CLEAN COAL TECHNOLOGY

DOE/FE-0219P

Clean Coal Technology Demonstration Program

Program Update 1990

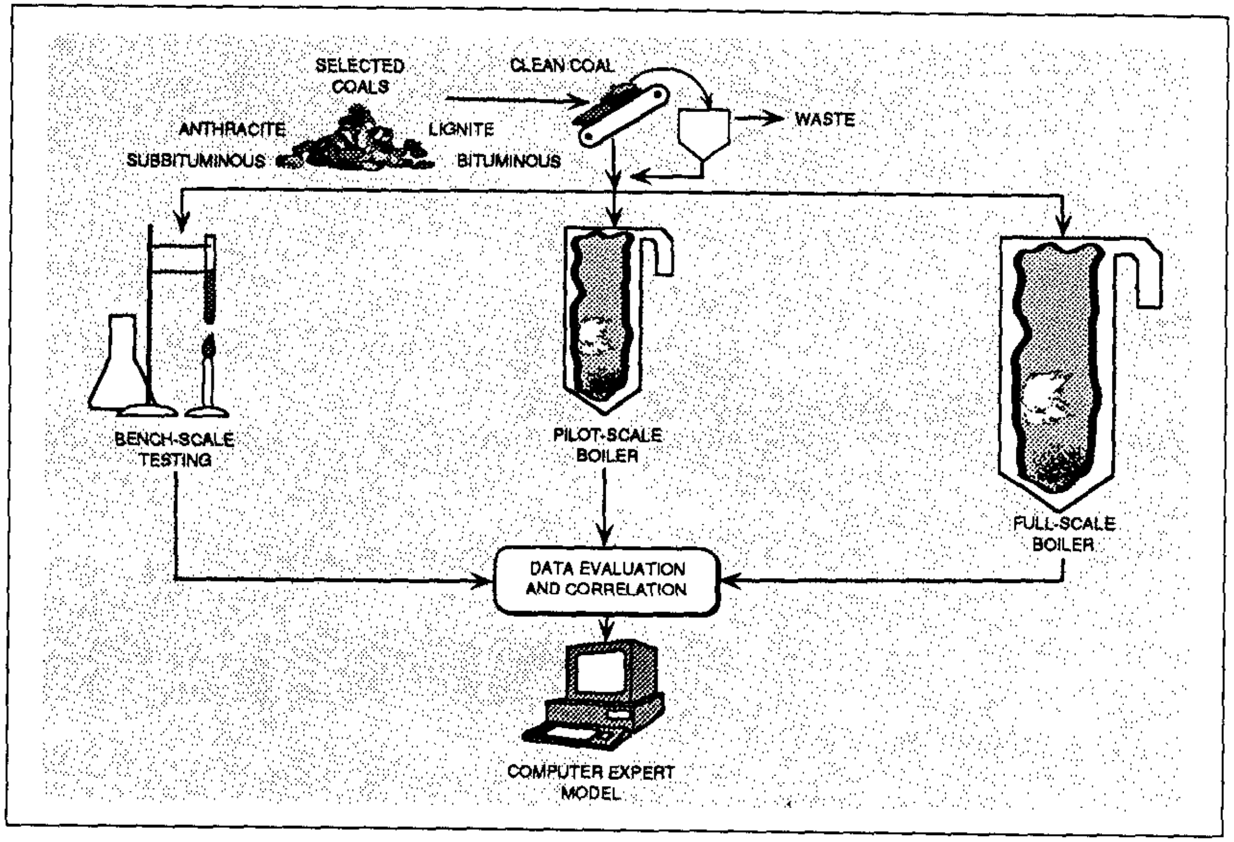
(As of December 31, 1990)

U.S. Department of Energy
Assistant Secretary for Fossil Energy

February 1991

CCT-I
Project Fact Sheets

Development of the Coal Quality Expert



Sponsor:

ABB Combustion Engineering, Inc., and CQ, Inc.

Additional Team Members:

Black and Veatch—cofunder and expert system developer
The Babcock & Wilcox Company—cofunder and pilot-scale testing
Electric Power Research Institute—cofunder
Electric Power Technologies, Inc.—field testing
Expert-EASE Systems Inc.—expert system architecture developer
University of North Dakota, Energy and Minerals Research Center—bench-scale testing
Alabama Power Company—host utility
Duquesne Light Company—host utility
Mississippi Power Company—host utility
Northern States Power Company—host utility
Pennsylvania Electric Company and New York State Electric & Gas Corporation—host site
Public Service of Oklahoma—host utility

Location:

Windsor, Hartford County, CT (pilot-scale tests)
Homer City, Indiana County, PA (Homer City, Unit 2)
Alliance, Columbiana County, OH (pilot-scale tests)
Wilsonville, Shelby County, AL (Gatson, Unit 5)
Bayport, Washington County, MN (King Station)
Gulfport, Harrison County, MS (Watson, Unit 4)
Oologah, Rogers County, OK (Northeastern, Unit 4)
Springdale, Westmoreland County, PA (Cheswick Station)
Grand Forks, Grand Forks County, ND (bench tests)

Congressional District:

Windsor, CT , 1st U.S. Congressional District
Homer City, PA, 4th U.S. Congressional District
Alliance, OH, 16th U.S. Congressional District
Wilsonville, AL, 2d U.S. Congressional District
Bayport, MN, 6th U.S. Congressional District
Gulfport, MS, 5th U.S. Congressional District
Oologah, OK, 3d U.S. Congressional District
Springdale, PA, 18th U.S. Congressional District
Grand Forks, ND, 1st U.S. Congressional District

Technology:

CQ, Inc.'s coal quality expert (CQE) computer model

Plant Capacity/Production:

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

Project Funding:

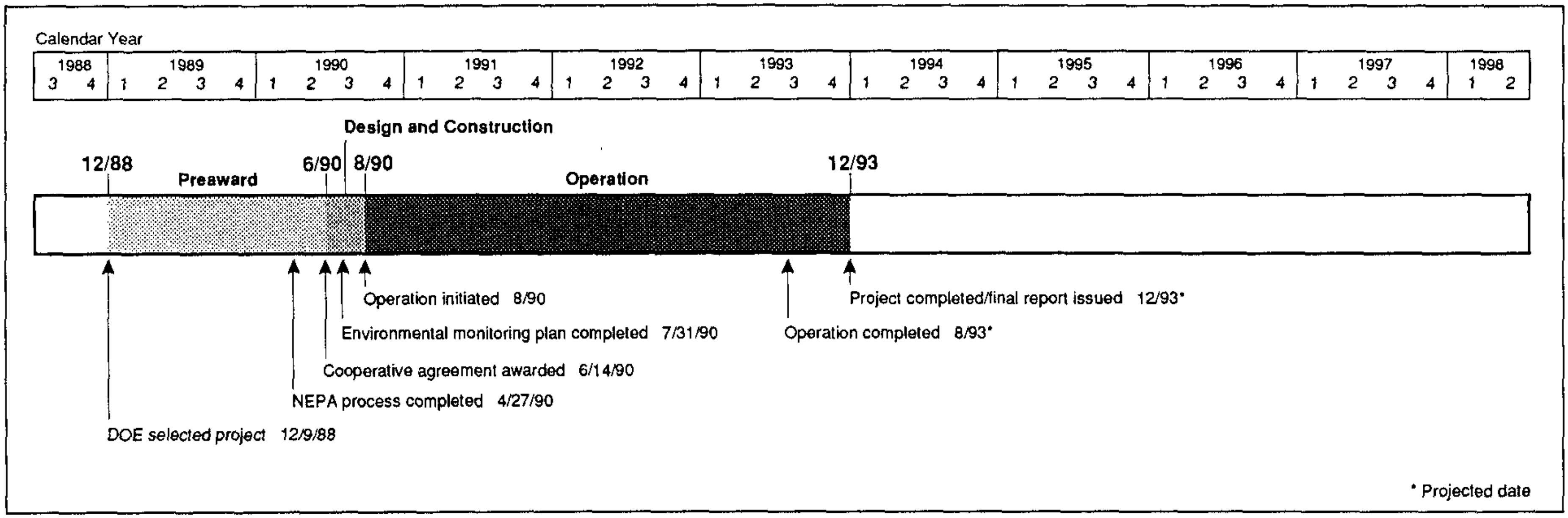
Total project cost	$17,382,258	100%
DOE	8,691,129	50
Participants	8,691,129	50

Project Objective:

To demonstrate an expert system that will run on a personal computer and provide coal-burning utilities with a predictive tool to assist in the selection of optimum quality coal for a specific boiler based on operational efficiency and environmental emissions.

Technology/Project Description:

Data derived from bench-, pilot-, and full-scale testing will be used to develop algorithms for inclusion into an expert computer model. Utilities may use the



information to predict the operating performance of coals not previously burned at a particular facility.

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

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

The project will provide a computer model, "Coal Quality Expert," that will run on a personal computer and predict reliably and inexpensively the operating performance of coals not previously burned at a facility.

Bench-scale testing will be performed at the University of North Dakota's Energy and Mineral Research Center in Grand Forks, ND; pilot-scale testing will be done at ABB Combustion Engineering's facilities in Windsor, CT, and Alliance, OH. The six field test sites are: Watson, Unit 4 (250 MWe), Gulfport, MS; Gatson, Unit 5 (880 MWe), Wilsonville, AL; Northeastern, Unit 4 (445 MWe), Oologah, AL; Homer City, Unit 2 (600 MWe), Homer City, PA; King (560 MWe), Bayport, MN; and Cheswick (500 MWe), Springdale, PA.

Project Status/Accomplishments:

The first of six field tests was conducted in August 1990 at Public Service of Oklahoma's Northeastern Unit 4, a 445-MWe tangentially fired supercritical unit commissioned in 1980. Comparative test burns of two coals were made to assess coal quality impacts on boiler performance and emissions. The two coals were a blend of 10% Oklahoma and 90% Wyoming and a blend of 30% Oklahoma and 70% Wyoming. Oklahoma coal has been cleaned and shipped to the pilot and bench sites for testing. Bench- and pilot-scale testing, begun in late 1990, will continue into early 1991.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on April 27, 1990.

It is projected that by using the CQE model, SO_2 and NO_x emissions can be significantly reduced on a national basis relative to a no-action alternative. The expert system will enable coal-fired utilities to select the optimum quality coal for their specific boiler to reduce SO_2 and NO_x emissions.

Commercial Application:

The CQE system is applicable to all electric power plants and industrial/institutional boilers that burn coal. The CQE will predict the operational and emission reduction benefits of using cleaned coal. Following the demonstration, CQ, Inc., will market the CQE system in the United States and abroad.

LIMB Demonstration Project Extension

Sponsor:
The Babcock & Wilcox Company

Additional Team Members:
Ohio Coal Development Office—cofunder
Consolidation Coal Company—cofunder and technology supplier
Ohio Edison Company—host utility

Location:
Lorain, OH (Ohio Edison's Edgewater Station)

Congressional District:
13th U.S. Congressional District

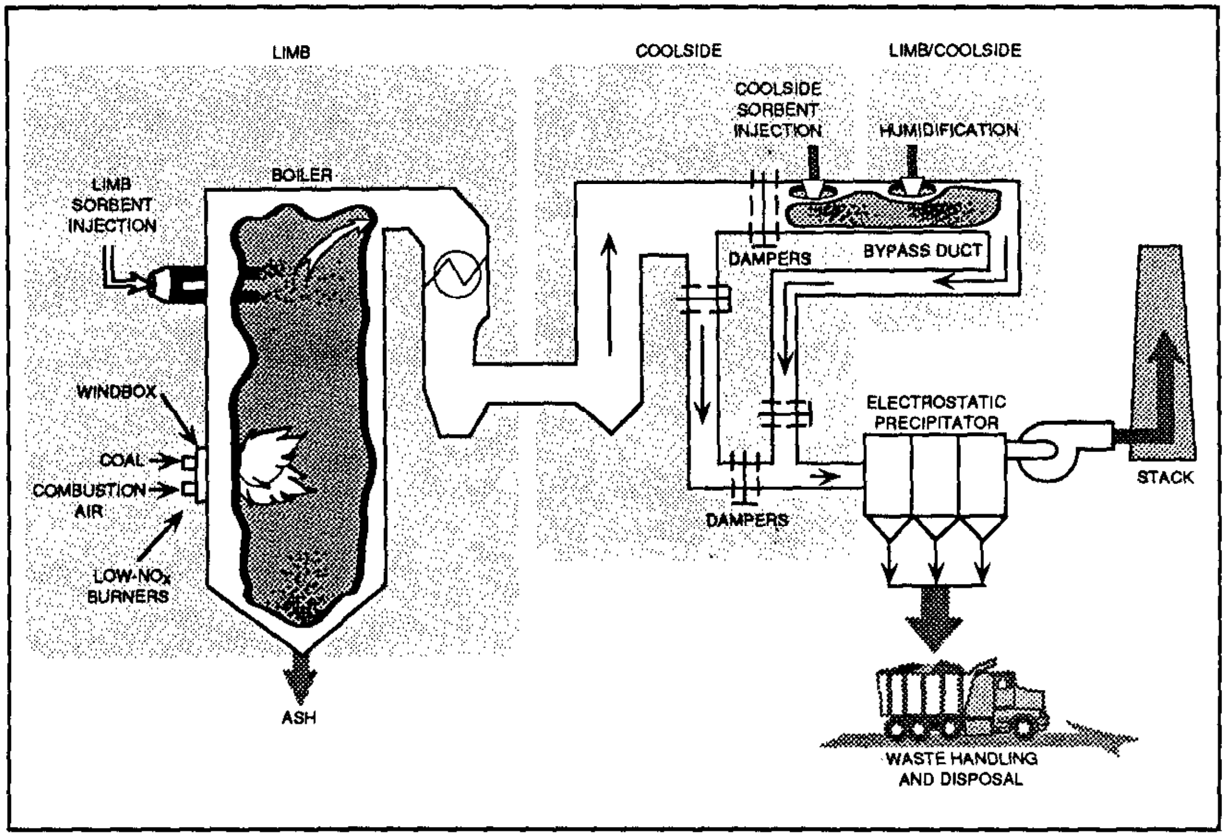
Technology:
The Babcock & Wilcox Company's limestone injection multistage burner (LIMB) system
Consolidation Coal Company's Coolside duct injection of lime sorbents

Plant Capacity/Production:
104 MWe

Project Funding:

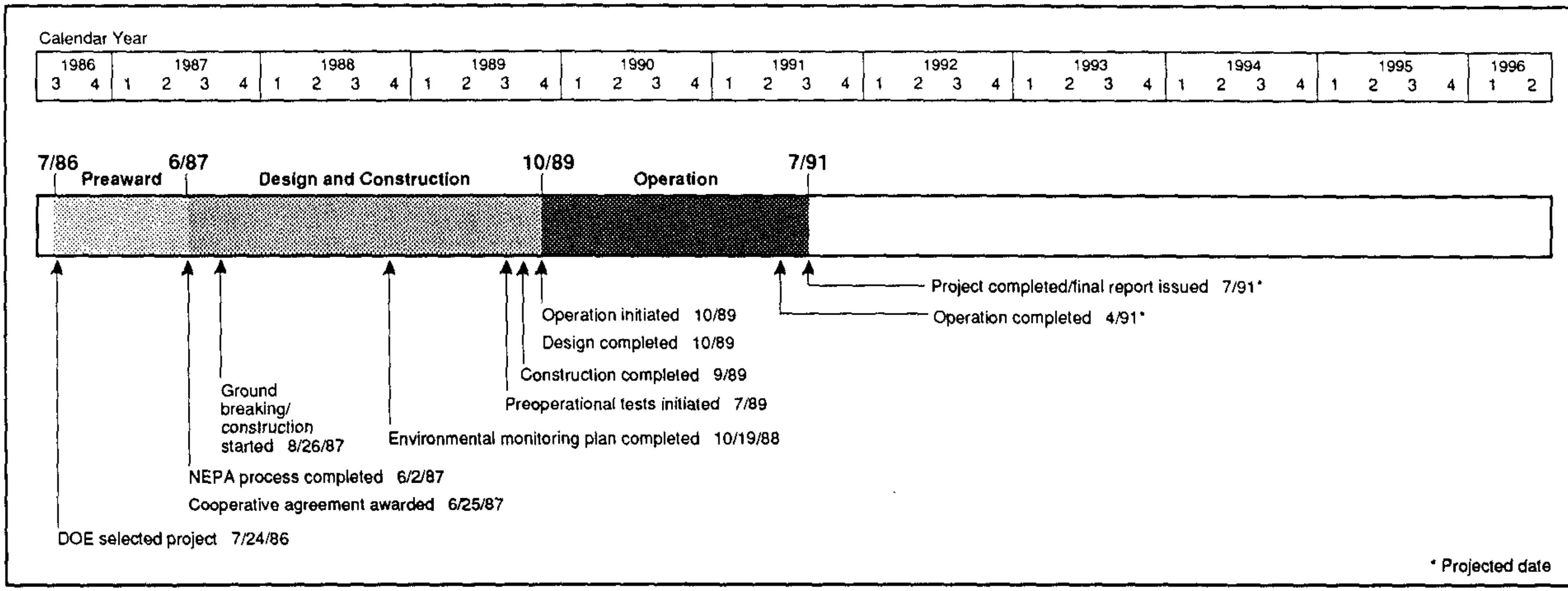
Total project cost	$19,404,940	100%
DOE	7,597,026	39
Participants	11,807,914	61

Project Objective:
To demonstrate, with a variety of coals and sorbents, the limestone injection multistage burner (LIMB) process as a retrofit system for simultaneous control of sulfur and nitrogen oxides in the combustion process, and that LIMB can achieve up to 60% NO_x and SO_2 reductions. Additionally, using the Coolside duct injection process, to test alternate sorbent and coal combinations to demonstrate in-duct sorbent injection, upstream of the humidifier and precipitator, to show SO_2 removal of up to 80%.



Technology/Project Description:
The LIMB process is expected to reduce SO_2 by 50–60% 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 the existing particulate removal equipment, either an electrostatic precipitator (ESP) or a baghouse. Humidification of the flue gas before it enters an ESP is necessary to maintain normal ESP operation and to enhance SO_2 removal. This project will test combinations of three coals, each with a different sulfur content (1.8%, 3.0%, and 3.8%), and four sorbents. The tests are expected to provide commercial-scale operating and maintenance data on a variety of coal/sorbent combinations with diverse SO_2 removals and costs. Both limestone and hydrated lime (calcitic and dolomitic) sorbents will be tested.

In the Coolside process, dry sorbent is injected into the flue gas after the boiler and before the ESP. The gas is humidified in this process to enhance both ESP performance and SO_2 absorption. Also, a chemical additive can be dissolved in the humidification water to improve SO_2 absorption. Because of these benefits, it is expected that humidification equipment will be part of most, if not all, commercial Coolside applications. The spent sorbent is also collected with the fly ash as in the LIMB process. Reduction of SO_2 by 50–80% is expected.



Both demonstrations will use the same low-NO_x burners, which control NO_x by injecting the coal and part of the combustion air simultaneously so that the first of the combustion reactions takes place in an oxygen-deficient environment. The balance of the combustion air is introduced in a second stage to complete the combustion process. Staged combustion has been found to reduce NO_x emissions by 50–60%.

This project is being conducted at Ohio Edison's Edgewater Plant in Lorain, OH, on a commercial, Babcock & Wilcox Carolina design, wall-fired 104-MWe boiler.

Project Status/Accomplishments:
The project has completed testing of the Coolside process and is in the middle of the LIMB extension testing, which runs until April 1991.

Coolside testing results indicate that this process can remove up to 70% of the SO_2 when using 3.0% sulfur coal at a 2:1 calcium-to-sulfur molar ratio using a commercially available hydrated lime, a 20 °F approach to adiabatic saturation, and an additive to the humidification water at a 0.2:1 sodium-to-calcium ratio. These results favorably confirmed the previous pilot-scale testing. The hydrated lime source affected SO_2 removal. Recycling spent sorbent significantly increased sorbent utilization. The project clearly achieved its objectives to retrofit a Coolside system to an existing boiler and reduce significantly the amount of SO_2 emitted without any adverse effects on the system. A complete report of this testing effort will be published in early 1991.

LIMB extension testing has shown similar SO_2 removal capabilities with the most reactive of the limes tested to date and heavy humidification (a 20 °F approach to adiabatic saturation). NO_x removal has been in the 40–50% range throughout both Coolside and LIMB testing.

Environmental Considerations:
NEPA compliance was satisfied with a memo-to-file signed on June 2, 1987.

Because of wide market application, SO_2 and NO_x reductions of 30% and 11% respectively by 2010 are projected on a national basis, assuming maximum commercialization of the technology. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
Sorbent injection is applicable to most utility and industrial coal-fired units and can be retrofitted with modest capital investment and downtime.

The LIMB and Coolside processes both provide an alternative to conventional wet flue gas desulfurization (FGD) processes. Both are expected to be substantially less expensive than wet FGD, and their space requirements are also substantially less. These factors are important in retrofit applications.

Arvah B. Hopkins Circulating Fluidized-Bed Repowering Project

Sponsor:
The City of Tallahassee

Additional Team Members:
Foster Wheeler Energy Corporation—technology supplier
Bechtel Power Corporation—engineer and constructor
City of Tallahassee—host utility

Location:
Tallahassee, Leon County, FL (Arvah B. Hopkins Station Unit 2)

Congressional District:
2d U.S. Congressional District

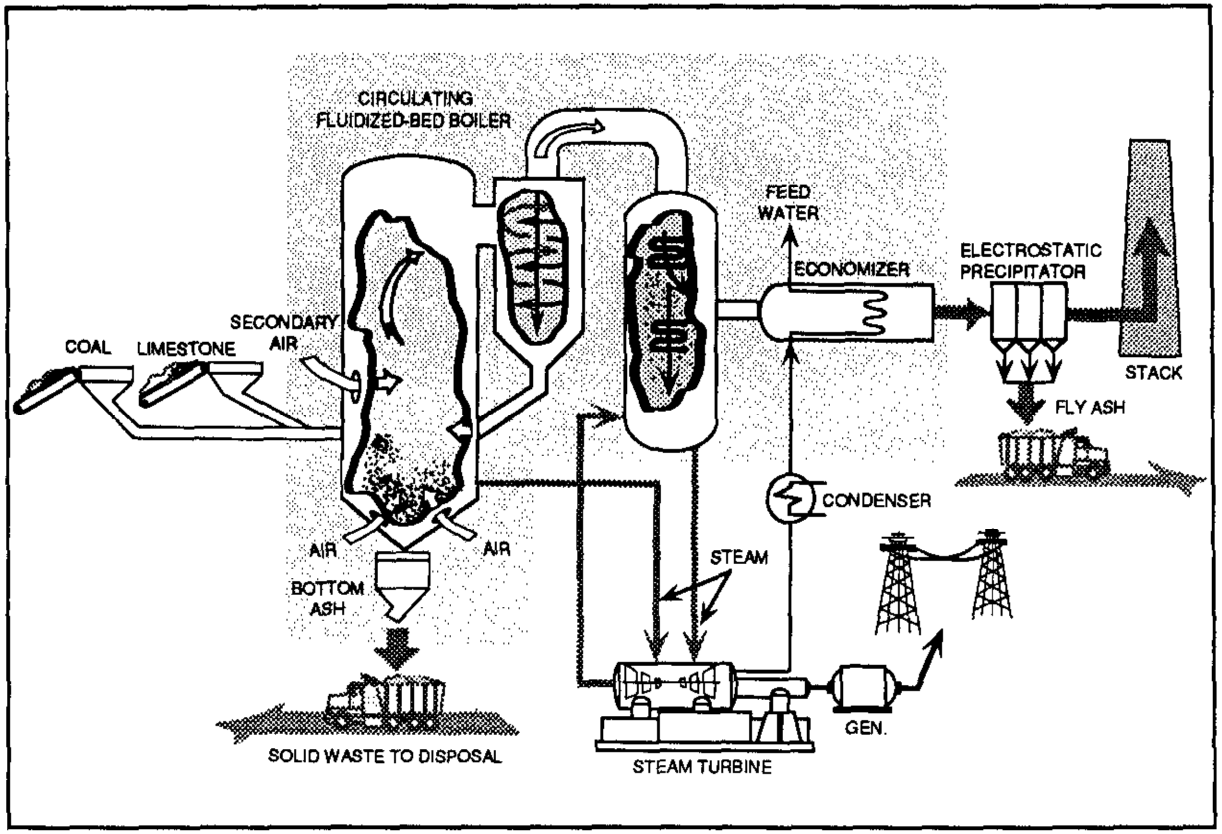
Technology:
Foster Wheeler's atmospheric circulating fluidized-bed combustor (ACFB)

Plant Capacity/Production:
250 MWe

Project Funding:

Total project cost	$276,791,974	100%
DOE	74,733,833	27
Participant	202,058,141	73

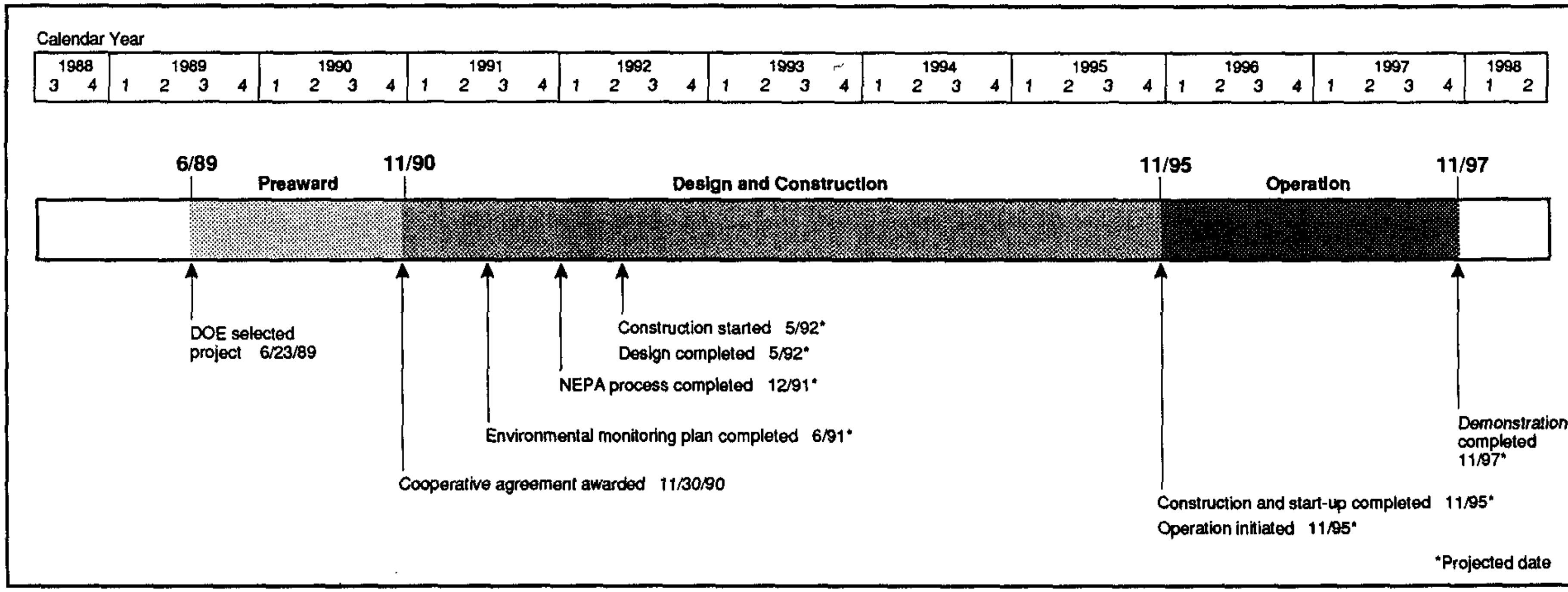
Project Objective:
To demonstrate ACFB at 250 MWe, representing a 1.7:1 scale-up from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance in the repowering of an existing oil-/natural gas-fired boiler at a utility site; and to provide the utility industry with the data necessary for evaluating a 250-MWe ACFB as a commercial alternative to accomplish greater than 90% SO_2 removal, to reduce NO_x emissions by 60%, 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 a water-wall combustor where initial combustion occurs. Combustion takes place at relatively low temperatures of 1,500–1,600 °F. 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.

Heat is removed by the water walls as well as by superheaters located within the circulating loop encompassing the combustor, particle separator, and solids recycle leg. Combustion gases that leave the particle separator are cooled in a convective back pass containing additional superheaters, water walls, and an economizer. The steam produced is sent to the steam turbine to generate power. Sulfur is absorbed by the sorbent and removed with the ash.

This project involves repowering an existing steam electric power plant by using a scaled-up ACFB boiler. A coal-fired ACFB steam-generating system will



replace the existing oil-/gas-fired steam-generating system used to drive a steam turbine. The existing turbine generator and the balance of the equipment are being retained.

Project Status/Accomplishments:

The cooperative agreement was awarded November 30, 1990. Design is under way.

Environmental Considerations:

The environmental information for the NEPA compliance process has been submitted by the participant.

The following are projected impacts from maximum commercialization of the ACFB technology on a national basis by 2010 relative to a no-action alternative:

- SO_2 reduction—44%
- NO_x reduction—17%
- Solid waste increase, but in a dry, granular form amenable to some by-product markets
- CO_2 reduction—5%

(Source: CCT Programmatic Environmental Impact Statement)

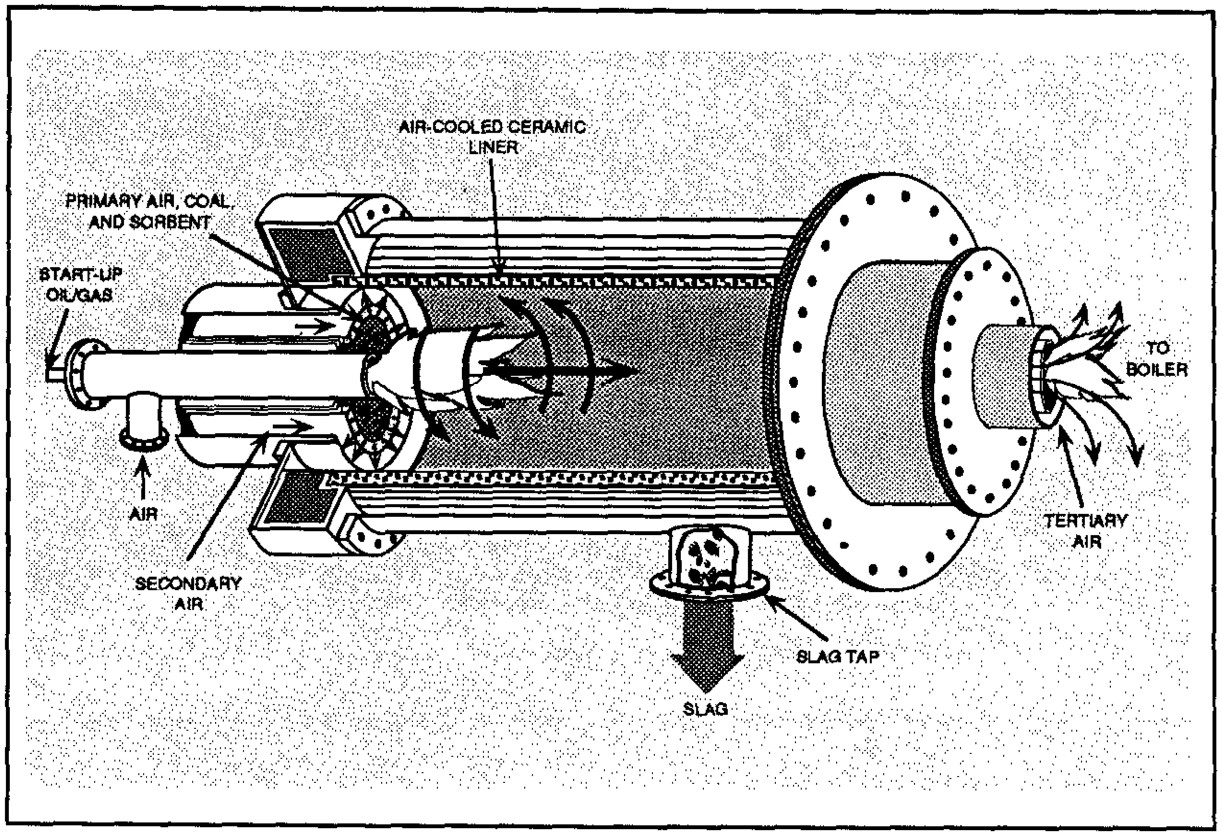
Commercial Application:

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. Coal of any sulfur content can be used, and any type or size of a coal-fired boiler can be repowered. Because an existing plant area is used, and coal- and waste-handling equipment as well as steam turbine equipment are retained, the life of a plant can be extended.

In its commercial configuration, ACFB technology offers several potential benefits when compared to conventional pulverized coal-fired systems:

- Lower capital costs
- Reduced SO_2 and NO_x emissions at lower costs
- Higher combustion efficiency
- Dry, granular solid waste

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



Sponsor:
Coal Tech Corporation

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

Location:
Williamsport, Lycoming County, PA (Tampella Keeler boiler manufacturing plant)

Congressional District:
17th U.S. Congressional District

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

Plant Capacity/Production:
23 million Btu/hr

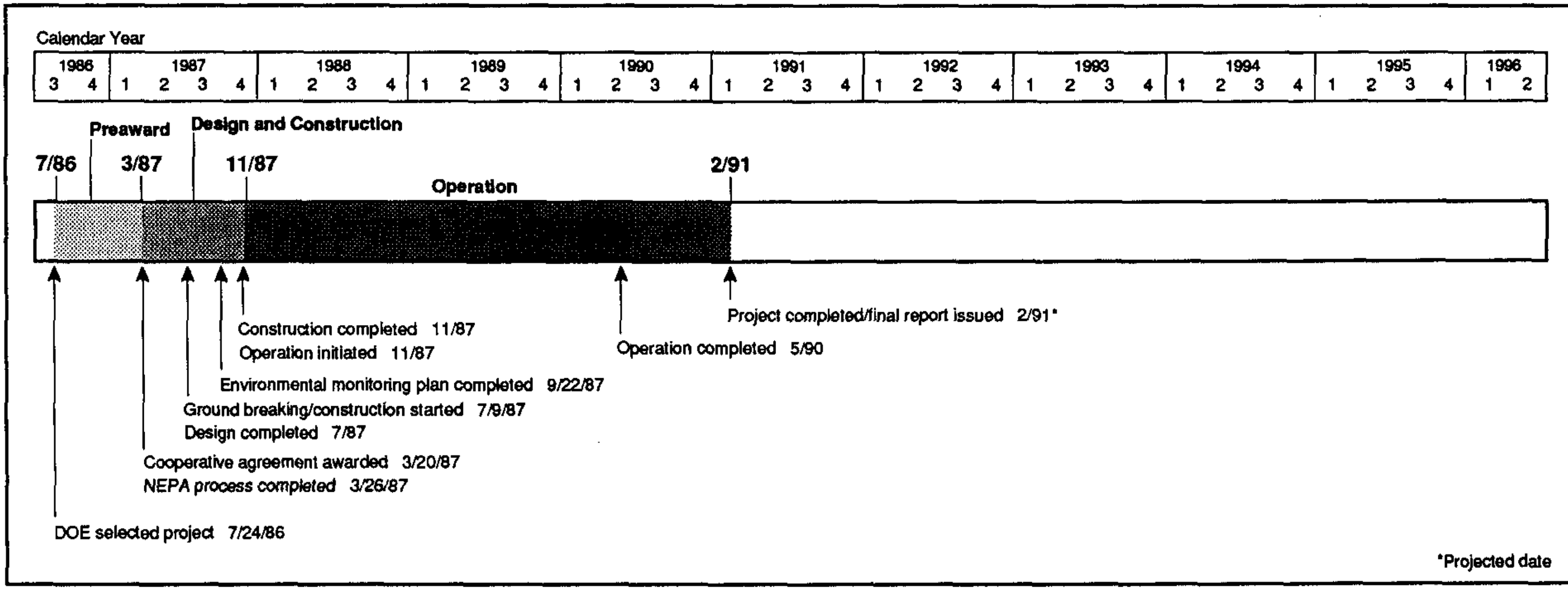
Project Funding:

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

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

Technology/Project Description:
Coal Tech's horizontal cyclone combustor is internally lined with ceramic that is air-cooled. Pulverized coal, air, and sorbent are injected 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. The fine coal pulverization allows combustion of approximately two-thirds of the coal particles near the cyclone wall, with the balance being burned on or near the wall. This improves combustion in the fuel-rich chamber, as well as slag retention. The slag contains over 90% 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.

The project features combustion of dry pulverized coal in an advanced, air-cooled, cyclone coal combustor retrofitted on a 23-million Btu/hr oil-designed package boiler located at the Tampella Keeler plant in Williamsport, PA. Pennsylvania bituminous coals containing from 1% to approximately 4% sulfur were tested to demonstrate that this combustor is capable of burning most U.S. coals in an environmentally acceptable manner.



Project Status/Accomplishments:

Coal Tech completed design, construction, and operation by year-end 1990 and will issue a final report in February 1991. The Coal Tech combustor was operated for approximately 1,000 hours under varying loads and conditions simulating industrial applications. Results indicate that Coal Tech has achieved most of the objectives that were set forth in the cooperative agreement during the 30-month test period. The test results indicate that Coal Tech's air-cooled, coal-fired, slagging combustor can successfully (1) be retrofitted to and operate efficiently over a wide stoichiometric range on previously oil- or gas-fired boilers, (2) reduce coal-derived NO_x emissions by approximately 75%, (3) remove up to 90% of the coal slag at the combustor slag tap upstream of the boiler, and (4) capture and remove with the slag about 10% of the sulfur contained in the coal. Coal Tech also has test results indicating that over 80% sulfur removal can be achieved through a combination of sorbent injection at and downstream of the combustor. Coal Tech has concluded that this novel air-cooled combustor design concept is sound and that sufficient design and operational information has been obtained from this CCT demonstration to scale up to 100 MMBtu/hr.

Environmental Considerations:

NEPA compliance was satisfied by a memo-to-file approved on March 26, 1987.

The advanced cyclone combustor is expected to reduce emissions as follows:

- SO_2 reduction—10%
- NO_x reduction—67%

The SO_2 emissions are reduced through sorbent injection. Additionally, up to 90% of the ash is removed with this process.

Commercial Application:

Coal Tech's advanced, air-cooled, slagging combustor permits the combustion of a wide range of U.S. coals, including high-sulfur coals. This combustor can be used to retrofit boilers that currently operate with oil or gas firing, due to the combustor's ability to effectively eliminate coal solids upstream of the boiler and to control NO_x and SO_2 emissions.

Nucla CFB Demonstration Project

Sponsor:
Colorado-Ute Electric Association, Inc.

Additional Team Members:
Pyropower Corporation—technology supplier
Technical Advisory Group (potential users)—cofunder
Electric Power Research Institute—technical support

Location:
Nucla, Montrose County, CO (Nucla Station)

Congressional District:
3d U.S. Congressional District

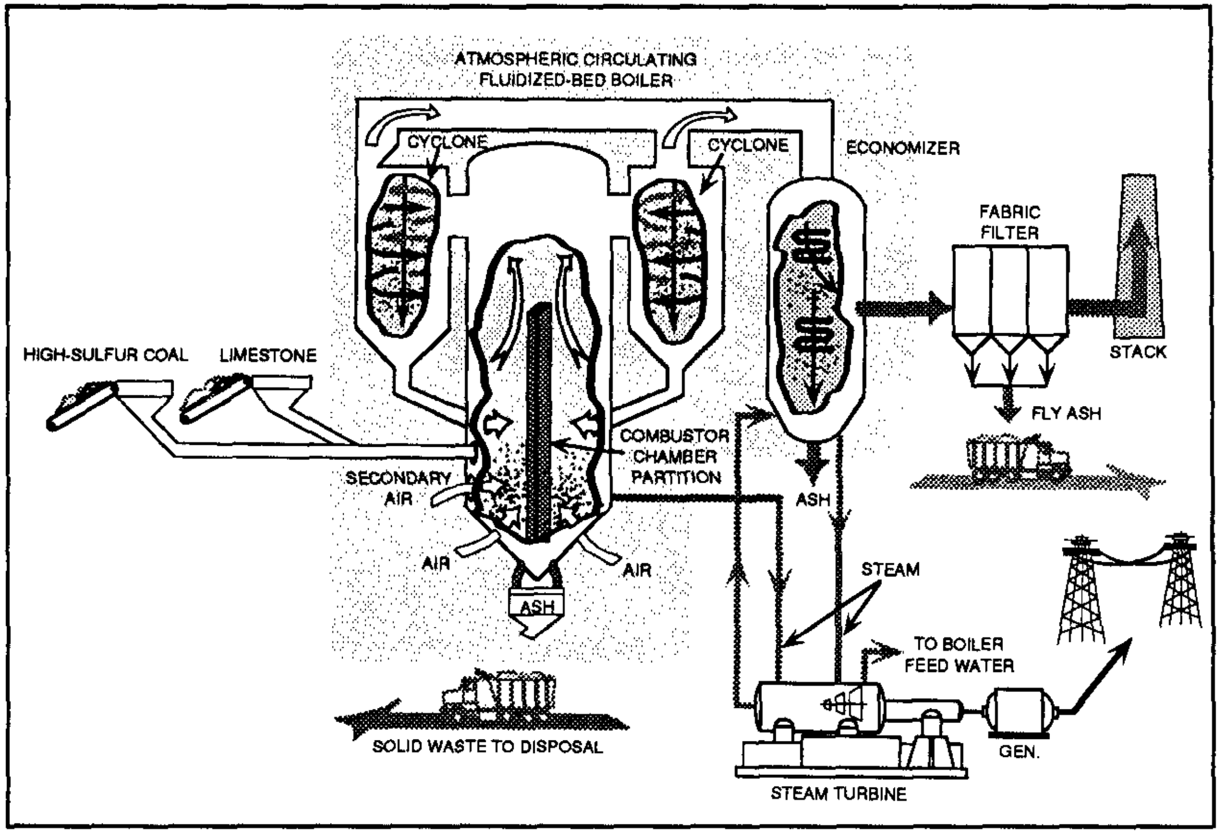
Technology:
Pyroprower's atmospheric circulating fluidized-bed combustion (ACFB) system

Plant Capacity/Production:
110 MWe

Project Funding:

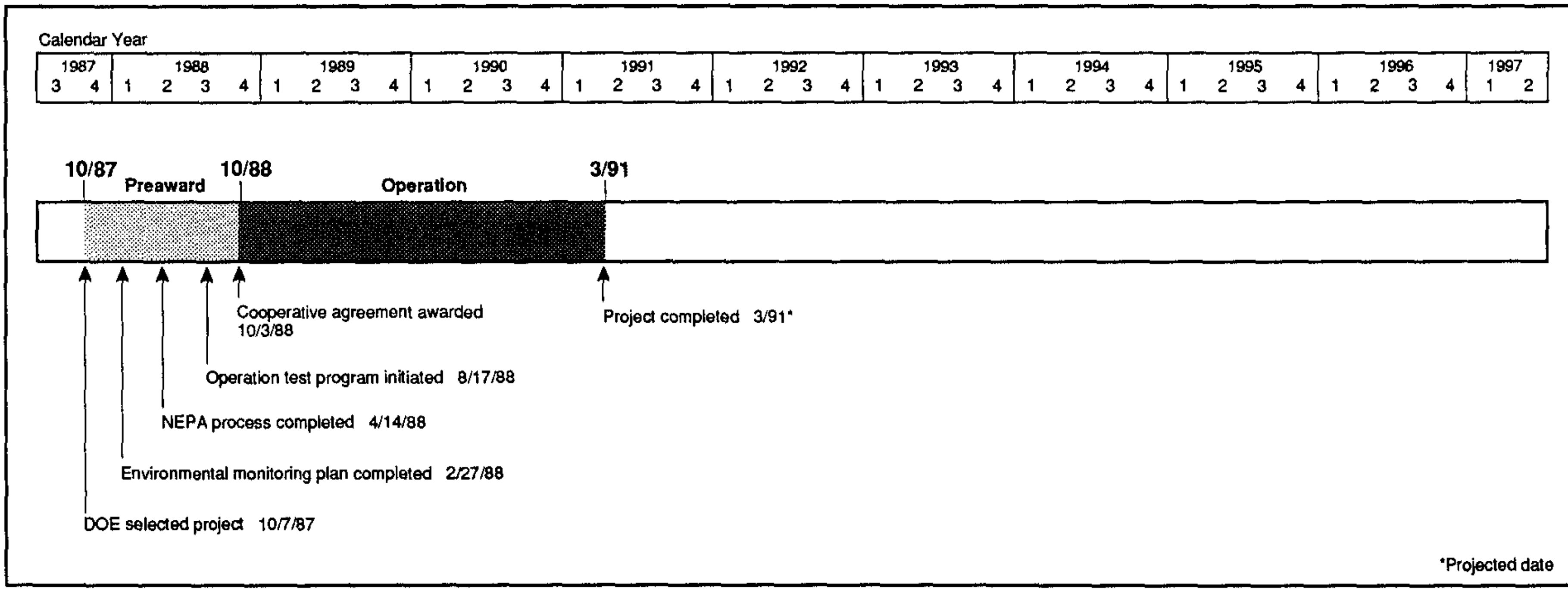
Total project cost	$54,087,000	100%
DOE	19,920,000	37
Participants	34,167,000	63

Project Objective:
To demonstrate ACFB at a scale of 110 MWe, representing a 2:1 scale-up 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% SO_2 removal, to reduce NO_x emissions by 60%, and to achieve an efficiency of 34% in a repowering mode.



Technology/Project Description:
The Nucla circulating fluidized-bed system operates at atmospheric pressure. In the combustion chamber, a stream of air fluidizes and entrains the bed material, which includes coal, coal ash, and a sulfur sorbent such as limestone. Combustion takes place at relatively low temperatures that limit NO_x formation. Calcium in the sorbent combines with SO_2 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 an electrostatic precipitator where the particulate matter is removed. The steam generated in the ACFB is used to generate power.

Three small, coal-fired, stoker-type boilers at the Colorado-Ute Nucla Station were replaced with a single ACFB steam generator capable of driving a new 74-MWe turbine generator. Extraction steam from this turbine generator will power the three existing turbine generators of 12 MWe each. The majority of other existing plant equipment is being used to minimize costs and to demonstrate the suitability of ACFB technology for repowering and life extension of existing units.



Project Status/Accomplishments:

The project was initially scheduled to be completed in August 1990 following a 2-year operational test program. Although some 12,500 hours of testing were accomplished, the test program could not be completed within the original schedule because of numerous plant outages for repairs and plant modifications that were mostly unrelated to the ACFB technology. Therefore, testing was extended to March 1991 to complete the program and determine the optimum operating conditions and performance with high-sulfur coals.

To date, Nucla has met all NSPS requirements with better than 90% sulfur capture, has typically achieved NO_x emissions less than 80 ppm, and has removed 99.9% of the particulates. Cost information is promising, with estimated capital cost at $873/kW and operating cost at $20/MW. This is competitive with pulverized coal units that are not limiting emissions as significantly as Nucla. Heat rates have averaged 11,900 Btu/kWh, somewhat in excess of those projected. Future testing will determine optimum operating parameters to maximize thermal efficiency.

Environmental Considerations:

NEPA compliance was satisfied April 14, 1988, with a memo-to-file. The performance to date of the demonstration has met or exceeded the improved environmental performance projections for the ACFB.

The following impacts are projected from maximum commercialization of the ACFB technology on a national basis by 2010 relative to a no-action alternative:

- SO_2 reduction—44%
- NO_x reduction—17%
- CO_2 reduction—5%

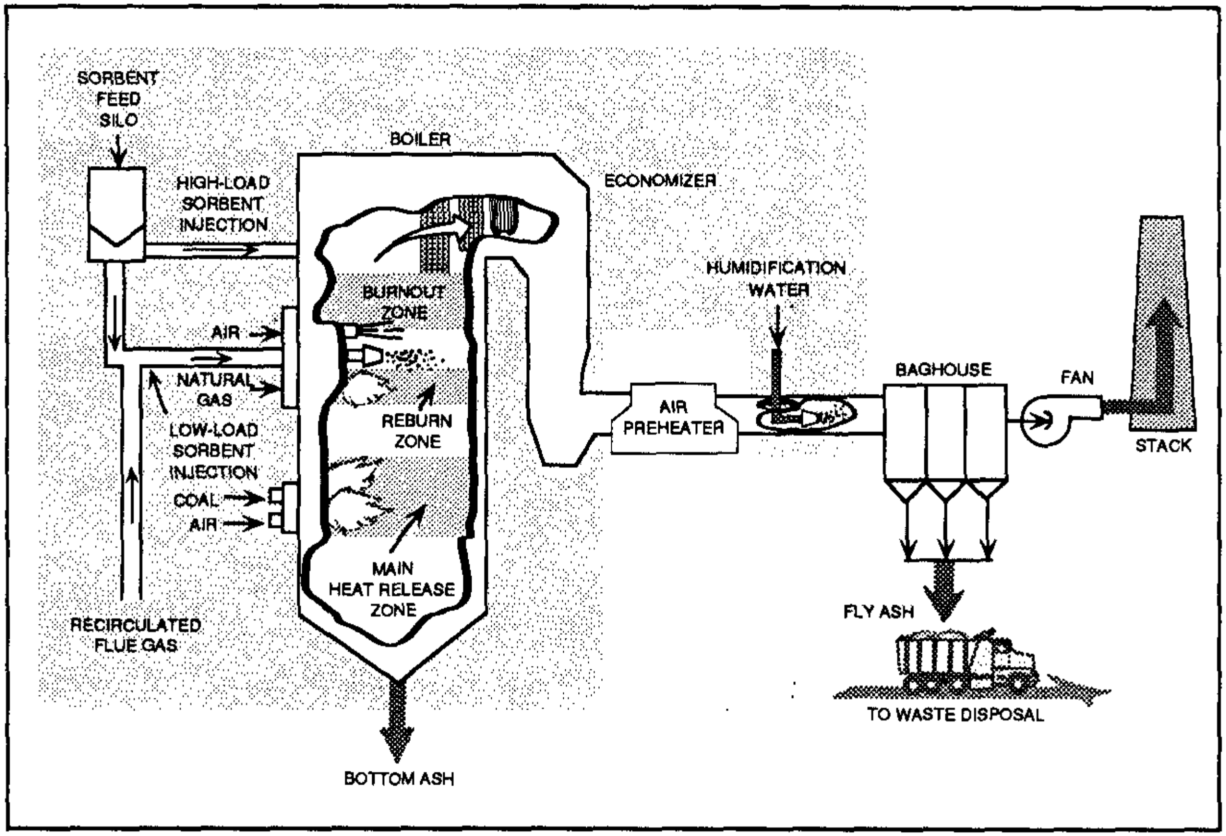
Although solid waste is expected to increase, it would be in a dry, granular form more amenable to alternative uses, such as construction aggregate, and requiring less land area for disposal than conventional scrubber sludge.

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

ACFBs have good potential for both the industrial and utility sectors in repowering existing coal-fired plants or constructing new facilities. In repowering applications, ACFB can increase capacity by an increment of approximately 15%. Coal of any sulfur content can be used. Because any type or size of boiler can be repowered by ACFB using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment, the life of the plant can be extended. Benefits of ACFB include 90% SO_2 reduction, 60–80% NO_x reduction, and control of pollutants at lower costs than are offered by existing technologies.

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection



Sponsor:
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 utility

City Water, Light and Power—host utility

Central Illinois Light Company—host utility

Locations:
Hennepin, Putnam County, IL (Illinois Power Company, Hennepin Plant)

Springfield, Sangamon County, IL (City Water, Light and Power, Lakeside Station)

Congressional District:
Hennepin, IL, 17th U.S. Congressional District

Springfield, IL, 20th U.S. Congressional District

Technology:
Energy and Environmental Research Corporation's gas reburning and sorbent injection process

Plant Capacity/Production:
Hennepin site: tangentially fired 80 MWe (nominal)

Springfield site: cyclone-fired 40 MWe (nominal)

Project Funding:

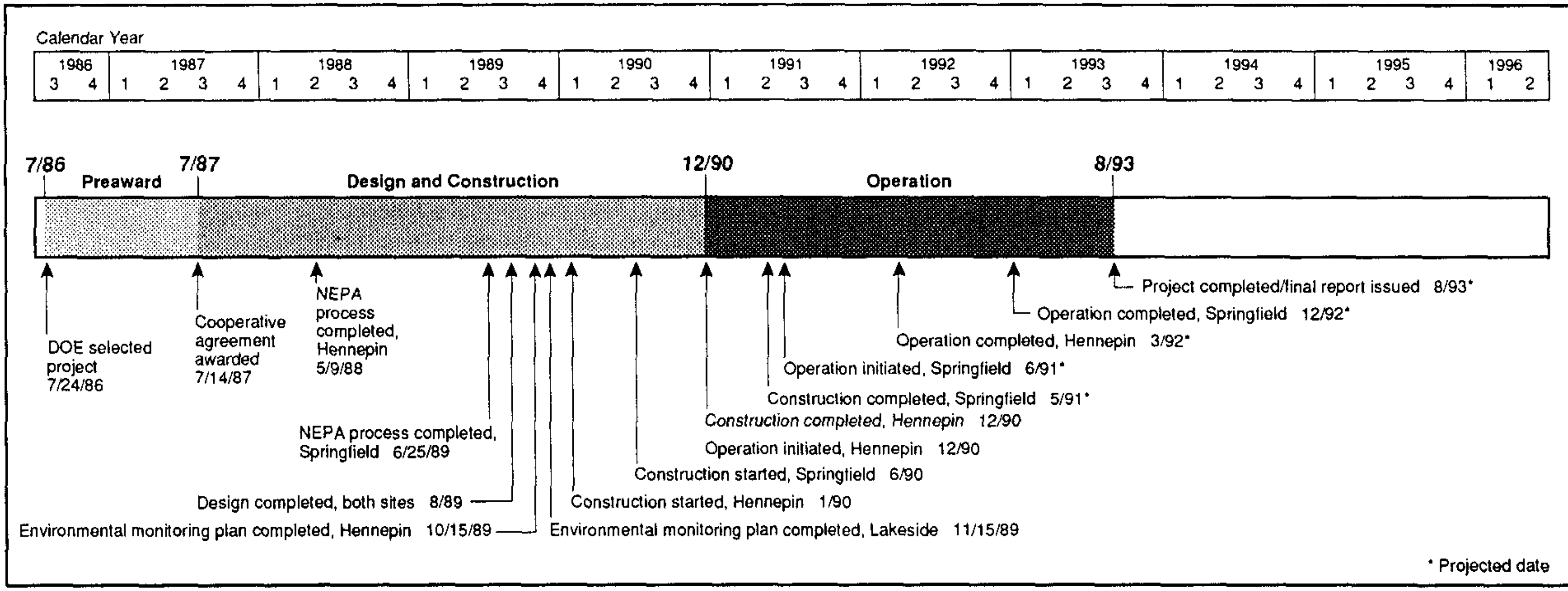
Total project cost	$29,998,253	100%
DOE	14,998,253	50
Participants	15,000,000	50

Project Objective:
To demonstrate gas reburning to attain 60% NO_x reduction along with sorbent injection to capture 50% of the SO_2 on two different boiler configurations: tangentially and cyclone fired.

Technology/Project Description:
Gas reburning is a postcombustion technology that is being developed primarily for the removal of NO_x. 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 compounds to be tested will be $CaCO_3$ (calcium carbonate) and $Ca(OH)_2$ (lime). This project will demonstrate the gas reburning and sorbent injection process on two separate boilers representing two different firing configurations, a tangentially fired 80-MWe boiler and a cyclone-fired 40-MWe boiler.

The project is expected to achieve 60% NO_x reduction and 50% SO_2 reduction on different boiler configurations at power plants burning high-sulfur midwestern coal.

The project will be conducted at the Illinois Power Company plant near Hennepin, IL, and the City Water, Light and Power plant in Springfield, IL.



Project Status/Accomplishments:
Permitting and engineering design efforts were completed in 1989 for the three original project sites, thus providing a more exact definition of project requirements for the sites under consideration. In 1990 plans to use the third site (near Bartonville, IL) were suspended. Construction activities for the tangentially fired boiler at the Hennepin site were completed in December 1990. Operation activities at the Hennepin site also began in December 1990. Construction has begun at the cyclone-fired site at Springfield, and significant progress has been made.

Environmental Considerations:
NEPA compliance for the two active demonstration sites has been satisfied:

- Hennepin site—memo-to-file approved on May 9, 1988
- Springfield site—environmental assessment approved and finding of no significant impact issued on June 25, 1989.

Assuming maximum commercialization, significant SO_2 and NO_x reductions (38% and 11% respectively) are projected to be achievable nationally by 2010 with enhancement of the use of coals by gas reburning and sorbent injection relative to a no-action alternative. Gas reburning will reduce emissions of NO_x, and sorbent injection will reduce emissions of SO_2. The gas reburning and sorbent injection process has wide applicability as it can be retrofitted to many coal-fired boilers. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
Gas reburning and sorbent injection is the unique combination of these two separate technologies. The commercial application for these technologies, both combined and separately, extends 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; additionally the technologies can be applied to new utility boilers. With 60% NO_x removal and 50% SO_2 removal, 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 without exceeding emission limits for NO_x and SO_2.

Prototype Commercial Coal/ Oil Coprocessing Plant

Sponsor:
Ohio Clean Fuels, Inc.

Additional Team Members:
Stone and Webster Engineering Company—engineer and constructor
Hydrocarbon Research, Inc.—technology owner
Ohio Coal Development Office—cofunder

Location:
Warren, Trumbell County, OH

Congressional District:
17th U.S. Congressional District

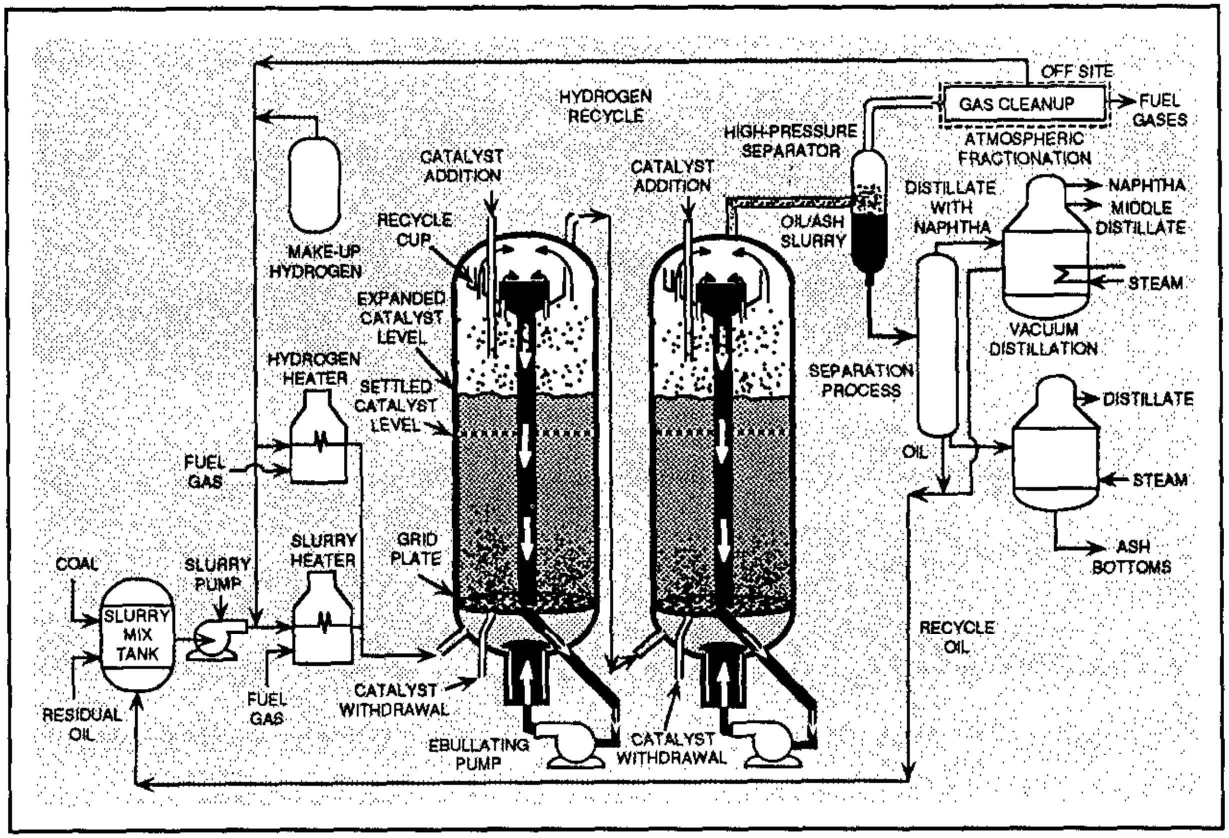
Technology:
Hydrocarbon Research's coal/oil coprocessing using ebullated-bed catalytic hydrogenation

Plant Capacity/Production:
About 11,750 barrels/day of liquid product processed from 800 tons/day of high-sulfur coal

Project Funding:

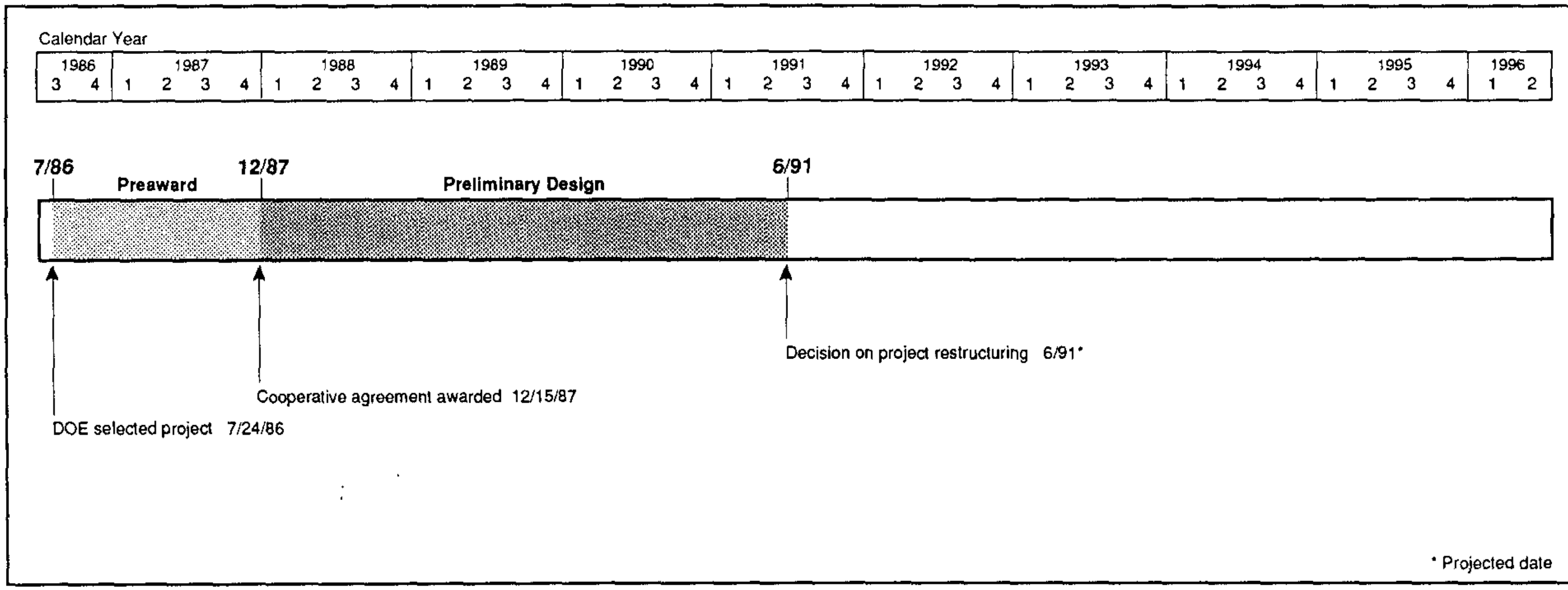
Total project cost	$225,674,805	100.0%
DOE	45,000,000	20
Participants	180,674,805	80

Project Objective:
To constitute a prototype commercial application of coal/oil coprocessing to process high-sulfur, high-nitrogen, bituminous coal and petroleum residuum to produce a clean-burning liquid fuel.



Technology/Project Description:
The project is intended to be a grass-roots facility; meaning that it is a self-sustaining, fully integrated chemical process facility. Coal is received and prepared by crushing and fine grinding and made into a coal/oil slurry by being blended with the heavy Cold Lake crude oil. This slurry is then pressurized and raised to reaction temperature and, along with a hydrogen gas stream, is fed to the ebullated catalyst-containing process reactors where the coal conversion takes place. The resulting mixture is then depressurized, and the liquid products are separated from the heavy, solids-containing stream. The hydrogen used in the process is produced by a conventional steam-reforming process that uses natural gas as its feedstock. The liquid products generated can be used directly as a boiler fuel or as a refinery feedstock for further upgrading to higher value products such as gasoline. The project will also produce propane, butane, sulfur, and ammonia as useful by-products. The low-value solids-containing stream can either be combusted on site to generate steam for process use or sold for direct use such as an aggregate for making concrete.

The prototype plant originally was proposed for a site in Warren, OH. It would process 800 tons/day of coal plus sufficient residuum to yield 11,750 barrels/day of clean distillate products. However, relocation of the project is under consideration in an effort to improve the economics and attract a host facility.



Project Status/Accomplishments:

Since June 1990, most of the project activities have been placed on hold pending the securing of a host facility for the project. All of the ongoing activities are focused on identifying such a host. No DOE cost-sharing has been provided for any activities since June 15, 1990.

Design activities were initiated in December 1987 and have progressed through completion of a preliminary process design. A process development unit (PDU) scale test program using the design Ohio coal and Cold Lake crude oil was successfully completed to confirm the basic process performance at design conditions. An alternate operating condition, known as once through (no recycle), performed surprisingly well and indicated that additional testing would be desirable and would serve to improve the overall economics of the process. Studies also showed favorable economics for integrating the process with an electric power utility to achieve air pollution control, when compared to pulverized coal/wet flue gas desulfurization or fluidized-bed technology and a high-conversion oil refinery that generates a variety of liquid fuels. Also, a comprehensive coprocessing technology assessment was completed. Reports on these studies will be issued as part of the project.

Environmental Considerations:

Environmental data for the NEPA compliance process have been compiled; however, further work is on hold pending site selection.

The following impacts are projected for coal/oil coprocessing on a national basis by 2010 assuming maximum commercialization of this technology:

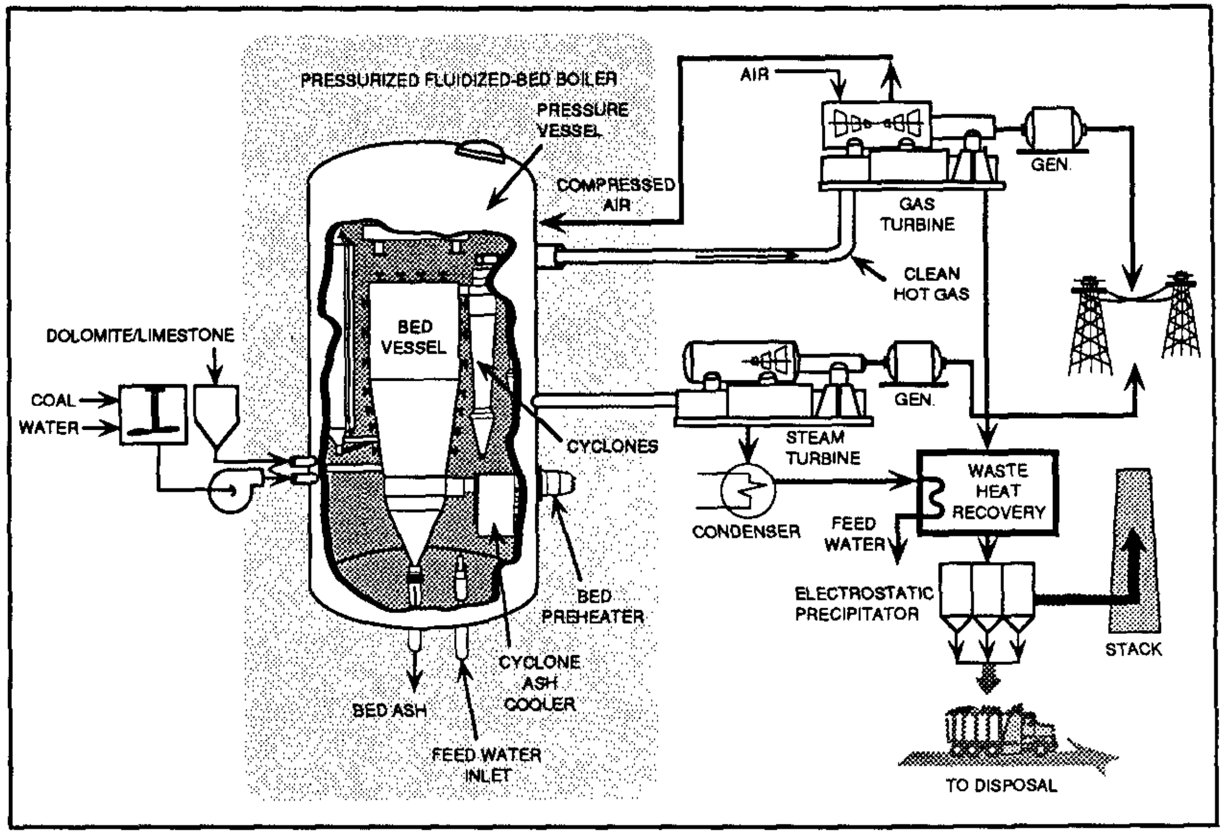
- SO_2 reduction—90%
- NO_x reduction—60%
- Reduction in metals in petroleum residuum—95%

The solid waste produced by this process consists of coal ash and fines that can be readily disposed of in landfills. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The coprocessing process can be designed to generate a variety of liquid products depending on a particular customer's needs. The process can be deployed as a stand alone coal/oil refinery or integrated with an electric utility or oil refinery. Current views are that the most economic application is the integrated oil refinery approach, which makes the best use of the liquids handling systems and supporting facilities already in place at such a facility; product distribution would also be simplified.

Tidd PFBC Demonstration Project



Sponsor:
The Ohio Power Company

Additional Team Members:
American Electric Power Service Corporation—design, construction, and management
ASEA Babcock—technology supplier
Ohio Coal Development Office—cofunder

Location:
Brilliant, Jefferson County, OH (Ohio Power Company's Tidd plant)

Congressional District:
18th U.S. Congressional District

Technology:
ASEA Babcock's pressurized fluidized-bed combustion (PFBC) system

Plant Capacity/Production:
70 MWe

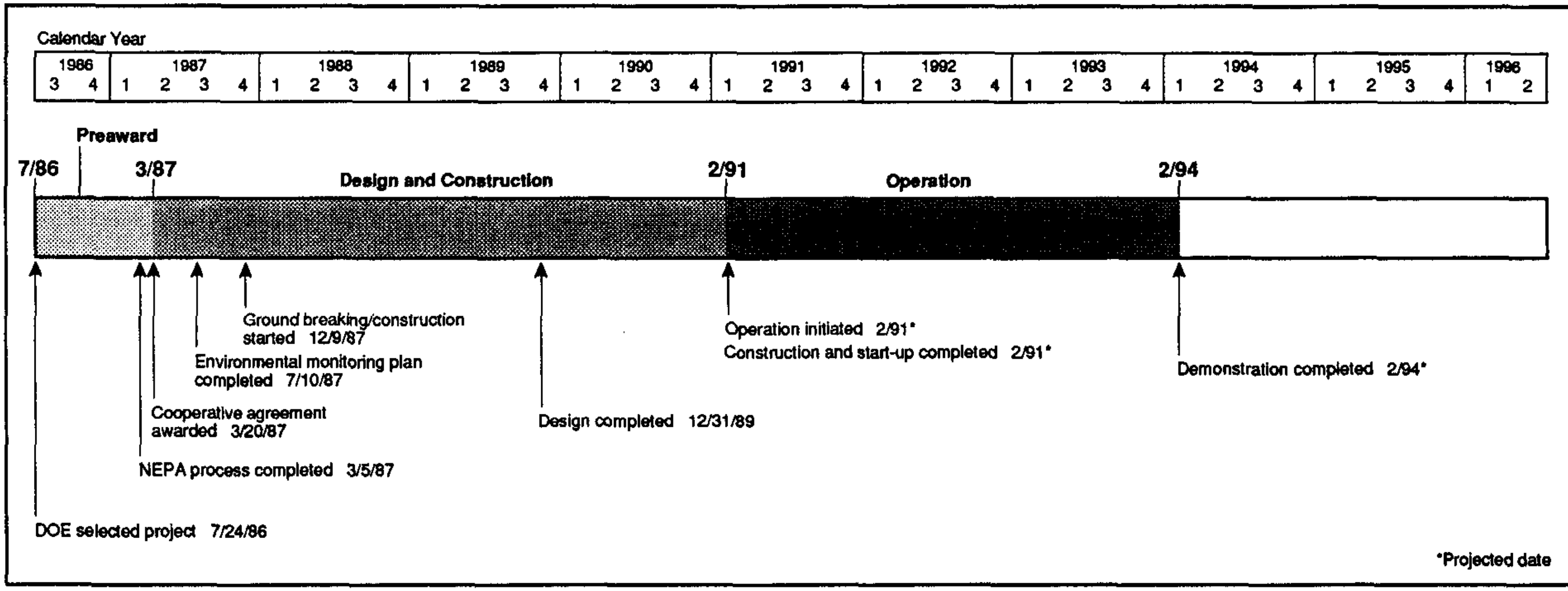
Project Funding:

Total project cost	$167,500,000	100%
DOE	60,200,000	36
Participants	107,300,000	64

Project Objective:
To demonstrate PFBC at a 70-MWe scale, representing a 5:1 scale-up 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% SO_2 removal, NO_x emission level of 0.2 lb/MMBtu, and an efficiency of 38% in a repowering mode using the existing steam system.

Technology/Project Description:
The ASEA Babcock PFBC technology uses a pressurized bubbling fluidized bed operating at 175 lb/in^2 atm. Pressurized combustion air is supplied by the gas turbine compressor. In the PFBC, the air fluidizes the bed material, which consists of fuel (a coal-water paste), coal ash, and dolomite sorbent. The hot combustion gases exiting the bed vessel with entrained ash particles pass through cyclones to remove 98% of the particles. The gas exits the pressure vessel and is expanded in a gas turbine to produce 16 MWe. The gas exiting the turbine is cooled in a waste heat recovery step and cleaned further in an electrostatic precipitator prior to discharge into the atmosphere. Pressurized boiler feedwater is converted to superheated steam in the tubes in the boiler zone of the pressure vessel. The steam exits at 1,335 lb/in^2 atm and 925 °F and passes through a steam turbine to produce 58 MWe. The dolomite in the bed reacts with the sulfur to form calcium sulfate, a dry, granular material, which is discharged with the ash for disposal or by-product recovery. The bed temperature of 1,600 °F reduces the formation of NO_x.

The project will entail the replacement of the Unit 1 boiler at the Tidd facility with the PFBC system and the addition of the gas cycle. The existing steam turbine, as well as condensate and feedwater systems, will be refurbished for use with the demonstration.



Project Status/Accomplishments:

Project construction was completed in late 1990, and electricity was successfully generated for the first time on December 6, 1990, with the plant operating in a combined-cycle mode. Start-up is proceeding, and operation is expected to begin in February 1991. The unit is in the preoperational test phase, and the various systems are being checked out in preoperation for full operation.

Much in the way of capital cost, design, and construction information has been learned and will be applied to the Sporn and other future projects. A topical report, *Tidd: The Nation's First PFBC Combined-Cycle Demonstration*, covering the information learned through the design and early portion of construction was published in March 1990.

Environmental Considerations:

NEPA compliance has been satisfied with a memo-to-file approved March 5, 1987.

The following impacts are projected from maximum commercialization of the PFBC technology on a national basis by 2010 relative to a no-action alternative:

- SO_2 reduction—48%
- NO_x reduction—17%
- Solid waste increase, but in a dry, granular form more amenable to alternative uses, such as construction aggregate, and requiring less land area for disposal than conventional scrubber sludge

(Source: CCT Programmatic Environmental Impact Statement)

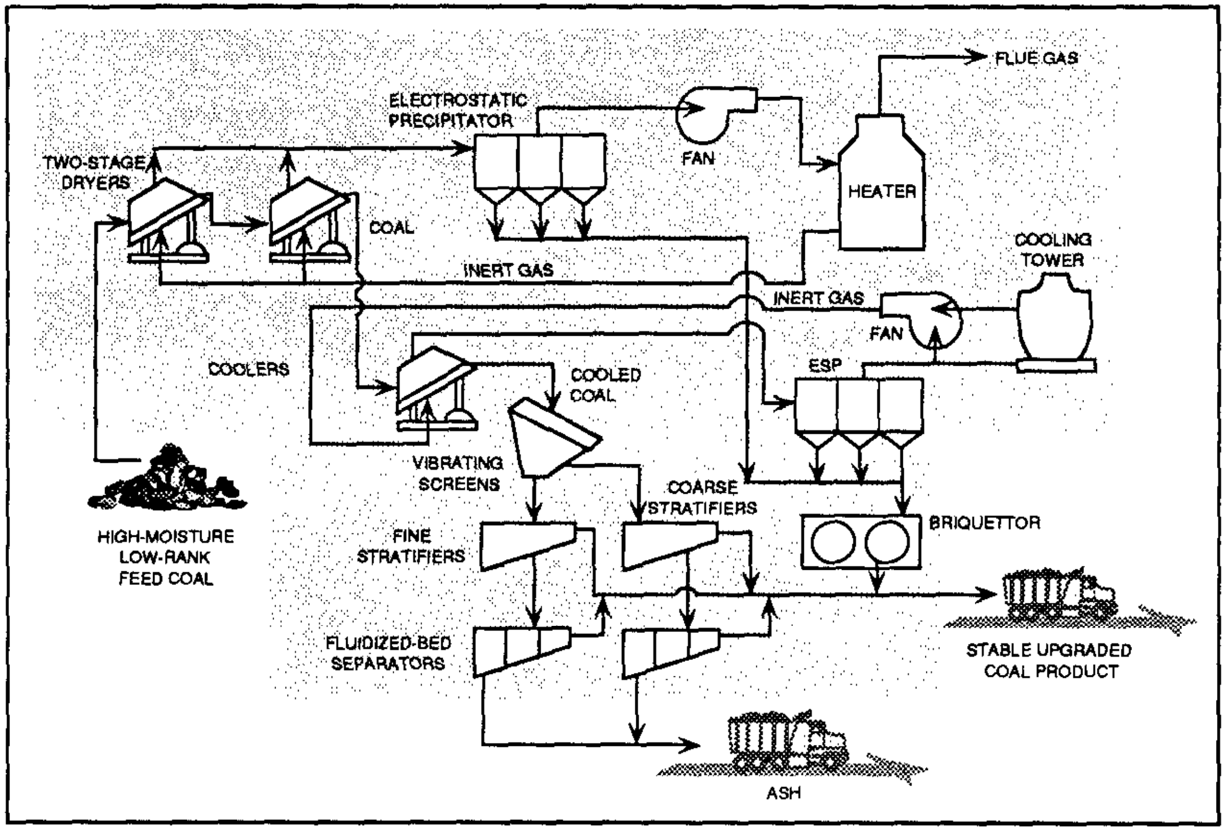
Commercial Application:

Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. It can be used to repower oil- and gas-fired boiler units, to repower coal-fired power plants, and to build new PFBC units. Combined-cycle PFBC technology appears to be best suited for electric utility applications for medium (100–400 MW) and large (> 400 MW) plants. In fact because of modular construction capability, PFBC generating plants will permit utilities to add increments of capacity economically to match load growth and to reduce utility financing requirements. Plant life can be extended by repowering with PFBC using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment.

The performance potential of PFBC technology in its commercial configuration is characterized below:

- SO_2 reduction—95%
- NO_x reduction—80%
- Plant efficiency—up to 45%
- Incremental power increase—40%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated

Advanced Coal Conversion Process Demonstration



Sponsor:

Western Energy Company

Additional Team Member:

Stone and Webster Engineering Company—engineer and constructor

Location:

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

Congressional District:

2d U.S. Congressional District

Technology:

Western Energy Company's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals

Plant Capacity/Production:

45 tons/hr of coal product

Project Funding:

Total project cost	$69,000,000	100%
DOE	34,500,000	50
Participants	34,500,000	50

Project Objective:

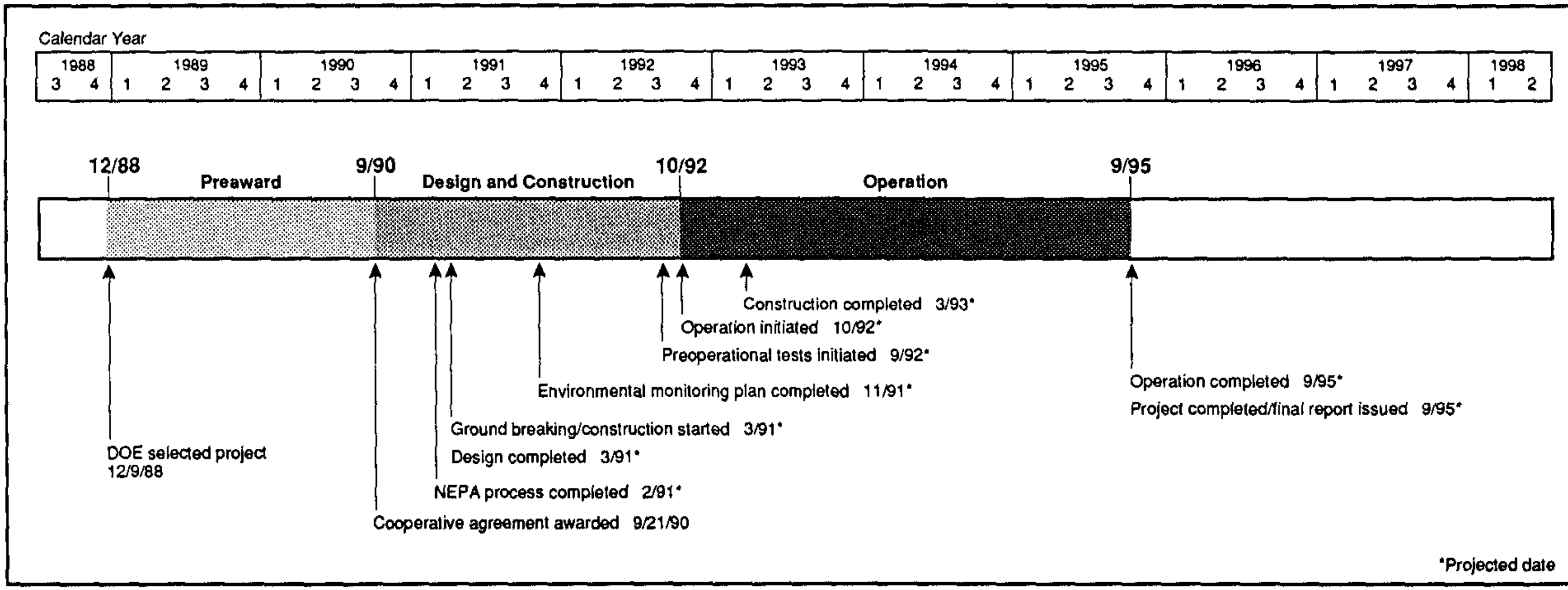
To demonstrate Western Energy's advanced coal conversion process to produce a stable coal product having moisture content as low as 1%, sulfur content as low as 0.3%, and a heating value up to 12,000 Btu/lb.

Technology/Project Description:

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

The project, if successful, will enhance low-rank western coals, usually with a moisture content of 25–55%, sulfur content of 0.5–1.5%, and heating value of 5,500–9,000 Btu/lb by producing a stable, upgraded coal 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-tons/hr unit will be located adjacent to a unit train loadout facility at Western Energy Company's Rosebud coal mine in MT. Although the demonstration plant will be one-tenth the size of a commercial facility, the process equipment will be at commercial scale because a full-sized commercial plant will have multiple process trains.



Project Status/Accomplishments:

The cooperative agreement was signed by DOE on September 21, 1990. Design work is ongoing. A subcontract has been signed with Stone and Webster Engineering Company for major engineering work. A short-duration process demonstration run was accomplished at Western Energy's pilot plant in Butte, MT, to verify preliminary process designs.

On December 12, 1990, Western Energy announced that is has joined with the NRG Group, a nonregulated subsidiary of Northern States Power Company based in Minneapolis, MN, to demonstrate and commercialize the technology. This clears the way for construction to begin in early 1991, with operation expected in 1992.

Environmental Considerations:

An environmental assessment and finding of no significant impact have been prepared and are being reviewed by DOE.

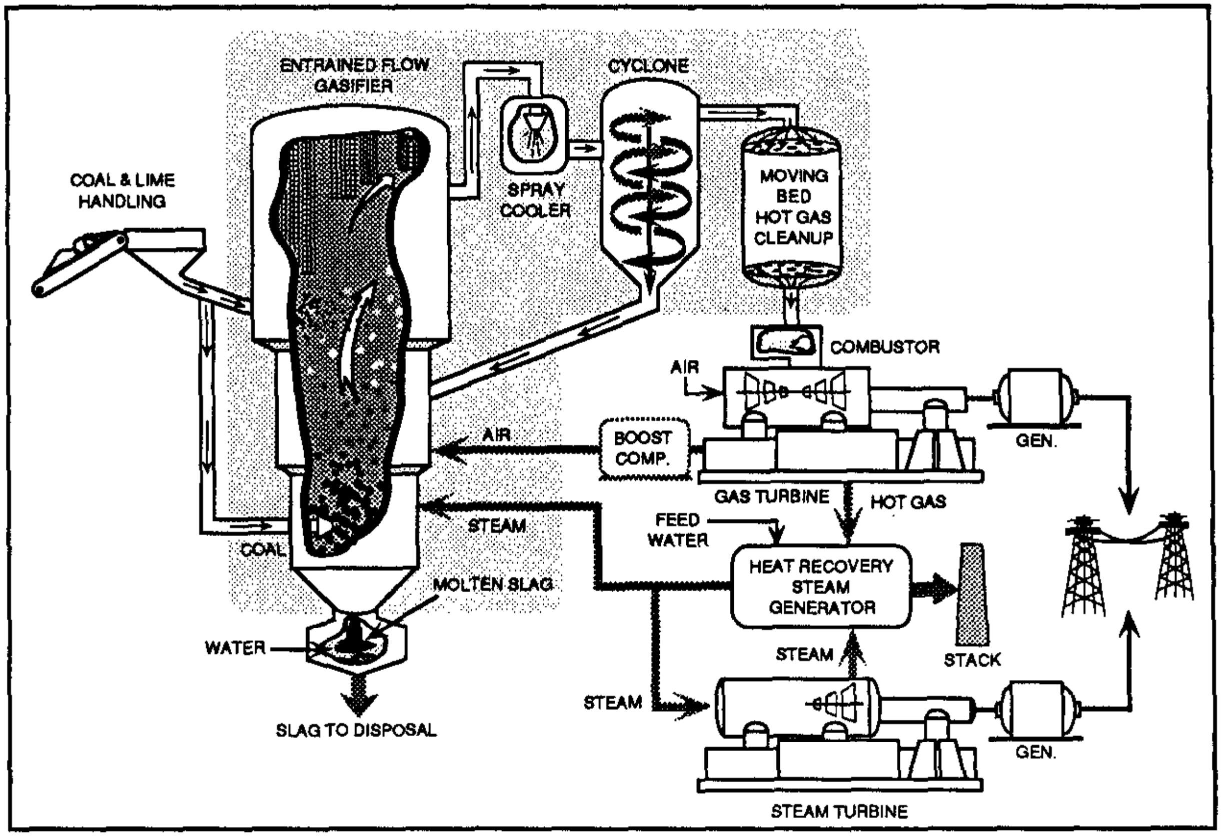
Because the advanced coal conversion process will produce a coal with a very low sulfur content, high heating value, and stable physical/chemical characteristics, it could have significant impact on SO_2 reduction relative to a no-action alternative.

Commercial Application:

Western Energy'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. Processed coal would be an ideal low-sulfur coal substitute for these and other plants, because it will allow operation under more restrictive emissions guidelines without requiring derating of the units or the addition of costly flue gas desulfurization systems. Western Energy's process, therefore, will be attractive to 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.

CCT-II
Project Fact Sheets

Combustion Engineering IGCC Repowering Project



Sponsor:

ABB Combustion Engineering, Inc.

Additional Team Members:

City Water, Light and Power—cofunder and host utility

State of Illinois, Department of Energy and Natural Resources—funding

Location:

Springfield, Sangamon County, IL (City Water, Light and Power's Lakeside Station)

Congressional District:

20th U.S. Congressional District

Technology:

ABB Combustion Engineering's integrated gasification combined-cycle (IGCC) system

Plant Capacity/Production:

65 MWe

Project Funding:

Total project cost	$270,700,000	100%
DOE	129,357,204	48
Participants	141,342,796	52

Project Objective:

To demonstrate an advanced dry-feed, air-blown, two-stage entrained-flow coal gasifier with limestone injection and the moving-bed zinc ferrite hot gas cleanup system; to evaluate a kinetic coal extruder; and to assess long-term reliability, availability, and maintainability at sufficient scale to determine commercial potential.

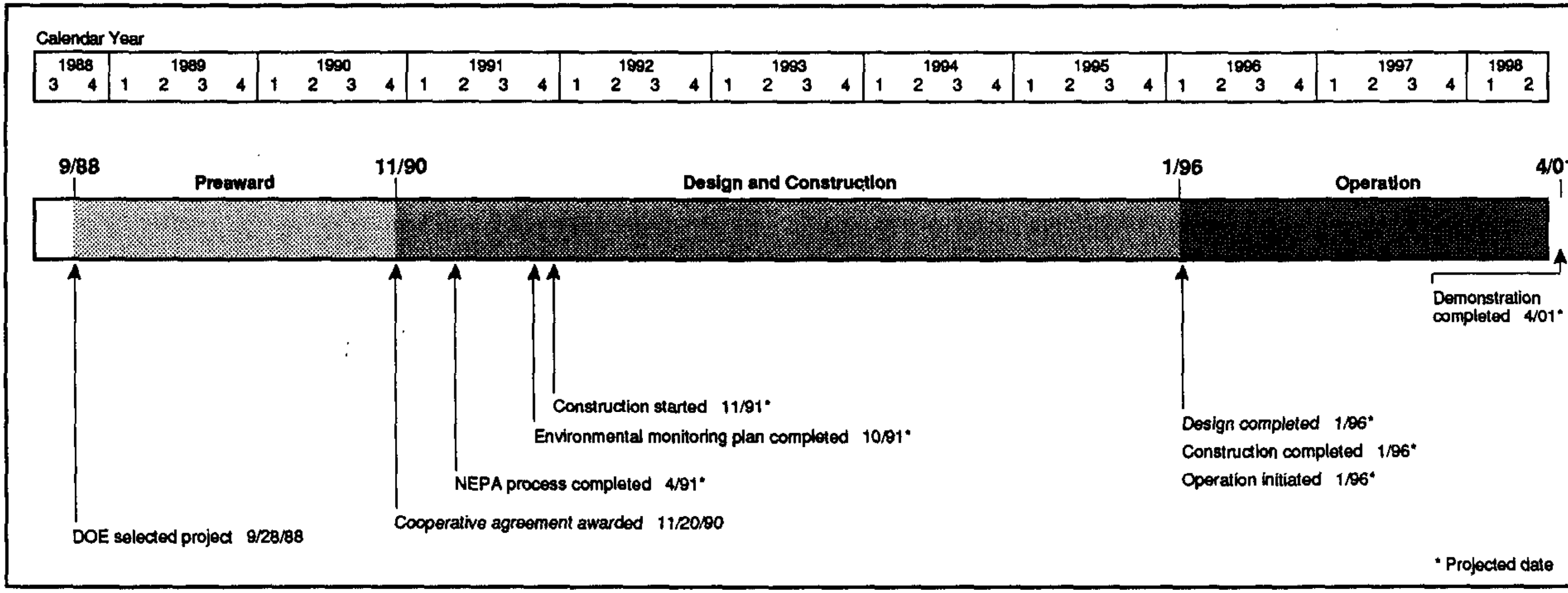
Technology/Project Description:

Pressurized pulverized coal is pneumatically transported to the gasifier. The gasifier essentially consists of a bottom combustor section and a top reductor 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 by various heat exchange surfaces and by water spray prior to gas cleanup. Char in the gas stream is captured by a high-efficiency cyclone, as well as by subsequent fine particulate removal systems, and recycled back to the gasifier.

A newly developed process is being used to remove sulfur from the hot gas: a moving bed of zinc ferrite sorbent and a limestone sorbent injection system provide in-bed desulfurization. Particulate emissions are removed 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. Approximately 40 MW 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 ferrite 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.



The demonstration project is converting 600 tons/day of coal into 65 MWe. This is being accomplished through the installation of an entrained-flow coal gasifier and the integration of a currently deactivated 25-MWe steam turbine with a 40-MWe gas turbine at City Water, Light and Power's Lakeside Station located in Springfield, IL.

Project Status/Accomplishments:

The cooperative agreement was awarded on November 20, 1990.

Preliminary design and project definition activities are under way. These are projected to be completed by November 1991 when the start of construction is planned.

Environmental Considerations:

The participant is preparing environmental information required by DOE for the process.

Assuming maximum commercialization of the IGCC technology on a national basis by the year 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—37%
- NO_x reduction—17%
- Solid waste reduction—5%
- CO_2 reduction—6%

(Source: CCT Programmatic Environmental Impact Statement)

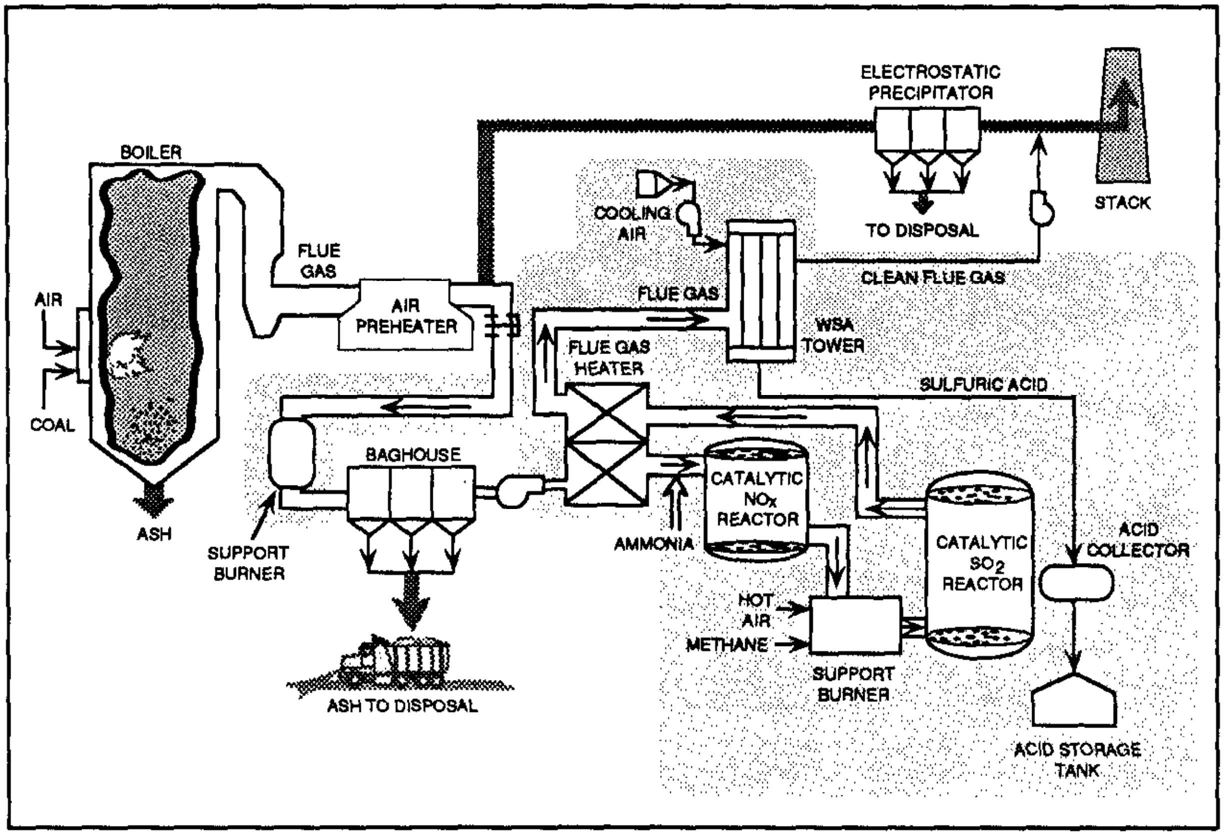
Commercial Application:

In recent years, IGCC has become a rapidly emerging alternative for new electricity generating plants. IGCC plants require 15% less land area than pulverized coal plants with flue gas desulfurization. IGCC technology also can be used in repowering, where a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added to replace the existing coal boiler. The remaining equipment is left in place, including the steam turbine and electrical generator.

The performance potential of IGCC technology in its commercial configuration is characterized as follows:

- SO_2 reduction—99%
- NO_x reduction—95%
- Plant efficiency—up to 48%
- Incremental power increase—230%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic addition of capacity increments to match load growth

WSA-SNOX Flue Gas Cleaning Demonstration Project



Sponsor:
ABB Combustion Engineering, Inc.

Additional Team Members:
Ohio Coal Development Office—cofunder
Ohio Edison Company—cofunder and host utility
Haldor Topsoe—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)

Congressional District:
17th U.S. Congressional District

Technology:
Haldor Topsoe's WSA-SNOX catalytic advanced flue gas cleanup system

Plant Capacity/Production:
35-MWe equivalent slip-stream from a 115-MWe boiler

Project Funding:

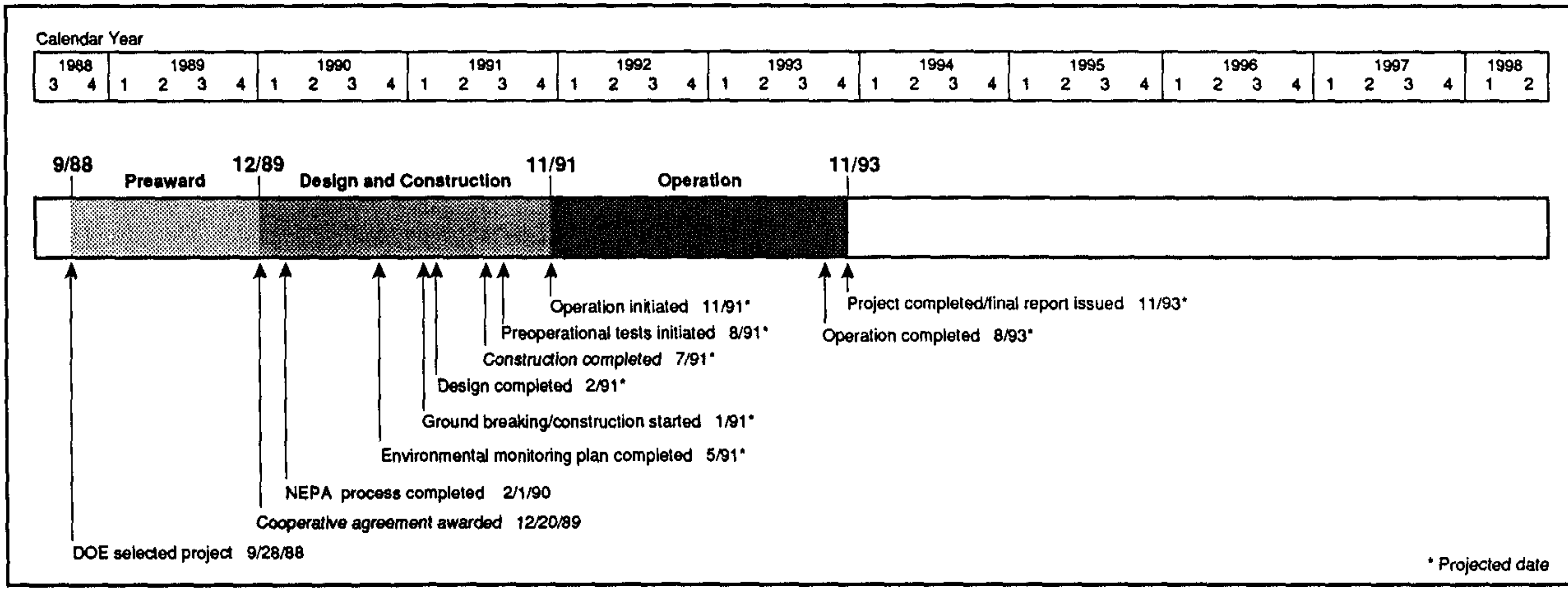
Total project cost	$31,438,408	100%
DOE	15,719,200	50
Participants	15,719,208	50

Project Objective:
To demonstrate on U.S. coals at an electric power plant that WSA-SNOX technology will catalytically remove 95% of the NO_x and SO_2 from flue gas and produce a salable by-product of concentrated sulfuric acid.

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

The technology, while using U.S. coals, is expected to remove 95% of the NO_x and SO_2 from flue gas and produce a salable sulfuric acid by-product. This is accomplished without the use of sorbents and with no waste by-products.

The demonstration unit is being installed at Ohio Edison's Niles Station in Niles, OH. The process will treat a 35-MWe equivalent slip-stream of flue gas from the 115-MWe Unit No. 2 boiler that burns a 3.4% sulfur coal. The process steps are virtually the same as for a full-scale plant, and commercial-scale components will be used.



Project Status/Accomplishments:

Under way concurrently are design and permitting activities and long-lead procurement. Construction is expected to commence in early 1991. All of the long-lead procurement equipment has been ordered, and a major portion of the design has been completed. A 35-MWe duct tie-in connection was installed at a point just beyond the ESP; the duct transports the flue gas to the high-efficiency baghouse.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on February 1, 1990.

Assuming maximum commercialization on a national basis by 2010 for the WSA-SNOX process relative to a no-action alternative, the following impacts are projected:

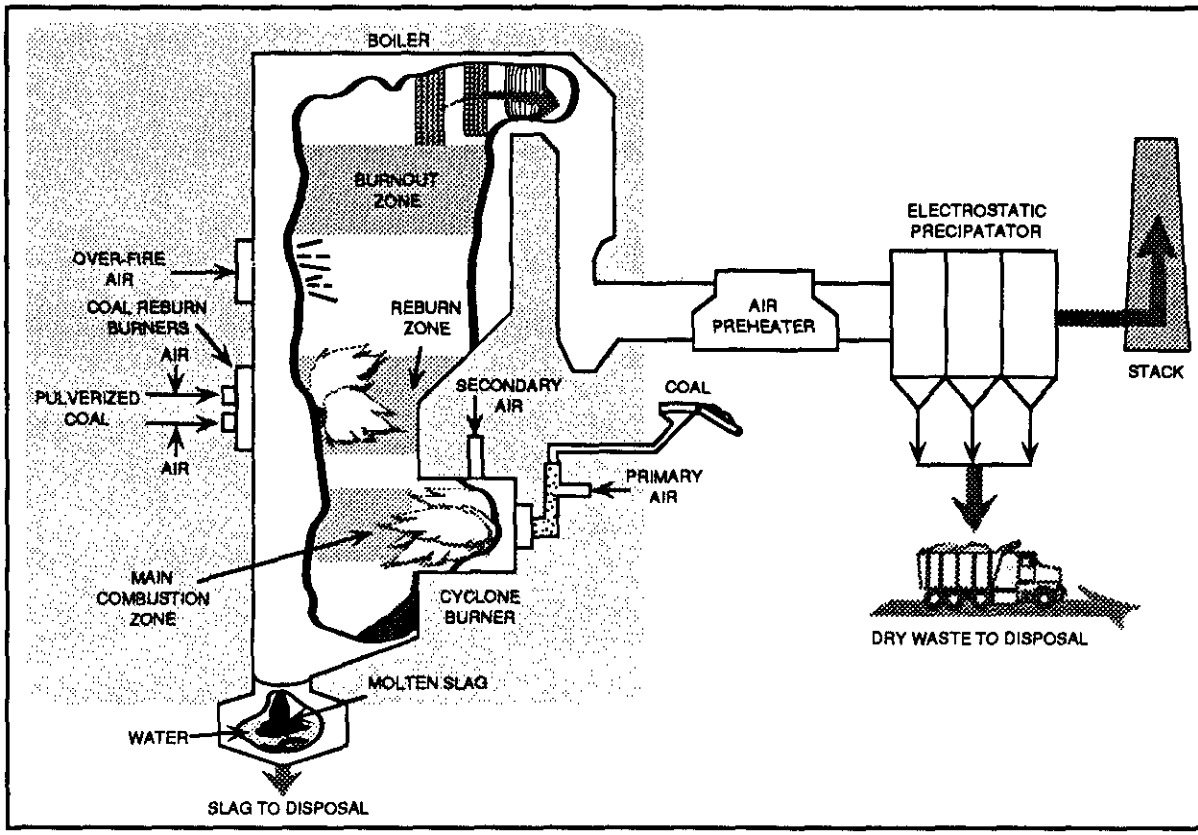
- SO_2 reduction—38%
- NO_x reduction—15%

The significant reductions of SO_2 and NO_X are projected to be achievable nationally due to the 95% removal of SO_2 and NO_x emissions from coal-fired boilers with the WSA-SNOX process and the wide applicability of the process. Moreover, the sulfuric acid produced is a salable by-product. No change in solid waste is anticipated because the technology produces no solid waste by-product. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control



Sponsor:

The Babcock & Wilcox Company

Additional Team Members:

Wisconsin Power and Light Company—cofunder and host utility
Sargent and Lundy—engineer for coal handling
Electric Power Research Institute—cofunder
State of Illionois, Department of Energy and Natural Resources—cofunder
Utility companies (10 cyclone boiler operators)—cofunders

Location:

Cassville, Grant County, WI (Nelson Dewey Station, Unit No. 2)

Congressional District:

3d U.S. Congressional District

Technology:

The Babcock & Wilcox Company's coal reburning system

Plant Capacity/Production:

100 MWe

Project Funding:

Total project cost	$10,655,261	100%
DOE	5,072,631	48
Participants	5,582,630	52

Project Objective:

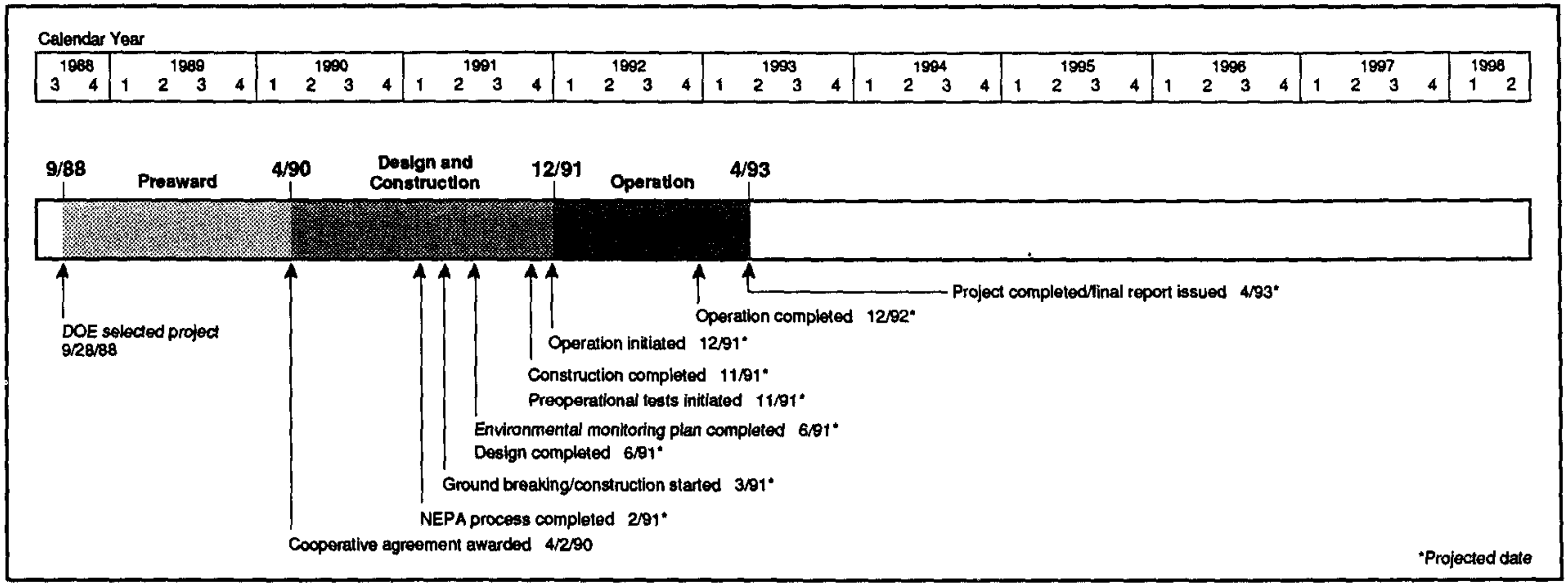
To evaluate the applicability of reburning technology for reducing NO_x emissions from a full-scale coal-fired cyclone boiler, pulverizing a portion of the primary coal fuel to use as the secondary, "reburning" fuel; and to achieve greater than 50% reduction in NO_x emissions with no serious impact on 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 main 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 boiler above the cyclones in the reburning zone to create an oxygen-deficient condition. The NO_x formed in the cyclone burners reacts with the resultant reducing flue gas to be converted into nitrogen and water 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 coal reburning technology can be applied with the cyclone burners operating within their normal, non-corrosive, oxidizing conditions, thereby minimizing the effects of reburn on the cyclone combustor and boiler performance.

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



Project Status/Accomplishments:

The project is proceeding with preliminary design, having completed the baseline boiler performance testing and performance modeling both with and without the proposed reburn retrofit. The detailed work plan and the project evaluation plan have been completed. Boiler performance results have been analyzed and incorporated into both physical and numerical models of the boiler. The modeling has demonstrated the need for a change from three to four reburners and over-fire air ports to assure adequate NO_x reduction.

Environmental Considerations:

An environmental analysis and a finding of no significant impact have been prepared and are being reviewed by DOE.

Significant reductions of NO_x (11%) are projected to be achievable nationally by 2010 due to the capability of the cyclone coal-reburning process to remove 50% of NO_x emissions from coal-fired boilers and the wide potential applicability of the process. Negligible changes in effluents are anticipated. The technology produces no solid waste product. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Currently, no proven retrofit combustion technology exists for reducing NO_x emissions from cyclone boilers. Coal reburning for cyclone boilers is expected to be a viable option as a retrofit combustion technology for NO_x control at reasonable capital and operating costs. All of the approximately 26,000 MWe of currently installed cyclone boilers are expected to require NO_x control to comply with the Clean Air Act Amendments of 1990.

SOX-NOX-ROX Box Flue Gas Cleanup Demonstration Project

Sponsor:
The Babcock & Wilcox Company

Additional Team Members:
Ohio Edison Company—cofunder and host utility
Ohio Coal Development Office—cofunder
Electric Power Research Institute—cofunder
Norton Company—cofunder and SCR catalyst supplier
Minneapolis Mining and Manufacturing Company—cofunder and filter bag supplier

Location:
Dilles Bottom, Belmont County, OH (R. E. Burger Plant, Unit No. 5)

Congressional District:
18th U.S. Congressional District

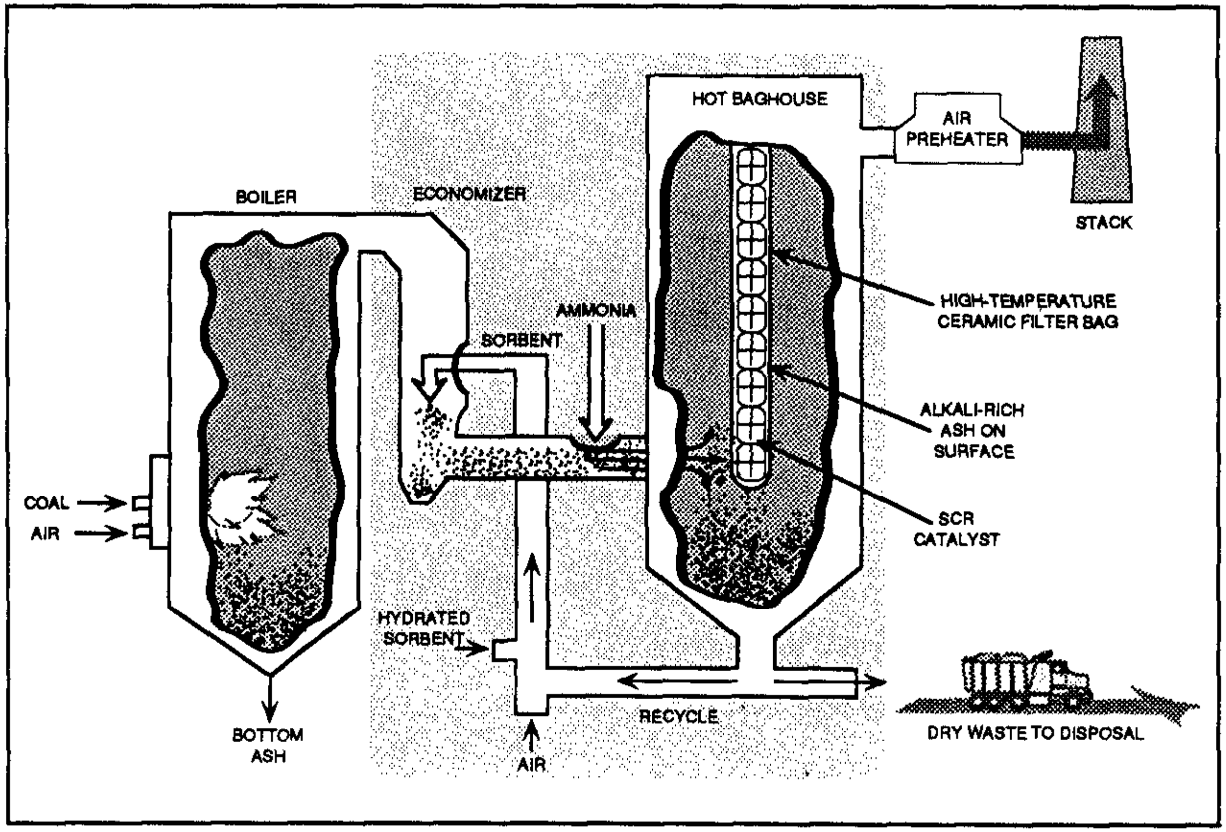
Technology:
The Babcock & Wilcox Company's SOX-NOX-ROX box (SNRB) process

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

Project Funding:

Total project cost	$10,640,293	100%
DOE	4,875,246	46
Participants	5,765,047	54

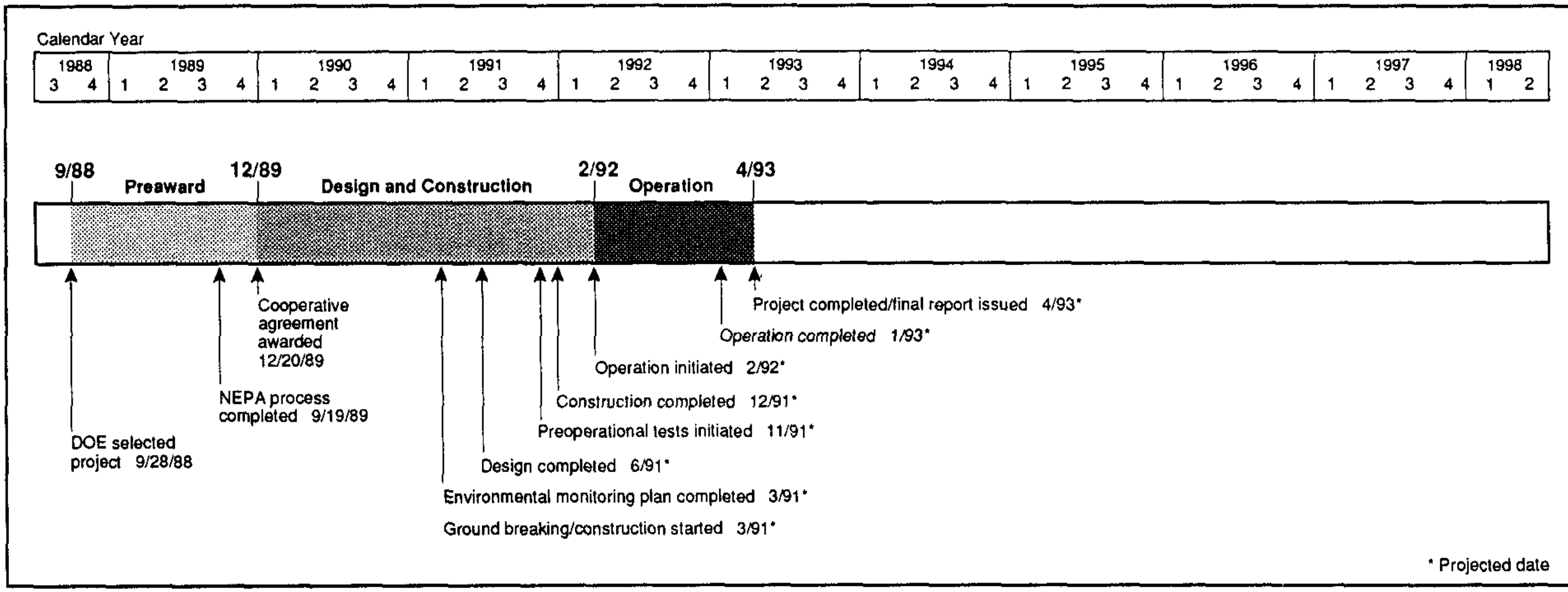
Project Objective:
To demonstrate that the SOX-NOX-ROX box process, used in retrofitting a high-sulfur-coal-fired power plant, can remove high levels of all pollutants using a single processing unit for treating flue gas, thereby lessening on-site space requirements and capital costs.



Technology/Project Description:
The SNRB process will combine the removal of SO_2, NO_x, and particulates in one unit—a high-temperature baghouse. SO_2 removal is accomplished using either calcium- or sodium-based sorbent injected into the flue gas. NO_x removal is accomplished by injecting ammonia (NH_3) to selectively reduce NO_x in the presence of a selective catalytic reduction, or SCR, catalyst. Particulate removal is accomplished by high-temperature ceramic fiber bag filters.

The SNRB demonstration unit is sized at 5 MWe and is large enough to demonstrate a commercial-scale baghouse module while minimizing the demonstration cost. Additionally, at this scale, the flue gas temperature can readily be controlled to determine the optimum temperature for maximum SO_2 and NO_x reductions.

The project will demonstrate the technical and economic feasibility of achieving 70–90% SO_2 removal, up to 90% NO_x removal, and 99% particulate removal at lower capital and operating and maintenance costs than other conventional systems. The demonstration will be conducted at Ohio Edison's R. E. Burger Plant, Unit No. 5, in Dilles Bottom, OH.



Project Status/Accomplishments:

The project is proceeding with detailed design. General arrangement of major equipment has been resolved, and bid packages have been issued for all of the major equipment. The pilot baghouse unit, sized to test commercial-sized bags, is complete, and initial test operations have begun.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on September 19, 1989.

Assuming maximum commercialization, the following impacts are projected on a national basis by 2010 for the SNRB process relative to a no-action alternative:

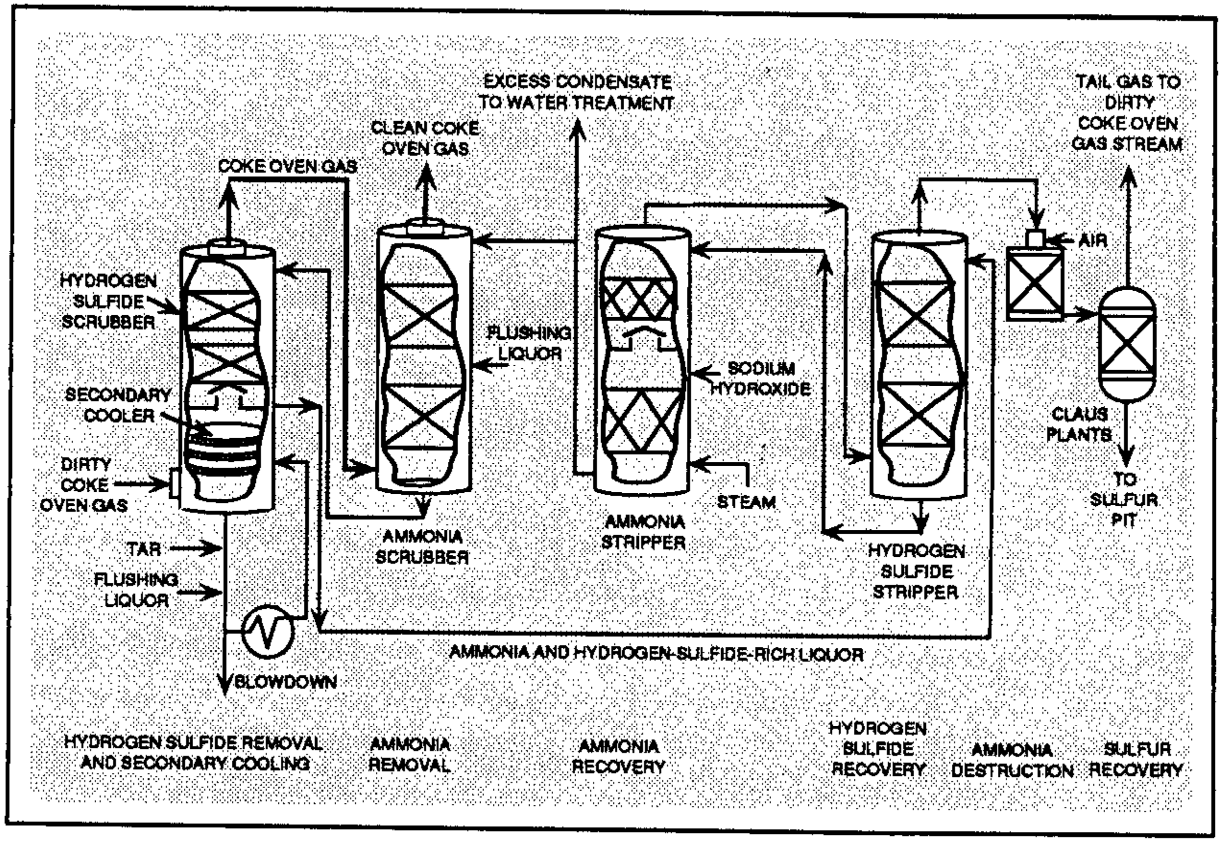
- SO_2 reduction—38%
- NO_x reduction—15%
- Solid waste increase—8%

The significant reductions of SO_2 and NO_x are projected to be achievable nationally due to the 70–90% removal of SO_2 and NO_x emissions from coal-fired boilers with the SNRB process and the wide applicability of the process. Negligible changes in liquid effluents are anticipated. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The SNRB process, upon being commercially demonstrated, offers removal of up to 90% of the SO_2 and NO_x and at least 99% of the particulates in a single unit with lower capital and operating costs and smaller space requirements than conventional flue gas cleanup technology. In addition, SNRB offers the potential for increasing boiler efficiency. The SNRB process can be used to retrofit a wide range of utility and industrial coal-fired boilers that are without scrubbing systems in order to achieve a high level of emissions control at favorable capital and operating costs.

Innovative Coke Oven Gas Cleaning System for Retrofit Applications



Sponsor:
Bethlehem Steel Corporation

Additional Team Member:
Davy/Still-Otto—technology developer

Location:
Sparrows Point, Baltimore County, MD (Bethlehem Steel Corporation's Sparrows Point Plant, Coke Oven Batteries A, 11, and 12)

Congressional District:
2d U.S. Congressional District

Technology:
Davy/Still-Otto's process for precombustion cleaning of coke oven gas (COG)

Plant Capacity/Production:
74 million std ft^3/day of COG

Project Funding:

Total project cost	$45,239,781	100%
DOE	13,500,000	30
Participant	31,739,781	70

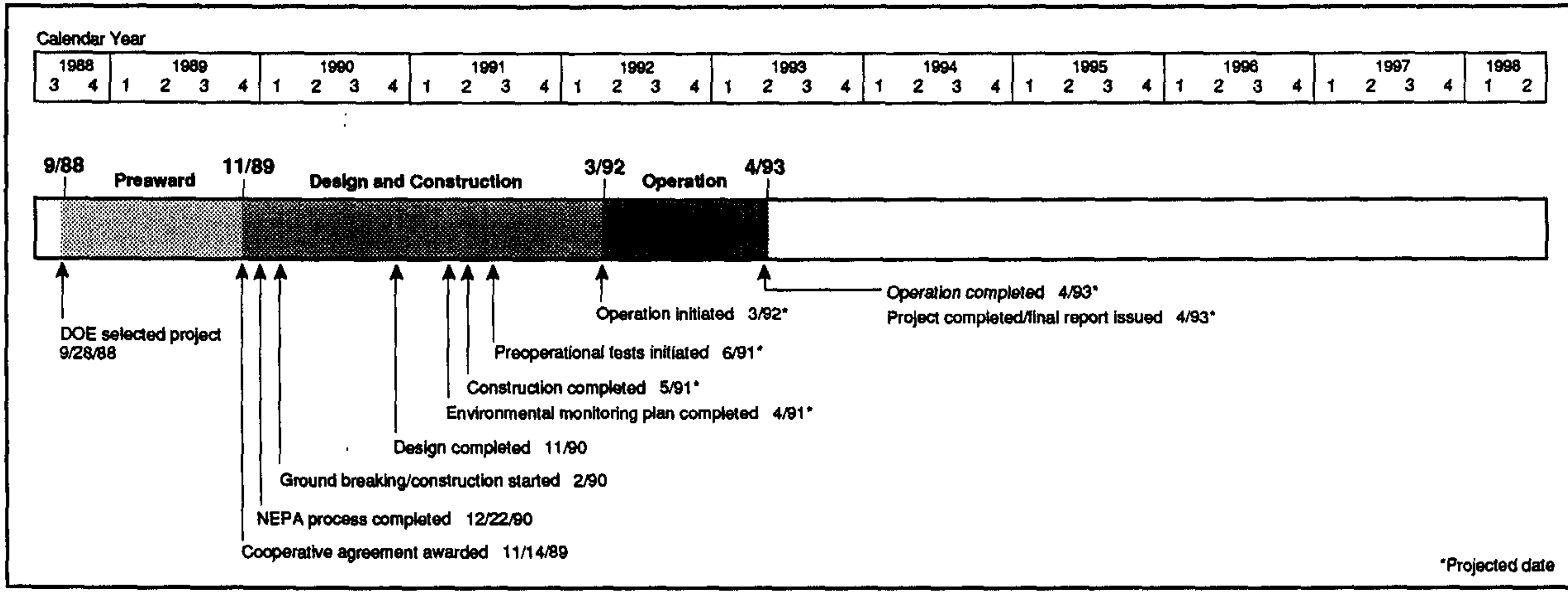
Project Objective:
To demonstrate a first-of-a-kind novel integration of commercially available process steps for simultaneous removal of hydrogen sulfide and ammonia from COG, recovery of hydrogen sulfide and ammonia, destruction of ammonia, and recovery of sulfur in a commercial-sized application; and to reduce SO_2 emissions by at least 80% accompanied by substantially reduced volatile organic compound emissions and ammonia discharge to wastewater treatment.

Technology/Project Description:
This project will demonstrate an innovative technology developed by Davy/Still-Otto for removing hydrogen sulfide (H_2S) and ammonia (NH_3) from COG. The process uses contaminated water produced in the coke oven batteries to absorb the hydrogen sulfide and ammonia contained in the COG. Both hydrogen sulfide and ammonia are steam stripped from the absorption liquor. The ammonia is destroyed in a catalytic reactor; the hydrogen sulfide is converted to elemental sulfur in a conventional Claus plant, and the sulfur is recovered as a salable by-product.

The technology is expected to reduce the hydrogen sulfide concentration in the cleaned COG by 84% and the ammonia concentration by approximately 99%.

Because the reagents used are indigenous in COG, costs associated with the purchase and handling of feed reagents, the handling and treatment of by-products, labor, and utilities are reduced.

This project involves the modification of the COG processing units at Bethlehem Steel's Sparrows Point Plant in Baltimore County, MD. The demonstration facility will process the entire COG stream from Coke Oven Batteries A, 11, and 12, which amounts to 74 million std ft^3/day. Currently, only 60% of this COG stream is desulfurized. The remaining 40% is used directly for under-firing the coke ovens.



Project Status/Accomplishments:

The detailed design phase of the project is complete. Fabrication of major equipment is proceeding, and many items have already been delivered to the construction site. On-site construction activity was initiated in February 1990 with the installation of pilings and foundations. Erection of the structural steel, major equipment, and piping began in September 1990.

The environmental monitoring plan is currently under review by DOE, and construction is well under way, proceeding toward the initiation of start-up and acceptance testing activities in June 1991.

Environmental Considerations:

The environmental assessment with a finding of no significant impact was approved by DOE on December 22, 1989.

The expected performance characteristics and applicable market of the proposed COG cleaning system were used to estimate the environmental impacts that may occur if this technology reaches full commercialization. The existing 30 coke oven plants in the U.S. emit about 300,000 tons/yr of SO_2. This COG cleaning process could be applicable to 24 plants with corresponding emission levels of 200,000 tons/yr of SO_2. If the technology were installed in all 24 plants, the SO_2 emissions could be reduced by 160,000 tons/yr. The ammonium sulfate, which is difficult to market and usually is disposed of as a solid waste, would be eliminated. Every 5–8 years, 5 tons of spent nickel catalyst would need to be returned to the vendor or disposed of as a hazardous waste, and 10 tons of spent alumina catalyst would need to be disposed of as a nonhazardous solid waste. Depending on the configuration of the coke oven facility where the technology is being implemented, the amount of water needed for cooling purposes would remain the same or be reduced, and the amount of pollutants in the wastewater would remain the same or be reduced.

Commercial Application:

The design for this innovative COG cleaning system is based on operating data that have been collected from individual process steps or combinations of individual process steps that have been successfully operated at commercial-sized COG treatment facilities. The novel integration of commercially available process steps is expected to reduce the overall cost of desulfurization, ensure reliable operation in applications exceeding 20 years, and provide a viable alternative to conventional technologies. Because the demonstration is designed to treat 74 million std ft^3/day of COG, the process will be of a commercial size that can be retrofitted into an above-average-sized coke-making facility. This project will demonstrate that it is possible to retrofit any existing coke-making facility in the United States with essentially no scale-up involved and without significant downtime.

PFBC Utility Demonstration Project

Sponsor:

The Ohio Power Company—cosponsor
The Appalachian Power Company—cosponsor

Additional Team Members:

American Electric Power Service Corporation—engineer
ASEA Babcock—technology supplier

Location:

New Haven, Mason County, WV (Ohio Power's and Appalachian Power's Philip Sporn Plant, Units 3 and 4)

Congressional District:

3d U. S. Congressional District

Technology:

ASEA Babcock's pressurized fluidized-bed combustion (PFBC) system

Plant Capacity/Production:

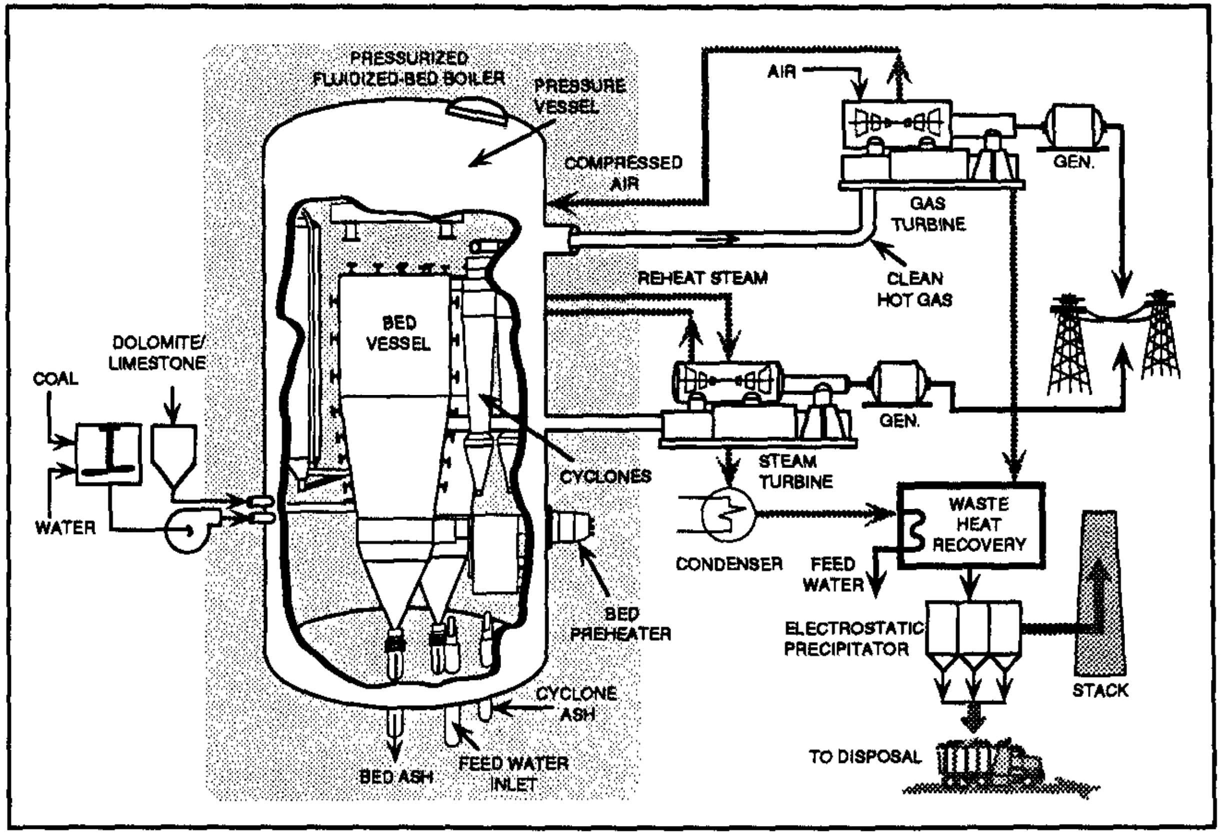
330 MWe

Project Funding:

Total project cost	$659,860,000	100%
DOE	184,800,000	28
Participants	475,060,000	72

Project Objective:

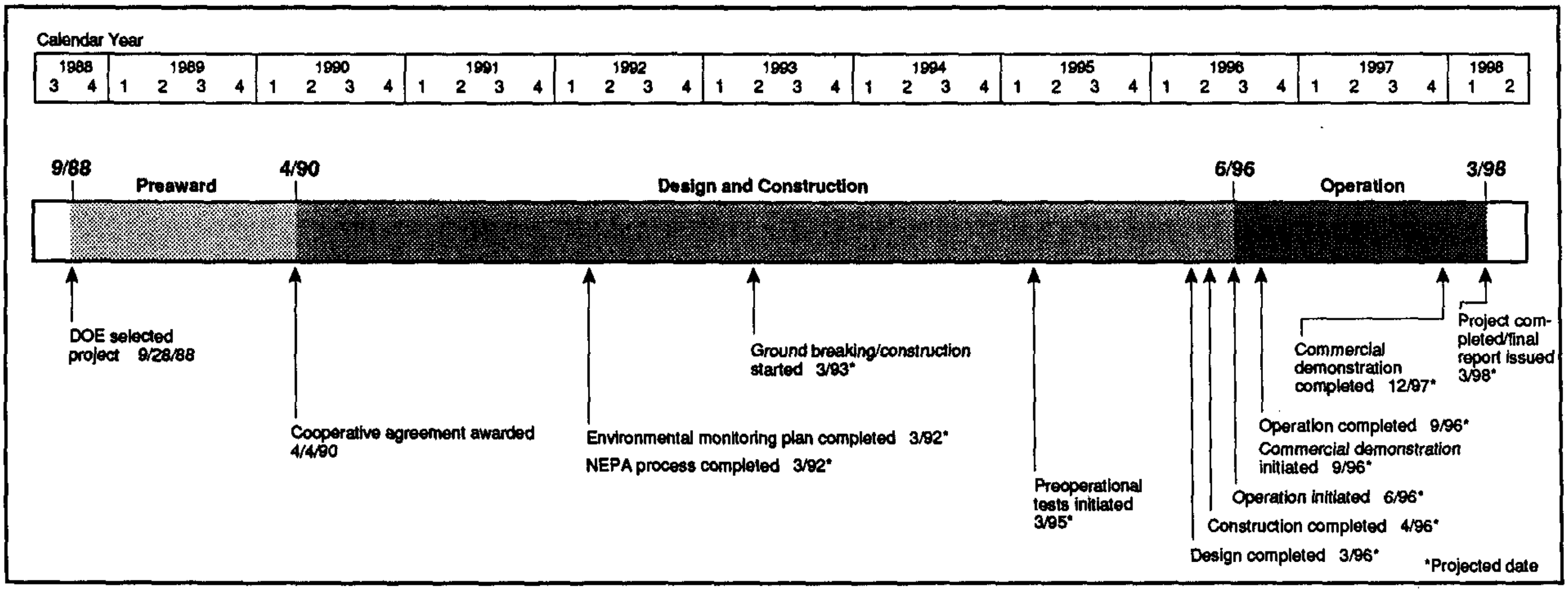
To demonstrate PFBC at 330 MWe, a large utility scale representing a four-fold scale-up of the technology, the world's largest PFBC, and the first commercial application of PFBC in the United States; to assess long-term reliability, availability, and maintainability of PFBC in a commercial operating mode and the integration of a reheat steam cycle; and to achieve 95% SO_2 reduction, at least 70% NO_x reduction, and an efficiency of 39% in a repowering mode using the existing steam system.



Technology/Project Description:

The ASEA Babcock PFBC technology uses a bubbling fluidized-bed boiler enclosed in a pressure vessel operated at 16 atm to produce combustion gases with sufficient energy to drive a gas turbine. The gas turbine exhaust is used to preheat boiler water, and the fluidized-bed boiler develops steam for the steam turbine. Because pressure in the boiler enhances combustion and heat transfer, the size of the vessel needed is reduced. Pressure also enhances sulfur capture by the sorbent. Sorbent (limestone or dolomite) is injected into the boiler and reacts with SO_2 to form unreactive calcium sulfate, a dry, granular material.

The project entails replacement of two 150-MWe units, Units 3 and 4 at the Philip Sporn Plant, with a single 330-MWe unit. Nearly one-fourth of the power is to be produced through an ASEA STAL GT-140P gas turbine with the balance generated through the existing steam turbines. The Philip Sporn Plant is co-owned by the Ohio Power Company and the Appalachian Power Company, both of which are operating companies of the American Electric Power Company, Inc.



Project Status/Accomplishments:

Project is nearing completion of preliminary engineering studies, which will incorporate an analysis addressing the merits of using the same technology for a greenfield plant. Project management and evaluation plans have been established, and significant progress has been made toward completing preliminary engineering studies that will set the stage for detailed design.

Environmental Considerations:

The environmental information volume is being prepared by the participant as requisite input to the NEPA compliance process.

Assuming maximum commercialization of the PFBC technology on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—48%
- NO_x reduction—17%
- Solid waste increase, but in dry, granular form, which has more amenable alternative uses, such as construction aggregate, and requires less land area for disposal than conventional scrubber sludge

(Source: CCT Programmatic Environmental Impact Statement)

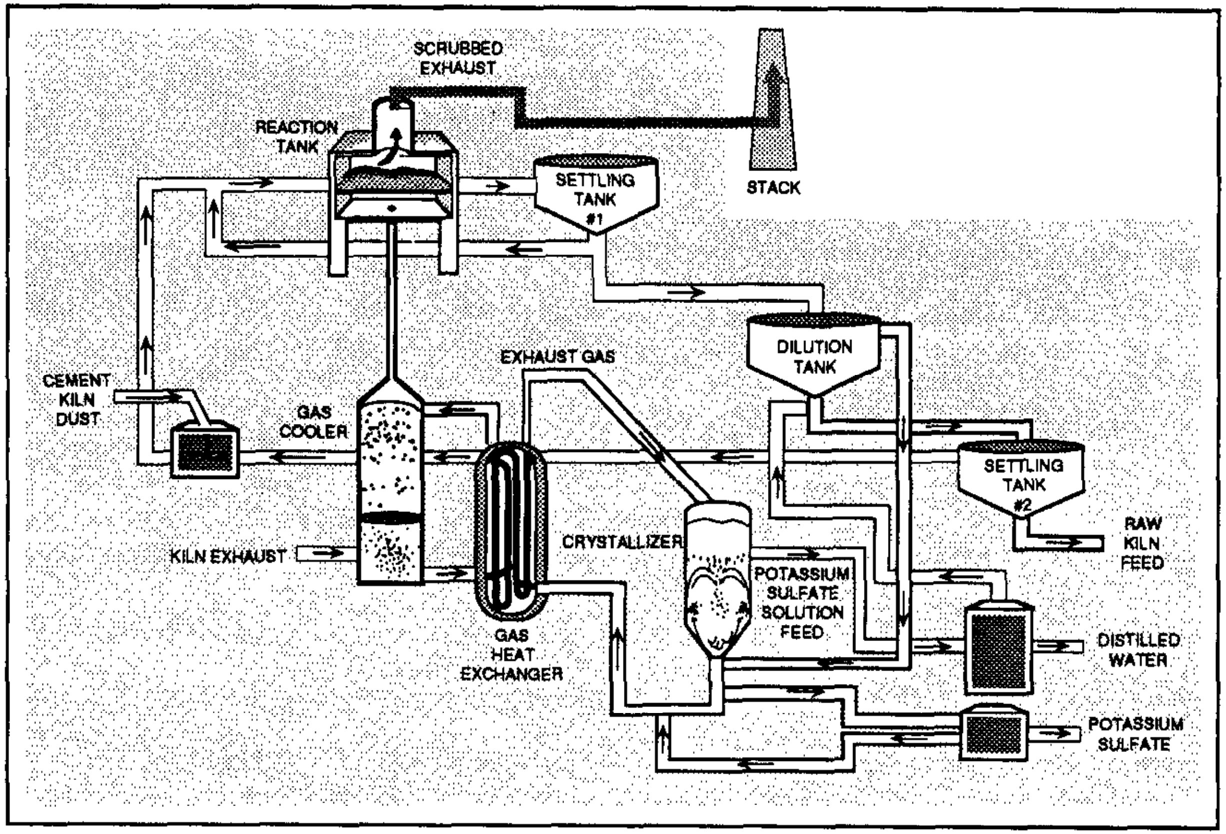
Commercial Application:

Combined-cycle PFBC allows for the combustion of a wide range of coals, including high-sulfur coals. It can be used to repower oil- and gas-fired boiler units while switching them to high-sulfur coal, to repower coal-fired power plants, and to build new PFBC units. Combined-cycle PFBC technology appears to be best suited for electric utility applications for medium (100–400 MWe) and large (> 400 MWe) plants. In fact, because of modular construction capability, PFBC generating plants will enable utilities to add increments of capacity economically to match load growth and to reduce utility financing requirements. Plant life can be extended by repowering with PFBC using the existing plant area, coal and waste handling equipment, and steam turbine equipment.

The performance potential of PFBC technology in its commercial configuration is characterized as follows:

- SO_2 reduction—95%
- NO_x reduction—80%
- Plant efficiency—up to 45%
- Incremental power increase—40%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic additions of capacity increments to match load growth

Cement Kiln Flue Gas Recovery Scrubber



Sponsor:
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

Cianbro Corporation—constructor

Location:
Thomaston, Knox County, ME (Dragon Products' coal-fired cement kiln)

Congressional District:
1st U.S. Congressional District

Technology:
Passamaquoddy Tribe's cement kiln flue gas recovery scrubber

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

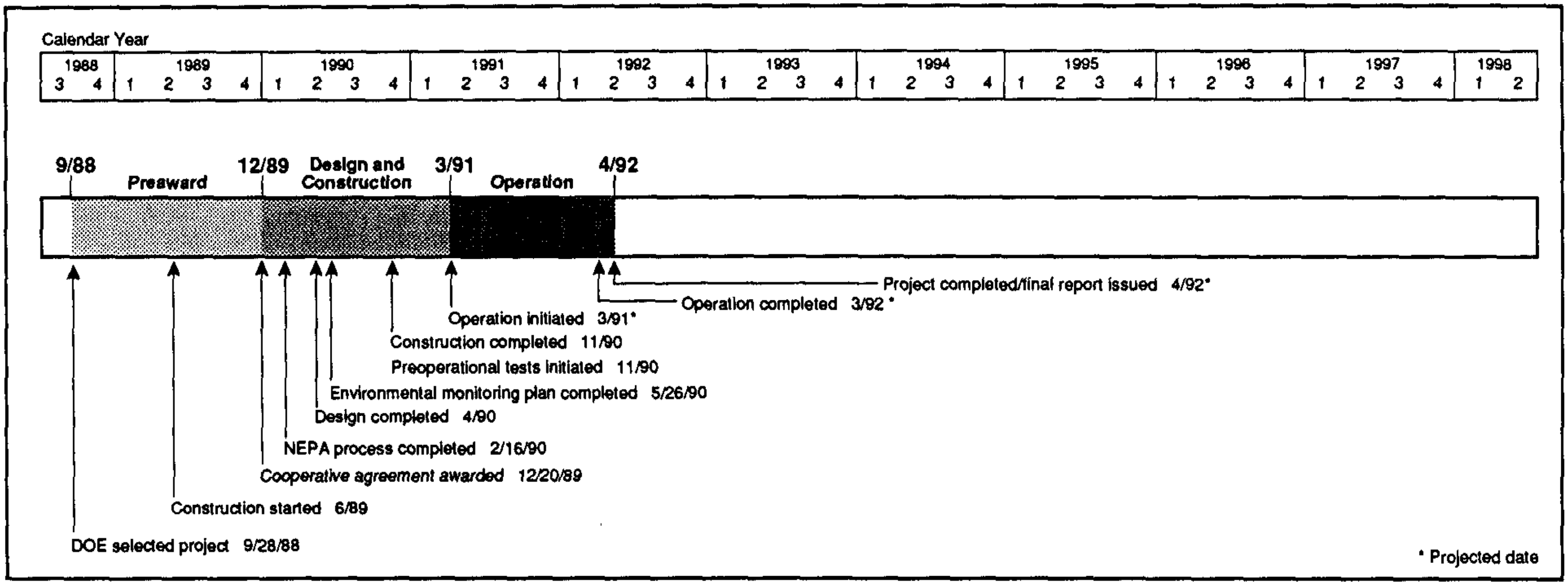
Project Funding:

Total project cost	$12,538,648	100%
DOE	5,903,195	47
Participants	6,635,453	53

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

Technology/Project Description:
The recovery scrubber technology 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 is being 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 resulting from the need to dispose of waste kiln dust from the cement-making process.



Project Status/Accomplishments:

The design phase of the project has been completed, and the construction phase is nearing completion. Initial start-up and testing of the scrubbing system has achieved the project objective of 90–95% SO_2 reduction. Operation is scheduled to begin in March 1991.

Environmental Considerations:

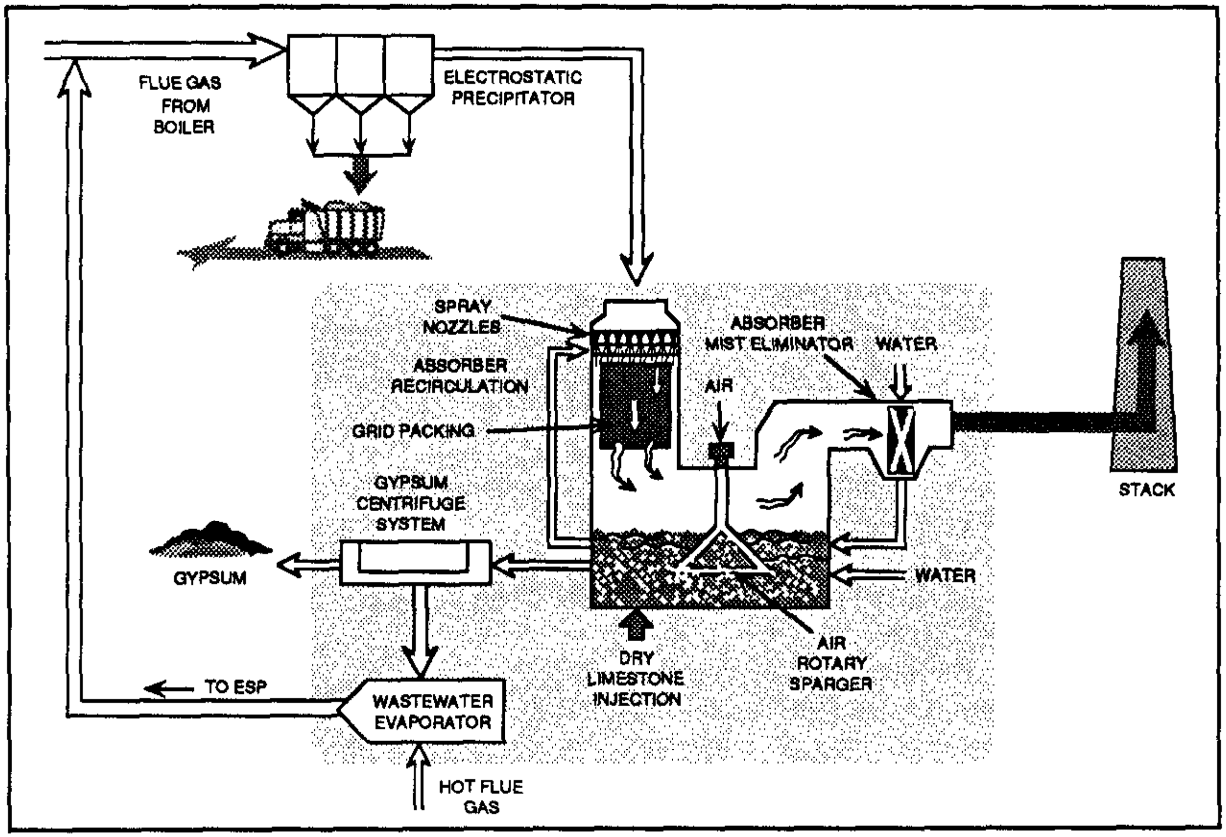
NEPA compliance has been satisfied through an environmental assessment, and a finding of no significant impact was approved February 16, 1990.

The expected performance characteristics and applicable market of the proposed cement kiln gas recovery scrubber were used to estimate the environmental impacts that might result if this technology were to reach full commercialization. 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 SO_2. 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, the SO_2 emissions could be reduced by approximately 150,000 tons/yr. The effect on NO_x emissions is being determined during the demonstration. Some reductions in NO_x emissions are expected. 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. 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.

Commercial Application:

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 a scrubber reactant. The scrubber produces no waste sludge thereby obviating the need for disposal in a landfill. The system potentially provides income from the sale of by-products, and there is no net cost of operation.

Advanced Flue Gas Desulfurization Demonstration Project



Sponsor:

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.)

Additonal Team Members:

Northern Indiana Public Service Company—cofunder and host utility

Mitsubishi Heavy Industries, Ltd. (parent company)—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)

Congressional District:

1st U.S. Congressional District

Technology:

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

Plant Capacity/Production:

528 MWe

Project Funding:

Total project cost	$150,497,000	100%
DOE	63,434,000	42
Participants	87,063,000	58

Project Objective:

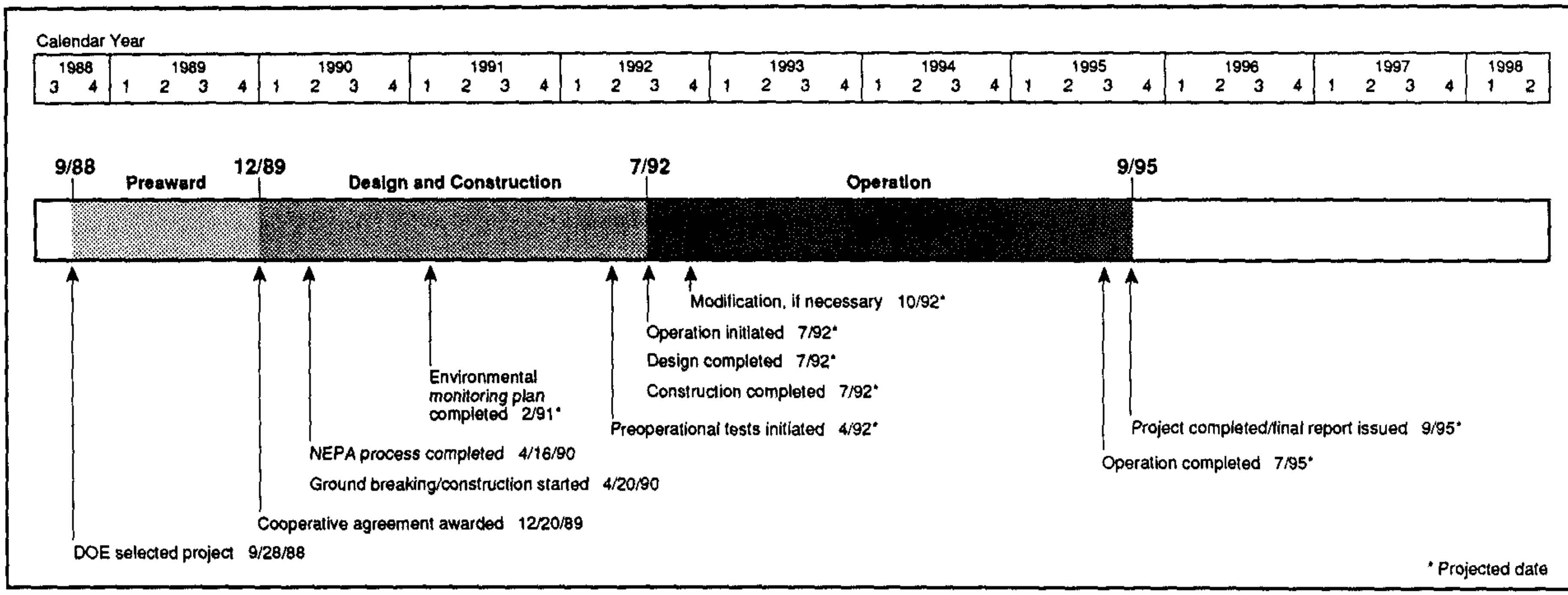
To demonstrate removal of 90–95% or more of the SO_2 at approximately one-half the cost of current conventional scrubbing technology; and to demonstrate significant reduction of space requirements.

Technology/Project Description:

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

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

The AFGD process being demonstrated is expected simultaneously to remove 90–95% or more of the SO_2, provide a commercial gypsum by-product, and evaporate wastewater.



The project also seeks to demonstrate a novel business concept, whereby Pure Air owns and operates the AFGD facility. Thus, Pure Air expects to specialize in pollution control activities, relieving the electric utility of the operation of the AFGD unit. Assuming that the 3-year demonstration is successful, Pure Air will continue to own the AFGD facility and to operate it as a contracted service to the utility for an additional 17-year period. The demonstration is located at Northern Indiana Power Service Company's 528-MWe Bailly Generating Station near Chesterton, IN.

Project Status/Accomplishments:

Design is approximately 90% complete; the remaining design activities will continue through the early stages of operation. Construction is approximately 35% complete; emphasis has been on site preparation, foundation installation, and structural assembly. Mechanical installation activities are slated for 1991, and start-up is on schedule for mid-1992. A pilot-plant test was performed for 2 weeks during February and March 1990. Using U.S. high-sulfur coal and limestone feedstocks, the pilot test was successful both in terms of SO_2 removal and gypsum purity levels.

Environmental Considerations:

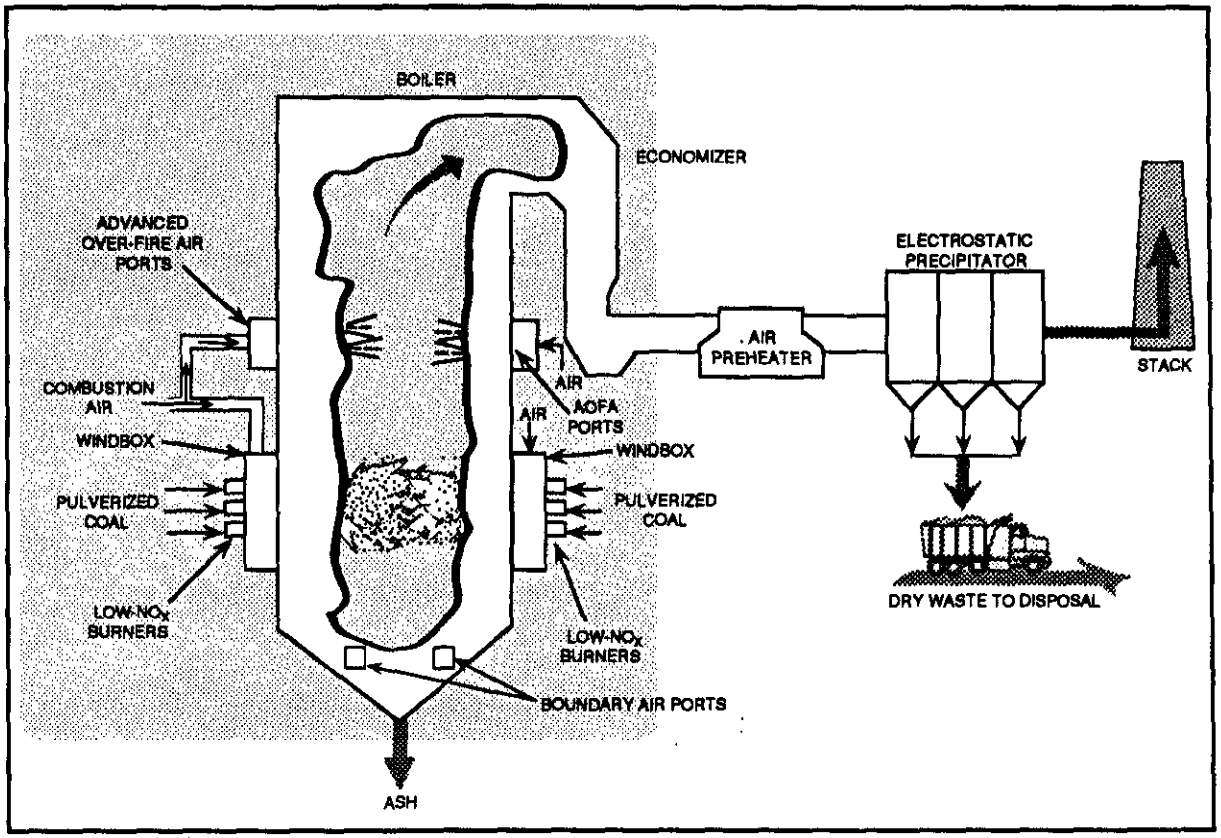
NEPA compliance has been satisfied by an environmental analysis, with a finding of no significant impact approved by DOE on April 16, 1990.

Assuming maximum commercialization of the AFGD process, a 48% reduction of SO_2 could be achieved on a national basis by 2010 relative to a no-action alternative. The significant reductions of SO_2 are projected to be achievable nationally due to the 90–95% SO_2 removal capability forecasted for the AFGD process and its wide potential applicability. Although the process potentially would increase solid waste by 9%, the gypsum by-product could be sold, depending on the local market conditions, thereby eliminating the need to dispose of it as a waste product. If there is no market for the gypsum by-product, it is readily disposable in a landfill. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler



Sponsor:
Southern Company Services, Inc.

Additional Team Members:
Electric Power Research Institute—cofunder
Foster Wheeler Energy Corporation—technology supplier
Georgia Power Company—host utility

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

Congressional District:
7th U.S. Congressional District

Technology:
Foster Wheeler's low-NO_x burner (LNB) with advanced over-fire air (AOFA)

Plant Capacity/Production:
500 MWe

Project Funding:

Total project cost	$11,711,229	100%
DOE	5,242,917	45
Participants	6,468,312	55

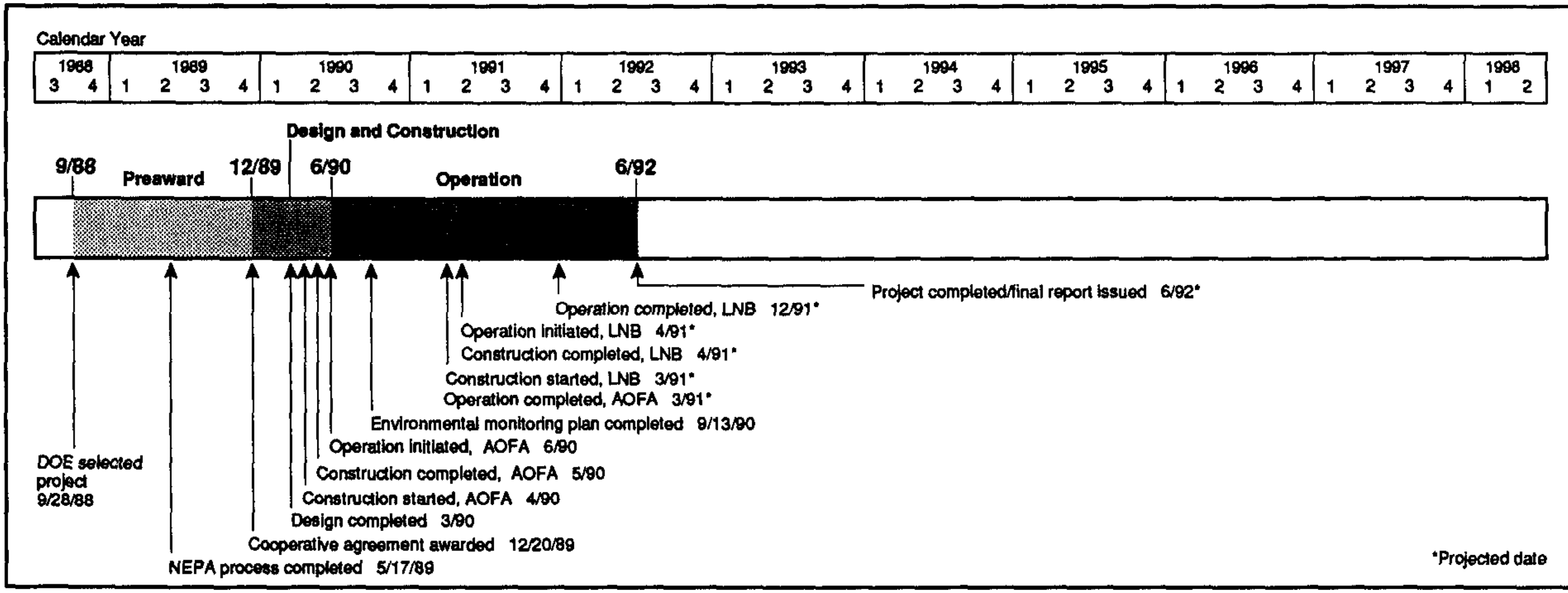
Project Objective:
To achieve 50% NO_x reduction with the AOFA/LNB system; to determine the contributions of AOFA and the LNB to NO_x reduction and the parameters determining optimum AOFA/LNB system performance; and to assess the long-term effects of AOFA and LNB on NO_x reduction and boiler performance.

Technology/Project Description:
AOFA involves (1) improving the mixing of over-fire 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 a 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 60% compared with conventional burners.

The demonstration is located at the Georgia Power Company's Hammond Plant, 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.



Project Status/Accomplishments:

Design activities are complete. Construction activities are under way, with the AOFA system designed and installed. The AOFA diagnostic and performance testing is complete, and the long-term AOFA testing began during October 1990. The 24 controlled-flow, split-flame LNBs have been designed and are under construction; installation is scheduled for March 1991.

During preliminary diagnostic and performance testing of the AOFA system, NO_x reductions in excess of 25% have been measured with a small increase in carbon loss on ignition. No significant change in boiler operation and combustion stability was experienced while operating with the AOFA system dampers.

Environmental Considerations:

NEPA compliance has been satisfied with a memo-to-file, which was approved on May 17, 1989.

Significant reductions of NO_x (11%) are projected nationally by 2010 from maximum commercialization of the technology due to the 60% removal capability forecasted and the wide applicability of the process. No changes in liquid effluents or solid wastes are anticipated. (Source: CCT Programmatic Environmental Impact Statement)

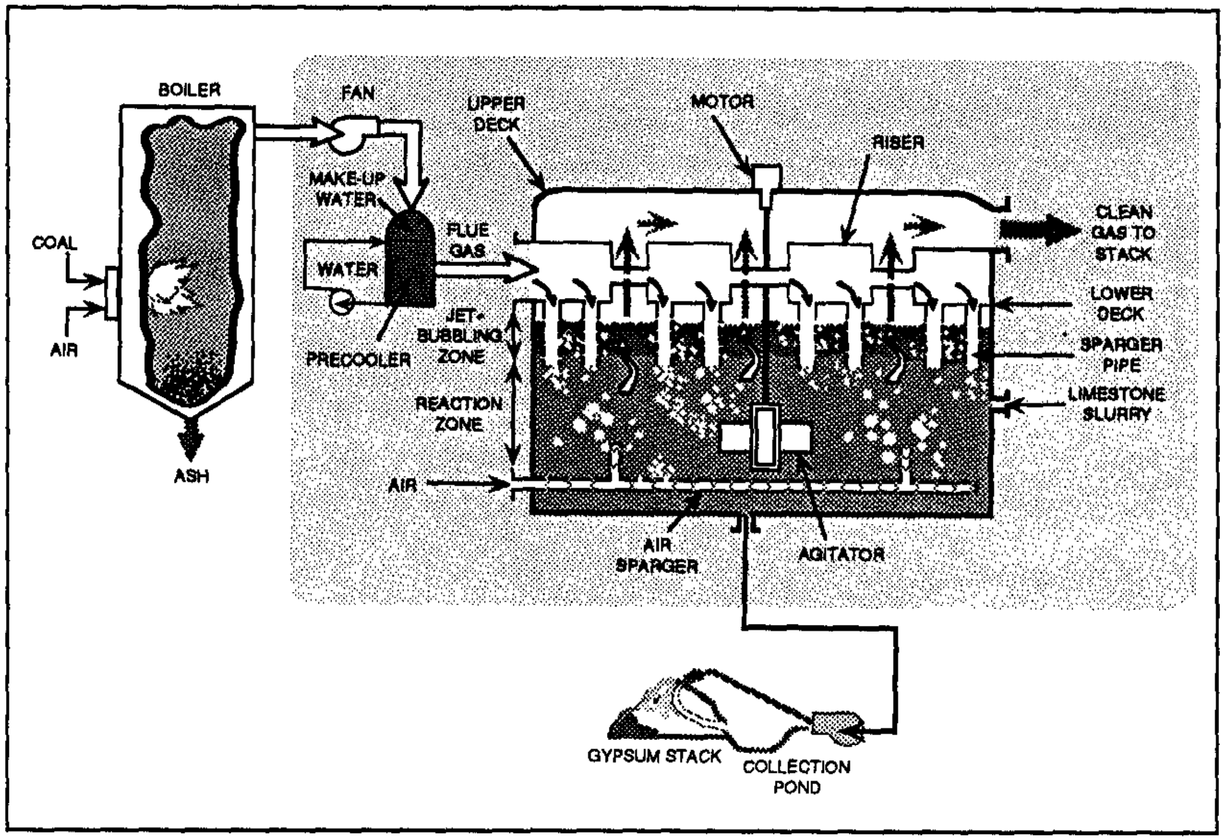
Commercial Application:

This technology is applicable for retrofitting the 422 pre-NSPS wall-fired boilers existing in the United States.

Commercialization of the technology will be aided by the following characteristics:

- Reduced short-term NO_x emissions by up to 60%
- Competitive capital and operating costs
- Relatively easy retrofit
- Little or no derating of the boiler
- Use of commercially available components

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



Sponsor:
Southern Company Services, Inc.

Additional Team Members:
Georgia Power Company—host utility
Electric Power Research Institute—cofunder
Radian Corporation—environmental and analytical consultant
Ershigs, Inc.—fiberglass fabricator
University of Georgia Research Foundation—by-product utilization studies

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

Congressional District:
6th U.S. Congressional District

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

Plant Capacity/Production:
100 MWe

Project Funding:

Total project cost	$35,843,678	100%
DOE	17,546,646	49
Participants	18,297,032	51

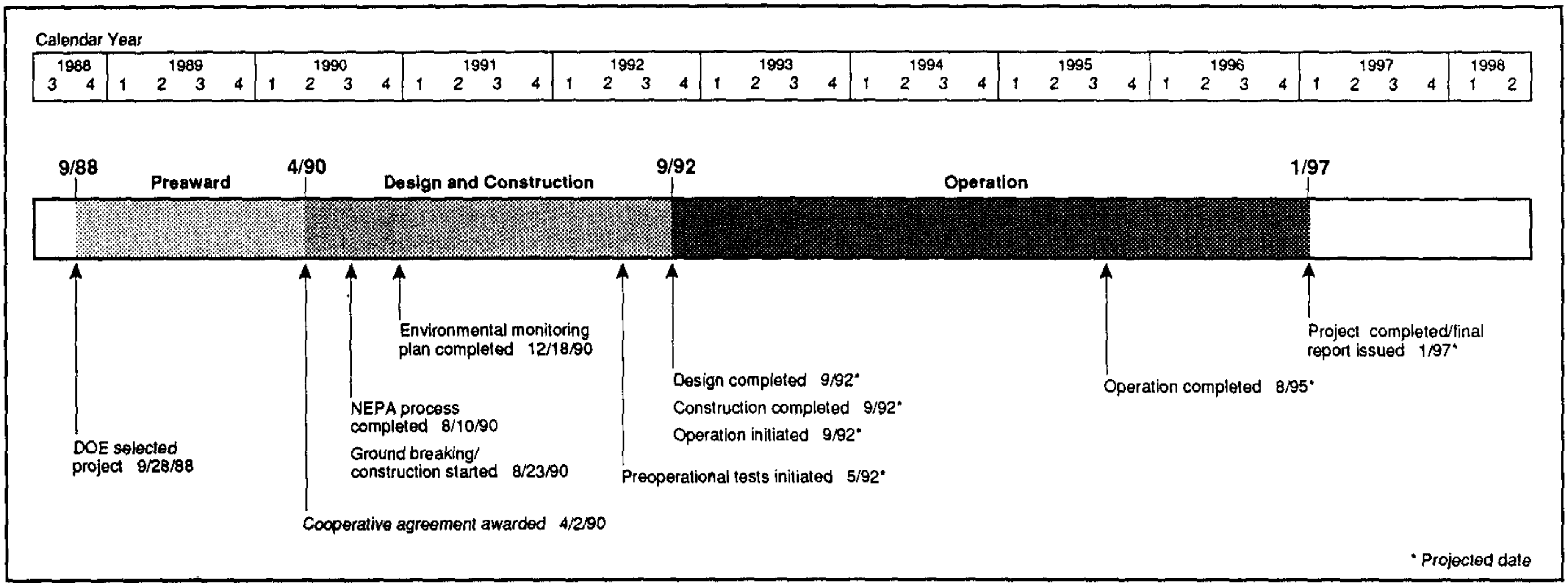
Project Objective:
To demonstrate the CT-121 flue gas desulfurization system, including several design innovations, at the 100-MWe scale; more specifically, to demonstrate 90% SO_2 control at high reliability with and without simultaneous particulate control with possible additional reductions in operating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

Technology/Project Description:
The project will demonstrate the CT-121 FGD process. This process uses a unique absorber design known as the jet-bubbling reactor, which combines limestone FGD reaction, forced oxidation, and gypsum crystallization in a one-process vessel. As a result, the process is mechanically and chemically simpler than conventional FGD processes and can be expected to exhibit lower cost characteristics.

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

As part of the project, innovations to the process will be evaluated to determine whether costs can be reduced further by using fiberglass-reinforced plastic absorbers, eliminating flue gas reheat and spare absorber module, and stacking gypsum to reduce waste management costs. The ability of this technology simultaneously to capture SO_2 and particulates will also be evaluated.

A 2.5% sulfur coal will be used to demonstrate 90% SO_2 control with high reliability, with and without simultaneous particulate control.



Georgia Power Company's 100-MWe Plant Yates Unit 1, near Newnan, GA (about 40 miles from Atlanta), will be retrofitted with the Chiyoda scrubber.

Project Status/Accomplishments:

Preliminary design was conducted over an 8-month period, which ended December 1, 1990. Design and construction activities commenced on June 2, 1990, and will continue for 27 months or until September 1992. Construction began at the Plant Yates site on August 23, 1990. Critical foundations have been poured. Detailed design decisions have been made concerning the innovative fiberglass-reinforced plastic absorber. Ershigs set up equipment on site and during December 1990 spun in place the 42-ft-high by 42-ft-diameter jet-bubbling reactor.

Environmental Considerations:

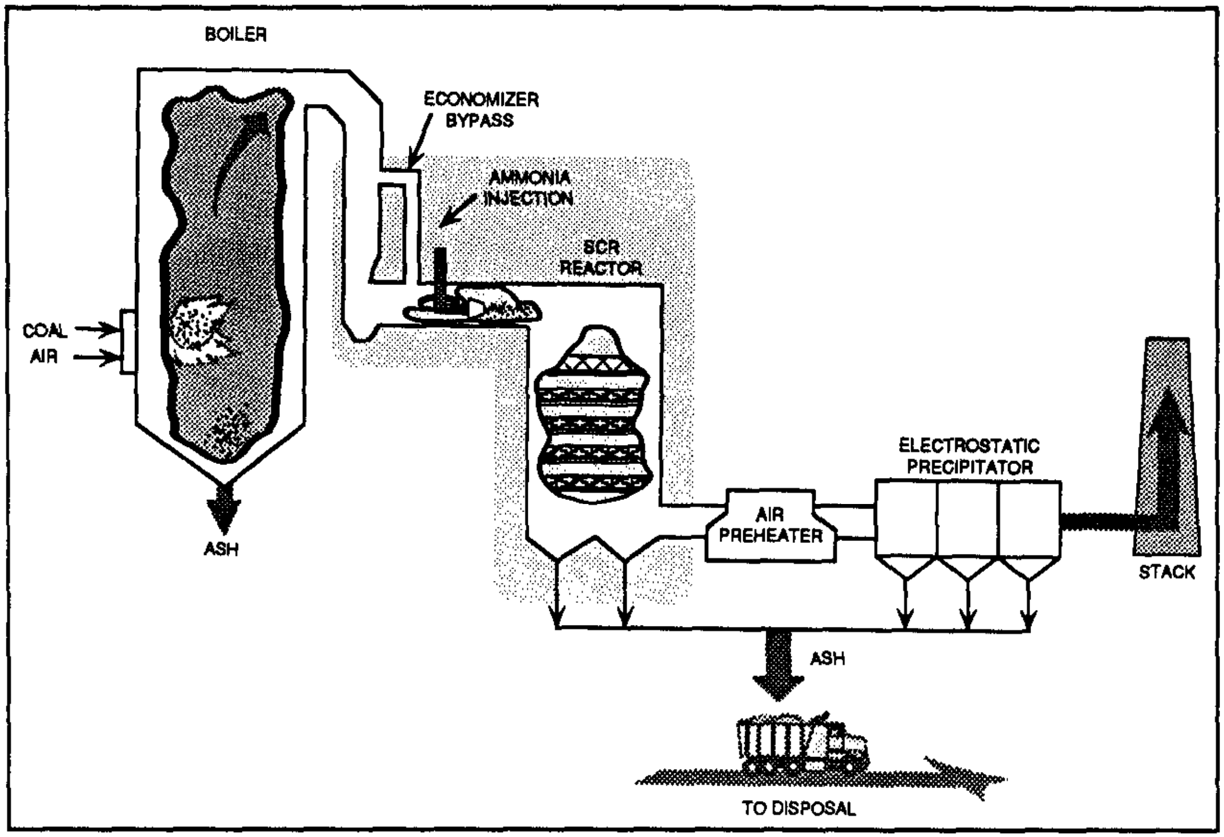
An environmental assessment with a finding of no significant impact was approved by DOE on August 10, 1990.

Assuming maximum commercialization of the CT-121 process on a national basis by 2010 relative to a no-action alternative, a 48% reduction of SO_2 could be achieved. The significant national reductions of SO_2 are attributable to the 90–95% SO_2 removal capability forecasted for the CT-121 process and the wide potential applicability of the process. Although solid waste would increase by 9%, the waste is readily disposable. The greatest environmental benefits may be achieved in the Northeast because of the large amount of coal-fired capacity in this region that can be retrofitted with the CT-121 process. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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. By the year 2010, this process would be applicable to 370,000 MWe of new and existing generating capacity. A 90% reduction in SO_2 emissions from only the retrofit portion of this capacity represents over 10,500,000 tons/year of potential SO_2 control.

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



Sponsor:
Southern Company Services, Inc.

Additional Team Members:
Electric Power Research Institute—cofunder
Gulf Power Company—host utility

Location:
Pensacola, Escambia County, FL (Gulf Power Company's Plant Crist)

Congressional District:
1st U.S. Congressional District

Technology:
Selective catalytic reduction (SCR)

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

Project Funding:

Total project cost	$15,574,355	100%
DOE	7,525,338	48
Participants	8,049,017	52

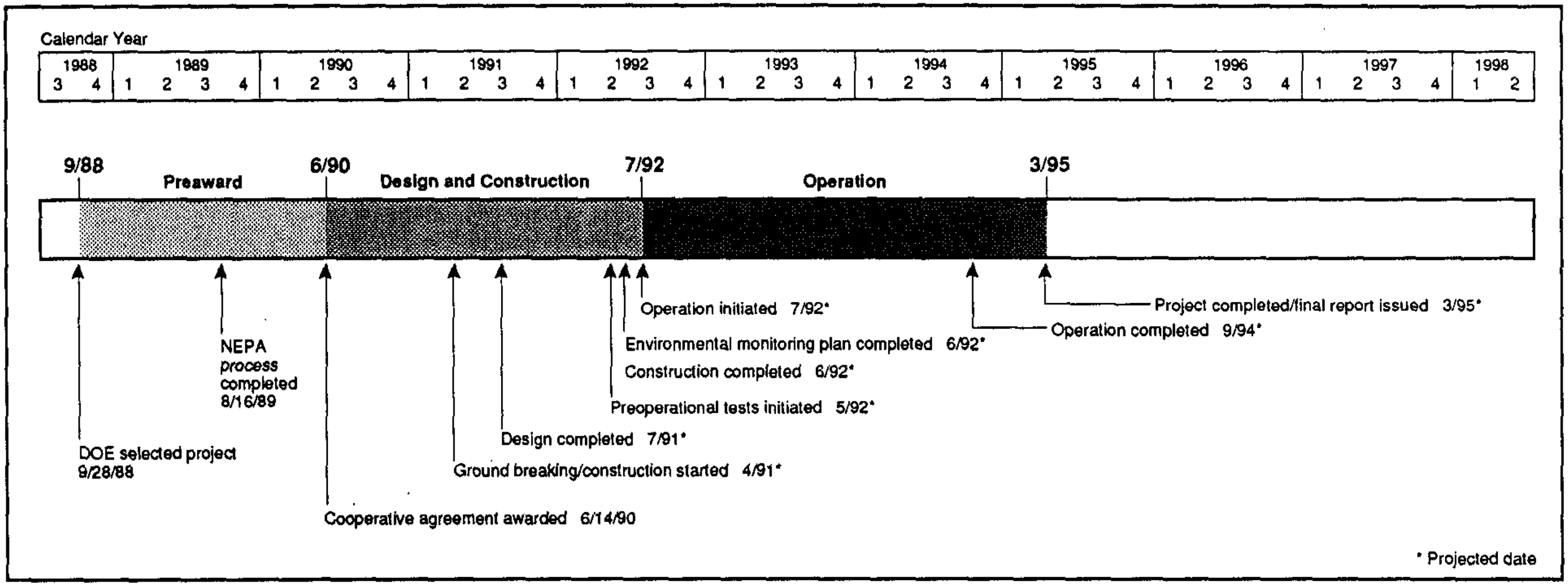
Project Objective:
To evaluate the performance of commercially available SCR catalysts when applied to operating conditions found in U.S. pulverized coal-fired utility boilers using U.S. high-sulfur coal under various operating conditions while achieving as much as 80% NO_x removal.

Technology/Project Description:
The SCR technology consists of injecting ammonia (NH_3) into boiler flue gas and passing it through a catalyst bed where the NO_x and NH_3 react to form nitrogen and water vapor.

In this demonstration project, the SCR facility consists of three 2.5-MWe SCR reactors, supplied by separate 5,000 std ft^3/min flue gas slip-streams, and six 0.20-MWe 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 (three U.S., two European, and two Japanese) will provide nine 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, has access to flue gas from burning approximately 3% sulfur coal under various NO_x and particulate levels.



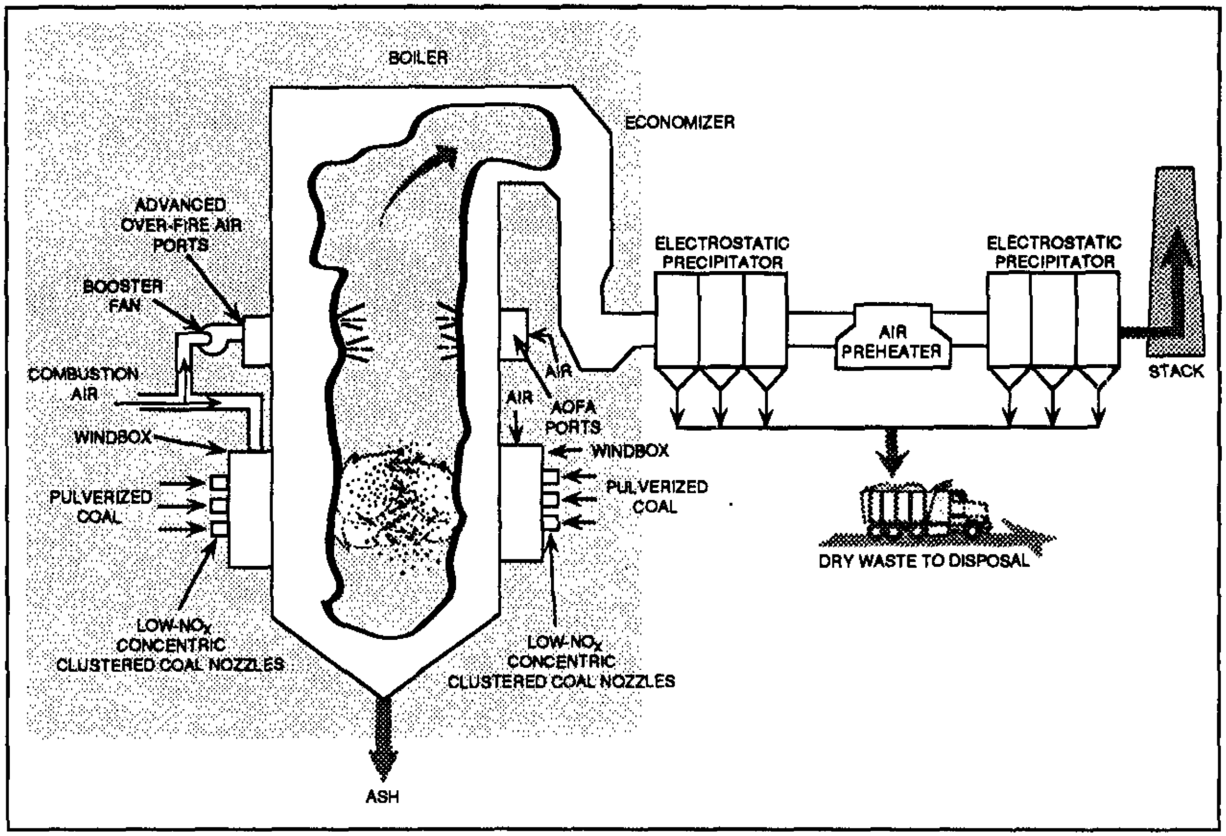
Project Status/Accomplishments:
Design activities are under way. Detailed measurements of baseline flue gas conditions at Plant Crist are complete and are under review. Final, detailed catalyst specifications have been received from each catalyst supplier. A review of these specifications is under way in order to finalize SCR reactor internal design.

Environmental Considerations:
NEPA compliance has been satisfied by a memo-to-file approved on August 16, 1989.

Assuming maximum commercialization of the SCR process on a national basis by 2010 relative to a no-action alternative could achieve a 15% NO_x reduction. The significant national reductions of NO_x are attributable to the 80% NO_x removal capability forecasted for the SCR process and the wide potential applicability of the process. There will be no additional solid waste because the spent catalyst will be returned to the respective catalyst suppliers. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
SCR technology can be applied to retrofit and new utility applications for removal of NO_x from flue gas. 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, over-fire 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.

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



Sponsor:
Southern Company Services, Inc.

Additional Team Members:
Gulf Power Company—cofunder and host utility
Electric Power Research Institute—cofunder
ABB Combustion Engineering, Inc.—burner/technology supplier

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

Congressional District:
1st U.S. Congressional District

Technology:
ABB Combustion Engineering, Inc.'s low-NO_x concentric-firing system (LNCFS) and concentric clustered tangential-firing system (CCTFS); advanced over-fire air (AOFA) system

Plant Capacity/Production:
180 MWe

Project Funding:

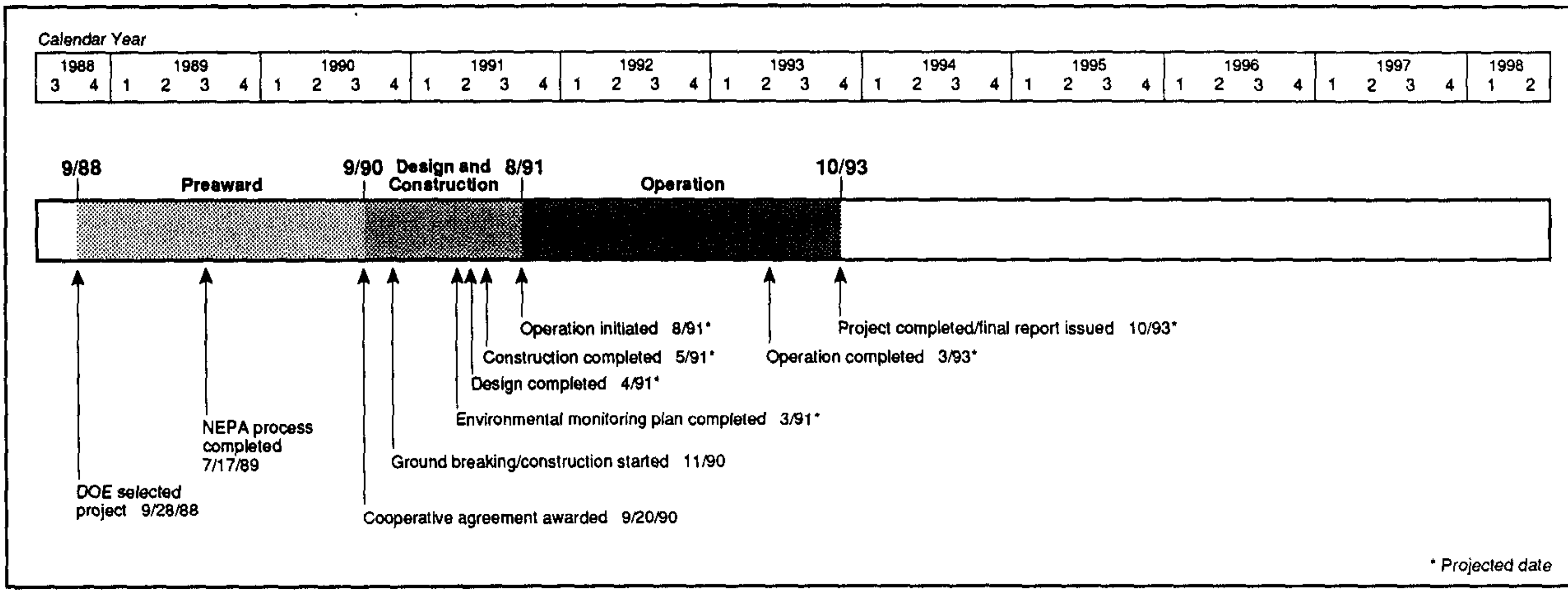
Total project cost	$8,555,303	100%
DOE	4,150,055	49
Participants	4,405,248	51

Project Objective:
To demonstrate advanced over-fire air, a low-NO_x concentric-firing system, and a concentric clustered tangential-firing system separately and in combination on a single reference boiler under typical dynamic operating conditions; and to achieve a 60% reduction in NO_x emission levels.

Technology/Project Description:
The AOFA process involves the mixing of over-fire air with the furnace gases to achieve complete combustion and the depletion of air from the burner zone to minimize NO_x formation.

The low-NO_x concentric firing system, or LNCFS, was developed solely for applications to tangentially fired steam generators and uses a technique of separating the fuel and air streams in the tangential-firing arrangement. LNCFS has two significant advantages over the standard tangential arrangement: NO_x is reduced, and furnace wall slagging is decreased.

In an LNCFS, fuel and primary air is surrounded with a layer of secondary or offset air. This air is directed into the furnace through offset air nozzles. Improvements to the tangentially fired combustion technique include (1) the addition of adjustable turning vanes to the secondary air nozzles, (2) the addition of horizontally adjustable offset air nozzle tips to the main auxiliary compartments and end auxiliary compartments, (3) the reduction in free area available in the coal compartments through which the fuel-air mixture can pass, and (4) the addition of divergent coal nozzle tips.



The concentric clustered tangential-firing system, or CCTFS, combines several established NO_x reduction techniques that are applicable to tangentially fired coal boilers. The concept is based on the premise that both over-fire air staging and final furnace oxygen content dominate in controlling the final NO_x levels. Clustered coal nozzles have been included to provide better NO_x control over the load range. Extensions from the LNCFS occur as different levels of NO_x reduction can be achieved through combinations of coal nozzle clustering close-coupled with over-fire air systems and separated over-fire air systems. Local fuel-rich zones in the furnace burner zone reduce NO_x formation.

The planned configuration is expected to reduce NO_x by 60% and decrease furnace wall slagging.

These low-NO_x technologies are being tested separately and then in combination on the 180-MWe tangentially fired Unit No. 2 coal boiler at Gulf Power's Plant Smith. Coals being tested during the demonstration include bituminous coals from IL, WV, AL, and KY in the 2.6–3.1% sulfur range.

Project Status/Accomplishments:

The cooperative agreement was awarded on September 20, 1990.

During the October 1990 plant outage, air heater baskets, instrumentation, sampling systems, and various support equipment were installed. Baseline diagnostic and performance tests were completed. Results are being analyzed.

Environmental Considerations:

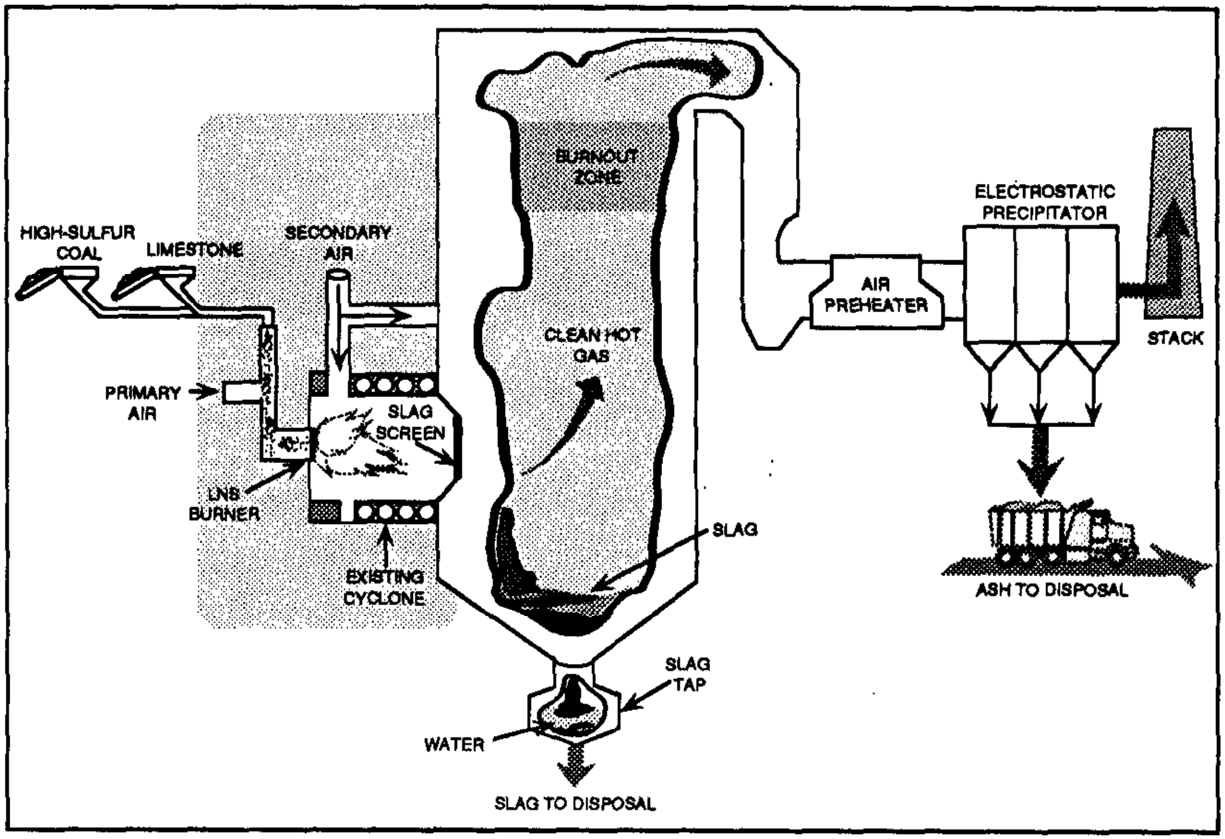
NEPA compliance has been satisfied by a memo-to-file approved by DOE on July 17, 1989.

Assuming maximum commercialization of the technology, significant reductions of NO_x (11%) are projected to be achievable nationally by 2010, due to the 60% removal capability forecasted and the wide applicability of the process. Negligible changes in liquid effluents are anticipated, and the technology produces no additional dry solid waste. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Commercial applications include a wide range of tangentially fired utility boilers throughout the United States and abroad. As an example, the Southern Company (which owns Southern Company Services, Inc.) has, within its system of electric utilities, over 20,000 MWe of coal-fired generating capacity. Approximately two-thirds of this capacity is based on pulverized-coal tangentially fired boilers.

Low-NO_x/SO_x Burner Retrofit for Utility Cyclone Boilers



Sponsor:

TransAlta Resources Investment Corporation

Additional Team Members:

State of Illinois, Department of Energy and Natural Resources—cofunder
Electric Power Research Intitute—cofunder
Southern Illinois Power Cooperative—host utility
Bechtel Power Corporation—engineer and constructor
Riley Stoker Corporation—boiler contractor

Location:

Marion, Williamson County, IL (Southern Illinois Power Cooperative's Marion Plant, Unit 1)

Congressional District:

22d U.S. Congressional District

Technology:

TransAlta's advanced slagging coal combustor, which is a low-NO_x, low-SO_x (LNS) burner

Plant Capacity/Production:

33 MWe

Project Funding:

Total project cost	$15,300,000	100%
DOE	6,788,000	44
Participants	8,512,000	56

Project Objective:

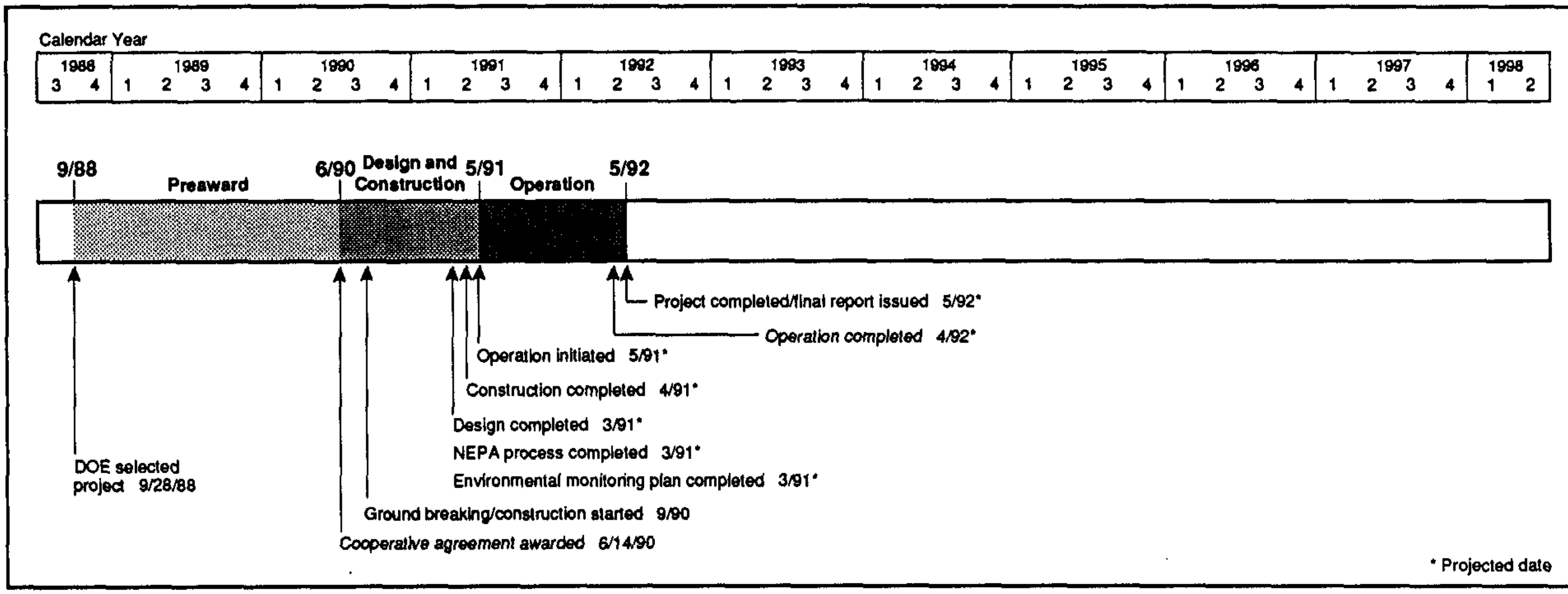
To demonstrate a low-NO_x, low-SO_x (LNS) burner retrofitted to a utility cyclone boiler; and to achieve at least 70% SO_x reduction on high-sulfur Illinois bituminous coals and control of NO_x emissions to less than 150 ppm.

Technology/Project Description:

The LNS burner is a pulverized coal-fired, entrained-flow combustion system with staged combustion. Classed as a slagging combustor, the LNS burner involves high-temperature, fuel-rich combustion for the control of both SO_2 and NO_x. High-sulfur bituminous coal, mixed with limestone, is burned in a refractory-lined, air- and water-cooled chamber. Using one-half of the total combustion air, the burner creates a hot fuel-rich gas. During combustion, sulfur is captured by the calcium from the limestone and is retained as a solid in the melted coal ash. Nitrogen chemically bound in the coal is converted to harmless molecular nitrogen due to the creation of a reducing zone. All of these operations are carried out in the burner.

The staged combustion is expected to achieve very low NO_x emissions, and injection of the limestone sorbent in the entrained-flow system is expected to achieve SO_2 reductions in excess of 70%. Because ash removal efficiency is high, there is no derating of the boiler, no added fly ash handling, and no degradation of boiler tube surfaces.

In this project, a cyclone-fired boiler is being retrofitted with LNS burners and a coal pulverizer system at the 33-MWe Unit 1 of Southern Illinois Power Cooperative's Marion Plant. Two LNS burners rated at 200 MMBtu/hr are being used to retrofit the existing cyclone boiler.



Project Status/Accomplishments:
The cooperative agreement was awarded on June 14, 1990.

Construction activities began in late 1990. Major equipment is being procured. Test plans are being finalized. Baseline tests were completed in November 1990. Construction and start-up are expected to be finished in April 1991, and operation is scheduled to begin in May 1991.

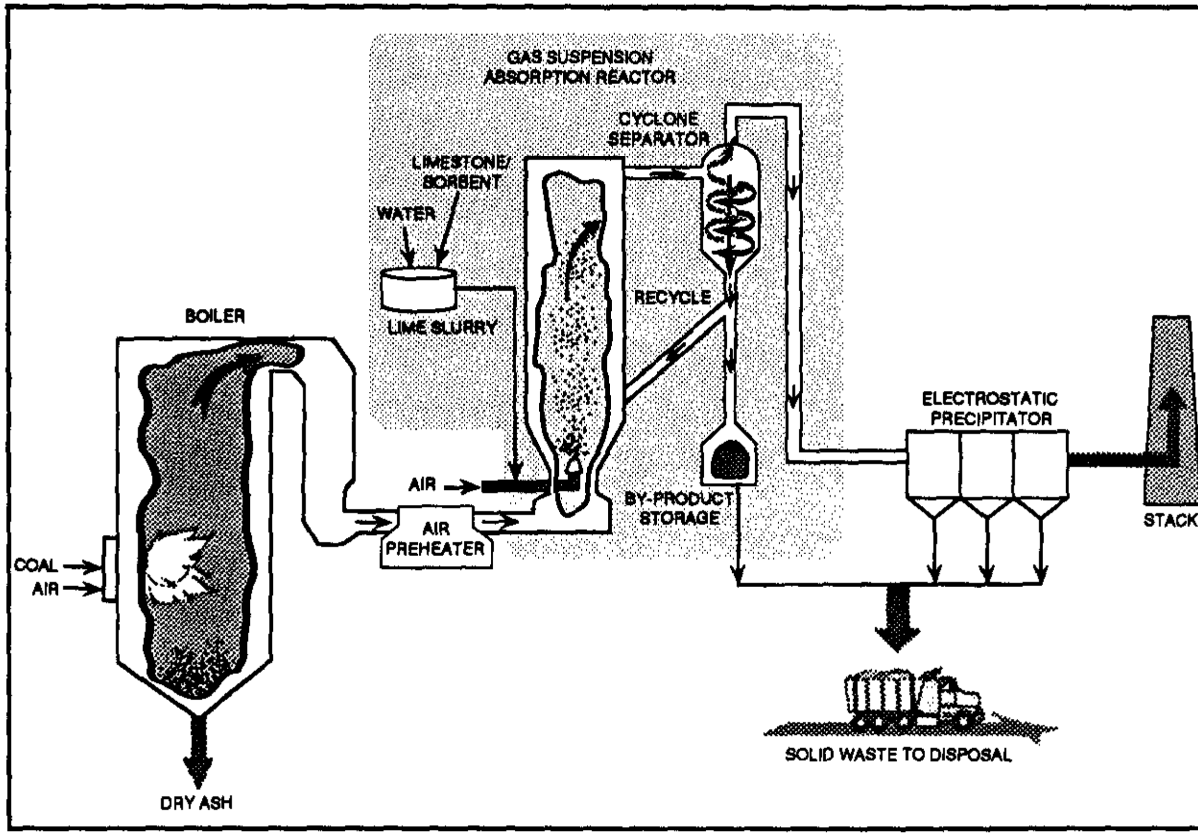
Environmental Considerations:
The environmental assessment with a finding of no significant impact has been prepared and is being reviewed by DOE.

Assuming maximum commercialization of the technology, significant reductions of SO_2 and NO_x (45% and 18% respectively) are projected to be achievable nationally by 2010 due to the capability of the LNS burner process to remove 70–90% of SO_2 and NO_x emissions from coal-fired boilers and the wide potential applicability of the process. Negligible changes in liquid effluents are anticipated, and although there is a 17% increase in solid waste, it is dry and readily disposable. The slag product may be used as road grit and/or sand blast grit, thereby minimizing disposal issues. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
Coal-fired utility cyclone boilers represent a total capacity of 26,000 MWe. Because most cyclone units are pre-NSPS, very few units use scrubbers for SO_2 control. Cyclone units also typically generate high NO_x emissions. The LNS burner has the potential to reduce both SO_2 and NO_x emission levels.

CCT-III
Project Fact Sheets

10-MW Demonstration of Gas Suspension Absorption



Sponsor:
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 Shawnee Fossil Plant)

Congressional District:
1st U. S. Congressional District

Technology:
FLS miljo a/s' gas suspension absorption (GSA) system for flue gas desulfurization (FGD)

Plant Capacity/Production:
10-MWe equivalent slip-stream of flue gas from a 150-MWe boiler

Project Funding:

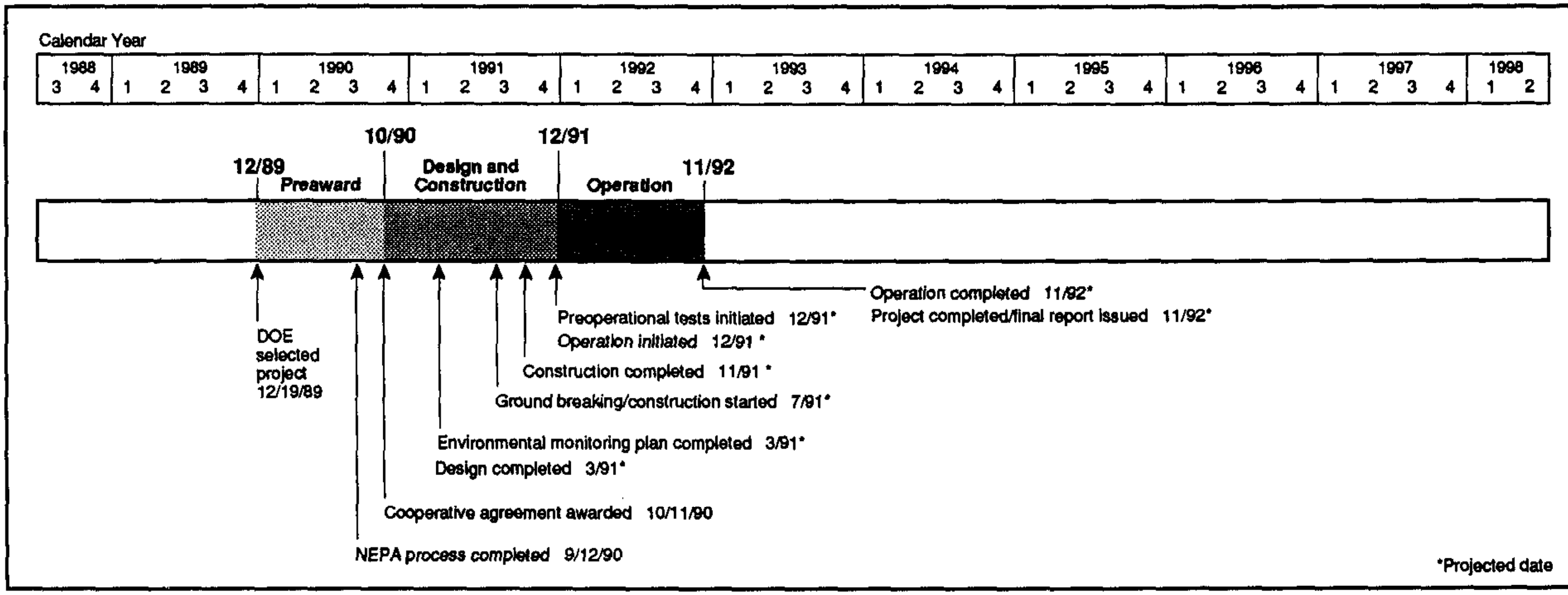
Total project cost	$6,920,679	100%
DOE	2,000,000	29
Participants	4,920,679	71

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 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 in an existing site disposal area.

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

This demonstration is utilizing a 10-MWe slip-stream of flue gas from a 150-MWe coal-fired boiler at the Tennessee Valley Authority's Shawnee Fossil Plant in West Paducah, KY.



Project Status/Accomplishments:
The cooperative agreement was awarded October 11, 1990. Preliminary process flow diagrams were prepared for discussion and review, and general arrangement drawings and sizing and layout of major equipment were completed.

Environmental Considerations:
NEPA compliance has been satisfied by a *memo-to-file* approved by DOE on September 12, 1990.

Assuming maximum commercialization of this technology, significant reductions of SO_2 (45%) are achievable nationally by 2010 due to the capability of the GSA process to remove at least 90% of the SO_2 emissions from coal-fired boilers and the wide potential applicability of the process. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
The GSA process offers several advantages over conventional FGD technologies. Airpol estimates that GSA is 40% cheaper than wet FGD and 20% cheaper than spray drying. Moreover, GSA is much simpler to build and operate than wet FGD and regenerable processes and requires much less space. Space requirements, operability, and ease of installation are comparable to spray dryers and duct injection. However, the SO_2 removal capability of the GSA technology (90%) compares to that of wet FGD and the regenerable processes, while dry injection processes and spray dryers generally remove about 50% and 90% respectively. This high removal rate makes the GSA process suitable for use with high-sulfur coal, unlike the spray dryer or dry injection processes, which are suitable only for low- and medium-sulfur coals.

In summary, GSA is expected to find commercial acceptance because it is the only semidry process that offers SO_2 removal rates comparable to the more costly and complex wet FGD systems. In addition, GSA offers relatively low sorbent consumption rates and may perform better than dry systems; it is both less costly and more effective than spray dryers.

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

Sponsor:
Air Products and Chemicals, Inc., and Dakota Gasification Company

Additional Team Member:
Chem Systems, Inc.—technology developer

Location:
Beulah, Mercer County, ND (Dakota Gasification Company's Great Plains Gasification Plant)
(An alternate site is being considered.)

Congressional District:
At-large U.S. Congressional District
(An alternate site is being considered.)

Technology:
Chem Systems' liquid-phase methanol (LPMEOH®) process

Plant Capacity/Production:
500 tons/day of methanol (or about 50 million gallons/yr)

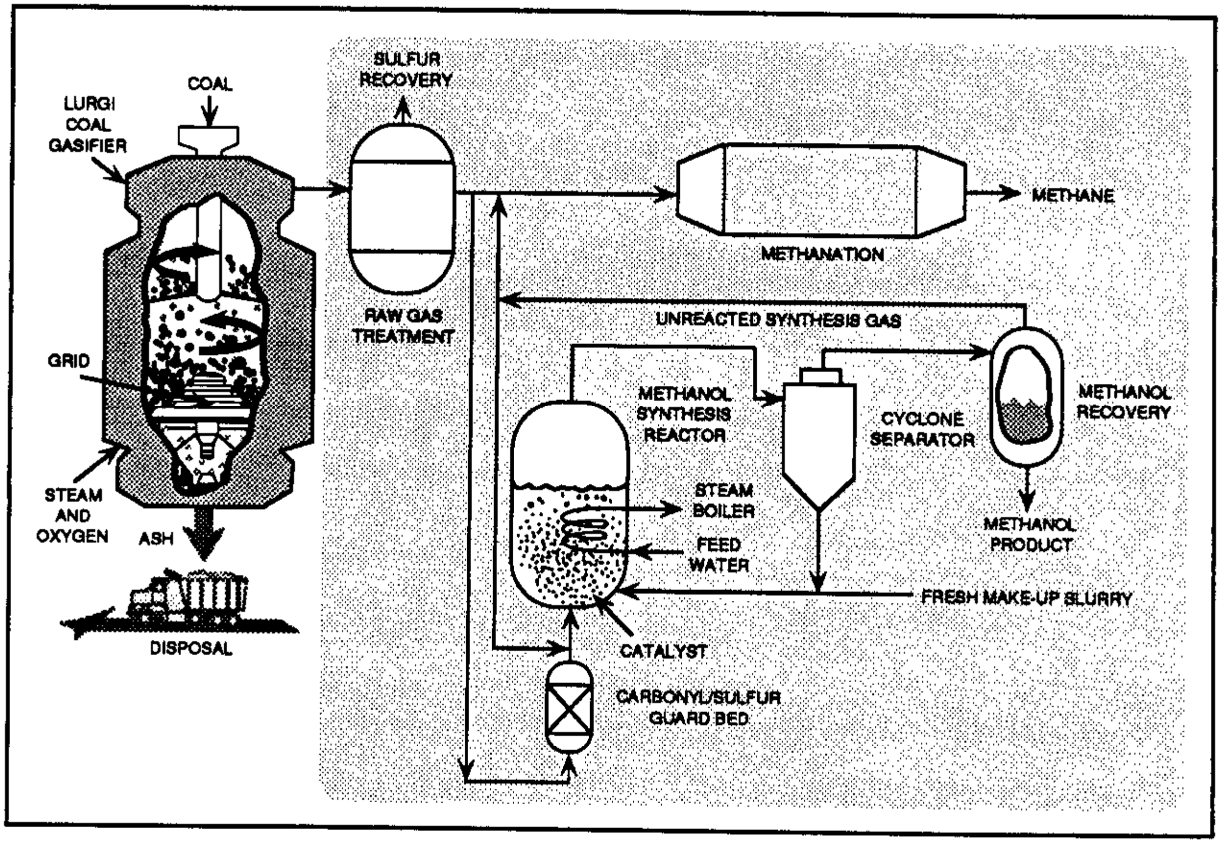
Project Funding:

Total project cost:	$213,701,857	100%
DOE	92,701,297	43
Participants	121,000,560	57

(Funding is subject to negotiation.)

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 low-SO_x, low-NO_x alternative fuel in boiler, turbine, and transportation applications.

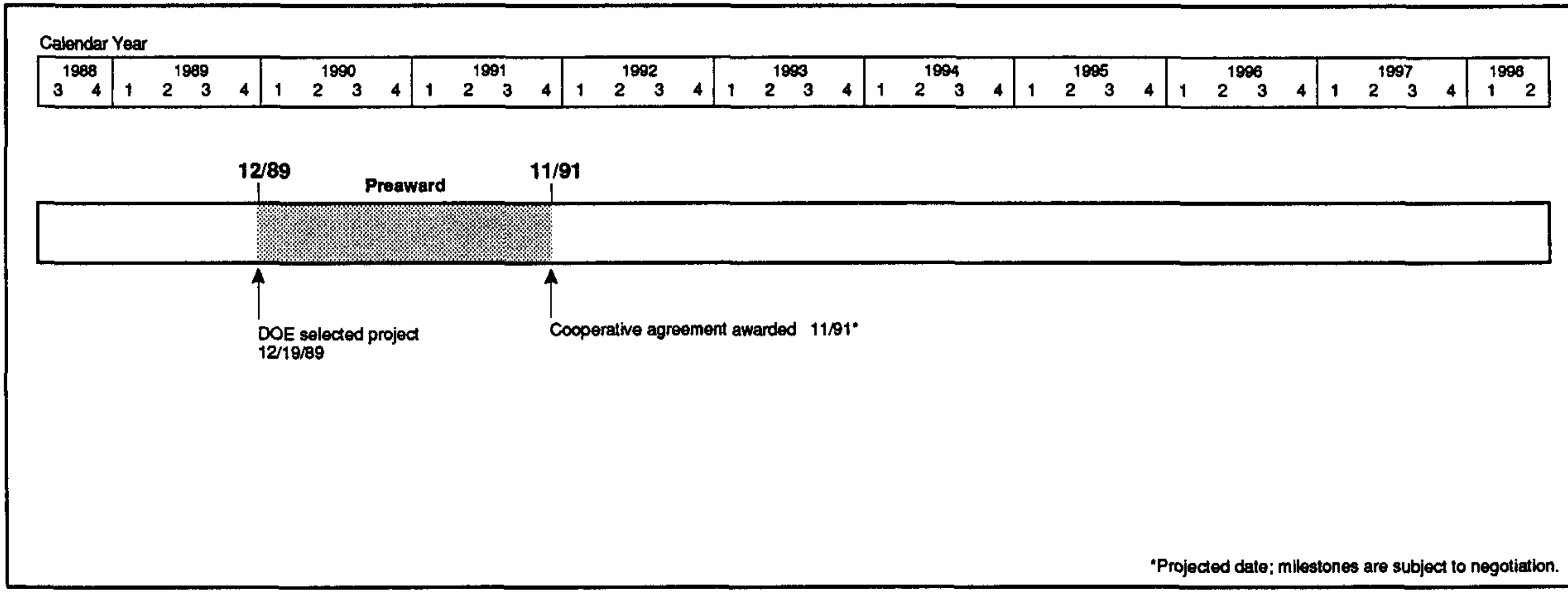
LPMEOH is a registered trademark of Chem Systems, Inc.



Technology/Project Description:
This project will demonstrate the LPMEOH® process to produce methanol from coal-derived synthesis gas on a commercial scale. The combined reactor and heat removal system in the LPMEOH® process differentiates it significantly from other commercial methanol processes. The liquid phase not only supports the catalyst, but functions as an efficient means to remove the heat of reaction away from the catalyst surface. This feature alone directly permits the use of a low ratio of hydrogen to carbon monoxide in the synthesis gas streams produced from coal gasification facilities as feed to the reactor without the need for shift conversion.

The performance of the LPMEOH® process for the synthesis of methanol is characterized as follows:

- Carbon monoxide conversion to methanol—13% per reactor per pass in a hydrogen-rich feed
- Methanol productivity comparable to gas-phase systems—6,000 kg of methanol per 1 kg of catalyst
- Raw methanol purity—95.6% (fuel-grade)
- Feed gas flexibility—permits the use of synthesis gas produced by any commercial coal gasification system to be used without shift conversion



- Diversity—can be integrated in coal gasification combined-cycle applications

Original plans sited the 500-ton/day LPMEOH® demonstration facility at Dakota Gasification Company's Great Plains Gasification Plant in Beulah, ND. A portion of the methanol produced at the LPMEOH® demonstration facility would be used in tests to determine its suitability in boiler, turbine, and transportation fuel applications. The remainder would be sold commercially. However, an alternate site is under consideration.

Project Status/Accomplishments:

The project is in negotiation. Several issues related to the business and management structure of the project have affected the schedule for negotiation of the cooperative agreement.

DOE was notified by the sponsors that the Great Plains Gasification Plant located in Beulah, ND, was unavailable for use as the project site. Subsequently, DOE granted an extension to October 18, 1991, for a new site to be identified and to develop the demonstration project at a suitable alternate site.

Environmental Considerations

Environmental information is being prepared for use in the NEPA process.

Virtually all of the sulfur (>99%) can be removed in the manufacturing process and converted into salable elemental sulfur or sulfuric acid. Nitrogen compounds (principally ammonia) generated in the gasification process are easily removed by cleanup systems and subsequently recovered as salable ammonia for fertilizer manufacture. The principal solid waste from the gasifer is coal ash, which is suitable for landfill disposal.

Commercial Application:

LPMEOH® technology can be used in several types of commercial applications. Of particular importance is the integration of the LPMEOH® process in integrated gasification combined-cycle (IGCC) applications. Currently recognized as one of the cleanest technologies for generating electric power from coal, IGCC can economically satisfy the most stringent environmental limits for SO_2 and NO_x. In an IGCC facility, LPMEOH® technology is expected to reduce capital costs and improve electric power generating flexibility by storing energy in the form of methanol. Because of the variety of fuel products produced by the indirect liquefaction process, the technology can be used to supply fuels for a wide range of applications in the utility or industrial sector. Virtually any size boiler that uses coal, distillate, residual oil, or natural gas can use the fuels. The technology can be used in both new and retrofit applications.

Healy Clean Coal Project

Sponsor:
Alaska Industrial Development and Export Authority

Additional Team Members:
Golden Valley Electric Association—host utility
Stone and Webster Engineering Company—engineer and constructor
TRW, Inc.—technology supplier
Joy Technologies—technology supplier

Location:
Healy, AK (Area is unincorporated and without counties.)

Congressional District:
At-large U.S. Congressional District

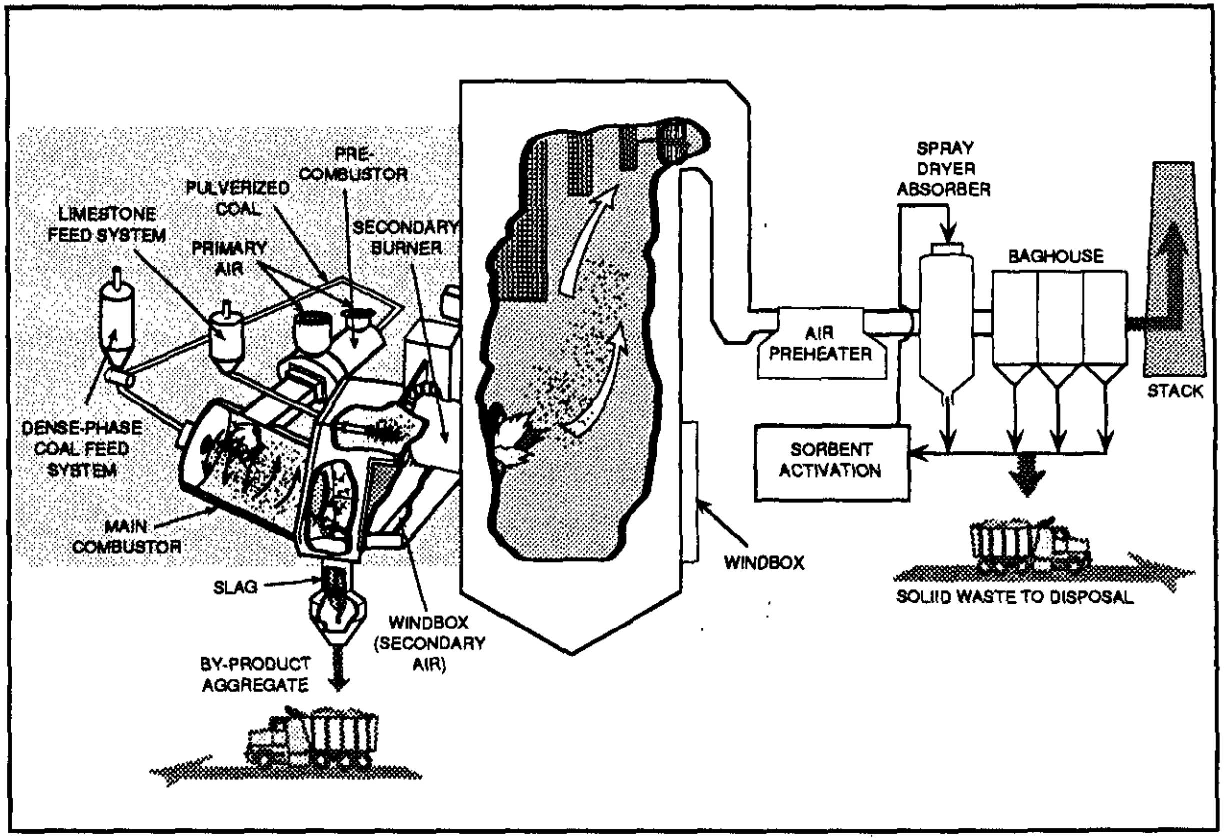
Technology:
TRW's advanced entrained (slagging) combustor
Joy Technologies' spray dryer absorber with sorbent recycle

Plant Capacity/Production:
50 MWe (net)

Project Funding:

Total project cost	$193,407,000	100%
DOE	93,862,000	48
Participants	99,545,000	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 emission control processes.

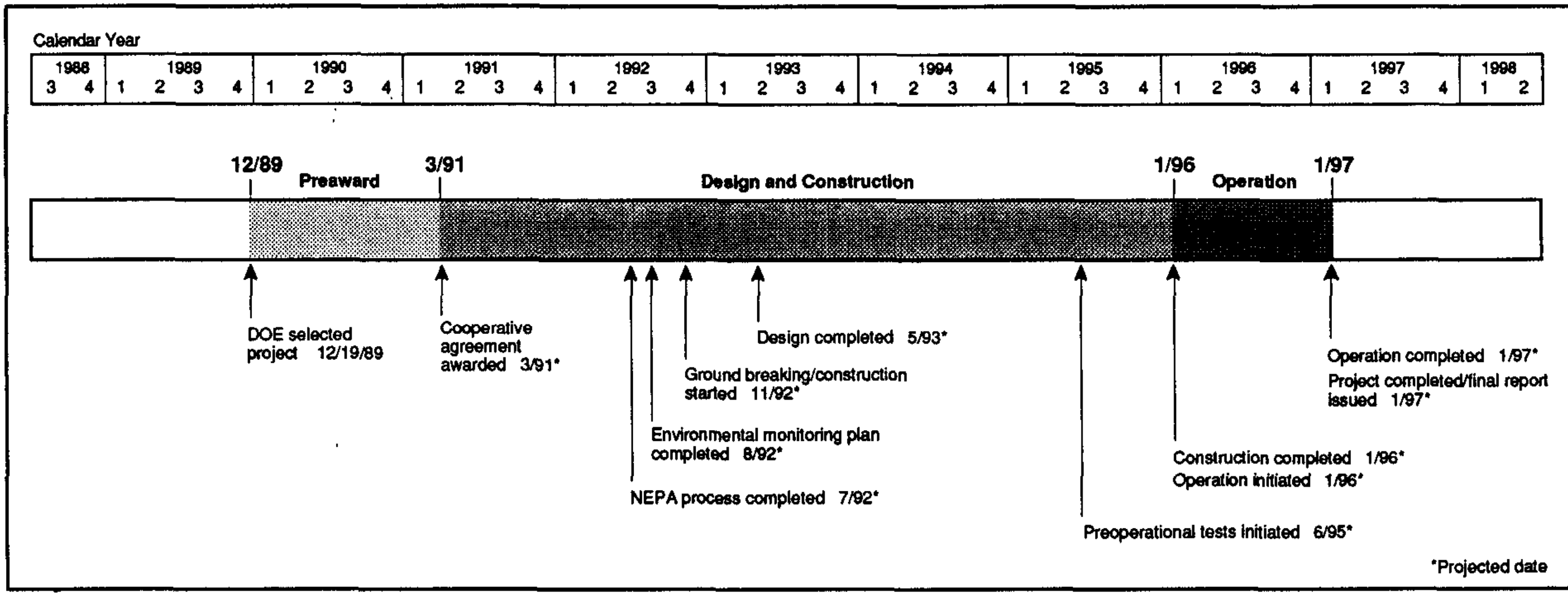


Technology/Project Description:
The heart of the system to be demonstrated is an all-metal combustor that consists of two cylindrical sections followed by a short duct that connects the combustor to the boiler. A separate precombustor burns about 25% of the coal, and the combustion air to the main (or slagging-stage) combustor is preheated by mixing it with the hot gases exhausted from the precombustor. The preheated air enters the main combustor section tangentially to impart a swirling motion to the coal and air. The balance of the coal is injected axially at the front end of this cylindrical section.

Molten slag collects on the walls of the combustor and flows toward an opening in the bottom of the main combustor where it falls into a water-filled slag tank. The slagging combustor declines slightly from horizontal to aid in the flow of the molten slag. Some slag solidifies on the water-cooled surface and serves to insulate and protect the metal walls from erosion and excessive temperatures.

The main combustion section operates at a slight air deficiency to reduce the amount of NO_x produced. Combustion products mix with sufficient air to complete the combustion reactions that take place in the boiler. The combustors are coupled with a specially designed boiler that, in addition to its heat recovery function, produces low NO_x levels, functions as a limestone calciner, and accomplishes first-stage SO_2 removal.

The process also uses a single spray dryer absorber vessel for second-stage sulfur removal and a lime activation system that recovers unused reagent from the particulate collected by the baghouse.



The slagging combustor with specially designed boiler and the spray dryer/recycle system should be capable of reducing NO_x by 70% and SO_2 by at least 90%.

The project involves design, construction, and operation of the slagging combustor spray dryer/sorbent recycle system at a greenfield site near Healy, AK, to provide power to the Golden Valley Electric Association.

Project Status/Accomplishments:

Negotiation has been completed; award of the cooperative agreement is pending congressional approval.

Environmental Considerations:

The environmental information is being prepared for use in the NEPA compliance process. DOE has published in the *Federal Register* a "Notice of Intent" to prepare an environmental impact statement and to conduct public scoping meetings for this project.

The following impacts are projected for the Healy demonstration on a national basis by 2010 with maximum commercialization of this technology:

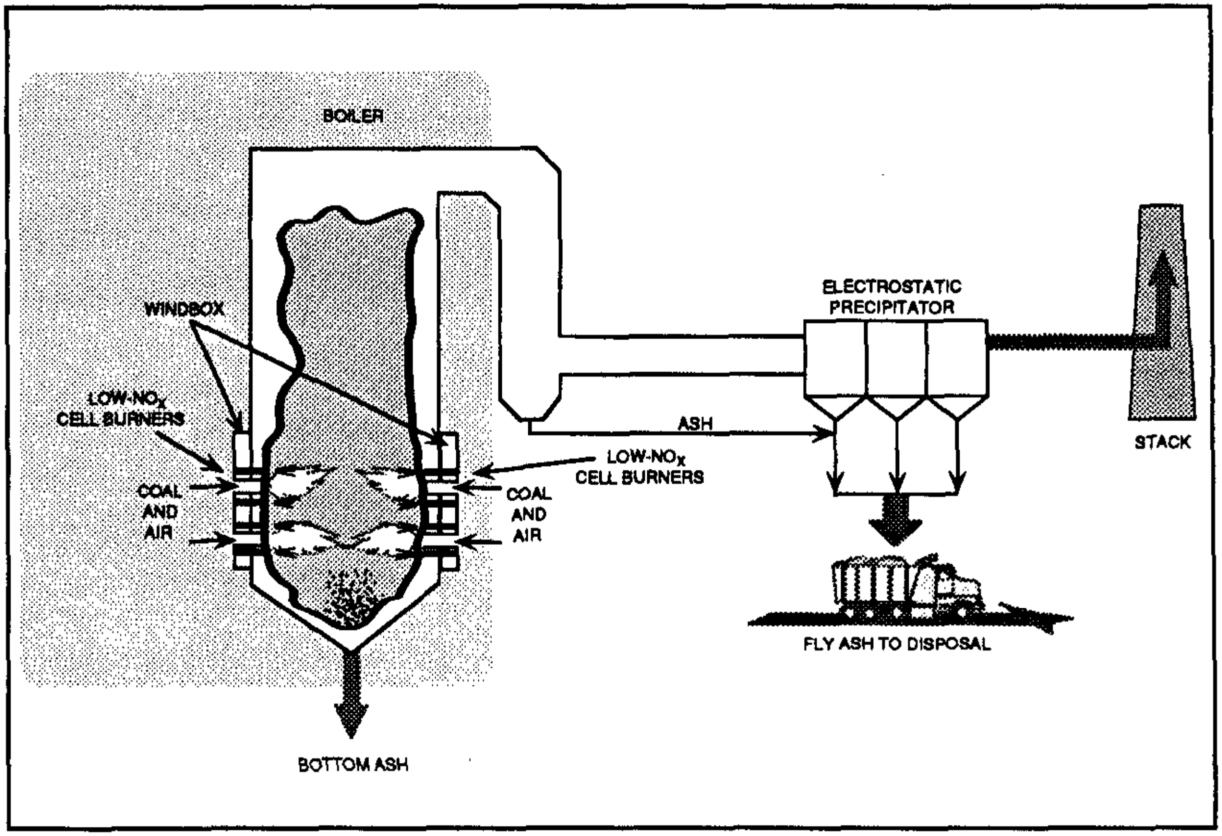
- SO_2 reduction—45%
- NO_x reduction—18%

Ash removal efficiencies in the combustor range from 70% to 80%. Much of the coal's ash content is removed as a molten slag by cyclonic action in the combustor and, when cool, is a dry, coarse solid suitable for a landfill. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

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. Furthermore, coal of any sulfur content can be used as long as the minimum ash content is 5%. The commercial availability of cost-effective and reliable systems for SO_2 and NO_x and particulate control is important to potential users planning new capacity, repowering, or retrofits to existing capacity in order to meet the Clean Air Act Amendments of 1990.

Full-Scale Demonstration of Low-NO_x Cell-Burner Retrofit



Sponsor:
The Babcock & Wilcox Company

Additional Team Members:
The Dayton Power and Light Company—cofunder and host utility
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 Company—cofunder

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

Congressional District:
6th U.S. Congressional District

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

Plant Capacity/Production:
605 MWe

Project Funding:

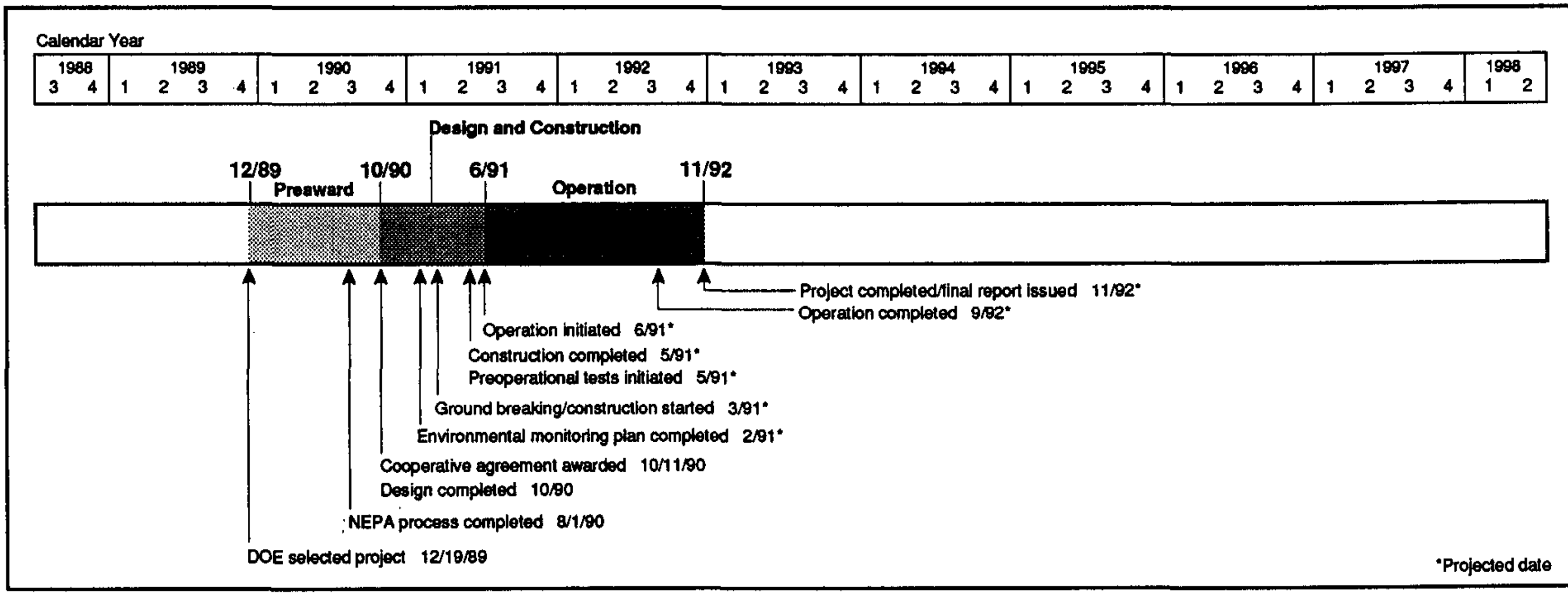
Total project cost	$9,796,204	100%
DOE	4,746,204	48
Participants	5,050,000	52

Project Objective:
To demonstrate through the first commercial-scale full burner retrofit the cost-effective reduction of NO_x from a large base-load coal-fired utility boiler with low-NO_x cell burners; 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 cell burner with a secondary-air port. The lower burner throat is enlarged to accommodate a large coal nozzle that has the same fuel input capability as two standard coal nozzles. The LNCB operates on the principle of staged combustion to reduce NO_x emissions. Approximately 70% of the total air (primary, secondary, and excess air) is supplied through or around the coal feed nozzle. The remainder of the air is directed to the upper port of each cell to complete the combustion process. The fuel-bound nitrogen compounds are converted to nitrogen gas, and the reduced flame temperature minimizes the formation of thermal NO_x.

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

The demonstration project will be 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 Southern Ohio Electric Company. The boiler unit is a B&W-designed, supercritical, once-through boiler equipped



with an electrostatic precipitator. This unit contains 24 two-nozzle cell burners arranged in an opposed firing configuration. Twelve burners (arranged in two rows of six burners each) are mounted on each of two opposing walls of the boiler. The proposed demonstration will require the removal of all 24 standard cell burners and the installation of 24 new LNCBs.

Project Status/Accomplishments:

Detailed design for the retrofit was completed at the end of October 1990, and procurement and burner fabrication are in progress. Preretrofit testing was completed in November 1990 and data analysis is under way. Initial numerical flow modeling of the boiler for both the preretrofit base case and the LNCB retrofit case has been completed. Major subcontractors have been selected with the exception of the burner installation contractor who will be selected in early 1991.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved by DOE on August 1, 1990.

This technology can be retrofitted only with boilers configured with cell-type burners. The retrofit market is limited to approximately 37 boilers that emit an estimated 728,000–1,312,000 tons/yr of NO_x.

Assuming maximum commercialization nationally of the LNCB technology by the year 2010, NO_x emissions could be reduced by 364,000–656,000 tons/yr relative to a no action alternative. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

This retrofit technology is applicable to approximately 37 coal-fired boilers that are equipped with cell-type burners, representing a total generating capacity of approximately 26,000 MWe.

Confined Zone Dispersion Flue Gas Desulfurization Demonstration

Sponsor:
Bechtel Corporation

Additional Team Members:
Pennsylvania Electric Company—cofunder and host utility
Pennsylvania Energy Development Authority—cofunder
New York State Electric and Gas Corporation—cofunder
Rockwell Lime Company—cofunder

Location:
Seward, Indiana County, PA (Pennsylvania Electric Company's Seward Station, Unit No. 15)

Congressional District:
4th U.S. Congressional District

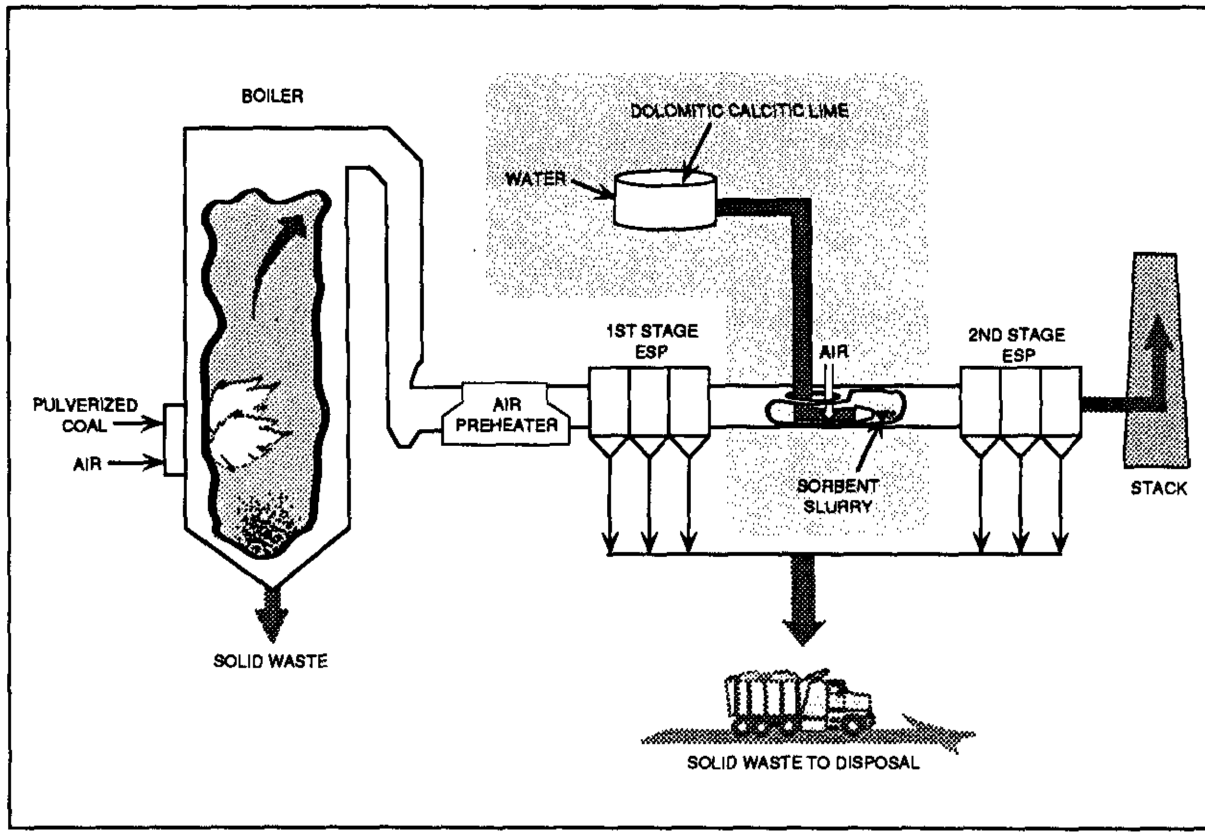
Technology:
Bechtel Corporation's in-duct, confined zone dispersion flue gas desulfurization (CZD/FGD) process

Plant Capacity/Production:
73.5 MWe

Project Funding:

Total project cost	$9,211,600	100%
DOE	4,605,800	50
Participants	4,605,800	50

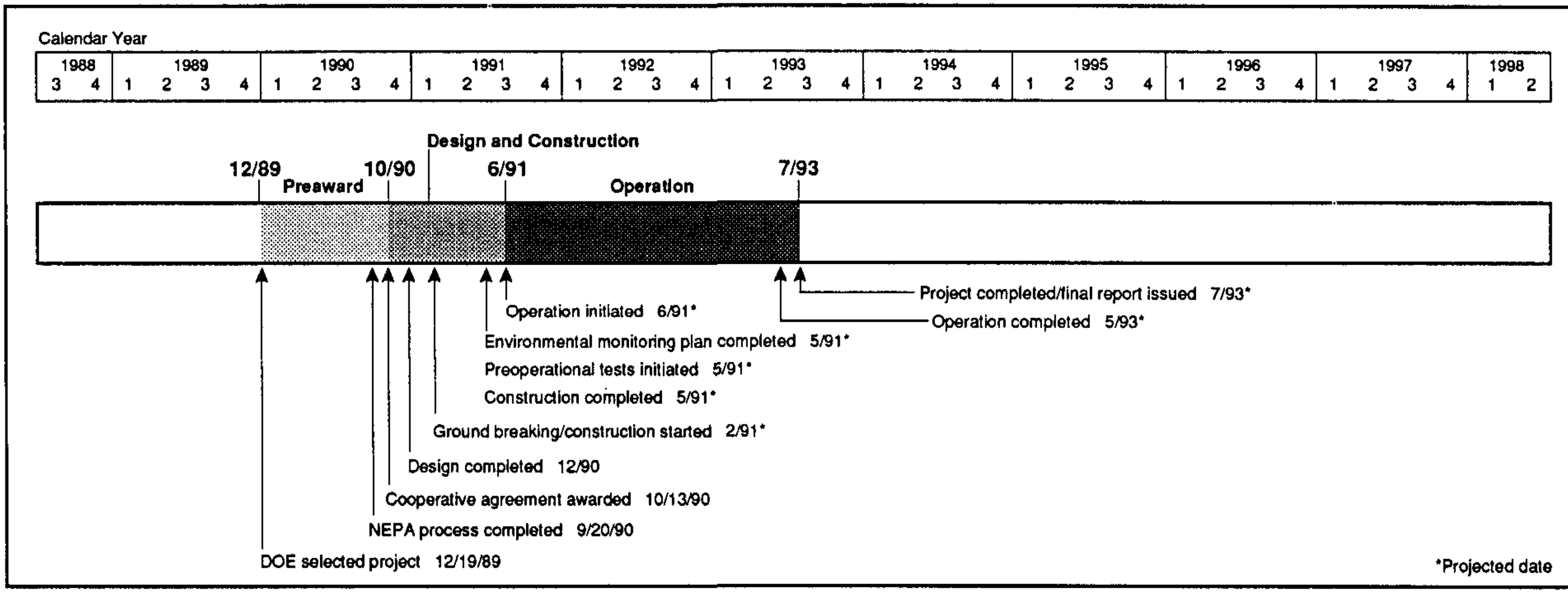
Project Objective:
To demonstrate SO_2 removal capabilities of in-duct CZD/FGD technology; more specifically, to define the optimum process operating parameters and to determine CZD/FGD's operability, reliability, and cost-effectiveness during long-term testing and its impact on downstream operations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



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

The CZD/FGD process is expected to remove 50% of SO_2 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, calcitic, etc.) with several atomizer designs using low- and high-sulfur coals to verify the effects on SO_2 removal and the capability of the ESP to control particulates. The demonstration 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. 15 is being routed through a modified duct between the first and second ESP. Pennsylvania bituminous coal (approximately 1.2–2.5%



sulfur) is being used in the project. After the variable test program is complete, continuous, fully automated and integrated (with the regular power plant) operation is planned for a year.

Project Status/Accomplishments/

The cooperative agreement was awarded on October 13, 1990. Design activities, which began in June 1990, were completed by the end of December 1990. Construction is scheduled to begin in February 1991, and start-up is expected to begin midyear. Operation is scheduled for June 1991.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved by DOE on September 20, 1990.

Sorbent injection technologies such as the CZD/FGD process could reduce national emissions of SO_2 by as much as 38% by 2010, assuming maximum commercialization of the technology. NSPS levels of SO_2 reduction could be satisfied with low-sulfur coal. Although the volume of solid waste is increased 8%, it is dry, nontoxic, and easily disposable.

Commercial Application:

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

A CZD system can be added to a utility boiler with a minimal capital investment of $25–55/kW of installed capacity, or one-third the cost of building a conventional wet scrubber. In addition to low capital cost, other advantages include small space requirements, ease of retrofit, and production of only nontoxic, disposable waste. The CZD technology is particularly well suited for retrofitting onto existing boilers, independent of type, age, size, or coal burned (e.g., type, sulfur content). The CZD installation does not require major power station alterations and can be easily and economically integrated into existing power plants.

Blast Furnace Granulated-Coal Injection System Demonstration Project

Sponsor:
Bethlehem Steel Corporation

Additional Team Members:
British Steel Consultants Overseas Services, Inc. (marketing arm of British Steel)—technology owner
Simon Macawber, Ltd.—equipment supplier
ATSI, Inc.—architect and engineer

Location:
Burns Harbor, Porter County, IN (Blast Furnace Units C and D)

Congressional District:
1st U.S. Congressional District

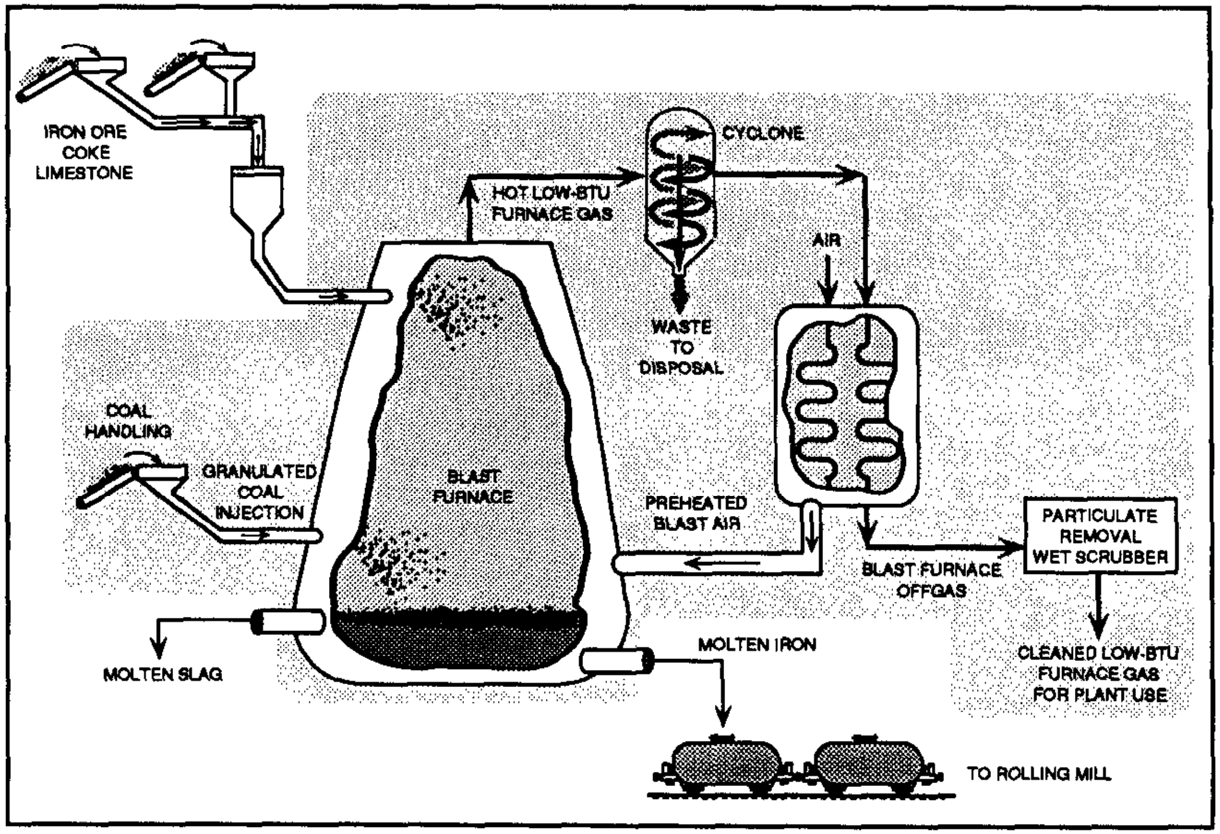
Technology:
British Steel's blast furnace granulated-coal injection (BFGCI) process

Plant Capacity/Production:
7,000 net tons/day of hot metal (each blast furnace)

Project Funding:

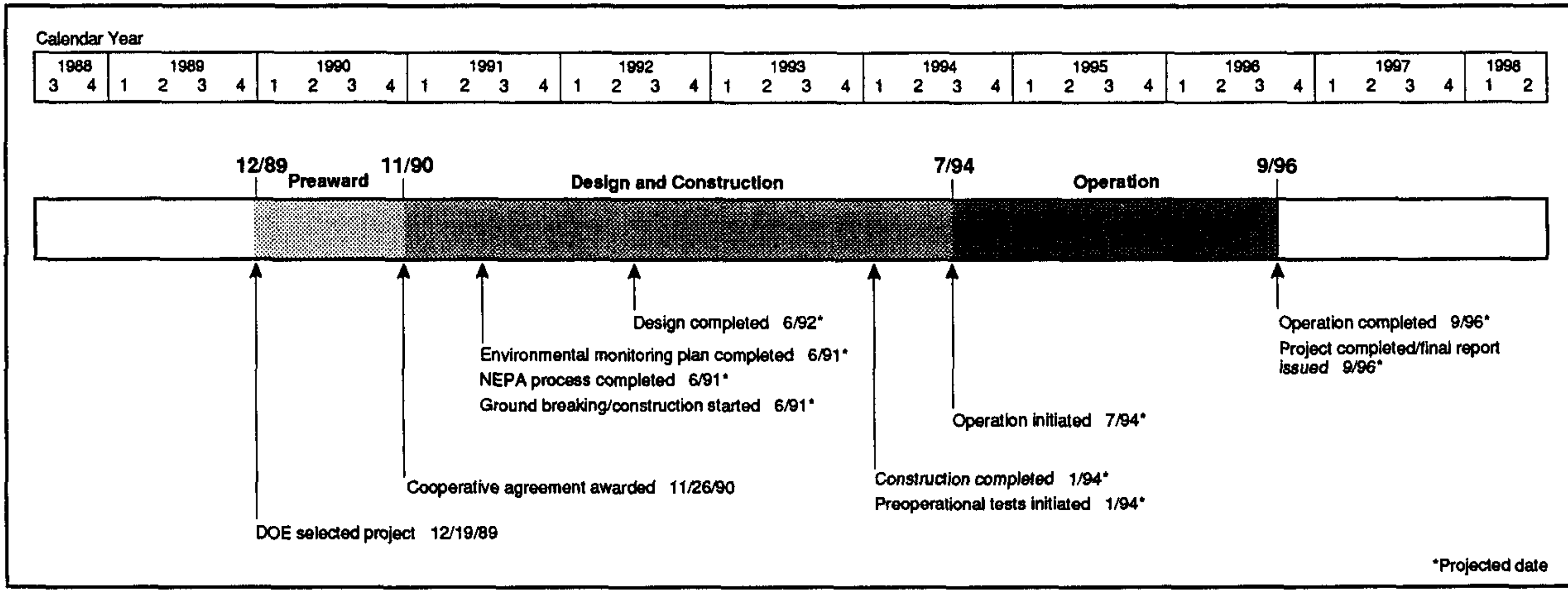
Total project cost	$143,800,000	100%
DOE	31,259,530	22
Participants	112,540,470	78

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 the raceway is important and is dependent upon many factors including temperature. Lowering of the 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 SO_2 and NO_x emissions 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 readily salable as a construction aggregate material and rock wool. In addition to the net SO_2 and NO_x 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.

Project Status/Accomplishments:

The cooperative agreement was awarded November 26, 1990. Design is under way; the conceptual design of the blast furnace granulated-coal injection system has been completed. Construction is scheduled to begin in mid-1991.

Environmental Considerations:

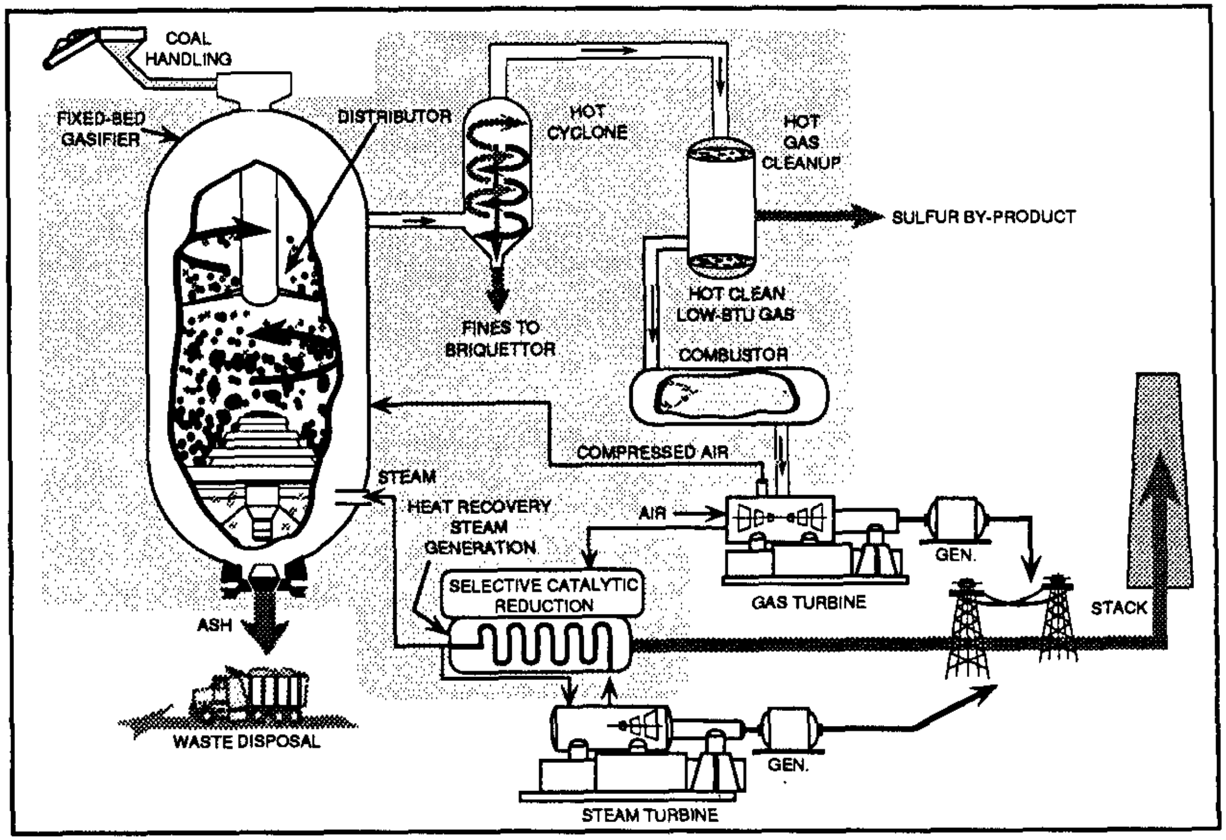
Environmental information for use in the NEPA compliance process has been compiled.

The largest reductions in emissions resulting from commercialization of the BFGCI technology are expected to occur in the coke-making process. As the BFGCI technology reaches full market penetration, the amount of coke required for blast furnaces would decrease, thus reducing the emissions associated with its production. Although a slight increase in slag can be expected from the coal ash, the slag is readily salable as construction aggregate or rock wool.

Commercial Application:

This technology can be applied to essentially all blast furnaces in the United States. It is anticipated that a wide variety of coals can be used.

Air-Blown/Integrated Gasification Combined-Cycle Project



Sponsor:
Clean Power Cogeneration Limited Partnership

Additional Team Member:
City of Tallahassee—host utility

Location:
Tallahassee, Leon County, FL (City of Tallahassee's Arvah B. Hopkins Station)

Congressional District:
2d U.S. Congressional District

Technology:
Lurgi-based integrated gasification combined-cycle (IGCC) system

Plant Capacity/Production:
120 MWe

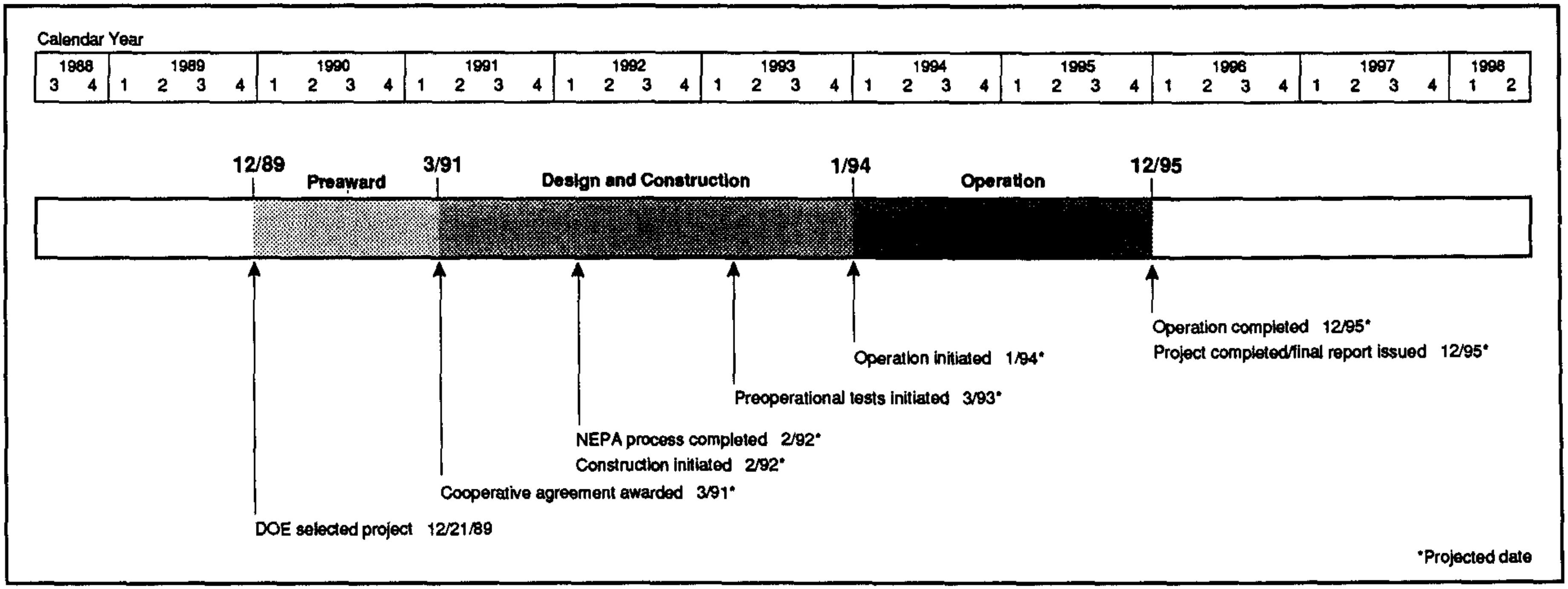
Project Funding:

Total project cost	$241,458,000	100%
DOE	120,729,000	50
Participants	120,729,000	50

Project Objective:
To demonstrate air-blown fixed-bed integrated gasification combined-cycle technology and to assess long-term reliability, availability, and maintainability at sufficient scale to determine commercial potential.

Technology/Project Description:
Coal is gasified in a pressurized, air-blown, fixed-bed gasifier. The low-Btu coal gas leaves the gasifier at approximately 1,000 °F and goes to a hot gas cleanup system where the removal of sulfur compounds is accomplished in a moving bed of solid sorbent. The cleaned gas is delivered to a combustor, which is on board the gas turbine frame. The gas turbine is integrated with the coal conversion system through pressurized air extraction, which is used as gasifier air supply. The steam generated in the heat recovery generator is used both for driving a conventional steam turbine generator set producing additional electricity and for gasifier blast. The project has the following subsystems: fixed-bed coal gasification (Lurgi), hot gas cleanup, a combustion turbine capable of using low-Btu coal gas, selective catalytic reduction for NO_x control, a briquettor to utilize coal fines, and the balance of plant.

In the demonstration project, a nominal 1,270 tons/day of coal is converted into 120 MWe. The base feed coal for the project is a high-sulfur Illinois Basin bituminous coal. The proposed site is the City of Tallahassee's Arvah B. Hopkins Station, which is located in Tallahassee, FL.



Project Status/Accomplishments:

The project is under negotiation.

Environmental Considerations:

Environmental information is being compiled for use in the NEPA compliance process.

Assuming maximum commercialization of IGCC technology on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—37%
- NO_x reduction—17%
- Solid waste reduction—5%
- CO_2 reduction—6%

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

In recent years, IGCC has become a rapidly emerging alternative for new electricity generating plants. Such plants require 15% less land area than pulverized coal plants with flue gas desulfurization. IGCC technology also can be used in repowering, where a gasifier, gas stream cleanup unit, gas turbine, and waste heat recovery boiler are added to replace the existing coal-fired boiler. The remaining equipment is left in place, including the steam turbine and electrical generator. Because of its advantages of modularity, rapid and staged on-line generation capability, high efficiency, environmental controllability, and reduced land and natural resource needs, another important application for IGCC is cogeneration under the PURPA Qualified Facility regulations.

The performance potential of IGCC technology in its commercial configuration is characterized as follows:

- SO_2 reduction—99%
- NO_x reduction—95%
- Plant efficiency—up to 48%
- Incremental power increase—230%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction— lends itself to economic addition of capacity increments to match load growth

Alma PCFB Repowering Project

Sponsor:
Dairyland Power Cooperative

Additional Team Members:
Pyropower Corporation—technology supplier
Black and Veatch—architect and engineer

Location:
Alma, Buffalo County, WI (Dairyland Power Cooperative's Alma Power Station, Units 1 and 2)
(Alternate sites are under consideration.)

Congressional District:
3d U.S. Congressional District

Technology:
Pyropower Corporation's pyroflow pressurized circulating fluidized-bed combustion (PCFB) combined-cycle system

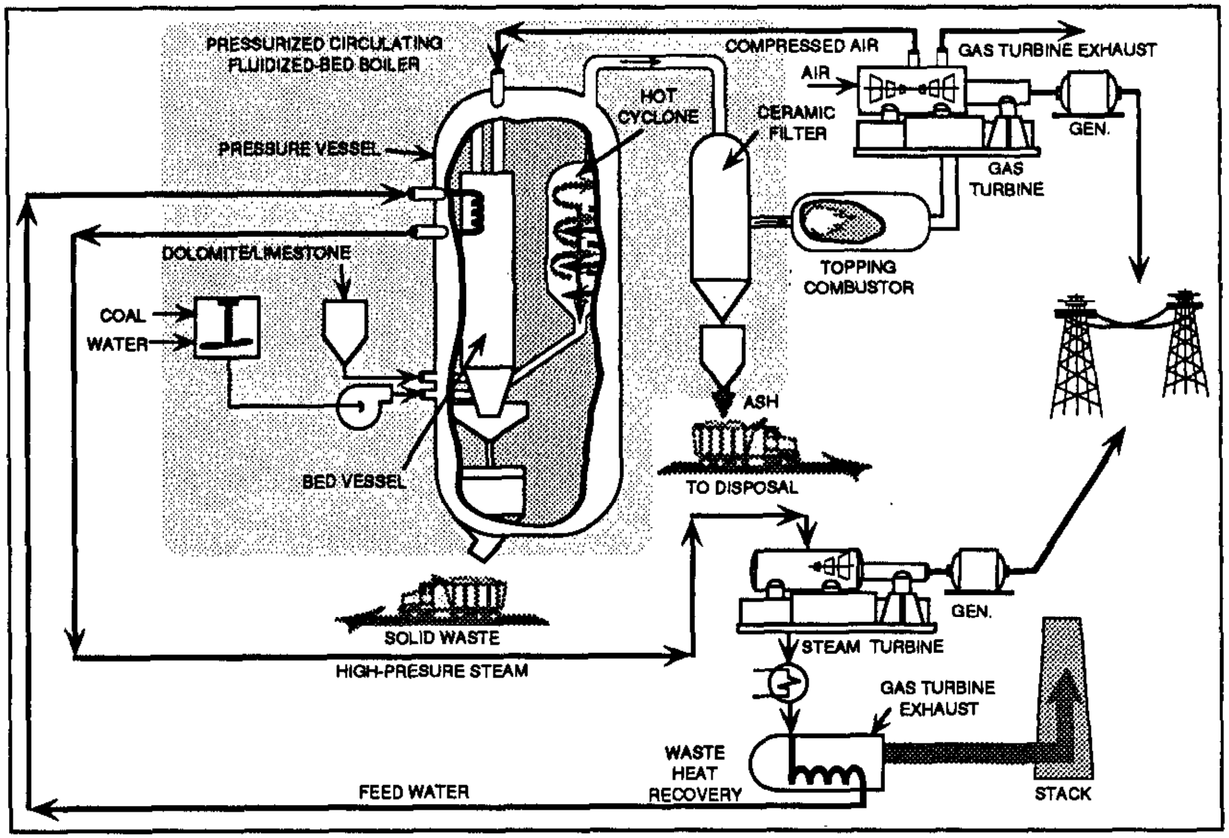
Plant Capacity/Production:
40 MWe

Project Funding:

Total project cost	$189,393,000	100%
DOE	93,253,000	48
Participants	96,140,000	52

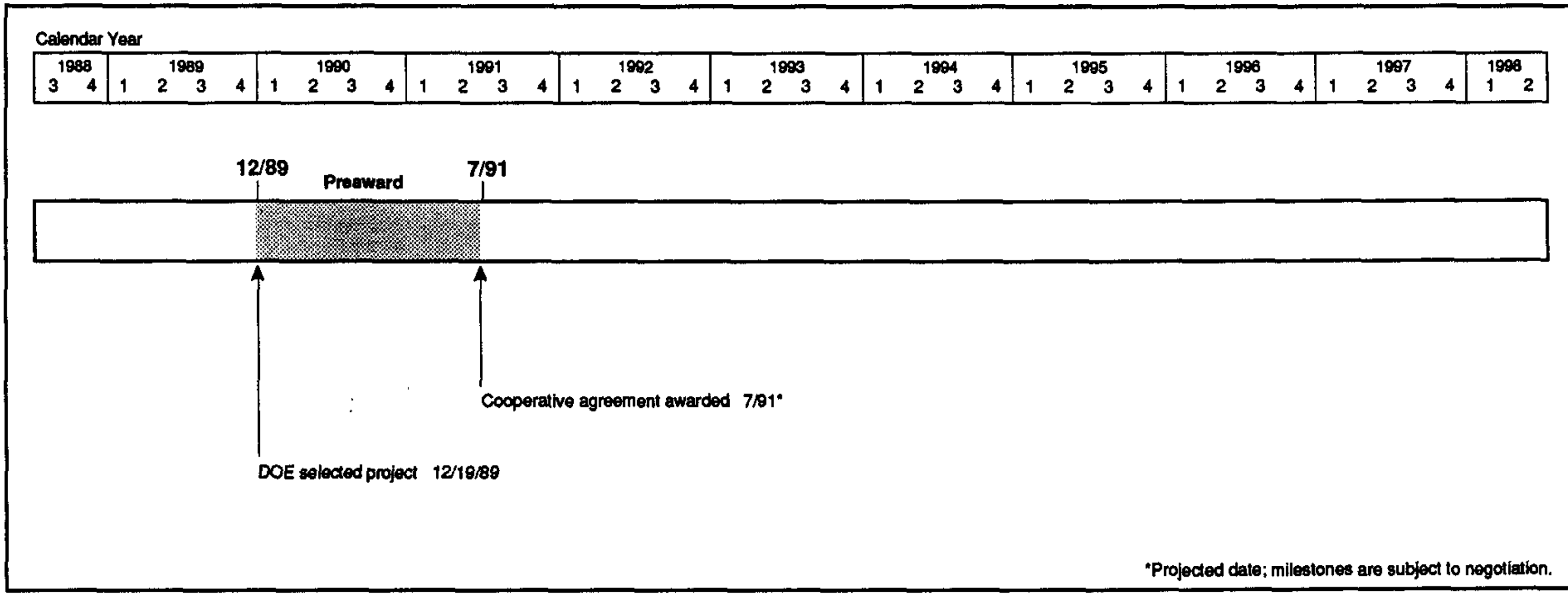
(Funding is subject to negotiation.)

Project Objective:
To demonstrate PCFB at sufficient scale to evaluate environmental, cost, and plant performance and to obtain the technical data requisite to commercialization of the technology; to assess efficiency improvements associated with integration of a hot gas cleanup system using a ceramic barrier filter and inclusion of a topping combustor; to achieve SO_2 reduction in excess of 90% and NO_x reduction of 70%; and to improve plant efficiency by up to 15% of its current rating.



Technology/Project Description:
In the PCFB process, coal is combusted at about 1,600 °F in a circulating fluidized bed contained within a pressure vessel. Limestone is used within the bed to absorb sulfur compounds. Particulates from the hot, pressurized combustion gases are removed by a ceramic filter. The clean gas is then expanded through a gas turbine. During peak load demand periods, the topping combustor is fired with fuel oil to raise the inlet temperature of the gases entering the gas turbine. Higher turbine operating temperature increases the turbine efficiency and power output. Steam generated within the PCFB combustor and the heat recovery steam generator downstream from the gas turbine are used to generate power in two existing steam turbines.

The Alma project would be the world's first large-scale demonstration of PCFB technology. As originally proposed, two commercially operating 18-MWe pulverized coal-fired steam turbines would be repowered with a single PCFB combustor integrated with an oil-fired topping combustor and a gas turbine module operating in a combined-cycle mode. The boilers proposed for repowering are Units 1 and 2 of the Alma Station located in Alma, WI. The repowered plant would have a capacity of at least 40 MWe. However, alternate sites are under consideration.



Project Status/Accomplishments:
The project is in negotiation.

Environmental Considerations:
Environmental information is being compiled for use in the NEPA compliance process.

Assuming maximum commercialization of the technology on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—48%
- NO_x reduction—17%
- Solid waste decrease—4%, with the solid waste in a dry, granular form amenable to alternative uses such as construction aggregate
- CO_2 reduction—8%

(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:
The combined-cycle PCFB system permits the combustion of a wide range of coals, including high-sulfur coals, and would compete with the bubbling-bed PFBC system. Like the bubbling-bed system, PCFB can be used to repower oil- and gas-fired boiler units, while switching them to high-sulfur coal; to repower coal-fired power plants; and to build new PCFB units. Combined-cycle PCFB technology appears to be best suited for electric utility applications in medium (100–400 MWe) and large (> 400 MWe) plants. Because of modular construction capability, PCFB generating plants permit utilities to add economical increments of capacity to match load growth and to repower with PCFB using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment.

The performance potential of PCFB technology is characterized as follows:

- SO_2 reduction—95%
- NO_x reduction—80%
- Plant efficiency increase—up to 45%
- Incremental plant efficiency—improved 8–15%
- Fuel flexibility—permits use of wide range of coals
- Compactness—high process efficiency reduces space requirements per unit of energy generated
- Modular construction—lends itself to economic additions of capacity increments to match load growth

ENCOAL Mild Coal Gasification Project

Sponsor:
ENCOAL Corporation (subsidiary of Shell Mining Company)

Additional Team Members:
Shell Mining Company—cofunder

TEK-KOL (partnership between Shell Mining Company and SGI International)—technology owner, supplier, and licensor

SGI International—technology developer

Triton Coal Company (subsidiary of Shell Mining Company)—host facility and coal supplier

The M. W. Kellogg Company—engineer and constructor

Location:
Near Gillette, Campbell County, WY (Buckskin Mine)

Congressional District:
At-large U.S. Congressional District

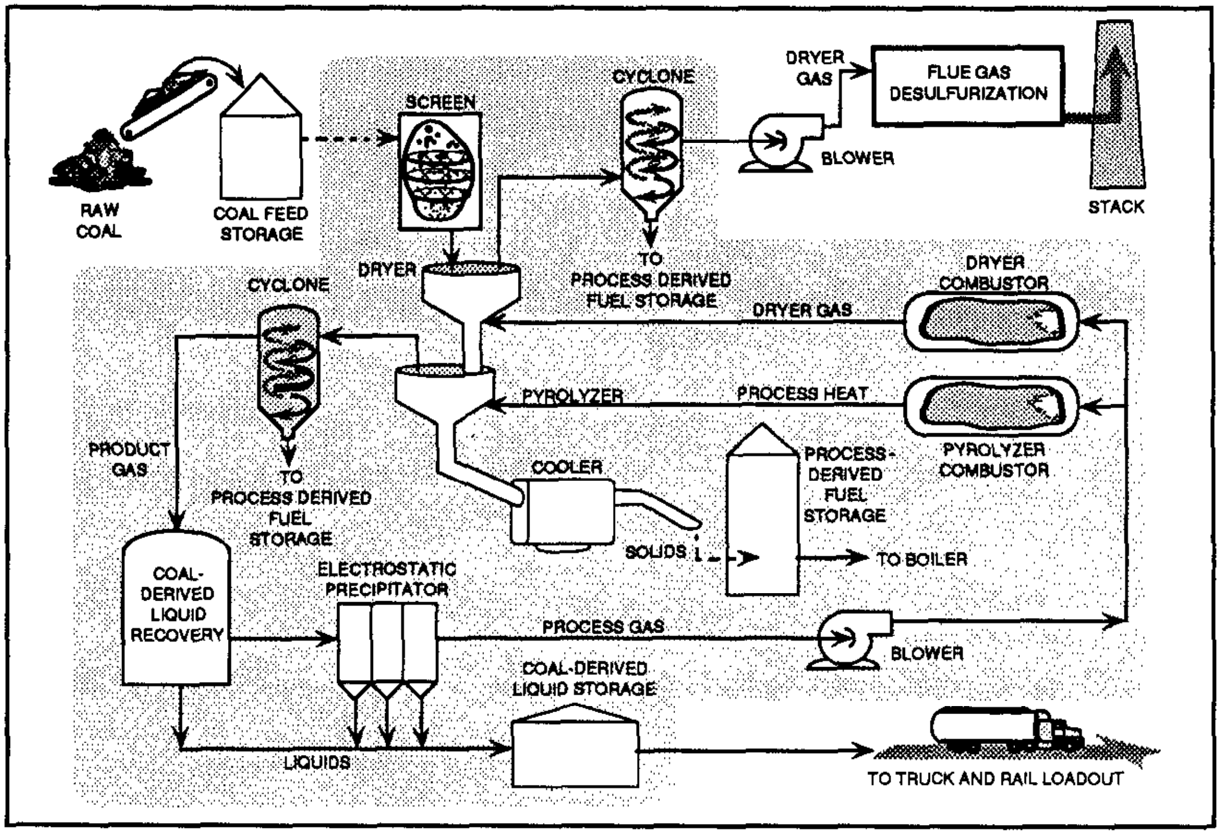
Technology:
SGI International's liquids from coal (LFC) process

Plant Capacity/Production:
1,000 tons/day of subbituminous coal feed

Project Funding:

Total project cost	$72,564,000	100%
DOE	36,282,000	50
Participants	36,282,000	50

Project Objective:
To demonstrate the integrated operation of a number of novel operating 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.

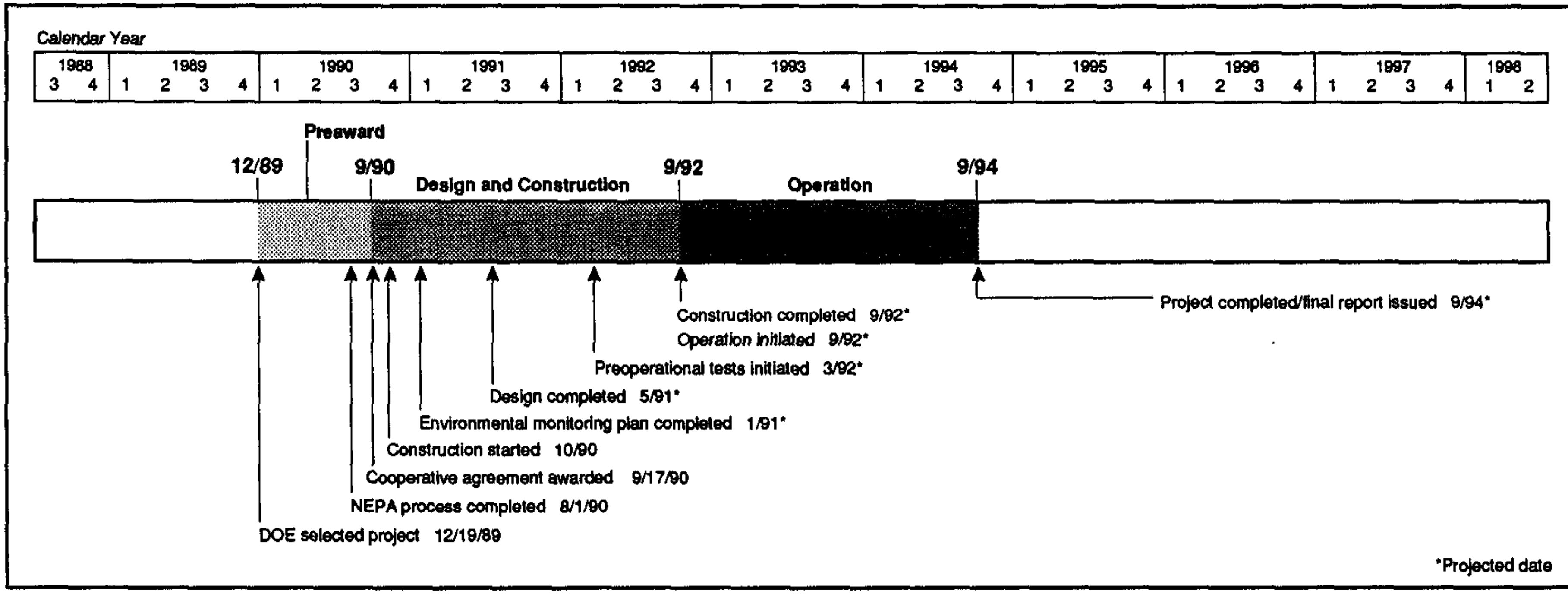


Technology/Project Description:
The ENCOAL mild coal gasification process involves heating coal under carefully controlled conditions. Coal is fed into a rotary grate dryer where it is heated by a hot gas stream to reduce the moisture content of the coal. The solid bulk temperature is controlled so that no significant amounts of methane, carbon monoxide, or carbon dioxide 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 venturi scrubber to remove particulates and a horizontal scrubber to remove SO_2, both using a sodium carbonate solution. The treated gas is vented to a stack, and the spent solution is discharged into a pond for evaporation.

The site of 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.



Project Status/Accomplishments:

The cooperative agreement for this project was awarded on September 17, 1990.

Both design and construction activities are ahead of schedule. Detailed design is 60% complete. The largest continuous concrete pour (3,000 yd^3 in a 32-hr period) ever performed in Wyoming was completed. Full mobilization of the field office is scheduled for March 1991.

Environmental Considerations:

NEPA compliance has been satisfied by an environmental assessment with a finding of no significant impact approved by DOE on August 1, 1990.

Assuming maximum commercialization of the mild coal gasification technology on a national basis by 2010 relative to a no-action alternative, the following impacts are projected:

- SO_2 reduction—5%
- NO_x reduction—2%
- Solid waste increase—14%; however, this is a dry, salable by-product.

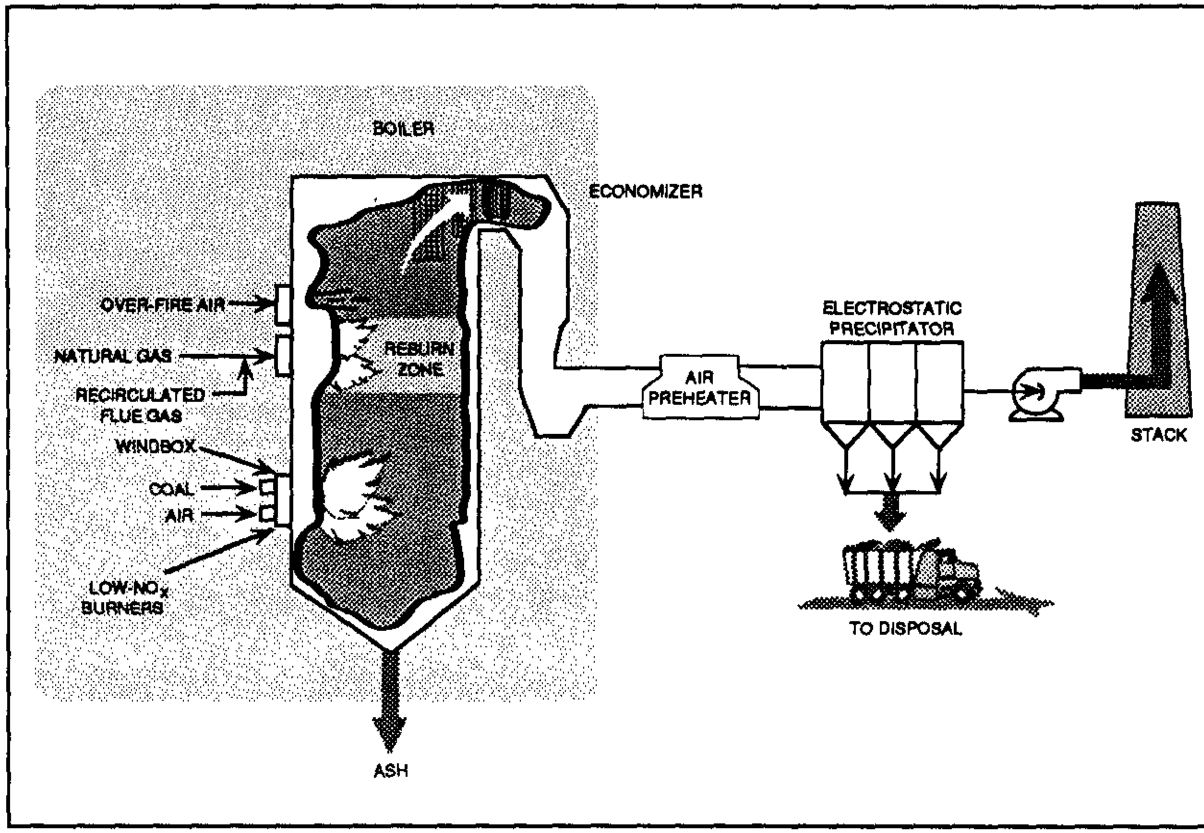
(Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

The liquid products from mild coal gasification can be used in any market in place of No. 6 fuel oil. The solid product can be used in any scale industrial or utility boiler. The feedstock for mild gasification facilities is being limited to lower sulfur, low-heating-value coals.

The potential benefits of this mild gasification technology in its commercial configuration are attributable to the increased heating value and lower sulfur content of the new solid fuel product, compared to the subbituminous feed stock and the production of liquid products requiring limited hydrotreating. The product fuels are expected to be used economically in commercial boilers and furnaces and to significantly reduce sulfur emissions at industrial and utility facilities currently burning high-sulfur bituminous fuels or fuel oils.

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



Sponsor:
Energy and Environmental Research Corporation

Additional Team Members:
Public Service Company of Colorado—cofunder and host utility
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)

Congressional District:
1st U.S. Congressional District

Technology:
Energy and Environmental Research Corporation's gas reburning and low-NO_x burner system

Plant Capacity/Production:
172 MWe

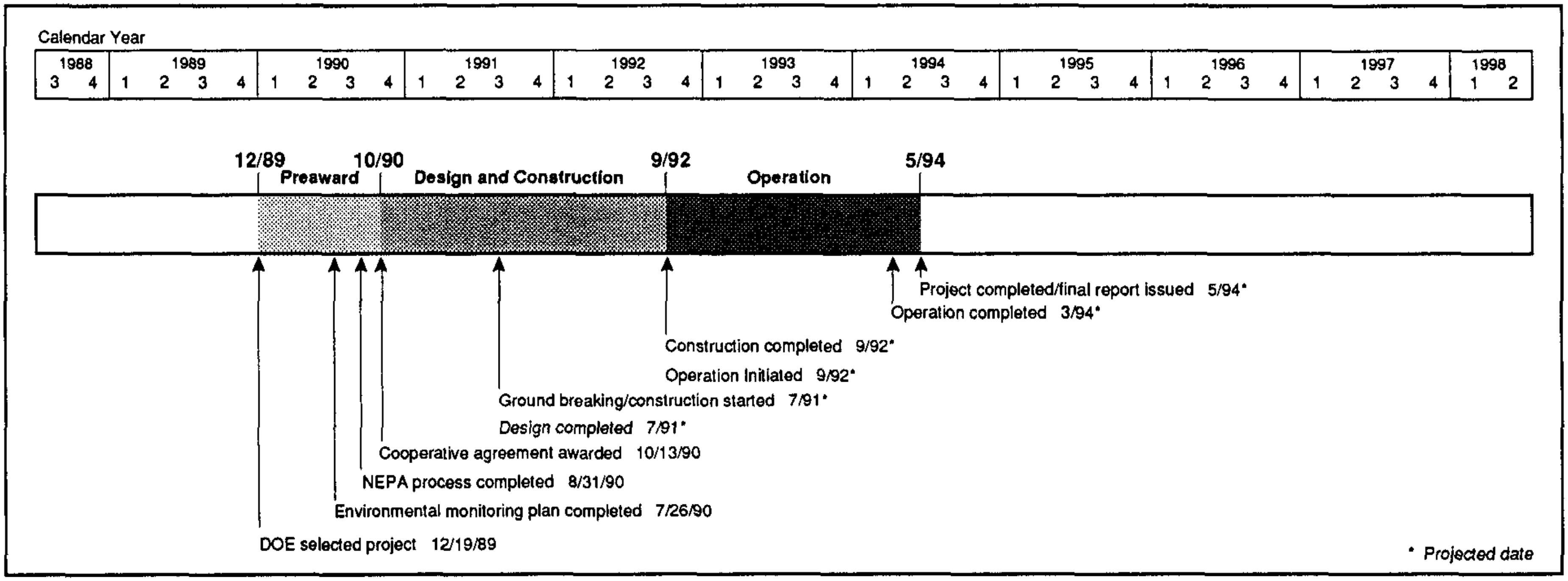
Project Funding:

Total project cost	$14,472,117	100%
DOE	7,236,058	50
Participants	7,236,059	50

Project Objective:
To attain up to a 75% 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 harmless 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 is projected to lower NO_x emissions by as much as 75%.

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 coal is being used.



Project Status/Accomplishments:

Design and permitting activities are proceeding well and are expected to be completed in July 1991. Preliminary high-velocity testing for baseline flue gas temperatures, velocities, and oxygen content was conducted. The environmental monitoring plan has been prepared.

Environmental Considerations:

NEPA compliance has been satisfied by a memo-to-file approved on August 31, 1990.

Assuming maximum commercialization of gas reburning and low-NO_x burners on a wall-fired boiler on a national basis by 2010 relative to a no-action alternative, NO_x emissions could be reduced by 13%. The substitution of gas for coal results in a 10% reduction of SO_2 on a national basis. No changes in liquid effluents or solid wastes are anticipated. (Source: CCT Programmatic Environmental Impact Statement)

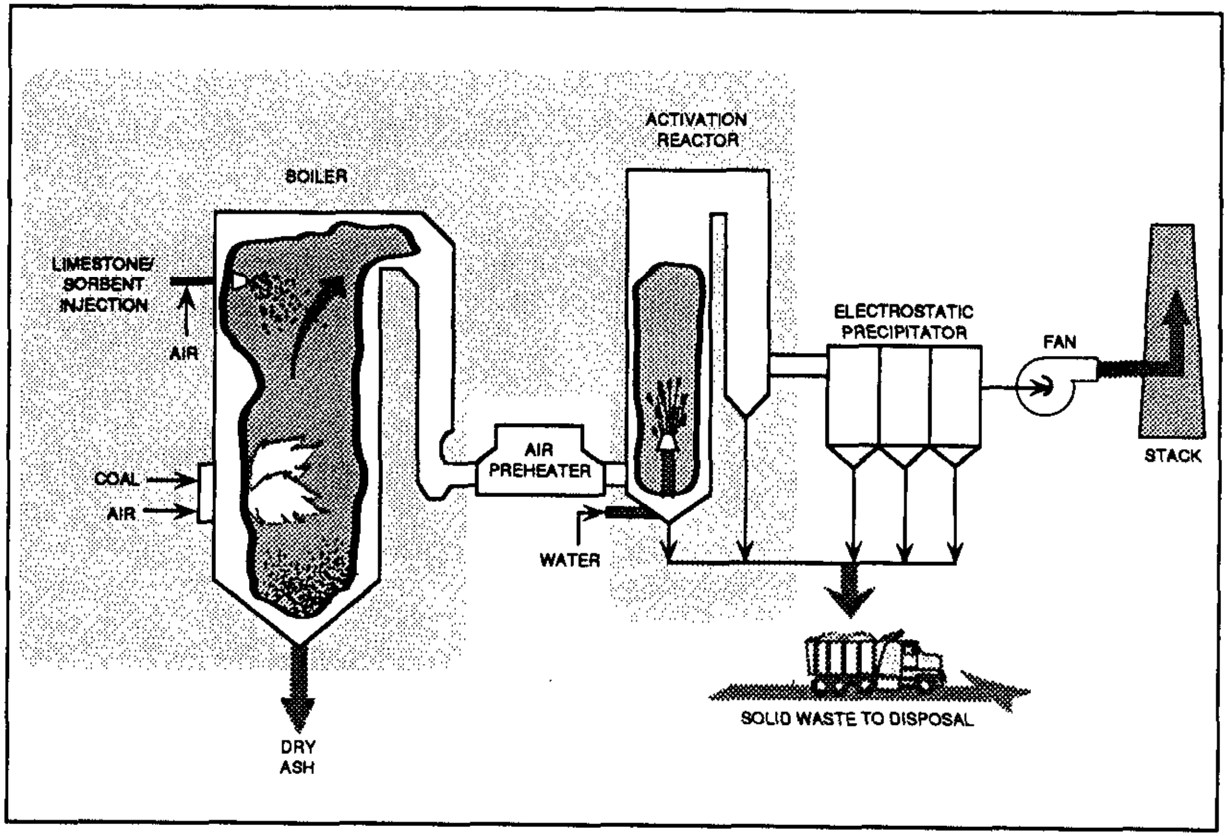
Commercial Application:

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

Specific features of this technology that increase its potential for commercialization are as follows:

- Can be retrofitted readily to existing units
- Reduces NO_x emissions by more than 70%
- Suitable for use with a wide range of coals
- Has the potential to improve boiler operability
- Has the potential to reduce the cost of electricity
- Consists of commercially available components
- Requires minimal space

LIFAC Sorbent Injection Desulfurization Demonstration Project



Sponsor:

LIFAC–North America (a joint venture between Tampella Keeler, a subsidiary of Tampella, Ltd., of Finland, and ICF Kaiser Engineers, Inc.)

Additional Team Members:

ICF Kaiser Engineers, Inc.—cofunder and project manager
Tampella, Ltd.—cofunder and technology owner
Richmond Power and Light—cofunder and host utility
Electric Power Research Institute—cofunder
Peabody Coal Company—cofunder
Black Beauty Coal Company—cofunder
LaFarge Corporation—cofunder

Location:

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

Congressional District:

2d U.S. Congressional District

Technology:

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

Plant Capacity/Production:

60 MWe

Project Funding:

Total project cost	$17,018,982	100%
DOE	8,509,491	50
Participants	8,509,491	50

Project Objective:

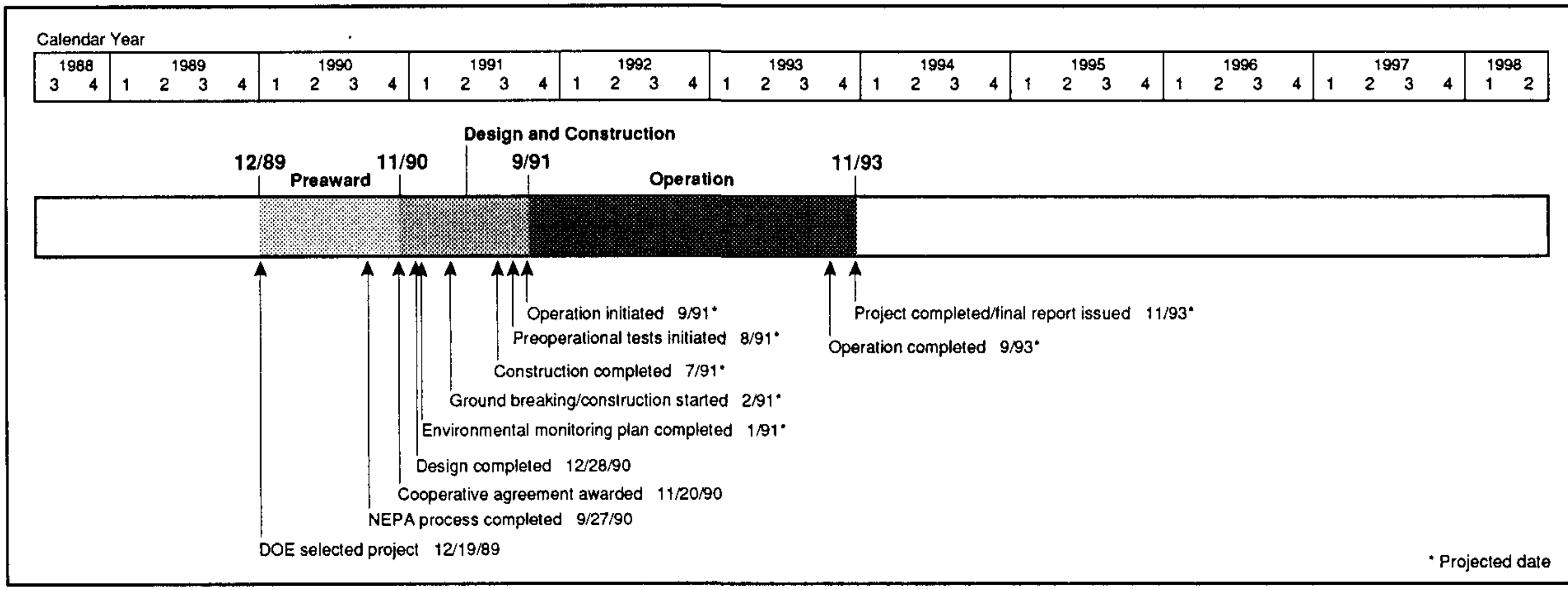
To demonstrate that electric power plants—especially those with space limitations—burning high-sulfur Indiana coals, can be retrofitted successfully with the LIFAC limestone injection process to remove 75–85% of the SO_2 from flue gas and produce a dry solid waste product for disposal in a landfill.

Technology/Project Description:

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

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

The process is being demonstrated at Whitewater Valley Station, a coal-fired power plant owned and operated by Richmond Power and Light and located in Richmond, IN. The 60-MWe Unit No. 2 is being retrofitted. The activation or humidification chamber is being located next to the boiler building near Unit No. 2.



Project Status/Accomplishments:
The cooperative agreement was awarded on November 20, 1990. The LIFAC team completed the development of the preliminary design package. Preparations are under way to procure the key pieces of equipment required for a March 1991 outage.

Environmental Considerations:
NEPA compliance has been satisfied by a memo-to-file approved on September 27, 1990.

Assuming maximum commercialization, significant reductions of SO_2 (45%) are projected to be achievable nationally by 2010 with the LIFAC process relative to a no-action alternative. The LIFAC process has wide applicability as it can be retrofitted to many coal-fired boilers. (Source: CCT Programmatic Environmental Impact Statement)

The benign waste material can be disposed in a landfill along with the fly ash. The material also may be used as a road bed or excavation fill material. Commercial use of the LIFAC by-product in the manufacture of construction materials is currently being investigated in Finland.

Commercial Application:
This process is suitable for application to all coal-fired utility or industrial boilers, especially those with tight space limitations. The LIFAC process offers the following advantages:

- It is less expensive to install than conventional wet flue gas desulfurization processes.
- It uses dry limestone instead of the more expensive lime.
- It is relatively simple to operate.
- It produces a dry, readily disposable waste.

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

Sponsor:
MK-Ferguson Company

Additional Team Members:
NOXSO Corporation—cofunder and technology supplier
W. R. Grace and Company—cofunder
Ohio Edison Company—cofunder and host utility
Ohio Coal Development Office—cofunder
Gas Research Institute—cofunder
Electric Power Research Institute—cofunder
East Ohio Gas Company—cofunder

Location:
Niles, Trumbull County, OH (Ohio Edison's Niles Station, Unit 1)

Congressional District:
17th U.S. Congressional District

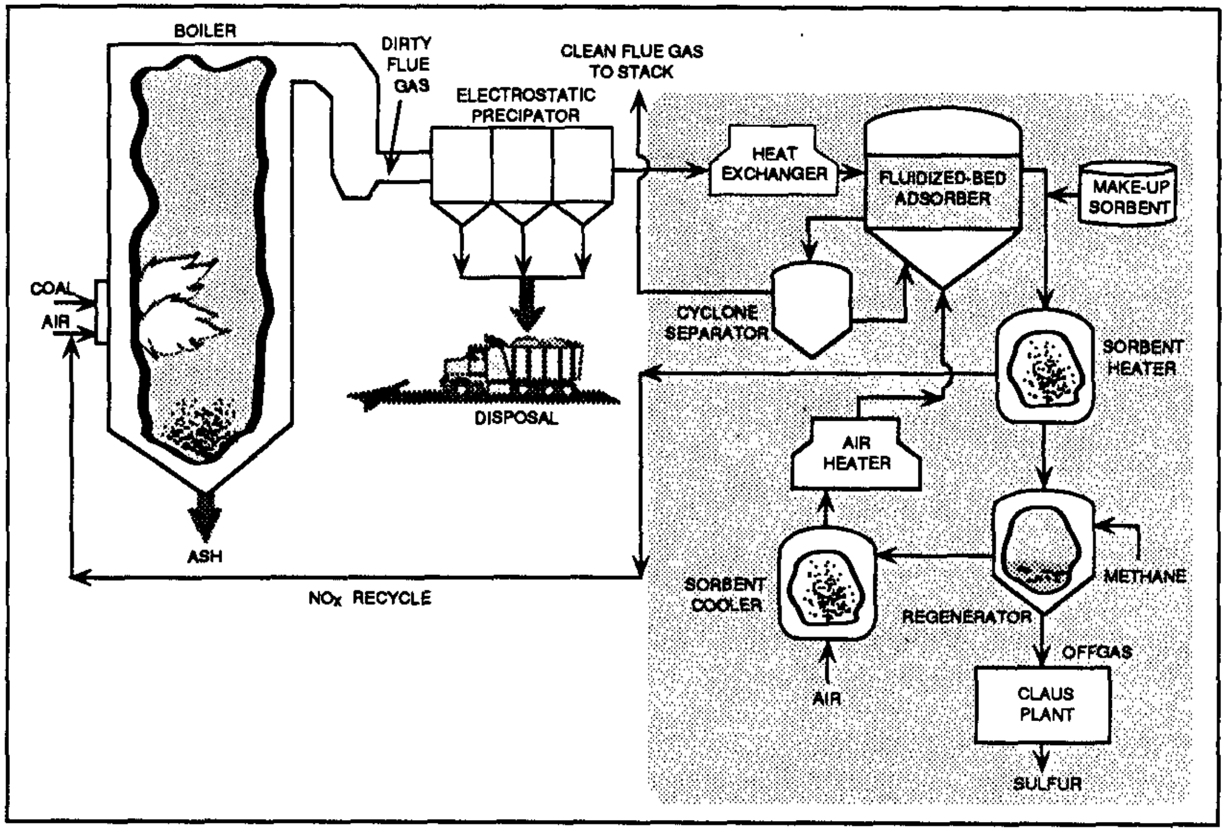
Technology:
NOXSO Corporation's dry, regenerable flue gas cleanup process

Plant Capacity/Production:
108 MWe

Project Funding:

Total project cost	$66,249,696	100%
DOE	33,124,848	50
Participants	33,124,848	50

Project Objective:
To demonstrate SO_2 and NO_x removal from a coal-fired boiler flue gas using the NOXSO process and to remove



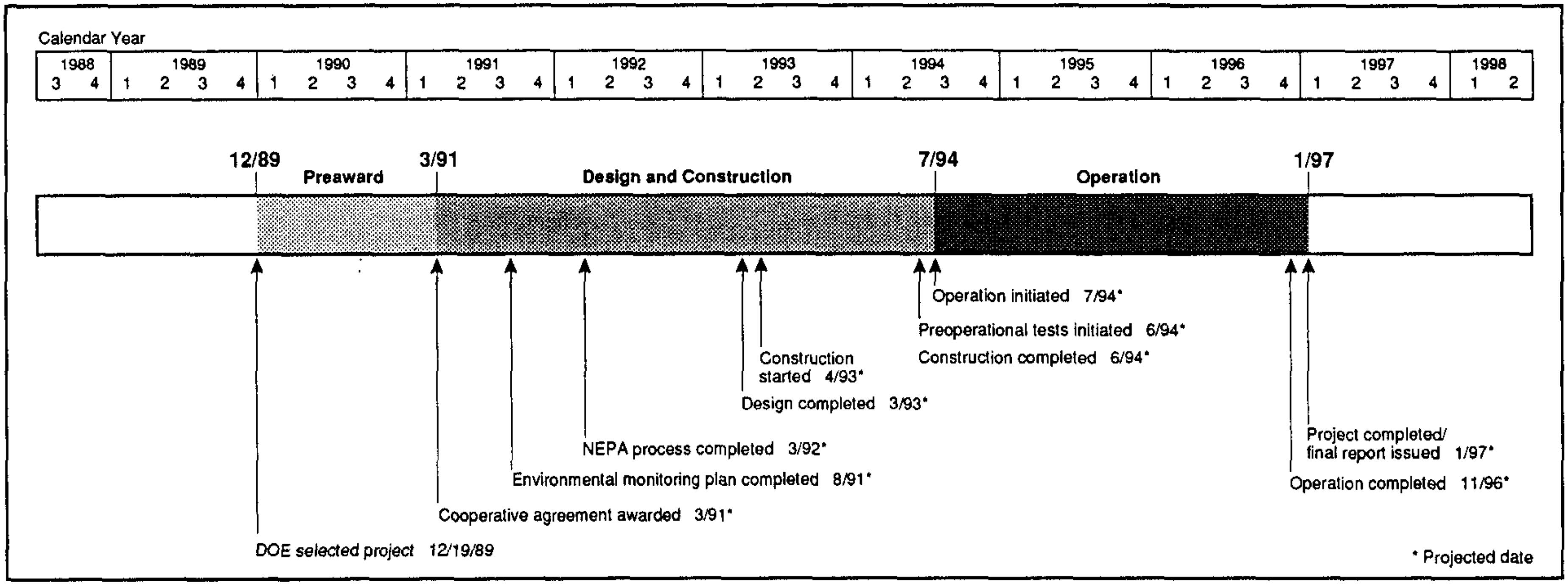
97% of the SO_2 and 70% of the NO_x from the flue gas exhausted to the atmosphere.

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

The NOXSO sorbent regenerates with heating, which causes the NO_x to desorb and partially decompose. The hot air containing the desorbed NO_x is recycled to the boiler where equilibrium processes cause destruction of this NO_x. The adsorbed sulfur is recovered from the sorbent in a regenerator where it reacts with methane at high temperature to produce an offgas with high concentrations of SO_2 and hydrogen sulfide (H_2S). This offgas is processed in a Claus plant to produce elemental sulfur, a salable by-product.

The process is expected to achieve SO_2 reductions of 97% and NO_x reductions of 70%.

The NOXSO process is being demonstrated at Ohio Edison's Niles Station, Unit 1, a 108-MWe cyclone boiler. MK-Ferguson will design, construct, and operate a full-scale commercial NOXSO unit to demonstrate process feasibility. The project is being structured so that data from the proof-of-concept facility being constructed at Ohio Edison's Toronto Station can



be available before the end of the project definition activity.

Project Status/Accomplishments:
Negotiation was completed in December 1990; approval of the cooperative agreement is pending congressional approval.

Environmental Considerations:
Environmental information is being compiled for use in the NEPA process.

By 2010, national emissions of SO_2 could be reduced by as much as 48% and NO_x by 11%, assuming maximum commercialization of this technology relative to a no-action alternative. Also, the process results in essentially no increase in solid waste and produces a salable by-product (sulfur). (Source: Programmatic Environmental Impact Statement)

Commercial Application:
The NOXSO process is applicable for retrofitting existing coal-fired power plants or for use in new facilities. The demonstration is expected to use southeastern Ohio and western Pennsylvania coal (3.2–3.5% sulfur average). The process is adaptable to coals with higher sulfur content.

Commercial-grade sulfur, a salable by-product, is produced. The technology is expected to be especially attractive to utilities that require high removal efficiencies for both SO_2 and NO_x and/or need to eliminate solid wastes.

Integrated Dry NO_x /SO_2 Emission Control System

Sponsor:
Public Service Company of Colorado

Additional Team Members:
Electric Power Research Institute—cofunder
Stone and Webster Engineering Company—engineer
The Babcock & Wilcox Company—burner developer
Fossil Energy Research Corporation—operational testing
Western Research Institute—fly ash evaluator
Colorado School of Mines—engineering research and testing
Vendor (to be determined)—urea system provider

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

Congressional District:
1st U.S Congressional District

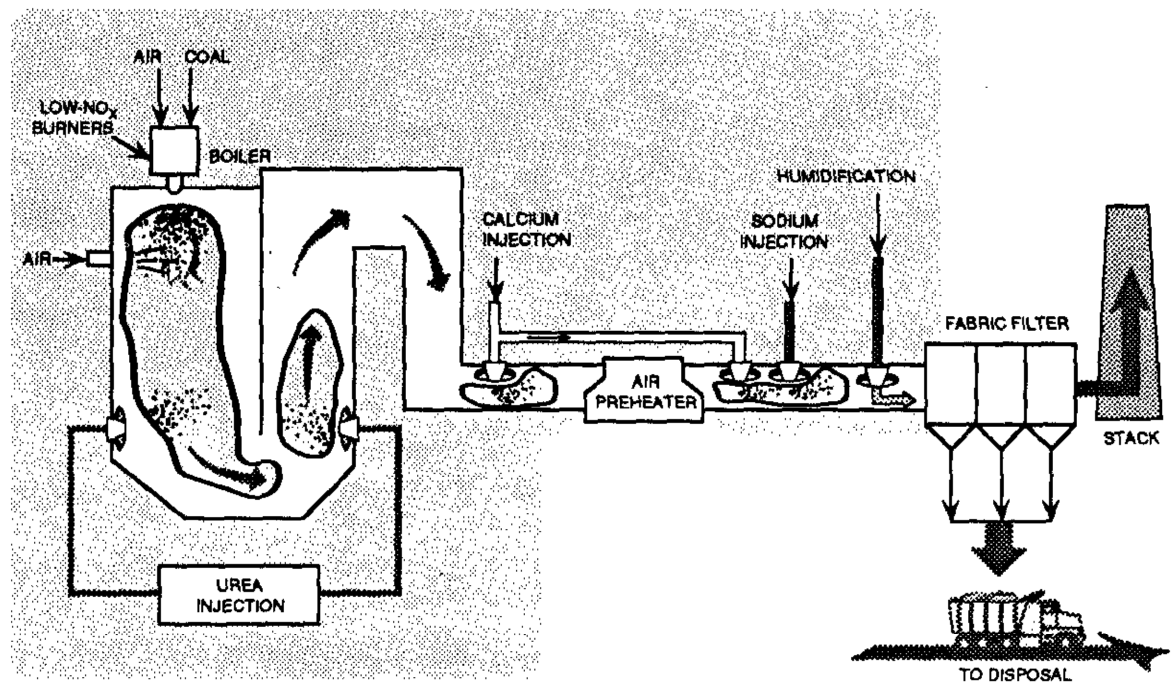
Technology:
The Babcock & Wilcox Company's low-NO_x burners, in-duct sorbent injection, and furnace (urea) injection

Plant Capacity/Production:
100 MWe

Project Funding:

Total project cost	$26,477,878	100%
DOE	13,238,939	50
Participants	13,238,939	50

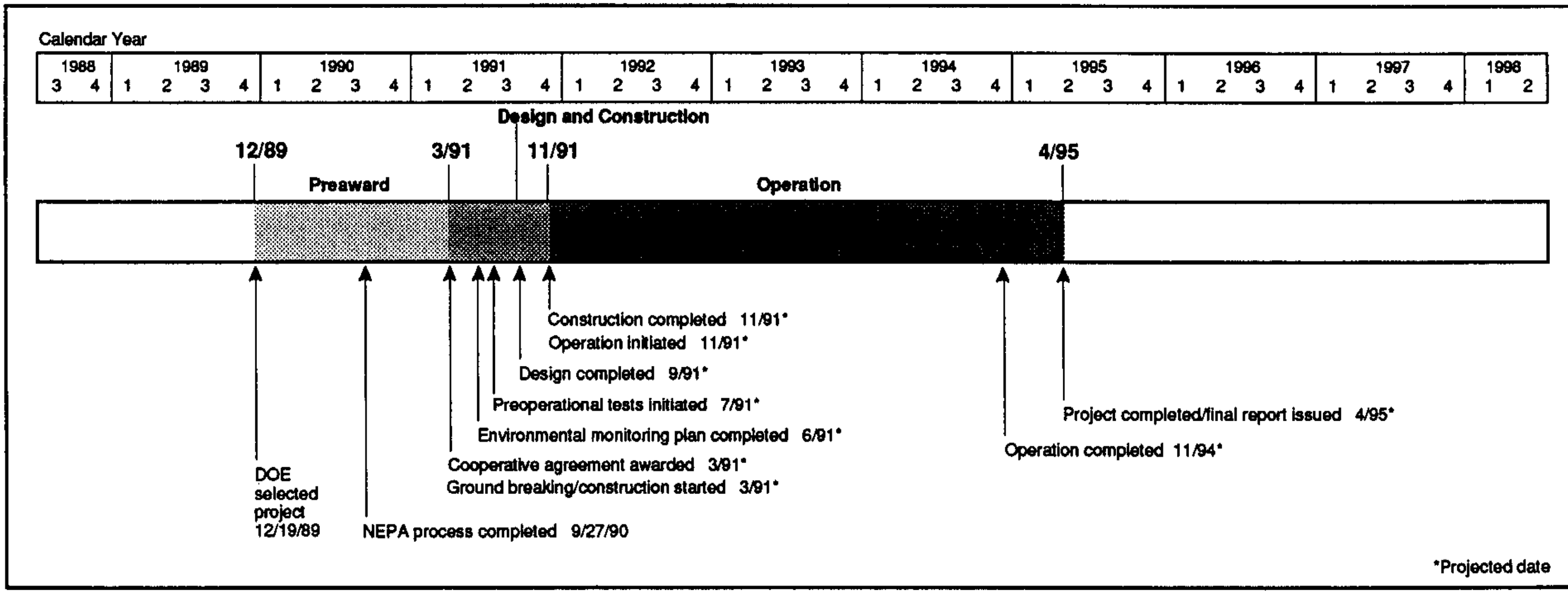
Project Objective:
To demonstrate the integration of three technologies to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection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



Technology/Project Description:
All of the testing will use Babcock & Wilcox's low-NO_x XCL down-fired burners with over-fire air. These burners control NO_x by injecting part of the coal and part of the combustion air in an oxygen-deficient environment. Additional fuel and combustion air are introduced in a second stage to advance the combustion process. Additional air is introduced to complete the combustion process and further enhance NO_x removal. The low-NO_x burners are expected to reduce up to 50% of the NO_x, and with added air, the system is expected to reduce NO_2 emissions by up to 70%. To reduce NO_x emissions even 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 SO_2 emissions. Either calcium is injected upstream of the air heater or sodium or calcium is injected downstream of the air heater. Humidification downstream of the dry sorbent injection enables the electrostatic precipitator to maintain performance. Humidification aids SO_2 capture and lowers flue gas temperature and gas flow, which improves particulate collection efficiency.

The three basic technology systems are being 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.



Project Status/Accomplishments:

Negotiation has been completed; award of the cooperative agreement is pending congressional approval.

Environmental Considerations:

NEPA compliance has been satisfied by the signing of a memo-to-file approved by DOE on September 27, 1990.

SO_2 reduction is in the range of 55–75%. Although the volume of solid waste is considerably increased, it is dry, easily disposed of, and nontoxic. From a national perspective, a 38% SO_2 reduction is projected by 2010, assuming maximum commercialization of the sorbent injection technology. Urea injection should enhance NO_x reduction, thereby increasing low-NO_x burner impact on national reductions from the presently projected 11%. (Source: CCT Programmatic Environmental Impact Statement)

Commercial Application:

Urea injection and sorbent injection are both applicable to most utility and industrial coal-fired units and can be retrofitted with modest capital investment and downtime.