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The NUCLA Circulating Fluidized-Bed Demonstration Project

A U.S. DOE Post-Project Assessment

June 1995

U.S. Department of Energy
Office of Fossil Energy
Morgantown Energy Technology Center
Morgantown, West Virginia

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This report is a post-project assessment of the Nucla Circulating Fluidized-Bed (CFB) Demonstration Project, the second project to be completed in the U.S. Department of Energy's (DOE) Clean Coal Technology (CCT) Demonstration Program. The CCT Demonstration Program is a government and industry cofunded technology development effort to demonstrate a new generation of innovative coal utilization processes in a series of full-scale facilities.

Nucla was the first successful utility repowering project in the U.S., increasing the capacity of the original power station from 36 MW_e to 110 MW_e and extending its life by 30 years.

In 1984, Colorado-Ute Electric Association (CUEA) repowered its Nucla Station facility with a 420,000 kilogram per hour (kg/h) (925,000 pound per hour [lb/h]), Ahlstrom Pyropower Incorporated (API), atmospheric CFB boiler and a new 74-megawatt electric (MW_e) steam turbine. This was the first successful utility repowering project in the U.S., increasing the capacity of the original Nucla station from 36 MW_e to 110 MW_e, and extending its life by 30 years. When sold in 1984, the Nucla atmospheric CFB boiler was the largest of its type ever sold worldwide, providing a critical link between small pilot and industrial facilities and commercial-size plants. As part of its demonstration of fluidized-bed combustion technology, the Electric Power Research Institute (EPRI) selected the plant in 1985 as a host for a detailed test program. Totally coal-fired testing of the unit began in July 1987. In August 1988, DOE began participating in the ongoing operations. The following October, CUEA was awarded a cooperative agreement that consolidated DOE's continuing involvement.

In the Nucla atmospheric CFB boiler, combustion and desulfurization both take place in the fluidized bed. Calcium in the sorbent captures sulfur dioxide (SO_2) gases. Combustion temperatures are controlled between 840 and 900 °C (1,550 and 1,650 °F), which is the most efficient range for desulfurization. In addition, these relatively low combustion temperatures limit NO_x formation. At various levels in the combustor, streams of secondary air complete the combustion of fuel in stages. Staged combustion also helps to suppress NO_x formation. In the upper zones, some particles become entrained in the combustion gas and are carried out the top of the combustion chambers and into the dual hot cyclones. Each hot cyclone separates the larger particles from the gas and recirculates them to the lower zones of the combustion chambers. This continuous circulation of coal char and sorbent particles is the novel feature of CFB technology. It helps to control boiler temperature and improves mixing, which extends the contact time of solids and gases, thus promoting coal utilization and sulfur capture.

The Nucla atmospheric CFB plant operated for more than 2 years under the terms of DOE's cooperative agreement. During the test effort, the design and reliability of the combustor and its support equipment were improved, and an operational database was developed for the scaleup and improvement of future designs. The ability of CFB technology to easily burn a variety of coals cleanly and efficiently was demonstrated. The emissions-control performance of the plant met or exceeded permit requirements. Although typical start-up and maintenance problems were experienced, they were related to deficiencies in ancillary equipment rather than the atmospheric CFB boiler.

As expected during the demonstration of a new technology, Nucla's average availability and capacity factor were below the typical utility averages. This was caused by part-load testing and numerous outages, some of which were required to inspect materials and remedy problems related to the boiler. In addition, CUEA was plagued by financial difficulties throughout the demonstration, which prevented the utility from making some of the capital improvements that would have enhanced the plant's reliability. However, by the last 3 months of the demonstration, most of the technical problems had been overcome and the plant's availability and capacity factor averaged 97.0 percent and 66.5 percent, respectively (Colorado-Ute Electric Association 1991).

During DOE's participation in the test program, the average cost of power production was $63.63/megawatt-hour. Despite Nucla's smaller size, this cost is competitive with utility-scale, pulverized coal units, which do not limit emissions as much as CFB technology (Colorado-Ute Electric Association 1992).

The Nucla CFB Demonstration Project significantly advanced the environmental, operational, and economic potential of atmospheric CFB technology, precipitating a large number of orders for atmospheric CFB equipment. By 1994, more than 200 atmospheric CFB boilers had been constructed worldwide. These atmospheric CFB units ranged in size from 1.5 to 250 MW_e, with a total capacity exceeding 8,000 MW_e (Rezaiyan and Gill 1994). Today, multiple CFB manufacturers are offering 150-MW_e atmospheric CFB units with commercial warranties. Although atmospheric CFB plants are generally selected for more difficult fuel and environmental applications, their average availabilities and capacity factors are now comparable to those of pulverized, coal-fired plants with flue gas desulfurization (PC/FGD). For sulfur removal, CFB Ca/S ratios remain high, creating significant amounts of solid waste that must be disposed of properly (Makansi 1991b). Although continued operation and improved reliability will increase marketplace confidence in CFB technology, demonstration of a utility-scale (greater than 200 MW_e) atmospheric CFB unit in the U.S. is still necessary to gain widespread acceptance by domestic utilities.

Although at least six larger atmospheric CFB units have been operated, the Nucla project's comprehensive CFB database continues to be an important and unique resource for the design of yet larger atmospheric CFB systems. To help disseminate this information to potential users, the Morgantown Energy Technology Center (METC) commissioned the design of a Reference Plant

Demonstration of a utility-scale (greater than 200 MW_e) atmospheric CFB unit in the U.S. is still necessary to gain widespread acceptance by domestic utilities.

featuring mature atmospheric CFB technology based on Nucla project experience (Rubow et al. 1992). The Reference Plant is comprised of two, 200-MW_e, atmospheric CFB combustors that supply steam to a turbine generator operating on a single-reheat, steam power cycle. The net power output is 400.5 MW_e, generated at an efficiency of 34.4 percent (calculated on a higher heating value [HHV] basis). The Reference Plant is expected to meet all applicable federal, state, and local environmental standards. Based on the operation of similar sized atmospheric CFB plants, the Reference Plant could be built in the near future and operate with high availability. Based on a 65-percent levelized capacity factor, the Reference Plant's levelized busbar cost of electricity (COE) is 85.1 mills/kilowatt-hour (kWh). (The actual capacity factor of the Reference Plant is expected to be significantly higher than the 65 percent assumed for economic projections.)

Although at least six larger atmospheric CFB units have been operated, the Nucla project's comprehensive CFB database continues to be an important and unique resource for the design of yet larger atmospheric CFB systems.

When successfully demonstrated at utility scale, atmospheric CFB technology is expected to capture a larger portion of the coal-based utility market, both for repowering and new capacity. Within this market, atmospheric CFB faces competition from well-proven PC/FGD systems. However, atmospheric CFB technology has several advantages over PC/FGD, including greater fuel flexibility, reduced coal preparation costs, lower NO_x emissions, and dry solids waste removal.

Atmospheric CFB technology could be especially successful in the near-term electric power market, before other advanced clean coal systems emerge. The Energy Information Administration (EIA), DOE's independent statistical and analytical agency, projects that more than 8 gigawatts (GW) of new coal-based capacity will be needed to replace retiring utility units before the year 2000. Combined with the growth expected in nonutility coal-based capacity, atmospheric CFB will compete for nearly 10 GW of coal-based power plants before the year 2000. The ability of atmospheric CFB technology to burn a variety of waste fuels and low-rank coals has given it a large competitive advantage in a growing industrial cogeneration market, which may be the market niche in which it achieves its greatest success. An additional 10 GW of new cogeneration capacity is expected before 2000 (U.S. Department of Energy 1994a). Around the turn of the century, integrated gasification combined cycle (IGCC) and pressurized fluidized-bed combustion (PFBC) systems will be demonstrated at utility scale, and atmospheric CFB will have to compete with the higher efficiency and superior environmental performance of these systems for its share of the large coal-based market expansion projected by the EIA.

Driven by population growth, a rising standard of living, and industrial expansion, the international power generation market is expected to substantially overshadow the domestic market. The demand for clean electric power generation technology is largest in China, which is expected to be the single most important market for coal-based power generation well into the next century. Since Chinese industry accounts for around half of the country's coal usage, great potential exists for many sales of atmospheric CFB units.

1 Introduction

1.1 CCT Demonstration Program

The Clean Coal Technology (CCT) Demonstration Program is a government and industry cofunded technology development effort to demonstrate a new generation of innovative coal utilization processes. One goal of the program is to furnish the energy marketplace with a variety of more energy efficient, environmentally superior, coal-based technologies. Demonstration projects seek to establish the commercial feasibility of the most promising coal technologies that have proceeded beyond the proof-of-concept stage. This report is a post-project assessment of the second project to be completed in the U.S. Department of Energy's (DOE) CCT Demonstration Program, the Nucla Circulating Fluidized-Bed (CFB) Demonstration Project.

1.2 Purpose of Post-Project Assessment

A major objective of the CCT Program is to provide the technical data necessary for the private sector to proceed confidently with the commercial replication of the demonstrated technologies. An essential element of meeting this goal is the dissemination of results from the demonstration projects. The Post-Project Assessment Report is an independent DOE appraisal of the success a completed project had in achieving its objectives and aiding in the commercialization of the demonstrated technology. The report also provides an assessment of the expected technical, environmental, and economic performance of the commercial version of the technology as well as an analysis of the commercial market.

1.3 Background of the Demonstration Project

In 1982, Colorado-Ute Electric Association (CUEA) (since purchased by the Tri-State Generation and Transmission Association, Inc.) evaluated options for upgrading its Nucla Station facility, which was burdened with low efficiency and high operating costs. The existing Nucla plant, located in southwestern Colorado, consisted of three identical, aging, stoker-fired boilers that supplied three 12.6-MW_e (megawatt electric) turbine generators with steam. After 2 years of study, a decision was made to retrofit the plant with a 420,000-kg/h (925,000-lb/h) Ahlstrom Pyropower Incorporated (API), atmospheric CFB boiler and a new 74-MW_e steam turbine, increasing the total plant output rating to 110 MW_e and extending the plant's life 30 years.

When sold in June 1984, the Nucla atmospheric CFB was the largest of its type ever sold worldwide. In 1985, the Electric Power Research Institute (EPRI) selected the plant for a detailed test program as part of its demonstration of fluidized-bed combustion technology. Most of the existing plant equipment was integrated into the new plant cycle with the major exception of the stoker-fired boilers, which were retired. All of the steam generated by the new atmospheric CFB boiler was received by the 74-MW_e turbine, which fed all three refurbished 12.6-MW_e turbines by interstage extraction. Construction of the Nucla Project occurred over 2 years and was completed in early 1987.

In April 1986, CUEA had submitted a proposal for Round 1 of the Clean Coal Program requesting financial assistance from DOE to test and evaluate the economic, environmental, and operational characteristics of atmospheric CFB boilers in a commercial electric power generation application. Although initially selected as an alternate, the DOE considered the project suitable for demonstrating the performance of atmospheric CFB technology in utility and retrofit applications. After negotiations with two of nine project finalists were terminated, the ongoing CUEA project was selected for negotiation on October 7, 1987.

An evaluation test program was formulated and jointly funded by DOE, CUEA, EPRI, and a technical advisory group of 26 interested utilities and technology companies. In August 1988, DOE began participating in the ongoing operations. The following October, CUEA was awarded a cooperative agreement (DE-FC21-89MC25137) that consolidated DOE's continuing involvement.

The Nucla atmospheric CFB plant operated for more than 2 years under the terms of DOE's cooperative agreement, providing operational and design data for scaleup of future designs. Phase I of the demonstration test program, jointly sponsored by EPRI and DOE, began in February 1987, and included cold-mode shakedown, hot-mode shakedown, acceptance tests, and detailed performance tests. Forty-five steady-state performance tests were completed by June 1990, the end of Phase I testing. Phase II tests, conducted from July 1990 to January 1991, included 27 steady-state performance tests. Phase II testing, sponsored solely by DOE, was completed in January 1991.

1.4 Pre-Project Technology Status

The commercial development of fluidized-bed technology can be traced back to the Winkler coal gasifiers built in Germany during the 1920s. By the 1950s, commercial fluidized-bed units were used as catalytic crackers in refineries, as roasters and as calciners. Research on fluidized-bed combustion during this period proved the technical feasibility of these units, but a number of factors, including the perception that they were more complex than stoker or pulverized coal-fired units, prevented their commercialization.

In the 1970s, regulations to reduce atmospheric pollution from coal-fired power plants renewed interest in fluidized-bed combustion. Two different versions of atmospheric fluidized-bed combustion technology were developed along parallel paths: bubbling fluidized bed (BFB) and circulating fluidized bed (CFB). The difference between the two types primarily relates to the fluidizing velocity used. A bubbling bed has a low fluidizing air velocity, normally 0.6 to 2.4 meters per second (m/s) (2 to 8 ft/s), resulting in a dense zone of material that remains in a specific area at the bottom of the combustor. Heat transfer tubes are submerged in this dense zone for steam generation. An atmospheric CFB boiler does not have a distinct, dense bed. Instead, its higher fluidizing air velocity (3.7 to 9.1 m/s) (12 to 30 ft/s) entrains the "bed" material out of the combustor and into a hot cyclone. There, solid particles are separated from the flue gas and recirculated to the combustor. A CFB boiler generates steam both within the combustion chamber's waterwall tubes and within design-specific devices that transfer heat from the hot streams of solids and gases.

Each technology has its own advantages and disadvantages. Both technologies provide the ability to burn a wide variety of coals and other combustibles. Both have reduced sulfur and nitrogen emissions and lower coal crushing costs than conventional, pulverized, coal-fired boilers. A CFB is more highly agitated than a BFB, which simplifies its coal feeding system. CFB was chosen over BFB for demonstration at the Nucla power station because it provided a higher combustion efficiency, a higher sulfur capture efficiency, and less likelihood for tube erosion (U.S. Department of Energy 1988).

The U.S. DOE and its predecessor agencies funded much of the development of atmospheric fluidized-bed technology. Some early work was performed at the Morgantown Energy Technology Center (METC) and at a DOE facility in Alexandria, Virginia. At METC, a variety of coals and low-quality fuels were burned in a 46-cm (centimeter) (18-inch) diameter combustor to measure combustion and sulfur dioxide capture. Similar measurements were done at the larger, 0.6- by 0.9-m (meter) (2- by 3-foot) combustor in Alexandria. Fuel feeding and heat transfer were also studied there. Much of the early research on combustion of lignites and other western coals was performed at the DOE Grand Forks Technology Center. DOE also sponsored fluidized-bed research at Argonne National Laboratory.

The first large-scale, fluidized-bed combustor was constructed by DOE at the Monongahela Power Company station in Rivesville, West Virginia, in 1975. This multi-cell, atmospheric unit operated for 4 years and could generate 20 MW_e. Three additional fluidized-bed combustors were sponsored by DOE in the 1970s. In Shamokin, Pennsylvania, a fluidized-bed boiler burning anthracite culm produced 9,000 kg/h (20,000 lb/h) steam for an industrial park. A 23,000 kg/h (50,000-lb/h) boiler was operated on bituminous coal at the U.S. Navy's Great Lakes Training Center in Chicago. In Washington, D.C., a 45,000 kg/h (100,000-lb/h) boiler burned bituminous coal to produce steam for institutional heating at Georgetown University (Halow, Shang, and Wilson 1982).

DOE also sponsored much of the significant fluidized-bed research performed in the 1980s, culminating in the Nucla demonstration. Through a DOE Program Research and Development Announcement, The M.W. Kellogg Company performed a bench-scale study of a circulating, atmospheric, fluidized-bed combustor, and Arthur D. Little, Inc., conducted cold-flow, proof-of-concept tests for a pulsed, bubbling, fluidized bed. DOE also cofunded the following industrial, fluidized-bed operations in the 1980s. In September 1984, a 4- by 5-meter (13- by 17-foot) atmospheric unit began burning anthracite culm to supply 27,000 kg/h (60,000 lb/h) steam to downtown businesses in Wilkes-Barre, Pennsylvania. One year later, a 1.5- by 6-meter (5- by 20-foot) atmospheric fluidized bed, which also burned anthracite culm, supplied 18,000 kg/h (40,000 lb/h) steam to heat the campus of East Stroudsburg College. Also in the mid-1980s, DOE cofunded the Tennessee Valley Authority's 20-MW_e pilot plant in Paducah, Kentucky. This atmospheric unit produced a large database for fluidized-bed technology (Halow and Shang 1986).

Shortly before the Nucla CFB Demonstration Project began, two API units significantly advanced CFB technology. In 1985, a cogeneration unit started producing 86,000 kg/h (190,000 lb/h) steam for the California Portland Cement Company in Colton, California. This system was the first coal-fired power station ever approved by California's South Coast Air Quality Management District, which determined that the CFB unit would not have an adverse environmental impact. In 1986, another cogeneration unit started producing 136,000 kg/h (300,000 lb/h) steam for General Motors Corporation in Pontiac, Michigan. The larger output of this unit placed CFB technology in a position to start competing with other technologies that burn solid fuels. Both of these systems won *Power Magazine*'s Powerplant Award (Ahlstrom Pyropower, Inc. 1992).

By 1988, about 40 commercial atmospheric CFB boilers, including Nucla, were operating around the world on a variety of fuels, including coal, lignite, peat, coke, and wood wastes. All these units were small compared to utility standards, ranging from 23,000 to 420,000 kg/h (50,000 to 925,000 lb/h) steam. The units were used to generate steam or for cogeneration of electricity and steam. Table 1 shows how the Nucla CFB boiler was nearly twice the size of any other API atmospheric CFB boiler operating in the U.S. in 1988.

The total rated capacity (i.e., the combined output of the boiler's dual combustion chambers) of the Nucla CFB boiler is 294 thermal megawatts (MW_t). When purchased in June 1984, the Nucla CFB boiler was 41 percent larger than any other CFB boiler sold worldwide. Until Nucla, the largest atmospheric CFB ever sold worldwide (208 MW_t) belonged to Stadtwerke Duisburg in Germany. The largest CFB ever sold in the U.S. before Nucla was an ABB-Combustion Engineering (ABB-CE)/Lurgi unit (204 MW_t) at the Scott Paper Company in Chester, Pennsylvania (Ahlstrom Pyropower, Inc. 1994).

Table 1. Domestic API CFB Units Operating in 1988

Customer	Start Date	Application	Fuel	Output Conditions	Output kg/h (lb/h)
Gulf Oil Exploration Bakersfield, CA	1983	Enhanced Oil Recovery	coal	17 MPa,* 350 °C (2,500 psig, 670 °F)	23,000 (50,000)
Cal Portland Cement Colton, CA	1985	Cogeneration	coal	4.5 MPa, 440 °C (650 psig, 825 °F)	86,000 (190,000)
B.F. Goodrich Henry, IL	1985	Process Steam	coal	3.4 MPa, 240 °C (500 psig, 470 °F)	57,000 (125,000)
Central Soya Chattanooga, TN	1985	Process Steam	coal	1.3 MPa, 200 °C (190 psig, 389 °F)	40,000 (88,000)
General Motors Pontiac, MI	1986	Cogeneration	coal, plant wastes	10 MPa, 510 °C (1,460 psig, 955 °F)	136,000 (300,000)
Iowa State University Ames, IA	1987	Cogeneration	coal	2.8 MPa, 400 °C (410 psig, 750 °F)	77,000 (x2) (170,000 (x2))
Colorado-Ute Nucla, CO	1987	Electric Power	coal	10.4 MPa, 540 °C (1,510 psig, 1,005 °F)	420,000 (925,000)
Corn Products Stockton, CA	1988	Cogeneration	coal	10.7 MPa, 510 °C (1,550 psig, 955 °F)	227,000 (500,000)
Fort Drum Watertown, NY	1988	Cogeneration	coal, oil, anthracite	10.5 MPa, 510 °C (1,525 psig, 950 °F)	79,000 (x3) (175,000 (x3))
Gilberton Power Co. West Mahoney, PA	1988	Cogeneration	100% anthracite waste	10.3 MPa, 510 °C (1,500 psig, 955 °F)	161,000 (x2) (355,000 (x2))
P.H. Glatfelter Springs Grove, PA	1988	Cogeneration	coal, wood, culm, oil	10.3 MPa, 510 °C (1,500 psig, 950 °F)	181,000 (400,000)

* Megapascal

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2 The Demonstrated Technology

2.1 Description of Technology

Figure 1 illustrates Nucla's atmospheric CFB system. The CFB boiler is composed of dual combustion chambers (each with its own hot cyclone) and a heat recovery chamber that encloses the primary and final superheaters and the economizer. Steam generated in the atmospheric CFB boiler through heat recovery is used by turbine generators to produce electrical power.

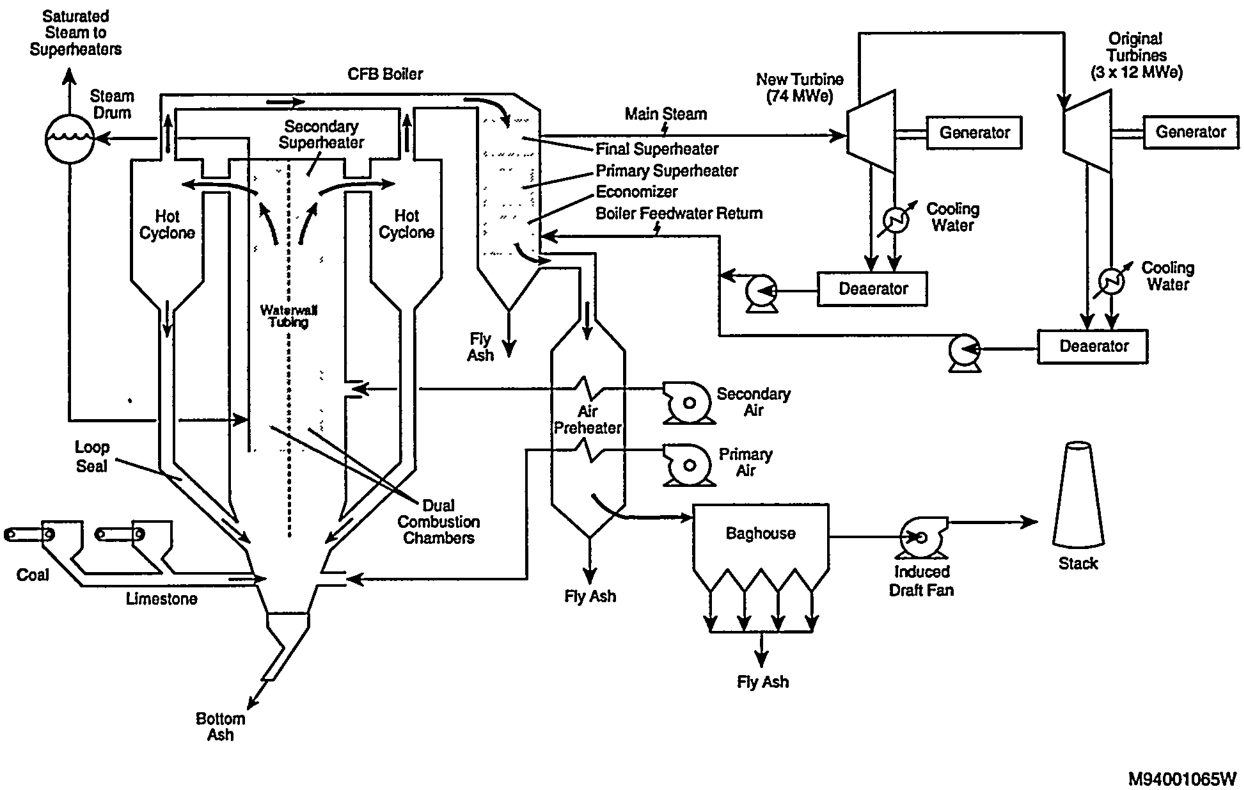

Figure 1. Nucla Circulating Fluidized-Bed System

2.1.1 Combustion Chambers

Each of the dual combustion chambers is 6.7 m (22 feet) wide, 7.3 m (24 feet) deep, and 34 m (110 feet) high. At full load, 2,000 kg/h (4,420 lb/h) of pulverized limestone (150 micrometers) is pneumatically fed through four ports into each combustion chamber. At three locations above the limestone ports, 52,800 kg/h (116,400 lb/h) (full-load rate) of crushed coal (0.6 cm [1/4 inch]) is gravity fed into each chamber. In the bottom of the combustor, preheated primary air flows through distributor nozzles to uniformly fluidize and entrain a bed of particles composed mostly of spent (calcined) limestone, ash, and calcium sulfate. Only 5 to 10 percent of the fluidized bed is unreacted limestone and unburned coal. The distributor nozzles have bubble caps to prevent bed particles from backsifting from the combustion chambers into the primary air windbox.

Combustion and desulfurization take place in the fluidized bed. Sulfur is captured by calcium in the sorbent and is ultimately removed with the ash. Combustion temperatures are controlled between 840 and 880 °C (1,550 and 1,620 °F), which is the most efficient range for desulfurization. In addition, these relatively low combustion temperatures limit NO_x formation. At various levels of the combustor, streams of secondary air complete the combustion of fuel in stages. Staged combustion also helps to suppress NO_x formation. Dry, spent ash is removed through bottom ash drain ports that lead to ash coolers.

The fluidized bed is most dense approximately at the level at which fuel is introduced. In the upper zones, some particles become entrained in the combustion gases and are carried out the top of the combustion chambers and into the dual hot cyclones.

2.1.2 Hot Cyclones

Each cyclone separates the larger particles from the gas and recirculates them to the lower zones of the combustion chambers through gravity-fed, non-mechanical loop seals. This continuous circulation of coal char and sorbent particles is the novel feature of CFB technology. It helps to control boiler temperature and improves mixing, which extends the contact time of solids and gases, thus promoting coal utilization and sulfur capture.

The cyclones are 7 m (23 feet) in diameter and 16 m (54 feet) high. Their chambers are lined with refractory for temperature and erosion protection. Inlet and outlet ducts and the loop seals are also refractory lined. High-temperature expansion joints connect the cyclone inlets and the loop seals to the combustion chamber.

2.1.3 Flue Gas

Hot flue gas, exhausted from the top of the two hot cyclones, is cooled as it passes through the primary and final superheaters. The gas is cooled further as it flows through the economizer and primary and secondary air heaters. Next, the cool flue gas passes through fabric filters (baghouse) for particulate removal. Finally, the flue gas passes through the induced draft fan and exits the stack. The variable-speed, induced draft fan maintains a constant pressure balance at the combustion chamber outlets.

2.1.4 Heat Recovery and Power Generation

Boiler feedwater, at 230 °C (440 °F) and 11.6 MPa (1,689 pounds per square inch [psig]), is heated by the hot flue gas in the economizer and delivered to the steam drum. From the steam drum, feedwater flows via downcomers to the combustion chamber waterwalls where it is evaporated into a steam and water mixture. This feedwater mixture circulates naturally between the single steam drum and the waterwall heat absorption surfaces of both combustion chambers. The arrangement of a single steam drum for separate combustion chambers is a unique feature of the Nucla Project.

Saturated steam exits the steam drum and flows through the primary, secondary, and final superheaters. The primary and final superheaters recover heat from the hot flue gas. The secondary superheater is composed of parallel, wrap-around, radiant superheater panels located in the upper zone of each combustion chamber.

Steam exits the final superheater at 540 °C (1,005 °F) and 10.4 MPa (1,510 psig) and is fed to the new, 74-MW_e turbine generator. A portion of this steam is provided to the original three turbine generators by automatically controlled interstage extraction. All the turbines operate in a condensing mode. Condensate (feedwater) is returned to a common hot well from which it is pumped through two low-pressure feedwater heaters and a deaerator. Finally, the feedwater is pumped through two high-pressure heaters and into the economizer.

2.2 Benefits of the Technology

Table 2 lists some benefits of atmospheric CFB technology.

Table 2. Benefits of Atmospheric CFB Technology

Area	Benefit
Environmental	High SO_2 Removal
	Major NO_x Reduction
	Dry Solid Waste Product, No Sludge
Operational	High Coal Combustion Efficiency
	High Reliability and Capacity Factor
	Ability to Handle "Problem" (Slagging, Fouling) Coal Varieties
	Ability to Co-fire Waste Fuels (Petroleum Coke, Coal-Washery Waste, Wood, Oil, Sludges, Tires, Biomass, Asphaltines, Refuse-Derived Fuel, etc.)
Economic	Reduced Coal Preparation Cost
	Fuel-Cost Savings Due to Burning Local Fuels, Including "Problem" Coal Varieties

2.3 Objectives of the Demonstration Project

The U.S. DOE, in its Comprehensive Report to Congress (U.S. Department of Energy 1988) and 1993 CCT Program Update (U.S. Department of Energy 1994b), listed the following objectives for the Nucla CFB Demonstration Project.

- *Demonstrate atmospheric CFB technology at a scale of 110 MW_e*: When sold in June 1984, the Nucla atmospheric CFB boiler was 41 percent larger than any other CFB boiler worldwide, providing a critical link between small pilot and industrial facilities and commercial-size plants. The Nucla scaleup significantly advanced the environmental, operational, and economic potential of atmospheric CFB technology.

- *Demonstrate fuel flexibility on a commercial scale and evaluate parameters and design features that limit unit capacity for ranges of fuel*: The Nucla CFB demonstrated the ability of atmospheric CFB technology to easily burn a variety of coals cleanly and efficiently. Three western bituminous coals were tested: Peabody coal (0.4 to 0.8 percent sulfur; 8 tests), Dorchester coal (1.5 percent sulfur; 2 tests), and Salt Creek coal (0.5 percent sulfur; 62 tests).

- *Perform integrated plant load following, control, and duty analyses to assess the capability of the technology to be applied to various load following and duty scenarios and to identify rate limiting design features*: A total of 72 steady-state performance tests were conducted: 22 tests at 50 percent load, 6 at 75 percent load, 2 at 90 percent load, and 42 at full load (110 MW_e). Dynamic response tests were also performed at rates up to 7 MW_e per minute.

- *Optimize performance of the CFB boiler*: Performance testing at Nucla established the effects of load, excess air, primary-to-secondary air ratio, unit operating temperature, coal- and limestone-feed configuration, coal type and coal size distribution on emissions performance, combustion and boiler efficiencies, heat-transfer rates, air-heater effectiveness, and baghouse efficiency. Boiler performance was optimized at the conclusion of testing.

- *Obtain commercial design, cost, performance, and environmental control data for subsequent comparisons with existing and alternative power generation options*: During the test effort, the design and reliability of the combustor and its support equipment were improved, and an operational database was developed. Although at least six larger atmospheric CFB units (e.g., the 250-MW_e, ABB-CE/Lurgi CFB unit at Grenoble, France) have been operated, the Nucla project's comprehensive CFB database continues to be an important and unique resource for the design of yet larger atmospheric CFB systems.

- *Verify expectations of the technology's economic, environmental, and technical performance in a repowering application at a utility site*: The Nucla CFB Demonstration project was the first successful utility repowering project in the U.S. It increased the capacity of the original Nucla station to 110 MW_e and extended its life by

30 years. CUEA's economic evaluation indicated that repowering Nucla resulted in a capital cost of $1,123 per total net kilowatt (kW), which was approximately 22 percent over the estimate published in 1984. At the time, however, this capital cost was still much lower than an alternative cost of installing new pulverized coal-fired capacity. (DOE did not fund any of Nucla's capital costs, although capital cost overruns are not uncommon for plants that are the first of their kind.) During DOE's participation in the test program, the average cost of power production, including the fixed costs of taxes, interest, depreciation, and insurance, was $63.63/megawatt-hour. Despite Nucla's smaller size, this cost proved very competitive with utility-scale, pulverized coal units that do not limit emissions as significantly.

The technical and environmental performance of the Nucla CFB demonstration project is detailed in the following objectives.

- ***Achieve a boiler efficiency of 88 to 89 percent***: Boiler efficiencies (HHV basis) ranged from 85.6 to 88.6 percent, depending on fuel moisture and sulfur contents (the latter affecting sorbent-calcination heat loss).

- ***Achieve an efficiency of 34 percent in a repowering mode***: Although repowering the Nucla station with atmospheric CFB technology increased its efficiency by 18 percent, a 34 percent efficiency was not achieved. The best system efficiency measured during a full-load, steady-state test was 31.1 percent. The average efficiency for the period September 1988 through January 1991 was 28.3 percent. System efficiency was adversely affected by the absence of steam reheat, the presence of three older 12.6-MW_e turbines in the overall steam cycle, a high Ca/S ratio, low superheat temperatures, and part-load testing.

- ***Achieve greater than 90 percent SO_2 removal***: At less than full boiler load, 95 percent sulfur removal was achieved from the baseline Salt Creek coal (0.5 percent sulfur) at a calcium-in-the-sorbent to sulfur-in-the-coal ratio of 4:1.

- ***Achieve a 60 percent reduction of NO_x emissions[1]***: During all tests, the average level of NO_x emissions was only .08 mg/kJ (0.18 lb/MMBtu), which corresponds to an 82 percent reduction.

- ***Comply with particulate emission standards***: Particulate emissions typically ranged from 0.0031 to 0.0054 mg/kJ (milligrams per Kilojoule) (0.0072 to 0.0125 lb/MMBtu), well below the permit level of 0.01 mg/kJ (0.03 lb/MMBtu).

All of the project's objectives were well within the broad environmental objective of Round I of the CCT Program to ***"use coal in a more environmentally responsive and efficient manner."***

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[1]Compared to the emission rate from an uncontrolled, pulverized, coal-fired power plant, one pound per million British Thermal Units (MMBtu) (U.S. Department of Energy 1989).

3 Results of the Demonstration

3.1 Summary of Testing

Even though the Nucla plant's output was increased from 36 MW_e to 110 MW_e, preliminary reviews by both the U.S. Environmental Protection Agency (EPA) and the Colorado Department of Health disclosed that no significant environmental impacts would be associated with the Nucla project. This was substantiated in tests done with Nucla coal at the Ahlstrom 1.5-MW_e pilot facility and later during plant operation (Rubow et al. 1992). National Environmental Policy Act (NEPA) compliance was satisfied with a memo to file dated April 1988.

In April 1988, the Nucla project was given *Power Magazine*'s Utility Environmental Conservation Award for demonstrating efficient use of the USA's extensive coal resources while protecting the environment.

The Nucla atmospheric CFB plant operated for more than 2 years under the terms of DOE's cooperative agreement, providing operational and design data for scaleup of future designs. Phase I of the demonstration test program, jointly sponsored by EPRI and DOE, began in February 1987, and included cold-mode shakedown, hot-mode shakedown, acceptance tests, and detailed performance tests. Cold-mode shakedown began in February 1987, and was completed in March 1989. Acceptance tests were also conducted during this period. Cold-mode shakedown involved calibrating instruments, commissioning the data acquisition system, developing specialized software, procuring and commissioning specialized test instrumentation, developing procedures, and training test personnel. By May 1987, turbine roll was achieved and totally coal-fueled operation was attained that July. Full load operation was achieved by March 1988. In April 1988, the Nucla project was given *Power Magazine*'s Utility Environmental Conservation Award for demonstrating efficient use of the USA's extensive coal resources while protecting the environment. By October 1988, acceptance tests had logged more than 4,400 hours of operation using low sulfur Colorado coals (Peabody and Dorchester). Hot-mode shakedown, which established the framework for future steady-state performance tests, was completed during March 1989. During shakedown and acceptance tests, many modifications were made, troubles corrected, and operating experience accumulated.

Following shakedown and acceptance testing, detailed performance testing at specified unit operating conditions began in April 1989. Forty-five steady-state performance tests were conducted by the time Phase I ended in June 1990. These Phase I tests established how various control variables, including load, excess air, primary-to-secondary air ratio, unit operating temperature, coal- and limestone-feed configuration, coal type, and coal size distribution affected various response variables, including emissions performance, combustion and boiler efficiencies, heat-transfer rates, air-heater effectiveness, and baghouse efficiency. Dynamic response testing was also performed during Phase I. From July 1990 to January 1991, 27 steady-state Phase II tests supplemented areas that were incompletely covered in Phase I, including additional dynamic-response testing. DOE was the sole sponsor of the Phase II tests. In all, a total of 72 steady-state performance tests were conducted: 22 tests at 50 percent load, 6 at 75 percent load, 2 at 90 percent load, and 42 at full load (110 MW_e). Three western bituminous coals were tested: Peabody coal (0.4 to 0.8 percent sulfur; 8 tests), Dorchester coal (1.5 percent sulfur; 2 tests), and Salt Creek coal (0.5 percent sulfur; 62 tests). By the demonstration's end, the unit had accumulated 15,707 hours of operation.

During the test effort, operator training was greatly enhanced, the design and reliability of the combustor and its support equipment were improved, and an operational database was developed. All of the independent process variables proposed in the original test matrix were tested except for limestone size, which could not be varied in a controllable manner due to problems with the limestone crusher. Typical data from the performance tests, listed in Table 3, shows that nearly all performance guarantees were met. These data were obtained when burning design coal (22 percent ash and 0.7 percent sulfur). All of the plant data are included in a final technical report prepared for the DOE by CUEA (Colorado-Ute Electric Association 1991).

3.2 Problems Overcome

Although typical start-up and maintenance problems were experienced, they were related to deficiencies in ancillary equipment rather than the atmospheric CFB boiler. In the acceptance tests using design coal (22 percent ash and 0.7 percent S), all performance guarantees were met except those for fan performance and flue gas duct pressure losses. Temperature cycles caused by the frequent forced outages exacerbated other problems and, in some respects, provided a more rigorous testing of materials than would be encountered in a full commercial unit with fewer start-ups.

Throughout the commissioning period, the boiler experienced typical start-up problems. These included coal feeder trips, steam leaks, valve linkage problems, valve packing leaks, generator trips and synchronization problems, propane feed difficulties, and steam line expansion interference. These problems were not specifically related to the technology being demonstrated.

Two construction problems involved boiler casing leaks and steam leaks on superheater field welds caused by weld contamination. These problems were discovered early in the program, repaired, and steps were taken to prevent their reoccurrence.

Of most concern were problems related to design scaleup from previous smaller boilers. Except for the primary air fan, which did not meet design specifications, no scaleup problem was serious enough to degrade operability or data collection. The fan was modified so that a key test variable, primary-to-secondary air ratio, could be controlled.

Backsifting of bed material from the combustion chambers into the windbox, which was most frequent at low-load operation, was a problem that was alleviated, but never eliminated, by increasing air flows at low load. A reinjection line was installed to return backsifted material to the loop seal. At various locations, the bubble cap design was also modified.

Although the limestone handling system improved with operating experience, leaking rotary valves, erratic weight signals, and shaker motor failures persisted throughout the test program. In addition, the limestone crusher was not able to vary the sorbent particle size in a controllable manner, and as a result, a finer-than-desired particle was produced. By contrast, the coal handling system was reliable and required relatively low maintenance.

The ash handling system was designed to remove, classify, and cool the bottom ash and return ash fines to the combustion chambers. Initially, the system suffered from handling and sizing problems, which reduced its capacity. These problems were solved by the addition of water sprays on the ash coolers and modifications to the ash cooler discharge lines and ash disposal transport lines.

Instrumentation problems included faulty oxygen analyzers, errors in combustion air flow indication, and plugged bed pressure taps. New oxygen analyzers were installed and other instrumentation problems were corrected.

Inadequately designed air dampers and actuators, which control the air-to-fuel ratio, were a problem until the dampers were modified and larger actuators were installed.

Refractory durability, although it improved, remained a concern and was monitored throughout the test program. Sections of refractory were replaced on the rear wall of the combustor, in the conical portions of the cyclones and in several areas of the loop seals. Surface spalling was also evident in the combustor. Changes in refractory materials, improved refractory installation procedures, and operation of the boiler system with less severe thermal transients helped to alleviate refractory failure.

The impact of circulating bed particles caused localized tube erosion at the refractory interface in the lower combustor, a condition ordinarily encountered in CFB boilers. Initial problems with the Nucla unit were overcome and a preventive program appeared to control tube erosion to satisfactory limits. In addition, 15-cm (6-inch) shelves were added over the top row of one secondary superheater panel to prevent tube erosion from the downward flow of abrasive solids.

In September 1987, an incident occurred that resulted in a 10-week outage. Following a waterwall tube leak, one of the two combustion chambers overheated when unburned coal ignited during a fan cooldown. This caused structural damage due to downward differential expansion between the two chambers. No metallurgical damage was sustained by boiler pressure parts, and after repairs were made, no further problems associated with the deformation were experienced (Rubow et al. 1992).

3.3 Key Operating Parameters

Key operating parameters included bed temperature, Ca/S ratio, coal- and limestone-feed configurations, fuel-to-air ratio, and primary-to-secondary air ratio.

3.3.1 Bed Temperature and Ca/S Ratio

During the performance tests, bed temperature was the most influential operating parameter on emissions. SO_2 and NO_x emissions increased with bed temperature while carbon monoxide (CO) emissions decreased with increasing bed temperature.

Most authorities agree that favorable equilibrium for sulfation at atmospheric pressure occurs in the range 840 to 880 °C (1,550 to 1,620 °F). At bed temperatures below 880 °C (1,620 °F) (i.e., less than full boiler load) 70 percent sulfur removal from the baseline Salt Creek coal (0.5 percent sulfur) was achieved at a Ca/S ratio of 1.5:1, and 95 percent sulfur removal was achieved at a Ca/S ratio of 4:1. At 930 °C (1,700 °F), a Ca/S ratio greater than 5:1 was required to maintain 70 percent sulfur capture. (These Ca/S ratios account for calcium in the sorbent only and do not include calcium in the coal.) This adversely impacted plant economics.

Although bed temperatures do have an effect on NO_x emissions, they are not problematic as long as the bed temperature is maintained around 870 °C (1,600 °F). NO_x emissions increased from 75 parts-per-million on a volume basis (ppmv) (measured dry at 3 percent oxygen) to 200 ppmv as the bed temperature was increased from 830 to 910 °C (1,525 to 1,675 °F). The highest emissions (about 240 ppmv) occurred at the highest furnace temperature (930 °C [1,700 °F]) well above the design point. An increase in NO_x with increased limestone feed was also noted.

3.3.2 Coal- and Limestone-Feed Configurations

The distribution of coal and sorbent feeds among various points of entry was studied. Balancing the coal feed between the front and rear walls yielded the lowest NO_x emissions and highest sulfur retention. Sulfur absorption was improved by injection of sorbent close to the coal-feed points.

The Ca/S ratio was minimized at a constant S retention if the coal-feed distribution (3 feeders) within each 6.7- by 7.3-m (22- by 24-foot) cell was as even as possible. This suggests that additional coal feeders would enhance emissions performance. However, additional feeders would also complicate the design and increase the capital cost.

At a constant total sorbent feed rate, the number of limestone feeders in operation had essentially no effect. This suggests that sorbent mixing occurs rapidly within the bed, and no sulfur capture occurs until after calcination.

Typically, NO_x emissions with all front-wall coal feed were 100 ppmv higher than those with the 50/50 split feed and 70 ppmv higher than with a balanced coal feed. This is believed to be caused by a locally high calcium-to-nitrogen (Ca/N) ratio. Oxidation of volatile nitrogen, present as ammonia (NH_3), is catalyzed by calcium oxide (CaO). This may cause higher NO_x emissions with increasing Ca/N weight ratios. Limestone feed location did not have a significant effect on NO_x.

3.3.3 Fuel-to-Air Ratio

Tests at various fuel-to-air ratios indicated that the plant can operate at very low excess air, but only with higher than desired combustion temperatures. Excess air had no significant impact on SO_2 and NO_x emissions except to the extent that it influenced bed temperatures. High excess air reduced combustion temperatures but had little, if any, detrimental effect on combustion or boiler efficiencies.

During tests, operation at excess-air levels under 10 percent resulted in increased CO emissions due to incomplete combustion. Excess air is normally about 20 percent.

3.3.4 Primary-to-Secondary Air Ratio

Unexpectedly, tests showed that the ratio of primary-to-secondary air had little effect on furnace control or SO_x, NO_x, and CO emissions.

3.4 Key Performance Measures

Key performance measures included combustion and boiler efficiencies, unit turndown, boiler temperature control, system heat rate, system availability, system capacity factor, emissions control, solid waste disposal, and wastewater discharge. Some of these performance measures are shown as a function of load in Table 3.

3.4.1 Combustion Efficiency

Combustion efficiency is a measure of the quantity of carbon that is fully oxidized to carbon dioxide (CO_2). Of the four exit sources of incompletely burned carbon, the largest (93 percent) was carbon in the fly ash. The bottom ash stream (5 percent) and carbon monoxide in the flue gas (2 percent) contained the balance of the incompletely burned carbon. The fourth possible source, hydrocarbons in the flue gas, was measured and found to be negligible. Combustion efficiency improved as the bed temperature was increased, ranging from 96.9 percent to 98.9 percent during performance testing. Considering the reduced cost of coal preparation for atmospheric CFB units, this compares well with the 99 percent combustion efficiency of pulverized coal-fired units.

3.4.2 Boiler Efficiency

Boiler efficiency is the percentage of the fuel's energy that is transferred to the superheated steam used in the turbine power cycle. 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

Table 3. Performance Test Data (When Burning Design Coal)

	Approximate Load (%)		
	100	75	50
MW_e (gross)	105.3	82.3	55.2
Auxiliary Power (%)[1]	10.4	8.1	7.2
Boiler Efficiency (%)	88.1	88.4	88.1
Combustion Efficiency (%)	98.1	98.6	99.7
NO_x (ppmv)[2]	59	56	26
SO_2 (ppmv)[2]	136	78	77
CO (ppmv)	99	92	119
O_2 (volume % dry)	3.9	3.8	5.65
Ca/S Molar Ratio[3]	2.05	2.46	2.84
Average Combustor Temperature, °C (°F)	851 (1563)	847 (1557)	812 (1493)

[1] Principal users of auxiliary power were the primary-air fan (2.6 MW [3,500 hp]), boiler-feed pumps (2 at 1.3 MW [1,750 hp]) and induced-draft fan (2.42 MW [3,250 hp]).

[2] The maximum allowable emissions for NO_x and SO_2 are 359 ppmv and 206 ppmv, respectively.

[3] Includes calcium contained in both coal and sorbent.

cooling water. Boiler efficiencies (HHV basis) ranged from 85.6 to 88.6 percent, depending primarily on fuel moisture and sulfur contents (the latter affecting sorbent-calcination heat loss). This is favorable for a non-reheat unit.

3.4.3 Unit Turndown

The capability of atmospheric CFB technology to meet varying demand in a utility setting was demonstrated. The 110-MW_e unit verified its specified capability of a 3:1 turndown, achieving stable operation on coal in the 27- to 34-MW_e range. For even lower demand, propane supplemental firing through the start-up burners can supply up to 20 MW_t. The rate at which the load can be changed may be limited by metallic parts and refractory-life considerations, e.g., in the hot cyclones. Dynamic tests at 5-MW_e/min load-change rate were considered successful. However, at 7-MW_e/min, it was difficult to control the steam-separator drum level.

Level control problems in the steam-separator drum persisted during startup and load changes, despite revisions of operating logic and increased operator attention, placing a burden on the propane start-up and make-up water systems. These control problems may have been caused by economizer boil-out during startup. In addition, it was speculated that since a single steam-separator drum served both combustion chambers, differences in their heat absorption may have caused an imbalanced water flow into the drum, complicating level control. In retrospect, the difficulties experienced with operational control and unbalanced firing indicate that the twin-furnace design recommended by API was unnecessarily conservative.

In retrospect, the difficulties experienced with operational control and unbalanced firing indicate that the twin-furnace design recommended by API was unnecessarily conservative.

3.4.4 Boiler Temperature Control

The two combustion chambers typically operated at different temperatures (up to 40 °C [100 °F] delta). These temperatures were also usually too high (up to 930 °C [1,700 °F]) for optimum utilization of the sorbent. Although many reasonable possibilities were posed, the causes of these problems were not determined with certainty.

3.4.5 System Heat Rate

The net system heat rate is the amount of fuel energy required by the plant to deliver one kilowatt-hour of electricity to the utility power grid. As a result of repowering the Nucla station with atmospheric CFB technology, its heat rate was improved (reduced) by 15 percent. The net system heat rate decreased with increasing boiler load, from 13,100 kJ/NkWh (Kilojoules per net kilowatt-hour) (12,400 Btu per net kilowatt-hour [Btu/NkWh]) at 50 percent of full load to 12,200 kJ/NkWh (11,600 Btu/NkWh) at full load. The best (lowest) value measured during a full-load, steady-state test was 11,580 kJ/NkWh (10,980 Btu/NkWh). The average heat rate for the period September 1988 through January 1991 was 12,719 kJ/NkWh (12,055 Btu/NkWh).

The heat rate was adversely affected in a variety of ways. The absence of steam reheat and the presence of three older 12.6-MW_e turbines limited the steam cycle efficiency. A high Ca/S ratio deprived the power cycle of heat by increasing the flowrate of hot bottom ash and by consuming heat during calcination. At full boiler load, certain radiant secondary-superheater tubes operated at 580 °C (1,075 °F), or 27 °C (50 °F) above the design point. To reduce these metal temperatures, the first-station attemperation spray-water flow rate was set higher, resulting in a reduction in main steam temperature to 520 °C (960 °F) at the steam-turbine inlet. This decreased

As a result of repowering the Nucla station with atmospheric CFB technology, its heat rate was improved (reduced) by 15 percent.

the efficiency of the steam cycle. In future units, a different design may be required in certain locations. Problems with the primary air fan limited the amount of excess oxygen. Since the best heat rate occurs at full load, part-load testing increased the average heat rate.

3.4.6 System Availability and Capacity Factor

Availability is the percentage of time a system is capable of operating over a given period. A system's capacity factor is the ratio of actual power generation to potential (full rated capacity) power generation over a given period. As expected during the demonstration of a new technology, Nucla's average availability and average capacity factor were below typical powerplant averages. Between July 1988 and January 1991, Nucla operated with an average availability of 58 percent and an average capacity factor of 40 percent. According to the North American Electric Reliability Council/Generating Availability Data System, non-CFB, coal-fired units in the 100- to 199-MW_e size range (mostly peaking or mid-load units) had an average availability and capacity factor of 83.9 percent and 49.7 percent, respectively (U.S. Department of Energy 1994b).

During the last three months of the demonstration, the average availability and average capacity factors were 97.0 percent and 66.5 percent, respectively.

These deficiencies were caused by both technical and financial reasons. Nucla's availability and capacity factor were reduced by part-load testing and numerous outages, some of which were required to inspect materials and remedy problems related to the boiler. By October 1991, the Nucla atmospheric CFB unit had been restarted nearly 175 times. In addition, CUEA was plagued by financial difficulties throughout the demonstration, which prevented the utility from making some of the capital improvements that would have enhanced the plant's reliability (Heller, Bush, and Friedman 1994). However, toward the end of the demonstration, most of the technical problems had been overcome. The average availability during Phase II testing (7 months) was 70 percent. During the last 3 months of the demonstration, the average availability and average capacity factors were 97 percent and 72 percent, respectively.

3.4.7 Emissions Control

The emissions-control performance of the plant met or exceeded permit requirements. Daily averages and 30-day rolling averages were recorded from 1988 until the demonstration's end in 1991 for SO_2 and NO_x emissions. Permit levels (30-day rolling average) for SO_2 (0.2 mg/kJ [0.4 lb/MMBtu]) and NO_x (0.2 mg/kJ [0.5 lb/MMBtu]) were consistently met except for a few SO_2 violations during the initial start-up period in 1988. During all tests, the average level of NO_x emissions was only 0.08 mg/kJ (0.18 lb/MMBtu). There were no permit restrictions for CO emissions, which varied between 70 and 140 ppmv. Particulate emissions typically ranged from 0.0031 to 0.0054 mg/kJ (0.0072 to 0.0125 lb/MMBtu), well below the permit level of 0.01 mg/kJ (0.03 lb/MMBtu). Typical plant emissions when burning design coal (22 percent ash and 0.7 percent sulfur) are shown in Table 3.

Maintaining adequate particulate removal was not a problem; however, early in the program, bag life was shorter than expected until the deflation (cleaning pulse) pressure was adjusted. During the last 4 months of the test program, after all baghouse operating problems were resolved, stack-opacity varied from 2 to 4 percent, which satisfies restriction levels set by the State.

3.4.8 Solid Waste Disposal

Solid wastes consist of bottom ash drained from the bed and fly ash collected in the bag collectors. Samples of bottom ash and fly ash were manually collected and analyzed in on-site laboratories. Table 4 lists a material balance showing the relative amounts of wastes collected during acceptance tests.

Table 4. Material Balance

	Coal	Limestone	Air	Total
INPUT thousand kg/h (thousand lb/h)	49.4 (108.8)	1.6 (3.6)	517.1 (1,140)	568.1 (1,252.4)
	Flue Gas	Fly Ash	Bed Drain	Total
OUTPUT thousand kg/h (thousand lb/h)	555.7 (1,225)	10.7 (23.6)	1.7 (3.8)	568.1 (1,252.4)

CFB ashes are environmentally inert and may be marketable on a site-specific basis, as was done (cement additive) at the California Portland Cement Company, Colton, California. CFB ash can also be used for agricultural soil amendment, waste and sludge stabilization, road base materials, and landfill capping.

In June 1989, the U.S. DOE, under its coal research and development program, constructed a landfill near the Nucla Station with bottom ash and flyash collected from the CFB boiler while it was fueled with low-sulfur subbituminous coal. As a result of the low sulfur input and sorbent feed requirement, the ash was relatively low in sulfate and lime content, which reduced the cementitious activity of the material. However, construction of the landfill with the CFB wastes was straightforward; typical ash conditioning and compaction techniques were used.

Three years of field monitoring the landfill test cell found no effects on the landfill environment produced either by surface runoff or leachate migration from the base of the test cell. The materials compacted in the test cell developed and maintained adequate compressive strength for landfill stability, although strength development was not as great as had been anticipated, and some evidence shows that the landfill permeability increased during the monitoring period. The permeability of the landfilled materials led to an increase in the landfill average moisture content over the past 3 years, but no leachate drainage appears to have occurred. Model results indicate that no leachate will be produced in the next 20 years. The runoff water quality met all applicable standards for dissolved solids, which is not surprising given the low volume of annual runoff (less than 19 liters [5 gallons]). Leaching tests of the initial CFB waste determined that concentrations of all regulated constituents were well below regulatory limits; concentrations of regulated trace metals were lower than in average western coal ash. Test leachate solutions prepared from CFB ash core samples indicate that hydration reactions in the test cell have helped stabilize most major ions in the wastes.

The results of this field study suggest that CFB combustion residues from the combustion of low-sulfur western coals will perform well in landfills in regions with low rainfall, high evapotranspiration, and significant depths to groundwater, such as are found in large areas of the western U.S. The high variability in the strength and permeability measurements of the landfill test cell suggests that increased attention to construction and engineering could be beneficial. Decreased waste permeability or soil cover could prevent the moisture buildup noted in the present test cell (Weinberg, Coel, and Butler 1994).

3.4.9 Wastewater Discharge

In the repowering of the Nucla station, the existing wastewater system was not modified. The boiler-drum blow down stream contains dissolved solids remaining after feedwater demineralization, plus additives for deoxygenation and pH correction. The cooling-tower blow down stream contains dissolved solids present in the river water makeup stream, plus additives for corrosion control. These streams, generically, are of the type generated by many power plants and are believed suitable for discharge to a publicly owned water treatment works. However, at Nucla Station, an evaporation pond was used due to low ambient humidity and low annual rainfall.

3.5 Demonstration Project Cost

CUEA's economic evaluation indicated that the total investment required to repower Nucla Station with atmospheric CFB technology was about $112.3 million. This represents a capital cost of $1,123 per total net kW, or approximately 22 percent over the estimate CUEA had published in 1984. At the time, however, this capital cost was still much lower than an alternative cost of installing new pulverized coal-fired generating capacity. (DOE did not fund any of Nucla's capital costs, although capital cost overruns are not uncommon for plants that are the first of their kind.)

During DOE's participation in the test program (September 1988 to January 1991), the total cost of power production, including operations, maintenance and fixed costs, was $54,750,819, or an average of $63.63/MWh. Fixed costs were about 62 percent of the total. Despite Nucla's smaller size, power production costs proved competitive with utility-scale, pulverized coal units that do not limit emissions as significantly.

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The government initially obligated \$19,920,000, or 36.4 percent of the estimated cost of test operations (U.S. Department of Energy 1994b). Of this obligated amount, \$17,433,951 was actually expended by the DOE to fund the project. In response to the stated policy of the DOE to recover an amount up to the Government's contribution to the project, the Tri-State Generation and Transmission Association, Inc., has begun to repay the Government in accordance with the Recoupment Plan included in the Cooperative Agreement. As of March 31, 1995, Tri-State Generation and Transmission Association had repaid \$303,540 to the DOE.

4 Post-Project Achievements

4.1 Nucla Boiler Upgrade

In April 1992, the Tri-State Generation and Transmission Association, Inc. (Tri-State), assumed ownership of the Nucla Station as the result of a bankruptcy reorganization process. At the time, the average availability of the plant remained below industry standards due to CUEA's financial difficulties and continuing problems with certain components of the CFB boiler. These components included secondary superheaters, air distribution nozzles, water wall tubes, expansion joints, wall boxes, and various refractory surfaces. To improve the plant's reliability, API was selected to replace, repair, or retrofit these components. These upgrades were accomplished during a 13-week period between May and August 1993. Operations resumed in September 1993, and the performance of Nucla Station improved significantly. During the 7 months following the upgrade, the plant had an average availability and capacity factor of 79.2 percent and 71.3 percent, respectively. Although the CFB boiler remained the most common cause for plant shutdowns, its reliability was expected to improve as problems were corrected (Heller, Bush, and Friedman 1994).

4.2 Current Commercial Status of CFB Technology

When sold in 1984, the Nucla atmospheric CFB boiler was the largest of its type ever sold worldwide, providing a critical link between small pilot and industrial facilities and commercial-size plants. This scaleup significantly advanced the environmental, operational, and economic potential of atmospheric CFB technology, saving API almost 3 years in establishing a commercial line of atmospheric CFB units (U.S. Department of Energy 1994b). Although at least six larger atmospheric CFB units have been operated, the Nucla project's comprehensive CFB database continues to be an important and unique resource for the design of yet larger atmospheric CFB systems.

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Another measure of Nucla's success has been the commercial acceptance of atmospheric CFB technology. By 1994, more than 200 atmospheric CFB boilers had been constructed worldwide. These atmospheric CFB units ranged in size from 1.5 to 250 MW_e, with a total capacity exceeding 8,000 MW_e (Rezaiyan and Gill 1994). Atmospheric CFB technology is now market driven, and boiler manufacturers are generally competitive in cost and performance. Multiple vendors offer 150-MW_e atmospheric CFB units with commercial warranties. Based on cumulative unit capacity, API has the largest share of the domestic market (33.0 percent), leading ABB-CE (26.5 percent), Foster Wheeler (11.3 percent), Tampella Power (7.9 percent), Riley Stoker (3.5 percent), and Babcock & Wilcox (2.3 percent). API and ABB-CE/Lurgi also dominate the atmospheric CFB market abroad, with 54.4 percent and 25.7 percent market share, respectively (Rezaiyan and Gill 1994). The advantages of each manufacturers' distinct design with regard to cost, operability, and reliability will become apparent as more experience is gained with atmospheric CFB plant operation.

Figure 2 shows how the operational success at Nucla helped precipitate a large number of orders for API's atmospheric CFB equipment. Firing peat and coal, an API atmospheric CFB boiler (125 MW_e with reheat) has produced steam for power production and district heating for more than 3 years in Seinajoki, Finland, with an average availability of 98.5 percent. A 527,100 kg/h (1,162,000 lb/h) API utility unit (180-MW gross with reheat) was the largest in the world when commissioned in late 1993 at Point Aconi, Nova Scotia (Darling 1994). In late 1992, two API atmospheric CFB reheat units started producing 180 MW_e and 14,000 kg/h (30,000 lb/h) steam at Applied Energy Services' low-rank, coal-fired, cogeneration plant in Barbers Point, Hawaii. With an equivalent forced outage rate of only 0.8 percent, the Barbers Point plant has achieved an availability of 97.5 percent (Smith 1993). In 1994, Ahlstrom Pyropower Inc., began offering a 1,400,000-kg/h (3,000,000-lb/h) (400 MW_e) reheat atmospheric CFB boiler to their customers.

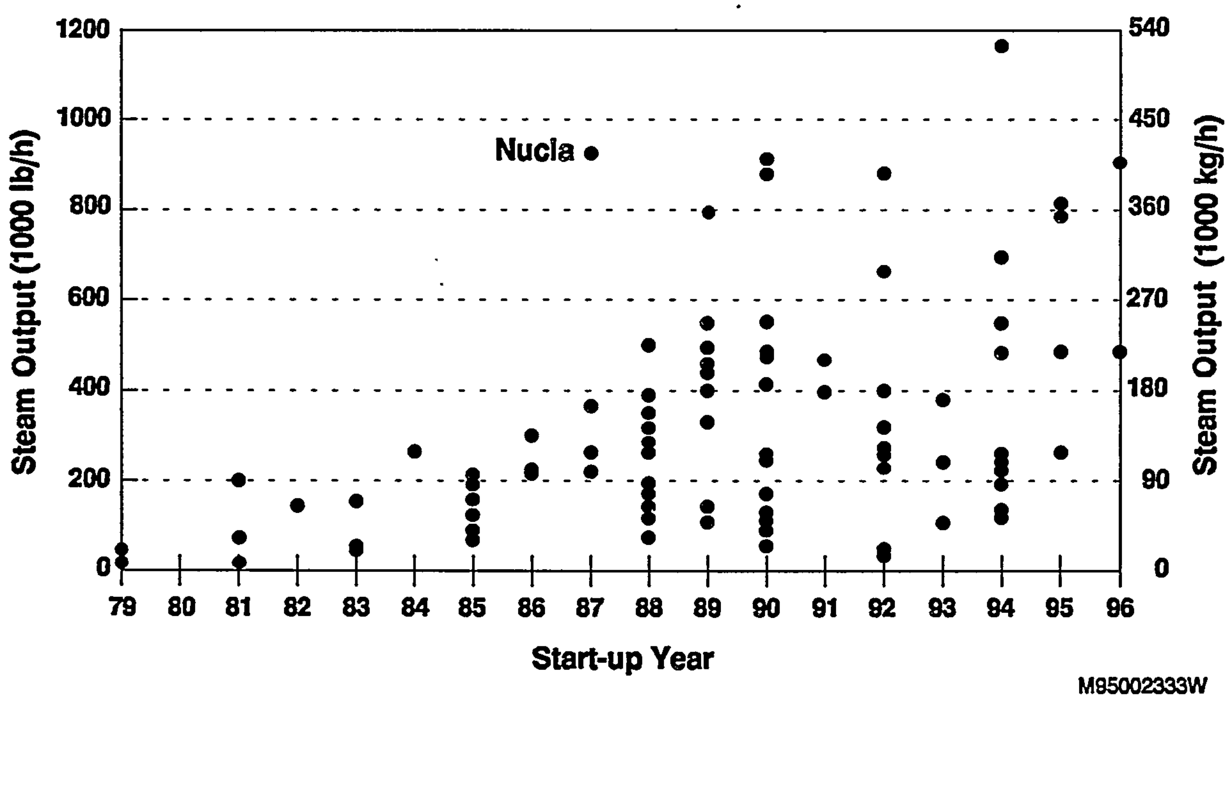


Figure 2. Worldwide Ahlstrom Pyroflow® CFB Boilers Operating or Under Construction

In 1990, ABB-CE supplied two 165-MW_e (gross), lignite-fired, reheat units to Robertson County, Texas, for Texas-New Mexico Power Company. When installed, these units were the largest atmospheric CFB boilers in the world. They are still the largest in the U.S. The Robertson County Station Unit 1 won *Power Magazine*'s 1991 Powerplant Award, achieving an excellent availability and capacity factor since its September 1990 startup (Makansi 1991a). Currently, the world's largest operating atmospheric CFB boiler was designed with ABB-CE/Lurgi technology. Electricité de France commissioned this 250-MW_e unit in 1994 at Grenoble, France.

The average availabilities and capacity factors of atmospheric CFB plants are now comparable to those of PC/FGD, although CFB Ca/S ratios remain high.

Foster Wheeler has built two 100-MW_e reheat units for the Nelson Industrial Steam Company in Westlake, Louisiana. In April 1991, a 20-MW_e, Foster Wheeler, atmospheric CFB boiler went into operation for Manitowoc Public Utilities in Wisconsin. Although the Manitowoc unit is cycled daily while burning a variety of waste fuels and coal types, it has maintained a high availability and met emission requirements for SO_x, NO_x, and particulates (Smith 1993). Foster Wheeler's CFB technology is also planned for the 250-MW_e, York County Energy Partners Cogeneration Project proposed to be built near York, Pennsylvania. This CCT project will demonstrate the largest CFB boiler in the U.S., moving CFB technology into the utility-scale size range. Key scaleup issues include thermal design, solids mixing, feed distribution, and cyclone design. Commercial operation is scheduled for 1997 (Vallone 1994).

In recent years, atmospheric CFB units have made great gains in availability and environmental performance. Although atmospheric CFB plants are generally selected for more difficult fuel and environmental applications, their average availabilities and capacity factors are now comparable to those of PC/FGD (Smith 1993). Furthermore, the emissions of SO_x and NO_x from atmospheric CFB plants has declined to the point that the technology can operate in regions with the strictest regulations. (For example, performance tests for a 96-MW [net], API atmospheric CFB cogeneration unit, which began operating in Trona, California, in 1990, yielded emissions 50 percent below the strict California permit levels [Vaughan 1991].) The Ca/S ratios that CFB units require for sulfur removal remain high, creating significant amounts of solid waste that must be disposed of properly (Makansi 1991b). Although continued operation and improved reliability will increase marketplace confidence in CFB technology, demonstration of a utility-scale (greater than 200 MW_e), atmospheric CFB unit in the U.S. is still necessary to gain widespread acceptance by domestic utilities.

Emissions from a 96-MW (net), API atmospheric CFB cogeneration unit operating in Trona, California, were 50 percent below the strict California permit levels.

4.3 Expected Performance of a Future Commercial Plant

Data from the Nucla Project have confirmed the predicted performance of atmospheric CFB technology, providing a basis for the design of future commercial CFB power plants. To help disseminate this information to potential users, METC commissioned the design of a 400-MW_e Reference Plant featuring mature atmospheric CFB technology based on Nucla project experience (Rubow et al. 1992). A reasonable extension of state-of-the-art atmospheric CFB technology was assumed.

The Reference Plant was designed with attributes considered important to the utility industry. The system designs and equipment selections were chosen using operating availability, overall cycle efficiency, and cost effectiveness in the same manner as would be done in a commercial plant design. The PC/FGD was considered as the utility standard, from which commercial comparisons were made. Design assumptions were therefore based on criteria used for PC/FGD plant applications, except where the new technology portions required special consideration. Assumptions concerning generic and geographical features were made to define the Reference Plant as a guide for designs and cost estimates. Similar assumptions can be made for future commercial versions of other clean coal plants that will permit valid comparisons to be made.

4.3.1 Reference Plant Design

The Reference Plant is comprised of two, 200-MW_e, atmospheric CFB combustors that supply steam to a 400-MW_e, turbine-generator operating on a 17 MPa/540 °C/540 °C (2400 psig/1,000 °F/1,000 °F) single-reheat steam power cycle. The net plant output power, after plant auxiliary power requirements are deducted, is 400 MW_e. The plant load is designed for base-load operation with occasional turndown to 25 percent plant load.

Two 200-MW_e combustors were selected for the following reasons.

- It is expected that a large portion of the utility industry will prefer a unit capable of generating 300 to 600 MW_e for the majority of the expansion envisioned in the 1990s and beyond. Hence, two 200-MW_e boilers, providing steam for a single 400-MW_e turbine-generator, were selected.

- The 200-MW_e boiler size chosen is a reasonable extension of similar units that are presently operating, and hence should be available as a mature technology in a reasonable time period. The problems encountered to date appear to be solvable within a scaleup of the technology of 2:1 or less, as it is in this case. Some atmospheric CFB boilers currently operating are even larger (e.g., 250 MW_e) than the combustors in the Reference Plant.

- Present-day control systems can be designed to successfully control two boilers and one turbine with reheat, thus providing an efficient coal-fired plant. Availability is enhanced by allowing one boiler to be taken out of service without shutting the plant down. In addition, increased efficiencies can be obtained at low loads by running only one boiler at its most efficient operating point.

The design used for the Reference Plant is improved from that used for the Nucla Plant in several significant areas. A specific boiler design was required to complete a conceptual plant design, so the design of API, the Nucla CFB supplier, was chosen for the Reference Plant, albeit with some modification. The following partial list includes the more important changes and their bases. In general, changes have been made to improve reliability where operation has shown the need for modification, or to address performance in terms of carbon burn-up efficiency, NO_x production, or limestone calcium utilization.

- A single combustion chamber was designed instead of two to alleviate flow distribution problems.

- Double loop seals were used to allow recirculating solids to re-enter the combustor in two distinct flow streams for better distribution (standard on API units since 1990).

- An in-combustor Omega™ superheat surface was designed to provide a flat surface parallel to the upward flowing gas in the combustor, thus minimizing erosion (standard on API units since 1990).

- In-combustor wingwalls were added to provide additional evaporative and superheat duty.

- The "wrap-around" combustor superheat surface was eliminated and the back-pass superheat hanger design was changed.

- A change in the air supply source was made to allow initial variation in the primary-to-secondary air split to provide optimum heat transfer, performance, and emission characteristics for the combustor system.

- Sixteen (instead of eight) limestone feed points were incorporated to improve contact with SO_2.

- A flyash reinjection system was added to optimize limestone utilization and carbon burnout (standard on API units since 1990).

- The refractory/waterwall interface design was changed to eliminate ash eddying and decrease erosion potential.

- Pigtail nozzles were used instead of bubblecaps to reduce backsifting of ash into the windbox and to decrease nozzle maintenance.

- Refractory brick was used instead of castable or gunnite to minimize erosion.

- A cyclone configuration change to lessen reentrainment and maximize gas residence time in the cyclone was made.

- A single piece vortex finder was added to the cyclone to prevent shortcutting and enhance particulate capture.

- The rotary feed valve/pressurization of the feed system was eliminated.

4.3.2 Expected Technical Performance

Based on the operation of similarly sized atmospheric CFB plants, the Reference Plant could be built in the near future and operate with high availability. The Reference Plant's levelized capacity factor is assumed to be 65 percent for economic projections, although a significantly higher value is expected. The plant was designed with components suitable for a 30-year life.

The overall performance of the Reference Plant operating at 100 percent load is summarized in Table 5. The net power output is 400.5 MW_e at an efficiency of 34.4 percent (higher heating value). It is expected that the combustor design will continue to change as more operating experience is obtained, and that improved performance, reliability, and cost competitiveness will be the result.

4.3.3 Expected Environmental Performance

The Reference Plant is expected to meet all applicable federal, state, and local environmental standards relating to air, water, solid waste, and noise. Environmental benefits of atmospheric CFB include 90 percent SO_2 reduction and 60 to 80 percent NO_x reduction. A calcium-in-the-limestone to sulfur-in-the-coal ratio of 2.5:1 ensures an SO_2 emission rate of less than 0.159 mg/kJ (0.371 lb/MMBtu) (92 percent reduction). CFB can control pollutants at lower costs than can traditional technologies.

4.3.4 Expected Economic Performance

An economic analysis of the Reference Plant was performed to provide expected capital and operation/maintenance (O&M) costs for a mature atmospheric CFB commercial plant. The Reference Plant was assumed to operate for 30 years, beginning in January 1992, with a 65 percent capacity factor. Costs were established consistent with EPRI Technical Assessment Guide (TAG) methodology. The capital and operating costs of the Reference Plant were combined with its performance to calculate the coal pile-to-busbar cost of electricity (COE) in levelized current dollars. Table 6 presents a summary of the Reference Plant's expected economic performance, and Figure 3 illustrates the composition of the COE.

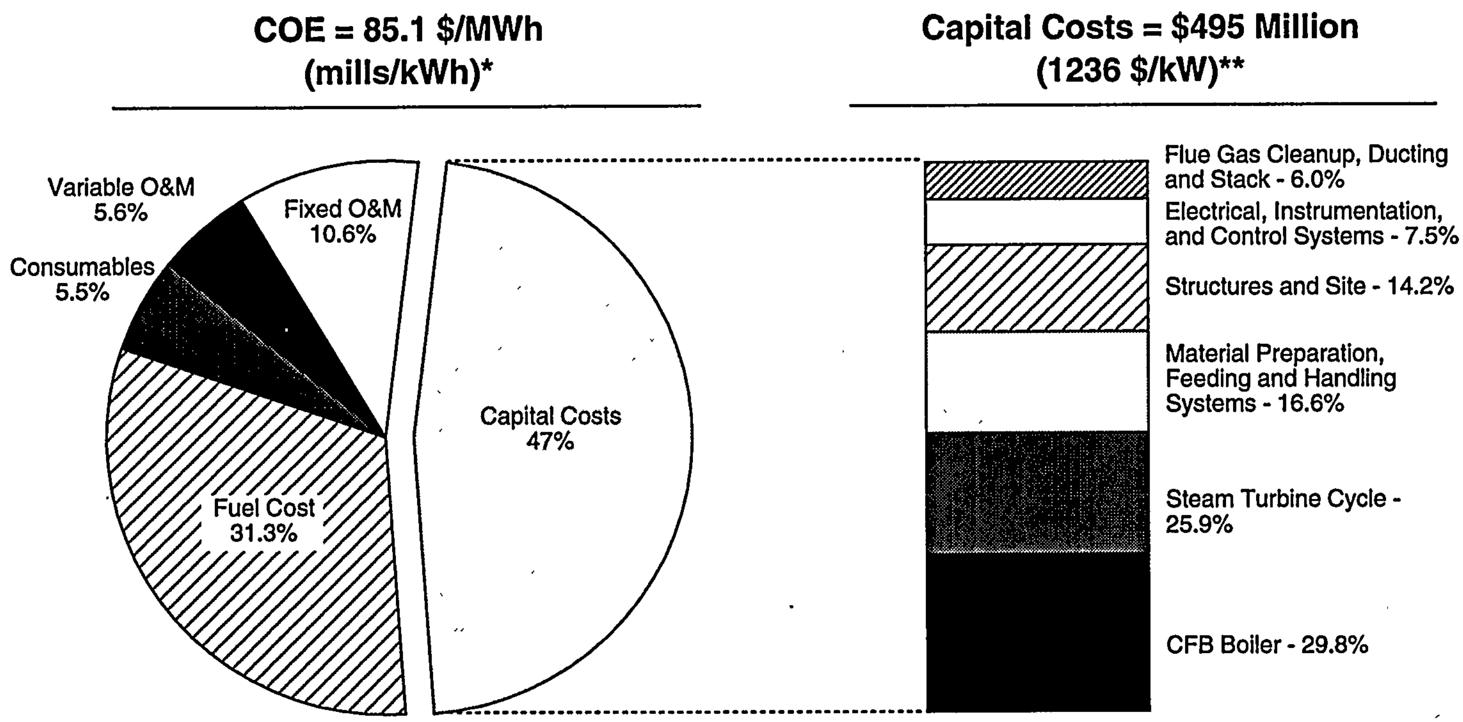
Table 5. Expected Technical Performance

CONSUMABLES	
As-Received Coal Feed, kg/h (lb/h)	148,940 (328,354)
Sulfur in As-Received Coal, % weight	2.89
Sorbent, kg/h (lb/h)	33,110 (72,990)
STEAM CYCLE	
Throttle Pressure, MPa (psig)	17 (2,400)
Throttle Temperature, °C (°F)	540 (1,000)
Reheat Outlet Temperature, °C (°F)	540 (1,000)
Condenser Cooling Duty, kJ/h (MMBtu/h)	2,040 E+6 (1,930)
POWER SUMMARY	
Gross Power, kW_e	437,114
Total Auxiliaries, kW_e	36,613
Net Power, kW_e	400,501
Net Efficiency, % HHV	34.4
Net Heat Rate, Btu/kWh (HHV)	9,930

Table 6. Summary of Economic Performance (1991 Dollars)

Total Capital Requirement[1]	$552.7 million	1,380 $/kW
Fixed O&M (1st Year)	31.82 $/kW-year	
Variable O&M (1st Year)	3.01 mills/kWh	
Total consumables (1st Year)	$6.6 million	2.89 $/kW
Fuel cost (1st Year)	$36.2 million	15.88 $/kW
Levelized Busbar COE	85.1 mills/kWh	

[1] In addition to the capital cost of the plant, the total capital requirement includes an allowance for costs during construction, a royalty allowance, preproduction costs, inventory capital, the costs of initial catalysts and chemicals and land cost.



* COE based on 30 year, levelized current dollars (1991 projection)

** Capital costs are in 1991 dollars and include engineering and contingency costs

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Figure 3. Expected COE for Atmospheric CFB Technology

5 Outlook for CFB Sales

5.1 Competitors

Today, atmospheric CFB technology must compete with nuclear power, renewable sources of electric power, oil- and gas-fired systems, and other coal-fired systems. Due to extremely difficult siting and licensing problems, the EIA does not expect any new nuclear plants to start operating before 2010. Hydroelectric capacity, the dominant renewable, is not expected to grow significantly since the best sources of hydropower have already been exploited. Although growing, the capacity from other renewable sources of electric power, such as biomass, municipal solid waste, geothermal, wind, and solar, is expected to remain relatively small (U.S. DOE 1994a).

Today's combined-cycle, natural gas-fired systems are very competitive, having high efficiencies, excellent environmental performance, and low risk, since they employ no new technology. Since their capital requirements are the lowest of any system (approximately half of a coal-fired plant), natural gas-fired plants can still generate electricity cheaper than new PC/FGD systems, even though the price of natural gas is around 50 percent higher than coal on a $/kJ ($/Btu) basis. However, utilities continue to be concerned about the long-term availability of natural gas supplies at a predictable price. More importantly, the price differential between natural gas and coal is expected to widen. Consequently, coal is expected to remain an attractive fuel choice for new baseload capacity and retain its majority portion of the electric power generation market.

Atmospheric CFB technology has several advantages over PC/FGD, including greater fuel flexibility, reduced coal preparation costs, lower NO_x emissions, and dry solids waste removal.

Within today's coal-based power generation market, atmospheric CFB's chief competition is PC/FGD systems. Atmospheric CFB technology has several advantages over PC/FGD, including greater fuel flexibility, reduced coal preparation costs, lower NO_x emissions, and dry solids waste removal. Low-rank coals that perform well in atmospheric CFB boilers are unattractive for use in conventional pulverized coal units due to costs of ash collection as well as pulverizer operation and maintenance. In general, as fuel quality decreases, atmospheric CFB becomes more competitive with PC/FGD since savings in fuel costs offset the added expenses of air compression.

Some advanced systems that are just now emerging into the electric power generation market will be fully commercial and ready to compete with atmospheric CFB systems around the turn of the century. Advanced systems based on coal include PFBC and IGCC. Both PFBC and IGCC have higher cycle efficiencies and lower emissions than atmospheric CFB.

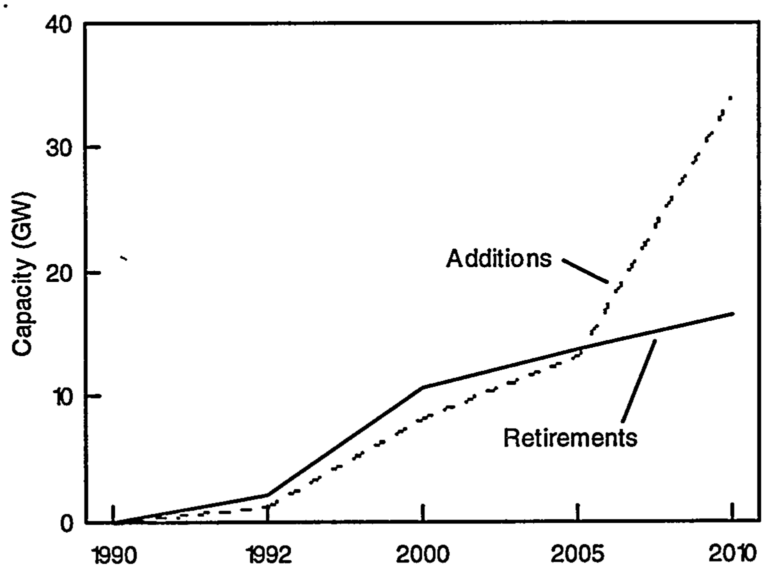
Natural gas-fired molten carbonate fuel cell systems are also expected to be commercialized around 2000, with higher efficiencies and lower emissions than the advanced coal-based systems.

5.2 Markets

5.2.1 Domestic Market

The EIA divides the domestic electric power generation market into two main categories: utility and nonutility. (Nonutility generation can be further subdivided into two markets: electric power generation and cogeneration, distinguished by whether electric power is the primary product.) Due to the deregulation of the electric power industry, utilities are facing a growing competitive challenge from nonutilities for market share. In 1992, more than 8 percent of all electric power generated in the U.S. was produced by nonutilities, including cogenerators. The rapid growth of the nonutility power generation industry is expected to continue. The EIA projects that nonutilities, including cogenerators, will install nearly 40 percent of U.S. electric power capacity additions (all fuels/technologies) from 1990 to 2010.

The EIA projects U.S. demand for electricity to grow slowly (1.0 to 1.5 percent per year) until 2010. In the near-term, this slow demand growth is expected to be met with demand-side management, repowering, life extension, and power purchases from nonutilities. New natural gas-fired cycles are expected to meet increasing peak and intermediate load requirements. The EIA projects that utilities will maintain their coal-based capacity at around 300 GW through the year 2000, adding around 8 GW of new coal-based capacity as old units are retired. (See Figure 4.) Utilities may be hesitant to add new capacity of their own since they are required by the Public Utility Regulatory Policies Act to purchase power from nonutilities that cogenerate or burn waste fuels. In addition, since utilities have little or no incentive to take the risk of installing advanced power technologies, they may even prefer to purchase nonutility power (Salvador, Bajura, and Mahajan 1994). After 2000, the existing U.S. baseload capacity will have to be expanded, and the EIA projects that coal-based plants will compete strongly, capturing an additional 26 GW of new capacity.

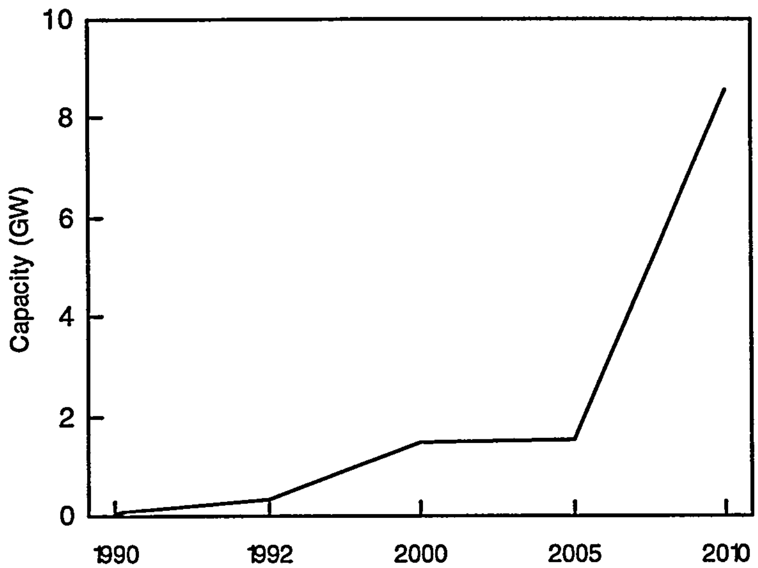


Adapted From: U.S. Department of Energy 1994a

Figure 4. Projected Electric Utility Additions and Retirements of Coal-Based Units (Cumulative)

The projections in Figure 4 do not include the modification of existing capacity, such as life extension and repowering. Considering the large number of old

U.S. power plants that need upgrading to increase efficiency and to meet the stringent environmental requirements of the 1990 Clean Air Act Amendments, this market could be larger than that for new capacity. Since the cost of repowering on a $/kW basis is many times the cost of life extension, it will make sense to repower only a fraction of these aging plants. The life of any type or size of boiler can be extended by repowering with atmospheric CFB. The existing plant area, steam turbine equipment, and coal- and waste-handling equipment can all be used. When successfully demonstrated at utility scale, atmospheric CFB technology is expected to capture a growing portion of the coal-based utility market, both for repowering and new capacity.



Adapted From: U.S. Department of Energy 1994a

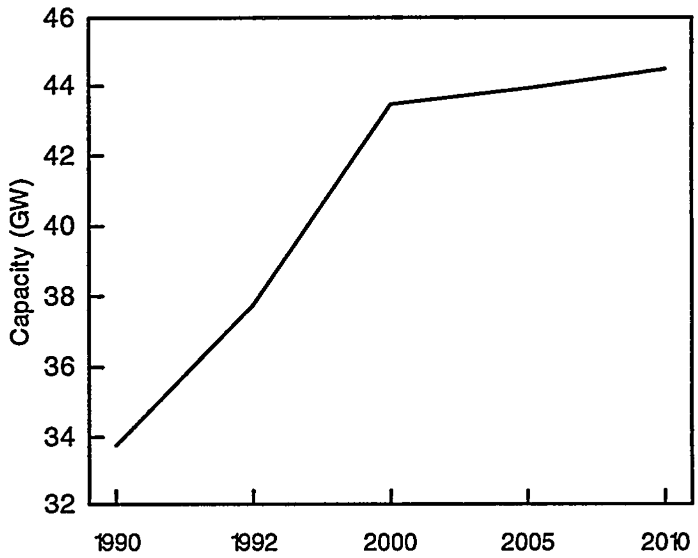
Figure 5. Projected Non-Utility Coal-Based Capacity, Excluding Cogenerators (Cumulative)

Atmospheric CFB technology has been successfully used in many nonutility power plants whose primary function is to sell electric power to the utility grid. While it is not cost effective for utilities to ship low-rank coals to large, distant power plants, nonutilities typically have smaller plants with more incentive to burn locally available low-quality fuels. Atmospheric CFB units are proven at these smaller sizes and can easily burn "problem" coal varieties. Figure 5 shows the EIA projections that nonutilities will add around 1.5 GW of coal-based capacity by 2005 before rapidly expanding another 7 GW by 2010. (Projections of nonutility coal-based capacity have varied significantly from year to year.) The projection in Figure 5 excludes two substantial markets in which CFB should compete very well: self-generation, which produces power for self-usage only, and cogeneration, in which electric power is sold but is not the primary product.

The vast majority of atmospheric CFB units in operation today cogenerate process steam and electricity for various industries. Atmospheric CFB technology is well proven at the smaller sizes (50 MW or less) typical of cogenerators. The ability of atmospheric CFB technology to burn a variety of waste fuels and low-rank coals has given it a large competitive advantage in a growing industrial cogeneration market. For example, biomass-fired electric power capacity, dominated by industrial cogenerators, is expected to grow 8 GW by 2010. As shown in Figure 6, the EIA projects that the total cogeneration market will expand by 10 GW before 2000. Because of CFB's unique qualifications, cogeneration may be the market niche in which it achieves its greatest success.

Because of CFB's unique qualifications, cogeneration may be the market niche in which it achieves its greatest success.

Atmospheric CFB technology could be especially successful in the near-term electric power market. The EIA projects that over 8 GW of new coal-based capacity will be needed to replace retiring utility units before the year 2000. Combined with the growth expected in nonutility coal-based capacity, atmospheric CFB will compete for nearly 10 GW of coal-based power plants before the year 2000. In addition, CFB should be successful in capturing a portion of the 10 GW of new cogeneration capacity expected before 2000. Around the turn of the century, IGCC and PFBC systems will be demonstrated at utility scale, and atmospheric CFB will have to compete with the higher efficiency and superior environmental performance of these systems for its share of the large coal-based market expansion projected by the EIA.



Adapted From: U.S. Department of Energy 1994a

Figure 6. Projected Cogenerator Capacity, All Fuels/Technologies (Cumulative)

5.2.2 International Market

Driven by population growth, a rising standard of living, and industrial expansion, the international power generation market is expected to be much larger than the domestic market. Governed by the same cost constraints as U.S. generators, foreign power producers will prefer to use indigenous fuels, of which coal is the dominant type. For example, many Asian and Pacific countries, such as Australia, China, India, Indonesia, Taiwan, and Thailand, are undergoing rapid economic expansion and have large reserves of low-quality coal and lignite, which atmospheric CFB technology can utilize very competitively (Ahlstrom Pyropower Inc. 1994).

The demand for clean electric power generation technology is largest in China, which is expected to be the single most important market for coal-based power generation well into the next century. China has built 10 GW of new capacity in each of the last 4 years and plans to add an additional 140 GW by 2000. Within the next 10 years, 70 GW of coal-based capacity is expected to be constructed (Makansi 1993). Since Chinese industry accounts for around half of the country's coal usage, great potential exists for sales of atmospheric CFB cogeneration units.

India will also be a significant market, with plans to add 36 GW of capacity by 2000 and an additional 58 GW by 2010. More than 60 percent of this new capacity is expected to be fueled by coal and lignite (Makansi 1993).

Atmospheric CFB technology is already competing in several international markets. Ahlstrom Pyropower, Inc., has units operating or under construction in Austria, Canada, the People's Republic of China, Denmark, Finland, France, Germany, India, Israel, Japan, the Republic of Korea, Scotland, Switzerland, Sweden, Taiwan, and Thailand (Ahlstrom Pyropower, Inc. 1994). Foster Wheeler has atmospheric CFB units operating in Japan and Spain.

Since Chinese industry accounts for around half of the country's coal usage, great potential exists for many sales of atmospheric CFB cogeneration units.

6 Acronyms and Abbreviations

API	Ahlstrom Pyropower Incorporated
BFB	bubbling fluidized bed
Btu/NkWh	British thermal unit per net kilowatt-hour
Ca/S	calcium to sulfur ratio
CaO	calcium oxide
CCT	Clean Coal Technology
CFB	Circulating Fluidized Bed
CO	carbon monoxide
CO_2	carbon dioxide
COE	cost of electricity
CUEA	Colorado-Ute Electric Association
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPRI	Electric Power Research Institute
ft/s	feet per second
GW	gigawatts
HHV	higher heating value
IGCC	integrated gasification combined cycle
kW	kilowatt
kWh	kilowatt-hour
lb/h	pound per hour
METC	Morgantown Energy Technology Center
mills/kWh	mills per kilowatt-hour
MMBtu	million British thermal units
MW_e	megawatt electric
MWh	megawatt-hour
MW_t	megawatt thermal
NEPA	National Environmental Policy Act
NH_3	ammonia
NO_x	nitrogen oxides
PC/FGD	pulverized coal/flue gas desulfurization
PFBC	pressurized fluidized-bed combustion
ppmv	parts per million on a volume basis

psig	pounds per square inch gauge
SO_2	sulfur dioxide
TAG	Technical Assessment Guide

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