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B&V Biomass Sizing Study
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GRU

Gainesville Regional Utilities

Biomass Sizing Study

FINAL REPORT
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1.0 Executive Summary

Gainesville Regional Utilities (GRU) has retained Black & Veatch to determine the optimal technology for the production of biomass-fired electrical generation at Deerhaven Generating Station. Three tasks were formulated as follows:

- Task 1—Identification of Technologies to be Considered
- Task 2—Development of Preliminary Technology Characteristics for Various Technologies and Unit Sizes
- Task 3—Estimation of Impacts Resulting from Incorporating Fuel Flexibility

This report summarizes the findings of Task 1, Task 2 and Task 3, including the relevant technology characteristics for biomass combustion technologies capable of providing between 50 and 100 MW of electrical generation.

1.1 Identification of Technologies to be Considered

Black & Veatch identified potential biomass-fired technologies that could be used for this application, focusing on those that are considered commercially available in the size range being considered. In evaluating suitable technologies, key criteria include cost effectiveness (on a life cycle basis), proven technology, reliability, tolerance to fuel variability, and ease of operation.

Black & Veatch reviewed both combustion and gasification technologies to determine their potential for a biomass-fired power generation facility. Details of this review are provided in Section 3.0 of this report. Based on proven performance in prior biomass power applications, Black & Veatch recommends three direct combustion technologies for further consideration. These technologies included:

- Stoker grate boilers
- Bubbling Fluidized Bed (BFB) boilers
- Circulating Fluidized Bed (CFB) boilers

These three technologies were the focus of Task 2 and Task 3.

1.2 Development of Preliminary Technology Characteristics

Following the identification of likely biomass-fired generation technologies, the defining characteristics of the appropriate generation system were determined through discussions with biomass boiler vendors, review of applicable environmental regulations, performance modeling of steam cycle and cost estimation of the likely system components.

1.2.1 Boiler Vendor Surveys

Biomass combustion equipment vendors were contacted to determine the current state of the art of the selected biomass combustion technologies and to identify the relevant operational parameters of the technologies. The vendors contacted during this survey included the following:

- Babcock & Wilcox
- Foster Wheeler
- Alstom
- Energy Products of Idaho
- Kvaerner
- McBurney
- PowerDyne (Detroit Stoker)
- Wellons Boiler

The information provided by vendors during the biomass boiler survey is presented in Section 4.1 of this report. The most significant findings of the survey include:

- Vendors capable of providing all three biomass combustion technologies (i.e., Babcock & Wilcox and Foster Wheeler) independently stated that BFBs are the best choice for units up to 70 MW in size. Babcock & Wilcox recommended the use of BFBs across the entire size range of 50 to 100 MW, while Foster Wheeler recommended the use of CFBs for units in the size range of 70 to 100 MW (above 650,000 lb/hr of steam).
- At the lower end of the size range (approximately 50 MW), the vendors recommended BFBs in favor of stokers due to the high moisture content of the biomass and low alkali content of woody biomass.
- At the higher end of the size range, Babcock & Wilcox recommended BFBs in the favor of CFBs due to the higher capital costs of CFBs.
- All vendors are capable of firing fuels with moisture contents in the range of 35 to 50 percent.
- All vendors claimed to be able to meet expected emission requirements for the biomass-only case. All vendors felt that SNCR would be necessary to comply with NOx limits, but little to no sulfur control would be required for the combustion of 100 percent biomass.

Based on the information regarding biomass-fired systems provided by the vendors, Black & Veatch recommends the following:

- A bubbling fluidized bed (BFB) boiler is recommended to provide steam for an electrical generation system fired by 100 percent biomass.
- The electrical generation capacity of the system will be determined by the availability of biomass fuel rather than any technical characteristic or limitation of the boiler system. Therefore, a detailed biomass resource assessment is recommended to identify potential biomass suppliers, to better establish the likely cost of the fuel, and to determine the optimal size of the system.
- Specific fuel characterization (fuel analyses) should be done as part of the resources assessment.

1.2.2 Air Permitting

Unless netting can be used to avoid PSD applicability, it is expected that the installation of a new wood-fired boiler at the Deerhaven facility would be considered a major modification to the facility under PSD regulations for a number of pollutants. If PSD is triggered, it will require installation of emission controls that are deemed to be BACT, and an AAQIA would be needed as part of the permit application. In general, a PSD permitting effort from start of application preparation to receiving an Agency permit is typically estimated to take 12 to 24 months. Another consideration when proposing to install additional electric utility steam generating units in Florida is whether the installation will be subject to the Florida Power Plant Siting Act. Going through the siting act approval process can add complexity and time to the overall permitting process. It is expected that, at a minimum, the installation of a new generating unit at Deerhaven would require a modification to the plant's Site Certification.

1.2.3 Performance Modeling

To quantify performance of the system and determine certain operating parameters, a model of the steam cycle was prepared, and heat and mass balances were developed for three operational scenarios. These scenarios include:

- 50 MW (net) Steam Cycle (steam provided by a Stoker boiler)
- 100 MW (net) Steam Cycle (steam provided by a CFB boiler)
- 100 MW (net) Steam Cycle, with Reheat (steam provided by a CFB boiler)

The results of thermal performance modeling are summarized in Table 1-1. The complete heat balances for the 50 MW scenario, the 100 MW CFB scenario and the 100 MW CFB with reheat scenario are provided in Appendix A, Appendix B and Appendix C, respectively.

The performance results for the 100 MW BFB case are based on the results for the 100 MW CFB case. Because the steam cycle parameters are identical for the BFB and CFB systems, the steam flows and conditions for these two cases are also identical. Furthermore, the differences in auxiliary power requirements for these two systems were assumed to be negligible, as the increased pressure drops through the CFB system are mitigated to some extent by the increased excess air requirements of the BFB. However, the boiler efficiency of the BFB was assumed to be approximately 3 percentage points lower for the BFB relative to the CFB due to increased excess air requirements and greater unburned carbon losses for the BFB. The lower boiler efficiency results in a slightly higher net plant heat rate and greater fuel requirements for the BFB relative to the CFB system, as shown in Table 1-1.

1.2.4 Cost and Operating Data

Cost estimates and operational parameters have been gathered for biomass-fired units based on similar projects. These estimates and operational parameters have been gathered for both a 50 MW BFB system and a 100 MW BFB system, and they include capital costs (EPC contracting basis), operating and maintenance (O&M) costs, cash flow during construction, maintenance schedules and availability assumptions. The complete data set is presented in Section 4.4. Key parameters for these systems are summarized in Table 1-2.

1.3 Impacts Resulting from the Incorporation of Fuel Flexibility

While the generation systems described in the previous sections have been assumed to utilize only biomass fuels, there may be fuel supply situations in which the ability to fire coal in the selected system would be advantageous. Black & Veatch consulted with boiler vendors, reviewed relevant permitting regulations and identified the required system modifications and associated costs to determine the extent to which the selected biomass systems may be capable of utilizing coal as a fuel.

If it is determined that the limited availability of biomass resources requires the combustion of coal at a more significant level (i.e., the unit's standard operating procedure includes the cofiring of coal at more than 20 percent of the heat input to the boiler), it is recommended that a CFB boiler rather than a BFB boiler be employed to generate steam, as CFBs are more capable of simultaneously combusting varied fuels.

Discussions with Babcock & Wilcox and Foster Wheeler indicated that capital costs of CFBs are roughly 10 percent to 15 percent greater than those of BFBs. As in the case of coal cofiring in a BFB, control systems would be required to limit the emission of sulfur dioxide. These systems would likely be composed of limestone injection equipment and downstream polishing reactors.

Table 1-1. Summary of System Performance Modeling. [a]

Full Load System Parameters	50 MW Stoker	100 MW BFB[b]	100 MW CFB	100 MW CFB (Reheat)
Turbine Gross Output (100% Load), kW	57,465	115,053	115,053	114,977
Turbine Heat Rate (100% Load), Btu/kWh	8,657	8,259	8,259	7,924
Total Auxiliary Power (100% Load), kW	7,470	15,000	15,000	15,000
Total Auxiliary Power (100% Load), %	13.0	13.0	13.0	13.0
Net Plant Output (100% Load), kW	50,000	100,050	100,050	99,980
Heat to Steam from Boiler (100% Load), MBtu/hr	497.9	951.2	951.2	913.4
Boiler Efficiency (HHV)	80.0	77.0	80.0	80.0
Boiler Heat Input (100% Load), MBtu/hr (HHV)	622.4	1,235.3	1,189.0	1,141.7
Biomass Fuel Requirement[c], tons/day	1,464	2,907	2,798	2,686
Number of Heaters	4	5	5	5
Part Load Heat Rate Calculations				
Net Plant Heat Rate (100% Load), Btu/kWh (HHV)	12,448	12,347	11,884	11,420
Net Plant Heat Rate (75% Load), Btu/kWh (HHV)	13,017	12,826	12,345	11,779
Net Plant Heat Rate (50% Load), Btu/kWh (HHV)	14,177	13,979	13,455	12,705

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.
Auxiliary power is assumed to be 13% of base load (100% load).
Water cooling with mechanical draft cooling tower is used.
Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.
Boiler efficiency is assumed to be 80% for all cases except the 100 MW BFB case.

[b] The thermal performance for the 100 MW BFB case was estimated from the modeling of the 100 MW CFB case. It was assumed that auxiliary power requirements would be roughly equivalent for the two systems, but boiler efficiency would be slightly lower for the BFB relative to the CFB because of the increased excess air requirements and greater unburned carbon losses for the BFB.

[c] Biomass fuel requirement, in tons per day, was calculated based on the boiler heat input and an assumed heating value of biomass of 5100 Btu/lb. This heating value assumes a biomass moisture content of 40%.

Table 1-2. Summary of Key Cost and Operational Data for BFB Systems.

	50 MW BFB System	100 MW BFB System
Total Project Capital Cost (EPC)*, $ (2006$)	142,290,957	242,907,204
Non-fuel O&M Cost**		
Fixed Non-fuel O&M, $/kW-yr (2006$)	91.04	55.65
Variable Non-fuel O&M, $/MWh (2006$)	4.13	3.13
Equivalent Availability Factor, %	88 to 90	88 to 90
Forced Outage Rate, %	5 to 8	5 to 8
Steam Generator Outages		
Duration, weeks	3	3
Frequency, years/outage	2 to 3	2 to 3
Steam Turbine Outages		
Duration, weeks	6	6
Frequency, years/outage	6 to 8	6 to 8

Notes:
* Total Project Cost is an estimate of overnight cost and does not include Owner's Costs such as Interest During Construction (IDC), Escalation or Permitting.
** Non-fuel O&M costs assume net generation of 50 MW and 100 MW, respectively.

The increase in capital costs for a 100 MW CFB unit with the capability to cofire 30 percent coal is shown in Table 1-3. Other costs may increase relative to the 100 MW biomass-fired BFB system, but these costs are not expected to be as significant as the costs identified in Table 1-3. Furthermore, Black & Veatch does not expect the change from a biomass-only BFB system to a cofired CFB system to alter the expected cash flow during construction, unit availability or outage schedule.

Table 1-3. Increase in Capital Cost of 100 MW CFB (30% Coal Cofiring).

Equipment	Cost (2006$)
Fluidized Bed*	4,713,000
Sulfur Dioxide Control**	11,483,000
Total	**16,169,000**

Notes:

* Increase in capital cost of a 100 MW CFB unit designed to fire a 70/30 biomass/coal fuel mixture relative to the cost of a 100 MW BFB designed to fire 100% biomass. Incremental cost assumed to be 10% of the equipment cost of a 100 MW BFB (as listed in Table 4-10).

** Capital cost of sulfur dioxide control equipment necessary to reduce SO2 emissions from a 100 MW CFB to permitted levels assuming a 70/30 biomass/coal fuel mixture. This estimate assumes a dry lime system coupled with an existing ESP for sorbent capture.

2.0 Introduction

Gainesville Regional Utilities (GRU) has retained Black & Veatch to determine the optimal technology for the production of biomass-fired electrical generation at Deerhaven Generating Station. The work was subdivided into the following three tasks:

- Task 1—Identification of Technologies to be Considered
- Task 2—Development of Preliminary Technology Characteristics for Various Technologies and Unit Sizes
- Task 3—Estimation of Impacts Resulting from Incorporating Fuel Flexibility

This report summarizes the findings of Task 1, Task 2 and Task 3, including the relevant technology characteristics for biomass combustion technologies capable of providing between 50 and 100 MW of electrical generation.

2.1 Background

GRU has received direction from the City Commission to pursue specific methods for meeting the City of Gainesville's future additional electric energy needs, one of which involves generation utilizing biomass fuel. Accordingly, GRU is investigating the feasibility of biomass-fired generation, which is to be located at the Deerhaven Generating Station. The selected biomass technology should be capable of burning 100 percent biomass and should have the ability to provide up to 100 MW of generation.

2.2 Objective

GRU intends to develop a production cost model to simulate the economic performance of the biomass concept. To provide the appropriate inputs to the economic model, Black & Veatch has been requested to estimate the optimum size for such a facility within the range of 50 MW to 100 MW, and the corresponding cost and performance characteristics for input to GRU's model.

The objective of Task 1 is to identify the most promising biomass-fired technologies for near-term energy production. The objective of Task 2 is to characterize performance and cost parameters of the selected technology concepts. These parameters are to be determined for the 100 percent biomass case and include capital costs, operation and maintenance costs, net capacity, auxiliary power consumption, biomass burn rate and net plant heat rate. The objective of Task 3 is to determine the extent to which the systems developed in Task 2 would be capable of firing coal, considering technical, regulatory and economic perspectives.

3.0 Identification of Technologies to be Considered

Black & Veatch reviewed a variety of potential biomass-fired technologies that could be used to provide 50 MW to 100 MW of electrical generation, including both direct combustion and gasification schemes. This investigation focused on those technologies that are considered commercially available in the size range being considered. In evaluating suitable technologies, key criteria include cost effectiveness (on a life cycle basis), proven technology, reliability, tolerance to fuel variability, and ease of operation. A discussion of the relevant characteristics of biomass technologies is presented in the following subsections.

3.1 Biomass Feedstock Considerations

Wood is the most common type of biomass currently used as fuel for electric power production, and considered to be the most likely choice for fueling a biomass power plant at Deerhaven. Other biomass fuels that can be used for power production include agricultural residues such as bagasse (sugar cane residues), dedicated fuel crops such as fast growing grasses and eucalyptus trees, dried manure and sewage sludge, and "black liquor" residues from pulp mills.

Biomass plants have typically had electric generating capacities of less than 50 MW because of the transportation costs inherent in the dispersed nature of the feedstock and the lower energy density of the fuel per unit volume, thus requiring larger volumes of fuel per megawatt-hour of production. As a result of the smaller scale of the plants and lower energy density of the fuels per unit of volume, biomass plants are commonly less efficient than modern fossil fuel plants. In addition to being less efficient, power production from biomass has typically been more expensive than conventional fossil fuels on a $/MBtu basis because of added transportation costs alluded to above. These factors have typically limited the use of biomass for electric power production to inexpensive waste biomass sources; however the rise in fossil fuel prices that has occurred over the last few years has created an economic environment in which a wider variety of biomass sources can be competitive.

3.2 Conversion Technology Options

The objective of Task 1 is to identify commercial technologies that could be attractive for a GRU-owned biomass-fueled power plant. For power generation from biomass fuels, direct combustion has long been the preferred technology. Almost all of the nearly 10,000 MW of biomass and waste fired power plants in the U.S. rely on direct combustion technology.

Biomass gasification is an emerging alternative that can be used in advanced power cycles such as integrated gasification combined cycle (IGCC). Further, by converting solid fuel to a combustible gas, gasification expands the end use options for biomass. Gasification allows the use of cleaner and more efficient power conversion processes such as gas turbines and fuel cells to produce power, and/or chemical synthesis to produce ethanol and other value added products.

Pyrolysis and anaerobic digestion are two other options for producing electric power from biomass. Pyrolysis offers similar promise to gasification. However, most pyrolysis processes are in the early stages of commercialization and focused on production of value added chemicals rather than steam or power. Finally, anaerobic digestion is suitable for niche applications where waste stabilization is a primary concern. Examples of appropriate fuels include dairy manure, hog manure, slaughterhouse waste, and food waste. Energy yield from anaerobic digestion systems is typically lower than combustion and gasification systems.

The remainder of this section reviews combustion, gasification, pyrolysis, and anaerobic digestion processes. Of these, combustion and gasification have greater promise and are explored in more detail. Anaerobic digestion and pyrolysis are included for completeness.

3.2.1 Direct Combustion Technologies

There are several proven direct combustion systems for burning biomass fuels. These include the following:

- Stoker grate boilers (dumping grate, traveling grate, vibrating grate, etc.);
- Bubbling fluidized bed boilers;
- Circulating fluidized bed boilers; and
- Pulverized fuel suspension fired boilers.

Except for pulverized fuel suspension fired boilers, which are generally only suitable for very dry, small size biomass fuels (e.g., rice husks), the various combustion devices are described further in this section.

3.2.1.1 Stoker Grate Boilers

Stoker combustion is a proven technology that has been successfully used with biomass fuels (primarily wood) for many years. In the stoker boiler, fuel feeders ("stokers") regulate the flow of fuel down chutes that penetrate the front wall of the boiler above a grate. Mechanical devices or jets of high-pressure air throw the fuel out into the furnace section and onto the grate. Because biomass fuel readily devolatilizes, much of the biomass burns in suspension. Therefore, a significant portion of the total combustion air is introduced as overfire air. The unburned char settles on the grate surface and char burnout is completed by preheated primary air introduced below the grate. The speed of the feeders is modulated to maintain output with changing fuel conditions or to respond to load changes.

The grate must be designed to support efficient combustion of the biomass char and allow removal of the ash. There are several types of grates used with stokers:

- **Dumping grates** – Relatively old technology for high ash fuels
- **Pin-hole grates** – Stationary grate design for low ash fuels such as sugar cane bagasse
- **Traveling grates** – Well-proven air-cooled conveying grate design suitable for most biomass fuels
- **Vibrating grates** – Water-cooled sloping grate that periodically vibrates to remove ash from the grate surface.

One of the most commonly used grates in new applications is the vibrating grate, which is shown in Figure 3-1. Compared to traveling grate stokers, vibrating grates have virtually no maintenance and have low excess air requirements which improve boiler efficiency and emissions. In a vibrating grate stoker, vibration of the grate causes ash to move toward the discharge end of the grate where it falls into the bottom ash collection and conveying system. The vibration of the grate is not continuous. The frequency, duration, and intensity of the grate vibrations are adjustable. This allows for optimization of the ash layer depth on the grate. About 40 percent of the ash will leave the boiler as bottom ash, and 60 percent will be fly ash.

The stoker boiler requires the biomass fuel to be sized. Depending on the manufacturer, the top size of the fuel may range from 3 to 6 inches. Black & Veatch recommends that fuel specifications require a top size of 3 inches. However, the stoker boiler has some flexibility to handle larger pieces. It is likely the stoker will be able to handle up to 5 percent of the total fuel feed as strips or stringers up to 12 inches in length. On the other hand, small fuel tends to burn more completely in suspension, and its contribution to the overall fuel mix also needs to be limited. The ash from small fuel particles leaves the furnace as fly ash instead of settling on the grate and forming a protective thermal layer. Generally, for full load operation, no more than 25 percent of the total fuel stream should be less than 1/4 inch, and no more than 6 percent should be less than 1/8 inch.

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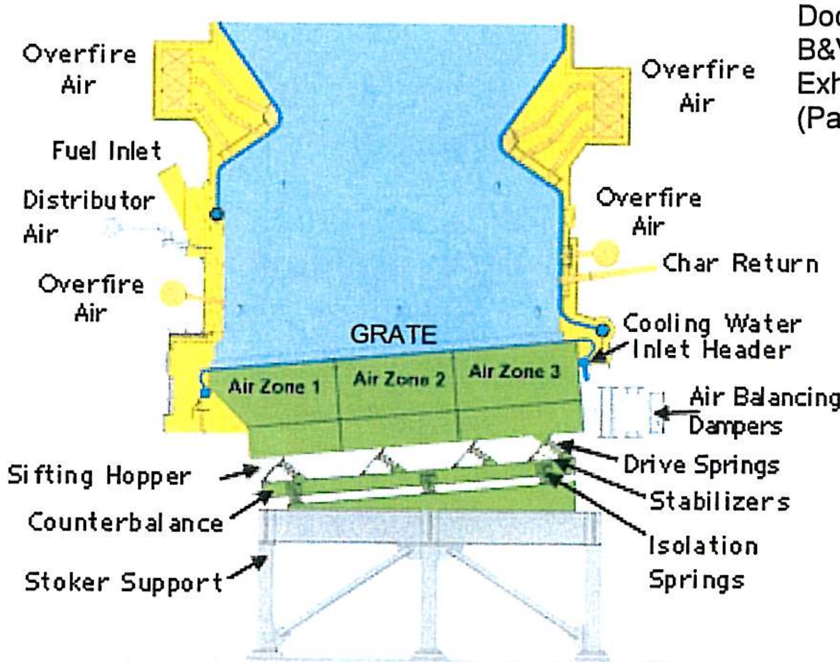

Figure 3-1. Vibrating Grate Stoker (Source: Riley Power).

Nitrogen oxide emissions from a new stoker boiler burning biomass waste can vary significantly with the type of biomass being burned, the moisture content of the biomass, temperature on the grate, and quantity of primary air. Although some plants report lower emissions, NOx emissions from biomass-fired stoker boilers typically range from 0.2 to 0.4 lb/MBtu. Selective non-catalytic reduction (SNCR) systems have been used in stoker boilers to reduce NOx emissions. In a SNCR system, a reagent (ammonia or urea) is injected into the flue gas to reduce NOx emissions levels by approximately 50 to 60 percent. Some facilities have reported higher reductions.

3.2.1.2 Bubbling Fluidized Bed Combustion

Combustion of biomass in fluidized bed boilers has been practiced for more than thirty years. In bubbling fluidized bed boilers, 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 output when fuel conditions or loads change. The fluidized bed consists of fuel, ash from the fuel, inert material (e.g., sand), and possibly a sorbent (e.g., limestone) to reduce sulfur emissions. In most biomass fired applications, the fuel typically has no or very little sulfur, thus limestone sorbent is not required and a sand bed is typically utilized. (There are some cases where biomass fuels can have higher sulfur content; for example, the sulfur content for wet cake and syrup residues from ethanol plants are somewhat higher, which may necessitate sorbent injection to control emissions).

The fluidized state of the bed is maintained by hot primary air flowing upward through the bed, as shown in Figure 3-2. The air is introduced through a grid to evenly distribute the air. The amount of air is just sufficient to cause the bed material to lift and separate. In this state, circulation patterns occur causing 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. Consequently, combustion temperatures can be kept low compared to other conventional fossil fuel burning 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 NOx formation. Low temperature is also an advantage with biomass fuels because they may have relatively low ash fusion temperatures. Low ash fusion temperatures can lead to excessive boiler slagging.

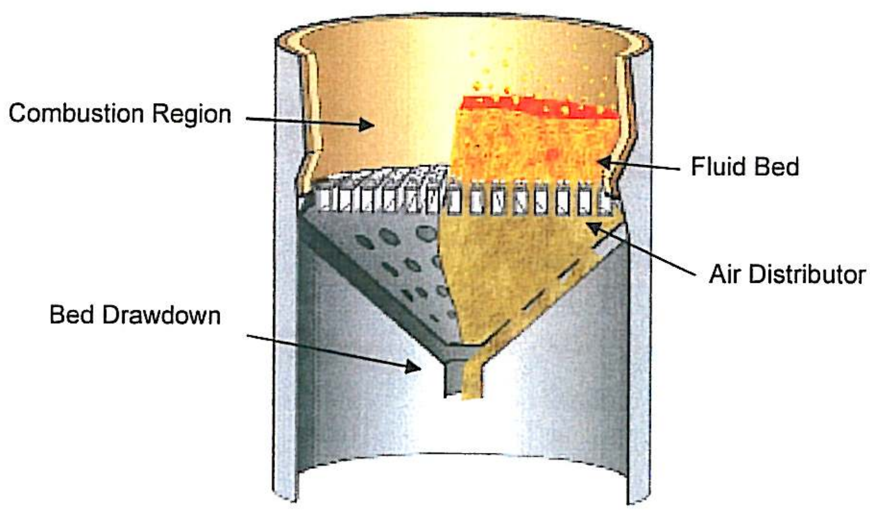

Figure 3-2. Typical Bubbling Fluidized Bed (source: Energy Products of Idaho).

In a bubbling bed boiler, the unit is generally designed to have flue gas velocities through the bed of less than 10 feet per second. This low velocity minimizes the amount of large solid material entrained in the flue gas stream. Management of tramp material and agglomerates in the bed is very important for long term reliable operation. For example, in the Energy Products of Idaho (EPI) bubbling fluidized bed boiler, there is a bed recycle system that withdraws material from the bottom of the fluidized bed. The removed bed material is screened to separate the tramp materials (dirt, and other noncombustibles) from the inert bed material, and the reclaimed inert material is recycled back to the bed.

As with a stoker boiler, the wood waste fuel rapidly devolatilizes. This results in 55 to 60 percent of the combustion occurring in the bed and 40 to 45 percent occurring above the bed. Overfire air is required to ensure complete combustion of the fuel.

The bubbling fluidized bed boiler requires sized fuel. For the EPI fluidized bed combustor, the top size of fuel should be 4 inches. Furthermore, while the stoker boiler has some flexibility to handle longer pieces, a three dimensional sizing criteria may be required for the fluidized bed boiler. This may require more screening and sizing operations to ensure that no dimension of the fuel exceeds the recommended upper limit.

Bubbling fluidized beds are fuel flexible and are technically capable of burning a wide variety of biomass fuels as well as coal. A disadvantage of bubbling fluidized beds compared to stokers is the large auxiliary power requirement for the fluidizing air fan. Further, they are typically more expensive than stokers.

Because of the low combustion temperatures, NOx emissions from a bubbling fluidized bed boiler burning biomass will be generally less than 0.20 lb/MBtu. In addition, the operating temperature of a bubbling fluidized bed is usually within the temperature range that allows a SNCR system to be effective. Another advantage with this type of system is that it has the potential to accommodate a wider range of fuel heating value and moisture content than the stoker boiler.

3.2.1.3 Circulating Fluidized Bed Combustion

As with bubbling fluidized bed boilers, circulating fluidized bed (CFB) units also offer a high degree of fuel flexibility and would be a suitable technology for burning biomass. As discussed earlier, with bubbling bed designs, gas velocities through the bed are typically less than 10 feet per second. In a circulating bed, fluidizing air velocity is maintained at 13 to 20 feet per second to prevent a dense bed from forming and to encourage carryover of solids from the bed. A solids separator (such as a cyclone) is used to recirculate the particles carried over from the furnace. Fuel is fed pneumatically into the combustor near the bottom of the unit and/or in the solids return leg.

Circulating fluidized beds share many of the same advantages as bubbling fluidized beds with regards to fuel flexibility, combustion efficiency, and emissions. The technology is better suited for larger sizes than stoker and bubbling fluidized bed combustion. The reason is that injection of fuel and limestone into the circulating media is much easier than evenly spreading the feed across a large grate or bubbling bed. While early circulating fluidized bed units were in the size range appropriate for most biomass plants (10-50 MW), present use of CFB technology is focused primarily on large fossil fueled units of 200 to 300 MW. Although manufacturers quote small CFBs, these units generally cost more than other combustion technologies, making them difficult to justify for smaller biomass plants.

Large CFBs are ideally suited to burn a broad mix of fossil and biomass fuels. Some CFBs have been designed to burn up to 100 percent biomass or 100 percent coal in the same unit. An example of a successful multi-fuel unit is the 240 MW CFB owned by Alholmens Kraft Oy in Finland. This plant burns a mix of wood, peat and lignite. This unit, shown in Figure 3-3, was supplied by Kvaerner Pulping and was commissioned in 2001. This is the largest biomass fired power plant in the world. At this scale, the technology is able to maximize economies and efficiencies of scale, similar to conventional coal plants.

Figure 3-3. Alholmens Kraft Multi-Fuel CFB (Source: Kvaerner).

3.2.1.4 Combustion Technology Summary Observations

This section (3.2.1) reviewed stoker grate boilers, bubbling fluidized bed combustion, and circulating fluidized bed combustion. The selection of combustion technology for a given application is influenced by the size of the unit, the characteristics of the biomass fuel, required emissions levels, and the amount and type of maintenance effort the owner will accept.

Although stoker boilers are the most widely used combustion technology for biomass, they are not always the most appropriate technical choice. For example, rice husks are most easily fired in fluidized beds or gasifiers because the lower operation temperatures reduce the risk of slagging. Stokers may also be used, but precautions should be taken to minimize the slagging potential. Fluidized beds are good choices in general because they can tolerate wide variations in fuel moisture content and size. Their lower operating temperatures also minimize concerns related to slagging and fouling. This allows fluidized beds to take advantage of low quality opportunity fuels that stokers might not be able to fire (such as wood from storm damaged trees in Florida that can have significant amounts of sand and dirt contamination). An additional advantage of fluidized beds is their inherently lower emissions and the ability to easily add sorbent to the bed to allow capture of sulfur. The turbulent action of the bed results in high combustion efficiency for fluidized beds; however, overall plant efficiency of fluidized bed units is usually slightly lower than stokers, due to the high auxiliary power consumption of the fluidizing air fans.

Considering economics, the choice of technology to use is somewhat related to size, as the capital costs of the different technologies scale differently. For units with a steam output equivalent of 25 MW of electrical generation and smaller, it is likely that the cost effective combustion technologies will be stoker and bubbling fluidized beds (BFBs). Stokers have lower capital costs (10 to 20 percent less than BFBs) and also have lower operations and maintenance costs. Although a single stoker can be designed to provide steam for systems as large as 100 MW, stokers are typically not cost competitive above 50 MW.

At sizes above 25 MW, circulating fluidized bed (CFB) combustion technology enters the mix of cost effective proven technologies. BFBs and CFBs are the most cost effective option for very large biomass plants (>70 MW). Ensuring consistent and even injection of fuel and limestone to the boiler is much easier for larger CFBs than stokers and BFBs. The fuel flexibility of a large CFB could allow it to utilize multiple fuel sources, including biomass and fossil fuels.

Table 3-1 compares the features of stoker and fluidized bed (bubbling and circulating) biomass boilers.

Table 3-1. General Comparison of Stoker and Fluidized Bed Technologies.

	Stoker Technologies	BFB and CFB Technologies
Efficiency Issues		
Boiler Efficiency	65-85	65-85
Auxiliary Power Consumption	7-12%	8-14%
Cost Issues		
Typical Total Plant Capital Cost	$2,500-$3,000/kW	$2,750-$3,500/kW
Operating and Maintenance Cost	$15-20/MWh	$16-22/MWh
Fuel Issues		
Fuel Flexibility	Good	Very Good
Ability to Handle High Moisture	Good	Very good
Slagging and Fouling Potential*	Fair with proper design	Good
Uncontrolled Emissions		
NOx Emissions	0.2 to 0.4 lb/Mbtu	Less than 0.2 lb/MBtu
SOx Emissions	Fuel dependent	Fuel dependent, but controllable with sorbent
CO Emissions	0.30 lb/MBtu	0.15 lb/MBtu

* Highly fuel dependent.

3.2.2 Gasification

Similar to coal gasification, biomass gasification is a thermal process to convert solid biomass into a gaseous fuel. This is accomplished by heating the biomass in an environment low in oxygen ("fuel rich"). Gasification is a promising process for biomass conversion. By converting solid fuel to a combustible gas, gasification offers the potential of using more advanced, efficient and environmentally benign energy conversion processes such as gas turbines and fuel cells to produce power, and chemical synthesis to produce ethanol and other value added products. Provided it is clean enough, the syngas created from gasification could also be used to displace natural gas currently used in gas-fired boilers, dryers, and other applications.

This section provides a brief history of biomass gasification, followed by a description of gasification fundamentals and a discussion of gas quality issues. The section also describes the various gasifier technology options, including gas conversion options and biomass integrated gasification combined cycle.

3.2.2.1 Gasification History

The history of gasification has been sporadic. Near the beginning of the twentieth century, over 12,000 large gasifiers were installed in North America in a period of just 30 years. These large systems provided gas to light city streets and heat various processes. Moreover, by the end of World War II, over one million small gasifiers had been used worldwide to produce fuel gas for automobiles. However, at the end of the war, the need for this emergency fuel disappeared; automobiles were reconverted to gasoline, and the arrival of large interstate natural gas pipelines put many municipal "gasworks" out of business. With the loss of equipment went the majority of the gasification artists – those who operated their generators with practical experience and intuition. In some cases, scientists and developers still struggle to reproduce with "state-of-the-art" technology what was routine operation half a century ago.

3.2.2.2 Gasification Fundamentals

Gasification is typically thought of as incomplete combustion of a fuel to produce a fuel gas with a low to medium heating value. Heat from partial combustion of the fuel is also generated, although this is not considered the primary useable product. Gasification lies between the extremes of combustion and pyrolysis (no oxygen) and occurs as the amount of oxygen supplied to the burning biomass is decreased. Biomass gasification can be described by the simple equation

$$\text{Biomass} + \text{limited oxygen} \rightarrow \text{fuel gas} + \text{heat}$$

Gasification occurs as the amount of oxygen, expressed in the equivalence ratio, is decreased. The equivalence ratio is defined as the ratio of the actual air-fuel ratio to the stoichiometric air-fuel ratio. Thus at an equivalence ratio of one, complete combustion theoretically occurs; at an equivalence ratio of zero, no oxygen is present and fuel pyrolysis occurs. Gasification occurs between the two extremes and is a combination of combustion and pyrolysis.

A formal definition of gasification might be the process that stores the maximum chemical energy in the gaseous portion of the products. Depending on the fuel and the reactor, the equivalence ratio for this condition can range between 0.25 and 0.35. An equivalence ratio of 0.25 represents the oxidation of one-fourth of the fuel. In most gasifiers, the heat released by burning this portion of the fuel pyrolyzes the remainder and produces a low heating value fuel gas. Below an equivalence ratio of 0.25, char (mostly solid carbon) begins to be substantially produced, and the gas production begins to taper off.

3.2.2.3 Gas Quality

The primary product of air-blown gasification is a low heating value fuel gas, typically 15 to 20 percent (150-200 Btu/ft^3) of the heating value of natural gas (1,000 Btu/ft^3). Gasifier fuel gas is alternatively known as syngas and producer gas. Combustible components of the gas include carbon monoxide, hydrogen, methane, and higher hydrocarbons such as ethane and propane. Inert components include nitrogen, carbon dioxide, water vapor, and trace pollutants and contaminants. The combustion of producer gas is illustrated in Figure 3-4.

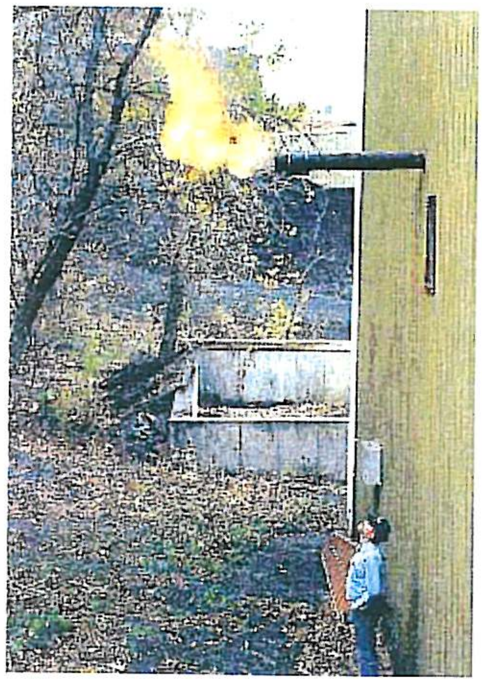

Figure 3-4. Gas Flare from an Experimental 5 TPD Biomass Gasifier.

The relatively poor quality of syngas from biomass gasification is a barrier for many applications. Most gasifiers use air to partially oxidize the fuel. Nitrogen, which comprises nearly half the volume of typical air-blown fuel gas, is inert and substantially decreases the heating value of the gas. Nitrogen can not be easily removed from the syngas using post-gasification processes; other approaches must be taken. The heating value of the fuel gas may be increased by using oxygen or steam instead of air to gasify the fuel or by indirectly heating the reactor. Either option removes most of the nitrogen from the fuel gas. Large coal gasification plants typically use pure oxygen as the oxidant and are able to achieve substantially increased gas heating values. However, the cost of building a separate oxygen plant is not justified for biomass facilities, which are typically less than 50 MW. Some alternative or indirectly-heated designs are promising, but these technologies are just now entering commercialization.

3.2.2.4 Gasifier Technology Options

There is a huge variety of gasification technologies including updraft, downdraft, fixed grate, entrained flow, fluidized bed, and molten metal baths. Unlike combustion technologies discussed previously, it is difficult to generally group and categorize gasification technologies because of the wide variety of process variables that differentiate designs. These include:

- **Reactor type** – Many of the same technologies that have been developed for combustion can be adapted for gasification. These include grate systems and bubbling and circulating fluidized beds. Some of these technologies can alternately operate between combustion and gasification modes simply by varying the balance and distribution of air and fuel in the reactor. Named for the direction of gas flow in the reactor, small updraft and downdraft gasifiers are more traditional designs and have been widely studied and used. Because they minimize tar production, downdraft gasifiers have been employed in small engine systems. Updraft gasifiers (such as the Primenergy gasifier) are more tolerant of high moisture fuels, but produce much more tar than downdraft gasifiers. For this reason, updraft gasifiers are usually operated close-coupled to burners. In addition to these types, there are a large number of other potential gasifier reactor designs including entrained flow (common for coal gasification) and molten metal baths.
- **Oxygen, steam, or air-blown** – Air blown gasification produces a fuel gas with a low heating value, typically 15 to 20 percent (150-200 Btu/scf) of the heating value of natural gas. The heating value of the gas may be increased by using oxygen or steam to gasify the fuel. Either option removes most of the inert nitrogen from the fuel gas, raising the gas heating value to near 500 Btu/scf. High heating value gas can be more readily used in combustion turbines and for chemical synthesis.
- **Heating method** – Air-blown gasification partially combusts biomass to provide the heat necessary to drive the gasification reactions. Instead of directly burning part of the fuel, indirect heating can be used to increase the gas heating value. Many methods have been devised to supply this energy. Some experimenters have simply heated the reactors externally with natural gas or electrical resistance heaters. These approaches have only been done on the research scale because they are not very efficient at supplying heat to the

reactor. More novel approaches for providing the heat include gasification in a molten metal bath, combustion of a portion of the fuel gas in immersed fire-tubes (MTCI), and dual circulating fluidized beds which circulate solids to transfer heat (FERCO).

- **Pressure** – Gasification systems can either be near atmospheric pressure or pressurized. Pressurized systems are preferred for applications that require the syngas be compressed (such as Fischer-Tropsch synthesis or gas turbines). However, pressurization complicates material feed and other aspects of the design.
- **Fuel gas conversion options** – There are many potential options for converting gasifier fuel gas to useful energy, as described further in the next section.

3.2.2.5 Gasification Fuel Gas Conversion Options

The primary advantage of gasification over combustion is the versatility of the gasification product. Gasification expands the use of solid fuel to include practically all the uses of natural gas and petroleum. Beyond higher efficiency power generation available through advanced processes, the gaseous product (specifically CO and H_2) can be used for chemical synthesis of methanol, ammonia, ethanol, and other chemicals. Gasification is also better suited than combustion for providing precise process heat control (e.g., for drying or glass-making).

The various fuel gas conversion options are illustrated in Figure 3-5. These options include:

- **Close-Coupled Boilers** – Fuel gas from gasifiers has been traditionally fired in close-coupled boilers for power generation via a standard steam power cycle, as shown in Figure 3-6. The fuel gas is combusted in a traditional oil or natural gas boiler to generate steam. The steam then drives a turbine to produce power. This setup provides the most conventional method of generating power but also one of the least efficient, with efficiencies comparable to direct combustion processes (20 to 25 percent). A potential advantage of this approach compared to direct combustion is that separate gasification allows one to remove ash material prior to the combustion stage. This can benefit downstream gas combustion devices by reducing particulate loading, emissions, and boiler corrosion and slagging caused by alkali material in the biomass. The fuel gas can also be cofired in existing fossil fuel boilers with little modification required to the boiler (see figure). This is a potentially attractive option for fossil fuel plant owners looking to add renewable fuel to their portfolio, without having to build a new greenfield plant. It is also attractive for industrial boilers looking to repower with biomass due to rising gas or coal costs. Compared to a greenfield biomass plant, the costs for a cofiring retrofit are much smaller.

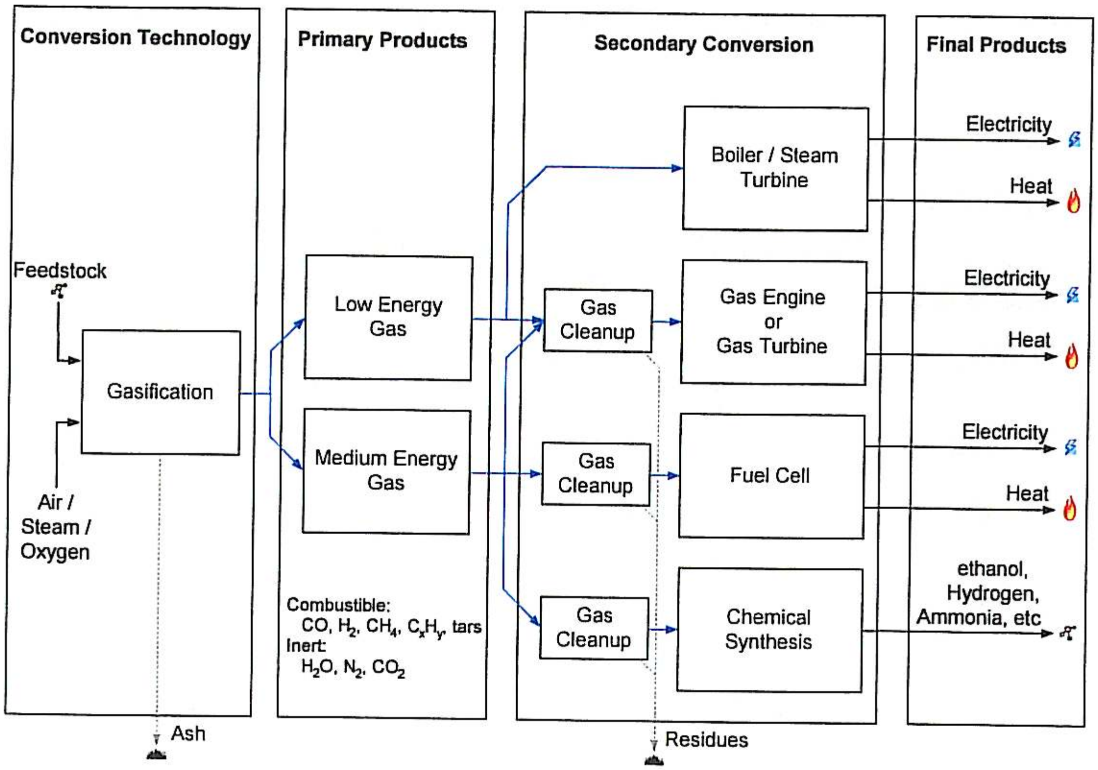

Figure 3-5. General Gasification Process Flow Options.

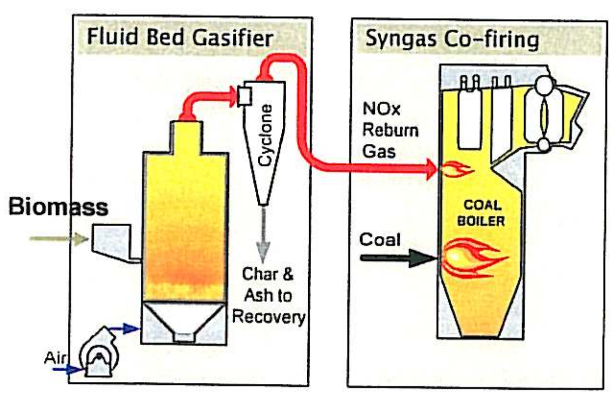

Figure 3-6. Gasification for Biomass Cofiring with Fossil Fuels.

- **Gas Engines and Turbines** – Gasifier fuel gas can also be fired in a reciprocating gas engine or gas turbine. Use of fuel gas in gas engines has been demonstrated, particularly for smaller system sizes. Derivatives of jet engine technology, gas turbines are more suited for larger sizes and are the centerpiece of integrated gasification combined cycle (IGCC) power plants, see further discussion below.
- **Fuel Cells** – Fuel cells electrochemically convert fuel gas and air into power. In general, fuel cells are not expected to be commercially available for a few years. Gasification is best suited for higher temperature fuel cells designs such as molten carbonate and solid oxide. Because fuel cells extract energy directly from fuel gases, they are very efficient throughout their size range. Integrated gasification fuel cell (IGFC) plants are not a commercial reality at this point because of high capital costs and developmental issues related to the extensive fuel gas conditioning and clean-up that is required.
- **Chemical Synthesis (including ethanol)** – The components of syngas, particularly carbon monoxide and hydrogen, can be used as "building blocks" for a large variety of chemicals, fuels, fertilizers, and other products. One of the more promising pathways is production of ultra-clean liquid fuels (such as methanol, ethanol, and diesel) through Fischer-Tropsch synthesis. Chemical synthesis using biomass gasification typically requires clean syngas and is largely in the demonstration phase. Gasification is heavily promoted as one of the key building blocks in the Department of Energy's "thermochemical platform" for the production of high value products, like ethanol, from biomass. Although ethanol synthesis via gasification is not yet a proven technology, gasification projects could be phased to demonstrate the technology incrementally (natural gas displacement followed by ethanol synthesis). Such an approach is being explored by Chippewa Valley Ethanol, near Benson, MN.
- **Stirling Engines** – Although not shown in the diagram, Stirling engines are another technology that can be used to convert the energy of the biomass syngas (or hot combustion gases) into electricity. A Stirling engine converts heat into useable mechanical energy by heating (expanding) and cooling (contracting) a captive gas such as helium or hydrogen. Unlike an internal combustion engine, where combustion occurs within the device, the Stirling engine is an external combustion device. Combustion takes place in another chamber and heat is transferred to the engine through a heat exchanger. The advantage is that the syngas or combustion gases do not need to be cleaned

prior to utilization. Stirling engines are typically small (< 100 kW) and are still in the research and development stage.

3.2.2.6 Biomass Integrated Gasification Combined Cycle

Up until the most recent focus on chemical synthesis applications, one of the principal focus areas for biomass gasification technology developers has been biomass integrated gasification combined cycle (IGCC). IGCC power plants are suitable for larger scale biomass conversion. Such plants consist of a gasifier or pyrolyzer that provides fuel gas to a standard gas turbine. The gas turbine burns the fuel and generates power. Sensible energy in the hot exhaust of the turbine can be recovered in a heat recovery steam generator (HRSG). Steam generated by the HRSG can be used for cogeneration and/or to power a steam turbine.

Commercial-scale IGCC coal-fired power plants are considered to be the most efficient solid-fuel technologies in operation today. Further development of this technology for biomass would benefit from improved gas clean-up. The most difficult part of the process is providing a clean gas to the gas turbine. Research in this area, specifically hot gas clean-up, is intensive. Biomass gasification systems should be lower cost than similar size coal IGCC plants because (1) the high reactivity (volatility) of biomass reduces gasifier costs, and (2) the low sulfur content of biomass reduces gas clean-up system costs. However, as with other biomass energy systems, gasification economics are hurt by difficulty reaching very large scales due to fuel supply constraints. Net conversion to electricity is projected to be approximately 35 percent for biomass IGCC plants, compared to 20 to 25 percent for conventional biomass combustion plants.

The potentially significant increase in efficiency has made biomass IGCC attractive to many developers and governments. Unfortunately, biomass IGCC projects around the globe have struggled to reach commercialization:

- **ARBRE, UK Project** – The 8 MW ARBRE IGCC project located near Eggborough in the United Kingdom was designed to use a TPS atmospheric circulating fluidized bed gasifier. The project included gas clean-up and a 5 MW Typhoon gas turbine. The project was to be fueled with locally grown wood. The project, originally estimated to cost over $40 million, was declared bankrupt after failing to achieve commercial operation. It was recently bought for around $4 million. Future status is unclear.
- **FERCO, Vermont Gasification Project** – The Vermont biomass gasification project, developed by Battelle/DOE and Future Energy Resources Corporation (FERCO), was only partially more successful. The project was sized to gasify up to 200 tpd of wood chips. Although FERCO did announce some

successful extended gasification trials, the project was never advanced to the IGCC stage (the syngas had been cofired in the adjacent wood stoker boiler). FERCO declared bankruptcy in 2002 after investing $10 million of its own money into the project (in addition to more than $30 million U.S. government funds). However, FERCO has now reorganized, and is actively seeking to sell gasification equipment again.

- **Hawaii Gasification Project** – The Hawaii gasification demonstration project was a pressurized air/oxygen gasifier designed to process up to 100 tpd of bagasse. The gasifier was designed by the Gas Technology Institute (GTI). The project was to include hot gas clean-up to allow the syngas to be fired in a gas turbine. The project had operated for about 500 hours but was halted due to ongoing problems with material handling and cessation of DOE funding. Carbona (formerly known as Tampella) has licensed the GTI gasifier design and is seeking to develop new projects with the technology.
- **Värnamo, Sweden** – The only large-scale IGCC project that has run for any appreciable length of time is the project in Värnamo, Sweden. The gasifier ran for more than 7,000 hours between 1993 and 1999. The demonstration project produced 6 MW of electricity and thermal energy. It was developed by Sydkraft AB and Foster Wheeler. The gasifier was a pressurized, air-blown circulating fluidized bed designed to gasify wood and wood waste. The project included warm gas clean-up and firing in a combustion turbine provided by European Gas Turbines. The project was not designed to be a full-scale commercial facility, and was closed in 1999 after completing demonstration trials.[1]

3.2.2.7 Making Advanced Gasification Projects Successful

The recent attempts to demonstrate IGCC have frustrated the biomass industry. Difficulties have been related not so much to the gasification process itself, but to supporting ancillary equipment, such as fuel handling and gas cleanup. Project budgets have generally not included enough contingency funding to overcome these issues. Given enough time, expertise, and capital, there are engineering solutions to these problems.

There are several suppliers of commercial gasification equipment, including Foster Wheeler, Energy Products of Idaho, and Primenergy. There are also numerous

[1] UC Davis, "Technology Assessment for Biomass Power Generation," October 2004, available at http://biomass.ucdavis.edu/pages/reports/UCD_SMUD_DRAFT_FINAL.pdf.

emerging vendors of advanced technologies that offer significant benefits (FERCO, Clean Energy / Pearson, and Frontline Bioenergy). Close cooperation with these suppliers and proper attention to ancillary systems will be necessary to make advanced biomass gasification projects successful. However, until there are proven, operating reference plants to visit, investors and lenders will remain skeptical of the technology.

Despite the recent problems with technology demonstration, the promise of (1) higher efficiency power production offered by IGCC or (2) the potential for lower cost ethanol production via a chemical synthesis platform remains attractive. One possible method to overcome the risks associated with advanced gasification processes is to develop a phased commercial project. In this approach, the various elements of the process would be built and proven sequentially prior to the next phase being implemented. For example, a project could be developed by building and proving the gasifier in a close-coupled boiler application first, prior to adding gas cleanup and advanced gas conversion processes. The economics and permitting of the project would be facilitated if an existing fossil fuel boiler could be identified to host the project.

The potential for advanced applications of gasification technology make the technology promising and worthy of further consideration for some applications. However, unlike combustion systems, for which there are commercial suppliers of proven technology, gasification is a more developmental technology. Although the first full-scale commercial systems for IGGC or chemical synthesis applications may be operational within five years, it will likely take 5 to 10 years before commercial systems are widely offered. This makes the technology less attractive to investors with shorter payback timeframes. On the other hand, investors who are more receptive to the risks and rewards associated with new technologies may find gasification to be an attractive approach.

3.2.3 Pyrolysis

Pyrolysis is the thermal decomposition of material in the absence of oxygen to produce a wide variety of products. It is an emerging biomass conversion process. To trace the word back to its Latin roots, pyrolysis is the breaking down (*lysis*) of a material with heat (*pyro*). Pyrolysis is performed with very little or no oxygen, and has been termed as "anaerobic combustion." Pyrolysis produces a variety of products, as described in the simple equation below:

$$\text{Fuel (solid)} + \text{Heat} \rightarrow \text{Fuel Gas} + \text{Char} + \text{Oil} + \text{Tar}$$

There are different types of pyrolysis, and the differences affect the end products of the process. Slow pyrolysis is the most conventional approach. The term "slow" is derived from the low fuel heating rates (less than 20°F/s). Additionally, temperatures are relatively low (less than 1,000°F), and char and oil/tar are the primary products. Fast pyrolysis, on the other hand, involves quick heat-up rates (20-200,000°F/s), and high temperatures (above 1,100°F). Rapid processing of the fuel freezes chemical reactions and allows for greater gas production at the expense of char, oil, and tar. Another classification, flash pyrolysis, is similar to fast pyrolysis in heat-up rates but occurs at lower temperatures (750-1,100°F). Flash pyrolysis focuses on the production of liquid tar and oil at the expense of gas and char. A general flow diagram for a typical pyrolysis system is included in Figure 3-7.

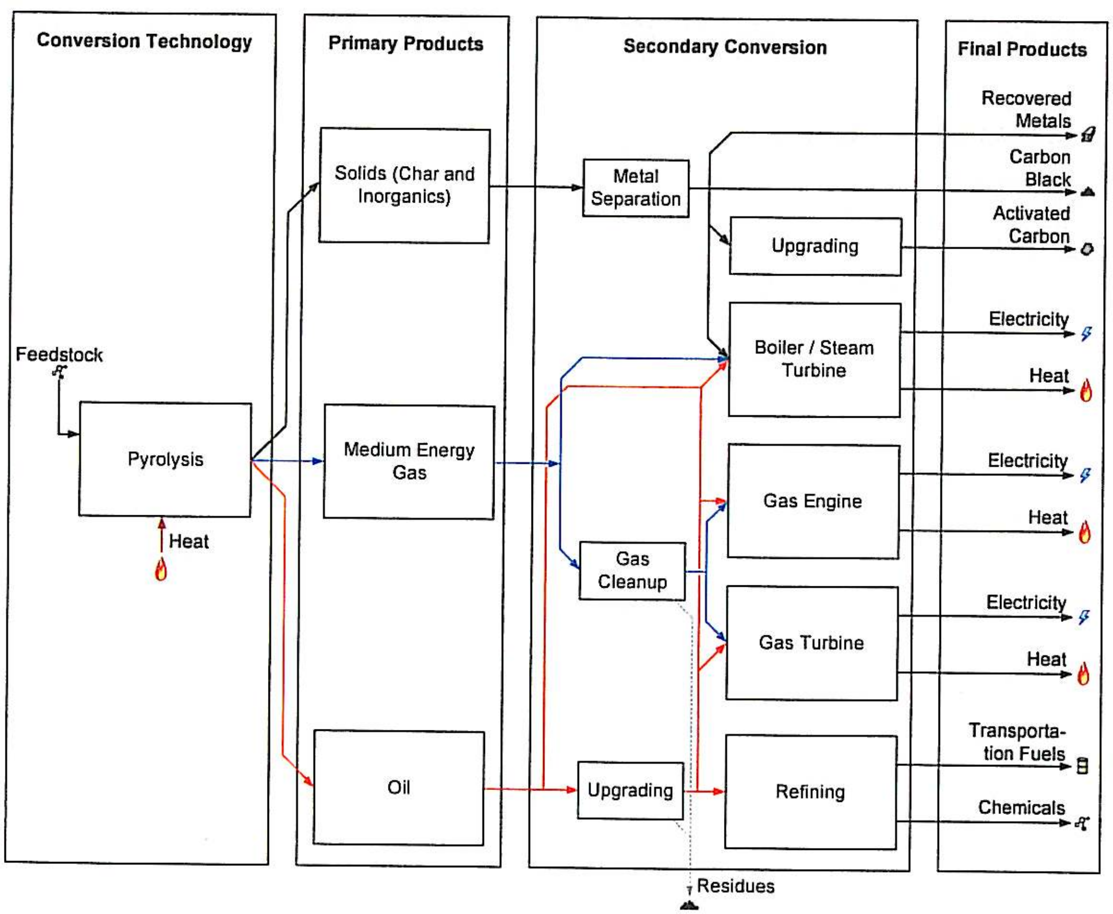

Figure 3-7. General Pyrolysis Process Flow Options.

Perhaps the most promising product from pyrolysis is bio-oil (see Figure 3-8). Bio-oil has potential applications as a replacement fuel for petroleum in boilers (and possibly heavy duty industrial gas turbines) or as a precursor for the creation of high value specialty chemicals (e.g., levoglucosan). Most pyrolysis processes are in the research, development and demonstration phase, and are not explored further in this study.

Figure 3-8. Bio-oil Produced from Pyrolysis (Source: Iowa State University).

3.3 Recommended Technologies for Further Consideration

Based on the observations provided above regarding the range of potential technologies that can be used for biomass-fired electric power production, three direct combustion technologies are recommended for further consideration for the biomass-fired unit at Deerhaven:

- Stoker grate boilers;
- Bubbling fluidized bed boilers; and
- Circulating fluidized bed boilers.

These technologies have demonstrated successful and reliable performance in prior biomass power applications and are considered fully commercial technologies.
A variety of gasification and pyrolysis technologies offer promise for future biomass power applications, and some of these appear ready for early "pioneer" demonstration projects. However, a substantial amount of risk will be incurred with these initial demonstrations, and are likely to entail research "fixes" (and related costs) for debugging problems that are more palatable when undertaken with significant government cost-sharing for the project. GRU has indicated a preference for commercially proven technologies rather than demonstration-stage technologies. Therefore, it is recommended that gasification or pyrolysis technologies be dropped from further consideration for this project.

4.0 Development of Preliminary Technology Characteristics

Following the identification of likely biomass-fired generation technologies, the defining characteristics of the appropriate generation system were determined through discussions with biomass boiler vendors, review of applicable environmental regulations, performance modeling of steam cycle and cost estimation of the likely system components. The findings are summarized in this section.

4.1 Boiler Vendor Surveys

Following the preliminary screening of technologies completed in Task 1, biomass combustion equipment vendors were contacted to determine the current state of the art of the selected biomass combustion technologies and to identify the relevant operational parameters of the technologies. To provide a basis for discussion, vendors were asked to identify the optimal equipment for the combustion of woody biomass fuels with moisture contents of 40 percent or greater. These systems were to be of sufficient size to supply steam to a steam turbine generator providing 50 to 100 MW of electrical generation. The vendors contacted during this survey are listed in Table 4-1.

Table 4-1. List of Contacted Biomass Boiler Vendors.

Vendor	Technologies Offered	Sales Representative	Phone
Babcock & Wilcox	Stoker, BFB, CFB	Michael Nickey	(281) 591-0139
Foster Wheeler	Stoker, BFB, CFB	Jim Utt	(719) 685-1986
Alstom[a]	Stoker, BFB, CFB	Vince Pacello	(913) 681-1616
Energy Products of Idaho	BFB	Patrick Travis	(208) 765-1611
Kvaerner	BFB	Hank Sherrod	(214) 783-5803
McBurney	Stoker	Greg Imig	(770) 925-7100
PowerDyne (Detroit Stoker)[b]	Stoker	Bryce Wilson	(816) 741-9779
Wellons Boiler	Biomass Boiler[c]	Bob Van Wassen	(412) 856-9745

Notes:

[a] Alstom declined to participate in discussions as the project size was deemed to be too large for their industrial group and too small for their utility group.

[b] Attempts were made to directly contact Detroit Stoker were attempted, but the inquiries were directed to PowerDyne, LLC, the regional distributor of Detroit Stoker equipment.

[c] The Wellons Boiler design is similar to modern stoker boilers, but contains features that are not found in typical stokers.

Prior to this survey, Black & Veatch anticipated that stoker boilers would be the preferred technology for units near 50 MW in size and that circulating fluidized bed boilers would be the preferred technology for units 75 MW in size and larger. However, as discussed below, through our vendor discussions, we found a strong case for the use of bubbling fluidized bed boiler technology throughout the 50 to 100 MW size range.

4.1.1 Findings of the Vendor Survey

Vendors capable of providing all three biomass combustion technologies under consideration were contacted first to determine which technology they currently recommend for biomass combustion in the defined size range. Key findings of the vendor survey include:

- Vendors capable of providing all three biomass combustion technologies under consideration (i.e., Babcock & Wilcox and Foster Wheeler) independently stated that BFBs would be the best choice for units up to 70 MW in size. Babcock & Wilcox recommended the use of BFBs across the entire size range, while Foster Wheeler recommended the use of CFBs for units in the size range of 70 to 100 MW (above 650,000 lb/hr of steam).
- At the lower end of the size range (approximately 50 MW), the vendors recommended BFBs in lieu of stokers because of the high moisture content of the biomass and low alkali content of woody biomass.
  - Stoker boilers would be an appropriate choice for fuels with moisture contents lower than 30 percent at the lower end of the size range. Foster Wheeler stated that a stoker boiler may also be appropriate if alkali contents were high, but the company declined to define the alkali level that would be considered "high" and recommended that a fuel analysis be completed prior to the final technology selection.
  - The operation of BFB is actually enhanced by fuels with moisture contents of approximately 40 to 50 percent; the presence of moisture in the fuel moderates the temperature of the fluidized bed and maintains an operating regime in which combustion is complete and NOx emissions are relatively low.
  - For optimal operation of a BFB, Babcock & Wilcox recommended that fuel moisture content be held within a 15 percentage point window (i.e., fuel moisture content be maintained in a range of 40% to 55% or another similarly sized range). This will allow the BFB to be designed for optimal performance for the selected fuel and reduce process upsets.
  - Since BFBs are considered a more modern technology, permitting of a BFB may be easier than permitting of a stoker system.

- Due to the lower operating temperature of BFBs and the use of flue gas recirculation (FGR), there is very little thermal NOx produced during BFB combustion of biomass. Virtually all of the NOx produced is believed to be fuel-derived. Uncontrolled NOx emissions for a BFB are in the ballpark of 0.15-0.20 lb/MBtu; utilization of an SNCR system may reduce this rate by 25%.
- The design of the boiler (waterwalls, superheater and backpasses) is very similar for the stoker and BFB-fired units. In fact, stokers have been modified to operate as BFBs. Due to the similarity in design, capital costs for similarly sized stokers and BFBs are roughly equivalent.

- At the higher end of the size range, Babcock & Wilcox recommended BFBs in lieu of CFBs due to the higher capital costs of CFBs.
  - According to Babcock & Wilcox, the capital costs of CFBs are approximately 10% to 15% higher than those of BFBs.
  - Operational costs for CFBs are also higher (Babcock & Wilcox did not quantify the difference) than BFBs. This is due to the higher auxiliary load of CFBs (due to higher pressure drops through the system, a CFB requires a higher horsepower blower) and higher costs associated with dust collection systems and other downstream equipment.

Following discussions with Babcock & Wilcox and Foster Wheeler, the other vendors listed in Table 4-1 were contacted. Pertinent notes from those discussions include:

- With the exception of Kvaerner, all of the remaining vendors would be limited to supplying units near 50 MW in size. Wellons Boiler would be required to provide two units to produce the requisite steam for a 50 MW system. The maximum steam flow rates and conditions of each of these vendor's systems are shown in Table 4-2.
- All vendors are capable of firing fuels with moisture contents in the range of 35 to 50 percent.
- All vendors claimed to be able to meet expected emission requirements for the biomass-only case. All vendors felt that SNCR would be necessary to comply with NOx limits, but little to no sulfur control would be required for the combustion of 100 percent biomass.

Table 4-2. Maximum Steam Flow Rates and Conditions by Vendor.

Vendor	Technology Offered	Steam Flow (lb/hr)	Steam Conditions (psig/°F)
Energy Products of Idaho	BFB	420,000	650/650
Kvaerner	BFB	920,000	1500/1005
McBurney	Stoker	500,000	Unspecified
PowerDyne (Detroit Stoker)	Stoker	500,000	Unspecified
Wellons Boiler	Biomass Boiler	500,000*	825/825

Notes:
* Wellons Boiler would require two 250,000 lb/hr units to provide 500,000 lb/hr.

4.1.2 Recommendations for the Biomass-Fired System

Based on the information provided by the vendors during the survey, Black & Veatch recommends the following:

- A bubbling fluidized bed (BFB) boiler is recommended to provide steam for an electrical generation system fired by 100 percent biomass.
- The electrical generation capacity of the system will be determined by the availability of biomass fuel rather than any technical characteristic or limitation of the boiler system. A detailed biomass resource assessment is recommended to identify potential biomass suppliers, to better establish the likely cost of the fuel, and to determine the optimal size of the system.
- Specific fuel characterization (fuel analyses) should be done as part of the resources assessment.

4.2 Air Permitting

The following is a high-level assessment of air permitting considerations associated with the possible installation of a biomass-fired stoker boiler or biomass-fired fluidized bed boiler at the Gainesville Regional Utility (GRU) Deerhaven Generating Station (hereinafter referred to as facility). A primary focus of this assessment is new source review (NSR) applicability and requirements. Other permitting issues, such as new source performance standard (NSPS) applicability, are also addressed.

4.2.1 Project Description

Based on information provided in the facility Title V permit, the facility currently consists of one 960 MBtu/hr fuel oil or natural gas fired boiler, one 2,428 MBtu/hr coal fired boiler, and one nominal 74 MW (990.6 MBtu/hr) simple cycle combustion turbine. GRU is considering installation of 50 to 100 MW of biomass-fired generation at Deerhaven. For the purposes of this assessment only emissions from the new boiler are considered and emissions from auxiliary project equipment including wood material handling and preparation processes are not discussed.

4.2.2 PSD Applicability

The prevention of significant deterioration (PSD) NSR regulations are the regulations of concern for facilities located in areas designated attainment or unclassifiable for all criteria pollutants. For areas classified nonattainment for a criteria pollutant, the nonattainment NSR regulations would be the regulations of concern for those pollutants designated nonattainment. Based on a review of information in the United States Environmental Protection Agency (USEPA) Green Book internet data base, Alachua County Florida is not classified nonattainment for any criteria pollutants. As such, PSD regulations would govern for the Deerhaven Facility.

The facility is one of 28 named source categories with a 100 ton per year (tpy) PSD major source threshold level. Because the existing facility has potential emissions greater than 100 tpy of at least one PSD pollutant, it is considered an existing major PSD source. The installation of a new emissions unit at an existing PSD major source is considered a modification to that major source. If the emissions increase and the net emissions increase associated with the installation of the new emissions unit are greater than the PSD significant emission rates (SERs), the modification is considered a major modification and is subject to PSD permitting. An emissions increase analysis must be conducted to determine the potential annual emissions for each PSD pollutant and determine PSD applicability for each pollutant. This entails a pollutant-by-pollutant emissions increase comparison with the PSD SERs. Table 4-3 below shows the SERs for the pollutants commonly associated with installation of a new boiler.

As an initial step in determining project PSD applicability, the Project potential to emit for each pollutant is compared to the respective SER for that pollutant to determine PSD applicability for that pollutant. Projected operating data and emission rates for each type of new boiler considered for the Project are shown in Table 4-4 below. Comparing the Table 4-4 estimated annual emissions with the SERs given in Table 4-3, it is seen that with all three units considered for the project, the potential emission increases are greater than the PSD SERs for NO_x, CO, PM/PM_{10} and SO_2. As such, unless it can be demonstrated that the project net emissions increase on a pollutant-by-pollutant basis are less than the respective SERs, the project would be subject to PSD for each of these pollutants. Note that the potential tpy emissions presented in Table 4-4 are based on unlimited full-load year round operation (8,760 hours per year operation at 100 percent load). Although one method to try to avoid PSD permitting is to accept a limit on the annual operation of a new emissions unit, it is seen by the level of emissions shown in Table 4-4 that a relatively significant limit on operations would be needed to avoid PSD permitting, and that approach is not discussed further in this assessment.

Table 4-3. PSD Significant Emission Rates.

PSD Pollutant	Significant Emission Rates (tons per year)
NO_x	40
SO_2	40
CO	100
VOC	40
PM	25
PM_{10}	15
Sulfuric acid mist	7
Lead	0.6

Table 4-4. Assumptions for Biomass-Fired Unit Emission Calculations.

	50 MW Stoker Boiler	Smaller-Scale (75 MW) CFB Boiler	Larger-Scale (100 MW) CFB Boiler
Net Power Output (MW)	50.0	75.0	100.0
Est. Auxiliary Load (MW)	7.5	8.3	11.0
Gross Power Output (MW)	57.5	83.3	111.0
Net Plant Heat Rate (Btu/kWh)	13,500	12,000	12,000
Est. Biomass Input (MBtu/hr)	675	900	1200
Emission Rates			
NOx (lb/MBtu)	0.150	0.075	0.075
CO (lb/MBtu)	0.300	0.100	0.100
VOC (lb/MBtu)	0.050	0.005	0.005
PM10 (lb/MBtu)	0.025	0.020	0.020
SO2 (lb/MBtu)	0.100	0.040	0.040

The determination of whether there is a net emissions increase is typically referred to as a netting analysis. A netting analysis only provides a favorable result if there have been or will be emission reductions at the facility during what is termed the netting contemporaneous period. The netting contemporaneous period covers the period beginning five years prior to commencing construction on the new project and ending when emission increases from the new project are first realized. Typical facility changes that may have or will result in emission decreases and thus be useful in considering whether a netting analysis would be beneficial are shutdown of existing emission units or the addition of controls to existing emission units, such as controls added to reduce NO_x or SO_2 emissions as part of a clean air interstate rule (CAIR) compliance strategy. With the netting analysis all contemporaneous emission decreases and increases, including the project emission increases are summed to determine if there is a net emission increase greater than the respective SER for each pollutant. Again, the netting analysis is done on a pollutant-by-pollutant basis to determine PSD applicability for each pollutant for which the project itself results in an emissions increase greater than the SER.

Note that the basis for this discussion is this installation of a new unit at an existing PSD major source (Deerhaven). If the new unit were to be located at a greenfield site, the initial determination of whether PSD would apply to the installation would be based on whether potential emissions of any single PSD pollutant were greater than the major source threshold level. As discussed previously, the major source threshold level for 28 listed source categories is 100 tpy, while all other facilities would have a major source threshold level of 250 tpy. The 100 tpy threshold source category that may be applicable to a new unit of the type considered in this analysis would be the category fossil fuel-fired steam electric plants of more than 250 MBtu/hr heat input. If the type of unit proposed for the Deerhaven facility were to be located at a Greenfield site a closer look at the design fuel for the unit would be needed to determine if it constituted a fossil-fuel fired unit and as such a 100 tpy source. Whether a 100 tpy or 250 tpy source, PSD applicability for a Greenfield site construction is first based on whether potential emissions of any single PSD pollutant exceed the applicable major source threshold level (either 100 tpy or 250 tpy). If so, then potential emissions of all other pollutants are compared to the SERs to determine PSD applicability. Therefore, in terms of PSD applicability, the advantage of locating at a Greenfield site is only gained if one can limit emissions of each PSD pollutant to less than the appropriate PSD major source threshold level.

Several requirements associated with PSD permitting can add complexity, costs, and increased permitting time to a project. PSD permitting includes the requirement to use best available control technology (BACT) and the requirement to conduct an ambient air quality impact analysis (AAQIA). Both the BACT requirement and the AAQIA will add complexity to the permit application preparation and processing of the permit by the permitting agency. This in turn results in an increase in the amount of time needed to obtain an air construction permit, which is needed before a facility can commence construction on a project. For these reasons, if the PSD permitting process can reasonably be avoided for a project, it is typically preferred to obtain a minor source construction permit. However, unless a netting analysis can be used to net out of PSD, it is typical for the installation of a new generating unit at a power plant to go through PSD permitting.

The following is a brief emissions control discussion. If the Project can avoid PSD applicability, an official best available control technology (BACT) analysis will not be required. However, without a netting analysis, it is expected that the proposed unit would be a PSD major modification and would need to go through a PSD BACT analysis. A good place to start in determining emission controls on similar units is to look at permit limits for similar projects. A preliminary review of the USEPA BACT/RACT/LAER Clearinghouse shows a limited listing of new biomass boilers over the last five years. Two of those listings are summarized here. The most recent listing for a CFB wood boiler with greater than 250 MBtu/hr heat input was for a 50 MW unit in New Hampshire with an October 25, 2004 permit issue date. The emission limits of this unit are shown in Table 4-5. A waste wood spreader stoker boiler was permitted in the state of Washington in 2002; the emission limits for this unit are shown in Table 4-6.

Table 4-5. Emission Limits of a 50 MW CFB Located in New Hampshire.

Pollutant	Units	Permitted Limit	Comments
NO_x	lb/MBtu	0.075	
SO_2	lb/MBtu	0.020	
CO	lb/MBtu	0. 100	BACT—PSD
VOC	lb/MBtu	0.005	
PM_{10}	lb/MBtu	0.025	MACT
Hg	lb/MBtu	3×10^{-6}	MACT
Sulfuric acid mist	lb/MBtu	0.020	MACT
NH_3	ppm	10	@ 7% O_2

Table 4-6. Emission Limits of a Biomass-Fired Stoker Located in Washington.

Pollutant	Units	Permitted Limit	Comments
NO_x	lb/MBtu	0.150	
CO	lb/MBtu	0.350	
PM	lb/MBtu	0.020	

4.2.3 Additional Regulatory Review

4.2.3.1 NSPS Applicability

A separate regulatory program that will likely be applicable to the Project wood fired boiler is the New Source Performance Standards (NSPS). The NSPS regulations are found in Part 60 of Volume 40 of the Code of Federal Regulations (CFR). NSPS Subparts D, Da, Db, and Dc apply to boilers, depending on the size of the boiler, the date of construction, reconstruction or modification of the boiler and the types of fuel fired in the boiler.

Preliminary NSPS applicability:

40 CFR 60 Subpart Da – *Standards of Performance for Electric Utility Steam Generating Units for Which Construction is Commenced After September 18, 1978* – is applicable to electric utility steam generating fossil fuel fired units of the designated size. Per 40 CFR 60.40Da, Subpart Da is applicable to each electric utility steam generating unit that is capable of combusting more than 250 MBtu/hr heat input of fossil fuel (either alone or in combination with any another fuel) and for which construction, reconstruction or modification commenced after September 18, 1978. Because wood is not considered a fossil fuel, applicability of Subpart Da to a wood boiler would be dependent on the extent, if any, that fossil fuels would also be used in the boiler. While a detailed review of Subpart Da is required to determine applicability and requirements, the following is a general listing of the PM, NO_x, and SO_2 standards applicable to a newly constructed unit subject to Subpart Da:

- PM standard of 0.015 lb/MBtu
- NO_x standard of 1.0 lb/MWh
- SO_2 standard of 1.4 lb/MWh

40 CFR 60 Subpart Db – *Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units* – is applicability to new facilities that have a heat

input capacity greater than 29 MW (100 million Btu/hr). Units subject to NSPS Subpart Da are not subject to Subpart Db. Since Subpart Db applicability is not limited to fossil fuel fired units, the new wood boiler would be subject to Subpart Db unless it is determined that Subpart Da is applicable. The Subpart Db standard for NO_x is a function of the fuel types used in the boiler and the capacity factor for use of the various fuel types. The following is a general listing of the PM, NO_x, and SO_2 standards for a new unit subject to Subpart Db:

- PM standard of 0.03 lb/MBtu
- NO_x standard of 0.2 lb/MBtu if the unit fires coal, oil, or natural gas or a mixture of these fuels, or with any other fuels, unless the facility has a federally enforceable requirement that limits operation of the unit to an annual capacity factor of 10 percent or less for coal, oil, and natural gas.
- SO_2 standard of 0.2 lb/MBtu

4.2.3.2 MACT Standard Applicability

The National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters is found at 40 CFR Part 63, Subpart DDDDD. These types of standards are commonly referred to as MACT (maximum achievable control technology) standards and this specific standard is commonly referred to as the industrial boiler MACT. A fossil-fuel fired electric utility steam generating unit of more than 25 megawatts that produces electricity for sale is not subject to the industrial boiler MACT. However, wood is not considered a fossil-fuel. If only wood is fired in the new unit, it appears that the proposed new unit would not meet this exemption and would be subject to the industrial boiler MACT. However, if wood is to be co-fired with a fossil fuel or a fossil fuel may be used as an alternative fuel source in the boiler, a more detailed analysis would be needed to determine whether the new unit would be subject to the industrial boiler MACT. Also, only affected units at major sources of hazardous air pollutants (HAPs) are subject to this MACT standard. Based on information provided in the Deerhaven facility Title V permit, the facility is an existing major source of HAPs.

4.2.3.3 CAIR Applicability

The Clean Air Interstate Rule (CAIR) includes a cap and trade program for NO_x and SO_2 emissions. A fossil-fuel fired boiler serving a generator with a nameplate capacity greater than 25 MWe producing electricity for sale is subject to CAIR. According to the definitions given in the CAIR regulations a fossil fuel fired unit is a unit that fires any amount of fossil fuel in a calendar year. As such, if fossil fuel is used in the new unit it may be subject to the CAIR cap and trade program.

4.2.3.4 Florida Power Plant Siting Act

The Florida Power Plant Siting Act provides procedures for obtaining all needed permits and approvals for a new electric utility facility or unit. The appropriate air construction permit application is one part of the overall siting act application. Going through the siting act approval process can add complexity and time to the overall permitting process. The GRU Deerhaven facility has gone through the Florida Power Plant Site Certification Act and as such has conditions of certification for the facility. It is expected that, at a minimum, the installation of a new generating unit at Deerhaven would require a modification to the plant's Site Certification.

4.2.4 Summary

In summary, unless netting can be used to avoid PSD applicability, it is expected that the installation of a new wood-fired boiler at the Deerhaven facility would be considered a major modification to the facility under PSD regulations for a number of pollutants. If PSD is triggered, it will require the need to install BACT level controls and an AAQIA would be needed as part of the permit application. In general, a PSD permitting effort from start of application preparation to receiving an Agency permit is typically estimated to take 12 to 24 months. Another consideration when proposing to install additional electric utility steam generating units in Florida is whether the installation will be subject to the Florida Power Plant Siting Act. It is expected that, at a minimum, the installation of a new generating unit at Deerhaven would require a modification to the plant's Site Certification.

4.3 Performance Modeling

To quantify performance of the system and determine certain operating parameters, a model of the steam cycle was constructed, and heat and mass balances were developed for three operational scenarios. These scenarios include:

- 50 MW (net) Steam Cycle
- 100 MW (net) Steam Cycle
- 100 MW (net) Steam Cycle, with Reheat

4.3.1 Model Assumptions and Results

Key assumptions of the thermal performance modeling include:

- Average ambient dry bulb temperature is assumed to be 59°F, and average relative humidity is assumed to be 50 percent.
- Boiler efficiency is assumed to be 80 percent.
- Steam temperature and pressure at the boiler outlet are assumed to be 955°F and 1528 psig for the 50 MW scenario. Steam temperature and pressure at the boiler outlet are assumed to be 955°F and 1815 psig for the 100 MW scenarios.
- A wet cooling system with a mechanical draft cooling tower is employed to condense steam.

The results of thermal performance modeling are summarized in Table 4-7. The complete results for the 50 MW scenario, the 100 MW scenario and the 100 MW with reheat scenario are provided in Appendix A, Appendix B and Appendix C, respectively.

The performance results for the 100 MW BFB case are based on the results for the 100 MW CFB case. Because the steam cycle parameters are identical for the BFB and CFB systems, the steam flows and conditions for these two cases are also identical. Furthermore, the differences in auxiliary power requirements for these two systems were assumed to be negligible, as the increased pressure drops through the CFB system are mitigated to some extent by the increased excess air requirements of the BFB. However, the boiler efficiency of the BFB was assumed to be approximately 3 percentage points lower for the BFB relative to the CFB due to increased excess air requirements and greater unburned carbon losses for the BFB. The lower boiler efficiency results in a slightly higher net plant heat rate and greater fuel requirements for the BFB relative to the CFB system, as shown in Table 4-7.

Partial load performance data was obtained by consideration of the operation of all scenarios at full (100 percent) load, 75 percent load and 50 percent load. Net plant heat rates at partial loads are illustrated in Figure 4-1.

4.3.2 Biomass Fuel Consumption Rates

The biomass fuel consumption of the facilities was estimated for each of the scenarios. This calculation assumed a higher heating value of 8500 Btu/lb for dry biomass and a moisture content of 40 percent for as-received biomass fuel. Thus, the higher heating value of the as-received biomass fuel was assumed to be 5100 Btu/lb. Given this heating value, the biomass fuel consumption of the 50 MW facility would be roughly 1460 tons per day (tpd). The biomass fuel consumption of the 100 MW facility without reheat would be approximately 2800 tpd, while the biomass fuel consumption of the 100 MW facility with reheat would be approximately 2690 tpd.

Table 4-7. Summary of System Performance Modeling. [a]

Full Load System Parameters	50 MW Stoker	100 MW BFB[b]	100 MW CFB	100 MW CFB (Reheat)
Turbine Gross Output (100% Load), kW	57,465	115,053	115,053	114,977
Turbine Heat Rate (100% Load), Btu/kWh	8,657	8,259	8,259	7,924
Total Auxiliary Power (100% Load), kW	7,470	15,000	15,000	15,000
Total Auxiliary Power (100% Load), %	13.0	13.0	13.0	13.0
Net Plant Output (100% Load), kW	50,000	100,050	100,050	99,980
Heat to Steam from Boiler (100% Load), MBtu/hr	497.9	951.2	951.2	913.4
Boiler Efficiency (HHV)	80.0	77.0	80.0	80.0
Boiler Heat Input (100% Load), MBtu/hr (HHV)	622.4	1,235.3	1,189.0	1,141.7
Biomass Fuel Requirement[c], tons/day	1,464	2,907	2,798	2,686
Number of Heaters	4	5	5	5
Part Load Heat Rate Calculations				
Net Plant Heat Rate (100% Load), Btu/kWh (HHV)	12,448	12,347	11,884	11,420
Net Plant Heat Rate (75% Load), Btu/kWh (HHV)	13,017	12,826	12,345	11,779
Net Plant Heat Rate (50% Load), Btu/kWh (HHV)	14,177	13,979	13,455	12,705

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.
Auxiliary power is assumed to be 13% of base load (100% load).
Water cooling with mechanical draft cooling tower is used.
Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.
Boiler efficiency is assumed to be 80% for all cases except the 100 MW BFB case.

[b] The thermal performance for the 100 MW BFB case was estimated from the modeling of the 100 MW CFB case. It was assumed that auxiliary power requirements would be roughly equivalent for the two systems, but boiler efficiency would be slightly lower for the BFB relative to the CFB because of the increased excess air requirements and greater unburned carbon losses for the BFB.

[c] Biomass fuel requirement, in tons per day, was calculated based on the boiler heat input and an assumed heating value of biomass of 5100 Btu/lb. This heating value assumes a biomass moisture content of 40%.

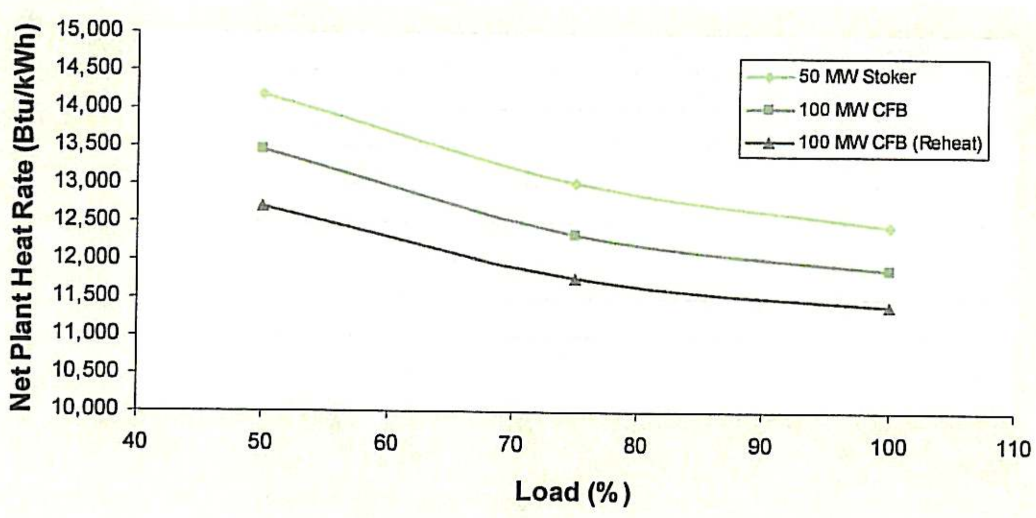

Figure 4-1. Partial Load Net Plant Heat Rate.

4.3.3 Feasibility of Reheat Systems

As indicated in Figure 4-1, the inclusion of reheat systems into the design of the 100 MW unit lowers the net plant heat rate from 11,900 Btu/kWh to 11,400 Btu/kWh, or approximately 4 percent. Based on the calculated biomass fuel consumption rates, this improved efficiency results in a reduction of fuel consumption by 34,000 tons per year. Assuming a biomass cost of $15 per ton, the inclusion of a reheat system results in fuel cost savings of roughly $500,000 per year.

As a general guideline, Black & Veatch assumed that the reheat system would have to pay for itself within ten years to be considered economically viable. Therefore, considering the estimated fuel cost savings, the addition of the reheat system must increase the required capital investment by less than $5,000,000. Black & Veatch estimates that the inclusion of a reheat system would increase the total capital investment required for the 100 MW system by roughly $15,000,000 to $20,000,000. Therefore, the reheat system does not appear to be economically viable. It should be noted that this conclusion is consistent with the opinions of boiler vendors expressed during the vendor survey discussed in Section 4.1. The consensus among vendors was that reheat systems are not economically viable unless the generation system size is significantly larger than 100 MW.

4.4 Cost and Operations Data

Cost estimates and operational parameters have been gathered for biomass-fired units based on similar projects. These estimates and operational parameters include capital costs (EPC contracting basis), operating and maintenance (O&M) costs, cash flow during construction, maintenance schedules and availability assumptions. This information is presented in the following subsections.

4.4.1 Capital Cost Estimates and Cash Flow during Construction

Cost estimates have been developed for both a 50 MW biomass-fired BFB system and a 100 MW biomass-fired BFB system. The cost estimates have been determined on an EPC-contracted basis. Assumptions of the cost estimates include:

- The plant site is the existing Deerhaven site, which is reasonably level and clear with no wetlands. Demolition of any existing structures is not included in this cost estimate. Sufficient space exists for the new boiler and steam turbine and for additional biomass storage. The site has sufficient area available to accommodate construction activities including, but not limited to, offices, laydown, and staging. The cost of piles under all major equipment is included.
- Wood chips will serve as fuel for the unit and will be delivered to the plant "ready to burn". No on-site processing is included. The 50 MW plant will require 1460 tons per day of biomass, and the 100 MW plant will require 2800 tons per day.
- The plant configuration consists of one bubbling fluidized bed (BFB) boiler with a Rankine steam cycle. All steam is sent to a condensing steam turbine. The 50 MW system will require 480,000 lb/hr of steam, and the 100 MW system will require 940,000 lb/hr of steam.
- Heat rejection from the main cycle is accomplished using a mechanical draft, evaporative cooling tower.
- Standard redundancy has been assumed for boiler feed pumps, feedwater heaters and condensate pumps.
- Air quality control is accomplished through the use of a Selective Noncatalytic Reduction (SNCR) system for NOx. A baghouse is included for particulate control. No SO2 control systems or equipment are included.

Direct cost assumptions include:

- All direct costs are expressed in 2006 US dollars.

- Direct costs include those associated with the purchase of equipment, erection, and contractors' services. Service contracts and construction indirects are included and cover all heavy equipment use such as turbine and transformer unloading equipment, cranes, hoists and earth moving equipment. This category also includes all performance testing during construction (welds, concrete, etc.), subcontractor profit and site services such as cleanup during construction and sanitary services and water. Field office expenses are included in this category.
- These costs are "overnight" costs excluding Owner's costs, escalation and interest-during-construction.
- Equipment shipping is included in the cost estimate.

Indirect cost assumptions include:

- General indirect costs include relay checkouts and testing; instrumentation and control equipment calibration and testing; systems and plant startup including services of an operating crew during testing and the initial operation period; operating crew training; and the electricity, water, and fuel used by contractors during construction. All standard insurances are included. An allowance is included for spare parts during startup.
- Engineering and related services include architectural and engineering (A/E) services, and other related costs.
- Field construction management services include field management staff and supporting staff personnel; field contract administration, field inspection, and quality assurance; project control; technical direction and management of startup and testing; cleanup expense for the portion not included in the direct-cost construction contracts; safety and medical services; guards and other security services; insurance premiums; and other required labor-related insurance. Telephone and other utility bills associated with construction are included.
- A contingency allowance is also included.

The cost estimates exclude Owner's "soft" costs. Potential costs that are typically classified as Owner's costs are listed in Table 4-8. Based on Black & Veatch experience, total Owner's costs can range between 35 to 65 percent of the EPC cost. The magnitude of Owner's costs is dependent upon the site specific requirements of each project.

Based on the assumptions identified above, cost estimates were developed for both the 50 MW and 100 MW biomass-fired BFB systems. The estimates are listed in Table 4-9 and Table 4-10, respectively.

The cash flow during construction is assumed to follow a general S-curve for both scenarios considered in the capital cost estimates. The monthly cash flows are listed in Table 4-11.

Table 4-8. Owner's "Soft" Costs.

Project Development:	**Plant Start-up / Construction Support:**
Site selection study	Owner's site mobilization
Land purchase / options / rezoning	O&M staff training
Transmission / gas pipeline rights of way	Initial test fluids and lubricants
Road modifications / upgrades	Initial inventory of chemicals / reagents
Demolition (if brownfield)	Consumables
Environmental permitting / offsets	Cost of fuel not recovered in power sales
Public relations / community development	Auxiliary power purchase
Site specific feasibility study	Construction risk insurance
Utility Interconnections:	**Taxes / Advisory Fees / Legal:**
Natural gas service (if applicable)	Taxes
Gas system upgrades (if applicable)	Market and environmental consultants
Electrical transmission	Owner's legal expenses:
Supply water	PPA
Waste water / sewer (if applicable)	Interconnect agreements
	Contract-procurement and construction
Spare Parts and Plant Equipment:	Property transfer
AQCS materials, supplies, and parts	
Boiler materials, supplies, and parts	**Financing:**
Steam turbine materials, supplies, and parts	Financial advisor, lender's legal, market analyst, and engineer
BOP equipment / tools	Interest during construction
Rolling stock	Loan administration and commitment fees
Plant furnishings and supplies	Debt service reserve fund
Owners Project Management:	**Owner's Contingency:**
Provide project management	Unidentified project scope increases
Perform engineering due diligence	Unidentified project requirements
Provide personnel for site construction management	Costs pending final agreement (e.g., interconnection contract) costs)

Table 4-9. Capital Cost Estimate—50 MW BFB (2006 Overnight Costs)*.

	Description	Total Cost (2006$)
Purchase Contracts		
61.0000	Civil/Structural	9,807,024
62.0000	Mechanical	
	Steam Generator	24,130,000
	Turbine Generator	7,200,000
	Balance of Plant	10,779,926
63.0000	Electrical	4,003,334
64.0000	Control	1,129,511
65.0000	Chemical	1,465,000
	Subtotal Purchase Contracts:	$58,514,795
Construction Contracts		
71.0000	Civil/Structural Construction	12,521,121
72.0000	Mechanical/Chemical Construction	14,589,584
73.0000	Electrical/Control Construction	4,409,935
78.0000	Service Contracts & Construction Indirects	8,277,990
	Subtotal Construction Contracts:	$39,798,630
	Total Direct Costs:	**$98,313,425**
Indirect Costs		
99.1100	Engineering Costs	10,530,000
99.1200	Construction Management	6,111,531
99.1300	Start-up Spare Parts	400,000
99.1400	Construction Utilities(Power & Water)	500,000
99.1500	Project Insurance	1,557,000
99.1600	Bonds	1,020,000
99.2200	Other Indirect Costs	23,859,000
	Total Indirect Costs:	**$43,977,531**
	Total Project Cost:**	**$142,290,957**

Notes:

* EPC Contracting basis.

** Total Project Cost does not include Owner's Costs such as Interest During Construction (IDC), Escalation or Permitting.

Table 4-10. Capital Cost Estimate—100 MW BFB (2006 Overnight Costs)*.

	Description	Total Cost (2006$)
Purchase Contracts		
61.0000	Civil/Structural	15,439,150
62.0000	Mechanical	
	Steam Generator	47,130,000
	Turbine Generator	14,000,000
	Balance of Plant	18,789,345
63.0000	Electrical	7,062,131
64.0000	Control	2,049,511
65.0000	Chemical	1,625,000
	Subtotal Purchase Contracts:	$106,095,137
Construction Contracts		
71.0000	Civil/Structural Construction	19,521,401
72.0000	Mechanical/Chemical Construction	24,180,692
73.0000	Electrical/Control Construction	7,832,178
78.0000	Service Contracts & Construction Indirects	11,950,577
	Subtotal Construction Contracts:	$63,484,847
	Total Direct Costs:	**$169,579,984**
Indirect Costs		
99.1100	Engineering Costs	15,795,000
99.1200	Construction Management	6,790,220
99.1300	Start-up Spare Parts	500,000
99.1400	Construction Utilities(Power & Water)	750,000
99.1500	Project Insurance	3,114,000
99.1600	Bonds	1,725,000
99.2200	Other Indirect Costs	44,653,000
	Total Indirect Costs:	**$73,327,220**
	Total Project Cost:**	**$242,907,204**

Notes:

* EPC Contracting basis.

** Total Project Cost does not include Owner's Costs such as Interest During Construction (IDC), Escalation or Permitting.

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Table 4-11. Cash Flow during Construction of Biomass-Fired Unit.

Month	Incremental	Cumulative
-9	0.22%	0.22%
-8	0.29%	0.51%
-7	0.39%	0.89%
-6	0.50%	1.40%
-5	0.65%	2.05%
-4	0.82%	2.87%
-3	1.03%	3.90%
-2	1.27%	5.17%
-1	1.54%	6.71%
1	1.84%	8.54%
2	2.17%	10.71%
3	2.51%	13.22%
4	2.87%	16.10%
5	3.24%	19.33%
6	3.591%	22.92%
7	3.926%	26.85%
8	4.229%	31.08%
9	4.488%	35.57%
10	4.693%	40.26%
11	4.835%	45.09%
12	4.907%	50.00%
13	4.907%	54.91%
14	4.835%	59.74%
15	4.693%	64.43%
16	4.488%	68.92%
17	4.229%	73.15%
18	3.926%	77.08%
19	3.591%	80.67%
20	3.236%	83.90%
21	2.873%	86.78%
22	2.513%	89.29%
23	2.166%	91.46%
24	1.839%	93.29%
25	1.538%	94.83%
26	1.268%	96.10%
27	1.030%	97.13%
28	0.824%	97.95%
29	0.649%	98.60%
30	0.504%	99.11%
31	0.386%	99.49%
32	0.291%	99.78%
33	0.216%	100.00%

4.4.2 Operating and Maintenance Parameters and Cost Estimates

Unit availability should be similar to other units currently in operation at Deerhaven. Typical availability assumptions for fluidized bed technologies are shown in Table 4-12.

Table 4-12. Expected Unit Availability.

	Availability Factor (%)	Equivalent Availability Factor (%)	Scheduled Outage Factor (%)	Forced Outage Factor (%)	Forced Outage Rate (%)
Range of Values	90 to 92	88 to 90	4 to 6	4 to 6	5 to 8
Suggested Values	91	89	4	5	6

System outages should be similar to other generation units. Expected duration and frequency of system outages is shown in Table 4-13.

Table 4-13. Unit Outage Schedule.

	Outage Duration (Weeks)	Outage Frequency (Years/Outage)
Steam Generator	3	2 to 3
Steam Turbine	6	6 to 8

Operating and maintenance (O&M) costs are defined as all production related expenses associated with the generation of steam and electric power. O&M costs typically include production and maintenance labor, chemical costs, water costs, ash disposal costs, maintenance parts and materials, and various other expenses associated with plant operation and maintenance. Not included in O&M costs are items such as fixed charges on capital investment which consist of return on investment, depreciation, and income taxes. Also not included are general utility office expenditures related to power generation and transmission. Operating and maintenance costs are typically split into fixed and variable components:

- **Fixed Operating and Maintenance Costs**—O&M costs that do not vary with the output of the facility. Such costs typically include staffing, insurance, property taxes, etc. Fixed O&M estimates were determined based on staff and labor cost estimates and an allowance for other fixed costs.
- **Variable Operating and Maintenance Costs**—O&M costs that vary with the output of the plant. These costs include consumables such as urea and

limestone as well as spare equipment parts and materials. Estimates for the variable O&M for the project were obtained from a cost build-up based upon Black & Veatch's experience with similar types and sizes of systems.

The O&M cost estimates for both the 50 MW and 100 MW facilities are shown in Table 4-14. Among other assumptions, the O&M costs calculations are based on the following key inputs:

- The 50 MW facility will require an operating and maintenance staff of 38 employees for 50 MW. The 100 MW facility will require an operating and maintenance staff of 44 employees.
- The capacity factor of the facility is assumed to be 85 percent, which is typical for biomass-fired generation facilities in this size range.
- Due to the uncertainty of fuel costs for the biomass facility, no assumption has been made for delivered fuel costs. Therefore, the O&M costs presented below are non-fuel O&M costs.

Table 4-14. Non-fuel O&M Cost Estimate.

	Fixed O&M Cost		Variable O&M Cost	
	($000/yr)	($/kW-yr)	($000/yr)	($/MWh)
50 MW Facility	4,552	91.04	1,541	4.13
100 MW Facility	5,562	55.65	2,335	3.13

5.0 Impacts Resulting from the Incorporation of Fuel Flexibility

While the generation systems described in the previous sections have been assumed to utilize only biomass fuels, there may be fuel supply situations in which the ability to fire coal in the selected system would be advantageous. Black & Veatch consulted with boiler vendors, reviewed relevant permitting regulations and identified the required system modifications and associated costs to determine the extent to which the selected biomass systems may be capable of utilizing coal as a fuel. The findings from these activities are summarized in the following subsections.

5.1 Opinions from Boiler Vendors

Boiler equipment vendors were contacted to discuss the possibility of firing coal in combustion equipment designed to fire biomass. The contacted vendors consisted of the vendors contacted to discuss the initial biomass system design, as shown in Table 4-1. Key findings obtained during discussions with vendor representatives include:

- Following discussions with their own technical experts, Babcock & Wilcox believed that it would be possible to cofire up to 20 percent coal in a BFB designed to combust biomass. Babcock & Wilcox stressed that this was "only an educated guess."
- Foster Wheeler stated that BFBs may be able to burn up to 30 percent coal and CFBs could be able to burn up to 70 percent coal in a unit designed to burn 100 percent biomass. Foster Wheeler also stated that it may be technically possible to burn 100 percent coal in a CFB designed for biomass combustion, but a detailed investigation would be required to confirm this belief. Foster Wheeler did not provide any indication of the effects on emissions when burning coal in unit designed for biomass combustion, other than to say it is likely that NOx and SOx would increase when combusting coal.
- EPI expressed concern developing BFB systems with extensive fuel flexibility, and the company identified the following issues with fuel-flexible units:
    - **Permitting:** Permitting would be complicated by the possibility of cofiring coal, as SOx would certainly increase significantly and other emissions would likely increase as well. To remain within permit limits, systems unnecessary for biomass combustion such as FGD would likely be required when cofiring, which would substantially increase capital costs associated with the project.

- **Heat Release:** The heat released during combustion of biomass is split evenly between the fluidized bed and the vapor space above the bed, while the heat released during combustion of coal is released almost completely within the bed. The combustion of coal would require additional heat transfer surface within the bed, which EPI does not typically include in their designs and would increase the cost of the system. B&W had mentioned this requirement as well.
- **Fan Size:** Combustion of coal requires more excess air than combustion of biomass. The system would either be fan-limited during combustion of coal or the fan would have to be oversized for biomass combustion to provide fuel flexibility.
- **Capital Cost:** EPI estimated that the extent of coal cofiring would be limited to roughly 10 percent to 20 percent from a technical feasibility perspective, but the company stated that the increased cost requirements of this fuel flexibility would likely limit the cofiring of coal to a much smaller percentage.

- Kvaerner has investigated the utilization of more traditional fuels in its biomass BFBs. Based on the results of these trials, Kvaerner limits the utilization of "hot fuels" such as coal, tire derived fuel (TDF), and pet coke to 20 percent of the heat input to the unit. Kvaerner recommended the use of a CFB if it was desired to cofire higher levels of coal on a regular basis.
- McBurney, Wellons Boiler and Detroit Stoker all limited coal utilization to 10 percent or less in their biomass stoker boilers, as the combustion of coal raised temperatures within the boiler and increased the production of pollutants.

5.2 Permitting Implications of Cofiring

The use of coal in the CFB will likely not affect whether the proposed new unit at the Deerhaven unit would have to go through PSD permitting, since it is likely that PSD will be triggered regardless of the type of fuel used. The type of fuel used in the units will likely be a factor when determining the case-by-case BACT requirements for the new units. The BACT requirements will likely be affected by whether the facility proposes that the permit allows the use of 100 percent coal in the new unit or whether it would simply allow for a small amount of coal cofiring to augment the primary (biomass) fuel. NSPS and other rule applicability, such as CAIR and the Clean Air Mercury Rule (CAMR) will also likely be affected by the use of coal in the proposed new unit.

5.3 Impacted Systems and Estimated Costs

The consensus among boiler vendors was that the cofiring of coal in BFBs would be limited to a relatively minor level of 10 percent to 20 percent of the heat input to the boiler. The utilization of coal above this level in BFBs would require additional in-bed heat transfer surface and downstream emissions control systems that would likely be cost-prohibitive, particularly if the coal was only sporadically added to the fuel mix.

If it is determined that the limited availability of biomass resources regularly requires the combustion of coal at a more significant level (i.e., more than 20 percent of the heat input to the boiler on a continuous basis), it is recommended that a CFB boiler rather than a BFB boiler be employed to generate steam, as CFBs are more capable of simultaneously combusting varied fuels. Discussions with Babcock & Wilcox and Foster Wheeler indicated that capital costs of CFBs are roughly 10 percent to 15 percent greater than those of BFBs. As in the case of coal cofiring in a BFB, emission control systems would be required to limit the emission of sulfur dioxide. These systems would likely be composed of limestone injection equipment and downstream polishing reactors.

The increase in capital costs for a 100 MW CFB unit with the capability to cofire 30 percent coal is shown in Table 5-1. Other costs may increase relative to the 100 MW biomass-fired BFB system, but these costs are not expected to be as significant as the costs identified in Table 5-1. Furthermore, Black & Veatch does not expect the change from a biomass-only BFB system to a cofired CFB system to alter the expected cash flow during construction, unit availability or outage schedule.

Table 5-1. Increase in Capital Cost of 100 MW CFB (30% Coal Cofiring).

Equipment	Cost (2006$)
Fluidized Bed*	4,713,000
Sulfur Dioxide Control**	11,483,000
Total	**16,169,000**

Notes:

* Increase in capital cost of a 100 MW CFB unit designed to fire a 70/30 biomass/coal fuel mixture relative to the cost of a 100 MW BFB designed to fire 100% biomass. Incremental cost assumed to be 10% of the equipment cost of a 100 MW BFB (as listed in Table 4-10).

** Capital cost of sulfur dioxide control equipment necessary to reduce SO2 emissions from a 100 MW CFB to permitted levels assuming a 70/30 biomass/coal fuel mixture. This estimate assumes a dry lime system coupled with an existing ESP for sorbent capture.

Appendix A. Heat Balance for 50 MW Stoker System

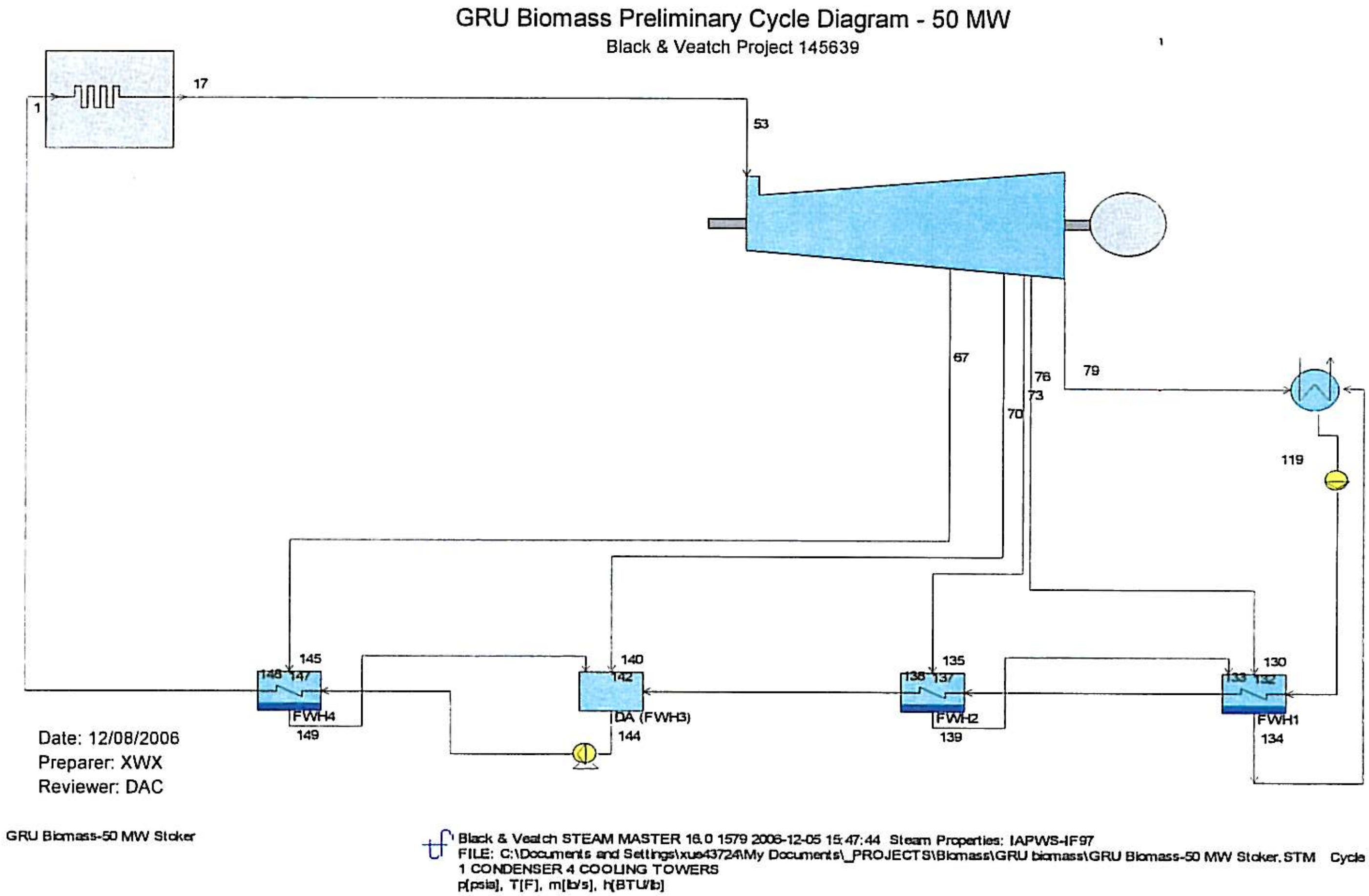

Figure A-1. Preliminary Steam Cycle Diagram—Biomass-Fired 50 MW Stoker.

Table A-1. Preliminary Heat Balance—Biomass-Fired 50 MW Stoker, 100% Load.

System Parameters				
Turbine Gross Output, kW	57,465			
Turbine Heat Rate, Btu/kWh	8,657			
Total Auxiliary Power, kW	7,470			
Total Auxiliary Power, %	13.0			
Net Plant Output, kW	50,000			
Heat to Steam from Boiler, MBtu/hr	497.9			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	622.4			
Net Plant Heat Rate, Btu/kWh (HHV)	12,448			
Number of Heaters	4			

STEAM MASTER Streams	P (psia)	T (°F)	h (Btu/lb)	m (kpph)
1 Feedwater into boiler		450.1	431.0	482.72
17 Steam leaving superheater	1528.0	955.0	1462.5	482.72
53 HPT inlet, before stop valves	1466.9	950.1	1461.6	482.72
67 ST group 2 addition / extraction	477.5	678.0	1346.0	-43.58
70 ST group 3 addition / extraction	167.0	458.4	1250.1	-39.33
73 ST group 4 addition / extraction	50.8	281.9	1161.9	-13.02
76 ST group 5 addition / extraction	9.7	192.0	1062.1	-32.21
79 ST group 6 addition / extraction	0.9	96.6	955.8	335.93
119 FW into condensate pump		96.6	64.7	399.81
130 FWH1A heating steam	9.1	188.6	1061.1	32.21
132 FWH1A feedwater inlet		96.9	65.5	399.81
133 FWH1A feedwater exit		183.6	152.1	399.81
134 FWH1A drain	9.1	107.0	75.0	63.23
135 FWH2A heating steam	47.2	277.4	1160.9	13.02
137 FWH2A feedwater inlet		183.6	152.1	399.81
138 FWH2A feedwater exit		272.4	241.7	399.81
139 FWH2A drain	47.2	193.6	161.8	30.88
140 FWH3A heating steam	155.3	453.9	1249.1	39.33
142 FWH3A feedwater inlet		272.5	241.7	399.81
144 FWH3A drain	155.3	361.2	333.6	482.72
145 FWH4A heating steam	444.0	672.5	1345.0	43.58
147 FWH4A feedwater inlet		366.4	341.2	482.72
148 FWH4A feedwater outlet		450.1	431.0	482.72
149 FWH4A drain	444.0	376.4	350.1	43.58

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.
[b] Auxiliary power is assumed to be 13% of base load.
[c] Water cooling with mechanical draft cooling tower is used.
[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.
[e] Boiler efficiency is assumed to be 80%.

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Table A-2. Preliminary Heat Balance—Biomass-Fired 50 MW Stoker, 75% Load.

System Parameters				
Turbine Gross Output, kW	43,291			
Turbine Heat Rate, Btu/kWh	8,829			
Total Auxiliary Power, kW	6,550			
Total Auxiliary Power, %	15.1			
Net Plant Output, kW	36,740			
Heat to Steam from Boiler, MBtu/hr	382.6			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	478.2			
Net Plant Heat Rate, Btu/kWh (HHV)	13,017			
Number of Heaters	4			
STEAM MASTER Streams	**P (psia)**	**T (°F)**	**h (Btu/lb)**	**m (kpph)**
1 Feedwater into boiler		427.1	405.8	362.06
17 Steam leaving superheater	1501.6	953.5	1462.5	362.06
53 HPT inlet, before stop valves	1466.9	950.1	1461.6	362.03
67 ST group 2 addition / extraction	361.8	666.2	1346.7	-29.91
70 ST group 3 addition / extraction	127.6	451.5	1251.3	-27.06
73 ST group 4 addition / extraction	38.7	265.3	1162.9	-8.51
76 ST group 5 addition / extraction	7.5	179.6	1063.7	-23.97
79 ST group 6 addition / extraction	0.7	88.4	957.9	258.21
119 FW into condensate pump		88.4	56.4	305.10
130 FWH1A heating steam	7.0	176.6	1062.7	23.97
132 FWH1A feedwater inlet		88.9	57.4	305.10
133 FWH1A feedwater exit		173.6	141.9	305.10
134 FWH1A drain	7.0	96.5	64.6	46.23
135 FWH2A heating steam	36.8	262.2	1161.9	8.510
137 FWH2A feedwater inlet		173.6	141.9	305.10
138 FWH2A feedwater exit		259.5	228.5	305.10
139 FWH2A drain	36.8	180.9	149.0	22.27
140 FWH3A heating steam	120.4	447.9	1250.3	27.06
142 FWH3A feedwater inlet		259.5	228.5	305.10
144 FWH3A drain	120.4	341.5	312.9	362.06
145 FWH4A heating steam	341.0	661.9	1345.7	29.91
147 FWH4A feedwater inlet		347.6	321.5	362.06
148 FWH4A feedwater outlet		427.1	405.8	362.06
149 FWH4A drain	341.0	353.5	325.7	29.91

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.

[b] Auxiliary power is assumed to be 13% of base load.

[c] Water cooling with mechanical draft cooling tower is used.

[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.

[e] Boiler efficiency is assumed to be 80%.

Table A-3. Preliminary Heat Balance—Biomass-Fired 50 MW Stoker, 50% Load.

System Parameters				
Turbine Gross Output, kW	28,863			
Turbine Heat Rate, Btu/kWh	9,120			
Total Auxiliary Power, kW	5,610			
Total Auxiliary Power, %	19.4			
Net Plant Output, kW	23,250			
Heat to Steam from Boiler, MBtu/hr	263.7			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	329.6			
Net Plant Heat Rate, Btu/kWh (HHV)	14,177			
Number of Heaters	4			

STEAM MASTER Streams	P (psia)	T (°F)	h (Btu/lb)	m (kpph)
1 Feedwater into boiler		394.6	370.9	241.57
17 Steam leaving superheater	1482.4	952.5	1462.5	241.57
53 HPT inlet, before stop valves	1466.9	950.1	1461.6	241.35
67 ST group 2 addition / extraction	244.5	654.4	1347.8	-17.26
70 ST group 3 addition / extraction	87.0	444.9	1252.8	-16.13
73 ST group 4 addition / extraction	26.4	248.4	1164.4	-4.28
76 ST group 5 addition / extraction	5.1	163.2	1065.7	-15.18
79 ST group 6 addition / extraction	0.5	78.8	962.1	178.41
119 FW into condensate pump		78.8	46.8	208.17
130 FWH1A heating steam	4.8	160.9	1064.7	15.18
132 FWH1A feedwater inlet		79.8	48.1	208.17
133 FWH1A feedwater exit		159	127.2	208.17
134 FWH1A drain	4.8	84.5	52.6	29.11
135 FWH2A heating steam	25.7	246	1163.4	4.28
137 FWH2A feedwater inlet		159	127.2	208.17
138 FWH2A feedwater exit		240.6	209.2	208.17
139 FWH2A drain	25.7	163.1	131.2	13.94
140 FWH3A heating steam	83.3	442.1	1251.8	16.13
142 FWH3A feedwater inlet		240.6	209.2	208.17
144 FWH3A drain	83.3	314.8	285.1	241.57
145 FWH4A heating steam	234.3	651.2	1346.8	17.26
147 FWH4A feedwater inlet		322.7	295.8	241.57
148 FWH4A feedwater outlet		394.6	370.9	241.57
149 FWH4A drain	234.3	325.4	296.2	17.26

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.
[b] Auxiliary power is assumed to be 13% of base load.
[c] Water cooling with mechanical draft cooling tower is used.
[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.
[e] Boiler efficiency is assumed to be 80%.

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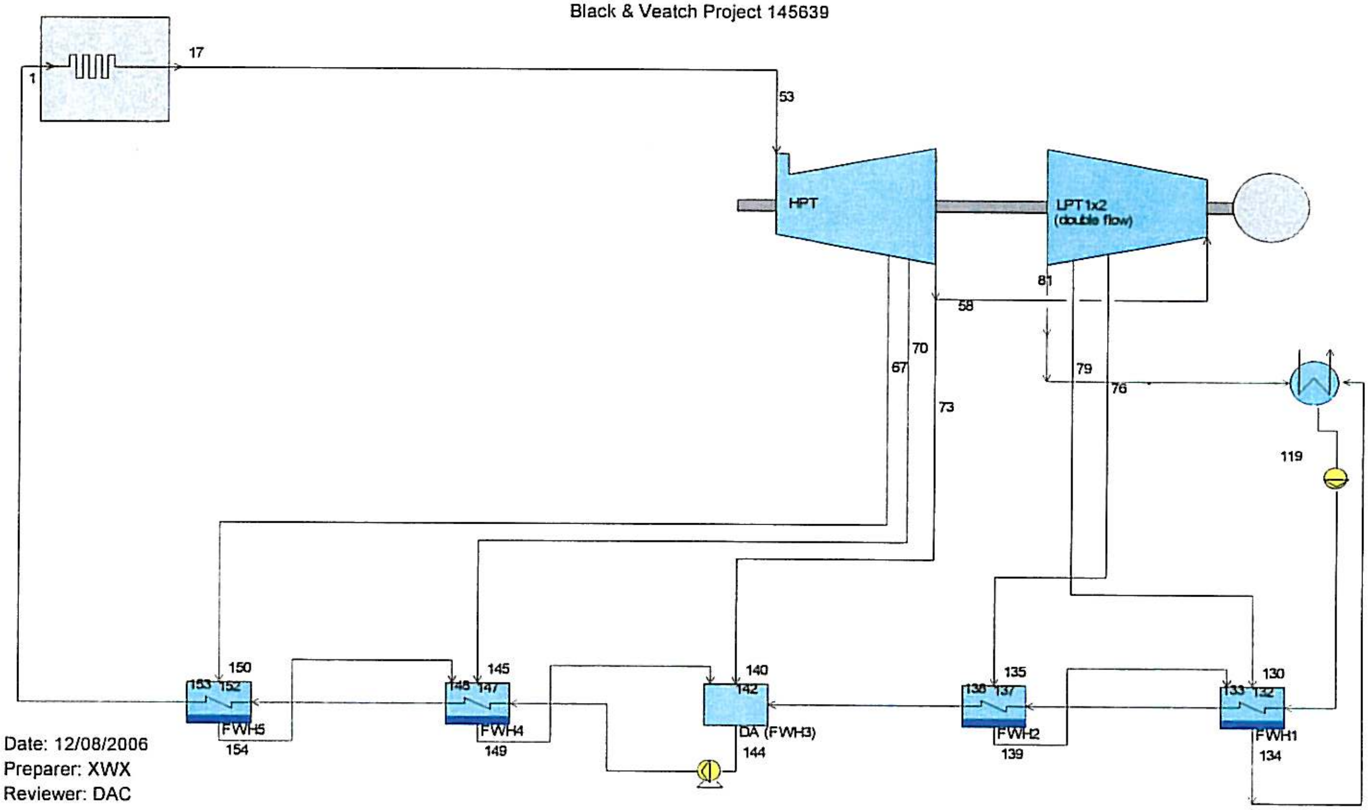
Appendix B. Heat Balance for 100 MW CFB System

GRU Biomass Preliminary Cycle Diagram - 100 MW CFB NonReheat Steam Turbine
Black & Veatch Project 145639



GRU Biomass-100MW CFB-NRH ST

Black & Veatch STEAM MASTER 16.0 1579 2006-12-05 16:21:17 Steam Properties: IAPWS-IF97
FILE: C:\Documents and Settings\xue43724\My Documents_PROJECTS\Biomass\GRU biomass\GRU Biomass-100 MW CFB-NRH ST.STM
1 CONDENSER 5 COOLING TOWERS
p[psia], T[F], m[lb/s], h[BTU/lb]

Figure B-1. Preliminary Steam Cycle Diagram—Biomass-Fired 100 MW CFB.

Table B-1. Preliminary Heat Balance—Biomass-Fired 100 MW CFB, 100% Load.

System Parameters				
Turbine Gross Output, kW	115,053			
Turbine Heat Rate, Btu/kWh	8,259			
Total Auxiliary Power, kW	15,000			
Total Auxiliary Power, %	13.0			
Net Plant Output, kW	100,050			
Heat to Steam from Boiler, MBtu/hr	951.2			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	1,189.0			
Net Plant Heat Rate, Btu/kWh (HHV)	11,884			
Number of Heaters	5			

STEAM MASTER Streams	P (psia)	T (°F)	h (Btu/lb)	m (kpph)
1 Feedwater into boiler		455.9	437.7	937.54
17 Steam leaving superheater	1815.0	955	1452.3	937.54
53 HPT inlet, before stop valves	1742.4	949.4	1451.3	937.44
67 ST group 2 addition / extraction	486.5	637.7	1322.2	-76.16
70 ST group 3 addition / extraction	224.3	475.6	1252.6	-61.58
73 ST group 4 addition / extraction	82.8	314.4	1176.8	-58.28
76 ST group 5 addition / extraction	29.6	249.5	1115.9	-55.40
79 ST group 6 addition / extraction	7.0	176.8	1033.8	-51.16
81 ST group 7 addition / extraction	0.9	96.6	936.9	633.20
119 FW into condensate pump		96.6	64.6	741.43
130 FWH1A heating steam	6.5	173.6	1032.8	51.16
132 FWH1A feedwater inlet		96.8	65.1	741.53
133 FWH1A feedwater exit		168.5	136.8	741.53
134 FWH1A drain	6.5	105.6	73.6	106.56
135 FWH2A heating steam	27.5	245.4	1114.9	55.40
137 FWH2A feedwater inlet		168.5	136.8	741.53
138 FWH2A feedwater exit		240.5	209.1	741.53
139 FWH2A drain	27.5	178.5	146.6	55.40
140 FWH3A heating steam	80.3	312.3	1175.8	58.28
142 FWH3A feedwater inlet		240.5	209.1	741.53
144 FWH3A drain	80.3	312.3	282.5	937.54
145 FWH4A heating steam	213.1	471.4	1251.6	61.58
147 FWH4A feedwater inlet		318.4	292.2	937.54
148 FWH4A feedwater outlet		384.1	360.4	937.54
149 FWH4A drain	213.1	328.4	299.4	137.74

150 FWH5A heating steam	462.2	633	1321.2	76.16
152 FWH5A feedwater inlet		384.1	360.4	937.54
153 FWH5A feedwater outlet		455.9	437.7	937.54
154 FWH5A drain	462.2	394.2	369.0	76.16

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.

[b] Auxiliary power is assumed to be 13% of base load.

[c] Water cooling with mechanical draft cooling tower is used.

[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.

[e] Boiler efficiency is assumed to be 80%.

Table B-2. Preliminary Heat Balance—Biomass-Fired 100 MW CFB, 75% Load.

System Parameters				
Turbine Gross Output, kW	88,591			
Turbine Heat Rate, Btu/kWh	8,301			
Total Auxiliary Power, kW	13,280			
Total Auxiliary Power, %	15.0			
Net Plant Output, kW	75,310			
Heat to Steam from Boiler, MBtu/hr	743.8			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	929.7			
Net Plant Heat Rate, Btu/kWh (HHV)	12,345			
Number of Heaters	5			

STEAM MASTER Streams	P (psia)	T (°F)	h (Btu/lb)	m (kpph)
1 Feedwater into boiler		431.1	410.5	676.74
17 Steam leaving superheater	1783.6	953.3	1452.3	703.39
53 HPT inlet, before stop valves	1742.4	949.4	1451.3	703.08
67 ST group 2 addition / extraction	364.8	599.2	1309.3	-50.07
70 ST group 3 addition / extraction	169.5	444.7	1242.2	-41.49
73 ST group 4 addition / extraction	63.1	296.0	1168.7	-41.28
76 ST group 5 addition / extraction	22.7	234.7	1109.3	-40.31
79 ST group 6 addition / extraction	5.4	165.2	1028.8	-38.87
81 ST group 7 addition / extraction	0.7	88.2	933.5	489.76
119 FW into condensate pump		88.1	56.2	570.61
130 FWH1A heating steam	5.0	162.3	1027.8	38.87
132 FWH1A feedwater inlet		88.5	56.8	570.54
133 FWH1A feedwater exit		159.4	127.6	570.54
134 FWH1A drain	5.0	95.1	63.1	79.18
135 FWH2A heating steam	21.3	231.2	1108.3	40.31
137 FWH2A feedwater inlet		159.4	127.6	570.54
138 FWH2A feedwater exit		227.9	196.4	570.54
139 FWH2A drain	21.3	166.6	134.6	40.31
140 FWH3A heating steam	61.5	294.3	1167.7	41.28
142 FWH3A feedwater inlet		228.0	196.4	570.54
144 FWH3A drain	61.5	294.4	263.9	703.39
145 FWH4A heating steam	163.0	441.3	1241.2	41.49
147 FWH4A feedwater inlet		301.9	275.0	676.74
148 FWH4A feedwater outlet		363.9	339.0	676.74
149 FWH4A drain	163.0	307.0	277.1	91.57

150 FWH5A heating steam	351.3	595.6	1308.3	50.07
152 FWH5A feedwater inlet		363.9	339.0	676.74
153 FWH5A feedwater outlet		431.1	410.5	676.74
154 FWH5A drain	351.3	369.5	342.6	50.07

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.
[b] Auxiliary power is assumed to be 13% of base load.
[c] Water cooling with mechanical draft cooling tower is used.
[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.
[e] Boiler efficiency is assumed to be 80%.

Table B-3. Preliminary Heat Balance—Biomass-Fired 100 MW CFB, 50% Load.

System Parameters				
Turbine Gross Output, kW	59,910			
Turbine Heat Rate, Btu/kWh	8,515			
Total Auxiliary Power, kW	11,410			
Total Auxiliary Power, %	19.0			
Net Plant Output, kW	48,500			
Heat to Steam from Boiler, MBtu/hr	522.1			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	652.6			
Net Plant Heat Rate, Btu/kWh (HHV)	13,455			
Number of Heaters	5			
STEAM MASTER Streams	**P (psia)**	**T (°F)**	**h (Btu/lb)**	**m (kpph)**
1 Feedwater into boiler		397.1	373.8	427.51
17 Steam leaving superheater	1760.8	952.0	1452.3	469.49
53 HPT inlet, before stop valves	1742.4	949.4	1451.3	468.72
67 ST group 2 addition / extraction	245.5	570.7	1303.2	-27.52
70 ST group 3 addition / extraction	115.4	423.0	1237.8	-22.83
73 ST group 4 addition / extraction	43.2	272.0	1165.7	-25.02
76 ST group 5 addition / extraction	15.6	214.9	1107.7	-25.98
79 ST group 6 addition / extraction	3.7	149.9	1028.4	-25.16
81 ST group 7 addition / extraction	0.5	78.7	936.3	341.31
119 FW into condensate pump		78.6	46.7	394.13
130 FWH1A heating steam	3.5	147.6	1027.4	25.16
132 FWH1A feedwater inlet		79.3	47.5	394.12
133 FWH1A feedwater exit		146.1	114.3	394.12
134 FWH1A drain	3.5	83.3	51.4	51.15
135 FWH2A heating steam	14.8	212.2	1106.7	25.98
137 FWH2A feedwater inlet		146.1	114.3	394.12
138 FWH2A feedwater exit		211.1	179.4	394.12
139 FWH2A drain	14.8	150.8	118.8	25.98
140 FWH3A heating steam	42.4	270.8	1164.7	25.02
142 FWH3A feedwater inlet		211.2	179.4	394.12
144 FWH3A drain	42.4	270.8	239.8	469.49
145 FWH4A heating steam	112.5	420.4	1236.8	22.83
147 FWH4A feedwater inlet		281.0	253.6	427.51
148 FWH4A feedwater outlet		336.0	309.9	427.51
149 FWH4A drain	112.5	283.0	252.4	50.35

150 FWH5A heating steam	239.5	567.9	1302.2	27.52
152 FWH5A feedwater inlet		336.0	309.9	427.51
153 FWH5A feedwater outlet		397.1	373.8	427.51
154 FWH5A drain	239.5	338.0	309.4	27.52

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.
[b] Auxiliary power is assumed to be 13% of base load.
[c] Water cooling with mechanical draft cooling tower is used.
[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.
[e] Boiler efficiency is assumed to be 80%.

Appendix C. Heat Balance for 100 MW CFB (Reheat) System

GRU Biomass Preliminary Cycle Diagram - 100 MW CFB Reheat Steam Turbine

Black & Veatch Project 145639

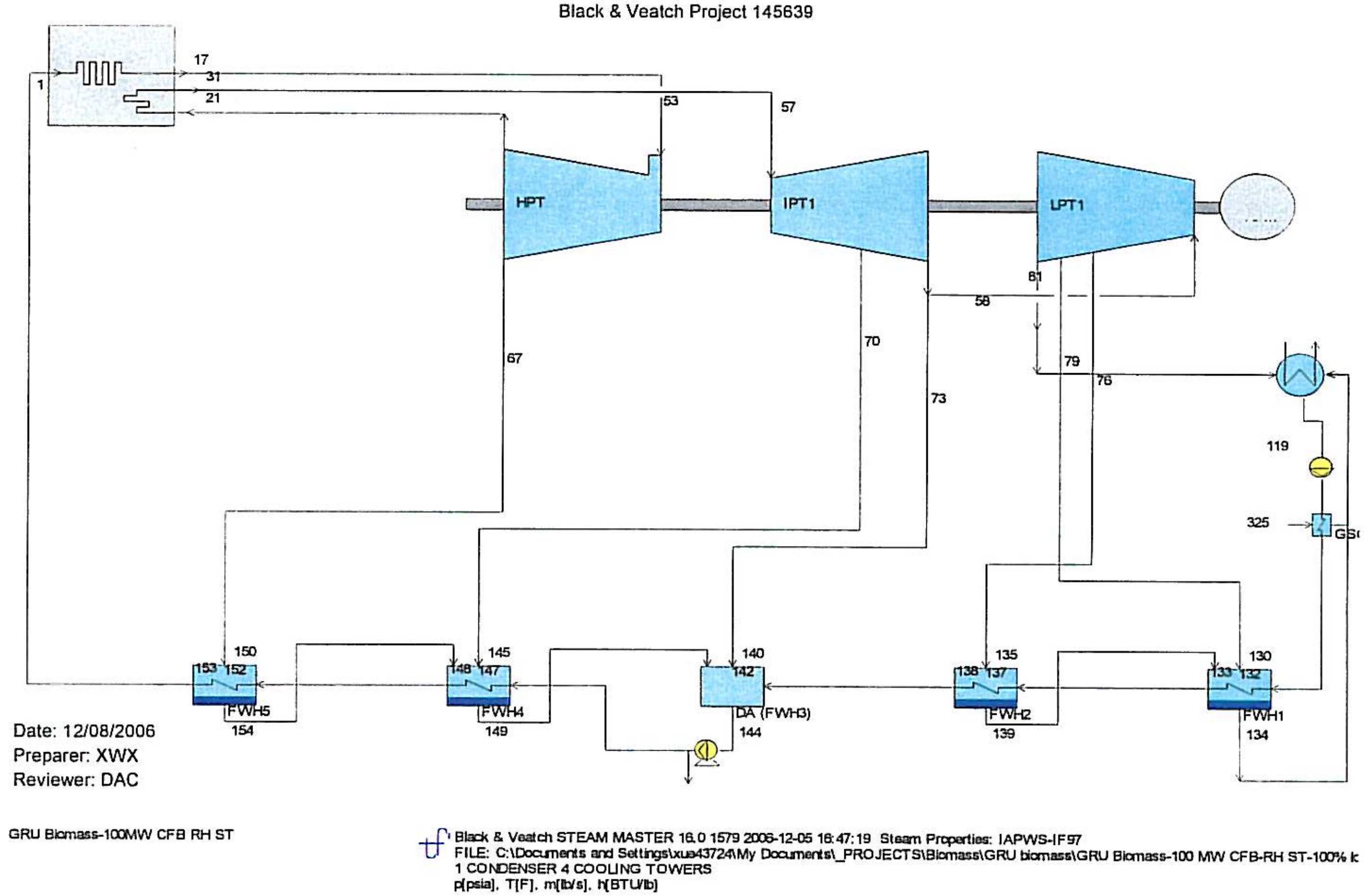


Figure C-1. Preliminary Steam Cycle Diagram—Biomass-Fired 100 MW CFB (with Reheat).

Table C-1. Preliminary Heat Balance—Biomass-Fired 100 MW CFB (with Reheat), 100% Load.

System Parameters				
Turbine Gross Output, kW	114,977			
Turbine Heat Rate, Btu/kWh	7,924			
Total Auxiliary Power, kW	15,000			
Total Auxiliary Power, %	13.0			
Net Plant Output, kW	99,980			
Heat to Steam from Boiler, MBtu/hr	913.4			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	1,141.7			
Net Plant Heat Rate, Btu/kWh (HHV)	11,420			
Number of Heaters	5			
STEAM MASTER Streams	**P (psia)**	**T (°F)**	**h (Btu/lb)**	**m (kpph)**
1 Feedwater into boiler		455.8	437.5	773.45
17 Steam leaving superheater	1815.0	955.0	1452.3	773.45
53 HPT inlet, before stop valves	457.4	618.2	1313.0	697.20
67 ST group 2 addition / extraction	431.5	952.3	1497.3	697.20
70 ST group 3 addition / extraction	1742.4	949.4	1451.3	773.31
73 ST group 4 addition / extraction	425.1	950.0	1496.3	697.20
76 ST group 5 addition / extraction	100.1	607.4	1333.1	625.26
79 ST group 6 addition / extraction	462.0	620.5	1314.0	-56.07
81 ST group 7 addition / extraction	232.2	799.9	1424.1	-41.33
119 FW into condensate pump	100.1	607.6	1333.2	-47.62
130 FWH1A heating steam	32.5	386.9	1231.2	-46.01
132 FWH1A feedwater inlet	6.8	175.8	1121.6	-36.29
133 FWH1A feedwater exit	0.9	96.7	1007.4	542.97
134 FWH1A drain		96.7	64.7	627.90
135 FWH2A heating steam	6.4	172.6	1120.6	36.29
137 FWH2A feedwater inlet		97.9	66.3	628.44
138 FWH2A feedwater exit		167.4	135.7	628.44
139 FWH2A drain	6.4	107.8	75.9	83.62
140 FWH3A heating steam	30.2	384.2	1230.3	46.01
142 FWH3A feedwater inlet		167.4	135.7	628.44
144 FWH3A drain		246.4	215.2	628.44
145 FWH4A heating steam	30.2	177.5	145.6	46.01
147 FWH4A feedwater inlet	97.1	605.1	1332.2	47.62
148 FWH4A feedwater outlet		246.5	215.2	628.44

149 FWH4A drain	97.1	325.7	296.3	773.45
150 FWH5A heating steam	220.6	797.0	1423.1	41.33
152 FWH5A feedwater inlet		331.7	305.7	773.45
153 FWH5A feedwater outlet		393.1	369.8	773.45
154 FWH5A drain	220.6	341.7	313.2	97.38

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.

[b] Auxiliary power is assumed to be 13% of base load.

[c] Water cooling with mechanical draft cooling tower is used.

[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.

[e] Boiler efficiency is assumed to be 80%.

Table C-2. Preliminary Heat Balance—Biomass-Fired 100 MW CFB (with Reheat), 75% Load.

System Parameters				
Turbine Gross Output, kW	89,273			
Turbine Heat Rate, Btu/kWh	7,930			
Total Auxiliary Power, kW	13,320			
Total Auxiliary Power, %	14.9			
Net Plant Output, kW	75,950			
Heat to Steam from Boiler, MBtu/hr	715.7			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	894.6			
Net Plant Heat Rate, Btu/kWh (HHV)	11,779			
Number of Heaters	5			

STEAM MASTER Streams	P (psia)	T (°F)	h (Btu/lb)	m (kpph)
1 Feedwater into boiler		432.1	411.5	558.71
17 Steam leaving superheater	1783.6	953.3	1452.3	579.94
53 HPT inlet, before stop valves	346.6	577.4	1298.4	528.13
67 ST group 2 addition / extraction	327.1	939.9	1494.0	528.13
70 ST group 3 addition / extraction	1742.4	949.4	1451.3	579.96
73 ST group 4 addition / extraction	322.2	937.7	1493.0	528.13
76 ST group 5 addition / extraction	76.6	600.3	1331.2	479.18
79 ST group 6 addition / extraction	349.9	579.7	1299.4	-36.08
81 ST group 7 addition / extraction	176.8	789.9	1421.4	-28.88
119 FW into condensate pump	76.6	600.7	1331.4	-33.49
130 FWH1A heating steam	25.0	382.1	1230.0	-33.28
132 FWH1A feedwater inlet	5.2	164.2	1120.8	-27.31
133 FWH1A feedwater exit	0.7	88.4	1008.0	418.58
134 FWH1A drain		88.4	56. 5	481.51
135 FWH2A heating steam	4.9	161.3	1119.8	27.31
137 FWH2A feedwater inlet		90.1	58.4	481.49
138 FWH2A feedwater exit		158.2	126.4	481.49
139 FWH2A drain	4.9	97.1	65.2	61.89
140 FWH3A heating steam	23.4	379.5	1229.0	33.28
142 FWH3A feedwater inlet		158.2	126.4	481.49
144 FWH3A drain		233.6	202.1	481.49
145 FWH4A heating steam	23.4	165.5	133.5	33.28
147 FWH4A feedwater inlet	74.7	598.4	1330.4	33.49
148 FWH4A feedwater outlet		233.6	202.1	481.49

149 FWH4A drain	74.7	307.3	277.3	579.94
150 FWH5A heating steam	169.4	787.4	1420.4	28.88
152 FWH5A feedwater inlet		314.7	288.1	558.71
153 FWH5A feedwater outlet		374.9	350.5	558.71
154 FWH5A drain	169.4	321.1	291.7	64.96

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.

[b] Auxiliary power is assumed to be 13% of base load.

[c] Water cooling with mechanical draft cooling tower is used.

[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.

[e] Boiler efficiency is assumed to be 80%.

Table C-3. Preliminary Heat Balance—Biomass-Fired 100 MW CFB (with Reheat), 50% Load.

System Parameters				
Turbine Gross Output, kW	60,834			
Turbine Heat Rate, Btu/kWh	8,081			
Total Auxiliary Power, kW	11,470			
Total Auxiliary Power, %	18.9			
Net Plant Output, kW	49,360			
Heat to Steam from Boiler, MBtu/hr	501.7			
Boiler Efficiency (HHV)	80.0			
Boiler Heat Input, MBtu/hr (HHV)	627.1			
Net Plant Heat Rate, Btu/kWh (HHV)	12,705			
Number of Heaters	5			

STEAM MASTER Streams	P (psia)	T (°F)	h (Btu/lb)	m (kpph)
1 Feedwater into boiler		399.2	376.0	352.93
17 Steam leaving superheater	1760.8	952.0	1452.3	386.66
53 HPT inlet, before stop valves	235.5	550.6	1293.2	356.06
67 ST group 2 addition / extraction	222.3	940.8	1497.8	356.06
70 ST group 3 addition / extraction	1742.4	949.4	1451.3	386.64
73 ST group 4 addition / extraction	219.1	938.7	1496.8	356.06
76 ST group 5 addition / extraction	52.9	605.2	1335.3	329.09
79 ST group 6 addition / extraction	237.8	552.9	1294.2	-19.20
81 ST group 7 addition / extraction	121.1	793.1	1425.4	-16.48
119 FW into condensate pump	52.9	605.7	1335.5	-20.27
130 FWH1A heating steam	17.3	387.3	1233.6	-21.28
132 FWH1A feedwater inlet	3.6	148.7	1123.2	-17.67
133 FWH1A feedwater exit	0.5	78.9	1014.3	290.14
134 FWH1A drain		78.9	47.0	330.69
135 FWH2A heating steam	3.4	146.4	1122.2	17.67
137 FWH2A feedwater inlet		81.5	49.7	330.71
138 FWH2A feedwater exit		145.0	113.1	330.71
139 FWH2A drain	3.4	85.8	53.9	39.52
140 FWH3A heating steam	16.4	384.9	1232.6	21.28
142 FWH3A feedwater inlet		145.0	113.2	330.71
144 FWH3A drain		216.5	184.9	330.71
145 FWH4A heating steam	16.4	149.8	117.8	21.28
147 FWH4A feedwater inlet	51.8	603.6	1334.5	20.27
148 FWH4A feedwater outlet		216.6	184.9	330.71

149 FWH4A drain	51.8	283.3	252.6	386.66
150 FWH5A heating steam	117.6	790.8	1424.4	16.48
152 FWH5A feedwater inlet		293.2	266.0	352.93
153 FWH5A feedwater outlet		348.9	323.3	352.93
154 FWH5A drain	117.6	295.7	265.4	35.68

Notes:

[a] Performance is preliminary and for information only. Not to be used for detailed design.
[b] Auxiliary power is assumed to be 13% of base load.
[c] Water cooling with mechanical draft cooling tower is used.
[d] Average ambient conditions of 59°F dry bulb temperature and 50% relative humidity are used.
[e] Boiler efficiency is assumed to be 80%.