Southeastern Regional Biomass Energy Program

Fluidized Bed Combustion and Gasification: A Guide for Biomass Waste Generators

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Department of Energy

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1.0 INTRODUCTION

Due to the rising cost and, at times, unreliable supply of conventional fuels such as coal, oil, and natural gas, many institutions, businesses, and manufacturers have been forced to evaluate the use of alternative fuel sources. One of the most attractive of these alternatives is biomass fuels. Due to the unique characteristics of biomass fuels, i.e. composition, reactivity, combustion characteristics, and emission potential, fluidized beds have been demonstrated to be a very attractive concept for utilizing them for energy production by either combustion or gasification processes.

This manual provides guidelines for the design and application of FBC and FBG systems for burning and gasifying biomass fuels. It is divided into three sections. Section 1 contains a description of FBC and FBG designs and applications. Section 2 provides information for the non technical biomass generator and/or decision maker. Section 3 provides detailed technical information for the designer and engineer responsible for evaluating the technical merits of an FBC or FBG facility. Appendix A provides a list of biomass fueled fluidized bed facilities. Appendix B contains responses to the survey of vendors offering fluidized bed units capable of utilizing biomass fuels. Appendix C gives a list of vendors who provide equipment that would be used in the preparation of biomass fuels. Appendix D provides addresses for federal and state environmental offices in the southeast.

1.0.1 Biomass Fuels

The term biomass covers an extremely broad spectrum of materials. Sources of biomass fuels include waste from manufacturing, agriculture, forestry, pulp and paper plants, residential waste, and landfills. Specifically these fuels can include: whole tree wood chips, sawmill waste wood, bark, prunings, straw, nut shells, hay, some manufacturing wastes, municipal solid wastes, refuse derived fuel, and sewage sludge.

Biomass materials can differ significantly from conventional fuels in areas such as heating value, fuel moisture, and ash chemistry. Each of these properties can influence the design and operation of a combustion or gasification unit. However, despite their range in values, the actual fuel heating value of biomass is reasonably consistent when compared on an ash and moisture free basis.

Most biomass fuels can be obtained for almost nothing or some suppliers may even pay for the disposal of their waste. As a result, biomass fuels can be much lower in cost than conventional fuels. The economics are particularly attractive when the biomass fuel can be used near the same facility where it was produced. This application can improve the economics of the fuel burning unit while reducing or eliminating the overall waste disposal.

Fluidized bed technology, utilizing biomass as a fuel source, falls into two distinct methodologies. Biomass can be used as a source of energy directly through combustion for providing heat energy - fluidized bed combustion (FBC), or indirectly by gasification and then using the resulting gas as the source of energy - fluidized bed gasification (FBG). FBCs are described in Section 1.1 and FBGs are described in Section 1.2.

The FBC systems as offered by the major boiler vendors, have been commercially available for over 10 years in this country and for longer abroad. Biomass fuels have been successfully fired on many of these units. Currently there are over 580 FBC units in operation or planned for operation. Of these, over 110 will be firing or co-firing some form of biomass fuel. Commercial warranties and guarantees are offered on all these units and, in most cases, these are competitive or better than those on conventional technologies for burning biomass. Appendix A contains a listing of the biomass FBC installations.

The worldwide experience base with fluidized bed combustion of alternate fuels has grown significantly since the early 1980s, with over 60 started after 1982. Alternate fuels are burned in both dedicated FBC boilers and in coal-fired FBC boilers converted to cofire alternate fuels. The experience base confirms that FBC technology is ideal for recovering energy from a wide range of alternate fuels derived from municipal, commercial, industrial, and agricultural wastes and for disposing of the portions of the wastes that can't be recycled. [1]

The fluidized bed gasification systems offered do not have the experience base of the FBC units. Most of the experience is in Europe. Although the designs are similar and performance comparable, the lack of demand for the low Btu gas produced by biomass gasifiers has thus far limited the commercial applications and the vendor aggressiveness in developing a product. Further, the lag in the development of a gas turbine using this gas has slowed the combined cycle applications development.

The FBG designs have been demonstrated on vendors bench and pilot scale facilities and are expected to perform similarly on commercial scale facilities. Competitive commercial warranties and guarantees are offered by the vendors indicating a degree of confidence. Further, these systems have been demonstrated in other parts of the world.

1.0.2 Fluidized Bed Fundamentals

The fluidization process begins with a bed of solid granular particles, such as sand or limestone, suspended by an upward flow of air or gas. As the velocity of the gas stream is increased, the individual particles begin to be suspended. At this point the minimum fluidizing velocity is achieved. As the air or gas flow is increased the bed material becomes highly agitated and begins to flow and mix freely. Bubbles, similar to those in a briskly boiling fluid, pass through the bed and the surface of the solids is diffused and no longer well defined. The bed material is said to be "fluidized" because it has the appearance and some of the properties of a boiling fluid. Continuing to increase air or gas flow results in increased entrainment of the bed particles.

Although each fluidized bed design has distinctly different design features, a common feature of each concept is the presence of the combustion or gasification chamber. Here the fuel and bed material are kept in suspension and circulation by the upward current of air and flue gas. The air is distributed uniformly into the bed via a perforated grid plate or a system of nozzles. To initiate combustion or gasification in the fluidized material, the bed temperature is elevated by using a startup fuel such as gas or oil, to a temperature capable of supporting combustion/gasification of the primary fuel. Figure 1.0-1 shows the fundamental concept of a fluidized bed.

During operation, fuel and sorbent are continuously fed into the unit. The bed will primarily consist of fuel ash, sand or lime, and sulfated sorbent (if needed). Unburned fuel will normally make up less than one percent of the bed. The bed material becomes an isothermal reactor with heat transfer from the bed material to boiler tube surface and to the fresh fuel and air. The turbulent mixing of air and fuel at temperatures above the ignition point of the fuel causes combustion/gasification to occur without the need for conventional burners.

Due to their unique design, FBC and FBG units can be fired with many types of fuels including the lower-grade coals, refuse derived fuels, coal-cleaning wastes, peat, biomass, and other hard-to-burn fuels. FBCs can also accommodate cofiring waste fuels in units designed for coal or other solid fuels with relative ease. As a result, FBC and FBG units are currently being used throughout the world to make use of, while disposing of, a wide range of solid waste fuels, including municipal and industrial solid wastes and sludges, agricultural wastes, and coal mining or cleaning wastes. [2]

If the fuel contains sulfur, a sorbent, such as limestone or dolomite, will be used as the bed material in order to capture the SO_2 released during combustion. For fuels with little or no sulfur, sand or another similar inert material can be used. The combustor temperature of FBC and FBG units is generally maintained in a range from 1450°F to 1650°F. These lower temperatures for FBC are required for optimum sulfur capture, i.e., the reaction of sulfur dioxide with calcined limestone. Even

Fluidized Bed Concept

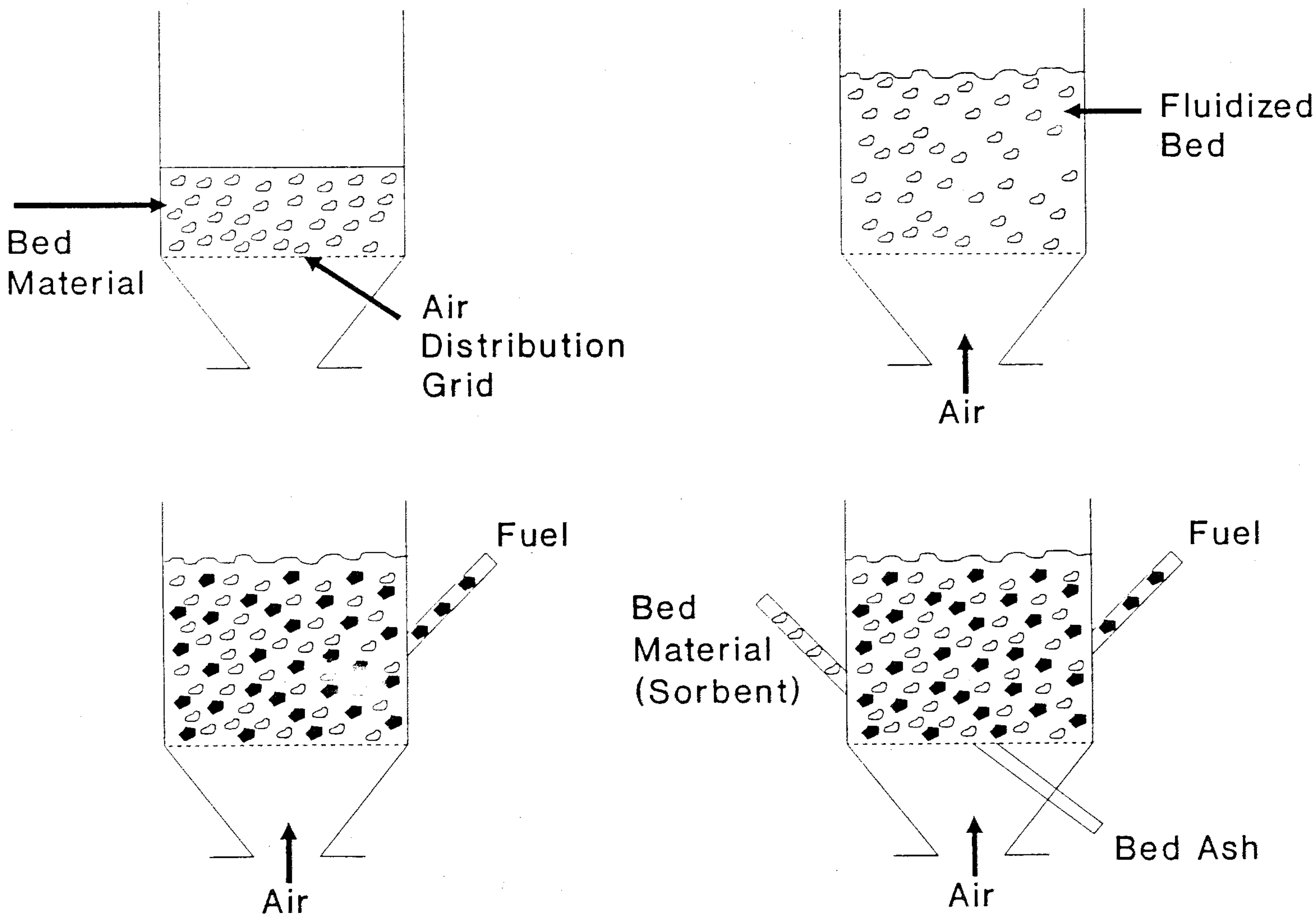

Figure 1.0-1

without a sulfur capture requirement, this temperature range is typically used since it allows the process to operate below the ash fusion temperature of most fuels. This lower operating temperature reduces slagging, fouling, and related corrosion from low melting point sodium, potassium, and sulfur compounds. Therefore FBCs and FBGs do not experience those problems to the extent they are commonly experienced on conventional units. Also, the biomass fuels tend to be very reactive and are efficiently combusted at low temperatures; therefore, nitrogen oxides (NO_x) emissions are significantly reduced by substantially eliminating thermal NO_x.

1.1 FLUIDIZED BED COMBUSTION SYSTEMS

There are two major types of fluidized bed combustion (FBC) units. These are bubbling fluidized bed combustion (BFBC) and circulating fluidized bed combustion (CFBC). Each of these designs are suitable for operation either at atmospheric (AFBC) or pressurized (PFBC) conditions. AFBC units are by far the most common and most commercially developed design.

The PFBC design offers the advantage of using a smaller unit to achieve the same capacity. This is due to the reduction in gas volume as a result of the increased pressure of the system. Further, the pressurized bubbling bed units have deeper beds and use lower fluidizing velocities which result in longer residence times. These factors will increase overall process performance. Finally, the pressurized flue gas can be used in a gas turbine prior to steam recovery components allowing for an increase in overall cycle efficiency. The disadvantages of PFBC include more complex equipment and systems. Although some vendors are offering PFBC units on a commercial basis, these designs are still in a developmental and demonstration phase, particularly for biomass fuels. The current designs are primarily for large utility scale applications using traditional fuels such as coal. At the present time, there are no PFBC projects currently planned using biomass fuels.

The BFBC and CFBC design concepts offer many similar, as well as many unique, design features. Likewise, the operating characteristics are similar in many areas while different in others. In many cases, the applicability and selection of one technology over the other is based on the fuel specification and/or availability.

The following sections give some of the unique characteristics of each of the FBC concepts.

1.1.1 Bubbling Fluidized Bed Combustion - BFBC

Bubbling fluidized bed combustion (BFBC) units were the first concept developed for commercial application. These units are characterized by a well defined dense bubbling fluidized bed. The fluidizing velocity for these units generally ranges from 4 to 12 fps, which maintains an expanded bed of solids 3 to 5 feet deep. Under fully fluidized conditions, the surface of the bed appears to bubble violently, similar to the boiling of water, hence, the name "bubbling" fluidized bed.

On many BFBC units, the bed temperature is controlled by the absorption of heat from fuel combustion through heat transfer surface (tube bundles) submerged in the bed and the flow of fuel into the bed. Some heat is also removed by the combustor which is usually constructed of waterwall panels. However, on some BFBC units burning biomass fuel, in-bed surface is not needed due to the high moisture content of the fuel. The vaporization of this moisture absorbs part of the combustion energy, thereby reducing the need for heat transfer surface. Typically, these units are also refractory lined in the bed region.

Additional heat is removed from the flue gas using waterwall combustor surface in the freeboard (the region above the bed) and conventional convective surfaces such as boiling bank, superheater, reheater, economizer and air heater. Alternatively, the hot flue gas can be used for process heat. Figure 1.1-1 shows the BFBC flow diagram.

The convection pass and air heater sections of these units resemble conventional designs. Typically, flue gas leaving the air heater passes through an electrostatic precipitator or baghouse (baghouses are more common in biomass applications) and then to an induced draft fan to be exhausted through the stack.

On BFBC units with in-bed heat transfer surface, boiler tubes submerged in the bed remove heat and maintain bed temperature at the optimum range of 1450°F to 1650°F. This is very effective heat absorption surface due to the high heat transfer coefficients available within a dense bed of fluidized solids. Approximately fifty percent of the

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BFBC FLOW DIAGRAM

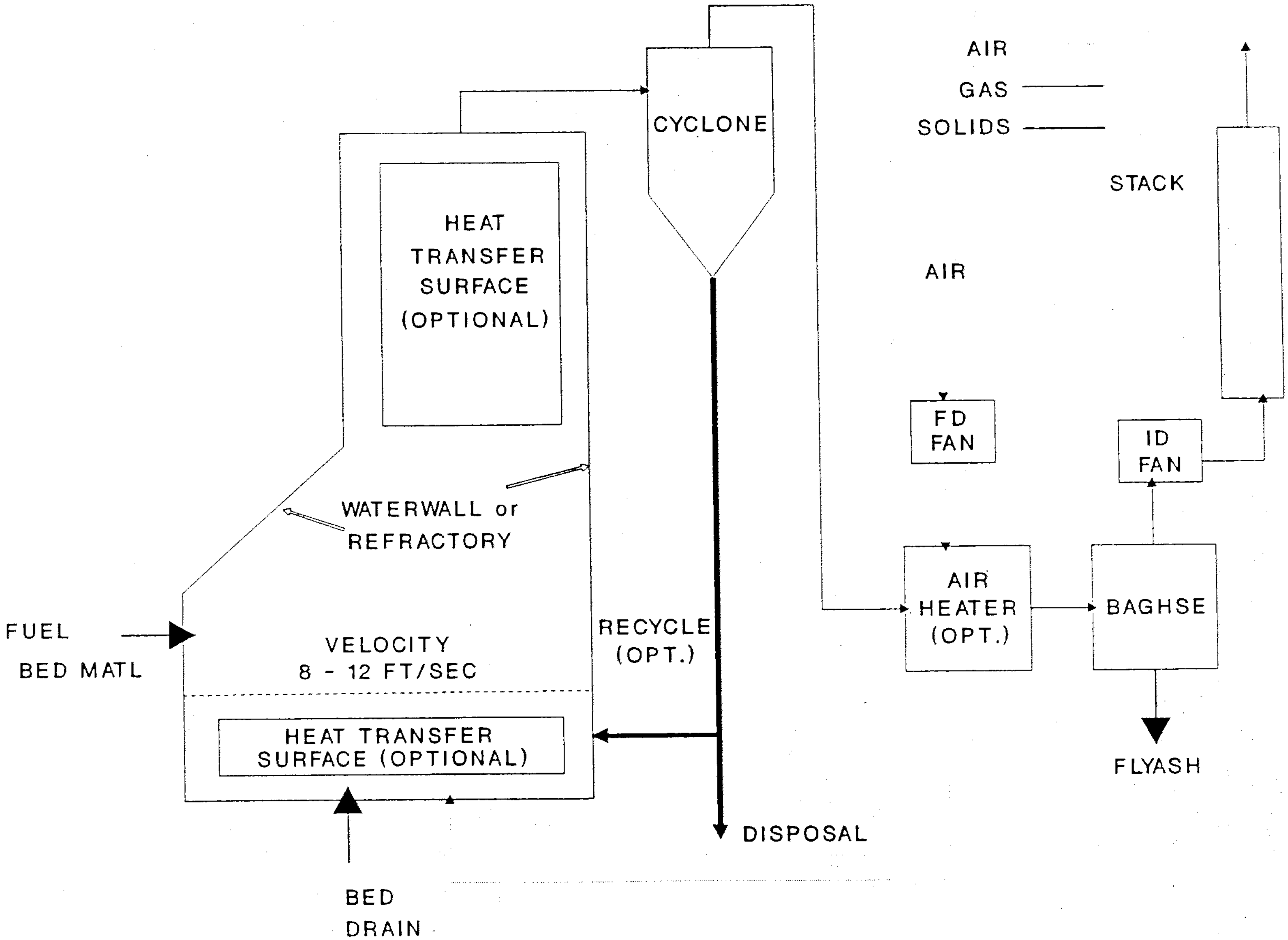


Figure 1.1-1

heat released in a BFBC can be absorbed by the in-bed heat transfer surface. This characteristic results in a smaller unit (due to lower surface area requirements) and subsequently, less capital costs for these heat exchangers. The remainder of heat is absorbed by waterwalls and tube bundles located in the convection pass. For units where the in-bed heat transfer surface has been eliminated, the heat duty is shifted to the convection pass.

Fuel and bed material can be fed to the combustor using either underbed, in-bed, or overbed feed. Underbed feeding provides a longer in-bed residence time for the fuel and sorbent particles than does overbed feeding, and therefore can result in a higher combustion efficiency and reduced sorbent consumption for hard to burn fuels. These differences become greater as the fuels become more difficult to burn.

Underbed feed, typically pneumatic, is more complex than overbed feed and generally requires more maintenance. A pressure seal is needed to force the fuel into the combustor and resist back pressure from the bed. The pressure seal may be a costly component and unreliable. The fuel must be sized and dried to below certain specifications to prevent feed line pluggage. This fuel requirement can require a fairly elaborate fuel preparation system. Generally underbed feed systems are not needed for biomass fuels.

In-bed feed is similar to underbed feed, particularly if the fuel is fed pneumatically. In some instances, a slurry in-bed feed system is used to feed biomass fuels such as sewage sludge or animal wastes where the moisture levels are extremely high. The slurry system normally involves the pumping of the fuel into the bed. This system is also more complex than overbed feeding but in certain cases may be the only method feasible.

Overbed feed uses proven reliable equipment and significantly reduces the complexity of the feed system. Overbed feed equipment options include conventional spreader feeders, air swept feeders/mills, and gravity feeders. Each of these simplifies the pressure seal needed for underbed feed systems. The major drawback with overbed feeding is the potential for excessive unburned carbon and/or poor sulfur capture. This condition is caused when the fines are elutriated from the combustor with the flue gas without adequate residence time for complete combustion. Also, since the oxides of sulfur (SO_x) produced from the combustion of the fines are released above the bed, and therefore have less chance to be captured by the limestone, SO_x emissions will rise unless additional sorbent is fed to the unit to maintain the same emission levels. In the case of biomass fuels these problems are normally avoided due to the low sulfur content and high reactivity of the fuel. Overbed feed is the predominant choice, and has been demonstrated to be effective, for efficient burning of biomass fuels.

In the combustion of any fuel, there are three important factors: time, temperature, and turbulence. Solids residence time in the furnace can be increased effectively by capturing the particles contained in the flue gas and reinjecting them back into the combustor. This process is generally referred to as solids recycle and it increases overall carbon burnup and lowers the sorbent requirement. These particles are usually separated from the flue gas using a low temperature cyclone type collection device. The use of recycle can help offset the negative effect of fines when feeding overbed because of the substantial increase in solids residence time. If the fuel is very reactive, as most biomass fuels are, flyash recycle may not be required.

BFBC units are offered commercially for a broad size range, from a small industrial scale of around 50 MBtu/hr unit to a large 2440 MBtu/hr or 200 MW (approximately 30 - 1380 Klb/hr steam flow) utility scale facility; although, the larger units are not typically used for biomass. Larger BFBCs are available but have not been completely demonstrated for commercial application. Commercial suppliers of BFBCs include ABB-CE, B&W, Foster Wheeler, Combustion Power, and JWP Energy Products, Inc. Table B-1 in Appendix B contains a summary of information supplied by these vendors regarding their commercial offerings, guarantees, applicable fuels, auxiliary equipment requirements, and other pertinent information on their systems.

1.1.2 Circulating Fluidized Bed Combustion - CFBC

Circulating fluidized bed combustion (CFBC) units are the second atmospheric fluidized bed combustion design concept that has been developed. The principal differences between BFBCs and CFBCs are the elimination of in-bed tubes and the use of much higher fluidizing velocities with the resulting entrainment of a large portion of the solids in the CFBC. The CFBC velocities range from 12 to 30 fps depending on the manufacturer. The high gas velocities and solids loadings in essence "stretch" the bed throughout the combustor such that there is no well defined bed. This produces a high degree of turbulence which quickly and uniformly mixes the fuel and bed material. This greatly simplifies fuel feeding and preparation requirements. The solids leaving the combustor are separated from the flue gas using a hot cyclone or other gas/solid separator and recycled back to the combustor. There are normally no heat transfer surfaces directly in the particle-gas stream due to erosion considerations. The cyclone collector operates at or near combustion temperatures. The combustor typically contains waterwall surface and, in some cases, wall superheat surface which helps to produce steam requirements and control combustor temperature in a range similar to BFBCs, i.e. 1450-1700°F. The associated high heat and mass transfer rates result in high combustion and sulfur capture efficiencies.

Fuel and bed material are fed into the lower section of the combustion chamber and primary combustor air is introduced through a distributor plate or sparger at the bottom of the combustor. There is no fixed bed depth, as in a BFBC boiler. Rather, the density of the bed varies throughout the combustor height, with the greatest density near the bottom where the fuel and sorbent/bed material are introduced. Combustion of the fuel takes place as it rises in the combustor. The air-to-fuel ratio is kept low in the lower section of the combustor to minimize NO_x emissions. Secondary air is introduced at higher elevations to maintain particle entrainment throughout the height of the combustor, to complete combustion of carbon, and to control combustor temperatures. Figure 1.1-2 shows a typical CFBC flow diagram.

CFBC FLOW DIAGRAM

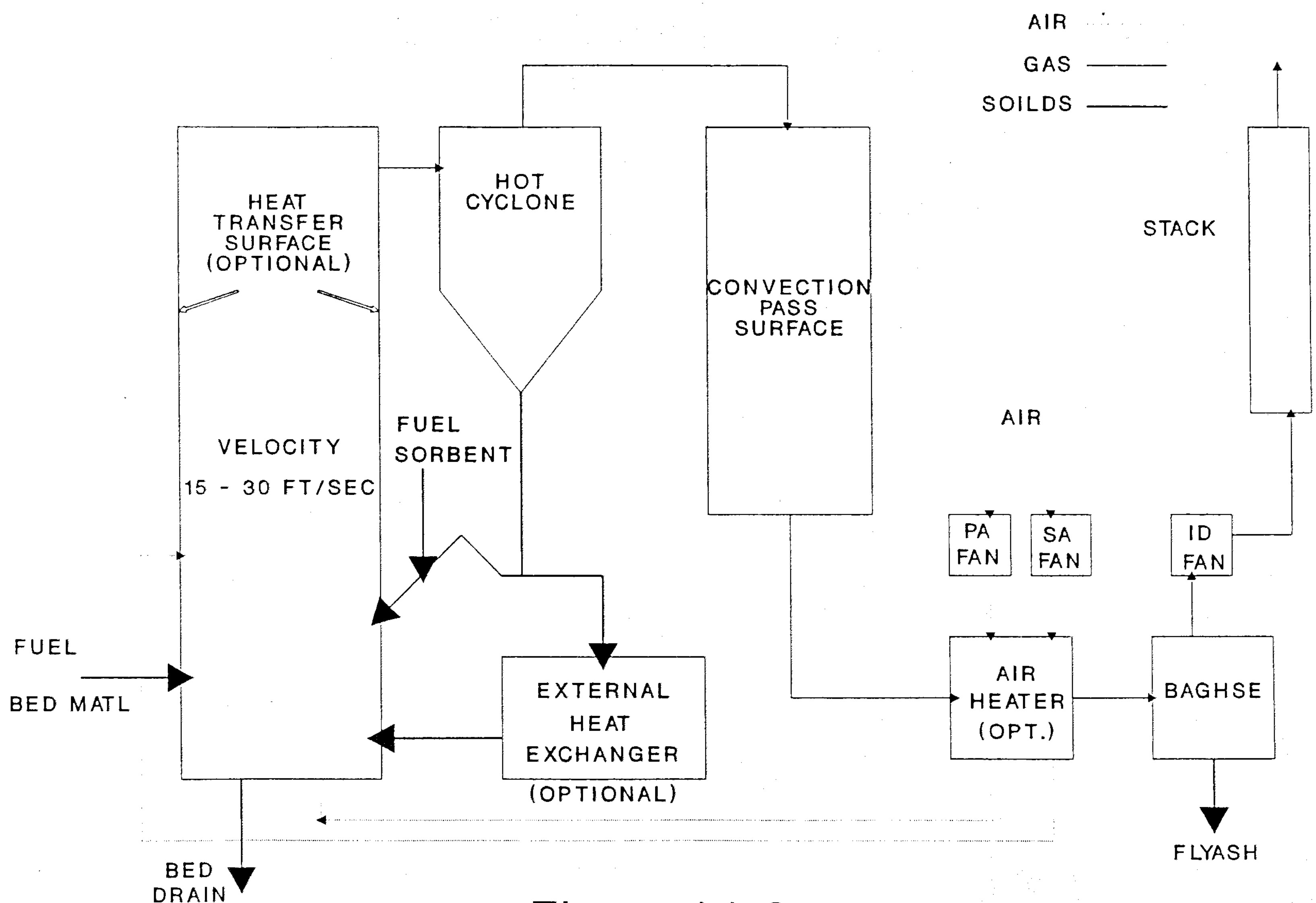


Figure 1.1-2

The hot combustion gases with the entrained solids leave the top of the combustion chamber and enter a hot particulate collection device, typically a refractory lined cyclone. The solids, which include some unburned carbon and unreacted bed material, are collected and returned to the combustor. In some designs, this material is fed to an external heat exchanger where it is cooled, thereby producing steam or heating water. Gases leaving the collection device can be used for process heat or directed to a convective pass steam generation section which may contain reheat (if applicable), superheat, boiling bank, economizer and air heater surfaces.

As in the BFBC unit, the convection pass and air heater sections of these units resemble conventional designs. Typically, flue gas leaving the air heater passes through an electrostatic precipitator or baghouse and then to an induced draft fan to be exhausted through the stack.

CFBC designs are of two general types; those that include an external fluid bed heat exchanger (EHE) and those that do not. The EHE is a low velocity, bubbling fluidized bed that is used to extract heat from the solids which are collected in the cyclones before they are returned to the combustor. No fuel or sorbent is fed to this bed. Physically, this component has a rectangular geometry and is located directly under the cyclones. It typically contains evaporator and/or superheat surface or reheat surface. The EHE provides an additional measure of control over the process by further decoupling the combustion and heat transfer processes. Although the EHE is typically a completely separate component from the combustor, on at least one design, this heat exchanger is an integral part of the recycle system and is internal to the combustor/recycle circuit. In this case the heat exchanger is called an INTREX, which stands for "Integrated Recycle Heat Exchanger".

Combustor temperature can be controlled within the required range by varying the amount of solids which do or do not pass through the EHE before returning to the combustor. This capability becomes even more important at reduced firing rates since the heat transfer to the waterwalls changes significantly as load changes. The EHE provides an excellent location for reheat and superheat surface because it is isolated from the combustor during startup. Also, it can be operated somewhat independently of the combustor to better control superheat or reheat temperature for load response. Approximately 25% of the heat is absorbed in the EHE with 40% in the combustor and 35% in the convection pass. Heat transfer surface erosion is a minor concern in the EHE since fluidizing velocities are typically only in the 1 to 5 fps range, i.e., much lower than seen by the in-bed heat transfer surface of a BFBC.

Most of the existing biomass CFBC units do not have an EHE due to initial cost considerations. Without the EHE, heat transfer in a CFBC boiler occurs primarily in two locations, the combustor waterwall and the convective pass downstream of the cyclones. The amount of the total energy released by the fuel that is absorbed in the combustor varies depending on the characteristics of the fuel. Fuels with a higher moisture content carry a greater amount of energy out of the combustor into the convective pass due to the greater amounts of flue gas that they generate. For high grade fuels, such as bituminous coals, typically 60% of the heat is absorbed in the combustor and 40% in the convection section. When low grade, high moisture fuels such as biomass are fired, 40% of the heat is absorbed in the combustor and 60% in the convection section.

The combustor temperature of CFBC designs without an EHE is controlled by balancing the rate of heat generated by combustion of the fuel with the heat absorption rate of the steam generating and superheater surfaces in the combustor. The heat transfer rates in the combustor increase significantly as the solids circulation rate and the solids gradient increase. This rate and gradient are controlled primarily by varying the gas velocity in the combustor and to a lesser degree by the amount of solids flux in the unit. These controls occur normally as the fuel and air are varied to maintain the required load. However, since these relationships and others that influence heat transfer are not all linear with firing rate, it is necessary to be able to make additional adjustments to control combustor temperature. These adjustments include varying the solids circulation rate, the ratio of primary to secondary air, total excess air, and the flue gas recirculation rate.

The CFBC technology was first developed in Europe and is now offered by several vendors in this country. Several commercial CFBC units are now in operation burning a wide variety of fuels including biomass. CFBC units range in size from a low capacity of 50 MBtu/hr to a large utility scale unit on the order of 3000 MBtu/hr or 250 MW (approximately 30 - 1720 Klb/hr steam flow). Again the larger CFBC units are not typically used in biomass applications. The maximum capacity is limited due to the height of the combustor and the size of the hot cyclones.

Commercial suppliers of CFBCs include ABB-CE, B&W, Foster Wheeler, Ahlstrom Pyropower, and Tampella. Table B-2 in Appendix B contains a summary of information supplied by these vendors regarding their commercial offerings, guarantees, applicable fuels, auxiliary equipment requirements, and other pertinent information on their systems.

1.1.3 Systems and Equipment

FBC design concepts offer some unique differences in plant systems and equipment. Evaluating the performance of this equipment and the system components is critical to making an overall comparison between the various options. The following sections discuss the major systems that should be considered.

1.1.3.1 Fuel Preparation

Most FBC units require that considerable attention be given to the as-fed fuel size distribution. Due to the lower combustor temperatures of FBC units, more residence time is required for the fuel particles to burn out. Fuel burnout is achieved through the physical dimensions of the unit and operating velocities and sometimes recycle of solids. The sizing of the fuel is very important. Very fine fuel particles can pass through the unit and may not be caught by the cyclone for recycle resulting in incomplete combustion. Conversely, too large of fuel size can cause fluidization problems in the combustor. The sensitivity of the size range varies between the FBC design concepts.

In addition, some FBC feed systems have limits on moisture and, therefore, must incorporate drying prior to feeding. Fuel moisture content might be limited for any or all of the following reasons: moisture in the fuel can cause corrosion of the fuel handling and feed system, moist fuel can form agglomerations and plug the feed system, and fuel moisture can reduce the unit efficiency as explained in Section 1.3.

On BFBCs with underbed feed, the fuel must be sized small enough to prevent feed line plugging. However the fines must be limited to maintain acceptable process performance levels. Depending on system design the surface moisture might also be limited to prevent feed system plugging. This would require that the fuel be purchased with a specified moisture limit or dried on site as a part of the fuel preparation system. This drying can be performed using a flue gas drying and sizing system. Alternatively, an oil or gas dryer can be used. Prepared fuel is stored in feed tanks prior to the unit feed system. Due to the high reactivity of biomass fuels, the complexity of the underbed feed system is not normally required.

On BFBC units with overbed feed systems, there is usually no surface moisture limit requirement. For hard to burn fuels, fines should be kept to a minimum due to the detrimental impact on process performance. For example, excess fines will burn in the freeboard, the region of the combustor above the bed, never entering the bed, and therefore, lose valuable in-bed residence time and mixing.

CFBC units typically have similar feed stock size requirements as the BFBC units. Section 1.3 discusses in greater detail the fuel preparation equipment and systems for FBC and FBG units utilizing biomass fuels.

1.1.3.2 <u>Feed Systems</u>

On FBC units, the feed system can be more complex than on conventional units, depending on the design and application. Only on overbed feed units, using gravity feed to a low pressure region, is the feed system uncomplicated. In general, feed system design is as much a function of the unit vendor as the fuel type or properties.

On units with underbed or in-bed feed systems, there are several critical components involved. These include feed tanks, feeders, splitters, and feed lines in pneumatic systems and feed tanks, feeders, pumps and feed lines in slurry systems. Depending on the particular system, any or all of these components could be under pressure. The key part of an underbed or in-bed system is the type of pressure seal used. These can include head seal legs, lockhopper systems, pump/screw feeders, and rotary feeders. The ability of this device to adequately seal and feed the fuel to the unit is probably the determining factor in the success of an underbed feed system. Of secondary concern in the BFBC is the ability to split the fuel to achieve good fuel distribution and limit erosion or wear and plugging of fuel feed lines.

Any underbed system should be evaluated based on its ability to reliably feed fuel to the unit with good distribution. Fuel feed trips, feed line plugs, and wear on system components should be monitored and correlated with fuel characteristics, combustor back pressure, and transport air conditions. Also, combustor operating conditions, such as bed temperatures and CO emissions, should be monitored to evaluate feed system distribution. In many cases, excursions in CO emissions can indicate a problem with feed line plugging or splitter inaccuracy. Monitoring feed blower back pressure and feed line temperature will also detect feed line plugs.

On overbed systems, stoker spreaders, air swept feeders/mills, or gravity chutes are usually used to feed and distribute the fuel. This type of feed system is typically very reliable. Problems that do occur are generally related to oversize particles, high moisture, and poor fuel distribution. Due to the low sulfur content and high reactivity of most biomass the majority of biomass fired FBC units will use overbed feed.

Figure 1.1-3 shows a typical air swept feeder arrangement that could be used on a biomass unit.

Since biomass units typically use an inert bed material, such as sand, the distribution of the material into the combustor is not critical. Therefore, a simple gravity chute feed system is normally used for the feed of additional bed material. Figure 1.1-4 shows the layout.

1.1.3.3 Recycle Systems

The first generation FBC units were low-velocity bubbling bed boilers. Elutriated solids from the bed were collected in cyclones and/or baghouse and sent to disposal. The disposed solids from these units contained a significant amount of unburned carbon, and in some cases, unreacted sorbent. As a result, the concept of recycle or reinjection of these solids back into the combustor was developed and incorporated into the design of later FBC units. On many current BFBC and CFBC units, the solids leaving the combustor are collected in a cyclone or similar device and can be "recycled" back to the combustor. Combustion efficiency and sulfur retention can be significantly improved with recycle.

Depending upon the type of FBC unit, the design of the recycle system can vary significantly. On traditional BFBC boilers, a cyclone is usually located downstream of convection pass heat exchangers. The solids leaving the combustor are collected and recycled "cold" (approximately 700°F) to the combustor. Since the bed operates at a specific temperature and velocity, there is some limit on the amount of cold recycle that is feasible with the BFBC unit. The recycle ratio (recycle solids feed rate/fuel feed rate) is usually on the order of 0 to 4. However, some designs place the cyclone before the convection pass and feed hot recycle. This is a very attractive option for repowering units where the old boiler is used as the convection pass heat exchanger. The cyclone or solids collection device typically captures 90-96% of the incoming

Air Swept Feeder

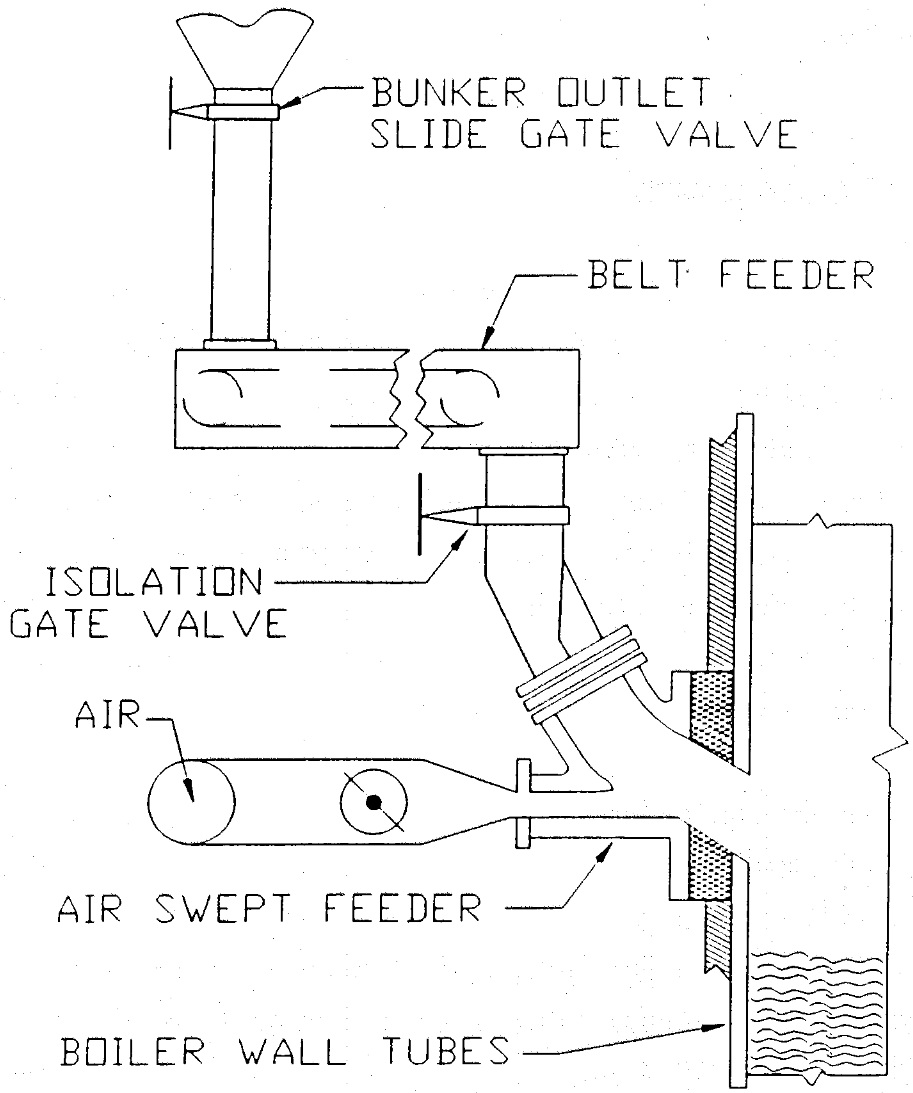


Figure 1.1-3

Overbed Limestone Feed System

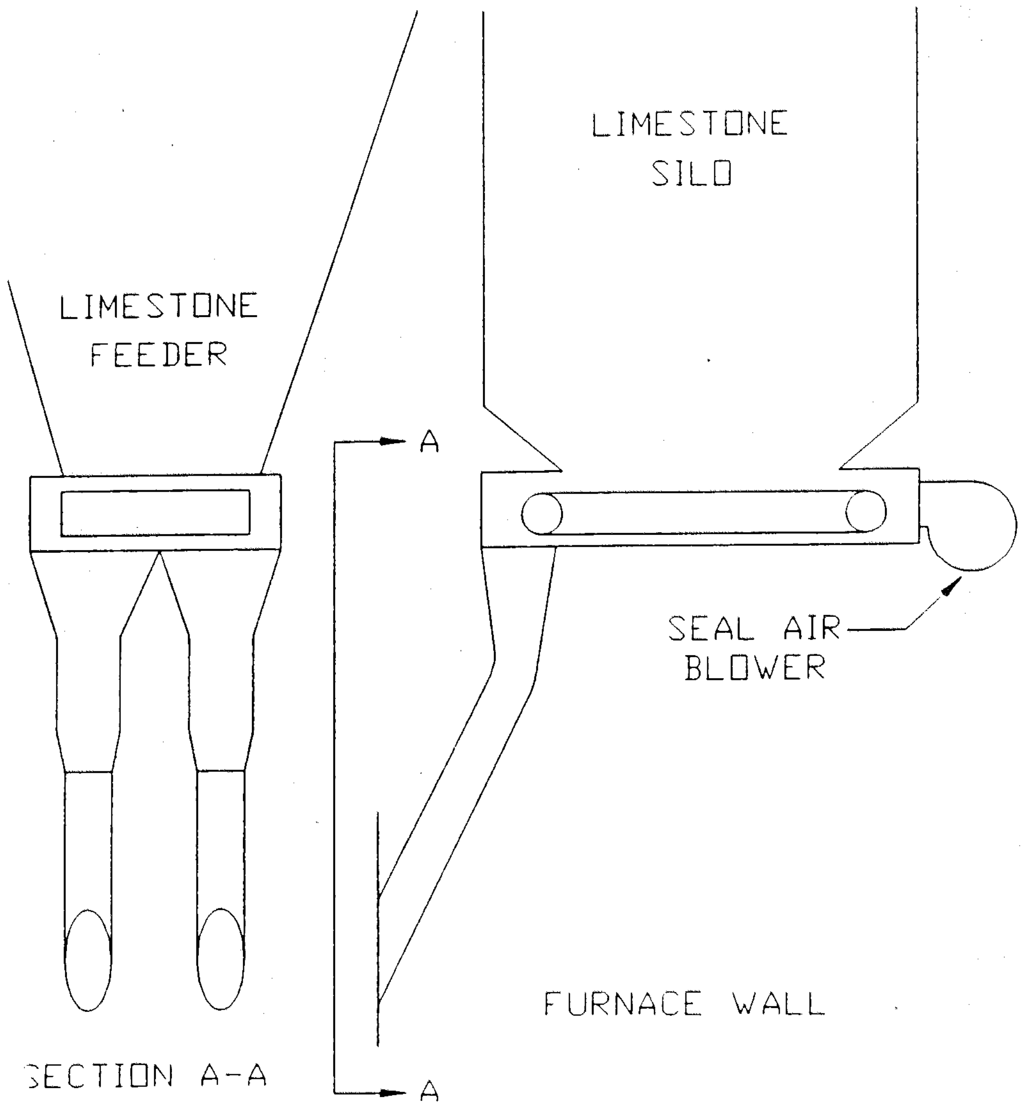


Figure 1.1-4

solids. The recycle feed rate is normally adjustable, with any excess material transported to disposal.

The recycle on BFBCs is typically distributed overbed by gravity or underbed depending on the vendor design. The underbed system requires a pressure seal and splitter device similar to the underbed feed system. Recent designs have incorporated the same head seal or dip leg technology used on CFBC boilers.

On CFBC units, a high percentage of the elutriated solids are collected in a "hot" cyclone (1600°F) located upstream of the convection pass surface and reinjected into the combustor via a solids head seal device. The flue gas with solids not captured by the cyclone continue on to the convection pass heat exchangers. The recycle solids are typically close to combustor temperature and, therefore, do not have a thermal impact on the unit. On CFBCs where EHEs are utilized, some of the collected solids are routed to the EHE prior to recycle to the combustor. These solids can be used to trim combustor temperature since a portion of the solid's heat is extracted in the EHE. Most CFBCs firing biomass will not utilize an EHE due to initial cost consideration and high moisture in some biomass fuels. When moisture is 50% or greater, this moisture cools the bed significantly. The solids from the cyclone or EHE are typically reinjected through the side walls of the lower combustor at one location only. The percentage of elutriated solids is very high on the CFBC unit, and combined with over 99% cyclone efficiency, the total recycle rates on these units is extremely high. Recycle ratios on CFBCs can range from 50 to 500.

Generally, recycle is not needed for combustion efficiency improvements on either BFBC or CFBC units burning biomass fuels due to the high reactivity of the fuel. However, the recycle system is inherent to the CFBC design no matter what fuel is used since recycle is an integral part of the CFBC process.

1.1.3.4 Ash Disposal

On most FBC units, the addition of limestone or other sorbent will greatly increase the amount of ash from the boiler. However, since an inert material such as sand is used with most biomass FBC units, the total amount of ash sent to disposal is not significantly different from conventional units. The sand, which does not easily attrit or breakdown, is pre-sized to remain in the system as long as possible.

On BFBC units, ash is disposed from three locations around the boiler; the bed drain, cyclone catch disposal, and baghouse or electrostatic precipitator (ESP) catch. The split between these three streams is based on fuel and limestone properties and unit operating conditions. On CFBC units, there are two primary disposal streams: bottom ash or bed drain, and baghouse flyash. There is no hot cyclone catch disposal on most CFBC units; all of the material caught by the hot cyclone is recycled back to the unit. Some CFBC units do have a secondary set of multiclones after the hot separation device that does have disposal. Bed cleaning or bed drain systems are common on biomass-fueled FBC plants to assist in removing large inert materials and returning usable sized material to the combustor.

The bed drain or bottom ash must be cooled prior to disposal. In many cases this waste stream can be significant enough to warrant recovery of the sensible heat from the material. For example, fluidized bed material coolers can use combustion air to cool the bed drain solids prior to disposal while simultaneously preheating the air. Figure 1.1-5 shows a typical fluidized bed ash cooler. Cyclone catch disposal on BFBC units is typically disposed at 700°F which means little heat recovery is possible.

1.1.3.5 Air/Gas System

Forced draft (FD) fans are required to supply air to the furnace for bed fluidization and to provide oxygen for combustion. Due to the higher pressure drop from the FD fan to the zero or balanced draft point, primarily caused by the distributor plate

Air-Cooled Fluidized Bed Ash Cooler

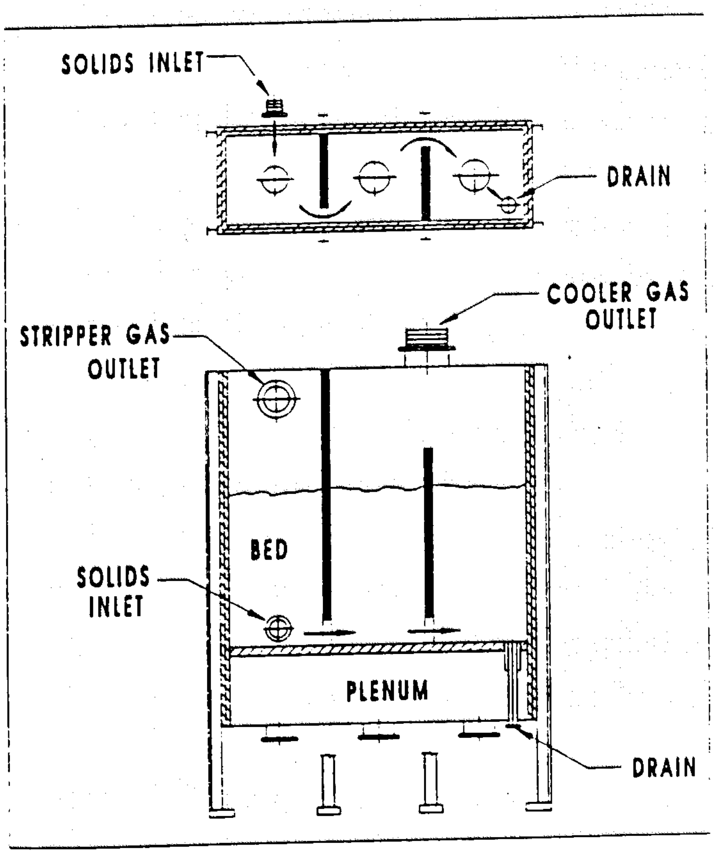


Figure 1.1-5

pressure drop and the presence of a bed or high combustor solids density, fluidized bed units will require a higher horsepower FD fan than conventional units.

On some applications an air preheater heats the combustion air with waste energy from the flue gas, thereby increasing the boiler efficiency. Care must be taken when selecting an air preheater for a fluidized bed application, since air duct pressures are significantly greater than found in a conventional furnace.

Standard induced draft (ID) fans are located at the outlet of the baghouse or ESP to draw flue gas through the baghouse or ESP and discharge it out the stack.

1.1.4 Materials of Construction

Key to the success and application of any technology is the application of suitable materials of construction. The ability of selected materials to support the process requirements in an economical manner is necessary for industry acceptance. BFBCs and CFBCs subject the combustor and associated materials of construction to different conditions than conventional units. Some of these conditions are harsher and some more benign. In general, existing materials of construction are suitable for FBCs. However, when selecting and evaluating the performance of these materials for FBC use, the operating environment needs to be kept in mind. BFBCs, with the use of a dense bed, expose in-bed heat exchangers to a rapidly fluctuating oxidizing/reducing gaseous environment at approximately 1550°F. Oxygen partial pressures typically vary between 10^{-1} and 10^{-14} atmospheres. Testing has shown that as long as metal temperatures are maintained below about 1200°F, problems of oxidation-sulfidation can be minimized. CFBCs with staged combustion, subject the lower portion of the combustors to a more continuous reducing condition which must be accommodated by the use of refractory materials to protect the metallic components. Because of this low oxygen environment, low iron content refractories should be used. FBCs, if operated properly, do not experience all the associated problems seen in other units which suffer from slagging.

1.2 FLUIDIZED BED GASIFICATION SYSTEMS

This section provides a description of fluidized bed gasifiers (FBGs). Section 1.2.1 describes bubbling fluidized bed gasifiers and Section 1.2.2 describes circulating fluidized bed gasifiers. Pressurized fluidized bed gasifiers, which may be either bubbling or circulating, are discussed separately in Section 1.2.3. Before getting into the details of the specifics of the equipment, a brief discussion of the gasification process and general design features is provided below.

Gasifiers are available in different styles with the most common types being updraft, downdraft, and fluidized bed. This report addresses fluidized bed gasifiers, which are found in two basic designs referred to as bubbling fluidized bed gasifiers (BFBGs) and circulating fluidized bed gasifiers (CFBGs). Figures 1.2-1 and 1.2-2 show typical layouts for a BFBG and a CFBG, respectively. Each of these designs are suitable for operation either at atmospheric or pressurized conditions and are in the early commercially stage with guarantees offered by several suppliers.

Gasification, in general, is a thermal process which involves the heating of a feedstock by partially combusting it with less than the necessary stoichiometric air requirement and driving off the combustible volatiles. Thermal gasification of biomass fuels can be achieved in both bubbling and circulating fluidized bed gasifiers at atmospheric or pressurized conditions. Biomass fuels are much more conducive to gasifying than coal due to their higher volatile content, higher reactivity, and lower required temperatures. For instance, coal gasification typically occurs in fluidized beds at around 1830°F versus only 1560°F for wood gasification. The required residence times are much shorter for biomass fuels, as well, 1/2 to 5 minutes for wood versus 30 to 180 minutes for coal. Additional advantages of biomass over coal include: less sulfur, CO_2 neutral, and renewable fuel. Disadvantages of biomass over coal are: more disperse, higher moisture, higher alkali, and lower bulk density. [3, 4]

BFBG Flow Diagram

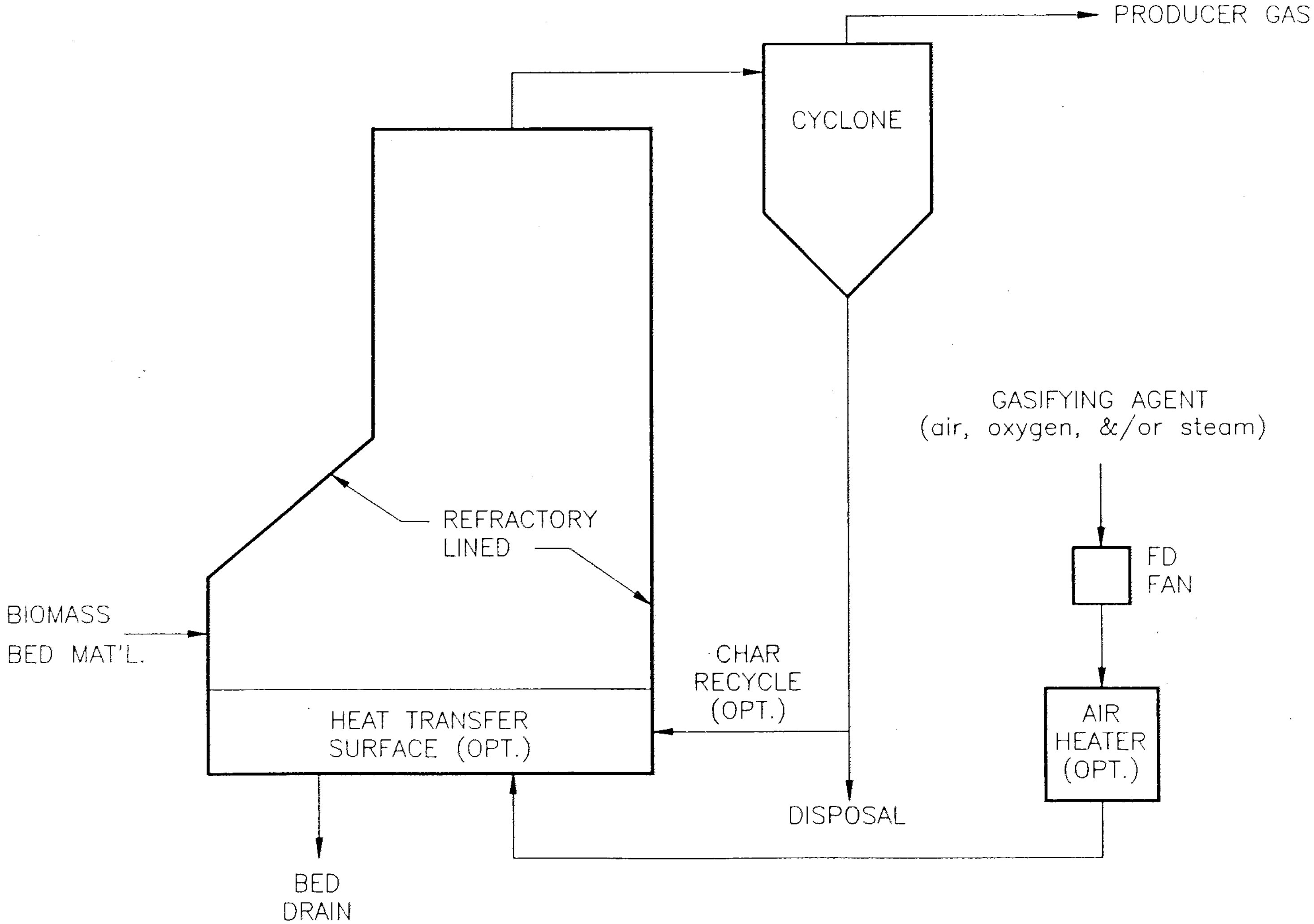


Figure 1.2-1

CFBG Flow Diagram

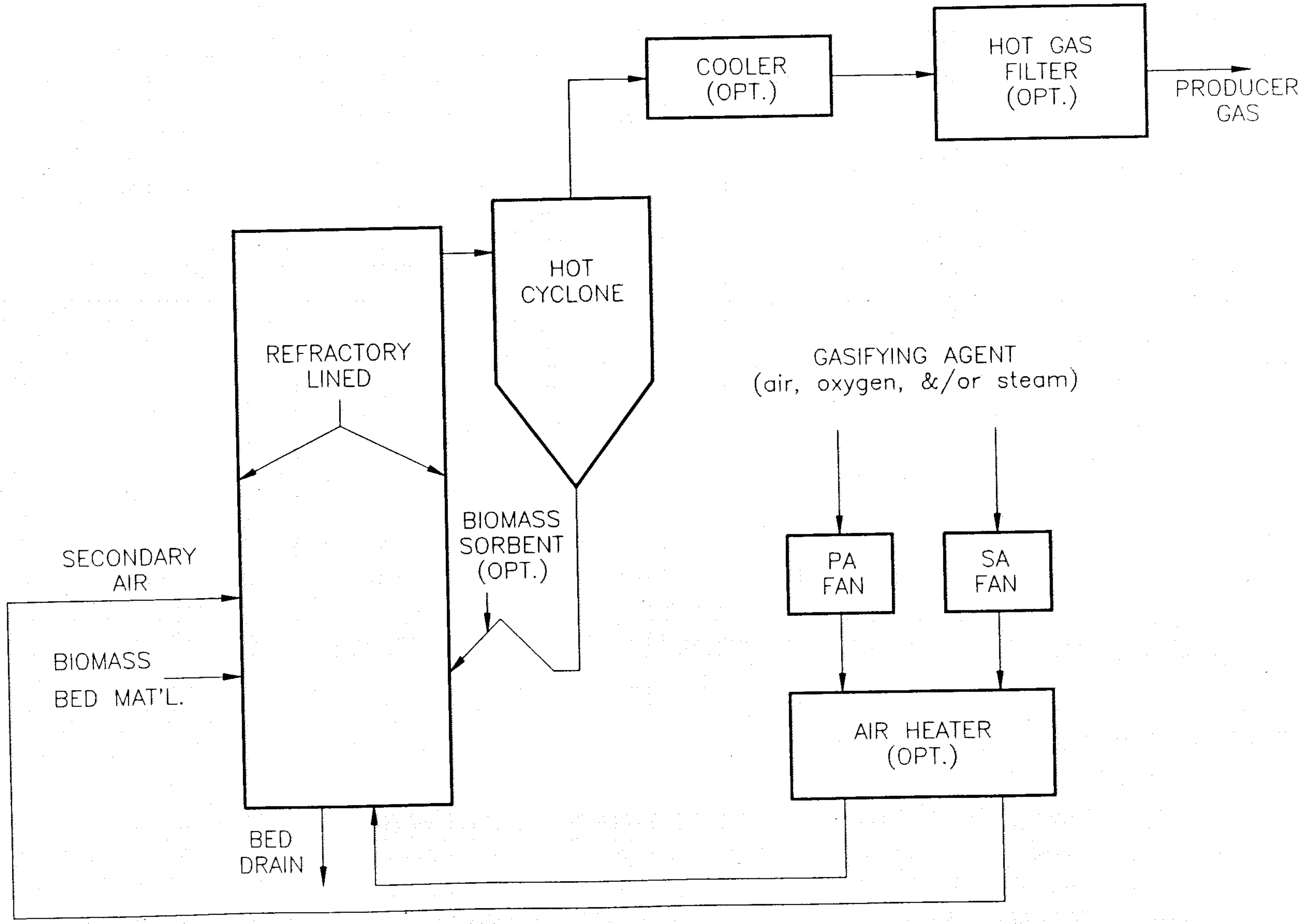


Figure 1.2-2

In the gasification process, gas is produced during two general reactions. One of the reactions is pyrolysis where the biomass volatile content is driven off at temperatures up to approximately 1100°F. Since biomass fuels are predominately volatile matter (75-85% on a dry basis), most of the gas is produced during the pyrolysis reactions. The other reaction consists of burning the remaining carbon (char) left from the pyrolysis reactions. Partial combustion of the char not only produces additional gas but also provides the necessary heat to maintain the pyrolysis reactions. Most of the evolved gases are not ignited. The resulting gas consists primarily of carbon monoxide, methane, hydrogen, carbon dioxide, and nitrogen. The gas can be stored for later use or piped to a burner for immediate combusting. The gas, typically, has a heating value on the order of 100 - 500 Btu/ft^3 (depending on reactor type), as opposed to natural gas which has a heating value of approximately 1000 Btu/ft^3.

The gas produced from gasifying biomass can be used for process heating, generation of process steam, and/or generation of electricity. This gas provides an energy source that is in a form that is easier to utilize and may also offer improvements in efficiency and emissions compared to direct combustion of the biomass. Biomass fuels less than about 50% moisture content are usually gasified by thermal processes. [3]

Along with the biomass gas, tars/oils and corrosive constituents may also be released which have to be dealt with. Removal of the tars requires that the gas be cooled to allow them to condense. However, cooling decreases the overall combustion efficiency of the process. The best method seems to be to burn the gas on site before the tar and oil condense. Particulate matter must also be separated from the gas before it is utilized in some applications. [5, 6]

Maximizing the conversion of the fuel carbon into gas while minimizing the production of tars and oils can be brought about by: increasing residence times, raising the gasification temperature, using a sorbent such as dolomite or limestone, using staged gasification, applying tar/oil cracking, using oxygen as the gasifying agent, recycling captured tar/oil to the gasifier, performing oxidation in a separate reactor, and using char/ash from the gasifier to dry the incoming wet fuel. [7]

Thermal gasification involves the use of a gasifying agent to react with the biomass and a heat source to drive the process. The most commonly used gasifying agents include air, oxygen, and steam. The heat source can be provided directly by partial combustion of the biomass feedstock or indirectly by an external heat source. The gasification process can be divided further into two categories: those which produce a low Btu gas (LBG) and those which produce a medium Btu gas (MBG). Both of these gases are referred to simply as "producer gas". The choice of gasifying agent and heat source used for gasifying influence the energy content of the resulting gas. The types of reactions that occur during gasification are shown in Table 1.2-1. The first four reactions in the table are exothermic and the last two endothermic. [8]

TABLE 1.2-1
GASIFICATION REACTIONS

$$C + O_2 \Rightarrow CO_2 \quad (1)$$

$$CO + 1/2O_2 \Rightarrow CO_2 \quad (2)$$

$$H_2O + CO \Rightarrow H_2 + CO_2 \quad (3)$$

$$C + 2H_2 \Rightarrow CH_4 \quad (4)$$

$$C + CO_2 \Rightarrow 2CO \quad (5)$$

$$H_2O + C \Rightarrow CO + H_2 \quad (6)$$

Many of the commercial gasifiers use air as the gasifying agent for economic reasons. This results in a LBG which has a heating value of 100 - 200 Btu/ft^3, about 10 to 20% of the value of natural gas. This means that LBG used to replace an existing natural gas application will result in either a derating of the unit or will require significant modifications. Its low heating value also makes it less economical to transport.

By using oxygen as the gasifying agent, the resulting producer gas is a MBG, since it is not diluted by the high level of nitrogen that is introduced when using air. The MBG produced, when using oxygen, has a heating value of 200 - 500 Btu/ft^3, but on the negative side requires the complexity of an oxygen source. The use of MBG offers the ability of replacing natural gas applications with less of an impact than LBG. MBG can also be more economically transported than LBG.

As would be expected, the moisture content of the biomass can have a detrimental influence on the resulting heating value of the gas, due to dilution. However, moisture available during char combustion can be beneficial as an added gasifying agent with the water reacting with the char to provide additional gasification (Table 1.2-1). This moisture may have to be supplemented with the introduction of steam, since drying of the biomass occurs during the pyrolysis reactions. Steam may also be injected to assist in controlling the operating temperature (the steam - carbon reaction is endothermic, i.e., absorbs heat) in the gasifier which can have a direct bearing on the composition of the gas produced. Moisture levels much above 20% by weight of the biomass are usually found to be harmful to the energy output.

The design of the gasifier (feed method, recycle, temperatures, pressure, velocities, etc.), characteristics of the biomass (size, moisture, volatility, density, etc.), and the ratio of gasifying agent to biomass are other factors which influence both the quality and quantity of the gas produced. The maximum gas energy output has been shown to occur when the stoichiometric ratio (air/fuel ratio actual divided by air/fuel ratio theoretical) is around 0.25 to 0.30. In comparison, this ratio is typically 1.1 to 2.0 for combustion systems. This ratio is also referred to as the "equivalence ratio" in some references. Using higher levels of gasifying agent can increase temperatures and lead to more combustion. Typical energy densities reported for atmospheric pressure gasifiers is on the order of 1 MBtu/hr for each square foot of bed area for a nominal 50% moisture biomass. Values from 0.5 to as high as 4 MBtu/hr/ft^2 have been reported, depending on the moisture level. The higher value above was with a low moisture (8%) pelletized wood fuel. [3, 4, 6, 8, 9]

The design and general operation of FBGs, including fuel preparation, are similar to their combustor counterparts and the reader is referred back to Section 1.1 for discussion of these general fluidized bed topics. The main differences between FBCs and FBGs are that the gasifiers are typically fully refractory lined and that they operate in a substoichiometric environment throughout the reactor. Otherwise, similar equipment components and layout are found for both the combustion and gasification fluidized bed technologies. This section of the report provides a description of commercially available biomass fueled BFBG and CFBG systems and describes unique features of each as compared to its combustor counterpart.

Fluidized bed gasifiers, as will be seen, have the flexibility to cover a wide range of sizes. Commercially available FBGs were identified covering sizes from as small as 8.5 MBtu/hr to as large as 500 MBtu/hr (see Table B-2 in Appendix B). The main advantages of FBGs over the other gasifier concepts are greater fuel flexibility and higher throughput. The main disadvantage of FBGs is the increased particulate loading that leaves the reactor with the gas. These pros and cons are discussed further in this section. [6]

The FBG is centered around a refractory lined vessel referred to as a "reactor" versus a "combustor" for an FBC which may or may not be refractory lined. The refractory is essential in the gasification process since the function of the reactor is only to provide a containment for the process. Combustion in the gasifier reactor should be limited only to that required for maintaining the desired operating temperatures for the gasification reactions. This temperature range is typically between 1100 to 1800°F. The "bed" consists of inert material, such as sand, and/or a sorbent, such as limestone. A sorbent would be used if sulfur removal requirements were dictated and/or if problems with alkali agglomeration or tar cracking were expected. The bed also contains, at any given time, a small amount of fuel along with the resulting char/ash from the combustion that occurs. All of these materials are fluidized in the bed by the gasification agent which might be air, oxygen, and/or steam.

One of the drawbacks of FBG is the increased particulate loading leaving the reactor. Most uses of LBG require some level of particulate removal. Typically, one or two stages of cyclone cleanup equipment are needed and are located immediately downstream of the reactor. The particulate loading exiting from an FBG, compared to a fixed bed reactor, is one to two orders of magnitude higher. [6]

Fluidized bed gasifiers have a wider range of fuel flexibility as compared to other types of gasifiers. However, a given FBG should not be characterized as being able to utilize any fuel with equivalent efficiency. For this reason, the most likely fuel source should be specified and used in the design stage for the fluidized bed gasifier. If a variety of fuels are planned for the gasifier, then the design should be compromised to best accommodate the range of fuel properties. This will result in a design in which the fuel supply will have the least impact on efficiency and operation.

Uniform process temperatures is one of the keys to the success of FBGs in burning a wide variety of fuels. The bed material acts as a large heat sink (thermal flywheel) with the amount of fuel in the bed at any one time being only a few percent of the total mass. The bed material is able to transfer this heat uniformly to the fuel particles. Through the turbulent mixing, the bed tends to keep the ash layer on the char particles scrubbed off which maximizes the gasification, combustion and char conversion reactions. The large quantity of hot bed material provides stability to the process and permits the use of a wide range of high moisture biomass fuels. Since temperatures are maintained more uniformly, regions of low temperatures (inefficiency and thermal instability) and high temperatures (agglomeration) are minimized. The FBG is able to operate with higher average temperatures than other gasifier types due to this uniform mixing behavior. This is beneficial in the conversion of the resultant tars and oils into gas. While the average temperature is higher in an FBG, it does not see the higher temperature extremes seen in other designs. This allows the FBG to operate with lower NO_x generated, less chance for agglomeration problems, and less severe duty for the mechanical components. [6, 8, 10]

Fluidized bed gasifiers are capable of operation with fuel moistures as high as 65% or higher. However, it is prudent to reduce the moisture content to as low as practical for process efficiency reasons and, more importantly, to maintain the moisture at a uniform level (typically within 10% of the design value). Larger variations in moisture content can be detrimental to the process due to problems associated with gas flow rate and quality of gas produced, changes in gasification kinetics and thermodynamics, and with operation stability. The output of a gasifier can be reduced by as much as 50% for an increase in the fuel moisture from 20 to 40%. An FBG only converts a portion of the biomass energy into a hot gas with the remainder of the energy being used for the gasification reactions. [7, 11]

Biomass fuels used in FBGs should have an ash softening temperature (reducing condition) greater than the FBG operating temperature to minimize the potential for agglomeration. Most of the commercial FBG suppliers suggest a fuel top size on the order of 2 to 4 inches. The reaction time for fuel gasification in FBGs is effected by the fuel particle size distribution. Small, low density fuel provides for fast reaction times but suffers from the problem of elutriating from the unit. Reaction times can be increased by reducing the velocity, increasing the bed depth, and/or increasing recycle. Potassium and sodium in the fuel can lead to erosion, corrosion, and agglomeration problems. One supplier recommends that these constituents be limited (by fuel selection, fuel blending, etc.) to 500 ppm to minimize these problems. Table B-2 in Appendix B gives the requirements for fuel specification and also typical biomass fuels applicable to commercial FBG designs. [12]

1.2.1 Bubbling Fluidized Bed Gasifiers (BFBGs)

The first fluidized bed units were of the bubbling design. BFBGs have either no recycle or recycle the char material at much lower rates than CFBGs. This results in some loss of efficiency in converting the biomass char into gas or in using the char as a combustible heat source for the gasification reactions.

Tests performed on a 400 KWt BFBG, using straw as the fuel, showed that bed temperature could be effected and controlled by such variables as stoichiometric air ratio and bed height. As expected, bed temperatures increased when the air ratio was increased (combustion increased) or bed height was decreased (less mass to heat). Also, dense bed pressures increased with increases in bed height and superficial velocity and decreases in stoichiometric air ratio. [6, 10]

Commercial suppliers of BFBGs include JWP Energy Products, PRM Energy, Pyropower, and Tampella. Table B-2 in Appendix B contains a summary of information supplied by these vendors regarding their commercial offerings, guarantees, applicable fuels, auxiliary equipment requirements, and other pertinent information on their systems.

1.2.2 Circulating Fluidized Bed Gasifiers (CFBGs)

The circulating fluidized bed design was developed as a refinement of the bubbling bed concept to allow higher rates of recycle of material back to the reactor to increase efficiency (combustion, gasification). CFBGs, due to their high recycle rates (high residence times), result in high levels of char burnout and additional gasification of the solid carbon remaining in the char. This should also result in lower levels of tars/oils in the gas stream. CFBGs require fewer feed points per square foot of gasifier plan area than BFBGs due to better mixing and should be less sensitive to moisture and size variations. The CFBG incurs a capital and operating penalty compared to a BFBG in that it has a higher parasitic power usage due to the higher fan power requirements needed to provide the increased recycle rates. [7]

The particulate loading from a CFBG is higher than from a BFBG due to the higher velocities that are used in the CFBG. For this reason and to create the high recycle ratios characteristic of CFBGs, these types of gasifiers are equipped with high efficiency large hot cyclones. Most of the solids leaving the CFBG are recycled back to the lower section of reactor. This material contains fuel ash, bed material, and fuel char. The char provides a source of heat for the new fuel that is introduced to the reactor. [6]

Commercial suppliers of CFBGs include Future Energy Resources (Battelle), Gotaverken Energy, and Pyropower. Table B-2 in Appendix B contains a summary of information supplied by these vendors regarding their commercial offerings, guarantees, applicable fuels, auxiliary equipment requirements, and other pertinent information on their systems.

1.2.3 Pressurized Fluidized Bed Gasifiers (PFBGs)

Pressurized fluidized bed gasifiers (PFBGs) can be either of the bubbling or circulating design. The effect of pressure on the gasification reactions is slight. The benefit of operating the FBG under pressure is in the effect it has on the size and cost of the equipment. The amount of fuel that can be fed to a PFBG is approximately related to the pressure ratio raised to the 0.6 power. For instance, operating the FBG at a pressure of 300 psia would allow a given reactor to process approximately 6 times the amount of fuel. Alternatively, the PFBG can be made smaller and process the same amount of fuel as an atmospheric FBG. PFBGs have the attractiveness of reduced size which could be an important parameter, especially as a retrofit or addition at a pre-existing facility. By pressurizing the process, smaller gasification train equipment can be used. More of the construction can be performed in the supplier's shop (modular design), requiring less field construction. Operating at higher pressures does result in an increase in equipment complexity. Scaleup to higher pressures (20-40 atmospheres) has not been demonstrated. [6, 7]

One of the benefits of operating under pressure is that the pressurized producer gas is ready for use in a gas turbine. This application is discussed further in Section 1.5. The PFBG operating pressure is primarily determined by the gas turbine inlet gas operating requirements.

The world's first integrated gasification combined cycle plant using a biomass gasifier was commissioned in 1993 in Sweden by Bioflow, a joint venture between Pyropower and Sydkraft. The plant uses a pressurized CFBG and has a capacity of 6.1 MWe of electricity (4.1 MWe from the gas turbine and 2 MWe from the steam turbine) and 9 MWe of district heating. It is fueled by waste wood and wood chips. The fuel is dried in a rotary drum dryer using flue gas from an auxiliary boiler. A lockhopper system is used to feed material into the gasifier. Gasifier, cyclone, and loop seal are all refractory lined. The cyclone is unique in that it has both solids and gas outlets at the bottom of the cyclone. Operating pressures exceed 300 psia with temperatures on the order of 1800°F. The larger size fraction of ash is discharged as bottom drain from the gasifier. The producer gas formed is cooled in a fire tube heat exchanger down to about 660°F before being cleaned of particulate in a ceramic filter. The clean gas is sent to the gas turbine where it produces about 4.1 MWe in the generator. Exhaust gas from the turbine is sent to a waste heat steam generator and produces superheated steam (600 psia and 880 °F). This steam enters a steam turbine and generates an additional 2 MWe of electricity. District heating capacity of 9 MWe is provided by the exhaust steam from the steam turbine. The facility is involved in a demonstration to optimize performance, equipment, and control and is scheduled to be turned over for commercial operation in the fall of 1995. [13]

1.3 BIOMASS FUEL PREPARATION EQUIPMENT

In general, biomass fuels are sourced from three broad categories, woody fuels, agricultural waste, and refuse derived fuels (RDF). Woody fuels include whole tree chips, sawmill waste, urban tree trimmings, orchard trimmings, broken pallets, and building demolition wood. Some examples of agricultural fuels are straws, bagasse, hulls, pits, cotton gin trash, and stems. RDF is usually processed from municipal solid waste, though other sources such as shredded currency, telephone books, or other bulk paper can be used. Each of these fuels can come in a wide variety of shapes, sizes, moistures, and densities. The primary objectives of fuel preparation are to assure the fuels can be reliably fed and burned in the unit. Since the feed system's reliability is a function of size and dryness, the fuel preparation system is needed to assure that the fuel is the proper size and moisture content. Further, depending on the conditions at the source, biomass fuel may also contain metal scraps or tramp iron and other detrimental materials which must be removed. For most fluidized bed units, the fuel preparation system is one of the most important systems.

The primary functions of the fuel preparation system are, generally, the drying of fuel, sizing of fuel, and removal of noncombustibles from the feed stock. However, other functions are performed in special cases. Municipal Solid Waste (MSW) is sorted and processed to produce RDF. Sawmill waste, many agricultural wastes, and RDF may be formed into pellets or briquettes. These operations are also considered as fuel preparation functions. Appendix C contains a listing of fuel preparation equipment vendors.

1.3.1 Processing Wood

1.3.1.1 Wood Drying

The objective of dryers is to make the wood easier to feed, easier to burn, and to allow production of more usable heat. Using dry wood increases the overall thermal efficiency of a boiler, since it is not necessary to waste energy vaporizing the moisture contained in the green wood. To illustrate this point, flame temperatures in a conventional combustor of 2300 to 2500°F are obtainable with dry wood, as compared to about 1800°F with green wood. While these flame temperatures do not represent the bed temperature in a fluidized bed combustor or gasifier, the effect on temperature and efficiency is the same. The flame temperature reflects the heat required to evaporate the water contained in the wood. Since less energy is robbed to evaporate the moisture, boiler efficiency is increased when dry wood is burned. Wood fuel also becomes easier to size and feed as moisture is removed.

It is important to know the following when choosing or designing a fuel drying system.

- Nature and type of material to be dried. Some materials require special considerations by the designer.

- Quantity of material to be dried. Both average and maximum flow rates are needed to select the proper type and size equipment.

- Maximum and minimum moisture content of the incoming feed stock and the required moisture content of the product fuel. These criteria affect the type of equipment selected and the energy required to dry the fuel.

- Maximum and minimum size and density of the material to be handled influences the design of the drying equipment, such as inlet and outlet size and gas velocity for some dryers.

There are two basic methods of reducing the moisture content of wood fuel: one uses hot gas to evaporate the water, and the other uses a mechanical press to remove the water. Hot gas dryers are more common and are available in many forms.

<u>Hot Gas Dryers</u> - The hot gas for these dryers can be supplied by a dedicated burner or can be sourced from combustor or gasifier flue gas. The use of flue gas as a drying medium is receiving considerable attention as it provides a significant advantage. This drying method offers improvement in cycle efficiency, since the dryer can extract some heat that would otherwise be discharged up the stack with the flue gas or in the case of a gasifier, boiler, turbine or engine exhaust. Further, flue gas has a very low oxygen content, which minimizes the risk of dust explosions. It is common for the gas leaving the dryer to be approximately 225°F. This is 100°F or more below what would be considered normal for stack temperatures of boilers with air heaters and economizers.

Acid condensation or dewpoint should be considered when designing a flue gas dryer. Acid dewpoint is usually associated with the sulfur in coal and the SO_3 content of the flue gas. The SO_3 can combine with moisture and condense out as sulfuric acid on surfaces which are below the acid dewpoint temperature. Since most biomass fuels have low sulfur contents, this will probably not be a problem. However, the high alkali content may lead to chlorine problems with some biomass fuels.

It is generally agreed that flue gas dryers should be considered in the design of wood-fired steam systems whenever the fuel total moisture exceeds 55%. They can be justified in most installations on the basis of efficiency gains alone. When designing a system, one of the first steps is to establish the desired moisture content of the fuel as it leaves the dryer. While at first glance it appears obvious that less moisture is better, that may not always be the case. Some information suggests that there is an optimum moisture level, possibly around 35%, which gives the best balance among dryer cost, plant performance, system efficiency, and problems associated with handling dry fuels, such as dusting and dust explosions.

The efficiency improvements associated with flue gas dryers have made retrofit of existing plants justifiable in some cases. However, the maximum benefit can be gained when the flue gas dryer is included as part of the original design and construction of the facility. Figure 1.3-1 shows a schematic of a biomass combustor with a flue gas dryer.

There are several types of hot gas dryers available on the market. These are:

<u>Rotary Dryers</u> - In a rotary dryer the wood is dried as it tumbles through a horizontal rotating drum. The wood and hot gas enter at the same end. As the wood enters the dryer, it is partially entrained in the gas and is carried horizontally through the rotating drum. Rotary dryers are of two types, single pass and triple pass. The single pass dryer has a smaller pressure drop, and consumes less fan horsepower. Consequently, it has a lower operating cost. Control of product moisture is not as precise as in a triple-pass dryer; however, this should not be a problem where the end goal of the dryer output is combustion. It is more of a problem for gasifiers where moisture consistency is important. Figure 1.3-2 shows an example of a triple pass drier. Both types are available commercially. See Appendix C for vendor information.

<u>Cascade Dryers</u> - In cascade dryers the wood fuel is dried by falling through streams of hot gas, much like the path of a lightweight sand would appear when tossed into a cascading fountain. Cascade dryers are used when large capacity drying is needed. No auxiliary fuel input or motor horsepower are required. However, the pressure drop demand across the unit must be taken up by the fan, thus some energy input is necessary. An example of a cascade dryer is shown by Figure 1.3-3.

<u>Flash dryer</u> - Flash-type dryers are simply several loops of duct. Drying occurs where the wet material and hot flue gas mingle. A flash dryer can be combined with a classifier and used to separate the fuel by size. In this application the flue gas is not only used as a drying medium, but it is also used

Combustor with Flue Gas Dryer

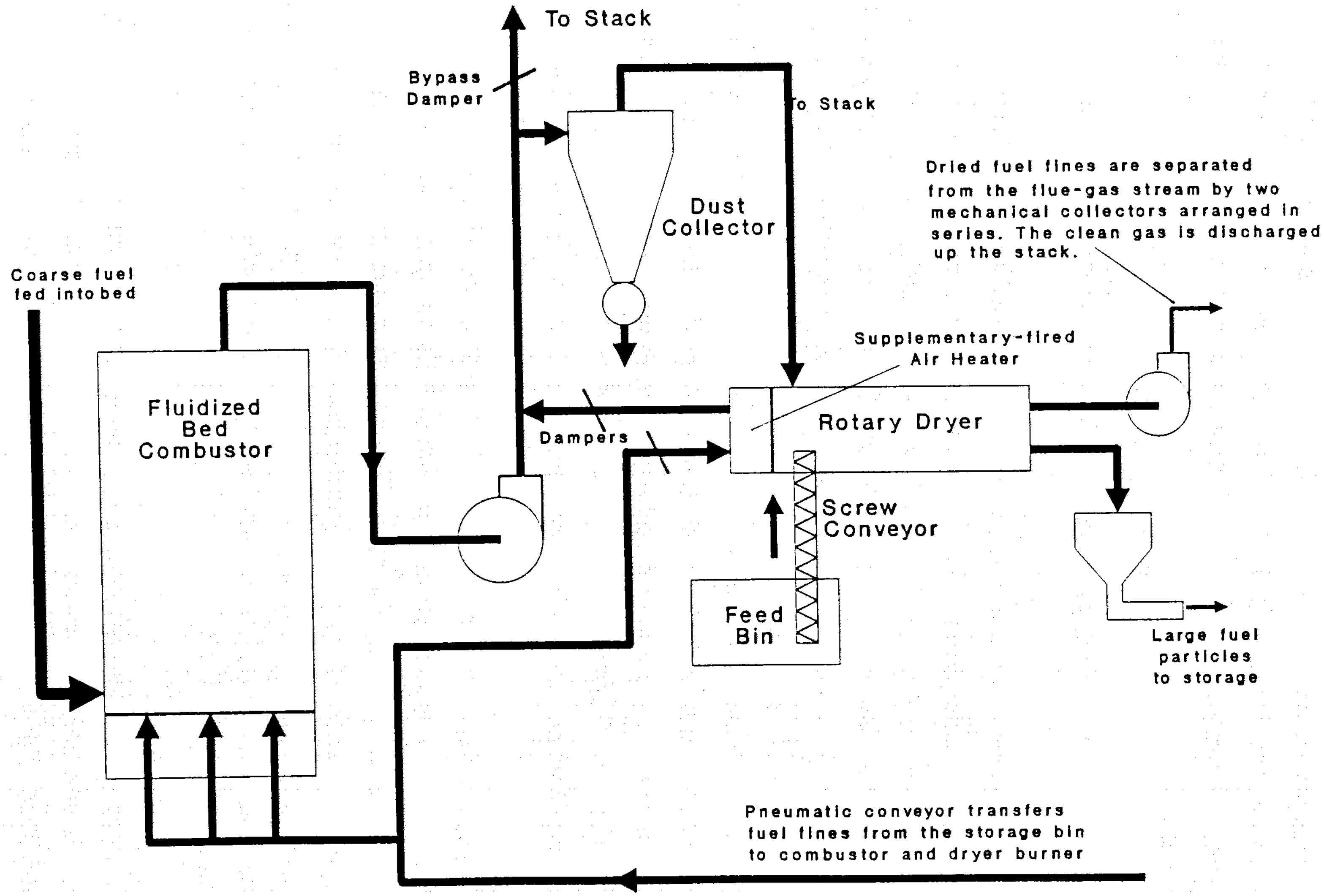


Figure 1.3-1

Source: Ref. 14

Rotary Drum Wood Drying System

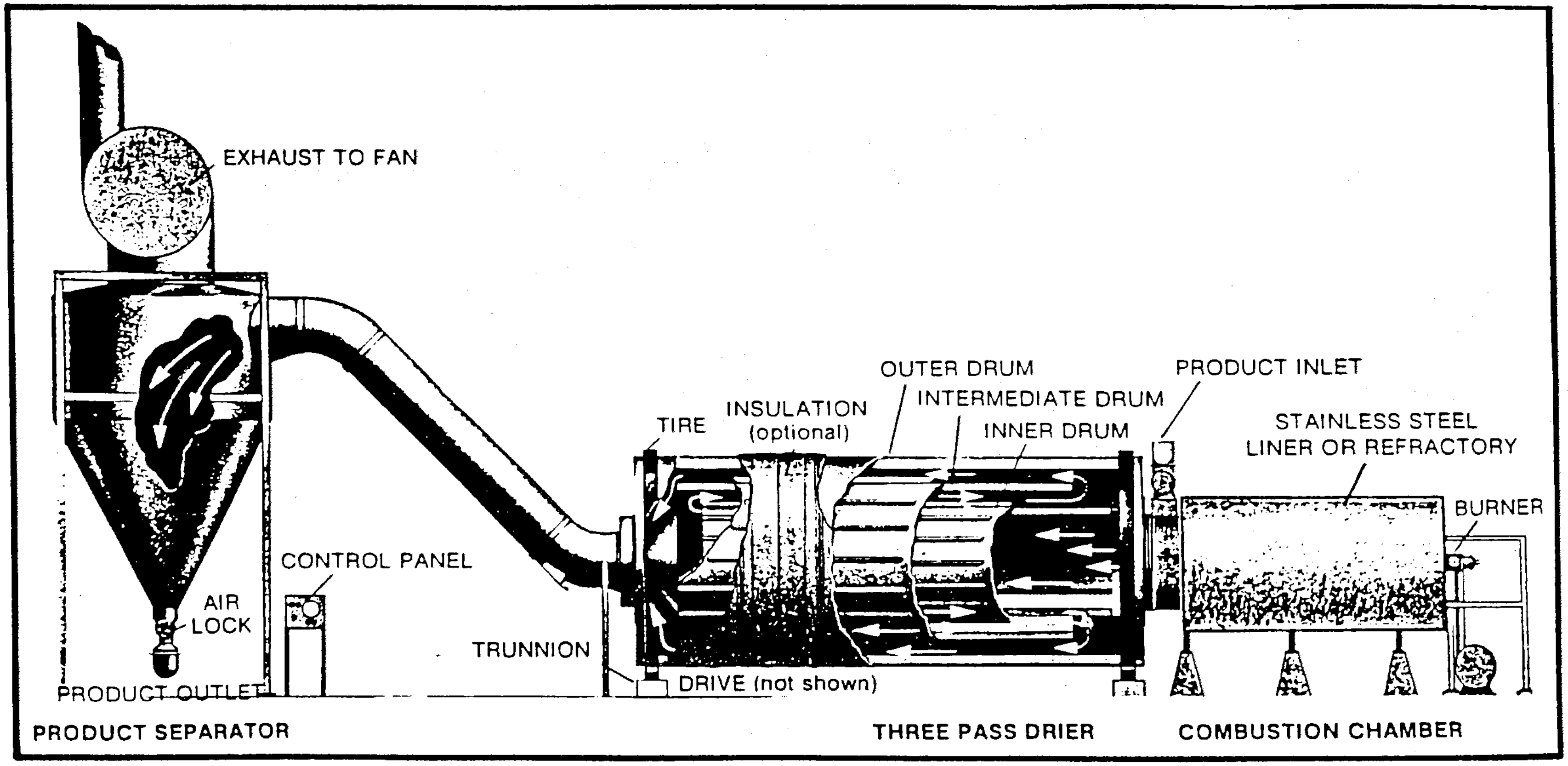
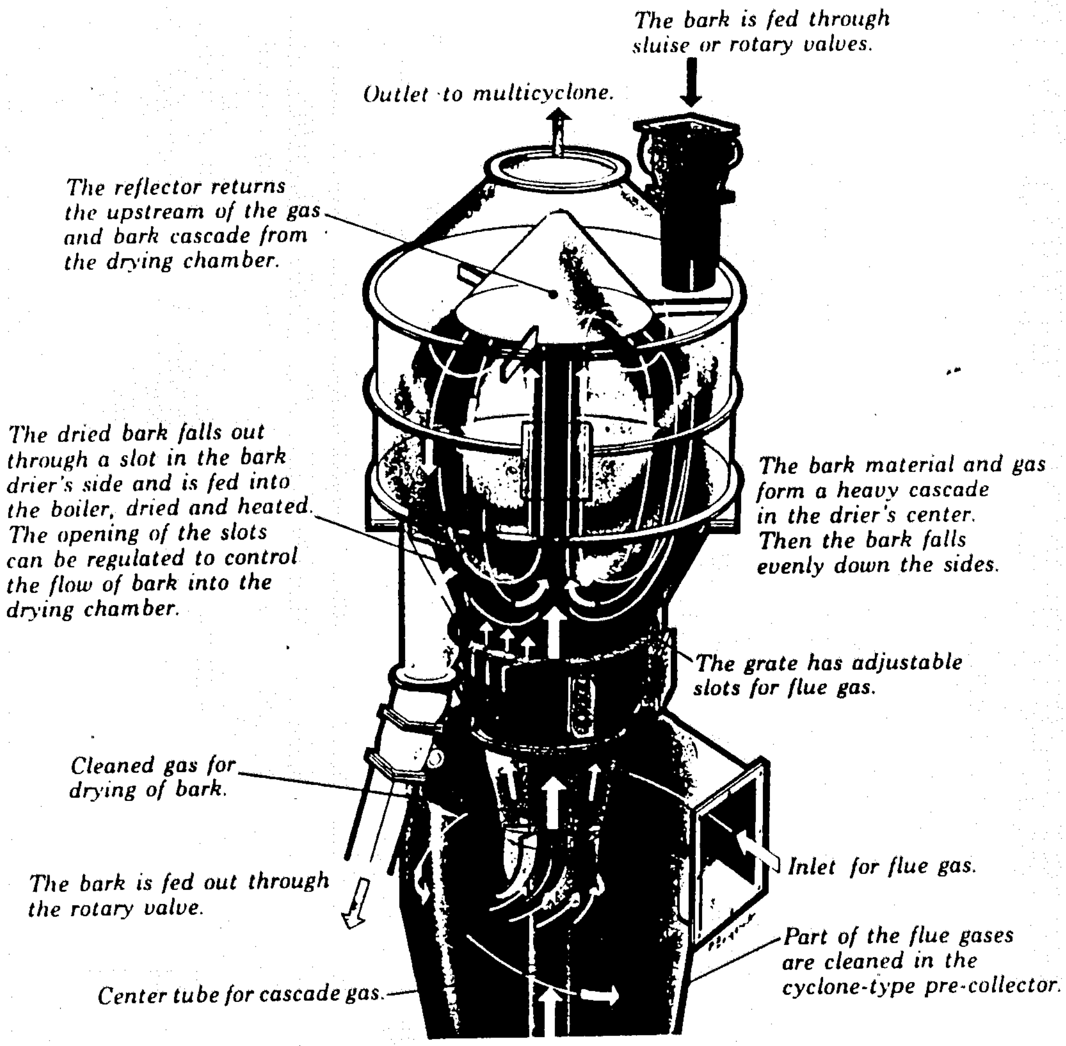


Figure 1.3-2

Source: Ref. 13

Cascade Dryer



Source: Ref. ~~18~~ 21

Figure 1.3-3

instead of air to pneumatically transport less dense and properly sized fuel vertically upward through a column, while the oversize fuel drops down to a hog or crusher. The hot flue gas dries this material as it transports the fuel upward. The flue gas and fuel are separated in a cyclone or set of cyclones at the top of the drying/classifying column. This arrangement has the advantage of combining drying and sizing; however, it is very sensitive to variations in density of the fuel. Air classifiers are discussed in Section 1.3.1.2.

Hot Hog Dryers - With this type of dryer the fuel is dried in the hog where size reduction also takes place. Hot hogs are reported to have high power requirements and maintenance costs. These dryers are limited in the amount of moisture they can remove and require that all fuel be hogged for drying, instead of just the oversize fuel. Safety issues have also been identified concerning hot hogs. Wood hogs are discussed further in the next section.

Hot Conveyor Dryers - This is a vibrating conveyor with holes in the tray which allow the flue gas or hot air to flow through the fuel as it is being transported. These dryers are typically used for applications of low volume and are reported to have high maintenance costs.

All drying systems require auxiliary equipment for the collection of fine material in the dryer exhaust. In general, these are more complicated where flue gas is used as a drying medium than for dedicated dryer burners, since the flue gas contains flyash. Dedicated burners are usually oil or gas fired and are a "clean" drying source. Systems to clean dryer gas may consist of single cyclone, multiclones, precipitators and/or baghouses.

Typically larger wood particles are collected in a hopper and bark and other fines are removed by cyclones. The remaining flyash is removed by precipitators or a baghouse.

Mechanical Press Dryers - Installed primarily in pulp-and-paper mills, mechanical or hydraulic presses squeeze water from bark that may contain up to 70% moisture. Applications for presses are limited because they cannot reduce the moisture level below about 55%. They also consume large amounts of power and require continual maintenance. Further, the water squeezed from the bark must be treated prior to its release to the environment. Presses can also be used as predryers for very wet fuel such as sludge or wet bark. In this case the fuel from the press would then be fed to a hot gas dryer. [14]

1.3.1.2 Wood Sizing

Ideally, biomass fuel would be delivered to or available at the facility in a size ready to feed into the combustor. However, this is not usually the case. Uniformly sized particles of wood or other biomass fuel facilitate the handling and combustion process, therefore sizing of the fuel is normally required. The first step in the sizing process is size classification of the fuel. The appropriate and undersize fuel require no further sizing. The oversize fuel is fed to a size reduction machine before entering the fuel feed system. Figure 1.3-4 shows a typical fuel sizing system.

Classification - It is important to know the following when selecting size classification equipment.

- Nature of the wood waste. Some materials require special consideration by the designer.

- Quantity of material to be classified. Both average and maximum flow rates are needed.

- Required product size. This is essential for obvious reasons. The required product size is determined by the combustor configuration and the limitations for the fuel feed system.

Fuels Sizing System with Disk Screen

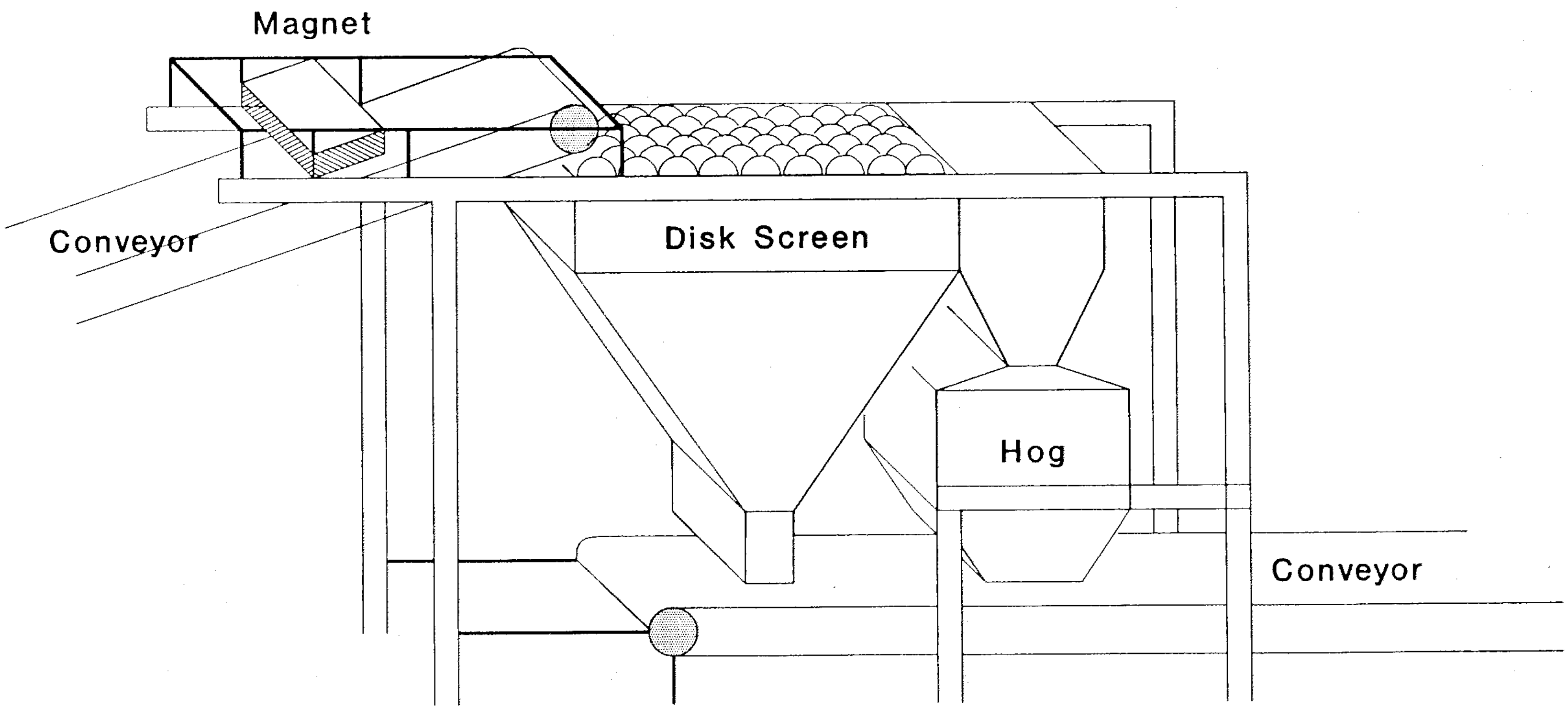


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Figure 1.3-4

- Size range of the raw fuel to be classified. This influences the inlet design and the design of the oversize outlet.

Disk and vibrating screens are the types of sizing equipment most widely used for wood fuel applications. Flotation and air classification are other methods used to screen and classify the fuel stream.

Disk Screen - The disk screen consists of overlapping rotating disks which allow fuel of the proper sized to fall through while oversize material is carried off. Advantages of disk screens include:

- Nonclogging, self-cleaning operation.

- High capacity compared to other types of screens. Equipment is available to process more than 40,000 ft^3/hr with a drive system rated less than 20 hp (15 KW).

- Variable product size. Disk spacing can be adjusted in the field to accommodate changes in fuel requirements of the plant lifetime.

A typical example of a disk screen is shown in Figure 1.3-4.

Vibrating Screen - A vibrating screen passes the fuel over a mesh and can be used to remove either oversized or undersized pieces. Vibrating screens generally have a smaller capacity than disk screens of a similar size. This type of screen is vulnerable to blinding or plugging, which can be caused by moisture in the fuel.

These screens are particularly well suited for removing dirt from the fuel. However, if dirt were to be fed into a fluidized bed combustor or gasifier, it would simply supplement the existing bed material and usually be of little significance. For this reason, dirt removal is generally not an issue with a fluidized bed combustor or gasifier. Further, vibrating screens are generally not selected to process the entire wood waste stream because of the smaller capacity compared to disk screens and their tendency to blind during the processing of unsized green wood fuel.

Flotation - Wood waste is dumped in a flume, and bark and wood are collected from the surface of the water as dirt and gravel settle to the bottom. A disadvantage of flotation is that the wood becomes saturated, reducing its net heating value. As with vibrating screens, the primary advantage of this method is the removal of dirt. Since dirt in fluidized bed fuel poses no significant problem, this method of sizing is not a viable means of classifying fluidized bed combustor or gasifier biomass fuel. Large rocks/gravel, however, can cause fluidization problems.

Air Classification - There are many variations and types of air classifiers, however, they all work on the same basic principle. The appropriately sized and less dense materials are pneumatically transported to a new location and the larger or more dense material are not transported, thereby providing separation. The geometry of the transport duct and location that the material is transported to vary with type of classifier. However, in most cases the oversize or dense materials drop out of the gas stream near the point where they are introduced. These systems are very sensitive to variations in the density of the fuel, which makes them vulnerable to trash material of low density such as empty soda cans or rags. These systems are normally not required for a fluidized bed combustor or gasifier burning most biomass fuels. However, air classifiers are very common in the processing of municipal solid waste as discussed in Section 1.3.3.

Size Reduction - Size reduction machines are commonly referred to as "hogs" when dealing with fresh cut wood, or "shredders" when dealing with any other waste products. Chippers and hammermills are the most common types of wood hogs.

Since hogs are expensive to operate, it is advisable to place the hog in a bypass loop or at the screen's oversize discharge and size the hog to reduce only the oversized portion of the fuel.

Unsized material can be extremely difficult to handle, particularly if it is compacted in storage. Hogs generally are adjusted to discharge the product with a top size of 2 to 3 inches, which is a good compromise among power costs for shredding and ease in handling. [14]

It is important to know the following when purchasing a hog:

- Maximum size of pieces of wood or bark to be handled by the machine. This influences the size of the hog inlet opening as well as other parameters.

- Nature of the wood waste. Some types of wood and bark require special consideration by the designer.

- Quantities of wood waste requiring size reduction. Both average and maximum flow rates are needed.

- Required product size. This factor has significant impact on hog capacity. The larger the allowable product size, the greater the capacity of a given machine and the lower the power consumption for a specified throughput. [14]

The required product size is determined by the combustor or gasifier configuration and the limitations for the fuel feed system. Chippers and hammermills are described as follows:

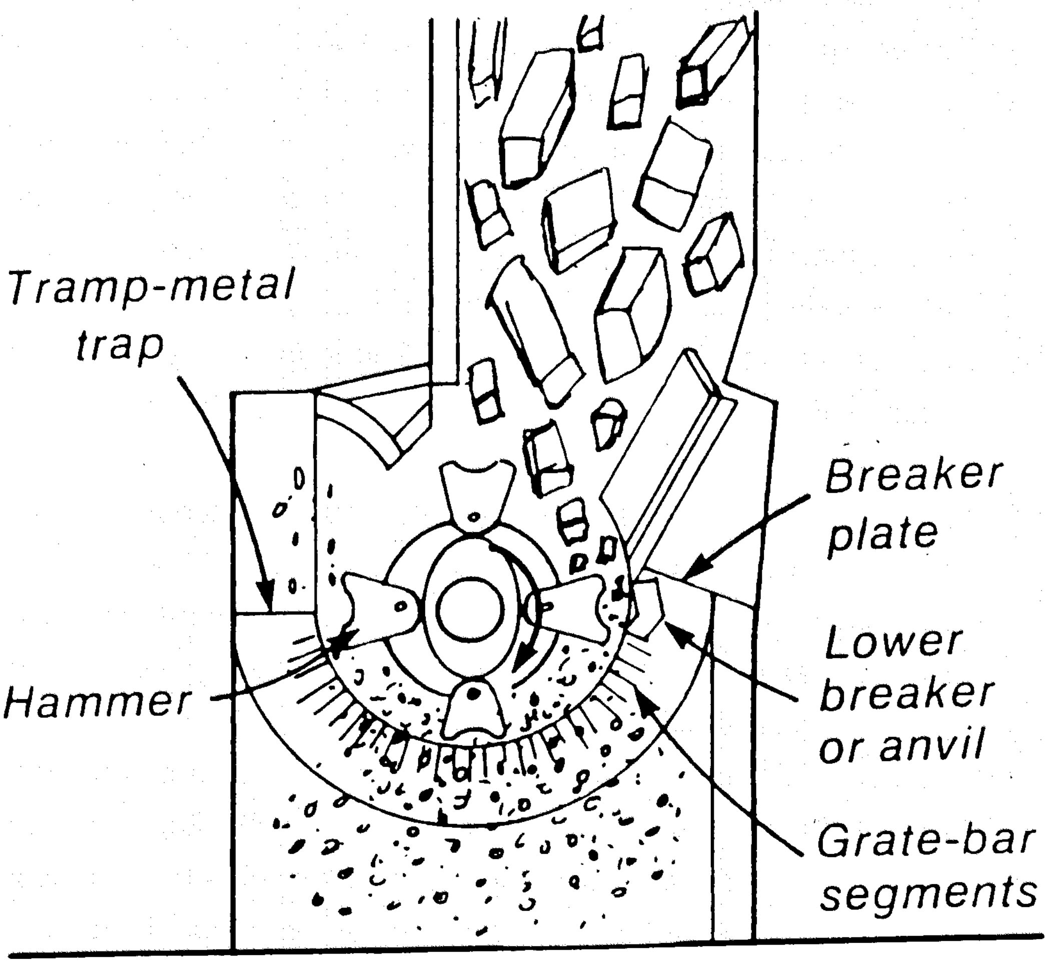
Knife Chippers - Chippers are high speed rotary devices (up to 1800 rpm) designed to reduce logs or heavy members of wood to chips. The wood enters a cavity in a rotating cylinder where sharp cutting blades are used to shave off a chip from the wood as the moving blade passes a stationary blade. These machines are not suitable for cutting paper or rubber but are ideal for wood. The cutters can be damaged by metals and other hard objects in the feedstock, which make these machines vulnerable to tramp iron. This places chippers at a substantial disadvantage for processing at the plant site since it is common for tramp iron and other trash to be included with the fuel source during transport to the plant. These machines are most common in a portable form and are used to chip trees, limbs, bark and brush where it is cut before transport to the plant for burning. Typically, chippers can handle fuel of any moisture content, which makes them well suited for use with fresh cut wood. With coordination between the plant and the wood harvesting organization, the chippers output size can be set within the combustor feed train's acceptable size range and no additional sizing will be needed before the fuel is fed into the combustor. [15]

Hammermills - These hogs can handle light iron (nominally 1/4 in. and smaller), such as small bolts and steel strapping, without incurring any damage. Further, these machines are normally protected against heavy tramp metal by a shear-pin arrangement. Figure 1.3-5 shows how a typical hammermill works. Wood is gravity fed through a large opening in the top of the hog, chopped between the hammers and the breaker plate and then ground between the hammers and the screen at the bottom of the unit. However, for hammermills to operate successfully, the fuel must be relatively dry. Therefore, if a hammermill is used for size reduction, the fuel should be dried before it is sized. [14]

1.3.1.3 Metal Separation

Metal removal should also be included as a part of the fuel preparation system to remove the contaminants in the fuel. Since metallic pieces tend to clog a fluidized bed, they should be removed as one step in the fuel preparation. In the case of a fluidized bed combustor or gasifier, the presence of rock and dirt is less of a problem

Hammer Mill Hog



Source: Ref. 14

Figure 1.3-5

than with conventional combustors. In a fluidized bed, small noncombustibles such as these will simply become part of the bed material; therefore, removal is not necessary if the fuel preparation and fuel feed systems are designed to handle these materials. Tramp iron and other magnetic scraps are usually removed ahead of the hog or hammermill by a magnet or metal detector.

1.3.2 Processing Agricultural Waste

The equipment needed to process agriculture waste will vary with the waste to be burned and the form in which it is received. In some cases agricultural waste can be fed to the combustor as it is received. Very commonly agricultural waste is baled for shipment. In these cases, a machine commonly referred to as a bale breaker is required. If further size reduction is required, a hammermill similar to that described above would be in order, though the detailed design of the equipment might vary.

Bale processing machines can be constructed in several configurations. One possible configuration is similar to a wood chipper, with knives mounted on a rotating drum. The bale sets on top of the drum and with the discharge below. These bale processing machines may be designed for high speed or low speed rotating drums. The high speed drum can create a significant fire risk and are prone to throw off their knives. However, the low speed drum chippers require a large quantity of torque and therefore, are a significant user of energy.

Another approach to separating bales is to saw them into pieces that can be accommodated by the fuel feed system. This can be accomplished with circular or reciprocating blades. If reciprocating blades are used, several reciprocating blades would cut through the bale and allow the pieces to fall into the fuel feed system. Several circular blades could also accomplish the same goal by moving across the bale thereby cutting it into sections that can be accommodated by the fuel feed system.

1.3.3 Processing Refuse Derived Fuel (RDF)

RDF is typically processed from municipal solid waste (MSW). The RDF is delivered to the plant in a ready to feed, ready to burn form. This fuel normally does not require any on site processing facilities; however, the processing facilities are of interest and will be discussed briefly.

The primary purpose of the RDF processing facility is to separate the combustibles, recyclables, and noncombustible non recyclables. The combustibles are sized and prepared to feed into the combustor. This is accomplish manually and by use of automated equipment. Often the manual sorting takes place at picking stations. These consist of conveyor belts which move the MSW by workers who manually remove certain items from the conveyor. Trommels are often used for size separation. This piece of equipment is illustrated by Figure 1.3-6. Disk screens and air classifiers are also used for size and density separation, and hammermills and shredders are used for size reduction. The order in which these components are arranged and the number of components varies with the recycling facilities available, and the capabilities of the fluidized bed unit and it's feed system. A typical RDF processing system is shown by Figure 1.3-7. The processing facility, illustrated in Figure 1.3-8, is planned by Kvaerner EnviroPower AB for use with a fluidized bed boiler to be constructed in Fayetteville, NC.

The following is a description of an operating RDF processing facility at Northern States Power Company's French Island Plant, which burns RDF blended with wood in a fluidized bed boiler. Figure 1.3-9 is a schematic of the material flow through this facility.

A receiving and storage area utilizes the "tipping floor" concept. This concept allows proper inspection of the waste stream before any processing. Once the waste stream passes the inspection point, it is conveyed to the processing area.

Trommel

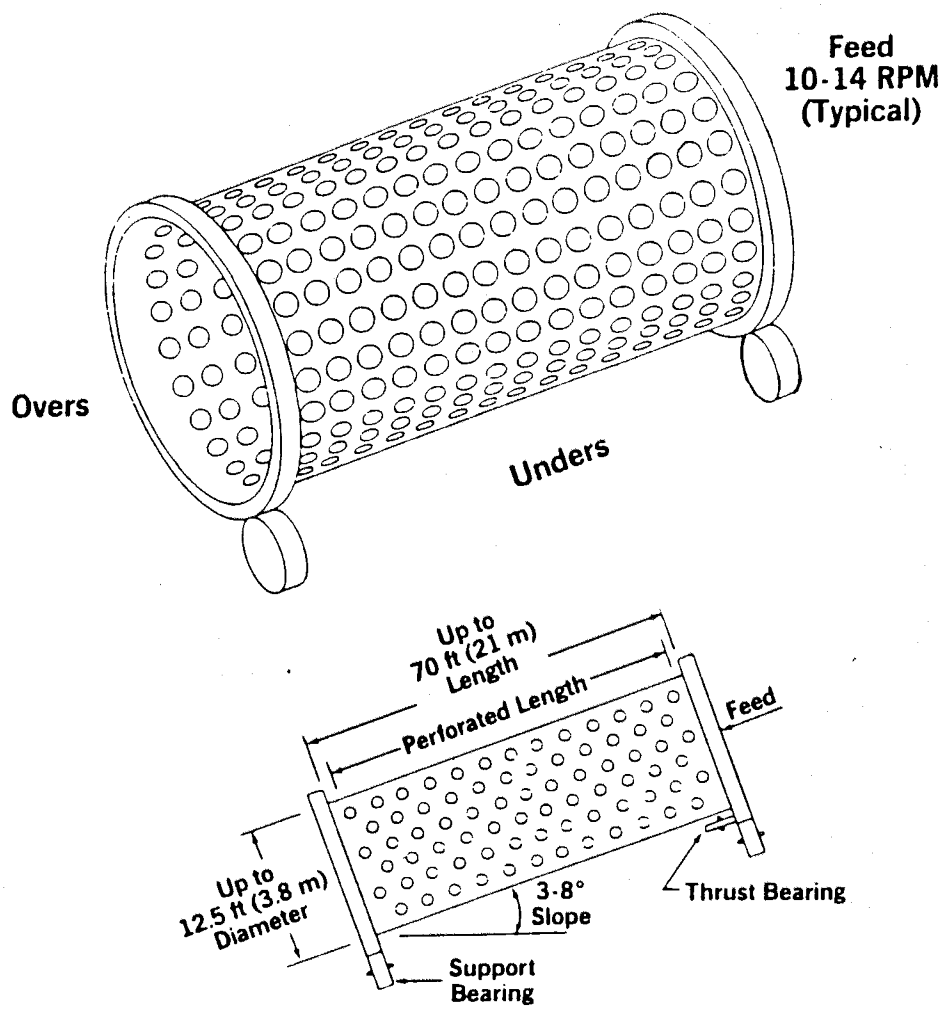


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Figure 1.3-6

Typical RDF Processing Facility Flow Diagram

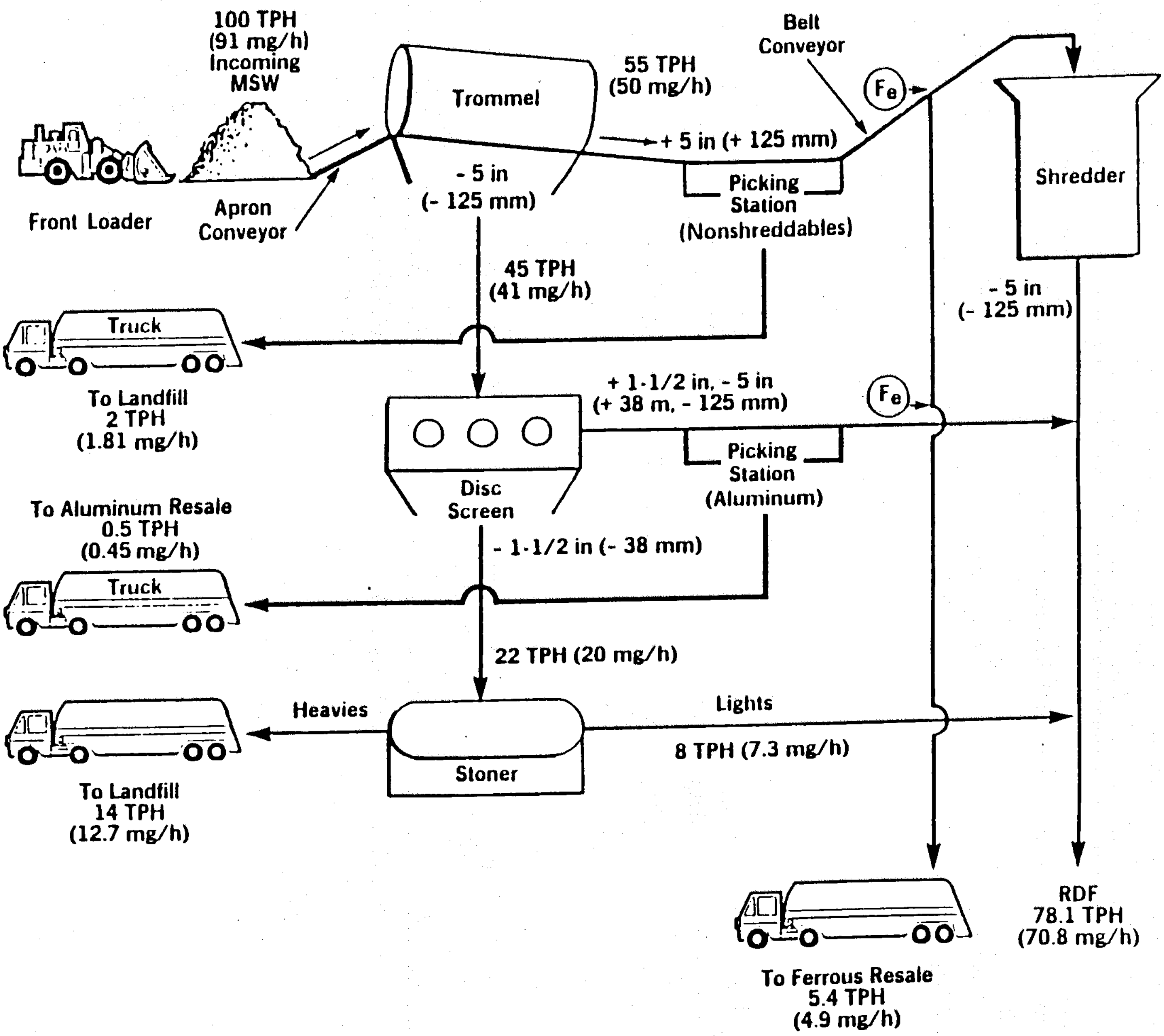

Figure 1.3-7

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Planned Kvaerner RDF Processing Facility

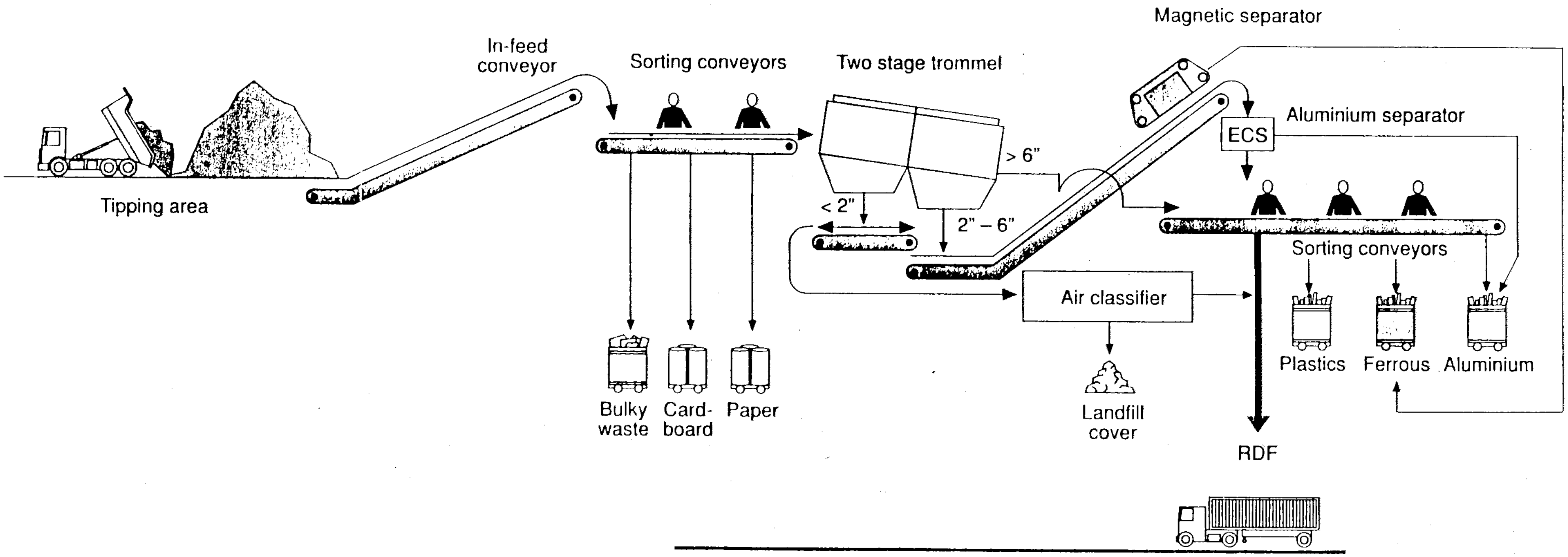

Figure 1.3-8

French Island RDF Processing Flow Chart

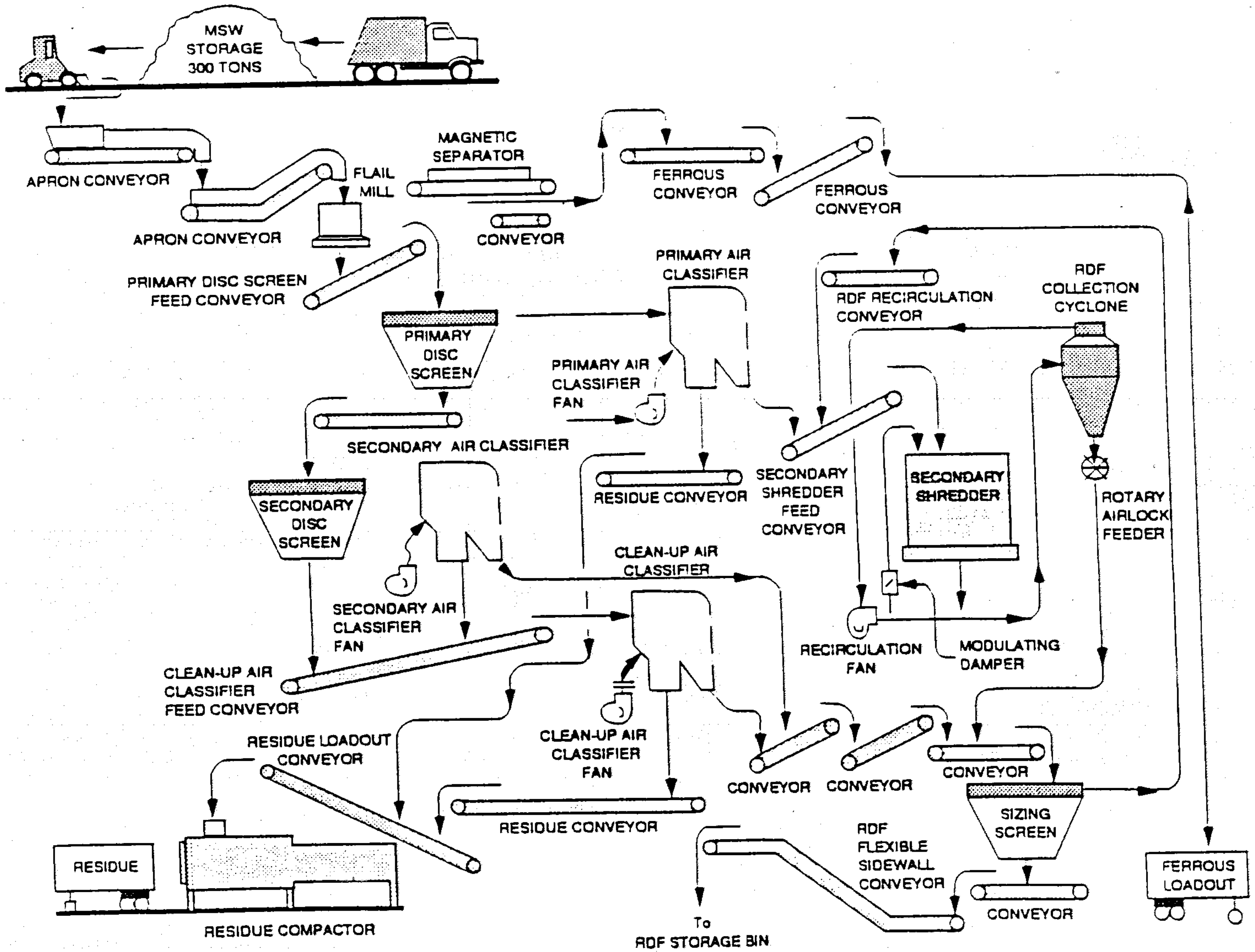

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Figure 1.3-9

A flail mill (similar to a hammermill) reduces the size of the MSW to a nominal 12 inches in size. The milled product is magnetically scalped by a deep draw belt-type magnetic separator. The ferrous preconcentrate from this unit is further refined, as required by market conditions or landfills.

Disc screens are used to accomplish a size separation at 4 inches and 2 inches. The oversize from the primary disc screen (+4") goes to an air density separator, which removes the heavy fraction (ferrous and non-ferrous tramp metals) from that stream. Tramp metals go to residue loadout, while the light fraction from the separator goes to the secondary shredder for final size reduction and RDF product load out. The undersize from the primary disc screen goes to the secondary disc screen, where that stream is further processed to concentrate the combustible and remove the non-ferrous metals and glass. The combustibles in this stream are then combined with the RDF product. The undersize from the secondary screen is further processed for the recovery of combustibles by an air density separator before being directed to residue loadout.

In summary, this design uses the concept of primary size reduction by flail mills, general sizing by disc screens and removal of specific recyclable items, such as ferrous materials. The recovery of small organics, as a valuable source of combustibles, is accomplished by density separation, which also reduces the volume of material going to landfill.

The final RDF stream consists of a composite of shredded material from the secondary shredder and "lights" from the secondary air knife. The RDF stream is conveyed to a check screen to size material for proper combustion. The oversize from this screen returns to the secondary shredder for additional size reduction. The undersize from this sizing operation goes to the RDF storage bin for ultimate retrieval and combustion in the boilers. [16]

1.3.4 Densification

Densification of biomass material has been of interest for quite some time, in spite of the questionable cost effectiveness. For example, the U.S. Navy was experimenting with densification processes in the early and mid 1970s. For the most part, densified biomass material takes three forms, bails, briquettes, and pellets. Bails are used primarily with agricultural waste and are prepared as a part of the farming process, therefore are not within the scope of this document. Briquetting and pelletizing are the forms of densification of interest for industrial and commercial use in fluidized bed combustor and gasifiers. Densification of biomass fuels provides several distinct advantages:

- Densified fuel is practically dust free, thereby reducing dust explosion potential in storage areas and minimizing particulate emissions in the flue gases.

- Densified fuel is uniform and relatively stable, thereby allowing good control of the combustion process.

- Densified fuel is free flowing, facilitating material handling and feed rate control.

- Densified material is of increased bulk density and low moisture content, providing a higher energy content per unit volume as well as economies in storage and transportation.

As densification processes have evolved, it is found that a significant quantity of energy is required to operate effective densification equipment, therefore the economics of producing pellets and briquettes is an important issue. The energy cost for densification negatively influences the sensitive economics of biomass fired plants and may make this form of biomass fuel financially unacceptable. Additionally, both cubes and pellets can pose combustion problems due to their high specific density and much longer burning time requirements, as well as settling in fluidized beds. [17]

1.3.4.1 Briquetting

Briquetting is a technology that can convert many types of biomass waste to a useful fuel, by compressing small combustible material into a brick-like form that can be used by industrial, institutional, or residential customers.

Briquettes can be produced by several types of machines, however, roll presses are proving to be the preferred method of production. These presses can compact a variety of different materials into many different briquette shapes and sizes and can be sized for a wide range of production capacity. Roll presses are classified into two main types, cantilevered or symmetrical. These names are taken according to the way in which the rolls are mounted on their bearings.

Cantilevered rolls are mounted outside their two bearing blocks, which results in the forming rolls protruding from one end of the press. These designs allow the rolls to remain more nearly parallel as compacting forces spread them apart, which generally keeps the briquettes more uniform in volume.

Symmetrical rolls are mounted between their bearing blocks on the roll press, which permits wider roll widths for more cavities, therefore, yielding a higher unit production capacity. This design is better suited to briquetting hot materials because the bearings can be located farther away from the rolls. They also are capable of greater roll separating forces for the same roll diameter. Symmetrical mounting also lets the rolls skew to maintain more uniform pressure across the roll face for more uniform briquette densities. [18]

Another type of briquetting machine is the crankshaft rampress. This machine was common in the early experiments of briquetting. The crankshaft rampress is very sensitive to varying conditions in the biomass, because the density of the briquette is determined by the friction between the biomass and the nozzle after the piston. This type of briquette press requires considerable skill to produce briquettes of an acceptable quality. [19]

Most any biomass material that has been reduced to a small size is a good candidate for briquetting. Many materials will require the use of binders or a lubricant to produce adequate quality briquettes. Binders are additives that increase the strength of the agglomerate, whereas lubricants decrease the coefficient of friction between individual particles, or between the surfaces of the agglomerate and the forming rolls. Some types of materials can function both as a binder and lubricant.

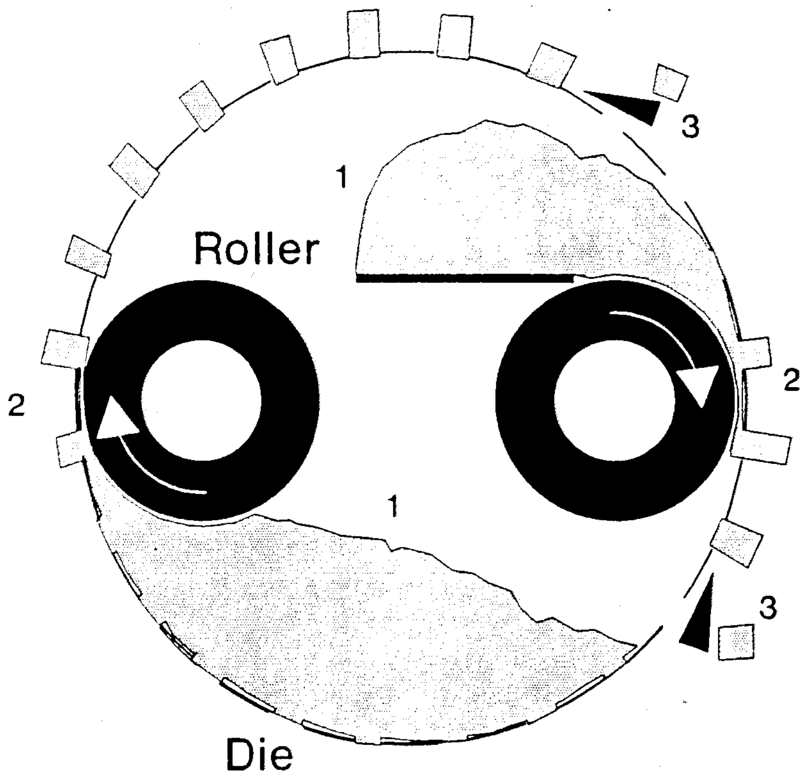
When briquetting with binders, mixing adds an important variable to briquetting quality. Proper mixing also can minimize costs by allowing use of less binder. Overmixing, however, can make the material too wet or too gummy, causing problems in the forming process. [18]

1.3.4.2 Pelletizing

Pelletizing machines are used to compress shredded refuse fuels into dense pellets, which can be stored, retrieved, and fed to a combustor or gasifier. The size of fuel pellets can vary. A typical pellet might be 0.25 inch in diameter and approximately one inch long. Fuel pellets can be made from wood waste, agricultural waste, or RDF. Since it requires virtually the same power and equipment to pelletize as to cube or briquette, the pellet is the desired product because of its ease of handling and burning. [15, 17]

Fuel is pelletized by pellet mills. The material to be pelletized is fed continuously into the pelleting cavity. Here it is directed equally to the wedges formed by the steel rollers and the inside face of the die, as shown by Figure 1.3-10. Rotation of the die causes the rollers to turn. The material is thus compressed by a wedging action under

Pellet Mill



1. Loose material is fed into pelleting cavity.
2. Rotation of die and roller pressure forces material through die, compressing it into pellets
3. Adjustable knives cut pellets to desired length

Figure 1.3-10

extreme pressure and thereby forced through the die holes. As the pellets are extruded, adjustable knives shear them to the desired length. Pellet mills may have two or three rollers and can be gear or belt driven.

The pellet quality and capacity will vary with the physical characteristics of the material being pelletized. Some will pelletize readily while others will require the addition of binders or lubricants to produce a practical operation. Such factors as moisture, density and lubricating characteristics, and particle size all contribute to the condition of the finished product.

Wood waste pellets can be made from excess hog wood, shavings, or sawdust. When pelletizing agricultural waste, combining various residues facilitates pelletizing. For example, 15 percent corn stalks or pea vines make straw much easier to pelletize. Leafy materials are also good binders. Most agricultural waste can be considered a candidate for pelletizing. For example, bagasse pellets were recently tested successfully in a gasifier by General Electric. [19]

Municipal solid waste provides an endless source of fuel when pelletized. Pelletizing this refuse allows the use of feed equipment designed for coal and blending with coal.

1.3.4.3 Economics of Densification

Densifying to pellets or briquettes is expensive. As a result, they can be used for fuel only in special cases. The energy requirements are generally very high, normally 5-10 percent of the lower heating value of the biomass. A typical processing cost is \$25-\$30/ton. Densification will negatively influence the already very sensitive economy of most biomass to energy plants. Other alternative should be considered very carefully to avoid going to the expense of densification. [19]

For industrial uses it is normally more practical to find another fuel source, or construct the plant to feed undensified material, than to spend the energy and money required by the densification processes. However, there is a small market for consumer oriented densified fuels. Wood wastes are currently being pelletized and sold for wood stoves used for residential heating. Compressed wood waste logs for fireplaces and wood stoves have been manufactured and sold for several years.

There have been several efforts made to process agricultural waste into cubes or pellets in the field instead of bailing. This has been proven impractical for several reasons: [17]

- The field rate of this type of equipment is 3-4 tons/hour and is limited to daylight hours.

- The additional cost of densifying these fuels ($25-30/dry ton) makes them prohibitive in cost as fuel. Alfalfa is the only crop now being pelletized or cubed, and for feed, not fuel.

- Any mechanical problems cause complete stoppage of the harvest as well as processing.

- Bailing can be done at 20-30 tons/hour ($20/ton) and the bales roadsided or collected at dispersed storage sites, thus quickly clearing the field for planting.

- Centrally located pelleting, cubing and auxiliary equipment can operate more efficiently, 24 hours a day at 6-10 tons/hour rates.

While densification has many attractive advantages, it is generally proven to be financially unpractical for industrial use. If energy cost and availability were to change significantly, this situation could change. However, in the current energy and financial climate, densified fuel must be considered carefully and is typically not the best option for the industrial user.

1.3.5 Fuel Management

1.3.5.1 Fuel Blending

Biomass fuels have significantly different properties and characteristics. In many cases the performance of the unit can be altered by mixing or blending two or more different fuels to obtain a composite fuel with the desired characteristics. A typical biomass fired facility may provide supply for their fuel feed system with a front end loader, and use one scoop of bagasse for every two scoops of wood chips, or some other combination. Some coal processing facilities have automated blending capabilities, and food processors use blending machines. These technologies could be applied to biomass fuels if the facility were large enough to justify the cost. Blending can often allow the use of a low cost fuel that might be unusable if fired independently.

1.3.5.2 Inventory Management

All wood fuels undergo losses in net available energy as a function of storage time. The primary cause of the short term depletion of available energy of openly stored wood is an increase in the surface layer moisture content due to precipitation. Therefore a "last in - first out" fuel management philosophy yields higher fuel efficiency in the short term. However, the loss of available energy in the wood is not linear with time as shown in Figure 1.3-11. Once saturation of the surface volume is achieved, further weather conditions will not affect the moisture content in the outer layer.

Eventually woody and other biomass fuels will begin to decay in their storage piles. Use of the "last in - first out" fuel management philosophy must be tempered with the need to burn older fuel before it begins to decay and to prevent storage pile fires.

Available Wood Energy Over Time

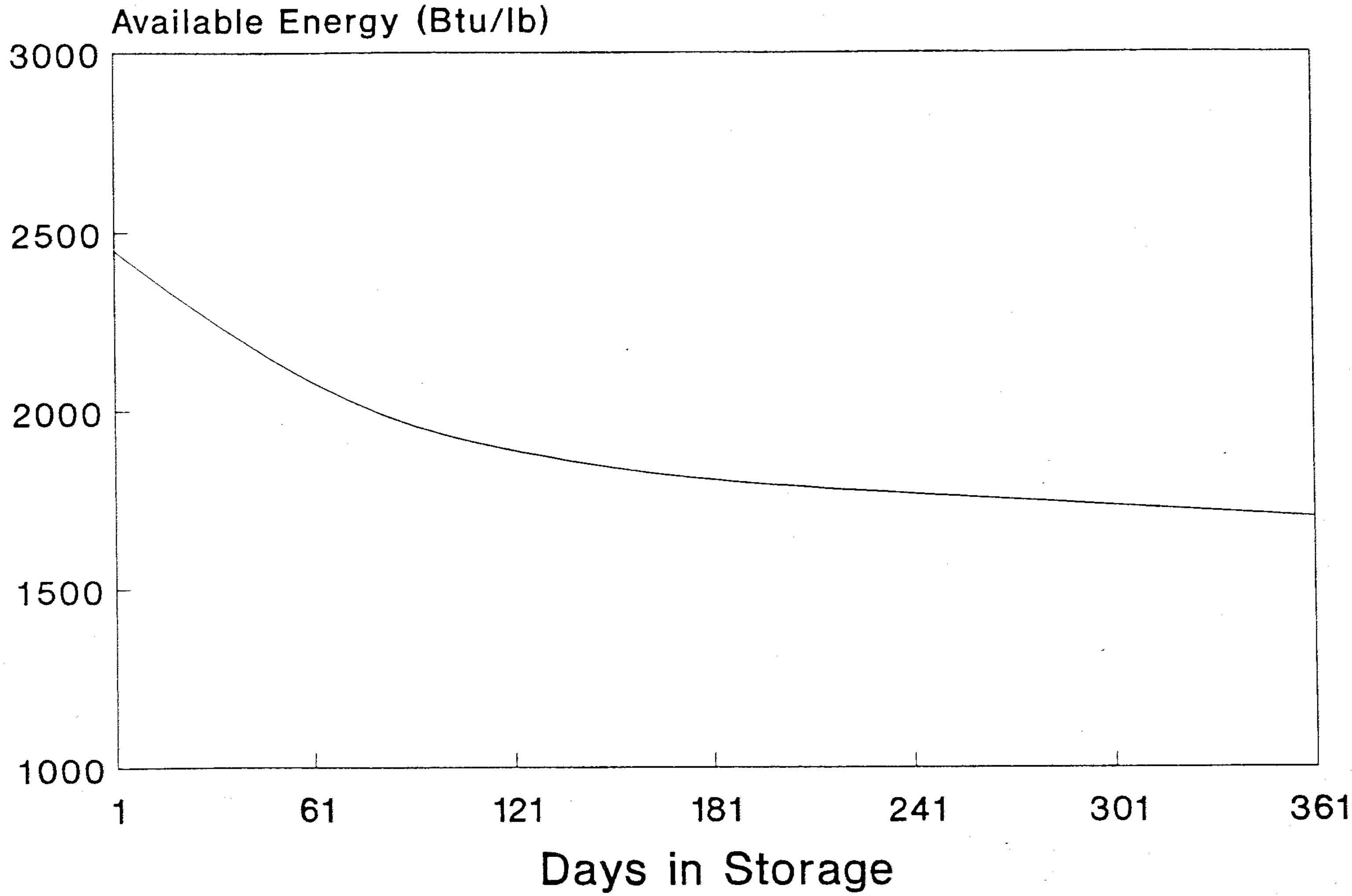


Figure 1.3-11

Source: Ref. 81

1.3.5.3 Fire Prevention

Fire prevention is a primary concern of any fuel storage facility and plant. For most biomass fuels, the greatest danger of fire exists under conditions that restrict and/or eliminate air flow through the pile (and consequently internal pile heat dissipation). A well-documented cause of spontaneous fires occurs during the winter months when a layer of ice can form over the outer pile surface. During such periods, internal pile heat cannot be dissipated and fires often result. High concentration of bark fines at the pile surface can also replicate this condition. Close observation of internal pile temperatures during these periods will help ascertain imminent danger. Therefore, the piles should be gravity constructed, not compacted and thermocouples should be buried in the fuel pile to allow temperature monitoring. The upper limit of pile temperature is normally considered to be 170°F.

1.4 APPLICATIONS USING FBCs

Energy from burning biomass in fluidized bed combustors is primarily used to generate steam or hot gas. The steam generated is most commonly used to produce electricity; however, there is a substantial use of steam for process heating. The most common and visible use of hot gas generating combustors is forced air furnaces for residential and commercial heating. This concept is also used in industrial systems as well.

1.4.1 Process Steam

Boiler steam is often used directly to provide process heat for paper mills and other chemical plants and for various forms of building heat. Central steam plants that supply low pressure steam or heated water are very common on college or university campuses as well as other multi-building complexes such as hospitals, prisons, and industrial complexes. However, steam building heat is not limited to multi-building complexes. Low pressure steam is also used for public and private elementary and high schools. Steam or hot water heat is also used in some greenhouse and nurseries and is even used as a residential heating medium in the northeast.

Many chemical processes used by commercial chemical producers require that heat be added to complete the desired reactions. It is common to provide this heat by low pressure steam. Most chemical plants either have an auxiliary boiler or purchase steam from another source close to the plant. External sources of steam can be electric generating plants (see Section 1.4.3) or steam supply plants built for that purpose.

A paper mill is a typical example of a plant which requires process heat and uses steam for that purpose. The textile industry often requires heat in their manufacturing process also. Wood product producers such as the furniture industry and lumber producers must dry the wood. Steam heated kilns are commonly used for this purpose.

Biomass fueled FBCs can be used to provide energy to any of these boilers. However, there is a practical limit to the temperature of the steam provided. Due to the materials for the boiler and the piping for transport it is not practical to use steam temperatures above 1000°F. This is normally higher than is needed for processes.

DuPont in Brevard, North Carolina operates a fluidized bed combustor that burns packing waste and waste plastics and X- ray film. The fuels burned contain paper, wood, polyethylene terphthalate, and polyvinyl butyryl. The steam produced from this boiler is used in the adjacent plant in the manufacturing of X-ray film.

The University of Montevallo in Montevallo, Alabama provides building heat and hot water using a biomass boiler fired by sawdust, woodchips, and bark.

1.4.2 Power from Steam Turbines

Most of the electricity generated in this country is produced by steam powered turbine generators. While the majority of these plants are either coal or nuclear fueled, there is a promising potential market for the use of biomass fuels.

A brief description of the production of electricity using steam is given below. The basic steam cycle is called the Rankine Cycle and has four major components as shown in Figure 1.4-1. These are:

1. Boiler or Steam Generator.
2. Turbine - Generator.
3. Condenser.
4. Feedwater Pump.

Rankine Cycle

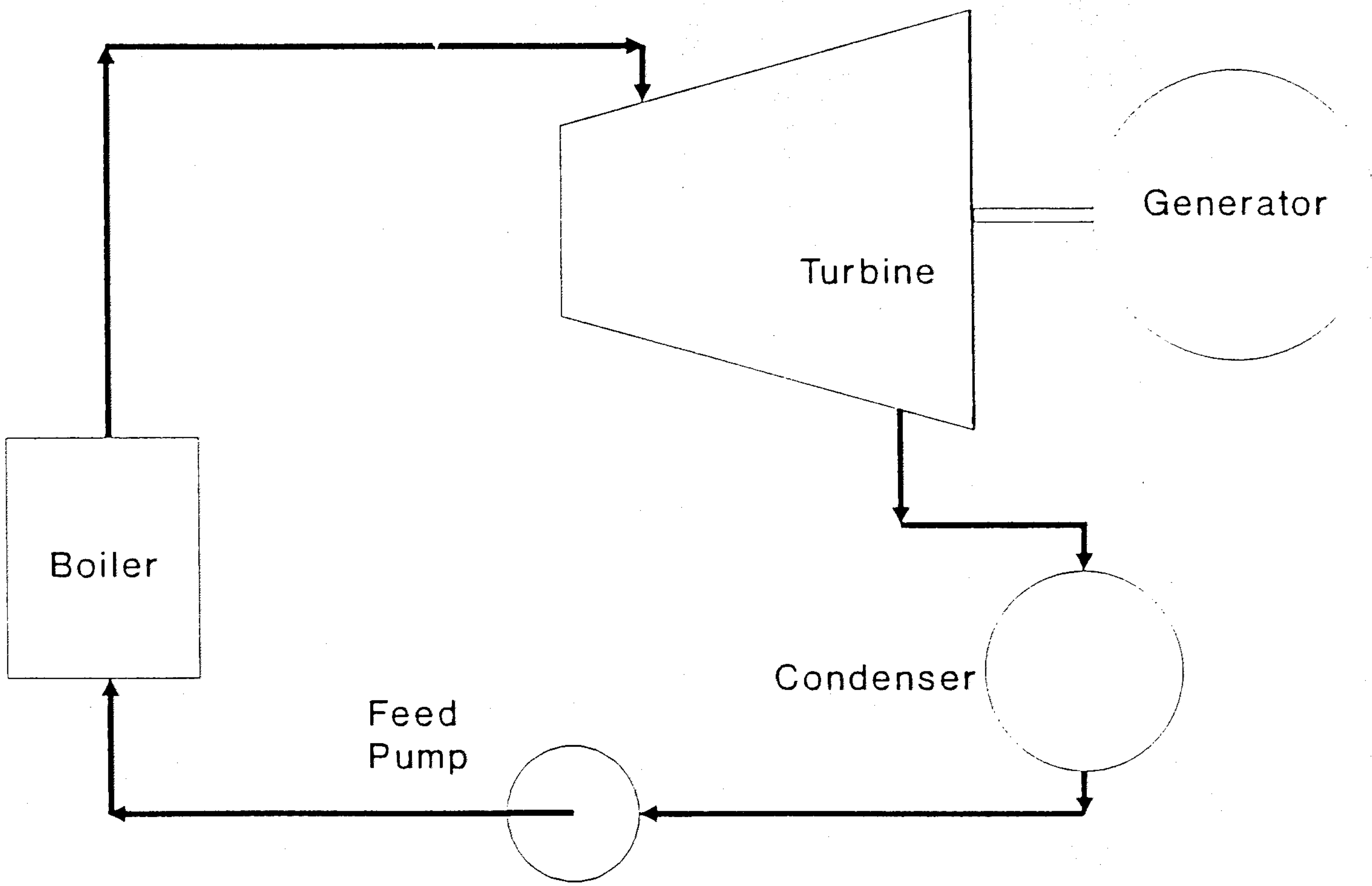


Figure 1.4-1

The boiler or steam generator extracts fuel energy and produces high pressure steam from water which has been fed to the boiler at high pressure. This steam is expanded through the turbine, which drives the turbine shaft which is used to turn an electric generator or perform other work. The low pressure steam from the turbine exhaust is returned to a liquid state (water) in the condenser. The water is then pressurized by the feedwater pumps and fed back to the boiler to complete the cycle.

Depending on the plant requirements for steam and electrical load, either a condensing or noncondensing steam turbine might be needed. Noncondensing steam turbines are found in the smaller size range (down to 500 KW) while condensing units are normally found in the larger size range (5000 KW and up). [20, 21]

Improvements to the process or cycle efficiency using steam turbines can be achieved by such measures as incorporating reheaters, feed water heaters, superheaters, and economizers on the boiler. The upper limit on efficiency from this type of plant is on the order of 35% which is achieved for the larger units (500 MWe size). Plants considering the use of biomass as the fuel for their FBC will be much smaller than this, on the order of 5 to 50 MW. The efficiency which can be expected from this size facility will be on the order of 30%. Small units are typically less efficient since there is less to gain by cycle enhancements so these are less extensive. The percentage of heat transfer losses on small units is also larger.

A typical example of a biomass fired FBC generating power is the Northern States Power Company which operates two 15 MWe fluidized bed boilers co-firing a blend of RDF and wood wastes at the French Island Generating Plant in Lacrosse, Wisconsin. These units, originally constructed in the 1940's were modified in the 1980's to fluidized bed boilers designed to burn a blend of wood waste and RDF. A MSW processing plant was constructed adjacent to the power plant to process LaCrosse county's MSW and provide the RDF supply. The wood is purchased from various local vendors. Other alternate fuels including railroad ties, peat, sewage sludge, and tires have also been tested at this facility. [16]

Pacific-Ultrapower has constructed a 25 MWe fluidized bed power plant in Chinese Camp, California which burns waste wood and agricultural wastes for electric power generation. Fuel supplied to the plant includes tree prunings, sawmill waste, and urban demolition wood. This facility includes an air cooled condenser/turbine. The boiler of this unit incorporates ammonia injection for NO_x emission control.

1.4.3 Cogeneration

Cogeneration, in general, is the simultaneous production of useful thermal energy and electric power from a common fuel source. Cogeneration has gained significantly in popularity over the last decade due in part to the ability to sell excess power brought about by PURPA (described later in this section). In most cases the low pressure turbine exhaust steam is used to provide some type of process heat, as shown in Figure 1.4-2. If higher pressure steam is needed, extraction steam can be used an shown in Figure 1.4-3. A considerable quantity of heat is also discharged with the flue gas. This heat can also be used, though this approach is less common than the use of low pressure steam. An overall increase in efficiency of fuel usage is experienced since the exhaust energy is utilized instead of going to a condenser. The magnitude of the efficiency increase is dependent on the process heat requirements and details of the cogeneration system configuration.

The ideal situation for cogeneration is where the power and steam requirements of a facility are such that there is relatively no lost energy from the cogeneration unit. However, this is not usually the case. In most applications the cogeneration unit will be designed to meet the steam load demands and any power produced will offset current power purchases. However, due to the rising cost of electricity, it may be attractive to build a much larger unit than required for steam purposes in order to meet power demands. Further, as discussed below, excess power can be sold to a local utility.

Cogeneration Cycle
With Backpressure Steam Turbine

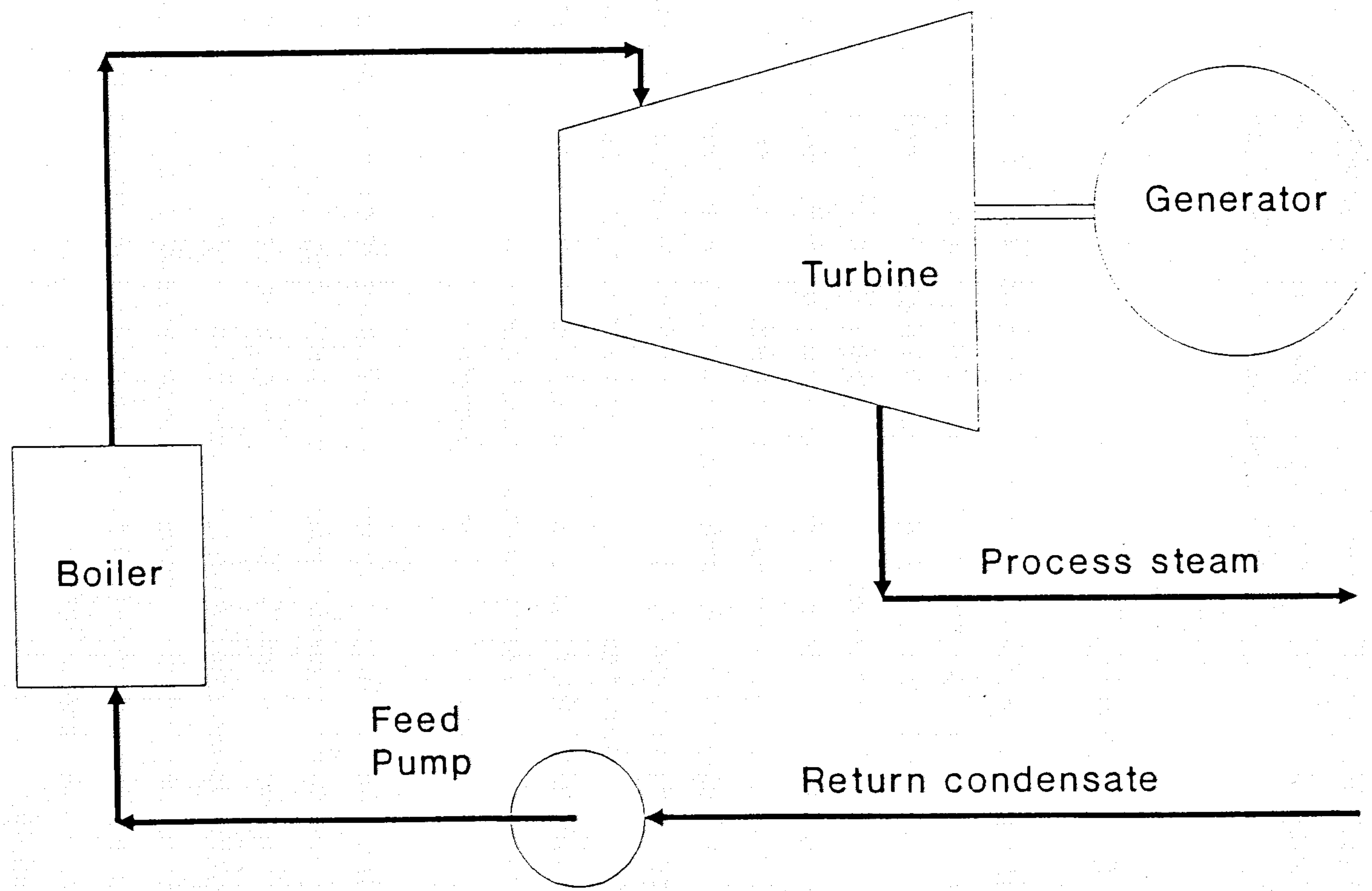


Figure 1.4-2

Cogeneration Cycle
With Extraction Condensing Turbine

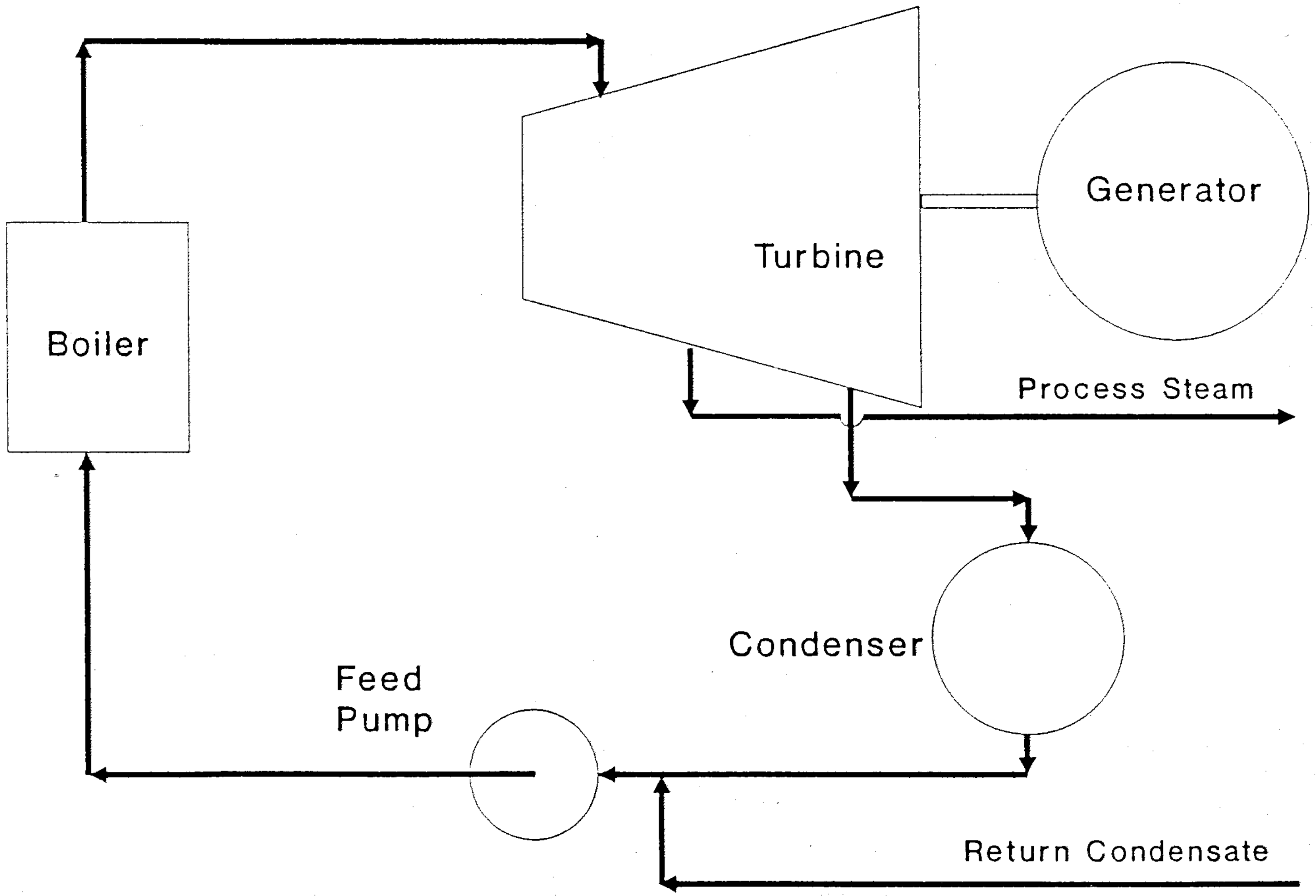


Figure 1.4-3

This increase in efficiency is not achieved without a price. The addition of the cogeneration system equipment is expensive and requires that the steam system be able to provide sufficient high quality steam (pressure, flow, and temperature) to meet turbine inlet requirements. The plant process steam requirements need to be large in order to consider cogeneration. Steam inlet pressures to the turbines are typically in the 450 to 650 psig range. Lower pressures can be used if the steam temperature needs of the process are low. Condensing extraction steam turbines are considered to be best suited for cogeneration where electrical and steam loads vary, but they experience some loss in overall efficiency since a condenser is required downstream to develop the maximum driving pressure drop across the turbine. Backpressure steam turbines, as the name implies, operate with a specified pressure at the turbine outlet to meet process heat requirements. Backpressure steam turbines are usually specified for installations of less than a few megawatts. [14, 22]

Colortile Manufacturing has installed a biomass combustor in the Melbourne, Arkansas facility. This boiler is fired by the wood waste from the manufacture of oak floor products. The steam from this unit is used to drive two steam turbines that reduce the pressure to 10 psig where it is used for lumber drying and building heat. The turbine drives an electric generator which produce 900 KW which is used inhouse.

New Hanover County in North Carolina has installed two FBC boilers to dispose of the county MSW. About 65% of the steam generated by these units is used to drive a turbine generator. The electricity generated is sold to Carolina Power and Light at full avoided cost rates under the provisions of PURPA. The remainder of the steam is sold to W. R. Grace as process steam for their agrochemical processing plant.

<u>PURPA</u> - In order to encourage the development of cogeneration facilities, the Public Utilities Regulatory Policies Act (PURPA) was instituted in 1978 to remove the regulatory obstacles that adversely effected the economics of operating a small cogeneration facility. This Act requires that state regulatory agencies establish rules governing the interconnection of cogenerators to the power grid and rates for the

exchange of power. To qualify as a cogenerator and receive the benefits provided by PURPA, a facility must:

- Generate electricity from the steam produced.
- Supply useful energy for industrial or commercial use through a sequential use of the steam produced.
- Have less than 50% ownership by a utility or utility holding company.

To be certified as a cogenerator, a facility must apply to the Federal Energy Regulatory Commission in Washington, D.C. PURPA provides rules and regulations controlling how a utility must deal with a cogenerator. The three primary regulations are:

- The opportunity to provide power to, and receive power from the power grid must be provided to the cogenerator. The utility is not allowed to require extensive equipment redundancy of the cogenerator.
- Utilities must purchase power from small-scale producers at just, reasonable, and nondiscriminatory rates. The utility must pay up to their avoided cost (defined below) to the cogenerator for the power it supplies.
- The utility must allow the cogenerator to purchase back-up power at reasonable rates regardless of the frequency of need.

The state energy agencies are required by PURPA to set the rates that utilities must pay to the cogenerators. The avoided costs are the marginal costs of the utility if it had generated the electricity or purchased it from another utility. The avoided cost is compared to the rates paid to cogenerators to assure fairness. For more information on rate determination see "Cogeneration from Biofuels: A Technical Guidebook". [20]

1.4.4 Other Combustor Applications

In some applications the production of hot air is required. While hot air can be generated from steam through a heat exchanger, it is not necessary to produce steam first. Hot air can be generated by placing a heat exchanger in the combustor directly above the flame. This configuration is commonly referred to as a fire box. The air is heated as it moves through the fire box. Examples of this arrangement are a forced air residential furnace or, in industry, a source of heat for a wood drying kiln.

Some processes require temperatures higher than is practical to produced by steam heating. In fact, the temperature can be so high that the process is best accomplished inside a furnace. The baking of brick is a good example of this type of process.

The flue gas produced by combustion contains a significant quantity of heat, therefore this flue gas is often used as a drying gas. However, the flue gas contains steam as a product of combustion, therefore, the dried product is limited to a minimum moisture content higher than that of the flue gas. Flue gas driers are often used for the drying of fuel as described in Section 1.3.1.

A combustor can be used to heat process fluids other than water or steam. In some cases it may be desirable to heat an oil or some other liquid to be used as a heating medium, such as hot oil heated drying kilns.

1.5 APPLICATIONS USING FBGs

Low and medium Btu gas (referred to as producer gas), derived from gasifying biomass in fluidized bed gasifiers, can be utilized in many applications where other fossil fuels such as coal, oil, and natural gas are currently being used. Gasification of biomass fuels in FBGs is considered to be in the early commercial development stage. Few FBGs have been installed to date, although there is a great deal of activity currently underway throughout the world. Low natural gas prices have stifled growth and, in some cases, caused shutdowns of existing plants due to poor economics. However, recent concerns regarding anticipated natural gas price increases, fuel supply availability, waste disposal requirements, economic competitiveness, and environmental issues (such as greenhouse gases) have caused a renewed interest in gasification. Most of this interest involves the use of FBGs.

Many current plants have the capability to generate their own in-house steam and hot air requirements by using gas or oil fired boilers. These plants, as well as others, can benefit from the use of biomass materials as a source of energy. FBG offers an attractive alternative to currently used fossil fuels. Potential end uses of the gas from an FBG include serving as a fuel for: (1) hot gas generation, (2) process steam generation, (3) steam turbines, (4) gas turbines, (5) combine cycles, (6) cogeneration, (7) internal combustion engines, and others. The following sections provide a brief discussion of these applications and gives current examples where appropriate. [23]

1.5.1 Hot Gas Generation

The most direct use of the producer gas from an FBG is to burn the gas as a heat source for a hot gas generator. As mentioned earlier, producer gas from an FBG can have a heating value ranging anywhere from about 150 to 500 Btu/ft^3, depending on the gasifying agent and particular gasifier design. Existing oil and gas burners can be easily converted to use biomass derived producer gas to generate hot gases. The burners should be able to handle high temperature gas to conserve the sensible heat of the producer gas as it exits the FBG. With the burner close coupled to the gasification reactor, the burner should also be able to withstand fine particulate that is entrained in the gas. One and sometimes two stages of cyclones are usually employed downstream of the FBG to clean the gas. Several gas burner manufacturers offer burners for producer gas. Conversion of existing burners might also require enlarging duct work to handle increased flows, adjusting capacity of I.D. fans, and/or some derating of the unit. These hot gases can be used for such uses as process air heaters and dryers (fuel supply, wood veneer, lumber, etc.). [4, 5]

JWP Energy Products utilized gases from the exit of a 6 MWe gasifier/boiler facility to dry the incoming biomass (wood) supply. The gases exited the boiler at around 350°F and were sent to a single pass, rotary drum dryer to dry the wood. At nominal conditions, the resulting hot gas could reduce the wood moisture from the as-received level of 37% to the desired moisture level of 25%. Flexibility was built into the plant to handle higher moisture levels of as-received wood by a bypass around the boiler's economizer. This allowed gas temperatures to be tempered from 350°F up to 550°F to keep the same desired as-fed wood moisture level. [8, 24]

Low Btu gases, alone, might not be appropriate for processes requiring high temperature drying and calcining (e.g. lime and cement kilns). However, MBG gas or LBG blended with a small amount of other fuel supply, such as natural gas, could develop the needed temperatures. Two gasifier units were operated in Florida (units now for sale), producing LBG which was burned to dry clay in a fluidized bed dryer. Likewise, PRM Energy offers a rice hull burning FBG which utilizes the gas for purposes such as drying paddy rice and citrus dehydration. [8, 23]

1.5.2 Process Steam Generation

Probably the most common use of the producer gas generated in an FBG is for burning in a boiler for production of steam (or hot water) for process purposes. Care must be taken to match fuel and air supply to steam requirements. Application of FBGs can be found with direct firing of small boilers less than 1 MWt. The use of biomass FBGs directly coupled to boilers is common in the Scandinavian countries with the steam used to serve small (~5 MWt output) district heating facilities. Canadian Industries Limited produced LBG by burning refuse derived fuel (RDF) in a pressurized FBG. The producer gas from this plant was cleaned and sent directly to a tangentially fired combustor. By close coupling the gasifier to the combustor, problems with condensibles in the LBG were avoided. [3, 4, 5]

Many plants have the attractive combination of existing boiler equipment and access to inexpensive biomass fuels, either in-house waste streams or regional biomass waste materials. These existing boilers are excellent candidates for accepting producer gas from a FBG to fire this equipment. The mass velocities in producer gas fired boilers will be higher than previously seen when using gas or oil firing for the same steam production due to the lower Btu content. It is important that the biomass fuel supply have relatively constant properties (e.g., moisture, volatile/fixed carbon ratio).

The State of California's Central Heating Plant in Sacramento is an example of a facility that installed an FBG for supplying producer gas to an existing boiler. While maintaining the existing boiler ID fan, the gasifier has been successfully used to generate steam flows of 55,000 pph for the boiler which was designed for 60,000 pph using gas or oil. Wood, which contained 30% moisture with a lower heating value of 5500 Btu/lb was used as the biomass fuel. The producer gas was supplemented with 10% (energy content basis) natural gas to assure a reliable energy supply of 50 MBtu/hr. Increased boiler efficiency is realized by using gasification as opposed to using a waste heat fired retrofit. Burning the producer gas directly in the boiler increases the radiant heat flow and minimizes the flue gas losses by requiring less excess air. A rule of thumb gives a 20-25% boiler derating using a waste heat conversion versus 5-10% when using a gasifier. [8, 11]

1.5.3 Steam Turbines

Another alternative for extracting the energy from biomass materials is using the producer gas for making steam to power a steam turbine (i.e., the Rankine Cycle: Heat from burning producer gas is used to generate steam, which is used to drive a steam turbine, which drives a generator to produce electricity). Depending on the plant requirements for steam and electrical load, either a condensing or noncondensing steam turbine might be used. Noncondensing steam turbines are found in the smaller size range (down to 500 KW) while condensing units are normally found in the larger size range (5000 KW and up). [20, 21]

The upper limit on efficiency from this type of plant is on the order of 35% which is achieved for the larger units (500 MWe size). Plants considering the use of biomass as the fuel for their FBG will be much smaller than this, on the order of 5 to 50 MW. The efficiency which can be expected from this size facility will be on the order of 30%.

An example of a facility that was equipped with an FBG and boiler/steam turbine is Catalyst Energy in North Powder, Oregon. This plant had a JWP Energy Products' Model FBG-100 gasifier which used wood residue to provide 90 MBtu/hr of producer gas with a design heating value of 150 Btu/ft^3. Actual measured heating value was 175 Btu/ft^3 which did not include any credit for sensible heat, condensibles, or char. This plant used flue gas from downstream of the boiler economizer (approximately 350 °F) to dry the wet wood to approximately 25% moisture in a rotary drum dryer. The producer gas generated in the FBG is burned in an A-type boiler to generate approximately 60,000 pph of steam at 425 psig and 825°F. The boiler efficiency of the unit was around 75%. If an FBC had been used with this same fuel, a boiler efficiency of approximately 70% would have been predicted. Auxiliary power requirements for the FBC concept would have been higher due to the higher required fluidizing air for combustion. Steam from the boiler was converted to electrical power in a reconditioned Westinghouse steam turbine-generator rated at 5.6 MWe. [24]

Southern California Edison has plans to dispose of municipal solid waste in an Advanced Integrated Recycling (AIR) Energy Recycling Facility (Figure 1.5-1). This project will produce refuse derived fuel (0.75 ton for every ton of municipal solid waste collected) which will be gasified in an FBG. The resulting producer gas will be fired in an existing boiler to produce steam for a steam turbine. It is estimated that the volume of waste to be landfilled will be reduced by more than 90% via the combined recycling and gasification processes. Potential uses of the resulting ash from the gasifier could reduce the landfill requirements even further. The projected annual benefit from this project include: generating 26 million KW-hrs, eliminating 260 million ft^3 of NO_x, and eliminating 12,000 tons of greenhouse gases while at the same time conserving 260 million ft^3 of natural gas. The RDF will be shredded into 2" nominal size material and fed into a CFBG. The RDF will replace 50 MBtu/hr of natural gas. The resulting producer gas will burn cleaner than natural gas due to its lower heat content and will result in less pollution. The design is considered to be modular (500 TPD modules) to accommodate small or large communities. Construction is scheduled to begin in 1995. [23, 25]

1.5.4 Gas Turbines

Gas turbines are an option for providing electricity using the producer gas from FBGs. Pressurized FBGs are being considered since they eliminate the added step of compressing the producer gas. Though oxygen produces a higher grade gas, air is the most logical choice for gasifying the biomass since oxygen plants at the biomass fueled plant size would be costly.

The gas turbine combines and compresses the producer gas and air prior to burning the mixture. The combustion products flow through an expansion turbine which is connected to a generator for producing electrical power. The exhaust stream from the gas turbine contains sufficient heat content which can be recovered in a hot air generator or in a boiler for process needs. Gas turbines offer the advantage of producing more electricity than a steam turbine for a given quality of steam

A.I.R. ENERGY FACILITY

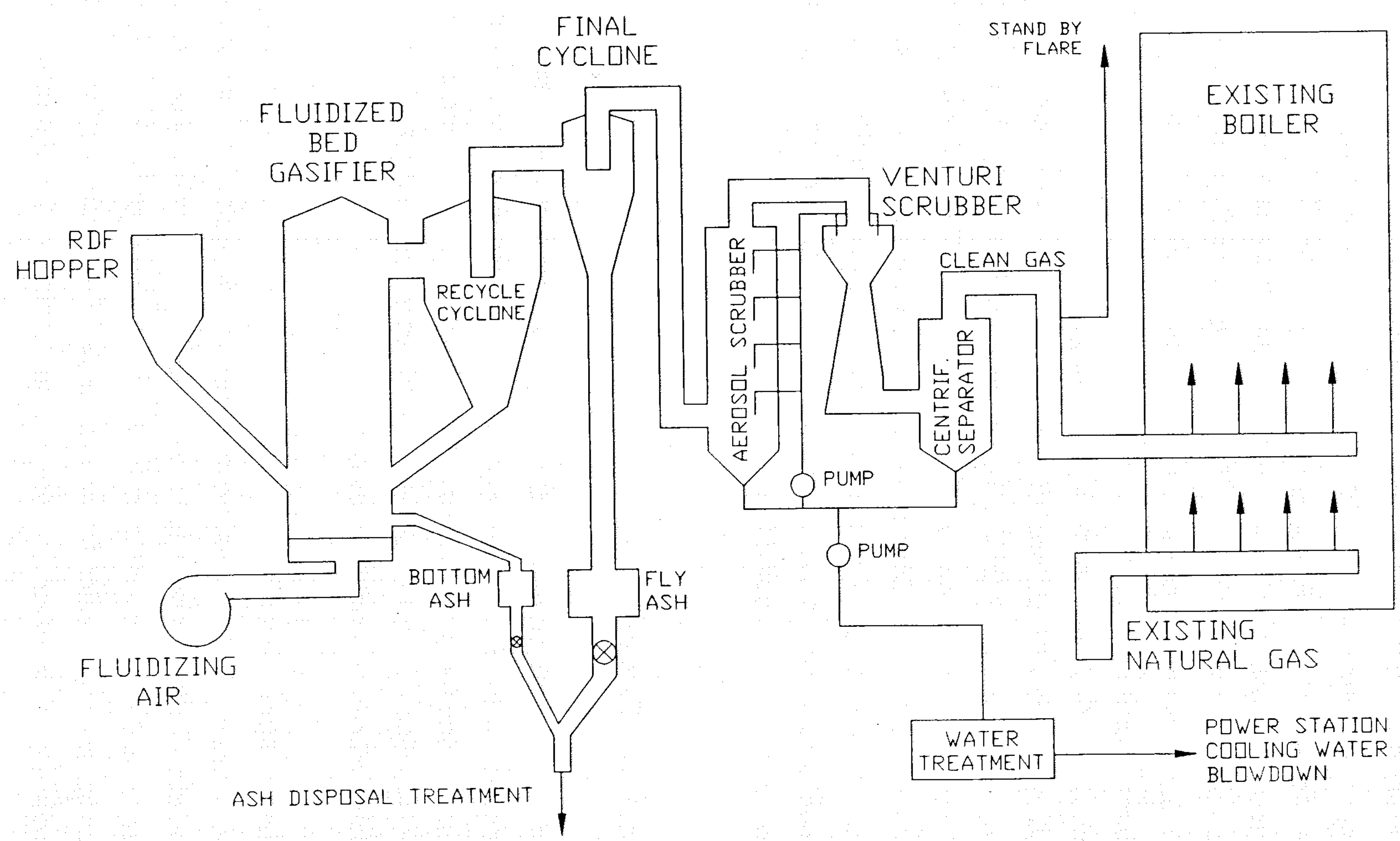


Figure 1.5-1

(Ref. 25)

requirements (same Btu input) due to their higher operating temperature limit. Small gas turbines are more applicable to facilities where heat usage is four to five times the electricity usage since small turbines have high excess air requirements and have low electrical efficiencies. Gas turbines in the range from 800 KW to 75 MW are available for use with FBGs. An FBG with 120 MBtu/hr of producer gas output would be appropriate for a 10 MW gas turbine. Some turbines can operate with LBG having a lower heating value of 100 Btu/ft^3, but a value of 150 Btu/ft^3 or greater is recommended. These values require that the biomass feedstock be less than about 30% moisture. [6, 7, 20]

Commercial applications of gas turbines used with FBGs are currently receiving a lot of consideration. However, this combination has not been demonstrated to date even though the technology for each has been demonstrated and are separately commercial. Gas turbines have undergone development for several decades and are a reliable method to provide electricity and thermal power. Gas turbines are noted for their high reliability, ease of siting, installation, startup, and operation, low capital cost per power output, high efficiency, low emissions, and long life. The main problem with using a gas turbine with an FBG is the amount of gas cleanup (particulates and alkali constituents) required to protect the turbine blades from erosion and corrosion (see Section 3.1.5). If economical methods for gas cleanup can be achieved, this method of energy conversion offers promise for improved energy conversion efficiency. [7, 8]

PFBGs have the benefit of operating at pressure levels suitable for gas turbines (90-150 psig). PFBGs coupled to gas turbines offer increased electrical production per lb of fuel when compared to cogeneration. Heavy duty combustion turbines are considered to be more suitable for use with biomass fueled FBGs than aeroderivative turbines (jet engines) at this time. The heavy duty combustion turbines operate at pressure ratios of 11 to 16, which matches the current proven PFBG operating pressures. The aeroderivative turbines, on the other hand, operate with higher pressure ratios, on the order of 18 to 32. Also, the tighter tolerances on the aeroderivative turbines improves its efficiency but dictates that the producer gas meet tighter particulate limits. The added requirement to further clean the gas, along with higher capital cost for the aeroderivative turbine, have to be weighed against its higher efficiency. The exhaust gas outlet temperature from the aeroderivative turbines is lower than the heavy duty combustion turbines and thus reduces the amount of energy available for the steam turbine if used in a combined cycle mode. [4, 7, 26]

1.5.5 Combined Cycle

Consideration is being given to using FBGs in a combined cycle application. Here, a biomass fed FBG produces LBG or MBG which is then fired in a conventional gas turbine (Brayton cycle). The turbine is modified to handle the low or medium Btu gas, with the waste heat from the gas turbine used to generate steam in a heat recovery steam generator for a conventional steam turbine (Rankine cycle). Simultaneous generation of electricity is provided by both turbines. Steam may also be extracted and/or exhausted from the steam turbine as needed for gasification or process heating requirements (combined cycle cogeneration). This arrangement provides the maximum heat recovery from the biomass fuel. Figure 1.5-2 shows the layout for a typical FBG combined cycle plant. Combined cycle designs are effective at meeting heat and work needs when single cycle designs are not effective. [20, 27]

These gasification plants, operated in a combined cycle mode, are referred to as IGCC plants (Integrated Gasification Combined Cycle). Advanced versions of these plants use steam dryers, air-and oxygen-blown FBGs, hot gas cleanup, advanced aeroderivative turbines, catalytic oil/tar removal, heat recovery steam generators, and steam turbines. Much of the current work in the application of biomass FBGs is with versions of the IGCC concept. This technology offers the potential of biomass to electricity conversion efficiencies of greater than 40% as compared to 30 to 35%. Much development work is in the current planning and implementation stages which will lead to significant growth in the coming years as the current scaleup activities are commercialized. [7]

FBG COMBINED CYCLE PLANT (BIG/CC FLOW DIAGRAM)

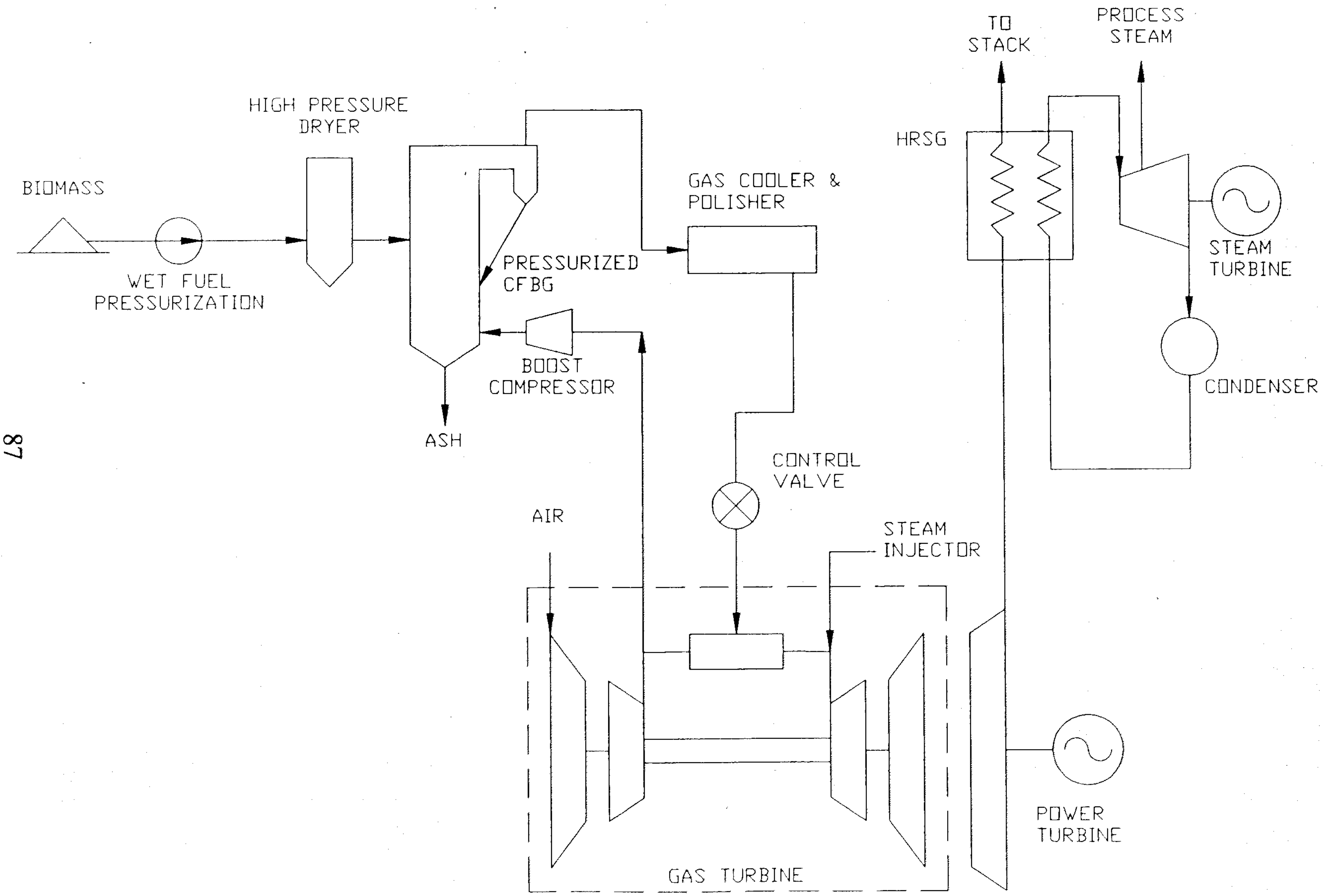


Figure 1.5-2

(Ref. 21)

The cost of gathering and transporting biomass fuels may limit the practical size of these plants to less than 50 MW (annual fuel requirement of about 600,000 tons), suggesting that aeroderivative gas turbines or small industrial gas turbines would be best suited to this type of application. [27]

Brazil is in the process of demonstrating IGCC using wood and sugar cane bagasse. The nomenclature for their technology is "BIG/CC" or Biomass Integrated Gas Turbine/Combined Cycle. The purpose of this project is to demonstrate the commercial application of this technology and its application to developing countries. The combined cycle requires additional capital investment over the open cycle but has an estimated 50% higher efficiency. The Brazil project will utilize a pressurized CFBG which is fed dried, pressurized fuel. Gas produced in the CFBG is processed in a cooler and polisher prior to the gas turbine. After combusting the producer gas, the exhaust gas from the gas turbine is routed to a bottoming cycle which includes a heat recovery steam generator, condensing steam turbine, and condenser. [21]

Bagasse produced during the milling season from sugar cane is a potential biomass fuel for the BIG/CC technology. Studies indicate that a plant based on a GE Model LM2500 gas turbine could generate 21 MWe from the gas turbine and 9 MWe from the steam turbine with an efficiency of 43%. One factor that has to be taken into consideration is the availability of bagasse. The milling season lasts for about 6 months in Brazil. Two possible operation modes are (1) operate the plant on bagasse for the milling season or (2) store the bagasse during the milling season and use it throughout the full year. [21]

1.5.6 Cogeneration

Cogeneration in biomass FBG application refers to the simultaneous production of electricity and thermal energy. In most cases, the thermal energy is supplied as process steam. The most common cogeneration plant involves the use of a steam turbine to produce the electrical power. Using a backpressure steam turbine allows low pressure steam from the steam turbine exhaust to be used as a source of process heat instead of being sent to a condenser. An overall increase in efficiency of fuel usage is experience since the exhaust energy is utilized instead of going to a condenser. [5]

This increase in efficiency is not achieved without a price. The addition of the cogeneration system is expensive and requires that the steam system be able to provide sufficient high quality steam (pressure, flow, and temperature) to meet turbine inlet requirements. The plant process steam demands need to be large in order to consider cogeneration. Steam inlet pressures to the turbines are typically in the 450 to 650 psig range. Lower pressures can be used if the steam temperature needs of the process are low. Condensing extraction steam turbines are noted to be best suited for cogeneration where electrical and steam loads vary, but they experience some loss in overall efficiency since a condenser is required downstream to develop the maximum driving pressure drop across the turbine. Backpressure steam turbines, as the name implies, operate with a specified pressure at the outlet to meet process heat requirements. Backpressure steam turbines are usually specified for installations of less than a few megawatts. [5, 20]

Combined cycle plants can also be operated in a cogeneration mode when the steam from the steam turbine is extracted or exhausted to meet process needs in a topping cycle. This arrangement provides maximum heat recovery from the biomass. A gas turbine with a steam topping cycle is another cogeneration option where exhaust gases from the gas turbine are used directly or are used to provide process steam in a heat recovery boiler. [5]

One technology that has spun off of the IGCC technology is referred to as biomass-gasifier steam-injected gas turbine cogeneration or "BIG/STIG". Natural gas fired aeroderivative gas turbines are now commercially available with steam injection. The primary purposes behind steam injection is to increase the output, NO_x reduction, and efficiency of the gas turbines. The BIG/STIG process offers potential as a near term option for biomass cogeneration, but still requires development and demonstration.

One of the attractive features of this technology is that it allows some balancing of the electrical production and heat usage when the requirement for the loads change (e.g., crop processing systems, district heating systems). Steam not needed for the heat load can be injected into the gas turbine to generate more electricity which can be sold to a utility. An example is given where the electrical output from a GE Model LM-5000 would increase from 39 MWe (28.6% efficiency) to 53 MWe (32.5% efficiency) when full steam injection was used. Unit capital cost of gas turbine plants are not as sensitive to scale as Rankine cycle electrical plants. This becomes an attractive feature with biomass fueled units since it provides for a cost effective installation of small scale facilities (0.1 to 100 MW). Biomass fueled units are more likely to be built in this size range since the biomass materials are typically dispersed over a wide area and have a low density. The commercial application of biomass fueled steam injected gas turbines is still in the development/demonstration phase. [6, 21, 28, 29]

The advantages of BIG/STIG over IGCC do not appear to be significant. The BIG/STIG system has a lower efficiency. Comparing the heat rate from a natural gas fired 51.4 MWe LM-5000 BIG/STIG system and a 56.5 MWe GE Frame 6B IGCC system showed the BIG/STIG system to have almost a 10% higher heat rate. There are also questions concerning the amount of steam the turbine can tolerate especially since biomass gas from an FBG can contain appreciable (> 15%) moisture. The BIG/STIG facility does not incur the capital cost of the steam turbine and its associated equipment (larger percentage of plant cost as plant size decreases), yet the capital costs from the EPRI 1989 TAG predict the BIG/STIG facility costs to be 60 to 100% higher than a combined cycle facility (both in a utility setting, firing natural gas). High purity water treatment will be required to ensure that the steam injection does not create corrosion problems for the high temperature components. [7, 30]

BIG/STIG does appear to be suitable for cogeneration application when the steam demand is cyclical and all the electric power can be utilized. Pulp and paper mills and food processors are potential users in this scenario if they are able to obtain attractive power sales agreements. One major consideration in using STIG is the availability of water since the steam injected is exhausted out the stack and is not recovered. [7]

1.5.7 Internal Combustion Engines

Producer gas from air and oxygen blown biomass FBGs can be burned in internal combustion (IC) engines, but only when supplemented with other higher grade fuels. For successful operation, the producer gas must be clean and engine modifications must be made. Because of the lower heating value of the producer gas compared to conventional IC engine fuels, engine derating will occur. The power from the engines can be used for shaft power, including mobile uses and for powering an electrical generator. The IC engine can be operated in a cogeneration mode by using the waste heat from the engine's cooling system for providing hot water, or low pressure steam can be produced in an exhaust heat exchanger. [20]

The producer gas must be blended with natural gas or some other high quality gaseous fuel for successful use in spark-ignition engines. The gaseous fuels must have heating values of at least 400 Btu/ft^3 and methane concentrations of 35% or more for ignition to take place. Also, the methane and carbon dioxide mixture will not burn if the volumetric amount of carbon dioxide is greater than three times the amount of methane. With typical producer gas heating values of about 300 Btu/ft^3 from oxygen blown gasifiers and 150 Btu/ft^3 from air blown gasifiers, and methane concentrations of 5 to 10%, substantial quantities of natural gas are required. [31-35]

When using biomass producer gas, compression ignition diesel engines require use of a pilot fuel for ignition, such as diesel fuel. This is because of the low cetane rating of the producer gas, which will not ignite by itself during the compression stroke. The pilot fuel requirement is usually on the order of 1 to 10% of the full load fuel rate. This pilot fuel is ignited in compression which in turn ignites the producer gas and air mixture. The producer gas is fed into the engine intake system, mixed with air, and sucked into the engine. [33, 34]

Particulate matter, tars, hydrogen sulfide (H_2S), and moisture in biomass producer gas concern IC engine manufacturers. Cyclones and bag filters can be used to remove particulates. Water scrubbers with demisters can be used to remove tars, H_2S, and particulates. Many manufacturers recommend H_2S limits of 10 ppm by volume. Water scrubbers also serve to cool the producer gas which allows greater mass flows to the engine, and hence, higher engine output. Manufacturers also recommend operating engines on clean fuels during startup and shutdown and maintaining engine oil temperatures high enough (approximately 190°F) to prevent condensation of water vapor and H_2S in the oil. [31, 36, 37]

During the energy crisis/oil embargo period of the 1970's, the use of producer gas from biomass was reexamined for application in developing and rural areas. Much work was done in Brazil and India, but interest was diverted as gas prices returned to more normal levels. Producer gas fired diesel generators (ASTRA technology) of about 20 KW have over four years of successful demonstration in a rural village in South India. [3]

An example of producer gas being used in biomass FBGs include work performed on the Hudson Bay project in Canada. Wood was used as the fuel supply for gasifying in a BFBG. The producer gas was cleaned and cooled and then fed to a naturally aspirated 250 hp Deutz diesel engine (Model F12L413F) which had been modified to burn producer gas. The diesel engine was purchased from the Imbert Co. in Germany. The diesel fuel injection system was changed to provide about 10% of the normal flow to be injected. The diesel engine was mounted on a common frame with a Brown Boveri generator rated at 150 KW. With the engine operating with 11% diesel fuel and the remainder producer gas, the engine output drops by about 20%. Otherwise, the engine performance was similar to operating with diesel fuel alone. [4]

2.0 NON-TECHNICAL FACTORS

This section of the guide presents a summary comparison of the FBC and FBG systems in a format designed for the waste generator or user and decision maker with little or no technical background. Factors discussed include process performance, reliability and availability, economics, environmental considerations, and experience. This discussion presents an overview of the characteristics related to each area without a detailed technical discussion. (Technical factors are covered in Section 3.0). The information is intended to allow the decision making staff of the biomass generator to evaluate the feasibility of an FBC or FBG project.

2.1 OVERALL SELECTION CRITERIA

As discussed in Sections 1.4 and 1.5, there are a broad range of potential applications available for using FBC and FBG systems. The decision to use either FBC or FBG in any particular application will most likely be the result of a detailed feasibility study considering the needs and requirement of the owner and current situations regarding energy and biomass production.

In general, there are some overall factors to be considered in biomass fueled facilities. Biomass fuels have several advantages over conventional solid fuels such as coal. They are typically more reactive, lower in sulfur, have a better potential for gasification at lower temperatures, are generally renewable, and of increasingly greater importance, they are CO_2 neutral. There are potential disadvantages, however, including higher moisture, higher alkali, and potentially higher costs associated with collection and transportation. Further, biomass fuels will have handling, feeding, and combustion characteristics that must be carefully evaluated when designing a combustion or gasification facility.

For most evaluations of biomass or any energy production facility, the primary concerns are related to efficiency, reliability, and environmental compliance. Critical areas that need to be investigated include:

- Fuel Handling, Preparation, and Feeding - Making the fuel or fuel mixture as homogeneous as possible before being fed to the furnace.

- Boiler Controls - Being able to change fuel and fuel mixes, and tuning all combustion and gasification parameters to accommodate the change with as little lag time as possible.

- Non-Fuel Components - Minimizing the affect of impurities on components in the areas of corrosion, erosion, etc.

- Emissions - Minimizing the impact of the fuel mix on the particulate collection device, scrubber, etc., and making sure that other noxious elements such as chlorides, acid gas, dioxins, and other products of incomplete combustion don't aggravate the emissions and are properly controlled. [38]

Another alternative which should also be considered is cofiring biomass fuels with another more conventional solid fuels such as coal. Due to their fuel flexibility characteristics, FBC and FBG unit are especially attractive for this type of application. Cofiring offers several positive aspects such as lower emissions than for 100% conventional solid fuel firing, higher thermal efficiency than for a 100% biomass unit, potential lower operating costs, and lower impact of the biomass fuel variations due to blending with the conventional fuel.

Equipment selected for these units must be designed to accommodate the effects of the variety of fuels. Equally important is for the fuel procurement organization to understand how various fuel characteristics will impact the unit operation. While coal is commonly purchased by Btu or with an average heating value assured, this is usually not the case for biomass. It is typically sold by weight or volume with no heating value guarantee.

It should be noted that the least expensive boilers are generally the ones with the least flexibility with regard to quality of fuel (i.e., moisture content, size, etc.) that may be burned. Thus, costs should be weighed against flexibility when selecting a boiler design. [5]

2.2 OPERABILITY

An important factor associated with a solid fuel burning unit is the overall operability of the facility. Operability can be defined as the ability of the unit to startup and shutdown efficiently and safely, and to maintain steady stable efficient operation across its required operating range. This is especially important in small scale industrial applications where the unit may be required to change load rapidly or where the fuel composition variance causes swings in the output of the unit.

Though FBC boilers are generally capable of tolerating fuels over wide ranges of heating values and impurities, they must be designed with a prior knowledge of the properties of the fuel that will ultimately be burned. This is needed for the fuel flexibility advantages to be realized. [2]

Sizing, moisture content, and type of biomass product will affect the fuel preparation equipment, the type of fuel feed system, and combustion method best suited for an application. The most desirable situation is to design the furnace for flexibility in the use of fuels not only for economic considerations, but also for emergency situations that may require a change from one fuel type to another. For example, situations may arise where a commercial facility may not be able to depend on obtaining dry material and may have to rely on fuel with a higher moisture content. In such a case, if the furnace/boiler cannot accommodate this change, efficiency and output could be greatly impaired. [5]

The operability of FBC and FBG units should be similar. The CFBC unit will exhibit a slightly higher turndown ratio due to the ability to vary excess air over a greater range than the bubbling bed unit. Both designs are limited only by the ability to maintain temperature while varying load, i.e. firing rate to the unit. If the bubbling bed has in-bed tubes, this can be done by raising and lowering the bed height. However, most biomass fueled BFBC units will not have in-bed tubes due to the large cooling effect of the high moisture content of the fuel.

The major factor affecting the overall operability of the unit will be the success of the fuel preparation and feeding systems. Since these are critical systems, it is always recommended that the fuel preparation and fuel feed systems be placed under the vendors scope of supply to assure the proper interface between these components. This reduces the complications of performance and contractual issues.

For most units, a supplemental fuel will be required for cold startups and in some cases for warm startups. If bed temperature can be maintained during a short outage, which is very possible on fluidized bed units due to the large thermal inertia of the bed, then a supplemental fuel may not be necessary for a hot restart. This has been one of the major advantages of the fluidized bed technology. In addition, for most cold startups some supplemental material may be required such as additional sorbent, spent bed material, or sand to provide makeup for the bed material which may have been disposed when the unit was shutdown.

In any case, in order to optimize the operability of the facility the design must allow for: (1) control of combustor temperatures in response to varying fuel moisture content and heating value, (2) burnout of volatiles released in the freeboard as a result of low fuel particle density and high volatiles content, (3) addition of inert bed material to compensate for the low ash content of most alternate fuels, (4) removal of rocks, wire, and other noncombustible tramp material to prevent buildup in the bed, (5) control of alkali and glass content of bed material to prevent bed defluidization and formation of deposits, caused by low melting point compounds present in the fuel or formed during combustion, (6) control of $S0_2$, NOx, HCI, heavy metal, and toxic emissions derived from alternate fuels, and (7) careful blending of alternate fuels to maintain moisture and heat contents within design ranges. [2]

2.3 RELIABILITY/AVAILABILITY

Perhaps the single most important factor to be considered in the selection of any technology for energy production is the ability of the unit to operate in a reliable manner and the availability of the facility to do this. A highly efficient unit is of little value if it cannot be operated at it's intended capacity and for a long enough period to justify it's existence. In most cases high reliability and capacity factor will make up for deficiencies in other areas such as process performance and maintenance.

Typically an availability of over 95% is expected for commercial energy production facilities. The available FBC systems have demonstrated the ability to reach and exceed this level on a variety of commercial units burning a variety of biomass fuels. It should be noted, however, that there are concerns to be evaluated during a feasibility study of an FBC system. The primary factor affecting the reliability and availability will be the success of the fuel preparation and feed systems.

Another problem which is not well understood is the problem of boiler fouling and corrosion caused by reactions of alkali metals from the fuel ash. This issue poses a significant impact on the availability of biomass fueled units. A significant portion of the fluidized bed facilities surveyed indicated having problems with erosion in the fluidized bed due to the highly abrasive nature of the bed material. In fluidized bed combustion, erosion will impact, to some extent, almost all components that come into contact with the bed material. Corrosion is another problem that has been reported by fluidized bed facilities. Similar to slagging, corrosion is related more to fuel type than reactor design. Erosion and corrosion of the refractory has also been a major problem. Improvements in refractory materials and installation methods have significantly reduced the impact of this problem. [39]

Of the operating FBG units (almost exclusively in Europe), the availability is very high, over 95%. However, the application of FBG in this country has been slow due to the cost and availability of other fuels such as natural gas and propane. Therefore the FBG units have not been commercially available for long enough to have track records for availability. The systems and equipment used on these units is virtually the same as on the FBC facilities and one could expect similar performance. The vendors are providing guarantees and warranties for availability and capacity factor for these units so the financial risk to the owner/operator is reduced. Reliability should also be fairly high for FBG designs.

Fluidized bed technology has been in existence for a long time and has been demonstrated commercially using biomass fuels for over a decade. Much experience has been gained from work that has been performed on coal fired FBC and FBG units. Continuous improvements in systems operations and design have led to increased performance and reliability. Further, the many hours of operation on FBC units using biomass has allowed for optimization of not only equipment design but also operator and labor expertise, and more efficient staffing of maintenance crews.

2.4 ECONOMICS

2.4.1 Capital and Installation Costs

Fluidized bed combustion (FBC) and fluidized bed gasifier (FBG) manufacturers were surveyed to obtain capital and installation costs for systems using biomass fuels. Ten vendors were contacted and nine responded to the survey. Eight of the vendors offered FBC steam generators, six offered FBGs, and two vendors offered FBC for application as hot gas generators. The vendors provided experience lists of FBC and FBG systems which they had supplied. These lists are included in Appendix A. Note that the vast majority of the biomass fueled systems supplied were FBC steam generators.

Following are discussions of the capital cost and installation cost survey results for these fluidized bed technologies.

2.4.1.1 FBC Steam Generators

Vendors offering both bubbling fluidized bed combustion (BFBC) and circulating fluidized bed combustion (CFBC) steam generators typically recommend BFBCs if the anticipated fuel is biomass alone. CFBCs are recommended if flexibility to burn both biomass fuels and coal is desired. The capital cost of CFBC steam generators is typically higher than BFBCs because of the large refractory lined cyclones and extra fan capacity for CFBCs. Cyclones and extra fan capacity are needed for solids recycle to improve combustion efficiency and limestone utilization for sulfur capture. Since most biomass fuels have little or no sulfur and are more reactive than coal, they burn efficiently in BFBCs without the need for high char and sorbent recycle rates. BFBCs designed for firing biomass fuels alone typically do not require in-bed heat transfer surface for bed temperature control. This is because heat to evaporate the high moisture content of the fuel is typically sufficient to control bed temperature without in-bed heat transfer surface. While simplifying the pressure part arrangement, this lack of in-bed tubes may reduce somewhat the capital cost advantage of BFBCs over CFBCs. This is because the heat transfer rate to in-bed tubes is three to five times higher than that to other boiler tubes and if in-bed tubes are used, the total heat transfer surface and, hence, size of the unit can be reduced.

Table 2.4-1 is a summary of the capital and installation cost information provided for fluidized bed combustion steam generation systems by the vendors in the surveys. The costs are separated into BFBC and CFBC steam generator categories. Complete surveys are presented in Appendix B. The costs presented for the FBC steam generation systems are for all equipment from the raw fuel storage tank outlet to the stack inlet. This includes fuel feed equipment, fans, ducts, combustor, steam generator pressure parts, cyclones, and emission control equipment. Fuel preparation system costs are for that equipment that the vendor felt was typically required, including storage, conveying, sizing (shredders, hoggers, hammer mills), size control (disc screens, trommels), and drying equipment.

Vendors were asked to provide costs for two different but typical capacity systems. The capacities of the BFBC systems for which costs were given ranged from 24 to 500 MBtu/hour on a heat input basis. CFBC system capacities tended to be larger, ranging from 100 to 423 MBtu/hour. In fact, one vendor gave information of a utility size steam generator of 250 MWe (equivalent to 3046 MBtu/hour heat input). Figure 2.4-1 is a plot of total capital and installation costs versus capacity for both BFBC and CFBC steam generator systems for firing biomass fuels. Comparing the two curves shows that the cost of a CFBC system is about three million dollars more than a similar size BFBC in the 25 to 550 MBtu/hr range. The slopes of the two curves also illustrate the economy of scale as cost per unit of capacity decreases with increasing system capacity. While reviewing these costs it must be recognized that capital cost estimates and quotes by vendors for a specific steam generation system can vary significantly. Factors effecting these costs include individual interpretation of the scope of supply and system specifications, as well as design life, market conditions, and site specific considerations.

TABLE 2.4-1

FBC STEAM GENERATORS
CAPITAL AND INSTALLATION COSTS
BIOMASS FIRED FLUIDIZED BED SYSTEMS

COMBUSTOR TYPE	BFBC					CFBC			
VENDOR	JWP-EPI	PYROPWR	KVAERNER	JWP-EPI	PYROPWR	KVAERNER	KVAERNER	ABB-CE	ABB-CE
CAPACITY:									
MBTU/HR input	24	84	100	250	502	100	250	423	3046
KLBS/HR stm flow	14	50	58	144	300	58	144	244	1720
MWe				18	37		18	30	250
BOILER EFFICIENCY[3]	70 TO 75	62 TO 75	72 TO 80	70 TO 75	62 TO 75	72 TO 80	72 TO 80	65 to 85	65 to 85
CAP COST (million $):									
STEAM GEN SYS	1.20	4.50	8.1	10.00	16.80	9.00	16.00	12.00	57.50
FUEL PREP	0.48	1.00	0.5	4.00	2.50	0.50	1.50	2.00	10.00
INSTALL COST (million $):									
COMBUST	0.30	1.10	2.25	3.50	5.60	2.50	5.00	4.60	17.00
FUEL PREP	0.11	0.30	0.2	1.00	0.60	0.20	0.50	0.50	2.50
TOT CAP+INSTALL COST:	2.09	6.90	11.05	18.50	25.50	12.20	23.00	19.10	87.00
INCREMENTAL COSTS:									
$/MBTU/HR	86900	82536	110500	74000	50837	122000	92000	45148	28561
$/LBS STEAM/HR	150	138	191	128	85	211	159	78	51

NOTES:

1. Steam generation system scope includes all equipment from fuel silo outlet to stack inlet, i.e. fans, fuel feed system, combustor and steam generator pressure parts, air and gas ducts, and cyclones, air preheaters, and emission controls.
2. Capital and installation costs for fuel preparation equipment were estimated for ABB-CE systems.
3. Boiler efficiency ranges primarily cover variability of fuel moisture content.

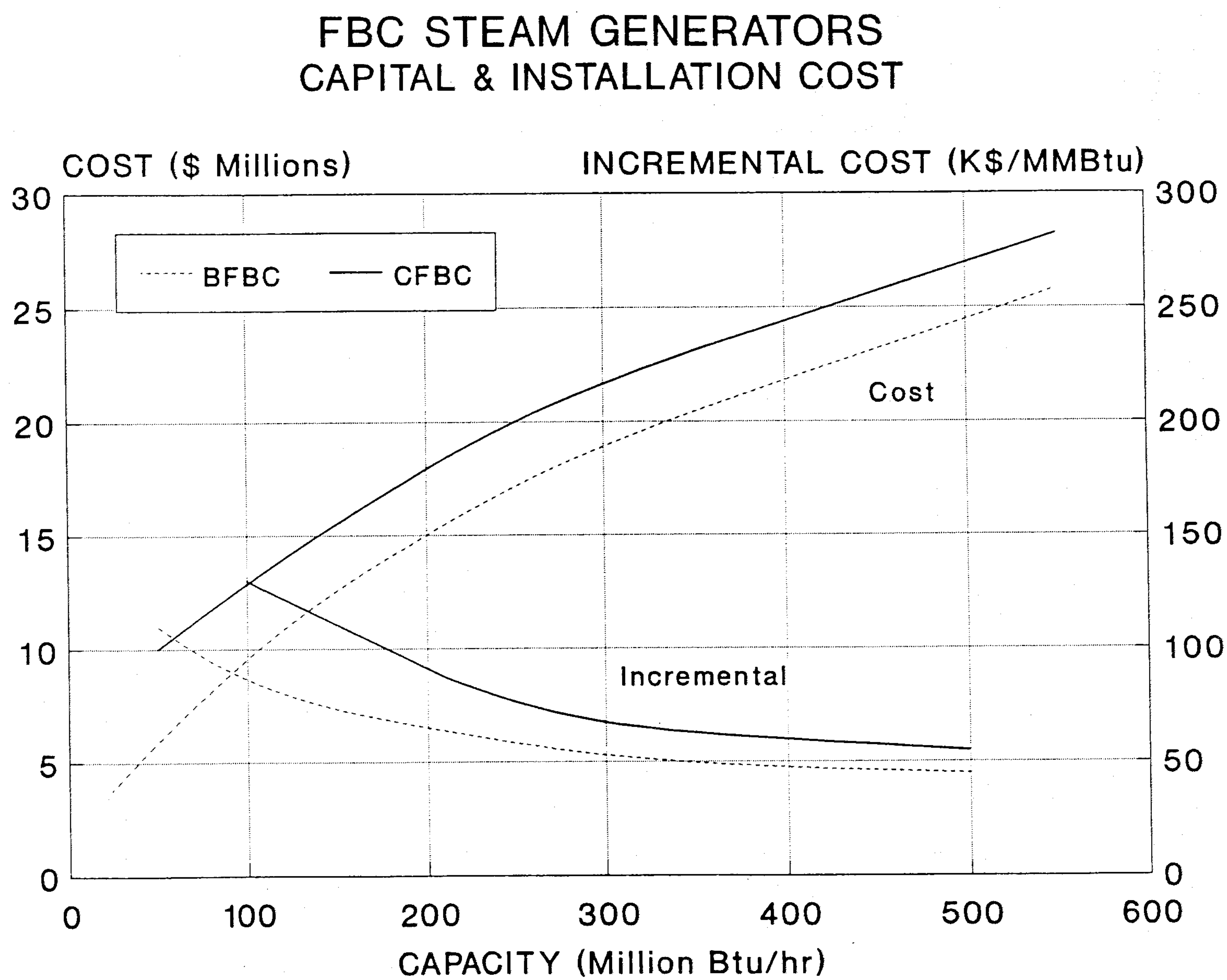

FBC STEAM GENERATORS
CAPITAL & INSTALLATION COST
COST ($ Millions)
INCREMENTAL COST (K$/MMBtu)
BFBC
CFBC
Cost
Incremental
0
5
10
15
20
25
30
0
50
100
150
200
250
300
0
100
200
300
400
500
600
CAPACITY (Million Btu/hr)

Figure 2.4-1

2.4.1.2 Fluidized Bed Gasifiers

Gasifier technology generally and fluidized bed biomass gasification specifically have not yet achieved a significant share of the energy conversion market particularly in the United States because of the relatively low price and plentiful supply of natural gas. Although several vendors offer commercial guarantees on gasification technologies, economic conditions have slowed development, specifically on issues such as long term performance and reliability of feed and ash systems and refractory. During the early and mid 1980's high natural gas prices, low known reserves, and tax incentives led to construction of seven commercial fluidized bed biomass gasifiers in the United States. As the price of natural gas dropped in the late 1980's many of these plants became uneconomical. Five of these plants have since been shut down for economic reasons. At least three of them are for sale. The two operating gasifiers burn waste fuel (rice hulls) generated at the plant site.

Presently, biomass gasification is economically viable in the United States only under certain special circumstances. Biomass gasification economics will not improve unless natural gas prices rise significantly. Under present conditions, the situations where biomass gasification might now succeed are those where an abundant and reliable feed stock supply exists at a very low cost in conjunction with an existing energy load. An example of such a situation might be a manufacturing facility generating a large quantity of biomass as a waste product while requiring a substantial process heating load or which is located in close proximity to such a heat load. An example is a lumber mill which generates sawdust and wood scraps that could be used as a fuel to provide heat for a kiln dryer.

Situations where the energy load is in the form of electric power might be attractive for an integrated gasification combined cycle (IGCC) system. An IGCC system consists of a biomass gasifier, gas turbine-generator, a waste heat steam generator, and a steam turbine-generator. The primary advantage of the IGCC system is its higher power production efficiency (40-50%) compared to a conventional power plant of 25-35%. Presently, the disadvantages of the IGCC system are the higher capital costs because of the additional equipment required (both a gas turbine generator set and a steam turbine generator set) and the inherent risk involved with an emerging technology. Two factors which would mitigate these disadvantages are a reliable fuel supply at a predictable and stable cost and an existing and stable electrical power load. Two vendors, Pyropower and Tampella, are now operating pilot/demonstration IGCC systems with fluidized bed gasifiers. Tampella offers commercial guarantees for their gasifier while Pyropower reports they are close to doing so.

Capital and installation costs provided by vendors for fluidized bed biomass gasifiers are summarized in Table 2.4-2. The costs presented are for all equipment from the raw fuel storage tank outlet to the outlet of gas clean-up equipment. This includes fuel feed equipment, fans, ducts, gasifier, and gas clean-up equipment. Fuel preparation system costs are for that equipment that the vendor felt was typically required, including storage, conveying, sizing (shredders, hoggers, hammer mills), size control (disc screens, trommels), and drying equipment.

Four of the six fluidized bed gasifier vendors provided cost information. Because of the poor market conditions, the experience level of the vendors with commercial fluidized bed biomass gasification systems is not quite as strong as it is with combustion systems. Only one, PRM Energy, of the six vendors responding to the survey now has commercial fluidized bed biomass gasifiers operating in the United States. Future Energy and Tampella have not yet sold a commercial gasifier, whereas JWP Energy Products and PRM Energy have sold gasifiers in the U.S., and Pyropower & Gotaverken have units which are now operating in Europe.

The costs presented in Table 2.4-2 are not readily comparable because of several technological differences between the systems in addition to the differences in capacity. The EPI, PRM Energy, and Pyropower gasifiers are air blown and, thus, produce low Btu gas (100-200 Btu/scf). The EPI system is a bubbling fluidized bed gasifier (BFBG) while the Pyropower unit is a circulating fluidized bed gasifier (CFBG). The PRM Energy unit is described by its manufacturer as having a "semi-fluidized" fuel bed with a proprietary mechanical bed agitation system. PRM Energy

TABLE 2.4–2

FLUIDIZED BED GASIFIERS
CAPITAL AND INSTALLATION COSTS
BIOMASS FIRED FLUIDIZED BED SYSTEMS

VENDOR	PRME	JWP–EPI	PYROPWR	PRME	FERCO
GASIFIER TYPE	MODIFIED FB[2]	BFB	CFB	MODIFIED FB[2]	CFB
CAPACITY MBTU/HR input	8	24	90	100	266
GAS Btu/lb	100–200	100–200	100–200	100–200	500
CAP COST (million $):					
GASIFIER SYSTEM	0.15	1.20	9	0.85	10.00
FUEL PREP	0.06	0.48	2	0.34	5.00
INSTALL COST (million $):					
GASIFIER SYSTEM	0.05	0.30	2.3	0.15	(Installation costs included in capital costs.)
FUEL PREP	0.02	0.12	0.5	0.09	
TOT CAP+INSTALL COST	0.28	2.10	13.80	1.43	15.00
INCREMENTAL COSTS: $/MBTU/HR	34375	87500	153333	14250	56391

NOTES:

1. Gasifier system scope includes all equipment from fuel silo outlet up to and including any gas clean up equipment, i.e. fans, fuel feed system, gasifier vessel, air and gas ducts, cyclones, and scrubbers.

2. The PRME system features a proprietary mechanically fluidized bed.

3. Fuel preparation system capital and installation costs were estimated for PRME and JWP–EPI.

calls it a modified fluidized bed gasifier. The Future Energy gasifier is the Battelle CFBG technology using steam for fluidization and indirect heating to produce an intermediate Btu gas (500 Btu/scf).

2.4.1.3 FBC Hot Gas Generators

Fluidized bed combustion (FBC) hot gas generators are sometimes useful for providing hot gas for a process heating application where combustion of the fuel external to the heating load is desirable. Examples of such applications are lumber drying kilns and wood veneer dryers.

JWP Energy Products and Pyropower offer fluidized bed combustors for hot gas generation. JWP Energy Products indicated that capital and installation costs for their hot gas FBC combustors are about 40% of the cost of their FBC steam generator units.

2.4.2 Operating and Maintenance Costs

Operating and maintenance (O&M) costs for fluidized bed combustion and gasification systems arc similar to those of other fuel burning technologies. The costs consist of fuel cost, routine operating and maintenance costs, ash disposal, major maintenance and capital equipment replacement, and insurance and taxes. Another annual cost not usually considered an O&M cost is the amortization of the capital and installation debt for the plant. A rule-of-thumb for estimating annual routine O&M costs is to use 5% of the capital cost. A rule-of-thumb for estimating annual costs for major maintenance and capital equipment replacement is 0.5% of the original equipment capital cost. Annual costs for taxes and insurance are typically estimated at 2.5% of equipment capital costs. [40, 41]

The largest component of the annual O&M costs of fuel burning facilities is usually the fuel cost. If the fuel is not a waste product generated at the plant site, its cost may range from 50 to 90% of the total O&M costs depending on plant capacity, delivered fuel price, and capacity factor. Transportation costs for biomass fuels are typically higher than fossil fuels on a $/MBtu basis because of its lower bulk density and, in many cases, higher moisture content. Capacity factor is defined as the ratio of the amount of steam, producer gas, or power produced in a specific time period to the production if the plant ran at rated capacity for the entire period. If the biomass fuel is a byproduct or waste of another process, then O&M costs can be reduced by as much as 50 to 90%, the percentages indicated above. Further, if use of the waste as a fuel eliminates the cost of disposal, then this cost can be included as an O&M cost credit.

Routine O&M costs, other than that for fuel, consist of costs for labor, utilities and auxiliary power, tools, solid waste disposal, spare parts inventory, and miscellaneous supplies and consumables. Labor includes that for operations and maintenance staffs and administrative support. Utilities and auxiliary power include water, electricity, and startup fuels such as fuel oil and natural gas.

2.4.3 System Costs For Two FBC Steam Generator Systems

Based upon previous sales of fluidized bed equipment by vendors in the United States for use with biomass, the typical system is a bubbling fluidized bed combustion steam generator. System capital, installation and operating costs along with incremental energy costs are presented in Table 2.4-3 for two typical capacity systems. The three most significant factors affecting incremental energy costs are capital cost, fuel cost, and capacity factor.

The most difficult variable to predict is fuel cost. The fuel cost can include material and transportation cost for the typical biomass fired FBC system. Thus, data for two cases are presented in Table 2.4-3. Case 1, labeled "Purchased Fuel", assumes the

TABLE 2.4–3

COSTS FOR TWO FBC STEAM GENERATION UNITS

BFBC STEAM GENERATOR WITH EXISTING PROCESS HEAT LOAD

	CASE 1 PURCHASED FUEL		CASE 2 WASTE FUEL	
CAPACITY:				
(MBTU/HR INPUT):	100	500	100	500
(1000 PPH STM FLOW):	55	275	55	275
(EQUIVALENT MWe):	8.2	41.0	8.2	41.0
CAPITAL COSTS ($$10^6$)[1]:	9	21.1	9	21.1
INSTALLATION COSTS ($$10^6$):	1	2.9	1	2.9
CAPACITY FACTOR (%): (Annual power production/potential power production)	85	85	85	85
FUEL: (wood chips, saw dust)				
COST ($/MBTU):	3.5	3.5	0	0
CONSUMPTION (@ 5000 BTU/LB) (TONS/HR):	10	50	10	50
(TONS/YEAR):	40,953	204,765	40,953	204,765
ENERGY PRODUCED:				
STEAM (MILLION LBS/YR):	40,953	204,765	40,953	204,765
EQUIVALENT ELECT POWER (MWH)	61,086	305,432	61,086	305,432
O & M COSTS ($1000/yr)[1]:				
FUEL:	2,606	13,031	0	0
ROUTINE O & M (@ 5% of cap cost including labor, maintence, utilities, & misc):	450	1,055	450	1,055
MAJOR MAINTENANCE & CAPITAL EQUIPMENT REPLACEMENT (@ 0.5% of cap cost):	45	106	45	106
INSURANCE & TAXES (@ 2.5% of cap cost):	225	528	225	528
CAPITAL DEBT REPAYMENT ($1000/yr): (100% of capital/install cost borrowed at 7% APR for 20 years)	944	2,265	944	2,265
TOTAL ANNUAL COSTS ($1000/yr):	4,270	16,984	1,664	3,953
INCREMENTAL ENERGY COST:				
STEAM PRODUCTION (CENTS/1000 LBS STEAM):	10.4	8.3	4.1	1.9
EQUIVALENT ELECTRIC POWER (CENTS/KWH @ 28% cycle efficiency)[1]:	7.0	5.6	2.7	1.3

[1]Capital and O & M costs include that of the steam generation and fuel prep equipment. They do not include the costs of land or steam turbine and generator equipment.

wood fuel is purchased from a fuel supplier and transported to the plant. Case 2, labeled "Waste Fuel", assumes that the fuel is a waste product generated by another process at the plant site. Thus, Case 2 fuel and transportation costs are considered to be zero. Comparing the two sets of data shows the extreme sensitivity of energy cost to fuel cost. Also, readily apparent upon examining the incremental energy cost data for the different capacity systems is the advantage of the economy of scale possessed by the larger system.

2.5 ENVIRONMENTAL CONSIDERATIONS

2.5.1 Air Pollution Control Requirements

Air pollution control requirements for new fluidized bed combustion and gasification systems depend upon the emission limitations prescribed in the construction permit issued for the project by the state or local regulatory agency having jurisdiction. This permit, issued prior to start of construction, will list the pollutants which must be controlled and the allowable emission levels of each. One of the first and most important steps that should be taken early in the developmental stage of any fuel combustion or gasification project is to contact the state or local air pollution board to identify applicable rules, regulations, and permit requirements. Appendix D contains a listing of state and federal air pollution control agencies with addresses and telephone numbers for the thirteen southeastern states.

Pollutants to be controlled and emission levels for any type of fuel burning equipment are determined principally by three items. These are plant location, system capacity, and predicted emissions based on fuel(s) to be burned and pollutant controls provided.

If the plant is to be located in an environmentally sensitive area such as a "nonattainment area" or one close to a large national park, then more stringent permitting procedures and emissions limits will apply. A nonattainment area is one in which levels of one or more criteria pollutants exceed National Ambient Air Quality Standards. Criteria pollutants are sulfur dioxide (SO_2), total suspended particulates (TSP), nitrogen oxides (NO_x), carbon monoxide (CO), ozone (O_3), and lead (Pb). System capacity along with fuel to be burned provide the basis for determining total potential or uncontrolled emissions from the plant. System capacity is also one criteria which might be used in setting emission limits. For example, systems greater than 250 MBtu/hr heat input may have to meet more stringent emission limits than ones below that level.

Air pollutants of concern from FBC systems using biomass fuels are the same as those of other technologies. These typically are SO_2, total suspended particulates (TSP), NO_x, CO, and volatile organic compounds (VOCs). If municipal solid waste (MSW) or refuse derived fuel (RDF) is the fuel, then hydrogen chloride (HCl), dioxin, furan, and metals are typically controlled. The FBC process is unique among combustion technologies in that it has the inherent capability of controlling the emissions of two important pollutants, SO_2 and NO_x. Since most biomass fuels have little or no sulfur, SO_2 is of little concern. Careful design and control of the combustion process can minimize and control CO, VOC, dioxin, and furan emissions. Thus, an FBC system burning a typical biomass fuel, other than MSW, may only require a particulate control device.

Following is a discussion of the various air pollution control devices and techniques used on FBCs with biomass fuels other than municipal solid waste:

> $\underline{SO_2}$ - Sulfur content of biomass fuels range typically from 0.01 to 0.10% by mass dry basis. The ash in biomass fuels is typically alkaline. Thus, by maintaining proper combustion and temperature conditions in the combustor, SO_2 emissions can usually be controlled to an acceptable level. If additional reactants are needed, then limestone can be fed to the combustor.
>
> <u>TSP</u> - Both baghouses and electrostatic precipitators (ESPs) are used to control particulate emissions from biomass fired FBCs. ESPs have been used on stoker fired biomass boilers because of the perceived risk of baghouse fires due to sparkler carryover. This led to use of ESPs on early biomass fired FBCs. However, more recent units have used baghouses successfully. The risk of baghouse fires with FBCs is considered low because of the greater carbon burnout of FBCs compared to the stoker fired units.
>
> $\underline{NO_x}$ - Because of the low nitrogen content of most biomass fuels (0.1-0.6% by mass, dry basis) and the low combustion temperature, the inherently low NO_x emissions from the FBC meet most current state and local limits. Where

additional control is needed, staged combustion, ammonia or urea injection, or selective catalytic reduction (SCR) may be employed.

CO, VOCs - CO and VOCs are products of incomplete combustion. Proper design of the combustor and control of the combustion process can adequately minimize emission of these pollutants. Attention to good fuel/air mixing, provisions for adequate fuel residence time in the combustion zone, and control of combustor temperature are important considerations.

Controls for air pollutant emissions that are of particular concern with municipal solid waste combustion, in addition to those discussed above are:

HCl, Dioxin/Furan - Most biomass fuels have little or no chlorine and require no controls. However, municipal solid waste usually does have a significant chlorine content (0.5 to 0.9% by weight) primarily from plastics. Almost all this chlorine converts to HCl and can contribute to formation of small quantities of chlorinated organic compounds such as dioxin and furan. Limestone injected into the combustor results in some control. The calcium-chlorine reaction kinetics differ from that of sulfur, as the HCl combines with calcium oxide primarily in the baghouse filter cake, where calcium chloride, a filterable solid, is formed. In most cases, additional control is required and it is accomplished with dry scrubbing, either by injecting dry hydrated lime into the gas duct or installing a spray dryer ahead of the baghouse. Dioxin and furan can be controlled by optimizing combustion conditions to assure complete combustion of volatile organic compounds.

Metals - Heavy metals emissions is typically not a concern of most biomass fuels because of the low ash content. However, MSW can contain significant amounts of metals from any number of sources. Collection of most heavy metals emissions from MSW combustion is accomplished by the baghouse or electrostatic precipitator, provided for particulate control. This is because most metals, such as lead, cadmium, and zinc either don't vaporize or, if they do, condense in the gas ducts downstream from the combustion zone and adhere to the flyash. Mercury, on the other hand, vaporizes, and remains a vapor when cooled to stack temperature (250-300°F). If mercury emissions must be controlled, injection of both activated carbon and sodium sulfide (Na_2S) have been found to be effective. These technologies have been applied to municipal waste combustors in Canada, Europe, and Japan and tested by EPA. [1, 42, 43]

2.5.2 Air Permits

State and local agencies are responsible for regulating and permitting facilities that emit pollutants to the air. Most biomass fueled fluidized bed combustion and gasification systems, unless very small, require separate air permits to construct or modify, and operate the unit. Permit applications must be submitted for all such systems so that the agency can make this determination.

The initial step is to secure a construction permit by submitting an application on forms that can be obtained from the regulatory agency. The application typically requires that the location of the facility, descriptive information on the process and emissions control equipment, and estimates of pollutants and pollutant emission rates be given. The regulatory agency reviews the application in regard to applicable federal, state, and local regulations. It may perform modeling studies or require that the applicant do so to evaluate the impact of the estimated emissions on the ambient air quality of the region prior to establishing pollutant emission limits and granting the construction permit. The construction permit defines emissions limits, emissions control requirements, testing, monitoring, records keeping, and reporting requirements. The process may take as little as 60 to 120 days for small projects or as much as a year or more for large projects. Construction permits must be granted prior the start of construction or modification.

Construction permits may also allow typically 60 to 180 days for startup and shakedown operation, emission testing and emissions monitor certification. Then, an operating permit application must be submitted along with reports of emissions test results. An operating permit will typically be granted if all the conditions of the construction permit have been met and the facility has demonstrated that it is capable of performing within the prescribed emissions limits. [44]

Title V of the Clean Air Act Amendments of 1990 required that state and local air pollution control agencies establish air pollution operating permit programs based upon regulatory guidelines issued by EPA. State programs must be at least as stringent as EPA's guidelines and local programs must be at least as stringent as its respective state program. Thus, permit requirements can vary from one state and local agency to another.

The new Title V permits apply to "major sources". Major sources are those which emit:

- 100 tons per year of a criteria pollutant (see section 2.5.1), or
- 10 tons per year of any hazardous pollutant, or
- 25 tons per year of any combination of hazardous pollutants.

All sources subject to the Title V program must submit permit applications within one year of EPA approval of the program. EPA guidelines allow state and local agencies to issue permits for periods up to five years. A schedule must be established by each agency for acting on the initial permit applications which assures that at least a third of these submitted applications are acted upon annually for three years. Permits must include all Clean Air Act requirements applicable to the source, including a schedule of compliance and applicable monitoring and reporting requirements. Sources must pay permit fees to cover the costs of the Title V permitting program. [2]

The new permit programs were scheduled to go into effect November 15, 1994. With all existing major sources required to submit applications and have them acted upon over the next three years, any new source permit application will only add to the workload. The possible result could be delay in obtaining a permit.

Biomass combustion and gasification facilities tend to be relatively small and to be low emitters of criteria and hazardous pollutants, with the possible exception of municipal solid waste/refuse derived fuel facilities. Thus, it is not anticipated that the Title V permit program will be a major obstacle to the typical biomass fluidized bed project. However, anyone anticipating construction of an air pollution source would be well advised to initiate discussions early with its state or local regulatory agency to determine the status and specific implications of the applicable Title V permit program.

3.0 TECHNICAL FACTORS

This section presents a detailed discussion of the technical aspects of FBC and FBG systems in a format designed for the technical or engineering staff of the waste generator. Areas of discussion include process performance, mechanical systems and equipment, environmental considerations, fuel and ash characteristics, availability, turndown, and supplemental fuel requirements. The information is intended to allow the engineering staff of the biomass generator to evaluate the technical feasibility of an FBC or FBG project.

3.1 PROCESS PERFORMANCE

The process performance of an FBC or FBG unit covers a broad spectrum of parameters. Primarily this includes combustion efficiency of the fuel, thermal efficiency of the unit, heat transfer characteristics, and the ability to maintain environmental compliance. In general, most of the FBC and FBG systems are comparable in terms of overall process performance. Commercial guarantees are offered by vendors which are competitive with conventional technologies burning standard fuels. Of course, the use of biomass fuels will effect the actual performance levels but this is generally a function of the fuel composition, and not due to system design or application.

3.1.1 Combustion Efficiency

Due to the high residence time and turbulent mixing in fluidized bed combustors, and high reactivity of biomass fuels combustion efficiency of these fuels is near 100%. By comparison, combustion efficiency for much less reactive conventional fuels such as coal is in the range of 98%-99%. As shown in Table B-1 in Appendix B, the FBC vendors will base guarantees on predicted combustion efficiencies greater than 99% for biomass fuels. [45]

Typically, vendors do not provide guarantees on combustion efficiency. Rather, the guarantee is on thermal efficiency. This is more commonly referred to as boiler efficiency, which is directly related to the combustion efficiency.

There is a distinct difference in boiler and combustion efficiency. Boiler efficiency is defined as the amount of heat energy that is absorbed by the water or steam in the boiler as a percentage of the total heat energy of the fuel entering the boiler. Combustion efficiency refers to the degree to which the fuel burns completely. [5]

Table 3.1-1 shows how some of the combustion variables influence boiler efficiency. Boiler efficiency is significantly affected by fuel composition. Typical biomass-fired fluidized bed boiler efficiencies are in the 70-80% range depending on the fuel burned. The high moisture content of many biomass fuels requires a significant amount of energy for vaporization. On units where the moisture content is reduced to 5 -10%, comparable to traditional fuels, the boiler efficiencies will also be comparable at around 85-90%. Table A-1 shows the vendors guaranteed boiler efficiencies.

It should be noted that there is a maximum amount of moisture that can be present in the fuel for it to maintain combustion. Otherwise, a supplementary fuel must be fired to stabilize the combustion process. Fuels with 60 -70% total moisture are generally considered to exceed the economical limit for the combustion of "wet"fuel. Figure 3.1-1 illustrates the relative change in the boiler efficiency with increasing fuel moisture content. For a fuel with 50% moisture content, the thermal efficiency would be approximately 15% less than that of a dry fuel. [46]

Typically FBC and FBG units burning biomass fuels will use sand as the bed material. The sand will be of a certain size specification in order to remain in the system for as long as possible. Therefore, the efficiency of the unit will not be impacted by the heating of fresh sand. However, the sand does play a critical role with regard to any

Table 3.1-1

Effect of Combustion Parameters on Boiler Efficiency

COMBUSTION PARAMETER	PARAMETER RANGE	BOILER EFFICIENCY RANGE	CHANGE IN BOILER EFFICIENCY
Fuel Moisture	0 - 50 %	86 - 72 %	14 %
Combustion Air Temperature	100 - 500°F	82 - 84 %	2 %
Exit Gas Temperature	200 - 400°F	85 - 80 %	5 %
Excess Air	20 - 40 %	83 - 82 %	1 %
Unburned Carbon in Ash	0 - 40 %	83 - 80 %	3 %

Base Conditions:	Fuel Moisture	- 20%
	Combustion Air	- 100°F
	Exit Gas	- 300°F
	Excess Air	- 30%
	Unburned Carbon in Ash	- 20%
	Boiler Efficiency	- 82%

Effect of Fuel Moisture On Boiler Efficiency

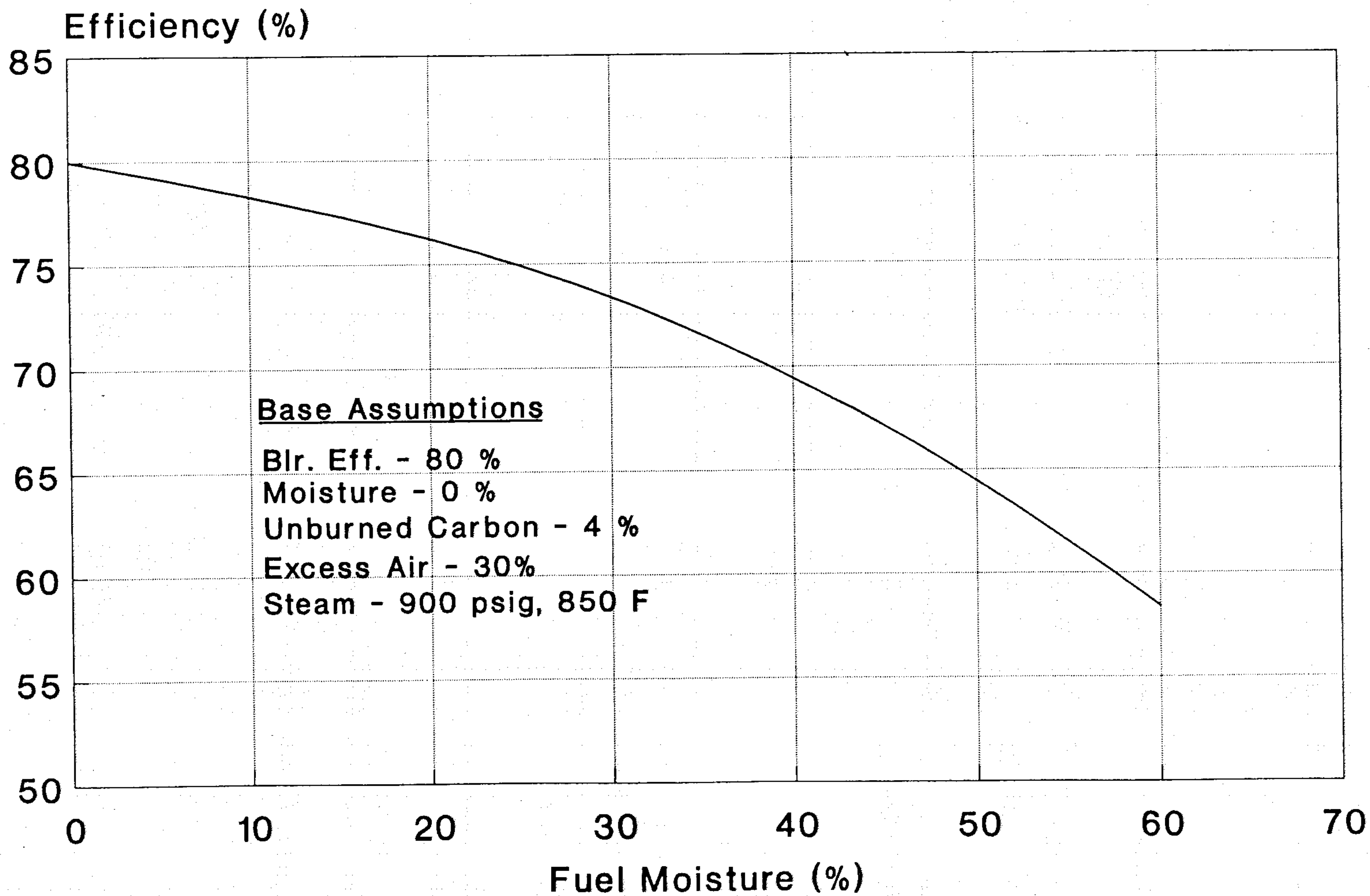


Figure 3.1-1

Source: Ref. 46

heat transfer to combustor surface such as waterwall panels. The use of sand will affect the overall ash split from the unit. If the only ash exiting the system is from the fuel ash, then the flyash will contain almost all of the ash, resulting in very little material to be drained from the bed.

On units where a sorbent, such as limestone or dolomite, is used for sulfur capture, or other purpose, (see Section 3.2), the process efficiency can be affected. The sorbent will require some of the fuel energy released for the calcination reaction. In cases where the fuel sulfur is high, this calcination loss can be negated by the sulfation process gain. However, if the sulfur is low, the calcined unsulfated limestone will attrit easily; which in turn will cause bed material to be lost from the system. For limestone applications, the flyash/bottom ash split is different from that with sand. Much of the sulfated lime will be denser and exit the unit as bottom ash. A typically split would be around 80/20.

The early generation bubbling bed units were not as efficient as their successors, the circulating bed design. However, with advances in both designs, the performance is now comparable for many fuels. In fact, in certain applications the bubbling bed is the more attractive option.

The bubbling bed unit, with its lower velocity and very pronounced dense bed region, may be more suitable for burning many of the biomass fuels. This is particularly true for those which have high volatile content and burn rapidly. These fuels tend to elutriate faster, but the lower velocity of the BFBC minimizes this elutriation of unburned fuel. For many fuels, the particles may become small so fast (due to their attrition characteristics) that they cannot be captured by the CFBC cyclone.

The CFBC on the other hand, with its higher velocity, solids flux and recycle rate, and longer overall solids residence time is more suited to the harder to burn fuels. This is provided they can be captured by the cyclone and remain with the circulating loop. Again, it is important to note that the preferred option will depend mostly on the choice of fuels to be used, more than the design or application of the facility. [45]

In either unit, key design considerations for achieving effective burnout include proper fuel penetration and mixing into the dense bed, proportioning of the combustion air with one or more stages of secondary air, effective mixing of the secondary air with the volatile gases, and adequate gas residence time.

Although the FBG units do not attempt to burn the fuel to complete combustion, the measure of it's ability to produce a usable gas as compared to the fuel energy input can be compared to a "combustion efficiency". With this in mind, the FBG units will also have a high energy conversion capability measure of performance. Most biomass fuels will gasify adequately in an FBG unit if given the proper fuel feed, recycle,and fluidization distributions. Table B-2 in Appendix B shows the expected efficiencies for FBG units.

3.1.2 Heat Rate

Net plant heat rate (NPHR) is used in the power production industry as the standard for determining and describing the performance of a unit. The NPHR is a measure of the overall unit thermal efficiency. It is defined as the fuel energy input divided by the net power produced, e.g. Btu/KWh. The lower the heat rate, the more efficient the unit as less fuel is needed to produce the same amount of power. Typically, the more efficient utility coal fired power plants have NPHR of around 10,000 Btu/KWh. Biomass units, due to the lower boiler efficiency, will have NPHRs in the 11,000 to 13,500 Btu/KWh range. Conventional units of comparable size have NPHRs of 10,500 to 11,500 Btu/KWh.

The NPHR is a function of several factors, including boiler efficiency, steam cycle characteristics, feedwater condensate and auxiliary power requirements, generator and turbine efficiencies. Of these factors, only boiler efficiency and auxiliary power will vary depending on technology concept. The other factors may vary from plant to plant, however, the differences will not be due to the boiler type. When evaluating net plant heat rates between vendors, care should be taken to account for these differences to make the comparison consistent.

Fluidized bed units, CFBCs in particular, will likely have higher auxiliary power requirements (+1%), as compared to conventional technologies, due to higher FD fan requirements. All other factors being equal, this 1% corresponds to a difference in the net plant heat rate of 100 Btu/KWh out of 10,000 Btu/KWh or approximately 1% of the heat rate.

Overall net plant heat rate will be higher for the biomass fuels installation as compared to conventional fuels such as coal or oil, or gas, due to the lower boiler efficiencies. However, the remainder of plant systems, such as turbines, generators, condensers, etc. will be similar for FBC and FBG units and therefore will perform to the same levels of efficiencies. A typical heat rate for an FBC power production facility, steam turbine, will be approx 10,000 Btu/KWh. The NPHR for an FBG facility in a gas turbine single cycle unit is slightly lower. This heat rate can be improved by using a combined cycle application with the FBG, i.e. gas turbine and steam turbine powered by the steam produced in a heat recovery steam generator. For this application heat rate can be lowered to 8500 Btu/KWh.

As stated previously, any limitation on efficiency and subsequently overall plant heat rate will be directly a function of the moisture in the fuel. Even with a higher NPHR, the savings from using a less expensive or free biomass fuel will typically outweigh any reduction in efficiency.

Unrelated to the combustor or gasifier technology there exist many enhancements to the Rankine steam cycle which can improve the efficiency of the cycle, and therefore the NPHR. However, they also add to the overall complexity of the system. Some of the more common enhancements are discussed below.

<u>Reheat Cycle</u> - The simple Rankine cycle suffers from the fact that excess moisture during the expansion process is detrimental to the performance and life of the turbine

as moisture can cause damage to the turbine blades over time. Superheat offers a simple way to improve the efficiency of the Rankine cycle and reduce the level of moisture in the latter stages of the turbine. But unfortunately, there are upper limits to operating pressures and temperature due to the limitations of the materials used to construct the boiler, turbine, pumps, condenser and piping. A reheat cycle can be used to provide greater efficiency and reduced moisture in the latter stages of the turbine and retain superheat temperatures and pressures within acceptable limits.

In the reheat cycle, steam is permitted to expand part of the way in the high pressure turbine, then is returned to the boiler and heated again and re-expanded through the low pressure turbine. The steam then goes to the condenser, feedwater pumps, and back to the boiler as in the Rankine cycle.

There is no theoretical limit to the number of stages of reheat that can be employed in a cycle. However, one or two stages are common. Three stages are used occasionally, but one is the most typically used. Reheating may be carried out in a section of the boiler supplying primary steam, in a separately fired heat exchanger, or in a steam to steam heat exchanger. In most modern units the superheater and the reheater are located in the same boiler. The reheat cycle is best adapted to systems where fairly high pressure and temperature superheated steam are used. The initial expansion through the high pressure turbine will leave a sufficiently high steam pressure for reheating. Figure 3.1-2 shows a simple reheat cycle.

Regenerative Cycle - A method of increasing the steam cycle efficiency without increasing the superheated steam pressure or temperature is the regenerative heating cycle. In both the Rankine and Reheat cycles, the condensate is returned to the boiler at the lowest temperature in the cycle. The regenerative cycle uses the waste heat from the turbine exhaust to increase the temperature of the boiler feedwater. This improves unit efficiency, since the feedwater is hotter when it enters the boiler, thereby requiring less heat to produce steam. The heat exchangers used to perform this task are commonly referred to as feedwater heaters. In general feedwater heaters are of three types; high pressure closed heaters, low pressure closed heaters, and

Reheat Cycle

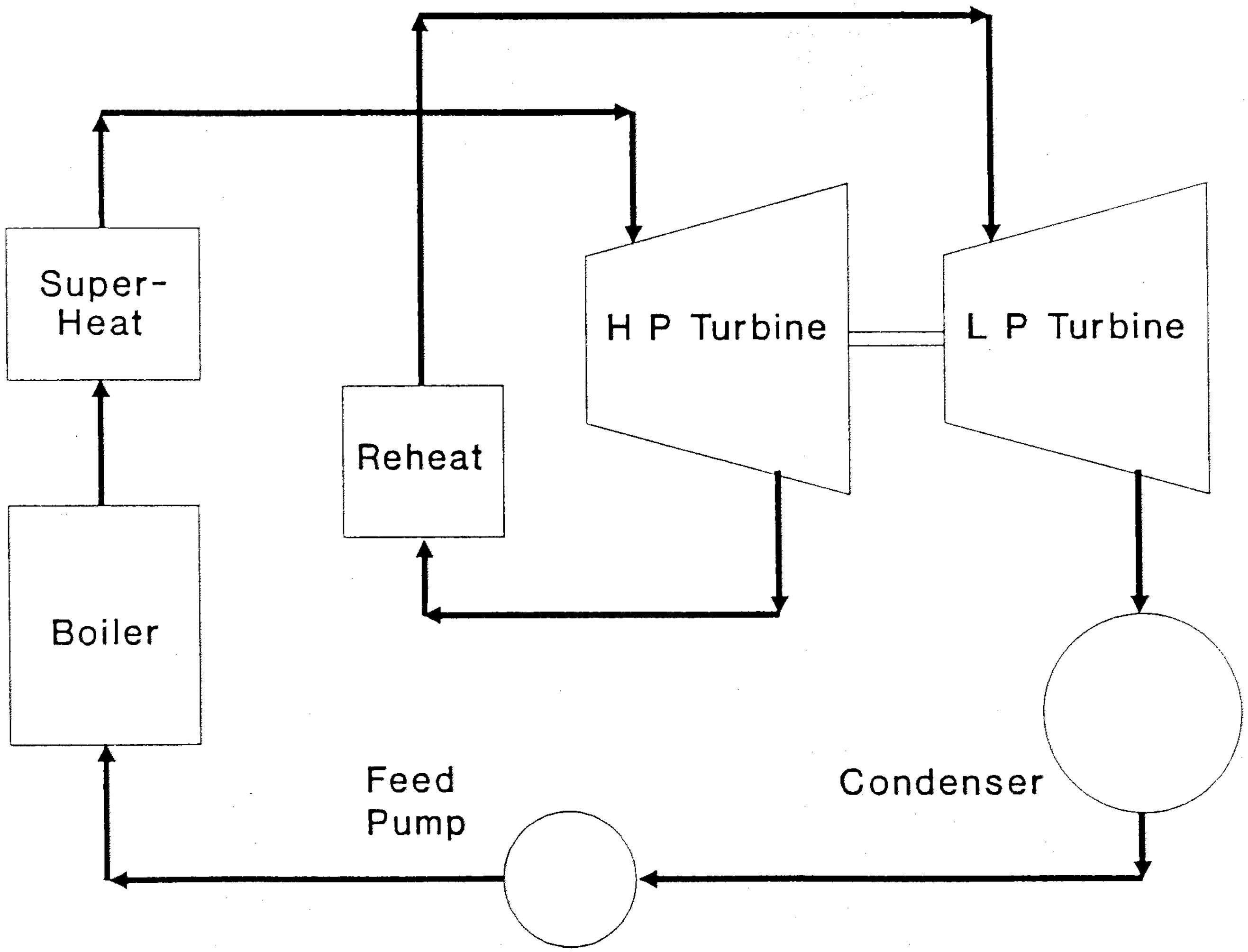


Figure 3.1-2

atmospheric pressure open heaters. The open heaters are more commonly called deaerators. Figure 3.1-3 shows a regenerative cycle.

<u>High Pressure Feedwater Heaters</u> - These shell and tube heat exchangers are placed downstream of the feedwater pumps and normally heated with extraction steam from the turbine. The feedwater commonly flows through the tube side of the heater at the feedwater pump discharge pressure. The shell side is used by the extraction steam and the pressure is dependant upon the turbine extraction point.

<u>Low Pressure Feedwater Heaters</u> - These heaters are upstream of the feedwater pumps and commonly located in the top of the condenser. They can be heated by turbine extraction steam or by the turbine exhaust steam. The water is supplied from the bottom of the condenser called the hotwell at or near atmospheric pressure.

<u>Deaerators</u> - These are open heat exchangers or mixing tanks that operate at atmospheric pressure. These also remove gases from the feedwater which may cause equipment corrosion. The water is supplied from the low pressure heaters or hotwell if low pressure heaters are not used. The heating fluid is commonly supplied by the drains from the high pressure heaters, but extraction steam can be used with the proper design.

<u>Hotwell Pumps</u> - The hotwell pumps are typically located near the bottom of the condenser and take the water which is usually below atmospheric pressure, from the condenser and pump it through the low pressure feedwater heater, and to the deaerator tank which is at atmospheric pressure.

<u>Typical Enhanced Steam Cycle</u> - All of the enhancements discussed above would be found in a modern power plant. The number if reheat cycles and feedwater heaters will vary with the size of the plant. In general, the larger the plant the more complex the regenerative and reheat cycles. Condensate treatment systems will vary depending

Regenerative Cycle

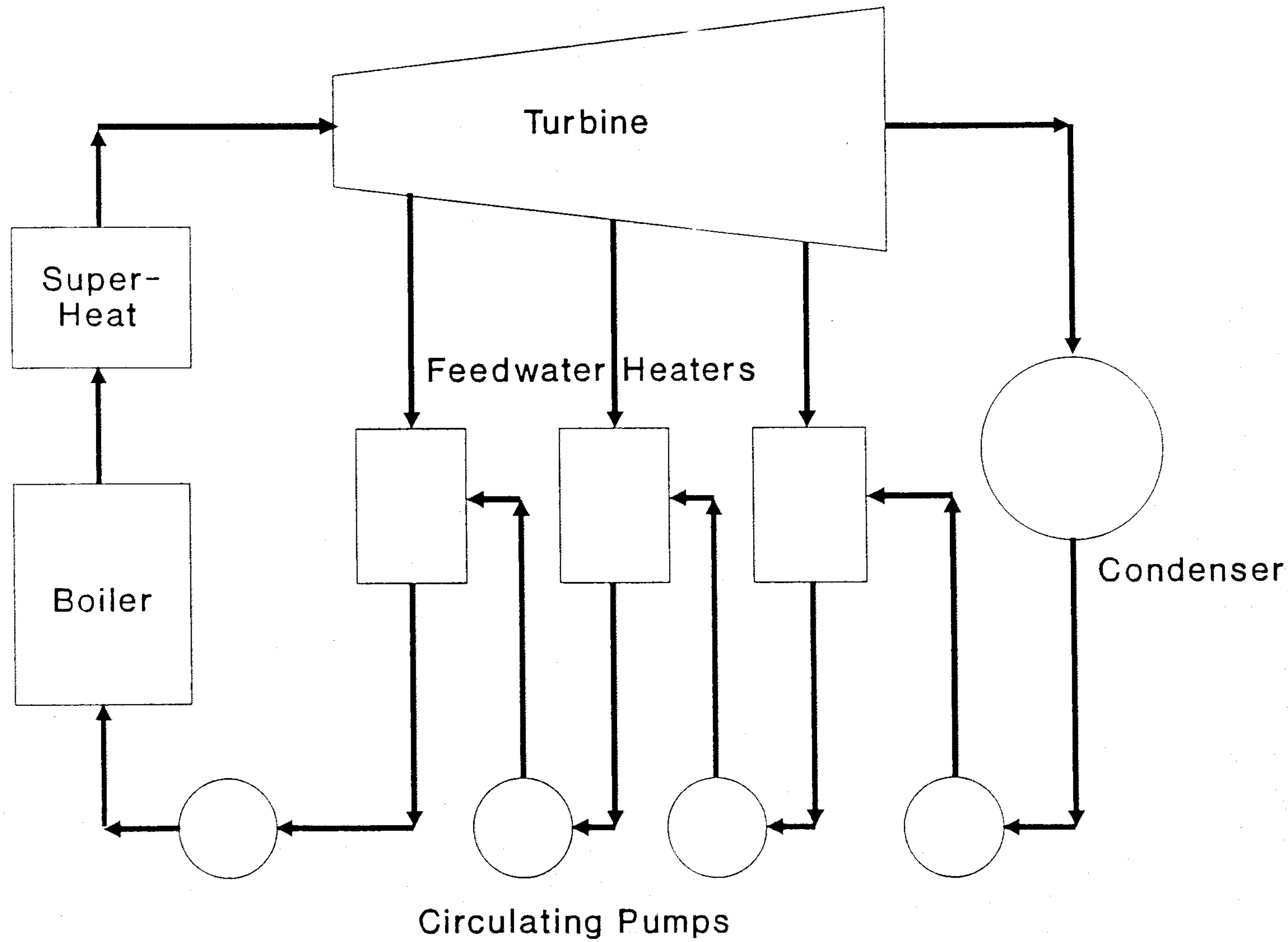


Figure 3.1-3

of the problems unique to each plant. As mentioned previously these enhancements are somewhat expensive and complex and are therefore typically only applied on larger scale units where the net benefit of small improvements in efficiency are significant.

Air Preheaters - While air preheaters are not an improvement to the Rankine cycle, they are commonly used with Rankine cycle enhancements. Steam generator air preheaters have two important functions. They cool the gases before passing to the atmosphere, and they raise the temperature of the incoming combustion air, thereby boosting boiler efficiency. This increases the rate of burning and helps raise the flame temperature.

3.1.3 Heat Transfer

Although CFB boilers can be designed to handle a wide range of fuels, the boiler is usually designed for an anticipated set of fuels. Variations of fuel quality outside this range can lead to operating problems. These problems may include: combustor temperature control, overheating of process equipment (cyclones, EHE, recycle feed, convection pass), too much or little air supply, too much or little fuel supply, too much or little sorbent supply, excess flyash, excess bottom ash, bed fouling and corrosion or erosion of combustor or other components. Proper maintenance of solids inventory in the boiler, which is imperative for stable operation and efficient heat transfer, requires good control over particle size distribution for both fuel and bed materials. Wide swings in moisture content can lead to unstable combustion and to imbalances in heat transfer in both the convective and the furnace sections of the boiler. [45]

Further, the lower heating value and high moisture content of biomass fuels often results in lower heat transfer requirements in the furnace section of an FBC boiler as compared to a conventionally fired unit. Thus, biomass fired units will require a higher proportion of convective heat transfer surface.

3.1.4 Cofiring

The many advantages of cofiring biomass with a conventional fuel are discussed in Section 2. There are, however, some technical concerns that must be recognized.

The key technical issue for cofiring is the negative impact on the existing boiler performance. Depending on the level, cofiring usually results in reduced power plant capacity and efficiency. The capacity derating can be significant depending on the original boiler design and the properties of the biomass. Specifically, the fouling of some biomass ashes can be severe and can increase the capacity derating as well as boiler maintenance. Most biomass fuels contain high moisture content and require large amounts of excess combustion air. This can cause capacity derating due to the higher flue gas flow in addition to the inherent efficiency penalties. Further, cofiring biomass fuels with higher moisture and ash contents and lower heating values than the primary coal fuel tends to reduce boiler efficiency and increase net heat rate relative to the base coal-fired FBC plant. [2, 45]

When considering cofiring, care must be taken to assure that the fuel mixture is uniform. This will provide for more stable combustor operation.

Although these factors require diligent evaluation, they typically will not outweigh the economic benefits of cofiring, particularly in the case of effective use of existing systems and equipment.

3.1.5 Emissions

A significant advantage of the fluidized bed unit over conventional combustors and incinerators is its ability to reduce undesirable gaseous emissions. Due to the low sulfur content of most biomass fuels, SO_2 emissions are typically not a concern on biomass units. However, in the situations where SO_2 reduction is required, all that is needed is to replace or supplement the sand bed material with a sorbent such as limestone, and SO_2 emissions can be controlled to almost any level required.

Further, due to the inherent low operating temperature of a fluidized bed unit, NO_x emissions are also relatively low. This is particularly true on units where the combustion air is staged so that the lower combustor is a reducing environment thus limiting the NO_x formation even further.

3.1.5.1 Fluidized Bed Combustors

The high combustion efficiency of the biomass fired fluidized bed unit results in virtually no unwanted CO emissions.

Uncontrolled particulate emissions from FBC boilers are typically higher than for conventional units due to the introduction of a solid sorbent or inert material to form the bed. Particulate emissions can be controlled in an FBC system using techniques similar to those used with conventional combustion systems, e.g., baghouses or electrostatic precipitators (ESP). When these techniques are used, particulate emissions from an FBC unit can be reduced to required levels at costs similar to the conventional units.

The most effective and accepted technology for reducing particulate emissions from an FBC unit burning biomass is a cyclone followed by a baghouse. The solid particulate, is a mixture of flyash, bed material, potentially calcium sulfate and calcium oxide, and combustibles. Cyclones are designed based on gas flow, temperature, particle size and density, solids loading, and removal requirements. In general, cyclone efficiency decreases as the diameter increases. Therefore, it is common to use multiple cyclones on larger units. The baghouse is sized based on the gas flow. Higher solids loading requires more surface area, i.e., low air/cloth ratio to maintain acceptable collection efficiencies and pressure drops.

3.1.5.2 Fluidized Bed Gasifiers

FBGs produce lower levels of CO, H_xC_y, and particulates than FBCs. This, however, doesn't infer that the FBGs are without emission problems. Emission concerns from FBGs include NO_x, alkalis, tars/oils, fine particulate, and trace metals. However, the emissions from biomass fueled FBGs do not present any new concerns compared to other fossil fired gasification or combustion methods. [20]

One of the primary concerns regarding the use of biomass in FBGs with gas turbines is the cleanup of the gas from the gasifier. The product gas can be burned in current gas turbine designs if the gas meets certain contaminant and temperature limits which are set by the turbine manufacturer. Product gas cleanup is needed to protect the turbines from the pollutants mentioned above which can cause problems of erosion and corrosion in the turbine and lead to excess maintenance costs and poor performance. Wet scrubbing of the product gas can be used to meet these criteria with conventional equipment. However, this method of cleaning is not the most desirable for several reasons including: product gas has to be cooled and then reheated, reduction of Btu content with tar/oil removal, water system capital cost and disposal complexities, and lower overall plant efficiency. [7, 47]

The permissible particulate limit for gas turbines varies. One vendor quoted an acceptable range of 2 to 20 ppm_w and another a range of 100 to 200 ppm_w. EPRI has proposed a specification which accounts for the increased damage caused by the larger size fraction of particles. This specification would limit particles greater than 20 microns to 0.1 ppm_w, particles between 10 and 20 microns to 1 ppm_w, and particles between 4 and 10 microns to 10 ppm_w. [6]

Cyclones are efficient for removal of particulate matter from an FBG in the size range of 5 to 10 microns or larger, but become less efficient for smaller particles. Cyclones are able to function over the full temperature and pressure range anticipated for FBGs. They are excellent choices for the first stage of particulate removal from FBGs since a large portion of the dust loading is in the larger size fractions where the cyclone performs best. However, further cleanup of the gas will probably be required to meet manufacturers specifications.

Research, development, and demonstration of more efficient hot gas cleanup concepts are being performed by several organizations in the US and Europe, as there are wide spread interests by both coal and biomass advanced power generation designers. The improvements in thermal efficiency and reduction in capital costs are worth the development of acceptable equipment. The hot gas cleanup equipment has upper temperature limitations of about 1200°F due to the gas turbine system materials of construction. Current valving materials are limited to 1000°F maximum. [7]

One of the projects currently underway in support of biomass fueled gasifiers is work sponsored by the US Department of Energy (DOE). As part of DOE's Biomass Power Program, Westinghouse, along with a consortium of others, is developing a hot gas cleanup system to be applied to the IGT RENUGAS PFBG design. This is a pressurized oxygen-blown fluidized bed process developed by the Institute of Gas Technology (IGT). Westinghouse will develop hot gas cleanup equipment to be proof tested on the IGT 10 ton/day pilot scale rig with follow up demonstration to be performed on a slipstream of a 100 ton/day scaleup of the IGT RENUGAS PFBG concept being constructed in Hawaii as part of the DOE biomass program. Filter testing was begun in early 1993. [47, 48]

The most promising hot gas cleanup concept for removing the fine particulate appears to be a ceramic candle filter. This design has been chosen for the Westinghouse project discussed above. Ceramic candles have been tested and shown to be extremely effective filters which can be cleaned by a reverse pulse jet. Present concerns with these filters are long term chemical stability and mechanical integrity (sealing, thermal shock, mechanical shock). Long term demonstration has yet to be performed, therefore, the potential issue of irreversible plugging remains an unknown. Other types of filter designs are also being evaluated in the development of alternative methods for hot gas cleanup. [47]

An alternative to hot gas cleanup is quenching and wet scrubbing of the gas. One of the advantages of quenching and wet scrubbing is that it results in a low NO_x producer gas; whereas, depending on the NO_x emission regulations, the exhaust from the gas turbines using hot gas cleanup will probably require some NO_x reduction attention.

The producer gas from the FBG, depending on the biomass material and operating conditions, will also have varying amounts of tars/oils. These constituents should remain in the vapor phase as long as the gas is maintained above 900°F. This would prevent condensation problems (fouling and Btu loss) associated with the tars/oils and also retain them in the gas to utilize their heat content (up to 10% of the total gas heating value). The tars/oils can also be cracked in the FBG with the assistance of a catalyst such as dolomite. [6, 7, 47]

Alkali vapors are the other constituent in FBG producer gas that must be taken into consideration. These vapors form from the sodium and potassium found in the biomass fuels and can cause hot corrosion of turbine components and lead to fouling. Depending on the levels and alkali compounds that are formed, condensing the alkali vapors is not desirable for the main reason that they tend to foul downstream equipment. [6, 47]

Westinghouse has developed a means of removing alkali vapors from hot gases by absorbing the vapors with a clay material (emathlite). They report success in reducing the alkali vapor concentration below the 20 to 50 ppb level set for current turbine limits. Coal gasification plants are reported to have alkali limits of 0.1 to 0.2 ppm_w. [6, 47]

3.1.6 Process Performance Summary

FBCs and FBGs are capable of efficiently combusting biomass fuels. However, due to high variability in the moisture and ash contents of these fuels, some constraints do apply. For example, if the moisture content exceeds 70% or the ash content exceeds

93%, the bed temperature cannot be sustained without supplemental fuel. Typically only sewage sludge falls into this category. Further, when ash and moisture contents vary over time, the combustor heat removal rate must be altered to maintain combustor temperature.

In general, FBC and FBG designs must allocate heat transfer surface properly, ensure adequate air, temperature and residence time in the freeboard above the fluidized bed to ensure complete burnout of volatiles and char in the combustor, and provide for careful fuel blending to smooth variations in fuel moisture and heat contents. [2]

3.2 EQUIPMENT DESIGN ISSUES

Vendors of commercially available FBCs and FBGs were sent questionnaires including questions regarding typical equipment maintenance items and replacement frequencies (lifetimes). Tables B-1 and B-2 in Appendix B contain the results of these questionnaires. The actual questionnaire responses are also given in Appendix B. A summary of the results from the questionnaires is given below.

Refractory lining failures were one of the major outage causing systems in early CFBC plants. Section 3.2.1 provides a summary of problems that have been faced with FBC refractory systems. Today vendors are predicting lifetimes of 4 to 15 years for these systems. The longer lifetimes are typically for the BFBCs (10-15 years) with shorter times predicted for the CFBCs (4-10 years). Refractory life in CFBCs is less than in BFBCs due to the higher particulate loadings and higher velocities that they encounter.

In-bed tubes have limited use for biomass fired fluidized bed units. In most cases, the use of in-bed tubes has been eliminated due to lack of need for this surfacing and also due to the fact that erosion has been a common problem. Where in-bed tubes are used, the lifetimes are predicted to be on the order of 5 years.

Expansion joints and seals have not been a major problem and with proper maintenance, these components can easily last for 10 to 20 years. Likewise, the life of the sizing and drying equipment with proper maintenance should survive for 10 plus years. It should be noted that the sizing and drying equipment, however, is out of the scope of many of the combustor and gasifier suppliers.

Due to the added complexity of the material handling systems, the operation and maintenance requirements for a biomass fueled fluidized bed plant can be expected to be greater than for an oil or gas fired plant but similar to a coal fired plant. The reliability of biomass plant equipment, being in most cases standard equipment, can be expected to be as good as that for facilities using the same equipment with other fuels. This assumes that the biomass fueled plant was designed with the proper margins (fuel variations, capacities, etc.) and receives similar maintenance attention as the other plants. [20, 24]

3.2.1 Problems and Solutions

Most of the problems experienced with the fluidized bed combustor and gasifier plants can be attributed to the characteristics of the fuel being used. This tends to be the case since the application of fluidized bed technology is usually geared towards utilizing the lower grade fuels that can not be handled as effectively by other combusting or gasifying technologies. However, the fluidized bed does not accept just any fuel without experiencing some problems or limitations. Some properties of the biomass that tend to cause problems include: low bulk density, high moisture, alkali content, and variableness of heating value. These characteristics lead to problems that fall into the general categories of erosion, corrosion, fouling, mechanical, and operations. The fouling category includes slagging, deposition, and agglomerating issues. The mechanical problems tend to deal primarily with the feed into and disposal out of the fluidized bed. Operational problems are also exacerbated by the biomass fuel properties.

Careful attention to fuel selection up front in the design stage can alleviate or lessen the impact the fuel properties will have on unit performance, availability, and maintenance. Both equipment suppliers and the owner/operator can benefit from knowing details regarding the physical and chemical properties of the fuel that is being proposed. If a variety of biomass sources are used to supply the unit, care should be taken to properly mix these materials to minimize the impact of variations from one source to the next. Also, fuel blending can be utilized to reduce any undesirable fuel properties to tolerable levels.

Listed in the following sections are some of the more common problems that have been seen with fluidized bed combustors and gasifiers and the steps that were taken to resolve them.

3.2.1.1 Erosion

Erosion, as discussed herein, is a general term that is used to describe wastage of materials of construction. These materials include not only the heat exchanger surfaces but also refractories which are widely used in fluidized bed combustors and gasifiers. The wastage may be by several means including pure erosion which has to do with particles impacting the wearing surface, abrasion which refers to particles sliding on the wearing surface, or a combination of these.

The majority of the fluidized bed biomass facilities report some problems with erosion. The bubbling fluidized bed units, which contain in-bed heat transfer surface, tend to experience erosion problems with wear concentrated on the vertical tubes and lower side of horizontal tubes. Circulating fluidized bed units, on the other hand, tend to experience higher wear on perturbances in the combustor/reactor such as at the waterwall/refractory interface, radiant heat transfer surfaces, and instrument ports. However, the increase in interest and use of fluidized beds in the industrial and utility markets during the past decade has helped to identify the causes and solutions to these problems. Solutions include design changes, improved materials, and different operating conditions. Many of these same boiler vendors offer fluidized bed designs today for use with biomass fuels which take advantage of these improvements. Some of the lessons learned are discussed below.

Fluidized beds are susceptible to erosion problems with any fuel since they tend to operate with relatively high velocities and have a high mass flux. Unless properly designed for, this increase in erosion potential can result in rapid loss of material from in-bed heat exchangers, waterwalls, convection pass heat exchangers, and refractories. The dense bed of these units are typically made up of an inert material such as sand

and/or a solid sorbent material such as limestone or dolomite. Sand, being primarily silica (S_iO_2), is much more erosive than most sorbents that are used. Also, ash and tramp material from the fuel fed to the fluidized bed can build up in the bed and cause erosion and other problems if not removed.

Since biomass fuels are low in ash, additional solid material must be added to the fluidized bed to provide the required amount of solids for process reasons. Sand is usually the material selected since it is readily available, properly sized, inexpensive, and does not easily attrit. However, as mentioned above, the use of sand can lead to erosion concerns. The feed rate of sand addition may also be a factor in the erosion rate as fresh sand and used sand do not necessarily have the same wear potential. Bed materials influence erosion by varying amounts depending on several parameters, with the more predominant factors being particle velocity, mass flux, particle composition, and particle size and shape. [49]

The single most important reason for high erosion rates in all types of fluidized beds is high particle velocities. Erosion has been shown to be proportional to velocity raised to a power, shown to be in the range of 1 to 4. Dramatic changes in the erosion rate have been reported for relatively small changes in velocity. An increase from 4.9 fps to 8.2 fps has produced a three fold increase in erosion. Some references state that there appears to be a threshold velocity below which their bed did not possess enough energy to cause erosion. Values of threshold velocities quoted ranged from 6.6 fps down to 2.6 fps. High velocities can produce slugging and lead to increased erosion in small units. Continued increase in velocity produces increased erosion until bed hydrodynamics switch from bubbling to turbulent regime. [50-59]

Testing has shown that the amount of material impacting on a surface has a direct bearing on the amount of wear experienced. Thus, units which have high recycle ratios will have higher potential for erosion. Biomass facilities which use sand for the bed material should minimize the mass flux in the combustor or reactor. Where possible, a more benign material such as limestone should be used. The decision as to which material to use may come down to deciding between the added cost for using limestone (less stable and less erosive) versus an inert material such as sand (stable but more erosive). [49]

One of the main reasons why many of the early FBC units suffered from high rates of erosion is related to the size of material which makes up the bed. Work was funded by the TVA to evaluate the effect of small additions of top size bed material at two test facilities. One facility added 20% grit (1-6 mm) to a standard size distribution of bed material. Instead of a smooth abraded surface, which was seen without the addition of the grit, the tubes were covered with pits at the end of the test. It appears that the larger material modified the bed hydrodynamics such that impact erosion occurred. The other facility saw nearly a two fold increase in tube erosion with the addition of only a small quantity of coarse material (mean particle diameter of 1.1 mm versus 0.98 mm). Extrapolating data from work in the U.K. at a superficial velocity of 6 fps, a reduction in mean particle size from 1.3 mm to 0.4 mm could reduce erosion rates by as much as a factor of four. With kinetic energy a linear function of mass, particle size could have a cubic order effect. The larger particle size in some units may be moving the fluidization regime. The U.K. work shows that for typical FBC conditions this B-to-D transformation occurs at a mean particle diameter of 2.2 mm. The influence of large particles on erosion is strongly coupled to the operating conditions of the unit, in particular the operating velocity which determines what size of material is fluidized and the ability of the unit to purge the large material which is not fluidized. If large material is allowed to buildup on the distributor plate in a defluidized state, it can cause preferential flow of air (higher velocities) in this region and lead to localized wear. [55-57, 60-66]

Not only is the size of the bed material important, but the physical characteristics of this material is also important. Parameters of interest include particle density, shape, composition, and hardness. Many of the early units operated with sand as the main bed material constituent and their experience has shown sand beds to produce higher erosion than fuel/limestone ash beds. Studies of CFB ash erosivity show it is a function of the SiO_2 content with the angularity of the SiO_2 particles also coming into play. Spherical sand particles compared to angular sand particles have shown an order of magnitude lower erosion rate. The angularity of limestone by-products, CaO and $CaSO_4$, does not appear to be a factor. [49, 50, 52, 67-70]

The quartz content of the bed material is a good indication of its erosion potential. Figure 3.2-1 shows the erosion trend of several materials used in ABB/CE CFBCs, demonstrating the effect of quartz content and particle velocity. The curves, in general, show an increase of erosion with quartz content. The anomaly in the data is the Fresno ash which was erosive but contained a low amount of quartz. It has been speculated that other crystalline materials in the ash were responsible for the high erosion. This same reference states that a low SiO_2/Al_2O_3 ratio in the ash will tend to develop soft alumina silicate clays and result in lower erosion. This is seen in Figure 3.2-1 by comparing the erosivity of the Westwood and Fresno ashes. They have similar SiO_2 content but the Al_2O_3 in the Westwood ash is three times higher. [49, 67]

If the bed ash material is not removed on a regular basis, the larger size fraction of this material can build up and cause problems not only with increased erosion but also operational problems with defluidization of the process. When this occurs, the unit has to be taken off-line and manually cleaned. Fluidized bed units should be equipped with an on-line bed cleaning system if this is anticipated to be a problem. These systems remove material on a frequent enough basis to prevent buildup of large particles. The large material is sent to disposal and the small material is reintroduced pneumatically back into the unit for further use. [24]

In addition to the bed material, fuel variability can also come into play in the erosion problems experienced at biomass fueled facilities. The fuel source may periodically contain dirt and tramp materials which can act as erosive elements. If the facility uses a fuel in which the moisture content varies, changes in the operation will be required to maintain proper control. These changes include varying the excess air and mass flux in the fluidized bed which can have a direct bearing on the erosion factors discussed above. As the moisture in the fuel is lowered, more excess air is needed to help control temperatures. Higher excess air leads to higher velocities and higher particle loadings, both of which tend to increase the erosion potential.

SPECIFIC WEIGHT LOSS vs VELOCITY
(Ref. 49)

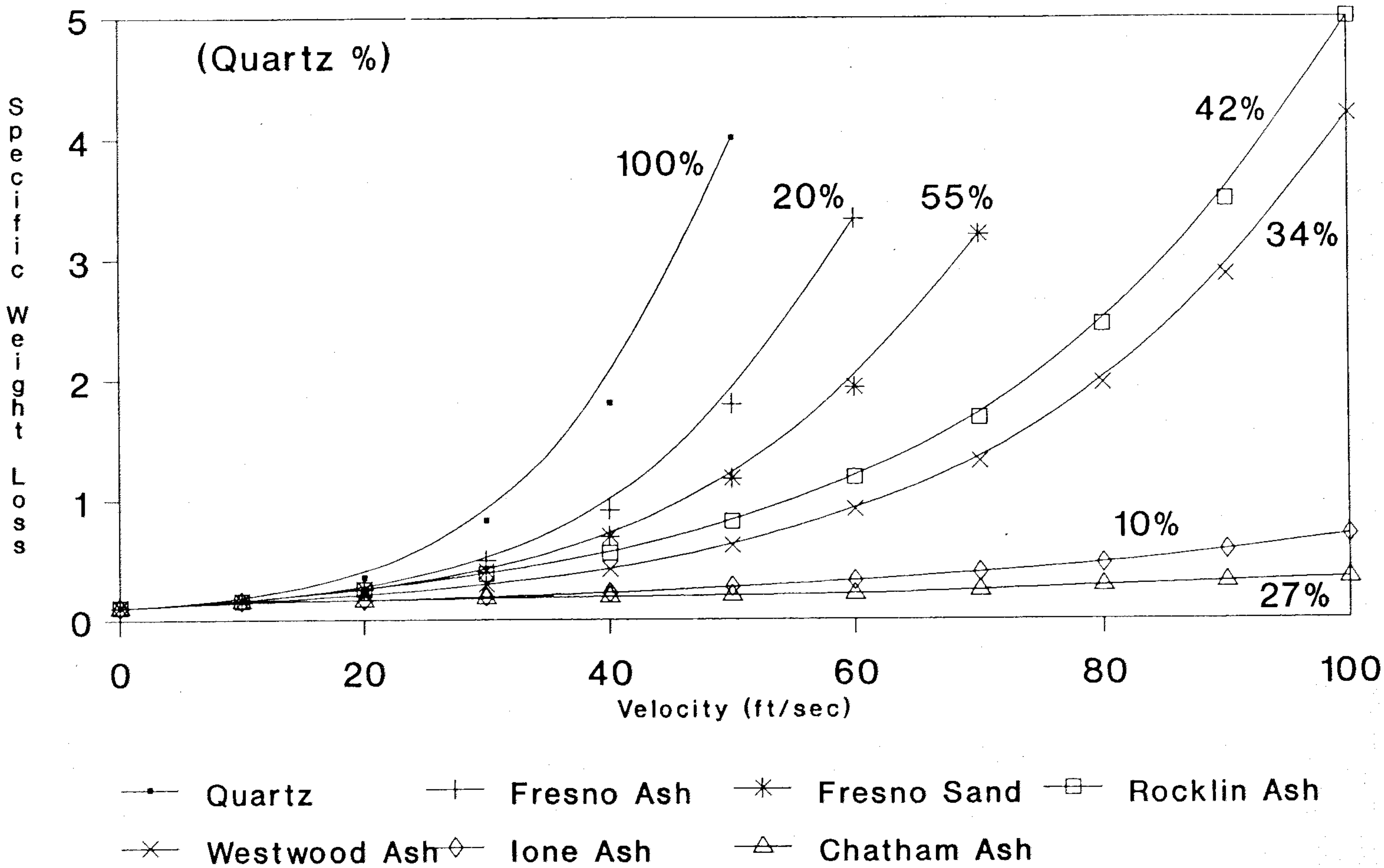


Figure 3.2-1

Erosion can also be a problem for components downstream of the fluidized bed, such as gas turbines, if the flue gas stream is not properly cleaned (see Section 3.1.5). FBGs produce dust loadings up to two orders of magnitude higher than fixed bed updraft gasifiers and thus require additional gas cleanup capacity. The use of high temperature alloy steel lined refractory ducting has been reported as a means to prevent the introduction of eroded particles from the refractory into the gas stream. [6, 26, 71]

Calipers and ultrasonic thickness gages are non-destructive instruments that can be used to monitor the erosion of the various components during scheduled outages to identify any potential trouble areas. More detailed examinations can be made using destructive techniques by periodically removing sections of the components for examination. This method is more suitable for evaluating corrosion concerns and internal surface problems.

3.2.1.2 Corrosion

Corrosion is another problem area that should be addressed in the design and application of fluidized bed technology for biomass fueled units. Corrosion has more to do with the particular fuels used than with the fluidized bed design itself. Many of the fuel candidates have been treated with chemicals for various reasons (pressure treated wood, creosote in telephone poles, pesticides, etc.), which may play a part in their corrosiveness. Fuels near salt water sources also have the potential to be high in chlorides which can lead to stress corrosion cracking problems. [7]

As mentioned earlier, limestone is a potential replacement for sand as the bed material in fluidized beds to reduce erosion concerns. It can also serve as an inhibitor for some corrosion concerns, as well. Most biomass fuels contain small amounts of chlorine and sulfur which can build up and reach higher levels of concentration in the bed material. These constituents can lead to corrosion of the metal and refractory surfaces at the operating temperatures seen in the fluidized bed. The use of limestone or other sorbents can be beneficial in reducing the corrosiveness of these components.

Depending on cost and operating conditions, it may only be necessary to supplement the sand with a small amount of sorbent to see a significant benefit. A mass balance shows that an input of 350 pph of limestone or dolomite is sufficient to neutralize the chlorine and sulfur constituents in a 22 MWe biomass fired fluidized bed boiler. The cost for this amount of sorbent is insignificant and the existing sand, fuel, or bed cleaning systems can be used to feed the material to the unit. The resulting compounds leave the boiler as a solid in the flyash stream and are not corrosive. [72]

The constituents found in the biomass fuel that lead to corrosion problems in fluidized beds include sodium, potassium, calcium, sulfur, and chlorine. Alkalies and salts in the fluidized bed, under certain conditions, develop eutectics which have melting and boiling points lower than operating temperatures. These molten and vapor products can attack fluidized bed components and downstream components as they are deposited out on the cooler surfaces. In addition to corrosion, fouling also occurs. When burning fuel from more than one source it is possible to develop even additional problems. Compounds that form include sulfates of sodium, potassium, and calcium and sodium chloride. [72]

Soot blowing is the most common method of cleaning off any deposits that tend to build up on the heat exchanger surfaces. Minimizing the deposits not only assists in removing the corrosive constituents but also helps in maintaining the proper heat transfer. By keeping temperatures limited as much as possible, using a beneficiating sorbent as needed, and by cleaning at an acceptable frequency, problems with deposition and corrosion should be minimized. Proper selection of the tube material for the superheater can also alleviate concerns regarding high temperature corrosion. Stainless austenitic grade materials (304H, 347H, etc.) throughout the superheater, although more costly, can provide a longer life. Any leeway in the selection of the fuel can provide added assistance by preventing the corrosive constituents from entering the system. Fuel blending can also be a means of lowering the concentration of corrosive constituents.

Refractory materials are typically selected based on their insulating and abrasion resistance. Corrosion is usually a secondary factor. Fluidized bed application should be less of a concern than other applications because of their inherent low operating temperatures. However, a few of the CFB units have reported that it appeared corrosion played a part in the poor performance of their refractories.

Chemical reactions can contribute to the destruction of refractory linings. In fluidized beds, this may be somewhat masked by the removal of the corrosion products by the abrasive nature of the circulating particulate. Refractories can react with the fuel ash, sorbent, and flue gas. These reactions can result in changes in the refractory crystal structure and even produce liquids. Phase diagrams can be used to determine what reactions are possible and can estimate at what temperatures they will occur. Sodium and potassium, for instance, can react with silica at temperatures below 1500°F. Fireclay refractories can react with limestone but require a higher temperature (approximately 2500°F) than normal fluidized bed operation. Generally, acid refractories should be used where acid fluxes exist. Silicon nitride bonded silicon carbide has better alkali resistance. Steam environments can accelerate the transformation of silicon carbide to silica which can result in spalling.

The reducing condition in the lower portion of the combustor and in the gasifiers is an area where corrosion may be a factor. High carbon monoxide levels can react with iron oxide in the refractory. Low iron content refractories should be used in these applications. Hydrogen can attack silica based refractory at temperatures above 2200°F. Reducing conditions also produce lower melting temperature slags. Proper selection of metal materials for anchors and strengthening fibers need to made based on the environment and temperatures expected.

3.2.1.3 Fouling

Fouling problems discussed in this section encompass related problems experienced in biomass fueled fluidized bed units including such problems as slagging, deposition, and agglomeration. Fouling of heat transfer surfaces can result in a significant reduction in heat transfer, causing loss of capacity and efficiency and increased maintenance requirements. Deposits and agglomerations can lead to operational upsets which can result in unit forced downtime. Slagging is normally avoided in FBCs and FBGs since they operate at temperatures below the ash softening temperature of the fuel ash. Reactions involving the alkali content of the ash, however, can lead to the development of low melting and boiling point compounds. Sodium and potassium are the primary ash constituents that cause problems and have been noted to buildup in a fluidized bed over time by absorption on the bed material. The chemical form that these alkalis are found in the biomass can lead to varying degrees of problems.

Agricultural wastes and the trimmings from trees are particularly bad with respect to alkali content, with rice straw being noted as one of the worst (almost 50 pounds of alkali per dry ton of fuel). The ash fusion temperature with these materials can be lowered from normal 2200°F to as low as 1300°F. Phase diagrams can be used to evaluate the potential for eutectics and the beneficial use of sorbents to improve this situation. A mixture of one-third K_2O and two-thirds SiO_2 melts at 1420°F even though the melting point of silica alone is 3100°F. [7, 71, 73]

Three types of alkaline deposits have been noted. The first type is formed by the very small sticky particles of alkali/silica that elutriate out of the fluidized bed and collect on the convective heat exchangers. These deposits build up causing problems with reduced heat transfer and can actually lead to flow blockage requiring shutdown of the unit for cleaning. The second type involves larger particles that tend to stay in the bed and act as a liquid cement with the bed material. Agglomerations, commonly known as "sand babies" form and with time will force the unit to shutdown if agglomerations are not removed with a bed cleaning system. Fluidization nozzles on the distributor plate can also become coated and plugged with time. The third type of alkaline deposits form when the fluidized bed temperatures are in the 1600 - 1700°F range. The deposits dissolve the sand material and form an amorphous material which looks like lava. Iron appears to assist in this process. If allowed to collect, these deposits will have to manually be removed. [73]

The general trend is to avoid high alkali containing feedstock materials if possible and, if not, to limit them to less than 15% of the total fuel heat input through blending with lower alkali content fuels. Other sources say even 10% mixtures can lead to unit shutdowns in a few days. Fluidized beds tend to be able to operate with higher levels of alkalies than other types of units due to their more intense mixing which can allow more effective use of neutralizers, such as limestone. As mentioned above, the addition of small quantities of limestone or other sorbent can lessen these problems. The addition of limestone has been shown to increase ash softening temperature in an FBC by several hundred degrees. [7, 71, 73, 74]

Evaluation of the potential biomass fuels should include a detailed ash analysis in addition to the normal proximate and ultimate fuel analyses that are performed. Ash fusion tests should be performed at low ashing temperatures to prevent vaporization of a portion of the alkalies. ASTM Procedure 1102, which uses an 1100°F ashing temperature, is an acceptable method. [7, 71, 73]

The coal fired industry has developed a rule of thumb in the use of alkali containing fuels. Coals are ranked according to the pounds of alkali ($Na_2O + K_2O$) per million Btu. Coals with a value between 0 and 0.4 lbs/MBtu offer a low slagging risk. A value between 0.4 and 0.8 lbs/MBtu represents coals that will probably slag. Coals with values $\geq$ 0.8 lbs/MBtu are a high slagging risk. Field tests have shown these to be good values for ranking biomass fuel slagging potential, as well. Wood chips have a value below 0.4 lbs/MBtu and, in general, do not slag. Urban wood waste has a value of 0.5 lbs/MBtu and does cause some slagging. Urban wood waste is handled more easily in fluidized bed units if the material smaller than one-eighth inch (last years growth) is removed (alkali content is noticeably reduced). Agricultural wastes have values ranging from about 1.0 to 5.6 lbs/MBtu and tree trimmings are about 0.7 lbs/MBtu, and both are noted to cause slagging problems.

Two similarly designed units (Fresno and Rocklin), manufactured by ABB/CE, were operated under similar conditions, but saw markedly different amounts of fouling. Upon examination of the fuel, the higher fouling unit was found to have almost five times the amount of alkali. At the present time, low temperature fluidized bed gasification is one of the few methods available for utilizing these high alkali biomass fuels. The National Renewable Energy Laboratory has recently funded a project to develop an understanding of the deposit formations from biomass fired fuels and to identify methods to safely increase the use of these higher alkali containing fuel sources. Tars and oils formed during the gasification of biomass fuels can also lead to fouling in fluidized bed units. Benzene and naphthalene are the two most common species. [73-75]

Minimizing the formation of deposits on convective pass superheater tubes was accomplished by one vendor by installing a screen tube section upstream of the superheater to drop the flue gas temperatures down to about 1350°F. This reduced the gas temperature below the ash softening temperature and kept the superheater clean. The lower gas temperature, however, required the superheater heat transfer area to be adjusted to account for the lower temperature. Sootblowers were used to keep boiler surfaces relatively clean and flue gas velocities in the boiler were maintained below 40 fps as additional conservatism. Sootblowing should be performed frequently to prevent thick deposits from having a chance to form. Too long of a time between cleaning can result in deposits which are extremely hard to remove. Examining trends in convective pass outlet gas temperature and amount of desuperheater spray required provides a good method of assessing the condition of the superheater surfacing. [74]

3.2.1.4 Mechanical Components

The reliability, availability, and maintainability of FBC and FBG facilities have been acceptable for the fluidized bed mechanical components. The major problems, other than erosion of heat exchangers discussed above, are in the areas of material feed to the unit and material disposal from the unit. These problems are not insurmountable but are areas that proper thought needs to be given to the design and operation of these systems.

Reliable uniform feed of material into fluidized bed combustors and gasifiers is critical to stable and efficient performance. Types of feed methods include rotary valves, lockhoppers, pneumatic, screws, pumps, and gravity. Rotary valve star feeders drop the fuel into pockets which are fixed to a central shaft. As the shaft rotates, the filled pockets empty on the bottom half of the cycle and fill on the top half of the cycle. Lockhoppers function by having a bin located between isolation valves. The lower valve closes and allows fuel to enter the bin at atmospheric pressure conditions. Once the bin is filled, the upper valve is closed and a pneumatic pressure source is used to convey the fuel out of the bin through the lower valve which has now been opened. Vents and pressure valving are required for this type of feeder. Lockhopper systems have not been commercially demonstrated with biomass fueled gasifiers above 150 psia. Since there is some risk for explosions from biomass fines, inert gas is also required.

Air swept feeders have also been used which use an air source to entrain fuel that is falling by gravity and pneumatically carry it into the unit. Air locks provide a seal between the feeder and the fuel supply hopper. Screws are used as a positive displacement device to auger the fuel into the unit. Plug flow screw feeders for pressurized feeding require higher moisture content biomass to assist in sealing. They require a substantial amount of power and are high maintenance items. The pressure boost per stage is limited to about 150 psi. Some of the pressurized units use slurry pumps to pump paste consistency fuels into the unit.

Finally, gravity systems can be used but require the fuel to be introduced into a negative pressure location. The consistency of biomass fuels (fibrous nature, moisture, etc.) only complicates the functioning of these types of feeders. Biomass fuels have the tendency to compress and arch, thus live bottom bins are needed. Use of the pressurized versions of FBC and FBG introduces an added complication. The feeders typically take material from a fuel bin and inject it into the fluidized bed vessel. Fluidized beds have the benefit of the large amount of hot solids in the bed which acts as a thermal flywheel. Short interruptions of flow are tolerable without causing major upsets in operation.

Just as important to the operation of these units is the removal of the waste products from the fluidized bed. Rotary valves and water cooled screws are the most commonly used ash disposal methods. This system has to operate in a hot (1100 - 1800 °F), pressurized environment. Materials are normally cooled to about 350°F to recover energy, protect personnel, and to permit use of standard ash handling equipment. Water cooled screws are by far the most common and successful method of cooling and disposing of ash from the units. Fluidized bed ash coolers have the added feature of being able to classify the drain material with the larger unwanted material sent to disposal and the smaller useful material reinjected back into the unit. Heat recovered from this cooler is returned directly to the unit. Failure to be able to reliably purge the large inert materials and agglomerations from the bed, while on line, will result in poor operating conditions and finally into a forced outage. [7]

The main problems experienced with the feed system of an FBC and FBG appear to be flow hangups and leakage back through the feeder. The feeder has to serve as a pressure seal between the pressure at the point where the fuel is introduced into the fluidized bed and the pressure in the fuel bin which is typically atmospheric. Leakage of producer gas back through the feeder of a FBG can lead to explosions in the feed system. This occurred on the SEI biomass fueled FBG in Florida. Minor gas explosions were experience in the fuel surge bins during early operation due to gas working its way back through the variable speed screw and into the surge bins. This problem was resolved by placing positive shut off slide gate valves between the surge bins and feed screws. Pressure relief discs were also installed in the surge bins as a safety precaution. Several rotary ash valves were experimented with at the SEI unit with little success. This facility was able to gain some success with air-operated, double flapper, tipping valves. Water cooled screws have to be supplemented with additional equipment to provide classification and reinjection of the ash and are subject to wear due to the abrasiveness of the materials they are required to handle. Potential problems for fluidized bed ash coolers include corrosion and erosion, lack of ability to cool the solids sufficiently, and added costs and complexity.

The design of this portion of the facility should be well thought out. Proper maintenance on the feed and disposal equipment is important to keep the unit functioning as designed. Cases have been reported where the knife blades on a rotary valve were not sharpened and maintained which led to plugs forming in the valve. High frequency failures of the rotary valve in this plant was later traced down to the blades being installed backwards. In addition to proper maintenance, flexibility in the design stage of including a redundant system could provide added assurance of meeting availability requirements. With a redundant system, each sized to handle full load, the systems would under normal mode only have to operate at 50% capacity. The tradeoff between increased availability versus increased capital cost need to be made. [24, 76, 77]

The placement of a hot cyclone between the gas outlet of the FBG and downstream application of the producer gas, such as in a boiler, is recommended. Elutriated char which can contain significant carbon content could be burned with the producer gas in the burner but experience has shown that boiler operational problems are not worth the benefit. Control and reliability issues due to the increased dust loading override any benefit in efficiency. A better method of utilizing this elutriated char is either recycle it back to the FBG or market the waste stream (material for charcoal briquettes market). [24]

3.2.1.5 Operability

The operation of a biomass fueled FBC or FBG unit, in relative terms, can be stated to be more challenging than an oil or gas fired facility but no more complex than a coal fired facility. As mentioned earlier, the ability to feed a uniform (quantity and quality) flow of biomass fuel is paramount to being able to operate a fluidized bed plant reliably. The fluidized bed with the large amount of hot solids provides for some stability in the process. A summary of problems that have been reported in the literature is given below.

One problem that occurs is the ability to maintain stable bed temperatures. In a gasifier, if the air-to-fuel ratio gets too low, reaction temperatures can not be maintained and bed temperatures will fluctuate. Agglomerations which may form and collect in the bed can have a detrimental effect on the fluidization properties of the bed and lead to temperature fluctuations, as well. In fact, monitoring temperature trends is one way of knowing that agglomeration problems may be occurring. [10]

One FBG facility experienced problems with too high superheat steam temperatures. The design temperature was 825°F but actual temperatures were greater than 1050°F. Changes which were made to resolve this problem included changing the flame shape from the burner, placing refractory over some of the superheat surface, installing a path to allcw some of the flue gas to bypass the superheater, and the installation of a desuperheater station. The addition of the refractory surface resulted in a hot surface where fouling occurred. This problem was resolved by restricting the fuel ash to the specified design values. This allowed the unit to operate with stable temperatures with little fouling. If wider selection of fuels are used, monthly shutdowns are required to clean the unit. [24]

Fuel changes in another unit caused a reduction in the ash fusion temperature, which resulted in the formation of soft clinkers. These clinkers collected in a crossover duct to the point where flow through the duct was restricted after only a couple of days. This problem was resolved by using flue gas recirculation to lower the freeboard gas temperature to about 1475°F. Where the gas environment is more oxidizing, operating at temperatures up to 1750°F has not caused any problems. [78]

3.2.2 Flame Temperature

The producer gas from an FBG contains combustibles, consisting primarily of carbon monoxide, hydrogen, and methane. Smaller amounts of higher hydrocarbons can also be found in the gas. One of the factors which affects the burning characteristics of this gas, and thus the burner design, is its flame temperature. This is the temperature created by the combustion of the fuel and varies, as expected, with the air-to-fuel ratio. Non-combustibles in the gas have a negative influence on the flame temperature due to their diluting effect. This temperature can be analytically determined based on the resulting composition of the producer gas but involves a very tedious calculational procedure. Typical values for several gases are shown in Table 3.2-1 for a range of equivalence ratios (fraction of stoichiometric air).

The flame temperature for the producer gas shown in Table 3.2-1 was calculated based on a composition of 26.0% CO, 3.0% H_2, and 0.5% CH_4. LBG from the SEI gasifier developed gas with a nominal composition of 15.5% CO, 12.67% H_2, and 5.72% CH_4. The combustion of this gas gave a self-sustaining flame in the range of 2200-2800°F. Higher values of flame temperature are given in the literature for biomass derived producer gas. One source quotes a value of 3200°F for LBG and 3490°F for MBG. Some of this difference in producer gas flame temperatures may be due to the composition of the gases evaluated and the calculational procedures used. The temperatures calculated in Table 3.2-1 are for atmospheric pressure conditions. Elevated pressure will have a slight decreasing effect on the flame temperature. Flame temperatures for combustion of wood vary from 2300 to 2500°F for dry wood down to 1800°F for green wood. [31, 79-83]

TABLE 3.2-1
FLAME TEMPERATURE (°F)
[Reference 79]

FUEL	EQUIVALENCE RATIO			
	0.8	1.0	1.2	1.4
HYDROGEN	3750	3930	3540	3210
CARBON MONOXIDE	3820	3860	3680	3390
METHANE	3590	3550	3200	2870
COAL GAS	3460	3590	3320	2980
NATURAL GAS	3550	3720	3380	3060
PRODUCER GAS	2580	2870	2670	2510

3.2.3 Air Flow

Air flow for a fluidized bed takes on many functions. The primary purposes for air flow are fluidization and combustion/gasification, with secondary functions of heat recovery, recycle, drying, and transporting. As can be seen from this list of uses, proper air flow design is necessary for the successful operation and performance of a fluidized bed unit. Requirements for the fluidization and combustion/gasification functions are discussed in more detail below.

Fluidization, as described in Section 1, involves the flowing of air up through a distributor plate to uniformly lift the bed material and provide the necessary velocities.

The velocity requirements are a function of the bed mass and particle size distribution, and are established to not only "float" the bed but also to provide the required amount of solids circulation. This is most evident in the CFBC design where primary air is brought up through the distributor plate to fluidize the dense bed, and secondary air is injected at higher elevations to increase velocities and cause the circulation of solids. Both air streams also serve as the source for combustion air. BFBCs typically operate in the 3-13 fps velocity range while CFBCs operate in the 7-33 fps velocity range. In these ranges, the beds can be described as being fully turbulent with excellent vertical mixing and to a lesser extent lateral mixing. This mixing promotes uniform operating temperatures. The BFBC operating velocity range is bound on the lower end by ensuring adequate mixing in the bed while the upper bound has more to do with erosion concerns and the elutriation of material out of the bed. The CFBC lower velocity operating point is set by combustion and bed temperature control concerns with the upper velocity established at the level necessary to achieve the desired solids circulation. [77]

The distributor plate for a fluidized bed unit is designed so that uniform flow is developed across the full area of the plate for all anticipated operating conditions. To accomplish this, sufficient pressure drop must be present across the plate at the minimum operating load. Setting this as low as possible, while maintaining acceptable fluidization, will minimize the fan size required and the power necessary to drive it. If too low a pressure drop is used, portions of the bed may become defluidized and result in such problems as agglomeration and poor performance. Depending on the design of the distributor plate air nozzle and the minimum load anticipated, approximately 3 or 4 inches of water pressure drop is usually required at the minimum operating conditions. For a unit with an operating range of 40 to 100% power, this would result in approximately 20 to 25 inches of pressure drop at full load (pressure drop increasing as square of velocity). Add to this pressure the pressure drop across the bed material, it becomes apparent that a high pressure forced draft (FD) fan is required.

Bubbling units operate with the zero pressure point at the top of the dense bed which is in the lower part of the unit. Circulating units, however, typically operate with the zero pressure point at the top of the unit, prior to entry into the cyclones. The bed in a CFB can be thought of as spread out over the full height of the combustor or gasifier and thus develops a pressure drop across this height depending primarily on the amount of bed mass entrained. When the pressure drops from the distributor plate, bed, dampers, and ducts are added together, FD fans capable of 60 to 100 inches of water outlet pressure are required. Surplus fan head capability, while adding capital and operating cost, does provide added operating flexibility. Because of the high fan outlet pressure, any preheating of the air in an air heater is better performed in a low leakage type heat exchanger, such as a tubular air heater. The air flow rate requirement for the FD fan is dependent on the air-to-fuel ratio required for the unit over the desired operating range. FBCs normally operate with about 3 to 4% excess O_2 in the flue gas. Since biomass fired units may operate with a variety of feedstocks, sufficient capacity should be available from the FD fan to handle all anticipated fuels. Induced draft fans are used to draw the flue gases and flyash materials from the top of the combustor/gasifier through the gas cleanup system and out the stack.

Another design requirement for the distributor plate is the ability to move material to the bed drain and cleaning system. Large inert material enters with the biomass fuel and needs to be purged from the bed on a regular basis to maintain successful operating and performance conditions. Agglomerations can also form and should be removed from the unit while on-line to assure unit availability. One vendor uses inverted "L" shaped fluidization nozzles which tend to move the large defluidized material toward the drain points. Once in the drain, classifying and reinjecting systems can send the large unwanted material to disposal and reintroduce the small useful material back into the unit.

Most BFB units operate with the combustion air supplied solely by the fluidization air through the distributor plate. This air may be supplemented with transport air from units with pneumatic feed of fuel, sorbent, or recycle (bed material and/or cyclone catch). Secondary combustion air is used in some cases to provide for staged combustion. CFBs, on the other hand, are almost always designed to operate with staged combustion. Primary air enters the unit through the distributor plate and secondary air is introduced at higher elevations, sometimes at more than one elevation. The air split is typically 50-70% being primary air and the remainder being secondary air. The lower section of the dense bed above the distributor plate operates in a reducing environment with the remaining air needed to reach stoichiometry provided by the secondary air. Separate fans are normally used to provide the secondary air since the fan head requirements are much lower (approximately 20 inches of water). Secondary air can be used to provide staged combustion to minimize NO_x formation, burn fuel that is fed overbed, reduce FD fan requirements, and control temperatures. [77]

Gasifiers operate with much less air (or other gasifying agent) than combustors. Where the combustors operate with excess air (typically 115-125% of stoichiometry), gasifiers normally operate substoichiometrically (typically with about 25-30% of stoichiometry). Trying to operate with lower amounts of air minimizes the gasification reactions of the char material while operating with higher amounts of air tends to cause more of the char and gases to combust and temperatures to increase. Combustion in gasifiers is only needed to develop the desired temperatures for the gasification reactions, typically 1100 to 1800°F. The general discussion above for BFBCs and CFBCs is also applicable for their gasifier counterparts.

3.3 EMISSION LIMITS AND TEST RESULTS

Emission limits set by regulatory agencies and actual stack emissions data for a number of biomass fueled fluidized bed combustion systems are presented in Tables 3.3-1 and 3.3-2. Table 3.3-1 presents data for systems utilizing a range of fuels including wood, wood waste, and agricultural waste fuels. Table 3.3-2 provides similar data for facilities burning refuse derived fuel (RDF) either alone or in combination with other biomass fuels or coal. [1, 84-89]

The United States Environmental Protection Agency (EPA) has not yet promulgated New Source Performance Standards (NSPS) for biomass fired combustion and gasification facilities other than those burning municipal solid waste (MSW), which by definition includes RDF. Regulation of the facilities burning biomass fuels other than MSW, thus far, have been left to the states. These regulations for the most part have been patterned after the NSPS for fossil fuel fired steam generators. Emphasis on SO_2 emissions has been relaxed by elimination of the percent reduction requirements because of the extremely low sulfur content of most biomass fuels.

Table 3.3-3 presents EPA NSPS for FBC municipal waste combustors (MWCs). Facilities that burn MSW with other fuels are subject to these standards at a minimum if 30% or more of the fuel is MSW or RDF. States must adopt these standards at a minimum, or impose more stringent ones. Thus, emissions limits and the application of them can, and do, vary from state to state.

Table 3.3-4 contains emissions test results for a number of pollutants regulated by some states but which are not yet regulated by EPA. Most, however, appear on the list of 189 toxic substances in the 1990 Clean Air Act Amendments for which EPA must establish permissible emissions levels. [90]

Table 3.3-5 contains predictions of emissions levels of key pollutants for commercial scale biomass fueled integrated gasification combined cycle (IGCC) plants. This data was provided by two IGCC system vendors, one of which, Tampella, now offers commercial guarantees. The other vendor, Ahlstrom Pyropower is very close to offering commercial guarantees. [91, 92]

TABLE 3.3–1

EMISSIONS AND EMISSIONS LIMITS
FLUIDIZED BED COMBUSTION SYSTEMS
WOOD, WASTE WOOD, & AGRICULTURAL WASTE FUELS

FACILITY	FUEL		SO_2 lb/MBtu	NO_X lb/MBtu	CO lb/MBtu	Hydrocarbons lb/MBtu	Particulates lb/MBtu	Emissions Controls
Babcock–Ultrapower West Enfield, Maine CFB, 218,600 lb/hr B&W stm. gen.	Whole tree chips (cedar, pine, spruce, hardwoods) sawdust	Limits :	–	0.158	0.158	–	unknown	staged combustion, electrostatic precip.
		Emissions:	–	–	–	–	–	
Sithe Energies Marysville, CA CFB, 164,000 lb/hr B&W stm. gen.	Dry mill waste, orchard prunings, urban wood waste	Limits :	0.051	0.051	0.128	–	0.035	staged combustion, electrostatic precip.
		Emissions:	–	–	–	–	–	
Ultrapower Rocklin, CA CFB, 220,000 lb/hr ABB CE stm. gen.	Dry mill waste, in–forest chips, orchard prunings, urban wood waste	Limits :	0.029	0.076	0.0157	–	0.03	staged combustion, electrostatic precip. thermal DENOX
		Emissions:	–	–	–	–	–	
Ultrapower Fresno, CA CFB, 220,000 lb/hr ABB CE stm. gen.	Orchard/vineyard prunings, urban wood waste, pits, shells, cotton stalks, rice straw	Limits :	0.0101	0.0817	0.0654	0.0282	.01 gr/dscf	staged combustion, electrostatic precip. thermal DENOX
		Emissions:	–	–	–	–	–	
Mendota Biomass Mendota, Ca CFB, 300,000 lb/hr Gotaverken stm gen	Almond prunings, urban wood waste, misc. pits & shells	Limits :	0.031	0.085	0.083	0.03	.01 gr/dscf	staged combustion, fabric filter thermal DENOX in–bed limestone
		Emissions:	–	–	–	–	–	
Ultrapower Chinese Camp, CA BFB, 208,680 lb/hr EPI stm. gen.	In–forest chips, Orchard prunings, urban wood waste	Limits :	0.014	0.158	0.15	–	0.07	staged combustion, electrostatic precip. thermal DENOX
		Emissions:	1 – 2 ppmv	50 ppmv	10 – 20 ppmv	Dioxin/Furan None detected	0.015 gr/sdcf @ 12% CO_2	
Delano Energy Delano, CA BFB, 255,000 lbs/hr EPI stm. gen.	Orchard prunings, urban wood waste, almond shells, cotton stalks	Limits :	0.033	0.08	0.14	0.08	.01 gr/dscf	Limestone inj/low S coal, baghouse
		Emissions:	0.001	0.058	0.015	0.0007	0.003	
Proctor & Gamble Greem Bay, WI BFB, 100 MBtu/hr EPI combustor	Wood residue (aspen bark and chips)	Limits :	0.046	0.03	0.03	–	0.04	Multiclone & electro–scrubber pebble bed filter
		Emissions:	–	–	–	–	–	

TABLE 3.3-2

EMISSIONS AND EMISSIONS LIMITS
FLUIDIZED BED COMBUSTION SYSTEMS
REFUSE DERIVED FUEL (RDF) & RDF WITH OTHER FUELS

FACILITY	FUEL		SO_2 lb/MBtu	NO_x lb/MBtu	CO lb/MBtu	HCl	Dioxin/Furan (EPA toxic equiv.)	Particulates lb/MBtu	Emissions Controls
Western Lake Superior Sanitary District Duluth, MN BFB, 2 @ 49,000 lb/hr EPI stm. gen.	RDF (26%), Sewage Sludge (74%)	Limits :	–	–	–	–	–	–	Cyclone, venturi scrubber, tray scrubber, demister
		Emissions:	92 – 121 ppmv, wet	15 – 43 ppmdv @ 7%	1 – 31 ppmdv @ 7% O_2	<1 ppmv, wet	.09–.14 ng/Nm^3 @ 7% O_2	.004 – .005 gr/sdcf @ 12% CO_2	
Korsta Facility Sundsvall, Sweden CFB, 20 MWth Gotaverken stm gen	100 % RDF	Limits :	–	–	–	–	–	–	Furnace limestone inj., duct hydrated lime inj., baghouse
		Emissions:	6 – 21 ppmdv	111 –138 ppmdv	11 – 20 ppmdv @ 7%	> 90% removal @ Ca/Cl of 4	.03–.3 ng/Nm^3 @ 7% O_2	>.005 gr/sdcf @ 7% O_2	
Northern States Power LaCross, WI BFB, 150,000 lb/hr EPI stm. gen. #1	Wood waste (50%), RDF (50%)	Limits :	–	–	–	–	–	–	Gravel bed filter.
		Emissions:	–	–	275 ppmv	24 – 177 ppmv	0.68 ng/Nm^3	0.05	
Northern States Power LaCross, WI BFB, 150,000 lb/hr EPI stm. gen. #2	Wood waste (75%), RDF (25%)	Limits :	–	–	–	–	–	–	Gravel bed filter.
		Emissions:	0.01 – 0.10	0.25 – 0.40	–	3 – 7 ppmv wet @ 12% CO_2	–	<0.06	
Tacoma City Light Div. Tacoma, Washington BFB, 528,000 lb/hr EPI combustors (2)	RDF, waste wood, low sulfur coal	Limits :	0.18 & 70% rem, 50 ppm if <50% coal	0.5	0.52	–	–	0.010 gr/sdcf @ 7% O_2	Baghouse, limestone injection, low S coal
		Emissions:	–	–	–	–	–	–	

TABLE 3.3–3
USEPA EMISSIONS LIMITS FOR
FLUIDIZED BED MUNICIPAL WASTE COMBUSTORS
GREATER THAN 250 TONS PER DAY
BUILT AFTER DECEMBER 20, 1989

SOURCE	SO_2	NO_X	CO	HCl	Dioxin/Furan (EPA toxic equiv)	Particulates (Metals
Code of Federal Regulations, Title 40, Part 60, Subpart Ea, July 1, 1992.	Greater of 80% Reduction or 30 ppmv @ 7% O_2	180 ppmv	100 ppmv	Greater of 95% Reduction or 25 @ ppmv @ 7% O_2	30 ng/Nm^3 @ 7% O_2	0.015 gr/sdcf @ 7% O_2

TABLE 3.3–4
ALDEHYDE, BENZENE, PHENOL, & TRACE METAL EMISSIONS
FROM TWO RDF FIRED FLUIDIZED BED COMBUSTION SYSTEMS

FACILITY	FUEL	Formaldehyde pph	Benzene pph	Phenols pph	Arsenic pph	Beryllium pph	Cadmium pph	Chromium pph	Lead pph	Nickel pph	Zinc pph
Northern States Power LaCross, WI BFB, 150,000 lb/hr EPI stm. gen. #1	Wood waste (50%), RDF (50%)	0.0014	0.45	–	0.043	0.001	0.0076	0.0008	0.24	0.024	0.075
Northern States Power LaCross, WI BFB, 150,000 lb/hr EPI stm. gen. #2	Wood waste (75%), RDF (25%)	7 – 10 ppm	1.4 ppm	not detected							

TABLE 3.3–5
PREDICTED EMISSIONS FOR TWO BIOMASS FUELED
INTEGRATED GASIFICATION COMBINED CYCLE (IGCC) POWER PLANTS

VENDOR	CAPACITY	FUEL	SO_2 lb/MM Btu	NO_X lb/MM Btu	Particulates lb/MM Btu
Alstrom Pyropower	20 – 150 MW	Wood chips	<.06	<.12	<.005
Tampella	125 MW	Wood chips	<.04	<.13	<.005

3.4 FUELS AND ASH

One of the primary considerations when designing any fluidized bed combustor or gasifier and its auxiliary equipment is the fuel to be burned and the ash it produces.

3.4.1 Biomass Fuels

Biomass fuels come from a variety of sources and have a wide range of properties. In general, biomass fuels are sourced from three broad categories: woody fuels, agricultural waste, and refuse derived fuels (RDF).

Biomass for wood burning power plants is provided from urban wood, fuel wood, wood byproducts, and waste wood. Wood fuels are produced on private wood lots, national forests, and state wood lots. Wood byproducts are mainly spent liquor and sawdust. Waste wood includes cull logs, hogged bark, and manufacturing residue. However, at present a large percentage of waste wood remains unutilized. The U. S. Department of Energy estimates that enough biomass waste will be available to allow the biomass power industry to expand modestly throughout the 1990s.

Agriculture and forestry, in addition to their main roles of producing food, fibers, and lumber, have become a source energy and other new uses. Large portions of these byproducts are currently either burned in the field or disposed of in landfills. Products such as straw, nutshells, rice hulls, bagasse, cotton gin trash, orchard trimmings, and forestry byproducts have potential as fuels for cofiring or as a blending component in biomass plants. [93]

RDF processed from municipal solid waste is a fuel of growing importance. The increase of government requirements on landfills has caused increased tipping fees at some landfills and closure at others. This presents a situation where the raw fuel is of a negative value large enough, in some cases, to pay for the processing of the MSW. A discussion of the processing methods is given in Section 1.3.5

3.4.2 Fuel Characteristics

Biomass fuel have many different characteristics. The discussion of biomass fuel characteristics will be divided by the three primary source groups for the fuels.

3.4.2.1 Wood Fuel Characteristics

The chemical and physical characteristics of wood and bark must be known in detail before work can begin on the design of fuel-handling, combustion, gasification, and pollution control systems. Although laboratory analysis shows that most species of wood and wood bark have approximately the same chemical composition on a dry basis, the moisture content can extend over a broad spectrum. Heating value, size range, and other properties influencing plant design also may vary so much that it has been said that the only consistent property of wood is its inconsistency. [14]

The principle characteristics of wood are expressed in a proximate analysis which also shows the exact chemical composition of a fuel without reference to the physical form in which the compounds appear. This provides a good indication of a fuel's behavior in the furnace. The analysis is relatively simple, involving the determination of the percentage of moisture, ash, and volatile matter, and the calculation of the percentage of fixed carbon which is determined by difference. Since the percentage of these four variables total 100, the fixed carbon can be found easily once the other three are known. If an ultimate analysis is not performed, it is also customary to determine separately the total amount of sulfur contained in the wood, as well as its higher and lower heating values.

The ultimate analysis of a fuel describes its elemental composition as a percentage of the sample's dry weight. Proximate and ultimate analysis for some typical wood fuels are given in Table 3.4-1.

Proximate and ultimate analysis are not routinely conducted on receipt of fuel at wood-fired plants. Wood waste transactions are based on weight or volume. Units of measurement used most often are tons and "units". A "unit" is defined as the amount of uncompacted wood waste that will fit into a 200-ft^3 container. [14]

<u>Moisture Content</u> - Moisture content is described in one of two ways: wet basis or dry basis. Those concerned with power generation most often consider moisture on a wet basis. The wet basis moisture content directly reflects the fuel value of the wood. Knowledge of both methods of calculating moisture content will be important when arranging wood fuel purchases, especially mill residue. The moisture content (M.C.) of wood on the wet basis is the weight of the water in a wood sample divided by the total weight of the sample. The dry basis moisture content is favored by foresters and producer/manufacturers of wood products (a prime source of mill residues). The M.C. of wood on a dry basis is the fractional water content or the weight of water divided by the sample weight when dried. [81]

The moisture content of bark and wood usually influences the design of both the firing equipment, gasifier, and the steam generator more than any other property. Bark from hydraulically debarked logs or from trees in areas with high rainfall, and sawdust from mills using water-cooled saws, may contain 65% moisture or more. At such high levels, combustion becomes unstable, and the fire goes out. Hog fuel (the term used to describe the mixture of wood and bark that is burned to produce steam in most wood fired stoker grate plants) normally contains 45 to 55% moisture on a wet basis. Sander dust and furniture plant scraps, which contain the least amount of moisture of the wood fuels (less than 10% on a wet basis) allow the highest boiler efficiencies. The vaporization of water to steam requires a heat input of 1,000 Btu/lb of water. Energy which could otherwise be useful in the steam production is thus

Table 3.4 – 1

Properties of Wood Fuels

Chemical Composition, % by weight (dry basis)

Constituent	Bark				Fir/Pine			Wood	
	Pine	Oak	Spruce	Red wood	Chips	Sawdust	Pellets	Red wood	Pine
Proximate Analysis									
Volatile Matter	72.9	76.0	69.9	72.6	75.1	80.6	83.3	82.5	79.4
Fixed Carbon	24.2	18.7	26.6	27.0	24.5	14.2	14.0	17.3	20.1
Ash	2.9	5.3	3.8	0.4	0.4	5.2	2.7	0.2	0.5
Ultimate Analysis									
Hydrogen	5.6	5.4	5.7	5.1	6.3	5.5	5.5	5.9	6.3
Carbon	53.4	49.7	51.8	51.9	50.7	50.5	50.0	53.5	51.8
Sulfur	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.0	0.0
Nitrogen	0.1	0.2	0.2	0.1	2.4	0.1	0.1	0.1	0.1
Oxygen	37.9	39.3	38.4	42.4	40.2	44.0	42.0	40.3	41.3
Ash	2.9	5.3	3.8	0.4	0.4	5.2	2.7	0.2	0.5
Heating Value									
Dry Basis,Btu/lb	9030	8370	8740	8350	8795	8305	8119	9220	9130

Source: Ref. 1 & 14

diverted to drying the wood fuel in the combustion chamber prior to actual burning of the wood. [14, 81]

<u>Ash Content</u> - Ash is the noncombustible mineral matter left behind when a fuel burns completely. The ash content of wood is low, generally less than 1% by weight. By contrast, the ash content of bark from most softwood (evergreen) species extends up to 3%, while that for hardwood (broad-leafed) species typically ranges from 2 to 5%. [14]

Besides the ash contained in the bark on the standing tree, harvesting and handling of logs frequently contribute more dirt, rock and sand. The amount of additional noncombustible material that clings to the bark depends on the logging methods, type of soil in the forest, method of transportation (wet or dry), and handling at the plant. Compared to the ash burden in most coal-fired boilers, however, relatively little noncombustible material is discharged from bark fired boilers. [14]

<u>Heating Value</u> - In judging the value of fuel, the heating value plays a basic part, because in buying fuel, actual energy units are being bought. When an oven-dry wood or bark sample is burned in a bomb-type calorimeter filled with oxygen under pressure, the fuel's higher heating value is measured. This assumes that the latent heat of water vapor contained in the combustion products is absorbed in the boiler. Since water vapor in the flue gas is not cooled below its dewpoint during normal boiler operation, this latent heat is not available for making steam. [14]

Woods of different species have approximately the same heating value on a moisture and resin free basis, about 8300 Btu/lb. But since resin has a heating value higher than that of the dominant cellulosic material (about 16,900 Btu/lb), resinous woods, such as Douglas fir and pine, contain about 9000 Btu/lb. Hardwoods, such as oak, have heating values near 8300 Btu/lb. Heating values for nonresinous barks may extend up to about 9800 Btu/lb; softwood barks range from 8800 to 10,800 Btu/lb. [14]

Particle Size - The particle size of wood waste can extend from 40 to 200 microns in sander dust to sawmill slabs several feet in length. Particle size and shape also influence the total energy content of any fuel shipment. A substantially greater heating value is obtained when bark is purchased on a unit basis than when sawdust or planer shavings of equivalent moisture content are purchased. [14]

3.4.2.2 Agricultural Waste Fuel Characteristics

Straw from cereals and similar stem-wastes from other crops constitute the largest source of plant waste matter arising in agriculture. They are distinguished from other crop wastes by relatively low content of moisture (about 14% moisture is commonly found with cereal straw). Hence, these wastes, as fuels, are ready to be combusted or thermally processed without further dehydration and processing. In contrast, wastes from vegetable-growing, which typically contain from 78 to 84% moisture, are most readily used for gas production via anaerobic digestion, unless they can be conveniently sun or air-dried.

Apart from wheat and barley, these relatively dry stem-wastes include rye and oat straw, rice straw and corn stalks, and dry residues from rape, dry peas and beans grown for fodder. Consideration of tropical crops includes sugar cane bagasse (the fibrous material left after sugar extraction), the woody stem wastes arising in the production of commercial fibers, such as jute, hemp and sisal, and bush prunings on tea plantations. Sugar cane bagasse is not very dry as it arises, but is usually pressed to about 50% solids content. [94]

There are other dry residues which are not stems, but which may be utilized in the same ways, such as nut shells. Examples are almond shells (which are sometimes used to fire boilers in Mediterranean countries), coconut shells, and the woody wastes which arise within agriculture when old vineyards or orchards are grubbed up for replanting. Naturally, a proportion of these fairly dry orchard wastes are utilized at present. Wherever it is convenient to do so, or where fossil fuel is especially scarce or expensive, wastes may have already been used as fuel. This has happened quite widely, for example, with sugar cane bagasse, which is often used to fire boilers to provide energy for the sugar cane processing plant itself. In the majority of cases, however, these wastes have not been used due to the much greater convenience of liquid fuels. [94]

The composition and energy contents of most of the crop residues discussed are given in Table 3.4-2. The most important observation here is that most of the residues contain significant levels of metabolizable energy. This is energy in a chemical form which is available to be absorbed by the animal to support its growth and metabolism. Many of the wastes also contain significant crude protein levels in the dry matter. This makes them suitable, to varying extents, as animal feeds, and amounts to a competitive use to energy conversion. Indeed, all the wastes listed are potential feedstuffs with the exception of potato haulm (on account of its toxicity) and much of the poorer quality cereal straws (where the metabolizable energy is too low to make them worthwhile). Below a metabolizable energy level of about 2580 Btu/lb, the residue takes up too much space in the alimentary canal and becomes counter-productive by excluding more nutritious food which the animal could have otherwise eaten. Indeed, the difference in metabolizable energy between spring and winter barley straw is significant in this respect and affects their usage on a major scale in practice.

<u>Moisture Content</u> - As with wood, the moisture content of agricultural waste fuel usually influences the design of both the firing equipment, gasifier, and the steam generator more than any other property. Straw and similar stem type agricultural waste contain the least amount of moisture of crop wastes (about 14%) and allow the highest boiler efficiencies. Bagasse typically contains over 50% moisture, which makes it difficult to fire without some type of drying. Leafy crop waste from vegetable crops are also very high in moisture and difficult to burn without some form of drying or dehydration. As discussed earlier, high moisture content feed stock causes a reduction in overall efficiency.

Table 3.4 – 2

Composition of Crop Residues

dry matter basis, typical values

Residue (units)	Metabolisable Energy (MJ/kg)	Gross Energy (MJ/kg)	Crude Protein (%)	Ash (%)
Wheat straw	5.6	17.6	2.9	7.1
Barley straw (spring)	7.3	18	3.8	5.3
Barley straw (winter)	5.8	17.8	3.7	6.6
Oat straw	6.8	17.9	2.8	5.7
Rye straw	6.3	18.2	3.6	3
Rape straw	6.5	18	3	4.5
Pea straw	6.5	17.9	10.5	7.7
Pea haulm and shucks(ensiled	8.7	16.9	16.7	20
Potato haulm	6.5	17.3	10.9	13.5
Potato haulm (ensiled)	6.4	17.1	12.8	22.4
Sugar beet tops	9.9	15.4	12.5	21.2
Sugar beet tops (ensiled)	7.9	13.4	10.4	32.2
Cabbage (outer leaves)	11.6	16.8	18.3	15
Cauliflower	12.1	17.9	29.1	11.3
Brussel sprout waste	11.4	17.9	18.4	7.4
Bean straw	7.4	18	5.2	5.3

Source: Ref. 94

Ash Content - For most biomass fuels, ash content of the fuel is quite low, typically less than five percent on dry basis. In addition, extraneous matter such as dirt or sand is inevitably present in some fuels as a result of the method of harvesting used. Since it is not practical to separate this extraneous matter from the fuel during sampling, the extraneous matter can increase the reported ash content. For instance, rice hulls have what appears to be a very high ash content (over 15%), however, the SiO_2 content is high, which likely means that the fuel contains a significant fraction of sand or dirt. Agricultural ash is also high in alkalis and should be limited. See Section 3.2.

Heating Value - Agricultural wastes tend to have a higher heating value (HHV) range, of about 6000 Btu/lb to 8800 Btu/lb. Peanut Hull and bagasse tend to have some of the high values with HHVs in the 8000 to 8700 Btu/lb range. Straws tend to cover the range of heating values depending on the species. HHV and ultimate analysis for various agricultural waste are given by Table 3.4-3.

3.4.2.3 MSW and RDF Fuel Characteristics

Tables 3.4-4 and 3.4-5 show the heterogeneous nature of a typical MSW fuel. The variance in constituent composition, weights, moisture content, and density provides a challenge to the system designer. Ranges of weight and moisture percentages, inorganic (ash) content, and approximate densities for some of the constituents are given in these tables. The composition of MSW varies from municipality to municipality and from season to season. Indicative of this variance is a study conducted by the National Bureau of Standards, now the National Institute of Standards and Technology, on the chlorine content of MSW based on samples taken at Baltimore County, Maryland, and Brooklyn, New York. The total chloride content (by mass) was 0.45 and 0.89%, respectively. Not only was the variance wide, but also the component contributing the largest fraction to the chlorine content was different; paper in Baltimore and plastics in Brooklyn. Systems and equipment design must reflect the varying composition of MSW and should be based on representative sampling for the area involved, not an average or typical data. [14]

Table 3.4-3

Properties of Agricultural Waste Fuels

Chemical Composition, % by weight (dry basis)

Constituent	Almond Prunings	Bagasse	Barley Straw	Corn Cobs	Cotton Gin Mash	Peanut Hulls	Rice Hulls	Rice Straw	Rice Straw	Wheat Straw
Proximate Analysis										
Volatile Matter	78.7	85.7							68.3	
Fixed Carbon	18.4	12.8							16.0	
Ash	2.8	1.5							15.6	
Ultimate Analysis										
Carbon	49.1	44.3	41.3	45.4	43.6	49.4	37.7	37.3	39.3	45.8
Hydrogen	5.9	6.3	5.7	5.7	5.5	6.2	5.0	5.2	4.9	6.2
Oxygen	41.9	47.4	44.1	46.4	42.1	40.5	36.3	38.0	39.5	41.3
Nitrogen	0.3	0.4	0.552	0.3	0.7	1.8	0.0	0.3	0.5	0.689
Sulfur	0.1	0.0	0.13	0.0	0.1			0.0	0.1	
Chlorine			1.71	0.52	0.63	0.04	0.17	1.92		0.4
Ash	2.8	1.5	6.5	1.6	7.4	2.0	20.8	17.3	15.6	5.5
Heating Value										
Dry Basis,Btu/lb	8322	8400	7438	8007	7441	8667	6887	6089	6644	8112

Source: Ref. 1 & 95

Table 3.4–4

Ranges of Weight, Moisture Percentages and Inorganic Composition for MSW Constituents

Refuse Item	Composition, %	Moisture, %	Inorganics %
Corrugated Boxboard	1.32–6.81	8.59–50.23	2.01–3.57
Newspaper	8.88–21.35	9.60–34.87	1.31–2.96
Magazines, books	2.05–3.74	7.23–26.27	11.91–19.01
All other paper	19.78–24.77	18.60–33.53	4.98–28.94
Plastics	2.00–6.82	3.62–19.65	3.72–10.72
Rubber, leather	1.22–2.60	3.57–18.42	4.12–24.99
Wood	1.18–6.58	8.09–24.98	1.56–5.62
Textiles	2.24–8.92	9.14–36.64	1.84–3.17
Yard trimmings	0.26–33.33	21.08–62.20	5.59–30.08
Food waste	7.23–16.45	52.35–73.45	4.59–21.87
Fines, < 1in.	2.83–11.75	10.10–43.00	53.00–66.72
Matallic	6.81–11.08	2.57–10.83	90.49
Glass,ceramics, etc.	7.13–23.06	0.59–6.00	99.02
Composite		16.77–42.10	30.56–35.91

Source: Ref. 14

TABLE 3.4 – 5

Approximate Densities of MSW Constituents

Refuse Item	lb/ft^3
Magazines	35
Paper	3–5
Cardboard	7
Corncobs	11
Green grass	3
Metal scraps	15
Rubber	44
Shoe leather	20
Vegetable food waste	14
Wood chips	15–25
Hardboard	33
Plastic bags	0.75
Plastics	2–7
Textiles	9–11
Cast iron, steel	450–490
Sand	90–117
Glass bottles, Unbroken	22
Glass bottles, broken (1.5"max.)	67
Aluminum, elemental	11
Aluminum cans (single can basis)	2–3

Source: Ref. 14

Unless the facility is designed specifically to accommodate them, not all materials are acceptable for use as waste fuels. Not acceptable as MSW feed for waste fuels are (1) materials that may cause a waste-to-energy facility to violate an air or water quality effluent standard or (2) items, when processed, that could cause harm or damage to personnel or hardware. Unacceptable materials include explosives, pathological and infectious wastes, radioactive wastes, poisons, concentrated acids and bases, human and animal remains, bulk quantities of paints, solvents, and other highly volatile materials, large amounts of coal, household appliances (refrigerators, stoves, air conditioners, etc.),bathtubs and sinks, bulk quantities of ferrous and nonferrous metals, incinerator residues, concentrations of heavy metals, oil sludges, excavation wastes, and any other concentrations of materials that may place the facility in violation of EPA regulations. This is largely an administrative rather than an engineering concern. [14]

Many waste-to-energy plants install equipment to process oversized bulky waste (OBW) for use as waste fuels or for ferrous recovery. The purpose of OBW processing equipment is to reduce in size materials that have value as waste fuel or as recyclable material, so they may be handled by other processing or material-handling equipment. Typical OBW materials are household furnishings (tables, chairs, davenports, dressers), mattresses, bed springs, rolled carpets, tires, timber, empty drums, light-gage scrap metals, demolition debris, bundled paper and corrugated boxes, and loose roofing materials. [14]

<u>Refuse Fuel Analysis</u> - Considerable engineering judgment is required to properly design a refuse burning and heat recovery system because the chemical analysis and calorific value of the fuel may vary from day to day, week to week, and location to location. The fuel analysis and higher heating value have significant impact on the design of the boiler and associated equipment. The heating value determines the heat input for a given quantity of fuel, while the chemical analysis determines the quantity of air required for combustion and the resulting flue gas quantity and quality. [14]

During the early stages of a project, it is in the engineer's best interest to specify the refuse analysis and heating value so there is a common base for comparison of the various offerings. However, the proper relationship of the analysis and heating value to each other must be maintained, to achieve the proper design. If the heating value is uncharacteristically high for the analysis, the air and flue gas systems will be undersized for the probable operating range of the unit. If the heating value for a given analysis is too low, the fuel burning capacity of the furnace will be limited and the contracted quantity of refuse will not be processed. [14]

The best cross correlation between analysis and heating value is obtained from the air quantity required to combust a MBtu of fuel. This value is remarkably consistent for most fuels, for example, for natural gas varying from 7.23 to 7.46 lb/MBtu. This same rationale can be applied to refuse. Table 3.4-6 presents a typical analysis of the various components of refuse (newspaper, plastic, wood, yard trimmings, food waste, etc.). The derived theoretical air values are shown. The required pounds of air per MBtu are reasonably consistent, varying from 7.2 to 7.3 for wood and wood products, to 7.35 for food and yard trimmings, to 7.64 for plastics. Test data from a number of RDF and MSW fuels on operating units show similar results. Here the majority of the data were centered about 7.5 with one-half of the data in the relatively small range of 7.3 to 7.7. [14]

When refuse is considered as a fuel, three of its components are critical: mineral matter, moisture, and organic matter. Although mineral matter is the root cause of most potential boiler problems, it has little participation in the gasification and combustion processes, except for metals that may be partially oxidized. Likewise, moisture does not participate in the combustion process, but does contribute to the moisture in the flue gas. The concern for the gasification and combustion processes is, therefore, limited to organic matter. [14]

Table 3.4-7 shows three example analyses provide for design purposes. Column 3 exemplifies the problem that can be anticipated if the heating value is not correlated to the chemical analysis. If the analysis in column 3 were used, the combustion fans,

Table 3.4–6

Analysis of Refuse Components, Percentage by Weight

Refuse Item	Comp. wt %	C	H	O	N	Cl	S	WATER	ASH
Corrugated Boxboard	5	36.79	5.08	35.41	0.11	0.12	0.23	20.00	2.26
Newspaper	12	36.62	4.66	31.76	0.11	0.11	0.19	25.00	1.55
Magazines, books	3	32.93	4.64	32.85	0.11	0.13	0.21	16.00	13.13
All other paper	23	32.41	4.51	29.91	0.31	0.61	0.19	23.00	9.06
Plastics	3	56.43	7.79	8.05	0.85	3.00	0.29	15.00	8.59
Rubber, leather	2	43.09	5.37	11.57	1.34	4.97	1.17	10.00	22.49
Wood	3	41.22	5.03	34.55	0.24	0.09	0.07	16.00	2.82
Textiles	3	37.23	5.02	27.11	3.11	0.27	0.28	25.00	1.98
Yard trimmings	10	23.29	2.93	17.54	0.89	0.13	0.15	45.00	10.07
Food waste	10	17.93	2.55	12.85	1.13	0.38	0.06	60.00	5.10
Fines, < 1in.	10	15.03	1.91	12.15	0.50	0.36	0.15	25.00	44.90
Metallic	7								
Glass,ceramics, etc.	9								
TOTAL	100								

Source: Ref. 14

Table 3.4–7

Effect of three Refuse Analysis on Combustion Air Requirements

Constiuent	1	2	3
Ash	25.63	9.43	21.3
S	0.44	0.27	0.2
H_2	3.38	4.72	3.85
C	23.45	33.47	21.7
H_2O	31.33	19.69	26.42
N_2	0.19	0.37	0.4
O_2	15.37	31.9	25.92
Cl_2	0.32	0.15	0.21
Total, %	100	100	100
HHV, Btu/lb	4174	5501	4713
Air, lb/10,000Btu	7.71	7.49	5.76

Source: Ref. 14

boiler, and flue-gas cleanup equipment would be undersized, and the desired tonnage of refuse could not be processed. [14]

In summary, engineers of refuse units should design for a range of heating values and analyses. This range will account for the following:

- The inherent heterogeneous nature of the fuel
- Fluctuations due to seasonal trends
- Forecasted projections that show a steady trend of increasing heating values in the future.

Throughout this range, the theoretical air must fall between 7.3 and 7.8 lb/MBtu. If the air required falls outside this range, a heating value should be inferred from the analysis by using a theoretical-air requirement of 7.5 lb/MBtu. In normal operation a combustor should be expected to operate near 125% of theoretical air, while a gasifier would normally operate at about 25% theoretical air. [14]

3.4.3 Fuel Delivery

As biomass fuels have different characteristics and sources, the delivery methods can vary. The discussion of biomass fuel delivery will be divided by the three primary source groups for the fuels.

3.4.3.1 <u>Wood Fuel Delivery</u>

Transportation is one of the largest components of fuel cycle cost for plants that buy hog fuel from outside sources. Estimates are that it can cost $1.00 per mile or more to haul wood and bark in a 25-ton van. This rate will vary as diesel fuel prices change. Most plants rely on contract haulers or the seller to deliver hog fuel. [96]

The type of truck used and the methods needed to unload the truck depend on the form of the fuel and the size of the facility. Small facilities usually cannot justify the cost of complex unloading and handling systems, whereas larger facilities that require more fuel can afford to invest in more sophisticated machinery. [20]

Four types of trucks are used to haul wood fuels: dump trucks, live-bottom trailers, conventional trailers, and hopper-bottom trucks. Dump trucks and live-bottom trailers have the advantage of being able to dump fuel directly into storage piles. Conventional semi-trailer delivery requires that the wood fuel user have some type of unloading equipment. Hopper-bottom trucks can only be utilized for delivery of densified or dry fuels. [20]

Dump trucks are best for small systems requiring no more than 2 to 3 loads per day, particularly where transportation distances are short. For longer delivery distances, the transportation cost per ton may be 2 to 4 times that of conventional semi-trailer delivery, however. If the facility obtains fuel on a "pick-up" basis, rather than by delivery, capital cost of dump trucks is generally low. [20]

Self unloading trailers offer another option for smaller systems. In most cases, these trailers are equipped with a live floor that "walks" the load out. Trailers range from 30 feet to 50 feet in length, and carry between 18 and 28 tons of wood fuel. A hydraulic power take-off, which receives its power directly from the tractor truck or an external pump, makes unloading a one person operation. The unloading operation averages 10 minutes. Several sites use these trailers for short term storage with the unloading rate controlled by fuel demand. The main advantage of this unloading system is that it does not require on-site unloading equipment. However, the cost of a live-bottom van is approximately twice the cost of an open trailer of equivalent size. [20]

A bulldozer or front-end loader is essential to shape the pile and compact the fuel deposited by self unloading trucks. Further, the payload of these vehicles is considerably less than that of a semitrailer, and they are more expensive to operate. Self-unloading vehicles may be economical when the plant and the fuel source are within a few miles of each other or when the plant requires only a few shipments per day. [20]

Conventional semi-trailers offer the most economical method of transporting wood fuels. These trailers can hold up to 22 tons of wood fuel and do not require special design for wood use. In fact, the method most widely used by suppliers of fuel chips is to blow the fuel directly from the chipper into a conventional semi-trailer. In small installations, semi-trailers can be unloaded by front-end loaders which, with the proper ramp or loading dock design, can be driven directly into the semi-trailer. A well trained operator can unload a trailer in less than an hour. The principal expense in this type of unloading is for labor. One drawback is the potential for damage to the trailer by careless operators. However, this is still the preferred method for unloading conventional semi-trailers at small installations. [20]

Large facilities are likely to employ hydraulic dumpers which can unload an entire semi-trailer in 3 to 5 minutes. Some hydraulic dumpers lift the entire truck and trailer while others require that the trailer be unhitched before being dumped. In either type, the maximum tilt is about 60 degrees and the hydraulic dumper can be fitted with automatic scales so that the weight of the load can be printed as the truck is dumped. For very wet, finely divided fuels such as green sawdust, some sticking in the trailer may occur, and mechanical scrapers or shakers may be incorporated into the dumper to ensure that the entire load is released. [20]

Another device used to unload conventional semi-trailers at large facilities is the Scoop-Roveyor. This apparatus is capable of unloading a 40-foot van in less than 15 minutes. Its functions are controlled by an operator who rides on the collection end of the scoop. These truck unloaders are considered cost-effective for medium and large-sized plants. [20]

Densified fuel is usually shipped in hopper-bottom trucks. These trucks are unloaded over a pit which is usually equipped with some kind of continuous transport conveyor to move the fuel to the storage area. Unloading of densified fuel is an extremely rapid and continuous process, but this advantage may be offset, as mentioned in Section 1.3, by the high cost of such fuel. [20]

A large facility would demand heavy truck traffic which may overload the area road and cause problems in the community. As an alternative to truck delivery, wood can be delivered by railcars or barges. Rail and barge transportation usually have a cost advantage over trucks when the fuel source is not local to the plant. Railcars and barges are usually unloaded with the same type of equipment used to discharge coal, such as rotary car dumpers and clamshell buckets.

Systems to unload the fuel should be designed to minimize the amount of time a delivery vehicle spends at the plant, since demurrage charges can accrue quickly. A practical problem with truck transportation is that these vehicles arrive at the plant on a random schedule and often come in groups of two or more. A rule of thumb for sizing a truck unloading system that operates a nominal 12 hour day, is to design it to handle one-half the daily volume in a 4 hour period. Thus, if one expects twenty 20-ton trucks per day, the system should be able to move 50 tons/h of wood waste from the unloading station to storage. [14]

3.4.3.2 Agricultural Waste Delivery

Agricultural residues will usually be delivered by a truck. If residues are in a finely divided or loose form, the same delivery methods that apply to wood are used. If the residues are in large round bales, the most economical method of transporting field harvested material is delivery by flat bed trailer. Specialized handling equipment has been developed for these bales. The unloader is similar to a fork lift and is designed to pick up a bale and move it with little damage to its integrity. Some trailers, designed especially for handling these bales, have a self-contained unloading system which pick the bales from the bed and lowers them to the ground. Delivery of food processing wastes is usually accomplished by truck, in the same manner that wood waste is delivered. [20]

3.4.3.3 MSW and RDF Handling and Delivery

Raw Waste Handling - The materials handling of MSW begins at the curbside of the home or business generating the refuse. In some cities, separation of the material to recover recyclables such as newspaper, ferrous metals, aluminum, and glass is provided for. The logistics of the municipality may favor spotting of the transfer station around the city, where smaller collecting trucks can dump their loads. Compactor trucks then transfer the MSW to the resource recovery plant. [14]

Receiving or Tipping Floor - On the incoming roadway to the resource recovery plant, the MSW loaded truck is weighed before it proceeds to the receiving or tipping floor area. The tipping floor is adjacent to the refuse storage pit that allows trucks to maneuver to unload into the pit. The area is normally enclosed and kept under slight negative pressure to keep odors to a minimum. This is accomplished by putting an induced-draft fan intake duct over the pit, drawing air from the pit area. [14]

Tipping floor entrance and exit doors should allow at least 25 ft horizontal and vertical clearances, should be at opposite ends of the building, and should be protected by barriers. Traffic flow through the area should be arranged to put the pit on the driver's left as the truck enters the tipping area, to allow better visibility. [14]

Careful consideration must be given to the number of tipping bays and the width of the tipping floor, since both have a direct influence on traffic flow. The number of bays should reflect the anticipated daily volume of refuse delivered, as well as the hours of delivery. The width of the tipping floor should be able to accommodate the largest vehicle that will enter the facility, which would normally be a transfer trailer. Large facilities of more than 1500 tons/day should have a tipping floor width of at least 125 ft of clear space. A front-end loader moves rejected material to one side of the tipping floor for disposal and for general housekeeping purposes. [14]

RDF Delivery - MSW can also be acquired as processed RDF with the non-combustible material removed. It is typically delivered in trucks and handled much the same as wood waste fuel. RDF can be supplied on a continuous basis, as it is produced year round.

3.4.4 Feedstock Preparation Requirements

As discussed in Section 1.3, the three primary concerns of fuel preparation are the proper size, acceptable moisture content, and elimination of noncombustibles.

3.4.4.1 Fuel Size

The fuel size requirements are dependent on the combustor or gasifier fuel feed system and bed design. A fluidized bed unit can be designed to use practically any size fuel. However, it is important to use the size fuel for which the unit is designed. If oversized fuel is used, fluidization problems will result, while if undersized fuel is used, excess elutriation will occur. A review of the commercially available fluidized bed combustor and gasifiers shows that a two-inch top size is the most common size. However, some units can use larger size fuel, while others may require smaller fuel.

3.4.4.2 Moisture Content

As with fuel size requirements, the moisture content requirements are a function of the unit design. Again reviewing the commercial units available, the most common requirement is 60 or 65% maximum total moisture content. Fuel of greater moisture can usually only be used by cofiring with coal or some other fossil fuel. Of course drier fuel can be used, and increases the units efficiency as less heat is used to evaporate the moisture in the fuel. Excess surface moisture can cause feed problems in some units. This is dependent on the feed system design chosen by the unit vendor. While not a requirement, a flue gas dryer can improve the overall efficiency of the unit by evaporating the fuels moisture with waste heat from the flue gas that would otherwise be discharge out the stack to the atmosphere. A more detailed explanation of flue gas dryers is given in Section 1.3.

3.4.4.3 Elimination of Noncombustibles

Noncombustibles such as metal and ceramics can often be contained in the feed stock, especially in MSW and RDF fuels. These materials tend to cause fouling in the bed and may cause damage to the fuel feed and bed drain systems. While a few manufactures claim that their units are unaffected by these noncombustibles in the fuel stream, most require that the items be removed.

3.4.5 Ash Characteristics

The ash content of biomass fuels is generally considered low when compared to coal. Ash contents of various biomass fuels are given with the ultimate analysis tables for the fuels in Section 3.4.2. The alkali content of the ash is usually higher than that of coal ash due to the chemical composition of biomass fuel. The alkali tends to react with sulfur and therefore reduce the SO_2 emissions, however, biomass fuels are typically low in sulfur, therefore this is not a significant advantage if the biomass is not cofired with coal. The alkali in the ash also tends to cause fouling of the convection pass and bed as described in Section 3.2.1. Therefore the alkali content of the biomass fuel ash is probably the most import chemical characteristic of biomass fuel ash.

When looking at biomass FBC and FBG ash characteristics, there are other considerations besides the fuel ash. The bed material can be very significant in determining the nature of the ash. Where limestone is used for bed material, a significant amount of dust is often included, which is commonly elutriated from the bed with the fuel ash. The same is true to a lesser extent when sand is used for bed material. Therefore the flyash stream is composed of the noncombustible from the fuel and fine bed material. If the unit has a bed drain system, which most do, the primary component in the bottom ash is the bed material.

Depending on the level of heavy metals in the biomass feed stock, heavy metals in the ash can be a concern. There is a possibility of contaminating the groundwater if the ash is disposed of in a landfill. This led to the establishment of Extraction Procedure (EP) Toxicity limits of ash. If below these limits, the ash does not have to be treated as a hazardous waste. Table 3.4-8 presents the EP Toxicity analysis of several ash streams. The current procedure for evaluating the mobility of ash constituents is referred to as the Toxicity Characteristic Leaching Procedure (TCLP).

The French Island "Wood/RDF" results are based on a blend of 50% wood and 50% RDF fuel burned in Northern States Power Company's French Island BFBC. The "Wood" results in Table 3.4-8 are from burning all wood fuel at this facility. The analysis was performed on the ash as deposited in the landfill, therefore the results are based on both flyash and bottom ash. A mass balance of this unit shows 2,287 pph of flyash and 120 pph of bottom ash. This should be indicative of the mixture in the test sample. The B&W 1'x1' test unit results are from tests performed at B&W's 1'x 1' AFBC pilot combustor in Alliance, Ohio, burning all RDF fuel. Ash was collected at three locations, as indicated in Table 3.4-8. The Sundsvall, Sweden results are from a CFB facility in Sweden that burns 100% RDF fuel. The "Urban Wood" result represent the testing of ash from demolition wood fired in a downdraft gasifier, not a FBG.

Table 3.4–8

EP Toxicity Test Results (mg/l)

Metal	EP Limit	French Island Wood/RDF	French Island Wood	Urban Wood	B&W 1'x1' Btm Ash	B&W 1'x1' Cyclone	B&W 1'x1' Baghouse	Sundsvall, Sweden Btm Ash	Sundsvall, Sweden Fly Ash
Arsenic	5	0.01	0.5	0.01	nd	nd	0.011	0.007	0.17
Barium	100	18.5	1.1	9.67	0.28	0.47	0.67	0.1	0.3
Cadmium	1	0.01	0.02	0.01	nd	nd	0.01	0.05	0.03
Chromium	5	0.05	0.19	0.02	0.11	2.3	4.3	0.12	0.04
Lead	5	0.7	0.05	7.38	0.06	nd	nd	0.35	0.04
Mercury	0.2	0.001	0.0032	0.0001	nd	nd	0.014	0.0002	0.001
Selenium	1	0.01	0.5	0.002	nd	nd	0.008	0.01	0.02
Silver	5	0.01	0.1	0.01	nd	nd	nd	0.04	0.02
Final pH	2.0–12.5	12.4	12.5						

nd – not detectable

Source: Ref. 16, 85, 95 & 97

3.4.5.1 Wood Ash Characteristics

Qualitatively, bark ash differs from coal ash. Although there is no such thing as a typical analysis, bark ash generally is high in calcium oxide, sodium oxide, and potassium oxide. Conversely, coal ash usually contains more silicon dioxide and aluminum oxide than bark ash. Table 3.4-9 gives some wood ash analysis information.

These differences may be significant in some cases where bark and coal are burned in combination. The reason is that if the bark has a high concentration of calcium oxide, this compound could act as a flux and reduce the fusion temperature of the mixture of ash to the point where slagging problems are possible. Also, high concentrations of sodium and potassium oxides may lead to superheater fouling.

At least one very large power plant fired with purchased wood fuel and coal in the northeast has reportedly found that the sulfur oxide emissions have been reduced from the anticipated values because of the combination wood and coal firing. That is, the sulfur in the coal combines with wood ash constituents and is removed from the furnace with bottom ash.

In fluidized bed units, both ash streams will be altered by the presence of bed material as discussed above. The effect of the bed material will vary depending on the bed material used and the gas and material flow characteristic of the unit selected. To illustrate this point, Table 3.4-10 give the analyses of ashes from four CFB combustors which use sand as bed material. The high level of quartz as $SiO2$ indicate the level of sand in the ash.

Examination of Table 3.4-8 reveals that the lead content of the urban demolition wood is substantially above the allowable limit. This is due to the lead contained in the paint on the wood. However, due to the addition of the bed material, the lead content in the ash of a fluidized bed unit would be diluted and subsequently might be well below the limit.

Table 3.4–9

Ash Properties of Wood Bark

	Pine	Oak	Spruce	Red wood
Ash Content % (dry basis)	2.9	5.3	3.8	0.4
Sulfur Content % (dry basis)	0.1	0.1	0.1	0.1
Ash Constituents, Percent of Ash				
Silicon dioxide (SO_2), %	39.0	11.1	32.0	14.3
Aluminum oxide (Al_2O_3), %	14.0	0.1	11.0	4.0
Iron oxide (Fe_2O_3), %	3.0	3.3	6.4	3.5
Calcium oxide (CaO), %	25.5	64.5	25.3	6.0
Magnesium oxide (MgO), %	6.5	1.2	4.1	6.6
Sodium oxide (Na2O), %	1.3	8.9	8.0	18.0
Potassium oxide (K_2O), %	6.0	0.2	2.4	10.6
Titanium oxide (TiO_2), %	0.2	0.1	0.8	0.3
Manganese oxide (Mn_3O_4), %	Trace	Trace	1.5	0.1
Sulfite (SO_3),%	0.3	2.0	2.1	7.4
Chloride (Cl), %	Trace	Trace	Trace	18.4
Other compounds %	4.2	8.6	6.4	10.8
Ash–Fusion Temperatures,^{o}F				
Initial deformation				
Reducing	2180	2690		
Oxidizing	2210	2680		
Softening				
Reducing	2240	2720		
Oxidizing	2280	2730		
Fluid				
Reducing	2310	2740		
Oxidizing	2350	2750		

Source: Ref. 14

Table 3.4–10

Ash Composition (%)

CFB	Westwood	Chatham	Ione	Rocklin	Fresno
Quartz	34.4	10.2	27	42	20.2
Mullite	4.4	<1	<1	1.8	<.1
Composition (%)					
SiO_2	63.8	13	46.6	75.6	66.1
Al_2O_3	22.1	3	16.7	9.6	7.7
$Fe_2 0_3$	2.7	4.5	2.2	2.7	1.5
CaO	2.7	43.5	23.9	3.7	11.7
MgO	0.8	0.9	0.6	1.4	2.2
Na_2O	0.3	0	0.3	2	2.4
K_2O	3.6	0.5	0.9	3	7.6
TiO_2	1.3	0.4	1.2	0.4	0.3
SO_3	0.7	33.9	5.5	<.1	<.1
$P_2 0_5$		0.3	<0.1	0.2	1
Carbon					
Base/Acid	0.12	3.01	0.43	0.015	0.33
Fe_2O_3/CaO	1	0.1	0.09	0.73	0.13
SiO_2/Al_2O_3	2.89	4.33	2.79	7.89	8.53

Source: Ref. 49

3.4.5.2 Agricultural Waste Ash Characteristics

Agricultural wastes, particularly rice straw, tend to contain low melting ashes. The low melting point and the alkali content of these ashes cause fouling problems as discussed in Section 3.2. Because of problems associated with combustion of agricultural wastes, many operators are limiting the volume going into the furnace by cofiring with other fuels, biomass or fossil.

3.4.5.3 MSW and RDF Ash Characteristics

MSW and RDF fuels are quite variable. Therefore, the ash characteristics of these fuels are not well defined. However, two significant concerns have been defined for dealing with MSW and RDF fuel ash. These are the ceramic content and the metals content. Heavy metals are of concern because they can concentrate in the ash. Glass and aluminum cause operational concerns because they can form molten phase compounds, and cause bed agglomerations, slagging, and/or fouling. Further, tramp metal and other noncombustibles can cause bed fluidization problems if allowed to accumulate in the combustor or gasifier.

Though it is not really feasible to give a set of typical ash analyses, a review of the ash analyses that have been performed on existing RDF fired plants will give an idea of the range of results that can be expected. Probably the largest concern with RDF ash is its disposal and the EP Toxicity levels of heavy metals. If the EP Toxicity limit is not met, the ash must be disposed as a hazardous waste. EP toxicity test results for several ash steams are given in Table 3.4-8. The fuels and units used to produce these ash streams were discussed previously.

3.4.6 Ash Handling Systems

On FBC and FBG units, the presence of sand or limestone bed material changes the nature of the ash. On most biomass FB units, ash is disposed of from two locations, the bed drain and the ESP or baghouse flyash. On some BFB and PFB units, a recycle system is used. If this is the case, excess recycle catch will be sent to disposal. This excess recycle is essentially the same material as the flyash. All recycle material is recycled back to the bed on CFB units.

3.4.6.1 Bed Drain Systems

In order to maintain proper bed chemistry, it is necessary to replace the bed material lost to elutriation due to attrition from the bed as flyash. It is also necessary to drain bed material to maintain proper bed level if new bed material is added. To accomplish this task, most FB units are equipped with bed drains located in the floor of the unit. Since the bed material temperature is near the combustion temperature (typically about 1500°F), it must be cooled before it can be handled. The most common bed letdown cooler types are: fluidized bed ash coolers, water cooled screw coolers and indirect air coolers.

After the bed ash is cooled, it is usually transported to a hopper for temporary storage before going to disposal. The transportation of the bed ash is usually handled either by pneumatic transport or mechanical conveying.

3.4.6.2 Flyash Handling Systems

Baghouses or ESPs are normally used to separate the flyash from the flue gas stream. Mechanical dust collectors such as multiclones are sometimes used to remove some of the flyash, but typically do not provide adequate particulate removal to meet present emission standards. Flyash is typically collected in hoppers then pneumatically transported to temporary storage.

3.5 TURNDOWN

Turndown is defined as the range of operation of the FBC or FBG. The limits of operation are determined by the acceptable temperature range that the process can maintain in a stable mode and by the amount of air necessary to maintain fluidization of the bed material.

Since many of the biomass fired plants are used in industrial applications, their required operation is typically across a wide load range. Turndown range and rate can have significant impact on the operation of a unit and the overall economics of the entire plant.

Load turndown in bubbling bed units is accomplished by one or a combination of methods: partial bed slumping and/or fluidizing air modulation (i.e., velocity turndown). Velocity turndown control consists of reducing fluidizing air flow (and fuel feed) to the bed as load is reduced. The reduced air flow results in a lower fluidized bed height, which exposes some of the heat transfer surface that would normally be submerged in the bed at full load. The reduced heat absorption to the tube bundle is designed to closely match the reduced heat input. Due to the need for maintaining minimum fluidization and bed temperature requirements, velocity turndown alone is only effective down to approximately 70 percent load.

Partial bed slumping consists of stopping airflow to part(s) of a segmented fluidized bed. This results in the defluidization of that section of bed which reduces overall heat absorption in proportion to its area, thus the load can be controlled. With these methods, bubbling bed units have demonstrated the ability to maintain steam temperatures down to 40 percent load and turndown ratios of 4 to 1.

With circulating bed units, load reduction is accomplished primarily by changing fuel and air flow to the combustor. As in the BFB, in order to maintain combustor temperature within acceptable values it is necessary to trim heat absorption in the combustor as the unit is turned down. Circulating bed units must also maintain a minimum fluidization velocity and therefore excess air will rise at lower loads. The minimum load will be limited by combustor temperature since the excess air will cool the unit as load is dropped. On CFB units without an EHE, primary and secondary air and solids modulation are used to trim temperatures during turndown. It is expected that these units can achieve 4 to 1 turndown ratios before the temperature drops below acceptable levels for sulfur capture and combustion. On units with an EHE, combustor temperature can be trimmed by varying the solids rate through the EHE. Units with EHEs can achieve turndown ratios up to 5 to 1.

The temperature range is defined by the application and the fuel characteristics. For example, if optimum sulfur capture is required, the typical range is 1450 to 1650°F. However, in the case of most biomass fuels sulfur capture is not a concern, therefore the range becomes wider. Acceptable ranges have been reported to be between approximately 1100°F and 1800°F. The minimum temperature is set to maintain thermal stability for the combustion and gasification processes. Operating at lower temperatures will result in a loss of efficiency since the char conversion reactions will be limited. On the other end of the operating range, the maximum temperature is set by the ash fusion temperature of the fuel and also any limits placed on the process by the materials of construction downstream of the combustor or gasifier.

Depending on the moisture content of the fuel, these temperature limits restrict the air-to-fuel ratio that can be sustained. In FBCs increasing air flow results in more cooling of the bed and less efficiency due to increased flue gas loss. Reducing air flow causes less fuel to be combusted, lowering temperature, and increasing CO and efficiency losses.

In FBGs, increasing air flow results in more combustion of the fuel which drives the temperature upwards. Reducing air flow lowers temperatures to the point where gasification reactions become less efficient. The range of air-to-fuel ratio has been found to be around 30 to 40% of stoichiometry. [8]

Turndown is also limited on FBCs at the low end by the air flow necessary to maintain good fluidization in the unit. For example if the air flow is reduced too much, the pressure drop across the distributor plate will fall below the level necessary to assure an even distribution of air to the bed.

In general, operating FBCs will be able to lower load to around 20-30% at which point they must increase excess air to maintain fluidization requirements. For most FBCs the overall turndown range is from 25-100% load. FBG units can operate successfully across a load range of 40-100%.

3.6 AVAILABILITY

FBC systems burning biomass fuels have demonstrated the ability to achieve high levels of availability and capacity factor. This is typically a critical factor in most power generation and cogeneration applications since the energy produced is needed on a continuous basis. Even though the economics of the facility do not require a high capacity factor (due to the cost savings of the fuel), the practical aspects of the application probably will.

It is possible that the biomass facility will be a supplemental unit to an existing energy production source. In this case, the unit may be designed to only operate for certain periods of the day or times of the year. Further, there may be situations where there is not enough fuel available to be able to operate the unit continuously, but a larger unit was bought for economic reasons. In either case, the capacity factor will be low due to the extended downtime during the year. The availability should always be above 90% for a well-designed and operating unit.

Factors affecting the availability of fluidized bed units using biomass fuels include problems caused by ash characteristics and by fuel impurities, such as rocks, dirt, and tramp metal. Principal problems have been associated with high alkali, such as potassium and sodium content, which is most pronounced in agricultural wastes and tree trimmings. These low melting ash constituents can cause fouling of boiler surfaces, deposition in cyclones, and agglomeration of bed materials. The best current solution for this problem is control of feed in the fuel preparation yard by limiting the quantities of undesirable materials and by judicious blending of different fuels for consistent quality of feed to the boiler. FB units must be designed to allow periodic removal of rocks and agglomerates from the bed during operation.

FBC units are commercially available with guarantees for 95-100% availability and near 100% capacity factors. However, it should be noted that some savings in capital and operating and maintenance cost may be achieved if less than 90% availability can be tolerated. For example, if an existing unit can still provide the energy needed during unexpected shutdowns in the biomass unit, it may be more economical to take the risk of using less reliable systems or equipment. This is particularly true if the existing fuel is also inexpensive, such as coal. A detailed feasibility study of the project goals and requirements can identify the merits of this type of application.

FBG units are similar to FBC units with regard to commercial guarantees for availability and capacity factor. However, as has been discussed previously, the lack of commercially demonstrated FBG facilities increases the risks associated with this technology. These risks are especially apparent in the area of availability. The FBG units have been demonstrated on smaller scale pilot units and mostly in units overseas. Factors such as process performance can be successfully scaled up to larger units by insuring consistent parameters such as temperature, residence times, and feed distributions. However, the scale up of equipment and system components is not as straight forward. This risk can be mitigated by close evaluation of the vendors design and commitments toward availability and reliability.

3.7 SUPPLEMENTAL FUEL

Most biomass fuels can be successfully used in an FBC or FBG unit without cofiring of any supplemental fuel. Only those fuels with a moisture content above 60% will require some secondary fuel in order to maintain the unit at the required combustion temperature. In most cases, this secondary fuel will be natural gas, oil, or coal. However, even the high moisture fuels, such as sewage sludge, can be utilized effectively by incorporating a drying system. See Section 1.5.

Most of the recent units being installed will have the capability to operate at full load on the secondary fuel in case of problems with the biomass fuel supply or feed. In any case, some supplemental fuel is needed to start up the unit. This can be done with natural gas or oil fired startup burners which bring the bed temperature up to the combustion temperature of the fuel.

Another alternative is to design the unit for cofiring of biomass with traditional fuels, such as coal. This has been an attractive approach taken by utilities where the biomass supply may not be large enough to warrant a dedicated facility. Even on smaller scale units, the use of coal and biomass allows some flexibility in operations. Further, these fuels have been demonstrated to burn well together and provide efficient and reliable operations to the facility, while potentially lowering air and solid waste emissions.

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5.0 ACRONYMS/NOMENCLATURE

ABB-CE	-	Asea Brown Boveri-Combustion Engineering
APR	-	annual percentage rate
atm	-	atmosphere
BFB	-	bubbling fluidized bed
BFBC	-	bubbling fluidized bed combustion
BFBG	-	bubbling fluidized bed gasification
BIG/STIG	-	Biomass Integrated Gasification/Steam Injected Gas Turbine
Btu	-	British thermal unit
B&W	-	Babcock and Wilcox Company
C	-	carbon
CaO	-	calcium oxide, lime
$CaSO_4$	-	calcium sulfate
CFB	-	circulating fluidized bed
CFBC	-	circulating fluidized bed combustion
CFBG	-	circulating fluidized bed gasification
CH4	-	methane
CO	-	carbon monoxide
CO_2	-	carbon dioxide
dscf	-	dry standard cubic feet
DOE	-	Department of Energy
EPA	-	Environmental Protection Agency
EPI	-	Energy Products of Idaho
EPRI	-	Electric Power Research Institute
ESP	-	electrostatic precipitator
°F, F	-	degrees Fahrenheit
FBC	-	fluidized bed combustion
FBG	-	fluidized bed gasification
fd fan	-	forced draft fan
fps	-	feet per second
ft	-	feet

GE	-	General Electric
gr	-	grains
H_2	-	hydrogen
H_2O	-	water
hr	-	hour
H_xC_y	-	hydrocarbons
IC	-	internal combustion
id fan	-	induced draft fan
IGCC	-	integrated gasification combined cycle
IGT	-	Institute of Gas Technology
in.,	-	inch
Klb	-	thousand pounds
KW	-	kilowatt (1,000 watts)
KWh	-	kilowatt-hr
KWt	-	kilowatt, thermal
lb	-	pound
LBG	-	low Btu gas
MBG	-	medium Btu gas
MBtu	-	million British Thermal Units
micron	-	one millionth of a meter
mm	-	millimeter
MM	-	million
MW	-	megawatt (1,000,000 watts)
MWe	-	megawatt, electrical
MWt	-	megawatt, thermal
ng	-	nanogram
Nm^3	-	normal cubic meter
NO_x	-	nitrogen oxides
NREL	-	National Renewable Energy Laboratory
O_2	-	oxygen
PFBC	-	pressurized fluidized bed combustion
PFBG	-	pressurized fluidized bed gasification

ppb	-	parts per billion
pph	-	pounds per hour
ppm	-	parts per million
ppm_d	-	parts per million, dry
ppm_w	-	parts per million, wet
psia	-	pounds per square inch, absolute
psig	-	pounds per square inch, gage
RDF	-	refuse derived fuel
SEI	-	Southern Electric International
SERBEP	-	Southeastern Regional Biomass Energy Program
SiO_2	-	silicon dioxide, sand
TPD	-	tons per day
TSP	-	total suspended particulates
TVA	-	Tennessee Valley Authority
yr	-	year

6.0 GLOSSARY

Attrition - The fracturing of particles into smaller particles.

Availability - Mathematically, the number of hours that a unit is available for operation in a given time period, divided by the total number of hours in that time period. Availability is normally evaluated on a monthly basis, though it can be evaluated over any period of time.

Bagasse - The waste product from sugar cane processing.

Baghouse - A device in the flue gas path that removes particles from the flue gas. The flue gas passes through a fabric filter or bag which removes the particles from the gas much the same as a household vacuum cleaner bag removes dirt from the air steam. The particulate matter is then remove from the bags. Typically baghouses are separated into several compartments with many bags in each compartment.

Capacity Factor - Mathematically, the total gross unit generation over a time period, divided by the maximum possible generation assuming the unit produced full load over the entire time period.

Cetane rating - An index that measures the ignition delay of diesel fuels, i.e., the time between injection of the fuel and its ignition.

Char - The solid carbon left when volatiles are driven off of a combustible material.

Combustion Efficiency - A measure of how completely well the fuel is burned. The combustion efficiency compares the amount of carbon utilized in the combustion process to the amount of carbon present in the fuel before combustion.

Conventional Units - Non fluidized bed units such as pulverized fuel units, cyclone burner units or stoker units.

Electrostatic Precipitator, ESP - A device in the flue gas path that removes particles from the gas. This device eliminates dust or other fine particles from the flue gas by charging the particles with an electric field and then attracting them to highly charged collector plates. The particles are then removed from the plates and sent to disposal.

Elutriated - As used with regard to fluidized bed technology, the carrying of particles out of the bed or combustor by the flowing gases.

Endothermic - A reaction that absorbs heat.

Entrained - Particle are considered entrained when they are moving with and being carried by a flowing gas or liquid.

Equivalence ratio - The ratio of air supplied divided by the stoichiometric amount of air required.

Eutectic - Combination of compounds which produce low melting points.

Exothermic - A reaction that releases heat.

Fines - Generally materials which are of a size and density to be elutriated from the bed are considered to be fines. This size and density will vary with unit design and operating parameters. Material 30 mesh and smaller is a fair rule of thumb.

Freeboard - In a bubbling fluidized bed unit, the area above the bed. One of the functions of the freeboard is to allow particle ejected from the bed to disengage and fall back into the bed. It is common for combustion of small fuel particles to occur in the freeboard. Technically a freeboard does not exist on a circulating bed units, however the upper region of some circulating fluidized bed combustors, especially when staged, is sometimes referred to as the freeboard.

Heat Rate - The amount of fuel heat input required to produce a given amount of electrical power, commonly expressed in units of Btu/KWh.

Hog Fuel - A mixture of wood and bark, usually reduced to 2-3 inch chips and produced by a wood hog, from which it derives it's name.

Isothermal - Occurring at constant temperature.

Mass flux - Pounds of material flowing per unit area.

Overbed Feed - Material which enters a fluidized bed unit at or above the top of a bubbling bed or the dense bed of a circulating unit.

Primary air - The air that is introduced for the purpose of providing the initial source of oxygen for the combustion or gasification process.

Producer gas - Low or medium Btu gas from a gasifier.

Recycle - The recirculation of material that is carried out of the unit and caught in a collection device (such as a cyclone) back into the unit, primarily for the purpose of increasing combustion efficiency and sorbent utilization.

Recycle ratio - Pounds of material that are recycled back to the unit per pound of fuel fed to the unit.

Residence Time - The time that the fuel molecules spent in the combustor.

Secondary air - The air that is introduced at a point above where the primary air is introduced for the purpose of providing additional air for the combustion or gasification reactions.

Solids gradient - A measure of the variation of the total quantity of solids in a fluidized bed unit over the height of the unit.

Sorbent - A material, such as limestone or dolomite, that is introduced for the purpose of removing unwanted gases, such as SO_2, from the flue gas.

Specific weight loss - Pounds of material lost per pound of original material.

Splash Zone - The interface area between the dense fluidized bed and the freeboard, where the bubbling solids splash up from the bed, and fall back into the bed.

Splitter - A device used to separate the flow of one large pneumatic transport line into several smaller pneumatic transport lines.

Staged Combustion - A process applied to fluidized bed combustion, such that the in-bed combustion takes place in an oxygen lean environment and additional air is added above the bed where the combustion process is completed. This reduces the production of NO_x in the unit with some detrimental effect on sulfur capture.

Stoichiometric - The theoretical amount of air required to completely combust a given amount of fuel.

Superficial velocity - The volumetric flow rate of air or gas divided by the cross sectional flow area.

Underbed Feed - Material which enters a fluidized bed unit at the bottom of the bed or through the combustor floor just above the air distributor.

Volatiles - The gaseous combustible compounds released from a fuel when it is heated.

Water Wall - The inside wall of a unit formed by parallel boiler tubes welded together with a fin between the tubes to form a gas tight enclosure. Water is circulated through the tubes to absorb heat from the process and make steam.

APPENDIX A

LISTING OF FBC BIOMASS INSTALLATIONS

FLUIDIZED BED COMBUSTION FACILITIES

FACILITY	LOCATION	TYPE/APPLICATION	CAPACITY	FUELS	MANUFACTURER	STARTUP
KELLEY ENTERPRISES	PITTSFIELD, MA	PROCESS STEAM	10,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1975
WALNUT PRODUCTS INC.	ST. JOSEPH, MISSOURI	PROCESS STEAM	10,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1975
IOWA–MISSOURI WALNUT CO.	ST. JOSEPH, MISSOURI	PROCESS STEAM	10,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1975
VERMONT STATE HOSPITAL	WATERBURY, VERMONT	PROCESS STEAM	10,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
ROSSI CORPORATION	HIGGANUM, CONNECTICUT	PROCESS STEAM	10,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1979
BOISE CASCADE CORP.	CASCADE, IDAHO	PROCESS STEAM	10,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1980
H&B LUMBER COMPANY	MARION, NC	PROCESS STEAM	15,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1975
CITY OF ESKJO, SWEDEN	ESKJO, SWEDEN	HOT WATER SYSTEM	17,000 LB/HR	RDF, WOOD WASTE	GENERATOR AB	1979
CITY OF ESKJO, SWEDEN	EKSJO, SWEDEN	HOT WATER SYSTEM	17,000 LB/HR	RDF, WOOD WASTE	GENERATOR AB–BFB	1979
N. CHEYENNE PINE CO.	ASHLAND, MONTANA	PROCESS STEAM	20,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1974
MERRITT BROTHERS LUMBER	PRIEST RIVER, IDAHO	PROCESS STEAM	20,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1976
CHAPLEAU LUMBER CO.	CHAPLEAU, ONTARIA	PROCESS STEAM	20,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
GEORGIA PACIFIC CORP.	PHILLIPS, WISCONSIN	DRYER–PROCESS STEAM	20,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
ATLANTA VEBEER CIRO,	BEAUFORT, NC	PROCESS STEAM	20,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
WADE LUMBER COMPANY	WADE, NC	PROCESS STEAM	20,000 LB/HR	BARK	EPI–BUBBLING	1979
NAGEL LUMBER CO., INC.	LAND O'LAKES, WISC.	PROCESS STEAM	20,700 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
OJI PAPER CO. TOMAKAMAI PLANT	HOKKAIDO, JAPAN	ELECTRIC POWER	22,046 LB/HR	PAPER SLUDGE & BARK BLEND WITH FUEL OIL	BABCOCK HITACHI–BFB	1985
KOGAP MANUFACTURING CO.	MEDFORD, OREGON	DRYER–PROCESS STEAM	24,000 LB/HR	HOG FUEL	EPI–BUBBLING	1979
DAW FOREST PRODUCTS	REDMOND, OREGON	DRYER–PROCESS STEAM	25,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1980
WEBSTER LUMBER CO.	BANGOR, WISCONSIN	PROCESS STEAM	26,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
BOISE CASCADE CORP.	EMMETT, IDAHO	PROCESS STEAM	26,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
WILLAMETTE INDUSTRIES	MONCURE, NC.	DRYER–PROCESS STEAM	26,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
WEYERHAEUSER COMPANY	LIVINGSTON, ALABAMA	DRYER–PROCESS STEAM	27,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1977
NORTHWEST MISSISSIPPI JUNIOR COLLEGE	SENATOBIA, MISSISSIPPI	PROCESS STEAM	27,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1980
IDAHO FOREST INDUSTRIES	COEUR d'ALENE, IDAHO	PROCESS STEAM	30,000 LB/HR	WOOD WASTE	EPI–BUBBLING	1973
CITY OF LANDSKRONA, SWEDEN	LANDSKRONA, SWEDEN	HOT WATER SYSTEMS	2 X 34,000 LB/HR	RDF, WOOD, COAL	GENERATOR AB	1983

FLUIDIZED BED COMBUSTION FACILITIES

FACILITY	LOCATION	TYPE/APPLICATION	CAPACITY	FUELS	MANUFACTURER	STARTUP
CITY OF BOLLNAS, SWEDEB	BOLNAS, SWEDEN	HOT WATER SYSTEMS	34,000 LB/HR	RDF, WOOD, PEAT	GENERATOR AB	1983
CITY OF VASTERVIK, SWEDEN	VASTERVIK, SWEDEN	HOT WATER SYSTEM	34,000 LB/HR	RDF, WOOD, PEAT	GENERATOR AB	1984
CITY OF BOLINAS, SWEDEN	BOLINAS, SWEDEN	2 HOT WATER SYSTEMS	34,000 LB/HR	RDF, WOOD, PEAT	GENERATOR AB-BFB	1983
CITY OF ESKJO, SWEDEN	EKSJO, SWEDEN	HOT WATER SYSTEM	34,000 LB/HR	WOOD WASTE	GENERATOR AB-BFB	
CITY OF VASTERVIK, SWEDEN	VASTERVIK, SWEDEN	2 HOT WATER SYSTEMS	34,000 LB/HR	RDF. WOOD, PEAT	GENERATOR AB-BFB	1984
JOBAN INDUSTRY	JAPAN	PROCESS STEAM	35,274 LB/HR	SLUDGE & WOOD WASTE	BABCOCK HITACHI-BFB	1989
DeARMOND STUD MILL	COEUR d'ALENE, IDAHO	PROCESS STEAM	40,000 LB/HR	WOOD WASTE	EPI-BUBBLING	1978
WEYERHAEUSER CO.	RAYMOND, WASH.	BOILER RETROFIT PROCESS STEAM	40,000 LB/HR	WOOD WASTE	EPI-BUBBLING	1975
LIDLAPING	SWEDEN	2 HOT WATER SYSTEMS	40,800 LB/HR	REFUSE, BIOMASS, COAL	GENERATOR AB-BFB	1985
CITY OF LIDLAPING, SWEDEN	LIDLAPING, SWEDEN	HOT WATER SYSTEM	40,800 LB/HR	RFD, BIOMASS, COAL	GENERATOR AB	
SUOMEN KUITULEVY OY	PIHLAVA, FINLAND	COGENERATION-RETROFIT	45,000 LB/HR	100% PEAT 100% WOODWASTE	AHLSTROM-CFB	1979
WESTERN LAKE SUPERIOR SEWAGE SANITATION DISTRICT	DULUTH, MINN.	PROCESS STEAM	2 X 45,000 LB/HR	RDF, DEWATERED SLUDGE OIL WOOD CHIPS	COPELAND	1982
BOISE CASCADE CORP.	KENORA, ONTARIO	BOILER RETROFIT-PROCESS STEAM	45,000 LB/HR	BARK, PAPER SLUDGE	EPI-BUBBLING	1977
DANTANI PLYWOOD CO., LTD. SHIMONOSEKI FACTORY	YAMAGUCHI, JAPAN	PROCESS STEAM	45.000 LB/HR	WOOD CHIPS	EPI-BUBBLING	1987
DANYA	JAPAN	PROCESS STEAM	46,297 LB/HR	WOOD WASTE	TAKUMA	1987
PARENCO PAPER	RENKUM, NETHERLANDS	COGENERATION	48,000 LB/HR	BARK, PAPER/WOOD, REFUSE PELLETS	THYSSEN ENGINEERING GMBH	1985
PARENCO PAPER	RENKUM, NETHERLANDS	COGENRATION	48,400 LB/HR	BARK, PAPER/WOOD, REFUSE PELLETS, DEINKING SLUDGE	THYSSEN ENGINEERING GMBH	1985
WLSSD	DULUH, MINN.	ORICESS STEAN	2 X 49,999 LB/HR	RDF, DEWATEREDSLUDGE, OIL, WOOD CHIPS	COPELAND-BUBBLING	1982
EHIME PLYWOOD INDUSTRIES MATSUIJAMA CITY FACTORY	EHIME, JAPAN	PROCESS STEAM	50,000 LB/HR	BARK CHIPS	EPI-BUFFLING	1988
ANGELHOLM ENERGIVERK	ANGELHOLM, SWEDEN	2 HOT WATER SYSTEM	51,000 LB/HR	WOOD CHIPS, PEAT	GENERATOR AB-BFB	1984
CITY OF SANDVIKEN, SWEDEN	SANDVIKEN, SWEDEN	2 HOT WATER SYSTEMS	51,000 LB/HR	WOOD, COAL, PEAT	GENERATOR AB-BFB	1983

FLUIDIZED BED COMBUSTION FACILITIES

FACILITY	LOCATION	TYPE/APPLICATION	CAPACITY	FUELS	MANUFACTURER	STARTUP
ENSO-GUZEIT OY	VARKAUS, FINLAND	COGENERATION-RETROFIT	55,000 LB/HR	100% WOODWASTE	AHLSTROM-CFB	1983
JAMES RIVER CORPORATION	BELLAMY, ALABAMA	PROCESS STEAM	55,000 LB/HR	WOOD WASTE	EPI-BUBBLING	1980
KAINUUN OSUUSMEIJERI	SOTKAMO, FINLAND	COGENRATION	59,000 LB/HR	100% OIL 67% WOODWASTE	AHLSTROM-CFB	1982
MILOUOT/MILOUMOR HAIFA BAY SETTLEMENT	MOBILE POST ASHRAT, ISRAEL	PROCESS STEAM	60,000 LB/HR	COTTON HULLS/WASTE	EPI-BUBBLING	1982
SOUTH VALLEY POWER JWP/EPI-WILLIAMS	CALEXICO, CAL.	ELECTRIC POWER	64,000 LB/HR	MANURE	EPI-BUBBLING	1989
SUNDSVALLS ENERGIVERK	SUNDSVALL, SWEDEN	COGENERATION	66,000 LB/HR	RDF, PEAT, WOOD WASTE	GOTAVERKEN-CFB	1984
CITY OF VASTERVIK, SWEDEN	VASTERVIK, SWEDEN	2 HOT WATER SYSTEMS	68,000 LB/HR	WOOD, COAL, PEAT	GENERATOR AB-BFB	1983
KATRINEHOLMS ENERGIVERK AB	SWEDEN	HOT WATER SYSTEM	68,000 LB/HR	COAL, WOOD	GENERATOR AB-BFB	1984
KIRBY LUMBER COMPANY	SILSBEE, TEXAS	PROCESS STEAM	70,000 LB/HR	WOOD WASTE	EPI-BUBBLING	1980
NESTLE	KOBE, JAPAN	COGENERATION	88,200 LB/HR	COFFEE GROUNDS	IHI	1986
SANDE PAPER MILL AVS	NORWAY	PROCESS STEAM	88,000 LB/HR	COAL, WOOD WASTE, RDF	GOTAVERKEN-CFB	1985
NESTLE	JAPAN	COGENERATION	93,000 LB/HR	COFFEE GROUNDS	IHI	1983
KERRY COOP	LISTOWEL, IRELAND	COGENERATION	117,000 LB/HR	COALS, PEATS, WOOD CHIPS, SAWDUST	FOSTER WHEELER POWER PRODUCTS LTD.	1984
GENERAL ELECTRIC CO. CALIFORNIA AGRICULTURAL POWER CORPORATION	CHOWCHILLA, CALIFORNIA	ELECTRIC POWER	120,000 LB/HR	AGRICULTURAL WASTE	EPI-BUBBLING	1988
OJI PAPER CO. EBETSU HILL	HOKKAIDO, JAPAN	ELECTRIC POWER	121,254 LB/HR	COAL WASH TAILINGS, BARK, SAWDUST,COAL	BABCOCK HITACHI-BFB	1988
GENERAL ELECTRIC CO. CALIFORNIA AGRICULTURAL POWER CORPORATION	EL NIDO, CALIFORNIA	ELECTRIC POWER	122,000 LB/HR	AGRICULTURAL WASTE	EPI-BUBBLING	1988
KARLSKOGA KOMMUN & NOBEL CHEMATUR	KARLSKOGA, SWEDEN	ELECTRIC POWER	140,000 LB/HR	COAL, PEAT, WOOD WASTE	GOTAVERKEN-CFB	1986
CALEDONIAN PAPER	IRVINE, SCOTLAND, GB	PROCESS STEAM	143,653 LB/HR	100% BARK/COAL 100% COAL	AHLSTROM-CFB	1989
NORHTERN STATES POWER CO.	LaCROSSE, WISC.	ELECTRIC POWER-RETROFIT	150,000 LB/HR	WOOD WASTE	EPI-BUBBLING	1981
NORTHERN STATES POWER CO. FRENCH ISLAND POWER STATION	LaCROSSE, WISC.	ELECTRIC POWER-RETROFIT	2 X 150,000 LB/HR	RDF & WOOD	EPI-BUBBLING	1987
NORTHERN STATES POWER CO. FRENCH ISLAND POWER STATION	LaCROSSE, WISCONSIN	ELECTRIC POWER-RETROFIT	2 X 150,000 LB/HR	RDF & WOOD	EPI	1991
PATRIA PAPIER &	FRANTSCHACH, AUSTRIA	COGENERATION-RETROFIT	154,000 LB/HR	100% BARK	AHLSTROM-CFB	1983

FLUIDIZED BED COMBUSTION FACILITIES

FACILITY	LOCATION	TYPE/APPLICATION	CAPACITY	FUELS	MANUFACTURER	STARTUP
ZELLSTOFF AG				100% OIL 67% BROWN COAL		
PAPYRUS KOPPARFORS AB	FORS, SWEDEN	COGENERATION	159,000 LB/HR	100% BARK 100% PEAT 100% COAL	AHLSTROM-CFB	1985
SITHE ENERGIES FEATHER RIVER PROJECT	MARYSVILLE, CA	ELECTRIC POWER	164,000 LB/HR	WOOD WASTE	B&W-CFB	1986
FORT DRUM	FORT DRUM, NY, USA	COGENERATION	3 X 175,000 LB/HR	100% COAL 100% ANTHRACITE 70% OIL WOOD CHIPS	PYROPOWER-CFB	1989
ULTRAPOWER	CHINESE STATION, CA	ELECTRIC POWER	208,600 LB/HR	WOOD WASTE ORCHARD PRUNINGS	EPI-BUBBLING	1985
METSALITON TEOLLISUUS OY	AANEKOSKI, FINLAND	COGENRATION-RETROFIT	220,000 LB/HR	90% WOODWASTE 90% PEAT 100% COAL 70% OIL	AHLSTROM-CFB	1985
ULTROPOWER	W. ENFIELD, ME	ELECTRIC POWER	220,000 LB/HR	WOOD WASTE	B&W-CFB	1986
ULTROPOWER	JONESBORO, ME	ELECTRIC POWER	220,000 LB/HR	WOOD WASTE	B&W-CFB	1986
ULTROPOWER	ROCKLIN, CA	ELECTRIC POWER	220,000 LB/HR	WOOD WASTE	ABB-COMBUSTION ENGINEERING-CFB	1989
ULTROPOWER	FRESNO, CA	ELECTRIC POWER	220,000 LB/HR	WOOD WASTE	ABB-COMBUSTION ENGINEERING-CFB	1988
THERMO ELECTRON ENERGY SYSTEMS	MENDOTA, CA, USA	ELECTRIC POWER	250,000 LB/HR	BIOMASS	GOTAVERKEN-CFB	1989
THERMO ELECTRON ENERGY SYSTEMS	WOODLAND, CA., USA	ELECTRIC POWER	250,000 LB/HR	BIOMASS	GOTAVERKEN-CFB	1989
CITY OF TACOMA DEPT. OF PUBLIC UTILITIES	TACOMA, WASH.	ELECTRIC POWER-RETROFIT	2 X 250,000 LB/HR	RDF, WOOD, COAL	EPI	1987
DELANO POWER PROJECT THERMA ELECTRON/SCHNEIDER	DELANO, CAL.	ELECTRIC POWER	255,000 LB/HR	AGRICULTURAL WASTE	EPI-BUBBLING	1989
CALIFORNIA AGRICULTURAL POWER COMPANY (CAPCO) FLUOR-DANIEL/ZUM	MADERA, CALIFORNIA	ELECTRIC POWER	260,000 LB/HR	AGRICULTURAL WASTE	EPI-BUBBLING	1989
P.H. GLATFELTER CO.	SPRING GROVE, PA, USA	COGENERATION	400,000 LB/HR	100% COAL/WOOD 55% OIL	PYROPOWER-CFB	1989
RUMFORD COGENERATION CO.	RUMFORD, ME, USA	COGENERATION	2 X 415,000 LB/HR	COAL, BIOMASS, OIL	PYROPOWER-CFB	1990
ENSO-GUZEIT OY	VARKAUS, FINLAND	COGENERATION	476,201 LB/HR	BIOMASS, COAL, OIL	AHLSTROM-CFB	1990
CITY OF TACOMA DEPT. OF PUBLIC UTILITIES	TACOMA, WASH.	ELECTRIC POWER-RETROFIT	536,000 LB/HR	RDF, WOOD, COAL	EPI-BUBBLING	1988

FACILITY	LOCATION	TYPE/APPLICATION	CAPACITY	FUELS	MANUFACTURER	STARTUP
OREBO ENERGI AB	OREBRO, SWEDEN	ELECTRIC POWER	562,000 LB/HR	COAL, PEAT, WOOD WASTE	GOTAVERKEN–CFB	1990
KAINUUN VOIMA OY	KHAANI, FINLAND	ELECTRIC POWER	794,000 LB/HR	100% PEAT, COAL, WOODWASTE, SLUDGE MIXTURE	AHLSTROM–CFB	1989
STUDSVIK	NYKOPING, SWEDEN	HOT WATER BOILER	.85MM Btu/hr	COAL,WOOD, PEAT	STUDAVIK–CFB	1979
CHALMERS UNIVERSITY	GOTHENBURG, SWEDEN	DISTRICT HEATING	5.5MM Btu/hr	BITUMINOUS COAL, BROWN COAL, PEAT & WOOD CHIPS	GENERATOR AB–BFB	1982
GENERATOR ENERGIPRODUKTION	TIDAHOLM, SWEDEN	HOT WATER SYSTEM	9MM Btu/hr	WOOD WASTE	GOTAVERKEN–CFB	1986
STUDSVIK ENERGI	SWEDEN	HOT WATER SYSTEM	10.5MM Btu/hr	PEAT, WOOD CHIPS, COAL	GOTAVERKEN–CFB	1981
BRUCK PAPER CO.	BRUCK, AUSTRIA	PROCESS STEAM	15 MWth	BARK, DEINKING SLUDGE	SIMMERING–GRAZ PAUKER AG–BFB	1984
AVESTA ENERGIVERK	AVESTA, SWEDEN	HOT WATER SYSTEM	52MM Btu/hr	COAL, PEAT, WOOD WASTE	GOTAVERKEN–CFB	1983
BODENS TORRVARME	BODEN, SWEDEN	HOT WATER SYSTEM	70MM Btu/hr	PEAT, WOOD CHIPS	GOTAVERKEN–CFB	1985
OSTERSUNDS FJARRVARME AB	OSTERSUND, SWEDEN	HOT WATER – DISTRICT HEATING	85 MM Btu/hr	100% BARK 100% PEAT 100% COAL	AHLSTROM, CFB	1985
NYKOPINGS VARMEVERK	NYKOPING, SWEDEN	HOT WATER SYSTEM	140MM Btu/hr	COAL, PEAT, WOOD WASTE	GOTAVERKEN–CFB	1984
MOINDALS, ENERGIVERK	MOINDAL, SWEDEN	HOT WATER SYSTEM	140MM Btu/hr	COAL, PEAT, WOOD WASTE	GOTAVERKEN–CFB	1984
UDDEVALLA ENERGIVERK	UDDEVALLA, SWEDEN	HOT WATER SYSTEM	140MM Btu/hr	COAL, PEAT, WOOD WASTE	GOTAVERKEN–CFB	1985
ESKILSTUNA VARMEVERK	ESKILSTUNA, SWEDEN	HOT WATER SYSTEM	170MM Btu/hr	WOOD WASTE, RDF	GOTAVERKEN–CFB	1986
ESKILSTUNA VARMEVERK	ESKILSTUNA, SWEDEN	HOT WATER SYSTEM	170MM Btu/hr	WOOD WASTE, RDF	GOTAVERKEN	1986

APPENDIX B

SUMMARY OF VENDOR SURVEY RESPONSES

Table B–1 (page 1 of 2)
Biomass Fluidized Bed Combustors Commercially Available

Vendor	ABB–CE	B & W	Energy Products	Gotaverken Energy
BFB Size	Not Available	10 Klb/hr & Up	12–360 MBtu/hr	100K–600Klb/hr
CFB Size	30–250 MW	35 Klb/hr & Up	Not Available	Not Available
Combustor Applications	Utility Boiler Industrial Boiler	Utility Boiler Industrial Boiler	Utility Boiler Industrial Boiler Hot Gas Generator	Industrial Boiler Pulp & Paper Industry
Commercial Guarantees Offered	Capacity Efficiency Emissions Aux Pwr Consumption	Capacity Efficiency Emissions	Capacity Efficiency Emissions	Capacity Efficiency Emissions Steam, Temp, & Press
Biomass Fuels	All Types	Any Biomass Coal & Waste Fuels	Wood Waste Paunch Manure Paper Sludge Municiple Sludge Agricultural Waste Plastics Demolition Waste RDF, Coal Shredded Tires	Wood Wood Waste Sludge Bark Waste Paper
Fuel Requirements				
Moisture	10 – 60%	60% max.	60% max.	60 – 65%
Size	1 – 2"	2" x 2"	4" minus	Determined by Feeder
Organics	No Limit			
Fuel Preparation Equipment Required				
Sizing	Hog & Screen		Shredder/Hammermill and Disc Screen	Screening only
Drying	None		Rotary Dryers or Screw Press	Not Required
Storage	Uncovered		Fuel & Plant Dependent	Uncovered
Fuel Feed Equipment Provided	Live Bottom Bin Variable Speed Screw Rotary Valve	Flipper Feeder or Air Swept Spout for Overbed Feed Screw Type In Bed Feeder for Fines	Storage Bins & Unloader Metering Bins Rotary Seal Valves Pneumatic or Mech Conveyors	Metering Screws Day Bin
Emission Equipment or Combustor Emission Levels				
Particulates	.015 lb/MBtu	Baghouse	Varies with Local Emissions Standards	ESP or Baghouse
SO2	90–95% removal	Inbed Capture or Dry Scrubber	Limestone Injection	None or Limestone
NOx	<.15lb/MBtu	SNCR or SCR or None as Required for Project	Ammonia or Urea Injection	None or Staged Combustion
Other			Monitoring Systems	
Bed Temperature	1550–1650 F	1550–1650F	1200–1600 F	1500 F
Fly ash	70%	Varies with Fuel	Mostly Fly ash	95%
Bottom ash	30%			
Bed Material	Limestone Sand Dolomite	Sand Limestone	Ione Grog	Sand
Boiler Efficiency		Varies with Fuel	70 – 75%	72 – 80%
Combustion Eff				99.5%
Energy Conv				
Equipment Lifetime and Maintenance				
Refractory	Variable		15 years	4 – 8 years
Inbed tubes	Not Used	See Survey	5 years	Not Used
Exp Jts & Seals	Variable	Not a Problem	20 years	
Sizing Eqpt		Out of scope	10 years	
Drying Eqpt		Out of scope	10 years	Not Used
Other			20 years	

Table B–1 (page 2 of 2)
Biomass Fluidized Bed Combustors Commercially Available

Vendor	Kvaerner	Pyropower	Tampella
BFB Size	10–150MBtu/hr	20K–600Klb/hr	Up to 1200Klb/hr
CFB Size	10–1000MBtu/hr	100Klb/hr – 400MWe	Open to Discussion
Combustor Applications	Utility Boiler Industrial Boiler	Utility Boiler Industrial Boiler Hot Gas Generator	Utility Boiler Industrial Boiler
Commercial Guarantees Offered	Capacity Efficiency Emissions	Capacity Efficiency Emissions	Capacity Efficiency Emissions See Survey
Biomass Fuels	Wood Peat Agriwaste Lignite	Mill Waste Forest Waste Energy Crops Sludge Peat	Wood Waste Pulp & Papermill Sludge Peat Agricultural Waste Fresh Wood Chips
Fuel Requirements			
Moisture	<60%	65% max	<65% – See Survey
Size	<6"	2"	<12" – See Survey
Organics	TBD	500 ppm max	
Fuel Preparation Equipment Required			
Sizing	Hog/shredder Screens	2" x 0	Screen, Crushing Metal Separation
Drying	Not typical	Sludge Dewatering Presses	Mech. Drying for Bark and Sludge
Storage	Site Dependent	Uncovered	Rain Dependent
Fuel Feed Equipment Provided	Overbed Spreader Stoker Feeder with Pressure Seal & Metering Bin Feed Conveyor	Gravimetric Feeder Drag Chain Conveyors Screw Conveyors	Feed Bin Metering Device Fuel Chutes Rotary Valves Air Swept Spouts Overbed Feeding
Emission Equipment or Combustor Emission Levels			
Particulates	Baghouse	ESP	ESP, Baghouse + Multiclone & Scrubber
SO2	Limestone In Bed Dry Scrubber	None or Sorbent Injection	None or CaOH Injection
NOx	Low Excess Air Staged Combustion	None or Ammonia Injection	Air Staging or SNCR or SCR
Other	Ammonia Injection See Survey		Active Coke Injection
Bed Temperature	1500 F	1400–1700 F	1350 – 1800 F BFB 1450 – 1700 F CFB
Fly ash	95%	10%	99%–BFB, 75%–CFB
Bottom ash	5%	90%	1%–BFB, 25%–CFB
Bed Material	Refractory Sand Limestone	Sand	Sand
Boiler Efficiency	72 – 80%	62 – 75%	
Combustion Eff	99.5%	98.5 – 99.9%	
Energy Conv		15K–19K Btu/Kwh	
Equipment Lifetime and Maintenance			
Refractory	4 – 7 years	BFB:10yr CFB:5yr	5 – 10 years
Inbed tubes	Not Used	Not Used	Not Used
Exp Jts & Seals		15 years +	NA–BFB, Varies–CFB
Sizing Eqpt		20 years	out of scope
Drying Eqpt	Not Used		out of scope
Other		20 years	See Survey

Table B–2 (page 1 of 2)
Biomass Fluidized Bed Gasifiers Commercially Available

Vendor	PRM Energy	Pyropower	Tampella
Gasifier sizes	8.5–300MBtu/hr		60–500MBtu/hr
Gasifier Type	MFBG	BFB & CFB	BFB
Gasifier Applications	Process Heat Maybe Gas Turbine	Process Heat Gas Turbine	Process Heat Gas Turbine IC Engines
Commercial Guarantees Offered	Capacity Efficiency Emissions	Capacity Efficiency Emissions	Capacity Efficiency Emissions
Biomass Fuels	Rice Husks Straw Wood Waste Peat Sludge Shells	Mill Waste Forest Waste Energy Crops Sludge Peat	Wood Chips Crushed Sod Peat Bark
Fuel Requirements			
Moisture	55% max	65% max	15 – 20%
Size	2"	2"	1/2" x 0
Organics		500 ppm max	
Fuel Preparation Equipment Required			
Sizing	Size to 2"	Size to 2" Max	Crusher or Chipper Screens
Drying	Dry to 55% Moisture	Sludge Dewatering Presses	FD Low Press Steam Dryer Heat Exc. & Cyclones
Storage	Uncovered	Uncovered	Covered Storage Silos for Dried Fuel
Fuel Feed Equipment Provided	Metering Bin Conveying Airlock Feeder Weigh Meter	Gravimetric Feeder Drag Chain Conveyors Screw Conveyors	Complete Feed Line Atms Weigh Hopper HP Surge Hopper HP Screw Feeder
Emission Equipment or Combustor Emission Levels			
Particulates	0.03Gr/NM3 – No Control Required	ESP	<5um, <.001gr/ft3 @O2 + 5%
SO2	11 ppm as SO3 Dependent on Fuel	None or Sorbent Injection	Negligible
NOx		None or Ammonia Injection	wSCR <.005lb/MBtu
Bed Temperature	1300 – 1800 F	1400 – 1700 F	1630 – 1740 F @ 290 – 370 psig
Fly ash		10%	60%
Bottom ash	99.9%	90%	40%
Bed Material	None	Sand	Dolomite
Boiler Efficiency	See Survey	62 – 75%	Overall 46.4%
Combustion Eff		98.5 – 99.9%	
Energy Conv		15K–19KBtu/hr	Carbon Conv 99.5%
Equipment Lifetime and Maintenance			
Refractory	12 yr proven	BFB:10yr CFB:5yr	Typical
Inbed Tubes	Not Used	Not Used	Not Used
Exp Jts & Seals	Not Used	15 years +	
Sizing Equipment	NA	20 years	Typical
Drying Equipment	NA		Typical
Other		20 years	

Table B–2 (page 2 of 2)
Biomass Fluidized Bed Gasifiers Commercially Available

Vendor	Battelle / Future Energy	Energy Products	Gotaverken Energy
Gasifier sizes	100–1K dry ton/day	48–300MBtu/hr	94–126MBtu/hr
Gasifier Type	CFB	BFB	CFB
Gasifier Applications	Process Heat Gas Turbine IC Engines	Process Heat	Process Heat
Commercial Guarantees Offered	Capacity Efficiency Emissions	Capacity Efficiency Emissions	Capacity Efficiency Emissions Steam, Temp, & Press
Biomass Fuels	All Types of Biomass Fuels	Wood Waste Paunch Manure Paper Sludge Municiple Sludge Agricultural Waste Plastics Demolition Waste RDF, Coal Shredded Tires	Wood Wood Waste Sludge Bark Waste Paper
Fuel Requirements			
Moisture	No Requirement	60% max.	60 – 65%
Size	2" minus	4" minus	Determined by Feeder
Organics	No Requirement		
Fuel Preparation Equipment Required			
Sizing	Coarse Chop to Yeild 2" minus	Shredder / Hammermill and Disc Screen	Screening Only
Drying	None Required	Rotary Dryers or Screw Press	Not Required
Storage	No Requirement, Site Regulations Vary	Fuel & Plant Dependent	Uncovered
Fuel Feed Equipment Provided	Spread Feed System Lock Hoppers Feed to Base of CFB Gasifier	Storage Bins & Unloader Metering Bins Rotary Seal Valves Pneumatic or Mech Conveyors	Metering Screws Day Bin
Emission Equipment or Combustor Emission Levels			
Particulates	Water Scrubber on Product Gas	Varies with Local Emissions Standards	ESP or Baghouse
SO2	None Typically Required	Limestone Injection	None or Limestone
NOx	None Typically Required	Ammonia or Urea Injection	None or Staged Combustion
Bed Temperature	1500–1600 F Gasifier 1800–1900 F Combustor	1200 – 1600 F	1500 F
Fly ash	100%	mostly fly ash	95%
Bottom ash			
Bed Material	Silica Sand	Ione Grog	Sand
Boiler Efficiency	Cold gas 75%	70 – 75%	72 – 80%
Combustion Eff	Total thermal 90%		99.5%
Energy Conv			
Equipment Lifetime and Maintenance			
Refractory	Unknown	15 years	4 – 8 years
Inbed Tubes	Not Used	5 years	Not Used
Exp Jts & Seals	Not Used	20 years	
Sizing Equipment	Unknown	10 years	
Drying Equipment		10 years	Not Used
Other		20 years	

FBC/FBG VENDOR QUESTIONAIRE
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A GUIDE FOR BIOMASS GENERATORS

1. Contact Information
Name: Edward F. Matthew, Business Development Manager Date: 4-Nov-93

Telephone: (203) 285-9957 Fax: (203) 285-5041

Company Name: ABB Combustion Engineering, Inc.
Address: 1000 Prospect Hill Road
Windsor, Connecticut 06095

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts.

3. Combustors offered (yes/no): BFB_____ , CFB YES .

4. Combustor size range: BFB ________________, CFB 30MW - 250 MW .

5. Combustor applications (yes/no): Utility Boiler YES , Industrial Boiler YES , Hot gas generator _______, Other (describe)________________.

6. Gasifiers offered (yes/no): BFB _____, CFB _____.

7. Gasifier size ranges: BFB ________________, CFB________________

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment _____, gas turbine _____, IC Engine _____.

9. Commercial guarantees offered (yes/no): Capacity YES , efficiency YES , emissions YES , other Aux. Power Consumption .

10. Acceptable types of biomass fuels systems designed for:
All types for CFB.

11. Required fuel characteristics: % moisture 10 - 60 , size range 1 - 2" max , Organics (Na, K, ...) No Limit , Other

12. Fuel preparation equipment typically required:

Sizing: 1 - 2" Max. Hogging / Screening

Drying: Not Required

Yard storage: Covered _____, Uncovered X , Comment:

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed): Live Bottom Bin
Variable Speed Screws
Rotary Valve

14. Emission control and/or gas clean–up equipment typically specified or required for:

Particulates: .015 lb/MM Btu

SO2: 90 – 95% Removal

NOx: <.15 lb/MM Btu

Other:

15. Performance:

Bed Temperature Range: 1550 – 1650 °F

Typical ash distribution (flyash/bottom ash): 70 / 30

Bed makeup material: Limestone, Sand, Dolomite, etc.

Typical efficiencies (boiler, combustion, energy conversion): 65 – 85%

Other:

16. Typical equipment maintenance items and replacement frequencies (lifetimes):
Refractory: Variable

Inbed tubes: None

Combustor/Gasifier expansion joints and seals: Variable

Sizing equipment:

Drying equipment:

Other:

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY		HIGH CAPACITY	
System Capacity	30 MW		250 MW	
Equipment	Capital Cost ($)	Install. Cost ($)	Capital Cost ($)	Install. Cost ($)
FB Combustor *	~ 12 million	~ 4.6 million	~ 57.5 million	~ 17 million
Fuel Prep System	N. A.	N. A.	N. A.	N. A.
Emission Controls	N. A.	N. A.	N. A.	N. A.
FB Gasifier	N. A.	N. A.	N. A.	N. A.
Fuel Prep System	N. A.	N. A.	N. A.	N. A.
Gas Cleanup	N. A.	N. A.	N. A.	N. A.

* Complete scope from fuel silo outlet to stack.

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1. Contact Information
Name: David Gibbs Date: 10/25/93

Telephone: (216) 860-1029 Fax: (216)860-6590

Company Name: Babcock & Wilcox
Address: 20 S. Van Buren Ave PO Box 351
Barberton, Ohio 44203

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts.

3. Combustors offered (yes/no): BFB YES , CFB YES .

4. Combustor size range: BFB Min – 10,000 lb/hr Steam Flow , CFB Min – 35,000 lb/hr Steam Flow .

5. Combustor applications (yes/no): Utility Boiler YES , Industrial Boiler YES , Hot gas generator No ,
Other (describe) ____.

6. Gasifiers offered (yes/no): BFB No , CFB No .

7. Gasifier size ranges: BFB N/A , CFB N/A .

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment ___, gas turbine ___,
IC Engine ___.

9. Commercial guarantees offered (yes/no): Capacity YES , efficiency YES , emissions YES ,
other ____.

10. Acceptable types of biomass fuels systems designed for:
Virtually Any Type Of Biomass Plus Coal & Waste Fuels Of All Types

11. Required fuel characteristics: % moisture ___, size range ___, Organics (Na, K, ...)
___, Other ___
Max. 60% Moisture Without Auxiliary Fuel Input

12. Fuel preparation equipment typically required:

Sizing: Nominal 2" x 2" For Wood/Bark

Drying: ____

Yard storage: Covered __, Uncovered ___, Comment: ____

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed):
Typically Flipper Feeder Or Air Swept Spout For OverBed,
May Be Screw Type In Bed Feeder For Very Fine Fuels.

14. Emission control and/or gas clean–up equipment typically specified or required for:

Particulates: Baghouse

SO2: Dry Scrubber Or In Bed Capture (Fuel Dependent)

NOx: SNCR or SCR or None ; As Required For Project

Other:

15. Performance:

Bed Temperature Range: Generally 1550 F To 1650 F

Typical ash distribution (flyash/bottom ash): Varies With Fuel

Bed makeup material: Sand Or Limestone In Most Cases

Typical efficiencies (boiler, combustion, energy conversion): Varies With Fuel

Other:

16. Typical equipment maintenance items and replacement frequencies (lifetimes):
Refractory:

Inbed tubes: Do Not use In Bed Tube Bundles ; Do Use In Bed Panel Sections When Required to Remove Heat from Bed which have not req'd significant maintenance

Combustor/Gasifier expansion joints and seals: Have Not Been A Problem

Sizing equipment: Generally Not In Our Scope

Drying equipment: Generally Not In Our Scope

Other:

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY		HIGH CAPACITY	
System Capacity				
Equipment	Capital Cost ($)	Install. Cost ($)	Capital Cost ($)	Install. Cost ($)
FB Combustor	Fuel & Project Specific		Fuel & Project Specific	
Fuel Prep System				
Emission Controls				
FB Gasifier				
Fuel Prep System				
Gas Cleanup				

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1. Contact Information
   Name: Thomas H. Daniels, Gen. Mgr. Marketing & Sales   Date: 11/30/93

   Telephone: (208) 765–1611   Fax: (208) 765–0503

   Company Name: Energy Products of Idaho
   Address: 4006 Industrial Avenue
   Coeur d'Alene, Idaho 83814

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts.

3. Combustors offered (yes/no): BFB YES , CFB No .

4. Combustor size range: BFB 12 MM Btu/Hr – 360 MM Btu/Hr , CFB N/A .

5. Combustor applications (yes/no): Utility Boiler YES , Industrial Boiler YES , Hot gas generator Yes , Other (describe) Thermal Fluid Heating .

6. Gasifiers offered (yes/no): BFB Yes , CFB No .

7. Gasifier size ranges: BFB 48 MM Btu/Hr – 300 MM Btu/Hr, , CFB N/A .

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment Yes , gas turbine No , IC Engine No .

9. Commercial guarantees offered (yes/no): Capacity YES , efficiency YES , emissions YES , other ______ .

10. Acceptable types of biomass fuels systems designed for: Wood Waste, Paunch Manure, Paper Sludge, Municipal Sludge, Agricultural Waste, Plastics, Demolition Waste, RDF, Coal, Shredded Tires

11. Required fuel characteristics: % moisture 60 , size range 4" Minus , Organics (Na, K, ...) ______ , Other ______

12. Fuel preparation equipment typically required:

    Sizing: Shredder Or Hammermill With Disc Screen For Sizing

    Drying: Rotary Dryers Or Screw Press For Sludge Or Paunch Manure Where Required Due To Excessive Moisture Content.

    Yard storage: Covered X , Uncovered X , Comment: Depends On Fuel & Plant Location

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed): Storage Bins And Unloader, Metering Bins, Rotary Seal Valves, Pneumatic Or Mechanical Conveyors To Under/Over Bed Feed Ports As Dictated By Fuel Sizing.

14. Emission control and/or gas clean–up equipment typically specified or required for:

Particulates: Cyclones, Multiclones, Baghouse, ESP's, ESB's, Wet Scrubbers (As required to meet local emission requirements).

SO2: Limestone Injection

NOx: Ammonia Or Urea Injection

Other: Continous Emissions Monitoring Systems

15. Performance:

Bed Temperature Range: 1200 Deg. F – 1600 Deg. F

Typical ash distribution (flyash/bottom ash): Fly Ash

Bed makeup material: Ione Grog

Typical efficiencies (boiler, combustion, energy conversion): 70 – 75 %

Other:

16. Typical equipment maintenance items and replacement frequencies (lifetimes):

Refractory: 15 Years

Inbed tubes: 5 Years

Combustor/Gasifier Expansion joints and seals: Fabricated Stainless Steel & Fabric – 20 Years

Sizing equipment: Shredders, Hammermills, Disc Screens, Trommels – 10 Years

Drying equipment: Rotary Drum Dryers, Screw Presses – 10 Years

Other: Fans, Boilers, Multiclones, Baghouses – 20 Years

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY			HIGH CAPACITY	
System Capacity	24 MM Btu/Hr			250 MM Btu/Hr	
Equipment	Capital Cost ($)	Install. Cost ($)		Capital Cost ($)	Install. Cost ($)
FB Combustor	$1,200,000	$300,000		$10,000,000	$3,500,000
Fuel Prep System	None	N/A		$4,000,000	$1,000,000
Emission Controls	None	N/A		Incl. In Above	Incl. In Above
FB Gasifier	$1,200,000	$300,000		N/A	N/A
Fuel Prep System	None	N/A		N/A	N/A
Gas Cleanup	None	N/A		N/A	N/A

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1. Contact Information
   Name: Ron Bailey   Date: 12/02/93

   Telephone: (501) 767–2100   Fax: (501) 767–6968

   Company Name: PRM Energy Systems Inc.
   Address: 504 Windamere Terrace
   Hot Springs, Arkansas 71913

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts.

3. Combustors offered (yes/no): BFB ___, CFB Modified Fluid Bed Gasifier.

4. Combustor size range: BFB ________, CFB ________.

5. Combustor applications (yes/no): Utility Boiler ' , Industrial Boiler __, Hot gas generator ___, Other (describe) ________.

6. Gasifiers offered (yes/no): BFB __, CFB MFBG.

7. Gasifier size ranges: MFBG 8.5 MMBtu/Hr – 300 MMBtu/Hr, CFB ________.

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment Yes, gas turbine Maybe, IC Engine No

9. Commercial guarantees offered (yes/no): Capacity YES, efficiency YES, emissions YES, other ________.

10. Acceptable types of biomass fuels systems designed for: Rice Husks, Straw, Wood Wastes Up To 55 % Moisture, Peat, Sludge, Shells, Etc

11. Required fuel characteristics: % moisture 0 – 55 %, size range 2 Inch, Organics (Na, K, ...) ________, Other ________

12. Fuel preparation equipment typically required:

    Sizing: Fed By Screw Conveyor – Usually 2" Dia.

    Drying: 55 % Moisture Max.

    Yard storage: Covered ___, Uncovered X, Comment: ________

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed): Metering Bin, Conveying, Airlock Feeder, Weigh Meter

14. Emission control and/or gas clean-up equipment typically specified or required for:

Particulates: 0.03 gr/NM^3 – No Control Required

SO2: 11 ppm as SO_3

NOx: Depend On Fuel

Other:

15. Performance:

Bed Temperature Range: 1300 F – 1800 F

Typical ash distribution (flyash/bottom ash): 99.9 % Bottom

Bed makeup material: None

Typical efficiencies (boiler, combustion, energy conversion):
Conversion: Dry – 85 % of Input Btu To Boiler (65 % green)

Other:

16. Typical equipment maintenance items and replacement frequencies (lifetimes):
Refractory: At Least 12 Yr. Of Proven Life

Inbed tubes: None

Combustor/Gasifier expansion joints and seals: None

Sizing equipment: N/A

Drying equipment: N/A

Other:

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY		HIGH CAPACITY	
System Capacity	8 Mil Btu/Hr input		100 Mil Btu/Hr input	
Equipment	Capital Cost ($)	Install. Cost ($)	Capital Cost ($)	Install. Cost ($)
FB Combustor				
Fuel Prep System				
Emission Controls				
FB Gasifier	150,000	200,000 *	850,000	1,000,000 *
Fuel Prep System	N/A			
Gas Cleanup	N/A			

* Total Installed Costs.

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1. Contact Information
   Name: John Barnes   Date: 12/14/93

   Telephone: (619) 458-3050   Fax: (619) 458-0653

   Company Name: Pyropower Corporation
   Address: 8925 Rehco Road
   San Diego, Ca 92121

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts.

3. Combustors offered (yes/no): BFB YES, CFB Yes-with coal.

4. Combustor size range: BFB 20,000 lb/hr - 600,000 lb/hr, CFB 100,000 lb/hr - 400 MWe.

5. Combustor applications (yes/no): Utility Boiler Yes, Industrial Boiler Yes, Hot gas generator Yes,
   Other (describe) ______

6. Gasifiers offered (yes/no): BFB Yes, CFB Yes.

7. Gasifier size ranges: BFB ______, CFB ______.

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment Yes, gas turbine Yes,
   IC Engine ____

9. Commercial guarantees offered (yes/no): Capacity YES, efficiency YES, emissions YES,
   other ______

10. Acceptable types of biomass fuels systems designed for: Mill Waste, Forest Waste,
    Energy Crops, Sludge, Peat

11. Required fuel characteristics: % moisture 65 % Max, size range 2", Organics (Na, K, ...)
    500 ppm max, Other ______
    With Higher Moisture Content - More Supplementary Firing Is Needed

12. Fuel preparation equipment typically required:

    Sizing: 2" x 0

    Drying: Dewatering 65% Max Moisture
    Typical Pulp & Paper Mill Bark Presses And Sludge Dewatering System Can Reach 55 - 60 % Moisture.

    Yard storage: Covered ___, Uncovered X, Comment: No Comment.

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed): Gravimetric Feeders, Drag Chain Conveyors, Screw Conveyors

14. Emission control and/or gas clean-up equipment typically specified or required for:

Particulates: ESP

SO2: None Usually, Sorbent Injection If Required.

NOx: None Usually, Ammonia Injection If Required.

Other: None

15. Performance:

Bed Temperature Range: 1400°F – 1700°F

Typical ash distribution (flyash/bottom ash): 10/90

Bed makeup material: Sand

Typical efficiencies (boiler, combustion, energy conversion): Boiler 62 – 75 %
Combustion: 98.5 – 99.9 % Energy: 15,000 – 19,000 Btu/Kwh

Other:

16. Typical equipment maintenance items and replacement frequencies (lifetimes):

Refractory: CFB: 5 Years BFB: 10 Years +
With Annual Maintenance

Inbed tubes: N/A

Combustor/Gasifier expansion joints and seals: 15 Years +

Sizing equipment: 20 Years with Annual Maintenance

Drying equipment:

Other: Sludge Dewatering: 20 Years With Annual Maintenance

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY		HIGH CAPACITY	
System Capacity	50,000 Lb/Hr Steam		300,000 Lb/Hr Steam	
Equipment	Capital Cost ($)	Install. Cost ($)	Capital Cost ($)	Install. Cost ($)
FB Combustor	4.5 Million	1.1 Million	16.8 Million	5.6 million
Fuel Prep System	1.0 Million	.3 Million	2.5 Million	.6 Million
Emission Controls	Included	Included	Included	Included
FB Gasifier	9.0 Million	2.3 Million	N/A	N/A
Fuel Prep System	2.0 Million	.5 Million	N/A	N/A
Gas Cleanup	Included	Included	N/A	N/A

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1. Contact Information
   Name: Eric Wasson Date: 12/14/93

   Telephone: (704) 541-1453 Fax: (704) 543-8172

   Company Name: Gotaverken Energy Systems Inc.
   Address: 8008 Corporate Center Dr.
   Charlotte, NC 28226

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts.

3. Combustors offered (yes/no): BFB YES , CFB No .

4. Combustor size range: BFB 100,000 - 600,000 lb steam/hr , CFB N/A .

5. Combustor applications (yes/no): Utility Boiler No , Industrial Boiler Yes , Hot gas generator No , Other (describe) Pulp & Paper

6. Gasifiers offered (yes/no): BFB No , CFB Yes .

7. Gasifier size ranges: BFB N/A , CFB 30 - 40 MW (t) .

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment Yes , gas turbine No , IC Engine No .

9. Commercial guarantees offered (yes/no): Capacity YES , efficiency YES , emissions YES , other Steam Temp., Press. .

10. Acceptable types of biomass fuels systems designed for: Wood, Wood Waste, Sludge, Bark, Waste Paper

11. Required fuel characteristics: % moisture 60 - 65 , size range * , Organics (Na, K, ...) ____ , Other
    * What Can Be Fed Can Be Fired.

12. Fuel preparation equipment typically required:

    Sizing: Screening only.

    Drying: Not Req'd.

    Yard storage: Covered ___ , Uncovered X , Comment: Wet Fuel Is O.K.

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed): Metering Screws, Day Bin.

14. Emission control and/or gas clean–up equipment typically specified or required for:

Particulates: Electr. Precip. or Baghouse

SO2: None / Limestone

NOx: None / Staged Combustion

Other:

15. Performance:

Bed Temperature Range: 1500 °F +/–

Typical ash distribution (flyash/bottom ash): 95 % flyash

Bed makeup material: Sand

Typical efficiencies (boiler, combustion, energy conversion): Boiler, 72 – 80 %
Comb, 99.5 %

Other:

16. Typical equipment maintenance items and replacement frequencies (lifetimes):
Refractory: 4 – 8 yrs

Inbed tubes: N/A

Combustor/Gasifier expansion joints and seals:

Sizing equipment:

Drying equipment: N/A

Other:

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY			HIGH CAPACITY	
System Capacity					
Equipment	Capital Cost ($)	Install. Cost ($)		Capital Cost ($)	Install. Cost ($)
FB Combustor					
Fuel Prep System					
Emission Controls					
FB Gasifier					
Fuel Prep System					
Gas Cleanup					

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1. Contact Information
Name: Michael L. Murphy   Date: 12-13-93

Telephone: (208) 664-4258   Fax: (208) 664-3615

Company Name: Kvaerner Environmental Tech
Address: 250 Northwest Blvd. Suite 203
Coeur d'Alene, ID 83814

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts.

3. Combustors offered (yes/no): BFB YES, CFB YES.

4. Combustor size range: BFB 10 - 150 MM Btu/ Hr, CFB 10 - 1000 MM Btu/Hr.

5. Combustor applications (yes/no): Utility Boiler YES, Industrial Boiler YES, Hot gas generator No, Other (describe) ______.

6. Gasifiers offered (yes/no): BFB No, CFB No.

7. Gasifier size ranges: BFB ______, CFB ______.

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment ___, gas turbine ___, IC Engine ___.

9. Commercial guarantees offered (yes/no): Capacity YES, efficiency YES, emissions YES, other ______.

10. Acceptable types of biomass fuels systems designed for:
Wood, Peat, Agriwaste, lignite.

11. Required fuel characteristics: % moisture < 60%, size range <6", Organics (Na, K, ...) TBD, Other ______

12. Fuel preparation equipment typically required:

Sizing: Fuel Dependent - Hogging / Screening / Shredding typically.

Drying: Not Typical

Yard storage: Covered X, Uncovered X, Comment: Dependent on site conditions.

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed): Overbed spreader stoker feeder w/ pressure seal and metering &/or feed conveyor.

14. Emission control and/or gas clean–up equipment typically specified or required for:

Particulates: Baghouse

SO2: Limestone in–bed plus dry scrubber, if req'd.

NOx: Low excess air, staged combustion, ammonia injection

Other: Chlorides – lime injection dry scrubber
Mercury – Low temp, activated C injection

15. Performance:

Bed Temperature Range: 1550 °F +/–

Typical ash distribution (flyash/bottom ash): 95% flyash

Bed makeup material: Refactory sand or limestone

Typical efficiencies (boiler, combustion, energy conversion):
Boiler – 72 – 80% (dep. on fuel), combustion – 99.5%

Other:

16. Typical equipment maintenance items and replacement frequencies (lifetimes):
Refractory: 4 – 7 yrs

Inbed tubes: None typically

Combustor/Gasifier expansion joints and seals:

Sizing equipment:

Drying equipment: N. A.

Other:

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY			HIGH CAPACITY	
System Capacity	CFB* 100 MM Btu/Hr in			CFB 250 MM Btu/Hr in	
Equipment	Capital Cost ($)	Install. Cost ($)		Capital Cost ($)	Install. Cost ($)
FB Combustor *	9.0 MILLION	2.5 MILLION		16.0 MILLION	5.0 MILLION
Fuel Prep System	.5 MILLION	.2 MILLION		1.5 MILLION	.5 MILLION
Emission Controls	inc.			inc.	
FB Gasifier					
Fuel Prep System					
Gas Cleanup					

*Costs for 100 MM Btu/Hr BFB about 10% less than CFB.

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1. Contact Information
Name: Mike Schmid Date: 12/06/93

Telephone: (717) 327-4457 Fax: (717) 327-4450

Company Name: Tampella Power Corp.
Address: 2600 Reach Road
Williamsport, Pa 17701

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts. *

3. Combustors offered (yes/no): BFB _, CFB_.

4. Combustor size range: BFB ______, CFB ______.

5. Combustor applications (yes/no): Utility Boiler __, Industrial Boiler __, Hot gas generator ___, Other (describe) ______.

6. Gasifiers offered (yes/no): BFB Yes, CFB No.

7. Gasifier size ranges: BFB 60 To 500 MM Btu/Hr (LHV), CFB N/A.

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment Yes, gas turbine Yes, IC Engine Yes.

9. Commercial guarantees offered (yes/no): Capacity YES, efficiency YES, emissions YES, other According To Site Specific Requirements.

10. Acceptable types of biomass fuels systems designed for: Wood Chips (hard wood / soft wood)
Crushed Sod Peat
Bark

11. Required fuel characteristics: % moisture 15 - 20, size range 1/2" x 0, Organics (Na, K, ...) ______, Other ______

12. Fuel preparation equipment typically required:

Sizing: Crusing Or Chipping Equipment To 1/2" x 0
Screening Of Oversized Particles

Drying: Superheated, Low Pressure Steam Dryer
With Circulation Fan, Heat Exchangers
And Cyclones

Yard storage: Covered Yes, Uncovered Yes, Comment: Covered Storage
Silos For Dryed Biomass

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed): Complete Biomass Feeding Line From Atmospheric Weigh Hopper To High Pressure Surge Hopper And Feeding Screw To Gasifier

14. Emission control and/or gas clean–up equipment typically specified or required for:

Particulates: < 5 um < 0.001 gr/ft3 (O_2 = 5 %)

SO2: Negligible

NOx: (With SCR) < 0.05 Lb/MM Btu

Other:

15. Performance:

Bed Temperature Range: 1630 – 1740°F @ 290 – 370 psig

Typical ash distribution (flyash/bottom ash): 60 % / 40 %

Bed makeup material: Dolomite

Typical efficiencies (boiler, combustion, energy conversion): Carbon Conversion > 99.5 %
Overall Efficiency 46.4 %

Other:

16. Typical equipment maintenance items and replacement frequencies (lifetimes): – only pilot plant experience

Refractory: Typical

Inbed tubes: N/A

Combustor/Gasifier Expansion joints and seals:

Sizing equipment: Typical

Drying equipment: Typical

Other:

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY		HIGH CAPACITY	
System Capacity	N/A		N/A	
Equipment	Capital Cost ($)	Install. Cost ($)	Capital Cost ($)	Install. Cost ($)
FB Combustor	N/A	N/A	N/A	N/A
Fuel Prep System	N/A	N/A	N/A	N/A
Emission Controls	N/A	N/A	N/A	N/A
FB Gasifier	N/A	N/A	N/A	N/A
Fuel Prep System	N/A	N/A	N/A	N/A
Gas Cleanup	N/A	N/A	N/A	N/A

* – 60 MM Btu/hr (Fuel Input) Pilot Plant Has Gasified > 1200 Tons of Biomass thru 12/93.
Plant Contact: Enviropower Inc (Finland)/Risto Hokajarvi +358 31 241 3555 Fax: +358 31 241 3599

FBC/FBG VENDOR QUESTIONAIRE
FLUIDIZED BED COMBUSTION AND GASIFICATION
A GUIDE FOR BIOMASS GENERATORS

1. Contact Information Name: Brian Martin, CFB Product Manager
Jukka Louhimo, BFB Product Manager — Date: October 29, 1993

Telephone: (717) 326-3361 — Fax: (717) 327-3141

Company Name: Tampella Power Corporation
Address: 2600 Reach Road, (P. O. Box 3308)
Williamsport, PA 17701-0308

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts.

3. Combustors offered (yes/no): BFB YES, CFB YES.

4. Combustor size range: BFB up to ~ 1,200,000 lb/hr, CFB ______.

5. Combustor applications (yes/no): Utility Boiler YES, Industrial Boiler YES, Hot gas generator No, Other (describe) ______.

6. Gasifiers offered (yes/no): BFB YES, CFB No. (See questionaire by Mike Schmid, Tampella Power Corp. for info. on gasifiers.)

7. Gasifier size ranges: BFB ______, CFB ______

8. Gasifier applications, I.e. fuel gas for (yes/no): process heating equipment ______, gas turbine ______, IC Engine ______.

9. Commercial guarantees offered (yes/no) for combustion systems: Capacity YES, efficiency YES, emissions YES, other Availability, turn-down ratio, load swing, unsupported firing.

10. Acceptable types of biomass fuels systems designed for:
Wood wastes, pulp & paper, mill sludges, peat, agricultural wastes, fresh wood chips

11. Required fuel characteristics: % moisture < 65* (<55 - 60**), size range <12 in (side + S + S), Organics (Na, K, ...) TBD, Other
Ash melting temp. > 1900 °F

* For fuel blend, individual fuels can be wetter BFB
** CFB

12. Fuel preparation equipment typically required:

Sizing: Screening, crushing, metal separation (magnet) equipment

Drying: Mechanical drying required for bark and sludge (typical)

Yard storage: Covered X, Uncovered X, Comment: Depends on rain amount

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed):

Feed bin, metering device, fuel chutes, rotary valves, air swept spouts – overbed feeding

14. Emission control and/or gas clean–up equipment typically specified or required for:

Particulates: ESP, baghouse + multiclone and scrubber

SO2: Not usually needed due to low sulphur in fuel
limestone / CaOH – injection possible

NOx: Primary method : Air staging
SNCR or SCR if needed

Other: Active coke injection before the baghouse (dioxins and HCl)

15. Performance:

	BFB	CFB
Bed Temperature Range:	1350 – 1800 °F	1450 – 1700 °F
Typical ash distribution (flyash/bottom ash):	99% / 1%	75% / 25%

Bed makeup material: Sand

Typical efficiencies (boiler, combustion, energy conversion): Comb. Efficiency 99.5%
(Boiler efficiency depends on fuel and selected exit gas temperature.)

Other: For CFB ~ 98% when coal is fired with biomass

16. Typical equipment maintenance items and replacement frequencies (lifetimes):

Refractory: > 5...10 years maintenance period

Inbed tubes: Not furnished

Combustor/Gasifier expansion joints and seals: NA for BFB / CFB: Depends on service

Sizing equipment: Normally out of our scope

Drying equipment: Normally out of our scope

Other: Fluidizing grid : nozzles don't need service, temperature probes 1 – 4 years

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

NA	LOW CAPACITY			HIGH CAPACITY	
System Capacity					
Equipment	Capital Cost ($)	Install. Cost ($)		Capital Cost ($)	Install. Cost ($)
FB Combustor *					
Fuel Prep System					
Emission Controls					
FB Gasifier					
Fuel Prep System					
Gas Cleanup					

FBC/FBG VENDOR QUESTIONAIRE
FLUIDIZED BED COMBUSTION AND GASIFICATION
A GUIDE FOR BIOMASS GENERATORS

1. Contact Information
Name: Mark Paisley / Milton Farris Date: 12/16/93

Telephone: (614) 424-4958 / 404-612-5575 Fax: (614) 424-3321 / 404-612-5560

Company Name: Battelle / Future Energy Resources
Address: 505 King Ave, Columbus, OH 43201 / 3350 Cumberland Circle NW, Suite 1500, Atlanta, GA 30339

2. Experience: Attach list of equipment sold with name of client, capacity, fuel types, current operating status (operating, mothballed, retired), and names and phone numbers of plant contacts. No commercial facilities

3. Combustors offered (yes/no): BFB ______, CFB ______

4. Combustor size range: BFB ______, CFB ______.

5. Combustor applications (yes/no): Utility Boiler ______, Industrial Boiler ______, Hot gas generator ______, Other (describe) ______.

6. Gasifiers offered (yes/no): BFB ______, CFB yes.

7. Gasifier size ranges: BFB ______, CFB 100 to 1000 drs tons/day

8. Gasifier applications, i.e. fuel gas for (yes/no): process heating equipment yes, gas turbine yes, IC Engine yes.

9. Commercial guarantees offered (yes/no): Capacity ______, efficiency ______, emissions ______, other Please obtain information from Future Energy.

10. Acceptable types of biomass fuels systems designed for: All types of biomass fuels

11. Required fuel characteristics: % moisture no requirement, size range 2" minus, Organics (Na, K, ...) no requirement, Other no other fuel requirements.

12. Fuel preparation equipment typically required:

Sizing: Coarse chop to yield 2" minus

Drying: None required

Yard storage: Covered x, Uncovered x, Comment: No requirement - storage as required by local regulations

13. List fuel feed equipment normally provided (metering, conveying, pressure seal, distribution, under/over bed): Spred feed system, lock hoppers, feed to base of CFB gasifier.

14. Emission control and/or gas clean-up equipment typically specified or required for:

Particulates: Water scrubber on product gas

SO2: None typically required

NOx: " " "

Other:

15. Performance:

Bed Temperature Range: Gasifier 1500 - 1600 F combustor 1800 - 1900 F

Typical ash distribution (flyash/bottom ash): 100% fly ash

Bed makeup material: silica sand

Typical efficiencies (boiler, combustion, energy conversion): cold gas efficiency - 75%
Total thermal efficiency including heat recovery - 90%

Other: Produces 500 Btu/SCF product gas - does not use oxygen

16. Typical equipment maintenance items and replacement frequencies (lifetimes):

Refractory: Unknown

Inbed tubes: No in bed tubes

Combustor/Gasifier expansion joints and seals: No expansion joints

Sizing equipment: Unknown - expected maintenance equal to wood fired boiler systems

Drying equipment:

Other:

17. Costs: (Indicate approximate capital and installation costs for following equipment typically in your scope of supply, including instruments and controls. Select two different, but typical capacity systems.)

	LOW CAPACITY		HIGH CAPACITY	
System Capacity	400 wet TPD			
Equipment	Capital Cost ($)	Install. Cost ($)	Capital Cost ($)	Install. Cost ($)
FB Combustor				
Fuel Prep System				
Emission Controls				
FB Gasifier	$10 million	incl. in cap.		
Fuel Prep System	$4-6 million	incl. in cap.		
Gas Cleanup	included in	gasifier cost.		

OWNER/OPERATOR QUESTIONAIRE
FLUIDIZED BED COMBUSTION AND GASIFICATION
A GUIDE FOR BIOMASS GENERATORS

1. Contact Information
Name: W. S. Bulpitt

Telephone: (404) 392–7634 Fax: (404) 393–9871

Company Name: Southern Electric International, Inc.
Address: 100 Ashford Central N.
Atlanta, Ga 30338

2. Energy Forms Produced

		(yes/no)	capacity
Steam for:	process heat		Btu or lb/hr
	electricity		kw
Gas for:	process heat	Y	200 MM Btu/hr
	electricity		kw

3. Plant Description
(Attach a block flow diagram and any brochures or written descriptive material, if available)

a. Fluidized Bed Combustor/Boiler or Gasifier (Check the appropriate spaces)

Bubbling Fluidized Bed (BFB) Combustor/Boiler ____ or Gasifier _x_.
Circulating Fluidized Bed (CFB) Combustor/Boiler ____ or Gasifier ____.
Gasifier supplies fuel gas to Gas Turbine ___, Internal Combustion Engine ___, or other process heating equipment _x_. If "other", state type: Lime Kilns, Boiler
Outlet Steam or Fuel Gas Conditions: 1400 °F, 1 psig.
Combustor or Gasifier Manufacturer: Power Recovery Systems

b. Fuel Preparation System

Does the fuel preparation system have the following (yes/no, and circle equipment you have):
1. Fuel sizing equipment (shredder, chipper, hogger, crusher, other)? Yes Is pre–sized fuel used? No
2. Fuel classifing equipment (vibrating or disc screen, air classifier, other)? ______
3. Fuel drying equipment (rotary drum, flulidized bed, flash, other)? ______
4. Pelletizing or briquet equipment? No
5. Fuel blending equipment? No

c. Fuel Gas Cleanup

Check spaces provided if special precautions or equipment are required for: fuel gas cooling ___, particulate control _x_, alkali metals control ___, other controls ___ for protection of gas turbine or internal combustion engine components. If "other" checked, list control equipment required: ______

d. Emission Control

Check spaces provided if control equipment is required for the listed polutants in gases discharged from the combustor/boiler, gas turbine, internal combustion engine, or other process heating equipment:

Particulate matter ___, SO2 ___, NOx ___, CO ___, Other ___. If "Other" checked, list pollutants: NONE

What control equipment is used? baghouse ____, electrostatic precipitator ____, scrubber ____, other (list) ______.

e. Ash Disposal

1. How is ash disposed: landfilled onsite _x_, offsite ___, or used by another party _x_.
2. Is equipment required for ash cooling _____, conveying _____, dust control ______.

4. Fuels, Sorbents, & Bed Makeup

Fuels used: wood chips _x_, sawdust _x_, bagasse _____, MSW_____, Straw _____, tree trimings _____, other (list) ____BARK____

Sorbents: limestone _____, dolomite _____, other (list) ______________.

Bed Material Makeup: sand _x_, limestone _____, other (list) ______________

5. Environmental Permits Required

Air (yes/no): _Yes_. Solid waste (yes/no): _No_. Other (list) ______________.

Air permit parameters limited: SO2 _____, NOx _____, CO _____, Particulate matter _x_, Other (list) VOC's from dryer

Results of most recent emissions test (indicate appropriate units): SO2__________, NOx __________, CO __________, Particulate matter __________, Other (list) __________

N/A – Startup not completed.

Solid waste parameters limited (list):______________

6. Performance

Typical net process efficiency or heat rate ____72 %____ (% or Btu/KWH).
Typical availability ___85___ % and capacity factor __________%.
Average annual production ______________.
How long has plant operated (years, months) ____3.5 YEARS____.

7. Plant History

How long to design plant: __24__ months. How long to construct plant: __12__ months.
When did plant first operate:___12/86___. Plant is operated on a continuous (yes/no) _____ or intermittent (yes/no) _____basis since completion of shakedown. What is present operating plan for plant?
SHUT DOWN
What is expected life of plant: ___20___ years

8. Plant Economics

Capital cost: $__8,000,000__.
Construction cost: $______________.
Annual operation and maintenance budget: $__1.5 million__.
Annual fuel costs: $__________.
Annual sorbent costs: $__________.
Annual ash disposal cost $__________, or credit $__________.
Value or cost of energy produced: ______________.

APPENDIX C

FUEL PREPARATION EQUIPMENT VENDORS

BIOMASS FUEL PREPARATION EQUIPMENT VENDORS

VENDOR	PRODUCT
AEROGLIDE CORP. 7100 HILLSBOROUGH ROAD RALEIGH , NC 27602 919-851-2000	DRYERS
AGNEW ENVIROMENTAL PRODUCTS CO. P.O. BOX 1168 GRANTS PASS , OR 97526 503/479-3396	BRIQUETTOR
AIR-O-FLEX EQUIPEMENT CO. 3030 E.HENNEPIN AVENUE MINNEAPOLIS , MN 55413 612/331-4925	TRUCK DUMPS
AIR-TECH INDUSTRIES, INC. 85 MADISON CIRCLE DRIVE 3. RUTHERFORD, NJ 07073 201/460-9730	AIR BAGS
AMERICAN HOIST & DRRRICK CO. 63 S. ROBERT STREET ST.PAUL , MN 55107 612/228-4321	WOOD BAILING MACHINERY
AMERICAN SHEET METAL, INC. P.O. BOX 9 TUALATIN , OR 97062 503/638-9611	WOOD, WASTE, STORAGE & CONVEYING SYSTEM
ARCHER BLOWER, INC. 6200 SW VIRGINIA AVENUE PORTLAND , OR 97201 503/246-7755	WOOD WASTES, STORAGE & CONVEYING SYSTEMS
ATLAS SYSTEMS CORPORATION P.O. BO 11496 SPOKANE , WA 99211 509/535-7775	WOOD RESIDUE STORAGE SILOS, AUTO. DISCHARGE SYST
BAHCO SYSTEMS, INC P.O. BOX 48116 ATLANTA , GA 30362 404/427-9051	BARK CLASSIFIERS & DRIERS, DUST COLLECTORS
BIO-SOLAR RESEARCH & DEV. CORP. P.O. BOX 762 EUGENE , OR 503/686-0765	WOOD PELLETS, PELLET SYSTEMS
BLACK CLAWSON, INC. P.O. BOX 1028 EVERETT , WA 98206 206/258-3555	FUEL PREPARATION COMPONENTS AND SYSTEMS
BOCATS, INC. P.O. BOX 1021 GARDEN CITY , KS 67846 316/275-7167	LIVE BOTTOM AND CHIP TRAILERS

VENDOR	PRODUCT
THE BONNOT COMPANY 805 LAKE STEET KENT , OH 44240 216/673–5829	DENSIFIED LOG EXTRUDERS
CALIFORNIA PELLET MILL CO. 1114 E. WABASH AVENUE CRAWFORDVILLE, IN 47933 317/322–6000	PELLETIZER EQUIPMENT
CEA,CARTER DAY COMPANY 500 73rd AVENUE, NE MINNEAPOLIS , MN 55430 612/571–1000	BULK STORAGE, WOOD RESIDUE HANDLING EQUIPMENT
CLARK'S SHEET METAL, INC. P.O. BOX 2428 EUGENE , OR 97402 503/343–3395	STORAGE HANDLING SYSTEMS FOR WOOD CHIPS & DUST
CONSOLIDATED BALING MACHINE CO. 155D 7th STREET BROOKLYN , NY 11215 212/625–0929	BALING PRESSES FOR WOOD RESIDUE
CORNELL MANUFACTURING INC. LACEYVILLE , PA 18623 717/869–1227	WOOD RESIDUE HANDLING EQUIP.,
DIVERSIFIED FUELS 975 OAK STREET EUGENE , OR 97401 503/484–0371	PELLETIZED FUEL FROM WOOD RESIDUE & EQUIPMENT
DYNAMIC INDUSTRIES, INC. P.O. BOX 466 BARNESVILLE , MN 56514 218/354–22[illegible]1	FRONT END LOADERS
EDERER INC. P.O. BOX 24708 SEATTLE , WA 98124 206/622–4421	RAKE CRANES, CONVEYORS
ERIEZ MAGNETICS ERIE , PA 16512 814/833–9881	METAL SEPARATORS
FERRO–TECH 467 EUREKA ROAD WYANDOOTE , MI 48912 313/282–7300	BRIQUETTING EQUIPMENT
FMC CORP.–MHS DIVISION 3400 WALNUT STREET COLMAR , PA 18915 215/822–0581	FUEL HANDLING SYSTEMS

VENDOR	PRODUCT
L.B. FOSTER CO. P.O. BOX 453 CARNEGIE , PA 15106 412/787-5500	ROOT EXTRACTORS
FULGRUM INDUSTRIES, INC. P.O. DRAWER G WADLEY , GA 30477 912/252-5223	TREE SHEARS - SAWMILL MANUFACTURER
ENERGY CONTROL ENGINEERING CORP. P.O. BOX 3064 CHARLOTTE , NC 704/375-1701	WOOD-FIRED BOILERS
GOODMAN EQUIPMENT CORPORATION 4834 SOUTH HALSTED STREET CHICAGO , IL 60609 312/927-7420	DOUBLE ANVIL WOOD HOG & CHIP MILLS
GRUENDLER CRUSHER & PULVERIER CO. 2915 N. MARKET STREET ST.LOUIS , MO 63106 314/531-1220	ROCK CRUSHING MANUFACTURER
GUARANTY FUELS, INC. P.O. BOX 748 INDEPENDENCE , KS 67301 316/331-0027	WOOD FUEL PELLETS
HALLCO MFG. CO., INC. 1001 1/2 MAINSTREE VANCOUVER , WA 98660 206/696-1170	LIVE BOTTOM TRAILERS
HARVEY ENGINEERING & MFG. CORP. RT.2, BOX 478 HOT SPRINGS , AR 71901 601/262-1010	FUEL SYSTEMS & WOODWORKING MACHINERY
HEIL COMPANY 3000 W. MONTANA MILWAUKEE , WI 53201 414/647-3101	DEHYDRATION EQUIPMENT
HOBBS ADAMS ENGINEERING CO., INC. 1100 OLLAND ROAD SUFFOLK , VA 23434 804/539-0232	FARM RELATED EQUIPMENT MANUFACTURER
S.W. HOOPER CORPORATION 211 POWER FERRY ROAD ATLANTA , GA 30339 404/955-4136	UNHOGGED FUEL RECLAMATION SYSTEMS
INDUSTRIAL BURNER 24 W. THIRD AVENUE SPOKANE , WA 99204 509/747-7965	FUEL PREPARATION, HANDLING SYSTEMS

VENDOR	PRODUCT
JACKSONVILLE BLOW PIPE CO. P.O. BOX 3687 JACKSONVILLE , FL 32206 904/355–5671	WOOD/BARK HOGS, BLOWER SYSTEMS
JEFFREY MFG. DIV., DRESSER INDUSTRI 500 E. MOREHEAD STREET/RM 221 CHARLOTTE , NC 28202 800/223–1954	FUEL HANDLING, PROCESSING EQUIP., HOGS
JOHN DEERE CORPORATION OTTUMWA , IA 515/684–4641	CROP RESIDUE DENSIFIERS
KINERGY CORPORATION 482 JENNINGS LANE LOUISVILLE , KY 40218 502/864–5901	SCREENS, FEEDERS & CONVEYORS
KOCKUMS INDUSTRIES P.O. BOX 108 TRUSSVILLE , AL 35173 205/655–3261	TOTAL TREE CHIPPERS
KOEHRING CANADA LTD. BOX 490 BRANTFORD, ON, N3T 519/752–6571	FELLER–BUNCHERS, FELLER–FORWARDERS
K–TRON CORPORATION P.O. BOX 548 GLASSBORO , NJ 08028 609/881–6500	METERING CONVEYORS
LAIDIG, INC. 1230 S. MERRIFIELD AVE. MISHAWAKA , IN 46644 219/256–02C4	WOOD REFUSE HANDLING SYSTEMS
LAMB INCORPORTATED 851 BELTLINE HIGHWAY MOBILE , AL 36606 205/479–7401	HOGS, HAMMERMILLS
LANDERS MACHINE CO. 207 E. BROADWAY FT. WORTH , TX 79104 817/336–5653	PELLETIZING MACHINERY
LEHIGH FORMING CO., INC. P.O. BOX 799 EASTON , PA 18042 215/258–0830	PELLET SYSTEMS
MARDEE, INC. 3129 E, WASHINGTON AVE. MADISON , WI 53704 608/244–3331	FUEL PREPRARATION, HANDLING STORAGE SYSTEM

VENDOR	PRODUCT
MAREN ENGINEERING CORP. 111 W. TAFT DRIVE SOUTH HOLLAND, IL 60473 312/333-6250	BALING PRESS, SAWDUST, HYDRAULIC BALING
McBURNEY CORPORATION P.O. BOX 47848 ATLANTA , GA 30362 404/448-8144	FUEL PREPARATION, HANDLING SYSTEMS
McCONNELL INDUSTRIES P.O. BOX 26210 BIRMINGHAM , AL 35226 205/942-3321	FUEL PREPARATION, HANDLING SYSTEMS, EQUIP. MFG.
M-E-C COMAPANY P.O. BOX 330 NEODESHA , JS 66757 316/325-2673	DRYERS, WOOD RESIDUE FUEL PREP. SYSTEMS
MELROE DIVISION/CLARK EQUIP. CO. FARGO , ND 58102 701/293-3220	FELLER-BUNCHERS
MODOMEKAN, INC. 2175 PARKLAKE DR.,NE/SUITE 300 ATLANTA , GA 30345 404/934/3151	WOOD RESIDUE STORAGE, HANDLING SYSTEMS
MORBARK INDUSTRIES P.O. BOX 1000 WINN , MI 48896 517/866-2381	FUEL HARVESTING MACHINERY, CHIP CLASS. HARDWARE
MUNSON MACHINERY CO., INC. 210 SEWARD AVENUE UTICA , NY 13505 315/797-0090	HOGS, HAMMERMILLS
NICHOLSON MANUFACTURING CO. 3670 E. MARGINAL WAY, SOUTH SEATTLE , WA 98114 205/682-2752	WOOD HANDLING AND PREPARATION
PEABODY GORDON-PIATT, INC. P. O. BOX 650 WINFIELD , KS 67156 316/221-4770	FUEL METERING BINS
PEERLESS ROYAL DIV.-ROYAL INDUSTRIE P.O. BOX 760 PARAGOULD , AR 72450 501/236-7753	& TRUCK DUMPS
PIEDMONT SILO COMPANY,INC. SOUTH DARING ROAD COVINGTON , GA 30209 404/786-3031	SILOS

VENDOR	PRODUCT
PRECISION CHIPPER CORP. P.O. BOX 360 LEEDS , AL 35094 205/640-5181	TOTAL TREE CHIPPERS
RADER PNEUMATICS, INC. P.O. BOX 20128 PORTLAND , OR 97220 503/255-5330	PNEUMATIC HANDLING & CONVEYING EQUIP.& TR
RADER SYSTEMS 2400 POPLAR AVE./ SUITE 312 MEMPHIS , TN 38112 901/761-3390	PNEUMATIC CONVEYORS, DISC SCREENS
RENS MANUFACTURING CO. P.O. BOX 337 CROSSWELL , OR 97426 503/895-2172	METAL DETECTORS
REXNORD,INC.-VIBRATING EQUIP. DIV. 3400 FERN VALLEY ROAD LOUISVILLE , KY 40213	VIBRATING CONVEYORS TO BOILER FEED
REYDCO TRADING P.O. BOX 3545 REDDING , CA 96001 916/347-5334	EXTRUDED LOGS & MACHINERY
ROME INDUSTRIES CEDARTOWN , GA 30125 404/748-7450	FELLER-BUNCHERS, SKIDDERS
ROYER FOUNDRY & MACHINE CO. KINGSTON , PA 18704 717/287-9624	CHIPPERS, SITE PREPARTION
SCHUTTE PULVERIZER CO., INC. 61 DEPOT STREET BUFFALO , NY 14240 716/855-1555	GRINDERS, CONVEYORS, ELEV. EQUIP.,DUMPS, HOISTS
SCREW CONVEYOR CORPORATION 600 HOFFMAN STREET HAMMOND , IN 46237 219/931-1450	WOOD CONVEYORS, TRUCK DUMPS
SELEM HAMMERMILL CO. 2601 INDUSTRIAL DRIVE SELEM , VA 24153 703/389-8696	INDUSTRIAL HAMMERMILLS
SPM GROUP, INC. 14 INVERNESS DRIVE, EAST ENGLEWOOD , CO 80111 303/770-1201	BRIQUETTES, BRIQUETTING MACH., DESIGN ENGINE
SPROUT-WALDRON, DIV.OF KOPPERS CO., 130 LOGAN STREET MUNCY , PA 17756	PELLETIZING EQUIPMEN

VENDOR	PRODUCT
STEARNS-ROGERS, INC. P.O. BOX 5888 DENVER , CO 80217 303/578-1100	ROTARY FUEL DRYERS FOR HOGGED WOOD FUEL
STEELCRAFT CORPORATION P.O. BOX 12408 MEMPHIS , TN 38112 901/452-5200	HIGH/LOW PRESSURE CONVEYORS,FILTER
STRONG MANUFACTURING CO. 498 EIGHT MILE ROAD REMUS , MI 49340 517/561-2280	TOTAL TREE CHIPPERS
TENNESSEE WOODEX P.O. BOX 10041 KNOXVILLE , TN 37919 615/588-7411	WOOD PELLET SALES
THERMAL WOODEX 07 WILLOW SPRINGS ROAD LaGRANGE , IL 60525 312/747-6600	FLUIDIZED-BED BURNERS
TOTEM EQIPMENT CO. P.O. BOX 3706 SEATTLE , WA 98214 206/762-9191	METAL DETECTORS
TRANSARTIC AIR, LTD. P.O. BOX 11573 VANCOUVER,B.C, 604/683-1123	WOOD BRIQUETTE SALES & SYSTEMS
TRIPPLE S DYNAMICS 1031 S. HASKELL DALLAS , TX 75223 214/821-9143	CONVEYORS, SIZING EQUIPMENT
UNION HEATING, INC. 7833 196 SOUTHWEST EDMONDS , WA 98020 206/725-4588	FUEL FEEDERS/DUTCH OVEN BOILERS, WASTE BURNE
WEAVER STAR SILO, INC. ROUTE4 MYERSTOWN , PA 17067 717/866-5708	SILOS
WELLONS, INC. P.O. BOX 381 SHERWOOD , OR 97140 503/625-6131	WOOD FUEL STORAGE BINS, CONVEYORS
WESCO TRAILER MFG. 1960 E. MAIN STREET WOODLAND , CA 95695 916/662-9606	CHIP VANS

VENDOR	PRODUCT
WEST SALEM MACHINERY 665 MURLARK STREET SALEM , OR 503/364-2213	HOGS, DISC SCREENS, SAWMILL EQUIP. MFG.
GUARANTY PERFORMANCE CO., INC. P.O. BOX 748 INDEPENDENCE , KS 67301 316/331-0027	ROTARY DRYERS, FUEL HANDLING EQUIPMENT

APPENDIX D

FEDERAL AND STATE ENVIRONMENTAL AGENCY OFFICES
SOUTHEASTERN STATES

APPENDIX D

FEDERAL AND STATE ENVIRONMENTAL AGENCY OFFICES
SOUTHEASTERN STATES

1. U. S. ENVIRONMENTAL PROTECTION AGENCY REGIONAL OFFICES:

REGION III: Delaware, D.C., Maryland, Pennsylvania, Virginia, West Virginia

OFFICE: 841 Chestnut Street
Philadelphia, PA 19107
(215) 597-9814

REGION IV: Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee

OFFICE: 345 Courtland, NE
Atlanta,GA 30365
(404) 347-4727

REGION VI: Arkansas, Louisiana, New Mexico, Oklahoma, Texas

OFFICE: 1445 Ross Avenue
12th Floor
Dallas, TX 75270
(214) 655-2100

REGION VII: Iowa, Kansas, Missouri, Nebraska

OFFICE: 726 Minnesota Avenue
Kansas City, KS 66101
(913) 551-7000

2. SOUTHEASTERN STATE OFFICES:

ALABAMA

Alabama Department of Environmental Management, 1751 Federal Drive, Montgomery, AL 36130 (205)271-7861

Air Division	(205) 271-7861
Industrial Water Division	(205) 271-7823
Land Division	(205) 271-7726
Permits Coordination Branch	(205) 271-7715

ARKANSAS

Arkansas Department of Pollution Control and Ecology, 8001 National Drive, P.O. Box 8913, Little Rock, AR 72219-8913 (501) 562-7444

Air and Hazardous Materials Division	(501) 562-7444
Water Quality Division	(501) 562-7444
Solid and Hazardous Waste Division	(504) 562-7444

FLORIDA

Department of Environmental Protection, Air Resources Management, Twin Towers Office Building, 2600 Blair Stone Road, Tallahassee, FL 32301 (904) 488-1344

Bureau of Air Regulations	(904) 488-1344
Bureau of Waste Water Management	(904) 488-0130
Bureau of Waste Management, Solid Waste Management Section	(904) 487-3299
Division of Environmental Permitting	(904) 488-0130

GEORGIA

Georgia Department of Natural Resources, Environmental Protection Division, 205 Butler Street, Suite 1152, Atlanta, GA 30334 (404) 656-4713

Air Protection Branch	(404) 363-7000
Water Protection Branch	(404) 656-4708
Land Protection Branch	(404) 362-2537

KENTUCKY

Kentucky Department for Environmental Protection, 316 St. Clair Mall, Frankfort, KY 40601 (502) 564-3382 NOTE: Will be moving in April of 1994 - need to get new address after that date.

Division of Air Pollution Control, Permit Review Branch	(502) 564-3382
Division of Water, Permit Review Branch	(502) 564-3410
Division of Waste Management, Permit Review Branch - Solid Waste	(502) 564-6716

LOUISIANA

Louisiana Department of Environmental Quality,. 7290 Bluebonnet Road, (see below for P.O. box nos.), Baton Rouge, LA 70810 (504) 765-0741

Air Quality Division -P.O.Box 82135	(504) 765-0219
Water Pollution Control Division P.O. Box 82215	(504) 765-0634
Solid Waste Division -P.O. Box 82178	(504) 765-0355

MISSISSIPPI

Mississippi Department of Natural Resources, Bureau of Pollution Control, 2380 Highway 80 West, P. O. Box 10385, Jackson, MS 39289 (601) 961-5171

Air Division . . . . (601) 961-5171
Water Quality Division . . . . (601) 961-5171
Solid and Hazardous Waste Division . . . . (601) 961-5171

MISSOURI

Missouri Department of Natural Resources, Division of Environmental Quality, 205 Jefferson Street, 1st Floor of Jefferson Building, P.O. Box 176, Jefferson City, MO 65102
(314) 751-4819

Air Pollution Control Program . . . . (314) 751-4817
Water Pollution Control Program,
Permit Section . . . . (314) 751-6825
Waste Management Program. Solid
Waste Section . . . . (314) 751-5410

NORTH CAROLINA

Division of Environmental Management, Department of Environment, Health and Human Resources, 512 North Salisbury Street, Raleigh, NC 27626-0535 (919) 733-3340

Air Quality Section . . . . (919) 733-3340
Water Quality Section . . . . (919) 733-5083
Solid & Hazardous Waste Branch . . . . (919) 733-4996

SOUTH CAROLINA

Department of Health and Environmental Control, J. Marion Sims Building, 2600 Bull Street, Columbia, SC 29201 (603) 758-5406

Bureau of Air Quality Control . . . . (803) 734-4750
Bureau of Water Pollution Control . . . . (803) 734-5300
Bureau of Solid and Hazardous
Waste Management . . . . (803) 734-5200

TENNESSEE

Department of Environment and Conservation, L & C Annex Building, 401 Church Street, Nashville, TN 37243 (see below for floor number and telephone number for the Division)

Division of Air Pollution Control
9th Floor . . . . (615) 532-0554
Division of Water Pollution Control,
Permit Section - 6th Floor . . . . (615) 532-0625
Division of Solid Waste Control Permit
Section - 5th Floor . . . . (615) 532-0780