Gainesville Regional Utilities

SUPPLEMENTARY STUDY OF GENERATING ALTERNATIVES FOR DEERHAVEN GENERATING STATION

Prepared by Black & Veatch Corporation
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NOTE:
Attached to the back of this report are several e-mails and memorandums which offer background and updates to the main body of the report. (DCB)

1.0 INTRODUCTION AND BACKGROUND

Gainesville Regional Utilities (GRU) is in the process of planning its next increment(s) of electric generating capacity. Among the concepts being considered are capacity additions and modifications at their Deerhaven Generating Station. That facility currently has two steam-electric units, Unit 1 is a gas/oil-fired unit and Unit 2 is a coal-fired unit. Consideration is being given to installing a third unit in the 225MW size range. It is expected to be a solid-fueled unit and may utilize either circulating fluidized bed (CFB) or pulverized coal (PC) steam generation technology, or possibly some other technology(ies). GRU has commissioned several studies to develop cost and performance information to be used in their comparative analyses. The purpose of this supplementary study is to provide additional complementary information of that type for areas of interest that have either not been examined previously or for which more in-depth information is desired

Specifically, GRU desires to add the following two aspects to the ongoing planning work.

1. Methods for incorporating biomass into the fuel mix. Their initial target is to generate as much as 30 MW using biomass. .
2. More rigorous treatment of the Integrated Gasification Combined Cycle (IGCC) generation technology.

With respect to the biomass issues, it is intended that this investigation identify the best way(s) to incorporate biomass into Deerhaven's fuel mix and impacts that can be expected to the balance of the plant, permits, etc. The work includes a review of pertinent work that may have already been done by others for GRU on the topic of biomass as a fuel.

With respect to IGCC, it is intended that the investigation should yield economic parameters for use by GRU in its production cost modeling and comparison of generation alternatives, and provide insight into the viability of owning and operating IGCC technology.

Additionally, GRU has requested that information be developed to evaluate the cost(s) of delaying implementation of a new unit by one year. It is currently envisioned that the planning, permitting, engineering, etc. for the new unit will be initiated in 2004 with commercial operation occurring in 2010. Thus far, all of the modeling for the various options has been based on that commercial date and the "overnight cost estimates" have been adjusted using an average factor of 3% to account for escalation of the capital cost estimates. For the purposes of performing some sensitivity analyses, GRU is interested in estimating the cost of delaying the start of the work from 2004 to 2005 and completion of the new unit from 2010 to 2011, a delay period of one year. That includes the capital cost of the plant as well as purchase of replacement power. It is expected that the calculation will not utilize an assumed overall average escalation rate, but rather will consider the individual escalation rates for each main element of the procurement and construction.

The results of the work of this supplementary study are summarized in Section 2, and the details area reported in Sections 3, 4 and 5.

2.0 EXECUTIVE SUMMARY

2.1 Incorporating Biomass Fuel into the Generation Mix

2.1.1 Review of Previous Work

The objective of this biomass investigation is to evaluate the potential for integration of biomass into the GRU generation mix. Biomass has been identified as a potential resource in the GRU Integrated Resource Planning process. Based on recent resource assessment studies, GRU is targeting the development of up to 30 MW of biomass either as a new stand-alone unit or integrated into existing and/or planned units at Deerhaven. Black & Veatch has prepared this assessment to assist GRU in characterizing biomass options. This section summarizes the study findings related to biomass fuel resources, possible conversion concepts, project conceptual design, and performance and cost estimates.

2.1.2 Review of Biomass Resource Assessment

Despites some conflicts in the data, it appears that there is a large and sustainable quantity of biomass in the immediate Gainesville area to support a major biomass project. GRU commissioned a report in 2003 by Don Post and Tom Cunilio titled "Biomass Options for GRU – Part II." The Post and Cunilio report identified 2,146 wet tons per day of biomass residue available within the immediate Gainesville area (25 mile radius). The preferred option for biomass utilization for this study requires on the order of 600 wet tons day. Further, data from other sources seems to indicate that if the collection radius is extended to 50 miles, the available resources could be much greater. The cost for this biomass is expected to be around $1.50/MBtu (all costs are in 2004$) – between the costs of urban wood waste and forest residues. Provided competing end uses do not arise, the price for biomass is expected to be stable in the near to long term. Competing end uses would include the opening of other biomass plants in the area.

2.1.3 Concept Selection Process

There are a wide variety of potential technologies for converting biomass into electric power. These can be broadly categorized into stand-alone and co-utilization alternatives. Black & Veatch identified 41 possible options and screened this list to four options for further analysis. These include:

- Stand Alone Unit – Stoker Grate Combustion
- Unit 2 Direct Cofiring with Separate of Blended Feed
- Unit 2 Indirect Cofiring Using Gasification
- New Unit 3 Direct Cofiring

In general, there are several advantages to cofiring wood with coal versus burning the wood in a dedicated plant. One of the greatest advantages of cofiring is that the capital cost is much lower than a stand alone biomass plant because less new equipment and land are required. The installed capital cost for cofiring is typically $100 to $600 per kW (replacement capacity), compared to greater than $2,000/kW for a stand alone plant. Also, because the larger coal plants are able to operate at higher steam temperatures and pressures than small biomass plants, the efficiency in cofiring applications is much higher than stand alone biomass plants. Cofiring in Unit 2 or 3 would be up to 50 percent more efficient than what could be obtained in a new 30 MW stoker.

Due to its low cost, ability to be incorporated into the design from the outset, and minimal impacts on unit operation and performance, Black & Veatch recommends that direct cofiring in the proposed Unit 3 CFB be the preferred option of the four investigated. As an alternative, indirect cofiring using gasification could be examined further for Unit 2. However, given the complexity of the already planned air quality control modifications for Unit 2, this option seems much less appealing. If Unit 2 is a focus of further investigation, gasification for cofiring is recommended over direct cofiring in Unit 2 due to the greater potential emissions benefits and the substantially reduced negative impacts on the existing plant equipment.

2.1.4 Conceptual Design

The wood waste will be cofired with pet coke and coal in the proposed 220 MW Unit 3 CFB. Generating 30 MW using biomass fuel would result in approximately 13.6 percent of the power output from Unit 3 being derived from the wood. It is assumed that biomass will displace coal, resulting in a final fuel mix of 13.6 percent wood, 36.4 percent coal, and 50 percent pet coke. Approximately 600 tons/day of biomass (at 5,657 Btu/lb) will need to be fired in Unit 3 to generate the equivalent of 30 MW.

The conceptual design is for one complete system with limited equipment redundancy (for example there is only one truck tipper and one reclaimer). Redundancy was limited because biomass is intended to be a supplemental fuel and is not critical to unit reliability. The major systems include the wood receiving system (including truck scale and hydraulic tipper), covered 5-day storage, and the wood reclaim and plant supply system consisting of various conveyors, a magnetic separator, disc screen and hog for “overs”, and the boiler feed bin.

2.1.5 Performance Impacts

Black & Veatch assessed the performance impacts of cofiring 13.6 percent wood, 36.4 percent coal, and 50 percent pet coke in a new 220 MW CFB. The performance estimate for the biomass cofiring case was compared against an estimate of burning a 50:50 mix of coal and petroleum coke. Black & Veatch projects that cofiring 13.6 percent wood waste will result in a small boiler efficiency decrease, from 89.3 to 88 percent. This change is not expected to impact net plant output, but it is estimated to result in a 1.5

percent increase in net plant heat rate, raising it from 9,464 to 9,604 Btu/kWh (HHV basis). By comparison, a typical stand-alone biomass plant would have a heat rate of around 14,000 Btu/kWh, about 50 percent higher.

Depending on the biomass fuel properties, uncontrolled emissions for SO_x, particulate, and CO_2, are all expected to decline approximately proportional to the biomass cofiring rate. However, after passing through the air quality control (AQC) equipment, it is not expected that significant differences will be realized for controlled emissions for SO_x and particulate. Nevertheless, the lower uncontrolled emissions of the biomass will result in less material and chemical consumption in the AQC systems (that is, baghouse bags and limestone/lime), and this is reflected in the operation and maintenance cost estimate. Given the inherently low NO_x emissions of the CFB technology, it is not expected that biomass will impact NO_x emissions.

2.1.6 Capital Cost Impacts

The incremental capital cost (excluding owner's cost) to include the biomass cofiring system in the Unit 3 design is estimated to be approximately $4.6 million. The estimate includes an allowance of $500,000 for modifications to the boiler design. The total capital cost estimate is equal to about $150 per kW of biomass capacity, or $21/kW when spread over the total cost/output of the 220 MW Unit 3. This cost is very small when compared to other renewable energy options such as wind ($1,200/kW) and solar photovoltaic ($8,500/kW).

2.1.7 Operation and Maintenance Cost Impacts

The estimated incremental operations and maintenance (O&M) costs for the biomass cofiring system are small. Fixed costs are estimated to increase by $1.35/kW-yr, primarily due to the additional biomass handling labor. Variable O&M costs are expected to decrease by $0.17/MWh, primarily related to reduced consumption of limestone and lime because of the low sulfur content of the biomass. The total net change in annual O&M is very minor, amounting to an estimated increase of only $26,000.

2.1.8 Conclusions and Recommendations

Biomass appears to be a viable resource for further investigation by GRU. There appears to be abundant biomass in the immediate vicinity of Gainesville to support at least 30 MW of biomass power. The cost for this biomass is likely to be about $1.50/MBtu. Given GRU's current plans, the most cost effective and efficient method to generate power from biomass is to incorporate it into the new Deerhaven 220 MW Unit 3 CFB. Cofiring of biomass in circulating fluidized bed boilers is well proven. In fact, there are boilers as large as the proposed Deerhaven Unit 3 that are 100 percent biomass fired. Approximately 600 tons/day of biomass (at 5,657 Btu/lb) will need to be fired in Unit 3 to generate the equivalent of 30 MW from biomass. The necessary receiving, storage, and feed equipment for this amount of biomass will have a capital cost on the order of $4.6 million dollars. No substantial impacts are expected on operation and maintenance of the plant, although the unit heat rate will be slightly increased (1.5 percent).

Recommended areas of particular focus for additional investigation include biomass resource availability, particularly in regards to cost, chemical and physical properties, delivery requirements, identification and perhaps preliminary negotiations with large fuel suppliers. The biomass systems should also be further integrated into the design for the new unit, including revised plant layouts, air quality system impacts, environmental permitting requirements, etc. GRU may also wish to explore the impacts of integrating a much larger biomass capability as part of its future plans for Unit 3. At present there do not appear to be technical or fuel supply reasons why Unit 3 could not accept up to 50 percent biomass. Although the economics of such a large commitment to biomass are uncertain, the incremental capital costs for installing a larger fuel handling system will be relatively modest. Further, GRU would not necessarily need to always fuel the boiler with 50 percent biomass; it would only need to use that amount that is economical given current market prices. The larger commitment to biomass would allow greater fuel arbitrage, long-term resource security, and the possibility of selling excess renewable energy credits or power to interested purchasers (such as in response to JEA's recent renewable energy solicitation). The economics of these benefits need to be balanced against the higher capital and fuel costs of the larger system.

2.2 Review of IGCC Technology and Development of Economic Parameters

2.2.1 Technology Description

A typical integrated gasification combined cycle (IGCC) plant for power generation from coal is shown on Figure 4-1. Pulverized coal is fed into the gasifier at approximately 450 psia with oxygen from an air separating unit (ASU). The raw fuel gas exits the gasifier at about 2,400 °F and is cooled to 400 °F in a syngas cooler. Steam produced in the syngas cooler is expanded in the steam turbine generator (STG). The cooled syngas is then scrubbed with water to remove dust, NH3, and hydrogen chloride. The syngas is cooled further and then scrubbed with solvents to remove sulfur compounds. The clean syngas is then injected into the combustion chamber of the combustion turbine generator (CTG). The heat from the CTG exhaust gas is used to generate steam in the heat recovery steam generator (HRSG), which is then expanded through the STG.

IGCC systems incorporate the steam production from the gasification system directly into the combined cycle application. Generally, the integration itself increases efficiency and lowers operating costs when compared to straight gasification and combined cycle generation, but the capital cost of IGCC is still high.

IGCC is the combination of two well-proven technologies. It would seem that this combination should be relatively easy. However, the economics of IGCC are much different from those of gasification. IGCC requires high thermal efficiency to compete in today's marketplace. This means that the simple quench processes used for chemical processing plants must be replaced by specially designed syngas coolers. These syngas coolers use the heat from the high temperature raw syngas to produce HP steam.

2.2.2 Gasification Overview

Gasification technology is commercially available. It is a simple technology that has been used for over 100 years. Gasification typically entails the reaction of a feedstock, either a solid or liquid, with oxygen and steam to produce a syngas. The feedstock is converted into syngas with a high-temperature, high pressure process under reducing conditions -- less than 50 percent of the oxygen required for complete combustion is used in the process.

High-temperature raw syngas is cooled and cleaned using technologies common to oil refining and natural gas purification. The cooler, clean syngas is then used in one or more of the following applications:

- Syngas for power
- Syngas for chemicals
- Syngas for liquids fuels
- Syngas for gaseous fuels

Traditionally, syngas production has been an intermediate step in the production of chemicals such as NH_3 to be used in the production of fertilizers.

The US DOE has compiled a gasification database consisting of 329 projects. The projects date back to 1952 and also include projects under development that are scheduled to be completed by 2004. Of these projects, 161 are of commercial scale. Of the commercial scale projects, 128 are operating or under construction, with the remaining 33 projects in the active planning stages. If all of the syngas produced from the 161 commercial scale projects was converted to electricity through the IGCC process, roughly 32,300 MW would be produced.

The Dakota Gasification Project is still the third largest gasification project in the world. The two largest projects are located in South Africa and are used to produce liquid fuels.

2.2.3 Gasification Process

There are at least 10 different commercially available gasification processes. These processes can be classified into three families based on the manner in which the fuel and oxidant flow through the gasifier: fluidized bed, entrained flow, and moving bed. Moving bed is frequently, although incorrectly, referred to as fixed bed.

The three families of gasification are roughly analogous to conventional solid fuel steam generators. Fluidized bed gasifiers operate on the same principle as fluidized bed combustors; entrained flow gasifiers are comparable to PC steam generators, and moving bed gasifiers are similar to grate firing. All three families are suitable for solid fuels.

Table 4-1 lists the characteristics of the generic types of gasifiers.

Moving bed gasifiers accept only solid fuels. They were originally designed for coal but can handle other solid fuels such as wastes. Moving bed gasifiers are the oldest of the three families and have the most commercial scale installations. The two primary moving bed processes are Lurgi and BGL.

The Lurgi dry ash process was developed in the 1930s. It is referred to as a dry ash process because the bed temperature is maintained below the fusion temperature, thus the ash is removed as a solid. The Dakota Gasification plant employs a Lurgi dry ash process. The Lurgi dry ash process is also being used to gasify lignite in the Czech Republic. The products of the Czech Republic project, which became commercial in 1996, are 350 MW of electricity and steam.

In the 1970s, British Gas Corporation (BG) and Lurgi developed a slagging moving bed gasifier that is referred to as the BGL gasifier. The fusion point of the ash is exceeded in the BGL. BGL gasifiers are being installed in several plants that use solid waste or a mixture of coal and sludge as the feedstock.

Commercial scale fluidized bed gasifiers are rare today. They only accept solid fuels and are best suited to fairly reactive fuels such as biomass. An advantage of the fluidized bed gasifier is the ability to process a wide range of solid fuels, including municipal solid waste (MSW). High ash coals are also best suited for the fluidized bed process.

There is a fluidized bed gasification project under development in the Czech Republic using lignite as the feedstock. It has a projected commercial operation date of 2003 and will produce 400 MW. It employs the High Temperature Winkler (HTW) fluidized bed gasification process. This HTW gasifier will be at the same location as the Lurgi dry ash gasifier discussed above.

2.2.4 Conceptual Design Used for this Study

The design selected for this study utilizes the Texaco Coal Gasification Process. It consists of a nominal 250 MW unit with a single train consisting of one air separation unit (ASU), one Texaco coal gasifier, and a 1x1 combined cycle with a GE 7FA combustion turbine. The Texaco coal gasifier is a quench type.

The raw syngas will be treated to remove particulate, ammonia, and sulfur prior to combustion. The clean syngas will be diluted with nitrogen and water vapor to enhance combustion turbine efficiency and control NOx to less than 17 ppmv (dry at 15% O2) in the flue gas. Flyash, slag, and sulfur will be saleable byproducts from gasification. Plant cooling will be provided by a cooling tower.

Estimated IGCC unit power ramp rates are:

- 3.5% load change in 5 seconds
- 5% load change in 30 seconds

- 40% load change at 3% load change per minute

The 3% load change per minute required to achieve a 40% load change is the gasifier ramp rate.

A cold plant startup takes about one day. A hot restart takes approximately 6 hours. The cold restart assumes the Air Separation Unit is already operating. Cool down of the Air Separation Unit takes an additional 24 hours.

2.2.5 Performance Estimates

Performance, Availability, and Emissions estimates for the 250 MW IGCC Unit are presented in Table 4-3. Estimates are provided for a single gasifier and two gasifiers (one operating and one spare).Unit performance is based on a site elevation of 172 feet and an ambient temperature of 72 F. As can be seen, the net plant heat rate based on higher heating value (HHV) of the fuel is about 9,100 btu/kWh.

Long term IGCC unit availability is expected to reach 85% for one gasifier. Commercial IGCC unit availability has been much less primarily during the first several years of operation. Experience gained from coal IGCC plants that have been operating since the mid-1990s will allow new IGCC plants to have higher availabilities. Long term IGCC unit forced outage rates are expected to range from 7 to 10%. The gas turbine(s) can operate on backup fuel when syngas is not available. The CC availability is expected to exceed 90%. A second, spare gasifier can increase IGCC unit availability above 90%.

The CO and NOx emissions estimates are based on current GE guarantees for their 7FA gas turbines firing syngas with nitrogen dilution without SCR or CO oxidation catalyst in the HRSG:

25 ppmvd CO in the gas turbine exhaust gas

25 ppmvd NOx (at 15%v O2) in gas turbine exhaust gas

The SO2 emissions estimate is based on 25 ppm total molar concentration of sulfur as H2S and COS in the syngas to the gas turbine. Overall IGCC unit sulfur removal efficiency is 98%.

2.2.6 Cost Estimates

The project includes all site, plant, and other facilities required in connection with an electric generating unit, excluding the plant substation. The power termination point is at the high side of the step-up transformer. All site development, structures, equipment, auxiliaries and accessories, piping, raceway, wiring and controls, and other facilities required for the complete unit are included.

The estimated capital cost of the plant studied is approximately $511.5 million. The estimate is summarized in Table 4-4.

Owner's cost for initial plant startup is estimated to be approximately $43 million and includes:

- Staff during construction, commissioning, and startup
- Utilities during construction, commissioning, and startup
- Coal, fuel oil, and natural gas during commissioning and startup
- Initial warehouse inventory excluding capital spares
- Out-of-scope plant modifications required to make the plant work

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The total O&M cost is estimated to be approximately $12 to $13/MWh. The O&M costs are tabulated in Table 4-5

2.3 Cost of Delaying Deerhaven Unit 3 by One Year

2.3.1 Impact to Capital Cost

To illustrate the uncertainty of future cost increases due to escalation rates, B&V estimated low, expected and high weighted-average composite annual escalation rates. The results are as follows:

- Low composite escalation rate – 2.1%
- Expected composite escalation rate – 2.7%
- High composite escalation rate – 3.7%

Applying those rates to the line items of the estimate results in the following,

Escalation Rate Case	Capital Cost increase
Low composite escalation rate	$11,312,000
Expected composite escalation rate	$15,021,000
High composite escalation rate	$21,670,000

The "expected" cost increase is estimated to be approximately $15 million.

2.3.2 Expected Trend in Replacement Power Cost

The spot market price for electricity in the State of Florida in 2011 will be a function of the following factors:

- State-wide load growth
- The mix of generating technologies in the State at the time (Steam, combustion turbine, combined cycle, diesel, etc.) and their efficiencies
- The fuel mix at the time
- The then current regulatory structure in the State (the existence of Retail Access or the continued operation of regulated monopolies).

Projected load growth in Florida, based on the compiled Ten Year Site Plans of the State utilities, amounts to an average of 2.5 percent per year between 2003 and 2011. Actual load growth may be higher given the historical tendency of the State utilities to under-forecast load. Current plans by State utilities to meet forecast growth call for the following additions to the existing generating mix:

- 11.5 GW of new combined cycle capacity
- 3 GW of repowerings or capacity additions at existing combined cycle sites
- 4.8 GW of new simple cycle combustion turbine capacity
- 0.3 GW of new coal capacity

In addition, the following capacity reductions are called for in State utility plans

- 1.1 GW of coal capacity retirements
- 1 GW of firm contract reductions

Implicit in the technology mix trend above is an increase in the percentage of State generating capacity that is dependent upon oil or natural gas. Approximately 65 percent of the State's capacity was oil or gas fuelled in 2003 increasing to 76 percent by 2011.

The average price of natural gas delivered to electric utilities in Florida in 2003 was $5.70/MBtu. A typical price of coal delivered to Florida utilities in 2003 was $1.81/MBtu. While several Florida utilities expect a correction in gas prices and a decrease in even the nominal delivered price of gas by 2011, a few utilities expect the price to climb even higher from 2003 levels. Expectations regarding the future direction of coal prices are far more consistent among the utilities; however, coal prices are no longer relevant to the spot price of electricity in 2011 because without additional coal capacity additions coal will cease to be "on the margin" any hours by 2011.

A check of the long-term forecast of natural gas prices in the US Department of Energy's 2004 Annual Energy Outlook appears to imply relatively level natural gas prices in nominal terms between 2003 and 2011 (meaning the price declines in real terms). The DOE price trend of zero nominal escalation in gas prices from 2003 through 2011 was used as the basis for the following forecast of spot market electric prices.

The forecast of 2011 spot market electric prices in Florida was initiated with a benchmark forecast of 2003 prices. Given the 2003 technology mix and State-wide loads, it was apparent that in 2003 coal steam units were on the margin approximately 17 percent of the time, combined cycle units were on the margin approximately 63 percent of the time, oil/gas steam units were on the margin 18 percent of the time and simple cycle combustion turbines and diesels were on the margin approximately 2 percent of the time. Based on typical operating heat rates and variable non-fuel O&M costs for each of these technologies and the fuel prices cited above, an average annual market energy price of $44/MWh was produced. Such a price is very consistent with short-term market forecasts posted by the electric market modeling company, HESI, and are consistent with earlier detailed Black & Veatch market forecasts after adjustment for the actual 2003 increase in natural gas prices.

Applying the 2011 capacity mix to the forecast loads for 2011, yields a forecast of 86 percent of the hours when combined cycle capacity will then be on the margin, 11 percent of the time when oil/gas steam capacity will be on the margin and 3 percent of the time when simple cycle combustion turbine and diesels are on the margin. The resultant annual average spot market price for electricity when projected gas prices are applied is $47/MWh in 2011. The forecast hourly price will vary throughout the year as a function of variations in the delivered price of natural gas while combined cycle units are the market makers and they will easily reach as high as $120/MWh when simple cycle combustion turbines with high start-up costs are started to meet short-lived spikes in the demand for power.

Because the average annual spot price of $47/MWh is based on the marginal operating costs of the last units dispatched to meet load each hour, it does not include a capacity component which may be included in the market price if either the Florida utilities are not required to maintain a required reserve margin by 2011 or if retail access eliminates the assurance of regulated returns. In either case, an equilibrium market price that will sustain investment in new generating capacity to meet growth must also include the marginal cost of capacity based on the cost of constructing new simple cycle combustion turbines. By 2011, the amortized cost of that capacity is estimated to be approximately $70/kW-yr or $8/MWh on an average annual basis bringing the total average annual 2011 market price to $55/MWh.

For the most part, capacity prices are extracted during peak hours during peak demand seasons rather than being charged equally each hour during the year. Prices during those periods are generally far higher than the marginal-cost-based prices discussed previously. In addition, should 2011 be a year of capacity deficiency in the market as were the years 1998-2001, market prices could rise many times higher than any of the equilibrium prices described above.

3.0 INCORPORATING BIOMASS FUEL INTO THE GENERATION MIX

The objective of this study is to evaluate the potential for integration of biomass into the GRU generation mix. Biomass has been identified as a potential resource in the GRU Integrated Resource Planning process. Based on recent resource assessment studies, GRU is targeting the development of up to 30 MW of biomass either as a new stand-alone unit or integrated into existing and/or planned units at Deerhaven. Black & Veatch has prepared this assessment to assist GRU in characterizing biomass options. Following a brief introduction to biomass, the sections of this report include:

- Review of Previous Work
- Review of Biomass Fuel Resources
- Concept Selection Process
- Conceptual Design
- Development of Performance Estimates
- Development of Cost Estimates
- Summary Results and Conclusions

Biomass has been used as an energy source for more than 1 million years. Even today, about 11 percent of the world's primary energy comes from biomass, according to the International Energy Agency. In the United States, which has the highest installed biomass power capacity in the world, biomass provides nearly 10 GW of power to the grid and is the largest non-hydro renewable resource. Biomass is one of the very few large, near-term, cost-competitive renewable energy options for Florida.

Biomass is any material of recent biological origin. Wood is the most common biomass fuel. Other biomass fuels include agricultural residues, dried manure and sewage sludge, black liquor, and dedicated fuel crops such as switchgrass and coppiced willow. There are also many municipal waste burners installed throughout the world. However, the construction of new municipal waste combustion plants has become almost impossible in the United States due to environmental concerns regarding toxic air emissions.

Compared to coal, biomass fuels are generally less dense, have a lower energy content, and are more difficult to handle. With some exceptions, these qualities generally economically disadvantage biomass compared to fossil fuels. But environmental benefits help make biomass an economically competitive fuel. Unlike fossil fuels, biomass is viewed as a carbon-neutral power generation option. While carbon dioxide is emitted during biomass combustion, an equal amount of carbon dioxide is absorbed from the atmosphere during the biomass growth phase. Thus, biomass fuels "recycle" atmospheric carbon, minimizing its global warming impact. Further, biomass fuels contain little sulfur compared to coal, and so produce less sulfur dioxide. Finally, unlike coal, biomass fuels typically contain only trace amounts of toxic metals, such as mercury, cadmium, and lead.

3.1 Review of Previous Work

Black & Veatch reviewed two documents that were previously written for GRU's planning efforts. These two documents were:

- Integrated Resource Plan - Alternatives for Meeting Gainesville's Electrical Requirements Through 2022, December 2003
- Wood Resource Assessment - "Biomass Options for GRU – Part II", November 2003

The wood resource assessment is discussed in detail in the next section. This section provides an overview of the integrated resource plan (IRP) as it relates to biomass.

GRU performed an integrated resource planning exercise to determine an optimal plan to meet their long term energy needs through 2022. The energy resources that were examined included solar, coal, petroleum coke and biomass. The IRP outlined the need for additional power generation capacity and identified a new 220 MW solid fuel power plant located at the existing Deerhaven site as a leading option. In addition, biomass was determined to be technically suitable to generate 30 MW of electrical capacity. Integrating biomass as a power generation strategy would lessen GRU's dependence on fossil fuels while achieving net emissions reductions. Simultaneously, there would be significant local job creation resulting from the fuel collection and transportation required for the project.

Previous to the IRP, a biomass resource assessment had been completed and it showed that there are sufficient resources locally available to generate at least 30 MW. The IRP indicated that the delivered biomass fuel price is estimated to be in the range of $13-22/ton. The biomass supply exhibits very little seasonality, making it a fairly dependable fuel. The ash was shown to have considerable value, ranging between $50 and 60/ton. The findings of this study are generally in agreement (Section 3.2); however, biomass ash would not be recoverable if biomass is directly cofired with fossil fuels.

There are numerous technologies suitable for generation power from biomass at this scale. One technology approach suggested by the IRP is construction of a stand alone biomass boiler that would generate supplemental steam for an existing steam turbine. The IRP adopted this approach based upon a perception that biomass cofiring is an emerging technology. GRU correctly states that cofiring can result in fuel feeding issues, increased corrosion, and reduce capacity. However, there are strategies that can alleviate these issues and there are numerous boilers that have successfully blended biomass and fossil fuels for many years. Direct cofiring can be economically and technically advantageous and encourages GRU to continue exploring both standalone and cofired biomass project options. Technology selection issues are explored further in Section 3.3.

In summary, GRU found that biomass ranked highly behind coal and energy conservation as a means to meet their long term capacity demands. They also found that biomass may not be the optimal fuel to completely satisfy the long term demand, but can play an important role in their overall portfolio. One of the primary findings is that biomass is suitable for further investigation. This report will provide further insight for GRU that will assist in determining the overall role that biomass can play in GRU's long term planning efforts.

3.2 Review of Biomass Fuel Resource Assessment

Biomass resource availability and cost are the primary drivers of biomass project economics. Wood, wood waste, and black liquor are the primary biomass resources and are typically concentrated in areas of high forest products industry activity. In rural areas the agricultural economy can produce significant fuel resources that may be collected and burned in biomass plants. These resources include corn stover, rice hulls, wheat straw, poultry litter, and other agricultural residues. Energy crops, such as switchgrass and short rotation woody crops, have also been identified as potential biomass sources. In urban areas, a biomass project might burn wood wastes such as construction debris, pallets, yard and tree trimmings, and railroad ties. Generally, availability of sufficient quantities of biomass is not as large of a concern as delivering the biomass to the power plant at a reasonable price.

Proper resource assessment is critical to project viability. This section provides an overview of biomass resources for possible utilization by GRU. This section is not meant to serve as a resource assessment for the biomass project, but is rather a review of work done by others. Black & Veatch has reviewed publicly available literature and a report that was prepared for GRU to assess the quantity and cost of biomass fuel material available in the Gainesville area. In addition, the discussion provided here will cover seasonal availability, fuel properties, collection and delivery methods.

3.2.1 Review of "Biomass Options for GRU – Part II"

GRU commissioned a report in 2003 by Don Post and Tom Cunilio titled "Biomass Options for GRU – Part II." This report was a follow-up to a 1998 report that assessed the biomass resource potential of the area around Gainesville. The focus of the new report was investigation of five resources:

- Residues from forestry activity
- Urban tree trimming waste

- Construction and demolition debris
- Energy crops
- Permitted wood burning operations

The results of the study for each of these categories are summarized and reviewed below.

3.2.1.1 Residues from Forest Activity

There is a very large amount of land around Gainesville with active forest activity. When trees are harvested, the non-commercial tops and branches are typically left behind. This is a potentially large biomass resource. The forest resources around Gainesville are varied, but consisted primarily of four species of trees. The analysis was based on the gross estimated forested area of each species. An average weight density per unit area for each species was applied to the estimated area and then an annual mass yield was estimated based on forestry practices typical of the region. The forest types investigated were:

- Planted Soft Pine
- Upland Hardwood
- Oak-Pine
- Natural Pine

Post and Cunilio used numerous assumptions regarding yields, harvest cycles, heating value, etc. to estimate how much energy could be collected or harvested from forest residues within a 25 mile radius of Gainesville. The 25 mile radius assumption is conservative. It is common for biomass facilities to source supplies from as much as 100 miles away from the facility. A collection area with a 100 mile radius is 16 times larger than a 25 mile radius collection area.

These forestry residue estimates are shown in Table 3-1. Note that the resource in the second line of Table 3-1 is the stumps from the pine trees in the first line. The practicality of collecting this resource seems limited. Black & Veatch has reviewed the energy yield calculations provided in the report and would suggest that the calculations need to be slightly revised, primarily to account for the moisture content of the forest residues. These revised estimates are shown in the last column of Table 3-1. Even at these reduced energy yields, available forestry residues alone could provide enough fuel for a 35 MW stand-alone biomass plant or cofiring 50 MW of biomass in a large, high-efficiency coal plant. The report did not specifically provide discussion of what the expected fuel prices might be. This should remain an issue for investigation if forest residues are to be considered as a primary fuel for a biomass plant.

Table 3-1. Forestry Residue Energy Yield Estimates.

Forest Type	Residue Yield, wet tons/day	Moisture Content, percent	Higher Heating Value, Btu/lb	Energy Yield MBtu/day	
				Post and Cunilio	Black & Veatch
Planted Soft Pine	226	25	9,000	4,084	3,051
Planted Soft Pine – Stumps	480	40	9,000	8,640	5,184
Upland Hardwood	198	25	8,000	3,564	2,376
Oak-Pine	52	25	8,500	936	663
Natural Pine	28.2	25	9,000	506	381
Totals	984.2	--	--	17,730	11,654

Source: "Biomass Options for GRU – Part II.", Post and Cunilio, 2003.

3.2.1.2 Urban Tree Trimming Wastes

The second wood resource evaluated by Post and Cunilio was urban tree trimming waste. This waste stream results from urban landscaping activities in which trees and limbs are removed by tree trimming services. The waste is nearly always chipped at the site of the removal and will be of relatively high moisture content (50 percent) unless allowed to air dry for a number of months. Post and Cunilio determined that there are four primary suppliers in the Gainesville area. These are summarized in Table 3-2.

Table 3-2. Gainesville Urban Tree Trimming Waste Sources.

Supplier	Production, wet tons/day	Price	Notes
ABC Tree Service	35	N/A	10 tons in chips; 25 tons in bulk
Gaston's	60	$10/ton	Mulch, fuel wood, compost
Ocala Tree Debris	140	$10/ton, fob	Fuel wood 4-6" screen
Southern Fuel Wood	20	N/A	Curb side pick-up not chipped
Totals	255		

Source: "Biomass Options for GRU – Part II.", Post and Cunilio, 2003.

Alternative markets for this fuel are limited. It is not clear whether the price indicated was intended to include delivery. It is also not clear whether the material that these four companies sell might contain high moisture, leafy materials. Leaves are undesirable and should be avoided, if possible. If these fuels are of reasonable quality, and the prices include delivery, then these resources may be of value to GRU.

3.2.1.3 Clearing, Construction and Demolition Debris

Construction and demolition debris typically includes clean dimensional scrap lumber. In this case, Post and Cunilio include only the trees and limbs that are removed from construction sites during land clearing operations. Two sources were named and together they seem to generate a significant amount of wood waste. A total of around 165 tons per day is estimated to be available from both Watson Construction and Osteen Brothers. GRU may also be able to supply up to 20 tons/day from its utility line clearing operations. The wood would likely be primarily hardwood with a heat content of 8,500 to 9,000 Btu/lb (dry-basis). Post and Cunilio suggest that the wood will be air dried with a moisture content of about 25 percent. However, it seems plausible that suppliers will minimize the amount of time between land clearing and deliveries to GRU, which will result in higher moisture content (around 50 percent).

Suppliers did not provide a specific price, but suggested that the price may only be that of the cost to chipping and screening. Alternative markets for this fuel are limited.

It seems likely that this production may decline when the new start housing market subsides. Additionally, this production may have some seasonality that the other resources will likely not exhibit. Finally, these suppliers may be difficult to lock into fuel supply contracts as they may be reluctant to depart from their primary business (construction) to provide fuel for a power plant.

3.2.1.4 Energy Crops

Post and Cunilio included a discussion of dedicated energy crops in their report. They divided the crops into two major categories: grasses and woody species. They provided a cost and production table which is shown in Table 3-3.

Table 3-3. Biomass Crops and Their Fuel Characteristics.

Crop	Yield, dry tons/acre	Cost, $/ton	Moisture, percent	Heating value, Btu/lb*
Grasses				
Elephant grass	16-22	24.94	22	8,178
Energy Cane	11.7-19	Nd	Nd	Nd
Sugarcane	15-25	22.92	16.8	8,668
Switchgrass	9-10	17.00	15	8,000
E-grass	Nd	Nd	Nd	Nd
Woody Species				
Giant Lucucaena	12-15	15-20	35	8,494
Cottonwood	12.5	32.67	35	4,728
Eucalyptus	11-15	35.00	35	8,370
Slash Pine	6-9	33-45	35	9,000
Summary	14	$25.79	27.6	7,920

Source: “Biomass Options for GRU – Part II.”, Post and Cunilio, 2003.
* Moisture, ash-free basis.

Post and Cunilio indicated that there are 75,368 acres of agricultural land that could be used to produce energy crops. It is unclear whether this land is currently available or if it is being planted with other, perhaps, more profitable crops that would preclude its use for energy crops. Assuming a yield of 14 dry tons per acre, Post and Cunilio estimated that if 25 percent of the available crop land were planted with energy crops, 722 tons per day of energy crops could be harvested. The estimated cost for Discussion of these results is provided later in this report.

3.2.1.5 Permitted Wood Burning Operations

Post and Cunilio point out that there may be opportunities to collect wood waste from areas that are being permitted for controlled fuel reduction burns. This resource is relatively unquantified and therefore not subjected to analysis here. Given the robust forestry industry in the region, if the areas that are being permitted for controlled burning could be profitably harvested for forest applications they would be. As GRU will likely place a lower value on wood resources than the local forest industries, this may be an economic niche for potential fuel wood. It is possible, as they indicate, that there could be opportunities through the Healthy Forest Initiative that would allow GRU or a fuel contractor to harvest the fuel on these otherwise unprofitable lands.

3.2.1.6 Summary

Table 3-4 summarizes the findings of the Post and Cunilio report with relative pricing as estimated by Black & Veatch. Prices on the low end of the range are likely to be around $10/wet ton up to and above $30/wet ton for the highest price fuels (energy crops).

Table 3-4. Summary of Biomass Availability from Post and Cunilio Report.

Source	Availability, wet tons day	Relative Price
Forestry residues	504	Moderate
Forestry residues -- stumps	480	High
Urban tree trimming	255	Low
Land clearing	185	Low
Energy crops=	722	Highest
Total	2,146	

The Post and Cunilio report identified 2,146 wet tons per day of biomass residue available within the immediate Gainesville area (25 mile radius). The preferred option for biomass utilization for this study requires on the order of 600 wet tons day.

The Post and Cunilio report has left out several potentially viable, low-cost biomass sources. Although an assessment of their potential is not included the scope of this project, they are listed for possible future investigation:

- Dried sewage sludge
- Primary and secondary wood products residues (sawmills, furniture factories, etc.)
- Landfill diverted clean wood waste (pallets, crates, construction debris, etc.)
- Selected agricultural residues (orchard prunings, poultry litter, straw, etc.)

3.2.2 Review of Other Publicly Available Sources

3.2.2.1 Oak Ridge National Laboratory Biomass Supply Curves

The US Department of Energy Oak Ridge National Laboratory (ORNL) has researched the availability and cost of biomass fuels for many years. Recently, they published a study that shows county level resource data for biomass. For every county in the US, they have estimated the quantities and costs of various biomass fuels. ORNL provides the resource data by setting constant price intervals and estimating how much biomass fuel is available in or within a certain distance of a specific county at those set price intervals. Black & Veatch investigated their assessment of the available biomass fuels in the area surrounding Alachua County. Resource assessments for 25 and 50 mile radii around Alachua County are provided in Table 3-5.

Table 3-5. ORNL Estimates of Biomass Available near Alachua County, dry tons/day.

Resource	Cost per dry ton ($2003)						
	$20	**$25**	**$30**	**$35**	**$40**	**$45**	**$50**
25 Mile Radius, dry tons/day							
Corn Stover	0	0	2	2	2	2	2
Hardwood - Cull Wood	30	238	375	386	386	400	405
Hybrid Poplar - Wildlife CRP	0	0	0	0	1	1	1
Softwood - Cull Wood	19	47	60	60	63	63	66
Softwood - Forest Logging Residue	0	16	52	55	55	55	55
Switchgrass – Cropped	0	0	0	38	38	38	38
Switchgrass – Idle	0	0	0	0	16	16	16
Switchgrass – Pasture	0	0	0	0	68	68	68
Switchgrass - Production CRP	0	0	0	0	1	1	1
50 Mile Radius, dry tons/day							
Corn Stover	0	0	1,893	1,893	1,893	1,893	1,893
Hardwood - Cull Wood	345	2,808	4,422	4,537	4,559	4,701	4,762
Hybrid Poplar - Wildlife CRP	0	0	0	0	47	47	47
Softwood - Cull Wood	99	249	321	329	334	342	345
Softwood - Forest Logging Residue	0	96	329	342	342	342	342
Switchgrass – Cropped	0	0	0	184	200	200	200
Switchgrass – Idle	0	0	0	0	71	71	71
Switchgrass – Pasture	0	0	0	0	268	340	340
Switchgrass - Production CRP	0	0	0	0	36	36	36
Source: Oak Ridge National Laboratory.							

Table 3-6. Bases of ORNL Biomass Resource Cost and Availability Data.

Biomass Resource	Feedstock description (dry tons)	Year$	Notes
Hardwood - Cull Wood	Chips in van in forest.	2000$	Cost includes collection, harvesting, c for risk and profit, and stumpage fee. branches, and leaves.
Hybrid Poplar - Wildlife CRP	Chips in van hooked to truck at the side of field. Field was previously in CRP. Poplar production was managed for wildlife considerations.	1997$	Price encompasses profit needed to co crops and costs of production and har
Softwood -Cull Wood	Chips in van in forest	2000$	Cost includes collection, harvesting, c for risk and profit, and stumpage fee. branches, leaves.
Softwood – Forest Logging Residues	Chips in van in forest	2000$	Cost includes collection, harvesting, c for risk and profit, and stumpage fee. branches, and leaves.
Switchgrass - Cropped	Round bales with twine at edge of field. Field was previously used for conventional crops.	1997$	Price encompasses profit needed to co crops and costs of production and har
Switchgrass – Idle	Round bales with twine at edge of field. Field was previously idle.	1997$	Price encompasses profit needed to co crops and costs of production and har
Switchgrass – Pasture	Round bales with twine at edge of field. Field was previously used for pasture.	1997$	Price encompasses profit needed to co crops and costs of production and har
Switchgrass - Production CRP	Round bales with twine at edge of field. Field was previously in CRP.	1997$	Price encompasses profit needed to co crops and costs of production and har
Corn Stover (unirrigated)	Round bales of corn stover (stem/leaves/cobs) with twine at edge of field	2002$	Cost includes nutrient replacement an variable).Supply has been constrained efficiency (75% of gross), and need to fed and wind erosion to tolerable losse moisture in rain-limited regions. Resid from irrigated corn in rain limited area

Source: Oak Ridge National Laboratory.

There seems to be adequate correlation between the two data sources for the softwood resource. Both point toward an available quantity just under 100,000 tons per year at a relatively low price (< $30/dry ton). However, there is large discrepancy between the opinions of how much hardwood might be available in the region. ORNL provides a higher estimate than do Post and Cunilio. The exact reason for this is not know; however, most of hardwood resource identified by ORNL is outside the Post and Cunilio search radius of 25 miles.

Another discrepancy is seen in the energy crop analyses between Post and Cunilio and ORNL. ORNL projects that there is a limited potential for energy crops less than $50/dry ton, although their survey did not include as many species as that of Post and Cunilio. In the experience of Black & Veatch, the ORNL data can be over-generalized because it was generated over the entire land area of the United States. However, the

ORNL methodology that is used has been subjected to peer review. While it projects a much more conservative answer than Post and Cunilio, it may well be more correct.

ORNL also identifies corn stover (corn stalks, cobs, and husks) as a major biomass resource within 50 miles. ORNL identifies nearly 2,000 dry tons per day available for less than $30/dry ton. This is an undelivered cost.

3.2.2.2 National Renewable Energy Laboratory – Urban Wood Waste Assessment

The National Renewable Energy Laboratory completed a study in November of 1998 that evaluated the urban wood waste resources in 30 cities across the United States.[1] Two of the cities evaluated were Macon-Warner Robins, GA and Lakeland-Winter Haven, FL. The results of these evaluations are presented as a point of comparison.

Urban wood waste is one of the lowest cost biomass resources because tipping fees can often be avoided if the material can be diverted from landfills. The classes of urban wood waste that were surveyed included municipal solid waste (MSW) wood, industrial wood, construction and demolition (C&D) wood. Briefly, these include:

MSW Wood	Industrial Wood	C&D Wood
Wood hauled with trash	Waste pallets	House construction waste
Yard waste	Truss manufacturing waste	Land clearing waste
Utility tree trimming	Wholesale lumber waste	
Tree service trimmings	Retail lumber waste	
	Woodworking waste	

Values for the quantities of the three classes of urban wood waste resources are provided in Table 3-7 for the national average computed in the study as well as the resource quantities local to the Macon and Lakeland areas. The table further states the percentage of each resource that is currently used as fuel. It should be noted that there is a trash burning power plant in Lakeland that likely accounts for the high fuel usage there. Finally, the table provides estimates of urban wood waste available in the Gainesville area based on the national averages and a population of 95,500 for Gainesville. This is a Black & Veatch estimate based on the NREL study.

It is difficult to compare these figures with those presented by Post and Cunilio because the definitions used are much more broadly developed for the NREL report. However, a comparison can be made based on the C&D category. Post and Cunilio estimated that 165 tons/per day are available from construction land clearing activities, while NREL estimates that only about 1/10 of that quantity would be available from all C&D sources.

[1] Wiltsee, G., “Urban Wood Waste Resource Assessment”, November 1998.

Table 3-7. NREL Urban Wood Waste Resource Estimate.

Location	Urban Wood Waste Production, ton/year/person			
	MSW Wood	Industrial Wood	C&D Wood	Totals
National Average	0.209	0.048	0.076	0.333
Macon-Warner Robins	0.267	0.027	0.053	0.347
Lakeland-Winter Haven	0.340	0.113	0.069	0.523
	Amount of Urban Wood Waste Used for Fuel, percent			
National Average	9.09	27.1	10.5	12.0
Macon-Warner Robins	0.0	66.7	0.0	5.2
Lakeland-Winter Haven	65.8	14.2	0.0	45.6
	Urban Wood Waste Production Estimate, tons/year			
Gainesville	20,000	4,580	7,260	31,840

Source: "Urban Wood Waste Resource Assessment," G. Wiltsee, National Renewable Energy Lab, November 1998.

3.2.3 Fuel Properties

On a moisture-free, ash-free basis, the composition of biomass is relatively consistent, with a higher heating value typically between 8,000 and 9,000 Btu/lb. Heating value is largely dependent on the moisture content of the fuel, and this can vary widely from below 10 percent to above 60 percent. Freshly cut wood is typically at least 50 percent moisture. Wood will burn in combustion devices at moisture contents up to 65 percent, although lower moisture is highly preferred. Given the wide variability in wood moisture content, it is strongly recommended that GRU procure wood on per Btu basis rather than on a per ton basis.

No fuel properties testing were done as part of this study. A typical wood fuel composition is provided in Table 3-8.

Table 3-8. Typical Waste Wood Ultimate Analysis.

Constituent	Percent weight
Carbon	32.4
Hydrogen	3.88
Sulfur	0.02
Oxygen	28.6
Nitrogen	0.17
Ash	3.21
Moisture	31.8
Higher Heating Value, Btu/lb	5,657

3.2.4 Seasonal Availability

With the exception of the wetter summer months, there should be little seasonality to the wood fuel supply in the Gainesville area. Typically, the months of June through August are the wettest and excessive rainfall can make access to forest lands difficult or impossible. It is likely that execution of proper fuel reserve strategies would be sufficient to prevent weather conditions from interrupting fuel supply significantly enough to force an outage.

3.2.5 Collection and Delivery Methods

The supply area for wood fuel will be limited to the immediate 50-100 miles around Gainesville. Because of this limited collection are, it should be assumed that all hauling and delivery will be performed with trucks.

It is recommended that the number of wood supply contracts be limited to a reasonable number. GRU may wish to procure at least 50 percent of its supplies through a few large contractors. The remainder of the wood should be collected, processed, and stored at wood depots scattered around the local area. It is recommended that operation of these depots be done through contractors. A small tipping fee could be charged to cover depot operation costs.

Wood fuel will be chipped and loaded into trucks for transport to the Deerhaven plant. The materials may require further sizing after size screening at the plant. The conceptual design for the plant includes minimal on-site storage capability: only 5 days. It is expected that most storage will be performed by outside suppliers.

3.2.6 Conclusions on Wood Supply

Despites some conflicts in the data, it appears that there is a large and sustainable quantity of biomass in the immediate Gainesville area to support a major biomass project. The Post and Cunilio report identified 2,146 wet tons per day of biomass residue available within the immediate Gainesville area (25 mile radius). The preferred option for biomass utilization for this study requires on the order of 600 wet tons day. Forestry residues from a 25 mile radius alone could provide enough fuel for a 35 MW stand-alone biomass plant or cofiring 50 MW of biomass in a large, high-efficiency coal plant. Further, data from ORNL seems to indicate that if the collection radius is extended to 50 miles, the available resources could be five times greater.

Unfortunately, fuel price is the largest variable and also the largest source of uncertainty. Urban wood waste will likely be the lowest cost resource (<$1/MBtu). The urban wood waste resource is somewhat limited in Gainesville, so average wood costs will likely be higher. It appears that logging residues will set a practical upper cap for the project. It seems reasonable to expect prices to range from $16-18/ton for delivered logging residues (50% moisture), which is similar in price for wood fuel deliveries to a local pulp mill. This cost is about $2/MBtu. In lieu of additional investigation and preliminary negotiations, a mid-range value of $1.50 may be appropriate. This is approximately $12.75/ton at 50% moisture (as-cut) and $17.85/ton at 30% moisture (air dried). Provided competing end uses do not arise, the price for biomass is expected to be stable in the near to long term. Competing end uses would include the opening of other biomass plants in the area.

3.3 Concept Selection Process

There is a huge variety of biomass resources, conversion technologies, and end products, as shown in the figure below. Biomass can be converted to end products as diverse as transportation fuels, chemicals, construction materials, and electric power. This report focuses on electricity generation technologies targeted to produce 30 MW net power.

The objective of this section is to introduce the potential biomass options, identify four leading alternatives, and then recommend one for further analysis.

Biomass Sources	Processing	Fuel Products	Markets
§ Forests	§ Drying	§ Solid Fuels	§ Electricity
- Natural regrowth	§ Extrusion	- Charcoal	§ Heat
- Energy forests	§ Compression	- Wood chips	§ Solid fuels e.g.(domestic)
- Forest residues	§ Chipping	- Pellets/ briquettes	§ Transport
- Processing residues	§ Carbonization	§ Gaseous fuels	
§ Agriculture	§ Anaerobic digestion	- Methane	
- Crop residues	§ Fermentation	- Pyrolysis gas	
- Processing residues	§ Gasification	- Producer gas	
- Energy crops	§ Pyrolysis	§ Liquid fuels	
§ Wastes	§ Fischer tropsch	- Plant esters/oils	
- Municipal	etc.processors	- Ethanol	
- Industrial		- Methanol/alcohols	
		- Pyrolysis liquids	
		- Other liquids	

Figure 3-1. Biomass Sources, Processing, Fuels and Markets (Renewable Energy World, Apr. 2003).

3.3.1 General Approach to Evaluation of Biomass Options

A wide variety of biomass technologies was considered for the screening process. For this analysis, biomass technologies were split into two groups: (1) stand alone plants that would be entirely new facilities dedicated to biomass electricity generation and (2) co-utilization applications that can be integrated into Deerhaven Generating Station, either in the existing gas/oil Unit 1, the existing coal Unit 2, or the planned coal/pet coke Unit 3.

For the stand alone options, four primary energy conversion processes were considered:

- **Anaerobic digestion** – microbial decomposition of organic material to produce methane.
- **Combustion** – complete oxidation (burning) of a fuel to release heat.
- **Gasification** – incomplete combustion of a fuel in a low oxygen environment to produce a combustible gas with a low to medium energy value.
- **Pyrolysis** – decomposition of a fuel by heat in the absence of oxygen to produce gas, oils, and char (carbon).

These basic conversion processes were combined with a number of different power generation devices (steam turbine, combustion turbine, reciprocating engine, Stirling engine, etc.) to generate the 17 stand alone options shown in Table 3-9.

For the co-utilization options, six basic energy conversion processes were considered:

- **Direct cofiring: blended/separate feed** – Biomass is directly burned in the coal boiler, either blended with coal feed prior to firing or injected as a separate feed.
- **Direct cofiring: torrefied wood** – Torrefied biomass is a product between raw wood and charcoal (see Figure 3-2). It can be readily pulverized in existing equipment and is a hydrophobic product. Torrefaction could be done off-site by a third party.
- **Indirect cofiring: gasification** – Combustible syngas produced by a biomass gasifier would be ducted to existing unit, possibly as a reburn gas for NO_x control.
- **Indirect cofiring: pyrolysis** – Pyrolysis produces a synthetic bio-oil as one of its products (see Figure 3-3). It is possible that the bio-oil could be fired in existing fuel oil burners at very low cost. As with torrefied wood, bio-oil could be produced offsite by a third party.
- **Indirect cofiring: separate boiler** – A separate biomass boiler is used to generate steam to inject into the main plant steam cycle at an appropriate location.
- **Indirect cofiring: separate combustor** – A separate biomass combustor is used to generate hot flue gas to inject into the main plant furnace at an appropriate location.

Figure 3-2. Torrefied Wood Chips (Source: Transnational Technology).

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

These processes were each evaluated for their suitability for integration with the gas/oil-fired Unit 1, the pulverized coal Unit 2, and the proposed Unit 3 (either pulverized coal or circulating fluidized bed). Table 3-9 shows the 24 co-utilization alternatives evaluated.

Table 3-9. Biomass Options Identified.

No	Technology	Technology Status	Location	Initial Rating	Comments
Stand Alone Options					
1	Stoker grate combustion	Commercial	Stand-alone	Very good	Most common biomass technology
2	Bubbling fluidized bed combustion	Commercial	Stand-alone	Good	Generally lower emissions than stoker combustion, but higher cost
3	Circulating fluidized bed combustion	Commercial	Stand-alone	Fair	More appropriate for larger units
4	Combustion based cogeneration	Commercial	Stand-alone	Fair	Sites may be limited based on IRP
5	Gasification close-coupled boiler	Commercial	Stand-alone	Fair	Very few advantages over direct combustion especially with wood fuel
6	Gasification with engine	Commercial	Stand-alone	Fair	Limited to smaller applications
7	Gasification combined cycle	Demonstration	Stand-alone	Fair	Recent difficulties with demonstration projects
8	Pyrolysis combined cycle	Development	Stand-alone	Fair	Good potential, but still in R&D stage
9	Pulverized fuel combustion	Commercial	Stand-alone	Poor	Not ideal with wood fuel
10	Anaerobic digestion	Demonstration	Stand-alone	Poor	Not proven at this scale with this feedstock
11	Pyrolysis with engine	Demonstration	Stand-alone	Poor	Suitable for smaller applications
12	Small modular biopower	Demonstration	Stand-alone	Poor	Technology generally still in early stages
13	Direct fired combustion turbine	Development	Stand-alone	Poor	Far-term technology
14	Indirect fired combustion turbine	Development	Stand-alone	Poor	Far-term technology
15	Stirling engine	Development	Stand-alone	Poor	Still under development, targeted at smaller applications
16	Whole-tree-energy combustion	Development	Stand-alone	Poor	Technology development has slowed substantially
17	Cellulosic ethanol production	Development	Stand-alone	Poor	Far-term technology targeted at transportation fuels
Cofiring Options					
18	Direct cofiring: blended/separate feed	Commercial	Unit 1	Poor	Unit 1 is gas/oil firied. Biomass ash would be a problem.
19	Direct cofiring: blended/separate feed	Commercial	Unit 2	Good	Up to 10% of heat input typically considered OK
20	Direct cofiring: blended/separate feed	Commercial	Unit 3 - PC	Good	Should be somewhat lower cost to integrate direct cofiring in new unit
21	Direct cofiring: blended/separate feed	Commercial	Unit 3 - CFB	Very good	A new CFB unit could be designed to have built-in fuel flexibility
22	Direct cofiring: torrefied wood	Development	Unit 1	Poor	Unit 1 is gas/oil firied. Biomass ash would be a problem.
23	Direct cofiring: torrefied wood	Development	Unit 2	Good	Could be easily blended with existing coal at minimal capital cost.
24	Direct cofiring: torrefied wood	Development	Unit 3 - PC	Good	same as above
25	Direct cofiring: torrefied wood	Development	Unit 3 - CFB	Poor	Torrefaction is unnecessary step for CFB
26	Indirect cofiring: gasification	Demonstration	Unit 1	Fair	Potential to totally repower unit
27	Indirect cofiring: pyrolysis	Development	Unit 1	Fair	Could make use of existing oil-firing equipment
28	Indirect cofiring: separate boiler	Commercial	Unit 1	Poor	High capital cost but only limited run hours
29	Indirect cofiring: separate combustor	Unknown	Unit 1	Poor	High capital cost but only limited run hours
30	Indirect cofiring: gasification	Demonstration	Unit 2	Good	Potential to use as reburn gas for NOx control is appealing
31	Indirect cofiring: pyrolysis	Development	Unit 2	Good	Could make use of existing oil-firing equipment
32	Indirect cofiring: separate boiler	Commercial	Unit 2	Good	Eliminates any negative impacts of biomass on existing equipment
33	Indirect cofiring: separate combustor	Unknown	Unit 2	Fair	Hot flue gas duct would be vary large
34	Indirect cofiring: gasification	Demonstration	Unit 3 - PC	Good	Potential to use as reburn gas for NOx control is appealing
35	Indirect cofiring: pyrolysis	Development	Unit 3 - PC	Fair	Could make use of oil-firing equipment
36	Indirect cofiring: separate boiler	Commercial	Unit 3 - PC	Fair	Seemingly better options
37	Indirect cofiring: separate combustor	Unknown	Unit 3 - PC	Poor	Hot flue gas duct would be vary large
38	Indirect cofiring: gasification	Demonstration	Unit 3 - CFB	Poor	Direct cofiring would be substantially lower cost with few disadvantages
39	Indirect cofiring: pyrolysis	Development	Unit 3 - CFB	Poor	same as above
40	Indirect cofiring: separate boiler	Commercial	Unit 3 - CFB	Poor	same as above
41	Indirect cofiring: separate combustor	Unknown	Unit 3 - CFB	Poor	same as above

Note: Above options may be used simultaneously for multiple units (for example cofiring 15 MW in both Unit 2 and the new Unit 3)

3.3.2 Findings: Preferred Options

Table 3-9 summarizes the 41 potential options evaluated for biomass utilization. Many of the options were excluded from further consideration for a variety of reasons:

- Technology is still under development (i.e. not technically proven) or is not currently commercially available.
- Technology is not compatible with the existing infrastructure (such as cofiring solid biomass in the oil/gas fired Unit 1).
- Option is not competitive economically (e.g. bubbling fluidized bed vs. stoker grate combustion).
- Application would be inappropriate at the 30 MW scale envisioned for this project (e.g. gasification with engine, small modular biopower).

Of the technology options identified, the following four options were determined to be the most technologically and economically advantageous.

Table 3-10. Top Biomass Options Evaluated.

No.	Description	Technology Status	Plant Location	Comments
1	Stoker Grate Combustion	Commercial	Stand Alone	Most common type of biomass technology.
19	Direct Cofiring – Blended / Separate Feed	Commercial	Unit 2	Up to 10 percent of heat input to the boiler is typically considered acceptable without significant impacts.
21	Direct Cofiring – Blended / Separate Feed	Commercial	Unit 3 – CFB Boiler	A new unit with a CFB boiler could be designed to have built-in fuel flexibility and burn a high percentage of biomass.
30	Indirect Cofiring – Gasification	Demonstration	Unit 2	Minimizes plant equipment impacts. Potential for use as a reburn gas for NO_x control is advantageous.

These four selected biomass technology options are discussed in further detail below.

3.3.2.1 Stand Alone Unit – Stoker Grate Combustion

A stand alone unit based on stoker grate combustion is the most common type of biomass power technology. Stokers have been used since the early half of the last century to generate power from wood waste. Combustion occurs on and above a grate generating steam to power a steam turbine. In most respects except scale, small biomass power plants are very similar to larger coal fired plants (see Figure 3-4).

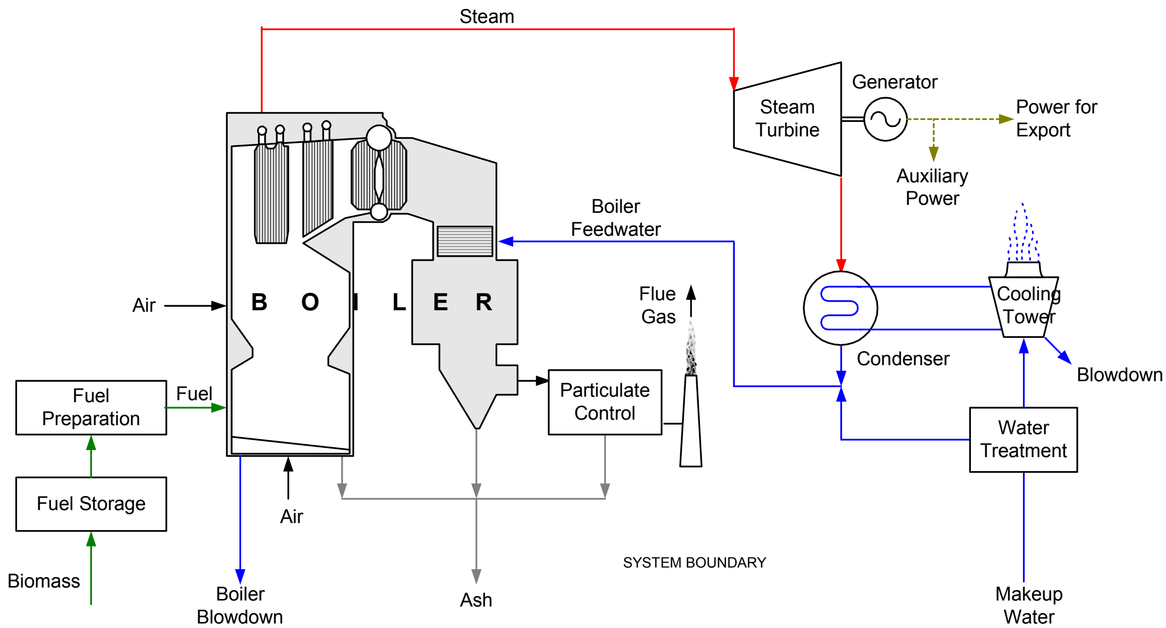

Figure 3-4. Typical Biomass Stoker Power Plant.

As a stand alone plant, the stoker option generates power from the biomass fuel (waste wood) independently of any of the other power generating units on site or in the GRU system. This has the advantage of not having any detrimental effects or impacts on the other units at Deerhaven Generating Station, such as increased slagging or reduced efficiency in the boiler. This option also has the advantage of the power plant, and in particular the boiler, being designed specifically for the particular biomass fuels to be burned. Further, it might be possible to locate the plant near a major source of the biomass fuel to reduce transportation costs.

The disadvantages of this technology are its higher cost and lower efficiency relative to cofiring. A stand alone unit will have a higher cost due to the amount of equipment and land that will be required when compared to retrofitting a much larger coal plant. The installed capital cost for this technology is typically $2,000 to $2,500 per kW net, with an operating efficiency of around 25 percent (14,000 Btu/kWh heat rate). The lower efficiency results in a greater quantity of wood required to generate the same power output. A stand alone plant would require approximately 870 tons per day of wood (at 30 percent moisture content) versus approximately 590 tons per day of wood for a cofiring system at a coal plant with a heat rate of around 9,500 Btu/kWh. This is an almost 50 percent increase in fuel requirements. In addition to the direct cost increase due to greater tonnage of fuel burned, it is possible that the average cost per ton burned will be higher for the stoker option. This is because higher price and/or more distant fuel sources will likely be needed to meet the larger fuel demand required by the stoker.

3.3.2.2 Direct Cofiring with Separate or Blended Feed in Unit 2

The second option is direct cofiring where wood fuel is burned in the existing 228 MW Unit 2 boiler with the regular coal fuel. Assuming no derating due to biomass, the wood fuel would contribute about 13 percent to the power output from the facility (30 / 228 MW). In practice, cofiring this much relatively high moisture biomass may result in a slight reduction in unit efficiency and capacity.

This option would require modifications to the Unit 2 boiler and would require a separate material handling system and storage system. The waste wood could be stored in one or multiple piles or could be stored off-site for just-in-time delivery. Covered storage to keep fuel dry is typically not practiced, although this is an option. The wood would be required to be pulverized, either in the existing coal pulverizers or in new dedicated mills designed just for biomass. The later is more likely given the volume of wood being considered. The waste wood fuel can be blended, or mixed-in, with the coal fuel or it can be injected as a separate feed into the boiler. Modifications to the existing boiler would be required for the injection of the waste wood fuel into the boiler. The Unit 2 boiler is a Riley dry-bottom, balanced draft, wall-fired turbo furnace unit with 18 burners in an opposed firing arrangement. The boiler modifications would include the installation of new injection ports for the waste wood fuel, along with the associated piping, valves, dampers, electrical equipment, and control system modifications.

There are several advantages to cofiring wood in the Unit 2 boiler. One of the greatest advantages of this method is that the capital cost is much lower than a stand alone biomass plant because less new equipment and land are required. The installed capital cost for this technology is typically \$300 to \$400 per kW net[2]. Also, as discussed above, the efficiency in cofiring applications is much higher than stand alone biomass plants. Cofiring in Unit 2 would be up to 50 percent more efficient than what could be obtained in a new stoker. Further, the cofiring project will have some positive impacts on Unit 2 operations. Cofiring the relatively clean biomass material in the Unit 2 boiler will likely result in reduced NO_x, CO_2, SO_2, and heavy metal (including mercury) emissions. These reductions may reduce the size and cost of planned air quality control equipment. For example, wood typically has very little sulfur. By cofiring 13 percent wood, Unit 2 sulfur emissions will be reduced nearly proportionately. Finally, it may be possible to obtain biomass at a lower cost than the coal currently being burned in Unit 2. This would lead to annual savings to help offset the initial capital investment for the cofiring equipment.

However, there are significant concerns with cofiring wood at this high of a rate in Unit 2. These include:

- Negative impact on plant capacity
- Negative impact on boiler performance
- Ash contamination impacting ability to sell coal ash
- Increased operation and maintenance costs
- Minimal NO_x reduction potential (usually proportional to biomass heat input)
- Boiler fouling/slagging due to high alkali in biomass ash (more of a concern with fast growing biomass, such as energy crops)

[2] Cost is given per kW of net biomass replacement capacity. For example, a 30 MW net biomass cofiring project at \$300/kW would have an initial cost of \$9,000,000.

- Potentially negative impacts on selective catalytic reduction air pollution control equipment (catalyst poisoning)

Specific impacts are difficult to predict without modeling the boiler (using a program such as Black & Veatch's VISTA); however, they are enough of a concern to warrant consideration of lower impact alternatives, such as indirect cofiring based on gasification. This is explored further below.

3.3.2.3 Indirect Cofiring via Gasification in Unit 2

An alternative to direct cofiring in Unit 2 is an indirect cofiring option where the wood fuel is first gasified before injection into the Unit 2 boiler. This option uses a process that converts the waste wood into a clean syngas for cofiring in the Unit 2 boiler. Under the right conditions, the gas can also be used as a reburn gas in the Unit 2 boiler to further reduce NO_x.

The biomass material would first be sized before being injected into a fluidized bed gasifier where the waste wood would be converted into hot syngas (see figure). The syngas could then be passed through a hot gas cyclone separator to remove particulate matter before it is injected into the Unit 2 boiler. The cyclone is optional and is recommended for biomass fuels high in ash or alkali matter. These are generally not a concern with clean wood residues.

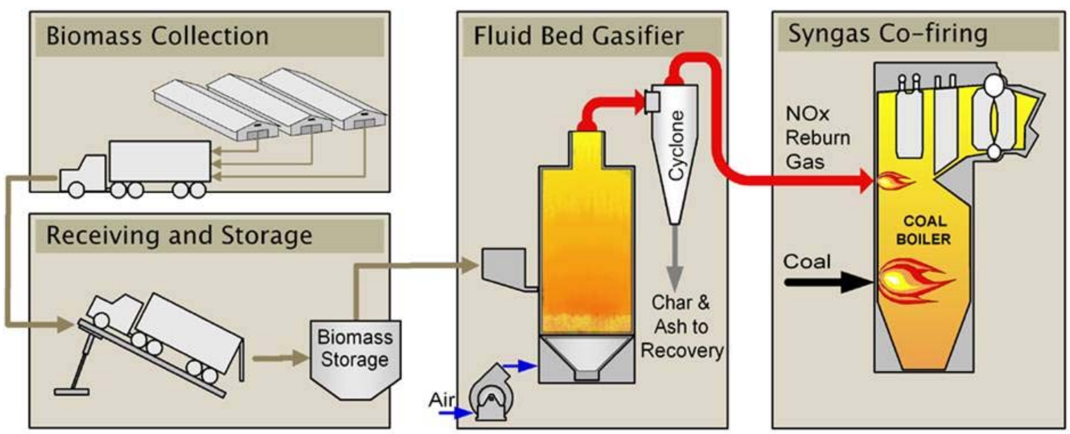

Figure 3-5. Indirect Cofiring based on Biomass Gasification.

The advantage of this option over direct cofiring is that negative effects on the boiler due to biomass ash (such as slagging, ash contamination, etc.) can be minimized. In addition, studies by Black & Veatch have predicted that boiler capacity and efficiency will not be negatively impacted with this approach and could possibly be improved. Additional burners would need to be installed in the boiler and could be used for NO_x reburn in the boiler furnace, if desired, to further reduce the amount of NO_x generated in the boiler. Boiler modeling would need to be performed to accurately predict the potential NO_x reduction due to reburning. As with the direct cofiring approach, this option could reduce the need for new air quality control equipment for Unit 2.

The main disadvantage of this option is the additional equipment and land area required to gasify the waste wood material, which results in a higher cost than simpler cofiring approaches. Further, this technology is not as well developed as the direct cofiring or stand alone options discussed above and therefore has greater risk. (There are a few reference projects currently operating.) However, the U.S. Department of Energy and other organizations are heavily promoting gasification and grant funding may be available to reduce the risk exposure to GRU. The installed capital cost for this technology is typically $400 to $700 per kW net (biomass capacity).

3.3.2.4 Direct Cofiring in New Unit 3 CFB Combustor

The final option considered is direct cofiring wood with coal and pet coke in the planned 220 MW Unit 3 CFB. Generating 30 MW using biomass fuel would result in approximately 13.6 percent of the power output from Unit 3 being derived from the wood. This option would allow the specifications for the Unit 3 boiler to incorporate the biomass fuel in the initial design process, most likely resulting in a higher operating efficiency when compared to the modification of the Unit 2 boiler, with lower operational and maintenance impacts.

The preferred Unit 3 boiler design would be a circulating fluidized bed boiler because this design provides the best fuel burning flexibility. Foster Wheeler has indicated that their CFB design could readily handle up to 50 percent wood heat input. There are similar sized CFBs around the world that burn a wide variety of fuels, including biomass. An example is the 240 MW CFB owned by Alholmens Kraft Oy in Finland which burns a mix of wood, peat and lignite. This unit was supplied by Kvaerner Pulping and was commissioned in 2001. The plant is shown in Figure 3-6.

Figure 3-6. Alholmens Kraft Multi-Fuel CFB (Source: Kvaerner).

A separate material handling system and storage system will likely be required. The waste wood fuel can be blended, or mixed-in, with the coal fuel or it can be injected as a separate feed into the boiler.

As with the other cofiring options, emissions relative to 100 percent fossil fuel firing will be reduced. However, significant reductions in NO_x may not be experienced due to the already inherently low NO_x emissions of the CFB design. This is one of the few disadvantages of this option compared to the other cofiring approaches.

The cost for this option will likely be the lowest of all the options considered due to the integration with the new unit. The installed capital cost for this technology will be significantly less than the direct cofiring option for Unit 2 at approximately $100 to $200 per kW of net biomass capacity. When spread over the total cost/output of the 220 MW Unit 3, cofiring will add approximately $14 to $28 per kW.

3.3.3 Recommended Option for Further Analysis

Due to its low cost, ability to be incorporated into the design from the outset, and minimal impacts on unit operation and performance, Black & Veatch recommends that direct cofiring in the proposed Unit 3 CFB be evaluated further. As an alternative, indirect cofiring using gasification could be examined further for Unit 2. However, given the complexity of the already planned air quality control modifications for Unit 2, this option seems much less appealing. If Unit 2 is a focus of further investigation, gasification for cofiring is recommended over direct cofiring in Unit 2 due to the greater potential emissions benefits and the substantially reduced negative impacts on the existing plant equipment.

3.4 Conceptual Design

This section describes the conceptual design for direct cofiring of the equivalent of 30 MW of wood waste in the proposed 220 MW Unit 3 CFB. The wood waste will be cofired with pet coke and coal. Generating 30 MW using biomass fuel would result in approximately 13.6 percent of the power output from Unit 3 being derived from the wood. It is assumed that biomass will displace coal, resulting in a final fuel mix of 13.6 percent wood, 36.4 percent coal, and 50 percent pet coke. Approximately 600 tons/day of biomass (at 5,657 Btu/lb) will need to be fired to generate the equivalent of 30 MW.

3.4.1 Conceptual Design Approach

The greatest challenge of cofiring waste wood is minimizing the capital equipment and operating staff costs. The system presented here represents a reasonable equipment selection to be cost competitive and reliable, but will not be as robust as the coal and pet-coke handling systems. The conceptual design is for one complete system with limited equipment redundancy (for example there is only one truck tipper and one reclaimer). Redundancy was limited because biomass is intended to be a supplemental fuel and is not critical to unit reliability. As this is only a concept definition study, detailed investigations into site drainage, permitting, layout, tie-in design, etc. are still required.

The following subsections describe the individual systems and components involved in the wood-waste handling system operation. The purpose of this system is to provide the boiler with sized, metal free, wood fuel. A diagram of the system is shown in Figure 3-7.

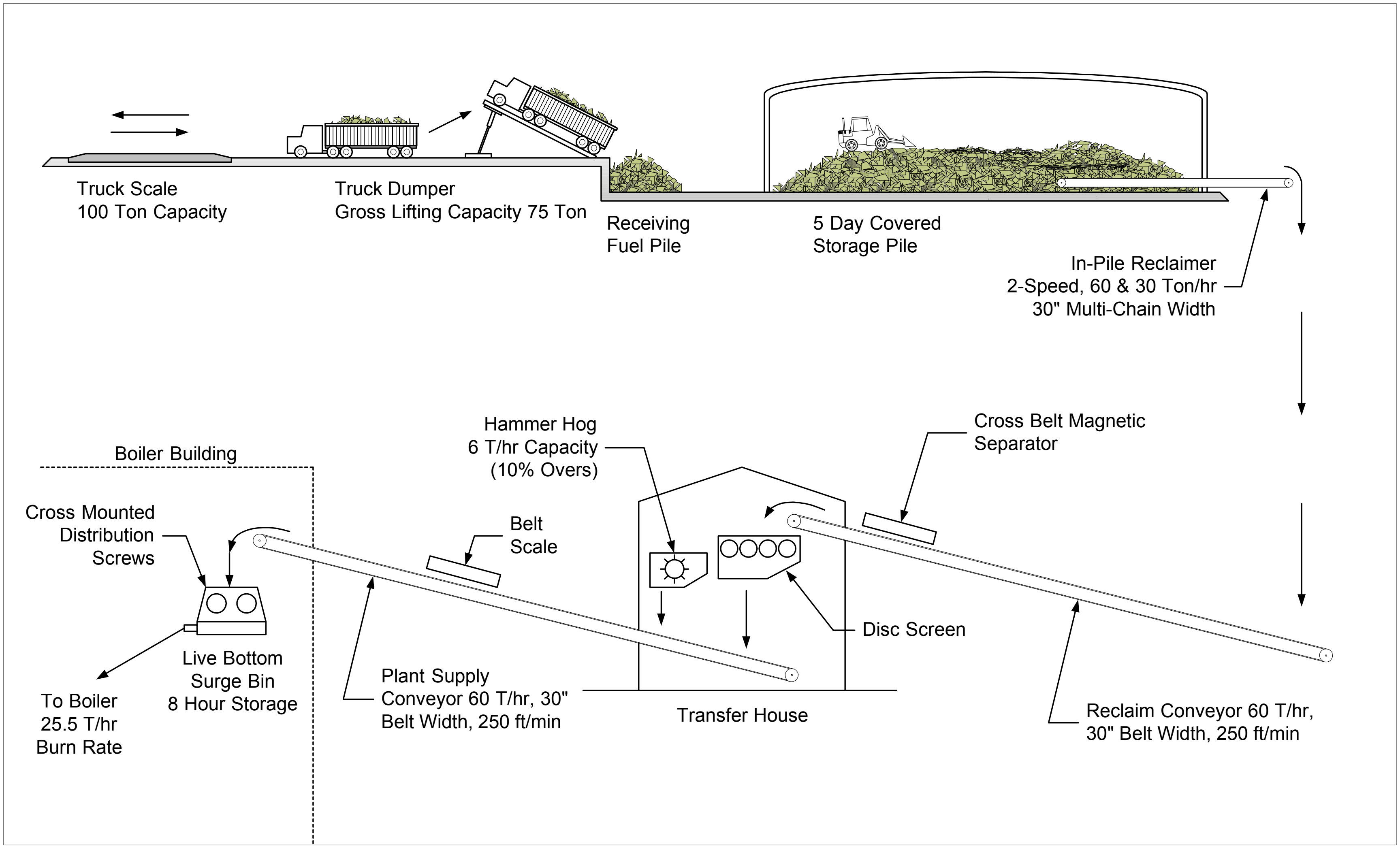

Figure 3-7. Wood Handling System Flow Diagram.

3.4.2 Wood Receiving System

The wood receiving system receives truck delivered waste wood and transfers it to the wood storage pile. The wood receiving system is comprised of the following major components:

- Truck dumper – 75 ton gross lifting capacity.
- Track dozers – provided by GRU.

The fuel for the plant will be delivered by trucks of up to 45 ton capacity. The fuel received by truck will either be chipped wood, hogged wood, sawdust, or planer mill fines. After being weighed, incoming trucks will proceed to the hydraulic elevating truck tipper. The load will be dumped directly to the ground in the pile area. Trucks with walking floor dischargers may directly dump their loads. From the dump point at the truck tipper, wood will be moved by mobile equipment either to the reclaimer area or to the storage pile.

The wood receiving and is sized to accommodate delivery of wood from outside sources by truck on a single shift per day, five working days per week basis. The receiving shift will be 12 hours per day. At full capacity, the plant will burn up to 4,300 tons of fuel per week, based on a nominal burn rate of 25.5 ton/hour, 5,657 Btu/lb fuel. Up to four trucks per hour will be received.

3.4.3 Wood Storage

It is expected that most fuel storage will be performed off-site by other companies (see Section 3.2). However, covered on-site wood storage is included to allow for 5 days of uninterrupted operation. The wood pile will cover approximately 0.60 acres with an average pile depth of 10 feet. The roof of the covered storage building will be approximately 25 feet high. The covered storage will allow for some minimal drying of the fuel and prevent absorption of additional moisture during rainy periods. Blending of wood chips and fines (such as sawdust) will be accomplished with mobile equipment on the pile. Uniform blending of wood chips and fines by mobile equipment in the pile area is a requirement for successful operation of the wood handling system.

3.4.4 Wood Reclaim and Plant Supply

The wood reclaim and plant supply system will receive fuel from the wood pile and transfer it to the boiler. The fuel will be reclaimed, screened, and then delivered to a live bottom bin by a conveyor. The fuel will then be fed to the boiler by screw feeders. Final sizing and weighing of the fuel will also be done within this system. The design of the reclaim system is heavily dependent on full and complete mixing of wood chips and fines by mobile equipment working on the wood storage pile. The major components of the reclaim and plant supply system are as follows:

- Two speed, multi-chain reclaimer with push walls (60 tons/hour maximum discharge capacity).
- Reclaim conveyor.

- In-line, self-cleaning magnetic separator.
- Disc screen.
- Hammer hog.
- Transfer house.
- Plant supply conveyor.
- Belt scale.
- Live-bottom bin with screw feeders and leveling screws (60 tons/hour capacity).
- Chutes, loading skirt boards, etc., as required.

Wood fuel will be transferred to the multi-chain reclaimer by mobile equipment from the truck tipper or the wood storage pile. The reclaimer will supply the 30-inch reclaim belt conveyor. This belt conveyor will have a capacity of 60 ton/hour and will transfer wood from the pile area to the transfer house for removal of any tramp metal and final material sizing on the way to the live bottom bin. The reclaimer will be designed to meet 100 percent of the plant wood fuel requirements.

In the transfer house, reclaimed material greater than 3 inches on any side will be segregated by disc screens, and the oversize pieces will be discharged to a hammer hog where they will be reduced in size to less than 3 inches on any side and loaded onto the 30-inch wide plant supply conveyor. Sawdust, fines, and material less than 3 inches will be routed through the disc screen and loaded onto the 30-inch wide plant supply conveyor. The fuel will be weighed by a digital electronic belt scale located on the plant supply conveyor.

The plant supply conveyor will load the live bottom surge bin at the boiler. The live bottom surge bin is an inverted-slope, fabricated-plate bin that provides fuel to the boiler fuel feed system. The bin will provide storage for 8 hours of wood-waste fuel at the nominal plant burn rate of 25.5 ton/hour. The bin will be equipped with sonic level detectors. These detectors will be used to stop or start the reclaimer and provide an alarm to the plant operators in the case of low fuel levels.

The capacity of the reclaim and plant supply system will be based on handling fuel with a moisture content of approximately 30 percent at the full plant burn rate of 25.5 tons/hour. The system-operating basis is a 24-hour per day operation with continuous feed and short-term surge capacity in the plant.

3.4.5 Major Equipment List

A summary of major equipment included in the design includes:

- Truck dumper
- Truck scale
- On-site domed waste wood storage building (5-day storage)
- Two speed, multi-chain reclaimer with push walls
- Reclaim conveyor

- Magnetic separator
- Disk screen
- Hammer hog
- Belt cleaner
- Live bottom surge bin
- Conveyor and transfer house
- Plant supply conveyor
- Belt scale
- Chutes, loading skirt boards, etc., as required
- Conveyor belt trimming
- Electrical equipment
- Data acquisition and control system

3.5 Development of Performance Estimates

This section describes the development of performance estimates for cofiring 30 MW of wood waste in the new Deerhaven 220 MW CFB.

3.5.1. Performance Estimate Approach

Black & Veatch assessed the performance impacts of cofiring 13.6 percent wood, 36.4 percent coal, and 50 percent pet coke in a new 220 MW CFB. Percentages are on a heat input basis. The biomass heat input has been selected to provide the equivalent of 30 MW net. Black & Veatch used its M10 boiler modeling software to estimate impacts to boiler efficiency, capacity, emissions, and other performance factors. The performance estimate for the biomass cofiring case was compared against an estimate of burning a 50:50 mix of coal and petroleum coke. The design fuel basis for the wood waste is provided in Table 3-8. Preliminary specifications were also received from Alstom and Foster Wheeler. This estimate is preliminary and should be refined as more information is gathered, particularly with respect to fuel properties and design fuel mix.

3.5.2 Performance Estimate Findings

The results of the performance modeling are provided in Table 3-11 for the 50:50 coal-pet coke case and the biomass cofiring case. The final column provides the percent change between the two cases. Black & Veatch projects that cofiring 13.6 percent wood waste will result in a small boiler efficiency decrease, from 89.3 to 88 percent. This change is not expected to impact net plant output, but it is estimated to result in a 1.5 percent increase in net plant heat rate, raising it from 9,464 to 9,604 Btu/kWh (HHV basis). By comparison, a typical stand-alone biomass plant would have a heat rate of around 14,000 Btu/kWh, about 50 percent higher.

Table 3-11. Biomass Cofiring Performance Estimates.

		50% pet coke / 50% coal	50.0% pet coke / 36.4% coal / 13.6% wood	Percent Change
Total Heat to Steam	MBtu/hr	1,858	1,858	0.0%
Boiler Efficiency, HHV	%	89.3%	88.0%	-1.5%
Heat Input, HHV	MBtu/hr	2,082	2,113	1.5%
Percent of Heat Input				
Pet Coke		50%	50.0%	0.0%
Coal		50%	36.4%	-27.3%
Wood			13.6%	
Heat Input				
Pet Coke	MBtu/hr	1,041	1,056	1.5%
Coal	MBtu/hr	1,041	768	-26.2%
Wood	MBtu/hr		288	
Gross Output	kW	244,440	244,440	0.0%
Pump Power Required	kW	6,780	6,780	0.0%
Total Auxiliary Load	kW	24,444	24,444	0.0%
% of Gross Output	%	10.00	10.00	0.0%
Net Power Output	kW	220,000	220,000	0.0%
Gross Turbine Heat Rate	Btu/kWh	7,603	7,603	0.0%
Net Turbine Heat Rate	Btu/kWh	7,820	7,820	0.0%
Gross Plant Heat Rate, HHV	Btu/kWh	8,760	8,890	1.5%
Net Plant Heat Rate, HHV	Btu/kWh	9,464	9,604	1.5%
Gross Plant Thermal Efficiency, HHV	%	38.96%	38.39%	-1.5%
Net Plant Thermal Efficiency, HHV	%	36.06%	35.54%	-1.5%

Other findings include:

- It is expected that auxiliary power consumption of the wood handling system will be relatively small. Increases in auxiliary power consumption due to the biomass systems will be largely offset by decreases due to reduced coal handling requirements.
- It is not expected that the biomass cofiring addition will significantly impact plant availability, forced outage rate, capacity factor, maintenance patterns, etc.
- Depending on the biomass fuel properties, uncontrolled emissions for SO_x, particulate, and CO_2, are all expected to decline approximately proportional to the biomass cofiring rate. However, after passing through the air quality control (AQC) equipment, it is not expected that significant differences will be realized for controlled emissions for SO_x and particulate. Nevertheless, the lower uncontrolled emissions of the biomass will result in less material and chemical consumption in the AQC systems (that is, baghouse bags and

- limestone/lime), and this is reflected in the operation and maintenance cost estimate. Given the inherently low NO_x emissions of the CFB technology, it is not expected that biomass will impact NO_x emissions.

3.6 Development of Cost Estimates

This section includes capital and operation and maintenance cost estimates for the biomass cofiring addition to Unit 3.

3.6.1 Capital Cost Estimate Approach

The capital cost estimate was developed based on historical costs from past Black & Veatch biomass projects and recent inquiries to boiler and wood handling system vendors. Costs are provided on an incremental basis, that is, they only include costs necessary to add biomass cofiring capability to the base CFB design. The capital cost estimate should be considered planning-level accuracy.

The project includes all site, plant, and other facilities required to generate the equivalent of 30 MW (net) of biomass. The cost estimate includes all facilities from receipt of the biomass by truck to the necessary modifications to the boiler to fire the biomass.

The project cost was developed based on the following general assumptions.

- Soil is suitable for spread footings with no pilings.
- Land purchase is not included.
- Site is level, no rock excavation required, no trees, no dewatering, no underground obstruction, and no fill requirements. Cut and fill balance is on site.
- No hazardous and/or contaminated material will be encountered on site and no removal or replacement of soil is required.
- Land right-of-way and permits are excluded.
- Startup and construction utilities such as water, power, fuel, and compressed gases are not included.
- Unlimited access to the project site is available.
- Suitable storage facilities/laydown areas are available immediately adjacent to the plant site.
- Construction to be performed on open shop basis.
- Cost for wetlands or threatened and endangered species impact mitigation are not included.
- No landscaping costs except overseeding have been included.
- Costs for a site geotechnical and subsurface report are not included.

The project cost was developed based on the following assumptions regarding direct and indirect costs.

- The estimate includes the major equipment identified in the Section 3.4 including instrumentation and control software, miscellaneous equipment, and equipment warranties.
- The cost estimate includes a $500,000 allowance for necessary CFB boiler modifications to incorporate waste wood fuel. The allowance includes possible increases in the boiler furnace size, heat transfer surface modifications, additional or increased size boiler auxiliary equipment (such as extra piping and wiring, extra burners, etc.), additional boiler steel, additional electronics and controls, etc. This estimate can be refined when a more accurate fuel composition is developed.
- Site preparation and equipment erection includes: site preparation, road construction, miscellaneous steel and equipment relocation, foundation erection, and equipment and building erection necessary for the biomass firing system.
- Use of biomass fuel may reduce the capital costs of plant systems. For example, if biomass is consistently available and fed to the boiler, coal handling system sizes could be reduced. Further the low ash content and relatively clean nature of biomass could result in lower capital costs for ash handling and air quality control equipment, respectively. However, it is likely that there may be times when economic biomass fuel is not available, and the facility design will need to reflect this “worst case” scenario. For this reason, no capital cost credits have been assumed for reduction in air quality control, fossil fuel handling, and ash handling systems due to biomass firing. The operating and maintenance cost estimate does reflect some savings in these areas, however.
- Indirect costs include engineering, spare equipment and parts, construction management, insurance and freight, and contractor’s and owner’s contingency.

Owner's costs are excluded. Owner's costs that are not included in the capital costs estimate are:

- Land
- Sales tax
- Project development
- Permitting
- Utilities (electricity, fuel oil, propane, water) for construction, commissioning, and startup
- Initial biomass supply
- Plant operating staff during commissioning and startup.

3.6.2 Capital Cost Estimate Findings

Table 3-12 summarizes the estimated incremental capital cost for the biomass cofiring system. The incremental capital cost (excluding owner's cost) is estimated to be approximately $4.6 million. This is equal to about $150/kW of biomass capacity, or $21/kW when spread over the total cost/output of the 220 MW Unit 3. Costs are presented in 2004 overnight dollars.

Table 3-12. Incremental Capital Cost for 30 MW Biomass Cofiring System (2004$).

Direct Costs	
Equipment Procurement	$1,847,000
CFB Boiler Upgrade (additional cost to incorporate waste wood fuel)	$500,000
Site Preparation and Equipment Erection Contract	$975,000
Indirect Costs	
Engineering	$335,000
Spare Equipment and Parts	$142,400
Construction Management	$191,100
Insurance and Freight	$38,200
Contingency	$573,300
Grand Total	**$4,602,000**

3.6.3 Operation and Maintenance Cost Estimate Approach

The operation and maintenance cost estimate is based on modifications to the operation and maintenance estimate developed in the Multi-Pollutant Compliance Planning and Deerhaven Expansion Comparison Report of September 2003. The O&M

estimate was developed by modifying individual line items impacted by the biomass cofiring system. In particular:

- An allowance is included for three additional fuel system operators to run the waste wood storage and handling systems. This is the largest cost increase due to the biomass cofiring system.
- Ash handling maintenance is slightly reduced due to the lower ash content of the wood fuel relative to coal.
- An allowance of $100,000 is included for biomass maintenance contingencies. This includes additional handling expense for biomass material.
- Annualized boiler maintenance costs were assumed to increase 10 percent due to the biomass.
- Ash disposal costs were reduced due to the lower ash content of the wood fuel relative to coal.
- Limestone and lime reagent costs for desulfurization were significantly reduced due to the very low sulfur content of the biomass. This is the largest cost decrease due to the biomass cofiring system.
- There is a slight reduction in costs for replacement bags for the baghouse due to the lower ash throughput of the system.

3.6.4 Operation and Maintenance Cost Estimate Findings

Table 3-13 summarizes the estimated incremental O&M cost for the biomass cofiring system. Fixed costs are estimated to increase by $1.35/kW-yr, primarily due to the additional biomass handling labor. Variable O&M costs are expected to decrease by $0.17/MWh, primarily related to reduced consumption of limestone and lime. The total net change in annual O&M is very minor, amounting to an estimated increase of only $26,000. Costs are presented in 2004 dollars.

Table 3-13. O&M Cost Estimate for 30 MW Biomass Cofiring System (2004$).

Fuel	50% pet coke / 50% coal	50.0% pet coke / 36.4% coal / 13.6% wood	Change
Fixed Costs	**$000**	**$000**	**$000**
Labor:			
Operations	$2,574	$2,768	$194
Maintenance	$1,236	$1,236	$0
Technical Services	$678	$678	$0
Administration	$361	$361	$0
Labor Subtotal:	**$4,849**	**$5,043**	**$194**
Maintenance:			
Boiler	$342	$342	$0
Turbine	$82	$82	$0
Ash Handling	$104	$98	-$6
Fuel Handling	$94	$103	$9
Water Treatment Facilities	$22	$22	$0
Waste Water Treatment Facilities	$18	$18	$0
FGD Plant (including CFB Limestone preparation plant)	$154	$154	$0
SCR (and associated systems)	$0	$0	$0
Particulate Control System (Baghouse/Precipitator)	$44	$44	$0
Miscellaneous Items & Balance Of Plant Steam Plant	$52	$52	$0
Contract Labor & Services (studies, reports, miscellaneous maintenance activities, etc.)	$328	$328	$0
Biomass Maintenance Contingencies (includes additional handling expense for biomass	$0	$100	$100
Maintenance Subtotal:	**$1,240**	**$1,343**	**$103**
Other Fixed Expenses:			
Property Taxes	$389	$389	$0
Office and Administrative Expenses (includes telephones, computers, printers, etc.)	$485	$485	$0
Insurance	$1,040	$1,040	$0
Other Fixed Expenses Subtotal:	**$1,914**	**$1,914**	**$0**
Total Fixed Costs:	**$8,003**	**$8,300**	**$297**
Variable Costs			
Outage Maintenance			
Turbine (Annualized)	$171	$171	$0
Boiler (Annualized)	$146	$161	$15
Balance Of Unit (Annualized) Per Unit	$149	$149	$0
Annualized Subtotal Outage Maintenance:	**$467**	**$482**	
Water			
Water	$230	$230	$0
Chemicals			
Boiler	$164	$164	$0
Cooling Tower	$307	$307	$0
Ash & FGD Byproduct Disposal			
Ash & FGD Byproduct Disposal	$700	$656	-$44
Desulfurization Equipment			
Limestone (wet scrubber or CFB units)	$2,907	$2,703	-$204
Lime Reagent (dry scrubbers)	$298	$268	-$30
Particulate Removal			
Bag Replacement (Annualized)	$80	$72	-$8
ESP Overhaul (Annualized)	$0	$0	$0
Selective Catalytic Reduction (SCR) (assuming full year operation)			
Reagent Consumption (ammonia or urea reagent)	$575	$575	$0
Catalyst Replacement	$0	$0	$0
Grid Tuning & Slip Testing	$25	$25	$0
Water, Chemicals, & Pollution Control Equipment:	**$5,286**	**$5,000**	**-$286**
Total Variable Costs:	**$5,753**	**$5,482**	**-$271**
Total Operation & Maintenance Costs:	**$13,755**	**$13,781**	**$26**
Annual Net Generation (MWh)	1,637,771	1,637,771	0
Fixed Costs Per Net Unit Of Capacity ($ per kW Net)	36.38	37.73	1.35
Variable Costs Per Unit Of Output ($ per MWh)	3.51	3.35	-0.17

3.7 Summary Results and Conclusions

Biomass appears to be a viable resource for further investigation by GRU. There appears to be abundant biomass in the immediate vicinity of Gainesville to support at least 30 MW of biomass power. The cost for this biomass is likely to be about $1.50/MBtu. Given GRU's current plans, the most cost effective and efficient method to generate power from biomass is to incorporate it into the new Deerhaven 220 MW Unit 3 CFB. Cofiring of biomass in circulating fluidized bed boilers is well proven. In fact, there are boilers as large as the proposed Deerhaven Unit 3 that are 100 percent biomass fired. Approximately 600 tons/day of biomass (at 5,657 Btu/lb) will need to be fired in Unit 3 to generate the equivalent of 30 MW from biomass. The necessary receiving, storage, and feed equipment for this amount of biomass will have a capital cost on the order of $4.6 million dollars. No substantial impacts are expected on operation and maintenance of the plant, although the unit heat rate will be slightly increased (1.5 percent).

Recommended areas of particular focus for additional investigation include biomass resource availability, particularly in regards to cost, chemical and physical properties, delivery requirements, identification and perhaps preliminary negotiations with large fuel suppliers. The biomass systems should also be further integrated into the design for the new unit, including revised plant layouts, air quality system impacts, environmental permitting requirements, etc. GRU may also wish to explore the impacts of integrating a much larger biomass capability as part of its future plans for Unit 3. At present there do not appear to be technical or fuel supply reasons why Unit 3 could not accept up to 50 percent biomass. Although the economics of such a large commitment to biomass are uncertain, the incremental capital costs for installing a larger fuel handling system will be relatively modest. Further, GRU would not necessarily need to always fuel the boiler with 50 percent biomass; it would only need to use the amount that is economical given current market prices. The larger commitment to biomass would allow greater fuel arbitrage, long-term resource security, and the possibility of selling excess renewable energy credits or power to interested purchasers (such as in response to JEA's recent renewable energy solicitation). The economics of these benefits need to be balanced against the higher capital and fuel costs of the larger system.

4.0 REVIEW OF IGCC TECHNOLOGY AND DEVELOPMENT OF ECONOMIC PARAMETERS

4.1 Technology Description

A typical IGCC plant for power generation from coal is shown on Figure 4-1. Pulverized coal is fed into the gasifier at approximately 450 psia with oxygen from an air separating unit (ASU). The raw fuel gas exits the gasifier at about 2,400 °F and is cooled to 400 °F in a syngas cooler. Steam produced in the syngas cooler is expanded in the steam turbine generator (STG). The cooled syngas is then scrubbed with water to remove dust, NH3, and hydrogen chloride. The syngas is cooled further and then scrubbed with solvents to remove sulfur compounds. The clean syngas is then injected into the combustion chamber of the combustion turbine generator (CTG). The heat from the CTG exhaust gas is used to generate steam in the heat recovery steam generator (HRSG), which is then expanded through the STG.

IGCC systems incorporate the steam production from the gasification system directly into the combined cycle application. Generally, the integration itself increases efficiency and lowers operating costs when compared to straight gasification and combined cycle generation, but the capital cost of IGCC is still high.

IGCC is the combination of two well-proven technologies. It would seem that this combination should be relatively easy. However, the economics of IGCC are much different from those of gasification. IGCC requires high thermal efficiency to compete in today's marketplace. This means that the simple quench processes used for chemical processing plants must be replaced by specially designed syngas coolers. These syngas coolers use the heat from the high temperature raw syngas to produce HP steam.

4.1.1 Gasification Overview

Gasification technology is commercially available. It is a simple technology that has been used for over 100 years. Gasification typically entails the reaction of a feedstock, either a solid or liquid, with oxygen and steam to produce a syngas. The feedstock is converted into syngas with a high-temperature, high pressure process under reducing conditions -- less than 50 percent of the oxygen required for complete combustion is used in the process.

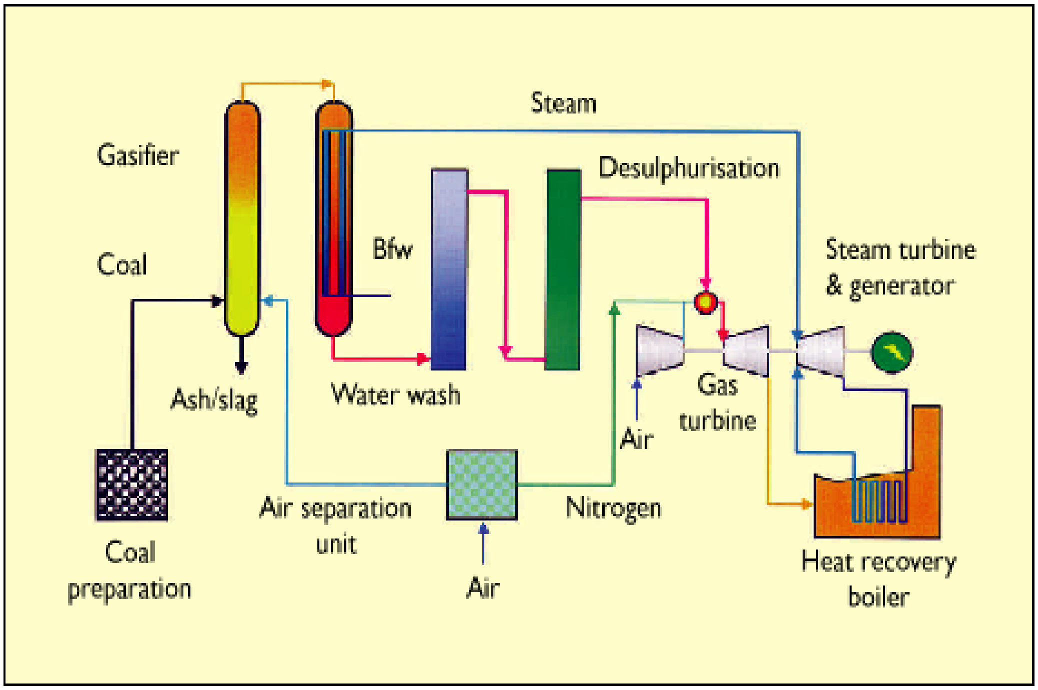

Figure 4-1. IGCC Basic Flow Diagram.

High-temperature raw syngas is cooled and cleaned using technologies common to oil refining and natural gas purification. The cooler, clean syngas is then used in one or more of the following applications:

- Syngas for power
- Syngas for chemicals
- Syngas for liquids fuels
- Syngas for gaseous fuels

Traditionally, syngas production has been an intermediate step in the production of chemicals such as NH_3 to be used in the production of fertilizers.

The US DOE has compiled a gasification database consisting of 329 projects. The projects date back to 1952 and also include projects under development that are scheduled to be completed by 2004. Of these projects, 161 are of commercial scale. Of the commercial scale projects, 128 are operating or under construction, with the remaining 33 projects in the active planning stages. If all of the syngas produced from the 161 commercial scale projects was converted to electricity through the IGCC process, roughly 32,300 MW would be produced.

The Dakota Gasification Project is still the third largest gasification project in the world. The two largest projects are located in South Africa and are used to produce liquid fuels.

4.1.2 Gasification Processes

There are at least 10 different commercially available gasification processes. These processes can be classified into three families based on the manner in which the fuel and oxidant flow through the gasifier: fluidized bed, entrained flow, and moving bed. Moving bed is frequently, although incorrectly, referred to as fixed bed.

The three families of gasification are roughly analogous to conventional solid fuel steam generators. Fluidized bed gasifiers operate on the same principle as fluidized bed combustors; entrained flow gasifiers are comparable to PC steam generators, and moving bed gasifiers are similar to grate firing. All three families are suitable for solid fuels.

Table 4-1 lists the characteristics of the generic types of gasifiers.

Moving bed gasifiers accept only solid fuels. They were originally designed for coal but can handle other solid fuels such as wastes. Moving bed gasifiers are the oldest of the three families and have the most commercial scale installations. The two primary moving bed processes are Lurgi and BGL.

The Lurgi dry ash process was developed in the 1930s. It is referred to as a dry ash process because the bed temperature is maintained below the fusion temperature, thus the ash -is removed as a solid. The Dakota Gasification plant employs a Lurgi dry ash process. The Lurgi dry ash process is also being used to gasify lignite in the Czech Republic. The products of the Czech Republic project, which became commercial in 1996, are 350 MW of electricity and steam.

In the 1970s, British Gas Corporation (BG) and Lurgi developed a slagging moving bed gasifier that is referred to as the BGL gasifier. The fusion point of the ash is exceeded in the BGL. BGL gasifiers are being installed in several plants that use solid waste or a mixture of coal and sludge as the feedstock.

Commercial scale fluidized bed gasifiers are rare today. They only accept solid fuels and are best suited to fairly reactive fuels such as biomass. An advantage of the fluidized bed gasifier is the ability to process a wide range of solid fuels, including municipal solid waste (MSW). High ash coals are also best suited for the fluidized bed process.

Table 4-1
Gasifier Characteristics

Gasifier	Feed Coal Size	Acceptability of Fines	Preferred Coal Rank	Gas Outlet Temperature (°F)	Oxidant Requirement	Distinguishing Characteristics	Key Technical Issue	Fuel Residence Time
Moving Bed, Dry Ash	Coarse (0.2 – 2.0 in)	Limited	Low	750 – 930	Low	Hydrocarbon Liquids (Tars and Oils) in the Raw Gas	Utilization of Fines and Hydrocarbon Liquids	15 – 30 minutes
Moving Bed, Slagging	Coarse (0.2 – 2.0 in)	Better Than Ash	High	750 – 930	Low	Hydrocarbon Liquids (Tars and Oils) in the Raw Gas	Utilization of Fines and Hydrocarbon Liquids	15 – 30 minutes
Entrained Flow, Slagging	Pulverized (< 0.01 in)	Unlimited	Any	> 2,200	High	Large Amount of Heat Energy in the Hot Raw Gas	Raw Gas Cooling	1 – 10 seconds
Fluidized Bed, Dry Ash	Crushed (0.02 – 0.2 in)	Good	Low	1,300 – 1,800	Moderate	Large Char Recycle Associated with FBC Operation	Carbon Conversion	5 – 50 seconds
Fluidized Bed, Agglomerating	Crushed (0.02 – 0.2 in)	Better Than Dry Ash	Any	1,300 – 1,800	Moderate	Large Char Recycle Associated with FBC Operation	Carbon Conversion	5 – 50 seconds

Adapted from: K. Rousaki, G. Couch, "Advanced Clean Coal Technologies and Low Value Coals," IEA Coal Research, The Clean Coal Centre, Nov. 2000.

There is a fluidized bed gasification project under development in the Czech Republic using lignite as the feedstock. It has a projected commercial operation date of 2003 and will produce 400 MW. It employs the High Temperature Winkler (HTW) fluidized bed gasification process. This HTW gasifier will be at the same location as the Lurgi dry ash gasifier discussed above.

4.2 Review of Coal Fuel Quality

The fuel to be gasified by the new unit is Eastern bituminous coal with a higher heating value of 12,335 Btu per pound, as-received. Briefly, the as-received coal composition will be as shown below. A detailed analysis is shown in Table 4-2.

Moisture	7.50 %wt as-received
Ash	9.83 %wt as-received
Sulfur	2.73 %wt as-received

The coal will be delivered to the site by rail. Rapid bottom dump hopper car unloading will be provided. Coal storage will be equivalent to 40 days of plant operation at design capacity. No. 2 fuel oil will be delivered by railcar or truck. One 56,000 barrel capacity fuel oil storage tank will be provided. Natural gas will be supplied by pipeline.

4.3 Conceptual Design

The unit will be an integrated gasification combined cycle (IGCC) electric generating unit using the Texaco Coal Gasification Process. The nominal 250 MW unit will be a single train consisting of one air separation unit (ASU), one Texaco coal gasifier, and a 1x1 combined cycle with a GE 7FA combustion turbine. The Texaco coal gasifier will be a quench type.

The systems included in the plant will be as follows:

- Coal Receiving & Handling
- Gasification
- Acid Gas Removal
- Sulfur Recovery
- Air Separation Unit
- Combined Cycle
- Balance of Plant

Table 4-2. High Sulfur Coal Analysis.			
Ultimate Coal Analysis	**Average**	**Range**	**Reference**
Carbon	67.6	65.57-69.63	Vista Model
Hydrogen (%)	4.2	4.07-4.33	Vista Model
Sulfur (%)	2.73	2.31-3.15	Vista Model
Nitrogen (%)	1.3	1.13-1.47	Vista Model
Oxygen (%)	6.79		Vista Model
Chlorine (%)	0.06	0.05-0.07	Vista Model
Ash (%)	9.83	7.68-8.30	Vista Model
Moisture (%)	7.50	5.85-9.15	Vista Model
Higher Heating Value, Btu/lb	12.335	12,026-12,634	Vista Model
Ash Analysis			
Silica (SiO_2)	46.43		Vista Model
Alumina (Al_2O_3)	21.02		Vista Model
Ferric Oxide (Fe_2O_3)	21.60		Vista Model
Titania (TiO_2)	0.93		Vista Model
Phosphate pentoxide (P_2O_5)	0.48		Vista Model
Lime (CaO)	3.52		Vista Model
Magnesia (MgO)	0.76		Vista Model
Sodium Oxide (Na_2O)	0.50	0.33-0.67	Vista Model
Potassium Oxide (K_2O)	1.75		Vista Model
Sulfur Trioxide (SO_3)	2.43		Vista Model
Undetermined	0.58		Vista Model
Trace Analysis (dry coal basis)			
Arsenic, ug/g	16.9	2.1-61.0	Assumption
Zinc, ug/g	14.8	4.1-37.0	Assumption
Vanadium, ug/g	27.1	4.6-71.0	Assumption
Mercury, ug/g	0.17	0.03-0.47	Assumption
Source: Multi-Pollutant Compliance Planning and Deerhaven Expansion Comparison – Final Report.			

The unit will gasify coal delivered by rail. The raw syngas will be treated to remove particulate, ammonia, and sulfur prior to combustion. The clean syngas will be diluted with nitrogen and water vapor to enhance combustion turbine efficiency and control NOx to less than 17 ppmv (dry at 15% O2) in the flue gas. Flyash, slag, and sulfur will be saleable byproducts from gasification. Wastewater treatment solids will be disposed of off site in an environmentally acceptable manner. Plant cooling will be provided by a cooling tower. Plant water will be supplied from an offsite source to the site boundary.

4.3.1 Unit Power Ramp Rate

Estimated IGCC unit power ramp rates are:

- 3.5% load change in 5 seconds
- 5% load change in 30 seconds
- 40% load change at 3% load change per minute

The initial ramp rates of 3.5% load change in 5 seconds and 5% load change in 30 seconds use the syngas stored in the gas path piping and equipment by pulling down the syngas supply pressure.

The 3% load change per minute required to achieve a 40% load change is the gasifier ramp rate.

4.3.2 Unit Startup Times

A cold plant startup will take about one day to perform the following steps:

1. Start coal preparation and produce coal slurry
2. Start the gasifier quench water circulation
3. Heat up the gasifier refractory with the startup burner
4. Warmup of syngas treating
5. Start coal slurry and oxygen flow to the gasifier
6. Start syngas flow through gas treating to flare
7. Establish syngas conditions suitable for gas turbine firing
8. Transfer gas turbine to syngas firing from fuel oil

A hot restart consisting of steps 5-8 above takes approximately 6 hours.

The cold restart assumes the Air Separation Unit is already operating. Cool down of the Air Separation Unit takes an additional 24 hours. Typically the Air Separation Unit remains cold (-300 F in cold box) during IGCC Plant shutdowns. The Air Separation Unit cold box is warmed to ambient temperatures to melt accumulated solid CO_2 about every five years when a major overhaul is performed on the air compressor. This cold box warmup is called a derime.

4.4 Performance Estimates

Performance, Availability, and Emissions estimates for the 250 MW IGCC Unit are presented in Table 4-3. Estimates are provided for a single gasifier and two gasifiers (one operating and one spare).Unit performance is based on a site elevation of 172 feet and an ambient temperature of 72 F.

Table 4-3. Texaco IGCC Performance, Availability, and Emissions Estimates.

	Single Gasifier	Two Gasifiers
Performance		
Coal to Gasifiers, AR STPD	2,213	2,213
Coal Feed Rate, MBtu/h (HHV)	2,275	2,275
Syngas to Gas Turbine(s), MBtu/hr LHV	1,690	1,690
Gas Turbine(s) Gross Power, MW	197	197
Steam Turbine Gross Power, MW	100	100
Total Gross Power, MW	297	297
Auxiliary Power Consumption & Losses, MW	47	47
Net Power, MW	250	250
IGCC Heat Rate, Coal Btu HHV/MW net	9,100	9,100
Availability		
IGCC First Year of Operation,%	30-70%	40-70%
IGCC Second Year of Operation, %	40-80%	60-80%
IGCC Third Year of Operation, %	50-85%	70-85%
IGCC After Third Year of Operation, %	75-85%	90%
CC with Backup Fuel, %	90%	90%
Emissions at 100% Load		
CO2, lb/MBtu HHV of AR Coal	242	242
CO, lb/MBtu HHV of AR Coal	0.05	0.05
SO2, lb/MBtu HHV of AR Coal	0.014	0.014
NOx, lb/MBtu HHV of Ar Coal	0.05	0.05
Particulate, lb/MBtu HHV of Ar Coal	0.013	0.013
Byproduct Sulfur, LTPD	52	52
Byproduct Slag/Flyash, STPD	218	218

Dilution of the syngas with a large volume of nitrogen and water vapor results in constant gas turbine power output over varying ambient temperature. Plant auxiliary power consumption increases with ambient temperature (primarily ASU air compressor and cooling tower fan power). Therefore plant net power output decreases slightly with increasing ambient temperature.

Long term IGCC unit availability is expected to reach 85% for one gasifier. Commercial IGCC unit availability has been much less primarily during the first several years of operation. Experience gained from coal IGCC plants that have been operating since the mid-1990s will allow new IGCC plants to have higher availabilities. Long term IGCC unit forced outage rates are expected to range from 7 to 10%. The gas turbine(s) can operate on backup fuel when syngas is not available. The CC availability is expected to exceed 90%. A second, spare gasifier can increase IGCC unit availability above 90%.

The CO and NOx emissions estimates are based on current GE guarantees for their 7FA gas turbines firing syngas with nitrogen dilution without SCR or CO oxidation catalyst in the HRSG:

25 ppmvd CO in the gas turbine exhaust gas

25 ppmvd NOx (at 15%v O2) in gas turbine exhaust gas

The SO2 emissions estimate is based on 25 ppm total molar concentration of sulfur as H2S and COS in the syngas to the gas turbine. Overall IGCC unit sulfur removal efficiency is 98%.

4.5 Cost Estimates

4.5.1 Capital Cost

The project includes all site, plant, and other facilities required in connection with an electric generating unit, excluding the plant substation. The power termination point is at the high side of the step-up transformer. All site development, structures, equipment, auxiliaries and accessories, piping, raceway, wiring and controls, and other facilities required for the complete unit are included.

The project cost was developed based on the following assumptions.

- Soil is suitable for spread footings with no pilings.
- Land purchase is not included.
- Site is level, no rock excavation required, no trees, no dewatering, no underground obstruction, and no fill requirements. Cut and fill balance is on site.
- No hazardous and/or contaminated material will be encountered on site and no removal or replacement of soil is required.
- Land right-of-way and permits are excluded.

- No cooling tower plume abatement is included.
- Costs to comply with any local noise requirements are not included.
- Startup and construction utilities such as water, power, fuel, and compressed gases are not included.
- Unlimited access to the project site is available.
- Suitable storage facilities/laydown areas are available immediately adjacent to the plant site.
- Construction to be performed on open shop basis.
- Cost for wetlands or threatened and endangered species impact mitigation are not included.
- Roadways are included only for area local to site. (An access road to the site is not included.)
- No landscaping costs except overseeding have been included.
- Costs for a site geotechnical and subsurface report are not included.
- Demolition or removal of any existing utilities, structures, etc. has not been included.
- First fills of chemicals, gases, fuel, and water storage tanks are not included.
- Costs for makeup water provisions are not included.
- Water termination point will be at site boundary.
- Sanitary waste piping will connect to local sewer on site
- Number 2 fuel oil will be used for combustion turbine backup fuel.
- Natural gas will be used for supplemental combustion turbine fuel and for flare pilot fuel.
- No plant communication is included.
- Plant dispatching and any special communications are not included.

Major facilities included are as follows.

- Onsite fencing, roads, and railroads.
- Construction facilities.
- Administrative offices, locker-shower-sanitary facilities, laboratories, and warehouse.
- Water management facilities including water supply and treatment, wastewater collection and treatment, and chemical storage equipment.
- Air Separation Unit
- Coal Preparation System
- Gasification System

- Syngas Treatment System
- Combustion Turbine/Steam Turbine and Generator. (indoors)
- Heat Recovery Steam generator. (outdoors)
- Air quality control equipment. (outdoors)
- Steam condensing equipment.
- Plant cooling equipment. (cooling tower)
- Service water supply and storage systems.
- Fire protection equipment.
- Coal unloading equipment (rapid bottom discharge bottom dump railcars), stacker/reclaimer, and transport conveyor.
- 40 days on-site coal storage. (10 days active)
- Flux additive handling facilities.
- On-site byproduct storage
- On-site solid waste landfill provisions.
- Control and electrical equipment for protection and operation of the generating unit.

A capital cost estimate for the 250 MW IGCC Unit is presented in Table 4-4.

The capital costs are for a typical EPC contract scope. Direct EPC Capital costs include:

- Equipment and materials
- Construction labor
- Capital spares
- Freight
- Commissioning

Indirect EPC Capital costs include:

- Engineering
- Construction Management
- Insurance and Bonds for EPC Contractor

Table 4-4. Texaco IGCC Capital Cost Estimate.

Purchase Contracts		**Single Gasifier**
61.0000	Civil/Structural	$38,170,761
62.0000	Mechanical	$161,308,179
63.0000	Electrical	$14,673,934
64.0000	Control	$6,894,695
65.0000	Chemical	$5,565,134
66.0000	Gasification Systems	$98,945,270
	Subtotal	**$325,557,973**
Construction Contracts		
71.0000	Civil/Structural/Construction	$1,891,012
72.0000	Mechanical/Chemical Construction	$560,842
73.0000	Electrical / Control Construction	$17,732,960
78.0000	Service Contract & Construction Indirects	$2,510,376
	Subtotal	**$22,695,189**
Indirect Costs		
99.1100	Engineering Costs (w/ G&A)	$25,603,641
99.1200	Construction Management (w/ G&A)	$9,144,157
99.1300	Startup Spare Parts	$4,267,273
99.1400	Construction Utilities (Power & Water)	$0
99.1500	Project Insurance	$3,875,904
99.2000	JV Costs	$0
99.2500	Allowance for Unknowns	$35,069,063
	Subtotal	**$77,960,038**
Total Project Cost (Overnight basis, traditional contracting)		**$426,213,200**
99.2200	Escalation	$0
99.2300	Owner's Costs – 20%	$85,242,640
	Total Capital Requirements – IGCC	**$511,455,840**

EPC costs include contingency for the EPC contractor.

Owner's costs are excluded. Owner's costs that are not included in the EPC costs are:

- Land
- Switchyard
- Transmission Line
- Sales Tax
- Permitting
- Utilities (electricity, fuel oil, propane, water) for construction, commissioning, and startup
- Coal
- Plant operating staff during commissioning and startup.
- Owner's contingency

4.5.2 Operation and Maintenance Cost

Operating and maintenance cost estimates for the 250 MW IGCC Unit are presented in Table 4-5.

The variable and total O&M costs in $/MWh are based on the respective capacity factors of 80% and 90% for one and two gasifiers and only net electricity produced from coal. The operating costs assume the sulfur, slag, and flyash will be sold at a price that breaks even with their handling cost. The costs do not include the cost of coal, fuel oil, or natural gas.

Scheduled maintenance will be performed annually and as needed. Each IGCC train will be shutdown for 2-3 weeks annually to perform the following maintenance:

- Combustion Turbine Generator: annual inspection, overhaul every 3 years
- Steam Turbine Generator: annual inspection, overhaul every six years
- Gasifier Feed Injector: replacement every 3-4 months, burners are refurbished
- Gasifier: annual inspection and refractory repair, hot face refractory replacement every 3 years, complete refractory replacement every 6 years
- Coal Mill: annual inspection, overhaul every 3 years
- Solids (Coal/Slag/Ash) Valves: annual inspection and refurbishment
- Coal Slurry Pumps: annual inspection and refurbishment
- Syngas Cooler: annual inspection, repair as needed
- Coal and Slag Conveyors: annual inspection, refurbish as needed
- Syngas Piping: annual inspection, replace or repair as needed
- Air Separation Unit: Cold Box Inspection/Deriming every 3 years
- Air Separation Unit Compressor: annual inspection, overhaul every 6 years

Table 4-5. Texaco IGCC O&M Cost Estimate.

Table Header	Single Gasifier	Two Gasifiers
Net Plant Capacity, MW	250	250
Long Term Plant Capacity Factor, %	80	90
Plant Staff	120	120
Plant Staff Expense, $ million/year	9.7	9.7
Fixed Operating Cost, $ million/year	11.7	11.7
Fixed Operating Cost, $/kW-yr	46.80	46.80
Variable Operating Cost, $ million/year	11	12.4
Variable Operating Cost, $/MWh	6.3	6.3
Total O&M Cost, $ million/year	22.7	24.1
Total O&M Cost, $/MWh	12.96	12.23

4.5.3 Startup Costs

Owner's costs for initial plant startup include:

- Staff during construction, commissioning, and startup
- Utilities during construction, commissioning, and startup
- Coal, fuel oil, and natural gas during commissioning and startup
- Initial warehouse inventory excluding capital spares
- Out-of-scope plant modifications required to make the plant work

The owner's cost for initial plant startup is estimated to be $43 million for the single gasifier, 250 MW IGCC unit, 10% of the EPC capital cost:

These costs assume the electricity sold during initial plant startup will cover the cost of coal, fuel oil, and natural gas. Fuel oil will be used as the gas turbine backup fuel. Natural gas is used for the gasifier startup burners, for flare pilot fuel, and for supplemental gas turbine fuel.

A cold plant startup will take about one day. During a cold plant startup a single gasifier train will consume approximately 3,000 MBtu HHV of coal and 40,000 M Btu HHV of fuel oil for the gas turbine. During this one day cold startup, the net electricity to the grid will be approximately 3300 MWh.

5.0 COST OF DELAYING DEERHAVEN UNIT 3 BY ONE YEAR

5.1 Estimate of Capital Cost Impact of Delaying the Start and Completion of Deerhaven Unit 3 by One Year

5.1.1 Study objective

The objective of this study is to estimate the order of magnitude of the increase in Total Capital Requirement to delay the schedule for the add-on Circulating Fluidized Bed (CFB) unit at the Deerhaven Station, Unit 3. The start and completion dates were assumed to be delayed one year with the commercial operation date being delayed from 2010 to 2011.

5.1.2 Annual Escalation Rates

Estimating the escalation rates for cost components of a coal fired power station over the next six (6) to seven (7) years is difficult due to numerous uncertainties such as labor costs and productivity, equipment and materials costs, fuel costs, inflation rate, general performance of the economy, impact of competing projects for common resources (equipment, labor, financing, etc.).

To illustrate the uncertainty of future cost increases due to escalation rates, B&V estimated low, expected and high weighted-average composite annual escalation rates. The results of the estimate are as follows:

- Low composite escalation rate – 2.1%
- Expected composite escalation rate – 2.7%
- High composite escalation rate – 3.7%

Senior level personnel experienced in coal plant costs, including estimating, engineering and proposal personnel, were consulted in developing this estimate.

A recent definitive cost estimate prepared by another very reputable engineering company for a similar coal project included an escalation amount based on an estimated annual composite escalation rate of about 2.5 percent per year. This compares very well with the results of this study.

These escalation rates were used to estimate the increase in the total capital requirements for Deerhaven Unit 3. Table A-1 in the Appendix shows the methodology used to estimate the composite, weighted-average annual escalation rates.

5.1.3 Capital Cost Estimate Analysis

This study is based on an overnight total project cost estimate of $350,100,000 for the 220 MW CFB add-on unit at the Deerhaven Station in June 2003 dollars. This is a conceptual level cost estimate developed for the purposes of comparing alternative plant configurations in a screening study. The scope of this cost estimate includes the physical power plant and is exclusive of Owner's costs.

Owner's costs includes allocations for Owner's reserve, project development cost, physical plant infrastructure outside the scope of the main plant, interest during construction, financing costs, operational spare parts, etc. Based on in-house proprietary data on similar projects, the magnitude of Owner's costs can be in the range of 35 to 40 percent of the total project cost. For this study, the estimate of Owner's costs resulted in an adder of about 37 percent which is in the expected range of values. Refer to Table A-2 in the Appendix for a listing of possible Owner's costs.

The increase in capital cost associated with a one year delay in the project was estimated by calculating the total capital requirement for the project for a 2010 COD and a 2011 COD. The cost impact of a one year delay is the difference between these two values.

This calculation was performed for the three cases of composite annual escalation rates to illustrate the range of cost increase for a one year delay in project schedule

The results of the estimate indicate that the cost increase can range from $11.3 million to $21.7 million with an expected cost increase of about $15 million.

Escalation Rate Case	Capital Cost increase
Low composite escalation rate	$11,312,000
Expected composite escalation rate	$15,021,000
High composite escalation rate	$21,670,000

The Table A-2 shows the methodology used to estimate the order of magnitude of the cost increase for a one year delay for the three escalation scenarios. This methodology uses simplifying assumptions that are based on actual project costs. The purpose of this calculation is to estimate the incremental cost increase due to project delay. It is not intended to estimate the project specific total capital requirement of the project. Other factors can impact the total capital requirement such as project specific development costs, financing costs, Interest during construction, labor productivity, etc.

5.2 Expected Trend in the Replacement Power Cost During the One Year Delay Period

5.2.1 Introduction

If a one-year delay in the construction of Gainesville Regional Utility's (GRU's) new Circulating Fluidized Bed (CFB) unit at the Deerhaven Station results in GRU's need to purchase power from the wholesale market, the following paragraphs describe the potential cost of replacement power from that market. While replacement power may at times come from other GRU generators when the load is sufficiently low or from other utilities on a bilateral contract basis; if replacement power is purchased on the spot market, the cost of that power is estimated below. Moreover, in 2004, seven years in advance of 2011, the basis for projecting both the spot and the contract price for electricity in 2011 are very similar. The following estimated prices are based on data and forecasts from the sources listed at the end of this task which may change with future updates.

5.2.2 Factors Influencing the Future Market Price of Electricity

The spot market price for electricity in the State of Florida in 2011 will be a function of the following factors:

- State-wide load growth
- The mix of generating technologies in the State at the time (Steam, combustion turbine, combined cycle, diesel, etc.) and their efficiencies
- The fuel mix at the time
- The then current regulatory structure in the State (the existence of Retail Access or the continued operation of regulated monopolies).

Continued healthy load growth in Florida offers an opportunity for a discernable change in the mix of fuel and efficiencies of generators "on the margin" by the year 2011. Spot market energy prices are determined by the variable operating cost of the last unit dispatched to meet the last increment of load in the market each hour. In regions with little or no load growth, market prices change only with changes in fuel prices, not as the result of changes in the fuel mix or changes in the efficiencies of generators associated with new generators being added to meet regional growth. Given Florida's healthy projected load growth, a significant amount of new generating capacity is planned and will impact the 2011 spot market in Florida.

Florida's utilities determine the future fuel and technology mix in the market based on the current mix and their decisions to retire units and add specific generators as described in their Ten Year Site Plans.

The regulatory structure will determine whether or not wholesale market prices must compensate the seller of power for the fixed cost of capacity. Under conditions of retail access where no power plant developer is assured of a market and a regulated return, the wholesale market prices must, over the long-run, be sufficient to cover the developers' cost to develop the plant and to provide a reasonable return. Without such inducements, investment to meet load growth will eventually dry up.

On the other hand, with continued franchise service areas, generating companies are reasonably assured of a return on their investment from their retail customers so they are willing to sell available excess capacity at prices just above their marginal costs. Market prices under such regulatory conditions tend to exclude capacity compensation. At this point it is impossible to predict for sure what kind of regulatory structure may be in place in Florida by 2011.

5.2.3 Key Factor Projections

Projected load growth in Florida, based on the compiled Ten Year Site Plans of the State utilities, amounts to an average of 2.5 percent per year between 2003 and 2011. Actual load growth may be higher given the historical tendency of the State utilities to under-forecast load. Current plans by State utilities to meet forecast growth call for the following additions to the existing generating mix:

- 11.5 GW of new combined cycle capacity
- 3 GW of repowerings or capacity additions at existing combined cycle sites
- 4.8 GW of new simple cycle combustion turbine capacity
- 0.3 GW of new coal capacity

In addition, the following capacity reductions are called for in State utility plans

- 1.1 GW of coal capacity retirements
- 1 GW of firm contract reductions

Figures 5-1. and 5-2. illustrate the current mix of generating capacity in the Florida market by technology along with the resulting mix in 2011 after the changes described above.

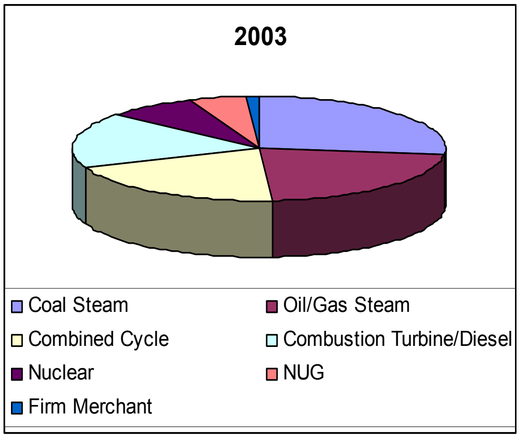

Figure 5-1. 2003 Florida Capacity Mix

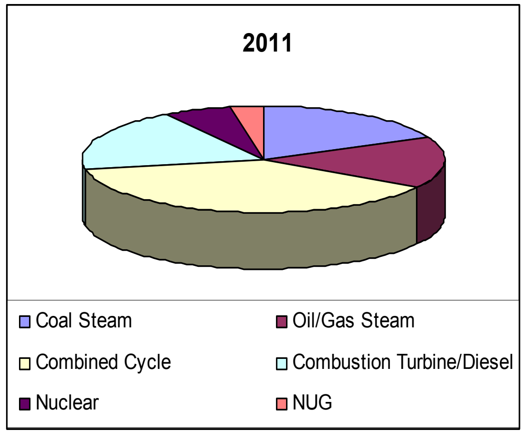

Figure 5-2. 2011 Florida Capacity Mix

Implicit in the technology mix trend above is an increase in the percentage of State generating capacity that is dependent upon oil or natural gas. Approximately 65 percent of the State's capacity was oil or gas fuelled in 2003 increasing to 76 percent by 2011.

The average price of natural gas delivered to electric utilities in Florida in 2003 was $5.70/MBtu. A typical price of coal delivered to Florida utilities in 2003 was $1.81/MBtu. While several Florida utilities expect a correction in gas prices and a decrease in even the nominal delivered price of gas by 2011, a few utilities expect the price to climb even higher from 2003 levels. Expectations regarding the future direction of coal prices are far more consistent among the utilities; however, coal prices are no longer relevant to the spot price of electricity in 2011 because without additional coal capacity additions coal will cease to be "on the margin" any hours by 2011. A check of the long-term forecast of natural gas prices in the US Department of Energy's 2004 Annual Energy Outlook appears to imply relatively level natural gas prices in nominal terms between 2003 and 2011 (meaning the price declines in real terms). The DOE price trend of zero nominal escalation in gas prices from 2003 through 2011 was used as the basis for the following forecast of spot market electric prices.

5.2.4 Market Price Forecast

The forecast of 2011 spot market electric prices in Florida was initiated with a benchmark forecast of 2003 prices. Given the 2003 technology mix and State-wide loads, it was apparent that in 2003 coal steam units were on the margin approximately 17 percent of the time, combined cycle units were on the margin approximately 63 percent of the time, oil/gas steam units were on the margin 18 percent of the time and simple cycle combustion turbines and diesels were on the margin approximately 2 percent of the time. Based on typical operating heat rates and variable non-fuel O&M costs for each of these technologies and the fuel prices cited above, an average annual market energy price of $44/MWh was produced. Such a price is very consistent with short-term market forecasts posted by the electric market modeling company, HESI, and are consistent with earlier detailed Black & Veatch market forecasts after adjustment for the actual 2003 increase in natural gas prices.

Applying the 2011 capacity mix to the forecast loads for 2011, yields a forecast of 86 percent of the hours when combined cycle capacity will then be on the margin, 11 percent of the time when oil/gas steam capacity will be on the margin and 3 percent of the time when simple cycle combustion turbine and diesels are on the margin. The resultant annual average spot market price for electricity when projected gas prices are applied is $47/MWh in 2011. The forecast hourly price will vary throughout the year as a function of variations in the delivered price of natural gas while combined cycle units are the market makers and they will easily reach as high as $120/MWh when simple cycle combustion turbines with high start-up costs are started to meet short-lived spikes in the demand for power.

Because the average annual spot price of $47/MWh is based on the marginal operating costs of the last units dispatched to meet load each hour, it does not include a capacity component which may be included in the market price if either the Florida utilities are not required to maintain a required reserve margin by 2011 or if retail access eliminates the assurance of regulated returns. In either case, an equilibrium market price that will sustain investment in new generating capacity to meet growth must also include the marginal cost of capacity based on the cost of constructing new simple cycle combustion turbines. By 2011, the amortized cost of that capacity is estimated to be approximately $70/kW-yr or $8/MWh on an average annual basis bringing the total average annual 2011 market price to $55/MWh.

For the most part, capacity prices are extracted during peak hours during peak demand seasons rather than being charged equally each hour during the year. Prices during those periods are generally far higher than the marginal-cost-based prices discussed previously. In addition, should 2011 be a year of capacity deficiency in the market as were the years 1998-2001, market prices could rise many times higher than any of the equilibrium prices described above.

Data Sources

US Department of Energy, 2004 Annual Energy Outlook, January, 2004.
FRCC 2003 Regional Load & Resource Plan, July 2003
A Review of Florida Electric Utility 2003 Ten-year Site Plans, FPSC, December 2003
December 2003 Natural Gas Monthly, Energy Information Administration
http://www.hesinet.com/html/marketwatch.html

APPENDIX

Gainesville Regional Utilities
Deerhaven Station Unit 3
Estimated Cost of Delaying Unit One Year
B&V Project 137196
Rev. 0
02-04-04

Traditional multiple contracts NOT EPC basis

		220 MW Add-on unit Subcritical CFB Base case 2010 COD	220 MW Add-on unit Subcritical CFB Adjusted case 2011 COD	220 MW Add-on unit Subcritical CFB Base case 2010 COD	220 MW Add-on unit Subcritical CFB Adjusted case 2011 COD	220 MW Add-on unit Subcritical CFB Base case 2010 COD	220 MW Add-on unit Subcritical CFB Adjusted case 2011 COD
Direct costs - Procurements and construction		**Low Escalation Rate ($ x 1000)**	**Low Escalation Rate ($ x 1000)**	**Expected Escalation Rate ($ x 1000)**	**Expected Escalation Rate ($ x 1000)**	**High Escalation Rate ($ x 1000)**	**High Escalation Rate ($ x 1000)**
Overnight total project cost		$350,100	$350,100	$350,100	$350,100	$350,100	$350,100
Escalation >		$42,395	$50,637	$55,249	$66,194	$77,439	$93,257
Total Plant Cost (TPC) >		**$392,495**	**$400,737**	**$405,349**	**$416,294**	**$427,539**	**$443,357**
OWNER"S COSTS							
Interconnections							
Electrical interconnection (S/S Only)		Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost
Water supply - wells only		Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost
Natural gas interconnection to existing main header		Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost	Included in EPC cost
Railroad interconnection		Exists - no added costs	Exists - no added costs	Exists - no added costs	Exists - no added costs	Exists - no added costs	Exists - no added costs
Total interconnection costs >		**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
Subtotal >		**$392,495**	**$400,737**	**$405,349**	**$416,294**	**$427,539**	**$443,357**
Development costs							
Project development costs		$3,363	$3,434	$3,473	$3,567	$3,664	$3,799
Contingency							
Owner'r reserve		$19,625	$20,037	$20,267	$20,815	$21,377	$22,168
Subtotal >		**$415,483**	**$424,208**	**$429,090**	**$440,676**	**$452,579**	**$469,324**
Indirect costs							
Builder's Risk Insurance		$2,242	$2,289	$2,316	$2,378	$2,442	$2,533
Commissioning fuel		$1,009	$1,030	$1,042	$1,070	$1,099	$1,140
Initial Coal inventory for 30 days		$2,522	$2,575	$2,605	$2,675	$2,748	$2,849
Other Owner's costs		$8,408	$8,585	$8,684	$8,918	$9,159	$9,498
Administrative & General expenses		$7,848	$8,012	$8,105	$8,323	$8,548	$8,865
Spare Parts		$1,682	$1,717	$1,737	$1,784	$1,832	$1,900
Initial studies & Preliminary Design		$2,242	$2,289	$2,316	$2,378	$2,442	$2,533
Buffer land		$0	$0	$0	$0	$0	$0
Transmission upgrades		$0	$0	$0	$0	$0	$0
Total Indirect Costs		$25,953	$26,498	$26,803	$27,527	$28,271	$29,317
TOTAL PROJECT COST >		**$441,436**	**$450,706**	**$455,894**	**$468,203**	**$480,850**	**$498,641**
Financing costs							
Debt issuance Costs		$1,000	$1,030	$1,000	$1,040	$1,000	$1,050
Underwriters Discount		$4,000	$4,120	$4,000	$4,160	$4,000	$4,200
Net Interest during construction cost	0.135	$59,594	$60,845	$61,546	$63,207	$64,915	$67,317
Debt service reserve fund	0.06	$30,362	$31,002	$31,346	$32,197	$33,046	$34,272
Total financing costs		**$94,956**	**$96,997**	**$97,892**	**$100,604**	**$102,961**	**$106,839**
Total Capital Requirement (TCR) >		**$536,392**	**$547,703**	**$553,786**	**$568,807**	**$583,810**	**$605,480**
			1.021		1.027		1.037
Cost increase due to one year delay >			**$11,312**		**$15,021**		**$21,670**
Ratio of TCR to TPC >		1.367	1.367	1.366	1.366	1.366	1.366

NOTES:
Note 1: Composite weighted average annual escalation rate.
Note 2: Number of years of escalation to midpoiunt of construction period
Note 3: Escalation multiplier = (1+ Escalation rate)^n where n + number of years of escalation

Note 4: Overnight total project cost estimate is the estimated capital cost in 2003 dollars of the physical plant that is "inside the fence" exclusive of Owner's costs. Overnight means that the cost estimate is based on a 2003 COD.

Annual Escalation rate	Note 1	2.1	2.1	2.7	2.7	3.7	3.7
Years from June 2003 to midpoint of construction period	Note 2	5.5	6.5	5.5	6.5	5.5	6.5
Escalation multiplier	Note 3	1.12	1.14	1.16	1.19	1.22	1.27

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-----Original Message-----
From: Miller, John B., Jr. (Jack) [mailto:millerjb@bv.com]
Sent: Thursday, September 30, 2004 11:27 AM
To: 'beckdc@gru.com'; 'casserleirl@gru.com'
Cc: Hurt, James M.; Ott, Ronald J. (Ron)
Subject: Biomass Utilization in Conjunction with an IGCC concept

Responding to yesterday's voicemail from you and our subsequent conversation, I offer the following update.

* Omission of the $4.6 million for biomass capability from the adjustments to the CFB estimate was an oversight. I'll fix that.
* Based on your preference not to try to utilize the biomass generated syngas in either Units 1 or 2, we are looking at alternatives involving more direct integration of that fuel/gas into the IGCC.
* Preliminarily, direct use of the biomass fuel in the IGCC gasifier does not appear to be technically advisable for a variety of reasons.
* Mixing of the biomass syngas with the coal syngas is technically possible, but will add complication that the vendors may push back from.
* Direct but separate co-firing of the coal syngas and biomass syngas in the CT is something that the CT vendors would definitely push back from.

If it is decided that gasification is not the best way to utilize biomass in concert with the IGCC project (should it be selected), then probably the most straight forward way to incorporate biomass into an IGCC capacity addition at Deerhaven would be to provide a stoker fired biomass boiler, and inject the steam into the power cycle of either units 1, 2 or 3. The cost of such a boiler and auxiliaries will be roughly the same as for a biomass gasifier, i.e. $20 million.
* The 10% "developmental contingency" is probably justifiable at 15% considering the potential cost items that it is intended to address. We will make that adjustment.

I am awaiting a little more internal discussion regarding the issue covered in the second bullet above.

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-----Original Message-----
From: Miller, John B., Jr. (Jack) [mailto:millerjb@bv.com]
Sent: Wednesday, September 29, 2004 12:03 AM
To: 'beckdc@GRU.com'; 'casserleirl@gru.com'
Cc: Slettehaugh, Robert A.; Scupham, Samuel K.; Gruber, George P.; Silver, Joseph A. (Alex); Freeland, Frederick H. (Fred); Yauger, Darlene S.
Subject: RE: GRU IGCC Cost Update Memo 092404.doc

GRU
137196
15.0000

Doug/Randy, attached is a memo reporting on our review and comparison of the IGCC and CFB cost estimates. Note that we have deleted Owner's Costs and also the cost of relocating the cooling tower - both at your request.

Please let me know if you have additional questions. Thanks. <<TA-004, Miller memo to Beck, - IGCC Cost Update Memo,092804.doc>>

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> -----Original Message-----
> From: Silver, Joseph A. (Alex)
> Sent: Friday, September 24, 2004 6:12 PM
> To: 'beckdc@GRU.com'
> Cc: Miller, John B., Jr. (Jack); Slettehaugh, Robert A.; Scupham, Samuel
> K.; Gruber, George P.
> Subject: GRU IGCC Cost Update Memo 092404.doc
>
> << File: GRU IGCC Cost Update Memo 092404.doc >>
>
> Doug:
>
> Per our telecon, attached please find our review and discussion of the
> issues raised during the September 20, 2004 meeting. If there are any

> questions, please feel free to call.
>
> Regards,
>
> J. Alex Silver
> Black & Veatch
> silverja@bv.com <mailto:silverja@bv.com>
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-----Original Message-----
From: Miller, John B., Jr. (Jack) [mailto:millerjb@bv.com]
Sent: Thursday, September 30, 2004 2:22 PM
To: 'beckdc@GRU.com'; 'casserleirl@gru.com'
Cc: Slettehaugh, Robert A.; Scupham, Samuel K.; Gruber, George P.; Silver, Joseph A. (Alex); Freeland, Frederick H. (Fred); Yauger, Darlene S.
Subject: GRU IGCC Cost Update Memo, Revised 093004.doc

GRU
137196
15.0000

I have attached a revision to the memo that I sent to you on September 29th, addressing the issues that you have raised recently about the comparability of the costs for CFB and IGCC technology, as included and evolved through our various studies and reports over the past 12 to 18 months. I believe that the attachment addresses those concerns and reflects our latest discussions. Please let me know if there is something additional that you need in this regard at this time. <<TA-004, Miller memo to Beck, - IGCC Cost Update Memo,Revised 093004.doc>>

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> Cc: Slettehaugh, Robert A.; Scupham, Samuel K.; Gruber, George P.;
> Silver, Joseph A. (Alex); Freeland, Frederick H. (Fred); Yauger,
> Darlene S.
> Subject: RE: GRU IGCC Cost Update Memo 092404.doc
>
> GRU
> 137196
> 15.0000

>
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> request.
>
> Please let me know if you have additional questions. Thanks. <<
File:
> TA-004, Miller memo to Beck, - IGCC Cost Update Memo,092804.doc >>
>
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>   Subject: GRU IGCC Cost Update Memo 092404.doc
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>   Per our telecon, attached please find our review and discussion
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>   If there are any questions, please feel free to call.
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>   Regards,
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BLACK & VEATCH CORPORATION
Consulting Engineering Services

MEMORANDUM

Gainesville Regional Utilities	B&V Project 137196
Deerhaven – Supplementary Study of Generating Alternatives	B&V File 15.0000
IGCC Cost Estimate Updates	September 28, 2004
	(Revised 09-30-04)

To: Randy Casserleigh
Doug Beck

From: Jack Miller

The purpose of this memorandum is to respond to the points that were discussed during our meeting of September 17, 2004 regarding the cost information that has been prepared for GRU's use in modeling the financial information for the generation concepts that are being considered for addition at Deerhaven. Specifically, there were several issues that were raised regarding the comparability of the cost estimates for the Circulating Fluid Bed (CFB) combustor and the Integrated Gasification Combined Cycle (IGCC) concepts. As you noted during our meeting, since the cost information for the concepts was developed and refined via several separate tasks over a period of several months, it was felt that a review was necessary to insure that the information was as consistent and comparable as possible.

There were essentially four areas that you requested Black & Veatch to revisit with respect to the CFB and IGCC estimates.

1. Compare the September 2003 CFB estimate to the IGCC estimate to be sure they are comparable as unit additions and do not include greenfield type infrastructure.
2. Review the items that were added to the September '03 CFB estimate to produce the March 2004 CFB estimate. Adjust them as necessary to reflect differences inherent in the two technologies, and then add them to the IGCC estimate accordingly.
3. Review the breakdown for the IGCC estimate to be sure that it is practical.
4. Identify a concept for incorporating 30 MW of biomass fuel into the IGCC case. Potential concepts include, (1) preparing and mixing the biomass with the coal prior to introduction into the gasifier, (2) gasifying the biomass separately and then mixing the two syngas fuel streams at some point in the process, and (3) gasifying the biomass separately and using the syngas in either Unit 1 or 2; (4) others. Add the capital costs associated with the selected concept to the adjusted IGCC estimate.

Our findings are as follows.

<u>Insure that both estimates are on the basis of a unit addition and not greenfield</u>

As the review was performed, it was determined that the cost figures for the IGCC were derived from information for the Shell process, even though the text describing the concept referred to it as the Texaco process. There is a significant cost difference between the two technologies, the Texaco process being considerably less costly (about $63 million less). If based on a single gasifier, the Texaco process has a lower reliability than the Shell process and is less efficient. Therefore, in order to make the IGCC process more comparable to the CFB, it was decided to base the estimate on a dual-train process. That adds about $15 million, so the net deduct to correct the original information to the Texaco process is about $48 million.

Regarding the greenfield issue, the original IGCC estimate was based on a greenfield application so there was cost for infrastructure that was not required as a unit addition. A deduct of 5% was used to account for the unnecessary cost.

These adjustments are summarized in Table A.

Table A - Summary of IGCC Brownfield Capital Cost Adjustments ($ million)	
Line Item	**IGCC**
Cost reduction – Replace Shell cost with dual-train Texaco	(48)
Adjust greenfield estimate to be brownfield (+/- 5% deduct)	(18)
Total Cost Adjustment	**(66)**

Consistent application of site-specific adjustments

The initial CFB estimates that were reported on in our September 2003 report were later adjusted to reflect certain site-specific requirements, including coal handling system modifications, water and wastewater treatment equipment additions, the possibility of having to relocate the existing mechanical draft cooling tower and others. The items total $36.5 million. In order to make the IGCC estimate comparable to the latest CFB estimate, all of those site-specific items should also be added to it. Adjustments were made to account for differences in the two technologies. For example, the CFB concept involves a 220 MW steam turbine generator and the IGCC has only a 100 MW steam turbine generator. Therefore the water supply and treatment implications are different.

The adjustments are summarized in Table B as follows.

Table B - Summary of CFB Brownfield Capital Cost Adjustments ($ millions)		
Line Item	**CFB**	**IGCC**
Water Management Issues		
Additional Water Supply Wells (100 MW STG for IGCC)	1.05	0.75
Pretreatment System	2.25	1.5
Additional Makeup Demineralizer	0.5	0.38
Brine Concentrator and Crystallizer	8	8
Coal Handling System Modifications	11.2	11.2
Other Adjustments		
Hurricane Wind Adjustments	1.75	1.75
Switchyard Modifications	2	2
Cooling Tower Relocation (deleted per GRU direction)	-	-
Total Cost	**26.75**	**25.58**

Note that the Cooling Tower Relocation line item has been deleted at GRU's request.

Review breakdown of the IGCC estimate to be sure that it is logical

The breakdown of costs presented in the March 2004 report is reasonable. There is a significant difference in project delivery methodology between the IGCC and CFB technologies. The procurement of IGCC equipment typically includes installation (furnish and erect) contracts. This will disproportionately weight the cost of the equipment procurement and result in lower construction contract costs. Direct comparison between the line items for the two technologies will illustrate this difference in procurement methods.

Identify a concept for incorporating 30 MW of biomass fuel into the IGCC concept

Based on a fairly cursory review, there are at least five ways to potentially incorporate biomass fuel into an IGCC capacity addition at Deerhaven. Those concepts and our brief, qualitative assessment of each are as follows

1. Direct use of the biomass fuel in the IGCC gasifier. This would entail preparing the biomass as a dense phase slurry and introducing it into the entrained bed gasifier either separately or mixed with the coal slurry. This does not appear to be technically advisable for a variety of reasons.
2. Mixing of the biomass syngas with the coal syngas prior to injection into the combustion turbine (CT). This is technically possible. It will entail compression and some special attention to gas cleanup which will most likely be a subject of discussion with the vendors, but it is certainly an option to consider. The installed cost of the biomass gasifier can be estimated at about $660/kW or roughly $20 million.
3. Direct but separate co-firing of the coal syngas and biomass syngas in the CT. This is something that the CT vendors would definitely push back from.
4. Utilize the biomass syngas in the steam generators of Units 1 and/or Unit 2. GRU has indicated that this option will introduce additional, unwanted complexity and cost into the operation and maintenance of the units, and is therefore not considered to be viable at this point.
5. Provide a stoker fired biomass boiler and inject the steam into the power cycle of either units 1, 2 or 3. This will entail design considerations regarding boiler control, feedwater and condensate balancing, etc., but it is certainly a viable concept. The cost of such a boiler and auxiliaries will be roughly the same as for a biomass gasifier.

At this point, the $20 million figure should account for either a biomass gasification or steam generation approach as outlined in (2) and (5), respectively. If IGCC is ultimately selected as the unit addition technology, a detailed study will be needed to identify the optimum way to incorporate biomass fuel into Deerhaven. The biomass adjustments are summarized in Table C.

Table C - Summary of IGCC Biomass Cofiring Capital Cost Adjustment ($ millions)

Line Item	CFB	IGCC
Add 30 MW Biomass Cofiring	4.6	20
Total Cost	**4.6**	**20**

Gainesville Regional Utilities B&V Project 137196
Deerhaven – Supplementary Study of Generating Alternatives September 27, 2004
IGCC Cost Estimate

Summarizing, the cost modifications that are identified in Tables A, B, and C are carried forward and presented in Table D. Thus far, the estimates and adjustments relating to the IGCC concept have reflected information available from the vendors and technical literature. Taken at face value, those sources indicate that the cost of IGCC is approaching that of other more conventional technologies such as CFBs; however, it must be pointed out that those cost trends for IGCC are based almost entirely on studies and not data collected from projects that have actually been constructed. There is general agreement in the technical community that an IGCC facility is likely to have more cost risk and significantly more risk with regard to the amount of time that will be required to fully commission the unit and attain the desired level of availability. Opinions on that issue range from three to five years. Table 4-3 in the March 2004 report provides an indication of the effects of the issue on availability. Those parameters can be used to test the effects on the operating and maintenance costs of the concept. In our opinion, there will be significant costs associated with that extended commissioning effort. Those cost items include but are not limited to

- Cost for natural gas when the gasifier is out of service.
- Cost associated with adverse heat rate impact when firing natural gas.
- Cost of replacement power.
- Cost of technical advisors from the major equipment suppliers for the duration of the development period.
- Cost of Owner’s staff for the duration of the development period.
- Cost of Owner’s consultants, engineers and specialist during this period.
- Additional capital cost for modifications and upgrades.
- Other unknown costs

In short, IGCC and CFB technologies are not directly comparable with respect to the maturity of the technology. Though CFB technology continues to evolve and scale up, it is considered a commercial technology. In our opinion, IGCC continues to be developmental. In order to account for that, we have included an additional allowance for developmental costs. This is an allowance of 15% and does not have a detailed, itemized basis; however, in our judgment, it is the right order of magnitude considering the types of additional costs that can potentially be incurred, and it is consistent with the fact that these are screening level cost estimates.

The adjustments and final cost estimates are summarized in Table D.

Table D - Summary of IGCC Capital Cost Adjustments ($ millions)

Line Item	**CFB**	**IGCC**
Original Project Cost	313.60	426.20
Table A Cost Adjustment	NA	(66.00)
Table B Cost Adjustment	26.75	25.58
Table C Cost Adjustment	4.6	20
Subtotal Cost Adjustment	31.35	(20.42)
Revised Project Cost	344.95	405.78
Allowance for developmental cost	Not required	61.00
	344.95	466.78
Owner’s Cost (Deleted per GRU direction)	-	-
Revised Cost ($ x 1,000,000)	**344.95**	**466.78**

Revised Cost ($/kW)	**$1,568/kW**	**$1,867/kW**

cc: File
A Silver
J Hurt
B Slettehaugh
G Gruber
Ron Ott
Don Knotts
Fred Freeland

Doug Beck, P.E.
Manager-Power Engineering
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-----Original Message-----
From: Miller, John B., Jr. (Jack) [mailto:millerjb@bv.com]
Sent: Monday, September 27, 2004 5:28 PM
To: 'beckdc@GRU.com'; 'casserleirl@gru.com'
Cc: Slettehaugh, Robert A.; Scupham, Samuel K.; Hurt, James M.
Subject: RE: GRU IGCC Cost Update Memo 092404.doc

Following-up on our conversations today.

I have asked the team in KC to base the IGCC estimate on a two-train configuration instead on a single-train. I believe this is appropriate in order to make it comparable to the CFB from the perspective of reliability/availability. That assumption will be reviewed by our IGCC experts before proceeding on that basis.

They are also revisiting the estimates to be sure that they are on the same basis with respect to common infrastructure (greenfield vs unit-addition), and the site specific additions that were made to the CFB concept ($36.5 million).

I expect to send you the corrected figures tomorrow afternoon.

One point worth making. Recently, the technical literature is showing a convergence of the capital cost of comparably sized CFB and IGCC units, with the IGCC remaining a few percentage points higher. We have seen some sources in which the CFB was actually shown to be slightly more costly. Since no one has actually built a significant sampling of IGCC units recently, the costs that are being reported are still "paper" costs and not based on actual cost experience, so I would expect them to be "softer" and less credible. Nonetheless, that is the trend that we are seeing in the literature.

I'll talk to you tomorrow afternoon. If you need to call me before that, I will be on my mobile at 904-472-0765.

Thanks.

J. B. (Jack) Miller
Regional Client Manager - Southeast
Black & Veatch Corporation - Jacksonville Office
10751 Deerwood Park Blvd. - Suite 130
Jacksonville, FL 32256
(904) 997-7109
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> -----Original Message-----
> From: Silver, Joseph A. (Alex)
> Sent: Friday, September 24, 2004 6:12 PM
> To: 'beckdc@GRU.com'
> Cc: Miller, John B., Jr. (Jack); Slettehaugh, Robert A.; Scupham,
Samuel
> K.; Gruber, George P.
> Subject: GRU IGCC Cost Update Memo 092404.doc
>
> << File: GRU IGCC Cost Update Memo 092404.doc >>
>
> Doug:
>
> Per our telecon, attached please find our review and discussion of
the
> issues raised during the September 20, 2004 meeting. If there are any
> questions, please feel free to call.
>
> Regards,
>
> J. Alex Silver
> Black & Veatch
> silverja@bv.com <mailto:silverja@bv.com>
> 913-458-8626 (office)
> 913-458-7803 (fax)
> 913-226-1400 (cell)
>
>

BLACK & VEATCH CORPORATION
Consulting Engineering Services

MEMORANDUM

Gainesville Regional Utilities	B&V Project 137196
Deerhaven – Supplementary Study of Generating Alternatives	B&V File 15.0000
IGCC Cost Estimate Updates	September 28, 2004

To: Randy Casserleigh
Doug Beck

From: Jack Miller

The purpose of this memorandum is to respond to the points that were discussed during our meeting of September 17, 2004 regarding the cost information that has been prepared for GRU's use in modeling the financial information for the generation concepts that are being considered for addition at Deerhaven. Specifically, there were several issues that were raised regarding the comparability of the cost estimates for the Circulating Fluid Bed (CFB) combustor and the Integrated Gasification Combined Cycle (IGCC) concepts. As you noted during our meeting, since the cost information for the concepts was developed and refined via several separate tasks over a period of several months, it was felt that a review was necessary to insure that the information was as consistent and comparable as possible.

There were essentially four areas that you requested Black & Veatch to revisit with respect to the CFB and IGCC estimates.

1. Compare the September 2003 CFB estimate to the IGCC estimate to be sure they are comparable as unit additions and do not include greenfield type infrastructure.
2. Review the items that were added to the September '03 CFB estimate to produce the March 2004 CFB estimate. Adjust them as necessary to reflect differences inherent in the two technologies, and then add them to the IGCC estimate accordingly.
3. Review the breakdown for the IGCC estimate to be sure that it is practical.
4. Identify a concept for incorporating 30 MW of biomass fuel into the IGCC case. Potential concepts include, (1) preparing and mixing the biomass with the coal prior to introduction into the gasifier, (2) gasifying the biomass separately and then mixing the two syngas fuel streams at some point in the process, and (3) gasifying the biomass separately and using the syngas in either Unit 1 or 2; (4) others. Add the capital costs associated with the selected concept to the adjusted IGCC estimate.

Our findings are as follows.

<u>Insure that both estimates are on the basis of a unit addition and not greenfield</u>

As the review was performed, it was determined that the cost figures for the IGCC were derived from information for the Shell process, even though the text describing the concept referred to it as the Texaco process. There is a significant cost differences between the two technologies, the Texaco process being considerably less costly (about $63 million less). If based on a single gasifier, the Texaco process has a lower reliability than the Shell process and is less efficient. Therefore, in order to make the IGCC process more comparable to the CFB, it was decided to

Gainesville Regional Utilities B&V Project 137196
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base the estimate on a dual-train process. That adds about $15 million, so the net deduct to correct the original information to the Texaco process is about $48 million.

Regarding the greenfield issue, the original IGCC estimate was based on a greenfield application so there was cost for infrastructure that was not required as a unit addition. A deduct of 5% was used to account for the unnecessary cost.

These adjustments are summarized in Table A.

Table A - Summary of IGCC Brownfield Capital Cost Adjustments ($ million)	
Line Item	**IGCC**
Cost reduction – Replace Shell cost with Texaco	(48)
Adjust greenfield estimate to be brownfield (+/- 5% deduct)	(18)
Total Cost Adjustment	**(66)**

Consistent application of site-specific adjustments

The initial CFB estimates that were reported on in our September 2003 report were later adjusted to reflect certain site-specific requirements, including coal handling system modifications, water and wastewater treatment equipment additions, the possibility of having to relocate the existing mechanical draft cooling tower and others. The items total $36.5 million. In order to make the IGCC estimate comparable to the latest CFB estimate, all of those site-specific items should also be added to it. Adjustments were made to account for differences in the two technologies. For example, the CFB concept involves a 220 MW steam turbine generator and the IGCC has only a 100 MW steam turbine generator. Therefore the water supply and treatment implications are different.

The adjustments are summarized in Table B as follows.

Table B - Summary of CFB Brownfield Capital Cost Adjustments ($ millions)		
Line Item	**CFB**	**IGCC**
Water Management Issues		
Additional Water Supply Wells (100 MW STG for IGCC)	1.05	0.75
Pretreatment System	2.25	1.5
Additional Makeup Demineralizer	0.5	0.375
Brine Concentrator and Crystallizer	8	8
Coal Handling System Modifications	11.2	5
Other Adjustments		
Hurricane Wind Adjustments	1.75	1.75
Switchyard Modifications	2	2
Cooling Tower Relocation (deleted per GRU direction)	-	-
Total Cost	**26.75**	**19.35**

Note that the Cooling Tower Relocation line item has been deleted at GRU's request.

Review breakdown of the IGCC estimate to be sure that it is logical

The breakdown of costs presented in the March 2004 report is reasonable. There is a significant difference in project delivery methodology between the IGCC and CFB technologies. The procurement of IGCC equipment typically includes installation (furnish and erect) contracts. This will disproportionately weight the cost of the equipment procurement and result in lower construction contract costs. Direct comparison between the line items for the two technologies will illustrate this difference in procurement methods.

Identify a concept for incorporating 30 MW of biomass fuel into the IGCC concept

Based on a fairly cursory review, it appears that the best method to integrate biomass cofiring into the IGCC alternative is to add an external gasifier for the biomass and cofire the syngas in the boilers of either Unit 1 or 2. A rough estimate of the installed cost of such a biomass facility is $660/kW.

Table C - Summary of IGCC Biomass Cofiring Capital Cost Adjustment ($ millions)	
Line Item	**IGCC**
Add 30 MW Biomass Cofiring – External gasifier coupled with Unit 1	19.8
Total Cost	**19.8**

Summarizing, the cost modifications that are identified in Tables A, B, and C are carried forward and presented in Table D. Thus far, the estimates and adjustments relating to the IGCC concept have reflected information available from the vendors and technical literature. Taken at face value, those sources indicate that the cost of IGCC is approaching that of other more conventional technologies such as CFBs; however, it must be pointed out that those cost trends for IGCC are based almost entirely on studies and not data collected from projects that have actually been constructed. There is general agreement in the technical community that an IGCC facility is likely to have more cost risk and significantly more risk with regard to the amount of time that will be required to fully commission the unit and attain the desired level of availability. Opinions on that issue range from three to five years. Table 4-3 in the March 2004 report provides an indication of the effects of the issue on availability. Those parameters can be used to test the effects on the operating and maintenance costs of the concept. In our opinion, there will be significant costs associated with that extended commissioning effort. Those cost items include but are not limited to

- Cost for natural gas when the gasifier is out of service.
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- Cost of Owner's staff for the duration of the development period.
- Cost of Owner's consultants, engineers and specialist during this period.
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Gainesville Regional Utilities B&V Project 137196
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In short, IGCC and CFB technologies are not directly comparable with respect to the maturity of the technology. Though CFB technology continues to evolve and scale up, it is considered a commercial technology. In our opinion, IGCC continues to be developmental. In order to account for that, we have included an additional allowance for developmental costs. This is an allowance of 10% and does not have a detailed, itemized basis; however, in our judgment, it is the right order of magnitude, and consistent with the fact that these are screening level cost estimates.

The adjustments and final cost estimates are summarized in Table D

Table D - Summary of IGCC Capital Cost Adjustments ($ millions)

Line Item	**CFB**	**IGCC**
Original Project Cost	313.60	426.20
Table A Cost Adjustment	NA	(66.00)
Table B Cost Adjustment	26.75	19.35
Table C Cost Adjustment	NA	19.80
Subtotal Cost Adjustment	26.75	(26.85)
Revised Project Cost	340.35	399.35
Allowance for developmental cost	Not required	40.00
	340.35	439.35
	$1,547/kW	$1,757/kW
Owner's Cost (Deleted per GRU direction)	-	-
Revised Cost ($ x 1,000,000)	**340.35**	**439.35**
Revised Cost ($/kW)	**$1,547/kW**	**$1,757/kW**

Note that the allowance for Owner's Costs has been deleted per GRU's instructions.

cc: File
A Silver
J Hurt
B Slettehaugh
G Gruber
Ron Ott
Don Knotts
Fred Freeland