Principles of Burner Design for Biomass Co-Firing

Bradley W. Moulton, P.E.
Foster Wheeler North America Corp.
Clinton, NJ 08809

Presented at
34th International Technical Conference on Coal Utilization & Fuel Systems
Clearwater, FL
May 31, 2009

TP_Firsys_09_02

Principles of Burner Design for Biomass Co-Firing

Bradley W. Moulton, PE
Foster Wheeler North America Corp
Clinton, NJ

ABSTRACT

Renewable portfolio standards and an intensified interest in greenhouse gas reduction has resulted in numerous utilities and industries, along with federal and state regulatory agencies, to consider biomass co-firing in both existing facilities and new facilities. Proposed biomass have included wood wastes ranging from bark to sawdust, agricultural materials (and wastes) such as switchgrass, alfalfa stalks, rice straw and hulls, poultry litter, hog waste, cattle manure, and more. The boilers proposed to utilize these fuels have included coal-fired cyclones, pulverized coal units, and circulating fluidized bed units.

Biomass co-firing can be applied to most pulverized coal boilers. Decisions on method of biomass handling and delivery are important considerations for a successful conversion. Perhaps the most critical design consideration is the integration of the co-firing equipment into the existing firing system. Full load unit capability for both 100% coal and biomass co-firing, emissions and long term boiler performance are only a few of the many important factors to take into account when retrofitting a pulverized coal boiler to co-fire biomass.

This paper summarizes the principles of burner design for biomass co-firing. It covers wall-fired (front and opposed) and tangential-fired boilers and focuses upon key burner design issues such as injector design and emissions associated with biomass co-firing. It draws upon the current and previous experiences of waste fuels and fuel blends, both co-firing in pulverized coal wall-fired and tangential-fired units. It also draws upon recent fuel characterization research to highlight the criticality of fuel-based issues.

INTRODUCTION

Co-firing of biomass with coal in coal-fired boilers is gaining increased interest in the utility market. Co-firing can provide a cost-effective option for utilities to address increasing renewable energy standards requirements as well as a being a means to mitigate greenhouse gases. Biomass is a renewable fuel and is typically considered CO2 neutral with respect to the overall greenhouse gas balance if the fossil fuel usage in harvesting and transporting the biomass is excluded.

Biomass co-firing interest and research began in the U.S. in 1992 with a research project conducted with Electric Power Research Institute (EPRI), Tennessee Valley Authority (TVA) and the U.S. Department of Energy and demonstrated at the Allen Fossil Plant, Colbert Fossil Plant and Kingston Fossil Plant. After the initial studies, several co-firing demonstrations have occurred as listed in [1]. Recent full-scale demonstrations include co-firing at Seward Generating Station, Ottumwa Generating Station and Plant Gadsden [2 – 4]

COAL AND BIOMASS FUEL CHARACTERISTICS

Careful consideration of fuel properties and their impacts need to be addressed when biomass co-firing is planned for a coal fired boiler. Table 1 compares analyses of sawdust, switchgrass and olive residues to those of two typical coals, a high volatile eastern bituminous and a sub-bituminous powder river basin (PRB) coal.

Proximate Analysis (as rec'd)	**Sawdust (spruce)**	**Switch-grass**	**Olive Residues**	**Eastern Bituminous (Pittsburgh Seam #8)**	**Powder River Basin (Rochelle/ N. Antelope)**
Moisture, %	34.93	15.00	6.00	3.50	27.30
Volatile Matter, %	55.03	65.18	73.10	38.60	32.10
Fixed Carbon, %	9.34	12.19	16.84	48.00	36.20
Ash, %	0.69	7.63	4.06	9.90	4.40
FC/VM Ratio	0.17	0.19	0.23	1.24	1.13
Bulk Density, lb/ft^3	18	6	55	55	55
Ultimate Analysis (as rec'd)					
Carbon, %	32.06	39.68	49.33	71.20	51.45
Hydrogen, %	3.86	4.95	7.39	4.70	3.50
Nitrogen, %	0.26	0.65	2.00	1.20	0.65
Sulfur, %	0.01	0.16	0.05	2.60	0.21
Oxygen, %	28.14	31.74	30.91	6.80	12.49
Chlorine, %	0.05	0.19	0.26	0.10	< 0.01
Higher Heating Value, Btu/lb	5,431	6,601	8,990	12,730	8,800
Nitrogen Loading, lb $N/10^6$ Btu	0.48	0.98	2.22	0.94	0.74
Sulfur Loading, lb $SO_2/10^6$ Btu	0.04	0.48	0.11	4.08	0.48
Chlorine Loading, lb $Cl/10^6$ Btu	0.092	0.288	0.289	0.079	0.011
Ash Elemental Analysis					
SiO_2, % (of total ash)	23.70	65.18	24.59	50.58	33.80
Al_2O_3, %	4.10	4.51	2.44	24.62	17.40
Fe_2O_3, %	1.65	2.03	1.34	17.16	5.62
TiO_2, %	0.36	0.24	0.13	1.10	1.38
CaO, %	39.95	5.60	8.50	1.13	23.81
MgO, %	4.84	3.00	1.87	0.62	5.60
Na_2O, %	2.25	0.58	0.51	0.39	1.89
K_2O, %	9.81	11.60	34.62	1.99	0.30
P_2O_5, %	2.06	4.50	5.64	0.39	1.10
SO_3, %	1.86	0.44	n.r.	1.11	8.20
Sodium Loading, lb $Na/10^9$ Btu	29	67	23	30	95
Potassium Loading, lb $K/10^9$ Btu	125	1,341	1,564	155	15
Ash Fusion Temps (Reducing)					
Initial Deformation, ˚F	n.r.	n.r.	2,129	2,220	2,125
Softening, ˚F	n.r.	n.r.	2,165	2,440	2,135
Hemispherical, ˚F	n.r.	n.r.	2,183	2,470	2,145
Fluid, ˚F	n.r.	n.r.	2,220	2,750	2,155

Abbreviations: n.r. = not reported
Sources: [5, 6]

Table 1. Characteristics of Selected Biomasses & Coals (As Received Basis)

The data from Table 1 highlights some of the important differences between the biomasses and coals. Note the higher moisture content, lower sulfur content and reduced heat content of the biomasses as compared to the typical U.S. coals. Of particular note, is the higher volatile matter content and subsequently lower fixed carbon to volatile matter (FC/VM) ratio. The FC/VM ratio is an indication of fuel reactivity and has a marked effect on NO_x emissions. Typically, fuels with lower FC/VM ratios show lower overall NOx emissions – e.g. PRB coals as compared to eastern bituminous coals.

Sulfur concentrations of most biomass are much typically lower than most coals, especially eastern bituminous coals. Consequently, SO_2 emissions can be reduced by co-firing biomass. Many biomasses have lower nitrogen contents which can produce lower NOx emissions due to the reduced conversion of fuel bound nitrogen to NO_x. However as seen in Table 1, this trend does not apply to all biomass. Alfalfa stalks, selected grasses, urban waste woods and olive residues can contain concentrations of nitrogen that are higher than typical coals when measured on a nitrogen loading (lb N/10^6 Btu) basis. Perhaps more importantly, with respect to NO_x emissions is the rate of nitrogen evolution.

During combustion, fuel bound nitrogen will either devolatalize with the volatile matter or remain behind in the char. Rapid devolatilization of the fuel nitrogen promotes longer residence times in the fuel rich, reducing zone of the flame. High volatile fuels therefore have more opportunity to realize the benefits of staged combustion – e.g., lower NOx emissions. Drop-tube reactor studies [7] have characterized the nitrogen evolution of several biomasses. Figure 1 shows the nitrogen volatilization patterns for a sawdust and switchgrass.

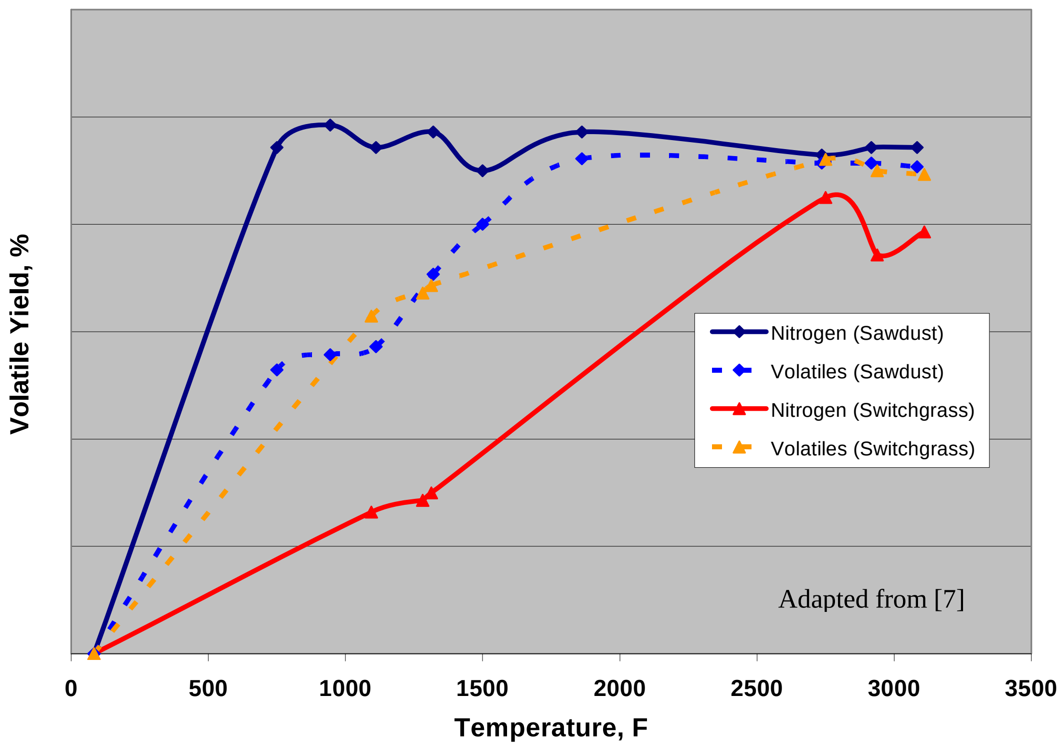


Figure 1. Nitrogen Volatilization of Sawdust and Switchgrass

As shown in Figure 1, the nitrogen in sawdust evolves earlier as compared to the switchgrass. In fact, contrary to most fuels [8], the sawdust nitrogen leads the total mass of volatiles evolved. The switchgrass nitrogen is retained more in the char and therefore will be largely oxidized to NO_x in the char burnout phase of the flame. This is supported by the experience at Ottumwa Generating Station where higher NOx emissions were reported co-firing switchgrass with PRB coal [3].

Finally, ash characteristics are an important parameter to consider when co-firing biomass. Chlorine contents of biomass can exceed those of typical coals when measured on chlorine loading (lb/10^6 Btu) basis. Chlorine, in conjunction with alkali metals found in high concentrations of biomasses such as sodium and potassium can lead to the formation of corrosion causing alkali-chlorides [9]. Sodium and potassium in high concentrations, lower ash fusion temperatures and can lead to localized waterwall slagging. However, designing a biomass co-firing system on the basis of ash analysis is not completely straightforward. Switchgrass potassium content can vary depending on when it is harvested – e.g., the timing of the biomass harvest has an effect. Switchgrass, for example, is better suited for co-firing when it's harvested in the fall because the nutrients get stored in the roots. If producers try to get two cuttings, it could create problems in a co-firing application because summer switchgrass has higher potassium content. [10]

COAL AND BIOMASS CO-FIRING IN BOILERS

Co-firing of biomass in coal-fired boilers can be divided into three categories; (1) direct co-firing where the biomass is introduced directly to the furnace, (2) indirect co-firing whereby the biomass is gasified and the resultant fuel gas is combusted in the furnace and (3) parallel combustion, which involves combustion of the biomass in a separate dedicated furnace and the product steam utilized within the coal plant steam system. Direct co-firing is primarily the method of biomass utilization within the U.S. Indirect co-firing and parallel combustion are recognized more in Europe [11], however direct co-firing still appears to be the favored co-firing technique.

This paper discusses the direct co-firing of biomass in coal-fired boilers. There are essentially two different approaches:

- Biomass can be mixed (co-mingled) with the coal upstream of the feeders – typically in the coal yard; and then processed through the milling and firing system.
- Biomass is handled and processed separately from the coal and introduced into the boiler within the confines of the existing firing system (e.g., co-axial with coal nozzles), dedicating a percentage of the existing burners to fire 100% biomass or using separate furnace waterwall penetrations.

The first approach has been used with some success on pulverized coal boilers with generally less than 5% biomass (by mass) [2, 11]. Introducing higher percentages of biomass through the coal milling system has demonstrated significant impacts on pulverizer performance – lower capacity due to higher moisture content of the biomass as well as reduced pulverizer exit temperatures. Biomasses tend to be highly fibrous - shredding along fiber lines and therefore do not tend to pulverize well using conventional pulverizer techniques. However, recent experience from Plant Gadsden, a tangential-fired unit in the U.S., demonstrated between 8 and 15% (by mass) green wood chips could be processed through the existing milling system [4]. There were no reported issues at wood chip levels of 10%. At 15%, there was slight reduction in boiler efficiency and low mill temperatures and high mill bowl under pressures caused a 5% load derate.

Consequently, the most applicable method of co-firing greater than 10% (by mass) biomass, is through separate handling and injection. Separate handling and metering of biomass has a higher capital cost associated with it, but it allows careful management of low bulk density fuels that may not blend well with coals. The following sections of this paper will focus on the separate direct co-firing equipment for tangential-fired and wall-fired boilers.

CO-FIRING BIOMASS IN TANGENTIAL-FIRED BOILERS

Figure 2 shows a Tangential Low NOx (TLN) System with Separated Overfire Air [12]. The fuel and air nozzles are arranged in an alternating pattern and fired from the corners of the furnace towards a common firing circle in the center of the furnace. This firing arrangement results in an intense, circular "fireball" throughout the entire furnace. This firing principle is well known throughout the power industry as a tangential or corner-fired furnace.

There are several methods to introduce biomass into a tangential-fired boiler, but in order to ensure sufficient residence time and furnace mixing of the biomass, the injectors should be located near the elevation of the center of the main windbox compartment and aimed towards the common firing circle.

- Mixed with the coal upstream of the pulverizers and introduced through the existing coal nozzles
- Coaxial with the coal nozzles
- Injection through biomass nozzles replacing coal nozzles
- Injection through separate, dedicated furnace waterwall openings
- Injection through the auxiliary air nozzle compartments in the main windbox

The first method and subsequent limitations has been discussed in the previous section. The second method requires modification of the coal inlet elbow to accommodate the biomass carrier pipe. There are two main drawbacks of this approach. First, the biomass carrier pipe displaces the available area for coal transport which may lead to a unit derate due to the reduced coal flow and second, the biomass carrier pipe is in the direct flow path of the coal particles thereby subject to erosion and maintenance issues. Replacing selected coal nozzles with biomass nozzles may be advantageous if the unit has sufficient milling capacity, thus avoiding a possible unit derate. Injection of biomass through separate, dedicated furnace waterwall openings requires pressure part modifications. Therefore, the recommended approach to co-fire biomass in tangential-fired units is through modification of the auxiliary air nozzle compartments in the main windbox.

An auxiliary air biomass nozzle needs to be designed to fit into the main windbox between the coal nozzles. Ideal locations are the auxiliary air nozzles between the middle coal elevations. The biomass nozzle should be designed with a round discharge at the center of the nozzle, large enough to meet the desired biomass flow requirements while simultaneously allowing for sufficient peripheral air quantities and velocities. Biomass transport and discharge velocities are typically on the order of 80 - 90 ft/s. While the peripheral air in the auxiliary air compartments is controlled by the windbox dampers; the nozzle should be designed such that over the control range of the dampers, the air exit velocities will be between 80 – 120 ft/s. Sufficient velocities of the peripheral air are required to keep the biomass ignition points off the tip of the nozzle. Figure 3 shows the biomass injection nozzle from Albright Generating Station [13]

Low NO_x TLN systems utilize separated overfire air (SOFA) to divert air above the main windbox and create sub-stoichiometric conditions in the lower furnace to promote low NOx reduction reactions. Due to these reducing atmospheres, NO_x formation is inhibited, but any fuel and/or air imbalances is likely to cause elevated CO emissions and unburned carbon in flyash. This effect must be factored into the design when co-firing biomass on tangential-fired boilers. The rapid devolatilization and high quantities of volatiles near the flame front compete with coal for the reduced available oxygen. If the air quantities in the lower furnace are not sufficient, coal burnout can be delayed. Subsequently, higher quantities of unburned carbon in flyash and CO emissions can be expected.

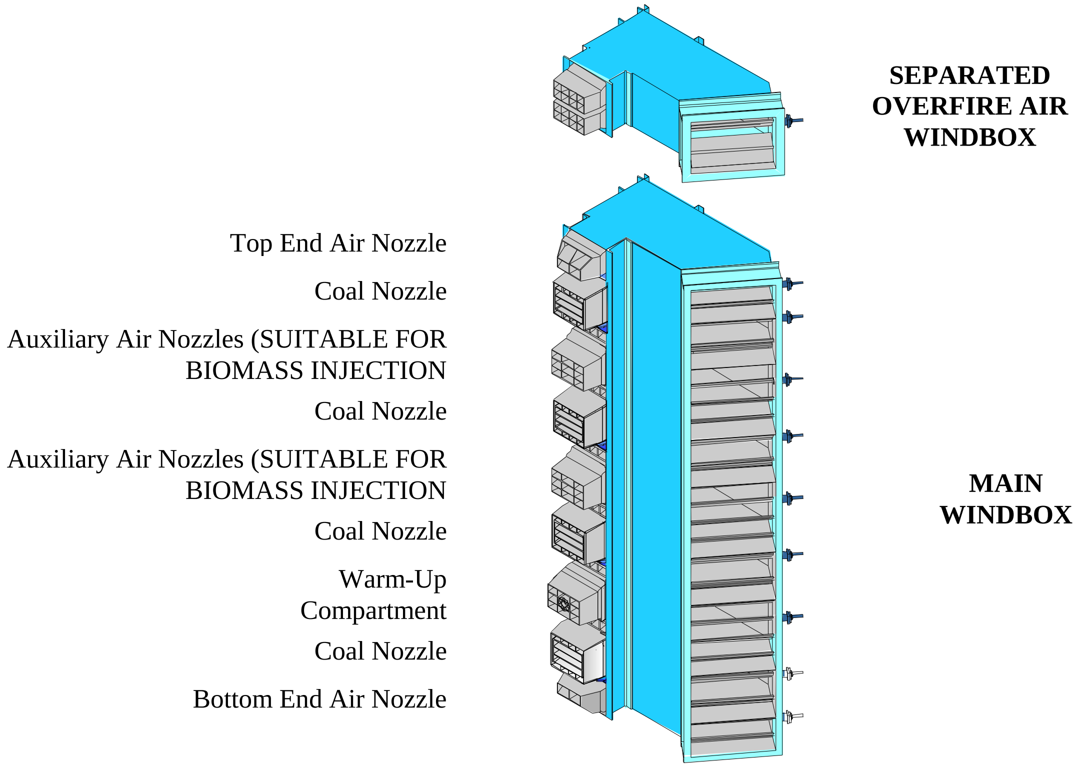
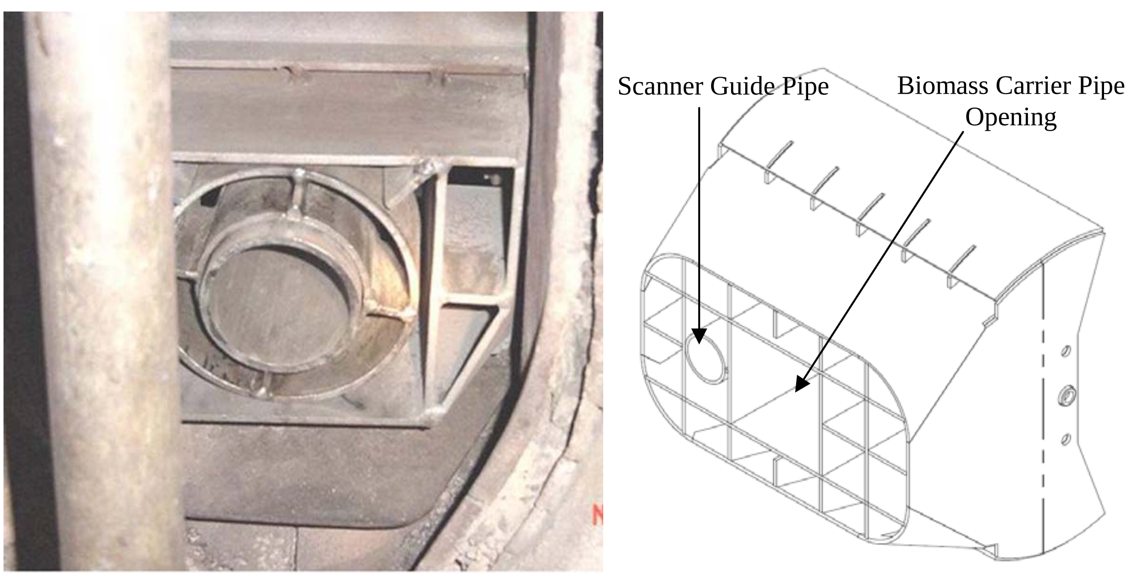


Figure 2. Tangential Low NOx (TLN) System Showing Suitable Locations for Biomass Injection



(a) *(b)*

Figure 3. (a) TLN Biomass Injector from Albright Generating Station
(b) Biomass Injector Showing Biomass Carrier Tube Opening and Scanner Guide Pipe

Several tangential coal-fired units have been retrofitted to co-fire biomass. At Albright Generating Station, lower NO_x and SO_2 emissions were reported with no appreciable increase in opacity or CO emissions when firing up to 10% (by mass) sawdust with eastern bituminous coal. Ottumwa Generating Station co-fired approximately 5% (by mass) switchgrass with PRB coal and reported lower SO_2

emissions, no change in CO emissions and higher NO_x emissions. A possible cause of the higher NO_x emissions was discussed in a previous section of this paper. Most recently, co-firing experience (Phase II) at Plant Gadsden demonstrated the ability to fire up to 15% (by mass) woody biomasses through the existing milling system with no detrimental effect on boiler operation. This was in contrast to earlier work (Phase I) at the plant that resulted in a slight unit derate due to low mill temperatures and high mill bowl under pressures when co-firing 15% (by mass) biomass. The reason given for the increased co-firing capability was the lower moisture content of the most recent biomass. SO_2 emissions were lower and particulate and CO emissions were unchanged for both test phases. Phase I testing showed NO_x emissions were unchanged when co-firing as compared to coal alone. However, Phase II testing showed lower NO_x emissions when co-firing as compared to coal [4].

CO-FIRING BIOMASS IN WALL-FIRED BOILERS

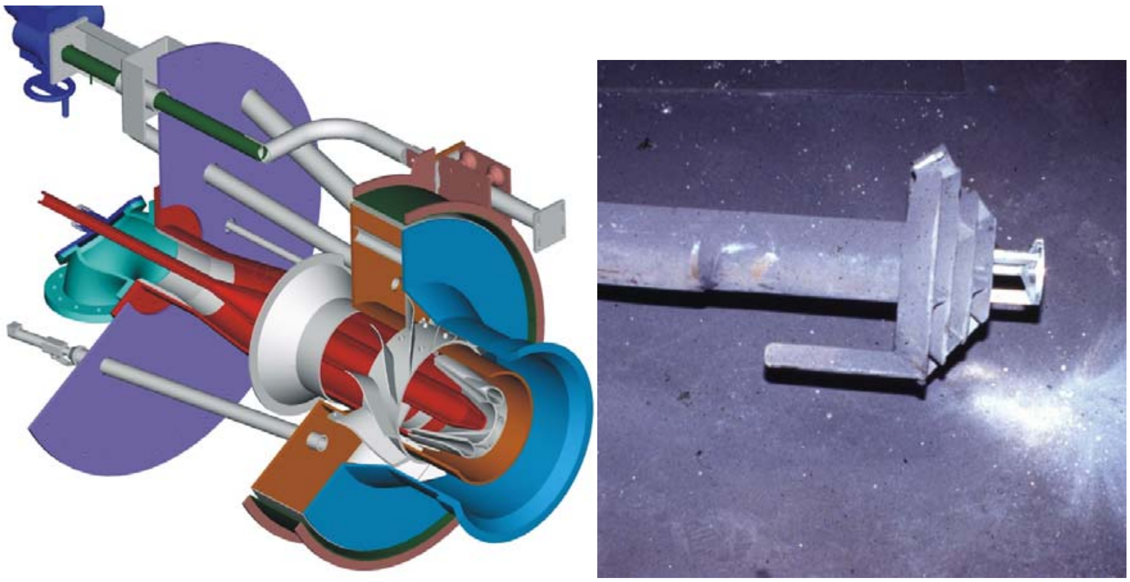
Adapting a wall-fired boiler to co-fire biomass is can be considerably more challenging as compared to a tangential-fired unit because of the many different burner configurations. Early, pre-NSPS burners were designed to promote good mixing of coal and air. These burners will have a single secondary air zone and consequently produce high NO_x emissions. A low NO_x burner as shown in Figure 4a will typically have one or two concentric annular air regions around a central coal nozzle. The secondary air is swirled to promote flame stability and local, peripheral mixing. The flame core is kept sub-stoichiometric by means of portioning the air into multiple (typically, dual) zones. The Vortex Series/Split Flame Low NO_x Burner shown in Figure 4a also has a specially designed coal nozzle tip to promote local fuel enhanced ignition, local fuel staging and consequently low NO_x emissions [14].

Biomass can be introduced into a wall-fired burner by several means:

- Mixed with the coal upstream of the pulverizers and introduced through the existing coal nozzles
- Coaxial with the coal nozzles
- Injection through biomass nozzles replacing coal nozzles
- Injection through separate, dedicated furnace waterwall openings

Most of the experience to date has been with the coaxial injection of biomass through the center of the coal nozzle. Wholesale conversion of entire burners to fire biomass presents the challenge of controlling the air to each burner and possibly requiring windbox modifications because the air requirements for biomass are very different as compared to coal.

At Seward Generating Station, up to 20% (by mass) sawdust was co-fired with a low (~22%) volatile bituminous coal. The front-wall fired boiler has two rows of three burners for a total of six burners. The center burners in each row were modified with a center located biomass carrier pipe and injector/distributor designed to deliver the sawdust to the discharge point of the coal nozzle tip. The injector/distributor is shown in Figure 4b.



(a) *(b)*

Figure 4. (a) Vortex Series/Split Flame (VS/SF) Low NOx Burner
(b) Biomass Injector/Distributor for Wall-Fired Applications

The burners at Seward were of an uncontrolled design. The introduction of highly volatile biomass, created a fuel rich region in the flame core which may have caused the Seward burners to behave similar to that of a Low NO_x burner. Whether or not that was the reason, NO_x emissions at Seward were decreased by more than 15% when co-firing.

Design of biomass injectors for wall-fired burners requires a methodical approach as follows:

1) Determine amount of biomass to be co-fired given configurations and limitations of existing firing equipment
2) Size the inner barrel biomass carrier pipe(s)
3) Design the injector/distributor with respect to the existing burner flow geometry and swirl patterns (if applicable)

The amount of biomass able to be co-fired will depend on the fuel properties (e.g., heat content, bulk density) as well as the current arrangement of burners. In addition, the amount of biomass will be limited by the size of the inner barrel biomass carrier pipe that can be located down the center of the coal pipe outer barrel without affecting the coal flame properties.

Low NOx burners are typically designed with primary air/coal particle discharge velocities between 80 – 120 ft/s. Locating the biomass carrier pipe and injector axially in the coal nozzle will reduce the area for primary air/coal particle transport and will result in higher burner tip velocities. Higher coal nozzle discharge velocities can have several undesirable results such as lower residence times, higher emissions, longer flames and possible flame impingement on opposing waterwall surfaces thereby ensuing local slagging. In addition, the biomass carrier pipe should be designed using an air to biomass ratio of approximately 1.7 – 2.2 lb/lb and a transport velocity of at least 80 ft/s. Therefore, there is an optimum biomass carrier pipe size that can be utilized in an existing low NO_x burner.

The injector is designed to rapidly disperse the biomass in the center of the flame so that the biomass rapidly devolatalizes and creates a separate fuel rich zone within the core of the coal flame to promote low NOx reduction. This "flame within a flame" concept is shown in Figure 5. The injector should be designed to divert the biomass slightly outwards in order to promote rapid devolatilization while at the same time maintaining the biomass flame internal to the overall coal flame. Since, low NOx burners already have fuel rich internal recirculation zone, careful design is critical to provide enough oxygen to both biomass and coal in order to prevent excessive delayed combustion and related higher unburned carbon in flyash and CO emissions.

Biomass fuels, as compared to coals, release greater quantities of volatile matter and therefore create a larger near flame fuel rich zone. As such, biomass fuels are expected to augment the performance of wall-fired, low NO_x burners provided the combustion equipment has been modified suitably.

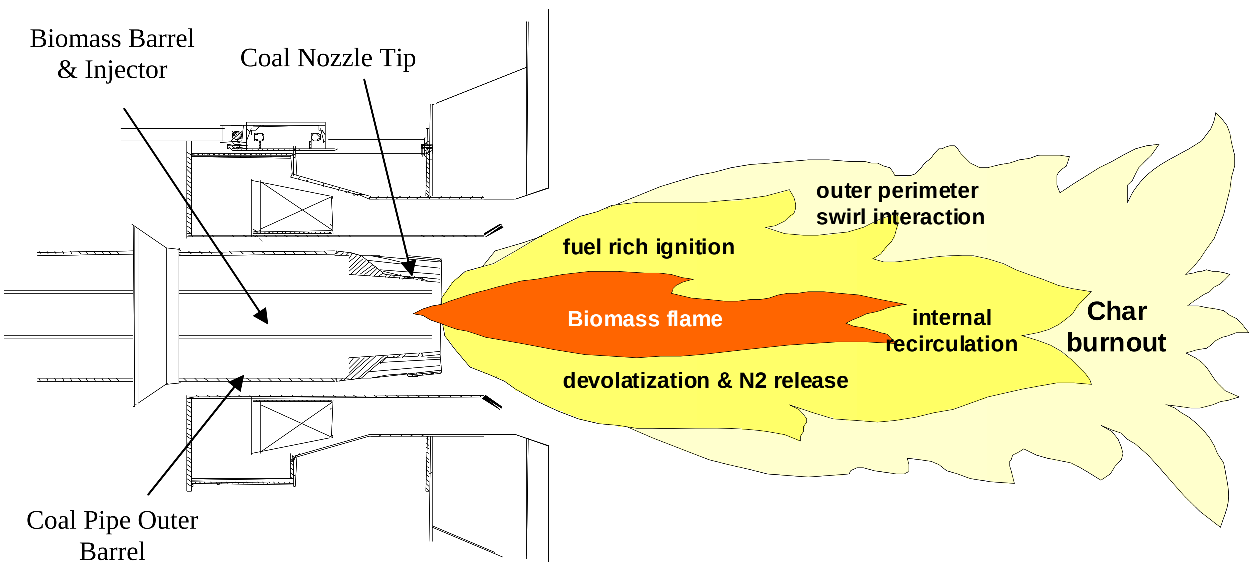


Figure 5. Wall-fired Burner with Biomass Co-Firing Illustrating the "Flame within a Flame Concept"

CONCLUSION

Recent experience has demonstrated that biomass co-firing can be successfully utilized in coal-fired boilers as an effective means of reducing greenhouse gases. The application of co-firing biomass in coal-fired boilers should continue to grow as greenhouse gas mitigation becomes more of a regulatory focal point. Renewable energy portfolio standards and possible tax incentives should also increase the opportunity for biomass co-firing with coal. Co-firing solutions are available for tangential and wall-fired boilers. Differences in biomass volatility, heat content and ash characteristics with respect to the co-fired coal must be considered when retrofitting an existing boiler to co-firing.

REFERENCES

1. Tillman, D. 2001. Final Report: EPRI-USDOE Cooperative Agreement: Cofiring Biomass with Coal. Contract No. DE-FC22-96PC96252. Electric Power Research Institute, Palo Alto, CA.
2. Biomass Cofiring: Field Test Results: Summary of Results of the Bailly and Seward Demonstrations. 1999. EPRI, Palo Alto, CA, U.S. Department of Energy Division of Energy Efficiency and Renewable Energy, Washington D.C.; U.S. Department of Energy Division Federal Energy Technology Center, Pittsburgh PA; Northern Indiana Public Service Company, Merrillville, IN; and GPU Generation, Inc., Johnstown, PA. TR-113903

3. Amos, W. A. Summary of Chariton Valley Switchgrass Co-Fire Testing at the Ottumwa Generating Station in Chillicothe, Iowa. 2002. Chariton Valley RC&D, Inc., Centerville, IA; NREL, Golden, CA; U.S. Department of Energy, Washington D.C.; Alliant Energy, Cedar Rapids, IA.

4. Boylan, D., Hobbs, W., Zemo, B., Johnson, T. 2008. Phase 2 Co-firing Testing of Wood Chips at Alabama Power's Plant Gadsden. Southern Company, Birmingham, AL.

5. Laux, S., Grusha, J., and Tillman, D. 2000. Co-firing of Biomass and Opportunity Fuels in Low NOx Burners. Proc. 25th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., March 6 – 9.

6. Miranda, T., Esteban, A., Rojas, S., Montero, I. and Ruiz, A. 2008. Combustion Analysis of Different Olive Residues. *International Journal of Molecular Sciences*. 9: 512 – 525.

7. Tillman, D. 2002. Internal Report – Fuel Characterization Techniques

8. Baxter, L., Mitchell, R. E., Fletcher, T. H., and Hurt, R. H. 1996. Nitrogen Release During Coal Combustion. *Energy & Fuels*. 10(1): 188 – 196.

9. Duong, D. and Tillman, D. 2009. Chlorine Issues with Biomass Cofiring in Pulverized Coal Boilers: Sources, Reactions, and Consequences – A Literature Review, presented at the 34th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., May 31 – June 5.

10. Schill, S. R. 2007. Harnessing the Power of Biomass. *Biomass Magazine* August.

11. Van Loo, S. and Koppejan, J. (eds.). 2008. The Handbook of Biomass Combustion & Co-Firing. Earthscan, Sterling, VA.

12. Grusha, J., Woldehanna, K., McCarthy, K., and Heinz, G. 1999. Long Term Results of the First US Low NOx Conversion of a Tangential Lignite Fired Unit. Proc. 24th International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., March 8 – 11.

13. Payette, K., Tillman, D., Banfield, T., and Nutter, T. 2002. Emissions Management at Albright Generating Station through Biomass Cofiring. Proc. 27th Coal Utilization Conference, Clearwater, FL March 4-7, 2002

14. Steitz, T., Grusha, J., and Cole, R. 1998. Wall Fired Low NOx Burner Evolution for Global NOx Compliance. Proc. 23rd International Technical Conference on Coal Utilization & Fuel Systems, Clearwater, FL., March 9 – 13.