Biomass for Steam and Power

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Introduction

This paper explores the use of equipment to fire biomass to replace fossil fuel in plant operations. Biomass is a low cost fuel that also reduces our carbon footprint. We'll discuss the technology and economics of fuel feed equipment, stoker boilers, bubbling fluidized bed boilers, circulating fluidized bed boilers, gasifiers, combustion control systems, emission controls, revenue and capital costs.

Most types of organic material can be burned for steam and power. In the final analysis, the choice of feedstock comes down to a matter of economics. The technology is currently available and new innovations are remarkable. Various types of wood waste have been burned in the forest products and pulp and paper industry for decades, if not centuries. Some locations are using agricultural wastes and products such as rice straw, rice hulls, corn stover, distiller grains, animal bedding waste, manure, bagasse etc. as boiler fuel.

Although applications exist to convert biomass to biofuels and chemicals, the intent of this discussion is to convert biomass for steam and power. Biomass can be burned directly in a boiler, or a gasifier can be utilized to produce syngas that can be used for a substitute fuel.

Fuel Handling

A robust material handling feed system is required to ensure the efficient operation of any of the combustion devices. Biomass is one of the more difficult materials to handle, and is especially obedient to Newton's 1st and 3rd Laws.

I. "Every object in a state of uniform motion tends to remain in that state of motion unless an external force is applied to it."

There are multiple external forces that prevent biomass from staying in motion.

III. "For every action there is an equal and opposite reaction."

Once in place, biomass tends to stay in place!

Biomass presents a variety of interesting challenges and takes special handling. Wood chips or wood waste materials tend to hang-up and bridge. After the bridge forms, biomass is difficult to move. Compaction makes the material stronger and must be avoided to ensure uninterrupted operation. As a part of a good boiler or gasifier operation, getting fuel to the plant reliability is key. Below is an example illustrating methods of handling biomass material.

Figure 1: Fuel Storage Silo with Traveling Screw

It is important to employ good fuel feed and conditioning systems. There should be enough "take away" capacity in order that fuel handling systems do not jam and plug. Materials must be screened adequately to remove sticks, oversize material, stones and tramp metal. Non-magnetic materials need to be detected to prevent damage to downstream systems.

Equipment must be accessible for lubrication, inspection and maintenance programs. Appropriate cleanouts should be designed where systems might plug. Storage vessels should be designed to prevent bridging. Bins may be tapered slightly outward to avoid compaction and help prevent bridging. Also, the outlet screw discharge rotates around the bin to ensure uniform flow through the bin and first-in/first-out operation.

Screw conveyor design is critical in handling biomass. Material handling is significantly different for biomass versus coal, gravel and ash applications. Biomass will compress,

compact, and gain strength in compression. Screws are tapered to improve flow characteristics.

Boilers & Gasifiers

Stoker fed units, bubbling fluidized bed boilers, circulating fluidized bed boilers and gasifiers are available for burning various biofuels. Let's review their operating characteristics to understand which applications are most appropriate for biomass.

Stokers

Stoker fed units were one of the first technologies to fire biomass. Still used today, they are reliable and efficient and can use a variety of fuels, including wood waste, municipal solid waste, and agricultural materials such as corn stover, straw, and animal waste. The stoker can also handle sludge and combination fuels, including coal, and tire derived fuel.

Improvements have been made with Computer Fluid Dynamic (CFD) modeling, improved overfire air systems, deep bed burning and emission controls. Older units have had small inefficient overfire air systems, which can result in lower efficiency, low steaming rates, poor carbon burnout, and high CO, NOx and particulate emissions. All boiler manufacturers and other suppliers now have improved combustion air systems to mitigate these issues.

Stokers can burn many types of fuels individually or in combination. Some operate similar to a gasifier with a deep bed of fuel on the grate. The bed can be burned in a low oxygen environment with undergrate air. Overfire air completes the combustion higher in the furnace. The advantage is a reserve of fuel in the boiler, ready to pick up an increase in steam demand. A rapid decrease in steam demand is attained by reducing undergrate air and fuel under controlled conditions.

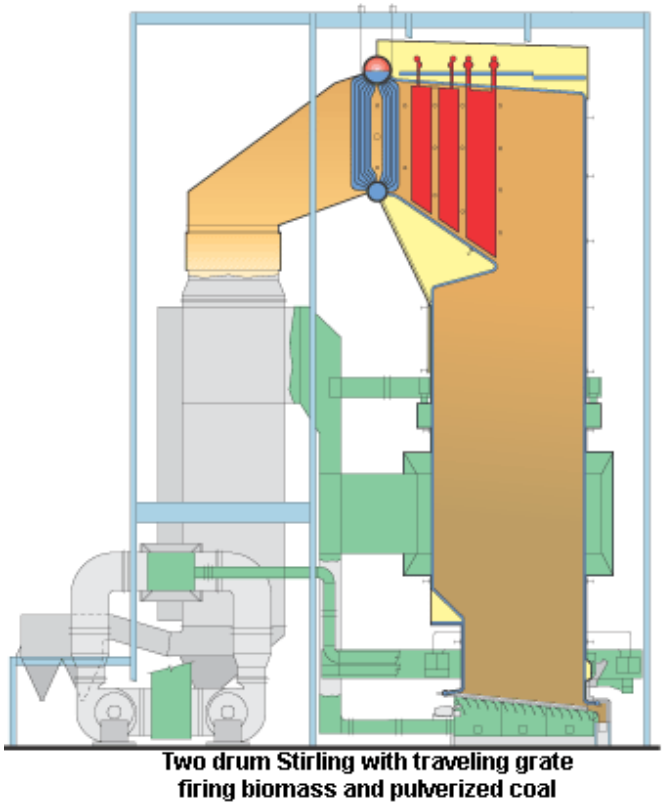


Figure 2: Stoker Boiler
Used with permission from Babcock & Wilcox

Stoker boilers are capable of handling many fuels. Their advantage is lower capital cost for clean biofuels with no sulfur. With sulfur bearing fuels, an SO_2 scrubber would be required. A Stirling boiler with a stoker and traveling grate is shown above.

These are used extensively in forest products, pulp and paper, and in power plant applications. The boilers have application in small to large sized industrial applications for firing many types of biomass and solid fuels.

Bubbling Fluidized Bed Boiler

Bubbling Fluidized Bed (BFB) Boilers are applicable for specific fuels, such as agricultural wastes and for combinations such as wood waste and paper mill sludge.
Well designed systems have low carbon monoxide and NOx emissions. Medium size applications range between 100,000 to 250,000 lb/hr of steam generation for bottom supported units and large applications to 700,000 lb/hr for top supported units. The bubbling bed of sand provides a heat sink which allows the boiler to handle various types of fuels and somewhat variable moisture contents.

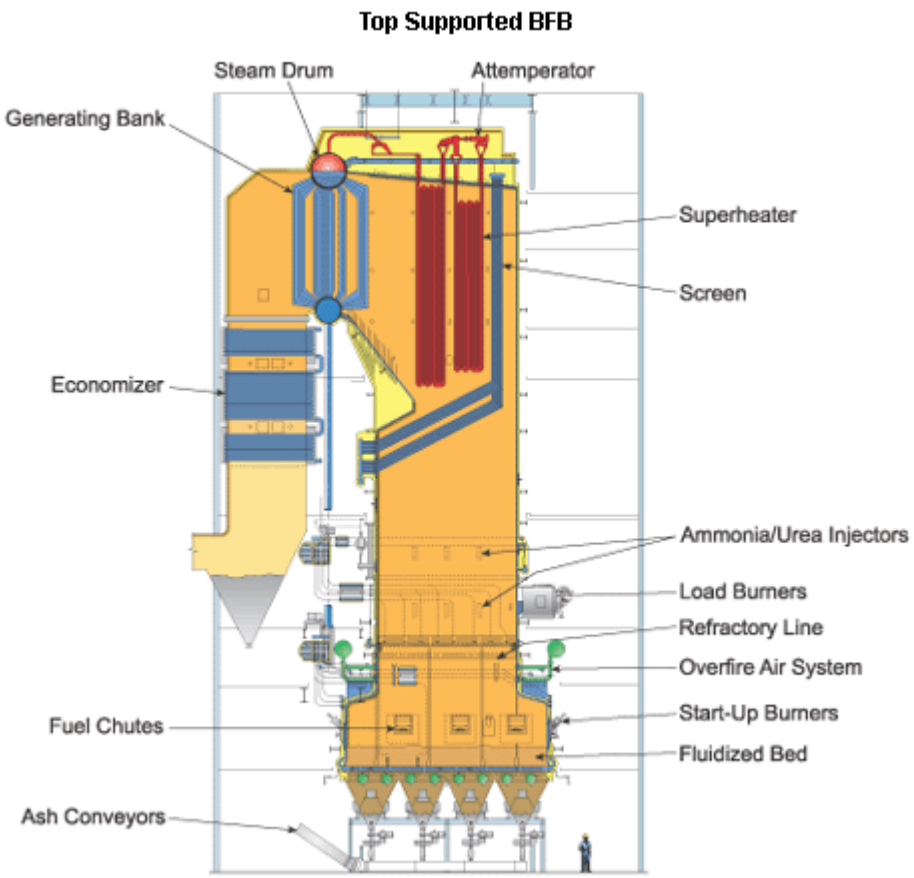


Figure 3: Bubbling Fluidized Bed Boiler – Top Supported
Used with permission from Babcock & Wilcox

At a paper mill in Wauna, Oregon, Georgia-Pacific operates and maintains a BFB boiler owned by a local Public Utility District for power generation. The boiler, installed in 1995, produces 120,000 lb/hr of steam from wood waste and paper mill sludge. The boiler has an excellent reliability and supplies steam to a steam turbine generator and the paper mill on a continuous basis.

The unit has ammonia and flue gas recirculation for NOx control, limestone for SO2 control, and baghouses for particulates. The baghouses also removes some SO2.

Circulating Fluidized Bed Boiler

A Circulating Fluidized Bed (CFB) Boiler works well with multiple fuels and mixed fuels. As it relates to alternate fuels and moisture content, this type of boiler is quite forgiving. Typically, the boilers are not used for biomass, but biomass can be considered in

combination with fuels such as coal. In general, the boilers would be used for large industrial applications and utility boilers with steaming rates of 250,000 to 1,500,000 lb/hr. The capital cost is reduced for back end emission control equipment because SO_2 control can be accomplished with lime within the circulating flue gas. The unit has low emissions for NOx due to lower firing temperatures.

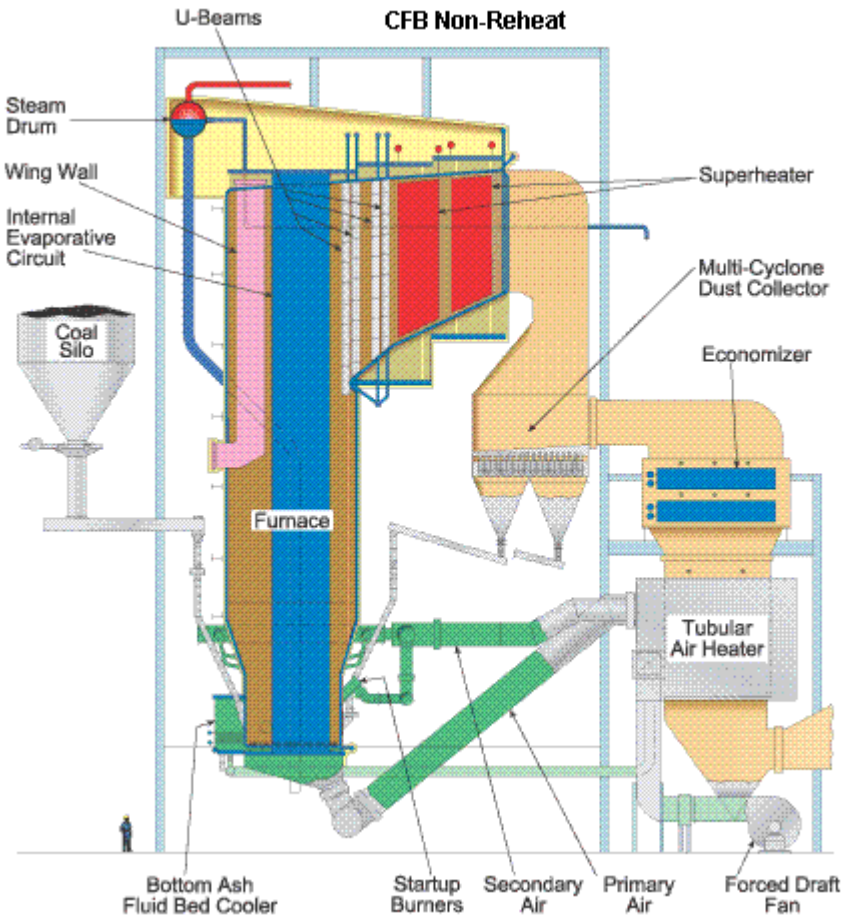


Figure 4: Circulating Fluidized Bed Boiler

Gasifiers

Gasification is an old technology used with coal to form producer gas, mainly carbon monoxide, and is now back in favor and considered "new" technology. There have been many improvements to this technology, which can be adapted to allow biomass to replace fossil fuels.

A gasifier itself is a piece of equipment that burns organic fuel in an oxygen-starved environment. This produces carbon monoxide, hydrogen, and methane, and small amounts

of other organic products. The CO, H_2 and CH_4 are the main components that are subsequently oxidized as fuel to produce heat.

Carbon reacts with water to form carbon monoxide, carbon dioxide and hydrogen at elevated temperatures.

$$C + H20 = CO + H2$$

$$C + 2H2O = CO2 + 2H2$$

Shown below is a gasifier by Nexterra, which produces syngas. The syngas temperature is controlled between 700 and 900 degrees F with 25% moisture fuel. Temperature is affected by moisture content of the fuel and controlled by varying the amount of flue gas recirculation and oxygen to the gasifier.

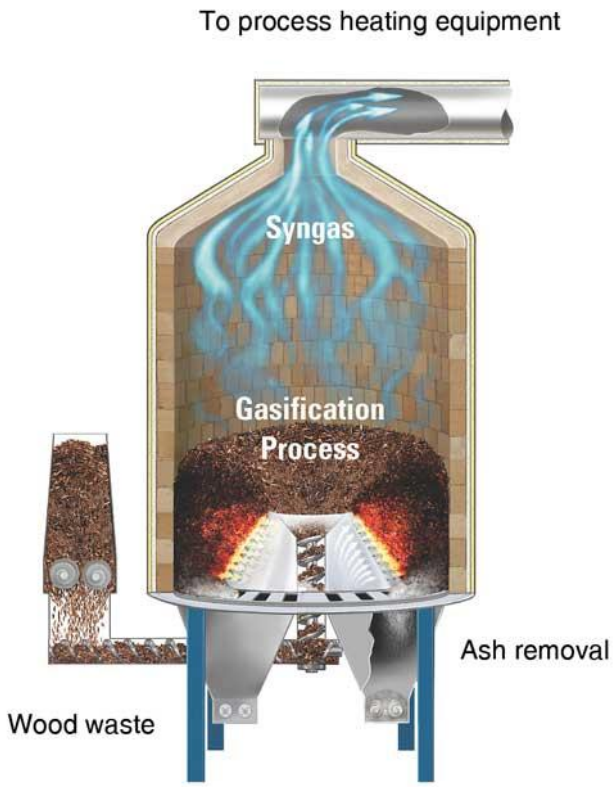
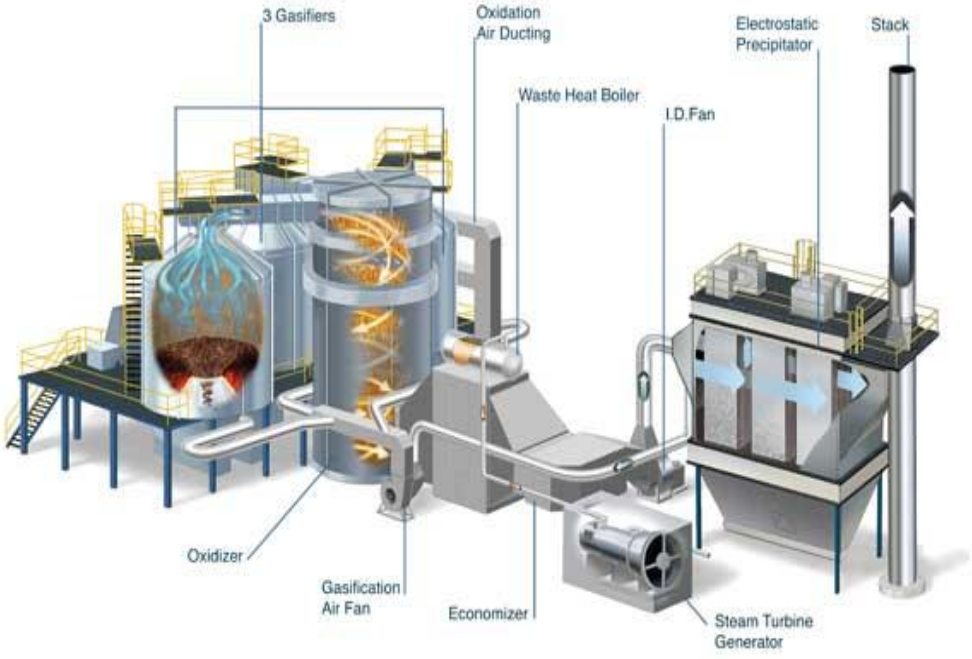


Figure 5: Nexterra Gasifier

Gasifiers clearly have some advantages. The gasification process operates at low firing temperatures, which results in less slagging in the gasifier furnace. The ash is light and feels similar to ash in your fireplace. The syngas is clean and also fires at a low temperature due to its low BTU content. This also results in less slagging in the superheater and generation banks of the downstream boiler.

This type of gasifier is good for single fuel applications. It produces lower NOx due to low furnace temperatures. The oxidizer burns the syngas and other organics and provides low CO and particulate emissions. Small units are available for low steam production rates in the range of 20,000 to 200,000 lb/hr. Multiple gasifiers are used to attain the higher production rates.

An example installation is shown in Figure 6. The gasifier is designed to produce 60,000 lb/hr of steam and 1.4 MW of electricity. Three gasifiers supply a single oxidizer. A waste heat recovery boiler produces 600 psig, 740 deg F steam. The steam turbine generator exhausts to the 110 psig steam system to heat the university campus. Capital cost of the facility, installed in 2007, was $20,000,000 and reduces the campus annual energy costs by $2,000,000. In addition, it generates approximately $600,000 per year of electrical energy.



Nexterra Biomass Gasification System at Johnson Controls' University of South Carolina Cogeneration Project.

Figure 6: Gasifier / Oxidizer Biomass Cogeneration Plant

Other gasifiers can produce a syngas of higher Btu quality by not using air in the gasifier. For instance, a bubbling bed steam reformer can produce a higher Btu syngas with superheated steam converting the biomass to carbon monoxide and hydrogen. The reaction is endothermic.

Shown below, pulse combustion heaters (PulseEnhanced ™ Heat Exchangers) burn a portion of the syngas to provide indirect heat to a bubbling bed of alumina oxide and biomass. The PulseEnhanced ™ Heat Exchanger in the bed is shown in Figure 7. Excess syngas would be available for steam and power generation or other uses.

Figure 7: PulseEnhanced ™ Heat Exchanger for TRI Bubbling Bed Steam Reformer

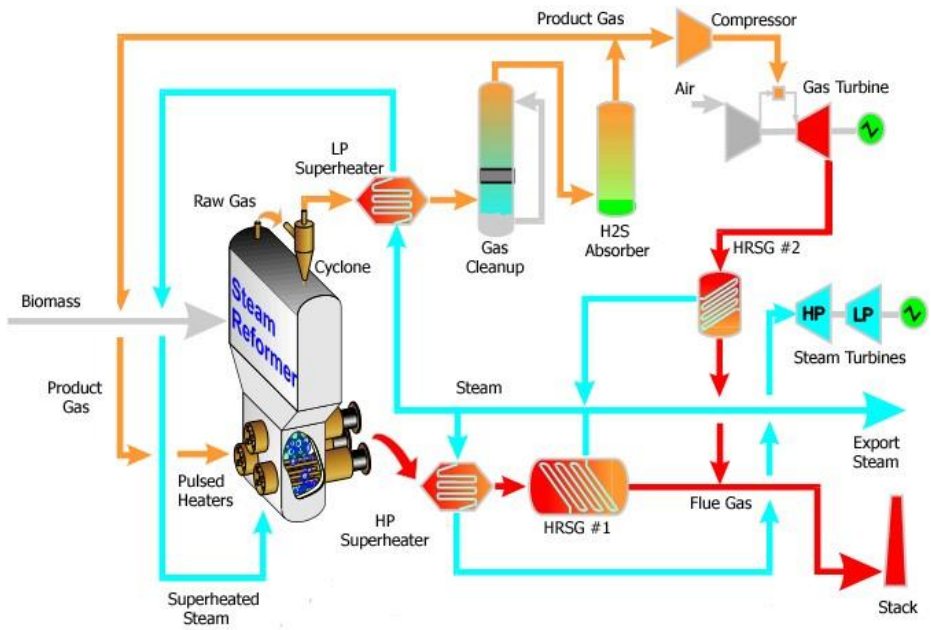


Figure 7A Steam Reformer Gasifier in Steam & Power Application

Combustion Controls

Proper combustion controls are required for efficient operation of all boilers and gasifiers. Good oxygen control is necessary for safety, proper combustion, and efficiency. Fuel to oxygen (or air) ratio is measured and controlled. Flue gas oxygen levels are measured and used for trim control. Programmed controls may be installed for startups, shutdowns and special transitions to avoid hazardous explosive conditions. Improved efficiency can be attained utilizing carbon monoxide controls and good overfire air distribution systems. Overfire air systems are often designed using CFD (Computer Fluidized Dynamics) design.

Contaminants

Contaminants such as potassium, sodium, chlorides, silica and phosphorus can create havoc in a boiler without proper design and chemistry. Variation in fuel type, fuel quality, season and moisture will create operational issues.

Sodium, potassium and phosphorus can cause slagging due to the reduction in the ash melting point. Chlorides from salts or plastics can cause corrosion, slagging and HCl emissions. Silica may cause slagging and erosion. Sulfur produces SO_2 emissions, SO_3 emissions, and cold end corrosion.

It is recommended to analyze the fuel ash for low fusion point and mix fuels or add materials such as lime to mitigate sticky ash. Sootblowers in specific boiler areas may be required to keep heat transfer surfaces clean.

Where possible, contaminants should be removed from the fuel.

Emissions

How are emissions kept under control for sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO), volatile organics (VOC's), particulates, and possibly other emissions?

SOx can be reduced internally with lime addition in FBB and CFB boilers. Otherwise backend equipment is needed using lime in a wet scrubber, or a spray dryer absorber with a baghouse.

NOx can be reduced with overfire air controls, SCR (selective catalytic reduction), SNCR (Selective non-catalytic reduction), and overfire air controls. Thermal NOx can be reduced with lower firing temperatures and with flue gas recirculation. Ammonia or urea is used to convert the NOx to nitrogen.

Carbon monoxide (CO) and volatile organic hydrocarbons (VOCs) are reduced with good combustion controls and good design with CFD (computerized fluid dynamic) modeling. Minimal air leakage with proper seals is helpful in reducing emissions and improving thermal efficiency. Combustion air systemsmust be controlled to ensure that the air is added in the proper ratios to the various injection points.

Note in Figures 8 and 9 that the FBB boilers have lower CO emissions due in part to better mixing and lower NOx emissions due to lower firing temperatures and low excess oxygen.

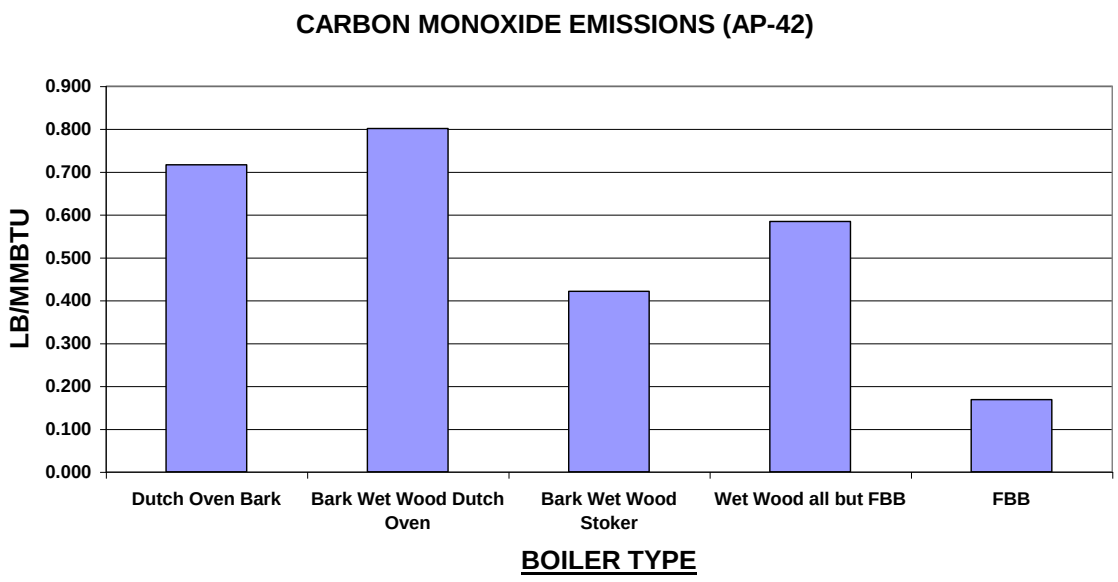


Figure 8: Carbon Monoxide Emissions

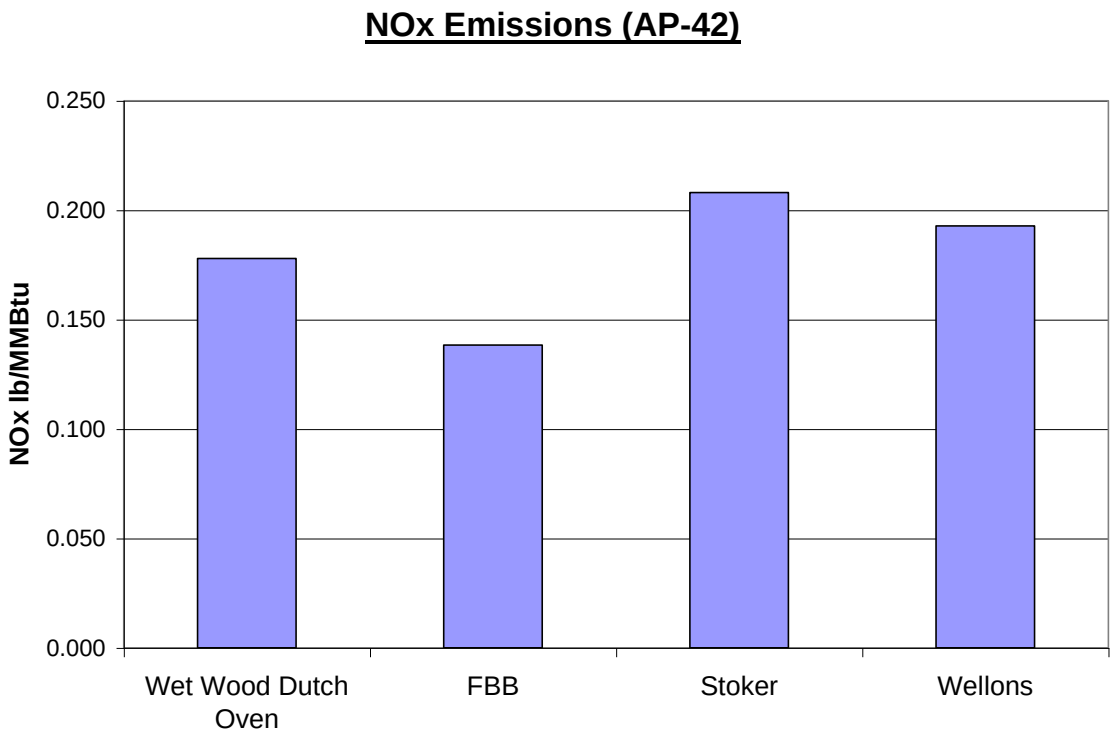


Figure 9: Nitrogen oxide emissions

Particulate emissions are typically controlled with a baghouse or an electrostatic precipitator.

Operating Costs

One of our goals is to reduce fossil fuel use in our steam and power plants. Biomass fueled boilers or gasifiers can be used to replace fuel oil or natural gas as one method to accomplish this goal. For a 100,000 lb/hr steam boiler operating costs can be reduced by more than 50%, depending on the cost of fuel as shown in Figure 10 below.

One option would be to use a gasifier to produce syngas or producer gas, which could be burned in a retrofitted existing boiler. Such a plant is starting up in the first half of 2008 at Chippewa Valley Ethanol Corporation in Benson, Minnesota. The gas is burned through a multifuel COEN burner on a conventional power boiler.

Burning biofuels can be accomplished economically and can help reduce our dependency on fossil fuels. For a 100,000 pound per hour boiler, natural gas at $8/MMBtu would have an annual fuel cost of $8,200,000. Biofuel costs could be half compared to natural gas.

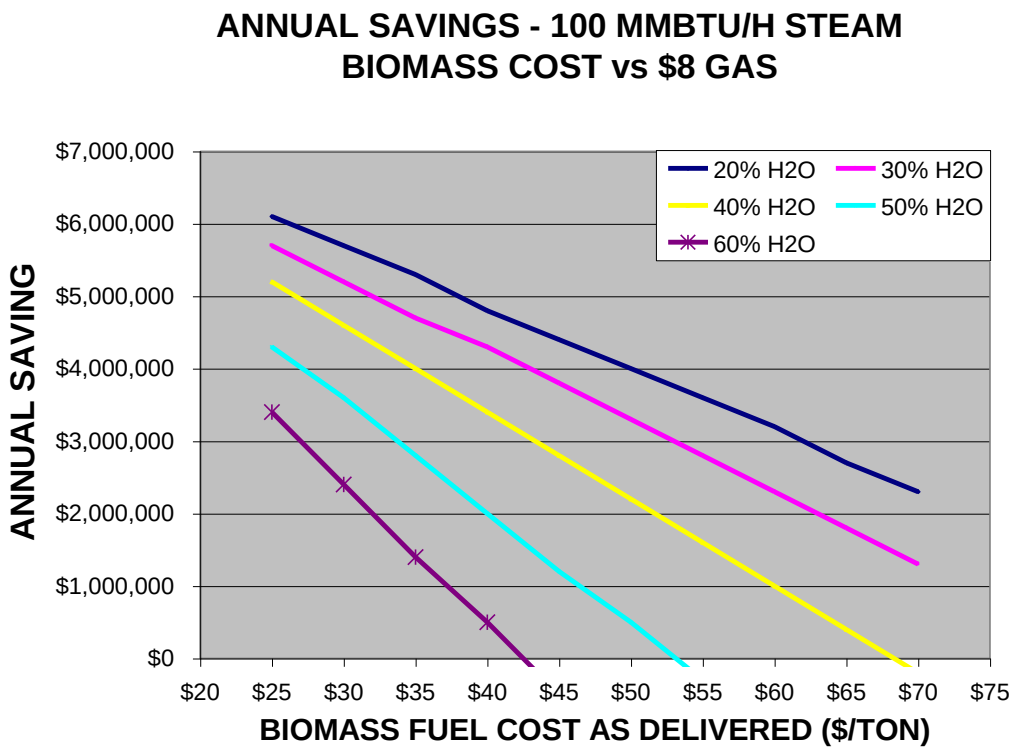


Figure 10: Fuel Savings – Biomass (as delivered) vs. Natural Gas

At the same time, should we consider power generation?

Extraction power from a steam turbine generator could be produced at less than $0.02/kwh. Based on a cost of a steam turbine generator at $1000/kw, and a fuel cost of $50/bdt, a 5 MW generator could provide additional revenue of $2,300,000 with a payback on capital of less than 2.5 years.

Condensing power is more expensive to produce due to the lower efficiency for condensing power generation but also for the higher cost of fuel. The fuel to the plant would be delivered from a greater distance for incremental power generation. Fuel for power might cost $0.04 to $0.06/kwh and would most likely not be economical.

Revenue for extraction power and condensing power is shown below.

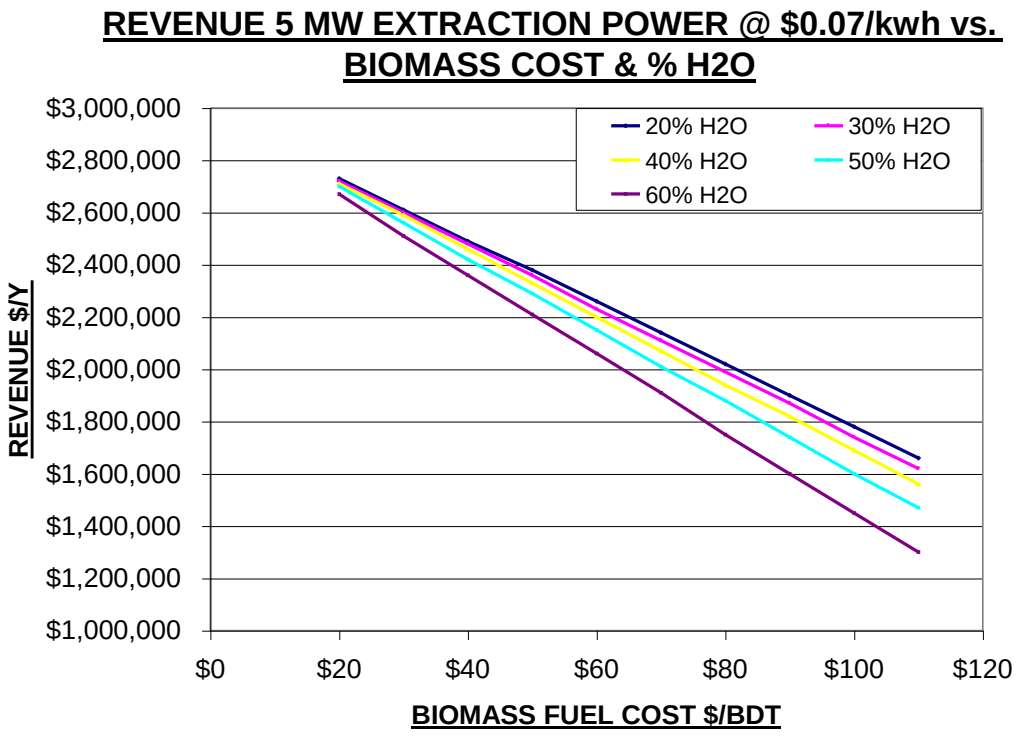


Figure 11: Added Revenue (minus fuel cost) from Extraction Power

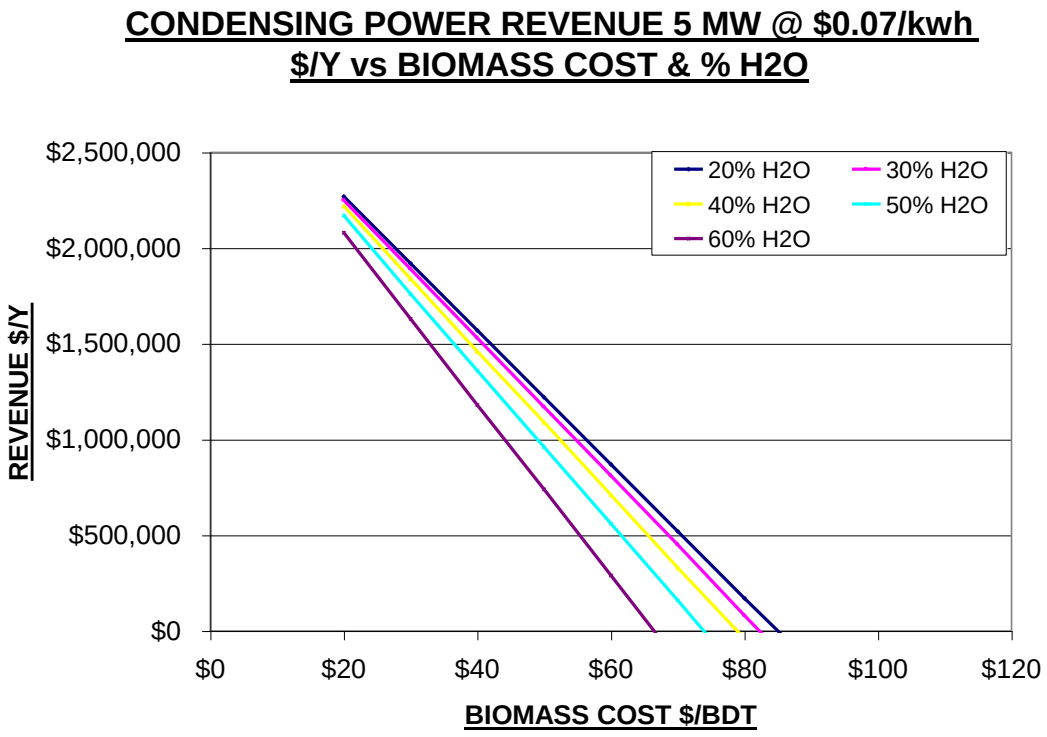


Figure 12: Added revenue (minus fuel cost) from Condensing Power

Capital Costs

Compared to natural gas, capital costs are higher for handling solid fuels and producing steam and power. The equipment is larger and more complex. More emission control equipment is also needed. The question becomes one of obtaining an acceptable return on investment with proper design of the equipment, a reasonable cost for biomass, and acceptable revenues for steam and power.

For a greenfield plant, such as at University of South Carolina shown in Figure 6, the simple payback could be 5 to 8 years on the $20,000,000 investment; not suitable for an industrial facility. Grants from DOE, utilities and other programs would be needed to make the facility viable. The objective here would be to look for utilities that require green power for increased revenues. Industrial facilities may have some infrastructure in place whereby the plant could modify existing equipment. Options may include cogeneration for increased efficiency, or adding extraction power tied into the plant process. In addition, thermal efficiency of existing industrial processes can be improved to reduce operating costs. Improved thermal efficiency can also be gained by reducing moisture in the fuel and reusing waste heat where possible.

Shown below is a breakdown for the capital cost of a biomass fired boiler for steam and power.

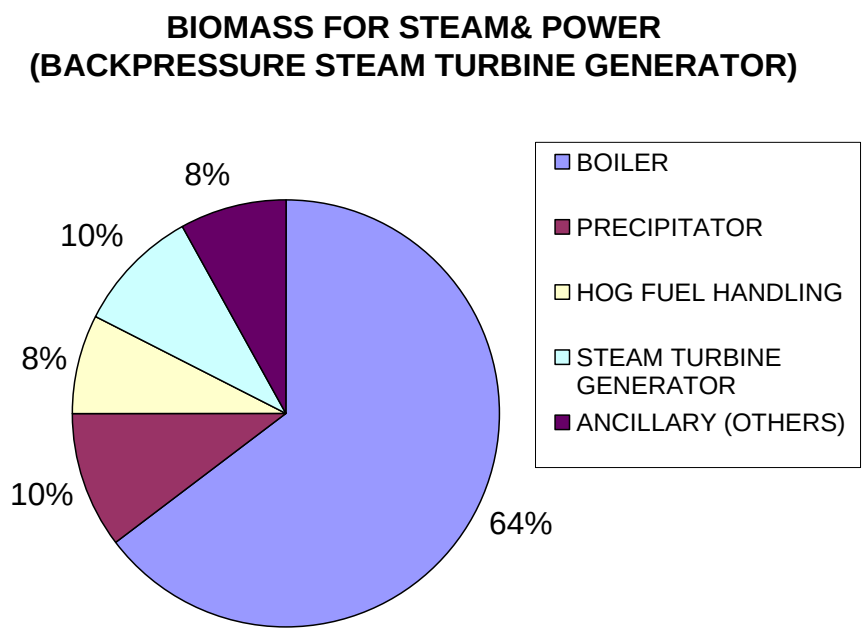


Figure 13: Capital Cost Biomass Fuel Boiler

The capital cost for a greenfield steam and power plant is high and may not be justifiable. As a result, existing infrastructure should be utilized wherever possible. Since the boiler is the largest capital cost, one should evaluate modifying an existing boiler to accept syngas to replace natural gas or fuel oil. Other considerations include utilizing:

- existing precipitators
- existing solid material or fuel handling facilities
- existing steam turbine generators

Can the facility produce other value added products from the syngas such as biofuels, ethanol or chemical products? If any parts of the existing infrastructure are not fully utilized, a gasifier can help supplement fuel systems and reduce energy costs.

Financing your CHP (combined heat and power) project independently may be difficult. Review 3rd party financing either from a private developer or from a utility that wants "green power" development. The payback on CHP projects is over 5 years and requires special financing.

Most biofuel plants cannot justify a green field steam and power plant on their own, unless there are other mitigating circumstances. For instance, a plant can burn sludge to reduce high landfill costs. Alternately, a plant could obtain tipping fees to burn sludge, biomass or municipal solid waste. If a utility needs to purchase green power as mandated by the state, such as WA, OR and others, the utility may pay for a significant portion of the power plant. Grant money also may be available for new technology development.

Plant experience

Fuel plugging and feeding issues can impact newly designed plants. Design of the fuel system by an experienced supplier.can mitigate this risk.

Stoker type boilers have many years of operating experience. Older boilers have room for improvement with better combustion control systems and overfire air systems. Reliability still remains excellent for most units.

CFB boilers are usually very large and are seldom used for biomass fueled applications.

BFB boilers have a history of high reliability with very satisfactory emissions. Items to be careful of include tube erosion from excessive velocity and turbulence, and sintering. Sintering can occur from high firing temperatures or low melting point eutectics due to sodium, potassium, chlorides, phosphorus or other non-process elements. Upset conditions and ID fan limitations can occur due to low temperatures, high moisture fuels, and low heating value fuels. Be watchful of corrosion or erosion issues due to boiler configuration

and plant design, resulting from unusual flue gas and combustion air distribution in tubular air heaters.

Gasifiers are becoming more popular for certain applications. Refractory design is important and appears to be holding up well. The ash from the gasifier is light and fluffy similar to that in a home fireplace. Observations show it is not sintering in downstream equipment. Long-term reliability and availability issues are yet to be determined but short-term operation is looking promising. Longer term operating experience will confirm the relaiability of these processes.

Conclusions

For firing biomass, good systems are available for many applications. From small to large units, almost any type of organic material, in one form or in combination, can be handled. Some fuels and combinations of fuel may need special treatment.

The economic solution is key to making the project successful. Boilers of different types make sense for medium to large projects while biomass gasifiers are making an impact in the small to medium size project range.

The cost of biomass fuel has a major impact on the return of investment. Fuel collection, delivery and storage at minimum costs are needed to make the large capital investment of the projects worthwhile.

Power generation can improve the project's return on investment. Cogeneration, where possible, produces power and exhausts the steam to a plant process. This may be a more economical solution compared to condensing power. Integration into an existing facility, grants from DOE or utilities, green power credits, and carbon credits all can make a project more feasible.

Acknowledgements:

Babcock & Wilcox
Energy Products of Idaho
Frontline Bioenergy
Georgia-Pacific Corporation
Johnson Controls
Kamengo
Laidig Systems
Kvaerner
Nexterra
Potlatch Corporation
TRI Thermochem Recovery International
University of South Carolina
U.S Department of Energy
Wellons

About Harris Group Inc.'s Biorefining Unit:

Harris Group Inc.'s biorefining unit provides full-service engineering and consulting services in the production of energy and chemicals from renewable feedstocks through sustainable technologies.

Our experience encompasses developing biomass processes that convert industrial, agricultural and municipal feedstocks into ethanol, biodiesel, biogas (methane), commodity chemicals, and other saleable products and byproducts.

Harris Group has worked alongside industry innovators, national laboratories and our customers to deliver process and design improvements for a variety of applications. Our goal is to make end products like ethanol, biodiesel and biogas highly competitive with fossil fuels and other comparable products.

Harris Group Inc. provides strategic support from feasibility through plant start-up with a core service of engineering and plant design. Specialty services include process conceptualization and development, research management and coordination, basic and detailed engineering, owner's engineering, financial due diligence and independent engineering, feasibility evaluation, process improvement and control systems integration.

For more information on how Harris Group can help with your existing alternative fuels facility or plans with your new facility, please contact:

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