5.   Biomass Conversion Technologies

In the context of this document, biomass conversion refers to the process of converting biomass into energy that will in turn be used to generate electricity and/or heat. The principal categories of biomass conversion technologies for power and heat production are ***direct-fired*** and ***gasification*** systems. Within the direct-fired category, specific technologies include stoker boilers, fluidized bed boilers, and cofiring. Within the gasification category, specific technologies include fixed bed gasifiers and fluidized bed gasifiers. Anaerobic digesters are also considered a biomass conversion technology; however, extensive information about digesters is readily available from EPA's AgSTAR Program <www.epa.gov/agstar> and therefore, will not be discussed within this chapter.

Biomass power systems are typically below 50 MW in size, compared to coal-fired plants, which are in the 100- to 1,000-MW range. Most of today's biomass power plants are ***direct-fired systems.*** The biomass fuel is burned in a boiler to produce high-pressure steam that is used to power a steam turbine-driven power generator. In many applications, steam is extracted from the turbine at medium pressures and temperatures and is used for process heat, space heating, or space cooling. ***Cofiring*** involves substituting biomass for a portion of the coal in an existing power plant boiler. It is the most economic near-term option for introducing new biomass power generation. Because much of the existing power plant equipment can be used without major modifications, cofiring is far less expensive than building a new biomass power plant. Compared to the coal it replaces, biomass reduces SO_2, NO_X, and certain other air emissions.

Biomass ***gasification*** systems operate by heating biomass in an environment where the solid biomass breaks down to form a flammable gas. The gas produced—synthesis gas, or syngas—can be cleaned, filtered, and then burned in a gas turbine in simple or combined-cycle mode, comparable to LFG or biogas produced from an anaerobic digester. In smaller systems, the syngas can be fired in reciprocating engines, microturbines, Stirling engines, or fuel cells. Gasification technologies using biomass byproducts are popular in the pulp and paper industry where they improve chemical recovery and generate process steam and electricity at higher efficiencies and with lower capital costs than conventional technologies. Pulp and paper industry byproducts that can be gasified include hogged wood, bark, and spent black liquor.

Table 5-1 provides a summary of biomass conversion technologies for producing heat and power.

Table 5-1. Summary of Biomass CHP Conversion Technologies

Biomass Conversion Technology	Common Fuel Types	Feed Size	Moisture Content	Capacity Range
Stoker grate, underfire stoker boilers	Sawdust, bark, chips, hog fuel, shavings, end cuts, sander dust	0.25–2 in.	10–50%	4 to 300 MW (many in the 20 to 50 MW range)
Fluidized bed boiler	Wood residue, peat, wide variety of fuels	< 2 in.	< 60%	Up to 300 MW (many in the 20 to 25 MW range)
Cofiring—pulverized coal boilers	Sawdust, bark, shavings, sander dust	< 0.25 in.	< 25%	Up to 1000 MW
Cofiring—stoker, fluidized bed boilers	Sawdust, bark, shavings, hog fuel	< 2 in.	10–50%	Up to 300 MW
Fixed bed gasifier	Chipped wood or hog fuel, rice hulls, shells, sewage sludge	0.25–4 in.	< 20%	Up to 50 MW
Fluidized bed gasifier	Most wood and agriculture residues	0.25–2 in.	15–30%	Up to 25 MW

Source: Based on Wright, 2006.

Modular systems employ some of the same technologies mentioned above, but on a smaller scale that is more applicable to farms, institutional buildings, and small industry. A number of modular systems are now under development and could be most useful in remote areas where biomass is abundant and electricity is scarce.

5.1   Direct-Fired Systems

The most common utilization of solid fuel biomass is direct combustion with the resulting hot flue gases producing steam in a boiler—a technology that goes back to the 19th century. Boilers today burn a variety of fuels and continue to play a major role in industrial process heating, commercial and institutional heating, and electricity generation. Boilers are differentiated by their configuration, size, and the quality of the steam or hot water produced. Boiler size is most often measured by the fuel input in MMBtu per hour (MMBtu/hr), but it may also be measured by output in pounds of steam per hour. Because large boilers are often used to generate electricity, it can also be useful to relate boiler size to power output in electric generating applications. Using typical boiler and steam turbine generating efficiencies, 100 MMBtu/hr heat input provides about 10 MW electric output.

The two most commonly used types of boilers for biomass firing are stoker boilers and fluidized bed boilers. Either of these can be fueled entirely by biomass fuel or cofired with a combination of biomass and coal. The efficiency, availability, operating issues, equipment and installed costs, O&M requirements and costs, and commercial status of each of these options are discussed below.

5.1.1   Boilers

*Characterization*

Stoker Boilers

Stoker boilers employ direct fire combustion of solid fuels with excess air, producing hot flue gases, which then produce steam in the heat exchange section of the boiler. The steam is used directly for heating purposes or passed through a steam turbine generator to produce electric power. Stoker-fired boilers were first introduced in the 1920s for coal; in the late 1940s the Detroit Stoker Company installed the first traveling grate spreader stoker boiler for wood. Mechanical stokers are the traditional technology that has been used to automatically supply solid fuels to a boiler. All stokers are designed to feed fuel onto a grate where it burns with air passing up through it. The stoker is located within the furnace section of the boiler and is designed to remove the ash residue after combustion. Stoker units use mechanical means to shift and add fuel to the fire that burns on and above the grate located near the base of the boiler. Heat is transferred from the fire and combustion gases to water tubes on the walls of the boiler.

Modern mechanical stokers consist of four elements, 1) a fuel admission system, 2) a stationary or moving grate assembly that supports the burning fuel and provides a pathway for the primary combustion air, 3) an overfire air system that supplies additional air to complete combustion and minimize atmospheric emissions, and 4) an ash discharge system. **Figure 5-1** illustrates the different sections of a stoker boiler.

A successful stoker installation requires selecting the correct size and type of stoker for the fuel being used and for the load conditions and capacity being served. Stoker boilers are typically described by their method of adding and distributing fuel. There are two general types of systems—*underfeed* and *overfeed*. Underfeed stokers supply both the fuel and air from under the grate, while overfeed stokers supply fuel from above the grate and air from below. Overfeed stokers are further divided into two types—*mass feed* and *spreader*. In the mass feed stoker, fuel is continuously fed onto one end of the grate

surface and travels horizontally across the grate as it burns. The residual ash is discharged from the opposite end. Combustion air is introduced from below the grate and moves up through the burning bed of fuel. In the spreader stoker, the most common type of stoker boiler, combustion air is again introduced primarily from below the grate but the fuel is thrown or spread uniformly across the grate area. The finer particles of fuel combust in suspension as they fall against the upward moving air. The remaining heavier pieces fall and burn on the grate surface, with any residual ash removed from the discharge end of the grate. Chain grate, traveling grate, and water-cooled vibrating grate stokers are other less common configurations that use various means to maintain an even, thin bed of burning fuel on the grate. Other specialized stoker boilers include balanced draft, cyclone-

Figure 5-1. Cut-Away View of a Traveling Grate Stoker Boiler

Source: ORNL, 2002.

fired, fixed bed, shaker hearth, tangential-fired, and wall-fired. Practical considerations limit stoker size and, consequently, the maximum steam generation rates. For coal firing, this maximum is about 350,000 pounds per hour (lb/hr); for wood or other biomass firing it is about 700,000 lb/hr.
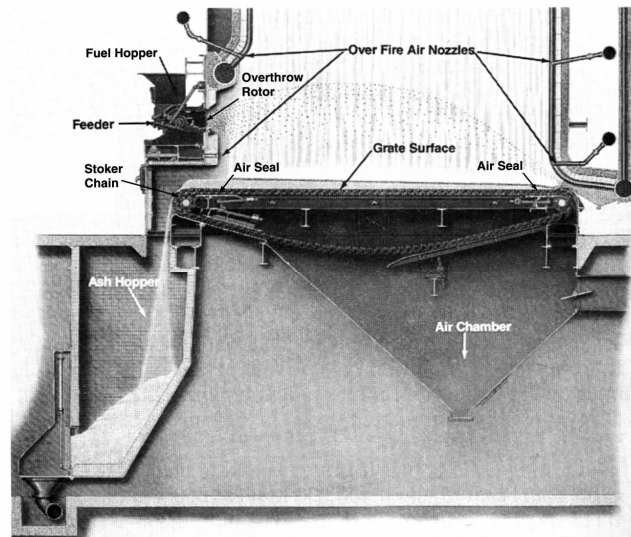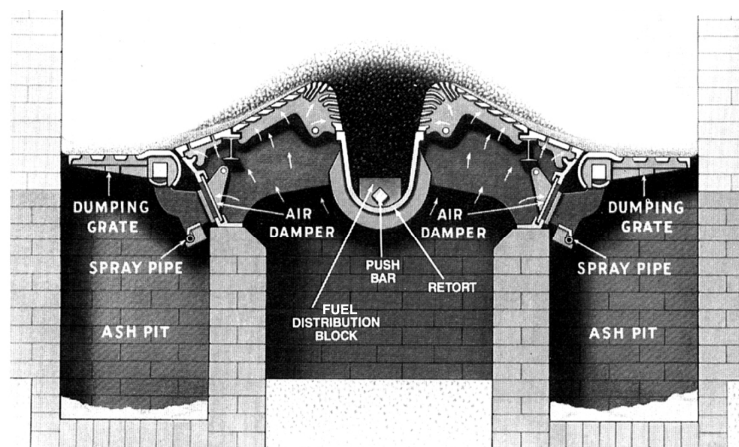
Underfeed Stokers

Underfeed stokers supply both fuel and primary combustion air from beneath the grate so that the top of the fuel pile is not cooled by cold and moist fuel or cold air. The fuel is moved into a hopper and onto the grate by either a screw- or ram-driven mechanism. Underfeed stokers push the fuel into the bottom of the bed of fuel while heat causes volatilization and complete combustion of the fuel by the time it rises to the top of the bed as ash and is discharged. As the fuel moves out over the grate where it is

exposed to air and radiant heat, it begins to burn and transfer heat to the water tubes. As with any combustion process, ash accumulates as the fuel, is burned. The two basic types of underfeed stokers are: 1) the horizontal-feed, side-ash discharge type and 2) the gravity-feed, rear-ash discharge type. A cross-section of an underfeed, side-ash discharge stoker is shown in **Figure 5-2**. The demand for underfeed stokers has diminished due to cost and environmental considerations. Underfeed stokers are best suited for relatively dry fuel (under 40 to 45 percent moisture.)

**Figure 5-2. Cross Section of Underfeed, Side-Ash Discharge Stoker**

Source: ORNL, 2002.

Overfeed Stokers

Overfeed stokers are generally classified by the way the fuel is distributed and burned within the boiler. The primary designations are mass-feed or spreader stokers. Mass-feed stokers introduce fuel continuously at one end of a grate. As the fuel moves into the boiler, it falls onto the grate by gravity. To control the amount of fuel that enters the boiler, a gate can be moved up or down, or the speed at which the fuel moves beneath the gate can be adjusted. Inside the boiler, the fuel burns as it travels along the grate. Primary combustion air flows upward from beneath the grate and through the burning bed of fuel, allowing for complete combustion. Any ash that remains on the grate is then discharged at the opposite end of the system. The two primary mass-feed stokers are 1) water-cooled vibrating grate and 2) moving (chain and traveling) grate stokers. A cross-section of an overfeed, water-cooled vibrating grate mass-fed stoker is presented in **Figure 5-3.**

Figure 5-3. Cross Section of Overfeed, Water-Cooled, Vibrating-Grate, Mass-Feed Stoker
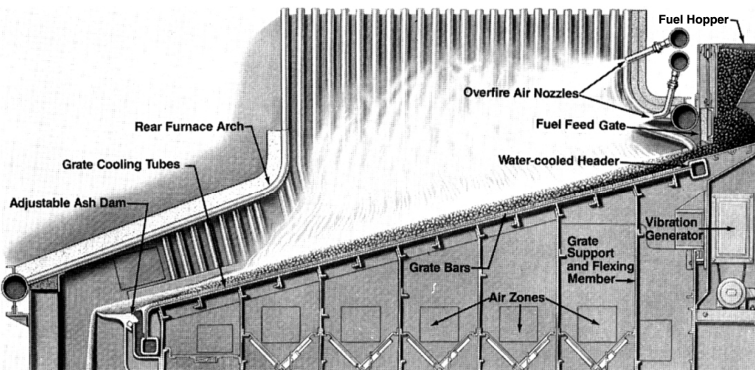
Source: ORNL, 2002.

Spreader Stokers

Spreader stokers are the most commonly used stokers because of their versatility. They are capable of distributing fuel evenly and to a uniform depth over the entire grate surface by using a device that propels the individual fuel particles into the air above the grate. Methods used to propel the fuel particles include air injection and underthrow and overthrow rotors. As the fuel is thrown into the boiler, fine particles ignite and burn while suspended in the combustion air. Due to suspension burning, response times of spreader stokers are better than for mass feed or underfeed stokers. The coarser particles that fall onto the grate end up burning in a thin bed of fuel on the grate. Primary combustion air is supplied from beneath the grate. Because the fuel is evenly distributed across the active grate area, the combustion air is uniformly distributed under and through the grate. A portion of the total combustion air is admitted through ports above the grate as overfire air, completing the combustion process. Grates for spreader stokers are generally designed to move rather than remain stationary. Therefore, traveling grates, air-cooled vibrating grates, and water-cooled vibrating grates are designs that have been used effectively. Modern boilers with spreader stokers incorporate:

- Equipment that distributes fuel uniformly over the grate.
- Specially designed air-metering grates.
- Dust collection and reinjection equipment.
- Forced draft fans for both undergrate and overfire air.
- Combustion controls to coordinate fuel and air supply with steam demand.[49]

---

[49] ORNL, 2002.

Along with the fuel feed system and furnace section geometry, air system design plays an important role in efficient and complete combustion of biomass fuels in stoker boilers. Excess air for bark, wood, and most biomass fuels is set at 25 percent or above for stoker firing. Because biomass fuels are typically highly volatile on a dry basis, are heterogeneous in size, and more often burn in suspension compared to coal, biomass combustion air systems are designed to provide more overfire air than those used for coal. Modern designs use undergrate and overfire quantities of 40 and 60 percent, respectively.

Fluidized Bed Boilers

Fluidized bed boilers are the most recent type of boiler developed for solid fuel combustion. The primary driving force for development of fluidized bed combustion is reduced SO_2 and NO_x emissions from coal combustion. As the technology developed, it became apparent that the process could efficiently burn biomass and other low-grade fuels that are difficult or impractical to burn with conventional methods.

In this method of combustion, fuel is burned in a bed of hot inert, or incombustible, particles suspended by an upward flow of combustion air that is injected from the bottom of the combustor to keep the bed in a floating or "fluidized" state. The scrubbing action of the bed material on the fuel enhances the combustion process by stripping away the CO_2 and solids residue (char) that normally forms around the fuel particles. This process allows oxygen to reach the combustible material more readily and increases the rate and efficiency of the combustion process. One advantage of mixing in the fluidized bed is that it allows a more compact design than in conventional water tube boiler designs. Natural gas or fuel oil can also be used as a start-up fuel to preheat the fluidized bed or as an auxiliary fuel when additional heat is required. The effective mixing of the bed makes fluidized bed boilers well-suited to burn solid refuse, wood waste, waste coals, and other non-standard fuels. **Figure 5-4** shows the components of a fluidized bed combustion boiler.

Figure 5-4. Cut-Away View of a Fluidized Bed Combustion Boiler
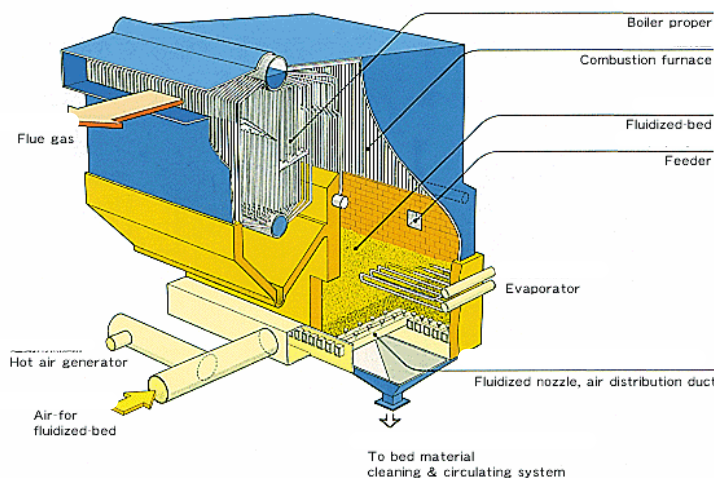
Source: Babcock & Wilcox, 2005.

The fluidized bed combustion process provides a means for efficiently mixing fuel with air for combustion. When fuel is introduced to the bed, it is quickly heated above its ignition temperature, ignites, and becomes part of the burning mass. The flow of air and fuel to the dense bed is controlled so that the desired amount of heat is released to the furnace section on a continuous basis. Typically, biomass is burned with 20 percent or higher excess air. Only a small fraction of the bed is combustible material; the remainder is comprised of inert material, such as sand. This inert material provides a large inventory of heat in the furnace section, dampening the effect of brief fluctuations in fuel supply or heating value on boiler steam output.

Fuels that contain a high concentration of ash, sulfur, and nitrogen can be burned efficiently in fluidized bed boilers while meeting stringent emission limitations. Due to long residence time and high intensity of mass transfer, fuel can be efficiently burned in a fluidized bed combustor at temperatures

considerably lower than in conventional combustion processes (1,400 to 1,600° F compared to 2,200° F for a spreader stoker boiler). The lower temperatures produce less NO_x, a significant benefit with high nitrogen-content wood and biomass fuels. SO_2 emissions from wood waste and biomass are generally insignificant, but where sulfur contamination of the fuel is an issue, limestone can be added to the fluid bed to achieve a high degree of sulfur capture. Fuels that are typically contaminated with sulfur include construction debris and some paper mill sludges.

Fluidized bed boilers are categorized as either atmospheric or pressurized units. Atmospheric fluidized bed boilers are further divided into bubbling-bed and circulating-bed units; the fundamental difference between bubbling-bed and circulating-bed boilers is the fluidization velocity (higher for circulating). Circulating fluidized bed boilers separate and capture fuel solids entrained in the high-velocity exhaust gas and return them to the bed for complete combustion. Atmospheric-pressure bubbling fluidized bed boilers are most commonly used with biomass fuels. The type of fluid bed selected is a function of the as-specified heating value of the biomass fuel. Bubbling bed technology is generally selected for fuels with lower heating values. The circulating bed is most suitable for fuels of higher heating values.

In a pressurized fluidized bed boiler, the entire fluidized bed combustor is encased inside a large pressure vessel. Burning solid fuels in a pressurized fluidized bed boiler produces a high-pressure stream of combustion gases. After the combustion gases pass through a hot gas cleanup system, they are fed into a gas turbine to make electricity, and the heat in the hot exhaust gas stream can be recovered to boil water for a steam turbine. Therefore, a pressurized fluidized bed boiler is more efficient, but also more complicated and expensive. Capital costs of pressurized fluidized bed combustion technology are higher than atmospheric fluidized beds.

Efficiency

Boiler efficiency is defined as the percentage of the fuel energy that is converted to steam energy. Major efficiency factors in biomass combustion are moisture content of the fuel, excess air introduced into the boiler, and the percentage of uncombusted or partially combusted fuel. According to the Council of Industrial Boiler Owners (CIBO), the general efficiency range of stoker and fluidized bed boilers is between 65 and 85 percent efficient.[50] Fuel type and availability have a major effect on efficiency because fuels with high heating values and low moisture content can yield efficiencies up to 25 percent higher than fuels having low heating values and high-moisture contents.

Biomass boilers are typically run with a considerable amount of excess air so that they can achieve complete combustion, but this has a negative impact on efficiency. A CIBO rule of thumb indicates that boiler efficiency can be increased 1 percent for each 15 percent reduction in excess air.[51]

Table 5-2 compares the efficiency of a biomass stoker and a fluidized bed boiler that are operated with 50 percent excess air with a final flue gas exit temperature of 350° F. The efficiencies are estimated based on the heat-loss method, which is a way of determining boiler efficiency by measuring the individual heat losses (expressed as a percent of heat input) and subtracting them from 100 percent. As can be seen in the table, the largest energy loss in a boiler is the heat that leaves the stack. This loss could amount to as much as 30 to 35 percent of the fuel input in older, poorly maintained boilers. The table shows that decreasing fuel moisture content from 30 to 0 percent increases thermal efficiency by about 6 percentage points. This estimate assumes that the air-fuel ratio is maintained by adjusting air input based on the input moisture content. If the quantity of air is not reduced when wetter fuel enters the boiler then efficiency will drop even more as fuel moisture is increased.

---

[50] Council of Industrial Boiler Owners, 1997.
[51] ORNL, 2002.

The primary difference in efficiency between a stoker boiler and a fluidized bed boiler is the amount of fuel that remains unburned. As shown in **Table 5-2**, the efficiency of fluidized bed boilers compares favorably with stoker boilers due to lower combustion losses. Stoker boilers can have 30 to 40 percent carbon in the ash and additional volatiles and CO in the flue gases, while fluidized bed boiler systems typically achieve nearly 100 percent fuel combustion. The turbulence in the combustor combined with the thermal inertia of the bed material provide for complete, controlled, and uniform combustion. These factors are key to maximizing the thermal efficiency, minimizing char, and controlling emissions.

Table 5-2. Biomass Boiler Efficiency as a Function of Input Fuel and Combustion Characteristics

Characteristics	Biomass Stoker		Biomass Fluidized Bed	
	Dry	**As Received**	**Dry**	**As Received**
Excess air (%)	50	50	50	50
Dry flue gas (lb/lb fuel)	15.25	10.675	15.25	10.675
Final exhaust temp (°F)	350	350	350	350
High heating value (HHV) of the fuel (Btu/lb)	8,500	5,950	8,500	5,950
Moisture content of fuel (%)	0	30	0	30
Hydrogen percent in the fuel (%)	4.59	3.21	4.59	3.21
Efficiency Losses				
Dry flue gas losses (%)	11.63	11.63	11.63	11.63
Moisture in fuel (%)	0.00	5.90	0.00	5.90
Latent heat (%)	5.69	5.69	5.69	5.69
Unburned fuel (%) (1)	3.50	3.50	0.25	0.25
Radiation and miscellaneous (%) (2)	2.03	2.03	2.03	2.03
Total Combustion Losses (%)	**22.85**	**28.74**	**19.60**	**25.49**
Boiler Efficiency HHV Basis (%)	**77.15**	**71.26**	**80.40**	**74.51**

(1) Estimated

(2) Includes radiation, moisture in air, and other miscellaneous issues.

When considering factors that influence boiler performance, it should be noted that efficiency is not constant throughout the entire operating range of a boiler. Peak efficiency generally occurs at a particular boiler output that is determined by design characteristics. Whenever boiler operations deviate from this output, the resulting performance is usually below peak efficiency. Operating continuously at peak efficiency is not practical due to seasonal demands, load variations and fuel property variations; however, operating at a steady load and avoiding cyclic or on-off operation can improve efficiency.

Operating Availability[52]

Typically, both stoker and fluidized boilers are designed for continuous operation, and design performance is in the 90+ percent availability range. Seasonal variability in fuel availability and/or quality can affect the plant availability, but this is a feedstock issue, not an issue of boiler performance. A well

---

[52] The availability of a power generation system is the percentage of time that the system can operate, or is "available" to operate. Both planned maintenance and unplanned outages have a negative effect upon system availability. Therefore an availability of 100% would represent a system that never broke down or needed maintenance (impossible to achieve in real operation).

designed biomass steam system has a reasonable expectation of operating in the 92 to 98 percent availability range.[53]

Operating Advantages and Disadvantages

Stoker and fluidized bed boilers have specific operating advantages and disadvantages with biomass fuels depending on the fuel characteristics and site requirements. Biomass fuels are extremely variable in terms of heating value, moisture content, and other factors that affect combustion. Wood and most other biomass fuels are composed primarily of cellulose and moisture. As discussed previously, the high proportion of moisture is significant because it acts as a heat sink during the combustion process. The latent heat of evaporation depresses flame temperature, taking heat energy away from steam production, and contributing to the difficulty of efficiently burning biomass fuels. Cellulose, in addition to containing the chemical energy released in combustion, contains fuel-bound oxygen. This oxygen decreases the theoretical air requirements for combustion and, accordingly, the amount of nitrogen included in the products of combustion. A few general guidelines for direct firing of wood and biomass in boilers include:

- Maintain stable combustion, which can be achieved in most water-cooled boilers with fuel moisture contents as high as 65 percent by weight, as received.

- Use of preheated combustion air reduces the time required for fuel drying prior to ignition and is essential to spreader stoker combustion systems. Design air temperatures will vary directly with moisture content.

- A high proportion of the combustible content of wood and other biomass fuels burns in the form of volatile compounds. A large proportion of the combustion air requirement, therefore, is added above the fuel in stoker and other conventional combustion boilers as overfire air.

- Solid chars produced in the initial stages of combustion of biomass fuels are of very low density. Conservative selection of furnace section size is used to reduce gas velocity and keep char entrainment into the flue gases and possibly out the stack at acceptable levels.

To ensure smooth fuel feeding, biomass fuels have to be carefully sized and processed. As discussed above, the moisture content of wood and other biomass waste can vary over a wide range, from 10 percent to more than 60 percent. To ensure steady heat input into the boiler using volumetric feeders, efficient homogenization of fuel with different moisture contents at the fuel yard is a necessity.

Biomass-based fuels can increase the risk of slagging and fouling of heat transfer surfaces and, in some cases, the risk of fireside corrosion as well. Potassium ash content is relatively high in fresh wood, green particles, and fast-growing biomass, which causes the ash to melt at low temperatures and leads to a tendency for fouling and slagging. Additionally, biomass fuels can contain chlorine, which, together with alkalis, can induce aggressive corrosion.

Table 5-3 provides a comparison of combustion characteristics and fuel issues for stoker and fluidized bed boilers. Stoker boilers have been around for a long time and are a relatively basic technology, whereas fluidized bed technology is newer and more complex, but offers more flexibility and operating control. Fluidized bed systems offer significant operating flexibility because they can operate under a wide range of load conditions. The thermal inertia of the bed material allows it to withstand changes in moisture and heating content of the fuel without negative impacts. Additionally, the low fuel

---

[53] Energy Products of Idaho, a company that provides fluidized bed boilers, has reported operating availabilities of 98 percent for their units, <www.energyproducts.com/fluidized_bed_combustors.htm>.

inventory present in the unit makes it responsive to variable loads. Another advantage is that the fluidized bed can also maintain efficiency during system turn-down. Fluidized bed manufacturers have reported that the operating flexibility of their units has allowed their customers to take advantage of utility incentive programs for generation that follows electric demand.[54]

Table 5-3. Comparison of Stoker and Fluidized Bed Boilers

Feature	Boiler Type	
	Stoker	**Fluidized Bed**
Combustion Mechanism		
Flow of solid fuel	Transported on stoker	Fluidized by combustion air and circulated through the combustion chamber and cyclone
Combustion zone	On the stoker	Entire area of the combustion furnace
Mass transfer	Slow	Active vertical movement-mass and heat transfer
Combustion Control		
Responsiveness	Slow response	Quick response
Excess air control	Difficult	Possible
Fuel Issues		
Applicability to various fuels	Fair	High
Fuel pretreatment	Generally not necessary	Lumps must be crushed
Environmental Factors		
Low sulfur oxide (SO_x) combustion	In-furnace desulfurization not possible	High rate of in-furnace desulfurization
Low NO_x combustion	Difficult	Inherently low NO_x
Appropriate facility size	Small	Medium to large

Equipment and Installed Costs

A biomass boiler system is a complex installation with many interrelated subsystems. An integrated steam system will include the fuel prep-yard and handling equipment, the boiler itself, induced and forced air fans, controls, and water treatment systems. Varying levels of emission control equipment will normally be needed as well. Most installations will include cyclone separators to capture large fly ash, a baghouse for fine particulate matter (PM), and a dry scrubber system. NO_x emissions control in stoker boilers is provided by a selective non-catalytic reduction system using urea or ammonia that is installed in the top of the boiler. Other control equipment includes acid gas removal system, stack, ash handling, and continuous emissions monitoring equipment if required.

Table 5-4 provides total capital cost estimates (equipment and installation) for both stoker and circulating fluidized bed steam systems for three biomass fuel feed rates: 100 tons/day, 600 tons/day and 900 tons/day. These feed rates are comparable to steam systems producing 20,000; 150,000 to 185,000; and 250,000 to 275,000 lb/hr of steam, respectively, depending on steam temperature and pressure. Installed costs can vary significantly depending on the scope of the equipment included, output steam conditions, geographical area, competitive market conditions, site requirements, emission control requirements, and prevailing labor rates. The estimates presented in the table are budgetary estimates based on published data and discussions with equipment suppliers and developers. The estimates are

---

[54] Energy Product of Idaho, n.d.

based on steam conditions that might be typical for a process heating-only application in the small 100 tons/day biomass unit (250 pounds per square inch gauge [psig] saturated steam), and higher steam pressures (750 psig) for a steam turbine CHP configuration in the larger units. The range of expected cost variations can be as high as +/- 35 percent depending on the site and system variables listed above. Steam conditions also have a significant impact on boiler cost; higher temperatures and pressures require thicker tubes and more expensive materials (see **Table 5-5**).

Table 5-4. Estimated Installed Capital Costs for a Biomass-Fueled Steam Plant

Characteristics	Biomass Fuel Feed (tons/day)		
	100	600	900
Biomass heat input (MMBtu/hr)	35.4	297.5	446.3
Steam pressure (psig)	275	750	750
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Stoker boiler equipment cost	$1,195,000	$7,980,000	$10,790,000
Other equipment and installation	$795,000	$10,020,000	$12,460,000
Total Installed Boiler System Cost	$1,990,000	$18,000,000	$23,250,000
Total Installed Biomass Prep-Yard*	$2,640,000	$5,430,000	$7,110,000
Total Installed Steam Plant Cost	**$4,630,000**	**$23,430,000**	**$30,360,000**
Unit Cost ($/lb steam)	$232	$142	$121
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Fluidized bed boiler equipment cost	$6,175,000	$14,490,000	$19,790,000
Other equipment and installation	$795,000	$10,020,000	$12,460,000
Total Installed Boiler System Cost	$6,970,000	$24,510,000	$32,250,000
Total Installed Biomass Prep-Yard*	$2,640,000	$5,430,000	$7,110,000
Total Installed Steam Plant Cost	**$9,610,000**	**$29,940,000**	**$39,360,000**
Unit Cost ($/lb steam)	$480	$171	$151

*Prep-Yard costs are estimated based on the capital cost curve developed in section 4.1.5
Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

As shown in **Table 5-4**, the prep-yard and fuel handling system represents a significant portion of the total steam system costs, ranging from 15 to 25 percent of the total steam system costs for the larger sized units and 25 to 50 percent of the total cost of the 100 tons/day steam system. Fluidized bed boiler equipment costs are higher than the simpler stoker technology; the fluidized bed boiler itself is more than three times as expensive as a stoker boiler in the smallest size shown; in the larger sizes, the fluidized bed boiler is 35 to 40 percent more expensive. The unit capital costs ($/lb steam) for a biomass-fueled steam plant, including the prep-yard costs, are 20 to 25 percent more expensive for the larger fluidized bed systems. A portion of the higher capital cost is offset by the higher output due to higher efficiency.

The cost of the boiler is also a function of the steam output conditions as shown in **Table 5-5.** Generating higher pressure and temperature steam requires special and more expensive alloys and thicker water tubes. Boilers producing very high pressure steam can be more than twice as expensive as boilers generating low pressure steam.

Table 5-5. Effect of Steam Output Conditions on Boiler Capital Costs

Steam Conditions	Boiler Cost Factor
150–250 psig	1.0
600–750 psig	1.15–1.25
1,250–1,500 psig	1.5–2.0

Source: Matches, 2003.

O&M Costs

Estimated non-fuel O&M costs for stoker and fluidized bed boiler systems are provided in **Table 5-6** for the three steam system sizes, based on published data and discussion with manufacturers. The O&M costs are evaluated within the context of an integrated plant. Total O&M costs include the labor for the prep-yard, and labor, materials, and parts for the boiler system itself. Boiler system O&M estimates were based on an annual non-labor component for spare parts and maintenance equipment assumed to be 2 percent of boiler capital costs. Variable costs for chemicals, water, and electricity needed to run blowers and auxiliary equipment were assumed to be approximately $0.20 to $0.25 per thousand pounds of steam output.

Table 5-6. Annual O&M Costs for a Biomass-Fueled Steam Plant

Characteristics	Biomass Fuel Feed (tons/day)		
	100	600	900
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Prep-yard labor	$400,000	$320,000	$320,000
Boiler section O&M	$160,000	$1,095,000	$1,110,000
Total Annual O&M	**$560,000**	**$1,415,000**	**$1,430,000**
Total Annual O&M ($/1,000 lb Steam)*	**$3.55**	**$1.09**	**$0.73**
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Prep-yard labor	$400,000	$320,000	$320,000
Boiler section O&M	$260,000	$1,190,000	$1,205,000
Total Annual O&M	**$660,000**	**$1,510,000**	**$1,525,000**
Total Annual O&M, ($/1,000 lb Steam)*	**$4.19**	**$1.09**	**$0.74**

*Based on 90 to 95 percent steam system capacity factor.
Source: Based on data from Antares Group, Inc., 2003; discussions with developers.

As shown in **Table 5-6**, the two boiler types are assumed to have the identical prep-yard labor requirement for the same output. The 100 tons/day plant uses a less automated system, so the labor requirement is higher than for the larger plants using an automated prep-yard. On a unit cost basis, O&M costs are higher for the fluidized bed boiler in the 100 tons/day size, but equal to the stoker boiler O&M costs for the two larger sizes.

Commercialization Status

Stoker boilers have long been a standard technology for biomass as well as coal, and are offered

by a number of manufacturers. Fluidized bed boilers are a more recent technology, but are also commercially available through a number of manufacturers. Until recently, however, fluidized bed boiler use has been more widespread in Europe than the United States, and many of the suppliers are European-based.

As shown in **Table 5-6,** when evaluated within the context of an integrated plant on a unit cost basis, O&M costs are higher for a smaller circulating fluidized bed processing 100 tons/day, but lower than the stoker boiler for the two larger sizes evaluated in this study.

Overall Cost and Performance Characteristics

A summary of the cost and performance of typical biomass steam systems is shown in **Table 5-7**.

Table 5-7. Summary of Biomass Combustion Boiler System Cost and Performance

|	Biomass Fuel Feed (tons/day)		
System	**100**	**600**	**900**
Biomass Fuel Characteristics			
Energy content (dry) (Btu/lb)	8,500	8,500	8,500
Moisture content (%)	50	30	30
Energy content (as received) (Btu/lb)	4,250	5,950	5,950
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Boiler efficiency (zero moisture) (%)	77	77	77
Boiler efficiency (moisture adjusted) (%)	63	71	71
Heat input to boiler (MMBtu/hr)	35.4	297.5	446.3
Heat input to steam (MMBtu/hr)	22.5	212.0	318.0
Capacity factor (%)	95	95	95
Cost Factors			
Total installed boiler costs	$1,990,000	$18,000,000	$23,250,000
Total installed steam system costs	$4,630,000	$23,430,000	$30,360,000
Unit capital cost ($/lb steam)	$232	$142	$121
Non-fuel O&M cost ($/1,000 lb steam)	$3.55	$1.09	$0.73
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Boiler efficiency (zero moisture) (%)	80	80	80
Boiler efficiency (moisture adjusted) (%)	67	75	75
Heat input to boiler (MMBtu/hr)	35.4	297.5	446.3
Heat input to steam (MMBtu/hr)	23.6	221.7	332.5
Capacity factor (%)	95	95	95
Cost Factors			
Total installed boiler costs	$6,970,000	$24,510,000	$32,250,000
Total installed steam system costs	$9,610,000	$29,940,000	$39,360,000
Unit capital cost ($/lb steam)	$480	$171	$151
Non-fuel O&M cost ($/1,000 lb steam)	$4.19	$1.09	$0.74

Source: NREL, 2003.

5.1.2 Cofiring

One of the most cost effective and easily implemented biomass energy technologies is cofiring with coal in existing coal-fired boilers. Cofiring refers to the practice of mixing biomass with a fossil fuel in high-efficiency boilers as a supplementary energy source. In biomass cofiring, biomass can substitute for up to 20 percent of the coal used in the boiler. Cofiring is typically used when either the supply of biomass is intermittent or when the moisture content of the biomass is high. At large plants, biomass is cofired with coal, and more coal is typically used than biomass. At small plants, biomass is cofired with natural gas, and more biomass is typically used than natural gas because the natural gas is used to stabilize combustion when biomass with high-moisture content is fed into the boiler.

Characterization

Figure 5-5 shows a process diagram for a standard coal-based cofiring plant. Biomass has been cofired with coal economically in commercial plants, which is principally viewed as a fuel cost reduction strategy. In certain situations, cofiring has provided opportunities for utilities to get fuel from wood manufacturing and other businesses at zero or negative cost. Overall production cost savings can also be achieved by replacing coal with inexpensive biomass fuel sources such as wood waste and waste paper. Typically, biomass fuel supplies should cost at least 20 percent less, on a thermal basis, than coal supplies before a cofiring project can be economically attractive.

Figure 5-5. Biomass Cofiring in Coal Power Plant
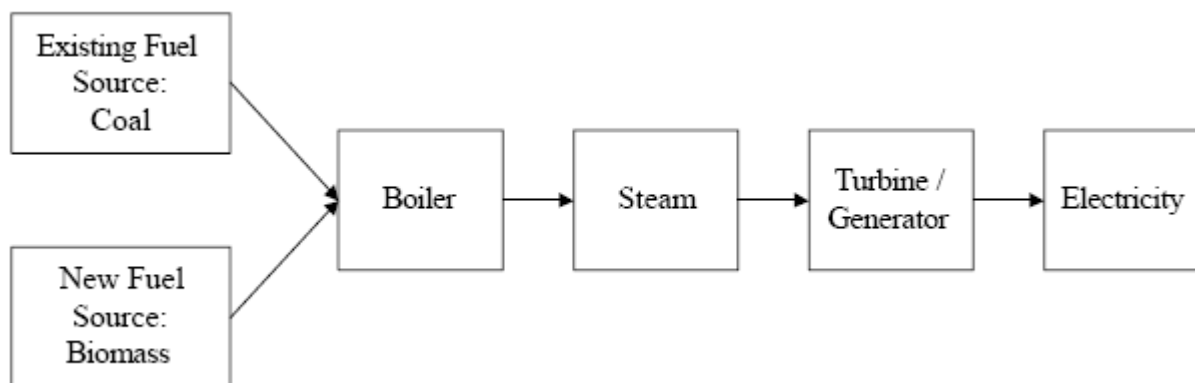
Source: Antares Group, Inc., 2003.

Biomass cofiring is mainly a retrofit application. A basic principle of cofiring is that significant changes to the boiler are not required beyond some minor burner modifications or additions necessary to introduce and burn the supplemental fuel. To meet this objective, cofiring biomass fuels is usually done on a limited basis, with the amount of biomass ranging from 5 to 15 percent of the total heat input to the boiler.[55] Biomass fuels that have been successfully cofired include wood and pelletized waste paper. Interest is growing in cofiring biomass among electric utilities and other users of coal boilers, chiefly due to the need to improve air emissions from coal-burning facilities, as well as to diversify fuel supplies.

Table 5-8 gives a sense of the size of typical utility cofiring power plants, the percentage of biomass fuel used (generally about 10 percent, but up to 50 percent), and the types of biomass feedstock used (wood, wood waste, wood residues, and sawdust).

---

[55] Fehrs and Donovan, 1999.

Table 5-8. Utility Cofiring Biomass With Coal (Continuous Operation)

Plant Name	Location	Biomass Feedstock	Total Plant (MW)	Biomass (MW)	Boiler Type
6th Street—Alliant Energy	Cedar Rapids, IA	Agricultural and wood waste	85	6.5	Fluidized bed
Bay Front—Northern States	Ashland, WI	Wood residues	34	5.0	Stoker
Colbert—Tennessee Valley Authority	Tuscumbia, AL	Wood residues	190	3.0	Pulverized coal
Greenridge—AES Corporation	Dresden, NY	Wood residues	108	10.0	Pulverized coal
King—Northern States Power	Bayport, MN	Sawdust	560	10.0	Cyclone
Tacoma Steam Plant #2	Tacoma, WA	Wood	25	12.5	Fluidized bed
Willow Island—Allegheny Energy	Pleasants, WV	Sawdust, tire-derived fuel	188	2.3	Cyclone
Yates—Southern Co./Georgia Power	Newnan, GA	Wood residues	150	2.0	Pulverized coal

Source: Antares Group, 2003

Efficiency

Usually, no major changes in boiler efficiency result from cofiring. However, some design and operational changes might be needed to maximize boiler efficiency while maintaining acceptable opacity, baghouse performance, and other operating requirements. Without these adjustments, boiler efficiency and performance can decrease. For example, at a biomass heat input level of 10 percent, boiler efficiency losses of 2 percent were measured during cofiring tests at a facility with a pulverized coal boiler when no adjustments were made.[56] Numerous cofiring projects have demonstrated that efficiency and performance losses can be minimized with proper awareness of operational issues.

Operating Availability

The availability of biomass and coal cofired boilers is similar to that of regular coal boilers, if proper modifications are made to the system. If some of the potential operating issues mentioned in the next section manifest, then availability might be negatively affected.

Operating Advantages and Disadvantages

Typically, cofiring biomass in an existing coal boiler requires modifications or additions to fuel handling, processing, storage, and feed systems. Slight modifications to existing operational procedures, such as increasing overfire air, might also be necessary, as well as increasing fuel feeder rates to compensate for the lower density and heating value of biomass.

As covered in Chapter 4, fuel characteristics and processing can greatly affect the ability to use biomass as a fuel in boilers. Wood chips are preferable to mulch-like material for cofiring with coal in stoker boilers because the chips are similar to stoker coal in terms of size and flow characteristics. This

---

[56] Tillman, 2000.

similarity minimizes problems with existing coal handling systems. When using a mulch-like material or a biomass supply with a high fraction of fine particles (sawdust size or smaller), periodic blockage of fuel flow openings in various areas of the conveying, storage, and feed systems can occur. These blockages can cause significant maintenance increases and operational problems; therefore, fuel should be processed to avoid difficulties with existing fuel feeding systems.

Another fuel consideration when dealing with biomass is the potential for problems with slagging, fouling, and corrosion. Some biomass fuels have high alkali (principally potassium) or chlorine content that can lead to unmanageable ash deposition problems on heat exchange and ash-handling surfaces. Chlorine in combustion gases, particularly at high temperatures, can cause accelerated corrosion of combustion system and flue gas cleanup components. These problems can be minimized or avoided by screening fuel supplies for materials high in chlorine and alkalis, limiting the biomass contribution to boiler heat input to 15 percent or less, using fuel additives, or increasing soot-blowing. The most troublesome biomass resource tends to be agricultural residues, including grasses and straws, which have high alkali and chlorine contents. In contrast, most woody materials and waste papers are relatively low in alkali and chlorine and should not present this problem.

Currently, about 25 percent of the fly ash from coal-fired power plants is used as a feedstock for cement and concrete production, while another 15 percent is used as a feedstock in other applications.[57] According to current industry standards,[58] only fly ash from coal combustion qualifies for use in cement/concrete applications. Cofiring biomass in a coal power plant would keep the fly ash from meeting the current standard. Similarly, coal fly ash will sometimes not meet the current standard when certain emissions control techniques are used, such as ammonia injection. Though these restrictions can impact the economics of biomass cofiring, the value of finding a productive use for fly ash and other coal combustion products is primarily the avoidance of a roughly $20/ton landfill fee. For coal with 10 percent ash content, this value would be worth about $2/ton of the input fuel cost. While the current restrictions are a barrier to considering cofiring in some applications, other uses of fly ash are not affected, and researchers are currently studying the impact of using fly ash from biomass and biomass/coal cofiring on concrete characteristics. Early results show that biomass and cofired fuels do not adversely affect the usefulness of fly ash in cement and concrete, and in fact might have some advantages.[59] It is likely that this work will eventually lead to a reevaluation of the standard and inclusion of fly ash from cofiring as an acceptable cement/concrete feedstock as has already happened in Europe.[60]

Equipment and Installed Costs

Cofiring typically does not involve added investment for the boiler equipment that is already in place for the coal-fired plant. There are additional costs for new fuel handling and processing equipment, boiler modifications, controls, engineering fees, and contingency. For blended fuel input systems, in which the biomass is added upstream of the coal fuel preparation equipment, the costs for the added feed preparation are on the order of 15 to 30 percent of the costs shown in the previous section in Table 5.4 for a dedicated biomass system. For systems using a separate fuel feed system, the costs are comparable to the costs ($/ton of biomass feed) for a dedicated biomass plant.

---

[57] American Coal Ash Association, n.d.

[58] ASTM C-618.

[59] Wang, 2007.

[60] In 2004, European Standard EN 450 dealing with fly ash specifications for use in concrete was approved for modification to include fly ash from a wide range of cofired biomass and waste feedstocks. These changes are in the process of being adopted by the European Union member countries.

O&M Issues

As discussed under capital costs, additional O&M to the boiler section attributable to the addition of biomass for cofiring is minimal. Maintenance requirements for boilers cofiring biomass and coal are similar to those for coal-only boilers. However, slight changes to previous operational procedures, such as increasing overfire air and fuel feeder speeds, might be needed. Increases in O&M costs for biomass cofiring with coal are almost entirely for the biomass receiving and feed preparation. For a blended system, the adjustments to feed preparation O&M are also on the order of 15 to 30 percent of the cost of a dedicated biomass plant.

Commercialization Status

Organizations such as electric utilities, DOE, and the Electric Power Research Institute (EPRI), have conducted research and field tests on biomass cofiring in small- and large-scale utility boilers for a number of years. These tests have shown that cofiring with biomass has been successfully accomplished in a wide range of boiler types, including cyclone, stoker, pulverized coal, and bubbling and circulating fluidized bed boilers. According to the Federal Energy Management Program, at least 182 separate boilers and organizations in the United States have cofired biomass with fossil fuels although this number is not comprehensive. Of the 182 cofiring operations, 114 (or 63 percent) have been at industrial facilities, 32 at utility-owned power plants, 18 at municipal boilers, 10 at educational institutions, and eight at federal facilities[61].

5.2   Gasification Technologies

Biomass gasification for power production involves heating solid biomass in an oxygen-starved environment to produce a low or medium calorific gas. Depending on the carbon and hydrogen content of the biomass and the gasifier's properties, the heating value of the syngas, can range anywhere from 100 to 500 Btu/cubic foot (10 to 50 percent that of natural gas). The heating value of syngas generally comes from CO and hydrogen produced by the gasification process. The remaining constituents are primarily CO_2 and other incombustible gases. Biomass gasification offers certain advantages over directly burning the biomass because the gas can be cleaned and filtered to remove problem chemical compounds before it is burned. Gasification can also be accomplished using chemicals or biologic action (e.g., anaerobic digestion); however, thermal gasification is currently the only commercial or near commercial option.

The fuel output from the gasification process is generally called *syngas,* though in common usage it might be called *wood gas*, *producer gas,* or *biogas*. Syngas can be produced through direct heating in an oxygen-starved environment, partial oxidation, or indirect heating in the absence of oxygen. Most gasification processes include several steps. The primary conversion process, called pyrolysis, is the thermal decomposition of solid biomass (in an oxygen-starved environment) to produce gases, liquids (tar), and char. Pyrolysis releases the volatile components of the biomass feed at around 1,100° F through a series of complex reactions. Biomass fuels are an ideal choice for pyrolysis because they have so many volatile components (70 to 85 percent on dry basis, compared to 30 percent for coal). The next step involves a further gasification process that converts the leftover tars and char into CO using steam and/or partial combustion. In coal gasification, pure oxygen or oxygen-enriched air is preferred as the oxidant because the resulting syngas produced has a higher heating value, and the process is more efficient. In biomass gasification, oxygen is generally not used because biomass ash has a lower melting point than coal ash, and because the scale of the plants is generally smaller.

---

[61] DOE, 2004.

Very high temperature processes involving passing the biomass through a plasma arc have been developed and tested primarily for waste remediation, contaminated wastes, and MSW. Plasma processes are not discussed in this report.

Compared with direct-fired biomass systems, gasification is not yet an established commercial technology. There is great interest, however, in the development and demonstration of biomass gasification for a number of reasons:

A gaseous fuel is more versatile than a solid fuel. It can be used in boilers, process heaters, turbines, engines and fuel cells, distributed in pipelines, and blended with natural gas or other gaseous fuels.

Gasification can remove fuel contaminants and reduce emissions compared to direct-fired systems.

Gasification can be designed to handle a wide range of biomass feedstocks, from woody residues to agricultural residues to dedicated crops, without major changes in the basic process.

Gasification can be used to process waste fuels, providing safe removal of biohazards and entrainment of heavy metals in non-reactive slag.

A gaseous fuel can be used in a high-efficiency power generation system, such as a gas turbine-combined cycle or fuel cells, provided it is cleaned of contaminants. When equipment is added to recover the heat from the turbine exhaust, system efficiencies can increase to 80 percent.
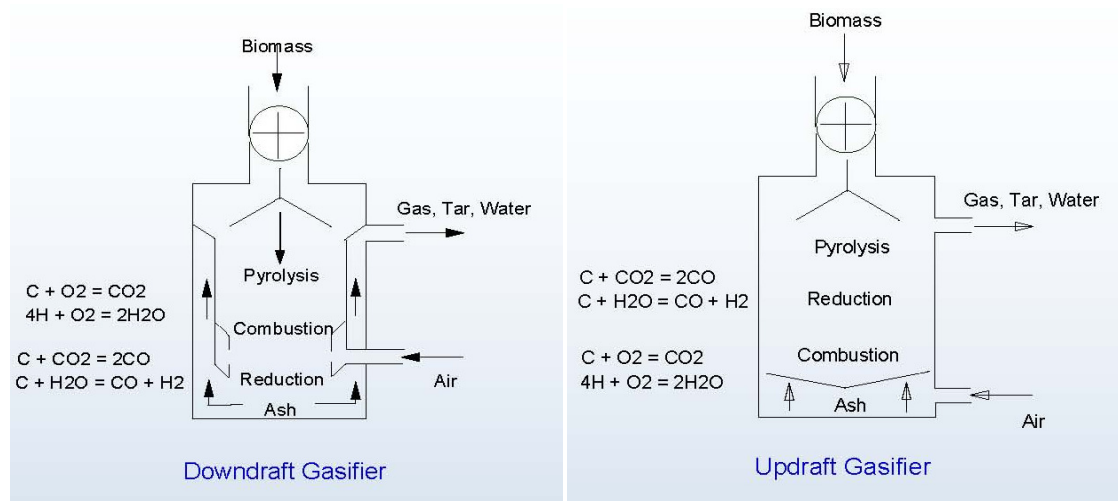
Like the direct combustion processes described in the previous section, two principal types of gasifiers have emerged: fixed bed and fluidized bed. Fixed bed gasifiers are typically simpler, less expensive, and produce a lower heat content syngas. Fluidized bed gasifiers are more complicated, more expensive, and produce a syngas with a higher heating value.

5.2.1   Gasifiers

Characterization

Fixed Bed Gasifiers

Fixed bed gasifiers typically have a fixed grate inside a refractory-lined shaft. The fresh biomass fuel is typically placed on top of the pile of fuel, char, and ash inside the gasifier. A further distinction is based on the direction of air (or oxygen) flow: downdraft (air flows down through the bed and leaves as biogas under the grate), updraft (air flows up through the grate and biogas is collected above the bed), or crossflow (air flows across the bed, exiting as biogas). Schematics of the primary section of the fixed bed gasifier types are shown in **Figure 5-6**.

Figure 5-6. Fixed Bed Gasifier Types

Downdraft Gasifier

Biomass

Gas, Tar, Water

Pyrolysis

$C + O_2 = CO_2$
$4H + O_2 = 2H_2O$

Combustion

$C + CO_2 = 2CO$
$C + H_2O = CO + H_2$

Reduction   Air

Ash

Updraft Gasifier

Biomass

Gas, Tar, Water

Pyrolysis

$C + CO_2 = 2CO$
$C + H_2O = CO + H_2$

Reduction

Combustion

$C + O_2 = CO_2$
$4H + O_2 = 2H_2O$

Ash

Air

Source: Bain, 2006.

Table 5-9 compares fixed bed gasifier types. **Table 5-10** provides typical physical characteristics of a fixed bed gasifier. Fixed bed gasifiers are usually limited in capacity, typically used for generation systems that are able to produce less than 5 MW. The physics of the refractory-lined shaft reactor vessel limits the diameter and thus the throughput. Developers have identified a good match between fixed bed gasifiers and small-scale distributed power generation equipment. However, the variable economics of biomass collection and feeding, coupled with the gasifier's low efficiency, make the economic viability of the technology particularly site-specific.

Table 5-9. Comparison of Fixed Bed Gasification Technologies

	Type of Gasifier		
	Downdraft	**Updraft**	**Crossflow**
Operation	Biomass is introduced from the top and moves downward. Oxidizer (air) is introduced at the top and flows downward. Syngas is extracted at the bottom at grate level.	Biomass is introduced from the top and moves downward. Oxidizer is introduced at the bottom and flows upward. Some drying occurs. Syngas is extracted at the top.	Biomass is introduced from the top and moves downward. Oxidizer is introduced at the bottom and flows across the bed. Syngas is extracted opposite the air nozzle at the grate.
Advantages	Tars and particulate in the syngas are lower, allowing direct use in some engines without cleanup. The grate is not exposed to high temperatures.	Can handle higher-moisture biomass. Higher temperatures can destroy some toxins and slag minerals and metal. Higher tar content adds to heating value.	Simplest of designs. Stronger circulation in the hot zone. Lower temperatures allow the use of less expensive construction materials.
Disadvantages	Biomass must be very dry (<20 percent moisture content). The syngas is hot and must be cooled if compression or extensive cleanup is required. About 4 to 7 percent of the carbon is unconverted and remains in the ash.	Higher tar content can foul engines or compressors. The grate is exposed to high temperatures and must be cooled or otherwise protected.	More complicated to operate. Reported issues with slagging. High levels of carbon (33%) in the ash.

**Table 5-10. Typical Characteristics of a Fixed Bed Gasifier**

Parameter	Fixed Bed, Downdraft
Fuel size (inches)	0.4-4
Fuel ash content (% weight)	<6
Operating temperature (°F)	1450-2550
Control	Simple
Turn-down ratio	4:1
Construction material	Mild steel + refractory
Capacity ($MW_{thermal}$) (tons biomass/day)	<5 (<30)
Start-up time	Minutes
Operator attention	Low
Tar content (lb/MMBtu product gas)	<1.2
Heating value (Btu/scf) HHV	130

Source: GasNet, n.d.

Fluidized Bed Gasifiers

Fluidized bed gasifiers utilize the same gasification processes and offer higher performance than fixed bed systems, but with greater complexity and cost. Similar to fluidized bed boilers, the primary gasification process takes place in a bed of hot inert materials suspended by an upward motion of oxygen-deprived gas (**Figure 5-7**). As the amount of gas is augmented to achieve greater throughput, the bed will begin to levitate and become "fluidized." Sand or alumina is often used to further improve the heat transfer. Notable benefits of fluidized bed devices are their high productivity (per area of bed) and flexibility. Fluidized bed gasifiers can also handle a wider range of biomass feedstocks with moisture contents up to 30 percent on average.

Figure 5-7. Fluidized Bed Gasifier
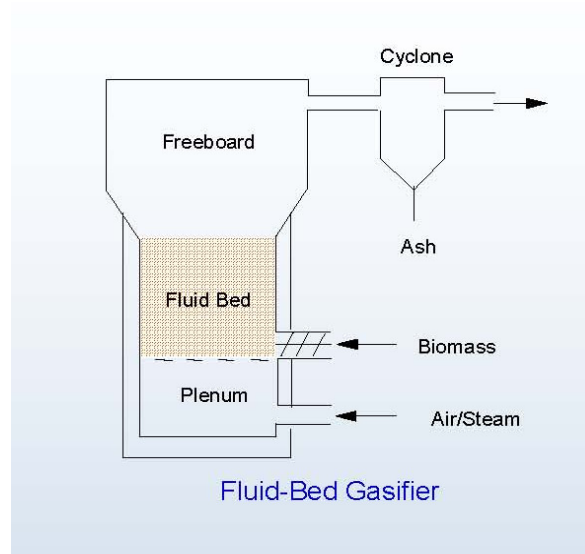
Source: Bain, 2006.

There are three stages of fluidization that can occur on the gasifier depending on the design: bubbling, recirculating, and entrained flow. At the lower end of fluidization, the bed expands and begins to act as a fluid. As the velocity is increased, the bed will begin to "bubble." With a further increase in airflow, the bed material begins to lift off the bed. This material is typically separated in a cyclone and "recirculated" to the bed. With still higher velocities, the bed material is entrained (i.e., picked up and carried off in the airflow).

Fluidized bed gasifiers can be designed to use a portion of the pyrolysis gases to generate the heat to drive the process, or they can be externally fired. Operating the gasifier at higher pressures increases the throughput; however, this also increases the gasifier's complexity and cost. In these units, the biomass is fully converted after going through the pyrolysis and char conversion processes.

By reducing the quantity of air and process temperature, it is possible to operate fluidized bed boilers as gasifiers. In this operating mode, the gasifiers produce a gas with a heating value of slightly more than 100 Btu/cubic foot (ft^3). This gas is burned above the bed as additional air supply is injected upstream of the boiler tube section.

Table 5-11 provides typical physical characteristics of a fluidized bed gasifier. A number of advanced-concept fluidized bed gasifiers aiming to produce a syngas with a heating value between 250 and 400 Btu/ft^3 are under development. This type of syngas would be more appropriate for use in gas

turbines, fuel cells, and reciprocating internal combustion engines; however, these advanced concept gasifiers have not reached the point where they are proven in commercial operation.

Table 5-11. Typical Characteristics of a Fluidized Bed Gasifier

Parameter	Fluidized Bed
Fuel size (inches)	0-0.8
Fuel ash content (% weight)	<25
Operating temperature (°F)	1,350-1,750
Control	Average
Turn-down ratio	3
Construction material	Heat-resistant steel
Capacity (MW$_{thermal}$) (biomass tons/day)	5 and up (> 30)
Start-up time	Hours
Operator attention	Average
Tar content (lb/MMBtu product gas)	<2
Heating value (Btu/scf) HHV	150

Source: GasNet, n.d.

Efficiency

Both fixed and fluidized bed biomass gasification uses similar types of equipment as direct combustion. The biomass fuel is fed into a combustion/reaction vessel with either a fixed, fluidized, or moving bed. The thermodynamics of heat loss are similar, but gasification conditions are different from direct combustion. In direct combustion, 10 to 14 times the weight of the fuel is introduced as air. In gasification, the air entering the reactor, if any, is only one to two times the weight of the fuel. This difference reduces heat losses from the reaction zone. On the other hand, the syngas exits the gasification reactor at very high temperatures (1,200 to 1,500° F); some of this heat loss can be recovered either directly through the use of heat exchangers in the gas cooling section, or indirectly through the use of heat recovery from the combustion of the syngas in the power generation section. To the extent that heat is used to preheat incoming air, introduce high-temperature steam, or dry the incoming biomass, the efficiency of biomass to syngas conversion will be increased. Heat that is recovered from the hot gas cooling section can also be added to the CHP heat recovery. In this case, the intermediate efficiency value of syngas conversion is not increased but the overall CHP efficiency is. These differences combine to produce biomass to syngas efficiencies (heating value of the syngas divided by the heating value of the biomass) of 60 to 80 percent. In integrated configurations, however, additional steam can be generated from cooling the hot syngas exiting the reactor prior to cleanup.

Operating Availability

Due to the fact that commercialization of biomass gasification plants is in its early stages, no facility survey information was found on their availability or reliability. Plants are designed for continuous operation, and design performance is in the 90+ percent range. Actual experience with emerging technology tends to result in lower availability than is experienced during broad commercial use, as materials handling problems, control issues, and component failures cause more frequent unplanned outages than are seen after accumulating additional operating experience. With a newly established support infrastructure, outages also tend to last longer before being fixed or solved. A well

designed system, however, has a reasonable expectation of operating in the 85 to 95 percent availability range.
Operating Issues

As discussed above, moisture content, gas cleanup, and operating pressure can all affect operation of a gasifier. There are a number of operating issues common to the different types of gasification systems.

Moisture Content

Green biomass, defined as freshly harvested plant material, can contain a significant amount of water by weight (up to 60 percent). This water does not contribute to the heat content of the syngas while consuming a significant amount of energy in gasification. Even though water cannot be burned (oxidized) at elevated temperatures, it will dissociate into its elemental components—hydrogen and oxygen. The hydrogen will contribute to the calorific value of the syngas. This reaction is very temperature-sensitive, and the hydrogen and oxygen will usually recombine into water vapor as the syngas cools. Therefore, the moisture content of biomass must be strictly limited. If there is excess moisture, the gasification process cannot sustain itself without an external source of heat. As the moisture content of the biomass increases, the net energy available in the syngas decreases. Fixed bed gasifiers that use internal combustion of the syngas typically utilize biomass with less than 20 percent moisture content. Fluidized bed gasifiers typically require less than 30 percent moisture content.

Green biomass is the most readily available and inexpensive biomass product. The drying process requires a considerable additional capital investment and increases the O&M costs. Unfortunately, the cost of the drying equipment (equipment cost and O&M cost) seldom covers the cost savings of using green biomass.

Gas Cleanup

As syngas leaves the gasifier, it contains several types of contaminants that are harmful to downstream equipment, ash handling, and emissions. The degree of gas cleanup must be appropriately matched to its intended use. For use in reciprocating engines, gas turbines, and especially fuel cells, a very clean gas is required. As discussed in **Table 5-12**, the primary contaminants in syngas are tars, particles, alkali compounds, and ammonia. The types of contaminants that are observed depend on the biomass feedstock and the gasification process used.

Table 5-12. Gas Cleanup Issues

Contaminant	Description	Treatment
Tar	Tars (creosote) are complex hydrocarbons that persist as condensable vapors.	Wet scrubbers, electrostatic precipitators, barrier filters, catalysts, or combustion.
Particles	Particles are very small, solid materials that typically include ash and unconverted biomass.	Cyclone separators, fabric filters, electrostatic precipitators, and wet scrubbers.
Alkali compounds	Potassium, alkali salts, and condensed alkali vapors are part of the chemical composition of biomass.	First, cool syngas below 1,200º F, causing the alkali vapors to condense. Second, use cyclone separators, fine fabric filters, electrostatic precipitators, and wet scrubbers.
Ammonia	Ammonia is formed from nitrogen (fuel-bound and in air) and hydrogen (in fuel and in moisture content). When syngas is burned, ammonia is converted to NO_x.	Catalysts, hydrocarbon reforming, or wet scrubbing.

Because gasification occurs at an elevated temperature, syngas can have as much as a third of its total energy in sensible heat. Cleaning the gas while it is hot would be advantageous from an energy use perspective, but this task is currently difficult to accomplish. Research is ongoing regarding hot gas filters, which can be applied in coal gasification, as well as other high-temperature processes. Wet scrubbers are currently one of the most reliable and least expensive options for gas cleanup, even though they sacrifice a large portion of the sensible heat of the syngas. Cooling the hot syngas can provide a source of steam for the cleaning process, power generation, or end-use.

Operating Pressure

Gasifiers can be operated at either atmospheric or elevated pressures. Air-blown, atmospheric gasifiers produce a very low Btu gas 110 to 170 Btu/scf. To introduce this gas into a gas turbine in the power generation section of the plant requires considerable compression energy, up to a third of the turbine's output. Therefore, it would be advantageous to produce the syngas at a high pressure so that it can be introduced directly into the combustion section of a gas turbine without additional compression. Pressurized reactors, however, do need to compress any combustion air or oxygen that is introduced into the reactor and maintain a pressure seal on the biomass input and ash removal systems.

Advantages and Disadvantages

Fixed bed and fluidized bed gasifiers have specific operating advantages and disadvantages with biomass fuels depending on the biomass characteristics and site requirements. **Table 5-13** provides a qualitative comparison of gasifier characteristics and operating issues for fixed bed and fluidized bed systems.

Table 5-13. Relative Advantages/Disadvantages of Gasifier Types

Gasifier	Advantages	Disadvantages
Updraft fixed bed	Mature for heat Small-scale applications Can handle high moisture No carbon in ash	Feed size limits High tar yields Scale limitations Low Btu gas Slagging potential
Downdraft fixed bed	Small-scale applications Low particulates Low tar	Feed size limits Scale limitations Low Btu gas Moisture-sensitive
Bubbling fluid bed	Large-scale applications Feed characteristics Direct/indirect heating Can produce higher Btu gas	Medium tar yield Higher particle loading
Circulating fluid bed	Large-scale applications Feed characteristics Can produce higher Btu gas	Medium tar yield Higher particle loading
Entrained flow fluid bed	Can be scaled Potential for low tar Potential for low methane Can produce higher Btu gas	Large amount of carrier gas Higher particle loading Particle size limits

Equipment and Installed Costs

The main cost for the gasification train is the primary gasification reactor itself. Supplementary processing can occur in a tar cracker. Indirect gasifiers have separate char combustors to supply heat. The next major part is the gas cleanup section, which includes ash removal, quench, bag filter, wet scrubber, and heat exchangers to cool the syngas and provide heat to other parts of the process or to contribute to the CHP heat utilization. Capital costs for the gasification section and for a biomass-to-syngas plant are shown in **Table 5-14**. These costs are estimated based on published estimates (Antares Group, Inc., 2003) and discussions with equipment suppliers. The unit costs do not show a uniform declining trend as a function of size, but instead vary depending on the process considered.

Table 5-14. Biomass Gasification Capital Costs to Produce Syngas

	Gasifier Cases			
	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Tons/day (as received)	100	260	450	1,200
Gasifier equipment	$1,225,000	$10,050,000	$15,158,000	$34,682,000
Installation	$612,000	$5,024,000	$7,578,000	$17,338,000
Total Installed Gasification	**$1,837,000**	**$15,074,000**	**$22,736,000**	**$52,020,000**
Biomass Prep Yard*	$2,639,700	$3,947,400	$4,972,000	$9,685,766
Total Installed Capital Cost	**$4,476,700**	**$19,021,400**	**$27,708,000**	**$61,705,766**
Unit Cost ($/MMBtu/hr) (syngas)	$127,164	$209,425	$174,130	$161,270

*Prep-Yard costs are estimated based on the capital cost curve developed in section 4.1.5
Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

O&M Costs

Non-fuel O&M costs for gasification include O&M labor, supervisory labor, water, ash removal, insurance, taxes, royalties, and other operating materials. These costs are estimated in **Table 5-15** based on published estimates and discussions with equipment suppliers.[62]

---

[62] Antares Group Inc., 2003

Table 5-15. Gasification O&M Cost Estimates for Syngas Production

	Gasifier Cases			
	Atmospheric Gasification	**Atmospheric Gasification**	**Atmospheric Gasification**	**High-Pressure Gasifier**
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/high-pressure
Tons/day (as received)	100	260	450	1,200
Net capacity, MMBtu/hr	35.2	90.8	159.1	382.6
Prep-yard labor costs	$400,000	$320,000	$320,000	$400,000
Gasifier section O&M	$502,000	$634,500	$789,500	$2,235,800
Total Annual O&M (to syngas)	**$902,000**	**$954,500**	**$1,109,500**	**$2,635,800**
Gasification O&M ($/MMBtu)	$3.250	$1.333	$0.884	$0.874

Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

A summary of the cost and performance for the range of biomass gasification systems considered is provided in **Table 5-16.**

Table 5-16. Biomass Gasification Cost and Performance

	Gasification Technologies			
	Atmospheric Gasification	**Atmospheric Gasification**	**Atmospheric Gasification**	**High-Pressure Gasifier**
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/high-pressure
Tons/day (as received)	100	260	450	1,200
Feedstock Characteristics				
Energy content dry (Btu/lb)	8,500	8,500	8,500	8,476
Moisture content (%)	30	30	30	38
Energy content as received (Btu/lb)	5,950	5,950	5,950	5,255
Biomass Conversion				
Gasifier efficiency (moisture adjusted)(%)	65	71	71	72
Biomass fuel value to gasifier (MMBtu/hr)	49.6	127.9	224.1	531.9
Fuel produced (MMBtu/hr)	32.2	90.8	159.1	382.6
Heating value (Btu/scf HHV)	110.0	110.0	110.0	128.8
Fuel pressure (psig)	Atmospheric	Atmospheric	Atmospheric	Pressurized
Plant capacity factor (%)	90	90	90	90
Capital Costs				
Gasifier equipment	$1,225,000	$10,050,000	$15,158,000	$34,682,000
Installation	$612,000	$5,024,000	$7,578,000	$17,338,000
Total Installed Gasification Section	**$1,837,000**	**$15,074,000**	**$22,736,000**	**$52,020,000**
Biomass Prep-Yard	$2,639,700	$3,947,400	$4,972,000	$9,685,766
Total Installed Capital Cost	**$4,476,700**	**$19,021,400**	**$27,708,000**	**$61,705,766**
Unit Cost ($/MMBtu/hr) (syngas)	$127,164	$209,425	$174,130	$161,270

Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

Commercial Status

The majority of commercial gasification projects use coal or petroleum coke as a feedstock. Biomass gasification technologies have been a subject of commercial interest for several decades. By the 1990s, CHP had been identified as a potential near-term technology. Research and development concentrated on integrated gasification combined cycle and gasification cofiring demonstrations, which led to a number of commercial-scale systems. In the United States, projects mostly processed hard-to-manage feedstocks like bagasse and alfalfa. Low-energy gasifiers are now commercially available, and dozens of small-scale facilities are in operation.

A review of gasifier manufacturers in Europe, the United States, and Canada[63] identified 50 manufacturers offering commercial gasification plants in which 75 percent of the designs were fixed bed downdraft type; 20 percent of the designs were fluidized bed systems. The actual number of biomass gasification systems in operation worldwide is unknown, but is estimated to be below 50 based on literature review and discussions with industry sources. There are only a handful of commercially operating biomass gasification systems in the United States at this time, and many of these are partially government-funded demonstration units. In comparison, there are currently more than 100 biomass-fueled fluidized bed boilers in operation around the world.

There is still a considerable amount of development activity underway to address existing technical and operational issues:

- **Gasification**—Some gasification technologies using biomass and black liquor have developed to the point of large-scale demonstration. However, gasifier systems have not reached widespread commercial availability for systems suitable for integration with hydrogen separation technologies for fuel cells or fuel synthesis. This is due in part to areas of fuel chemistry that are not established enough to support the commercial demonstration programs and facilitate the development and scale-up of advanced gasifiers and gas cleanup systems.

- **Syngas cleanup and conditioning**—The raw gases from biomass systems do not currently meet strict quality standards for downstream fuel, chemical synthesis catalysts, or those for some power technologies. These gases will require cleaning and conditioning to remove contaminants such as tar, particulates, alkali, ammonia, chlorine, and sulfur. Available cleanup technologies do not yet meet the needed cost, performance, or environmental criteria needed to achieve commercial implementation.

- **Sensors and controls**—Development of effective process controls is needed to maintain plant performance and emissions at target levels with varying load, fuel properties, and atmospheric conditions. New sensors and analytical instruments are under development to optimize control systems for thermochemical systems.

- **Process integration**—As with all new process technologies, demonstrating sustained integrated performance that meets technical, environmental, and safety requirements at sufficiently large scale is essential to supporting commercialization. Applications such as black liquor integration in paper mills has the added complexity of being attached to an existing commercial process where the unit operations associated with steam production, power, pulping, and chemical recovery must all be integrated.

---

[63] European Biomass Industry Association, n.d.

- **Containment (materials of construction)**—Experience with existing gasifiers indicates that gasification reactions are difficult to contain and that materials development for reactor shells and internals, refractory materials to line containment vessels, vessel design, and increased knowledge of bed behavior and agglomeration will improve performance over the long term.

5.3 Modular Systems

Modular biomass-fueled CHP systems are defined as small systems, less than 5 MW, though typically smaller, with the main operating components coming in one or more pre-engineered and packaged modules for simple installation at the user's site. The systems typically include a fuel processor (combustion or gasification), necessary intermediate fuel cleanup, an electric generator, and heat recovery from both the power generation and energy conversion sections. An automatic fuel storage and delivery system must be added for a complete operating system.

Small modular biomass systems can supply electricity to rural areas, farms, businesses, and remote villages. These systems use locally available biomass fuels such as wood, crop waste, animal manure, and LFG. Development of biomass-fueled modular power systems is of great interest internationally as a means to bring power to isolated communities in areas lacking power and fuel infrastructure. In the United States, there is interest in small systems to utilize opportunity fuels from a local area, such as crop wastes or fire control forest thinnings.

A partial listing of specific developer/manufacturer modular systems is provided in Appendix D.

Characterization

Modular systems are essentially scaled down versions of larger systems. There are systems that use direct-fired technology with steam power, and systems that use gasification technology and gaseous fuel burning power technologies (discussed in Chapter 6) such as internal combustion engines, microturbines, and Stirling engines. There are also direct fired systems that use Stirling engines for power production, as well as systems that employ gasification, wherein the hot raw gas is combusted to raise steam.

Modular Gasification Systems

Figure 5-8 shows a schematic of a 75-kW modular biomass gasification system that is representative of systems under development. The figure shows that there are eight submodules included in the basic system and that the storage and feed submodules are not included.

Basic Package Modules

1. Automatic biomass feed system.

2. Dryer to reduce the feedstock moisture content.

3. Chip sorter for sizing.

4. Heat exchanger that extracts heat from the gasifier for use in the dryer and for onsite thermal applications.

5. Gasifier feeder.

6. A downdraft gasifier producing low Btu gas (heating value of about 110 Btu/scf—HHV).

7. Filtering stages that remove particulates.

8. The power module—this can be an internal combustion engine designed to run on low Btu fuel, a microturbine, a Stirling engine, or even a fuel cell. The power module also has heat recovery equipment to provide additional useable thermal energy for onsite use. Because the gas is of such a low Btu content, propane or natural gas is required on system start-up. After start-up, the system can run on the syngas alone.

Systems such as these will require feedstock storage with an in-place delivery system. An in-ground storage bunker with a moving bed would allow direct delivery of fuel loads into the automated system. This can consist of a permanently installed live bottom van into which dump trucks can deliver a sized fuel supply.

Figure 5-8. Example Modular Biomass Gasification System
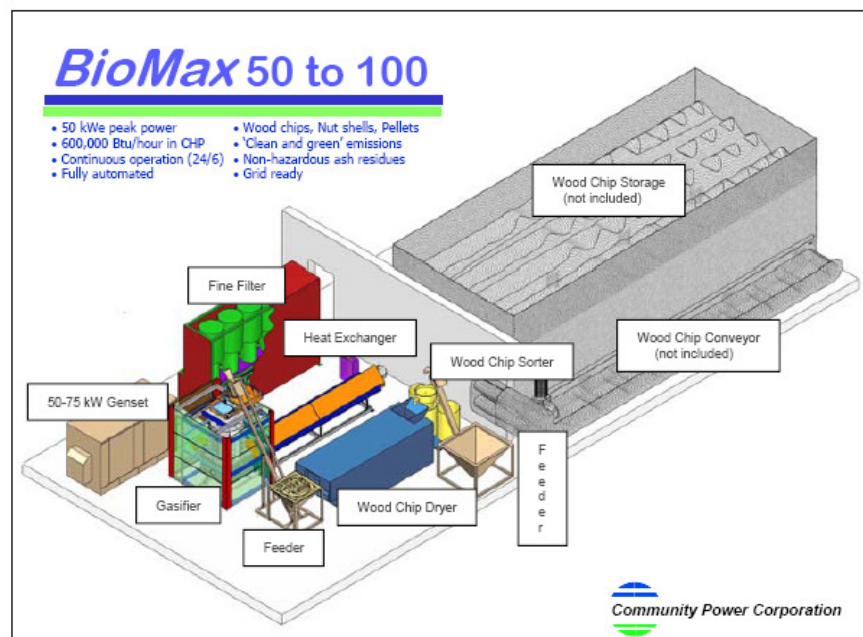
Source: Community Power Corporation, n.d.

Modular Combustion Systems[64]

Direct combustion in fixed bed combustors is a commercial technology in larger sizes. In these larger systems, as characterized previously, power is generated by steam turbines. In modular systems, other power systems are being developed that are more suitable for small-sized applications. The typical power and heat cycles being employed or explored for use are as follows:

• Steam cycle

• Organic Rankine cycle (ORC)

• Brayton cycle, hot air turbine

---

[64] Example shown, BioMax, is developed by Community Power Corporation.

- Entropic cycle, as defined by its developer, similar to Organic Rankine cycle but with a higher temperature differential producing higher efficiencies

- Stirling Engine, external combustion

Modular power and heat cycles that can be driven by biomass combustion are shown in **Figure 5-9.**

Figure 5-9. Heat Engine Power Cycles for Modular Biomass Combustion Systems[65]
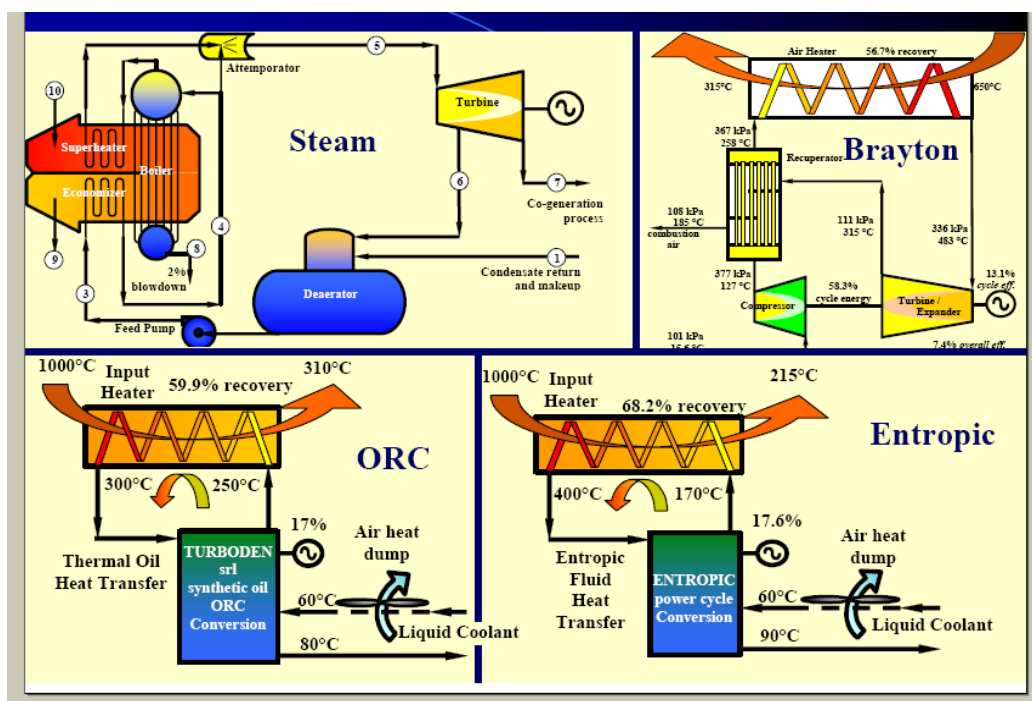
Source: Smith, 2006.

In addition to the four power cycles shown, very small (500 watts to 10 kW) modular systems are being developed using Stirling engine technology. The generators will convert various biomass fuels (wood, wood pellets, sawdust, chips, or biomass waste) to electricity and useful heat.[66] These systems typically convert 10 to 20 percent of the fuel energy to electricity; 60 to 70 percent of fuel energy is then available for heating water and spaces. The burner for the prototype system includes a ceramic fire box and a fuel hopper with a fuel capacity of 24 hours. It accomplishes complete two-stage combustion with comparatively low emissions. The Stirling engine-alternator requires minimal maintenance because its gas bearings eliminate contact, friction, and wear. Its projected life is 40,000 hours.

Modular Hybrid Gasification/Combustion Systems

The modular hybrid gasification/combustion system operates functionally like a direct combustion system. Power is derived by a back-pressure steam turbine that also provides steam for onsite thermal energy requirements. The difference is that the combustion chamber is actually a gasification system that uses a two-chamber gasifier approach. The system is similar to a two-stage combustion boiler

---

[65] Smith, 2006.

[66] A system under development by Sunpower Stirling engine technology licensee is External Power LLC of Indianapolis.

design. This approach allows the production of gas in a relatively cool chamber at temperatures from 1,000°F to 1,400°F, and then combustion in a relatively hot chamber—the boiler—at temperatures up to 2,300°F. These temperatures allow the complete removal of carbon from the fuel in the gasifier, and more complete oxidation of complex organics in the oxidation zone. The combination of these features results in a clean-burning, fuel-efficient system. CHP units include small back-pressure steam turbines from 100 kW up to several megawatts.

This approach combines the simplicity and low cost of a combustion system with the gasification advantages of more complete carbon conversion and cleaner combustion characteristics. An example of a modular gasification/combustion system is shown in **Figure 5-10**. This system has the capability to use fuels with moisture contents ranging from 6 to 55 percent (wet basis). The system also has a 20:1 turn-down ratio to allow it to idle during periods of low heat demand.

Figure 5-10. Example of Modular Gasification/Combustion Process
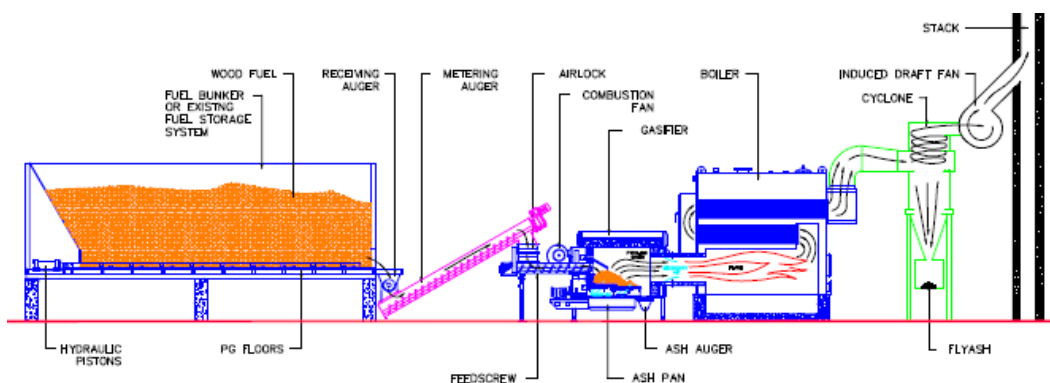
Source: Chiptec® Wood Energy Systems, n.d. [67]

Efficiency

Modular system electric generation efficiencies are typically fairly low as shown in **Table 5-17**. In applications requiring considerable thermal energy, the overall CHP efficiencies are comparable to gas-fired systems. However, the electric to thermal ratio for these systems is much lower, so more of the total useful energy is delivered in the form of heat rather than in the form of higher value electricity.

---

[67] Example shown is a patented process by Chiptec® Wood Energy Systems, Burlington, Vermont.

Table 5-17. Efficiencies of Modular Biomass Systems, Based on Conversion of Switchgrass at 20 Percent Moisture

| System Type	Electric Efficiency	Thermal Energy Delivered	Overall CHP Efficiency
Small steam	6%	59%	65%
Air Brayton	8%	41%	49%
Organic Rankine	11%	56%	67%
Entropic	13%	63%	76%
Stirling	13%	64%	77%
Modular gasifier	16–22%	29–53%	55–75%
Hybrid gasifier/combustor	<15%	45–55%	60–70%

Operating Advantages and Disadvantages

The main operating advantages today are in the use of opportunity biomass fuels of low value such as wood chips or forest thinnings. In addition, many of the systems are targeted at remote applications where it would be too costly to connect to grid electricity.

The main disadvantage affecting all types of modular systems is the comparatively high capital costs associated with all of the required equipment. This equipment also takes up considerable space compared to conventional gas-fired CHP systems. The engine generator systems occupy only about 5 percent of the total space required for the modular biomass system. Another disadvantage is the need for maintenance and repairs associated with the many subsystems, particularly the solids handling components and filters.

Equipment and Installed Cost

Equipment costs are speculative. Information in this section is as provided by the vendors and secondary sources. **Figure 5-11** shows a range of costs ($/kW) for different types of direct-fired systems. It is not clear that these costs include the costs of feedstock storage and delivery, which would add another $600 to 1,000/kW to the overall costs.

Figure 5-11. Size and Cost Ranges for Direct-Fired Modular Systems[68]
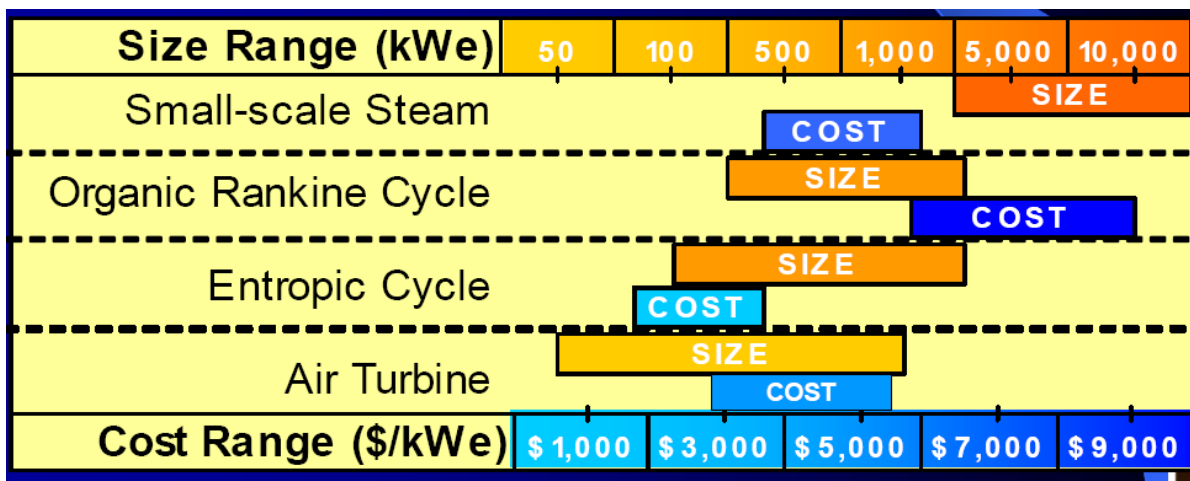
Source: Smith, 2006.

Modular gasification costs are estimated to be between $2,500 to $4,000/kW for the basic equipment with another $600 to $1,000/kW for a biomass storage bunker and $1,000 to $2,000/kW for installation.

The hybrid gasification/combustion system by itself costs about $300/kW. This component must be matched with feedstock storage and delivery ($600 to $1,000/kW), small-scale boiler, small-scale steam turbine generator ($900 to $1,200/kW), and other equipment, including controls, cyclone fly ash recovery system, and exhaust stack. Overall installed capital costs would be $12,000 to $18,000/kW.

O&M Costs

Most modular systems are characterized by continuous operation, automatic ash and char extraction, automatic feed, and automatic process control. Maintenance of 0.5 to 3 hours per week is required for monitoring feedstock deliveries, ash removal, filter cleaning or replacement, and inspecting and fixing problems with the automatic feed system. In addition, prime movers such as internal combustion engines or microturbines require similar maintenance attention as for gas-fired systems.

The overall costs and reliability of these systems has not yet been established.

Commercial Status

There are a number of small development companies working on modular biomass heat and power systems (listed in Appendix D). Most of the systems that have been installed in the United States are part of research, development, and demonstration projects funded by a variety of federal and state sources. DOE has an active research and development program on modular biomass as does USDA and the U.S. Forest Service. The United Nations also has an ongoing program in this area to develop village power systems using biomass.

---

[68] Smith, 2006.