern Company Services, Inc.

Contacts:

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

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

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

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

Participant:

Southern Company Services, Inc.

Contacts:

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

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

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

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

Participant:

Southern Company Services, Inc.

Contacts:

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

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

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

Environmental Control Devices/SO₂ Control Technologies

10-MWe Demonstration of Gas Suspension Absorption

Participant:

AirPol, Inc.

Contacts:

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

AirPol, Inc.
3 Century Drive
Parsippany, NJ 07054

Lawrence Saroff, DOE/HQ, (301) 903-9483
Sharon K. Marchant, PETC, (412) 892-6008

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Participant:

Bechtel Corporation

Contacts:

Joseph T. Newman, Project Manager
(415) 768-1189
(415) 7678-3580 (FAX)

Bechtel Corporation
P. O. Box 193965
San Francisco, CA 94119-3965

Stanley Roberts, DOE/HQ, (301) 903-9431
Joanna M. Markusen, PETC, (412) 892-5734

**LIFAC Sorbent Injection Desulfurization
Demonstration Project**

Participant:
LIFAC-North America
Contacts:
Jim Hervol, Project Manager
(412) 497-2235
(412) 497-2298 (fax)
ICF Kaiser Engineers, Inc.
4 Gateway Center
Pittsburgh, PA 15222-1207
Lawrence Saroff, DOE/HQ, (301) 903-9483
Joanna M. Markussen, PETC, (412) 892-5734

**Advanced Flue Gas Desulfurization
Demonstration Project**

Participant:
Pure Air on the Lake, L.P.
Contacts:
Don Vymazal, Manager, Contract Administration
(610) 481-3687
Pure Air on the Lake, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501
Lawrence Saroff, DOE/HQ, (301) 903-9483
Karen M. Khonsari, PETC, (412) 892-6106

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

Participant:
Southern Company Services, Inc.
Contacts:
David P. Burford, Project Manager
(205) 870-6329
Southern Company Services, Inc.
P.O. Box 2625
Birmingham, AL 35202-2625
Lawrence Saroff, DOE/HQ, (301) 903-9483
Karen M. Khonsari, PETC, (412) 892-6106

**Environmental Control Devices/Combined
SO₂/NO_x Control Technologies**

**SNOX™ Flue Gas Cleaning Demonstration
Project**
Participant:
ABB Environmental Systems
Contacts:
Bill Kingston, Project Manager
(205) 995-5368
ABB Environmental Systems
P.O. Box 43030
Birmingham, AL 35243
Stanley Roberts, DOE/HQ, (301) 903-9431
James U. Watts, PETC, (412) 892-5991

**LIMB Demonstration Project Extension and
Coolside Demonstration**

Participant:
The Babcock & Wilcox Company
Contacts:
Paul Nolan
(216) 860-1074
(216) 860-2045 (fax)
The Babcock & Wilcox Company
20 South Van Buren Avenue
P.O. Box 351
Barberton, OH 44203-0351
William Fernald, DOE/HQ, (301) 903-9448
Joanna M. Markussen, PETC, (412) 892-5734

**SOx-NOx-Rox Box™ Flue Gas Cleanup
Demonstration Project**

Participant:
The Babcock & Wilcox Company
Contacts:
Kevin Redinger
(216) 829-7719
The Babcock & Wilcox Company
1562 Beeson Street
Alliance, OH 44601
William Fernald, DOE/HQ, (301) 903-9448
John C. McDowell, PETC, (412) 892-6237

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection

Participant:
Energy and Environmental Research Corporation

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

Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718

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

Milliken Clean Coal Technology Demonstration Project

Participant:
New York State Electric & Gas Corporation

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

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

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

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

Participant:
NOXSO Corporation

Contacts:
James Black
(412) 854-1200

NOXSO Corporation
2414 Lytle Road
Bethel Park, PA 15102-2704

Stanley Roberts, DOE/HQ, (301) 903-9431
Jerry L. Hebb, PETC, (412) 892-6079

Integrated Dry NO_x/SO₂ Emissions Control System

Participant:
Public Service Company of Colorado

Contacts:
Terry Hunt, Project Manager
(303) 329-1113

Public Service Company of Colorado
5900 East 39th Avenue
Denver, CO 80207

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

Coal Processing for Clean Fuels/Coal Preparation Technologies

Development of the Coal Quality Expert

Participants:
ABB Combustion Engineering, Inc., and CQ Inc.

Contacts:
Clark Harrison, President
(412) 479-6016

CQ Inc.
One Quality Center
P.O. Box 280
Homer City, PA 15748-0280

Douglas Archer, DOE/HQ, (301) 903-9443
Scott M. Smouse, PETC, (412) 892-5725

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

Participant:
Custom Coals International

Contacts:
Robin Godfrey, President and CEO
(412) 642-2625

Custom Coals International
100 First Avenue, Suite 500
Pittsburgh, PA 15222

Douglas Archer, DOE/HQ, (301) 903-9443
Joseph B. Renk, PETC, (412) 892-6249

Advanced Coal Conversion Process Demonstration

Participant:

Rosebud SynCoal Partnership

Contacts:

Ray W. Sheldon, P.E., Director of Development
(406) 748-2366 or (406) 252-2277

Rosebud SynCoal Partnership
P.O. Box 7137

Billings, MT 59103-7137

Douglas Archer, DOE/HQ, (301) 903-9443
Joseph B. Renk, PETC, (412) 892-6249

Coal Processing for Clean Fuels/Mild Gasification

ENCOAL Mild Coal Gasification Project

Participant:

ENCOAL Corporation

Contacts:

J.P. (Jim) Frederick, Project Manager
(307) 686-5493
(307) 682-7938 (fax)

ENCOAL Corporation
P.O. Box 3038
Gillette, WY 82717

Douglas Archer, DOE/HQ, (301) 903-9443
Douglas M. Jewell, METC, (304) 285-4720

Coal Processing for Clean Fuels/Indirect Liquefaction

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

Participant:

Air Products Liquid Phase Conversion Company, L.P.

Contacts:

William R. Brown, Project Manager
(215) 481-7584

Air Products Liquid Phase Conversion Company, L.P.

7201 Hamilton Boulevard
Allentown, PA 18195-1501

Douglas Archer, DOE/HQ, (301) 903-9443
Robert M. Kornosky, PETC, (412) 892-4521

Industrial Applications

Blast Furnace Granulated-Coal Injection System Demonstration Project

Participant:

Bethlehem Steel Corporation

Contacts:

Robert W. Bouman, Project Manager
(610) 694-6792
(610) 694-2981 (fax)

Bethlehem Steel Corporation
Homer Research Laboratory
Building C, Room 211
Bethlehem, PA 18016

Jeffrey Summers, DOE/HQ, (301) 903-4412
Douglas M. Jewell, METC, (304) 285-4720

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

Participant:

Centerior Energy Corporation

Contacts:

Barry Halper
(610) 481-7685
(610) 481-2393 (fax)

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

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

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

Participant:

Coal Tech Corporation

Contacts:

Bert Zauderer, President
(215) 667-0442

Coal Tech Corporation
P.O. Box 154
Merion, PA 19066

Stanley Roberts, DOE/HQ, (301) 903-9431
Arthur L. Baldwin, PETC, (412) 892-6011

Cement Kiln Flue Gas Recovery Scrubber

Participant:

Passamaquoddy Tribe

Contacts:

Garrett Morrison, Project Manager
(207) 594-5555

Passamaquoddy Technology, L.P.

P.O. Box 350

Thomaston, ME 04861-0350

Jeffrey Summers, DOE/HQ, (301) 903-4412

John C. McDowell, PETC, (412) 892-6237

**Demonstration of Pulse Combustion in an
Application for Steam Gasification of Coal**

Participant:

ThermoChem, Inc.

Contacts:

William Steedman, Program Manager

(410) 997-9671

ThermoChem, Inc.

5570 Sterrett Place, Suite 210

Columbia, MD 21044

William Fernald, DOE/HQ, (301) 903-9448

Douglas F. Gyorko, PETC, (412) 892-6173

Appendix F: Acronyms and Abbreviations

Acronyms

ABB CE	ABB Combustion Engineering, Inc.	CX	categorical exclusion	HAP, HAPs	hazardous air pollutant(s)
ABB ES	ABB Environmental Systems	CZD	confined zone dispersion	HHV	high heating value
ACFB	atmospheric circulating fluidized bed	DME	dimethyl ether	HRSG	heat recovery steam generator
AFBC	atmospheric fluidized-bed combustion	DOE	U.S. Department of Energy	IGCC	integrated gasification combined cycle
		DOE/HQ	U.S. Department of Energy Headquarters	JBR	jet-bubbling reactor
AFGD	advanced flue gas desulfurization	EA	environmental assessment	LHV	low heating value
AIDEA	Alaska Industrial Development and Export Authority	EER	Energy and Environmental Research Corporation	LIMB	limestone injection multistage burner
AOFA	advanced overfire air	EFCC	externally fired combined cycle	LNB	low-NO _x burner
AR&TD	advanced research and technology development	EIA	Energy Information Administration	LNCFS	low-NO _x concentric-firing system
		EIS	environmental impact statement	LSFO	limestone forced oxidation
BFGCI	blast furnace granulated-coal injection	EMP	environmental monitoring plan	MCFC	molten carbonate fuel cell
BG	British Gas	EPA	U.S. Environmental Protection Agency	METC	Morgantown Energy Technology Center
BG/L	British Gas/Lurgi	EPACT	Energy Policy Act of 1992	MTCI	Manufacturing and Technology Conversion International
B&W	The Babcock & Wilcox Company	EPRI	Electric Power Research Institute	MTF	memorandum (memoranda)-to-file
CAAA	Clean Air Act Amendments of 1990	ESP	electrostatic precipitator	NEPA	National Environmental Policy Act
CCOFA	close-coupled over-fire air	EWG	exempt wholesale generator	NOPR	Notice of Proposed Rulemaking
CCT	clean coal technology	FBC	fluidized-bed combustion	NSPS	New Source Performance Standards
CCT Program	Clean Coal Technology Demonstration Program	FERC	Federal Energy Regulatory Commission	NTIS	National Technical Information Service
CDCC	coal-fueled diesel engine combined cycle	FGD	flue gas desulfurization	NYSEG	New York State Electric & Gas Corporation
CDL	coal-derived liquid	FONSI	finding of no significant impact	PCFB	pressurized circulating fluidized bed
CEQ	Council on Environmental Quality	FRP	fiberglass-reinforced plastic	PDF	process-derived fuel
CFB	circulating fluidized bed	FY	fiscal year	PEIS	programmatic environmental impact statement
COG	coke oven gas	GE	General Electric	PETC	Pittsburgh Energy Technology Center
CQE	Coal Quality Expert	GPM	gallons per minute		
		GR	gas reburning		
		GR-LNB	gas reburning and low-NO _x burner		
		GR-SI	gas reburning and sorbent injection		
		GSA	gas suspension absorption		

Abbreviations

States are abbreviated using two-letter postal codes.

PFBC	pressurized fluidized-bed combustion	mo, mos	month, months
PJBH	pulse jet baghouse	MgCO ₃	magnesium carbonate
PON	program opportunity notice	MgO	magnesium oxide
PSSC	Public Service Company of Colorado	MW	megawatt(s)
PURPA	Public Utility Regulatory Policies Act of 1972	MWe	megawatt(s)-electric
R&D	research and development	MWt	megawatt(s)-thermal
RD&D	research, development, and demonstration	N ₂	atmospheric nitrogen
SBIR	Small Business Innovative Research	Na/Ca	molar ratio of sodium to calcium
SCR	selective catalytic reduction	Na ₂ S	molar ratio of sodium to sulfur
SCS	Southern Company Services, Inc.	NaOH	sodium hydroxide
SI	sorbent injection	Na ₂ CO ₃	sodium carbonate
SNCR	selective noncatalytic reduction	NH ₃	ammonia
SOFA	separated over-fire air	NO ₂	nitrogen dioxide
STTR	Small Business Technology Transfer Program	NO _x	nitrogen oxides
TVA	Tennessee Valley Authority	O ₂	oxygen
UBCL	unburned carbon boiler efficiency losses	ppm	parts per million (mass)
U.K.	United Kingdom	ppmv	parts per million by volume
U.S.	United States	psi	pound(s) per square inch
VOC	volatile organic compound	rpm	revolutions per minute
WLFO	wet limestone, forced oxidation	S	sulfur
		SO ₂	sulfur dioxide
		SO ₃	sulfur trioxide
		std ft ³	standard cubic feet
		Yr, yrs	year, years
		atm	atmosphere(s)
		avg	average
		Btu	British thermal unit
		C/H	molar ratio of carbon to hydrogen
		CaCO ₃	calcium carbonate (calcitic limestone)
		CaO	calcium oxide (lime)
		Ca(OH) ₂	calcium hydroxide (calcitic hydrated lime)
		Ca(OH) ₂ •MgO	dolomitic hydrated lime
		Ca/S	molar ratio of calcium to sulfur
		CaSO ₃	calcium sulfite
		CaSO ₄	calcium sulfate
		CO	carbon monoxide
		CO ₂	carbon dioxide
		°F	degrees Fahrenheit
		ft, ft ² , ft ³	foot (feet), square feet, cubic feet
		GW	gigawatt(s)
		GWe	gigawatt(s)-electric
		H ₂ S	hydrogen sulfide
		H ₂ SO ₄	sulfuric acid
		HCl	hydrogen chloride
		HF	hydrogen fluoride
		hr, hrs	hour, hours
		in, in ² , in ³	inch(es), square inches, cubic inches
		KCl	potassium chloride
		K ₂ SO ₄	potassium sulfate
		kW	kilowatt
		kWh	kilowatt-hour
		lb, lbs	pound, pounds

Index of CCT Projects

- ABB Combustion Engineering, Inc.'s Combustion Engineering IGCC Repowering Project 1-5, 2-5, 2-8, 2-18, 2-20, 2-22, 3-6, 6-15, 7-2, 7-4, 7-20-21, B-3, C-3, D-2, E-2
- ABB Combustion Engineering, Inc.'s and CQ Inc.'s Development of the Coal Quality Expert 1-6, 2-5, 2-10, 2-17, 2-22, 3-7, 3-8, 4-8, 6-1, 6-9, 6-20, 7-3, 7-4, 7-78-79, B-1, B-3, C-2, D-6, E-6
- ABB Environmental Systems' SNOX™ Flue Gas Cleaning Demonstration Project ES-5, 1-5, 2-5, 2-9, 2-17, 2-24, 3-7, 4-7, 5-4, 5-41-42, 6-18, 7-3, 7-4, 7-62-63, B-2, B-5, C-10, D-5, E-5
- Air Products Liquid Phase Conversion Company, L.P.'s Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process 1-6, 2-6, 2-10, 2-18, 2-23, 3-7, 6-2, 6-16, 6-23, 7-3, 7-4, 7-86-87, B-4, C-12, D-6, E-6
- AirPol, Inc.'s 10-MWe Demonstration of Gas Suspension Absorption ES-5, 1-5, 2-6, 2-9, 2-17, 2-23, 2-24, 3-7, 3-8, 4-6, 5-4, 5-25-27, 6-18, 7-3, 7-4, 7-52-53, B-2, B-5, C-8, D-4, E-4
- Alaska Industrial Development and Export Authority's Healy Clean Coal Project 1-5, 1-16, 2-6, 2-8, 2-19, 2-23, 2-24, 3-6, 6-1, 6-5, 6-16, 7-2, 7-4, 7-30-31, B-3, C-5, D-3, E-3
- The Appalachian Power Company's PFBC Utility Demonstration Project 1-5, 2-5, 2-8, 2-20, 2-22, 3-6, 6-15, 7-2, 7-4, 7-8-9, B-2, C-2, D-1, E-1
- Arthur D. Little, Inc.'s Coal Diesel Combined-Cycle Project 1-5, 2-7, 2-8, 2-20, 2-23, 2-24, 3-6, 6-16, 7-2, 7-4, 7-32-33, B-4, C-5, D-3, E-3
- The Babcock & Wilcox Company's Demonstration of Coal Reburning for Cyclone Boiler NO_x Control ES-4, 1-5, 2-5, 2-9, 2-18, 2-22, 2-24, 3-7, 4-5, 5-4, 5-14-16, 6-17, 7-2, 7-4, 7-38-39, B-2, B-4, C-6, D-3, E-3
- The Babcock & Wilcox Company's Full-Scale Demonstration of Low-NO_x Cell Burner Retrofit ES-4, 1-5, 2-6, 2-9, 2-17, 2-23, 3-7, 3-8, 4-5, 4-11, 5-4, 5-17-5-18, 6-17, 7-2, 7-4, 7-40-41, B-2, B-5, C-6, D-3, E-3
- The Babcock & Wilcox Company's SOx-NOx-Rox Box™ Flue Gas Cleanup Demonstration Project ES-5, 1-5, 2-5, 2-9, 2-17, 2-22, 2-24, 3-7, 5-4, 5-46-48, 6-18, 7-3, 7-4, 7-66-67, B-2, B-4, C-10, D-5, E-5
- The Appalachian Power Company's PFBC Utility Demonstration Project 1-5, 2-5, 2-8, 2-20, 2-22, 3-6, 6-15, 7-2, 7-4, 7-8-9, B-2, C-2, D-1, E-1
- Bechtel Corporation's Confined Zone Dispersion Flue Gas Desulfurization Demonstration ES-5, 1-5, 2-6, 2-9, 2-17, 2-23, 3-7, 5-4, 5-28-29, 6-18, 7-3, 7-4, 7-54-55, B-4, C-9, D-4, E-4
- Bethlehem Steel Corporation's Blast Furnace Granulated-Coal Injection System Demonstration Project 1-6, 2-6, 2-11, 2-18, 2-23, 3-6, 6-1, 6-14, 6-21, 7-3, 7-4, 7-90-91, B-3, D-7, E-7
- Centerior Energy Corporation's Clean Power from Integrated Coal/Ore Reduction (COREX®) 1-6, 2-7, 2-11, 2-20, 2-23, 2-24, 3-6, 6-21, 7-3, 7-4, 7-92-93, B-4, C-13, D-7, E-7
- Clean Energy Partnership Limited Partnership's Clean Energy Demonstration Project 1-5, 2-7, 2-8, 2-20, 2-23, 2-24, 3-6, 6-15, 7-2, 7-4, 7-22-23, B-4, C-4, D-2, E-2
- Coal Tech Corporation's Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control ES-6, 1-6, 1-24, 2-5, 2-11, 2-17, 2-22, 3-6, 5-4, 5-54-55, 6-21, 7-3, 7-4, 7-94-95, B-1, B-3, C-13, D-7, E-7
- Colorado-Ute Electric Association, Inc. (see *Tri-State Generation and Transmission Association, Inc.*)
- Custom Coals International's Self-Scrubbing Coal™. An Integrated Approach to Clean Air 1-6, 2-6, 2-10, 2-18, 2-23, 2-24, 3-7, 4-8, 6-1, 6-10, 6-20, 7-3, 7-4, 7-80-81, B-4, C-12, D-6, E-6

- DMEC-1 Limited Partnership's PCFB Demonstration Project 1-5, 2-6, 2-8, 2-20, 2-23, 3-6, 6-15, 7-2, 7-4, 7-10-11, B-3, C-2, D-1, E-1
- ENCOAL Corporation's ENCOAL Mild Coal Gasification Project ES-7, 1-6, 1-23, 2-6, 2-10, 2-18, 2-23, 2-24, 3-7, 4-9, 6-1, 6-12, 6-20, 7-3, 7-4, 7-6, 7-84-85, B-2, C-12, D-6, E-7
- Energy and Environmental Research Corporation's Enhancing the Use of Coals by Gas Reburning and Sorbent Injection ES-6, 1-5, 2-5, 2-9, 2-17, 2-18, 2-22, 3-7, 4-7, 5-4, 5-49-52, 6-19, 7-3, 7-4, 7-68-69, B-1, B-5, C-11, D-5, E-6
- Energy and Environmental Research Corporation's Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler ES-4, 1-5, 2-6, 2-9, 2-17, 2-23, 3-7, 4-5, 5-1, 5-4, 5-19-20, 6-17, 7-2, 7-4, 7-42-43, B-2, B-5, C-6, D-3, E-3
- Four Rivers Energy Partners, L.P.'s Four Rivers Energy Modernization Project 1-5, 2-7, 2-8, 2-20, 2-23, 2-24, 3-6, 6-15, 7-2, 7-4, 7-12-13, B-4, C-2, D-1, E-1
- LIFAC-North America's LIFAC Sorbent Injection Desulfurization Demonstration Project ES-5, 1-6, 2-6, 2-9, 2-17, 2-23, 3-7, 4-6, 5-4, 5-30-32, 6-18, 7-3, 7-4, 7-56-57, B-3, B-5, C-9, D-4, E-5
- New York State Electric & Gas Corporation's Micronized Coal Reburning Demonstration for NO_x Control 1-6, 2-6, 2-9, 2-20, 2-23, 3-7, 6-17, 7-2, 7-4, 7-44-45, B-3, B-5, C-6, D-3, E-4
- New York State Electric & Gas Corporation's Milliken Clean Coal Technology Demonstration Project 1-6, 2-6, 2-9, 2-18, 2-23, 2-24, 3-7, 4-7, 4-9, 6-1, 6-7, 6-19, 7-3, 7-4, 7-70-71, B-4, B-5, C-11, D-5, E-6
- NOXSO Corporation's Commercial Demonstration of the NOXSO SO₂/NO_x Removal Flue Gas Cleanup System 1-6, 2-6, 2-9, 2-18, 2-23, 3-7, 6-19, 7-3, 7-5, 7-72-73, B-3, B-4, C-11, D-6, E-6
- The Ohio Power Company's Tidd PFBC Demonstration Project ES-3, ES-4, 1-5, 1-13, 1-15, 2-5, 2-8, 2-17, 2-22, 2-24, 3-6, 4-3, 4-4, 4-11, 5-1, 5-4, 5-6-9, 6-15, 7-2, 7-5, 7-14-15, B-1, B-5, C-2, D-1, E-1
- Passamaquoddy Tribe's Cement Kiln Flue Gas Recovery Scrubber ES-6, 1-6, 2-5, 2-11, 2-18, 2-22, 3-6, 4-3, 4-9, 5-4, 5-56-58, 6-21, 7-3, 7-5, 7-96-97, B-2, B-4, C-14, D-7, E-8
- Pennsylvania Electric Company's Warren Station Externally Fired Combined-Cycle Demonstration Project 1-5, 2-7, 2-8, 2-18, 2-23, 2-24, 3-6, 6-16, 7-2, 7-5, 7-34-35, B-4, C-6, D-3, E-3
- Public Service Company of Colorado's Integrated Dry NO_x/SO₂ Emissions Control System 1-6, 2-6, 2-9, 2-17, 2-24, 3-7, 4-7, 4-16, 5-2, 6-1, 6-8, 6-19, 7-3, 7-5, 7-74-75, B-3, C-11, D-6, E-6
- Pure Air on the Lake, L.P.'s Advanced Flue Gas Desulfurization Demonstration Project ES-5, ES-7, 1-6, 1-20, 2-5, 2-9, 2-18, 2-22-24, 3-7, 3-8, 4-3, 4-6, 4-11, 5-1, 5-2, 5-4, 5-33-36, 6-18, 7-3, 7-5, 7-58-59, B-2, B-5, C-9, D-4, E-5
- Rosebud SynCoal Partnership's Advanced Coal Conversion Process Demonstration ES-7, 1-6, 1-22, 2-5, 2-10, 2-18, 2-22, 3-7, 4-8, 6-1, 6-10, 6-20, 7-3, 7-5, 7-82-83, B-2, C-12, D-6, E-7
- Sierra Pacific Power Company's Piñon Pine IGCC Power Project 1-5, 2-6, 2-8, 2-19, 2-23, 2-24, 3-6, 6-1, 6-2, 6-16, 7-2, 7-5, 7-24-25, B-3, C-4, D-2, E-2
- Southern Company Services, Inc.'s Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler 1-6, 2-5, 2-9, 2-17, 2-22, 2-24, 3-7, 4-5, 4-9, 6-1, 6-6, 6-17, 7-2, 7-5, 7-46-47, B-2, C-7, D-3, E-4
- Southern Company Services, Inc.'s Demonstration of Innovative Applications of Technology for the CT-121 FGD Process ES-5, 1-6, 2-5, 2-9, 2-18, 2-22, 2-24, 3-7, 4-6, 4-11, 5-1, 5-3, 5-4, 5-37-40, 6-17, 6-18, 7-3, 7-5, 7-60-61, B-2, B-5, C-9, D-4, E-5
- Southern Company Services, Inc.'s Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers ES-4, 1-6, 2-5, 2-9, 2-17, 2-22, 3-7, 5-1, 5-2, 5-4, 5-23-24, 6-17, 7-2, 7-5, 7-48-49, B-2, B-5, C-8, D-3, E-4
- Southern Company Services, Inc.'s 180-MW_e Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers ES-4, 1-6, 2-5, 2-9, 2-17, 2-22, 2-24, 3-7, 4-5, 5-4, 5-21, 5-22, 6-17, 7-2, 7-5, 7-50-51, B-2, B-4, C-7, D-4, E-4

Tampa Electric Company's Tampa Electric
Integrated Gasification Combined-Cycle Project
1-5, 1-16, 2-6, 2-8, 2-19, 2-23, 2-24, 3-6, 6-1, 6-3,
6-16, 7-2, 7-5, 7-26-27, B-3, C-4, D-2, E-2

ThermoChem, Inc.'s Demonstration of Pulse
Combustion in an Application for Steam Gasification
of Coal 1-6, 2-6, 2-11, 2-20, 2-23, 2-24, 3-6, 6-21,
7-3, 7-5, 7-98-99, B-4, C-14, D-7, E-8

Tri-State Generation and Transmission Association,
Inc.'s Nucla CFB Demonstration Project ES-3,
ES-4, 1-5, 1-13, 1-14, 2-5, 2-8, 2-17, 2-22, 3-6, 3-8,
4-3, 4-4, 5-4, 5-10-12, 6-1, 6-15, 7-2, 7-5, 7-16-17,
B-1, B-3, C-3, D-1, E-1

Wabash River Coal Gasification Repowering Project
Joint Venture's Wabash River Coal Gasification
Repowering Project ES-3, 1-5, 1-8, 1-16, 2-6, 2-8,
2-18, 2-23, 2-24, 3-6, 4-3, 4-4, 4-12, 6-1, 6-4, 6-16,
7-2, 7-5, 7-28-29, B-3, C-5, D-2, E-2

York County Energy Partners, L.P.'s ACFB
Demonstration Project 1-5, 2-5, 2-8, 2-19, 2-20,
2-22, 2-24, 3-6, 6-15, 7-2, 7-5, 7-18-19, B-3, C-3,
D-2, E-2