ELECTRIC POWER RESEARCH INSTITUTE

Renewable Energy Technology Engineering and Economic Evaluation: Biomass Power Plants 2007

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Technical Update, March 2008

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PRODUCT DESCRIPTION

In 2006 EPRI initiated a project to conduct engineering and economic evaluations of renewable energy technologies in support of the annual updates of the EPRI *Renewable Energy Technical Assessment Guide (TAG-RE)*. The 2007 engineering and economic evaluation in this report addresses 100% biomass-fired stoker and circulating fluidized bed boiler power plants.

Results & Findings

The evaluation estimated boiler efficiency, steam cycle heat rate, auxiliary power consumption, net plant heat rate, operation and maintenance (O&M) labor costs, maintenance materials, fuel needs, and raw material requirements for 25-, 50-, and 100-MW plants. Project results indicate an economy-of-scale advantage for larger plants and a small cost advantage for the circulating fluidized bed (CFB) design. For both capital and annual O&M costs, the costs per kW and MWh are the lowest for 100-MW plants and the highest for 25-MW plants. CFB boilers are slightly more preferable than stoker boilers for a biomass plant because of their higher boiler efficiency, lower capital costs, and lower expected NO_x and particulate emissions.

Challenges & Objective(s)

The objective was to prepare an engineering and economic evaluation (including generic design, performance, and cost estimates) of 100% biomass combustion power plants.

Applications, Values & Use

Developers considering new biomass facilities can use the data from this project to evaluate general performance and overall system cost. Since the designs in this project were developed without features unique to an actual facility, site-specific information is necessary to develop detailed results with a greater level of certainty. The data also will be useful for retrofitting existing coal units to 100% biomass combustion.

Reducing carbon dioxide emissions from the power sector is another potential benefit from using biomass to generate power. A 2004 National Renewable Energy Laboratory (NREL) study estimated that direct firing of biomass to generate power reduced the life-cycle global warming potential (GWP) of biomass power generation by 148% relative to that of coal. In addition to fuel switching, the GWP reduction factors include eliminating the need for additional coal mining, reducing the miles traveled to transport the fuel to the power plant, and eliminating methane emissions that would otherwise be generated by placing wood waste in landfills.

EPRI Perspective

Utilities with an adequate local supply of biomass are considering various technology scenarios for generating from that resource. This report will provide a starting point for a technical and economic analysis of two likely options.

Approach

The project team addressed thermal efficiency, capital and operating costs, resource requirements, environmental emissions, and other metrics of biomass combustion in stoker and CFB boilers. The base case was a 50-MW plant with 25- and 100-MW cases developed using the 50-MW base case as a reference. The team assumed that their hypothetical site was suitable for a biomass power plant with no major site improvements required. The model plant consisted of a biomass fuel handling system, a boiler island, a turbine island, an emission control system, and the balance of plant.

Keywords

Biomass firing
Biopower
Stoker boiler
Fluidized bed boiler

ABSTRACT

This study prepared an engineering and economic evaluation of 25-, 50-, and 100-MW biomass combustion power plants fired by 100% biomass fuel. The study estimated boiler efficiency, steam cycle heat rate, auxiliary power consumption, net plant heat rate, operation and maintenance (O&M) labor costs, maintenance materials, fuel needs, and raw material requirements. For both capital and annual O&M costs, the costs per kW or MWh are the lowest for 100-MW plants and the highest for 25-MW plants. Due to their higher boiler efficiency, lower capital costs, and lower expected NOx and particulate emissions, circulating fluidized bed (CFB) boilers are slightly more preferable than stoker boilers for a biomass plant. Developers considering new biomass facilities can use the data from this project as a first step when evaluating general performance and overall system costs. The data also will be useful for retrofitting existing coal units to 100% biomass combustion.

CONTENTS

1
EXECUTIVE SUMMARY

The objective of this report is to prepare an engineering and economic evaluation of biomass combustion power plants fired by 100% biomass fuel. The evaluation addressed the thermal efficiency, capital and operating costs, resource requirements, environmental emissions, and other metrics of biomass combustion in stoker and circulating fluidized bed (CFB) boilers. The base case is a 50-MW plant, and 25- and 100-MW sensitivity cases are developed using the 50 MW base case as a reference. There is no specific site selected for this study. It is assumed that the site is suitable for a biomass power plant with no major site improvement required.

Figure 1-1 shows the process flow diagram of the biomass plant. The plant consists of a biomass fuel handling system, a boiler island, a turbine island, an emission control system, and the balance of plant.

Fuel handling system: Trucks deliver wood chips to the plant. After being weighed by electronic scales, the trucks unload the wood chips into dumpers. A conveyor system with magnets and non-ferrous metal detector removes metal debris from the feedstock before further processing. The woodchips then go through a disc screen and hammermill to reduce their size. Open pile and live storage silos are used for on-site plant feedstock storage. Another set of belt conveyors transports the wood chips to the boiler feed system.

Boiler island: There are two types of boilers evaluated in this study, stoker and CFB types. For the stoker boiler, a traveling grate spreader has a moving grate cooled by under-fire air is used. The ash removal system drag chain and screw conveyors transport the ash from the boiler to the bottom ash hopper. The fly ash is collected by electrostatic precipitators. For the CFB case, the principal components of the CFB boiler include a water-cooled combustor/ evaporator, refractory-lined cyclone separators, superheater, economizer and convection pass heat transfer elements, fans and blowers, primary and secondary air heaters, an induced draft fan, and bottom ash coolers. The fly ash is collected by baghouses.

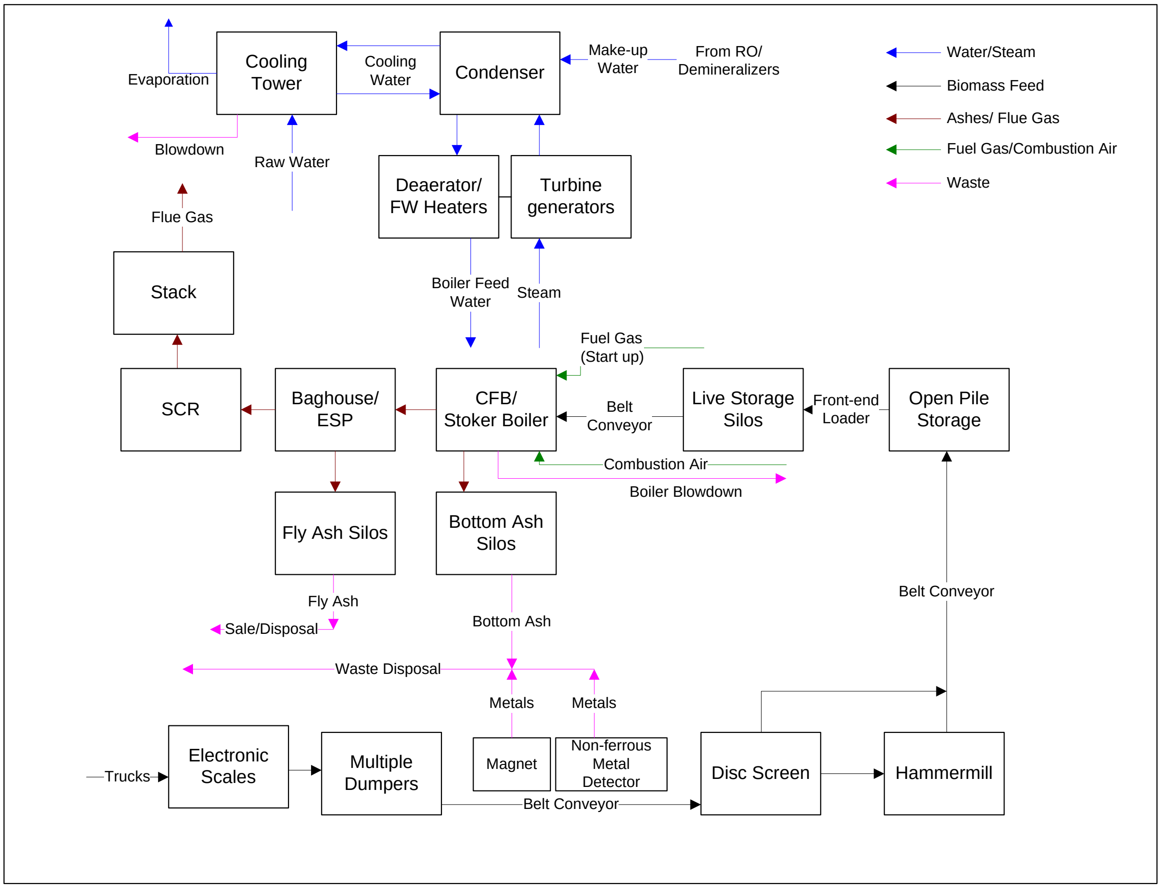

Figure 1-1
Process Flow Diagram of Biomass Combustion Power Plant

Turbine island: Steam produced in the boiler island goes through the steam turbine to generate electricity. The turbine exhaust enters the steam condenser for cooling. Condensate is returned to the boiler as feedwater to complete the steam Rankine cycle. Cooling water is contained in a closed loop system cooled by a mechanical draft cooling tower. Make-up water is required for evaporative losses and normal blowdown.

Emission control system: Both boilers have flue gas particulate control equipment. The particulate control for the stoker boiler is an electrostatic precipitator (ESP) and the CFB boilers uses a baghouse. The fly ash and bottom ash from the boilers are stored in ash silos. To reduce NOx emissions, both boiler types are equipped with selective catalytic reduction (SCR) systems. While some biomass fed boilers may not require downstream NOx control, this equipment is included for this generic design.

Balance of Plant: The balance of plant includes condensate and boiler feedwater systems, steam systems, water systems, service cooling water systems, wastewater treatment, compressed air systems, fire protection systems, heating, ventilating, and air conditioning systems, cranes and hoists, and electrical components.

The plant performance for both 50 MW cases is summarized in Table 1-1.

Table 1-1
50 MWe Base Case Plant Performance, Both Boilers

Parameters	Unit	Stoker	CFB
		Values	
Net Generator Output	kWe	56,465	56,985
Parasitic Load and Losses	kWe	6,465	6,985
Net Plant Output	kWe	50,000	50,000
Boiler Efficiency	%	75.9	82.6
Boiler Steam Output	klb/hr	440	442
Net Heat Rate	BTU/kWh	12,931	11,876
Capacity Factor	%	80	80
Fuel HHV (AR)	BTU/lb	4,750	4,750
Fuel Moisture (AR)	%	45	45
Fuel Required	tons/hr	69	64

The capital cost estimates for all the cases are summarized in Table 1-2. The Total Plant Investment (TPI) is calculated using EPRI TAG guidelines for cost escalation and accumulated funds used during construction (AFUDC) for a two-year construction period. The Total Capital Requirement (TCR) includes costs for start-up fees, spare parts, taxes/insurance, reserves, and working capital. It is assumed that there is no cost for land, since this is a biomass plant at an existing site. In general, the capital costs of the CFB cases are slightly lower than those of the stoker boiler cases due to less complexity in the overall CFB design. The cost per MW decreases as the plant size increases, clearly showing the economy of scale advantage.

Table 1-2
Capital Cost Estimate Summary

September 2007$		Stoker			CFB		
		25 MW	50 MW	100 MW	25 MW	50 MW	100 MW
Total Plant Cost	$000	58,671	85,802	126,360	57,461	83,982	123,606
Total Plant Investment	$000	60,138	87,947	129,519	58,897	86,082	126,696
Total Capital Requirement	$000	67,179	98,243	144,682	65,793	96,160	141,529
	$/kW	2,687	1,965	1,447	2,632	1,923	1,415

The non-fuel annual operating and maintenance costs (O&M cost) have only minor differences between the types of boilers. The accounted costs differences include the difference in maintenance costs and the waste disposal costs. Other variations such as the difference in ammonia use by the SCR are not addressed by this initial estimate. The operating costs include both fixed and variable costs. Fixed cost includes both fixed labor costs and fixed maintenance costs. Variable costs include consumable products such as make-up water usage, chemicals, and variable maintenance costs. Fuel costs are different due to the different efficiency of the two boilers. The costs summarized in Table 1-3 are based on an 80% plant capacity factor.

Table 1-3
Annual O&M Costs at 80% Capacity

		Stoker Boiler			CFB		
		25 MW	50 MW	100 MW	25 MW	50 MW	100 MW
Total Fixed Operating Costs	$000/yr	3,965	4,779	6,763	3.929	4,724	6,680
	$/kW-yr	158.61	95.58	67.63	157.15	94.49	66.80
Total Variable Operating Costs	$000/yr	532	1,051	2,091	532	1,050	2,090
	$/MWh	3.04	3.00	2.98	3.04	3.00	2.98
Fuel Costs ($20/ton)	$000/yr	5,083	9,731	16,920	4,698	8,942	15,774
	$/MWh	29.01	27.77	24.14	26.81	25.52	22.51

The major differences between the cases are the higher boiler efficiency (seven percentage points) of the CFB boiler and the lower level of particulates and NOx emissions in the CFB flue gas. This assumes the same capacity factor (80%) in both cases. The stoker boiler uses an ESP to collect the fly ash while the CFB boiler uses baghouses. Baghouses are less expensive than ESPs, and therefore, the capital costs of the CFB boiler plant are lower than those of the stoker boiler plant. The design analysis with input from boiler vendors shows that all other plant components are expected to be roughly the same.

Based on this study, CFB boilers are slightly more preferable technology than stoker boilers for a biomass plant because of their (1) higher boiler efficiency, (2) lower capital costs, and (3) lower expected NOx and particulate emissions. This analysis assumes 80% capacity factor for each facility. Other criteria to consider in future study when comparing the two technologies are 1) the ease of operation, 2) a more detailed capital and O&M cost, 3) full simulation of the entire plant.

A sensitivity study run to estimate the impact of in-site drying shows that lowering the feedstock moisture content will be able to improve the boiler efficiency and reduce the boiler size and feedstock requirements. However, assuming that the capacity factor of the overall plant is unchanged between the cases, it is expected that the cost of including a separate dryer and using non-waste plant heat will exceed the benefits gained. Drying should only be performed if required to improve plant availability.

Areas for future analysis help gain better insight into the design and more accuracy with the cost estimates include the following:

- Additional Drying Studies
- Specific Site Analysis
- Environmental Equipment Case Analysis
- Fuel Quality Range

2
INTRODUCTION

Background

In 2006 EPRI initiated a new project to conduct engineering and economic evaluations of renewable energy technologies, including wind, biomass, solar, geothermal, hydro, ocean tidal and wave, and others. The results were used in the 2006 EPRI *Renewable Energy Technical Assessment Guide (TAG-RE)*, a key product of EPRI's renewable energy program[1]. The success of this work led to interest in expanding the analysis to other areas. The 2007 engineering and economic evaluation presented in this report addresses retrofitting small-scale coal-fired utility boilers to cofire biomass and coal.

Biomass is a major source of US renewable energy with a great deal of expansion potential. In 2005, biomass contributed 2.7 quadrillion BTUs of energy to the 69 quadrillion BTUs produced in the US, or roughly 4 percent[2]. This includes not just power generation, but also heat and steam generation at industrial facilities. In terms of overall energy produced from renewable sources, biomass is typically near the top with hydropower. Direct-fired biomass combustion (not including landfill gas) produced 38.7 billion kWhs of electricity in the US during 2005, from a nameplate capacity of 6,200 MW at roughly 120 facilities[3].

Biomass conversion to power has much greater potential than what is currently being realized. The US Departments of Energy and Agriculture estimate that utilization of woody biomass could increase by 2.5 times over current application since nearly 400 million dry tonnes per year of suitable feedstock supply exists[4]. In addition, a further 900 million tonnes of agricultural residues also exist that could be available for use in the energy sector. Potential benefits from the use of biomass to generate power include revitalizing rural economies, utilization of old, small power generation equipment, and reducing carbon dioxide emissions from the power sector. A 2004 National Renewable Energy Laboratory (NREL) study estimated that direct firing of biomass to generate power reduced the global warming potential (GWP) from power generation by 148

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[1] Electric Power Research Institute, Renewable Energy Technical Assessment Guide—TAG-RE: 2006, EPRI 1012722, March 2007.

[2] Oak Ridge National Laboratory, Biomass Energy Databook Edition 1, ORNL/TM-2006/571, September 2006.

[3] US Department of Energy, Energy Information Agency, available at www.eia.doe.gov

[4] US Department of Energy and US Department of Agriculture, Biomass as Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion-Ton Annual Supply, DOE/GO-102005-2135, April 2005.

percent relative to coal combustion on a complete lifecycle basis[5]. GWP is reduced from not just fuel switching, but also by eliminating the need for additional mining, reducing relative miles traveled to move feedstock, and avoiding the methane that would be emitted from placing wood waste in landfills.

Despite the availability of biomass fuel and the potential benefits, the utilization of biomass resources to make power is not growing rapidly in the U.S. Growth during this decade has been roughly one percent per year. The downside to the use of biomass for power includes feedstock availability, size limitations for large base load projects, and environmental concerns with regard to particulate emissions. While certain applications, such as distributed power needs in heavily forested areas, are well suited to the use of biomass, the number of overall applications has been limited.

A set of new drivers are taking shape that may increase the use of biomass. The first is the enactment of Renewable Portfolio Standards (RPS) in an increasing number of states. As of 2007, 24 states and the District of Columbia had implemented RPS legislation. While biomass has not yet played a large role in states meeting their initial RPS goals, the aggressive nature of some RPS mandates will likely lead to new biomass facilities in the future. This will be especially true in areas that have limited capacity to produce renewable energy from wind and solar resources. The Southeastern US is the best example of a region that could substantially increase biomass utilization if RPS legislation becomes more widespread.

A second major driver is the repowering of small coal-fired power plants. Small plants tend to be old, inefficient, and do not possess many of the advanced controls and environmental management devices present in modern facilities. As such, many of these plants are being shutdown throughout the world once tighter environmental regulations are enacted. Trends of this nature are being witnessed in a number of countries, including China. Instead of shutting down and scrapping these facilities, the existing capital in place could be adapted to use biomass as a feedstock.

Scope of Work

The scope of work includes the engineering and economic evaluations of the thermal efficiency, capital and operating costs, resource requirements, environmental emissions, and other metrics for the following combustion technologies: 1) 100% biomass combustion in stoker and circulating fluidized bed boilers and 2) retrofitting small utility coal boilers to 100% biomass firing with either stoker or circulating fluidized bed (CFB) boilers. The work was performed under the following four tasks:

- Task 1: Economic Methodology and Design and Economic Assumptions
- Task 2: 100% Biomass Combustion
- Task 3:Retrofitting an Existing Coal Unit to 100% Biomass Combustion
- Task 4: Final Report

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[5] Spath, P., and Mann, M., "Biomass Power and Conventional Fossil Systems with and without CO_2 Sequestration – Comparing the Energy Balance, Greenhouse Gas Emissions and Economics", US Department of Energy, National Renewable Energy Laboratory, report NREL/TP-510-32575, January 2004.

This report addresses the work completed for Task 2. The objective is to evaluate the performance, cost, and environmental emissions of 100% biomass combustion. The engineering needs and economics for two types of boilers: a stoker and circulating fluidized bed boiler. The base case design is a 50-MW plant; 25- and 100-MW cases are also developed using the 50-MW base case as a reference.

For all cases, woodchips as biomass fuel is used. It is assumed that woodchips are delivered to the plant with on site fuel processing system to reduce them to the appropriate size. Both the stoker boiler and CFB boiler cases have similar fuel storage and fuel handling systems. On site drying of biomass fuel is evaluated as a fuel moisture sensitivity case. The general design for each facility is as follows:

- Stoker Boiler Plant: The stoker boiler plant consists of a single grate-fed stoker boiler and single admission non reheat steam turbine with 1,500 psig, 950°F steam, and 2.5" HgA (1.23 psia) condenser back pressure. The feedwater heating is done with turbine extraction. A wet cooling tower for condenser cooling system is included. A standard utility boiler plant configuration with DCS controls, required emission controls (consisting of both flue gas particulate and NOx control), and zero liquid discharge is used.
- CFB Boiler Plant: The CFB boiler plant is similar to the stoker boiler plant, except for the boiler island, associated auxiliaries, and emissions control system.

For each boiler type, this study developed a process flow diagram and plant description, and estimated the boiler efficiency, steam cycle heat rate, auxiliary power consumption, net plant heat rate, overnight construction cost in September 2007 $, O&M labor cost, maintenance materials, fuel needs, and raw material requirements. The financial analysis estimates the capital costs and fixed and variable O&M costs.

Application to Future Work

The data generated by this task can be used by developers considering new biomass facilities to evaluate general performance and overall system cost. If the results are attractive, given the range of uncertainty in this preliminary design, more detailed investigation should be performed to further refine the estimates. This will provide a more suitable estimate for making project specific decisions, since this is a generic site design.

The data from this Task will also be the benchmark for the retrofit case performed in Task 3. Feedstock handling, some boiler design data, and environmental control equipment will be directly applied to the retrofit case. In addition, the equipment available at the coal facility being retrofitted can be evaluated versus the equipment list developed during this Task to determine what can be salvaged and what new equipment would be required.

3
DESIGN BASIS AND METHODOLOGY

Site Information

No specific site has been selected for this study; however, it can be assumed to be a typical site in Southeastern, Midwestern, or Northeastern area of the US. It is also assumed that the site is level, suitable for power plant construction, and no major site improvement is required. The site has access to major highways, railroad and transmission lines and has access to adequate raw water from lake or river with fresh water quality. Table 3-1 shows the assumed ambient conditions.

Table 3-1
Site Ambient Conditions

Parameters	Unit	Values
Ambient Temperature	F	70
Ambient Pressure	psia	14.69
Ambient Relative Humidity		60%
Dew Point Temperature	F	55
Wet Bulb Temperature	F	60

The site seismic conditions, wind and snow loading are not considered for this study. Although, these factors may have some impact on capital costs, they will not have any impact on plant performance evaluated in the study.

Fuel Characteristics

The fuel characteristics are provided by EPRI. Table 3-2 summarizes the fuel characteristics of the feedstock. In addition, it is assumed that the density of the wood is 24.0 lb/ft^3, based on high density wood parameters reported by Oak Ridge National Laboratory (ORNL)[6]. The assumed fuel ash content is lower than what is expected for wood feedstocks. The design should be able to

[6] Badger, P., "Processing Cost Analysis for Biomass Feedstocks", US Department of Energy, Oak Ridge National Laboratory, report ORNL/TM-2002/199, October 2002.

handle higher ash content feedstocks as well, but consideration should be made for the impact that higher ash content will have on the boiler design and ash handling systems.

Table 3-2
Fuel Characteristics

Parameter	Units	Value
Moisture	% ar	45.0
Ash	% db	0.1
HHV	Btu/lb, dry	8500
	Btu/lb ar	4750
Proximate Analysis, dry basis		
Volatiles	%	85.0
Fixed Carbon	%	14.9
Ash	%	0.10
Ultimate Analysis, dry basis		
Carbon	%	49.7
Hydrogen	%	6.4
Nitrogen	%	0.2
Sulfur	%	0.2
Oxygen	%	43.4
Ash	%	0.1

Environmental Requirements

It is likely that the new plant will require New Source Review for Prevention of Significant Deterioration (PSD) or permitting for Non Attainment Area (NAA) depending on the location. While a wood boiler does not fall under one of the 28 source categories for PSD review, it is expected that the unit will emit more than the minimum threshold of 250 tonnes per year of at least one criteria pollutant.

It is not the intent of this study to review in detail requirements of PSD for new source permitting; and it is assumed that the proposed biomass facility will deploy best available control technology (BACT) to meet the emission requirements. This implies baghouses or ESPs for particulate control and an SCR unit for NOx reduction. The anticipated emission limits for NOx, SO_2, CO and particulates are identified in Section 4. It is assumed that currently available control technologies for the boiler design, NOx and particulate controls will be adequate to meet the CO, NOx and PM_{10} limits. With very low sulfur content in the woodchips, it is assumed that no post combustion flue gas desulfurization is required. The same emission design basis is used for the 25- and 100-MW plants.

A zero water discharge facility is assumed for design. Residual waste water from the process is held in holding ponds and mixed with bottom ash for disposal off site. It is assumed that fly ash will be utilized as a construction material.

Steam Generator

Two separate steam generation systems are evaluated – a stoker boiler and a CFB boiler. Stoker boilers have been used for over one hundred years. For a wood firing application, an air-cooled mechanical rotating grate design is used. Stoker boilers are offered by all major industrial boiler manufacturers. The total heat duty of the boiler is expected to be 550-650 MMBtu/hr to support a 50-MW (net) steam turbine output. The boiler has a fuel feed system with multiple chutes to feed the fuel over the grate. Air is supplied under the grate as well as over fire air for complete combustion. The boiler is modeled based on typical radiant and convection heat transfer for a fossil boiler and expected heat losses to determine size, efficiency and fuel requirements. The cost of the boiler is based on vendor and in-house boiler data.

The design basis for the CFB boiler is similar to that of the stoker boiler, with steam generation conditions to support a 50-MW steam turbine. The basic design parameters are based on current generation of CFB boiler design for 440 klbs/hr steam production. The cost estimates for the CFB boilers are based on information from boiler vendors and past CFB projects for waste coal facilities.

The detailed design parameters for the both steam generation systems are provided in Section 4.

Fuel Handling

The basis for the fuel handling section design is from ORNL data. Equipment sizing and cost information in the ORNL report are provided for 20- and 50-MW plants. The data for the 20-MW plant in the report are used to determine the size and cost of the 25-MW plant. Most of the equipment sized for the 20-MW plant is adequate for the 25-MW plant. The 100-MW plant cost data are scaled from those for the 50-MW plant. Appropriate indices are used to scale all costs to constant September 2007 US dollars.

Balance of Plant

The balance of plant consist of a steam cycle with condensing steam turbine with steam extraction for feedwater heating, a condenser, a mechanical draft wet cooling tower, ash handling and disposal system, water treatment, and plant electrical and control system.

The steam cycle design is based on a 50-MW turbine design for a recent renewables project. The detailed steam/Rankine cycle was validated with GateCycle® software. The complete steam cycle with four closed loop feed water heaters and one open loop deaerator system is fairly common in a 20- to 80-MW steam turbine design. The 100-MW plant design includes a reheat turbine, similar to reheat turbines in 100-MW and larger fossil plants.

Design basis and major equipment sizing for a 50 MW plant are outlined in Section 4.

Ash Silos

Ash content in the feedstock is 0.1% dry basis (db). The ash will either be fly ash or bottom ash. The percentage distribution and density of the fly ash and bottom ash is summarized in Table 3-3. It is assumed that the ash is disposed off-site. Fly ash has economical value and can be sold for cement production. The ash disposal schedule is five days per week during the weekdays, which means that the silos must be sized to meet the ash production of three days of operation. As a safety factor, the silos are oversized by 20%.

Table 3-3
Ash Properties

Parameters	Units	Fly Ash	Bottom Ash
Percentage in CFB	%	80	20
Percentage in Stoker	%	60	40
Density	lbs/ft^3	45	105

Performance

A steam cycle was developed for a nominal 50-MW turbine generator plant using GateCycle® to determine the system performance. The GateCycle® modeled a steam turbine, condenser, cooling tower, feedwater heaters, deaerator, feedwater and condensate pumps, and cooling water pumps. The simulation results from GateCycle® provided steam requirements and thermal duty for the steam generator. The boiler was modeled to calculate fuel requirements, primary and combustion air flow, and flue gas flow to match with boiler steam production for the GateCycle®. Finally, overall cycle efficiency and heat rate were calculated. Fuel analysis was used to determine quantity of ash generated and was used to size fly ash particulate collection system and ash silos for bottom ash and fly ash.

The following steam cycle parameters were selected:

- Inlet steam at 1500 psig and 950°F
- Steam turbine exhaust at 2.5" of HgA or 1.25 psia
- Wet cooling tower with 70°F water and 60% relative humidity
- Four closed feedwater heaters and one deaerator at 100 psig operating pressure

The detailed plant performance for the 50-MW plant is provided in Section 4.

Power Output

The plant is designed for 50-MWe net output at the high side of the generator step-up transformer after accounting for the auxiliary load. Nominal rating of the steam turbine is approximately 56 MWe.

Water Consumption

Water consumption for the biomass plant is largely for the boiler steam cycle and makeup for the cooling tower. Boiler losses are due to steam leakage and boiler blowdown. These are assumed to be 2% of nominal steam flow. The cooling tower losses are due to evaporative losses, drift losses and cooling tower blowdown. The estimate for total water consumption for the boiler and cooling tower is provided in Section 4.

Waste Streams

The major liquid waste streams are boiler blowdown, cooling tower blowdown, and regenerative waste from the water treatment. The boiler blowdown can be directed to the cooling tower and reduced to one waste stream. Both the cooling tower waste stream and regenerative waste stream are treated to comply with National Pollutant Discharge Elimination System (NPDES) permit before discharge from the plant.

4
50 MW PLANT DESIGN AND COST ESTIMATE

Overview

The facility is a stand-alone 50-MW woodchip burning power plant to be located at a typical site in Southeastern, Midwestern, or Northeastern area of the US. Electric power produced by the facility is delivered to the local electrical transmission grid.

The plant includes a fuel handling system supplying woodchips from a truck unloading hopper to the boiler which produces superheated steam at 1500 psig and 950ºF. Steam is supplied to a condensing turbine which drives a synchronous generator. Regenerative feedwater heating is used to increase steam cycle efficiency. Turbine exhaust is condensed in a water-cooled condenser.

Flue gases exiting the boiler pass through an SCR unit for NOx reduction, an ESP or baghouse to remove particulates, and a Lungstrum type air heater to preheat the incoming combustion air. Cooled bed ash and fly ash are collected and pneumatically conveyed to separate ash silos. The fly ash and bottom ash from the silos are discharged into trucks for disposal and/or sale offsite.

Equipment specification, sizing, types of equipment, material quantities, and material types listed here are developed for a feasibility level study and should be treated as a guideline. Final equipment specifications and equipment selection will be determined during the detailed design phase.

Plant Design

Figure 4-1 shows the general process flow diagram for the biomass combustion power plant. The process diagrams are similar for both boiler types. The diagram includes the fuel handling and preparation process, the boiler, the air quality control units, the steam turbine, and auxiliary units.

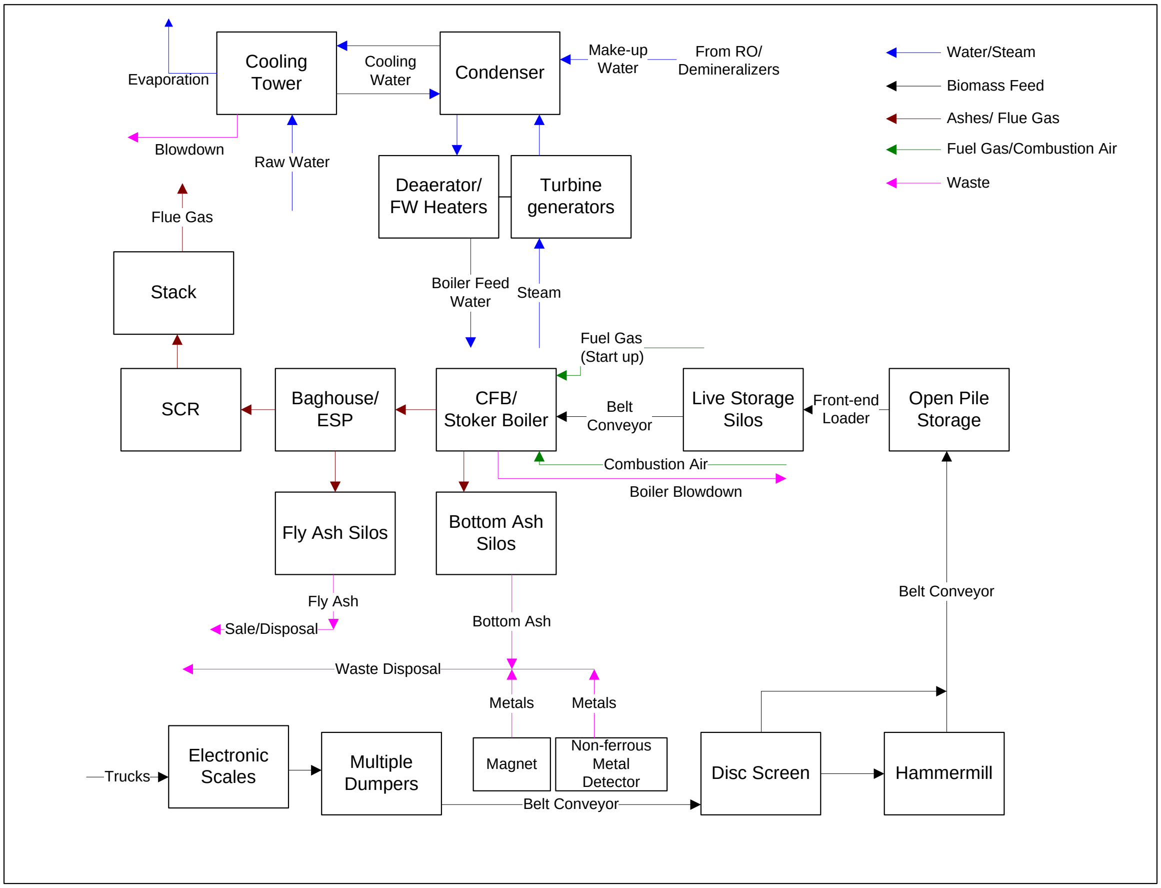

Figure 4-1
Process Flow Diagram of Biomass Combustion Power Plant

Table 4-1 summarizes the fuel requirement. The fuel requirement is based on the high heating value (HHV) of the fuel. For the 50-MW plant, 69 and 64 tons per hour of woodchips are fed to the stoker and CFB boiler, respectively. CFB boilers require less feedstock because CFB boilers have higher boiler efficiencies. The feedstock flowrate is calculated based on the fuel characteristics and the plant performance.

Table 4-1
Fuel Requirement for 50-MW

Parameter	Units	Stoker	CFB
Hourly requirement	tons/hr	69.4	63.8
Daily requirement	tons/day	1,666	1,531
Trucks per day (25 tons/truck)		67	62

Feedstock Handling

The fuel handling and preparation system consists of electronic scales, dumpers, hopper, conveyor, magnets, non-ferrous metal detector, disc screen, hammermill, open pile storage, front end loaders, and live storage silos.

Truck delivery and electronic scales: Most of the wood fuel is assumed to be delivered by truck to the site. Drive-on scales are used to determine the weight of wood that is being delivered by trucks. The facility should have one electric scale. Truck delivery is scheduled to occur for eight hours per day, 7 days per week.

Dumpers: Whole-truck dumpers with hoppers are recommended for a 50-MW plant because of their short unloading time. Dump units can tilt the whole truck for fast unloading. A 50-MW plant needs two dumpers to accommodate the fuel requirements.

Hopper: The hopper is used for feeding wood chips into the scalping screen-hog processing system. The capacity of the hopper is 671 ft^3. It can process 108.6 tons of wood chips per hour. The drag chain live bottom is 29.5 ft long.

Conveyor: A 36–inch wide trough-idler cleated belt conveyor with 39-ft discharge height and 110-ft length is used to transfer the feedstock from the dumpers to the storage. The conveyor angle is 22 degrees. The power consumption of the conveyor is 11.25 kW.

Magnets and non-ferrous metal detector: After the dumpers, the wood passes through a belt conveyor equipped with a magnet and non-ferrous metal detectors. Self-cleaning magnets are used to remove ferrous metals. When non-ferrous metals are detected, the belt conveyor stops to allow visual inspection and removal of the metal by an operator.

Disc screen: The wood will then pass through a disc screen to remove particles of acceptable size prior entering the hammermill. A disc screen uses rotating disks to move oversized chips across the top while the rest of the chips fall between the screen openings. The oversized chips are discharged to the hammermill, and the rest of the chips are conveyed to storage. The screener dimensions are 72 by 96 inches, and it consumes 5.6 kW of electricity.

Hammermill: After passing through the disc screen, the oversized particles are ground with a hammermill. It is assumed that only 30% of the wood chips are sent to the hammermill. The 112-kW hog with electric motors operating at high torque and high speed will produce particle sizes in the range of 0.1 to 0.5 inches. The ground wood will then be sent via conveyor belts to storage.

Storage: Open pile storage is commonly used for large-scale facilities, unless the climate is not suitable. For plants larger than 10 MW, pads are constructed with leveled earth and crushed rock base. Pads are necessary to prevent debris such as rocks and soil. The maximum height of the pile is assumed to be 29.5 ft due to environmental regulations for wind-blown debris. Table A-1 shows the base dimensions and area of the storage area. The shape of the open pile storage is assumed to be a truncated square pyramid with 45° side slopes. An 11.5 ft wide driveway surrounds the pile. The open pile storage can hold feedstock for a period of four weeks. Front-end loaders are used to retrieve fuel from open pile storage.

Table 4-2
Onsite Storage for 50 MW Plant

Design Parameter	Units	50-MW Plant
Capacity	ton	46,657
Volume	ft^3	3,892,538
Base dimension (w/ 11.5 ft driveway)	ft	416
Base Area	ft^2	172,702
	acre	4.0

Front end loader: Front end loader is used to transport the feedstock from the open pile storage to the live storage silos. One hopper with 318 ft^3 of bucket is sufficient for the plant.

Live storage silos: Metal silos are used to store the feedstock near the boiler for 4 to 12 hours. For the 50-MW plant, there is an eight hours storage buffer. The silos are oversized by 20%. Table 4-3 summarizes the design parameters of the live storage silos.

Table 4-3
Live Storage Silos for 50-MW Plant

Design Parameter	Units	50-MW Plant
Capacity	ton	555
Volume	ft3	46,340
Silos volume requirement	ft3	55,608
Number of Silos		3

Boiler Island

The feedstock is combusted in the boiler to provide heat for generating steam. There are different types of boilers used for power generation. The design of both CFB and stoker boilers are completed as part of this study. Each boiler type is described below, and detailed specifications are presented in Appendix C.

CFB Boiler

A drum-type, natural circulation, CFB boiler generates steam at 1500 psig and 955ºF at the superheater outlet. The boiler is enclosed. Pressure part components of the boiler are designed in accordance with the ASME Boiler and Pressure Vessel Code, and the boiler performance/acceptance test is conducted in accordance with ASME PTC procedures.

Principal components of the CFB boiler include a water-cooled combustor/evaporator, refractory-lined cyclone separators, superheater, economizer convection pass heat transfer elements, fans, blowers, primary and secondary air heaters, an induced draft fan, and bottom ash coolers. Pertinent design features include:

1. Designed for specific wood waste and wood chips as primary fuel and a range of fuel specification listed in Table 3-2.
2. Guaranteed performance parameters include the continuous steam output rate, steam quality leaving the drum, main steam outlet temperature, nitrous oxide emissions, SO_2 emissions, particulate emissions, boiler efficiency, power consumption, and fuel flow.
3. A maximum convection pass flue gas velocity of 50 feet per second.
4. An in-line convection pass superheater/economizer heating surface arrangement.
5. Ash hoppers with an eight-hour storage requirement.
6. Tubular primary and secondary air heaters.
7. No.2 distillate fuel oil start-up system rated at approximately 35 percent of maximum continuous rating (MCR) heat input.
8. A steam temperature control range of 70 to 100 percent of the maximum continuous rating (MCR).
9. A 300°F uncorrected gas temperature exiting the air heaters at MCR operations with the performance grade fuel.
10. Single full-capacity primary and secondary air fans that are designed for the fuels specified.
11. A single induced draft fan, designed for the fuels specified.
12. A bed ash cooling system that will reduce the temperature of the ash stream.

The CFB boiler and SCR/ESP equipment are designed to meet the air quality emissions limits identified in the sub-section of Emission Limits for the Wood Fired CFB Plant in Section 4. Specifically, the nitrogen oxide (NOx) emissions control employs a staged combustion process that introduces secondary air at various levels in the combustor and, when combined with the low combustion temperature, reduces the thermal NOx emissions. The NOx emissions are further reduced by SCR with ammonia injection. While SCR may not be necessary for all wood-fired boilers at all geographic locations, this case assumes that BACT standards will require SCR for this design. CFB boiler vendors include Foster Wheeler, Babcock & Wilcox, Kaverner (formerly Tampella), and Riley Power.

Stoker Boiler

The traveling grate spreader stoker boiler is a subcritical, natural circulation, wood-chip fired, balance-draft furnace with boiler rated capacity of 415,000 lb/hr MCR steam flow at 1500 psig and 950°F superheater outlet temperature. No external dryers are provided; and the wood fuel dries in the boiler combustion section. The steam generator is a balanced draft unit with forced draft (FD) and induced draft (ID) fans. Natural gas (or fuel oil) is the backup fuel and is used for ignition and for flame stability at loads lower than 50% of maximum or during firing with fuel with over 50% moisture. The boiler is enclosed in a building to provide weather protection and to facilitate maintenance during the winter.

In the basic stoker design, the bottom of the furnace is a moving grate which is cooled by under-fire air. The under-fire air rate defines the maximum temperature of the grate and thus the allowable feed moisture content. More modern designs include a sloping reciprocating water-cooled grate. Reciprocating grates are attractive due to simplicity and low fly ash carryover. Combustion is completed using over-fire air. Furnace wall configurations include straight and bull nose water walls.

The ash removal system consists of a combination of drag chain and screw conveyors that collect ash from the boiler grate, siftings hopper, air heater, mechanical collector, and electrostatic precipitator. Bottom ash is discharged from the traveling grate to a water-filled bottom ash hopper. Bottom ash is continuously removed from the bottom ash hopper by a submerged chain conveyor system. Fly ash from the economizer hopper, air heater hopper, cyclone collectors, and ESP hoppers is removed in a dry condition with pneumatic conveyor to fly ash silos. The bottom ash is then trucked to an onsite or offsite landfill for disposal. Fly ash is either disposed as waste or sold as filler material for construction.

Stoker boiler vendors include Zurn, Foster-Wheeler, B&W and Riley Power (a division of Babcock Power).

Turbine Island

The steam turbine island components are described in this sub-section. Appendices D and E presents the overall and low- and high pressure steam turbine design parameters.

Condensing Steam Turbine

The condensing turbine uses 1500 psig, 950°F throttle steam and the steam cycle has five stages of extraction for feedwater heating and deaeration. The extraction steam system is designed in accordance with standards developed by the ASME for the prevention of turbine water induction. The steam turbine has an integral lubrication and hydraulic control system and includes a lube oil conditioner, lube oil coolers, an AC-operated or a shaft-driven lube oil pump, both with a DC backup pump.

The generator is a two-pole, synchronous, 3600-rpm machine and includes necessary ground, instrument transformers, surge protection, and excitation equipment. The MVA rating of the generator is adequate to deliver maximum output at 100 percent main steam flow at a back pressure of two psia. The generator lube oil system is integrated with the turbine system. The generator is air cooled. Stop valves are provided to isolate the turbine from the boiler during startup and to provide for emergency over speed trip following loss of electrical load.

The turbine has a full complement of supervisory instruments and fault detection devices. These include but are not limited to vibration, over speed, hydraulic system and lubricating system alarms.

Water Cooled Steam Condenser and Cooling Tower

The steam condenser condenses steam from the turbine exhaust and is designed for a turbine exhaust pressure of two psia and an ambient dry bulb air temperature of 55°F. The cooling water is a closed loop system and is cooled in a mechanical draft cooling tower. The cooling tower requires make up for the evaporative losses and normal blowdown. There is also makeup water for normal cycle condensate losses. The steam condenser contains of two or more cells located below the LP turbine. Each cell has a tube bundle cooled by circulating water from the cooling tower.

During low load operation (approximately less than 5% of rating) or winter operation, the cooling tower fans can operate at reduced speed or shut off completely for freeze protection. The condenser air removal system establishes and maintains a vacuum in the condenser. The system includes a steam-driven hogging ejector for startup and steam-driven holding ejectors to maintain vacuum during normal plant operation.

Emission Control System

Particulates Control

Electrostatic Precipitator (ESP)

The ESP system is a particulate collection device that removes particles from a flowing gas using the force of an induced electrostatic charge to collect particulate matter. ESP removes fly ash from the flue gas. This is the technology used in the stoker boiler design.

Flue gas from the air heater will first enter the ESP through an inlet manifold which distributes the gas to the plate or tubular chambers with electrodes. Collected particulates are retained on the surface of the plate and the cleaned flue gas exits through the ESP. Flow from individual ESP chambers is collected in a manifold, where it will flow to the inlet of the induced draft fan.

When the particulate buildup on the surface of the plate (or tubes) reaches a preset thickness, as determined by the pressure drop across a row of plates, an automatic, off-line, cleaning cycle is initiated. Hoppers located below the collection chambers collect the particulates released from the plate surfaces during cleaning. Hoppers have an eight-hour storage capacity at full load. A pneumatic transfer system transports the particulate from the hoppers to the ash storage silo.

Baghouses

Baghouses, also called fabric filters, use “bags” as filters to remove the fly ash from the CFB flue gas. The particulate content of the CFB flue gas is expected to be lower than that for the stoker boiler case due to the cyclones present internal to the CFB design. In order to reduce capital and operating costs, baghouses are chosen over an ESP for the CFB plant. The stack gas passes through the filters and the fly ash is collected either on the outside surface of the bags or inside the bags depending on selected flow pattern. When the pressure drop across the bags reaches a preset level, the bags are shaken and the fly ash falls into a collection hopper.

The baghouse has point level measurement devices to indicate ash level. Each hopper has a high level switch to indicate when the hopper should be emptied. Hoppers have baffles down the center and require two high level switches, one for each side of the baffle. The low-level switches are used to indicate an empty hopper condition.

Ash Silos

Ash silos store the fly ash and bottom ash from the boilers. The bottom ash is collected from the bottom of the boilers, and the fly ash is collected from either the ESP or the baghouses. The ash is stored in silos until it is disposed of or sold. Table 4-4 shows the silo design parameters for the CFB and stoker boilers.

Table 4-4
Ash Silos Design Parameters

Design Parameter	Units	CFB Boiler	Stoker Boiler
Total ash weight	tons/day	0.84	0.92
Fly Ash			
Capacity	tons/day	0.7	0.5
Volume	ft^3	90	73
Silo volume requirement	ft^3	108	88
Number of fly ash silos		2	2
Bottom Ash			
Capacity	ton/day	0.2	0.4
Volume	ft^3	10	21
Silo volume requirement	ft^3	12	25
Number of bottom ash silos		1	1

Selective Catalytic Reduction (SCR)

An SCR unit is used in both designs for NOx control. While some plants may not require an SCR to meet local requirements, it is included here as a BACT contingency.

The SCR uses ammonia to reduce NOx in the flue gas to nitrogen and water in presence of a catalyst (typically vanadium pentoxide). The SCR is located between the boiler and the economizer and ESP or baghouse. The SCR reactor comprises of honeycomb catalyst placed in the gas path. Aqueous ammonia is sprayed into the flue gas stream at 650°F upstream of the catalyst. The ammonia spray is controlled by monitoring NOx concentration in the stack gases via a continuous emission monitor (CEM).

Balance of Plant

The balance of plant equipment is described below, and the design parameters are listed in Appendices D and E.

Condensate and Boiler Feedwater Systems

Condensate System

The condensate system pumps condensate from the condenser receiver through the air ejector condenser, gland steam condenser, and the low pressure feedwater heaters to the deaerator. The system maintains a stable level in the deaerator over the entire range of plant operation.

Major components of the condensate system are:

Condensate pumps: Two 100-percent-capacity, centrifugal, vertical, can-type, condensate pumps are used. The pumps are driven by induction electric motors. Net positive suction head (NPSH) available at the pumps is based on the lowest water level in the condenser receiver. Seal water is provided from the condensate pump discharge header.

Low pressure feedwater heaters: Two low pressure feedwater heaters are used. The heaters are horizontal, full-capacity, single-shell, U-tube heat exchangers with stainless steel tubes and are designed in accordance with HEI standards for closed feedwater heaters.

Gland steam condenser: One gland steam condenser in used to condense, deaerate, and reuse gland steam leakage from the main turbine shaft seals. The condenser is an air-cooled heat exchanger, designed in accordance with HEI standards for heat exchangers.

Air ejector condenser: One integral inter and after condenser is used to condense the steam and vent non-condensable gases withdrawn via the steam jet air ejectors.

Feedwater System

The feedwater system pumps feedwater from the deaerator storage tank to the economizer inlet of the boilers. The system controls feedwater flow in response to steam flow and maintains proper boiler drum level. The feedwater system also provides spray water to the boiler superheater spray attemperator for superheater outlet temperature control. The feedwater temperature at the economizer inlet is approximately 350°F. The feedwater system design flow is based on a full, 100 percent load heat balance steam flow, including additional requirements for steam generator blowdown and auxiliary steam services.

Two 50-percent-capacity motor-driven boiler feed pumps are used. The pumps are multistage, horizontal, centrifugal, and driven by constant speed electric motors. A third pump has diesel engine drive and is utilized in situations where both motor-driven pumps are out of service. This mode of operation is intended for short periods only to provide cool down flow to the boiler drum upon the total loss of power.

The deaerator is a spray-tray type, consisting of a heater and a storage tank, designed in accordance with the HEI standards for deaerators. The deaerator storage capacity is sufficient for five minutes of feedwater system operation at full load.

Steam Systems

Main steam system: The main steam system is designed to supply superheated steam from the boiler superheater outlet to the turbine generator. The piping system is designed for a steam flow of 300,000 pounds per hour at the boiler main steam outlet conditions of 1600 psig and 950°F. Steam conditions at the turbine inlet are 1500 psig and 950°F.

The extraction steam system is designed to heat feedwater to a final temperature of about 350°F.

The feedwater heater consists of one direct contact deaerating heater, two high pressure closed feedwater heaters, and two low pressure feedwater heaters. The No.2 low pressure heater drains into the No.1 low pressure heater, which drains to the condenser hotwell. Each heater also has an emergency dump line which discharges directly to the condenser hotwell.

Water Systems

The raw water concentration of dissolved solids is likely to be high. Demineralization alone is not cost effective for these high ionic loadings, so a two-step process of desalination and demineralization is used.

The first step is reverse osmosis (RO). The RO unit is sized for 55 gpm, using an approximate 75 percent recovery and downstream water requirement for the demineralizer and domestic water system. The RO unit produces high quality fresh water which is suitable for use as domestic water without additional treatment other than chlorination.

The RO effluent still requires demineralization before it can be used for boiler feedwater makeup. Two demineralizer trains of 35 gpm each are included, each consisting of a mixed bed cation/anion exchanger. Additionally, a single shared decarbonator is required for removal of the large quantities of bicarbonate ion present.

Condensate storage tank: One condensate storage tank with a storage capacity of 10,000 gallons is provided to receive and store demineralized water from the makeup water demineralizers. The storage capacity represents approximately eight hours of operation during full steam flow.

Condensate transfer pump: One 100-percent-capacity, horizontal, centrifugal pump driven by an induction type electric motor is provided to supply condensate from the condensate storage tank to the condenser hotwell.

Boiler fill system: A motor-driven boiler fill/demineralized water pump is used to supply demineralized water to the boiler drum, and serves to move condensate from the condensate storage tank to the demineralizer regeneration chemical feed systems.

Service Cooling Water System

The service cooling water system provides cooling water at 85°F (maximum) for plant auxiliaries. Two 100 percent capacity, horizontal pumps are provided. The pumps take suction from the service cooling tower basin and discharge the water to the various equipment coolers. After flowing through the equipment coolers, cooling water returns to the service cooling tower. A basket strainer is provided in the system to filter the water.

Wastewater

Demineralizer wastewater is neutralized in the 3,000 gallon neutralization tank then pumped to the wastewater holding tank. The cooling tower blowdown, plant drains and other wastewater streams are pumped to the wastewater holding tank directly.

Compressed Air Systems

Service air system: The service air system furnishes oil-free air to the service air header. The service air header supplies air to various facility areas and adequate hose stations are provided for individual equipment areas. In addition, the service air receiver supplies the instrument air system.

Two 100-percent-capacity non-lubricated compressors with coolers and an air receiver are used. The compressors take suction through intake filters/silencers. The system is designed to maintain a minimum 80 psig pressure at the point of connection to plant equipment.

Instrument air system: The instrument air system provides dry oil-free air. Air supplied by the service air receiver passes through a filter-dryer unit, where it is dried and filtered to instrument quality at a dew point of -40°F.

Fire Protection System

The plant fire protection water supply and fire pumps draw water from the raw water storage tank and are designed to supply 1200 gpm with a 100-percent capacity motor-driven fire pump. A 100-percent-capacity diesel-driven fire pump is provided to back up the electric motor-driven fire pump.

Heating, Ventilating, and Air Conditioning Systems

The heating, ventilating, and air conditioning (HVAC) systems servicing the control room and occupied areas of the administration building are designed to maintain the comfort of the personnel. The cooling capacity is estimated with cooling loads based on heat generated by the mechanical equipment, lighting, and the people occupying the areas during normal plant operation.

Cranes and Hoists

A bridge crane that spans the turbine building is provided for servicing the turbine generator. The capacity rating of the crane is based on the heaviest component of the turbine generator, other than the stator, to be lifted for disassembly and maintenance. The crane is rated for a 25 ton lift on the main hoist and a 5 ton lift on the auxiliary hoist.

Hoists: Manually operated hoists and trolleys are provided for maintenance of the equipment in the facility.

Electrical

General Design Criteria

The electrical facilities are designed with sufficient ratings and capacities to permit generating and transmitting the guaranteed net electrical plant MW output. Further, the electrical facilities are able to support the start-up and operation of station electrical loads necessary to support electrical power and steam production, as well as normal and necessary station services. The generator is designed to accept the defined turbine output at nominal process steam extraction. The generator step-up transformer will be sized in MVA to match the turbine generator.

Appendix E provides more detail for all aspects of the electric system.

Plant Performance

Stoker Boiler

Table 4-5 shows the plant performance for the 50-MWe stoker boiler plant. The generator output is 56.5 MWe. Accounting for different losses in the plant, the net plant output is 50 MWe.

Table 4-5
50-MWe Stoker Plant Performance

Performance Parameters	Units	50-MW Plant
Gross Generator Output	kWe	56,465
Parasitic Load and Losses	kWe	6,465
Net Plant Output	kWe	50,000
Boiler Efficiency	%	75.9
Boiler Steam Output	klb/hr	440
Heat Rate	BTU/kWh	12,931
Capacity Factor	%	80
Fuel HHV (AR)	BTU/lb	4,750
Fuel Moisture (AR)	%	45
Fuel Required	tons/hr	69

The plant performance calculations are based on the fuel specification provided by EPRI. For the high moisture and low HHV contents of the as received fuel, the calculated boiler efficiency is 75.9%. With drier fuel and a higher HHV, boiler efficiency could improve. The sensitivity analysis of fuel moisture is covered later in this section.

The gross generator output is adjusted to yield net output, allowing for plant electrical service, including the plant auxiliary load of boiler fans, feedwater pumps, condensate pump, cooling water pumps and cooling tower fans, fuel handling, and flue gas treatment; and miscellaneous loads of water treatment, air compressors, plant control system, building HVAC and lighting.

CFB Boiler

Table 4-6 lists plant performance data for a 50-MW CFB boiler plant. The CFB plant is designed for a larger steam turbine output than the stoker plant to account for the larger primary air fans required for fluidization. The calculated gross plant output for the CFB plant is 56.985 MW.

Table 4-6
50-MW CFB Plant Performance

Performance Parameters	Units	50-MW Plant
Net Generator Output	kWe	56,985
Parasitic Load and Losses	kWe	6,985
Net Plant Output	kWe	50,000
Boiler Efficiency	%	82.6
Boiler Steam Output	klb/hr	442
Heat Rate	BTU/kWh	11,876
Capacity Factor	%	80
Fuel HHV (AR)	BTU/lb	4,750
Fuel Moisture (AR)	%	45
Fuel Required	tons/hr	64

Comparing Tables 4-5 and 4-6, it is evident that the CFB boiler is more suited for fuels with high moisture contents. The boiler efficiency for the CFB plant is higher as expected. Overall, the net plant heat rate for the CFB plant is 8% better than that of the stoker boiler plant. The better performance of CFB plant can be attributed to more complete combustion of the fuel in the fluidized bed due to longer residence time, and better heat transfer in the furnace due to more stable furnace temperatures. An additional advantage of the CFB plant is that it can handle a wide fluctuation of fuel quality and fuel moisture.

Emission Limits for the Wood Fired Plant

Flue gas monitoring is in accordance with the State Air Quality Bureau Permit and Code of Federal Regulations 40 CFR 60 for nitrogen oxides, sulfur dioxide, carbon monoxide and particulates as PM_{10}. Emissions limits are based on EPA guidelines using MACT. The plant is designed to not to exceed the following emission parameters:

Table 4-7
Emission Limits for Biomass Fired Plants

Wood Chips			
Criteria Pollutant	**ppm @ 3% O_2**	**lb/MWh**	**lb/MMBtu**
NOx as NO_2	49	0.67	0.07
SO_2	50	0.95	0.10
CO	127	1.05	0.11
Total Particulates (PM_{10})		0.20	0.02

The plant is designed so that it can meet these emissions targets. Particulate emissions are controlled through either an ESP (stoker boiler) or internal cyclones and a baghouse (CFB boiler). The low sulfur content of the wood feedstock should maintain SOx emissions well below EPA requirements. If sulfur emissions become an issue, limestone injection into the CFB or construction of a downstream FGD unit for the stoker case can be added. Finally, the SCR in both designs should maintain the NOx emissions at a low level.

Water Quality

Appendix E provides information on raw water, feedwater, and wastewater qualities.

Equipment List

The equipment list is provided in Appendix A. The list includes major equipment in the plant from fuel handling to emission control equipments.

Cost Estimates

Capital Cost

Basis and Methodology

The first step in developing the cost estimate was to prepare a detailed equipment list based on the preliminary process flow diagram. GateCycle® simulation was used to size much of the power island equipment for the 50-MW plant. In-house databases, ASPEN ICARUS, and vendor contacts are used to estimate major equipment costs. The pricing was adjusted to include commodity prices associated with the equipment. Previous construction cost estimates and ASPEN ICARUS methods were used to determine material, labor and equipment installed costs. The material costs were adjusted to include 4% freight charges and 5% sales tax as separate line items. The costs were also adjusted to reflect uncertainty based on vendor contacts and level of complexity for the equipment and system. Home office engineering and on site field construction management labor costs were determined based on level of effort from similar engineering projects.

All costs were adjusted to September 2007 dollars. The total cost estimates are overnight construction cost for the 50-MW stoker and CFB plants. It should be noted that these costs do not include owner's costs for project development, land acquisition, or financing and AFDUC costs during construction.

For the 25- and 100-MW cases, appropriate scale factors were used to estimate similar overnight construction costs.

Results

Tables 4-8 and 4-9 show the capital cost estimates for the stoker and CFB boiler cases, respectively. Appendix B provides additional details for the cost estimates. The total plant cost was developed by estimating the cost of major equipment and systems. Based on the confidence level of specific equipment and site construction costs, different levels of contingency between 10 to 20% were applied. For example, steam turbine generator costs are well documented resulting in high level of confidence in the cost and low contingency.

The Total Plant Investment (TPI) is calculated using EPRI TAG guidelines for cost escalation and AFUDC for a two year construction period. Assuming a 4.1% cost escalation and a 9.2% AFUDC, this adds 2.5% to the overall project costs. The Total Capital Requirement (TCR) includes costs for start-up fees (1% of EPC costs), spare parts (2%), taxes/insurance (2%), reserves (5%), and working capital (2%). It is assumed that there is no cost for land, since the biomass plant will be constructed at existing coal fired plant site.

Table 4-8
Capital Cost Estimate Summary for 50-MW Stoker Boiler Plant (September 2007$)

	Equipment & Materials	Labor	Total	Contingency	Total
Item	$1,000	$1,000	$1,000	%	$1,000
Boiler and Boiler Island Auxiliaries	20,080	8,800	28,880	10%	31,768
Turbine/Steam Cycle Auxiliaries	12,877	4,114	16,991	10%	18,690
Condenser and Cooling Tower	1,290	979	2,269	15%	2,609
Environmental Control Systems	9,025	1,420	10,445	20%	12,534
Fuel Prep and Fuel Handling	1,805	1,203	3,008	10%	3,309
Master Control System	200	130	330	10%	363
Electrical	490	177	667	10%	734
Plant Auxiliaries and Other Items	858	334	1,192	20%	1,430
Civil/Structural and Other Items	450	770	1,220	15%	1,403
Freight Charges (4% of Material)	1,883	0	1,883	10%	2,071
Sales Tax (5% of Material Cost)	2,354	0	2,354	5%	2,471
Total Field Cost			**69,239**	**12%**	**77,383**

Table 4-8 (continued)
Capital Cost Estimate Summary for 50-MW Stoker Boiler Plant (September 2007$)

	Equipment & Materials	Labor	Total	Contingency	Total
Engineering, Procurement, and Home Office			4,133	15%	4,752
Construction Management and Field Procurement			1,716	15%	1,974
Startup and Checkout			1,472	15%	1,693
Total EPC			**7,321**	**15%**	**8,419**
Total Plant Cost			76,559	12%	85,802
Total Plant Investment					87,947
Total Capital Requirement					**$98,243** **$1,965/ kW**

Table 4-9
Capital Cost Estimate Summary for 50-MW CFB Boiler Plant (September 2007 $)

	Equipment & Materials	Labor	Total	Contingency	Total
Item	$1,000	$1,000	$1,000	%	$1,000
Boiler and Boiler Island Auxiliaries	19,630	8,600	28,230	10%	31,053
Turbine/Steam Cycle Auxiliaries	12,877	4,114	16,991	10%	18,690
Condenser and Cooling Tower	1,290	979	2,269	15%	2,609
Environmental Control Systems	8,225	1,400	9,625	20%	11,550
Fuel Prep and Fuel Handling	1,805	1,203	3,008	10%	3,309
Master Control System	200	130	330	10%	363
Electrical	490	177	667	10%	734
Plant Auxiliaries and Other Items	858	334	1,192	20%	1,430
Civil/Structural and Other Items	450	770	1,220	15%	1,403
Freight Charges (4% of Material)	1,833	0	1,833	10%	2,016
Sales Tax (5% of Material Cost)	2,291	0	2,291	5%	2,406
Total Field Cost			**67,656**	**12%**	**75,563**
Engineering, Procurement, and Home Office			4,133	15%	4,752
Construction Management and Field Procurement			1,716	15%	1,974

Table 4-9 (continued)
Capital Cost Estimate Summary for 50-MW CFB Boiler Plant (September 2007 $)

	Equipment & Materials	Labor	Total	Contingency	Total
Startup and Checkout			1,472	15%	1,693
Total EPC			**7,321**	**15%**	**8,419**
Total Plant Cost			74,977	12%	83,982
Total Plant Investment					86,082
Total Capital Requirementd					**96,160** **$1,923/ kW)**

As would be expected, the items with the largest cost in each design are the boiler, steam turbine, and environmental control equipment. Since most of the items included in this design are standard, well-proven pieces of equipment, the level of uncertainty in the cost estimates is relatively low. One major area of uncertainty is in the environmental control equipment. The cost of the environmental control units would drop significantly if an SCR is not included in the design, since an SCR for a unit this size is expected to cost $6 to $7 million.

Boiler vendors confirmed that at this level of detail, there is unlikely to be a significant cost difference between the two designs. The capital costs of the CFB boiler cases are slightly lower because baghouses are less expensive than the ESPs, used by stoker boilers for particulate control.

O&M Costs

Basis and Methodology

The annual operating and maintenance costs (O&M costs) are separated into three components: fixed and variable O&M and fuel. The fixed costs include labor costs and maintenance costs. The variable costs include consumables used in the plant except fuel. The fuel cost covers the delivered cost of the fuel burned in the unit. The labor projections for the biomass plant are based on previous experience from past designs of biomass combustion and other electric generation units. The annual maintenance costs are assumed to be 3% of the total overnight construction cost. Some of the consumables consumption is based on data from the Integrated Environmental Control Model (IECM)[7], including water consumption and ammonia consumption. Other consumables consumption and their unit costs are based on calculations and previous experience. The annual O&M costs are based on a capacity factor of 80%.

[7] Carnegie Mellon University, Integrated Environmental Control Model, available at http://www.iecm-online.com/

The O&M staffing plan for the 50-MW plant was developed assuming that biomass plant will be part of an existing utility plant which is already set up to handle management, accounting, procurement, and other functions, and only basic operational and maintenance staff is required. The following labor categories and positions are required for the 50-MW biomass plant. The plant is operated by three-member crews. Shifts run for 12 hours with two crews per day. Crews report to work 30 minutes prior to the shift turnover to receive shift operating instructions and to pass information on critical operations and maintenance. Each crew member is allotted 30 minutes for a meal break. Thus, each shift covers 12.5 hours, with 0.5 hours meal break and 12 hours of labor. Crews operate on a four days on / four days off rotation. This requires 84 hours on average per crew member for each two-week pay period and four complete shift teams are engaged, plus a fifth crew that provides coverage for individual vacations, sick leave, and holidays.

Chief responsibilities for each crew member are defined below:

Shift Superintendent. The shift superintendent is the chief operator who mans the control station and simultaneously directs the activities of the shift crew. The shift superintendent is a degreed engineer who understands the plant, understands the technical and physical operations, and makes key operating decisions. The shift superintendent ensures compliance with plant quality, safety, industrial hygiene, and environmental requirements.

Support Operator. The support operator aids the shift superintendent with plant operation. The support operator is also tasked with bulk material handling such as feedstock receipts/inspection/weigh-in and ash weigh-out/disposal shipments. The support operator attends to feed and ash sampling/characterization, waste water disposal sampling, and provides general plant support in relief of the shift superintendent. The support operator is also responsible for monitoring plant emissions rates, including daily/weekly calibration of effluent gas monitors. The support operator verifies that plant operating records and daily logs are correct. This position coordinates fuel characterizations and waste water analyses.

Millwright. The shift millwright conducts hourly and daily equipment inspections, safety rounds, completes scheduled equipment process maintenance, supports equipment maintenance and equipment replacements, contracts and supervises crafts such as pipe fitters, electricians, welders, and special instrument technicians when such functions exceed the millwright's capabilities.

Subcontractors are also required for the plant. The subcontracted crafters provide maintenance support for the plant, in crafts such as welding, pipe fitting, insulation, painting, and carpentry. Other administrative supports are provided off-site. The annual cost for these services is estimated to be 25% of the total annual operating labor costs. Including the maintenance cost (3% of the total overnight construction cost), the total fixed operating costs for the 50 MW plant is $95.58 /kW-yr for the stoker boiler and $94.49 /kW-yr for the CFB.

Variable operating cost consists of raw materials and utilities consumed by the plant. Besides fuel costs, major consumables include water, water treating chemicals, ammonia, SCR catalyst, and other chemicals. The total variable operating cost, excluding fuel, is $3.00 /MWh.

Table 4-10 summarizes the annual plant O&M costs. The O&M costs for both the stoker boiler and CFB boiler are very similar for all non-fuel items. The maintenance cost for the CFB boiler is likely to be slightly lower due to the use of a baghouse instead of an ESP for particulates removal. In addition, the amount of ammonia used for the CFB boiler will be slightly less because less NOx is formed due to a lower boiler firing temperature. However, since total NOx emissions were not rigorously calculated, the estimated ammonia use for this level of analysis is assumed to be the same. Fuel costs are different for the two plants due to the different boiler efficiencies.

Table 4-10
Annual O&M Expenses for 50-MWe Plant

Position	Number of Employee or Hours	Base Salary or Hourly Rate	Stoker Total Annual Cost	CFB Total Annual Cost
Shift Superintendent	5	$81,000	$405,000	$405,000
Support Operator	5	$48,500	$242,500	$242,500
Millwright	5	$64,500	$322,500	$322,500
Total Base Salaries and Wages			$970,000	$970,000
General Overhead and Benefits 1			$582,000	$582,000
Subtotal Wages			$1,552,000	$1,552,000
Subcontracted Crafts				
Welder	1200	$80/hr	$96,000	$96,000
Electrician	640	$75/hr	$48,000	$48,000
Pipe Fitter	600	$65/hr	$39,000	$39,000
Insulator/Painter	400	$60/hr	$24,000	$24,000
Carpenter	400	$55/hr	$22,000	$22,000
Instrument Technician	400	$90/hr	$36,000	$36,000
Subtotal Subcontracted Labor			$265,000	$265,000
Annual Operating Labor Cost			$1,552,000	$1,552,000
Administrative & Support Labor 2			$388,000	$388,000
Subcontracted Labor Cost			$265,000	$265,000
Maintenance Cost 3			$2,574,058	$2,519,469
Total Fixed Operating Costs			**$4,779,058**	**$4,724,469**
			$95.58 /kW-yr	**$94.49 /kW-yr**

Table 4-10 (continued)
Annual O&M Expenses for 50-MWe Plant

Consumables	Consumption (per day)	Unit Cost	Stoker Total Annual Cost	CFB Total Annual Cost
Water(/1000 gallons)	935	1.20	$327,551	$327,551
Chemicals				
Ammonia (ton)	1.7	228.00	$110,458	$110,458
Other Chemicals4			$240,000	$240,000
Subtotal Chemicals			$350,458	$350,458
Other				
Supplemental Fuel(MBtu)	0	0.00	$0	$0
RO/Demineralizers			$25,000	$25,000
SCR Catalyst Replacement (ft3)	740/yr	450	$333,000	$333,000
Vehicle Fuel (gallons)	2500/yr	4	$10,000	$10,000
Emission Penalties	0	0.00	$0	$0
Subtotal Other			$368,000	$368,000
Waste Disposal				
Flyash (ton) - Stoker	0.5	18.00	$2,890	
Bottom Ash(ton) - Stoker	0.4	18.00	$1,927	
Flyash (ton) - CFB	0.7	18.00		$3,541
Bottom Ash(ton) - CFB	0.2	18.00		$885
Subtotal Solid Waste Disposal			$4,817	$4,426
Total Variable Operating Costs			**$1,050,825**	**$1,050,435**
			$3.00 /MWh	**$3.00 /MWh**
Fuel (tons) - Stoker	1,666	20.00	$9,731,237	
Fuel (tons) - CFB	1,531	20.00		$8,941,899
Fuel Costs			$27.77 /MWh	$25.52 /MWh

[1] 60% of total salaries

[2] 25% of total annual operating labor cost

[3] 3% of total overnight construction cost

[4] Including boiler-treatment chemical, softener, cooling-tower treatment chemical

Sensitivity Case: On-site Drying of Biomass Fuel

A literature survey and our analysis confirm that dry fuel improves boiler performance. Table 4-11 shows that, with the same HHV heat input to the boiler, LHV input to the boiler increases as the fuel moisture content decreases. (Note: as fuel moisture decreases, the difference between HHV and LHV decreases. With 0% moisture and no fuel bound hydrogen, LHV and HHV are the same). With higher fuel HHV value less fuel will be required. The major benefit of the fuel drying is improvement in boiler efficiency.

Table 4-11
50-MW Stoker Boiler Performance vs. Fuel Moisture Content

Parameter	Units	% Moisture					
Fuel Analysis		45%	40%	30%	20%	10%	0%
Fuel HHV	Btu/lb ar	4,750	5,100	5,950	6,800	7,650	8,500
Volatiles, %	AR Basis	0.4675	0.5100	0.5950	0.6800	0.7650	0.8500
Fixed Carbon, %	AR Basis	0.0820	0.0894	0.1043	0.1192	0.1341	0.1490
Ash, %	AR Basis	0.0006	0.0006	0.0007	0.0008	0.0009	0.0010
Moisture	AR Basis	0.4500	0.4000	0.3000	0.2000	0.1000	0.0000
Boiler Heat Input HHV	MMBTU /hr	637	637	637	637	637	637
Boiler Heat Input LHV	MMBTU /hr	530	540	558	572	583	592
Total Fuel Input	lb/hr	134,101	124,898	107,055	93,674	83,265	74,939
Steam Flow	lb/hr	440,000	442,390	460,723	474,454	485,117	493,632
Feedwater	lb/hr	433,480	442,390	460,723	474,454	485,117	493,632
Boiler Efficiency (HHV) Basis		77.0%	77.4%	80.6%	82.9%	84.7%	86.2%
Turbine Net Output	MW	50.00	50.27	52.35	53.92	55.13	56.09
Net Plant Net Heat Rate	BTU/kWh	12,740	12,671	12,167	11,814	11,555	11,355
Net Thermal Efficiency	%	26.8%	26.9%	28.0%	28.9%	29.5%	30.0%

The tradeoff required to raise the boiler efficiency is the input of heat to dry the fuel. If that energy is subtracted from the heat input to the boiler, net plant heat rate will not change significantly. Hence, on site drying of fuel is essentially efficiency-neutral, but will likely lead to overall higher site capital costs due to the construction of a separate dryer. This capital investment will add to the cost of electricity. Also, the drying operation does drive off some of the fuel volatiles, which will likely need to be collected and burned in the boiler due to environmental permits. Developing the plant infrastructure to accomplish this will further add to the cost of on-site drying.

Based on this analysis, it appears that the fuel moisture sensitivity should be analyzed based on market price of the fuels with different moisture content. As mentioned above, on site drying of fuel does not offer any significant advantage. If the price for different moisture content fuels is available, the above heat rate calculations can be used to determine the impact on electricity price.

5
DESIGN AND COST ESTIMATES FOR 25- AND 100-MW PLANTS

Plant Descriptions

Biomass fired power plants tend to be much smaller than fossil fuel units due to the difficulty in transporting large quantities of biomass feedstock to the plant. The sizes of most biomass units are therefore limited by the amount of fuel that can be reasonably obtained. In addition, many biomass plants are located close to large biomass sources, which are typically forest and agriculture sites away from major load centers. This also limits the size of most biomass-fired plants.

This evaluation also addressed the design requirements and cost for 25- and 100-MW stoker and CFB biomass power plants. Due to impractical limits on plant sizing, 100-MW units are on the high end of the size range considered for biomass plants. The level of uncertainty in the cost of this design is higher than for small- scale units due to the lack of experience in building large biomass plants. In theory, however, the design of a 100-MW unit should not change considerably from the 50-MW base case. Many small biomass units have been developed in recent years, making development of a 25-MW unit (and smaller) a well understood process.

The process flowsheets of both plants are the same as those for the 50-MW CFB and stoker boiler cases. The feed handling section of the plant uses the same equipment, although sizes and the number of silos have changed. The boilers and emissions control equipment change in size depending on the basis for the plant output. Given that many fossil fuel boilers have been sized at a range much greater than this, there should not be any problems with the scale-up or down of the 50-MW boiler islands. The steam turbine and auxiliary equipment in the power island can also be easily sized to the specifications of the plant.

Differences from 50-MW Design

The basic designs of the 25-, 50- and 100-MW plants are the same. The 25-MW plant is identical with smaller footprint and smaller equipment. The 100-MW plant uses a reheat cycle to improve efficiency. A reheat cycle is also possible for the 50-MW plant, but major turbine vendors have stated that they do not offer a reheat turbine for 50-MW or lower ratings. The Rankine cycle efficiency for the 25-MW plant is slightly lower due to slightly higher percent auxiliary load. For the 100-MW plant, the efficiency is three to four percentage points higher than that for the 50-MW plant, due to the reheat cycle.

Fuel Requirement

Table 5-1 presents the fuel requirements for the 25- and 100-MW plants, which are based on the fuel characteristics presented in Chapter 3 and the plant performance. The major difference between the CFB and stoker cases is the boiler efficiency which leads to different feedstock requirements.

Table 5-1
Fuel Requirements for 25- and 100-MW Plants

Parameter	Units	Stoker		CFB	
		25 MW Plant	100 MW Plant	25 MW Plant	100 MW Plant
Hourly requirement	ton/hr	36	121	34	113
Daily requirement	ton/day	870	2897	804	2701
Trucks per day (25 tons/truck)		35	116	33	109

Feedstock Handling

25-MW Plant

Dumpers: Only one whole truck dumper with hopper is required.

Hopper: The capacity of hopper is 406 ft^3. It is capable of processing up to 43 tons of wood chips per hour.

Conveyors: A 24-inch wide trough-idler cleated belt conveyor with 39-ft discharge height and 110 ft long is used to transfer the feedstock from the dumpers to the storage. The conveyor has an angle of 22 degrees. The power consumption of the conveyor is 11.25 kW.

Disc screen: The screener dimensions are 48 by 72 inches. It consumes 3.75 kW of electricity.

Hammermill: A 75 kW hog is used.

Storage: 2.3 acres of land is required for four week storage. Table 5-2 summarizes the onsite storage requirement of the 25 MW plant.

Table 5-2
Onsite Storage Design Parameters for 25-MW Plant

Design Parameter	Units	25-MW Plant
Capacity	ton	24,369
Volume	ft^3	2,033,117
Base Area	ft^2	99,159
	acre	2.3

Live storage silos: One metal silo is needed for eight hours of live storage. Table 5-3 summarizes the parameters of the live storage silo.

Table 5-3
Live Storage Silos for 25-MW Plant

Parameter	Units	25-MW Plant
Tonnage	ton	290
Volume	ft^3	24,204
Silos volume requirement	ft^3	29,045
Number of Silos		2

100-MW Plant

Dumpers: Four whole truck dumpers with hopper are required.

Hopper: The capacity of the hopper is 1,342 ft^3. It is capable of processing up to 217.2 tons of wood chips per hour.

Conveyors: A 72-inch wide trough-idler cleated belt conveyor with 39 ft discharge height and 110 ft long is used to transfer the feedstock from the dumpers to the storage. The conveyor has an angle of 22 degrees. The power usage of the conveyor is 23.5 kW.

Disc screen: The screener dimensions are of 96 by 144 inches. It consumes 9.7 kW of electricity.

Hammermill: A 190- kW hog is used.

Storage: 6.5 acres of land is required for four week storage.

Table 5-4 summarizes the onsite storage requirement of the 100-MW plant.

Table 5-4
Onsite Storage Design Parameters for 100-MW Plant

Design Parameter	Units	100 MW Plant
Capacity	ton	81,122
Volume	ft^3	6,767,977
Base Area	ft^2	282,228
	acre	6.5

Live storage silos: For the 100-MW plant, it has only four hours of live storage instead of eight hours because of the number of silos required. The parameters of the live storage silos are summarized in Table 5-5.

Table 5-5
Live Storage Silo Design Parameters for 100-MW Plant

Design Parameter	Units	100-MW Plant
Capacity	ton	483
Volume	ft^3	40,286
Silos volume requirement	ft^3	48,343
Number of Silos		2

Plant Performance

The following table lists plant performance for the 25- and 100-MW stoker boiler designs. The design of the 25-MW plant is similar to that of the 50-MW plant. However, for the 100-MW plant, a reheat turbine is used to improve efficiency. The design fuel contains 45% moisture and 4,750 Btu/lb HHV for both cases. As shown for the 50-MW plant, the boiler performance can be improved by using drier fuel, resulting in a higher heat rate and improved efficiency.

Table 5-5 and Table 5-6 summarize the performance of the 25- and 100-MW stoker boiler and CFB boiler cases. The 25-MW case is similar to the 50-MW CFB boiler case, and the 100- MW CFB boiler case assumes a reheat steam cycle. As expected, CFB performance is slightly better than stoker boiler case. The analysis also shows a higher efficiency in the larger plants; while these increases in efficiency may be on the high side, these results are reasonable at this stage of analysis. The main reasons for higher efficiency at large scale are:

1. The auxiliary load per pound of steam produced is lower for the boiler, fuel handling system, and boiler draft.
2. Boiler designers are able to optimize radiant and convection zone more effectively with larger furnace volume, effectively increasing heat transfer area and efficiency.
3. With the reheat steam in the 100-MW case, heat transfer gradients through the boiler are more gradual than non reheat boilers.
4. Although, fuel specs and hence fuel moisture are same for both boilers, larger boilers are able to absorb high moisture fuel with less impact on boiler operation. Therefore, boiler vendors are able to assign higher confidence in heat transfer rates.

Table 5-6
25-and 100-MW Stoker Boiler Performance

Performance Parameter	Units	25-MW Plant	100-MW Plant
		Values	
Gross Generator Output	kWe	28,519	110,813
Parasitic Load and Losses	kWe	3,519	10,813
Net Plant Output	kWe	25,000	100,000
Boiler Efficiency	%	74.4	78.5
Boiler Steam Output	klb/hr	240	690
Net Heat Rate	BTU/kWh	14,400	11,800
Capacity Factor	%	80	80
Fuel HHV (AR)	BTU/lb	4,750	4,750
Fuel Moisture (AR)	%	45	45
Fuel Required	tons/hr	36.3	120.7

Table 5-7
25-and 100-MW CFB Boiler Performance

Performance Parameter	Unit	25-MW Plant	100-MW Plant
		Values	
Net Generator Output	kWe	29,200	111,280
Parasitic Load and Losses	kWe	4,200	11,280
Net Plant Output	kWe	25,000	100,000
Boiler Efficiency	%	80.5	84.2
Boiler Steam Output	klb/hr	242	690
Net Heat Rate	BTU/kWh	12,193	11,657
Capacity Factor	%	80	80
Fuel HHV (AR)	BTU/lb	4,750	4,750
Fuel Moisture (AR)	%	45	45
Fuel Required	tons/hr	33.5	112.5

Cost Estimates

Tables 5-8 and 5-9 summarize the capital cost estimate for the 25- and 100-MW plants. For stoker boilers, the total overnight construction costs are $2,347 /kW and $1,264 /kW for 25- and 100-MW plants respectively. For CFB boilers, the capital costs are slightly lower due to the lower cost of the baghouses used for CFB boilers vs. the ESPs used for stoker boilers.. For the 25-and 100-MW CFB plants, the total overnight construction costs are $2,298 /kW and $1,236 /kW, respectively. It is clear that larger biomass plants can claim a significant economy of scale advantage. Project developers should consider building plants as large as possible within their capacity to obtain feedstock and have a market for the produced electricity.

The Total Plant Investment (TPI) and Total Capital Requirement (TCR) for each case are estimated using the same methodology used in Section 4. The TPI includes escalation during construction and allowance for funds during construction, assuming a two-year construction schedule, and the TCR includes a 12% allowance for owner costs for permitting and siting, start-up fees, spare parts, taxes/insurance, reserves, and working capital. It is assumed that the cost of land is zero.

The capital cost estimates for the 25-MW and 100-MW stoker boiler cases are mostly scaled from the 50-MW stoker boiler case. However, the capital costs of some fuel preparation and fuel handling equipment are not scaled as they depend only on the number of equipment units required. For example, the cost of live storage silos depends only on the number of silos used in the plant. Appendix B provides a detailed list and cost breakdown of the fuel handling system components.

Table 5-8
Capital Cost Estimates for 25-, 50-, and 100-MW Stoker Boiler Plants

Rated Capacity	25 MW	50 MW	100 MW
Cost Component (September 2007 $)	**$1,000**	**$1,000**	**$1,000**
Boiler and Boiler Island Auxiliaries	21,349	31,768	47,999
Turbine and Steam Cycle Auxiliaries	12,513	18,690	28,258
Condenser and Cooling Tower	1,767	2,609	3,937
Environmental Control System	8,338	12,534	18,971
Fuel Prep and Fuel Handling	2,308	3,309	4,312
Master Control System	245	363	548
Electrical	492	734	1,109
Plant Auxiliaries and Other Items	960	1,430	2,162
Civil/Structural and Other Items	961	1,403	2,113
Total Freight Charges @ 4% of Material Cost	1,370	2,071	3,123
Sales Tax @ 5% of Material Cost	1,634	2,471	3,726
Total Field Cost	51,936	77,383	116,257

Table 5-8 (continued)
Capital Cost Estimates for 25-, 50-, and 100-MW Stoker Boiler Plants

Rated Capacity	25 MW	50 MW	100 MW
Cost Component (September 2007 $)	**$1,000**	**$1,000**	**$1,000**
Engineering, Procurement, and Home Office	3,802	4,752	5,703
Construction Management and Field Procurement	1,579	1,974	2,368
Startup and Checkout	1,354	1,693	2,031
Total EPC	6,735	8,419	10,103
Total Plant Cost	58,671	85,802	126,360
Total Plant Investment	60,138	87,947	129,519
Total Capital Requirement ($000)	67,179	98,243	144,682
Total Capital Requirement ($/kW)	**2,687**	**1,965**	**1,447**

Table 5-9
Capital Cost Estimates for 25-, 50-, and 100-MW CFB Boiler Plants

Rated Capacity	25 MW	50 MW	100 MW
Cost Component (September 2007 $)	**$1,000**	**$1,000**	**$1,000**
Boiler and Boiler Island Auxiliaries	20,868	31,053	46,919
Turbine and Steam Cycle Auxiliaries	12,513	18,690	28,258
Condenser and Cooling Tower	1,767	2,609	3,937
Environmental Control System	7,688	11,550	17,480
Fuel Prep and Fuel Handling	2,308	3,309	4,312
Master Control System	245	363	548
Electrical	492	734	1,109
Plant Auxiliaries and Other Items	960	1,430	2,162
Civil/Structural and Other Items	961	1,403	2,113
Total Freight Charges (4% on Material)	1,333	2,016	3,039
Sales Tax @ 5% of Material Cost	1,591	2,406	3,626
Total Field Cost	50,726	75,563	113,503
Engineering, Procurement, and Home Office	3,802	4,752	5,703
Construction Management and Field Procurement	1,579	1,974	2,368
Startup and Checkout	1,354	1,693	2,031

Table 5-9 (continued)
Capital Cost Estimates for 25-, 50-, and 100-MW CFB Boiler Plants

Rated Capacity	25 MW	50 MW	100 MW
Cost Component (September 2007 $)	**$1,000**	**$1,000**	**$1,000**
Total EPC	6,735	8,419	10,103
Total Plant Cost	57,461	83,982	123,606
Total Plant Investment	58,897	85,563	126,696
Total Capital Requirement ($000)	65,793	95,580	141,529
Total Capital Requirement ($/kW)	**2,632**	**1,923**	**1,415**

Table 5-10 summarizes the annual O&M costs for the 25- and 100-MW plants. The costs are based on a capacity factor of 80%. Appendix B provides a detail description of the O&M cost breakdown for the 25- and 100-MW plants. The labor requirement is the same for the 25- and 50-MW plants. For the 100-MW plant, additional labor is required as listed below. These are positions that were assumed not to be necessary or that could be shared among multiple sites for 25- and 50-MW plants.

General Plant Manager: Responsible for all personnel and plant decisions, including new employee hiring, operator training, fuel contracts, maintenance contracts, general equipment purchases, external communications, and operating schedules. Engineering degree required, with 10+ years of chemical plant operating experience.

Secretary/Receptionist: Supports the General Plant Manager. Receives visitors, answers phone, and attends to office administrative duties.

Plant Engineer: Responsible for the optimization, new systems design, and engineering troubleshooting within the plant. Engineering degree required, with 5+ years of chemical plant operating experience.

Millwright Assistant: Supports millwright and accompanies millwright and contracted crafts, particularly during dangerous work activities, such as confined space entries and working from heights. The millwright assistant supports tool setup, job errands, and plant cleanup.

Computer Technician: Support computer infrastructure within the plant. Information Technology degree required.

For variable costs, some of the consumables consumption are based on IECM simulation, including water consumption, ammonia consumption, and SCR catalyst replacement. Other consumables costs are scaled from the 50-MW plant.

Table 5-10
Operating and Maintenance Cost Estimates or 25-, 50- and 100-MW Stoker and CFB Boiler Plants (September 2007 $)

September 2007 $		Stoker Boiler			CFB		
		25 MW	50 MW	100 MW	25 MW	50 MW	100 MW
Total Fixed O&M Costs	000/yr	,965	,779	,763	,929	,724	,680
	/kW-yr	158.61	95.58	67.63	57.15	4.49	66.80
Total Variable O&M Costs	000/yr	532	1,051	2,091	532	1,050	2,090
	/MWh	.04	.00	2.98	3.04	3.00	2.98
Fuel Cost ($20/ton)	$000/yr	5,083	9,731	6,920	4,698	8,942	5,774
	$/MWh	9.01	27.77	24.14	26.81	5.52	22.51

6
SUMMARY AND CONCLUSIONS

The purpose of this study was to develop the generic design, performance, and cost estimates of biomass combustion facilities for 25-, 50-, and 100-MW plants. Since the designs were developed without features unique to an actual facility, application of the information within this report should be adapted as best as possible to each specific situation. While the information presented is a good starting point to determining the unit cost and performance, site specific information is necessary to develop detailed results with a greater level of certainty.

The major differences between the cases are the higher efficiency (eight percentage points) of the CFB plant and the lower level of particulates and NOx emissions in the CFB flue gas. This assumes the same capacity factor (80%) for both cases. The stoker boiler uses an ESP to collect the fly ash while the CFB boiler uses baghouses. Baghouses are less expensive than ESPs, and therefore, the capital costs of the CFB boiler plants are lower than those of the stoker boiler plant. The design analysis was done with input from boiler vendors and shows that the costs of all other plant components are expected to be roughly the same for the stoker and CFB boiler plants.

The non-fuel annual O&M costs for the stoker and CFB boiler plants are assumed to be very similar, and there are only slight differences in O&M costs between the two types of boilers. The ammonia consumption of the SCR unit should be lower for CFB boilers because less NOx is formed in the boiler. The formation rate of NOx is primarily a function of temperature is higher at high temperature. Stoker boilers operate at a higher temperature than CFB boilers, and therefore, CFB boilers produce less NOx. The thermal efficiency differences between the two boiler types leads to a proportional difference in biomass feed requirements.

The expected emissions of biomass facilities based on this design are expected to be low and well within EPA regulations. The use of biomass feedstock, coupled with an SCR and ESP or baghouse, will keep all criteria emissions low. Depending on the technology chosen and location of the plant, a SCR unit may not be necessary. This would reduce the cost of the 50-MW case by nearly $7MM. Assuming biomass firing is CO_2-neutral, the CO_2 emissions derived from fossil fuels are near zero and are be substantially lower than those of a fossil fuel plant with the same rating.

Biomass-fired CFB boiler plants have slight advantages vs stoker boiler plants due to 1) higher boiler efficiency, 2) lower capital costs, and 3) lower NOx and particulate emissions. Other criteria to consider in future studies of biomass power plants are 1) the ease of operation, 2) more detailed capital and O&M cost estimates, 3) full simulation of the entire plant.

The results clearly show an economy of scale advantage for larger plants and a small cost advantage for the CFB design. For both capital and annual O&M costs, the costs per kW or MWh are the lowest for 100-MW plants and the highest for 25-MW plants. Table 6-1 compares the capital cost estimates for each of the plant cases.

Table 6-1
Capital Cost Estimate Comparison (September 2007 $)

September 2007 $		Stoker			CFB		
		25 MW	50 MW	100 MW	25 MW	50 MW	100 MW
Total Plant Cost	$000	58,671	85,802	126,360	57,461	83,982	23,606
Total Plant Investment	$000	60,138	87,947	129,519	58,897	86,082	26,696
Total Capital Requirement	$000	67,179	98,243	144,682	65,793	96,160	141,529
	$/kW	2,687	1,965	1,447	2,632	1,923	1,415

The annual non-fuel O&M costs are very similar for both types of boilers. Fuel costs vary based on boiler efficiency. Table 6-2 compares the fixed and variable O&M and fuel costs for the power plant cases.

Table 6-2
Annual O&M Cost Estimate Comparison (September 2007 $)

September 2007 $		Stoke Boiler			CFB		
		25 MW	50 MW	100 MW	25 MW	50 MW	100 MW
Total Fixed Operating Costs	$000/yr	3,965	4,779	6,763	3,929	4,724	6,680
	$/kW-yr	158.61	95.58	.63	.15	.49	.80
Total Variable Operating Costs	$000/yr	532	1,051	2,091	532	1,050	2,090
	$/MWh	3.04	3.00	2.98	3.04	3.00	2.98
Fuel Cost ($20/ton)	$000/yr	5,083	9,731	16,,920	4,698	8,942	15,774
	$//MWh	29.01	27.77	24.14	26.81	25.52	22.51

A sensitivity study estimated the impact of on-site drying of the biomass fuel. It shows that reducing the feedstock moisture content increases the boiler efficiency and reduces the boiler size and feedstock requirements. However, assuming that the capacity factor of the overall plant is unchanged between the cases, it is expected that the cost of the separate dryer and using non-waste plant heat would exceed the benefits of reducing the fuel moisture content. Drying should only be performed if required to improve plant availability.

Areas for future analysis that would help gain better insight into the design and more accurate cost estimates include:

- Additional Drying Studies: The analysis rigorously examined the impact of lower moisture feed on the boiler and power island. However, a detailed heat integration and new system design was not performed. A more detailed investigation could better quantify the system impacts and determine if there are sources of waste heat that could be applied to raise the system efficiency. In addition, there may be instances where paying a premium for off-site drying is justified.

- Specific Site Analysis: Information presented in this report is appropriate for a generic initial design and cost estimate, with an accuracy of ±30%. Information about a specific site with specific boiler and performance information would be able to reduce this level of uncertainty.
- Environmental Equipment Needed: An SCR is included in this design due to the generic nature of the assumptions. Some biomass fired units may require only an SNCR or no catalytic reduction at all. Greater detail on the boiler flue gas composition coupled with a specific site location could determine specific project needs.
- Fuel Quality Range: The designs were performed assuming a very specific fuel quality. The quality of biomass fuel could vary substantially as the moisture and ash contents vary. Performance over a range of fuel qualities should be investigated to determine how this would impact the system design and cost.
- Availability Analysis: Both CFB and stoker designs, as well as the drying sensitivity study, assumed the same plant availability. Input from vendors on a specific site design could help determine if these assumptions are valid and how they may impact technology decisions.

A
EQUIPMENT LIST

Table A-1
Equipment List for 50-MW Plant

Equipment Description	Qty
Boiler and Boiler Island Auxiliaries	
Boiler	1
FD Fans	2
ID Fans	2
Air Preheaters	1
Fuel Feeders and Live Storage	6
Feedwater/Steam Piping	1
Turbine and Steam Cycle Auxiliaries	
Turbine Generator	1
Turbine EHC Control System	1
Feedwater Heaters	4
Deaerator	1
Condensate Pump	3
Feedwater Pumps	3
Condenser and Cooling Tower	
Condenser	1
Condenser Air Ejection System	1
Condensate Storage	1
Cooling Tower	1
Circulating Pumps	2

Table A-1 (continued)
Equipment List for 50-MW Plant

Equipment Description	Qty
Environmental Control Flue Gas Treatment System	
SCR and Ammonia Injection System	1
ESP or Bag House	1
Stack	1
Ash Silos (Fly ash)	2 (CFB) 1 (Stoker)
Ash Silos (Bottom ash)	1 (CFB) 2(Stoker)
Ash Conveying System	2
CEM System	1
Fuel Prep and Fuel Handling	
Scales, electronic	1
Whole truck dumper w/ hopper	2
Hopper	1
Conveyor, belted	1
Magnet, self-cleaning bar	1
Non-ferrous metal detector	1
Scalping disk screen	1
Hammermill	1
Open pile	1
Front end loader	1
Live storage silos	2
Master Control System	
Plant DCS System	1
Instrumentation	1

Table A-1 (continued)
Equipment List for 50-MW Plant

Equipment Description	Qty
Electrical	
4160 Load Center	2
480 MCC	4
Distribution and Step up Transformer	3
UPS and Inverter and Battery	1
120 V system	1
Plant Lighting	1
Plant HVAC	1
Lightening Protection System	1
Plant Auxiliaries and Other Items	
Fire Protection/Detection System	1
Compressed Air System	1
Water Treatment System	1
Chemical Treatment System	1
Cooling Water Chemical Treatment	1
Waste Water Disposal and Treatment	1

B

COST ESTIMATE TABLES

Table B-1
Equipment Cost Estimate for 50-MW Stoker Boiler (September 2007 $)

Description	Qty	Unit	Material ($ 000)	Labor ($ 000)	Total ($ 000)
Boiler and Boiler Island Auxiliaries					
Boiler	1		16,000	8,000	24,000
FD Fans	2		500	75	575
ID Fans	2		650	80	730
Air Preheaters	1		250	25	275
Fuel Feeders and Live Storage	6		180	120	300
Feedwater/Steam Piping	1	Lot	2,500	500	3,000
Total Boiler Island			20,080	8,800	28,880
Turbine and Steam Cycle Auxiliaries					
Turbine Generator	1		12,500	4,000	16,500
Turbine EHC Control System	1	Lot	Incl		0
Feedwater Heaters	4		260	80	340
Deaerator	1		45	20	65
Condensate Pump	3		24	6	30
Feedwater Pumps	3		48	8	56
Total Turbine Island			12,877	4,114	16,991
Condenser and Cooling Tower					
Condenser	1		750	150	900
Condenser Air Ejection System	1		50	5	55
Condensate Storage	1		60	20	80
Cooling Tower	1		400	800	1,200
Circulating Pumps	2		30	4	34
Total Condenser/Cooling Tower			1,290	979	2,269

Table B-1 (continued)
Equipment Cost Estimate for 50-MW Stoker Boiler (September 2007 $)

Description	Qty	Unit	Material ($ 000)	Labor ($ 000)	Total ($ 000)
Environmental Control Flue Gas Treatment System					
SCR and Ammonia Injection System	1	Lot	6,000	800	6,800
ESP or Bag House	1		2,500	400	2,900
Stack	1		80	50	130
Ash Silos (FA & BA)	3		150	25	175
Ash Conveying System	2		250	125	375
CEM System	1		45	20	65
Total Flue Gas Treatment/Emission Control			9,025	1,420	10,445
Fuel Prep and Fuel Handling					
Scales, electronic	1		148	Incl	148
Whole truck dumper w/ hopper	2		813	Incl	813
Hopper	1		57	Incl	57
Conveyor, belted	1		71	Incl	71
Magnet, self-cleaning bar	1		23	Incl	23
Non-ferrous metal detector	1		13	Incl	13
Scalping disk screen	1		42	Incl	42
Hammermill	1		80	Incl	80
Open pile	1		135	Incl	135
Front end loader	1		337	Incl	337
Live storage silos	3		1,289	Incl	1,289
Total Fuel Prep and Fuel Handling			3,008		3,008
Master Control System					
Plant DCS System	1	Lot	80	50	130
Instrumentation	1	Lot	120	80	200
Total Plant Control System			200	130	330
Electrical					
4160 Load Center	2		90	30	120

Table B-1 (continued)
Equipment Cost Estimate for 50-MW Stoker Boiler (September 2007 $)

Description	Qty	Unit	Material ($ 000)	Labor ($ 000)	Total ($ 000)
480 MCC	4		120	40	160
Distribution and Step up Transformer	3		180	60	240
UPS and Inverter and Battery	1		30	15	45
120 V system	1		20	10	30
Plant Lighting	1		15	10	25
Plant HVAC	1		30	10	40
Lightening Protection System	1		5	2	7
Total Plant Electrical System			490	177	667
Plant Auxiliaries and Other Items					
Fire Protection/Detection System	1		25	15	40
Compressed Air System	1		8	2	10
Water Treatment System	1		750	300	1,050
Chemical Treatment System	1		45	10	55
Cooling Water Chemical Treatment	1		5	2	7
Waste Water Disposal and Treatment	1		25	5	30
Total Plant Auxiliary System			858	334	1,192
Civil/Structural and Other Items					0
Plant Civil Work	1	Lot	45	200	245
Plant Structural/Foundation	1	Lot	200	250	450
Insulation	1	Lot	125	200	325
Painting	1	Lot	80	120	200
Total Plant Civil/Structural & Misc.			450	770	1,220
Total Plant Cost			48,278	16,724	65,002
Freight Charges @4% of Material			1,931		
Sales Tax @5% of Material			2,414		

Table B-2
Equipment Cost Estimate for 50-MW CFB Boiler (September 2007 $)

Description	Qty	Unit	Material ($ 000)	Labor ($ 000)	Total ($ 000)
Boiler and Boiler Island Auxiliaries					
Boiler	1		15,500	7,800	23,300
FD Fans	2		550	75	625
ID Fans	2		650	80	730
Air Preheaters	1		250	25	275
Fuel Feeders and Live Storage	6		180	120	300
Feedwater/Steam Piping	1	Lot	2,500	500	3,000
Total Boiler Island			19,630	8,600	28,230
Turbine and Steam Cycle Auxiliaries					
Turbine Generator	1		12,500	4,000	16,500
Turbine EHC Control System	1	Lot	Incl		0
Feedwater Heaters	4		260	80	340
Deaerator	1		45	20	65
Condensate Pump	3		24	6	30
Feedwater Pumps	3		48	8	56
Total Turbine Island			12,877	4,114	16,991
Condenser and Cooling Tower					
Condenser	1		750	150	900
Condenser Air Ejection System	1		50	5	55
Condensate Storage	1		60	20	80
Cooling Tower	1		400	800	1,200
Circulating Pumps	2		30	4	34
Total Condenser/Cooling Tower			1,290	979	2,269
Environmental Control Flue Gas Treatment System					
SCR and Ammonia Injection System	1	Lot	5,500	800	6,300
ESP or Bag House	1		2,200	380	2,580

Table B-2 (continued)
Equipment Cost Estimate for 50-MW CFB Boiler (September 2007 $)

Description	Qty	Unit	Material ($ 000)	Labor ($ 000)	Total ($ 000)
Stack	1		80	50	130
Ash Silos (FA & BA)	3		150	25	175
Ash Conveying System	2		250	125	375
CEM System	1		45	20	65
Total Flue Gas Treatment/Emission Control			8,225	1,400	9,625
Fuel Prep and Fuel Handling					
Scales, electronic	1		148	Incl	148
Whole truck dumper w/ hopper	2		813	Incl	813
Hopper	1		57	Incl	57
Conveyor, belted	1		71	Incl	71
Magnet, self-cleaning bar	1		23	Incl	23
Non-ferrous metal detector	1		13	Incl	13
Scalping disk screen	1		42	Incl	42
Hammermill	1		80	Incl	80
Open pile	1		135	Incl	135
Front end loader	1		337	Incl	337
Live storage silos	3		1,289	Incl	1,289
Total Fuel Prep and Fuel Handling			3,008		3,008
Master Control System					
Plant DCS System	1	Lot	80	50	130
Instrumentation	1	Lot	120	80	200
Total Plant Control System			200	130	330
Electrical					
4160 Load Center	2		90	30	120
480 MCC	4		120	40	160
Distribution and Step up Transformer	3		180	60	240
UPS and Inverter and Battery	1		30	15	45

Table B-2 (continued)
Equipment Cost Estimate for 50-MW CFB Boiler (September 2007 $)

Description	Qty	Unit	Material ($ 000)	Labor ($ 000)	Total ($ 000)
120 V system	1		20	10	30
Plant Lighting	1		15	10	25
Plant HVAC	1		30	10	40
Lightening Protection System	1		5	2	7
Total Plant Electrical System			490	177	667
Plant Auxiliaries and Other Items					
Fire Protection/Detection System	1		25	15	40
Compressed Air System	1		8	2	10
Water Treatment System	1		750	300	1,050
Chemical Treatment System	1		45	10	55
Cooling Water Chemical Treatment	1		5	2	7
Waste Water Disposal and Treatment	1		25	5	30
Total Plant Auxiliary System			858	334	1,192
Civil/Structural and Other Items					0
Plant Civil Work	1	Lot	45	200	245
Plant Structural/Foundation	1	Lot	200	250	450
Insulation	1	Lot	125	200	325
Painting	1	Lot	80	120	200
Total Plant Civil/Structural & Misc			450	770	1,220
Total Plant Cost			47,028	16,504	63,532
Freight Charges @4% of Material			1,881		
Sales Tax @5% of Material			2,351		

Table B-3
Engineering, Procurement, and Home Office Costs Estimate for 50-MW Plant (September 2007 $)

Position	Number of People	Duration, years	Direct Wage, $/hr	Annual Cost[1,2]	TotalCost
Final Design and Procurement					
Project Manager	1	1.0	$60	$314,000	$314,000
Project Engineer	1	1.0	$55	$288,000	$288,000
Project Administrator	1	1.0	$25	$131,000	$131,000
Mechanical					
- Lead	1	1.0	$50	$262,000	$262,000
- Engineer	2	0.75	$45	$236,000	$354,000
Civil/Structural					
- Lead	1	1.0	$50	$262,000	$262,000
- Engineer	1	0.75	$45	$236,000	$177,000
Control/Instrumentation					
- Lead	1	1.0	$50	$262,000	$262,000
- Engineer	2	0.75	$45	$236,000	$354,000
Electrical					
- Lead	1	1.0	$50	$262,000	$262,000
- Engineer	2	0.75	$45	$236,000	$354,000
Plant Design	1	0.75	$45	$236,000	$177,000
Technical Specialists	1	0.75	$55	$288,000	$216,000
Procurement					
- Lead	1	1.0	$55	$288,000	$288,000
- Buyer	2	0.75	$35	$183,000	$274,500
Project Controls	1	1.0	$30	$157,000	$157,000
Total Design and Procurement Cost					$4,132,500

Table B-3 (continued)
Engineering, Procurement, and Home Office Costs Estimate for 50-MW Plant (September 2007 $)

Position	Number of People	Duration, years	Direct Wage, $/hr	Annual Cost[1,2]	Total Cost
Construction Management and Field Procurement					
Construction Manager	1	0.75	$60	$314,000	$235,500
Project Engineer	1	0.75	$55	$288,000	$216,000
Project Administrator	1	0.75	$25	$131,000	$98,250
Mechanical	1	0.50	$45	$236,000	$118,000
Plant Design	1	0.50	$45	$236,000	$118,000
Civil/Structural	1	0.50	$45	$236,000	$118,000
Control/Instrumentation	1	0.75	$45	$236,000	$177,000
Electrical	1	0.50	$45	$236,000	$118,000
Technical Specialists	1	0.50	$55	$288,000	$144,000
Procurement	1	0.75	$40	$210,000	$157,500
Project Controls	1	0.75	$30	$157,000	$117,750
Warehouse Clerk	1	0.75	$25	$131,000	$98,250
Total Construction Management and Field Procurement Cost					$1,716,250
Startup and Checkout					
Startup Manager	1	0.5	$60	$384,000	$192,000
Project Administrator	1	0.5	$25	$160,000	$80,000
Mechanical	2	0.5	$45	$288,000	$288,000
Control/Instrumentation	2	0.5	$45	$288,000	$288,000
Electrical	1	0.5	$45	$288,000	$144,000
Technical Specialists	1	0.5	$55	$352,000	$176,000
Procurement	1	0.5	$40	$256,000	$128,000
Project Controls	1	0.5	$30	$192,000	$96,000
Warehouse Clerk	1	0.5	$25	$160,000	$80,000
Total Startup and Checkout Cost					$1,472,000

[1] 40% added to direct salaries for payroll additives
[2] 80% added to total salaries for overhead and profit

Table B-4
Fuel Handling Cost for 25-MW and 100-MW Plants (September 2007 $)

Handling Unit	25 MW		100 MW	
	Qty	$ 000	Qty	$ 000
Scales, electronic	1	148	1	148
Whole truck dumper w/ hopper	1	407	4	1,627
Hopper, live-bottom, 9 mdrg chain conveyor	1	48	1	86
Conveyor, belted (33.5 m length)	1	69	1	108
Magnet, self-cleaning bar	1	18	1	35
Non-ferrous metal detector	1	13	1	20
Scalping disk screen	1	33	1	63
Hammermill (hammer hog)	1	67	1	122
Open pile w/ concrete pad	2	8	2	8
Open pile - dirt pad	1	91	1	171
Front end loader, rubber tired, w/ 9 m3 bucket	1	337	2	673
Live storage silos	2	859	2	859
Total		**2,098**		**3,920**

Table B-5
Annual O&M Expense for 25-MW plant (September 2007 $)

Operating & Maintenance Labor				
Position	**Number of employee or hours**	**Base Salary or Hourly Rate**	**Stoker Total Annual Cost**	**CFB Total Annual Cost**
General Plant Manager	5	$81,000	$405,000	$405,000
Secretary/ Receptionist	5	$48,500	$242,500	$242,500
Plant Engineer	5	$64,500	$322,500	$322,500
Total Base Salaries and Wages			$970,000	$970,000
General Overhead and Benefits [1]			$582,000	$582,000
Subtotal Wages			$1,552,000	$1,552,000
Subcontracted Crafts				
Welder	1200	$80/hr	$96,000	$96,000
Electrician	640	$75/hr	$48,000	$48,000
Pipe Fitter	600	$65/hr	$39,000	$39,000
Insulator/Painter	400	$60/hr	$24,000	$24,000
Carpenter	400	$55/hr	$22,000	$22,000
Instrument Technician	400	$90/hr	$36,000	$36,000
Subtotal Subcontracted Labor			$265,000	$265,000
Annual Operating Labor Cost			**$1,552,000**	**$1,552,000**
Administrative & Support Labor [2]			**$388,000**	**$388,000**
Subcontracted Labor Cost			**$265,000**	**$265,000**
Maintenance Cost [3]			**$1,760,136**	**$1,723,827**
Total Fixed Operating Costs			**$3,965,136**	**$3,928,827**
			$158.61/kW-yr	**$157.15 /kW-yr**

Table B-5 (continued)
Annual O&M Expense for 25-MW plant (September 2007 $)

Variable Operating Costs				
Consumables	**Consumption (per day)**	**Unit Cost**	**Stoker Total Annual Cost**	**CFB Total Annual Cost**
Water(/1000 gallons)	467	1.20	$163,775	$163,775
Chemicals				
Ammonia (ton)	0.8	228.00	$55,732	$55,732
Other Chemicals [4]			$120,000	$120,000
Subtotal Chemicals			$175,732	$175,732
Other				
Supplemental Fuel(MBtu)	0	0.00	$0	$0
RO/Demineralizers			$12,500	$12,500
SCR Catalyst Replacement (ft^3)	373/yr	450	$167,850	$167,850
Vehicle Fuel (gallons)	2500/yr	4	$10,000	$10,000
Subtotal Other			$190,350	$190,350
Waste Disposal				
Fly ash (ton) - Stoker	0.3	18.00	$1,510	
Bottom Ash(ton) - Stoker	0.2	18.00	$1,006	
Fly ash (ton) - CFB	0.4	18.00		$1,860
Bottom Ash(ton) - CFB	0.1	18.00		$465
Subtotal Solid Waste Disposal			$2,516	$2,325
Total Variable Operating Costs			$532,373	$532,183
			$3.04 /MWh	$3.04 /MWh
Fuel (tons) - Stoker	870	20.00	$5,082,737	
Fuel (tons) - CFB	804	20.00		$4,697,586
Fuel Costs			$29.01 /MWh	$26.81 /MWh

[1] 60% of total salaries

[2] 25% of total annual operating labor cost

[3] 3% of total overnight construction cost

[4] Including boiler-treatment chemical, softener, cooling-tower treatment chemical

Table B-6
Annual O&M Expenses for 100-MW Plant (September 2007 $)

Operating & Maintenance Labor				
Position	**Number of Employee or Hours**	**Base Salary or Hourly Rate**	**Stoker Total Annual Cost**	**CFB Total Annual Cost**
General Plant Manager	1	$100,000	$100,000	$100,000
Secretary/ Receptionist	1	$25,000	$25,000	$25,000
Plant Engineer	1	$62,400	$62,400	$62,400
Shift Superintendent	5	$81,000	$405,000	$405,000
Support Operator	5	$48,500	$242,500	$242,500
Millwright	5	$64,500	$322,500	$322,500
Millwright Assistant	5	$28,800	$144,000	$144,000
Computer Technician	1	$52,000	$52,000	$52,000
Total Base Salaries and Wages			$1,353,400	$1,353,400
General Overhead and Benefits [1]			$812,040	$812,040
Subtotal Wages			$2,165,440	$2,165,440
Subcontracted Crafts				
Welder	1200	$80/hr	$96,000	$96,000
Electrician	640	$75/hr	$48,000	$48,000
Pipe Fitter	600	$65/hr	$39,000	$39,000
Insulator/Painter	400	$60/hr	$24,000	$24,000
Carpenter	400	$55/hr	$22,000	$22,000
Instrument Technician	400	$90/hr	$36,000	$36,000
Subtotal Subcontracted Labor			$265,000	$265,000
Annual Operating Labor Cost			$2,165,440	$2,165,440
Administrative & Support Labor [2]			$541,360	$541,360

Table B-6 (continued)
Annual O&M Expenses for 100-MW Plant (September 2007 $)

Operating & Maintenance Labor				
Position	**Number of Employee or Hours**	**Base Salary or Hourly Rate**	**Stoker Total Annual Cost**	**CFB Total Annual Cost**
Subcontracted Labor Cost			$265,000	$265,000
Maintenance Cost [3]			$3,790,799	$3,708,173
Total Fixed Operating Costs			**$6,762,599**	**$6,679,973**
			$67.63 /kW-yr	**$66.80 /kW-yr**
Variable Operating Costs				
Consumables	**Consumption (per day)**	**Unit Cost**	**Stoker Total Annual Cost**	**CFB Total Annual Cost**
Water(/1000 gallons)	1,870	1.20	$655,102	$655,102
Chemicals				
Ammonia (ton)	3.3	228.00	$218,423	$218,423
Other Chemicals [4]			$480,000	$480,000
Subtotal Chemicals			$698,423	$698,423
Other				
Supplemental Fuel(MBtu)	0	0.00	$0	$0
RO/Demineralizers			$50,000	$50,000
SCR Catalyst Replacement (ft^3)	1464/yr	450	$658,800	$658,800
Vehicle Fuel (gallons)	5000/yr	4	$20,000	$20,000
Subtotal Other			$728,800	$728,800
Waste Disposal				
Fly ash (ton) - Stoker	1.0	18.00	$5,025	
Bottom Ash(ton) - Stoker	0.6	18.00	$3,350	
Fly ash (ton) - CFB	1.2	18.00		$6,247
Bottom Ash(ton) - CFB	0.3	18.00		$1,562
Subtotal Solid Waste Disposal			$8,375	$7,808

Table B-6 (continued)
Annual O&M Expenses for 100-MW Plant (September 2007 $)

Variable Operating Costs				
Consumables	**Consumption (per day)**	**Unit Cost**	**Stoker Total Annual Cost**	**CFB Total Annual Cost**
Total Variable Operating Costs			**$2,090,700**	**$2,090,133**
			$2.98 /MWh	**$2.98 /MWh**
Fuel (tons) - Stoker	**2,897**	**20.00**	**$16,919,755**	
Fuel (tons) - CFB	**2,701**	**20.00**		**$15,774,356**
Fuel Costs			**$24.14 /MWh**	**$22.51 /MWh**

[1] 60% of total salaries
[2] 25% of total annual operating labor cost
[3] 3% of total overnight construction cost
[4] Including boiler-treatment chemical, softener, cooling-tower treatment chemical

C

BOILER SPECIFICATIONS FOR 50-MW PLANT

Table C-1
Specifications for 50-MW Stoker Boiler Plant

Parameter	Value	Units
Boiler Specifications		
Unit Size	50	MW
Furnace heat release (based on grate area)	600,000	Btu/ft^2/hr
Furnace heat release (furnace volume basis)	6,750	Btu/ft^3/hr
Rated Main Steam flow (VWO)	420,000	lbs/hr
MS pressure	1650	psig
MS Temperature	950	°F
Fuels	Wood Chips/Oil starting fuel	
No. of burners	4 for Oil	
Fuel Feeders	8 pneumatic	
Water wall tubes	carbon steel Side-2”OD; Roof-2 ¼” OD	
Flue Gas Conditioning		
NOx control	SCR	
Particulate	ESP	
Main Steam piping	Low alloy ferric steel P22	
Furnace Dimension	35 x 30 x 85	w x l x h (ft)
Soot Blowers	8 dual purpose	
FD fans	2 axial single stage variable pitch 4.16kV/900 rpm/300 kW	
ID fans	2 radial 750 rpm 4.16kv/250 kW	

Table C-1 (continued)
Specifications for 50-MW Stoker Boiler Plant

Flue Gas Conditioning		
Air Pre-heater	2 lungstrom regenerative 3-tier trisector, 415V / 5 HP	
Boiler Efficiency	>82	%

Table C-2
Specifications for 50-MW CFB Plant

Parameter	Value	Units
Boiler Specifications		
Unit Size	50	MW
Furnace heat release (furnace volume basis)	7,000	$Btu/ft^3/hr$
Rated Main Steam flow (VWO)	420,000	lbs/hr
MS pressure	1650	psig
MS Temperature	950	F
Fuels	Wood Chips/ #2 Oil starting fuel	
No. of burners	4 for #2 Oil for startup	
	8 for fuel	
Fuel Feeders	8 Gravimetric Feeders	
Water wall tubes	carbon steel Side-2”OD; Roof-2 ¼” OD	
Flue Gas Conditioning		
Cyclone Separator	1 Refractory lined cyclone separator	
NOx control	SCR or SNCR	
Particulate	Baghouse	
Main Steam piping	Low alloy ferric steel P22	
Furnace Dimensions (Front and Back Pass)	30 x 30 x 80 Front/ 10x12x60 with Cyclone	w x l x h (ft)
Soot Blowers	12 dual purpose	
PA fans	2 axial single stage variable pitch 4.16kV/900 rpm/400 kW	
FD Fan	2 axial single stage variable pitch 4.16kV/900 rpm/150 kW	
ID fans	2 radial 750 rpm 4.16kv/ 400 kW	

Table C-2 (continued)
Specifications for 50-MW CFB Plant

Parameter	Value	Units
Fluoseal Fan	1 radial 480V/100 kW	
Air Preheater	Tubular Type Primary and Secondary Air heaters	
Boiler Efficiency	>85	%

D

SYSTEM DESIGN BASIS

Table D-1
System Design Basis

Equipment/Ports	Flow	Pressure	Temperature	Enthalpy
	lb/hr	psia	°F	Btu/lb
Condenser				
Main Steam Inlet	348,000	2.00	126	966
Main Exit	380,656	2.00	126	94
Cooling Water Inlet	15,498,774	24.00	71	39
Cooling Water Exit	15,498,774	24.00	91	59
Auxiliary Steam Inlet	5,445	5.00	283	1,187
Auxiliary Water Inlet	27,211	10.00	129	97
Condensate Pump				
Main Inlet	380,656	2.00	126	94
Control Valve Outlet	380,656	100.00	126	94
Internal Pump Flow	380,656	2.00	126	94
Cooling Tower				
Water Inlet	15,498,774	24.00	91	59
Water Outlet	15,498,774	14.70	71	39
Makeup	321,071	15.00	60	28
Blowdown	80,113	14.70	71	39
Gas Inlet	15,643,608	14.70	70	2
Gas Outlet	15,884,410	14.67	84	6
Cooling Zone Water Outlet	15,257,816	14.70	71	39
Evaporation Loss	240,803	0.56	84	1,098
Flash Loss	-	14.70	91	59
Drift Loss	155	14.70	91	59

Table D-1 (continued)
System Design Basis

Equipment/Ports	Flow	Pressure	Temperature	Enthalpy
	lb/hr	psia	°F	Btu/lb
Cooling Water Pump				
Main Inlet	15,498,774	14.70	71	39
Control Valve Outlet	15,498,774	24.00	71	39
Internal Pump Flow	15,498,774	14.70	71	39
DA Vent valve				
Inlet	5,445	100.00	328	1,187
Outlet	5,445	5.00	283	1,187
Deaerator				
Main Steam Inlet	40,000	110.00	365	1,206
Main Boiler Feed Water Inlet	380,656	100.00	190	159
Main Boiler Feed Water Outlet	442,200	100.00	278	247
Vent Steam Outlet	5,445	100.00	328	1,187
Second Auxiliary Inlet	27,000	180.00	292	261
Feedwater Pump				
Main Inlet	442,200	100.00	278	247
Control Valve Outlet	442,200	1,650.00	287	259
Internal Pump Flow	442,200	100.00	278	247
FW to Boiler				
Inlet	442,200	1,650.00	345	319
FWH1 LP Feedwater Heater 1				
Inlet	442,200	1,650.00	345	319
Extraction Inlet	10,000	10.00	193	1,051
Drain Outlet	25,000	10.00	135	103
Boiler Feed Water Inlet	380,656	100.00	126	94
Boiler Feed Water Outlet	380,656	100.00	152	120
Drain Inlet	15,000	30.00	161	129
FWH2 LP Feedwater Heater 2				
Extraction Inlet	15,000	30.00	250	1,118
Drain Outlet	15,000	30.00	161	129
Boiler Feed Water Inlet	380,656	100.00	152	120
Boiler Feed Water Outlet	380,656	100.00	190	159

Table D-1 (continued)
System Design Basis

Equipment/Ports	Flow	Pressure	Temperature	Enthalpy
	lb/hr	psia	°F	Btu/lb
FWH3 HP Feedwater Heater 1				
Extraction Inlet	15,000	30.00	250	1,118
Drain Outlet	15,000	30.00	161	129
Boiler Feed Water Inlet	380,656	100.00	152	120
Boiler Feed Water Outlet	380,656	100.00	190	159
FWH4 HP Feedwater Heater 2				
Extraction Inlet	12,000	250.00	519	1,275
Drain Outlet	12,000	250.00	329	300
Boiler Feed Water Inlet	442,200	1,650.00	320	293
Boiler Feed Water Outlet	442,200	1,650.00	345	319
HP Turbine				
Steam Inlet	440,000	1,515.00	950	1,459
Main Outlet	373,000	85.00	321	1,187
Second Extraction	12,000	250.00	519	1,275
Third Extraction	15,000	180.00	455	1,246
Fourth Extraction	40,000	110.00	365	1,206
Expansion Line End	373,000	85.00	321	1,187
LP Turbine				
Steam Inlet	373,000	85.00	321	1,187
Main Outlet	348,000	2.00	126	966
Second Extraction	15,000	30.00	250	1,118
Fourth Extraction	10,000	10.00	193	1,051
Expansion Line End	348,000	2.00	126	966
Main Steam to Turbine				
Steam Flow	440,000	1,515.00	950	1,459
Make Up Water to Steam Cycle				
Feedwater	2,211	15.00	60	28

E

EQUIPMENT DESIGN PARAMETERS

Table E-1
Condenser Design Parameters

Parameters	Unit	Value
Surface Area	ft^2	13,881.26
Calculated Effectiveness		0.36
Calculated Duty	BTU/hr	3.09E+08
Fixed Cooling Water Temperature Rise	F	20.00
Exergetic Efficiency (beta)		0.24
Exit Subcooling	F	0.00
Overall Heat Transfer Coefficient	BTU/hr-ft^2-F	501.91

Table E-2
Condensate Pump Design Parameters

Parameters	Unit	Value
Actual Isentropic Efficiency		0.85
Calculated Pressure Ratio		50.00
Calculated Pump Exit Pressure	psia	120.00
Developed Head	ft	275.78
Net Positive Suction Head Available	ft	-5.57E-07
Pump Work	kW	-46.52
Rated Mass Flow Rate	lb/hr	915,008.20
Rated Volumetric Flow Rate	ft^3/hr	14,850.38
Rated Speed		3,600.00
Rated Head	ft	3,500.04
Exergetic Efficiency (beta!)		0.96

Table E-3
Cooling Tower Design Parameters

Parameters	Unit	Value
Cooling Tower Duty	BTU/hr	3.11E+08
Total Fan Power	kW	495.87
Current Approach	°F	10.00
Current Merkel Number (Me)		2.54
Calculated Inlet Relative Humidity		0.60
Calculated Inlet Wet Bulb Temperature	°F	61.06
Exit Relative Humidity		0.98
Blowdown Fraction	fraction	0.01
Evaporation Loss Fraction	fraction	0.02
Number of Fans (Bays)		3.00
Gas Side Pressure Drop	in H_2O	0.83
Cycles of Concentration		4.00
Drift Loss Fraction	fraction	1.00E-05

Table E-4
Cooling Tower Pump Design Parameters

Parameters	Unit	Value
Actual Isentropic Efficiency		0.85
Calculated Pressure Ratio		1.63
Calculated Pump Exit Pressure	psia	49.00
Calculated P. Diff (Pump Exit - Control Valve Exit)	psia	25.00
Developed Head	ft	79.29
Net Positive Suction Head Available	ft	33.10
Recirculation Rate		0.00
Pump Work	kW	-544.52
Rated Mass Flow Rate	lb/hr	915,008.20
Rated Volumetric Flow Rate	ft^3/hr	14,686.61
Rated Speed		3,600.00
Rated Head	ft	3,500.04
Exergetic Efficiency (beta!)		0.24

Table E-5
Feedwater Pump Design Parameters

Parameters	Unit	Value
Actual Isentropic Efficiency		0.85
Calculated Pressure Ratio		16.50
Calculated Pump Exit Pressure	psia	3,300.00
Calculated P. Diff (Pump Exit - Control Valve Exit)	psia	1,650.00
Developed Head	ft	7,944.57
Net Positive Suction Head Available	ft	130.30
Pump Work	kW	-1,556.66
Rated Mass Flow Rate	lb/hr	915,008.20
Rated Volumetric Flow Rate	ft^3/hr	15,775.50
Rated Speed		3,600.00
Rated Head	ft	3,500.04
Exergetic Efficiency (beta!)		0.89

Table E-6
Feedwater Heater Design Parameters

Feedwater Heater Data	Unit	LP FWH1	LP FWH2	HP FWH3	HP FWH4
Calculated Duty	BTU/hr	9,769,261	14,686,424	15,082,692	11,578,170
Calculated Heat Losses	BTU/hr	-97,693	-146,864	-150,827	-115,782
Total Surface Area	ft^2	835.00	497.00	1,556.00	642.00
Terminal Temperature Difference	F	41.28	59.88	53.06	55.59
Drain Cooler Approach	F	9.00	9.00	5.00	9.00
Exergetic Efficiency (beta!)		0.77	0.78	0.96	0.98
Steam Section Heat Transfer Coefficient.	BTU/hr-ft^2-F	123.28	123.28	123.28	123.28
Condensing Section Heat Transfer Coefficient	BTU/hr-ft^2-F	598.77	598.77	598.77	598.77
Drain Cooler Heat Transfer Coefficient	BTU/hr-ft^2-F	352.22	352.22	352.22	352.22
Steam Section Effectiveness		-	-	-	-

Table E-6 (continued)
Feedwater Heater Design Parameters

Feedwater Heater Data	Unit	LP FWH1	LP FWH2	HP FWH3	HP FWH4
Condensing Section Effectiveness.		0.36	0.37	0.36	0.30
Drain Cooler Effectiveness		0.87	0.91	0.94	0.89
Desuperheating Section Area	ft^2	-	-	-	-
Condensing Section Area	ft^2	283.42	294.31	337.47	270.93
Drain Cooler Section Area	ft^2	551.23	202.69	1,218.54	370.67
Number of HTX Passes		2.00	2.00	2.00	2.00
Energy loss fraction	fraction	0.01	0.01	0.01	0.01
Fouling factor	ft^2-F-hr/BTU	-	-	-	-

Table E-7
HP Steam Turbine Design Parameters

Parameters	Value	Unit
ST Inlet		
Control Valve Pressure Drop	0.02	fraction
Current Control Valve Set.	1.00	
Throttle Flow Ratio	1.00	
ST Outlet		
Exhaust Annulus Area	55.60	ft^2
Exhaust Volumetric Flow	1,940,960	ft^3/hr
Bowl		
Current Bowl Pressure	1,484.70	psia
Bowl Stodola CQ	8,261.75	
Extraction 1		
Expansion Line Pressure	250.00	psia
Expansion Line Enthalpy at Extraction Point	1,274.53	BTU/lb
Extraction 2		
Expansion Line Pressure	180.00	psia
Expansion Line Enthalpy at Extraction Point	1,245.96	BTU/lb
Expansion Line Quality at Extraction Point	1.00	
Extraction 3		
Expansion Line Pressure	110.00	psia
Expansion Line Enthalpy at Extraction Point	1,206.14	BTU/lb

Table E-8
LP Steam Turbine Design Parameters

Parameters	Value	Unit
ST Inlet		
Control Valve Pressure Drop	0.02	fraction
Current Control Valve Set.	1.00	
Throttle Flow Ratio	1.00	
ST Outlet		
Number of Flow Ends	1.00	
Exhaust Annulus Area	55.60	ft^2
Exhaust Volumetric Flow	5.20E+07	ft^3/hr
Bowl		
Current Bowl Pressure	83.30	psia
Bowl Stodola CQ	96,081.60	
Extraction 1		
Expansion Line Pressure	30.00	psia
Expansion Line Enthalpy at Extraction Point	1,117.84	BTU/lb
Extraction 2		
Expansion Line Pressure	10.00	psia
Expansion Line Enthalpy at Extraction Point	1,051.31	BTU/lb
Extraction 3		
Expansion Line Pressure	10.00	psia
Expansion Line Enthalpy at Extraction Point	1051.31	BTU/lb

Electrical System Detail

Voltages

The electrical system, subsystems, and equipment defined in this report operate at the following nominal voltages:

	Volts (AC)
1. Grid interconnection	115,000
2. Generator output	13,800
3. Auxiliary system, medium voltage	4160
4. Auxiliary system, low voltage	480
5. Low voltage motors	120 AC and 125 DC

Major electrical equipment consists of the following items:

1. 115kV switchyard equipment including 115kV power circuit breakers, wave traps, disconnects and an air break switch.
2. Generator step-up transformer 13.8 kV/115kV
3. Non-segregated phase bus duct or cable
4. 13.8 kV generator breaker
5. Auxiliary transformer
6. 4.16 kV switchgear
7. Motor control center transformers (4.16 kV/480 V)
8. 480 V motor control centers (MCC's)
9. Distribution panels
10. 125 V dc system (battery, charger, and distribution panel boards)
11. Uninterruptible power supply system
12. Protective relaying, metering, and controls Cable and wire, as required
13. Electrical heat tracing
14. Motors
15. Lighting system (normal and emergency)
16. Grounding and cathodic protection system, as required
17. Raceways for power, control, and instrumentation cables

The following sections contain detailed descriptions of major electrical equipment listed above.

Generator step-up transformer and high voltage (115 kV) circuit breakers: The generator step-up transformer is rated for the required MVA at 60°C rise, FAA cooling, three-phase, 60 hertz, 121/13.8 kV, 480 kV BIL or as required for the site. The high voltage winding is connected in wye, with the neutral solidly grounded. The low voltage winding is connected in delta. The transformer is equipped with lightning arresters and a no-load five-position tap changer on the high voltage side, standard accessories, and protective devices.

The circuit breakers and associated structure at the site are compatible for overhead line interconnection with MPC's transmission system rated at 115 kV (nominal), with minimum and maximum impedances of the MPC system.

Generator to generator step-up transformer connection: The generator is connected to the generator step-up transformer with either a non-segregated phase bus duct or 15-kV shielded, triplexed cable.

13.8-kV Generator breaker assembly: The generator breaker assembly consists of a 13.8-kV class draw out type circuit breaker. The circuit breaker, with current and potential transformers, is of the metal clad switchgear type. The breaker is located below the generator.

Auxiliary transformer: The auxiliary transformer is installed adjacent to the generator step-up transformer and is connected through a tap from the generator non-segregated phase bus or 15-kV shielded cable. The transformer is rated according to the required auxiliary load with an option to increase its rating in the future by 25 percent by adding fans: 65.C rise, three phase, 60 hertz, 13.8-4.16 kV/4.16 kV, 110 kV SIL. The high voltage winding is connected in delta. This winding is equipped with a hand-operated, no-load five-position tap changer. The low voltage winding is connected in wye and the neutral will be grounded through a resistor. The low voltage windings are connected by cables to the 4,160-V switchgear. The transformer impedance is calculated to permit starting the largest motor without affecting the operation of other equipment, and the transformer carrys all remaining loads. However, the transformer impedance, is sufficient to limit the short-circuit duty on the 4,160 V switchgear to less than the rated value for the switchgear. The transformer is equipped with standard accessories and protective devices.

4.16 kV switchgear: The 4.16 kV switchgear/MCC assemblies are of the indoor type. The lineup includes removable links and required fused contactors for transformer feeders (latched) and as starters for motors. In general, large motors (those over 200 hp) are supplied from this source.

Motor control center transformers (4.16 kV/480 V): The MCC transformers are three phase, 60 hertz, 4.16 kV-480/277 V. The high-voltage winding of these transformers is equipped with a hand-operated tap changer and connected in delta. The transformer impedance limits the short-circuit currents on the MCC's to lower than design values. The low voltage winding is connected in wye and solidly grounded.

480-V motor control centers: 480-V motor control centers are NEMA Class 1, Type B, with plug-in, combination, across-the-line starters with molded-case breakers or fuses.

The motor control centers supply and control most 480-V motors of 200 hp and smaller, lighting and power panel transformers, and small 480-V loads. Each combination motor starter is equipped with a 120-V control transformer. The feeder circuit breakers are 600 V class and are equipped with thermal magnetic series trip devices. Motor control centers are located close to their loads. Indoor motor control centers have NEMA Type 1 enclosures. Motor control centers located outdoors have NEMA Type 3R enclosures.

Distribution panels: The distribution panels consist of 120/208 V, three-phase, four-wire panel boards supplied from the 480-V motor control centers through step-down transformers. Associated loads include 1/2-hp and smaller motors, space heaters, solenoid valves, non-critical control panels, and lighting fixtures. Where required, 120 V receptacles are provided. AC power panels, rated 480/277 V, three phase, four-wire, supplied from the 480-V motor control centers are provided to feed lighting fixtures, space heaters, and miscellaneous three phase loads.

125- V DC system: The 125-V DC system provides control power for the protective relays, 13.8-kV switchgear, the 120-kV breaker and miscellaneous devices of the process control and instrumentation as well as power for emergency motors, the UPS system and other emergency services. The system consists of a lead calcium 60-cell storage battery, a static battery charger, a spare battery charger and one DC panel. This equipment is located under the main plant control room. The battery size is dictated by the normal and emergency plant requirements and has sufficient capacity to permit safe shutdown of the turbine generator. The DC system is sized to power the turbine emergency lube oil pump long enough to satisfy the manufacturer's requirements plus maintain the plant essential control systems for at least two hours. The battery charger is sized to bring the battery from full discharge to full charge in less than 24 hours while simultaneously carrying the normal continuous load. The charger is supplied by a 480-V motor control center. One dc distribution panel will be provided.

Uninterruptible power supply system: Facility systems that require a highly reliable source of 120-V AC power, such as boiler control systems, processor controls, and certain instrumentation loads, are powered from the uninterruptible power supply (UPS) system. The 120-V UPS distribution panel is connected to an inverter which has an associated static bypass transfer switch to a 120-V AC source. Under normal conditions, power is supplied to the distribution panel from the inverter, which derives power from the 125-V DC system described earlier.

Protective relaying: Protective relays are provided for the electrical system to permit isolation of faulted or overloaded equipment and cables as quickly as possible to minimize equipment damage and limit the extent of system outages. Major components such as the generator, large transformers, and the 115-kV circuit breaker have primary and backup relaying. Current and potential transformers are connected to provide overlapping zones of protection. Relays are operated from independent circuits of the 125-V DC system and are mounted in a freestanding panel.

Faults that have high probability of not self-clearing will trip and lock out appropriate breakers and devices. Manual system restoration is permitted for faults of a temporary nature.

Generator protection: The generator is monitored for winding faults by percentage differential current relays. Generator backup protection uses an over current relay with voltage restraint.

Stator ground faults are detected by a voltage relay connected across the neutral grounding resistor.

Other generator protective relaying includes reverse power, phase current imbalance, loss of excitation, voltage imbalance, field ground, over and under frequency, and synchronizing check.

Generator step-up and auxi1iary transformer protection: Internal transformer faults are detected by rate-of-rise pressure relays furnished with the transformer. Percentage differential current relays also detect internal transformer faults.

Transformer overloads are detected by time over current relays. An overcurrent relay is placed in the auxiliary transformer and the generator step-up transformer neutral-to-ground connections to detect ground faults.

High winding and oil temperatures and low oil levels are alarmed.

Cables and wires: Cables and wires of the following types are included:

- 13.8-kV and 4.16-kV system: Either single conductor, three-conductor or triplexed, fully insulated, 15-kV, and 5-kV stranded, soft drawn copper for 90°C normal operation meeting IEEE 383 or UL 1072 flame tests.
- 480-V system: Multi-conductor or triplexed, 600-V class, stranded soft drawn copper cable for 90°C normal operation meeting IEEE 383 or UL 1581 flame tests.
- Control systems (except instrumentation): Multi-conductor 600-V class stranded, soft drawn tinned or alloy-coated soft drawn copper, No. 14 or larger, 90°C normal operation meeting UL1581 flame tests. Shielding may be required.
- Instrumentation: Cable for instrumentation and low level signal circuits rated at 300-V, stranded copper, #18 AWG or larger, twisted, aluminum mylar shield, copper drawn wire, 90°C normal operation meeting UL 1581 flame tests.
- RTDs and thermocouples: Shielded multiconductor, 90°C normal operation meeting UL 1581 flame tests. High temperature insulation will be used in high temperature areas.
- Lighting circuit: No. 12 or larger, copper conductors, in conduit or sheathed cable.

Electrical heat tracing: Electrical heat tracing will be provided for outdoor piping and instrumentation sensing lines that may be subject to freezing.

Motors: Motors in general are squirrel cage induction type, designed for full voltage starting, except where the specific application dictates otherwise. Motors larger than 200 hp, in general, are rated 4,000 V for use on a 4,160-V, three-phase, 60-hertz, resistance grounded system, or are rated 460 V for use on a 480 V, three-phase, 60 hertz, solidly grounded system. Smaller motors are single phase, AC or DC, as required by the function of the motor. Motors have Class B or other insulation as required by the application. To prevent damage by moisture condensation, motors for outdoor service that are rated larger than 25 hp have space heaters, which are automatically activated when the motor is idle, except for specially designed motors for which it would not be practical to install space heaters. Weather-protected; NEMA Type II enclosures are provided for 4,000-V motors installed outdoors. Totally enclosed fan-cooled (TEFC) or totally enclosed non-ventilated (TENV) enclosures are utilized on other motors installed outdoors. Motors installed indoors have drip-proof enclosures unless the location or application requires a different type of enclosure.

Lighting system: Lighting consists of a 480/277 and a 120/208-V distribution system. Normal lighting in the boiler, cooling tower, flue gas treatment system, turbine generator and fuel handling areas are provided by high pressure sodium and incandescent fixtures. Lighting for control room and battery rooms are provided by fluorescent fixtures. Outdoor lighting for roadways, parking areas, and plant access are supplied by high pressure sodium and floodlighting fixtures mounted on poles. Illumination levels for all areas are based on recommendations of the Illuminating Engineering Society (IES). Stack obstruction lights, if required, are provided in accordance with FAA regulations. Emergency lighting is provided by battery packs for normally accessed locations to permit egress to the nearest ground level in the event of an emergency.

Grounding and cathodic protection system: A grounding system is furnished in accordance with the requirements of the National Electrical Code to ensure proper grounding of the system, structures, and equipment facilities as well as for personnel safety. An insulated instrument ground system is connected to the distributed control system' (DCS) manufacturer's requirements if required by the selected DCS supplier.

The conductor is an annealed, concentric-stranded, bare copper cable of sufficient size to carry the maximum expected ground-fault current without fusing. The design of grounding is done in such a manner as to limit the touch and step potential, where applicable, to safe values under fault conditions. All underground joints in the ground grid are made by compression grid connector type (UTM wrench-lock). Steel-to-copper connections for grounding of the columns are above ground. Exposed connections are made with bolted or compression-type connectors.

Cathodic protection is provided for buried carbon steel pipe runs. The condenser water box is protected by sacrificial anodes if necessary. Insulation flanges will be used where pipe connections are made between in-plant and out of plant components. .

Raceways for power, control, and instrumentation cables: The raceways for power, control and instrumentation cables are run in duct bank, cable trench, cable tray, and conduit, as required by site and plant layout conditions. Aluminum sheathed or metal-clad cable may be used in lieu of conduit. Lighting and nonessential power cables may be direct burial. The cable tray system is protected by covers in areas when cables may be subject to physical damage. The design of the tray system is based on NEC requirements. Galvanized steel or aluminum trays are provided.

Exposed cable runs between trays and motors, push button stations, and other local devices use galvanized rigid steel or IMC conduits. Flexible conduits are used at the connection to equipment and devices subject to removal vibrations or uneven settlement. Separate raceways are provided for 15 kV and 5 kV power cables. Installation of 600 V power and control cables is in accordance with the requirements of the NEC. Separate raceways or tray barriers in the general control trays are provided for isolating low-power, low-voltage signal cables if necessary.

Water Quality

Raw Water Supply Quality

The flow into the raw water holding tank shall be continuous, year around. The typical water quality analysis listed below:

Table E-9
Raw Water Supply Quality

Parameter	Unit	Value
Temperature	°F	70
Oxygen	ppm	6
Hardness	ppm	86
Suspended Matter	ppm	0.1
pH		6.87
Silica	ppm	10
Alkalinity	ppm	100
Dissolved Solids	µ-mho/cm	500

Source: Cleaver Brooks, "The Boiler Book",
Wisconsin: Aqua-Chem, 2000.

Feedwater Quality

Makeup water to the condensate and feedwater systems is supplied by the makeup water treatment system. The water quality analysis for the system, as specified by the boiler manufacturer, is summarized below:

Table E-10
Feedwater Quality

Parameter	Unit	Value
Oxygen	ppm	<0.007[1]
Hardness (as $CaCo_3$)	ppm	0
pH		8.5-9.5
Silica	ppm	0.020
Iron	ppm	0.01
Copper	ppm	0.005
Total Solids	ppm	0.15
Organic		0

[1] Limits of feedwater.
Source: B&W Steam Generation – Feedwater Quality for 1,000 -2,000 psi boilers

Wastewater Quality

The plant is a zero liquid discharge plant. The water evaporates in the cooling tower and fresh water is used as make up water. Residual waste water from the process is held in holding ponds and mixed with bottom ash for disposal off site. Plant waste is separated from the run-off water. All waste streams will be treated to comply with NPDES permit before discharge from the plant.

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