CLEAN
COAL
TECHNOLOGY

DOE/FE-0272

Clean Coal Technology Demonstration Program

Program Update 1992

(As of December 31, 1992)

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

February 1993

Fact Sheets of Completed Projects

LIMB Demonstration Project Extension and Coolside Demonstration

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)

Technology:
The Babcock & Wilcox Company's limestone injection multistage burner (LIMB) system; Babcock & Wilcox DRB-XCL™ low-NO_x burners

Consolidation Coal Company's Coolside duct injection of lime sorbents

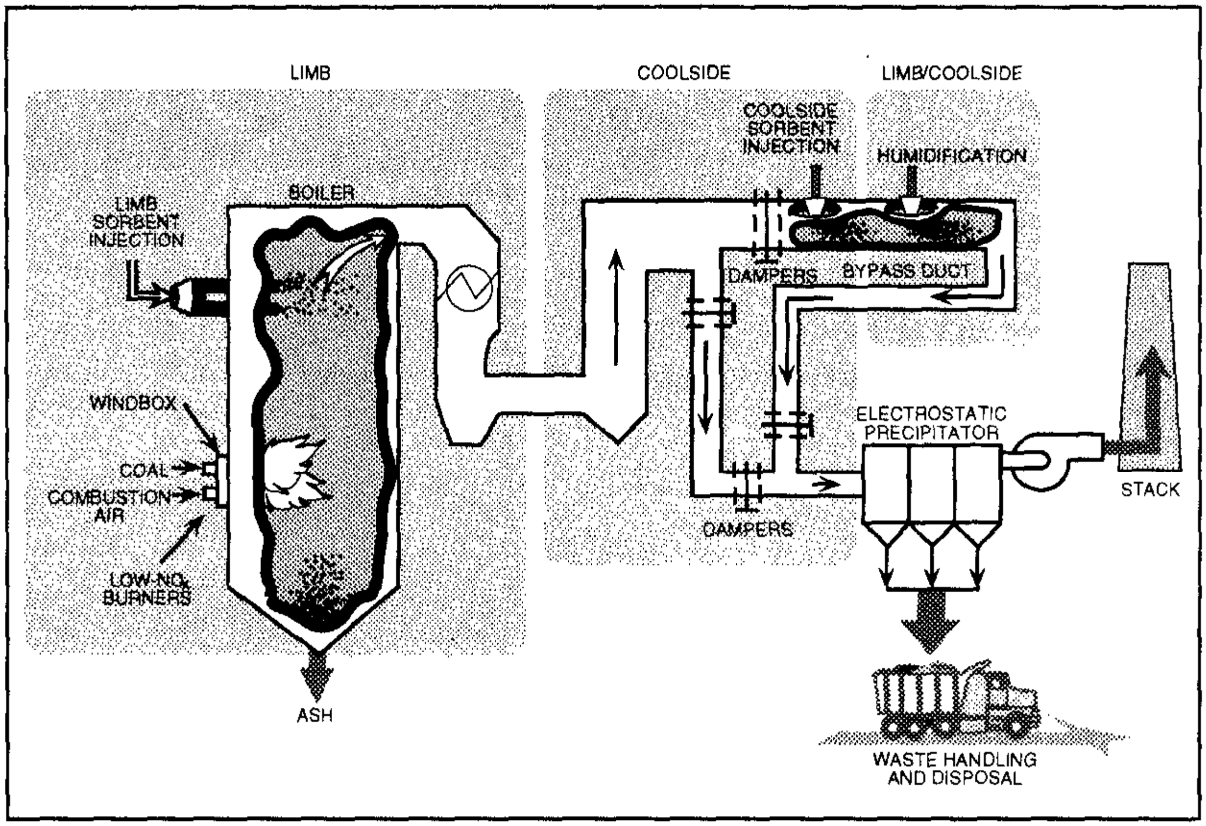
Plant Capacity/Production:
105 MWe

Project Funding:

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

Subprogram:
CCT-I

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



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

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

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

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

Project Results/Accomplishments:

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

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

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

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

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

Commercial Applications:

Both LIMB and Coolside technologies are applicable to most utility and industrial coal-fired units and provide alternatives to conventional wet flue gas desulfurization (FGD) processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. Depending on the plant capacity factor and the coal's sulfur content, they can be economically competititive with FGD systems. For example, using 2.5% sulfur coal at a 65% plant capacity factor, LIMB can be cost competitive with conventional wet FGD up to 450 MWe and Coolside up to 220 MWe. The environmental benefits for LIMB are 40–50% lower NO_x and more than 60% lower SO_2 emissions, and for Coolside up to 70% lower SO_2 emissions. The waste from each of these processes is dry and easily handled and contains unreacted lime that has potential commercial application. Both processes have the ability to handle all coal types, especially low- to medium-sulfur coals.

Project Schedule:

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

Final Reports:

- T.R. Goots, M.J. DePero, and P.S. Nolan. *LIMB Demonstration Project Extension and Coolside Demonstration.* The Babcock & Wilcox Company. October 1992.
- D.C. McCoy et al. *The Edgewater Coolside Process Demonstration: A Topical Report.* CONSOL Inc. February 1992.

Advanced Cyclone Combustor with Internal 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 Power Corporation—host site

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

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

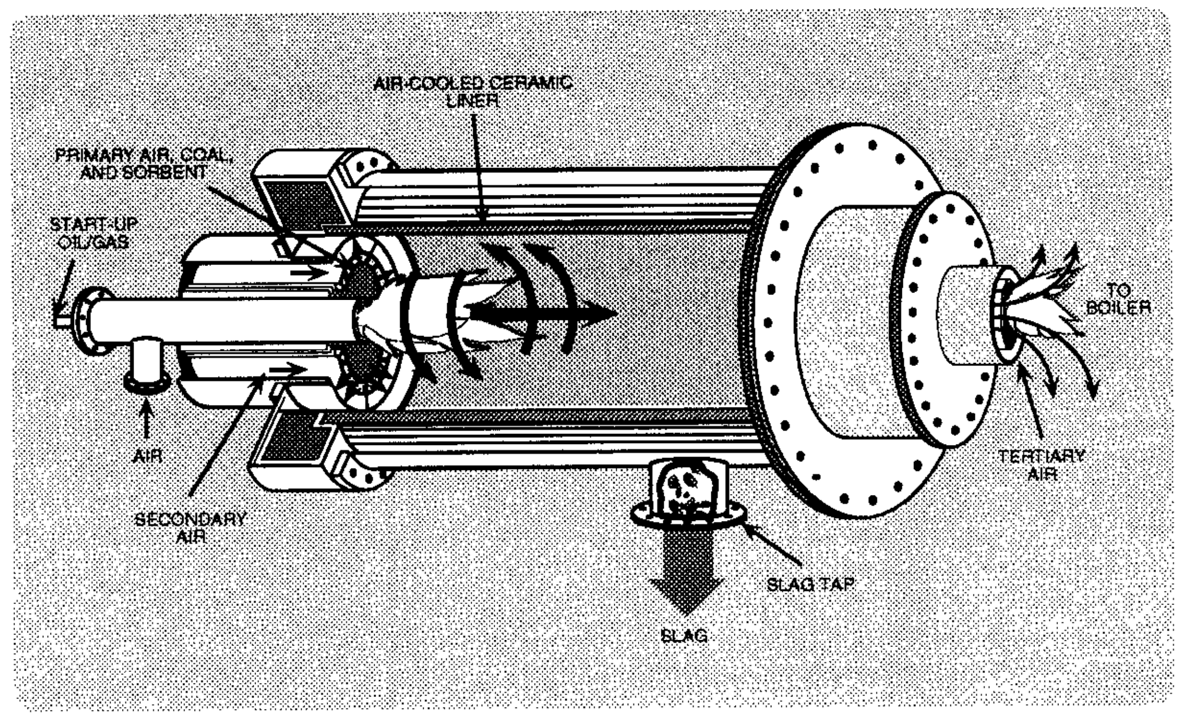
Plant Capacity/Production:
23 million Btu/hr

Project Funding:

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

Subprogram:
CCT-I

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



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

In Coal Tech's demonstration, an advanced, air-cooled, cyclone coal combustor was retrofitted to a 23-million-Btu/hr, oil-designed package boiler located at the Tampella Power Corporation boiler factory in Williamsport, PA. Air cooling took place in a very compact combustor which could be retrofitted to a wide range of industrial and utility boiler designs without disturbing the boiler's water-steam circuit. NO_x reduction was achieved by staged combustion, and SO_2 was captured by injection of limestone into the combustor.

The cyclonic action inside the combustor forced the coal ash and sorbent to the walls where it could be collected as liquid slag. Under optimum operating conditions, the slag would contain a significant fraction of vitrified coal sulfur. Downstream sorbent injection into the boiler provided additional sulfur removal capacity.

Project Results/Accomplishments:

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

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

Coal Tech reported the following test results:

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

Commercial Applications:

Coal Tech has concluded that, while the combustor is not yet fully ready for sale with commercial guarantees, it is ready to be further scaled up for commercial applications (100 million Btu/hr), such as combustion of waste solid fuels, limited sulfur control in coal-fired boilers, and conversion of ash to slag.

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

Project Schedule:

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

Final Report:

B. Zauderer and E.S. Fleming. *The Demonstration of an Advanced Cyclone Coal Combustor, with Internal Sulfur, Nitrogen, and Ash Control for theConversion of a 23 MMBtu/Hour Oil Fired Boiler to Pulverized Coal; Volume 1–Final Technical Report; Volume 2–Appendices I, II, III, IV, and V; Volume 3–Appendix VI.* Coal Tech Corporation. August 1991. (Available from NTIS as DE 9200-2587 and DE 9200-2588-T7.)

Nucla CFB Demonstration Project

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

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

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

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

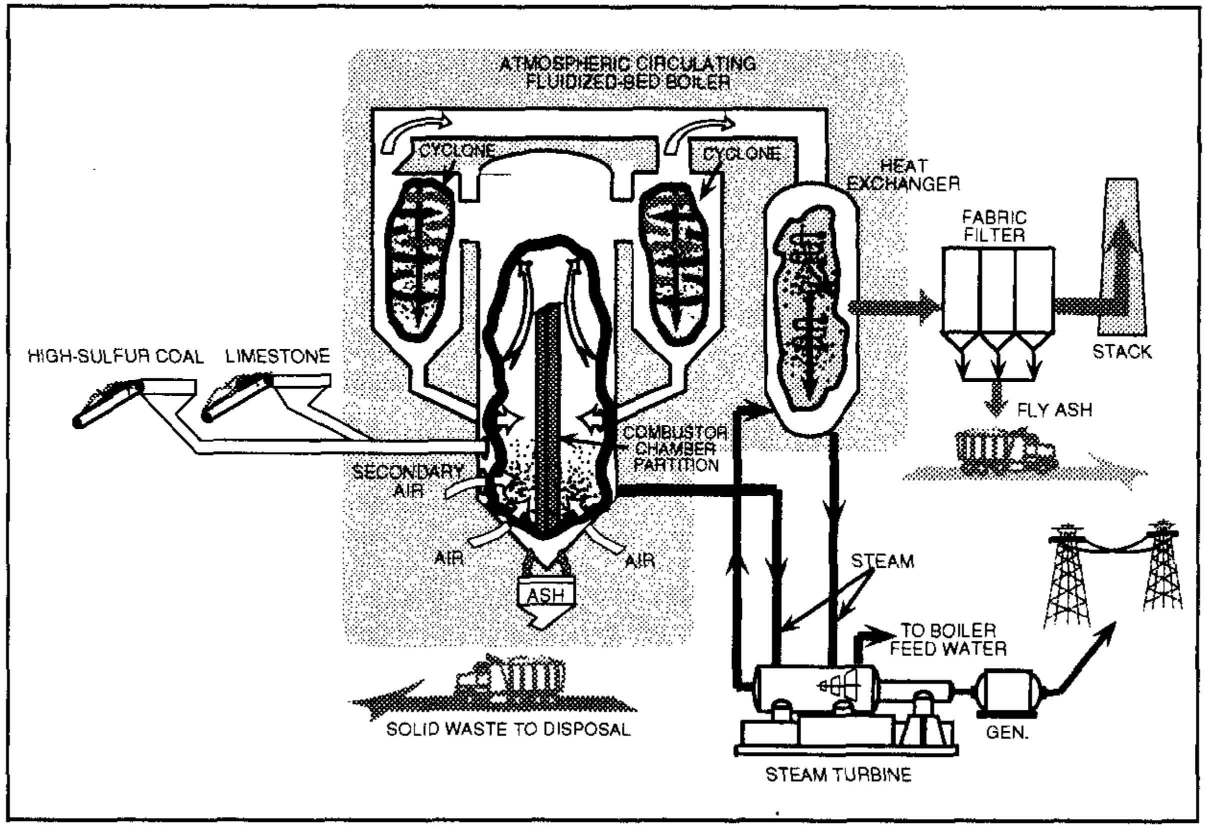
Plant Capacity/Production:
110 MWe

Project Funding:

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

Subprogram:
CCT-I

Project Objective:
To demonstrate ACFB at a scale of 110 MWe, representing a 2:1 scaleup from previously demonstrated capacities; to verify expectations of the technology's economic, environmental, and technical performance in a repowering application at a utility site; to accomplish greater than 90% SO_2 removal; to reduce NO_x emissions by 60%; and to achieve an efficiency of 34% in a repowering mode.



Technology/Project Description:
Nucla's circulating fluidized-bed system operates at atmospheric pressure. In the combustion chamber, a stream of air fluidizes and entrains a bed of coal, coal ash, and sorbent (e.g., limestone). Relatively low combustion temperatures limit NO_x formation. Calcium in the sorbent combines with 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 a baghouse where the particulate matter is removed. The steam generated in the ACFB is used to generate electric power.

Three small, coal-fired, stoker-type boilers at Nucla Station were replaced with a new 925,000-lb/hr ACFB steam generator capable of driving a new 74-MWe turbine generator. Extraction steam from this turbine generator powers three existing turbine generators (12 MWe each). Three western coals were tested: Peabody coal (0.4–0.8% sulfur), Dorchester coal (1.5% sulfur), and Salt Creek coal (0.5% suflur).

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

Project Results/Accomplishments:

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

- Results indicated strong correlations of absolute CO, SO_2, and NO_x emissions levels with combustor operating temperatures. Although NSPS compliance was maintained, a penalty on limestone feed requirements for sulfur retention was realized at the higher operating temperatures. Below 1,620 °F, 70% sulfur retention was achieved with 1.5 Ca/S, and 95% sulfur retention was achieved with 4.0 Ca/S. Around 1,700 °F, Ca/S greater than 5.0 was required to maintain 70% sulfur capture.
- The NO_x emissions for all tests were less than 0.34 lb/million Btu, which was well within the emission limit of 0.60 lb/million Btu. The average level of NO_x emissions for all tests was 0.18lb/million Btu.
- Combustion efficiency, a measure of the quantity of carbon that is fully oxidized to CO_2, ranged from 96.9% to 98.9%. Of the four exit sources of incompletely burned carbon, the largest was carbon contained in the fly ash (93%). The next largest (5%) was carbon contained in the bottom ash stream, and the remaining feed-carbon loss (2%) was incompletely oxidized CO in the flue gas. The fourth possible source, hydrocarbons in the flue gas, was measured and found to be negligible.
- Boiler efficiencies for 68 performance tests varied from 85.6% to 88.6%. The contributions to boiler heat loss were identified as unburned carbon; sensible heat in dry flue gas; fuel and sorbent moisture; latent heat in burning hydrogen; sorbent calcination, radiation, and convection; and bottom ash cooling water. Net plant heat rate decreased with increasing boiler load, from 12,400 Btu/kWh at 50% of full load to 11,600 Btu/kWh at full load. The lowest value achieved during a full-load steady-state test was 10,980 Btu/kWh. These values were affected by the absence of reheat, the presence of the three older 12.5-MWe turbines in the overall steam cycle, the number of unit restarts, and part-load testing.
- Over the range of operating temperatures at which testing was performed at Nucla, bed temperature was found to be the most influential operating parameter. With the possible exception of coal-feed configuration and excess air at elevated temperatures, bed temperature was the only parameter that had a measurable impact on emissions or efficiencies. Emissions of SO_2 and NO_x were found to increase with increasing combustor temperatures while CO emissions decreased with increasing temperature. Combustion efficiency also improved as the temperature was increased.

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

Commercial Applications:

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

Project Schedule:

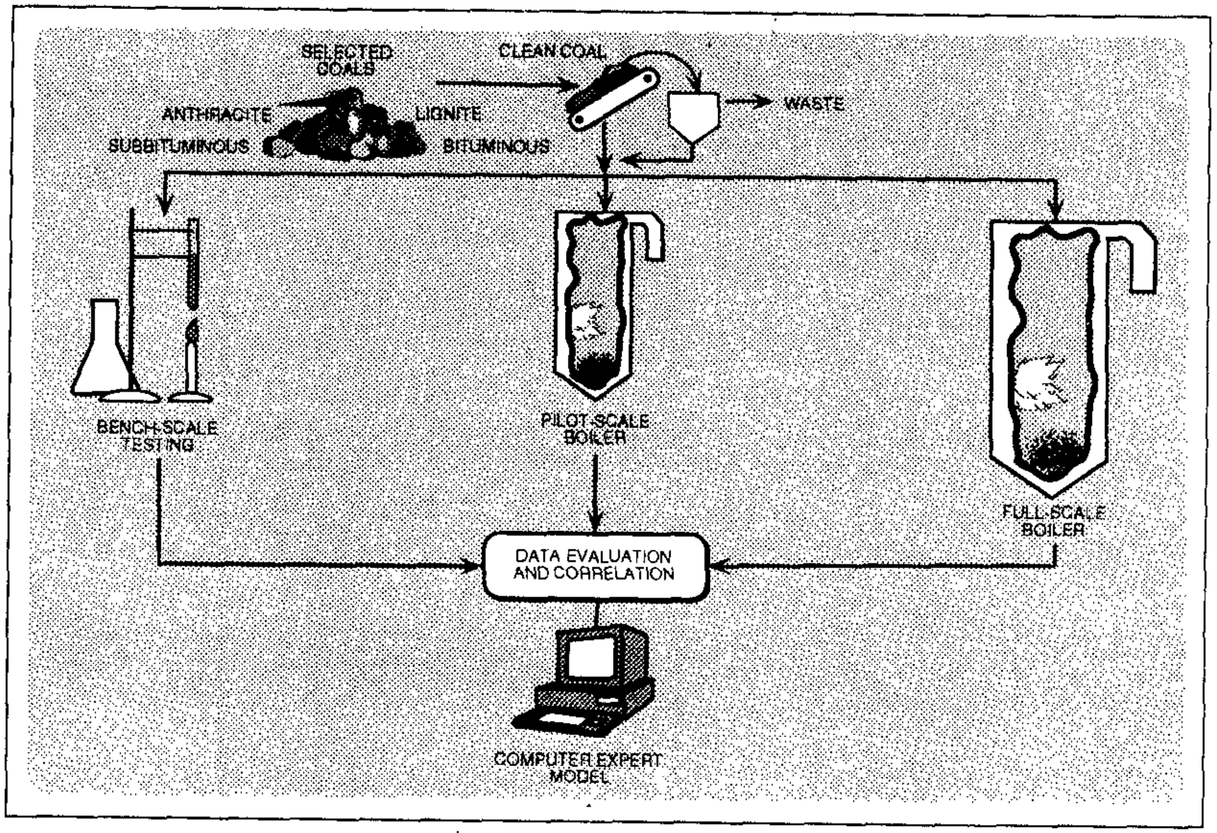
DOE selected project (CCT-I)	10/7/87
Cooperative agreement awarded	10/3/88
NEPA process completed (MTF)	4/18/88
Environmental monitoring plan completed	2/27/88
Operational testing	8/88–1/91
Project completed/final report issued	4/92

Final Reports:

- *Nucla Circulating Atmospheric Fluidized Bed Demonstration Project: Final Report.* Colorado-Ute Electric Association, Inc. October 1991. (Available from NTIS as DE 9200-1122.)
- *Economic Evaluation Report: Topical Report.* Colorado-Ute Electric Association, Inc. March 1992. (Available from NTIS as DE 9300-0212.)
- *Clean Coal Reference Plants: Atmospheric CFB; Final Report.* Gilbert/Commonwealth, Inc. June 1992.

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
Electric Power Research Institute—cofunder
The Babcock & Wilcox Company—cofunder and pilot-scale testing
Guild Products, Inc.—expert system architecture developer
Electric Power Technologies, Inc.—field testing
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 utilities
Public Service of Oklahoma—host utility

Locations:

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

Technology:

CQ, Inc.'s EPRI 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	$21,727,822	100%
DOE	10,863,911	50
Participants	10,863,911	50

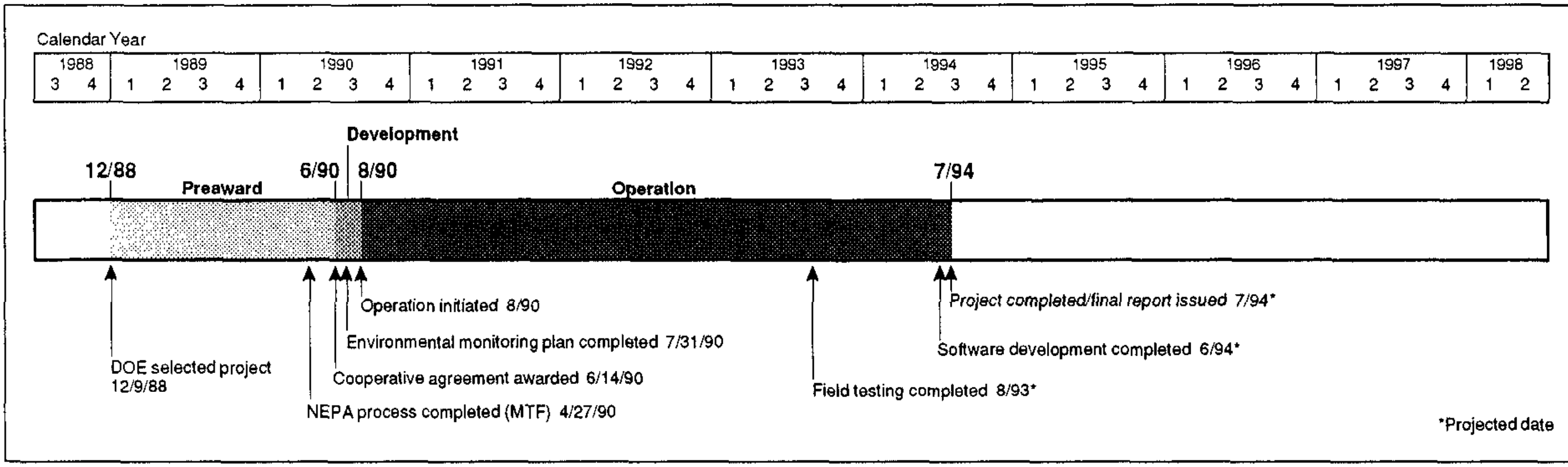
Project Objective:

To demonstrate an expert system that can be 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, cost, and environmental emissions.

Technology/Project Description:

Data derived from bench-, pilot-, and full-scale testing are being used to develop algorithms for inclusion into an expert model, the Coal Quality Expert, that can be run on a personal computer. Utilities may use the information to predict the operating performance and cost of coals not previously burned at a particular facility.

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



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

Bench-scale testing will be performed at ABB Combustion Engineering's facilities in Windsor, CT, and 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: Gatson, Unit 5 (880 MWe), Wilsonville, AL; Cheswick Station (500 MWe), Springdale, PA; Watson, Unit 4 (250 MWe), Gulfport, MS; King Station (560 MWe), Bayport, MN; Homer City, Unit 2 (600 MWe), Homer City, PA; and Northeastern, Unit 4 (445 MWe), Oologah, OK.

Project Status/Accomplishments:

Four of six field tests have been completed, including Public Service of Oklahoma's Northeastern Unit 4, Mississippi Power Company's Watson Unit 4, Northern States Power Company's King Station, and Alabama Power Company's Gaston Unit 5. Coals tested include Wyoming, blends of Wyoming/Oklahoma, Illinois, and western Kentucky, and a blend of Wyoming/Montana/petroleum coke. The CQE "Acid Rain Advisor" software package was commercially released in June 1992.

The project duration has been extended 5 months to allow sufficient time to complete software development following field testing.

Commercial Applications:

The expert system will enable coal-fired utilities to select the optimum quality coals at the lowest price for their specific boilers to reduce SO_2 and NO_x emissions.

The CQE system is applicable to all electric power plants and industrial/institutional boilers that burn coal. The system 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.

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

Locations:

Hennepin, Putnam County, IL (Illinois Power Company's, Hennepin Plant)

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

Technology:

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

Plant Capacity/Production:

Hennepin: tangentially fired 80 MWe (nominal)

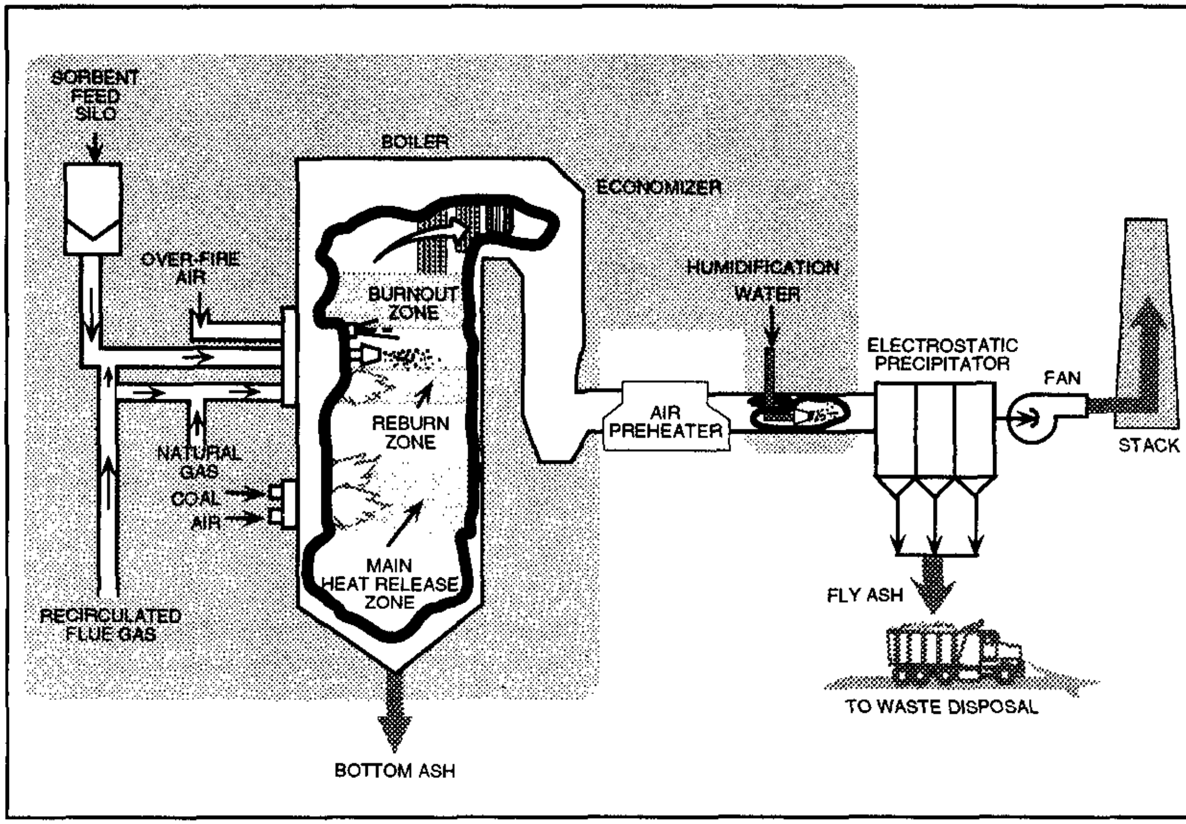
Lakeside: cyclone-fired 40 MWe (nominal)

Project Funding:

Total project cost	$37,497,816	100%
DOE	18,747,816	50
Participants	18,750,000	50

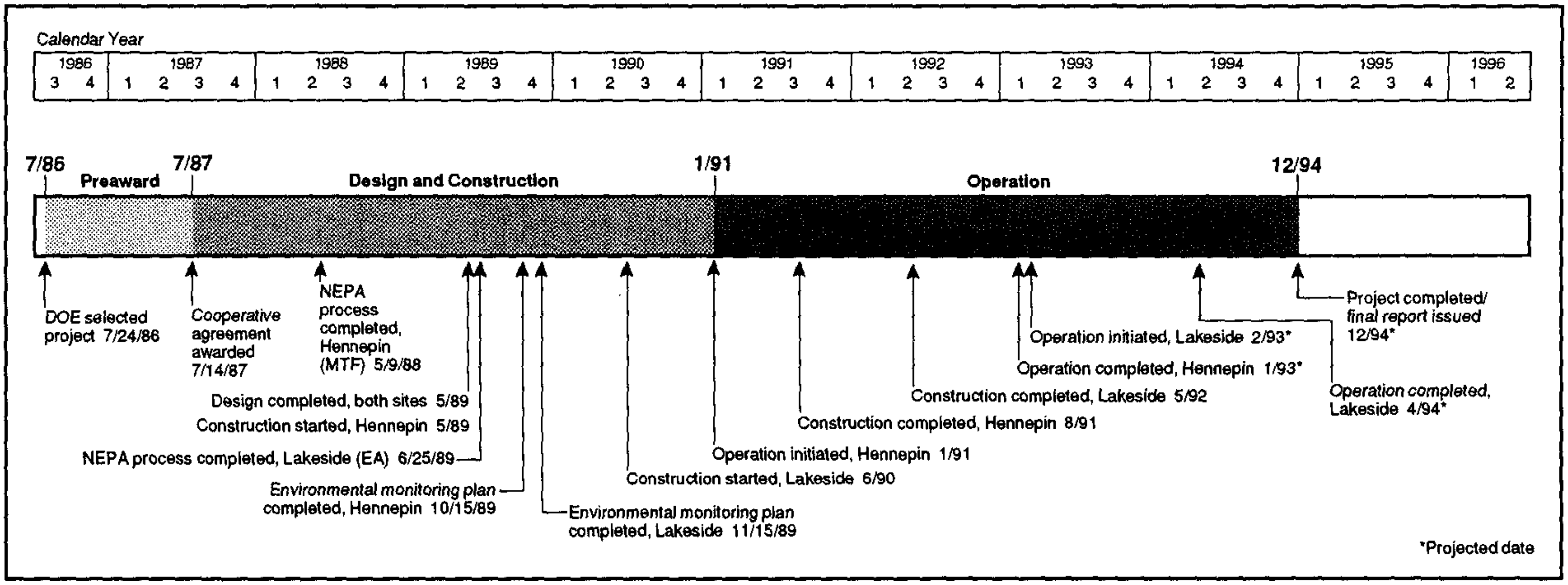
Project Objective:

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 fired 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 compound to be tested is $Ca(OH)_2$ (lime). The process 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. 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 at Illinois Power Company's Hennepin Plant in Hennepin, IL, and a cyclone-fired 40-MWe boiler at City Water, Light and Power's Lakeside Station in Springfield, IL.



Project Status/Accomplishments:
Permitting and engineering design efforts were completed for the three original project sites; however, in 1990, plans for the third site (Bartonville, IL) were suspended.

Construction is complete at both Hennepin and Springfield, IL, sites. Operations at the Hennepin site began January 1991. Long-term baseline testing at Hennepin started in mid-1991 after shakedown operations had been completed. Baseline testing, including testing with a promoted and a high-surface-area lime, was completed in January 1993. During the course of testing, NO_x reductions through gas reburning have ranged as high as 77%, 65% being routine, exceeding the project objective of 60%. Sorbent injection reduced SO_2 emissions as much as 62%, with 52.5% reduction being routine, also exceeding the project objective of 50%. The calcium-to-sulfur ratio is about 1.75:1.

At the Lakeside site in Springfield, IL, construction was essentially completed in May 1992, and the unit was temporarily placed on hold. Some minor construction activities were completed in October. Long-term baseline testing will start in February 1993 and is expected to be completed in April 1994.

The project schedule has been extended to allow at least 12 months of gas-reburning and sorbent-injection demonstration operation under normal load dispatch at Lakeside and to allow demonstration of one or more alternate sorbents.

Commercial Applications:
Gas reburning and sorbent injection is the unique combination of two separate technologies. The commercial applications for these technologies, both separately and combined, extend to both utility companies and industry in the United States and abroad. In the United States alone, these two technologies can be applied to over 900 pre-NSPS utility boilers; the technologies also can be applied to new utility boilers. With NO_x and SO_2 removal exceeding 60% and 50%, respectively, these technologies have the potential to extend the life of a boiler or power plant and also provide a way to use higher sulfur coals. The technologies are not sensitive to the type of coal used, regardless of its nitrogen or sulfur content.

Tidd PFBC Demonstration Project

Sponsor:
The Ohio Power Company

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

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

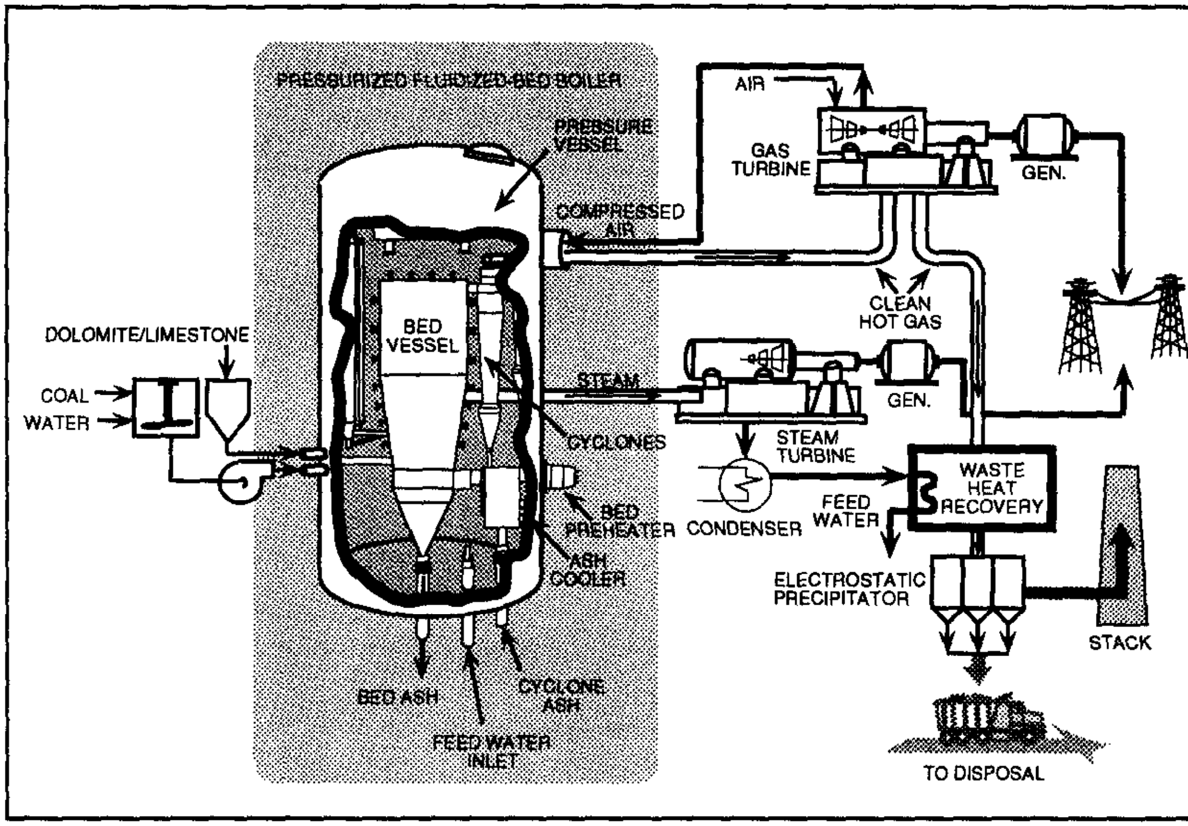
Technology:
The Babcock & Wilcox Company's pressurized fluidized-bed combustion (PFBC) system (under license from ABB Carbon)

Plant Capacity/Production:
70 MWe

Project Funding:

Total project cost	$193,540,000	100%
DOE	60,200,000	31
Participants	133,340,000	69

Project Objective:
To demonstrate PFBC at a 70-MWe scale, representing a 13:1 scaleup from the pilot plant facility; to verify expectations of the technology's economic, environmental, and technical performance in a combined-cycle repowering application at a utility site; and to accomplish greater than 90% SO_2 removal, NO_x emission level of 0.2 lb/million Btu, and an efficiency of 38% in a repowering mode using the existing steam system.

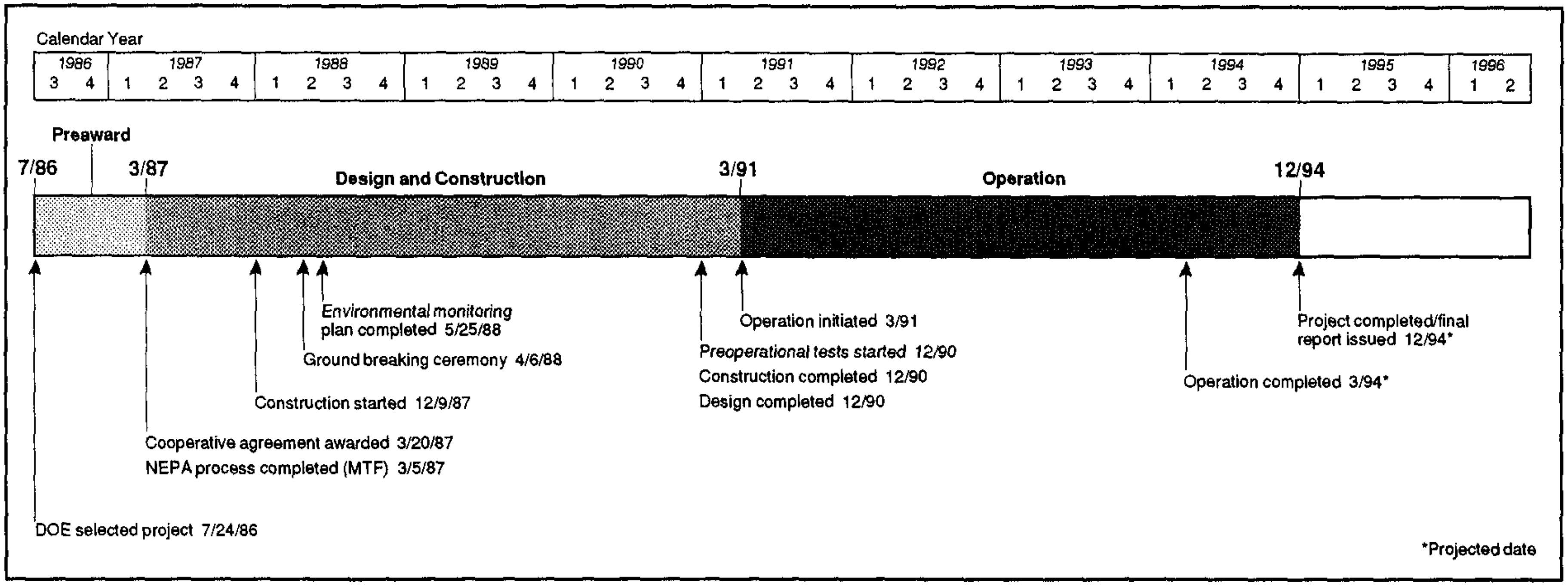


Technology/Project Description:
Tidd is the first large-scale demonstration of PFBC in the United States and one of only three worldwide. The boiler, cyclones, bed reinjection vessels, and associated hardware are encapsulated in a pressure vessel 45 ft in diameter and 70 ft high. The facility was designed so that one-seventh of the hot gases produced could be routed to a slipstream to test advanced filtration devices.

The Tidd facility is a bubbling fluidized-bed combustion process operating at 12 atm (175 lb/in² atm). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material which consists of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent. Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material which is easily disposed of or is usable as a by-product. A low bed-temperature of 1,600 °F limits NO_x formation.

The hot combustion gases exit the bed vessel with entrained ash particles, 98% of which are removed when the gases pass through cyclones. The cleaned gases are then expanded through a 15-MWe gas turbine. The gases exiting the turbine are cooled via a waste heat economizer and further cleaned in an electrostatic precipitator.

The Tidd steam turbine operates at a pressure of 1,305 lb/in² atm and a temperature of 925 °F to produce approximately 55 MWe. Superheated steam is produced from pressurized boiler feed water in the in-bed combustor tubes. Steam generated within the combustor and the heat recovery system downstream of the gas



turbine is used to generate power in a previously existing steam turbine. Due to repowering, plant efficiency was improved by 10% to a heat rate of 9,750 Btu/kWh (an efficiency of 35.1% based on HHV).

Project Status/Accomplishments:
American Electric Power Company received two national awards in 1992 for Tidd: *Power Magazine's* "1991 Power Plant of the Year" award and a National Energy Resources Organization award.

During 1992, the facility's environmental compliance test and 30-day acceptance test were completed, a hot-gas filtration test loop was installed, and several parametric tests (e.g., sorbent mixing into fuel paste, limestone sorbent, revalidation of 30-day acceptance, etc.) were conducted. Approximately one-half of the project's 3-year operating period has been completed.

Results from the compliance test showed that the unit could operate within its permit. SO_2 emissions were less than 0.51 lb/million Btu (90% capture), NO_x emissions were less than 0.24 lb/million Btu, and particulate emissions were less than 0.02 lb/million Btu.

Early in 1992 the unit experienced high-cycle fatigue cracks in the low-pressure turbine and problems in the secondary ash removal system, but these problems appear to have been corrected. By year end, the facility had accumulated more than 3,000 hours of coal-fueled tests, 2,000 hours of which were accumulated in 1992.

Commercial Application:
Combined-cycle PFBC permits use of a wide range of coals, including high-sulfur coals. Bubbling PFBC technology, along with other advanced technologies, will compete with circulating PFBC systems to repower or replace conventional power plants. PFBC technology appears to be best suited for applications of 50 MWe or larger. Capable of being constructed modularly, PFBC generating plants permit utilities to add increments of capacity economically to match load growth. Plant life can be extended by repowering with PFBC using the existing plant area, coal- and waste-handling equipment, and steam turbine equipment. Another advantage for repowering applications is the compactness of the process due to pressurized operation, which reduces space requirements per unit of energy generated.

In a fully mature system, the projected net heat rate is 8,500 Btu/kWh (based on HHV) which equates to 40.2% efficiency. An advanced cycle that integrates a small gasifier could yield heat rates approaching 7,500 Btu/kWh (45% efficiency).

The environmental attributes of a mature system include in-situ sulfur removal of 95% and NO_x emissions reduction levels less than 0.1 lb/million Btu. Although the system generates a slight increase in solid waste as compared to conventional systems, the dry material is either disposable or potentially usable.

Advanced Coal Conversion Process Demonstration

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

Additional Team Member:
Stone and Webster Engineering Company—architect/engineer

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

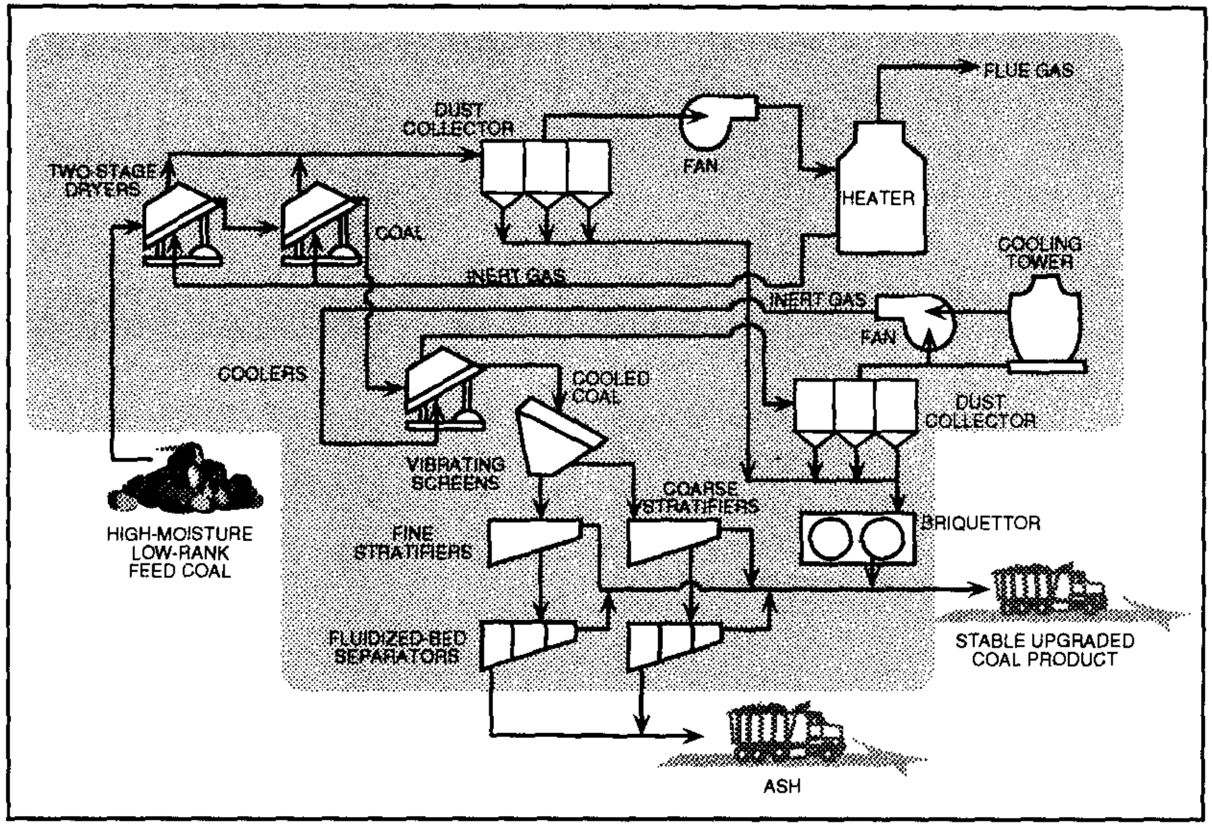
Technology:
Western Energy Company's advanced coal conversion process for upgrading low-rank subbituminous and lignite coals

Plant Capacity/Production:
45 tons/hr of SynCoal™ product (300,000 tons/yr)

Project Funding:

Total project cost	$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 a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.

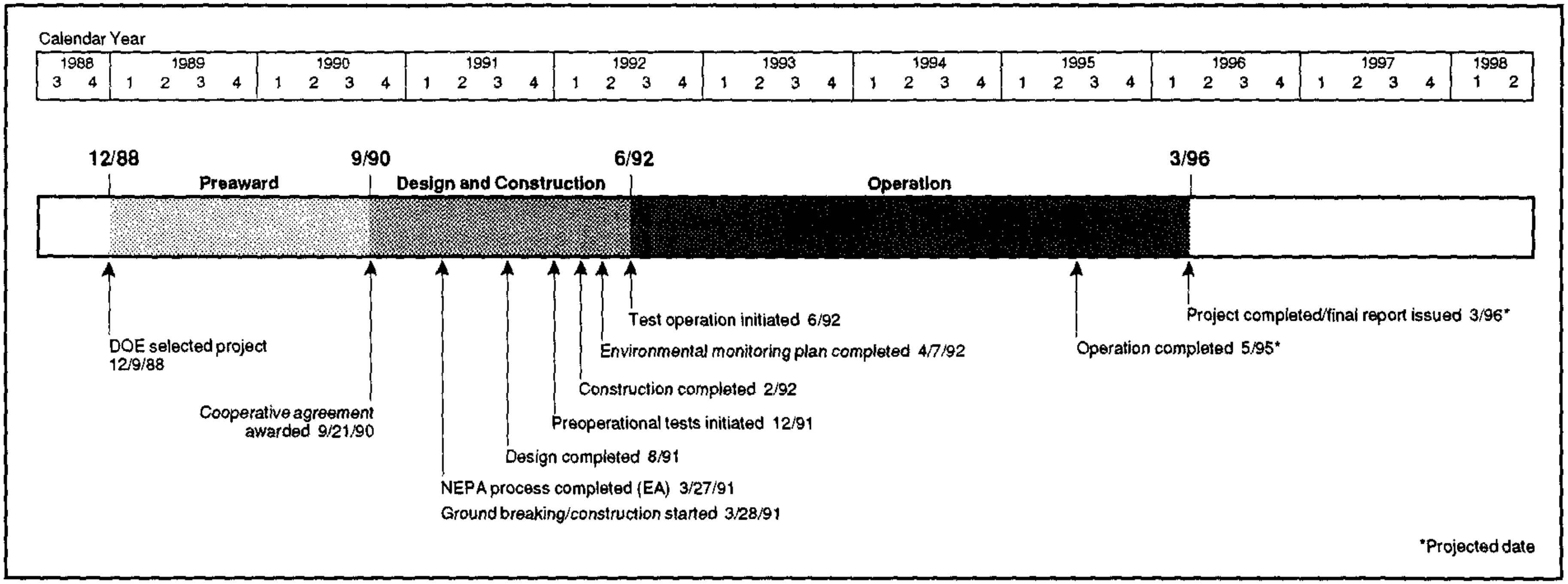


Technology/Project Description:
Being demonstrated is an advanced thermal coal-drying process coupled with physical cleaning techniques to upgrade high-moisture, low-rank coals to produce a high-quality, low-sulfur fuel. The coal is processed through two fluidized-bed reactors that remove loosely held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

The technology, if successfully demonstrated, enhances 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 SynCoal™ product with a moisture content as low as 1%, sulfur content as low as 0.3%, and heating value up to 12,000 Btu/lb.

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

SynCoal is a trademark of the Rosebud SynCoal Partnership.



Project Status/Accomplishments:

On December 12, 1990, Western Energy Company, a subsidiary of Montana Power Company, announced that it had joined with the NRG Group, a nonregulated subsidiary of Northern States Power Company based in Minneapolis, MN, to demonstrate and commercialize this coal conversion technology.

Ground was broken on March 28, 1991. By June, pieces of major equipment were arriving on site. The construction of two 6,000-ton product storage silos and all foundation work was completed by July. The main process facility structure and the control/administration building were completed by November. Initial "turnover" of equipment started in December, and final construction was completed in February 1992. Initial "hot" operations began in March 1992. Plant operational activities are under way with full operations scheduled for the second quarter of 1993. Through December 1992, the plant had operated 384 hours, and initial shipments of approximately 2,100 tons of SynCoal™ product were delivered by truck to Montana Power Company for trial burns at Colstrip Unit 3 and the J.E. Corette Plant in Billings, MT. A 5,000-ton rail shipment for test burn at Northern States Power Company's Riverside Plant in Minneapolis is scheduled for April 1993.

Commercial Applications:

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. SynCoal™ 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. The advanced coal conversion process will produce SynCoal™ which has a very low sulfur content, high heating value, and stable physical/chemical characteristics; it could have significant impact on SO_2 reduction. 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.

York County Energy Partners Cogeneration Project

Sponsor:

York County Energy Partners, L.P. (a limited partnership which includes Air Products and Chemicals, Inc.)

Additional Team Members:

J.E. Baker Company—site host
Foster Wheeler Energy Corporation — technology supplier

Location:

West Manchester Township, York County, PA (greenfield site)

Technology:

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

Plant Capacity/Production:

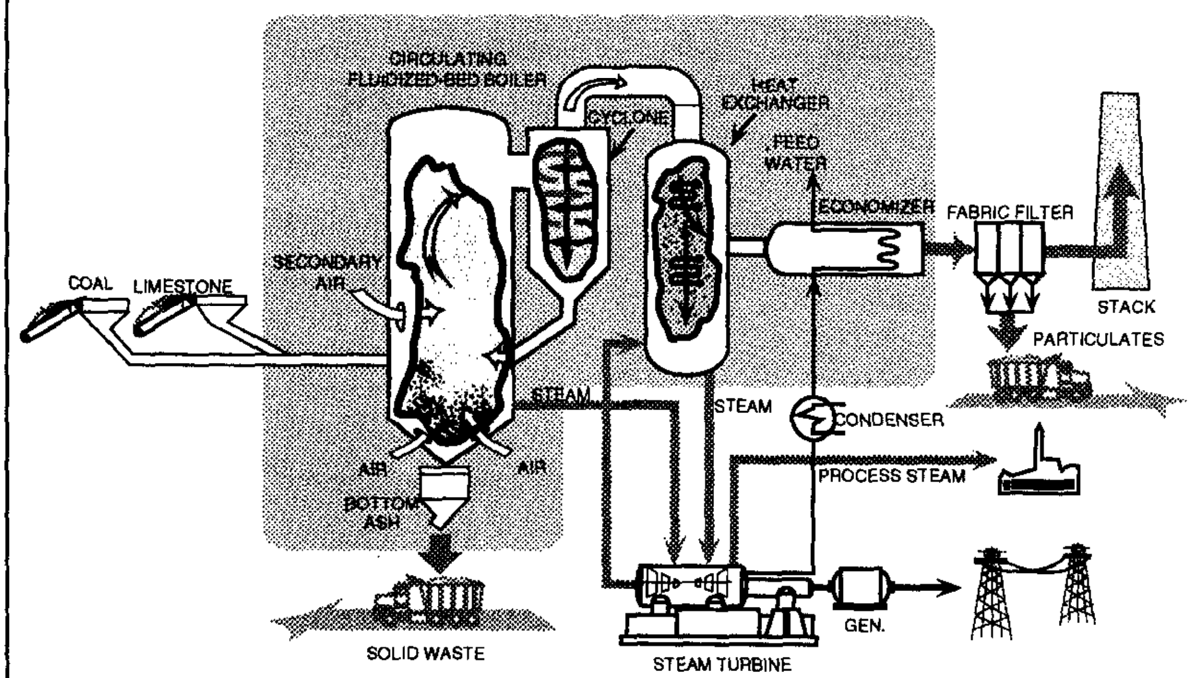
227 MWe (net) and 50,000 lb/hr steam

Project Funding:

Total project cost	\$374,345,450	100%
DOE	74,733,833	20
Participant	299,611,617	80

Project Objective:

To demonstrate ACFB at 250 MWe, representing a 1.7:1 scaleup from previously constructed facilities; to verify expectations of the technology's economic, environmental, and technical performance in a greenfield cogeneration application; and to provide cogenerators, as well as utility and non-utility power producers, 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% when compared with conventional technology, and to achieve a steam efficiency of 88%.



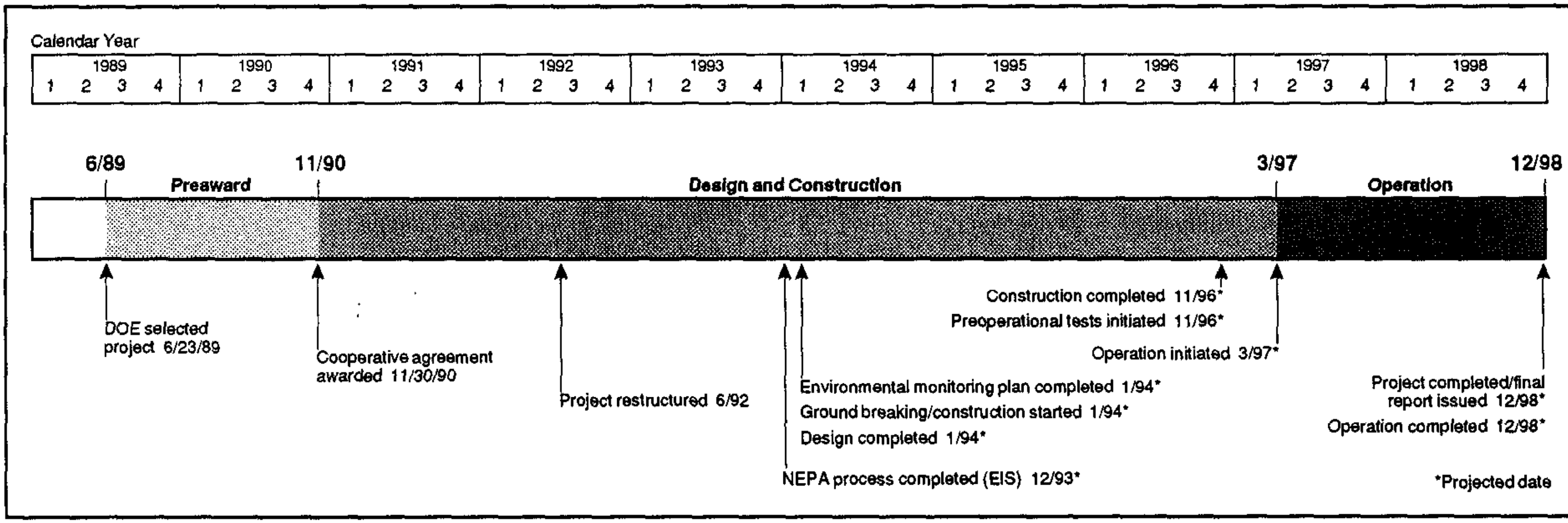
Technology/Project Description:

In this project, the circulating fluidized-bed combustor operates at atmospheric pressure. Coal, primary air, and a solid sorbent, such as limestone, are introduced into the lower portion of the combustor where initial combustion occurs. As coal particles decrease in size due to combustion and breakage, they are carried higher in the combustor to an area where secondary air is introduced. As the coal particles continue to be reduced in size, the coal, along with some of the sorbent, is carried out of the combustor, collected in a particle separator, and recycled to the lower portion of the combustor. The sorbent in the bed removes sulfur during the combustion process, eliminating the need for scrubbers.

Steam is generated in tubes placed along the combustor's walls and superheated in tube bundles placed in the solids-circulating stream and the flue gas stream. The steam is then used to produce power in a conventional steam cycle.

The project will demonstrate ACFB in a 250-MWe greenfield cogeneration application in York County, PA. The sponsor has an electrical power purchase agreement with Metropolitan Edison Company to supply up to 227 MWe and a steam purchase agreement with J.E. Baker Company to supply steam to the brickmaking facility located adjacent to the project site.

The heat rate for this cogeneration plant is expected to be 9,200 Btu/kWh (37% efficiency). Expected SO_2 emissions from this demonstration plant are below 0.24 lb/million Btu (92% reduction). This technology operates at lower temperatures than conventional boilers, thus reducing NO_x production. In addition, installation of a selective non-catalytic reduction system



planned for the facility is expected to reduce the NO_x emissions by an additional 50%.

Project Status/Accomplishments:
During 1992, the project was restructured and relocated to a new site in West Manchester, PA. The project is in the preliminary design stage. The sponsor is negotiating agreements with major equipment vendors and with coal and limestone suppliers. Environmental information for use in the NEPA process has been prepared. A public scoping meeting was held in August 1992 to solicit public comments on preparation of the project's environmental impact statement.

Commercial Applications:
ACFB technology has good potential for application in both the industrial and utility sectors, whether for use in repowering existing plants or in new facilities. ACFB is attractive for both baseload and dispatchable power applications because it can be efficiently turned down to 25% of full load. Coal of any sulfur content can be used, and any type or size of a coal-fired boiler can be repowered. 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; and dry, granular solid waste which is easily disposed of or which may be a salable by-product.

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—cofunder

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

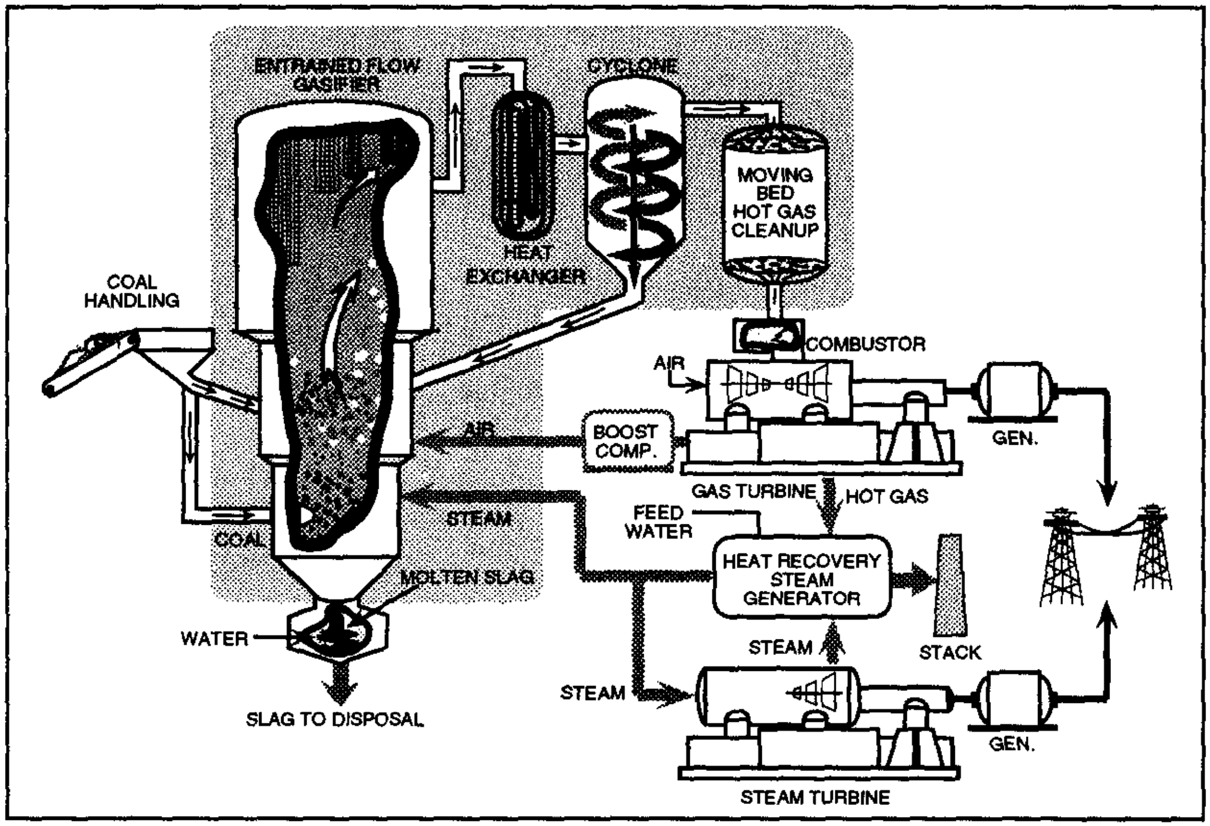
Technology:
ABB Combustion Engineering's integrated gasification combined-cycle (IGCC) system

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 a moving-bed, zinc titanate, hot-gas cleanup system; to assess long-term reliability and maintainability of the system at a sufficient scale to determine commercial potential.



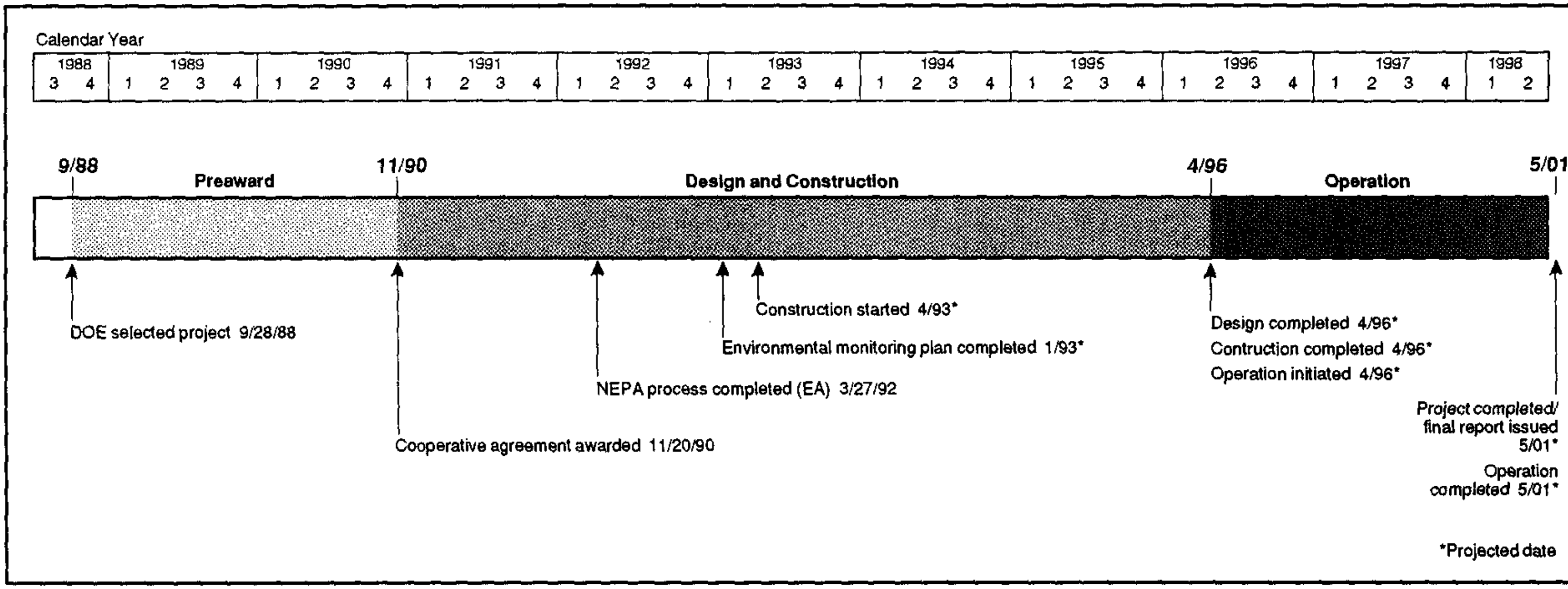
Technology/Project Description:
Pressurized pulverized coal is pneumatically transported to the gasifier. The gasifier essentially consists of a bottom combustor section and a top reductor section. Coal is fed into both sections. A slag tap at the bottom of the combustor allows molten slag to flow into 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 in a heat exchanger. Char in the gas stream is captured by a high-efficiency cyclone, as well as by a subsequent fine-particulate removal system, and recycled back to the gasifier.

A newly developed process consisting of a moving bed of zinc titanate sorbent is being used to remove sulfur from the hot gas. Particulate emissions are 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. About 40 MWe are generated by a gas turbine. Extracted air from the gas turbine is used to meet the high-pressure air requirements of the gasifier and the zinc titanate desulfurization system. Exhaust gases from the gas turbine are used to produce steam which is fed to a bottoming cycle to generate an additional 25 MWe.

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 25-MWe steam turbine with a 40-MWe gas turbine at City Water, Light and Power's Lakeside Station located in Springfield, IL. The anticipated heat rate for the repowered unit is 8,800 Btu/kWh (an efficiency of 38.8%). SO_2 emissions are expected to be less than 0.1 lb/million Btu (99% reduction). NO_x emissions are also expected to be less than 0.1 lb/million Btu (90% reduction).

Project Status/Accomplishments:

System definition and preliminary design activities are complete. Refurbishment of existing facilities at the Lakeside Station is in progress. Also, due to advances in high-temperature sorbent development and successful tests of hot-gas cleanup devices, the project will demonstrate a moving-bed hot-gas cleanup system using a zinc titanate sorbent.

An environmental assessment with a finding of no significant impact was completed March 27, 1992.

Commercial Applications:

The IGCC system being demonstrated in this project is suitable for both repowering and new power plant applications. Repowering aging plants with this technology will improve plant efficiency and reduce emissions of SO_2, NO_x, and CO_2. Also, the modular design of the gasifier will permit a range of units to be considered for repowering.

Due to the advantages of modularity, rapid and staged on-line generation capability, high efficiency, fuel flexibility, environmental controllability, and reduced land and natural resource needs, the IGCC system is also a strong contender for new electric power generating facilities. Further, without the need for an oxygen plant, the ABB Combustion Engineering technology represents a potentially simpler approach to gasification-based power generation. A single-train IGCC system based on this gasifier is capable of producing more than 150 MWe. A commercial-scale facility based on the ABB Combustion Engineering technology is expected to have a heat rate less than 8,000 Btu/kWh (efficiency greater than 43%). This heat rate is expected to realize at least a 20% improvement in efficiency compared to a conventional pulverized-coal-fired plant with flue gas desulfurization. The improved system efficiency also results in a similar decrease in CO_2 emissions.

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)

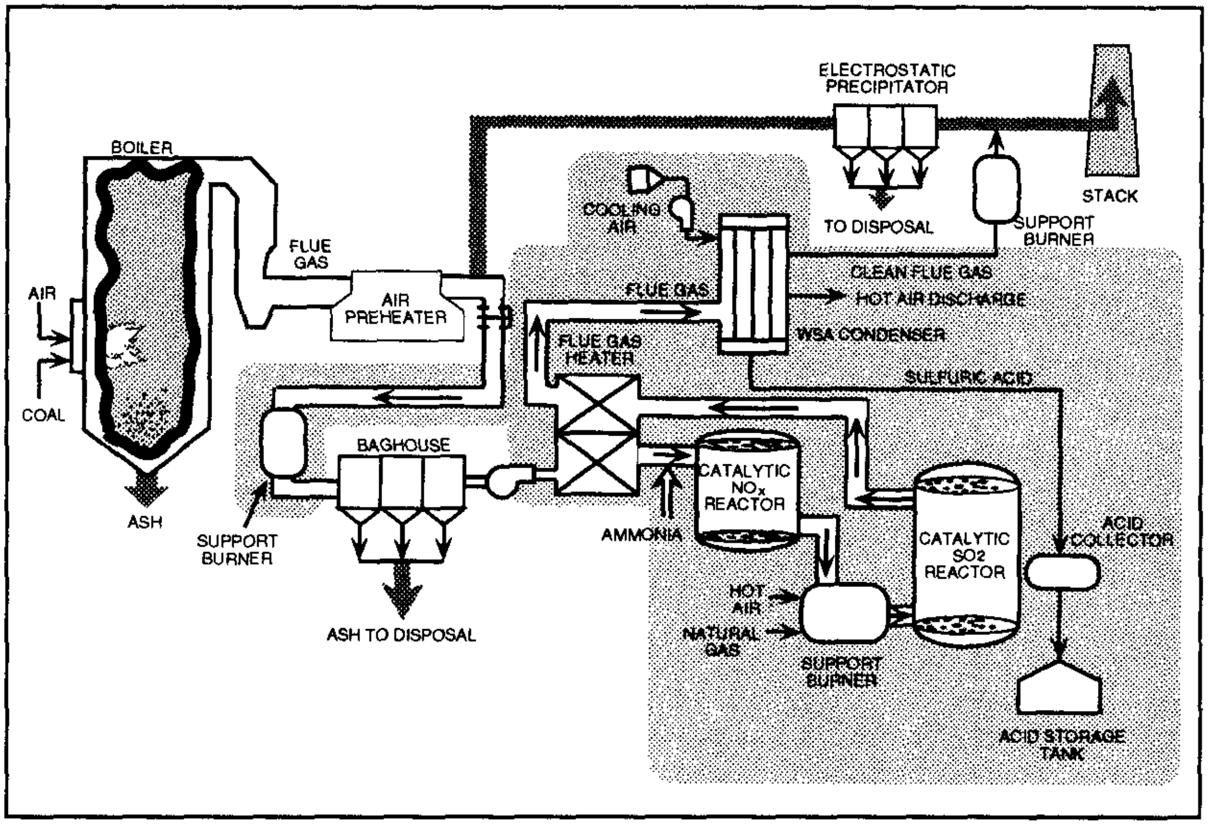
Technology:
Haldor Topsoe's SNOX catalytic advanced flue gas cleanup system

Plant Capacity/Production:
35-MWe equivalent slip-stream from a 108-MWe boiler

Project Funding:

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

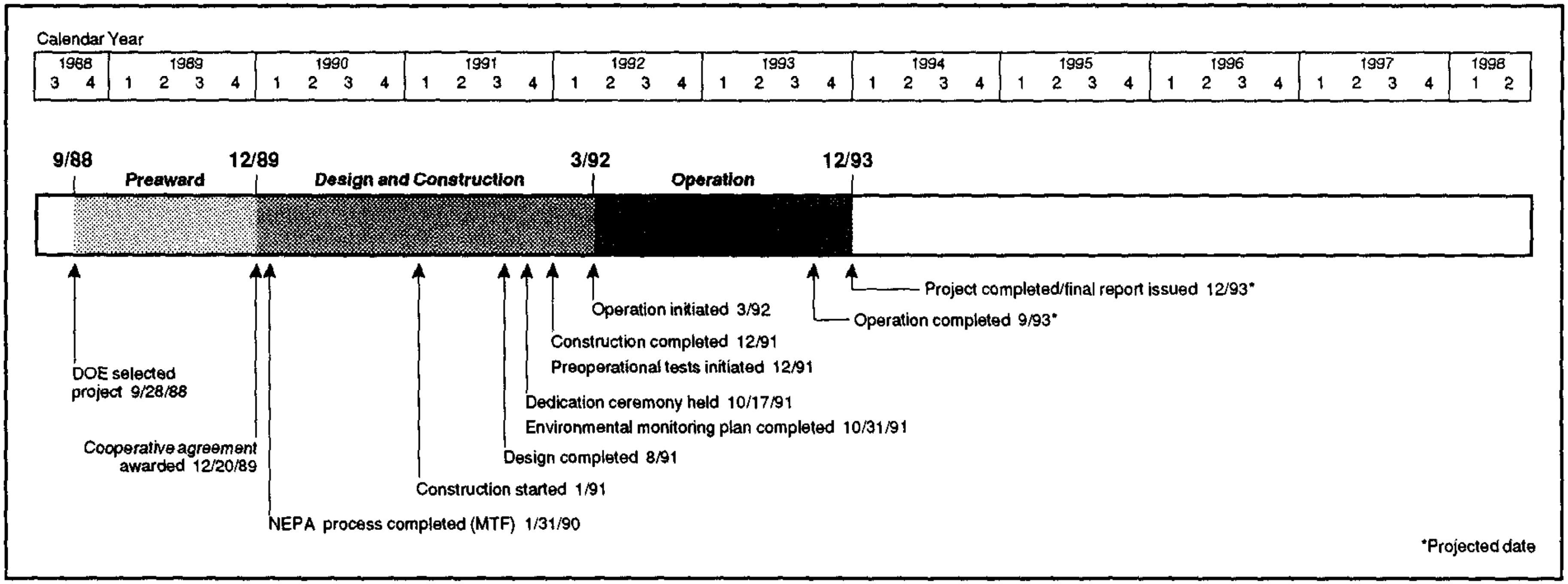
Project Objective:
To demonstrate on U.S. coals at an electric power plant that SNOX technology will catalytically remove 95% of SO_2 and more than 90% of NO_x from flue gas and produce a salable by-product of concentrated sulfuric acid.



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

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

The demonstration unit is installed at Ohio Edison's Niles Station in Niles, OH. The process is treating a 35-MWe equivalent slipstream of flue gas from the 108-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 are being used.



Project Status/Accomplishments:

Construction was completed in December 1991, and operation commenced in March 1992. After 2 months of operation, test results met or exceeded design objectives, as follows:

- SO_2 removal—96% in tests (95% design)
- NO_x removal—94% in tests (90% design)
- H_2SO_4 purity—93% in tests (93% design)

The SNOX unit has undergone little process tuning, and, as more information is generated, performance may even improve. The system has operated more than 2,450 hours during 1992, producing approximately 234,000 gallons of sulfuric acid which was sold for industrial use.

Commercial Applications:

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

PFBC Utility Demonstration Project

Sponsor:

The Appalachian Power Company

Additional Team Members:

American Electric Power Service Corporation—design, construction, and management

The Babcock & Wilcox Company—technology supplier

Location:

New Haven, Mason County, WV (greenfield facility adjacent to Appalachian Power Company's Mountaineer Plant)

Technology:

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

Plant Capacity/Production:

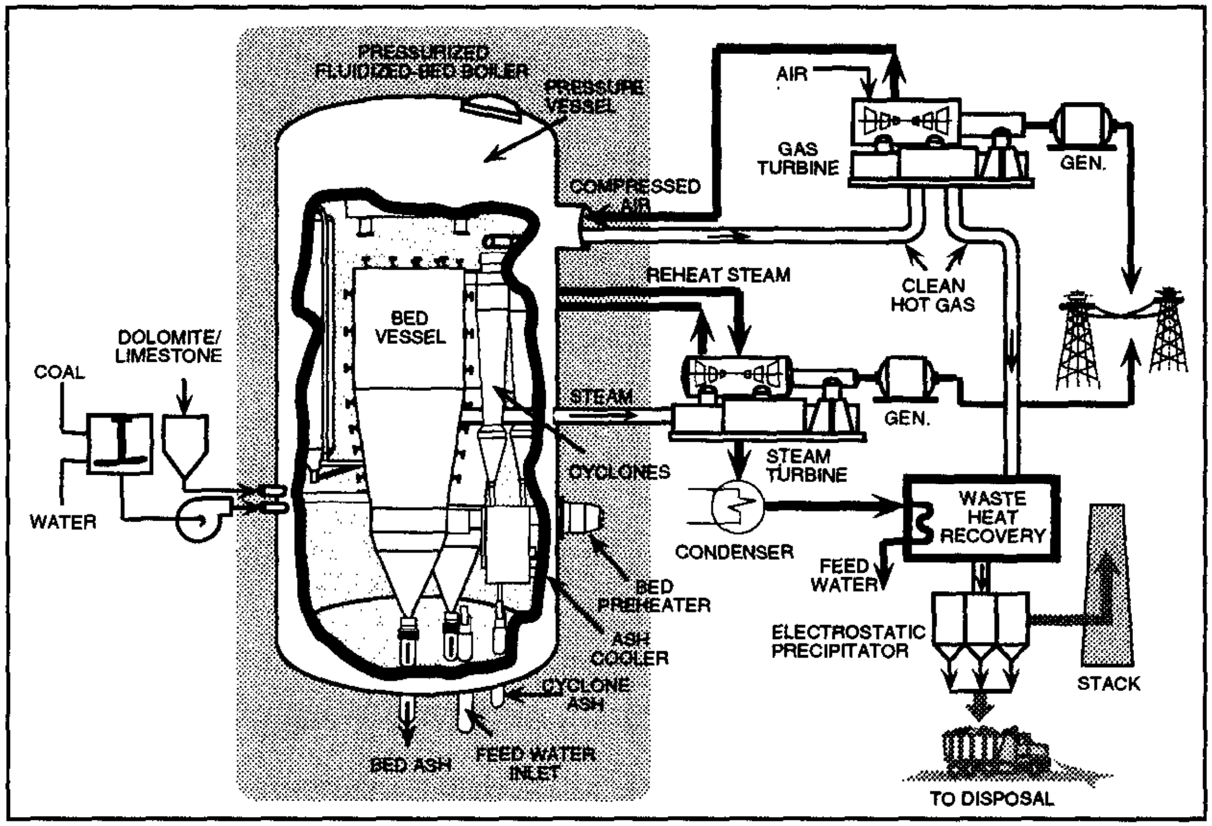
340 MWe (net)

Project Funding:

Total project cost	$917,944,000	100%
DOE	184,800,000	20
Participants	733,144,000	80

Project Objective:

To demonstrate PFBC at 340 MWe, a large utility scale representing a four-fold scaleup 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.



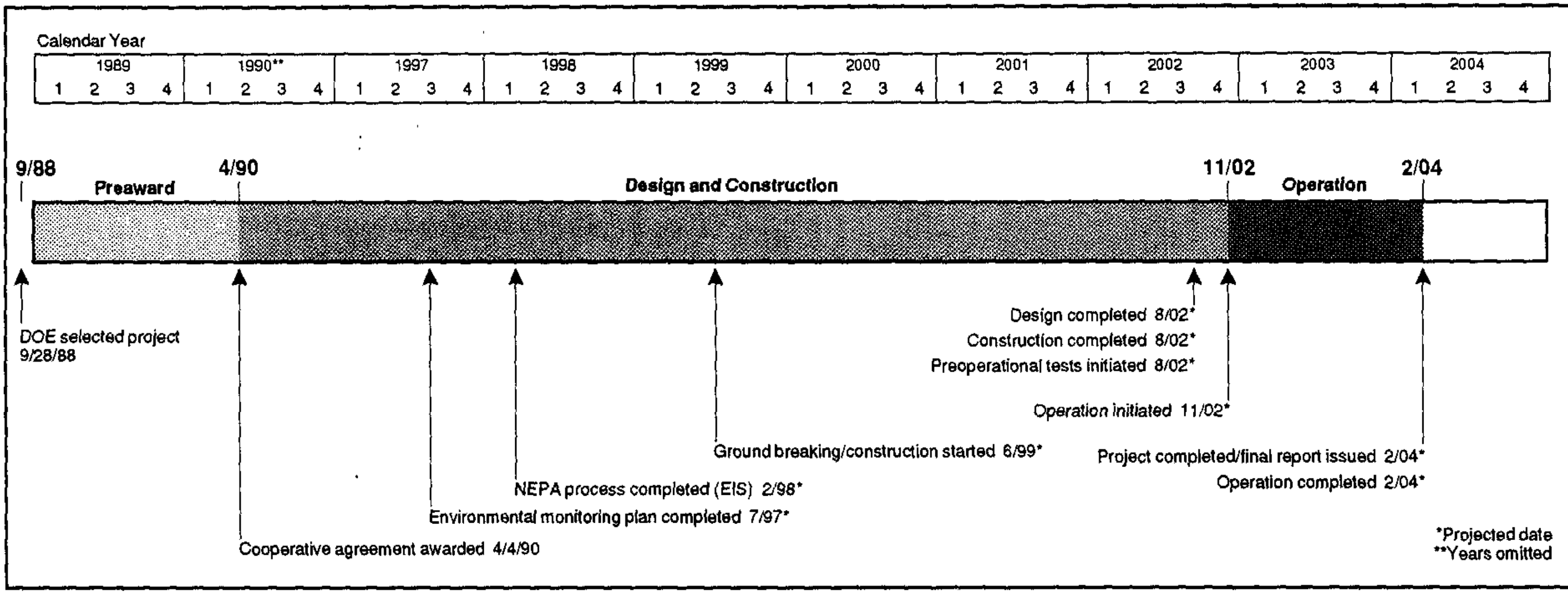
Technology/Project Description:

This project will be a greenfield facility located adjacent to the existing Mountaineer and Sporn plants. The most noticeable aspect of the unit is that the boiler, cyclones, reinjection vessel, and associated hardware are encapsulated in a pressure vessel 60 ft in diameter and 100 ft high.

The project incorporates a bubbling fluidized-bed process operating at 16 atm (235 lb/in^2 atm). Pressurized combustion air is supplied by the turbine compressor to fluidize the bed material (consisting of a coal-water fuel paste, coal ash, and a dolomite or limestone sorbent). Dolomite or limestone in the bed reacts with sulfur to form calcium sulfate, a dry, granular bed-ash material, which is easily disposed of or used as a by-product. A low bed-temperature of 1,600 °F limits NO_x formation.

The hot combustion gases exit the bed vessel with entrained ash particles, 98% of which are removed when the gases pass through cyclones. An option being considered is to employ some advanced filtration devices in the design. The cleaned gases are then expanded through a 75-MWe gas turbine.

The reheat system turbine operates at a state-of-the-art pressure and temperature to produce at least 250 MWe. Superheated steam will be produced from pressurized boiler-feed water in the tubes submerged in the fluidized bed. The projected heat rate for this unit is 8,500 Btu/kWh (40.2% efficiency based on HHV). SO_2 emissions are expected to be reduced by 95% and NO_x emissions by 80%.



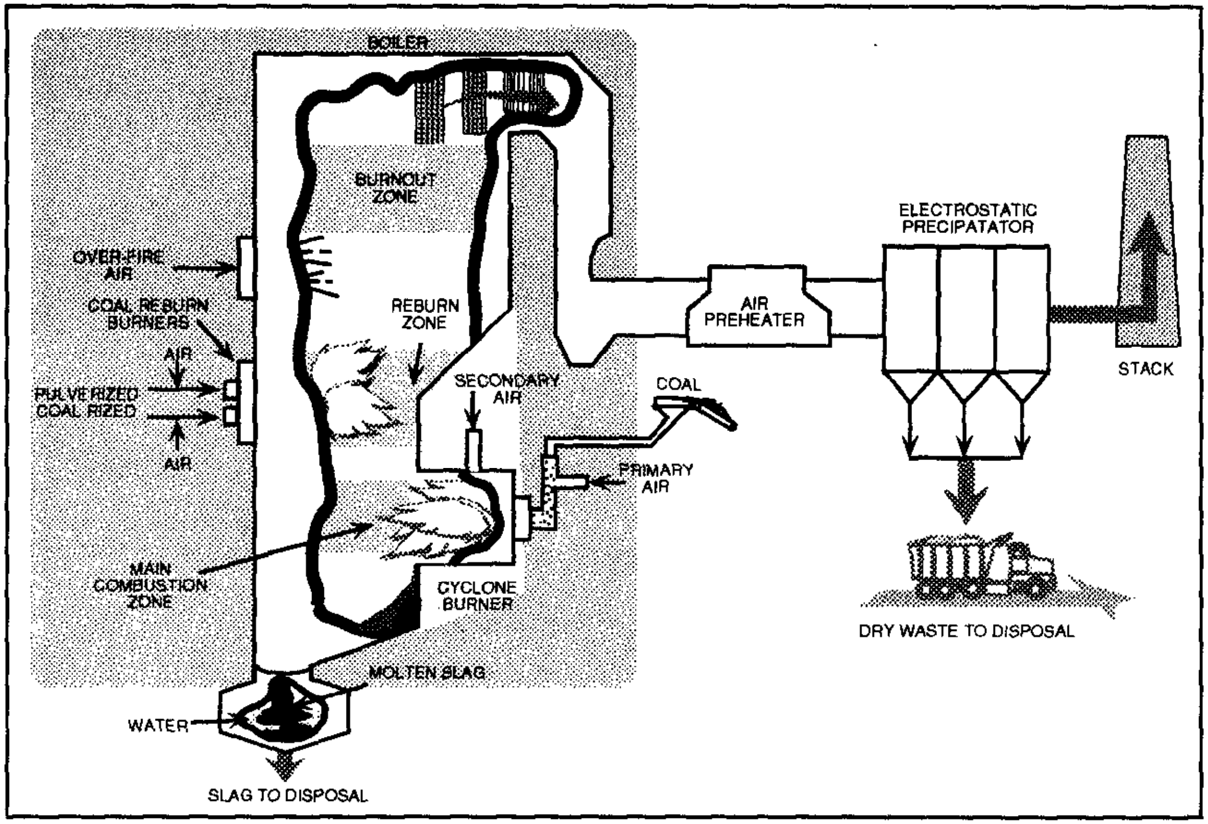
Project Status/Accomplishments:
During 1992, DOE approved restructuring and continuation of the project. Value engineering and preliminary design efforts are under way. The aim is to reduce the technical and economic risks of the project during the time before the utility's load growth warrants construction of the new power plant. The Babcock & Wilcox Company, the technology vendor, is conducting the value engineering efforts, including optimization of scaleup parameters, improved sulfur capture, and capital cost reductions.

Commercial Applications:
This project will be the initial version of a commercial plant. Combined-cycle PFBC systems permit the combustion of a wide range of coals, including high-sulfur coals. This technology will compete with circulating PFBC systems to repower or replace conventional power plants with a technology capable of using high-sulfur coals in an environmentally sound manner.

PFBC technology appears to be best suited for a wide range of applications beginning at the 50-MWe size. Because of modular construction capability, PFBC generating plants permit utilities to add economical increments of capacity to match load growth and/or to easily repower existing plants using available coal- and waste-handling equipment, and existing steam turbines. Another advantage for repowering is the compactness of the process because of pressurized operation.

The projected net heat rate for the commercial plant will be 8,500 Btu/kWh (based on HHV) which equates to an efficiency of 40.2%. An advanced cycle that integrates a small gasifier could yield heat rates approaching 7,500 Btu/kWh (45% efficiency). Environmental attributes include in-situ sulfur reduction of 95% and NO_x emissions reduction to 0.1 lb/million Btu. Although the system may generate a slight increase of solid waste as compared to conventional systems, the dry material is either disposable or potentially usable.

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 Illinois, Department of Energy and Natural Resources—cofunder
Utility companies (14 cyclone boiler operators)—cofunders

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

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

Plant Capacity/Production:
100 MWe

Project Funding:

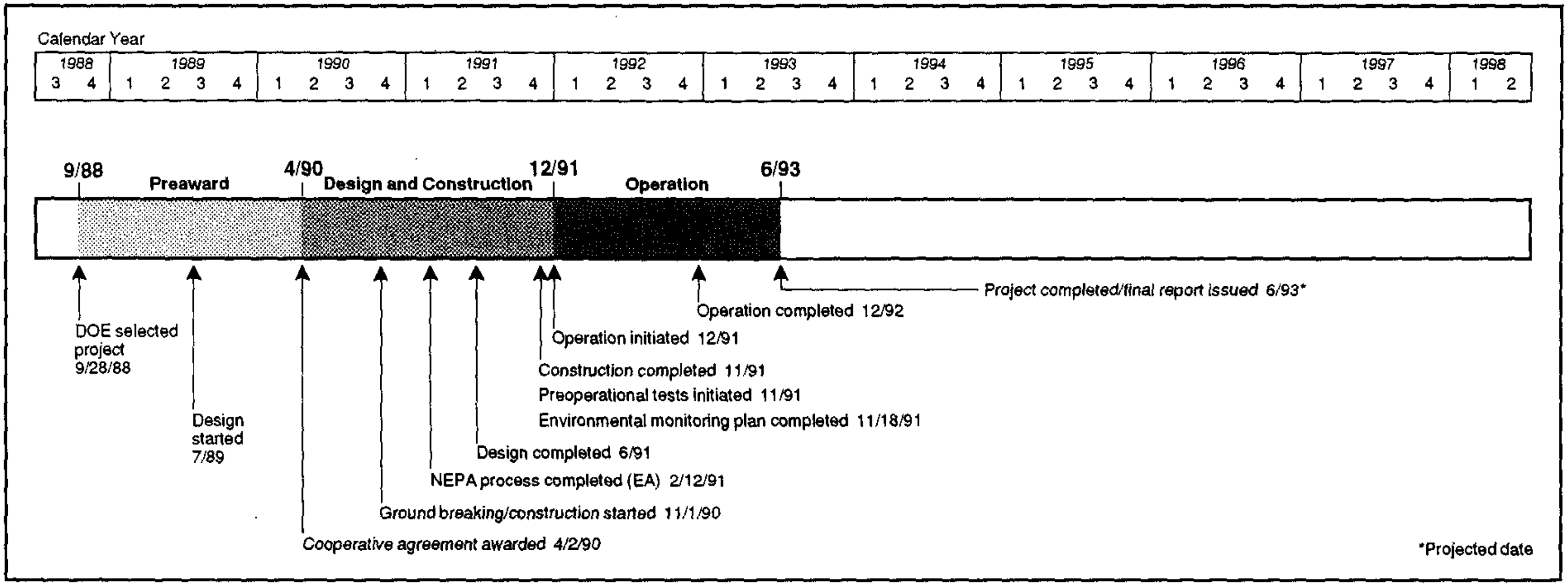
Total project cost	$13,071,559	100%
DOE	6,213,929	48
Participants	6,857,630	52

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 combined production of boiler slag and dry waste from the electrostatic precipitator remains unchanged with coal reburning because the required coal input for the same boiler load is constant.

The coal reburning technology can be applied with the cyclone burners operating within their normal, noncorrosive, 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. The coal specified for testing is Lamar coal from Indiana. It is bituminous coal with about 1.8% sulfur. Low-Btu, low-sulfur western coal is also being tested.

Project Status/Accomplishments:

Operational testing began in December 1991 and continued through 1992. Results of testing in 1992 indicated that NO_x emissions were reduced by about 55% between 110 MWe (full load) and 70 MWe. From 70 MWe to 40 MWe, the NO_x reductions ranged from 50% to 35%. Long-range testing was completed in early October 1992, followed by a 3-week outage on the boiler. Air toxics emissions monitoring was conducted in November 1992. Reburn testing of western coal as well as all testing scheduled for the Nelson Dewey Station was completed in December 1992.

Commercial Applications:

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

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

Coal reburning has economic advantages. Although capital costs for coal handling and preparation are higher than for other fuels, the overall cost differential favors coal. Coal's cost differential and dependability of supply give it the long-run advantage. Another advantage of the reburn system is its ability to utilize different coals.

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
Minnesota Mining and Manufacturing Company cofunder and filter bag supplier

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

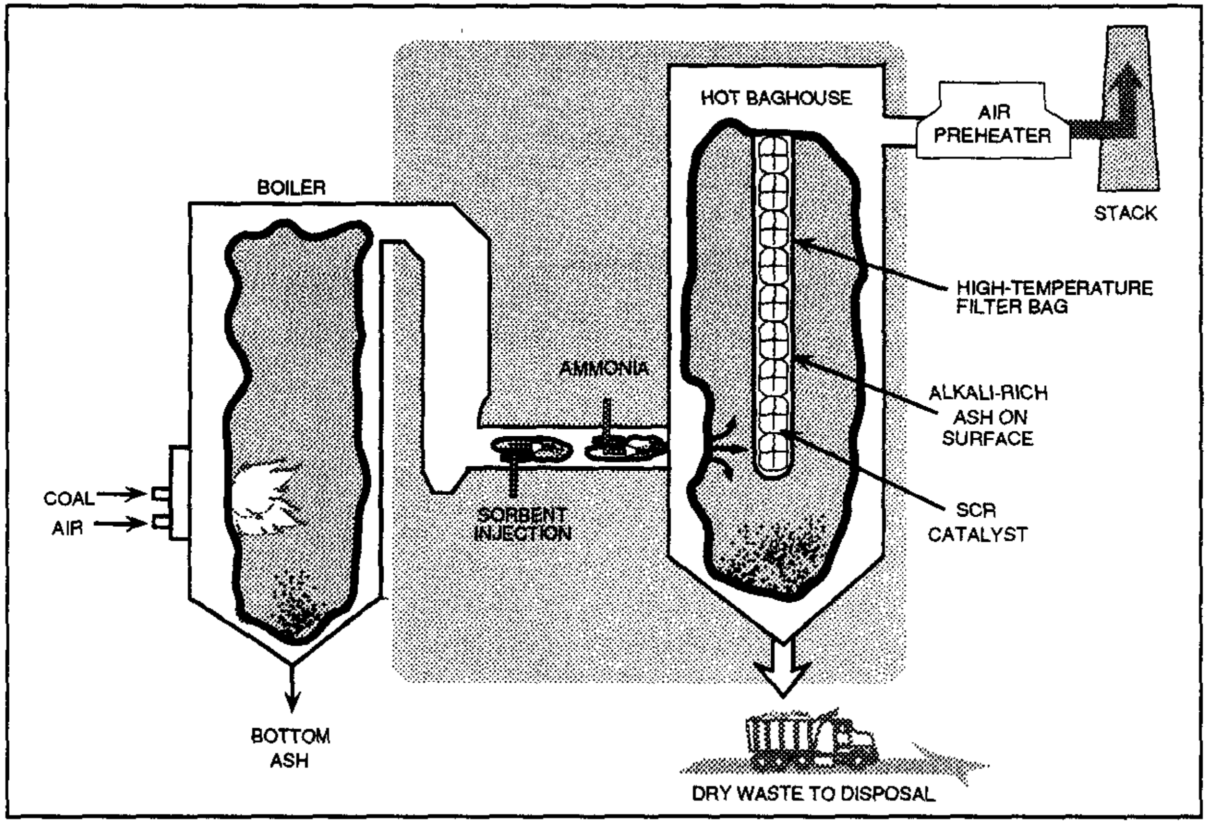
Technology:
The Babcock & Wilcox Company's SOX-NOX-ROX box (SNRB) process

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

Project Funding:

Total project cost	$13,327,277	100%
DOE	6,094,057	46
Participants	7,233,220	54

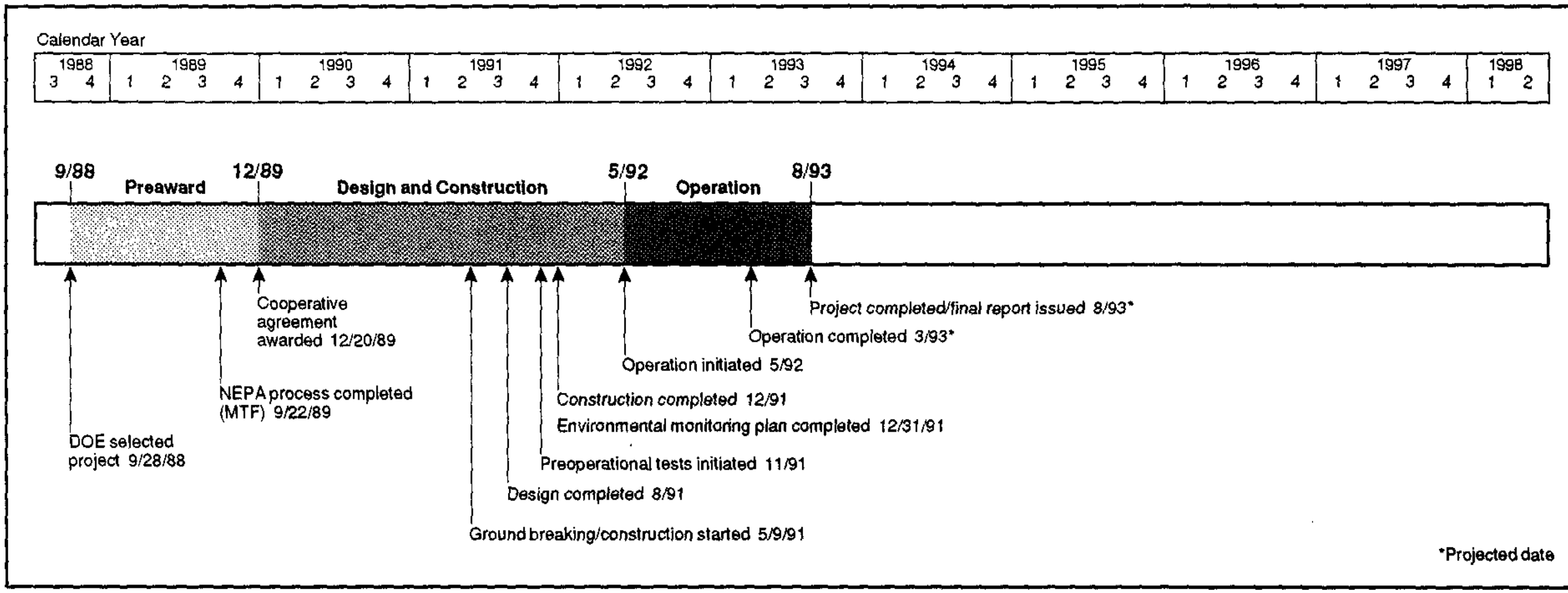
Project Objective:
To demonstrate that the SOX-NOX-ROX box process, used in retrofitting a high-sulfur-coal-fired power plant, can remove high levels of all three pollutants using a single processing unit for treating flue gas, thereby lessening on-site space requirements and capital costs.



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

The 5-MWe SNRB demonstration unit is large enough to demonstrate commercial-scale components while minimizing the demonstration cost. Additionally, at this scale, the flue gas temperature can be readily 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 greater than 70% SO_2 removal, up to 90% NO_x removal, and 99% particulate removal at lower capital, operating, and maintenance costs than a combination of conventional systems. The demonstration will be conducted at Ohio Edison Company's R.E. Burger Plant, Unit No. 5, in Dilles Bottom, OH. Bituminous coal with an average sulfur content of 3.4% is being burned at this site.



Project Status/Accomplishments:

Operations and testing of the unit on the 5-MWe equivalent slipstream at the R.E. Burger Plant began in May 1992. Emission control performance has exceeded project goals. SO_2 reduction has reached 85% at a calcium-to-sulfur ratio of 2.0:1 and 850 °F baghouse temperature. NO_x emissions have been reduced by greater than 90% with ammonia slip less than 10 ppm. Particulate emissions are consistently less than 0.03 lb/million Btu. Approximately 2,600 hours of testing have been completed at the R.E. Burger Plant. Testing is expected to be completed in March 1993.

Approximately 3,800 hours of testing and three types of fabric filters have been accumulated at the Fabric Durability Test Facility in Colorado Springs. This testing was completed in December 1992.

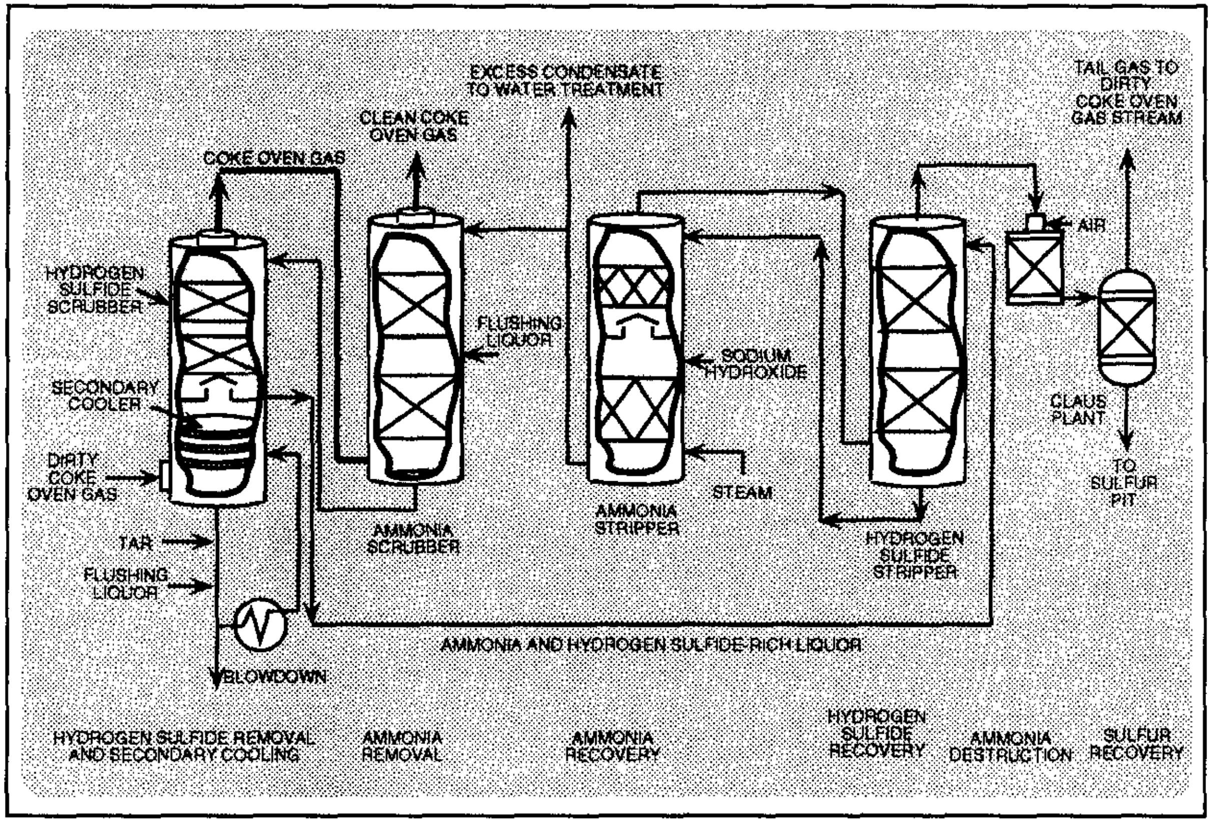
An air toxics emissions test program has been finalized by the participant and is scheduled to be completed in February 1993.

Commercial Applications:

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

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

Innovative Coke Oven Gas Cleaning System for Retrofit Applications



Sponsor:
Bethlehem Steel Corporation

Additional Team Member:
Still-Otto—technology developer

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

Technology:
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:

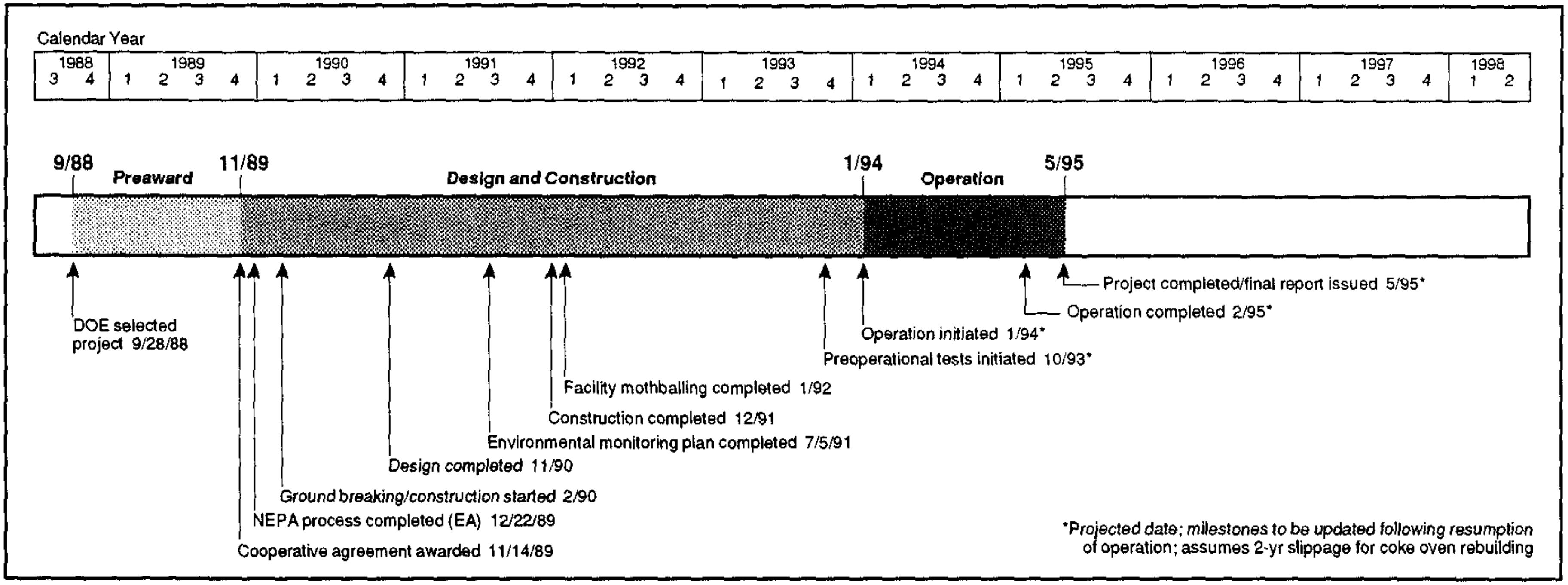
Total project cost	$45,239,781	100%
DOE	13,500,000	30
Participant	31,739,781	70

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 emissions of volatile organic compounds and discharge of ammonia to wastewater treatment.

Technology/Project Description:
This project is demonstrating an innovative technology developed by Still-Otto for removing hydrogen sulfide and ammonia 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; hydrogen sulfide is converted to elemental sulfur in a conventional Claus plant, and sulfur is recovered as a salable by-product.

The technology is expected to reduce the hydrogen sulfide concentration in the cleaned COG by 88% 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 is processing the entire COG stream from Coke Oven Batteries A, 11, and 12, which amounts to 74 million std ft^3/day. These coke oven batteries produce up to 1.2 million tons/yr of coke from a blend of Pennsylvania and Virginia coals having sulfur contents ranging from 0.8% to 1.37%. The raw COG has a hydrogen sulfide content of 175–340 grains/100 ft^3. Currently, only 60% of this COG stream is desulfurized. The remaining 40% is used directly for under-firing the coke ovens.



Project Status/Accomplishments:

On September 16, 1991, Bethlehem Steel Corporation announced that all coke production will be suspended at its Sparrows Point facility for at least 2 years. This decision was made due to the rapid deterioration of the coke ovens. During this period, an evaluation will be made to explore alternatives for resumption of coke production. Bethlehem Steel's intent is for long-term coke independence at the facility.

Construction of the coke oven gas cleaning demonstration facility is complete, and the unit has been mothballed to maintain it in good shape so that hot commissioning, start-up, and operation can be accomplished successfully when coke-making operations are resumed.

Given the high background levels of contaminants present in the coke oven batteries, specific air toxics monitoring is not contemplated at this time. Baseline environmental sampling is complete.

Commercial Applications:

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 (a commercial size), the project will demonstrate that it is possible to retrofit any existing coke-making facility in the United States with essentially no scaleup involved and without significant downtime.

Bethlehem Steel will license the use of this COG-cleaning technology through Still-Otto to the existing 30 coke oven plants in the United States which emit about 300,000 tons/yr of SO_2. This COG-cleaning process could be applicable to 24 plants with corresponding SO_2 emission levels of 200,000 tons/yr. If the technology were installed in all 24 plants, the SO_2 emissions could be reduced by 160,000 tons/yr. Eliminated would be the ammonium sulfate which is difficult to market and usually is disposed of as a solid waste. 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.

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 Company's coal-fired cement kiln)

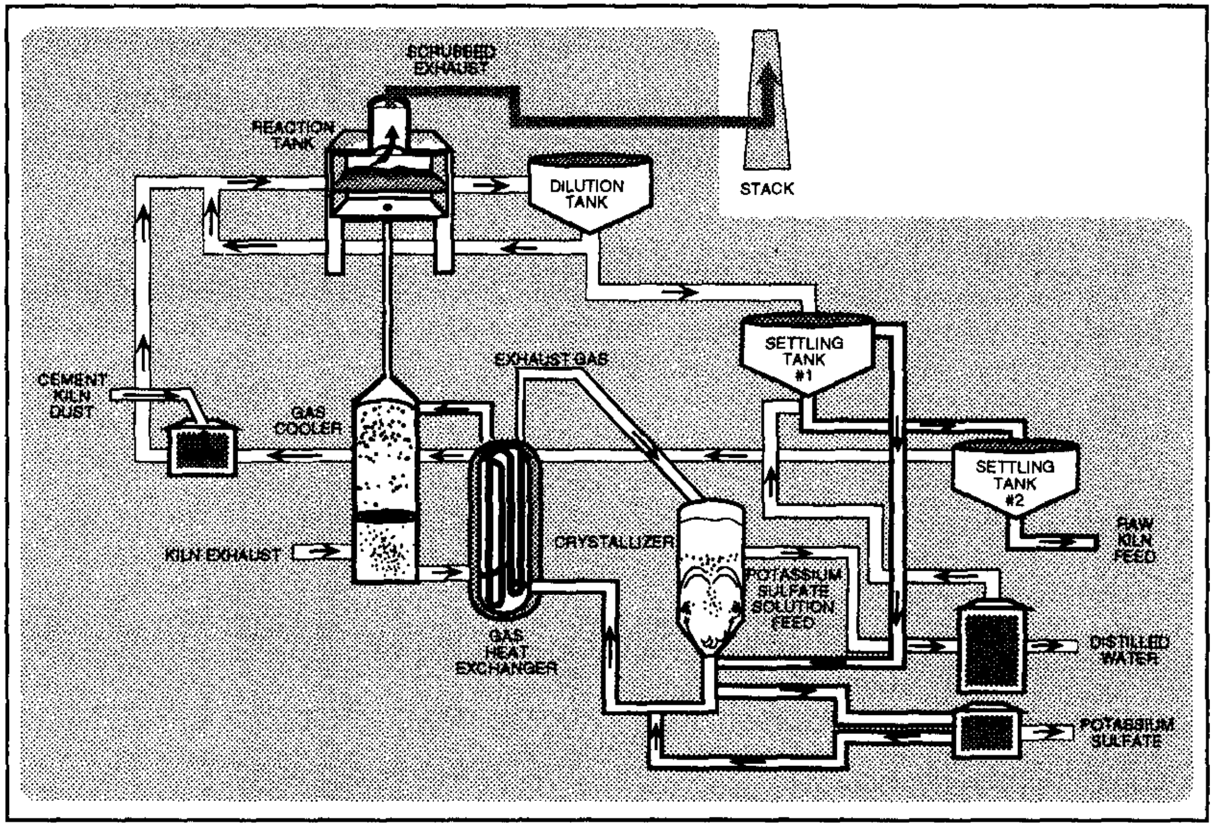
Technology:
Passamaquoddy Tribe's cement kiln flue gas recovery scrubber

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	$16,500,000	100%
DOE	5,982,592	36
Participants	10,517,408	64

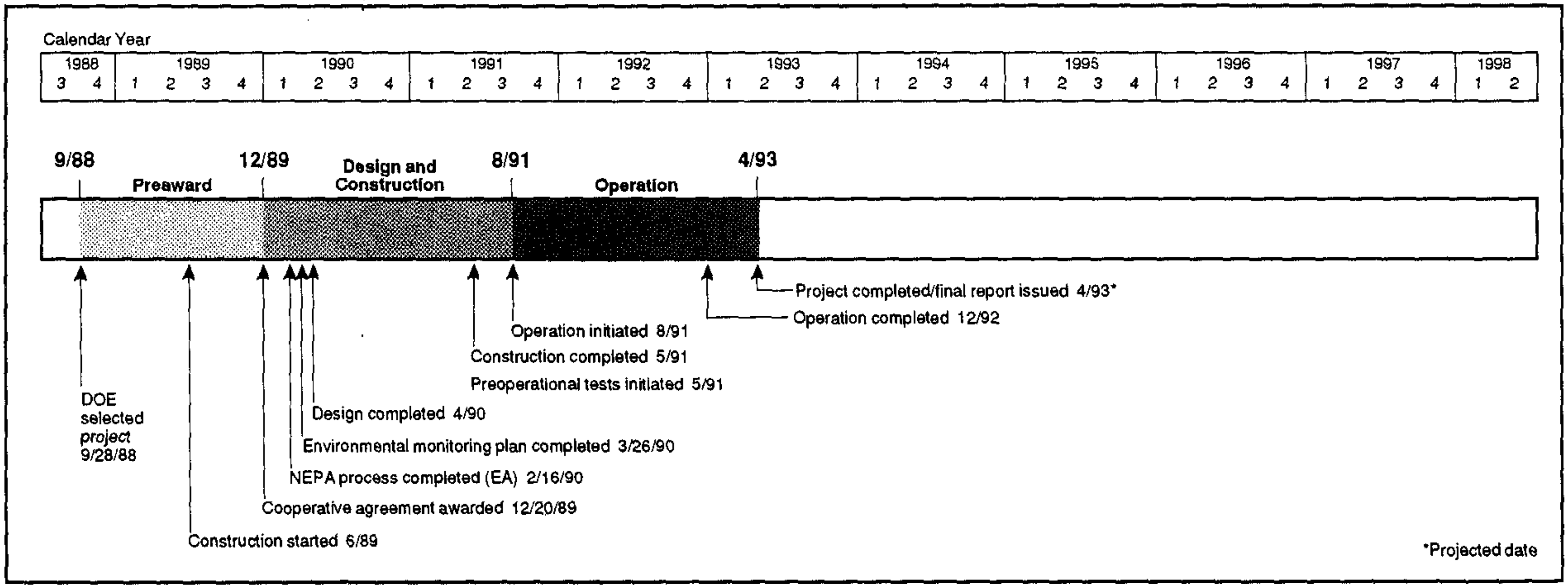
Project Objective:
To retrofit and demonstrate a full-scale industrial scrubber and waste recovery system for a coal-burning wet process cement kiln using waste dust as the reagent to accomplish 90–95% SO_2 reduction using high-sulfur eastern coals and to produce a commercial by-product, potassium-based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

The kiln burns bituminous coal containing approximately 3% sulfur.



Project Status/Accomplishments:

The recovery scrubber began operations in August 1991 and has continued operations with several temporary shutdowns for normal kiln repairs and maintenance and a more lengthy shutdown from January to May 1992 due to poor economic conditions in the area. In a 5-month period from May to September 1992, the plant produced approximately 140,000 tons of cement while the scrubber removed 70 tons of SO_2 and treated 6,000 tons of kiln dust for return to the kiln as raw feed. Initial testing of the scrubbing system achieved the project objective of 90–95% SO_2 emission reduction, with a maximum reduction of 98%. Project operations continued through December 1992 when the scrubber became a permanent part of the Dragon facility. The final report is expected at the end of April 1993.

Commercial Applications:

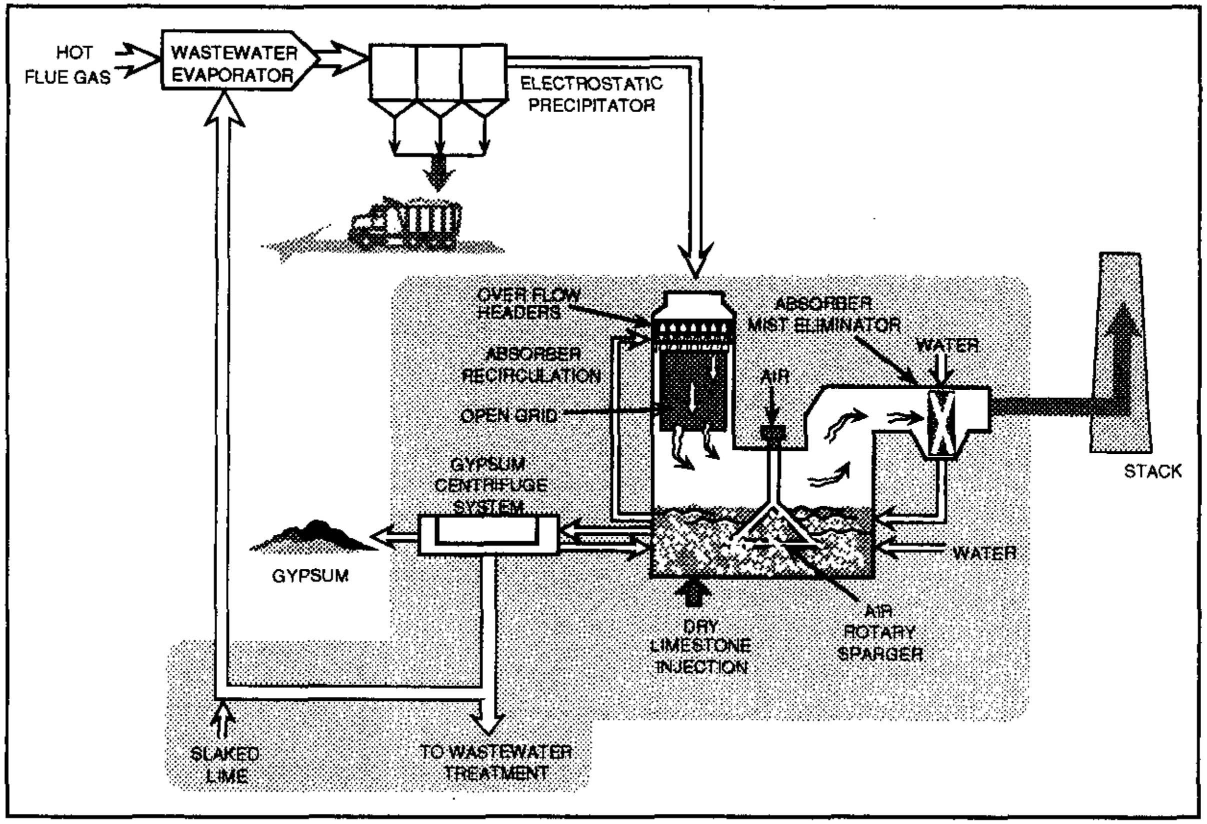
The recovery scrubber permits the use of high-sulfur coal in cement kilns using available waste dust as the reagent, without requiring the purchase of other materials as scrubber reactant.

There are over 250 cement kiln installations in the United States and along the St. Lawrence River in Canada emitting approximately 230,000 tons/yr of 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.

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

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



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)

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.

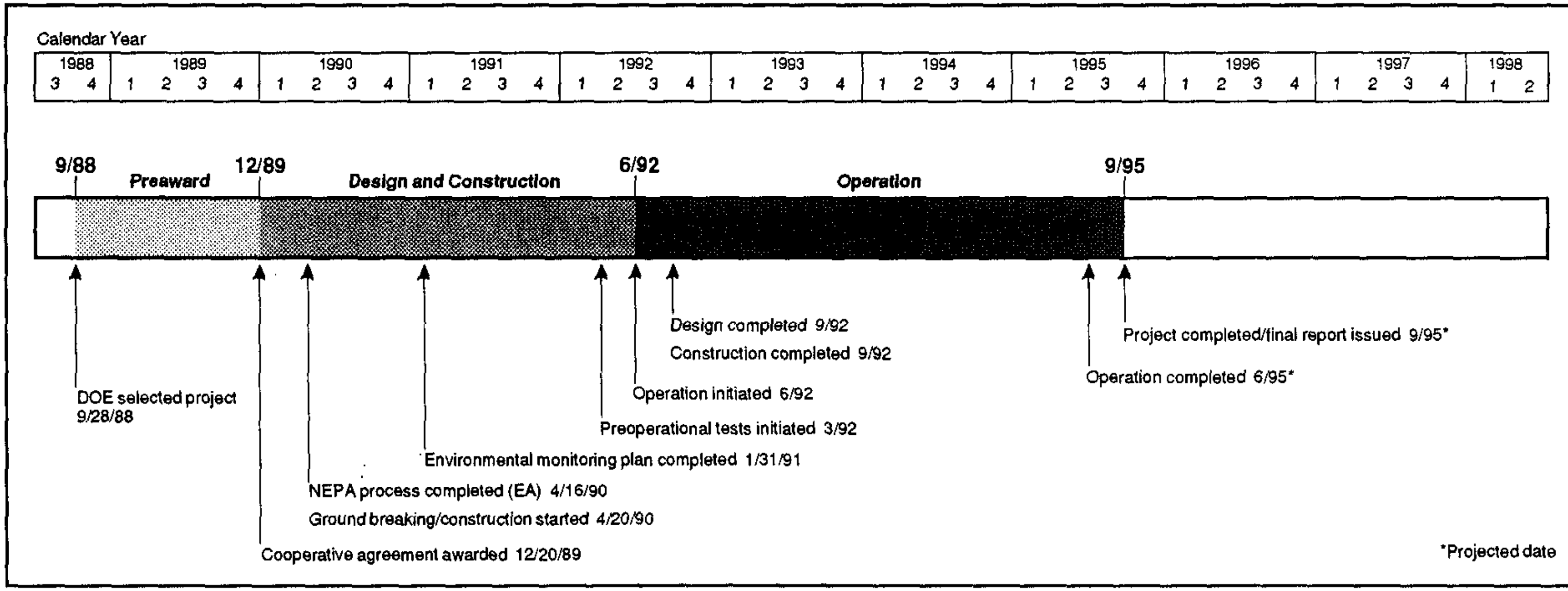
Technology/Project Description:

In this project, Pure Air has built a single SO_2 absorber for a 528-MWe power plant. Although this is the largest capacity absorber module in the United States, it has relatively modest space requirements because no spare or backup absorber modules are required. The absorber performs three functions in a single vessel: prequencher, absorber, and oxidation of sludge to gypsum. Additionally, the absorber is of a 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 has demonstrated simultaneous removal of 90–95% or more of the SO_2 while providing a commercial gypsum by-product and is demonstrating wastewater evaporation.

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 Public Service Company's 528-MWe Bailly Generating Station near Chesterton, IN.

Project Status/Accomplishments:

Design is complete. To confirm process design, pilot testing was performed in 1990, successfully meeting both SO_2 removal and gypsum purity levels using U.S. high-sulfur coal and limestone feedstocks. A long-term performance test was conducted in 1991 to verify operational parameters for the air rotary sparger; it, too, was successful.

Construction was completed ahead of schedule, despite the occurrence of a ground subsidence event at the Bailly station on July 2, 1991. The AFGD facility began operations in June 1992. By year end, operations had gone well; SO_2 removals in excess of 95% and average by-product gypsum purities of 96–97% had been achieved. Tests on the utility's standard coal (3–3.5% sulfur) were completed.

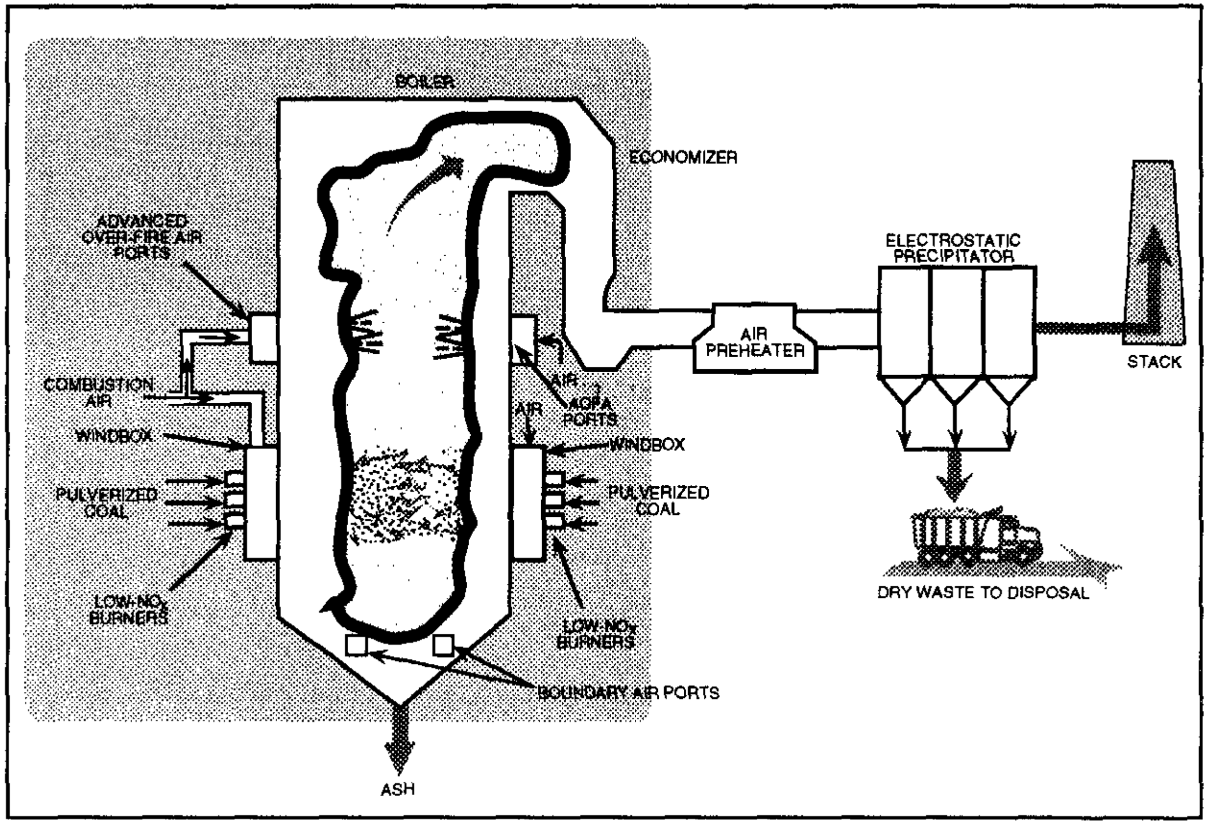
Commercial Applications:

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

The AFGD facility will reduce SO_2 emissions at the Bailly Station by approximately 50,000 tons/yr. Further, the gypsum by-product and wastewater evaporation will demonstrate that SO_2 control can occur without increased solid waste or wastewater production.

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

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 Company's Plant Hammond, Unit No. 4)

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	$14,710,909	100%
DOE	6,553,526	45
Participants	8,157,383	55

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

Project Objective:

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

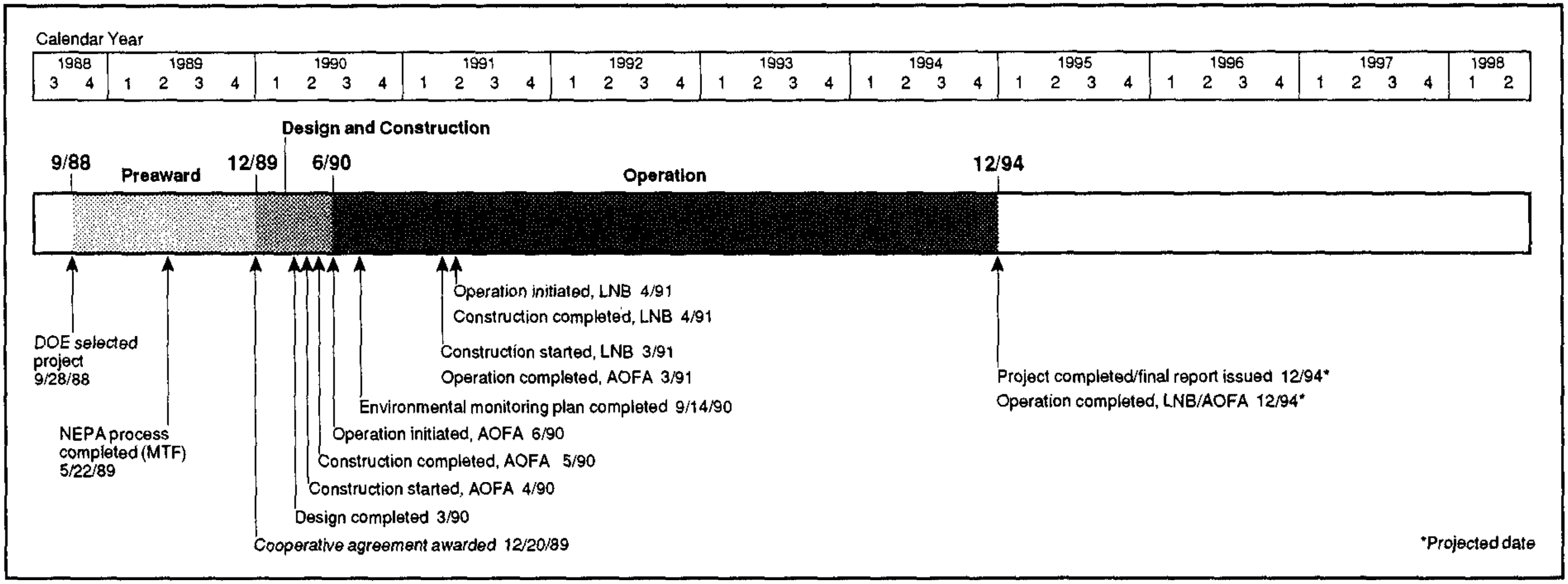
Technology/Project Description:

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

Based on earlier experience, the use of AOFA in conjunction with LNB can reduce NO_x emissions by as much as 60% compared with conventional burners.

The demonstration is located at the Georgia Power Company's Plant Hammond, Unit No. 4. The boiler is a nominal 500-MWe pulverized coal, wall-fired unit, which is representative of most of the existing pre-NSPS wall-fired utility boilers in the United States.



Project Status/Accomplishments:

Analysis of more than 80 days of AOFA operating data has provided statistically reliable results indicating that, depending upon load, NO_x reductions of 24% are achievable under normal long-term operation.

Preliminary data analysis for both short-parametric and long-term LNB operation tests indicates NO_x reductions of 48% are achievable under full-load conditions.

For both AOFA and LNB, preliminary analysis indicated significant increases of flyash loss on ignition values as compared to the baseline values. Results also show that post-LNB retrofit precipitator particulate mass loading and gas flow rates are substantially above baseline values.

Combined LNB/AOFA tests began in late-1992 and will continue into 1993. Delays in completion of planned testing have resulted from operating the test boiler at reduced loads to meet particulate compliance limits. A variance is being sought from the State of Georgia to allow completion of the planned tests.

New work has been added to the test schedule, including installation and testing of an advanced LNB digital control system that has the potential to optimize LNB/AOFA performance. Completion of the final analysis of project data and issuance of the final report are scheduled for December 1994.

Pre-retrofit LNB air toxics testing was performed to establish a baseline. Additional air toxics testing with the combined LNB/AOFA configuration is planned for early 1993.

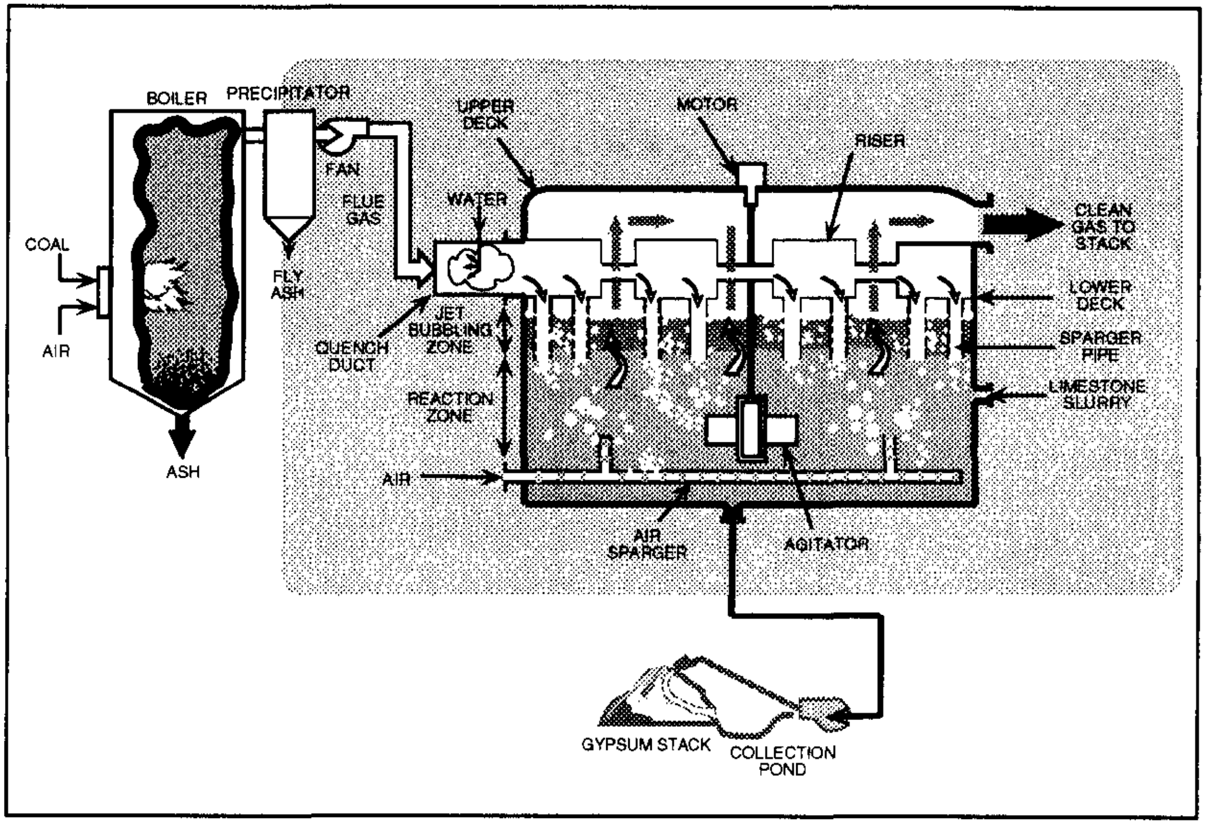
Commercial Applications:

The technology is applicable, in the United States, for retrofitting the 422 existing pre-NSPS wall-fired boilers, which burn a variety of coals, including bituminous, subbituminous, and lignite coal.

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)

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:

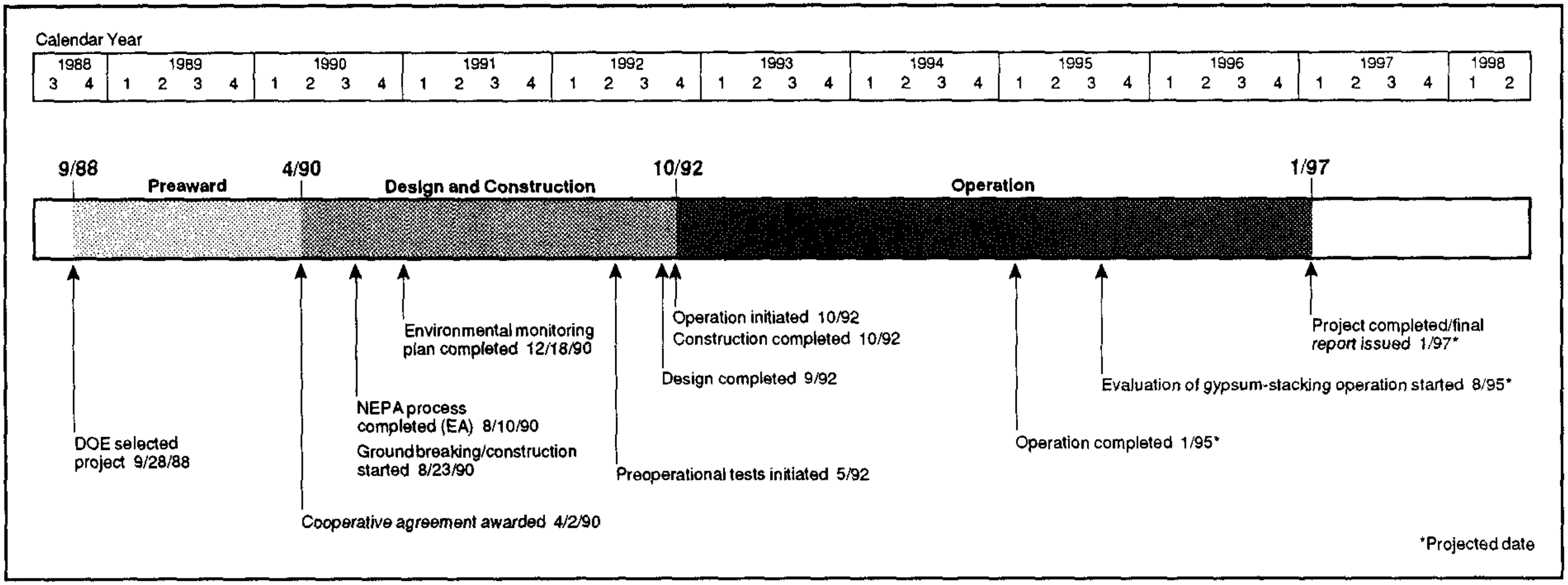
The project is demonstrating the CT-121 FGD process, which uses a unique absorber design known as the jet-bubbling reactor (JBR). The process combines limestone FGD reaction, forced oxidation, and gypsum crystallization in one process vessel. The process is mechanically and chemically simpler than conventional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

The flue gas enters 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 to form gypsum. The slurry is dewatered in a gypsum stack, which involves filling a dyked area with gypsum slurry. Gypsum solids settle in the dyked area, and clear water flows to a retention pond. The clear water from the pond is returned to the process.

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

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

The site is Georgia Power Company's 100-MWe Plant Yates, Unit No. 1, near Newnan, GA.



Project Status/Accomplishments:
Construction was completed in October 1992, and all system components were turned over to the plant for operations. All requests by the Georgia Environmental Protection Division and the Georgia Geological Survey have been fulfilled, and the permit for the waste disposal area was issued. Operations started at the end of October following a 1-week outage.

Initial experience has been very good, with almost no off-line time attributable to the scrubber. At inlet SO_2 levels of about 2,000 ppm, the CT-121 system removes over 90% of the SO_2 at all loads and conditions at expected pH and pressure drop with 100% limestone utilization. Continuous emission monitors and the flow monitors were calibrated and certified in November, and the data reduction system is currently compiling data every 15 seconds on over 140 data points.

The calcium sulfate produced has been placed in a Hypalon-lined gypsum "stacking" area for the development of an above-ground gypsum stack similar to those found in the phosphate fertilizer industry. Preliminary observations show no evidence of acidic "rain out" from the fiberglass-reinforced plastic scrubber chimney, indicating that the static flow control modifications in the chimney elbow are working as expected. Testing for parametric values and for particulate loadings will begin in early 1993.

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

Specific features of this technology that will enhance its potential for commercialization follow: (1) fiberglass construction can be used, eliminating the need for rubber-lined carbon steel or costly alloys; (2) no spare absorber is required because the system is at least 98% reliable; (3) reheating of the flue gas is not necessary; (4) both SO_2 and particulates are removed from flue gas; (5) more than 99% of the calcium in the limestone reagent is used; (6) the gypsum by-product can be stored safely and easily or used in commercial applications; (7) the CT-121 operating costs are the lowest for state-of-the-art FGD systems; (8) there is no known size limit for this technology; (9) utilities and industrial concerns could make immediate use of this technology; and (10) the system is not sensitive to the type of coal used or its sulfur content.

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

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

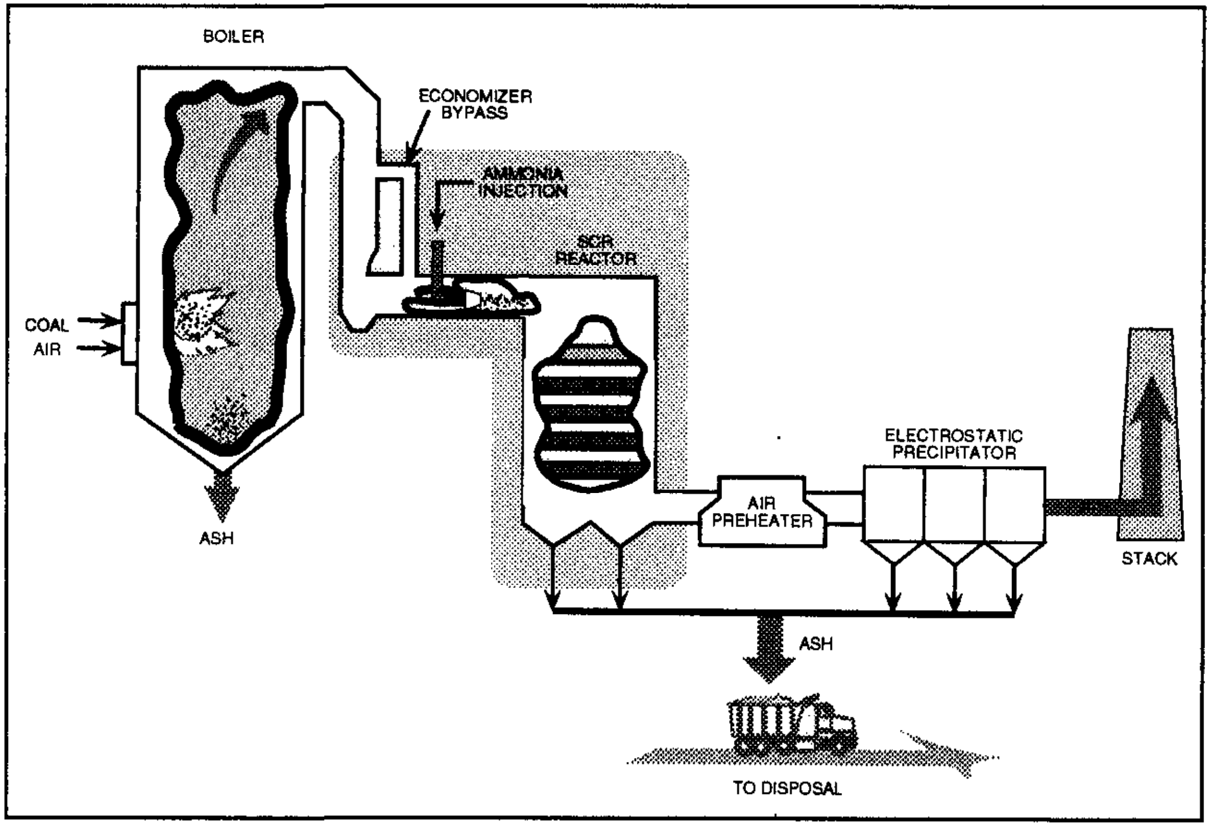
Technology:
Selective catalytic reduction (SCR)

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	$15,574,705	100%
DOE	7,525,338	48
Participants	8,049,367	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.

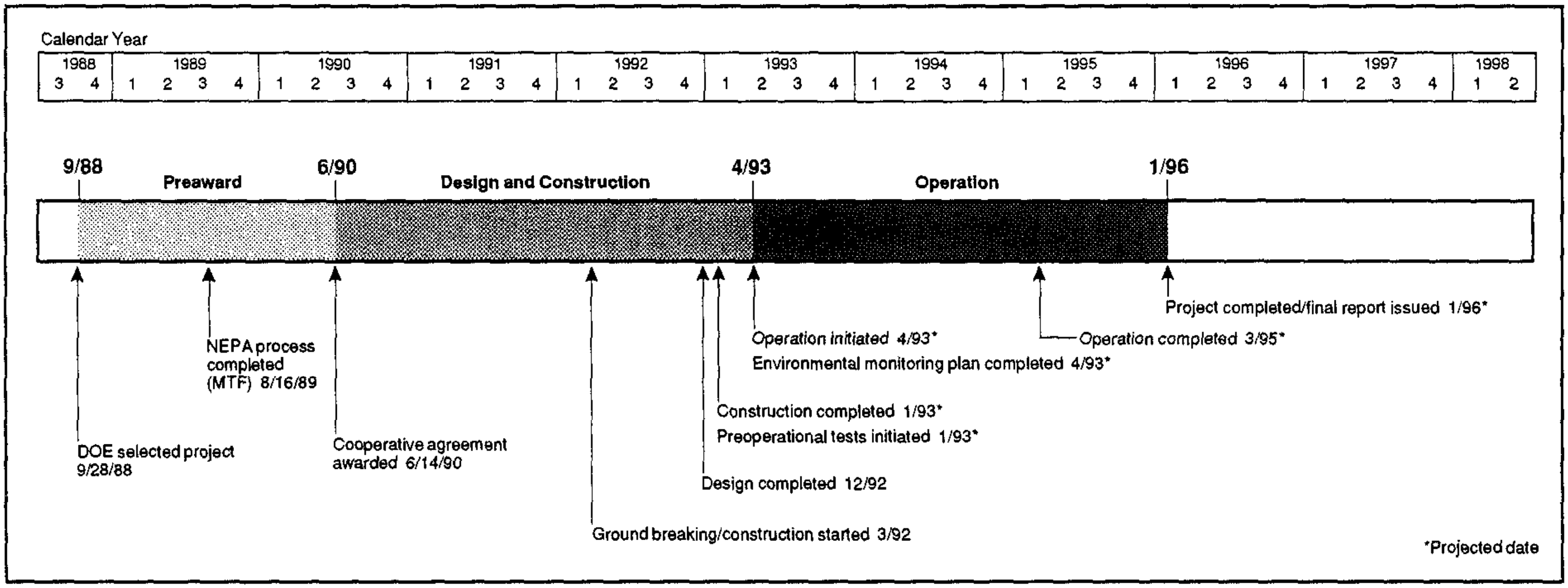


Technology/Project Description:
The SCR technology consists of injecting ammonia into boiler flue gas and passing it through a catalyst bed where the NO_x and ammonia react to form nitrogen and water vapor.

In this demonstration project, the SCR facility consists of three 2.5-MWe SCR reactors, supplied by separate 5,000 std ft^3/min flue gas slipstreams, 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 the burning of principally Illinois No. 5 coal with approximately 3% sulfur under various NO_x and particulate levels.



Project Status/Accomplishments:

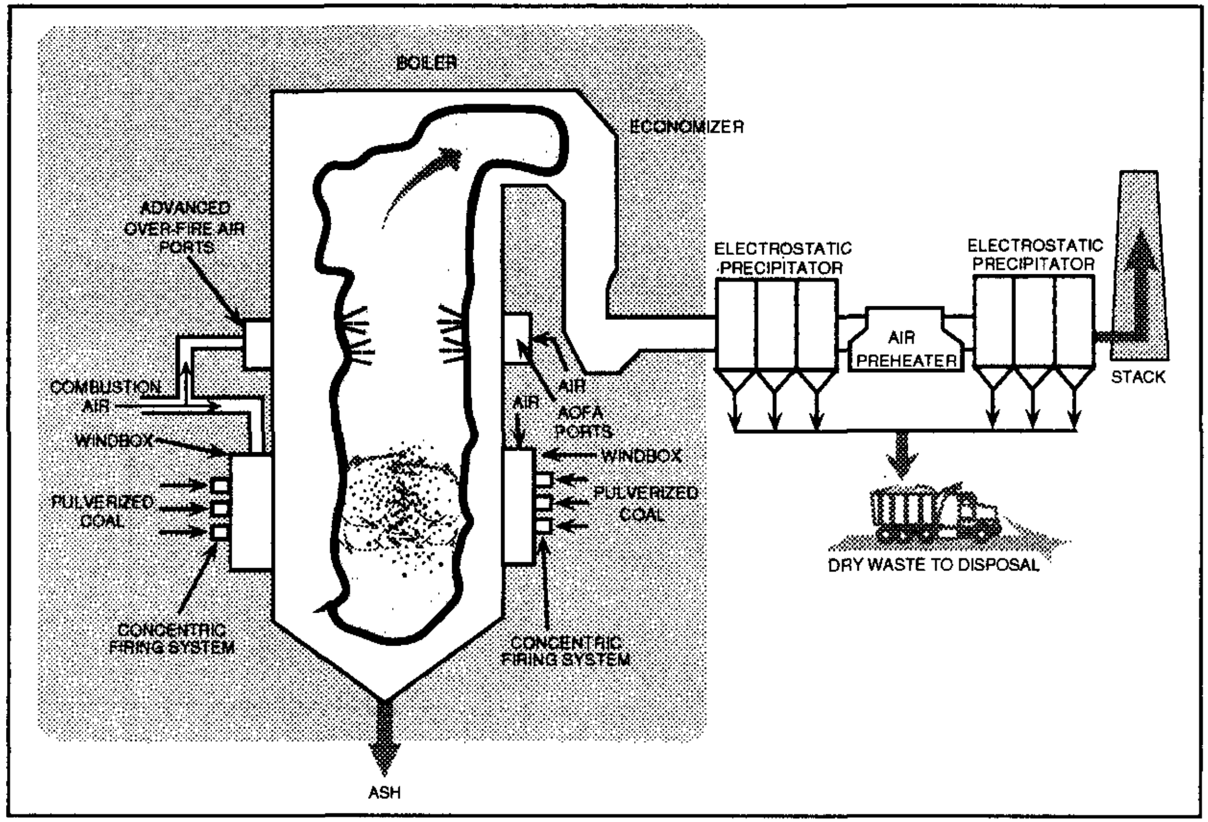
Follow-up work on the environmental monitoring plan was completed in late-1992. Detailed engineering, construction, and start-up are under way. Detail design engineering is over 90% complete. Major subsystems (including the air preheaters, gas/air fans, venturis, distributed control/data acquisition system, electrical system, bypass heat exchangers, cyclones, flue gas/air electric heaters, gas analyzing system, and ammonia storage system) have been specified and ordered, and a majority of the equipment has been delivered to the site for installation. The SCR reactor design and fabrication have been completed, and the reactors have been delivered to the site. Construction began at the end of March 1992. All of the major construction contracts have been awarded. Foundations, structural steel fabrication, and structural steel erection have been completed. Practically all of the major process equipment has been installed. Construction of the control room and installation of ductwork, piping, insulation, electrical cables and switchgears are nearly finished. Start-up is scheduled for January 1993, with long-term operation expected to begin in April 1993.

Catalyst suppliers have provided detailed information of laboratory reactor design and operations, and a common laboratory testing protocol has been established. The contract for the required testing and analytical services has been awarded.

Commercial Applications:

SCR technology can be applied to existing and new utility applications for removal of NO_x from flue gas for virtually any size boiler. There are approximately 1,041 coal-fired utility boilers in active commercial service in the United States; these boilers represent a total generating capacity of 296,000 MWe. Assuming that SCR technology is installed on dry-bottom boilers that are not equipped with low-NO_x combustion technologies (i.e., low-NO_x burners, 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 from 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.—cofunder and technology supplier

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

Technology:
ABB Combustion Engineering's low-NO_x concentric firing system (LNCFS) with advanced over-fire air (AOFA), clustered coal nozzles, and offset air

Plant Capacity/Production:
180 MWe

Project Funding:

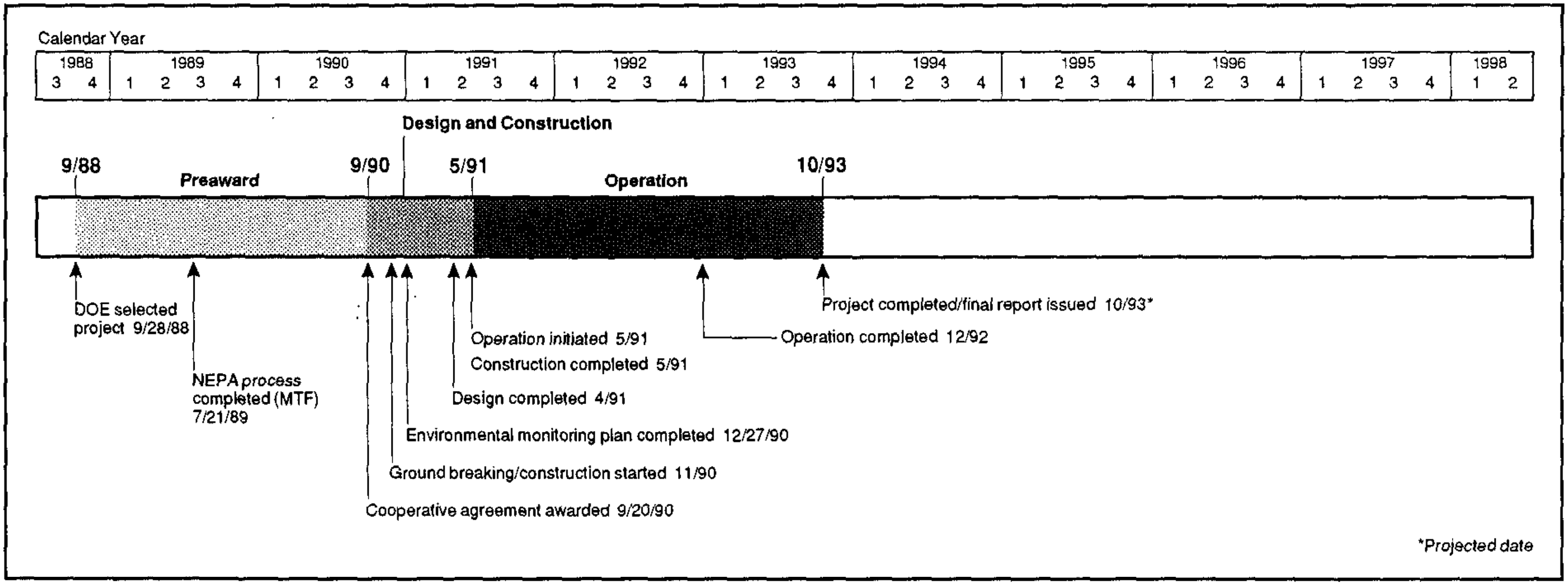
Total project cost	$9,024,765	100%
DOE	4,377,791	49
Participants	4,646,974	51

Project Objective:
To demonstrate in a stepwise fashion the short- and long-term NO_x reduction capabilities of low-NO_x concentric firing system (LNCFS) Levels I, II, and III on a single reference boiler under typical dynamic operating conditions, and evaluate the cost effectiveness of each low-NO_x combustion technique.

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

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

In addition to over-fire air, the LNCFS incorporates other NO_x reducing techniques into the combustion process. Using offset air, two concentric circular combustion regions are formed. The majority of the coal is contained in the fuel-rich inner region. This region is surrounded by a fuel-lean zone containing combustion



air. The size of this outer circle of combustion air can be varied using adjustable offset air nozzles. Separation of air and coal at the burner level further reduces production of NO_x.

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

Project Status/Accomplishments:

The LNCFS Level II tests were completed in September 1991, resulting in a maximum NO_x reduction of 40% at full load. The LNCFS Level II was converted to LNCFS Level III during a 2-week outage in November 1991 by installing close-couple over-fire air nozzles in the top of the main windbox. The LNCFS Level III testing, completed in April 1992, showed that NO_x emissions were reduced by a maximum of 48%; however, this decrease in NO_x emissions was accompanied by an increase in flyash carbon content. Finally, LNCFS Level I was evaluated by closing the separated over-fire air dampers of the Level III system. Testing of the Level I system, completed in December 1992, showed a maximum NO_x reduction of 38% at full load.

Testing to investigate the effects of low-NO_x combustion on the emissions of air toxics was also completed. A report is expected in 1993.

Commercial Applications:

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

Environmental benefits to be realized with these in-furnace emission control technologies are primarily based upon reducing NO_x emissions from fossil-fuel-fired power plants. Potential exists for annual NO_x emission reductions of 10%, depending on the unit load scenario and the tangentially fired NO_x control selected.

CCT-III
Project Fact Sheets

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

Sponsor:
Air Products and Chemicals, Inc.

Additional Team Members:
Acurex Environmental Corporation — fuel methanol testing and cofunder
Texaco Syngas Inc.—host site and cofunder
Dakota Gasification Company—technology consultant

Location:
Daggett, San Bernardino County, CA (Cool Water Gasification Facility; Texaco Syngas, Inc., negotiating purchase of site)

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

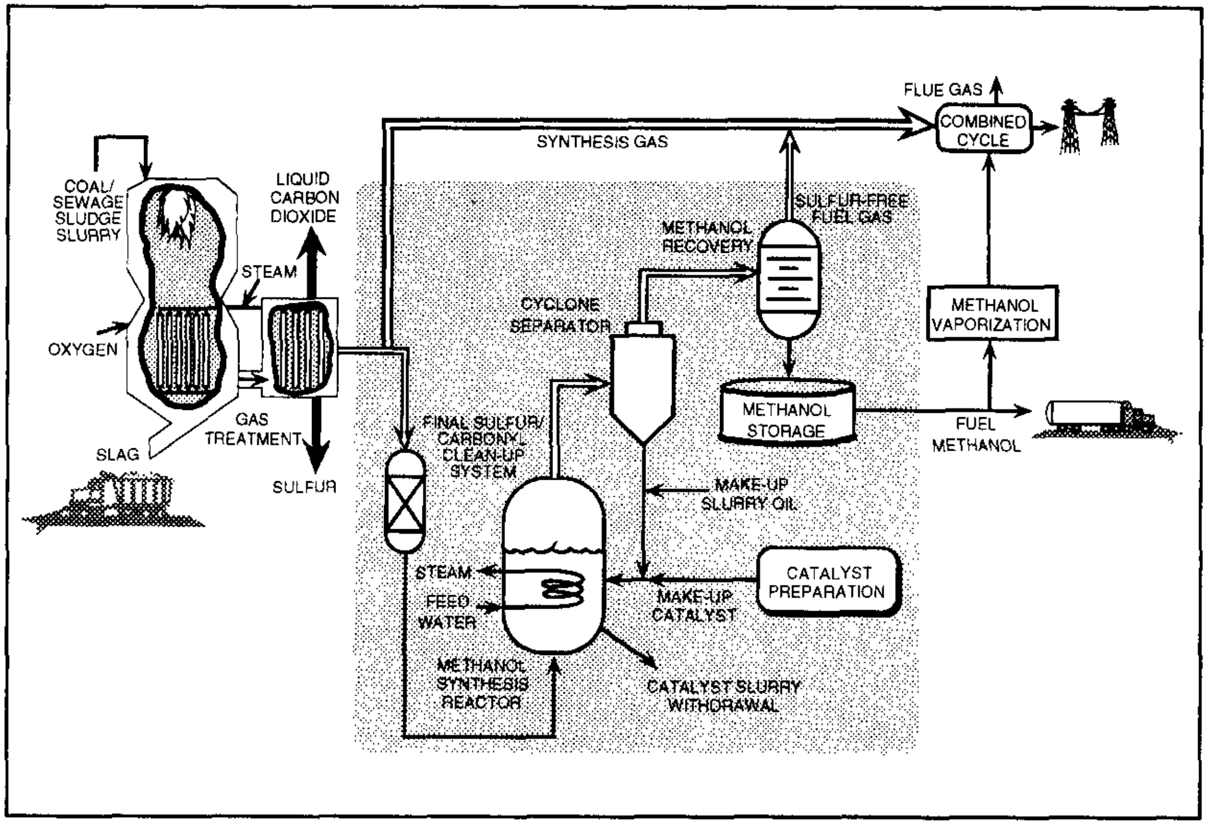
Plant Capacity/Production:
150 tons/day of methanol

Project Funding:

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

Project Objective:
To demonstrate on a commercial scale the production of methanol from coal-derived synthesis gas using the LPMEOH™ process; and to determine the suitability of methanol produced during this demonstration for use as a low-SO_x, low-NO_x alternative fuel in boiler, turbine, and transportation applications.

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

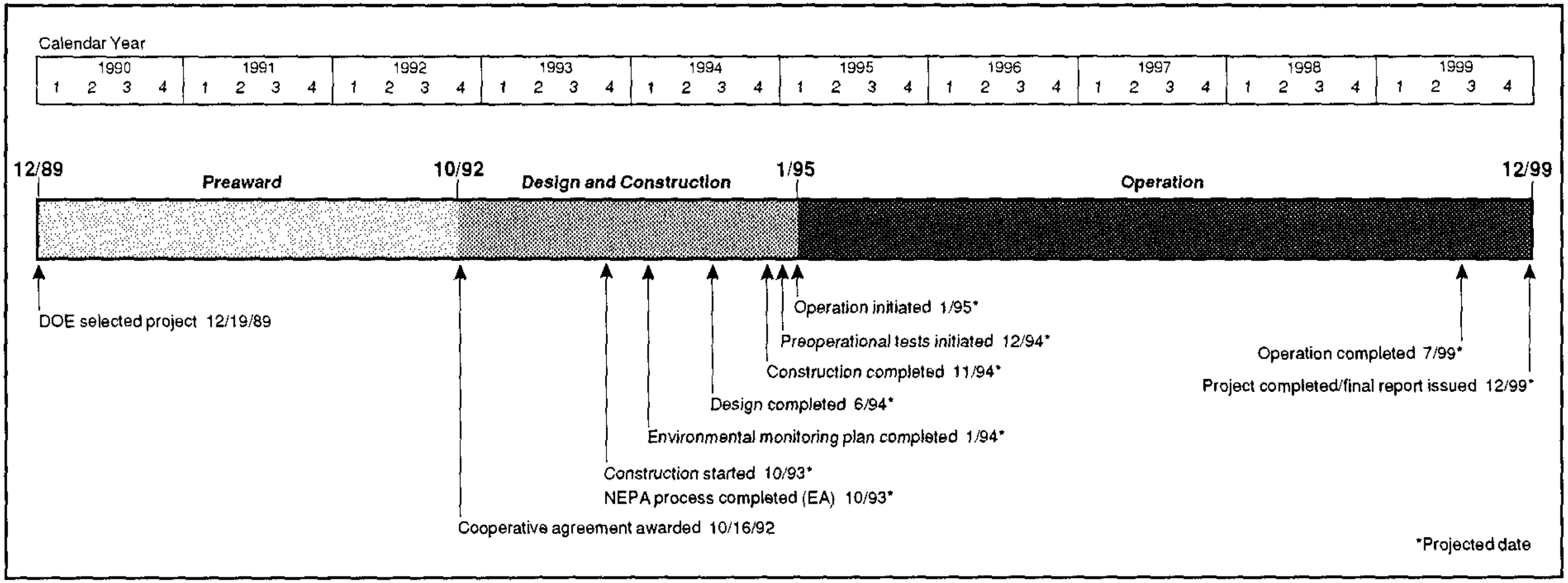


Technology/Project Description:
This project is demonstrating the LPMEOH™ process to produce methanol from coal-derived synthesis gas on a commercial scale. The combined reactor and heat removal system is different from other commercial methanol processes. The liquid phase not only supports the catalyst but functions as an efficient means to remove the heat of reaction away from the catalyst surface. This feature permits the direct use of synthesis gas streams 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 lb of methanol per 1 lb of catalyst
- Raw methanol purity—97.5%
- Feed gas flexibility—permits the use of synthesis gas produced by any commercial coal gasification system to be used without shift conversion

DOE also will receive data on the use of a combined feedstock of coal and sewage sludge. A western bituminous low-sulfur coal is to be used. However, Texaco's gasification process has been proven on a wide variety of coals and other feedstocks. The use of coal and sewage sludge represents a new solution to a significant environmental problem. Also the project



will demonstrate combined IGCC/LPMEOH™ operation to produce power and a liquid fuel in a load-following mode.

Project Status/Accomplishments:

DOE approved a site change to the Cool Water Gasification Facility located at Daggett, CA. Texaco Syngas, Inc., is negotiating to purchase the facility and plans to recommission it in 1995. A portion of the synthesis gas stream (up to 50%) will be diverted to a nominal 150-ton/day LPMEOH™ unit.

A cooperative agreement was awarded in October 1992. The participants are now developing the relevant environmental information needed for the NEPA process, obtaining the required permits, and initiating project definition activities, including the development of an environmental monitoring plan that incorporates an air toxics monitoring program.

Commercial Applications:

Methanol can be substituted for conventional fuels in stationary and mobile combustion applications. Methanol is an excellent peaking fuel. It contains no sulfur and has exceptionally low-NO_x characteristics when burned. Fuel methanol can be produced from coal as a co-product in an IGCC facility. Among the cleanest coal technologies for generating electric power, IGCC can economically satisfy the most stringent environmental limits for SO_2 and NO_x. About 99% of the sulfur can be removed in the manufacturing process and converted into salable elemental sulfur or sulfuric acid. Nitrogen compounds generated in the gasification process are easily removed by cleanup systems and may be recovered as salable ammonia for fertilizer manufacture. The solid waste from the gasifier is an inert, granular slag which can be used as an aggregate for road and building materials.

The LPMEOH™ process is an advanced methanol production technology which can lower the cost of electricity produced in IGCC electric power plants. A flexibility-enhancing add-on feature, the LPMEOH™ process produces methanol during off-peak periods for later use to provide a back-up and peaking fuel. Unique power production load-following flexibility not normally associated with coal-based electric power production plants is available using IGCC/LPMEOH™.

A variety of fuel products may be produced by the indirect liquefaction process. These may be used to supply fuels for a wide range of applications in the utility or industrial sector. The technology can be used in both new and retrofit applications.

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

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 National Center for Emissions Research)

Technology:

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

Plant Capacity/Production:

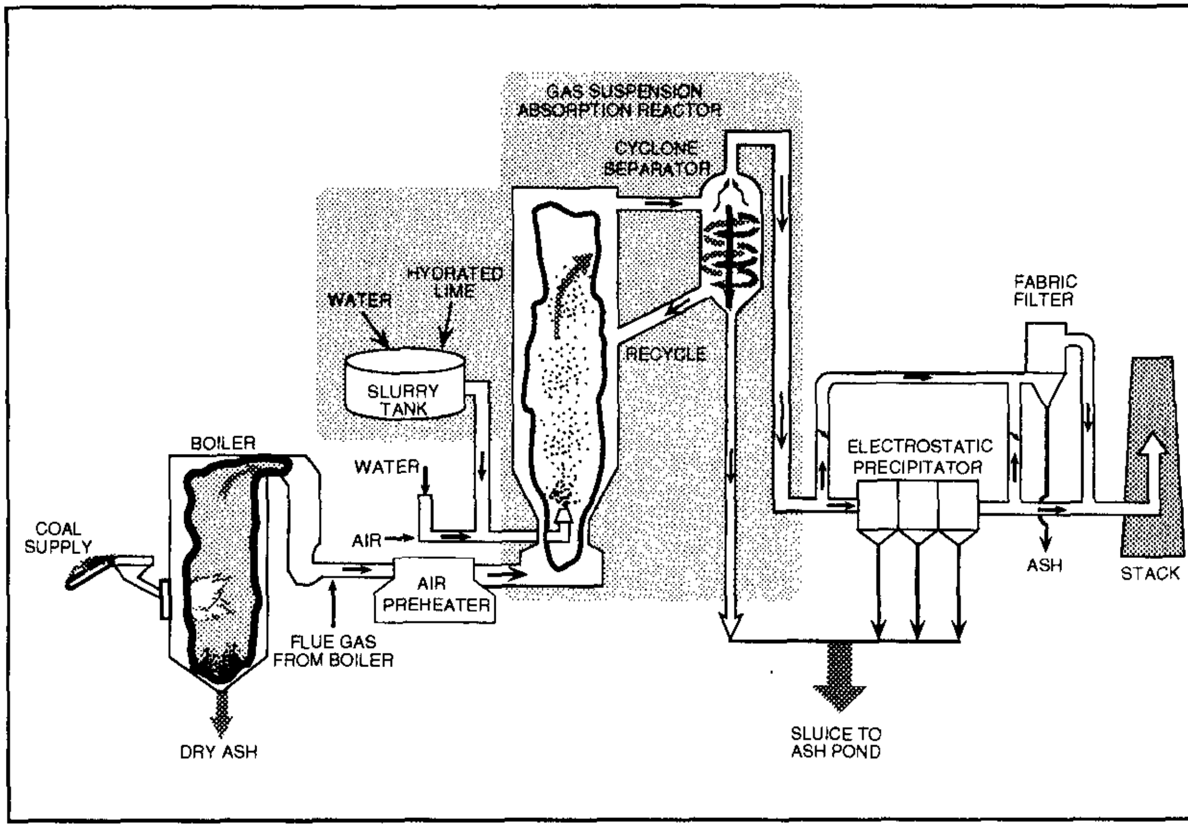
10-MWe equivalent slipstream of flue gas from a 150-MWe boiler

Project Funding:

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

Project Objective:

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



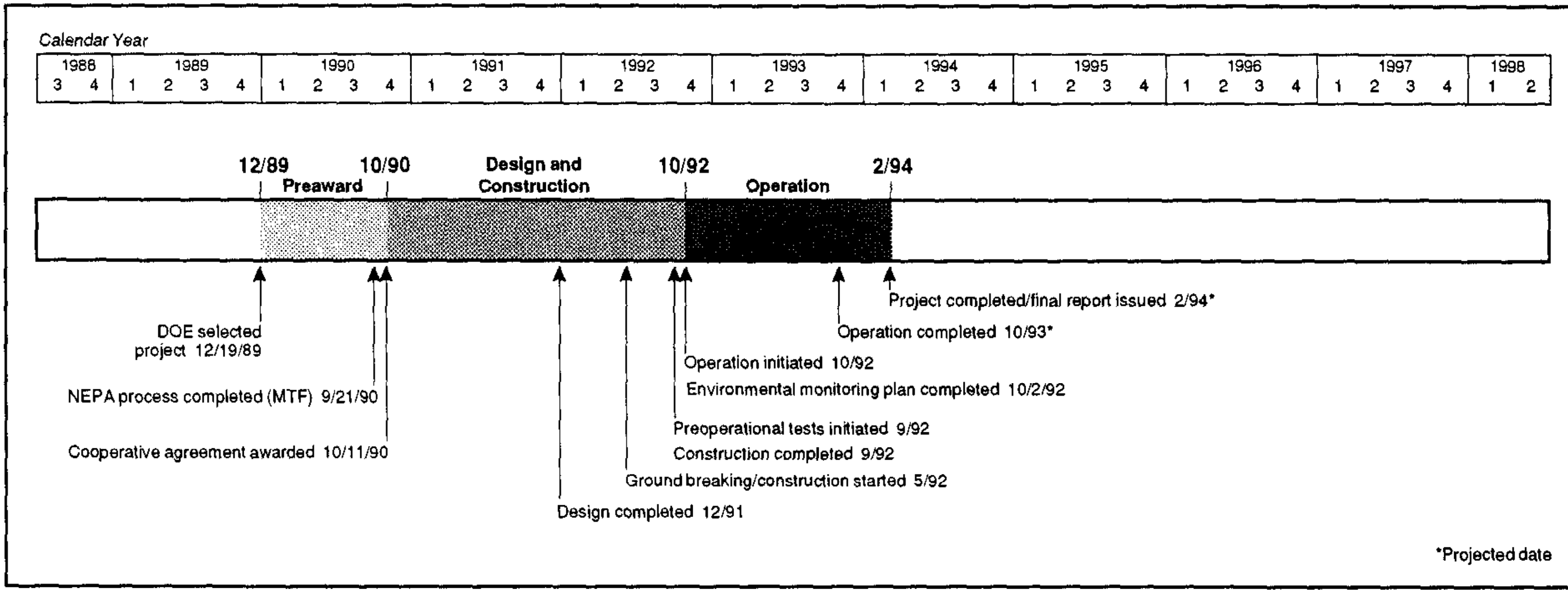
Technology/Project Description:

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

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

A western Kentucky coal with a sulfur content of about 3% is being used.

This project is located at the National Center for Emissions Research and is utilizing a 10-MWe slipstream of flue gas from a 150-MWe coal-fired boiler at the Tennessee Valley Authority's Shawnee Fossil Plant in West Paducah, KY.



Project Status/Accomplishments:

Engineering and design tasks were completed on time according to the revised project schedule incorporating the 1-year delay in obtaining the host site. The fabrication and construction effort was completed in August 1992, ahead of schedule. The GSA and associated equipment was checked out and ready for operation by the end of September 1992. The environmental monitoring plan was completed October 2, 1992.

AirPol began start-up of the GSA system in October 1992. The GSA will be operated and tested over 12 months. Also, the cooperative agreement was amended to add air toxics and 1-MWe fabric filter testing. Preliminary tests conducted to determine the GSA operating limits indicated that 99+% SO_2 removal can be achieved both with and without calcium chloride addition. The tests were conducted using 3% sulfur coal and 0.03% chloride. The project duration was extended 5 months to allow time for final reporting.

Commercial Applications:

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.

GSA is expected to find commercial acceptance because it is the only semi-dry 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.

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

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
TRW, Inc.—technology supplier
Joy Technologies, Inc.—technology supplier

Location:
Healy, Denali Borough, AK (greenfield site)

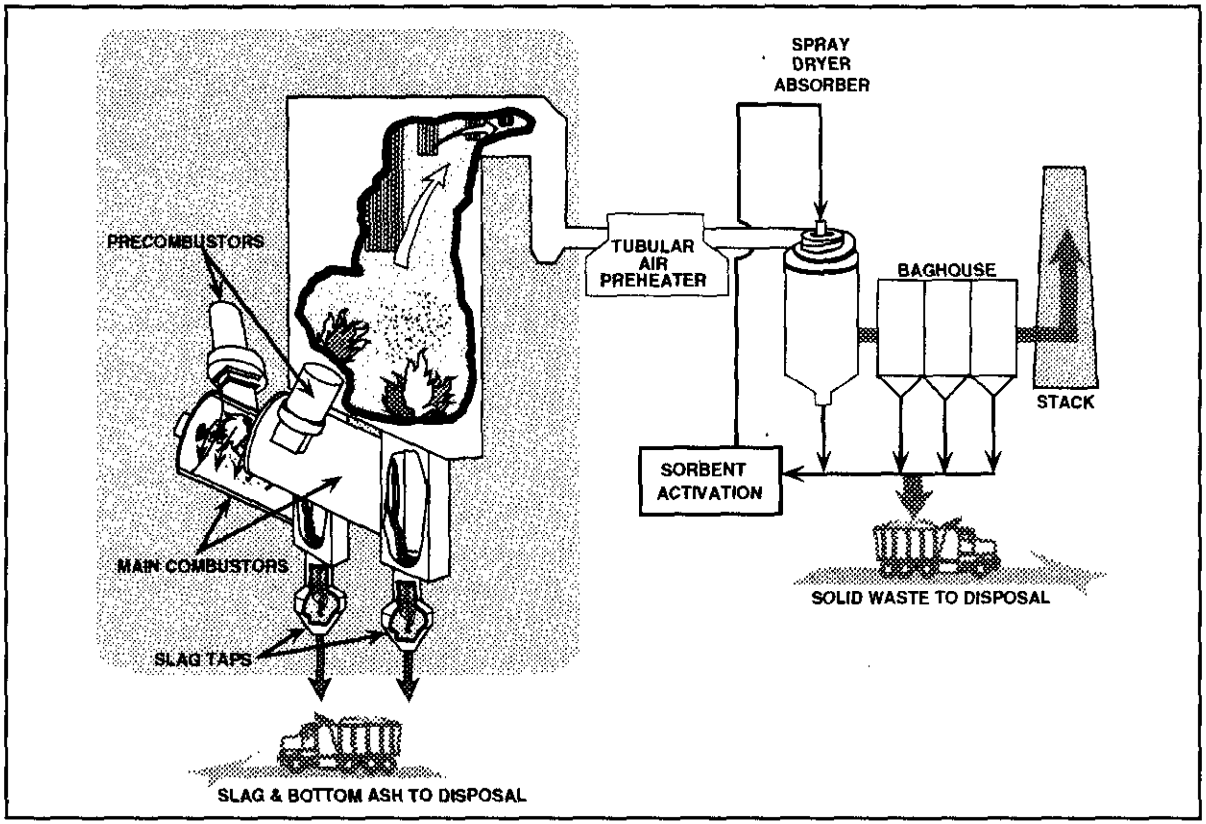
Technology:
TRW's advanced entrained (slagging) combustor
Joy Technologies' spray dryer absorber with sorbent recycle

Plant Capacity/Production:
50 MWe (nominal electric output)

Project Funding:

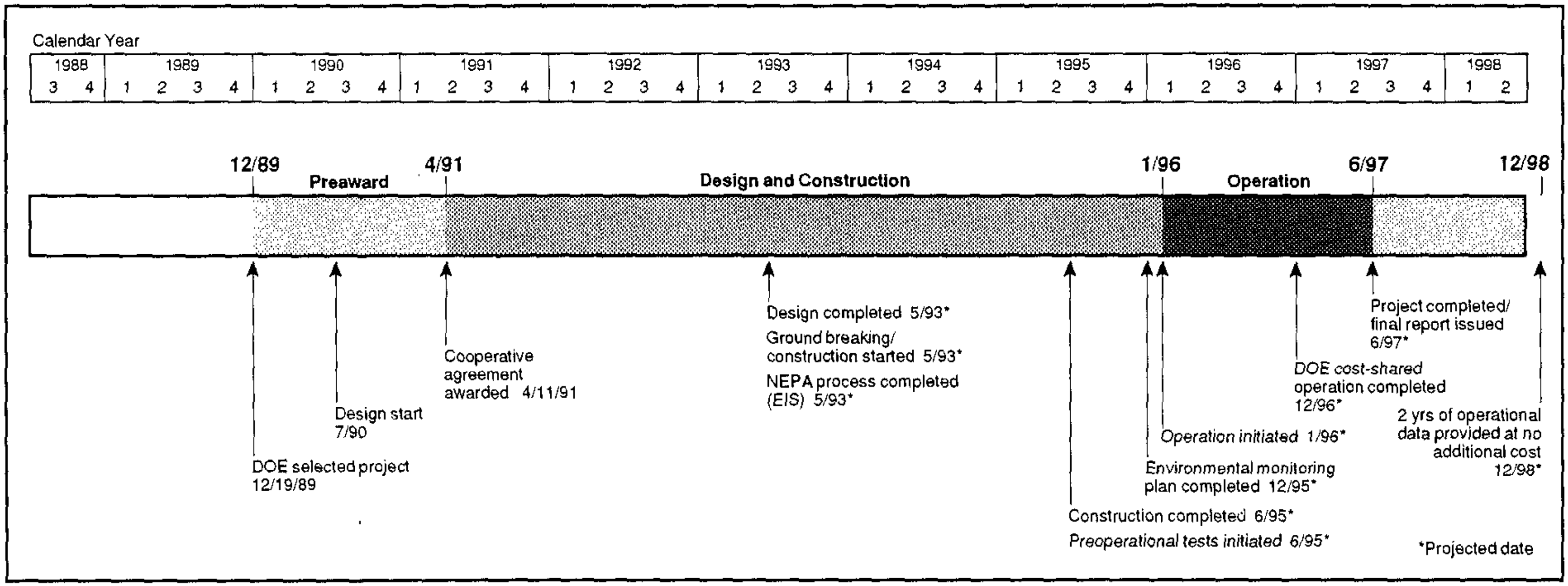
Total project cost	$215,000,000	100%
DOE	103,693,000	48
Participants	111,307,000	52

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



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

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



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

The project involves a greenfield site near Healy, AK. Power will go to the Golden Valley Electric Association. The plant will provide 3 years of data, with 2 years of data being provided at no cost to DOE.

Project Status/Accomplishments:

Test burns using Healy project fuel were completed at TRW's Cleveland facility. Joy/Niro testing of flash calcined sorbent was completed at the Copenhagen facility. A full-scale precombustor was constructed and test fired at TRW's Capistrano, CA, test facility to verify scaleup designs. The project is on schedule with approximately 60% of the design completed.

A draft EIS has been completed and public meetings were held in December 1992 to obtain comments.

Commercial Applications:

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

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 Company's J.M. Stuart Plant, Unit No. 4)

Technology:
The Babcock & Wilcox Company's Low-NO_x Cell™ burner (LNCB™) system

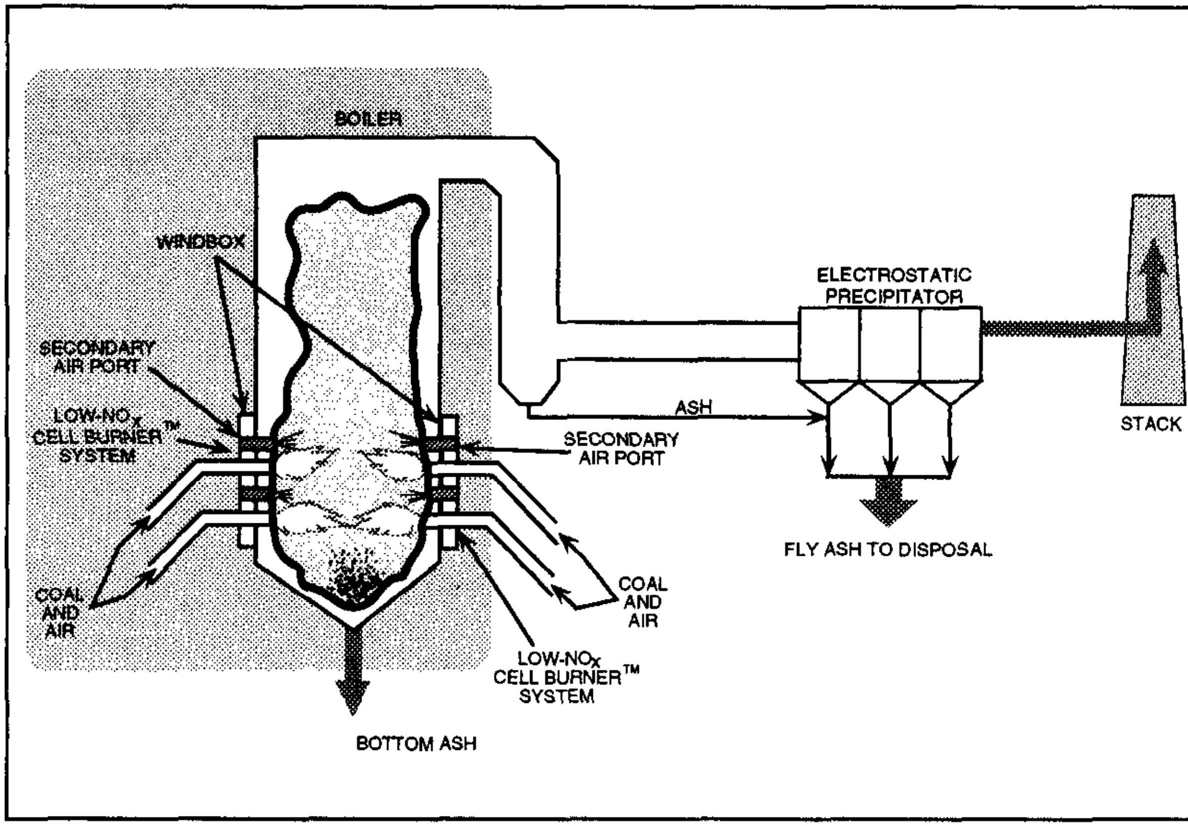
Plant Capacity/Production:
605 MWe

Project Funding:

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

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

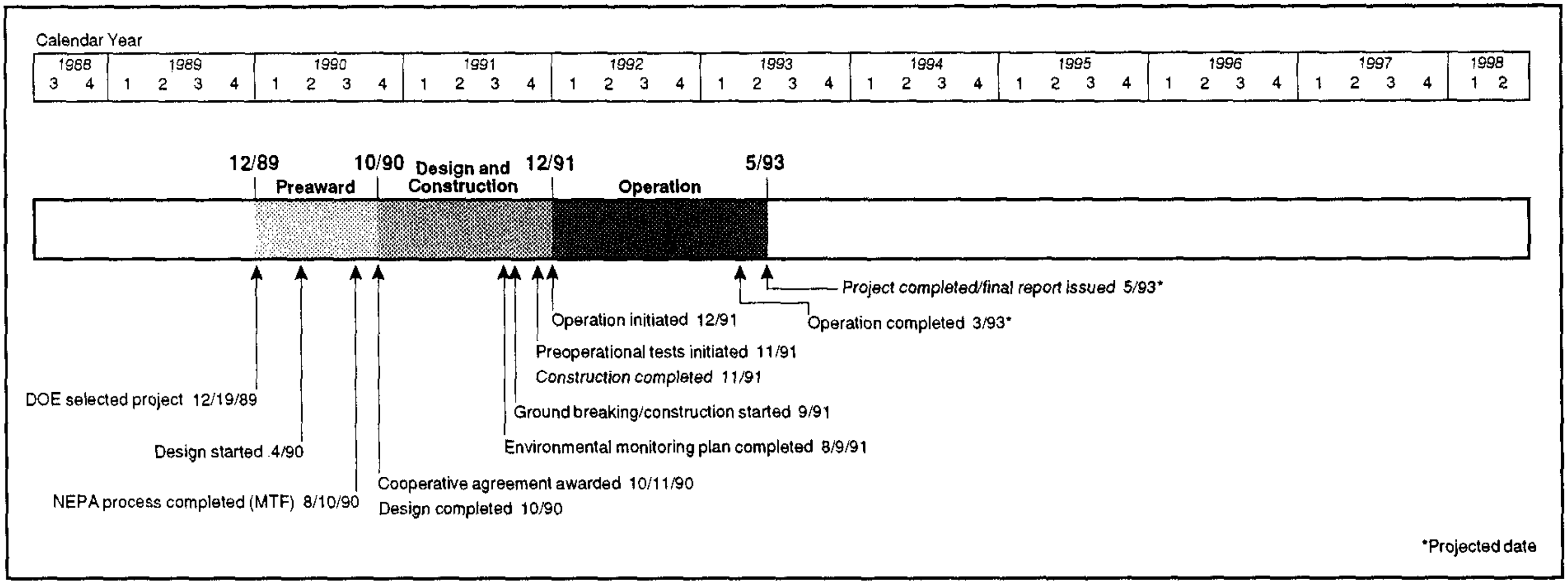
Low-NO_x Cell burner and LNCB are trademarks of The Babcock & Wilcox Company.



Technology/Project Description:
Low-NO_x Cell™ burner technology replaces the upper coal nozzle of the standard cell burner with a secondary-air port. The lower burner coal nozzle is enlarged to the same fuel input capability as two standard coal nozzles. The Low-NO_x Cell™ burner 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 is being conducted at a large-scale power plant operated by The Dayton Power and Light Company and jointly owned with the Cincinnati Gas and Electric Company and the Columbus Southern 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. All 24 standard cell burners are being removed, and 24 new burners are being installed.

Project Status/Accomplishments:

Pre-retrofit baseline testing completed in November 1990 showed NO_x emissions of 1.17 lb/million Btu. Preliminary testing completed in December 1991 showed that the best NO_x emissions reduction was only 35%. Also, high concentrations of CO and H_2S in combustion gases in the lower furnace, below the lowest row of burners, were unacceptable due to potential for corrosion and other hazards.

Pilot-scale testing and simulated boiler testing indicated that narrower, angled coal impellers would improve NO_x reduction. Also, numerical simulation of the combustion gas flows and composition profiles in the furnace section of the boiler for several alternative burner configurations produced an effective and economical burner configuration for minimizing the CO and H_2S concentrations in the lower furnace. The best computer generated solution was inverting the air port and burner components of every other LNCB™ unit on the lower row.

These changes were installed in May 1992, and testing of the LNCB™ system was resumed. The LNCB™ retrofitted boiler is now achieving 55% NO_x reduction (0.526 lb/million Btu). The CO and H_2S concentrations in the lower furnace are below the baseline levels. In addition, carbon in the fly ash for the LNCB™ system is 3–4% (loss on ignition) and the CO concentration in the flue gas is 40–50 ppm.

The laboratory corrosion and H_2S-probing work shows that there is risk of increased tube wastage on bare furnace wall tubes because of the deep staging technique used by the LNCB™. The risk is greater for once-through (universal pressure) boilers due to their inherently higher operating tube-metal temperatures in the burner zone, compared to drum boilers. Field-verified analysis is needed to confirm or refute the laboratory analysis and to identify potential operations and maintenance costs associated with LNCB™ technology.

Commercial Applications:

Currently there are 34 operating cell-burner-fired boilers for which the LNCB™ system is applicable. Of these, 29 are opposed-wall-fired with two rows of two-nozzle cells. The average size is 766 MWe.

The low cost and short outage time for retrofit make the LNCB™ design attractive. Typically, the retrofit capital-cost will be $8–12/kW in 1990 dollars, based upon DOE's 500-MWe reference unit. The outage time can be as short as 5 weeks because of the "plug-in" design. The LNCB™ system can be installed at about half the cost and outage time for other commercial low-NO_x burner installations.

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 & Gas Corporation—cofunder
Rockwell Lime Company—cofunder

Location:

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

Technology:

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

Plant Capacity/Production:

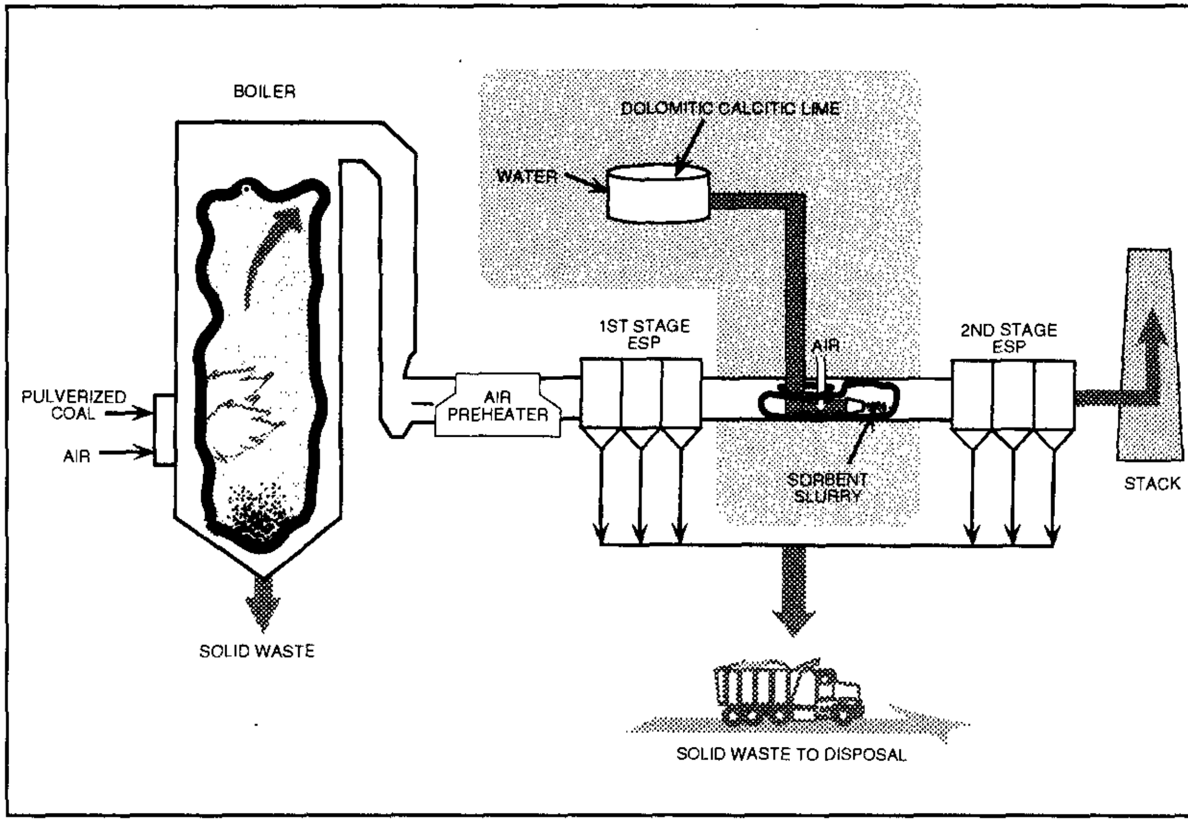
73.5 MWe

Project Funding:

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

Project Objective:

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

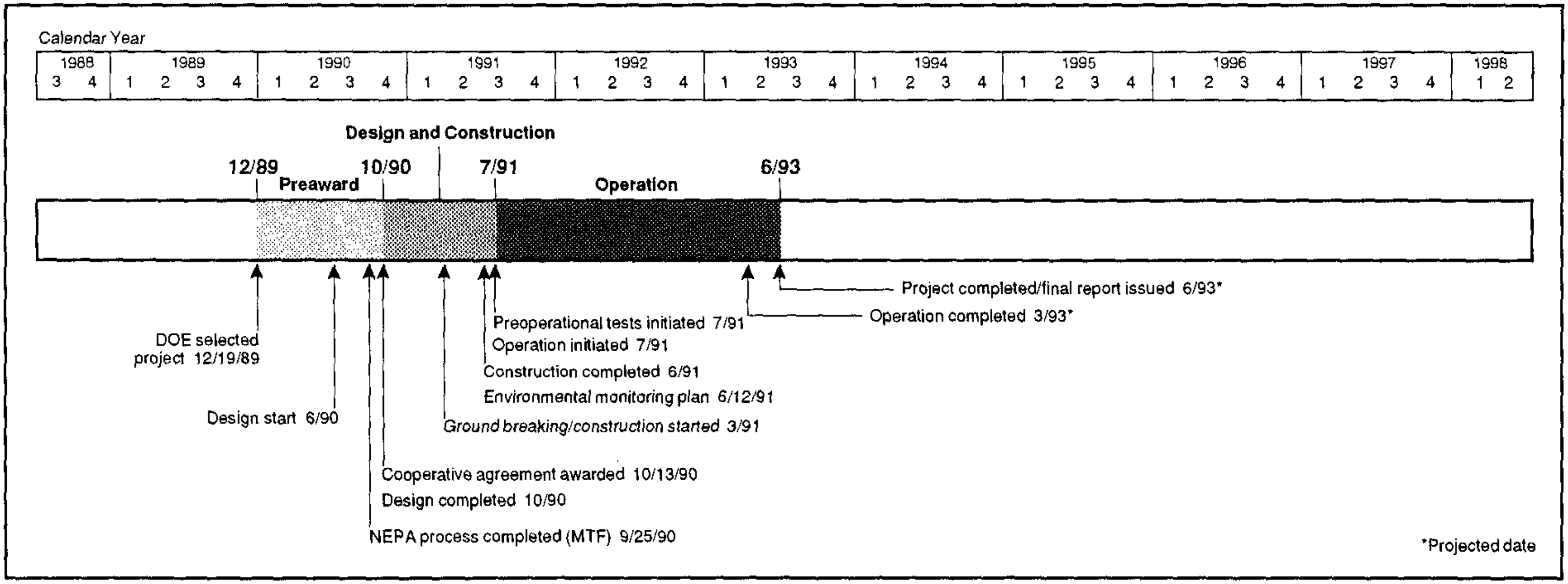


Technology/Project Description:

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

The CZD/FGD process is expected to remove up to 50% of the 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 and calcitic limes) with several atomizer designs using low- and high-sulfur coals to verify the effects on SO_2 removal and the capability of the ESP to control particulates. The demonstration 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, longer 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 6 months.

Project Status/Accomplishments:

Bechtel began its 18-month, two-part test program for the CZD process in July 1991. The first 12 months of the test program consisted primarily of parametric testing. The second part includes a 6-month continuous operation test period with the system being operated under fully automatic control by the host utility boiler operators. Initially, the new atomizing nozzles were thoroughly tested both outside and inside the duct. The lime slurry injection parametric test program, which began in October 1991, was completed in August 1992, and the goal of 50% SO_2 reduction was achieved. Continuous operations testing is under way; it involves three-shift, fully automatic operations by operators of the host utility company. Bechtel intends to conduct additional performance tests during this period.

Commercial Applications:

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

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

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 Corporation)—technology owner
Simon-Macawber, Ltd.—equipment supplier
Fluor Daniel, Inc.—architect and engineer
ATSI, Inc.—injection equipment engineer (U.S. technology licensee)

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

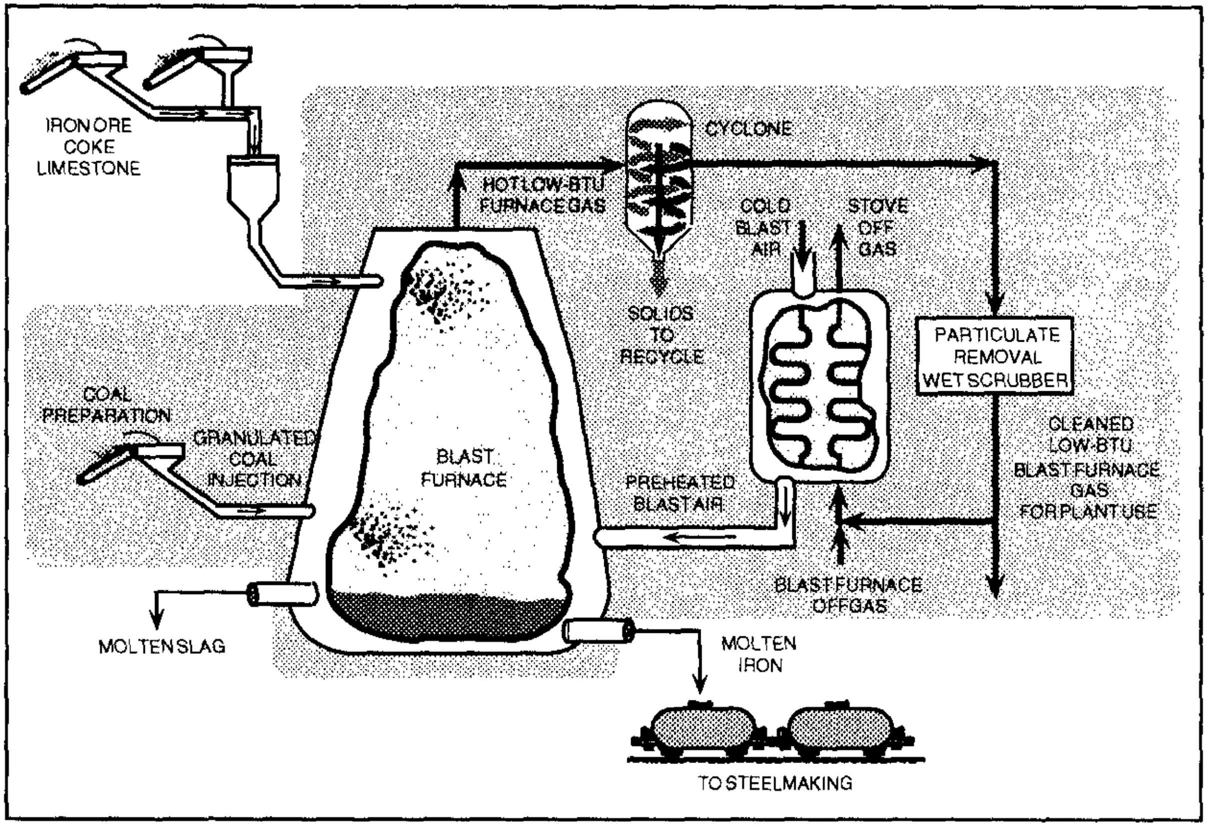
Technology:
British Steel's blast furnace granulated-coal injection (BFGCI) process

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

Project Funding:

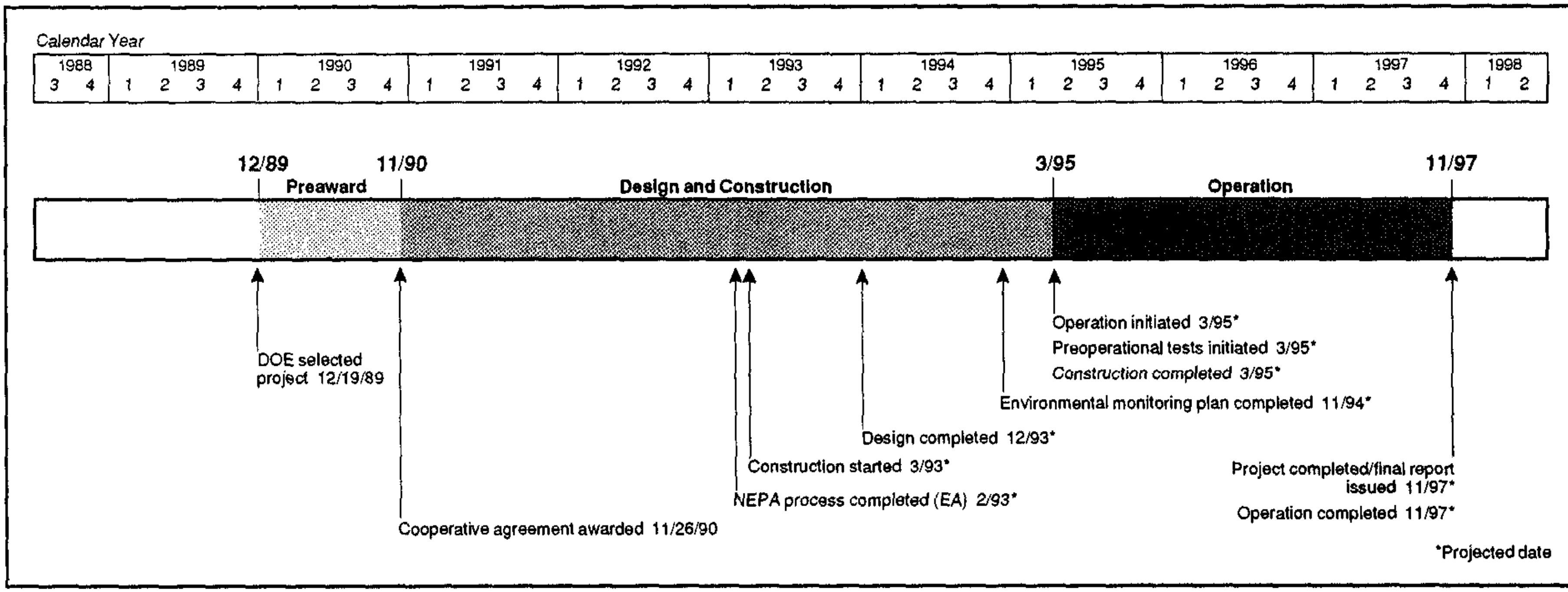
Total project cost	$143,800,000	100%
DOE	31,259,530	22
Participants	112,540,470	78

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 a raceway is important and is dependent upon many factors including temperature. Lowering of a raceway temperature, which can occur with gas injection, reduces blast furnace production rates. Coal, with a lower hydrogen content than either gas or oil, does not cause as severe a reduction in raceway temperatures. In addition to displacing injected natural gas, the coal injected through the tuyeres displaces coke, the primary blast furnace fuel and reductant (reducing agent), on approximately a pound-for-pound basis. Because coke production results in significant emissions of NO_x, SO_2, and air toxics and coal could replace up to 40% of the coke requirement, BFGCI technology has significant potential to reduce emissions and enhance blast furnace production.

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



Two high-capacity blast furnaces, Units C and D at Bethlehem Steel Corporation's Burns Harbor Plant, are being retrofitted with BFGCI technology. Each unit has a production capacity of 7,000 net tons/day of hot metal. The two units will use about 2,800 tons/day of coal during full operation.

Project Status/Accomplishments:

Process engineering and preliminary design are in progress. Technology license agreements have been signed between Bethlehem Steel Corporation; British Steel Consultants Overseas Services, Inc.; ATSI, Inc.; and Simon-Macawber, Ltd. Due to poor economics in the steel industry and in order to contain capital requirements, the sponsor has been actively exploring third-party owner-financing for certain nonproprietary equipment and plant sections. Bethlehem Steel has made significant progress in design efforts and has made large capital outlays to complete the prerequisite blast-furnace modifications needed for the retrofits.

The project schedule has been extended due to a longer-than-expected period to complete formal negotiation of a technology license acceptable to both domestic and foreign organizations. The project schedule has also been impacted by the recent ongoing recession and its particularly harsh impact on the steel industry.

An environmental assessment is under way.

Commercial Applications:

BFGCI technology can be applied to essentially all U.S. blast furnaces. The technology should be applicable to any rank coal commercially available in the United States. The environmental impacts of commercial application are primarily indirect and consist of a significant reduction of emissions resulting from diminished coke-making requirements.

PCFB Demonstration Project

Sponsor:
DMEC-1 Limited Partnership (a partnership between Dairyland Power Cooperative and Midwest Power Systems, Inc. [previously Iowa Power, Inc.])

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

Location:
Pleasant Hill, Polk County, IA (Des Moines Energy Center)

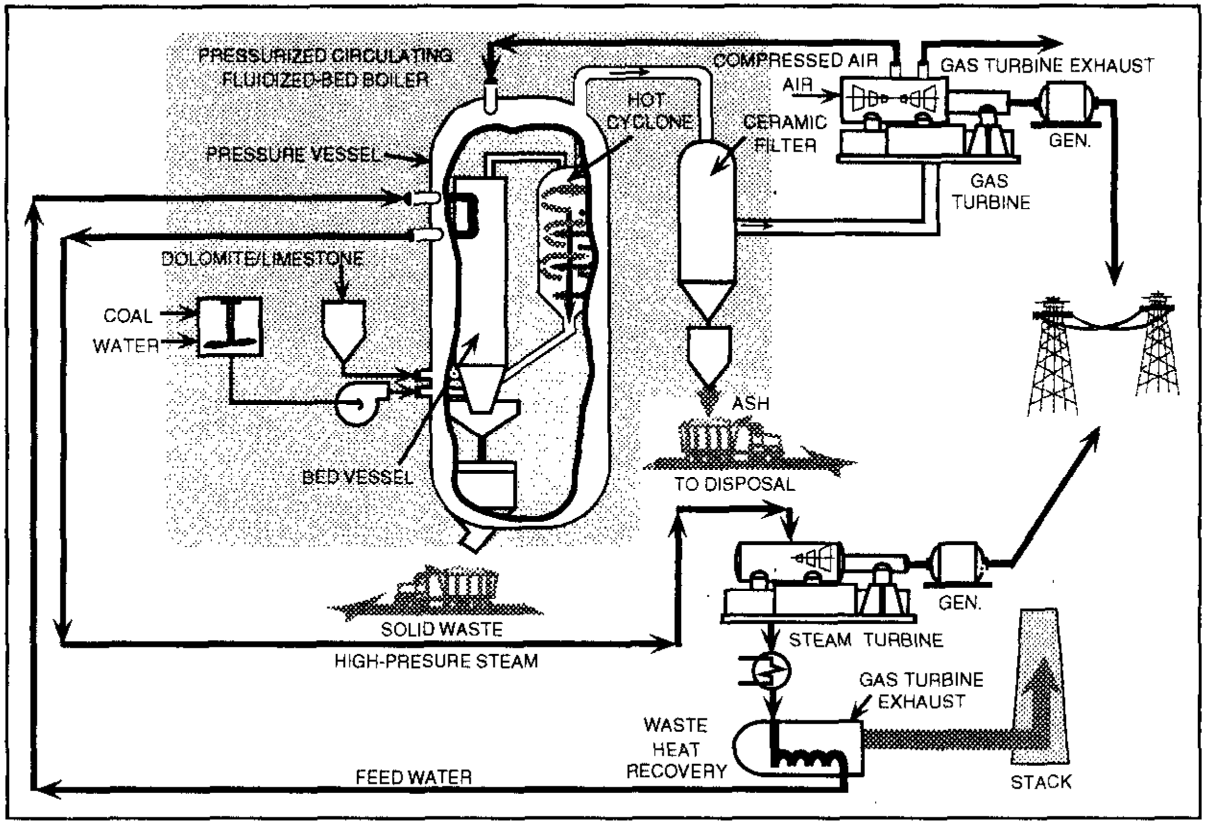
Technology:
Pyropower Corporation's PYROFLOW pressurized circulating fluidized-bed combustion (PCFB) combined-cycle system

Plant Capacity/Production:
80 MWe

Project Funding:

Total project cost	$202,959,000	100%
DOE	93,253,000	46
Participants	109,706,000	54

Project Objective:
To demonstrate PCFB at sufficient scale to evaluate environmental, cost, and plant performance and to obtain the technical data required for commercialization of the technology; to assess operating performance of unique features that include an integral ceramic hot-gas filter and slightly modified, commercially available gas turbine.

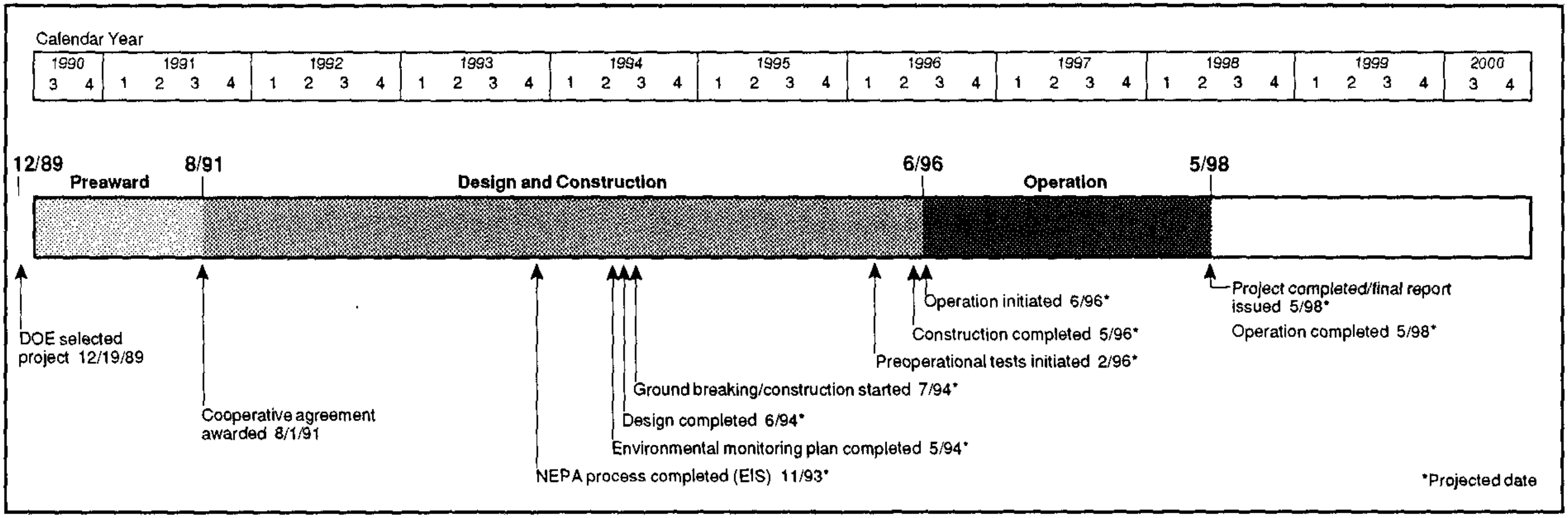


Technology/Project Description:
In the PCFB process, coal is combusted at about 1,600 °F and 12 atm in a circulating fluidized bed contained within a pressure vessel. Coal is pumped into the PCFB via a water slurry while dolomite or limestone is added to the combustion process to absorb sulfur compounds. Particulates from the hot, pressurized combustion gases are removed by a ceramic filter, and the clean gases are then expanded through a gas turbine. The solid waste (bed and fly ash) from the process is dry, easily disposed of, and potentially usable. Steam generated within the PCFB combustor and the heat recovery system downstream of the gas turbine is used to generate power in an existing steam turbine.

The project would be the world's first large-scale demonstration of PCFB technology. The project also would be the first commercial application of hot gas cleanup and the first use of a nonruggedized gas turbine in a pressurized fluidized-bed application.

A boiler at the Des Moines Energy Center is being repowered by a single PCFB combustor. The facility, owned by Midwest Power Company, is located southeast of Des Moines, IA. Midwest Power plans to continue PCFB operations commercially after the demonstration.

Repowering the plant with a PCFB will improve the plant's heat rate to 10,400 Btu/kWh (an efficiency of 32.8% based on HHV) which is a 15% improvement over the previous plant. SO_2 emissions will be limited to 0.71 lb/million Btu (90% reduction) and NO_x emissions will be less than 0.03 lb/million Btu (70% reduction).



Project Status/Accomplishments:

Preliminary design efforts to finalize the technical scope, cost baseline, and business aspects of the project continued during 1992. In August 1992, design efforts were extended for 10 months to provide additional time to factor in results from ongoing hot-gas filtration tests.

Environmental information for use in the NEPA process has been developed and the public scoping meeting was held. Drafting of the environmental impact statement has begun.

Commercial Applications:

By demonstrating plant reliability and performance, this project serves as a bridge for scaling up to a larger plant and a stepping stone toward moving PCFB to commercial readiness. 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 or replace conventional power plants. PCFB technology appears to be best suited for utility and industrial applications of 50 MWe or larger. Because of modular construction capability, PCFB generating plants permit utilities to add economical increments of capacity to match load growth and/or to repower plants using existing coal- and waste-handling equipment, and steam turbines. Another advantage for repowering applications is the compactness of the process due to pressurized operation, which reduces space requirements per unit of energy generated.

The commercial version of PCFB technology will include the integration of a topping combustor to fully utilize commercially available gas turbines. The projected net heat rate for this system is 7,964 Btu/kWh (based on HHV) which equates to 42.8% efficiency.

Environmental attributes include in-situ sulfur removal of 95%, NO_x emissions less than 0.3 lb/million Btu, and particulate matter discharge less than 0.03 lb/million Btu. Solid waste will increase slightly as compared to conventional systems, but the dry material is disposable or potentially usable.

ENCOAL Mild Coal Gasification Project

Sponsor:
ENCOAL Corporation (a subsidiary of SMC Mining Company)

Additional Team Members:
SMC Mining Company—cofunder

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

SGI International—technology developer

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

The M.W. Kellogg Company—engineer and constructor

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

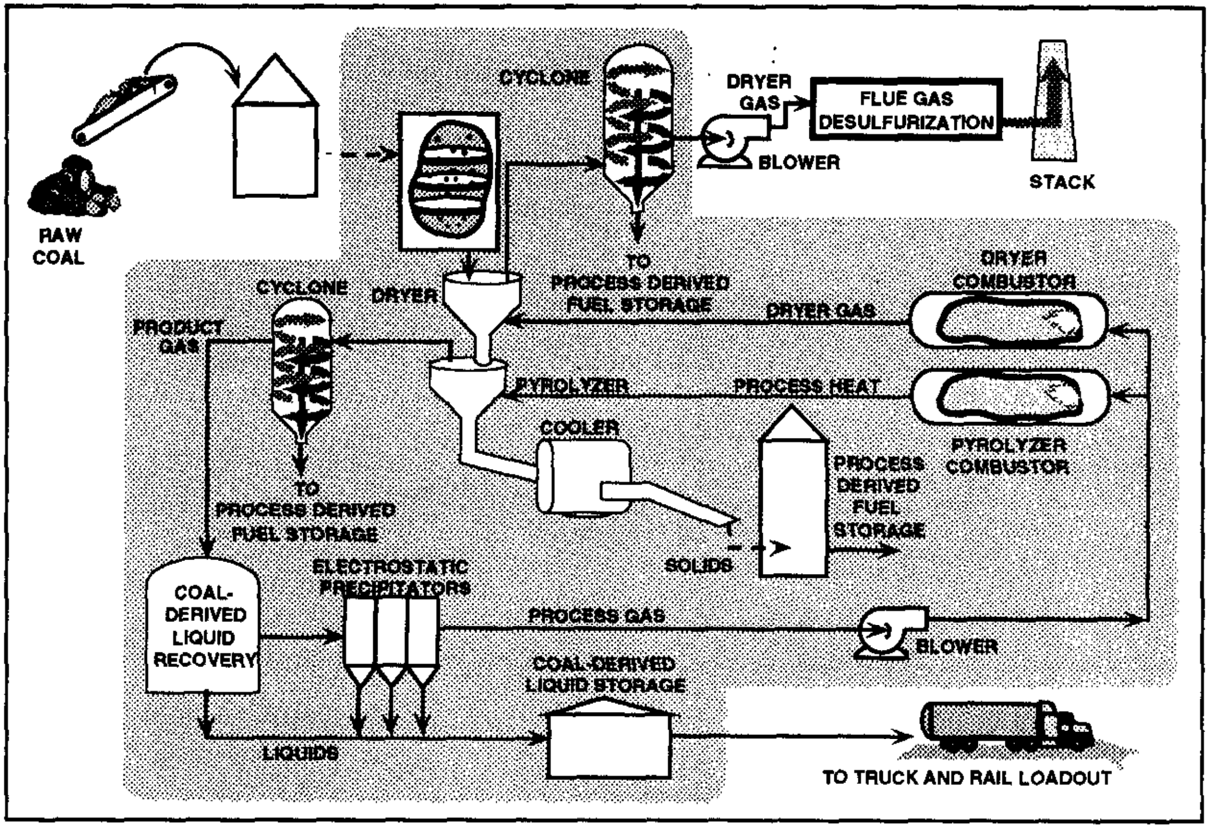
Technology:
SGI International's liquids from coal process

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

Project Funding:

Total project cost	$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 processing steps to produce two higher value fuel forms from mild gasification of low-sulfur subbituminous coal; and to provide sufficient products for potential end users to conduct burn tests.

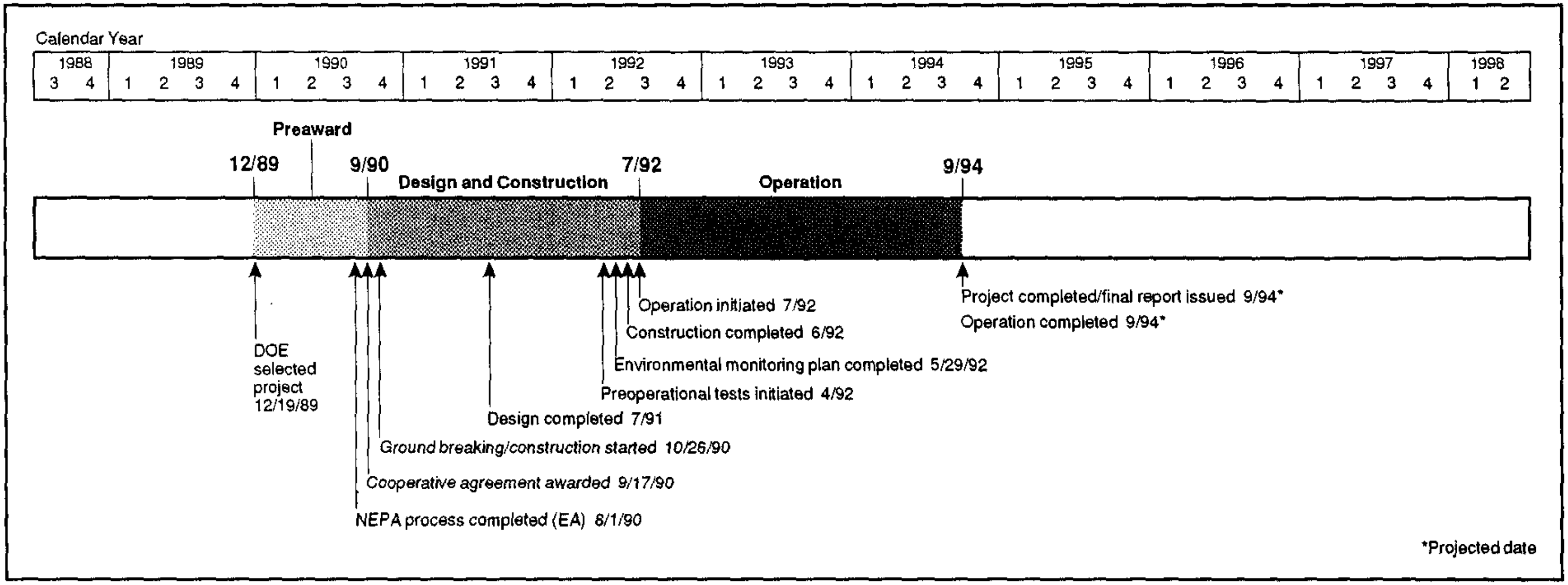


Technology/Project Description:
The ENCOAL mild coal gasification process involves heating coal under carefully controlled conditions. Coal is fed into a rotary grate dryer where it is heated by a hot gas stream to reduce the coal's moisture content. The solid bulk temperature is controlled so that no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

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

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

The ENCOAL project is located within Campbell County, WY, at Triton Coal Company's Buckskin Mine, 10 miles north of Gillette. The plant makes use of the present coal-handling facilities at the mine.



Project Status/Accomplishments:
The project is now in operation. Construction and plant start-up were completed in mid-1992, 2 months ahead of schedule.

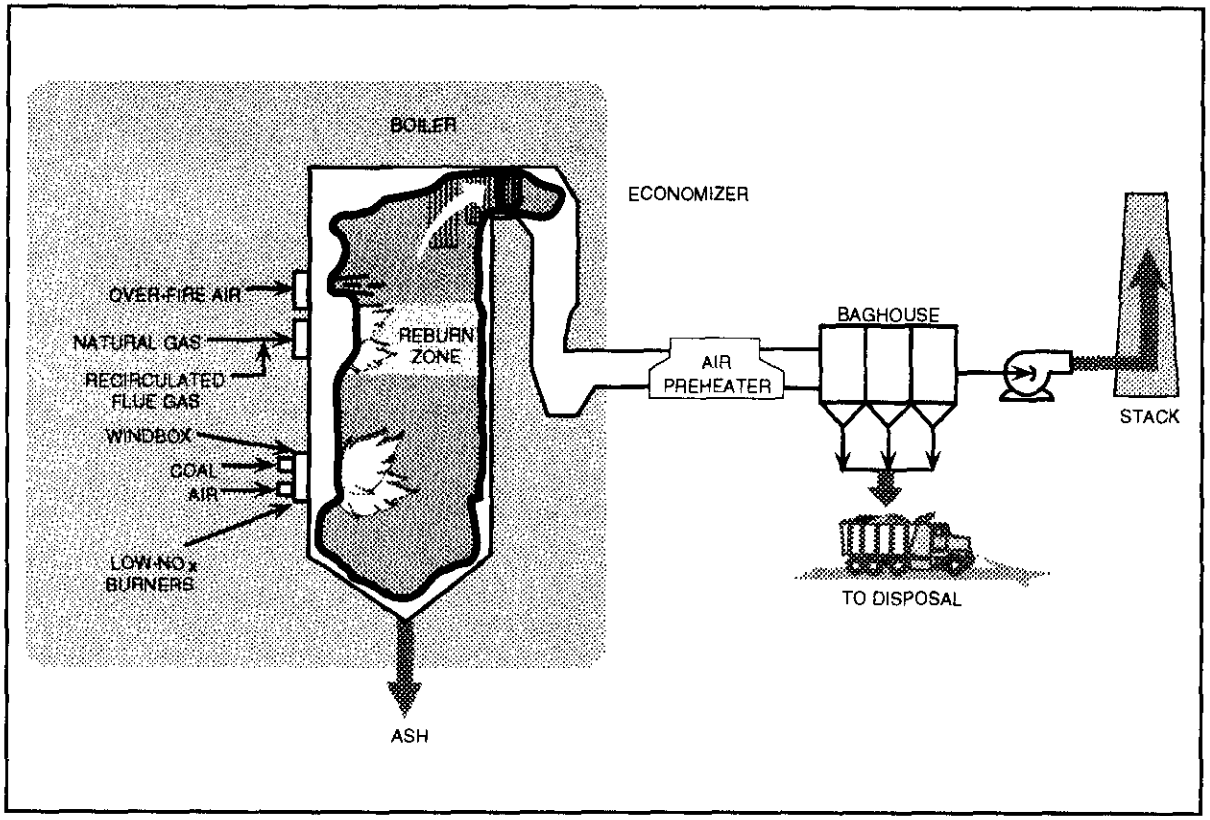
The plant has made several planned runs, with equipment or process changes after each, in an attempt to optimize plant operability and the quality of each product. The requirements of all environmental permits have been met in the plant operations conducted to date. Wisconsin Power & Light has agreed to purchase about 30,000 tons of the solid, process-derived fuel (PDF). TEXPAR Energy Inc. of Waukesha, WI, will purchase up to 135,000 barrels/yr of the liquid product. The PDF has been tested on-site and has been successfully burned in a large-scale laboratory combustion furnace. Analysis has shown that the heating value of the feed coal is upgraded from 8,400 Btu/lb to about 12,000 Btu/lb. The particle size of the PDF is smaller than the run-of-mine coal but is not expected to be a problem. The stability of the solid product requires more testing because it has not been comparable to run-of-mine coal in tests performed to date. Three railroad tank cars of liquid product have been shipped to TEXPAR.

In November 1992, Zeigler Coal Holding Company purchased the primary assets and operations of the Shell Mining Company (renamed SMC Mining Company after acquisition). ENCOAL remains a subsidiary of SMC Mining Company, and no material impact on the project or the future commercialization of the technology is expected as a result of this business transaction.

Commercial Applications:
The liquid products from mild coal gasification can be used in existing markets in place of No. 6 fuel oil. The solid product can be used in most industrial or utility boilers. The feedstock for mild gasification facilities is being limited to high-moisture, low-heating-value coals.

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

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)

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

Plant Capacity/Production:
172 MWe

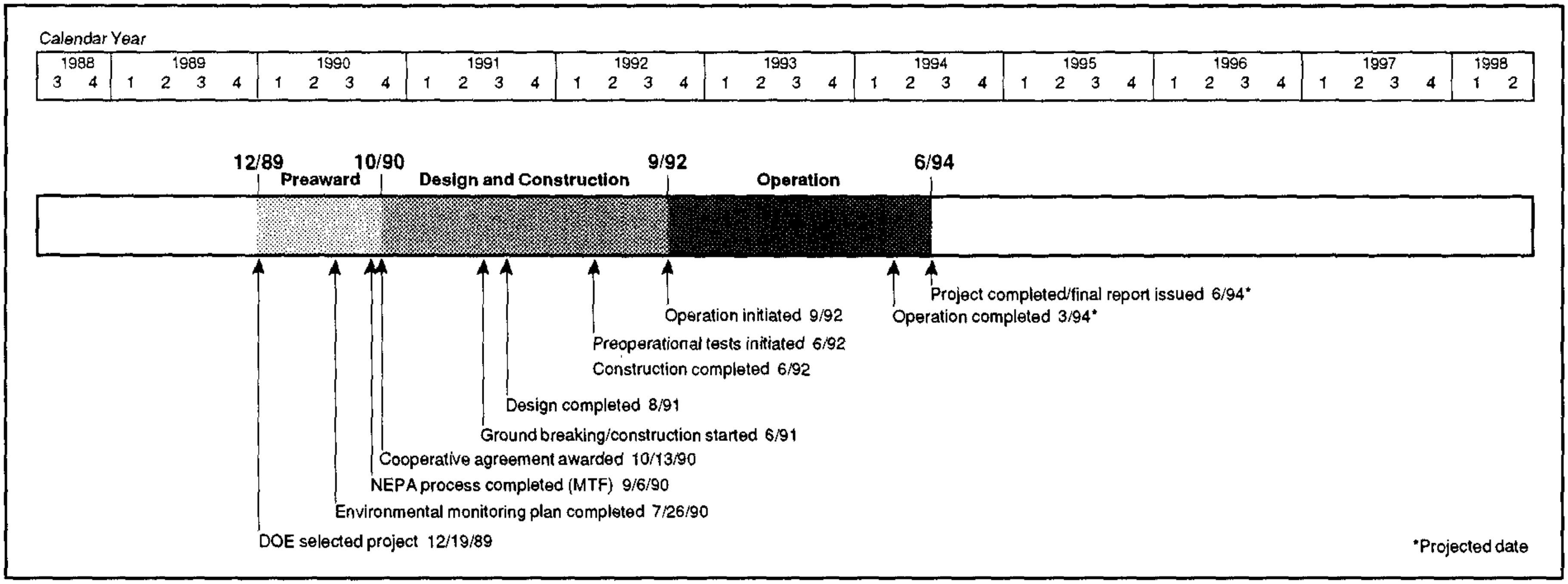
Project Funding:

Total project cost	$16,194,172	100%
DOE	8,097,085	50
Participants	8,097,087	50

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

Technology/Project Description:
Gas reburning involves firing natural gas (up to 20% of total fuel input) above the main coal combustion zone in a boiler. This upper-level firing creates a slightly fuel-rich zone. NO_x drifting upward from the lower region of the furnace is "reburned" in this zone and converted to 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 70% or more.

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. A variety of western bituminous coals containing 0.35–0.66% sulfur are being used in this demonstration.



Project Status/Accomplishments:

Permitting activities have been completed. Construction started in mid-1991 and was completed in June 1992, about 3 months ahead of schedule. Construction included the installation of new boiler penetrations, new burners, refractory, and insulation. All of the equipment that was installed during construction was checked out and found to be functional. Start of operation was delayed during the period July–August 1992 when the Public Service Company of Colorado rebuilt the four coal-pulverizing mills to enhance the flow of primary air to the boiler. Optimization of the gas-reburning unit started in late-September and was followed by a brief outage in November for minor modifications to the tertiary air system. Parametric studies started in October and were completed in December 1992. Preliminary analysis indicated NO_x reductions of up to 70% at 150 MWe. Long-term 1-year load-following operations will start in February 1993. Long-term operations will be completed in 1994.

Commercial Applications:

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

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

- Can be retrofitted to existing units
- Reduces NO_x emissions by 70% or more
- 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

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

LIFAC Sorbent Injection Desulfurization Demonstration Project

Sponsor:

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

Additional Team Members:

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

Location:

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

Technology:

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

Plant Capacity/Production:

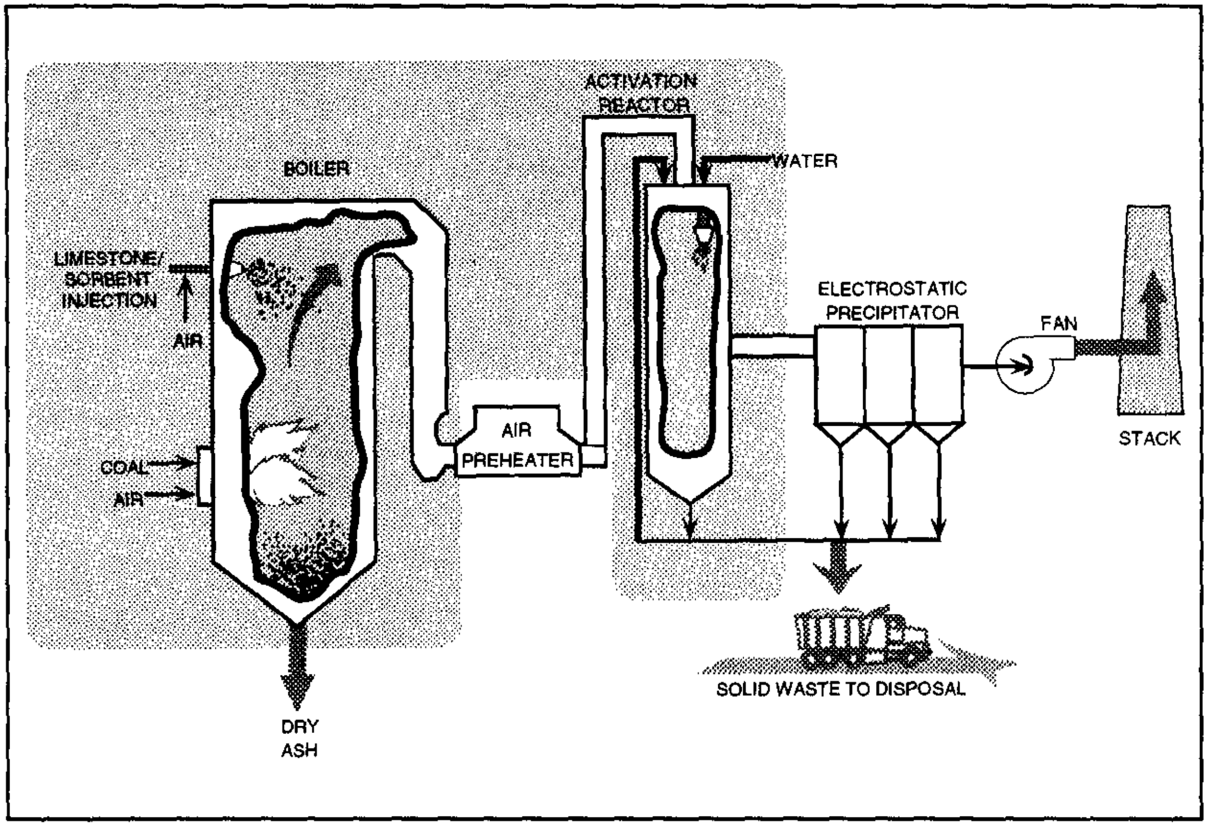
60 MWe

Project Funding:

Total project cost	$21,393,772	100%
DOE	10,636,863	50
Participants	10,756,909	50

Project Objective:

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

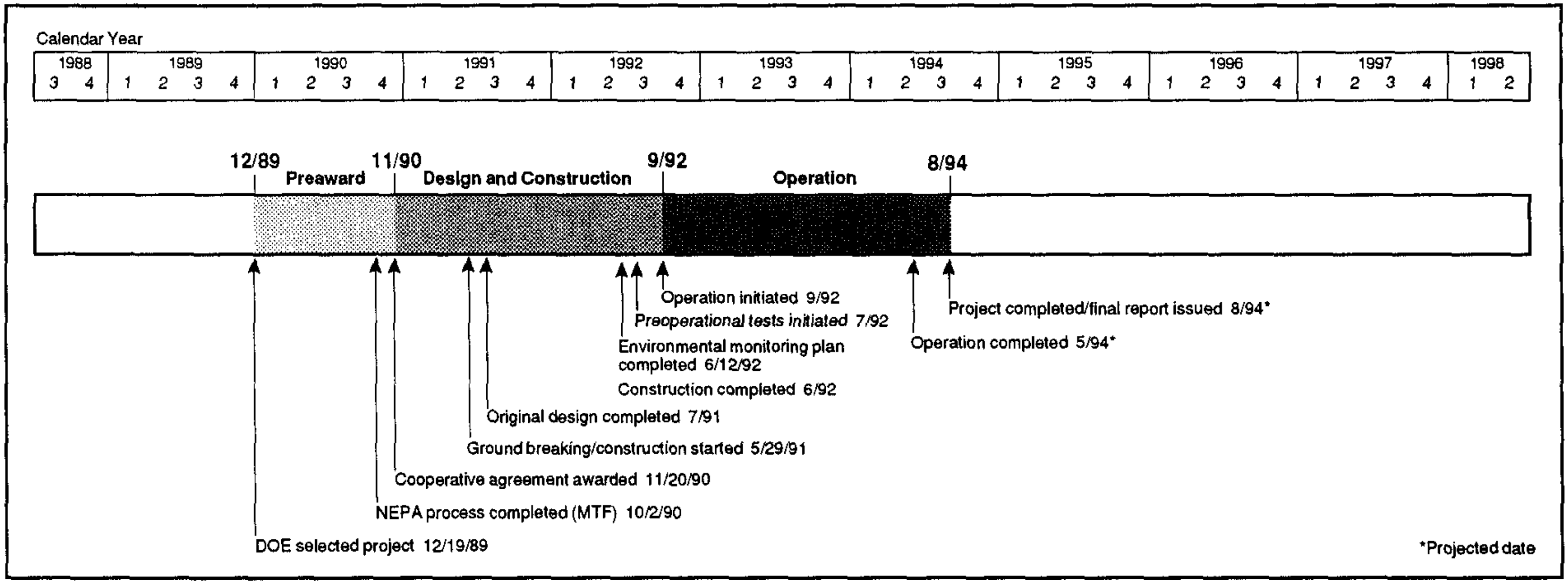


Technology/Project Description:

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

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

The process is being demonstrated at the Whitewater Valley Station, 60-MWe Unit No. 2. This coal-fired unit is owned and operated by Richmond Power & Light and is located in Richmond, IN.



Project Status/Accomplishments:

All plant tie-ins were successfully completed during the scheduled March 1991 outage. To improve LIFAC efficiency from 75% to 85%, the process was modified to recirculate sorbent material, which contains about 25% unreacted limestone. Formal ground breaking for the new equipment occurred on May 29, 1991. Construction was completed in June 1992, and shakedown operations began in July. Baseline testing was completed by August 1992. Parametric testing, first attempted in September 1992, was delayed 3 months to resolve mechanical and electrical problems with the LIFAC system.

The environmental monitoring plan was completed in June 1992.

Commercial Applications:

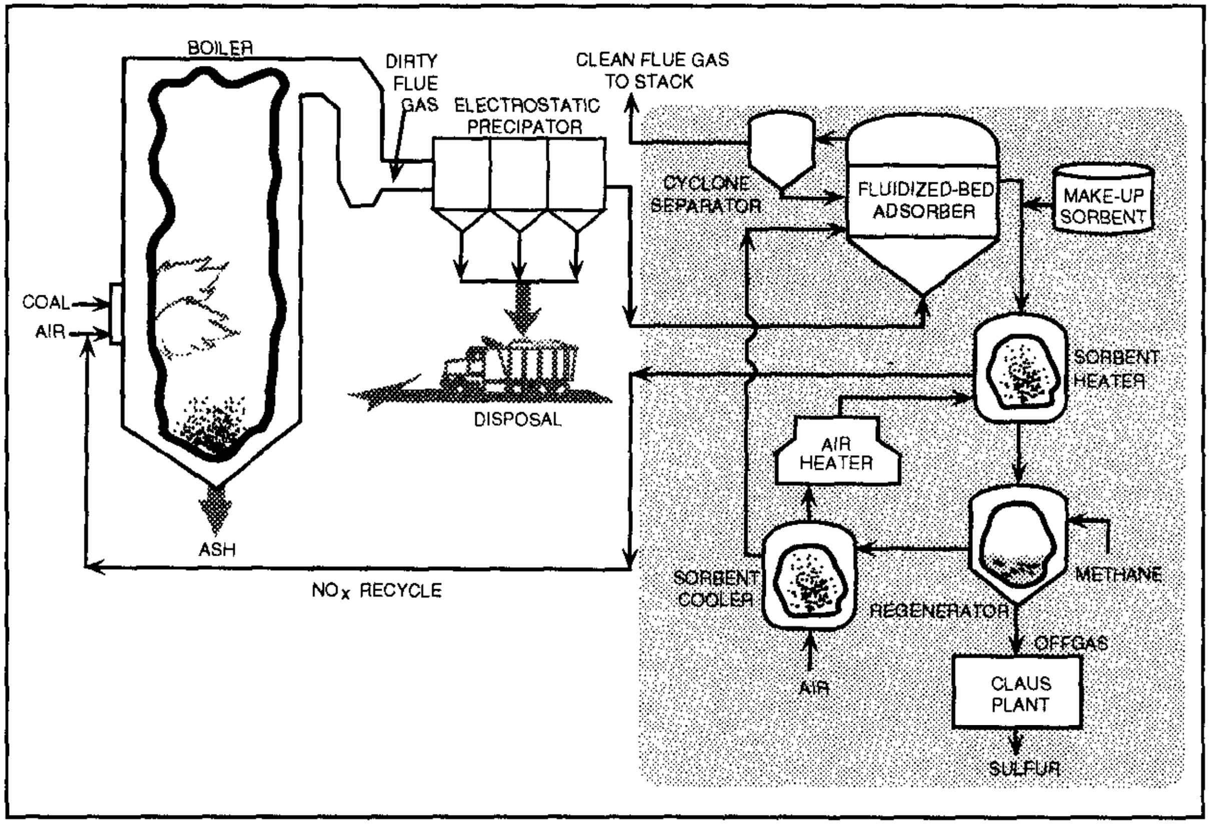
This process is suitable for application to all coal-fired utility or industrial boilers, especially those with tight space limitations. The LIFAC process offers the following advantages:

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

The benign waste material can be disposed of 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.

The potential market penetration of LIFAC is assumed to be 20% of the smaller and medium-size power plants (500 MWe or less) and some industrial sites. LIFAC sales are projected to total 18,000 MWe of capacity over the next decade.

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 Company's Niles Station, Unit 1)

Technology:

NOXSO Corporation's dry, regenerable flue gas cleanup process

Plant Capacity/Production:

115 MWe

Project Funding:

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

Project Objective:

To demonstrate removal of 97% of the SO_2 and 70% of the NO_x from a coal-fired boiler's flue gas using the NOXSO process.

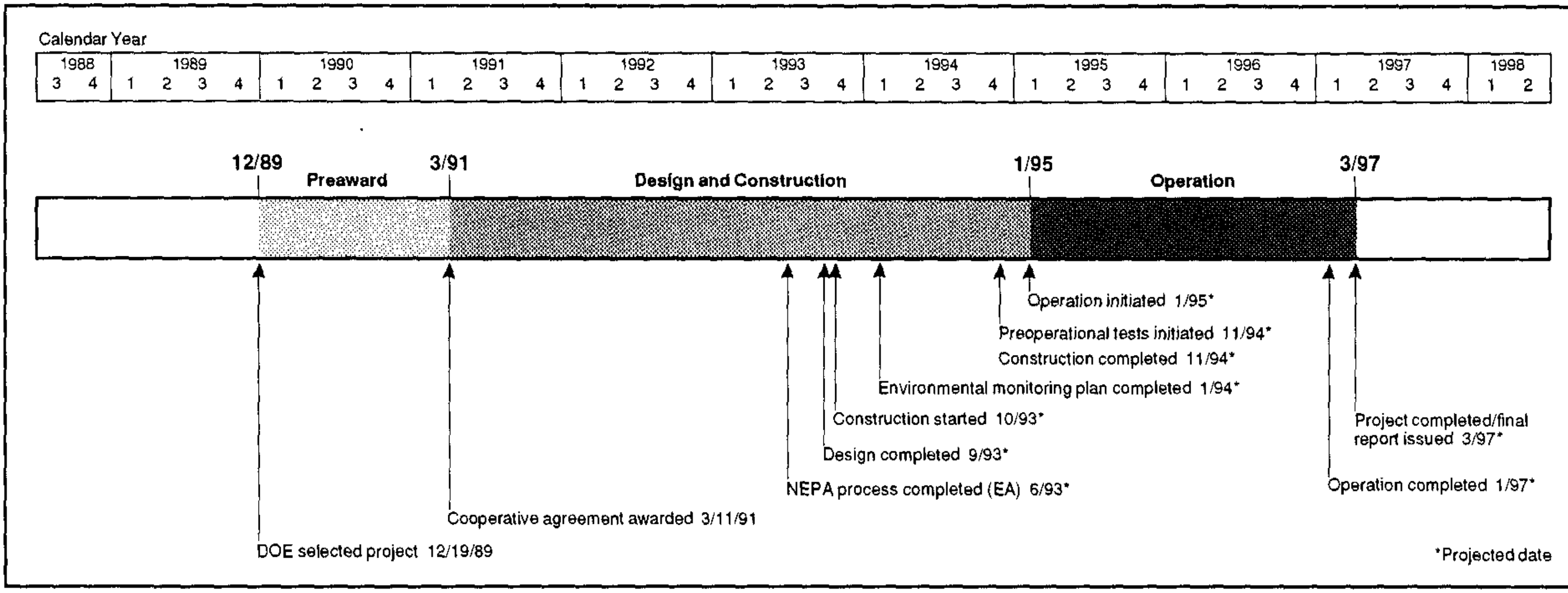
Technology/Project Description:

The NOXSO process is a dry, regenerable system capable of removing both SO_2 and NO_x in flue gas from coal-fired utility boilers burning medium- to high-sulfur coals. In the basic process, the flue gas passes through a fluidized-bed adsorber located downstream of the precipitator; 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 NO_x is desorbed from the NOXSO sorbent when heated by a stream of hot air. The hot air containing the desorbed NO_x is recycled to the boiler where equilibrium processes cause destruction of the NO_x. The 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 pro-cessed 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 Company's Niles Station, Unit 1, a 115-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 at Ohio Edison Company's Toronto Station can be available before the end of the project definition activity.

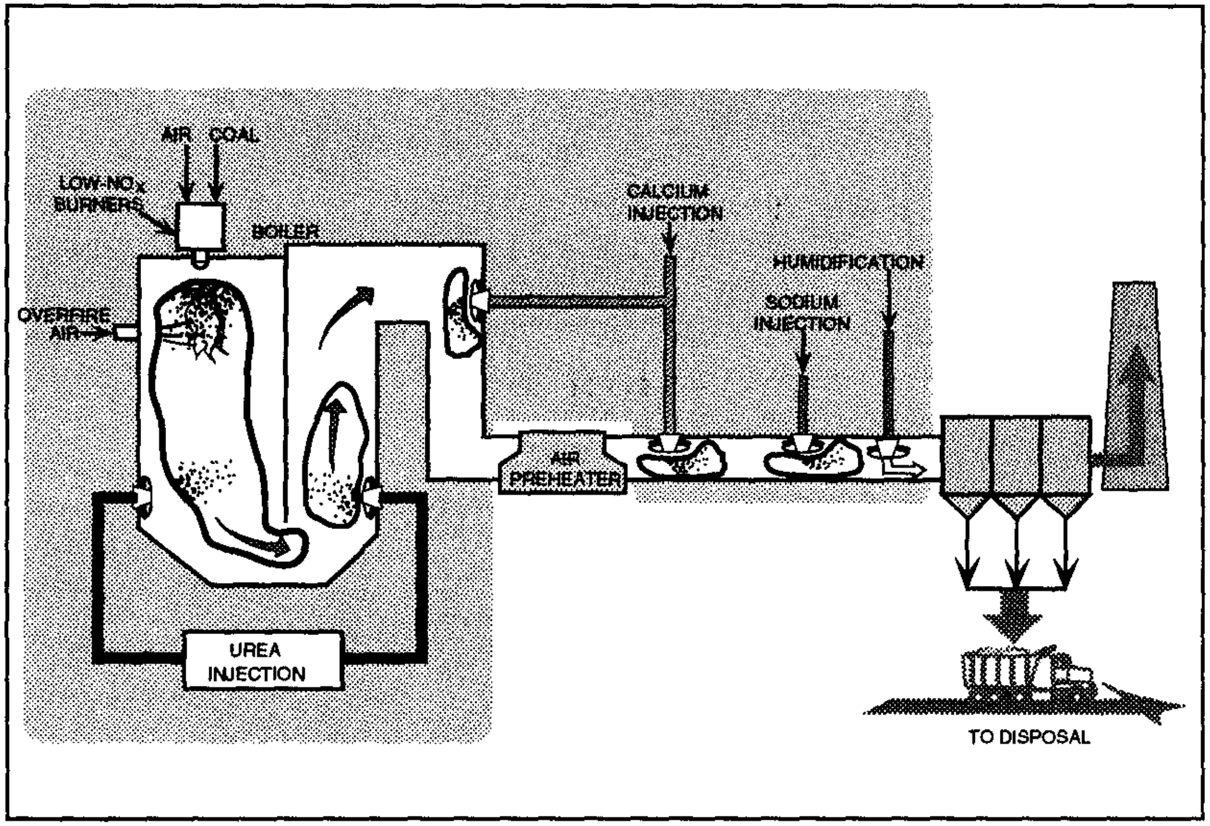


Project Status/Accomplishments:
The proof-of-concept, pilot-plant testing, which was proceeding in parallel with the project definition phase of the demonstration project, is complete, with results as expected. Preliminary process flow diagrams, piping and instrumentation diagrams, equipment specifications, and plant arrangement drawings have been prepared. Power plant, site, and process-specific environmental information has been compiled for use in the NEPA process.

Commercial Applications:
The NOXSO process is applicable for retrofit or new facilities. The process is suitable for utility and industrial coal-fired boilers of 75 MWt or larger. The demonstration is using southeastern Ohio and western Pennsylvania coal (3.2–3.5% sulfur average); however, 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 Emissions Control System



Sponsor:
Public Service Company of Colorado

Additional Team Members:
Electric Power Research Institute—cofunder
Stone and Webster Engineering Corporation—engineer
The Babcock & Wilcox Company—burner developer
Fossil Energy Research Corporation—operational testing
Western Research Institute—flyash evaluator
Colorado School of Mines—bench-scale engineering research and testing
Noell, Inc.—urea-injection system provider

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

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

Plant Capacity/Production:
100 MWe

Project Funding:

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

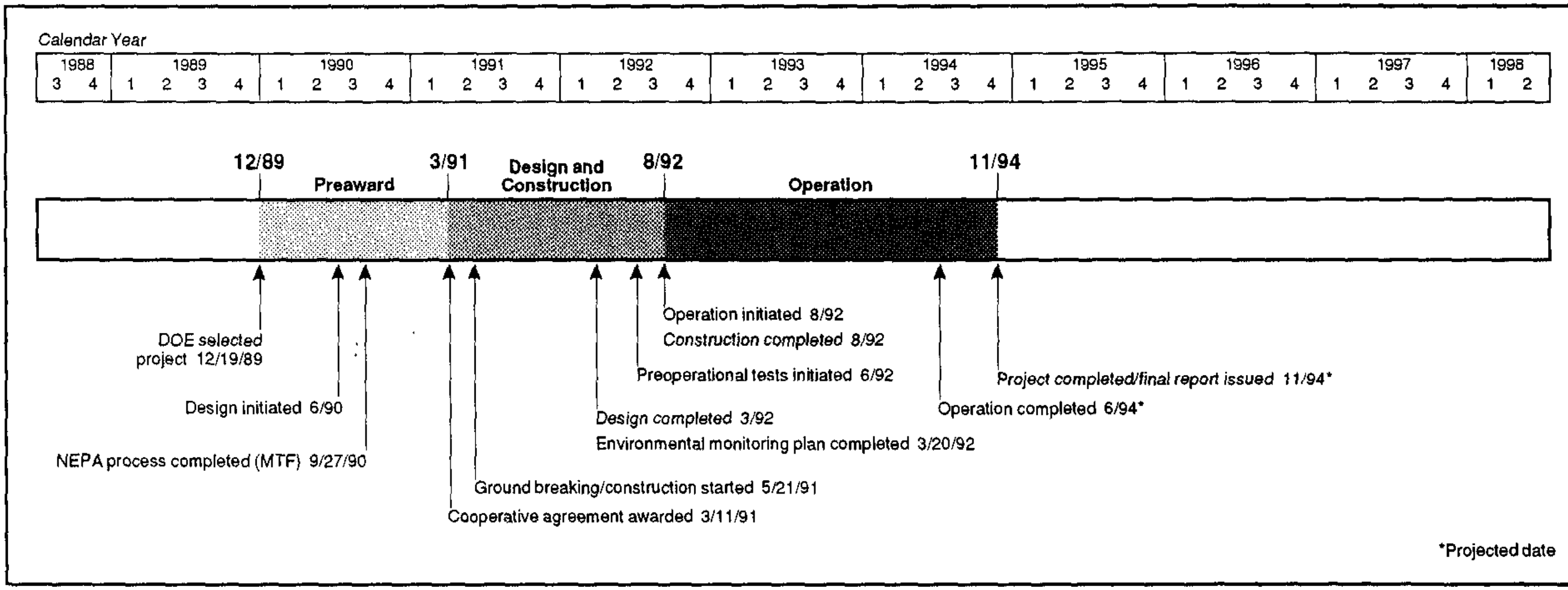
Project Objective:
To demonstrate the integration of three technologies to achieve up to 70% reduction in NO_x and SO_2 emissions; more specifically, to assess the integration of a down-fired low-NO_x burner with in-furnace urea injection for additional NO_x removal and dry sorbent in-duct injection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

Technology/Project Description:
All of the testing is using Babcock & Wilcox's low-NO_x DRB-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 NO_x emissions by up to 50%, and, with added air, 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 aids SO_2 capture and lowers flue gas temperature and gas flow, which can decrease pressure drop at the fabric filter dust collector.

Low-sulfur (0.4%) western bituminous coal is the main fuel being tested, but for a run of short duration (less than 1 month), eastern bituminous coal containing 2.5% sulfur is being used.

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



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

Project Status/Accomplishments:

Baseline testing of the boiler without any modifications was completed in mid-December 1991. Baseline testing of the boiler with urea injection began in early February 1992 and continued for approximately 1 month. Construction requiring plant outage was completed in May 1992, and then preoperational testing of the boiler with low-NO_x burners and NO_x ports began. Operational testing of these two key components started in early August 1992.

Testing of the combustion modifications was completed in late-October 1992. While firing western bituminous coal, NO_x was reduced from an original baseline of 1.15 lb/million Btu to about 0.4 lb/million Btu—a 65% reduction—with no operating problems. Short-term testing while firing natural gas also was completed. In-furnace urea injection testing began in January 1993 and is scheduled to continue for 2 months.

The environmental monitoring plan was conditionally approved on March 20, 1992, pending the inclusion of air toxics testing information.

Commercial Applications:

Either the entire integrated dry NO_x/SO_2 emissions control system or the individual technologies are applicable to most utility and industrial coal-fired units. They provide a lower capital-cost alternative to conventional wet flue gas desulfurization processes. They can be retrofitted with modest capital investment and downtime, and their space requirements are substantially less. They can be applied to any unit size but are mostly applicable to the older, small- to mid-size units. They can reduce NO_x emissions by up to 70% and SO_2 emissions by 55–75%, and they produce a dry solid waste product. These processes have the ability to handle all coal types, especially coals with low- to mid-sulfur content.

Tampa Electric Integrated Gasification Combined-Cycle Project

Sponsor:
Tampa Electric Company

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

Location:
Lakeland, Polk County, FL (Tampa Electric Company's Polk Power Station)

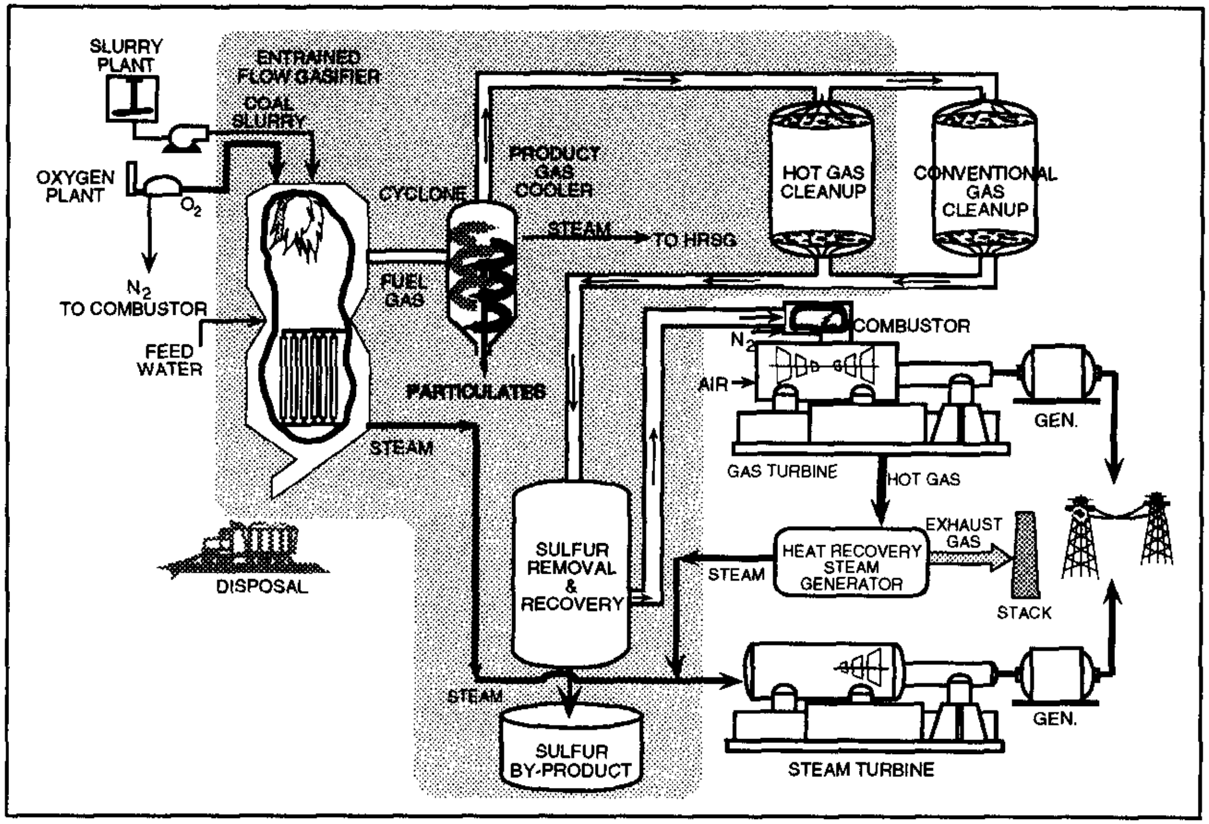
Technology:
Integrated gasification combined-cycle (IGCC) system using Texaco's pressurized, oxygen-blown, entrained-flow gasifier technology and incorporating both conventional, low-temperature acid-gas removal and hot-gas moving-bed desulfurization

Plant Capacity/Production:
260 MWe (net)

Project Funding:

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

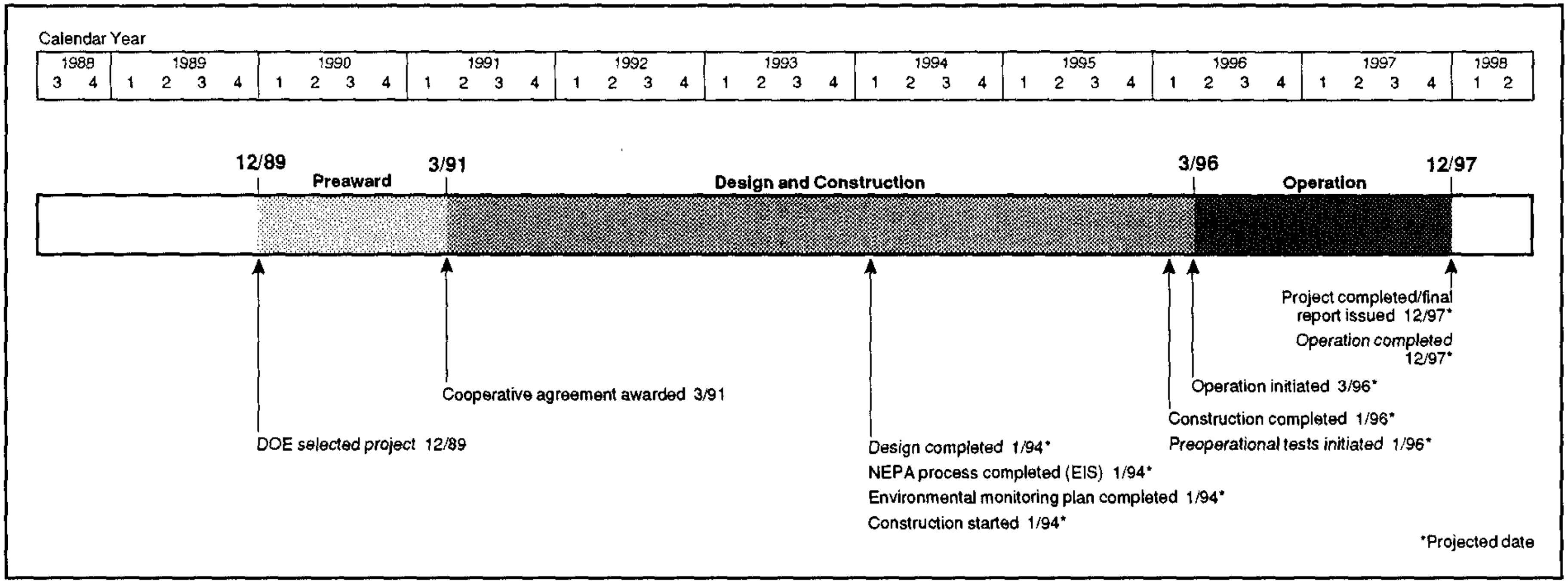
Project Objective:
To demonstrate the IGCC technology in a greenfield, commercial, electric utility application at the 260-MWe size with a Texaco gasifier. To demonstrate the integrated performance of a zinc-titanate hot-gas cleanup



system, conventional cold-gas cleanup, and an advanced gas turbine with nitrogen injection (from the air separation plant) for power augmentation and NO_x control.

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

The cooled gases flow to a particulate-removal section before entering gas-cleanup trains. About 50% of the syngas is passed through a moving bed of zinc-titanate absorbent to remove sulfur. The remaining syngas is further cooled through a series of heat exchangers before entering a conventional gas-cleanup train where sulfur is removed by an acid-gas removal system. These cleanup systems combined are expected to maintain sulfur levels below 0.21 lb/million Btu (96% capture). The cleaned gases are then routed to a combined-cycle system for power generation. A gas turbine generates about 192 MWe. Thermally generated NO_x is controlled to below 0.27 lb/million Btu by injecting nitrogen as a dilutent in the turbine's combustion section. A heat-recovery steam-generator uses heat from the gas-turbine exhaust to produce high-pressure steam. This steam, along with the steam generated in the gasification process, is routed to the steam turbine to generate



an additional 130 MWe. The IGCC heat rate for this demonstration is expected to be below 8,500 Btu/kWh (more than 40% efficient).

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

Project Status/Accomplishments:

The cooperative agreement was modified in March 1992 to change the sponsor from Clean Power Cogeneration L.P. to Tampa Electric Company. In addition, the site of the project was moved from Tallahassee to Polk County, FL, and the gasification technology was changed from air-blown fixed-bed to oxygen-blown entrained-flow.

The project is in the preliminary design stage. License agreements have been obtained with Texaco for the gasification technology and General Electric for the frame 7F turbine-based combined-cycle.

Environmental information for use in the NEPA process has been developed. Tampa Electric Company has submitted an extensive Site Certification Application to the State of Florida to support all of the environmental permits for the Polk County site. In August 1992, a public scoping meeting was held to solicit comments on preparation of the environmental impact statement.

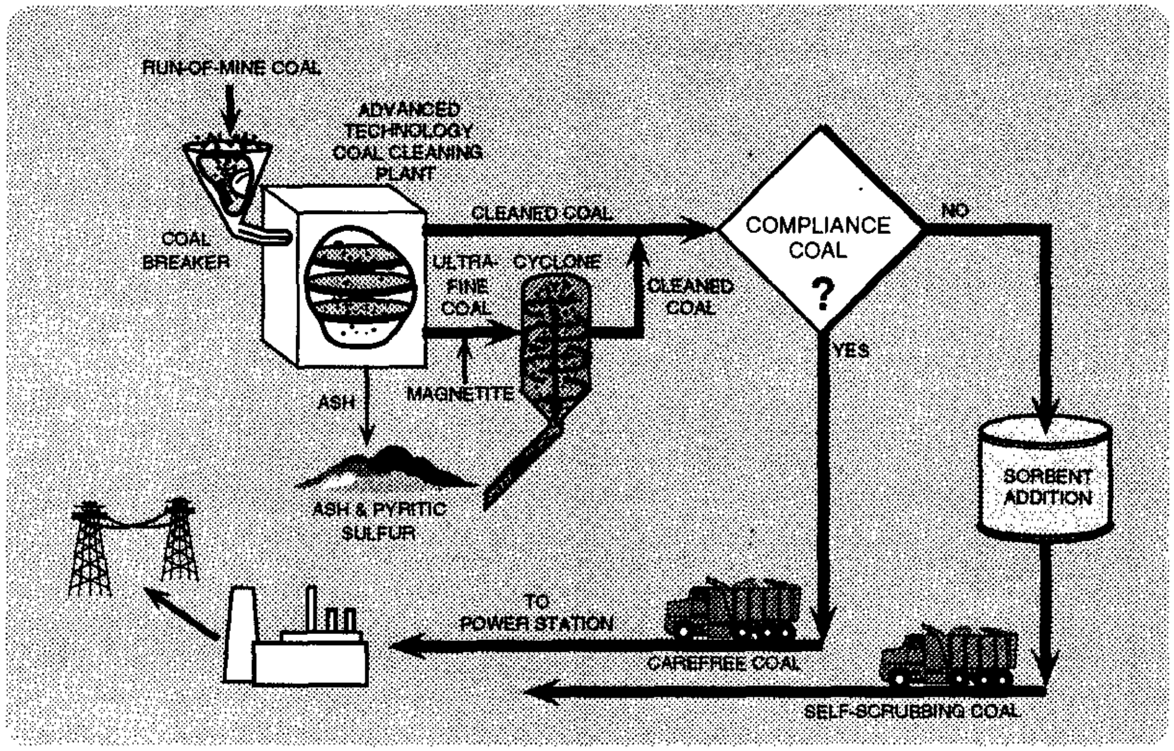
Commercial Applications:

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

The Texaco-based system has already been proven capable of handling both subbituminous and bituminous coals. This demonstration project is scaling up the technology from Cool Water's 100 MWe to the 260-MWe size.

CCT-IV
Project Fact Sheets

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



Sponsor:

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

Additional Team Members:

Duquesne Light Company—host utility
Richmond Power & Light—host utility
Centerior Service Company—host utility
CQ, Inc.—operator
ICF Kaiser Engineers, Inc.—engineer and constructor

Locations:

Stoystown, Somerset County, PA (advanced coal-cleaning plant)
Springdale, Allegheny County, PA (combustion tests at Duquesne Light Company's Cheswick Power Station)
Richmond, Wayne County, IN (combustion tests at Richmond Power & Light's Whitewater Valley Station, Unit No. 2)
Ashtabula, Trumbull County, OH (combustion tests at Centerior Service Company's Ashtabula C-Plant)

Technology:

Coal preparation using advanced physical coal cleaning and fine magnetite separation technology plus sorbent addition technology

Plant Capacity/Production:

350 tons/hr

Project Funding:

Total project cost	$81,726,346	100%
DOE	38,038,656	47
Participants	43,687,690	53

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

Project Objective:

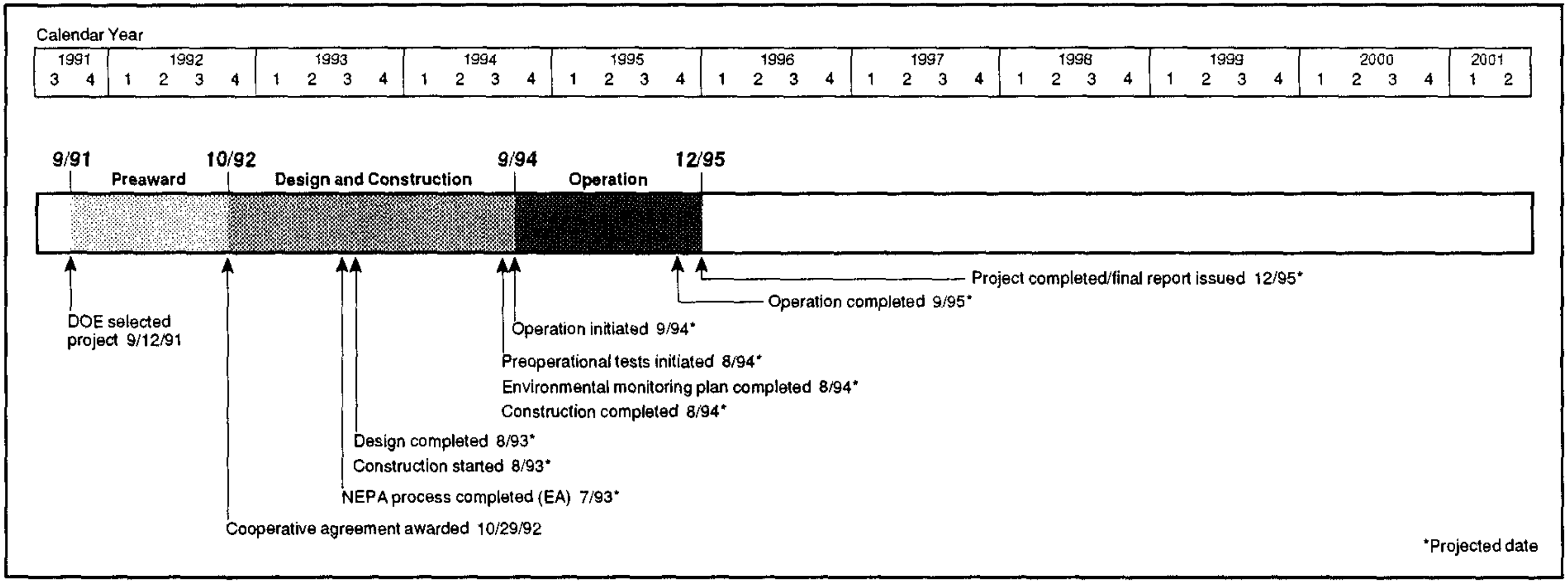
To demonstrate advanced coal-cleaning unit processes to produce low-cost compliance coals that can meet full requirements for commercial-scale utility power plants to satisfy CAAA of 1990 provisions.

Technology/Project Description:

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

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

Self-Scrubbing Coal™ is produced by taking Carefree Coal™, with its reduced pyritic sulfur and ash content, and adding to it sorbents, promoters, and catalysts. Self-Scrubbing Coal™ is expected to achieve compliance with virtually any U.S. coal feedstock through in-boiler absorption of SO_2 emissions. The reduced ash content of the Self-Scrubbing Coal™



permits the addition of relatively large amounts of sorbent without exceeding the ash specifications of the boiler or overloading the electrostatic precipitator.

A 350-ton/hr advanced coal-cleaning plant is being designed and constructed at a site in Stoystown, PA. The advanced coal-cleaning plant will manufacture Self-Scrubbing Coal™ and Carefree Coal™. Two medium- to high-sulfur coals—Illinois No. 5 from Wabash County, IL, and Lower Freeport Seam coal from Belmont County, OH—will be used to produce Self-Scrubbing Coal™. Carefree Coal™ will be made using Sewickley coal from Greene County, PA. The Sewickley coal will be combustion tested at Duquesne Light Company's Cheswick Power Station located near Pittsburgh, PA; the Illinois No. 5 coal will be tested at Richmond Power & Light's Whitewater Valley Station Unit No. 2 located in Richmond, IN; and the Lower Freemont Seam coal will be tested at Centerior Service Company's Ashtabula C-Plant.

Project Status/Accomplishments:

The cooperative agreement was awarded in October 1992. Design work has started. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

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

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

Milliken Clean Coal Technology Demonstration Project

Sponsor:
New York State Electric & Gas Corporation

Additional Team Members:
Consolidation Coal Company—technical consultant
Saarberg-Hölter-Umwelttechnik, GmbH—technology supplier
The Stebbins Engineering and Manufacturing Company—technology supplier
NALCO Fuel Tech—technology supplier

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

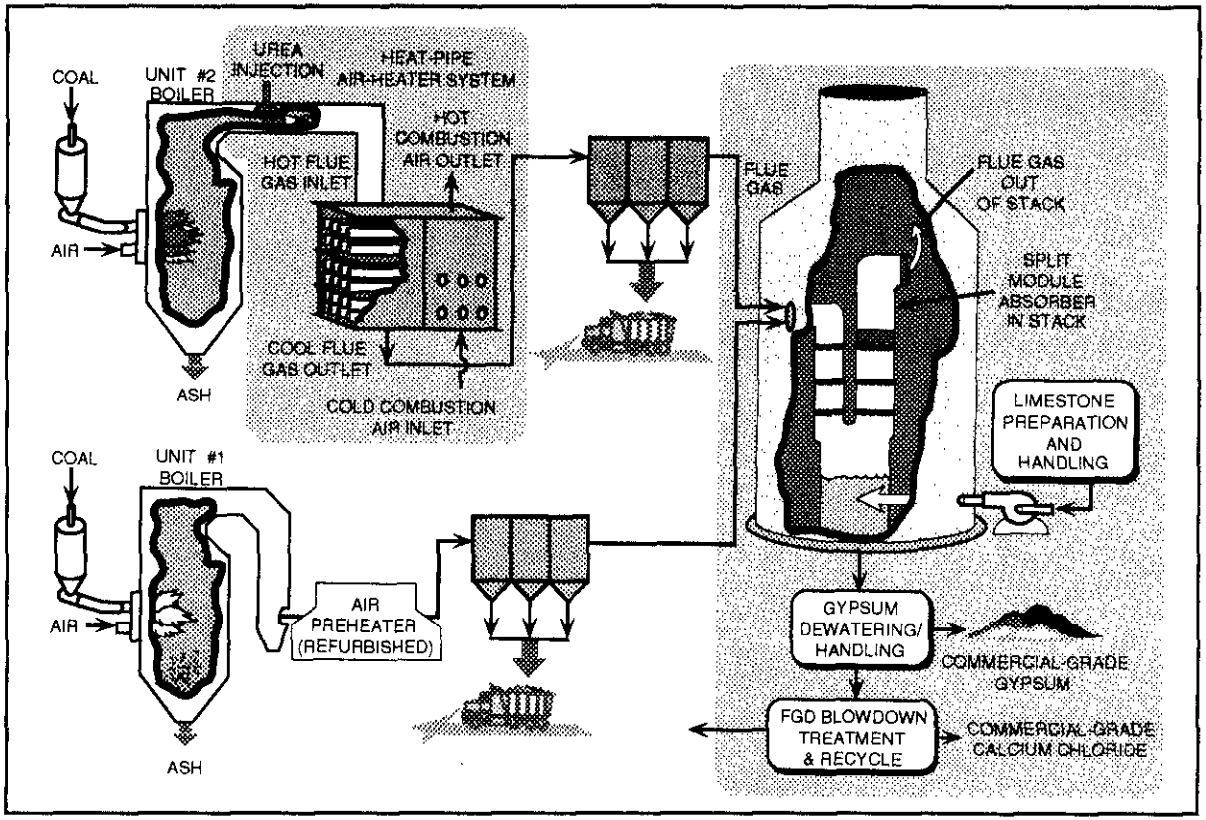
Technology:
Flue gas cleanup using Saarberg-Hölter-Umwelttechnik's (S-H-U) formic-acid-enhanced, wet limestone scrubber technology; NALCO Fuel Tech's NO_xOUT urea injection system; Stebbins' tile-lined split-module absorber; and heat-pipe air-heater system

Plant Capacity/Production:
300 MWe

Project Funding:

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

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



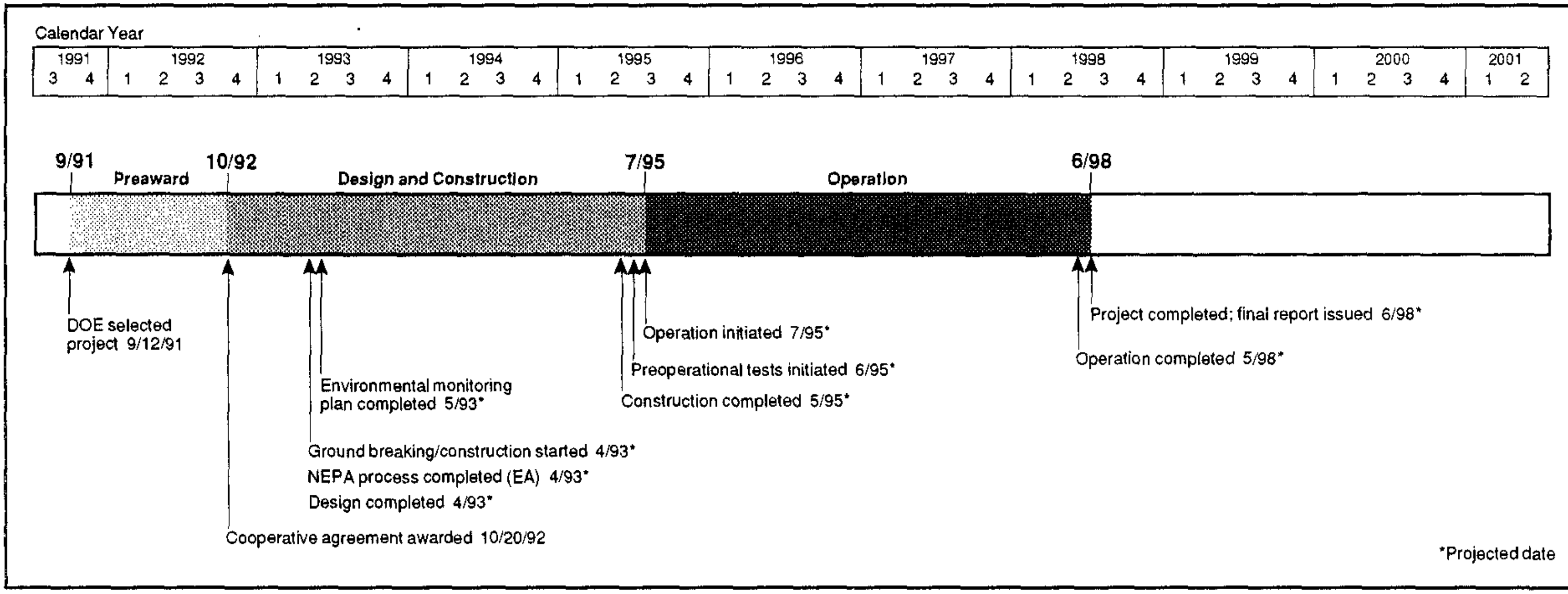
Technology/Project Description:
The S-H-U wet flue gas desulfurization process is a formic-acid-enhanced, wet limestone process which results in very high SO_2 removal with low energy consumption and the production of commercial-grade gypsum.

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

The NALCO Fuel Tech NO_xOUT system removes NO_x by the injection of urea into the boiler gas. This facet of the project, in conjunction with other combustion modifications, will reduce NO_x emissions and produce marketable fly ash.

A heat-pipe air-heater system will be used with advanced temperature controls to reduce both air leakage and the air heater's flue gas exit temperature. Ultimate emissions reductions with increased boiler efficiencies will result.

The project is designed for "total environmental and energy management," a concept encompassing low emissions, low energy consumption, improved combustion, upgraded boiler controls, and reduced solid waste. The system is being designed to achieve at least a 95% SO_2 removal efficiency using limestone while burning



high-sulfur coal. NO_x reductions will be achieved using selective non-catalytic reduction technology and separate combustion modifications. The system has zero wastewater discharge and produces marketable by-products (e.g., commercial-grade gypsum, calcium chloride, and fly ash), minimizing solid waste.

New York State Electric & Gas plans to demonstrate these technologies at Units 1 and 2 of its Milliken Station located in Lansing, NY. Pittsburgh, Freeport, and Kittaning coals, with sulfur contents of 1.5%, 2.9%, and 4.0%, will be used.

Project Status:

The cooperative agreement was awarded on October 20, 1992. Environmental information is being prepared for use in the NEPA process. The environmental monitoring plan is being prepared. New York State completed its environmental review and issued permits in August 1992.

Commercial Applications:

The S-H-U SO_2 removal process, the NALCO NO_xOUT non-catalytic reduction process, Stebbins' tile-lined split-module absorber, and heat-pipe air-heater technology are applicable to virtually all electric utility power plants. Commercialization of all technologies in both retrofit and greenfield applications of virtually any megawatt size is expected. The high removal efficiency, up to 98% for SO_2 and up to 30% beyond combustion modifications for NO_x, will make the combination of these technologies attractive.

The space-saving design features of the S-H-U, NALCO, Stebbins, and heat-pipe technologies, combined with the production of marketable by-products, offer significant incentives to generating stations with limited on-site space. In addition, the inherent energy efficiency of the combined technologies minimizes any secondary environmental impacts from the operation of pollution control equipment.

Piñon Pine IGCC Power Project

Sponsor:

Sierra Pacific Power Company

Additional Team Members:

Foster Wheeler USA Corporation—architect, engineer, and constructor

The M.W. Kellogg Company—technology supplier

Location:

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

Technology:

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

Plant Capacity/Production:

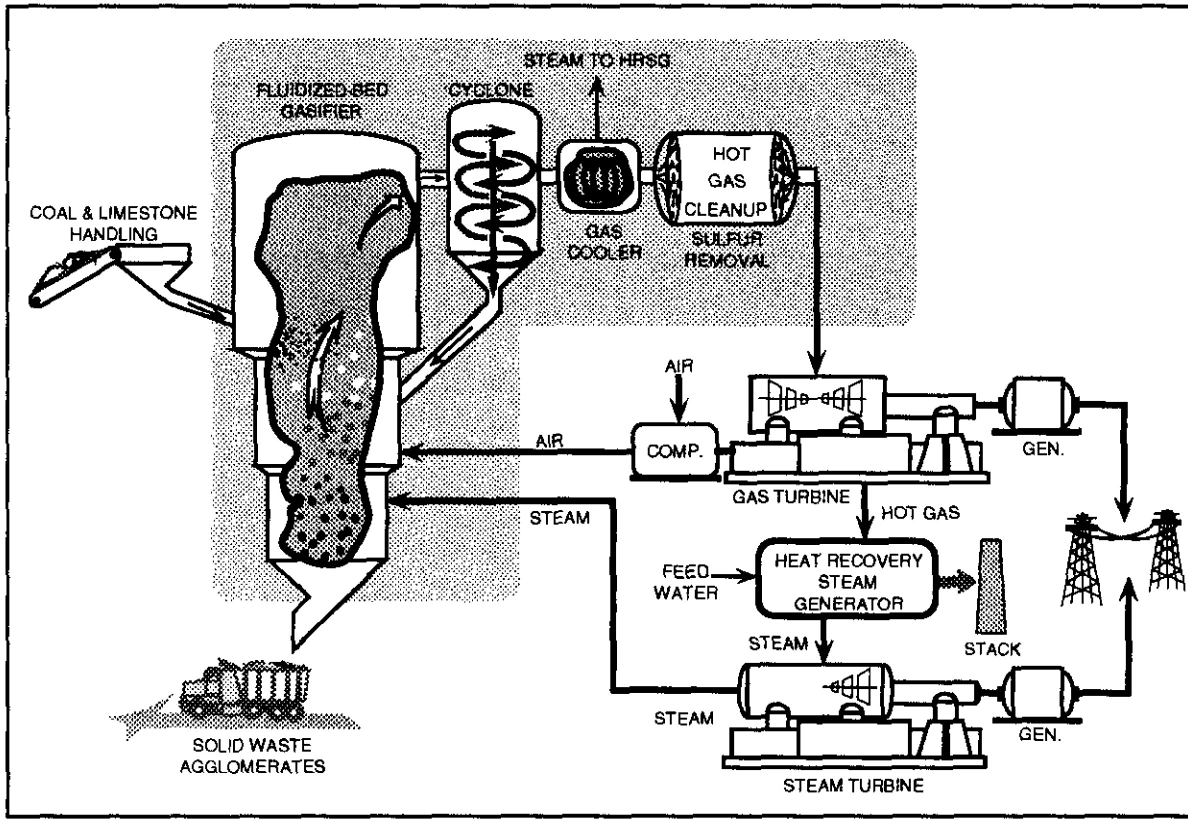
80 MWe (net)

Project Funding:

Total project cost	$269, 993,100	100%
DOE	134,996,550	50
Participant	134,996,550	50

Project Objective:

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



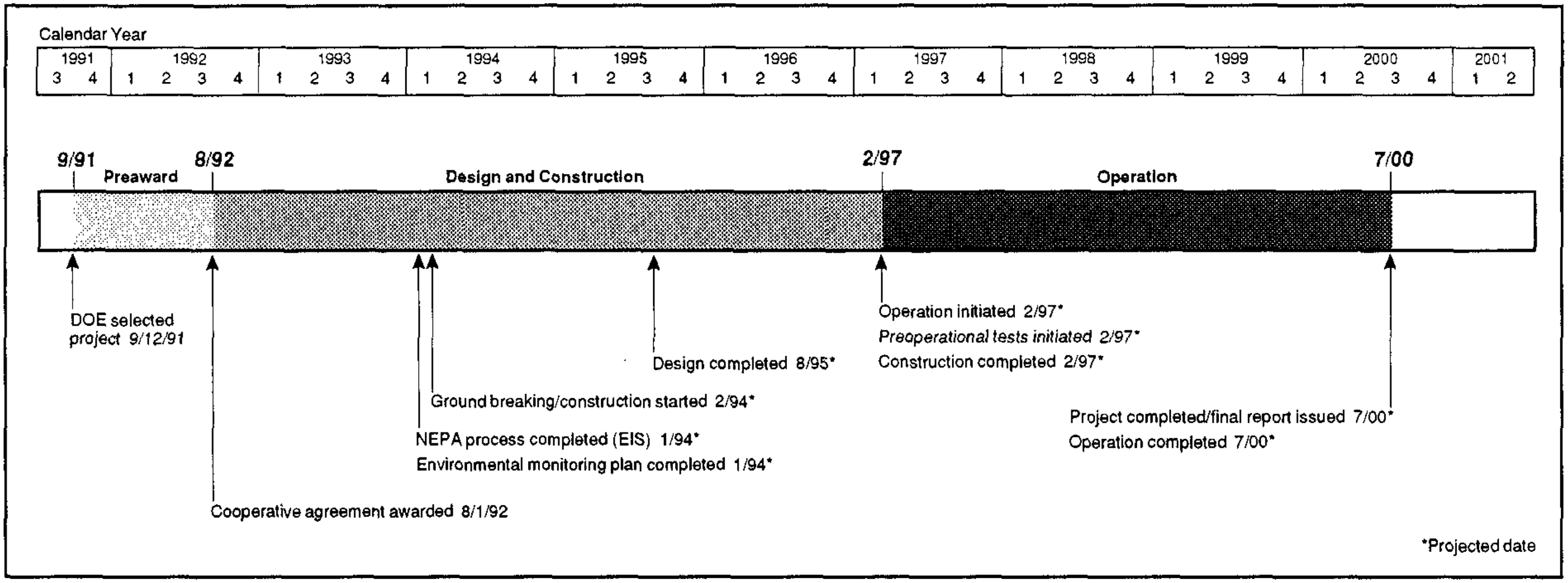
Technology/Project Description:

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

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

The hot, cleaned gas then enters the combustion turbine which is coupled to a generator designed to produce 56 MWe (gross). Exhaust gas is used to produce steam in a heat recovery steam generator. Superheated high-pressure steam drives a condensing steam turbine-generator designed to produce about 30 MWe (gross).

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



In the demonstration project, a nominal 800 tons/day of coal is converted into 86 MWe (gross), or 80 MWe (net) for export to the grid. Western bituminous coal from Utah is the design coal; tests with higher sulfur and lower rank coals also are planned. The gasifier is being built at Sierra Pacific Power Company's Tracy Station, near Reno, NV.

Project Status/Accomplishments:

The cooperative agreement was awarded August 1, 1992. The sponsor's major activities centered on preparing and submitting its Triennial Resource Plan to the Public Service Commission of Nevada (PSCN). The plan recommended the Piñon Pine IGCC project as the least-cost option for new baseload. In a public meeting on November 23, 1992, the PSCN requested that Sierra Pacific Power Company refile a portion of the plan which includes the IGCC project; the request concerned overall long-term aspects of the plan and was not directly related to the proposed IGCC project. The refiled plan is due in April 1993, with a final ruling by the PSCN expected by July 1. The PSCN directed Sierra Pacific to take whatever steps are necessary to maintain Piñon Pine as an option in the meantime.

Environmental information is being prepared for the NEPA process. Three public scoping meetings were held in the Reno area to support preparation of an environmental impact statement.

Commercial Applications:

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

The KRW IGCC technology is capable of gasifying all types of coals, including high-sulfur and high-swelling coals, as well as bio- or refuse-derived waste, with minimal environmental impact. This versatility provides numerous economic advantages for the depressed mineral extraction and cleanup industries. There are no significant process waste streams that require remediation. The only solid waste from the plant is a mixture of ash and calcium sulfate, a non-hazardous waste. SO_2 emissions are expected to be below 0.045 lb/million Btu (98–99% reduction for most high-sulfur coals). NO_x emissions are expected to be below 0.053 lb/million Btu, and emissions of particulates are expected to be below 0.01 lb/million Btu.

Toms Creek IGCC Demonstration Project

Sponsor:
TAMCO Power Partners (a partnership between TP [TAMCO] Company, a subsidiary of Tampella Power Corporation, and CP [TAMCO] Company, a subsidiary of Coastal Power Production Company)

Additional Team Member:
Institute of Gas Technology—technology developer and consultant

Location:
Coeburn, Wise County, VA (Virginia Iron, Coal, and Coke Company's Toms Creek Mine)

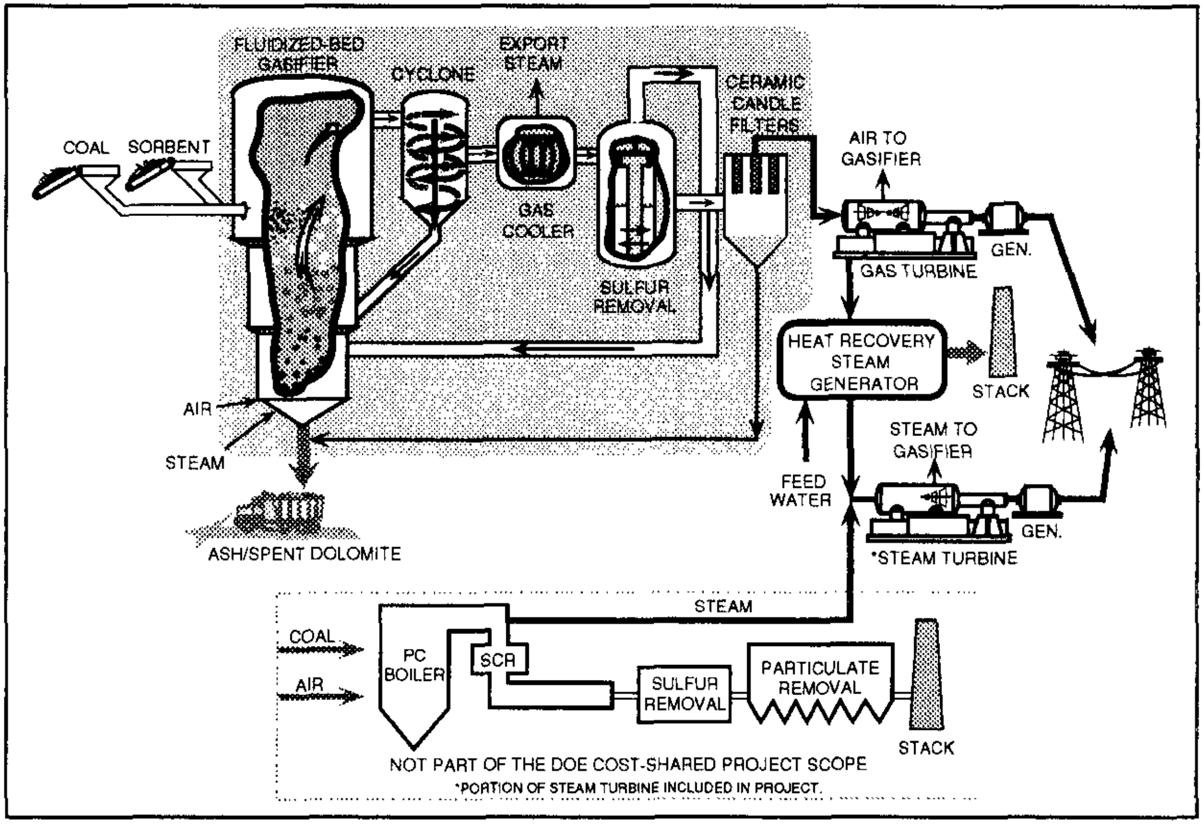
Technology:
Integrated gasification combined-cycle (IGCC) using the Tampella U-GAS* fluidized-bed gasification system

Plant Capacity/Production:
190 MWe (55 MWe IGCC and 135 MWe pulverized coal)

Project Funding:

Total project cost	$196,570,000	100%
DOE	95,000,000	48
Participant	101,570,000	52

Project Objective:
To demonstrate an air-blown, fluidized-bed gasification, combined-cycle technology, incorporating hot gas cleanup, for generating electricity and to assess the system's environmental and economic performance for meeting future energy needs. Also to demonstrate the newly developed zinc titanate fluidized-bed hot-gas cleanup technology.



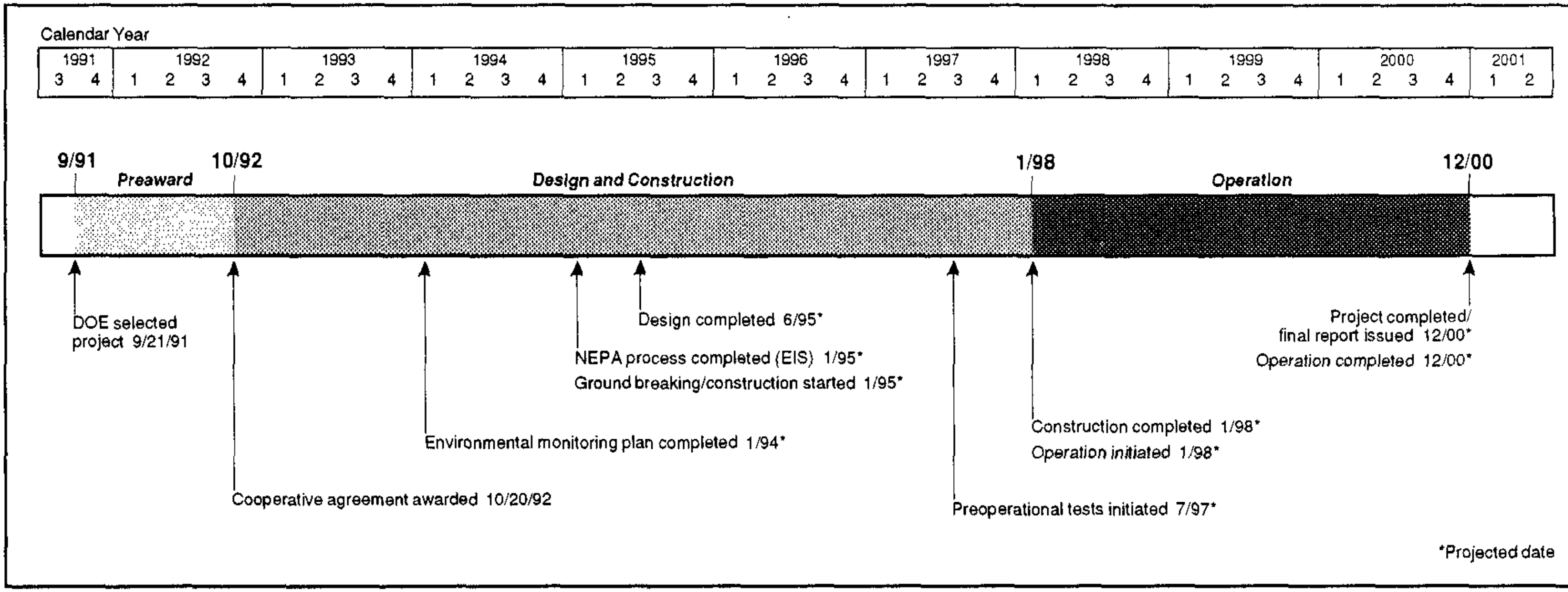
Technology/Project Description:
Being demonstrated is an IGCC system in which air-blown operation has replaced the more conventional oxygen-blown gasifier operation and hot gas cleanup has replaced cold gas cleanup with the usual associated sulfur recovery.

Coal is gasified in a pressurized, air-blown, fluidized-bed gasifier in the presence of a calcium-based sorbent. About 90% sulfur removal is accomplished in the gasifier. Solids entrained in the gas are collected by cyclones in two stages. The low-Btu gas, which leaves the secondary cyclone at 1,800–1,900 °F, is cooled to about 1,000 °F before entering the post-gasifier desulfurization unit where zinc titanate is used to remove the bulk of the remaining sulfur in the gas. This is accomplished in two fluidized beds. In the first bed, the sulfur is absorbed by the zinc titanate; the zinc titanate is regenerated in the second bed. In the final hot-gas-cleaning step, a ceramic candle filter removes particulates. The gas is then sent to the gas turbine combustor which has been modified to burn low-Btu gas.

Hot exhaust gases from the gas turbine are directed to a heat recovery steam generator. The steam generated is used both for driving a conventional steam turbine generator to produce additional electricity and to provide steam feed to the gasifier.

About 430 tons/day of bituminous coal are converted into 55 MWe by the gas turbine. A conventional pulverized coal boiler produces another 135 MWe through the shared steam turbine generator. Also, 50,000 lb/hr of steam are generated for export to a coal preparation plant located next to the demonstration facility. The electric power is sold to a utility.

U-GAS is a registered trademark of the Institute of Gas Technology.



The facility is a greenfield plant located outside Coeburn, VA, next to the Toms Creek Mine owned by Virginia Iron, Coal, and Coke Company, a subsidiary of Coastal Power Production Company.

Project Status/Accomplishments:

The cooperative agreement was signed on October 20, 1992. Preliminary design and project definition studies are under way. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The Toms Creek IGCC system is suitable for new power plants, repowering needs, and cogeneration applications.

In recent years, IGCC has become a rapidly emerging alternative for new electric generating plants. Such plants require 15% less land area than pulverized coal plants with flue gas desulfurization, and exhibit substantially improved thermal efficiency and environmental performance. Because of its advantages of modularity, rapid and staged on-line generation capability, high efficiency, environmental controllability, and reduced land and natural resource needs, IGCC is a strong contender for widespread application for meeting future U.S. energy needs. Another important application for IGCC is cogeneration under PURPA's Qualifying Facilities provisions.

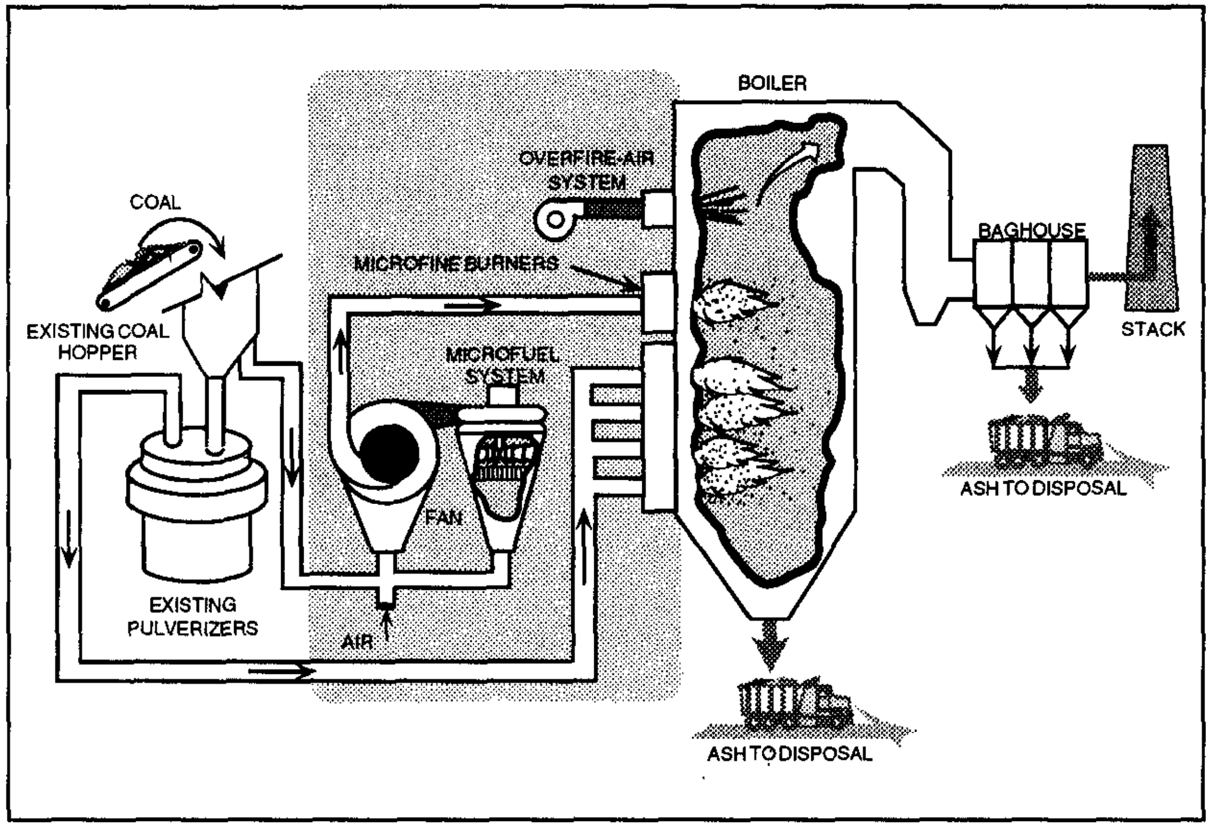
The heat rate of the demonstration facility is expected to be 8,720 Btu/kWh (39% efficiency) with SO_2 emissions reductions of 99% (0.056 lb/million Btu release). NO_x emissions are estimated to be 0.09 lb/ million Btu.

A larger, commercial-scale, 271-MWe greenfield facility based on the Toms Creek technology is estimated to have a heat rate of 7,750 Btu/kWh (44% efficiency). This represents a 20% increase in thermal efficiency and a corresponding reduction in CO_2 emissions as compared to a conventional pulverized coal plant equipped with a scrubber.

The U-GAS® technology is capable of gasifying all types of coals, including high-sulfur and high-swelling coal feedstocks.

The total system being demonstrated is compact, reducing space requirements, and is very amenable to smaller capacity, modular construction situations. There are no significant wastewater streams, and the solid waste from the gasifier is ash and calcium sulfate, which is discharged as a non-hazardous waste.

Micronized Coal Reburning Demonstration for NO_x Control on a 175-MWe Wall-Fired Unit



Sponsor:
Tennessee Valley Authority

Additional Team Members:
Duke/Fluor Daniel (partnership between Duke Engineering & Services, Inc., and Fluor Daniel, Inc.)—engineer and constructor
Fuller Company—technology supplier
R-C Environmental Services and Technology—technical consultant

Location:
West Paducah, McCracken County, KY (Tennessee Valley Authority's Shawnee Fossil Plant)

Technology:
Advanced NO_x control using micronized-coal-reburning combustion technology

Plant Capacity/Production:
175 MWe

Project Funding:

Total project cost	$7,330,041	100%
DOE	3,514,755	48
Participants	3,815,286	52

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

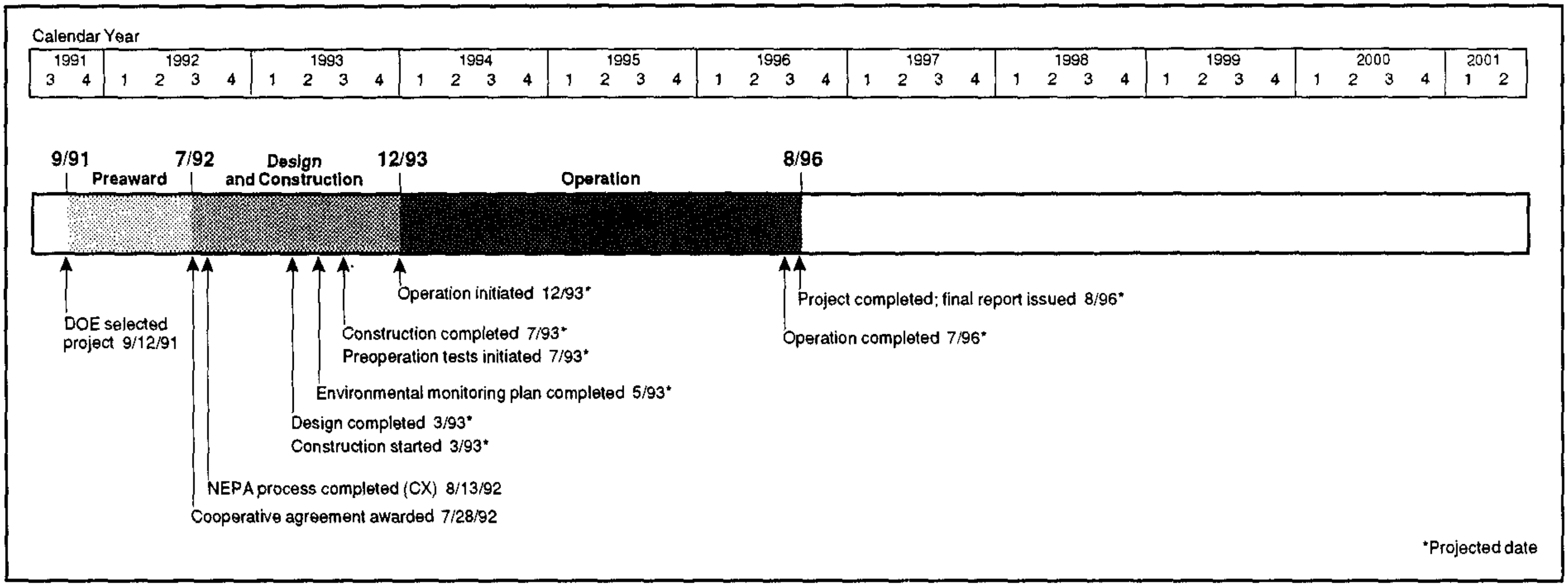
MicroMill is a trademark of the Fuller Company.

Technology/Project Description:
The technology is being applied to a 175-MWe front-wall-fired, dry-bottom furnace. The coal currently used to fire the furnace (low-sulfur bituminous coal from Kentucky or West Virginia) will be the reburning fuel. The reburning coal, which can comprise up to 30% of the total fuel, is micronized (80% below 325 mesh) and injected into the furnace above the main burner, the region where NO_x formation occurs.

Central to the project technology is the two-element MicroFuel system, which consists of a patented centrifugal-pneumatic MicroMill™ and an external classifier. The mill is capable of grinding coal into a fine powder without the mechanical attrition or roll crushing normally associated with coal mills. The MicroMill™ is being installed between the existing pulverizers and the newly installed microfine burners for the project.

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

The combination of micronized coal, supplying 30% of the total furnace fuel requirements, and advanced reburning utilizing that requirement in conjunction with fuel/air staging, provides flexible options for



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

The Tennessee Valley Authority plans to retrofit its Shawnee Fossil Plant, located near West Paducah, KY, with the micronized-coal-reburning technology.

Project Status/Accomplishments:

Design efforts began shortly after the cooperative agreement was awarded in July 1992. Design and construction are expected to overlap for a short period, with construction being completed in mid-1993. The environmental monitoring plan is being prepared and is expected to be complete in early spring 1993.

The Fuller Company purchased MicroFuel Corporation (the technology supplier) in September 1992 and will assume MicroFuel's obligations to this project.

NEPA compliance has been satisfied through a categorical exclusion approved on August 13, 1992.

Commercial Applications:

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

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

Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal

Sponsor:
ThermoChem, Inc.

Additional Team Member:
Manufacturing and Technology Conversion International, Inc.—technology supplier

Location:
Near Gillette, Campbell County, WY (Caballo Rojo Mine)

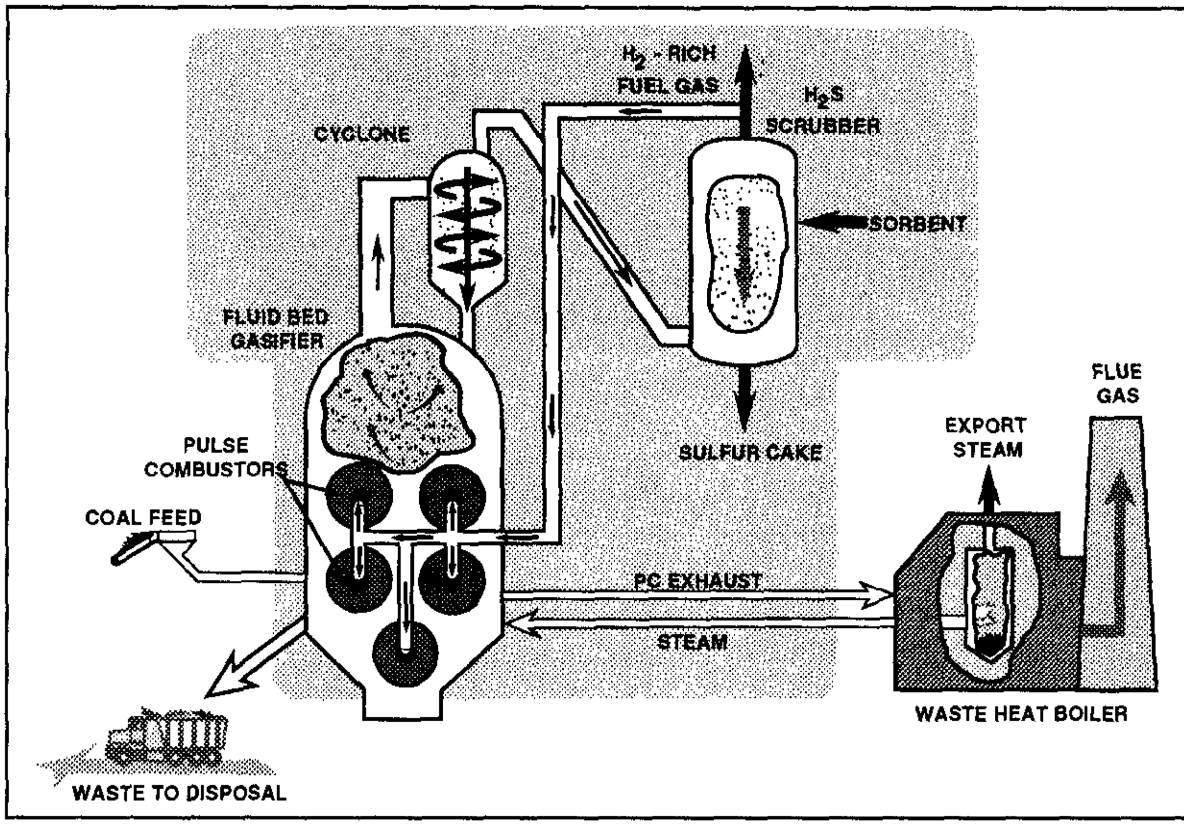
Technology:
Advanced combustion using Manufacturing and Technology Conversion International's (MTCI) pulse combustor/gasifier

Plant Capacity/Production:
161 million Btu/hr of 325 Btu/std ft^3 medium-Btu fuel gas plus 40,000 lb/hr of export steam

Project Funding:

Total project cost	$37,333,474	100%
DOE	18,666,737	50
Participants	18,666,737	50

Project Objective:
To demonstrate the MTCI pulse combustor in an application for steam gasification of coal to produce a medium-Btu fuel gas from subbituminous coal.

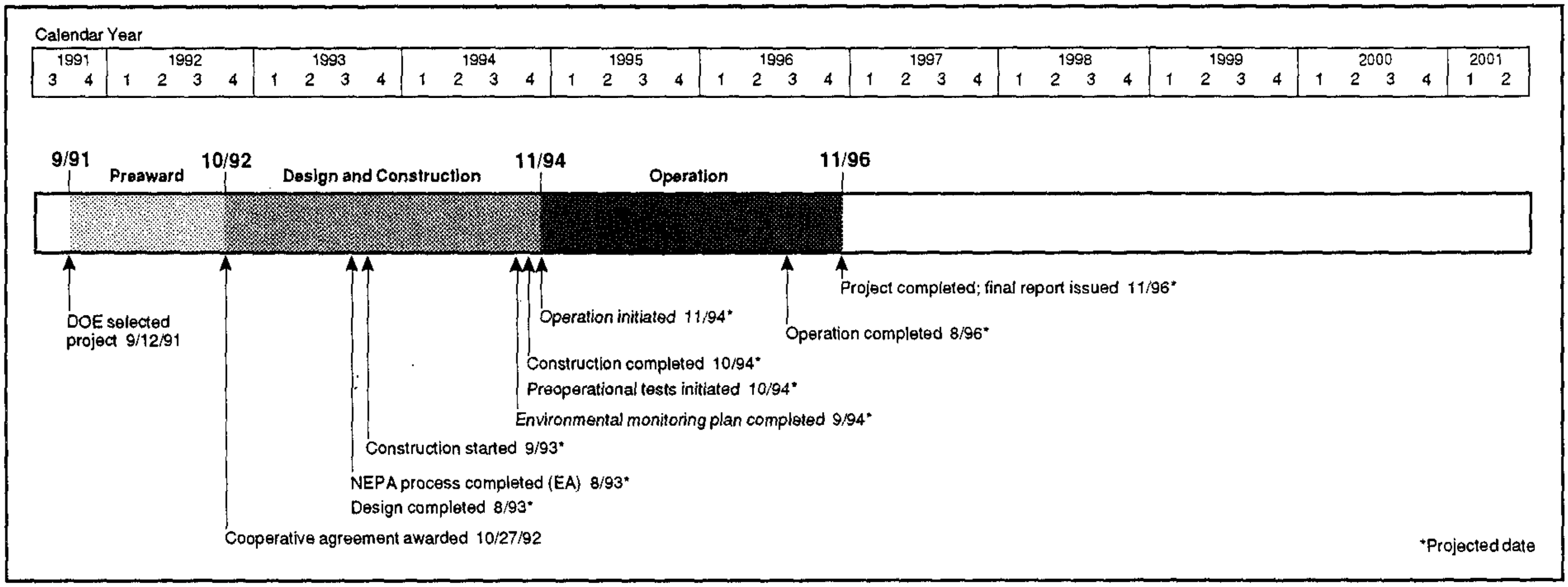


Technology/Project Description:
The MTCI fluidized-bed gasifier incorporates an innovative indirect heating process for thermochemical steam gasification of coal to produce hydrogen-rich, clean, medium-Btu fuel gas without the need for an oxygen plant. The indirect heat transfer is provided by MTCI's multiple resonance tube pulse combustor technology with the resonance tubes comprising the heat exchanger immersed in the fluidized-bed reactor. Heat transfer is 3–5 times greater than other indirectly heated gasifier concepts, allowing the heat transfer surface to be minimized.

The demonstration plant's overall efficiency is expected to be 72% or more. In major commercial applications, char combustion and heat recovery operations can be included to enhance overall plant efficiency.

SO_2 emissions are controlled by scrubbing the product gas using the Sulfur-Ox process. A market for the by-product sulfur is being sought, and disposal methods are being evaluated.

The demonstration facility will be built at the Caballo Rojo Mine in conjunction with a new facility to demonstrate the K-Fuel coal-upgrading process. Water required to gasify the subbituminous coal will be produced by the K-Fuel process and the steam produced in the gasification demonstration facility will be used in the K-Fuel facility. The product gas will be burned in a gas turbine to generate electricity to operate both facilities.



Project Status/Accomplishments:

The cooperative agreement was awarded on October 27, 1992, and design activities are under way. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The MTCI fluidized-bed gasifier is expected to provide the exceptional environmental performance exhibited by coal gasification in general. SO_2 emissions are controlled by removing hydrogen sulfide from the product gas prior to combustion; removal efficiencies approaching 99% are possible. Particulate emissions are also controlled in highly efficient scrubbers. Finally, the MTCI pulse combustion technology that provides the required gasifier heat is an inherently low-NO_x combustion process, thereby assuring that NO_x emissions are substantially below acceptable limits.

Because of its potential for reducing emissions while producing a clean-burning, hydrogen-rich fuel gas, the MTCI fluidized-bed gasifier is expected to have considerable commercial potential. Some of the early industrial applications of this technology are expected to be waste-to-energy or waste and coal co-fired facilities for power and steam generation. One of the more promising non-coal applications is processing of kraft black liquor.

The processing of pulp results in the production of about 88 million tons of by-product black liquor. The current practice of using black liquor recovery boilers to produce steam and electricity is inefficient. Replacing these boilers with MTCI gasifiers would significantly improve the conversion efficiency. The estimated market for MTCI gasifiers in this application alone is 28 units annually.

Another potential application for the technology is in industrial coal gasification because of its modularity and ability to produce a medium-Btu gas without requiring an oxygen plant. In the short term, the most significant application of this technology is likely to be in conjunction with coal-upgrading facilities as demonstrated in this project.

Demonstration of the Union Carbide CANSOLV™ System at the ALCOA Generating Corporation Warrick Power Plant

Sponsor:
Union Carbide Chemicals and Plastics Company Inc.

Additional Team Members:
Aluminum Company of America (ALCOA) Generating Corporation—host and cofunder
Stone and Webster Engineering Corporation—engineer

Location:
Newburgh, Warrick County, IN (ALCOA Generating Corporation's Warrick Generating Station Unit No. 2)

Technology:
Flue gas cleanup using Union Carbide Chemicals and Plastics Company's CANSOLV™ regenerable flue gas desulfurization (FGD) system

Plant Capacity/Production:
75 MWe

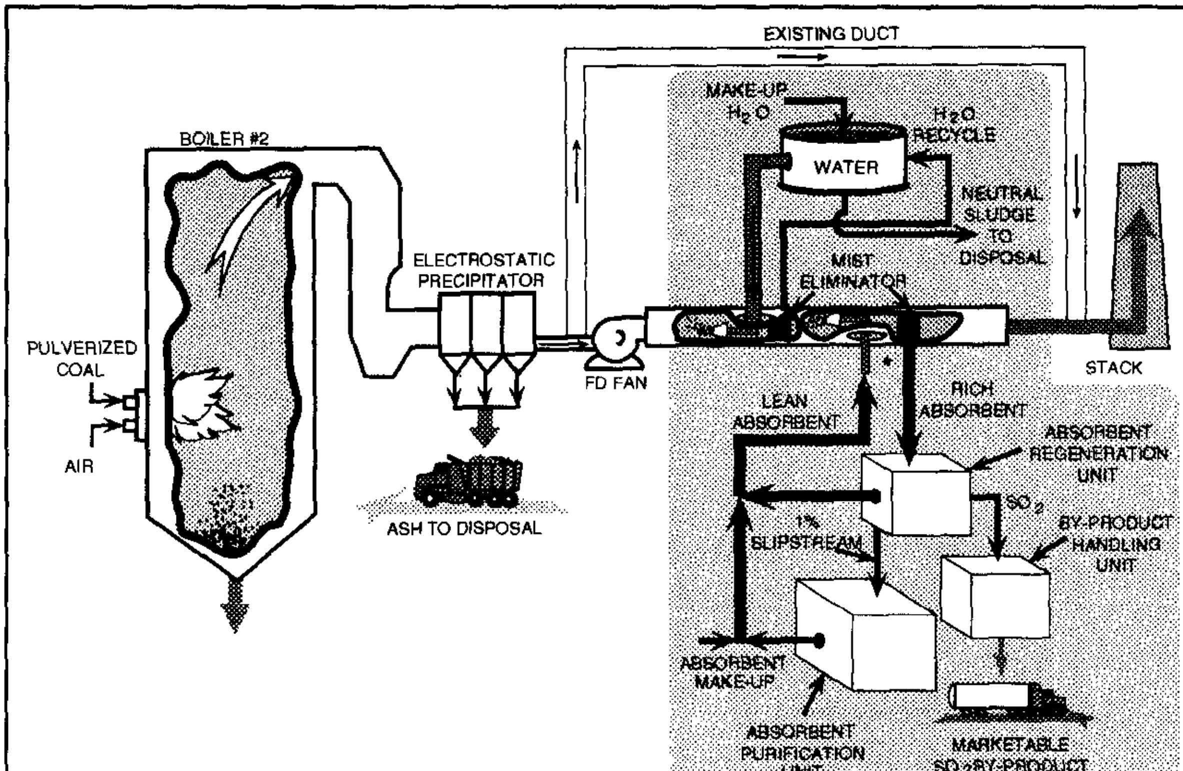
Project Funding:

Total Project Cost	$32,715,000	100%
DOE	16,357,500	50
Participants	16,357,500	50

(Funding amounts reflect those contained in the proposal and are subject to negotiation.)

Project Objective:
To demonstrate the CANSOLV™ regenerable flue gas desulfurization system to achieve SO_2 removal efficiencies of at least 99%.

CANSOLV is a trademark of Union Carbide Chemicals and Plastics Company Inc.



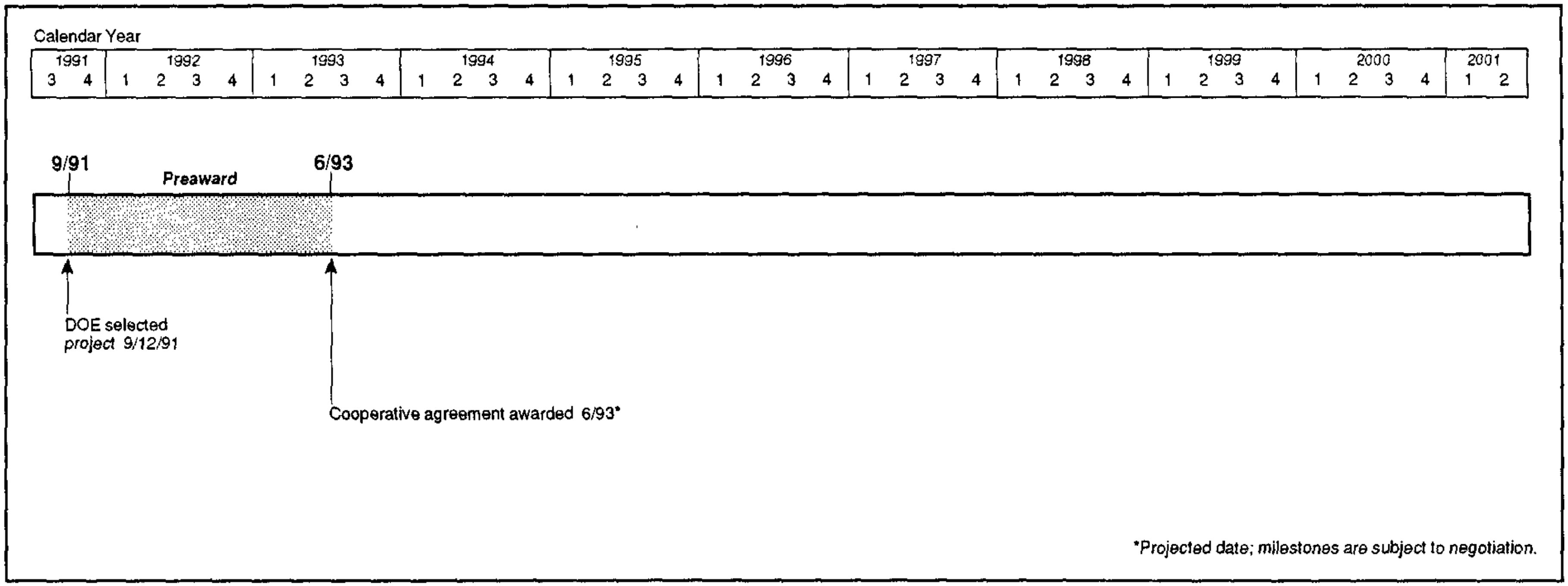
* NOTE: One of three stages of sorbent injection

Technology/Project Description:
In the CANSOLV™ process, untreated flue gas enters the process from a particulate control device, such as a electrostatic precipitator, where it is contacted first by water and then by an aqueous solution of the SO_2 absorbent, both introduced to the gas stream as ultra-fine droplets through atomizing nozzles. Following each spraying section, mist elimination equipment removes the droplets from the gas stream, and after the last section, the treated gas is released to the chimney.

The water loop removes any particulate matter remaining in the gas, saturates the gas, and absorbs any chlorides and fluorides. The SO_2 is scrubbed from the flue gas by contact with the absorbent solution. In the absorbent loop, rich absorbent laden with SO_2 is routed to the absorbent regeneration unit where, through the application of heat, the SO_2 is stripped from the absorbent. The SO_2 stream is converted to salable products appropriate to local market conditions and opportunities. A 1% slipstream is taken from the recirculating lean absorbent and treated in the absorbent purification unit to prevent the build-up of impurities.

An advanced FGD technology, the CANSOLV™ process is capable of SO_2 capture rates over 99%. The demonstration project is using Indiana high-sulfur bituminous coal, with a sulfur content of about 3.4%.

ALCOA Generating Corporation's Warrick Generating Station Unit No. 2, located in Newburgh, IN, will be retrofitted with a newly designed and constructed CANSOLV™ scrubber facility capable of treating 50% of the flue gas from the unit.



Project Status/Accomplishments:

The project is in negotiation. At the sponsor's request, DOE's negotiating deadline was extended 7½ months so that the sponsor could find a partner to share the project risk. Environmental information is being prepared for use in the NEPA process.

Commercial Applications:

The CANSOLV™ process is attractive for both new and retrofit utility and industrial applications.

The process is designed to operate as an in-duct scrubber system, without the need for costly scrubbing vessels. Regeneration occurs in relatively small vessels requiring a minimal amount of space. Consequently the process potentially is applicable to the many space-constrained facilities. CANSOLV™ may be integrated effectively with other NO_x and particulate control systems to provide for overall emission control.

The CANSOLV™ process is a viable alternative to and economically competitive with conventional wet FGD processes. CANSOLV™ can be retrofitted with modest capital investment and downtime, and its space requirements are substantially less. CANSOLV™ can reduce SO_2 emissions by up to 99% while producing only minimal solid or liquid waste. The SO_2 removed from the flue gas can be converted to a salable by-product—liquid SO_2, sulfuric acid, or elemental sulfur. CANSOLV™ can handle all types of coal.

Wabash River Coal Gasification Repowering Project

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

Additional Team Members:
PSI Energy, Inc.—host utility
Destec Energy, Inc.—engineer, gas plant operator, and technology supplier
Electric Power Research Institute—cofunder

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

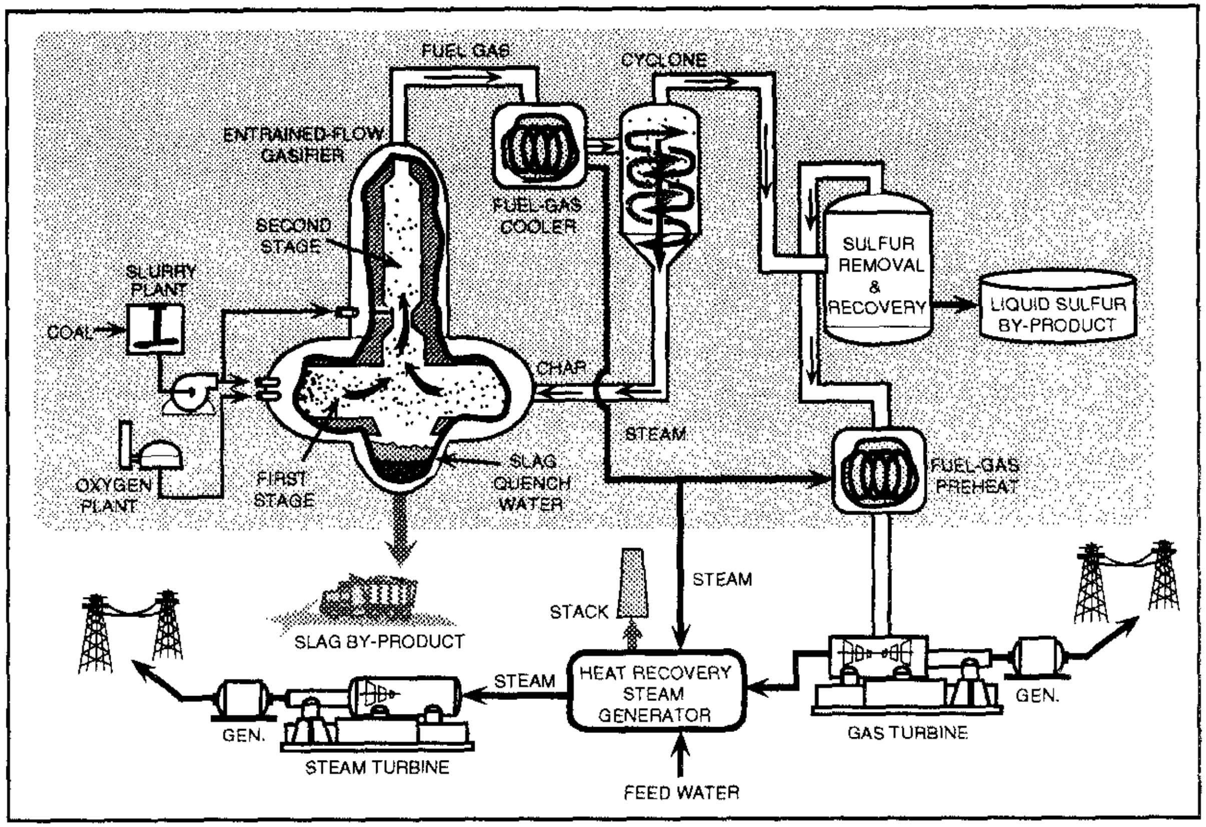
Technology:
Integrated gasification combined-cycle (IGCC) using Destec's two-stage, entrained-flow gasification system

Plant Capacity/Production:
268 MWe (net)

Project Funding:

Total Project cost	$396,000,000	100%
DOE	198,000,000	50
Participant	198,000,000	50

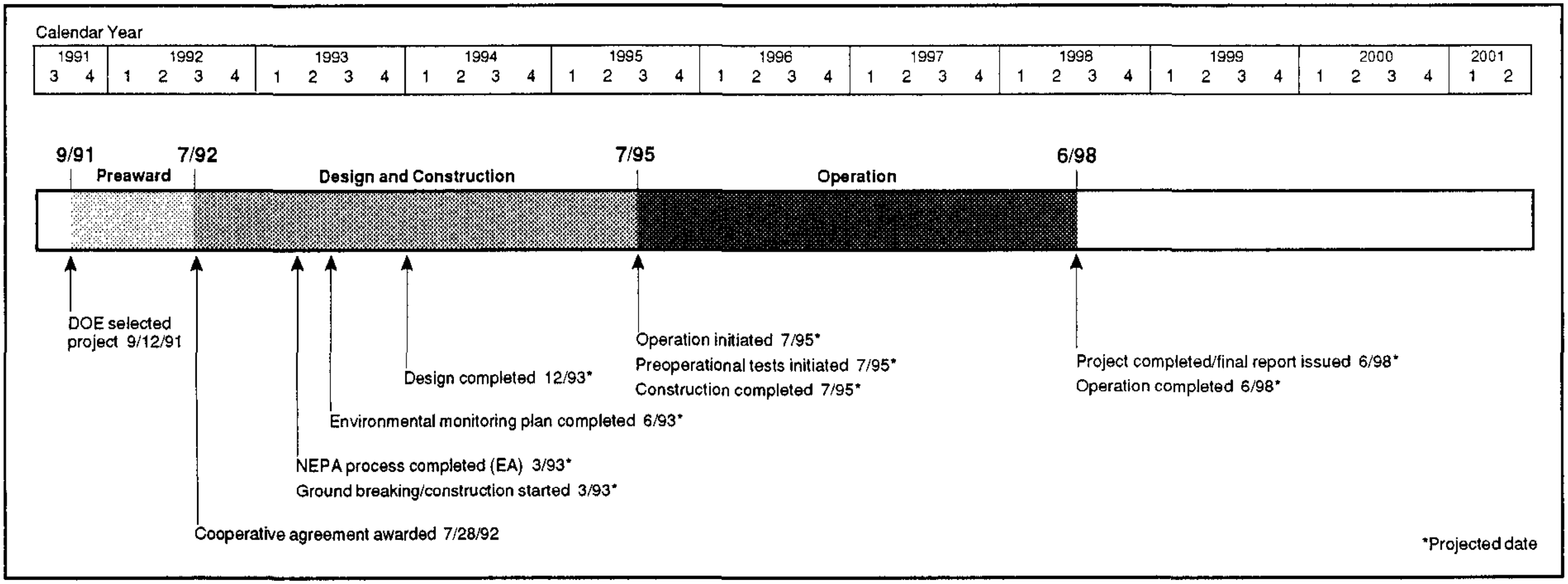
Project Objective:
To demonstrate utility repowering with a two-stage, oxygen-blown IGCC system, including advancements in the technology relevant to the use of high-sulfur bituminous coal, and to assess long-term reliability, availability, and maintainability of the system at a fully commercial scale.



Technology/Project Description:
Coal is ground, slurried with water, and gasified in a pressurized, two-stage (entrained flow slagging first stage and non-slagging second stage), oxygen-blown, entrained-flow gasifier. The product gas is cooled through heat exchangers and passed through a conventional cold gas cleanup system which removes particulates, ammonia, and sulfur. The clean, medium-Btu gas is then reheated and burned in an advanced 192-MWe gas turbine. Hot exhaust from the gas turbine is passed through a heat recovery steam generator to produce high-pressure steam. High-pressure steam is also produced from the gasification plant and superheated in the heat recovery steam generator. The combined high-pressure steam flow is supplied to an existing 110-MWe steam turbine.

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

One of six units at PSI Energy's Wabash River Generating Station, located in West Terre Haute, IN, is being repowered. The demonstration unit will be designed to generate 268 MWe net using 2,544 tons/day of high-sulfur, Illinois Basin bituminous coal. The anticipated heat rate for the repowered unit is 8,974 Btu/kWh (38% efficiency). Using high-sulfur bituminous coal, SO_2 emissions are expected to be less than 0.2 lb/million Btu (98% reduction). NO_x emissions are expected to be less than 0.1 lb/million Btu (90%



reduction). Upon completion, the project will represent the largest single-train IGCC plant in operation in the United States.

Project Status/Accomplishments:

The cooperative agreement was signed on July 28, 1992. Initial design efforts and preliminary site preparation are under way. In December 1992, a draft environmental assessment was prepared, as required by the NEPA process. Applications for air and water permits were filed with the Indiana Department of Environmental Management, and a Petition for Need was filed with the Indiana regulatory commission.

Commercial Applications:

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

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

Appendix E: CCT Project Contacts

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

CCT-I Projects

Development of the Coal Quality Expert
Sponsors: ABB Combustion Engineering, Inc., and CQ, Inc.
Contact: Clark Harrison, President
(412) 479-6016

CQ, Inc.
One Quality Center
P.O. Box 280
Homer City, PA 15748-0280

LIMB Demonstration Project Extension and Coolside Demonstration
Sponsor: The Babcock & Wilcox Company
Contact: Todd Johnson, Senior Marketing Specialist
(216) 829-7355

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

Advanced Cyclone Combustor with Internal Sulfur, Nitrogen, and Ash Control
Sponsor: Coal Tech Corporation
Contact: Bert Zauderer, President
(215) 667-0442

Coal Tech Corporation
P.O. Box 154
Merion, PA 19066

Nucla CFB Demonstration Project
Sponsor: Tri-State Generation and Transmission Association, Inc.
Contact: Raymond Keith, Executive Vice President
(303) 249-4501

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

Enhancing the Use of Coals by Gas Reburning and Sorbent Injection
Sponsor: Energy and Environmental Research Corporation
Contact: Blair A. Folsom, Senior Vice President
(714) 859-8851

Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718

Tidd PFBC Demonstration Project
Sponsor: American Electric Power Service Corporation as agent for The Ohio Power Company
Contact: Mario Marrocco, Manager, PFBC Programs
(614) 223-1740

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

Advanced Coal Conversion Process Demonstration
Sponsor: Rosebud SynCoal Partnership
Contact: Ray W. Sheldon, Project Manager
(406) 748-2366 and/or (406) 252-2277

Rosebud SynCoal Partnership
P.O. Box 7137
Billings, MT 59103-7137

York County Circulating Fluidized-Bed Cogeneration Project
Sponsor: York County Energy Partners, L.P.
Contact: Bradley Hahn, Project Manager
(215) 481-3955

York County Energy Partners, L.P.
2146 White Street
York, PA 17404

CCT-II Projects

Combustion Engineering IGCC Repowering Project
Sponsor: ABB Combustion Engineering, Inc.
Contact: Robert W. Glamuzina, Project Manager
(203) 285-5904

ABB Combustion Engineering, Inc.
P.O. Box 500
Windsor, CT 06095-0500

SNOX Flue Gas Cleaning Demonstration Project
Sponsor: ABB Combustion Engineering, Inc.
Contact: Bill Kingston, Project Manager
(205) 995-5368

Environmental Systems Division
ABB Combustion Engineering, Inc.
P.O. Box 43030
Birmingham, AL 35243

Demonstration of Coal Reburning for Cyclone Boiler NO_x Control
Sponsor: The Babcock & Wilcox Company
Contact: Todd Johnson, Senior Marketing Specialist
(216) 829-7355

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

SOX-NOX-ROX Box Flue Gas Cleanup Demonstration Project
Sponsor: The Babcock & Wilcox Company
Contact: Todd Johnson, Senior Marketing Specialist
(216) 829-7355

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

Innovative Coke Oven Gas Cleaning System for Retrofit Applications
Sponsor: Bethlehem Steel Corporation
Contact: Marshall R. Mazer, Project Manager
(215) 694-2389

Bethlehem Steel Corporation
1739 Martin Tower
1170 8th Avenue
Bethlehem, PA 18016

PFBC Utility Demonstration Project
Sponsor: The Appalachian Power Company
Contact: Mario Marrocco, Manager, PFBC Programs
(614) 223-1740

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

Cement Kiln Flue Gas Recovery Scrubber
Sponsor: Passamaquoddy Tribe
Contact: Garrett Morrison, Project Manager
(207) 594-5555

Passamaquoddy Technology, L.P.
P.O. Box 350
Thomaston, ME 04861-0350

Advanced Flue Gas Desulfurization Demonstration Project
Sponsor: Pure Air on the Lake, L.P.
Contact: Don Vymazal, Manager, Contract Administration
(215) 481-3687

Pure Air on the Lake, L.P.
7201 Hamilton Boulevard
Allentown, PA 18195-1501

Demonstration of Advanced Combustion Techniques for a Wall-Fired Boiler
Sponsor: Southern Company Services, Inc.
Contact: John N. Sorge, ICCT Project Manager
(205) 877-7426

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

Demonstration of Innovative Applications of Technology for the CT-121 FGD Process
Sponsor: Southern Company Services, Inc.
Contact: David P. Burford, Project Manager
(205) 870-6329

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

Demonstration of Selective Catalytic Reduction Technology for the Control of NO_x Emissions from High-Sulfur-Coal-Fired Boilers
Sponsor: Southern Company Services, Inc.
Contact: J.D. (Doug) Maxwell, Project Manager
(205) 877-7614

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

180-MWe Demonstration of Advanced Tangentially Fired Combustion Techniques for the Reduction of NO_x Emissions from Coal-Fired Boilers
Sponsor: Southern Company Services, Inc.
Contact: Robert R. Hardman, Project Manager
(205) 877-7772

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

CCT-III Projects

10-MW Demonstration of Gas Suspension Absorption
Sponsor: AirPol, Inc.
Contact: Frank E. Hsu, Project Manager
(201) 288-7070

AirPol, Inc.
32 Henry Street
Teterboro, NJ 07608

Commercial-Scale Demonstration of the Liquid-Phase Methanol (LPMEOH™) Process
Sponsor: Air Products and Chemicals, Inc.
Contact: William R. Brown, Project Manager
(215) 481-7584

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

Healy Clean Coal Project
Sponsor: Alaska Industrial Development and Export Authority
Contact: John Olson, Project Manager
(907) 561-8050

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

Full-Scale Demonstration of Low-NO_x Cell™ Burner Retrofit
Sponsor: The Babcock & Wilcox Company
Contact: Todd Johnson, Senior Marketing Specialist
(216) 829-7355

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

Confined Zone Dispersion Flue Gas Desulfurization Demonstration
Sponsor: Bechtel Corporation
Contact: Allen G. Rubin, Project Manager
(415) 768-6514

Bechtel Corporation
P.O. Box 3965
San Francisco, CA 94119-3965

Blast Furnace Granulated Coal Injection System Demonstration Project
Sponsor: Bethlehem Steel Corporation
Contact: Daniel Kwasnoski, Project Director
(215) 694-6478

Bethlehem Steel Corporation
1739 Martin Tower
1170 8th Avenue
Bethlehem, PA 18016

PCFB Demonstration Project
Sponsor: DMEC-1 Limited Partnership
Contact: Gary Kruempel, Project Manager, Midwest Power, Inc.
(515) 281-2459

Midwest Power, Inc.
666 Grand Avenue
Des Moines, IA 50303

ENCOAL Mild Coal Gasification Project
Sponsor: ENCOAL Corporation
Contact: Jim Frederick, Project Manager
(307) 686-5493

ENCOAL Corporation
P.O. Box 3038
Gillette, WY 82717

Evaluation of Gas Reburning and Low-NO_x Burners on a Wall-Fired Boiler
Sponsor: Energy and Environmental Research Corporation
Contact: Blair A. Folsom, Senior Vice President
(714) 859-8851

Energy and Environmental Research Corporation
18 Mason
Irvine, CA 92718

LIFAC Sorbent Injection Desulfurization Demonstration Project
Sponsor: LIFAC–North America
Contact: Jim Hervol, Project Manager
(412) 497-2735

ICF Kaiser Engineers, Inc.
4 Gateway Center
Pittsburgh, PA 15222-1207

Commercial Demonstration of the NOXSO SO_2/NO_x Removal Flue Gas Cleanup System
Sponsor: MK-Ferguson Company
Contact: Eugene R. Recher, Program Manager
(216) 523-5923

MK-Ferguson Company
1500 West 3d Street
Cleveland, OH 44114

Integrated Dry NO_x/SO_2 Emissions Control System
Sponsor: Public Service Company of Colorado
Contact: Gordon A. Schott, Project Manager
(303) 329-1702

Public Service Company of Colorado
5900 East 39th Avenue
Denver, CO 80207

Tampa Electric Integrated Gasification Combined-Cycle Project
Sponsor: Tampa Electric Company
Contact: Donald E. Pless, Project Manager
(813) 228-1332

Tampa Electric Company
P.O. Box 111
Tampa, FL 33601-0111

CCT-IV Projects

Self-Scrubbing Coal™: An Integrated Approach to Clean Air
Sponsor: Custom Coals International
Contact: Robin Godfrey, Project Manager
(412) 642-2625

Custom Coals International
100 First Avenue, Suite 500
Pittsburgh, PA 15222

Milliken Clean Coal Technology Demonstration Project
Sponsor: New York State Electric & Gas Corporation
Contact: Dennis O'Dea, Project Manager
(607) 729-2551

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

Piñon Pine IGCC Power Project
Sponsor: Sierra Pacific Power Company
Contact: Jack Motter, Project Manager
(702) 689-4013

Sierra Pacific Power Company
6100 Neil Road
Reno, NV 89520-0400

Toms Creek IGCC Demonstration Project
Sponsor: TAMCO Power Partners
Contact: J.G. Patel, Vice President, New Technology
(404) 984-8871

Tampella Power Corporation
2300 Windy Ridge Parkway, Suite 225
Marietta, GA 30067

Micronized Coal Reburning Demonstration of NO_x Control on a 175-MWe Wall-Fired Unit
Sponsor: Tennessee Valley Authority
Contact: Tom Butler, Mechanical Engineer
(615) 751-6120

Tennessee Valley Authority
1101 Market Street, ATTN: MR-3A
Chattanooga, TN 37402

Demonstration of Pulse Combustion in an Application for Steam Gasification of Coal
Sponsor: ThermoChem, Inc.
Contact: William Steedman, Program Manager
(410) 997-9671

ThermoChem, Inc.
5570 Sterrett Place, Suite 210
Columbia, MD 21044

Demonstration of the Union Carbide CANSOLV™ System at the ALCOA Generating Corporation Warrick Power Plant
Sponsor: Union Carbide Chemicals and Plastics Company Inc.
Contact: Alex B. Barnett, Market Manager, Flue Gas Treating
(203) 794-2561

Union Carbide Chemicals and Plastics
Company Inc.
39 Old Ridgebury Road J3-386
Danbury, CT 06817-0001

Wabash River Coal Gasification Repowering Project
Sponsor: Wabash River Coal Gasification Repowering Project Joint Venture
Contact: David G. Sundstrom, Business Development Manager
(713) 974-8238

Destec Energy, Inc.
2500 City West Boulevard, Suite 1700
Houston, TX 77042