TECHNICAL PUBLICATION

Biomass Conversion Strategies for Existing Power Plants

Evaluation Criteria and Feasibility Analysis

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Presented at

Power-Gen International
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ABSTRACT

With today's increased interest in biomass fuels for the production of electric power, the conversion of existing fossil fuel-fired power plants to 100% biomass is an increasingly appealing option. There is a need to understand the effect on boiler performance and the modifications required when investigating the feasibility of converting to biomass firing.

This paper reviews the evaluation criteria and limiting factors applicable to biomass conversions for both the boiler and environmental equipment. Specific topics include:

- *Typical biomass power plant sizes*
- *Furnace size requirements for biomass (retention time, heat release rates)*
- *Boiler heating surface design (tube spacing and fouling from constituents in the fuel)*
- *Flue gas velocities and erosion*
- *Maximum load evaluation, considering the moisture in the fuel*
- *Typical boiler options for improved performance*
- *Hot air requirements*
- *Fan capacities*
- *Typical combustion system modifications*
- *Typical environmental requirements (CO, NO_x, VOC, UBC)*
- *Typical environmental equipment modifications*
- *Space requirements*

In conclusion, the paper will establish a general guideline and provide key criteria to evaluate when considering the conversion of an existing power plant to biomass firing. Example designs will also be included.

INTRODUCTION

New boilers are the ideal situation for firing biomass fuels. However, the design requirements imposed by biomass fuels makes it expensive and difficult to develop a new greenfield site. An alternative to building new biomass plants is the conversion of existing boilers. Biomass conversions offer a second life to boilers that are experiencing poor heat rates or are in need of repair. They also provide an appealing alternative to the decommissioning of a plant or the purchase of expensive environmental control equipment. By converting units to fire biomass fuels, power producers will add desirable renewable energy to their portfolios as well as providing an economical solution to revamping their outdated plants.

To understand biomass firing and the conversion of an existing boiler to biomass firing you need to first have a basic knowledge of biomass fuels and their combustion characteristics. The first section of this paper will review the basics of biomass fuels.

Background on Biomass Fuels

The term biomass refers to any organic non-fossil fuel. Solid biomass fuels can be organized into primary fuel groups: which are woods, herbaceous energy crops, agricultural residues, and waste materials. Biomass can also be obtained as a liquid or gaseous fuel, such as bio-diesel or landfill gas.

* *Wood Fuels*
  Wood Chips, Wood Pellets, Timber Residue, Sawdust, Bark

* *Energy Crops*
  Miscanthus, Switchgrass, Straws

* *Agricultural Residues*
  Bagasse, Olive Pits, Rice Hulls, Sunflower Hulls, Almond Shells

* *Waste Materials*
  Refuse Derived Fuel (RDF), Paper Pellets (PDF), Construction & Demolition Debris (C&D), Poultry/Turkey Derived Fuel (PDF)

* *Bio-Diesel*

* *Landfill Gas*

Note: It is typically beneficial for the overall plant's success to design the combustion and boiler systems to be capable of firing more that one type of biomass fuel. This allows the plant the ability to burn alternate fuels during fuel shortages and/or high fuel costs. Firing alternate fuels includes both firing a single alternate fuel and possibly co-firing multiple alternate fuels.

Biomass fuels and their combustion characteristics can vary significantly from fuel to fuel. The fuel properties of importance in the design of the boiler and combustion system include:

- Moisture
- Heating value
- Slagging and Fouling tendencies
- Corrosive elements
- Erosive elements
- Size

To evaluate the biomass fuel characteristics it is important to understand the composition of both the fuel and ash. To obtain this information, an ultimate and proximate fuel analysis, a fuel ash mineral analysis and a size distribution analysis needs to be performed.

Note: During the initial stages of developing a biomass project, the detail fuel, ash and size analyses information may not be known. During these initial stages, the specific types of biomass fuels need only be established. Based on the type of biomass fuel, a typical industry fuel, ash, and size analyses can be used. As the project develops further and appears feasible, the actual detailed fuel ash, and size analyses are required for fine-tuning of the boiler design.

The following table lists a variety of biomass fuels showing the typical wide range in chemical analysis.

Table 1

Properties of Various Biomass Fuels

		Wood Fuels		Energy Crops		Agricultural Residues	Waste Materials	
Analysis	**Unit**	**Wood Chips (40% Moisture)**	**Sawdust (As Rec'd)**	**Miscanthus (As Rec'd)**	**Switchgrass (As Rec'd)**	**Rice Hulls (As Rec'd)**	**Paper Pellets (As Rec'd)**	**RDF (As Rec'd)**
H_2O	%	40.70	11.45	14.54	9.80	10.94	6.40	19.50
Carbon	%	29.49	44.24	40.41	42.10	34.58	41.46	32.59
Hydrogen	%	3.62	5.24	4.92	5.20	4.23	5.34	3.86
Nitrogen	%	0.06	0.03	0.28	0.69	0.46	0.18	0.42
Oxygen	%	25.64	38.76	37.19	33.70	31.69	37.61	30.45
Sulfur	%	0.01	0.01	0.05	0.17	0.05	0.13	0.21
Ash	%	0.50	0.28	2.61	8.10	18.05	8.80	12.97
Chlorine	%	—	—	0.05	0.17	0.11	0.08	—
HHV	Btu/lb	4,958	7,415	6,879	7,002	6,065	7,068	5,446
Elemental Ash Analysis								
SiO_2	%	1.44	35.36	61.84	65.18	91.42	41.70	33.81
Al_2O_3	%	0.41	11.54	0.98	4.51	0.78	33.00	12.71
TiO_2	%	0.11	0.92	0.05	0.24	0.02	4.60	1.66
Fe_2O_3	%	0.15	7.62	1.35	2.03	0.14	1.70	5.47
CaO	%	31.00	24.9	9.61	5.60	3.21	11.90	23.44
MgO	%	6.81	3.81	2.46	3.00	<0.01	1.20	5.64
Na_2O	%	0.35	1.71	0.33	0.58	0.21	1.70	1.19
K_2O	%	26.60	5.75	11.60	11.60	3.71	0.30	0.20
SO_3	%	1.53	0.78	2.63	0.44	0.72	4.00	2.63
P_2O_5	%	4.47	1.90	4.20	4.50	0.43	0.00	0.67
Undetermined	%	23.33	5.71	4.95	2.32	0	0	12.58
Total	%	100	100	100	100	100	100	100
Alkali Content	%	26.95	7.46	11.93	12.18	3.92	2.00	1.39

The fuel elements and their affects on the combustion and boiler systems design include:

Fuel Element	Affects on Design
Fuel H_2O	Boiler Efficiency, Combustion Air
Temperature	
HHV	Fuel Flow
Sulfur, Chlorine	Boiler Materials, Emissions
% Ash	Fouling, Slagging, Erosion
Ash Fusion Temperature	Fouling, Slagging
SiO_2	Erosion, Slagging

Typical slagging/fouling characteristics for various fuels are shown in Figure 1. The figure bases the slagging and fouling tendencies on ash and alkali content, which is only part of the analysis. Other factors, such as SiO_2 content, moisture content and ash fusion temperature, combined with experience and testing, must be considered when designing a biomass-fired unit.

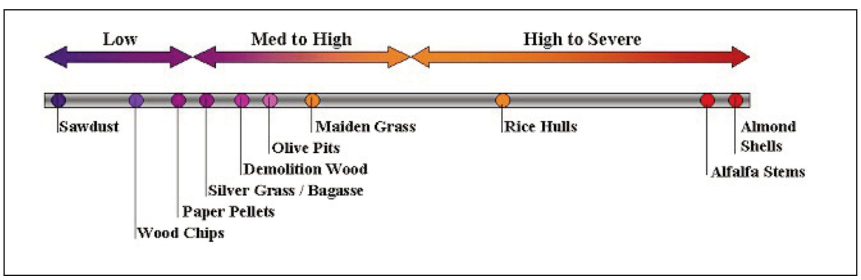


Figure 1: Fouling & Slagging Tendencies of Some Biomass Fuels

Fuel moisture is another example of how the fuel analysis affects the design. The following graph depicts the fuel flow rate and boiler efficiency based on various fuel moisture content.

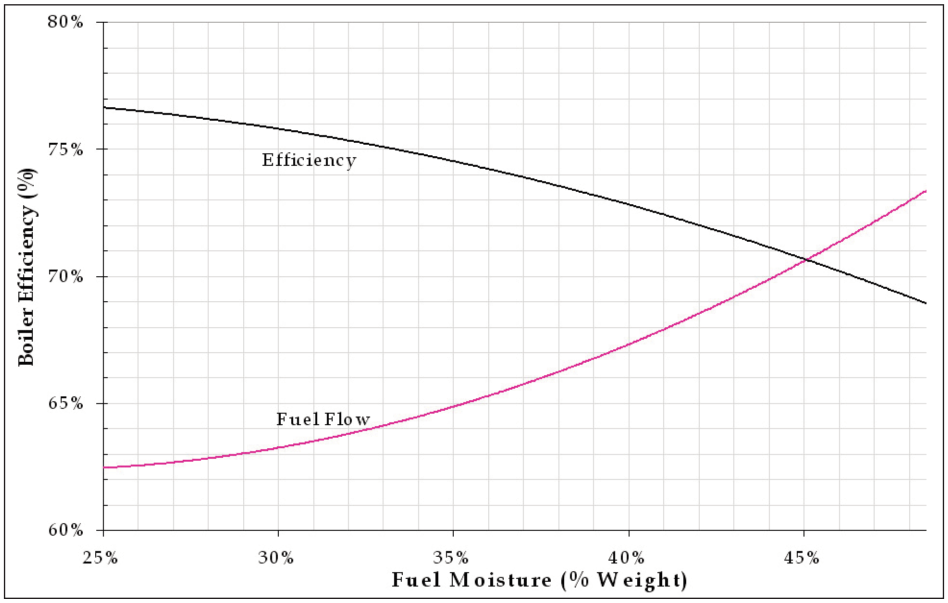


Figure 2: Boiler Efficiency and Fuel Flow vs. Fuel Moisture Content

Engineering a 100% Biomass Conversion Project

An area of industry interest is the conversion of smaller coal fired utility boilers to biomass firing. The following discussion is a recommended "Phased Approach" for converting a pulverized coal boiler to a modernized biomass stoker design. These phases allow the project to be stopped if a "fatal flaw" is discovered without wasting engineering time and resources.

Phase 1: Initial Screening

The first phase is an initial screening of the boiler in question. This screening gives a rough idea of whether or not the boiler is a candidate for a biomass conversion. General screening guidelines include:

* Preferably 5-80MW units (50kpph to 800kpph steam flow)
* Existing pulverized coal or stoker fired units are more favorable
* Oil and gas units usually are not good candidates due to their smaller furnace size and tight tube spacing
* Typically biomass units require preheated air. The unit should have an airheater, or space for the addition of one, if the biomass fuel has a high moisture content

If the Initial Screening results are positive, the project continues to Phase 2.

Phase 2: Feasibility Study

The next phase includes an initial engineering feasibility analysis of the boiler performance and boiler modifications required to convert to biomass fuels. This is not detail engineering (which will be done in Phases 3 and 4) but is a shortened analysis to evaluate the basic boiler performance and mechanical parameters. If the conversion appears feasible then the project will go to the next phase.

* Based on the biomass fuel selected, determine fuel characteristics:
  - ♦ Fouling/Slagging analysis
  - ♦ Moisture content
  - ♦ Ash analysis
  - ♦ Erosion analysis
  - ♦ Corrosion analysis
* Perform combustion calculations:
  - ♦ Combustion air required
  - ♦ Flue gas flow produced
* Calculate boiler efficiency:
  - ♦ Establish fuel flow required
* Review the furnace size, grate heat release rates, and furnace retention time
* Calculate the flue gas velocities through the tube bundles
* Based on the above information the (preliminary) maximum boiler steaming capacity firing biomass fuels can be established
* Based the fuel flow and combustion conditions, calculate the (preliminary) uncontrolled and controlled emissions
* Perform a rough evaluation of the equipment modifications required:
  - ♦ Combustion system modifications
  - ♦ Boiler modifications
  - ♦ Emission control equipment modifications

If the Feasibility Study results meet the load capacity, emissions and expected modifications, the project continues to the next phase.

Phase 3: Initial Engineering Evaluation

By this phase, the boiler has shown promise in being converted to biomass firing. Now, time and resources are dedicated to provide the engineering needed for a successful biomass conversion. The following list details the additional items completed in this phase.

* Heat transfer calculations:
  - ♦ Establish final superheat & reheat steam temperatures
  - ♦ Establish furnace exit gas temperature
  - ♦ Surface areas of superheat, reheat, boiler bank, and economizer

* Refine the boiler heat balance analysis developed in the initial feasibility review

* Determine SH tube metals

* Pressure drop calculations, steam, gas and air side

* Review flue gas velocities through tube bundles and draft losses

* Evaluate the auxiliary equipment capacity for firing wood, which includes:
  - ♦ Air heater
  - ♦ Forced draft fan
  - ♦ Induced draft fan

* Evaluate emissions and options for emissions control

* Develop arrangement drawings:
  - ♦ Site visits / field measurements

Phase 4: Detailed Engineering Phase

* Develop accurate arrangement drawings that identify any site equipment interferences

* Finalize equipment sizing and performance based on site information

* At the end of this phase develop:
  - ♦ "Firm" boiler and AQCS material cost estimates
  - ♦ Drawings necessary to obtain a construction cost estimate

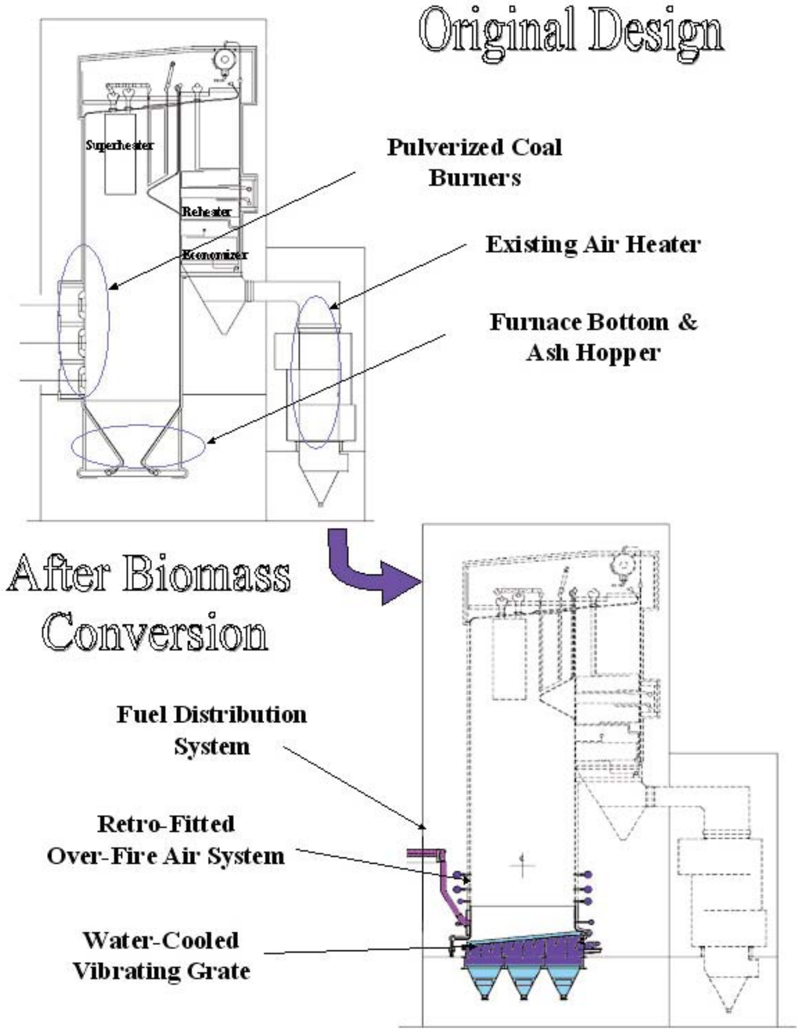


Figure 3: Boiler Modifications for Biomass Conversion

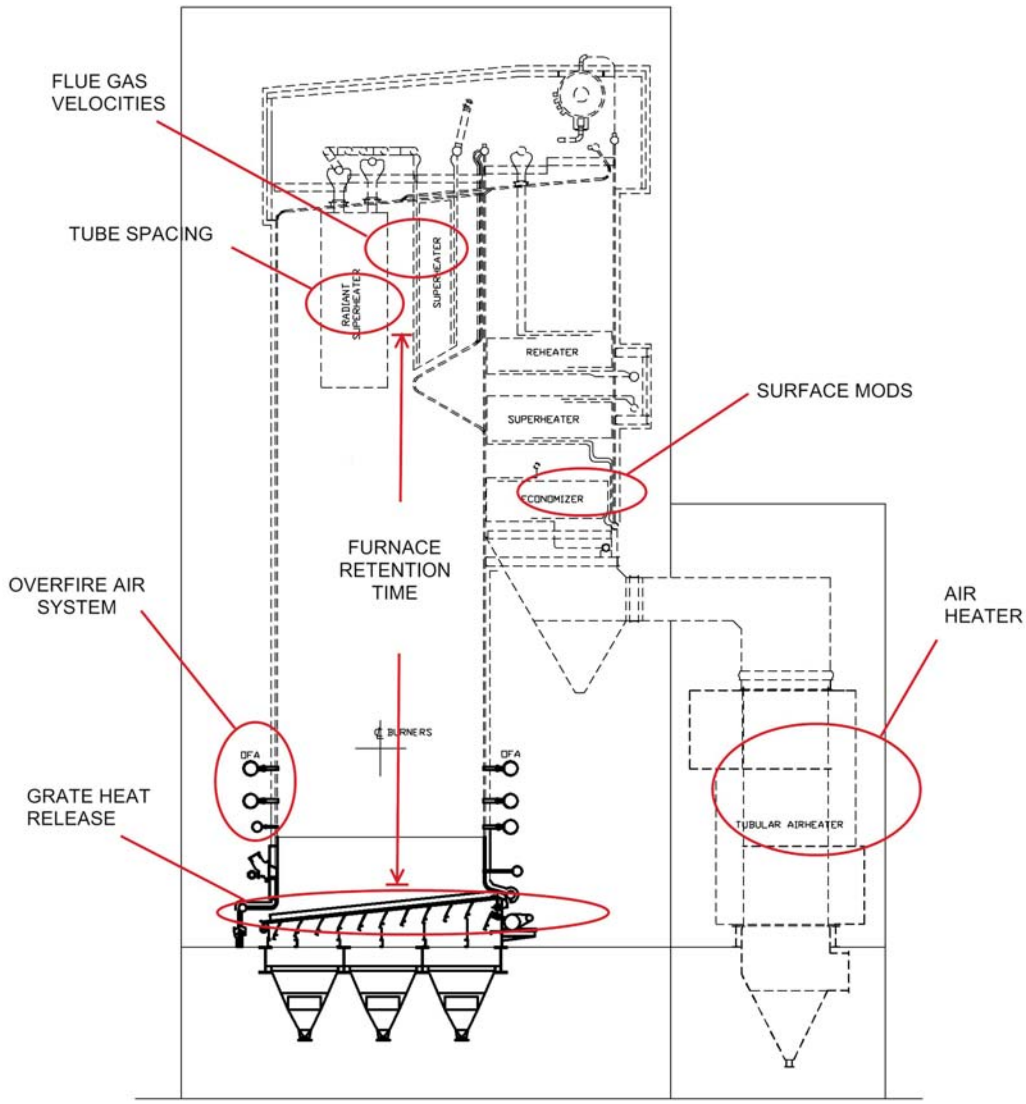


Figure 4: Evaluating a Biomass Conversion

Comparison of 2005 through 2007

Recalling from Erickson and Staudt i, NO_x reduction overall improved during the period from 2004 to 2005 for most SCRs monitored in that study. We perform here a similar evaluation for the period from 2004 to 2005. Figure 1 shows the trends for 2005 to 2007 for NO_x reduction versus the percent of units that provided that NO_x reduction or less. In general, NO_x reduction was still generally good, with 50% of the units evaluated achieving 85% or higher NO_x reduction in all years and at least 20% of the units at or above 90% removal. However there was a trend toward slightly lower fleet-wide levels of NO_x removal. Except for some units achieving over 95% in 2007, the curves are very similar Environmental Considerations

Biomass conversions of a coal-fired power plant can provide significant environmental benefits. By converting to biomass, an owner may be able to reduce its air emissions from power generation. Carbon dioxide (CO_2), sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury can be reduced relative to what would have been emitted from burning coal.

SO_x

Biomass usually has lower sulfur content than coal, so conversions result in a reduction of SO_x emissions because of a displacement of sulfur in the fuel blend. Emissions of SO_2 are generally reduced in proportion to the heat input provided by the biomass. Babcock Power has information of the effectiveness of SO_2 (and HCl) removal by the alkaline flyash resulting from firing biomass, which can be sufficient to mitigate the need for further acid gas removal.

Particulates

When considering the impact of biomass conversion on the particulate control devices in a coal fired power plant, particularly for electrostatic precipitators (ESP), the primary technical concern for the flyash is the differences in chemical composition and the smaller particles formed. Testing has shown that biomass flyash has a higher fraction of submicron particles, potentially adversely affecting the performance of the ESP. Nevertheless, the resistivity of the biomass flyash is typically in the range that an ESP can readily handle, so the existing ESP may be sufficient to meet the original permit requirements. However, it has been seen that regulators generally require lower particulate matter (PM) emissions when a major retrofit is undertaken. This requires producers to achieve emissions of 0.015 lb/MBtu or lower. This typically requires an ESP with an SCA of 350 or higher, which can be realized by adding fields to an existing ESP or by installing a new unit. Each application has to be evaluated. If a baghouse exists, the higher flue gas flow rates associated with biomass firing might exceed the design air to cloth ratio for the existing baghouse so it needs to be assessed.

NO_x

Most biomass fuels contain less fuel-bound nitrogen than coal, thus the anticipated NO_x emissions would be reduced when a unit is converted to fire 100% biomass. However, the effects on NO_x emissions are less certain than CO_2 and SO_2. In full-scale biomass applications many other factors contribute to NO_x formation. Biomass conversions have been shown to reduce NO_x emissions in most large-scale boilers, but not all.

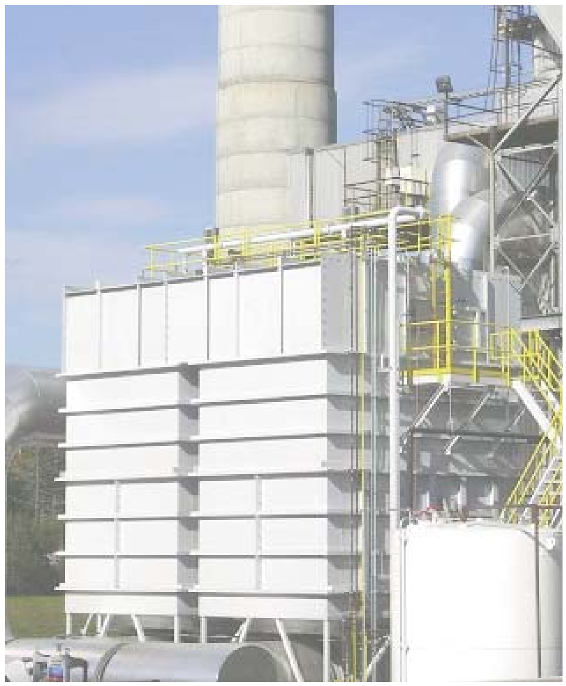
There is another important consideration when considering co-firing biomass in a coal fired power plant. The conventional technology for attaining high NO_x reductions is Selective Catalytic Reduction (SCR). Many US coal fired power plants have had "conventional" SCRs installed between the last heat transfer surface, typically the economizer, and the unit airheater. This location produces flue gas at 600 to 800ºF, which is the ideal temperature for the catalyst. The gas may be laden with ash particles due to its location upstream of the ESP or baghouse. A conventional SCR is not suitable in processes where the ash may contain poisons such as sodium, potassium, lead, or arsenic. Biomass flyash contains high percentages of potassium and sodium, thus a potential catalyst poisoning issue exists. When firing biomass, the alkali and alkaline earth metals can potentially deactivate the SCR catalyst by physically masking or chemically poisoning the catalyst.

Babcock Power has constantly tracked the deactivation of the SCR catalyst on units firing 100% biomass and determined that in low dust applications for the SCR, using RSCR technology, the deactivation rate is very slow with a catalyst life expectancy of well over five years. However, one of the RSCR systems is used on a boiler with poor dust removal upstream of the RSCR and noticeable deactivation has been observed, perhaps three times faster than applications with low dust.

Therefore, it is recommended that a low dust or "tail-end" SCR system be used to achieve long catalyst life and also keep NO_x emissions below the level that Selective Non-Catalytic Reduction (SNCR) can achieve (about 0.12 lb/MBtu). These systems are positioned at the end of the plant before the flue gas flows to the stack. The issue at this point in the plant is the low gas temperature, which is well below the temperature required for the SCR catalyst. The RSCR technology is one approach to solving this issue.

An RSCR system with six canisters on a 50 MW unit

The primary application of an RSCR system is the reduction of NO_x emissions in the flue gas found at the tail end of the biomass boiler where gas temperatures are cool, typically 300 to 400ºF. In an RSCR, the temperature of the flue gas is temporarily elevated for optimal catalyst performance and the heat is recovered before sending the clean flue gas to the stack. The main advantage of an RSCR system is its high thermal efficiency versus standard tail-end solutions in which a heat exchanger and duct burners are used. The RSCR thermal efficiency can be guaranteed as high as 95% in contrast to standard tail-end solutions that typically achieve 70-75% efficiency. This higher thermal efficiency means that fuel consumption for the RSCR is typically 10-15% of that consumed by a standard tail-end SCR. For a 50 MW boiler, these savings translate to approximately $3M in reduced annual fuel costs.



An installed two canister RSCR System on a 15 MW unit

The RSCR system has been operating successfully for as long as five years on four wood-fired boilers in the US — two 15 MW units in New Hampshire, a 54 MW unit in Vermont, and a 50 MW unit in Maine. Both 15 MW plants and the 54 MW plant use whole tree chips as fuel; the 50 MW plant uses whole tree chips, waste wood, and construction and demolition wood as fuel for the boilers. The goal of all installations was to qualify for Connecticut Renewable Energy Credits (REC). The state requirement for qualifying for RECs is achieving NO_x levels of 0.075 lb/MBtu or less on a quarterly average. In addition, a layer of precious metal CO oxidation catalyst can be provided on top of the SCR catalyst to achieve >50% CO reduction simultaneously with NO_x reduction, achieving CO emissions of <0.1 lb/MBtu.

The inlet NO_x levels at the sites are typically in the range of 0.20 to 0.26 lb/MBtu. SNCR is not used, nor is it needed. These inlet levels are comparable to the uncontrolled NO_x emissions observed in biomass conversion projects. While designed to reduce NO_x levels by 70 to 75%, the systems have been able to reduce NO_x levels significantly below 0.075 lb/MBtu. Outlet emissions of 0.075 lb/MBtu result in total annual NO_x emissions of <250TPY for a 50MW biomass boiler.

In conclusion, the emissions from converting coal-fired boilers to 100% biomass can be controlled to low levels using proven and efficient technologies and should not be viewed as an impediment in pursuing a biomass conversion project.