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A Comparison of Fluid-Bed Technologies for Renewable Energy Applications

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Abstract

Renewable Portfolio Standards (RPS) programs have been in place for approximately ten years. Many of the early programs were passed as part of state laws establishing electricity deregulation. While there are a number of renewable resources, an increasingly important one is biomass. Unlike some other renewables, biomass-based power is dispatchable and has a high capacity factor, making it an attractive choice for renewable energy project developers.

Babcock & Wilcox Power Generation Group, Inc. (B&W PGG) has many years of experience with fluid-bed technologies and offers circulating fluidized-bed (CFB), bubbling fluidized-bed (BFB) along with stoker/grate fired boilers for biomass fuels. The technology choice is typically driven by the fuel selected and emissions profile required. The emerging renewable energy market activity over the last several years indicates that many developers and regulators have shown a preference toward fluidized-bed technology for new projects. A previous B&W PGG technical paper (BR-1802) compared stoker/grate to bubbling fluidized-bed technology. That paper evaluated a bubbling bed as the preferred technology over a stoker for typical moisture virgin woody biomass fuels on the basis of lower O&M costs, lower capital cost and lower emissions.

The following paper will evaluate a case study comparing BFB and CFB technologies for large-scale biomass projects. The conditions set for this evaluation would be a 50MW greenfield project firing a typical woody biomass.

Fluid-bed technology

In the 1970s, fluidized-bed combustion technology was first applied to large-scale utility boiler units to explore new ways of burning solid fuels in an environmentally acceptable and efficient manner. Fluidized-bed units burn fuel in an air-suspended mass (or bed) of particles. Fluidized-bed combustion benefits include fuel flexibility and the ability to combust fuels such as biomass or waste fuels. Biomass and waste fuels are difficult to burn in conventional systems because of their low heating value, low fixed carbon, high moisture content, or other challenging combustion characteristics.

The fluidizing process is the forced flow of gaseous constituents through a stacked height of solid particles. At high enough gas velocities, the gas/solids mass exhibits fluid-like properties, thus the term fluidized-bed. The following example helps illustrate the process. Fig. 1a shows a simple furnace with an air supply plenum at the bottom, which is an air distributor that promotes even air flow through the bed of sand or other granular material.

If a small quantity of air flows through the air distributor, it will pass through the voids of an immobile mass of sand. For low velocities, the air does not exert much force on the particles and they remain in place. This condition is called a fixed bed and is shown in Fig. 1b.

By increasing the air pressure and resulting flow rate, the air exerts greater force on the sand and reduces the gravitational contact forces between the particles. By increasing the air flow further, the drag forces on the particles will eventually counterbalance the gravitational forces and the particles become suspended in the upward stream. The point where the bed starts to behave as a fluid is called the minimum fluidization condition. The increase in bed volume is insignificant when compared with the non-fluidized case (Fig. 1c).

As the air flow increases further, the bed becomes less uniform, bubbles of air start to form, and the bed becomes turbulent. This is called a bubbling fluidized-bed (BFB), shown in Fig. 1d. The volume occupied by the air/solids mixture increases substantially. There is an obvious bed level and a distinct transition between the bed and the space above.

A further increase in air flow causes the particles to become entrained and elutriate the bed into the furnace. If the solids are caught, separated from the air, and returned to the bed, they will circulate around a loop, defined as a circulating fluidized-bed (Fig. 1e). Unlike the bubbling bed, the CFB has no distinct transition between the dense bed in the bottom of the furnace and the dilute zone above. The solids concentration gradually decreases between these two zones.

Bed combustion temperature control is fundamental to fluid-bed boilers. Bed temperature is controlled to limit emissions, and to limit bed material agglomeration. Agglomeration can be caused by ash containing high amounts of alkali (such as sodium and potassium), other metals and phosphates, combining with alumina and silica to form low melting point eutectics that coat the bed particles. If the alkali concentration is too high, the coating can melt and cause solid particles to join together. As a result, these larger agglomerated particles become too heavy and hinder fluidization. If left unchecked, the bed can solidify and stop the combustion process. For this reason certain high alkali fuels are unacceptable for fluidized-bed combustion technologies. Such fuels are typically agro-based where the plants are fertilized or the ground is rich in alkali.

Today, BFB boilers, with a bed of fluidized particles that remain in the lower furnace, are used primarily in specialty fuel applications such as biomass fuels. CFB boilers, with solids circulating through the entire furnace volume, address larger steam generator applications and a broad range of fuels.

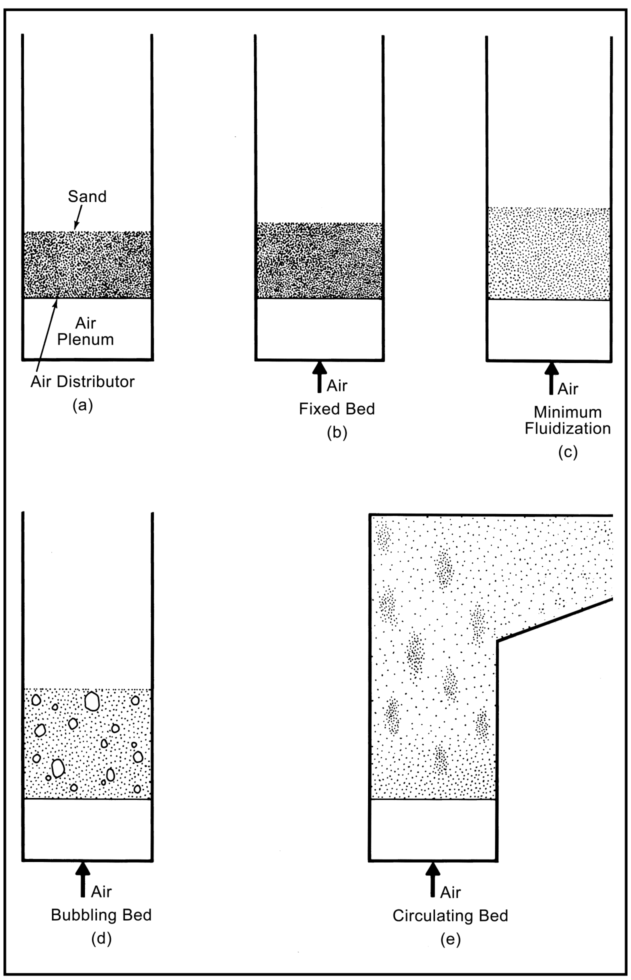

Fig. 1 Fluid-bed conditions.

Bubbling fluidized-bed boilers

A typical BFB furnace (Fig. 2) consists of a horizontal air distributor with an array of bubble caps. This provides the fluidizing air to the lower furnace bed material. The bubble caps are closely spaced so that air flow is distributed uniformly over the furnace plan area. The lower furnace is filled with sand or other noncombustible material such as crushed limestone or bed material from prior operation. Air flow is forced upward through the material, and the bed expands. The air flow through the bed is very uniform due to a high number bubble caps and bed pressure drop.

The B&W PGG BFB boiler is an open bottom design. The open bottom system is characterized by the fluidizing air bubble caps and pipes mounted on widely spaced distribution ducts. Stationary bed material fills the hoppers and furnace bottom up to the level of the bubble caps, above which the bed material is fluidized by the air flow. The open spacing is effective in removing larger rocks and debris from the active bed area as bed material moves down through hoppers. This design is particularly attractive in biomass and waste fuel applications containing noncombustible debris.

The typical operating temperature range of a bubbling bed is 1350 to 1650F. Actual operating bed temperature is dictated by fuel moisture, ash analysis and alkali content. Bed temperature is controlled by combustion stoichiometry. Even at these low combustion temperatures, high convective and radiative heat transfer from the bed material to the fuel particles provides sufficient ignition energy to evaporate moisture, heat the ash, and combust the remaining fuel without significantly changing the bulk bed temperature.

Circulating fluidized-bed boilers

Like a BFB, the CFB furnace has a flat floor horizontal air distributor with bubble caps (Fig. 3). It provides fluidizing air to the lower furnace bed material. The bubble caps are closely spaced for uniform air distribution over the furnace plan area. 50 to 70% percent of the total combustion air enters the furnace through the bubble caps with the balance injected through overfire air (OFA) ports.

The upward flow of solids decreases with increased furnace height. The heavier particles recirculate within the furnace resulting in decreased local density as a function of furnace height. In the B&W PGG internal recirculation

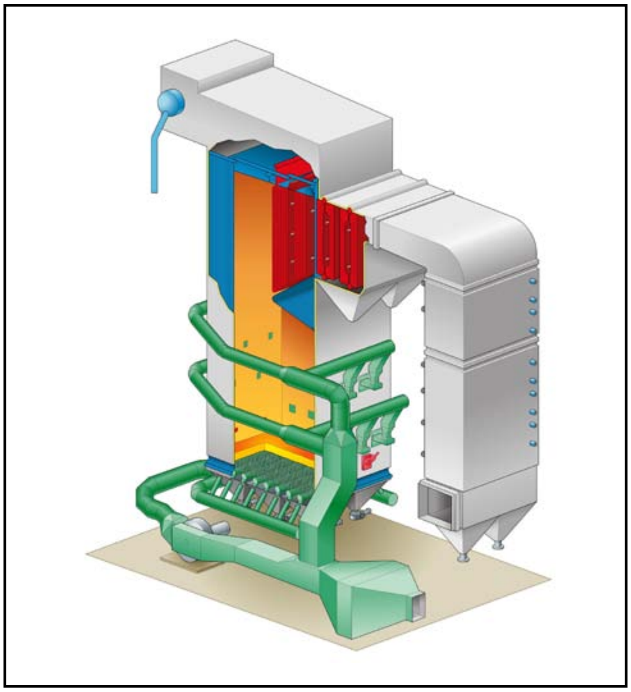

Fig. 2 Bubbling fluidized-bed boiler.

(IR-CFB) design, U-beam collectors located at the furnace exit collect and recirculate gas-laden solids prior to entering the convection pass. A significant portion of the remaining entrained solids are collected by multi-cyclone dust collectors (MDC) in the backpass. Nearly 100% particle capture is possible with this arrangement.

Bed particle size distribution and makeup rate are required for proper fluidization. If the bed material is too coarse, the bed will be too deep, de-fluidize, and slump. If the particles are too fine, they become entrained, leave the furnace, and create overall solids inventory problems. A stable lower furnace bed and an adequate solids inventory in the upper furnace dictate the furnace exit gas temperature.

The furnace enclosure and in-furnace heating surfaces (water-cooled panels or steam-cooled wing walls) define the furnace temperature profile. Furnace heating surface and a high solids recirculation rate result in uniform furnace gas temperatures throughout the furnace. CFB bed temperatures range from 1500 to 1600F. The lower furnace above the air distributor is covered by a thin layer of highly conductive refractory for tube corrosion and erosion protection. All other furnace enclosures are bare tube construction.

Uncontrolled emissions

Combustion technology choice is dependent upon fuel characteristics and emissions requirements. Fuel variability makes an exact comparison difficult, but because of the tight combustion temperature band, the CFB has potential, incrementally lower uncontrolled emissions as compared to a BFB burning the same wood fuel. Historically, air permit emission levels were high enough that they did not influence the combustion technology selection process. The industry trend is now driving permit levels to lower and lower values. This suggests a potential break point where the CFB may have an advantage by being able to achieve a given nitrogen oxides (NO_X) limit without the use of selective catalytic reactor (SCR) technology.

Biomass firing requires the control of carbon monoxide (CO), volatile organic compounds (VOCs), NO_X, and at times sulfur dioxide (SO_2) and hydrochloric acid (HCl).

With BFB technology, CO and VOCs are controlled by good fluidization, uniform fuel distribution and a properly designed overfire air system. NO_X is controlled by bed stoichiometry. A staged overfire air system provides approximately 15 to 25% NO_X reduction.

For the CFB, high furnace solids recirculation rates, deep staging, low excess air (below 3% O_2) coupled with a uniform furnace temperature profile, result in low carbon losses and low uncontrolled NO_X formation. Like the BFB, a CFB's CO and VOC emissions are controlled by good fluidization and uniform air/fuel distribution, supplemented by high solids recirculation rates.

Post-combustion emissions considerations

Recently, regulatory agencies have begun to push for tighter emissions targets. Historically, post-combustion NO_X control on biomass boilers (if required) would be achieved by utilizing selective non-catalytic reduction (SNCR) technology. The SNCR process involves injecting ammonia

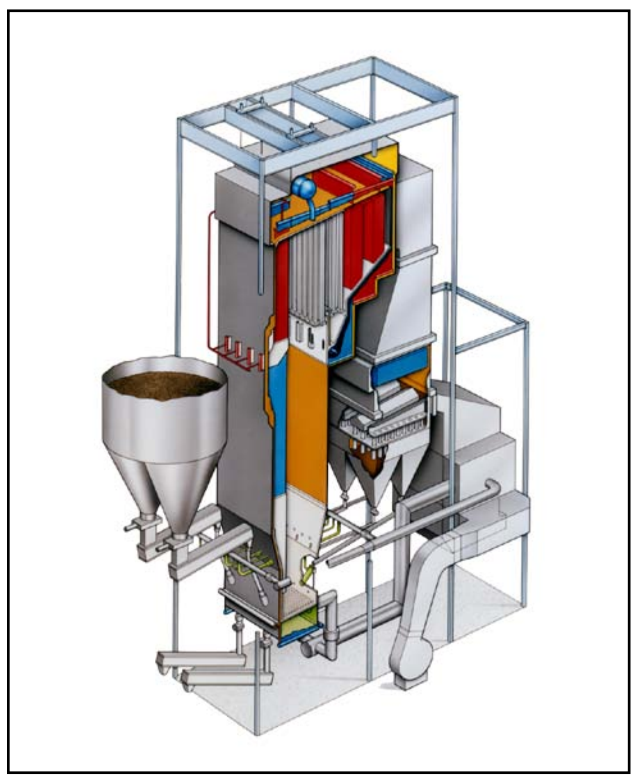

Fig. 3 Circulating fluidized-bed boiler.

or urea in a 1600 to 1900F gas temperature window to reduce uncontrolled NO_X while producing water vapor and nitrogen. There are practical SNCR-based NO_X reduction limits. The reaction is not perfect. Ammonia slip (excess ammonia due to imperfect mixing) and residence time (in the 1600 to 1900F temperature window) are integral to the reaction process.

SCR technology can achieve higher NO_X reduction with ammonia slip values less than SNCR systems. The conventional "high dust" SCR process involves injecting ammonia in a typical 600 to 750F temperature window upstream of a catalyst surface. Again the ammonia reacts with the NO_X to produce water vapor and nitrogen. SCR catalyst manufacturers have deactivation concerns due to biomass flyash poisoning and unburned carbon carryover. While there is limited biomass-fired SCR experience in the U.S., the industry experience base is growing. That experience supports fluid-bed technology with a conventional SCR for clean wood fuels. Operating results indicate a catalyst life that would be acceptable to most operating companies. The industry is also gaining experience with "low dust" SCR applications. The reaction process is the same as the high dust application; however, a low dust SCR places the catalyst downstream of particulate controls.

Typically biomass has low sulfur content. Inherent wood ash alkalis provide some SO_2 and HCl emissions reduction. SO_2 control, if necessary, can be accomplished with reagent injection. The potential SO_2 generated in a BFB can be reduced by as much as 50 to 80%, based upon the sulfur conversion rate coupled with sufficient Ca/S molar ratios. HCl emissions are reduced by excess SO_2 reagent. In fact, HCl is preferentially removed over SO_2 given the correct temperature window. For CFBs, SO_2 reductions of 90 to 95% are typically achieved with limestone added to the bed material. The calcining reaction is a primary reason the IR-CFB combustion process controls furnace temperature over the entire furnace height.

The particulate matter leaving the boiler system can be controlled by either a baghouse or an electrostatic precipitator. The use of a baghouse, in lieu of a precipitator, enhances SO_2 removal and other acid gases such as HCI due to the intimate gas-to-solids contact created within the filter cake.

Case study

For a recent biomass proposal opportunity, the project developer specified fluidized-bed combustion, but left the technology choice (CFB or BFB) to the boiler manufacturer. The fuel was defined as a typical woody biomass, with a 35 to 55% moisture range. Since uncontrolled emissions such as NO_X and SO_2 can be lower in a CFB, the preferred technology was not obvious. Ultimately the correct decision went beyond the boiler; i.e., uncontrolled emissions, to include the air quality control system (AQCS) necessary to meet specified controlled emissions targets. This led to the development of two complete "chute-to-stack" systems, and evaluating the merits of each.

In an effort to expedite the permitting process, the owner/operator made a voluntary decision to limit the total emissions to levels below what may have been expected through the normal permitting process. This strategy is being employed by many project developers in the current renewables market, with the intended goal being to reduce the permitting time span. Since fluidized-bed technology was being utilized, CO and VOC emissions are controlled by good combustion with no special equipment being required outside of the boiler setting. Dry sorbent injection upstream of particulate capture was required to meet the target HCl limits for both technologies. The dry sorbent injection system had the added benefit of SO_2 control. Both the CFB and BFB would be equipped with a baghouse and therefore had no influence on the combustion technology choice.

The differentiating AQCS driver was the NO_X control equipment required to meet 0.08 lb/MBtu, at a low ammonia slip level. The CFB could meet the NO_X target with SNCR while the BFB required an SCR. Comparing the two proposed designs, the CFB/SNCR arrangement had less NO_X operating margin. NO_X margin becomes even more significant when ammonia slip is an evaluation criteria or a guaranteed parameter. The BFB/SCR arrangement provides increased NO_X removal capability especially when evaluated in conjunction with a low ammonia slip target.

Costs

Capital costs Each fluid-bed technology has a unique scope of supply and, in turn, individualized capital cost. The BFB technology limits fluidizing action to the lower furnace. The furnace draft is controlled to be balanced or slightly negative in the mid to upper furnace. The bubbling-bed design allows the removal of bed material without the need for forced cooling. Except for the BFB bottom and the sand reclaim system, there is no other specialized equipment needed in this system.

The CFB technology circulates the bed material throughout the boiler setting. How bed material is captured and recirculated is manufacturer-specific. The most common devices are either a hot cyclone or U-Beams. A CFB lower furnace operates at a positive pressure. To overcome furnace pressure, the fuel feeders require air-locks. Bottom ash is typically hot so a water-cooled screw or a bed ash cooler must be used. Most vendors have in-bed heat transfer surface or furnace division walls inherent to their designs.

From a NO_X control perspective there are significant capital cost differences between SNCR and SCR technologies. Both SNCR and SCR technologies require an ammonia system. Downstream of the ammonia system there are significant capital cost differences between the technologies. The SNCR system is simple. Ammonia piped to the furnace is injected though multiple small nozzles. The SCR system is separate from and downstream of the BFB boiler on a standalone structure. Components include catalyst, casing, lagging, insulation, sootblowers, platforms and ladders, additional flues, ammonia injection equipment and flow mixers. The addition of SCR NO_X reduction technology is a capital intensive investment. SCR technology is several times more costly (capital) than SNCR.

While evaluating the total capital costs for the two offerings on a "chute-to-stack" basis, it was discovered that the additional capital cost associated with the SCR was more than offset by the additional costs of the CFB boiler system. Even though there were slight overall cost differences between the CFB/SNCR and BFB/SCR systems, analysis suggested a capital cost premium of 15% for the CFB design.

It should be recognized that there will be a point (or points) where SNCR could be sufficient to meet the NO_X requirements. For CFBs this may be an evaluation based on operating margin. Or the NO_X requirement may show BFB/SNCR being acceptable. Conversely, if NO_X emissions are ratcheted down to even tighter values SCR technology may be required regardless of the combustion process.

Operating and maintenance costs For the case study design, on a "chute-to-stack" basis, the CFB has higher parasitic load as compared to comparable BFB boilers. For some fuels, BFB technology may utilize flue gas recirculation to control bed temperature. Should that be the case, the BFB will require an additional fan in service thus increasing parasitic load, and the power evaluations begin to approach one another.

The BFB's SCR has additional operating costs over an SNCR system associated with a catalyst management plan and increased gas-side system resistance. This is partially offset by decreased reagent consumption.

With regard to maintenance, the CFB technology, with its recirculating solids inventory, increases the potential for abrasion and wear throughout the furnace cavity and bed material separation equipment. This adds to the CFB maintenance costs over the life of the unit.

Conclusions

Ultimately B&W PGG chose to offer the BFB/SCR over the CFB/SNCR system due to lower capital cost, lower O&M cost and improved margins on NO_X requirements leading to increased fuel flexibility. The customer selected the B&W PGG BFB/SCR arrangement after evaluating it against other CFB boiler system offerings. It is believed that many of the conclusions drawn by B&W PGG's internal evaluation were validated by the customer through the competitive bid process.

While BFB was the preferred technology choice for this case study, CFB technology has a role to play in the renewable energy market. CFB technology is widely recognized as the preferred choice where high Btu fuels dominate or when project requirements dictate low moisture fuels. CFB technology provides fuel flexibility in that it can burn wood and high Btu fuels. A CFB was chosen on a recent repowering project in New Hampshire when the customer mandated such fuel flexibility as a requirement. CFBs are commonplace for European renewable energy projects firing a large percentage of lower moisture fuels such as clean urban waste wood.

For the case study evaluated in this paper, which was a typical virgin woody biomass in the normal moisture range of 35 to 55%, BFB technology is the preferred technology over the life cycle of the project when all evaluation factors are considered. The proper fluidized-bed technology choice is not always obvious and should be evaluated on a case-by-case basis. Parasitic power requirements play a very important role in the evaluation process and ultimately system reliability is critical for any given project. That evaluation begins with a thorough understanding of fuels, fuel variability and ash characteristic while being further influenced by emissions requirements.

Acknowledgment

Selected items in this paper were adapted from Chapter 17 – Fluidized Bed Combustion, *Steam/its generation and use*, Edition 41, The Babcock & Wilcox Company (2005).

Disclaimer