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An Overview of Atmospheric Fluidized Bed Combustion Systems as Applied to Army Scale Central Heat Plants

by
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Based on this evaluation, AFBC technology is a practical option for both new and retrofit boilers at Army central heat plants. Although AFBC boilers are economically competitive with conventional coal fired boilers and offer greater fuel flexibility, AFBC boilers firing coal are not competitive with oil or gas in the current energy market.

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FOREWORD

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AN OVERVIEW OF ATMOSPHERIC FLUIDIZED BED COMBUSTION SYSTEMS AS APPLIED TO ARMY SCALE CENTRAL HEAT PLANTS

1 INTRODUCTION

Background

Atmospheric Fluidized Bed Combustion (AFBC) technology has the potential to use alternative fuel sources such as coal, wood, or waste, and is able to reduce and control nitrogen oxide (NOx) and sulfur dioxide (SO_2) emissions. This report reviews AFBC technology for possible use in Army boilers in the size range of 20,000 to 300,000 lb/h steam.*

AFBC involves burning sulfur-containing fuel particles suspended in an air stream, which causes them to behave like a fluid. The bed of particles is normally only about 10 percent fuel; the remainder is inert materials and sorbent (dolomite or limestone), which is used to capture up to 90 percent of the sulfur. This sorbent is continually injected into the bed while a gravity drain system withdraws spent material and ash particles. Combustion also occurs at relatively low temperatures (1400 to 1500 °F), which maximizes sulfur capture. This low bed temperature also reduces NOx emission while minimizing clinker (a hard mass of fused furnace refuse) formation. Fly ash and spent sorbent are removed from the stack gas by particulate collectors. This technology is very insensitive to the fuel quality, allowing solids with a widely varying calorific value to be burned. Typically, AFBC technology is applied in new plants, but recent developments of a shallow bed AFBC system by Wormser Engineering, Inc. has shown that it may also be used as a retrofit technology. The steam produced by AFBC ranges from low-pressure process steam to superheated high-pressure steam. AFBC has also been applied to cogeneration, where high-pressure steam drives turbines to generate electricity. Low pressure steam from the steam turbines is then used for process applications.

Objective

This report provides planners and design engineers an overview of the fuel handling, combustion, emissions control, and project economics of AFBC technologies as applied to Army scale boilers, both new and retrofit designed for gas and/or oil.

Approach

Current AFBC boiler manufacturers were contacted to obtain product information, published literature, and a list of AFBC boiler installations. This material was compared and evaluated to determine the capabilities and drawbacks of AFBC technologies. Detailed information on AFBC boiler installations, including the ability of these boilers to meet emission standards, was also evaluated. The technical and economic factors of AFBC boilers were evalutated.

Mode of Technology Transfer

It is recommended that the information in this report be transferred as a Technical Note (TN).

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* A metric conversion table is on page 79.

2 BOILER DESCRIPTIONS

Characterization of AFBC Technologies

Atmospheric fluidized bed boilers consist of a chamber in which fuel is burned while being suspended in a gaseous mixture with inert material and sorbent. The sorbent (most commonly limestone) reacts with SO_2 released during combustion to form a solid sulfate material. The fluidized bed is maintained at 1400 to 1500 °F to maximize sulfur capture. This low temperature also reduces NOx emission while minimizing clinker formation. Although these characteristics are common to all fluidized bed boilers, the fuel and solvent feed systems, ash recycle/removal methods, and heat transfer surface vary, depending on the type of AFBC boiler. Three types are discussed below.

Bubbling Bed

Many design options are used with bubbling fluidized bed combustors (BFBCs), including ash recycle, underbed or in-bed feeding, and staged combustion. Figure 1 shows a diagram of a typical BFBC. The combustion air enters the bottom of the bed to produce a velocity of 6 to 16 feet per second (ft/s), flows up through an air distributor plate, and passes through the bed containing the solid fuel, limestone, and ash particles. The maximum size of the bed particles is usually 0.25 in. Crushed coal and sorbent are fed to the bed continuously.

Between 40 and 55 percent of the heat released in burning the fuel is transferred to the water and steam in the tubes surrounding and submerged in the bed. Convective heat transfer surfaces located in the path of the exiting combustion gases generate additional steam. Flue gas particulates entrained in the combustion products are removed by cyclones, bag filters, or electrostatic precipitators (ESPs). Captured particles are sometimes recycled back to the main bed or burned in a separate fluidized bed combustor called a carbon burnup cell.

Fuel and Sorbent Feed. To achieve high combustion efficiency and maximum sorbent use, the feed system must be designed to evenly distribute the fuel and sorbent into the combustor. The three types of feed systems used in BFBCs—overbed, underbed, and in-bed—are illustrated in Figure 2.

Overbed feed systems supply fuel and/or sorbent to the surface of the fluidized bed by a spreader, screw conveyor, or through a chute by gravity. Overbed spreaders are generally used for larger boilers because one feeder can cover a large area. Overbed feed screws or chutes can be used in situations where it is not critical to spread the fuel evenly over the entire bed surface. Some designs use chutes with attached cones to spread the fuel over a broader range. Almost any fuel can be used in overbed systems. Coal fines do not interfere with the feed. However, fines can become entrained in the exit gas, resulting in large amounts of unburned carbon in the ash.

Underbed feed systems introduce fuel and/or sorbent into the bed by a pneumatic feeder through the bottom of the combustion zone. Carbon losses with this system are less than with an overbed feed because the fines are retained longer in the combustion zone. However, pneumatic underbed feeding is rarely used, partly due to the complexity and cost of using several injection points to ensure proper distribution.

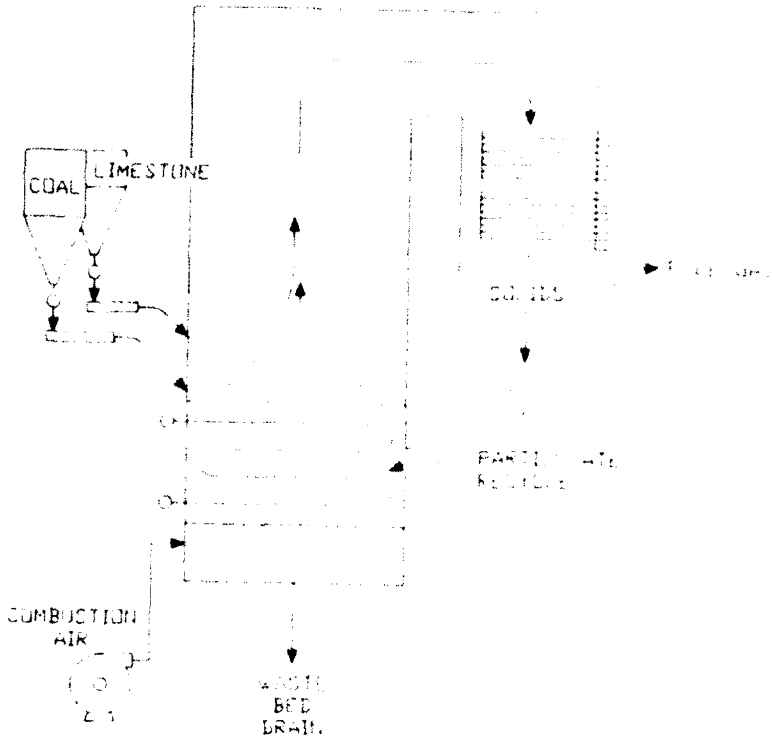

Figure 1. Diagram of bubbling fluidized bed combuster (BFBC).

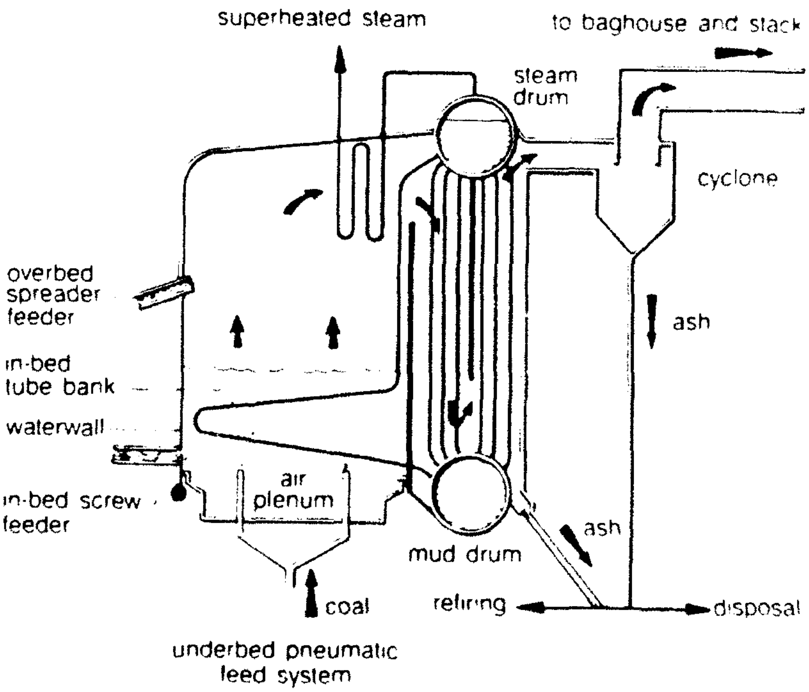

Figure 2. BFBC illustrating three types of coal feeding.

In-bed feed systems enter the side of the bed beneath the surface of the combustion zone. This feeder is suitable for feeding fines and is generally used for smaller boilers since fuel enters at only one point.

Ash Recycle/Ash Removal. Ash collected from the gas stream in the convective boiler sections and cyclones is recycled to improve combustion efficiency and capture SO_2. The mass flow ratio is defined as the ratio of returned ash to fresh coal. BFBCs commonly use recycle ratios of 4:1 or less.

Ash is generally removed through drain ports in each bed compartment. The drain port location (along the sides, in the corners, or in the center) is a vendor preference.

Heat Transfer Surface and Boiler Designs. Watertube heat transfer surfaces are located in the fluidized bed to control the bed temperature. These transfer surfaces are rows of tubes placed vertically, horizontally, or sloped. Because sloping promotes erosion due to flow patterns created by the tubes, tubes are usually placed almost horizontal. However, horizontal tubes require forced circulation pumps while sloped tubes use natural circulation patterns. Membrane type waterwalls can also be used for bed transfer surfaces. Because the fuel contacts the watertube surfaces, high heat transfer rates are obtained and the overall heat transfer surface and boiler volume can be reduced.

After the hot flue gas exits the bed, it enters the external convection passes above the bed. This section can be designed as either a firetube or watertube section and can be used for economizer or superheating purposes.

Particulate Collection. The fluidized bed boiler must achieve a carbon use of at least 90 percent to be competitive with a conventional boiler. Combustion efficiency can be improved by recycling ash particles to the bed. Cyclones are generally used after the boiler to capture and recycle the ash and sorbent. A baghouse or electrostatic precipitator (ESP) is usually used as the final dust collector.

Circulating Bed

The circulating fluidized bed combustor (CFBC) differs from the BFBC in that the solid particles are entrained in the fluidizing gases and the bed thickness is not well defined. Most of the entrained particles are captured by a cyclone system and reinjected into the combustor; therefore, ash recycle is inherent to CFBCs. A diagram of a CFBC boiler is shown in Figure 3. CFBC designs usually require tall combustors with large combustion zone volumes and relatively large cyclone ash collector systems.

Primary combustion air at 20 to 30 ft/s is supplied as the fluidizing medium, while secondary air is supplied at the sidewalls of the combustion chamber. The combustion chamber is usually designed as a waterwall. From the combustor, the flue gases pass through a transition pipe into a hot-solids separator. The solids return via a reentry downcomer and may be cooled in an external heat exchanger (EHE). The flue gases pass the heating convection surfaces of the boiler and are then cleaned in a baghouse or ESP.

Fuel and Sorbent Feeding. A typical feed system for a CFBC would use a screw feeder or rotary valve to meter the fuel and sorbent flow. (Designs using a spreader are also in use.) The fuel enters the combustor through one or two feeders. A CFBC requires fewer feeding points than a BFBC. A CFBC is tolerant of uneven fuel distribution because of the high mixing rates in the combustor. Also, because

[1] J.F. Thomas, R.W. Gregory, and M. Takadyasu, *Atmospheric Fluidized Bed Boilers for Industry*, IEA Coal Research (November 1986).

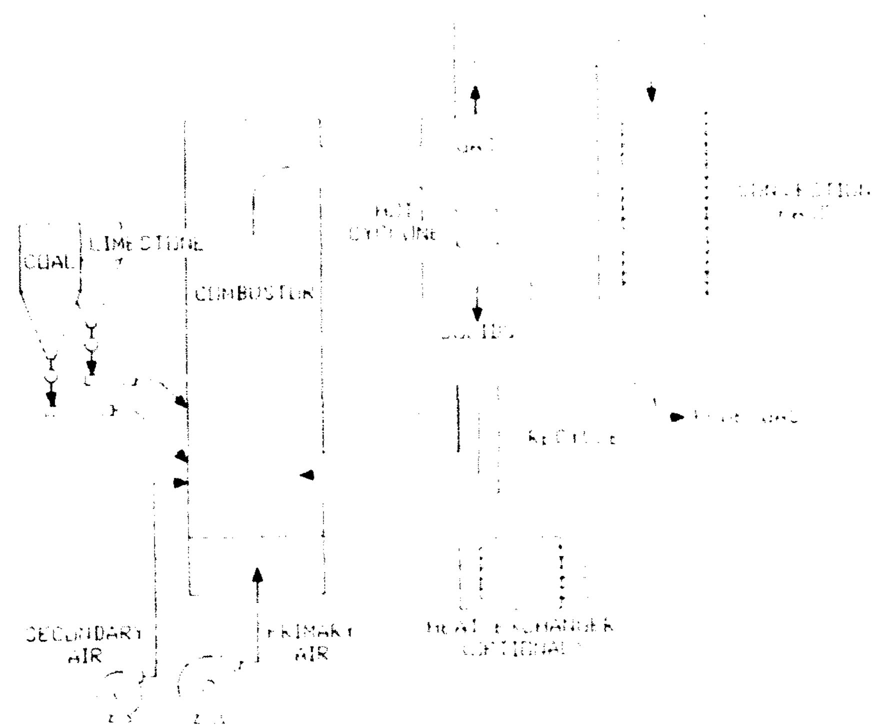

Figure 3. Diagram of a circulating fluidized bed combustor (CFBC).

a CFBC is a higher velocity boiler, it can tolerate somewhat larger fuel particles (0.25 to 2.5 in.). Due to the recirculation scheme of the CFBC, fines do not decrease the combustion efficiency. Coal drying generally is not required for the boiler itself, but may be required for the solids handling equipment.

Heat Transfer Surface and Boiler Design. CFBC designs consist of a vertical combustor that may be refractory lined, with waterwall heat transfer surfaces in the upper regions, or may be waterwall lined. The cyclone after the combustor is normally refractory lined, although heat transfer surfaces may be included in some designs. Individual designs are distinguished primarily by the presence and performance of the EHE and the hot-solids separation and reinjection techniques.

An EHE is essentially a refractory-lined box containing an air-distribution grid and an immersed tube bundle designed to cool material from the cyclone before it is returned to the combustor. Fluidizing velocity is low in the EHE, less than 3 ft/s, while solids density and heat transfer coefficients are high. Little or no combustion takes place in the EHE. One advantage of an EHE is that it can easily compensate for variations in heat absorption rates caused by changes in fuel properties and load conditions. Heat transfer in the EHE increases when heat absorption in the combustor decreases and vice versa. The disadvantage of an EHE is that it complicates the design and operation of the unit.[2]

Ash Recycle/Ash Removal. Solids recycling is an inherent part of CFBC systems. Most of the entrained solids that leave the combustor are captured by the cyclone and returned to the combustion zone. The recycle ratio for coal-burning CFBC systems is typically 20:1 or greater.

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[2] J. Makansi and R. Schwieger, "Fluidized-Bed Boilers," *Power* (May 1987)

Ash is removed from the bed to control the amount of solids and to purge the system. Ash may be removed at the bottom of the combustor, the economizer hopper, the EHE, or the recycle leg to the combustor. The hot ash can also be used to preheat feedwater or combustion air, thus increasing the overall thermal efficiency of the boiler. Once cooled, it is removed by conventional means.

Solids Separation. Most CFBCs have at least one cyclone to keep the solids circulating. The cyclone may be water- or steam-cooled to reduce the amount of high temperature, refractory-lined ductwork and to improve thermal efficiency.

A U-beam separator has also been used as a particle collector. It is comprised of U-shaped bars installed in a staggered array in a horizontal section of the pipe where the gas makes a 90-degree turn exiting the combustor. As the gas stream decelerates by about 50 percent compared to the combustor shaft velocity, particles impinge on the bars and fall into a hopper. This method avoids the use of thick refractory surfaces in a high abrasion environment, such as in a cyclone where velocities are often quadrupled. The U-beam section also adds residence time (by reducing the gas stream velocity), which improves combustion efficiency. In addition to the U/beams, this design calls for a multicyclone separator after the economizer. Solids captured here can be either recycled or extracted. This backup collector is used to eliminate potential problems resulting from switching from high to low ash coal.[3]

Multiple Bed

Multiple bed combustion (MBC) takes place in two fluidized beds in succession (two-stage combustion). Primary combustion occurs between 1650 and 1750 °F in the lower bed. Secondary combustion occurs at about 1500 °F in the upper bed. SO_2 emission is controlled by injecting sorbent into the upper bed. The upper bed also improves combustion efficiency and allows for a compact design.

Crushed and sized coal is normally fed to the lower bed pneumatically. To avoid clogging, the coal must be dried. Primary air, which serves as the fluidizing medium, is brought into an air plenum that contains nozzles to assure uniform air distribution over the bottom of the bed. Combustion gases released from the lower bed, together with secondary air added through the distribution plate for the upper bed, act as the fluidizing medium in the upper bed. Small unburned particles from the lower bed are burned in the upper bed. The uniform secondary air distribution results in very efficient combustion.

Flue gases leaving the combustor pass through the convection section, which may be integrated with the boiler or be arranged as a waste heat boiler. There is no need for fly ash reinjection. Before the gases are released to the atmosphere, they are cleaned by a baghouse or ESP.

Energy from the boiler is controlled by varying the fluidization air flow, fuel input, and feedwater flow. A turndown of 3:1 (30 percent of maximum lead) is possible with no subdivision of the bed. A 15:1 turndown is possible with intermittent operation. Load following of 15 percent/min can also be achieved. .Several existing boilers have been retrofitted into an AFBC boiler by using the multiple bed design.

Retrofits

AFBC retrofitting may be an attractive alternative for existing boilers. Boiler types that lend themselves to retrofitting include pulverized coal, cyclone, stoker, oil, and gas. However, not every boiler

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[3] J. Makasi and R. Schwieger.

is suitable for AFBC retrofitting. Much depends on the size and age of the boiler. Some important considerations are:

- Water/steam circulation design
- Furnace bottom to grade clearance
- Air heater type and arrangement
- Boiler support
- Type of particulate control device
- Fan capacity
- Space available.

The heat output available from a fluidized bed boiler depends on the bed area and the fluidizing velocity. Figure 4 presents the approximate bed area and heat release rate needed to provide the thermal output at a given fluidizing velocity. If the required bed area is similar to the existing boiler area, a retrofit may be possible. However, if the existing boiler area is smaller than required, the boiler area will have to be increased or stacked beds added.

A typical conversion involving extended furnace area in an oil/gas fired boiler is shown in Figure 5. Simple circulation systems, such as those found in low-pressure units are best suited for AFBC retrofits because rearranging the heating surfaces is not necessary.

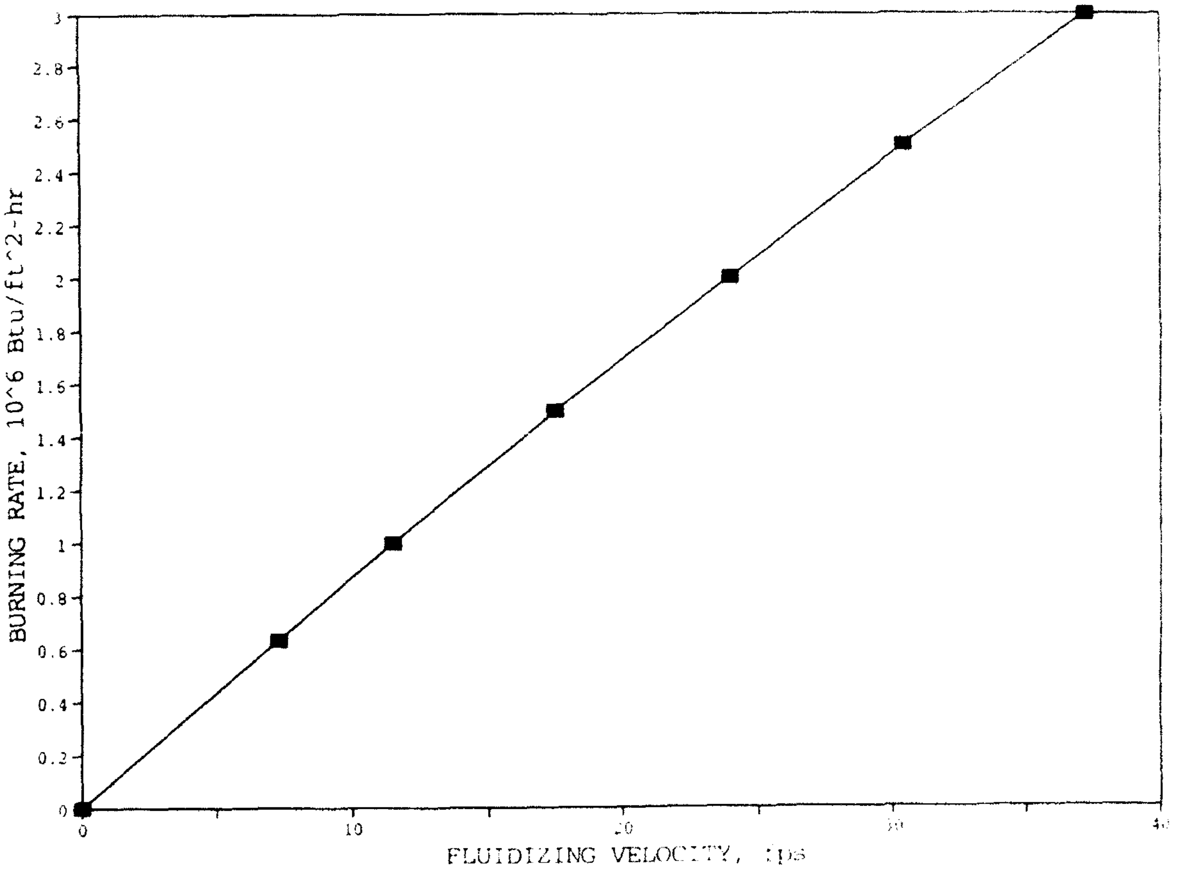

Figure 4. Bed sizing area.

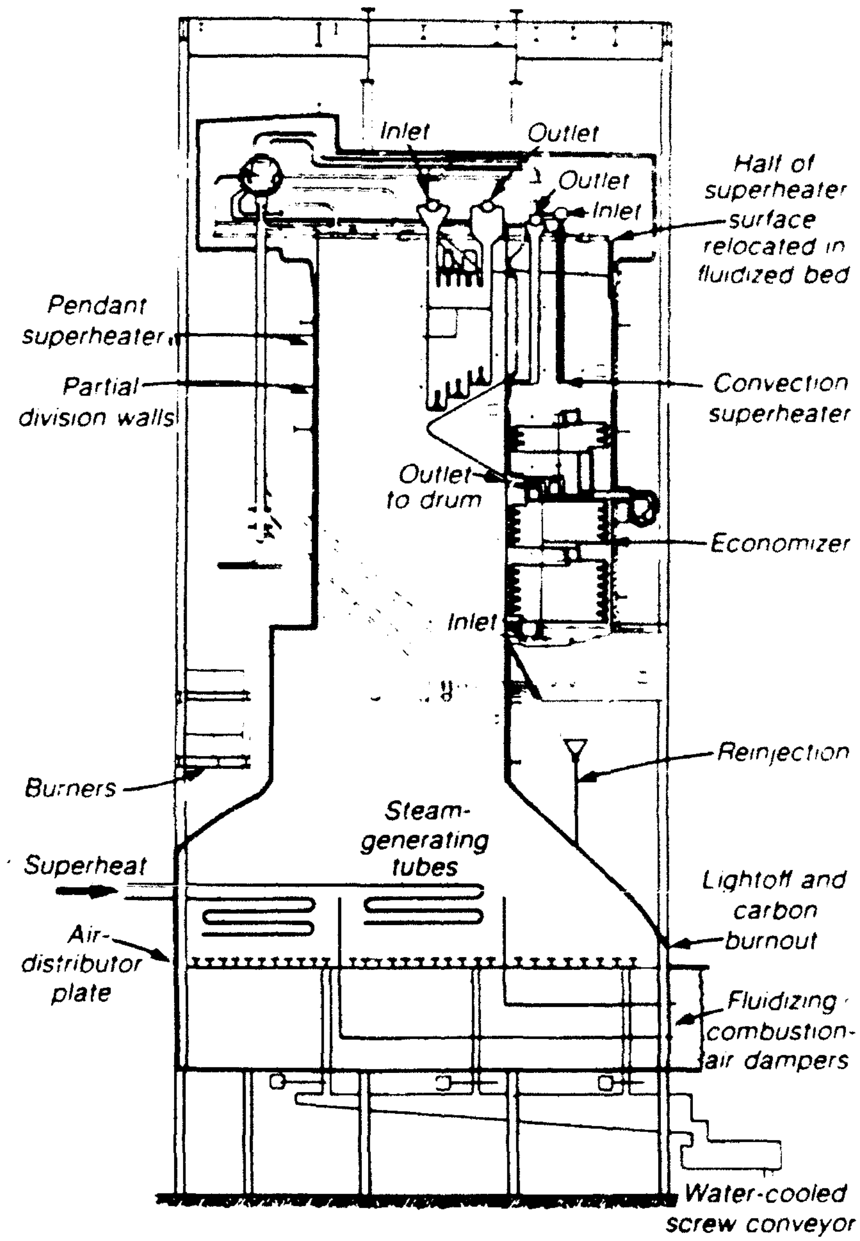

Figure 5. Retrofit involving extended furnace area in oil/gas boiler.

Air heaters on existing units are usually rotary regenerative units. Air leakage is possible, especially with the higher air pressure required for the fluidization air. Additionally, forced draft fan pressures as high as 40 to 60 in. water column may be required. This pressure is considerably higher than that in many existing boilers, except cyclone units. Two options are available for retrofits; either replace the fan or add booster fans. The induced draft (ID) fan is usually suitable, but the pressure drop caused by adding a fabric filter may require a larger fan. Particulate control in retrofits is accomplished by a baghouse.

An existing boiler may need additional support, either at the top or bottom, because of the AFBC bed weight. Available space around the existing boiler is an important consideration for the practicality of an AFBC retrofit. An AFBC needs space for the air plenum under the air distribution plate. On a coal fired boiler, this space is provided by removing the ash hopper. Oil/gas fired boilers may need some modifications (ductwork or piping). Additional space is also needed for the baghouse and the dry pneumatic bottom ash system. The existing fly ash system can be used, but may need modification. Storage space for sorbent and coal is also required.

Characterization of Conventional Coal Fired Boilers

Conventional coal fired steam generators include stoker fired systems and pulverized coal fired systems. Stoker fired systems are generally smaller and simpler, with steam production limited to 300,000 lb/h when coal of widely varying properties is burned. Pulverized coal fired systems are generally larger; steam production rates for these systems are generally greater than 200,000 lb/h.

Fixed Grate Combustors

Underfeed Stokers. The fixed grate, underfeed stoker is usually a horizontal-feed, single retort system. Coal is fed from a hopper by a reciprocating ram, or a screw, to a central trough called a retort. As the coal rises in the retort and is subjected to heat from the burning coal above, volatile gases are distilled off and mixed with air supplied through tuyeres (nozzles) above each side of the retort and through the side grates. The volatile mixture burns as it passes upward through the incandescent zone, sustaining ignition of the rising coal. Burning continues as the incoming coal forces the fuel bed to the sides. Combustion is completed by the time the bed reaches the side grates from which ash is discharged.

This stoker is commonly arranged to withdraw coal from a bunker and inject it into the fire bed by means of a single screw conveyor enclosed in a tube. Underfeed stokers can be built with various other coal handling arrangements, but direct feed from a bunker or bin is usual. The screw itself is the coal metering element. Ash is removed by raking the hearth area that surrounds the central coal retort and grate. Stokers with various mechanical means of ash removal have been built, but are uncommon. Ash removal by hand becomes a problem in the larger stokers.

Coal for the underfeed stoker must not contain lumps too large to pass through the screw. Figure 6 indicates the suitable coal sizes for all types of stoker boilers. Fine coal can be burned efficiently, provided that the stoker air supply has sufficient pressure to pass through a bed of fines. Coal preparation is normally not required other than to screen out oversized lumps. Any low-swelling or nonswelling coal, including lignites of up to 40 percent water content, can be burned successfully. High-swelling coal is unsuitable because it tends to build up a large pile of coke over the retort.

Underfeed stokers can be used with any heat removal device that has heat transfer surfaces above the furnace. When correctly operated with suitable coal at reasonable firing rates, underfeed stoker fired combustors emit little smoke, and only a low concentration of particulates entrained in the flue gas. Under these conditions pollution control equipment (other than an adequate stack) would not be required. Large installations burning high ash coals may require flue gas cleaning equipment. Cyclones or multicyclones are usually adequate.

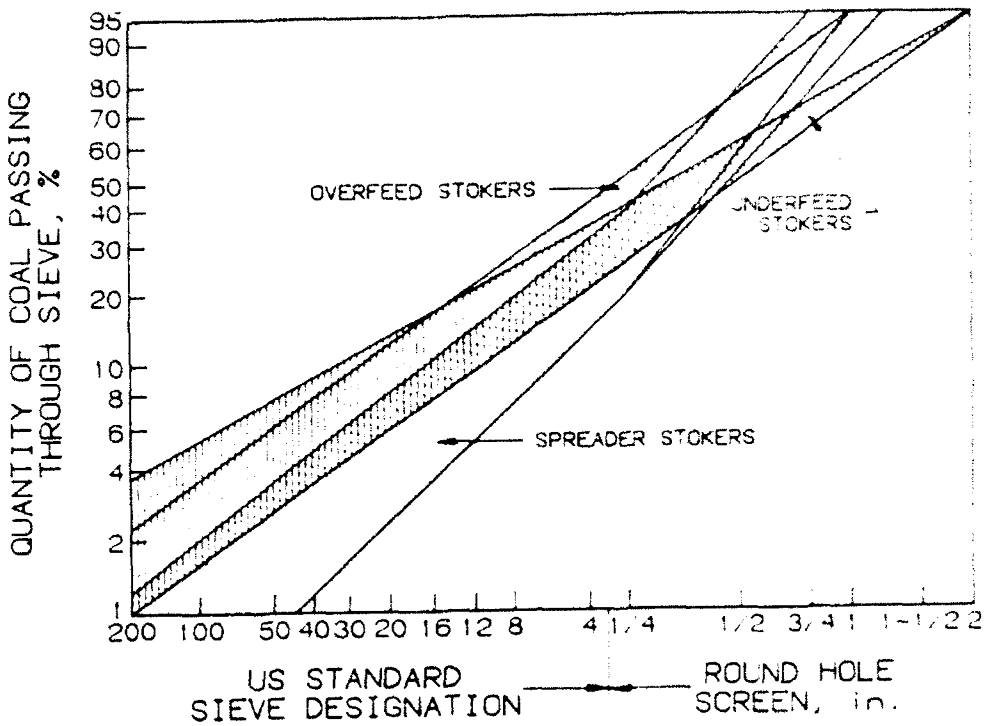

Figure 6. Recommended limits of coal sizing for conventional boilers. (R. Schwieger, "Industrial Boilers–What's Happening Today," *Power*, February 1977 and February 1978.)

The underfeed stoker is an efficient combustion device, and losses of unburned fuel in the ash should not exceed 20 percent of the true ash weight. The only auxiliary energy required is electric power to drive the feed screw and the forced draft fan. These will typically use power equivalent to 0.2 to 0.4 percent of the stoker thermal output.

The underfeed stoker has low capital, maintenance, and operating costs. Maintenance is required in periodic replacement of the cast iron sections, and clearing the conveying screw if it becomes jammed.

Spreader Stoker. The spreader stoker is a device designed to distribute coal into the furnace over the fire with a uniform, but variable spreading action. This method permits suspension burning of fine coal while the larger and heavier lumps fall onto the grate for combustion on a thin fast-burning bed. The actual spreading device can be a rotating mechanical thrower, an air-swept spout, or a distributing nozzle using a tangential or conical air stream to spread the coal on the grate.

Usually mechanical grates are used with a spreader stoker. Mechanical grates tip the ash into a hopper, where it is picked up by a mechanical, hydraulic, or pneumatic conveying system. These stokers are usually equipped with fully mechanized ash disposal systems.

The spreader stoker is particularly suitable for applications where rapid load changes can occur. The suspension burning of the fines results in almost immediate ignition and the thin fuel bed can be quickly burned down should the load be shed. Any kind or rank of coal can be burned, although anthracite may cause some difficulties because of its low volatile content. Because much of the coal burns in suspension, large changes in the particle size grading of the coal can upset the operation of a spreader stoker. Figure 6 shows the recommended limits of coal sizing for stokers. Waste fuels such as wood bark or hogged wood can also be burned.

Spreader stokers require a regulated and uniform supply of coal to the spreading device. Accordingly, a spreader stoker usually has a separate coal metering device that feeds the spreader. This may be a screw, a rotary feeder, or a belt feeder. Ash handling from a fixed grate fired by a spreader stoker entails raking the ash by hand over fairly long distances, which usually limits the size of the boiler.

The spreader stoker can handle almost any type of coal. Low-ash coals are preferred, to reduce the ash removal. Coal grading should be as uniform as possible to avoid large variations in the quantity of coal burned in suspension.

Because much fine coal is burned in suspension, spreader stokers may have a large carryover of solids in the flue gas. The particulates carried by the flue gas may include considerable amounts of unburned fuel, up to 70 percent in some cases, and typically 50 percent. For a coal of 7 percent ash, this means that about 2.6 percent of the coal fired is likely to escape with the ash. Cyclones and baghouses or ESPs are typically required for cleanup.

The spreader stoker has very low energy requirements. The grate drive, the spreader drive, and the combustion air fans are unlikely to total more than 0.5 percent of the thermal input of coal. If a baghouse is required, this figure could increase to 1.5 percent of thermal output. These power input figures do not include that proportion of fan power that is required to overcome gas flow resistance in the boiler.

Operating costs of spreader stokers are low. Routine maintenance is due to the spreader mechanism and grate sections. Spreader stokers are also low in capital costs, simple and easy to operate and maintain, highly efficient, easy to control under varying loads, and tolerant of different types and sizes of coal. Some detailed grate designs are discussed below.

Dump Grate. The dump grate consists of sections for each coal feeder with corresponding sectionalized under-grate air plenums. This allows the fuel and air supply to be interrupted while a section of the grate "dumps" ash without disturbing the other sections. Dumping grate stokers tip the ash into a pit or hopper, where it is picked up by a conveying system. Coal ash should not exceed 10 percent for dumping grates, unless the heat release rate per unit area of grate surface is reduced by 25 to 30 percent.

Traveling Grates. Mechanical traveling grates act as their own feeders, and hence are provided with a feed bin as an integral part of the stoker. Any kind of mechanical coal conveyor, either continuous or discontinuous action, can be used to load coal into the feed bin. Traveling grate stokers consist of an entire grate that moves like an endless belt. Coal on the grate is burned as it is conveyed to the rear of the furnace where the remaining ash is dumped. A drag chain conveyor working in water is commonly used to remove the hot ash. Traveling grates are capable of burning a wide range of coals, from high rank eastern bituminous to lignite or brown coal. Very high swelling bituminous coal may present difficulties, and is the least suitable fuel. The size of the coal has a direct bearing on the boiler efficiency and particulate emissions.

Traveling grates offer fast response to load swings. Turndowns of 5:1 or greater are possible, but optimum combustion conditions generally deteriorate at ratios above 3:1. Boilers ranging from about 75,000 to 400,000 lb/h have been the primary market of traveling grate stokers.

Generally, the particulate emissions are low and the solids are very small particle size. Usually a cyclone mechanical collector is used to clean the gas.

Oscillating Bar Grates. Oscillating bar grates have a horizontal grate formed from bars that propel the burning coal along the grate. Coal is fed into the fire bed from the end. This stoker was designed for moderately-swelling bituminous coals that form a coherent fuel bed.

Side or Bulk Feed Chain or Moving Grate. A chain grate is a type of traveling grate that can be fed by gravity from a hopper. An adjustable gate regulates the coal bed thickness. The upper surface of the coal is heated and ignited by radiation from a refractory arch over the fuel bed, and from the flame itself. The rate of burning is limited by the rate of ignition. Low rank coals with high water content give much lower apparent burning rates than higher rank, low moisture coals. The bed continues to burn, becoming progressively thinner as it moves through the furnace, and combustion continues. At the far end of the grate's travel, the ash falls from the chain into an ash pit. This differs from the chain grate used with the spreader stoker where the chain usually discharges the ash at the front of the boiler.

If parts of the grate surface form structural parts of the chain that moves, the stoker is called a "chain grate." If the grate is separate, carried by the chain and detachable therefrom, it is called a "moving grate" stoker. The characteristics of both types are similar. The moving grate is usually more costly to buy and install, but may have somewhat lower maintenance costs.

For chain and moving grate stokers, the coal enters at one end and burns down gradually as it traverses the furnace. Any type of coal can be burned on these grates, but different arrangements of ignition arches and overfire air may be required for fuels with either very high or very low volatiles content. The stoker responds very slowly to changes in demand. It emits much less solid matter to the flue gas than does any spreader stoker, but it requires a considerably larger grate area for a given output than does a moving grate spreader stoker.

Inclined Rotating Grate. This moving grate is similar to the oscillating bar grate, but is set on an angle of 10 to 15 degrees. Movement of the grate bars causes the fuel bed to roll over and over as it moves along the grate. This type of grate was used 40 to 50 years ago in large boilers to burn high moisture lignite. This grate system is much more expensive than either spreader or chain grates, and has no advantage with any normal coal; therefore it is rarely used.

Pulverized Coal Boilers

A pulverized coal (PC) firing system burns coal particles in a fine spray. A PC combustor can burn coal with an ash content up to 47 percent, provided that the coal is ground to a small enough particle size. Fuel required for a PC coal boiler is processed in mills that grind to 200 mesh or finer. This coal is entrained into the burners by preheated primary air. The secondary air is preheated, conveyed to the boiler, and distributed at points around and above the burners. Inside the boiler, the coal particles are subjected to heat and mixed with the preheated air. The fuel vaporizes almost instantly into combustion gases and particles or char. The particles of char contain the sulfur and are quickly oxidized into carbon dioxide (CO_2) and SO_2. Proper control of both SO_2 and NOx requires additional equipment. NOx formation can be reduced by using staged combustion, recirculation of flue gases, water injection, or some other means to reduce the combustion temperature. All of these control methods, except staged combustion, reduce the efficiency of the boiler. NOx can also be reduced chemically by injecting ammonia or urea. SOx can be removed in a wet scrubber by reaction with calcium carbonate. The quantity of limestone required by the scrubber varies with the sulfur content of the fuel, the temperature of the flue gases, and the natural pH of the wetted fly ash/flue gas mixture. An average ratio of 1.4:1 is typical for 90 percent removal.

A properly designed and operated PC boiler can hold carbon efficiency loss to less than 0.5 percent, but a traveling grate spreader stoker can do no better than about 4 percent with 50 percent ash reinjection. One penalty for the higher efficiency of the PC fired boiler is the power required to operate the pulverizers. Pollution control costs may also be higher with the PC fired boiler because all fuel is burned in suspension.

Advantages of AFBC Over Conventional Coal Fired Boilers

A summary of the major claimed advantages of AFBC boilers is presented below. These claims are described briefly here, but many are dealt with quantitatively and in greater detail in Chapters 3 and 4.

• By using the high heat transfer rates of in-bed boiler tubes, AFBCs have been claimed to require less overall heat transfer surface. This should result in smaller boilers than for stoker or pulverized coal units.

• Operating temperatures are below the formation point for thermally induced NOx. Staged combustion can also be applied to minimize oxidation of fuel-bound nitrogen.

• The lower combustion temperature avoids the appreciable slagging and fouling associated with PC fired and stoker fired units.

• AFBC boilers can burn various solid fuels and wastes. Usually these units can burn natural gas and fuel oil as backup fuels. This flexibility is attractive because it allows the use of alternative fuels.

• AFBC systems can burn higher sulfur coals without having expensive scrubber systems, and still meet air quality standards. This is achieved by the direct contact of combustion gases and sorbent during the combustion process in the fluidized bed. The dry solid stabilized waste product sulfate, rather than sulfite, is easily disposed of.

• The fluidizing mechanism, or added turbulence, offers several advantages: less volatilization of alkali components, reduced chance for hot spots on boiler and shell surfaces, less sensitivity to the quantity and nature of the ash in the fuel, and smaller furnace volume.

3 CAPABILITY OF AFBC TECHNOLOGIES

Combustion Efficiency/Boiler Efficiency

Combustion efficiencies (carbon utilization) for AFBC boilers range from 70 to 99.5 percent.[4] The loss in combustion efficiency arises from incomplete combustion of fixed carbon (char) and volatiles. Higher efficiencies are attained through modifications of the system. This increases both the complexity of the system and the cost. Table 1 summarizes the measured combustion efficiencies from commercial boilers and demonstration units.

Table 1

Combustion Efficiencies of AFBC Boilers*

FBC Boiler Design	Type of Fuel	Combustion Efficiency, %
BFBC with overbed feeding (no recycle)	bituminous - high fines	85-98
	bituminous - low fines	90-94
	bituminous - low fines, high volatiles	94-97
	lignite/subbituminous	97-98
	anthracite/bituminous wash tailings	70-85
BFBC with overbed feeding and ash recycle	bituminous - high fines	94-95
	bituminous - low fines	98-99
	bituminous - low fines, high volatiles	98-99.5
	lignite/subbituminous	98-99
	anthracite/bituminous wash tailings	80-93
BFBC with pneumatic underbed feeding and ash recycle	bituminous	96-98
	bituminous - high volatiles	98-99.5
	lignite/subbituminous	98-99.5
	anthracite/bituminous wash tailings	85-95
CFBC	bituminous	97-99.5
	lignite/subbituminous	>99
	anthracite/bituminous wash tailings	97-98
Multibed pneumatic underbed feed	coal, peat, wood chips	98

* Source: J.F. Thomas, R.W. Gregory, and M. Takadyasu.

The combustion efficiency depends on the fuel reactivity, volatile content, and particle size. Reactive coals such as lignite or subbituminous will burn relatively efficiently without using ash recycle

[4] J.F. Thomas, R.W. Gregory, and M. Takadyasu.

or underbed feeding. The reactivity of bituminous coals may be sensitive to fines content. Unreactive fuels such as anthracite may result in low efficiencies. These fuels may burn more efficiently in an underfeed bubbling boiler with ash recycle or in a CFBC system. Because many uses of AFBC boilers include burning of less efficient solid wastes, many researchers feel that AFBC boilers' efficiencies should not be compared with conventional boilers' efficiencies.

Since the AFBC technology is relatively new, calculating the boiler efficiency of fluidized bed boilers is not as well defined as it is for conventional boilers. In addition, the design conditions can vary from one supplier to another and each has its own method for determining performance. Table 2 summarizes the boiler efficiencies reported from commercial boilers and demonstration units. The high performance CFBC boiler's efficiency is comparable to the PC boiler's efficiency.

Fuel Flexibility

AFBC boiler systems as noted have a large degree of fuel flexibility. AFBC boilers can be designed to burn almost any fuel with reasonable efficiency. However, problems due to heat transfer restrictions can arise when switching fuels. The moisture, volatiles content, and reactivity of fuels play an important role in the heat release and temperature distribution within the boiler. When the fuel is switched, the heat release may no longer correspond to the designed heat transfer surfaces.

BFBCs using overbed feeding and no ash recycle are limited to firing various grades of coal, oil, gas, and coal mixed with moderate amounts of waste. Most experience is with coals that are stoker grades. Lower grade coals can be used if the size is controlled and the ash removal system has sufficient capacity. However, lower grade coals yield a lower combustion efficiency. Coals with high fines may be burned more efficiently with ash recycle and underbed feeding. It is possible to switch between fuels of various types if the fuels are similar (e.g., bituminous to subbituminous coal). In addition, some BFBCs fire coal mixed with moderate amounts of combustible waste, wood, peat, or other fuel. Designs that include controlled staged combustion and/or flue gas recycle in addition to ash recycle, have the greatest fuel flexibility.

CFBC systems are the most tolerant of different fuels. CFBC systems can fire a wide range of coals as well as oil, gas, waste mixed with coal, and peat. Staged combustion, flue gas recycle, and external heat exchanger systems enhance the fuel flexibility. The design known as the multisolids CFBC, which features large stones in the dense zone and an EHE, can handle a wide variety of fuels. A commercial unit has fired bituminous coal, 45 percent ash coal, anthracite duff, peat, and wood.

Table 2

Boiler Efficiencies for AFBC Boilers and Conventional Boilers*

AFBC Boiler Design	Boiler Efficiency, %
High efficiency CFBC	89.45
Low efficiency CFBC	85.66
Bubbling Bed	83.49
Stoker	87.14
Pulverized coal	89.19

* Source: G.L. Gould and M.W. McComas, "Know How Efficiencies Vary Among Fluidized-Bed Boilers," *Power* (January 1987).

The multiple bed combustion system has also had success burning different fuels. Successful tests have been completed using coal, peat, and wood chips.

Emission Characteristics

Sulfur Capture Capabilities

Table 3 presents the sulfur capture capabilities of AFBC systems. During combustion of solid fuels containing sulfur, the sulfur is oxidized to sulfur dioxide. AFBC boilers remove the sulfur dioxide by adding sorbent (limestone or dolomite) directly to the bed. The principle chemical reactions are discussed in the following paragraphs.

Calcination

If limestone ($CaCO_3$) is added to the combustion chamber, an endothermic calcination reaction to produce calcium oxide, or lime (CaO) takes place.

$$CaCO_3 \dashrightarrow CaO + CO_2 \qquad \text{[Eq 1]}$$

This reaction proceeds only if the partial pressure of carbon dioxide, determined by the excess air level, is less than the equilibrium carbon dioxide partial pressure, which is itself dependent on the bed temperature. The reaction takes place in the required excess air level at about 1500 to 1750 °F. The rate and extent of calcination is governed by the amount that the equilibrium temperature is exceeded.

If dolomite ($CaCO_3 \bullet MgCO_3$) is used, the reaction is more complex. The first step is thermal decomposition to form a mixture of calcium and magnesium carbonate, which occurs at bed temperatures

Table 3

Sulfur Capture Capabilities of AFBC Boilers*

AFBC Boiler Design	% SO_2 Capture	Calcium/Sulfur Ratio	Notes
BFBC with overbed feeding no ash recycle	60	3.0	
BFBC wth overbed feeding and ash recycle	70	1.7-2.5	low fines
	70	2.5-3.0	high fines
	90	2.8-5.0	
BFBC with pneumatic underbed feeding no ash recycle	70	1.8-2.5	
	90	3.0	
BFBC with pneumatic underbed feeding and ash recycle	70	1.5-1.8	
	90	2.0-3.0	
CFBC	90	1.5-2.0	
	95	3.0	

* Source: J.F. Thomas, R.W. Gregory, and M. Takadyasu.

above 1100 °F. Any magnesium carbonate produced is rapidly calcined, in all fluidized combustor conditions, to produce a half-calcined dolomite.

$$CaCO_3 + MgCO_3 \text{--->} CaCO_3 + MgO + O_2 \qquad [Eq\ 2]$$

For an atmospheric combustor, further calcination of the calcium carbonate component will take place according to the reaction in Equation 1.

Sulphation

The lime (CaO) generated by calcination of the sorbent reacts with the SO_2 in the presence of oxygen to form calcium sulphate.

$$CaO + SO_2 + 1/2\ O_2 \text{--->} CaSO_4 \qquad [Eq\ 3]$$

In the case of fully or half-calcined dolomite, the magnesia (MgO) produced is inert to SO_2. It is only the calcium component that reacts with SO_2. Therefore, the system needs more dolomite than limestone to capture a comparable amount of sulfur. Sulfur dioxide can also react directly with calcium carbonate ($CaCO_3$) present in uncalcined or partially calcined sorbents, according to:

$$CaCO_3 + SO_2 + 1/2\ O_2 \text{--->} CaSO_4 + CO_2 \qquad [Eq\ 4]$$

Sorbent must be added continuously; the spent sorbent must be removed continuously to prevent accumulation in the bed. The method of removal is either by direct elutriation (entrainment in the exhaust gas stream) from the bed if a small enough particle size is used (< 200 microns), or by means of overflow and recycling for larger particle sizes (< 500 microns).

Based on the stoichiometry of the sulphation reaction, the theoretical additive feed rate is one mole of calcium oxide to each mole of sulfur in the coal, or a calcium to sulfur (Ca/S) mole ratio of 1. This corresponds to 3.12 lb limestone or 5.75 lb dolomite per each pound of sulfur in the coal. It is impossible to achieve total desulfurization because the reaction product $CaSO_4$ blocks the sorbent's pores and reduces its reactivity. Figure 7 shows a typical plot of sulfur retention and the degree of sulphation as a function of Ca/S ratio. At the theoretical Ca/S ratio, about 30 percent reduction in SO_2 emission is achieved. For 75 to 90 percent sulfur retention, the typical requirement for emission standards, a Ca/S ratio between 3 and 5 must be used. For fuels with a high sulfur content, the sorbent will be a significant proportion of the feedstock.

Nitrous Oxide Control

Measured NOx emission levels of various AFBC designs are given in Table 4. In most cases, AFBC systems can burn typical coals and stay well below the NOx emission limits.

During combustion, NOx can originate from the oxidation of atmospheric nitrogen (thermal oxidation) or from the oxidation of the fuel nitrogen. Thermal NOx emissions increase with temperature. At the low operating temperatures of fluidized bed combustors, NOx formation is predominantly caused by oxidation of the fuel nitrogen with less than 5 percent of the NOx produced by thermal oxidation.

Turndown and Load Following

Turndown and load following capabilities are summarized in Table 5. The capabilities of CFBC boilers are generally better than BFBCs, but turndown and load following are dependent on the specific AFBC design.

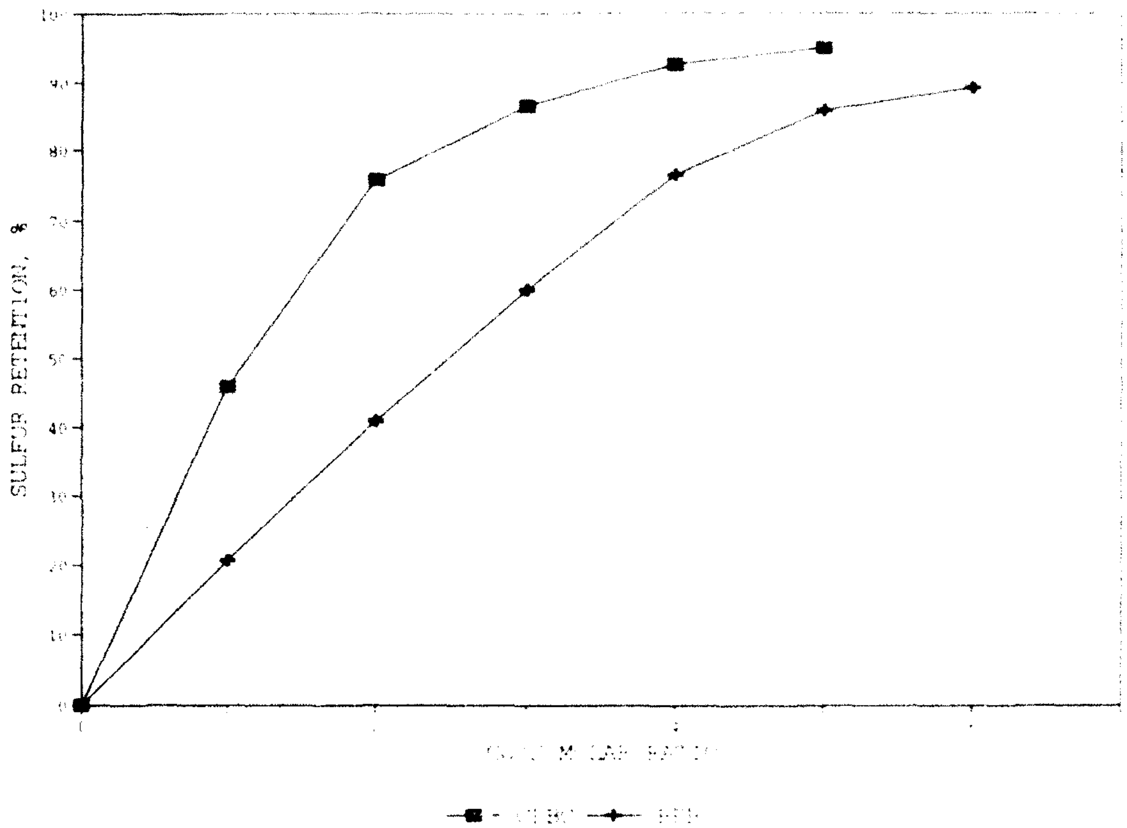

Figure 7. Projected performance of sorbent.

In a CFBC, as the firing rate decreases, the combustor temperature tends to decline. This tendency is corrected by the control system that decreases the flow of cooled solids from the recycle loop. Heat is absorbed in three sections of the boiler system: the upper section of the combustor in waterwall surfaces, the recycle heat exchanger, and the convective surface downstream of the combustor/recycle subsystem. Heat absorption in the combustor and in the gas backpass tend to decline in rough proportion to the firing rate. The heat absorption in the recycle heat exchanger decreases more rapidly than the firing rate. This rapid decrease occurs because the solids flow is reduced in response to the need to maintain a constant combustor temperature. Consequently, there is a shift of heat duty toward the combustor and bypass as the load is reduced.

Turndown in a BFBC typically requires a decline in bed temperature with load. The superheater is normally located in the bed along with a major portion of the evaporative surface. The bed provides a uniformly high heat transfer rate for efficient surface utilization. As the load is reduced, the bed temperature is allowed to decline to a minimum temperature of 1500 °F. Zoned bed operation permits a wide turndown range, such as 8 to 1. A turndown of 4 to 1 with a three-zoned bed is common. As the bed temperature reaches the lower limit, a portion of the bed is slumped by closing the fluidizing air damper. The fuel is restricted to the remainder of the active bed. Overall AFBC systems are noted to have slow load response, but some designs with higher response rates compare favorably with conventional boilers.[5]

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[5] J.R. Comparato, "The Thermodynamics and System Design of FBC Boilers," *Fluidized Bed Boilers: Design and Application* (Pergamon Press, 1984).

Table 4

Nitrogen Oxide Levels for AFBC Boilers*

AFBC System Design	NOx Emissions (lb/MBtu)
BFBC with ash recycle underbed feeding	0.13 - 0.40
BFBC with ash recycle overred feeding	0.28 - 0.60
BFBC with staged combustion and ash recycle overbed feeding	0.17 - 0.30
CFBC	0.24 - 0.42
CFBC with staged combustion	0.10 -0.30

* Bituminous coal feed with 1 to 2 percent fuel nitrogen. Source: J.F. Thomas, R.W. Gregory, and M. Takadyasu.

Table 5

Turndown and Load Following for AFBC Boilers*

Boiler Design	Turndown (%)	Load Following (%/min)
BFBC	65-40 velocity control >40 by bed slumping or on/off operation	3-7
CFBC without EFE	33-25	4-10
CFBC with EHE	25-13	5-20

* Source: J.F. Thomas, R.W. Gregory, and M. Takadyasu.

4 DRAWBACKS OF AFBC TECHNOLOGIES

Combustion Limitations

One shortcoming of the AFBC systems is the poor combustion efficiency compared to that of the conventional coal fired boilers. AFBC boilers have a low combustion temperature and short freeboard residence time compared to stoker and pulverized boilers. The flue gas from a fluidized bed contains a high concentration of coal fines and combustibles. If the heating value of the coal fines is lost, the boiler will have a poor combustion efficiency. This is especially true for small boilers. Possible solutions to this problem must either improve the combustion rate of these particles or increase the residence time in the combustion zone. The following paragraphs will highlight some options to improve the combustion efficiency.

A carbon burnup cell (CBC) uses a separate fluidized bed operated at a much lower fluidization velocity and higher temperature to burn the fly ash collected from the main fluidized bed. A delicate balance is required for both the main bed and CBC to be operated in sequence. If the main bed is operated as an efficient combustor, the CBC will not have enough fuel. Due to the high combustion temperature in the CBC, the calcium sulfate concentrated in the sulfated sorbent fines can decompose to sulfur dioxide. The high temperature in the CBC may also convert more fuel nitrogen into nitrogen oxides.

Fly ash collected in the primary dust collection system can be reintroduced into the boiler to improve combustion efficiency, for either overbed or underbed feeding. The efficiency for overbed feeding is less than that for underbed feeding over the recycle ratios tested. Recycle may not be advantageous when using reactive coals, but it can greatly improve combustion efficiency of less reactive fuels.

The success of ash recycle requires sufficient temperature, adequate residence time, and good mixing. In some of the conventional fluidized bed boilers, the freeboard is designed for heat extraction. The reinjected fly ash is barely heated by the fluidized bed before being elutriated into the freeboard. Shortly after, it is collected by the dust collection system. This can form a closed loop of fly ash circulating through the fluidized bed, freeboard, and dust collection and reinjection systems. In addition to causing a high dust loading, distorted in-bed fluidization, erosion of boiler components, and blinding of the bag filter, fly ash reinjection is not beneficial unless the freeboard temperature is high enough to maintain some degree of fly ash combustion. Fly ash reinjection has two desirable effects: the renewal of fresh sorbent surface for additional sulfur retention, and the promotion of nitrogen oxide reduction by the carbon-rich fly ash particles.[6]

Effort has focused on feed methods to increase the length of time particles stay in the combustion zone. An overbed feed system can feed solid fuels over an area of about 100 sq ft from a single feed point. The overbed spreader is intended to distribute coal to the top of the bubbling bed such that the natural mixing of the bed will result in even combustion. Some particles are carried upward by the fluidization gases. Highly reactive particles may burn up in the freeboard zone, but for less reactive coals, this feed system often requires double screened coal to remove the finer particles that would be carried out of the combustor and cause low combustion efficiencies. Pneumatic underbed feeding can result in more uniform fuel distribution and higher combustion efficiency. This system requires only single screening to control the maximum size. Because fuel is introduced at the bottom of the combustor, fine particles have more time to burn before being carried off. This system is more complicated and more expensive than the overbed feeding method. In-bed feeding is a compromise between overbed and

[6] J-Y Shang, "An Overview of Fluidized-Bed Combustion Boilers," *Fluidized Bed Boiler: Design and Application* (Pergamon Press, 1984).

underbed feeding and introduces fuels into the bed zone through one or more feeders in the sidewalls. This method might not be suitable in large BFBCs because the fuel cannot be distributed evenly enough by the natural mixing of the bed, and clinkering may occur. For smaller beds, in-bed feeding avoids the complexities of underbed feeding while still giving the fine particles time to burn before leaving the combustion zone.

Underbed pneumatic feeding improves combustion efficiency from about 87 or 88 percent to 92 percent for a bituminous coal when ash recycle is not used and when the coal consists of about 20 percent fines. Tests done with 7 percent fines show no substantial improvement by using underbed feeding. Also little advantage is gained by using underbed feeding for very reactive feeds because the fuel reacts well using overbed feeding.[7]

The efficiency of fluidized bed boilers is generally lower than for conventional boilers, except for the highest efficiency CFBC boilers. Some losses and gains associated with the fluidized bed boiler are discussed below.

Heat is absorbed when the moisture in the sorbent is converted to vapor. The actual loss depends on the amount of sorbent used to meet the necessary sulfur removal level. For a Ca/S molar ratio of 1.5, the loss is 0.06 percent, but the loss increases to 0.10 percent if the molar ratio is raised to 2.5.

Energy is also required to convert the calcium carbonate and magnesium carbonate in the sorbent to calcium oxide and magnesium oxide. The heat of reaction for the calcination of calcium carbonate is frequently listed as 787 Btu/lb of material. For magnesium carbonate, 509 Btu/lb is frequently listed. By using consistent heats of reaction, the calcination losses will be directly dependent on the Ca/S ratio. A ratio of 1.5 gives a calcination loss of about 1 percent while a ratio of 2.5 increases the loss to 1.7 percent.

Heat is produced in the reaction of SO_2 and calcium oxide to produce calcium sulfate. The heat of reaction is about 6511 Btu/lb of sulfur. Sulphation gain is directly proportional to the amount of SO_2 removed.

Heat is lost due to heating of the excess air. This loss depends on the quality of the fuel and the exit gas temperature. The loss is slightly higher for the CFBC boiler since additional air is required for the calcination reactions and carbon dioxide is liberated during this reaction. Sensible heat is lost with the boiler ash (bottom ash and flyash). Losses can be reduced if heat in the bed ash is recovered.

Radiation and convection losses show wide variations. Actual loss for a unit depends on the amount of refractory or insulation and the method of cooling.[8]

Fuel Limitations

An AFBC boiler can be designed to burn almost any fuel; however, once the design is fixed, only a limited range of fuels can be burned without adversely affecting boiler performance.

A BFBC usually is built with a fixed in-bed surface area; however, this can be varied somewhat by dropping the bed height. Because of the different characteristics of fuels, the fixed arrangement of heating surfaces does not always efficiently remove the heat. For example, fuels with high volatiles and moisture content require no in-bed cooling, but hard coal requires much more in-bed cooling surface to prevent hot spots.

[7] J.F. Thomas, R.W. Gregory, and M. Takadyasu.
[8] G.L. Gould and M.W. McComas.

CFCBs have large and well mixed combustion zones with ash recycles of 20:1 or more. Because of the design of the combustion zone in a CFBC, it is better able than a BFBC to burn varying fuels.

Ash recycle helps to improve the combustion efficiency for less reactive fuels in BFBCs. CFBC systems can use an external heat exchanger that controls cooling of the recycle ash. This helps broaden the fuel choice because by controlling the temperature of part or all of the solids that are recirculated, the combustor temperature can also be controlled. Staged combustion and flue gas recycle can also help control combustion, which can also broaden the fuel choice.

Often, it is not the boiler itself but the handling system that limits the multifuel capacity. The fuel handling system must be designed for the fuels that will be used. If the properties of the fuels vary, the fuel handling systems must be able to handle the variations. This may require multiple feeding systems. Also, if oil or gas capability is required, special burners or nozzle designs are required.

Emission Problems

AFBC boilers capture SO_2 by using sorbent as a bed material. Presently, AFBC systems can meet very stringent SO_2 emission standards. Most of the concern with SO_2 removal is the large amount of sorbent consumed.

The Ca/S ratio in a BFBC is usually 2.5:5 and the Ca/S ratio for CFBC is 1.5:2.5. Typically, the Ca/S ratio used in AFBC boilers is 2:1 Reducing the sorbent requirements is important because the cost of buying and disposing of sorbent may be a significant portion of the overall operating costs.

Low sorbent/calcium use may be due to inadequate contact time for the solid-gas mixture in the fluidized bed, and the formation of a diffusion-resisting calcium sulfate crust that deters the diffusion of sulfur dioxide into the interior of the calcined sorbent. The solution to these problems is to increase the contact time between the sorbent and sulfur dioxide and to enhance the sorbent's sulfur retention properties.

Pretreating limestone-based sulfur sorbents to open the pores for sulfur dioxide diffusion can be done by precalcination. Treating the sorbents with carbon dioxide can also control the pore size.[9]

To increase the residence time of the solids, underbed and in-bed feed methods combined with ash recycle have been used. The improvement in sulfur capture due to underbed feeding depends on the presence of sufficient feedpoints to achieve good distribution. CFBC systems inherently have a high degree of ash recycling and solids-gas contact throughout the combustion zone and therefore have better sorbent utilization than BFBC systems.

The bed temperature is an important parameter in controlling the sulfur retention. The optimal temperature is about 1400 to 1500 °F. This temperature restriction can affect turndown, load following, and combustion efficiency. Other parameters that influence sulfur capture include bed depth, fluidization velocity, freeboard conditions, sorbent type, and particle size distribution.

Disposing of spent sorbent from AFBCs can pose problems. Under the Resource Conservation and Recovery Act (RCRA), solid wastes from AFBCs can be classified hazardous and may require registration and special disposal. These requirements can affect AFBC costs, and various options for disposal should be considered. Presently, the wastes are disposed of in sanitary landfills. Potential environmental

[9] J-Y. Shang.

concerns are the pH and the high concentration of calcium, sulfate, and total dissolved solids in the leachates, which are above drinking water standards in some cases.[10]

AFBCs generally achieve NOx emission levels lower than conventional combustion technologies, and more stringent NOx regulations may require careful design of future boilers. AFBC boilers usually operate with combustion temperatures below 1650 °F and little NOx is formed from nitrogen in the combustion air. Poorly distributed coal fines or reactive fuel may cause hot spots in the bed. Therefore, a design that promotes adequate mixing and even distribution of the feed is necessary. CFBCs have large, well mixed combustion zones with high ash recycle rates; therefore hot spots are not a problem.

Staged combustion has been used to minimize NOx formation by introducing secondary air above the bed. The reactions that occur because of the staged combustion scheme are:

$$NOx + C \dashrightarrow N_2 + CO \qquad [Eq\ 5]$$

$$NOx + CO \dashrightarrow Nx + CO_2 \qquad [Eq\ 6]$$

Carbon monoxide (CO) emission limits may be very strict in some regions. To keep the NOx emissions low, the oxygen is kept low; and as the oxygen supply is limited, more CO is formed. CO emissions are met under the current regulations, but may pose problems in the future.

Operating Problems

Solids Handling

The major mechanical problems of AFBCs generally are due to the fuel and sorbent feed systems. A reliable feed system capable of distributing the material equally across the bed is vital to the further development of large scale AFBC systems.

Although underbed feed systems provide a longer residence time for the solid particles than overbed feeding, and therefore better carbon and sorbent utilization, a major limitation to underbed systems is the required number of feed points (one feed point for every 9 sq ft). Pneumatic underbed systems have special feeders that transfer the coal and/or sorbent from storage hoppers into pneumatic feed lines. At some point, the transported material is split into smaller streams before injection into the BFBC.

Erosion and plugging are the main problems of feed systems. Erosion is especially prominent in the tube bends, elbows, junctions, and flow splitters and any other points where flow disturbances cause the particles to impinge on a surface. Plugging usually occurs where there is a restriction or substantial change in the flow path.

Erosion can be reduced by limiting flow disturbances in straight tube runs and by using hard materials such as ceramics to protect elbows, bends, and splitters. Designs that allow the feed material to form a layer on the erosion-prone surfaces have shown promise.

Plugging problems can be lessened by controlling the combination of fines and moisture and by eliminating oversized feed particles. Coal moisture should be limited to less than 5 percent. Oversized particles will not move through the system easily and will lodge or collect at certain points. Nonuniform flow of particles in the lines may also cause a blockage to form. The physical properties of the fuel and

[10] R.P. Krishman and K.O. Johnsson, *International Energy Technology Assessment—Atmospheric Fluidized Bed Combustion*, ORNL/TM-8033 (Oak Ridge National Laboratories, April 1982).

sorbent (moisture content, fines fraction, erosiveness, tendency to bridge or form blockages) must be known to ensure proper design of the feeding system.

The major concern in overbed feeding is the excessive carryover of unburned coal. Fines can escape and burn in the freeboard above the fluidized bed, allowing most of the resulting SO_2 to escape. Coal fines must be reduced to ensure proper combustion.

Load Following and Control

Conventional solid fuel boilers have inherently better turndown and load following characteristics than AFBC systems. When a load reduction is required in a PC boiler, the fuel feed rate and air rate are reduced to the demand level. In an AFBC boiler, this reduction in load must be achieved at a nearly constant temperature to maintain high combustion efficiency and SO_2 removal. Maintaining the temperature is difficult because of the heat transfer characteristics of the fluidized bed and the tube matrix in the bed.

Turndown in a BFBC can be achieved by partial bed slumping, in which segments of the fluid bed can be defluidized to reduce the load at constant temperature. This almost completely stops heat transfer to the tube bank in this bed section. There may be a substantial delay when increasing load and temperature as a section is put back into operation.

Turndown can also be achieved by reducing the fluidizing gas velocity so that the in-bed heat transfer area is decreased. The bed zone shrinks and uncovers the uppermost bed tubes as the velocity is lowered. Bed material discharge may also be used to reduce bed height, leaving the upper in-bed tubes exposed to the freeboard. These techniques have been used to turn down to about 40 percent load.

The rate of turndown is generally slower for BFBCs than for conventional solid fuel boilers. Turndown rates as high as 7 percent/min are possible when bed slumping is not used and rates of 3 percent/min are possible when slumping is used. CFBC systems with external heat exchangers may achieve a 15 to 20 percent/min turndown while those without may only achieve a 4 percent/min turndown.[11] Most CFBC boilers can accept turndown to 33 to 25 percent of full load, although values down to 12 percent have been reported.

Air Fluidization

In most cases, poor bed fluidization is due to the presence of oversize inert particles or because of an air distribution problem. Oversize particles can be introduced as feed or can be generated by ash agglomeration. Improper air distribution is usually caused by poor design of the distributor system or by a material failure or blockage.

Some faulty air distributors were built in the past. Some of the problems included overheating, poor air nozzle design, and insufficient pressure drop across the distributor assembly, which caused unstable air flow or channeling of air through a small portion of the distributor. Due to previous experience, current designs usually feature well protected (usually water cooled) distributor plates that cause little difficulty. Figure 8 shows various types of air nozzles.

Oversized particles may be reduced by screening the fuel. Particle agglomeration is usually caused by hot zones in the bed and can be avoided by proper AFBC design and careful operating procedures.

[11] J.F. Thomas, R.W. Gregory, and M. Takadyasu.

Startup Time

The startup times of AFBC boilers may be longer than for conventional systems. BFBCs require 3 to 8 hours and CFBCs require over 8 hours.[12] The startup time depends on the amount of bed material and refractory to heat up without causing thermal shock.

Erosion/Corrosion

Erosion and corrosion of construction materials have caused serious problems with AFBC boiler systems, primarily due to the presence of solids moving at relatively high velocities, the high temperatures, and corrosive combustor environments.

Oxidation and sulfidation corrosion occur when metal sulfides in or on the surface of an alloy accelerate the oxidation of the component. In extreme cases, the corrosion attack can produce holes through the tube and significantly degrade tube life. The effects of oxidation and sulfidation are often not readily apparent. Oxidation and sulfidation attack is enhanced by a low concentration of oxygen in the bed (i.e., partial pressure of about 10 to 12 atmospheres) and may occur on the coal feed points, in-bed heat exchanger, water wall and freeboard heat exchanger, in-bed support structure, uncooled tube supports, and thermocouple assemblies.

Erosion of in-bed components is caused by solid particles moving in the bed. Properties of the impacting particles, the bed material, and the flow characteristics have a pronounced effect on erosion. Much of the erosion is also believed to be the result of excessively large bubbles caused by poor air distribution.

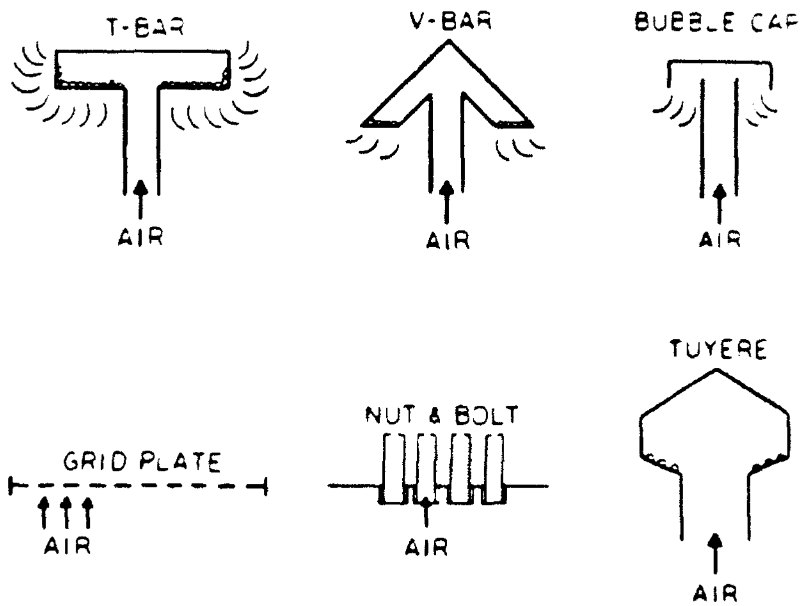

Figure 8. Air nozzles.

[12] J.F. Thomas, R.W. Gregory, and M. Takadyasu.

The erosion problems outside the combustor are mainly due to the solids handling equipment. Both the feed lines and valves are subject to erosive wear. When erosion problems are found, the air flow can be redirected by inserting a fin or wing. Also, the affected sections can be covered with refractory. The in-bed tubes can be replaced with thicker walled tubes, fined or studded tubes, or a tube made of different metal. Metal sprays may also be used to protect the sections.

To avoid corrosion and erosion, the design of AFBC should minimize the impingement of particulate material on component surfaces and permit easy replacement of problem parts. Also, the use of hard metals, coatings, and ceramics should be investigated to reduce material loss. Iron-based ferritic alloys with high chromium content, austenitic stainless steels, nickel based alloys, and cobalt based alloys have been used for in-bed tubes. The recommended material for the water cooled membrane walls is 50 percent chromium and 50 percent molybdenum steel. This alloy is capable of withstanding the corrosive environment of the bed and the thermal stresses associated with startup and shutdown over a 20-year design life. Support structures, tube hangers, and other uncooled components of the combustor will experience temperatures almost as high as the fuel temperature. High-chromium alloys are recommended for this application. Hard-faced coatings on carbon or alloy steels can be used to reduce wear in solids feed lines.

Fluidized bed industrial boilers that use water tubes and low temperature (about 600 °F) do not present serious material problems. These units are usually small and do not have elaborate support structures. The uncooled structures in these units are designed to withstand the bed temperatures.

Cogeneration AFBC systems may have serious materials problems. In these systems, steam is heated in a closed cycle to about 1500 °F and is then expanded through a gas turbine for electric generation. About 25 percent of the energy is converted to electricity, while .0 percent of the remaining energy is used as process heat. Tube metal temperatures can exceed 1200 °F and the performance of presently recommended alloys is questionable.[13]

[13] R.P. Krishman and K.O. Johnsson.

5 AFBC MANUFACTURERS

Vendor List

This section discusses the manufacturers of AFBC boilers in the United States. Table 6 lists the names and addresses of AFBC manufacturers. The discussion below highlights the main design features of each of the AFBC boiler manufacturers' products and indicates the extent to which the company has been and is involved in AFBC technology.

Description of Vendor Packages

Babcock & Wilcox (B&W)

To date B&W has installed four BFBC boilers. They have also installed or plan to install nine CFBCs. B&W recently entered the CFBC market after purchasing the technical knowledge from Studsvik Energiteknik, Sweden. Their CFBC boiler does not have an EHE but does have a U-beam separator. The separator returns the solids through individual stand pipes to the bottom of the combustor. The largest fraction, from the primary separator, is recycled to the bed at a rate controlled by an L-valve. Figure 9 shows the principle of the L-valve operation. A small amount of air injected slightly upstream of the elbow partially fluidizes or "aerates" a local zone within it, thus permitting flow of the recycled solids at a rate proportional to the degree of aeration, or modulation of the flow.

Combustion Engineering (CE) Power Systems

CE's main effort in AFBC technology is in developing the CFBC (Figure 10). The solids are separated from the flue gas by one or more cyclones and continuously returned to the combustor by a nonmechanical valve. Optionally, a controlled amount of solids from the cyclone(s) can be passed through an EHE and then to the combustor. CE's boilers are based on Lurgi technology and have been improved by their own boiler expertise.

Combustion Power Company (CPC)

CPC describes their AFBC boiler as a "fines" circulating fluidized bed boiler (Figure 11). It is a hybrid design in which the lower bubbling bed section is coupled with an upper zone that has high material circulation rates. This combination allows good mixing and residence times and high sorbent utilization rates afforded by the circulation features.

Dedert Corporation (DED), Thermal Processes Division

Dedert has mainly been involved with small BFBC boilers (20,000 lb/h steam max). Presently, with the lower cost of fuel and the influx of more companies in the fluidized bed boiler market, Dedert is not actively pursuing the AFBC technology.

Energy Products of Idaho (EPI)

Most of the systems built by EPI have been in the range of 10,000 to 40,000 lb/h steam, but they offer a BFBC as large as 300,000 lb/h. They are working on a retrofit for Northern States Power Company at the French Island Power Plant in LaCrosse, Wisconsin. The project entails the design, manufacture, installation, and startup of the retrofit of an existing 150,000 lb/h boiler. The boiler will produce steam at 450 psi and 750 °F to drive a 15 megawatts electrical (MWe) turbine generator. The conversion includes the replacement of the boiler grate with a BFBC unit complete with in-bed surfaces. A new economizer and air heater will be added.

Table 6

List of AFBC Boiler Manufacturers

Babcock & Wilcox Co.
20 S. Van Buren Ave.
Barberton, OH 44203
Robert J. Johns
(216) 860-2310

Combustion Power Co., Inc.
1020 Marsh, Suite 100
Menlo Park, CA 94025
Michael O'Hagan
(415) 324-4744

Energy Products of Idaho
4006 Industrial Ave.
Coeur d'Alene, ID 83814
Brian Meckel
(208) 765-1611

Fluidyne Engineering Corp.
3900 Olson Memorial Hwy.
Minneapolis, MN 55422
M. Carroll
(612) 544-2721

Keeler/Dorr-Oliver
238 West St.
Williamsport, PA 17701
Chris Lombardi
(717) 326-3361

Pyropower Corp.
P.O. Box 85480
San Diego, CA 92138
Jayne A. Gudmundsson
(619) 458-3081

Stone Johnston Corp.
300 Pine St.
Ferrysburg, M: 4909
Bob Shedd
(616) 842-5050

Wormser Engineering, Inc.
67 S. Bedford St.
West Lobby, 4th Floor
Burlington, MA 01803.5129
Richard Sadowski
(617) 273-44001

CE Power Systems
1000 Prospect Hill Rd.
Windsor, CT 06095
Jeff A. Quintno
(203) 324-4744

Dedert Corp.
Thermal Processes Division
2000 Governors Dr.
Olympia Fields,IL 60461
J.L. Burghard
(312) 747-7000

Energy Resources Co., Inc.
One Alewife Place
Cambridge, MA 02140
(617) 661-3111

Foster Wheeler Energy Corp.
110 S. Orange Ave.
Livingston, NJ 07039
Robert L. Gamble
(201) 533-3210

Power Recovery Systems Inc.
181 Ringe Ave. Extension
Cambridge, MA 02140
Peter Vanderschans
(617) 576-1900

Riley Stoker Corp.
9 Neponset St.
Worcester, MA 01606
Bob Lisauskas
(617) 792-4800

Sulzer Bros., Inc.
200 Park Avenue
New York, NY 10166
Walter Gadient
(212) 949-0999

York-Shipley Inc.
P.O. Box 349
York, PA 17403
Martin Gilligan
(717) 755-1081

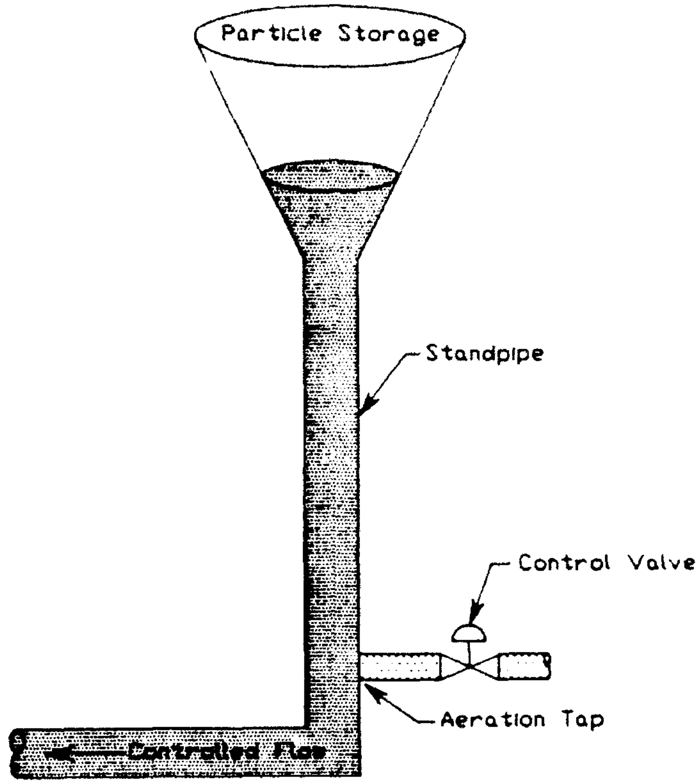

Figure 9. Babcock & Wilcox "L" valve operation.

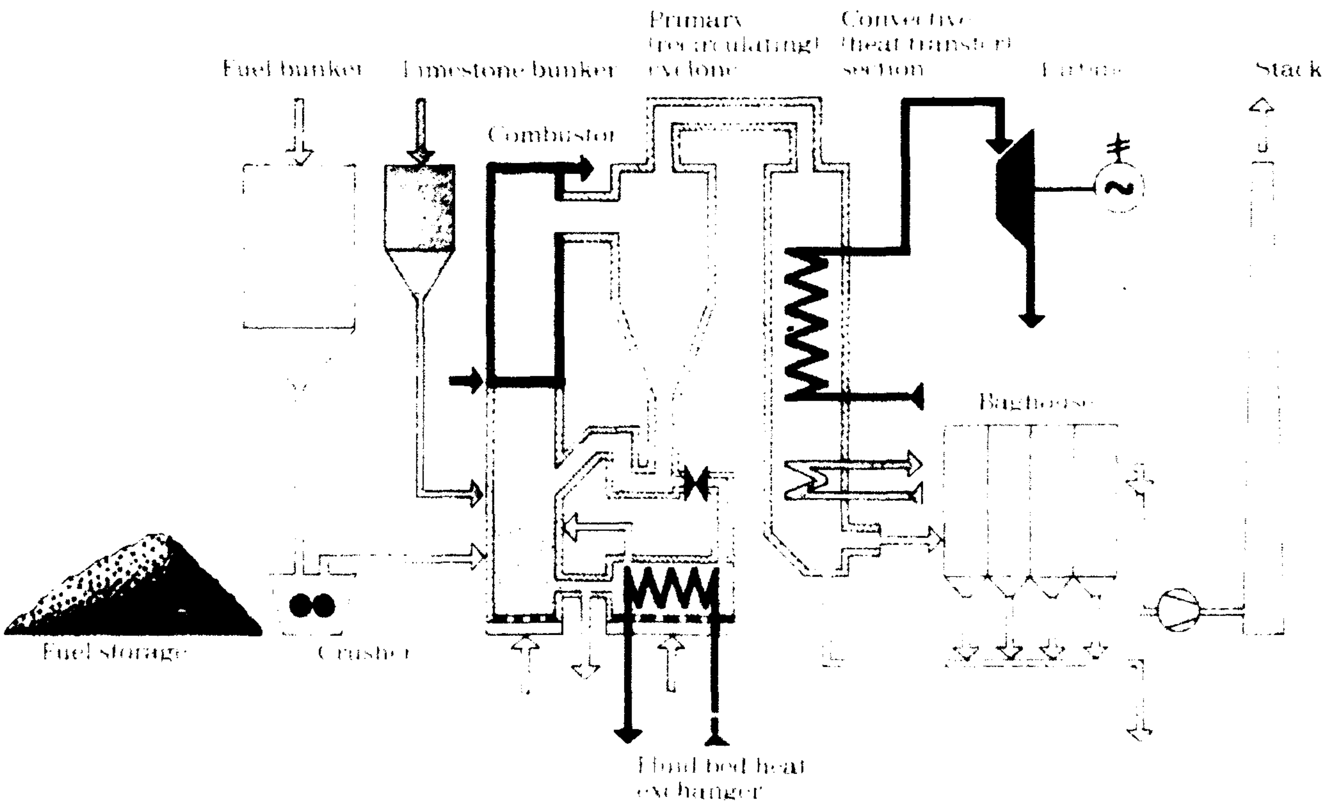

Figure 10. Combustion Engineering's CFBC system. (Courtesy of CE Power Systems)

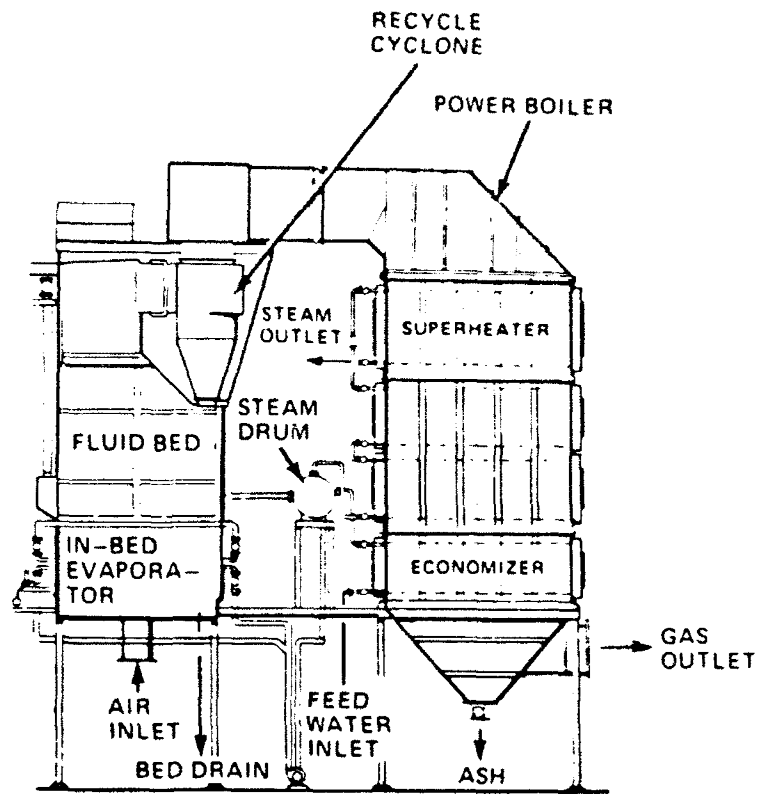

Figure 11. Combustion Power Company fines circulating fluid bed boiler.
(Courtesy of CPC)

Fluidyne Engineering Corp. (FEC)

Fluidyne is primarily seeking the BFBC market. They have built two BFBC boilers that are operating satisfactorily.

Foster Wheeler Energy Corporation (FWC)

Foster Wheeler has had six bubbling fluidized bed projects in the United States. They use a conventional box type unit with water-cooled walls. They also use a solids separation cyclone enclosed in furnace waterwalls to minimize refractory needs and to provide for quicker startups from cold condition. Coarse coal is used and no external solids cooling is employed (Figures 12 and 13).

Keeler/Dorr-Oliver (KDO)

Keeler/Dorr-Oliver started their first BFBC in 1981. They have recently started up their first CFBC boilers at the Archer Daniels Midland Company (see **CFBC Boiler** in Chapter 6). The Keeler/Dorr-Oliver CFBC is fairly simple if the optional EHE is omitted. With its "FluoSeal" recycle seal pot, the

Keeler/Dorr-Oliver boiler is nearly identical to Pyropower's. If the optional EHE is retained, the boiler becomes nearly equivalent to the Lurgi/ Combustion Engineering boiler. Because of the current interest in CFBC boilers, Keeler/Dorr-Oliver has recently devoted much effort to developing the CFBC technology, although their BFBC boilers are still available.

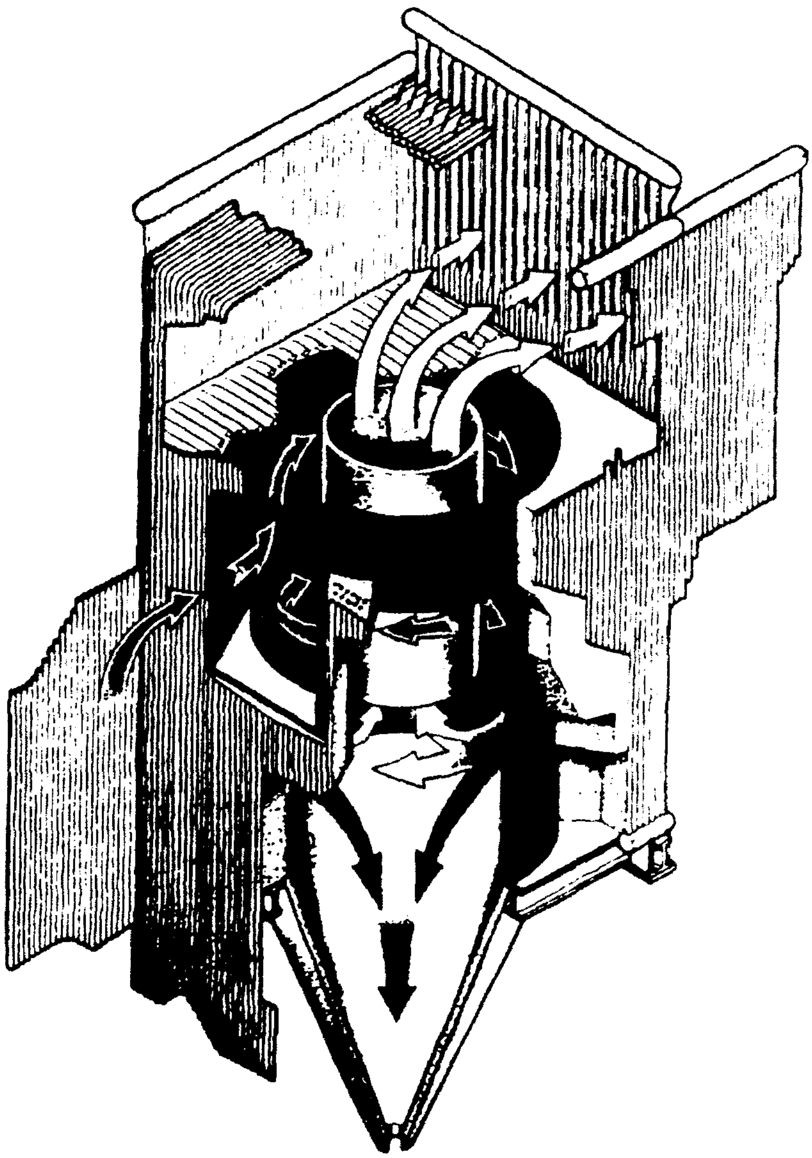

Figure 12. Foster Wheeler Cyclone design. (Courtesy of FW)

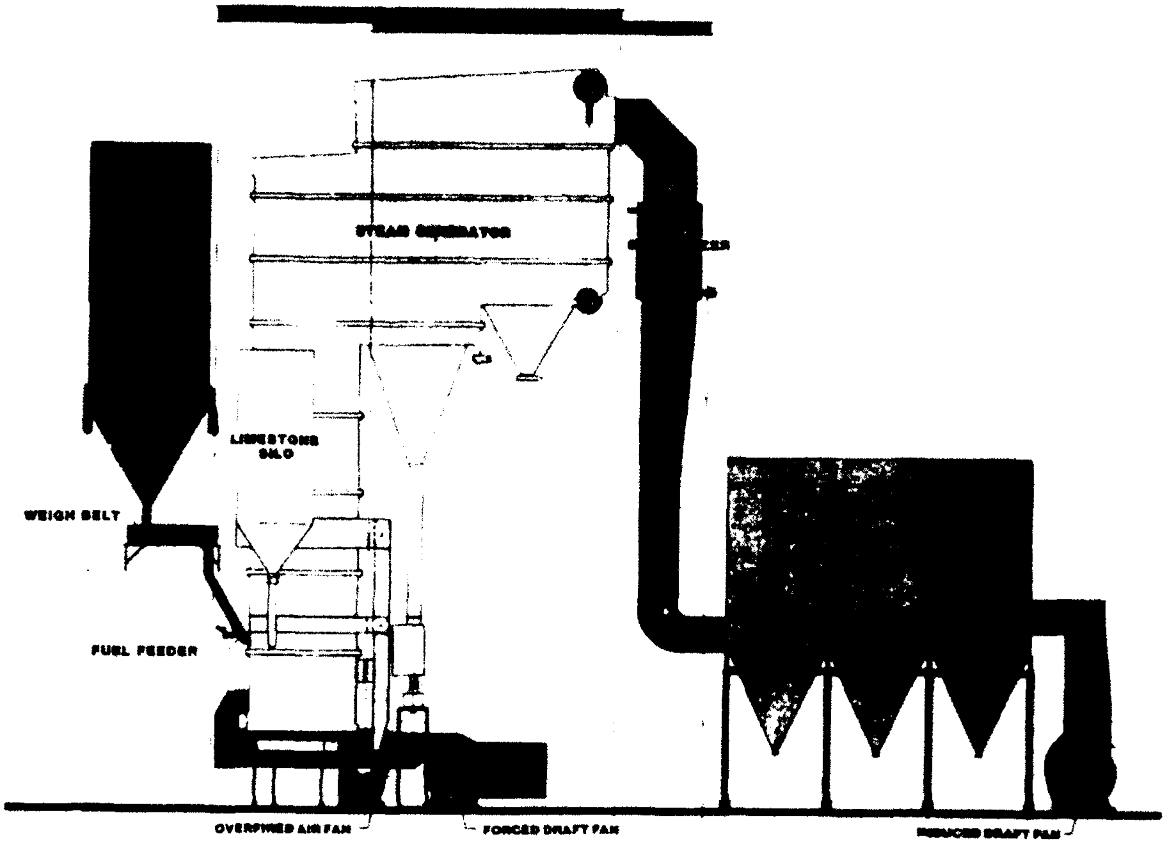

Figure 13. Foster Wheeler boiler layout. (Courtesy of FW)

Power Recovery Systems (PRS)

Power Recovery Systems is primarily involved with gasification processes but is interested in the AFBC market. They built one commercial and one pilot BFBC boiler. The commercial boiler is no longer running.

Pyropower Corporation (PRY)

Pyropower Corporation's owner, A. Ahlstrom, developed the Pyroflow CFBC technology in the 1960's. There are 43 Ahlstrom Pyroflow units in operation or under construction in the United States and abroad. Pyropower does not offer BFBC boilers.

The Pyropower CFBC boiler is one of the simplest. The system consists of a combustor and a cyclone to return the solids, with the solids flow rate controlled (but not modulated) by a so-called "loop seal" which is essentially a gently fluidized bed within a container. No external solids cooling is employed. The superheater surface may be located in the upper furnace if needed. Pyropower introduced their first commercial CFBC boiler in 1980. They have sold 16 units in the United States and several abroad.

Riley Stoker Corporation (RS)

Riley Stoker is licensed by Battelle to offer the multisolid CFBC (MSCFBC) boiler, (see Figures 14 and 15). The primary difference between the MSCFBC and the CFBC is the location of the heat transfer area. In the MSCFBC boiler, steam generation occurs in the EHE, not in the combustor. Solids are returned to the combustor by separate hot-recycle and cold-recycle legs at rates controlled by L-valves. The unique character of the multisolid EHE is that, unlike those in the Lurgi/Combustion Engineering and

Keeler/ Dorr-Oliver designs, it is not dispensable but is an integral part of the system. Another unique feature of the design is that it uses in-bed tubes to distribute primary air within a dense bed of large, inert particles. Below the distributor, the bed is fixed; above it, the bed is fluidized but stabilized in the bubbling regime by the presence of the large particles. This stabilization increases the residence time of the fuel particles to promote more complete combustion. Riley Stoker is in the construction phase or start-up phase for six boilers in the United States.

Stone Johnston Corporation (SJ)

Stone Johnston Corporatjon has installed over 20 industrial and commercial BFBC packaged boilers ranging from 2,500 to 50,000 lb/h.

The SJ design consists of a tapered watercooled combustion chamber divided into three parts by closely pitched divider tubes. The distributors consist of injection nozzles that use an air/gas mixture for startup. The distributor also incorporates oil/air nozzles to allow the unit to use multiple fuels (Figure 16).

The complete package includes a combustion coal and sorbent hopper/feeder, an integral multiple cyclone, and combustion air fans. An integral I.D. fan is used if secondary waste gas cleaning is not required. The boiler is started by a pilot ignitor that lights the gas/air mixture over the primary bed. When the flame in the central bed has been established and the bed temperature is brought up to a temperature suitable for firing solid fuel, the two side beds may be sequentially started as demanded by the boiler control system. The combustion control system maintains an appropriate firing rate by a combination of variation in fluidizing air and by turning beds sequentially on and off as required. The fluidized bed depth is about 30 in., which results in a low combustion air power requirement compared to boilers with deeper beds.

Sulzer Bros, Inc. (SUL)

Sulzer Brothers Limited is located in Switzerland. Their United States counterparts are capable of supplying an AFBC boiler, but have not yet built any AFBC boilers in the United States.

Wormser Engineering, Inc. (WOR)

Wormser manufactures dual bed fluidized combustion systems (Figures 17 and 18). The company now has four pilot plants and eight full-sized dual bed AFBCs operating or sold: two in Sweden, one in Japan, the others in the United States. Their capacities range from 30,000 to 150,000 lb/h steam. Wormser units can be used as a front-end retrofit to an existing oil or gas boiler.

York-Shipley, Inc. (YS)

York-Shipley was involved in the past with small BFBC boilers. Because of the lack of interest in BFBC boilers, they have not been actively involved in the market. They are in the process of developing an advanced Vortex AFBC boiler.

Summary of AFBC Manufacturers' Designs

Table 7 summarizes the boiler designs and operating ranges offered by AFBC manufacturers.

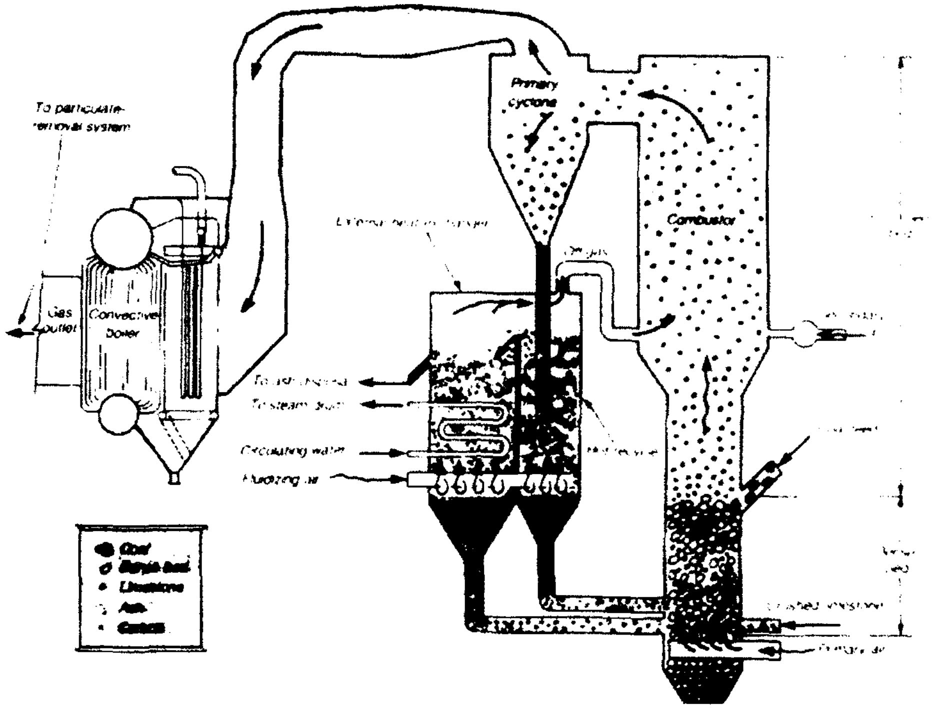

Figure 14. Riley Stoker MSCFB boiler design. (Courtesy of Riley Stoker)

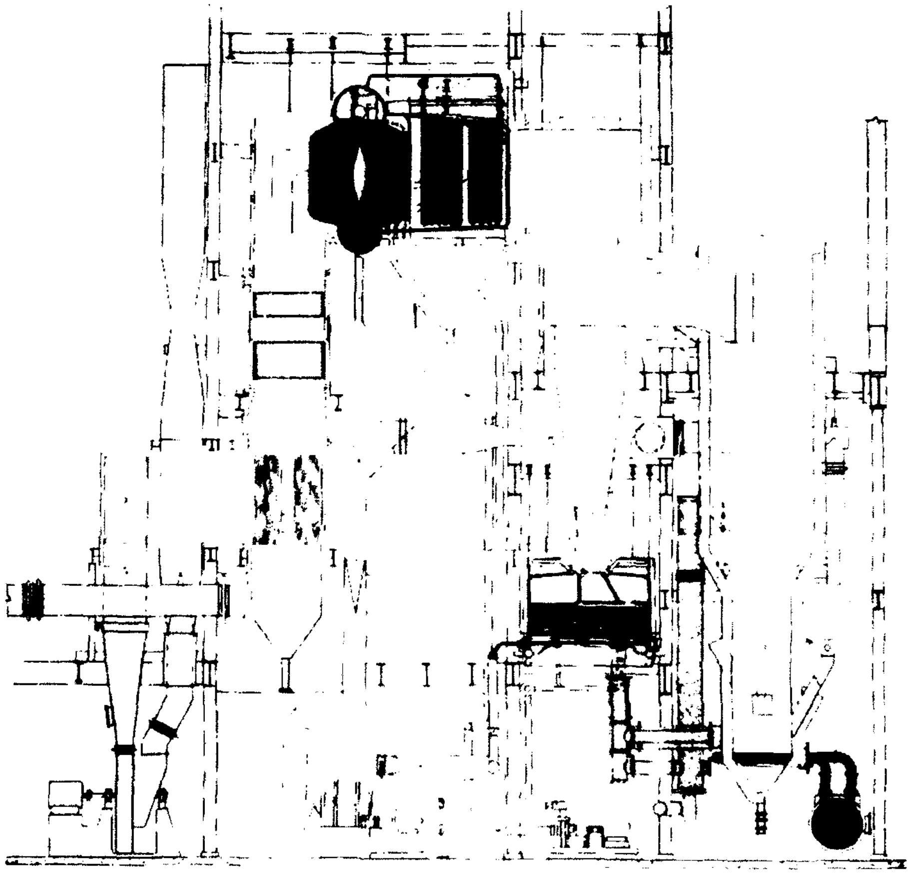

Figure 15. Riley Stoker MSCFB boiler layout. (Courtesy of Riley Stoker)

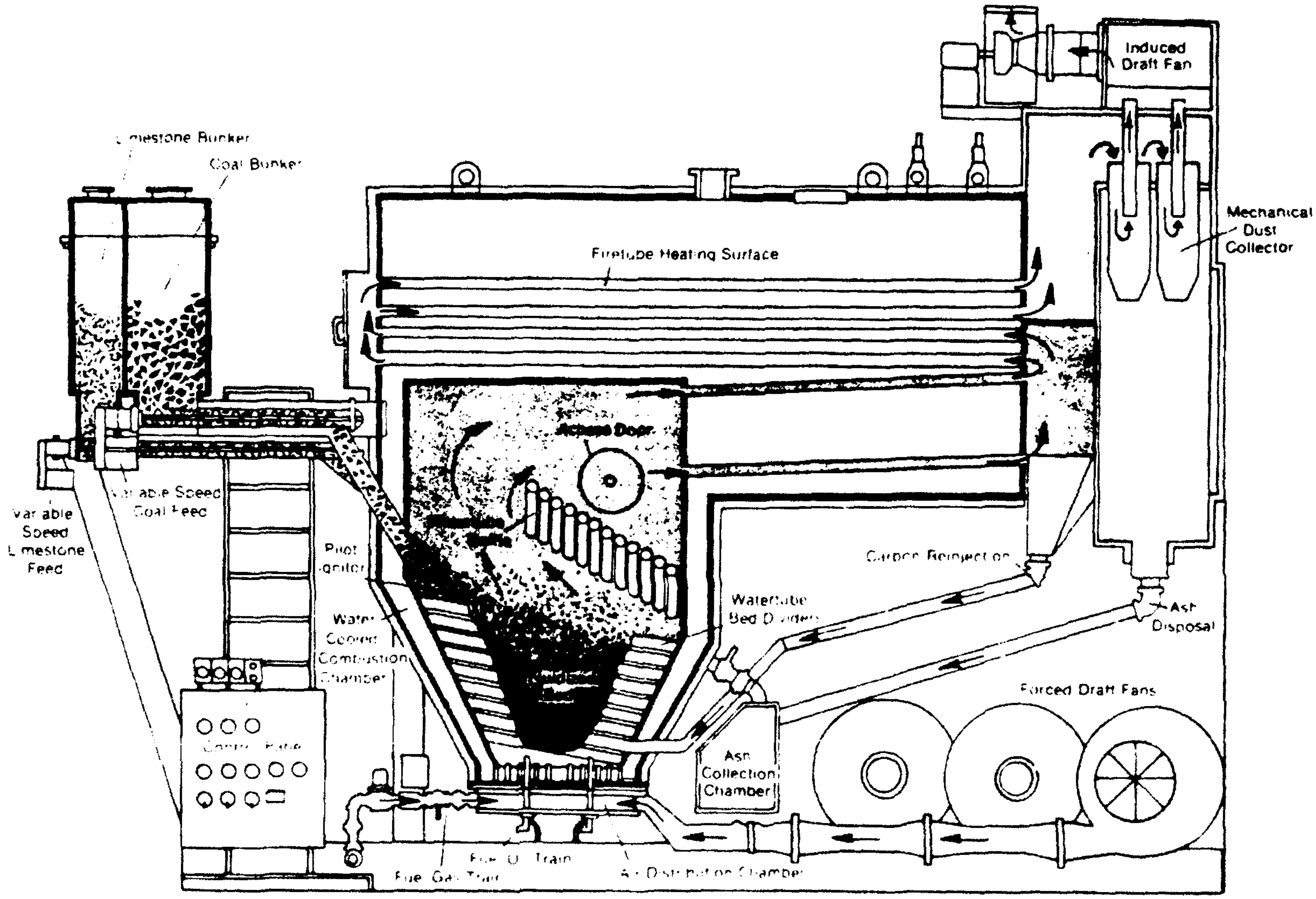

Figure 16. Stone Johnstone boiler. (Courtesy of Stone Johnstone)

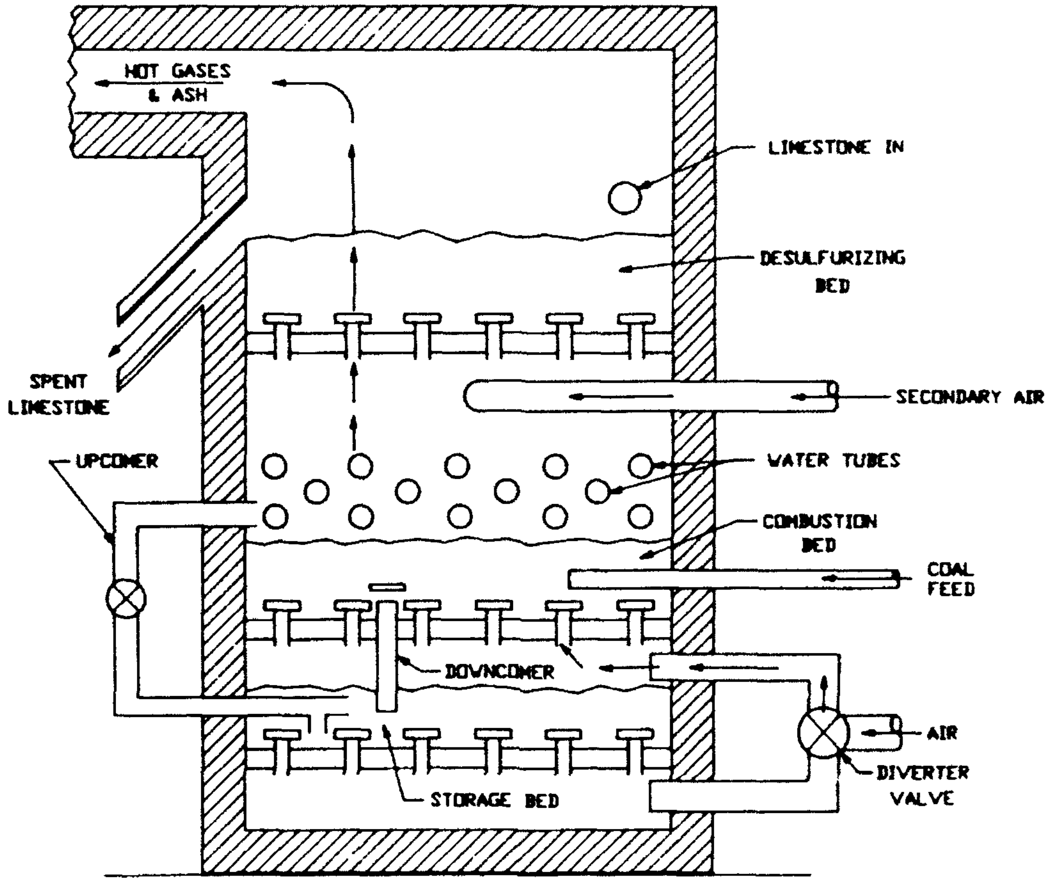

Figure 17. Wormser's dual bed system.

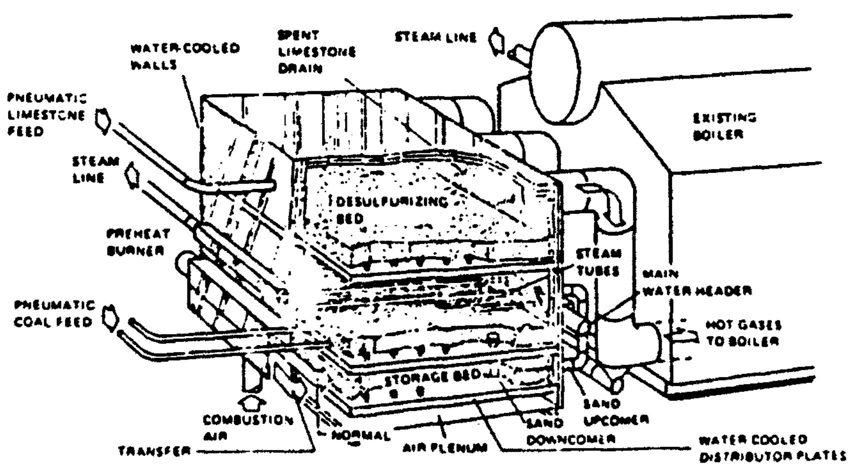

Figure 18. Wormser's dual bed boiler.

Table 7

AFBC Boiler Manufacturer Listing

Company	Company Technology Licensed From	Company Affiliated With	Type of Boiler	Capacity (1000 lb/hr)	Pressure (psig)	Temperature (°F)
Babcock & Wilcox Co.	Studsvich Energiteknik AB (Sweden)	--	B C	50 to 1500	125 to 2400	Sat to 1000
Combustion Engineering Power Systems	--	Lurgi Gmbh (FRG)	B C	50 to 1800	Up to 2400	Sat to 1005
Combustion Power Co.	--	--	C	40 to 250	Up to 1500	Sat to 1000
Dedert Co.	--	--	B	5 to 100	Up to 900	Sat to 825
Energy Products of Idaho	--	--	B	Up to 300	Up to 1400	Sat to 950
FluiDyne Engineering Corp.	--	--	B	12 to 150	15 to 1000	Sat to 950
Foster Wheeler Energy Corp.	--	Foster Wheeler Power Products Ltd. (UK)	B C	35 to 1500	150 to 2400	Sat to 1050
Keeler/Dorr- Oliver Boiler Co.	--	--	B C	40 to 800	Up to 1800	Sat to 1000
Power Recovery Systems Inc.	--	--	B	10 to 100	Up to 850	Up to 950
Pyropower Corp.	--	A. Ahlstrom Oy (Finland)	C	88 to 1100	Up to 2000	Sat to 1050
Riley Stoker Corp.	Studsvich Energiteknik AB (Sweden)	--	C	50 to 1500	Up to 2400	Sat to 1005
Stone Johnston Corp.	Combustion Systems (UK)	Stone FluidFire Ltd. (UK)	B	2.5 to 70	Up to 700	Sat to 750
Sulzer Bros. Inc.	--	--	B	20 to 200	150 to 1500	Sat to 950
Wormser Engineering Inc.	--	Ube-Wormser Ltd. (Japan)	B	20 to 200	Up to 2600	Up to 1000
York-Shipley Inc.	--	--	B C	2 to 80	15 to 600	Sat to 750

6 DISCUSSION OF AFBC BOILER INSTALLATIONS

AFBC Boilers in the United States

The Appendix contains a list of the installed and anticipated AFBC boilers. There are approximately 200 units built or planned in the United States. This large number indicates that the technology is rapidly maturing and has taken a significant place in the boiler market. Presently, there are fewer CFBC boilers than BFBC boilers, due mainly to the relative newness of CFBC technology. However, the number of CFBC units is increasing. The most recent CFBC systems tend to be in the larger end of the size range for AFBC boilers. The BFBC boilers have remained the smaller end of the boiler market.

Bubbling Bed

Midwest Solvents Company built a BFBC that was partly funded by the Illinois Department of Energy and Natural Resources (Figure 19). The 120,000 lb/h, 685 psig, 750 °F boiler went on line in June 1984. Foster Wheeler Energy Corp., the boiler's manufacturer, and consulting engineers Bibb and Associates, Inc., custom designed it to fit into the distillery's existing powerhouse alongside three standby boilers.

Foster Wheeler incorporated several innovations into the boiler, including:

- Chromized in-bed tubes for greater resistance to erosion.
- In-bed tube angle of 12-1/2 degrees. This shallow angle maintains natural circulation while reducing the angle of incidence of the bed material traveling up between the tubes.
- L-shaped directional nozzles in the grid plate to provide increased horizontal movement within the bed and direct large noncombustible matter in the bed towards the drain area.
- A two-stage convective superheater.

Limestone bed material, sized 1/8 in. to 20 mesh, is fed to the boiler by a screw conveyor from the storage bunker. Two pipes deposit it in the bed. Midwest Solvents Company receives coal by truck from two nearby mines. The sulfur content is from 2.5 to 3 percent. The coal must be sized 1-1/2 in. x 0, with not more than 20 percent under 1/4 in. It enters the boiler via a conventional spreader stoker feed system that was selected for its high rate of availability.

Startup of the boiler is accomplished with an in-dust burner capable of providing up to 20 percent of the unit's rated heat input. A burner of this size permits low-load operation, if desired. Hot combustion air enters a plenum underneath the air distribution plate, which is surrounded with a waterwall surface to maintain a uniform temperature. The air distribution plate is also water cooled, allowing it to expand at the same rate as the adjoining waterwalls.

Full steam load can be reached within 10 to 15 minutes. The fluidized bed depth varies from 2-3/4 to 4 ft. Air velocity through the bed is approximately 4 ft/s. The plant is currently operating at about 90,000 lb/h of steam, 30,000 lb/h below its maximum rating.

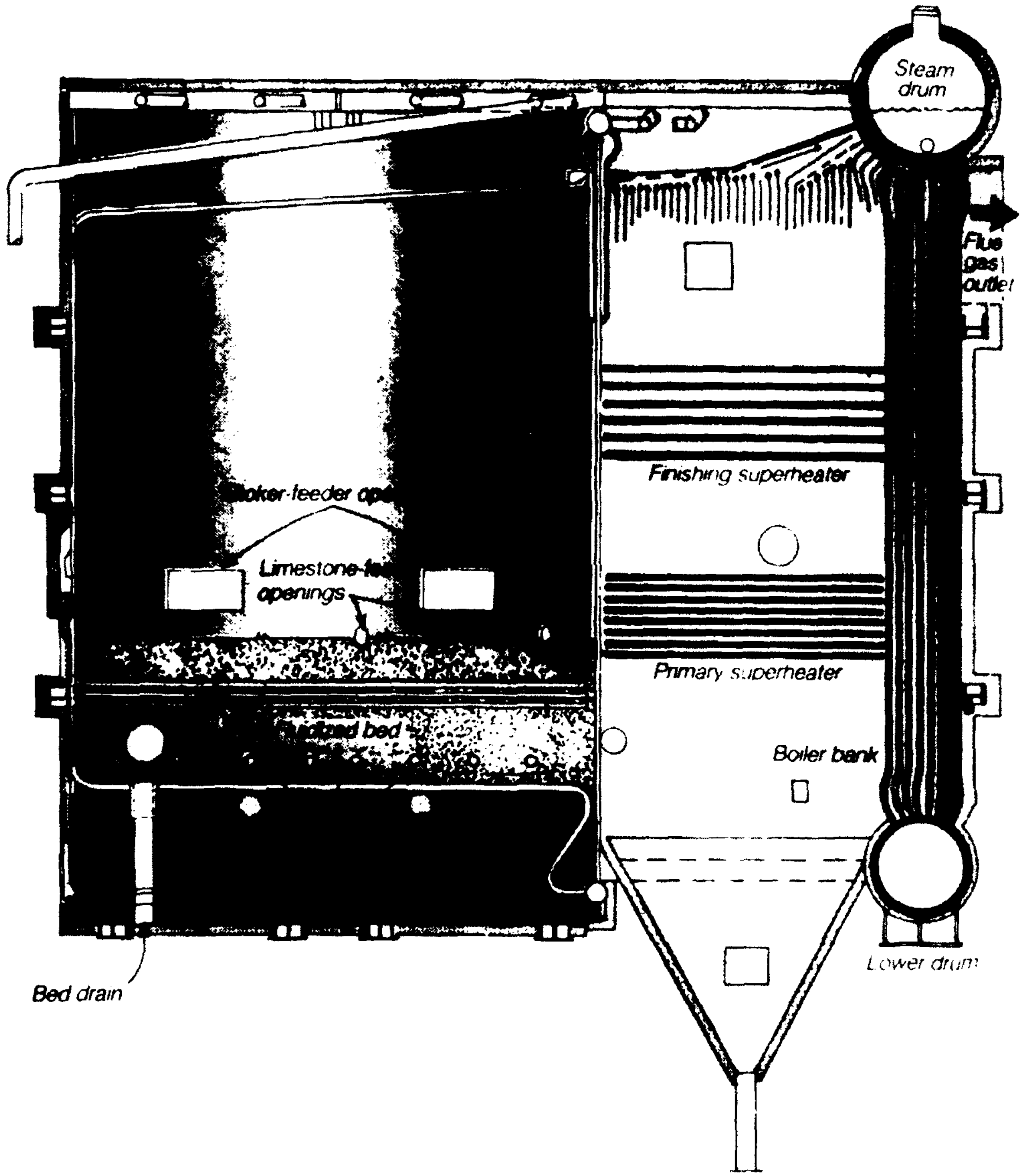

Figure 19. Midwest Solvents Company boiler.

Steam is routed to a backpressure turbine/generator at 650 psig, and is exhausted at 175 psig. This unit cogenerates about 3.5 MWe. Some of the lower pressure steam goes directly to process cooking and distillation. The remainder is put through a mechanical recompression evaporator, a boiler feedwater pump and a pressure reducing valve that bring the steam down to 20 psi for additional process use.

Flue gas leaving the bed flows into the freeboard zone and then up through the furnace and between the screen tubes to the superheater. After passing through the convective superheater, the flue gas turns to enter the boiler bank and follows a straight path to the top of that heat transfer section.

A multicyclone dust collector at the exit of the boiler bank returns the heavy ash particles (those containing a relatively high percentage of unburned carbon) to the bed. The flue gas steam containing fine fly ash particles flows through an economizer and fabric filter before being discharged from the plant stack. Some flue gas is used in the process plant for air drying.

On April 21, 1985, Midwest Solvents Company shut down the boiler for inspection after 7296 hours of operation. The overall condition of the boiler was excellent. The lower bed area waterwalls showed some minimal signs of ball stud and refractory erosion. The screen tubes at the furnace exit were polished, but testing proved they were well above the minimum wall thickness.

Plant equipment problems have centered on the turbine/generator; the governor had to be replaced after several failures. The screw cooler handling the limestone bed material has occasionally broken down as well. Finally, high ash levels in one fabric filter module were found to be a result of failure in the cleaning controls. An inspection showed the unit had operated for several days without being cleaned.

In accordance with the contract between Midwest Solvents Company and the Illinois Department of Energy and Natural Resources, a test and evaluation period was run on the fluidized bed boiler. Table 8 summarizes the major test results.

CFBC Boiler

Keeler/Dorr-Oliver is in the process of designing, manufacturing, and erecting eight CFBC boilers for the Archer Daniels Midland (ADM) Company (Figure 20). The project consists of five boilers (425,000 lb/h, 1300 psig, 900 °F) at Decatur, IL and three boilers (477,000 lb/h, 1300 psig, 900 °F) at Cedar Rapids, IA. All five Decatur units are currently operating.

Coal arrives at the Decatur plant by rail cars and/or trucks and is conveyed by belt conveyor either directly to the coal crusher or to the coal storage dome. The dome has a 10-day storage capacity. The coal is carried from the dome to the crusher by a belt conveyor. Another belt conveyor then carries it to 20-hr capacity coal bunkers where it is distributed via a tripper conveyor.

Limestone arrives by truck and is moved to either the limestone storage silos by bucket elevator or to the limestone bunkers by a conveyor system. From the bunkers, both the coal and limestone drop through gravity chutes into feeders that control the flow to the boilers. The coal is metered by two gravimetric belt feeders; the limestone is metered by two variable speed screws. The screws discharge into the outlets of the gravimetric feeders where the coal and limestone mix and finally fall into the boiler. The limestone feed rate can be manually regulated for a predetermined coal-to-limestone ratio, or automatically regulated based on a measurement of the sulfur dioxide in the flue gas. Each feed system consists of seal legs to prevent gas flow back through the feed system. The feed system design provides 100 percent redundancy.

Table 8

Midwest Solvents Company Operating Data

Parameter	**Result**
Boiler Performance	
Overall Efficiency, %	82.9
Calcium/Sulfur Ratio	2.7
Combustion Efficiency, %	95.2
Emission Tests	
Particulate, lb/MBtu	.021
Sulfur Dioxide, lb/MBtu	1.07
Nitrogen Oxides, lb/MBtu	.45
Carbon Monoxide, ppm	484
Turbine Generator	
Heat Rate, Btu/kwh	4,444
Availability, %	93.3
Superheat Control	755 +/- 5 °F
Load Change	20,000 pph in 30 sec
Turndown, %	25

* Source: Bibb and Associates, Inc., *Test and Evaluation Period of 120,000 PPH Atmosperic Fluidized Bed Combustion Boiler With 3500 kW Cogenerated Electric Power*, ILENR/CD-87/02 (Illinois Department of Energy and Natural Resources [ILENR], March 1985).

The boiler uses both a dense bubbling bed and a dilute fast bed. The bubbling bed is located at the bottom of the boiler and the dilute phase is above it.

Preheated primary air is introduced through a plenum (water-cooled to control metal fatigue) at the bottom of the dense phase. Preheated secondary air is introduced at two levels to promote the dilute phase. All water evaporation is handled in the waterwall combustion chamber of the fluid bed boiler, eliminating the need for a convection bank. A natural circulation system feeds water from the drum downcomers to the lower heads. Risers return to the steam drum. The membrane walls of the combustion chamber are lined with refractory due to the substoichiometric chemistry and the high degree of turbulence in the bed.

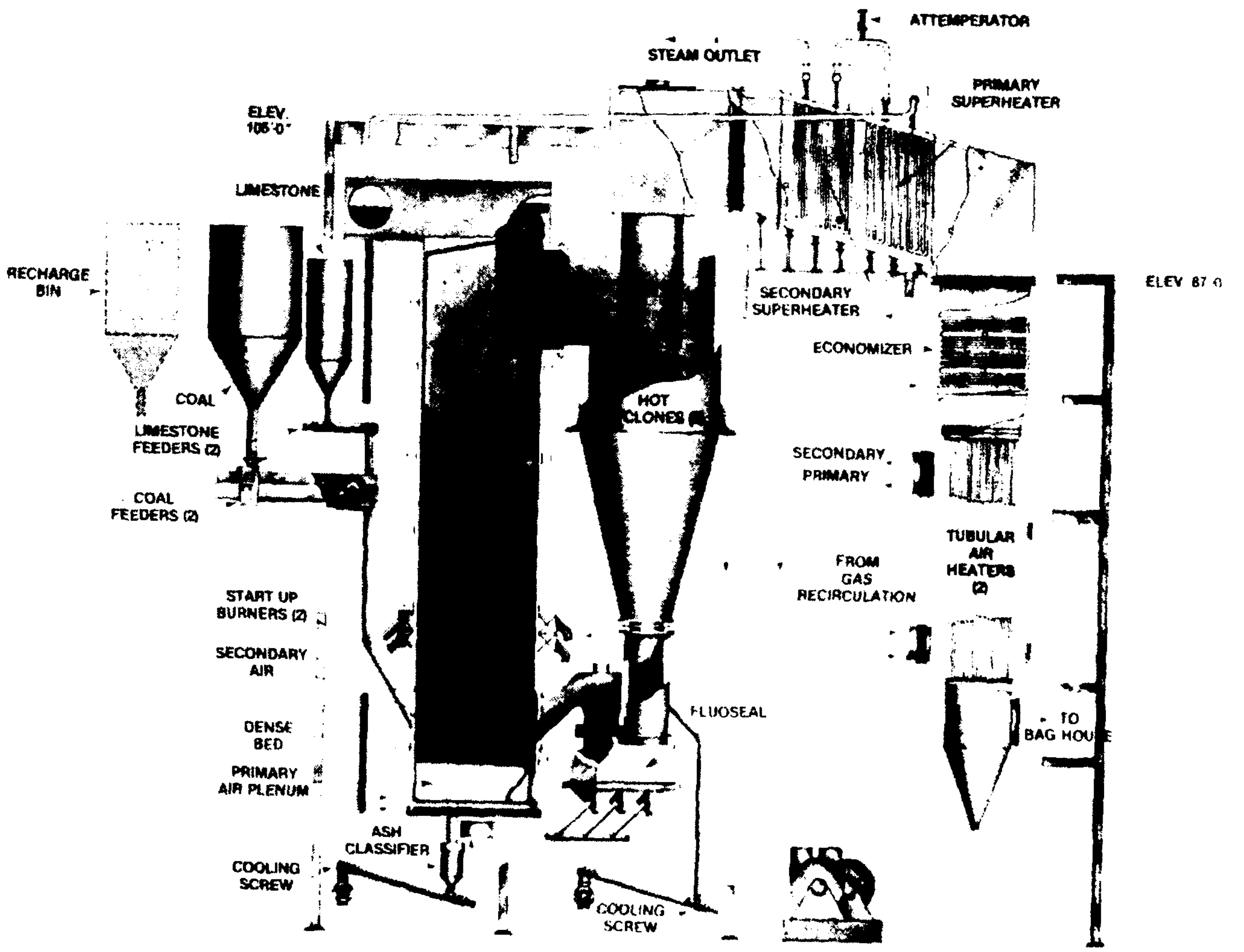

Figure 20. Archer Daniels Midland boiler. (Courtesy of KDO)

cooled screws before it enters a pneumatic ash handling system. The fine fraction of the ash is recirculated to the combustor by two pneumatic lifts. Fine ash removed from the FluoSeal is also cooled in a water-cooled screw before entering the pneumatic ash handling system. The fly ash from the air heater and baghouse are directed to the pneumatic system without being cooled.

Gases leaving the hot cyclone enter the superheater section. The superheating of the steam consumes 26 percent of the total energy available in the system. Additional heat recovery takes place in the economizer, which is directly downstream of the superheater. Final heat recovery takes place in two air heaters; one supplies primary air, and the other supplies secondary air.

The plant layout provides space for the addition of a multicyclone dust collector. The multicyclone would add flexibility to the types of fuels and sorbents used. A baghouse is used for final gas clean up. I.D. fans are used to maintain zero pressure at the boiler outlet. The fans, controlled by inlet control dampers, all discharge to a common stack.

The plant has one central control room containing a computer microprocessor. Operating data consisting of process variables and equipment status are displayed on computer terminals. System commands are given through an operator keyboard.

Unit One first fired coal on February 21, 1987. Unit Two was fired 2 months later and Unit Three was fired 4 months later. The performance tests for acceptance of the project by the client occurred on April 16 and 17, 1987. Unit One was tested by an outside firm hired by ADM. Boiler efficiency was 85.4 percent and the total boiler system duty was 93.2 percent of the design duty. Combustion efficiency for the performance test was 98.6 to 98.7 percent (Table 9). To date, emission tests have not been performed. The table also lists the performance data for the design case and the Keeler/Dorr-Oliver pilot plant which was used to simulate the boilers at ADM.

The project appears to be running smoothly. KDO reported a 95 percent availability during the first 12 weeks of operation for Unit One, and a 98 percent availability during the first 4 weeks of operation for Unit Two. ADM operators estimated a boiler downtime once a month due to boiler tube erosion.

In December 1983, a contract was awarded to Pyropower to supply a 125,000 lb/h, 400 psig saturated steam boiler to B.F. Goodrich's Henry, Illinois, vinyl and specialty chemicals plant (Figure 21). The project included all equipment required for solid fuel handling. The initial coal firing began in October 1985. Overall, the facility meets the performance requirements of maximum continuous rate, thermal efficiency, limestone efficiency, turndown ratio, load response, and emissions. Table 10 reviews the operating data.

Coal is received by truck and is normally unloaded directly to a yard hopper. A covered belt conveyor moves the coal from the yard hopper through a metal separator and a metal detector into a crusher, where it is crushed to 1/2 in. x 0 or smaller. The coal may bypass the crusher if presized coal is purchased. The crushed coal is then pneumatically conveyed by a dense phase transfer system to a 450-ton coal silo. The silo can store enough coal for 4 days. Coal feed to the boiler is handled by a pressurized gravimetric belt feeder that is controlled automatically based on steam demand.

Presized limestone is delivered to the plant by pneumatic truck and is conveyed to a 350-ton silo. Limestone feed is monitored by a double helix screw feeder and is based on the coal feed rate and trimmed by the actual SO_2 emissions. Limestone is then pneumatically conveyed into the combustion chamber.

The boiler is designed to produce 125,000 lb/h of saturated steam at a pressure of 500 psig with natural circulation, but operates at 400 psig. The lower combustion section is refractory lined. Approximately 45 percent of the evaporation takes place in the combustion chamber waterwalls. The gases and entrained solids travel from the combustion chamber to a single refractory-lined cyclone, where

Table 9

Archer Daniels Midland Operating Data*

Parameter	ADM Decatur Design	Performance Test	KDO Pilot Plant
Combustion Efficiency, %	98.5	98.7	99.4-99.7
Boiler Efficiency, %	85.4	85.4	**
Boiler Duty, MBtu/hr	422	397	4.71
SO_2 Emissions, ppm	542	***	140-210
SO_2 Emissions, lb/MBtu	1.2	***	.32-.52
Nx Emissions, lb/MBtu	280	***	179-224
CO Emissions, ppm	0.4	***	.29-.39
CO Emissions, lb/M Btu	60	***	51-59
HC Emissions, ppm	< 10	***	none
Fuel Analysis (%, as received basis)			
C	53.50	56.50	60.90
H	3.69	3.69	4.61
S	4.10	3.71	3.25
N	1.03	.93	1.11
O	6.91	9.42	7.29
Ash	14.00	9.35	9.68
H_2O	16.80	16.40	13.16
HHV, Btu/lb	9,600	10,440	10,970

* Source: Bibb and Associates, Inc.
** Boiler Efficiency for the pilot plant system is much lower than a commercial plant because of the small boiler size.
*** Emmision tests have not yet been performed.

the solids are separated and returned to the combustion chamber. The gases then travel through the convection bank, an economizer, and on to a baghouse. Exit gas temperature is about 344 °F.

More than half of the combustion air is injected as primary air through grid nozzles at the base of the bed. Secondary air is injected through nozzles at several locations. Dust loading in the convection section is minimal due to ash removal in the hot cyclone. Due to the low operating temperature, ash softening does not occur, and as a result, soot blowing is only required every other day.

Spent bed material is removed at a rate to maintain the proper bed inventory in the combustion chamber. The removal system consists of two ash coolers, ash screws, and an ash transfer system to a silo. The ash coolers are cylindrical and have a fluidizing grid at the bottom. Water is not required for either the ash coolers or the transport screws. The ash is conveyed by a pneumatic transfer system. Spent bed ash is stored in a separate silo from the fly ash.

The boiler is controlled by a microprocessor-based distributed control system that provides a network of redundant multifunction controllers and associated equipment for analog control, sequential control, and operator interface. All control equipment is interconnected on a redundant plant loop. The operator interfaces through one of three computer keyboards. The control system has the capability to log all alarms, provide trends, produce custom graphics, and store and retrieve pertinent data.

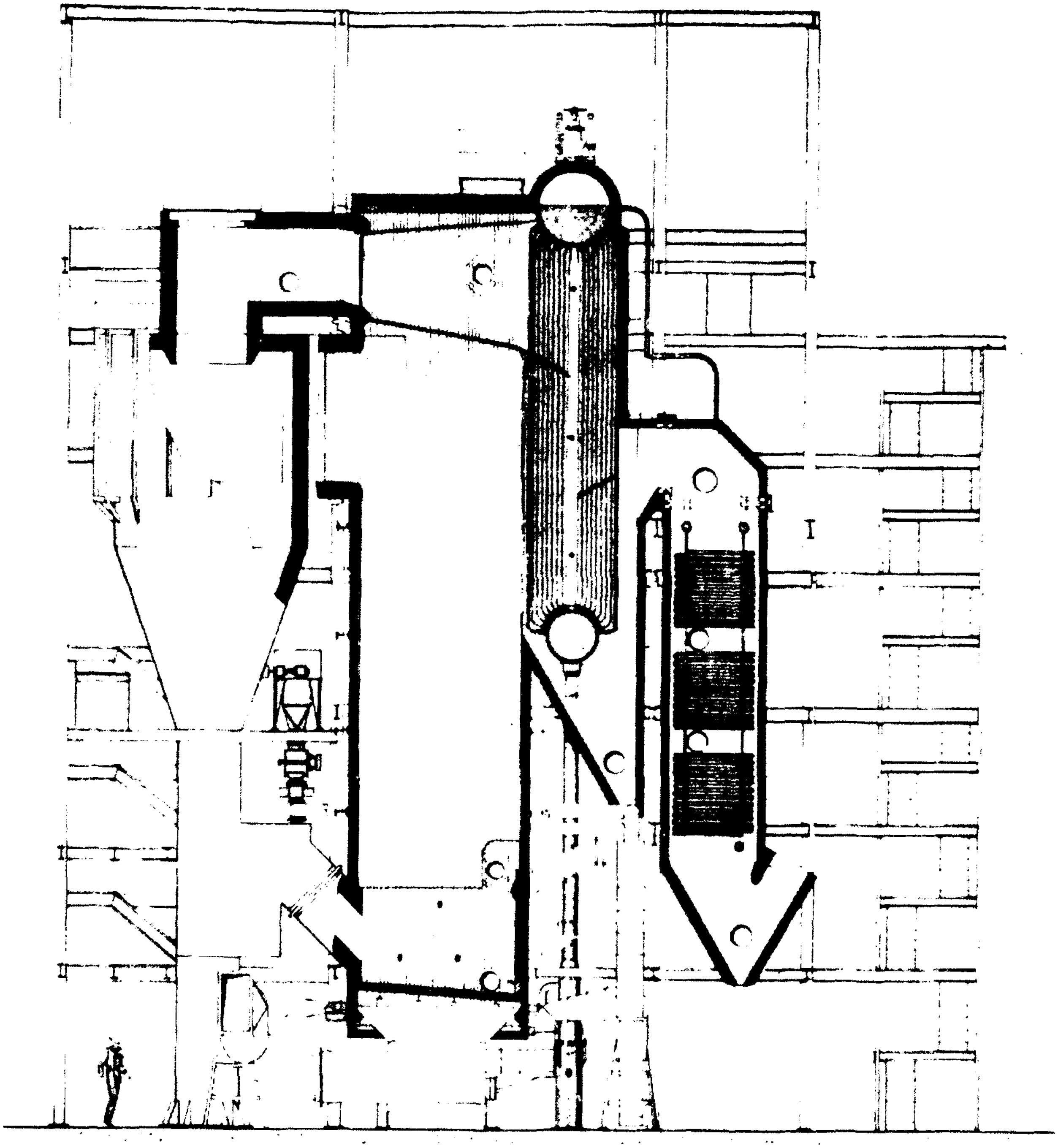

Figure 21. B.F. Goodrich boiler. (Courtesy of Pyropower)

Table 10

B. F. Goodrich Operating Data*

Parameter	**Result**
Steam rate, lb/h	125,000
Pressure, psig	400
Boiler efficiency, %	85.7
Calcium/Sulfur Molar Ratio	2.19
Load change capability	25,000 in 10 min
Turn down, % of MCR	33
Particulate, lb/MBtu	0.0073
Sulfur Dioxide, lb/MBtu	0.782
Nitrogen Oxides, lb/MBtu	0.382
Carbon Monoxide, ppm dry	33
Total Hydrocarbon, ppm	1.7

* Source: R.C. Linnenman, *Summary of Successful Demonstration of the 125,000 PPH Pryopower Circulating Fluidized Bed Combustion Boiler*, ILENRCD-87/01 (ILENR, April 1985).

In 1986, the system was operated 6144 hours out of a potential 6959 hours. System availability has thus been 88 percent. Of the 815 hours the system did not run, 212 are due to control system difficulties, 328 to unspecified reasons, 251 to time required for modifications, and 24 to operator errors, fuel problems, and unscheduled maintenance of auxiliary equipment. For this period of evaluation, the boiler had an availability of 96 percent.

One significant operational problem has been with feeding the high moisture coal through a rotary feeder. A temporary modification to wash the rotary was successful in keeping the boiler on line. Permanent modifications were made and the boiler continues online.

Multiple Bed

Wormser Engineering has installed a 70,000 lb/h (650 psig, saturated) dual bed in Amarillo, Texas, which has been in operation since 1983. The unit operates at full load for two shifts, 6 days a week, with reduced load on the third shift. Electricity is also cogenerated.

Coal is delivered by truck from Colorado. The coal feed system, which is 15 ft tall, is mounted under the coal bin. The coal is fed from the bin to a rotary valve via a screw feeder. The coal is then dried by preheated transport air that passes through it. The drier burner modulates according to variations in the coal moisture, and consumes up to 1 percent of the AFBC's firing rate. After it is dried, the coal is crushed and split in a stream splitter. The transport air then carries the coal to the boiler by way of 18 pipes. Stainless steel nozzles at the ends of the pipes distribute the coal evenly over the combustion bed.

Limestone and makeup sand are also delivered by truck. The limestone is fed from a hopper to a screw feeder, through a rotary valve, and then to a crusher for final sizing. No dryer or stream splitters are required.

The firing train is shown in Figure 22. The combustion bed consists of a shallow bed of sand, normally 6 to 8 in. The operating temperature is about 1750 °F. Water tubes are located within the bed.

The coal is fed slightly above the primary air distributor plates. One coal feed pipe is used for each 9 sq ft of bed area. Secondary air is added in the combustor's freeboard. The secondary air serves to cool the gases to the optimum desulfurization temperature.

The desulfurizing bed has a settled bed height of less than 12 in. Limestone is added by a single pipe over the bed. Spent limestone is removed at an overflow drain at the bed's surface. Since the residence time of the limestone particles is about 10 h, no attempt is made to counterflow the limestone through the bed. This bed is normally operated at 1550 °F.

A storage bed is used to control the combustor bed level, which is required for turndowns greater than 3:1. Without it, bed material would have to be cooled and dumped with each reduction in load, and fresh sand provided with each increase. The storage bed also serves as a letdown cooler for the combustion bed if oversize materials need to be removed, and provides a reservoir of makeup sand to compensate for carryover losses. Solids flow to the storage bed through a standpipe, which is operated by a single valve. In use, the valve is opened, filling the standpipe. The combustion air is then diverted to the storage bed plenum, allowing the solids to flow from the pipe and spread across the storage bed. Because the standpipe is full, the upward flow of air and solids is prevented. The upcomer returns the solids when required. These solids are about 300 °F. In operation, the storage bed is again fluidized by combustion air, and the upcomer valve is opened. Air flows through the upcomer, driven by the pressure drop through the combustion bed. Solids from the storage bed are drawn up the sump pipe and injected into the airstream. Use of the sump pipe limits the solids injection rate, thus avoiding choking of the upcomer. The storage bed plenum is divided into three segments to increase the superficial velocity at the low temperatures found there. A separate upcomer services each segment.

The boiler grates have a water-cooled casing, which is lined with tiles for heat retention and insulation. The distributor plates are also water cooled and insulated. The water path through the grate starts at the boiler's steam drum and then passes though the circulator pump, AFBC, and back to the steam drum for steam/water separation.

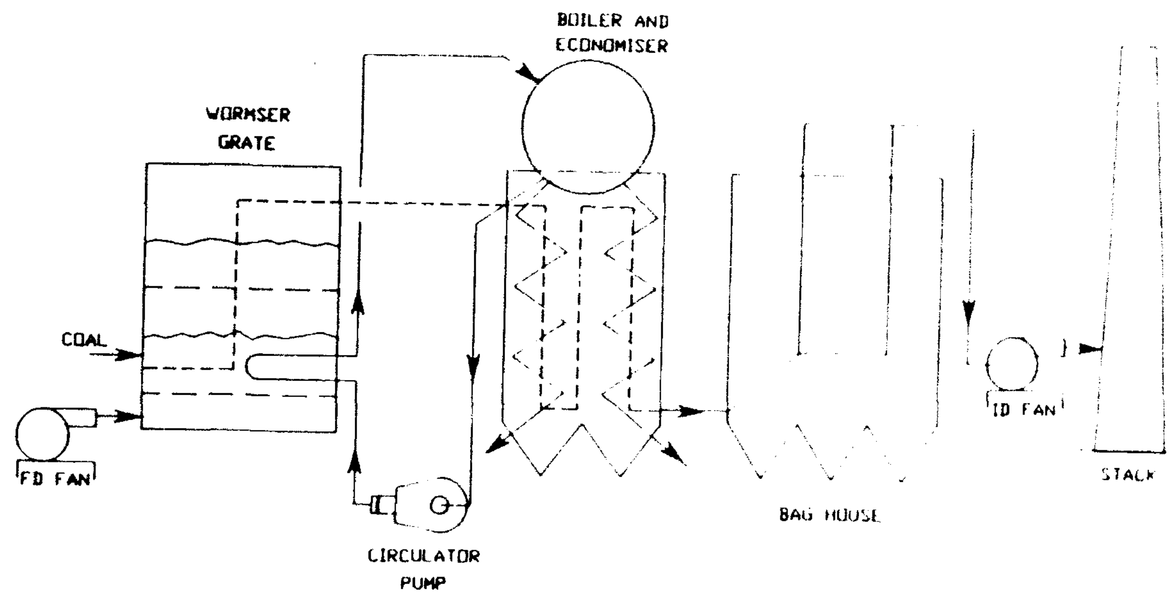

Figure 22. Wormser Engineering firing train.

Each bed is a single module, measuring 10 by 17 ft. The overall height of the unit is 14 ft 3 in. The pressure drop through the dual beds at full load is 1.1 psi.

The combustion gases leave the grate by a refractory-lined duct, pass through the boiler/economizer, and leave via the baghouse and I.D. fan. Most of the coal ash leaves the fluidized bed with the flue gases and is collected at the boiler's dropout hoppers and baghouse hopper. Combustion bed overflow material and spent limestone are cooled before being removed by pneumatic conveyors.

One of the major problem areas with this technology was that the original water treatment system was too small and produced water with high dissolved solids. This problem was solved by doubling the demineralizer capacity. Also, the dense-phase coal feed system was repiped to reduce line plugging between the storage silo and the coal preparation and feed system surge bin. During shutdown, the in-bed steam generating tubes, which had been damaged due to overheating during the initial startup, were replaced. Analysis of the tubes revealed a combination of overheating and internal (water side) corrosion had contributed to the early tube failure. This problem has been corrected, and inspection of the replacement tubes after 17 months of additional operation showed no internal tube damage and no external tube erosion. Finally, the combustor casing seals were modified to minimize thermal stress tears that had previously allowed outside air to leak into the system.

For the first 21 months of commercial operation, the AFBC availability was 95 percent while the entire plant operated 85 percent of the time. The problems causing the outages were related to equipment failure and fuel. Equipment failure (thermocouples, coal rotary valve, windbox seal, and control panel overheating) accounted for most of the unavailability; coal impurities accounted for the rest of the unavailability time. Solving the equipment failures should reduce unavailability to 3.7 percent.

East Colorado coals are burned most of the time. Tests were run on higher sulfur coal and Midwest bituminous coals to optimize the Ca/S mole ratio and determine the effect on desulfurization efficiencies. During the runs, high desulfurization efficiencies were achieved with relatively low Ca/S ratios while burning coal with a sulfur content over 4 percent. Tests run on relatively low-sulfur western coal showed the ability to reduce sulfur emission levels to 0.02 to 0.03 lb/Mbtu.

When low-nitrogen coal (0.7 percent) was used, NOx emissions were at 0.2 to 0.3 lb/MBtu. When high-nitrogen coal (1.7 percent) was used, the NOx emissions were brought down to the 0.3 lb/MBtu range by increasing the staged combustion air split.

The carbon utilization has been between 95 and 98 percent. The ability of the upper bed to consume 2/3 of the carbon emitted from the lower bed eliminates the need for carbon reclaim systems. Dual bed AFBCs are the only type that do not require fly ash reinjection systems to enhance the combustion efficiency. Continuous turndown of 3:1 can be achieved by increasing the air flow, which in turn controls the bed height and the amount of in-bed tubes covered by the bed.

Wormser has also retrofitted a 85,000 lb/h process steam boiler at the Kraft Company (formerly Anderson Clayton) in Jacksonville, IL. The project was partly funded by the Illinois State Government. Although the boiler has operated, several problems have delayed the expected full-time operation.

The limestone and coal are received in bulk and transferred to pits. Conveyors carry the materials from the pits to separate silos. The coal and ash are metered by load cells in the silos. From the silos, the limestone is sent to a crusher and the coal is sent to a crusher and a dryer. Finally, the materials are pneumatically fed to the boiler. The boiler was previously used for gas and oil firing and was built over a basement to allow room below the boiler for installation of bottom ash removal equipment for coal firing. To modify the boiler to a multiple fluidized bed boiler, grates were added at the bottom and extend into the basement. From the boiler, the gases pass through an economizer and a baghouse.

As part of the funding from the Illinois State Government, Kraft is to complete a 30-day test to obtain performance, operating, and emissions data.

The major problems encount ed by this retrofit were caused by the solids handling, including improper limestone and coal sizing due to the crushers, inaccurate weighing of the coal and limestone feeds to the boiler due to the load cells used on the silos, structural problems in the limestone silo causing the silo to buckle, and a fire in the coal silo. These problems were corrected, but the system is still not operating due to the ash handling system. This problem is being worked on.

7 EMISSION STANDARDS

Current Federal Standards

The Federal New Source Performance Standards (NSPS) for boilers are summarized in Table 11. The Federal Government initially set standards for fossil fuel fired steam generating units of more than 73 MW heat input rate (250 MBtu/h) that were built after August 17, 1971. New standards for industrial boilers greater than 100 MBtu heat input per hour have been added. These include NOx, SO_2, and particulate emissions. Emissions for boilers less than 100 MBtu heat input per hour were proposed in June 1989.

Current California Standards

Boilers must comply with both Federal and State regulations. Many states have adopted the Federal emission regulations. However, California has more stringent regulations than the Government. The South Coast Air Quality Management District was created by California State law as the agency responsible for management of air quality in Los Angeles, Orange, and Riverside Counties and the nondesert portion of San Bernardino County.[14]

Rule 476 indicates:

> A person shall not discharge into the atmosphere from any equipment having a maximum heat input rate of more than 12.5 million kilogram calories (50 MBtu) per hour used to produce steam, for which a permit to build, erect, install or expand is required after May 7, 1976, air contaminants that exceed the following:
>
> (1) Oxides of nitrogen, expressed as nitrogen dioxide (NO_2), calculated at 3 percent oxygen on a dry basis averaged over a minimum of 15 minutes—125 ppm when using gas fuel and 225 ppm when using liquid or solid fuel.
>
> (2) Particulate matter discharged into the atmosphere from the burning of any kind of material containing carbon in a free or combined state that exceeds both of the following two limits:
>
> (A) 5 kg (11 lb)/h.
>
> (B) 23 mg/m^3 (0.01 gr/cu ft) calculated at 3 percent oxygen on a dry basis averaged over a minimum of 15 consecutive minutes.

Rule 405 indicates:

> A person shall not discharge into the atmosphere from any source, solid particulate matter including lead and lead compounds in excess of the rate shown in [Table 12]. (Process weight is defined as the total weight of all materials introduced into any specific process which may discharge contaminants into the atmosphere.) Solid fuels charged will be considered as part of the process weight, but liquid and gaseous fuels and air will not.

Rule 431.3 indicates:

> A person shall not burn any solid fossil fuel having a sulfur content which will emit more than 0.56 lb of SO_2/MBtu. The provisions of this rule shall not apply to the use of a solid fossil fuel with higher sulfur

[14] *Rules and Regulations*, South Coast Air Quality Management District, El Monte, CA (June 1987).

Table 11

Federal Emission Standards for Boilers

Emission		Standard
Fossil Fuel Fired Steam Generators Greater Than 250 MBtu/h*		
SOx		1.2 lb/MBtu
NOx		0.70 lb/MBtu solid fossil fuel, and/or wood 0.60 lb/MBtu lignite 0.80 lb/MBtu lignite from ND, SD, MT
Particulates	0.1 lb/MMBtu	
Opacity		Not more than 20 % opacity except for one 6-minute period per hour of not more than 27%
Fired Industrial Boilers greater than 100 MBtu/h**		
SO_2		1.2 lb/MBtu, 90% reduction total sulfur
NOx		0.60 lb/MBtu
Particulates	0.05 lb/MBtu coal	0.10 lb/MBtu wood
Fired Industrial Boilers smaller than 100 MBtu/h***		
SO_2	coal	1.2 lb/MBtu, 90% reduction of total sulfur
	coal in FBCs	1.2 lb/MBtu, 80% reduction of total sulfur
	coal using an emerging technology to control SO_2	0.60 lb/MBtu, 50% reduction of total sulfur
	oil	0.50 lb/MBtu, 0.5% by weight of total sulfur
Particulates	coal only or w/other fuels ≤10%	0.05 lb/MBtu
	coal only or w/other fuels >10%	0.10 lb/MBtu
	wood only or w/other fuels (except coal):wood≥30%	0.10 lb/MBtu
	wood only or w/other fuels (except coal):wood<30%	0.30 lb/MBtu
Opacity		Not more than 20% (6-minute average) opacity except for one 6-minute period per hour of not more than 27% opacity.

*Built after August 17, 1971.
**Emmisions are per unit heat input.
***Built after June 9, 1989. Emmissions are per unit heat input.

content where process conditions or control equipment remove sulfur compounds from stack gases to the extent that the emission of sulfur compounds into the atmosphere is no greater than that which could be emitted by using a fuel that complies with provisions of this rule.

As a minimum, the above rules are to be followed. The District will deny permits to construct unless the Best Available Control Technology (BACT) is employed for each nonattainment air contaminant. BACT means the most stringent emission change limitation or control technique which:

(1) Has been achieved in practice for such a permit unit category or class of source; or

(2) Is contained in any State Implementation Plan (SIP) approved by the USEPA for such a permit unit category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer that such limitation or control technique is not presently achievable; or

Table 12

State of California Particulate Emission Standards*

Process Wt.	Max. Discharge Rate** lb/hr	Process Wght. lb/hr	Max. Discharge Rate lb/hr
220 or less	0.99	331	1.29
441	1.55	551	1.77
661	1.98	772	2.17
882	2.34	992	2.51
1102	2.67	1323	2.95
1543	3.22	1764	3.47
1984	3.70	2205	3.92
2756	4.42	3307	4.86
3858	5.27	4409	5.65
4960	6.00	5512	6.34
6063	6.65	6614	6/95
7165	7.23	7716	7.50
8818	8.02	9921	8.50
11020	8.95	13230	9.78
15430	10.5	17640	11.2
19840	11.7	22050	12.0
27560	12.6	33070	13.2
38580	13.7	44090	14.1
55120	14.9	66140	15.5
77160	16.1	88180	16.6
99210	17.1	110200	17.5
132300	18.2	154300	18.9
176400	19.5	198400	20.1
220599	20.6	275600	21.7
330700	22.6	385800	23.5
440900	24.2	496000	24.9
551200	25.5	6606300	26.1
661400	26.6	716500	27.1
771600	27.6	881800	28.5
992100	29.3	1102000 or more	30.0

* *Rules and Regulations.*

** Max. Discharge Rate = the rate allowed for solid particulate matter (aggregate discharged from all points of process).

(3) Is any other emission control technique found by the Executive Officer to be technologically feasible and cost effective for such class or category of sources or for a specific source. No emissions limitation or control technique, the application of which would result in emissions from a new or modified source in excess of the amount allowable under the NSPS or promulgated by the USEPA pursuant to Section 111 of the Clean Air Act, may be considered BACT.

Ability of AFBC Boilers To Meet Emission Standards

Table 13 summarizes the emission information obtained from AFBC manufacturers. Comparing this information and the emission standards shows that AFBC boilers can meet the NSPS of 1.2 lb/MBtu with a 90 percent removal. For BFBC boilers with overbed feed to meet the 90 percent reduction, a large Ca/S ratio is required (2.8:5.0). If underbed feeding and ash recycle is used, the required Ca/S ratio is 2.0:3.0. On the other hand, a CFBC requires a smaller Ca/S ratio (1.5:2.0) to meet the reduction.

In most cases, AFBC systems can burn typical coals and stay well below the NOx emission limits. As mentioned in Chapter 3, NOx emissions are low because of the low operating temperature in the AFBC combustor, which results in little NOx formed from N_2 in the combustion air. However, for this to be true in a BFBC, the design must prevent the presence of hot zones that generate NOx. A design that promotes adequate bed mixing and ensures even fuel distribution in the bed will avoid hot spots.

CFBC systems inherently have a large, well-mixed combustion zone with high ash recycle rates. Therefore the problems due to hot zones would normally not be expected for CFBCs.

Little attention has been given to NOx emissions because the standards are easily met in most cases. Particulate emissions in both BFBCs and CFBCs are removed efficiently in a baghouse.

Table 13

AFBC Manufacturer's Emissions

Company	SO_x Emissions Boiler Type	NO_x Removed	Particulates lb/mm Btu	lb/MM Btu
Babcock & Wilcox Co.	B C	90%	0.6	0.05
CE Power Systems	B C	98% 0.2lb/mm Btu	0.30 0.15	0.03
Combustion Power Company, Inc.	C	95% 20-30 ppm Btu	0.30-0.15	0.03
Dedert Corp.	B	N/A	N/A	N/A
Energy Products of Idaho	B	80-85%	0.2-0.5	N/A
Fluidyne Engineering Corp.	B	per bact	per bact	per bact
Foster Wheeler Engineering Corp.	B C	N/A	N/A	N/A
Keeler/Dorr-Oliver	B C	To comply	To comply	To comply
Power Recovery Systems, Inc.	B	N/A	N/A	N/A
Pyropower Corp.	C	90-95%	0.5	0.003
Riley Stoker Corp.	c(msfb)	90%	100-200 ppm	N/A
Stone Johnston Corp.	B	N/A	N/A	N/A
Sulzur Bros., Inc.	B	80-85%	0.3	0.002
Wormser Engineering Inc.	M	70-96%	0.2-0.6	0.02-0.1
York Shipley Inc.	N/A	N/A	N/A	N/A

8 EVALUATION OF COAL FIRED BOILERS

Technical Factors

The following information offers several reasons for choosing an AFBC boiler over the alternatives of stoker and pulverized systems:

- Greater fuel flexibility—the ability to burn low grade, high grade, and waste fuels. Materials and fuels that have been successfully burned in AFBC units include:

Coal of all types	Natural gas
Pelletized wood waste	#2 and #6 oil
Pelletized paper waste	Peat
Sawdust	Asphalt shingle waste
Shredded rubber	Petroleum coke
Industrial waste oil	Oil shale
Anthracite culm	Fruit pits
Wood chips	Rice hulls
Alcohol mash waste	Sewage sludge
Paper mill sludge	Municipal refuse
Carpet waste	Coal washing waste
Biomass waste	Sulfur-laden waste gases
Vegetable compost	Paint sludge

- Lower power requirements for fuel preparation than for PC boilers.
- Wide range of fuel variations:
  a) +/- 5-10 percent pulverized firing
  b) +/- 10-15 percent stoker firing
  c) +/- 25-30 percent AFBC.
- Better ability to handle a wide range of fuels:
  a) Moisture 0 to 80 percent
  b) Ash 0 to 90 percent
  c) Heat values from 500 to 15,000 Btu/lb.
- Easy disposal of solid waste products (by landfill). The wet scrubbers required in conventional boiler systems create capital- and labor-intensive water management and maintenance problems. Surveys of existing powerplant data indicate wet scrubber reliability (ratio of time system operated to time system was called on to operate) to be approximately 81 to 83 percent.
- Lower operating temperatures and better distribution, therefore there is:
  a) Much improved NOx control
  b) Minimal fouling and slagging potential
  c) Thermally homogeneous combustion—lower potential for localized hot or cold spots
  d) Prevented vitrification of the ash particles, causing them to be less abrasive than ash from stokers or PC fired units.
- Lower SO_2 emission without expensive downstream equipment.
- Higher heat transfer rates—4 to 6 times greater than radiative or convective heat transfer boilers.
- Smaller furnace volume (extra furnace volume is not required to allow ash to cool below its softening temperature) and higher heat transfer rates.
- Less manpower required.
- Less auxiliary equipment required than for pc units (e.g., pulverizers and deslagging equipment).

An AFBC is characterized by:

- Low gas velocity operation (4 to 12 ft/sec).
- Fixed bed depth (4 to 5 ft) with submerged tube bundles.
- Either a pneumatic underbed feeder or an overbed spreader feeder.

The following undesirable results are found with the bubbling bed:

- Low combustion effeciency when burning hard-to-burn fuels.
- High fly ash recycle to improve combustion efficiency and sulfur capture.

The use of fly ash recycle in bubbling beds generally complicates the already complex feed system and requires (1) more auxiliary power, (2) limited submerged heat transfer tube spacing with poor load following capability, and (3) only 40 percent load turndown with a 7 percent/min load change rate without bed slumping. Using bed slumping for load reduction can require a large margin of fan power to ensure that the bed solids are refluidized easily. The slumped bed surface may also overheat and result in clinker formation, especially when burning coal with low ash softening temperatures.

The CFBC features high gas velocity (10 to 25 ft/s), highly turbulent flow characteristics with intensive solid mixing, an absence of a defined bed level, and small bed particles. The advantages of this design are:

- Combustion efficiency of 98 to 99.5 percent when burning medium- to high-volatile fuels, without the need for baghouse fly ash reinjection.
- Better than 90 percent sulfur capture at the Ca/S ratio of 1.5:3.0 for medium sulfur coal to petroleum coke and 1.4:1.6 for high sulfur bituminous coal.
- NOx emissions less than 150 ppm for a wide range of operating conditions.
- No submerged heat transfer tubes in the combustor. The heat transfer surface is located at the membrane wall and is situated parallel to the flow direction in the combustion chamber. This arrangement eliminates potential severe erosion problems caused by large solids circulation.
- The CFBC system requires only one feed point for 100 to 300 sq ft of grid area, depending upon the fuel type and its burning characteristics. (A BFBC requires one feed point for every 9 to 18 sq ft of bed area.)
- A fuel throughput per unit base area of 2 to 3 times is possible due to the higher combustion velocities.

The CFBC has slightly better performance characteristics for combustion efficiency and sorbent use for sulfur capture. However, the CFBC design does not scale down well. A small output CFBC will be nearly as tall as a much higher output unit. The design air/fuel residence time in the combustor is typically 3 to 5 seconds. With the nominal 20 ft/s velocity seen in the CFBC, the boiler ends up being 60 to 100 ft tall regardless of the unit size. Therefore the CFBC does not effectively scale down to the smaller unit sizes. Manufacturers feel that the smallest economically practical size unit is between 50,000 and 100,000 lb/h of steam. The bed area of a CFBC is less than one-half that of a BFBC. However, due to the CFBC's height requirement, the boiler volumes are nearly the same. The important fact is that the boiler heat transfer surface can be reduced for either BFBC or CFBC more than that of pulverized or stoker coal boilers due to the heat transfer rate of a fluidized bed combustor.

Since CFBC is not cost effective for very small units (below 100,000 lb/h), BFBC is the practical choice in this size range. Other applications where BFBC may be a better choice include waste incineration and converting PC units to fluidized bed combustion units. A summary comparison of BFBC and CFBC units is shown in Tables 14 and 15.

Table 14

BFBC/CFBC Comparison*

Parameter	BFBC	CFBC
Size	All sizes	100,000 - 1,500,000 lb/h
Combustion eff.	Base	2 - 3% better
Sorbent use	Up to 100% more	Base
Bed area	2-1/2 times	Base
Fuel feed	overbed/underbed	in-bed
Heat recovery	In-bed tubes	No in-bed tubes
Boiler controls	Conventional	Conventional
Material handling	Conventional	Conventional
Startup	4 hours	8 hours
O&M	Base	Lower
Cost		Similar
Plant power auxiliary		Similar if BFBC is overbed feed system, BFBC more if underbed feed system
Comb. volume		Similar
Heat transfer		Average similar

* Source: B.N. Gaglia and A. Hall, "Comparison of Bubbling and Circulating Fluidized Bed Industrial Steam Generation," *Proceedings of the 1987 International Conference on Fluidized-Bed Combustion* (1987). Reprint permission granted by The American Society of Mechanical Engineers (ASME).

Economic Factors

In 1986, Stearns Catalytic performed AFBC cost studies for the U.S. Department of Energy.[15] The following discussion is based on those studies and has been updated to 1987 dollars. The studies included reviewing 10,000, 50,000, 100,000, and 200,000 lb/h units operating at 350 psig saturated steam, with no electric power generation. The costs are accurate to plus or minus 20 percent. The major design parameters are listed below:

- Main steam conditions are 350 psig saturated; feedwater inlet temperature is 240 °F.
- Fuel, limestone, and ash are stored on site. Fuel is stored in closed silos. Limestone and ash are in a 5-day enclosed silo.

[15] B.N. Gaglia and R.L. Claussen, *Fluidized-Bed Combustion Development, Volume I, Industrial Steam Generation*, DOE/MC/22024-2339 (Department of Energy [DOE], 1986).

Table 15

BFBC/CFBC Comparison for 100,000 lb/h unit*

Parameter	BFBC	CFBC
Height, ft	40	100
Length, ft	35	55
Width, ft	20	30
Bed Area, sq ft	180	81
Combustion Vol, ft^3	6300	6000
Boiler Eff, %	87.1	88.5
Ca/S (70% Ret.)	3.2:1	1.5:1

*Source: B.N. Gaglia and A. Hall. Reprint permission granted by ASME.

- The boiler installation is completely independent of the other plant facilities, including the control room.
- The plant is designed to minimize emission discharge (i.e., fugitive dust and waste disposal). Existing facilities are used for sanitary waste disposal and surface run off.
- The boiler is semi-enclosed.
- Raw water is available.
- Costs for solid waste disposal are not included.
- Four coals are studied to provide a representative range of available industrial coals:
  - Ohio, 4 percent sulfur, 12,400 Btu, $.89/MBtu
  - Illinois, 3 percent sulfur, 11,645 Btu, $1.03/MBtu
  - Pennsylvania, 2 percent sulfur, 12,870 Btu, $1.05/MBtu
  - West Virginia, 1 percent sulfur, 12,850 Btu, $1.09/MBtu
- The limestone sorbent has an average reactivity.
- Both sorbent and fuel are assumed to be delivered by truck from mines 100 miles away.

All the major equipment included in the costs for the industrial steam plant is listed below:

1. Boiler

- Pressure Parts
  - Evaporative Surfaces
  - Economizer
  - External Heat Exchanger (Steam Side)
  - Steam Drum and Internal
  - Mud Drums
  - Headers
  - Downcomers
  - Riser Tubes
  - Safety Valves
  - Feedwater Piping From Control Valve

- Instrumentation and Control System
  - Trim (Gages, Glasses, and Valves)
  - Three Element Feedwater Control
  - Fuel and Air Flow Controls
  - Steam Temperature Control
  - Control Computer
  - Data Logger
  - Combustion Gas Sample Panel
  - Process Instruments and Transmitters
  - Miscellaneous Motors and Controls

- Fuel and Sorbent Feed System
  - Gravimetric Feeders
  - Rotary Valves
  - Chutes and Slide Gate Valves
  - Startup Burners
  - Startup Fuel Supply and Control System

- Air and Flue Gas System
  - F.D. Fan With Motor
  - I.D. Fan With Motor
  - Fluidizing Blowers
  - Air Ducting
  - Flue Ducting
  - Air Dampers, Primary and Secondary
  - Inlet Air Dampers
  - Flue Gas Dampers
  - Baghouse
  - Baghouse Bypass
  - Mechanical Dust Collector/Cyclone
  - Air Heater (Tubular)

- Ash Systems
  - L-Valve and Reinjection System
  - External Heat Exchanger and Ash Drain
  - Recycle Ash Liner
  - Ash Cooler
  - Ash Valves

- Miscellaneous
  - Structural Steel and Supports
  - Tie Bars and Buckstays
  - Refractory
  - Platforms, Stairs, and Walkways
  - Insulation and Lagging
  - Startup Spares
  - Spare Parts

2. Condensate and Feedwater System

   - Condensate Recovery Tank
   - Condensate Storage Tank
   - Condensate Pumps (2)
   - Condensate Control Valves
   - Dearator
   - Boiler Feed Pumps (2)
   - Level Control Valve

3. Boiler Vents and Drain System

   - Blow Down Flash Tank
   - Blow Down Tank
   - Blow Down Valves
   - Safety Valve Stacks

4. Chemical Feed and Water Treatment System

   - Water Softener
   - Sodium Sulfite Tank and Pump
   - Chloride Alkalizer
   - Phosphate Tank and Pump
   - Amine Tank and Pump

5. Material Handling System

   • Coal Handling
     - Coal Reclaim Hopper
     - Unloading Vibrating Feeder
     - Belt Conveyor System
     - Crusher
     - Dust Collector
     - Scrap Metal Magnet
     - Silo Mass Conveyors
     - Plant Silos (two, 8-h capacity each)

   • Limestone Handling System
     - Truck Unloading System
     - Storage Silo (5-day capacity)
     - Silo Dust Collector
     - Pressure Feeders (2)
     - Conveying Blowers
     - Pneumatic Transfer Line
     - Day Bin (16-h capacity)
     - Bin Dust Collector

   • Ash Handling System
     - Ash Silo (5-day storage)
     - Dry and Wet Unloaders
     - Vacuum Blowers (2)

- Silo Vent Filter
- Receiver Separator
- Ash Silo Fluidizing Blowers (2)
- Pneumatic Transfer System
- Baghouse Hopper Fluidizing Blowers (2)
- Baghouse Hopper Fluidizing Air Heaters (2)

6. Compressed Air System

   - Plant Air Compressor (2 with 100 percent capacity)
   - Plant Air Receiver
   - Instrument Air Prefilter
   - Instrument Air Oil Filter
   - Instrument Air Dryer
   - Instrument Air Afterfilter

7. Electrical System

   - Motor Control Center
   - Cable/Trays/Conduit

8. Miscellaneous

   - Control Room
   - Plant Drains
   - Smoke Stack
   - HVAC System

Table 16 reviews the capital cost estimates for 10,000, 50,000, 100,000, and 200,000 lb/h steam facilities. Within the level of accuracy of the budget pricing there were no cost differences between the CFBC and the BFBC. Therefore, the costs provided represent the costs of producing steam from either type of facility. Figure 23 shows the plant capital cost in millions of dollars based on the lb/h steam rate.

Table 17 and Figure 24 present the capital costs in dollars per pound per hour (PPH) of steam. Operating and maintenance costs are summarized in Table 18 and Figure 25. Table 19 derives the average auxiliary power requirements for each of the plant sizes. These costs are included in the operating and maintenance costs.

To verify the accuracy of the capital costs discussed above, additional references were compared with the average costs (regardless of coal type) to Stearns Catalytic (Table 20 and Figure 26). Also included is the cost for the 85,000 lb/h dual bed Wormser retrofit in Jacksonville, IL. Additional retrofit costs were estimated by using a scaling factor of 0.65. In addition, estimates were performed to determine the cost breakdown for boiler plant sizes of 10,000, 50,000, 100,000, and 200,000 (Tables 21 through 24). It appears that within the degree of accuracy, the cost estimates of Stearns Catalytic are comparable to the different sources.

Table 25 compares the capital costs of 150,000 lb/h boilers; traveling grate spreader stoker, PC, CFBC, and BFBC. Table 26 compares the annual operating and maintenance costs. The information in these comparisons was obtained from R.A. Malone, Black & Veatch.

Table 16

AFBC Capital Cost Estimates*

Steam Rate (lb/h)	Coal	Capital Cost (August 1987 dollars)
10,000	OH	2,811,100
	IL	2,809,100
	PA	2,809,400
	WV	2,809,100
50,000	OH	7,765,000
	IL	7,725,800
	PA	7,569,600
	WV	7,603,800
100,000	OH	12,288,800
	IL	12,216,100
	PA	12,127,100
	WV	11,916,900
200,000	OH	19,463,300
	IL	19,292,019
	PA	19,270,900
	WV	18,934,500

*Source: B.N. Gaglia and R.L. Claussen.

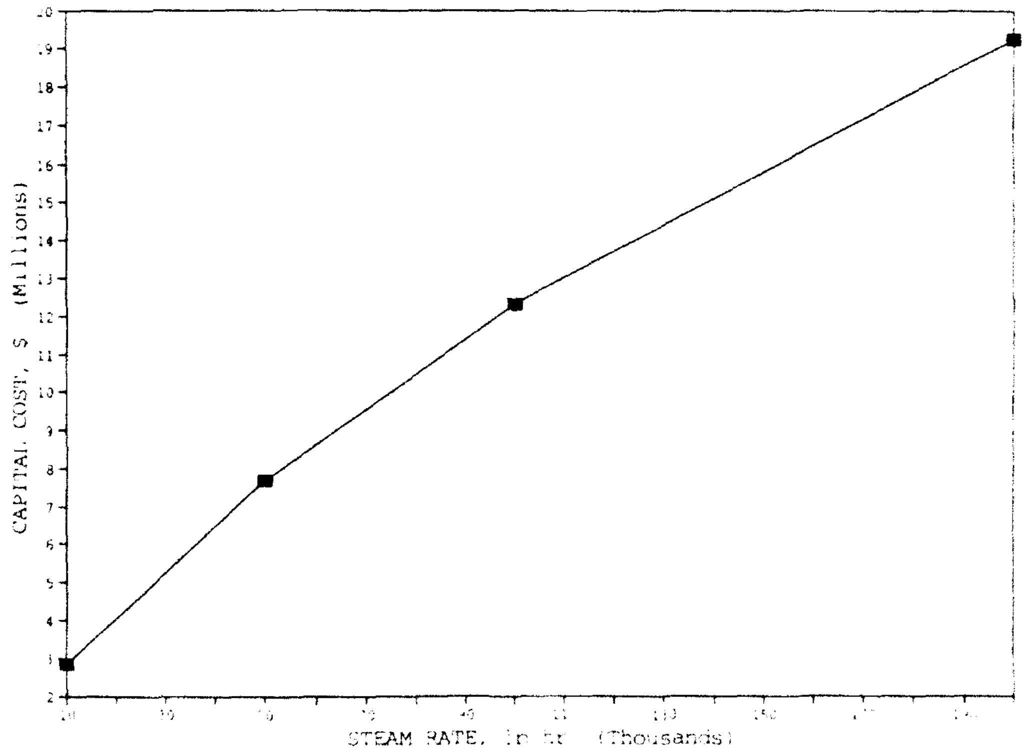

Figure 23. AFBC capital costs vs steam rate.

Table 17

AFBC Capital Costs*

Steam Rate (lb/h)	Coal	Cost ($/PPH) (August 1987 dollars)
10,000	OH	281
	IL	281
	PA	281
	WV	281
50,000	OH	155
	IL	154
	PA	153
	WV	152
100,000	OH	122
	IL	132
	PA	122
	WV	120
200,000	OH	97
	IL	96
	PA	95
	WV	95

*Source: B.N. Gaglia and R.L. Claussen.

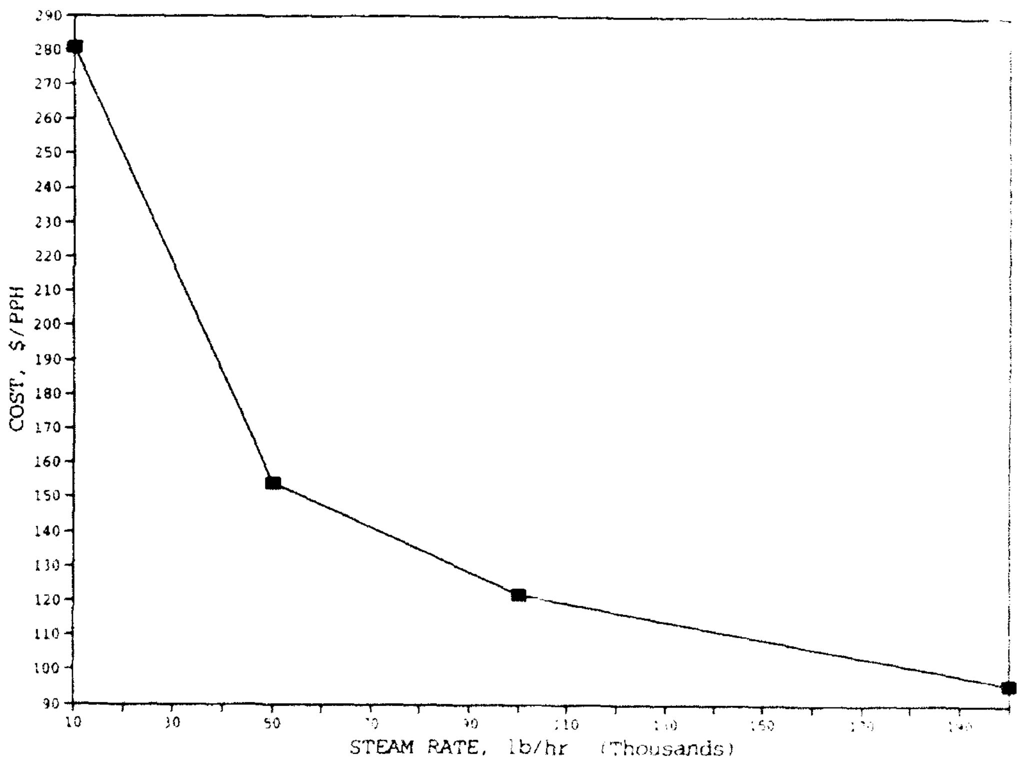

Figure 24. AFBC capital costs per PPH vs steam rate.

Table 18

AFBC Annual Operating and Maintenance Costs*

Steam Rate (lb/h)	Boiler	Coal	Annual Operating Cost (August 1987 dollars)
10,000	BFBC	OH	498,940
		IL	501,513
		PA	480,334
		WV	471,324
50,000	BFBC	OH	1,397,514
		IL	1,417,848
		PA	1,307,252
		WV	1,265,100
100,000	BFBC	OH	2,472,407
		IL	2,510,943
		PA	2,300,947
		WV	2,217,680
200,000	BFBC	OH	4,401,012
		IL	4,477,640
		PA	4,054,180
		WV	3,891,785
50,000	CFBC	OH	1,273,156
		IL	1,317,815
		PA	1,243,027
		WV	1,234,624
100,000	CFBC	OH	2,227,475
		IL	2,318,577
		PA	2,182,111
		WV	2,158,672
200,000	CFBC	OH	3,912,711
		IL	4,093,520
		PA	3,821,826
		WV	3,774,074

*Source: B.N. Gaglia and R.L. Claussen.

According to Stearns Catalytic, within the level of accuracy, BFBC and CFBC combustion steam generators are also competitive in the full size range. Because the CFBC does not scale down well, CFBC technology is not economically practical below 50,000 lb/h and may be questionable below 100,000 lb/h. The total plant capital costs (Stearns Catalytic) range from $2,700,000 for a 10,000 lb/h unit to $19,000,000 for a 200,000 lb/h unit. The total plant cost per pound of steam ranges from $275 for a 10,000 lb/h unit to $95 for a 200,000 lb/h unit. The annual operation and maintenance (O&M) compared to unit size varied from $20/lb of steam for the 200,000 lb/h unit up to $49/lb of steam for the 10,000 lb/h unit. Typically the O&M costs amount to approximately 60 percent of the levelized steam costs and 40 percent of the fixed costs. The O&M labor requirements for the smaller units are nearly as much as for the larger units. Therefore, O&M represents a much greater proportion of the total steam cost in the small

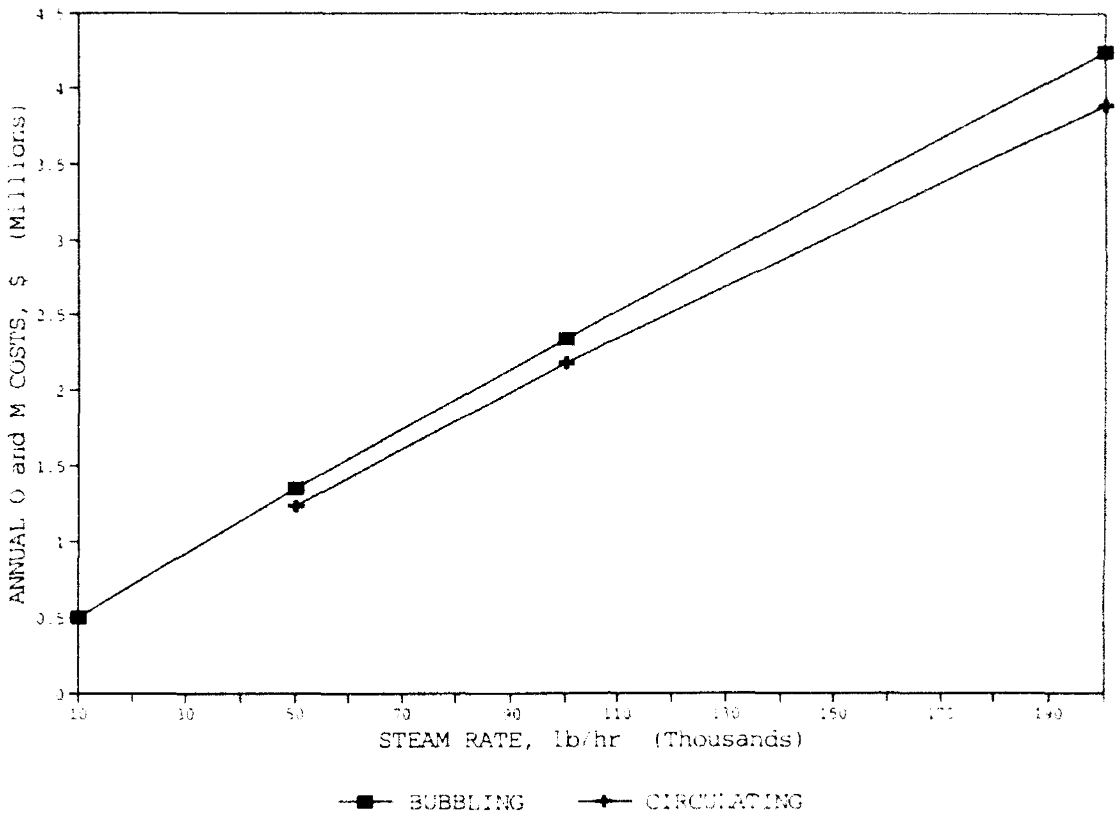

Figure 25. AFBC annual operating and maintenance costs.

Table 19

Average Auxiliary Power Requirements*

	10,000**	50,000	100,000	200,000
Boiler				
- Fan, Blowers	35	170	340	680
- Boiler Feed Pump	30	75	100	150
Misc. Building Loads	8	15	24	43
Material Handling***	19	44	58	110
Total, hp	92	304	522	983
Total, kW/h	69	225	389	733
Cost, $/h'	3.11	10.15	17.51	32.99
Annual Cost''	$24,480	$80,056	$138,009	$260,054
kW/1000 lb Steam	6.9	4.50	3.89	3.67
$/1000 lb Steam	.311	.203	.175	.165

* Source: B.N. Gaglia and R.L. Claussen.
** In pounds per hour.
***Intermittent loads leveled on 24-h basis.
' $0.045/kWh.
'' Based on 90 percent capacity factor 7884 h/y.

Table 20

Capital Costs From Other Sources

Source	Boiler Type	Steam Rate (lb/h)	Cost($M)
Illinois Dept. of Energy[1]	BFBC	120,000	11.552
R.A. Malone[2]	BFBC	150,000	12.448
	CFBC	150,000	12.747
Bruce St. John[3]	BFBC	100,000	10.558
	CFBC	250,000	19.915
DOE[4]	BFBC	15,000	2.647
DOE[5]	BFBC	150,000	12.452
Stearns Catalytic[6] (average costs for alternate coals see Table 19)	BFBC/CFBC	10,000	2.8
	BFBC/CFBC	50,000	7.6
	BFBC/CFBC	100,000	12.1
	BFBC/CFBC	200,000	19.3
In-house	BFBC/CFBC	10,000	2.85
	BFBC/CFBC	50,000	7.91
	BFBC/CFBC	100,000	13.73
	BFBC/CFBC	200,000	20.81
State of IL	Retrofit	85,000	5.0
	Retrofit	150,000*	7.3
	Retrofit	40,000*	3.1

units. The cost of labor could be more than 40 percent of the steam cost for the 10,000 lb/h unit and only about 10 percent for the 200,000 lb/h unit. Due to the fuel and limestone efficiency, the total annual O&M costs increase more rapidly for the BFBC unit than for the CFBC unit.

As indicated in Tables 25 and 26, the capital costs are slightly higher for the AFBC boilers than for the traveling grate spreader stoker boiler, but are lower than for the PC boiler. The operating and maintenance costs on the other hand are much lower for AFBC boilers.

[1] Bibb and Associates, Inc.

[2] R.A. Malone, Black and Veatch Engineers-Architects, *Economics of Fluid Bed, Pulverized Coal, and Spreader Stoker Steam Generators*, Paper presented to Council of Industrial Boiler Owners, Fluidized Bed Seminar (December 1985).

[3] B.St. John, "Economics of Atmospheric Fluidized-Bed Boilers, *Chemical Engineering (December 8, 1986)*.

[4] F.W. Shirley and R. D. Little, *Advanced Atmospheric Fluidized—Bed Combustion Design, Spouted Bed*, DOE/MC/21172 (DOE, November 1985).

[5] C.S. Mah, et al., *System Design Study to Reduce Capital and Operating Cost of a Moving Distributor, AFB Advanced Concept—Comparison With an Oil-Fired Boiler*, DOE/MC/21171-2069 (DOE, December 1985).

[6] B.N. Gaglia and R.L. Claussen.

* Scaled from 85,000 size.

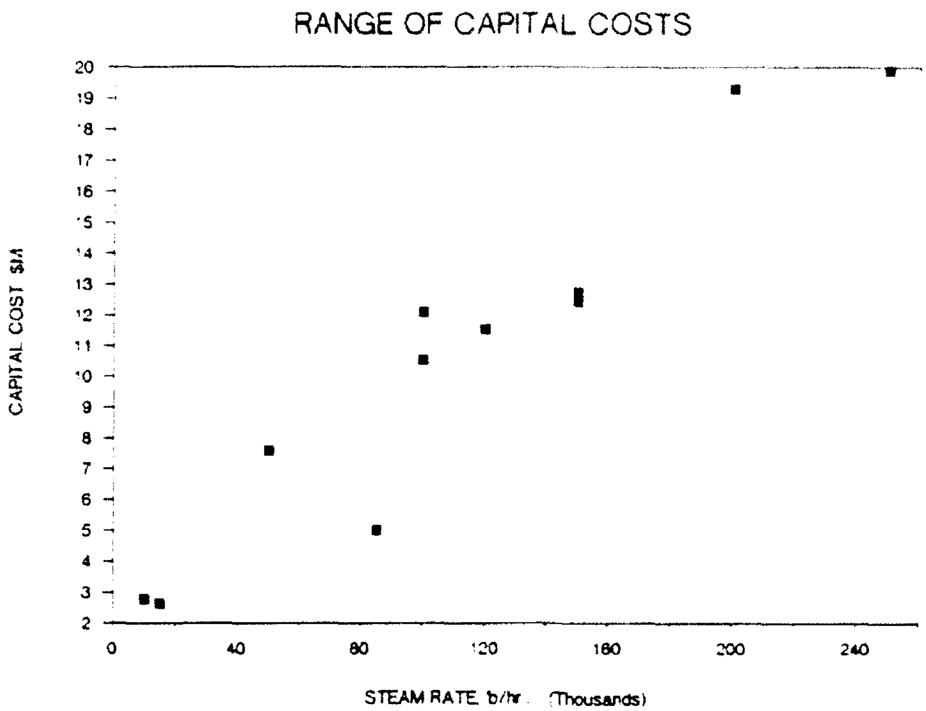

Figure 26. Range of AFBC capital costs.

Table 21

Cost Breakdown for 10,000 lb/h AFBC Plant

	Cost($)	Installed Cost ($)
Equipment		
Boiler & Baghouse	782,609	900,000 *
Feedwater Equipment	18,900	21,735 *
Material Handling	434,783	500,000 **
Stack	90,370	103,925 ***
Ash Removal System	98,500	113,275 ***
Total Cost (TC)		1,638.9 †
Piping (installed)		77,200 *
Instrumentation (installed)		42,100 *
Electrical (installed)		109,400 *
Engineering & Installation (60% of TC)††	983,361	
Total Installed Cost (TIC)		2,850,996

* J.H. Kleinau, "Applications for Circulating Fluid Bed Boilers," *1985 Pulping Conference Book 2*, (October 1985).

** G.L. Gould and M.W. McComas.

*** J. Stringer, "Materials Selection in Atmospheric Fluidized Bed Combustion Systems," *Fluidized Bed Boilers: Design and Application* (Pergamon Press, 1984).

† B.N. Gaglia and R.L. Claussen.

†† Costs include engineering, supervision, construction expenses, contractors fee, contingencies, and working capital.

Table 22

Cost Breakdown for 50,000 lb/h AFBC Plant

	Cost($)	Installed Cost($)
Equipment		
Boiler & Baghouse	2,880,400	3,312,500 *
Feedwater Equipment	27,400	31,510 *
Material Handling	582,609	670,000 **
Stack	202,000	232,300 ***
Ash Removal System	259,000	297,850 ***
Total Cost (TC)		4,544,160
Piping (installed)		216000 *
Instrumentation (installed)		117,700 *
Electrical (installed)		306,000 *
Engineering & Installation (60% of TC)†		2,726,496
Total Installed Cost (TIC)		7,910,356

* J.H. Kleinau.

** G.L. Gould and M.W. McComas.

*** J. Stringer.

† Costs include engineering, supervision, construction expenses, contractors fee, contingencies, and working capital.

Table 23

Cost Breakdown for 100,000 lb/h AFBC Plant

	Cost($)	Installed Cost($)
Equipment		
Boiler & Baghouse	5,485,478	6,308,300 *
Feedwater Equipment	32,400	37,260 *
Material Handling	704,300	809,945 **
Stack	286,000	328,900 ***
Ash Removal System	392,000	450,800 ***
Total Cost (TC)		7,935,205
Piping (installed)		348,600 *
Instrumentation (installed)		190,000 *
Electrical (installed)		493,900 *
Engineering & Installation (60% of TC)[†]		4,761,23
Total Installed Cost (TIC)		13,728,828

* J.H. Kleinau.
** G.L. Gould and M.W. McComas.
*** J. Stringer.
[†] Costs include engineering, supervision, construction expenses, contractors fee, contingencies, and working capital.

Table 24

Cost Breakdown for 200,000 lb/h AFBC Plant

	Cost($)	**Installed Cost($)**
Equipment		
Boiler & Baghouse	8,413,043	9,675,000 *
Feedwater Equipment	43,500	50,025 *
Material Handling	965,218	1,110,000 **
Stack	404,347	465,000 ***
Ash Removal System	594,000	683,100 ***
Total Cost (TC		11,983,125 ***
Piping (installed)		551,800 *
Instrumentation (installed)		300,700 *
Electrical (installed)		781,800 *
Engineering & Installation (60% of TC)†		7,189,875
Total Installed Cost (TIC)		20,807,300

* J.H. Kleinau.
** G.L. Gould and M.W. McComas.
*** J. Stringer.
† Costs include engineering, supervision, construction expenses, contractors fee, contingencies, and working capital.

Table 25

Capital Cost Comparison of 150,000 lb/h Boilers

Parameter	Stoker	PC	BFBC	CFBC
Boiler and Auxiliaries	3325 *	5650	6400	6250
Material Handling	1050	1050	1050	1050
Stack	500	500	350	350
FGD System	2000	2000	-	-
Ash Removal System	430	430	500	500
Baghouse	600	600	600	600
General Construction	1340	1500	1400	1650
Mechanical Construction	800	1000	800	1000
Electrical Construction	900	1050	975	975
I&C Construction	350	450	400	400
Total Capital Cost	11,295	14,230	12,475	12,775

* In thousands of dollars.

Table 26

Comparison of Operating Costs for 150,000 lb/h Boilers

Parameter	Stoker	PC	BFBC	CFBC
Fixed Charges on Capital*	1694 **	2135	1871	1916
Operating Cost				
Fuel Cost	2470	1886	2168	1976
Labor	875	525	525	525
Maintenance	113	142	125	128
Auxiliary Power	320	412	463	492
Sorbent Cost	71	65	190	123
Waste Disposal	76	69	31	31
Total Annual Cost	5619	5584	5373	5191

* Fixed Charge Rate is 15 percent.
** In thousands of dollars.

9 SUMMARY

AFBC technology is a practical option for both new and retrofit boilers at Army central heat plants. Boilers using this technology can be designed to burn various solid fuels and waste with reasonable efficiency. However, once the design is fixed, only a limited range of fuels can be burned without adversely affecting the boiler's performance. By using the high heat transfer rates available from in-bed tubes, the boilers can be designed smaller and still yield the same output. The lower operating temperatures and staged combustion of these boilers minimize slagging, fouling, and nitrogen oxidation. AFBC systems can burn high sulfur coals without having expensive scrubber systems, and still meet air quality standards.

One shortcoming of AFBC systems is that the flue gas contains a high concentration of coal fines and combustibles. Solutions to this problem must either improve the combustion rate of these particles or increase the residence time in the combustion zone. Another shortcoming is that a large amount of sorbent must be used to meet stringent SO_2 emission standards. This problem can be resolved by increasing the contact time between the sorbent and SO_2 and by enhancing the sorbent's sulfur retention properties. Reducing the amount of sorbent needed is important because the cost of buying and disposing of sorbent may be a significant portion of the overall operating costs. The major mechanical problems of AFBCs generally are due to the fuel and sorbent feed systems. A reliable feed system capable of distributing the material across the bed is vital to the further development of large scale AFBC systems. Erosion and corrosion have caused serious problems with AFBC systems. These problems can be minimized by changing the boiler design to reduce the impingement of particulate material on component surfaces and by using hard metals and coatings.

Within the level of accuracy of the cost estimates, the capital costs for new BFBC and CFBC boilers are similar, although the operating and maintenance costs are higher for the BFBC. One key factor in deciding between these two types of boilers is that the CFBC does not scale down well. The CFBC is not economically practical in a size less than 50,000 lb/h, and may not be practical in a size less than 100,000 lb/h.

Metric Conversion Table

1 ft	=	0.305m
1 in.	=	2.54cm
1 lb/h	=	0.126 g/s
1 psi	=	89.300 g/m^2
1 Btu/lb	=	0.556 cal/g
1 sqft	=	0.093m^2
°C	=	0.55 (°F - 32)

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APPENDIX: AFBC INSTALLATIONS IN THE UNITED STATES

Plant Owner	Plant Location	Boiler Type	Boiler Manufacturer	No. of Units	Boiler Capacity (each 1000 lb/hr)	Design Fuel	Operation Date
A.E. Staley	Decatur, IL	C	RS	2	375	C	1988
Abbott Laboratories	Casa Grande, AZ	B	SJC	1	25	C	1984
Air Products and Chemicals Inc.	Stockton, CA	C	PYR	1	500	Bit	1988
Alcohol Distillation Plant	Bardstown, KY	B	SJC	1	10	C	1981
American Can Company	Bellamy, AL	B	EPI/YS	1	55	WW	1980
Amoco	Texas City, TX	C	NA	1	180 MW	C	1986
Anderson Clayton	Jacksonville, IL	R,M	WOR	1	85	C	1987
Applied Energy Services Inc.	Thames, CT	C	CE-Lurgi	2	672	Bit	1989
Applied Energy Services	Shady Point, OK	C	CE-Lurgi	4	570	C	1990
Archbaod Power Corp.	Archbald, PA	C	RS	1	200	AntCul	1989
Archer Danials Midland Co.	Lincoln, NE	B	WOR/ASEA	1	150	Sub	1986
Archer Danials Midland Co.	Frankfort, IN	B	NA	1	80	Sub	1988
Archer Danials Midland Co.	Mankota, MN	R,M	WOR/ASEA	1	120	Sub	1986
Archer Danials Midland Co.	Kansas City, MO	R,M	WOR/ASEA	1	80	NA	1986
Archer Danials Midland Co.	Des Moines, IA	R,M	WOR/ASEA	1	150	Sub	1987
Archer Danials Midland	Decatur, IL	C	KDO	5	425	Bit	1986
Archer Danials Midland	Cedar Rapids, IA	C	KDO	3	477	Bit	1987
Ashland Petroleum Co.	Catlettsburg, KY	B	FWC	2	325	PrG	1983
Atlantic Veneer Corp.	Beaufort, NC	B	EPI/YS	1	35	WW	1977
Atlantic Veneer Corp.	Beaufort, NC	B	EPI/YS	1	24	WW	1981
B.F. Goodrich	Henry, IL	C	PYR	1	125	C	1985
BW	Somerset, PA	C	BW	1	30 MW	Tails	1987
Babcock and Wilcox Co.	Alliance, OH	B	BW	1	20	C	1978
Babcock-Ultrapower	Jonesboro, ME	C	BW	1	220	WW	1986
Biogen Power Inc.	Ivanah, CA	C	CPC	1	150	C	1987
Blue Triange Hardwoods	Everette, PA	B	EPI/YS	1	11	WW	1984
Boise Cascade Corp.	Cascade, IA	B	EPI	1	10	WW	1980
Boise Cascade Corp.	Moncure, NC	B	EPI	1	15	WW	1977

Plant Owner	Plant Location	Boiler Type	Boiler Manufacturer	No. of Units	Boiler Capacity (each 1000 lb/hr)	Design Fuel	Operation Date
Boise Cascade Corp.	Emmett, IA	B	EPI	1	26	WW	1977
CCEI	Palisade, CO	C	Lurgi	1	80 MW	Tails	1988
California Portland Cement Co.	Colton, CA	C	PYR	1	190	C	1985
Campbell Soup Co.	Maxton, NC	B	SJC	3	50	Pr,W,C	1982
Campbell Soup Co.	Napoleon, OH	B	SJC	3	50	Pr,W,C	1982
Campbell Soup Co.	Salisbury, MD	B	SJC	3	50	Pr,W,C	1982
Central Ohio Psychiatric Hospital	Columbus, OH	B	FCL	1	60	C	NA
Central Soya Co.	Chattonooga, TN	C	PYR	1	88	C	1985
Central Soya Co.	Marion, OH	B	SJC	1	40	C	1979
Certain Teed Corp.	Oxford, NC	B	DED	1	7	AsS	1984
Certain-Teed Corp.	Richmond, CA	B	DED	1	4	AsS	1984
City of Los Angeles	Los Angeles, CA	C	CPC	3	NA	S	1987
City of Tacoma	Tacoma, WA	R,B	EPI	2	536 (total)	RDF,C,W	1988
Colorado-Ute Electric	Nucla, CO	C	PYR	1	925	C	1987
Conoco Inc.	Uvalde, TX	B	SWC	1	50	C,L,CK	1981*
Correctional Faclity	Danville, IL	B	SJC	1	12	WW	1982
Daw Forest Products	Redmond, OR	B	EPI	1	25	WW	1980
De Armond Stud Mill	Coeur d'Alene, ID	B	EPI	1	40	WW	1978
Diamond	Everette, MA	C	PYR	1	80 MW	Tails	1989
Diamond International Corp.	Redmond, OR	B	SJC	1	25	WW	1980
ESRC	St. Louis, MO	C	NA	1	80 MW	C	1988
East Stroudsburg State College	E. Stroudsburg, PA	B	FEC/IBW	1	40	Ant Cul	1984
Eastmont Forest Products	Ashland, MT	B	EPI	1	20	WW	1974
Electric Power Research Institute	Alliance, OH	B	BW	1	20	C,W,O,S,L	1973
Electro	Philadelphia, MA	C	Ce-Lurgi	1	60 MW	Tails	1987
Energy Factors Inc.	Marysville, CA	C	BW	1	164	WW	1986
Energy Factors Inc.	Stockton, CA	C	CPC	2	203	Bit	1987
Environmental Power Corp.	Scrubgrass, PA	C	TFC	2	400	Gob	1988
ERCO Systems Inc.	Cambridge, MA	B	ERC/IBW	1	30	C	1980
Facility Heating	Raybrook, NY	B	SJC	1	250 BHP	W,O	1986

Plant Owner	Plant Location	Boiler Type	Boiler Manufacturer	No. of Units	Boiler Capacity (each 1000 lb/hr)	Design Fuel	Operation Date
Fleming Lumber Co.	Crestview, FL	B	SJC	1	20	WW	1981
Frankville Signal Energy	Frackville, PA	C	KDO	1	410	Tails	1988
CWF Power Systems Co.	Fresno & King County, CA	C	CPC	3	212	C	1989
GWF Power Systems Co.	Torrance, CA	B	CPC	1	31 MW	CK	1980
General Motors Corp.	Fort Wayne, IN	C	RS	2	150	C	1987
General Motors Corp.	Pontiac, MI	C	PYR	1	300	C	1986
Georgetown University	Washington, D.C.	B	FWC	1	100	Bit	1979
Georgia Pacific Corp.	Phillips, WI	B	EPI	1	20	WW	1977
Gilbert	Frackville, PA	C	CE-Lurgi	1	80 MW	T	1987
Gilberton Power Co.	West Mahoney, PA	C	PYR	2	355	Cul	1988
Griffin Industries Inc.	Newberry, IN	B	SJC	1	40	Gob	1983
Gulf Oil Exploration and Production Co.	Bakersfield, CA	B	PYR	1	50	C	1983*
H&B Lumber Co.	Marion, NC	B	EPI/YS	1	15	WW	1976
Havco Wood Products Inc.	Cape Girardeau, MO	B	EPI/YS	1	12	WW	1978
House of Raeford Inc.	Rose Hill, NC	B	YS	1	43	WW	1982
IBM Corp.	Charlotte, NC	B	SJC	1	20	C	1980
Idaho Forest Industries	Coeur d'Alene, ID	B	EPI	1	30	WW	1973
Idaho National Engineering Corp.	Idaho Falls, ID	B	FWC	2	68	Sub	1984
Interpow	Halfmoon, NY	B	NA	1	200 MW	C	1988
Ione Energy Inc.	Ione, CA	C	CE	1	149	L	1987
Iowa Beef Processors Inc.	Amarillo, TX	R,B	WOR	1	70	C	1982
Iowa State University	Ames, IA	C	PYR	2	170	Bit	NA
Iowa-Missouri Walnut Co.	St. Joseph, MO	B	EPI/YS	1	10	WW	1975
J.A. Jones Construction Company	Ft. Drum, NY	C	PYR	3	175	C,Ant,O	1989
J.A. Olson Co.	Winona, MS	B	YS	1	7	WW	1978
Keeler/Dorr-Oliver	Williamsport, PA	B	KDO	1	9	V	1985
Kellogg	Houston, TX	C	NA	1	.75 MW	C	1985
Kelly Enterprises	Pittsfield, MA	B	EPI/YS	1	10	WW	1975
Kentucky Agriculture Energy Corp.	Franklin, KY	B	FWC	2	60	Bit	1982
Kentucky Center for Energy Research	Lexington, KY	B	DED	1	3 MMBtu	C	NA

Plant Owner	Plant Location	Boiler Type	Boiler Manufacturer	No. of Units	Boiler Capacity (each 1000 lb/hr)	Design Fuel	Operation Date
Kerr-McGee Chemical	Trona, CA	C	PYR	1	108 MW	C	NA
Kirby Lumber Co.	Silsbee, TX	B	EPI	1	70	WW	1980
Kogap Manufacturing Co.	Medford, OR	B	EPI	1	24	HF	1979
LCP	Geddes, NY	C	BW	1	20 MW	C	1988
Lauhoff Grain Co.	Danville, IL	C	BW	1	226	Bit	NA
Lidsay Olive Growers	Lindsay, CA	B	EPI	1	10	WW	1982*
Lidsay Olive Growers	Lindsay, CA	B	FEC	1	20	WW	NA
Los Angeles County Sanitation District	Carson, CA	C	BW	3	48	S	1988
Manufacturing Plant	Fortville, IN	B	SJC	1	2.5	C	1980
McCallco Inc	Hugesville, PA	B	YS	1	8	WW	1978
Merritt Brothers Lumber Co.	Priest River, ID	B	EPI	1	20	WW	1976
Metric Constructors of Florida Crushed Stone	Brooksville, FL	B	BW	1	75 MW	L	1986
Midwest Solvents Co.	Pekin, IL	B	FWC	1	120	C	1984
Monongahela Power Co.	Rivesville, WV	B	FWC	1	300	Bit	1976*
Montana-Dakota Utilities Co.	Mandan, ND	R,B	BW	1	700	1	1987
Mt. Carmel Cogen Project	NA	C	FWC	2	192	Ant,Cul	1989
Multnomah Plywood Corp.	St. Helens, OR	B	EPI	1	20	WW	1979
NYS Dept. of Correction	Wilton, NY	B	DED	1	5 MW	W	1999
NYS Dept. of Mental Health	Binghamton, NY	B	DED	1	11	WW	1981
Nagel Lumber Co. Inc.	Land O'Lakes, WI	B	EPI	1	20.7	WW	1977
Nelson Industries Inc.	Fortville, IN	B	SJC	1	3	C	1981
Northeastern Power Co.	Kline Twp, PA	C	CE	1	435	Cul	1988
Northern States	Burnsville, MN	R,B	FWC	1	1039	Sub	1986
Northern States Power Co.	Redwing	NA	BW	2	140	RDF	NA
Northern States Power Co.	Wilmarth	NA	BW	2	140	RDF	NA
Northern States Power Co.	LaCrosse, WI	R,B	EPI	1	150	RDF,W	1987
Northern States Power Co.	LaCrosse, WI	R,B	EPI	1	150	WW	1981
Northwest Mississippi Junior College	Senatobia, MS	B	EPI/YS	1	[illegible]	WW	1980
Overton Co.	Kenly, NC	B	EPI/YS	1	[illegible]	WW	1977

Plant Owner	Plant Location	Boiler Type	Boiler Manufacturer	No. of Units	Boiler Capacity (each 1000 lb/hr)	Design Fuel	Operation Date
Owen-Spencer Scool	Spencer, IN	B	SJC	2	3	C	1981
PH Glatfelter Co.	Spring Grove, PA	C	PYR	1	400	Bit	NA
Power Recovery Systems Inc.	Cambridge, MA	B	PRS	1	20	C	1980
Providence College	Providence, RI	B	SJC	2	20	C	1984
Quaker State Oil	Newell, WV	B	KDO	2	120	Bit	1985
Resource Electric Corp.	Rochester, NH	B	CPC	1	70	Wst	1986
Rossi Corporation	Higganum, CT	B	EPI/YS	1	10	WW	1979
Schuylkill Energy Resources Inc.	St. Nicholas, PA	C	CE	1	825	Cul	1989
Scott Paper Co.	Chester, PA	C	CE	1	650	C	1986
Shamokin Industrial Corp.	Shamokin, PA	B	KDO	1	23.4	Cul	1981
Shawmut Engineering Co.	Erie, PA	B	CPC	2	24 MW	Wst	1987
Shell	Bakersfield, CA	C	PYR	1	50 MW	C	1988
Southeast Missouri State University	Cape Girardeau, MO	R,M	WOR	1	50	NA	1987
State of California	Sacramento, CA	R,B	EPI	1	45	W	1982
Steam Heat Authority	Wilkes-Barre, PA	B	KDO	1	60	Cul	1984
Caruthers Thermo-Flood Corp.	Winfield, KS	C	SWC	1	5	C,CK,L	1981
Sumter Plywood Corp.	Livingston, AL	B	EPI	1	27	W	1977
TRW	Cleveland, OH	C	NA	1	180 MW	C	1985
Tennessee Valley Authority	Paducah, KY	C	CE	1	1100	Bit	1988
Tennessee Valley Authority	Paducah, KY	B	BW	1	170	C	1982
Tacoma Public Utilities	Tacoma, WA	C	EPI	2	264	WW	NA
Technical Center	Warren, MI	B	SJC	1	0.3 MW	C	NA
Texas Tar Sands Ltd.	Maverick County, TX	B	PRS/C-E Natco	1	50	Sub	1982*
Texas-New Mexico Power Co.	Robertson County, TX	C	CE	1	1100	L	1990
The Standard Oil Co. (Ohio)	Lima, OH	B	KDO	1	70	Bit	1984*
Time Energy Systems Inc.	North Powder, OR	B	EPI	1	60	WW	1986
U.S. Dept. of HUD	Norfolk, VA	B	SFC/IBW	1	10 MMBtu	T,Wo	198.
U.S. Navy	Great Lakes, IL	B	CE	1	50	C	1981*

Plant Owner	Plant Location	Boiler Type	Boiler Manufacturer	No. of Units	Boiler Capacity (each 1000 lb/hr)	Design Fuel	Operation Date
Ultra Systems	Kern County, CA	C	CE-Lurgi	2	220	WW	1988
Ultra Systems Inc.	Fresno/Rocklin, CA	C	BW	1	164	WW	1986
Ultrapower Inc.	W. Enfield, ME	C	BW	1	220	W	1986
Ultrapower Incorporated	Chinese Station, CA	B	EPI	1	208.6	WW	1985
Undisclosed	Newport, RI	R,M	WOR	1	25 MW	C	1987
Undisclosed Paper Co.	Undisclosed, US	C	FWC	1	320	Bit	1988
University Demonstation	Roanoke, VA	B	SJC	1	0.3 MW	C	NA
University Heating	Towson, MD	B	SJC	1	30	C	1986
University of Iowa	Iowa City, IA	C	RS	1	170	C	NA
University of Missouri	Columbia, MO	C	RS	1	200	C	1987
Valley View Energy Corp.	Hereford/Grover, TX	C	CE	2	430	S	1989
Van Buren County Alcohol Inc.	Bonaparte, IA	B	DED	1	20	C	1981
Vermont State Hospital	Waterbury, VT	B	EPI/YS	1	10	WW	1977
Viking	Lincoln, MI	B	Bechtel	1	15 MW	W	1986
Viking	McBain, MI	B	Bechtel	1	15 MW	W	1986
WVU	Morgantown, WV	B	BWC	1	23 MW	C	1986
Wade Lumber Company	Wade, NC	B	EPI/YS	1	20	BK	1978
Walnut Products	St. Joseph, MO	B	EPI/YS	1	10	WW	1975
Webster Lumber Co.	Bangor, WI	B	EPI/YS	1	26	WW	1977
Wepco	Oak Creek, WI	B	FWC	1	150 MW	C	1999
Westwood Energy Properties	Joliet, PA	C	CE	1	271	Cul	1987
Weyerhaeuser Co.	Longview, WA	R,B	CPC	1	NA	S	1977
Weyerhaeuser Co.	Livingston, AL	B	EPI	1	27	WW	1977
Weyerhaeuser Co.	Raymond, WA	R,B	EPI	1	40	WW	1975
Wormser	Rochester, NH	R,M	WOR	1	15 MW	C	1999
York Casket Co.	York, PA	B	YS	1	7	WW	1983

* - Not currently operating.

SYMBOLS

FUELS		
Ant	-	Anthracite
AsS	-	Asphalt, Shingle Waste
Bit	-	Bituminous
Bk	-	Bark
C	-	Coal
CK	-	Petroleum Coke
Cul	-	Culm
Gob	-	Bituminous Mining Wastes
HF	-	Hog Fuel
L	-	Lignite
NG	-	Natural Gas
O	-	Oil
PrG	-	Process Gases
PrW	-	Process Wastes
RDF	-	Refuse D·ied Fuel
S	-	Sludge
Sub	-	Subbituminous Coal
T	-	Tires
V	-	Variety
W	-	Wood
WW	-	Waste Wood
Wo	-	Waste Oils
Wst	-	Wastes

Boiler Types		
C	-	Circulating
B	-	Bubbling
R	-	Retrofit
M	-	Multiple

SYMBOLS
(COMPANY NAMES)

ASEA	-	ASEA-Stal Laval
BW	-	Babcock and Wilcox Co.
CE	-	Combustion Engineering Power Systems
CPC	-	Combustion Power Co.
DED	-	Dedert Corp., Thermal Processes Div.
DFC	-	Deborah Fluidized Combustion Ltd. (UK)
EPI	-	Energy Products of Idaho
FCL	-	Fluidized Combustion Contractors Ltd.
FEC	-	Fluidyne Engineering Corp.
FWC	-	Foster Wheeler Energy Corp.
IBW	-	International Boiler Works
KDO	-	Keeler/Dorr-Oliver Boiler Co.
PRS	-	Power Recovery Systems Inc.
PYR	-	Pyropower Corp.
RS	-	Riley Stoker Corp.
SJC	-	Stone Johnston Corp.
SWC	-	Struthers Wells Corp.
TFC	-	Thermo-Flood Corp. (formerly Struthers Thermo-Flood Corp.)
WOR	-	Wormser Engineering Inc.
YS	-	York-Shipley Inc.

GLOSSARY OF TERMS

Agglomerating: A caking characteristic of coal that, in the volatile matter determination, causes it to give a coke residue in the form of an agglomerate button.

Ambient Air: The air that surrounds the equipment.

Analysis: Quantitative determination of the constituent parts of a fuel.

Analysis, Proximate: Analysis of a solid fuel determining moisture, volatile matter, fixed carbon, and ash expressed as percentages of the total weight of the sample.

Analysis, Ultimate: Chemical analysis of solid, liquid, or gaseous fuels. In the case of coal, determination of carbon, hydrogen, sulfur, nitrogen, oxygen, and ash.

Anthracite: ASTM coal classification by rank: dry fixed carbon 92 percent or more and less than 98 percent; and dry volatile matter 8 percent or less and more than 2 percent on a mineral matter free basis. Known as "hard coal."

As-Fired Fuel: Fuel in the condition as received at the plant.

Ash: The incombustible solid matter in fuel.

Ash Bed: A layer of refuse left on the grate or deposited on a furnace floor after the fuel is burned.

Ash-Free Basis: The method of reporting fuel analysis whereby ash is deducte other constituents are recalculated to total 100 percent.

Barley: Anthracite coal size - through 3/16-in. round mesh screen, over 3/32-in. round mesh screen; otherwise known as No. 3 Buckwheat.

Bed Moisture: The moisture in coal when in the seam.

Bituminous Coal: ASTM Coal classification by rank on a mineral matter free basis and with bed moisture only:

> Low Volatile: Dry fixed carbon 78 percent or more and less than 86 percent; and dry volatile matter 22 percent or less and more than 14 percent.
> Medium Volatile: Dry fixed carbon 69 percent or more and less than 78 percent; and dry volatile matter 31 percent or less and more than 22 percent.
> High Volatile (A): Dry fixed carbon less than 69 percent; and dry volatile matter more than 31 percent; moist Btu 14,000 or more.
> High Volatile (B): Moist Btu 13,000 or more and less than 14,000.
> High Volatile (C): Moist Btu 11,000 or more and less than 13,000 (either agglomerating or nonweathering).

Boiler: A closed pressure vessel in which a liquid, usually water, is vaporized by the application of heat.

> Water Tube: A boiler in which the tubes contain water and steam, the heat being applied to the outside surface.
> Fire Tube: A boiler with straight tubes, which are surrounded by water and steam and through which the products of combustion pass.

British Thermal Unit (Btu): The mean British Thermal Unit is 1/180 of the heat required to raise the temperature of 1 pound of water from 32 °F to 212 °F at a constant atmospheric pressure. It is about equal to the quantity of heat required to raise 1 pound of water 1 °F. A Btu is essentially 252 calories.

Brown Coal: Lignite coal lowest in classification according to rank. Moist (bed moisture only) Btu less than 8300, unconsolidated in structure.

Buckwheat: Anthracite coal size:
- No. 1 (Buckwheat) - through 9/16-in., over 5/16-in. round mesh screen.
- No. 2 (Rice) - through 5/16-in., over 3/16-in. round mesh screen.
- No. 3 (Barley) - through 3/16-in., over 3/31-in. round mesh screen.
- No. 4 through 3/32-in.< over 3/64-in. round mesh screen.
- No. 5 through 3/64-in. round mesh screen.

Caking: Property of certain coals to become plastic when heated and form large masses of coal.

Calorie: The mean calorie is 1/100 of the heat required to raise the temperature of 1 gram of water from 0 °C to 100 °C at a constant atmospheric pressure. It is about equal to the quantity of heat required to raise one gram of water 1 °C. A more recent definition is: A calorie is 4.186 joules, a joule being the amount of heat produced by a watt in one second.

Calorific Value: The number of heat units liberated per unit of quantity of a fuel burned in a calorimeter under prescribed conditions.

Calorimeter: Apparatus for determining the calorific value of a fuel.

Carbon: Element. The principal combustible constituent of all fuels.

Carbon Loss: The loss representing the unliberated thermal energy occasioned by failure to oxidize some of the carbon in the fuel.

Chain: A series of links, flexibly connected in a continuous succession.

Chain Grate Stoker: A stoker which has a moving endless chain as a grate surface, onto which coal is fed directly from a hopper.

Cinder: Particles of partially burned fuel from which volatile gases have been driven off, which are carried from the furnace by the products of combustion.

Class: Rank of coal.

Classification: Method of separating coals with reference to their properties - See Rank.

Clinker: A hard compact congealed mass of fused furnace refuse, usually slag.

Clinkering: The formation of clinkers.

Coal: Solid hydrocarbon fuel formed by ancient decomposition of woody substances under conditions of heat and pressure.

Coking: The conversion by heating in the absence or near absence of air, of a carbonaceous fuel, particularly certain bituminous coals, to a coherent, firm cellular carbon product known as coke.

Combustible: The heat producing constituents of a fuel.

Combustible In Refuse: Combustible matter in the solid refuse resulting from the incomplete combustion of fuel.

Combustion: The rapid chemical combination of oxygen with the combustible elements of a fuel resulting in the production of heat.

Combustion Chamber: See Furnace.

Combustion Rate: The quantity of fuel fired per unit of time, as pounds of coal per hour.

Complete Combustion: The complete oxidation of all the combustible constituents of a fuel.

Culm: The fine refuse from anthracite production.

Design Load: The load for which a steam generating unit is designed, usually considered the maximum load to be carried.

Design Pressure: The maximum allowable working pressure permitted under the rules of the ASME Construction Code.

Distillation Zone: The region, in a solid fuel bed, in which volatile constituents of the fuel are vaporized.

Dry, Ash Free Basis: The method of reporting fuel analysis with ash and moisture eliminated and remaining constituents recalculated to total 100 percent.

Dry Mineral Matter Free Basis: The method of reporting fuel analysis with mositure and ash, plus other mineral matter eliminated and remaining constituents recalculated to total 100 percent.

Dump Grate Stoker: One equipped with movable ash trays, or grates, by means of which the ash can be discharged at any desirable interval.

Dust: Particles of gas-borne solid matter larger than 1 micron in diameter.

Economizer: A heat recovery device designed to transfer heat from the products of combustion to a fluid, usually feedwater.

Efficiency: The ratio of output to input. The efficiency of a steam generating unit is the ratio of the heat absorbed by water and steam to the heat in the fuel fired.

Electrostatic Precipitator: A device for collecting dust, mist, or fume from a gas stream, by placing an electrical charge on the particle and removing that particle onto a collection electrode.

Excess Air: Air supplied for combustion in excess of that theoretically required for complete oxidation.

Ferric Percentage: Actual ferric iron in slag, expressed as percentage of the total iron calculated as ferric iron.

Filter (Cloth): A porous fabric that separates dust from a gas stream allowing the gas to pass through.

Fineness: The percentage by weight of a standard sample of a pulverized material that passes through a standard screen of specified mesh when subjected to a prescribed sampling and screening procedure.

Fines: Sizes below a specified range.

Fire Box: The equivalent of a furnace.

Fixed Ash: That portion of the ash derived from the original vegetation including all intimately contained minerals.

Fixed Carbon: The carbonaceous residue less the ash remaining in the test container after the volatile matter has been driven off in making the proximate analysis of a solid fuel.

Flue Dust: The particles of gas-borne solid matter carried in the products of combustion.

Flue Gas: The gaseous products of combustion in the flue to the stack.

Fly Ash: The fine particles of ash carried by the products of combustion.

Fouling: The accumulation of refuse in gas passages or on heat absorbing surfaces which results in undesirable restrictions to the flow of gas or heat.

Free Ash: Ash which is not included in the fixed ash.

Free Moisture: Same as surface moisture. It is that portion of the moisture in the coal which comes from external sources as water seepage, rain, snow, condensation, etc.

Friability: The tendency of coal to crumble or break into small pieces.

Fuel-Air Mixture: Mixture of fuel and air.

Fuel-Air Ratio: The ratio of the weight, or volume, of the fuel to the air.

Fuel Bed: Layer of burning fuel on a furnace grate.

Fuel Bed Resistance: The static pressure differential across a fuel bed.

Furnace: An enclosed space provided for the combustion of fuel.

Furnace Volume: The cubical content of the furnace or combustion chamber.

Fusibility: Property of slag to fuse and coalesce into a homogeneous mass.

Fusion: The melting of ash.

Grate: The surface on which fuel is supported and burned, and through which air is passed for combustion.

Grate Bars: Those parts of the fuel supporting surface arranged to admit air for combustion.

Grindability: Grindability is the characteristic of coal representing its ease of pulverizing and is one of the factors used in determining the capacity of a pulverizer. The index is relative: a larger value, such as 100, represents coals easy to pulverize; a smaller value, such as 40, represent coals difficult to pulverize.

Heat Release: The total quantity of thermal energy above a fixed datum introduced into a furnace by the fuel, considered to be the product of the hourly fuel rate and its high heat value, expressed in Btu per hour per cubic foot of furnace volume.

High Heat Value: See Calorific Value.

Hydrocarbon: A chemical compound of hydrogen and carbon.

Inches Water Gage (w.g.): Usual term for expressing a measurement of relatively low pressures or differentials by means of a U-tube. One inch w.g. equals 5.2 pounds per square foot or 0.036 pounds per square inch.

Inherent Moisture: Sometimes called the bed moisture, it is moisture so closely held by the coal substance that it does not produce wetness.

Initial Deformation: The temperature at which a standard ash cone exhibits the first signs of rounding or bending of the apex when heated in accordance with a prescribed procedure.

Lignite: A consolidated coal of low classification according to rank; moist (bed moisture only) Btu less than 8300.

Load: The rate of output.

Load Factor: The ratio of the average load in a given period to the maximum load carried during that period.

Low Heat Value: The high heat value minus the latent heat of vaporization of the water formed by burning the hydrogen in the fuel.

Mechanical Stoker: A device consisting of a mechanically operated fuel feeding mechanism and a grate, and is used for the purpose of feeding solid fuel into a furnace, distributing it over the grate, admitting air to the fuel for the purpose of combustion, and providing a means for removal of refuse.

Overfeed Stoker: A stoker in which fuel is fed onto grates above the point of air admission to the fuel bed.

Underfeed Stoker: A stoker in which fuel is introduced through retorts at a level below the location of air distribution to the fuel bed.

Micron: One millionth of a meter. The diameter of flyash particles is usually expressed in microns.

Mineral Matter Free Basis: The method of reporting coal analysis whereby the ash plus other constituents in the original coal are eliminated and the other constituents recalculated to total 100 percent.

Moisture and Ash Free Basis: Method of reporting coal analysis - See "Dry Ash Free Basis"

Multiple Retort Stoker: An underfeed stoker consisting of two or more retorts, parallel and adjacent to each other, but separated by a line of tuyeres, and arranged so that the refuse is discharged at the ends of the retorts.

Nut: Anthracite coal designation through 1-5/8-in., over 15/16-in. round mesh screen. Bituminous coal size designation by some chosen screen mesh size, as 2-in. X 3/4-in..

Nut and Slack: A combination of Nut and Slack coal, such as 2-in. X 3/4-in. Nut plus 3/4-in. X 0 Slack (see Slack).

Overfire Air: Air for combustion admitted into the furnace at a point above the fuel bed.

Oxidation: Chemical combination with oxygen.

Oxidizing Atmosphere: An atmosphere which tends to promote the oxidation of immersed materials.

Particle Size: A measure of flyash, expressed in microns or percent passing through a standard mesh screen.

Pea: Anthracite or bituminous coal size. In anthracite through 13/16-in., over 9/16-in. round mesh screen, in bituminous 3/4-in. X 3/8-in..

Peak Load: The maximum load carried for a stated short period of time.

ppm: Abbreviation for parts per million.

Pressure Drop: The difference in pressure between two points in a system, at least of which one is above atmospheric pressure, and caused by resistance to flow.

Proximate Analysis: See Analysis, Proximate.

Pulverized Fuel: Solid fuel reduced to a fine size.

Pulverizer: A machine that reduces a solid fuel to a fineness suitable for burning in suspension.
- High Speed: Over 800 rpm, including impact and attrition pulverizers.
- Medium Speed: Between 70 and 300 rpm, including roller and ball pulverizers.
- Low Speed: Under 70 rpm, including ball or tube pulverizers.

Rank: Method of coal classification based on the degree of progressive alteration in the natural series from brown coal to meta-anthracite. The limits under classification according to rank are on mineral matter free basis.

Rated Capacity: The manufacturers, stated capacity rating for mechanical equipment, for instance, the maximum continuous capacity in pounds of steam per hour for which a boiler is designed.

Reducing Atmosphere: An atmosphere that tends to promote the removal of oxygen from a chemical compound.

Reinjection: The procedure of returning collected flyash to the furnace of a boiler for the purpose of burning out its carbon content.

Retort: A trough or channel in an underfeed stoker, extending within the furnace, through which fuel is forced upward into the fuel bed.

Rice: Anthracite coal size, otherwise known as No. 2 Buckwheat - through 5/16-in. over 3/16-in. round mesh screen.

Run of Mine: Unscreened bituminous coal as it comes from the mine.

Scrubber: Apparatus for removal of solids from gases by entrainment in water.

Secondary Air: Air for combustion supplied to the furnace to supplement primary air.

Semi-Anthracite: A coal classification according to rank. Dry fixed carbon 86 percent or more and less than 92 percent and dry volatile matter 14 percent or less and more than 8 percent, on a mineral matter free basis.

Semi-Bituminous: A former coal classification according to rank - including Low Volatile Bituminous.

Single Retort Stoker: An underfeed stoker using one retort only in the assembly of the complete stoker. A single furnace may contain one or more single retort stokers.

Slack: A rock formation sometimes overlaying or mixed with a coal seam. In connection with anthracite coal, any material which has less than 40 percent fixed carbon.

Slacking: Breaking down of friable coals due to changes in moisture content.

Slag: Molten or fused refuse.

Soot: Unburned particles of carbon derived from hydrocarbons.

Spontaneous Combustion: Ignition of combustible material following slow oxidation without the application of high temperature from an external source.

Stoker: See Mechanical Stoker.

Subbituminous Coal: Coal Classification according to rank:

A. Moist Btu 11,000 or more and less than 13,000.
B. Moist Btu 9,500 or more and less txan 11,000.
C. Moist Btu 8,500 or more and less than 9,500.

Surface Moisture: That portion of the moisture in the coal which comes from external sources as water seepage, rain, snow, condensation, etc.

Tangential Firing: A method of firing by which a number of burners are so located in the furnace walls that the center lines of the burners are tangential to an imaginary circle. Corner firing is usually included in this type.

Tempering Moisture: Water added to certain coals which, as received, have insufficient moisture content for proper combustion on stokers.

Total Moisture: The sum of inherent and surface moisture in coal.

Traveling Grate Stoker: A stoker similar to a chain grate stoker with the exception that the grate is separate from, but is supported on and driven by chains. Only enough chain strands are used as may be required to support and drive the grate.

Ultimate Analysis: See Analysis, Ultimate.

Volatile Matter: Those products given off by a material as gas or vapor, determined by definite prescribed methods.

Washed Size: Sizes of coal which have been washed.

Weathering: Same as Slacking.

Zone Control: The control of air flow into individual zones of a stoker.

Zone: Divisions of the stoker windbox in which air can be maintained at different and controllable pressures.

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