# Engineering and Economic Evaluation of Biomass Power Plants

*100% Biomass Repowering, Biomass Co-Firing, and Bubbling Fluidized Bed Biomass Combustion*

**1019762**

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# ABSTRACT

For areas with abundant supplies of biomass resources and for areas with limited wind and solar options, biomass energy projects might be a technically and economically viable means to achieve renewable energy goals and mandates. To minimize capital costs associated with these projects, biomass can be fired in a unit modified to fire 100% biomass fuels (that is, biomass repowering) or can be co-fired with coal in an existing coal-fired unit. Both of these methods use existing equipment and facilities. This engineering and economic evaluation addresses three primary cases: 1) repowering of an existing 100-MW coal-fired unit to fire blended, woody biomass fuels; 2) co-firing coal and biomass in an existing 250-MW coal-fired unit, with blended, woody biomass providing 10% of the heat input to the unit; and 3) development of a new, dedicated biomass-fired power plant using a bubbling fluidized bed combustion system. The designs of these biomass systems are based on current best practices for utility facilities located in the United States. Within the report, impacts of variations in biomass fuel composition and moisture content are identified. For the co-fired case, impacts of varying heat input levels are also described. The total capital requirement estimate is US$1970 per kW for the primary repowering case and US$1690 per kW for the primary co-firing case, based on fraction heat input provided by biomass. Total capital requirement estimates for installation of a 50-MW and a 100-MW standalone biomass plant (firing 100% woody biomass) are US$5590 per kW and US$4050 per kW, respectively.

Levelized cost of electricity (LCOE) for the primary repowering case is calculated considering the estimated cost of biomass fuels and the non-fuel operations and maintenance costs of the repowered facility. For the primary co-firing case, the incremental LCOE (that is, generation costs relative to the existing LCOE for coal-fired generation at the co-fired unit) is calculated considering the estimated coal and biomass fuel costs and incremental non-fuel operations and maintenance costs of biomass handling, processing, and combustion systems. Excluding the potential impact of the investment tax credit, the LCOE calculated for the primary repowering case is US$88 per MWh, and the incremental LCOE calculated for the primary co-firing case is US$31 per MWh. The LCOE for the stand-alone bubbling fluidized bed cases, calculated considering the estimated cost of biomass fuels and non-fuel operations and maintenance, is US$126 per MWh for the 50-MW woody biomass case, US$100 per MWh for the 100-MW woody biomass case, and US$133 per MWh for the 50-MW switchgrass case.

All costs are in third quarter 2010 U.S. dollars, and the real-dollar levelized costs assume a 55:45 debt-to-equity ratio, 4% per year interest on debt, 8% per year return on equity, and no inflation. Repowering and co-firing cases assume a 20-year plant life, and standalone bubbling fluidized bed cases assume a 30-year plant life. The LCOE calculations considering the potential impact of the investment tax credit are presented for each technology in the respective report sections.

**Keywords**
Biomass co-firing
Biomass repowering
Bubbling fluidized bed
Economic assessment
Engineering assessment
Levelized cost of electricity (LCOE)

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# 1
# INTRODUCTION

## Background

In 2006 EPRI initiated a new project to conduct engineering and economic evaluations of renewable energy technologies, including wind, biomass, solar, geothermal, hydro, ocean tidal and wave, and others. The goal of these evaluations is to develop objective and consistent assessments of the current and future performance of the technologies with regard to thermal efficiency, capital and O&M costs, resource requirements, environmental emissions, and other metrics. In addition, the resulting data are used in the annual updates of the EPRI Renewable Energy Technology Guide (RETG), which is a key product of EPRI's renewable energy program.

## Objective

The objective of this report is to develop high-level characterizations of a representative 100 percent biomass repowered power plant, a representative biomass co-fired power plant, and standalone biomass-fired power plants employing bubbling fluidized bed (BFB) combustion systems. The characterizations of the repowering and co-firing cases are intended to provide a guide illustrating the analyses and engineering required to modify such facilities. The characterizations of the biomass-fired BFB cases are intended to provide a guide illustrating the analyses and engineering required to develop and construct such facilities.

## Scope

The scope of the evaluation of each technology included establishment of design and economic assumptions, conceptual design, capital and operation and maintenance costs, and levelized cost of electricity.

## Report Organization

Following this introduction, this report is organized into the following chapters:

Chapter 2 presents the design basis and economic assumptions developed for this study and employed in the evaluation of the biomass cases.

Chapter 3 presents the results of the engineering and economic evaluation of the performance, capital, O&M, and levelized cost of energy ($/MWh) estimates for the 100 percent biomass repowered base case and the two alternative cases. This chapter presents the levelized cost of electricity for each case to show the relative spread of the expected energy costs.

Chapter 4 presents the results of the engineering and economic evaluation of the performance, capital, O&M, and levelized cost of energy ($/MWh) estimates for the biomass co-fired base case and the two alternative cases. This chapter presents the levelized cost of electricity for each case to show the relative spread of the expected energy costs.

Chapter 5 presents the results of the engineering and economic evaluation of the performance, capital, O&M, and levelized cost of energy ($/MWh) estimates for the three standalone biomass-fired BFB cases. This chapter presents the levelized cost of electricity for each case to show the relative spread of the expected energy costs.

Chapter 6 presents biomass technology monitoring and development tables characterizing repowering, co-firing and standalone biomass-fired BFB technologies.

# 2
# BIOMASS REPOWERING AND CO-FIRING DESIGN BASIS AND COST ASSUMPTIONS

The first task of this study was to develop the design basis and economic assumptions for the biomass evaluations, including parameters of the general design of the repowering and co-firing systems, system capacity for repowering and typical limits of co-firing, and the cost development methodology associated with these systems.

## System Design Basis

The assumptions developed for the biomass repowering, co-firing scenarios, and bubbling fluidized bed evaluations are presented in Table 2-1, 2-2, and 2-3, respectively.

**Table 2-1**
**Design Basis for 100% Biomass Repowering Scenario Base and Sensitivity Cases**

| Parameter | Units | Repower Base Case | Repower Alternate Case 1 | Repower Alternate Case 2 |
|---|---|---|---|---|
| Net Capacity* | MW | 100 (coal) | 100 (coal) | 100 (coal) |
| Boiler Type | | PC | PC | PC |
| Capacity Factor | % | 85 | 85 | 85 |
| *Biomass Properties* | | | | |
| Fuel Type | | Undried, mixed biomass | Dried biomass | Torrefied biomass |
| Heating Value (dry) | Btu/lb | 8,670 | 8,670 | 13,600 |
| Moisture Content | % | 45 | 30 | 6 |
| Consumption | tph | 80 | 60 | 30 |
| | MBtu/h | 756 | 756 | 756 |
| Fuel Cost | $/MBtu | 3.55 | 3.55 | 7.80 |
| *Emission Limits* | | | | |
| $SO_2$ | lb/MBtu | 0.025 | 0.025 | 0.025 |
| $NO_X$ | lb/MBtu | 0.100 | 0.100 | 0.100 |
| PM | lb/MBtu | 0.012 | 0.012 | 0.012 |

Notes:

* Rated capacity assumes repowering and/or modification of an existing 100-MW coal-fired boiler. Firing biomass in the unit may result in a derate in capacity.

**Table 2-2**
**Design Basis for Biomass Co-firing Scenario Base and Sensitivity Cases**

| Parameter | Units | 100% Coal-fired Base Case | Co-fired Alternate Case 1 | | | Co-fired Alternate Case 2 | | | Co-fired Alternate Case 3 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Co-firing Method | | n/a | Separate Injection | | | Separate Injection | | | Separate Injection | | |
| Net Capacity | MW | 250 | 250 | | | 250 | | | 250 | | |
| Boiler Type | | Wall-fired PC | Wall-fired PC | | | Wall-fired PC | | | Wall-fired PC | | |
| Capacity Factor | % | 80 | 80 | | | 80 | | | 80 | | |
| *Biomass Properties* | | | | | | | | | | | |
| Fuel Type | | n/a | Undried, mixed biomass | | | Dried biomass | | | Torrefied biomass | | |
| Heating Value (dry) | Btu/lb | n/a | 8,670 | | | 8,670 | | | 13,600 | | |
| Moisture Content | % | n/a | 45 | | | 30 | | | 6 | | |
| Biomass Heat Input | % | 0 | 5 | 10 | 15 | 5 | 10 | 15 | 5 | 10 | 15 |
| Biomass Consumption | tph | 0 | 15 | 25 | 40 | 10 | 20 | 30 | 5 | 10 | 15 |
| | MBtu/h | 0 | 125 | 250 | 375 | 120 | 245 | 370 | 120 | 245 | 365 |
| Fuel Cost | $/MBtu | n/a | 3.55 | | | 3.55 | | | | | |
| *Coal Properties* | | | | | | | | | | | |
| Type | | Central Appalachian | Central Appalachian | | | Central Appalachian | | | Central Appalachian | | |
| Heating Value | Btu/lb | 12,210 | 12,210 | | | 12,210 | | | 12,210 | | |
| Biomass Heat Input | % | 0 | 5 | 10 | 15 | 5 | 10 | 15 | 5 | 10 | 15 |
| Coal Consumption | tph | 100 | 95 | 90 | 85 | 95 | 90 | 85 | 95 | 90 | 85 |
| Cost | $/MBtu | 3.30 | 3.30 | | | 3.30 | | | 3.30 | | |
| *Emission Limits* | | | | | | | | | | | |
| $SO_2$ | lb/MBtu | 0.060 | 0.060 | | | 0.060 | | | 0.060 | | |
| $NO_X$ | lb/MBtu | 0.050 | 0.050 | | | 0.050 | | | 0.050 | | |
| PM | lb/MBtu | 0.010 | 0.010 | | | 0.010 | | | 0.010 | | |

**Table 2-3**
**Biomass Fired BFB Combustion Scenario Design Basis**

| Parameter | Units | 50-MW Woody Biomass Case | 100-MW Woody Biomass Case | 50-MW Wood/ Switchgrass Case[1] |
|---|---|---|---|---|
| Net Capacity | MW | 50 | 100 | 50 |
| Boiler Type | | BFB | BFB | BFB |
| Capacity Factor | % | 85 | 85 | 85 |
| *Biomass Properties* | | | | |
| Fuel Type | | Woody Biomass | Woody Biomass | Switchgrass and woody biomass |
| Heating Value (dry) | Btu/lb | 8,670 | 8,670 | 7,300 |
| Moisture Content | % | 45 | 45 | 15 |
| Consumption | tph | 73.2 | 135.2 | 69.8 |
| | MBtu/h | 698.2 | 1289.4 | 705.9 |
| Fuel Cost[2] | $/MBtu | 3.55 | 3.55 | 3.85 |
| *Emission Limits* | | | | |
| $NO_X$ | lb/MBtu | 0.10-0.12 | 0.10 | 0.10-0.12 |
| $SO_2$ | lb/MBtu | 0.04-0.08 | 0.01 | 0.04-0.08 |
| PM total | lb/MBtu | 0.015-0.035 | 0.018 | 0.015-0.035 |

Notes:

[1] Switchgrass will be co-fired with woody biomass, with switchgrass providing 20 percent of the heat input to the boiler. The heating value shown is for the switchgrass only. The blended value is 8,397 Btu/lb dry.

[2] The fuel cost for the wood/switchgrass case assumes a woody biomass cost of $3.55/MBtu and a switchgrass cost of $5.00/MBtu. Considering the relative proportion of each (i.e., 80% woody biomass and 20% switchgrass), the average cost of biomass fuel for the facility is estimated to be $3.85/MBtu.

## Biomass and Coal Property Assumptions

Table 2-4 presents the heat content and proximate and ultimate analyses for the biomass fuels under consideration and the baseline coal assumed in the repowering and co-firing cases. Table 2-5 summarizes the ash mineral analysis for each of the fuels.

**Table 2-4**
**Baseline Fuel Quality: Heat Content, Proximate, and Ultimate Analyses**

| Fuel Quality Parameter | Baseline Coal[1] | Raw Wood, 45% Moisture | Dried Wood, 30% Moisture | Torrefied Wood | As-received Switchgrass |
|---|---|---|---|---|---|
| Higher Heating Value, Btu/lbm | 12,210 | 4,770 | 6,070 | 12,760 | 6,210 |
| *Proximate Analysis*[2] | | | | | |
| Moisture, % | 8.5 | 45.00 | 30.00 | 6.2 | 15.0 |
| Ash, % | 11.24 | 2.18 | 2.77 | 1.78 | 5.7 |
| Volatile Matter, % | 29.57 | 45.32 | 57.68 | 19.66 | 66.00 |
| Fixed Carbon, % | 50.72 | 7.49 | 9.54 | 72.35 | 13.30 |
| *Ultimate Analysis*[2] | | | | | |
| Carbon, % | 69.96 | 27.67 | 35.22 | 78.24 | 40.00 |
| Hydrogen, % | 4.47 | 2.53 | 3.22 | 3.19 | 4.93 |
| Nitrogen, % | 1.36 | 0.57 | 0.73 | 0.56 | 0.52 |
| Sulfur, % | 1.03 | 0.06 | 0.08 | 0.01 | 0.10 |
| Chlorine, % | 0.00 | 0.02 | 0.03 | 0.00 | 0.22 |
| Moisture, % | 8.47 | 45.00 | 30.00 | 6.21 | 15.00 |
| Ash, % | 11.24 | 2.18 | 2.77 | 1.78 | 5.70 |
| Oxygen, % | 3.47 | 21.96 | 27.96 | 10.01 | 33.6 |

Notes:
[1] Baseline coal is assumed to be Central Appalachian (CAPP) coal.
[2] As-received values.

**Table 2-5**
**Baseline Fuel Ash Mineral and Other Analyses**

| Fuel Ash Analysis | Baseline Coal[1] | Raw Wood, 45% Moisture | Dried Wood, 30% Moisture | Torrefied Wood | As-received Switchgrass |
|---|---|---|---|---|---|
| Silica, % | 56.01 | 17.78 | 17.78 | 25.22 | 59.30 |
| Alumina, % | 25.95 | 3.55 | 3.55 | 4.46 | 4.30 |
| Titania, % | 1.17 | 0.50 | 0.50 | 0.03 | 0.20 |
| Iron Oxide, % | 9.14 | 1.58 | 1.58 | 3.03 | 2.75 |
| Lime, % | 1.41 | 45.46 | 45.46 | 24.21 | 6.70 |
| Magnesia, % | 1.24 | 7.48 | 7.48 | 13.41 | 3.60 |
| Potassium Oxide, % | 2.88 | 8.52 | 8.52 | 13.42 | 12.70 |
| Sodium, % | 0.43 | 2.13 | 2.13 | 0.56 | 0.53 |
| Sulfur Trioxide, % | 1.49 | 2.78 | 2.78 | 4.57 | 0.40 |
| Phosphorous Pentoxide, % | 0.25 | 7.44 | 7.44 | 9.33 | 7.60 |
| Undetermined, % | 0.03 | 2.78 | 2.78 | 1.76 | 1.92 |
| *Miscellaneous Properties* | | | | | |
| Ash Softening Temperature[2], °F | 2,567 | 2,184 | 2,184 | 2,142 | 1,898 |
| Hardgrove Grindability | 50.5 | 35 | 35 | 56 | undetermined |
| Calculated $SO_2$, lbm/MBtu | 1.69 | 0.25 | 0.25 | 0.016 | 0.39 |
| Mercury[3], ppm | 0.12 | 0.02 | 0.02 | 0.01 | 0.02 |
| Mercury[3], lbm/TBtu | 9.00 | 2.31 | 2.31 | 0.735 | 2.37 |

Notes:
[1] Baseline coal is assumed to be Central Appalachian (CAPP).
[2] Reducing atmosphere basis.
[3] Mercury content determined on a dry, whole-fuel basis.

## Biomass Receiving Assumptions

The biomass receiving, unloading, sizing, storage, and reclaim system is assumed to be automated to the extent practical, requiring minimum operating manpower and little or no movement of the fuel material via manual means such as front end loaders or bulldozers. Equipment redundancy and system design margins are included to insure a continuous fuel feed to the unit.

Truck scales and belt scales are included to determine the fuel delivery rate and the feed rate to the boiler. Magnets will extract tramp metal. It is anticipated that dust suppression and fire protections systems will be required.

### *Truck Receipt*

For the repowering and co-firing cases, it is assumed that each existing coal plant has at least one automated truck scale to record and verify coal deliveries. Upon arriving at the facility, each truck is weighed and provided a ticket from an automated dispenser and then proceeds to the unloading area. After unloading, the same process is repeated, but in reverse. The scale records the tare on the ticket, thereby determining the weight of the coal delivered. Similar systems have been used successfully at other power facilities and throughout other industries.

For biomass, it is assumed that the same system is utilized. However, the increase in the number of truck deliveries requires at least two scales to minimize delays due to scale congestion.

For the standalone biomass-fired BFB cases, it is assumed that biomass deliveries will be by truck, and that trucks would be accepted 10 hours per day on weekdays and 5 hours per day on Saturday. Each site would require two automated truck scales (one receiving and one exiting) to record and verify deliveries. Two scales are required to accommodate the volume of trucks deliveries and to minimize delays due to scale congestion.

### Woody Biomass Receipt

On an equivalent energy basis, the space required to store biomass is approximately four times that of coal. Because of this and because biomass is a supplemental fuel for the co-firing scenario, the biomass pile capacity is assumed to be sufficient to provide at least three days of supply[1] for the co-firing method under consideration. For repowering and standalone biomass-fired BFB cases in which biomass is the primary fuel, a biomass pile capacity sufficient for 28 days of supply is assumed.

In all cases, it is assumed that hydraulically-tipped, whole-truck dumpers are used to unload woody biomass. These dumpers are operated by the drivers. Because the drivers must exit their truck to operate the dumpers, it is assumed that the truck dumpers cycle a maximum of five times per hour. While biomass is assumed to be consumed on a continuous basis, it is assumed that biomass truck deliveries are accepted 55 hours per week (ten hours per day on weekdays and five hours per day on Saturday).

### Switchgrass Receipt

Switchgrass will be received by truck in half-ton square bales (3’x4’x8’), with approximately 30 bales per truck. Trucks cross the scales (both ways as with woody biomass) and are then unloaded by fast acting over head cranes capable of lifting (10) bales per pick. The bales will either be stacked in an enclosed storage building or immediately placed on the processing line.

The covered storage capacity will be 5 days operation at 20 percent of the boiler maximum continuous rating (MCR). Additional storage is assumed to be provided off site by the siwtchgrass suppliers.

### Summary of Material Handling Assumptions

Table 2-6 summarizes the major assumptions related to the biomass material handling for both the biomass repowering and biomass co-firing scenarios. Table 2-7 summarizes the major assumptions related to the biomass material handling for standalone biomass-fired BFB cases.

[1] For conservatism in space allocation and yard layout, a biomass pile sufficient for a seven-day supply was shown on the site arrangement drawing.

**Table 2-6**
**Biomass Material Handling Parameters for Repowering and Co-firing Cases**

| Parameter | Biomass Repowering | | Biomass Co-firing | |
|---|---|---|---|---|
| Material Size, as received | 3" minus | | 3" minus | |
| Material Size, final | 3" minus | | 1/4" minus | |
| Biomass Heat Input, % | 100 | 5 | 10 | 15 |
| Fuel Consumption at Boiler, tph | 105 | 13 | 26 | 39 |
| Delivery Method | Truck | | Truck | |
| Trucks Received | 10 hours per day / 5.5 days per wk | | 10 hours per day / 5.5 days per wk | |
| Days of Storage | 28+ | | 3 - 7 | |
| Boiler Feeding Method | Modified biomass feeders | | Pneumatic conveyors | |

**Table 2-7**
**Biomass Material Handling Parameters for Standalone BFB Cases**

| Parameter | Woody Biomass | Switchgrass |
|---|---|---|
| Material Size, as received | 4" minus | Half ton bales |
| Material Size, final | 2 ½" x ½" minus | 3" minus |
| Biomass Heat Input, % | 100% | 20% maximum in fuel blend with wood chips. |
| Delivery Method | Truck | Truck |
| Trucks Received | 10 hours per day / 5.5 days per wk | 10 hours per day / 5.5 days per wk |
| Unloading method | Hydraulic dumpers | Bridge crane |
| Days of Storage | 20+ uncovered | 5 covered |
| Boiler Feeding Method | Biomass feeders | Blended with woody biomass |

## Cost and Economic Assumptions

Preliminary, order-of-magnitude estimates of the incremental capital costs were developed for the base case biomass repowering and co-firing cases considered in this study, based upon the preliminary design parameters and EPRI methodology. Similarly, preliminary, order-of-magnitude capital cost estimates were also developed for standalone biomass-fired BFB cases considered in this study. Capital cost estimates for major equipment items are based on Black & Veatch's cost database and contacts with potential technology suppliers. Balance-of-plant equipment and construction are estimated on the basis of past experience with similar projects. Allowances for indirect costs such as engineering, permitting, general indirect costs, and construction management are also included. Both the repowering and co-firing capital cost estimates include an estimate of any required modifications to the host plant. A local labor wage rate and productivity are based on the preliminary assumptions developed for this study.

For all of the primary cases under consideration, preliminary estimates of non-fuel operations and maintenance (O&M) costs were developed. These estimates are based on project staffing plans, vendors' maintenance requirements and guidelines, estimates of consumables, experience from other renewable energy plants, and other sources. O&M costs associated with biomass-fired boiler operation, fuel handling, ash production, and equipment O&M were considered. For the co-firing scenario, the EPRI Vista® fuel impact model was employed to estimate the impacts of biomass co-firing on plant O&M costs, including the effects on ash production, coal consumption, equipment O&M, differential unit availability, and other factors.

The economic assumptions used in this study include financial parameters that affect the levelized fixed charge rate (i.e., project life, debt/equity ratio, interest rate on debt, return on equity, tax depreciation schedule, and production tax credit). Major assumptions used to calculate the LCOE for the base case repowering and co-firing scenarios are summarized in Table 2-8.

**Table 2-8**
**Parameters for Financial Analysis**

| Parameter | Units | Value |
|---|---|---|
| *Plant Lifespan and Financial Timing Assumptions* | | |
| Reference year for cost and economic assumptions | | 2010 |
| Operating period (project lifespan) for Repowering/Co-firing | years | 20 |
| Operating period (project lifespan) for Standalone BFB | years | 30 |
| *Operations and Maintenance (O&M) Assumptions* | | |
| FOM escalation | % / year | 0.0 |
| VOM escalation | % / year | 0.0 |
| *Capital Cost Assumptions* | | |
| Debt-to-equity ratio | % / % | 55 / 45 |
| Debt financing term | years | 15 |
| Interest on debt | % / year | 4.0 |
| Equity rate | % / year | 8.0 |
| *Tax-Related Assumptions* | | |
| Depreciation term / method | | 5-year / MACRS |
| Tax rate | % | 40 |
| General inflation | % / year | 0.0 |
| *Fuel-Related Assumptions* | | |
| Fuel cost escalation | % / year | 0.0 |

# 3

# 100% BIOMASS REPOWERING ENGINEERING AND ECONOMIC EVALUATION

This chapter presents the results of the engineering and economic evaluation of a representative biomass power plant at which the existing pulverized coal (PC) boiler systems are repowered to burn 100 percent biomass fuel. Three biomass repowering scenarios are considered:

- Base Case: a 100-MW (net) PC boiler modified to a bubbling fluidized bed (BFB) boiler and fired with raw, mixed woody biomass residues.
- Alternate Case 1: a 100-MW (net) PC boiler modified to a BFB boiler and fired with dried woody biomass residues.
- Alternate Case 2: a 100-MW (net) PC boiler modified to a BFB boiler and fired with torrefied biomass residues.

## Introduction to Biomass Repowering

In general, there are two options for biomass repowering projects: boiler modification or boiler replacement. The most appropriate choice will depend on several factors, including:

- Condition of the existing boiler systems and ancillary systems.
- Impact on rated capacity.
- Site space constraints.
- Characteristics of the available biomass fuels.
- Desired capital cost range.
- Permitting considerations.

For existing coal-fired stoker and fluidized bed boiler systems, changing the fuel from coal to biomass may be accomplished with minimal modification of the boilers, provided that the units were originally designed with some capability to fire a variety of fuels. It should be noted that the units would still likely require significant modification to the existing fuel receipt, handling, and feeding systems.

Because of the fine particle size required for combustion in suspension-fired PC boiler systems, significant boiler modifications are required. Biomass fuels cannot be sized to the extent that coal may be sized because of the varying material properties of these fuels. While coal may be sized to pass through a 200 mesh screen (with openings of approximately 0.003 inches), sizing woody biomass fuels to a top size of less than 1/8” to 1/4" may be challenging. Therefore, to fire a fuel stream consisting solely of biomass fuels in a boiler originally designed to fire pulverized coal, the boiler must be modified to use a combustion system capable of firing fuels with a larger particle size. That is, the pulverized coal firing systems must be replaced by a stoker or fluidized bed combustion system within the existing boiler structure (retaining the majority existing heat transfer surfaces and ancillary systems) or the entire boiler must be replaced with a boiler system designed to fire biomass fuels.

Regarding boiler technologies, viable options for wood-fired electrical generation projects include stoker boilers, bubbling fluidized bed (BFB) boilers, and circulating fluidized bed (CFB) boilers and external gasification of the biomass. The selection of a technology for firing woody biomass is not trivial. Cost, performance, and operational issues must be considered. In general for wood-fired projects with generation capacities greater than 50-MW but less than 100-MW, BFB boilers have been found to be the preferred technology. For the conversion of an existing 100-MW coal-fired boiler, therefore, a BFB combustion technology was selected as the appropriate technology for boiler conversion.

At facilities where PC units (of both industrial and utility scales) have been converted to fire biomass, the conversions have largely been accomplished by replacing the existing coal-fired steam generators with new and distinct biomass-fired steam generators. There is very little experience with the conversion of a PC unit to a BFB system. Full conversion of wall-fired or corner-fired PC boiler to a BFB boiler to fire 100% biomass alters the fundamental principals of the combustion process.

## Biomass Repowering Strategies

Coal-fired units may be repowered to fire biomass fuels by modifying the existing boiler systems or by replacing the existing boiler in its entirety. These methods are described further in the following subsections.

### *Biomass Repowering via Modification of Existing Boiler*

Modification of coal-fired boilers to fire biomass fuels is achieved by removing the lower furnace section (including the coal burner systems and much of the secondary air systems), as shown in Figure 3-1. This strategy maintains the existing heat transfer surfaces located in the upper portion of the boiler and the existing steam cycle. To allow for the combustion of biomass as the sole fuel for the unit, a grate or fluidized bed system is installed in place of the coal burner systems.

Because the material handling properties of coal and biomass are dissimilar, modifications of the existing fuel handling systems are likely. The specific equipment required and the material handling strategies employed depend upon the level of automation desired in the biomass

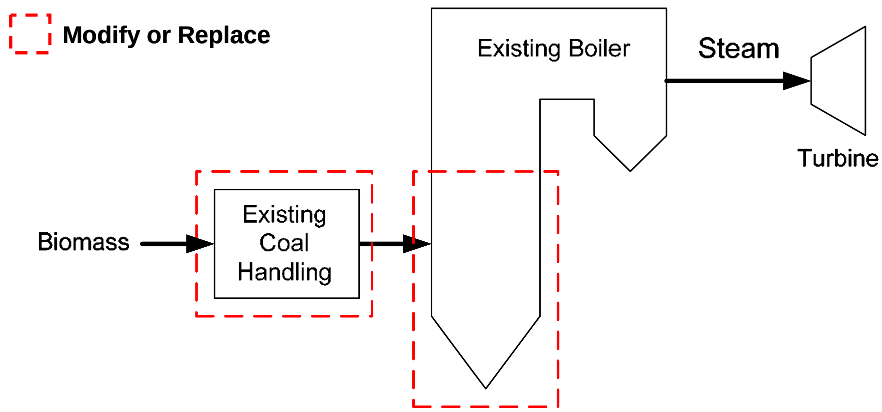


**Figure 3-1**
**Biomass Repowering via Modification of Existing Boiler**

receiving/stockout systems and the biomass reclaiming systems. These material handling systems can be fully-automated to minimize the number of operators required in the biomass fuel yard, or the systems could use mobile equipment, requiring a greater number of operators.

Because of (1) the differences in operating temperatures of BFB systems relative to PC systems, (2) the differences in fuel properties of biomass and coal, and (3) the re-use of heat transfer surfaces optimized for the coal-fired unit, the repowered (via boiler conversion) unit will likely be derated from its coal-fired generating capacity. Boiler suppliers are estimating a reduction in steam capacity and generation of 30 to 40% (as documented in Appendix C).

By modifying the existing unit and accounting for the likely derate, it is assumed that the unit remains in compliance with existing air permits (related to PSD and NSPS regulations), and no additional air quality control (AQC) systems is required. However, as repowering entails unit modifications, an analysis of potential emissions (comparing previous [pre-repowering] emissions and expected [post-repowering] emissions) will be required by the appropriate regulatory agencies. Additional AQC systems may be required based on the regulatory rulings.

### *Biomass Repowering via Replacement of Existing Boiler*

As an alternative to modifying the existing boiler, the existing boiler may be replaced with a new and distinct boiler, as shown in Figure 3-2. Like the boiler modification strategy, this strategy would utilize the existing steam cycle. However, this strategy may avoid a derate by replacing the coal boiler with a boiler designed to fire biomass while maintaining the previous steam generation capacity. This strategy is also appropriate for repowering coal boilers at the end of their serviceable life.

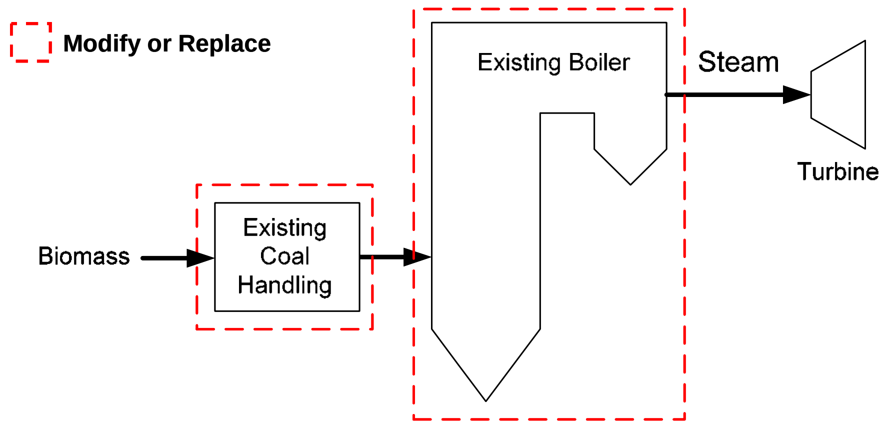


**Figure 3-2**
**Biomass Repowering via Replacement**

Like the modification strategy, repowering via boiler replacement will require modification of the existing fuel handling systems in most cases. The specific equipment required and the material handling strategies employed depend upon the level of automation desired in the biomass receiving/stockout systems and the biomass reclaiming systems.

One advantage of the replacement strategy relative to the modification strategy is that the biomass-fired boiler may be constructed while the existing coal-fired boiler remains in operation. However, space constraints must be a consideration for any retrofit project. Construction of the biomass-fired boiler while the coal-fired boiler remains in operation requires that sufficient area be available within the site to allow erection of the biomass-fired boiler and the associated construction laydown.

While the coal-fired boiler may remain in service during construction of the biomass-fired boiler, the coal-fired boiler must be offline prior to tie-in of the biomass-fired boiler with the existing steam cycle. Following the installation and commissioning of the biomass-fired boiler, it is assumed that the unit will remain in compliance with existing air permits (related to PSD and NSPS regulations), and no additional air quality control (AQC) systems will be required. However, as the replacement of the coal-fired boiler with a biomass-fired boiler will be classified either as a unit modification or as an installation of a new unit, an analysis of potential emissions (comparing previous [pre-repowering] emissions and expected [post-repowering] emissions) will be required by the appropriate regulatory agencies. Additional AQC systems may be required based on the regulatory rulings.

### *Biomass Repowering Concerns*

In general, plant owners and operators have raised numerous concerns about negative impacts of PC unit conversions on plant operations. The concerns include the following:

- As described earlier, upon conversion of a coal-fired PC combustion system to a biomass-fired BFB system, the net generation capacity of the repowered unit is reduced, resulting in a derate of the unit.

- There are concerns that repowering will increase operations and maintenance costs (on a $/MWh basis). These concerns are attributed to the reduced generation capacity and the potential for increased boiler fouling/slagging due to the high alkali in biomass ash. It should be noted that the concern regarding fouling/slagging is associated with the combustion of fast growing biomass, such as energy crops, rather than woody biomass.
- For units employing Selective Catalytic Reduction (SCR) systems for control of $NO_x$ emissions, there is potential for increased SCR catalyst degradation due to catalyst poisoning and pluggage from constituents of woody biomass ash. There is a lack of consensus among catalyst suppliers regarding the extent of this concern. It is recommended that the supplier of the SCR catalyst be consulted regarding this concern.
- While it is assumed that (1) the repowered unit (via conversion) employs the existing air quality control (AQC) systems and (2) the repowered (via conversion) unit adheres to Prevention of Significant Deterioration (PSD) and New Source Performance Standard (NSPS) regulations, there is uncertainty regarding modifications to Maximum Achievable Control Technology (MACT) standards. Biomass-fired boilers are regulated by Industrial Boiler MACT standards rather than Electric Generating Unit MACT standards. However, Industrial Boiler MACT standards have not been finalized, and it is believed that a great number of comments regarding these standards are associated with regulation of biomass-fired boilers. These regulations may require modification or addition to the existing AQC systems at the existing facility if one or more unit is repowered.

### *Biomass Repowering Benefits and Barriers*

There are both benefits and barriers associated with repowering existing systems with biomass. Without reiterating the technical pros and cons discussed elsewhere, these can be summarized as follows.

#### Benefits:

- Repowered power plants employ existing staffs, existing transmission access, and other pre-existing site facilities.
- Repowering provides a direct replacement for coal generation capacity. However, there is the potential for unit derating to occur.
- Biomass repowered power plants are renewable, baseload generation. Other renewables, such as wind and solar PV are variable generators.
- Biomass repowering may be less expensive than building new capacity, because repowering makes use of existing equipment (e.g., steam turbine generator and air quality control systems).
- Biomass repowering projects support rural economies through development of local biomass supply infrastructure and associated jobs.

- Repowering power plants have greenhouse gas and portfolio standard implications. Depending upon the definitions in federal- and state-level greenhouse gas regulations and renewable portfolio standards, biomass fuels may be considered carbon-neutral and the electricity generated by such projects may be allowable with respect to renewable portfolio standards requirements.

Barriers:

- Plant and corporate management and operations staff may be hesitant to alter a plant that is working well. Many have committed themselves to maximizing the efficiency and availability of the plant by improving performance, technology, and operations and maintenance practices over time. Changing fuel as well as boiler configuration will result in a new operating environment. It is critical to the success of any biomass conversion project to have project champions at both the plant and corporate levels. Without this, a conversion project is likely to encounter insurmountable challenges.
- The economics of a biomass project are typically competitive compared to the cost of adding other renewables to a generation portfolio. However, without regulatory assistance, such as a renewable portfolio standard (RPS), many biomass plants will not be competitive with coal.
- The biomass fuel supply infrastructure is immature in many regions of the country, and biomass suppliers may find it difficult to meet utility procurement standards.
- Fluidized bed boilers suppliers (including both BFB and CFB) have little experience with operations of 100% biomass above 100-MW.
- There is limited experience converting PC units to biomass-fired BFB technology. Determining the impacts to the unit output would require extensive modeling and evaluation by the original equipment manufacturer (OEM) or other steam generator equipment supplier. A more detailed, unit-specific modeling effort would be required to determine the exact derating that would occur.

### *Experience with Biomass Repowering*

Based on communications with steam generator suppliers, there is no commercial experience with the modification of PC units (via conversion of the furnace to a fluidized bed technology) firing biomass in the United States.

The authors are aware of only one utility-scale biomass repowering project completed in the United States (i.e., Schiller Station, at which the existing coal-fired boiler was replaced with a fluidized bed boiler designed to fire biomass). However, there are a number of repowering projects under consideration in both the United States and Canada. These are discussed below.

## United States

- **Public Service Company of New Hampshire--Schiller Station.**[2] The Northern Wood Power Project (NWPP) at Public Service of New Hampshire's (PSNH) Schiller Station in Portsmouth, New Hampshire, was commissioned in December 2006, after Unit 5 at Schiller Station was repowered with a wood-fired circulating fluidized bed (CFB) boiler. Unit 5 was originally put into service in the 1950s, and it was refurbished in 1984. The CFB is sized to produce 450,000 pounds per hour of steam at 1,250 psi and 950° F. For repowering, the existing Unit 5 turbine was overhauled and the existing balance-of-plant equipment was used. This is one of the larger renewable energy projects to replace an equivalent fossil-fired unit.

- **Georgia Power--Plant Mitchell.**[3] Georgia Power is considering the development of what would be one of the largest biomass power plants in the nation at Plant Mitchell, near Albany, Georgia. The project would convert a 155-MW unit that has been operating since 1964 to a 96-MW biomass-fired boiler. The unit would require approximately one million wet tons per year of biomass, which would consist of waste from logging operations within a 100 mile radius of the facility. Georgia Power has put this project on hold until it is known how the EPA regulations may affect industrial boiler emissions. Following definition of the new EPA rules, Georgia Power plans to study other boiler technologies to ascertain whether the new EPA rules significantly impact the cost of the biomass boiler conversion currently planned. Southern Company has termed this conversion a "retooling." It is unclear if the retooling will involve the installation of a new steam generator or an existing modified furnace design.

- **Red Hawk Energy--Mt. Poso Cogeneration Facility.**[4] The Mt. Poso Cogeneration facility, located near Bakersfield, California, has been operating on a combination of fossil fuels since 1989. The existing 49-MW circulating fluidized bed unit will be repowered to fire woody biomass with an expected capacity of 44 MW. The Mt. Poso facility has provided power to Pacific Gas and Electric Company (PG&E), and the utility will also be the power customer when the conversion to biomass is complete. This $50 million repowering project is expected to be completed in 2011. It is unclear if the repowering will be a total replacement of the current steam generator or a conversion of the existing unit.

- **University of Georgia.**[5] The 45-year old coal steam boiler at the University of Georgia's Physical Plant is nearing the end of its operational life. Replacing the existing coal/natural gas boiler with a new unit designed to fire local wood waste is being considered as a possibility. Replacement of the boiler alone is estimated to cost $30 million, which does not

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[2] Power Magazine, "PSNH's Northern Wood Power Project repowers coal-fired plant with new fluidized-bed combustor." August 2007. Accessed online: http://www.powermag.com/coal/PSNHs-Northern-Wood-Power-Project-repowers-coal-fired-plant-with-new-fluidized-bed-combustor_211.html September 2010.

[3] Georgia Power: Plant Mitchell Biomass Conversion. Accessed online: http://www.georgiapower.com/environment/plantmitchell.asp September 2010.

[4] Mt. Poso Cogeneration Company. Accessed online: http://mtposo.com/TheConversion/tabid/59/Default.aspx September 2010.

[5] University of Georgia, "Coal may not be in the future for University: Renewable fuel source essential." March 2010. Accessed online: http://www.redandblack.com/2010/03/28/coal-may-not-be-in-future-for-universityrenewable-fuel-source-essential/ September 2010.

include the fuel or the transportation system. A development timeline for this potential project has not been established.

- **DTE Energy Services--Stoneman Power Plant.**[6] DTE Energy Services converted the 50-MW Stoneman Power Plant near Cassville, Wisconsin, to burn wood waste. This facility was originally constructed in 1950. With the biomass conversion, the rated capacity of the facility is decreased to 40-MW. The converted Stoneman Station began operating in October 2010. This conversion is a total replacement of the existing steam generator.

- **Portland General Electric--Boardman Power Plant.**[7] Portland General Electric (PGE) is evaluating the future of its 585-MW coal-fired Boardman power plant in eastern Oregon. Boardman is the state's only coal-fired facility, as well as its largest source of emissions. PGE is considering conversion of the plant to burn biomass, perhaps torrefied biomass. PGE estimates that the facility would require two million (as-received) tons per year of torrefied biomass. It is estimated that converting the Boardman plant to burn torrefied biomass would cost between $350 and $450 million, in addition to the $200 million for emission controls. The utility is currently planning test burns of wood pellets co-fired with coal at the plant. Other options are being considered to replace capacity for power generation at Boardman in the next 10 to 30 years, including additional wind, solar, and natural gas development.

- **Hu Honua Bioenergy, LLC--Hu Honua Bioenergy Facility.**[8] Hu Honua Bioenergy, LLC is retrofitting the former coal-burning plant at Pepe'ekeo, Hawaii to a 24-MW biomass-fired power plant. The facility plans to utilize locally grown crops for fuel. The company is in the process of applying for project approvals from local authorities. Few details are available on the project development timeline.

### Canada

As part of a strategy by the province of Ontario to reduce greenhouse gas emissions, in 2007 a regulation was adopted that mandates phasing out the generation of electricity from coal at Ontario Power Generation's (OPG) coal-fired generating stations by December 31, 2014. The government also identified interim targets limiting $CO_2$ emissions from OPG's coal-fired fleet to one-third of 2003 emission levels by 2011. OPG operates five fossil-fired stations with a total installed capacity of 8,177 MW. These regulations have significant implications for biomass repowering for OPG's five fossil-fired generating stations. OPG is testing biomass at all five of its facilities, and details follow on two of these.

[6] DTE Energy Services, "DTE Energy Services Signs Purchase Agreements for Stoneman Power Plant." May 2008. Accessed online: http://dteenergy.mediaroom.com/index.php?s=43&item=318 September 2010.
[7] The Oregonian, "Boardman coal-burning power plant may have a future after all: biomass." January 2010. Accessed online: http://www.oregonlive.com/news/index.ssf/2010/01/coal-burning_power_plant_in_bo.html September 2010.
[8] Hu Honua Bioenergy LLC. Accessed online: http://huhonua.com/about-hu-honua/ September 2010.

- **Ontario Power Generation--Nanticoke Generating Station**[9] - the Nanticoke Generating Station, located on the north shore of Lake Erie, has been investigating the use of biomass as a coal offset option since 2005. The facility is equipped with eight 500-MW units. Nanticoke completed the first biomass injection test in 2006 using wheat shorts. Then in 2007, a direct-injection system using agricultural residues was placed in service. Since then, a number of other tests have been completed, including firing pelletized biomass and a dedicated milling concept which fires 100% biomass fuel.

- **Ontario Power Generation--Atikokan Generating Station**[10] - Following the lead of the Nanticoke facility, Atikokan began setting up its own test program using pelletized biomass as a fuel source. The Atikokan facility, located in Northwest Ontario, is equipped with a single Babcock & Wilcox natural circulation boiler. Since 2008, several test periods have been completed, including those that fired 100% wood and reached full load on wood.

## Design and Performance of Existing 100-MW Pulverized Coal Unit

It is assumed that the existing coal-fired unit employs a wall-fired pulverized-coal (PC) boiler system with a net generating capacity of 100-MW.[11]

Wall-fired units are typically fitted with numerous burners mounted on the front and/or rear wall of the furnace. Each burner is fed coal, primary air, and secondary air to safely and efficiently burn the pulverized coal. Primary air is the carrier for the pulverized coal fed to that individual burner, and secondary air is typically fed to the periphery of the coal and primary air stream to provide sufficient oxygen for complete combustion of the coal. In many units, once the initial combustion has taken place at the burners, the balance of the combustion air is provided by over-fire air ports to enable complete combustion of the vaporized fuel components prior to being cooled by the radiant and convective heat transfer surfaces of the boiler.

[9] Ontario Power Generation, Nanticoke Generating Station. Accessed online: http://www.opg.com/power/fossil/nanticoke.asp September 2010.
[10] Ontario Power Generation, Atikokan Generating Station. Accessed online: http://www.opg.com/power/fossil/atikokan.asp September 2010.
[11] The majority of PC boiler combustion systems at power generating facilities in the United States are of two types: wall-fired or tangentially-fired. Both types of furnace fire coal in suspension. The primary differences between the two are burner arrangement and flame configuration. Boiler modifications for repowering projects (with a bubbling fluidized bed replacing the lower part of the furnace) would be similar for wall-fired and T-fired units.

Table 3-1 summarizes the assumed performance parameters for a representative 100-MW wall fired PC unit.

**Table 3-1**
**Plant Performance Summary for 100-MW Coal-Fired PC Unit**

| Parameter | Units | Value |
|---|---|---|
| Gross Plant Output | kW | 113,000 |
| Turbine Heat Rate | Btu/kWh | 8,218 |
| | | |
| Total Auxiliary Power | kW | 13,000 |
| | % | 11.5 |
| Net Plant Output | kW | 100,000 |
| | | |
| Heat to Steam from Boiler | MBtu/h | 941 |
| Boiler Efficiency | % | 88.0 |
| Boiler Heat Input | MBtu/h | 1,069 |
| Coal Consumption | tons per hour | 43.8 |
| Net Plant Heat Rate | Btu/kWh | 10,692 |
| Notes:<br>1. Auxiliary power is assumed.<br>2. Once through cooling is assumed.<br>3. Average ambient conditions of 62.1° F dry bulb temperature and 54.8° F wet bulb temperature. Dew point temperature (49.6° F) is assumed to be the cold water temperature. | | |

To control emissions of nitrogen oxides ($NO_x$), it is assumed that the coal-fired unit employs low-$NO_x$ burners and Selective Non-Catalytic Reduction (SNCR).

To control emissions of particulate matter (PM), it is assumed that the coal-fired unit employs a cold-side electrostatic precipitator (ESP).

Because of the typical age of units of this scale, it is assumed that the coal-fired unit employs no systems for the control of sulfur dioxide ($SO_2$) or acid gases such as hydrogen chloride (HCl).

### *Relevant Characteristics of BFB Boiler Systems for Biomass Repowering*

Biomass has been burned in BFB boilers for more than thirty years. BFB combustion systems are capable of accommodating a wide range of fuel heating values and moisture contents. The fluidized bed consists of fuel, ash from the fuel, inert material (e.g., sand), and possibly a sorbent (e.g., limestone) for sulfur control. Sorbent injection, if required in biomass applications, can cause bed agglomeration issues. In most biomass applications, the fuel typically has very little sulfur, and sorbent is not required.

As shown in Figure 3-3, the fluidized state of the bed is maintained by hot primary air flowing upward through the bed. The air is introduced through a grid for even distribution. The amount of air is just sufficient to cause the bed material to fluidize. BFBs operate at low fluidizing velocities (about 3 to 10 ft/s), and the bed material maintains a relatively high solid density. This operation results in a well-defined bed surface with only a small fraction of the solids entrained in the flue gas stream leaving the bed. Hot sand in the bed effectively dries and volatilizes the fuel introduced. In this state, circulation patterns occur, which causes fuel discharged on top of the bed to mix throughout the bed. Because of the turbulent mixing, heat transfer rates are very high, and combustion efficiency is good. The bed retains most of the heat of combustion; therefore, it is well-suited for low heating value, high moisture fuels, such as biomass.

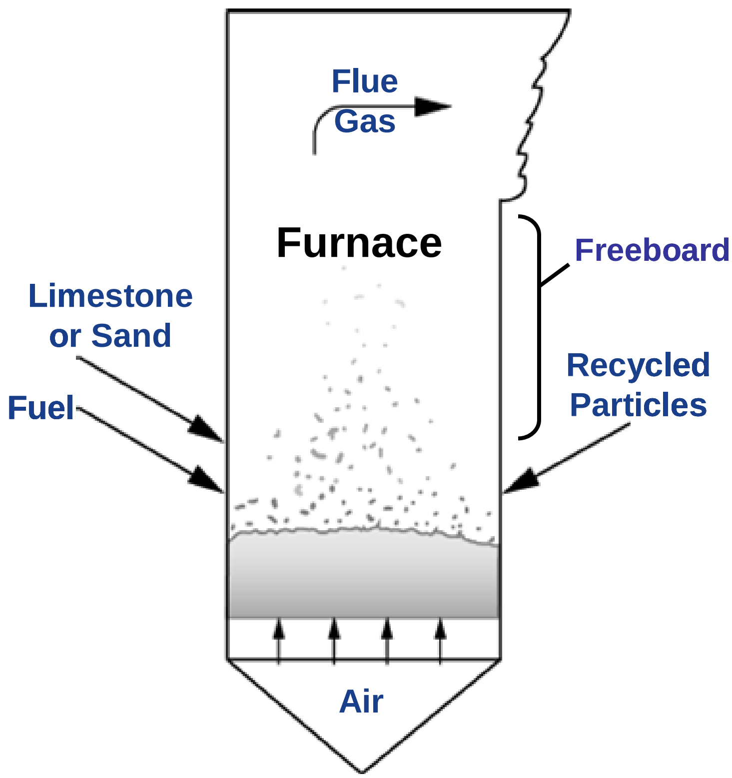


**Figure 3-3**
**Simplified Diagram of a BFB System**

Because the woody biomass fuel rapidly devolatizes, 50 to 60 percent of the combustion occurs in the bed and 40 to 45 percent occurs above the bed. Overfire air is required to ensure complete combustion of the fuel.

Combustion temperatures can be kept relatively low compared to other conventional fossil fuel-fired boilers. The bed may also be operated in a sub-stoichiometric mode with additional air added in the freeboard (i.e., the portion of the furnace above the bubbling bed) to complete combustion. The low bed temperatures and air staging associated with BFBs provides multiple benefits. First, these operational characteristics reduce $NO_x$ formation (uncontrolled $NO_x$ emission rates for BFB systems are generally less than 0.20 lbm/MBtu). Second, the relatively low operating temperatures of BFB systems are typically within the temperature range for effective operation of SNCR systems. Finally, the lower bed temperature is likely to remain below the ash fusion temperature of the biomass fuels, reducing the potential for boiler slagging.

Because of the low combustion temperatures, $NO_X$ emissions from a BFB boiler burning biomass will be low. In addition, the operating temperature of a BFB is usually within the temperature range that allows SNCR systems to be effective.

## *Boiler System Modifications and Unit Performance Impacts*

### Boiler System Modifications

When converting a boiler system from a PC to a BFB unit, boiler modifications will be unit-specific. However, while the scope of work will vary from unit to unit, it is expected that, in each case, the conversion of the PC unit to BFB will include the removal of the bottom section of the furnace (including all existing combustion equipment) and the installation of a flat bottom bed section (including refractory, provisions for bed material, and a tube floor with bubble caps). An illustration of the bed section that would be added with a BFB arrangement is shown in Figure 3-4.

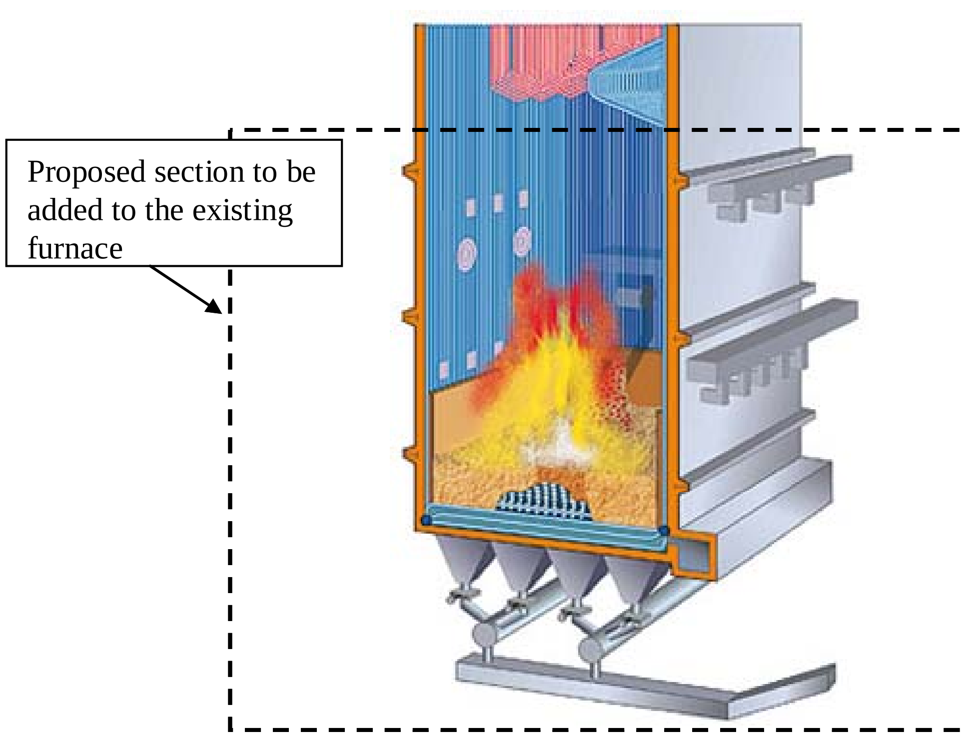


**Figure 3-4**
**Example BFB Assembly (Source: Metso)**

The conversion of the PC unit to a BFB design may require the removal and/or modifications of existing boiler equipment, including the following components:

- Burner systems.
- Bottom ash handling systems.

- Coal pulverizer systems.
- Coal delivery systems, including piping, feed valves and feeders.
- Windbox.
- Asbestos/lead, if present.

The bottom ash handling system will be removed with the bottom of the furnace and replaced with systems designed to accommodate the firing of woody biomass in a BFB system (if necessary). The windbox and all other combustion air ductwork will be removed with the bottom of the furnace and redirected to accommodate the installation of the BFB bed. All hazardous material (e.g., asbestos or lead) removal and containment will have to be considered in the installation and removal scope.

In addition, conversion may require replacement or significant modification of existing boiler equipment, including following components:

- Primary air systems (i.e., fans).
- Secondary air systems, including ductwork, penetrations and air injection ports.
- Waterwall panels
- Reheater/superheater surfaces.
- Attemporator (desuperheater) systems.
- Air heater systems.
- Sootblowing systems.
- Boiler instrumentation and controls.
- Fire protection.
- Boiler foundations and structural steel.

It is expected that total steam production will be reduced and that modifications to the heat transfer sections of the furnace will need to be performed in order to reduce the potential impacts to the overall steam production cycle. Existing conditions such as free boiler space and locations of structural steel will impact the type and extent of heat transfer surface modifications that are feasible. Cost-benefit issues will also affect the type of modifications made.

It is recommended that modifications to limit erosion of heat transfer surfaces be considered. Changes in ash characteristics, flue gas volume flows, gas velocity, and firing temperatures all influence the potential for erosion in the furnace. Additional protection of waterwalls (e.g., cladding, spray coatings and weld overlays) may be required when considering the conversion to a BFB firing woody biomass.

Regarding existing boiler foundations, boiler suppliers have indicated that reinforcement may be required to accommodate the added weight of the new bottom-supported grate. The degree of reinforcement depends upon the amount of refractory required as well as the total mass of the installed bed.

Components such as steam piping, valves, water conditioning systems, feedwater heaters, and pumps are expected to be minimally affected. However, these components should be investigated for design capacities and to confirm that proper operational parameters are being used after the conversion.

The specific geometry of the furnace will dictate the required modifications. An example of this is the total dimensions of the furnace. Boiler suppliers have indicated that for square systems with dimensions of 30' x 30' or 40' x 40', the design may require two fuel injection points; one along the front wall and one along the back wall. These two injection points will ensure a uniform $O_2$ profile at the exit of the furnace. Typically, the fuel delivery system is located on adjacent walls at a common point on each wall. The vertical arrangement of the furnace will also impact the final design of the bottom section to be added. The amount of refractory and the potential modifications to the heat transfer sections are unit specific and will have to be determined on a site-by-site basis during detailed analysis by the selected supplier.

With a unit conversion, it is expected that the new system would reuse as many of the existing interfaces as possible. The expected interface points with systems or services with the existing steam generator systems are listed in Appendix D. These are not expected to change with the conversion of the existing PC boiler to a BFB system.

In addition to the BFB boiler system components (e.g., biomass fuel feeding systems, fluidization equipment such as bubble cap assemblies and bed material) and modifications to existing systems (mentioned above), the following items may be included in the scope of work for a boiler conversion. (This listing is intended to be indicative only.)

- Insulation/refractory/lagging.
- All electrical wiring, including cable tray, conduit, and cable.
- Valves, fittings, hangers, expansion joints.
- All auxiliary installation equipment.
- NFPA audit and all systems to comply with specifications related to the installation.
- All associated motors and electrical systems.
- Demolition/relocation of existing equipment.

## Unit Performance Impacts

**When modifying both the design and fuel of an existing boiler system, the performance of the unit will be impacted.**

Table 3-2 presents boiler efficiency impacts related only to the fuel conversion from coal to woody biomass. Effects on radiation and convection losses, slag, and fly ash loss have been excluded due to the variations in these losses between units.

**Table 3-2**
**Example Boiler Efficiency Impacts**

| Parameter | Units | Coal-fired PC Unit | Woody biomass-fired BFB Unit |
|---|---|---|---|
| Dry Gas Loss | % | 5.10 | 4.20 |
| Loss from Moisture in Air (Sensible Only) | % | 0.12 | 0.05 |
| Loss from Moisture in Fuel (Sensible and Latent) | % | 0.79 | 10.86 |
| Loss from Hydrogen in Fuel (Sensible and Latent) | % | 3.70 | 5.46 |
| Unburned Carbon Loss | % | 0.56 | 0.14 |
| **Total** | **%** | **10.27** | **20.70** |

Boiler suppliers indicate that additional reductions in steam production will result due to the increased gas weight and high volume flows through the furnace when firing woody biomass. These suppliers indicated that a unit converted from a coal-fired PC boiler to a wood-fired BFB may be derated by as much 30 to 40 percent of the coal-fired generation capacity. In the case presented in this report, it is estimated that the existing 100-MW coal-fired PC unit would be derated to 60-MW of net generation capacity upon conversion to BFB unit and repowering with woody biomass fuel.

Table 3-3 summarizes the unit performance parameters for the repowered biomass BFB unit.

**Table 3-3**
**Plant Performance Summary for Biomass-fired BFB Boiler**

| Parameter | Units | Coal-fired PC Unit | Woody biomass-fired BFB Unit |
|---|---|---|---|
| Turbine Gross Output | kW | 113,000 | 68,200 |
| Turbine Heat Rate | Btu/kWh | 8,218 | 8,635 |
| | | | |
| Total Auxiliary Power | kW | 13,000 | 8,200 |
| | % | 11.5 | 12.0 |
| Net Plant Output | kW | 100,000 | 60,000 |
| | | | |
| Heat to Steam from Boiler | MBtu/h | 941 | 589 |
| Boiler Efficiency | % | 88.0 | 78.0 |
| Boiler Heat Input | MBtu/h | 1,069 | 756 |
| Coal Consumption | tons/h | 43.8 | 0 |
| Biomass Consumption | tons/h | 0 | 79.3 |
| Net Plant Heat Rate | Btu/kWh | 10,690 | 12,600 |

Notes:
1. Auxiliary power is assumed.
2. Once through cooling is assumed.
3. Average ambient conditions of 62.1° F dry bulb temperature and 54.8° F wet bulb temperature. Dew point temperature (49.6° F) is assumed to be the cold water temperature.

## Emissions Impacts

For the purpose of air permitting (relative to Prevention of Significant Deterioration [PSD] and New Source Performance Standards [NSPS] regulations), repowering a coal-fired unit as a biomass-fired unit is considered a unit modification (regardless of whether the boiler is modified or replaced in its entirety). An emission analysis of the unit (or facility, if the unit is located and operated along with other existing units at a single location) will be required to demonstrate the anticipated change in emissions relative to the actual reported emissions of the unit prior to repowering.

Because (1) these emissions are reported in tons per year (for PSD regulations) and tons per hour (for NSPS regulations) and (2) the biomass-fired unit is anticipated to be derated 30 to 40 percent of the original coal-fired generation capacity, it is assumed that the anticipated emissions of the repowered unit will be significantly less than the actual emissions of the coal-fired unit. Therefore, it is assumed that the existing AQC systems will be sufficient for the control of nitrogen oxides ($NO_x$), sulfur dioxide ($SO_2$) and particulate matter (PM).[12]

[12] While the repowered unit is expected to comply with its current PSD and NSPS regulations, it is uncertain whether the repowered unit will be required to install additional AQC systems to comply with the Industrial Boiler Maximum Achievable Control Technology (MACT) standards that will be finalized imminently. Proposed MACT standards were released in June of 2010, but the final standards have not been released.

### *Nitrogen Oxides*

Nitrogen oxides ($NO_x$) are a byproduct of combustion, and the generation rate of $NO_x$ is highly dependent on combustion stability, fuel quality, and air and fuel distribution. Operational tuning of the boiler is conducted and maintained to minimize fuel gas components such as $NO_x$ and carbon monoxide (CO). Improved methods of fuel and air distribution (based on combustion system design tools such as computational fluid dynamics [CFD] modeling) can have large impacts on these emission components.

As stated previously, BFB boilers are capable of achieving an uncontrolled $NO_x$ emission rate of 0.15 to 0.20 lb/MBtu. It is assumed that the appropriate operation of SNCR systems would reduce emissions of $NO_x$ to approximately 0.10 lb/MBtu. However, the use of biomass-compatible SCR systems would be required to achieve these levels.

### *Sulfur Oxides*

The emission of sulfur oxides ($SO_x$) is solely-fuel dependent (i.e., dependent upon sulfur present in the biomass fuels). Because the sulfur content of biomass fuels is very low relative to coal, a biomass-fired unit is expected to have minimal $SO_x$ emissions relative to those of a similarly sized coal-fired unit. If an existing unit has no existing sulfur control systems, it is not anticipated that such systems would be required upon repowering as a biomass-fired unit.

### *Particulate Matter*

Considering the anticipated derate of the repowered unit, it is assumed that the existing particulate control system (i.e., electrostatic precipitator [ESP]) is capable of achieving the emission limits for particulate matter.

## *Material Handling System Modifications*

The nature of woody biomass (i.e., raw wood chips) requires a completely different material handling system than that used for the coal-fired plant.[13] A typical coal handling system for a 100-MW PC facility is depicted by drawing DS-0001A in Appendix B. However, woody biomass has a much lower bulk density than coal and has a propensity to interlock and mat (thereby plugging conveying equipment not designed to transport biomass fuels). Because of these biomass properties, a material handling system designed to handle coal cannot be used to handle biomass fuels except in very small quantities when mixed with the coal in co-milling applications.

It is typically less expensive to remove coal residues and then abandon the existing coal handling system in place, assuming that the new biomass handling system can be constructed at a different location than the existing coal handling equipment.

[13] Note that, unlike "raw" wood chips, torrefied biomass can usually be pulverized to a size that may be handled with the existing coal handling system.

The biomass handling approach for the repowered 60-MW BFB facility is depicted by drawing DS-0003A in Appendix B. The lower heating value of wood chips and a longer dumping cycle time[14] dictates the need for four truck dump stations whereas only one station was required for coal.

Conveyor belt scales are used to control biomass feed rates within the handling system, as well as provide biomass consumption data for unit performance calculations.

Generally, dust wet suppression is utilized on incoming biomass unloading and stockout equipment. Wet methods are more effective than dry methods within large open areas (e.g., open truck dump hoppers or stocking out through open air). Dust dry collection would be utilized in other areas (following reclaim of biomass fuels) because it is undesirable to add moisture and because capture airflow rates can be smaller in smaller chutes and other equipment.

A self-cleaning magnetic separator is utilized on a belt conveyor for ferrous tramp metal removal. In addition, a metal detector is used on a belt conveyor for ferrous and non-ferrous metal detection, marking, and annunciation to permit manual inspection and removal.

As biomass dust is combustible and explosive, fire detection and/or suppression is utilized throughout the system.

It is assumed that arriving wood chips are pre-sized off-site to the maximum size for combustion in a BFB boiler (i.e., 3 inches). However, disc screens are employed on-site to reject any oversize material, which can be accumulated and periodically ground to an acceptable size in a truck-mounted grinder before re-entering the biomass handling system.

The low bulk density of the biomass and relatively low heating value result in relatively low-capacity boiler feed bins. As such, it is necessary to provide a biomass handling system that operates continuously to keep them filled.

This biomass material handling system is designed on the basis of woody biomass with a moisture content of up to 45 percent as-received. The fuel may be dried naturally in onsite storage to a nominal moisture content of 30 percent or as required by the BFB steam generator. While the moisture content of the biomass may affect BFB performance, the biomass handling system is designed for worst-case conditions of 45 percent moisture and is not affected by variations in biomass moisture content associated with the alterative biomass cases.

### Material Handling Equipment

Table 3-4 lists the biomass material handling equipment required for the base-case repowered 60-MW unit (i.e., firing blended, undried woody biomass). The tag number references the equipment listed on the material handling process flow diagrams in Appendix B.

[14] The longer cycle time is generally due to the need for the driver to exit the truck while it is locked onto a platform and tipped up at a steep angle to discharge the woody biomass.

**Table 3-4**
**Biomass Material Handling Equipment Listing**

| Description | Tag |
|---|---|
| Truck Scale | SCL-1A |
| Truck Scale | SCL-1B |
| Hydraulic Truck Dumper with Receiving Hopper | DMP-1A |
| Hydraulic Truck Dumper with Receiving Hopper | DMP-1B |
| Hydraulic Truck Dumper with Receiving Hopper | DMP-2A |
| Hydraulic Truck Dumper with Receiving Hopper | DMP-2B |
| Drag Chain Feeder | FDR-1A |
| Drag Chain Feeder | FDR-1B |
| Apron Feeder | FDR-2A |
| Apron Feeder | FDR-2B |
| Collecting Belt Conveyor | CVY-1A |
| Belt Conveyor Scale | SCL-2A |
| Collecting Belt Conveyor | CVY-1B |
| Belt Conveyor Scale | SCL-2B |
| Disc Screen (including Screening Tower) | SCN-1A |
| Disc Screen (including Screening Tower) | SCN-1B |
| Belt Conveyor | CVY-2A |
| Belt Conveyor | CVY-2B |
| Slewing Cleated Receiving Conveyor | CVY-3A |
| Slewing Cleated Receiving Conveyor | CVY-3B |
| Oversized Grinder | GRN-1 |
| Biomass Receiving Dust Wet Suppression System | |
| Stamler Feeder | FDR-3 |
| Belt Conveyor | CVY-4 |
| Belt Conveyor Scale | SCL-3 |
| Self-Cleaning Magnetic Separator | SEP-1 |
| Disc Screen (including Screening Tower) | SCN-2 |
| Dust Collector | DCO-1 |
| Belt Conveyor | CVY-5 |
| Belt Conveyor Scale | SCL-4 |
| Self-Cleaning Magnetic Separator | SEP-2 |
| Tramp Metal Detector | TMD-1 |
| Distribution Drag Chain Conveyor (including Transfer Tower) | CVY-6 |
| Overfill Return Belt Conveyor | CVY-7 |
| Belt Conveyor Scale | SCL-5 |
| Dust Collector | DCO-2 |
| Boiler Live Bottom Feed Bins | |

### *Biomass Systems Footprint*

The biomass handling system for the 60-MW BFB facility is shown on the site arrangement drawing DS-0003 in Appendix A. The coal handling system is generally assumed to be abandoned in place.[15] However, major modifications are required in the transfer tower adjacent to the boiler use bins to remove coal chutes and conveyors as required to permit the addition of biomass chutes and conveyors.

[15] See Note 13.

The biomass reserve storage pile shown represents 28 days of storage.

Generally, the biomass handling system can be modified to fit other sites following these guidelines:

- The biomass receiving and stockout system is somewhat “modular” or “stand-alone” and can be located and arranged as desired. It is best to locate the system to minimize truck traffic through more populated or busy areas of the plant and to locate the stockout piles in close proximity to the reclaim feeder to minimize dozing.

- The reclaim system and associated disc screen / transfer building can be located as desired. Certain horizontal separation distances are required to attain the vertical heights needed (due to the maximum allowable incline of belt conveyors) for feeding the disc screen and the elevated boiler use bins.

- The biomass reserve storage pile can be located as desired. Distances from the stockout piles and the reclaim feeder should be short to minimize dozing distances. A sufficient buffer should be maintained around the pile to allow for a runoff collection ditch.

## Estimated Costs for Biomass Repowering

Table 3-6 presents the Total Capital Requirement and O&M estimates for the base-case biomass repowering scenario (see Table 3-5). This section describes the development of the cost estimates, identifies the assumptions used in the development of the estimates, and presents the estimates. The resulting levelized cost of electricity (LCOE) estimates for the biomass repowering scenarios are also provided in this section.

**Table 3-5**
**Summary of Biomass Repowering Base Case**

| Parameter | Biomass Repowering Base Case Scenario |
|---|---|
| Net Capacity (Coal) | 100-MW |
| Original Boiler Type | Wall-fired PC |
| Net Capacity (Biomass) | 60-MW |
| Biomass Boiler Type | BFB |
| Capacity Factor | 85% |
| *Biomass Properties* | |
| Fuel Type | Undried, blended biomass |
| Heating Value (dry) | 8,670 Btu/lb |
| Moisture Content | 45% |

### *Total Capital Requirement Estimates*

Table 3-6 summarizes the Total Capital Requirement estimates for the primary biomass repowering case. The costs are primarily dependent upon the method of repowering selected for the project. Other project parameters affecting the cost to some extent include the following:

- Scale of project (i.e., biomass-fired generation capacity, in terms of MW).
- Required system upgrades/replacement of existing equipment (e.g., fuel handling, steam cycle systems).
- Required infrastructure upgrades (i.e., plant roadways).
- Biomass storage strategy.

Capital cost estimates for the biomass repowering scenario were developed assuming a turnkey engineering, procurement, and construction (EPC) contract to execute the project. Capital costs for these projects are divided into two categories: direct costs and indirect costs. Direct costs include the costs associated with the purchase and installation of major equipment and balance-of-plant (BOP) equipment. Capital cost estimates for major equipment items are based upon recent vendor quotations. The capital costs associated with BOP equipment and construction and any required facility modifications (i.e., boiler modifications) were estimated based on past experience with similar projects.

Indirect costs include construction indirects, engineering, construction management, and contingency. Allowances for indirect costs were included in these estimates. The specific items included as construction indirect costs include the following:

- Construction supervision.
- Purchase of small tools and consumables.
- Site services.
- Construction safety program (including development and compliance).
- Installation of temporary facilities.
- Installation of temporary utilities.
- Rental of construction equipment.
- Heavy haul of construction materials and equipment.
- Preoperational startup and testing.
- Insurances (including builder's risk and general liability).
- Construction permits (excluding Construction Air Permit).
- Performance bond.
- EPC contractor profit.

An allowance for Owner's Costs (i.e., due diligence, permitting, legal and other development costs) is included. This allowance is calculated as 10 percent of the Total Plant Cost.

### Operation and Maintenance Cost Estimates

Table 3-6 summarizes the fixed and variable operation and maintenance (O&M) cost estimates for the biomass repowering scenario. Fixed O&M costs consist of wages and wage-related overheads for the permanent plant staff, routine equipment maintenance, and other fees. Variable O&M costs include costs associated with equipment maintenance during outages, catalyst/reagents, chemicals, water, and other consumables. Fuel costs are determined separately and are not included in either fixed or variable O&M costs.

The fixed and variable O&M costs for the biomass repowering case assume the following:

- The repowering case uses a retrofit BFB boiler.
- The fuel is undried, woody biomass with 45% moisture.
- Estimated gross capacity factor is 85%.
- Forced outage factor is 4%.
- Net plant heat rate is 12,600 Btu/kWh.
- Plant staff average wage rate is $56,590 per year.
- The burden rate is 40%.
- Staff supplies and materials are estimated to be 5% of staff salary.
- Estimated employee training cost and incentive pay/bonuses are included.
- Routine maintenance costs are estimated based on Black & Veatch experience and manufacturer input.
- Contract services include costs for services not directly related to power production.
- Insurance and property taxes are not included.
- The variable O&M analysis is based on a repeating maintenance schedule over the life of the plant.
- Variable O&M costs associated with the steam turbine are estimated based on a typical overhaul schedule (including both minor and major overhauls).
- Frequency of boiler overhaul is every year.
- Frequency of turbine and generator major inspection is every six years.
- Steam turbine, generator, boiler, and other balance of plant maintenance costs are based on Black & Veatch experience and vendor data recommendations.
- SNCR costs are included.
- Water treatment costs are included for water make-up and demineralization where needed.

- BFB bed sand cost is $20 per ton.
- Demineralized water treatment cost is $5 per 1,000 gallons.
- City water cost is $1 per 1,000 gallons.
- Ash disposal cost is $6 per ton.
- Anhydrous ammonia cost is $800 per ton.
- Aqueous ammonia cost is $315 per ton.
- The O&M cost estimates are in 3rd-quarter 2010 US dollars.

### *Biomass Repowering Cost Estimate Results*

Table 3-6 summarizes the biomass repowering cost and performance characteristics.

### *Levelized Cost of Electricity*

The levelized cost of electricity (LCOE) considers the levelized fixed charge on total capital requirement, fixed and variable O&M, and fuel cost. It represents the present value of the total life-cycle costs normalized by the total annual MWh generated the facility. LCOE is calculated in units of dollars per megawatt hour ($/MWh) in constant 3rd-quarter 2010 dollars.

#### Levelized Fixed Charge Rate

The levelized fixed charge rate (LCFR) is the factor applied to the Total Capital Requirement to yield the annual fixed charge on the capital investment. For an investor-owned utility, the components of the annual fixed charge include depreciation, interest on debt, return on equity, income and property taxes, insurance, and other administrative costs. For the economic assumptions presented in Table 2-8 and 20-year project life, the LFCR is estimated to be 8.50% per year without consideration of the ITC, and 7.33% with the ITC. The Fixed Capital Charge Component of cash flow is summarized in Table 3-7.

Levelized Cost of Electricity EstimatesTable 3-8 presents the LCOE results for the base case and two sensitivity cases. LCOE estimates were calculated with and without the benefits of the Investment Tax Credit (ITC), for the reason that it is presently uncertain whether biomass repowering projects would qualify for the ITC.

If the Investment Tax Credit (ITC, equivalent to 30 percent of Total Capital Requirement) is not applied, the LCOE estimates are $88/MWh for the base case ($3.55/MBtu biomass fuel cost) and $76/MWh and $101/MWh for the two sensitivity cases (biomass fuel cost is $2.55 and $4.55/MBtu, respectively). If the ITC is applied, the LCOE is reduced by approximately $8/MWh in each case, as shown inTable 3-8.

**Table 3-6**
**Biomass Repowering Characteristics and Total Capital Requirement Estimate (3rd-Quarter 2010$)**

| | | | |
|---|---|---|---|
| **Rated Capacity** | | | |
| Plant Size (units x unit size, MW) | 1 x 60 | | |
| **Physical Plant** | | | |
| Unit Life, Years | 20 | | |
| **Scheduling** | | | |
| Preconst., License & Design Time, Years | 2.0 | | |
| Idealized Plant Construction Time, Years | 0.75 | | |
| Hypothetical In-Service Date | January 1, 2011 | | |
| **Capital Costs** | **($1,000)** | **($/kW)** | **(%)** |
| *Major Equipment Costs* | | | |
| Fuel Handling/Prep | $16,540 | $280/kW | 16% |
| Boiler Modification | $50,000 | $830/kW | 47% |
| **Total Major Equipment Costs** | **$66,540** | **$1,110** | **63%** |
| *Direct Balance of Plant Costs* | | | |
| Site Work, Foundations, Roadways | $970 | $20/kW | 1% |
| Electrical Equipment, Cable, & Raceway | $750 | $10/kW | 1% |
| Instrumentation & Controls | $1,670 | $30/kW | 2% |
| **Total Direct Balance of Plant Costs** | **$3,390** | **$60/kW** | **3%** |
| *Indirect Balance of Plant Costs* | | | |
| Facilities, Engineering, and Const. Mgt. | $15,390 | $260/kW | 15% |
| Project & Process Contingency & Fees | $20,680 | $340/kW | 19% |
| **Total Indirect Balance of Plant Costs** | **$36,070** | **$600/kW** | **34%** |
| *Total Costs* | | | |
| **Total Plant Costs** | **$106,000** | **$1,770/kW** | **100%** |
| AFUDC (Interest during construction) | $1,200 | $20/kW | -- |
| **Total Plant Investment (incl. AFUDC)** | **$107,200** | **$1,790/kW** | **--** |
| **Owner's Cost** | **$10,700** | **$180/kW** | **--** |
| **Total Capital Requirement** | **$117,900** | **$1,970/kW** | **--** |
| **O&M Costs** | | | |
| Fixed, $/kW-yr | 132 | | |
| Variable, $/MWh | 3.50 | | |
| **Performance/Unit Availability** | | | |
| Net Heat Rate (Full Load), Btu/kWh | 12,600 | | |
| Equivalent Planned Outage Rate, % | 4 | | |
| Duty Cycle | Baseload | | |
| Minimum Load, % | 40 | | |
| **Emission Rates** | | | |
| $NO_x$, lb/MBtu | 0.15 - 0.24 | | |
| $SO_x$, lb/MBtu | fuel dependent | | |
| Particulate, lb/MBtu | <0.02 | | |
| **Confidence and Accuracy Rating** | | | |
| Technology Development Rating | Commercial | | |
| Design & Cost Estimate Rating | Simplified | | |

**Table 3-7**
**Biomass Repowering Levelized Fixed Capital Charge Component (3rd-Quarter 2010 $)**

| Scenario | Levelized Fixed Charge Rate | Fixed Capital Charge Component of Cash Flow[1] |
|---|---|---|
| With ITC | 7.33% | $101/kW-yr |
| Without ITC | 8.50% | $168/kW-yr |

Notes:

[1] Fixed Capital Charge Component of Cash Flow calculated by multiplying the LFCR by the Total Capital Requirement. The components of the annual fixed charge include amortization, depreciation, return on equity, income and property taxes, insurance, and other administrative costs. This value does not include charges associated with fixed O&M costs.

**Table 3-8**
**Biomass Repowering Levelized Cost of Electricity Estimates (3rd-Quarter 2010 $)**

| Cost | Base Case | Sensitivity Case 1[1] | Sensitivity Case 2[1] |
|---|---|---|---|
| **Biomass Fuel Cost ($/MBtu)** | 3.55 | 2.55 | 4.55 |
| | | | |
| **Levelized Cost of Electricity[2] With ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 18 | 18 | 18 |
| Variable O&M Component of LCOE ($/MWh) | 3 | 3 | 3 |
| Fuel Component of LCOE ($/MWh) | 45 | 32 | 57 |
| Capital Charge Component of LCOE ($/MWh) | 14 | 14 | 14 |
| **Total[3] ($/MWh)** | **80** | **67** | **92** |
| | | | |
| **Levelized Cost of Electricity[2] Without ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 18 | 18 | 18 |
| Variable O&M Component of LCOE ($/MWh) | 3 | 3 | 3 |
| Fuel Component of LCOE ($/MWh) | 45 | 32 | 57 |
| Capital Charge Component of LCOE ($/MWh) | 22 | 22 | 22 |
| **Total[3] ($/MWh)** | **88** | **76** | **101** |

Notes:

[1] Sensitivity Cases assume biomass fuel costs are $1.00/MBtu above and below the base cost of $3.55/MBtu.

[2] Estimate of LCOE assumes an 85% capacity factor, 20-year project life, and constant dollars.

[3] Sum of LCOE component values may not equal Total value due to rounding.

# 4

# BIOMASS CO-FIRING ENGINEERING AND ECONOMIC EVALUATION

This chapter presents the results of the engineering and economic evaluation of a representative power plant at which biomass and coal are co-fired in existing steam boilers. The evaluation considered the following scenarios:

- Base case: a 250-MW wall-fired PC boiler fired by Central Appalachian coal.
- Alternate Case 1: a 250-MW wall-fired PC boiler co-fired with undried, blended biomass residues at heat input levels of 5, 10, and 15%.
- Alternate Case 2: a 250-MW wall-fired PC boiler co-fired with dried biomass residues at heat input levels of 5, 10, and 15%.
- Alternate Case 3: a 250-MW wall-fired PC boiler co-fired with torrefied biomass residues at heat input levels of 5, 10, and 15%.

## Introduction to Biomass Co-firing

Similar to those for repowering, there are several methods of biomass co-firing that can be employed for a project. The most appropriate method is a function of biomass fuel properties, the coal boiler technology, and site-specific parameters such as the space available for co-firing systems and impacts on downstream air quality control systems and ash and other by-product recovery.

Stoker and fluidized bed boilers generally require minimal modifications to accept biomass, provided that they were initially designed with some fuel flexibility. Cyclone boilers and pulverized coal (PC) boilers require smaller fuel particle size than stokers and fluidized beds and, therefore, may necessitate additional processing of the biomass prior to combustion. There are two basic approaches to co-firing. The first is to blend the fuels and feed them together to the coal processing equipment (i.e., crushers or pulverizers). In a cyclone boiler, generally up to 10 percent of the coal heat input can be replaced by biomass fuels. The smaller fuel particle size requirement of a PC boiler generally limits the fuel replacement to perhaps three percent. Another approach is to develop a separate biomass processing system, in which high co-firing percentages (10 percent and greater) in a PC unit can be accomplished, although at somewhat higher cost.

### *Biomass Co-firing Issues*

Even at limited co-firing rates, plant owners and operators have raised numerous concerns about the negative impacts of co-firing on plant operations. These include the following:

- Negative impacts on plant capacity.
- Negative impact on boiler performance.
- Ash contamination, which impacts ability to sell coal ash.
- Increased operation and maintenance costs.
- Minimal $NO_X$ reduction potential (usually proportional to biomass heat input).
- Boiler fouling/slagging because of the high alkali in biomass. This is particularly a concern with fast growing biomass, such as energy crops.
- Potentially negative impacts on selective catalytic reduction (SCR) air pollution control equipment (catalyst poisoning).

Most of these concerns can be addressed through proper system design, fuel selection, and limiting the level of co-firing.

### *Biomass Co-firing Benefits and Barriers*

There are both benefits and barriers associated with biomass co-firing.

#### Benefits

- Compared to other renewable energy options, biomass co-firing presents a low investment risk. The initial capital outlay can be as much as 20 times less than other renewable technologies for the same amount of energy from biomass co-firing. Further, biomass co-firing projects can be quickly installed and integrated into a portfolio.
- Should biomass prices rise to an uneconomic point, the boiler can still produce power from coal.
- All biomass co-firing projects generally realize emissions performance improvements relative to 100 percent coal-fired power generation. For example, clean biomass fuel firing typically reduces emissions of sulfur, non-biogenic carbon dioxide, nitrogen oxides, and metals, such as mercury.
- Alternative biomass fuels can provide a hedge against fossil fuel price volatility and provide leverage in coal contract negotiations.
- In some cases, utilities may be able to recover boiler capacity lost during past boiler modifications, particularly a switch to lower quality coals (e.g., mill derating). In the case of

mill-limited units, separate injection or gasification methods of co-firing would be employed. Co-milling methods would not alleviate capacity reductions in mill-limited units.

- Utilities can realize positive public relations by providing win/win integrated environmental waste disposal solutions. For example, by adding sewage sludge pellet co-firing to an existing boiler, utilities can assist the local community by burning a waste that might otherwise be landfilled and incur a cost. All parties realize cost savings and benefits.

### Barriers

- Plant and corporate management and operations staff may be hesitant to alter their plants. Plant personnel typically commit to maximizing the efficiency and availability of their plants by improving performance, technology, and operations and maintenance practices over time.
- The economics of a co-firing project are typically very good when compared to the cost of adding other renewables to a generation portfolio. However, without regulatory motivations, such as compliance with a renewable portfolio standard (RPS) mandate, biomass fuel costs are generally not competitive with coal.
- Co-firing may impact the salability of fly ash as an admixture to the cement industry.
- The biomass fuel supply infrastructure is immature in many regions of the country, and biomass suppliers may find it difficult to meet utility procurement standards.

## *Lessons Learned from Utility Co-firing Projects*

While interest in co-firing has increased significantly in recent years, utility experience with biomass co-firing in the United States has primarily come from demonstration projects funded by the U.S. Department of Energy (DOE). These demonstrations are summarized in Table 4-1. The demonstrations have included a variety of biomass and coal types, boiler configurations, and co-firing approaches. The tests have indicated that co-firing is technically successful and have quantified minimal boiler efficiency/capacity impacts while verifying $NO_X$, $SO_2$, and $CO_2$ reductions.

**Table 4-1**
**U.S. DOE-Sponsored Utility Co-firing Demonstrations**

| Utility and Plant | Boiler Capacity and Type | Biomass Heat Input (%) | Biomass Type | Average Moisture (%) | Coal Type | Biomass Feeding Method |
|---|---|---|---|---|---|---|
| TVA Allen | 272-MW cyclone | 10 | Sawdust | 44 | Illinois Basin, Utah bituminous | Blending biomass and coal |
| TVA Colbert | 190-MW wall-fired | 1.5 | Sawdust | 44 | Eastern bituminous | Blending biomass and coal |
| AES Greenidge*,** | 108-MW tangential | 10 | Wood waste | 30 | Eastern bituminous | Separate injection |
| GPU Seward | 32-MW wall-fired | 10 | Sawdust | 44 | Eastern bituminous | Separate injection |
| MG&E Blount St. | 50-MW wall-fired | 10 | Switchgrass | 10 | Midwest bituminous | Separate injection |
| NIPSCO Michigan City | 469-MW cyclone | 6.5 | Urban wood waste | 30 | PRB, Utah bituminous | Blending biomass and coal |
| NIPSCO Bailly** | 194-MW cyclone | 5 - 10 | Wood waste | 14 | Illinois, Utah bituminous | Blending (trifire) |
| Allegheny Willow Island | 188-MW cyclone | 5 - 10 | Wood | | Eastern bituminous | Blending (trifire) |
| Allegheny Allbright | 150-MW tangential | 5 - 10 | Ground wood | | Eastern bituminous | Separate injection |

Source: Paul Grabowski, "Biomass Co-firing," available at: www.brdisolutions.com/pdfs/PGCofiring.pdf
Notes:
* AES Greenidge Power Plant was formerly operated by New York State Electric & Gas (NYSEG).
** Flue Gas Desulfurization (FGD) systems are employed at AES Greenidge Power Plant and NIPSCO Bailly Generating Station. AES Greenidge employs a dry FGD system, and NIPSCO Bailly employs a wet FGD system (source: Global Energy Decisions' Ventyx database).

From a review of a number of reports and technical papers from the DOE co-firing program, general conclusions, which are specific to pulverized coal units, are as follows:

- From a purely technical perspective, a separate, independent biomass fuel delivery and injection system is preferred rather than feeding biomass through the existing coal conveying, pulverizing, and injection system.
- Co-milling a blended feed of coal and biomass can significantly impact pulverizer amperes and capacity depending on the type and quantity of biomass. For these reasons, blended feed can cause a unit derate, particularly if the unit is already near mill capacity.
- When fired separately, a biomass co-firing system could mitigate a derate of the boiler caused by limited mill capacity or switching to fuels of lower quality.
- Co-firing coal and biomass fuels generally results in lower $SO_2$, $NO_X$, $CO_2$, mercury, and other emissions than firing with 100% coal firing. Percent reductions in emissions are typically proportional to the co-firing percentage (on a heat input basis), although reductions in $NO_X$ have been more difficult to accurately predict.
- Wood fuel can be pneumatically conveyed for significantly long distances relative to typical plant dimensions.

- Boiler efficiencies are not significantly reduced and plant net heat rates are not significantly increased when co-firing with biomass (where biomass fuels provide less than 10 percent of the total heat input to the boiler).
- Wood was continually co-fired for long periods in utility boilers with few appreciable negative effects.
- Fly ash salability can be negatively affected by commingling wood and coal fly ash.

## Biomass Co-firing Strategies

Approaches to biomass co-firing generally fall into one of two categories: direct co-firing and indirect co-firing methods. Direct co-firing methods include co-milling and separate injection. Indirect co-firing methods include separate combustion, pyrolysis, and gasification systems. The scope of this study is limited to direct co-firing methods.

### *Co-milling of Biomass and Coal*

The simplest method of direct biomass co-firing involves physically blending and mixing the biomass with the existing fuel stream prior to injection in the boiler. For PC plants, co-milling can be implemented by adding biomass to coal as it is reclaimed and fed through the existing coal pulverizers. Figure 4-1 provides a high-level schematic of co-milling of biomass and coal.

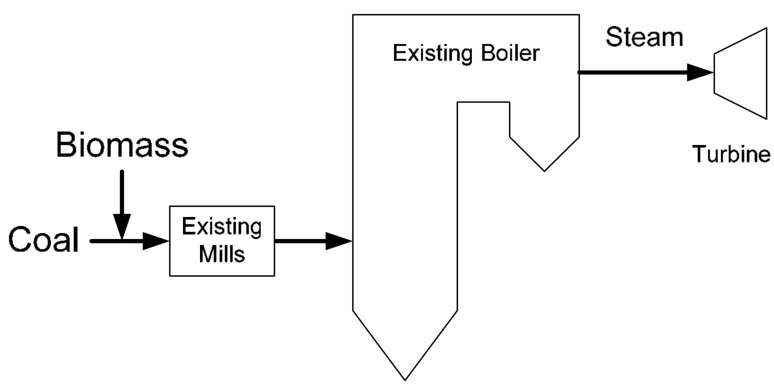


**Figure 4-1**
**Co-milling of Biomass and Coal**

Although co-milling is the simplest method of co-firing, additional equipment would be required to receive biomass deliveries, which are likely to arrive via truck. Depending upon the form and dimensions of the delivered biomass, sizing equipment is also required to reduce the biomass fuels to a suitable top size for processing in the existing coal pulverizers.

Following sizing, biomass can be blended with coal in the fuel yard, using mobile equipment to mix biomass and coal as it is pushed into reclaim bunkers (i.e., pile mixing). Alternatively, conveyors can be employed to add biomass on top of the reclaimed coal on the existing coal reclaim belts (i.e., belt mixing). The preferred blending method for a given site depends upon the available space in the existing coal yard, the proximity of the biomass sizing processes to the existing coal reclaim belt systems, and the level of automation desired in the biomass handling systems.

As with the handling systems for repowering, the specific equipment required and the material handling strategies employed depend upon the level of automation desired in the biomass receiving/stockout systems and the biomass reclaiming systems.

To mitigate concerns regarding operating impacts to the coal pulverizers with co-milling, the biomass heat input is typically limited to two to three percent of the heat input to the boiler for PC units when co-milling. However, it should be noted that when co-milling torrefied biomass with coal is expected to be less problematic than co-milling as-received or dried biomass with coal. In this fashion, the torrefied biomass may provide up to 10 percent of the heat input to the boiler.

Boiler efficiency impacts are small when co-milling of biomass fuels is limited to less than three percent of the total heat input to the boiler. The impacts of latent and sensible heat losses are likely to be less than a fraction of a percent. In addition, unburned carbon and excess air levels are unlikely to change significantly for this low amount of biomass fuel heat input.

### *Direct Co-firing with Separate Fuel Handling and Injection*

Figure 4-2 illustrates a second method of biomass co-firing which employs a separate handling and injection system to deliver biomass fuels to the existing boiler. This separate system has no negative maintenance or operational effects on the existing fuel preparation system.

Separate injection methods are used in PC boilers to increase the amount of biomass that can be co-fired. A separate injection system is also more controllable than a co-milling system in which biomass and coal are blended upstream of the boiler systems. Separate injection of co-fired biomass has been proven to be capable of supplying 10 percent of the heat input required for numerous wall-fired and tangentially-fired PC boilers. There are also reports of successful installations of up to 20 percent in Europe. This level of co-firing is significantly higher than that recommended for the co-milling approach.

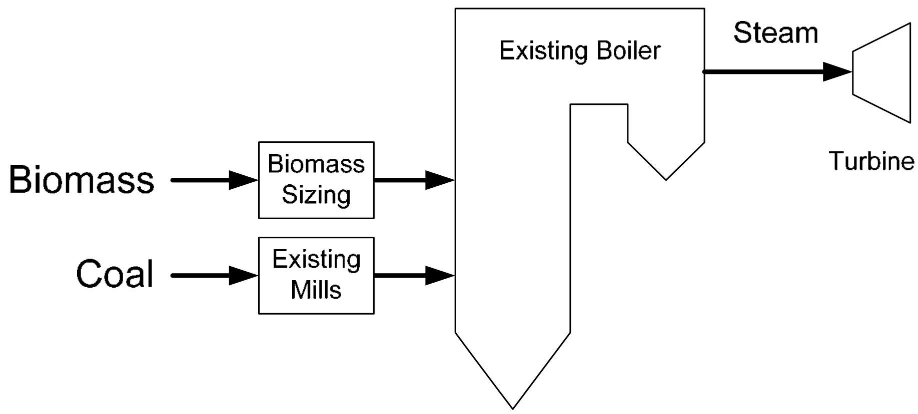


**Figure 4-2**
**Direct Co-firing with Separate Injection**

For tangentially-fired PC units, the ideal location for dedicated biomass injection ports is at each corner of the furnace, with at least one coal burner above and one coal burner below the biomass injection ports. For wall-fired units, the ideal location for dedicated biomass injection ports is along the sidewall at an elevation near the middle of the burner levels. The biomass should be ground to less than 1/4 inch top-size before injection. To ensure the satisfactory operation of this system, biomass would not be injected below a specified minimum boiler load.

Co-firing of 10 percent biomass may reduce boiler efficiency, although this reduction is expected to be less than one percentage point of the boiler efficiency when firing 100 percent coal. This reduction in efficiency would be primarily due to increases in latent heat losses due to the higher moisture and hydrogen content of the fuel mix overall.

While a separate injection co-firing project may be sited at an existing facility, new material handling equipment will be required. A new receiving/storage area dedicated to biomass would likely be needed. This biomass material handling area would include equipment for unloading, storing, reclaiming, and conveying fuel. To allow for less stringent fuel specifications and to increase the quantities of biomass available, some fuel processing would be advantageous (i.e., screening and sizing).

Similar to co-milling applications, the specific equipment required and the material handling strategies employed depend upon the level of automation desired in the biomass receiving/ stockout and biomass reclaiming systems.

## Preliminary Design Parameters

### *Boiler Modifications*

Boiler modifications for the separate injection of biomass fuels in a wall-fired PC boiler include the installation of (1) dedicated biomass burners, (2) igniters and flame scanning equipment, (3) tie-in to the existing windbox, (4) required instrumentation and controls (I&C) and electrical systems and (5) required refractory and insulation. In addition, modifications to existing boiler tubes will be required at the locations of the biomass injection ports.

When determining the appropriate location for new biomass dedicated burners, the main concerns are available residence time, proximity to existing burners and their associated flames, and burner sizing requirements. It is anticipated that the burners would be located at an elevation near the middle of the existing coal burners to essentially “bury” the biomass flame inside the existing coal flame. By locating the biomass in such a position, flames from the existing coal burners interface with the biomass burners and help complete burnout of the biomass product.

The quantity of biomass fuels delivered to a single biomass-fired burner is determined by the capabilities of the pneumatic conveyance system. When separately injected, it is assumed that biomass fuels are pneumatically conveyed to the boiler via a 12-inch diameter pipe. Based on previous experience with similar projects, the maximum delivery rate for biomass pneumatically conveyed through a 12-inch pipe is approximately 7.5 tons per hour (tph). Considering the required biomass flow rates for co-firing a 250-MW unit, a total of four biomass burners would be required when biomass provides 10 percent of the heat input to the unit.

When co-firing with torrefied biomass, it is assumed that these fuels are co-milled with coal in the existing coal pulverizers, and the coal and biomass are co-combusted in the existing coal burners. Even when co-firing with torrefied biomass providing 15 percent of the heat input to the 250-MW boiler, it is not anticipated that modifications to the existing steam generator equipment will be required. The existing flame monitoring and ignition systems are not likely to be affected by co-firing torrefied biomass with coal.

### *Biomass Material Handling*

The nature of raw wood chips requires a completely different material handling system than that used for the coal fired plant.[16] A typical coal handling system for a 250-MW PC facility is depicted by drawing DS-0002A in Appendix B. Woody biomass has a much lower bulk density than coal and has a propensity for the material to interlock and mat (thereby plugging material handling systems not designed to handle biomass fuels). Because of these properties, material handling systems designed to handle coal cannot be used to handle biomass, except in very small quantities when mixed with the coal in co-milling applications. Furthermore, when co-firing via separate injection, the existing coal handling system will remain in service, so it is necessary to construct the biomass handling system at a different location.

This biomass handling approach for a 250-MW PC facility co-firing biomass is depicted by drawing DS-0004A in Appendix B. These drawings are based on the 10% biomass co-firing case, but the 5 and 15% co-firing scenarios would be similar.

[16] Note that unlike “raw” wood chips, torrefied biomass is expected to be pulverized to a size that may be handled with the existing coal handling system (including co-milling in the case of co-firing). Therefore, in the case of torrefied biomass, the existing coal handling system is utilized and a new woody biomass handling system would not be required. A flow study of the specific torrefied biomass to be used as fuel should be conducted to determine if bin modifications are required, and a co-milling test at the desired co-firing percentage should be conducted to verify mill performance.

It is assumed that arriving wood chips are pre-sized off-site to a maximum size as required for the on-site preparation system, presumed in this case to be minus three inches. Any material determined to be oversize (via screening) would be moved aside and periodically ground to an acceptable size in a truck-mounted grinder before re-entering the biomass handling system.

Arriving woody biomass chips are stocked out with an automatic linear stacker in a windrow-shaped pile, sufficiently narrow that the pile would lend itself to being covered with a clear-span roof. Depending on the geographical location of the plant, it is likely that, at a minimum, a roof, would be required to keep precipitation off the pile while allowing adequate air circulation around the pile for additional drying. This allows the incoming biomass (typically 45 percent moisture unless it has been dried off-site) to dry naturally to approximately 12 percent moisture, as required for the air-swept mills to reduce it in size to minus $^{1}/_{4}$ inch for direct injection into a PC boiler.

Biomass from the windrow-shaped pile would be reclaimed with an automatic side-arm scraper reclaimer. The reclaimed biomass stream would be split between two grinding trains. Each train would begin with a scalping screen arranged such that the “overs” or “rejects” would be directed to a primary wood hog, but all of the “unders” or “accepts,” whose particle sizes are deemed acceptable for feeding into the air-swept secondary wood hog without additional grinding, would bypass the primary wood hog to prevent overloading. Downstream from the scalping screen and primary wood hog, all wood chips would be split and directed into a pair of air-swept secondary wood hogs for final grinding to the required minus $^{1}/_{4}$-inch particle size. Product from each air-swept secondary wood hog would be collected in a fabric filter unit and fed through a rotary airlock onto a collecting belt conveyor. The collecting belt conveyor would transport the dry, ground, wood chips to a live-bottom bin where it would be accumulated.

Dry and ground wood chips are fed from the live-bottom bin and directed into four pneumatic injection systems for co-firing in the boiler.

As an option, in geographical locations where it would be difficult to naturally dry the biomass to approximately 12 percent moisture, a short recirculation conveyor could be added to take reclaimed biomass and direct it back to the linear stacker during times when the material was too wet to process. This would allow the biomass pile to be “turned over” and re-stacked to facilitate natural drying.

Conveyor belt scales would be used to control biomass feed rates within the handling system, as well as to provide biomass consumption data for unit performance calculations.

Generally, wet dust suppression would be utilized on incoming biomass unloading and stockout equipment due to issues of effectiveness when large open areas are involved (e.g., large, open truck dump hoppers or stocking out through open air). Dust dry collection would be utilized in other areas after reclaim, since it is undesirable to add moisture and since capture airflow rates can be smaller in smaller chutes and other equipment.

A self-cleaning magnetic separator is utilized on a belt conveyor for ferrous tramp metal removal. In addition, a metal detector is used on the belt conveyor to detect ferrous and non-ferrous metal and mark it for manual inspection and removal.

As biomass dust is combustible, fire detection and / or suppression is utilized throughout the system.

## Material Handling Equipment

Table 4-2 lists the anticipated biomass material handling equipment required for the co-firing case. As noted previously, the material handling system assumes that biomass fuels provide ten percent of the heat input to the boiler, but material handling systems designed for when biomass fuels provide 5 and 15 percent of the heat input to the boiler would be similar. The tag number references the equipment listed on the material handling process flow diagrams provided in Appendix B.

**Table 4-2**
**Biomass Material Handling Equipment Listing**

| Description | Tag |
|---|---|
| Truck Scale | SCL-1A |
| Truck Scale | SCL-1B |
| Hydraulic Truck Dumper with Receiving Hopper HPR-1 | DMP-1 |
| Drag Chain Feeder / Conveyor | CVY-1 |
| Belt Conveyor | CVY-2 |
| Horizontal / Oversized Grinder | GRN-1 |
| Belt Conveyor Scale | SCL-2 |
| Linear Stacker | STK-1 |
| Side Arm Scraper Reclaimer | RCL-1 |
| Belt Conveyor | CVY-3 |
| Belt Conveyor Scale | SCL-3 |
| Self-Cleaning Magnetic Separator | SEP-1 |
| Tramp Metal Detector | TMD-1 |
| Dust Collector | DCO-1 |
| Belt Conveyor (including Transfer Tower) | CVY-4 |
| Splitter Gate | GAT-1 |
| Scalping Screener | SCN-1 |
| Scalping Screener | SCN-2 |
| Primary Wood Hog | GRN-2 |
| Primary Wood Hog | GRN-3 |
| Splitter Gate | GAT-2 |
| Splitter Gate | GAT-3 |
| Drag Chain Conveyor | CVY-5 |
| Drag Chain Conveyor | CVY-6 |
| Drag Chain Conveyor | CVY-7 |
| Drag Chain Conveyor | CVY-8 |
| Air Swept Secondary Hog | GRN-4 |
| Air Swept Secondary Hog | GRN-5 |
| Air Swept Secondary Hog | GRN-6 |

**Table 4-3 (continued)**
**Biomass Material Handling Equipment Listing**

| | |
|---|---|
| Vacuum Filter Receiver | FLT-1 |
| Vacuum Filter Receiver | FLT-2 |
| Vacuum Filter Receiver | FLT-3 |
| Vacuum Filter Receiver | FLT-4 |
| Rotary Airlock Feeder | FDR-1 |
| Rotary Airlock Feeder | FDR-2 |
| Rotary Airlock Feeder | FDR-3 |
| Rotary Airlock Feeder | FDR-4 |
| Belt Conveyor (including Processing Building) | CVY-9 |
| Belt Conveyor Scale | SCL-4 |
| Dust Collector | DCO-2 |
| Self-Cleaning Magnetic Separator | SEP-2 |
| Live Bottom Bin (including Separate Injection Equipment Building) | HPR-2 |
| Bin Vent Filter | FLT-5 |
| Screw Feeder | FDR-5 |
| Screw Feeder | FDR-6 |
| Screw Feeder | FDR-7 |
| Screw Feeder | FDR-8 |
| Rotary Airlock Feeder | FDR-9 |
| Rotary Airlock Feeder | FDR-10 |
| Rotary Airlock Feeder | FDR-11 |
| Rotary Airlock Feeder | FDR-12 |
| Dust Collector | DCO-3 |
| Pneumatic Pressure Blower (including Sound Enclosure) | BLR-1 |
| Pneumatic Pressure Blower (including Sound Enclosure) | BLR-2 |
| Pneumatic Pressure Blower (including Sound Enclosure) | BLR-3 |
| Pneumatic Pressure Blower (including Sound Enclosure) | BLR-4 |

## *Biomass Co-firing Systems Footprint*

The biomass handling system for the 250-MW PC facility co-firing biomass is shown on the site arrangement drawing DS-0004 in Appendix A.

The biomass storage pile shown provides seven days of storage.

Generally, the biomass handling system can be modified to fit other sites following these guidelines:

- The biomass receiving and stockout system is necessarily linked with the reclaim system and must be co-located as such. It is best to locate the system to minimize truck traffic through more populated or busy areas of the plant.

- The milling system can be located as desired. Certain horizontal separation distances are required to attain the vertical height needed (due to inclined belt conveyors) for feeding the scalping screens located at the highest point in the building.
- The biomass live bottom feed bin can be located as desired. A clear routing path must be considered for the pneumatic conveying lines heading to the boiler.

## Biomass Co-firing Plant Performance

The next phase of this study involved analyzing the impacts of biomass co-firing on the conceptual 250-MW power plant using the EPRI Vista fuel quality impact analysis program. Three biomass fuels were evaluated (raw, dried, and torrefied biomass), each at three heat input levels (5, 10, and 15 percent). Both the raw and dried biomass fuels were assumed to be injected directly into the coal boiler, bypassing the fuel handling and milling systems. The torrefied biomass was assumed to be co-milled.

### *Overview of the EPRI Vista Fuel Quality Impact Analysis Program*

The EPRI Vista fuel quality impact model (see Figure 4-3) is a computer program which predicts how changes in fuel quality or fuel sources at a coal-fired power plant will impact plant performance, derates, emissions, maintenance and availability, and economics. Originating from the earlier EPRI Coal Quality Impact Model (CQIM), the EPRI Vista program has been developed over 12 years and is currently supported by 25 utility companies in the United States and abroad. The Vista program focuses on all parts of the power plant which are impacted by coal quality:

- Coal handling systems.
- Pulverizers, cyclones, and stoker feed systems.
- Steam generator effects, such as steaming capability, slagging and fouling, and tube failure mechanisms.
- Air and gas fans, preheat coils, and air heater systems.
- Electrostatic precipitators (ESPs) and fabric filter baghouses.

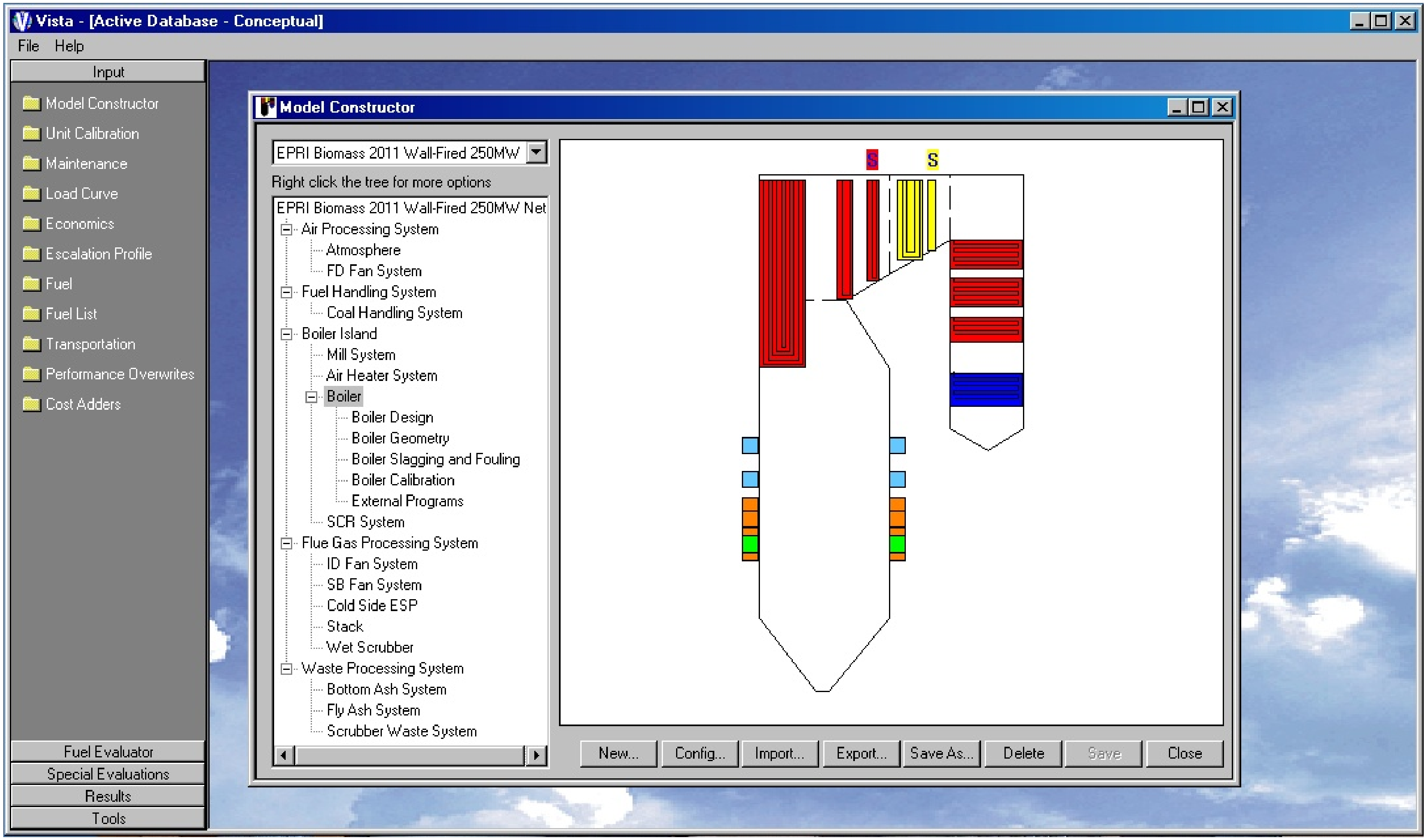


**Figure 4-3**
**Screen Shot of the EPRI Vista Program**

- Selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR) systems.
- Wet, semi-dry, and dry flue gas desulfurization (FGD) scrubbers.
- Bottom ash, fly ash, gypsum, and scrubber waste disposal systems.

Vista can be used to perform studies for many different fuel quality-related situations which could impact a coal-fired power plant, such as coal blending scenarios, biomass and opportunity fuel firing, oil or gas co-firing with coal, coal specification variability analysis using sensitivity coals, Monte Carlo probability analyses, operations and maintenance sensitivity, and capital upgrades to the power plant. The output from a Vista analysis consists of performance, emissions, operations and maintenance, availability, and economic results which are presented in Excel spreadsheet form in either pre-defined or custom-created spreadsheets. More than 2,000 results are available for each fuel analyzed.

### *Conceptual Model Overview*

The conceptual Vista model used in this evaluation is a 250-MW (net) wall-fired pulverized coal unit employing attemperation spray for reheat steam temperature control. This unit was originally designed for high-sulfur Northern Appalachian coal and currently burns low to mid-sulfur Central Appalachian (CAPP) coal as its baseline fuel. The unit operates at a baseloaded net capacity factor of 80%, and has a 90% equivalent availability factor (EAF) based on both planned and unplanned maintenance outages.

Fuel is supplied to the boiler by four Combustion Engineering RPS 743 exhauster-type mills. Two forced-draft and two induced-draft fans were installed when the unit was built. Air quality control upgrades, two scrubber booster fans, were added to assist with flue gas processing. $NO_X$ control is via low-$NO_X$ burners and a close-coupled and separated overfire system, with a urea-reagent selective catalytic reduction (SCR) system downstream of the boiler. The SCR system is capable of 90% $NO_X$ removal. Particulate control is via a cold-side electrostatic precipitator (ESP) with a 99.5% collection efficiency, as well as some fly ash removal by the scrubber. The scrubber is a wet limestone scrubber with a baseline $SO_2$ removal efficiency of 96%. Table 4-3 shows the unit emissions limits and actual emissions when burning the baseline coal.

### *Coal and Biomass Quality and Evaluation Scenarios*

The cofiring evaluation addressed three biomass fuels:

- A "raw" or undried woody biomass with 45% total moisture content.
- A "dried" woody biomass with 30% total moisture content.
- A torrefied biomass with 6.2% total moisture content.

It was assumed that these fuels would be blended with the baseline coal for the conceptual unit at heat input levels of 5, 10, and 15% of the total boiler heat input. For the woody biomass cases, all biomass fuel was assumed to be directly injected into the unit via dedicated biomass burners located between the first and second burner rows in the furnace. Because of its favorable fuel properties the torrefied biomass was assumed to be blended with the coal on a reclaim belt entering the boiler building. Table 4-4 and Table 4-5 present detailed fuel quality for the baseline coal and the three biomass co-firing cases.

**Table 4-3**
**Emissions Limits and Baseline Coal Emissions for the Conceptual Coal Unit**

| Emissions Parameter | Emissions Limit | Actual Emissions with the Baseline Coal Quality |
|---|---|---|
| Sulfur dioxide ($SO_2$), lbm/MBtu | 0.06 | 0.06 |
| Nitrogen oxides ($NO_X$), lbm/MBtu | 0.05 | 0.05 |
| Opacity, % | 20.0 | 6.0 |
| Particulate Emissions, lbm/MBtu | 0.01 | 0.004 |
| Mercury, lbm/year | N/A | 93.2 |
| Carbon Dioxide ($CO_2$), ton/year | N/A | 1,819,820 |

**Table 4-4**
**Woody Biomass Fuel Quality: Heat Content, Proximate, and Ultimate Analyses**

| Fuel Quality Parameter | Baseline CAPP Coal | Raw Wood, 45% Moisture | Dried Wood, 30% Moisture | Torrefied Wood |
|---|---|---|---|---|
| Higher Heating Value, Btu/lbm | 12,207 | 4,768 | 6,068 | 12,759 |
| *Proximate Analysis** | | | | |
| Moisture, % | 8.47 | 45.00 | 30.00 | 6.21 |
| Ash, % | 11.24 | 2.18 | 2.77 | 1.78 |
| Volatile Matter, % | 29.57 | 45.32 | 57.68 | 19.66 |
| Fixed Carbon, % | 50.72 | 7.50 | 9.54 | 72.35 |
| *Ultimate Analysis** | | | | |
| Carbon, % | 69.96 | 27.67 | 35.22 | 78.24 |
| Hydrogen, % | 4.47 | 2.53 | 3.22 | 3.19 |
| Nitrogen, % | 1.36 | 0.57 | 0.73 | 0.56 |
| Sulfur, % | 1.03 | 0.06 | 0.08 | 0.01 |
| Chlorine, %** | 0.15 | 0.02 | 0.03 | 0.00 |
| Moisture, % | 8.47 | 45.00 | 30.00 | 6.21 |
| Ash, % | 11.24 | 2.18 | 2.77 | 1.78 |
| Oxygen, % | 3.47 | 21.97 | 27.96 | 10.01 |

Notes:
* As received values.
** Although not in the ASTM ultimate analysis, chlorine is often reported with it.

**Table 4-5**
**Woody Biomass Fuel Quality: Ash Mineral and Other Analyses**

| Fuel Quality Parameter | Baseline CAPP Coal | Raw Wood, 45% Moisture | Dried Wood, 30% Moisture | Torrefied Wood |
|---|---|---|---|---|
| Silica, % | 56.01 | 17.78 | 17.78 | 25.22 |
| Alumina, % | 25.95 | 3.55 | 3.55 | 4.46 |
| Titania, % | 1.17 | 0.50 | 0.50 | 0.03 |
| Iron Oxide, % | 9.14 | 1.58 | 1.58 | 3.03 |
| Lime, % | 1.41 | 45.46 | 45.46 | 24.21 |
| Magnesia, % | 1.24 | 7.48 | 7.48 | 13.41 |
| Potassium Oxide, % | 2.88 | 8.52 | 8.52 | 13.42 |
| Sodium, % | 0.43 | 2.13 | 2.13 | 0.56 |
| Sulfur Trioxide, % | 1.49 | 2.78 | 2.78 | 4.57 |
| Phosphorus Pentoxide, % | 0.25 | 7.44 | 7.44 | 9.33 |
| Undetermined, % | 0.04 | 2.78 | 2.78 | 1.76 |
| *Miscellaneous Properties* | | | | |
| Ash Softening Temperature, ºF* | 2,567 | 2,184 | 2,184 | 2,142 |
| Hardgrove Grindability | 50.5 | 35 | 35 | 56 |
| Calculated $SO_2$, lbm/MBtu | 1.69 | 0.25 | 0.25 | 0.016 |
| Mercury, dry whole-fuel basis, ppm | 0.12 | 0.02 | 0.02 | 0.01 |
| Mercury, dry whole-fuel basis, lbm/TBtu | 9.00 | 2.31 | 2.31 | 0.735 |

Notes:

* Reducing atmosphere basis.

## *Co-firing Raw Biomass*

The baseline coal quality and the raw, undried woody biomass cases (introduced via separate injection) were evaluated for the conceptual unit using the Vista program at 5%, 10%, and 15% biomass heat input. The results of this analysis are discussed below and summarized in Table 4-6.

### Milling System

Since the separate injection cases all pass a significant amount of the boiler heat input around the milling system, the milling system capacity increased for all separate injection cases. This improved the mill capacity margins so much that for the 15% biomass case, three-mill operation was possible (but not advisable, as mill margins were probably below the level at which plant operators would feel comfortable). This improvement in milling capacity provides some notable benefits to the overall equivalent availability of the unit, and gives operators more flexibility for accommodating poor quality coal. The milling system drying capability also increased for all separate injection cases relative to the baseline coal case. As a result, exhauster fan margins improved, and the required primary air temperature at the mill inlet also improved (because of the availability of a greater overall primary air/fuel ratio).

### Forced Draft Fans

Forced draft fan margins improve as the amount of biomass fire quantity increases, caused by improvements in the overall furnace stoichiometry resulting from mixing biomass with coal. This effect is small, however, and should not be relied upon to provide a solution for a unit which currently is suffering from limitations due to insufficient forced draft fan capacity.

### Boiler – Unburned Carbon and $NO_x$

Boiler $NO_X$ production decreases from 3.0 to 8.6% for the biomass cases, and greater amounts of biomass result in lower emissions. The primary reason for this decrease is a reduction in the net fuel nitrogen and an increase in the relative portion of fuel nitrogen contained in the volatile matter of the fuel. The SCR system is configured to achieve a constant 90% removal efficiency. No problems are predicted for achieving this level of operation. Fly ash loss on ignition (LOI) is predicted to decrease as the biomass fuel heat input increased, because the biomass fuel has a lower fixed carbon content than the coal.

The Vista program assumes that size distribution of the biomass to the separate injection burners is “idealized,” meaning that all equipment is in working order and no unusual sizing problems exist. It is possible that variations in the actual sizing and grinding operations of the biomass on a day to day, or even an hourly basis, could result in spikes of high LOI fly ash and bottom ash. Furthermore, specific impacts to the SCR catalyst resulting from biomass combustion were not modeled in this study, as this is a highly site-specific issue that depends considerably upon the type of catalyst active material installed.

### Boiler – Slagging and Fouling

The Vista program uses 18 different industry-based factors to determine how slagging (defined as buildup primarily on the waterwall surfaces) changes as a function of fuel quality and operations. Overall, Vista predicts a small increase in the level of waterwall slagging, increasing as the biomass mass flowrate increases. The primary driver for slagging is the high calcium content of the biomass ash, which leads to a reduction in the overall ash fusion temperatures of the fuel. This increase in slagging level leads to an increase in wall sootblower use, which is predicted to change from being operated three times per day to nearly continuous operation. At 15% biomass heat input, the slagging level reaches a point where a 4.3% margin exists in terms of the boiler heat input, indicating that slagging derates are very possible if the biomass co-firing level is increased significantly or the biomass or coal ash quality declines.

The Vista program uses 15 different industry-based factors to determine how high temperature fouling (defined as buildup primarily on upper furnace tube surfaces) will change as a function of fuel quality and operations. Two of these factors are biomass-specific, which are only applied on a weighted basis for fuels or fuel blends containing biomass. The Vista program predicts no significant changes in high temperature fouling for any of the biomass co-firing cases, and fouling overall was judged to be "Low." This is primarily because, for the selected fuel, the woody biomass ash is low in minerals which are typically problematic in the upper furnace (such as sodium). It is a generally benign fuel from that perspective.

### Electrostatic Precipitator

Both the opacity and the particulate mass emissions rate were predicted to increase as the level of biomass co-firing was increased. The reasons for these changes are:

- The fly ash resistivity of the biomass blend cases is worse than that of the baseline coal, resulting in a slower particulate migration velocity.
- The gas volumetric flow through the precipitator increases slightly.

The primary reason for the worsening of fly ash resistivity in the biomass co-firing cases is a reduction in $SO_3$ production. Relative to the baseline coal case, the $SO_3$ is predicted to decrease as much as 42% for the 15% biomass co-firing case. Overall, a 70% increase in the particulate mass emissions rate was predicted for the 15% biomass case relative to the baseline coal case. The maximum particulate mass emissions and opacity are 0.0066 lbm/MBtu and 9.9%, respectively.

### Induced Draft and Scrubber Booster Fans

The operating margins of both the induced draft and the scrubber booster fans decrease as the amount of co-fired biomass increases. This is partially caused by reductions in the net unit heat rate resulting from the higher moisture content of the biomass and by the difference in furnace stoichiometry required for the biomass fuels. It is further exacerbated by the fact that the baseline conceptual unit has a moderately high air heater leakage of 23%, and an additional 1.4% cold-side ESP ductwork leakage. Although no actual derate was predicted, the operating margins for the induced draft fans are dangerously low at only 1.8%. As a result, in practice it is possible that biomass use at the conceptual unit in this configuration may be limited to 5% by heat input.

### Scrubber and Waste Systems

The conceptual unit scrubber is assumed to achieve 96% $SO_2$ removal for all cases, and no limitations were predicted. In this analysis, an ash sulfur capture of 10% is assumed for all bituminous coals, and 5% sulfur capture in ash is assumed for the biomass fuels. No scrubber limitations are predicted, and the lower sulfur loading of the biomass fuel results in a slight improvement in scrubber system operations. There is a possibility that fine biomass ash may accumulate in the scrubber gypsum to the level that there could be a concern, but the Vista program is not able to predict this. Furthermore, any impact on frothing in the thickening system caused by changes in ash properties cannot be predicted by the Vista program.

### Fly Ash and Bottom Ash Systems

A reduction in the overall ash mass loading of the fuel leads to a small reduction in the required operation of the bottom and fly ash handling systems. No significant problems are noted by the Vista program for the relatively low levels of biomass ash entering the system. It is possible that the high calcium content of the biomass ash may result in some cementation if the ash is exposed to water, but for this study no such problems were predicted.

### Overall Unit Efficiency, Heat Rate, and Capability

The primary impact of adding higher moisture and higher hydrogen content biomass fuel to the unit is an increase in the latent heat losses. As expected, the 15% biomass heat input case has the highest latent heat losses, 5.91% (versus 4.27% for the baseline coal case). When these losses are combined with changes in unburned combustible losses and sensible heat losses, the net result is a reduction in the boiler efficiency as the biomass quantity increases. The lowest efficiency occurs for the 15% biomass heat input case, at 86.13% (versus 87.38% for the baseline coal case). When the difference in boiler efficiency is added to the differences in the auxiliary power and steaming ability of the unit, the overall net plant heat rate (NPHR) of the unit is expected to increase from a baseline of 9,762.5 to 10,037.3 Btu/kWh. Note that these results do not include the overall NPHR impact of supplying auxiliary power to new biomass receipt, handling, reclaim, processing, and sizing equipment. As a result, it is expected that the actual NPHR would be slightly higher (worse) in real-world operation.

### Maintenance and Availability Results

Since the mill loading is reduced by employing separate injection of biomass, mill forced outage hours are predicted to be reduced for all biomass separate injection cases. The best case is the 15% biomass heat input case, where the mill forced outage rate decreases by nearly 60 hours per year. Predicted boiler tube failures are reduced for all of the biomass co-firing cases. Waterwall tube failures are most reduced, caused by reductions in both sulfur and chloride loading within the fuel mixture. Suspended tube bank failures are reduced because of a decrease in fly ash erosion (due to both a reduction in the ash mass loading and the predicted ash abrasiveness). As a result, the overall equivalent availability factor of the unit improves for the biomass cases, with the greatest improvement being 0.76% for the 15% biomass heat input case, which represents, on average, an increased unit availability of 66 hours per year.

Table 4-6 summarizes the performance results for these cases.

**Table 4-6**
**Performance Estimates for Undried Biomass Co-firing**

| Performance Parameter | Coal | Coal +5% Undried Biomass | Coal +10% Undried Biomass | Coal +15% Undried Biomass |
|---|---|---|---|---|
| ***Full-Load Results*** | | | | |
| Gross Power, MW | 261.50 | 261.50 | 261.50 | 261.50 |
| Net Power, MW | 250.00 | 248.46 | 248.52 | 247.88 |
| Boiler Efficiency, % | 87.38 | 87.10 | 86.62 | 86.13 |
| Fly ash LOI, % | 5.79 | 4.95 | 4.66 | 4.42 |
| NPHR, Btu/kWh | 9,762.5 | 9,892.5 | 9,951.8 | 10,037.3 |
| Total Heat Input, MBtu/hr | 2,440.6 | 2,457.9 | 2,473.3 | 2,488.0 |
| Biomass Heat Input, MBtu/hr | 0.0 | 122.9 | 247.3 | 373.2 |
| Coal Burn Rate, ton/hr | 99.97 | 95.65 | 91.18 | 86.63 |
| Biomass Burn Rate, ton/hr | 0.00 | 12.89 | 25.94 | 39.14 |
| Forced Draft Fan Margin, % | 3.4 | 4.4 | 4.6 | 4.9 |
| Induced Draft Fan Margin, % | 4.3 | 3.6 | 2.6 | 1.8 |
| Mill Capacity Margin, % | 18.2 | 23.6 | 29.6 | 36.4 |
| Slagging Potential | Low | Low/Medium | Low/Medium | Low/Medium |
| Fouling Potential | Low | Low | Low | Low |
| Potential Derate, MW | 0.00 | 0.00 | 0.00 | 0.00 |
| Most Limiting Item | None | None | None | None |
| $SO_2$ Emissions, lbm/MBtu | 0.06 | 0.06 | 0.06 | 0.06 |
| Boiler $NO_x$, lbm/MBtu | 0.32 | 0.31 | 0.30 | 0.29 |
| $NO_x$ Emissions, lbm/MBtu | 0.05 | 0.05 | 0.05 | 0.05 |
| Particulate Emissions, lbm/MBtu | 0.004 | 0.005 | 0.006 | 0.007 |
| Unit Opacity, % | 6.0 | 7.4 | 8.9 | 9.9 |
| ***Annual Results*** | | | | |
| Coal Burn Rate, kton/year | 706.63 | 675.39 | 643.14 | 610.65 |
| Biomass Burn Rate, kton/year | 0.00 | 91.00 | 182.94 | 275.88 |
| $SO_2$ Emissions, ton/year | 518 | 521 | 523 | 526 |
| $NO_x$ Emissions, ton/year | 431 | 434 | 436 | 438 |
| $CO_2$ Emissions, ton/year | 1,821,150 | 1,833,090 | 1,843,340 | 1,853,990 |
| Non-renewable $CO_2$ Emissions, ton/year | 1,821,150 | 1,732,521 | 1,649,775 | 1,566,427 |
| Mercury Emissions, lbm/year | 93.2 | 86.8 | 81.0 | 75.8 |
| Net Capacity Factor, % | 80.00 | 80.08 | 80.08 | 80.05 |
| Equivalent Availability, % | 90.00 | 90.23 | 90.54 | 90.76 |

### Co-firing Raw Biomass Conclusions

Only a few immediate operations concerns were noted for any of the raw biomass co-firing cases. The level of furnace water wall slagging was predicted to increase, and induced draft and scrubber booster fan capacity was reduced significantly. Particulate mass emissions and the unit opacity both increased, but there were still comfortable margins before the emissions limit would be exceeded. Mill margins improved significantly at the unit, and these, along with improvements in boiler tube outages, helped drive a significant improvement in the maintenance and availability performance of the unit. It is likely that 15% biomass co-firing of the undried biomass could be supported for this case, provided leakage repairs were made to the air heater and ESP ductwork.

## *Co-firing Dried Biomass*

The baseline coal quality and the dried 30% moisture woody biomass cases (introduced via separate injection) were evaluated for the conceptual unit using the Vista program at 5, 10, and 15% biomass heat input. The results of this analysis are discussed below and summarized in Table 4-7.

### Milling System

Because separate injection passes a significant amount of the boiler heat input around the milling system, the milling system capacity increases for all separate injection cases. As in the undried biomass case, this improves the mill capacity margins so much that at 15% biomass heat input, three-mill operation is possible (but not advisable, as mill margins are probably below the level which plant operators would feel comfortable with). As in the prior cases, this improves the overall equivalent availability of the unit, and could give operators more flexibility for accommodating poor quality coal. Relative to the baseline coal case, the milling system drying capability also increases for all separate injection cases, exhaust fan margins improve, and the required primary air temperature at the mill inlet also decreases.

### Forced Draft Fans

As in the undried biomass cases, forced draft fan margins improve as the amount of biomass fire quantity increases, caused by improvements in the overall furnace stoichiometry resulting from mixing biomass with coal. This effect is small, however, and should not be relied upon to provide a solution for a unit which is currently experiencing limitations due to insufficient forced draft fan capacity.

### Boiler – Unburned Carbon and $NO_x$

Boiler $NO_X$ production decreases from 3.3 to 9.5% for the biomass cases, with greater amounts of biomass resulting in lower emissions. The primary reason for this decrease is a reduction in the net fuel nitrogen content and an increase in the relative portion of fuel nitrogen contained in the volatile matter of the fuel. The reason for the greater $NO_X$ benefit of co-firing dried versus undried biomass is the lower heat flux at the biomass burner injection point with dried biomass, because boiler efficiency increases, which in turn results in slightly lower furnace temperatures. The SCR system was configured to achieve a constant 90% removal efficiency, and no problems are predicted for achieving that level of operation. Fly ash LOI is predicted to decrease as the amount of biomass fuel heat input increases, because the biomass fuel has a lower fixed carbon content overall than the coal.

The Vista program assumes that size distribution of the biomass to the separate injection burners is “idealized,” meaning that all equipment is in working order and no unusual sizing problems exist. It is very possible that variations in the actual sizing and grinding operations of the biomass on a day-to-day, or even hourly basis, could result in spikes of high LOI fly ash and bottom ash. Furthermore, specific impacts to the SCR catalyst resulting from biomass combustion were not modeled in this study, as this is a highly site-specific problem which depends considerably upon the type of catalyst active material installed.

### Boiler – Slagging and Fouling

Overall, Vista predicted a small increase in the level of waterwall slagging, which increased as biomass mass flow increased, at a level very similar to that of the undried biomass cases. As a result, this increase in slagging level led to an increase in wall sootblower use from being operated three times per day to nearly continuous operation. At 15% biomass heat input, the slagging level reaches the point where a 4.3% margin exists in boiler heat input, indicating that slagging derates are very possible if the biomass co-firing level increases significantly, or the biomass or coal ash quality declines. The Vista program predicts no significant changes in high temperature fouling tendency for any of the biomass co-firing cases, and fouling overall is judged to be "low." Here again, the primary reason for this is the selection of a woody biomass fuel with a low ash sodium content.

### Electrostatic Precipitator

Both the opacity and the particulate mass emissions rate are predicted to increase as the level of biomass co-firing increases. The reasons are the same as those for the undried biomass cases: increased fly ash resistivity and increased in the flue gas volumetric flow rate through the precipitator. However, both particulate mass emissions and opacity are predicted to increase less than that for the undried biomass cases, with the maximum particulate mass emissions and opacity being 0.0055 lbm/MBtu and 8.5%, respectively.

### Induced Draft and Scrubber Booster Fans

The operating margins of both the induced draft and the scrubber booster fans decrease as the level of biomass co-firing increases, but much less so than for the undried biomass case. As a result, even at 15% heat input of biomass, the induced draft fan margins only deviated slightly from their baseline coal margins (from 4.3% baseline to 4.1%). Here again, this situation is exacerbated by the fact that the baseline conceptual unit has a moderately high air heater leakage of 23% and an additional 1.4% cold-side ESP ductwork leakage.

### Scrubber and Waste Systems

The conceptual unit scrubber is assumed to achieve 96% $SO_2$ removal, and no limitations are predicted for any cases. Lower sulfur content of the biomass fuel resulted in a slight improvement in scrubber system operations. There is a possibility that fine biomass ash may accumulate in the scrubber gypsum at a level where there could be a concern, but the Vista program is not able to predict this. Furthermore, any impact on frothing in the thickening system due to changes in ash properties cannot be predicted by the Vista program.

### Fly Ash and Bottom Ash Systems

A reduction in the overall ash mass loading of the fuel leads to a small reduction in the required operation of the bottom and fly ash handling systems. No significant problems are noted by the Vista program for the relatively low levels of biomass ash entering the system. It is possible that the high calcium content of the biomass ash could result in some cementation if the ash is exposed to water, but no such problems are predicted in this study.

### Overall Unit Efficiency, Heat Rate, and Capability

The primary impact of adding moisture and hydrogen content biomass fuel to the fuel blend is an increase in the latent heat losses of the unit. As expected, the 15% biomass heat input case has the highest latent heat losses, at 5.19% (versus 4.27% for the baseline coal case). When these losses are combined with changes in unburned combustible losses and sensible heat losses, the net result is a reduction in the boiler efficiency as the biomass quantity increases. The worst case is the 15% biomass heat input case, which has a predicted boiler efficiency of 86.91% (versus 87.38% for the baseline coal case). When the difference in boiler efficiency is added to the differences in the auxiliary power and steaming ability of the unit, the overall net plant heat rate (NPHR) of the unit increases from the baseline of 9,763 to 9,958 Btu/kWh. Note again that these results do not include the overall NPHR impact of supplying auxiliary power to new biomass receipt, handling, reclaim, processing, and sizing equipment. As a result, it is expected that the actual NPHR would be slightly higher in real-world operation. Overall, it appears that the net effect of drying the biomass by 15% moisture content is an improvement of 79 Btu/kWh.

### Maintenance and Availability Results

Because the mill loading is reduced with the use of separate injection, reduced mill forced outage hours are predicted for all biomass separate injection cases. The best case is the 15% biomass heat input case, where the mill forced outage rate decreased by nearly 60 hours per year. Predicted boiler tube failures are reduced for all of the biomass co-firing cases. Waterwall tube failures were reduced because of reductions in both sulfur and chloride loading in the fuel mixture. Suspended tube bank failures were reduced because of a decrease in fly ash erosion (caused by both a reduction in the ash mass loading and the predicted ash abrasiveness). As a result, the overall equivalent availability factor of the unit improved for the biomass co-firing cases, with the greatest improvement being 0.76% for the 15% biomass heat input case. This represents, on average, an increase in unit availability of 66 hours per year.

Table 4-7 presents the plant performance results for these cases.

### Co-firing Dried Biomass Conclusions

Relative to the undried biomass cases, there are only some very small improvements for using the dried biomass. The level of waterwall slagging increase is nearly identical, and although $NO_X$, $SO_2$, particulate, and opacity emissions improve slightly, it is questionable whether these improvements would be sufficient to justify using dried biomass fuel. The strongest case to be made for the use of the dried biomass is the reduced impact it would have on the induced draft and scrubber booster fan capacity margins. It may be more advantageous to focus instead on reducing air heater and other flue gas system leakages. It is likely that 10% or more co-firing of the dried woody biomass could be achievable on a long-term basis.

## *Co-firing Torrefied Biomass*

The baseline coal quality and the torrefied wood biomass cases (blended with the coal on the main plant supply belt) were evaluated for the conceptual unit using the Vista program at 5, 10, and 15% biomass heat input. The results of this analysis are discussed below and summarized in Table 4-8.

### Milling System

All co-milling cases assumed that the wood mix is blended with the coal before being sent to the coal bunkers/silos; thus, all of the biomass is required to be processed by the mills. Normally sending biomass through the coal mills is inadvisable. Biomass fuel does not process within the mills like coal does, and it can build up, clog the mills, and lead to fire and explosion risks. However, torrefied biomass is an engineered fuel which is considerably different from any other biomass fuel. As a result it can be produced with very favorable properties in terms of heat content, moisture content, ash content, sulfur content, and grindability performance. In fact, for this case, the torrefied biomass is generally a better fuel than the baseline coal. Therefore, it is no surprise that many aspects of unit performance improve as torrefied biomass content of the blended fuel mixture increases.

**Table 4-7**
**Performance Estimates for Torrified Biomass Co-firing**

| Performance Parameter | Coal | Coal +5% Dried Biomass | Coal +10% Dried Biomass | Coal +15% Dried Biomass |
|---|---|---|---|---|
| ***Full-Load Results*** | | | | |
| Gross Power, MW | 261.50 | 261.50 | 261.50 | 261.50 |
| Net Power, MW | 250.00 | 248.49 | 248.58 | 247.97 |
| Boiler Efficiency, % | 87.38 | 87.28 | 87.13 | 86.91 |
| Fly ash LOI, % | 5.79 | 5.39 | 4.79 | 4.58 |
| NPHR, Btu/kWh | 9,762.5 | 9,867.7 | 9,901.6 | 9,958.1 |
| Total Heat Input, MBtu/hr | 2,440.6 | 2,452.1 | 2,461.4 | 2,469.3 |
| Biomass Heat Input, MBtu/hr | 0.0 | 122.6 | 246.1 | 370.4 |
| Coal Burn Rate, ton/hr | 99.97 | 95.42 | 90.74 | 85.97 |
| Biomass Burn Rate, ton/hr | 0.00 | 10.10 | 20.28 | 30.52 |
| Forced Draft Fan Margin, % | 3.4 | 4.7 | 5.1 | 5.6 |
| Induced Draft Fan Margin, % | 4.3 | 4.3 | 4.2 | 4.1 |
| Mill Capacity Margin, % | 18.2 | 23.9 | 30.3 | 37.5 |
| Slagging Potential | Low | Low/Medium | Low/Medium | Low/Medium |
| Fouling Potential | Low | Low | Low | Low/Medium |
| Potential Derate, MW | 0.00 | 0.00 | 0.00 | 0.00 |
| Most Limiting Item | None | None | None | None |
| $SO_2$ Emissions, lbm/MBtu | 0.06 | 0.06 | 0.06 | 0.06 |
| Boiler $NO_x$, lbm/MBtu | 0.32 | 0.31 | 0.30 | 0.29 |
| $NO_x$ Emissions, lbm/MBtu | 0.05 | 0.05 | 0.05 | 0.05 |
| Particulate Emissions, lbm/MBtu | 0.004 | 0.004 | 0.005 | 0.006 |
| Unit Opacity, % | 6.0 | 6.7 | 7.7 | 8.5 |
| ***Annual Results*** | | | | |
| Coal Burn Rate, kton/year | 706.63 | 673.70 | 639.84 | 605.72 |
| Biomass Burn Rate, kton/year | 0.00 | 71.32 | 143.00 | 215.01 |
| $SO_2$ Emissions, ton/year | 518 | 519 | 521 | 522 |
| $NO_x$ Emissions, ton/year | 431 | 433 | 434 | 435 |
| $CO_2$ Emissions, ton/year | 1,821,150 | 1,828,460 | 1,833,850 | 1,838,990 |
| Non-renewable $CO_2$ Emissions, ton/year | 1,821,150 | 1,728,162 | 1,641,320 | 1,553,790 |
| Mercury Emissions, lbm/year | 93.2 | 88.4 | 83.8 | 79.4 |
| Net Capacity Factor, % | 80.00 | 80.08 | 80.08 | 80.05 |
| Equivalent Availability, % | 90.00 | 90.24 | 90.56 | 90.76 |

Because of reductions in the fuel burn rate and improvements in the Hardgrove Grindability Index, the milling system capacity increases slightly for all torrefied wood cases. It should be noted that no significant industry experience has been developed for grinding of either torrefied wood pellets or chips. This improves the mill capacity margins by a maximum of roughly 3%--not enough to significantly change mill operations. This improvement in milling capacity improves the overall equivalent availability of the unit slightly as well. The milling system drying capability improves very slightly, because the slightly lower moisture content of the torrefied wood slightly improves exhauster fan margins.

### Forced Draft Fans

Forced draft fan margins increase as the amount of biomass fire quantity increases, because of improvements in the overall furnace stoichiometry resulting from mixing torrefied biomass with coal. This effect is small, however, and should not be relied upon to provide a solution for a unit with insufficient forced draft fan capacity.

### Boiler – Unburned Carbon and $NO_x$

Boiler $NO_X$ production rates decrease 1.2% to 3.9% for the three torrefied wood heat input cases relative to the baseline coal case, with greater amounts of biomass resulting in lower $NO_X$ emissions.

No problems are predicted for the SCR system at a constant 90% removal efficiency. Fly ash LOI is predicted to increase as the amount of torrefied wood biomass fuel heat input increases, because the torrefied wood biomass fuel has a much higher fixed carbon content than coal.

The Vista program assumes that the size distribution of the biomass to the separate injection burners is “idealized,” meaning that all equipment is in working order and no unusual sizing problems exist. It is very possible that variations in the actual sizing and grinding operations of the biomass on a day-to-day, or even hourly basis, could result in spikes of high LOI fly ash and bottom ash. Furthermore, specific impacts to the SCR catalyst resulting from biomass combustion are not modeled for this study, as this is a highly site-specific problem which depends considerably upon the type of active catalyst material used.

### Boiler – Slagging and Fouling

Overall, Vista predicts a small increase in the level of waterwall slagging, increasing as the amount of biomass mass flow increases. The primary driver for this is the high calcium and magnesium content of the biomass ash, which reduces the overall ash fusion temperatures of the fuel. This increase in slagging level leads to an increase in wall sootblower use, which is predicted to increase from being operated three times per day to nearly continuous operation. At 15% biomass heat input, the slagging level reaches the point where a 5.7% margin exists in boiler heat input, indicating that slagging derates are very possible if the biomass co-firing level increases significantly or the biomass or coal ash quality declines. The Vista program predicts no significant changes in high temperature fouling for any of the biomass co-firing cases, and fouling overall is judged to be "low." The primary reason for this is fuel selection. Because the torrefied wood biomass ash is low in minerals, which are typically problematic in the upper furnace (such as sodium), it is a generally benign fuel relative to boiler fouling.

### Electrostatic Precipitator

Both the opacity and the particulate mass emissions rate are predicted to increase as the level of torrefied wood biomass co-firing increases, but much less than either the undried or dried biomass cases. The increase is primarily due to an increase in the fly ash resistivity, which slightly reduces the collection efficiency of the ESP. Overall, only a 7% increase in the particulate mass emissions rate is predicted for the 15% biomass case relative to the baseline coal case. The maximum particulate mass emissions and opacity are 0.0042 lbm/MBtu and 6.5%, respectively.

### Induced Draft and Scrubber Booster Fans

The operating margins of both the induced draft and the scrubber booster fans increase as the level of biomass co-firing increases. This is caused largely by a reduction in the overall fuel burn rate due to the higher heat content of the torrefied wood biomass. This is a notable difference from the cases of the undried and dried biomass.

### Scrubber and Waste Systems

The conceptual unit scrubber is assumed to achieve 96% $SO_2$ removal. In this analysis, an ash sulfur capture of 10% is assumed for all bituminous coals, and 5% sulfur capture in ash is assumed for the biomass fuels. No scrubber limitations are predicted and, in fact, the lower sulfur loading of the biomass fuel results in a slight improvement in scrubber performance. There is a possibility that fine biomass ash may accumulate in the scrubber gypsum to a level where it could be a concern, but the Vista program is not able to predict this. Furthermore, any impact on frothing in the thickening system due to changes in ash properties cannot be predicted by the Vista program.

### Fly Ash and Bottom Ash Systems

A reduction in the overall ash mass loading of the fuel led to a small reduction in the required operation of the bottom and fly ash handling systems. No significant problems were noted by the Vista program for the relatively low levels of biomass ash which entered the system. It is possible that the high calcium content of the biomass ash could result in some cementation if the ash is exposed to water, but for this study no such problems were predicted.

### Overall Unit Efficiency, Heat Rate, and Capability

The primary impact of adding higher moisture and hydrogen content biomass fuels to the unit is an increase in the latent heat losses of the unit. However, since the torrefied wood biomass has a lower moisture content than the baseline coal, a reduction in the latent heat losses occurs. For the 15% biomass heat input case, the latent heat losses are 4.07% (versus 4.27% for the baseline coal case). There is a small but steady increase in unburned combustible losses as the proportion of heat input from torrefied wood increases, although the effect is more than offset by the reduction in latent heat losses. The net result is an improvement in the boiler efficiency as the torrefied biomass quantity increases, with the best case being the 15% biomass heat input case, at 87.69% (versus 87.38% for the baseline coal case). When the difference in boiler efficiency is added to the differences in the auxiliary power and steaming ability of the unit, then the overall net plant heat rate (NPHR) of the unit is expected to increase only slightly from a baseline of 9,763 to 9,812 Btu/kWh. Note that these results do not include the overall NPHR impact of supplying auxiliary power to new biomass receipt, handling, reclaim, processing, and sizing equipment. As a result, it is expected that the actual NPHR would be slightly higher in real-world operation. However, the impact is less for the torrefied wood biomass case than for either of the direct-injected biomass cases in this study, due to the lack of fuel grinding and sizing equipment, lack of pneumatic conveyors and fans, etc.

### Maintenance and Availability Results

Although the mills are required to process all of the biomass fuel, the favorable characteristics of the torrefied wood biomass results in reduced net mill loading as biomass heat input increases. For the 15% biomass heat input case, the mill forced outage rate decreased by nine hours per year. Predicted boiler tube failures are reduced for all of the biomass co-firing cases. Waterwall tube failures are reduced, due to reductions in both sulfur and chloride loading in the fuel mixture. Suspended tube bank failures are reduced because of a decrease in fly ash erosion due to reduction of both ash mass loading and the predicted ash abrasiveness. As a result, the overall equivalent availability factor of the unit improves for the biomass cases, with the greatest improvement being 0.15% for the 15% biomass heat input case. This represents, on average, an increase in unit availability of 13 hours per year.

Table 4-8 presents performance estimates for the torrefied biomass co-firing cases.

### Co-firing Torrefied Biomass Conclusions

Very few immediate operations concerns are noted for any of the torrefied wood biomass co-firing cases, with the main concern being the increase in the level of furnace water wall slagging. The increase in flyash LOI may be a problem if fly ash sales are impacted. However, it is almost certain that with the use of biomass, finding a buyer for non-ASTM compliant coal and biomass ash would be difficult or impossible. Particulate mass emissions and the unit opacity both increase only very slightly--not enough to be any concern for operators. Mill margins improved slightly. Along with improvements in boiler tube outages, these result in a small improvement in the maintenance and availability performance of the unit. It is likely that 15% biomass co-firing could be supported using torrefied wood biomass (assuming a sufficient supply of torrefied biomass is able to be procured).

**Table 4-8**
**Performance Estimates for Co-Milled Torrefied Biomass Co-firing Cases**

| Performance Parameter | Coal | Coal +5% Torrefied Wood Biomass | Coal +10% Torrefied Wood Biomass | Coal +15% Torrefied Wood Biomass |
|---|---|---|---|---|
| ***Full-Load Results*** | | | | |
| Gross Power, MW | 261.50 | 261.50 | 261.50 | 261.50 |
| Net Power, MW | 250.00 | 248.40 | 248.48 | 248.58 |
| Boiler Efficiency, % | 87.38 | 87.56 | 87.63 | 87.69 |
| Fly ash LOI, % | 5.79 | 6.00 | 6.36 | 6.75 |
| NPHR, Btu/kWh | 9,762.5 | 9,830.7 | 9,822.8 | 9,811.5 |
| Total Heat Input, MBtu/hr | 2,440.6 | 2,441.9 | 2,440.8 | 2,438.9 |
| Biomass Heat Input, MBtu/hr | 0.0 | 122.1 | 244.1 | 365.8 |
| Coal Burn Rate, ton/hr | 99.97 | 95.02 | 89.98 | 84.92 |
| Biomass Burn Rate, ton/hr | 0.00 | 4.78 | 9.56 | 14.34 |
| Forced Draft Fan Margin, % | 3.4 | 4.5 | 4.5 | 4.8 |
| Induced Draft Fan Margin, % | 4.3 | 4.3 | 4.5 | 4.8 |
| Mill Capacity Margin, % | 18.2 | 18.8 | 19.5 | 20.3 |
| Slagging Potential | Low | Low/Medium | Low/Medium | Low/Medium |
| Fouling Potential | Low | Low | Low | Low |
| Potential Derate, MW | 0.00 | 0.00 | 0.00 | 0.00 |
| Most Limiting Item | None | None | None | None |
| $SO_2$ Emissions, lbm/MBtu | 0.06 | 0.06 | 0.06 | 0.06 |
| Boiler $NO_x$, lbm/MBtu | 0.32 | 0.32 | 0.31 | 0.31 |
| $NO_x$ Emissions, lbm/MBtu | 0.05 | 0.05 | 0.05 | 0.05 |
| Particulate Emissions, lbm/MBtu | 0.004 | 0.004 | 0.004 | 0.004 |
| Unit Opacity, % | 6.0 | 5.8 | 6.2 | 6.5 |
| ***Annual Results*** | | | | |
| Coal Burn Rate, kton/year | 706.63 | 671.73 | 636.10 | 600.39 |
| Biomass Burn Rate, kton/year | 0.00 | 33.82 | 67.62 | 101.36 |
| $SO_2$ Emissions, ton/year | 518 | 518 | 518 | 517 |
| $NO_x$ Emissions, ton/year | 431 | 432 | 431 | 431 |
| $CO_2$ Emissions, ton/year | 1,821,150 | 1,828,160 | 1,833,190 | 1,837,880 |
| Non-renewable $CO_2$ Emissions, ton/year | 1,821,150 | 1,723,132 | 1,631,721 | 1,540,110 |
| Mercury Emissions, lbm/year | 93.2 | 89.1 | 84.8 | 80.6 |
| Net Capacity Factor, % | 80.00 | 80.08 | 80.09 | 80.09 |
| Equivalent Availability, % | 90.00 | 90.01 | 90.08 | 90.15 |

### Conclusions of the Vista Analysis

The Vista analysis of the three different types of biomass reveals several critical items about biomass co-firing. First, co-firing biomass at a coal power plant has the potential to impact many areas of the power plant which are vital to its performance, emissions, and operations and maintenance. Co-firing biomass, if carried out properly, has the potential to benefit some aspects of plant operations, but also the potential to limit plant operations:

- The primary impact on boiler efficiency and plant heat rate from biomass co-firing results from the moisture content of the biomass.
- Obviously, any introduction of a fuel into the boiler which bypasses the mills has the potential to improve mill capacity and operations, but it may impact unit efficiency and emissions unless the heat input and fuel and air distribution are properly balanced.
- Air-side fans may benefit from direct injection of biomass, but gas-side fans may be negatively impacted.
- The lower ash content of biomass fuel may at first appear to be a universal advantage, but the ash may be lower in fly ash resistivity and have a greater propensity to slag and foul the unit (on a per-pound basis). However, the erosion potential is likely diminished and the demands on fly and bottom ash handling systems is likely reduced.
- $SO_2$ reduction can be significant with biomass co-firing because of the low sulfur content of the biomass fuel. $NO_X$ benefits can occur because of the low nitrogen content of biomass fuels. However, biomass fuels with high amounts of fixed carbon content (such as torrefied wood) can see a much smaller reduction in $NO_X$.

Although biomass co-firing experience is increasing in the industry, it is quite limited compared to coal firing experience. As a result, there is much that is not well understood about biomass co-firing impacts in coal boilers. The formation of $NO_X$ during combustion, slagging and fouling effects, corrosion of boiler tubes, SCR catalyst impacts, and impacts to advanced emissions control systems are all areas where additional research and experience are needed.

## Estimated Costs for Biomass Co-firing

Black & Veatch has developed capital and O&M cost estimates for the base case biomass co-firing scenario considered in this study (see Table 4-9). This section describes the development of the capital, operation and maintainence, and levelized cost estimates, the assumptions used, and presents the resulting cost estimates.

### Total Capital Requirement

Similar to repowering projects, biomass co-firing capital cost requirements are primarily dependent upon the method of co-firing selected. Other project parameters affecting the capital cost include the following:

- Boiler technology (i.e., particle size requirements)
- Scale of project (i.e., biomass flow rates and material handling strategies)
- Conveyor lengths
- Required infrastructure upgrades (i.e., plant roadways)
- Biomass storage strategy

**Table 4-9**
**Summary of Biomass Co-firing Base Case**

| Parameter | Biomass Co-firing Base Case Scenario |
|---|---|
| Co-firing Method | Separate Injection |
| Net Capacity | 250-MW |
| Boiler Type | Wall-fired Pulverized Coal |
| Capacity Factor | 80% |
| Biomass Heat Input | 10% |
| *Biomass Properties* | |
| Fuel Type | Undried, blended biomass |
| Heating Value (dry) | 8,670 Btu/lb |
| Moisture Content | 45% |
| *Coal Properties* | |
| Type | Central Appalachian |
| Heating Value | 12,207 Btu/lb |

Capital cost estimates for the biomass co-firing scenario were developed assuming that a turnkey engineering, procurement, and construction (EPC) contracting strategy will be employed to execute the project. Capital costs for these projects are divided into two categories: direct costs and indirect costs. Direct costs include the costs associated with the purchase and installation of major equipment and balance-of-plant (BOP) equipment. Capital cost estimates for major equipment items were based upon vendor quotations received by Black & Veatch. The capital costs associated with BOP equipment and construction and any required facility modifications (i.e., boiler modifications) were estimated based on past experience with similar projects.

Indirect costs include costs such as construction indirects, engineering, construction management, and contingency. Allowances for indirect costs were included in these estimates. The specific items included as construction indirect costs include the following:

- Construction supervision.
- Purchase of small tools and consumables.
- Site services.
- Construction safety program (including development and compliance).
- Installation of temporary facilities.

- Installation of temporary utilities.
- Rental of construction equipment.
- Transportation of heavy construction materials and equipment.
- Preoperational startup and testing.
- Insurance (including builder’s risk and general liability).
- Construction permits (excluding Construction Air Permit).
- Performance bond.
- EPC contractor profit.

An allowance for Owner’s Costs (i.e., due diligence, permitting, legal and other development costs) is included. This allowance is calculated as 10 percent of the Total Plant Cost.

### *Operation and Maintenance Cost Estimates*

Fixed and variable operation and maintenance (O&M) costs for the primary biomass co-firing case are estimated. Fixed O&M costs consist of wages and wage-related overheads for the permanent plant staff, routine equipment maintenance, and other fees. Variable O&M costs include costs associated with equipment outage maintenance, catalyst/reagents, chemicals, water, and other consumables. Fuel costs are determined separately and are not included in either the fixed or variable O&M costs.

The assumptions used in developing the fixed and variable O&M costs for the biomass co-firing case are as follows:

- The co-firing case assumes a PC boiler.
- The co-fired fuel is an undried, woody biomass with a 45% moisture content that makes up 10% of the heat input to the boiler.
- Estimated gross capacity factor is 80%.
- Forced outage rate is 4%.
- Net plant heat rate is 9,760 Btu/kWh.
- Plant staff average wage rate is $56,590 per year.
- The salary burden rate is 40%.
- Staff supplies and materials are estimated to be 5% of staff salary.
- Estimated employee training cost and incentive pay/bonuses are included.
- Routine maintenance costs are estimated based on Black & Veatch experience and manufacturer input.

- Contract services include costs for services not directly related to power production.
- Insurance and property taxes are not included.
- The variable O&M analysis is based on a repeating maintenance schedule over the life of the plant.
- Variable O&M costs associated with the steam turbine are estimated based on a typical overhaul schedule (including both minor and major overhauls).
- Frequency of boiler overhaul is every year.
- Frequency of turbine and generator major inspection is every six years.
- Steam turbine, generator, boiler, and other balance of plant maintenance costs are based on Black & Veatch experience and vendor data recommendations.
- SCR costs are included.
- Water treatment costs are included for water make-up and demineralized water where needed.
- Demineralized water treatment cost is $5 per 1,000 gallons.
- City water cost is $1 per 1,000 gallons.
- Ash disposal cost is $6 per ton.
- Anhydrous ammonia cost is $800 per ton.
- Aqueous ammonia cost is $315 per ton.
- Costs are in 3$^{rd}$-quarter 2010 US dollars.

### *Biomass Co-firing Cost Estimate Results*

Table 4-10 summarizes the total capital requirement and O&M estimates for the primary biomass co-firing case. Costs presented on $/kW basis are determined based on biomass-fired capacity (i.e., equivalent power output of 25 MW).

### *Levelized Cost of Electricity*

The levelized cost of electricity (LCOE) considers the levelized fixed charge on total capital requirement, fixed and variable O&M, and fuel cost. It represents the present value of the total life-cycle costs over 20 years divided by the total annual MWh generated at the facility. LCOE is calculated in units of dollars per megawatt hour ($/MWh) and in constant 3$^{rd}$-quarter 2010 dollars.

## Levelized Fixed Charge Rate

The levelized fixed charge rate (LCFR) is the factor applied to the Total Capital Requirement to yield the annual fixed charge on the capital investment. For an investor-owned utility, the components of the annual fixed charge include depreciation, interest on debt, return on equity, income and property taxes, insurance, and other administrative costs. For the economic assumptions presented in Table 2-8 and 20-year project life, the LFCR is estimated to be 8.50% per year without consideration of the ITC, and 7.33% with the ITC. The Fixed Capital Charge Component of cash flow is summarized in Table 4-11.

Levelized Cost of Electricity EstimatesTable 4-12 presents the incremental LCOE (i.e., levelized cost exceeding the cost of electricity for baseload coal operation at the co-fired facility) for the base case and two sensitivity cases. LCOE estimates were generated both with and without the benefits of the ITC, for the reason that it is presently uncertain whether co-firing projects would qualify for the ITC.

If the ITC (equivalent to 30 percent of Total Capital Requirement) is not applied, the incremental LCOE estimates are $31/MWh for the base case (0.25 $/MBtu incremental biomass fuel cost vs. coal), and $21/MWh and $41/MWh for the two sensitivity cases (-$0.75/MBtu and $1.25/MBtu vs. coal, respectively). If the ITC is applied, the incremental LCOE is reduced by approximately $8/MWh in each case as shown in Table 4-12.

**Table 4-10**
**Biomass Co-firing Characteristics and Total Capital Requirement Estimate (3rd-Quarter 2010$)**

| **Rated Capacity** | **Biomass Co-firing** | | |
|---|---|---|---|
| Coal plant size (units x unit size), MW | 1 x 250-MW | | |
| Biomass fuel feed system | Separate Injection | | |
| Fraction of plant output from biomass, % | 10 | | |
| Equivalent power output, MW | 25 | | |
| **Physical Plant** | | | |
| Unit life, years | 20 | | |
| **Scheduling** | | | |
| Preconst., License & Design Time, Years | 1.5 | | |
| Idealized Plant Construction Time, Years | 0.5 | | |
| Hypothetical In-Service Date | January 1, 2011 | | |
| **Incremental Total Capital Requirement** | **($ 1,000)** | **($/kW)[1]** | **(%)** |
| *Major Equipment Costs* | | | |
| Fuel Handling/Prep | $23,120 | $930/kW | 61% |
| Boiler Modification | $1,610 | $60/kW | 4% |
| **Total Major Equipment Costs** | **$24,730** | **$990/kW** | **65%** |
| *Direct Balance of Plant Costs* | | | |
| Site Work, Foundations, Roadways | $1,040 | $40/kW | 3% |
| Electrical Equipment, Cable, & Raceway | $340 | $10/kW | 1% |
| Instrumentation & Controls | $1,220 | $50/kW | 3% |
| **Total Direct Balance of Plant Costs** | **$2,600** | **$100/kW** | **7%** |
| *Indirect Balance of Plant Costs* | | | |
| Facilities, Engineering, and Const. Mgt. | $4,390 | $180/kW | 12% |
| Project & Process Contingency & Fees | $6,510 | $260/kW | 17% |
| **Total Indirect Balance of Plant Costs** | **$10,900** | **$440/kW** | **29%** |
| *Total Costs* | | | |
| **Total Plant Costs** | **$38,230** | **$1,530/kW** | **100%** |
| AFUDC (Interest during construction) | $250 | $10/kW | -- |
| **Total Plant Investment (incl. AFUDC)** | **$38,480** | **$1,540/kW** | **--** |
| **Owner's Cost** | **$3,850** | **$150/kW** | **--** |
| **Total Capital Requirement** | **$42,330** | **$1,690/kW** | **--** |
| **Incremental O&M Costs (co-firing systems only)** | | | |
| Fixed, $/kW-yr | 21.60 | | |
| Variable, $/MWh | 4.90 | | |
| **Performance/Unit Availability** | | | |
| Net Plant Heat Rate, Btu/kWh (HHV) | 9,760 | | |
| Equivalent Planned Outage Rate, % | 4 | | |
| Duty Cycle | Baseload | | |
| Minimum Load, % | 40 | | |
| **Emission Rates** | | | |
| $NO_x$, lb/MBtu | 0.05 | | |
| $SO_x$, lb/MBtu | 0.06 | | |
| Particulates, lb/MBtu | 0.006 | | |
| **Confidence and Accuracy Rating** | | | |
| Technology Development Rating | Commercial | | |
| Design & Cost Estimate Rating | Simplified | | |

Notes:1. Costs presented on $/kW basis are determined based on biomass-fired capacity (i.e., equivalent power output of 25 MW).

**Table 4-11**
**Biomass Co-firing Levelized Fixed Capital Charge Component (3rd-Quarter 2010 $)**

| Scenario | Levelized Fixed Charge Rate | Fixed Capital Charge Component of Cash Flow[1] |
|---|---|---|
| With ITC | 7.33% | $87/kW-yr |
| Without ITC | 8.50% | $144/kW-yr |

Notes:

[1] Fixed Capital Charge Component of Cash Flow calculated by multiplying the LFCR by the Total Capital Requirement. The components of the annual fixed charge include amortization depreciation, return on equity, income and property taxes, insurance, and other administrative costs. This value does not include charges associated with fixed O&M costs.

**Table 4-12**
**Biomass Co-firing Levelized Cost of Electricity Estimates (3rd-Quarter 2010 $)**

| Cost | Base Case | Sensitivity Case 1[1] | Sensitivity Case 2[1] |
|---|---|---|---|
| **Incremental Biomass Fuel Cost ($/MBtu)** | +0.25 | -0.75 | +1.25 |
| | | | |
| **Levelized Cost of Electricity[2] With ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 3 | 3 | 3 |
| Variable O&M Component of LCOE ($/MWh) | 5 | 5 | 5 |
| Fuel Component of LCOE ($/MWh) | 2 | (7) | 12 |
| Capital Charge Component of LCOE ($/MWh) | 12 | 12 | 12 |
| **Total[3] ($/MWh)** | **23** | **13** | **33** |
| | | | |
| **Levelized Cost of Electricity[2] Without ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 3 | 3 | 3 |
| Variable O&M Component of LCOE ($/MWh) | 5 | 5 | 5 |
| Fuel Component of LCOE ($/MWh) | 2 | (7) | 12 |
| Capital Charge Component of LCOE ($/MWh) | 20 | 20 | 20 |
| **Total[3] ($/MWh)** | **31** | **21** | **41** |

Notes:

[1] Sensitivity Cases assume biomass fuel costs different than the base case, at $0.75/MBtu below and $1.25/MBtu above the $3.30/MBtu cost assumed for coal.

[2] Estimate of LCOE assumes an 85% capacity factor, 20-year project life, and constant dollars.

[3] Sum of LCOE component values may not equal Total value due to rounding.

# 5
# BIOMASS-FIRED BUBBLING FLUIDIZED BED COMBUSTION ENGINEERING AND ECONOMIC EVALUATION

This chapter presents the results of the design and performance of a representative power plant at which biomass is fired in bubbling fluidized bed steam boilers. Seven scenarios have been evaluated, including two biomass fuels, three plant ratings and three plant locations. The scenarios are summarized as follows:

- 1x50-MW woody biomass-fired BFB facility at three locations:  West (representative of California), Southeast (representative of Georgia) and Midwest (representative of Ohio, Minnesota and Wisconsin).
- 1x100-MW woody biomass-fired BFB facility at the same three locations.
- 1x50-MW BFB facility co-fired with woody biomass and switchgrass. This scenario evaluated for one location:  Southeast (representative of Florida).

## Introduction to Biomass Fired BFB Combustion

Combustion of biomass in BFB boilers has been practiced for more than 30 years. Early BFB boiler installations were typically smaller in capacity and located at papermills with their ample availability of waste wood fuel. Recently, major utilities are considering larger, greenfield biomass fired BFB based plants in the 100-MW range to diversify their renewable fuels portfolio.

The domestic market is beginning to evaluate agricultural residues, dried manure, sewage sludge, and dedicated fuel crops for firing or cofiring in BFB boilers. Much of this new development is driven by state renewable portfolio standards (RPS's) and federal tax policies. Recently, rising fossil fuel prices and concerns about greenhouse gases have also contributed to development.

This study will focuses on woody biomass fired in a dedicated BFB boiler. Consideration is also given to cofiring switchgrass with woody biomass.

## Biomass Fired BFB Combustion Design Basis and Cost Assumptions

Section 2 of this study highlights the site and design assumptions for the biomass projects under consideration. These assumptions include parameters for the general design of the biomass fired BFB combustion systems, system capacity, and the cost development methodology associated with these systems.

### *System Design Basis*

The assumptions developed for the Biomass Fired BFB Combustion scenarios are presented in Table 2-3.

### *Biomass Property Assumptions*

Table 2-4 and Table 2-5 present the fuel properties for the woody biomass fuels and switchgrass (typical for that fuel grown in Florida).

### *Biomass Receipt Assumptions*

The biomass receiving, unloading, sizing, storage, and reclaim system is assumed to automated, requiring minimum operating manpower and little or no movement of the fuel material via manual means such as front end loaders or bulldozers. Equipment redundancy and system design margins are included to insure a continuous fuel feed to the unit.

Truck scales and belt scales are included to determine the fuel delivery rate and the feed rate to the boiler. Magnets will extract tramp metal. Dust suppression and fire protections systems are required.

#### Truck Receipt

It is assumed that biomass deliveries will be by truck, and that trucks would be accepted ten hours per day on weekdays and five hours per day on Saturday. Each site requires two automated truck scales (one receiving and one exiting) to record and verify deliveries. Two scales are required to accommodate the volume of trucks deliveries and to minimize delays due to scale congestion.

#### Woody Biomass Receipt, Stockout, and Reclaim

Hydraulically-tipped, whole truck, drive over dumpers are used to unload woody biomass. The truck dumpers cycle a maximum of five times per hour with the assumption that one dumper may be off-line for maintenance at any one time.

Stockout and reclaim utilize radial or linear stacker/reclaimer systems. For the scenarios in which woody biomass is the primary fuel, a biomass pile capacity sufficient for a minimum of 28 days operation at the boiler maximum continuous rating (MCR) was assumed.

A single variable-speed conveyor delivers the woody biomass to metering bins in the boiler plant, which provide a combined storage capacity of one hour. Conveying from the metering bins to the boiler is also achieved via variable-speed conveyors.

### Switchgrass Receipt, Stockout, and Reclaim

Switchgrass is received by truck in half ton square bales (3'x4'x8'), with approximately 30 bales per truck. Trucks cross the scales (both ways as with woody biomass) and are then unloaded by fast acting over head cranes capable of lifting (10) bales per pick. The bales are either stacked in an enclosed storage building or immediately placed on the processing line.

The covered storage capacity is 5 days operation at 20 percent of the boiler maximum continuous rating (MCR). Additional storage is assumed to be provided off site by the switchgrass suppliers.

From storage, bales are conveyed to the destringer and into the Horizontal Grinder for sizing to 3" minus size. Magnets and stone separators are included.

The sized biomass is then conveyed to the Blending Chute and Conveyor feeding into the Woody Biomass Stream running to the boiler. The woody biomass system is sufficiently sized so the facility has the capability of operating on 100 percent woody biomass if switchgrass is not available.

Table 5-1 summarizes the major assumptions related to the biomass material handling for the biomass fired BFB combustion scenarios. Additional design details are included in the section titled "Biomass Fired BFB Combustion Material Handling Systems."

**Table 5-1**
**Biomass Material Handling Parameters**

| Parameter | Woody Biomass | Switchgrass |
|---|---|---|
| Material Size, as received | 4" minus | Half ton bales |
| Material Size, final | 2 ½" x ½" minus | 3" minus |
| Biomass Heat Input, % | 100 | 20 max when cofired |
| Delivery Method | Truck | Truck |
| Trucks Received | 10 hours per day / 5.5 days per wk | 10 hours per day / 5.5 days per wk |
| Unloading method | Hydraulic dumpers | Bridge crane |
| Days of Storage | 20+ uncovered | 5 covered |
| Boiler Feeding Method | Biomass feeders | Blended with woody biomass |

## *Cost and Economic Assumptions*

The cost assumptions listed in Section 2 of this study apply to the Biomass Fired BFB Combustion scenarios.

The facility design and the approach to the cost estimates are generally identical for the various sites under consideration. The limited site specific cost impacts are summarized in the section titled "Costs for Biomass-Fired BFB Combustion."

## Biomass-Fired BFB Combustion Plant Performance

Table 5-2 summarizes the unit performance parameters at 100 percent rated conditions. These performance estimates are assumed to be the valid for all plant locations.

**Table 5-2**
**Plant Performance Summary for Biomass-fired BFB Boiler**

| Parameter | Units | 50-MW Woody Biomass BFB | 100-MW Woody Biomass BFB | 50-MW Switchgrass/ Wood BFB |
|---|---|---|---|---|
| Turbine Gross Output | kW | 58,824 | 113,636 | 59,524 |
| Turbine Heat Rate | Btu/kWh | 8,902 | 8,505 | 8,895 |
| | | | | |
| Total Auxiliary Power | kW | 8,824 | 13,636 | 9,524 |
| Total Auxiliary Power | % | 15 | 12 | 16 |
| Net Plant Output | kW | 50,000 | 100,000 | 50,000 |
| | | | | |
| Boiler Efficiency | % | 75 | 75 | 75 |
| Boiler Heat Input | MBtu/h | 698.2 | 1289.4 | 705.9 |
| Biomass Consumption | tons/h | 73.2 | 135.2 | 69.8 |
| Net Plant Heat Rate | Btu/kWh | 13,964 | 12,894 | 14,119 |

Notes:

1. Auxiliary power is assumed.
2. Wet cooling tower is assumed
3. Average ambient conditions of 62.1° F dry bulb temperature and 54.8° F wet bulb temperature. Dew point temperature (49.6° F) is assumed to be the cold water temperature.
4. Switchgrass is cofired with woody biomass up to 20 percent.

## Biomass Fired BFB Combustion Engineering and Economic Evaluation Results

### *Bubbling Fluidized Bed Boiler*

In BFB boilers (see Figure 3-3 and Figure 5-1), fuel feeders discharge either to chutes that drop the fuel into the bed or to fuel conveyors that distribute the fuel to feed points around the boiler. The speed of the feeders is modulated to maintain steam output when fuel conditions or loads change. The fluidized bed consists of fuel, ash from the fuel and an inert material (typically sand). Sorbent injection in the bed (typically limestone) is not generally required in biomass applications due to the low sulfur content in the fuel. If sulfur removal is required, it is typically accomplished in the gas stream.

The fluidized state of the bed is maintained by hot primary air flowing upward through the bed. The air is introduced through a grid for even distribution. The amount of air is just sufficient to cause the bed material to lift and separate. BFBs operate at low fluidizing velocities (about 3 to 10 ft/s), and the bed material maintains a relatively high solid density. This operation results in a well-defined bed surface with only a small fraction of the solids entrained in the flue gas stream leaving the bed. Hot sand in the bed effectively dries and volatilizes the fuel introduced. In this state, circulation patterns occur, which causes fuel discharged on top of the bed to mix throughout the bed. Because of the turbulent mixing, heat transfer rates are very high, and combustion efficiency is good. The bed retains most of the heat of combustion; therefore, it is well-suited for low heating value, high moisture fuels, such as biomass. Combustion temperatures can be kept relatively low compared to other conventional fossil fuel-fired boilers. The bed may also be operated in a sub-stoichiometric mode with additional air added in the freeboard to complete combustion. Low bed temperatures and air staging reduces $NO_X$ formation. The lower bed temperature is likely to remain below the ash fusion temperature of the biomass fuels, reducing the potential for boiler slagging.

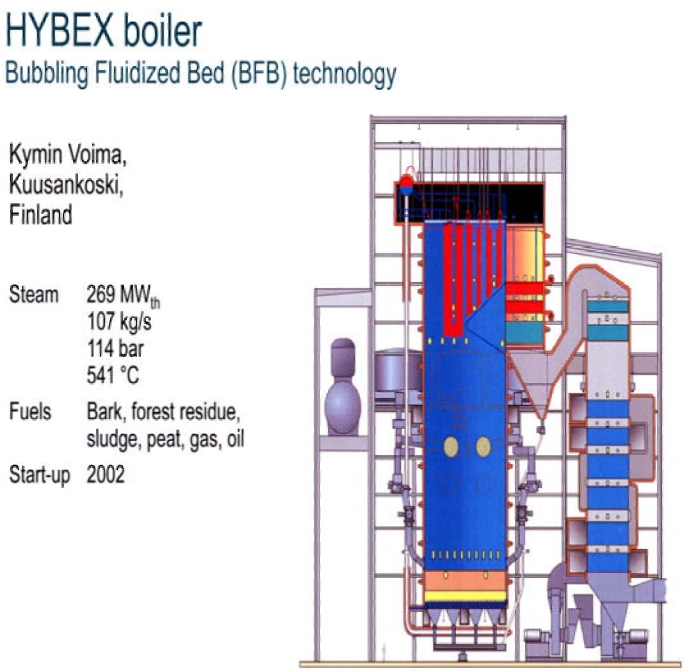


**Figure 5-1**
**Example Woody Biomass-fired BFB System (Source: Metso)**

Because the woody biomass fuel rapidly devolatizes, 50 to 60% of the combustion occurs in the bed and 40 to 45% occurs above the bed. Overfire air is required to ensure complete combustion of the fuel.

Due to the low combustion temperatures, uncontrolled $NO_X$ emissions from a biomass-fired BFB boiler will generally be less than 0.20 lb/MBtu. In addition, the operating temperature of a BFB is usually within the temperature range that allows a selective non-catalytic reduction (SNCR) system to be effective. Another advantage with this type of system is that it has the potential to accommodate a wide range of fuel heating values and moisture contents. With proper design, BFBs should be able to process a diverse mix of fuels simultaneously (e.g., a mixture of wood waste, agricultural residues, and biosolids). One disadvantage of the BFB is the large auxiliary power requirement for the fluidizing air fan.

BFBs traditionally range from 20 to 75 MW, with 100-MW being the upper limit. BFBs are technically capable of burning a wide variety of biomass fuels, provided that the fuel is sized appropriately. A three-dimensional sizing criteria may be required for the fluidized bed boiler, which may require more screening and sizing operations in the woodyard to ensure that no dimension of the fuel exceeds the recommended upper limit.

One advantage of fluidized bed combustors is that the fluid bed medium provides thermal inertia that compensates for variations in non-homogeneous fuels, including variations in heating value and moisture content. This results in a consistent heat output and flue gas quality. The high heat transfer of the fluid bed medium also provides high carbon burnout.

The typical boiler efficiency for bubbling bed combustion units firing biomass is approximately 75 to 78 percent. NOx control is required regardless of the fuel, and the prevailing technology for NOx control is SNCR, although SCR has recently been permitted on several biomass units proposed in Florida. Control of PM10 would typically be accomplished with a fabric filter. Controls for other pollutants may be necessary as part of the permitting process or the unit's applicability to the proposed Industrial Boiler MACT.

### *Biomass Fuel Concerns*

There are numerous technical concerns with biomass fuels that can affect plant design and operation including alkali, moisture, and chlorine. Common biomass fuels with the highest alkali contents are typically crop residues (such as rice and grain straws), grasses (including switchgrass), and animal manure. Woody biomass can provide lower alkalinity levels, depending on the blend being burned.

The ash from biomass fuels can have high levels of alkali components. The alkali components of ash, particularly potassium and sodium compounds such as potassium oxide ($K_2O$) and sodium oxide ($Na_2O$), cause the ash to remain sticky at a much lower temperature than coal ash. This increased stickiness creates the potential for serious slagging and fouling problems. In fluidized bed technologies, high alkali content can also lead to bed agglomeration. Figure 5-2 shows boiler slagging caused by the combustion of urban tree trimmings, a relatively low alkali fuel. To remove the sticky material from the boiler surfaces, it is required to perform soot blowing, implement operational procedures such as slag shedding, or have regularly scheduled outages to manually clean the unit. While none of these factors are critical flaws with regard to technical feasibility, they do present significant maintenance and availability burdens that need to be accounted for. These concerns can be substantially reduced if the potential for alkali deposition is properly considered during boiler design.

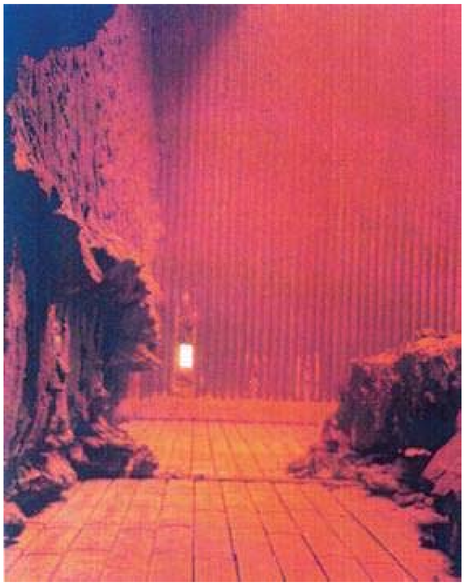

**Figure 5-2.**
**Boiler Slagging After Operating for 4 Days on Urban Tree Trimmings (Source: T.R. Miles).**

The problems associated with alkali materials in biomass vary widely between different biomass fuels. To a certain extent, slagging potential can be determined by analysis of fuel properties. However, the slagging tendency of a particular fuel cannot be predicted from fuel properties alone. Boiler design and operating conditions (especially temperature) have a large impact on the nature of deposits. Gasification of high alkali fuels and subsequent combustion of the gas in the boiler may reduce ash deposition. The success of this approach depends on maintaining gasification temperatures below combustion temperatures. Temperatures of 1,400° F and below have been shown to significantly reduce deposition.

One alternative that can be considered, particularly for fluidized bed conversion technologies, is the addition of limestone or other additives (such as magnesium oxide) to the fuel feed. The limestone reduces agglomeration in the fluidized bed.

High moisture content in biomass can reduce efficiency of combustion processes and may necessitate the need for supplemental fuel. The heating value of a biomass fuel is inversely proportional to its moisture content. In addition, boiler efficiency is negatively impacted by high moisture fuels. Fuel that is too wet may not burn. Biomass with a moisture content of up to 65 percent by weight can be burned in some combustion technologies while maintaining stable combustion without the use of a supplemental fuel. If the moisture content is higher than 65 percent, the fuel can still be burned, provided supplemental fuel is burned or some other process is used to recover exhaust heat for air or fuel preheating.

High chlorine content in some biomass fuels can lead to high temperature corrosion. Most wood-fueled power plants have outputs of less than 50-MWe. Large biomass combustion plants routinely operate with steam conditions of 1,250 psig and 900° F, and some plants operate with steam temperatures of 950° F. However, if the fuel contains significant amounts of chlorine (i.e., greater than 0.1 percent), steam temperatures should be limited to less than 800° F, to minimize corrosion of reactor surfaces.

Finally, the ash of some biomass fuels is also highly abrasive, which can lead to erosion of boiler and material handling surfaces.

### Biomass Fired BFB Combustion Concerns

In general, plant owners and operators have raised numerous concerns about negative impacts of biomass firing on plant operations. The concerns include the following:

- There are concerns that biomass firing will result in relatively high operations and maintenance costs (on a $/MWh basis). These concerns are attributed to the potential for increased boiler fouling/slagging due to the high alkali in biomass ash. It should be noted that this fouling/slagging concern is primarily associated with the combustion of fast growing biomass, such as switchgrass, rather than clean woody biomass.
- The material handling system is a significant part of the biomass fired facility. The low bulk density of the biomass, combined with a lower heating value, would result in a large and complex material handling system. On a volume basis, the woodyard for a 100-MW biomass facility would roughly equate to a 1,000-MW coal fired facility. Redundancy and design margins are required to insure a continuous fuel feed to the boiler since there is typically no back-up fuel. In addition, the fuel feed into the furnace and the distribution on the bed is critical to efficient firing and controlled emissions.
- For units employing Selective Catalytic Reduction (SCR) systems for control of $NO_x$ emissions, there is potential for increased SCR catalyst degradation due to catalyst poisoning and pluggage from constituents of biomass ash. There is a lack of consensus among catalyst suppliers regarding the extent of this concern. It is recommended that the supplier of the SCR catalyst be consulted during the design process once the site specific ultimate fuel and ash analysis is available.
- Biomass-fired boilers will be regulated by the pending Industrial Boiler MACT standards rather than Utility MACT standards. The final version of these standards may require more stringent control measures, potentially including oxidation catalyst for CO control, activated carbon injection for mercury control and dioxin/furan control, and sorbent injection for HCl control. The oxidation catalyst may experience similar poisoning and pluggage as the SCR catalyst described above. If a source is able to remain an area (minor) source of Hazardous Air Pollutants (HAPs), it could avoid major source MACT standards and rather be subject to area source standards which limit only PM and CO emissions. Costs for these more stringent controls are not included in this study.

### Biomass Fired BFB Combustion Benefits and Barriers

There are both benefits and barriers associated with selecting biomass as the primary fuel for a greenfield BFB based facility. Without reiterating the technical pros and cons discussed elsewhere, these can be summarized as follows.

Compared to coal, biomass fuels are generally less dense, have lower energy content, and are more difficult to handle. With some exceptions, these qualities generally mean that biomass fuel is disadvantaged economically compared to fossil fuels. Positive and negative aspects of biomass fuels, relative to coal, are summarized in Table 5-3.

**Table 5-3**
**Biomass Compared to Coal**

| Biomass Negatives | Biomass Positives |
|---|---|
| • Lower Heating Value<br>• Lower Density<br>• More Variability<br>• More Difficult to Handle<br>• Can Be High in Moisture Content<br>• More Geographically Disperse<br>• Limited Fuel Market<br>• Potential for Elevated Alkali Content | • Lower Sulfur, Heavy Metals, and Other Pollutants<br>• Potentially Lower and More Stable Cost<br>• Generally Low Ash Content<br>• Renewable Energy<br>• “Green” Image<br>• Incentives May Be Available<br>• Reduced Greenhouse Gas Emissions<br>• Local Economic Development Benefits |

Environmental benefits can help make biomass an economically competitive fuel. Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation option. While carbon dioxide ($CO_2$) is emitted during biomass combustion, an equal amount of $CO_2$ is absorbed from the atmosphere during the biomass growth phase. Thus, biomass fuels “recycle” atmospheric carbon, minimizing its global warming impact. In addition, biomass fuels contain little sulfur compared to coal, and therefore, produce less sulfur dioxide ($SO_2$). Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead.

Environmental issues also affect biomass resource collection. Several states impose specific criteria on biomass resources for them to be classified as renewable energy sources. A key concern is sustainability of the feedstock. Projects relying on forestry or agricultural products must be careful to ensure that fuel harvesting and collection practices are sustainable and provide a net benefit to the environment. Many biomass projects target utilization of biomass waste material for energy production, saving valuable landfill space.

The dispersed nature of the feedstock and the large quantities of fuel required has typically limited the capacity of biomass plants to less than 50-MW. Biomass plants commonly have lower efficiencies than modern coal plants due in part to this smaller scale, but also due to the higher moisture content of the biomass fuel compared to coal. The recent trend toward larger biomass plants in the 100-MW range is an attempt to take advantage of the economies of scale.

Biomass is typically more expensive than coal. Prices for biomass fuels vary widely depending on the source. Some fuels are considered wastes and may be available for power generation at no cost. In some cases, accepting biomass as a fuel may result in a small revenue stream for the facility (for MSW burners, tipping fees are the primary revenue source). On the other hand, premiums may be paid for fuels from dedicated energy crops (including switchgrass), or when fuel supplies are limited. Unlike fossil fuels, it has historically not been economical to transport biomass fuels over long distances (greater than 100 miles) due to their low energy density. However, in Europe, high fossil fuel prices and the value of $CO_2$ have led to the import of biomass from very distant locations, including sources in the United States and other foreign countries.

### *Market and Experience with Biomass Fired BFB Combustion*

There is a wide variety of existing domestic woody biomass fired BFB plants below 50-MW. These plants have established that the BFB technology is well suited for small scale woody biomass firing.

A number of utility-based, greenfield, woody biomass fired BFB projects in the 50- to 100-MW range are currently in the design stage in the United States. Several have been issued a final air permit, and at least one is under construction. A representative list of facilities is provided in Table 5-4.

In Europe and Asia, there are small, stoker boiler plants with slagging superheaters that are firing 100 percent straw or other agricultural waste type materials.

Based on communications with steam generator suppliers, there is no commercial experience firing 100 percent switchgrass in BFB boilers. There are a few documented cases of cofiring switchgrass with coal in existing PC fired boilers, but the percentage of switchgrass is very low. The steam generator suppliers speculate that cofiring switchgrass with woody biomass in a BFB may be feasible, with the switchgrass contribution not more than 20 percent.

Firing of switchgrass in gasifiers or in stoker boilers is not considered relevant in this study.

**Table 5-4**
**Summary of Woody Biomass Facilities**

| Facility | Capacity, MW | Location | Primary Fuel | Project Status |
|---|---|---|---|---|
| Schiller Station PSNH | 50 | New Hampshire | Wood chips | COD December 2006 |
| Nacogdoches, Southern Company | 100 | Texas | Wood residues | Under construction. COD summer 2010 |
| Warren County, Oglethorpe | 100 | Georgia | Woody Biomass | Air permit received, on hold pending IB MACT |
| Yellow Pine, Gen Power | 110 | Georgia | Woodwaste from timber harvesting | Currently stalled in development |
| Gainesville Renewable Energy Center | 100 | Florida | Forest residue, wood processing residue, municipal wood waste | Draft air permit issued July 2010. COD in late 2013 |
| Florida Biomass Energy | 60 | Florida | Clean woody biomass | Final air permit issued June 2010 |
| Hamilton County, Adage | 50 | Florida | Clean woody biomass | Start construction in 2010. COD in mid 2012 |
| Greenway, Roll Cast | 50 | Georgia | Forest residue, mill residue, clean urban wood waste | Start construction in 2010. COD mid 2012 |

## Impacts of Biomass Fired BFB Combustion on Air Quality Control Systems

Under Prevention of Significant Deterioration (PSD) regulations, stationary emission sources are classified as minor or major sources of emissions. For those areas in attainment with National Ambient Air Quality Standards (assumed for all scenarios except California which may be nonattainment), biomass-fired facilities are considered major sources if the facility has the potential to emit more than 250 tons per year (tpy) of one of the following criteria pollutants: nitrogen oxides (NOx), carbon monoxide (CO), sulfur oxides (SOx), volatile organic compounds (VOC), and particulate matter (PM/PM10). Those facilities deemed major sources are subject to major source PSD review. Major sources must employ Best Available Control Technologies (BACT) to limit their emissions and conduct ambient air quality analyses, including dispersion modeling. The PSD permitting process increases the time and effort required to obtain air construction permits, and compliance with BACT requirements typically results in more stringent emission limits for the facility.

Small-scale biomass facilities with capacities less than 40-MW can typically limit emissions to less than 250 tpy for each criteria pollutant. With conventional control technologies for the reduction of NOx (i.e., selective non-catalytic reduction, or SNCR, technology) and particulates (i.e., either fabric filters or electrostatic precipitators), these facilities can typically avoid PSD requirements. However, for facilities with capacities of 50-MW, limiting emissions to less than 250 tons/yr for each criteria pollutant, is not cost-effective as the emission rates to achieve minor source status (on a lb/MBtu basis) are more stringent than those required by BACT review. These facilities will likely be subject to major source PSD review. The option would be to limit the number of operating hours per year to stay below the emission threshold. This strategy is acceptable for dispatchable assets but is not practical for units such as biomass-fired facilities, which are expected to operate as baseload units. It is assumed that limits to hours of operation for biomass facilities are not economically viable.

### *100-MW Scenario*

The 100-MW woody biomass fired facility will be classified as a PSD major source, thus requiring the full BACT analysis and dispersion modeling. Typical air quality control systems would include SNCR for NOx controls, sorbent duct injection for $SO_2$ control and a pulse jet fabric filter baghouse for particulate control. The California scenarios will require an SCR. Existing biomass facilities do not typically employ CO controls other than combustion controls (i.e., control of furnace temperatures and excess air flows).

The overall permitting schedule would be 12 to18 months.

Ranges of likely air emission permit limits for a 100-MW biomass facility are listed in Table 5-5.

### *50-MW Scenarios*

Typically, air quality control systems for 50-MW biomass facilities include SNCR for NOx controls and a fabric filter baghouse for particulate control. The California scenarios will require an SCR. As with the 100-MW plant, CO controls are based on combustion controls (i.e., control of furnace temperatures and excess air flows). Depending on the location of the facility and the fuel properties of the biomass fuel fired, sorbent duct injection systems may be required to limit sulfur emissions.

The overall permitting schedule for the 50-MW scenarios would be approximately 6 to 8 months if the facility is a minor source and 12 to18 months if considered as a major PSD source.

Ranges of likely air emission permit limits for a 50-MW biomass facility are listed in Table 5-6.

### *California Scenario AQCS*

The 50- or 100-MW woody biomass facility sited in California will require a BACT analysis regardless of triggering PSD. Since the majority of the state is nonattainment for ozone, the BACT will actually equate to a LAER analysis. BACT for NOx will most likely be SCR (assuming it is technically feasible) since it will provide a higher removal efficiency. The recent woody biomass projects in Florida have been permitted with an SCR, which sets the precedent. The cost for the SCR has been included for the California based scenarios.

**Table 5-5**
**Likely Air Permit Limits for 100-MW Biomass Plant**

| Criteria Pollutant [a] | Permitted Emission Limit [b] (lb/MBtu) |
|---|---|
| Nitrogen Oxides ($NO_x$) | 0.07 - 0.10 |
| Carbon Monoxide (CO) | 0.08 – 0.10 |
| Sulfur Oxides ($SO_x$) | 0.02 – 0.05 |
| Particulate Matter ($PM/PM_{10}$) | 0.018 [c] |

Notes:

[a]Emission limits are determined by state regulatory agencies and vary from state to state. Permits for existing biomass facilities vary in which pollutants are specifically regulated and in the limit value.

[b]Project site is assumed to be located in a county in attainment with NAAQS, except California.

[c]Particulate matter emission limits include front-half (i.e., filterable) and back-half (i.e., condensable) particulate emissions.

**Table 5-6**
**Likely Air Permit Limits for 50-MW Biomass Plant**

| Criteria Pollutant [a] | Permitted Emission Limit [b] (lb/MBtu) |
|---|---|
| Nitrogen Oxides ($NO_x$) | 0.02 – 0.12 |
| Carbon Monoxide (CO) | 0.10 – 0.20 |
| Sulfur Oxides ($SO_x$) | 0.04 – 0.08 |
| Particulate Matter ($PM/PM_{10}$) | 0.015 – 0.035 [c] |

Notes:

[a]Emission limits are determined by state regulatory agencies and vary from state to state. Permits for existing biomass facilities vary in which pollutants are specifically regulated and in the limit value.

[b]Project site is assumed to be located in a county in attainment with NAAQS, except California.

[c]Particulate matter emission limits include front-half (i.e., filterable) and back-half (i.e., condensable) particulate emissions.

It is feasible that BACT for CO may require the use of an oxidation catalyst. However, it also may be possible to comply with the Boiler MACT without the catalyst. For this study, the oxidation catalyst has not been included but recognizes that further, more detailed analysis will be required for verification once the specific site is selected.

Three additional requirements that should be considered are summarized below.

- *<u>Offsets</u>: The California permitting process could add the need to obtain offset/emission reduction credits for pollutants like NOx, SO2, PM, VOC and CO depending on where in California the source is locating. Offsets can be difficult and costly to obtain and should be given consideration early in the permitting process. The costs for these offsets are not included in the project costs summarized in this report.*
- *<u>Siting Process</u>: The Legislature has given the California Energy Commission (CEC) the statutory authority to license thermal power plants of 50 megawatts or greater along with the transmission lines, fuel supply lines, and related facilities to serve them. The CEC Application for Certification (AFC) process is equivalent to a full NEPA-type review (called CEQA in California) with numerous environmental reports and studies that must be completed prior to receiving the Commission's final decision. The application preparation and review time is a long lead time item easily taking over a year.*
- *<u>Green House Gas</u>: California also has GHG emission performance standards (EPS). Power plants using only biomass fuels that would otherwise be disposed of utilizing open burning, forest accumulation, spreading, composting, uncontrolled landfill, or landfill utilizing gas collection with flare or engine are determined to be compliant with the EPS. Biomass includes but is not limited to agricultural waste, wood waste, and landfill gas.*

## Biomass Fired BFB Combustion Material Handling Systems

### *Woody Biomass Material Handling*

A complete woody biomass receiving, handling, storage and reclaim system for the 50 and 100-MW BFB facilities is required.

The biomass material handling system is based on woody biomass with a design moisture content of 45 percent as-received and worst case of 50 percent moisture. The fuel may be dried naturally in onsite storage but this is assumed to be minimal. The biomass handling system capacity is designed for worst-case conditions of 50 percent moisture.

Upon arriving at the facility, each truck is weighed at the receiving scale, provided a ticket from an automated dispenser, and then proceeds to the unloading area. After unloading, the same process is repeated but in reverse. The exiting scale records the tare on the ticket, thereby determining the weight of the fuel delivered.

The relatively low heating value of wood chips and a longer dumping cycle time per truck dictates the need for four truck dump stations for the 50-MW facility. Conveyor belt scales are used to control biomass feed rates within the handling system, as well as to provide biomass consumption data for unit performance calculations.

It is assumed that arriving wood chips are chipped in the woods to the maximum as-received size of approximately 4 inches. Disc screens are employed on-site to reject any oversize material, which can be sized in hammermills or “hogs” to an acceptable size as required by the boiler supplier.

On-site storage is accomplished with linear or radial stacker / reclaimer systems. The minimum storage capacity is assumed to be 28 days operation at the rated boiler MCR while firing the worst case fuel. The site specific fuel supply study will finalize this on-site storage based on availability and proximity of the fuel.

The low bulk density of the biomass, combined with a lower heating value, results in relatively low capacity boiler feed bins (in the 1 hour range). As such, it is necessary to provide a biomass handling system that operates continuously to keep them filled. The feed conveyor to the boiler is assumed to be a variable-speed design.

Generally, wet dust suppression is utilized on incoming biomass unloading and stockout equipment. Wet methods are more effective than dry methods within large open areas (e.g., open truck dump hoppers or stocking out through open air). Dust dry collection is utilized in other areas (following reclaim of biomass fuels) because it is undesirable to add moisture and because capture airflow rates can be smaller in smaller chutes and other equipment.

A self-cleaning magnetic separator is utilized on belt conveyors for ferrous tramp metal removal. In addition, a metal detector is used on belt conveyors used to detect and mark ferrous and non-ferrous metals and mark these items prior to manual removal.

As biomass dust is combustible and explosive, fire detection and/or suppression is utilized throughout the system.

#### Woody Biomass Material Handling Equipment

Table 5-7 lists the biomass material handling equipment required for the base case 50-MW unit (i.e., firing blended, undried woody biomass).

### *Switchgrass Material Handling*

A complete switchgrass receiving, handling, storage and reclaim system for the 50-MW BFB facility is required. The switchgrass handling system will be rated at 20 percent of the boiler MCR.

The system consists of one bale train and one process sizing train, rated at approximately 15 tons per hour (TPH). The sized switchgrass is blended with the woody biomass on the conveyor feeding the boiler metering bins. The woody biomass part of this system is as described above for the 100 percent woody biomass fired-facility. This system will be sufficiently sized so the facility has the capability of operating on 100 percent woody biomass if switchgrass is not available.

**Table 5-7**
**Woody Biomass Material Handling Equipment Listing**

| Description | Tag |
|---|---|
| Truck Scale | SCL-1A |
| Truck Scale | SCL-1B |
| Hydraulic Truck Dumper with Receiving Hopper | DMP-1A |
| Hydraulic Truck Dumper with Receiving Hopper | DMP-1B |
| Hydraulic Truck Dumper with Receiving Hopper | DMP-2A |
| Hydraulic Truck Dumper with Receiving Hopper | DMP-2B |
| Drag Chain Feeder | FDR-1A |
| Drag Chain Feeder | FDR-1B |
| Apron Feeder | FDR-2A |
| Apron Feeder | FDR-2B |
| Collecting Belt Conveyor | CVY-1A |
| Belt Conveyor Scale | SCL-2A |
| Collecting Belt Conveyor | CVY-1B |
| Belt Conveyor Scale | SCL-2B |
| Disc Screen (including Screening Tower) | SCN-1A |
| Disc Screen (including Screening Tower) | SCN-1B |
| Belt Conveyor | CVY-2A |
| Belt Conveyor | CVY-2B |
| Slewing Cleated Receiving Conveyor | CVY-3A |
| Slewing Cleated Receiving Conveyor | CVY-3B |
| Oversized Grinder | GRN-1 |
| Biomass Receiving Dust Wet Suppression System | |
| Stamler Feeder | FDR-3 |
| Belt Conveyor | CVY-4 |
| Belt Conveyor Scale | SCL-3 |
| Self-Cleaning Magnetic Separator | SEP-1 |
| Disc Screen (including Screening Tower) | SCN-2 |
| Dust Collector | DCO-1 |
| Belt Conveyor | CVY-5 |
| Belt Conveyor Scale | SCL-4 |
| Self-Cleaning Magnetic Separator | SEP-2 |
| Tramp Metal Detector | TMD-1 |
| Distribution Drag Chain Conveyor (including Transfer Tower) | CVY-6 |
| Overfill Return Belt Conveyor | CVY-7 |
| Belt Conveyor Scale | SCL-5 |
| Dust Collector | DCO-2 |
| Boiler Live Bottom Feed Bins | |

The biomass fuel is harvested into bales, which have approximate dimensions of 8 ft long x 4 ft wide x 3 ft high and weigh approximately 1000 pounds each. The bales are delivered to the site on flatbed trailers with approximately (30) bales on each. The bales are unloaded from trucks with a fast acting overhead bridge crane that can lift (10) bales at a time. The bales are either stacked in the storage building or immediately placed on the processing line. The Bridge Crane has weigh scales and moisture analyzers which are used to record the received quantities and moisture levels of the bales.

The stored bales are picked up with bridge crane (or potentially mobile equipment) and placed onto the Storage Receiving Building Drag Chain Pre-Feeders CVY 1 and Steel Top Conveyors CVY 2 then conveyed onto the process lines. The binding twine is cut automatically and retrieved from the bale by Destringers prior to the bales feeding into the Horizontal Grinder, GRN 1, which debale and size the biomass to 3 inch minus size.

The biomass is collected and conveyed by V-Cleat Rubber Conveyor CVY 3 to the Blending Chute and Conveyor feeding into the Woody Biomass Stream. The Inline Magnetic Separator collects all foreign metal objects captured during the sizing process. Preceding the Magnetic Separator is a Cleanup Fines Bin with live bottom screws to return loose or spilled material from housekeeping activities into the process stream. At the outlet of the Horizontal Grinders are stone traps where rocks or other heavy non-metallic objects are separated out of the material being sent to the boiler.

The Processing Building Process Dust Collector collects airborne biomass material from the transfer and other process points, while the heavier material continues down the conveying path. The Processing Building Process Dust Collector discharges into the processing line downstream of the Grinder discharge. The Processing Building (ambient air) Dust Collector (by others) also collects dust and also discharges into the processing line downstream of the Grinder discharge. Building Dust Collectors filter the air in the Storage Receiving Building processing areas and the Process Building.

### Switchgrass Material Handling Equipment

Table 5-8 lists the switchgrass material handling equipment required for the 50-MW unit scenario.

## Biomass Fired BFB Combustion Systems Siting

The siting for the biomass fired BFB Combustion facilities requires close proximity to a variety of commodities, utilities and services. Fuel supply, water supply and electrical interconnection may be the more critical items. Detailed studies are required to evaluative the availability of these services.

Based on the experience of the authors in both siting and detailed design of solid fuel power facilities, a minimum of 0.9 to 1.3 acres are required per megawatt of facility capacity. Therefore, a 50-MW plant would require a site roughly 45 to 65 acres in size. Site specific constraints, such as requirements for additional buffers for adjacent residential areas or increased fuel storage, may increase the required acreage. This land requirement would include areas designated for the following purposes:

- Power block and other major equipment
- Maintenance and operations buildings

**Table 5-8**
**Switchgrass Material Handling Equipment Listing**

| Description | Tag |
|---|---|
| Processing and Storage Bldg | Bldg 1 |
| Bridge Crane | CRN 1 |
| Mobile Bale Front Loader (optional) | LDR-1 |
| Dust Collection System for Storage Bldg Processing Area | DC-1 |
| Building Mechanical Ventilation | |
| Truck Air Sweep | |
| Drag Chain Pre-feeder | CVY-1 |
| Steel Top Conveyor | CVY-2 |
| Chain Conveyor Feeder GRN-1 In | CVR-1 |
| Destringer | DSR-1 |
| Horizontal Grinder | GRN-1 |
| Chain Conveyor Feeder GRN-1 Out | CVR-2 |
| Magnetic Separator | Mag 1 |
| Stone Trap | |
| V Cleat Rubber Belt | CVY-3 |
| Bin Cleanup Fines En Masse Conveyor | |
| Switchgrass/Wood Blend Conveyor and Chute | CVY-B |

- Fuel delivery and long-term fuel storage
- Access roads
- Construction lay-down and parking
- Drainage requirements
- Underground utilities
- Noise mitigation
- Buffer between plant and neighboring lands

Generally, the biomass handling system can be modified to fit the site. It is desirable to locate the biomass receiving and stockout system to minimize truck traffic through more populated or busy areas of the plant. The unloading systems and the disc screen / hog transfer building can be located as desired. Certain horizontal separation distances are required to attain the vertical heights needed (due to the maximum allowable incline of belt conveyors) for feeding the disc screen and the elevated boiler bins. The biomass stockout / reclaim system and the related biomass storage pile(s) or building(s) can be located as desired. A sufficient buffer should be maintained around the biomass storage pile to allow for a runoff collection ditch.

Based on experience of the authors with solid fuel power generation facilities employing Rankine power cycle systems and wet cooling methods (i.e., mechanical draft cooling towers), a 50-MW facility operating at average ambient conditions would require 1.1 to 1.3 million gallons per day (MGD). This water requirement would include:

- Makeup water for steam power cycle, including allowances for steam losses and blow-down
- Makeup water for circulating (cooling) water systems
- Service water
- Potable water

Of these requirements, makeup requirements for the circulating water systems are the largest quantity.

## Costs for Biomass Fired BFB Combustion

Capital and O&M cost estimates for the biomass fired BFB combustion scenarios considered in this study (see Table 5-9) have been developed. This section discusses the development of the cost estimates, identifies the assumptions used in the development of the estimates, and presents these cost estimates.

**Table 5-9**
**Summary of Biomass Fired BFB Combusion Base Case**

| Parameter | 50-MW Woody Biomass | 100-MW Woody Biomass | 50-MW Switchgrass / Wood |
|---|---|---|---|
| Net Capacity | 50-MW | 100-MW | 50-MW |
| Boiler Type | BFB | BFB | BFB |
| Capacity Factor | 85% | 85% | 85% |
| Biomass Heat Input | 100% | 100% | 20%Switchgrass<br>80% Woody Biomass |
| *Biomass Properties* | | | |
| Fuel Type | Undried blended biomass | Undried blended biomass | Woody biomass blended w/ as received switchgrass |
| Higher Heating Value (dry) | 8,670 Btu/lb | 8,670 Btu/lb | 7,304 Btu/lb Switchgrass |
| Moisture Content | 45% | 45% | 15% Switchgrass |

### *Total Capital Requirement Estimates*

Similar to repowering projects and biomass co-firing, the biomass fired BFB combustion facility capital cost requirements are primarily dependent upon the boiler combustion constraints selected. Other project parameters affecting the capital cost include the following:

- Boiler technology (i.e., BFB and AQCS systems).
- Scale of project (i.e., capacity, biomass flow rates and material handling strategies).
- Biomass storage strategy.
- Conveyor distances.
- Required infrastructure (i.e., utilities, buildings, plant roadways).

Capital cost estimates for the three biomass fired BFB combustion scenarios were developed that assume a turnkey engineering, procurement, and construction (EPC) project execution strategy. Capital costs for these projects are divided into two categories: direct costs and indirect costs. Direct costs include the costs associated with the purchase and installation of major equipment and balance-of-plant (BOP) equipment. Capital cost estimates for major equipment items are based upon vendor quotations. Note that the AQCS equipment is typically provided by the boiler supplier, so those AQCS equipment costs are included in the boiler cost totals rather than listed separately. The capital costs associated with Powerblock and BOP equipment and construction were estimated based on past experience with similar projects. Assumptions apply to both the 50-MW and 100-MW facilities

Indirect costs include construction indirects, engineering, construction management, and contingency. Allowances for indirect costs were included in these estimates. The specific items included as construction indirect costs include the following:

- Construction supervision.
- Purchase of small tools and consumables.
- Site services.
- Construction safety program (including development and compliance).
- Installation of temporary facilities.
- Installation of temporary utilities.
- Rental of construction equipment.
- Heavy haul of construction materials and equipment.
- Preoperational startup and testing.
- Insurance (including builder’s risk and general liability).

- Construction permits (excluding Construction Air Permit).
- Performance bond.
- EPC contractor profit.

An allowance for Owner's Costs (i.e., due diligence, permitting, legal and other development costs) is included. This allowance is calculated as 10 percent of the Total Plant Cost.

Site specific cost estimated differences are summarized as follows:

- The Georgia site will be open shop. The Midwest and California sites will be union shop.
- In Georgia and California, the boiler building will not be enclosed and will be located outdoors under a roof. The boiler building will be enclosed in the Midwest.
- Cycle heat rejection will be accomplished with a water-cooled condenser and a mechanical draft cooling tower in Georgia and the Midwest. An air cooled condenser is assumed for California.
- NOx control for the southeast and Midwest scenarios will be SNCR. The California based scenarios will include SCR. A CO oxidation catalyst is not included.
- The 2006 International Building Code (IBC) applies. Estimates are based on an assumed design for wind resistance will be based on a basic wind speed (3 second gust) of 90 mph, Exposure C, and an importance factor of 1.15. For each site, structures will be designed with adequate strength to withstand forces and displacements based on mapped maximum considered earthquake response accelerations, as determined in the IBC.
- All foundation elements are assumed to be shallow (spread footings, mats, and slabs), and bearing capacity governs the foundation size and type. Foundation depth is adjusted for the Midwest site.
- In all cases, water from the local municipality will be used for service water, fire water, cycle makeup treatment supply, and potable water.

### *Operation and Maintenance Cost Estimates*

Fixed and variable operations and maintenance (O&M) costs for the biomass fired BFB combustion scenario are provided. Fixed O&M costs consist of wages and wage-related overheads for the permanent plant staff, routine equipment maintenance, and other fees. Variable O&M costs include costs associated with equipment outage maintenance, catalyst/reagents, chemicals, municipal water, and other consumables. Fuel costs are determined separately and are not included in either fixed or variable O&M costs.

The assumptions used in developing the fixed and variable O&M costs for the biomass BFB cases are as follows:

- The boiler is a bubbling fluidized bed for all cases.
- The woody biomass fuel is raw, undried, with a 45% moisture content that will make up 100% of the heat input to the boiler.
- Estimated gross capacity factor is 85%.
- Forced outage rate is 4%.
- Net plant heat rate is as shown in Table 5-2.
- Plant staff average unburdened wage rate is $56,590 per year.
- The burden rate is 40%.
- Staff supplies and materials are estimated to be 5% of staff salary.
- Estimated employee training cost and incentive pay/bonuses are included.
- Routine maintenance costs are estimated based on experience with similar facilities and manufacturer input.
- Contract services include costs for services not directly related to power production.
- Insurance and property taxes are not included.
- The variable O&M analysis is based on a repeating maintenance schedule over the life of the plant.
- Variable O&M costs associated with the steam turbine are estimated based on a typical overhaul schedule (including both minor and major overhauls).
- Frequency of boiler overhaul is every year. The switchgrass-fired scenario may require more frequent cleaning of the heat transfer surfaces.
- Frequency of turbine and generator major inspection is every 6 years.
- Steam turbine, generator, boiler, and other balance of plant maintenance costs are based on Black & Veatch experience and vendor data recommendations.
- SCR costs are included for the California scenarios. SNCR costs are included for Southeastern and Midwest scenarios.
- Water treatment costs are included for water make-up and demineralized water where needed.
- Demineralized water treatment costs are $5 per 1,000 gallons.
- City water cost is $1 per 1,000 gallons.
- Ash disposal cost is $6 per ton.

- Anhydrous ammonia cost is $800 per ton.
- Aqueous ammonia cost is $315 per ton.
- The O&M analysis was completed in 3rd-quarter 2010 US dollars.

## *Biomass Fired BFB Combustion Cost Estimate Results*

**Table 5-10 through**

**Table 5-12 summarize the cost estimate characteristics and overall results for the biomass-fired BFB cases (assuming location in the Southeastern United States). The cost estimates shown in Table 5-10 through**

Table 5-12 assume that the plants are located in the southeastern United States. The total costs for all scenarios, including the Midwest and West cases, are summarized in Table B-1 and Table B-2. Table B-3 thru Table B-9 summarize the capital costs by category for each scenario.

## *Levelized Cost of Electricity*

The levelized cost of electricity (LCOE) considers the levelized fixed charge on total capital requirement, fixed and variable O&M and fuel cost. It represents the present value of the total life-cycle costs over the 30-year life of the project, divided by the total annual MWh generated at the facility. LCOE is calculated in units of dollars per megawatt hour ($/MWh) in constant 3rd-quarter 2010 dollars.

### Levelized Fixed Charge Rate

The levelized fixed charge rate (LCFR) is the factor applied to the Total Capital Requirement to yield the annual fixed charge on the capital investment. For an investor-owned utility, the typical components of the annual fixed charge include depreciation, interest on debt, return on equity, income and property taxes, insurance, and other administrative costs. For the economic assumptions presented in Table 2-8 and 30-year project life, the 30-year LFCR is estimated to be 7.42% per year with the consideration of the ITC, and 6.40% with the ITC. The fixed charge components of cash flow for the biomass-fired BFB cases are summarized in Table 5-14.

### Levelized Cost of Electricity Estimates

Table 5-15 through Table 5-17 present the LCOE for the primary biomass-fired BFB cases. The calculations assume that facilities are located in the southeastern United States. Levelized costs of electiricy were estimated for two scenarios, one with and without the 30% Investment Tax Credit. Relative to repowering and co-firing cases, it is more likely that standalone biomass-fired BFB projects would be eligible for the ITC, provided that the applying entities (i.e., project owners) are eligible and the project commences operation prior to the expiration of the ITC.

**Table 5-10**
**50 MW Woody Biomass-Fired BFB Characteristics and Total Capital Requirement Estimate – Southeast US (3rd-Quarter 2010$)**

| Parameter | 50 MW Woody Biomass BFB | | |
|---|---|---|---|
| **Rated Capacity** | | | |
| Plant size (units x unit size), MW | 1 x 50 MW | | |
| Biomass fuel feed system | Mechanical | | |
| Fraction of plant output from biomass, % | 100 | | |
| **Physical Plant** | | | |
| Unit life, years | 30 | | |
| **Scheduling** | | | |
| Preconst., License & Design Time, Years | 1 | | |
| Idealized Plant Construction Time, Years | 2.5 | | |
| Hypothetical In-Service Date | January 2011 | | |
| **Total Capital Requirement, $/kW** | **($1,000)** | **($/kW)** | **(%)** |
| *Major Equipment Costs* | | | |
| Steam Generator System | $67,450 | $1,350 | 27% |
| Turbine Island System | $18,600 | $370 | 8% |
| Biomass Handling | $17,500 | $350 | 7% |
| Environmental Controls | $5,400 | $110 | 2% |
| **Total Major Equipment Costs** | **$108,950** | **$2,180** | **44%** |
| *Direct Balance of Plant Costs* | | | |
| BOP Facilities | $41,750 | $840 | 17% |
| General Facilities & Site Specific | $18,850 | $380 | 8% |
| **Total Direct Balance of Plant Costs** | **$60,600** | **$1,220** | **25%** |
| *Indirect Balance of Plant Costs* | | | |
| Engineering Fee & Construction Man. | $66,550 | $1,330 | 27% |
| Process Contingency | $1,600 | $30 | 3% |
| Project Contingency | $8,500 | $170 | 1% |
| **Total Indirect Balance of Plant Costs** | **$76,650** | **$1,530** | **31%** |
| *Total Costs* | | | |
| **Total Plant Costs** | **$246,200** | **$4,930** | **100%** |
| AFUDC (Interest during construction) | $8,150 | $160 | -- |
| **Total Plant Investment (incl. AFUDC)** | **$254,350** | **$5,090** | **--** |
| Total Owner's Cost, $/kW | $25,500 | $510 | -- |
| **Total Capital Requirement** | **$279,800** | **$5,590** | **--** |
| **Operation and Maintenance Costs, $/kW** | | | |
| Fixed, $\$/kW_{biomass}$-yr | 113 | | |
| Variable, $\$/MWh_{biomass}$ | 5.80 | | |
| **Performance/Unit Availability** | | | |
| Net Plant Heat Rate, Btu/kWh (HHV) | 13,964 | | |
| Equivalent Planned Outage Rate, % | 4 | | |
| Duty Cycle | Baseload | | |
| Minimum Load, % | 40 | | |
| **Emission Rates** | | | |
| $NO_x$, lb/MBtu | 0.10 – 0.12 | | |
| $SO_x$, lb/MBtu | 0.04 – 0.08 | | |
| Particulates, total, lb/MBtu | 0.015 – 0.035 | | |

**Table 5-10 (continued)**
**50 MW Woody Biomass-Fired BFB Characteristics and Total Capital Requirement Estimate – Southeast US (3rd-Quarter 2010$)**

| **Confidence and Accuracy Rating** | |
|---|---|
| Technology Development Rating | Commercial |
| Design & Cost Estimate Rating | Simplified |

**Table 5-11**
**100 MW Woody Biomass-Fired BFB Characteristics and Total Capital Requirement Estimate – Southeast US (3rd-Quarter 2010$)**

| **Parameter** | **100 MW Woody Biomass BFB** | | |
|---|---|---|---|
| **Rated Capacity** | | | |
| Plant size (units x unit size), MW | 1 x 100 MW | | |
| Biomass fuel feed system | Mechanical | | |
| Fraction of plant output from biomass, % | 100 | | |
| **Physical Plant** | | | |
| Unit life, years | 30 | | |
| **Scheduling** | | | |
| Preconst., License & Design Time, Years | 1.5 | | |
| Idealized Plant Construction Time, Years | 3 | | |
| Hypothetical In-Service Date | January 2011 | | |
| **Total Capital Requirement, $/kW** | **($1,000)** | **($/kW)** | **(%)** |
| *Major Equipment Costs* | | | |
| Steam Generator System | $104,500 | $1,050 | 30% |
| Turbine Island System | $29,500 | $300 | 8% |
| Biomass Handling | $27,100 | $270 | 8% |
| Environmental Controls | $7,300 | $70 | 2% |
| **Total Major Equipment Costs** | **$168,400** | **$1,690** | **48%** |
| *Direct Balance of Plant Costs* | | | |
| BOP Facilities | $54,600 | $550 | 15% |
| General Facilities & Site Specific | $25,600 | $260 | 7% |
| **Total Direct Balance of Plant Costs** | **$80,200** | **$810** | **23%** |
| *Indirect Balance of Plant Costs* | | | |
| Engineering Fee & Construction Man. | $89,200 | $890 | 25% |
| Process Contingency | $2,500 | $30 | 1% |
| Project Contingency | $12,400 | $120 | 4% |
| **Total Indirect Balance of Plant Costs** | **$104,100** | **$1,040** | **30%** |
| *Total Costs* | | | |
| **Total Plant Costs** | **$352,700** | **$3,530** | **100%** |
| AFUDC (Interest during construction) | $15,700 | $160 | -- |
| **Total Plant Investment (incl. AFUDC)** | **$368,400** | **$3,680** | **--** |
| Total Owner's Cost, $/kW | $36,800 | $370 | -- |
| **Total Capital Requirement** | **$405,200** | **$4,050** | **--** |

**Table 5-11 (continued)**
**100 MW Woody Biomass-Fired BFB Characteristics and Total Capital Requirement Estimate – Southeast US (3rd-Quarter 2010$)**

| | |
|---|---|
| **Operation and Maintenance Costs, $/kW** | |
| Fixed O&M, $/kW-yr | 63 |
| Variable O&M, $/MWh | 5.10 |
| **Performance/Unit Availability** | |
| Net Plant Heat Rate, Btu/kWh (HHV) | 12,894 |
| Equivalent Planned Outage Rate, % | 4 |
| Duty Cycle | Baseload |
| Minimum Load, % | 40 |
| **Emission Rates** | |
| $NO_x$, lb/MBtu | 0.1 |
| $SO_x$, lb/MBtu | 0.01 |
| Particulates, total, lb/MBtu | 0.018 |
| **Confidence and Accuracy Rating** | |
| Technology Development Rating | Commercial |
| Design & Cost Estimate Rating | Simplified |

**Table 5-12**
**50 MW Switchgrass/Wood-Fired BFB Characteristics and Total Capital Requirement Estimate – Southeast US (3rd-Quarter 2010$)**

| **Parameter** | **50 MW Switchgrass BFB** | | |
|---|---|---|---|
| **Rated Capacity** | | | |
| Plant size (units x unit size), MW | 1 x 50 MW | | |
| Biomass fuel feed system | Mechanical | | |
| Fraction of plant output from biomass, % | 80/20 Wood/Switchgrass | | |
| **Physical Plant** | | | |
| Unit life, years | 30 | | |
| **Scheduling** | | | |
| Preconst., License & Design Time, Years | 1 | | |
| Idealized Plant Construction Time, Years | 2.5 | | |
| Hypothetical In-Service Date[1] | January 2011 | | |
| **Total Capital Requirement, $/kW** | **($1,000)** | **($/kW)** | **(%)** |
| *Major Equipment Costs* | | | |
| Steam Generator System | $67,450 | $1,350 | 26% |
| Turbine Island System | $18,200 | $370 | 7% |
| Biomass Handling | $23,850 | $480 | 9% |
| Environmental Controls | $5,400 | $110 | 2% |
| **Total Major Equipment Costs** | **$115,300** | **$2,310** | **45%** |
| *Direct Balance of Plant Costs* | | | |
| BOP Facilities | $41,950 | $840 | 16% |
| General Facilities & Site Specific | $20,950 | $420 | 8% |
| **Total Direct Balance of Plant Costs** | **$62,900** | **$1,260** | **25%** |

**Table 5-13 (continued)**
**50 MW Switchgrass/Wood-Fired BFB Characteristics and Total Capital Requirement Estimate – Southeast US (3rd-Quarter 2010$)**

| | | | |
|---|---|---|---|
| *Indirect Balance of Plant Costs* | | | |
| Engineering Fee & Construction Man. | $66,800 | $1,340 | 26% |
| Process Contingency | $1,600 | $30 | 1% |
| Project Contingency | $8,900 | $180 | 3% |
| **Total Indirect Balance of Plant Costs** | **$77,300** | **$1,550** | **30%** |
| *Total Costs* | | | |
| **Total Plant Costs** | **$255,500** | **$5,120** | **100%** |
| AFUDC (Interest during construction) | $8,400 | $170 | -- |
| Total Plant Investment (incl. AFUDC) | **$263,900** | **$5,278** | **--** |
| Total Owner's Cost, $/kW | $26,400 | $530 | -- |
| **Total Capital Requirement** | **$290,300** | **$5,810** | **--** |
| **Operation and Maintenance Costs** | | | |
| Fixed O&M, $/kW-yr | 114 | | |
| Variable O&M, $/kW-yr | 5.85 | | |
| **Performance/Unit Availability** | | | |
| Net Plant Heat Rate, Btu/kWh (HHV) | 14,119 | | |
| Equivalent Planned Outage Rate, % | 4 | | |
| Duty Cycle | Baseload | | |
| Minimum Load, % | 40 | | |
| **Emission Rates** | | | |
| $NO_x$, lb/MBtu | 0.10 – 0.12 | | |
| $SO_x$, lb/MBtu | 0.04 – 0.08 | | |
| Particulates, total, lb/MBtu | 0.015 – 0.035 | | |
| **Confidence and Accuracy Rating** | | | |
| Technology Development Rating | Developing | | |
| Design & Cost Estimate Rating | Simplified | | |

**Table 5-14**
**Biomass-fired BFB Levelized Fixed Capital Charge Component (3rd-Quarter 2010 $)**

| Scenario | Levelized Fixed Charge Rate | Fixed Capital Charge Component of Cash Flow[1] |
|---|---|---|
| 50 MW Woody Biomass-Fired BFB with ITC | 6.40% | $250/kW-yr |
| 50 MW Woody Biomass-Fired BFB without ITC | 7.42% | $415/kW-yr |
| 100 MW Woody Biomass-Fired BFB with ITC | 6.40% | $181/kW-yr |
| 100 MW Woody Biomass-Fired BFB without ITC | 7.42% | $300/kW-yr |
| 50 MW Switchgrass-fired BFB with ITC | 6.40% | $260/kW-yr |
| 50 MW Switchgrass-fired BFB without ITC | 7.42% | $431/kW-yr |

Notes:

[1] Fixed Capital Charge Component of Cash Flow calculated by multiplying the LFCR by the Total Capital Requirement. The components of the annual fixed charge include amortization, depreciation, return on equity, income and property taxes, insurance, and other administrative costs. This value does not include charges associated with fixed O&M costs.

**Table 5-15**
**50-MW Woody Biomass BFB Levelized Cost of Electricity Estimates (3rd-Quarter 2010 $)**

| Cost | Base Case | Sensitivity Case 1[1] | Sensitivity Case 2[1] |
|---|---|---|---|
| **Biomass Fuel Cost, $/MBtu** | 3.55 | 2.55 | 4.55 |
| | | | |
| **Levelized Cost of Electricity[2] With ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 15 | 15 | 15 |
| Variable O&M Component of LCOE ($/MWh) | 6 | 6 | 6 |
| Fuel Component of LCOE ($/MWh) | 50 | 36 | 64 |
| Capital Charge Component of LCOE ($/MWh) | 34 | 34 | 34 |
| **Total[3] ($/MWh)** | **104** | **90** | **118** |
| | | | |
| **Levelized Cost of Electricity[2] Without ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 15 | 15 | 15 |
| Variable O&M Component of LCOE ($/MWh) | 6 | 6 | 6 |
| Fuel Component of LCOE ($/MWh) | 50 | 36 | 64 |
| Capital Charge Component of LCOE ($/MWh) | 56 | 56 | 56 |
| **Total[3] ($/MWh)** | **126** | **112** | **140** |

Notes:

[1] Sensitivity Cases assume biomass fuel costs different than the base case, at $1/MBtu above and below the base cost of $3.55/MBtu.

[2] Estimate of LCOE assumes an 85% capacity factor, 30-year project life, and constant dollars.

[3] Sum of LCOE component values may not equal Total value due to rounding.

**Table 5-16**
**100-MW Woody Biomass BFB Levelized Cost of Electricity Estimates (3rd-Quarter 2010 $)**

| Cost | Base Case | Sensitivity Case 1* | Sensitivity Case 2* |
|---|---|---|---|
| **Biomass Fuel Cost, $/MBtu** | 3.55 | 2.55 | 4.55 |
| | | | |
| **Levelized Cost of Electricity[2] With ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 8 | 8 | 8 |
| Variable O&M Component of LCOE ($/MWh) | 5 | 5 | 5 |
| Fuel Component of LCOE ($/MWh) | 46 | 33 | 59 |
| Capital Charge Component of LCOE ($/MWh) | 24 | 24 | 24 |
| **Total[3] ($/MWh)** | **84** | **71** | **97** |
| | | | |
| **Levelized Cost of Electricity[2] Without ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 8 | 8 | 8 |
| Variable O&M Component of LCOE ($/MWh) | 5 | 5 | 5 |
| Fuel Component of LCOE ($/MWh) | 46 | 33 | 59 |
| Capital Charge Component of LCOE ($/MWh) | 40 | 40 | 40 |
| **Total[3] ($/MWh)** | **100** | **87** | **113** |

Notes:

[1] Sensitivity Cases assume biomass fuel costs different than the base case, at $1/MBtu above and below the base cost of $3.55/MBtu.

[2] Estimate of LCOE assumes an 85% capacity factor, 30-year project life, and constant dollars.

[3] Sum of LCOE component values may not equal Total value due to rounding.

**Table 5-17**
**50-MW Switchgrass/Wood BFB Levelized Cost of Electricity Estimates (3rd-Quarter 2010 $)**

| Cost | Base Case | Sensitivity Case 1* | Sensitivity Case 2* |
|---|---|---|---|
| **Biomass Fuel Cost ($/MBtu)** | 3.85 | 2.85 | 4.85 |
| **Switchgrass Fuel Cost ($/MBtu)** | 5.05 | 4.05 | 6.05 |
| | | | |
| **Levelized Cost of Electricity[2] With ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 15 | 15 | 15 |
| Variable O&M Component of LCOE ($/MWh) | 6 | 6 | 6 |
| Fuel Component of LCOE ($/MWh) | 54 | 40 | 68 |
| Capital Charge Component of LCOE ($/MWh) | 35 | 35 | 35 |
| **Total[3]** | **110** | **96** | **125** |
| | | | |
| **Levelized Cost of Electricity[2] Without ITC ($/MWh)** | | | |
| Fixed O&M Component of LCOE ($/MWh) | 15 | 15 | 15 |
| Variable O&M Component of LCOE ($/MWh) | 6 | 6 | 6 |
| Fuel Component of LCOE ($/MWh) | 54 | 40 | 68 |
| Capital Charge Component of LCOE ($/MWh) | 58 | 58 | 58 |
| **Total[3]** | **133** | **119** | **148** |

Notes:

[1] Sensitivity Cases assume biomass fuel costs different than the base case, at $1/MBtu above and below the base cost of $3.55/MBtu.

[2] Estimate of LCOE assumes an 85% capacity factor, 30-year project life, and constant dollars.

[3] Sum of LCOE component values may not equal Total value due to rounding.

# 6 BIOMASS TECHNOLOGY DEVELOPMENT CHARACTERIZATION TABLES

This chapter presents biomass technology monitoring and development tables characterizing repowering, co-firing and standalone biomass-fired BFB technologies.

Table 6-1 presents a monitoring guide of biomass power generation systems.

Table 6-2, Table 6-3 and Table 6-4 present technology process development “maps” for biomass repowering, biomass co-firing and standalone biomass-fired BFB technologies, respectively.

**Table 6-1**
**Technology Monitoring Guide – Biomass Power Generation Systems**

| Technologies | R&D Intensity | Leading Developers of Science or Technology: Government Organizations | Non-profit Organizations | Industrial Firms | Leading Vendors | Major Trends | Changes to Watch for | Unresolved Issues |
|---|---|---|---|---|---|---|---|---|
| **Repowering** | Low | DOE-EERE Biopower, DOE Fossil Energy | EPRI | Public Service of New Hampshire, Ontario Power Generation, Southern Company | Babcock & Wilcox, Babcock Power, Foster Wheeler, Metso | Trend toward repowering older, smaller (i.e., less than 150 MW) units. | Development of biomass fuel aggregators to supply quantities sufficient for plants greater than 100 MW. | Pending environmental regulations, particularly related to control of CO, may impact project viability. Regulatory picture for $CO_2$ emissions unclear |
| **Co-firing** | Medium | DOE-EERE Biopower, DOE Fossil Energy | EPRI | Southern Company, Colorado Springs Utilities, AES | Alstom, Babcock & Wilcox, Babcock Power, Foster Wheeler, Metso, Doosan, KEMA | Trend toward examining co-firing potential in units of all scales. | Development of gasification methods of co-firing. | Impacts of co-firing on existing installed SCR catalysts, corrosion, fouling |
| **Standalone BFB** | Medium | DOE-EERE Biopower, DOE Fossil Energy | Biomass Energy Resource Center, World Bank, Asian Development Bank, Sandia National Lab | Southern Company, Oglethorpe | B&W, Metso, Foster Wheeler, EPI, AE&E Von Roll, Adage | Trend toward larger capacity plants (up to 100 MW). Increased interest in opportunity fuels. | SCR and CO catalyst requirement and locations in the gas stream | High alkalinity fuels result in slagging and fouling. Pending environmental regulations related to control of CO may impact project viability. |

**Table 6-2**
**Technology Process Development Map – Biomass Repowering**

| Technology Development and Assessment: 100% Biomass Repowering. | | |
|---|---|---|
| | ***Current Status*** | ***Future Considerations or Trends*** |
| **Features and Characteristics of Technology** | Replacement of small or obselete PC boilers with stokers or BFB boilers. Maintains existing steam cycle and BOP. | Combustion technology fully developed. |
| **Major Technical Issues** | Minimizing CO and NOx emissions during start-up, shutdown and upset conditions. | Compliance with more stringent environmental regulations. Boiler slagging with high-alkalinity fuels. |
| **Key Vendor Activities** | Vendors are applying established and appropriate combustion technologies as part of a repowering solution. | R&D on appropriate emission control systems to comply with new regulations. |
| **Resource Requirements That Impact Technology** | The most practical fuels at this time are wood or wood-derived biomass. Fuels are relatively benign. Firing of herbaceous fuels is common in Europe and China. | Future fuels may be herbaceous, which may be more corrosive/fouling to the boiler. |
| **Key Business and Market Indicators** | It is difficult to find a consistent, economical supply for more than 15-25MW of biomass. Delivered product guarantees are poor and inconsistent. Fuel quality measurement and quality control lacking. | Value of CO2 will impact economic viability of projects. |
| **Key technology needs** | None identified. | Continuing focus on higher efficiency, lower emissions and lower first cost. |
| **Technology Outlook** | Current technology is sufficient for use at most power plants. | Ability to leverage more variable/opportunity fuels needed. |
| **Development Timeframe** | | |
| **Research** | 1980's. | |
| **Development** | 1990's | |
| **Demonstration** | 2000's. | |
| **Projected Commercialization Date** | 2000's. | |

**Table 6-3**
**Technology Process Development Map – Biomass Co-firing**

| Technology Development and Assessment: 100% Biomass Co-firing. | | |
|---|---|---|
| | ***Current Status*** | ***Future Considerations or Trends*** |
| **Features and Characteristics of Technology** | Blending with coal to send to the power plant (most cases) or separate injection into the boiler. | Direct injection into existing coal pipes (done rarely now), gasifcation, liquifaction, increased torrefied product availability. |
| **Major Technical Issues** | When blended with the coal, the ability of the mills to handle the high-moisture poor-grindability fuel. When directly injected, the ability of boiler combustion controls to maintain good NOX/CO/UBC balance. Poor to no ability to receive/ stockout/reclaim biomass. | More advanced combustion controls with additional in-furnace CO/NOX monitoring could improve feasibility. Potential conflict with new emissions controls for MACT. |
| **Key Vendor Activities** | Vendor activities are scattered, small-scale, and inconsistent. Transportation modes are limited to mostly truck. | Engineered fuels (pellets/torrefied biomass) from a centralized supplier with rail/barge access. |
| **Resource Requirements That Impact Technology** | The most practical fuels at this time are wood or wood-derived biomass. Fuels are relatively benign. Firing of herbaceous fuels is common in Europe and China. | Future fuels are more likely to be herbaceous and be more corrosive/fouling to the boiler. Unless torrefied, most herbaceous fuels will not work in coal mills. |
| **Key Business and Market Indicators** | It is difficult to find a consistent, economical supply for more than 15-25MW of biomass. Delivered product guarantees are poor and inconsistent. Fuel quality measurement and quality control lacking. | Much larger supplies of a much more consistent fuel are needed. Testing should be standardized and standard operating procedure as the case of coal. Value of CO2 will impact economic viability of projects. |
| **Key technology needs** | Improved testing of co-milled biomass to find solutions to co-milling problems. | Improved understanding of equipment impacts (slagging/fouling/NOX) and MACT emissions (furans/dioxins/PAH) needed. |
| **Technology Outlook** | Current technology is sufficient for use at most power plants. | Ability to leverage more variable/opportunity fuels needed. |
| **Development Timeframe** | | |
| **Research** | 1980's. | |
| **Development** | 1990's | |
| **Demonstration** | 1990's | |
| **Projected Commercialization Date** | 2000's. | |

**Table 6-4**
**Technology Process Development Map – Standalone Biomass-fired BFB**

| Technology Development and Assessment: 100% Biomass Repowering. | | |
|---|---|---|
| | ***Current Status*** | ***Future Considerations or Trends*** |
| **Features and Characteristics of Technology** | Stationary, inert fluidized bed with furnace above | Technology fully developed. |
| **Major Technical Issues** | Minimizing CO and NOx emissions during start-up, shutdown and upset conditions. | Compliance with more stringent environmental regs. Boiler slagging with high alkalinity fuels. |
| **Key Vendor Activities** | Marketing larger sized Biomass fired BFB units | R&D on appropriate emission control systems to comply with new regulations. R&D for various biofuels including start-up on biodiesel. |
| **Resource Requirements That Impact Technology** | Fuel feed, ash handling, bed management | |
| **Key Business and Market Indicators** | Technology of choice for woody biomass firing in the 50 MW size range. | Value of CO2 will impact economic viability of projects. |
| **Key technology needs** | Fully established for woody biomass up to 100 MW. There is a need for greater fuel flexibility. | Continuing focus on higher efficiency, lower emissions and lower first cost. Need to demonstrate switchgrass firing (at some level) in a BFB. |
| **Technology Outlook** | More high capacity units installed and operational history to provide lessons learned. | Installations with clean SCR and CO catalyst. Start-up with biodiesel |
| **Development Timeframe** | | |
| **Research** | 1960's | |
| **Development** | 1970's | |
| **Demonstration** | 1980's | |
| **Projected Commercialization Date** | 1990's | |

# A
# INTERFACE POINTS OF REPOWERED BOILER WITH EXISTING UNIT SYSTEMS

**Table A-1**
**Existing Interfaces Used in Repowered System**

| System | Description |
|---|---|
| *Steam* | |
| Main Steam | Outlet header of final superheater downstream of the last safety valve, and including SRVs to be installed in the main steam pipe. |
| Superheater | Inlet of the desuperheater inlet valve flange. |
| Safety valve exhausts and vents | To atmosphere at a minimum of 3 meters above the roof. Each safety valve exhaust shall be provided separately, complete with silencer |
| Auxiliary steam for steam coil air preheater and glycol heat exchangers (from stationary auxiliary steam header) | At a common point near boiler column for steam supply for air preheating. |
| Auxiliary steam for pulverizer inerting system | At a common point near boiler column. |
| Auxiliary steam for regenerative air heater soot blower (during startup) | At a common connection for alternative steam supply for soot blowing steam. |
| *Water* | Outlet of feed water regulating station outlet isolation valve, excluding the isolation valve. |
| Feed water | Inlet to the block valve in the superheater spray control stations. |
| Spray water for desuperheaters | Inlet of non-return and stop valve in boiler fill line, including valves. |
| Boiler filling | Inlet of non-return valve in the boiler hydraulic test line. |
| Boiler hydraulic testing | All high-pressure drains to respective drain headers located at operating floor near boiler column including branch isolation valves. |
| Drains | Common point near first row of boiler column at level including branch isolation valves. |
| Cooling water | Common point near first row of boiler column at level including branch isolation valves. |
| Service water | Common point near first row of boiler column at level, including branch isolation valves. |
| Regenerative Air Heater (RAH) wash water | Manifold terminal near regenerative air heater rotor housing, including isolation valves. |
| RAH deluge | Outlet of feed water regulating station outlet isolation valve, excluding the isolation valve. |
| *Miscellaneous* | |
| Sampling lines | Up to the sample coolers at the Fireman floor level, including high-press. isolation valves. |
| Vent pipes | To atmosphere a minimum of 10 feet above roof. |
| Nitrogen filling | Inlet of isolation valves on superheater outlet header. |
| *Fuel* | |
| Biomass | Outlet flange of raw biomass bunker/bins, including mating flanges. |
| Natural gas/oil | At existing connections. |
| Oil drain | Boiler front with isolation valves in respective areas. |
| *Air* | |
| Combustion air | Inlet of FD fan silencer units. |
| Compressed air (boiler equipment uses service aid) | Common point near first row of boiler column. |
| Instrument air | Common point near first row of boiler column. |
| *Flue gas* | |
| Flue gas | Air heater outlet. |
| *Ash* | |
| Furnace bottom ash | Collection point for solids from BFB bed. |
| Fly ash and DFGD solids | Outlet flange of hoppers below economizers, outlet flange below recycle bin for solids extraction, and outlet flange of ash hopper below air heater units. |

**Table A-2 (continued)**
**Existing Interfaces Used in Repowered System**

| | |
|---|---|
| *Electrical, Control, and Instrument.* | |
| Remote temp. measurement taps on pressure and non-pressure parts | Stubs. |
| Remote pressure / level measurement taps on pressure parts | Outlet of isolation valves. |
| Test temp. taps on pressure parts | Thermowells with caps. |
| Test temperature taps on non-pressure parts. | Stubs with caps. |
| Pressure part tube metal temperature thermocouples | Junction boxes with cold junction compensation up to control room. |
| Air flow measurements | Stubs. |
| Electric motor drives | Terminal boxes with cable glands and lugs. |
| Panels | Removable gland plate without cable glands and lugs. |
| BMS field equipment | Junction box |
| Soot blower MCC | Incoming and outgoing cable termination points. |

# B

# DETAILED BIOMASS-FIRED BUBBLING FLUIDIZED BED PLANT COST SUMMARIES

**Table B-1**
**Biomass Fired BFB Combustion: Total Capital Cost Summary Table**

| **Capacity** | **1x50-MW** | **1x50-MW** | **1x50-MW** | **1x50-MW** | **1x100-MW** | **1x100-MW** | **1x100-MW** |
|---|---|---|---|---|---|---|---|
| **Location** | **Southeast** | **Midwest** | **West** | **Florida** | **Southeast** | **Midwest** | **West** |
| **Fuel** | **Woody Biomass** | **Woody Biomass** | **Woody Biomass** | **Switchgrass/ Wood** | **Woody Biomass** | **Woody Biomass** | **Woody Biomass** |
| Steam Generator System | $ 67,449,543 | $ 67,857,476 | $ 77,903,054 | $ 67,449,543 | $ 104,526,768 | $ 104,998,832 | $ 120,367,087 |
| Turbine Island System | $ 18,604,275 | $ 18,866,097 | $ 24,323,599 | $ 18,604,275 | $ 29,545,978 | $ 30,882,570 | $ 31,046,741 |
| Biomass Handling | $ 17,521,240 | $ 17,721,013 | $ 17,574,540 | $ 23,869,240 | $ 27,075,864 | $ 27,400,501 | $ 27,511,058 |
| BOP Facilities | $ 41,758,853 | $ 46,643,279 | $ 48,213,524 | $ 41,945,165 | $ 54,572,915 | $ 60,527,368 | $ 62,960,141 |
| Environmental Controls | $ 513,350 | $ 519,650 | $ 521,960 | $ 513,350 | $ 533,150 | $ 539,900 | $ 542,232 |
| CO2 Control | | | | | | | |
| CO Control | | | | | | | |
| SO2 Control | $ 377,200 | $ 396,400 | $ 403,440 | $ 377,200 | $ 477,200 | $ 507,200 | $ 514,768 |
| NOx Control | $ 748,745 | $ 810,469 | $ 830,134 | $ 748,745 | $ 905,485 | $ 975,460 | $ 998,358 |
| Particulate | $ 749,520 | $ 1,035,000 | $ 1,132,296 | $ 749,520 | $ 1,309,600 | $ 1,825,600 | $ 2,007,936 |
| Thermal (wet cooling tower ) | $ 1,560,442 | $ 2,089,975 | $ 8,305,202 | $ 1,560,442 | $ 2,229,203 | $ 3,235,160 | $ 15,980,000 |
| Solid Waste | $ 1,461,960 | $ 1,608,300 | $ 1,635,075 | $ 1,461,960 | $ 1,881,960 | $ 2,034060 | $ 2,115,810 |
| Hg Control | | | | | | | |
| VOC | | | | | | | |
| General facilities and Site Specific | $ 18,859,337 | $ 20,124,521 | $ 23,318,933 | $ 20,939,512 | $ 25,635,930 | $ 30,908,465 | $ 33,044,580 |
| Engineering Fee & Construction Man. | $ 66,558,247 | $ 69,603,467 | $ 89,354,655 | $ 66,810,204 | $ 89,230,812 | $ 95,275,470 | $ 124,043,390 |
| Process Contingency | $ 1,612,291 | $ 1,630,420 | $ 1,913,848 | $ 1,612,291 | $ 2,495,530 | $ 2,501,130 | $ 2,796,250 |
| Project Contingency | $ 8,480,223 | $ 8,911,149 | $ 10,208,088 | $ 8,910,948 | $ 12,434,703 | $ 13,191,756 | $ 14,854,436 |
| **Total Overnight Turnkey EPC Cost,** | **$ 246,255,226** | **$ 257,778,661** | **$ 305,638,347** | **$ 255,552,394** | **$ 352,855,098** | **$ 374,803,473** | **$ 438,782,785** |
| $/kW Installed | $ 4,925 | $ 5,156 | $ 6,113 | $ 5,111 | $ 3,529 | $ 3,748 | $ 4,388 |

**Table B-2**
**Biomass Fired BFB Combustion: $/kW Summary Table**

| Capacity | 1x50-MW | 1x50-MW | 1x50-MW | 1x50-MW | 1x100-MW | 1x100-MW | 1x100-MW |
|---|---|---|---|---|---|---|---|
| Location | Southeast | Midwest | West | Florida | Southeast | Midwest | West |
| Fuel | Woody Biomass | Woody Biomass | Woody Biomass | Switchgrass/ Wood | Woody Biomass | Woody Biomass | Woody Biomass |
| Steam Generator System | $ 1,349 | $ 1,357 | $ 1,588 | $ 1,349 | $ 1,045 | $ 1,050 | $ 1,204 |
| Turbine Island System | $ 372 | $ 377 | $ 486 | $ 372 | $ 295 | $ 309 | $ 310 |
| Biomass Handling | $ 350 | $ 354 | $ 351 | $ 477 | $ 271 | $ 274 | $ 275 |
| BOP Facilities | $ 835 | $ 933 | $ 964 | $ 839 | $ 546 | $ 605 | $ 630 |
| Environmental Controls | $ 10 | $ 10 | $ 10 | $ 10 | $ 5 | $ 5 | $ 5 |
| CO2 Control | | | | | | | |
| CO Control | | | | | | | |
| SO2 Control | $ 8 | $ 8 | $ 8 | $ 8 | $ 5 | $ 5 | $ 5 |
| NOx Control | $ 15 | $ 16 | $ 17 | $ 15 | $ 9 | $ 10 | $ 10 |
| Particulate | $ 15 | $ 21 | $ 23 | $ 15 | $ 13 | $ 18 | $ 20 |
| Thermal (wet cooling tower ) | $ 31 | $ 42 | $ 166 | $ 31 | $ 22 | $ 32 | $ 160 |
| Solid Waste | $ 29 | $ 32 | $ 33 | $ 29 | $ 19 | $ 20 | $ 21 |
| Hg Control | | | | | | | |
| VOC | | | | | | | |
| General facilities and Site Specific | $ 377 | $ 402 | $ 466 | $ 419 | $ 256 | $ 309 | $ 330 |
| Engineering Fee & Construction Man. | $ 1,331 | $ 1,392 | $ 1,787 | $ 1,336 | $ 892 | $ 953 | $ 1,240 |
| Process Contingency | $ 32 | $ 32 | $ 38 | $ 32 | $ 25 | $ 25 | $ 28 |
| Project Contingency | $ 170 | $ 178 | $ 204 | $ 178 | $ 124 | $ 132 | $ 149 |
| **Total Overnight Turnkey EPC Cost, $/kW** | **$ 4,925** | **$ 5,156** | **$ 6,113** | **$ 5,111** | **$ 3,529** | **$ 3,748** | **$ 4,388** |

**Table B-3**
**1x50-MW Woody Biomass Fired BFB Combustion Capital Cost Summary: Southeast**

| Base Location: Southeast | DF Material | DF Labor | Indirects | Subcontracts | Total |
|---|---|---|---|---|---|
| Steam Generator System | $ 51,045,970 | $ 16,043,880 | | $ 359,693 | $ 67,449,543 |
| Turbine Island System | $ 17,884,138 | $ 617,683 | | $ 102,453 | $ 18,604,275 |
| Biomass Handling | $ 10,624,764 | $ 257,846 | | $ 6,638,630 | $ 17,521,240 |
| BOP Facilities | $ 21,556,910 | $ 11,681,887 | | $ 8,520,057 | $ 41,758,853 |
| Environmental Controls | $ 451,100 | $ 15,960 | | $ 46,290 | $ 513,350 |
| CO2 Control | | | | | |
| CO Control | | | | | |
| SO2 Control | $ 326,400 | $ 48,640 | | $ 2,106 | $ 377,200 |
| NOx Control | $ 596,661 | $ 150,868 | | $ 1,216 | $ 748,745 |
| Particulate | $ 36,960 | $ 709,536 | | $ 3,024 | $ 749,520 |
| Thermal (wet cooling tower) | $ 146,916 | $ 101,506 | | $ 1,312,020 | $ 1,560,442 |
| Solid Waste | $ 1,090,080 | $ 370,728 | | $ 1,152 | $ 1,461,960 |
| Hg Control | | | | | |
| VOC | | | | | |
| General facilities and Site Specific | $ 4,572,605 | $ 4,773,057 | | $ 9,513,675 | $ 18,859,337 |
| Engineering Fee & Construction Man. | | | $ 24,297,985 | $ 42,260,262 | $ 66,558,247 |
| Process Contingency | | | $ 1,612,291 | | $ 1,612,291 |
| Project Contingency | | | $ 8,480,223 | | $ 8,480,223 |
| **Total Overnight Turnkey EPC Cost, $** | **$ 108,332,504** | **$ 34,771,590** | **$ 34,390,500** | **$ 68,760,632** | **$ 246,255,226** |
| $/kW Installed | | | | | $ 4,925 |

**Table B-4**
**1x50-MW Woody Biomass Fired BFB Combustion Capital Cost Summary: Midwest**

| Base Location: Midwest | DF Material | DF Labor | Indirects | Subcontracts | Total |
|---|---|---|---|---|---|
| Steam Generator System | $ 51,047,400 | $ 16,450,266 | | $ 359,810 | $ 67,857,476 |
| Turbine Island System | $ 17,892,938 | $ 869,986 | | $ 103,173 | $ 18,866,097 |
| Biomass Handling | $ 10,767,192 | $ 366,438 | | $ 6,587,384 | $ 17,721,013 |
| BOP Facilities | $ 21,792,038 | $ 16,329,971 | | $ 8,521,270 | $ 46,643,279 |
| Environmental Controls | $ 451,100 | $ 22,260 | | $ 46,290 | $ 519,650 |
| CO2 Control | | | | | |
| CO Control | | | | | |
| SO2 Control | $ 326,400 | $ 67,840 | | $ 2,160 | $ 396,400 |
| NOx Control | $ 597,723 | $ 211,444 | | $ 1,303 | $ 810,469 |
| Particulate | $ 39,600 | $ 992,160 | | $ 3,240 | $ 1,035,000 |
| Thermal (wet cooling tower) | $ 157,410 | $ 151,686 | | $ 1,780,879 | $ 2,089,975 |
| Solid Waste | $ 1,090,080 | $ 517,068 | | $ 1,152 | $ 1,608,300 |
| Hg Control | | | | | |
| VOC | | | | | |
| General facilities and Site Specific | $ 4,637,786 | $ 6,827,464 | | $ 8,659,271 | $ 20,124,521 |
| Engineering Fee & Construction Man. | | | $ 28,374,832 | $ 41,228,635 | $ 69,603,467 |
| Process Contingency | | | $ 1,630,420 | | $ 1,630,420 |
| Project Contingency | | | $ 8,911,149 | | $ 8,911,149 |
| **Total Overnight Turnkey EPC Cost, $** | **$ 108,799,666** | **$ 42,806,582** | **$ 38,916,401** | **$ 67,294,568** | **$ 257,778,661** |
| $/kW Installed | | | | | $ 5,156 |

**Table B-5**
**1x50-MW Woody Biomass Fired BFB Combustion Capital Cost Summary: West**

| Base Location: West | DF Material | DF Labor | Indirects | Subcontracts | Total |
|---|---|---|---|---|---|
| Steam Generator System | $ 60,945,970 | $ 16,597,391 | | $ 359,693 | $ 77,903,054 |
| Turbine Island System | $ 22,870,238 | $ 950,907 | | $ 502,453 | $ 24,323,599 |
| Biomass Handling | $ 10,613,604 | $ 372,307 | | $ 6,588,630 | $ 17,574,540 |
| BOP Facilities | $ 21,703,660 | $ 17,989,807 | | $ 8,520,057 | $ 48,213,524 |
| Environmental Controls | $ 451,100 | $ 24,570 | | $ 46,290 | $ 521,960 |
| CO2 Control | | | | | |
| CO Control | | | | | |
| SO2 Control | $ 326,400 | $ 74,880 | | $ 2,160 | $ 403,440 |
| NOx Control | $ 596,661 | $ 232,257 | | $ 1,216 | $ 830,134 |
| Particulate | $ 36,960 | $ 1,092,312 | | $ 3,024 | $ 1,132,296 |
| Thermal (wet cooling tower) | $ 146,916 | $ 2,130,640 | | $ 6,027,645 | $ 8,305,202 |
| Solid Waste | $ 1,073,37 | $ 560,547 | | $ 1,152 | $ 1,635,075 |
| Hg Control | | | | | |
| VOC | | | | | |
| General facilities and Site Specific | $ 5,104,776 | $ 7,904,853 | | $ 10,399,304 | $ 23,318,933 |
| Engineering Fee & Construction Man. | | | $ 29,630,804 | $ 59,723,851 | $ 89,354,655 |
| Process Contingency | | | $ 1,913,848 | | $ 1,913,848 |
| Project Contingency | | | $ 10,208,088 | | $ 10,208,088 |
| **Total Overnight Turnkey EPC Cost, $** | **$ 123,779,661** | **$ 47,930,471** | **$ 41,752,740** | **$ 92,175,476** | **$ 305,638,347** |
| $/kW Installed | | | | | $ 6,113 |

**Table B-6**
**1x50-MW Switchgrass Fired BFB Combustion Capital Cost Summary: Southeast**

| Base Location: Southeast | DF Material | DF Labor | Indirects | Subcontracts | Total |
|---|---|---|---|---|---|
| Steam Generator System | $ 51,045,970 | $ 16,043,880 | | $ 359,693 | $ 67,449,543 |
| Turbine Island System | $ 17,884,138 | $ 617,683 | | $ 102,453 | $ 18,604,275 |
| Biomass Handling | $ 10,734,764 | $ 333,846 | | $ 12,800,630 | $ 23,869,240 |
| BOP Facilities | $ 21,662,055 | $ 11,763,053 | | $ 8,520,057 | $ 41,945,165 |
| Environmental Controls | $451,100 | $ 15,960 | | $ 46,290 | $ 513,350 |
| CO2 Control | | | | | |
| CO Control | | | | | |
| SO2 Control | $ 326,400 | $ 48,640 | | $ 2,160 | $ 377,200 |
| NOx Control | $ 596,661 | $ 150,868 | | $1,216 | $ 748,745 |
| Particulate | $ 36,960 | $ 709,536 | | $ 3,024 | $ 749,520 |
| Thermal (wet cooling tower) | $ 146,916 | $ 101,506 | | $ 1,312,020 | $ 1,560,442 |
| Solid Waste | $ 1,090,080 | $ 370,728 | | $ 1,152 | $ 1,461,960 |
| Hg Control | | | | | |
| VOC | | | | | |
| General facilities and Site Specific | $ 4,671,770 | $ 4,944,587 | | $ 11,323,155 | $ 20,939,512 |
| Engineering Fee & Construction Man. | | | $ 24,297,985 | $ 42,512,218 | $ 66,810,204 |
| Process Contingency | | | $ 1,612,291 | | $ 1,612,291 |
| Project Contingency | | | $ 8,910,948 | | $ 8,910,948 |
| **Total Overnight Turnkey EPC Cost, $** | **$ 108,646,814** | **$ 35,100,287** | **$ 34,821,224** | **$ 76,984,069** | **$ 255,552,394** |
| $/kW Installed | | | | | $ 5,111 |

**Table B-7**
**1x100-MW Woody Biomass Fired BFB Combustion Capital Cost Summary: Southeast**

| Base Location: Southeast | DF Material | DF Labor | Indirects | Subcontracts | Total |
|---|---|---|---|---|---|
| Steam Generator System | $ 77,788,288 | $ 26,378,085 | | $ 360,395 | $ 104,526,768 |
| Turbine Island System | $ 27,918,648 | $ 1,480,967 | | $ 146,362 | $ 29,545,978 |
| Biomass Handling | $ 17,501,086 | $ 368,351 | | $ 9,206,427 | $ 27,075,864 |
| BOP Facilities | $ 28,321,614 | $ 14,966,650 | | $ 11,284,651 | $ 54,572,915 |
| Environmental Controls | $ 451,100 | $ 15,960 | | $ 66,090 | $ 533,150 |
| CO2 Control | | | | | |
| CO Control | | | | | |
| SO2 Control | $ 426,400 | $ 48,640 | | $ 2,160 | $ 477,200 |
| NOx Control | $ 748,480 | $ 155,268 | | $ 1,737 | $ 905,485 |
| Particulate | $ 52,800 | $ 1,252,480 | | $ 4,320 | $ 1,309,600 |
| Thermal (wet cooling tower) | $ 209,880 | $ 145,008 | | $ 1,874,315 | $ 2,229,203 |
| Solid Waste | $ 1,510,080 | $ 370,728 | | $ 1,152 | $ 1,881,960 |
| Hg Control | | | | | |
| VOC | | | | | |
| General facilities and Site Specific | $ 6,038,939 | $ 6,702,616 | | $ 12,894,375 | $ 25,635,930 |
| Engineering Fee & Construction Man. | | | $ 32,756,512 | $ 56,474,300 | $ 89,230,812 |
| Process Contingency | | | $ 2,495,530 | | $ 2,495,530 |
| Project Contingency | | | $ 12,434,703 | | $ 12,434,703 |
| **Total Overnight Turnkey EPC Cost, $** | **$ 160,967,314** | **$ 51,884,754** | **$ 47,686,745** | **$ 92,316,285** | **$ 352,855,098** |
| $/kW Installed | | | | | $ 3,529 |

**Table B-8**
**1x100-MW Woody Biomass Fired BFB Combustion Capital Cost Summary: Midwest**

| Base Location: Midwest | DF Material | DF Labor | Indirects | Subcontracts | Total |
|---|---|---|---|---|---|
| Steam Generator System | $ 77,813,698 | $ 26,822,660 | | $ 362,474 | $ 104,998,832 |
| Turbine Island System | $ 28,233,848 | $ 2,099,480 | | $ 549,242 | $ 30,882,570 |
| Biomass Handling | $ 17,588,712 | $ 598,193 | | $ 9,213,596 | $ 27,400,501 |
| BOP Facilities | $ 28,341,788 | $ 20,899,278 | | $ 11,286,302 | $ 60,527,368 |
| Environmental Controls | $ 451,320 | $ 22,472 | | $ 66,108 | $ 539,900 |
| CO2 Control | | | | | |
| CO Control | | | | | |
| SO2 Control | $ 431,680 | $ 72,928 | | $ 2,592 | $ 507,200 |
| NOx Control | $ 752,726 | $ 220,650 | | $ 2,084 | $ 975,460 |
| Particulate | $ 63,360 | $ 1,757,056 | | $ 5,184 | $ 1,825,600 |
| Thermal (wet cooling tower) | $ 251,856 | $ 242,698 | | $ 2,740,606 | $ 3,235,160 |
| Solid Waste | $ 1,512,896 | $ 519,782 | | $ 1,382 | $ 2,034060 |
| Hg Control | | | | | |
| VOC | | | | | |
| General facilities and Site Specific | $ 6,231,059 | $ 9,903,295 | | $ 14,774,111 | $ 30,908,465 |
| Engineering Fee & Construction Man. | | | $ 36,662,240 | $ 58,613,231 | $ 95,275,470 |
| Process Contingency | | | $ 2,501,130 | | $ 2,501,130 |
| Project Contingency | | | $ 13,191,756 | | $ 13,191,756 |
| **Total Overnight Turnkey EPC Cost, $** | **$ 161,672,943** | **$ 63,158,491** | **$ 52,355,126** | **$ 97,616,913** | **$ 374,803,473** |
| $/kW Installed | | | | | $ 3,748 |

**Table B-9**
**1x100-MW Woody Biomass Fired BFB Combustion Capital Cost Summary: West**

| Base Location: West | DF Material | DF Labor | Indirects | Subcontracts | Total |
|---|---|---|---|---|---|
| Steam Generator System | $ 93,025,379 | $ 26,979,234 | | $ 362,474 | $ 120,367,087 |
| Turbine Island System | $ 28,211,848 | $ 2,293,950 | | $ 540,942 | $ 31,046,741 |
| Biomass Handling | $ 17,622,408 | $ 675,053 | | $ 9,213,596 | $ 27,511,058 |
| BOP Facilities | $ 28,601,088 | $ 23,072,752 | | $ 11,286,302 | $ 62,960,141 |
| Environmental Controls | $ 451,320 | $ 24,804 | | $ 66,108 | $ 542,232 |
| CO2 Control | | | | | |
| CO Control | | | | | |
| SO2 Control | $ 431,680 | $ 80,496 | | $ 2,592 | $ 514,768 |
| NOx Control | $ 752,726 | $ 243,547 | | $ 2,084 | $ 998,358 |
| Particulate | $ 63,360 | $ 1,939,392 | | $ 5,184 | $ 2,007,936 |
| Thermal (wet cooling tower) | | $ 3,948,750 | | $ 12,031,250 | $ 15,980,000 |
| Solid Waste | $ 1,530,176 | $ 584,251 | | $ 1,382 | $ 2,115,810 |
| Hg Control | | | | | |
| VOC | | | | | |
| General facilities and Site Specific | $ 6,632,819 | $ 11,693,517 | | $ 14,718,245 | $ 33,044,580 |
| Engineering Fee & Construction Man. | | | $ 40,179,283 | $ 83,864,107 | $ 124,043,390 |
| Process Contingency | | | $ 2,796,250 | | $ 2,796,250 |
| Project Contingency | | | $ 14,854,436 | | $ 14,854,436 |
| **Total Overnight Turnkey EPC Cost, $** | **$ 177,322,804** | **$ 71,535,746** | **$ 57,829,969** | **$ 132,094,266** | **$ 438,782,785** |
| $/kW Installed | | | | | $ 4,388 |

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